External review of Heywood RIT-T

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DOCUMENT INFORMATION

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1. Executive Summary

Introduction

This document presents an independent review for the Australian Energy Regulator by Oakley Greenwood as to whether the Heywood RIT-T satisfies the requirements for the preparation of Regulatory Test for Transmission (RIT-T) contained in cl 5.16.6 of the National Electricity Rules (NER).

The Heywood RIT-T has been prepared jointly by ElectraNet and the Australian Energy Market Operator in its capacity as a Transmission Network Services Provider in Victoria (ElectraNet & AEMO) to assess the likely market benefits of an increase in the capability of interconnection between South Australia and Victoria via Heywood.

Under the requirements for a RIT-T in the NER the option to augment transmission capability that delivers the highest net economic market benefit is nominated as the *preferred option*.

The review considers each of the key elements of the RIT-T:

- Need for investment and selection of credible options;
- Analysis of market benefits and selection of preferred option; and
- Consultation through published material and proponent and responses to submissions.

The review makes extensive use of detailed supporting material published by ElectraNet & AEMO and supplementary information in response to stakeholder submissions, however, the review did not involve repeating the market modelling.

Principal finding

The review has found that the requirements of the RIT-T have been satisfied and that accordingly Option 1b has been correctly identified as the preferred option.

Further findings

In addition to the principal finding the review finds that:

- Each of the functional steps in undertaking an assessment of market benefits under the RIT-T was performed satisfactorily overall;
- The selection of credible options was appropriate. The selection was tested against the range of generic approaches available to enhance market benefits including enhancement and duplication of the existing network, greenfield developments and mitigation (through demand reduction) and found to cover each technique.;
- Classes of market benefits assessed included all classes likely to be significant;
- When requested to elaborate and provide more detailed information, on balance and accounting for additional information provided after the publication of the Project Assessment Conclusions Report (PACR), ElectraNet & AEMO responded reasonably. Responses included provision of more detailed information, adding scenarios and where appropriate explanations of why additional information was not relevant or available. In concluding that ElectraNet & AEMO's responses were reasonable we note that the Heywood RIT-T involved a major analysis effort and although the published material was extensive it is inevitable that particular stakeholders will seek more detail on certain items. Ultimately a balance needs to be struck and a focus maintained on the objective of the RIT-T to rank credible options. We note that responses to stakeholder requests played a significant part in presentation of a complex analysis;

- As capital deferral benefit (i.e. changes in expenditure on generation investment) was a significant component of net benefit, the basis for adoption of a common investment schedule for a number of the options warranted a more robust justification. For the purposes of the review the risk of error from this choice was assessed using a process of deduction which concluded the common schedules were not likely to change the outcome of the RIT-T;
- In respect of the classes of market benefit regarded as not material, greater use of qualitative analysis could have provided additional assistance to distinguish between options with similar quantitative benefits;
- Assessment of the benefits of Option 5, the demand management option, involves more uncertainty than other options and is critically dependent on the size of the program. The net benefit of Option 5 is more likely to have been higher than lower for plausible different sizes of program, but not to the point where, given the information available on costs, the choice of preferred option would be likely to change;
- In respect of optionality as a possible source of benefit, “simple” probability weighted scenarios will not necessarily assess benefit adequately; however, the selection of Option 1b as the preferred option was not affected in this case; and
- Although changes in network losses were an insignificant component of overall net benefits in all scenarios and did not affect the conclusions, analysis using average rather than marginal factors should have been used to assess costs.

2. Introduction

2.1. Background

This document presents a review for the Australian Energy Regulator AER) on whether the preferred option identified in the ElectraNet/Australian Energy Market Operator's (ElectraNet & AEMO) South Australia to Victoria (Heywood) Upgrade Regulatory Investment Test to Transmission (Heywood RIT) satisfies the requirements of the RIT-T contained in cl 5.16 of the National Electricity Rules (NER).

Paraphrasing cl 5.6.5B of the NER, the preferred option is the credible option that maximises the present value of net economic benefit in meeting a need for investment identified in a RIT-T.

In accordance the requirements of the NER ElectraNet & AEMO issued:

- A Project Specification Consultation Report in October 2011;
- A Project Assessment Draft Report (PADR) in September 2012;
- A Project Assessment Conclusions Report (PACR) in January 2013.

Each of these reports was accompanied by relevant technical data including detailed generation expansion plans and material (dated 11 December 2011 on the AEMO website) including a listing of relevant constraints and other technical data used in modelling.

ElectraNet & AEMO had previously undertaken a South Australia Interconnector Feasibility Study in 201-11 which informed initial stages of the work.

Submissions to the formal consultation pages have been posted to the AEMO website.[1]

On 5 April 2013 ElectraNet & AEMO requested AER to make a determination under cl 5.16.6 of the NER as to whether the Heywood RIT-T satisfies the requirements of the NER. A number of items of correspondence has also been received from a number of stakeholders and ElectraNet & AEMO have provided responses since the publication of the PACR. This correspondence has been posted to the AER website.[2]

In a letter to AER dated 21 June from ElectraNet & AEMO responding requests for information as part of the correspondence at item 3.2 ElectraNet & AEMO advised that there is now greater certainty about demand in the South East of South Australia and that "…. *Under these conditions the PACR findings support a South East transformer control scheme as part of the preferred option. For this reason the ElectraNet proposes to include the South East control scheme in the scope of the Heywood Interconnector Upgrade project.*" Oakley Greenwood understands the AER will the proposal in the completed RIT-T and potential changes as separate matters.

3. Focus of the review

The review made extensive use of the written PACR and associated Appendix 1 which presents detailed quantitative results in spreadsheet form but did not involve repeating the primary quantitative analysis undertaken by ElectraNet & AEMO.

1 See http://www.aemo.com.au/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission-RITTs/Heywood-Interconnector-RIT-T

2 See http://www.aer.gov.au/node/19916

The substance of stakeholder input to the various stages of consultation is a central part of the RIT-T and has informed preparation of ElectraNet & AEMO's PACR. This review pays particular attention to that input and ElectraNet & AEMO's responses but does not include a detailed submission by submission analysis. The review was also informed by material provided by ElectraNet & AEMO in response to a series of questions and a face-to-face meeting held during the course of the review noted above.

3.1. Approach

The RIT-T process laid down in the NER is a standard weighted scenario cost-benefit analysis of options. At cl 5.16 in relation to the RIT-T the NER states in part (reformatted to assist presentation):

The *regulatory investment test for transmission* must:

(1) be based on a cost-benefit analysis that is to include an assessment of reasonable scenarios of future supply and demand if each *credible option* were implemented compared to the situation where no option is implemented;

(2) not require a level of analysis that is disproportionate to the scale and likely impact of each of the *credible options* being considered;

(3) be capable of being applied in a predictable, transparent and consistent manner; require the Transmission Network Service Provider to consider the following classes of market benefits that could be delivered by the credible option:

(i) changes in fuel consumption arising through different patterns of *generation dispatch*;
(ii) changes in voluntary *load* curtailment;
(iii) changes in involuntary *load shedding*, with the market benefit to be considered using a reasonable forecast of the value of electricity to consumers;
(iv) changes in costs for parties, other than the *Transmission Network Service Provider*, due to:

(a) differences in the timing of new *plant*;
(b) differences in capital costs; and
(c) differences in the operating and maintenance costs;

(v) differences in the timing of *transmission investment*;
(vi) changes in *network* losses;
(vii) changes in *ancillary services* costs;
(viii) competition benefits.

In summary the major functional steps in undertaking a RIT-T are:

- Identify need;
- Identify credible options;
- Specify reasonable scenarios and assess "state of the world";
- Identify relevant classes of market benefit to be (and not to be) assessed;
- Analyse credible options including methodology and assumptions; and
- Select preferred option.

This review examines ElectraNet & AEMO's considerations at each of the major steps including interactions and responses to stakeholder input.

In the PACR (and the earlier PADR) ElectraNet & AEMO describe a number of the approximations and judgements that were used in the course of the analysis. Approximations and judgements are commonly made to render the analysis of highly complex and long term industry operation practical, and in themselves are unremarkable. However, in order to provide more than a general expression of comfort along the lines “an assumption about this aspect of analysis is reasonable and that the one taken is plausible”, we have examined key assumptions more deeply. We have asked questions around factors that might invalidate assumptions or indicate that certain classes of benefit that were not assessed should have been and in particular what one would need to believe about the situation to alter the selection of the preferred option.

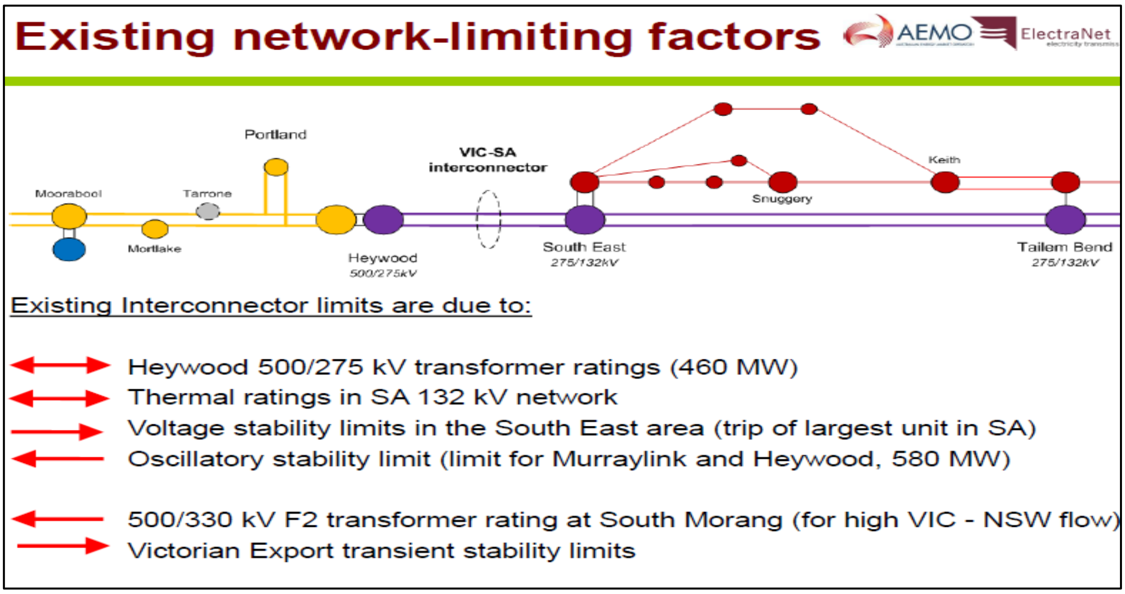
4. Need

Under the NER *need* for network investment can be to increase economic market benefit or to meet a prescribed reliability criterion. ElectraNet & AEMO have declared that the need to be met in this case is to increase market benefits.

A market benefit based *need* can only be demonstrated from analysis of the expected impact on market benefits of investment options. The only limitation being that the net market benefit must be positive - as opposed to a situation for a reliability-based *need* where market benefit may be negative if the preferred option is the most cost effective way to meet the reliability criterion.

ElectraNet & AEMO note that the current configuration of the electricity network in the south east of South Australia and south west of Victoria has a number of factors that cap the ability of the National Electricity Market (NEM) to deliver market benefit. Figure 1, which is taken from a presentation by ElectraNet & AEMO, illustrates the network configuration and summarises the nature of the limitations in this area. In the Heywood RIT-T documentation ElectraNet & AEMO claim that a number of options to amend the configuration all provide positive net market benefits. Review of their analysis of benefits is at the core of this review.

Figure 1 Simplified diagram of network connections and current factors constraining market benefits



Source: ElectraNet & AEMO presentation to public forum 21 November 2011

5. Credible options

5.1. Introduction

Construction of credible options requires considerable expertise combined with local knowledge. To assist review of whether a full suite of options has been considered Oakley Greenwood has firstly reviewed whether each of the generic approaches to managing network limitations that are available within the industry has been considered. Secondly, we have examined the detailed analysis of the nine options ElectraNet & AEMO have identified as credible. Thirdly, we have considered if there are other options that should be considered - primarily those identified by stakeholders in submissions.

