People. Power. Possibilities.

Reinforcing the NSW Southern Shared Network to increase transfer capacity to demand centres (HumeLink)

17 December 2021

Contents

1. Context for this addendum

Transgrid initiated a RIT-T consultation process in June 2019 to identify a project that:

- increases the transfer capacity and stability limits between the Snowy Mountains and major load centres of Sydney, Newcastle and Wollongong, thereby enabling access to lower cost generation to meet demand in these major load centres; and
- facilitates the development of renewable generation in southern NSW.

The RIT-T process culminated with Transgrid publishing the Project Assessment Conclusions Report (PACR) for the HumeLink RIT-T on 29 July 2021. The preferred option identified in the PACR involves constructing new 500 kV double circuit transmission lines in an electrical 'loop' between Maragle, Wagga Wagga and Bannaby (referred to as 'Option 3C'). The estimated cost of this option is $3.3 billion.

1.1. Dispute of PACR and AER determination

Wunelli Pty Ltd raised a dispute on 16 August 2021 under rule 5.16B of the National Electricity Rules (NER), on the grounds that the PACR failed to consider all credible options to address the network need. The grounds the dispute asserted included that:

- it is not clear whether the route corridors for costing the different options have been optimised for double circuit construction; and
- Transgrid has provided insufficient transparency about the double circuit configuration of the preferred option.

The Australian Energy Regulator (AER) published its dispute determination on 24 November 2021,[1] which includes the view that Transgrid did not meet the RIT-T requirements with respect to its consideration of credible options. Specifically, the AER concluded that Transgrid could reasonably have been expected to include in the RIT-T analysis a full double circuit configuration of Option 1C (referred to as 'Option 1C-new' in the AER's determination and this addendum), in order to assess the net economic benefit associated with this option.

Consequently, the AER requires Transgrid to amend the HumeLink PACR to include:[2]

- A full double circuit option for the path between Maragle and Bannaby as a credible option: Option 1C-new.
- The estimated capital cost of this option, including the estimated biodiversity offset costs. The AER requires Transgrid, when doing so, to explain the accuracy of these costs and ensure it is consistent with the expected accuracy of the top two ranked options in the original PACR.
- A complete comparative cost benefit analysis (with and without competition benefits), including Option 1C-new for each scenario and its impact on the ranking of the credible options assessed in the PACR.

[1] AER, *Reinforcing the NSW Southern Shared Network (Humelink): Determination on dispute – application of the regulatory investment test for transmission*, November 2021.

[2] AER, *Reinforcing the NSW Southern Shared Network (Humelink): Determination on dispute – application of the regulatory investment test for transmission*, November 2021, p 26.

- Sensitivity analysis for Option 1C-new as assessed for Options 2C and 3C in the PACR, to demonstrate the robustness of the RIT-T modelling outcomes. In particular, the AER requires that Transgrid include the following sensitivities for Option 1C-new in the central scenario:
  - the impact of the Kurri Kurri and Tallawarra B gas generators;
  - the impact of delaying VNI West until 2035/36;
  - the impact on the positioning analysis of adopting the draft 2021 IASR assumptions;
  - the impact of adopting alternate scenario weightings i.e. higher weighting of the step change scenario which is an increase of 10 per cent to the 2020 ISP scenario weightings;
  - the impact of 25 per cent higher and lower network capital costs of the credible options (including the adoption of P90 costs); and
  - the impact of alternate commercial discount rate assumptions i.e. a high discount rate of 7.90 per cent and a low discount rate of 2.23 per cent.

The AER considers that these amendments will ensure Option 1C-new is presented alongside the two top ranked options, improving the ability of stakeholders to understand and compare this option and ensuring the transparency and credibility of the RIT-T process.

1.2. Coverage of this addendum

This addendum has been prepared in response to the AER's determination and extends the analysis presented in the HumeLink PACR published in July 2021 and provides other information for the specific purpose of satisfying the AER's requirements in its dispute determination, as set out above.

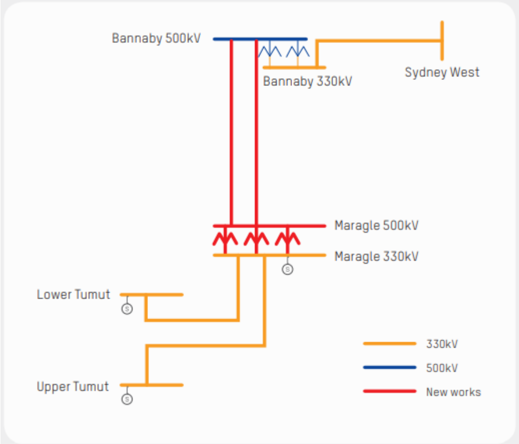
The content of this addendum reflects information that would have been contained in the HumeLink PACR had Option 1C-new been included in the earlier assessment. In particular it provides:

- A description of Option 1C-new and its associated cost estimate (set out in section 1.3 below), equivalent to the descriptions of the other options provided in section 5 of the July 2021 PACR.
- An updated section ('Section 2 - Net present value results'), which presents the results for the positioning assessment, RIT-T assessment and sensitivities across all eight options (ie, the seven options included in the July 2021 PACR and Option 1C-new).
  - This section can be read in place of the corresponding section 8 in the July 2021 PACR.
  - The expanded assessment continues to draw on the same input assumptions that were available and adopted at the time of the July 2021 PACR assessment.

In satisfying the AER's requirements, the addendum and its contents does not preclude or prejudice any other public consultation or process being undertaken in relation to HumeLink.

1.3. Option 1C-new – A new 500 kV line between Maragle and Bannaby

Option 1C-new which has been included in this addendum is a variant of Option 1C that involves constructing a new double circuit 500 kV line (instead of two lines) between Maragle and Bannaby.



The high level scope includes:

- Construct a double circuit 500 kV transmission line:
  - Between Maragle Substation and Bannaby 500 kV Substation (274km)
- Three new 500/330/33 kV 1,500 MVA transformers at Maragle Substation
- Augment the Maragle Substation to accommodate the additional transmission lines
- Augment the existing Bannaby Substation to accommodate the additional transmission lines.

Preliminary modelling indicates that an additional 2,510 MW generation could be accommodated at times of average import from VIC and average renewable generation in southern NSW under this option.

The estimated capital cost of this option is approximately $2,695 million, which includes $858 million of estimated biodiversity costs.

The cost estimate for Option 1C-new is a 'Class 4' estimate (as defined by the AACE (Association for the Advancement of Cost Engineering) classification system). This is consistent with the estimates derived for Option 2C and Option 3C in the July 2021 PACR. For these Class 4 estimates, Transgrid has provided the P50 value (50% probability of underrun) for each option.

The primary and secondary characteristics for Class 4 cost estimates are set out in **Error! Reference source not found.**[3] below. A detailed discussion of cost estimates is provided in the July 2021 HumeLink PACR (section 4.4).

Table 1 – Cost estimate classification matrix for the power transmission line infrastructure industries

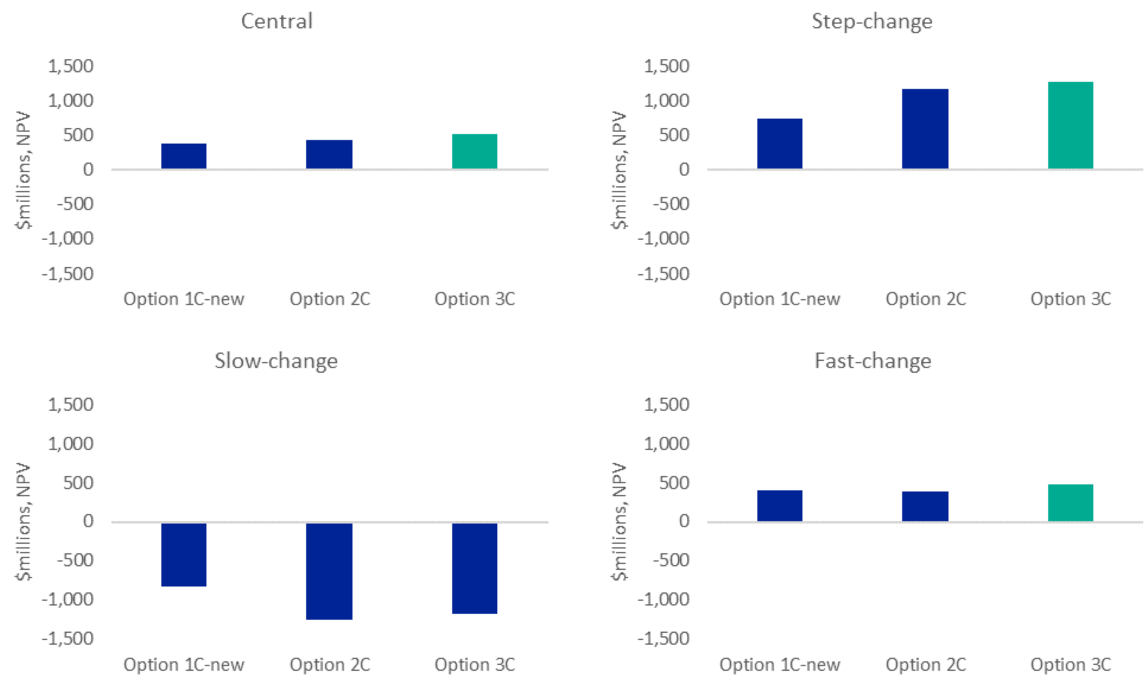
	Primary characteristic		Secondary characteristic	
Estimate class	**Maturity level of project definition deliverables** Expressed as % of complete definition	**End usage** Typical purpose of estimate	**Methodology** Typical estimating method	**Expected accuracy range** Typical variation in low and high ranges at an 80% confidence interval
Class 4	1% to 15%	Study or feasibility	Cost/length factored or parametric models	L: -15% to -30% H: +20% to +50%

[3] Table and figure captions

1.4. The preferred option remains a new 500 kV double-circuit lines in an electrical 'loop' between Maragle, Wagga Wagga and Bannaby (Option 3C)

The results of the expanded assessment in this addendum confirms the findings of the July 2021 PACR assessment that Option 3C, comprised of new 500 kV double-circuit lines in an electrical 'loop' between Maragle, Wagga Wagga and Bannaby, provides the greatest net benefits across all scenarios. Option 3C is found to have positive net benefits under all scenarios investigated, except for the slow-change scenario.

Figure E.1 – Estimated net benefits for each scenario, $2020/21[4,5]



Note: The three options shown above reflect those with the greatest expected net benefits based on the positioning assessment undertaken across all eight credible options.

While the slow-change scenario finds negative net benefits for all three of the top-ranked options, this scenario is considered the least likely of the four scenarios and is given a 10 per cent weighting in the analysis, consistent with the recommended weighting in the 2020 ISP.[6]

On a weighted-basis, Option 3C is expected to deliver approximately $491 million of net benefits (as shown in Table 2) and is ranked first out of the options assessed (with estimated net benefits that are 23 per cent greater than the second-ranked option, Option 2C and 46 per cent greater than for Option 1C-new). Option 3C is therefore the preferred option overall under the RIT-T.

Table 2 Estimated net benefits on a weighted basis, $2020/21

Weighted basis	Option 1C-new	Option 2C	Option 3C
$millions, NPV	335	399	**491**
Rank	3	2	**1**

4 All dollars presented in this report are $2020/21, unless otherwise stated.
5 Numbering of figures and tables in the Addendum follows the numbering used in the July 2021 PACR, unless tables are new (eg Table 1 and Table 2).
6 AEMO, 2020 Integrated System Plan, July 2020, p. 86

2. Net present value results

Summary of key points:

- **We have undertaken a positioning assessment covering all eight credible options (including Option 1C-new) across each of the four ISP scenarios and find that Option 3C is consistently the top-ranked option, delivering positive net benefits in all scenarios, with the exception of the slow-change scenario, as well as on a weighted basis (in order of $39 million in present value terms).**
- **The formal RIT-T assessment builds on the positioning assessment and includes estimates of the additional competition benefits expected from the top three ranked options (Option 1C-new, Option 2C and Option 3C). We find that Option 3C continues to be strongly preferred (with expected net benefits increasing to $491 million in present value terms).**
- **Under all scenarios, the benefits for Option 3C are primarily driven by avoided, or deferred, costs associated with generation and storage build.**
- **Avoided generator fuel costs, competition benefits and avoided transmission capital costs to connect new Renewable Energy Zones (REZ) make up the vast majority of other market benefits estimated for Option 3C, with their relativities varying across the scenarios.**
- **This conclusion is found to be robust to a range of sensitivity tests.**
- **All market benefits for the credible options are presented as being relative to the base case for each scenario, i.e., the state of the world without a HumeLink option in it.**

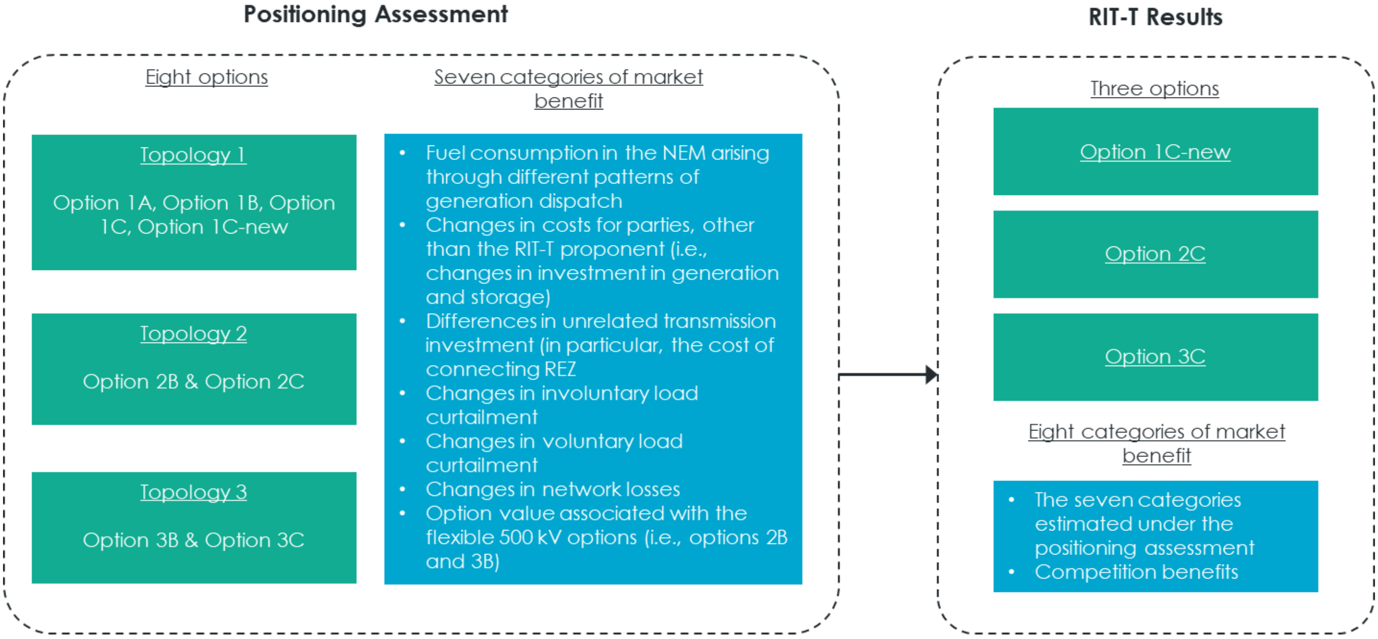
2.1. Structure of the NPV assessment

We applied a two-stage approach to the NPV assessment for the PACR and for this PACR addendum. Specifically, we have:

- undertaken a positioning assessment, which covers all eight credible options (including Option 1C-new) across each of the four ISP scenarios; then
- focused the formal RIT-T assessment on the top three ranked options from the positioning assessment (i.e., Option 1C-new, Option 2C and Option 3C).

The key difference between these two stages is that the formal RIT-T assessment includes estimates of the additional competition benefits expected from the top three ranked options. This is considered a proportionate approach to assessing all eight credible options given the complexities and modelling resources required to estimate competition benefits.

Figure 5 – Structure of the NPV assessment



2.2. Positioning assessment (excluding competition benefits)

The positioning assessment assesses all eight credible options across each of the four ISP scenarios. It does not include competition benefits since the modelling required is considerable for each option and is not considered a proportionate exercise for most of the options, based on the positioning assessment set-out below. Competition benefits have been estimated for the top-ranked options coming out of the positioning assessment and are presented in section 2.3 below.

Central scenario

The central scenario reflects AEMO's moderate demand forecasts (including Demand-Side Participation (DSP)), neutral gas and coal price forecasts, coal plants retiring on an economic basis (or at the end of their announced/technical lives), as well as a national emissions reduction of around 28 per cent below 2005 levels by 2030.

AEMO describes the central scenario as reflecting 'the current transition of the energy industry under current policy settings and technology trajectories, where the transition from fossil fuels to renewable generation is generally led by market forces and supported by current federal and state government policies'.[7]

The assessment in this PACR addendum finds that Option 3C has the highest expected net benefit of $49 million under these assumptions and is one of two options with a positive expected net benefit.[8] Option 1C-new is the second-ranked option with estimated positive net benefits of $40 million, which is 18 per cent lower than Option 3C.

