PROJECT ENERGYCONNECT

Updated Cost Benefit Analysis

30 September 2020

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Revision Record					
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9 Sep 2020	Final Draft	Final draft for AER review	Brad Harrison	Hugo Klingenberg Simon Appleby	Rainer Korte
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Executive Summary

Project EnergyConnect (PEC) is the proposed new 330 kV electricity interconnector between Robertstown in South Australia and Wagga Wagga in New South Wales that also includes a short 220 kV line from Buronga in New South Wales and Red Cliffs in northwest Victoria.

ElectraNet completed the Regulatory Investment Test for Transmission (RIT-T) with the release of a Project Assessment Conclusion Report (PACR) on 13 February 2019, which concluded that Project EnergyConnect was the preferred option that satisfied the requirements of the RIT-T.

On 24 January 2020 the Australian Energy Regulator (AER) issued a formal determination that found that ElectraNet had correctly identified Project EnergyConnect as the preferred option.

The National Electricity Rules (NER) require ElectraNet to consider whether, in its reasonable opinion, there has been a “material change in circumstances” that might lead to a change in the preferred option and thereby potentially require reapplication of the RIT-T. Since the RIT-T was concluded there have been significant changes in both project costs and benefits from those assessed in the RIT-T.

Accordingly, ElectraNet has investigated whether there has been a “material change of circumstances” that would change the outcome of the RIT-T. This has involved taking into account updated information on both costs and benefits, while applying the same modelling methodology reviewed and endorsed by the AER.

The purpose of this report is to present the outcomes of this updated cost benefit analysis.

ElectraNet has reviewed the latest information available on the range of inputs and assumptions that impact on the modelled costs and benefits of Project EnergyConnect. This has involved reviewing all of the updated inputs and assumptions to the Australian Energy Market Operator (AEMO)’s final 2020 Integrated System Plan (ISP) and seeking additional independent expert advice to validate the updated inputs in key areas, including gas price forecasts, generator heat rates and generator technical parameters.

ElectraNet has aligned its updated cost benefit analysis with the modelling inputs and assumptions used by AEMO in the 2020 ISP, which have been tested with stakeholders through an extensive consultation process. ElectraNet has also incorporated the latest information and advice published by AEMO on the new and emerging system security issues in South Australia into its analysis.

ElectraNet has engaged with stakeholders on its updated cost benefit modelling and consulted specifically on its approach to the use of variable generator heat rates as a refinement to the original PACR modelling methodology reviewed and endorsed by the AER. The variable heat rates adopted are also aligned with the 2020 ISP. This engagement included multiple stakeholder updates, a stakeholder webinar attended by over 100 people, individual stakeholder meetings and publication of these engagement outcomes.

ElectraNet’s updated cost benefit analysis has been based on the 2020 ISP central scenario and specifically AEMO’s actionable ISP development path 8, which represents a conservative risk-based scenario that includes an accelerated timeframe for the VNI West project of 2027-28 to cater for the possibility of early retirement of conventional generation in Victoria without timely replacement.

The outcomes of this updated cost benefit analysis demonstrate that:

- The gross (i.e. total) benefits of Project EnergyConnect are significantly higher than the sensitivity reported by the AER in its January 2020 RIT-T Determination, rising from $1,246m to $1,866m in present value terms;
- Capital costs have also increased, rising from $1.53bn to $2.43bn ($2018-19) (equivalent to $977m and $1,673m in present value terms respectively);
- The net market benefit after taking into account the latest benefits and costs for the project is $148m based on the scenario considered;
- Project EnergyConnect continues to deliver positive net benefits at capital costs of up to $2.7bn ($2018-19);
- The closest ranked alternative option assessed in the RIT-T, Victorian Option D, delivers minimal positive net benefits that would be removed with a less than a 2 per cent increase in costs. As in previous assessments undertaken at the time of the AER's RIT-T determination, this option remains less preferable;
- Therefore, the outcome of the RIT-T remains unchanged, with Project EnergyConnect continuing to deliver positive net market benefits and remaining the preferred option; and
- Net benefits are expected to increase significantly with later delivery of VNI West, which is the expected outcome in the majority of future scenarios considered in AEMO's ISP. Our sensitivity testing has found that net benefits would be between $115m and $176m higher if VNI West is delayed under the central scenario.

On the basis of this updated cost benefit analysis, ElectraNet concludes that there has been no material change in circumstances as defined in the Rules and the outcome of the RIT-T remains unchanged, consistent with the AER's RIT-T Determination.

Increased benefits could be expected from Project EnergyConnect under the majority of alternative scenarios considered in the ISP. In addition, a range of further unquantified benefits are also expected to be delivered through improved power system resilience.

This underscores AEMO's recognition of Project EnergyConnect as an "essential foundational measure" to address emerging system security risks that are growing year on year and the inclusion of the project as a central part of the ISP's roadmap for the transition of the power system.

Taken together, this provides confidence that the economic case for the project remains strong as an investment essential to Australia's energy future.

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1. Introduction

Project EnergyConnect (PEC) is a proposed new 330 kV electricity interconnector between Robertstown in South Australia and Wagga Wagga in New South Wales that includes a short 220 kV line from Buronga in New South Wales to Red Cliffs in northwest Victoria.

ElectraNet completed the Regulatory Investment Test for Transmission (RIT-T) with the release of a Project Assessment Conclusions Report (PACR) on 13 February 2019 which concluded that Project EnergyConnect was the preferred option that satisfied the requirements of the RIT-T.

On 24 January 2020 the Australian Energy Regulatory (AER) issued a determination under clause 5.16.6 of the National Electricity Rules approving the RIT-T assessment and concluding that ElectraNet had correctly identified Project EnergyConnect as the preferred option.

The AER in its determination described the business case for the project as “robust” and determined that the proposed interconnector remained the most “credible option that maximises the net economic benefit” in the NEM, ultimately benefiting electricity customers.

While the AER concluded that it is “satisfied the RIT-T has been successfully completed”, it noted that “any significant changes to the costs of the preferred option could have a material impact on the outcome of the RIT-T”.

The National Electricity Rules (NER) require ElectraNet to consider whether, in its reasonable opinion, there has been a “material change in circumstances” that might lead to a change in the preferred option and thereby potentially require reapplication of the RIT-T.

Accordingly, in the event of material changes in costs or benefits, the AER expects ElectraNet to consider the impacts on the outcomes of the RIT-T, and to provide evidence of that consideration to the AER, including updated analysis demonstrating whether the preferred option continues to be the preferred option.

Since the RIT-T was concluded in February 2019 there have been significant changes in both project costs and benefits from those assessed in the RIT-T.

ElectraNet has therefore investigated whether there has been a “material change of circumstances” that would change the outcome of the RIT-T, taking into account new information on both costs and benefits, working closely with the Australian Energy Market Operator (AEMO) to align with the Final 2020 Integrated System Plan (ISP).

This report presents the outcomes of this updated cost benefit assessment for the AER and stakeholders.

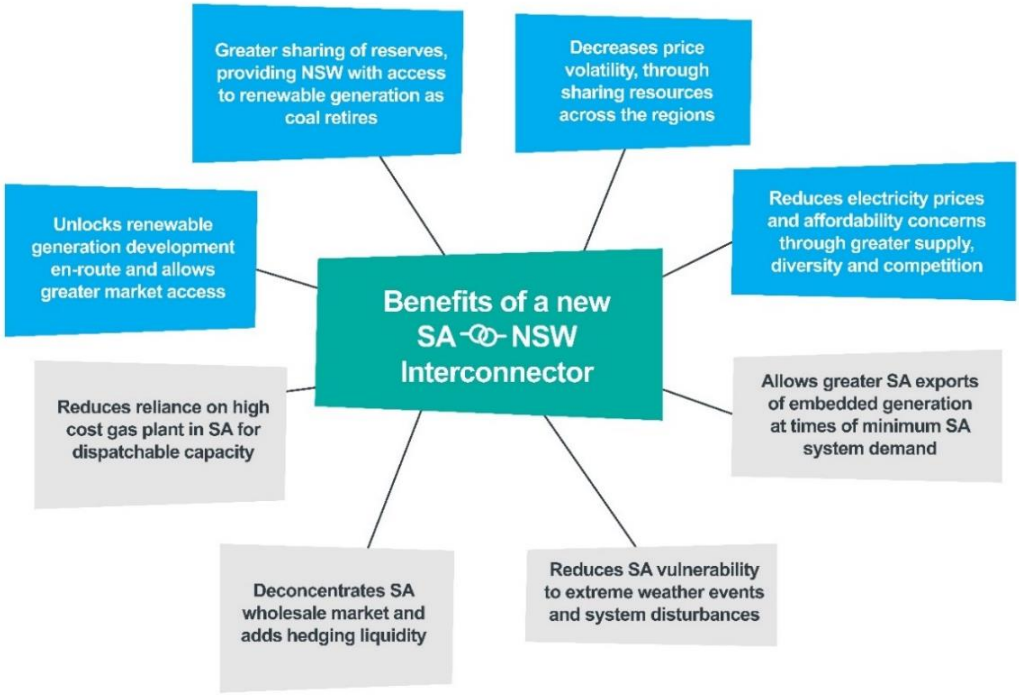
1.1 Context

PEC has been identified as a central part of AEMO's roadmap in the ISP for the transition of the power system. The final 2020 ISP classified PEC as an 'actionable ISP project' which will deliver net market benefits and support energy market transition through:[1]

- lowering dispatch costs, initially in South Australia, through increasing access to supply options across regions;
- facilitating the transition to a lower carbon emissions future and the adoption of new technologies, through improving access to high quality renewable resources across regions; and
- enhancing security of electricity supply in South Australia.

