South Australia – Victoria (Heywood) Interconnector Upgrade

RIT-T: Project Assessment Conclusions Report

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Executive summary

This Project Assessment Conclusions Report (PACR) has been prepared by ElectraNet and the Australian Energy Market Operator (AEMO) in accordance with the requirements of the Regulatory Investment Test for Transmission (RIT-T) process set out in the National Electricity Rules (NER). The PACR is the third and final stage of the RIT-T process.

The PACR recommends no change to the preferred option from the Project Assessment Draft Report (PADR) for investment to increase the transfer capability of the South Australia to Victorian (Heywood) Interconnector. The PACR shows that this option delivers a net market benefit through significant reductions in generation dispatch costs over the longer term.

The preferred option to install a third transformer and 500 kV bus tie at Heywood in Victoria, series compensation on 275 kV transmission lines in South Australia, and 132 kV network reconfiguration works in South Australia is expected to increase interconnector capability by about 40% in both directions. This would enable increased wind energy exports from South Australia and also increase imports of lower cost generation into South Australia, particularly at times of peak demand.

The estimated commissioning date for this option is July 2016. The total capital cost of the option is estimated at $107.7m ($2011/12, equating to $79.8m in present value terms), reflecting $45.0m investment in Victoria and $62.7m in South Australia, with net market benefits of more than $190m (in present value terms) over the life of the project with positive net benefits commencing from the first year of operation.

Identified need

The Heywood Interconnector is located between the South East (South Australia) and Heywood (Victoria) substations. Historically this interconnector has predominantly been used to import power into South Australia. However over the past few years, with the addition of significant amounts of wind generation in South Australia, the interconnector is also being used to export power from South Australia.

The 'identified need' for the proposed investment is an increase in the sum of producer and consumer surplus, i.e., an increase in net market benefit.

Two main limitations currently affecting the Heywood interconnector have been identified. The first involves thermal capabilities and voltage stability limitations in south-east South Australia. The second is the transformer capacity at Heywood. Alleviating both these limitations would increase the import and export capability of the interconnection. ElectraNet and AEMO consider that increasing the capability of the interconnection will achieve an overall increase in net market benefit in the National Electricity Market (NEM). This is demonstrated in the analysis presented in this PACR.

Credible options included in the assessment

The following nine options have been included as potential credible options in the RIT-T analysis:

- Option 1a – Installation of a 3rd 370 MVA 500/275 kV transformer at Heywood and 500 kV bus tie, plus a 100 MVAr capacitor at South East substation and reconfiguration of the 132 kV network between Snuggery-Keith and Keith-Tailem Bend (South Australia). Estimated commissioning date of July 2016.
- Option 1b – Installation of a 3rd 370 MVA 500/275 kV transformer at Heywood and 500 kV bus tie, plus 275 kV series compensation in South Australia and reconfiguration of the 132 kV network between Snuggery-Keith and Keith-Tailem Bend (South Australia). Estimated commissioning date of July 2016.
- Option 2a – Construction of a 3rd 160 MVA 275/132 kV transformer at South East substation plus Option 1a.
- Option 2b – Construction of a 3rd 160 MVA 275/132 kV transformer at South East substation plus Option 1b.
- Option 3 - Construct a new Krongart-Heywood 500 kV interconnector and associated 275 kV works between Krongart and Tungkillo (South Australia). Staged works, with estimated commissioning dates of July 2025 and July 2030.
- Option 4 – Option 1a minus 3rd 500/275 kV transformer at Heywood.
- Option 5 – Five-year, 200 MW demand management (DM) program beginning in 2013 plus Option 1b, deferred by two years (therefore an estimated commissioning date of July 2018).
- Option 6a – Control scheme applying to specific wind generation in South Australia and the South East substation, and a 500 kV bus tie at Heywood. Estimated commissioning date of July 2015.
- Option 6b – Control scheme applying to specific wind generation in South Australia and the South East substation (estimated commissioning date July 2015) plus Option 1b, minus the 3rd 500/275 kV transformer at Heywood (estimated commissioning date of July 2016).

Many of these credible options involve different combinations of particular investment components.

These credible options were developed following a process of detailed consideration of potential investment components, particularly in relation to the works in South Australia. This analysis involved detailed consideration of the:

- Existing thermal capacity limitations due to the low capacity 132 kV lines (Snuggery-Keith and Keith-Tailem Bend #1) which are operated in parallel with the South East-Tailem Bend 275 kV transmission lines.
- Condition and age of the low capacity 132 kV transmission lines.
- Impact of those lines on existing and anticipated network constraints.
- Impact of the removal of those lines on thermal capacity, local voltages, voltage/transient stability reductions and the South East transformer constraints.

Apart from Option 3, in all cases these options relate to works either within or close to existing substation boundaries and do not involve new line works.[1]

[1] Note that the series compensation will be built at a new site, where ElectraNet already owns the land.

Options 5, 6a and 6b all include a non-network component, reflecting non-network options identified in earlier submissions to the Project Specification Consultation Report (PSCR) by stakeholders. For Options 5 and 6b the non-network component has been considered together with a network component, as market modelling analysis identified that these combinations would have a greater net market benefit than the non-network component alone.

Option 4 is also added to take into account submissions to the PSCR by stakeholders. This option considers the benefits of only alleviating existing limitations in the south east of the South Australia network and firming up the existing notional interconnector limit of +/- 460 MW.

The notional (maximum theoretical) interconnector capabilities provided by these options are shown in Table E-1 below, with the preferred option highlighted. The interconnector transfer capability achieved at any point in time will be subject to network and local conditions such as the level of demand, and generation dispatch outcomes. The limits shown for Options 6a and 6b would be under high wind output in south east South Australia and would reduce with lower levels of wind generation. Without additional wind farms in the south east of South Australia, the notional limit for Option 6b would be 570 MW.

Table E-1: Notional interconnector limits for options (MW)

Option	Description	Notional limit (MW)		Change from current (MW)	
		SA to VIC	VIC to SA	SA to VIC	VIC to SA
Option 1a	3rd Heywood transformer + 100 MVAr capacitor + 132 kV works	550	550	90	90
Option 1b	3rd Heywood transformer + series compensation + 132 kV works	650	650	190	190
Option 2a	Option 1a + 3rd South East transformer	550	550	90	90
Option 2b	Option 1b + 3rd South East transformer	650	650	190	190
Option 3	New Krongart-Heywood 500 kV interconnector + 275 kV works	2,400	2,400	1,940	1,940
Option 4	132 kV works + 100 MVAr capacitor	460	460	-	-
Option 5	200 MW DM + Option 1b	650	650	190	190
Option 6a	Control schemes + 500 kV bus tie	550	460	90	-
Option 6b	Control schemes + Option 1b minus 3rd Heywood transformer	570 / 690*	460	110-230	-

** Note the 690MW notional limit depends on additional wind connecting in the Krongart region of South Australia.*

Scenarios analysed

ElectraNet and AEMO have adopted the following four reasonable future scenarios in undertaking the RIT-T analysis presented in this PACR (the weight applied to each scenario is shown in brackets):

- **Scenario 1**: Central scenario (29%) – assumes medium economic and demand growth (consistent with the 2011 ESOO), the core Treasury carbon price projections and a central view regarding the earliest timings for new technologies.
- **Scenario 2**: Low scenario (13%) – assumes low economic and demand growth (consistent with the 2011 ESOO), the high Treasury carbon price projections and delays the assumed timings for new technologies by two years.
- **Scenario 3**: High scenario (17%) – assumes high economic growth, high demand growth (consistent with the 2011 ESOO, and modified to include additional new spot-loads in the Eyre Peninsula and at Olympic Dam), the core Treasury carbon price projections and brings forward the assumed timings for new technologies by two years.
- **Scenario 4**: Revised central scenario (41%) – assumes medium economic and demand growth (consistent with AEMO's 2012 National Electricity Forecasting Report) and a central view of the earliest timings for new technologies[2]. Scenario 4 also includes a lower carbon price assumption than in the other three scenarios, specifically three years of a fixed carbon price and the legislated carbon floor continuing beyond 2017.

These scenarios reflect a wide range of variations in assumptions in relation to those variables that may materially affect the relative assessment of options under the RIT-T, including differences in future demand levels and future carbon prices.

Market benefits

The assessment conducted under this RIT-T has involved detailed market modelling using a market dispatch model (Prophet), combined with the development of alternative generation expansion plans (utilising PLEXOS software).

Table E-2 summarises the net market benefit in net present value (NPV) terms for each credible option. The net market benefit for each option (the present value (PV) market benefits minus the PV cost) reflects the weighted net market benefit across the four reasonable scenarios considered. The table also shows the corresponding ranking of each option under the RIT-T, with the options ranked from 1 to 9 in order of descending net market benefit. Option 1b, the preferred option, has been highlighted.

[2] The central view corresponds with the estimated 'First year available for construction' provided for each technology in the Worley Parsons report: *Cost of construction New Generation Technology*, 10 July 2012. Available: http://aemo.com.au/Electricity/Planning/Related-Information/2012-Planning-Assumptions.

Table E-2: Net market benefit for each credible option (PV, $2011/12m)

Option	Description	Costs	Market benefit	Net market benefit	Ranking under RIT-T
Option 1a	3rd Heywood transformer + 100 MVAr capacitor + 132 kV works	57.8	222.2	164.4	4
Option 1b	3rd Heywood transformer + series compensation + 132 kV works	79.8	270.5	190.8	=1
Option 2a	Option 1a + 3rd South East transformer	70.7	227.5	156.8	6
Option 2b	Option 1b + 3rd South East transformer	92.7	270.4	177.7	3
Option 3	New Krongart-Heywood 500 kV interconnector + 275 kV works	212.2	303.0	90.8	8
Option 4	132 kV works + 100 MVAr capacitor	30.6	155.6	125.0	7
Option 5	200 MW DM + Option 1b	147.1	304.1	156.9	5
Option 6a	Control schemes + 500 kV bus tie	17.6	18.5	1.8	9
Option 6b	Control schemes + Option 1b minus 3rd Heywood transformer	64.1	253.1	190.0	=1

The results of the NPV assessment highlight that the key categories of market benefit for this RIT-T are changes in fuel consumption and changes in generation investment costs. Changes in network losses and involuntary load shedding (unserved energy) form only a very minor part of the market benefit calculated for any of the nine options.

This result holds across all four scenarios modelled. The pattern of market benefits varies over time, across scenarios, and between options (particularly between Option 3 (new Krongart 500 kV interconnector) and the other options). However in all cases market benefits are driven by enabling an increase in output from lower operating cost and low emission generation sources, displacing output from higher operating cost and/or higher emission generation sources.

The precise nature of the change in generation dispatch varies with the reasonable scenario considered. Under scenarios 1, 2 and 3, the majority of the options result in an *increase* in investment in low operating cost and low emission generation (i.e. an overall market cost), the cost of which is off-set by the resulting reductions in dispatch costs. In scenario 4 this additional generation investment does not occur to the same extent due to lower demand and fewer coal-fired plant retirements. However, there are still substantial market benefits from changes in existing generation under scenario 4.

Table E-2 shows that all of the credible options considered have a positive net market benefit. As a consequence, all of the options are ranked higher than the 'do nothing' option,[3] and could be expected to deliver an overall net benefit to the market.

The results show that:

- Option 6a (Stand-alone control schemes + bus tie) is a clear outlier in terms of net market benefit, with an overall net market benefit orders of magnitude below that of the other credible options.
- The higher cost of Option 3 (new Krongart-Heywood 500 kV interconnector + 275 kV works) is not outweighed by substantially higher benefits, compared to the other options; resulting in the overall net market benefit for this option being materially below that of other options.
- The lower costs for Option 1a (which includes a 100 MVAr capacitor) do not offset the lower market benefits of this option, compared with Option 1b (which include series compensation), resulting in Option 1a having a lower net market benefit than Option 1b.
- The incremental costs of adding the 3rd transformer at South East substation under Options 2a and 2b are not offset by the additional market benefits.
- There are additional net benefits with including the 3rd Heywood transformer (Options 1a and 1b) compared with only undertaking the 132 kV works in South Australia and installing a 100 MVAr capacitor (Option 4).
- The additional market benefit associated with including a DM component (Option 5) is outweighed by the higher cost of that option compared with the network component alone.

It is also clear from Table E-2 that Option 1b (3rd Heywood transformer + series compensation + 132 kV works) and Option 6b (Control schemes + Option 1b, minus 3rd Heywood transformer) have the highest net market benefit, but cannot be materially distinguished on the basis of net market benefit alone.

The impact of the control schemes is to expand the export capacity from South Australia at lower cost than with the 3rd Heywood transformer. Option 6b therefore has greater market benefits under those scenarios in which there is substantial investment in renewable generation in South Australia which is then exported, i.e. the high and low scenarios. In contrast, adding a 3rd transformer at Heywood increases both the import and export capability of the interconnector. Option 1b therefore enables additional exports from South Australia, albeit at a lower level than is facilitated by the control schemes, whilst also enabling increased imports of lower cost generation into South Australia.

The difference in net market benefit between Option 6b and Option 1b is only $0.8m, or 0.42% of the total net market benefit estimated for Option 1b. The relative ranking of these two options is sensitive to relatively small changes in key input assumptions (as shown by the sensitivity analysis presented in

[3] The base case is equivalent to 'doing nothing', and represents the system as-is. Market benefits are calculated by comparing the option results with the base case.

this PACR). However in no cases does either option emerge with a substantially higher net market benefit than the other. The net market benefit between Option 6b and Option 1b is therefore essentially the same, across all of the scenarios considered.

