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Dear Hugo,

ElectraNet 2018, South Australia Energy Transformation, Project Assessment Draft Report

We welcome the opportunity to comment on ElectraNet's ongoing work on the South Australian Energy Transformation and the publication of the Project Assessment Draft Report (PADR). EnergyAustralia is one of Australia's largest energy companies with over 2.6 million electricity and gas accounts in NSW, Victoria, Queensland, South Australia, and the Australian Capital Territory. We also own and operate a multi-billion dollar energy generation portfolio across Australia, including coal, gas, and wind assets with control of over 4,500MW of generation in the National Electricity Market (NEM).

The cost of additional high voltage interconnection between South Australia and other adjacent NEM states is significant. Given that these costs would be recovered from electricity customers across the lifetime of the asset (likely greater than 40 years) it is important that the process and modelling of identifying the net benefits is as accurate as possible. Current policy uncertainty in the energy market may drive changes to system reliability requirements, emission reduction and market operation. This coupled with the speed of new technology developments and costs has the potential to drastically alter the NEM as we know it today. As customers pay for any network investment and bear the investment risk it is important that any long-term network investment and its projected benefits is sufficiently scrutinised to ensure customers benefit from their investment.

1. General comments on modelling

We appreciate that ElectraNet released additional information on the their PADR modelling during the consultation period. However, we remain concerned about the lack of detailed results and the lack of clarity around some of the input assumptions that have been made, for example cycling of thermal units.[1] ElectraNet has provided a break-down of the financial-year market benefits (and costs) of the interconnector option but does not provide any additional information on how these market benefits are derived. The modelling results provided around generator expansion and retirement allows for an understanding of the location, time and type of generation changes, but to verify these outputs additional information needs to be provided on how existing and new plant is dispatched. While minimum up and down times for coal plant has been assumed by ElectraNet, there is no information around the technical limitations of other thermal plant

[1] Additional information in response to public forums, https://www.electranet.com.au/projects/south-australian-energy-transformation/

(e.g. Combined Cycle Gas Turbines (CCGT)) and the associated start costs of these units. We are concerned that without providing clarity of assumptions around these technical characteristics of thermal units, the PADR modelling may be providing unrealistic dispatch outcomes and potentially overstating the benefits of fuel savings.

We recognise that the modelling requirements for such a significant project are challenging, but we stress that there needs to be considerable due diligence around modelling completed by ElectraNet. The results must provide comfort that the assessment has considered all credible options and scenarios, with these transparently communicated to participants to allow an informed decision around investment in new interconnection to be made.

2. South Australian system security and reliability

Currently there is significant focus from government, customers and the media on reliability and security in the NEM. ElectraNet has correctly identified that since the Project Assessment Consultation Report (PACR) there have been a number of market developments that have improved the outlook of power system security and reliability in South Australia. For example, the AEMC's rule changes on managing power system fault levels and Rate of Change of Frequency (RoCoF), as well as proposed changes to generator technical performance.[2] With these security improvements a South Australian system black like the one that occurred in 2016 seems unlikely to occur again. We do not agree that the identified need should include enhancing the security of electricity supply; including management of inertia, frequency response and system strength as this has been addressed in previous market developments and rule changes. Further, the interconnector should not adversely cause other system security and/or reliability issues in the short or longer-term future.

Given that the specification of the South Australia system strength remediation solution is yet to be finalised, we strongly encourage ElectraNet to ensure that the inertia assumptions in the PADR modelling align with AEMO's inertia assumptions for the future solution.[3] We are concerned that the assumed inertia level is low relative to AEMO's modelled requirement and could see directions in South Australia continuing. If they did, this could influence the preferred option for remediation, or lead to other network assets being installed prior to commissioning of additional interconnection.[4] A higher level of inertia would alleviate the need for a tight RoCoF limit on the Heywood interconnector and would make the South Australia system more resilient to loss of the current interconnector. Potentially, this may enable a lower cost non-network solution.

While system strength remediation will meet the minimum level of the non-synchronous cap there may be benefits from building out to the higher 1,870MW cap. We would like ElectraNet to provide a sensitivity analysis applying the higher non-synchronous cap to, and removing the RoCoF constraint from, the base case to test the impact on benefits solely from the increased transfer capacity of interconnection. This should be assessed separately from other technical limitations that are resolvable via alternate means.

