ElectraNet

Project EnergyConnect – Stakeholder Webinar 20 August 2020

On 20 August 2020 ElectraNet held a webinar to provide stakeholders with an update on Project EnergyConnect and an overview of the updated cost benefit analysis being undertaken. An opportunity for questions was provided before and during the meeting, several of which were addressed in the time available during the webinar.

The following provides a complete record of the issues raised by stakeholders at the webinar and in subsequent discussions, together with responses to the issues raised.

Issue	Response
Updated cost benefit assessment	
Will the proponents be undertaking improved sensitivity analysis as part of the Cost Benefit Analysis (CBA) to be reviewed by the AER?	The RIT-T on this project was concluded in 2019 after a comprehensive assessment which incorporated a wide range of scenarios and sensitivities. The AER approved the outcomes of the assessment in its January 2020 Determination, noting that the impact of any changes in costs and benefits should be considered to determine whether this impacts on the outcome of the RIT-T. We are now investigating whether there has been any change in circumstances under the Rules (meaning there has been a change to the outcome of the RIT-T) through our updated cost benefit assessment, based on updated inputs and assumptions aligned with AEMO's 2020 ISP. For the purpose of this updated assessment we are focusing on the optimal development path adopted in the ISP under the central scenario, and it is not necessary to reconsider the range of sensitivities and scenarios already assessed in the original RIT-T. We provided an initial overview of the outcomes of our updated assessment at the stakeholder webinar on 20 August 2020 and will be publishing full details of the outcomes on our website. We will also be seeking confirmation from the AER of the economic case for the project based on its detailed review of the updated cost benefit modelling before a contingent project application is submitted.
Does the updated CBA also still look at the relative merits of EnergyConnect with its increased costs against the other options considered in the PACR, or a counterfactual of new local supplies?	Yes, the updated assessment considers the relative costs and benefits of Project EnergyConnect (PEC) compared with a base case in which the project does not proceed. The updated assessment also considers the net benefits of PEC compared with an SA-Vic interconnector as the closest ranked alternative option.
Is there any formal industry consultation (beyond AER and this session) on the revised cost benefit analysis?	We will be publishing full details of the outcomes of the updated assessment on our website and will look to hold a follow up webinar to allow for further engagement with stakeholders. The AER will also be independently assessing the outcomes of the assessment, and we will be seeking confirmation from the AER of the economic case for the project based on this assessment.

Issue	Response
How are non-network options being considered in the updated assessment?	The updated cost benefit assessment already fully captures the commercial development of non-network investments such as energy storage and generation developments in both the base case and in the interconnector case, based on the latest capital cost curves assumed in the 2020 ISP. Any consideration of non-interconnector options is therefore focused on testing whether additional investments in these technologies of sufficient scale would deliver greater positive net benefits relative to an interconnector solution. The RIT-T assessment considered an optimised non-interconnector solution as an alternative to the range of network options considered. While contributing to network security, it was found that a non-interconnector solution could not fully meet all requirements of the identified need, including the ability to share energy and reserves across regions and support the transformation of the energy system through unlocking renewable energy developments. Consequently, the non-network solution was found to be the lowest ranked option in all scenarios considered in the original assessment and to deliver negative net benefits overall. This outcome would not be expected to change in the updated cost benefit assessment because costs for most essential elements of the non-interconnector solution have increased substantially since the RIT-T concluded and ongoing investigation of emerging security challenges by AEMO in South Australia continues to find that Project EnergyConnect is a foundational element of addressing these challenges.
How can consumers have confidence that they are getting the best outcome that meets the NEO when the reason for no further consumer engagement is that because AEMO has it as a priority project (based on $1.99b capex) it is good to proceed? The ElectraNet submission to the AER claimed >$900m in net benefits and the AER said it is closer to $250m; so why should consumers have confidence that the revised net benefits based on ElectraNet's modelling are robust when there is no more external scrutiny?	The AER approved the RIT-T assessment for the project after an extensive review process, including the advice of an independent consultant. This review upheld both the methodology and outcome of the RIT-T assessment. The updated cost benefit assessment applies the same methodology as reviewed and approved by the AER, based on updated inputs and assumptions aligned with the 2020 ISP that have been thoroughly consulted on with stakeholders by AEMO. We will be publishing full details of our assessment and will be seeking confirmation from the AER of the economic case for the project based on its detailed review of the updated cost benefit analysis. We will also look to hold a follow up webinar to allow for further engagement with stakeholders. The Boards of ElectraNet and TransGrid are committed to proceed with the project only if a sound economic case can be demonstrated.