In summary Oakley Greenwood concludes that ElectraNet and AEMO have met the requirements of the RT-T in respect of their selection of credible options.

5.2. Generic approaches to unlocking additional market benefits.

We have grouped my assessment of the generic approaches for removing impediments to increased market benefits as follows:

- Augmentation approaches
  - Enhance capability of existing assets – this approach is often the lowest cost and may involve upgrading of secondary plant such as cooling fans on primary plant, upgrading control systems and use of condition sensitive dynamic ratings in conjunction with enhanced monitoring.
  - Duplicate existing assets/paths – in this approach existing infrastructure may be duplicated e.g. by additional transformers within existing sub stations. It is generally more expensive than enhancing the capability of existing assets
  - Establish greenfield path – new greenfield flow paths are generally more expensive but have larger impacts than enhancement or duplication
- Mitigation approaches
  - Manage/reduce loading – Customers may be prepared to accept a payment to reduce their demand at critical times – i.e. to enter into a demand management program. Where the demand management payment is less than the cost of upgrading the network it can be a more cost-effective response.
  - Configuration changes – In our experience it is common practice for network configurations to move through stages of simple radial feeders, meshed networks and then progressive reduction in the degree of meshing and removal of older low capacity elements from service as the network expands. Timely retirement of a highly loaded network element from service and reliance on newer larger capacity elements obviously removes any constraints due to the retired element. Similar mitigation effects can be achieved by operating the network with some elements in a standby or backup mode and only switched into service when needed to cover periods of breakdown or maintenance of other normally in-service elements.

5.3. Credible options consider each of the generic approaches

Oakley Greenwood considers that across the nine options analysed by ElectraNet & AEMO in the PACR, each approach has been considered as follows:

- Options 1a and 1b involve (the same) significant change to the 132kV network in the south east of South Australia including removal from service of a heavily loaded line, addition of a third transformer and bus-tie at Heywood plus capacitors to support voltage on the main network. They differ in the technical details of the approach used to support main system voltages in that Option 1a uses shunt capacitance at South East Sub Station and Option 1b uses series capacitor compensation on the South East to Tailem Bend lines. Both options therefore involve enhancement and duplication of existing flow paths and reduction of loading on certain lines.
- Options 2a and 2b test the impact of the addition of a third transformer at South East over and above Options 1a and 1b respectively. They therefore also involve both enhancement, duplication and mitigation approaches.
- Option 3 provides a greenfield addition of a new flow path and therefore examines the impact of a new interconnection path at 500kV between Tailem Bend and Heywood.
- Option 4 is the same as Option 1a except it omits the third transformer at Heywood and thus provides an indication of the impact of this transformer.
- Option 5 assesses the value of a demand management program on Option 1b – to reduce (critical) loading together with deferral of network upgrades for two years.
- Option 6a considers the impact of control schemes to manage loading on the existing South East and Heywood transformers and South East to Heywood transmission lines at critical times.
- Option 6b includes control schemes (as in Option 6a) plus the South Australian intra-regional network within Option 1b (but does not include the third transformer at Heywood. It therefore effectively assesses the impact of substituting control schemes for the third Heywood transformer in Option 1b.
- In addition to reviewing analysis of the identified options a key question for this review is whether there are any alternative combinations that might allow even higher market benefits. In responses to the consultation stages a number of stakeholders suggested alternatives that are in the main variants or staged implementation of the credible options listed by ElectraNet & AEMO who provided responses in the PADR and PACR and additional comment in the communications during the course of this review. In some cases ElectraNet & AEMO have included options in the list above (e.g. Option 6a was included in response to submission from Infigen – see PACR pg 35) and in some cases they have provided argument as to why an alternative is not expected to deliver higher benefits than the options already in the list and in other cases why the time and effort of analysis is not justified. A number of ElectraNet & AEMO responses have been informed by their analysis highlighting, the iterative nature of option development.

In summary Oakley Greenwood considers that each generic approach to provide for additional market benefit has been considered in forming the final set of options and that each of the options are appropriate for consideration.

Later sections of this report address the comments from stakeholders and ElectraNet and AEMO's responses and whether the particular combination of mechanisms includes the best option.

In this respect the Heywood RIT-T meets the requirements for a RIT-T.

6. Scenarios and state of the world

The RIT-T employs a traditional scenario approach to assessing likely future benefits. The design of scenarios and choice of sensitivities are vital parts of this approach. ElectraNet & AEMO have based the analysis on three scenarios used in AEMO planning processes plus a fourth scenario added following stakeholder submissions during the consultation phase of the RIT-T. Details of the scenarios are provided in the PADR and PACR.

Scenarios should be internally consistent, plausible sets of conditions that might prevail and determine a "state of the world" or outcomes in each case. In the context of a RIT-T concerning an increase in interconnector capability, factors such as demand, costs for generation investment and operation and the cost of investment alternatives being considered are the key inputs. Sensitivities should test the impact of individual elements of a scenario but should not vary parameters to the point that the set of conditions is no longer an internally consistent package. The RIT-T and associated guidelines issued by the AER set out a series of requirements and details of the nature of analysis expected.

Use of the scenarios employed by AEMO in its broader planning has the advantage that they have been subject to consultation with NEM participants. However, between the start of the RIT-T process and its completion there was significant change in actual market conditions, including a material reduction in forecast demand and changes to the likely level of carbon price. These factors are key inputs to forecasts of future conditions in the NEM. Further, actual demand was well below forecast levels meaning the starting point for scenarios was no longer accurate. Other changes had also occurred, for example in relation to retirement or expectations for closure of certain generation plant. As a result the scenarios in the earlier stages no longer covered the full range of plausible futures. In response ElectraNet & AEMO added a fourth scenario with lower demand, lower carbon price and changes to retirement.

There is little that can be done about changes during the course of an investigation. However, prima facie, changes which invalidate the starting point for all scenarios suggests that with benefit of hindsight there was a gap in the levels of demand in the scenarios. It is notable, however, that no stakeholder submissions included concern about the design of the scenarios at the time. By the time the PADR was released in September 2012 there had been downward revisions of demand and policy changes announced and stakeholders called for additional scenarios. Some also called for the RIT-T process to be halted until there was more certainty about a number of aspects of the design of the scenarios.

For the PACR, ElectraNet & AEMO added a fourth scenario with lower demand and different assumptions about other key factors raised in submissions. They assigned the additional scenario a significant (41 per cent) weighting in final analysis. ElectraNet & AEMO also presented sensitivities which included a weighting of 70 per cent to the additional scenario (and found that the ranking of options did not change).

In the circumstances, the process for developing and responding to changes and the substance of the scenarios are reasonable and meet the requirements of the RIT-T.

Finally, it is notable that a number of stakeholder submissions called for the Heywood RIT process to be paused pending clarification concerning current policy matters. While a pause is presumably within the ambit of ElectraNet & AEMO, We observe that long term investment planning in many industries is commonly undertaken in the face of uncertainty. Over the last decade for example, planning in the NEM has been undertaken in the context of both increases and decreases in forecast local and national demand growth, considerable (and continuing) policy uncertainty about carbon pricing, major changes in renewable energy policies and in the outlook for pricing and availability of gas. A pause in planning would seem appropriate if one could have confidence that uncertainty would materially diminish in the near future – however, recent history suggests this is not likely.

7. Classes of Market Benefits

This section reviews the classes of market benefits that ElectraNet & AEMO have assessed in detail. ElectraNet & AEMO have also chosen not to analyse certain types of possible benefit on the grounds they are immaterial. These are discussed in section 11 in the light of detailed results from the analysis that has been undertaken.

7.1. Assessed classes of market benefits

Within a RIT-T each class of possible market benefit can either be assessed quantitatively, qualitatively or not assessed at all on the basis that the TNSP(s) regards the particular type of benefit as irrelevant or immaterial.

ElectraNet & AEMO note they believe it is appropriate to explicitly analyse the following types of market benefit:

- Changes in generator fuel consumption (including the impact on carbon costs);
- Changes in voluntary load curtailment;
- Changes in involuntary load shedding;
- Changes in costs for parties other than the TNSP – which includes changes in investment and dispatch costs by generators and wholesale customers (e.g. Retailers); and
- Changes in network losses.

ElectraNet & AEMO have used market modelling to identify each of these benefits. Market modelling is required under the RIT-T guidelines issued by AER unless there is reason to consider market modelling is not appropriate. ElectraNet & AEMO have noted they believe market modelling is appropriate and I concur with that conclusion.

ElectraNet & AEMO have used well-established industry models Plexos (to determine investment schedules) and Prophet (to determine dispatch). The modelling has been undertaken for the entire NEM and therefore accounts for changes in all regions of the NEM. This approach therefore meets the requirements of the RIT-T to assess impacts on parties other than the proponent.

Models of this type determine economically rational investment and dispatch across the NEM. They assume all parties act in an efficient manner at all times given the costs, demands and operating constraints provided as input (by ElectraNet & AEMO). The effects of different options and different scenarios are reflected in the input data for each case and they assess all of the classes of benefit listed at the same time. Accordingly the input data and design is crucial.

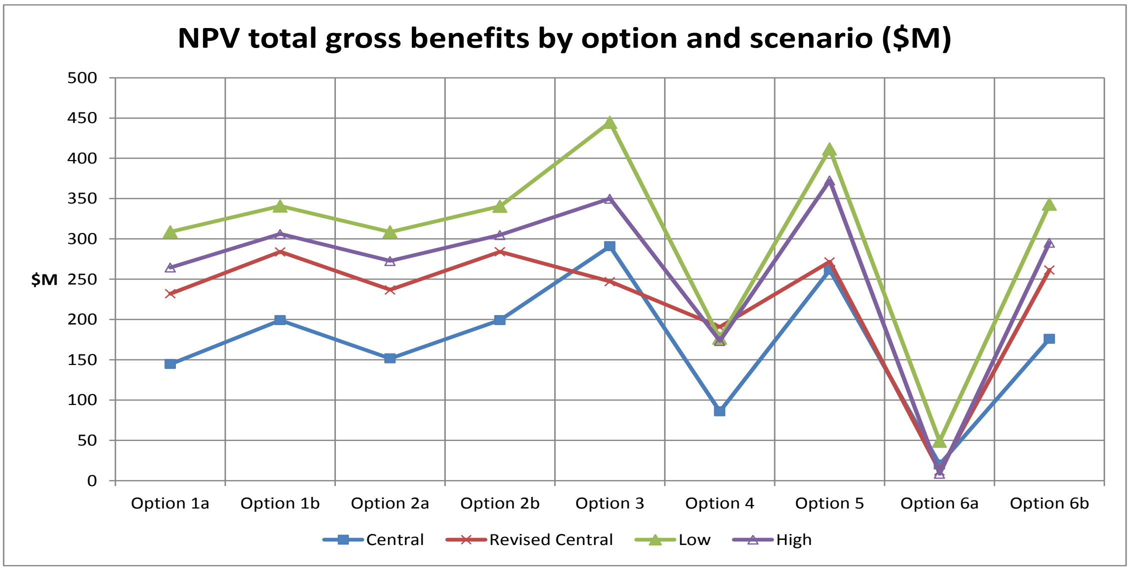
These are standard classes of benefit and we agree each should be assessed. A more pertinent question is whether any of the classes of benefit ElectraNet & AEMO have considered to be immaterial or not relevant and therefore omitted should have been assessed. This question is addressed in detail in section 11 in light of analysis that has been presented by ElectraNet and AEMO. In section 11 Oakley Greenwood concludes that none of the omitted classes of benefit need be included.

8. Assessment of market benefits

Across the PACR and its appendices ElectraNet & AEMO present detailed results of analyses for costs and each class of benefit on an annual basis. These results are aggregated into discounted gross benefits and costs and net values in the reports.

