Oakley Greenwood

# SA Energy Transformation RIT-T: External review

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# DISCLAIMER

In preparing this report Oakley Greenwood relies on a combination of Oakley Greenwood analysis of material provided by ElectraNet supported by discussion and other communication with ElectraNet. Oakley Greenwood has recorded our interpretation of these inputs in good faith but disclaims all responsibility for the accuracy of interpretation. The opinions and conclusions noted in the report are provided on the basis of the interpretations noted.

# DOCUMENT INFORMATION

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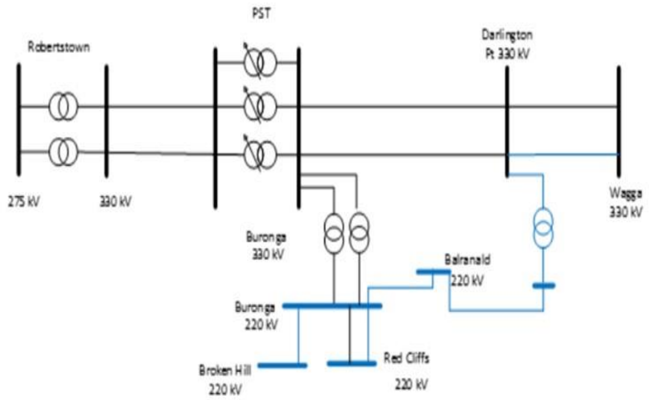
# 1. Introduction and key findings

Oakley Greenwood was engaged by ElectraNet to provide an external review of aspects of the development of the Project Assessment Conclusions Report (PACR) within the Regulatory Test for Transmission (RIT-T) that ElectraNet is conducting for a project entitled the South Australian Energy Transformation project (SAET). Our analysis is built on a review of the modelling for the Project Assessment Draft Report (PADR) that was published in June 2018.

In particular, we were asked to review the framework for modelling the electricity market that was undertaken as part of the analysis of the benefits of the preferred option. The scope of this present review is focused on assessing the robustness of the methodology, the credibility of inputs to suit the methodology and the plausibility of the results.

The preferred option (C3) calls for creation of new infrastructure to connect Robertstown in South Australia to Wagga in NSW, via Buronga and with an augmentation to Red Cliffs as shown in Figure 1.

Figure 1 Electrical configuration for Option C3




- a new 330 kV double circuit line between Robertstown and Buronga;
- a new 330 kV double circuit line between Buronga and Darlington Point;
- a new single circuit 330 kV line between Darlington Point and Wagga Wagga;
- a new 330 kV substation at Robertstown, including 275/330 kV transformers at Robertstown;
- new 330 kV Phase Shift Transformers at Buronga (in order to share power transfers between new and existing interconnectors);
- two 330/220 kV transformers at Buronga;
- augmentation of existing substations at Robertstown, Buronga, Darlington Point, Wagga Wagga and Red Cliffs;
- a new double circuit 220 kV line (conductor strung on one side and operated as a single circuit) from Buronga to Red Cliffs in Victoria;
- turn in the existing 275 kV line between Robertstown and Para into Tungkillo;
- static and dynamic reactive plant at Robertstown, Buronga and Darlington Point; and
- a Special Protection Scheme (to detect and manage loss of either interconnectors).

Source: ElectraNet

## Key findings

In summary we find that:

- The basic methodology for modelling is sound and also broadly aligns with AEMO's approach in its Integrated System Plan (ISP);
- The results we have reviewed are plausible in that outputs are reasonable for the methodology and inputs used;
- A number of factors we consider to be risks to the net benefit turning negative have been quantitatively assessed by ElectraNet and found to reduce the net benefit, but not to the point where the net benefit is less than zero in the central scenario;
- There are a number of other risks where ElectraNet has provided a qualitative assessment or otherwise determined the risks are able to be mitigated such that net benefit remains positive. In particular the risks that:
  - New entrant battery storage and existing peaking gas fired units with low profitability (measured by short run marginal cost (SRMC) prices) will continue to be contracted under cap style contracts (either explicit or within vertically integrated gentailers), that such contracts will be available or another market mechanism will emerge to ensure their standing costs are met. It is important to note that this is a risk that is inherent in all modelling based on SRMC and the RIT-T requires that market modelling be undertaken on a 'least-cost' basis[1] in the first instance. Existing peaking plant typically shows low profitability now and is implicitly supported by contracts, the assumption in the modelling is that this will continue at broadly the same level; and
  - In the event Pelican Point and Osborne are expected to be retained in service through to the early 2030s (and longer in some sensitivities) that a mechanism to ensure their costs are covered is available given that their profitability at SRMC prices will be very low for much of the time. The mechanism may simply be that sufficiently high spot prices are implicitly expected or these units are contracted for other reasons. We note the central case (and the ISP) avoid this concern as all major gas plant is withdrawn as the SAET project comes on line.
- We also raise two matters that are beyond formal assessment of the framework for modelling for the purposes of a RIT-T but may impact operation of the South Australian network and therefore the broader industry context and the role of the SAET proposal.
  - The first is whether emerging high impact low probability (HILP) situations should be factored into the analysis of reliability if all major gas plant withdraws to be replaced by new large interconnections and greater levels of intermittent sources of generation and storage. In these circumstances the South Australian region will be both capacity and energy constrained. ElectraNet has provided high level analysis to show the exposure is relatively limited in practice.

