2020 ISP Appendix 2. Cost Benefit Analysis

July 2020

Important notice

PURPOSE

This is Appendix 2 to the Final 2020 Integrated System Plan (ISP), available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp.

AEMO publishes this 2020 ISP pursuant to its functions under section 49(2) of the National Electricity Law (which defines AEMO's functions as National Transmission Planner) and its broader functions under the National Electricity Rules to maintain and improve power system security. In addition, AEMO has had regard to the National Electricity Amendment (Integrated System Planning) Rule 2020 which commenced on 1 July 2020 during the development of the 2020 ISP.

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VERSION CONTROL

Version	Release date	Changes
1.0	30/7/2020	Initial release

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Summary

The Cost Benefit Analysis appendix details the economic assessment of the candidate development paths across the respective scenarios.

All values presented are 30 June 2019 real dollars unless stated otherwise. Net Present Value (NPV) outcomes are discounted back to 30 June 2019 based on a discount rate equivalent to the WACC assumed for each scenario[1].

[1] More information on the assumed WACC for each scenario, and other key inputs is available in the 2020 ISP assumptions workbook, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines.

A2.1. Introduction

This appendix sets out the cost-benefit analysis used in this ISP to inform selection of the optimal development path. AEMO modelled candidate development paths under a range of five plausible future scenarios, four market event sensitivities, and two additional sensitivities associated with potentially material changes in inputs.

The methodology of the cost-benefit analyses is set out in the following sections of this Appendix:

- **Categories of market benefits considered (A2.2.1)** – this section sets out the modelled categories of market benefits considered, ranging from savings associated with deferral of capital expenditure for new generation and transmission, to the fuel cost savings and reductions in voluntary load shedding.
- **Calculating the net benefits of transmission developments using an equivalent annual annuity approach (A2.2.3)** – this section sets out the preferred method applied in the cost benefit analyses to treat all capital investments as equivalent annual annuities. This method allows projects with different asset lifetimes to be considered on the same basis. Mathematically, the approach is equivalent to other methods which take a lump-sum approach to capital investments and apply a terminal value to the remaining asset value that falls outside of the simulation horizon.
- **A scenario-weighted approach to calculating net market benefits (A2.2.4)** – this section sets out the rationale for scenario weightings adopted in assessing and ranking candidate development paths under the mandatory scenario-weighted approach outlined in Part D of the Body of the Report.
- **Determining the least cost development path for each scenario (A2.3)** – many alternative investment decisions are able to meet the future system's physical requirements. These alternative options were assessed using cost-benefit analysis to identify the least-cost development path for each scenario. The net market benefit of the transmission investments of each path were compared against a counterfactual with no new transmission investment beyond what is already committed.
- **Assessing benefits of candidate development paths under each scenario (A2.4)** – this section sets out how candidate development paths, selected through inspection of the various least cost development paths, perform under each scenario. Option value associated with potential staging of various projects is also considered.
- **Testing the resilience of the candidate development paths to events that may occur (A2.5)** – specific events that may happen in the near future, ranging from the early closure of Victorian brown coal generation to the implementation of the Tasmanian Renewable Energy Target (TRET) are considered to identify the robustness of the candidate development paths.

Details of the PSS®E modelling used for these purposes are provided in Appendix 9.

A2.2. Understanding the cost benefit analysis

A2.2.1 Categories of market benefits considered

The ISP applies the AER draft Cost Benefit Analysis (CBA) guidelines to the extent possible. This identifies many market benefit categories that summarise the total change in producer and consumer surplus from the development of the ISP projects (actionable and future) within each candidate development path. The classes of benefits include:

- Changes in fuel consumption.
- Changes in voluntary load curtailment and involuntary load shedding.
- Changes in development capital costs, operating and maintenance costs.
- Changes in transmission losses.
- Option value provided by transmission developments that increase resilience to market risks.

To maximise transparency for stakeholders, AEMO categorised cost savings at a more granular level than is specified by the draft CBA guidelines.

The cost categories considered in modelling, and all other total aggregate system costs figures referred to in this Appendix, are defined in Table 1.

Table 1 System cost categories

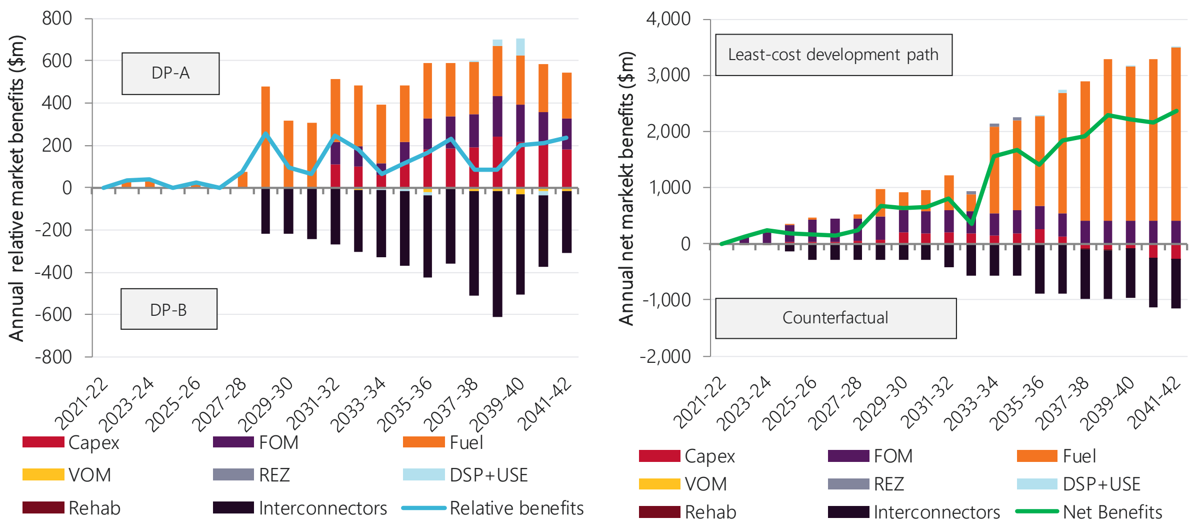
Cost category	CBA market benefit category	Description
Capex	Changes in development capital costs, operating and maintenance costs	Capital expenditure for new generators, annualised (see explanation below)
FOM	Changes in development capital costs, operating and maintenance costs	Fixed operation and maintenance cost (including life extension costs where applicable). These life extension refurbishment costs can result in a material increase in total system FOM costs year to year and are captured within the year the refurbishment occurs.
VOM	Changes in development capital costs, operating and maintenance costs	Variable operation and maintenance cost.
Rehab	Changes in development capital costs, operating and maintenance costs	Rehabilitation costs due to generator retirements.
Fuel	Changes in fuel consumption	Fuel cost for thermal generation plant.
USE+DSP	Voluntary load curtailment and involuntary load shedding	Cost of unserved energy and demand side participation.

Cost category	CBA market benefit category	Description
Network (actionable and future ISP projects)	Changes in development capital costs, operating and maintenance costs	Cost of network development of inter-regional augmentations, including transmission maintenance costs, and actionable early works costs.
Network (generic REZ network costs)	Changes in development capital costs, operating and maintenance costs	Generic REZ network costs represent the estimated cost of increasing hosting capacity for future REZ where specific ISP projects have not yet been identified.

A2.2.2 Interpreting net benefits graphics in this appendix

This appendix presents a number of charts comparing the projected benefits of two different modelled paths over time, as shown in the examples below.

Figure 1 Example interpretation of relative market benefits diagrams used in this Appendix



Interpreting the figures:

- The stacked columns illustrate the projected values for different classes of benefits for each case on an annual basis.
- A positive value indicates the benefits of development path A (DP-A in the figure on the left), and a negative value indicates the benefits of development path B (DP-B in the same figure). For example, the orange and red bars represent greater fuel and generation capital deferral cost savings in DP-A, while the black bars below the line on the left chart indicate greater transmission cost savings in DP-B.
- The blue line represents the projected annual difference in benefits between the two cases. Where the blue line is above the x-axis then DP-A is returning a greater market benefit than DP-B. Conversely, where the blue line is below the x-axis, then DP-B is returning a greater market benefit than DP-A.
- For figures that compare a development path to the counterfactual, the net benefits are represented with a green line. Similar to the previous interpretation, if that line is above the x-axis then the development path presents a positive net benefit. If that line is below the x-axis, the development path represents a net market cost.
- These annual benefits are then converted into a net present value of benefits accumulated over the forecast horizon.

A2.2.3 Calculating net benefits of transmission developments using an equivalent annual annuity approach

To ascertain the net costs and benefits of a scenario relative to a counterfactual, AEMO has annualised all infrastructure costs (generation, storage and transmission) using an equivalent annual annuity method. This is done using the following formula, which converts project capital costs into a stream of annual payments over the economic life of the asset under development. For a transmission asset, for example, this asset life is equivalent to 50 years.

$$P = \frac{C * r}{(1 - (1 + r)^{-t})}$$

where P equals the annual cost of the development, C represents the development's capital costs, r is our weighted average cost of capital[2] (WACC), and t is the economic life of the asset to be annualised over.

This method is commonly used to evaluate projects with different asset lifetimes, as it allows assets of different lifespans to be considered on the same basis. By annualising all costs and benefits, the year-on-year cost of each development path can be compared against the counterfactual, and then the costs of each path/counterfactual to be discounted to 1st of July 2019-20 to determine the net benefits, using the below formula:

$$NPV = \sum_{i=0}^{t} \frac{P_i}{(1 + r)^t}$$

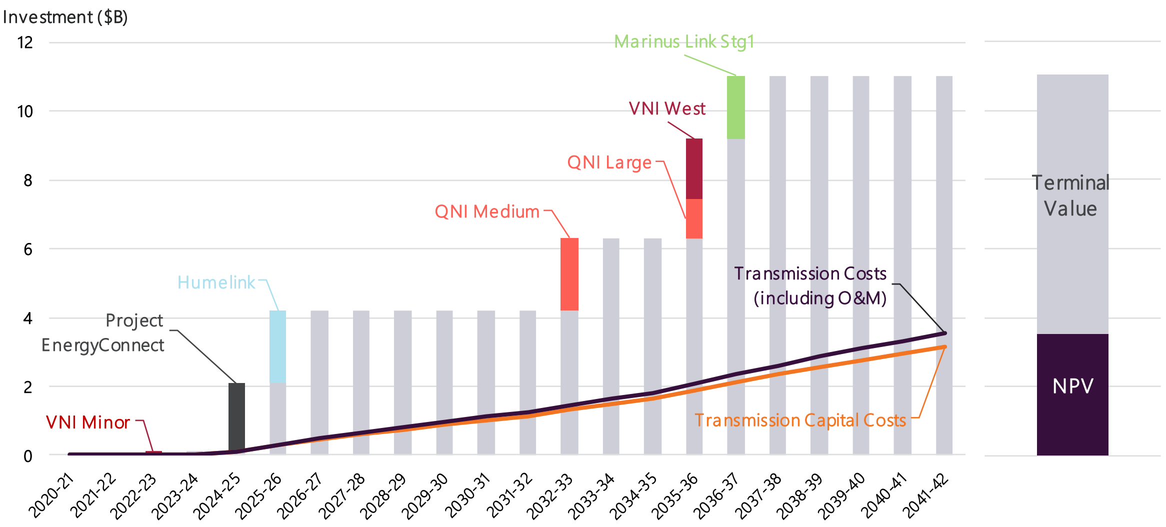
where P_t represents the annualised payments from above, and t is the number of years between 2019-20 and 2041-42.

As the 2020 ISP modelling horizon ends in 2042, there is, however, an implicit assumption that benefits associated with the interconnector beyond this point are greater than or equal to the remaining cost of the interconnector. This is a reasonable assumption to make given that benefits of interconnection in the optimal development path generally increase over time as more coal fired generation retires and is replaced with VRE.

Figure 2 below compares this approach with an alternative approach considering up-front interconnector investment. By the end of the modelling horizon, AEMO's modelling approach explicitly accounts for 32% of the total lifetime transmission investment costs, which in the modelling were weighed against the annual benefits of that transmission investment (also only assessed over the modelling horizon).

[2] The WACC is 5.9% in all scenarios, except for Slow Change, which adopts a WACC of 7.9%, to account for the more challenging economic environment.

Figure 2 Example of transmission investment costs, up-front relative to equivalent annuity costs



A2.2.4 A scenario-weighted approach to calculating net market benefits

Net market benefits were weighted by the relative likelihood of each scenario occurring, in line with the AER's mandatory 'scenario-weighted' approach. This approach, and an alternative least-regrets approach are discussed in Part D.

AEMO has developed weightings for each scenario to apply in calculating net market benefits of each Candidate Development Path, as required in the draft CBA guidelines. These weightings consider the relative likelihood of each scenario and market event sensitivity, given the necessary changes required for the scenario to unfold, and/or the relative likelihood of particular market events. There is inevitably an element of subjectivity associated with these scenario weightings that is avoided in using the least-regret approach. While the mandatory inclusion of scenario weightings was introduced by the AER in its guidelines too late for AEMO to consult on its selection, in future ISPs the weightings will be consulted on. The scenario that maximises net market benefits under the mandatory scenario-weighted approach is relatively insensitive to the choice of weightings. Table 2 presents these assumed weightings.

Table 2 Assumed weightings of each scenario and market event sensitivity

Scenario	Weighting (%)
Central	20
Fast Change	15
Central-West Orana REZ sensitivity	15
Early coal closure sensitivity	10
Closure of industrial load sensitivity	10
High DER	10
Step Change	10
Slow Change	5
Delay of Snowy 2.0 sensitivity	5

In the absence of better information, the default position is to assume all scenarios and market event sensitivities are equally likely to occur. This would lead to each having a weighting of 11% (1/9, given there are nine scenarios and market event sensitivities and their weightings need to sum to 100%). This is used as a starting point for adjusting weightings for scenarios that are consider more or less likely to occur than others.

