Victoria to NSW Interconnector West (VNI West)

Market modelling report forecasting gross market benefits for the additional options analysis

22 February 2023

Building a better working world

Release Notice

Ernst & Young ("EY") was engaged on the instructions of NSW Electricity Networks Operations Pty Limited, as trustee for NSW Electricity Networks Operations Trust ("Transgrid"), to undertake market modelling of system costs and benefits to assess two options for the Victoria to NSW Interconnector West (VNI West) Regulatory Investment Test for Transmission ("VNI West RIT-T").

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. No further work has been undertaken by EY since the date of the Report to update it.

EY has prepared the Report for the benefit of Transgrid and has considered only the interest of Transgrid. EY has not been engaged to act, and has not acted, as advisor to any other party. Accordingly, EY makes no representations as to the appropriateness, accuracy or completeness of the Report for any other party's purposes. Our work commenced on 22 September 2021 and was completed on 15 February 2023. Therefore, our Report does not take account of events or circumstances arising after 15 February 2023 and we have no responsibility to update the Report for such events or circumstances.

No reliance may be placed upon the Report or any of its contents by any party other than Transgrid ("Third Parties"). Any Third Parties receiving a copy of the Report must make and rely on their own enquiries in relation to the issues to which the Report relates, the contents of the Report and all matters arising from or relating to or in any way connected with the Report or its contents. EY disclaims all responsibility to any Third Parties for any loss or liability that the Third Parties may suffer or incur arising from or relating to or in any way connected with the contents of the Report, the provision of the Report to the Third Parties or the reliance upon the Report by the Third Parties.

No claim or demand or any actions or proceedings may be brought against EY arising from or connected with the contents of the Report or the provision of the Report to the Third Parties. EY will be released and forever discharged from any such claims, demands, actions or proceedings. Our Report is based, in part, on the information provided to us by Transgrid and other stakeholders engaged in this process. We have relied on the accuracy of the information gathered through these sources. We do not imply, and it should not be construed that we have performed an audit, verification or due diligence procedures on any of the information provided to us. We have not independently verified, nor accept any responsibility or liability for independently verifying, any such information nor do we make any representation as to the accuracy or completeness of the information. We accept no liability for any loss or damage, which may result from your reliance on any research, analyses or information so supplied.

Modelling work performed as part of our scope inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual outcomes, because events and circumstances frequently do not occur as expected, and those differences may be material. We take no responsibility that the projected outcomes will be achieved. We highlight that our analysis and Report do not constitute investment advice or a recommendation to you on a future course of action. We provide no assurance that the scenarios we have modelled will be accepted by any relevant authority or third party.

Readers are advised that the outcomes provided are based on many detailed assumptions underpinning the scenario, and the key assumptions are described in the Report. These assumptions were selected by Transgrid after public consultation. The modelled scenario represents one possible future option for the development and operation of the National Electricity Market, and it must be acknowledged that many 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

Transgrid has engaged EY to undertake market modelling of system costs and benefits of the options related to the Victoria to New South Wales (NSW) Interconnector West (VNI West) network development for application of the Regulatory Investment Test for Transmission (RIT-T).

The VNI West RIT-T is a joint RIT-T by Transgrid (as the transmission network service provider in NSW) and Australian Energy Market Operator (AEMO) Victorian Planning (AVP). Although assumptions and input data sources were selected by both parties, we took instruction from Transgrid as our client. The selection of input assumptions and modelling methodology follows the *Cost benefit analysis guidelines* (CBA guidelines) published by the Australian Energy Regulator (AER)[1] which contain the applicable RIT-T guidelines for actionable Integrated System Plan (ISP) projects including VNI West.

This Report forms a supplementary report to the additional consultation report prepared and published by Transgrid and AVP[2], and describes the key modelling outcomes and insights as well as the assumptions and input data sources jointly prepared by Transgrid and AVP in accordance with the CBA guidelines and the modelling methods used. The Report should be read in conjunction with the consultation report published by Transgrid and AVP[2]. Accompanying results workbooks to the Report are also available containing forecast annual benefits by category as well as capacity and generation outlooks by region and Renewable Energy Zone (REZ).

EY was engaged to compute the least-cost generation dispatch and capacity development plan for the National Electricity Market (NEM) associated with the VNI West options (including the counterfactual Base Case without VNI West) for the Step Change, Progressive Change and Hydrogen Superpower scenarios issued in the AEMO 2022 ISP[3]. In addition, based on joint agreement between Transgrid and AVP, we were requested to incorporate more recent inputs and assumptions updates based on new information since the publication of 2022 ISP, as follows:

- Announced retirement of Loy Yang A in 2035[4]
- Announced retirement of Torrens Island B in 2026[5].

The Report also adopted some changes in modelling in response to submissions to the Project Assessment Draft Report (PADR), as jointly agreed by Transgrid and AVP, namely:

- **Modelling period extended:** the modelling period was extended from the 25-year PADR period (2023-24 to 2047-48) to 27 years (2023-24 to 2049-50) in line with 2022 ISP.
- **Discrete carbon budget**: a carbon budget was applied in each decade to limit the transfer of emissions savings between early and late model years. This change better aligns with

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[1] AER, August 2020. *Cost benefit analysis guidelines*. Available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable/final-decision Accessed 12 January 2022

[2] Transgrid and AEMO, *Victoria to NSW Interconnector West – additional consultation report*. Available at: https://www.transgrid.com.au/projects-innovation/victoria-to-nsw-interconnector-west.

[3] AEMO, *2022 ISP*, available at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp, and AEMO, *Inputs assumptions and scenarios workbook v3.3*, available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios. Accessed on 21 January 2023.AEMO, *2022 ISP*, available at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp, and AEMO, *Inputs assumptions and scenarios workbook v3.3*, available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios. Accessed on 21 January 2023.

[4] AEMO generation information and expected closure years, February 2023, available at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/2022/nem-generation-information-feb-2022.xlsx?la=en, AGL, *Review of Strategic Direction Outcomes & FY23 Guidance,* Available at: https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2022/september/review-of-strategic-direction-outcomes-and-fy23-guidance. Accessed 22 November 2022

[5] AGL, *AGL Torrens Power Station,* Available at: https://www.agl.com.au/about-agl/how-we-source-energy/agl-torrens. Accessed 2 February 2023.

stakeholders' expectations of investment and divestment look-ahead periods and reduces anticipatory benefits of VNI West forecast in the PADR, associated with a delay in coal withdrawals with VNI West.

- **Coal retirement outcomes from 2022 ISP:** scenario-specific outcomes were adopted as input assumptions in each scenario's Base Case and all option cases to be consistent with the efficient development of the power system as identified in 2022 ISP.
- **Annualised gross market benefits presentation**: capex and fixed operation and maintenance (FOM) cost savings associated with deferred or avoided generation investment are presented on an annualised basis consistent with 2022 ISP. In contrast, the PADR presented the entire capital costs (including FOM costs) of the new plants in the year(s) of differential outcomes to highlight the timing of capacity changes that drive expected capex benefits. This is purely a presentational choice and does not affect the overall forecast gross benefits of the options.

Based on the joint agreement between Transgrid and AVP, we were requested to model seven options. In addition to Option 1 and Option 2 that were modelled in the PADR, five new options were added by Transgrid and AVP. All seven options assessed:

- involve a 500 kV double circuit transmission line,
- originate at Dinawan, in NSW, with connection to Project EnergyConnect,
- include new terminal stations near Kerang, in Victoria, with a connection to the existing 220 kV line to Kerang.

The differences between the options relate to the Victorian scope and key input parameters provided by Transgrid and AVP are outlined in Table 1. Note that while the anticipated Western Renewable Link (WRL) Project, as currently designed[6], is applied in the Base Case, VNI West Option 1 and Option 2, for the new options the WRL network configuration and its impact on Western Victoria (V2) REZ transmission limits differs depending on the option, as detailed in the additional consultation report by Transgrid and AVP[2].

Table 1: Summary the modelled Base Cases and VNI West options[2]

Option	Description	Indicative impact on transfer capacity (MW)		Indicative impact on REZ transmission limit	
		VIC to NSW	NSW to VIC	Individually (MW)	Total (MW)
Alternative Base Case	No VNI West, no Western Renewable Link (WRL)	N/A	N/A	Murray River (V2): +0 Western Vic (V3): +0 South West NSW[7] (N5): +0	NA
Base Case	No VNI West, with Western Renewable Link (WRL)	N/A	N/A	Murray River (V2): +0 Western Vic (V3): +600 South West NSW (N5): +0	+600
1	VNI West to north of Ballarat	+1,930	+1,800	Murray River (V2): +1,600 Western Vic (V3, WRL timing): +600 Western Vic (V3, VNI West timing): +550 South West NSW (N5): +900	+3,650

[6] AEMO, *Western Renewables Link Project*, Available at:https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/victorian_transmission/2022/aemo--clause-5164z3-analysis--wrl-project--november-2022.pdf?la=en&hash=6C69FC7AAEB1C36FE0A3F65AC99BB614. Accessed 30 January 2023.

[7] For the South West NSW (N5) REZ, transmission limit is modelled as follows. For the Base Cases and alternative Base Cases, Transgrid advised to apply 600 MW increase in the limit after the Project Energy Connect (PEC), followed by an additional 200 MW after HumeLink. For VNI West options, with the PEC Enhanced, the increase in N5 transmission limit after PEC is assumed to be 800 MW, followed by 1,000 MW after HumeLink.

Option	Description	Indicative impact on transfer capacity (MW)		Indicative impact on REZ transmission limit	
		VIC to NSW	NSW to VIC	Individually (MW)	Total (MW)
1A	VNI West to north of Ballarat with spur uprate to 500kV	+1,930	+1,800	Murray River (V2): +1,600 Western Vic (V3, WRL timing): +1,460 Western Vic (V3, VNI West timing): +750 South West NSW (N5): +900	+4,710
2	Option 1 plus non-network virtual transmission line (VTL)	+250 from the VTL +1,930 from VNI West (via Kerang)	+250 from the VTL +1,800 from VNI West (via Kerang)	Same as Option 1 once it is commissioned. That is, no additional REZ hosting capacity associated with VTL component.	+3,650
3	VNI West to Waubra/Lexton	+1,830	+1,650	Murray River (V2): +1,600 Western Vic (V3, WRL timing): +950 Western Vic (V3, VNI West timing): +700 South West NSW (N5): +900	+4,150
3A	VNI West to Waubra/Lexton with spur uprate to 500kV	+1,830	+1,650	Murray River (V2): +1,600 Western Vic (V3, WRL timing): +2,590 Western Vic (V3, VNI West timing): +1,400 South West NSW (N5): +900	+6,490
4	VNI West to Bulgana via Bendigo	+1,700	+1,475	Murray River (V2): +1,600 Western Vic (V3, WRL timing): +1,460 Western Vic (V3, VNI West timing): +580 South West NSW (N5): +900	+4,540
5	VNI West to Bulgana	+1,930	+1,650	Murray River (V2): +850 Western Vic (V3, WRL timing): +1,460 Western Vic (V3, VNI West timing): +200 South West NSW (N5): +900	+3,410

In addition, jointly agreed between Transgrid and AVP, we were requested to assess the impact on gross market benefits of the following sensitivities:

- Assessment of the gross benefits of VNI West for Option 3A and Option 5 in the Step Change scenario assuming the Victorian offshore wind target becomes a committed policy.
- Assessment of the combined gross benefits for VNI West options *and* WRL for all seven options and all three scenarios by simulation of an alternative counterfactual Base Case in each scenario.
- Combining the offshore wind and no WRL counterfactual sensitivities to assess the combined gross benefits for VNI West options *and* WRL for Option 3A and Option 5 in the Step Change scenarios assuming the Victorian offshore wind target becomes a committed policy.

To assess the least-cost solution, EY's Time Sequential Integrated Resource Planner (TSIRP) model is used that makes decisions for each hourly trading interval in relation to:

- the generation dispatch level for each power plant along with the charging and discharging of storage. Generators are assumed to dispatch at their short run marginal cost (SRMC), which is derived from their variable operation and maintenance (VOM) and fuel costs. The generation for each trading interval is subject to the modelled availability of power stations in each hour (those that are not on planned or un-planned outages), network limitations and energy limits (e.g., storage levels).
- commissioning new entrant capacity for wind, solar PV SAT, OCGT[8], large-scale battery (LS Battery), pumped hydro energy storage (PHES) and hydrogen turbine technology (only applied in the Hydrogen Superpower scenario).
- the withdrawal of existing generation on a least-cost basis, often to meet the emissions budgets assumed in the modelled scenarios. In response to stakeholder feedback to the PADR, Transgrid and AVP advised that the retirement schedule for the coal-fired generators be adopted from 2022 ISP scenario outcomes. Note that Loy Yang A retirement in the Progressive Change scenario is assumed to be no later than 1 July 2035, as per the latest announcement for this power plant retirement. Other scenarios forecast retirement earlier than this date.
- Expansion of transmission network upgrades for REZs. Note that the model, in accordance with the RIT-T instrument and AER CBA guidelines for actionable ISP projects, adopts the committed, anticipated and actionable ISP projects from 2022 ISP in all relevant states of the world. Most future ISP projects are modelled as transmission options to be built on the least cost basis. Specifically, all future REZ transmission expansions are allowed to be built if they are part of the least cost solution, considering the expansion cost (in $/MW) for each REZ provided in 2022 ISP. The two future ISP projects that were an exception to this, as advised by Transgrid and AVP, are QNI Connect being an interconnector and New England REZ extension being infrastructure needed to enable the 8 GW of renewable generation capacity in this REZ: a minimum objective set under the NSW Electricity Infrastructure Investment Act 2020. It was necessary to model these future ISP projects explicitly to ensure an appropriate representation of the Central NSW (NCEN) and Northern NSW (NNS) subregions in market modelling.

The hourly decisions consider certain operational constraints[9] that include:

- supply must equal demand in each region for all trading intervals plus a reserve margin, with unserved energy (USE) costed at the value of customer reliability (VCR)[10],
- minimum loads for coal generators,
- interconnector flow limits (between regions),
- intra-regional flow limits (between zones in northern NSW),
- dynamically modelled (weather temperature based or seasonal and time of day based) intra-regional flow limits for the detailed network modelled in Victoria and Southern NSW through DC load flow (DCLF),
- maximum and minimum storage (conventional storage hydro, PHES and large-scale battery) reservoir limits and cyclic efficiency,
- new entrant capacity build limits for wind and solar for each REZ where applicable, and PHES in each region,
- carbon budget constraints, as defined in the ISP for the modelled scenarios,

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[8] PV = photovoltaics, SAT = Single Axis Tracking, OCGT = Open-Cycle Gas Turbine

[9] The constraints are generally aligned with the 2022 ISP, while additional network constraints are modelled to present a higher network resolution in Victoria and South NSW.

[10] Based on AER, December 2021, *Values of Customer Reliability Final report on VCR values.* These are the same values applied in AEMO's 2022 ISP, available at: https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf

- renewable energy policies where applicable by region or NEM-wide, and
- other constraints such as network thermal and stability constraints, as defined in the Report.

From the hourly time-sequential modelling we computed the following costs, as defined in the RIT-T:

- capital costs of new generation capacity installed (capex),
- total FOM costs of all generation capacity,
- total VOM costs of all generation capacity,
- total fuel costs of all generation capacity,
- total cost of voluntary (demand-side participation, DSP) and involuntary load curtailment (unserved energy, USE),
- transmission expansion costs associated with REZ development, defined in the ISP methodology report as the amount of power that can be transferred from the REZ through the shared transmission network. REZ transmission limits can be increased by augmenting the shared transmission network (modelled as a network expansion cost)[11]. Note that the REZ transmission cost is different to the connection cost of new generators within the REZ.

The forecast gross market benefits capture the impact of transmission losses to the extent that losses across interconnectors and intra-connectors affect the generation that needs to be dispatched in each trading interval. The forecast gross market benefits also capture the impact of differences in cyclic efficiency losses in storages, including PHES and large-scale battery between each VNI West option and the counterfactual Base Case.

For each simulation with a VNI West option and in a matched no augmentation counterfactual (referred to as the Base Case), we computed the sum of these cost components and compared the difference between each option and the Base Case. The difference in present value terms of costs is the forecast gross market benefits[12] due to the presence of the corresponding option. This aligns with the classes of market benefits identified in 2022 ISP, as required by the RIT-T instrument. For all scenarios, benefits presented in real June 2021 dollars discounted to June 2021 using a 5.5% real, pre-tax discount rate, consistent with the value applied by AEMO in 2022 ISP[3] as required by the CBA guidelines[1].

Forecast gross market benefits in core scenarios

Table 2 summarises the forecast gross market benefits over the modelled horizon (2023-24 to 2049-50) for all options across all scenarios. In addition, the breakdown of gross market benefits by category for Option 3A and Option 5 are shown in Figure 1 for the three scenarios. These two options have the highest net market benefits as calculated by Transgrid and AVP in the additional consultation report[2]. The numbers in the chart represent the net present value difference of each option relative to the scenario-specific Base Case. The forecast gross market benefits of each option in each scenario need to be compared to the relevant option cost to determine the forecast net economic benefit for that option. The determination of the preferred option is also dependent on option costs. The cost assessment and calculation of net economic benefits (gross market benefits minus option costs) was conducted outside of this Report by Transgrid and AVP. For the combined VNI West and WRL sensitivity, the forecast gross market benefits of each option in each scenario need to be compared to the relevant combined cost of WRL and the VNI West option to determine the forecast net economic benefit for that option and WRL.

[11] AEMO, *ISP methodology, dated 20 August 2021*, https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-isp-methodology.pdf?la=en, accessed on 16 February 2023

[12] In this Report we use the term *gross market benefit* to mean "market benefit" as defined in the AER's *Cost benefit analysis guidelines*, and "net economic benefit" in the same manner defined in the guidelines.

Table 2: Summary of forecast gross market benefits of all VNI West options relative to each scenario's Base Case, millions real June 2021 dollars discounted to June 2021 dollars

Option	Description	Timing	Forecast gross market benefits ($m)		
			Step Change	Progressive Change	Hydrogen Superpower
1	VNI West to north of Ballarat	Hydrogen Superpower: 1 July 2030 Step Change: 1 July 2031 Progressive Change: 1 July 2038	3,743	1,450	4,127
1A	VNI West to north of Ballarat with spur uprate to 500kV	Hydrogen Superpower: 1 July 2030 Step Change: 1 July 2031 Progressive Change: 1 July 2038	4,179	1,726	4,439
2	Option 1 plus non-network VTL	VTL: 1 July 2026 Hydrogen Superpower: 1 July 2030 Step Change: 1 July 2031 Progressive Change: 1 July 2038	3,886	1,566	4,397
3	VNI West to Waubra/Lexton	Hydrogen Superpower: 1 July 2030 Step Change: 1 July 2031 Progressive Change: 1 July 2038	3,895	1,557	4,164
3A	VNI West to Waubra/Lexton with spur uprate to 500 kV	Hydrogen Superpower: 1 July 2030 Step Change: 1 July 2031 Progressive Change: 1 July 2038	4,253	1,797	4,392
4	VNI West to Bulgana via Bendigo	Hydrogen Superpower: 1 July 2030 Step Change: 1 July 2031 Progressive Change: 1 July 2038	3,918	1,605	4,072
5	VNI West to Bulgana	Hydrogen Superpower: 1 July 2030 Step Change: 1 July 2031 Progressive Change: 1 July 2038	3,921	1,598	4,191

Table 3, Table 4 and Table 5 summarise the gross market benefits for the modelled sensitivities.

Table 3: Gross market benefits for the offshore wind sensitivity, millions real June 2021 dollars discounted to June 2021 dollars

Option	Forecast gross market benefits ($m)	
	Offshore Wind Sensitivity – Step Change Scenario	Core – Step Change Scenario
Option 3A	3,049	4,253
Option 5	3,087	3,921

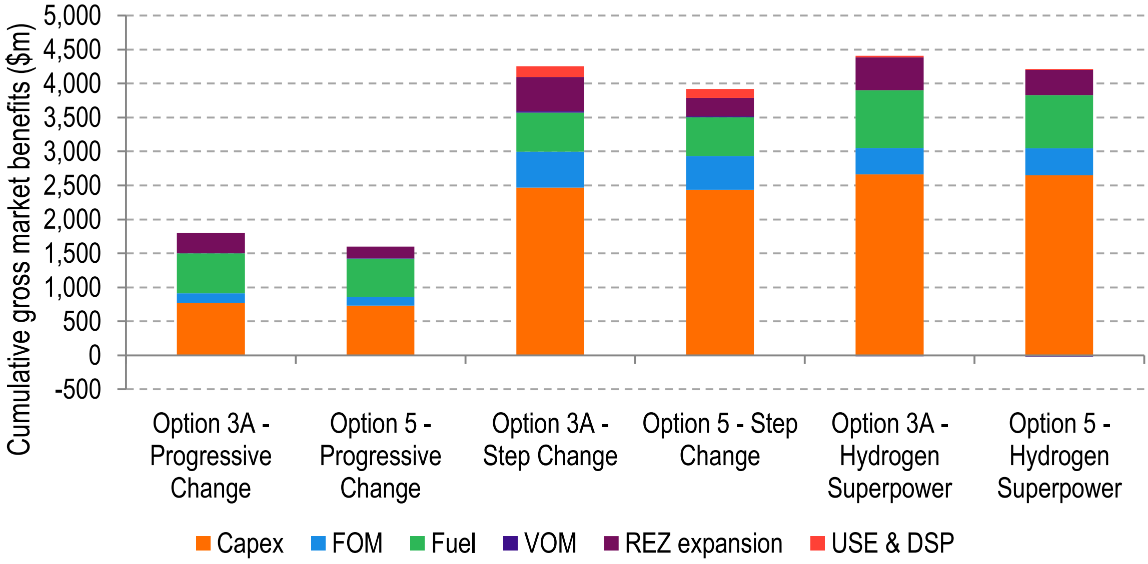
Table 4: Summary of forecast gross market benefits relative to the alternative Base Case (without WRL), millions real June 2021 dollars discounted to June 2021 dollars

Option	Forecast gross market benefits ($m)		
	Step Change	Progressive Change	Hydrogen Superpower
1	5,085	2,174	5,023
1A	5,521	2,449	5,335
2	5,228	2,290	5,293
3	5,236	2,281	5,059
3A	5,595	2,520	5,228
4	5,260	2,329	4,967
5	5,263	2,322	5,086

Table 5: Forecast gross market benefits for the combined VNI West+WRL and offshore wind sensitivity to the Step Change scenario, millions real June 2021 dollars discounted to June 2021 dollars

Option	Forecast gross market benefits ($m)	
	Combined VNI West+WRL sensitivity, without offshore wind targets	Combined VNI West+WRL sensitivity, with offshore wind targets imposed
Option 3A	5,595	3,820
Option 5	5,263	3,858

Figure 1: Composition of forecast total gross market benefits for the top ranked options, millions real June 2021 dollars discounted to June 2021 dollars



Both Option 3A and Option 5 are expected to achieve their highest forecast gross market benefits in the Hydrogen Superpower scenario, and their lowest gross market benefits in the Progressive Change scenario. The forecast gross market benefits for Option 3A range between just under $1.8b in the Progressive Change scenario, $4.25b in the Step Change scenario and around $4.4b in the Hydrogen Superpower scenario. The forecast gross market benefits for Option 5 are expected to be around $200m, $201m and $313m less than that of Option 3A in the Progressive Change, Hydrogen Superpower and Step Change scenarios, respectively.

The sources of forecast benefits and the key drivers are as follows:

Core simulations

- Capex and FOM cost savings make up the largest proportion of forecast benefits across all modelled scenarios and VNI West options. The primary drivers of the forecast cost savings are:
  - VNI West is forecast to provide access to cheaper renewable generation and reduce renewable generation spill, meaning less new capacity is needed to supply demand while meeting constraints including carbon budget and network constraints (particularly in Victoria).
  - Additional transmission capacity in REZs along the VNI West corridor, as well as increased resource sharing from NSW, is likely to enable expensive renewable capacity candidates in Victoria to be avoided and replaced by cheaper capacity candidates in other REZs.
- Forecast fuel cost savings across all scenarios and options are a result of less gas generation, and in the Hydrogen Superpower scenario, less hydrogen turbine generation. Without VNI West, gas and hydrogen turbines are required to firm variable renewable generation and meet peak demand requirements in Victoria, particularly in the 2030s when coal generation is forecast to retire.
- REZ expansion costs are representative of the costs associated with increasing transmission capacity of a REZ. Increasing the transmission capacity of a REZ increases the amount of generation that can be dispatched from that REZ. The primary drivers of REZ expansion cost savings across the VNI West options are:
  - VNI West is assumed to increase the transmission capacity of Western Victoria (V3), Murray River (V2) and the South-West NSW (N5) REZs (see the associated incremental increases in limits in Table 1, as provided by Transgrid and AVP). This is forecast to provide access to additional renewable capacity at a lower cost to other REZs where transmission upgrade costs must be incurred.

- The REZ expansion savings are lowest in the Progressive Change scenario where the forecast transition to renewables is not as rapid as the other scenarios and less investment is needed in additional REZ transmission capacity, and what investment is needed, is forecast to occur later.

The largest source of difference in expected gross market benefits between Option 3A and Option 5 is forecast to be the REZ expansion cost savings. Option 3A is forecast to have increased REZ expansion savings compared to Option 5, since Option 3A is considered to increase the Western Victoria (V3) REZ transmission limits to a larger extent than Option 5, as provided by Transgrid and AVP. This allows increased capacity to be installed in this REZ compared to Option 5, reducing the need for investment in transmission upgrades to other REZs.

Offshore wind sensitivity

In the offshore wind sensitivity (Step Change scenario only), offshore wind targets are assumed to be imposed in Victoria in all states of the world. In this sensitivity, expected capex and FOM cost savings, fuel cost savings and REZ expansion savings are all forecast to be lower than in the core simulation results where offshore wind is not committed, and rather can be built on the least cost basis. This is the case for both Option 3A and Option 5. The reduction in benefits for both options in the offshore wind sensitivity occurs because committing[13] offshore wind capacity in Victoria reduces the amount of other new wind, solar and storage investment that is forecast in the NEM in the Base Case. This is particularly true for Victoria and NSW. Reducing the amount of new capacity installed in the Base Case is forecast to reduce the opportunity for VNI West to enable capital to be more efficiently allocated and shared across the NEM, particularly in NSW and Victoria.

Option 5 is forecast to have higher gross market benefits in the offshore wind sensitivity compared to Option 3A. This result is the opposite to what was forecast in the core runs where Option 3A had the highest forecast gross market benefits. This occurs because with offshore wind, the extra unlocked transmission for Western Victoria (V3) REZ in Option 3A compared to Option 5 is not as beneficial as the extra 100 MW northward limit increase in VNI provided in Option 5 compared to Option 3A.

Combined forecast benefits of VNI West and WRL relative to the alternative Base Case sensitivity

In the alternative Base Case without WRL, the forecast gross market benefits (particularly capex and FOM expenditure) in the NEM significantly increases (for example, around $1.3b increase for Option 3A in the Step Change scenario, see Table 2 and Table 4). This is partly due to the existing congestion in western and north-west Victoria remaining in place, limiting generation from these areas. The assumption that there will be no unlocked transmission network capacity for REZs impacted by VNI West and WRL also diverts investment to higher cost locations and technologies.

Combined forecast benefits of VNI West and WRL relative to the alternative Base Case - offshore wind sensitivity

Committing offshore wind in the alternative Base Case (without WRL) is forecast to result in:

- an increase in forecast gross market benefits to $5,595m for Option 3A and $5,265m for Option 5 relative to the original Base Case of $4,253m for Option 3A and $3,921m for Option 5. Relative to the Base Case (and consequently VNI West Option 3A and Option 5), it is forecast that in the alternative Base Case, capex and FOM expenditure in the NEM significantly increase, followed by an increase in REZ transmission expansion costs.
- a decrease in forecast gross market benefits relative to when offshore wind is not a committed policy (see Table 5)., a similar trend to the results for the benefits of options relevant to the Base Case is forecast. Relative to the Base Case (and consequently VNI West Option 3A and

[13] Note that, for offshore wind sensitivity, the model is allowed to build offshore wind in either or both of Portland Coast and Gippsland wile meeting the requirement of capacity in each year through modelled constraints.

Option 5), it is forecast that in the alternative Base Case, capex and FOM expenditure in the NEM significantly increase, followed by an increase in REZ transmission expansion costs.

2. Introduction

Transgrid has engaged EY to undertake market modelling of system costs and benefits of the options related to the Victoria to NSW Interconnector West (VNI West) RIT-T.

The VNI West RIT-T is a joint RIT-T by Transgrid (as the transmission network service provider in NSW) and AEMO in its role as the Victorian planner (AVP). Although assumptions and input data sources were selected by both parties, we took instruction from Transgrid as our client. The selection of input assumptions and modelling methodology follows the CBA guidelines published by the AER[1] which contain the applicable RIT-T guidelines for actionable ISP projects including VNI West.