The relative ranking of Option 6b and Option 1b is also not affected by changes that increase the weighting given to scenario 4, i.e., low demand, low carbon price. The net benefits from both options increase under scenario 4. Increasing the weighting given to this scenario results in Option 1b continuing to be ranked ahead of Option 6b, although the difference between the options is still not material.

ElectraNet and AEMO note that there are several core investment elements which are common across both of these options, namely:

- Reconfiguration of the 132 kV network between Snuggery-Keith and Keith-Tailem Bend (South Australia).
- 275 kV series compensation in South Australia.
- The installation of a bus tie at Heywood.

These investment components therefore clearly form part of the preferred option.

The question is therefore whether these 'core' network components should be coupled with a 3rd transformer at Heywood (Option 1b) or control schemes at Heywood and South East (Option 6b).

ElectraNet and AEMO note that there is substantial uncertainty in relation to the commercial feasibility of the control schemes, as issues relating to liabilities and associated indemnities would need to be worked through. It is anticipated that significant further work would be required, with an uncertain outcome, since initial investigation of commercial issues indicates that the commercial issues are not straightforward. The issue of technical feasibility would also need to be subject to further detailed investigation, particularly in relation to issues of wider system security and the overload ratings of the Heywood transformers.

Given that the RIT-T analysis has not shown that there would be substantial additional benefits associated with adopting the control scheme rather than a 3rd Heywood transformer, ElectraNet and AEMO do not consider that the additional time and costs required to conclusively address the uncertainties identified above would be warranted. Undertaking this assessment would delay the finalisation of the current process, and the time at which the investment could be implemented. The RIT-T analysis has shown that Option 1b is expected to deliver market benefits from the year in which it is commissioned. Delay in making an investment decision would deprive the market of $10m to $30m of annual benefits. In addition, undertaking this further analysis would not be expected to increase the estimated net market benefits of Option 6b and, if anything, may decrease its estimated net market benefits if additional investments are required to ensure technical feasibility.

ElectraNet and AEMO also note that the higher transfer capacity associated with Option 6b is predicated on there being additional wind generation locating near Krongart. However, there remains substantial uncertainty surrounding these developments, with no proposals for new generation currently nearing committed status.

ElectraNet and AEMO also note that proceeding with Option 1b does not preclude the potential addition of either or both of the Heywood and South East transformer control schemes at a later stage. In particular, the market benefits of a stand-alone control scheme in the south east of South

Australia will continue to be monitored by ElectraNet to assess the viability of investment independently of this RIT-T. However deferring development of these components represents a prudent staged approach to augmenting the Heywood interconnector capability considering future uncertainties.

In the light of the uncertainties associated with selecting the control scheme component, in preference to the technical and commercial certainty of adding a 3rd transformer at Heywood, ElectraNet and AEMO have determined that the preferred option for investment is Option 1b: installation of a 3rd transformer at Heywood and 500 kV bus tie, plus 275 kV series compensation in South Australia and reconfiguration of the 132 kV network between Snuggery-Keith and Keith-Tailem Bend (South Australia).

Following completion of the detailed design phase of this augmentation, and the update of the operational NEM constraint equations to reflect the 650 MW nominal interconnector limit, the economic benefits of further expanding interconnector capacity will be subject to ongoing review by AEMO and ElectraNet through established national and joint planning processes.

Changes from the Project Assessment Draft Report

The NER requires that the PACR include the matters required to be included in the earlier PADR, together with a summary of, and responses to, any submissions received in response to the PADR. Accordingly, this PACR repeats much of the material and analysis presented in the earlier PADR. However the discussion and analysis has been revised where relevant, to address points raised in submissions as well as further analysis by ElectraNet and AEMO since the publication of the PADR. The PACR also elaborates on some aspects of the process and analysis undertaken for this RIT-T, where submissions have indicated that the detail in the earlier PADR may not have been sufficient. A detailed summary of the issues raised in submissions and ElectraNet and AEMO's response to those issues is contained in section 4 of this PACR.

Key changes to the PACR resulting from PADR submissions include the following:

- The operating costs of the control schemes included in Options 6a and 6b have been revised to reflect the adjusted [4] estimate of those operating costs made by David Strong and Associates (DSA), rather than the generic assumption that had been used in the PADR.
- The sensitivity analysis undertaken has been expanded, and encompasses variations in the assumed capital costs for the control scheme (including the removal of the telecommunications costs), +/- 30% changes in assumed network costs, a higher discount rate (16%) and a shortened analysis period (20 years).
- The PACR also includes a discussion of the preliminary quantification of the benefits associated with a reduction in the impact of a major transformer outage at Heywood. This analysis shows that the probability-weighted magnitude of this benefit is in the order of $5.6m (probability-adjusted, net present value across the assessment period, assuming a 10% discount rate), for options which include a 3rd transformer at Heywood.
- The individual net market benefits for each credible option, under each scenario including for scenario 4, which reflects low demand and low carbon price assumptions and does not

[4] A sensitivity using the non-adjusted DSA costs has also been included in Section 6.3.2.

assume the closure of Hazelwood or the conversion of Playford. The robustness of the RIT-T assessment to different scenario weightings has been expanded, to include placing additional weight on scenario 4.

- Consideration of a number of variants to the credible options included in the PADR, as proposed in submissions, including the addition of a control scheme at South East substation to consider the constraint arising due to the South East Transformers as part of Option 1b; addition of a control scheme at both Heywood and South East as part of Option 1b; and the replacement of the existing Heywood transformers with units with higher short term ratings.

Several submissions suggested that the RIT-T analysis should be expanded to include additional scenarios, relating to low demand and low carbon prices. ElectraNet and AEMO consider that the four scenarios considered in the analysis already adequately capture an appropriate range of different assumptions in relation to future demand and carbon prices. Scenario 4 reflects the medium demand forecast in AEMO's 2012 National Electricity Forecasting Report (NEFR), which is substantially below the demand forecasts in the other scenarios (which are based on forecasts in the 2011 Electricity Statement of Opportunities). It also reflects a low carbon price assumption, as well as no forced closures of brown coal generation, or conversion of Playford B. The RIT-T analysis shows that the net market benefit of the preferred option (Option 1b) is actually higher under this low demand, low carbon scenario than it is under Scenario 1, which has both higher demand and a higher carbon price. The realisation of net market benefits is therefore not dependent on a high demand and high carbon price environment, and is robust across a wide range of valid assumptions as to future developments.

Sensitivities conducted in relation to the weightings applied to each of the scenarios indicate that the RIT-T outcome is robust to a wide-range of alternative weightings, including those where a substantially higher weighting is given to the low demand, low carbon scenario, i.e., scenario 4. Further, the preferred option (Option 1b) is preferred under scenario 4 when considered on a standalone basis. Given this result, ElectraNet and AEMO do not consider that the substantial costs of undertaking additional market modelling in order to incorporate further scenarios would be justified, as it would not be expected to materially impact the outcome of the RIT-T assessment.

The scenario analysis incorporated in the RIT-T assessment is also the means by which uncertainty in relation to future outcomes is addressed. There will always be uncertainty in relation to key parameters such as the future demand level, the development of new technologies and future policies (including but not limited to carbon pricing). Delaying the finalisation of the RIT-T assessment, as called for in submissions by some stakeholders, will not remove this uncertainty, particularly given the long life of the assets involved in this investment. Whilst some issues may become clearer over time, other uncertain issues can be expected to emerge. ElectraNet and AEMO consider that the range of assumptions adopted in the reasonable scenarios used for this analysis adequately addresses future uncertainties, and ensures that the investment decision is robust across potential different futures.

Preferred option and next steps

The preferred option for investment is Option 1b: installation of a 3rd transformer at Heywood and 500 kV bus tie, plus 275 kV series compensation in South Australia and reconfiguration of the 132 kV network between Snuggery-Keith and Keith-Tailem Bend (South Australia). This option satisfies the RIT-T. The estimated commissioning date for this option is July 2016. The total capital cost of this option is estimated at $107.7m ($2011/12).

This PACR represents the final stage in the RIT-T process. The Rules provide for any dispute to the decision to proceed with the preferred option to be lodged with the AER by 22 February 2013. If no formal dispute is raised or on the resolution of any dispute, ElectraNet will commence the pre-investment activities necessary to proceed with the South Australian components of the preferred option, including seeking a formal determination by the AER[5] in the first half of 2013 that the proposed investment satisfies the RIT-T, followed by seeking AER approval of this investment as a contingent project. AEMO will develop a functional requirements specification for the Victorian components of the preferred option, which is expected to be put to tender in the second half of 2013.

[5] Under clause 5.16.6(a) of the National Electricity Rules.

Contents

Appendix I – NPV and generation data – See separate spreadsheet.

Tables

Figures

1 Introduction

1.1 Overview

This Project Assessment Conclusions Report (PACR) has been prepared by ElectraNet and the Australian Energy Market Operator (AEMO) in accordance with the requirements of the National Electricity Rules (NER) clause 5.16.4.

The PACR represents the third and final stage of the formal process set out in the NER in relation to the application of the Regulatory Investment Test – Transmission (RIT-T) for the South Australia–Victoria (Heywood) Interconnector upgrade. The first stage was the release of the Project Specification Consultation Report (PSCR) in October 2011.[6] This was followed by the release of the Project Assessment Draft Report (PADR) in September 2012.[7] ElectraNet and AEMO held a public forum in relation to the PADR on 27 September 2012.

This formal consultation process follows the earlier South Australian Interconnector Feasibility Study (Joint Feasibility Study) published in February 2011[8] and AEMO's 2010 National Transmission Network Development Plan (NTNDP), which indicated the possibility of net market benefits from increasing the capacity of the existing 275 kV interconnector between South Australia and Victoria.

This PACR:

- Describes the identified need which ElectraNet and AEMO are seeking to address, namely an increase in overall net market benefit.
- Describes the credible options that ElectraNet and AEMO consider may address the identified need.
- Summarises and provides commentary on the submissions received on the PADR.
- Provides a quantification of costs and classes of material market benefit for each of the credible options, together with an outline of the methodologies adopted by ElectraNet and AEMO in undertaking this quantification.
- Provides the results of the net present value (NPV) analysis for each credible option assessed, together with accompanying explanatory statements.
- Identifies the preferred option for investment by ElectraNet and AEMO.

Appendices to this PACR provide further information in relation to the assumptions adopted for the RIT-T assessment (Appendices C and D), submissions to the PADR and the earlier PSCR (Appendices E and F) and the NPV and generation results dataset of the RIT-T assessment (Appendix I – provided in a separate spreadsheet).

[6] AEMO - ElectraNet, South Australia – Victoria (Heywood) Interconnector Upgrade RIT-T: Project Specification Consultation Report, October 2011 http://www.electranet.com.au/network/current-planned-developments/south-east/new-developmentpage-9/rcview/

[7] AEMO - ElectraNet, Sou h Australia – Victoria (Heywood) Interconnector Upgrade RIT-T: Project Assessment Draft Report, September 2012 http://www.electranet.com.au/network/current-planned-developments/south-east/new-developmentpage-9/rcview/

[8] ElectraNet-AEMO Joint Feasibility Study http://www.aemo.com.au/planning/saifs.html.

1.2 Changes from the PADR

The NER requires that the PACR include the matters required to be included in the earlier PADR, together with a summary of, and responses to, any submissions received in response to the PADR.[9] Accordingly, this PACR repeats much of the material and analysis presented in the earlier PADR. However the discussion and analysis has been revised where relevant, to address points raised in submissions as well as further analysis by ElectraNet and AEMO since the publication of the PADR. The PACR also elaborates on some aspects of the process and analysis undertaken for this RIT-T, where submissions have indicated that the detail in the earlier PADR may not have been sufficient.

A detailed summary of the issues raised in submissions and ElectraNet and AEMO's response to those issues is contained in section 4 of this PACR. Appendix E also summarises the points made in submissions, and notes where these are discussed in the main body of the report.

Key changes to the PACR resulting from PADR submissions include the following:

- The operating costs of the control schemes included in Options 6a and 6b have been revised to reflect the adjusted[10] estimate of those operating costs made by David Strong and Associates (DSA), rather than the generic assumption that had been used in the PADR (section 6.1).
- The sensitivity analysis undertaken and reported in the PACR (section 6.3.2) has been expanded, and encompasses variations in the assumed capital costs for the control scheme (including the removal of the telecommunications costs), +/- 30% changes in assumed network costs, a higher discount rate (16%) and a shortened analysis period (20 years). The net market benefits for each credible option under each scenario are now also included.
- The PACR also includes a discussion of the preliminary quantification of the benefits associated with a reduction in the impact of a major transformer outage at Heywood (section 4.12). This analysis shows that the probability-weighted magnitude of this benefit is in the order of $5.6m (probability-adjusted, net present value assuming a 10% discount rate across the assessment period), for options which include a 3rd transformer at Heywood. An indicative sensitivity analysis reflecting the incorporation of this benefit into the RIT-T assessment has also been included (section 6.3.2).
- The robustness of the RIT-T assessment to different scenario weightings has also been expanded, to include placing additional weight on the scenario reflecting low demand and low carbon price assumptions (i.e. scenario 4, section 6.3.2)
- Consideration of a number of variants to the credible options included in the PADR, as proposed in submissions, including the addition of a control scheme at South East substation as part of Option 1b; addition of a control scheme at both Heywood and South East as part of Option 1b; and the replacement of the existing Heywood transformers with units higher short term ratings (section 4.13).