[7] AEMO, *2019 forecasting and planning scenarios, inputs, and assumptions*, August 2019, p. 3.

[8] Calculation of benefits and costs have involved escalation of capital cost inputs and wholesale market benefit inputs. Capital cost inputs are estimated in real 2019/20 dollars and inflated to real 2020/21 dollars. Similarly, wholesale market benefit inputs are modelled in real 2018/19 dollars and inflated to real 2020/21 dollars (except for IASR sensitivity inputs, where market benefit inputs are modelled in 2019/20 dollars). We have used Australia CPI (ABS Series ID A2325846C) to inflate inputs to real 2020/21 dollars. Adjustments to June 2020 and September 2020 quarter CPI were made to smooth out the effects of deflation during these quarters due to the effect of the COVID-19 pandemic. These adjustments were made as the pandemic significantly reduced price levels for furnishings, household equipment and services, transport and education components of CPI that, while relevant for CPI as a whole, is less relevant for transmission project costs or the long term value consumers receive from transmission projects. We also have estimated June 2021 quarter CPI based on an annual inflation rate of 2.5 per cent, being the mid-range of RBA's long term inflation target.

Figure 6 shows the overall estimated net benefit for each option under the central scenario.

Figure 6 – Summary of the estimated net benefits under the central scenario – excluding competition benefits

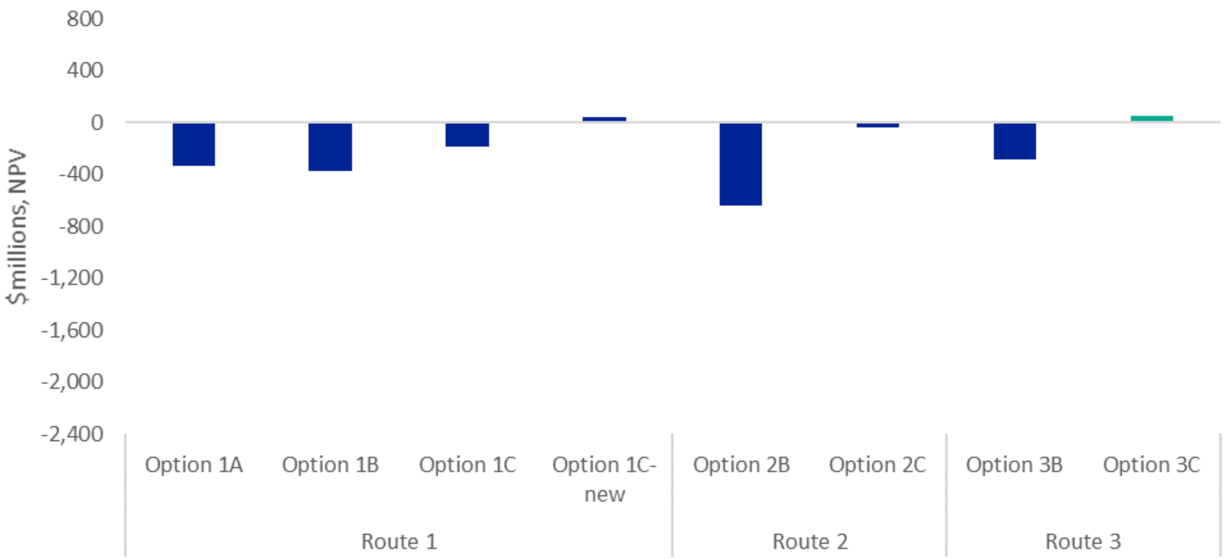
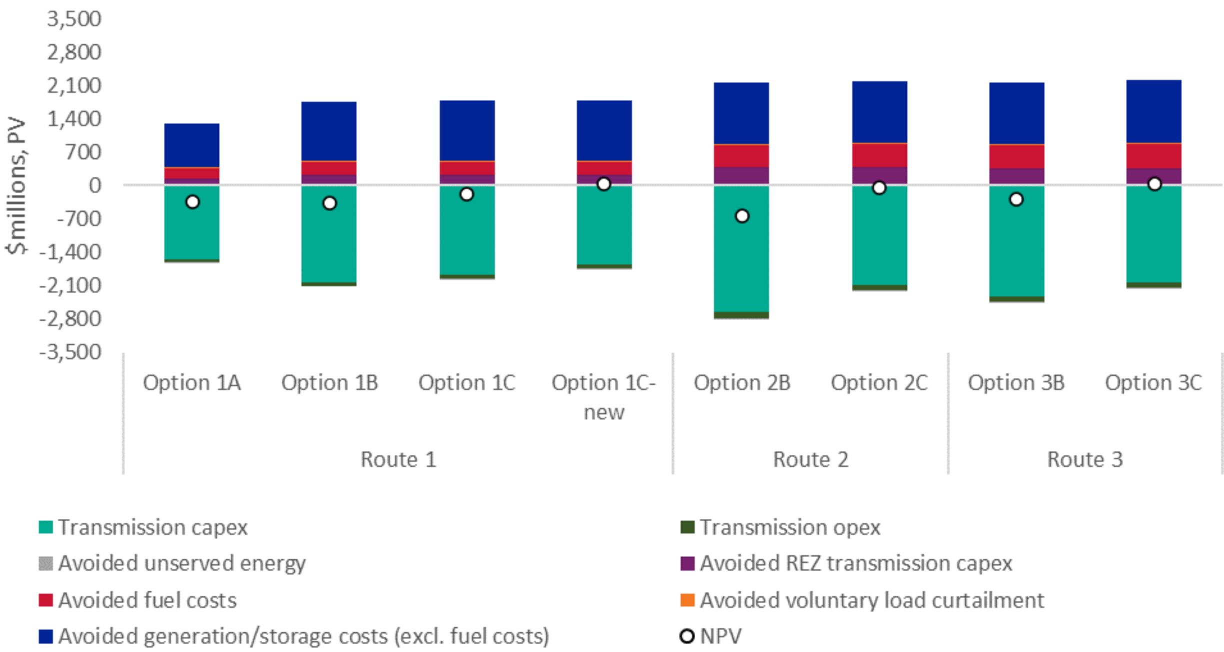


Figure 7 shows the composition of estimated net benefits for each option under the central scenario.

Figure 7 – Breakdown of estimated net benefits under the central scenario – excluding competition benefits



The key findings from the assessment of each option under the central scenario (excluding competition benefits) are that:[9]

[9] The detailed descriptions of the drivers of the key market benefit categories below are based on the market modelling results for Option 3C. Please refer to the accompanying market modelling results, and report, released alongside the PACR for more detail on the market modelling results for all options. We note that the wholesale market benefits for Option 1C-new (excluding competition benefits) are the same as those for Option 1C reported in the PACR and earlier market modelling report.

- All credible options beside Option 1C-new and Option 3C are found to deliver negative net market benefits, ranging from approximately -$33 million (Option 2C) to -$639 million (Option 2B).
- The fixed 500 kV options (i.e., the 'C' options) provide the greatest net benefit of the options considered on account of these options providing the greatest (and earliest) increase in transfer capacity.
- Market benefits of all options are primarily derived from avoided/deferred generation and storage capital costs (shown by the blue sections of each bar in Figure 7 respectively).
  - These benefits are primarily driven by avoided/deferred large-scale storage (LS battery) developments and avoided solar developments from 2030. While the deferred LS battery capacity starts to be built in the late 2030s, avoided open cycle gas turbine (OCGT) build from the late 2030s and pumped hydro from the early 2040s results in further market benefits.
  - The market modelling indicates that the majority of capacity deferral/avoidance occurs in New South Wales and, to a lesser extent, in Queensland. Southern states are forecast to have additional installations of renewables as HumeLink allows for a more diverse and higher quality of capacity mix.
- Avoided fuel costs are the second most material category of market benefit estimated across the options (shown by the red sections of each bar in Figure 7).
  - These arise primarily from lower black coal generation in New South Wales in the early years of the assessment period.
  - In the later years of the modelling period, lower gas generation in New South Wales is forecast to also contribute to fuel cost savings.
- REZ transmission cost savings (shown by the orange sections of each bar in Figure 7) are mainly driven by HumeLink allowing builds in REZs with free transmission capacity such as Wagga Wagga and West Victoria to replace/defer REZ transmission expansion in REZs such as Central West Orana.

Figure 8 below presents the estimated cumulative expected gross benefits for Option 3C for each year of the assessment period under the central scenario.[10] It shows the cumulative market benefits, in present value terms (and so the final year's stacked bars align with the overall breakdown of estimated market benefits shown in Figure 7 above).

[10] This figure only presents the annual breakdown of estimated gross benefits for the preferred option. The separately released spreadsheet presents an annual breakdown of costs and benefits for all options including Option 1C-new. Since this figure shows the cumulative gross benefits in present value terms, the height of the bar in 2045-46 equates to the gross benefits for Option 3C shown in Figure 7 above.

Figure 8 – Breakdown of cumulative gross benefits for Option 3C under the central scenario[11] - excluding competition benefits

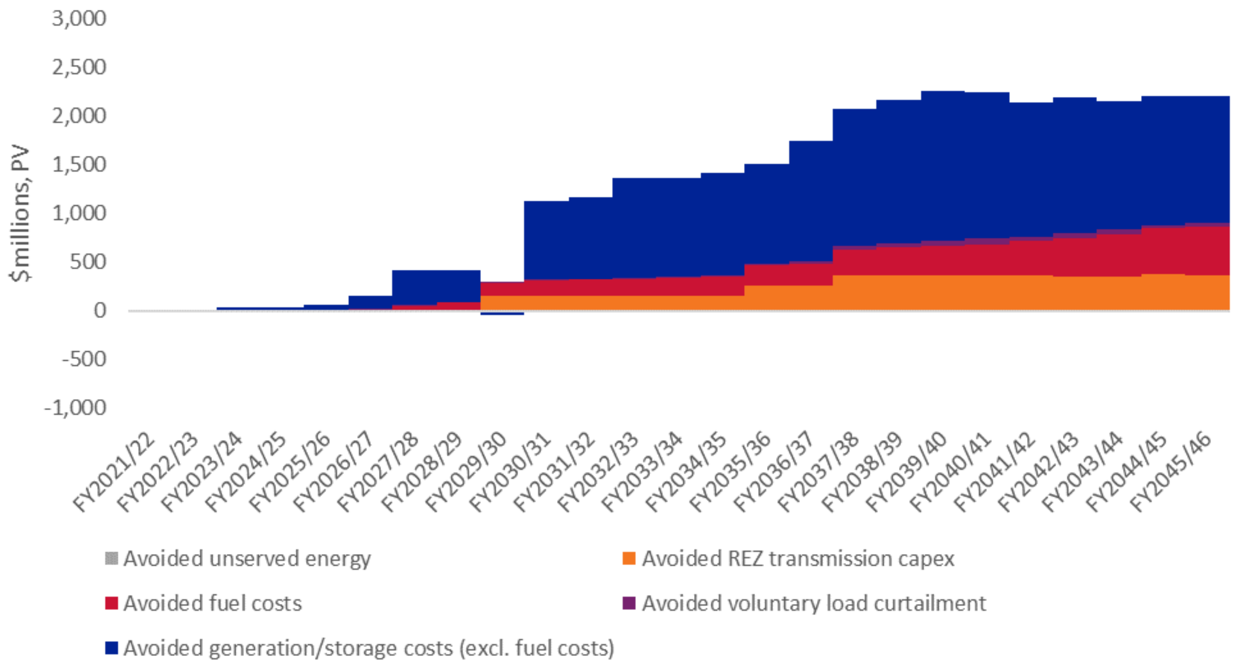


Figure 9 summarises the difference in generation and storage output modelled for Option 3C (in TWh), compared to the base case, i.e., what is found to be driving the avoided fuel cost benefit. The accompanying market modelling results workbook provides the data underpinning this chart, as well as the same data for all other options and scenarios (at both the technology and regional levels),[12] including for Option 1C-new.

[11] While all generator and storage capital costs have been included in the market modelling on an annualised basis, this chart, and all charts of this nature in the PACR and this PACR addendum, present the entire capital costs of these plant in the year avoided in order to highlight the timing of the expected market benefits. This is purely a presentational choice that we have made to assist with relaying the timing of expected benefits (i.e., when thermal plant retire) and does not affect the overall estimated net benefit of the options.

[12] We note that the wholesale market benefits for Option 1C-new (excluding competition benefits) are the same as those for Option 1C.

Figure 9 – Difference in output with Option 3C, compared to the base case, under the central scenario

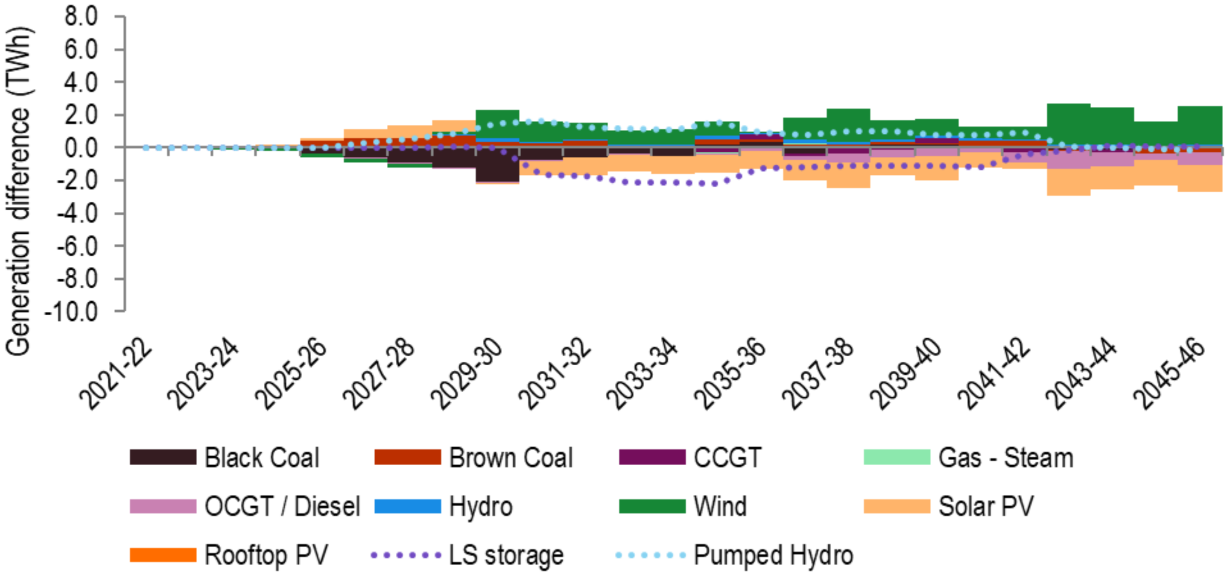
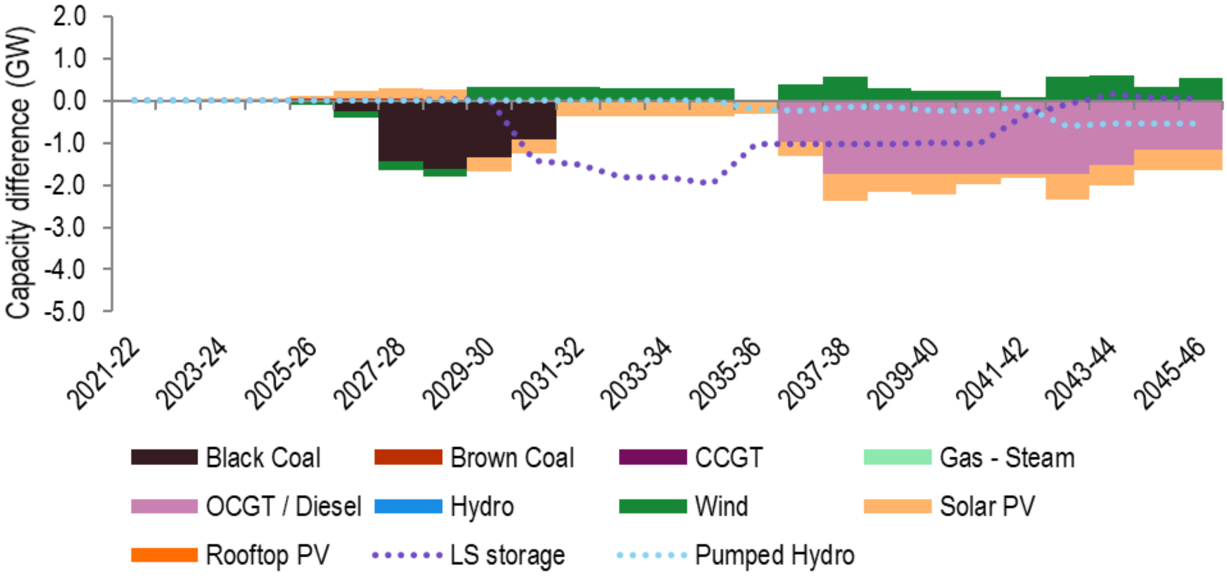


Figure 10 summarises the difference in generation and storage capacity modelled for Option 3C (in GW), compared to the base case, i.e., what is found to be driving the avoided or deferred costs associated with generation and storage benefit.