This Report forms a supplementary report to the additional consultation report published by Transgrid and AVP[2]. It describes the key modelling outcomes and insights as well as the assumptions and input data sources selected by Transgrid and AVP in accordance with the CBA guidelines and the modelling methods used. The Report should be read in conjunction with the consultation report published by Transgrid and AVP[2]. Accompanying results workbooks are also available containing forecast annual benefits by category as well as capacity and generation outlooks by region and REZ.

EY recomputed the least-cost generation dispatch and capacity development plan for the NEM, adopting the changes to the input assumptions relative the PADR to reflect updated market information and stakeholder feedback to the PADR, as jointly agreed between Transgrid and AVP, namely[2]:

- Announced retirement of Loy Yang A in 2035.
- Announced retirement of Torrens Island B in 2026.
- The modelling period was extended 204950 in line with 2022 ISP.
- A carbon budget was applied in each decade to limit the transfer of emissions savings between early and late model years.
- Coal retirement outcomes from 2022 ISP were adopted as input assumptions in each scenario's base case and all option cases.

Other input assumptions remained the same as the PADR and were generally derived from 2022 ISP[3], in accordance with the RIT-T instrument and CBA guidelines[1].The options were defined by Transgrid and AVP and are described in detail in the consultation report. This is an independent study using inputs defined by Transgrid and AVP, in which the modelling methodology follows the RIT-T guidelines for actionable ISP projects published by the AER[1].

The descriptions of outcomes in this Report are focussed on identifying and explaining the key sources of forecast gross market benefits. The categories of potential gross market benefits modelled include all the classes of benefits identified in 2022 ISP (and no additional classes), as follows:

- capital costs of new generation capacity installed,
- total FOM costs of all generation capacity,
- total VOM costs of all generation 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, impacting the calculated classes of potential benefits mentioned above.

Each category of gross market benefits is computed annually across a modelling period from 2023-24 to 2049-50. Benefits presented in real June 2021 dollars discounted to June 2021 using a 5.5% real, pre-tax discount rate as agreed jointly by Transgrid and AVP. This value is consistent with the value applied by AEMO in 2022 ISP[3], as required by the CBA guidelines[1].

This modelling considers the options outlined in the Table 6[2].

Table 6: Summary the modelled Base Cases and VNI West options[2]

Option	Description	Indicative impact on transfer capacity (MW)		Indicative impact on REZ transmission limit	
		VIC to NSW	NSW to VIC	Individually (MW)	Total (MW)
Alternative Base Case	No VNI West, no Western Renewable Link (WRL)	N/A	N/A	Murray River (V2): +0 Western Vic (V3): +0 South West NSW (N5)[14]: +0	NA
Base Case	No VNI West, with Western Renewable Link (WRL)	N/A	N/A	Murray River (V2): +0 Western Vic (V3): +600 South West NSW (N5): +0	+600
1	VNI West to north of Ballarat	+1,930	+1,800	Murray River (V2): +1,600 Western Vic (V3, WRL timing): +600 Western Vic (V3, VNI West timing): +550 South West NSW (N5): +900	+3,650
1A	VNI West to north of Ballarat with spur uprate to 500kV	+1,930	+1,800	Murray River (V2): +1,600 Western Vic (V3, WRL timing): +1,460 Western Vic (V3, VNI West timing): +750 South West NSW (N5): +900	+4,710
2	Option 1 plus non-network VTL	+250 from the VTL +1,930 from VNI West (via Kerang)	+250 from the VTL +1,800 from VNI West (via Kerang)	Same as Option 1 once it is commissioned. That is, no additional REZ hosting capacity associated with VTL component.	+3,650
3	VNI West to Waubra/Lexton	+1,830	+1,650	Murray River (V2): +1,600 Western Vic (V3, WRL timing): +950 Western Vic (V3, VNI West timing): +700 South West NSW (N5): +900	+4,150
3A	VNI West to Waubra/Lexton with spur uprate to 500 kV	+1,830	+1,650	Murray River (V2): +1,600 Western Vic (V3, WRL timing): +2,590 Western Vic (V3, VNI West timing): +1,400 South West NSW (N5): +900	+6,490

[14] For the South West NSW (N5) REZ, transmission limit is modelled as follows. For the Base Case and alternative Base Case, Transgrid advised to apply 600 MW increase in the limit after the Project Energy Connect (PEC), followed by an additional 200 MW after HumeLink. For VNI West options, with the PEC Enhanced, the increase in N5 transmission limit after PEC is assumed to be 800 MW, followed by 1,000 MW after HumeLink.

Option	Description	Indicative impact on transfer capacity (MW)		Indicative impact on REZ transmission limit	
		VIC to NSW	NSW to VIC	Individually (MW)	Total (MW)
4	VNI West to Bulgana via Bendigo	+1,700	+1,475	Murray River (V2): +1,600 Western Vic (V3, WRL timing): +1,460 Western Vic (V3, VNI West timing): +580 South West NSW (N5): +900	+4,540
5	VNI West to Bulgana	+1,930	+1,650	Murray River (V2): +850 Western Vic (V3, WRL timing): +1,460 Western Vic (V3, VNI West timing): +200 South West NSW (N5): +900	+3,410

In addition, based on agreement by Transgrid and AVP, we modelled sensitivities assessing the impact of a Victorian offshore wind target on the benefits of Option 3A and Option 5 in the Step Change scenarios[15]. Furthermore, sensitivities assessed the gross market benefits of all seven VNI West options combined with the corresponding WRL augmentation compared to an alternative counterfactual Base Case in which the WRL project is excluded. A combined assessment of gross market benefits of VNI West (Options 3A and Option 5) and WRL in the Step Change scenario with the Victorian offshore wind target committed was also performed.

The forecast gross market benefits of each option need to be compared to the cost of the relevant option to determine the forecast net economic benefit for that option[16]. The assessment of costs and calculation of net economic benefits and preferred option was conducted outside of this Report by Transgrid and AVP using the forecast gross market benefits from this Report and other inputs[2].The Report is structured as follows:

- Section 3 provides an overview of changes to modelling since the PADR and relative to 2022 ISP.
- Section 4 provides the market modelling outcomes for the core simulations and sensitivities.
- Appendix A summaries the forecast renewable energy and emissions outcomes focusing on the Step Change scenario.
- Appendix B describes the scenario assumptions used in the modelling.
- Appendix C discusses market modelling methodology.
- Appendix D outlines model design and input data related to representation of the transmission network, transmission losses and demand.
- Appendix E outlines model design and input data related to supply.

[15] The Victorian Government's Offshore Wind Policy does not yet meet the criteria under the Rules necessary to be considered a "committed policy" and therefore is not included in the core scenarios.
[16] Or in the alternative counterfactual sensitivities, the net economic benefit for VNI West and WRL is computed by comparing the gross benefits to the combined cost of the relevant VNI West options plus the WRL project.

3. Changes from the PADR and 2022 ISP

3.1 New VNI West options assessed

Based on the joint agreement between Transgrid and AVP, we were requested to model options outlined in the Table 6. In addition to Option 1 and Option 2 that were modelled in the PADR, five new options were added by Transgrid and AVP.

All seven options assessed:

- Involve a 500 kV double circuit transmission line.
- Originate at Dinawan, in NSW, with connection to Project EnergyConnect.
- Include new terminal stations near Kerang, in Victoria, with a connection to the existing 220 kV line to Kerang.

The differences in the options relate to the Victorian scope and key input parameters provided by Transgrid and AVP are outlined in Table 6 in Section 2.

3.2 Changes in other input assumptions

3.2.1 Modelling period

In response to the PADR consultation feedback, Transgrid and AVP advised to adopt the modelling period of 2023 to 2050 (27 years) in line with 2022 ISP. This is a 2-year extension of the PADR market modelling period which went to 2047-48.

3.2.2 Carbon budget modelling

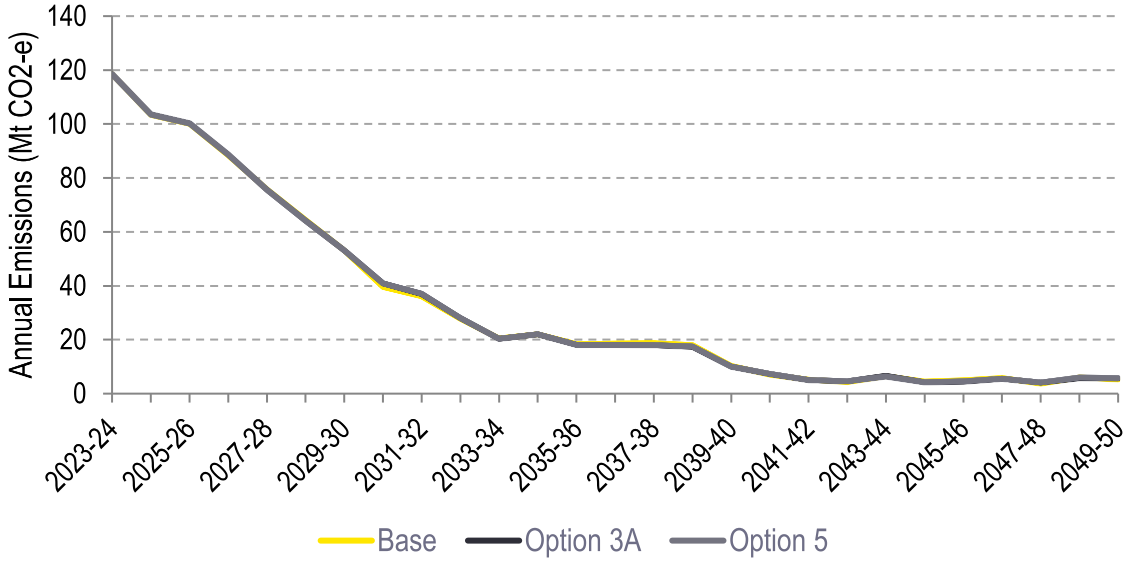
The PADR modelling implemented a single cumulative carbon budget over the modelling horizon (to 2048) based on the scenario-specific ISP input assumptions[3], with nested checkpoints based on the scenario-specific ISP emissions outcomes[2]. For example, interim budget checkpoints were imposed for the period of 1 July 2023 to 1 July 2030 and another for 1 July 2023 to 1 July 2040. This method allowed the model to 'bank' earlier emissions savings for later use if it was least-cost to do so.

The PADR modelling forecasts that the most cost-efficient way to meet the carbon budget to 2048 without VNI West was to withdraw coal in the current decade and bank emissions savings, rather than build significant volumes of more expensive solar and wind resources with high levels of spill, particularly during spring and summer in the last decade, even when supported by significant storage capacity of medium depth. With VNI West, the model foresaw the opportunity to utilise diverse resources, especially renewables, once VNI West was built and thus a reduced need for gas generation in later years. These later emissions savings meant coal-fired generators were forecast to withdraw more slowly in the 2020s with VNI West, although carbon budget constraints (to 2050 and interim checkpoints) were still met.

While this appears to be the most efficient outcome in both modelled states of the world if investors and generators had perfect foresight, submissions to the PADR highlighted that, in reality, investment and divestment decisions are normally made based on near- to mid-term considerations. Furthermore, a delay in coal retirements with VNI West in place (relative to a Base Case without VNI West ever built) is contrary to stakeholder expectations.

In response to the PADR submissions, Transgrid and AVP adopted a change in carbon budget modelling so that emissions are progressively reduced in all states of the world, more in line with 2022 ISP (see Figure 2). In the updated modelling, a discrete carbon budget applies in each decade to limit the transfer of emissions savings between early and late years within the modelled period. Discrete budgets were crafted from 2022 ISP outcomes based on the following periods: 1 July 2023 to 1 July 2030, 1 July 2030 to 1 July 2040 and finally 1 July 2040 to 1 July 2050. This change better aligns with stakeholders' expectations of investment and divestment look-ahead periods (as evidenced by the PADR feedback received) and reduces anticipatory benefits of VNI West.

Figure 2: Forecast emissions outcomes for the Base Case, Option 3A and Option 5 in the Step Change scenario

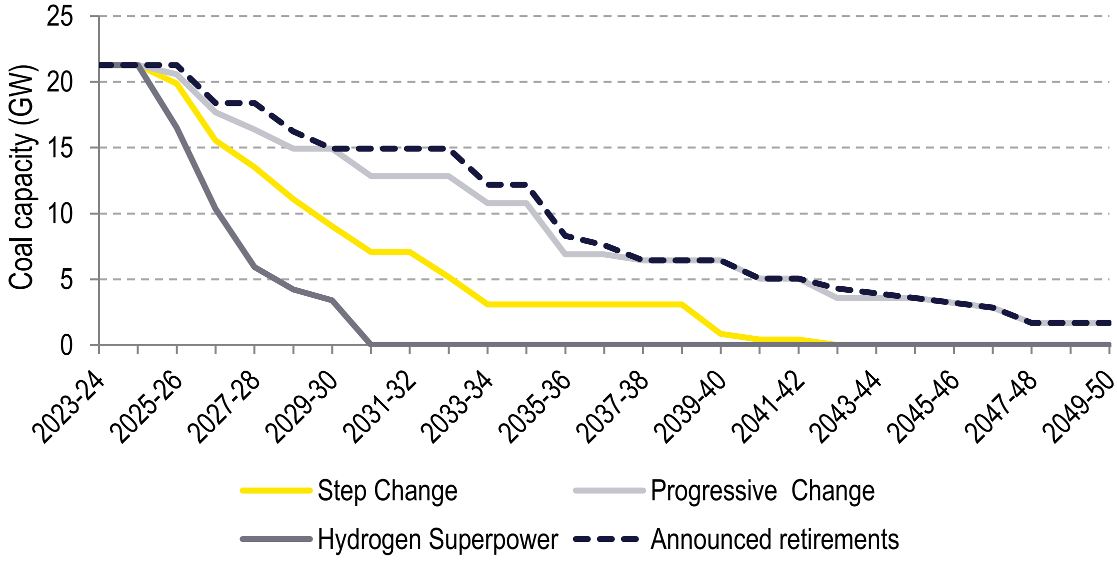


3.2.3 Adopting ISP coal retirement outcomes

In response to stakeholder feedback to the PADR regarding anticipatory benefits and VNI West delaying coal withdrawal of service (as discussed in Section 3.2.2), Transgrid and AVP also advised to adopt 2022 ISP coal retirement outcomes and apply the retirements for the Base Case and VNI West options to avoid early/deferral of coal retirements between the Base Case and VNI West options. Note that while it has not been specifically assessed by us, in practice this change is expected to have little impact on reducing anticipatory benefits over and above the change in carbon budget approach discussed in Section 3.2.2.

Forecast coal capacity retirements across all scenarios are illustrated in Figure 3. Note that, following Loy Yang A's announced retirement in 2035[4], Transgrid and AVP advised to adopt 1 July 2035 as the latest retirement date in the modelling. In practice, this only affected the capacity outlook outcomes in the Progressive Change scenario, as this coal plant is forecast to retire earlier than this date in the other two scenarios.

Figure 3: Forecast coal capacity in the NEM by year across all scenarios in each scenario's Base Case (2022 ISP outcomes, provided by Transgrid and AVP)[17]



3.3 Change in presentation of forecast gross market benefits

In the PADR, gross market benefits were presented with the entire capital cost savings (including FOM savings) associated with the avoidance or deferral of build of new plant in the year avoided. This was purely a presentational choice made by Transgrid and AVP to assist with interpreting the timing of capacity changes that drive expected capex benefits and did not affect the overall gross benefits of the options.

In response to the PADR feedback, Transgrid and AVP advised to adopt an annualised capex and FOM presentation consistent with how these savings are presented in 2022 ISP to help avoid confusion that may be leading to stakeholders misinterpreting the results.

An example of the same gross market benefit outcomes presented using the two alternative approaches is given in Figure 4 and Figure 5. For reference, we have also provided the undiscounted annual gross market benefits of Option 3A in Figure 6, showing the forecast fuel cost savings mostly in 2030s, followed by an increase in capex savings in 2040s.

[17] In the figure the Eraring capacity is included for the 2025-26 year but in the model the capacity is retired on the announced retirement date of 19 August 2025.

Figure 4: Forecast cumulative gross market benefit for Option 3A under the Step Change scenario, millions real June 2021 dollars discounted to June 2021 dollars – annualised approach

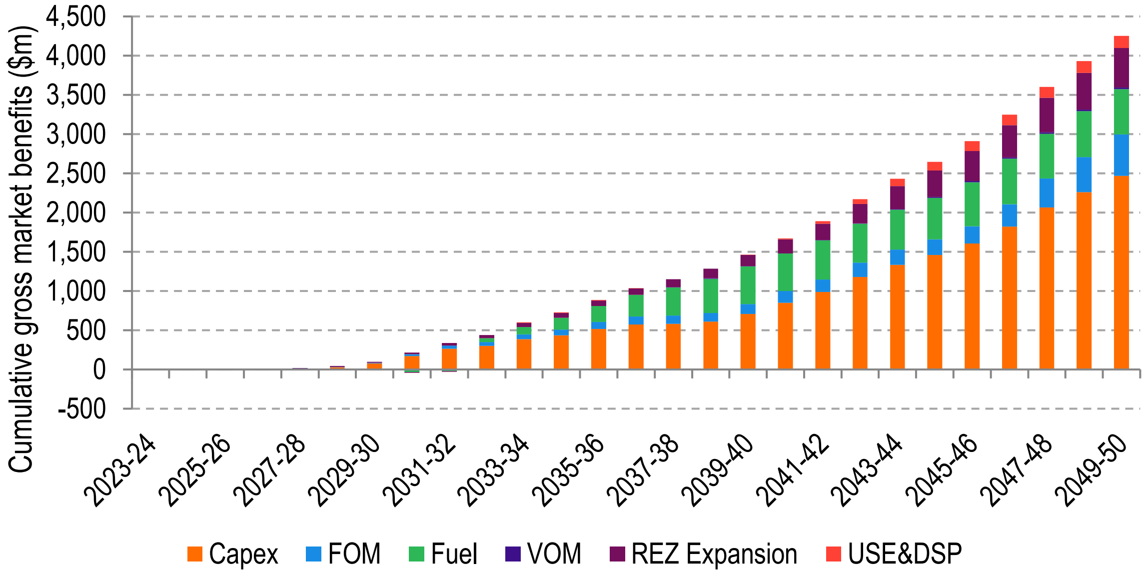


Figure 5: Forecast cumulative gross market benefit for Option 3A under the Step Change scenario, millions real June 2021 dollars discounted to June 2021 dollars – lumpy approach

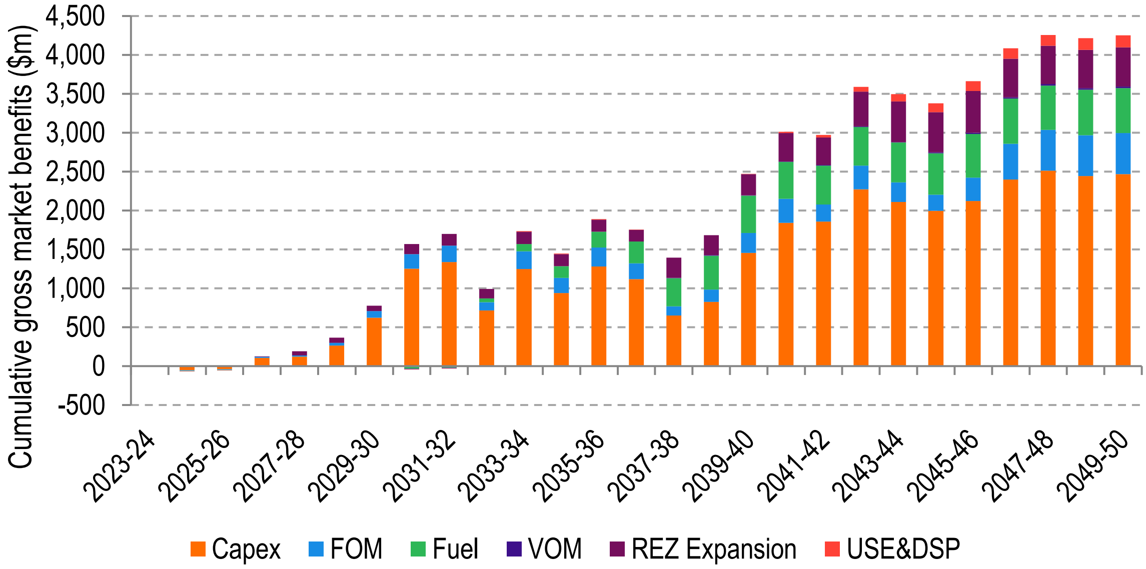
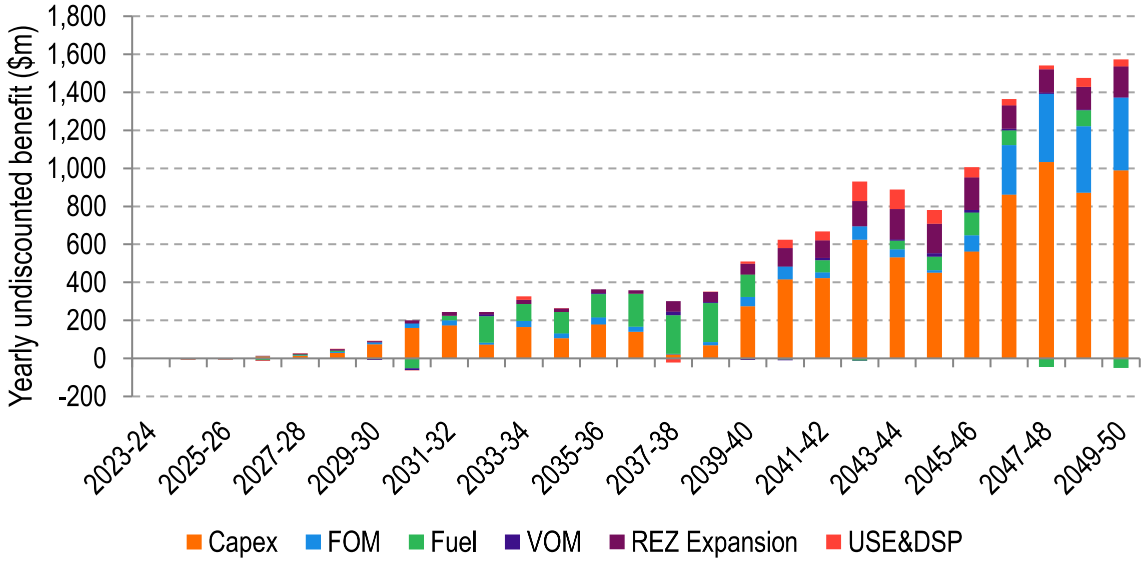


Figure 6: Forecast *undiscounted* annual (not cumulative) gross market benefits for Option 3A under the Step Change scenario, millions real June 2021 dollars



3.4 Changes in assumptions from 2022 ISP

There were two changes in input assumptions adopted relative to 2022 ISP. Transgrid and AVP advised us to incorporate these based on updated market information since the publication of 2022 ISP, namely:

- announced retirement of Loy Yang A in 2035[4]
- announced retirement of Torrens Island B in 2026[5].

We also note that the input assumptions to the counterfactual Base Case differs to the counterfactual reported in 2022 ISP by design. In the ISP, the counterfactual does not include any network augmentations contained in the Candidate Development Paths (CDP). In this Report, the counterfactual only differs in input assumptions related to VNI West as summarised in Table 1. That is, there are a number of other significant transmission investments in the counterfactual Base Case for each scenario. This is aligned with the RIT-T instrument that specifies that the RIT-T proponent must adopt the most recent ISP parameters unless there is a demonstrable reason not to, and the CBA guidelines that require other actionable ISP projects to be included across all states of the world (including the Base Case). In this Report, there is a unique Base Case for each scenario and sensitivity.

4. Forecast gross market benefit outcomes

The following sections discuss the market modelling results, focusing on the top ranked options as assessed by Transgrid and AVP in the additional consultation report [2].

4.1 Counterfactual Base Case discussions – Step Change scenario

This section discusses the new capacity required in the Step Change Base Case and how renewable energy and emissions targets are achieved/overachieved in the NEM to help establish the credibility of the Base Case in response to stakeholder questions received in the PADR consultation.

The assumptions in the Base Case and VNI West options only differ in the presence/absence of VNI West augmentations (and its impact on interconnector/intra-connector limits as well as available REZ transmission capacity along the VNI West corridor), and all other input assumptions are the same. Generation, storage and other REZ transmission development are derived in each state of the world as model outcomes, but not input assumptions.

Across all modelled scenarios (and all states of the world), particularly the Step Change and Hydrogen Superpower scenarios, significant investment in new generation capacity is forecast in the NEM to supply increasing demand and replace existing thermal generation. The pace and scale of investment is dependent on the scenario's demand forecast, government policies and carbon budgets. The Step Change scenario is allocated the highest weighting of 52% by the ISP 2022. In this scenario, the NEM is forecast to require up to around 178 GW of new capacity (in excess of existing, committed and anticipated generators and storages) from large-scale generation and storage, including 78 GW of solar, 62 GW of wind and 28 GW of storage (both large-scale battery and PHES) in the Base Case. In particular, Victoria requires up to around 31 GW of new capacity, including 11 GW of solar, 12 GW of wind and 4.4 GW of storage (both large-scale battery and PHES) in the Base Case in the Step Change scenario. Note that existing, committed and anticipated generators and storages, as listed in 2022 ISP, and their retirement dates (e.g. end of technical life for renewables) are also modelled.

In terms of specific renewable energy and emissions targets, the Step Change Base Case is forecast to have the following outcomes:

- ► All the legislated emissions and renewable targets including VRET, VRET2, TRET, QRET[18], NSW Electricity Infrastructure Roadmap, and the NEM emissions reduction of 43% by 2030 are overachieved in this scenario. In addition, most of the recent renewable and emissions announcements, though not legislated yet, are forecast to be met/overachieved (with the main exception being the Victorian Government's offshore wind targets).
- ► The NEM is forecast to achieve around 81% of total generation from wind and solar by 2030-31.
- ► The NEM is forecast to achieve around 77% of emission reduction on 2005 level by 2030.
- ► Furthermore, the NEM renewable energy share in the final year of study (2050) is expected to be around 98% and the carbon budget constraint is forecast to be met. In the Step Change scenario this is 886 Mt CO_2-e cumulative emissions from 2023-24 to 2049-50 (defined by the ISP for the global temperature increase of ~1.8ºC by 2100).
- ► For Victoria in particular, the modelling outcomes forecast that all the recent announced emissions targets by 2030 and 2035 are overachieved (e.g. around 98% emissions reduction on 2005 level is forecast in 2035-36). In addition, renewable energy share of Victoria generation is above the recently announced targets for the region. Storage targets (if these include both large-scale and distributed/consumer energy resources) are also met for 2030 and 2035. Offshore wind is not enforced in the core simulations although multiple offshore

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[18] VRET = Victorian Renewable Energy Target; TRET = Tasmanian Renewable Energy Target; QRET = Queensland Renewable Energy Target

wind locations, as defined by 2022 ISP, are allowed to be built if least cost to do so. Note that sensitivities have been modelled to assess its impact on VNI West benefits.

A detailed assessment of forecast model outcomes against legislated and announced but as-yet unlegislated targets is provided in Appendix A.

While all legislated emissions and renewable energy targets are met in the Base Case in this scenario, moderate levels of gas generation are still forecast to be required to firm renewables and maintain reliable supply, particularly after forecast coal power plant closure. Gas generation is forecast to peak in 2030s, followed by a slight decline towards the end of the study period, despite electricity consumption nearly doubling by 2050. Some of this growth in electricity consumption is due to assumed partial electrification of the gas system in Victoria (as assumed in the 2022 ISP) and most of this new demand is supplied by renewable generation.

4.2 Summary of forecast gross market benefits

Table 7 shows the forecast gross market benefits all options across all scenarios.