AEMO's **Central scenario** includes the best estimates of policy initiatives, technology innovations and consumer-developments behind the meter at the time the scenarios were developed and is therefore considered the 'most likely' scenario. With this as a reference, AEMO has developed weightings for each of the other scenarios assessing the likelihood relative to the Central scenario:

- The **Fast Change scenario** reflects a faster degree of market-led innovation, with grid-scale solutions providing appropriate economies of scale deployment. The DER uptake is stronger than the Central scenario. This DER investment includes distributed PV systems, EV uptake, and behind-the-meter battery installations. Differences in assumptions relative to the Central scenario are not significant and therefore is assumed to be only slightly less likely than the Central scenario to occur.
- The **Central-West Orana REZ sensitivity** has all the same assumptions as the Central scenario, except it assumes accelerated development of 2 GW of VRE in the REZ in response to the New South Wales Electricity Strategy. It is therefore assumed to be only slightly less likely than the Central scenario to occur.
- Compared to the Central scenario, both the **early coal closure sensitivity** and the **closure of industrial load sensitivity** are considered less likely to occur but are still highly credible risks to consider. The relative weightings applied to these market event sensitivities effectively assume there is a 30% chance of occurring. For example, if a RIT-T proponent were to consider only the Central scenario and the early Yallourn closure scenario, the relative weightings selected in this ISP would result in the RIT-T proponent applying the Central scenario with 66.7% relative likelihood, and the early Yallourn closure scenario with 33.3% relative likelihood.
- The **High DER scenario** reflects a stronger focus on consumer-led developments, with stronger DER uptake than the Central scenario and reflects a much greater degree of behind-the meter-storage development. This is considered less likely than the Fast Change scenario and has therefore been assigned a lower weighting.
- The **Step Change scenario** reflects the fastest and most challenging energy market transition; however, it is most in line with global ambitions to decarbonise to meet the Paris Agreement and state's continue to promote rapid VRE development through renewable energy targets. While a challenging scenario to achieve, the scenario reflects a reasonable potential future that is consistent with policy ambitions. Its relative likelihood has been set to half the Central scenario (10%).
- The **Slow Change scenario** reflects the slowest energy market transition. It effectively steps away from Federal and state ambitions to embrace new technologies, inconsistent with the Federal Government's technology roadmap and global climate ambitions, and coal fired generation refurbishments are observed. While weak economic growth may persist globally in the near term in response to the global coronavirus pandemic, building global resilience to climate change remains a priority for many. The Slow Change scenario narrative is therefore inconsistent with the current environment. In fact, slow demand growth coupled with continued rapid development of VRE and DER could accelerate the pace of the NEM transition. Its relatively likelihood has therefore been set to one-quarter of the Central scenario (5%).
- The **delay of Snowy 2.0 sensitivity** has a low relative weighting applied to it as current indications are that this project is on track for delivery as planned.

A2.3. Determining the least-cost development path for each scenario

The development paths presented in Part D are based on hundreds of interconnector combinations and permutations with respect to the timing of candidate interconnectors, considering the impact these developments have on other market developments (such as VRE, storage, and GPG developments).

The below example provides a concise simplified example of the general approach taken to identify the scenario-specific least-cost optimal timing of specific interconnectors that then comprise a candidate development path.

A2.3.1 Identifying the preferred timing of interconnectors

AEMO uses an integrated model (IM) to identify the likely preferred size and timing of transmission and generation developments in a co-optimised manner, as described in AEMO's ISP Methodology and Market Modelling Methodology[3]. This modelling provides an initial guide for more detailed, iterative simulations to identify the preferred timing of individual interconnectors, including the specific augmentation options.

The identified optimal timing of interconnector augmentations typically aligns with announced retirement dates of thermal generation plant, or state-based renewable energy policies. Increased interconnection may alleviate the need for additional local generation development in response to retirements by allowing for additional inter-regional support, or otherwise allows excess renewable generation produced via state-based targets to be exported to other regions in greater volume.

For example, to identify the optimal timing of the QNI Medium project, AEMO initially tested several different timings, associated with retirements of coal-fired generation in New South Wales and Queensland:

- 2028-29, linked to the announced retirement of Callide B in Queensland.
- 2029-30, linked to the announced retirement of Vales Point in New South Wales and the final modelled year that the QRET is driving additional VRE developments in Queensland.
- 2032-33, linked to the announced retirement of Eraring in New South Wales.
- No QNI Medium augmentation.

Figure 3 presents the differences in market benefits between introducing QNI Medium in 2028-29 and not at all, in the Central scenario. Positive values show benefits of the augmentation, and negative values the benefits (primarily lower system costs) without augmentation.

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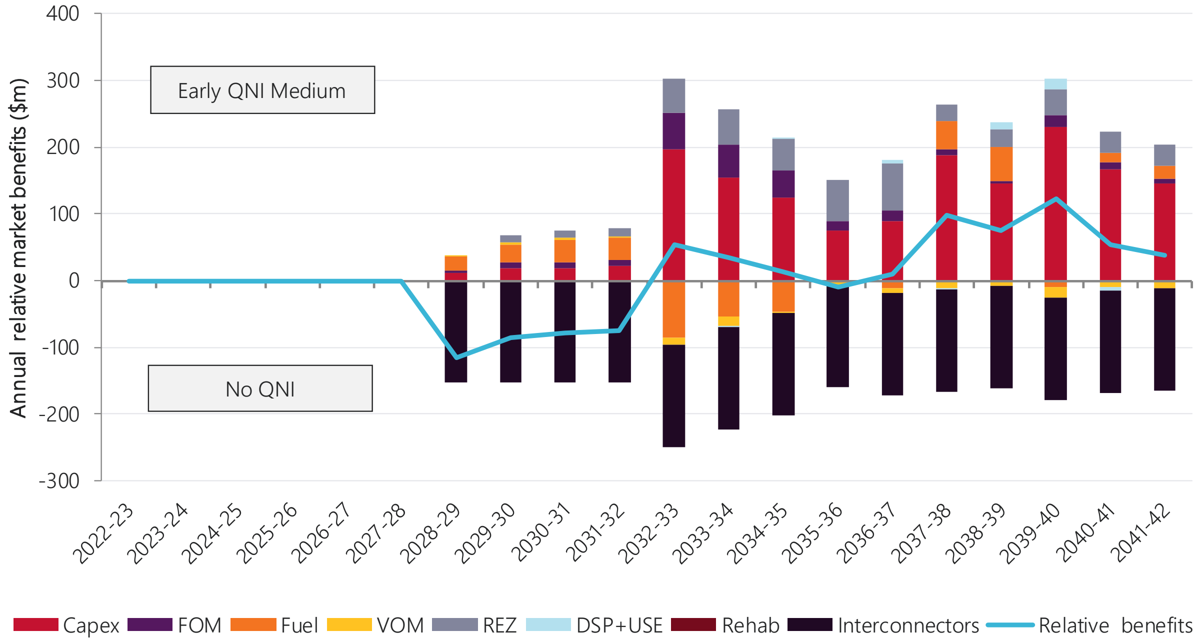
[3] At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp.

Figure 3 Forecast annual relative benefits of QNI Medium when introduced in 2028-29, Central scenario



While there are gross benefits from generator capital deferral and fuel cost savings early on, the augmentation does not deliver positive net market benefits until 2032-33 (where the blue line first crosses the x-axis), which is indicative of the "true" optimal timing of the interconnector in this scenario under the given assumptions. This optimal timing indication is then examined in further iterative modelling to ensure the robustness of the initial findings.

This timing aligns with the retirement of Eraring and suggests additional interconnection to support thermal retirements in New South Wales is a cost-effective solution after Eraring's closure in 2032-33. Before this, the cost associated with the augmentation outweighs the benefits achieved by minor capital deferral and fuel cost savings.

The "indicative" timing of the interconnector was then applied and simulated to confirm the optimal timing of the respective interconnector. As stated above, this was conducted numerous times to explore multiple combinations and permutations of transmission development timings.

The following sections present the key CBA workings used to determine the least-cost development paths for each of the five core scenarios, showing the least-cost development path and the "next best" alternative assessed, but ultimately not selected.

A2.3.2 Least-cost development path for Central scenario

In the process of identifying the least-cost development paths for each scenario, several different timings of interconnectors were analysed. Four of the more favourable development paths for the Central scenario are presented in Table 3.

The least-cost development path for the Central scenario (DP1) includes the completion of low-regret transmission projects (VNI Minor, Project EnergyConnect, Central-West Orana REZ Transmission Link and HumeLink) and the fixed path to develop QNI Medium by 2032-33, QNI Large by 2035-36, VNI West by 2035-36 and Marinus Link (Stage 1 only) by 2036-37.

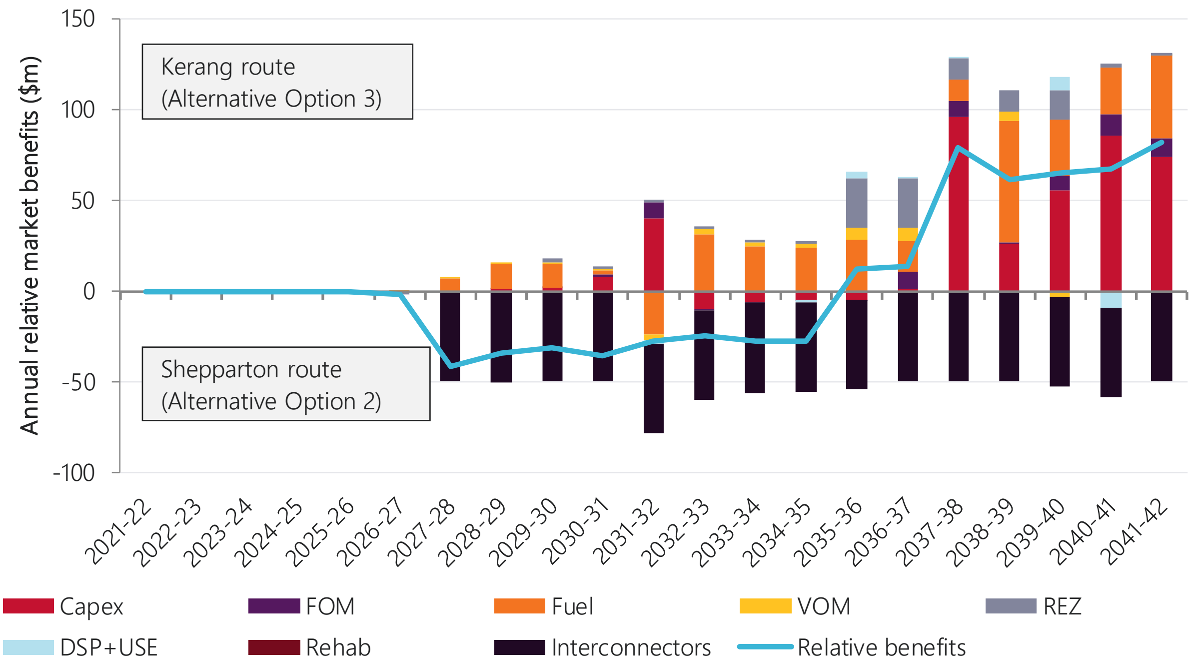
Comparing the alternative options in Table 3, it can be concluded that investing in either the Shepparton route or the Kerang route for VNI West would provide similar net market benefits, despite differences in costs, with all other interconnectors being built at the same instance. The cost benefit analysis alone does not categorically favour one option over the other.

Table 3 Examples of favourable development paths analysed in the Central scenario

Option	Interconnector options										Relative reduction in net benefits ($M)
	QNI Minor	VNI Minor	Hume Link	Project EnergyConnect	QNI Medium	QNI Large	VNI West (Kerang route)	VNI West (Shepparton route)	Marinus Link Stage 1	Marinus Link Stage 2	
DP1	2022-23	2022-23	2025-26	2024-25	2032-33	2035-36	-	2035-36	2036-37	-	-
Alternative options											
1	2022-23	2022-23	2025-26	2024-25	2032-33	2035-36	2035-36	-	2036-37	-	- 3.53
2	2022-23	2022-23	2025-26	2024-25	2032-33	2035-36	-	2027-28	2036-37	-	- 369
3	2022-23	2022-23	2025-26	2024-25	2032-33	2035-36	2027-28	-	2036-37	-	- 378.39

As depicted in Figure 4, the differences between both VNI West routes (Kerang/Shepparton) are in NPV terms similar, but vary over the course of the outlook. These relatively minor differences can be attributed to either the benefits of a lower cost network augmentation (Shepparton) or fuel cost savings and capital deferral post 2035-36 (Kerang). The RIT-T will determine the preferred route.

Figure 4 Forecast annual relative benefits of VNI West (Shepparton route against Kerang route) when introduced in 2027-28, Central scenario



A2.3.3 Least-cost development path for Slow Change scenario

The least-cost development path in the Slow Change scenario (DP2) requires only the completion of low regret transmission projects (VNI Minor, Project EnergyConnect, Central-West Orana REZ Transmission Link and HumeLink). Unlike all the other scenarios, the Slow Change scenario's least-cost development path does not require actioning of the other transmission projects due to the scenario having a significantly slower energy transition. This slow-down in transition is a consequence of slower economic growth and lower policy, commercial and consumer motivation to invest in technologies required to reduce emissions (for example, the refurbishment of coal-fired generation is observed, and renewable energy targets are abandoned).

Table 4 below shows the scenario's least-cost development path against two other favourable development options for the Slow Change scenario. Due to the assumptions considered above for the Slow Change scenario, the signal to develop interconnectors is moderated, effectively resulting in a position were only one major interconnector is required to maximise net benefits. Ultimately the introduction of Project EnergyConnect was identified as the augmentation that maximised benefits whilst able to assist in inter-regional energy transfers between the southern and northern regions. Other interconnectors could potentially address this role but resulted in a reduction of net benefits.

Table 4 Examples of favourable candidate development paths analysed in the Slow Change scenario

Option	Interconnector options										Relative reduction in net benefits ($M)
	QNI Minor	VNI Minor	Hume Link	Project EnergyConnect	QNI Medium	QNI Large	VNI West (Kerang route)	VNI West (Shepparton route)	Marinus Link Stage 1	Marinus Link Stage 2	
DP2	2022-23	2022-23	2025-26	2024-25	-	-	-	-	-	-	-
Alternative options											
1	2022-23	2022-23	2025-26	-	-	-	2029-30	-	-	-	- 63.52
2	2022-23	2022-23	-	-	-	2035-36	-	-	-	-	- 250.10

A2.3.4 Least-cost development path for Fast Change scenario

Table 5 presents four of the more favourable development paths for the Fast Change scenario. In the Fast Change scenario, the least-cost development path (DP3) requires the completion of low regret transmission projects (VNI Minor, Project EnergyConnect, Central-West Orana REZ Transmission Link and HumeLink) and development of QNI Medium by 2032-33, QNI Large by 2035-36, VNI West by 2035-36 and Marinus Link Stage 1 by 2031-32; this is accelerated compared to the Central scenario.