Issue	Response
Given certain assumptions are absolutely critical (gas price assumptions, capital costs etc.) will you undertake sensitivity analysis and make public? Given that consumers will end up paying for this project in the longer term do you believe this is a reasonable approach and is it something the AER will ask for anyway?	A comprehensive RIT-T assessment has been undertaken incorporating a wide range of scenarios and sensitivities, as reviewed and approved by the AER. The updated cost benefit assessment considers whether there has been any change to the outcome of the RIT-T based on the latest information on costs and benefits, considering the optimal development path in the ISP under the central scenario. We will be publishing full details of the outcomes on our website. We will also be seeking confirmation from the AER of the economic case for the project based on its detailed review of the updated cost benefit modelling.
Spending $2.3bn to save a net $400m appears a questionable investment.	The ISP demonstrates that PEC and other network investments included in the optimal development path deliver average weighted net benefits across all scenarios and sensitivities of over $11bn (and in some scenarios much more) compared with the counterfactual involving no ISP investments. Our updated cost benefit analysis considers only the central scenario identified by AEMO in the ISP for the optimal development path, which carries net benefits across all ISP projects of $7.3bn. PEC was recommended by AEMO in the 2018 ISP and confirmed as a low regret investment in the 2020 ISP, indicating this investment is robust to a range of possible futures. On this basis PEC has been included in all ISP candidate development paths.
Another webinar should be held after releasing the CBA.	We will look to hold a follow up webinar to allow for further engagement with stakeholders following the release of the updated cost benefit assessment.
What discount rates are you using in the updated CBA? We note that the ISP CBA guideline just published by the AER provides further guidance on this.	We have updated the central discount rate to 5.9% in our assessment consistent with the 2020 ISP. This builds on the range of sensitivity analysis previously undertaken in the RIT-T assessment. While we understand the discount rate assumptions in the 2020 ISP broadly align with the approach outlined in the recently published AER ISP Guidelines, we note that these Guidelines do not apply under the new ISP Rules to the 2020 ISP, nor to PEC given the advanced state of the project.
Cost allocation	
Can the cost allocation breakdown of PEC between NSW and SA consumers be described please? Who pays what share.	Under the current framework, the costs associated with PEC would be allocated to customers in SA and NSW on a geographic basis. ElectraNet and TransGrid remain committed to delivering PEC at the lowest possible cost and continue to work through competitive procurement processes to firm up capital cost estimates that will form the basis of applications to seek contingent project funding from the AER. These cost estimates are expected to be available by September 2020.

Issue	Response
Transfer capacity	
Is PEC really 800 MW additional or only 500 MW when combined with current Vic to SA transfer? Does this 500 MW require special demand and generator tripping protection schemes to achieve this 500 MW transfer increase?	Project EnergyConnect will deliver an additional 800 MW of transfer capacity between SA and NSW. Heywood and PEC will share a combined transfer limit of 1,300 MW into South Australia, which is in addition to the existing capacity of the Murraylink interconnector. Either interconnector can be fully utilised in these circumstances with AEMO's dispatch process determining the optimal mix of supply to South Australia and the flow on each interconnector. In addition to increasing interconnector capacity, PEC will also improve the capacity of the network to connect generation across Renewable Energy Zones (REZs) in South Australia, New South Wales and Victoria. A special protection scheme will be implemented to cater for the low probability event of the loss of one of the double circuit interconnectors once PEC is in operation, enabling the transfer capacity above to be achieved on a continuous basis.
ISP Modelling	
Can you please confirm EnergyConnect was endogenous to the ISP study and that the timing of 2024/25 is AEMOs recommendation?	The modelling conducted for the ISP was undertaken to identify the optimal development path with the combination of transmission investments that delivers the greatest net benefit. AEMO also undertook analysis to determine whether the plan delivers greater net benefit with or without individual projects such as PEC. The inclusion of PEC in the optimal development path was therefore an outcome of, rather than an input to, the ISP modelling. The ISP identified that PEC delivers benefits as soon as it can be built, with 2024-25 adopted as the notional delivery date.
Can you confirm whether AEMO used the latest increased costs for PEC in the ISP? I thought AEMO only used ~$2bn?	AEMO assumed an increase in all transmission costs in the ISP of 30% from previous estimates. Consistent with this, AEMO used $1.99bn for the costs of PEC in the ISP.
How much does the inclusion of actionable projects influence the benefits assigned to PEC in the CBA?	ElectraNet has included the actionable ISP projects identified in the 2020 ISP in its updated cost benefit assessment, including the accelerated VNI West timing. ElectraNet has not separately tested the impacts of PEC without the actionable projects in the ISP. However, the previous analysis assumed only committed projects in the assessment. The consistent outcomes of these assessments we have undertaken indicate that PEC continues to deliver a positive net benefit with or without the remaining ISP projects.