Table 7: Summary of forecast gross market benefits of all VNI West options relative to each scenario's Base Case, millions real June 2021 dollars discounted to June 2021 dollars

Option	Description	Timing	Potential gross market benefits ($m)		
			Step Change	Progressive Change	Hydrogen Superpower
1	VNI West to north of Ballarat	Hydrogen Superpower: 1 July 2030 Step Change: 1 July 2031 Progressive Change: 1 July 2038	3,743	1,450	4,127
1A	VNI West to north of Ballarat with spur uprate to 500kV	Hydrogen Superpower: 1 July 2030 Step Change: 1 July 2031 Progressive Change: 1 July 2038	4,179	1,726	4,439
2	Option 1 plus non-network VTL	VTL: 1 July 2026 Hydrogen Superpower: 1 July 2030 Step Change: 1 July 2031 Progressive Change: 1 July 2038	3,886	1,566	4,397
3	VNI West to Waubra/Lexton	Hydrogen Superpower: 1 July 2030 Step Change: 1 July 2031 Progressive Change: 1 July 2038	3,895	1,557	4,164
3A	VNI West to Waubra/Lexton with spur uprate to 500 kV	Hydrogen Superpower: 1 July 2030	4,253	1,797	4,392

Option	Description	Timing	Potential gross market benefits ($m)		
			Step Change	Progressive Change	Hydrogen Superpower
		Step Change: 1 July 2031 Progressive Change: 1 July 2038			
4	VNI West to Bulgana via Bendigo	Hydrogen Superpower: 1 July 2030 Step Change: 1 July 2031 Progressive Change: 1 July 2038	3,918	1,605	4,072
5	VNI West to Bulgana	Hydrogen Superpower: 1 July 2030 Step Change: 1 July 2031 Progressive Change: 1 July 2038	3,921	1,598	4,191

4.3 Overview of sources of VNI West benefits

This section gives an overview of the sources of benefits of VNI West, followed by the remainder of Section 4 which details the specific sources of benefits of VNI West options in specific scenarios.

4.3.1 Land costs for wind and solar generation in Victoria

There is finite land available for wind and solar generation capacity to be built on in the NEM, with each region having different levels of land availability. Table 8 lists the assumed capacity of onshore wind and solar that can be built in each mainland region in the first tranche capital cost, sourced from the ISP 2022[19]. Capacity built beyond these limits incurs additional costs. Victoria has significantly lower levels of onshore resources available than other regions. Without increased interconnection with other mainland regions, additional costs must be incurred to access land to build sufficient generation in Victoria to meet growing demand.

Table 8: Available onshore capacity in each mainland region before incurring additional costs[19]

Region	Capacity available for install without resource Violation costs	
	Wind (MW)	Solar (MW)
QLD	42,180	50,225
NSW	21,100	29,212
VIC	9,642	8,300
SA	16,800	27,200

As advised by Transgrid and AVP, VNI West is considered to increase transfer capacity between Victoria and NSW allowing for increased load and generation sharing between the two regions and the rest of the mainland, increasing Victoria's access to cheaper generation capacity. Additionally,

[19] AEMO, *Input and Assumptions Workbook v3.3,* Available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios Accessed 1 February 2023

VNI West is also considered to unlock renewable generation capacity in REZs along the VNI West corridor. Both attributes are expected to translate into significant forecast capex and FOM cost savings, fuel cost savings and REZ expansion savings.

4.3.2 Capex and FOM cost savings

Capex and FOM cost savings are forecast to make up the largest proportion of potential benefits across all modelled scenarios and VNI west options. The primary drivers of the forecast cost savings are as follows:

- Including VNI West is forecast to reduce the expected spill of wind and solar generation and allow access to higher quality renewable resources, meaning less capacity is expected to be needed (particularly in Victoria).
- Forecast additional transmission capacity in REZs along the VNI West corridor, as well as expected increased resource sharing from NSW, is forecast to enable expensive renewable capacity in Victoria to be deferred or avoided and replaced by cheaper capacity in other REZs, including Western Victoria (V3) and Murray River (V2)).

4.3.3 Fuel cost savings

Fuel cost savings across all scenarios and options are a result of reduced expected gas generation with VNI West, and in the Hydrogen Superpower scenario, less expected hydrogen turbine generation. Without VNI West, gas and hydrogen turbines are required to meet demand requirements in Victoria. Fuel cost savings from VNI West are generally driven by:

- Expected increased interconnector limits between Victoria and NSW are forecast to avoid the build of peaking gas capacity to meet peak demand requirements in Victoria. In the Hydrogen Superpower scenario, peaking capacity is forecast to be provided by hydrogen turbines rather than gas.
- Increased transmission capacity in REZs along the VNI West corridor is expected to allow access to additional renewable capacity, further reducing Victorian reliance on gas.

4.3.4 REZ expansion savings

REZ expansion costs are representative of the estimated costs associated with increasing transmission capacity of a REZ. Increasing the transmission capacity of a REZ increases the amount of generation that can be dispatched from that REZ[20]. Future REZ transmission expansions, being different to the generator connection costs, are considered as transmission network upgrade options which can be built if they are part of the least cost solution. The primary drivers of REZ expansion savings across the VNI West options are:

- VNI West is expected to increase the transmission capacity of Western Victoria (V3), Murray River (V2) and the South West NSW (N5) REZs, as provided by Transgrid and AVP. Improved access to these REZs is expected to shift investment in renewables towards these REZs, reducing the need to invest in transmission upgrades to other REZs.
- The REZ expansion savings are lowest in the Progressive Change scenario where the forecast transition to renewables is not as rapid as the other scenarios and less overall investment (and later investment) is needed in additional REZ transmission capacity.

4.4 Market modelling outcomes for Option 3A

In this section, the modelling outcomes for Option 3A for all scenarios are analysed. The outcomes presented include forecast gross market benefit of this option, capacity mix, and generation mix compared to the Base Case.

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[20] Specifically increases the assumed limit on a dispatch constraint for all generators in a REZ.

4.4.1 Step Change scenario

The forecast cumulative gross market benefits for Option 3A in the Step Change scenario are shown in Figure 7 using an annualised presentation of capex and FOM benefits. Furthermore, the corresponding differences in the forecast capacity and generation outlooks across the NEM between Option 3A and the Base Case in the same scenario are presented in Figure 8 and Figure 10, respectively. NEM capacity forecast for this option is also provided in Figure 8.

Figure 7: Forecast cumulative gross market benefit for Option 3A under the Step Change scenario, millions real June 2021 dollars discounted to June 2021 dollars

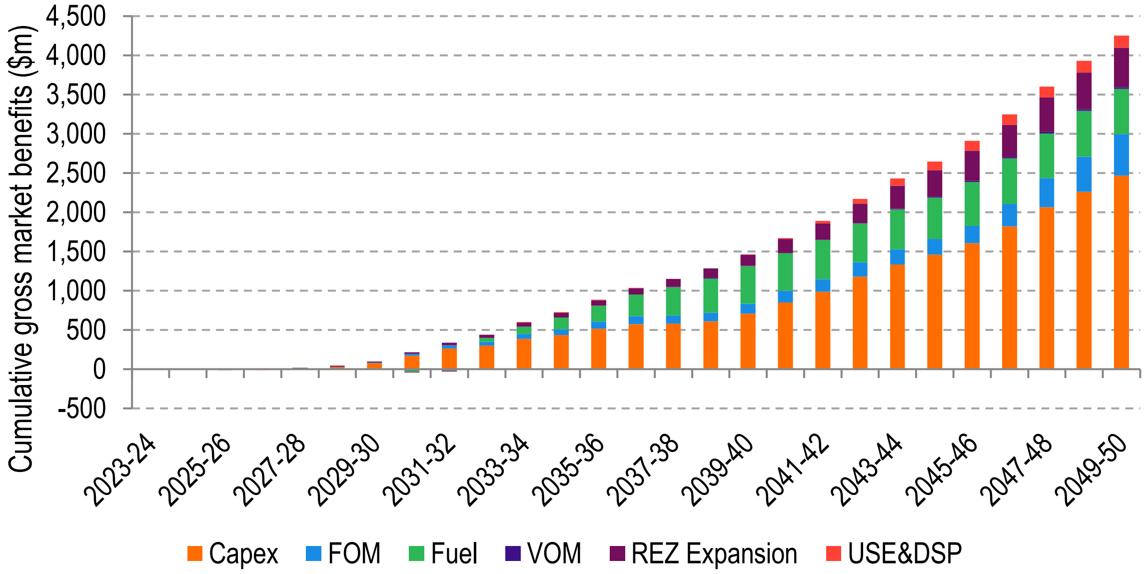


Figure 8: Forecast NEM capacity for Option 3A in the Step Change scenario

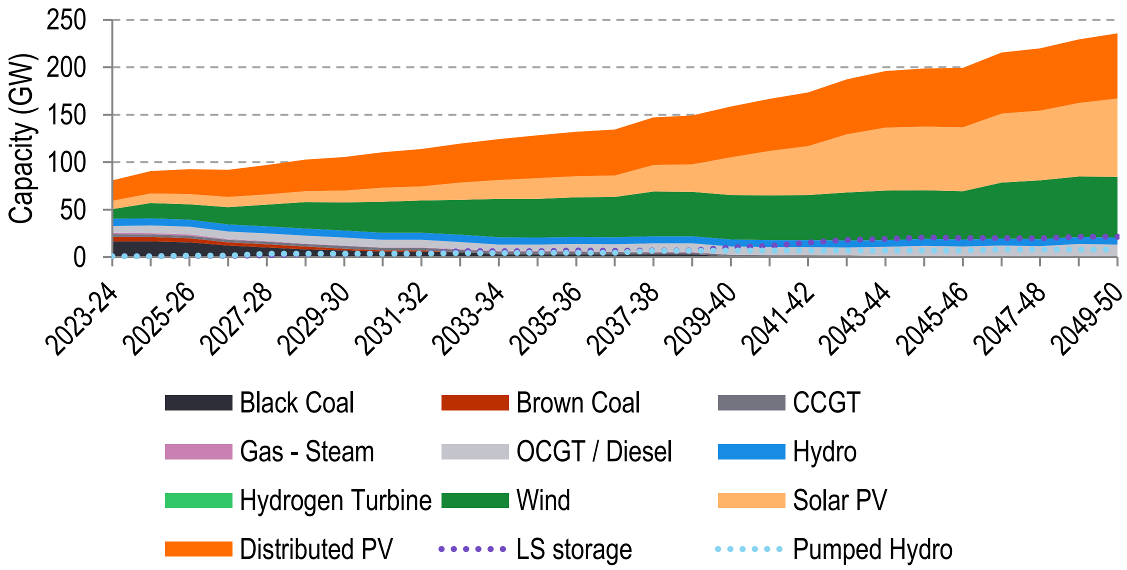


Figure 9: Difference in NEM capacity forecast between Option 3A and Base Case in the Step Change scenario

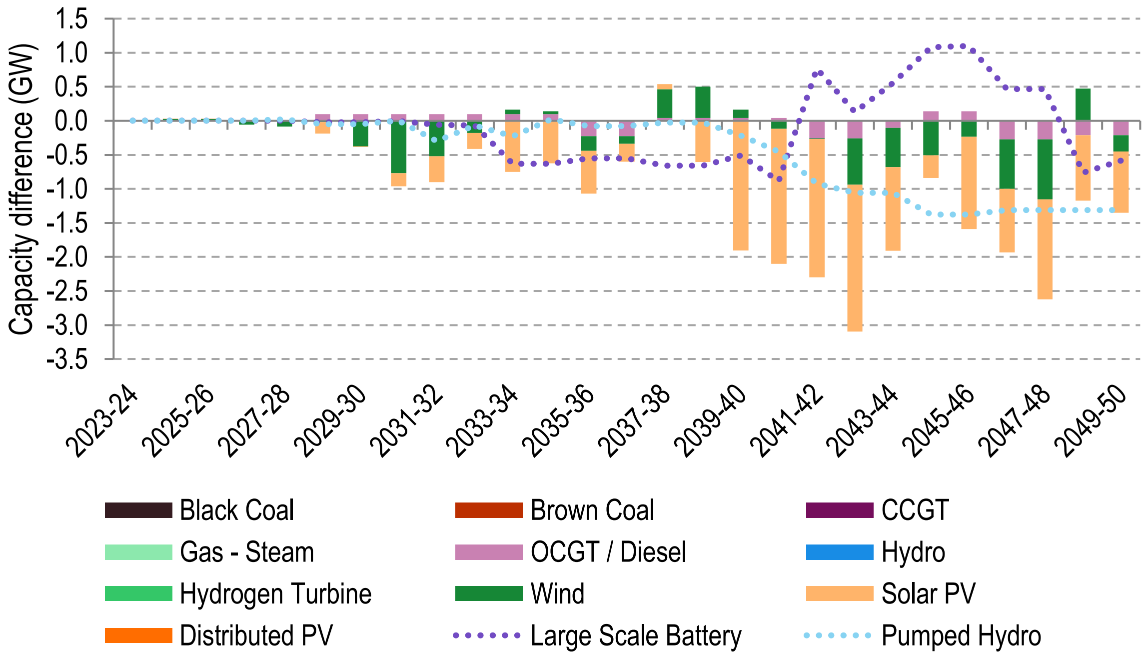
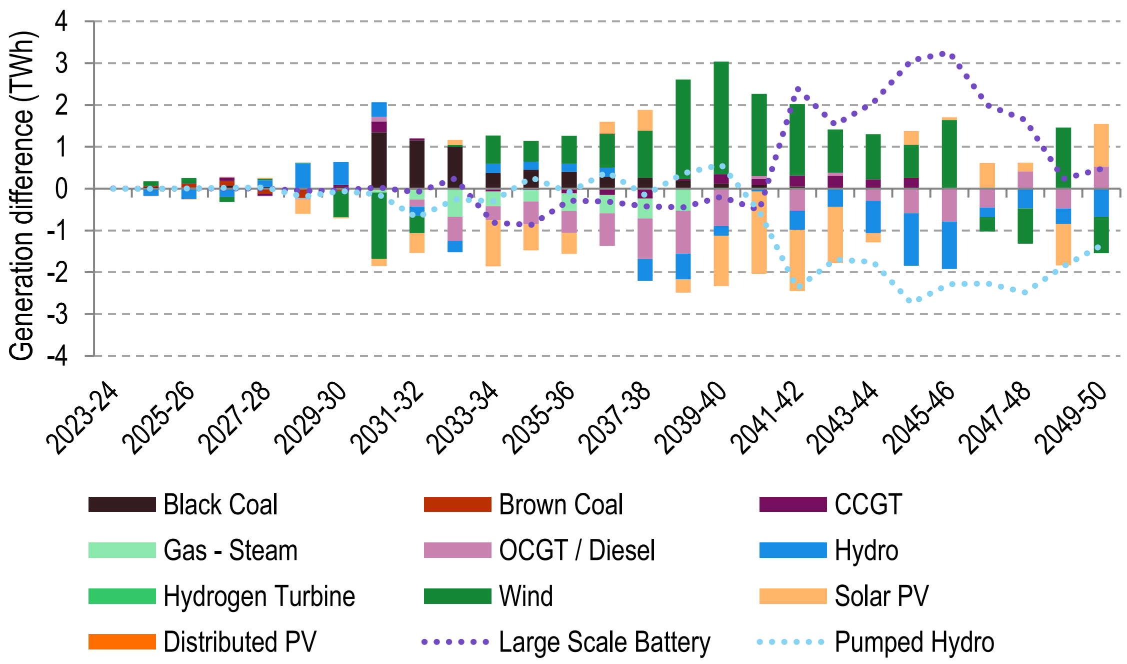


Figure 10: Difference in NEM generation forecast between Option 3A and Base Case in the Step Change scenario



Capex savings are forecast to account for the major share of benefits, followed by fuel costs, FOM and REZ transmission expansion savings.

- VNI West Option 3A is forecast to avoid some solar and storage (mostly PHES) investment and to a smaller extent gas capacity in the NEM which results in capex and FOM cost savings. However, as shown in Figure 8, significant new capacity, including wind, solar and storage, is forecast in this option by the end of modelling period.
    - Without VNI West Option 3A, generally extra solar capacity in combination with storage, and in later years peaking gas is required to supply Victorian demand in this region (due to lower assumed interconnection and less assumed transmission capacity connecting

Western Victoria (V3) and Murray River (V2) REZs). In addition, generally more solar, storage and to some extent wind is required in the other southern regions of Tasmania and South Australia in the Base Case.

- ► With VNI West Option 3A, while there is still significant capacity investment expected in all regions (see Figure 8), some investment is forecast to shift to solar and storage in NSW. This option is also forecast to enable generation diversity in the NEM, as well as more efficient utilisation of Snowy 2.0, all resulting in less capacity, including storage, required in Victoria.
- ► The recently announced Victorian emissions and renewable targets are forecast to be overachieved with Option 3A as they were in the Base Case. The recently announced storage targets in Victoria of 6.3 GW by 2035 are also forecast to be nearly met, though short by only 100 MW. For further detail, refer to Appendix A.
- ► As advised by Transgrid and AVP, VNI West Option 3A is also considered to unlock significantly more transmission capacity to the Western Victoria (V3) REZ which is forecast to result in additional wind build in this REZ relative to the Base Case. This is forecast to displace investment in wind capacity in other REZs within Victoria and NSW.
- ► Overall, the amount of forecast capacity investment is lower with VNI West Option 3A for the forecast same/more renewable generation due to improved access to higher capacity factor REZs and reduced forecast spill. Across the NEM, VNI West Option 3A is forecast to reduce solar spill volume by 4% and wind spill volume by 9% relative to the Base Case. However, the interaction of several factors affects the amount of spill in each REZ and region: the change in distribution of renewable investment, the change in ratio of wind to solar investment in each REZ, and the direct effect of additional transmission access to some REZs in Victoria and NSW associated with VNI West Option 3A. The volume of spill is forecast to reduce in regions with reduced investment (solar and wind spill Queensland, South Australia and Tasmania, wind spill in NSW), but can increase in volume where renewable investment increases due to VNI West Option 3A (solar spill in NSW). In Victoria, wind spill volume is forecast to decrease with VNI West Option 3A despite a forecast increase in wind investment, while solar spill volumes are forecast to increase slightly despite a forecast decrease in solar investment.
- ► Slightly different annual hydro generation patterns in the Base Case and VNI West Option 3A are forecast. With VNI West, generally more wind generation is forecast in Victoria. Wind generation is expected to compete with hydro generation, particularly in Tasmania, and as hydro has higher assumed running costs compared to wind, this is forecast to result in more hydro spill relative to the Base Case.

► VNI West Option 3A is forecast to avoid some peaking gas generation in Victoria which results in fuel cost savings.

- ► Peaking gas generation is required in Victoria in the counterfactual Base Case in order to supply peak demand in this region after retirement or subsequent to the retirement of brown coal and relatively lower interconnection to the rest of the mainland.

► As advised by Transgrid and AVP, VNI West Option 3A is considered to unlock transmission capacity for the South West NSW (N5), Murray River (V2) and Western Victoria (V3) REZs. As a result, a shift in investment in renewables towards these REZs is forecast, with an associated reduction in investment in renewable capacity in REZs which need transmission upgrades in the Base Case. This is forecast to result in expected REZ transmission cost savings.

- ► It is forecast that with VNI West Option 3A generally more wind and in later years more solar is built in Western Victoria (V3), while Murray River (V2) and South West NSW (N5) are forecast to build more solar.
- ► On the other hand, it is forecast VNI West Option 3A reduces the capacity needed in the remaining Victorian REZs as well as other regions REZs such as Wagga Wagga (N6), Isaac (Q4), Banana (Q9), Far North Queensland (Q1), Leigh Creek (S6), North East Tasmania (T1) and Central Highlands (T3). As a result, REZ transmission cost savings are forecast in

these REZs. Despite this avoided or deferred capacity, renewable energy targets, including Queensland announced targets, are forecast to be met (see Appendix A).

- It is also forecast that VNI West Option 3A results in DSP & USE costs savings, although to a smaller extent.

4.4.2 Progressive Change scenario

The forecast cumulative gross market benefits for Option 3A in the Progressive Change scenario are shown in Figure 11. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 3A and the Base Case are shown in Figure 12 and Figure 13.

Figure 11: Forecast cumulative gross market benefit for Option 3A under the Progressive Change scenario, millions real June 2021 dollars discounted to June 2021 dollars

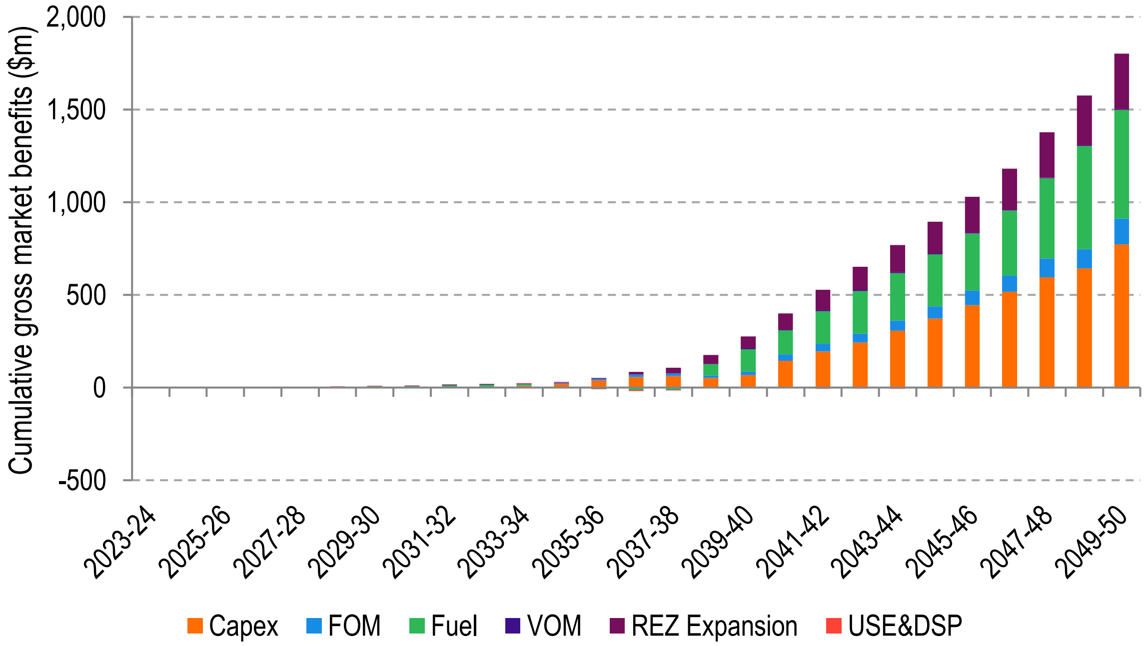


Figure 12: Difference in NEM capacity forecast between Option 3A and Base Case in the Progressive Change scenario

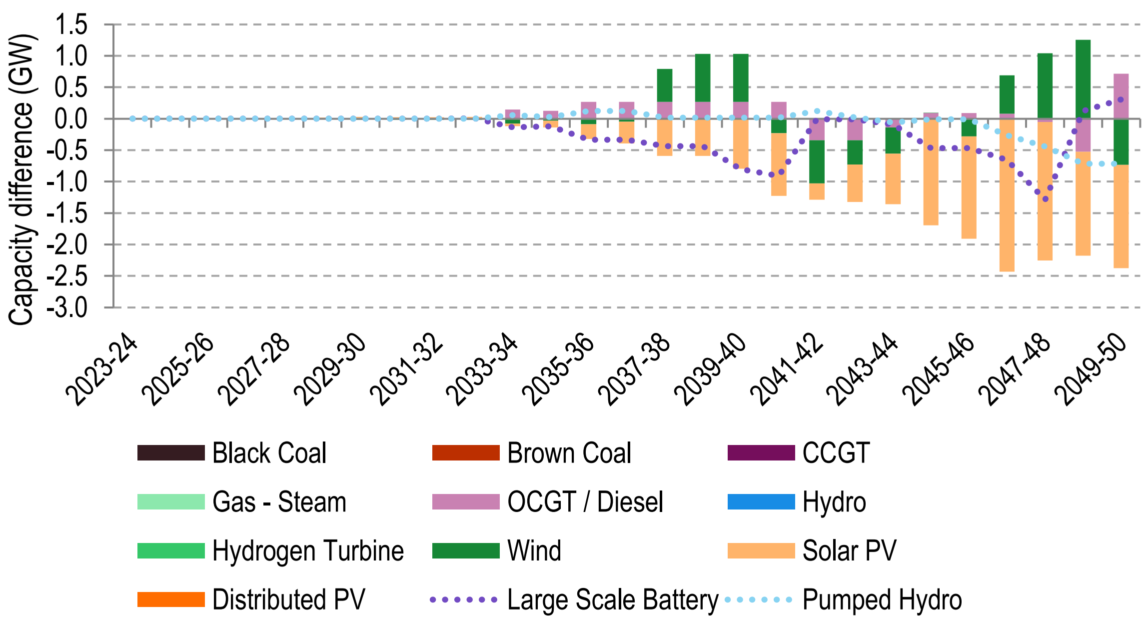
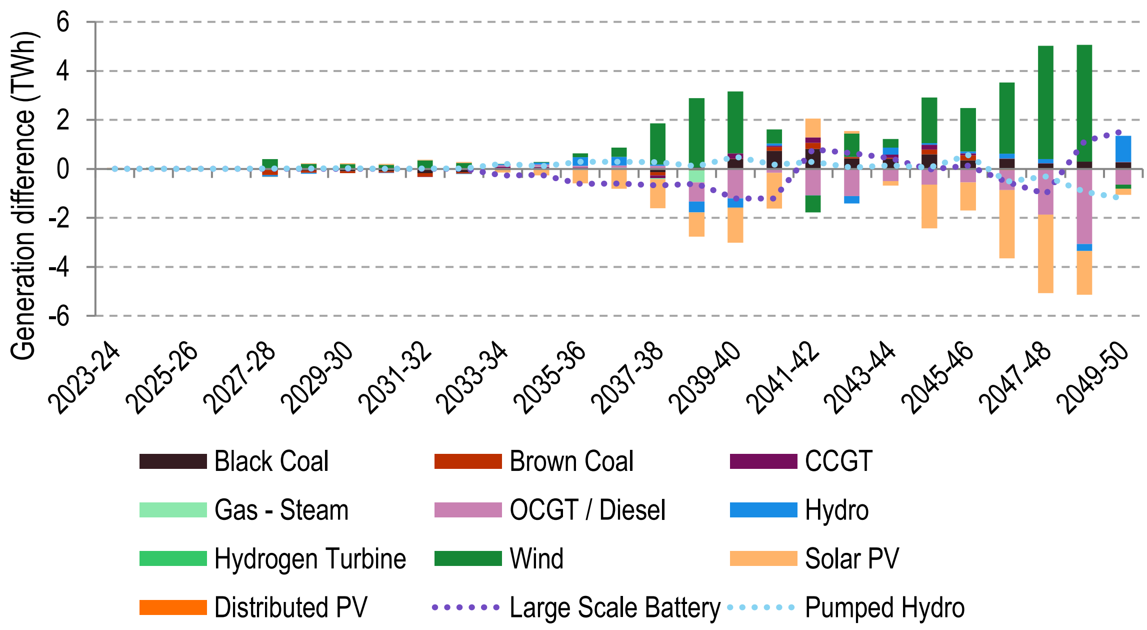


Figure 13: Difference in NEM generation forecast between Option 3A and Base Case in the Progressive Change scenario



The largest sources of forecast gross market benefits in this scenario are capex savings from deferred and avoided capacity build, followed by reduced fuel costs as well as reduced REZ transmission expansion costs.

- The Progressive Change scenario forecasts significantly lower benefits than the Step Change scenario due to the assumed lower pace of demand growth, less restrictive carbon budget and the later 2038-39 timing of VNI West commissioning.
- Similar to the Step Change scenario, in the Progressive Change scenario VNI West Option 3A is generally forecast to result in avoiding some solar and storage, though it is also forecast that this option results in changing of the timing of wind and gas build. Overall, this results in capex and FOM cost savings.
  - With VNI West Option 3A, and with the associated increase in transmission capacity for the REZs, particularly Western Victoria, as well as more interconnection with NSW (as advised by Transgrid and AVP), more wind investment is forecast in the affected REZs in Victoria which reduces the need for investment in other Victorian REZs. The overall benefits of VNI West Option 3A are a reduced forecast need for solar, storage and gas in Victoria, as well as generally less wind investment in Tasmania, with less wind, solar and storage build in South Australia and Queensland. However, with this option in place, generally more solar and storage is forecast to be built in NSW, though some wind capacity is avoided in this region.
  - The Progressive Change scenario is forecast to have less renewable spill compared with the Step Change scenario. However, similar to the Step Change scenario it is forecast that with more interconnection and REZ access enabled by VNI West Option 3A, resources are more efficiently utilised. Overall, across the NEM, Option 3A is forecast to reduce solar spill by 4% and wind spill by 10% relative to the Base Case.
- Fuel cost savings are forecast to be a more significant source of market benefits in the Progressive Change scenario than the Step Change scenario. These savings are mainly due to a forecast reduction in gas generation in Victoria with VNI West Option 3A. With a less restrictive carbon budget in this scenario, the least cost generation and dispatch outlook includes more gas generation in the Base Case in Victoria to meet demand. Avoiding this generation with VNI West Option 3A is forecast to result in fuel cost savings.
- More expected renewable build in the REZs with the associated unlocked transmission capacity due to VNI West Option 3A, as advised by Transgrid and AVP, is forecast to result in less build

in some other REZs which is required in the Base case. This is forecast to result in REZ transmission cost savings.