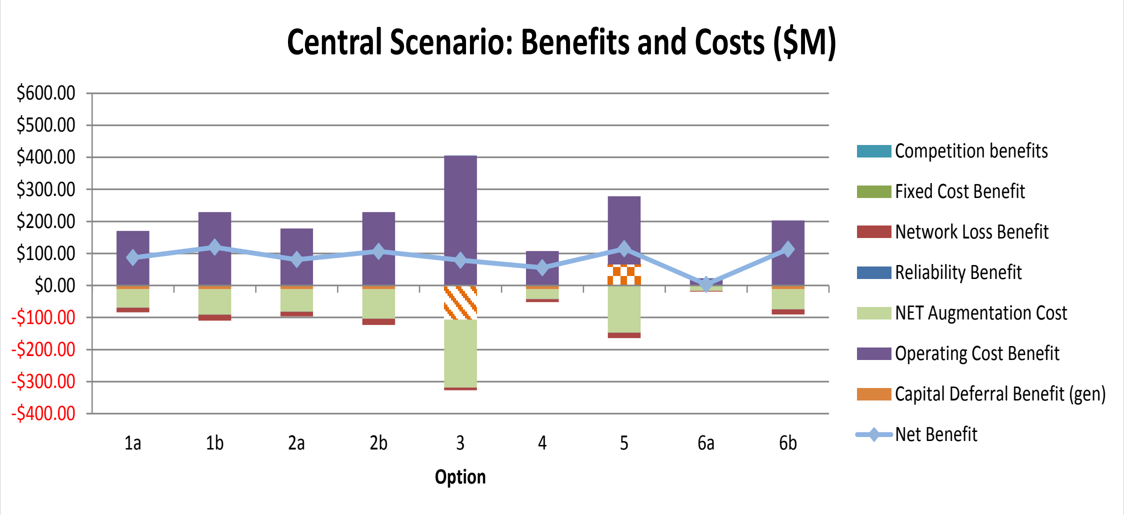
To assist our analysis we prepared the Net Present Value (NPV) of total benefits for each option and the benefits for each class along with costs as listed in Appendix 1 of the PACR as shown in Figure 2 through Figure 6. This process has also confirmed that the aggregated values in the PACR have been accurately derived from the annual results.[3] The following sections discuss key aspects of the methodology and analysis and refer back to the figures.

Figure 2 Total benefits by option and scenario



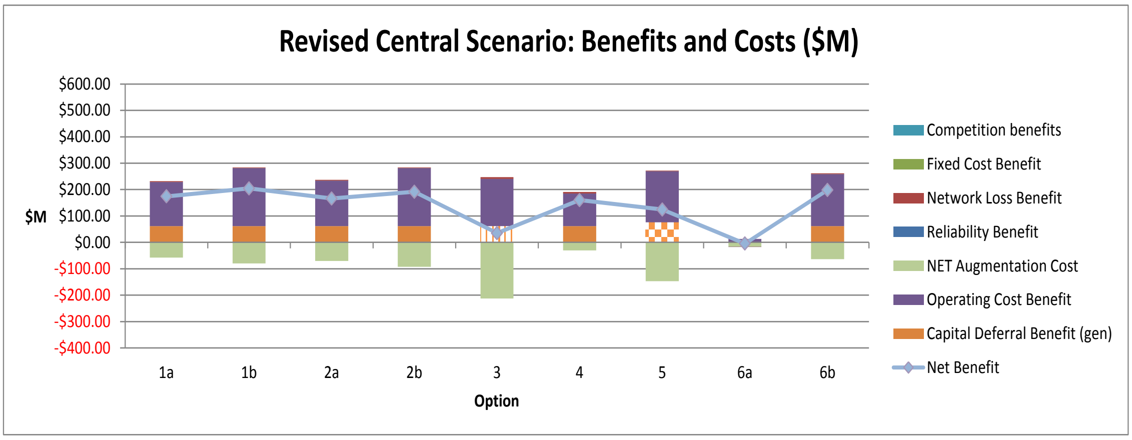
3 The results require that the tables are extended for the full period to 2054 using the average of the final five years for each class of benefit (which does not match the value listed as "on-going" value in all cases).

Figure 3 Central Scenario discounted benefits and costs by option



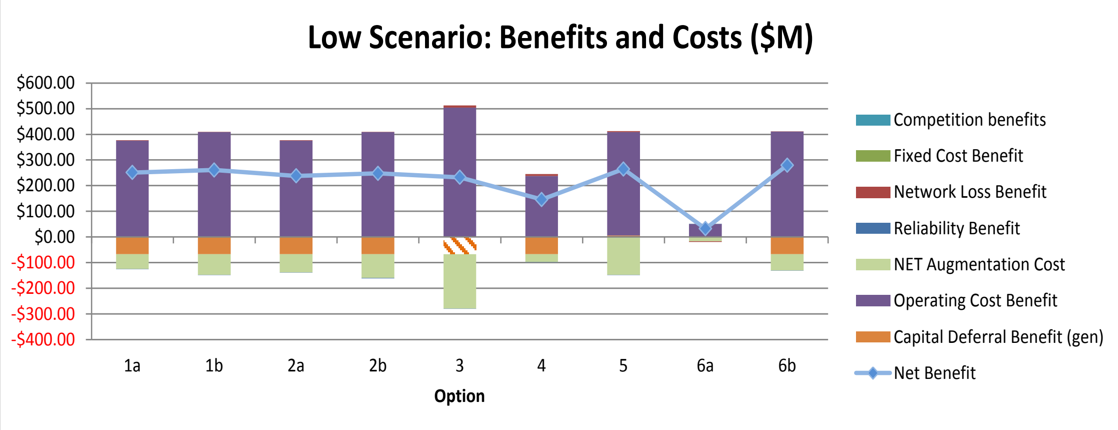
Note 1: Capital deferral benefits are based on a common generation investment schedule for Options 1a, 1b, 2a, 2b, 4 and 6b. Option 5 schedule differs from this by deferral of 200MW of capacity. Analysis of Option 6a was based on the base case for each scenario and hence shows no capital deferral benefit. Separate generation schedules were determined for Option 3 (diagonal hatched capital deferral bar) and Option 5 (cross hatched capital deferral bar) - see discussion in section 9.

Figure 4 Revised Central Scenario discounted benefits and costs by option



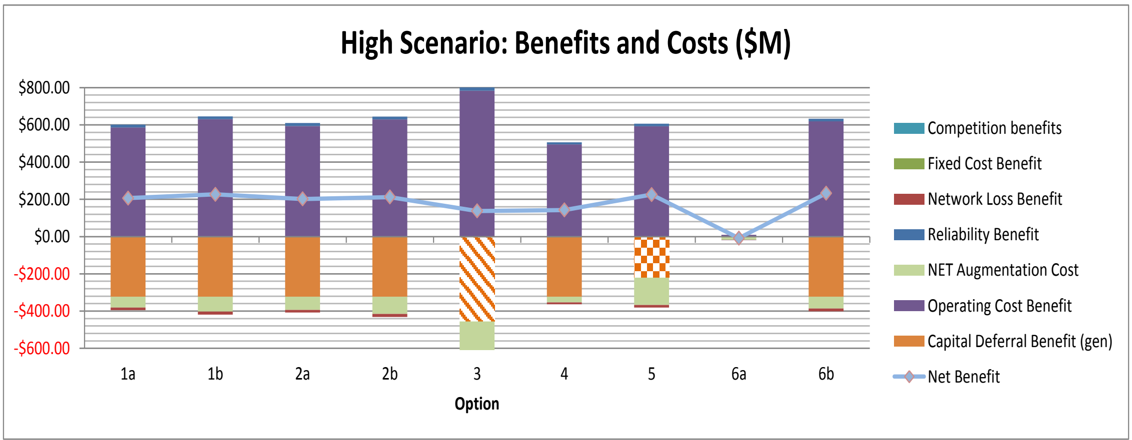
Note 1: Capital deferral benefits are based on a common generation investment schedule for Options 1a, 1b, 2a, 2b, 3, 4 and 6b. Option 3 (hatched capital cost bar) uses this investment plan in this scenario. Option 5 schedule (cross-hatched capital deferral bar) differs from this by deferral of 200MW of capacity in South Australia. Analysis of Option 6a was based on the base case for each scenario and hence shows no capital deferral benefit. See discussion in section 9.

Figure 5 Low Scenario discounted benefits and costs by option



Capital deferral benefits are based on a common generation investment schedule for Options 1a, 1b, 2a, 2b, 4 and 6b. Option 5 schedule differs from this by deferral of 200MW of capacity. Analysis of Option 6a was based on the base case for each scenario and hence shows no capital deferral benefit. Separate generation schedules were determined for Option 3 (diagonal bars) and Option 5 (cross hatched) - see discussion in section 9.

Figure 6 High Scenario discounted benefits and costs by option



Note 1: Alternative presentation of grid lines for Figure 6 has been used to highlight different vertical scale.

Note 2: Capital deferral benefits are based on a common generation investment schedule for Options 1a, 1b, 2a, 2b, 4 and 6b. Option 5 schedule differs from this by deferral of 200MW of capacity. Analysis of Option 6a was based on the base case for each scenario and hence shows no capital deferral benefit. Separate generation schedules were determined for Option 3 (diagonal capital deferral bars) and Option 5 (cross hatched capital deferral bars) - see discussion in section 9.

9. Methodology and assumptions

ElectraNet & AEMO describe the methodology used to assess the classes of market benefits they identified in section 5 of the PACR and describe the basis and source of input data. Methodology and assumptions should be chosen jointly as an internally consistent analysis package. The following sections comment on relevant aspects.

9.1. Introduction

Using market modelling, the assessment of market benefits for nominated options under specified scenarios involves the following steps:

1. For scenario 1
    a. For the base case (do nothing) determine:
        i. generation investment schedule
        ii. dispatch of each plant
    b. For each option determine:
        i. generation investment schedule
        ii. dispatch of each plant.
    c. Calculate change in costs for each class of market benefit between base case and option.
2. Repeat for each scenario.
3. Assign weighting to each scenario and determine weighted (gross) benefit.
4. Calculate weighted net benefit of each option by subtracting the cost of each option from the weighted (gross) benefit.
5. Identify the option with highest net benefit, account for relevant assumptions and approximations and nominate the preferred option.

The next sections discuss selected aspects of each of these steps in the Heywood RIT-T with emphasis on key approximations, assumptions and stakeholder submissions.

9.1.1. Capital deferral - methodology

The results in the Heywood RIT-T show that benefits from deferral of investment in new generation assets is one of the three major components of net benefit (along with operating cost benefit and augmentation cost). Investment in generation appears in a generation schedule or expansion plan. The Plexos model has been used to determine the cost effective mix of future generation assets. A model of this type assesses total capital and operating costs over the modelling horizon subject to a number of factors including meeting demand, providing reserve margin and observing network operating limits. In principle each combination of demand, capital and operating cost and network configuration will lead to a different generation schedule.

Section 9.2 begins a discussion of the impact of ElectraNet & AEMO's use of common schedules for a number of options. This discussion is then extended by a process of deduction to show that the number of options that can logically be considered as potentially offering the highest net benefit can be significantly reduced. Thus, this process can serve as a plausibility test of the overall conclusion of the analysis.

Subject to comments about the use of common investment schedules in section 9.3.1 and separate processes to determine investment schedules and dispatch in section 9.3.2 the approach used to determine the investment schedules themselves is industry standard practice and entirely satisfactory for the purpose of the RIT-T analysis. It therefore meets the requirements for a RIT-T in this respect.

9.1.2. Operating cost and network loss benefit - methodology

Other than the cost of the network options themselves operating cost benefits are the other major component of net benefit. Operating cost benefits arise from changes in the cost of fuel (and as required under the AER RIT-T guidelines, including carbon impost). The Prophet model was used to assess operating costs for the generation investment schedule determined using Plexos. This is also an industry standard model and the approach for calculating generator operating cost differences is satisfactory for the purposes of the RIT–T analysis. It therefore meets the requirements for a RIT-T in this respect.

