Delta electricity

ElectraNet
PO Box 7096
Hutt Street Post Office
ADELAIDE SA 5000

Submitted via email: consultation@electranet.com.au

31 August 2018

South Australian Energy Transformation RIT-T: PADR Submission

Delta Electricity is pleased to provide its comments on the South Australian Energy Transformation Project Assessment Draft Report (PADR). Delta owns and operates the 1320MW Vales Point power station in NSW and is licensed to sell electricity to large customers across the National Electricity Market (NEM). Delta has operated coal and gas fired generating plant in the NEM since its start in 1998 and is an active participant in both the electricity and gas trading markets.

Large transmission projects are costly and long lived. It is critical, therefore, that the Regulated Investment Test -Transmission (RIT-T) process include the maximum rigor in assessing economic net benefits for a large spread of possible future scenarios to ensure there is a high degree of certainty that benefits will flow across the full life of a project. This is particularly challenging in a period when the electricity market is rapidly transitioning to low greenhouse gas emissions, and when there is a high degree of uncertainty around future generation mix and energy storage technologies.

In an environment of significant change, there is a high risk that the modelled economic benefits will not be realised and/or the project could end up delivering a costly 'stranded asset'. Delta's view is that this is highly likely beyond 2030 given the anticipated shift in the generation technology mix in NSW, Queensland and Victoria. Retiring coal fired power stations in these regions will remove the low-cost supplies that provide the majority of the benefits to the project. This risk is reinforced by the 2018 AEMO Electricity Statement of Opportunities, which highlights that new generating plant will be needed in NSW to maintain reliability once Liddell retires in 2022. The plant that replaces retiring coal fired power stations is very likely to be gas plant which would result in generation costs increasing to match those in South Australia, thereby negating any benefit to the market.

It is Delta's view that the PADR does not present a sufficiently compelling case in support of the recommended $1.5b option for a new SA-NSW interconnector. This view is supported by a comprehensive independent review of the PADR by Marsden Jacob. The report by Marsden Jacob is included in this submission as Attachment 1. Delta's primary concerns revolve around the size of the estimated net benefit, modelling assumptions, inequity in the distribution of costs compared to benefits, and the risk of a stranded asset. These concerns, and suggestions for additional modelling and provision of information, are described herein.

Project Cost and Options

The proposed SA-NSW interconnector has a 920km route length with an estimated capital cost of $1.5b based on a preliminary design only. The cost estimate uses a standardised approach that does not appear to take account of the unique challenges and costs related to its location. For instance, there are likely to be significant hurdles related to environmental approvals and obtaining new easements. Given that the net benefits assessed under the central case are modest compared to the capital cost, an independent assessment of the potential for a material cost overrun should be performed.

The PADR has responded to concerns about the limited number of options assessed, and their considerable size in terms of capital cost and capacity. The information provided suggests the preferred option will not be greatly utilised in terms of average MW flows. This is evident in the modest net benefit of the central case and by the fact SA is frequently a net exporter of energy. A 750MW increase in interconnection appears to be a massive over build for the benefits identified. A smaller, lower cost, option may not necessarily deliver the highest returns in the modelling undertaken, but it will deliver most of the benefits at a greatly reduced risk to consumers.

Delta supports a re-assessment of the less grandiose options identified in the initial consideration of upgraded SA interconnection, in light of the outcomes of the RIT-T assessment. For example, it is likely that net benefits can be gained from a less ambitious project that strengthens the existing network in southern NSW in combination with ElectraNet's Option C1.

Assessment of benefits

Delta questions the veracity of the $1b assessed benefits from the preferred option. The first order[1] benefit is identified as avoided fuel cost. This is high cost SA gas generation being displaced by lower cost coal fired generation in NSW and QLD. There is a serious deficiency in the quantification of this benefit, being the low assumed NSW fuel cost[2] under the 'neutral' and 'high coal cost' scenarios. NSW generators are exposed to export parity prices for their fuel requirements. The current Newcastle Port price for thermal coal is currently above $5.30/GJ[3] and is not projected to fall back to levels assumed by ElectraNet. Any additional NSW coal-fired generation arising from the SA-NSW interconnector will have a marginal cost linked to the export coal price, and the RIT-T reference case should reflect this reality. A high coal cost scenario would need to apply at least a $1.50/GJ uplift to current export parity pricing given historical price variances.

The PADR[4] states that, in response to submissions that expressed concern about SA system security if SA gas plant were to close, "the modelling ensures that under each of the interconnector scenarios, system strength is maintained at the Robertstown node through either synchronous generation or network solutions, such as synchronous condensers". This is not a surprising result given that the generator expansion modelling

[1] South Australian Energy Transformation. Adelaide Public Forum presentation 18 July 2018, page 30.
[2] SA Energy Transformation RIT-T Market Modelling Report, 29 June 2018.
[3] KPMG 'Consenus' Coal Price and FX market forecast June/July 2018 (Newcastle thermal coal)
[4] SA Energy Transformation Project Draft Assessment Report, 29 June 2018, p.39.

data indicates that under all scenarios there is at least 1800MW of thermal gas/liquid fuel capacity remaining available in SA. However, this statement on system security may not hold true if the major SA gas power plants close due to the projected lower market prices.

The point raised in earlier submissions about the closure of gas plant in SA does not appear to have been addressed. The SA region currently has an average system demand of around 1400MW, 850MW of interconnection, 2200MW of large scale renewable generation (currently) and 2800MW of gas plant that runs at very low capacity factors. Adding another 750MW of interconnection makes the closure of major SA gas plant a realistic scenario. This is a scenario that should be assessed because of the high cost associated with maintaining system security and reliability if the SA to NSW interconnector trips. These costs are likely to be material as AEMO's RERT response could require large ongoing payments to keep the existing gas major plants available on system standby.

Marsden Jacob has identified a number of issues related to the NSW to SA power transfer limits (p.5). This detail is critical because any restriction in NSW to SA transfer capacity will materially affect the assessed benefits from the dispatch of lower low-cost coal generation displacing SA gas plant. In relation to transparency of information, Marsden Jacob is of the view that there are insufficient modelling results published to allow stakeholders to confirm the conclusions reached in relation to the preferred option. Delta recommends that more detailed modelling results be published along with a thorough assessment by AEMO of any impact on NSW import/export capability.

Inequity in consumer electricity costs compared to distribution of assessed benefits

The PADR[5] states that NSW's three million residential customers will benefit from a $20/annum reduction in their electricity bills. This is a dubious figure at best and appears to be based on the new interconnector enabling low cost renewable generation displacing higher cost conventional generation[6]. The ACIL Allen report reference case forecasts consistently higher prices in SA compared to NSW[7]. A direct interconnection between the States will, on average, bring prices together. SA prices should fall, but NSW prices should rise. The amount of new renewable generation in the NEM will ultimately be driven by greenhouse gas abatement targets and any economic benefits that flow from this new renewable generation cannot be attributable to a new interconnector.

Of the $1.5b capital investment, it is estimated that close to $1b will be invested in NSW assets. It is understood the cost of the NSW part of the project will most likely be recovered from NSW electricity customers over the life of the project. The PADR is quite clear in its articulation of the project's benefits being lowering dispatch costs in SA and enhancing the security of electricity supply in SA. On this basis it appears inequitable that NSW electricity customers shoulder two thirds of the cost. Should the project proceed, it is recommended that the project be conducted in way that the cost of the

[5] SA Energy Transformation Project Draft Assessment Report, 29 June 2018, p.3.
[6] SA Energy Transformation Project Draft Assessment Report, 29 June 2018, p.27.
[7] ACIL Allen South Australia - NSW Interconnector Preliminary Analysis of Potential Impact on Electricity Prices, p.7

project is allocated between ElectraNet and TransGrid in proportion to the net market benefits obtained by consumers in the relative States.