- It is forecast that with VNI West Option 3A generally more wind is built in Western Victoria (V3) REZ, while Murray River (V2) and South West NSW (N5) REZs are forecast to build more solar.
- On the other hand, VNI West Option 3A is expected to reduce the capacity needed in the remaining Victorian REZs and to a smaller extent in REZs in other regions. This is forecast to result in REZ transmission cost savings in these REZs.

4.4.3 Hydrogen Superpower scenario

The forecast cumulative gross market benefits for Option 3A in the Hydrogen Superpower scenario are shown in Figure 14. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 3A and the Base Case in this scenario are shown in Figure 15 and Figure 16.

Figure 14: Forecast cumulative gross market benefit for Option 3A under the Hydrogen Superpower scenario, millions real June 2021 dollars discounted to June 2021 dollars

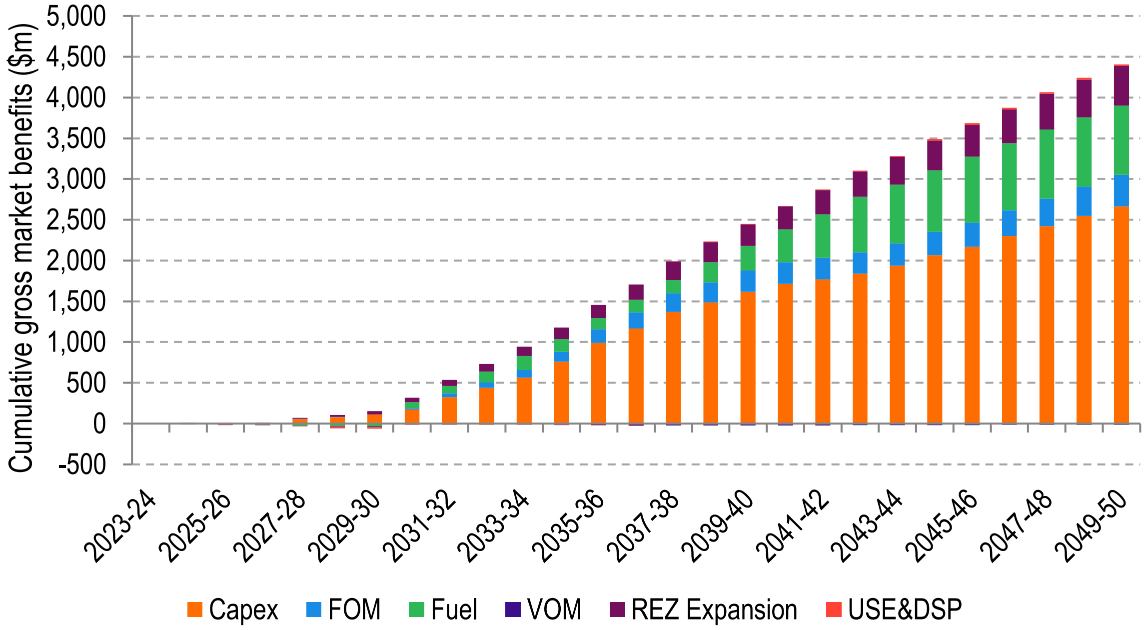


Figure 15: Difference in the NEM capacity forecast between Option 3A and Base Case in the Hydrogen Superpower scenario

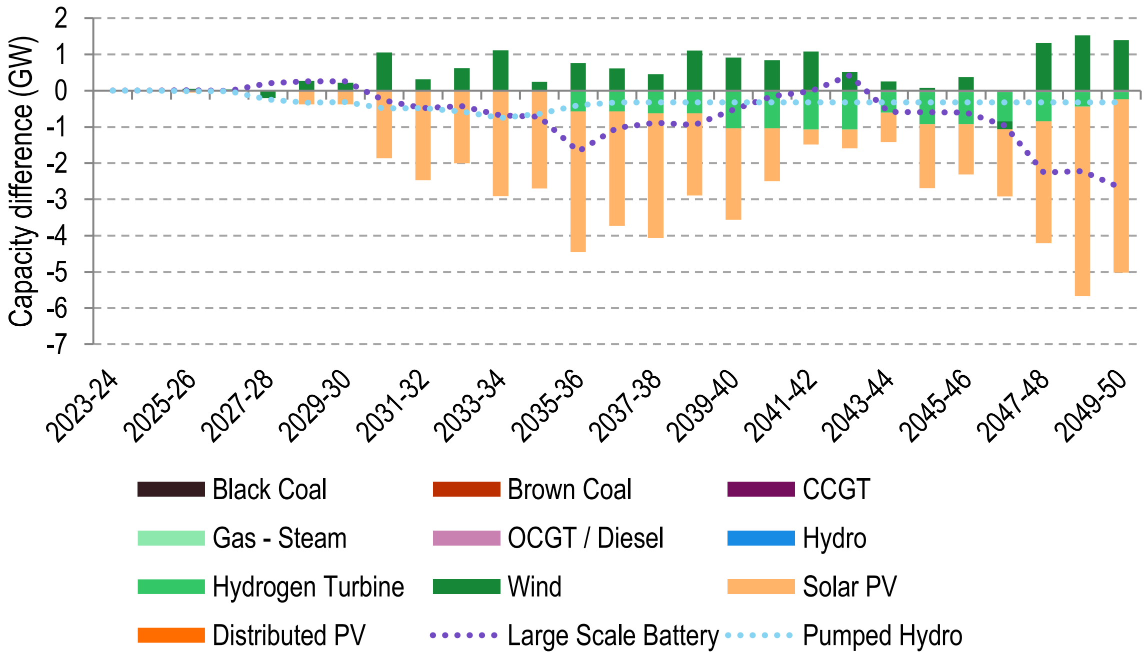
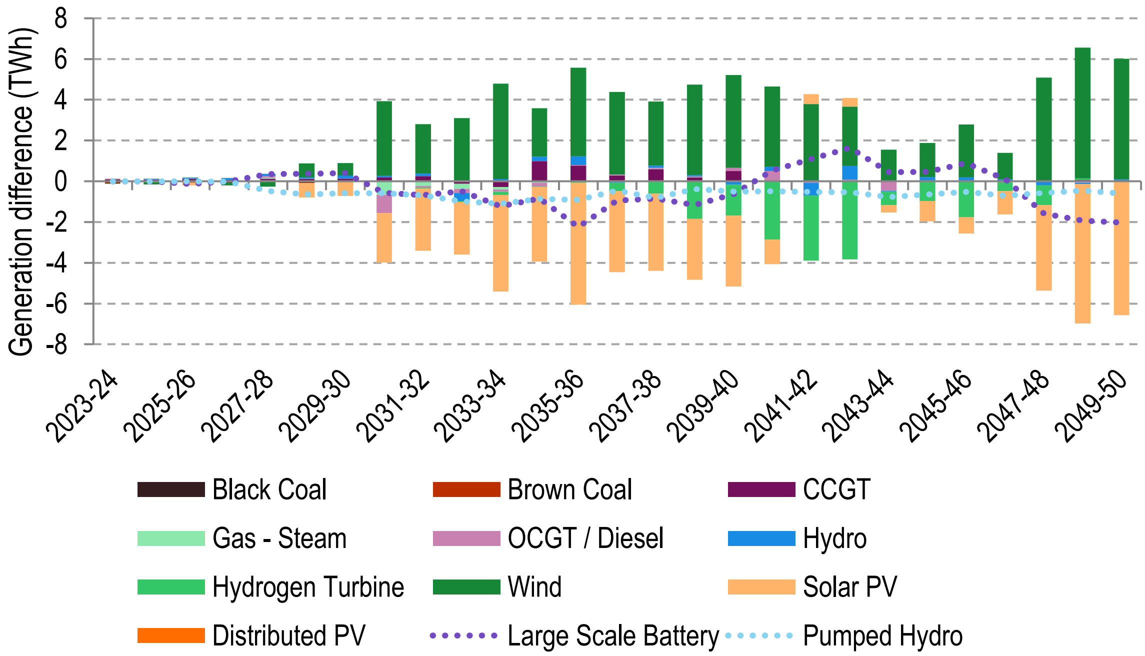


Figure 16: Difference in NEM generation forecast between Option 3A and Base Case in the Hydrogen Superpower scenario



The primary contributing factors of forecast gross market benefits in this scenario are derived from capex savings, followed by fuel, REZ transmission expansion and FOM cost savings.

- Hydrogen Superpower scenario is forecast to have the highest benefits among all scenarios, due to the more aggressive assumptions, particularly demand growth and a more restrictive carbon budget.
- Similar to the Step Change scenario, in the Hydrogen Superpower scenario VNI West Option 3A is forecast to avoid some solar and storage. In addition, hydrogen turbine capacity is forecast

to be avoided, although some extra wind capacity is forecast. Overall, this results in significant capex and FOM cost savings.

    - With the assumed significant demand growth as well as forecast rapid coal retirement in this scenario based on the 2022 ISP, and without an increase in the interconnection, significantly more solar capacity in combination with storage, and in later years hydrogen turbine is required to supply Victoria demand in this region. It is forecast overbuilding of new capacity with relatively high spill is required to meet the demand in all seasons.
    - With VNI West Option 3A, some of the capacity in Victoria is forecast to be avoided and instead replaced by some extra solar and storage mostly in NSW, although at a smaller capacity. This option is forecast to enable generation diversity in the NEM, as well as more efficient utilisation of Snowy 2.0, all resulting in less capacity, including storage, required in Victoria. In addition, with the associated increase in transmission capacity in the Western Victoria REZ (as advised by Transgrid and AVP), significant wind capacity is forecast in this REZ replacing mostly solar capacity elsewhere in Victoria.
    - It is also forecast that South Australia and Tasmania require extra solar, large-scale battery and wind in the counterfactual Base Case. Specifically, with the assumed significant hydrogen demand growth in Tasmania in the last few years, it is forecast that significant solar and storage is required in this region in the Base Case, some of which is forecast to be avoided with VNI West Option 3A.
    - Due to significant renewable investment in this scenario, considerable renewable spill is forecast in the Base Case, being significantly more than other scenarios. However, similar to the other scenarios, with improved interconnection enabled by VNI West Option 3A, resources are forecast to be more efficiently utilised. Across the NEM, VNI West Option 3A is forecast to reduce renewable spill, particularly wind spill volume by 4% relative to the Base Case.
- It is forecast that VNI West Option 3A results in avoiding hydrogen turbine generation in Victoria which results in fuel cost savings. Hydrogen turbines are built in the Base Case in this scenario, since with the significantly more restrictive carbon budget compared with the Step Change scenario, gas generation is significantly limited in this scenario.
    - Hydrogen turbine generation is required in Victoria in the Base Case in order to supply demand in this region after/during the closure of brown coal and relatively lower interconnection to the rest of the mainland.
- Similar to the Step Change scenario, more renewable build in the REZs with the unlocked transmission capacity due to VNI West Option 3A is forecast to result in less build in some other REZs which is required in the Base case. This is forecast to result in REZ transmission cost savings.
    - It is forecast that with VNI West Option 3A generally more wind and solar is built in Western Victoria (V3) REZ, while Murray River (V2) and South West NSW (N5) REZs are forecast to have more solar build with this option in place. In addition, more renewable is forecast to be built in high quality REZs, mostly in Central West Orana (N3).
    - On the other hand, it is forecast VNI West Option 3A reduces the capacity needed in the remaining Victorian REZs, as well as REZs in other regions. This is forecast to result in REZ transmission cost savings in these REZs.

4.5 Market modelling outcomes for Option 5

This section provides market modelling results for VNI West Option 5 across all three modelled scenarios. Generally, Option 5 is forecast to have relatively similar trend in gross market benefits to Option 3A. The key differences in forecast outcomes are the level of resource sharing between Victoria and NSW as well as the renewable build in Western Victoria (V3) and Murray River (V2) REZ, all driven by the input assumptions for this option which have been derived by AVP and Transgrid through power system analysis.

4.5.1 Step Change Scenario

The forecast cumulative gross market benefits for Option 5 in the Step Change scenario are shown in Figure 17. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 5 and Base Case in this scenario are shown in Figure 18 and Figure 20, respectively. NEM capacity forecast for this option is also provided in Figure 18.

Figure 17: Forecast additional cumulative gross market benefits for Option 5 relative to Base Case under the Step Change scenario, millions real June 2021 dollars discounted to June 2021 dollars

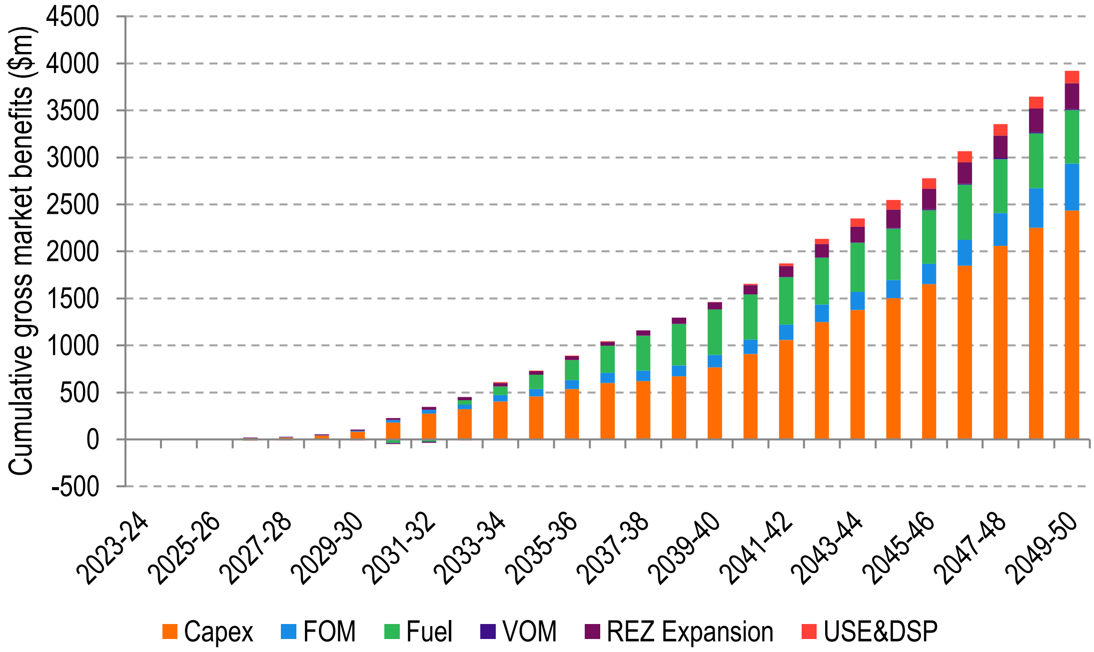


Figure 18: Forecast NEM capacity for Option 5 in the Step Change scenario

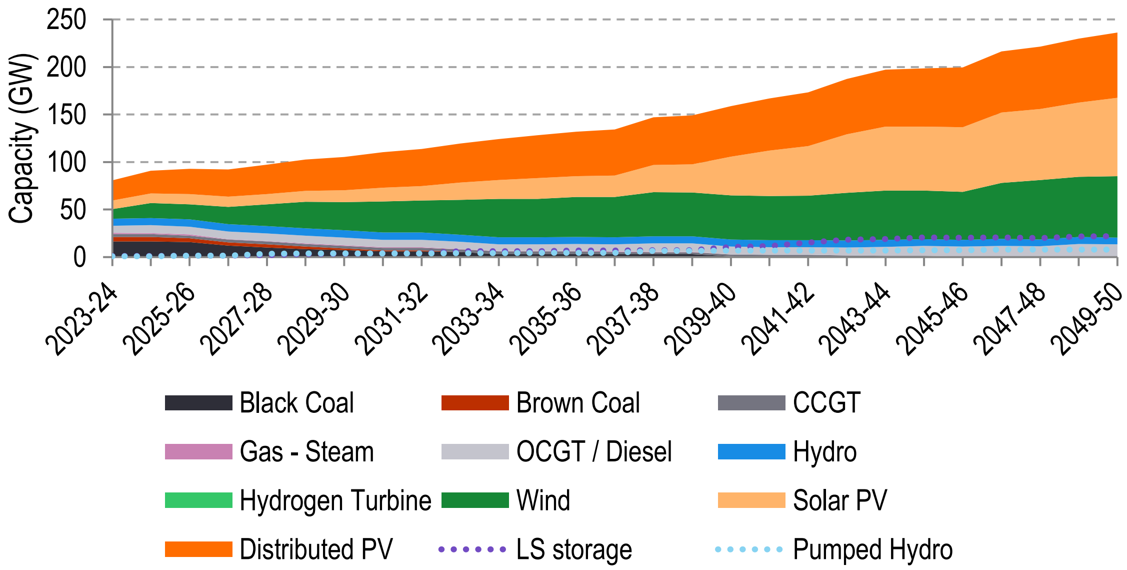


Figure 19: Difference in NEM capacity forecast between Option 5 and Base Case in the Step Change scenario

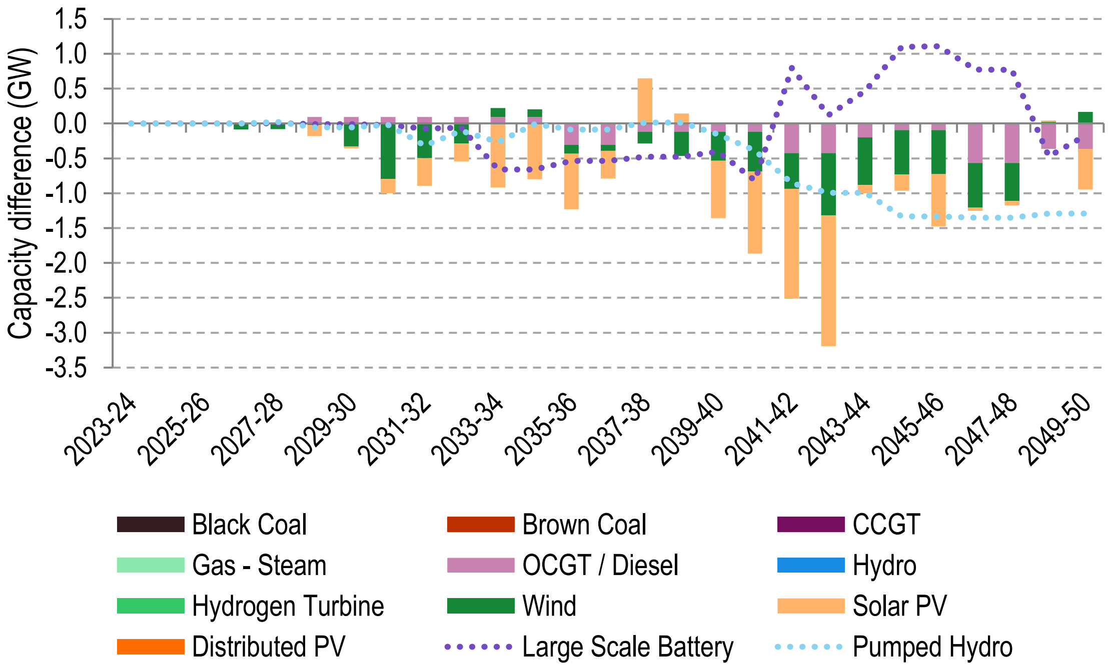
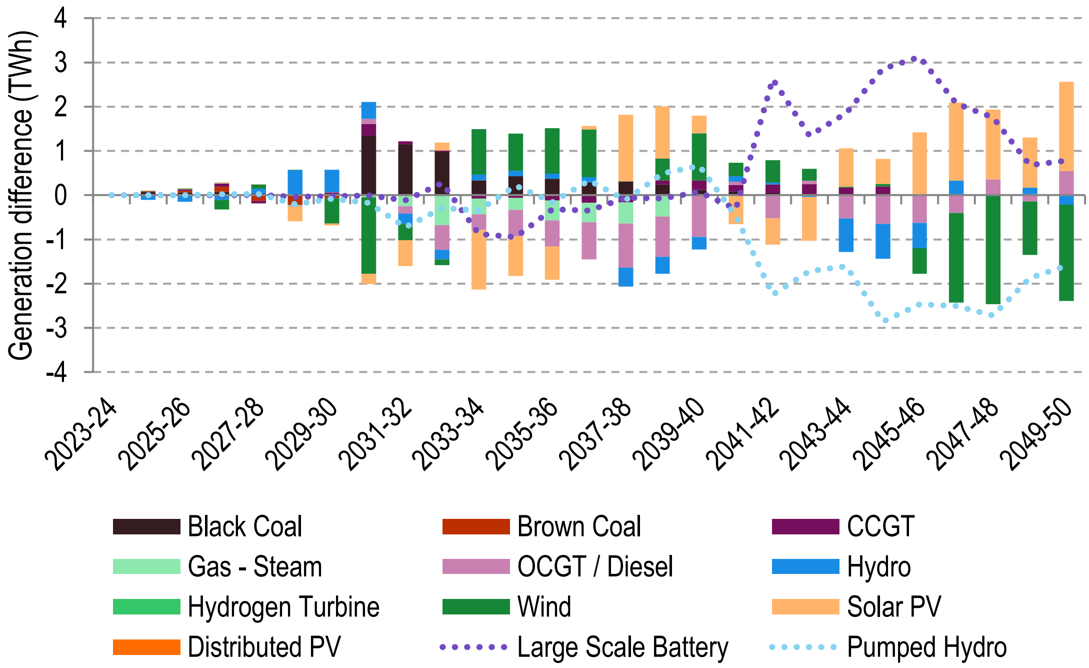


Figure 20: Difference in NEM generation forecast between Option 5 and Base Case in the Step Change scenario



Capex savings are forecast to account for the major share of estimated benefits, followed by fuel costs, FOM and REZ transmission expansion savings.

- VNI West Option 5 is forecast to generally avoid PHES investment and to a smaller extent gas capacity in the NEM. It is also forecast that this option results in deferring some wind and solar capacity investment. The capacity avoided and deferred is expected to result in capex and FOM cost savings.
    - As with Option 3A, without VNI West Option 5, generally extra solar capacity in combination with storage, and in later years peaking gas is required to supply Victorian demand in this region. In addition, generally more solar, storage and to some extent wind

is required in the other southern regions of Tasmania and South Australia in the Base Case.

- ► With VNI West Option 5, while there is still significant capacity investment in all regions (see Figure 18), some investment is forecast to shift to solar, storage and in later years wind in NSW. This option is also forecast to enable generation diversity in the NEM, as well as more efficient utilisation of Snowy 2.0, all resulting in less capacity, including storage, required in Victoria.
- ► Particularly, similar to the Base Case, the recently announced Victorian emissions and renewable targets are overachieved in Victoria in this option. The recently announced storage target in Victoria of 6.3 GW 2035 is nearly met, though short by 100 MW. For the further detail, refer to Appendix A.
- ► Although to a smaller extent than Option 3A, as provided by Transgrid and AVP, VNI West Option 5 is also considered to provide relatively high transmission capacity to the Western Victoria (V3) REZ which is forecast to unlock significant additional wind build in this REZ relative to the Base Case. This is forecast to displace investment in wind capacity in other REZs within Victoria and NSW.
- ► Overall, the amount of forecast capacity investment is also lower with VNI West Option 5 due to improved access to higher capacity factor REZs and reduced forecast spill. Across the NEM, VNI West Option 5 is forecast to reduce solar spill volume by 3% and wind spill volume by 7% relative to the Base Case. However, similar to Option 3A, wind and solar spill between the Base Case and Option 5 depend on some other factors such as the amount of new capacity in each REZ and each region.

- ► VNI West Option 5 is forecast to avoid peaking gas generation in Victoria which results in fuel cost savings. The Base Case is forecast to require some gas generation, particularly in Victoria, after the brown coal retirements while there is relatively lower interconnection to the rest of the mainland.
- ► As advised by Transgrid and AVP, VNI West Option 5 is associated to unlock transmission capacity for the South West NSW (N5), Murray River (V2) and Western Victoria (V3) REZs. As a result, a shift in investment in renewables towards these REZs is forecast, with an associated reduction in investment in renewable capacity in REZs which need transmission upgrades in the Base Case. This results in expected REZ transmission cost savings.
    - ► It is forecast that with VNI West Option 5 generally more wind and in later years more solar is built in Western Victoria (V3), while Murray River (V2) is forecast to build more solar. South West NSW (N5) is generally expected to build more solar and to a smaller extent wind in later years, with Option 5 in place.
    - ► In addition, with the diversity of resources and inter-regional sharing provided by this option, more investment in higher quality REZs such as Central West Orana (N3) and Darling Downs (Q8) is forecast and used to support Victoria as required.
    - ► On the other hand, it is forecast VNI West Option 5 reduces the capacity needed in the remaining Victorian REZs as well as REZs in other regions. As a result, REZ transmission cost savings are forecast in these REZs. Despite this avoided or deferred capacity, renewable energy targets, including Queensland announced targets, are forecast to be met (see Appendix A).

4.5.2 Progressive Change Scenario

The forecast cumulative gross market benefits for VNI West Option 5 in the Progressive Change scenario are shown in Figure 21. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 5 and Base Case in this scenario are shown in Figure 22 and Figure 23, respectively.

Figure 21: Forecast additional cumulative gross market benefit for Option 5 relative to Base Case under the Progressive Change scenario, millions real June 2021 dollars discounted to June 2021 dollars

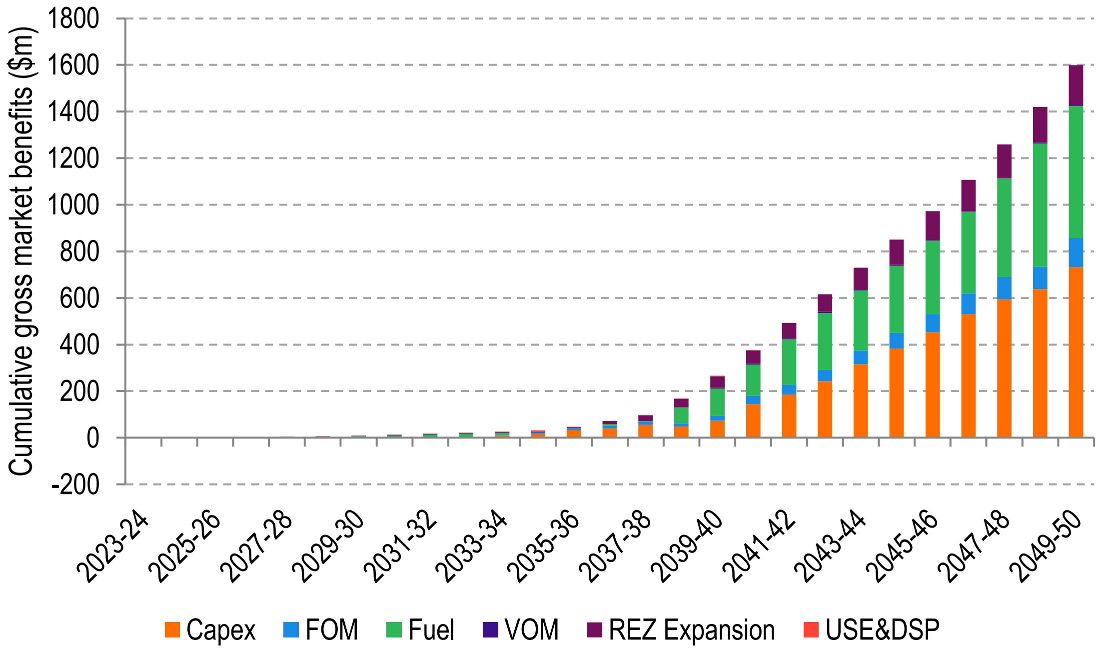


Figure 22: Difference in NEM capacity forecast between Option 5 and Base Case in the Progressive Change scenario

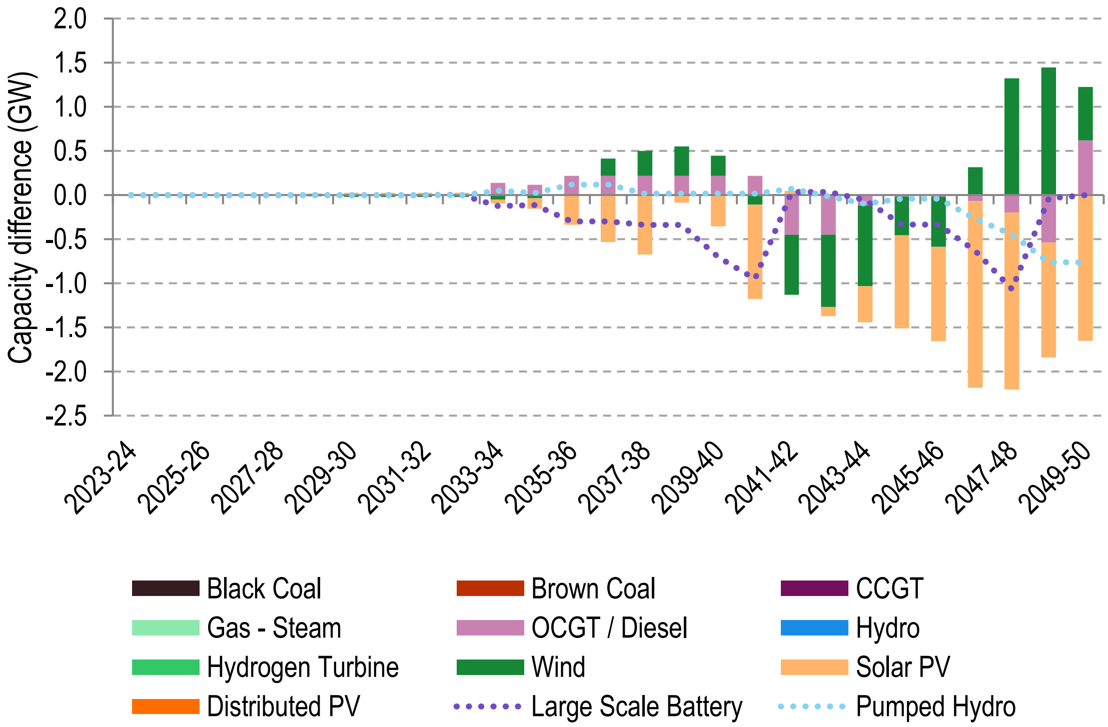
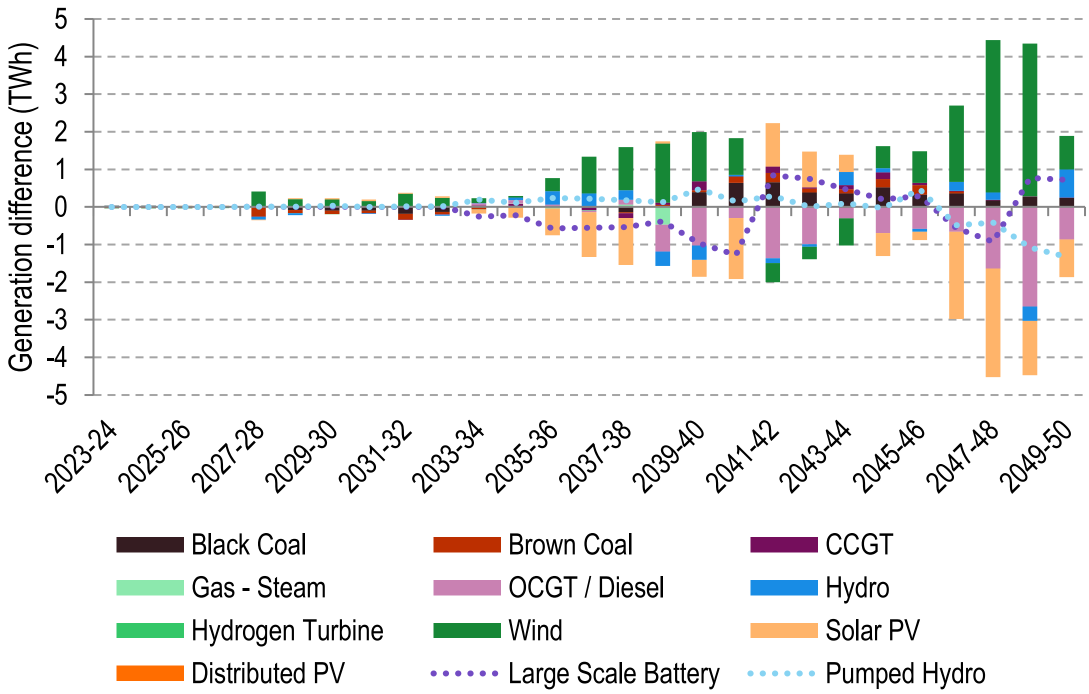


Figure 23: Difference in NEM generation forecast between Option 5 and Base Case in the Progressive Change scenario



The largest sources of forecast gross market benefits in this scenario are capex savings from deferred and avoided capacity build, followed by reduced fuel costs as well as reduced REZ transmission expansion costs.