AEMO has also recommended PEC as an "essential foundational measure" to address emerging system security risks that are growing year on year.

As demonstrated through the detailed market modelling undertaken to date, PEC is expected to deliver a broad range of benefits across the NEM, as shown below.



For NSW customers, the interconnector improves diversity of supply and access to cheaper renewable energy sources as the coal fleet progressively retires, while also unlocking significant renewable energy development along the route.

For SA customers, the interconnector provides access to additional capacity when needed to replace expensive gas generation and improves power system resilience and security.

1 AEMO, 2020 Integrated System Plan, July 2020, p.86.

2. Recent Developments

2.1 Benefits

Market conditions have changed since the RIT-T was concluded in February 2019 and the AER's RIT-T determination in January 2020 that lead to an overall increase in the benefits of Project EnergyConnect. Changes to key input assumptions contributing to increased benefits include:

- Forecast delivered gas prices to Adelaide have increased.
- Capital cost estimates for large scale energy storage investment in Australia and specifically in South Australia have increased. Pumped storage costs have increased significantly and whilst battery energy storage prices have decreased since the determination, the net effect has been an increase in the costs of storage solutions.
- New committed generator developments specifically along the anticipated path of Project EnergyConnect have been confirmed.
- Snowy 2.0 and HumeLink are now committed ISP projects leading to a twofold effect where Project EnergyConnect provides a direct link between Snowy 2.0's deep storages and an improvement in access between Project EnergyConnect and Sydney.
- Committed and forecast retirement of South Australian generators including the retirement of Osborne in 2023 and various other dispatchable plant in South Australia during the 2030s.

AEMO's ISP has also settled on a development path that includes an accelerated timing for VNI West to be delivered by 2027-28. This is a risk-based timeframe to address a potential scenario involving the early retirement of conventional generation in Victoria without timely replacement investment in firm capacity.

In adopting that timing AEMO notes that based on the quantified benefits of the ISP, this timing reduces the benefits from the optimal timing of VNI West of 2035-36. The accelerated timing of this project is anticipated to similarly impact on the modelled benefits of Project EnergyConnect.

Even with accelerated VNI West timing, AEMO continues to find that Project EnergyConnect is required in all potential development paths.

The updated modelling inputs are discussed in more detail in Section 3.

The COVID-19 pandemic has severely impacted on the South Australian, national and global economies.

This has had some effect on short to medium term demand forecasts, while long term forecasts remain resilient to the short-term effects. As a result, demand forecasts across AEMO's scenarios remain within the range tested in the RIT-T. It is also noted that within this range demand has not been found to be a significant influence on the magnitude of benefits.

Commodity markets, and in particular global LNG markets, have experienced unprecedented price volatility. However, medium to long-term gas prices remain considerably higher than tested in the RIT-T and the AER's 5.16.6 review increasing the anticipated benefits of Project EnergyConnect. The basis of these forecasts is discussed in more detail in 3.4

2.2 Costs

There is a general increase in transmission costs being experienced across the NEM, with AEMO reporting an approximate 30% increase in transmission capital costs in its Final 2020 ISP.

ElectraNet and TransGrid are committed to delivering Project EnergyConnect at the lowest practicable cost to customers. Both ElectraNet and TransGrid have been working through competitive procurement processes with construction contractors to firm up capital cost estimates that form the basis of Contingent Project Applications to the AER. This updated cost benefit analysis uses the updated costs from these Contingent Project Applications as lodged with the AER on 30 September 2020 to ensure this cost benefit analysis aligns with the expected customer impact of the project.

A total project cost of $2.43b ($2018-19) has been used with an NPV cost of $1.67b.

We have also adopted a cost increase of 30% for all other transmission costs in line with the 2020 ISP.

3. Updated modelling inputs

Table 1 presents the key updated inputs and assumptions applied in the cost benefit assessment, aligned to the AEMO 2020 ISP

Table 1 - Updated assumptions for the 2020 ISP

Key Changes	Source	Comments
Demand Forecasts	Final 2020 ISP	Demand forecasts have been updated in line with the 2020 ISP.
Committed generation projects	Final 2020 ISP	Committed generation projects throughout the NEM have been updated in line with the 2020 ISP.
Thermal generator variable heat rates	Final 2020 ISP	Minimum Capacity Factors (MCFs) applied in the PACR were a proxy for plant characteristics that were not otherwise modelled. We have replaced fixed (or static) heat rates with variable heat rates in the time sequential modelling in line with the 2020 ISP. ElectraNet engaged Aurecon to provide independent advice on variable heat rates that supports the AEMO 2020 ISP heat rate data.
Gas prices	Final 2020 ISP	Gas price forecasts have been updated in line with the 2020 ISP. ElectraNet engaged EnergyQuest to provide independent advice on gas price forecasts that supports the AEMO 2020 ISP data.
Coal prices	Final 2020 ISP	Coal prices have been updated in line with the 2020 ISP.
New entrant generator capital costs	Final 2020 ISP	New entrant generator capital costs, including pumped hydro and battery energy storage costs have been updated in line with the 2020 ISP.
Transmission capital costs	Final 2020 ISP	The capital costs of ISP transmission projects have been updated in line with the 2020 ISP.
Renewable Energy Targets	Final 2020 ISP	Includes consideration of the latest Queensland, Victorian and Tasmanian Renewable Energy Targets in line with the 2020 ISP.
Renewable Energy Zones	Final 2020 ISP	Includes consideration of the NSW Central-West Orana REZ expansion in line with the 2020 ISP.
New emerging system security requirements in South Australia	Final 2020 ISP	We are including new emerging system security constraints identified by AEMO in our updated cost benefit analysis in line with advice in the 2020 ISP.
PEC capital cost forecasts	Competitive market pricing	Project capital cost forecasts are largely based on competitive market pricing that is included in Contingent Project Applications lodged with the AER on 30 September 2020.

3.1 Timing

The RIT-T PACR modelled the preferred option as fully available from 1 July 2023.

The 2020 ISP finds Project EnergyConnect should be in place as soon as it can be built. ElectraNet has modelled Project EnergyConnect as available from 1 January 2024. In line with the 2020 ISP, a period of inter-network testing is also assumed before the full capability of the interconnector can be made available over the first 6 months, as follows.

Table 2 – PEC Internetwork testing release of capacity

Timing	Combined import limits	Combined export limits	PEC Limits	Two-unit constraint
1-Jan-24	750	-750	600	Removed
1-Apr-24	1,000	-1,050	600	
1-Jul-24	1,300	-1,450	800	

3.2 Network developments

3.2.1 Line route refinements

The following updated network parameters have been included in the modelling.

In South Australia, ElectraNet is proposing to develop the new Bundey substation around 10 km east of Robertstown to provide the required 330 kV to 275 kV transformation for the new interconnector. This will be connected to the existing Robertstown 275 kV substation. Electrically, this is no different to transformation occurring within the Robertstown substation.

In New South Wales, TransGrid is proposing a line route refinement which involves a more direct route between Buronga and Wagga Wagga that reduces the line length and avoids high-quality irrigated farming land, connecting to a new substation at Dinawan rather than Darlington Point. The optimised path leads to lower costs with a lower line length, optimised development of the South West renewable energy zone, aligns with the VNI West interconnector upgrade, and reduces project delivery risk.[2]

Neither of these changes has a material impact on the benefits of Project EnergyConnect as determined in the RIT-T.

[2] TransGrid, *Transmission Annual Planning Report*, 2020

3.2.2 ISP transmission projects

In the PACR, ElectraNet assumed that only committed projects and ISP group 1 projects were included in the base case. In addition, one group 2 project – a medium scale upgrade of QNI was also assumed to test the benefits of a Queensland to South Australia interconnector deferring the need for this project.

The AER has recently published its final Cost Benefit Analysis guidelines to make the integrated system plan actionable. This will apply to future RIT-T assessments and includes a requirement to include all other actionable ISP projects in the base case. Consistent with this, the base case has been updated to include actionable projects from AEMO's 2020 ISP actionable development plan (development plan 8). This development plan includes the following committed projects:

- South Australia system strength remediation
- Western Victoria Transmission Network Project
- QNI Minor.

As noted above, AEMO's ISP has settled on a development plan that includes an accelerated timing for VNI West to be delivered by 2027-28. This is not the optimal timing of VNI West quantified by the central scenario but represents a risk-based timeframe to address a potential scenario involving the early retirement of conventional generation in Victoria without timely replacement investment.

Table 3 below lists the timing for the remaining actionable ISP projects assumed in the base case.

As noted by AEMO, the accelerated timing of VNI West reduces the level of market benefits compared with the ISP's optimal development path[3] and correspondingly impacts on Project EnergyConnect. Delay in the delivery of VNI West increases the benefits of Project EnergyConnect.

Table 3 – ISP projects and timing included in the updated analysis

Project	Timing
Victoria to NSW minor	2022-23
Central West Orana	2024-25
HumeLink	2025-26
VNI West	2027-28

Marinus Link stage 1 and 2 are not included in the optimal development path until AEMO's decision rules are satisfied, consistent with the 2020 ISP.

[3] AEMO, *Integrated System Plan p72*, 2020

ElectraNet has modelled VNI West from 2027-28 consistent with the earliest timing adopted in the 2020 ISP. VNI West has two paths under consideration referred to as KerangLink and SheppartonLink.

ElectraNet has assumed the path of SheppartonLink in our economic modelling. The choice of path is unlikely to influence the calculation of benefits.

However, the choice of path does impact on the incremental costs of PEC to the NEM. KerangLink passes along the same corridor as Project EnergyConnect and is a higher capacity interconnector. Duplication of transmission through this corridor at 330 kV in 2024 and 500 kV in 2027-28 would not be an efficient or optimised solution and would not deliver the overall investment that maximises the net economic benefits to customers. An more efficient solution would be for Project EnergyConnect to develop this corridor at 500 kV capable and to operate at 330 kV until VNI West requires the 500 kV capacity.