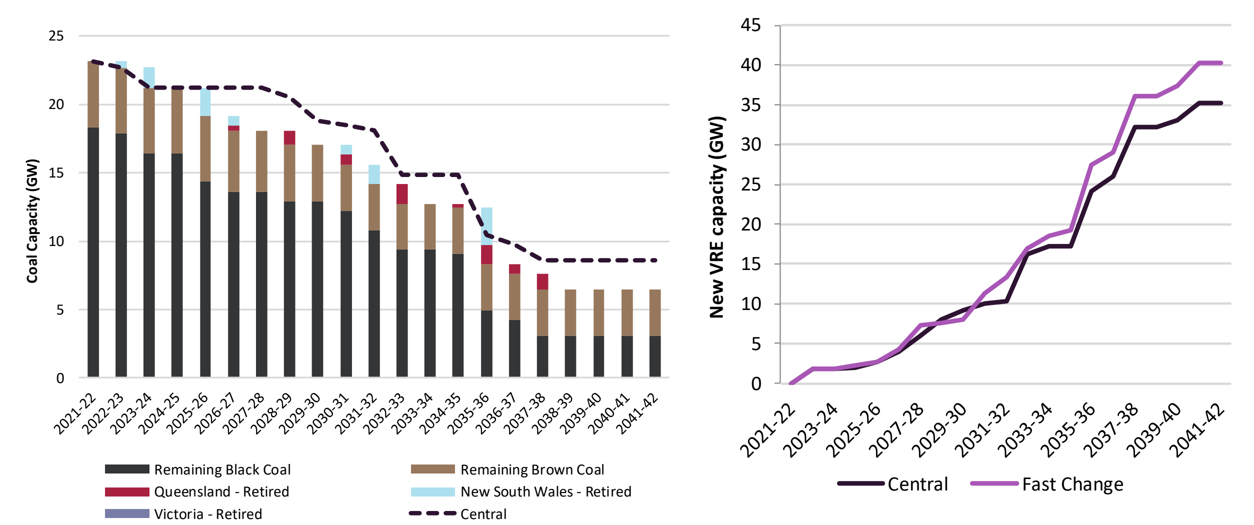
Table 5 Examples of favourable candidate development paths analysed in the Fast Change scenario

Option	Interconnector options										Relative reduction in net benefits ($M)
	QNI Minor	VNI Minor	Hume Link	Project EnergyConnect	QNI Medium	QNI Large	VNI West (Kerang route)	VNI West (Shepparton route)	Marinus Link Stage 1	Marinus Link Stage 2	
DP3	2022-23	2022-23	2025-26	2024-25	2032-33	2035-36	-	2035-36	2031-32	-	-
Alternative options											
1	2022-23	2022-23	2025-26	2024-25	2032-33	2035-36	-	2035-36	2031-32	2035-36	- 14.63
2	2022-23	2022-23	2025-26	2024-25	2032-33	2035-36	2035-36	-	2036-37	-	- 23.87
3	2022-23	2022-23	2025-26	2024-25	2032-33	2035-36	-	2035-36	2036-37	-	- 64.37

The table highlights the relative benefit of the Kerang route of VNI West in this scenario. In Fast Change, and with a commissioning by 2035-36, the Kerang route delivers approximately $40 million greater benefits than the Shepparton route (in NPV terms), with all other inter-regional transmission developments held constant. While not tested, the net market benefits of the least cost development path in this scenario may also have been slightly greater with the Kerang route. However, given there is insufficient detail in the modelling alone to adequately differentiate the two routes, the Shepparton route was carried forward for inclusion in the candidate development paths due to it being the lowest cost option in more of the scenarios and sensitivities considered. Further, being lower cost, it was less regretful in the Slow Change scenario. The RIT-T will determine the preferred route.

Due to the carbon budget assumed in this scenario, coal plants are retired at a more rapid rate than the Central Scenario, increasing the value of earlier VRE and firming support from Tasmania to offset these retirements. This accelerates the timing of transmission investments (Marinus Link) relative to scenarios without a carbon budget or TRET. The relative pace of coal retirements and VRE build up is shown in Figure 5 below. These earlier retirements lead to a greater penetration of VRE to meet this scenario's emissions budget.

Figure 5 Forecast coal retirements to 2041-42 and VRE build up, Fast Change scenario



A2.3.5 Least-cost development path for Step Change scenario

Among all the candidate development paths analysed in the Step Change scenario, three of the more favourable paths are presented in Table 6. The least-cost development path in the Step Change scenario (DP4) requires development of all major interconnectors, which includes QNI Medium, QNI Large, VNI West and Marinus Link, in addition to the development of priority transmission projects. While the Kerang route for VNI West has greater net benefits (in NPV terms) than the Shepparton route in this scenario, the Shepparton route was carried forward for inclusion in the candidate development paths due to it being the lowest cost option in more of the scenarios and sensitivities considered. Further, being lower cost, it was less regretful in the Slow Change scenario. The RIT-T will determine the preferred route.

Unlike all the other scenarios, the Step Change scenario requires accelerated development of both stages of Marinus Link (Stage 1 by 2028-29 and Stage 2 by 2031-32). This is partly due to the need to advance coal retirement in the Step Change scenario to meet the scenario's carbon budget, as well as the inclusion of TRET in this scenario. Accelerating the development of both Marinus Link cables allows for higher emission reductions by exporting excess renewable generation from Tasmania to the mainland.

Table 6 Examples of favourable candidate development paths analysed in the Step Change scenario

Option	Interconnector options										Relative reduction in net benefits ($M)
	QNI Minor	VNI Minor	Hume Link	Project EnergyConnect	QNI Medium	QNI Large	VNI West (Kerang route)	VNI West (Shepparton route)	Marinus Link Stage 1	Marinus Link Stage 2	
DP4	2022-23	2022-23	2025-26	2024-25	2032-33	2035-36	-	2035-36	2028-29	2031-32	-
Alternative options											
1	2022-23	2022-23	2025-26	2024-25	2032-33	2035-36	2035-36	-	2028-29	2031-32	80.25
2	2022-23	2022-23	2025-26	2024-25	2032-33	2035-36	-	2027-28	2028-29	2031-32	- 179.03
3	2022-23	2022-23	2025-26	2024-25	2032-33	2035-36	-	2035-36	2031-32	2035-36	- 185.54

A2.3.6 Least-cost development path for High DER scenario

Table 7 presents some examples of the more favourable candidate development paths in the High DER scenario. The least-cost development path in the High DER scenario (DP5) requires the completion of low regret transmission projects (VNI Minor, Project EnergyConnect, Central-West Orana REZ Transmission Link and Hume Link) and the development of QNI Medium by 2032-33, QNI Large by 2035-36, Marinus Link Stage 1 in 2031-32 and Marinus Link Stage 2 in 2035-36.

Table 7 Examples of favourable candidate development paths analysed in the High DER scenario

Option	Interconnector options										Relative reduction in net benefits ($M)
	QNI Minor	VNI Minor	Hume Link	Project EnergyConnect	QNI Medium	QNI Large	VNI West (Kerang route)	VNI West (Shepparton route)	Marinus Link Stage 1	Marinus Link Stage 2	
DP5	2022-23	2022-23	2025-26	2024-25	2032-33	2035-36	-	-	2031-32	2035-36	-
Alternative options											
1	2022-23	2022-23	2025-26	2024-25	2032-33	2035-36	-	2035-36	2031-32	-	- 38.81
2	2022-23	2022-23	2025-26	2024-25	2032-33	2035-36	-	2035-36	2031-32	2035-36	- 56.95
3	2022-23	2022-23	2025-26	2024-25	2032-33	2035-36	2035-36	-	2031-32	2035-36	- 73.73

Due to increased levels of DER uptake across the NEM (particularly behind-the-meter storage acting as VPPs), the High DER scenario's least-cost development path does not require the development of the VNI West augmentation, although the alternative options with VNI West included deliver only $39 million to $57 million fewer net market benefits on a NPV basis (as evidenced in comparing the rows of Table 7) . However, with the inclusion of the TRET in this scenario, both stages of Marinus Link are required to export excess renewable generation from Tasmania to the mainland.

A2.3.7 The benefits of least cost development paths in each scenario

The following sections outline the annual benefits and costs of each scenario for each of the candidate development paths, relative to the counterfactual without further transmission development, as explained in Section D3. Further detail on the transmission projects themselves is provided in Appendix 3.

Counterfactual developments under the Central scenario and the benefits of network augmentations

The ISP counterfactual scenario identifies that a significant increase in system costs is forecast, mainly from fuel costs associated with operating GPG to replace retiring aging assets across the NEM. Without investments in transmission projects (including developments to support REZs), the transition to lower-cost VRE is compromised, relying much more strongly on GPG.

The figures below present the net difference between the least-cost development path for the Central scenario and the counterfactual where no transmission is developed.

Figure 6 demonstrates that:

- The counterfactual scenario does not invest in transmission development, with cost savings associated with this lower investment (relative to the least cost development path) rising to approximately $785 million a year by 2039-40.
- The least cost development path projects a material reduction in fuel costs, as a result of the expanded development and sharing of new VRE resources across the NEM, providing a net annualised benefit of approximately $3.7 billion in 2039-40.
- The combined generation and storage capital costs under both development paths are broadly similar – there is no major capital deferral benefits in either the path.

The annual net market benefits of the least cost development path is represented by the green line in Figure 6. By 2039-40, the least cost development path is forecast to provide a net benefit of around $3.2 billion a year in real dollar terms.

Under the Central scenario, the net benefits of transmission developments accrue materially from 2032-33. The least cost development path develops significant transmission expansion in the 2030s to assist in the connection of VRE in REZs to replace retiring thermal generators. Intra-regional REZ developments are complemented by major inter-regional transmission corridors that facilitate the efficient connection of new REZs, and the sharing of this new energy source with the broader NEM. Without this transmission investment, retiring coal generation must be replaced with alternative energy sources – particularly GPG or higher relative cost VRE limited by existing transmission capabilities. Once spare VRE hosting capacity is consumed in the counterfactual, the higher reliance on GPG materially increases system costs (from the 2030s).

Figure 6 Net market benefits of the least cost development path to 2041-42 relative to the counterfactual for Central scenario

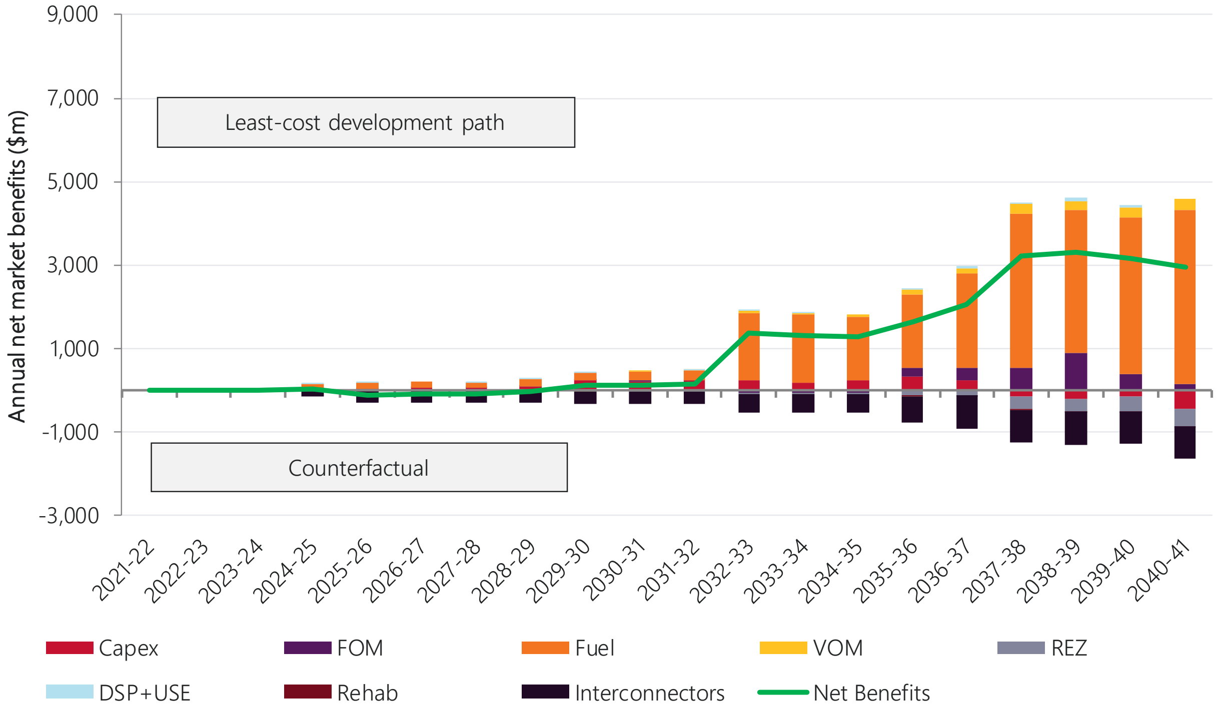


Table 8 provides a summary of the total net market benefits to 2041-42 of the least cost development path in comparison to the counterfactual, in net present value (NPV) terms. This shows that cumulative gross benefits of Figure 6 above, discounted back to present value, is $11.9 billion, delivered in the form of cost savings. Most of this benefit is due to greater use of low fuel cost generation, lowering overall fuel costs by $10 billion. In contrast, the cumulative cost of transmission (including REZ expansions) in this development path, annualised and discounted back to present value is $4.2 billion. Net market benefits of $7.7 billion (NPV) are therefore delivered to consumers from this least cost development path.

Table 8 Net market benefits of least-cost development path by category, Central scenario

Benefit category	Net Benefit ($M)
Capex	$570
FOM	$692
Fuel	$10,045
VOM	$511
USE+DSP	$124
Rehab	-$10
Gross Market Benefits	**$11,932**
Network (actionable and future ISP projects)	-$3,530
Network (generic REZ network costs)	-$714
Total Net Benefits	**$7,688**

A similar outcome was obtained for the other eight scenarios and market event sensitivities where there is a significant reliance on local gas generation in the absence of additional network interconnection that enables reasonable expansion of the VRE fleet. A summary for each of the other scenarios is presented in the following section.

A2.3.8 Counterfactual developments under the alternative core scenarios

Similar outcomes to the Central scenario are observed across the other core scenarios and market event sensitivities. In all scenarios at least some portion of the aging coal generation fleet is retired, and the lost energy generation requires replacement. Addressing the reduction in coal generation is achieved through the expansion of VRE resources, complemented by energy storages, DER and sometimes, GPG.

From Table 8 and Table 9 an investment of between $2.3 billion and $6.4 billion (in NPV terms) in the form of interconnectors and REZ expansions will provide between $56 million and $40.7 billion of net market benefits (also in NPV terms) in the form of cost savings.

Figure 7 **Net market benefits of the scenario-specific least-cost development path to 2041-42 relative to the counterfactual scenario for (clockwise from top left) Slow Change, Fast Change, Step Change and High DER**

As per the Central scenario, most of this benefit is due to greater use of lower fuel cost generation, particularly VRE rather than GPG operation, lowering overall fuel costs by between $1.0 billion and $18.7 billion.

There are also capital deferral benefits, ranging from $389 million to $24 billion, where significant investment is required especially in the Fast Change and Step Change scenarios. Under the counterfactual for these scenarios (where more of the retiring coal generation is replaced by GPG rather than VRE), the coal fleet needs to retire earlier than in the least cost development paths for these same scenarios in order to still meet carbon budgets.