- The Progressive Change scenario forecasts significantly lower benefits than the Step Change scenario due to the assumed lower pace of demand growth, less restrictive carbon budget and the later 2038-39 timing of VNI West commissioning.
- Similar to the Step Change scenario, in the Progressive Change scenario VNI West Option 5 is forecast to generally result in avoiding some solar and PHES, though it is also forecast that this option results in changing of the timing of wind and gas build, and specifically build more wind in the last few years of the study. Overall, this is forecast to result in capex and FOM cost savings.
    - With VNI West Option 5, and with the assumption of unlocked transmission capacity for the REZs as well as more interconnection with NSW, more wind investment is forecast in Victoria which reduces the need for investment of solar and storage in this region. In addition, less gas build is forecast in this region with Option 5 in place. Furthermore, generally less wind, solar and storage build is forecast in other regions such as Tasmania, South Australia and Queensland. However, with this option in place, generally more solar and wind investment is forecast in NSW.
    - The Progressive Change scenario is forecast to have less renewable spill compared with the Step Change Scenario. However, similar to the Step Change scenario it is forecast that with the more interconnection and REZ access enabled by VNI West Option 5 for Victoria to NSW and the rest of the mainland, resources are more efficiently utilised. Overall across the NEM, this option is forecast to reduce solar spill by 3% and wind spill by 9% relative to the Base Case.
- Fuel cost savings are forecast to be a greater source of market benefits in the Progressive Change scenario than Step Change scenario. These savings are mainly due to a forecast reduction in gas generation in Victoria with VNI West Option 5.
- More renewable build is expected in the REZs with the associated unlocked transmission capacity due to VNI West Option 5. This results in less renewable generation built in some other REZs which is required in the Base case. This is forecast to result in REZ transmission

cost savings. This trend is similar to Step Change scenario, but to a smaller extent and only occurs from around the mid-2030s.

- It is forecast that with VNI West Option 5 generally more wind is built in Western Victoria (V3) REZ, while Murray River (V2) and South West NSW (N5) REZs are forecast to build more solar, with some extra wind build in South West NSW (V5).
- On the other hand, it is forecast VNI West Option 5 reduces the capacity needed in the remaining Victorian REZs and to a smaller extent REZ in other regions. This is forecast to result in REZ transmission cost savings in these REZs.

4.5.3 Hydrogen Superpower Scenario

The forecast cumulative gross market benefits for VNI West Option 5 in the Hydrogen Superpower scenario are shown in Figure 24. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 5 and the Base Case in this scenario are shown in Figure 25 and Figure 26, respectively.

Figure 24: Forecast cumulative gross market benefit for Option 5 relative to Base Case under the Hydrogen Superpower scenario, millions real June 2021 dollars discounted to June 2021 dollars

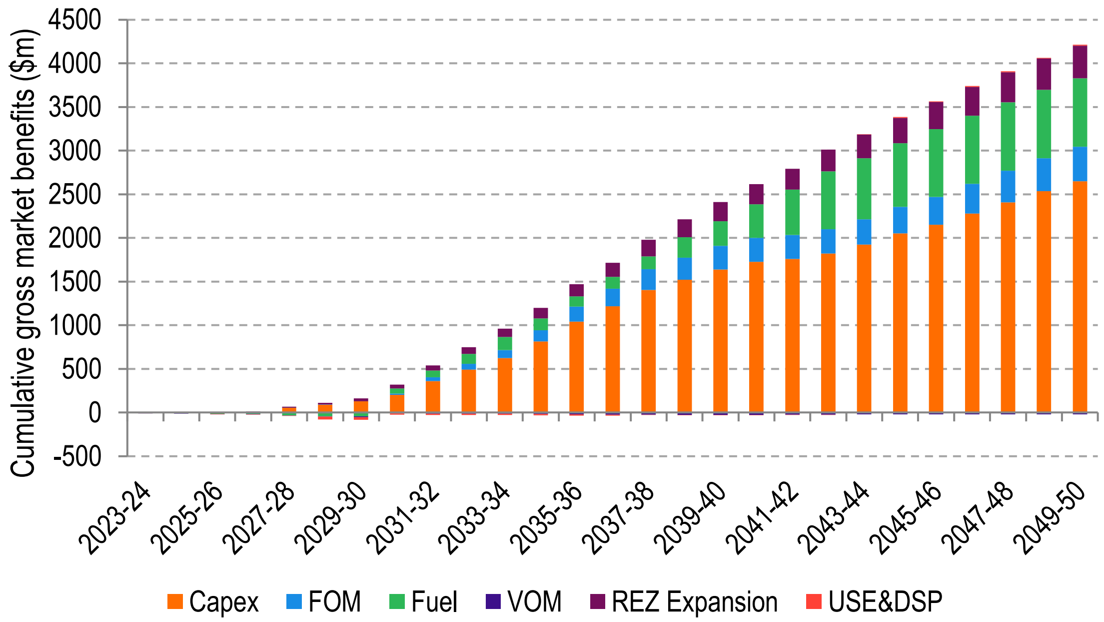


Figure 25: Difference in NEM capacity forecast between Option 5 and Base Case in the Hydrogen Superpower scenario

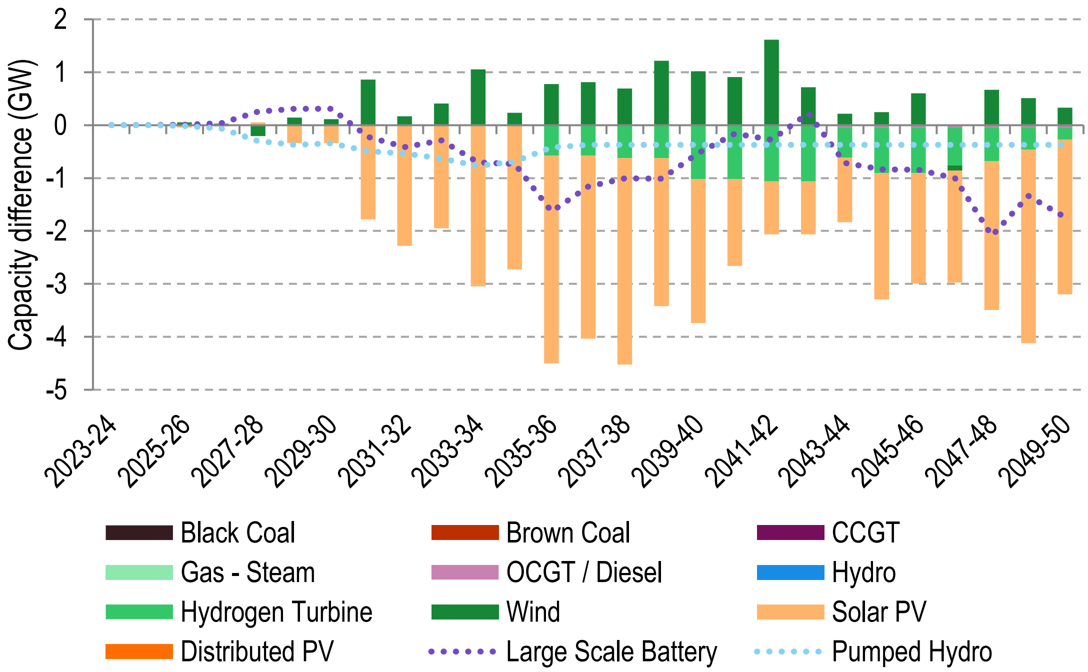
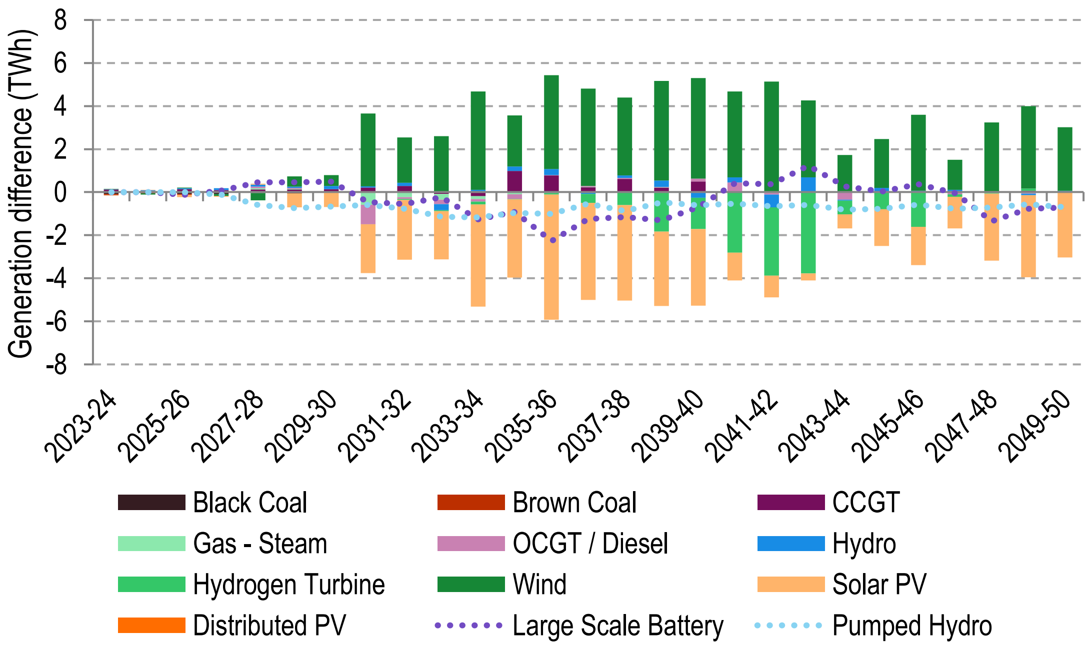


Figure 26: Difference in NEM generation forecast between Option 5 and Base Case in the Hydrogen Superpower scenario



The most significant source of forecast gross market benefits in this scenario are derived from capex and FOM cost savings, followed by fuel and REZ transmission expansion cost savings. The timing and source of these benefits are attributable to the following:

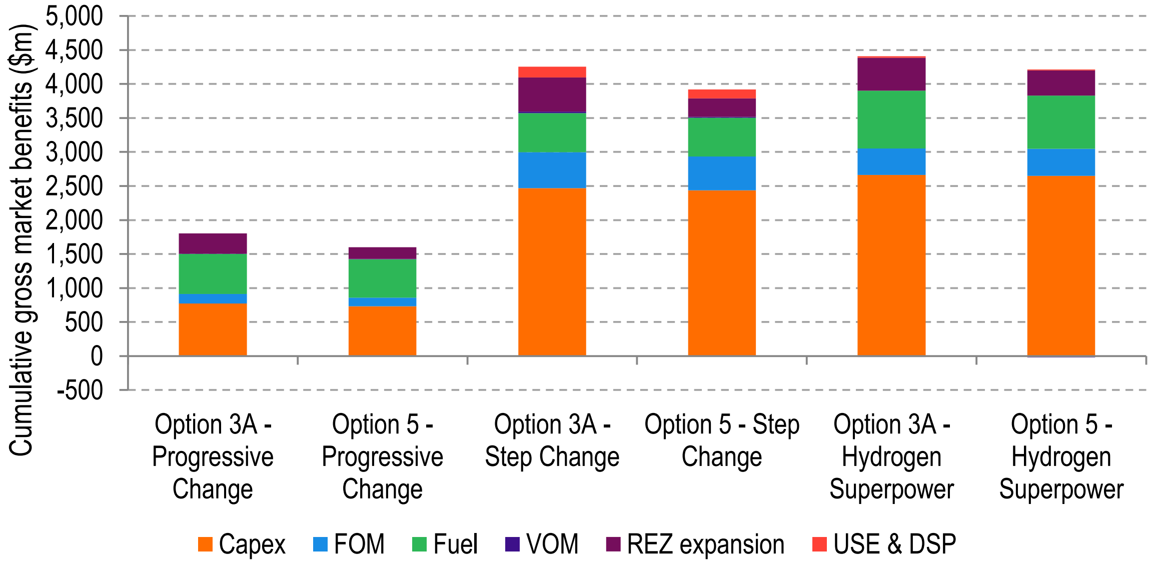
- The Hydrogen Superpower scenario is forecast to have the highest benefits among all scenarios, due to more aggressive assumptions, particularly demand growth and a more restrictive carbon budget.
- Similar to the Step Change scenario, in the Hydrogen Superpower scenario VNI West Option 5 is expected to avoid some solar and storage investment. In addition, Hydrogen Turbine capacity is avoided while some extra wind capacity is forecast. Overall, these capacity changes results in capex and FOM cost savings.

  - With the assumed significant demand growth as well as rapid coal retirement in this scenario based on 2022 ISP, and without an increase in the interconnection, significantly more solar capacity in combination with storage, and in later years hydrogen turbines are required to supply demand in Victoria.
  - With VNI West Option 5, some of this capacity in Victoria is forecast to be avoided and instead replaced by some extra solar and storage in NSW and South Australia, although at a lower capacity. In addition, with the associated increase transmission capacity in the Western Victoria (V3) REZ, significant wind investment is forecast in this REZ replacing mostly solar capacity elsewhere in Victoria.
  - This option is forecast to enable generation diversity in the NEM, as well as more efficient utilisation of Snowy 2.0, all resulting in less capacity, including storage, required in Victoria.
  - Furthermore, with the assumed significant hydrogen demand growth in Tasmania in the last few years, it is forecast that significant solar and storage is required in this region in the Base Case. Some of this is forecast to be avoided with VNI West Option 5, as it is forecast to enable more renewable generation in Victoria and also other mainland regions.
  - Due to forecast significant renewable investment in this scenario, considerable renewable spill is forecast, which is significantly more than other scenarios. However, similar to the other scenarios, with more interconnection between Victoria and NSW enabled by VNI West Option 5, it is forecast that resources are more efficiently utilised. Across the NEM, VNI West Option 5 is forecast to reduce solar spill by 1% and wind spill volume by 4% relative to the Base Case.
- It is forecast that VNI West Option 5 results in avoiding Hydrogen Turbine generation in Victoria which results in fuel cost savings. Without VNI West Option 5 it is forecast that hydrogen turbines are required to meet demand in Victoria while also adhering to the more restrictive carbon budget in this scenario.
- With VNI West Option 5 REZs impacted by the option have increased transmission capacity. This is forecast to result in less capacity being built in other REZs which is required in the Base case. This is forecast to result in REZ transmission cost savings.
  - With VNI West Option 5 more wind and solar is forecast to be built in Western Victoria (V3), while Murray River (V2) and South West NSW (N5) are forecast to build more solar. In addition, more renewable capacity is forecast to be built in high quality REZs, mostly in Central West Orana (N3) but to a lower extent in other regions such as South Australia REZs.
  - Additionally, it is forecast VNI West Option 5 reduces the capacity needed in the remaining Victorian REZs, particularly Gippsland solar, as well as REZs in other regions. This is forecast to result in REZ transmission cost savings in these REZs.

4.6 Analysis of Option 3A vs Option 5

This section discusses the difference in gross market benefits in the core runs between Option 3A and Option 5. Figure 27 shows the categories of benefits for both options in all scenarios.

Figure 27: Forecast gross market benefits for Option 3A and Option 5 in the Step Change scenario



The following summarises the differences between Option 3A and Option 5 focusing on the Step Change scenario. The largest source of difference in forecast gross market benefits between the two options are REZ expansion cost savings. Option 3A has increased forecast REZ expansion savings compared to Option 5 due to the following:

- Option 3A is assumed to increase the Western Victoria (V3) REZ transmission limits to a larger extent than Option 5. This is forecast to allow increased capacity to be installed in this REZ compared to Option 5, as shown in Figure 28. This reduces the need for investment in transmission upgrades for other REZs.
- As advised by Transgrid and AVP, The Murray River (V2) REZ transmission limit is also considered to have more unlocked transmission capacity in Option 3A than Option 5 (Option 3A increases the Murray River transmission limit by 1,600 MW, whereas Option 5 increases it by 850 MW). The difference in forecast capacity outcomes between the two options in the Murray River REZ is shown in Figure 29. Again, this additional capacity is forecast to offset the need for investment in transmission upgrades for other REZs.

Figure 28: Forecast new entrant capacity in Western Victoria REZ (V3) - Step Change scenario

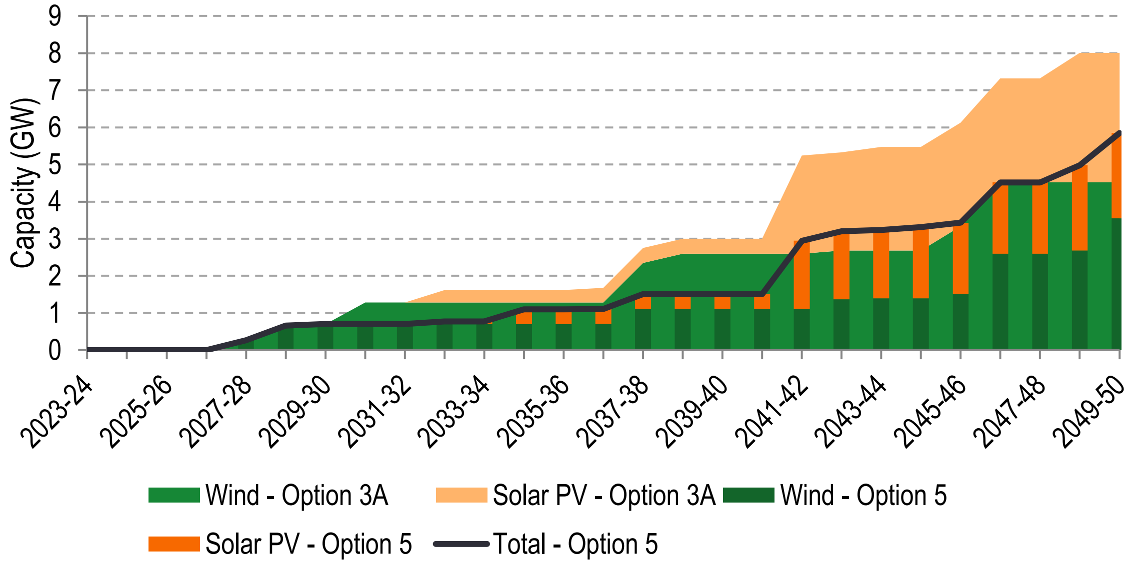
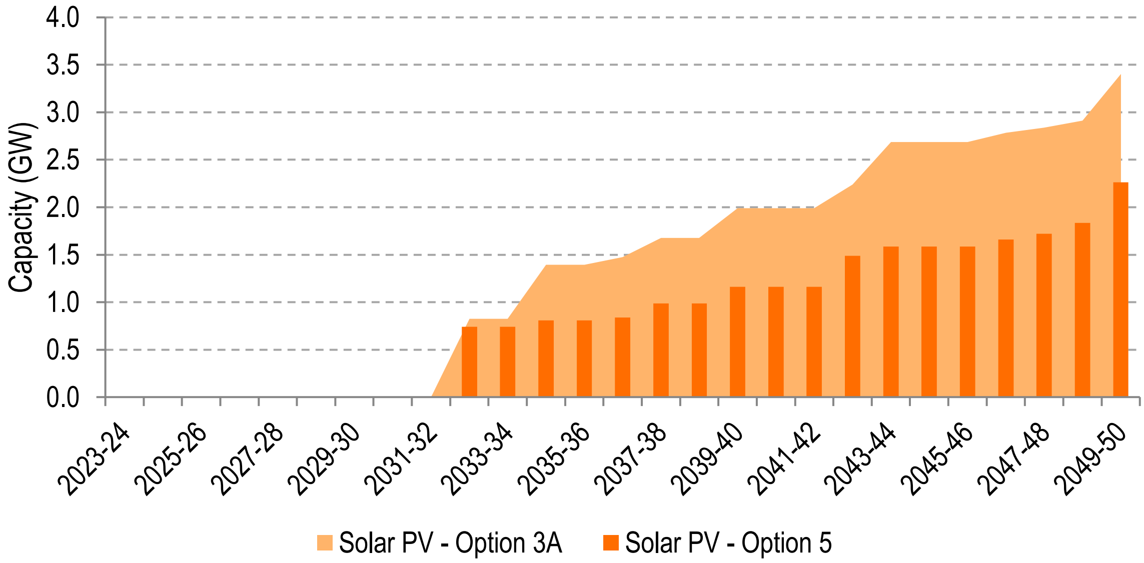


Figure 29: Forecast new entrant capacity in Murray River REZ (V2) - Step Change scenario



In the Progressive Change scenario, the forecast gross market benefits for Option 5 compared to Option 3A is forecast to decrease by $199m. The reduction in difference between the gross market benefits between the two options can be attributed to the following:

- Up until at least 2030 investment in new generation capacity is largely driven by state-based energy policies such as QRET, VRET, VRET2, TRET and the NSW Electricity Infrastructure Roadmap. This means that the capacity outlook between options in this scenario are similar up until 2030.
- The additional transmission capacity that is unlocked in the Western Victoria (V3) REZ with Option 3A in 2027-28 is therefore not expected to be as beneficial as it was in the Step Change scenario where investment was at an accelerated rate and driven by increased demand and a more restrictive carbon budget.

In the Hydrogen Superpower scenario, the reduction in forecast gross market benefits for Option 5 compared to Option 3A is $201m, which is again slightly below the difference in the Step Change scenario. REZ expansion savings, followed by fuel cost savings are the main sources of additional benefits associated with Option 3A compared to Option 5. These are attributed to:

- REZ expansion savings are forecast to accrue from 2027-28 due to the increased transmission capacity for Western Victoria (V3) REZ which reduces investment in upgrading transmission in other REZs.
- Additional fuel cost savings are forecast as a result of less hydrogen turbine generation forecast with Option 3A. This is forecast to be due to additional low-cost wind and solar capacity being installed in Victoria due to increased Western Victoria (V3) and Murray River (V2) REZ transmission limits.

4.7 Flow duration curves – Step Change

As illustrated in Figure 45, a nodal model is applied in the modelling which covers the major substations in Victoria and southern NSW. DC load flow is applied for the nodal model, considering the limitations of the modelled lines. In addition, several cut-set constraints are modelled in order to capture the stability and N-1 thermal constraints for this area (list of cut-set constraints and their limits are shown in Table 17, Table 18 as well as Table 19 and Table 20).

This section provides the market modelling outcomes for the key binding cut-set constraints in the flow path of VNI West, namely VNI and SWNSW to Wagga, in the Step Change scenario. For the purpose of this Report, "VNI flow" refers to the aggregate flow across this cut-set.

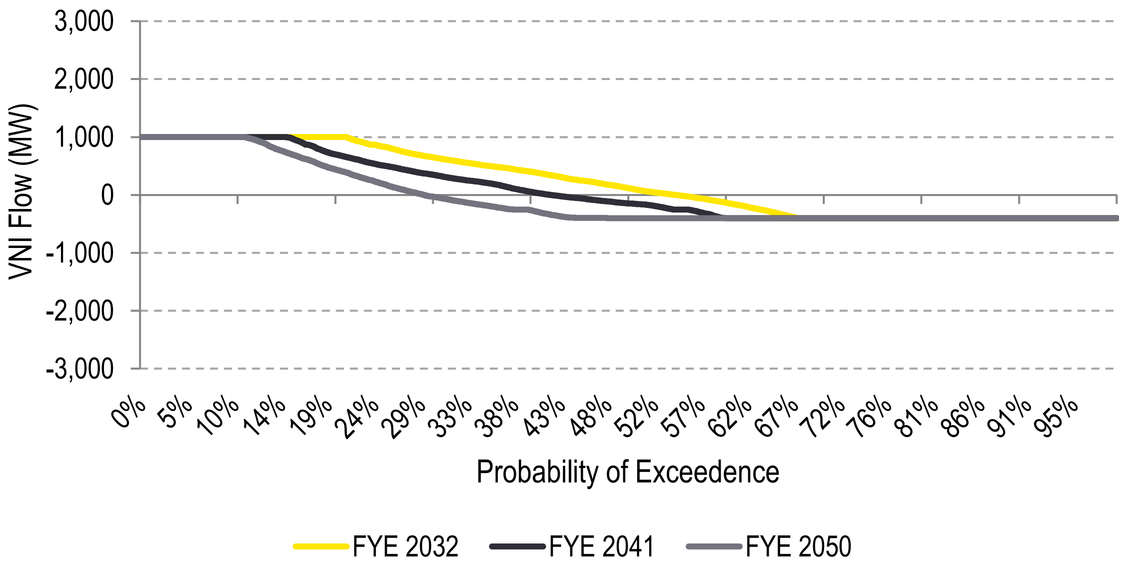
4.7.1 VNI duration curves

This section discusses the VNI flow expected in the Base Case, Option 3A and Option 5 across three selected financial years after VNI West is commissioned in the Step Change scenario. In this section the export direction is defined as flow from Victoria to NSW, and the import direction as flow from NSW to Victoria.

Three annual duration curves for VNI in the Base Case are shown in Figure 30. As VNI West is not assumed to be commissioned in the Base Case the flow is limited to 1,000 MW in the export direction, and 400 MW in the import direction. In the financial year 2031-32 VNI is at the import limit approximately 35% of the time, and at the export limit approximately 20% of the time. From the 2030s through to 2050, the VNI flow is forecast to trend towards importing more, with the import limit being reached approximately 55% of the time in financial year 2049-50.