In the detailed results, changes in network losses are shown to be minor. Notwithstanding this minor effect we note that in section 6.2.5 of the PACR ElectraNet & AEMO describe the calculation of intra-regional network as being based on marginal loss factors. We consider that for the purpose of the RIT-T, losses should be based on actual or average loss factors not marginal factors. Marginal loss factors are used in the NEM to signal marginal effects for dispatch priority and spot pricing but do calculate actual loss .[4]

The analysis in the Heywood RIT-T is a comparison of the differences in actual costs for generation investment and operation and network costs and similarly losses should be actual. Although, changes in average loss will generally (depending on the circumstances) be even smaller than for marginal loss and thus will remain insignificant in the assessment of net benefit.

9.1.3. Changes in voluntary and involuntary load reductions

Modelling of voluntary and involuntary load reductions within a least cost modelling environment is very approximate.

The economic effects of reduction in load will in principle impact the net benefits. The RIT-T guidelines note that the reserve margin developed by AEMO, which is a major determinant of involuntary reduction in modelling, may be used in RIT-T analysis to determine the level of generation investment. ElectraNet & AEMO have followed this practice. However, this is an approximation to the actual market outcome as the reserve margin may change over time in order to deliver the NEM reliability standard due to changes in demand profile and generation technology. An alternative might be to assume that NEM settings are adjusted in light of developments so that the unserved energy standard is met each year. However, this will not readily be incorporated in least cost modelling where a reserve margin is the only practical way forward. The difference in involuntary shedding is likely to be very small in any event and thus the effect of this approximation is likely to be small.

Voluntary reductions arise from consumer responses to changes in market price and any targeted arrangements not directly related to prevailing wholesale price. If an augmentation option reduces the occurrence of high prices then voluntary reductions may reduce and this will provide a benefit. Least cost modelling will result in very high prices only at times of physical scarcity and thus be capable of “seeing” only some of the possible situations for voluntary reduction. ElectraNet & AEMO have noted that voluntary reduction in this circumstance is included in the Prophet model.

4 Specific provision is made in the NEM energy settlement for the difference arising from the average and marginal losses within the “loss settlement residue”.

Overall, least cost modelling cannot accurately assess either voluntary or involuntary load reduction with any accuracy. ElectraNet & AEMO implicitly note this as well. Hence the inclusion of these benefits in assessments would be problematic if they were material, but as they are not, the approximations are immaterial.

9.2. Generation capital and operating cost assumptions

The data about capital and operating costs on which the model determines investment and dispatch are clearly critical to the calculation of market benefit. ElectraNet & AEMO have relied heavily on data in other AEMO analysis, in particular the National Transmission Development Plan. These data have been subject to extensive consultation with NEM stakeholders previously, with detail published on the AEMO website. On this basis the AEMO data is a sound starting point for the Heywood RIT-T but should be varied where there is reason.

Section 6 discusses variation to the demand within the Revised Central Scenario and ElectraNet and AEMO's response to stakeholder comment about gas prices post 2030 is noted in Section 10.1. Apart from these two items the data used on the supply side of the analysis in the RIT-T was not challenged by stakeholders – control scheme costs were challenged and are discussed in section 14. As the AEMO process was extensive and soundly based all other items are reasonable. ElectraNet and AEMO have recognised the change in demand in the Revised Scenario and as discussed in Section 10.1 the gas price post 2030 is not likely to change the choice of preferred options. Accordingly the data used within the modelling relating to generation and for demand satisfies the requirements of the RIT-T (see section 14 in respect of network costs).

9.3. Generation investment schedules (expansion plans)

9.3.1. Common schedules

ElectraNet & AEMO have developed forecasts of generation investment schedule in three groups for each scenario. Each group has the same investment schedule within a scenario:

- Options 1a, 1b, 2a, 2b, 4 and 6b
- Option 3 (new 500kV interconnection)
- Option 5 (Demand side management and deferral of Option 1b network augmentation)

Option 6a (the stand-alone control scheme) was judged by ElectraNet & AEMO to have no effect on the likely investment pattern and hence deliver no capacity deferral benefit. As a result the investment schedule for this option was unchanged from the base case. Oakley Greenwood's view is that this is a reasonable conclusion as the scheme would act only when flows were close to limit and only be needed when output from local wind generation is high and a critical network outage occurs.

9.3.2. Separation of investment and dispatch analyses

There are a number of points about the groupings for calculation of investment schedules.

Generation investment schedules should be determined in conjunction with dispatch. This is the only way that total cost can be assessed – for example to choose the lowest discounted total cost over a period of many years between two generators, one with low capital cost but high operating cost against another with higher capital cost but lower operating cost. The PACR notes that ElectraNet & AEMO have used one model to determine investment and another to examine detailed dispatch.

We interpret the discussion in section 5.3.1 of the PACR (in particular footnote #76) as noting that investment decisions accounted for dispatch in a more approximate manner in the Plexos model than in the detailed treatment of dispatch in the Prophet model, which was used to identify operational benefits. That is, the capital deferral benefits were derived from analysis using Plexos, and the operational benefits from analysis using Prophet.

Investment should only be assessed over a long time period but this can be an onerous computational task and it is common practice to separate the calculation of investment schedule from dispatch in some form in order to render the overall calculation tractable. In general separation of calculations is best suited to situations where there is a focus on either investment or detailed dispatch. In this case precision is implied in both as capacity deferral benefits and operation benefits are separately analysed and this warrants further consideration.

There is a risk in separating the processes which is highlighted by the note in section 5.3.1 of the PACR, which observes that, in respect of Option 3 in Scenario 4, the generation investment schedule used for Options 1, 2 and 3 gave higher market benefits than the schedule derived specifically for Option 3. Clearly it is appropriate to use a schedule that maximises overall benefit, but it begs the question of whether there may be another investment schedule that might lead to even higher benefits for this option, or for others. Section 5.3.1 of the PACR also notes that a key reason for adopting common schedules was the variability in results when separate investment schedules for each option were attempted.

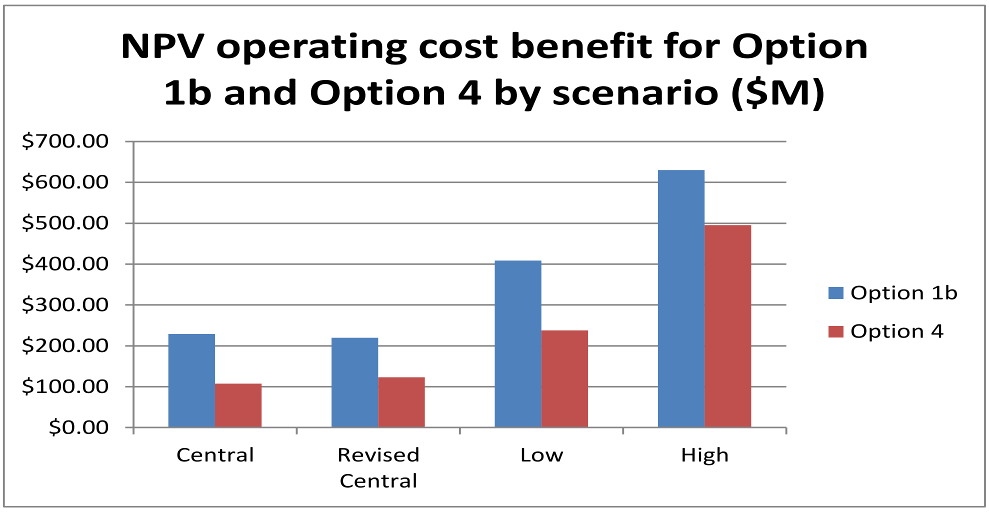
It follows that where a common investment schedule has been adopted for a number of options, differences in gross benefit will arise only from operational differences and minor impacts such as losses, as any capital deferral benefit will be common to the options with common investment. Net benefit will differ by the differences in the gross benefit and cost of each option.

Given the judgements and analytical risks noted here, we have considered the potential for different options to show different benefits to those listed in the event that individual investment schedules had been developed. Put another way we have considered what one would need to believe about costs and benefits in order for the choice of preferred option to change

Building on the discussion above, different operating costs would be indicative of different total costs which in principle may change the combination of plants that could be expected to deliver lowest system wide costs over time. A different investment schedule will generally result in a different operating pattern and therefore operating costs. By adopting the same investment schedule for Options 1a, 1b, 2a, 2b, 4 and 6b ElectraNet & AEMO are affecting the comparison of both capital deferral (by tacitly assuming there is no difference between these options in this regard) and indirectly of operating costs.

Using the logic just described, if operating costs are materially different, prima facie, investment schedules and costs may be different. It is notable that operating benefits are materially different with the largest gap appearing in the Revised Central Scenario where Option 4 benefit is only 56% of that of Option 1b as shown in Figure 7.

Figure 7 Comparison of Option 1b and Option 4 operating cost benefit



Source: OGW analysis of Heywood RIT-T Appendix 1

It is therefore relevant to ask if it is plausible that there would be approximately similar investment patterns. If there is doubt, a crucial question for this review is whether the differences are material in the sense that it would change which option provides maximum net benefit.

The next section is directed at reconciling the approach ElectraNet & AEMO have taken in respect of investment schedules, but is then extended to show that the number of options that need to be considered further in order to assess the relativity of their benefits can be reduced. The section therefore reviews the validity of the assumption of identical investment schedules but is also a means to cross-check the ranking of options without repeating the quantitative analysis.

9.3.3. Filtering investment schedules and ultimately the number of options

This section examines the implications of ElectraNet and AEMO's approach to investment schedules. It draws on the detailed results in Appendix 1 to the PACR and Figure 2 through Figure 6.

1. In respect of Options 1a and 1b
    a. These differ only in the form of voltage support - shunt capacitance in Option 1a and series compensation in Option 1b.
    b. Option 1b is shown to deliver higher savings in operating costs and thus higher benefits <u>assuming the same investment schedule</u>. For any set of (common) assumptions and inputs such as fuel cost, it is reasonable to conclude that a difference in favour of Option 1b will always occur regardless of the numerical value of those assumptions, although the size of the gap may vary.

   c. If the same investment schedule is a valid assumption, we can therefore eliminate Option 1a from further consideration as a candidate as the preferred option. To consider if this is the case, it can be seen that Option 1b is noted as having a higher nominal limit (refer Table 3.2 PACR). As a result it is reasonable to conclude that if there were to be any difference in the investment schedules between Options 1a and 1b there would be a greater opportunity for total cost savings in Option 1b and thus an increase in the difference in benefit. Such an outcome would make Option 1b even more attractive relative to Option 1a. Accordingly it is safe to assume Option 1a will not provide higher benefits than Option 1b and it can be eliminated from further consideration.

2. In respect of Options 2a and 2b

   a. Similar logic applies when comparing Option 2a and Option 2b as these are identical to Options 1a and 1b respectively with the addition of a third transformer at South East in each case. Accordingly Option 2b will offer greater benefits than Option 2a and Option 2a can therefore be eliminated as a candidate for preferred option.

3. In respect of Options 1b and 2b

   a. These options differ only by the inclusion of a third 132/275kV transformer at South East in Option 2b. The detailed results in the PACR show only trivial differences in operational savings between them, <u>assuming the same investment schedule</u>. This result indicates that the operational benefits relative to the base case are approximately equal with and without the third transformer at South East - after accounting for changes to the 132kV network.

   b. In other words once the works on the 132kV intra-regional network are completed transformation capacity at South East is not expected to constrain flows and accordingly the third transformer would provide no additional market benefit within these options. On this basis Options 1b and 2b would be highly likely to have the same investment schedule, but Option 2b always have higher costs. Accordingly Option 2b can be eliminated from consideration.

   c. However, it is notable that in the current network configuration South East transformation capacity has been noted by ElectraNet & AEMO as a significant limiting factor on operation.

4. In respect of Option 3

   a. This option creates a new and large greenfield flow path via Krongart. It involves substantial additional cost and may provide substantially higher market benefit. Review of Figure 3 through Figure 6 shows that while the gross benefits of this Option are likely to be higher in all scenarios its cost is markedly higher and thus net benefit less than the majority of other options. Option 3 therefore can be eliminated from further consideration.