1 AER, *Regulatory Investment Test for Transmission,* June 2010, paragraph 21(a).

- The second is to highlight the importance of initiatives already underway through the Energy Security Board (ESB) and the ISP related to developments across network, generation, storage and demand-side to ensure timing of changes in the different sectors are coordinated. While guidelines for the conduct of RIT-Ts have recently been amended to require account to be taken of these initiatives, which ElectraNet has done, the analysis underlines their importance.

# 2. Approach

Market modelling of a project as large as the SAET involves very large amounts of data and detailed analysis. Our review did not attempt to repeat the modelling but was focussed on assessing the robustness of the methodology, the credibility of the inputs to suit the methodology and the plausibility of results which may highlight problematic areas of the methodology or the operation of the model.

We were provided with detailed outputs of the central scenario and one of the sensitivities which examined a different set of assumptions relating to retirement of the South Australian gas stations. We were also provided with responses to questions we raised about risks we identified that might affect the sign of net benefit, viz whether the risks could show negative benefit if the risks were realised.

ElectraNet answered on the basis of other runs and consideration of input assumptions and in cases where ElectraNet had conducted quantitative analysis we were provided with a summary of relevant model runs. We have also reviewed in detail annual summaries regarding the investment phase and the hourly dispatch related to the central scenario.

In assessing results, we have focussed on the primary sources of benefit identified by ElectraNet in their Market Modelling report and also considered whether there are any sources of benefit (or cost) that have been missed.

The RIT-T provides an assessment of proposed augmentations for two reasons or need: economic market benefits or to meet reliability standards. The SAET is for enhanced market benefit and is assessed by comparing the economic costs for future development with and without the proposal under consideration.[2]

As a result net benefit is driven by differences between a base case where the proposal does not proceed and the case where it does proceed. Given that ElectraNet's market modelling shows that savings in gas use, which is strongly related to future utilisation levels and potential retirement of existing gas plant, are the dominant source of benefit we pay particular attention to retirement decisions in both the base case and the case where the preferred option proceeds. Retirement decisions may also be affected by the relative costs for new plant compared to gas and coal costs for existing plant.

A summary of the components of costs and benefits prepared by ElectraNet is presented in Appendix A and will be referred to as each risk is discussed in the following sections. In the central scenario the Present Value (PV) of the cost of the project is $1,244M and the PV of the dominant benefit due to saving in fuel costs ($1,791M) and after accounting for smaller costs and benefits the nett benefit is $766M.

2 Where a RIT-T is assessing how to meet a Reliability standard the assessment seeks the least cost way to meet the need.

# 3. ElectraNet modelling methodology

## 3.1. Overview

In order to review results of modelling it is important to have a clear picture of the methodology that was used, especially for a complex assessment such as for the SAET. This section provides a high-level summary or our understanding. More detailed explanations are to be found in ElectraNet Market Modelling Methodology report to be released alongside the PACR.

Modelling was undertaken in two parts. A long-term (LT) model that assesses entry and exit of generation, storage and demand-side facilities as well as network upgrades across the NEM. The resultant portfolio of facilities is a key input to a short-term (ST) model that assesses the dispatch of each facility and its impact on operation of the NEM and attendant costs.

Analysis in both the LT and ST models was on the basis of cost of capital and operating components and did not explicitly consider market behaviours or market prices. This approach is consistent with the guidelines for conducting a RIT-T, which is essentially an economic cost benefit analysis (although it does not preclude modelling of prices where appropriate). A number of scenarios and sensitivities around different inputs that might be affected by price-based modelling were used to test the sensitivity of the overall result to different conclusions around key factors such as retirement of existing plant.

Both models used a deterministic approach represented by a single pass through the model based on representative input values. Therefore neither model considers the statistical range of costs and dispatch outcomes that are possible in practice but addresses this by assessing the impact of a range of scenarios and sensitivities.

Modelling was run to 2040 and a terminal value used to approximate the period beyond 2040.

The capabilities of intermittent resources are presented to the models as a single representative trace drawn from AEMO data.

There are strong similarities between the LT and ST models used by ElectraNet but also some important differences. Both are chronological or time sequential models, that is they represent the functioning of the market and power system sequentially over a period of time and can therefore assess the impact of intermittent plant that is only available at certain times of the day, in particular solar and the effect of storage linked to it.

Assessment of entry and exit over an extended period of time is a computationally complex task in any model. For the LT modelling for the Project Assessment Draft Report (PADR) a traditional load block representation of the power system was used that optimised entry and exit over the full horizon in a single pass. However, intermittent generation sources, especially solar, are very difficult to represent in a load block model because the blocks are formed without regard to time of day, whereas the generation that is available to meet the demand is very much dependant on time of day.[3]

Using sequential modelling for the analysis of entry and exit in the LT model for the PACR is a material refinement in approach from the limitations of the load block modelling used in the previous stages of the RIT-T including the PADR.

3 An extreme example of the problem is that as load blocks are formed from similar demands across a year or season a block may include daylight and night-time demands. If generation from solar in the daylight hours is then assumed to be available for the block as a whole it can result in the perverse outcome of solar generating at midnight (even if no associated storage is present). Modellers must develop methods to overcome this situation and this creates considerable complexity and requires further approximations.

For the PACR, ElectraNet has used a simplified chronological representation in the LT model to identify entry and exit of generation capacity except where it is based on end of technical life as well as storage and demand side facilities. Corresponding augmentation of network capability, in particular for renewable energy zones (REZs), has also been assessed in the LT model. The key simplification involves breaking the period for analysis into 8-year blocks and representing days within each year in 8 variable length periods such that each period is designed to represent part of the day – for example the period overnight may be 2 hours long but during the day 10 hours.