Table 9 Net market benefits of least-cost scenario optimal development path by category for High DER, Fast Change, Step Change and Slow Change scenarios

Benefit category	Net Benefit ($M)			
	Slow Change	Fast Change	Step Change	High DER
Capex	$389	$7,951	$23,842	$768
FOM	$917	-$872	$3,704	$888
Fuel	$1,046	$11,339	$18,670	$6,250
VOM	-$2	$383	$722	$293
USE+DSP	$19	$148	$128	$86
Rehab	-$52	$251	$33	-$9
Gross Market Benefits	**$2,317**	**$19,200**	**$47,100**	**$8,277**
Network (actionable and future ISP projects)	-$2,255	-$3,814	-$4,407	-$3,746
Network (generic REZ network costs)	-$6	-$1,008	-$1,955	-$526
Total Net Benefits	**$56**	**$14,379**	**$40,738**	**$4,004**

A2.4. Assessing benefits of candidate development paths under each scenario

Eight candidate development paths were selected through inspection of the least cost development paths for each scenario, identifying elements of the paths that were common, and also, elements where the timing of investment depends on how the future unfolds. Elements that are less certain are typically more suited to staging, so that investment decisions can be adapted over time.

Through this inspection, the five least cost development paths for each scenario were selected, along with three additional development paths either staging, or varying the timing of Marinus Link and VNI West, as discussed in Part D.

To maximise development path flexibility (and minimise regret), early works for immediate progression were considered for Marinus Link (in all three additional development paths: DP6, DP7 and DP8) and VNI West (in one of the additional development paths, DP7). Early works comprise all feasibility, design and approvals phases, including marine and land surveys, for both cables, to the point of being ready to commence construction.

TasNetworks advises that completing the early works now would cost $140 million, while completing them in seven to ten years would be $174 million, including the cost of any re-working. The time value of money reduces that $34 million gap to $20 million on a NPV basis, and this cost has been included in DP6, DP7 and DP8. In the Slow Change scenario, where Marinus Link is not eventually built, the NPV of the early works cost equivalent to approximately $123 million in current dollars[4].

Initial estimates of the costs of early works for VNI West lie between $150-200 million, and will be further refined in the RIT-T. However, since these activities are required whenever the project is completed, the true early works cost is simply the cost of bringing them forward. For example, the NPV in current dollars of bringing forward costs of $150m would only be $52 million if VNI West is eventually built, and approximately $139 million if it is not. These costs have been included in DP7.

Rows in Table 10 represent the different candidate development paths, while columns refer to the different scenarios and market event sensitivities that have been considered (see Table 6 in Section D2.1 for details of transmission projects and timings of each candidate development path).

[4] The Slow Change scenario applies a WACC that is greater than other scenarios.

Table 10 Candidate development path matrix

Candidate development paths	Scenarios/sensitivities								
	Central	Step Change	Slow change	Fast Change	High DER	Central-West Orana REZ sensitivity	Early coal closure	Delay of Snowy 2.0	Closure of industrial load
DP1 (optimal in Central)	DP1	DP1	DP1	DP1	DP1	DP1	DP1	DP1	DP1
DP2 (Optimal in Slow Change)	DP2	DP2	DP2	DP2	DP2	DP2	DP2	DP2	DP2
DP3 (Optimal in Fast Change)	DP3	DP3	DP3	DP3	DP3	DP3	DP3	DP3	DP3
DP4 Optimal in Step Change)	DP4	DP4	DP4	DP4	DP4	DP4	DP4	DP4	DP4
DP5 (Optimal in High DER)	DP5	DP5	DP5	DP5	DP5	DP5	DP5	DP5	DP5
DP6 (Central early works on Marinus Link)	DP1	DP4	DP2 With QNI Medium from 2031-32 and VNI West in 2035-36	DP3	DP5 With VNI West in 2035-36	DP1	DP1	DP1	DP1
DP7 (Central early works on Marinus Link and VNI West)	DP1	DP4	DP2 With QNI Medium from 2031-32	DP3	DP5	DP1	DP1	DP1	DP1
DP8 (Accelerated VNI West with early works on Marinus Link)	DP1 With VNI West in 2027-28	DP4 With VNI West in 2027-28	DP2 With QNI Medium from 2031-32 and VNI West in 2027-28	DP3 With VNI West in 2027-28	DP5 With VNI West in 2027-28	DP1 With VNI West in 2027-28	DP1 With VNI West in 2027-28	DP1 With VNI West in 2027-28	DP1 With VNI West in 2027-28

To evaluate performance of each candidate development path, and inform selection of the optimal development path, AEMO has compared the total system costs of each candidate development path against the counterfactual, under each scenario and market event sensitivity. All candidate development paths deliver significant market benefits relative to the counterfactual, but differences between candidate development paths are often much smaller. This indicates there is much lower regret in potentially over-investing, or selecting sub-optimal timing, than there is in not investing in any future network.

A2.4.1 Central scenario

Table 11 presents the difference in net market benefits for all the various DPs assessed relative to DP1, the least cost development path for the Central scenario.

Table 11 Net market benefits of candidate development paths relative to DP1, Central scenario

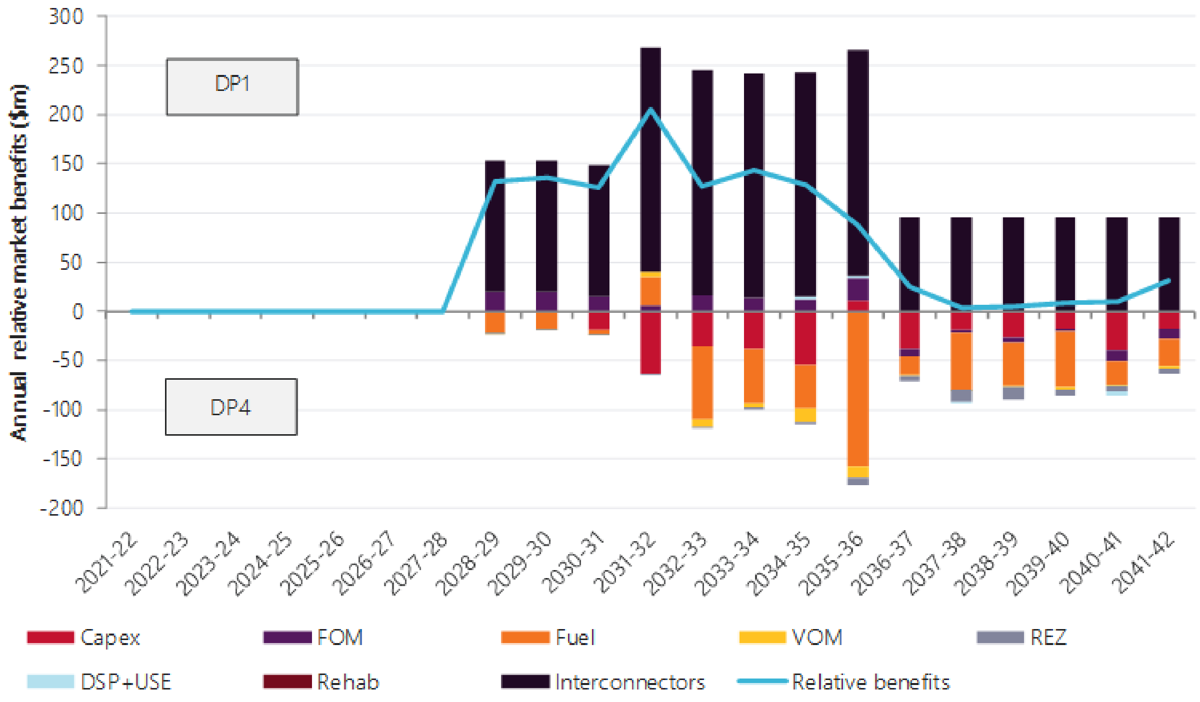
Development path	Net market benefits ($M) (ordered highest to lowest)	Net market benefits relative to DP1 ($M)
DP1 (least cost in Central)	7,688	-
DP6 (Early works on Marinus Link, giving flexibility to deliver it earlier or not at all, but otherwise the developments are in line with Central)	7,667	-20
DP7 (Early works on Marinus Link and VNI West, giving flexibility to deliver them both earlier or not at all, but otherwise the developments are in line with Central)	7,615	-72
DP3 (least cost in Fast Change)	7,564	-123
DP5 (least cost in High DER)	7,479	-208
DP2 (least cost in Slow Change)	7,413	-275
DP8 (Accelerated VNI West with early works on Marinus Link)	7,298	-389
DP4 (least cost in Step Change)	7,152	-535

As shown in Table 11, the relative difference in net market benefits between each development path and DP1 (the least-cost development path for the Central scenario) ranges from -$20 million (DP6) to -$535 million (DP4).

Figure 8 presents the difference in total system costs between DP1 and DP4 (where immediate action is taken to develop both stages of Marinus Link) where a positive value indicates a lower total system cost (higher net market benefits) in DP1 relative to DP4 and vice versa – the best, and worst performing DPs under the Central scenario.

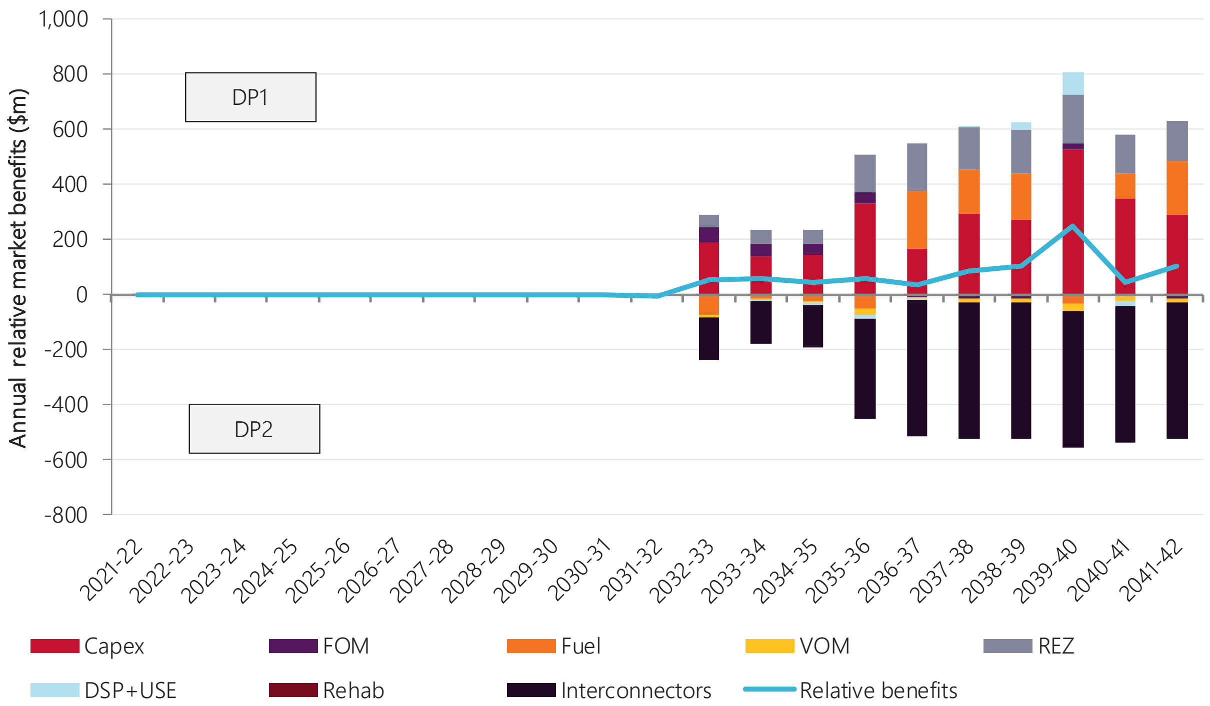
It is evident that the difference in cost across most years stems from interconnector developments where transmission projects, specifically Marinus Link (Stage 1 and Stage 2) are accelerated in DP4. In this scenario, these costs outweigh any benefits derived from early Marinus Link development, resulting in an additional $535 million cost relative to the least-cost optimal development path in the Central scenario.

Figure 8 Relative market benefits between DP1 and DP4 to 2041-42 for the Central scenario



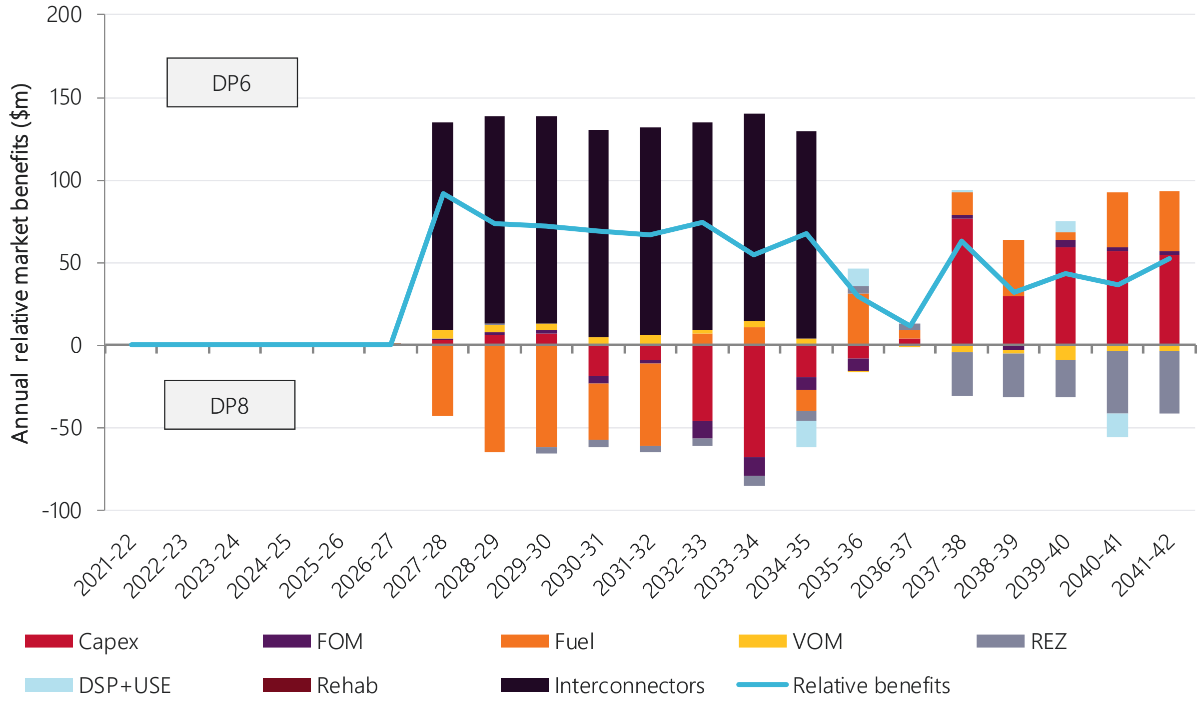
In contrast, Figure 9 compares how DP2 – the candidate development path with only low regret investments included – performs against DP1 under the Central scenario. Without QNI (both Medium and Large), VNI West or Marinus Link (both cables), DP2 delivers fewer net market benefits (that is, total system costs increase from 2032 onwards when more black and brown coal generation retires).