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[2] https://www.aemc.gov.au/rule-changes/generator-technical-performance-standards, https://www.aemc.gov.au/rule-changes/managing-power-system-fault-levels

[3] https://www.electranet.com.au/what-we-do/projects/power-system-strength/

[4] http://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf

3. Impact on local generation

Most market benefits from additional interconnection stem from avoided fuel costs. South Australian gas generation is displaced by the higher output of lower priced coal generation and to some extent additional renewable generation (by removal of non-synchronous cap). It is our understanding that in the modelling outcomes, Torrens Island B Power Station (TIPSB) closes as it is not required in the least cost modelling once new interconnection is completed. Essentially, its capacity is replaced by the interconnector and its load factor becomes low. The PADR counts this as a market benefit, made up of a reduction in fixed costs and fuel costs savings due to its previous output being replaced by lower priced generation.

The modelling finds that the remaining South Australian synchronous mid merit generation, Pelican Point Power Station (PPPS) and Osborne Power Station (OSB), remain in operation after the completion of the interconnector. These stations remain open due to their lower fixed cost assumptions ($5m and $1.8m for PPPS and OSB respectively *vs* $34m for TIPSB) and lower variable costs due to their higher efficiencies. These stations are also still required by the model to meet the minimum reserve levels assumed by ElectraNet. This arises as it is cheaper for the model to keep this plant open rather than replace it. What the least cost model does not consider is the commercial realities of the significantly lower load factors that these plants will face and the inability to recover not only their fixed maintenance costs (as specified above) but also costs associated with procuring sufficient firm gas and transport for commercial operation.

Additional interconnection will without doubt have some impact on wholesale prices in South Australia and we do not believe that ElectraNet has sufficiently considered or presented (in the modelling) the potential *'knock on'* effects and the commercial realities of the remaining synchronous generation. Upon completion of new interconnection, the Integrated System Plan (ISP) has the retirement of all local mid merit synchronous generation, including TIPSB, PPPS and OSB for a combined total of around 1,400MW.[5] We urge ElectraNet to provide further clarity around the difference in generator retirements in South Australia between the ISP and the PADR modelling.

We believe that the retirement of local mid merit generation in South Australia making the State solely reliant on interconnection for security and reliability is not in the best interest of customers and the State in general. While additional interconnector may somewhat improve the resilience of the South Australia power system (removing the reliance on the Heywood interconnector) the impact on early retirement of local generation may remove any benefits from this.

4. Availability of hedging products

The Regulatory Investment Test for Transmission (RIT-T) process does not explicitly require ElectraNet to consider the effects on the availability of hedging products in South Australia but, given the potential impact on local generation from new interconnection, this should be considered. The PADR modelling benefits come from a reduction in wholesale prices in South Australia, but the availability of hedging products is also important to customers to allow them to manage their energy exposure. ElectraNet's modelling assumes that local generation remains open to satisfy the minimum reserve

[5] ISP modelling database, 2018 Generation and Transmission Outlooks, https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/ISP-database

levels as under the least cost model this is cheaper than building new capacity. Whereas further interconnection will likely lead to commercial retirements of local generation with limited additional dispatchable capacity being installed to replace this. Local generators are the main suppliers of energy hedging products in the South Australian market, for example swap contracts. A reduction in supply of contracts due to generator closure with no associated change in energy demand is likely to lead to higher prices for these contracts. South Australia's contract market is already relatively illiquid compared to other NEM States due to the small size of the market. The proposal has the potential to exacerbate this situation and therefore the availability of hedging products must not be ignored.

While the interconnector will provide greater access to lower priced generation from other NEM States, what it does not do is create any additional firm capacity in South Australia. Financial intermediaries, for example banks, are at times willing to step in and take a short position in the market, increasing the supply of contracts. However, with additional interconnector capacity (interconnectors would represent ~50% of South Australian peak load) they will be unlikely willing to supply such a large volume of missing contracts. New interconnection could lead to higher contracting costs for customers due to the reduction of supply of hedging contracts.

One benefit of the non-network option that is not recognised by ElectraNet's RIT-T is the likely increase (or at least preservation) of local dispatchable generation in the State and hence the supply of hedge contracts. The early closure of dispatchable low emission intensive generation (from new interconnection) appears to be contrary to current recommendations from the ACCC which have encouraged the Federal Government to look at underwriting new dispatchable generation projects.[6]

5. Non-network option

It is not clear if the Entura modelling has considered other market developments such as changes to the generator technical performance standards[7] and the do no harm component of the managing power system fault level rule change.[8] Entura identifies that a network option will provide some increase in fault level (at its point of connection) and a modest increase in voltage control. What they haven't identified is that further fault level and or voltage regulation requirements will still likely be required adding additional costs to the interconnector option.