Figure 10 – Difference in cumulative capacity built with Option 3C, compared to the base case, under the central scenario



While this section (as well as subsections for the fast change, step change, slow change and slow change scenarios) focusses on the drivers of market benefits for Option 3C, we note that the drivers are effectively the same for the second and third ranked options (Option 1C-new and 2C) under this scenario.

Fast-change scenario

The fast-change scenario reflects a state of the world where there is a rapid technology-led transition of the power system and a ‘fast-change’ in emissions. Assumptions made in the fast-change scenario include

AEMO's moderate demand forecasts (including DSP), neutral gas and coal price forecasts, carbon budget, and economic retirements of coal plants.

AEMO describes the fast-change scenario as reflecting a 'rapid technology-led transformation, particularly at grid scale, where advancements in large scale technology improvements and targeted policy support reduce the economic barriers of the energy transmission. In this scenario, coordinated national and international action towards achieving emissions reductions, leading to manufacturing advancements, automation, accelerated retirement of existing generators, and integration of transport into the energy sector'.[13]

The PACR assessment finds that Option 3C has the highest expected net benefit under these assumptions and is one of three options with positive net benefits (the others being Option 1C-new and Option 2C). Option 3C is estimated to deliver approximately $91 million in net benefits under this scenario, while the second-ranked option (Option 1C-new) has positive estimated net benefits of $86 million, which is 5 per cent lower than Option 3C.

Figure 11 – Summary of the estimated net benefits under the fast-change scenario – excluding competition benefits

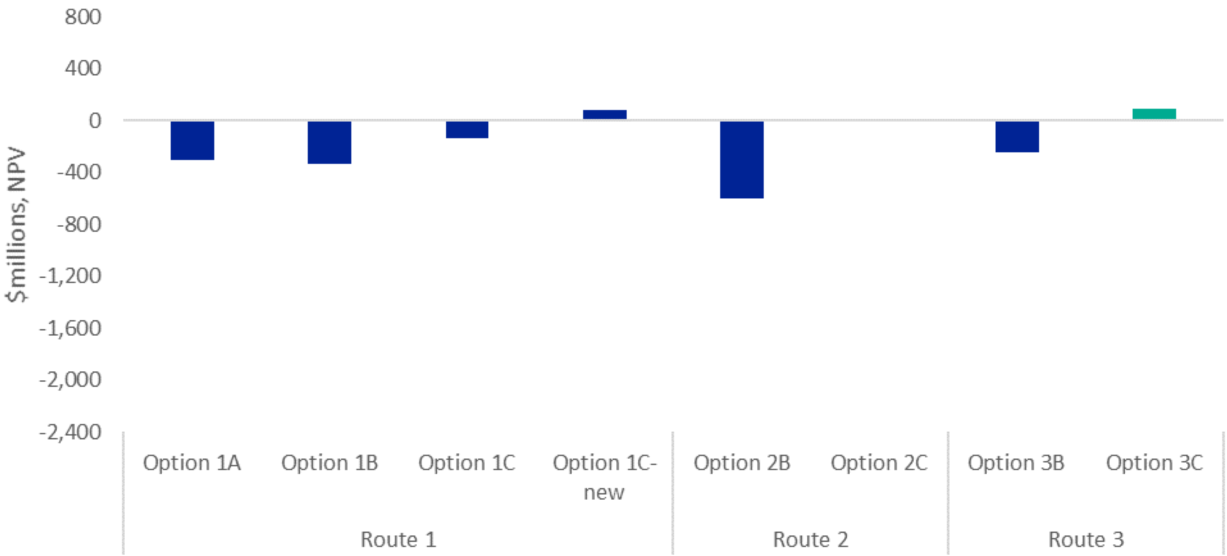
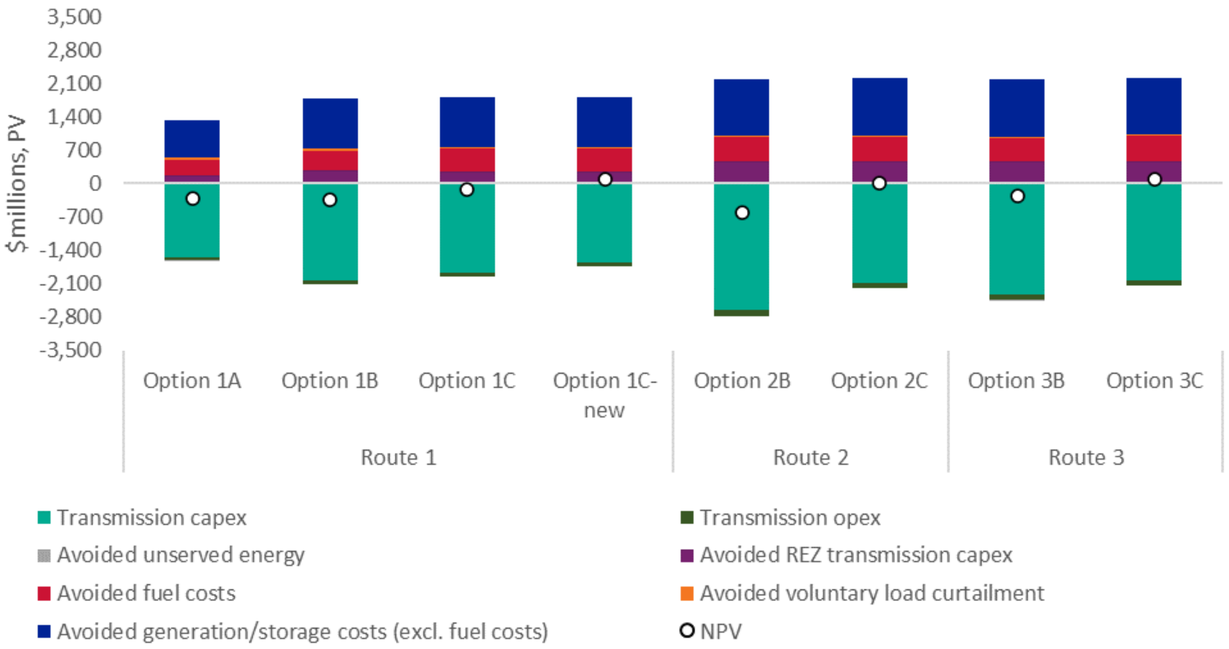


Figure 12 shows the composition of estimated net benefits for each option under the fast-change scenario.

Figure 12 – Breakdown of estimated net benefits under the fast-change scenario – excluding competition benefits

[13] AEMO, *2019 forecasting and planning scenarios, inputs, and assumptions*, August 2019, p. 4.



The key findings from the assessment of each option under the fast-change scenario (excluding competition benefits) are that:[14]

- The fast-change scenario results in a slightly higher estimated net benefits for all options compared to the central scenario.
  - The fast-change scenario increases the estimated net benefits compared to the central scenario by between approximately $27 million (Option 1A) and $46 million (Option 1C and Option 1C-new).
- The fixed 500 kV options (i.e., the 'C' options) continue to provide the greatest net benefit of all options considered on account of these options providing the greatest (and earliest) increase in transfer capacity.
- Market benefits of all options (besides the topology 1 options) are mostly derived from avoided generation and storage costs in the wholesale market (shown by the blue section of bars in Figure). Avoided fuel costs (red section of bars in Figure 12) and avoided REZ transmission capex (purple section of bars in Figure 12) also contribute significantly to gross wholesale market benefits.
  - As for the central scenario, this scenario finds that avoided/deferred capex is primarily from LS batteries and OCGTs in NSW. By the end of the study period, the model forecasts avoidance of OCGT and pumped hydro as well as more brown coal retirement with Option 3C, while more LS battery, wind and solar capacities are expected to be built.
  - Fuel cost savings are also expected to be mainly due to lower black coal generation in NSW in the early years of the assessment period, followed by lower gas generation later on.
  - REZ transmission capex is also avoided, mainly in 2029 and the mid-2030s, as Option 3C allows builds in REZs with free transmission capacity such as Wagga Wagga and other REZs in South

[14] The detailed descriptions of the drivers of the key market benefit categories below are based on the market modelling results for Option 3C. Please refer to the accompanying market modelling results, and report, released alongside the PACR for more detail on the market modelling results for all options.

Australia and Victoria to replace installations in REZs that incur transmission build in the base case.

Figure 13 below presents the estimated cumulative expected gross benefits for Option 3C for each year of the assessment period under the fast-change scenario.

Figure 13 – Breakdown of cumulative gross benefits for Option 3C under the fast-change scenario – excluding competition benefits

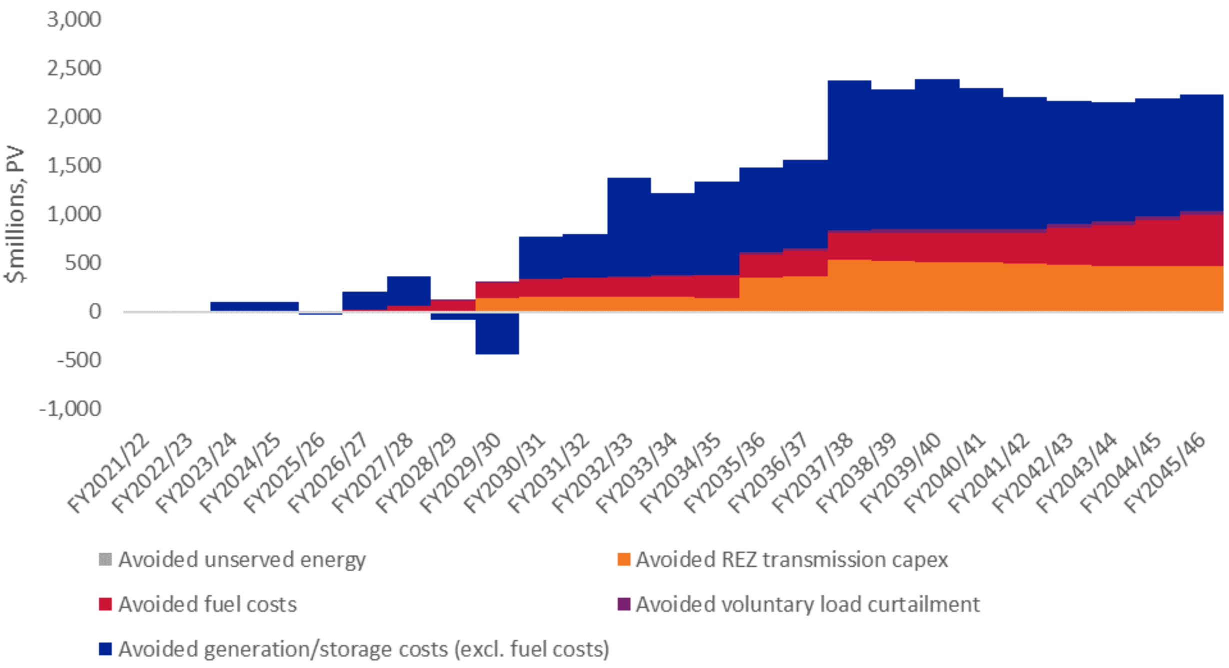


Figure 14 summarises the difference in generation and storage output modelled for Option 3C (in TWh), compared to the base case.

Figure 14 – Difference in output with Option 3C, compared to the base case, under the fast-change scenario

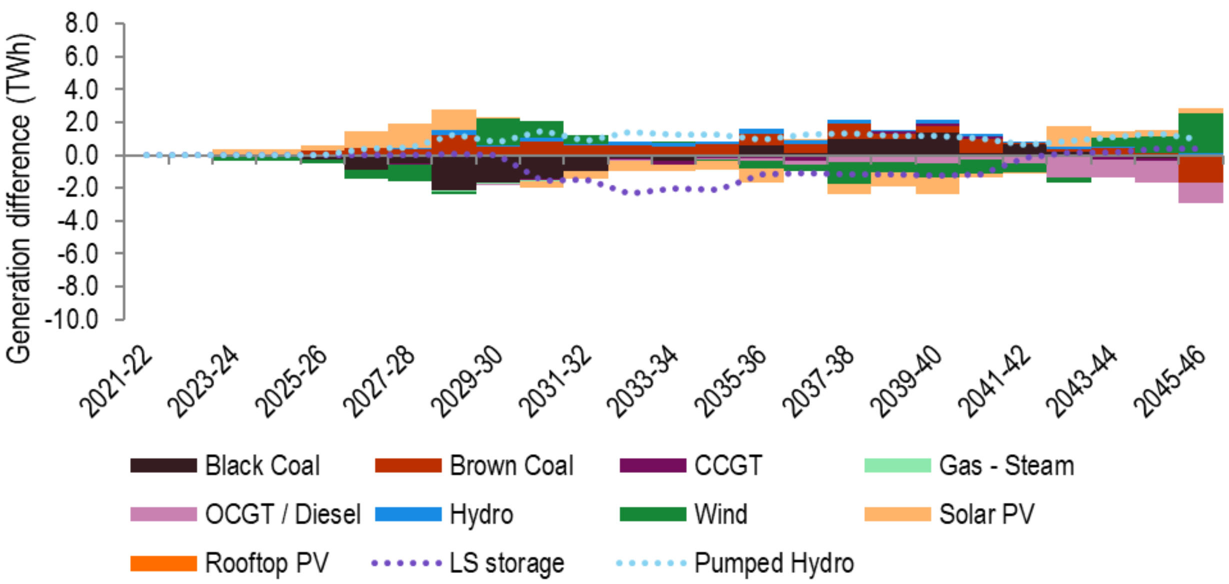
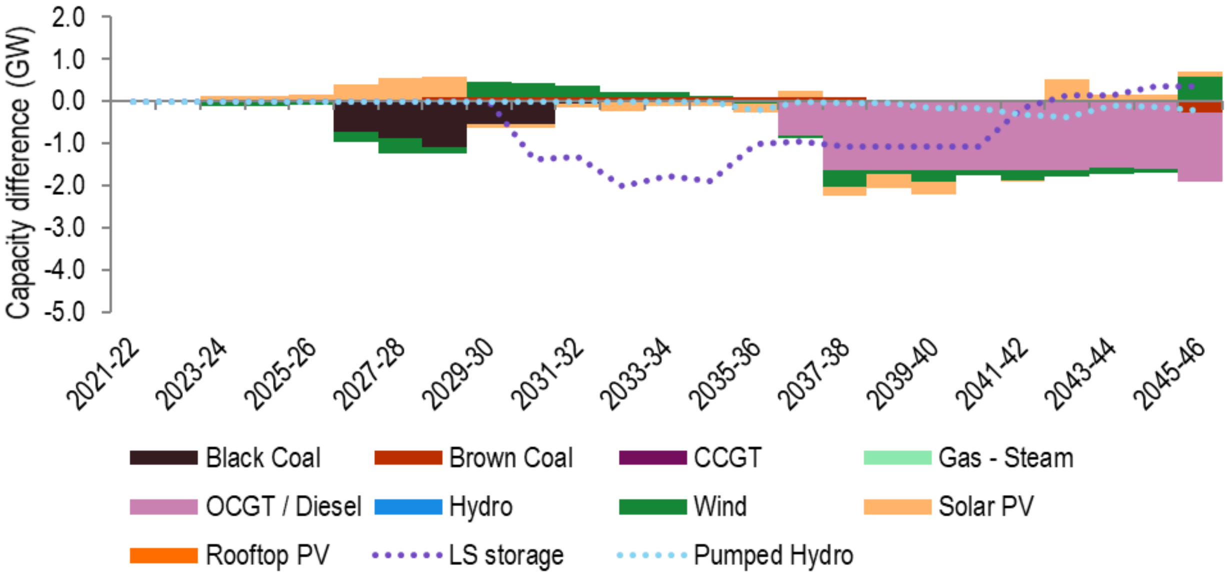


Figure 15 summarises the difference in generation and storage capacity modelled for Option 3C (in GW), compared to the base case.

Figure 15 – Difference in cumulative capacity built with Option 3C, compared to the base case, under the fast-change scenario



Step-change scenario

The step-change scenario reflects a state of the world where there is strong action on climate change and a 'step-change' in emissions, including AEMO's high demand forecasts (including DSP), fast gas and coal price forecasts, coal plants retiring earlier than the central scenario, as well as a restrictive carbon budget.

AEMO describe the step-change scenario as reflecting 'strong action on climate change that leads to a step-change reduction of greenhouse gas emissions'. In this scenario, aggressive global decarbonisation leads to faster technological improvements, accelerated exit of existing coal generators, greater electrification of the transport sector with increased infrastructure developments, energy digitalisation, and consumer-led innovation'.[15]

The assessment in this PACR addendum finds that Option 3C continues to be the top-ranked option under this scenario and is estimated to deliver $634 million in net benefits, while the second-ranked option becomes Option 2C (rather than Option 1C-new, which falls to fourth-ranked), with estimated net benefits of $537 million, which is 15 per cent lower than Option 3C. Under the step-change scenario, the net benefits of all options are found to increase significantly yielding positive expected net benefits, with the exception of Option 1A, Option 1B and Option 2B.

Figure 16 shows the overall estimated net benefit for each option under the step-change scenario.

[15] AEMO, *2019 forecasting and planning scenarios, inputs, and assumptions*, August 2019, p. 4.