This assumption has therefore been modelled in our analysis to be internally consistent with the assumption of an earlier project timing for VNI West in the scenario considered.

ElectraNet has assessed the effect of these options on the costs of the preferred option with a 50% weighting to each outcome. The weighted effect of efficient development is a $61m increase in benefits.

The timing of VNI West remains highly uncertain and is later in the majority of scenarios considered in the 2020 ISP. The optimal development timing based on the quantified benefits is 2035-36. The assumed accelerated timing of 2027-28 reduces the benefits of the optimal development path by $369m in the central scenario.[4]

3.2.3 Renewable Energy Zone expansion

AEMO has updated the forecast transmission costs for all Renewable Energy Zone developments with an increase of at least 30% in the ISP. The classification, naming and capability of REZs have also been updated since the RIT-T. These updates have all been incorporated into the updated modelling.

3.3 Plant technical characteristics

The AER's established RIT-T guidelines require that plant technical characteristics are realistic. In its 5.16.6 RIT-T determination, the AER considered that "ElectraNet is required to adopt representations of plant characteristics that are as accurate as possible".[5]

ElectraNet has engaged with AEMO to refine plant technical characteristics to improve the accuracy of generator representations in the economic model, as explained below.

[4] AEMO, Integrated System Plan, 2020

[5] AER, *Decision South Australian Energy Transformation*, 2020.

3.3.1 Variable heat rates

In its RIT-T determination the AER disagreed with applying Minimum Capacity Factors (MCFs) to SA Gas Powered Generation (GPG) in the modelling of market benefits.

We have, therefore, removed the use of MCFs from the updated cost benefit analysis, and instead have worked closely with AEMO to consider a more accurate representation of SA GPG operation with MCFs removed.

This includes replacing fixed or static heat rates for thermal generators with variable heat rates that more accurately represent plant behaviour at different levels of generator output.

Both ElectraNet and AEMO are now including variable heat rates for all thermal generators in the NEM in their market modelling where relevant – this provides a more accurate representation of operating efficiency and therefore fuel costs.

Previously, thermal generators were modelled based on their level of efficiency at full output regardless of their output level – this underestimates fuel consumption and therefore costs because thermal plant (especially GPG in SA) often operates at lower levels of output that is relatively less efficient and burns more fuel at these lower levels of output.

AEMO derived variable heat rates for all existing generators in the NEM from input/ output curves of new entrant technologies provided by GHD. ElectraNet engaged Aurecon to provide independent advice on variable heat rates, amongst other things. This advice aligns closely with AEMO's calculated values. While differences were observed on gas powered steam turbines and brown coal plant, these differences are not material enough to vary from the most recent ISP parameters.

ElectraNet has consulted separately with stakeholders on this matter in an update released to the market on 24 July 2020 available on our website[6]. This update specifically invited submissions on the application of variable heat rates to thermal generators in the market benefits modelling.

Submissions were received from the EUAA, PIAC, Reach Solar Energy, Energy Australia, ERM Power and Major Energy Users (MEU). EUAA, PIAC and ERM Power made no comment on the application of variable heat rates but rather expressed concerns about the uncertainty of increased costs and benefits and the economic viability of the project.

Reach Solar Energy supported the application of variable heat rates. EnergyAustralia provided updates to the heat rates for some of its plant.

MEU suggested retaining the previous fixed heat rates and not trying to finesse them.

6 ElectraNet stakeholder update 24 July 2020.

The submissions are available here on ElectraNet's website together with a response to the key points made. In summary, ElectraNet has confirmed the application of variable heat rates on the basis of the feedback received.

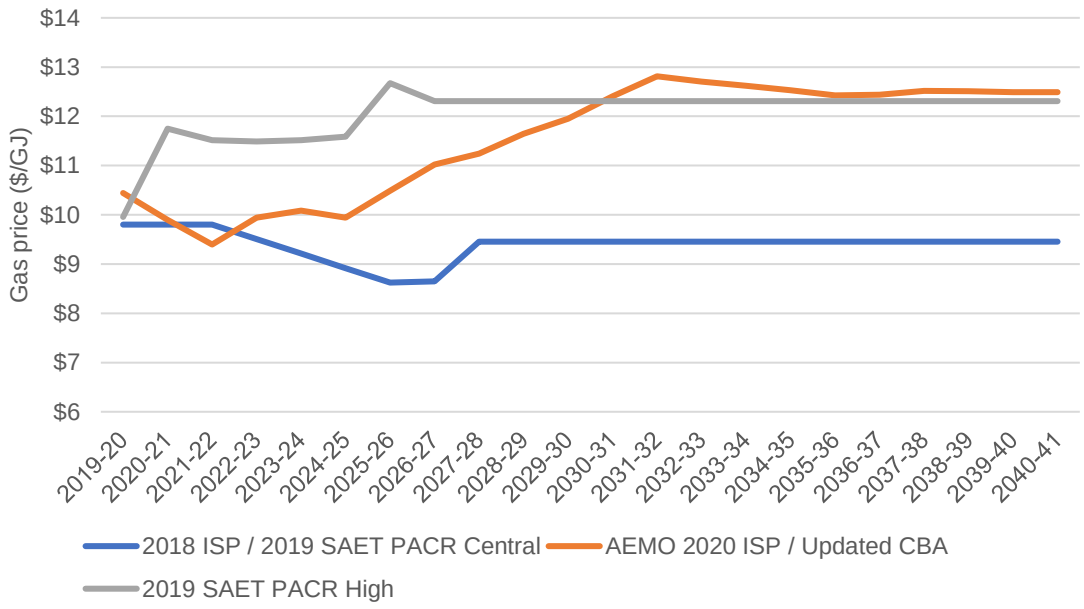
3.4 Gas prices for Gas Powered Generators

Since ElectraNet concluded the RIT-T, gas price expectations have risen considerably and align more closely with the gas prices assumed under the High RIT-T scenario. In broad terms, prices in the eastern states are expected to follow an upward trend of 3 AUD/GJ up to 2032, this is reflected in the 2020 ISP central scenario[7].

Avoided variable fuel costs are the single largest benefit of Project EnergyConnect. Most of the avoided fuel expense has occurred on South Australian GPG with an increase in gas prices likely to increase the value of the avoided fuel costs.

Figure 1 presents the delivered gas price to Torrens Island in South Australia in the PACR Central, PACR High and the 2020 ISP Central forecast. The PACR Central is drawn from the 2018 ISP Central scenario.

Figure 1 - Comparison of gas prices delivered to Torrens Island ($2018-19)



Due to the COVID-19 pandemic, many commodity markets have experienced severe short-term dislocation. This has also occurred in the international and domestic gas markets.

ElectraNet engaged EnergyQuest to provide updated forecasts for gas prices delivered to South Australia for GPG to address whether the immediate uncertainty caused by COVID-19 will lead to a long term lowering of the gas price.

[7] Core Energy, Wholesale Gas Price Outlook 2019-2040

Notwithstanding any near-term impacts, EnergyQuest considers that the impacts of COVID-19 are not likely to reduce gas prices in the longer term. EnergyQuest finds that the market will operate to the following phases:

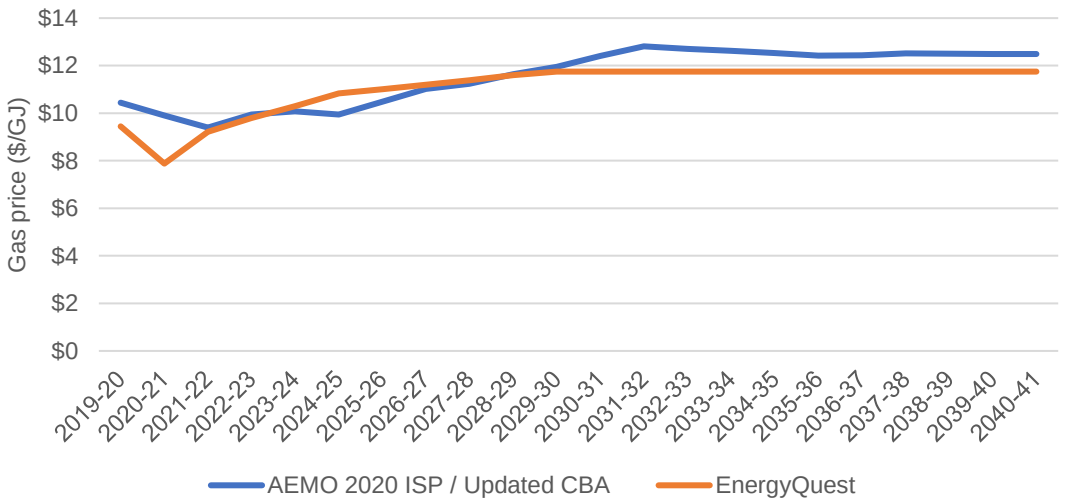
Balanced supply/demand phase ends in 2025 with the requirement for the first LNG import project.

Transition phase to 2029 ends with the emergence of a supply shortfall even with the mothballing of an LNG export train and the diversion of two-thirds of another train to the domestic market.

Shortfall phase to 2036 includes a period of demand destruction as there are no known 2P gas reserves or likely contingent resources to meet demand. CSG fields lose over 100 PJ pa deliverability – the equivalent of an LNG import terminal every year. This phase ends with the conclusion of the LNG contracts.

Figure 2 presents the delivered central gas price from EnergyQuest compared to AEMO's 2020 ISP forecast. EnergyQuest considers gas prices rise faster than the AEMO Central forecast but settle at a slightly lower price. Both forecasts are materially higher than forecasts used in the PACR central scenario.