[9] NER 5.16.4(v).

[10] A sensitivity using the non-adjusted DSA costs has also been included in Section 6.3.2.

1.3 Next steps

This PACR represents the final stage in the RIT-T process under the NER.

The Rules provide for any dispute to the decision to proceed with the preferred option to be lodged with the AER within 30 days of the date of publication of the report (i.e., by 22 February 2013). If no formal dispute is raised or on the resolution of any dispute, ElectraNet will commence the pre-investment activities necessary to proceed with the South Australian components of the preferred option, including seeking a formal determination by the AER[11] in the first half of 2013 that the proposed investment satisfies the RIT-T, followed by seeking AER approval of this investment as a contingent project. AEMO will develop a functional requirements specification for the Victorian components of the preferred option, which is expected to be put to tender in the second half of 2013.

Further details in relation to this project can be obtained from:

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[11] Under clause 5.16.6(a) of the National Electricity Rules.

2 Identified need

2.1 Background

The Heywood Interconnector is located between the South East (South Australia) and Heywood (Victoria) substations. This interconnector was constructed in 1988. It features a 500 kV to 275 kV transformation at Heywood and 275 kV lines from Heywood to South East. Historically this interconnector has predominantly been used to import power into South Australia. However over the past few years, with the addition of significant amounts of wind generation in South Australia, the interconnector is now also being used to export power from South Australia.

In February 2011, ElectraNet and AEMO published the results of the Joint Feasibility Study. The purpose of the study was to assess the potential economic benefits from increasing the transfer capacity between South Australia and the rest of the National Electricity Market (NEM). An increase in interconnector capacity would provide South Australia with increased access to reliable, lower cost thermal generation from the rest of the NEM, particularly at peak times, and also enable further development of South Australia's renewable generation resources.

The study found that:

- There is potential for augmenting transmission capacity between South Australia and the rest of the NEM.
- An incremental upgrade to the existing interconnector showed the largest net economic benefit.

ElectraNet and AEMO have now extended the analysis conducted in the Joint Feasibility Study by undertaking a formal RIT-T assessment of potential options for augmenting the capacity of the Heywood interconnector. The PSCR in relation to this RIT-T application was published in October 2011 and the PADR was published in September 2012.

2.2 Summary of the identified need

The 'identified need' for the proposed investment is an increase in the sum of producer and consumer surplus, i.e. an increase in net market benefit. ElectraNet and AEMO believe that reducing existing constraints and augmenting the capability of the Heywood Interconnector capability will achieve this.

Consideration has been given in particular to:

- Increasing the thermal and voltage stability limits in south-east South Australia.[12]
- Increasing the transformer capacity at Heywood.

The Heywood Interconnector has a maximum short-term capacity rating of ±460 MW due to the N-1[13] rating of the two 500/275 kV transformers at the Heywood substation in Victoria.

[12] Previous studies by ElectraNet and AEMO which assessed the increase of the South Australian Oscillatory Export limit from 420 MW to 580 MW were also extended to examine the works required to increase this limit to 870 MW. These studies concluded that this increased level of export can be achieved, but will require the retuning of existing power system stabilisers.

[13] N-1 loading is the loading following the loss of the most critical network element.

However the actual power transfer capability is often restricted due to constraints including voltage limits or thermal limits that vary under different operating conditions.

AEMO's Constraint Reports for 2011 and 2010[14] show that:

- The power transfer capability from Victoria to South Australia is frequently restricted by voltage stability limits in south-east South Australia, particularly during high demand conditions and when there is high generation in south-east South Australia (bound for 1,027 hours in 2011 and 542 hours in 2010).
- The power transfer capability from South Australia to Victoria is frequently restricted by the thermal capability of the South East 275/132 kV transformers in South Australia (bound for 195 hours in 2011 and 204 hours in 2010).
- The power transfer capability In relation to the Keith to Tailem Bend 132 kV lines is a limiting factor for the Victoria to South Australia limit on the Heywood interconnector (bound for 18 hours in both 2010 and 2011), with a Marginal Cost of Constraint (MCC)[15] of $544,000.

The 275 kV transmission lines between the Heywood and South East substations are rated up to about 45% higher than the presently limiting transformer section of the interconnector flow path. The existing transformer capacity limitation affects the extent to which power can flow across the interconnector. Specifically it affects the amount of generation from other regions in the NEM which can be used to meet peak demand conditions in South Australia. It also restricts the amount of wind generation which can be exported from South Australia at times of high wind output and low South Australian demand. South Australia is recognised as having one of the best wind resources in the NEM, as well as having the potential for the future development of large-scale geothermal generation.

The expansion of the Heywood Interconnector has been previously discussed in:

- AEMO's 2010 NTNDP.[16]
- AEMO–ElectraNet's Joint Interconnector Feasibility Study.
- Annual Planning Reports (APR) in both South Australia[17] and Victoria.[18]
- The South Australia – Victoria (Heywood) Interconnector Upgrade RIT-T PSCR.
- The South Australia – Victoria (Heywood) Interconnector Upgrade RIT-T PADR.

Expanding the transfer capacity of the Heywood Interconnector would relieve the current limitations, and would increase both the import and export capability of the interconnection. The RIT-T analysis has shown that this is expected to result in an increase in market benefit, resulting from changes in generation investment patterns and a reduction in overall NEM dispatch costs. The precise source of market benefits depending on the reasonable scenario adopted. For scenarios with low demand (scenario 4), the overall net market benefit of the investment primarily reflects dispatch cost benefits (and is higher than in the higher demand growth scenarios).

[14] http://www.aemo.com.au/electricityops/0200-0006.html.

[15] The MCC for an individual constraint equation is calculated using an MCC rerun of the market dispatch engine, with the violating constraint equation removed or the binding constraint equation relieved by one megawatt. This shows how much the cost of generation (based on generator bids) will be reduced at the margin.

[16] http://www.aemo.com.au/en/Electricity/Planning/2010-National-Transmission-Network-Development-Plan.

[17] http://www.electranet.com.au/network/transmission-planning/annual-planning-report/.

[18] http://www.aemo.com.au/planning/VAPR2011/vapr html.

3 Credible options included in the RIT-T analysis

The following nine options have been included as potential credible options in the RIT-T analysis:

- Option 1a – Installation of a 3rd 370 MVA 500/275 kV transformer at Heywood and 500 kV bus tie, plus a 100 MVAr capacitor at South East substation and reconfiguration of the 132 kV network between Snuggery-Keith and Keith-Tailem Bend (South Australia).
- Option 1b – Installation of a 3rd 370 MVA 500/275 kV transformer at Heywood and 500 kV bus tie, plus 275 kV series compensation in South Australia and reconfiguration of the 132 kV network between Snuggery-Keith and Keith-Tailem Bend (South Australia).
- Option 2a – Construction of a 3rd 160 MVA 275/132 kV transformer at South East substation plus Option 1a.
- Option 2b – Construction of a 3rd 160 MVA 275/132 kV transformer at South East substation plus Option 1b.
- Option 3 - Construct a new Krongart-Heywood 500 kV interconnector and associated 275 kV works between Krongart and Tungkillo (South Australia).
- Option 4 – Option 1a minus 3rd 500/275 kV transformer at Heywood.
- Option 5 – Five-year, 200 MW demand management (DM) program beginning in 2013 plus Option 1b, deferred by two years.
- Option 6a – Control scheme applying to specific wind generation in South Australia and the South East substation and 500 kV bus tie.
- Option 6b – Control scheme applying to specific wind generation in South Australia and the South East substation plus Option 1b, minus the 3rd 500/275 kV transformer at Heywood.

These options were all included in the RIT-T assessment presented in the PADR.[19]

[19] The PADR also included a discussion of options which had not been progressed from the PSCR stage, together with the reasons why. See section 3.3 of the earlier PADR.

Table 3-1 provides an overview of which components are included in each option.

Table 3-1: Overview of the option components

Option	Service Date	3rd Heywood Tx	3rd South East Tx	Heywood bus tie	Control Schemes	DM	132 kV works	Series Comp	100 MVAr Capacitor
Option 1a	July 2016	✓		✓			✓		✓
Option 1b	July 2016	✓		✓			✓	✓	
Option 2a	July 2016	✓	✓	✓			✓		✓
Option 2b	July 2016	✓	✓	✓			✓	✓	
Option 3	See option description in section 3.1								
Option 4	July 2016			✓			✓		✓
Option 5	July 2018[a]	✓		✓		✓	✓	✓	
Option 6a	July 2015			✓	✓				
Option 6b	July 2016[a]			✓	✓		✓	✓	

[a] The dates shown are for the network component, not the DM and control scheme components.

With the exception of Option 3 (new Krongart-Heywood 500 kV interconnector), all of these options relate to works within existing substation boundaries and do not involve new line works.[20]

The notional (maximum theoretical) interconnector capabilities provided by these options are shown in Table 3-2 below. The interconnector transfer capability achieved at any point in time will be subject to network and local conditions such as the level of demand, and generation dispatch outcomes. The limits shown for Options 6a and 6b would be under high wind output in south east South Australia. Without additional wind farms in the south east of South Australia, the notional limit for Option 6b would be 570 MW.

[20] Note that the series compensation will be built at a new site, where ElectraNet already owns the land.

Table 3-2: Notional interconnector limits for options (MW)

Option	Description	Notional limit (MW)		Change from current (MW)	
		SA to VIC	VIC to SA	SA to VIC	VIC to SA
Option 1a	3rd Heywood transformer + 100 MVAr capacitor + 132 kV works	550	550	90	90
Option 1b	3rd Heywood transformer + series compensation + 132 kV works	650	650	190	190
Option 2a	Option 1a + 3rd South East transformer	550	550	90	90
Option 2b	Option 1b + 3rd South East transformer	650	650	190	190
Option 3	New Krongart-Heywood 500 kV interconnector + 275 kV works	2,400	2,400	1,940	1,940
Option 4	132 kV works + 100 MVAr capacitor	460	460	-	-
Option 5	200 MW DM + Option 1b	650	650	190	190
Option 6a	Control schemes + 500 kV bus tie	550	460	90	-
Option 6b	Control schemes + Option 1b minus 3rd Heywood transformer	570 / 690	460	110-230	-

3.1 Network option development in South Australia

As part of this RIT-T, ElectraNet and AEMO have subjected each of the credible options to a detailed analysis, prior to being identified as relevant investments for consideration. Several submissions to the PADR raised questions in relation to the proposed network developments in the south east of South Australia in particular. ElectraNet and AEMO have therefore included more information in relation to how the options for investment in South Australia have been developed, as part of this PACR.

A number of factors have been given detailed consideration in the development of network options in South Australia, including:

- Existing thermal capacity limitations due to the low capacity 132 kV transmission lines (Snuggery-Keith and Keith-Tailem Bend #1 132 kV lines) which are operated in parallel with the South East-Tailem Bend 275 kV lines.
- The condition and age of low 132 kV capacity transmission lines and associated foreshadowed ongoing maintenance costs.

- Impact of these lines on:
    - Existing network constraints; and
    - Anticipated future network constraints due to an upgrade in interconnector capacity.
- Impact of the removal of these transmission lines on:
    - Thermal capacity – considering both local issues as well transfer capability across the Adelaide to South East transmission corridor.
    - Local voltages – ability to maintain the local voltages as per NER requirements.
    - Voltage/Transient stability reduction – due to an increase in impedance across the Adelaide to South East corridor.
    - South East transformer constraints.

The methodology adopted in consideration of the above issues is discussed below:

The Snuggery-Keith and Keith-Tailem Bend #1 lines were built in 1961. While these lines are not the oldest lines ElectraNet has in its transmission network, age is not the primary indicator for replacement/removal of assets. Due to their geographical location, the condition of the lines has significantly deteriorated, and will require maintenance expenditure of up to $55m over the next 15 years in order to keep them in a safe and serviceable condition. Furthermore, the ratings of these lines are about one third of the newer and higher capacity parallel 132 kV line, and have therefore been a source of constraints to the Heywood interconnector capability from Victoria to South East. This occurs particularly at peak load times and on occasions has resulted in price separation between Victoria and South Australia.

These factors have led ElectraNet to consider the utility of these two transmission lines in the future development of the regional system in the South East region. A detailed least cost analysis was carried out to analyse various options involving maintaining/retaining, replacing and removal of the two lines.

Additionally the option of totally un-meshing the 132 kV system from the 275 kV system (to prevent parallel flows on the 132 kV system) was also assessed. While un-meshing the 132 kV system improves the thermal transfer capability, it causes local voltage issues as well as reduction in transient/voltage stability limits in the Adelaide to South East flow path. To manage these local issues, appropriate levels of additional reactive support is required.

The detailed technical-economic assessment concluded that the least cost solution for the regional development is to remove both these transmission lines and add some additional local reactive support. The removal of any plant, protection or other limitations on the remaining lines was also included as part of the scope of this solution.

On the basis of this least cost solution, the need for maintaining and augmenting the transfer capacity up to the +/- 650 MW interconnector capacity was assessed in detail, from both thermal and transient/voltage stability considerations, with a view to identifying an optimal solution. This assessment resulted in development of two distinct solutions, namely: i) shunt compensation at South East which delivers about 50% of the incremental augmentation identified; and ii) series compensation of the 275 kV lines between South East and Tailem Bend which delivers 100% of the incremental augmentation. As the cost difference between the two sub-options is significantly different, it was considered prudent to consider the two as distinct options in the RIT-T.