Figure 16 – Summary of the estimated net benefits under the step-change scenario – excluding competition benefits

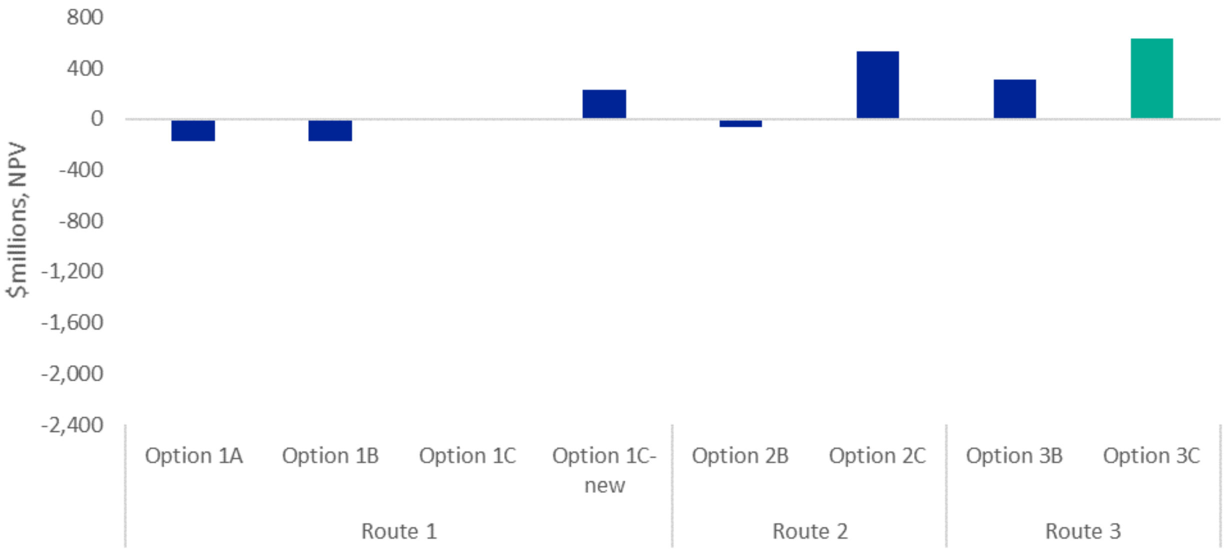
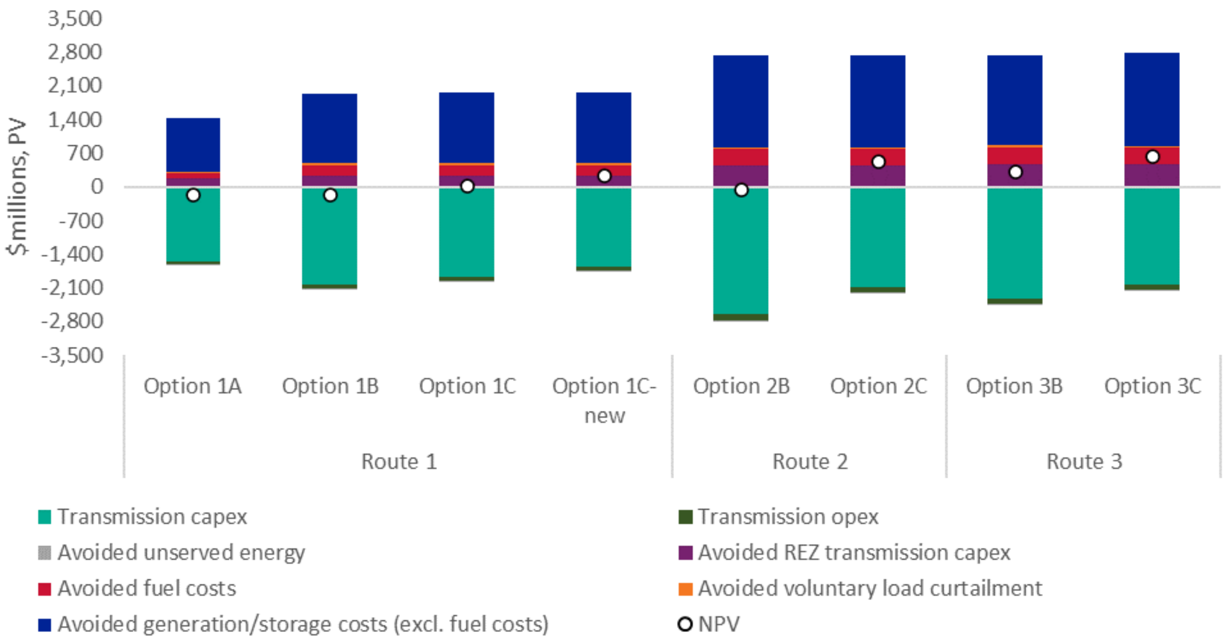


Figure 17 shows the composition of estimated net benefits for each option under the step-change scenario.

Figure 17 – Breakdown of estimated net benefits under the step-change scenario – excluding competition benefits



The key findings from the assessment of each option under the step-change scenario (excluding competition benefits) are that:[16]

- The step-change results in greater estimated net benefits for all options than under the central scenario, with the change from the central scenario ranging from approximately $155 million (Option 1A) to $596 million (Option 3B).
- The fixed 500 kV options (i.e., the 'C' options) continue to provide the greatest net benefit within each route considered on account of these options providing the greatest (and earliest) increase in transfer capacity.
- Market benefits of all options are primarily derived from avoided generation and storage costs (shown by the blue sections of bars in Figure 17) and are expected to accrue as soon as HumeLink is commissioned and then significantly increase from around 2035/36.
  - These benefits are found to be most significant around the time large black coal generators are expected to retire and are initially driven by an increased utilisation of Snowy 2.0 and changes in capacity mix that result in the avoidance of LS battery build in New South Wales from 2026/27.
  - The forecast capex savings from the mid-2030s are mostly driven by the deferral/avoidance of solar investment followed by the avoidance of OCGT installations, with some wind build forecast to be brought forward (however, the reduced wind build in Queensland in the 2040s is offset by the additional wind installation in southern states, particularly Victoria, in those years).
- Avoided or deferred REZ transmission capex is the second most material category of market benefit estimated across the options (shown by the purple section of bars in Figure 17).
  - These benefits start from 2027/28 as wind and solar installations are forecast to be built in Wagga Wagga and South Australia instead of the Central West Orana REZ and Queensland, avoiding transmission costs.
- Fuel cost savings are expected to be lower than for the central scenario, mainly due to higher coal retirements in the step-change scenario.
  - The modelled fuel cost savings start from the late 2030s, where gas generation is avoided.

Figure 18 below presents the estimated cumulative expected gross benefits for Option 3C for each year of the assessment period under the step-change scenario.

[16] The detailed descriptions of the drivers of the key market benefit categories below are based on the market modelling results for Option 3C. Please refer to the market modelling results, and report, released alongside the PACR for more detail on the market modelling results for all options. This includes Option 1C-new, which has the same wholesale market benefits (excluding competition benefits) as Option 1C.

Figure 18 – Breakdown of cumulative gross benefits for Option 3C under the step-change scenario – excluding competition benefits

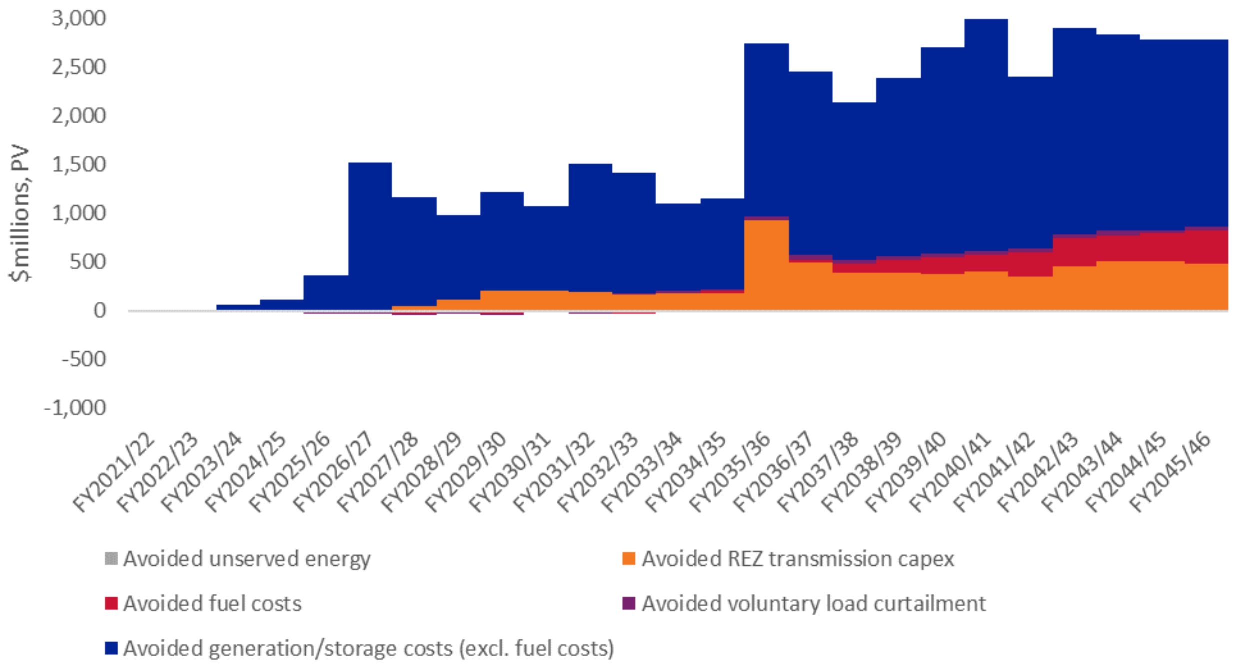


Figure 19 summarises the difference in generation and storage output modelled for Option 3C (in TWh), compared to the base case.

Figure 19 – Difference in output with Option 3C, compared to the base case, under the step-change scenario

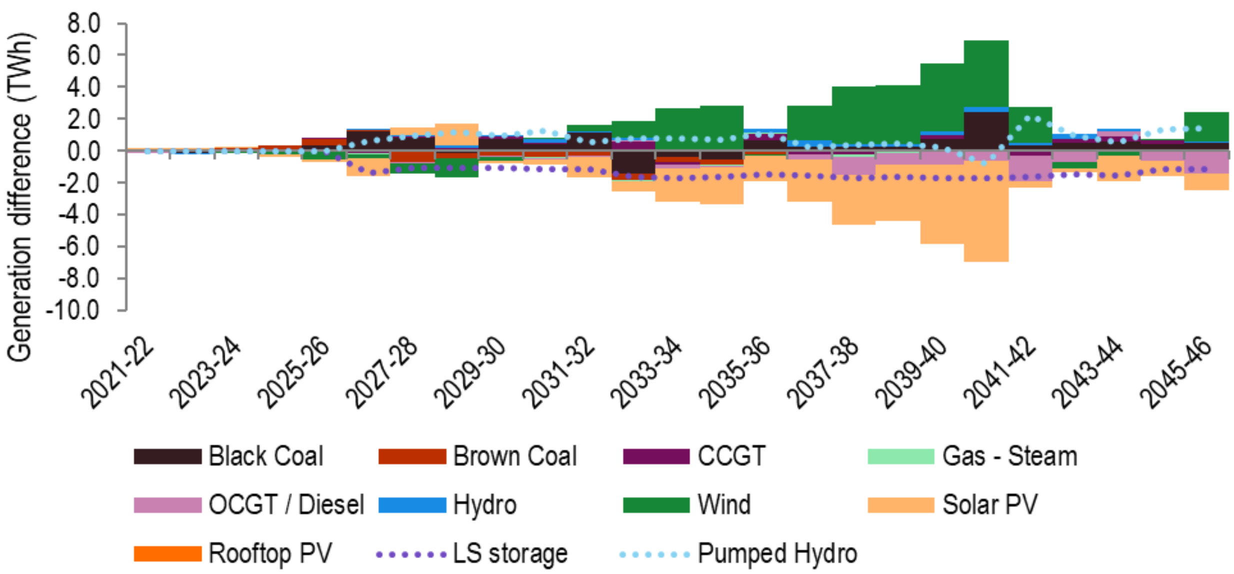
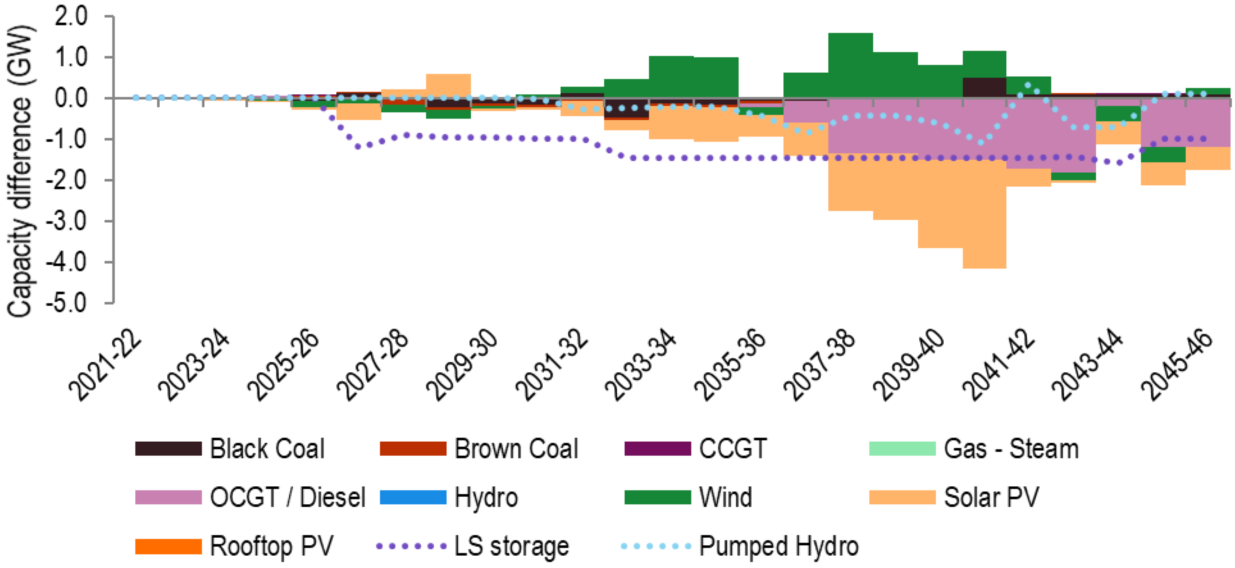


Figure 20 summarises the difference in generation and storage capacity modelled for Option 3C (in GW), compared to the base case.

Figure 20 – Difference in cumulative capacity built with Option 3C, compared to the base case, under the step-change scenario



Slow-change scenario

The slow-change scenario is made up of a set of conservative assumptions reflecting a future world of lower demand forecasts (including DSP), slow gas and coal price forecasts and coal plants allowed a ten-year life extension (if economic to do so). While the slow-change scenario assumes the same national emissions reduction as the central scenario by 2030, it assumes lower state-based renewables commitments. The slow-change scenario also excludes VNI West going ahead.

AEMO describe the slow-change scenario as reflecting 'a general slow-down of the energy transition. It is characterised by slower advancements in technology and reductions in technology costs, low population growth, and low political, commercial, and consumer motivation to make the upfront investments required for significant emissions reduction'.[17]

The slow-change scenario is therefore intended to represent the lower end of the potential range of realistic net benefits associated with the various options.

We note that the slow-change scenario is considered the least likely of the four scenarios and is given a 10 per cent weighting in the analysis, consistent with the recommended weighting in the 2020 ISP.[18] In addition, we note that recent commentary from the ESB[19] suggests that the NEM is in fact tracking closest to the step-change currently.[20]

All options are found to have significantly negative net benefits under the slow-change scenario. Option 1C-new is found to have the least negative net benefits at around -$985 million. Option 3C becomes the

17 AEMO, *2019 forecasting and planning scenarios, inputs, and assumptions*, August 2019, p. 3.
18 AEMO, 2020 Integrated System Plan, July 2020, p. 86
19 See Renew Economy, *"We are headed for step change:" ESB's Kerry Schott on new market design,* Parkinson, G., 30 September 2020 (accessed via https://reneweconomy.com.au/we-are-headed-for-step-change-esbs-kerry-schott-on-new-market-design-89487/ on 7 July 2021), Argus Media, Australia tops step-change energy transition scenario, Morrison, K., 7 May 2021 (accessed via https://www.argusmedia.com/en/news/2212777-australia-tops-stepchange-energy-transition-scenario on 7 July 2021) & ESB, *The Health of the National Electricity Market 2020*, Volume 1: The ESB Health of the NEM Report, 5 January 2020, p. 8.
20 We have investigated the impact of this via a sensitivity, in section 2.4.4, that applies a higher weight to the step-change scenario in-line with this commentary.

fourth ranked option with an estimated negative net market cost that is approximately 36 per cent greater than Option 1C-new.

Figure 21 shows the overall estimated net benefit for each option under the slow-change scenario.

