24 Feb 2020

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TransGrid - HumeLink Project Assessment Draft Report (PADR) consultation 2020

EnergyAustralia is one of Australia's largest energy companies with around 2.5 million electricity and gas accounts across eastern Australia. We also own, operate and contract an energy generation portfolio across Australia, including coal, gas, battery storage, demand response, wind and solar assets, with control of over 4,500MW of generation capacity.

In reviewing TransGrid's cost benefit analysis report, and associated supporting material and models, we are appreciative of with effort taken to transparently outline the investment case, including sensitivities. Of note is the attention to matters raised by stakeholders during the Project Specification Consultation Report (PSCR) consultation, and how these have been considered. We genuinely agree that the PADR analysis has benefited from this extensive stakeholder consultation.

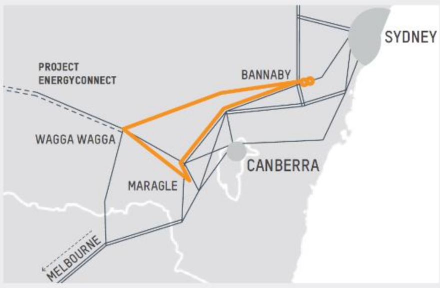
This submission focuses on requests for further analysis and information regarding the timing of investment and assumptions regarding generation capacity, particularly for pumped hydro and coal. It also requests publication of specific data that will help to build confidence in the investment decision.

Overview of PADR (including EY market modelling report and Houston Kemp NPV model)

TransGrid's PADR report outlines:

- Option 3c is preferred, which involves constructing substation equipment and three new transmission lines (Maragle-Wagga, Wagga-Bannaby, and Maragle Bannaby) designed and operated at 500kV.
- This option establishes around 2,570MW of new firm capacity under average import levels from Victoria and wind generation in southern NSW.
- Indicative capex is $1.35b, plus annual opex estimated at 1% of capex per annum.
- Timing for commissioning is 2024/25.

3 New transmission lines in a 'loop' between Maragle, Bannaby and Wagga Wagga (and power flow control between Bannaby and Sydney where needed to provide 2,000 MW capacity)



- Weighted NPV benefits to the NEM across the four scenarios are $1.1b by 2044/45, relative to the counterfactual (no transmission) case and range from $370 – $1.4b in each scenario.
- Material benefits are avoided capex for solar, peaking gas plant and more pumped hydro (beyond Snowy 2.0) in NSW, and avoided fuel costs.
- Common across all scenarios is: VNI minor and QNI minor upgrades from July 2022, EnergyConnect completed in 2023, Snowy 2.0 and Western VIC from July 2025, and no QNI Stage 2.

The following sections outline areas EnergyAustralia requests TransGrid to consider further, and to provide details of conclusions, as TransGrid progresses through to its Project Assessment Conclusions Report (PACR).

More details on the timing of transmission options

We consider that the timing of the network options considered needs further discussion.

It appears that the preferred option 3c has been timed for 2024/25 [1] and this is deterministic across all scenarios and sensitives when describing gross benefits, costs, or net benefits. It is our expectation that the optimal timing is likely to vary and we would like to see specific validation on the optimal timing in each scenario and across the sensitivities. Are there regret costs in some cases, or under some sensitivities, if the project proceeds in 2024/25?

Specifically, we would like to understand what the optimal timing is in the slow-change scenario; in the case where Snowy 2.0 does not proceed, and where the Maragle-Wagga-Bannaby is staged earlier, and then followed by the Maragle-Bannaby leg of the loop. We would also like to understand any change in optimal timing if costs were to increase by 25%.

Furthermore, AEMO's draft 2020 ISP describes this project as a 'no regrets' option in 2025/26[2] – what drives this inconsistency in timing between the ISP and the PADR?

Noting a real, pre-tax discount rate of 5.9% has been adopted with sensitivities at 2.85% and 8.95%, can TransGrid please clarify if this applies to the discounted cash flow analysis and generator hurdles rates as well as when determining the annualised costs of the transmission investment and therefore in determining the optimal timing?

We also note that in several cases there appears to be significant avoided generation or storage capital costs (excl. fuel costs) in the years well before the transmission is commissioned. Can TransGrid please explain the basis for this?

Capacity build out

EnergyAustralia requests additional information and analysis from TransGrid on the assumed changes in the supply side, notably in Pumped Hydro Energy Storage (PHES) and

[1] TransGrid, *Humelink Project Assessment Draft Report,* Page 4
[2] AEMO, Draft Integrated System Plan 2020, Table 4, Page 51

coal-fired installed capacity. We seek to understand the level of reliance the conclusions have on these assumptions and whether the system will be operationally manageable.

EnergyAustralia is concerned that the central case assumes an additional 11,300 GW of long duration pumped hydro storage, in addition to the capacity provided by Snowy 2.0, is required by 2044/45. This seems ambitious, bordering on implausible, and represents a 'technology bet' that undermines the broader findings. Further, the lack of utility scale batteries appears to be clearly disconnected from what is happening in the market today. Gas-fired generation is also missing from the supply mix.

We question TransGrid's modelling where it relies so heavily on PHES, given the high development risk and continued uncertainty regarding resource availability, construction costs and the economic threat of competing storage technologies. For these reasons we consider TransGrid should produce a sensitivity that genuinely challenges the presumption of PHES playing a critical role in the transition of the electricity system.

Further, can TransGrid publish EYs findings of the sensitivities around Snowy 2.0: not proceeding, halving the planned storage, having reduced capacity, and reduced round trip efficiency, on the timing of the preferred option? Is the investment case robust to these changes?