Figure 2 – EnergyQuest comparison of gas prices delivered to Torrens Island ($2018-19)



The independent advice provided by EnergyQuest supports the use of AEMO's 2020 ISP central forecasts in the updated market benefits modelling.

A summary of the EnergyQuest report is available on ElectraNet's website.[8]

[8] EnergyQuest, Summary – Future gas prices in South Australia, May 2020

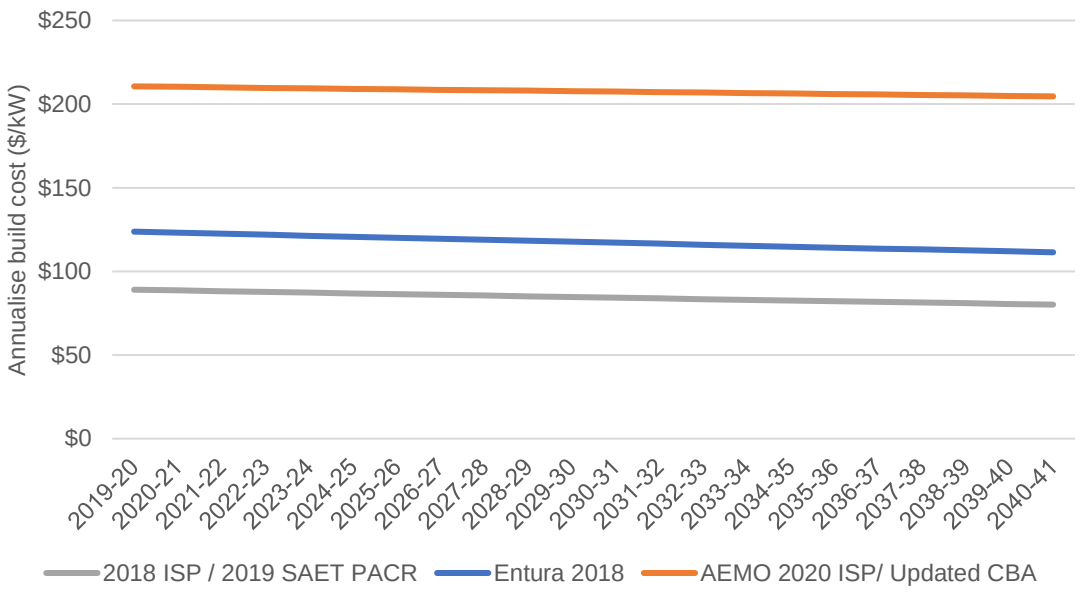
3.5 Capital costs for pumped hydro storage

Pumped hydro capital costs have been updated since the PACR.

Immediately prior to the publication of the PACR – but too late to be considered – AEMO published a report from Entura that found pumped hydro capital costs were materially higher than assumed in the 2018 ISP and in the PACR. The Entura costs were used in the Draft 2019 ISP.

Following consultation on the draft ISP, AEMO subsequently further increased the capital cost estimates of pumped hydro. Figure 3 shows the annualised cost per megawatt of pumped hydro in South Australia.

Figure 3 – Increasing pumped hydro capital costs in the SAET and ISP ($2018-19)



ElectraNet has applied AEMO's 2020 ISP assumptions in its modelling.

3.6 Capital costs for battery storage

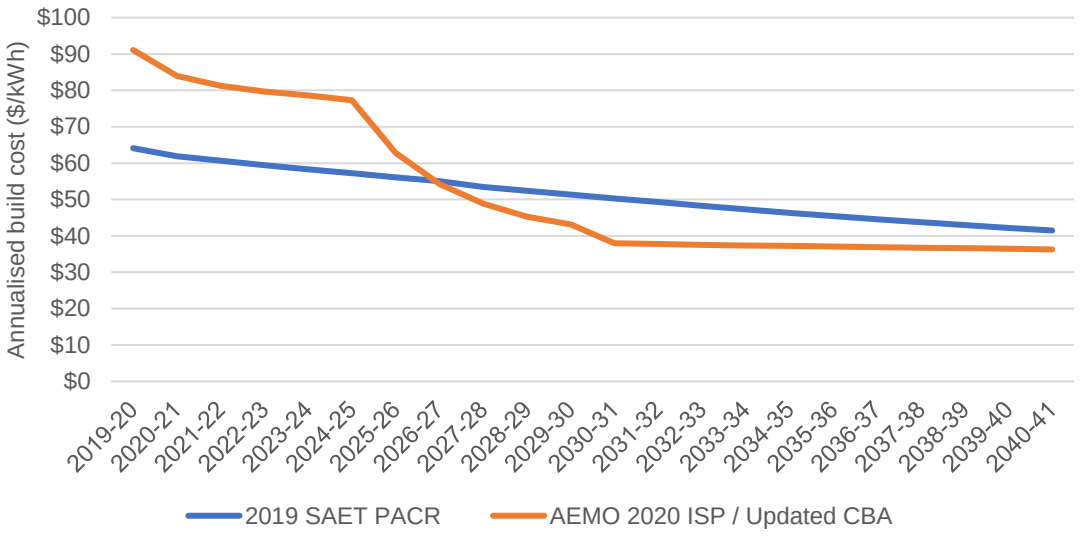
AEMO's 2-hour battery storage capital cost estimates have been updated in the 2020 ISP. From 2025, costs are forecast to rapidly decline. The updated cost forecasts are shown in Figure 4 and compared with the cost of the same 2-hour battery in the SAET PACR.

AEMO's modelled costs differ across the country with remote locations attracting build cost penalties. The values presented below are for medium South Australian regional factors with low to medium costs covering all of the interconnected South Australian system. Modelled investment in South Australia for battery storage occurs in the Adelaide metropolitan area and incurs the low regional cost factor. The regional cost factors were not applied during the RIT-T.

As can be seen, battery storage costs start higher than considered in the RIT-T, decline rapidly and conclude slightly cheaper than previously considered.

The effects of the lower storage costs are discussed in section 5.3.

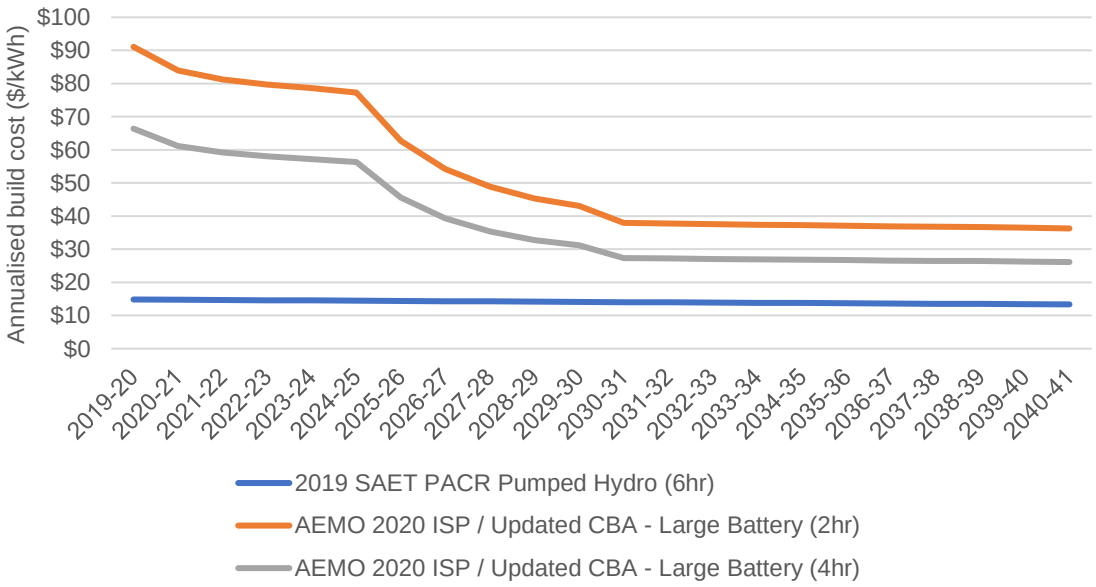
Figure 4 – Updated battery storage annualised capital costs ($2018-19)



The combined effect of higher pumped hydro costs and lower battery storage costs leads to batteries being the cheapest form of large-scale energy storage. However, the cost of energy storage per unit of storage remains higher than tested in the PACR.

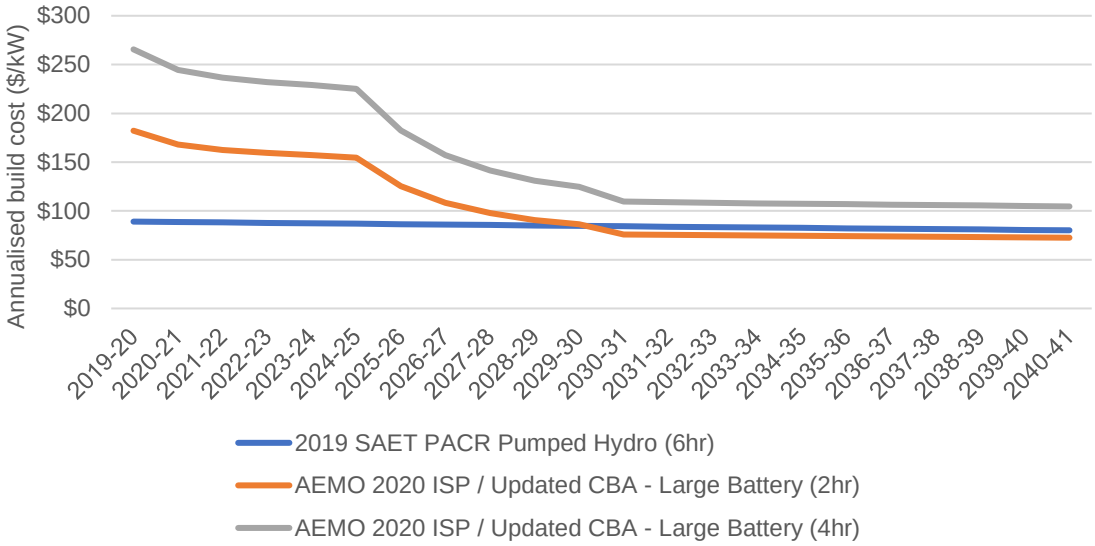
This is demonstrated in Figure 5.