Figure 21 – Summary of the estimated net benefits under the slow-change scenario – excluding competition benefits

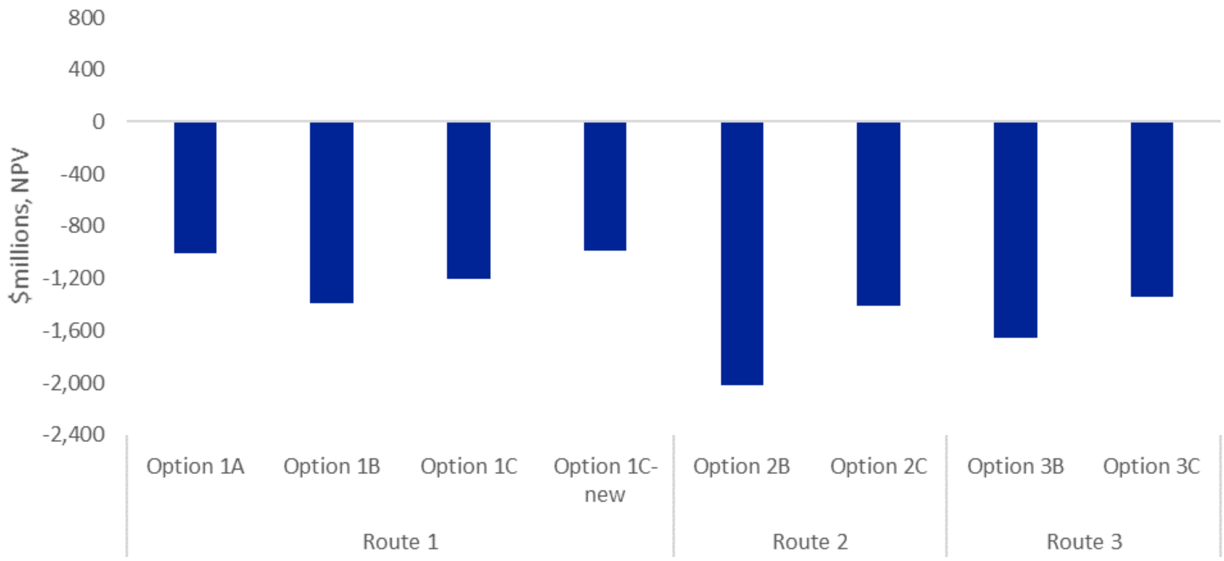
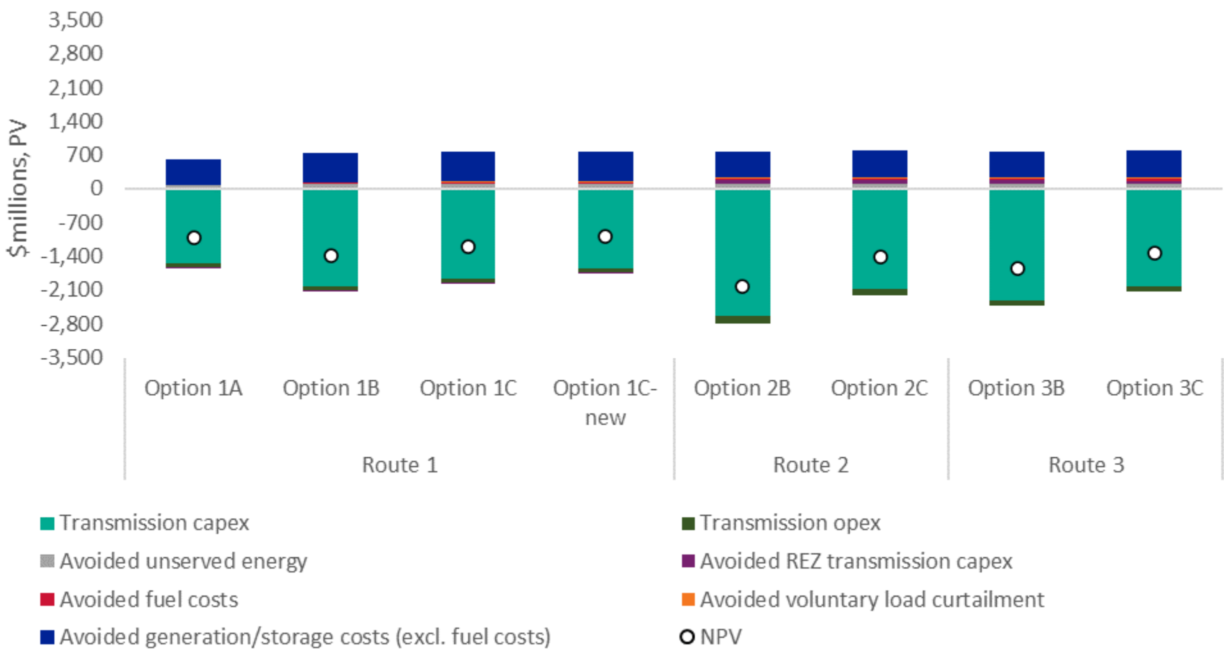


Figure 22 shows the composition of estimated net benefits for each option under the slow-change scenario.

Figure 22 – Breakdown of estimated net benefits under the slow-change scenario – excluding competition benefits



The key findings from the assessment of each option under the slow-change scenario (excluding competition benefits) are that:[21]

- The estimated net market benefits for all options fall significantly relative to the central scenario (and are all negative).
- The fixed 500 kV options (i.e., the 'C' options) continue to provide the greatest net benefit (least net cost) of all options considered that are able to operate at 500 kV on account of these options providing the greatest (and earliest) increase in transfer capacity.
- The flexible 500 kV options are found to be upgraded from 330 kV to 500 kV in 2035-36, being the time at which the benefits from upgrading to 500 kV exceed the annualised upgrade cost under this scenario.
- The market benefits for all options are almost completely driven by avoided or deferred costs associated with generation and storage (shown by the blue bars in Figure 22).
  - The market modelling finds that this is driven primarily by avoided LS battery investment in New South Wales from around 2032/33.
  - Other wholesale market benefit categories are found to be of a smaller scale under the slow scenario than the other scenarios.
  - Overall, due to the low demand and assumptions regarding the NSW Roadmap in this scenario as well as life extension of coal plants, HumeLink is forecast to have significantly lower market benefits as compared to the other scenarios.

Figure 23 below presents the estimated cumulative expected gross benefits for Option 3C for each year of the assessment period under the slow-change scenario. It shows that the majority of the overall benefits have accrued by 2032-33 under this scenario.

[21] The detailed descriptions of the drivers of the key market benefit categories below are based on the market modelling results for Option 3C. Please refer to the accompanying market modelling results, and report, released alongside the PACR for more detail on the market modelling results for all options. This includes Option 1C-new, which has the same wholesale market benefits (excluding competition benefits) as Option 1C.

Figure 23 – Breakdown of cumulative gross benefits for Option 3C under the slow-change scenario – excluding competition benefits

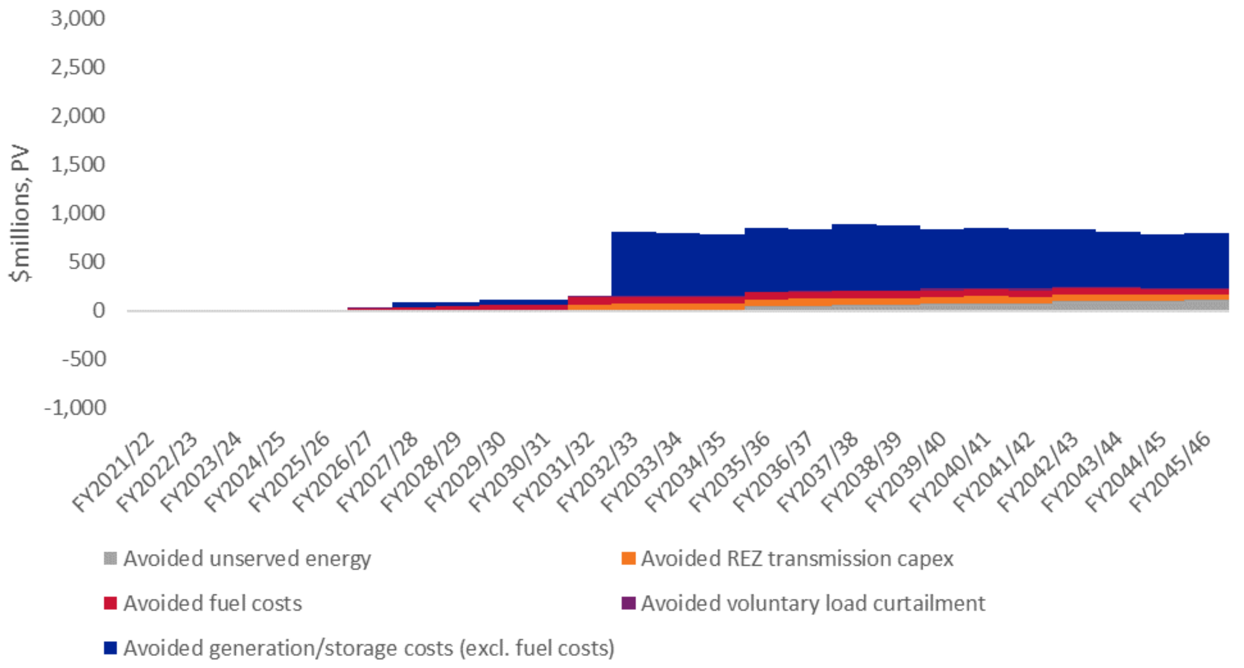


Figure 24 summarises the difference in generation and storage output modelled for Option 3C (in TWh), compared to the base case.

Figure 24 – Difference in output with Option 3C, compared to the base case, under the slow-change scenario

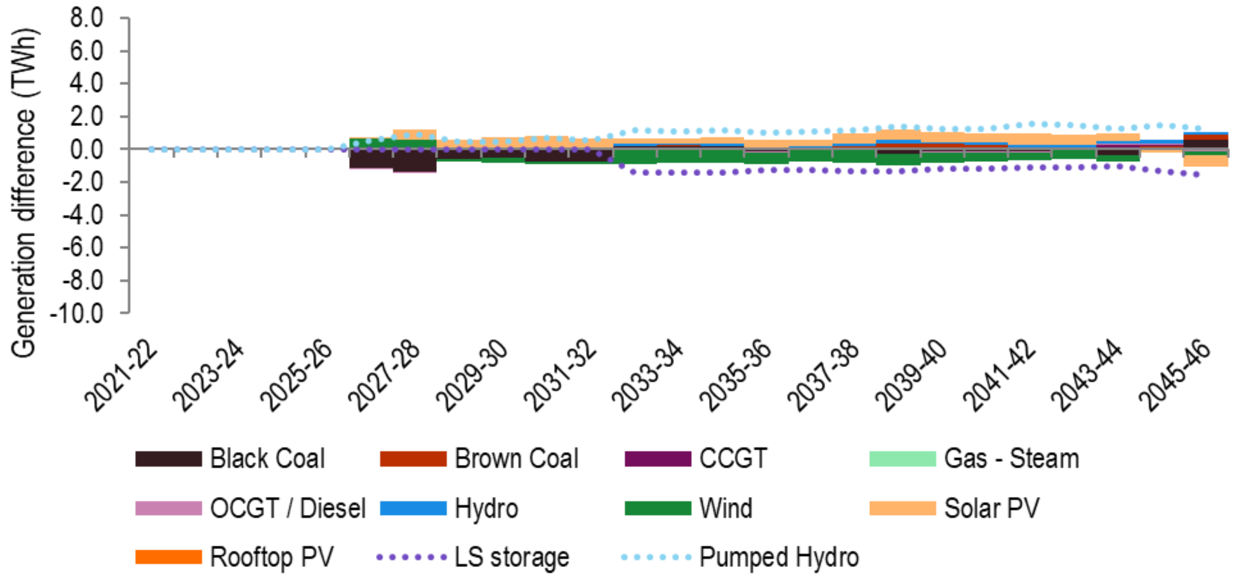
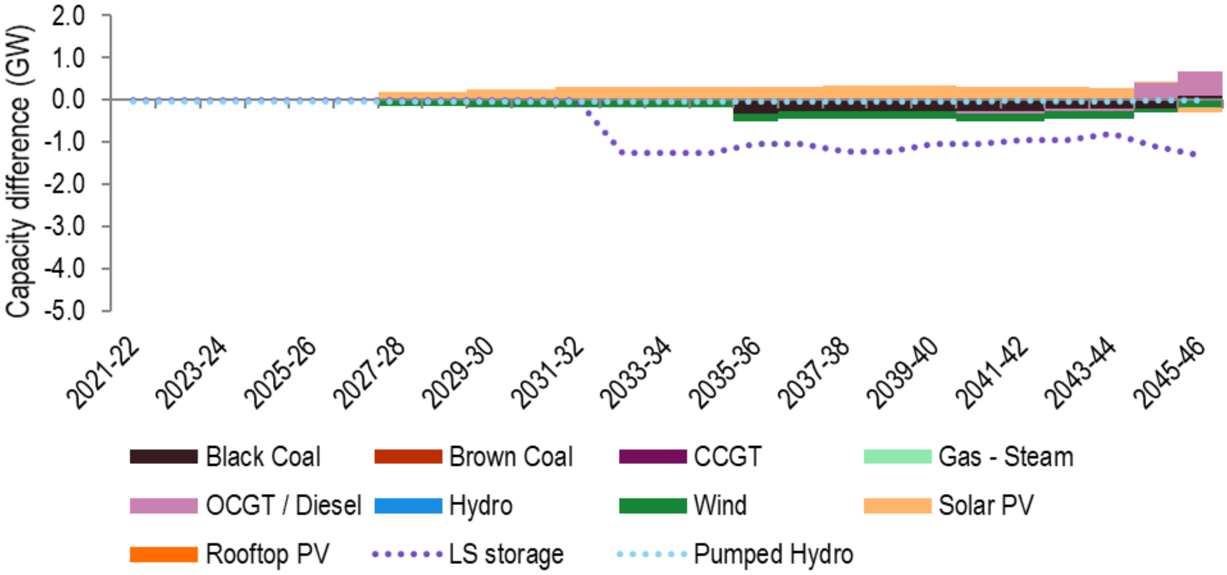


Figure 25 summarises the difference in generation and storage capacity modelled for Option 3C (in GW), compared to the base case.

Figure 25 – Difference in cumulative capacity built with Option 3C, compared to the base case, under the slow-change scenario



Weighted net benefits

Figure 26 shows the estimated net benefits for each of the credible options weighted across the four scenarios investigated (and discussed above) according to the following weights - central: 40 per cent, step change: 20 per cent, slow change: 10 per cent, and fast change: 30 per cent.[22]

On a weighted-basis, Option 3C is the top-ranked option and is the only option to have positive net market benefits. Option 3C is expected to deliver approximately $39 million in net benefits (excluding competition benefits), which is around $50 million more than the second-ranked option (Option 1C-new) in present value terms.[23] This equates to Option 1C-new having 128 per cent lower net benefits than Option 3C.

Figure 26 – Summary of the estimated net benefits, weighted across the four scenarios – excluding competition benefits

[22] Section 6.2 of the July 2021 PACR sets out the scenario weightings using the probabilities proposed by AEMO in the final 2020 ISP

[23] Option 1C-new has -$11 million net benefits on a weighted basis, which is 128 per cent lower than Option 3C.

The top three ranked options (i.e., Option 1C-new, Option 2C and Option 3C) are assessed further in section 2.3 below.

2.3. RIT-T results

This section presents the RIT-T assessment for the PACR addendum. Specifically, it builds upon the positioning assessment discussed above by presenting the net market benefits for the three top-ranked options coming out of that analysis (i.e., Option 1C-new, Option 2C and Option 3C), across each of the four ISP scenarios investigated, as well as capturing the eighth category of market benefits estimated for these options, i.e,, competition benefits.

The seven market benefits estimated for each option in section 2.2 above remain unchanged in this section. We therefore do not repeat the discussion of these for each scenario but, instead, focus the discussion of the new category of market benefit captured in this assessment, i.e., competition benefits.

Central scenario

All three of the options are found to deliver strongly positive net benefits, under the central scenario, ranging from $375 million to $520 million in present value terms. Overall, Option 3C continues to be the top-ranked option with estimated net benefits that are approximately 21 per cent greater than the second-ranked option (Option 2C).

Competition benefits add significantly to each option's estimated net benefits (between $335 million and $471 million across the options), which is approximately 16 percent to 18 per cent of their estimated gross wholesale market benefits for the three options considered.

The competition benefits associated with Option 1C-new are materially below those for Options 2C and 3C. This reflects the different topology of Option 1C-new, which does not involve a transmission line going via Wagga Wagga. Options 2C and 3C, which do go via Wagga Wagga, are able to access additional capacity from renewable generation in South West NSW and allow additional transfer capacity between South Australia and Victoria via Wagga Wagga into NSW major load centres. The lower competition benefits for Option 1C-new outweigh the lower costs for Option 1C-new and result in a lower overall net market benefit.

Figure 27 shows the overall estimated net benefit for each option under the central scenario. The 'core net benefits' shown in this chart (and all charts of this nature in this section), are the net benefits estimated in section 2.1 above, i.e., the net benefits factoring in the seven categories of market benefit estimated as part of the positioning assessment and the option costs.