Issue	Response
What are the benefits if VNI West is not accelerated or delayed?	AEMO states that the accelerated VNI West timing reduces the quantified benefits of its plan when compared to the optimal later timing of VNI West by $369m in total in the central scenario (in addition to reduced benefits of $20m from early works on Marinus Link). We would expect the accelerated timing of VNI West to be having a proportional impact on PEC, indicating that net benefits would be expected to be greater if VNI West were not accelerated.
Gas forecasts	
With regards to the $12/GJ long term gas cost how do you get comfortable based on current Federal commentary around a long run cost of $6 to 9/GJ?	ElectraNet has applied the Central scenario gas forecast in the 2020 ISP adopted by AEMO based on independent expert advice and consulted on in its annual planning assumptions review. ElectraNet tested the gas prices in the light of COVID-19 through independent expert advice from EnergyQuest which supported the use of AEMO's assumptions. Long-term market dynamics are not anticipated to be influenced by the current short-term market dislocation.
When you say you will publish a summary of the Energy Quest report, what prevents the full publication to give confidence on transparency?	The EnergyQuest report was commissioned under licence that prevents its full publication. A summary of the report has been prepared by EnergyQuest for the purposes of publication. This report can be directly compared with earlier summary reports prepared by EnergyQuest published during the course of the RIT-T assessment. The EnergyQuest advice has provided added confidence in the AEMO gas price forecasts we have adopted as noted above, which are already publicly available.
With regards to your assumption on higher gas usage in power generation in SA, given a number of parties are moving to peaking gas plants (AGL Barkers Inlet, Energy Australia Hallett) etc. and overall gas demand is predicted to reduce in SA, can you please provide further information on this?	We are forecasting a significant reduction in gas usage in power generation in SA in the base case of our assessment compared to current levels. ElectraNet has reflected all committed generation projects included in AEMO's ISP planning assumptions in its updated cost benefit assessment, together with announced generator retirements.
At what gas price do the net benefits disappear? Is there a sensitivity case if gas is only $8/GJ? A locked in gas price of $12 will result in a significant loss of load as firms close operation.	ElectraNet undertook sensitivity testing of gas prices during the RIT-T assessment, which demonstrated the outcome to remain robust to a wide range of gas prices. The wide range of scenarios and sensitivities included in the ISP again demonstrate PEC remains robust to a range of possible futures and forecast assumptions, including gas prices.

Issue	Response
System security & resilience	
Is AEMO saying that the recently released Part 1 of the PSFRR report adequately addresses the issues around system security (non-credible loss of Heywood) and we do not need to wait until Part 2 in December? If so then where is that discussed in Part 1?	The latest information on the system security issues facing South Australia is described in detail in an AEMO report prepared for the South Australian Government[1]. These include voltage disturbance constraints and fast frequency response requirements, each of which are alleviated by PEC and have been modelled in our updated cost benefit analysis. These constraints are not dependent on the outcomes of the 2020 Power System Frequency Reliability Review (PSFRR). Based on AEMO's report to the South Australian Government we have also modelled a third constraint to manage the risk of non-credible loss of the Heywood interconnector. This constraint was also addressed in the PSFRR, as set out in the Executive Summary, section 7.5 and Appendix A of the Stage 1 report of that review. This constraint is expected to have little 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.
What is the basis for the 2-unit synchronous generator assumption?	Further information on the need for 2 synchronous generators is presented in AEMO's 2020 ISP.[2] In summary, the ISP 2020 continues to assume that following the installation of four synchronous condensers in SA (including flywheels) that at least 2 large synchronous generators would be required to be online at all times in the absence of further interconnection. We have continued to align our updated cost benefit assessment with the ISP. AEMO's detailed studies show this is a minimum requirement for security in South Australia in order to provide: • Operational reserves for ramping • Frequency control following separation events • Operating reserves for energy balance following separation events AEMO has more recently declared an inertia shortfall in SA. This shortfall relates to a short-term need for additional inertia services over a two-year period prior to any new interconnector, and has no direct bearing on the updated cost benefit assessment.