In ElectraNet's low and central scenarios the benefits are only around $400m, compared to a capital cost of $1.5Bn. An increase in the capital cost of the project by 25% would likely eliminate the net market benefits. Since material cost over-runs can occur in infrastructure projects it is crucial that consumers are not exposed to this risk. If the project proceeds it is critical that the regulated asset value of the interconnector, on which transmission company revenues are determined, should not exceed the cost used by ElectraNet in assessing the market benefits. This would provide some comfort to stakeholders that at least a small amount of risk will be borne by the project proponents.

Modelling Scenarios and Sensitivities

As noted by Marsden Jacob (p.7), the assessed scenarios fall within a narrow narrative of NEM outlooks. With considerable uncertainty around energy and carbon emission reduction policy, and its impact on future generation mix, a very broad range of assumptions and scenarios should be fully assessed. For example:

- an earlier closure of Yallourn Power station would shift higher generation to NSW generators and reduce the quantity of avoided fuel costs;
- if coal prices in NSW continue to rise the current high coal cost case effectively becomes the base case assumption;
- an early development of the "battery of the nation" initiative will reduce the avoided fuel cost benefit;
- if AEMO determines a minimum amount of reliable dispatchable gas generation in SA (given the NSW intra-regional constraint) a range of assessed benefits will be reduced;
- if NSW implements the equivalent of VRET there will be early closure of NSW coal fired generation; and
- if the South Australian Government fully implements its policy to deploy up to 450MW of residential batteries this will have a material negative impact on the assessed benefits.

Delta encourages ElectraNet to broaden the analysis with additional scenarios, rather than additional sensitivity analysis. By examining the impact of a different assumption as an individual sensitivity, the PADR will still present a picture of only positive net returns for all scenarios associated with the preferred option. This picture is disingenuous. An improved assessment of project downside would be new scenarios that combine changes in assumptions that have a reasonable likelihood of occurring. For example, combining the SA government's battery policy with a reduced coal to gas price differential would almost certainly produce a net negative NPV. This scenario is realistic as coal costs are predicted to remain much higher than that assumed in the modelling and the new SA Government is proceeding with its battery policy. A more comprehensive list of scenarios will provide an improved insight into the 'stranded asset' risk faced by electricity consumers.

The RIT-T guidelines allow for the use of market modelling that incorporates commercial behavior where it is warranted. Delta believes that since the benefits from this project are largely based on cost advantages, though reliability costs should also be included, modelling should consider scenarios with realistic generator dispatch bidding rather than SRMC dispatch bidding. In addition, ElectraNet should examine the likely commercial outcomes for different generation based on profitability under the full range of future scenarios. This is particularly critical as the assumed closure dates may change.

Deferred network investment benefit

The PADR attributes benefits to the project from the deferral of Renewable Energy Zone (REZ) transmission works. Delta believes these benefits should be excluded. The idea of REZ's were supported by the Finkel review and have been evaluated by AEMO as part of its Integrated System Plan (ISP). However, Delta notes that there is no firm proposal to construct transmission to these zones. AEMO's ISP is itself currently only a proposed system development plan. It is far from being accepted as a definitive plan and even further from being implemented. Therefore, the inclusion of benefits from the ISP is highly speculative. Delta recommends that transmission deferrals only be contemplated for approved projects. This is a similar approach applied to committed generation in the non-network option, which only contemplates advanced generation proposals.

Anthony Callan
Executive Manager Marketing

Attach:

MARSDEN JACOB ASSOCIATES

30 August 2018

Review of Riverlink RIT-T undertaken by ElectraNet

Marsden Jacob Associates (Marsden Jacob) is pleased to provide this independent submission to Delta Electricity in relation to the review of the RIT-T material and modelling that has been published by ElectraNet as part of the South Australia – New South Wales Interconnector RIT-T process.

This submission presents a review of the ElectraNet RIT-T process and modelling for the purposes of providing opinion and recommendations on matters relevant to this RIT-T application.

About Marsden Jacob

Marsden Jacob is one of Australasia's leading economic consultancy firms that provides independent research and analysis on economic, financial and public policy issues in areas that include energy, water, transport, agriculture and public policy.

Andrew Campbell of Marsden Jacob undertook the review presented in this submission. Andrew has provided advice on the RIT-T since its inception, has undertaken modelling as part of RIT-T applications, and has undertaken numerous least cost and market simulation modelling of the NEM since its inception.

As a prelude to this review, Marsden Jacob acknowledge the work of ElectraNet and their efforts to laisse with interested parties and stakeholders through public information sessions.

All parties appreciate there is a lot at stake here and that future market efficiency requires processes that provide for informed decisions. A vital part of such processes is transparency that provides for a full understanding of the key drivers (in this review, the costs assumed and the basis of the economics and assessment approach).

Material reviewed

This submission involved reviewing the relevant reports published by ElectraNet, and related reports, and attendance at the "deep dive" session held by ElectraNet on 17th August 2018.

A list of the reports reviewed is presented in Appendix 1 of this submission.

Structure of this review

The review has been structured in the following order (consistent with the logical development of a cost benefits analysis):

- Characterisation of the increased transmission that the respective projects provide to the market, and project costs;
- The suitability of the scenarios selected to cover the range of reasonable market outcomes and the suitability of the modelling approach used;
- The consistency of the modelling results to the described economic logic;
- The assessed market benefits;
- Review of process and transparency.

Notes to this Submission

The "project" refers to the proposed SA-NSW interconnector being considered.

Riverlink refers to the preferred project Option C3i.

Extracts from stated reports are presented as indented and smaller text.

Abbreviations used

South Australia Energy Transformation	SAET
Project Specification Consultation Report	PSCR
Project Assessment Draft Report	PADR
Project Assessment Conclusions Report	PACR
Market Modelling Approach and Assumptions Report 21 December 2017	MMAAR
Market Modelling Report 29 June 2018	MMR
Network Technical Assumptions 29 June 2018	NTAR

Key Findings and Recommendations

The review concluded that the benefits ascribed to Riverlink have not been demonstrated. The reasons for this are detailed in this report and include the following:

- There has been insufficient information released on key matters required to support the economics (expressed as a project NPV) presented. Potentially serious issues with the modelling and calculation of benefits were identified and include:
  - the change in transmissions limits to and from SA and Victoria on the combined NSW-SA and NSW-Victoria (notional) interconnectors;
  - the economic basis of new entry supply (solar, wind, storage);
  - assumptions regarding NSW coal power station costs to increase production levels;
  - the basis of REZ transmission saving, when no detailed transmission assessment work was presented;
  - the modelling methodology used.
- Potential inconsistency between model outcomes and market benefits presented;
- The scenarios modelled does not provide for the potential range of reasonably foreseeable scenarios; and
- The allocation of Riverlink benefits to NSW is based on the assumption that flows on Riverlink relate to flows to / from NSW consumers, which is not supported.

It is the view of Marsden Jacob that before consultation on the PADR can be finalised and a determination made on the RIT-T the following recommendations be adopted by ElectraNet:

- the full modelling information and results be released to stakeholders for comment;
- an independent review into the modelling be undertaken which should specifically address the impact the project has on the change in all transmission limits, NSW coal costs, a clear description of the modelling approach and assumptions, and a wider spread of scenarios that covers the reasonably foreseeable range of scenarios;
- additional modelling be undertaken, if necessary, to address any issues identified by stakeholders and by the independent reviewer.