Figure 9 Difference in relative market benefits between DP1 and DP2 to 2041-42 for the Central scenario



Under the Central scenario, advancing VNI West development to 2027-28 and commencing early works on Marinus Link (as in DP8) represents a reduction in net market benefits (an increase in total system cost) of $389M, as seen in Figure 10. The increased fuel cost saving in DP8 is insufficient to cover the cost of advancing VNI West and commencing early works on Marinus Link. The ability for new transmission to better utilise existing resources and defer the need for new generation and storage are also evident in Figure 10, with capex incurred earlier in DP6.

Figure 10 Difference in relative market benefits between DP6 and DP8 to 2041-42 for the Central scenario



A2.4.2 Slow Change scenario

Table 12 presents the difference in net market benefits for all the various DPs for the Slow Change scenario.

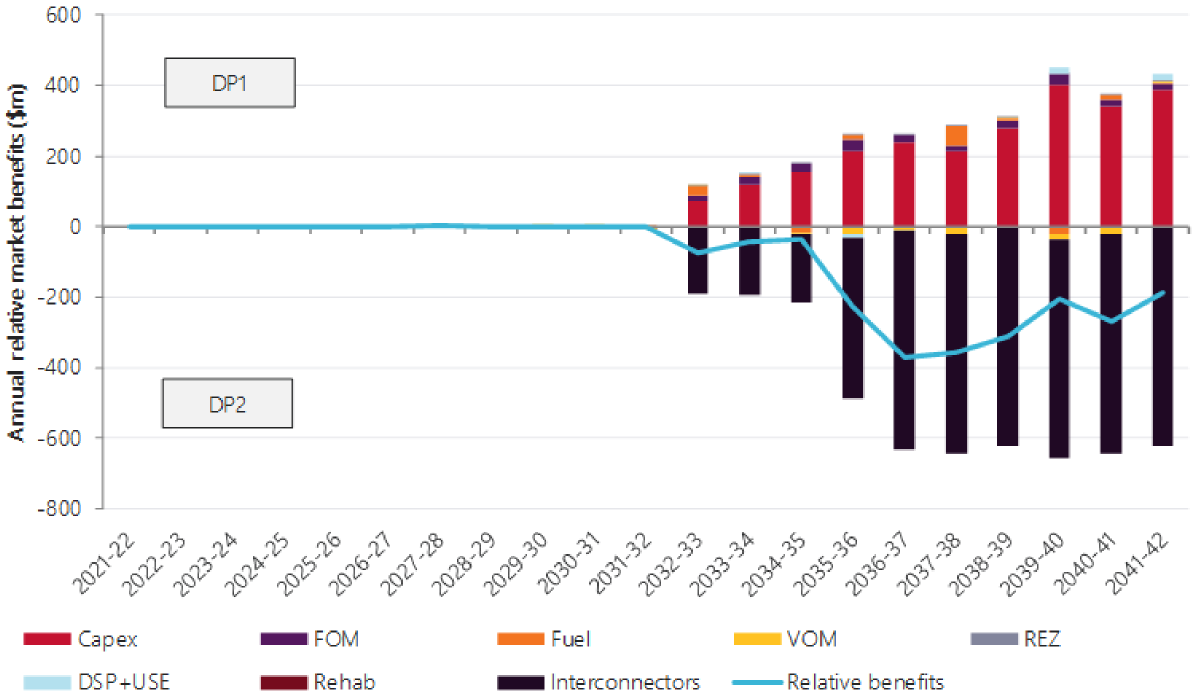
The relative difference in net market benefits between each DP and DP2 ranges from -$475 million (DP6) to -$1.25 billion (DP4), with the greatest regret being if all transmission projects identified in the DPs are progressed at the relatively early timing of the Step Change's least-cost optimal development path (DP4). For the Slow Change scenario, only DP2 presents a positive net market benefit, highlighting that the pace of transition (with coal refurbishments and lower DER and consumer demand) reduces the benefits from significant transmission development.

Table 12 Net market benefits of candidate development paths relative to DP2, Slow Change scenario

Development path	Net market benefits ($M) (ordered highest to lowest)	Net market benefits relative to DP2 ($M)
DP2 (least cost in Slow Change)	56	-
DP6 (Early works on Marinus Link, giving flexibility to deliver it earlier or not at all, but otherwise the developments are in line with Central)	-419	-475
DP1 (least cost in Central)	-427	-483
DP7 (Early works on Marinus Link and VNI West, giving flexibility to deliver them both earlier or not at all, but otherwise the developments are in line with Central)	-456	-512
DP3 (least cost in Fast Change)	-630	-687
DP5 (least cost in High DER)	-640	-696
DP8 (Accelerated VNI West with early works on Marinus Link)	-680	-736
DP4 (least cost in Step Change)	-1,193	-1,249

Figure 11 presents a comparison between the least-cost development path for the Slow Change scenario, (DP2), and DP1. Pursuing DP1 in the Slow Change scenario delivers approximately $483 million NPV fewer net market benefits than DP2, highlighting some risk of over-investing in this scenario if future investment decisions are locked-in today and there is no access to recourse at a later time. This cost, incurred to develop the additional interconnection, is not covered by the benefits. Consequently, an increase in total system cost (i.e. a reduction in net market benefits) is forecast from 2032. DP6, with early works on Marinus Link progressing immediately, performs slightly more favourably than DP1 in this scenario as the regret of over-investing is minimised by electing not to progress through to construction of the first cable.

Figure 11 Difference in relative market benefits between DP1 and DP2 to 2041-42 for the Slow Change scenario



A2.4.3 Fast Change scenario

Table 13 presents the difference in net market benefits for all the DPs assessed in the Fast Change scenario.

Table 13 Net market benefits of the candidate development paths relative to DP3, Fast Change scenario

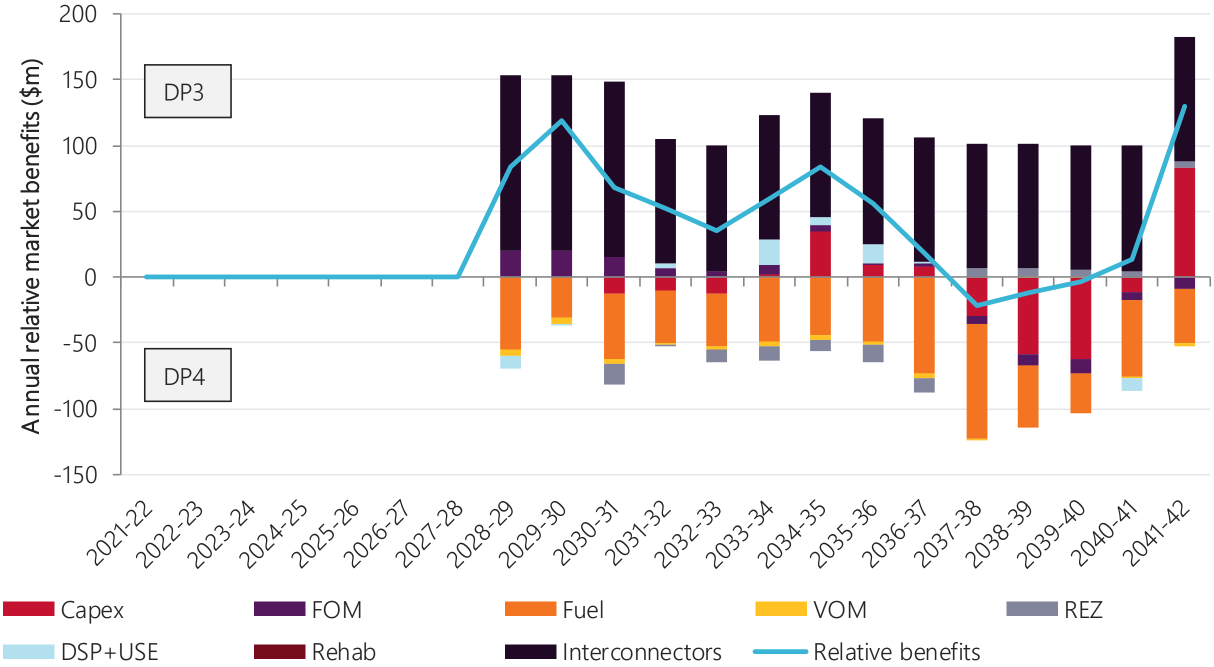
Development Path	Net market benefits ($M) (ordered highest to lowest)	Net market benefits relative to DP3 ($M)
DP3 (least cost in Fast Change)	14,379	-
DP6 (Early works on Marinus Link, giving flexibility to deliver it earlier or not at all, but otherwise the developments are in line with Central)	14,379	0
DP7 (Early works on Marinus Link and VNI West, giving flexibility to deliver them both earlier or not at all, but otherwise the developments are in line with Central)	14,326	-52
DP1 (least cost in Central)	14,314	-64
DP5 (least cost in High DER)	14,276	-102
DP2 (least cost in Slow Change)	14,171	-207
DP4 (least cost in Step Change)	14,081	-298
DP8 (Accelerated VNI West with early works on Marinus Link)	14,051	-328

Note. DP3 and DP6 present equivalent market benefits, as DP6 enables the flexibility to deliver Marinus.Link at an early delivery date (in or before 2031-32). In DP3 the project is delivered by this early date, and therefore the cost of the early works that enable that flexibility is effectively zero, given that the delivery schedule is advanced in both DPs. DP7 and DP8 also enable the flexibility to deliver Marinus Link early, but they also include either VNI West early works or accelerated development.

One of the largest differences in net market benefits relative to DP3 (the least cost development path in the Fast Change scenario) is DP4 (-$298 million), which is the least-cost development path in the Step Change scenario. In DP4, both Marinus Link cables are built early (2028-29 and 2031-32) whereas in DP3, only one stage of Marinus Link is built, in 2031-32.

Figure 12 compares the total system cost between these two development paths. Most years present positive values, indicating an overall higher net benefits for DP3 relative to DP4 due to the additional costs associated with an accelerated development of Marinus Link. Under DP4, the fuel cost savings associated with liberating Tasmanian generation production are insufficient to justify the costs of advancing both Marinus Link cables and the complementary mainland storage required at the end of the planning horizon to best utilise this additional wind production.

Figure 12 Difference in relative market benefits between DP3 and DP4 to 2041-42 for the Fast Change scenario



A2.4.4 Step Change scenario

Table 14 presents the difference in net market benefits for all the various DPs assessed in the Step Change scenario.

Table 14 Net market benefits of candidate development paths relative to DP4, Step Change scenario

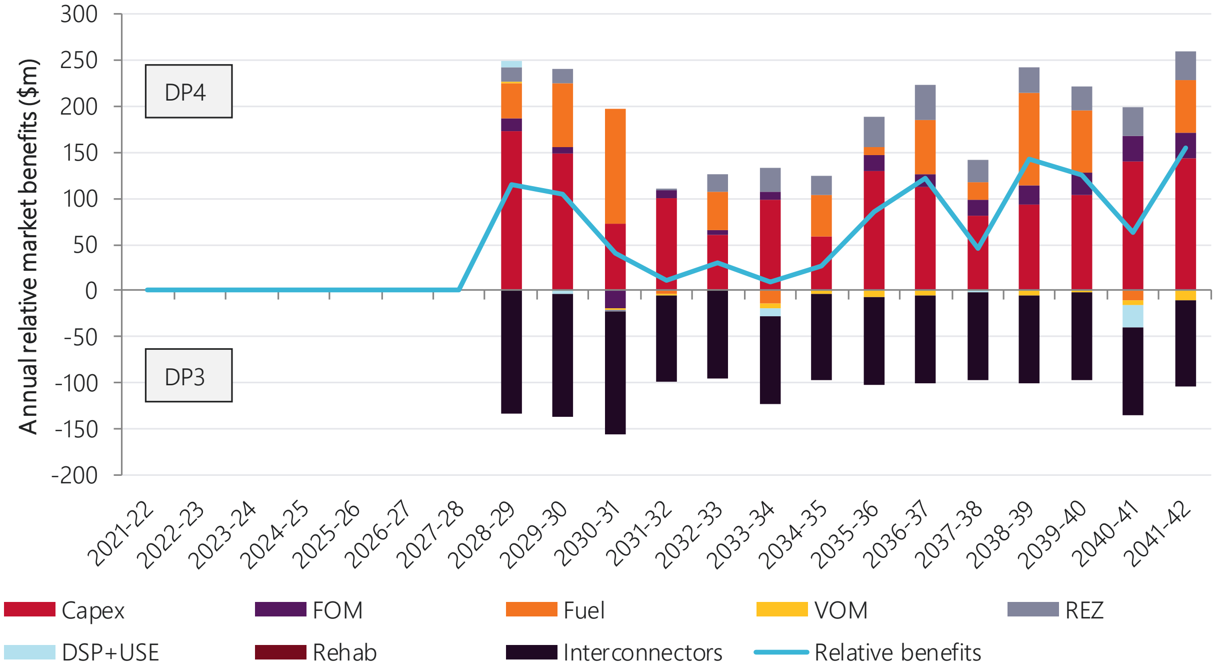
Development Path	Net market benefits ($M)	Net market benefits relative to DP5 ($M)
DP4 (least cost in Step Change)	40,738	-
DP6 (Early works on Marinus Link, giving flexibility to deliver it earlier or not at all, but otherwise the developments are in line with Central)	40,738	-
DP7 (Early works on Marinus Link and VNI West, giving flexibility to deliver them both earlier or not at all, but otherwise the developments are in line with Central)	40,686	-52
DP8 (Accelerated VNI West with early works on Marinus Link)	40,559	-179
DP3 (least cost in Fast Change)	40,330	-408
DP5 (least cost in High DER)	40,190	-548
DP1 (least cost in Central)	39,761	-977
DP2 (least cost in Slow Change)	38,333	-2,405

Note. DP4 and DP6 present equivalent market benefits, as DP6 enables the flexibility to deliver Marinus.Link at an early delivery date (in or before 2031-32). In DP4 the project is delivered by this early date, and therefore the cost of the early works that enable that flexibility is effectively zero, given that the delivery schedule is advanced in both DPs. DP7 and DP8 also enable the flexibility to deliver Marinus Link early, but they also include either VNI West early works or accelerated development.

The net market benefits of all the candidate development paths in the Step Change scenario presented in Table 14 are the highest among all scenarios which highlights the significance of developing new transmission infrastructure to enable the transition to VRE (with storage and other firming technologies) in a scenario with strong carbon abatement ambition. As highlighted previously, the benefits are accrued predominantly from savings in capital expenditure and fuel costs. The relative difference in net market benefits between each DP and DP4 (the least cost development path for Step Change scenario) ranges from -$52 million (DP7) to -$2,405 million (DP2). This highlights the significance of developing major interconnectors in this scenario and the risks of under-investment.

Figure 13 presents the difference in total system costs between DP4 and DP3 in the Step Change scenario. As per the Fast Change scenario section, this comparison was performed to compare the benefits of advancing/investing in both Marinus Link cables (in 2028-29 and 2031-32 i.e. DP4) against investing in only one cable (in 2031-32 i.e. DP3). It reaffirms that advancing Marinus Link and building both cables is beneficial in the Step Change scenario, as more local capacity response is required on the mainland when Marinus Link's build is delayed (DP3).