The LT modelling also used a simplified representation of the transmission network similar to the regional representation used in dispatch of the market in AEMO's dispatch systems, though with some modifications. The real time AEMO dispatch representation relies on knowledge of the transmission network and its operating constraints at the time. These limitations are incorporated in dispatch calculations through a series of mathematical constraint equations. However, as this representation assumes a known network it is unsuitable for analysis over an extended period of time where the network may need to be expanded.

Longer term modelling can presume the network will be developed to match the expansion of generation or consider costs of relieving constraints to more accurately assess location and amount of capacity development. ElectraNet has adopted an approach similar to that used by AEMO in the Integrated System Plan (ISP) and has incorporated additional constraints to limit capacity expansion in parts of the network with known limitations, adding an additional cost for expansion beyond those limits.

ElectraNet has also assumed the development of Renewable Energy Zones (REZ's) which are resource rich areas expected to be attractive for renewable generation proponents. Where a REZ is served by a weaker part of the network and may not be able to accommodate development of all of the resource without augmentation of the network, ElectraNet's modelling allows development up to the limit of the network between each REZ and the main grid and imposes an additional cost (a constraint cost) on development beyond that limit. The cost of the constraint is then taken as a capital cost and the amount of network capacity taken up assumed to be enhanced network capacity which is carried over to the ST model.

In the ST modelling a nodal representation was used to model the transmission network apart from the REZs which are represented by a single line to the regional reference node with the capacity determined in the LT model. A nodal representation requires that each line in the transmission network is separately accounted for and is therefore more accurate. The operating constraints in the ST model therefore represent the capability of each line (and transformers etc) augmented as indicated by the modelling in the LT model of the REZs as well as system wide security limits. This is a tractable computation for hourly analysis as the ST model does not make entry or exit decisions but focusses on dispatch and network flows. The one exception to this is that the capacity of pumped hydro plant is fine-tuned according to economics in dispatch (for example the LT model builds capacity without regard to unit size and the ST model adjusts the amounts to expected unit capacities).

As noted earlier, retirement decisions are a critical indirect driver for reduction in fuel use and also fixed costs and we pay particular attention to whether the reductions can be attributed to the introduction of the SAET project and would not also occur in the base case, for example in the event a unit simply reached the end of its technical life.

ElectraNet has adopted the results of AEMO's ISP modelling in respect of timing of retirement of gas generation plant in South Australia as its central scenario except that it uses a staggered shut down of Torrens Island in its base case (without the SAET proposal). In the ISP the three major gas fired generators in SA withdraw close to the time the SAET interconnector is brought on line. ElectraNet then conduct sensitivity tests around the timing of withdrawal of the gas plant using the results of modelling to test when it is economic for retirement up to the technical life of the plant. Economic retirement occurs when revenue from the Spot Market with prices based only on marginal cost (not price) is insufficient to meet fixed operating cost or at 50 years of service which is considered the end of technical life in one case.

In the LT model, ElectraNet does not assess the impact of network losses on decisions about entry or exit (ElectraNet advise that it has determined that the magnitude of losses found from the ST model show that losses are not material).

Government policy mandates for particular types of generation will overlay the choice of generation including in which state the developments occur. These may be imposed from time to time. Further, experience over recent years shows that significant lumpy developments and changes would not always be predicted from modelling – for example the complete shutdown of Hazelwood with very short notice and initiatives such as Snowy 2 and Battery of a Nation as well as construction of new interconnection which may be justified would not necessarily have been predicted. As a result lumpy developments five, ten and fifteen years from now are equally likely to not be predicted. Any major network development will change the environment for future generation investment and any major generation development will have an impact on future network loading and possibly on construction.

For this reason, the requirements for preparation of a RIT-T require it to include consideration of credible scenarios and to include sensitivity testing. The SAET is one such very lumpy step change within South Australia. Further, security constraints which were not anticipated 5 years ago are now dominant issues.

In previous RIT-Ts, for example the upgrade of the Heywood interconnection, we are aware that loading on parallel secondary circuits was a significant issue. For the PACR ElectraNet has assessed both secondary circuit loading and loading of lines at either end of the new interconnection in South Australia and in NSW. ElectraNet has confirmed that ratings and important contingencies for intra-regional network in NSW were reviewed by TransGrid for NSW and AEMO (as TNSP) for Victoria and that ElectraNet drew on its own resources for limits within SA.

## 3.2. Modelling methodology is sound, devil is in the detail

On balance we consider the methodology employed by ElectraNet to be sound and capable of assessing costs and benefits in a robust and transparent manner. In this respect we understand ElectraNet is proposing a wider range of information be published in the PACR compared to the PADR.

However, the devil is in the detail as a robust methodology can only produce robust outcomes if the input data and scenarios and sensitivities are also robust. The remainder of this report focusses on these details based on analysis of the two detailed study outputs and responses we received to our enquires from ElectraNet and summaries of the more extensive analysis ElectraNet has undertaken and described in its PACR modelling report.

# 4. Scenarios and sensitivities

An important part of assessing economic benefit in modelling is to construct robust scenarios, often described as different 'states of the world' and sensitivities to test the materiality of individual assumptions within each scenario. The importance of the timing of retirement of existing plant was discussed earlier. Two other significant cost inputs relate to the costs of gas and coal.