Review Commentary

1 Summary

Project characterisation

The project characterisation is limited to (1) Riverlink line flow limit, and (2) the combined Heywood and Riverlink import and export limit to / from South Australian (SA). There is no information provided on the change in combined Riverlink and NSW-Vic limits, and no information on how the limits provided change with conditions. For example, not provided was the combined limit of Riverlink and Victoria to NSW flow limits.

Project costing

While the use of terminal value is within proper practice, and given that Riverlink is a long-life asset investment, the study needs to provide an assessment of its economics post year 21.

The sample of scenarios

The scenarios used fall within a narrow narrative of NEM outlooks. As illustrated in this report, a simple review of uncertainties revealed additional reasonable scenarios that could exhibit different economics compared to the scenarios used.

The original workplan provided by ElectraNet in 2017 included a Phase 2 where a wider set of scenarios would be considered however, this did not occur. Failing to consider the full range of reasonable scenarios creates a high risk that the economics of Riverlink presented will not be representative and consumers may be required to pay for an asset that is uneconomic.

Key modelling assumptions

A number of assumptions have been made that have not been explained. These include

- coal prices and the capability of the NSW coal power stations to increase production. This was fundamental to the gas savings reported;
- the basis of REZ transmission costs and the how Riverlink impacts these costs. This was fundamental to the economics of renewable generation location;
- the economic basis for battery development.

Modelling approach

While the model and approach used (at a high level) are consistent with RIT-T guidelines, the representation in a number of aspects needs to be clarified. This includes the use of unspecified reserve margins in the least cost modelling, reducing generation (coal and possibly gas) capacity to match historical generation levels, and undertaking the price impact modelling on a different basis than that for the market benefits assessment.

While the modelling was stated as having the same assumptions as the AEMO ISP in "all material aspects", the results are different in meaningful ways. It is suspected from the material released that this relates to the modelling approach.

Based on Marsden Jacob's extensive modelling experience, these issues threaten the veracity of the results obtained.

Modelling results and market benefits

Basic information on the results of the modelling has not been provided, thereby limiting the understanding of the economics and how this was achieved. This includes project utilisation, dynamics of gas reduction, change in VRE development and location.

The requirement for full release of modelling information is essential as the results of the modelling, such as how SA maintains a secure system with Riverlink replacing Torrens Island, require explanation.

The limited release of modelling data is also not consistent with the stated need and value by ElectraNet of transparency.

2 Project Characterisation

Utmost amongst the essential elements of a RIT-T cost-benefit analysis (CBA) is the accuracy of the characterisation of what the project provides to the market. It is this level of service, as described by the change in transmission limits, that is being valued. An error in this characterisation could lead to commensurate error in the assessment of the benefits delivered by the project. This can lead to inefficient development of transmission assets with subsequent negative efficiency impacts on generation investment.

This section reviews the technical description and change in transmission limits provided by the preferred project (C3i).

Project C3i

The PADR describes the project and the components of the project. While not repeated here this consists of works from Robertstown to Wagg Wagga (and no transmission upgrades beyond Wagga Wagga). The issue of costs and terminal value are addressed in the next section.

Transmission limits (inter-regional and intra-regional) are security limits that limit generation dispatch outcomes such that the system remains secure following a critical continency.

Interregional limits define the flow limits on (notional) interconnectors. The dimensions to these limits are as follows:

- The directional flow limits on the notional interconnector (which is an import to one region and an export to another region noting losses have flows at each end slightly different);
- The directional combined flow to a region when there are two or more interconnectors.

The increase in transmission limits (such as provided by Riverlink) is defined through:

- The increase in interregional line flow limits; and
- The increase intra-regional flow limits (that would define combined line flow limits).

The NEM interconnector representation between NSW, Victoria and South Australia is shown in Figure 1. The numbers in the figure show the line limits.

References to the limits associated with Option C3i are as follows:

- Interconnector flow limits[1] (Section 1.3 NTAR Table 1[2])
  - Heywood: 750 MW
  - New Interconnector: 800 MW

[1] Referred to as "Notional Maximum Capability (MW)"

[2] This section states "Table 1 identifies the notional maximum capability of interconnectors – both the Heywood interconnector and a new interconnector (under different options) – in the economic modelling. These values should be used as a guide on the maximum possible power transfer capability of the interconnector under favourable operating conditions."

- Combined Limits C3i (Section 3.4 NTAR Table 53)
  - Combined Import limits (Heywood improvement) 1300 MW
  - Combined Export limits (Heywood improvement) 1450 MW
- Section 5.5.2 NTAR

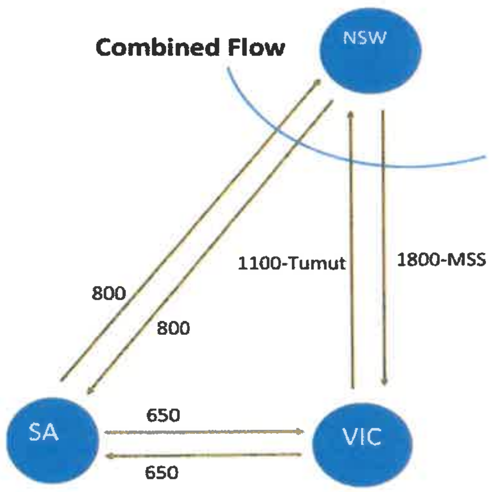
  Intra-regional issues in NSW do not specifically affect the NSW to Robertstown thermal capability and goes on to say …

  Preliminary view of any significant impacts on other interconnector capability

  - Unlikely to impact on QNI transfer capacity
  - NSW-SA interconnector flow may be limited by the NSW-VIC and VIC-SA transfer limits under certain conditions
  - NSW-VIC and VIC-SA transfer will need to consider the trip of one circuit of NSW – SA interconnector.

Figure 1 Representation of Riverlink

NEM Regional Representation



Combined limits

The TNAR only specifies the combined limits for flow to and from SA:

Max SA export (SA-Vic + SA-NSW) = 1450 MW

Max SA import (Vic-SA + NSW- SA) = 1300 MW

The TNAR does not specify the combined limits for flow to and from NSW, other than the qualified statements in Section 5.5.2 of the NTAR.

The PADR and TTAR only present the interconnector line flow limits and total South Australian export and import limits due to all interconnectors connected to SA. To the knowledge of the author there are no combined limits to and from NSW (excluding QNI) presented in the PADR or the TNAR (or any of the other reports).

Figure 2 presents a simplified diagram of the physical constraints associated with interconnection limits between SA, Victoria and NSW4. This shows that by terminating at Wagga Wagga, flows from Riverlink are subject to the same transmission limits to NSW (reference node) as the existing Vic-NSW interconnector. Importantly also, by terminating

[3] This section states "The total combined import limit (Heywood + new AC option) is set by the amount of allowable load-shedding, battery injection, and transient limits for the new interconnector for loss of the Heywood interconnector, except for the 500 kV and HVDC Queensland."

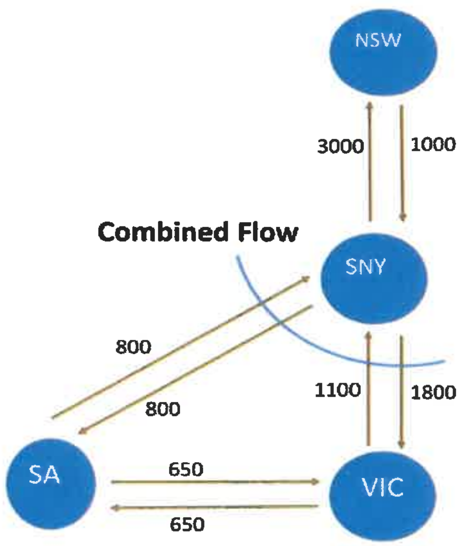
[4] This mirrors the regional representation prior to the abolition of the Snowy region.

at Wagga Wagga, it is not stated how much additional firm capacity (under all conditions) is available to SA and Victoria from NSW (including Snowy Hydro).