VNI is expected to become increasingly importing as the limited onshore resources in Victoria is forecast to become fully utilised and brown coal is forecast to retire, so that Victoria is expected to rely more on imports from other NEM regions (such as NSW) to meet growing demand.

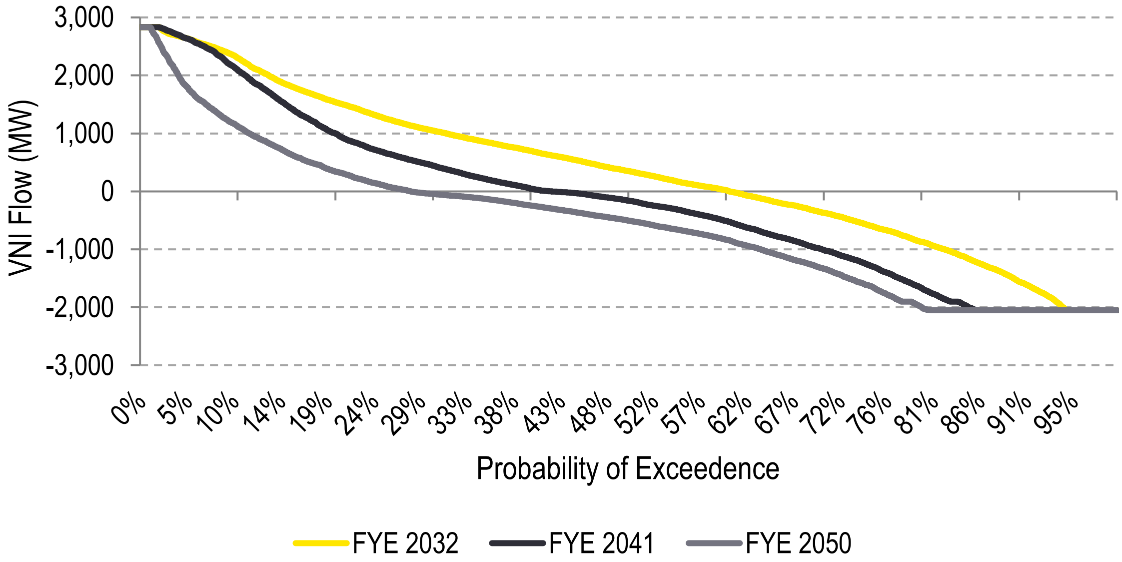
Figure 30: VNI duration curve in the Step Change scenario for the Base Case



Below in Figure 31 three annual duration curves are shown for the VNI with VNI West Option 3A commissioned. Compared to Figure 30 the VNI limits in both directions have increased, the full range of the upgraded interconnector is expected to be utilised, and congestion on the interconnector is expected to be relieved compared to the Base Case. In financial year 2031-32 the interconnector is at the import limit approximately 5% of the time, compared to 35% In the Base Case.

The VNI is expected to import more generation into Victoria in the later years of the study, for the same reasons as was mentioned above for the Base Case but is forecast to be constrained on import far less.

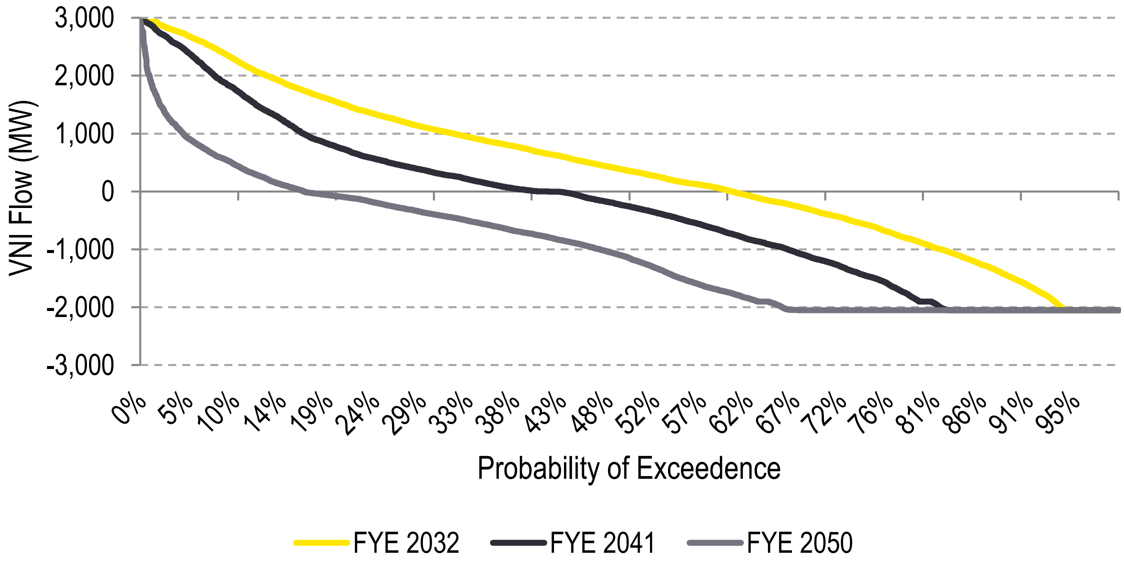
Figure 31: VNI duration curve in the Step Change scenario for Option 3A



Three annual duration curves are shown in Figure 32 for VNI with VNI West Option 5 commissioned. The overall trend, that VNI becomes increasingly importing to Victoria over the modelling horizon again is expected to hold true. However, compared to Option 3A, Option 5 is forecast to import more into Victoria in the later years of the model. In financial year 2049-50 VNI is expected to be at its import limit approximately 35% of the time and importing to Victoria at any level approximately 80% of the time. This is compared to Option 3A being at its import limit around 20% of the time and importing at any level around 70% of the time.

Increased imports into Victoria with Option 5 compared to Option 3A is primarily due to reduced transmission capacity for the Western Victoria (V3) and Murray River (V2) REZs in Option 5 compared with Option 3A. Reduced transmission capacity is forecast to reduce the total capacity of new generation that is installed in Victoria, and results in more generation being imported on VNI to meet demand. Despite this increased import into Victoria with Option 5, the model still forecasts significant renewable investment in Victoria.

Figure 32: VNI duration curve in the Step Change scenario for Option 5



4.7.2 SWNSW to Wagga flow duration curve

SWNSW to Wagga covers the equivalenced lines from Darlington Point to Wagga Wagga and the PEC lines from Dinawan to Wagga Wagga, all shown as Darlington Point and Dinawan to Wagga Wagga in Figure 45, and the limits are provided in Table 23. This section provides forecast outcomes of the flow duration curves for this cut-set. Figure 33, Figure 34 and Figure 35 show the flow duration curve of the cut-set for the Base Case, Option 3A and Option 5. The modelling forecasts that while the flow towards Wagga Wagga (which is forecast to supply load in NSW load centres as well as Snowy 2.0 pumping) is capped in the Base Case, particularly in later years of the study, VNI West Option 3A and Option 5 are forecast to unlock the transmission network limitation in the area and allow more flow towards Wagga Wagga.

Figure 33: SWNSW to Wagga Wagga flow duration curves - Base Case Step Change scenario

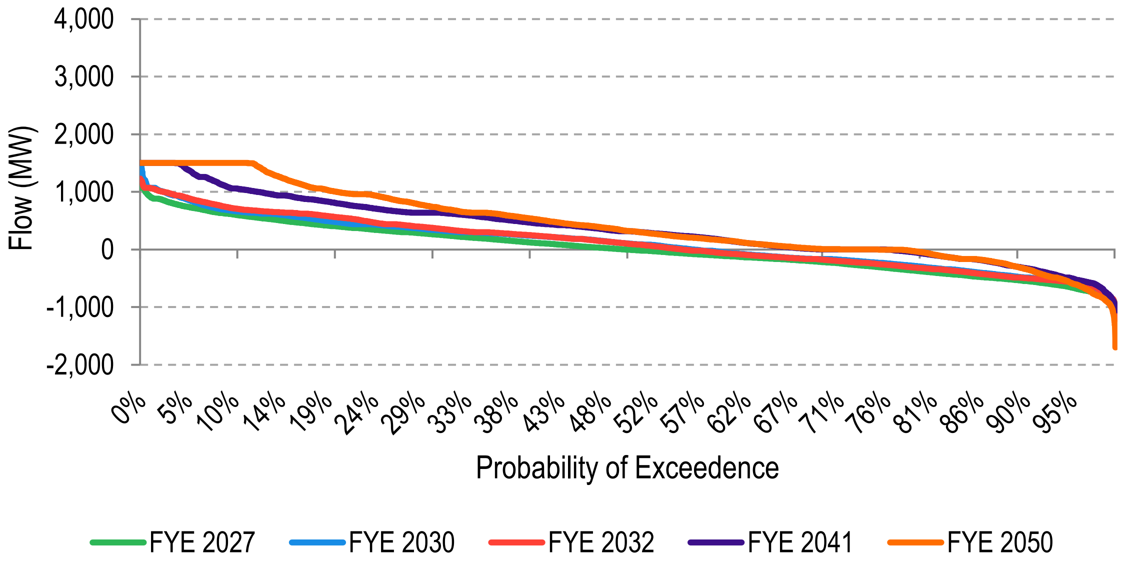


Figure 34: SWNSW to Wagga Wagga flow duration curves - Option 3A Step Change scenario

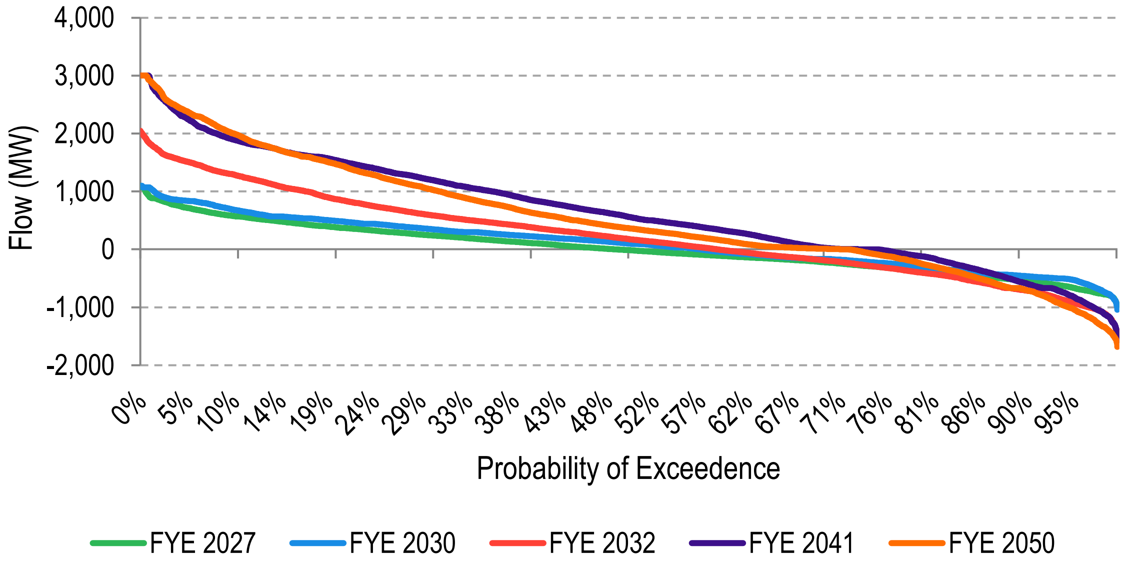
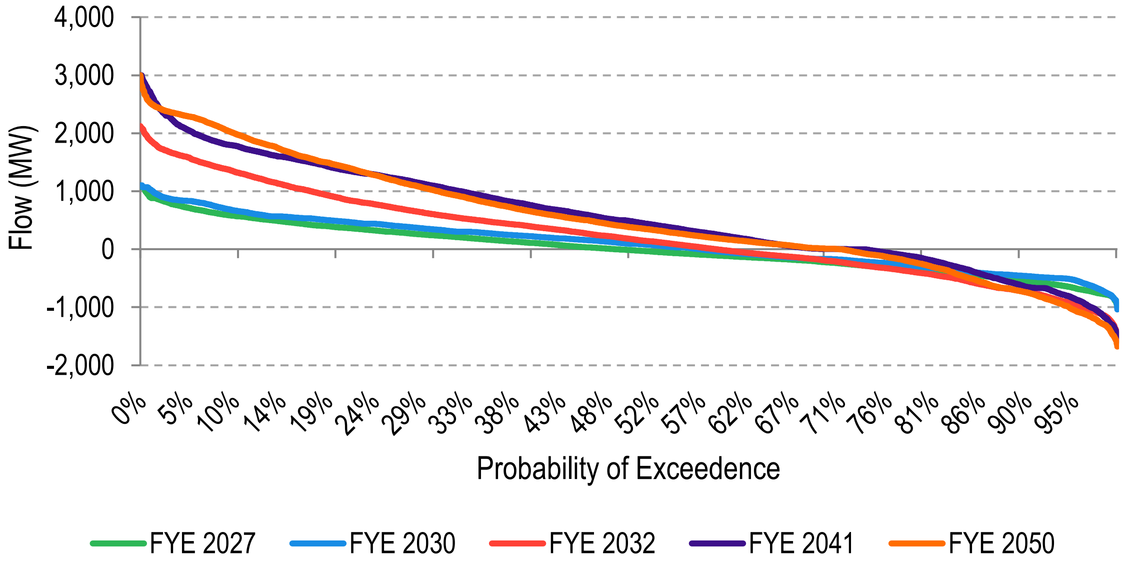


Figure 35: SWNSW to Wagga Wagga flow duration curves - Option 5 Step Change scenario



4.8 Market modelling outcomes for sensitivities

Sensitivities have been modelled to assess the impact of offshore wind on VNI West Option 3A and Option 5 (Step Change scenario) as well as the gross market benefits relative to an alternative counterfactual Base Case without WRL (all options, all scenarios), and a combination of the two sensitivities (Option 3A and Option 5, Step Change scenario).

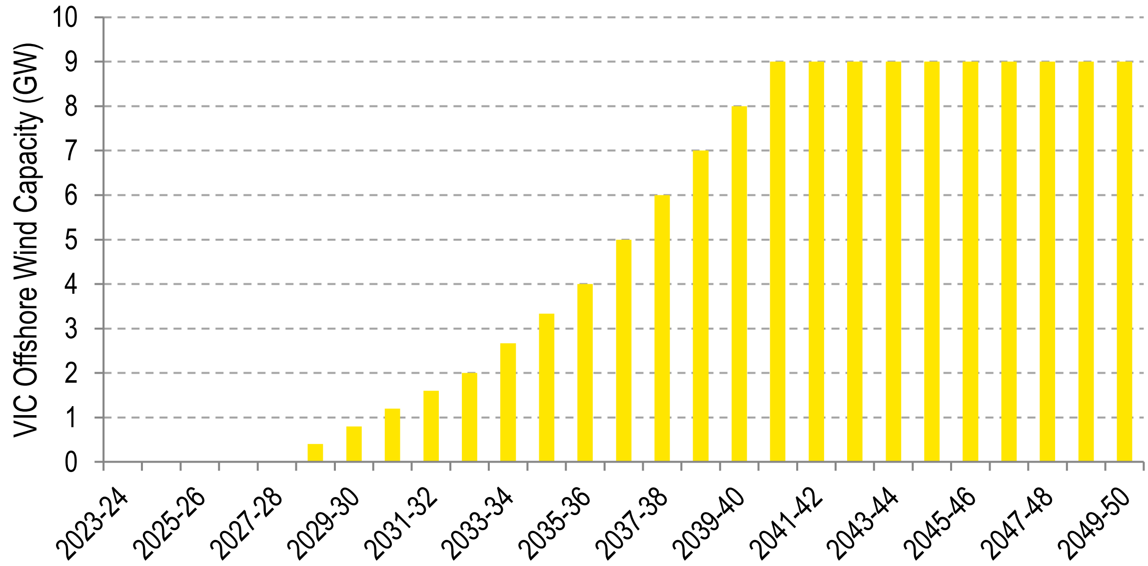
4.8.1 Offshore wind sensitivity - Step Change scenario

This section summarises the modelling outcomes for VNI West Option 3A and Option 5 gross market benefits relative to the Base Case in the offshore wind sensitivity.

The offshore wind sensitivity was implemented by committing offshore wind in Victoria at a rate consistent with the capacities outlined in the Victorian Governments offshore wind directions paper[21] in the Base Case and VNI West options. Figure 36 shows the rate at which offshore wind was installed in this sensitivity. Two offshore wind locations were considered, Gippsland and Portland, with the model building in each location at least cost in the Base Case and VNI West options to meet the minimum targets defined in each year (i.e. the capacity of offshore wind in the Base Case and with VNI West options was the same but the distribution between the two locations could differ if it is least-cost to do so).

[21] Victorian Government, *Victoria's Offshore Wind Policy Directions Paper*, available at: https://engage.vic.gov.au/victorias-offshore-wind-policy-directions-paper-developing-the-offshore-wind-sector accessed 25 January 2022

Figure 36: Victorian offshore wind capacity commitment schedule



The sensitivity was considered in the Step Change scenario and the forecast gross market benefits for Option 3A and Option 5 relative to the Base Case are shown in Table 9. For both Option 3A and Option 5 gross market benefits are forecast to reduce in this sensitivity relative to the core case. Note that core simulations do not enforce the offshore wind targets in Victoria as they do not meet the criteria required to be treated as committed policy, but the offshore wind build is allowed on a least-cost basis.

Table 9: Forecast gross market benefits for the offshore wind sensitivity, millions real June 2021 dollars discounted to June 2021 dollars

Option	Potential gross market benefits ($m)	
	Offshore wind sensitivity – Step Change scenario	Core – Step Change scenario
Option 3A	3,049	4,253
Option 5	3,087	3,921

4.8.1.1 Sources of market benefits

Figure 37, Figure 38 and Figure 39 display the forecast cumulative gross market benefits, NEM capacity difference and generation difference respectively for Option 3A compared to the Base Case in the offshore wind sensitivity. The results for Option 5 are provided in the accompanying results workbooks. Trends are forecast to be similar; capex and FOM cost savings, fuel cost savings and REZ expansion savings are all forecast to decrease for both options in this sensitivity compared to the core results where offshore wind is not committed.

Figure 37: Forecast cumulative gross market benefit for Option 3A relative to the Base Case in the offshore wind sensitivity in the Step Change scenario, millions real June 2021 dollars discounted to June 2021 dollars

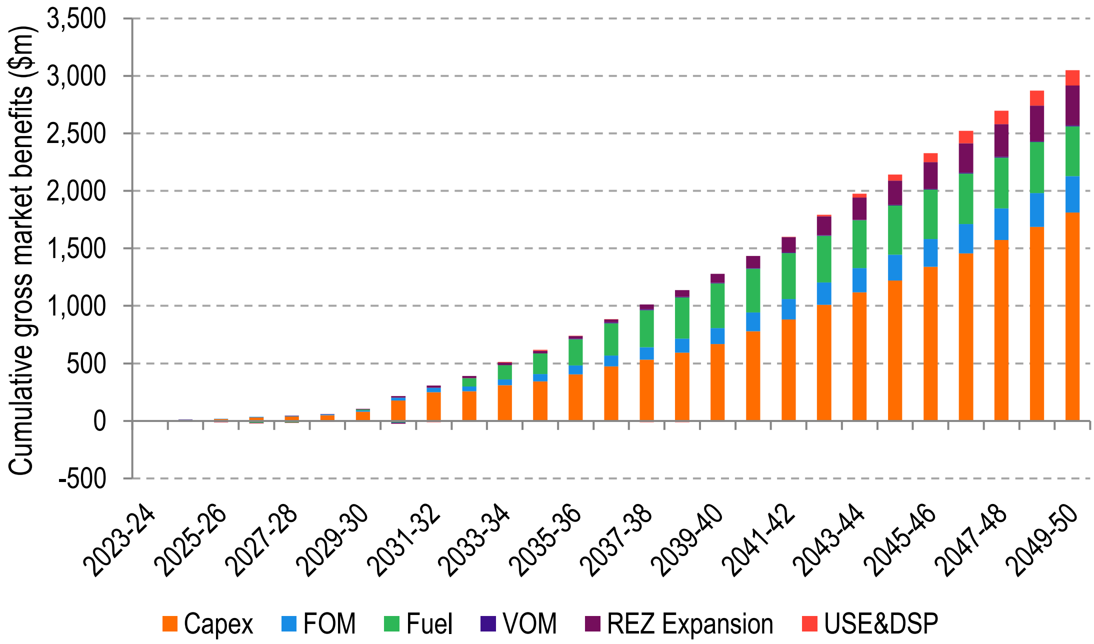


Figure 38: Difference in NEM capacity forecast for Option 3A relative to the Base Case in the offshore wind sensitivity in the Step Change scenario

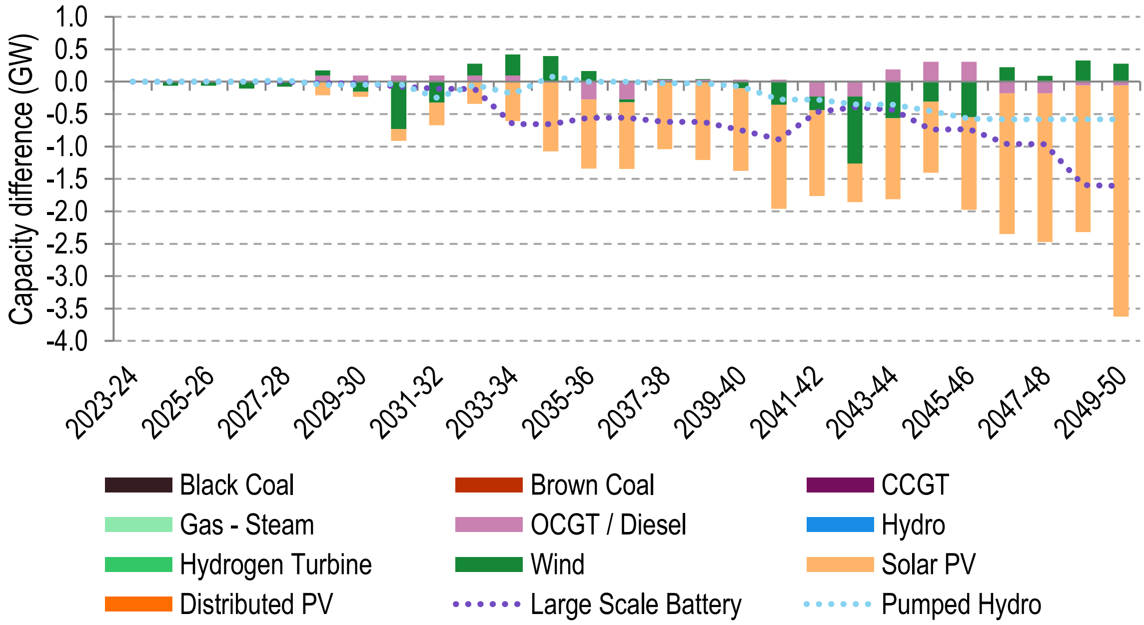
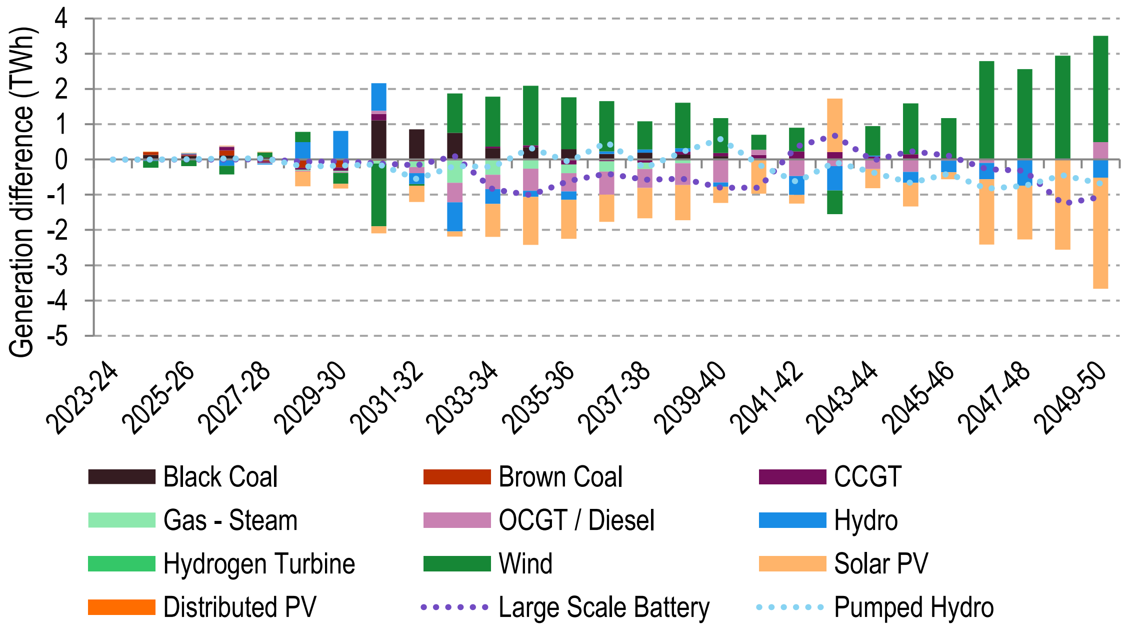


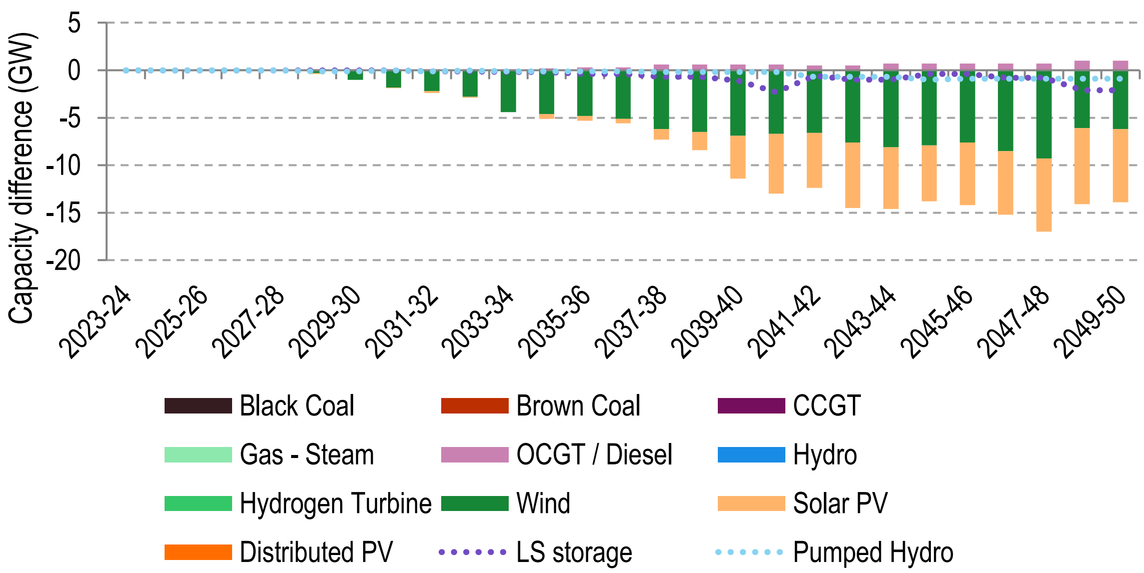
Figure 39: Difference in NEM generation forecast for Option 3A relative to the Base Case in the offshore wind sensitivity in the Step Change scenario



The reduction in the forecast benefits for Option 3A in the offshore wind sensitivity relative to the core simulation can be attributed to the following:

- Committing offshore wind capacity in Victoria reduces the amount of additional wind, solar and storage investment that is forecast to be installed at least-cost in the NEM to supply the demand in the Base Case, this is particularly true for Victoria and NSW (see Figure 40 for the NEM).
- Reducing the amount of new capacity installed in the Base Case (i.e. built at the least cost in excess of the enforced offshore wind capacity) is forecast to reduce the opportunity for VNI West to enable capital to be more efficiently allocated and shared across the NEM, particularly in NSW and Victoria.

Figure 40: Difference in the NEM non-committed (excluding the enforced offshore wind targets), new entrant capacity installed at least-cost between the offshore wind sensitivity Base Case and Core Base Case, Step Change scenario



As with the core simulation outcomes, VNI West is forecast to allow for increased generation sharing between Victoria and NSW, while also improving transmission access to some REZs. This is forecast to allow access and sharing of cheaper and more efficient resources. However, as shown above, in the case with offshore wind assumed to be committed, the need for access to these cheaper resources is reduced (although still exists) and so the expected benefits also reduce. In terms of market benefit categories:

- This is forecast to reduce expected capex and FOM cost savings of VNI West relative to the core Step Change scenario simulations.
- It is also forecast to reduce expected REZ expansion cost savings.
- Fuel cost savings are also expected to reduce relative to the core Step Change scenario simulations as enforcing offshore wind as a target reduces expected gas use in the sensitivity Base Case (relative to the core Step Change scenario Base Case), which results in reduced opportunity for fuel cost savings with VNI West in place.