As noted, ElectraNet has adopted the assumptions in AEMO's ISP as its base case with the exception of Torrens Island B retiring at a slower rate in the ElectraNet central scenario base case. This is important as those assumptions include that the three major gas stations in SA (Torrens B, Pelican Point and Osborne) are withdrawn immediately following commissioning of the SAET project, but the smaller stations in South Australia remain in service.[4]

ElectraNet has used three primary scenarios based on the cost of gas and other key variables (as described in the PACR modelling report). Gas assumptions comprise:

- Low scenario with a gas price of $7.40/GJ delivered to Adelaide
- Central scenario with a gas price of $9.15/GJ delivered to Adelaide
- High scenario with a gas price of $11.87/GJ delivered to Adelaide

The price of black coal for NSW power stations in the reference cases varied from $1.82/GJ in 2024 to $4.101/GJ in 2040 ($2018). Details for each station were based on AEMO's ISP data. In the high coal price scenario black coal for all stations in NSW was $6.8/GJ by 2025.

Demand was taken from the forecasts used in AEMO's 2018 Electricity Statement of Opportunities. The high, central and low scenarios tested different projections for demand.

The capability of new entrant wind and solar plant was based on a single average trace of hourly capability for each major zone developed by AEMO. Existing generators also had a single average trace of hourly capability developed by AEMO. Both sets of traces were used in the ISP.

Sensitivities tested the following changes:

- Alternate timing for retirement of Pelican Point and Osborne in South Australia (detailed results reviewed for this report) which also included an increase in the minimum amount of gas that the model was required to dispatch for generation, effectively forcing a level of dispatch from gas;
- Higher coal ($6.80/GJ from 2025 to the end of the horizon) leading to faster retirement of NSW coal plant and narrowing the gap between coal and gas costs;
- Higher project costs (up 25%);
- Assumption that battery storage would be developed rather than the lower cost pumped hydro; and
- Torrens Island B would retire several years earlier at 50 years of service (in 2026).

## 4.1. Scenarios and sensitivities are suitable to test net benefit

In our view this design of scenarios is appropriate for the assessment of range potential benefits and costs of the SAET proposal and the sensitivities address the risks that we have identified where a quantitative analysis is practicable and each is discussed in the following sections.

4 Torrens A is assumed to be shutdown before entry of the SAET proposal

# 5. Plausibility assessments

Our approach to the review includes assessment of the plausibility of results generally, as well as assessment of results that are central to the main conclusions[5].

Results of modelling can be assessed at a high level for plausibility and relativity. For example is relative dispatch volume or price different in the expected direction in the base case as compared to the proposal? Ratios such as spot revenue: operating cost can be used to review decisions about retirement or assumptions about implicit additional contract support.

However, this metric should be understood as representing a worst case assessment for revenue as, by design, cost based modelling does not account for market bidding which may see higher prices and therefore higher revenues. Other outputs such as the level of emissions and changes in cost of dispatch are also important

The use of SRMC as the basis for modelling raises the risk that, notwithstanding the requirements of the RIT-T, critical decisions, such as entry and exit, which in practice are made on the basis of commercial market prices, may not align with decisions that would be indicated from SRMC analysis.

Our view is that forecasting market prices is challenging at the best of times but especially so at times of major change in the industry. The inclusion of market price modelling also requires far more time and effort. Assessing dispatch for a given investment profile on the basis of SRMC is much less problematic than establishing the profile in the first instance as the relativity between generation sources is generally consistent with the SRMC order but entry and exit is related to the relativity of generator internal costs and revenue from the market. Low SRMC profitability may not mean low profitability under market conditions and a profitable outcome under SRMC conditions will in most circumstances mean a profitable market price outcome.

The risk is therefore only a risk, not a certainty, that the entry and exit profile will be distorted if assessments are made purely on the basis of SRMC. In the case of a RIT-T, what is important is to assess whether alternative means to retain plant in service, for example to satisfy a reserve margin criterion, is realistic and also whether the likely difference in outcomes is conservative or pessimistic in terms of the value of a project being assessed by the RIT-T.

Assessing the impact on dispatch for a plausible range of entry and exit conditions that might result from commercial behaviours is a reasonable substitute for assessments based on market price forecasting – and indeed arguably even more robust given the uncertainties of market price forecasting.

A number of assumptions have been made and are identified as specific risks later in this report (e.g. the role of Renewable Energy Zones and assumptions about how low capacity factor plant will enter and be retained in the market). ElectraNet has assumed that over the long term the design of the market will allow the most cost-effective sources of generation to enter, exit and operate and that network development will, if cost effective, occur to support the generation and maintain reliability and security. We discuss (and support) this assumption in respect of risks later in this report.

5 For example, review of an early version of results found that output reported from Tasmanian Hydro was unusually low in one year. Given that the output of Tasmanian Hydro is not critical to the assessment of the value of SAET. In discussion with ElectraNet this was found to be a reporting issue, not a fault and was readily corrected.

ElectraNet has advised it has assumed separate processes will address an emerging question about management of stability of the South Australian network (especially at very low demands). Despite these improvements, if South Australia were separated from the NEM, there are material risks to the operation of the grid in its current configuration.

It is important to note that an un-costed benefit of the SAET proposal is that separation is much less likely. As it considers alternative measures to maintain security are available ElectraNet has not classified the SAET proposal as essential for maintenance of system security.

We also did a spot check on one year of hourly demands and price outcomes. These results were also within the range that we expected for the case. SRMC annual price results were also assessed. We consider these results are within the range that would be expected for the cases assessed

As part of our plausibility assessments we examined the level of $CO_{2\text{-}e}$ emissions in the cases that were provided to us. The central scenario case based on the ISP has materially lower emissions than ElectraNet's alternative case. This situation was at first surprising but is explained by a higher minimum generation for gas plant setting in the central scenario (in the base and the option), forcing high generation from gas across the NEM and lower coal generation.[6]

## 5.1. Results are plausible

We consider the results are plausible, that is for the inputs and methodology applied, the results are within the range expected.