Figure 13 Difference in relative market benefits between DP4 and DP3 to 2041-42 for the Step Change scenario



A2.4.5 High DER scenario

Table 15 presents the difference in net market benefits for all the various DPs assessed in the High DER scenario.

Table 15 Net market benefits of the candidate development paths, relative to DP5, High DER scenario

Development path	Net market benefits ($M)	Net market benefits relative to DP5 ($M)
DP5 (least cost in High DER)	4,004	-
DP3 (least cost in Fast Change)	3,965	-39
DP6 (Early works on Marinus Link, giving flexibility to deliver it earlier or not at all, but otherwise the developments are in line with Central)	3,947	-57
DP1 (least cost in Central)	3,900	-104
DP7 (Early works on Marinus Link and VNI West, giving flexibility to deliver them both earlier or not at all, but otherwise the developments are in line with Central)	3,863	-142
DP8 (Accelerated VNI West with early works on Marinus Link)	3,665	-339
DP4 (least cost in Step Change)	3,620	-384
DP2 (least cost in Slow Change)	3,201	-803

The relative difference in net market benefits between each development path and DP5 ranges from -$39 million (DP3) to -$803 million (DP2).

Figure 14 presents the difference in total system costs between the least-cost development path in the High DER scenario (DP5) and DP1. The main difference between these two development paths is the later timing of Marinus Link in DP1 (and the development of only the first cable), which reduces the net market benefits in this scenario by $104 million (NPV). This scenario assumes TRET is legislated, and therefore development paths without both Marinus Link cables lead to significant volumes of VRE curtailment in Tasmania.

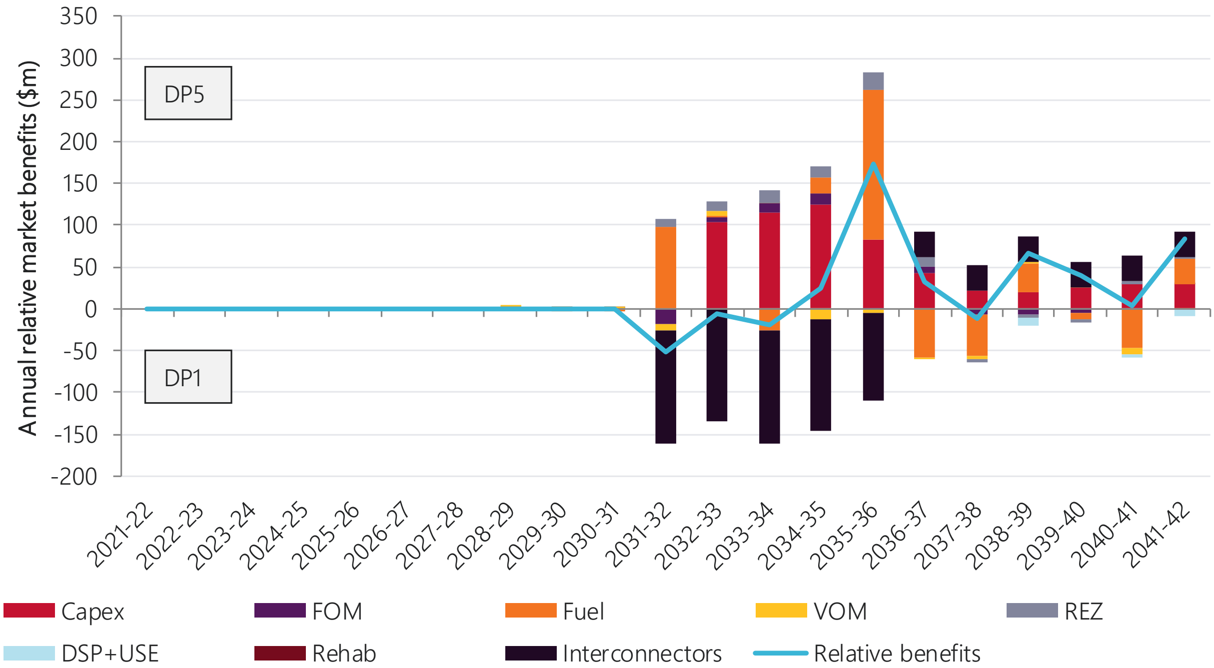
There is a very slight increase in total system costs (decrease in net benefits) from 2031-32 to 2033-34 for DP5 relative to DP1, mainly due to the advanced investment in Stage 1 of Marinus Link in DP5, even though across the full planning horizon DP5 delivers greater net market benefits. Without the advanced timing of Marinus Link the mainland requires significant additional dispatchable capacity, primarily a combination of solar and storages, to address the retirement of Eraring Power Station.

This mainland solar and storage response is primarily required from 2032-33 to 2034-35 during which time, hydro and wind production associated with the TRET is unable to reach the mainland to assist in the absence of Marinus Link. Post 2035-36 with the retirement of Bayswater Power Station and continued growth in the TRET, significant benefits are realised with both stages of Marinus Link.

From 2035-36, with the full liberation of the Tasmanian hydro and wind generation, the utilisation of the solar and storage response developed between 2032-33 and 2034-35 is significantly reduced and results in a prolonged capital repayment cost with limited corresponding benefit to the system. Bringing forward development of Marinus Link avoids the need to build this capacity in the first place.

Although the immediate solar and storage response results in slightly lower total system costs during 2032-33 to 2034-35, the long-term benefits of a coordinated transmission and generation response facilitated by Marinus Link liberating the TRET generation is ultimately a lower cost outcome for the system over the outlook period.

Figure 14 Difference in relative benefits between DP5 and DP1 to 2041-42 for the High DER scenario



A2.5. Testing the resilience of the candidate development paths to events that may occur in the Central scenario

This section examines the robustness of the candidate development paths in the Central scenario to two additional sensitivities which test the impact of potentially material changes to inputs, and four market event sensitivities which look at risks to consumers if investment and retirement timings vary.

The two additional sensitivities were considered regarding recent/potential changes in policy and demand assumptions that could lead to an update of the Central scenario in the near term. They are:

- **Inclusion of TRET:** if the announced TRET is legislated, to support 200% renewable energy generation in Tasmania by 2040.
- **Updated demand**: testing materiality of the changes in the Central scenario demand forecast developed for the 2020 ESOO that captures the estimated impact of COVID-19 as well as the record distributed PV sales observed in 2019.

The four market event sensitivities considered were:

- **Delay of Snowy 2.0:** if the project was delayed unexpectedly without replacement.
- **Early coal closure:** if brown coal power plants reduce generation earlier than submitted retirements, without replacement. A reduction is possible through early retirement, seasonal mothballing or long-term maintenance .
- **Central-West Orana REZ:** if the New South Wales Electricity Strategy attracts at least 2 GW of additional VRE in the Central-west Orana REZ by 2027-28.
- **Closure of industrial load:** if a large smelter in both Victoria and Tasmania closes in 2021-22.

The robustness of each candidate plan was measured by assessing whether the impact of the event on total net market benefits diminished with the candidate development path in place, or conversely, whether stranded asset risk increased if these events transpired.

Table 16 presents the reduction in net market benefit impact of different sensitivities in the Central scenario under the candidate development paths. The table demonstrates that the benefits identified from the Central scenario are resilient to most market event sensitivities. The closure of industrial load sensitivity, with its lower consumption, has relatively lower benefits in most development paths from the transmission investments (demonstrated by a higher relative benefit from DP2 (the least-cost development path for Slow Change).

The table also demonstrates the increased benefit from earlier transmission investments (specifically Marinus Link and VNI West) associated with DP3, DP4, DP5 and DP8 if TRET is legislated, and to help manage the increased variability of demand in the Updated Demand sensitivity.

Table 16 Reduction in net market benefit impact of different market events and policy settings in the Central scenario under the candidate DPs ($ million)

Candidate development paths	Reduction in net market benefits in Central scenario, relative to DP1	Impacts on net market benefits of each development path in Central scenario under different market events				Impacts on net market benefits in Central scenario using new input assumptions	
		Delay Snowy 2.0	Early coal closure	Central West Orana REZ	Closure of industrial load	Inclusion of TRET	Updated demand
DP1 – Central least cost	0	0	0	0	0	-228	0
DP2 – Slow Change least cost	-275	0	16	10	65	-748	0
DP3 – Fast Change least cost	-123	0	-3	2	-53	91	114
DP4 – Step Change least cost	-535	0	3	-6	-112	229	269
DP5 – High DER least cost	-208	0	-12	6	-131	152	72
DP6 – Central early works on Marinus Link	-20	0	0	0	0	20	0
DP7 – Central early works on Marinus Link and VNI West	-72	0	0	0	0	20	0
DP8 – Accelerated VNI West timing with early works on Marinus Link	-389	-8	171	-34	96	193	180

It should be noted here that only the four market event sensitivities formed part of the scenario-weighted net market benefit DP ranking shown in Table 7 of Part D. The other two sensitivities are considered more structural in nature and may result in a revised plan.

The impacts on net market benefits of candidate DPs, and whether these market event sensitivities change the ranking of the DPs are detailed in sections below. The projected resource mix of these respective outcomes is included in Appendix 4.

A2.5.1 Delay of Snowy 2.0 sensitivity

While Snowy 2.0 is a committed project, prudent planning must consider the impact to the power system if the project was not delivered on time with the current commissioning schedule.

AEMO has conducted a sensitivity with a four-year delay to the project for the candidate development paths, under the broader settings of the Central scenario. The transmission required to unlock the project – the HumeLink transmission project – is assumed to be delivered independent to the Snowy 2.0 project and is therefore delivered on-schedule within this sensitivity, by 2025-26.

Under all candidate development paths, AEMO's analysis forecasts that the power system is relatively resilient to such a delay, with minimal impact to the overall market benefits of the network development, as shown in Table 16. There is therefore little regret associated with building HumeLink to the current timeline, even if Snowy 2.0 is delayed.

The impact on the resource mix in the NEM with a delay of Snowy 2.0 is detailed in Appendix 4.

A2.5.2 Early coal closure sensitivity

Under recent NER changes, participants are required to provide at least three and a half years' notice of closure. However, some generation technologies and particularly transmission infrastructure can take much longer than that to plan and build, so the power system, and consumers, remain exposed to risks of unplanned early retirements or extended outages of coal-fired generation if the system was planned and developed to be 'just in time'.

ISP modelling considers the risk of unplanned early retirements or extended outages of coal-fired generation. For the purposes of this analysis, AEMO has assumed the entire Yallourn brown coal power station in Victoria closes in 2027-28, several years earlier than the scheduled retirement of some of the power station's units.

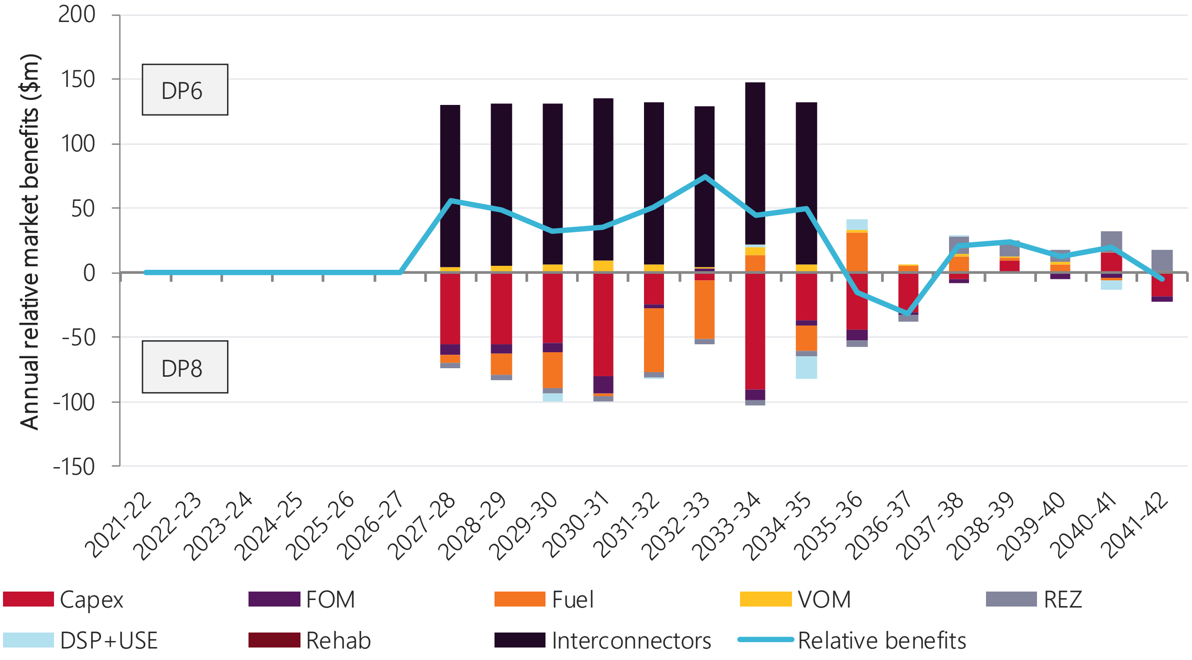
An earlier than expected retirement of Yallourn increases the value of building VNI West early, relative to the other DPs. As shown in Table 16, if Yallourn were to retire early, the potential reduction of net market benefits of delivering VNI West early reduced from $369 million NPV to $198 million (DP6 less DP8). In other words, early Yallourn closure increases the value of accelerated VNI West relative to the Central scenario by $171 million. However, this market event does not change the ranking of the development paths.

Figure 15 compares DP6 and DP8 with an early Yallourn closure and shows that an earlier than expected retirement of Yallourn is anticipated to be more efficiently addressed by a combination of generation development alternatives than the early build of VNI West provided the market appropriately incentivises the investment. Under the current Central scenario assumptions, early delivery of VNI West provides significant generation/storage capital deferral benefits by avoiding mainly 390 MW of storage capacity builds in Victoria and South Australia and about 550 MW of solar capacity builds in New South Wales.

If TRET is legislated, or if demand assumptions are updated to the latest 2020 ESOO forecasts, then having VNI West in ahead of an early closure of Yallourn would be much more beneficial, as discussed in the sensitivity analysis later in this section.

Appendix 4 illustrates how the loss of Yallourn Power Station affects forecast generation investments in Victoria and other regions under current Central scenario assumptions.