5. In respect of Option 4

   a. Option 4 is the same as Option 1a without a third transformer at Heywood. ElectraNet & AEMO have concluded that the same investment schedule would apply as for Option 1a, (and 1b, 2a and 2b). A logical corollary is that even though the third transformer at Heywood will provide greater import and export capability, and in all scenarios this leads to materially higher operational savings than for Option 4, this will not affect the generation investment schedule.

b. It is not intuitively obvious why this would be the case. However, if there is any difference, the lower transfer capability without the third Heywood transformer would reasonably be expected to reduce the capital deferment benefit of Option 4 relative to Option 1a.

c. Further, the lower interconnector capability would provide less opportunity to achieve operational savings so that the combined benefit would be less than that reported for Option 4. Accordingly Option 4 would show less benefit than reported and still less than Option 1a, which as has already been argued will be less than Option 1b. On this basis Option 4 can also be eliminated as a contender to achieve higher net benefits than Option 1b.

6. In respect of Option 5

   a. Option 5 involves a demand management program for five years and a two year delay to Option 1b. ElectraNet & AEMO have assumed the same generation investment schedule for Option 1b other than a 200MW deferment of OCGT investment in the delay window. However, ElectraNet & AEMO have noted that detailed work would be needed to confirm if the deferment of OCGT capacity will be as great as 200MW. If it is less, the capacity deferral benefit in the analysis of this option would be less than assumed.

   b. The cost for the demand side program (which ElectraNet & AEMO note were provided by EnerNOC) are:

      i. $120,000/MW/yr for capital cost, which is of the same order as the annualised capital cost of Open Cycle Gas Turbine (OCGT) plant; and

      ii. $750/MWh for dispatch, which is higher than what would be expected for OCGT, although only low levels of dispatch are likely. As a result capital deferral benefits due to delay in network augmentation are offset by an increase in augmentation project cost and in the Central Scenario this is close to a zero sum.

   c. Assessment of the merits of demand management for this RIT-T is more complex than a situation where there is a choice between network investment, demand management or generation in order to meet a defined network reliability standard. In that situation the lowest cost option is clearly preferable and a demand management scheme for a number of years may allow more costly network investment to be deferred until demand growth outstrips the ability of demand management capability.

   d. In the case of the Heywood RIT-T where benefit is related to generation investment and variable market dispatch outcomes, as opposed to customer demand, both generation reliability (reflected in minimum reserve margin within the least cost analysis) and network market benefits are involved.

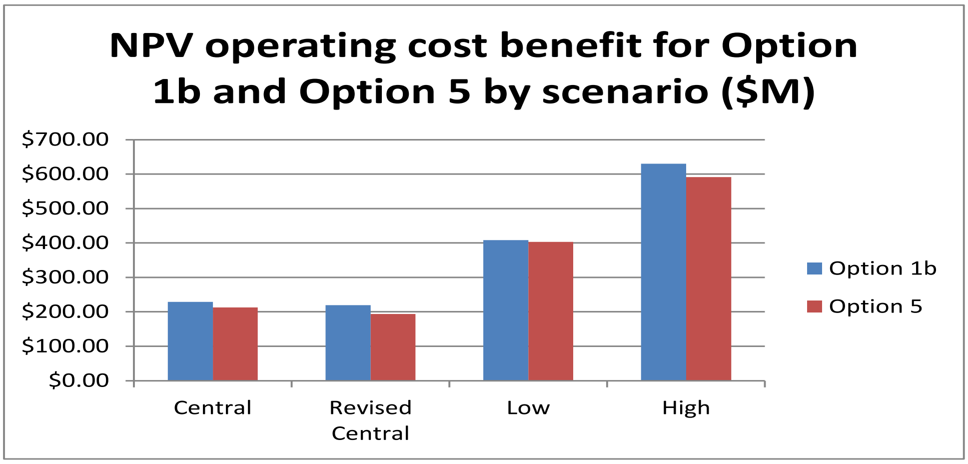
   e. The base cases for the scenarios in the RIT-T have been prepared assuming only generation options are available and ensure the reserve margin is maintained – see section 5.3.1 PACR . In analyses for all options other than Option 5, results show the degree to which the various network augmentations can replace the generation investment in the base case(s) and the resultant economic market benefit.

f. In Option 5, ElectraNet & AEMO have shifted the time that network augmentation commences back two years and overlaid a fixed size of demand management program and investigated the resultant reduction in generation capacity and impact on dispatch costs.

g. As noted, in the central scenario this combination has approximately the same net market benefit as Option 1b. ElectraNet & AEMO have noted that they have undertaken screening analysis (not detailed) that showed a two year deferral of the network augmentation in addition to demand management program optimised market benefits – see page 35 of PACR.

h. In respect of operating cost benefit, it is notable that in all scenarios operating cost benefit of Option 5 tracks that of Option 1b, but is always a little less – see Figure 8. This result is to be expected as the dispatch cost assumed for the demand management program ($750/MWh) is greater than that of an OCGT.

Figure 8 Comparison of Option 1b and Option 5 operating cost benefit



Source: OGW analysis of Heywood RIT-T Appendix 1

i. On this basis the analysis shows that a demand management program can be cost-effectively deployed to delay investment in generation to meet the reserve margin prior to the time that network augmentation can occur. However, because the demand management costs are of the same order as generation the net saving will be small and actual savings will be very dependent on final costs.

j. Finally, we note that in section 5.3.1 (last para) of the PACR ElectraNet & AEMO note they have considered the same size demand management in each scenario effectively treating the program as a fixed component of the network augmentation option. This appears consistent with the structure of the RIT-T as the alternative would be to treat the program as a competitive market initiative alongside generation investment.

k. Option 5 is therefore only ranked lower than Option 1b and 6b as a result of this choice and we consider it should remain a contender at this point of the review.

7. In respect of Option 6a

    a. ElectraNet & AEMO have concluded that this option will have no impact on the NEM-wide investment schedule. Oakley Greenwood's view is that this is plausible as the option is designed to enhance the capability for SA to export when wind generation levels are high and it is reasonable to assume that market price will be low at these times and have little impact on investment decisions. Accordingly we concur that Option 6a is unlikely to a capacity deferral benefit.

8. In respect of Option 6b

    a. Under this option the control schemes available under Option 1a at Heywood and South East substitute for the third transformer at Heywood. ElectraNet & AEMO have assumed that there will be no impact on investment schedule relative to that for Option 1b (and 1a, 2a and 2b). This is their conclusion even though the control schemes will ensure export capability matches that of three transformers - see section 3.3 PACR.

    b. However, the control scheme at Heywood will only be of use when output from the relevant wind generators is high. It will have no impact on the economics of investment in generation plant in South Australia under high load import conditions or where investment elsewhere would reduce use of high cost fuel in South Australia.

    c. These factors mean the capacity deferral benefit of Option 6b is if anything over-stated, as the ability to manage flows using the control schemes will at best match that of the third transformer and the analysis shows equal or lower operating cost benefits in each scenario. However, the control schemes have lower cost.

    d. Accordingly Option 6b remains as a contender at this point.

9.3.4. Three options remain as potential preferred options

The discussion in the previous section was initiated in order to review the use of common investment schedules and consequential capacity deferral benefits. Its conclusions also provide a cross check on the ranking of options and allow the number of options in the list of nine considered by ElectraNet & AEMO which warrant being taken forward to the following three:

- Option 1b
- Option 5
- Option 6b

This conclusion holds regardless of scenario or sensitivity parameter. As a result other factors than those in the detailed analysis will need to be used to identify a preferred option. Before looking at that question the following sections review a range of possibly relevant factors and in particular consider if other factors should have been included in the market benefit analysis. Section 14 then returns to the question of preferred option.

10. Could assumptions about factors such as fuel cost and LRET affect the ranking of the nine options examined by ElectraNet and AEMO?

In any assessment of market benefits, assumptions about factors such as the cost of fuel, generation plant and network connection can be critical. Different assumptions can change the ranking of credible options and potentially reduce the benefits from an option to the point where costs outweigh benefits. Consistent with the approach taken in other parts of this review Oakley Greenwood firstly considers if plausible changes to assumptions are likely to change the ranking and secondly if gross benefits could be reduced to the point where costs outweigh benefits.

If there are such factors it would indicate ElectraNet & AEMO should have given greater attention to them or considered different cases.

In summary in the following we conclude that while there are plausible variations to the cases analysed in the Heywood RIT, none are likely to lead to material change in the selection of preferred option. This conclusion is consistent with ElectraNet & AEMO's judgements about the design of the scenarios on these matters.

10.1. Gas prices

Gas price is likely to be a key determinant of the level of dispatch benefits and will also influence generation investment schedules. Historically Adelaide prices ex Moomba have been higher than prices ex Longford in Victoria. Together with low incremental costs for coal in Victoria and (albeit not as low as in Victoria), NSW, this difference has resulted in significant power flows into South Australia. The forecasts for gas price used by ElectraNet & AEMO reflect a continuing differential that would support a continuation of this pattern for import. Export from South Australia would be driven by high levels of output from wind.

Our judgement is that while the differential in gas price may decrease, for example if Longford prices shadow Moomba price more closely, higher transport costs and higher fugitive emissions from Moomba will mean there is little reason to expect the differential to disappear. A lower differential would reduce the absolute level of gross market benefit and accordingly net market benefit of each of the options. However, any reduction in differential will be common to all options and is unlikely to alter the ranking between them as incremental generation investment other than for renewable resources with minimal operating cost) will be gas-fired for many years.

However, it is reasonable to ask if the ranking does not change, might a lower differential lead to the market benefit reducing to below the cost of augmentation? It is difficult to be definitive without explicit analysis, but it is likely that there will be market benefit from increased interconnection even at a low gas price differential as the major driver for flow into South Australia for a number of years is likely to be the difference between South Australian gas price and Victorian and NSW coal. This difference is likely to remain at least until carbon price increases significantly. The contention that benefit will continue is supported by the results from the scenarios in the ElectraNet & AEMO analysis with the higher carbon prices (Scenarios 1, 2 and 3) and assumptions that coal plant would be retired in Victoria and replaced by gas that still show substantial operational market benefits.

On this basis it is reasonable to conclude that for plausibly lower levels of differential in gas prices between South Australia and Victoria, gas prices will not alter the ranking of options or whether there will be a net market benefit.

Macquarie Generation's submission of 8 July was accompanied by a report of further work by Frontier Economics which was critical of the absolute level of gas price used by ElectraNet & AEMO in the years after 2030, suggesting that the price rise shown was too high. ElectraNet & AEMO were asked to respond to this point and noted a) that the projections are below those in the latest AEMO published material and b) the majority of market benefits accrue before the period of concern and exceed the cost of the option before 2030. ElectraNet and AEMO concluded that differences in gas price would be common to all options and therefore would be most unlikely to change the choice of preferred option. ElectraNet and AEMO's response was published by AER on 24 July.

Looked at another way a lower absolute gas price would reduce the differential between gas and coal. However as the concern relates to prices post 2030 and the majority of market benefit accrues before then it is reasonable to conclude that this would be unlikely to change the choice of preferred option.

Accordingly, without passing opinion on the veracity of gas price forecasts post 2030 used in the Heywood RIT-T, we concur that in the circumstances a lower gas price in this period would be unlikely to change the ranking of options and therefore unlikely to change the choice of preferred option.

10.2. LRET

The analysis by ElectraNet & AEMO assumes the full LRET will be met (see PACR section 5.31) as it is a "hard target" within the modelling. They note that the assumption is common to both base case and options. However, they offer no comment in relation to impact on market benefits if the LRET is not met.

Generation plant installed under the LRET receives revenue from the energy market and from renewable energy certificates. Revenue from certificates contributes to any difference between the plant cost and energy market revenue but is capped at a penalty price. At a lower carbon price this may mean the external support will be insufficient to fully cover the cost of renewable plant and the LRET may not be met. This situation is more likely in Scenario 4 (the Revised Central Scenario) which has the lowest carbon price.