4.8.1.2 Option 5 vs Option 3A in the offshore wind sensitivity

The reduction in gross market benefits for Option 5 in this sensitivity are a result of the same mechanisms discussed in Section 4.8.1.1. The following section highlights the differences between Option 3A and Option 5 in the offshore wind sensitivity.

Referring to Table 9, while both Option 3A and Option 5 are expected to have reduced forecast gross market benefits in the offshore wind sensitivity, Option 5 is now expected to have higher forecast gross market benefits compared to Option 3A. This result contrasts with the forecast in the core simulations where Option 3A had the forecast highest gross market benefits. The primary drivers for this outcome are outlined in this section.

Even though Option 3A is considered to provide significantly more transmission for Western Victoria (V3) REZ compared with Option 5 (as provided by Transgrid and AVP, see Table 10), with offshore wind committed in Victoria there is a lower need for additional new capacity in Victorian onshore REZs. It can be seen in Figure 41 and Figure 42, that the additional transmission capacity in the Western Victoria (V3) REZ for Option 3A is not utilised until late in the modelled period.

Table 10: Western Victoria REZ (V3) transmission limits

Option	Western Victoria (V3) REZ transmission limits (MW)		
	Existing	With WRL plus spur 500kV uprate	With remainder of VNI West[22]
Option 3A	650	3,240	4,640
Option 5	650	2,110	2,310

[22] For the purpose of this analysis, the spur 500kV uprate of WRL is considered part of VNI West and included in both these options. In this context, the "remainder" of VNI West is all the network infrastructure required to connect EnergyConnect (at Dinawan) to the WRL project (at either Waubra/Lexton in the case of Option 3A or Bulgana in the case of Option 5).

Figure 41: Western Victoria (V3) REZ non-committed new entrant capacity with Option 3A. offshore wind sensitivity

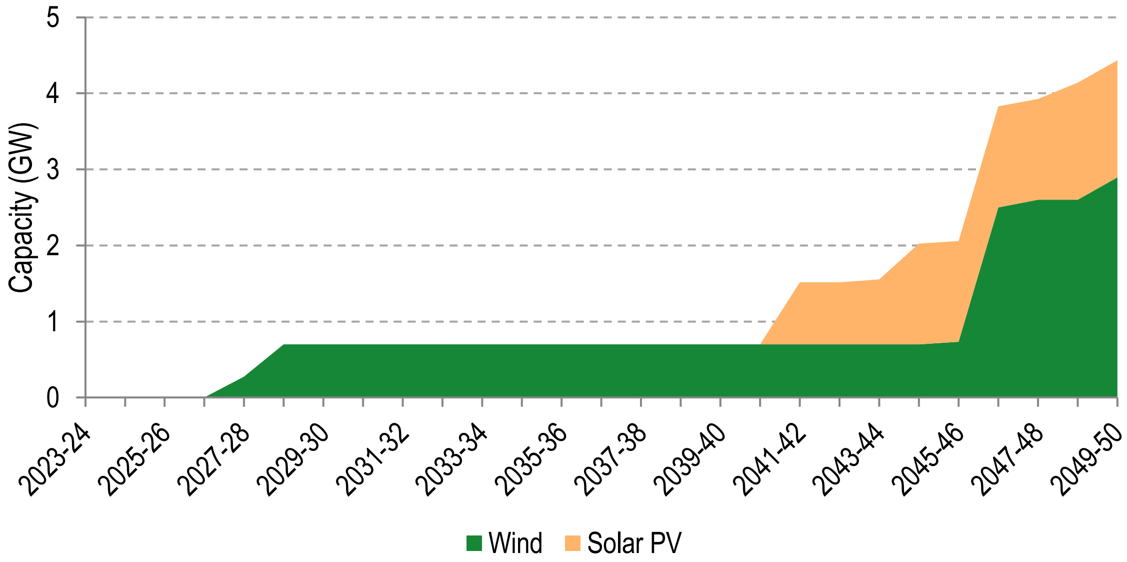
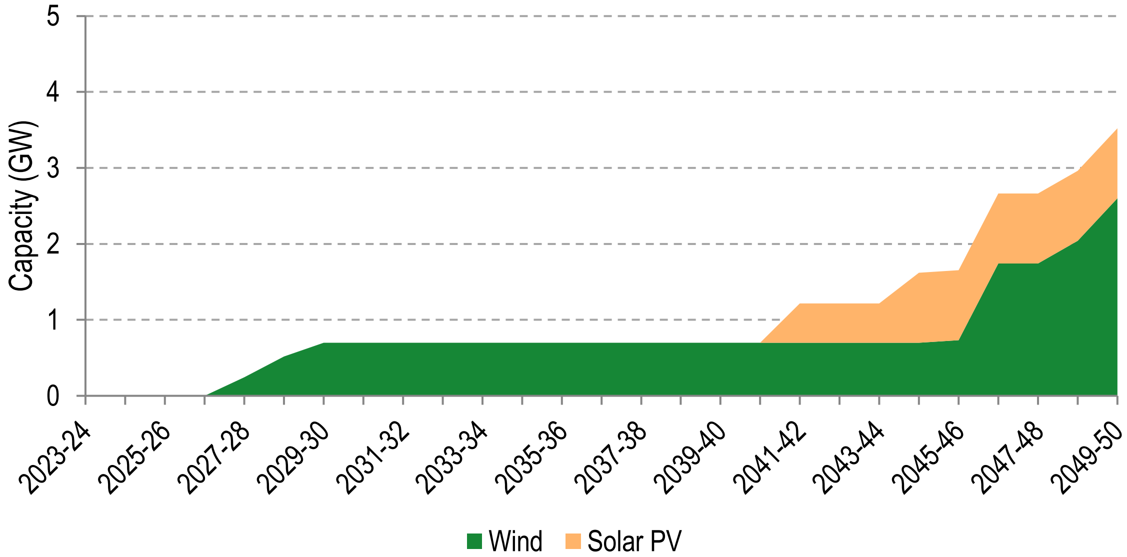


Figure 42: Western Victoria (V3) new entrant capacity with Option 5, offshore wind sensitivity



Option 3A and 5 also differ in their export (Victoria to NSW) limits as shown in Table 11; Option 5 has a slightly higher export limit than Option 3A. In the core Step Change scenario simulations, the VNI flow is expected to just reach its export limit in both Option 3A and Option 5 (refer to Figure 31 and Figure 32). With Option 5, VNI was expected to export more than 1,000 MW less than 5% of the time in the final year of the model. This indicates that Option 5 is expected to utilise the additional 100 MW export limit (compared to Option 3A) only a small amount of time and is not expected to derive significant value from this additional limit in the core Step Change scenario.

As shown in Figure 43 and Figure 44, when offshore wind is assumed to be committed, VNI flow in both Option 3A and Option 5 is expected to reach its respective option-specific export limit for a similar amount of time with both options (around 3% of time). VNI flow is forecast to be more balanced in both directions, as opposed to the core simulation that it is forecast to be heavily in southward direction. Furthermore, it is seen that the higher northward limit of Option 5 is utilised.

Table 11: Victoria to NSW Interconnector (VNI) limits

Option	VNI limits	
	Export (northward) limit (MW)	Import (southward) limit (MW)
Option 3A	2,830	2,050
Option 5	2,930	2,050

Figure 43: Option 5 VNI flow duration curve for the offshore wind sensitivity to the Step Change scenario

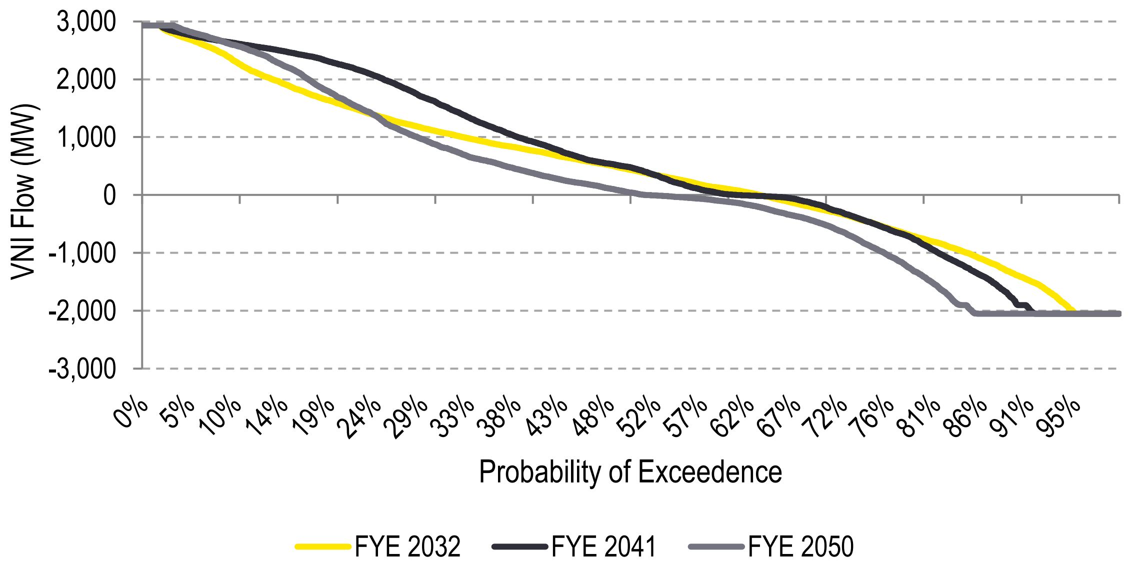
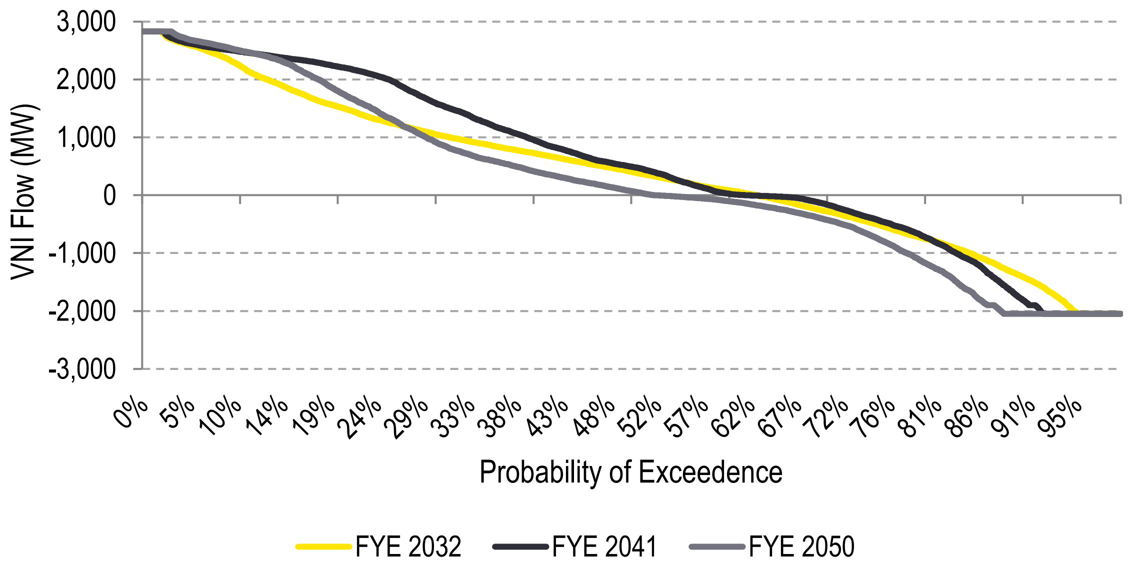


Figure 44: Option 3A VNI flow duration curve for the offshore wind sensitivity to the Step Change scenario



4.8.2 Combined VNI West and WRL sensitivity

This section summarises the modelling outcomes for VNI West Option 3A and Option 5 in the combined VNI West and WRL sensitivity. This sensitivity was implemented by removing the WRL project from the relevant scenario Base Cases. Hereafter we call them alternative Base Cases, and alternative Base Cases with offshore wind. The forecast gross market benefits presented in this sensitivity are attributed to both the WRL and VNI West projects (see Table 12). To determine the forecast net economic benefit for that option and WRL the forecast gross benefits need to be compared to the relevant combined cost of WRL and the relevant VNI West option.

Table 12: Forecast gross market benefits for the combined VNI West and WRL sensitivity. millions real June 2021 dollars discounted to June 2021 dollars

Option	Potential gross market benefits ($m)					
	Relative to the alternative Base Case			Relative to the core Base Case		
	Step Change	Progressive Change	Hydrogen Superpower	Step Change	Progressive Change	Hydrogen Superpower
3A	5,595	2,520	5,288	4,253	1,797	4,392
5	5,263	2,322	5,086	3,921	1,598	4,191

In each scenario's alternative Base Case, forecast capex and FOM costs in the NEM significantly increase (relative to the Base Case), as do the expected REZ transmission expansion costs. Consequently, the difference in total system costs (the gross market benefits) between either VNI West Option 3A or Option 5 and this alternative Base Case is also forecast to be higher. The trends in the Step Change scenario are as follows:

- The additional forecast capex and FOM costs in the alternative Base Case are expected in all regions, but predominantly in Victoria.
- In the absence of WRL, forecast wind investment in Victoria is advanced from the early 2030s to the mid-late 2020s as existing capacity in western Victoria remains constrained. This is forecast to result in increased expected capex and FOM costs.
- Across the NEM in the alternative Base Case some wind investment in the mid-2040s is forecast to be brought forward, while overall less solar capacity is required by the end of the study period.
- By the end of the assessment period wind capacity in Victoria is forecast to be the same in the Base Case and the alternative Base Case. However, more offshore wind is forecast in the alternative Base Case (driven by the least-cost outcome, not by imposing any offshore wind targets). This is because all onshore resources in Victoria are fully utilised in the alternative Base Case due to limited access to REZs. This is forecast to result in more capex costs in the alternative Base Case, since the capital costs of offshore wind are assumed to be higher than onshore wind, consistent with the assumptions used in 2022 ISP.
- Other regions, in general, are forecast to require more wind and solar, and to a smaller extent storage.

In the alternative Base Case, the transmission capacity of the Western Victoria (V3) REZ is limited to the existing network (which is already congested), resulting in shifting of new investment in Victoria to other REZs such as Central North Victoria (V6) and South-West Victoria (V4). This is forecast to result in the need for more (or advanced) transmission upgrade for these REZs, and as such more REZ transmission costs.

4.8.3 Combined VNI West and WRL with offshore wind sensitivity to the Step Change scenario

We were also requested by Transgrid and AVP to model the impact of offshore wind sensitivity to the Step Change scenario with the alternative Base Case. Table 13 shows the forecast gross market benefits of Option 3A and Option 5 relative to the alternative Base Case.

Table 13: Forecast gross market benefits for the combined VNI West+WRL and offshore wind sensitivity to the Step Change scenario, millions real June 2021 dollars discounted to June 2021 dollars

Option	Potential gross market benefits ($m)	
	Combined VNI West+WRL sensitivity, without offshore wind committed	Combined VNI West+WRL and offshore wind sensitivity
Option 3A	5,595	3,820
Option 5	5,263	3,858

Committing offshore wind in this sensitivity is forecast to reduce the benefits of VNI West following a similar trend to the previous offshore wind sensitivity (Section 4.8.1). Particularly, by committing offshore wind, there is reduced expected investment in additional new capacity, particularly in Victoria, which is forecast to result in less capex costs in the alternative Base Case, resulting in fewer degrees of freedom to deliver investment efficiencies due to VNI West options.

As with the alternative Base Case without offshore wind committed in Victoria, even with the presence of offshore wind in the alternative Base Case, REZs such as South West Victoria (V4) and Central North Victoria (V6) are forecast to require more capacity, and as such more REZ transmission expansion.

Appendix A Emissions and renewable energy outcomes in the Step Change scenario

This section summarises the emissions and renewable energy outcomes for the Base Case, Option 3A and Option 5 in the Step Change scenario.

Table 14: emissions and renewable energy outcomes – Step Change scenario

Region	Category	Target	Status of target	Base Case	Option 3A	Option 5
Victoria	Emissions	28-33% below 2005 by 2025	Legislated	53% emissions reduction	53% emissions reduction	53% emissions reduction
		45-50% below 2005 by 2030	Legislated	86% emissions reduction	86% emissions reduction	86% emissions reduction
		75-80% below 2005 by 2035	Vic Labor election announcement after ISP 2022, not yet legislated	99% emissions reduction	99% emissions reduction	99% emissions reduction
		Net zero by 2045	Vic Labor election announcement after ISP 2022, not yet legislated	97% emissions reduction	98% emissions reduction	98% emissions reduction
	Renewables	40% by 2025 renewable generation in Victoria as a percentage of total Victorian generation	Legislated	52%	55%	55%
		50% by 2030 renewable generation in Victoria as a percentage of total Victorian generation	Legislated	83%	84%	84%
		65% by 2030 renewable generation in Victoria as a percentage of total Victorian generation	Vic Labor election announcement after ISP 2022, not yet legislated	83%	84%	84%

Region	Category	Target	Status of target	Base Case	Option 3A	Option 5
		95% by 2035 renewable generation in Victoria as a percentage of total Victorian generation	Vic Labor election announcement after ISP 2022, not yet legislated	97%	98%	98%.
	Storage	>= 2.6 GW by 2030	Vic Labor election announcement after ISP 2022, not yet legislated	3.5 GW total = 0.6 GW large scale plus 2.9 GW embedded	3.4 GW total = 0.5 GW large scale plus 2.9 GW embedded	3.4 GW total = 0.5 GW large scale plus 2.9 GW embedded
		>= 6.3 GW by 2035	Vic Labor election announcement after ISP 2022, not yet legislated	7.4 GW total = 1.7 GW large scale plus 5.2GW embedded	6.2 GW total = 1.0 GW large scale plus 5.2GW embedded	6.2 GW total = 1.0 GW large scale plus 5.2GW embedded
	Offshore wind	2 GW by 2032	Announced after ISP 2022 assumptions finalised, not yet legislated	modelled as a sensitivity	modelled as a sensitivity	modelled as a sensitivity
		4 GW by 2035				
		9 GW by 2040				
New South Wales	Electricity Infrastructure Roadmap - Renewables	2,500 GWh of renewable generation in 2024-25 increasing to 24,600 GWh in 2029-30	Legislated	34,458 GWh in 2024-25 and 60,624 GWh in 2029-30	34,454 GWh in 2024-25 and 60,626 GWh in 2029-30	34,430 GWh in 2024-25 and 60,581 GWh in 2029-30
	Electricity Infrastructure Roadmap - Storage	2 GW by 2029-30	Legislated	2 GW	2 GW	2 GW
		(8 hrs or more)				
	Emissions	50% emissions reduction below 2005 levels by 2030	Announced	78%	77%	77%
		Net zero by 2050	Announced	98%	98%	98%

Region	Category	Target	Status of target	Base Case	Option 3A	Option 5
Queensland	Renewables	50% by 2030 renewable generation in Queensland as a percentage of total Queensland generation	Legislated	73%	71%	71%.
		70% by 2032 renewable generation in Queensland as a percentage of total Queensland generation	Announced in Queensland Energy and Jobs Plan after ISP 2022, not yet legislated	80%	79%	79%
		80% by 2035 renewable generation in Queensland as a percentage of total Queensland generation	Announced in Queensland Energy and Jobs Plan after ISP 2022, not yet legislated	84%	84%	84%
	Emissions	50% below 2005 by 2030	Announced in Queensland Energy and Jobs Plan after ISP 2022, not yet legislated	64% emissions reduction	63% emissions reduction	63% emissions reduction
		90% below 2005 by 2035	Announced in Queensland Energy and Jobs Plan after ISP 2022, not yet legislated	79% emissions reduction	79% emissions reduction	79% emissions reduction
		Net zero by 2050	Announced in Queensland Energy and Jobs Plan after ISP 2022, not yet legislated	97% emissions reduction	95% emissions reduction	96% emissions reduction
Tasmania	Renewables	15,750 GWh by 2030	Legislated	19,121 GWh in 2030-31	18,468 GWh in 2030-31	18,596 GWh in 2030-31
		21,000 GWh by 2040	Legislated	22,835 GWh in 2040-41	22,374 GWh in 2040-41	22,679 GWh in 2040-41
	Renewables		Announced	90%	90%	90%

Region	Category	Target	Status of target	Base Case	Option 3A	Option 5
South Australia		100% new renewables by 2030				
Australia economy-wide	Emissions	43% below 2005 levels by 2030	Legislated after ISP 2022	78% emissions reduction	77% emissions reduction	77% emissions reduction
		Net zero by 2050	Legislated after ISP 2022	97% emissions reduction	97% emissions reduction	97% emissions reduction

Appendix B Scenario assumptions

Key assumptions for modelled Scenarios

The options proposed by Transgrid and AVP have been assessed under the Step Change, Progressive Change and Hydrogen Superpower scenarios from 2022 ISP[3,23], using the corresponding inputs and assumptions as summarised in Table 15. We were also requested to incorporate modifications to AEMO's input and assumptions based on updated information since the publication of 2022 ISP, as follows:

- retirement of Loy Yang A in 2035[4]
- retirement of Torrens Island B in 2026[5].

Table 15: Overview of key input parameters in the Step Change, Progressive Change and Hydrogen Superpower scenarios

Key drivers input parameter	Scenario		
	Step Change	Progressive Change	Hydrogen Superpower
Underlying consumption	ESOO 2021[24] (ISP 2022) - Step Change	ESOO 2021[24] (ISP 2022) - Progressive Change	ESOO 2021[24] (ISP 2022) - Hydrogen Superpower
Committed and anticipated generation	ISP 2022		
New entrant capital cost for wind, solar PV, SAT, OCGT, PHES large-scale batteries and hydrogen turbine	2021 Inputs and Assumptions Workbook[25] - Step Change	2021 Inputs and Assumptions Workbook[25] - Progressive Change	2021 Inputs and Assumptions Workbook[25] - Hydrogen Superpower
Retirements of coal-fired power stations	2022 ISP coal retirement outcomes in the Step Change scenario	2022 ISP coal retirement outcomes. Updated to reflect recently announced closure dates for Loy Yang coal fired power stations	2022 ISP coal retirement outcomes
Gas fuel cost	2021 Inputs and Assumptions Workbook[25] - Step Change: Lewis Grey Advisory 2020, Step Change	2021 Inputs and Assumptions Workbook[25] - Progressive Change: Lewis Grey Advisory 2020, Central	2021 Inputs and Assumptions Workbook[25] - Hydrogen Superpower: Lewis Grey Advisory 2020, Step Change
Coal fuel cost	2021 Inputs and Assumptions Workbook[25] - Step Change: Wood Mackenzie, Step Change	2021 Inputs and Assumptions Workbook[25] - Progressive Change: Wood Mackenzie, Central	2021 Inputs and Assumptions Workbook[25] - Hydrogen Superpower: Wood Mackenzie, Step Change

[23] The AER's *Cost benefit analysis guidelines* requires that the RIT-T proponent of an actionable ISP project adopts the scenarios specified in the AEMO ISP as relevant.
[24] AEMO, *National Electricity and Gas Forecasting*, http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational,
[25] *2021 Inputs and Assumptions Workbook v3.3*, https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios. Accessed on 5 November 2022.

Key drivers input parameter	Scenario		
	Step Change	Progressive Change	Hydrogen Superpower
NEM carbon budget	2021 Inputs and Assumptions Workbook[25] - Step Change: 891 Mt CO_2-e 2023-24 to 2050-51	2021 Inputs and Assumptions Workbook[25] - Progressive Change: 932 Mt CO_2-e 2030-31 to 2050-51	2021 Inputs and Assumptions Workbook[25] - Hydrogen Superpower: 453 Mt CO_2-e 2023-24 to 2050-51
Victorian Renewable Energy Target (VRET)	40% renewable energy by 2025 and 50% renewable energy by 2030[25] VRET2 including 600 MW of renewable capacity by 2025[25]		
Queensland Renewable Energy Target (QRET)	50% by 2030[25]		
Tasmanian Renewable Energy Target (TRET)	100% by 2022, 150% by 2030 and 200% Renewable generation by 2040, excluding hydro[25]		
NSW Electricity Infrastructure Roadmap	12 GW NSW Roadmap, with 3 GW in the Central West Orana REZ, modelled as generation constraint per 2022 ISP and 2 GW of long duration storage (8 hrs or more) by 2029-30[25]		
NSW to Queensland Interconnector Upgrade (QNI Minor)	QNI minor commissioned by July 2022[25]		
Victoria to NSW Interconnector Upgrade (VNI Minor)	VNI Minor commissioned by December 2022[25]		
Victorian SIPS	300 MW/450 MWh, 250 MW for SIPS service during summer. In the summer months the remaining 50 MW can be deployed in the market on a commercial basis, in the winter months the full capacity is available. From April 2032 the full capacity is available to the market.[25]		
EnergyConnect	2022 ISP: EnergyConnect commissioned by July 2026		
Western Renewable Link (WRL)	WRL by July 2027		
HumeLink	2022 ISP[3] outcome - Step Change: HumeLink commissioned by July 2028	2022 ISP[3]. outcome - Progressive Change: HumeLink commissioned by July 2035	2022 ISP[3]. outcome - Hydrogen Superpower: HumeLink commissioned by July 2027
New-England REZ Transmission	2022 ISP outcome[3] - Step Change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2035	2022 ISP outcome[3] - Progressive Change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2038	2022 ISP outcome[3] - Hydrogen Superpower: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2031, and stage 3 by July 2042
Marinus Link	2022 ISP[3] outcome:1st cable commissioned by July 2029 and 2nd cable by July 2031		
QNI Connect	2022 ISP[3] outcome - Step Change: QNI Connect commissioned by July 2032	2022 ISP[3] outcome - Progressive Change: QNI Connect commissioned by July 2036	2022 ISP[3] outcome - Hydrogen Superpower: QNI Connect commissioned by July 2029 and stage 2 to be commissioned by July 2030

Key drivers input parameter	Scenario		
	Step Change	Progressive Change	Hydrogen Superpower
VNI West	2022 ISP[3] outcome - Progressive Change: VNI West commissioned by July 2031	2022 ISP[3] outcome - Progressive Change: VNI West commissioned by July 2038	2022 ISP[3] outcome - Hydrogen Superpower: VNI West commissioned by July 2030
Snowy 2.0	Snowy 2.0 is commissioned by December 2026[25]		

Appendix C Methodology

Long-term investment planning

EY has used linear programming techniques to perform hourly time-sequential, least-cost, long-term NEM development optimisation modelling spanning from 2023-24 to 2049-50. The modelling methodology follows the RIT-T guidelines for actionable ISP projects published by the AER[1].

Based on the full set of input assumptions, the TSIRP 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,
- FOM,
- VOM,
- fuel usage,
- DSP and USE,
- transmission expansion costs associated with REZ development,
- transmission 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[26] trading interval in relation to:

- the generation dispatch level for each power plant along with the charging and discharging of storage. Generators are assumed to run at their SRMC, which is derived from their VOM and fuel costs. The generation for each trading interval is subject to the modelled availability of power stations in each hour (those that are not on planned or unplanned outages), network limitations and energy limits (e.g., storage levels).
- commissioning new entrant capacity for wind, offshore wind, solar PV SAT, OCGT, large-scale battery and PHES[8]. Hydrogen turbine technology is only modelled as available in the Hydrogen Superpower scenario. Nuclear and other technically feasible technology options were screened and found that they would not be a part of the least cost plan.

These hourly decisions take into account constraints that include:

- supply must equal demand in each region for all trading intervals, while maintaining a reserve margin, with USE costed at the VCR[10],
- minimum loads for some generators,
- transmission interconnector flow limits (between regions),
- intra-regional flow limits (between zones in NSW),
- intra-regional flow limits for a detailed network modelled in Victoria and Southern NSW through DCLF,
- maximum and minimum storage reservoir limits (for conventional storage hydro, PHES and large-scale battery),

[26] 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.

- new entrant capacity build limits and costs associated with increasing these limits beyond the resource limit for wind and solar in each REZ where applicable, 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 NSW and Victoria through modelling of zones with intra-regional limits and losses. Within these zones and within regions, no further detail of the transmission network is considered. More detail on the transmission network representation is given in Appendix D.

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

The model meets the specified carbon budget assumed in each scenario 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. An assumed energy limit is placed on coal-fired power stations where specified in 2022 ISP dataset[25]. The running cost for these generators is the sum of the VOM and fuel costs. FOM costs are another component of the running cost of generators contributing to potential earlier economic withdrawal [27]. Coal generators and some CCGTs[28] 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 their variable costs will be recovered 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, large-scale battery and virtual power plants (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 large-scale battery operate in pumping or charging mode.