We note that the network option would also require some post-contingent load shedding in South Australia for the non-credible loss of either Heywood or the new interconnector, whereas minimisation of load-shedding in the non-network solution has been prescribed "*to make [it] comparable to [additional interconnection]*". Load shedding should be considered as a solution to assist in managing the non-credible loss of an interconnector (in both the network and non-network option). That is, the cost of load shedding using a recognised measure of value of customer reliability (VCR) should be assessed as an economic alternative.

The solution technical performance modelling completed by Entura does not appear to cover a realistic range of scenarios. Most cases fail to consider inter-regional energy flow

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[6] Recommendation 4, Retail Electricity Pricing Inquiry – Final Report
[7] https://www.aemc.gov.au/rule-changes/generator-technical-performance-standards
[8] https://www.aemc.gov.au/rule-changes/managing-power-system-fault-levels

pricing impacts and the implications around local generation dispatch. We had problems reconciling the supply and demand balance across scenarios. For example, case 5 has only ~450MW of synchronous generation dispatched but the row '*Synchronous Inertia'* appears high compared to identified plant online. It is also not clear why TIPSB is dispatched preferentially to PPPS in several scenarios. PPPS should be preferentially dispatched due to its higher efficiency when TIPSB is dispatched higher than 160MW (the approximate PPPS minimum generation level). We urge ElectraNet to provide clarity around some of the pre-interconnector trip assumptions to allow participants to fully understand the robustness of the modelling completed.

As highlighted in the PADR, the growth of rooftop solar is continuing to impact minimum demand levels with minimum operational demand expected to approach zero as early as 2020.[9] While we recognise that there are significant challenges around controlling distributed energy resources to manage interconnector flows, investment in additional interconnection to manage this does not appear to produce the lowest cost outcome for customers.

We recognise that a non-interconnector solution does include several risk and uncertainties, but the same can be said for any interconnection option as well. A significant advantage of the non-interconnector option is the flexibility of the shorter-term Network Support Agreement (NSAs) that would allow any market, policy or generation changes[10] to be considered with a network option still possible in the future. The network option carries all the risk that the modelling and scenarios run have captured a wide enough range of uncertainties and that the future market benefits are sufficiently accurate and probable to eventuate. We see that there is significant option value in the non-interconnector option that is not captured by ElectraNet.

6. Market benefits

Market benefits across all network scenarios are primarily driven by fuel savings as additional interconnection allows lower cost generation to displace more expensive local gas generation. The market benefits in the high scenario are increased dramatically due to the tightening of the RoCoF standard (From 3Hz/s to 1Hz/s) and the subsequent reduction in flows on Heywood in the base case. The weighting of the different scenarios (25% low, 50% central, 25% high) means that the tightening of the RoCoF standard skews the reported market benefits. ElectraNet identify that most other jurisdictions around the world have much tighter RoCoF standards but it has not considered whether these standards apply to both credible and non-credible contingencies.[11] There appears to be no additional system security benefits from tightening of the RoCoF standard to 1Hz/s. The current 3Hz/s was selected to ensure that a non-credible loss of the interconnector would prevent a repeat of a local system black event. If a tightening of the RoCoF standard to 1Hz/s is targeted by ElectraNet to minimise load shedding from a non-credible loss of an interconnector, then expected VCR should be considered when weighing up the economics of load shedding versus the building of new interconnection.

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[9] http://forecasting.aemo.com.au/Electricity/MinimumDemand/Operational

[10] For example, there are already several new projects announced, e.g. Infigen's announcement of battery storage at Lake Bonney Wind Farm, https://www.afr.com/technology/infigen-energy-to-install-38m-battery-in-south-australia-20180815-h13znd

[11] For example, ElectraNet cite Ireland as similar – whilst it has a similar magnitude of interconnection, average demand is roughly triple that of South Australia, and there is a considerable fleet of dispatchable generation with its associated inertia, so the incremental cost or benefit a stricter RoCoF standard is immaterial. ElectraNet analysis shows the cost of imposing this in South Australia would cost $1b (in the base case).