In summary there is no quantification presented on the increase in import limit from NSW to the combined Victoria / SA region associated with Riverlink. This was recognised by ElectraNet at the "deep dive' session.

Figure 2 Representation of Riverlink

Physical Representation



Combined flows

The characterisation of Riverlink does not specify the limit on flows from NSW and Snowy generators to the combined SA and Victorian region.

The representation of the combined limits of the Vic-NSW and SA-NSW interconnectors are a most important issue and should be stated. The following are required:

- The net increase in limit to SA (across the cut set of Heywood and SA-NSW interconnector) under various conditions;
- The net increase in limit to NSW (across the cut set of Vic-NSW and SA-NSW interconnectors) under various conditions;
- How this was precisely represented in the modelling.

Any overrepresentation of capacity would result in an overvaluing of the project(s).

3 Project Costs

This review makes no comment on the capital and operating costs of the project options. These costs are required to be costs that would reflect a competitive tender process.

We make comment on the approach to limit the cost-benefit analysis to 21 years and to ascribe a terminal value at the end of assessment period. This assumes that the NPV of the project from year 22 to the end of the project life is zero. Of course, if evaluated, the NPV over years 23 to 50 could be either positive or negative.

From the deep dive session on 17th August 2018 ElectraNet stated that, had a terminal value of zero been ascribed, option C3i would continue to be economic and the preferred project.

This needs to be demonstrated.

4 Scenarios

The selection of scenarios that represent the range of reasonable outcomes is fundamental to project assessment under the RIT-T (see box below for RIT-T scenario requirement). Failure to include a full range of reasonable scenarios, that would show results very different to the limited set of scenarios selected, can result in incorrect economic assessment and inefficient investment.

> **Box 1 RT-T Scenario Requirement**
>
> Regulatory investment test for transmission application guidelines, June 2010, Section 3.5 Methodology for calculating market benefits, under the heading "States of the world and reasonable scenarios" says:
>
> > The derivation of states of the world with and without a credible option in place and the comparison between the credible option and the base case states of the world must be undertaken across all reasonable scenarios.
>
> The section goes on to describe a process to identify what variables should be varied in the process to determine reasonable scenarios, which is those variables that:
>
> > the TNSP reasonably believes could change the ranking of credible options.

It is assessed that the scenarios selected and modelled did not represent a reasonable spread of scenarios that can occur looking forward.

While the central scenario is a reasonable scenario, the other two scenarios were very similar in market outlook except for changes in gas price, inertia, and capital costs. The high and low scenarios are possibly best presented as a sensitivity to the central scenario as the fundamental scenario narrative in each is very similar. This includes a level of emission abatement which is the same in the central and low scenarios and only slightly higher in the high scenario[5].

Uncertainties that represent reasonable scenarios can be readily demonstrated:

- Yallourn power station closes early (say in the mid 2020's). With no additional interconnection from NSW coal generation (refer to Figure 2) a significant proportion of the generation responsible for reducing gas generation (and associated costs) may be gone. At $100M p.a. fuel saving in the central scenario, this could significantly impact the economics of Riverlink;
- Battery of the Nation is developed by the early to mid-2020's. This may have the impact of reducing a large quantum of the reduction in gas generation attributed to Riverlink;
- AGL closes Torrens Island B without Riverlink and replaces this with new gas generation, solar and storage. This would impact the reduction in gas generation savings attributed to Riverlink as well as the reduction in generator fixed costs;
- NSW enacts renewable generation targets and coal plant operation changes to a lower capacity factor role.

These are only a few examples of the uncertainty in future market outcomes. They are by any definition reasonable scenarios and scenarios that would potentially impact the economics of Riverlink.

[5] This assumes the dynamics of the NEG in relation to transaction costs and residual emissions exposure that may be faced by some retailers is not included.

The assessment of the robustness of Riverlink to a range of reasonable outcomes, such as those listed above, is required as part of the RIT-T cost benefit assessment.

The potential spread of outcomes brings into question the suitability of the use of a high and a low scenario, which by design has the average benefits across the scenarios near or higher than the central scenario.

5 Modelling Approach – Market Benefits

The RIT-T is unambiguous in that the modelling undertaken must properly represent the market benefits that would be expected to result from the project.

Box 2 The RIT-T states that:

> (5) Subject to paragraph 7 and 8, the market benefit must include the following benefits:
>
> (h) competition benefits being net changes in market benefit arising from the impact of the credible option on participant bidding behaviour;
>
> ...
>
> (7) A transmission network service provider must quantify all classes of market benefits which are determined to be material in the transmission network service provider's reasonable opinion
>
> ...
>
> (21) Market development modelling must be:
>
> (a) undertaken on a 'least-cost' basis; and
>
> (b) if appropriate, undertaken on a 'market driven' basis, where ...

In relation to the models used, ElectraNet state[6] the following:

> The model builds generation and energy storage (battery and pumped hydro) to ensure the Reliability Standard is met (Section: Long-term representation).
>
> The long-term representation performs a least cost expansion of the grid out to 2040. The linear program solves across the horizon in one pass with perfect foresight. (Section: Long-term representation).
>
> The short-term representation is dispatched according to Short Run Marginal Cost (SRMC) as required by the RIT-T. The short-term representation solves each year individually with the fleet of generators made available by the long-term representation (Time sequential "Short-Term" representation).
>
> the linear program least cost model used solves across the horizon in one pass with perfect foresight with the solution providing the generation development / retirement and dispatch[7].

Generation (including storage) development in a least cost linear program model is based on two streams of value[8]:

- Meeting regional reserve requirement (known as capacity revenue); and
- Dispatching and receiving the price of the marginal generator.

[6] SA Energy Transformation RIT-T Market Modelling Report 29 June 2018

[7] A linear program model consists of an "objective function" that expresses the costs of generation over the period and the constraints that exist in the market. The linear program model producers a solution that minimises costs subject to the constraints. Riverlink would increase the limit on certain transmission constraints.

[8] In the least cost solution, all generators that enter are economic based on the solution capacity and energy prices.

Long term modelling – regional reserve requirements

A critical issue in the model solution are the regional reserve margins used and the capacity attributed to different supply technologies margins (i.e. solar, wind, batteries of limited energy storage) in satisfying the regional reserve requirements (in order to satisfy reliability). The basis of the reserve margins and the contribution different technologies make to satisfying these margins are fundamental to the solution of least cost models.

Issues regarding reserve margins not addressed in the ElectraNet reports include:

- The basis of the capacity reserve margins and how these change through the 21-year study period:
  - AEMO used to develop and publish such reserve margins but ceased publishing these, the reason given was that they were no longer suitable for expressing the capacity needs of the NEM
  - Their development requires extensive reliability modelling;
- The capacity contribution to regional reserve requirements attributable to different storage technologies. Issues include the firmness of capacity available at the time of regional maximum demand, and the reduction in firmness associated with limited energy storage;
- The contribution to the SA regional reserve margin attributed to a SA-NSW interconnector (noting that there are no new transmission works from Wagga Wagga).

The basis of such regional reserve margin requirements and the contribution the project provides needs to be fully explained.