Reserve constraint in long-term investment planning

The TSIRP 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.

All dispatchable generators in each region are eligible to contribute to reserve (except PHES, VPPs and large-scale battery[29]) and headroom that is available from interconnectors. The hourly modelling accounts for load diversity and sharing of reserves across the NEM and so minimises the

[27] Note that earlier coal withdrawal in TSIRP is an outcome of the least cost optimisation rather than revenue assessment.

[28] Close cycle gas turbines

[29] PHES and large-scale battery 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.

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 consecutive contingency reserve requirement was applied with a high penalty cost. This amount of reserve ensures there is 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). This constraint is applied to only a subset of simulation hours when demand is high to reduce the optimisation problem size.

There are three 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.
- In NSW, where the major proportion of load and dispatchable generation is concentrated in the Central NSW (NCEN) zone, the same rules are applied as for the NSW region except headroom on intra-connectors between adjacent zones does not contribute to reserve. This is because even if there is headroom on the NCEN intra-connectors, it is likely that the flows from the north and south into NCEN reflect the upstream network limits. However, intra-connectors still implicitly contribute to reserve because increased flow can displace dispatchable generators within NCEN allowing them to contribute to reserve.

Cost-benefit analysis

From the hourly time-sequential modelling the following categories of costs defined in the RIT-T are computed:

- capital costs of new generation capacity installed,
- total FOM costs of all generation capacity,
- total VOM costs of all generation capacity,
- total fuel costs of all generation capacity,
- total cost of voluntary and involuntary load curtailment, called DSP and USE,
- transmission expansion costs associated with REZ development.

For each scenario a matched no option counterfactual (referred to as the Base Case) long term investment plan is simulated. The changes in each of the cost categories are computed as the forecast gross market benefits due to the option, as defined in the RIT-T. The RIT-T instrument requires RIT-T for actionable ISP projects to calculate all classes of benefits identified in the ISP.

Each component of forecast gross market benefits is computed annually over the 25-year modelling period. In this Report, we summarise the benefit and cost streams using a single value computed as the net present value[30], discounted to June 2021 at a 5.5% real, pre-tax discount rate as agreed jointly by Transgrid and AVP. This value is consistent with the value applied by AEMO in 2022 ISP[3], as required by the CBA guidelines[1].

The forecast gross market benefits of each option need to be compared to the relevant option cost to determine whether there is a positive forecast net economic benefit. The determination of the forecast net economic benefit and preferred option was conducted outside of this Report by Transgrid and AVP[2] using the forecast gross market benefits from this Report and other inputs.

[30] We use the term net present value rather than present value as there are positive and negative components of market benefits captured; however, we do not consider augmentation costs.

Appendix D Transmission and demand

Regional and zonal definitions

Jointly agreed by Transgrid and AVP, we were requested to split NSW into sub-regions or zones in the modelling presented in this Report[31], as listed in Table 16. In addition, southern NSW and Victorian networks are modelled with higher resolution through several nodes and an overlayed DC power flow model in TSIRP. This network representation varies from that applied in 2022 ISP but in Transgrid and AVP's views, enables better representation of intra-regional network limitations and transmission losses in the relevant parts of the network.

Table 16: Regions, zones and reference nodes

Region	Zone	Zonal Reference Node
Queensland	Queensland (QLD)	South Pine 275 kV
New South Wales	Northern New South Wales (NNS)	Armidale 330 kV
	Central New South Wales (NCEN)	Sydney West 330 kV
	Darlington Point	Darlington Point 330 kV
	Dinawan	Dinawan 330kV
	Buronga	Buronga 330kV
	Canberra	Canberra 330 kV
	Bannaby	Bannaby 330 kV
	Yass	Yass 330 kV
	Wagga	Wagga 330 kV
	Lower Tumut	Lower Tumut 330 kV
	Snowy (Maragle)	Snowy (Maragle) 330 kV
	Upper Tumut	Upper Tumut 330 kV
Victoria	Murray	Murray 330 kV
	Dederang	Dederang 330 kV
	Southern Victoria	Thomastown 66 kV
	Shepparton	Shepparton 220kV
	Bendigo	Bendigo 220kV
	Kerang	Kerang 220KV
	Red Cliffs	Red Cliffs 220kV
	Horsham	Horsham 220kV
	Ballarat	Ballarat 220kV

[31] TransGrid, *HumeLink PACR market modelling*, Available at: https://www.transgrid.com.au/media/vqzdxwl3/humelink-pacr-ey-market-modelling-report.pdf, accessed 21 January 2023.

Region	Zone	Zonal Reference Node
South Australia	South Australia (SA)	Torrens Island 66 kV
Tasmania	Tasmania (TAS)	Georgetown 220 kV

The borders of each zone or region are defined by the cut-sets listed in Table 17, as defined by Transgrid. Dynamic loss equations are defined between reference nodes across these cut-sets.

Table 17: Key cut-set definitions

Border	Lines
NNS-NCEN	Line 88 Muswellbrook - Tamworth Line 84 Liddell - Tamworth Line 96T Hawks Nest - Taree Line 9C8 Stroud - Brandy Hill
NCEN- Canberra	Line 61 Gullen Range - Bannaby Line 3W Kangaroo Valley - Capital Line 4/5 Yass - Marulan Line 973 Yass - Cowra Line 999 Yass - Cowra Line 98J Shoalhaven - Evans Lane Line 28P West Tomerong - Evans Lane and new HumeLink lines for each option
Canberra/Yass-Bannaby	Line 61 Gullen Range - Bannaby Line 3W Kangaroo Valley - Capital Lines 4 &5 Yass - Marulan and new HumeLink lines from Maragle/Wagga to Bannaby for each option
Snowy cut-set	Line 01 Upper Tumut to Canberra Line 2 Upper Tumut to Yass Line 07 Lower Tumut to Canberra Line 3 Lower Tumut to Yass
Buronga-SA	New 330 kV double circuit from Buronga - Robertstown (after assumed commissioning of EnergyConnect)

Table 18 summarises the key cut-set limits in the Canberra zone and from Canberra to NCEN, as defined by Transgrid.

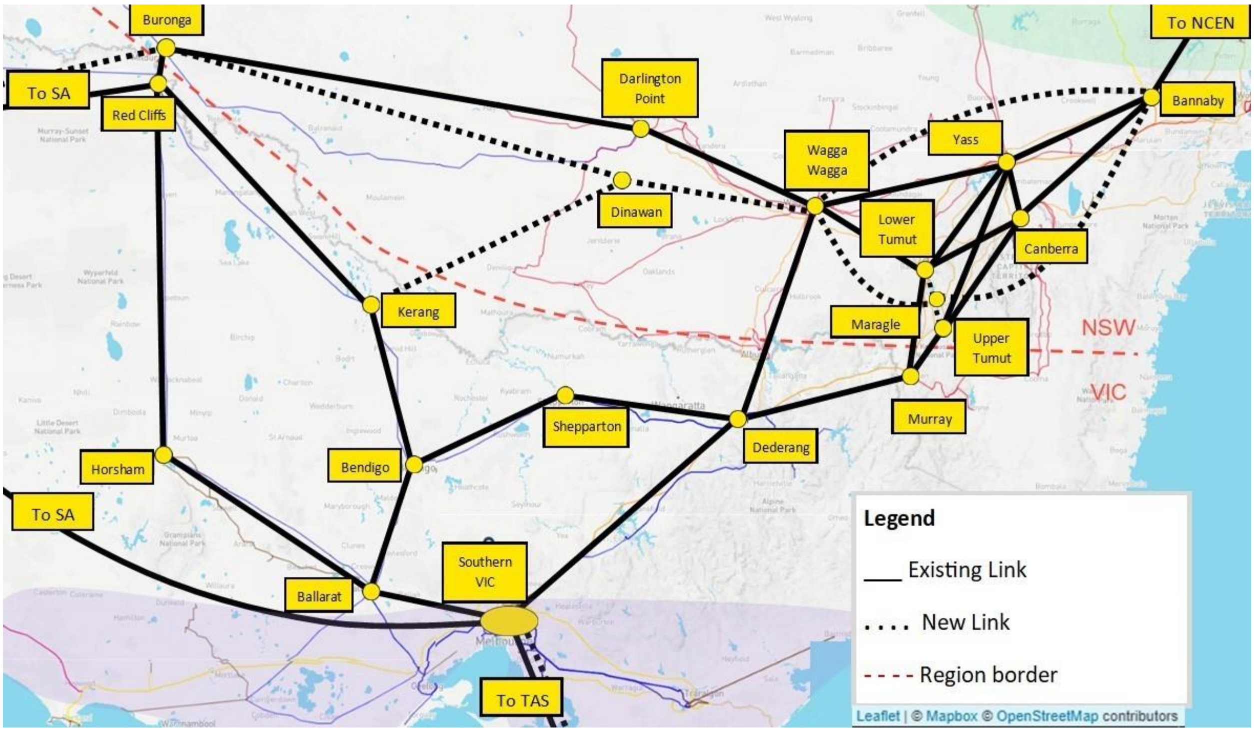
Table 18: Key cut-set limits (MW)

Options	Bidirectional limit (MW)
Snowy cut-set	3,080
Snowy cut-set + HumeLink lines	5,372
Canberra/Yass - Bannaby cut-set	4,900
Canberra-NCEN cut-set	4,500
Bannaby-NCEN	4,500

Victoria and South NSW network model

Jointly agreed between Transgrid and AVP, we were requested to model Victoria and southern NSW networks with a higher resolution through modelling several nodes. The network representation is illustrated in Figure 45. Major high-voltage substations in Victoria and southern NSW are modelled as nodes with the equivalenced lines linking between them. The only exception in Victoria is "Southern VIC" node which represents the areas of southern Victoria from Latrobe Valley to Portland. The lines are derived by equivalencing the network connecting the given nodes in the subregion. Demand components are split across the nodes based on their half-hourly proportion of the overall NSW load in 2017-18. Furthermore, generators within this subregion are mapped into the nearest node. TSIRP models the flows and losses for this network using DCLF equations. DCLF is a simplified AC load flow which neglects reactive power flows. The model also captures the losses for the given lines through piecewise linear functions using the equivalent resistance of those lines.

Figure 45: Southern NSW and Victoria DC powerflow network[32,33]



The cut-set definition and limits of the VNI are shown in Table 19 and Table 20

Table 19: VNI cut-set

Border	Lines
Victoria - NSW	220 kV line between Red Cliffs and Buronga 330 kV lines from Murray to Lower Tumut and Upper Tumut 330 kV line from Wodonga to Jindera (modelled as Dederang to Wagga in DC power flow model) Additional circuit between Red Cliffs and Buronga as part of Energy Connect Double circuit 500 kV line from Kerang to Dinawan, as part of VNI West

32 This map is a graphical representation of the modelled network, not a map of existing or proposed transmission routes.

33 Underlying map from AEMO, *AEMO Map,* Available at: https://www.aemo.com.au/aemo/apps/visualisations/map.html, Accessed 16 May 2022.

Table 20: Transfer limits of Victoria to NSW

Description	Import limit (MW)	Export limit (MW)
Original limits	400 all periods	870 peak demand 1,000 summer 1,000 winter
Post Victorian SIPS contract with no VNI West	250 peak demand 400 summer 400 winter	870 peak demand 1,000 summer 1,000 winter
Post VNI West commissioning with SIPS contract in place	400 + increased transfer limit for the relevant VNI West option in all periods	the above + increased transfer limit for the relevant VNI West option
Post VNI West commissioning and SIPS contract ended	4250 + increased transfer limit for the relevant VNI West option during peak demand 400 + increased transfer limit for the relevant VNI West option or the remaining periods	Same as above

Power Flow Controllers (PFCs) are assumed in VNI West options, which are expected to change the reactance of some Victorian transmission lines as shown Table 21. As advised by Transgrid and AVP, the PFC is expected to increase the current reactance of the lines by the compensation percentages shown in Table 21.

Table 21: PFC impact on reactance of Victorian lines

Line	Compensation (%)
Dederang - Murray No.1	60%
Dederang - Murray No.2	60%
Eildon - Thomastown	83%
South Morang - Thomastown	157%

Interconnector and intra-connector loss models

Dynamic loss equations for the existing network are generally sourced from AEMO's *Regions and Marginal Loss Factors*[34]. New dynamic loss equations are computed for several conditions, including:

- when a new link is defined e.g., NNS-NCEN, SA-Buronga (EnergyConnect), Bannaby-NCEN,
- all the Victorian and southern NSW equivalenced lines between the modelled nodes, through their equivalent resistance, and
- when future upgrades involving conductor changes are modelled e.g., VNI West, QNI and Marinus Link.

The network snapshots to compute the loss equations were provided by Transgrid and AVP.

[34] AEMO, *Marginal Loss Factors for the 2018-19 Financial Year*. Available at: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries. Accessed 2 May 2022.

Interconnector and intra-connector capabilities

The notional limits imposed on interconnectors are shown in Table 22. 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:

- Heywood + Project 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.

Table 22: Notional interconnector capabilities used in the modelling (sourced from AEMO 2022 ISP[25])

Interconnector (From node – To node)	Import[35] notional limit	Export[36] notional limit
QNI[37]	1,205 MW peak demand 1,165 MW summer 1,170 MW winter	685 MW peak demand 745 MW summer/winter
QNI Connect 1[38]	2,285 MW peak demand 2,245 MW summer 2,250 MW winter	1,595 MW peak demand 1,655 MW summer/winter
QNI Connect 2[38]	3,085 MW peak demand 3,045 MW summer 3,050 MW winter	2,145 MW peak demand 2,205 MW summer/winter
Terranora (NNS-SQ)	130 MW peak demand 150 MW summer 200 MW winter	0 MW peak demand 50 MW summer/winter
EnergyConnect (Buronga-SA)	800 MW	800 MW
Heywood (VIC-SA)	650 MW (before EnergyConnect) 750 MW (after EnergyConnect)	650 MW (before EnergyConnect) 750 MW (after EnergyConnect)
Murraylink (VIC-SA)	200 MW	220 MW
Basslink (TAS-VIC)	478 MW	478 MW
Marinus Link (TAS-VIC)	750 MW for the first stage and 1,500 MW after the second stage	750 MW for the first leg and 1,500 MW after the second leg

NSW has been split into zones with the following limits imposed between the zones defined in Table 23.

[35] 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.
[36] 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.
[37] Flow on QNI may be limited due to additional constraints.
[38] AEMO, 10 December 2021. *Appendix 5: Network Investments (Appendix to Draft 2022 ISP for the National Electricity market)*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/2022-draft-isp-consultation. Accessed 22 April 2022.

Table 23: Intra-connector notional limits imposed in modelling for NSW

Intra-connector (From node – To node)	Import notional limit	Export notional limit
NCEN-NNS	1,177 MW (after QNI Minor) Limit will increase after NEW England REZ augmentations as mentioned in the Draft 2022 ISP[3].	1,377 MW (after QNI Minor) Limit will increase after NEW England REZ augmentations as mentioned in the Draft 2022 ISP[3].
WAG-SWNSW (provided by Transgrid)	300 MW (before EnergyConnect) 1,100 MW (after EnergyConnect) 1,500 MW (after HumeLink without PEC Enhanced, applied in the Base Cases)1,900 MW (after HumeLink with PEC Enhanced, applied in the VNI West options) 3,000 MW (after VNI West)	500 MW (before EnergyConnect) 1,300 MW (after EnergyConnect) 1,700 MW (after HumeLink without PEC Enhanced, applied in the Base Cases)2,100 MW (after HumeLink, with PEC Enhanced, applied in the VNI West options) 2,700 MW (after VNI West)

Demand

The TSIRP model captures operational demand (energy consumption which is net of rooftop PV and other non-scheduled generation) diversity across regions by basing the overall shape of hourly demand on nine historical financial years ranging from 2010-11 to 2018-19.

Specifically, the key steps in creating the hourly demand forecast are as follows:

- the historical underlying demand has been calculated as the sum of historical operational demand and the estimated rooftop PV generation based on historical monthly rooftop PV capacity and solar insolation and historical data for other non-scheduled generation,
- the nine-year hourly pattern has been projected forward to meet future forecast annual peak demand and energy in each region (scenario-dependent),
- the nine reference years are repeated sequentially throughout the modelling horizon as shown in Figure 46,
- the future hourly rooftop PV generation has been estimated based on insolation in the corresponding reference year and the projection of future rooftop PV capacity, which is subtracted from the forecast underlying demand along with other behind-the-meter components (e.g., electric vehicles, domestic battery and other small non-scheduled generation) to get a projection of hourly operational demand.

Figure 46: Sequence of demand reference years applied to forecast

Modelled year	Reference year
2023-24	2014-15
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

Modelled year	Reference year
2032-33	2014-15
2033-34	2015-16
2034-35	2016-17
2035-36	2017-18
2036-37	2018-19
...	...
2043-44	2016-17
2044-45	2017-18
2045-46	2018-19
2046-47	2010-11
2047-48	2011-12
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 intervals shifting later in the day throughout the forecast.

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

Transgrid and AVP selected demand forecasts from the ESOO 2021[24] consistent with the relevant scenarios in the ISP 2022[25] which are used as inputs to the modelling. Figure 47 and Figure 48 show the NEM operational energy and distributed PV (rooftop PV and small-scale non-scheduled PV) for the modelled scenarios.

Figure 47: Annual operational demand in the modelled scenarios for the NEM[24]

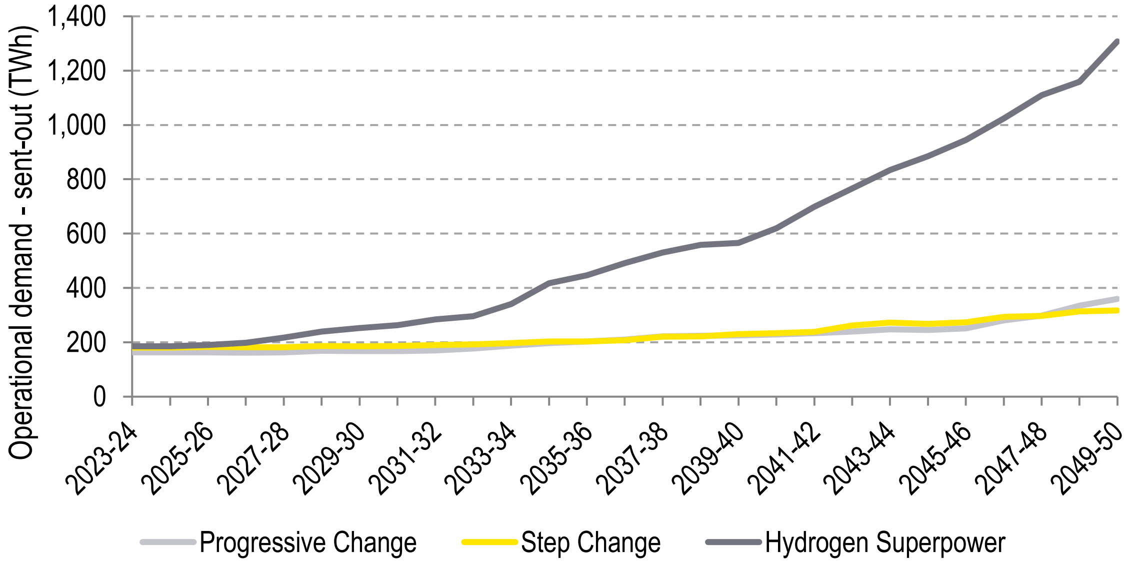
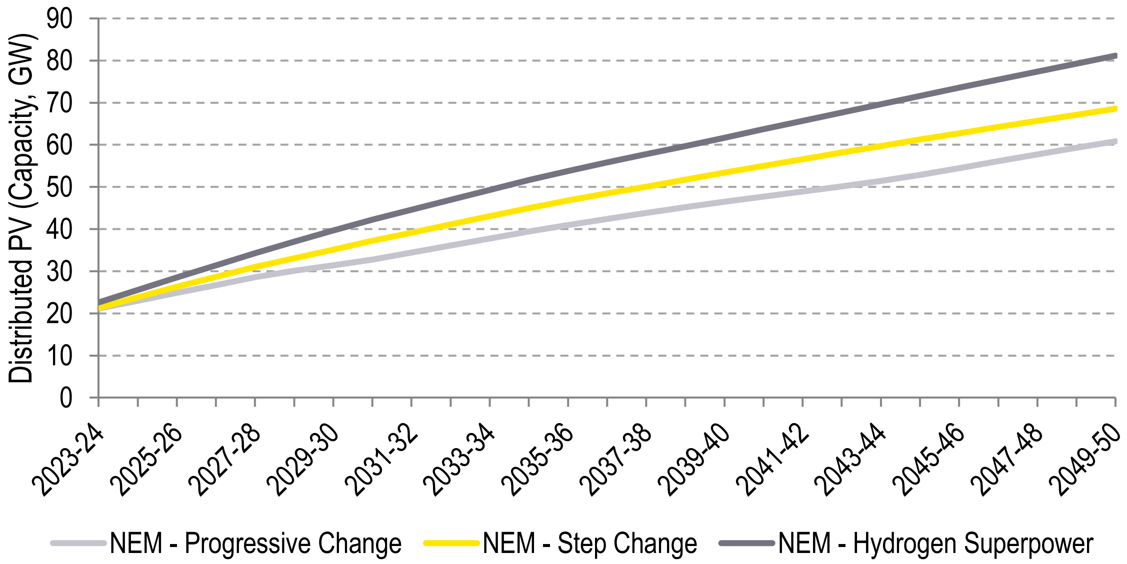


Figure 48: Annual distributed PV (rooftop PV and small non-scheduled PV) uptake in the NEM[24]



The ESOO 2021 demand forecasts for NSW and Victoria are split into the corresponding zones/nodes that have been defined. Transgrid obtained from AEMO half-hourly scaling factors to convert regional load to connection point loads which are used to split the regional demand into the zones. Doing so captures the diversity of demand profiles between the different zones in these regions.

Appendix E Supply

Wind and solar energy projects and REZ representation

Several generators not yet built are committed in all simulations, including the Base Case and each option. The source of this list is the AEMO 2021 ISP Inputs and Assumptions workbook[25], existing, committed and anticipated projects with updates based on new information since the publication of 2022 ISP[3].

Existing and new wind and solar projects are modelled based on nine years of historical weather data[39]. The methodology for each category of wind and solar project is summarised in Table 24 and explained further in this section of the Report.

Table 24: 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[40] 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 2021 ISP Inputs and Assumptions workbook[25].	
	Generic REZ new entrants	Reference year specific targets based on AEMO 2021 ISP Inputs and Assumptions workbook[25]. One high quality option and one medium quality trace per REZ.	
Solar PV FFP	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 2021 ISP Inputs and Assumptions workbook[25].	
	Generic REZ new entrant	Reference year specific targets based on AEMO 2021 ISP Inputs and Assumptions workbook[25].	
Rooftop PV and small non-scheduled solar PV	Existing and new entrant	Long-term average capacity factor based on AEMO 2021 ISP Inputs and Assumptions workbook[25].	Capacity factor varies with reference year based on historical insolation measurements.

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 shape

[39] 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 21 January 2023.

[40] 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 21 January 2023.

of demand. 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 Figure 46.

The availability profiles for wind generation are derived from simulated wind speeds from the Australian Bureau of Meteorology's Numerical Weather Prediction systems[41] 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 draft 2021 ISP inputs and assumptions[25] for each REZ (new entrant wind farms, as listed in Table 25).

The availability profiles for solar are derived using solar irradiation data downloaded 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 (generic new entrant solar farms as listed in Table 25).

Table 25: Assumed REZ wind and solar average capacity factors over the nine modelled reference years[25]

Region	REZ	Wind		Solar SAT
		High quality	Medium quality	
Queensland	Far North Queensland	55%	48%	27%
	North Queensland Clean Energy Hub	44%	37%	30%
	Northern Queensland	Tech not available	Tech not available	28%
	Isaac	37%	32%	28%
	Barcaldine	34%	31%	32%
	Fitzroy	38%	33%	28%
	Wide Bay	32%	31%	26%
	Darling Downs	39%	34%	27%
	Banana	31%	28%	29%
New South Wales	North West NSW	Tech not available	Tech not available	29%
	New England	39%	38%	26%
	Central West Orana	37%	34%	27%
	Broken Hill	33%	31%	30%
	South West NSW	30%	30%	27%
	Wagga Wagga	28%	27%	26%
	Cooma-Monaro	43%	40%	Tech not available
Victoria	Ovens Murray	Tech not available	Tech not available	24%
	Murray River	Tech not available	Tech not available	27%

[41] 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 21 January 2023.

Region	REZ	Wind		Solar SAT
		High quality	Medium quality	
	Western Victoria	41%	37%	23%
	South West Victoria	41%	39%	Tech not available
	Gippsland[42]	39%	34%	20%
	Central North Victoria	33%	31%	26%
South Australia	South East SA	39%	37%	23%
	Riverland	29%	28%	27%
	Mid-North SA	39%	37%	26%
	Yorke Peninsula	37%	36%	Tech not available
	Northern SA	37%	35%	28%
	Leigh Creek	41%	39%	30%
	Roxby Downs	Tech not available	Tech not available	30%
	Eastern Eyre Peninsula	40%	38%	24%
	Western Eyre Peninsula	39%	38%	27%
Tasmania	North East Tasmania	45%	43%	22%
	North West Tasmania[43]	50%	46%	19%
	Central Highlands	56%	54%	20%

Wind and solar capacity expansion in each REZ is limited by four parameters based on AEMO's 2021 Inputs and Assumptions workbook[25].

- 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.

The TSIRP model incurs the additional transmission expansion cost to build more capacity up to the resource limit if it is part of the least-cost development plan.

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 2021 Inputs and Assumptions workbook[25].

[42] Gippsland has an option for Offshore wind with an average capacity factor of 46%.
[43] North West Tasmania has an option for Offshore wind with an average capacity factor of 50%.

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 the various upgrade options. 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 2021 Inputs and Assumptions workbook[10].

Generator technical parameters

Technical generator parameters applied are as detailed in the AEMO 2021 Inputs and Assumptions workbook[10] for AEMO's long-term planning model, except as noted in the Report.

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, in line with the AEMO 2021 Inputs and Assumptions workbook[10]. Maximum loads vary seasonally. This materially reduces the amount of available capacity in the summer periods.

A maximum capacity factor of 75% is assumed for NSW coal, as per the AEMO 2021 Inputs and Assumptions workbook[10].

Gas-fired generators

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.

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.

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.

Storage-limited generators

Conventional hydro with storages, PHES and batteries are dispatched in each trading 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 2021 Inputs and Assumptions workbook and the median hydro climate factor trajectory for the respective scenario applied[10]. The Tasmanian hydro schemes were modelled using a ten-pond model, with additional information sourced from the TasNetworks Input assumptions and scenario workbook for Project Marinus Project Assessment Conclusions Report (PACR)[44].

[44] TasNetworks, *Input assumptions and scenario workbook for Project Marinus PACR*. Available at https://www.marinuslink.com.au/rit-t-process/. Accessed on 26 April 2022

Appendix F Glossary of terms

Abbreviation	Meaning
AC	Alternating Current
AEMO	Australian Energy Market Operator
AER	Australia Energy Regulator
AVP	AEMO Victorian Planning
$b	Billion dollars
Capex	Capital Expenditure
CBA guidelines	Cost Benefit Analysis guidelines
CDP	Candidate Development Path
CO_2	Carbon Dioxide
CCGT	Combined-Cycle Gas Turbine
DC	Direct Current
DCLF	Direct Current Load Flow
DSP	Demand Side Participation
ESOO	Electricity Statement of Opportunities
FFP	Fixed Flat Plate
FOM	Fixed Operation and Maintenance
GW	Gigawatt
GWh	Gigawatt-hour
ISP	Integrated System Plan
LS battery	Large-scale battery storage (as distinct from behind-the-meter battery storage)
$m	Million dollars
Mt	Mega Ton
MW	Megawatt
MWh	Megawatt-hour
NCEN	Central New South Wales (NEM zone)
NEM	National Electricity Market
NNS	Northern New South Wales (NEM zone)
NSW	New South Wales
OCGT	Open-Cycle Gas Turbine
PACR	Project Assessment Conclusion Report
PADR	Project Assessment Draft Report

Abbreviation	Meaning
PFC	Power Flow Controller
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
SRMC	Short-Run Marginal Cost
SWNSW	South West New South Wales (NEM zone)
TAS	Tasmania
TRET	Tasmanian Renewable Energy Target
TSIRP	Time-sequential integrated resource planner
TW	Terawatt
TWh	Terawatt-hour
USE	Unserved Energy
VCR	Value of Customer Reliability
VIC	Victoria
VNI	Victoria-New South Wales Interconnector
VOM	Variable Operation and Maintenance
VRET	Victorian Renewable Energy Target
VPP	Virtual Power Plant
VTL	Virtual Transmission Line
WRL	Western Renewables Link

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