By assuming the LRET will be met in full, ElectraNet & AEMO may be over-estimating the level of investment in renewable generation, especially in Scenario 4, the Revised Central Scenario. Detailed market price studies would be needed to determine if this is the case or not. A submission from GDF-Suez Australian Energy noted the risk that LRET targets might be varied and criticised the absence of scenarios with different targets but there was no other comment from stakeholders on this point.

As with other types of potential market benefit that have not been comprehensively assessed, the question is whether the assumption that LRET will be met has a material impact on the conclusion of the RIT-T. If the LRET is assumed to be met in both the base case (with no upgrade) and each of the options, will this affect the difference in costs and therefore the market benefit of the different options or leave the difference essentially unchanged? And if it does affect the difference, will it be material?

Least cost analysis of the type used in the Heywood RIT-T does not forecast market price and therefore is unable to assess if there will be a shortfall due to lack of wholesale market return. Analysis which determines market price based on commercial bidding behaviour is needed for this purpose. ElectraNet & AEMO summarise the issues and difficulties relating to forecasting of market price in the context of Competition Benefits in section 6.4 of the PACR where they conclude there is no need to assess competition benefits. ElectraNet & AEMO have not discussed the need for assessment of whether the LRET is met but have noted that they have adopted the target that was in place at the time of the study – and is still in place.

It is difficult to be definitive without undertaking detailed studies of the profitability of investment in renewable energy plant relative to likely renewable certificate support. It is also likely that detailed studies will be subject to considerable uncertainty for similar reasons to the uncertainty relating to analysis of competition benefits. In addition uncertainty would be increased if account is taken of conceivable revisions to policy settings (for example to SRES if LRET is not met), jurisdictional renewable and efficiency obligations and possibly extending to operating and contracting strategies for gas volumes and coal plant availability in the face of any reduction in renewable generation in South Australia. While these factors create uncertainty it is notable that South Australia is a highly prospective region for the technology most likely to be installed to meet the LRET, i.e. wind.

Inspection of the detailed investment schedule for the scenario with the lowest assumption about carbon price, the Revised Central Scenario (see Heywood RIT-T Appendix 1 Final Expansion Plan spreadsheet tab), shows that post 2015 additional new investment in renewable technologies other than wind is primarily outside the South Australian region until at least 2030 when geothermal begins to enter in a number of regions. This observation suggests there may be relatively less impact on the investment schedule in South Australia compared to other regions, especially in the earlier years of the analysis.

As noted the prime question is whether the ranking of options would change if LRET was not met and we consider this is a matter that should have been addressed. However, it is reasonable to expect that while there are factors which would reduce the profitable level of LRET investment, there are other factors which may counteract this, and on balance any shortfall would be common to all options and be unlikely to affect the ranking.

10.3. Minimum Generation

In responses to the PADR stakeholders questioned the use of minimum generation levels for coal plant. In the PACR ElectraNet & AEMO explain that this is a pragmatic device in the modelling to simulate the effect of expected voluntary cycling of some units at low demand. We note that this is a common approach as the alternative is a more complex unit commitment model that significantly increases the computing time and is itself subject to approximations. To test the materiality it is possible to rerun cases with higher minimum loads that assume no cycling, but this is also an approximation.

ElectraNet and AEMO note that the minimum loading levels used in the studies do not presume all units are cycled, are common to both base and option cases, and modelling results show dispatch below a level suggesting any cycling, is infrequent (see PACR pg 63). As a result we consider the approach is reasonable in the context of the Heywood RIT. That said it would be less appropriate if the objective was to examine market prices or the operation of the directly affected power stations.

10.4. Scheduled retirement and technology conversion

A criticism by stakeholders of the design of scenarios presented in the PADR was that ElectraNet & AEMO had made assumptions about the retirement of Hazelwood power station and conversion of Playford Power Station to Open Cycle Gas Turbine technology. International Power (now GDF-Suez Australian Energy) and Alinta respectively advised that these assumptions were not valid.

ElectraNet & AEMO noted the assumptions about retirement and technology conversion were taken from previous work undertaken at a time when they expected negotiations for the Contract for Closure associated with the Commonwealth Government's Clean Energy Package would lead to these outcomes – see page 63 PACR In light of the advice from the relevant generators ElectraNet & AEMO have not assumed these changes in the additional Revised Central Scenario and note that the ranking of options has not changed.

As the ranking did not change in the case where the retirement and technology transition were not included we accept ElectraNet & AEMO's view that the assumptions are not material in the context of the RIT-T.

10.5. Least cost analysis with perfect foresight rather than market investment with uncertainty

A point not discussed by ElectraNet & AEMO but worth a brief note relates to the use of least cost analysis. ElectraNet & AEMO note they have been guided by the RIT-T requirement for least cost analysis using market modelling (unless there is a reason not to use modelling).

Market models that account for market bidding behaviour will generally show a trend to the same generation mix as a least cost model over the longer term. Put another way, in the longer term models presume perfect competition which will progressively erode (any) prevailing imbalance in economic mix of generation technologies or market power (if any). An exception to this general position would occur if the behaviour modelling also models which portfolio will make investments so that (any) market power is retained to the extent possible. This is not generally done and would be speculative.

In practice investment decisions will reflect a range of factors that are not readily incorporated in electricity market modelling. These factors include business by business risk policy, strategic objectives for investments, competing uses of capital, ad hoc opportunistic situations and availability of land and fuel. Models attempt to account for some of these factors by analysis over different time periods and by the use of different discount rates. ElectraNet & AEMO have included sensitivities based on discount rate to test this last point and found no change in ranking.

We note the analysis did not consider higher discount rates for different technologies/cost structures <u>within</u> scenarios for investments with more volatile returns such as peaking generators. However:

- While the use of common investment schedules for a number of options may mask differences due to these effects; but
- All of these factors would be common to the base case and option cases, and differences will therefore be small and more relevant to an assessment of individual generator investments than to the relativity of market benefits.

Overall and notwithstanding that the RIT-T guidelines direct least cost modelling as the primary mode of analysis, as a matter of judgement long term planning studies to identify generation costs can safely be undertaken on the basis of least cost modelling.

11. Could classes of market benefit not assessed by ElectraNet & AEMO affect the choice of preferred option?

11.1. Changes in ancillary service costs.

ElectraNet & AEMO note that Frequency Control Ancillary Services (FCAS) represent a relatively small percentage of energy costs and that Network Control Ancillary Services (NCAS) and System Restart Services are unlikely to change, and accordingly ancillary service costs are unlikely to be material to the RIT-T. Oakley Greenwood concurs in principle, although we note that the demand management program in Option 5 and control schemes in Options 6a and 6b could be considered as a form of NCAS, but these are explicitly analysed in the main report and as a result their costs and benefits are included under these headings.

11.2. Changes in unrelated transmission benefit.

ElectraNet & AEMO advise they have not identified any unrelated transmission which would be affected. Stakeholders have raised issues around transmission in Victoria and ElectraNet & AEMO have responded – see section 12.

11.3. Optionality

AEMO &ElectraNet discuss optionality and suggest that optionality should be identified by well selected scenarios. They also consider this view aligns with discussion by the AER in its guidelines for the RIT-T where it is suggested well-chosen that options and probability weighted scenarios can assess optionality.

The key characteristic of optionality is that it is concerned with preparing to deal with changes to one or more exogenous input parameters within the analysis horizon – this is consistent with the AER's note concerning changes to future information.

Option analysis differs from classic scenario analysis in that a scenario typically examines the outcome assuming perfect foresight across the modelling horizon and accounts for uncertainty by assigning probabilities to each scenario as a whole. An option analysis breaks the analysis into multiple paths and assigns probabilities to the different paths. To illustrate the difference, consider the following situation:

- If demand is assumed to grow at 0.5 per cent for the first 5 years of a study and has a 50 per cent chance of continuing to grow at 0.5 per cent and 50 per cent chance of growing at 2 per cent starting in 5 years;
- The demand at the end of horizon will fall between that for growth over the full period at 0.5 per cent and growth at 2 per cent, but will not be equal to either;
- More importantly the resultant new investment in generation in the first 5 years may be different if there is (only) a probability of the growth rate increasing than if either rate was assumed from the start;
- This may mean that it is more cost effective to sacrifice a certain economy of scale benefit and build a small(er) CCGT plant at the start with the probability that a second one may be needed later but also a probability that nothing will be needed until after the end of the assessment period (when the discounted value will be minimal); and
- The picture is more complicated but conceptually similar if different technologies are taken into account.

Scenario results and sensitivities in the Heywood RIT-T all show Option 1b with the highest or at most only marginally less than the highest market benefit. This outcome is not surprising as the investment schedule for the top three options (Options 1b, 5 and 6b) are derived from the same base. This result suggests that, at least for the model parameters that vary between the scenarios and sensitivities, changes to those parameters within a scenario would lead to no change to ranking. In terms of the example above the observed result is the equivalent of finding that the same option has highest market benefit regardless of whether demand grows at 0.5 per cent, 2 per cent or 0.5 increasing to 2 per cent.

On this basis there is no obvious combination of parameters that a formal analysis of options would provide more insight than the probability weighted scenarios and sensitivities in this case.

We also note that in responding to stakeholder input in relation to alternative options in section 4.13 of the PACR ElectraNet & AEMO state that delay to allow time for more detailed analysis of control schemes would only be warranted if the proposed approach precluded addition of control schemes and dynamic ratings at some point in the future <u>if justified</u>. In our view this argument highlights the potential role of option analysis. Turning the point in the PACR around, had Option 1b precluded later use of control schemes and access to <u>possibly</u> greater market benefit, option analysis would have been needed to assess the probability weighted benefit of that situation compared to another option that did provide flexibility. It would provide a different result to probability weighted analyses of scenarios with and without control schemes from the start.

11.4. High Impact Low Probability (HILP) Events

Following submissions to the PADR ElectraNet & AEMO have provided discussion about the impact of a prolonged outage of a transformer at Heywood. They note the impact would be severe but the probability of occurrence very low and hence the impact on net present value of such an outage would be low and immaterial.

We concur with this view if the loss leads to increased operational costs or load shedding of the order of the NEM Reliability Standard. However, if it is assumed that over time generation investment across the NEM adjusts to take advantage of increased interconnection capability pertaining to each option, then a prolonged outage at Heywood will reduce the effective capacity available to meet demand in South Australia. Where this adds to operating cost the probability weighted cost is likely to be immaterial as suggested by ElectraNet & AEMO. However, a prolonged outage may lead to more than minimal load shedding and in our view it should be priced considerably higher given the increased disruption and public policy and political implications which by definition are not considered in determining the wholesale energy price cap (MCP or typical network planning Value of Customer Reliability (VCR). However, there is no established mechanism to determine a value for more extensive interruption.

Of the three options identified to this point as possible preferred options this HILP effect is likely to favour Option 1b. The reason for this is that:

- prolonged deployment of a demand side scheme in Option 5 that is designed to cover only limited peak conditions is unlikely – this is not to say additional demand management could not be arranged at additional cost but we would expect there will be restrictions on the number of times the demand management options can be called in a year; and
- in Option 6b the limiting factor with one transformer out of service is likely to be the ability of the South Australian system to withstand loss of the remaining transformer, meaning the control scheme will be of no value during a prolonged outage of one of the transformers.

In summary, while accounting for HILP events is unlikely to change the market benefits significantly, to the extent there is any effect it is likely to enhance the value of Option 1b more than other options.

11.5. Competition benefit and firmness of SRA

At section 6.4 of the Heywood RIT-T ElectraNet & AEMO discuss competition benefits. They note that the RIT-T defines competition benefits as ”net changes in market benefit arising from the impact of the credible option on participant bidding behaviour”.

ElectraNet & AEMO also note a number of factors that complicate this analysis. We concur that modelling of changes in behaviours is problematic for the reasons noted.

ElectraNet & AEMO conclude that the complexity of such analysis would be disproportionate to benefit but nevertheless note that they did undertake some studies to test the possible significance of competition benefits. The result of that work (not reported in detail in the Heywood RIT-T), was that any competition benefits would be small. ElectraNet & AEMO note that Option 3, which involves a larger increase in interconnector capability, would be most likely to see the highest competition benefit, and Option 6b would see less than Option 1b. We concur with these comparisons but also concur that it would be inappropriate to rely heavily on competition benefits to distinguish between options.