Figure 27 – Summary of the estimated net benefits under the central scenario – including competition benefits

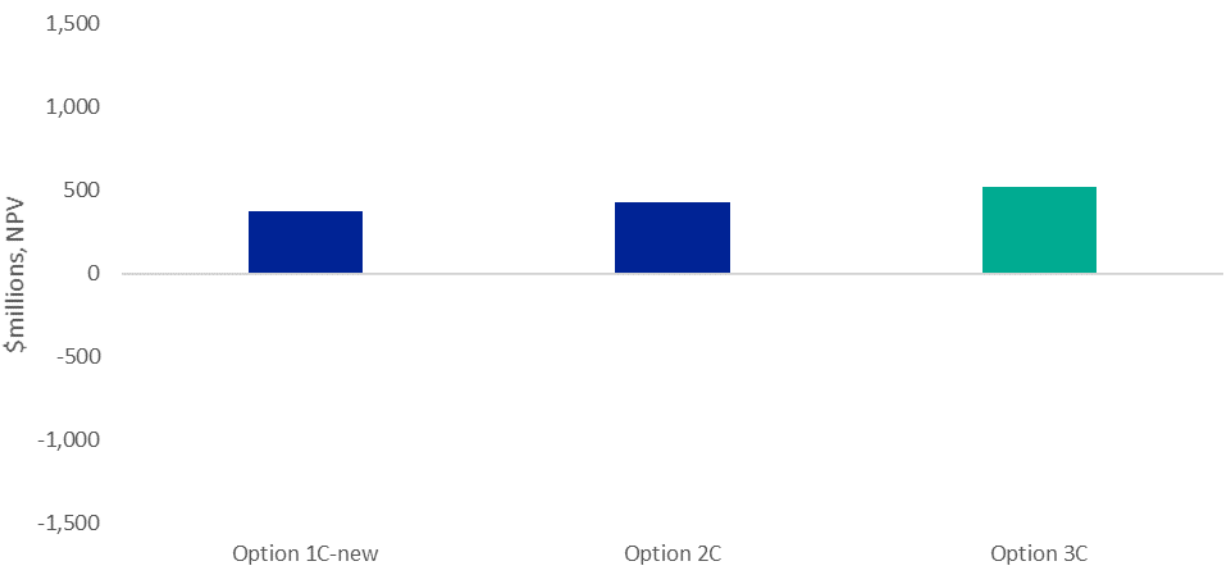
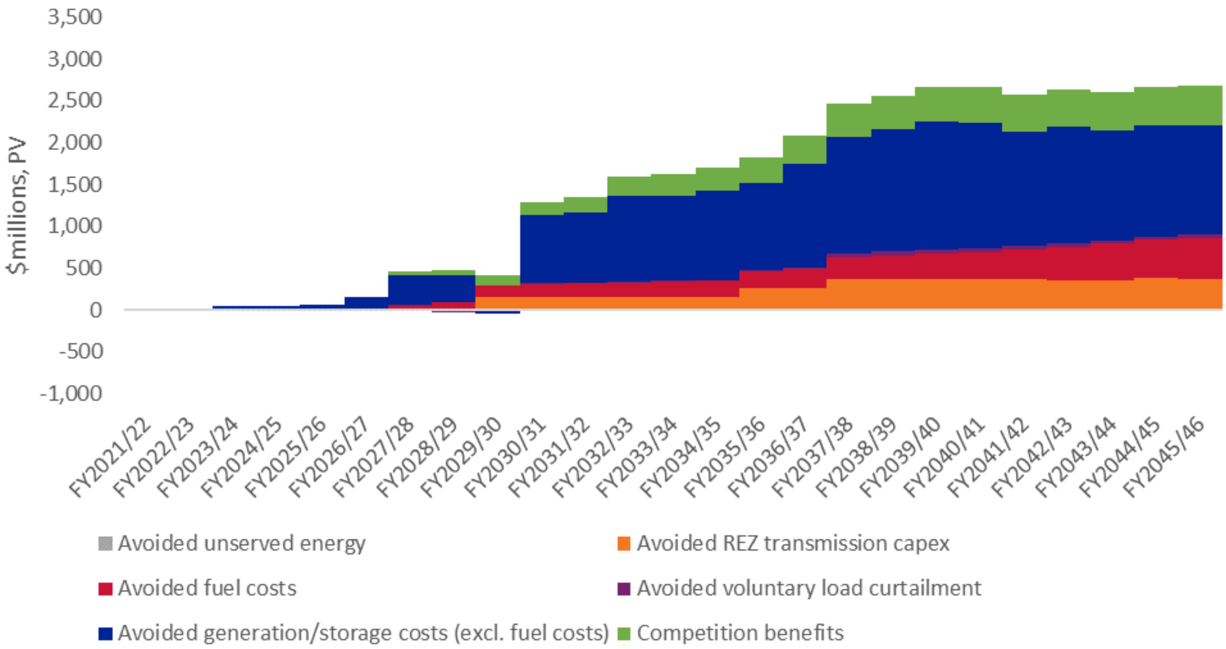


Figure 28 below presents the estimated cumulative expected gross benefits for Option 3C for each year of the assessment period under the central scenario. It shows the cumulative market benefits, in present value terms (and so the final year's stacked bars align with the overall breakdown of estimated market benefits shown in Figure 27 above). This figure, and all figures of this nature in section 2.3, update the corresponding figures in section 2.2 to include the estimated competition benefits.

Figure 28 – Breakdown of cumulative gross benefits for Option 3C under the central scenario – including competition benefits



Competition benefits are expected to accrue from shortly after Option 3C is commissioned and are material across the assessment period, ultimately contributing 18 per cent of the total expected gross benefits. Under this scenario, around 59 per cent of the competition benefits are comprised of wholesale market cost savings with the remainder made up of demand response benefits.

Fast-change scenario

Each of the options is found to deliver strongly positive net benefits under the fast-change scenario, ranging from $394 million to $487 million in present value terms. Overall, Option 3C is the top-ranked option with estimated net benefits that are approximately 21 per cent greater than the second-ranked option (Option 2C).

Competition benefits add significantly to each option's estimated net benefits (between $318 million and $396 million across the options), which is approximately 15 per cent of their estimated gross benefits for the three options considered.

Figure 29 shows the overall estimated net benefit for each option under the fast-change scenario.

Figure 29 – Summary of the estimated net benefits under the fast-change scenario – including competition benefits

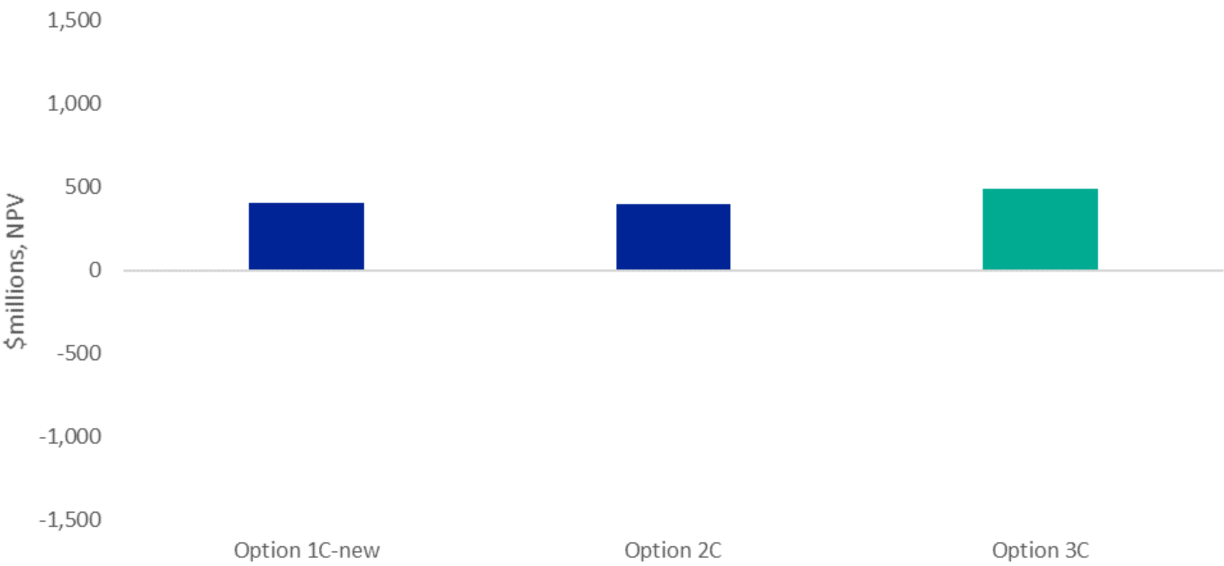
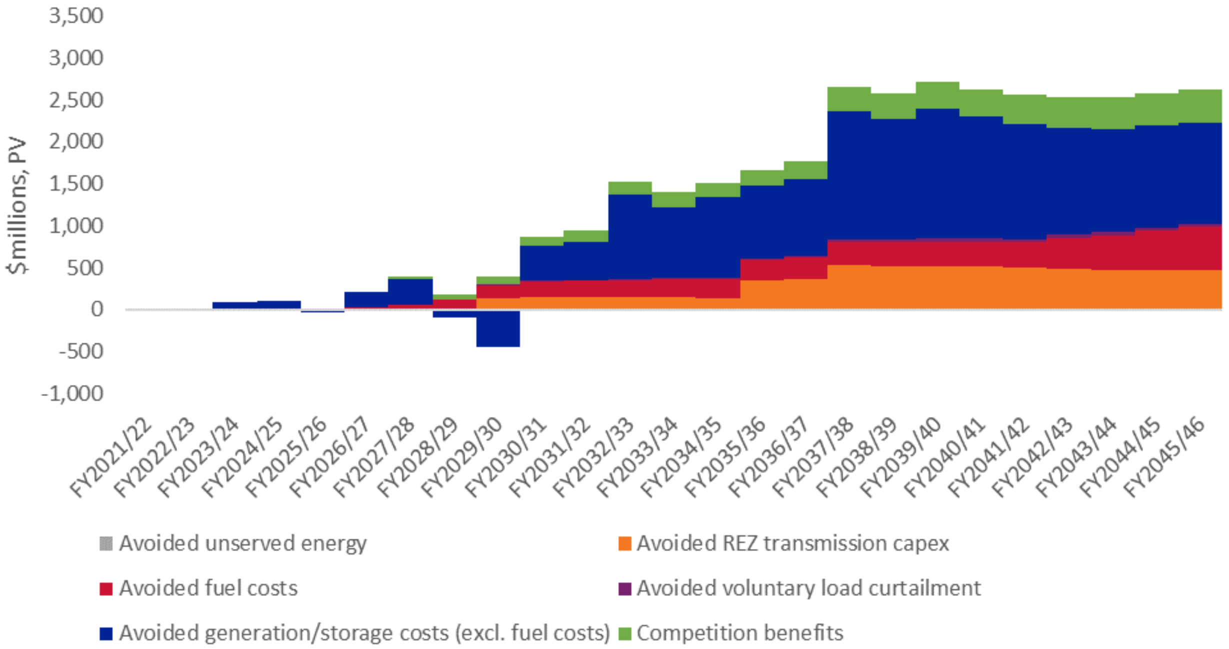


Figure 30 below presents the estimated cumulative expected gross benefits for Option 3C for each year of the assessment period under the fast-change scenario. It shows the cumulative market benefits, in present value terms (and so the final year's stacked bars align with the overall breakdown of estimated market benefits shown in Figure 29 above).

Figure 30 – Breakdown of cumulative gross benefits for Option 3C under the fast-change scenario – including competition benefits



Competition benefits are expected from shortly after Option 3C is commissioned and are material across the assessment period, ultimately contributing 15 per cent of the total expected gross benefits. Under this scenario, around 48 per cent of the competition benefits are comprised of wholesale market cost savings with the remainder made up of demand response benefits.

Step-change scenario

Each of the options is found to deliver strongly positive net benefits under the step-change scenario, ranging from $735 million to $1,271 million in present value terms. Overall, Option 3C is the top-ranked option with estimated net benefits that are approximately 9 per cent greater than the second-ranked option (Option 2C).

Competition benefits add significantly to each option's estimated net benefits (between $507 million and $637 million across the options), which is approximately 19 to 21 per cent of their estimated gross benefits for the three options considered.

Figure 31 shows the overall estimated net benefit for each option under the step-change scenario.

Figure 31 – Summary of the estimated net benefits under the step-change scenario – including competition benefits

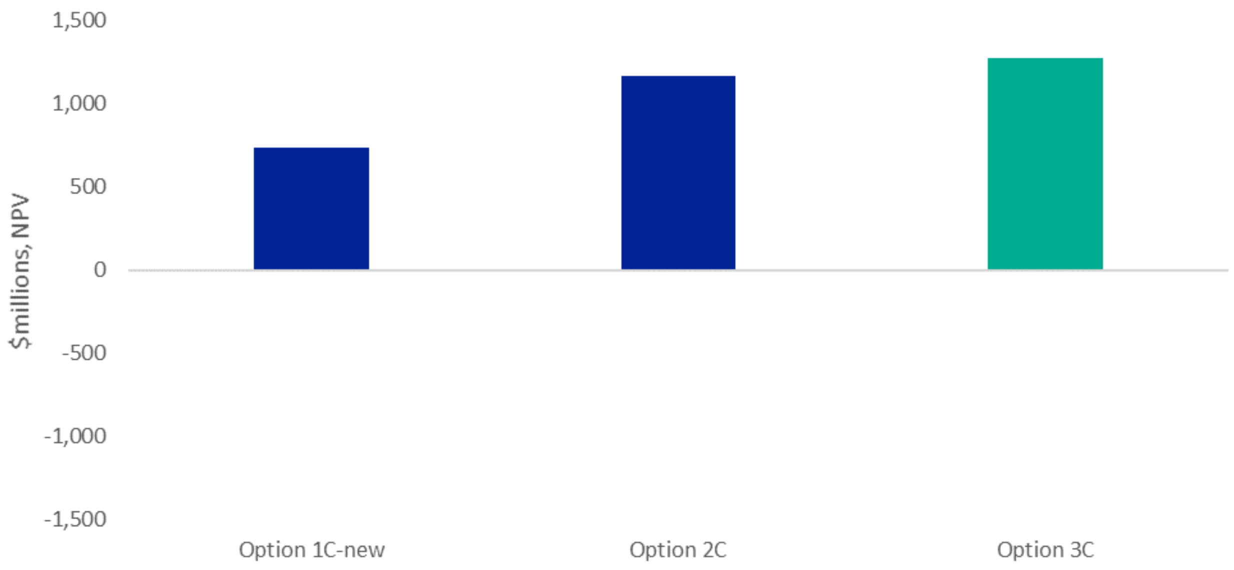
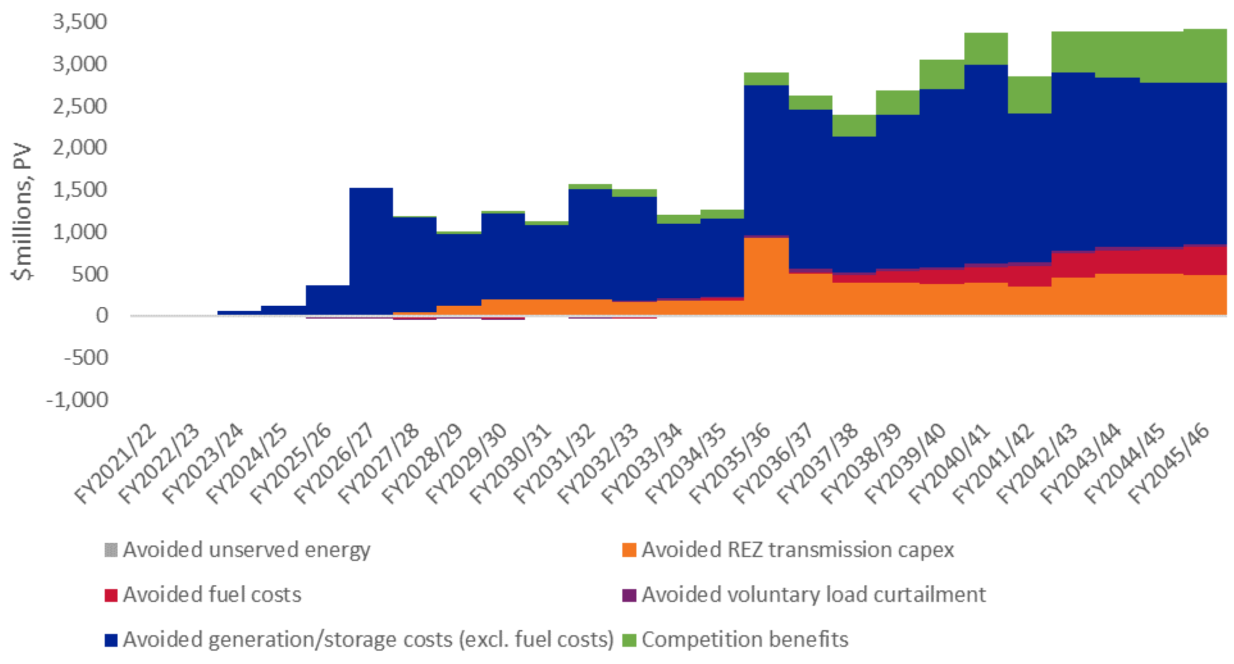


Figure 32 below presents the estimated cumulative expected gross benefits for Option 3C for each year of the assessment period under the step-change scenario. It shows the cumulative market benefits, in present value terms (and so the final year's stacked bars align with the overall breakdown of estimated market benefits shown in Figure 31 above).