Figure 5 – Annualised cost of pumped storage energy capacity ($2018-19)



The costs of dispatchable power capability from storages has increased to 2030 and declined slightly from 2030 as shown in Figure 6 below.

Figure 6 – Annualised cost of pumped storage power capacity ($2018-19)



ElectraNet has applied AEMO's 2020 ISP cost assumptions above in its modelling.

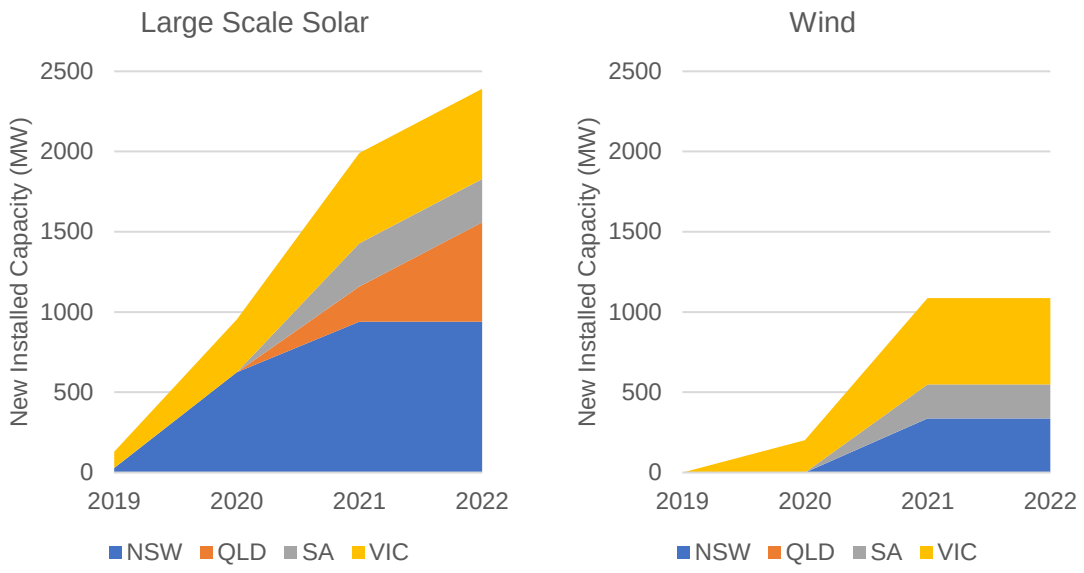
3.7 New generators and retirements

3.7.1 New committed generators

Generator development in the NEM continues at a rapid pace. Since the PACR was published numerous new entrants have entered the market or reached committed status and the PACR noted several new entrants that were not included in the analysis.

In the 2020 ISP, committed new generator and energy storage projects have been updated. Most notably, Snowy 2.0 pumped hydro is committed from 2025 together with the HumeLink transmission upgrade. In addition, between 2020 and 2022, a high volume of renewable energy projects (solar and wind) will become operational in NSW, SA and VIC (Figure 7).

Figure 7 – New committed renewable energy projects in the NEM since PACR modelling



ElectraNet has applied these updated commitments in its modelling.

3.7.2 Generator retirements

Since 2019 AEMO has been publishing expected retirement dates as advised by power station owners in accordance with NER 2.2.1(e)(2A). AEMO is incorporating this information in the ISP as the last date that a generator can retire. Most notably, Osborne Power Station has announced its scheduled exit in 2023.[9]

In addition, between 2030 and 2035, around 500 MW of dispatchable capacity from gas and diesel generators in South Australia will be retired from the market (Figure 8) and Pelican Point is removed from 2037.

All these generators were assumed to be operating to 2040 in the RIT-T analysis with and without Project EnergyConnect. Torrens Island B is also removed no later than 2035.

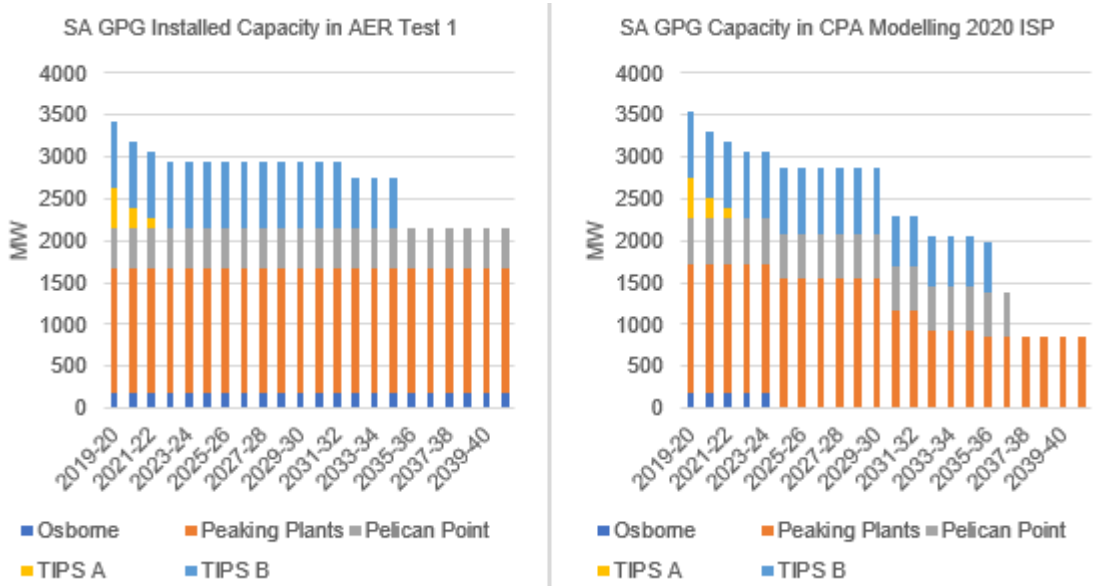
ElectraNet's models may also select generators for earlier retirement. The updated analysis leads to many further retirements that were not considered in the RIT-T.

The effect of these retirements is that significant additional investment in additional firm capacity such as GPG, batteries or pumped hydro will occur in the base case. With PEC, the additional firm transfer capacity (800 MW) will lead to more efficient investment patterns and the avoidance of some of this investment.

The updated firm capacity available in South Australia from existing dispatchable sources assumed in the 2020 ISP is presented in Figure 8 below.

[9] AEMO, Generating unit expected closure year, June 2020

Figure 8 – Updated retirements of convention generation since the PACR



ElectraNet has applied these updated retirement assumptions in its modelling.

3.8 South Australian system security requirements

AEMO has identified new emerging system security requirements for South Australia due to the continuing growth of distributed energy resources and reducing minimum demand levels. We are including these new requirements in the updated cost benefit analysis to the extent described below.

AEMO's report to the Government of South Australia recommends PEC proceeds as an "essential foundational measure" to address the system security risks identified. PEC would reduce the likelihood of South Australia islanding from the NEM and alleviate the most challenging system security issues identified in AEMO's analysis.

On 19 June 2020, the SA Government announced a plan entitled South Australian Energy Solution – A secure transition to affordable renewable energy to address the advice provided by AEMO. A central feature of this is a commitment to implement Project EnergyConnect. AEMO recommended in the ISP the appropriate methodology to model several emerging issues that Project EnergyConnect will alleviate.10

AEMO has identified that a voltage disturbance triggered by the loss of a conventional generator in Metropolitan Adelaide would lead to a loss of over half the distributed PV inverters, compounding the supply and demand imbalance. Based on this advice, ElectraNet has updated the constraint equations that manage voltage and transient stability limits, and this has been incorporated into the updated cost benefit analysis. Project EnergyConnect acts to mitigate the impact of this constraint.

[10] AEMO, Integrated System Plan Appendix 7, 2020

AEMO has also identified that South Australia requires 400 MW of fast frequency response, of which 195 MW would be from investment in new battery storage requirements.11 This has also been incorporated into the updated cost benefit analysis. Project EnergyConnect acts to removes the need for this investment in FFR.

Finally, based on AEMO's advice to the South Australian Government we have also modelled a third type of constraint to manage the risk of the loss of the Heywood. While Project EnergyConnect would remove the need for these constraints, these have less impact on the assessment as it constrains imports to SA to manage islanding risk under high local generation (PV) output conditions when SA is likely to be exporting.

3.9 Victorian Option (Option D)

All actionable ISP projects have experienced increased costs prior to delivery. This is being reflected in the 2020 ISP by AEMO incorporating a 30% increase to all transmission projects and to REZ expansion costs.

ElectraNet has adopted the ISP increased transmission costs in its analysis of the Victorian option (Option D in the RIT-T).

The Victorian option represents a less resilient solution due to its proximity to the existing Heywood interconnector. On the South Australian side, both interconnectors would pass through a single substation. Similarly, on the Victorian side, both interconnector corridors remain relatively close geographically.

The risks of developing the Victorian option as an alternative to Project EnergyConnect have been demonstrated in the first few months of 2020:

- On 30 January 2020 cyclonic conditions in western Victoria led to the electrical islanding of South Australia for two weeks.
- Summer 2019-20 bushfires reiterated the risks to widespread effects of bushfires that both the Heywood interconnector and the new interconnector would face.