# 6. Assessments and risk factors

As noted in the introduction, the focus of our brief relates to the framework to assess the preferred option. As a result the key assessment metric is whether the analysis shows a net positive market benefit for the preferred option.

A number of features of the methodology are worth noting as robust:

- The use of chronological modelling in the LT (as well as the ST) phases is a significant improvement compared to the PADR;
- Representation of network constraints were reviewed and verified by the relevant TNSP which mitigates a significant risk that intra-regional constraints will not be adequately assessed;
- The representation of changes in REZ transmission development and associated costs is a robust means to assess the impact of the SAET project on these costs (short of the impractical option of performing a detailed RIT-T for each of these projects within this RIT-T); and
- Use of firm interconnector limits for the modelling is a conservative assumption. Although in the ISP central scenario all major gas plant in SA is shut down immediately and there are no further material savings in fuel cost to be made even if the limit was set higher and therefore the conservative assumption primarily relates to reliability assessments and flows from South Australia.

6 Minimum levels of gas for generation are applied in modelling to reflect assumptions that generators that may be called on to run occasionally for an extended period will find it necessary to contract for a minimum volume and associated transport.

The central scenario drawn from AEMO's ISP study, sees retirement of Torrens B, Pelican Point and Osborne immediately after the SAET interconnector is commissioned. In this case pumped hydro is developed in South Australia coincident with withdrawal of the gas units.

As the analysis is cost rather than price based, ElectraNet has not independently studied the case for these withdrawals from first principles but has run sensitivities which result in different shutdown timings.

In the alternative scenario developed by ElectraNet, all units at Torrens B are shut down by or at the time the SAET proposal is commissioned whilst retaining Pelican Point and Osborne in service, with the ability for these plants to be shut down on the basis of (SRMC) profitability. In this case both Pelican Point and Osborne remain in service through to 2040. It is notable that in this case SRMC operating profitability is well below breakeven for these stations until 2033. ElectraNet advises the model retains them in service in order to meet reserve requirements for reliability at minimum cost in preference to replacing them and building pumped hydro or other plant that can provide firm capacity.

The sensitivities on the central case with Torrens Island B retired in 2026 when it reaches 50 years of service and where Pelican Point and Osborne stations are constrained to remain in service throughout but operating in the same manner as they do in the base case test the impact of different timing for gas station shutdown.

The low profitability underlines the expectation that these plants will be contracted or there will be another mechanism to support them. Alternatively, but untested, that market price outcomes based on commercial bidding will be sufficient to support these plants remaining in service until market conditions related to retirement of coal plants in Victoria and NSW lift SRMC after 2030. This is a bigger risk than the similar argument for the raft of smaller peaking plants that also remain in service. It is a risk that is avoided in the cases in the ISP developed by both ElectraNet and AEMO as none of the large gas stations remain in service in those cases but pumped hydro is developed to provide capacity reserves.

ElectraNet has also assessed a situation in which no pumped hydro eventuates and Pelican Point and Osborne remains in service. If this were to eventuate a means to meet the fixed costs of these stations operating at low capacity factor would be needed. In this regard, ElectraNet advise they consider there are other storage technologies available and a number of government incentives to support development of storage.

## 6.1. Risk factors

On the basis of the evaluation of the cases we have been provided with we sought further information about a series of conditions that potentially risk turning the net benefit in these cases negative. In a number of cases ElectraNet had already prepared sensitivity cases which addressed submissions to the PADR that had also raised a number of these matters. The following describes our considerations.

### 6.1.1. Benefit due to reduced difference between gas and coal costs

ElectraNet's analysis (see Appendix A) shows a major source of the benefit of the SAET preferred option is expected to be from fuel cost savings which raises the question as to what conditions might result in that benefit evaporating? Fuel cost savings are largely based on the difference between the cost of coal and the cost of gas. This gap will be narrowed by a higher cost of coal and/or a lower price of gas.

ElectraNet has tested a wider range of possible gas prices than previously (and wider than was tested in the ISP) of between $7.40/GJ and $11.87/GJ. In the central scenario gas cost delivered to Adelaide was $9.15/GJ. In the central scenario NSW coal prices were taken from the AEMO ISP and ranged from $1.82/GJ in 2024 (expressed in $2018) up to $4.11/GJ in 2040.

The most significant reduction in net benefit associated with fuel costs came from higher cost for black coal in NSW (the principal source of replacement energy for displaced gas). ElectraNet tested a case with the price of coal set to $6.80/GJ for all NSW coal generators taking effect progressively from 2022 to by 2025, extending through to the end of the modelling horizon[7] – also see below for consequential impact of higher cost.

Coincident high gas price and low coal price was not considered on the basis that it is unlikely prices for gas and coal would be negatively correlated.

The range of gas and coal prices tested appears reasonable

### 6.1.2. Early withdrawal of NSW coal plant – tested through higher price for coal

ElectraNet advise that they have tested the potential for early retirement of black coal stations which would reduce the availability for coal to replace gas on economic grounds through the high coal cost sensitivity (i.e. $6.80/GJ from 2025). The impact of narrowing the price difference between gas and coal in this sensitivity was compounded by the model choosing not to undertake refurbishment of black coal plant on economic grounds, reducing its availability to supply South Australia. The net benefit resulting from higher coal costs reduced the net benefit to $71M in the central scenario – See Appendix A.