Figure 32 – Breakdown of cumulative gross benefits for Option 3C under the step-change scenario – including competition benefits



Competition benefits do not appear until later in the period under the step-change scenario, compared to the central and fast-change scenarios, but are material by the end of the assessment period, ultimately contributing 19 per cent of the total expected gross benefits. Under this scenario, almost all of the competition benefits are made up of demand response benefits (92 per cent), with wholesale market cost savings making up the remainder.

Slow-change scenario

None of the options is found to deliver a positive net benefit under the slow-change scenario, even once competition benefits are included, with negative net benefits (net costs) ranging from -$1,253 million to -$829 million in present value terms. Overall, Option 1C-new is the top-ranked option with estimated net costs that are approximately 30 per cent lower than the second-ranked option (Option 3C).

Competition benefits add to each option's estimated net benefits (between $156 million and $163 million for Option 1C-new and Option 3C respectively), which is approximately 17 per cent of estimated gross benefits for both options.

Figure 33 shows the overall estimated net benefit for each option under the slow-change scenario.

Figure 33 – Summary of the estimated net benefits under the slow-change scenario – including competition benefits

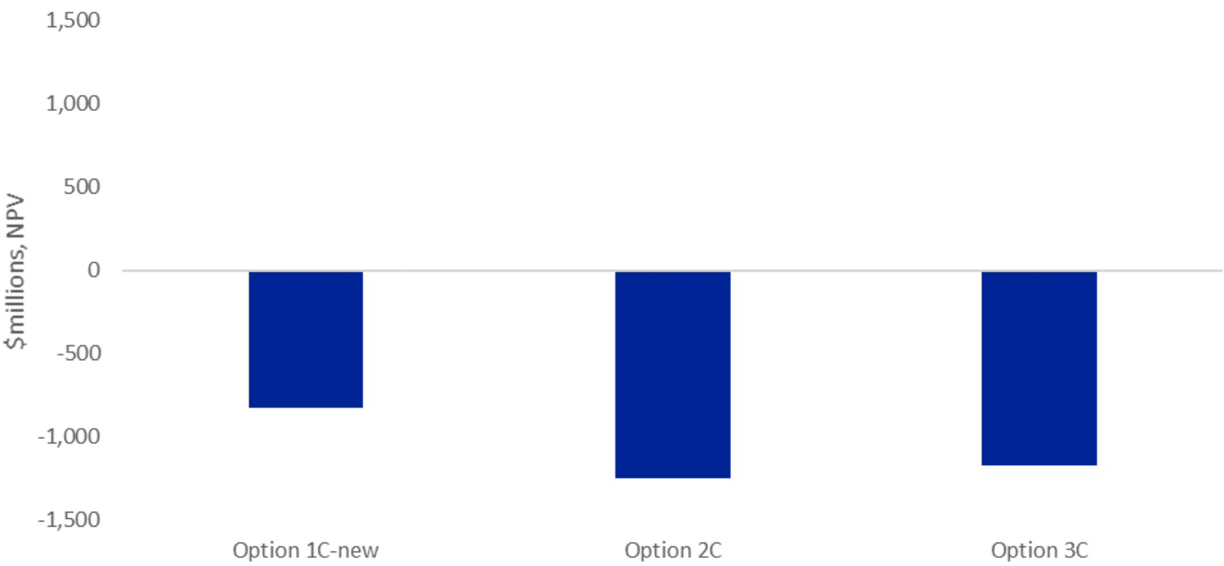
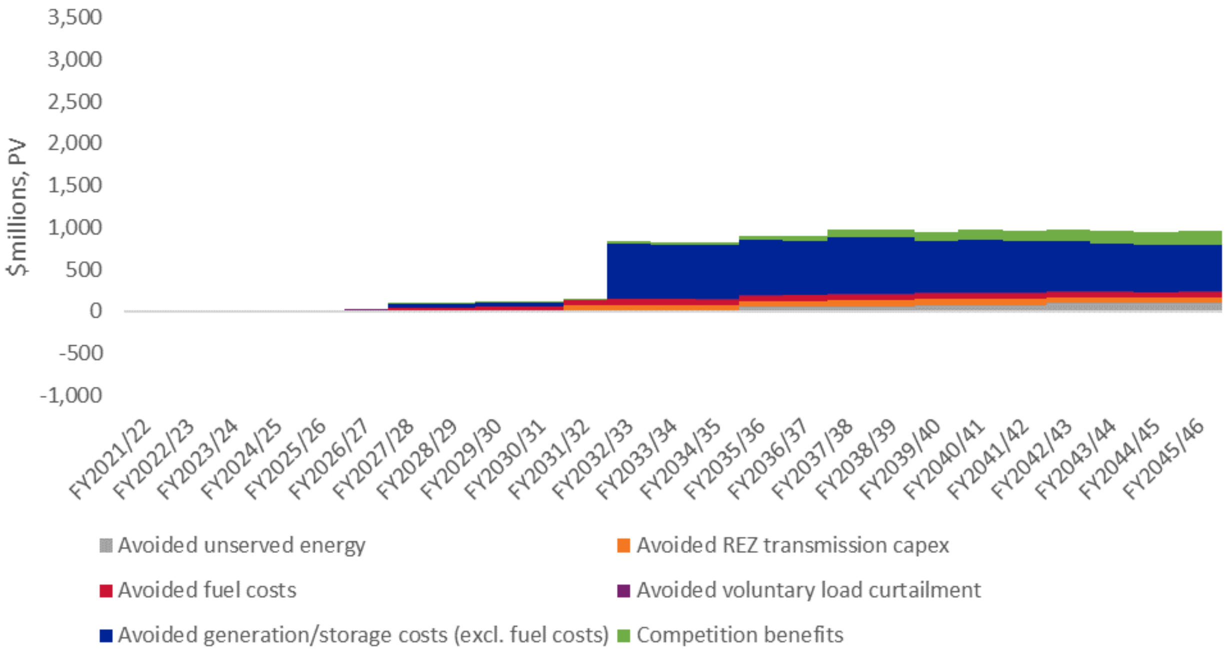


Figure 34 below presents the estimated cumulative expected gross benefits for Option 3C for each year of the assessment period under the slow-change scenario. It shows the cumulative market benefits, in present value terms (and so the final year's stacked bars align with the overall breakdown of estimated market benefits shown in Figure 33 above).

Figure 34 – Breakdown of cumulative gross benefits for Option 3C under the slow-change scenario – including competition benefits



Competition benefits, along with all benefits, are much lower under the slow-change scenario compared to the other three scenarios. They appear from around midway through the period and remain constant from then, ultimately contributing 17 per cent of the total expected gross benefits. Under this scenario, around 50 per cent of the competition benefits are comprised of wholesale market cost savings with the remainder made up of demand response benefits.

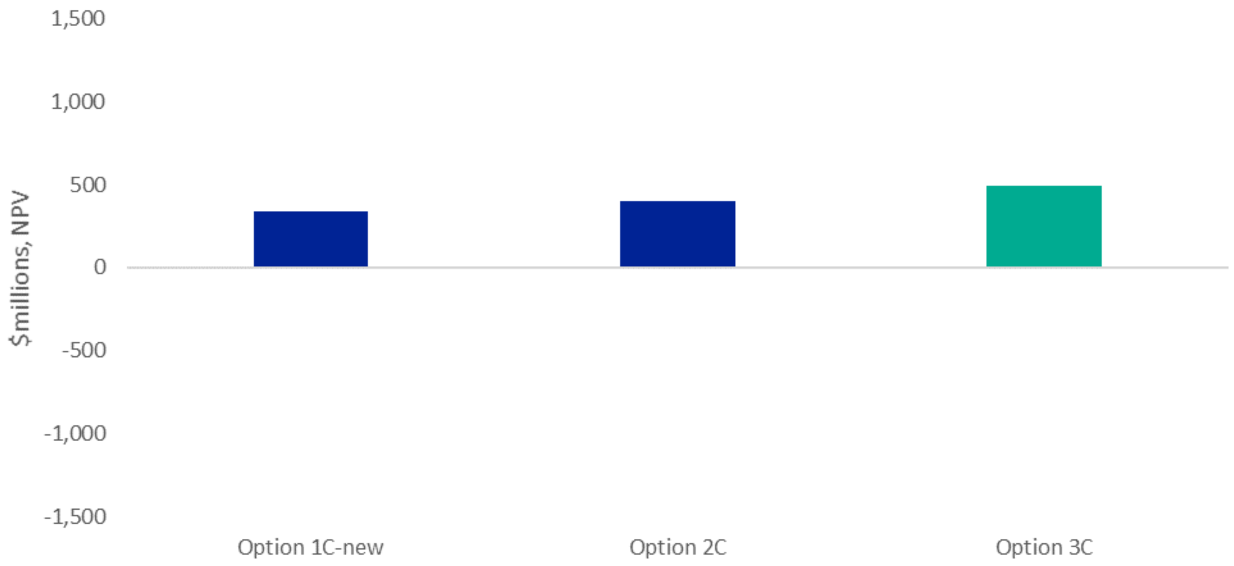
Weighted net benefits

Figure 35 shows the estimated net benefits for each of the credible options weighted across the four scenarios according to the following weights - central: 40 per cent, step change: 20 per cent, slow change: 10 per cent, and fast change: 30 per cent.[24]

On a weighted-basis, Option 3C is the top-ranked option and is expected to deliver approximately $491 million in net benefits, which is around 23 per cent greater than the net benefits of the second-ranked option (Option 2C).

[24] Section 6.2 of the July 2021 PACR sets out the scenario weightings using the probabilities proposed by AEMO in the final 2020 ISP.

Figure 35 – Summary of the estimated net benefits, weighted across the four scenarios – including competition benefits



2.4. Sensitivity analysis

A range of sensitivity analyses has been undertaken to test the robustness of the PACR addendum modelling outcomes.

Specifically, we have assessed a number of sensitivities that involve additional market modelling, namely:

- the impact of the recently announced new Kurri Kurri and Tallawarra B gas generators;
- delaying VNI West until 2035/36 (in-line with the core 2020 ISP assumption for the central scenario);
- whether adding the MPFC solution proposed by Smart Wires would increase the expected net benefits of the preferred option; and
- the impact on the positioning analysis of adopting the draft 2021 IASR assumptions.

Each of these sensitivity tests has been designed to test the robustness of the net benefit outcomes for Option 3C. The market modelling for each of the above sensitivities has not been undertaken for all credible options and scenarios. This is due to the computational time required to complete such an exercise and the fact that the four core scenarios outlined in the sections above already include significant variability in the underlying assumptions and find that Option 3C is the top-ranked option. Instead, our sensitivity analysis is in most cases focused on the top three ranked options from the positioning assessment (ie, Option 1C-new, Option 2C and Option 3C) and the central scenario.

Three other sensitivity tests that do not require wholesale market modelling have also been investigated, namely adopting:

- higher weighting of the step-change scenario, in-line with recent commentary from the ESB;
- higher and lower network capital costs of the credible options (including the adoption of P90 costs); and
- alternate commercial discount rate assumptions.

Each of the sensitivity tests are discussed below.

2.4.1. Impact of the recently announced new Kurri Kurri and Tallawarra B gas generators

In early May 2021, there were two announcements regarding Federal Government funding for new gas-fired generators in NSW. Namely:

- on 3 May 2021, EnergyAustralia announced it would build the 316 MW Tallawarra B gas-hydrogen plant with $83 million in Government support;[25] and
- on 18 May 2021, the Federal Government announced it will spend up to $600 million to build a new 660 MW gas plant at Kurri Kurri in NSW.[26]

These developments are not reflected in our wholesale market modelling assumptions, which are based on the 2020 ISP. However we have considered the impact that these two developments would have on the expected net benefits of Options 1C-new, 2C and 3C.

Under the central scenario, we find that the estimated net benefits of Option 3C decrease by around 36 per cent assuming the new Kurri Kurri and Tallawarra B gas generators are commissioned. However, overall Option 3C continues to provide substantial positive net market benefits. We find that Option 3C still delivers approximately $334 million in net benefits. Option 3C has around 36 per cent higher net benefits than the second-ranked option (Option 2C) and 90 per cent higher than the third ranked option (Option 1C-new).

Figure 36 shows the overall estimated net benefit for each option under this sensitivity, as well as under the RIT-T outcome (i.e., the net benefits estimated in section 2.3 above).

Figure 36 – Net benefits assuming the new Kurri Kurri and Tallawarra B gas generators – including competition benefits

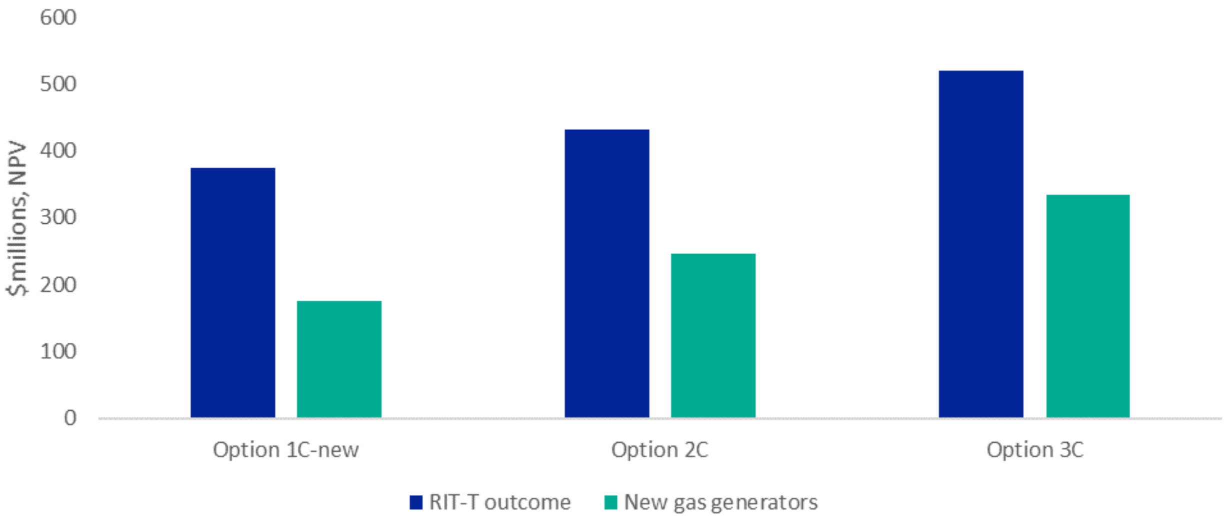
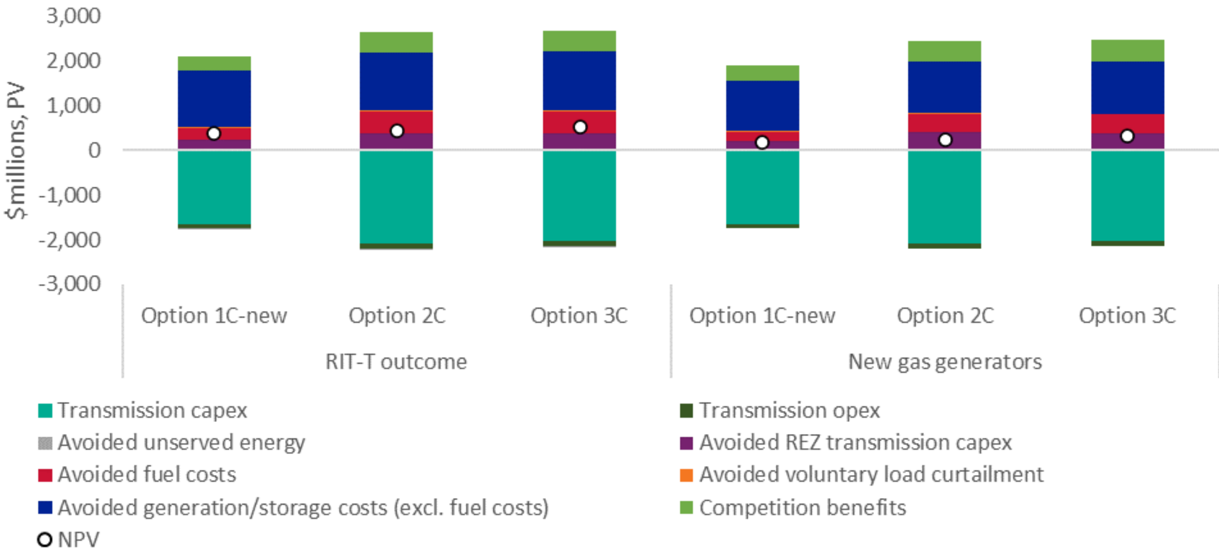


Figure 37 breaks down the estimated net benefits under the core RIT-T outcome (i.e., the net benefits estimated in section 2.3 above) on the left-hand side and assuming the new gas generators on the right-hand side. The largest reduction in estimated benefits for the preferred option is found to come from avoided generation/storage costs (shown in blue below).