The proximity of the two paths would see the South Australian grid exposed to higher risk of events affecting both paths. Network hardening costs included in the RIT-T have been updated in line with the 2020 ISP cost of a new entrant OCGT.

The timing of the Victorian option is linked to the Western Victorian RIT-T with connection assumed to occur by 1 July 2025 and inter-network testing and commissioning to be completed progressively.

[11] AEMO, ISP Appendix 7, 2020.

4. 2020 ISP Findings

The optimal development path in AEMO's 2020 ISP delivers a weighted benefit of $11bn across the 8 scenarios modelled, with benefits under the central scenario of around $7bn.[12]

AEMO continues to find that Project EnergyConnect is required immediately in all scenarios. Specifically, it finds that the delivery of the project would[13].

- Deliver a wide range of market benefits that outweigh its cost;
- Significantly reduce the likelihood of operating South Australia as an electrical island, and therefore mitigate the need to procure Fast Frequency Response (FFR) to manage islanded operation;
- Resolve the need to maintain headroom of the Heywood interconnector for credible contingencies in South Australia; and
- Reduce the likelihood of operating in conditions where a separation of the South Australian power system is credible and therefore reduce the impact of limits that manage those conditions.

The analysis of the full ISP development plan and associated scenarios and insights of that plan can be applied generally to Project EnergyConnect. AEMO found that the benefits of the central scenario are lower than the weighted benefits of the full range of scenarios assessed in the ISP. As such, the benefits of PEC can be expected to be correspondingly higher across the full range of scenarios in the ISP than the benefits presented in this report for the central scenario only.

Those scenarios that represent an accelerated transition to renewable generation sources such as Fast Change and Step Change demonstrated much higher benefits than the central scenario benefits of $7bn, with estimated benefits of $14bn and $44bn respectively. These higher benefits are expected to apply correspondingly to Project EnergyConnect under these scenarios.

[12] AEMO, Integrated System Plan, 2020

[13] AEMO 2020 Integrated System Plan, Appendix A7.6.

5. Results

This section discusses the updated benefits of Project EnergyConnect and the next closest ranked alternative considered in the RIT-T, Victorian Option D.

The quantified net benefits of Project EnergyConnect remain positive and it remains the preferred option.

As discussed by AEMO in the 2020 ISP, the quantification of benefits for the actionable ISP are important and insightful tools for the selection of the appropriate development path. However, the approaches used for quantification should not bind the selection of the preferred path, and a broader range of risk factors still need to be considered.

The Victorian option is found to deliver only marginal positive net benefits on the updated cost benefit assessment. In addition, the Victorian option remains inherently less resilient due to a shared corridor with the existing Heywood interconnector.

5.1 Net Benefits

Aligning inputs with the central scenario of the final 2020 ISP has increased the gross market benefits of PEC from $1,246m to $1,866m or around $620m in present value terms.

The capital costs of PEC have also increased, rising from $1.53bn to $2.43bn ($2018-19) equating to an increase from $977m to $1,673m in present value terms.

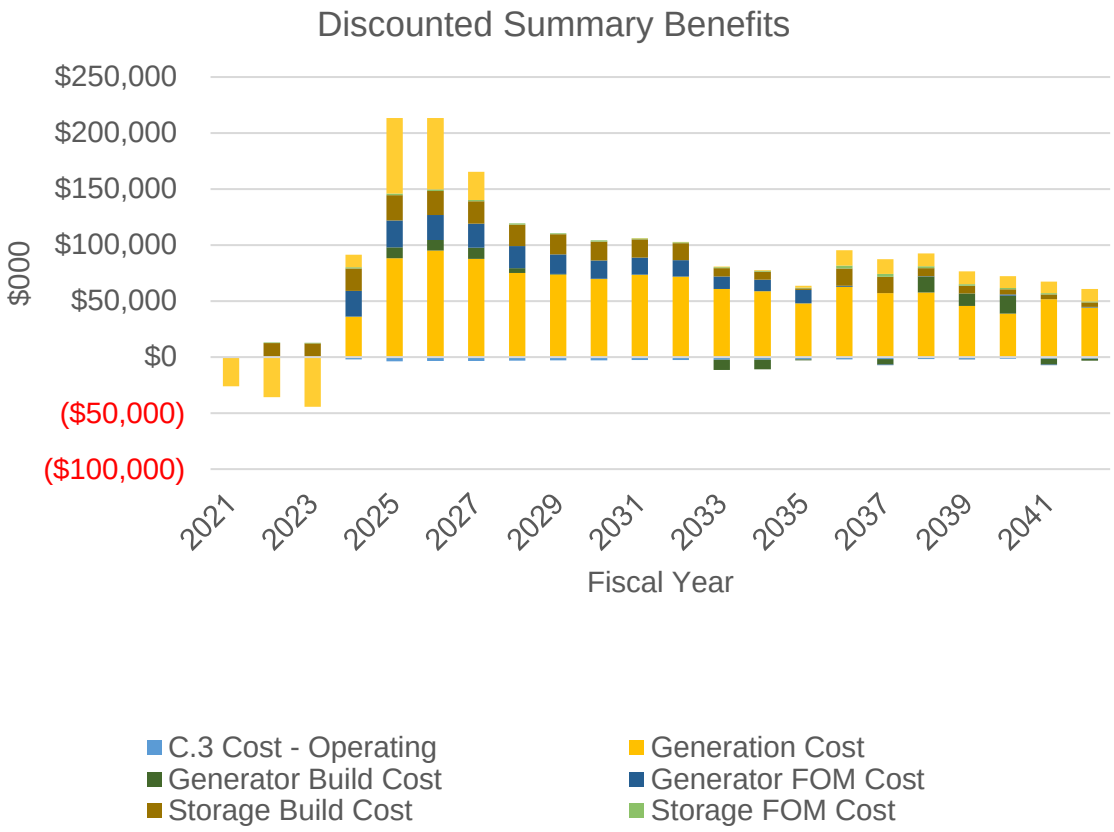
The net market benefits of the AER's Central Sensitivity 1 reported in its RIT-T Determination was $269m. On the basis of the updated cost benefit analysis the net market benefit is found to be $148m.

This option remains robust to further cost increases up to a break-even capital cost for the preferred option of $2.7bn ($2018-19).

A delay to the project timing of VNI West would increase the benefits of the preferred option by between $115m and $176m, noting that delayed timing is assumed in the majority of scenarios considered in AEMO's ISP.

The time profile of discounted benefits (and costs) as found by the economic modelling is presented in Figure 9 below, showing that benefits remain consistently positive across the forecast period following the commissioning of Project EnergyConnect, with maximum benefits delivered in the early years.

Figure 9 - Discounted costs and benefits of Project EnergyConnect



5.2 SA Gas Powered Generator usage

This section presents the SA fuel usage in ElectraNet's updated analysis and compares this to AEMO's ISP.

Updated input assumptions are leading to an increase in the amount of gas used in the base case compared to AER Sensitivity 1. Gas usage remains much lower than has been observed historically and much lower than was considered in the PACR central scenario, as demonstrated in Figure 10.

With Project EnergyConnect, gas usage is reduced throughout the period to 2040 compared to the base case.

In the 2030s gas usage increases as the coal fleet retires, this occurs in both the base case and with Project EnergyConnect although with Project EnergyConnect the increase is lower, as demonstrated in Figure 11. Investment in gas fired generation is also reduced with PEC during this period.

Figure 10 – Comparative gas usage of South Australian GPG (without PEC)