We also note TransGrid has outlined several departures from the 2020 ISP (including advanced closing of half of the coal power station capacity in the NEM by 2 to 5 years in three of the four scenarios), on the basis it was not available at the time of running its studies – we seek a view on how these departures affect the net benefits and timing of the preferred option if they are carried forward in the PACR.

We note the sensitivity studies around closure of coal plant based on economic viability. Observing very low annual capacity factor of some stations (<50%), we encourage more details of these studies to be summarised and published, including the full cost benefit analysis and impacts on option timing and net benefits, as well as details on the closure criteria applied. This is particularly the case in recognising the important sensitivity, that allows retirement and life extension, has the effect of materially reducing the gross benefits by $755m (>60%).

Critically, we seek more detail from TransGrid on how much dispatchable capacity is available in NSW and more broadly across the NEM in the scenario outlooks. While recognising that the second most material benefit in the study is avoided investment in new dispatchable generation, we have concerns about how the power system will be operated on a day to day basis with the reduced levels of dispatchable capacity as outlined in the study. Three questions occur to us that need to be resolved for the forecast scenarios to be plausible:

- How dependant is power system operation, or maintaining the reliability standard, on the implausible levels of PHES from the long-term planning? If the forecast capacity of PHES does not arrive, does the system face significant security and reliability challenges?

- Will system strength, low inertia or frequency/voltage control issues prevail that have not been considered in the study?

- Will the remaining dispatchable coal plants be able to ramp up and down to efficiently support the swings in intermittent generation from new capacity built as a result of the new interconnector?

Finally, we seek greater clarification on capital cost assumptions for new capacity build used by TransGrid in the PADR:

- Can TransGrid confirm the cost of Snowy 2.0 is treated as a sunk cost?

- If a hypothetical market driven announcement to install a 500MW OCGT/CCGT in NSW (upstream of Bannaby) occurred in the next few months, can TransGrid outline if this would also be treated as a sunk cost, and whether this would have any bearing on the cost benefits analysis and the preferred timing?

Modelling assumptions and methodology

We have several concerns with the assumptions used to model the future network.

Our primary concern, consistent with comments made in our submission to AEMO's draft ISP, is that the modelling of hydro assumes perfect foresight and is targeted to reduce total system costs. We think this is unreasonable and that basing development path and investment decisions on operational assumptions that are grossly inconsistent with reality is a concern. We seek TransGrid's considerations of whether the benefits outlined in the PADR are overstated because hydro modelling assumes perfect foresight and is targeted to reduce total system costs.

We also question whether Snowy Hydro's considerable portfolio after the construction of Snowy 2.0 could influence dispatch outcomes away from the perfect outcomes represented in SRMC bidding? Failure to adequately model realistic outcomes undermines the integrity of the study.

Regarding modelling of diversity in peak demand across regions – if each region is scaled to a forecast peak demand independently of other regions, then the coincident peak demand diversity factor will naturally and systemically reduce. This means that each region's peak will occur more diverse than it did based on historical experience. This could cause an overreliance on interconnectors and their ability to share reserves. We request TransGrid confirm that historical peak demand coincident factors are maintained in the demand traces. A strong example of the implications for coincident demand is the events on 31 January 2020 when there was record coincident demand across NSW, Victoria and South Australia.

Beyond these concerns, we have specific requests and suggestions for the EY and TransGrid modelling and published information. In terms of the EY market modelling, can TransGrid:

- explain how EY has calibrated its market modelling to actual outcomes, and how it extrapolates this over the outlook period,
- outline EYs use of its own generation forced outage rates (FOR) and Mean time to Repair (MTTR) – and can it be explained how they differ from those used by AEMO in its ISP, and

- explain and publish the dynamic loss equations and changes, including discussion on whether there are any material benefits in terms of loss savings.

In terms of further modelling, can TransGrid:

- Outline whether transient and voltage stability limits are included in modelling, and whether they impact on the transfer capacity modelled in the system technical assessment studies?

- Confirm if the network project costs include easements and land acquisition allowances?

- Confirm the transmission asset economic lives used, and the 1% O&M capex per annum assumption are consistent with AER views when approving expenditure allowances?

- Confirm what needs to be done to refine 'midpoint' costs for the purposes of the PACR?

- Can the investment decision be delayed until these matters are much clearer? We see this as critical, as end customers bear both the risk of cost increases and the risk of the estimated benefits not being realised?

- Confirm the transmission asset economic lives used, and the 1% O&M capex per annum assumption is consistent with AER views when approving expenditure allowances?

- Summarise the preconditions and insights into the methodology used to determine the cost estimate ($450m) if two lines of an interconnector were to fail simultaneously? Ideally, we would like to see views on the probability of this event, the forced outage rate and the mean time to repair.

Further insights and details to build confidence

To provide further transparency and build confidence in the investment decision for which the cost and benefits will be borne by end consumers for decades, we encourage TransGrid to publish:

- Its modelled price outcomes, including duration curves and intraday price shape. These are key drivers for economic build of storage and peaking generation and consumer costs, and we would like to review these to better understand the capacity planning outcomes, and the relative impacts of interconnector investment.
- Regional benefits relative to regional costs - the study highlights lower fuel costs and generation and storage capex for the overall market, but how are regional costs and benefits attributed, particularly for NSW, SA and VIC.
- The cumulative transmission capex/opex on annual profile charts (Figures 5, 10, 15 and 20).
- Whether the Bannaby to Sydney West (Line 39) transmission line constrains optimal dispatch over the outlook period, once the preferred option has been installed?

- Utilisation of HumeLink (% of transfer capacity), including intraday flows and duration curves.

We trust this submission is constructive in nature, and if you would like to discuss it further, please contact Georgina Snelling on 03 9976 8482 or Georgina.snelling@energyaustralia.com.au.

Regards

Georgina Snelling
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