A closely related matter is the degree of firmness of interconnector capability and this affects regional participation and whether the full benefits seen in least cost analysis will be realised.

NEM-wide modelling on a least cost basis or using market bidding behaviour implicitly assumes that if there is an economic benefit for investment that leads to generation-rich and load-rich regions on the basis of spot price outcomes, then it will occur. Put another way the implication is that there will be parties in one NEM region prepared to financially underwrite a regional surplus (via financial hedges) in another on the basis of the outcomes from the modelling – which do not assess market price. The Inter-regional Settlement Residue (IRSR) mechanism is a key means to make such underwriting commercially viable. However, the IRSR mechanism is only as firm as the prevailing level of interconnection flow and this lack of firmness can undermine the extent to which market based responses will match modelled outcomes.

Developments such as the AEMC’s Optional Firm Access may mitigate this as a risk over time but for the time being IRSR trading is affected by the firmness of the financial protection available. The impact of the different options on the operation of the IRSR process including the change in “firmness” has not been considered in the analysis and was not discussed by ElectraNet and AEMO. However, a directional conclusion about materiality can be reached from the following qualitative argument;

- If lack of firmness were material it would inhibit the ability of the options to deliver all of the capital deferral benefits observed in the modelling;
- Compared to the preferred option (Option 1b) firmness is likely to have a greater (negative) impact on Option 4 as this has only two transformers at Heywood and a lesser impact on Option 3 which adds another flow path;
- Discussion in section 9.3.3 above has already noted that Option 4 is unlikely to be superior to Option 1b; and
- Lack of firmness is likely to have a similar impact on other options and therefore not affect the relative ranking between them. As a result only Option 3 might see a relative improvement in its ranking.

The difference would be difficult to quantify, however, inspection of the capital deferral benefits between option 1b and 3 shows that depending on the scenario, around 25 per cent of the capital deferral benefits of Option 1b would need to be lost in order for Option 3 to show a higher net benefit. This would seem unlikely.

Hence, we conclude that neither firmness nor competition is likely to materially affect the ranking of options.

11.6. Summary

On the basis of the above analysis classes of market benefit that have not been quantitatively assessed are unlikely to be material and accordingly the list of classes of benefits assessed complies with the RIT-T.

12. Intra-regional congestion

12.1. South Australia

A number of stakeholders made reference to intra-regional congestion within South Australia in their submissions to the PADR, in particular International Power (GDF-Suez Australian Energy), Alinta, and NGF. In addition, following publication of the PACR, Macquarie Generation (supported by independent quantitative analysis of market benefits) expressed concern and sought clarification and increased transparency of the treatment of intra-regional congestion. A number of other submissions also discussed matters related to congestion in the south-east of South Australia.

These concerns related to three broad areas:

- Whether ElectraNet and AEMO had accounted for all relevant sources of congestion;
- Whether ElectraNet and AEMO had accounted for all relevant costs of projects that the RIT-T notes will be needed to reduce congestion to the level assumed in the analysis; and
- Transparency, in that details of half hourly flows were not released, meaning stakeholders were unable to review intra-regional flows.

ElectraNet & AEMO responded to submissions to the PADR in the PACR. In the PACR ElectraNet & AEMO included additional analysis and at pages 59 and 60 make explicit their view that for those options that include a package of works associated with the 132kV network (including removal from service of part of that network), the only constraint that they expect will remain will be associated with transformation at South East. However, they did not include detailed information on network flows.

In the PACR, ElectraNet & AEMO note that a prime reason the current level of congestion on the 132kV network will be relieved is that a section of the network creating significant limitation will be removed from service as it is old and requiring expensive maintenance. We note that it is common to see a progressive transition of meshed networks into a series of ‘spokes and hubs” over time, including to relieve loading on the weakest elements of parallel links such as in the south east of South Australia.

ElectraNet & AEMO note that one consequence of removal of part of the 132kV network from service is that a greater proportion of flow will be shifted onto the main 275kV network - as the division of flow in parallel paths within an electrical network is determined by the relative impedance of the paths and removal of part of the 132kV network will increase its impedance. This means there will be less flow in the 132kV network and its weakest link will no longer be present.

In response to Macquarie Generation's submissions (supported by analysis from Frontier Economics) following publication of the PACR and a subsequent meeting convened by the AER with ElectraNet and AEMO during the course of this review, further detail and information was provided by ElectraNet & AEMO covering:

- Hourly flow duration curves for all options under the Revised Central Scenario; and
- Histograms of the incidence of binding constraints.[5]

Macquarie Generation commented further on this material and observed that the incidence of congestion forecast within the RIT-T modelling in the next few years is higher than the current trend and that an explanation for this had not been provided. ElectraNet and AEMO noted that while it is feasible to extract hourly network flows the modelling was not configured to store these in readily accessible form and for that reason limited their response to the annual summary of binding constraints.[6] Macquarie Generation subsequently noted a number of detailed questions they considered that had not been answered by the annual summaries.[7]

Our view is that detail of hourly flow and limits will provide only some of the relevant information. The information can be expected to show network flow running up to a relevant limit based on the constraint equations released by ElectraNet a& AEMO dated 11 December 2013 (noted as part of the package of available information in section 2.1) . At best this information will confirm the trend already reported in the RIT-T. However, it will not address the key underlying point about whether future congestion will be reduced to the degree claimed unless the derivation of the future limits is also explained.

Limits, or rather the constraint equations, are inputs to market modelling and are based on separate analysis using loadflows and relevant dynamic analysis of the power system to determine coefficients of the relevant equations. New generation sites and changed loading patterns over time will mean these coefficients will be different to now, potentially significantly so. As a result the level of congestion can only be confirmed with knowledge of both the modelled flows and the basis of the constraints in each option.

Market modelling does not model intra-regional networks directly. It restricts inter-regional market flows according to constraint equations which account for consequential intra-regional network loading. Development of constraint equations is a process that involves extensive network modelling. It is not a single analysis that can be tabled readily for review – in practice results can only be tested by observation of actual network loading or from extensive in network modelling.

This situation is inherent to the regional design of the NEM: it applies for current operation of the market (using constraints developed in accordance with cl 3.8.19 of the NER) and future modelling. But the impact of constraints can be material and lack of detail is an inherent limit on transparency in both actual operation and modelling. This point was put to ElectraNet and AEMO in the meeting of 18 July. ElectraNet and AEMO advised that the development of constraints followed the same process to that used in actual operation of the NEM – this is recorded in the minutes of the meeting and further detail is provided by ElectraNet & AEMO in their letter of 24 July, both published on the AER website.

5 See ElectraNet/AEMO 21 June at http://www.aer.gov.au/node/19916

6 ElectraNet & AEMO noted that the analysis was undertaken on an hourly basis

7 See Macquarie Generation 8 July at http://www.aer.gov.au/node/19916

Therefore, absent a full recalculation of both likely flows and likely future constraints it is not feasible to numerically confirm the claims of a RIT-T proponent in this respect. As noted this is an inherent limitation of a process like the RIT-T in the NEM.

Accordingly review of credibility and plausibility becomes a key mechanism to assess the veracity of analysis. Proponents can also be called on to provide written statements on relevant matters. In the PACR ElectraNet & AEMO have included unqualified statements about the level of congestion expected in the future and associated explanations. In one matter the PACR was ambiguous and this created confusion as the text appeared to say certain constraints (including constraints in the network around South Morang in Victoria) had not been included. ElectraNet and AEMO were questioned on this point and gave written clarification that the intent was to note that the relevant constraints were not listed in the particular table in the PACR but had been included in the analysis. This was consistent with the full list of constraints and the histograms (noted above) where relevant constraints were noted as binding. Similarly ElectraNet & AEMO confirmed in writing that modelling accounted for operating conditions where the maximum capability of the upgraded interconnection would not be available. Relevant constraints do show as binding in the results presented.

More particularly, ElectraNet and AEMO were called on to provide written confirmation that all potential network constraints that might limit market benefits in the Heywood RIT-T had been included in the RIT-T analysis. This confirmation was provided and is published on the AER website.

12.2. Victoria

Stakeholder submissions raised concern about congestion within Victoria, in particular relating to the network around South Morang. ElectraNet & AEMO discuss this point in section 4.16 of the PACR where they note "…..These constraints remain significant limits on flows in South Australia." ElectraNet & AEMO then discuss the nature of shifting bottlenecks including limitations on other flows in South Australia.

In this same section ElectraNet & AEMO state "…..the relevant consideration in the RIT-T is whether net market benefits to the NEM are increased by moving to the next bottleneck and not whether specific areas of the NEM will become congested."

Our view is that this is a correct and logical interpretation. As these constraints limit the potential benefits of an augmentation it is crucial that they are accounted for. They are relevant to selection of credible options to the extent that different options may cost effectively provide greater benefits – such as in the case of Option 3.

There is, however, a judgement about the boundary of a project and what should require a separate RIT-T. This is essentially a practical matter. In this instance material benefits and a manageable package of work has been identified.

12.3. Summary

Relief of intra-regional congestion creates a significant percentage of the market benefits identified in the Heywood RIT-T. The preceding sections discuss why intra-regional congestion is the most difficult aspect to substantiate given the complex nature of intra-regional constraints.

The key requirement of the RIT-T is that a proponent must determine which credible option is expected to deliver the greatest market benefits and cl 5.16.6 requires that the AER is satisfied this has been done. In respect of network constraints, all constraints may impact on the assessment of the preferred option. Some constraints have an obvious form – for example a transformer thermal limit – others such as the intra-regional network constraints for the south east of South Australia are more complex.

The RIT-T requirement is for analysis to be undertaken in a "predictable, transparent and consistent manner". In the interests of transparency, stakeholders have sought higher levels of detail than initially provided. ElectraNet & AEMO have provided additional information but less than was sought. The analysis in the preceding paragraphs concludes that the detail being sought would have provided only part of the information needed to fully validate the analysis of market benefits and begs the question about what level of detail is adequate and practical.

We consider that together, provision of:

- Written advice that the internal process (provided to AER) used to develop constraints used within the Heywood RIT-T is equivalent to the process employed for operation of the NEM in practice;
- A listing of all constraint equations - released by ElectraNet & AEMO on 21 December 2012;
- Annual summaries of binding constraints;
- Plausible explanations (quantitative in part and qualitative in other respect) for all points about intra-regional congestion raised by stakeholders (including each of the eight issues listed by Macquarie Generation in its letter dated 8 July and addressed by ElectraNet & AEMO in their reply of 24 July);
- Written confirmation that all relevant potential constraints have been accounted for; and
- Written confirmation that costs for relief of intra-regional congestion assumed have been incorporated

  is a satisfactory demonstration in the circumstances that relevant and appropriate consideration of intra-regional constraints has been incorporated in the Heywood RIT-T and that it therefore meets the requirements of the RIT-T in this respect.

We also note that the additional information and cross-checking in response to stakeholder submissions has enhanced that demonstration.

However, detailed chronological network flows from the market modelling have not been provided. As noted if chronological results were released they would not detail sub-regional flows and would not demonstrate that new/amended constraint equations were accurate. ElectraNet & AEMO's advice is that extracting detailed flows within the market model is possible but would require significant effort and therefore cost. While this information would clearly add some information it would not be determinative and the information provided represents a plausible and consistent demonstration within the inherent limitations of the NEM design and the provisions of the RIT-T.

13. Are there credible options not considered by ElectraNet & AEMO?

To this point the focus of this review has been on the nine credible options assessed in detail by ElectraNet & AEMO. This section considers ElectraNet & AEMO's responses to submissions from stakeholders suggesting alternative options.

Looking at the alternatives in the order in which they appear in the PACR:

13.1. Stand-alone South East control scheme

In effect ElectraNet & AEMO argue (see section 4.13 PACR) that this alternative would be viable if it were to be part of a longer term development, but if not, while it will deliver market benefits, these will not be sufficient to warrant the cost.