1 AEMO, *Minimum operational demand thresholds in South Australia*, May 2020 available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/SA_Advisory/2020/Minimum-Operational-Demand-Thresholds-in-South-Australia-Review.

2 AEMO, *2020 ISP Appendix 7: Future Power System Security*, 30 July 2020 available at: https://www.aemo.com.au/-/media/files/major-publications/isp/2020/appendix--7.pdf?la=en.

Issue	Response
What alternatives to PEC were included in the modelling for the provision of power system services for which PEC benefits are claimed? How would a market for PSS impact the benefits claimed?	ElectraNet has included in the base case of its updated assessment all foundational solutions as recommended by AEMO and adopted by the South Australian Government to address the emerging system security issues in SA. However, while these measures prevent emerging system security issues continuing to worsen, at relatively low cost, they do not fully solve or avoid these issues. The emergence of a possible future market for provision of some or all of these power system services could provide an alternative mechanism of delivering the same outcomes, albeit at unknown cost. The measures modelled provide a low-cost proxy for these possible future market solutions.
What is the actual benefit delivered to consumers by the improvement in resilience? What benefits do consumers see?	While the project is expected to deliver improvements in power system resilience, these benefits fall outside of the RIT-T assessment and have not been quantified. Providing diverse interconnector paths improves the ability of the power system to withstand the impact of extreme events such as bushfire or severe storms, and dramatically reduces the risk of an electrical islanding or cascade failure event in South Australia and associated widespread loss of customer supply.
Is it possible to explain the benefits of PEC if SA is islanded and also from a system stability perspective?	An unquantified benefit of PEC is that it reduces the risk of islanded operation of the South Australian electrical system. Currently, the operation of the Heywood interconnector is limited to manage the largest credible contingency event, reducing its available transfer capacity. Under unusual operating conditions, the loss of the interconnector itself may also be classified as a credible contingency event, with its capacity constrained further to manage this risk. As an example, the recent inertia shortfall AEMO has declared in SA is expected to be addressed by contracting for Fast Frequency Response (FFR) from suitable providers. AEMO considers it very likely that no inertia shortfalls will be declared in South Australia following any commissioning of a second double circuit AC interconnector to South Australia such as Project EnergyConnect. This is because the likelihood of the South Australia region of the NEM being islanded would be significantly reduced. With Project EnergyConnect in place, the loss of either interconnector would be managed as a credible contingency event. PEC therefore results in an improvement to the level of resilience of the network whilst also increasing the transfer capability between South Australia and New South Wales. In addition, the above-mentioned FFR services would not be required anymore.

Issue	Response
Are there other local/cheaper solutions to support that rooftop PV 'shake off' to a transmission event - especially if this factor has been used to affect the CBA?	The benefits of addressing these risks is based on our best estimate of the costs of the likely alternative solutions in the absence of PEC as recommended by AEMO. Project EnergyConnect will also deliver additional benefits for consumers not considered in the RIT-T by addressing the impacts of constrained DER output.
My understanding is that resilience benefits are not an allowable benefit in the RIT-T - so it seems misleading to claim them?	Resilience benefits can be included in a RIT-T if the benefit is quantified and translated to a class of market benefits (e.g. a reduction in involuntary load shedding). However, resilience benefits have not been quantified or included in the updated cost benefit assessment. Rather they are described in general terms for the information of stakeholders as an additional outcome expected to flow from the project.
We cannot have a multi-billion-dollar investment in another interconnector which we will all pay for, without guaranteeing abolishment of ultra-fast load shedding on large industrial customers.	The requirement for under frequency load shedding to be available in response to extreme events to prevent the collapse of the power system is expected to continue under the Rules. However, the risk and impact of such events is dramatically reduced by the addition of a second interconnector.
Customer price impacts	
How much more are the actual customer savings given that they pay marginal price x demand, not fuel saving?	Previous price impact modelling indicated an annual flow on benefit to customers through reduced wholesale prices in the order of 6-7 times the cost of the transmission investment. Any updated information on these potential savings will be shared as it becomes available.
Plant retirement	
Has AEMO engaged with the owners of the Osborne Power Station in relation to the stated 2023 closure date projected?	ElectraNet has adopted the announced generation closure dates as advised by proponents under the National Electricity Rules - the date for Osbourne retirement is that currently advised by the owners. Were Osborne not to retire in 2023, this would likely materially increase the benefits available from PEC as this would increase the level of gas fired generation in SA that could be displaced by a new interconnector. For comparison, in the RIT-T Osborne was not treated as a committed retirement and was available in the base case to 2040.
Project costs	
Will the proponents only claim for increased RAB based on forecast costs in the RIT-T process or based on actual build costs?	Under the Rules, the AER is required to issue a contingent project decision awarding the efficient level of capital expenditure required to deliver the project. Once completed, the final delivered cost of the project is required to be included in the respective regulated asset bases of TransGrid and ElectraNet. In the intervening period, any overspend is funded by the businesses, and conversely any underspend is retained by the businesses.