The proposed solution addresses all thermal limitations on the existing regional 132kv system, except for the existing South East transformer constraints. The impact of these solutions on the existing transformer constraints were also considered. Load flows which simulated conditions when the South East constraints are invoked indicated that power frequently flows from North to South through the South East 132 kV system, adding to the 132/275 kV flows on the South East transformers. The reconfiguration actually reduces the net North to South flow through the 132 kV network as one of the paths is removed and therefore reduces the constraint. This reduced flow is even more noticeable with the series compensation of the parallel 275 kV lines. However, as load flows are based on snapshot operating conditions, it was considered prudent to assess this as a separate option involving a solution to alleviate any such constraints (i.e. the 3rd transformer at South East).

Finally, revised voltage/stability and thermal constraint equations were developed to be used in the market modelling for the RIT-T.

ElectraNet and AEMO note that there are some emerging thermal limitations in the Tailem Bend to Tungkillo corridor, the extent of which is subject to the demand and generation development in the South East and Eastern Hills region of South Australia. The constraint is influenced by a number of uncertain variables, and the options to alleviate the constraint involve either the uprating of the Tailem Bend to Tungkillo 275 kV line or the stringing of the third Tailem Bend to Tungkillo circuit as an alternative means to increase the corridor’s capacity. At this time, neither of these alternatives have been assessed in detail, however, ElectraNet and AEMO consider it likely that a relatively low cost uprate will be feasible once a full mechanical assessment of the line in question is completed. This incremental augmentation would be considered in a separate RIT-T.

3.2 Description of the credible network options assessed

This section provides a description of each of the credible network options assessed in the RIT-T, including:

- The technical characteristics of the option.
- The estimated construction timetable and commissioning date.
- The estimated capital and operating & maintenance costs.

The impact on selected existing network constraints of each option is provided in Appendix D, Table D-4. Some of these network options have been discussed at a high level in AEMO’s 2010 and 2011 NTNDP[21] and in ElectraNet’s 2012 Annual Planning Report.[22]

Section 3.2 provides the equivalent description of each of the credible non-network options assessed in the RIT-T.

[21] AEMO, 2011 NTNDP, section 2.2.4; AEMO, 2010 NTNDP, sec ion 4.6.3.

[22] http://www.electranet.com.au/network/transmission-planning/annual-planning-report/.

Option 1a – Installation of a 3rd 370 MVA 500/275 kV transformer at Heywood and 500 kV bus tie plus a 100 MVAr capacitor at South East substation and reconfiguration of 132 kV network

Option 1a maximises the use of spare capacity available on the Heywood–South East transmission line, by augmenting the existing capacity of the Heywood transformers. Option 1a is depicted in Figure 3.1.

Option 1a includes the installation of a 3rd 370 MVA 500/275 kV transformer and associated works at Heywood, together with the installation of a 100 MVAr capacitor at South East substation to provide the reactive support required to support the higher interconnector capacity.

The option also includes some network reconfiguration of the existing 132 kV lines between Snuggery–Keith and Keith–Tailem Bend in South Australia, which currently cause some thermal limitations on the Heywood transfer capacity. The current lines were built in the early 1960s and are in poor condition and also close to the end of their technical life. This option would include a full decommissioning of these lines and network reconfiguration to optimise the interconnector capability along with additional reactive support on the 132 kV system to support local voltages. The reactive support that will be required on the 132 kV system includes two 15 MVAr 132 kV capacitors at Keith/Penola substations and one 15 MVAr capacitor at Blanche substation.[23] The Blanche capacitor is an advancement of a proposed project by 2 years.

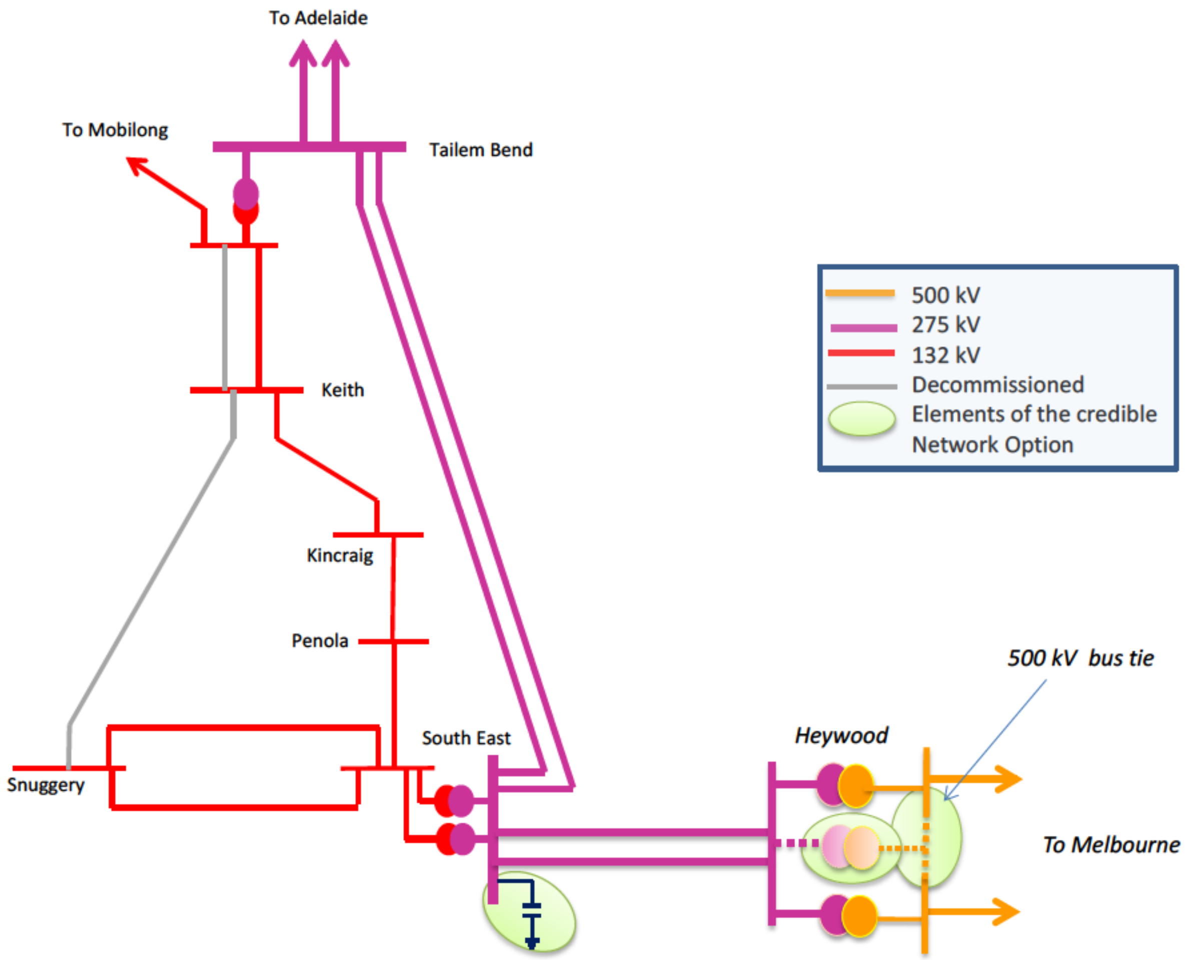
The estimated capital cost of this option is $78.0m. This cost is comprised of:

- 3rd 370 MVA 500/275 kV transformer and bus tie at Heywood (Victoria): $45.0m.
- Installation of a 100 MVAr capacitor (South Australia): $4.4m.
- Reconfiguration and decommissioning of 132 kV network (South Australia): $28.6m.

Annual operating costs have been estimated at 2% of this capital cost. The estimated construction timetable is up to three years, with a commissioning date of July 2016.

[23] The exact timing of this investment would be confirmed by the most recent demand forecasts at the time before implementation.

Figure 3-1: Option 1a - Installation of a 3rd 370 MVA 500/275 kV transformer at Heywood and 500 kV bus tie plus a 100 MVAr capacitor at South East substation and 132 kV works



Option 1b – Installation of a 3rd 370 MVA 500/275 kV transformer at Heywood and 500 kV bus tie plus series compensation of 275 kV lines and reconfiguration of 132 kV network

Option 1b is depicted in Figure 3.2. This option is the same as Option 1a, but with series compensation of the Tailem Bend to South East 275 kV lines at Black Range to provide reactive support, rather than a capacitor at South East substation. Option 1a is depicted in Figure 3.1.

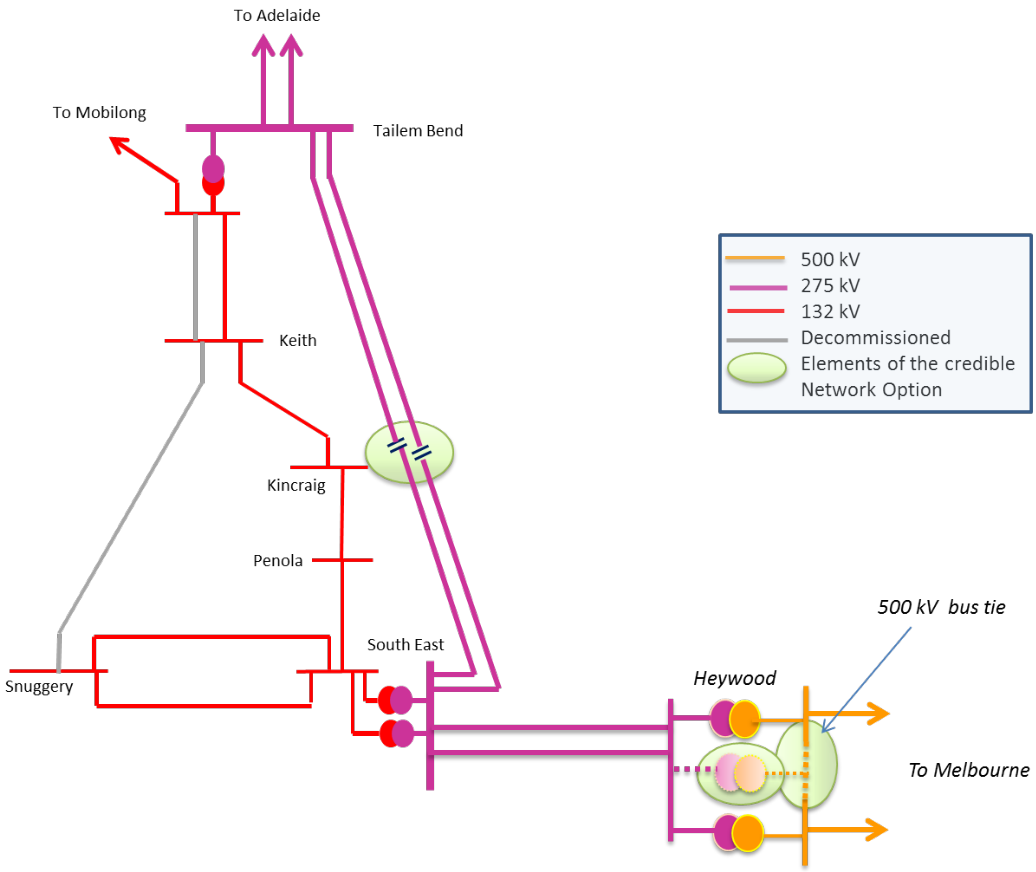
The option also includes network reconfiguration of the existing 132 kV lines between Snuggery–Keith and Keith–Tailem Bend along with additional reactive support on the 132 kV system to support local voltages, as discussed above for Option 1a.

The estimated capital cost of this option is $107.7m. This cost is comprised of:

- 3rd 370 MVA 500/275 kV transformer and bus tie at Heywood (Victoria): $45.0m.
- 275 kV series compensation (South Australia): $34.1m.
- Reconfiguration and decommissioning of 132 kV network (South Australia): $28.6m.

Annual operating costs have been estimated at 2% of this capital cost. The estimated construction timetable is up to three years, with a potential commissioning date of July 2016.