Long term modelling – battery economics and development

Issues regarding batteries not addressed in the ElectraNet reports include:

- The assumed storage hours of batteries considered suitable to provide capacity for reliability;
- Whether batteries are independently developed or simply "stapled" to solar and wind generation projects. Modelling data released post the deep dive sessions had the change in solar PV capacity (MW) in both SA and NSW due to Riverlink accompanied by the same change on storage capacity (MW). This suggests a "stapling" assumption;

The above matters are fundamental to the modelling and the presentation of these matters to the transparency of the modelling. No information has been provided in this regard.

Short term modelling - generation dispatch

It is normal and essential modelling practice to assess what is the appropriate representation of matters such as generator bidding. Such practice necessitates that models be checked against past market outcomes (often mandated in commercial due diligence).

Of relevance to the RIT-T modelling is the assumption of SRMC bidding, noting that ElectraNet state that this was assumed in the time sequential "short term" representation.

A comparison of the flow on the Heywood interconnector under SRMC and realistic bidding is shown in Figure 3 below. This shows the very significant impact SRMC bidding has on what has been observed[9].

[9] Sustained SRMC bidding is not observed for reasons which include:

- The coal generators would not be profitable and would exit the market without financial support;

The assumption and treatment of SRMC bidding would appear to be a most important issue in the valuation of a new interconnector. It would appear most appropriate that a scenario of realistic bidding be included in the modelling.

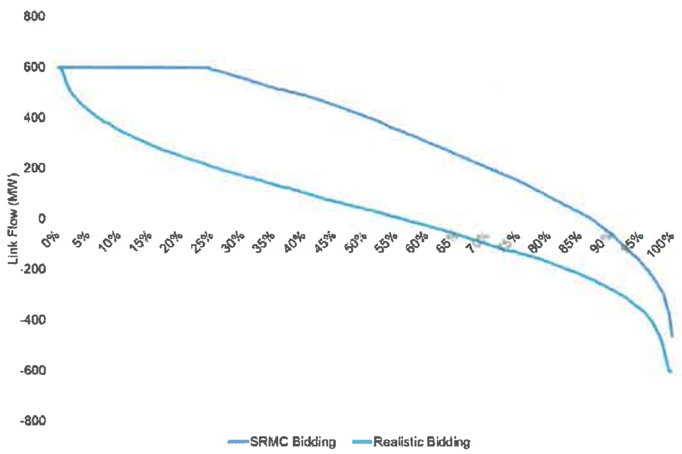
At the "deep dive" session on 17th August 2018, in response a question, ElectraNet replied that coal generators had been modelled as bidding SRMC but with their respective capacities reduced in order to have generator outputs consistent with that observed. While this was indicated as being undertaken on the short-term sequential modelling, it was not clear what was undertaken in the long-term least cost modelling.

If this is what was done it represents a significant and potential error in the modelling approach. Issues include:

- As coal generators close, the remaining coal generators will be incentivised to increase their capacity factor of operation. Past history may be a poor guide to the future;
- The full capacity of coal power stations will be important to managing the variability of increasing VRE;
- The operation of coal power station influences gas generation.

These are important matters that need to be clarified.

Figure 3 Heywood Interconnector Flow Duration Curve - SRMC and Realistic Bidding



The comparison of Heywood flows under SRMC and realistic bidding shows much greater flows under SRMC bidding.

This reflect coal plant operating at substantially higher capacity factors

6 Modelling Results

The economics of Riverlink are derived from changes in capital expenditure (i.e. new generation including storage), savings through plant closures, and reduced cost through lower costs of generation. Having modelling results which detail these changes is fundamental to understanding the economics.

In response to requests at the "deep dive" sessions, ElectraNet provided the modelling results of annual capacity of existing and new generation for the three scenarios modelled (i.e. Central, Low, High). From this the change in generation capacity by generation type was determined, and this is shown in Figure 4 below for SA and NSW. There were no changes in installed capacity in Victoria or Queensland due to Riverlink.

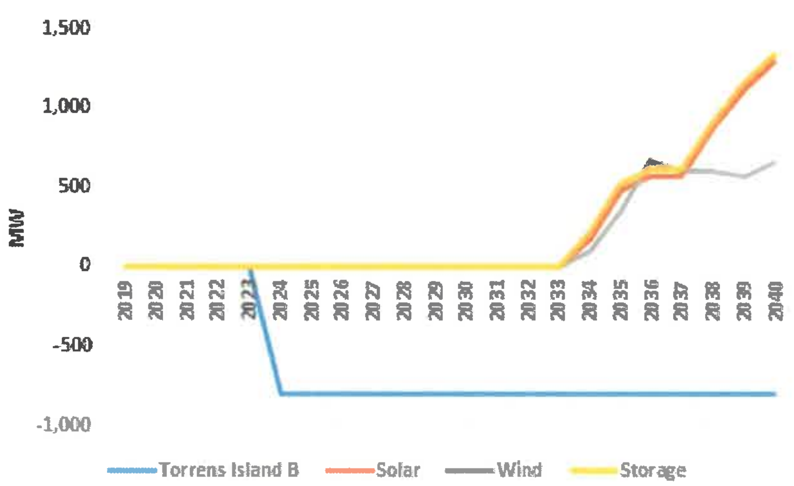
- The coal quantities to support such production may result in increased production costs.

The modelling results did not include the level of production from generators, which meant it was not possible to determine how Riverlink changed generation dispatch (this being fundamental to assessing the fuel cost savings from the major change in gas generation).

Observations from Figure 4 are as follows:

- Over the period 2024 to 2033, 800 MW of dispatchable capacity is removed from SA (Torrens Island B) without any other dispatchable generation developed in SA or Victoria. The interpretation from this is that Riverlink is assumed to be capable of providing 800 MW of firm capacity to SA;
- By 2040 Riverlink results in 3,285 MW of additional development in SA (1,314 MW solar, 657 wind, 1,314 MW storage) and 1,952 MW less development in NSW (166 MW new entrant, 714 MW solar, 357 wind, 714 MW storage). The hours of storage associate with the deferred storage is not specified. There are no changes in Victoria and Queensland;

Figure 4 Change in Generation (incl. Storage) Installed MW due to Riverlink (1)

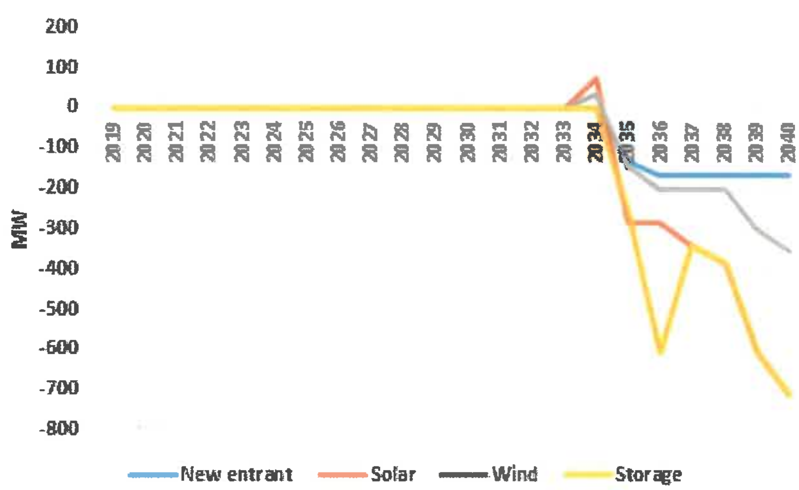


South Australia

Torrens Island closed in 2040. No other changes until 2033.

Solar development is matched with an equal capacity of storage. Hours associated with storage not provided.

Wind increases post 2033.



New South Wales

Solar development reduces and is matched with an equal reduction in the capacity of storage developed. Hours associated with storage not provided.