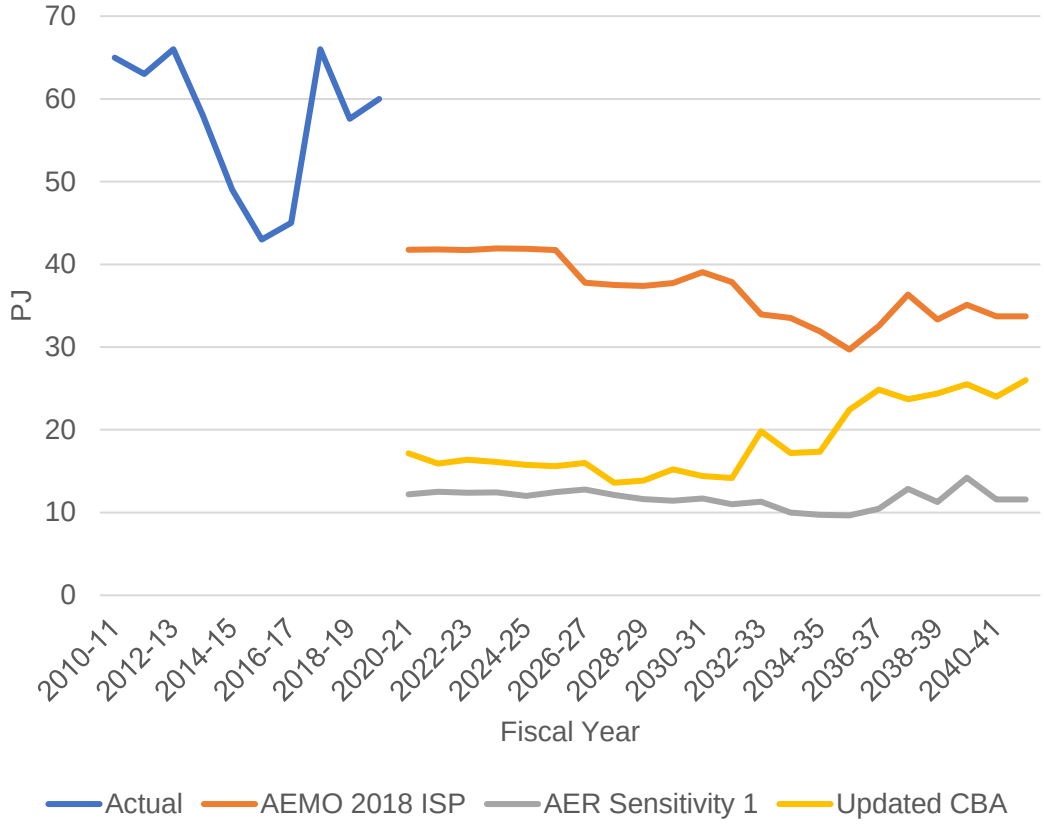
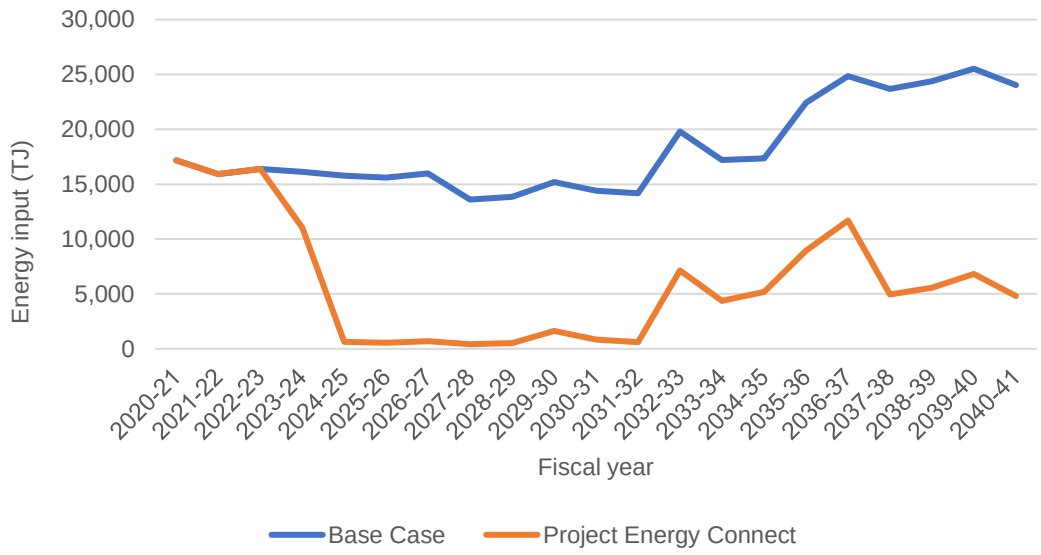


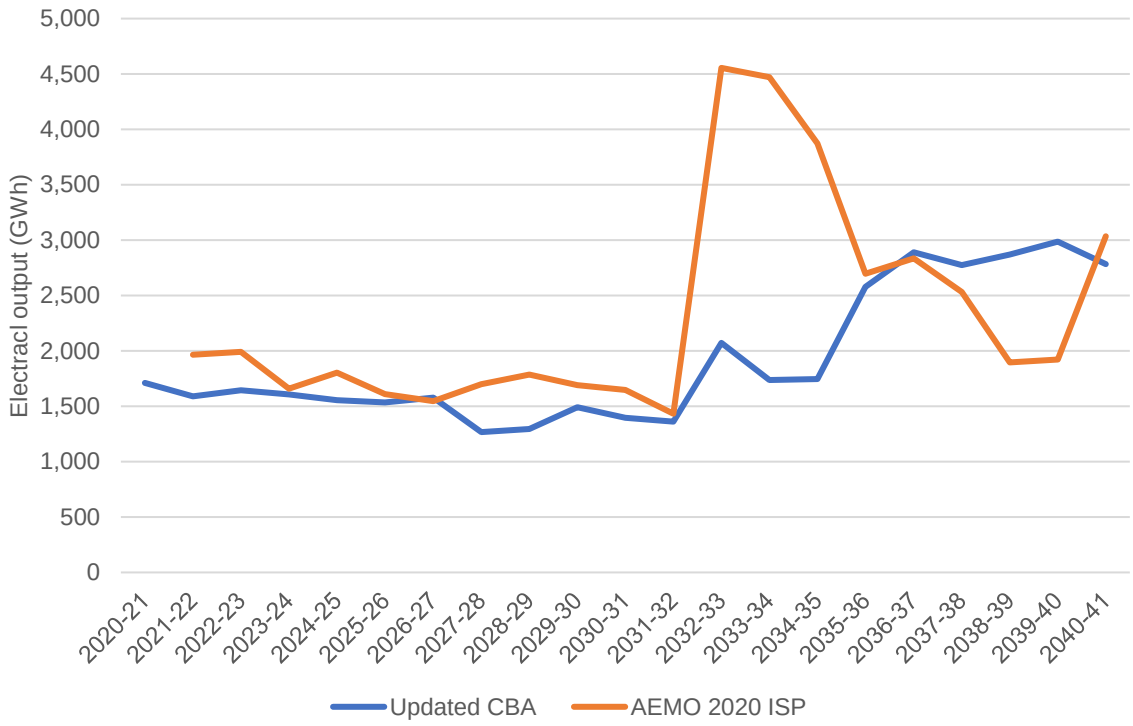
Figure 11 – SA GPG gas usage with and without PEC



By comparison, AEMO's 2020 ISP finds similar gas usage patterns with central base case SA GPG electrical output provided in Figure 12 below compared to ElectraNet's base case to 2032. AEMO forecasts greater volatility in energy output during the early 2030s in the central scenario.

Significantly, both ElectraNet and AEMO are finding much lower gas usage levels than have occurred even in the recent past, and both models predict that gas usage will increase in the future.

Figure 12 – SA GPG electrical output without PEC



5.3 VNI West cost impact

As noted above, the VNI West project has two diverse paths under consideration referred to as KerangLink and SheppartonLink.

The incremental cost of PEC if KerangLink is assumed will decrease by around $120m in PV terms based on the assumptions explained in section 3.2.2.

SheppartonLink will have no impact on the costs of PEC.

The probability weighted expected impact on the costs of PEC is subsequently around a $61m reduction in the PV cost.

In this report we have tested the sensitivity of the benefits to a delay in the timing of VNI West. We have found that net benefits would be between $115m and $176m higher if VNI West is delayed.

Equally, we have found that even if the benefits of the avoided transmission costs of VNI West were excluded from the analysis (which would be internally inconsistent, as noted above) these benefits do not alter the conclusion that Project EnergyConnect remains the preferred option.

5.4 Generator investments

The investment profile broadly aligns with AEMO's findings. Some of the similarities include an increase in the overall level of investment required with supply side options approaching 100 GW in ElectraNet's models and reaching 100 GW in AEMO's models.

Wind is generally the preferred option over solar. This is likely to be influenced by the higher costs of storage per unit of energy storage in the latest results. Whilst battery investment capex declines over the period, the energy density remains higher than in the PACR. Given the higher capacity factor of wind over solar, the storage requirements for wind will be correspondingly lower.

Figure 13 – Project EnergyConnect installed capacity by state

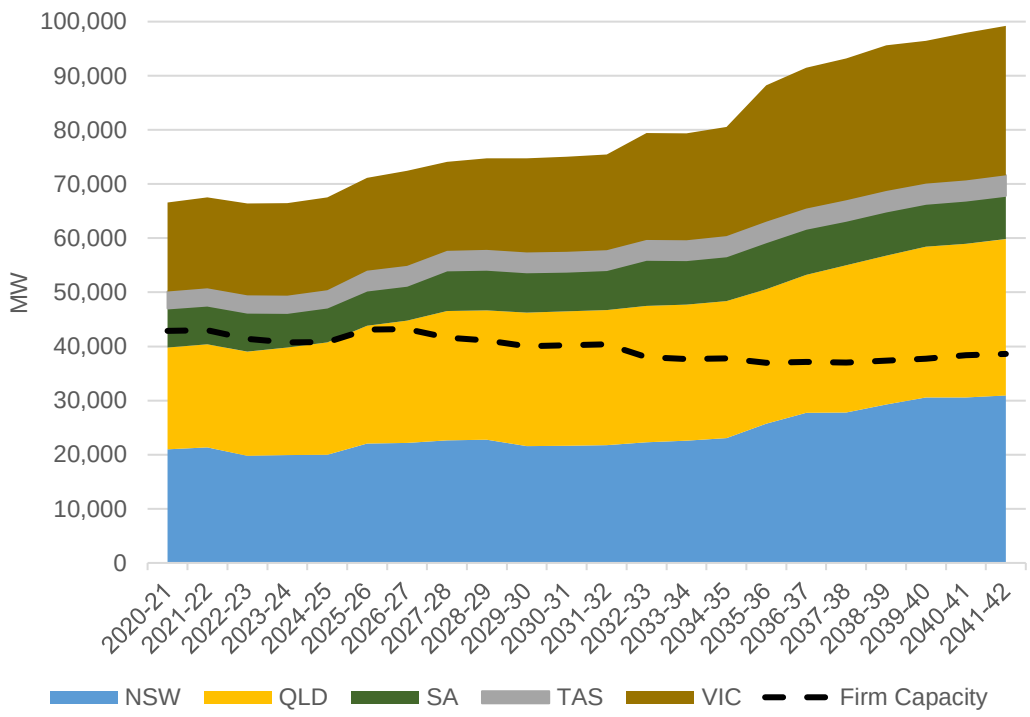
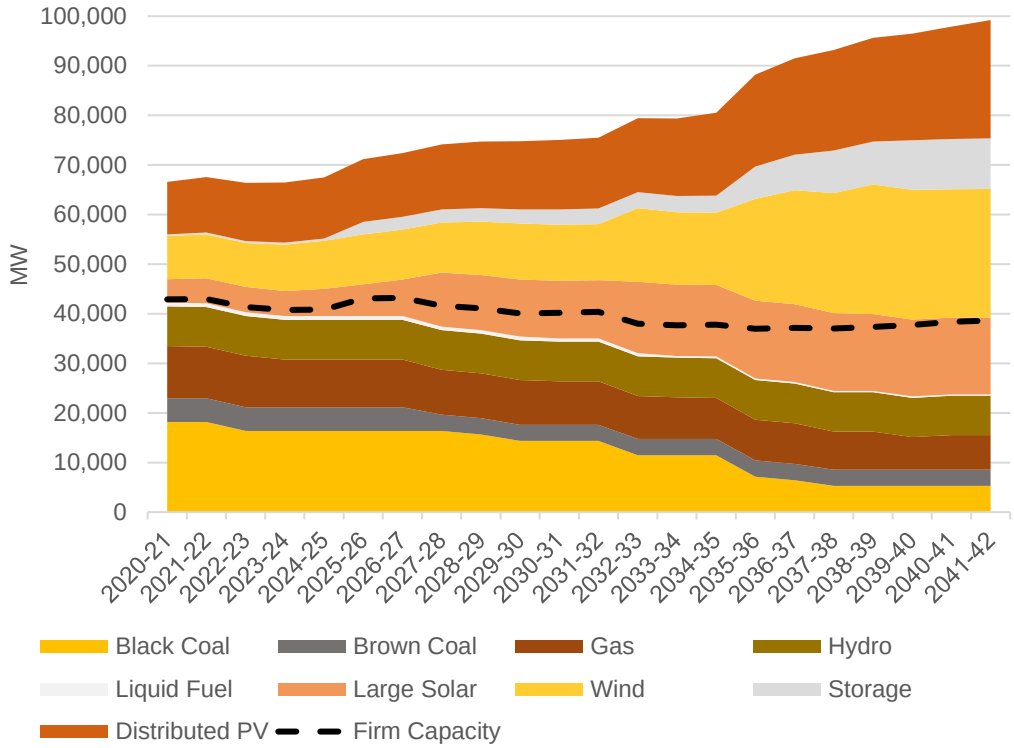