Figure 3-2: Option 1b - Installation of a 3rd 370 MVA 500/275 kV transformer at Heywood and 500 kV bus tie plus series compensation of 275 kV lines and 132 kV works



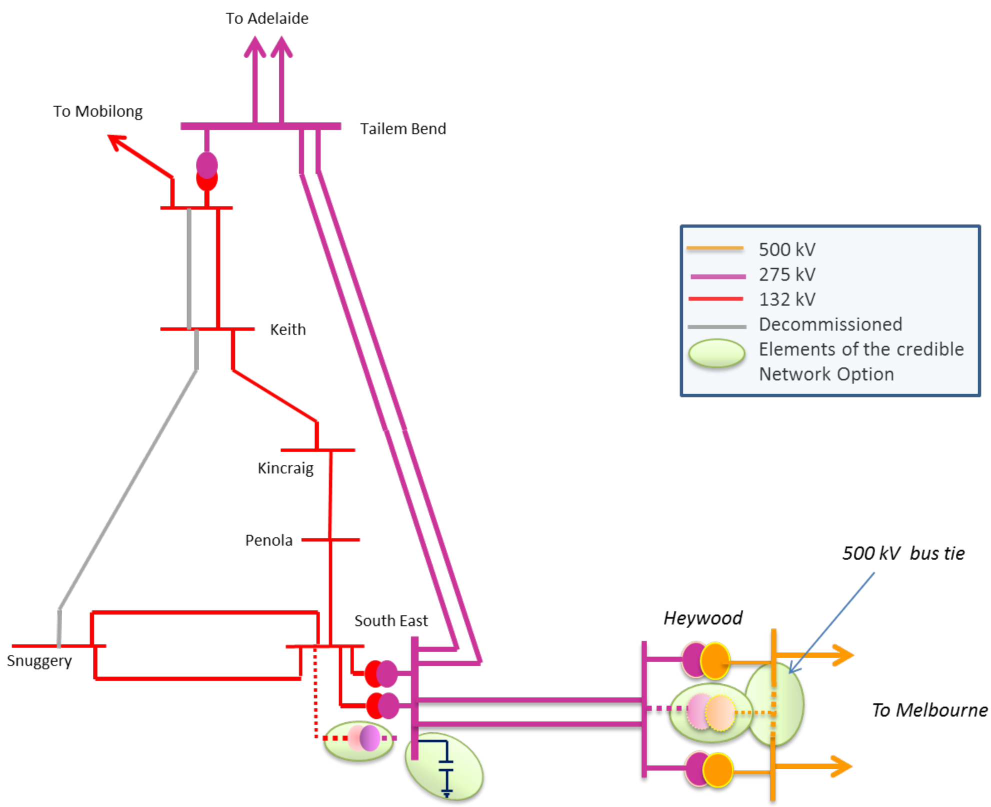
Option 2a – Construction of a 3rd 160 MVA 275/132 kV transformer at South East substation plus Option 1a

The existing capacity of the transformers at South East substation causes restrictions to exports from South Australia as well as constraints to wind generation in the South East region, and is forecast to limit imports into South Australia in the future.[24]

ElectraNet and AEMO have therefore also considered the net market benefit associated with adding a 3rd 160 MVA 275/132 kV transformer at South East substation, in addition to the works included under Option 1a. ElectraNet and AEMO note that the inclusion of a 3rd transformer at South East substation as part of the network options being considered was requested in the submission to the PSCR by Alinta and the private generators.[25]

This option is depicted in Figure 3.3 below.

Figure 3-3: Option 2a - Installation of a 3rd 160 MVA 275/132 kV transformer at South East plus Option 1a



The estimated capital cost of the 3rd transformer at South East and associated works is $17.4m. The total capital cost of this option is therefore $95.4m. Annual operating costs have been estimated at 2% of this capital cost. The estimated construction timetable remains three years, with a commissioning date of July 2016.

[24] AEMO, 2011 NTNDP.

[25] See section F.2.

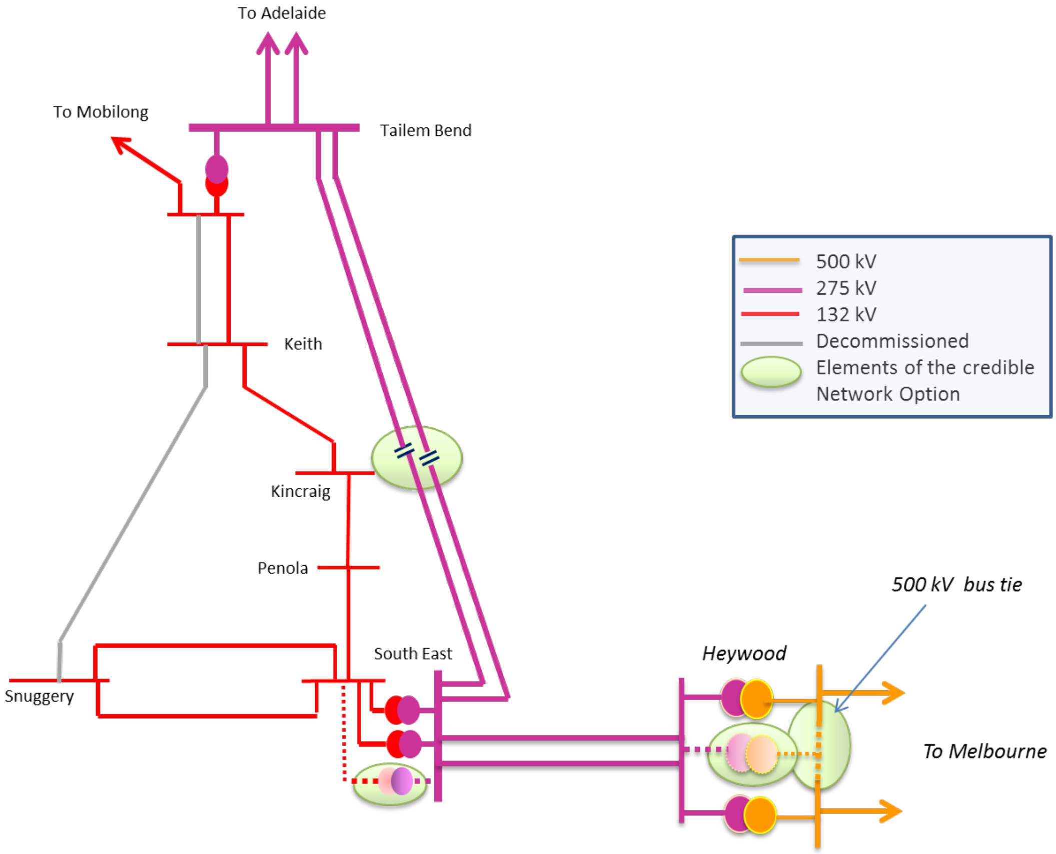
Option 2b - Construction of a 3rd 160 MVA 275/132 kV transformer at South East plus Option 1b

Option 2b includes a 3rd 160 MVA 275/132 kV transformer at South East substation, together with the works set out under Option 1b. This option is shown in Figure 3.4.

The estimated capital cost of the 3rd transformer at South East and associated works is $17.4m. The total capital cost of option is therefore $125.1m. Annual operating costs have been estimated at 2% of this capital cost.

The estimated construction timetable is again three years, with a commissioning date of July 2016.

Figure 3-4: Option 2b - Installation of a 3rd 160 MVA 275/132 kV transformer at South East plus Option 1b



Option 3 – New Krongart–Heywood 500 kV interconnector and associated 275 kV works

This is a greenfield option which would provide a much higher Heywood Interconnector capacity (about 2,000 MW additional capacity). This is the lowest cost of all the high-capacity interconnector options considered previously in studies such as AEMO's 2010 NTNDP and the AEMO-ElectraNet Joint Feasibility Study. While the estimated cost of this option is higher than that of Options 1a and 1b discussed above, the higher capacity may potentially provide greater net market benefits than those other options. ElectraNet and AEMO have therefore considered it prudent to evaluate this as a separate option under the RIT-T.

The scope of this option includes both a new Krongart-Heywood 500 kV interconnector, as well as associated works on the 275 kV network between Krongart and Tungkillo.

The estimated capital cost of this option is dependent on the assumed timing and staging of development. By initially operating the new interconnector at 275 kV, some substation and transformer costs can be deferred.

Specifically, works on the interconnector and the associated works on the 275 kV network in South Australia could be staged as follows:

- Stage 1: Establish a new 275 kV switching station at Krongart and build a 500 kV double circuit line from Krongart to Heywood (initially operated at 275 kV), plus 500/275 kV transformers at Heywood and stringing a 3rd circuit between Tailem Bend and Tungkillo.
- Stage 2: Create a 500 kV switchyard at Krongart, add 500/275 kV transformers at Krongart and re-connect the Heywood end line termination to the 500 kV side of the Heywood substation, plus add a new double circuit line from Krongart to Tailem Bend.

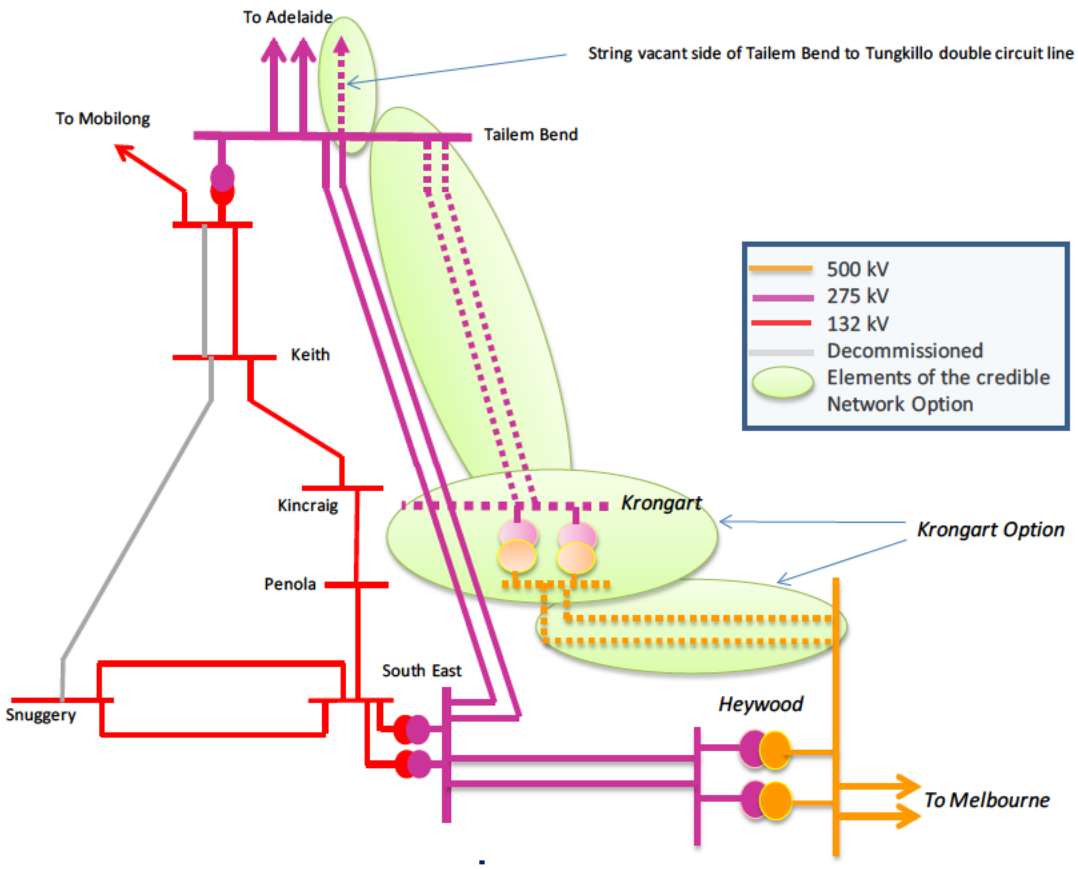
On the basis of the staged development set out above, the total estimated capital cost of this option is $888.8m:

- Krongart Stage 1 works: $417.3m
  - $368.0m for the Heywood and Krongart works (Victoria).
  - $49.3m for Tailem Bend – Tungkillo 275 kV works (South Australia).
- Krongart Stage 2 works: $471.5m
  - $164.5m for upgrades to 500 kV (Victoria).
  - $307.0m for Tailem Bend – Krongart 275 kV works (South Australia).

Annual operating costs have been estimated at 2% of this capital cost.

The estimated construction timetable is 7–10 years, with a commissioning date of July 2025 for Stage 1 and the 275 kV works, and July 2030 for Stage 2. These estimated commissioning dates are based on the optimal timings identified by the earlier Joint Feasibility Study.

Figure 3-5: Option 3 – New Krongart-Heywood 500 kV Interconnector and associated 275 kV works



Option 4 – Option 1a minus 3rd Heywood transformer

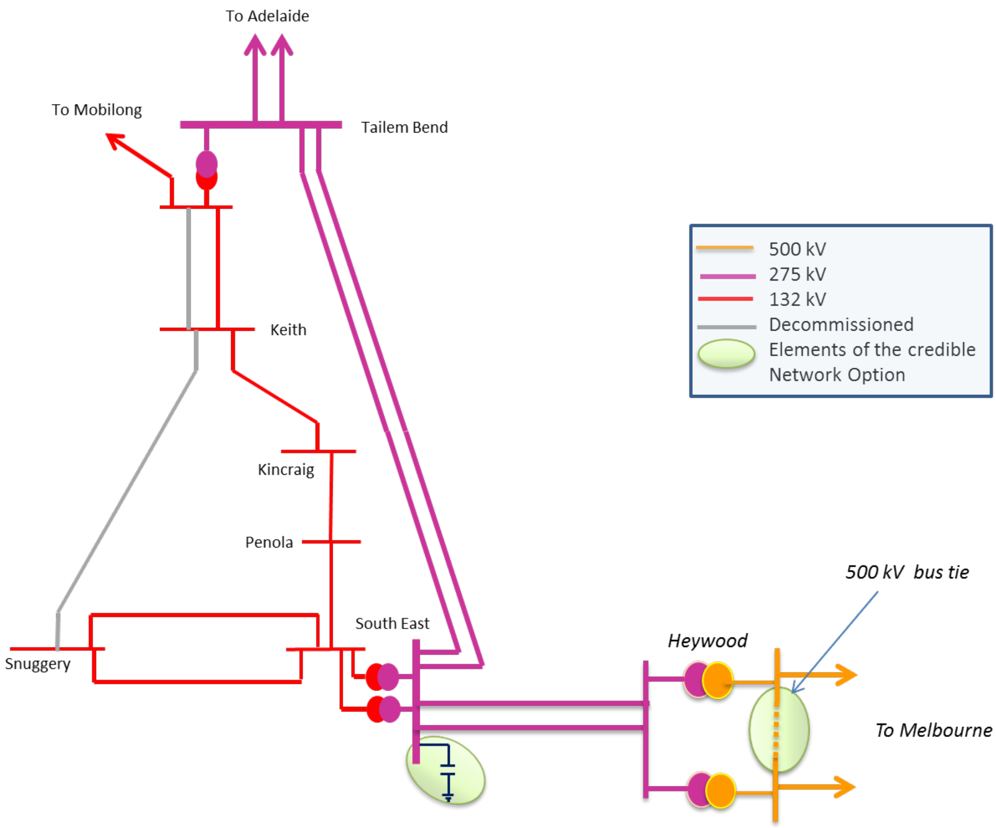
ElectraNet and AEMO have included as a credible network option an option which includes works to address constraints on the 132 kV network in South Australia but does not include installation of a 3rd 500/275 kV transformer at Heywood. This option was included in the PADR following submissions on the earlier PSCR from the group of private generators and Alinta, raising a concern about the need for the Heywood transformer augmentation if the existing 460 MW capacity of the Heywood interconnector is maintained on a firmer basis, by addressing network congestion issues in South Australia.