Wind increases post 2033.

A new entrant (unspecified) also reduces.

Note (1) Information received after the 17 August Deep Dive Session

Questions from these results not explained in the material provided by ElectraNet include:

- Is Riverlink assumed to provide 800 MW of firm capacity to SA? If so, what generation is being used to provide this firm capacity;
- The economics of an additional 1,971 MW of solar/wind generation in SA given the risk of demand reduction and the existing penetration of renewable generation in SA;
- The basis for 1,072 MW of solar/wind generation being more economic in SA than NSW is understood to be based on transmission deferment. The basis for this estimate has not be provided;
- Given the different regional sizes and penetrations of renewable generation, on what basis does Riverlink defer the same proportion of storage with renewables in NSW and SA (both States have 1 MW of storage linked to each MW of renewables).

Without fundamental questions such as these being properly answered the economics of Riverlink cannot be supported. The next section reviews the market benefits ascribed to Riverlink.

7 Reported Modelled Market Benefits

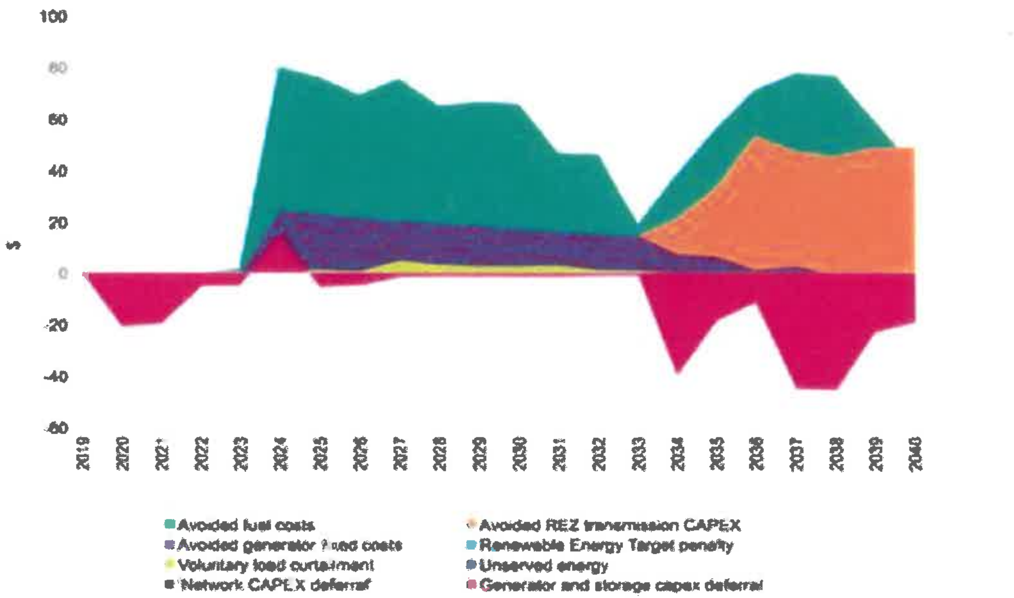
The PADR (Section 9.2 Gross market benefits – Modelling results) provides a high-level composition of the gross market benefits in Figure 7 of that report, and this is shown below in Figure 5.

An indication of the size of the benefit components is given in the executive summary of the abovementioned report:

> The preferred option is estimated to deliver net market benefits of around $1 billion over 21 years (in present value terms), including wholesale market fuel cost savings of around $100 million per annum putting downward pressure on wholesale electricity prices with flow on benefits to customer pricing. Independent modelling by ACIL Allen estimates an overall reduction in the average annual residential customer bill of up to about $30 in South Australia and $20 in New South Wales

Figure 5 Figure 7 from the RIT-T Modelling Report

Figure 7 – Breakdown of gross market benefits for Option C.3.i over time – central scenario



From the above figure and the narrative, the following are noted:

- Gross market benefits are in the order of $2B (accounting for the residual value of the project after 21 years);
- Fuel saving is the major market benefit;
- The second largest saving would appear to be avoided generator fixed costs. At the deep dive session on 17th August this was explained to include Torrens Island closure in the early 2020's saving $20M per year (about what is shown above);
- Post 2033 avoided Renewable Energy Zone (REZ) transmission dominates. This is counter balanced somewhat by the bringing forward solar and wind generation

An assessment of the unit costs of the market benefit categories (Central scenario) can be obtained through a comparison of the changes in generation (including storage) presented in Figure 4 and the market benefits presented in Figure 5. These unit costs are presented in the sections that follow.

The particular market benefits associated with Torrens Island B closure and REZ are considered in turn below.

Torrens Island B

The closure of Torrens Island B is a major component of the economics of Riverlink, and is understood to account for:

- A significant component of saved gas costs;
- Most of the saved generator fixed costs.

As previously noted, the closure of this plant removes 800 MW of capacity from 2024, which is matched closely by the capacity of Riverlink. As previously noted, there is no technical assessment provided as to the quantity of firm capacity that can be obtained from generation in NSW (i.e. Snowy Hydro, NSW coal and gas generators). In this regard the following are noted:

- Riverlink does not increase the capacity available from NSW coal generators;
- The transmission from the Snowy Wagga area is utilised in providing the current firm capacity from NSW to Victoria, and there is no technical analysis presented in how much of this would be available to Riverlink. ElectraNet did recognise that there are constraints norther of Wagga Wagga that would influence the amount of flow that can be achieved on Riverlink. Most importantly, there was no indication as to the combined flow on the NSW to SA and NSW to VIC cut set would be.
- Riverlink may increase the capacity available from Victoria but it is not stated what the power flows would be for this to be provided. In any event, on extreme high demand days Victoria will not have spare capacity and any increase in Victoria to SA link capacity will not provide additional capacity to SA;
- With the above issues not addressed it is not possible to assume that Riverlink capacity can be used to replace Torrens Island B without any replacement capacity in SA (such replacement would likely be gas plant and storage). The modelling of the central case has Torrens Island B closing in 2024 with zero replacement of dispatchable capacity in SA. It is understood the modelling assumes that new gas plant is not developed in SA and that storage development is moderate. Limited storage cannot replace gas generation for reliability purposes;
- Such a closure and capacity contribution by Riverlink may also incentivise additional renewable development in Victoria, given REZ savings.

- The assumptions of fuel differentials between regions and associated generator dispatch. Of relevance is that fuel costs have changed, particularly coal, since the modelling assumptions were developed;

The modelling outcomes could eventuate if Riverlink were ascribed capacity value that would contribute to satisfying the SA reserve requirement. Without any capacity value it may not be economic to replace Torrens Island B as per the ElectraNet modelling.

The basis of this dynamic and value ascribed to the closure of Torrens Island must be fully described.

Generator and Storage Deferral Costs

The reported generator and storage deferral costs[10] need additional explanation:

- As there are no changes between the without and with Riverlink cases until 2033, except for the closure of Torrens Island B in 2024, the generator and storage deferral costs commencing 2019 do not appear consistent with the change in capacity profile;
- The per unit annualised costs for the category "generator and storage deferral costs" are \$97/kW (about \$33/MWh) in 2034, reducing to \$21/kW (about \$7/MWh) by 2040. These costs per kW are very low, and lower than in the stated assumptions.

Renewable Energy Zones

Post 2033, the major component of market benefits is associated with "avoided REZ transmission CAPEX". These costs were \$75/kW over the period 2035 to 2040.

The assumption is that such saving can be associated with:

- A reduction in renewable generation development in NSW; or
- Reduction in REZ capex for renewable generation that is assumed developed with or without Riverlink. If this were the case, then it would be expected that such transmission would not be included in Riverlink costs and the benefit would not exist.