[25] https://www.nsw.gov.au/media-releases/australias-first-green-hydrogen-and-gas-power-plant
[26] https://www.minister.industry.gov.au/ministers/taylor/media-releases/protecting-families-and-businesses-higher-energy-prices

Figure 37 – Breakdown of estimated net benefits assuming with and without the new Kurri Kurri and Tallawarra B gas generators

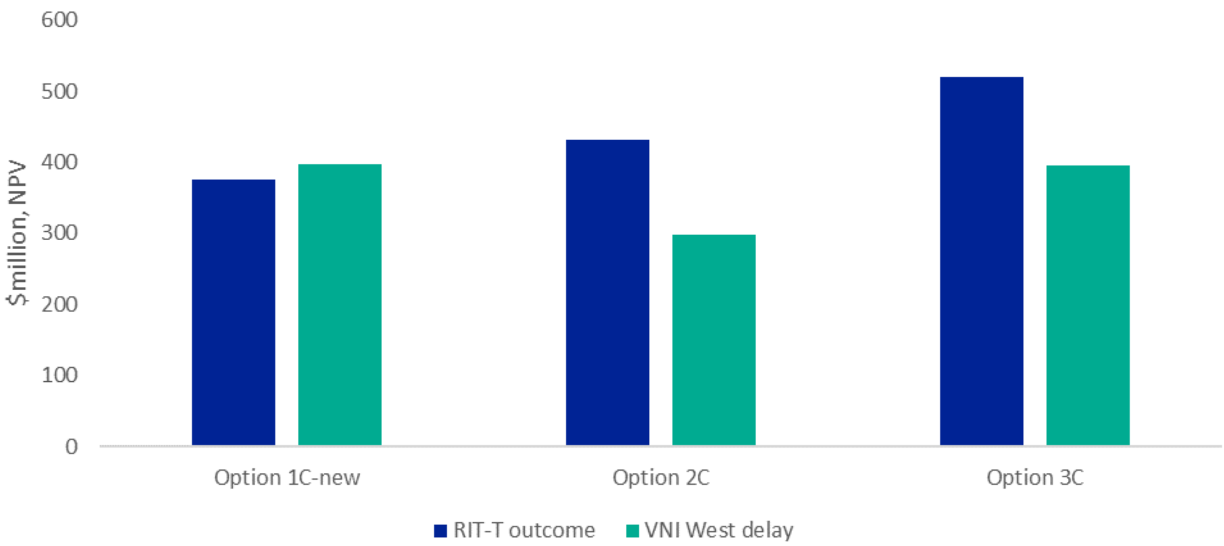


2.4.2. Impact of the assumed timing for VNI West

Our wholesale market modelling is based on an assumed commissioning date for VNI West of 2028/29. This is based on AEMO's 2020 ISP accelerated delivery date for VNI West and our current view of the earliest commissioning date for this investment. However, we have investigated the impact of delaying the commissioning date of VNI West to until 2035/36, in-line with the 2020 ISP core assumption for the central scenario.

Figure 38 shows the overall estimated net benefit for each option under this sensitivity, as well as under the RIT-T assessment.

Figure 38 – Net benefits assuming VNI West is delayed until 2035/36 – including competition benefits



Under this sensitivity, net benefits for Option 2C and 3C decrease, while net benefits increase for Option 1C-new. Option 2C and Option 3C unlock network constraints from Wagga Wagga to the major load centres in NSW, and VNI West is expected to unlock this flow path even further to South West NSW and Victoria. This allows better utilisation of cheaper resources, particularly in South West NSW and the NSW southern region. As a result, delaying VNI West is expected to reduce this opportunity for these two options and result in lower wholesale market benefits. However, delaying VNI West is not expected to impact the wholesale market benefit of Option 1C-new (it even marginally increases the market benefit of this option). This is because in Option 1C-new the network constraint on the eastern side of Wagga Wagga remains, regardless of the presence or absence of VNI West.

Under the central scenario, we find that the estimated net benefits of Option 3C decreases by around 24 per cent if it is assumed that VNI West is delayed until 2035/36 (departing from the core assumption of 2028/29). Under this assumption, Option 3C is effectively ranked first equal with Option 1C-new, which is only $1.3 million or 0.32 per cent higher net benefits than Option 3C. Consequently, Option 1C-new and Option 3C are considered to be effectively ranked equal first.

2.4.3. Expected impact of MPFC

We have considered whether MPFC can add to the expected net benefits of the preferred option, in response to the submission from Smart Wires.

Under the central scenario, we find that the estimated net benefits of Option 3C decrease by $7 million assuming it is coupled with the MPFC solution proposed by Smart Wires (under these assumptions, Option 3C is found to deliver approximately $513 million in net benefits). Consequently, we find that the cost of providing additional capacity through MPFC is not outweighed by the additional expected market benefits at this point in time.

2.4.4. Alternate weighting of the scenarios in-line with recent commentary

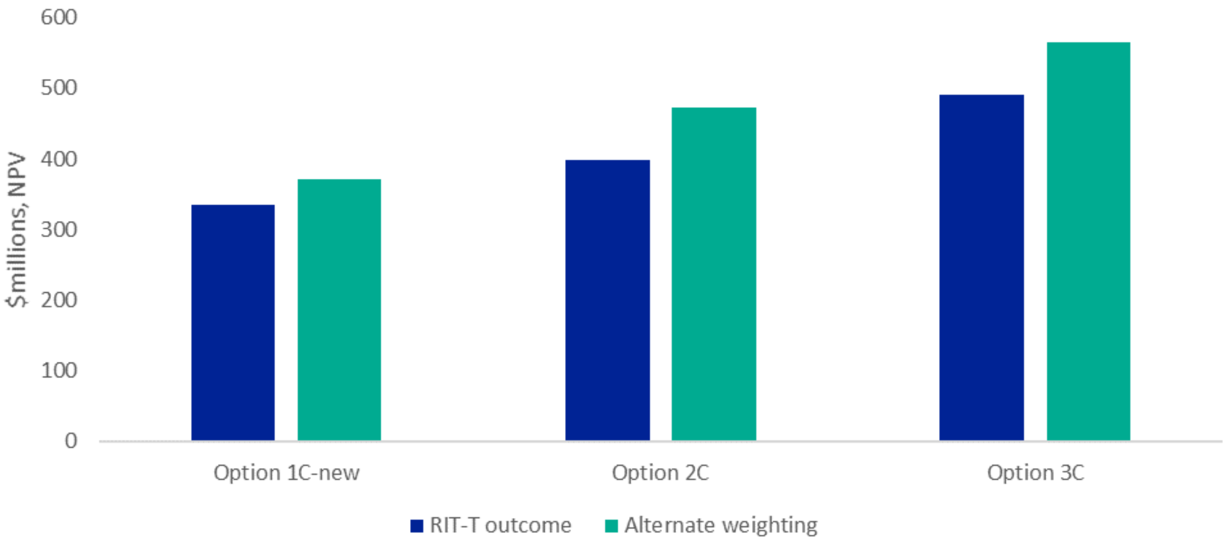
We have investigated the effects of assuming alternate scenario weightings based on more recent information than the 2020 ISP. Specifically, and informed by ESB commentary that the NEM is on step-change scenario, we have applied the following scenario weightings as part of this sensitivity:

- 30 per cent to the central scenario (i.e., a decrease of 10 per cent);
- 30 per cent to the fast-change scenario;
- 30 per cent to the step-change scenario (i.e., an increase of 10 per cent); and
- 10 per cent to the slow-change scenario.

We find that the estimated net benefits of Option 3C increase by around 15 per cent under these assumed weightings compared to the weightings for HumeLink set out in the 2020 ISP. Under these weightings, Option 3C is found to deliver $566 million in net benefits on a weighted basis, which is approximately $93 million greater than the second-ranked option (Option 2C) and approximately $194 million greater than the third ranked option (Option 1C-new).

Figure 39 shows the overall estimated net benefit for each option under this sensitivity, as well as under the ISP weightings.

Figure 39 – Net benefits assuming alternate scenario weightings – including competition benefits

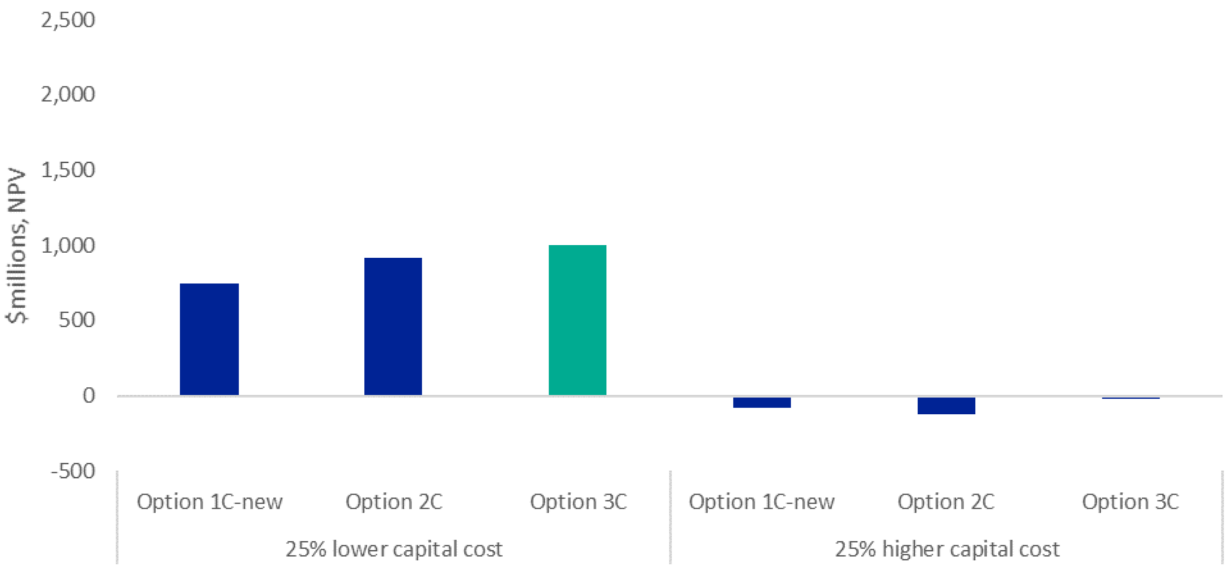


2.4.5. Higher and lower network capital costs of the credible options

We have tested the sensitivity of the results to the underlying network capital costs of the credible options.

Figure 40 shows that Option 3C remains the top-ranked credible option if the capital cost assumptions are varied by 25 per cent (higher or lower) across all three options. Under the assumption of 25% lower capital costs, the net benefits of Option 3C increase to $999 million. However, under the 25 per cent higher assumed capital costs, Option 3C is found to have negative net benefits of -$17 million.

Figure 40 – Impact of 25 per cent higher and lower network capital costs, weighted NPVs – including competition benefits



We find that if Option 3C's capital costs are more than 24 per cent higher than the central estimates, it would no longer have positive estimated net benefits (on a weighted-basis). We also find that if Option 2C's costs were to remain constant, Option 3C's costs would need to increase by more than 4 per cent for Option 2C to become preferred.

There is currently a high degree of uncertainty in relation to the accuracy of the capital cost estimates (which are 'class 4' estimates for each of these three options), consistent with the stage that the project is currently at. We also note that a substantial proportion of the costs of HumeLink will relate to biodiversity offset costs, which are determined by external processes.

For completeness, we have also considered alternate 'P90' capex estimates, which are higher than the P50 estimates used in the main RIT-T analysis, and allow for additional contingencies. Specifically, the P90 capex estimates have an expected 90 per cent probability of cost underrun, while the P50 capex estimates have a 50 per cent expected probability of cost underrun. Figure 41 shows that both options have significantly negative weighted net benefits under P90 capex estimates (with the preferred option expected to result in a net cost of approximately $193 million).

Figure 41 – P50 capex estimates compared to P90 capex estimates, weighted NPVs – including competition benefits

We will be undertaking further detailed analysis in relation to the costs of the preferred option as part of progressing this project, following the initial CPA. Any increase in the estimated costs of the project resulting from this analysis would result in AEMO needing to issue a 'feedback loop' confirmation that the project remains consistent with the ISP optimal development path, before we could lodge a further CPA. Consumers can therefore have confidence that any increase in the cost estimate for the preferred option will only result in the project proceeding if AEMO confirms that it remains part of the ISP at the higher cost.

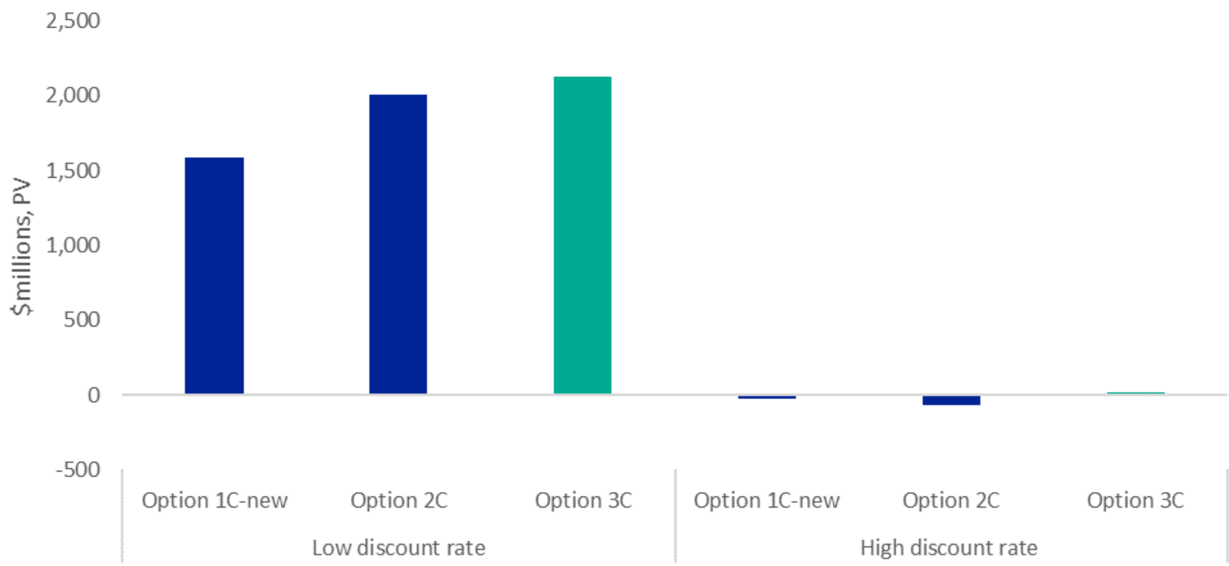
2.4.6. Alternate commercial discount rate assumptions

Figure 42 illustrates the sensitivity of the results to adopting different discount rate assumptions in the NPV assessment. In particular, it illustrates the impact of adopting:

- a high discount rate of 7.90 per cent; and
- a low discount rate of 2.23 per cent.

Option 3C is the top-ranked option under both alternate assumptions and continues to deliver positive net benefits, albeit only marginally under the high discount rate assumption. We consider that a discount rate of 7.90 per cent is at the extreme end for commercial discount rates today, and note that the draft 2021 IASR assumptions propose a 4.80 per cent discount rate as part of the central scenario (which is lower than our assumed central rate of 5.90 per cent).

Figure 42 – Impact of different assumed discount rates, weighted NPVs – including competition benefits



We have extended this sensitivity and find a discount rate that is higher than 7.98 per cent would result in Option 3C having a negative estimated net benefit.

2.4.7. Adopting AEMO's draft 2021 IASR assumptions

This sensitivity reapplies the positioning assessment to the three top-ranked options, adopting the draft 2021 IASR assumptions published by AEMO in December 2020.[27] It provides insight into the possible outcomes of the forthcoming 'feedback loop' assessment if AEMO adopts the final 2021 IASR assumptions (due to be published by the end of July 2021) for this analysis. We consider that adopting the most recently consulted upon final IASR assumptions, which will underpin the 2022 ISP, in applying the feedback loop would be consistent with the objectives of the overall actionable ISP framework.

Under the central scenario, we find that the estimated net benefits under the positioning assessment for Option 3C increase significantly using the draft 2021 IASR assumptions, and becomes substantially positive. Under the draft 2021 IASR assumptions, Option 3C is found to deliver approximately $436 million in net benefits. Option 3C has around 22 per cent greater net benefits than the second-ranked option (Option 2C) and 373 per cent greater net benefits than the third-ranked option (Option 1C-new) under draft 2021 IASR assumptions.

Figure 43 shows the overall estimated net benefit for each option under this sensitivity, as well as under the 'positioning assessment net benefits' (i.e., the net benefits estimated in section 2.3 above, which excludes competition benefits).

[27] AEMO, Draft 2021 Inputs Assumptions and Scenarios Report (IASR), 17 December 2020.

Figure 43 – Net benefits under the central scenario (excluding competition benefits) adopting AEMO's draft 2021 IASR assumptions – excluding competition benefits

It is important to note that the net benefits shown above do not include competition benefits. The analysis in the PACR and in this addendum demonstrates that competition benefits are material for this RIT-T (as illustrated in section 2.3). Including competition benefits alongside the 2021 IASR assumptions can therefore be expected to further increase the net benefits of Option 1C-new, Option 2C and Option 3C. We anticipate that AEMO will need to consider competition benefits in applying the feedback loop to HumeLink.