Specifically Option 4 covers the same works included in Option 1a, minus the 3rd 500/275 kV transformer at Heywood. That is, the decommissioning of the Keith-Snuggery and Keith-Tailem Bend 132 kV lines, together with the installation of a 100 MVAr capacitor. In addition, a 500 kV bus tie at Heywood would still be required to address thermal and voltage issues on the Victorian side of the network, even without a 3rd transformer at Heywood. The 3rd transformer at South East has not been included in this option, as the results from the market modelling analysis show that inclusion of the 3rd South East transformer (i.e. Option 2a) does not increase the overall net market benefit compared with Option 1a.

This option is depicted in Figure 3.6. The estimated capital cost of this option is $40.6m.

The estimated construction timetable would be three years, with a commissioning date of July 2016.

Figure 3-6: Option 4 – 132 kV Works between Snuggery-Keith and Keith-Tailem Bend plus 100 MVAr capacitor and a 500 kV bus tie at Heywood



3.3 Description of the credible non-network options assessed

ElectraNet and AEMO have included three options which have a non-network component as part of the credible options considered for this RIT-T. These non-network components reflect specific options raised in submissions to the earlier PSCR. ElectraNet and AEMO note that for the purposes of discussion in this PACR, the automatic control schemes have been considered to be 'non-network options', as although these control schemes would be owned by the relevant TNSPs, the control scheme component does not include network augmentation.

For two of these options, the non-network component has been considered together with a network component, as preliminary screening identified that these combinations would have a greater net market benefit than the non-network component alone.

Option 5 – Five-year, 200 MW demand management program plus Option 1b, deferred by two years

EnerNOC[26] identified in a submission to the PSCR that it would be a proponent for a demand management (DM) option, and requested that a DM option be considered in the RIT-T assessment. In its initial submission EnerNOC noted that a DM option could be either temporary or permanent, and

[26] EnerNOC Australia Pty Ltd.

could either be considered on a stand-alone basis, or used to defer an eventual network augmentation.

In a second submission to the PSCR, EnerNOC proposed to provide up to 200 MW of firm demand response capacity, which they guarantee would be available during the contracted period, to be agreed with ElectraNet. EnerNOC proposed a five year (60 month) contract period in relation to this capability, with contract costs to be based on both a per MW availability fee and a per MWh dispatch fee. EnerNOC would accept financial penalties for failing to provide firm capacity availability by established milestone dates and for failing to deliver contracted capacity during dispatches.

For the purposes of the RIT-T assessment, ElectraNet and AEMO have modelled this option as representing 200 MW of DM capability, available for five years from July 2013. ElectraNet and AEMO have adopted an indicative cost of $120,000/MW/annum for the availability fee and $750/MWh for the dispatch fee, based on cost estimates suggested by EnerNOC, in order to establish an indicative cost for the DM component. ElectraNet and AEMO note that the option proposed by EnerNOC was a proposal, rather than a firm offer. Therefore both the MW DM capability and the costs would need to be subject to further verification and agreement before this option could be implemented.

ElectraNet and AEMO have combined this DM component with a deferred augmentation of the Heywood Interconnector capacity. Initial screening work indicated that in combination these investments are likely to have a greater net market benefit than the DM component alone. In order to establish the combination of DM and network augmentation likely to yield the highest net market benefit, the network component reflects the network option which has been found to have the highest net market benefit, considered on a stand-alone basis, i.e. Option 1b. The commissioning date for this network investment is deferred until July 2018, two years after the commissioning date for the network component considered on a stand-alone basis.

The additional of a 500 kV bus tie has not been deferred in this analysis. In this option the bus tie makes allowances for the later installation of the Heywood transformer. The cost of the 500 kV bus tie in this instance has been estimated at $14.5m, and the Heywood transformer at $36m.

Option 6a – Control schemes applying to specific wind generation in South Australia and South East substation and 500 kV bus tie

Overview

The second non-network option included in the RIT-T analysis comprises automatic control schemes, which would trip specific participating wind generation (both existing and future) in south east South Australia to manage thermal limitations of the South East transformers, the South East to Heywood lines and the Heywood transformers, following an N-1 event, in order to provide an increased South Australia to Victoria export capability. This option has been considered both on a stand-alone basis (Option 6a) and also combined with network investment (Option 6b – discussed below). Although the market benefits of stand-alone control schemes may be expected to be lower than where such schemes are coupled with network augmentation, a stand-alone option would also have a substantially lower cost, and therefore has the potential overall to have a greater net market benefit.

The commissioning date for this option is assumed to be July 2015.

This option was included in the PADR following Infigen Energy's submission to the PSCR which proposed the use of advanced control schemes for wind generation in south-east South Australia and south-west Victoria.[27] Infigen suggested that such control schemes could be similar in principle to the Basslink Network Control Special Protection scheme, which Alinta notes has been successfully applied in Tasmania. Several other submissions to the PSCR noted that they considered Infigen's proposed scheme to be a potentially credible non-network option, worthy of further consideration.[28]

ElectraNet and AEMO note that Infigen's submission contained a high level control scheme concept, but with limited detail. Given the interest expressed in the control scheme concept by stakeholders, ElectraNet and AEMO engaged independent consultants (David Strong & Associates (DSA)) to provide an initial, high-level review of whether a control scheme of the type suggested by Infigen may be technically feasible and, if so, to provide an indication of the costs and other design details of such an option, in order for it to be considered as part of the RIT-T analysis. The DSA report was released alongside the PADR. It should be noted that DSA's review did not include detailed testing or specific contractual discussions. It also did not include the detailed power system studies that would be necessary in order to confirm that the scheme will not cause any system security risks/issues. SP AusNet also reviewed the control scheme proposal and provided updated costs for the assets required in the Victorian region.

Infigen had proposed that the control scheme could apply to its Lake Bonney wind farms, as well as any new wind generators in both south-east South Australia and south-west Victoria. However AEMO notes that the line ratings for the 500 kV part of the network are higher than that had been assumed by Infigen, and as a consequence the scope of the control scheme would be more appropriately limited to wind farms in South Australia, and in particular the Lake Bonney wind farms and new wind farms connecting in the vicinity of Krongart in South Australia.

In addition, DSA recommended that a separate control scheme be put in place at South East substation to trip Lake Bonney wind farm in order to address the South East substation 275/132 kV transformer constraint.

The Heywood control scheme would enable the existing Heywood interconnector to be operated closer to its full capacity under system normal conditions, as the control scheme would provide the means of addressing overloads following a contingency event. Specifically, the control scheme would enable the wind generators who participate in the scheme to be tripped following a contingency event, in order to prevent overloading of any of the remaining transmission lines or transformers. This would potentially enable the interconnector to be operated to a higher capacity at times when the participating wind generators are operating while exporting power from South Australia. Any extra capacity that can be gained will be linked to the output of participating generators at any given time. The control scheme will not provide any benefit in terms of enhancing the capacity for importing power into South Australia.

[27] Infigen Energy, South-Australia- Victoria (Heywood) Interconnector Upgrade, RIT-T: Project Specification Consulta ion Report, 30 January 2012.

[28] See section 4.3.

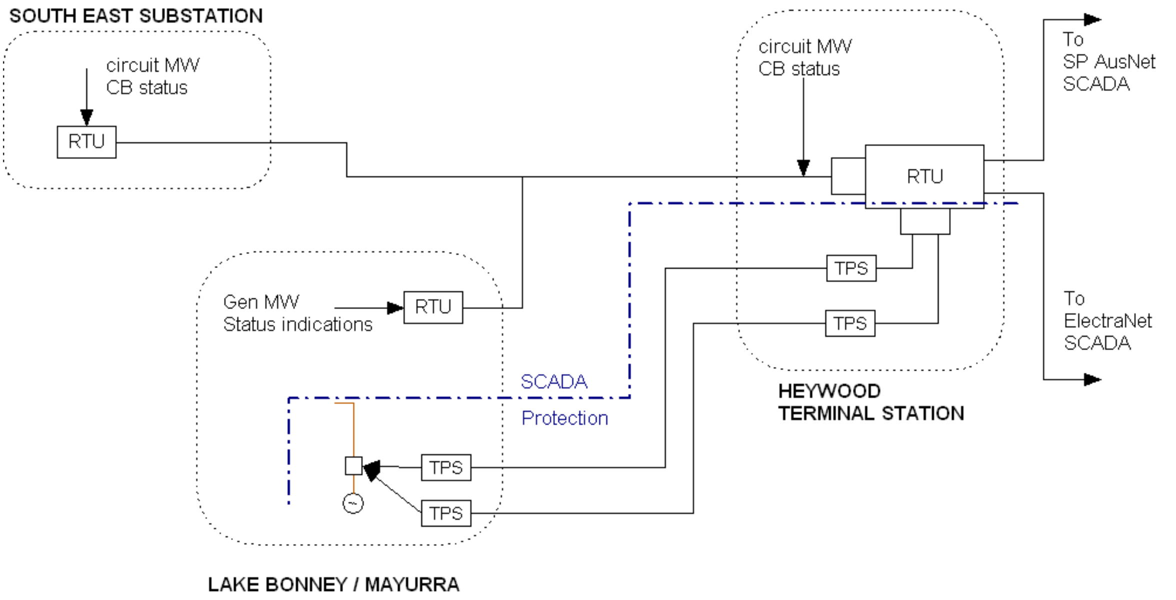
Inclusion of control schemes in the RIT-T assessment

For the purposes of including the control schemes in the RIT-T analysis, ElectraNet and AEMO have assumed that:

- A control scheme would apply to Infigen's Lake Bonney wind farms (Heywood control scheme).
- A separate control scheme would be put in place between the Lake Bonney wind farms and South East substation (South East control scheme).
- New wind generators connecting in the vicinity of Krongart would be incorporated within the Heywood control scheme only.

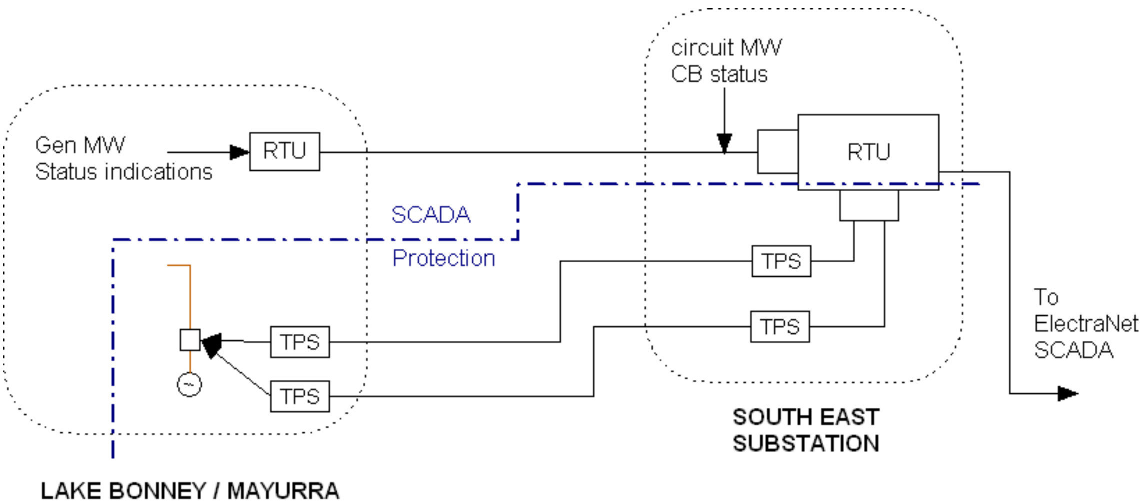
The control schemes are depicted in Figure 3-7 and Figure 3-8.

Figure 3-7: Heywood control scheme design concept



Source: David Strong and Associates

Figure 3-8: South East control scheme design concept



Source: David Strong and Associates

Technical and commercial feasibility of control schemes

Under the NER a credible option needs to be technically and commercially feasible.[29]

DSA has concluded that implementing the proposed control schemes is technically feasible. However, ElectraNet and AEMO note that this conclusion relates to the feasibility of implementing the scheme between the network business and the generators subject to the scheme. DSA's assessment did not include a review of the implications for wider aspects of system security, which would also be an important component in establishing the technical feasibility of the control scheme option, and would require further detailed studies. This is discussed further below in relation to the overload rating for the Heywood transformers.

The DSA report noted that since the majority of the assets to be protected by the control scheme for the wind generators are in Victoria, SP AusNet would be the logical owner of the Heywood control scheme. DSA therefore recommended that AEMO (as the provider of prescribed transmission services in Victoria) contract with SP AusNet for the implementation and ownership of the Heywood control scheme. However DSA noted that it would also be possible for AEMO to put the project out to tender.