Figure 14 – Project EnergyConnect installed capacity by technology



5.5 Transmission deferral benefits

REZ deferral benefits are steady from the PACR where PEC allowed for the avoidance of around $103m in avoided transmission investment.

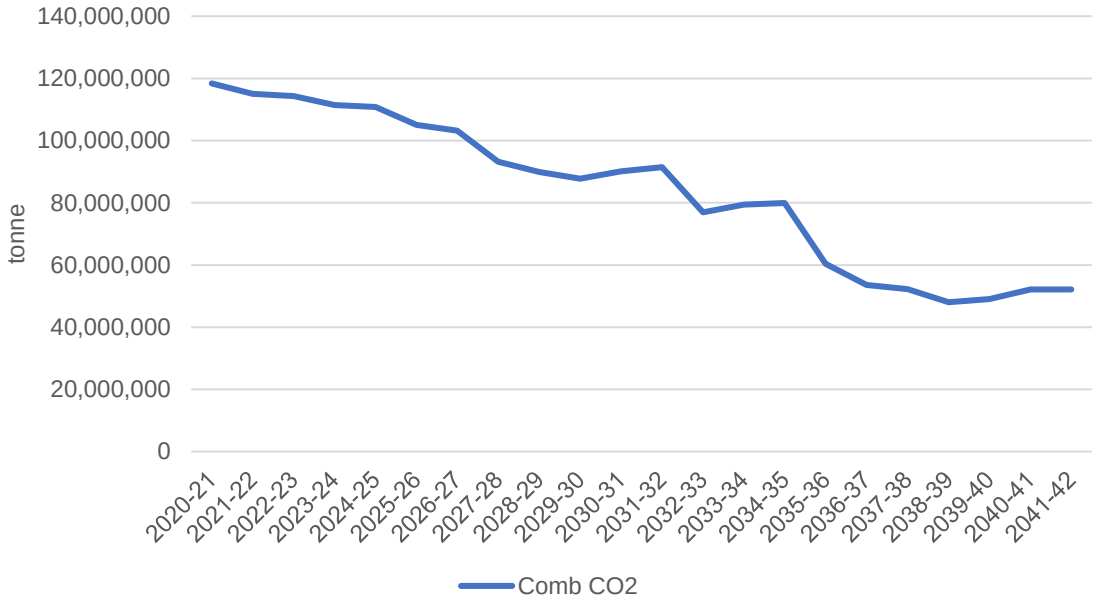
Overall transmission deferral benefits are now estimated at $146m, including the avoided transmission costs of efficient delivery of Project EnergyConnect and VNI West at $61m.

5.6 Emissions

The figure below presents total NEM emissions with Project EnergyConnect in place. Whilst no emissions target is modelled in this scenario, observed emissions of 1,889 mt CO2-e meet the ISP's Fast Change carbon budget of 2,208 mt CO2-e and are within 423 mt CO2-e of the Step Change carbon budget of 1,465 mt CO2-e.

AEMO's central development path 1 emissions are 1,993 mt CO2-e to 2040, within around 4 mt CO2-e (or within 0.2%) of the above results.

Figure 15 – Project EnergyConnect emission production



5.7 Victorian option (Option D)

The Victorian option did not demonstrate positive net market benefits under the AER's preferred methodology during the AER's review of the RIT-T.

This outcome remains effectively unchanged under the updated cost benefit assessment with higher costs and net benefits remaining minimal.

The gross benefits of Option D (South Australia-Victoria interconnector) increase based on the updated inputs and assumptions modelled above, increasing from $553m[14] to $1,108m.

The net benefits of this option improve from the previous modelling, but effectively remain break-even after accounting for the increase in transmission costs assumed in the final 2020 ISP (as discussed in section 2.2.1) with an NPV benefit of $18m. Whilst positive, a further increase in costs of less than 2 per cent would remove any net market benefit.

A comparison of the breakdown of the gross benefits by category of Project EnergyConnect and Victorian Option D is shown in Table 4 below.

[14] AER Information Request #11, December 2019

Table 4 – NPV gross benefits by category

Category	Project EnergyConnect Gross Benefit ($m)	Victorian (Option D) Gross Benefit ($m)
Avoided Generation Variable Costs	$1,197	$833
Avoided Storage Variable Costs	$0	$0
Avoided Generator Fixed Costs	$207	$166
Avoided Storage Fixed Cost	$24	$15
Avoided Transmission Build Cost	$146	-$8
Avoided Generator Build Costs	$46	-$27
Avoided Storage Build Costs	$268	$126
Avoided Demand Side Participation	-$23	$2
Total	$1,866	$1,108

6. Conclusion

ElectraNet has reviewed the latest information available on the range of inputs and assumptions that impact on the modelled costs and benefits of Project EnergyConnect.

This has involved reviewing all of the updated inputs and assumptions to AEMO's final 2020 ISP and seeking additional independent expert advice to validate the updated inputs in key areas, including gas price forecasts, generator heat rates and generator technical parameters.

ElectraNet has aligned its updated cost benefit analysis with the modelling inputs and assumptions used by AEMO in the 2020 ISP, which have been tested with stakeholders through an extensive consultation process.

ElectraNet has also consulted specifically on its approach to the use of variable generator heat rates as a refinement to the original PACR methodology reviewed and endorsed by the AER. These variable heat rates are also aligned with the 2020 ISP.

ElectraNet's updated cost benefit analysis has been based on the 2020 ISP central scenario and specifically AEMO's actionable ISP development path 8, which represents a conservative risk-based scenario that includes an accelerated timeframe for VNI West of 2027-28 to cater for the possibility of early retirement of conventional generation in Victoria without timely replacement investment in firm capacity.

The outcomes of this updated cost benefit analysis demonstrate that:

- The gross (i.e. total) benefits of Project EnergyConnect are significantly higher than for the sensitivity reported by the AER in its January 2020 RIT-T Determination, rising from $1,246m to $1,866m in present value terms;
- Capital costs have also increased, rising from $1.53bn to $2.43bn ($2018-19) (equivalent to $977m and $1,673m in present value terms respectively);
- Project EnergyConnect continues to deliver a positive net market benefit after taking into account the latest benefits and costs for the project of $148m based on the scenario considered;
- Project EnergyConnect continues to deliver positive net benefits at capital costs of up to $2.7bn ($2018-19);
- The closest ranked alternative option assessed in the RIT-T, Victorian Option D, delivers minimal net benefits that would be removed with a less than a 2 per cent increase in cost. As in previous assessments undertaken at the time of the AER's RIT-T determination, this option remains less preferable;
- The outcome of the RIT-T remains unchanged, with Project EnergyConnect remaining the preferred option; and

- Net benefits are expected to increase significantly with later delivery of VNI West, which is the expected outcome in the majority of future scenarios considered in AEMO's ISP. Our sensitivity testing has found that net benefits would be between $115m and $176m higher if VNI West is delayed under the central scenario.

On the basis of this updated cost benefit analysis, ElectraNet concludes that there has been no material change in circumstances as defined in the Rules and the outcome of the RIT-T remains unchanged, consistent with the AER's RIT-T Determination.

Increased benefits could be expected from Project EnergyConnect under the majority of alternative scenarios considered in the ISP. In addition, a range of further unquantified benefits are also expected to be delivered through improved power system resilience.

This underscores AEMO's recognition of Project EnergyConnect as an "essential foundational measure" to address emerging system security risks that are growing year on year and the inclusion of the project as a central part of the ISP's roadmap for the transition of the power system.

Taken together, this provides confidence that the economic case for the project remains strong as an investment essential to Australia's energy future.

ElectraNet