However, net benefits from this alternative are sensitive to demand (see Table 4.1 PACR) and the breakeven point appears to be a demand reduction of between 10 and 20 per cent. ElectraNet & AEMO also note there are some circumstances in which a South East control scheme will be beneficial and nothing will preclude it being added at a later stage. On the information presented this may eventuate but will be dependent on decisions by individual large customers.

On this basis it is reasonable to conclude that an option for a stand-alone south east control scheme would not deliver higher benefits than the identified preferred option.

ElectraNet & AEMO also note that short term ratings for the South East transformers are being investigated but any enhancements would be outside the current Heywood RIT-T proposal. As noted in section 2.1 ElectraNet & AEMO noted in their letter of 21 June that they consider there is now sufficient certainty about demand to include a control scheme affecting the operation of South East Transformer in the project Also as noted we understand that a change of this nature would fall outside the formal Heywood RIT-T process.

13.2. Expanded South East 132kV control scheme

ElectraNet & AEMO have concluded that removal of the lines to which this alternative would be directed is a better approach to managing the relevant limitations. On the basis of the analysis presented this appears correct.

At a very general level it is also not surprising to see older network elements removed from service as part of a mitigation approach to managing network constraints as the network in the South East was developed with little generation in the area and no interconnection – see section 5.2 valid.

13.3. Option 1b plus Option 6a

ElectraNet & AEMO acknowledge the potential for significant increase in interconnector capability by combining these two credible options. However, they argue against this alternative <u>within the current RIT-T</u> on practical grounds. They note the likelihood that significant delay would be incurred in order to undertake the extensive technical studies that would be needed in light of the significant increase in capacity that would be involved, and the concerns that would be likely to arise regardingcommercial and technical matters related to the control schemes in Option 6a.

Concern about delay to allow time for analysis of what would be a major change in network operation is reasonable. We am less convinced that the effort required to resolve commercial and outstanding issues relating to the control schemes would pose a major impediment.

But we concur with the point made by ElectraNet &AEMO as follows " *….the only justification for a delay would be if implementation of any solution now prevented a higher net benefit solution being implemented at a later date"* see PACR page 60. ElectraNet & AEMO then note that Option 6a can be added to Option 1b at a later stage without sacrificing the benefits from early implementation of Option 1b (or other derivatives of its design).

In effect ElectraNet & AEMO are saying that had the regulatory process just started, this alternative may have more merit. But given the effort that has already been expended starting with the Joint Feasibility study (which would need to be repeated), it is counter-productive to forgo obtaining the benefits expected to be derived from Option 1b as soon as possible given Option 1a can be added later. I do note no estimate of the time delay that would be involved has been given. However, this seems a persuasive argument in the circumstances. However, as noted above ElectraNet and AEMO have advised an intention to add a control scheme to the Heywood Interconnector Upgrade project. While this is a logical extension foreshadowed by the discussion in the PACR we understand it will fall outside of the formal Heywood RIT-T process.

13.4. Higher rated transformers at Heywood (in conjunction with a control scheme to manage Heywood transformer loading)

ElectraNet & AEMO report advice from SP AusNet that a combination of technical considerations relating to the construction of the Heywood and South East transmission lines, and the need for extended outages if Heywood transformers were to be replaced, make this alternative impractical.

13.5. Alternative approaches to managing intra-regional limitations in South Australia

A number of submissions proposed alternatives to managing the 132kV intra-regional constraints the including addition of a third transformer at South East, and expressed general concern as to whether the proposals would be effective in managing these constraints.

ElectraNet & AEMO note that Option 2a provides assessment of the impact of a third South East transformer. I also note that Option 2b is a comparison of the effect of the third South East transformer with Option 1b.

Submissions also called for consideration of variants of Option 4 including coupling a third transformer with this option. ElectraNet & AEMO’s response was, in effect, that other cases with higher starting benefits (e.g. Option 1a) have shown the benefits of the third transformer are limited and it is reasonable to expect that inclusion with Option 4 (which in itself is lower than Option 2a in all scenarios) will not realise higher benefits. I concur with this logic.

Of the different submissions ElectraNet & AEMO acknowledge that dynamic transformer ratings are the most prospective.

13.6. Staged approaches

In section 4.13 of the PACR ElectraNet & AEMO note that a number of submissions suggest consideration of alternatives to stage the timing of development of different options. ElectraNet & AEMO provide reasonable explanations of technical reasons why the alternatives suggested are not practical.

13.7. Alternative options – concluding comment

In summary there is merit in a number of the proposed alternatives indicating informed engagement by stakeholders. However, on balance each of the responses from ElectraNet & AEMO appear to be reasonable and pragmatic in the circumstances.

In reaching this conclusion I am aware that stakeholders and ElectraNet & AEMO are dealing with a long time frame and complex technical and commercial matters within a regulatory process defined by the NER. While the NER requires a TNSP to assess credible options it also allows for a TNSP to not consider particular options on the basis of excessive cost, time or complexity of analysis. ElectraNet & AEMO have relied on this type of provision in a number of cases but have also generally provided technical or commercial bases as well. It is a matter of judgement as to whether the discretion has been reasonably exercised and this will determine how many and how deeply alternative suggestions are examined.

Finally I note that:

- In respect of alternative suggestions in a number of cases the reasonableness of arguments against further analysis in the eyes of stakeholders, , for example about short term ratings and additional control schemes, may depend on the future assessments foreshadowed by ElectraNet & AEMO actually occurring. In this regard I note that other than the last resort planning powers, the NER does obligate these future considerations;
- The last resort planning power is specifically limited to inter-regional flow paths. It has not been tested and it is not clear where the boundary between inter-regional and intra-regional would lie; and.

  This RIT-T is dealing with a complex set of technical and commercial issues for mechanisms to facilitate increased market benefits and it is understandably very difficult for stakeholders to engage via written submissions. The AER may wish to consider how to facilitate more flexible exchanges in future applications.

14. Costs

The RIT-T is a cost benefit analysis and therefore requires cost in order to calculate net benefit.

Capital costs for generation have been addressed earlier in this report in the sections dealing with generation investment schedules are from sources used extensively by AEMO in preparation of the National Transmission Network Plan and Electricity Statement of Opportunities. These data are consulted on widely and no stakeholder comment was critical of these estimates. It is reasonable therefore to accept these costs as meeting the requirements of the RIT-T.

Fuel costs have also been drawn from AEMO sources and consulted on previously. Section 10.1 discusses concern in stakeholder submissions that cost of gas post 2030 is too high. ElectraNet and AEMO defended the costs used. The critical question for this review of the RIT-T is whether lower gas costs post 2030 would be likely to change the ranking between options and in section 10.1 we concluded that this was unlikely. Accordingly, it is reasonable to conclude that the requirements of the RIT-T have been met.

Similarly the costs for demand management have also been discussed in consideration of Option 5 where it is noted that ElectraNet & AEMO have adopted the cost framework proposed by a major proponent of demand management EnerNOC. These costs have not been challenged by others.

The source of costs for control schemes were the subject of considerable stakeholder comment including in relation to the independence of the estimates – see Infigen submission for example. In section 4.10 of the PACR ElectraNet and AEMO noted that the costs prepared by the external advisor engaged to advise on control schemes (David Strong and Associates - DSA) were unable to cover a number of related cost elements such as those related to plant protection systems. In adopting capital costs aligned with SP AusNet advice ElectraNet & AEMO note the lower end of the range of possible costs was adopted. However, the operating cost proposed by DSA was used and sensitivities run, as described in the PACR. These costs are relatively small relative to overall costs and benefits assessed in the Heywood RIT-T and unlikely to affect the ranking of options and therefore seem fit for purpose.

The proposal in the Heywood RIT-T involves a combination of new items of plant, enhancement of existing network and removal from service of existing network creating new costs and some savings making external review difficult.

Capital costs for elements such as transmission line, transformer and reactive plant were itemised in the PADR and carried forward into the PACR. No stakeholder submission criticised the values although there were submissions calling for independent review which has not been provided. With some exceptions the costs align with values in the earlier Joint Feasibility Study which was also subject to consultation and informed by external advice in relation to costs.[8]

An independent submission in relation to the Feasibility Study considered the new transmission line build costs to be too low but costs for other elements reasonable, although subject to uncertainty where changes were being made to existing network. Other than in Option 3 new lines and easements are not involved in the Heywood RIT-T.

In the Heywood RIT-T it is notable that ElectraNet & AEMO have allowed a markedly higher cost for 132kV works within South Australia than was allowed in the Feasibility Study.[9] In the context of stakeholder comments about the independence of network cost estimates it is useful to note the potential for an indirect discipline on ElectraNet in that while the outcome of a RIT-T cost benefit analysis will be more favourable if costs are assumed to be low, this may (subject to AER determination) mean a lower addition to the revenue base in the future.

Operating costs are generally significantly less than capital costs. ElectraNet & AEMO have allowed a generic two per cent of asset costs for operating costs but have not provided justification for this figure - except in the case of the control schemes as noted above. For the Heywood RIT-T the relevant issue is the change in operating cost for the new assets at existing sites - except for Option 3 which is not in contention as preferred option. The change in cost is therefore complex to assess.

8 http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Network-Operations/NEM-South-Australian-Interconnector-Feasibility-Study-Final-Report and in the interests of full disclosure the author of this review also provided peer review of the Feasibility Study, accessed August 2013

9 Submission by John Diesendorf at http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Network-Operations/NEM-South-Australian-Interconnector-Feasibility-Study-Final-Report, accessed August 2013

There are few sources of reference for operating costs on an asset by asset basis. Most formal regulatory processes focus on operating costs of businesses rather than individual projects or assets. There is also a risk in making comparisons based on a percentage of asset cost given the wide range of factors that can influence operating cost, including geographic and load diversity and scale.[10] However, a paper recently developed in the context of the UK industry provides a mechanism to illustrate the relative size and influence of relevant factors on a range of transmission technologies.[11] On balance we consider the generic two per cent allowance to be reasonable and therefore meet the requirements of the RIT-T.

15. Preferred option

ElectraNet & AEMO conclude that Options 1b and 6b were potential preferred options on the basis of quantified market benefits but concluded Option 1b should be the preferred option. To this point this review has suggested Option 5 should be included as a candidate for preferred option as well.

For Option 1b *not* to be the preferred option:

- In Option 5 the financial benefits of the deferral of network expenditure and substitution of demand management for OCGT investment in the early years would need to outweigh the cost of a demand management program plus any so far unaccounted benefits (and costs); or
- In Option 6b the full costs of the control schemes would need to be less than the cost of the third transformer, including costs and agreements for participation in control schemes by relevant new entrants plus any so far unaccounted benefits (and costs).

As noted in section 9.3.3, Option 5 appears to rank well below Option 1b and 6b in the weighted average analysis as ElectraNet & AEMO have used the same size demand management program in all scenarios.

In the current circumstances, however, we can note that while the cost of the demand management program in Option 5 is of the same order as the OCGT plant it is a substitute for, the principal economic benefit of Option 5 in the current case is the financial benefit of deferral of network expenditure offset by deferral of operating cost benefits from increased network capability. For the deferral time proposed, if the sizing were to be as proposed by ElectraNet & AEMO Option 5 has a weighted average benefit below that of Option 1b and would be clearly inferior to Option 1b. On this basis, given the cost structure of the particular program there would be no clear benefit to adopt Option 5.

In respect of Option 6b, as noted we consider that factors such as SRA firmness and HILP costs as well as the points noted by ElectraNet & AEMO associated with contract set up favour Option 1b.

On this basis we conclude that on balance ElectraNet & AEMO have correctly identified Option 1b as the preferred option in this circumstance. Finally we note future consideration of demand management programs would be made more complex if there were a clear cost difference.

10 See a discussion prepared by Benchmark Economics for Western Power (2005) - http://www.erawa.com.au/cproot/2660/2/Appendix%202%20%20Benchmark%20Economics%20report%20Vol%202.pdf

11 See http://www.atvinnuvegaraduneyti.is/media/fylgigogn-raflinur-i-jord/9-Transmission-report.pdf, accessed August 2013