Figure 15 Difference in relative benefits between interconnector paths with VNI West built in 2035-36 (DP6) and VNI West built in 2027-28 (DP8) for the early Yallourn closure scenario



A2.5.3 Closure of industrial load sensitivity

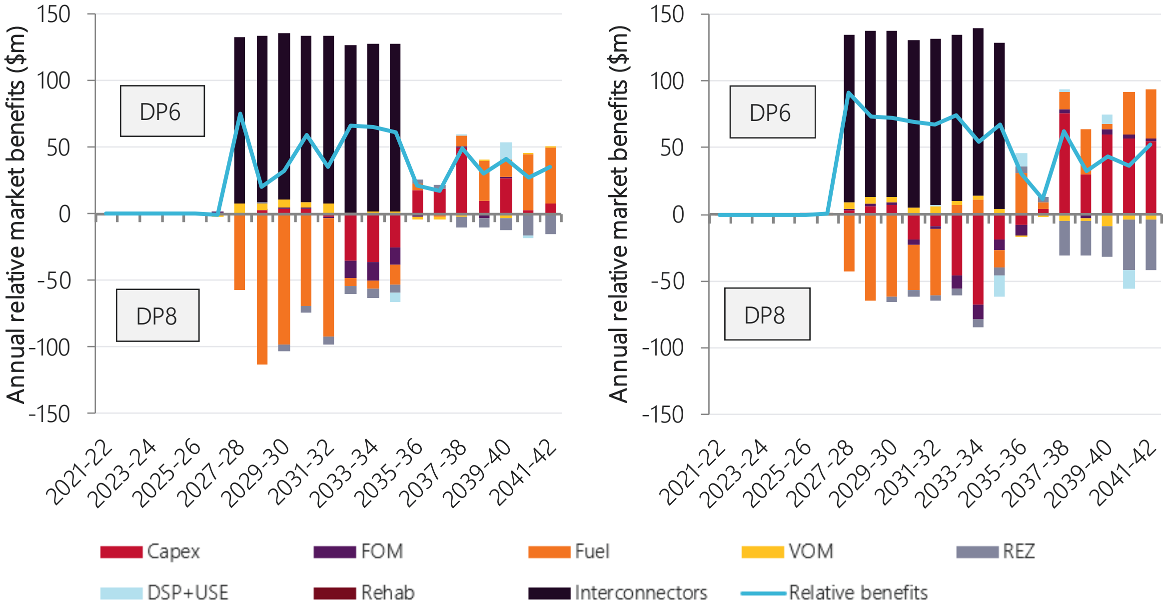
This sensitivity considers the potential impact on the Central scenario of the early closure of a major industrial load in Victoria and Tasmania. The sensitivity assumes these loads are closed in the next two years and that the VRET target will be unaffected (that is, the VRET is not reduced, but will lead to increased availability to export generation to other NEM regions with less industrial consumption in Victoria and Tasmania).

Due to multiple interconnector paths to adjacent regions, the impact of an industrial load closure is forecast to impact more than just the Victorian and Tasmanian regions. Detailed analysis on the impact on the supply mix in the NEM can be found in Appendix 4.

As shown in Table 16, the industrial load closures are forecast to have various impacts across the candidate development paths under the Central scenario. Additional cost savings can be observed where less interconnection requirements are needed in the NEM such as the Slow Change development path, where load closures increased benefits by $65 million. Moreover, while still a more costly alternative to DP1, early VNI West benefits in DP8 increase by $96 million relative to the Central scenario.

This is presented in Figure 16, which compares the difference in total system costs between development paths with VNI West built late (2035-36) and VNI West built early (2027-28) for both the industrial load closure sensitivity and the Central scenario. Early VNI West development delivers fuel cost savings from black coal generators until the expected scheduled of retirements, and capital deferral benefits as a result of a reduced need for additional grid-scale capacity to meet the demand.

Figure 16 Difference in relative benefits between development paths with VNI West built in 2035-36 (DP6) and VNI West built in 2027-28 (DP8) for the industrial load closure scenario (left) and Central scenario (right)

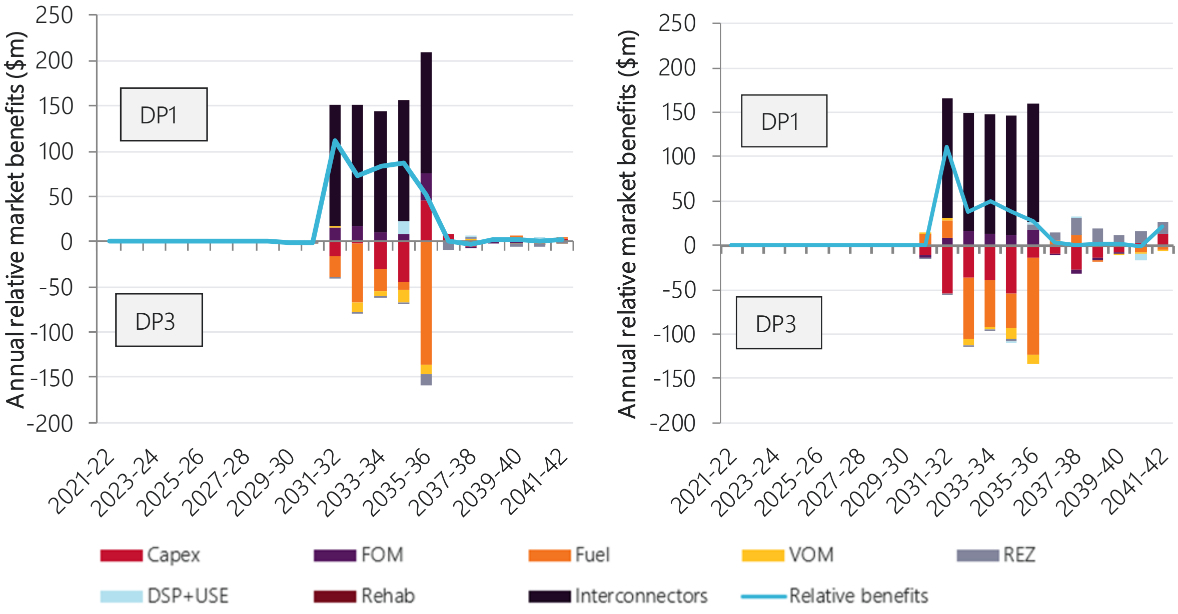


Conversely, industrial load closures reduce the benefits of advancing the first cable of Marinus Link (as in DP3) by $53 million relative to the Central scenario. Although the closure of load in Tasmania increases the availability of renewable energy export to the mainland, the increased available energy is insufficient to recover the costs associated with early development of the interconnector.

Figure 17 presents the breakdown of the difference in net benefits between DP1 (least-cost development path in Central scenario) and DP3 (least-cost development path in Fast Change scenario), with the only difference between DP1 and DP3 being the earlier timing of Marinus Link (Stage 1) in DP3.

The cost of advancing Marinus Link outweighs the capital deferral benefits and fuel cost savings, although only by a small margin. This cost difference is higher for the industrial load closure scenario relative to the Central scenario, especially from 2032-33 to 2035-36. This is due to the lessened need for the development of additional storage technologies, mainly in South Australia, in the industrial load closure scenario meaning there are fewer capital deferral opportunities associated with advancing the interconnector.

Figure 17 Difference in relative benefits between interconnector paths with Marinus Link (Stage 1) built in 2036-37 (DP1) and Marinus Link (Stage 1) built in 2031-32 (DP3) for the industrial load closure scenario (left) and Central scenario (right)



A2.5.4 Central-West Orana REZ sensitivity

The Central-West Orana REZ is highlighted in the New South Wales Government's Electricity Strategy[5] for development as the first coordinated REZ in New South Wales. It is expected that the proposed transmission upgrades would support up to 3,000 MW of new renewable generation capacity within New South Wales by the mid-2020s.

AEMO has carried out a market event sensitivity under the Central scenario to assess how the New South Wales Government's Electricity Strategy could impact the timing and magnitude of generation development and determine the influence on the candidate development paths.

Table 16 demonstrates the various impacts across the candidate development paths under the Central scenario. Similar to Central Scenario, DP1 remains the least-cost development under this sensitivity. There are minor impacts on the net market benefits across the development paths with the highest being in DP8 where the cost to accelerate VNI West is greater than the fuel and generator cost savings, reducing the net market benefits of that development path.

Comparing the net market benefits of DP1 under this sensitivity ($8,730 million) versus the Central scenario ($7,688 million) shown in Table 8 of Part D, on first glance it would appear that the early Central-West Orana REZ development produces over $1 billion NPV of benefits to consumers. However, this sensitivity excludes the capital cost of the VRE being developed in the REZ (which would be in excess of $1 billion), since the VRE is effectively treated as committed. The scenario and the sensitivity cannot therefore be meaningfully compared on a like for like basis.

The overall impact to the generation mix is described in more detail in Appendix 4.

[5] See https://energy.nsw.gov.au/government-and-regulation/electricity-strategy.

A2.5.5 Inclusion of TRET sensitivity

The Tasmanian Government's announced renewable energy target proposes to extend the existing target of 100% renewable energy by 2022 to a target of 200% renewable energy by 2040, with an interim target of 150% by 2030 assumed[6]. AEMO has conducted this sensitivity under the Central scenario to explore the potential impact of this policy on the optimal development path.

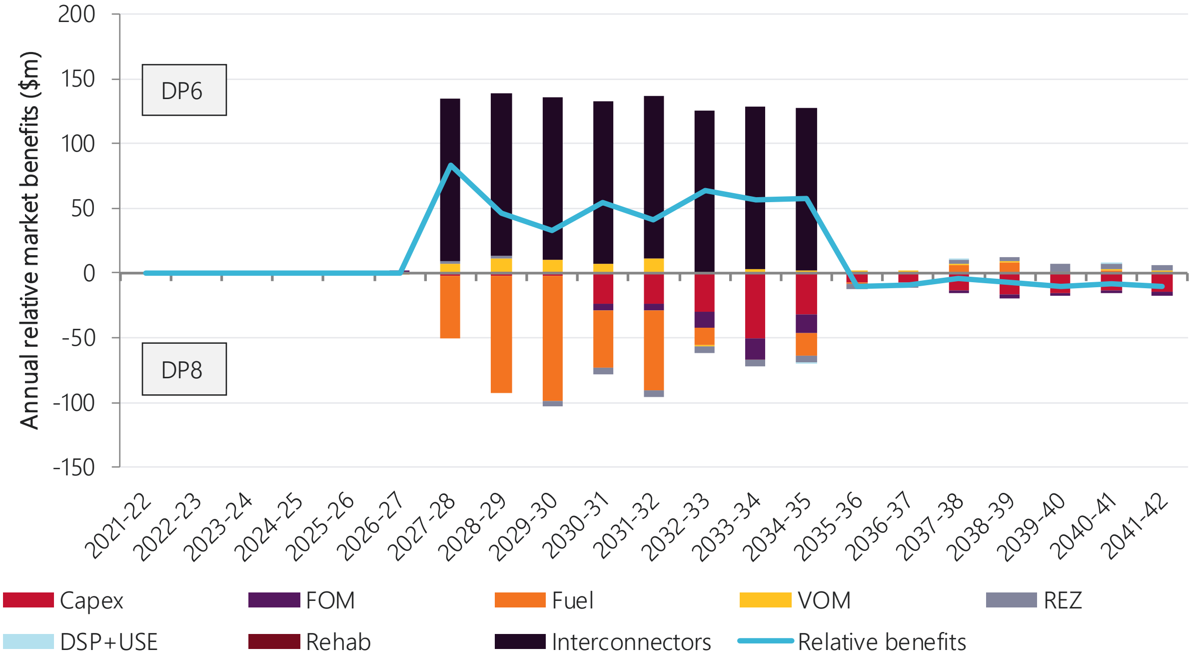
In the event of TRET legislation, the optimal timing of Marinus Link Stage 1 is advanced from 2036-37 (DP1) to 2031-32, with Stage 2 developed in 2035-36 in the least cost development path. In this sensitivity, the TRET increases the value of delivering not just the first cable of Marinus Link at a relatively early commissioning timeframe, but also increases the value of the second cable as Tasmanian VRE continues to expand to 2040. Of all the candidate development paths considered, DP6 is the one that maximises the benefits in this case as it maintains flexibility on the timing and overall sizing of the interconnector. In other words, progressing with Marinus Link early works minimises regret under the Central scenario if TRET were to be legislated.

Table 16 (at the start of Section A2.5) showed that the legislation of TRET has various impacts on relative net market benefits across the candidate development paths under the Central scenario,. As TRET drives more investments in generation capacity in Tasmania, bringing forward Marinus Link allows more energy exports to the mainland earlier, deferring generator capital costs and therefore increasing net market benefits. Conversely if Marinus Link was not commissioned early enough, as in DP1 and DP2, Tasmanian VRE may hit export constraints, and there may be a need for additional local load to consume excess local generation or spill that surplus energy. The policy announcement is coupled with the potential for local hydrogen development, which may utilise the excess VRE generated in Tasmania – though this has not been modelled in the 2020 ISP.

Figure 18 shows the difference in total system costs between DP6 and DP8 (early VNI West) under the Central scenario with TRET. If the TRET is legislated, the potential reduction in net market benefits of delivering VNI West early reduces from $369 million NPV (DP8 compared to DP6 in original Central scenario) to $196 million. In other words, if the TRET is legislated and Marinus Link is built by 2031-32, the value of accelerated VNI West relative to the Central scenario increases by $173 million. This is because bringing forward VNI West allows any energy exported from Tasmania that is surplus to Victoria's requirements to be delivered through to New South Wales, providing fuel cost savings and deferring generator capital costs.

[6] Incumbent Tasmanian hydro generation can vary significantly between years due to the level of rainfall caught in the dam and waterway catchments, and as AEMO's modelling captures weather variability between years there may be overs/unders in the achievement of the TRET targets. More information on AEMO's modelling methodology for weather variability ("reference years") is provided in the Market Modelling Methodology, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines.

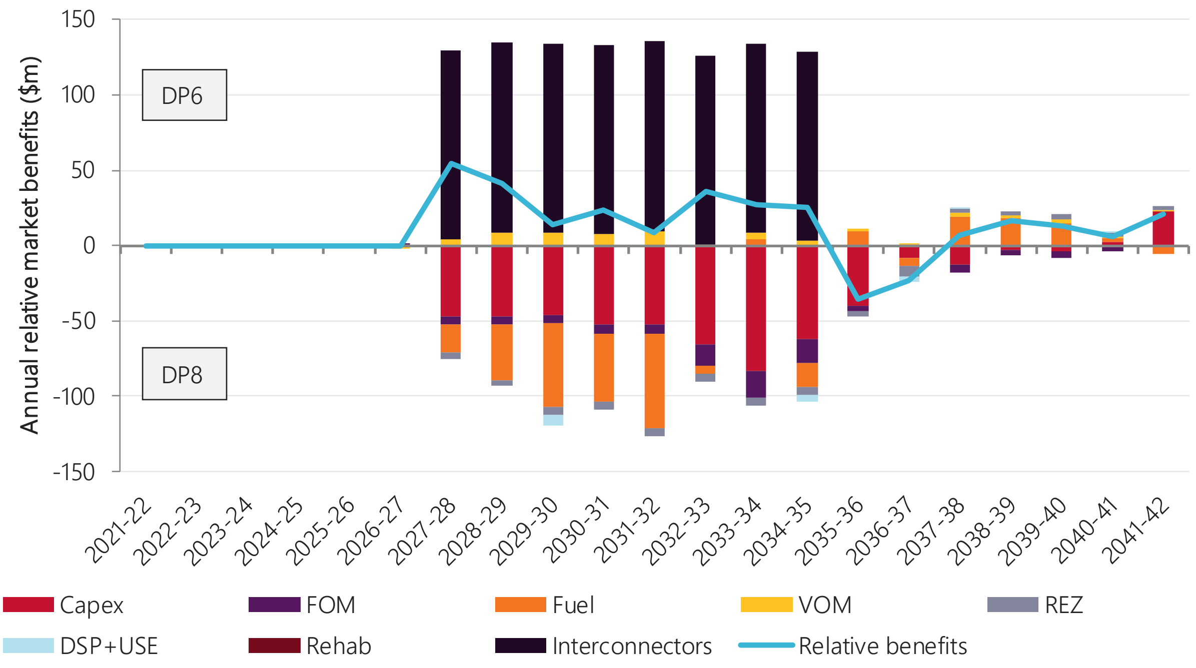
Figure 18 Difference in relative benefits between development paths with VNI West built in 2035-36 (DP6) and VNI West built in 2027-28 (DP8) under TRET



Under TRET, an earlier than expected retirement of Yallourn may be addressed by generation/storage development alternatives, Marinus Link, and/or the early build of VNI West.