In our view, ElectraNet hasn't provided sufficient evidence to justify a further tightening of the RoCoF standard.

While the assumptions in the high case might represent the upper reasonable bound for each category, we do not consider it appropriate to apply all these assumptions in the one scenario. These assumptions interact with each other leading to overstated benefits that are very unlikely be representative of the upper reasonable bound of the benefits. The purpose of the high case is to test the solution for a more restrictive requirement, we see it being beneficial to also test in isolation the increased transfer capacity provided by additional interconnection separate to technical limits addressable by alternative means (i.e. removing RoCoF limits and low synchronous cap). This would allow assessment of the incremental benefit for incremental costs.

ElectraNet also includes benefits associated with the avoided costs from Renewable Energy Zones (REZ). The REZ concept came from the Finkel Review and is referred to in the ISP, but it's incorrect to include these as a market benefit under the current RIT-T process.[12] Further, the market benefits identified in the PADR from avoided transmission investment do not commence until 2033 with there being considerable uncertainty around market changes across this time. Any market benefits from REZ appear to be speculative at best.

We question whether the quantitative assessment of market benefits is appropriate. Net Present Value (NPV) provides a measure of profitability of a project by discounting the cash inflows and outflows across the life of the project. It does not consider the amount of capital required (and capital efficiency) to complete the project. This is reinforced by the outcomes of the ACIL report, which found that in nominal terms over the first three years the reduction in annual residential customer bills in South Australia and New South Wales would be only $30 and $20 respectively (approximately a 1% saving).[13] The associated benefits to customers are limited and, weighed against the significant risk in the range of the interconnector benefits, do not assist in justifying the project.

7. Emissions

The preferred project should satisfy the identified need. ElectraNet has identified one of these needs as "*facilitating the transition to a lower carbon emissions future*". In the immediate term, the outcome of additional interconnection appears rather to be an <u>increase</u> in emissions as lower emission mid merit gas generation is displaced by cheaper and more emission intensive black coal generation from New South Wales and Queensland. Reduction in emissions would appear to occur only once coal generators retire in the future. This outcome is likely regardless of whether the interconnector is built or not. It appears that the proposal does not meet the stated emissions objective. We would therefore like to see more detail modelling from ElectraNet around the trajectory of the actual emission benefits any additional interconnection would provide.

8. Interconnector constraint modelling

[12] https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-minor-amendments-2017
[13] https://www.electranet.com.au/wp-content/uploads/projects/2016/11/ACIL-Allen_market-modelling-impact-new-interconnect_report-04072018.pdf

For such a high cost and long-term investment, it is important that any constraints and or network limitation are identified to ensure that the market benefits are sufficiently robust. As an example, the upgrade of the Heywood interconnector has not been able to achieve its specified performance for considerable amounts of time due to generation mix changes in South Australia coupled system security requirements. It is likely that, over the long life of the asset, there will be significant changes in the NEM and the generation mix. To enable good decision-making, the modelling scenarios and sensitivities must consider this.

There are several other factors missing from the analysis that we recommend for inclusion:

- Market impacts that may occur due to the required major outages to parts of the network to facilitate upgrades which may constrain power flows on other parts of the network.

- Market impacts from ongoing maintenance of interconnector(s). That is any flow limits on interconnectors to manage a post contingent loss of the remaining interconnector(s).

9. Conclusion

After having comprehensively reviewed the PADR, supporting material and analysis we are concerned that this falls short of the robust assessment that should precede such a large investment. Customers fund and bear all investment risk of a network project, ElectraNet must show evidence that a project provides benefit to customers to justify such an investment. We believe this has not been sufficiently demonstrated.

The PADR modelling does not realistically capture the commercial realities of the effect of additional interconnection on local synchronous generation. We urge ElectraNet to consider the impact on South Australian customers' ability to access hedging contracts, as the net outcome of additional interconnection is likely to be a reduction in supply of these contracts.

ElectraNet should also provide clarity on additional interconnector benefits after removing the non-synchronous cap and RoCoF limits in the base case, which are resolvable by alternative means. This would help identify the incremental benefits of an interconnector option, versus the incremental costs associated with the project. We believe the non-interconnector option does have option value given the current speed of new generator investments, policy and market uncertainty and the ability for a network option to still be considered in the future.

For any additional information, or to discuss this submission please contact Andrew Godfrey on 03 8628 1630 or Andrew.Godfrey@energyaustralia.com.au.

Regards

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