Testing higher price of black coal does not necessarily test reduced availability but coupled with analysis of the impact of refurbishment costs does adequately test reduced availability in this case.

### 6.1.3. Early withdrawal of Victorian Brown Coal

Early retirement of Yallourn W PS, currently assumed to be on the basis of age in the early 2030s could reduce the availability of energy to flow into South Australia.

ElectraNet advises it considers that the risks of early Yallourn retirement would be no more significant to the benefits of the preferred option than the early retirement and increased costs of black coal in NSW. In the black coal sensitivity, a greater quantum of black coal is removed than the installed capacity of Yallourn (1,400 MW). For example, in the black coal sensitivity, by 2027 over 3,400 MW of black coal has been retired earlier than compared to the base central scenario.

This assessment is reasonable

### 6.1.4. Higher project costs

The other key mechanism by which the net positive benefit might be reduced or go negative is if costs for SAET are higher. ElectraNet advise that they have assessed the potential for costs to be 25 per cent higher in a sensitivity on the central scenario and found that the net benefit remains positive, at $589M - see Appendix A.

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7 The value in a submission from NSW generator to the PADR

### 6.1.5. Explicit carbon price & international offsets

ElectraNet has not included specific consideration of a carbon price and therefore a reason to consider international offsets being reapplied in the Australian electricity sector. A carbon price would also narrow the gap between gas and coal as it would add more to the price of coal than to the price of gas. However, ElectraNet note that the low scenario has no emission reduction target and this would be similar to the effect of very low priced emission certificates and also that the higher coal price sensitivity closes the gap between coal and gas in the same way as a price on carbon would.

Our expectation is that only a very high price on carbon is likely to have a significant impact but have only quantitatively assessed this point at a very high level.

### 6.1.6. Snowy 2

Development of Snowy 2 will require additional transmission within NSW as noted in AEMO's ISP. ElectraNet consider that these developments will remove a number of constraints within NSW that are having some effect on the SAET project and will therefore reduce the cost of the SAET project in isolation and reduce network constraints beyond Wagga Wagga thereby increasing the calculated net benefit of the SAET.

Put another way, network augmentation will be required to facilitate Snowy 2. Both Snowy 2 and the SAET projects will benefit. For this reason, explicit assessment of the impact does not appear necessary.

### 6.1.7. Will pumped hydro be developed in time or to the degree anticipated?

In the central scenario, pumped hydro storage of 700MW is built by the model by the time the SAET preferred option is commissioned. We consider it will be prudent to consider the impact if this level of build does not occur or is delayed. In this regard, ElectraNet notes the significant number and scope of potential storage options listed on AEMO's website (1,750MW at the time of writing) and a confidential submission to the SAET RIT-T. In addition, ElectraNet notes the number and scope of SA government support and incentive programs that will support development of levels of storage in excess of the model's requirements. These give ElectraNet confidence about the probability that this level of storage will occur, albeit not all being longer duration pumped storage.

Nevertheless, ElectraNet has modelled sensitivities with no pumped hydro and with Pelican Point and Osborne remaining in service with the same output as in the base case (a conservative assumption, as there is no fuel cost saving) but needing a funding mechanism as discussed earlier. In these sensitivities the net benefit is reduced but remains positive, at $608M and $172M respectively – see Appendix A.

The reason for our concern about development of pumped hydro is that the modelling forecasts a significant amount and we consider there is a risk that all of the commercial, regulatory and environmental approvals for this amount of a technology new to the state and in some cases new to the NEM (e.g. sea water pumped hydro) will eventuate by the time assumed.

As noted, the basis for the central case to install pumped hydro is to provide capacity to meet the reserve margin. Pumped hydro does not appear in the alternative build sensitivity until 2036. In the event pumped hydro installation were delayed ElectraNet anticipate that other storage options could be developed with an increase in cost over pumped hydro – also see section 6.1.10 in respect of potential over-reliance on storage for high impact low probability combinations of interconnector outages.

### 6.1.8. Retention of minor gas and liquid fuelled generation plants in South Australia (and elsewhere)

In the cases we have reviewed the profitability of all peaking gas plants in South Australia is very low, well below covering fixed costs. This is understandable given the SRMC basis for the analysis, which as noted does not consider market bidding behaviour and is therefore a very conservative assessment of profitability. We understand these units are retained in service in the model in order to meet reserve margins at least cost.

ElectraNet advise that their assumption is that cap hedging contracts (or presumably the equivalent within vertically integrated gentailers) will be available to cover the costs of these units in the future in the same way they are today. Failing this, other forms of contract or revenue sources will be needed to support the costs of these units and these will be common to both the with and without cases. ElectraNet also advise of price based modelling undertaken for other purposes that shows these units would be profitable in their own right and this adds to their confidence.

Without suggesting which mechanism is more likely our view is that it is a reasonable assumption that the costs of the units needed to meet reserve margins will be covered and accordingly accept that these costs will be covered in both base and option cases. Their capital and operating costs are appropriately accounted for in ElectraNet's modelling. We also note that as this assumption is made in both the with SAET and without SAET cases the cost of the support for the costs of the peakers may not affect the outcome of the RIT-T. However, the SAET is likely to change the profile of market prices in SA and reduce the incidence of price spikes and therefore the price of the cap contracts. This has not been directly assessed.

### 6.1.9. New entrant battery and pumped hydro storage is operated at low capacity factors

ElectraNet advise the model is adding pumped hydro storage often to satisfy reserve margins at least cost. For similar reasons to the retention of smaller gas plant (see above) there is an assumption that one of a number of mechanisms will provide support to cover costs. As noted, this is an assumption but is reasonable in the circumstance as it relates to minimum reserves for reliability.