DSA highlight that the provision of the Heywood control scheme would require the following agreements:

- Control scheme implementation and ownership (AEMO-SP AusNet).
- Communication service provision (SP AusNet – ElectraNet).
- Generator tripping services agreement (AEMO - generators).
- Generator control scheme participation agreements (SP AusNet – generators).
- Site occupancy license of lease agreements (various).

In relation to the South East control scheme, ElectraNet would have responsibility for ensuring that the requisite arrangements were established for the items shown in the list above, and would be the owner of the assets.

As noted in the PADR, from initial discussions ElectraNet and AEMO consider that there is a substantial degree of uncertainty in relation to the commercial feasibility of the proposed control scheme, as it gives rise to potential liability issues and may require generators to indemnify the relevant TNSPs. Detailed consideration and discussion of the contractual arrangements would be a key next step in developing this option to the point where it could be implemented. In the absence of the RIT-T analysis indicating that there would be substantially higher net benefits associated with this option compared to other credible options, the additional cost and time involved in conducting and concluding these negotiations is not warranted.

ElectraNet and AEMO also note the higher transfer capacity associated with the control scheme in Option 6a is predicated on there being additional wind generation locating near Krongart. However, there is currently significant uncertainty surrounding wind developments in this area, with no developments approaching committed status. [30]

[29] NER, 5.15.2(a)(2).

[30] ElectraNet and AEMO note that Infigen's proposed Woakwine wind development, which is located in the Krongart area, currently satisfies less than three of AEMO's commitment criteria. This is discussed further in section 4.9 below.

ElectraNet and AEMO have undertaken initial discussions with SP AusNet, and would like to record their appreciation for SP AusNet's cooperation and input into consideration of the control scheme option for this RIT-T. The discussions with SP AusNet have focused on technical feasibility rather than specific contractual and commercial issues and have highlighted the criticality of the transformers at Heywood to the operation, safety and stability of the Victorian transmission network. Notwithstanding this criticality, SP AusNet has indicated that it would consider operating the transformers at Heywood outside of the current operating envelope, subject to addressing all risks resulting from this operating mode. Specifically, SP AusNet is able to provide a 1.5 second short-term rating as highlighted in the DSA report, subject to specific calculations being performed and verified.

Under current practice, when ordering a new transformer, any abnormal overload requirement would be part of the tender specification and factored into the design. This has not occurred for the Heywood transformers. In addition, the Heywood transformers have a tertiary winding that supplies a load connection to a third party, which SP AusNet must guarantee and which needs to be given full consideration when analysing the overload rating of the transformers. There would therefore need to be further consideration of the technical feasibility of operating the Heywood transformers in the manner that would be required under the control scheme. ElectraNet and AEMO consider that the cost of undertaking further work relating to establishing the technical feasibility of the control scheme would only be warranted if the RIT-T analysis were to indicate that this option would have a substantially higher net market benefit than other credible options, which is not the case.

Notwithstanding that there are questions in relation to both the technical and commercial feasibility of the control schemes, ElectraNet and AEMO have incorporated this option in the RIT-T analysis reported in this PACR (and in the earlier PADR), in order to assess whether such control schemes would be likely to have higher net market benefits than the other credible options identified. The issues relating to technical and commercial feasibility would need to be subject to further examination if this option were shown to have substantially higher net market benefits than other options and therefore to be identified as the preferred option for implementation.

As outlined in section 4.10 below, Infigen in its submission on the PADR has called for ElectraNet and AEMO to undertake further work to conclusively determine the technical and commercial feasibility of the control scheme option, on the basis that the PADR has shown that this option has substantial net market benefits. However, ElectraNet and AEMO note that the control scheme option is not expected to have provide substantially higher net market benefits relative to those of other credible options (namely Option 1b). ElectraNet and AEMO do not therefore believe that the additional time and cost of pursuing further analysis would be warranted.

Control scheme costs

The capital costs of the control schemes included in this RIT-T have been based on the estimate provided by DSA and SP AusNet as follows:

- Heywood control scheme: $12.0m.
- South East control scheme: $1.0m.
- Additional cost of adding in new wind generation at Krongart to the Heywood control scheme: $1.0m.

An estimate received from SP AusNet included additional equipment required to implement the control schemes, that were not included within DSA's high-level assessment. For the purposes of this

RIT-T assessment, DSA's cost estimates (capital and operating) have been adjusted upward by approximately 25% to account for the following:

- Ensure all required equipment was accounted for in the cost estimates.
- Adopting a mediated value for the estimates, given the difference between the DSA and SP AusNet estimates.

ElectraNet and AEMO note that the adjusted costs used are still within the DSA estimate accuracy of +-30%.

A number of costs are common to the two control schemes, and have been incorporated only into the cost of the Heywood control scheme. In particular the full cost of the digital radio ($4.5m) is reflected in the costs for the Heywood control scheme.

For each control scheme, operating costs have been estimated by DSA at $1.5m over the life of the schemes out to 2040 (being a total of $3.0m).[31] Including the adjustment (+25%), this cost totals $3.87m.[32] This cost has been included in the RIT-T analysis presented in this PACR, in place of the assumption in the PADR that annual operating costs would be 2% of the capital costs.[33]

Infigen in its submission to the PADR requested that the costs of the control scheme be based on the DSA cost estimates, rather than an adjustment to those estimates to reflect cost information received from SP AusNet. ElectraNet and AEMO note that the DSA cost estimates do not cover all of the elements that would be required for the control scheme. In particular the DSA estimates did not assess the requirements for new protection relays associated with the transformer protection and voltage regulation, as well as modification of existing control schemes associated with the transformers. The SP AusNet costs also made use of alternative control system hardware compared with that proposed by DSA, in order to comply with the standard control scheme design as used at other sites. The adjustment to the DSA costs to ensure inclusion of all costs as described above therefore appears warranted. The cost estimates provided by SP AusNet were more comprehensive than those estimated by DSA as they were able to assess in more detail the existing assets. ElectraNet and AEMO further note that the adjusted costs used remain below the upper end of the cost estimates received from SP AusNet. For the purposes of this RIT-T, ElectraNet and AEMO have retained the estimate of capital costs for the control scheme used in the PADR. However, sensitivity analysis in relation to these costs has been undertaken, and is reported in section 6.3.2.

The above capital cost estimate includes the costs of communication links at Heywood. Several submissions proposed that these costs should be excluded, at least as a sensitivity, in light of ElectraNet's proposal that a communications capability be put in place for other network operational purposes as part of its Revenue Proposal to the Australian Energy Regulator (AER). The AER's Draft Decision in relation to ElectraNet's Revenue Proposal was released on November 30, and reflects a 28.2% reduction in capital expenditure compared with that proposed by ElectraNet and does not include an explicit consideration of this communications cost.[34] ElectraNet and AEMO therefore consider it reasonable to assume the full cost of communications equipment as part of the costs of the control scheme. Notwithstanding the AER's Draft Decision, the sensitivity test suggested by

[31] The estimate of $1.548m has been rounded to $1.5m (non-adjusted).

[32] The 25% adjustment to the DSA operating costs remains appropriate, given that these costs reflect substantial capital investment components, every ten years (comprising almost half of the overall cost estimate).

[33] This change was made in response to submissions requesting that he DSA costs be used as the basis for the control scheme costs.

[34] AER Draft Decision, ElectraNet 2012-14 to 2017-18, p. 31. The AER's Final Decision is due by 30 April 2013.

stakeholders has also been undertaken, and is reported in section 6.3.2. ElectraNet and AEMO also note that SP AusNet has recommended that two geographically diverse telecommunication paths are implemented between Heywood and South East substations. This would add a further $6.5m to the capital cost. This additional cost has not been included in the capital costs used in the RIT-T assessment, but has been incorporated as part of the sensitivity analysis.

In addition, it is possible that there would be costs associated with generator participation in the schemes. In initial discussions, Infigen has noted that it would not require payment for the participation of its Lake Bonney wind farm in the control scheme. For the purposes of the RIT-T analysis, ElectraNet and AEMO have therefore assumed no generator participation costs. However, ElectraNet and AEMO note that owners of new wind generation connecting at Krongart may require payment to participate in the scheme which will be an additional cost to the option.

In addition, a 500 kV bus tie at Heywood would still be required to address thermal and voltage issues on the Victorian side of the network under this option. The capital cost of the bus tie is estimated at $7.6m.

DSA and SP AusNet have both estimated that the control scheme would take two years to implement. The commissioning date for this option is therefore assumed to be July 2015.

Option 6b – Control scheme applying to specific wind generation in South Australia and South East substation plus Option 1b minus the 3rd Heywood transformer

The control schemes discussed above (i.e. Option 6a) have also been considered in combination with the network augmentation found to have the highest net market benefit, specifically Option 1b.

The 3rd transformer at Heywood has however been excluded from this option, as the installation of the control scheme represents an alternative means of managing the transformer capacity limitation at Heywood.

The cost of this option is:

- Control schemes: $12.0m for the control scheme, plus operating costs of $3.87m (see description as part of the earlier discussion of Option 6a).
- South East control scheme: $1.0m
- Adding additional wind at Krongart: $1.0m
- Network component: $70.3m.

The expected commissioning date for the control scheme part of this option remains July 2015, whilst the commissioning date for the network component is July 2016, in line with the commissioning date for Option 1b considered on a stand-alone basis.

3.4 Options proposed in submissions to the PADR

Several submissions to the PADR proposed additional and/or revised credible options. Each of these proposals is discussed in detail in section 4.13. This section presents a brief summary of some of the main additional options/variants considered as part of the finalisation of the RIT-T analysis.

Stand-alone South East control scheme

Infigen proposed that a stand-alone South East control scheme should be considered, both in isolation and in conjunction with other options. This control scheme would be as proposed by DSA for South Australia, i.e., a control scheme to manage the constraints due to the South East transformers, by tripping 132 kV connected wind farms to avoid a N-1 overload of the South East transformer.

ElectraNet has undertaken additional analysis in relation to the potential market benefits that may be associated with adding a control scheme in relation to the South East transformer only, to allow a non-firm increase in the transformer's capability to inject energy into the 275 kV network.

The additional analysis undertaken does not support incorporating a control scheme at South East as part of a credible option, since under what are currently considered to be the most likely demand conditions the control scheme would have a negative net market benefit, resulting in the net market benefit of the overall option being reduced. However ElectraNet intends to continue to monitor the situation, and will undertake further analysis going forward, as warranted. ElectraNet notes that the investment in a control scheme at South East is one which could be made independently and is not tied to the outcome of this RIT-T analysis.

A more detailed description of ElectraNet and AEMO's analysis of this option is set out in section 4.13 below.

Option 1b (third Heywood transformer) + Option 6a (control scheme)

Infigen and CEC both suggested that the control schemes could be considered in combination with Option 1b.

ElectraNet and AEMO note that including the control scheme in addition to the third Heywood transformer would potentially substantially increase the available capacity of the interconnector. DSA has estimated this could be up to 1,100 MVA.[35] ElectraNet and AEMO further note that the technical assessment in this RIT-T has been limited to obtain a notional +-650 MW capability from the interconnector and any further large increase in capacity will require significant additional work and potentially significantly more investment (e.g. new line between Tailem Bend to Tungkillo, significant additional static and dynamic reactive support, etc.) to sustain such the high transfer capability.

Further, ElectraNet and AEMO appreciate that it is possible that the additional capacity provided by the inclusion of the control scheme element may result in additional market benefits, which may outweigh the additional costs of the control scheme. However, as discussed in section 4.10 and in section 6.3.2, the commercial and technical feasibility of the control scheme is not assured at this time, and would require additional costs and a delay in the RIT-T assessment process

The economic benefits of further expanding interconnector capacity will be subject to ongoing review by AEMO and ElectraNet through established national and joint planning processes. Further discussion of ElectraNet and AEMO's consideration of this option can be found in section 4.13 below.

Installation of higher rated transformers at Heywood

Infigen proposed a number of other potential modifications to a combined Option 1b plus control scheme option. Infigen commented that there has been no consideration given to an option to retrofit

[35] DSA Report, Section 5.4 p. 16.

the existing transformers with short term overloading capability or entirely replacing the transformers with new transformers with a higher rating.

SP AusNet have advised that for the prolonged operation of the South East to Heywood 275 kV transmission lines flows should be kept to below 85% of the continuous rating to avoid long term deterioration of the conductors. This means that with a control scheme and three transformers at Heywood, the transmission line between Heywood and South East would be the limiting factor, and consideration of higher rated transformers is not warranted. SP AusNet has also advised that in situ replacement of both the existing transformers to enable higher short term ratings will require long outages and therefore the first transformer will have to be replaced adjacent to the existing units in order to minimise outage times. This will increase the project cost compared with in situ replacement of both units.

ElectraNet and AEMO consider that, based on the feedback provided by SP AusNet, this option does not warrant further investigation. Further discussion of ElectraNet and AEMO's analysis of this option can be found in section 4.13 below.

4 Submissions to the Project Assessment Draft Report

ElectraNet and AEMO received eight submissions[36] to the PADR, from:

- The National Generators Forum (the NGF).
- The Southern Australian Council of Social Service (SACOSS).
- South Australia Minister for Mineral Resources and Energy, Tom Koutsantonis.
- Infigen Energy (Infigen).
- International Power-GDF Suez Australia (International Power).
- SP AusNet.
- Alinta Energy (Alinta).
- Clean Energy Council (CEC).[37]

The issues raised in these submissions, and ElectraNet and AEMO's responses to those issues are discussed in this section. In addition, specific issues raised in submissions are also discussed in the relevant sections throughout this PACR, and the analysis reflected in this PACR has been revised to take into account points made in submissions, where appropriate.