Such capex saving cannot be associated with increased renewable generation that occurred in SA as the transmission capex associated with this increased renewable generation would not have been required without Riverlink.

The dynamics and transmission cost assumptions are required.

8 Consistency of Modelling to the AEMO ISP

The consistency of RIT-T modelling to be AEMO Integrated Energy Plan (ISP) is important as ElectraNet state that the assumptions used in the RIT-T modelling are in all material aspects the same as that developed by AEMO in the ISP modelling[11].

This implies that the NEM outlook developed by ElectraNet should in all material aspects be the same as that developed by AEMO in the ISP modelling. Based on that premise, the results of the ISP modelling should reflect the modelling results of the ElectraNet RIT-T modelling.

---

[10] As Riverlink results in additional renewable generation and storage the deferral costs are negative.

[11] The PADR states in the executive summary "In assessing options under this RIT-T, we have reflected the assumptions adopted by AEMO in the ISP in all material respects. We have also taken into account the complementary investments identified by AEMO as part of the ISP, in particular the investments being considered by AEMO's Western Victoria Renewable Integration RIT-T and the identification of priority REZ zones in the Riverland and Murray River areas of South Australia and New South Wales."

AEMO did publish the modelling results of the ISP modelling and Marsden Jacob have plotted these results. A comparison of these two capacity developments shows the following:

- While the quantity (MW) of utility solar, utility wind and utility storage in 2040 are similar, timing of the development of these assets is quite different;
- The RIT-T modelling has the total capacity of installed generation at about 13,000 MW more in 2027 than in the ISP modelling.

These differences are very difficult to explain given that "all material assumptions" have been stated as being the same.

These differences would have a material impact on the economics of a SA-NSW interconnector.

Figure 6Error! Reference source not found. shows the graph of capacity development by type for the AEMO ISP Neutral scenario and for the by ElectraNet Central scenario[12] (noting the MMR did not disclose whether this included the project or not).

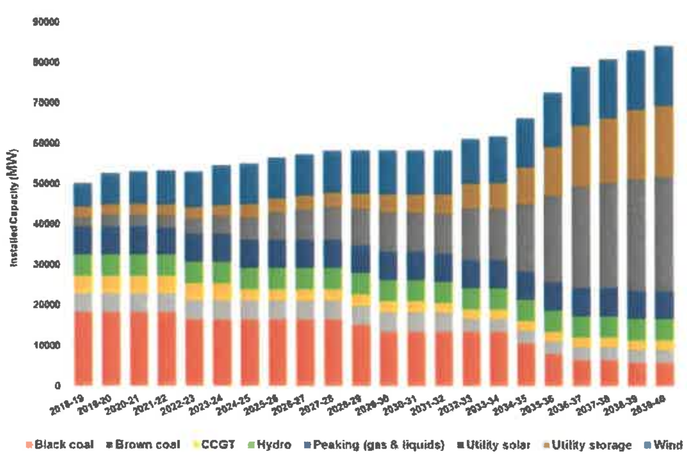
A comparison of these two capacity developments shows the following:

- While the quantity (MW) of utility solar, utility wind and utility storage in 2040 are similar, timing of the development of these assets is quite different;
- The RIT-T modelling has the total capacity of installed generation at about 13,000 MW more in 2027 than in the ISP modelling.

These differences are very difficult to explain given that "all material assumptions" have been stated as being the same.

These differences would have a material impact on the economics of a SA-NSW interconnector.

Figure 6 ISP and ElectraNet Central Scenario

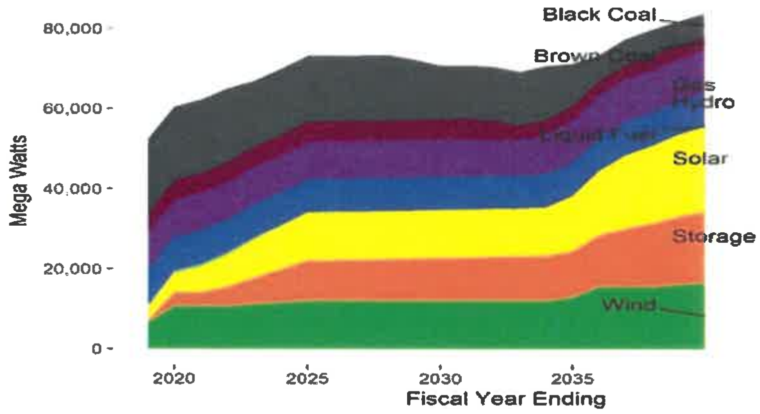


ISP Neutral Scenario

SA-NSW interconnector is in.

Graph by Marsden Jacob using AEMO ISP data

[12] Figure 3 in the MMR



Central Scenario Installed Capacity

Not stated if the SA-NSW interconnector is in.

SA Energy Transformation RIT-T Market Modelling Report 29 June 2018, Figure 3

9 Consumer Price Changes

From the information published by ElectraNet it appears clear that reducing energy prices to consumers through greater competition in generation was a key motivation for the RIT-T.

However, it was stated by ElectraNet that the RIT-T application has economics based on market benefits as prescribed by the RIT-T guidelines.[13]

To quantify the impact of a SA-NSW interconnector to SA and NSW electricity prices, ElectraNet commissioned and published a study undertaken by ACIL Tasman on the impact a SA-NSW interconnector would have to SA and NSW residential and small business electricity prices. The impact involved ACIL Tasman modelling the change in SA and NSW spot energy prices and change in TUOS charges associated with the cost of a new SA-NSW interconnector.

The assumptions regarding the SA-NSW interconnector were stated as follows:

- capacity of 800 MW in either direction
- Heywood interconnector limited to thermal capacity of 750MW when the new interconnector is in place
- aggregate transfer limit of 1,300MW across the new interconnector and the existing Heywood interconnector.
- Electrical losses on the new interconnector were assumed to be the same as those on the Heywood interconnector.

While the report was very brief with minimal detail, the report did provide an explanation for the type of modelling undertaken. The ACIL Tasman modelling utilised electric market simulation modelling that the RIT-T describes as being based on realistic generator bidding. This is very different than the modelling based on SRMC bidding that ElectraNet state was used in the assessment of market benefits. Noting the issue of increased transfer to NSW, the ACIL Tasman modelling would be expected to have flows on interconnectors closer to what is observed, rather than what would be obtained under SRMC bidding (see Figure 4 in this report).

---

[13] Section 4.3.1 of the PADR states "To clarify, the intention of our analysis is not to attempt to capture lower wholesale prices as a RIT-T market benefit, but rather to help provide context for the extent of wholesale market changes brought about by a new interconnector. We have clarified the identified need in this PADR accordingly."

Spot price benefit and market benefit consistency

The very different modelling approaches used by ACIL Tasman (in determining spot price impacts) and ElectraNet (in determining market benefits) means there is no evidence that the reported spot price reductions and market benefits are both simultaneously possible.

Modelling based on the methodology used by ACIL may result in significantly lower market benefits. According to the RIT-T guidelines this scenario should be tested.

TUOS Allocation

The allocation of TUOS charges to SA and NSW was not explained. However, the cost impact was reported as (in $/annual):

- Representative residential customer in SA: $9.0
- Small business customer in SA: $5.0
- Representative residential customer in NSW: $18.0
- Small business customer in NSW: $10.0

Given the respective sizes of the SA and NSW markets, it would appear than more than 60% of the cost of the new interconnector would be paid by NSW consumers. However, NSW consumers may not receive any benefit as Riverlink may not increase power flow limits to NSW.