### 6.1.10. High Impact Low Probability threat to reliability

In scenarios and sensitivities that assume all major gas plant in South Australia is retired, the reliability of the South Australian grid will be dependent on a combination of peaking generation, interconnector flow, wind generation, solar and storage. The modelling has assessed the capability to manage peak loading conditions but only average energy production conditions.

Although it is a low probability, the potential for two of the four circuits of the two large interconnectors (SA to Vic and the proposed SA to NSW) to be out of service simultaneously in combination with storage being exhausted under low wind conditions would mean that high South Australian demand would not be able to be met.

Such a combination of conditions would constitute, a new high impact low probability condition for the region. It is also an indicator for the future in other regions of the NEM as technology mix changes, but as with a number of other developments, be seen in South Australia earlier than elsewhere. In particular, the region would be subject to short term energy and capacity constraints driven by availability of a smaller number of larger sources of supply than today. However, ElectraNet advises that the demand that creates exposure to this type of risk in South Australia occurs only around 1 percent of the time which when coupled to the probability of demand and network conditions highlights its status as a high impact low probability condition..

Further, the sensitivity referred to earlier (see section 6.1.7) whereby Pelican Point and Osborne remain in service would address any resultant gap if reliability of supply is to be protected from such as situation as a matter policy. Also as noted that sensitivity is conservative in that no allowance for reduction in gas use at these stations due to the introduction of the SAET proposal is assumed, resulting in a lower net benefit of $172M – see Appendix A.

Alternatively, additional peaking thermal generation units could be constructed. Although not considered on the basis of current cost, in the longer term, solar thermal may also be able to play a role in meeting this gap depending on the duration of its storage.

### 6.1.11. Is the modelling horizon and terminal value methodology appropriate?

The benefit of a longer modelling horizon is that modellers can be sure the results have reached a stable result year on year which is more likely if the cost of plant and fuel is relatively stable, demand is changing slowly and there are no major policy shifts in the last couple of years or are expected just after the end of the horizon. A very long horizon means that after discounting the effect on the NPV of costs and benefits at the end of the horizon is reduced. When, for logistical reasons, shorter modelling horizons (e.g. well less than the asset life) are used it is important to incorporate the impact of costs and benefits after the end of the modelling horizon – a terminal value. In the cases we reviewed there is still some volatility in benefits at the end of the horizon, highlighting the importance of terminal value. However, ElectraNet advise that the rankings between options have stabilised if the modelling runs only to 2040.

In practice, there are a number of approaches used in economics to determine terminal value. ElectraNet has adopted a terminal value based on the discounted undepreciated cost of the SAET project after 2040 in line with one of the approaches described in assessment guidelines including Infrastructure Australia.[8] Factors such as the duration of analysis relative to asset life and whether the asset is already a regulated asset and the materiality of the resultant terminal value are relevant consideration for a RIT-T.

Our preference is that in the circumstances of a RIT-T for long duration assets seeking regulated status the terminal value should be grounded in an assessment of benefit beyond the end of the modelling period, which is also consistent with approaches described in the same assessment guidelines. We note that while the discounted undepreciated cost approach adopted by ElectraNet is not directly related to the benefits, we and ElectraNet have each assessed the value based on benefit at the end of the horizon and find that it is greater than the value used by ElectraNet. As a result the net benefit used by ElectraNet is based on a terminal value at the conservative end of the range supported by financial guidelines. It is also notable that in most sensitivities ignoring the terminal value does not make the net benefit less than zero.

### 6.1.12. The REZ transmission concept is not incorporated in the National Electricity Rules

A matter identified in submissions to the PADR was that ElectraNet's analysis (as well as the ISP) assumed development of Renewable Energy Zones (REZs) which are not yet recognised in the NER. However, recent guidance from the AER (RIT-T Application guidelines) is that a RIT-T should account for potential REZs and also results of AEMO's ISP).

8 https://infrastructureaustralia.gov.au/policy-publications/publications/files/Infrastructure_Australia_Assessment_Framework_2018.pdf

### 6.1.13. The net benefit is understated because new REZ developments are emerging

The risks discussed so far have been focussed threats to achieving the net benefit in the central scenario. We note there are also circumstances where recent developments may overtake the modelled assumptions and result in higher rather than lower benefits.

Since the preferred option of the SAET proposal was announced proponents of developments in the south west of NSW have put forward proposals for greater levels of development than have been assumed in the RIT-T modelling. These proposals would require additional transmission to be developed over time. The SAET would see some of this development occurring earlier rather than being required exclusively for the SAET project. The cost of the SAET would need to carry costs for earlier development or possibly a share of the total, but not the full cost. As a result, the net benefits of the SAET proposal would increase.

### 6.1.14. Broader industry context

Outside the scope of a RIT-T and our review, but important for the industry in a time of major change, we note that markets such as the NEM can create incentives for the amount of entry and exit, but are not necessarily good at coordinating timing to avoid periods of over or under supply.

This is a matter beyond the control of ElectraNet and very difficult to incorporate within the framework of a RIT-T. Where shutdown of large amounts of generating capacity are being predicted it highlights the need for close monitoring and appropriate action by relevant government and market authorities.

As a result, our concern about pumped hydro development and the shutdown of all gas fired plant may ultimately be one of coordination of timing. As noted, ElectraNet does not directly control the timing of withdrawal or the development of market generation or demand side facilities and the mechanism to retain these plants in service would need to be developed within the market or broader regulatory government mechanisms which we note are matters currently being addressed through the ISP and the work of the ESB.