Issue	Response
What is driving an increase in costs? The 2020 TransGrid APR indicates a cost of $3B for PEC, why is there such a big difference in forecast costs.	AEMO's ISP has assumed an increase in transmission costs in the order of 30% from those previously assumed based on the latest information on prevailing costs in the current market environment. The TransGrid TAPR noted PEC "will deliver benefits at total project costs of up to approximately $3 billion"[3], an upper cost limit. This finding was based on the input assumptions published in the draft 2020 ISP. While the current project is being impacted by these cost pressures, both ElectraNet and TransGrid are committed to delivering PEC at the lowest possible cost to customers and continue to work through competitive procurement processes to firm up capital cost estimates that will form the basis of applications to seek contingent project funding from the AER. These cost estimates are expected to be available by September 2020.
Line route	
Is Dinawan [substation] in this RIT-T or the new TransGrid voltage collapse one? Can you please confirm?	The refinement of the interconnector path for PEC through Dinawan (bypassing Darlington Point) has been necessary to optimise the line route and secure the required transmission line easements while minimising overall project costs. This refinement does not materially affect the level of net benefits, as the effect of the recently revealed voltage collapse constraint at Darlington Point was not modelled in the RIT-T. TransGrid has initiated a separate RIT-T process to address these network constraints[4].
Have the cost increases arisen even though the scope has reduced materially as the project no longer cuts in at Darlington Point – so no extra substation, and a shorter route?	The route refinement has not materially impacted on the scope and cost of the project. Whilst the project now bypasses Darlington Point, it does include a new 330 switchyard at Dinawan in southern NSW as discussed above.
Has the route of the interconnector been confirmed? Will it be published?	The route for the interconnector continues to be developed and refined as the detailed site investigations and consultation with affected communities progresses. Further details can be found on the Project EnergyConnect website[5].
Procurement	
Is the contractor as described by TransGrid for the complete line SA to NSW (one set of project contracts)?	ElectraNet and TransGrid will be contracting for works in South Australia and New South Wales separately through their respective competitive tendering processes. Both ElectraNet and TransGrid remain committed to driving least cost outcomes through these competitive processes.

[3] TransGrid, Transmission Annual Planning Report 2020, page 26.

[4] TransGrid, *Improving stability in South-Western NSW: RIT-T – Project Specification Consultation Report*, 31 July 2020, available at: https://www.transgrid.com.au/what-we-do/projects/regulatory-investment-tests/Documents/TransGrid%20PSCR_Stabilising%20SW%20NSW.pdf.

[5] https://www.projectenergyconnect.com.au/.

Issue	Response
Risk	
Proponents get a regulated return for whatever is spent with no capability for post construction review. Why wouldn't the proponents be confident with a risk-free return - proponents incur no risk.	The AER is required to issue a contingent project decision awarding the efficient level of capital expenditure required to deliver the project. Once completed, the final delivered cost of the project is required to be included in the respective regulated asset bases of TransGrid and ElectraNet. In the intervening period, any overspend is funded by the businesses, and conversely any underspend is retained by the businesses. The AER also applies an ex post review process under its expenditure forecast assessment guidelines in the event that a capital expenditure allowance is overspent. Given the difficulty in obtaining financing in the current environment, both businesses are strongly incentivised to deliver the project at least cost.
Timeframes	
Is there a view on the schedule impact of these additional cost/benefit checks/studies?	We are working to conclude the updated cost benefit assessment as soon as possible in order to proceed with a contingent project application for the project. Provided applications are lodged in a timely manner, the AER has foreshadowed a contingent project decision by the end of 2020 is possible.
When will contingent project application likely occur?	The contingent project application is expected to be lodged in September 2020 when final cost estimates are expected to be available.

Further information on the updated cost and benefit assessment will be released shortly and a second webinar will also be scheduled for stakeholders in the coming weeks.

31 August 2020