10 Process and Transparency

This submission concludes with observations regarding process and transparency in the process.

Process

As the start of the RIT-T process ElectraNet stated that a process consisting of three phases would be undertaken. This is most important as it determined the level of detailed analysis undertaken in the first phase.

The description by ElectraNet on this is given in the MMAAR (Section 2 Overall modelling approach proposed for this RIT-T assessment) which stated that:

> "ElectraNet intends to approach to the RIT-T assessment as three distinct phases to ensure the modelling approach is manageable and fit for purpose:
>
> - Phase 1: First-pass screening of costs and benefits to prioritise credible options and, if appropriate, eliminate clearly lower ranked options.
> - Phase 2: More detailed analysis of the benefits of prioritised shortlisted options, based on a more detailed engineering assessment of the options, and developing a more thorough understanding of the drivers and risks to the assessed market benefits.
> - Phase 3: Verification of outcomes to ensure that the decision to screen out lower ranked options in Phase 1 remains robust."

The need for Phase 2 modelling was also stated (by ElectraNet) in the published slides of Public Forum presentation dated 8 December 2016 "South Australian Energy Transformation regulatory investment test (RIT-T)".

This noted that Phase 2 would involve the more detailed scenario analysis which will consider:

- Global, national and state climate change policies;

- Major grid developments across the NEM and in SA;
- Rapid consumer changes;
  - Massive storage adoption;
  - Internet of Things and tariffs;
  - Electric vehicles;
- Generator and load retirements.

It could be interpreted that Phase 1 refers to the PSCR and Phase 2 to the PADR, although this is not clear. In this regard the following are noted:

- The PSCR did not undertake any first pass of the costs and benefits of the options identified;
- The PADR did provide additional detail on the composition of the projects than in the PSCR;
- The PADR did not address the level of detail regarding the change in transmission limits that would be expected in the detailed modelling. For example, in relation to the SA-NSW interconnector option the PSCR states:[14]

  > The notional capability of the interconnector is likely to be reduced at times due to deep network limitations and outages. Capability will be influenced by conditions in Victoria, in addition to conditions in South Australia and New South Wales

  The transmission limits presented in the PADR were a flat limit, did not contain any dynamic description, did not contain any description of losses, and did not contain any description of combined limits to NSW.

The issue of the level of engineering and modelling detail undertaken is a critical issue to the confidence that can be placed on the economics presented, particularly as the process appears to be circumventing the Phase 2 process what was outlined at the start of the RIT-T.

Transparency

Transparency is essential if the service level and economics of the respective projects are to be understood. Both the AER and ElectraNet have stated the importance of transparency in the RIT-T process.

- The AER states in their report "Regulatory investment test for transmission application guidelines June 2010":

  > The RIT-T is intended to promote efficient transmission investment in the national electricity market (the NEM) and ensure greater consistency, transparency and predictability in transmission investment decision making.

- ElectraNet states respectively in the PADR (Section 4.5.6) and MMR (Section 1 Introduction)

  > We understand the importance of transparency in the RIT-T process and have endeavoured to release all the information necessary for stakeholders to assess the robustness of the modelling results.
  >
  > The intention of this report is to provide greater transparency and insights into ElectraNet's market modelling, with a focus on how the base case for three future scenarios investigated has been modelled.

[14] Section 5.3 Option 2 – interconnector from mid-north SA to NSW

Despite the above statements, the modelling information and results provided by ElectraNet was low. We note the request at the deep dive session on 17th August, by a number of attendees, of the need for additional data. Additional data was provided following these sessions but was still inadequate in several important areas.

This limited provision of modelling detail has meant that is not possible to have an understanding of how the benefits were derived.

In this regard the following are examples of what would be expected to be provided from a modelling exercise:

- A precise and complete description of the change in transmission limits associated with the project;
- Spreadsheet of detailed modelling results in the without project and with project cases. While annual installed capacity was provided following the deep dive sessions, not provided were the change in generation dispatch, the utilisation of each project, power flows at time of regional maximum demand etc.;
- Explanation of what comprises the individual breakdown components (such as capital cost savings);
- The basis and costs of the REZ savings;
- Explanation of the AEMO reserve margins which are stated as used in the least cost modelling for the assessment of reliability (AEMO ceased publishing reserve margin).

Without such detail the modelling results cannot be understood and can only be taken on faith.

Options development

The report SA Energy Transformation RIT-T Project Specification Consultation Report 7 November 2016, Executive Summary states the basis for the need[15]. Statement includes:

> "Additional interconnection between National Electricity Market (NEM) regions can result in greater competition between generation sources, thereby delivering lower overall energy prices for customers, in addition to facilitating an increase in renewable generation and addressing security of supply concerns associated with energy market transition."
>
> "The identified need for this RIT-T is driven by allowing greater competition between generators in different regions …"
>
> "… and facilitating the transition to lower carbon emissions and the adoption of new technologies"
>
> "A new interconnector or non-network alternatives would put downward pressure on energy prices in South Australia. Specifically, new interconnector options would enable demand in South Australia to be met through using surplus low cost generating capacity that currently exists elsewhere in the NEM. This will lower the overall costs of electricity supply across the market as a whole."

The calculation of market benefits are described correctly and the report lists the components as specified by the RIT-T. However, the report incorrectly includes (Section 6.3) the wealth transfer associated with "changes in penalties payable under the Large-scale Renewable Energy Target (LRET)". This is stated in Section 6.3.3 as "not material" and thus is assumed not to impact the economic assessment.

The consideration and selection of options should:

[15] The quotes occur in the referred to paper in different locations.

- Be based only on market benefits, and should not consider the impact on wealth transfers;
- Be technological neutral and treat the possible range of energy / environmental policies through scenario analysis (as was indicated for Phase 2 modelling but that never occurred).

This process of option selection and scenario development would appear not to be consistent with the basis of the RIT-T.

Appendix 1 Documents reviewed

The documents reviewed for this review included the following:

- Final decision, Regulatory investment test for transmission and regulatory investment test for transmission application guidelines. June 2010;
- Regulatory investment test for transmission application guidelines, June 2010;
- South Australian Transmission Annual Planning Report, 29 June 2018;
- SA Energy Transformation RIT-T: Project Specification Consultation Report 7 November 2016;
- SA Energy Transformation RIT-T: Market Modelling Approach and Assumptions Report
- Electricity Network Transformation Roadmap, Interim Program Report; 21 December 2016;
- South Australian Energy Transformation regulatory investment test (RIT-T) Public Forum 8 December 2016;
- South Australian Energy Transformation PSCR Supplementary Information Paper 13 February 2017;
- SA Energy Transformation RIT-T Project Assessment Draft Report 29 June 2018;
- SA Energy Transformation RIT-T Market Modelling Report 29 June 2018;
- SA Energy Transformation RIT-T Network Technical Assumptions 29 June 2018;
- SA Energy Transformation RIT-T Basis of Estimate 29 June 2018;
- SA Energy Transformation RIT-T, Consolidated Non-interconnector Option, Entura, 5 June 2018;
- South Australia New South Wales Interconnector, Preliminary Analysis of potential Impact on Electricity Prices. 3 July 2018;
- Market Modelling and Assumptions Databook (Excel spreadsheet);
- Project Specification Consultation Report, Additional interconnection between Victoria and Tasmania July 2018;
- Oakley Greenwood: RIT-T Market Modelling, high level review. June 2018;
- AEMO Integrated System Plan July 2018;
- Battery of the Nation reports – 2017, April 2018, August 2018;
- Information released by ElectraNet following the "Deep Dive" sessions in August 2018.