## 6.2. Identified risks have been addressed

We have identified a series of risks to the net benefit being lower than ElectraNet's central scenario. We consider that each has been quantitatively assessed where practicable or alternatively qualitatively argued to not be of material risk of leading to a net negative benefit.

We have also noted management of some of the risks relies on factors outside the control of ElectraNet but that there are processes in train through AEMO's ISP and the ESB that would manage the risks in these areas and it is therefore reasonable for ElectraNet to rely on these processes.

# 7. Conclusion

In this work our task has been to:

- Review the modelling framework used by ElectraNet in assessing the benefits and costs of the South Australian Energy Transformation (SAET) proposal for additional interconnection between South Australia and New South Wales (specifically Option C 3): and
- Provide our independent opinion of its fitness for supporting the Regulatory Investment Test for Transmission (RIT-T) for that project.

Our review has assessed:

- The modelling methodology, which we found to be fit for purpose although we also noted the importance of the design and conduct of scenarios and sensitivities to test the robustness of the modelling outcomes to alterations in the inputs regarding and assumed conditions under which the project would operate (the devil in the detail);
- The plausibility of detailed results from the central scenario and one of sensitivities (based on different starting point for the retirement of gas-fired plant in South Australia). We consider these are plausible in that the results are consistent with expectations for the methodology and inputs; and
- A number of risks that we have identified that could reduce the net benefits. ElectraNet has adequately assessed these quantitively or qualitatively.

The key risk that has not been evaluated quantitatively is a matter that is inherent in the RIT-T process and relates to the central role of SRMC based modelling. This is that the number of generating units found by the modelling to be needed to underwrite reserve margins will be commercially viable. ElectraNet has qualitatively assessed that they will be, and there is good argument this is correct, especially for existing peaking units which are already operating with very low revenue relative to cost. For units such as Pelican Point and Osborne our view is that it is possible other new mechanisms may be needed, but that it is reasonable to assume that sufficient capacity to support reliability will be adopted. Further it is reasonable for a RIT-T analysis to presume a least-cost approach will emerge. Accordingly, it is our view that the risks we have identified have been adequately addressed.

We have also commented on a number of matters outside the scope of a RIT-T modelling analysis but which have the potential to impact the broader market framework within which the RIT-T sits. These include:

- The speed and size of change within the industry and whether market responses will be sufficiently coordinated to ensure reliability of supply is maintained as the modelling suggests. This is matter beyond a single RIT-T or a single network business, only government or market authorities can manage this risk and we have noted is central to the work of the ESB and AEMO's ISP;
- Whether assumptions about development, including regulatory and environmental approvals for the scope, type and timing of pumped hydro appearing in central scenario can be realised. ElectraNet has addressed this risk in sensitivities; and
- Whether high impact low probability (HILP) conditions that could impact state-wide reliability under extreme conditions should be accounted for in the standards that are an input to RIT-T modelling but are beyond the current standards. ElectraNet has included analysis of the level of exposure to such HILP events in its modelling report.

## Appendix A: Summary of scenario and sensitivity outcomes

| Scenario/Sensitivity | TOTAL | Capital cost | Terminal value | Planned routine maintenance & refurbishment | Difference in timing of unrelated expenditure | Difference in timing of unrelated expenditure | Fuel consumption from generation dispatch | Voluntary load curtailment | Costs for non RIT-T proponent parties | Costs for non RIT-T proponent parties | Costs for non RIT-T proponent parties |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Renewable Energy Zones | ISP Build Limits - Transmission | | | Storage Build Costs | Generator Annualised Build Cost | Generator FoM |
| Central scenario | 766,678,935 | -1,244,109,256 | 279,502,324 | -12,448,457 | 96,492,764 | 10,271,596 | 1,791,529,087 | 778,495 | -420,912,768 | 110,038,249 | 155,536,901 |
| Central - Coal retirement and price | 71,840,174 | -1,244,109,256 | 279,502,324 | -12,448,457 | 172,638,131 | 10,271,596 | 836,716,274 | 53,706 | -242,483,128 | 141,334,664 | 130,364,320 |
| Central - Higher project costs - 25% | 584,860,840 | -1,482,388,562 | 337,151,676 | -13,636,597 | 96,492,764 | 10,271,596 | 1,791,529,087 | 778,495 | -420,912,768 | 110,038,249 | 155,536,901 |
| Central scenario - batteries replace pumped hydro | 608,118,975 | -1,244,109,256 | 279,502,324 | -12,448,457 | 96,492,764 | 10,271,596 | 1,791,529,087 | 778,495 | -579,472,728 | 110,038,249 | 155,536,901 |
| | | | | | | | | | | | |
| Central - Early TIPS B retirement (retires at 50 yrs ) | 526,807,115 | -1,244,109,256 | 279,502,324 | -12,448,457 | 96,492,764 | 10,271,596 | 1,622,035,833 | 778,495 | -420,912,768 | 110,038,249 | 85,158,335 |
| Central - Pelican and Osborne base case operation | 172,412,791 | -1,244,109,256 | 279,502,324 | -12,448,457 | 96,492,764 | 10,271,596 | 699,034,483 | 778,495 | 77,315,692 | 110,038,249 | 155,536,901 |
| | | | | | | | | | | | |
| ElectraNet Alternative | 128,781,345 | -1,245,030,977 | 279,719,195 | -13,636,597 | 96,492,764 | 10,271,596 | 650,009,511 | -1,121,955 | 86,502,656 | 110,038,250 | 155,536,901 |

Source: ElectraNet