As shown in Figure 19, the early delivery of VNI West provides significant generation capital deferral benefits by avoiding mainly storage technology builds in Victoria and South Australia and solar development in New South Wales. Under the TRET, an early Marinus Link development will deliver Tasmania's surplus energy to Victoria. As Victoria would not need all of Tasmania's surplus energy, even if Yallourn retires early, there may be additional surplus generation from Victoria and Tasmania that can be exported to New South Wales from VNI West. Under TRET, an earlier than expected retirement of Yallourn reduces the potential reduction of net market benefits of delivering VNI West early further from $369 million NPV (in original Central scenario) to $196 million and hence increasing value of accelerated VNI West relative to the Central scenario to $173 million.

Figure 19 Difference in relative benefits between interconnector paths with VNI West built in 2035-36 (DP6) and VNI West built in 2027-28 (DP8) under TRET and early Yallourn closure



The impact of the legislation of TRET on the Tasmania VRE developments and the NEM resource mix is presented in Appendix 4.

A2.5.6 Updated demand sensitivity

The COVID-19 pandemic is having a lasting downward impact on energy consumers, particularly while commercial and industrial operations are reduced, despite potential increased residential loads. The actions taken to stop the spread of the virus are expected to have a lasting downward impact on electricity demand in the short to medium term, as consumption in the commercial and industrial sectors declines. Meanwhile, record sales of distributed PV systems observed throughout 2019 suggest a higher-than-expected uptake of distributed energy resources, both presently and into the future, than what has been assumed under the Central scenario for this ISP. An increased forecast uptake of DER is similarly expected to result in a reduction in overall levels of operational demand as more load is serviced from behind-the-meter, and more volatility in demand from one period to the next, as distributed PV carves out demand in the middle of the day.

This updated demand sensitivity explores the effects of both impacts on electricity demand in the Central scenario. Modelling for this sensitivity uses revised operational demand forecasts that have been prepared for the Central scenario of the 2020 ESOO and represents AEMO's latest view of the most likely future demand forecast.

Under the revised demand forecasts, the total system cost incurred is lower than in the Central scenario by approximately $2 billion across all candidate development paths, as there is less cost associated with supplying a lower level of operational demand. However, it should be noted that these costs do not consider the cost associated with the increased uptake of DER, nor do they consider the cost of distribution level investments required to support these resources.

Table 16 (at the start of Section A2.5) demonstrates that the least-cost development path for the updated demand sensitivity in the Central scenario remains DP1. This updated demand provides a significant forecast reduction of net market benefits gaps for candidate development paths with early Marinus Link (DP3, DP4, and DP5) and early VNI West (DP8) with the greatest reduction being for DP5 which builds both Marinus Link cables early, followed by DP8. Under this updated demand sensitivity, the potential reduction in net market benefits of delivering VNI West early reduces from $369 million NPV to $189 million (DP6 less DP8). In other words, the updated demand forecast increases the value of accelerated VNI West relative to the Central scenario by $180 million. However, if Yallourn were to retire early, the value of having VNI West early increases even further. In this case, the reduction in net market benefit of delivering VNI West early rather than late would be only $5 million.

Figure 20 shows the difference in total system costs between DP6 and DP8 (early VNI West) under the updated demand sensitivity. The variability in operational demand in the updated demand sensitivity (due to slightly higher maximum demands longer term, and increased uptake of DER) would increase the dispatchable capacity needs in the NEM, particularly the value of storage in filling demand troughs in the day through charging, and discharging during evening peak. An early delivery of VNI West is projected to provide benefits by offering flexibility, thereby reducing the need to build storages in Victoria and South Australia and reducing fuel costs, although without considering some of the resilience benefits provided by this development path (see Appendix 6), the cost of delivering VNI West early still outweigh the benefits.

Figure 20 Difference in relative benefits between candidate development paths with VNI West built in 2035-36 (DP6) and VNI West built in 2027-28 (DP8) under updated demand sensitivity in Central scenario

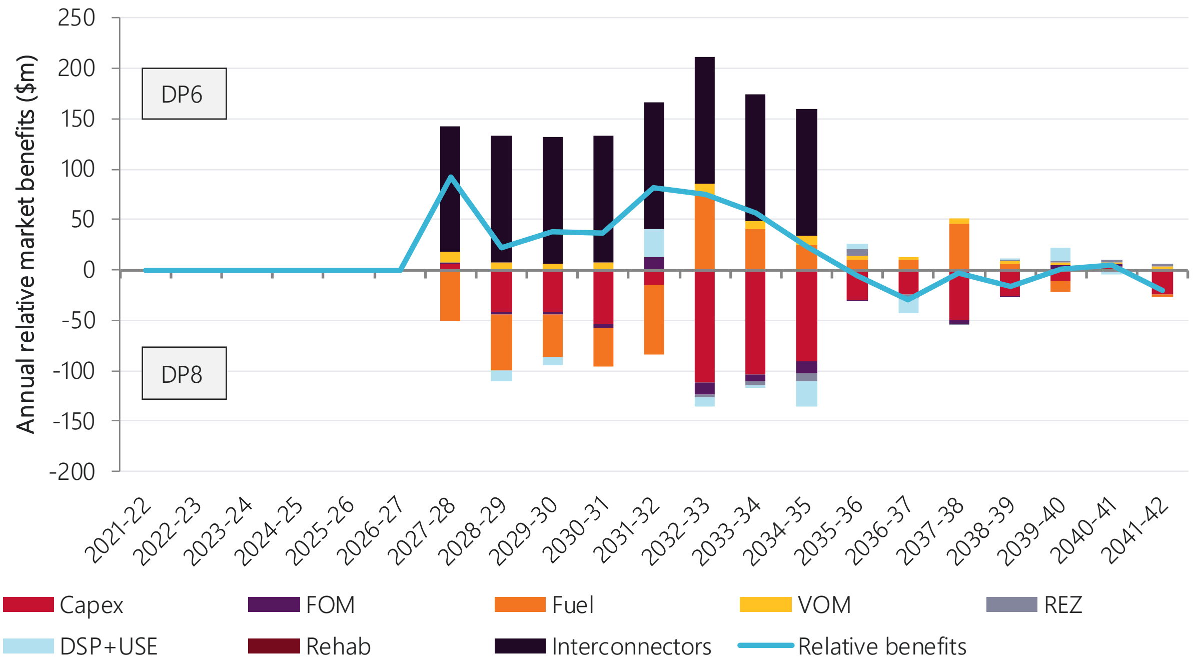
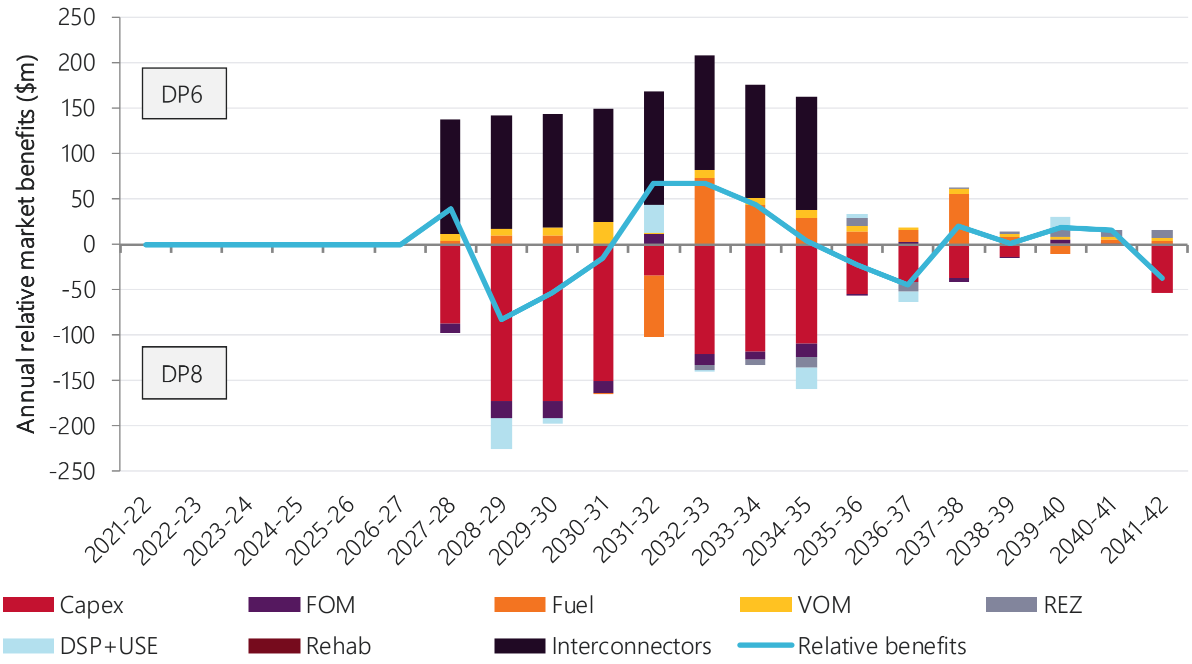


Figure 21 shows the difference in total system costs between DP6 and DP8 (early VNI West) under the updated demand sensitivity with an early Yallourn closure. Under these settings, an early delivery of VNI West is projected to deliver positive net market benefits in early years through the deferral of generator capital costs, with accelerated interconnection alleviating the need to build significant additional dispatchable resources (over 1 GW – see Appendix 4). While these positive benefits are eroded by negative net market benefits for a couple of years in the 2030s before Bayswater closes, the increase in total system costs of only $5 million to deliver VNI West early is greatly reduced compared to under the Central scenario.

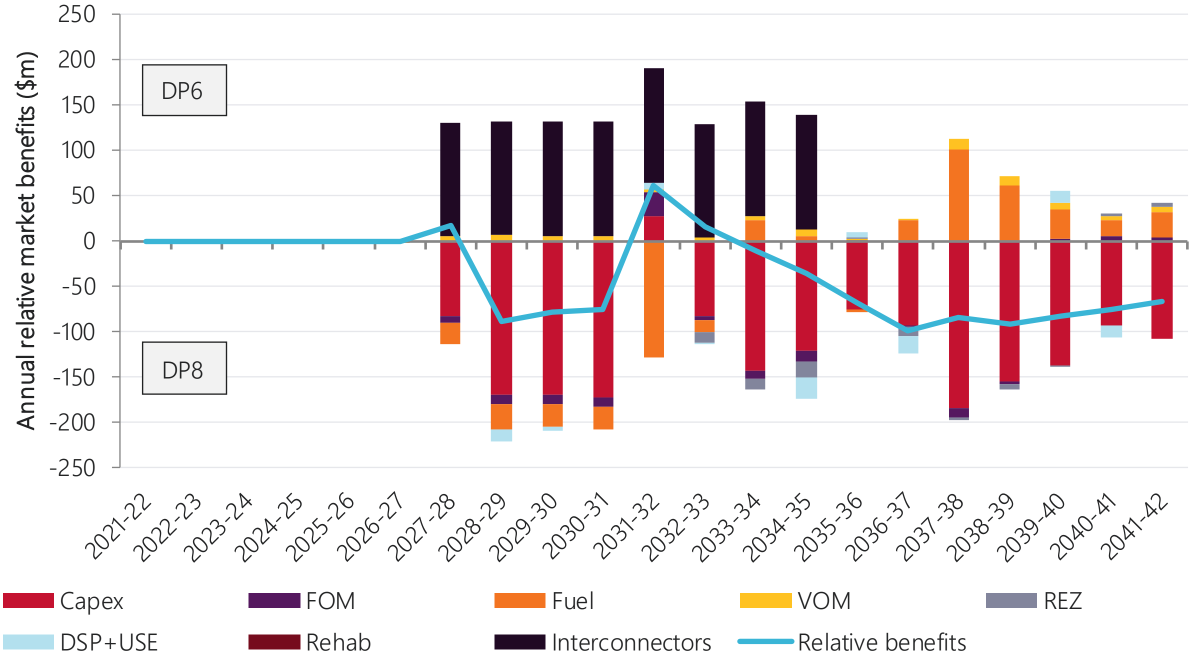
Figure 21 Difference in relative benefits between candidate development paths with VNI West built in 2035-36 (DP6) and VNI West built in 2027-28 (DP8) under updated demand sensitivity in Central scenario with early Yallourn closure



This assumes that over 1 GW of market-based dispatchable capacity would be developed in Victoria and South Australia ahead of the earlier than expected closure of Yallourn. In recent history, there is little evidence that current market signals are adequate to incentivise this investment, and the risk to consumers of under-investment is significant (leads to supply and price scarcity risks).

The 2020 ISP therefore conducted an additional sensitivity under the Central scenario to test the value of early delivery of VNI West under the updated demand sensitivity with an early Yallourn closure, assuming no new market-based dispatchable storage until 2032-33. As shown in Figure 22, under these settings, an early delivery of VNI West (DP8) is projected to deliver higher net market benefits of $284 million compared to late delivery of VNI West (DP6). If delivered late, up to 1.3 GW of new GPG needs to be developed in southern regions instead of energy storage, to maintain reliability of supply. As detailed in Appendix 4, early delivery of VNI West avoids this additional capacity.

Figure 22 Difference in relative benefits between candidate development paths with VNI West built in 2035-36 (DP6) and VNI West built in 2027-28 (DP8) under updated demand sensitivity in Central scenario with early Yallourn closure and no new market-based dispatchable storage until 2032



With a reduction in consumption in the revised forecasts primarily driven by a higher uptake of distributed PV, there is a corresponding decrease in the amount of large-scale VRE capacity forecast to be built. However the revised forecasts consider higher maximum and lower minimum demands, requiring greater uptake of flexible storages and GPG.

Further discussion on the effect of the updated demand forecast on the NEM resource mix can be found in Appendix 4.