4.1 Consultation process

Alinta stated in its submission that it is unclear what weight is given to submissions made by stakeholders and commented that the entire process may have benefitted from the establishment of a stakeholder reference group or similar to canvass options and issues.

ElectraNet and AEMO note that in conducting this RIT-T significant effort and costs have been expended in order to achieve a level of consultation and engagement with stakeholders. ElectraNet and AEMO conducted two public forums as part of the PSCR process and the PADR process, and have also met individually with submitters to both the PSCR and PADR to discuss the specific issues raised in submissions.

Each of the submissions received on the PSCR was discussed at length in meetings with the parties that made the submissions and in the PADR.[38] Submissions received on the PSCR resulted in substantial further analysis by ElectraNet and AEMO and in a number of new credible options being included in the RIT-T analysis in the PADR. In particular:

[36] PADR submissions can be accessed at: http://www.aemo.com.au/Electricity/Planning/Reports/Regulatory-Investment-Tests-for-Transmission-RITTs/Heywood-Interconnector-RIT-T.

[37] CEC's submission was received on 15 November 2012, after the 26 October 2012 closing date for submissions. ElectraNet and AEMO have been able to accommodate consideration of this late submission in this PACR.

[38] See in Section 4 of the PADR. The specific issues raised by Alinta in its submission to the PSCR and referenced again in its submission to the PADR were discussed in section 4.2 and 4.3 of the PADR, and in section 3.1 of the PADR in relation to the inclusion of Option 4 (p. 15). These issues are also responded to again in this section of the PACR.

- Options 5, 6a and 6b all include a non-network component, reflecting non-network options identified in submissions to the PSCR.
- The inclusion of a 3rd transformer at South East substation was requested in the submission to the PSCR by the private generators, and was reflected by the addition of Options 2a and 2b in the analysis. [39]
- Option 4 was included in the PADR following submissions on the PSCR from the group of private generators and Alinta that questioned the need for the Heywood transformer augmentation if the existing 460 MW capacity of the Heywood interconnector is instead maintained on a firmer basis, by addressing network congestion issues in South Australia.[40]

In relation to the inclusion of the control scheme option, Infigen's submission to the PSCR presented a relatively high level concept for the suggested control scheme. ElectraNet and AEMO undertook considerable additional analysis in order to develop the control scheme option to a point where it could be included in the RIT-T analysis, including engaging independent consultants (David Strong & Associates (DSA)) to assist in further developing this option.

ElectraNet and AEMO note that the practicality of progressing the RIT-T analysis in a timely fashion, and the ultimate responsibility given to TNSPs under the NER to identify the option which passes the RIT-T means that establishing a working group to progress the analysis would be unlikely to provide greater value than the already significant engagement approach adopted. ElectraNet and AEMO are conscious of the need to maintain a level playing field and ensure that all stakeholders have equal access to information, whilst recognising that individual transmission investments can be expected to benefit some stakeholders at the expense of others. ElectraNet and AEMO are also conscious of the need to ensure that the analysis is completed in a timely fashion, and is proportionate, given the highly resource-intensive nature of the market modelling required to analyse investments of this nature.

ElectraNet and AEMO consider that the process which they have adopted in relation to this RIT-T has struck an appropriate balance between stakeholder engagement, competitive neutrality and the need to progress the analysis in a timely fashion.

4.2 Finalisation of the PACR in light of uncertainty

The South Australian Minister for Mineral Resources and Energy noted in the PADR submission support for a quick finalisation of the PACR, in order to enable the upgrade to occur at the earliest opportunity.

In contrast, International Power and the NGF both expressed the view that the PACR should be delayed. International Power considered that, in light of several recent policy announcements and pending policy decisions, ElectraNet and AEMO should review their modelling and delay a decision until after the outcome of the Climate Change Authority's (CCA) Renewable Energy Target review.[41] The NGF considers that the demand forecasts utilised in the current models are too high and that the RIT-T process should be suspended until the release of AEMO's 2013 National Energy Forecast Report (NEFR), which the NGF expects to include a significant downward revision in peak demand.

[39] See section 3.1 of the PADR, p. 12.

[40] See section 3.1 of the PADR, p. 15.

[41] The specific issue of changes in the LRET target is discussed further in section 4.3.

Similarly, the CEC stated that the majority of modelling scenarios do not use the latest AEMO published demand forecasts and that the Heywood RIT-T would benefit from the use of the updated 2013 NEFR demand forecasts. SACOSS stated that, in light of AEMO recently revising downward demand forecasts and the regulatory environment being in a 'state of flux', the Heywood RIT-T should proceed conservatively, potentially to the point of delaying or staging the investment, in order to ensure that the identified need holds true over the coming years.

ElectraNet and AEMO note that there will always be uncertainty regarding the assumptions underpinning a RIT-T analysis as, for the most part, these assumptions rely on expectations of future outcomes (including future government policies and demand forecasts). Delaying the timing of the PACR will not remove uncertainty from the analysis, although it may change the specific issues considered to be subject to uncertainty. Whilst some issues may be clarified by delaying the PACR, there is no reason to expect that other issues (including other government policy developments, future gas prices and specific demand developments) will not emerge which are equally uncertain.

This uncertainty is dealt with under the RIT-T framework via the inclusion of reasonable scenarios in the analysis that capture a range of possible future states of the world. As discussed in more detail in section 4.3 below, ElectraNet and AEMO believe that a sufficient range of future scenarios have been modelled as part of this RIT-T to address the inherent uncertainty in the underlying assumptions, ensuring that the selection of the preferred investment option is robust over a range of possible outcomes. This is particularly the case given the long-lived nature of the investment, and the corresponding period over which the analysis is conducted. Whilst the current focus is on low demand outcomes, over a 40 year period it is possible that demand conditions could fluctuate substantially.

In addition, delaying the finalisation of the analysis (and ultimately the commissioning date of the preferred option) will deprive those who produce, consume and transport electricity in the market of market benefits associated with the investment. The RIT-T analysis shows that Option 1b is estimated to return $25.7m[42] market benefits (in absolute terms) from the first year in which it is commissioned. Delaying the release of the PACR would delay investment, and push the realisation of these benefits further into the future.

4.3 Changes to the regulatory environment

SACOSS commented that the regulatory environment is currently in a 'state of flux' and mentioned a number of reviews and proposals that have a relationship to the matters being considered in this RIT-T, including: the AEMC's Transmission Frameworks Review; Power of Choice Review; Economic Regulation of Network Service Providers Rule Change and Inter-regional Transmission Charging Rule Change; the Productivity Commission Inquiry into Electricity Network Regulatory Frameworks; and the broader recommendations of the Review of the Limited Merits Review Regime for the Standing Council on Energy and Resources (SCER). As noted earlier, SACOSS suggested that in light of the uncertainty created by the current high number of review processes, the Heywood RIT-T should proceed conservatively, potentially to the point of delaying or staging the investment.

ElectraNet and AEMO note that many of the reviews highlighted by SACOSS focus on the incentives and approach contained in the framework for economic regulation. It would not therefore be expected that the changes being considered would result in a different investment decision (distinct from the

[42] This is the weighted average across the four scenarios considered.

later assessment by the AER of the appropriate treatment of the costs of that investment). For those reviews which may result in changes to the planning process, it is not evident that this change in process would be expected to lead to the identification of a different preferred investment in the current case.

SACOSS also suggested that the Optional Firm Access proposal of the AEMC's Transmission Frameworks Review may provide a more market-based and efficient driver for network investment in increasing the export potential of South Australia's wind energy resource.

ElectraNet and AEMO note that the Optional Firm Access approach would be an alternative to the current RIT-T process in the NER. However, this approach currently remains subject to review by the AEMC, and ultimately would need to be subject to a decision by SCER to introduce this framework into the NER, and would require a detailed implementation process. At this point in time, ElectraNet and AEMO are required to consider the process under the current NER, i.e. the RIT-T.

4.4 Inclusion of additional reasonable scenarios

A number of submitters suggested that the range of reasonable scenarios adopted for the RIT-T be expanded, to reflect potential changes in government policies going forward, and to take account of the demand forecasts in AEMO's forthcoming 2013 NEFR.

The NGF noted that three of the four scenarios considered by ElectraNet and AEMO incorporate Federal Treasury modelling estimates of forward carbon prices that were completed more than 12 months ago and suggested that a zero carbon price scenario should be included in the analysis. Similarly, both Alinta and International Power commented that none of the scenarios include a low carbon price reflective of current and predicted carbon forward prices. They assert that the high carbon prices assumed in the model are unlikely to occur, leading to an overestimation of the benefits arising from displacing fossil fuel plants with lower greenhouse emitting plants.

As discussed in the previous sections, several submissions (the NGF, CEC) proposed delaying the finalisation of the analysis so that it could incorporate the demand forecasts in the 2013 NEFR, which stakeholders expected to be lower than the demand forecasts used in the scenarios to date.

The NGF and Alinta called into question the relevancy of the current fixed targets employed by the LRET program, instead suggesting a downward revision of the LRET target.

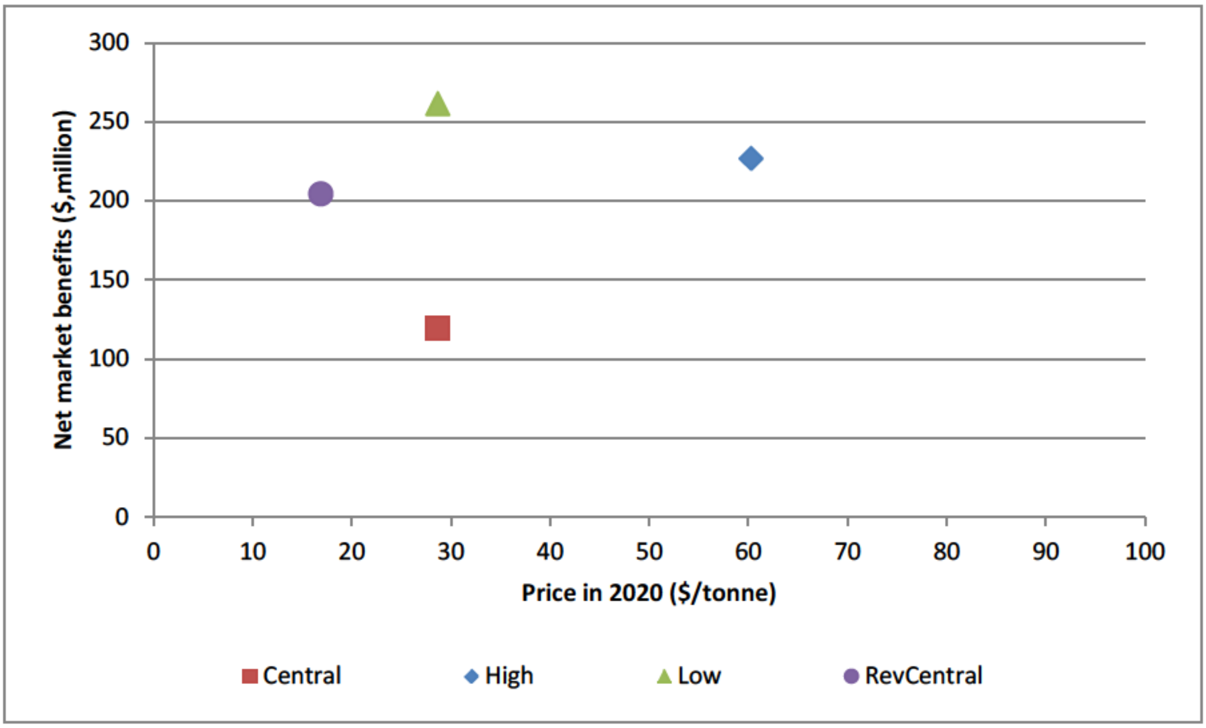
In relation to the uncertain level of future carbon prices, ElectraNet and AEMO consider that it is important that the RIT-T analysis is robust across possible ranges of future carbon price outcomes, and does not focus too tightly on current conditions. ElectraNet and AEMO therefore believe that it is appropriate that a range of future carbon price scenarios are included in the RIT-T analysis to address this uncertainty. ElectraNet and AEMO also note that the revised central scenario (scenario 4) includes the assumption of a low carbon price, and shows that Option 1b provides substantial market benefits (higher than those in the central scenario) and is the highest ranked option under this scenario. ElectraNet and AEMO do not therefore expect that including additional 'low carbon' scenarios would materially change the RIT-T outcome, and consider that the substantive costs required to undertake additional scenario analysis would therefore be disproportionate.

An approximation of the impact of including additional low scenarios into the analysis can be made by increasing the weighting given to scenario 4, compared with scenarios which include a higher carbon price. ElectraNet and AEMO have expanded the sensitivity analysis of scenario weightings in the

RIT-T to incorporate this analysis, which is reported in section 6.3.2 and shows that giving a higher weight to scenario 4 results continues to support the identification of Option 1b as the preferred option.

Further, Figure 4-1 below illustrates the assumptions made under each scenario in relation to the carbon price (using 2020 as a 'snapshot' year),[43] as well as the net market benefits of Option 1b under each scenario. It demonstrates that there is no linear relationship between the assumed carbon price and the estimated net market benefits of Option 1b. Including a lower (or zero) carbon price scenario will therefore not necessarily lower the net market benefits estimated for Option 1b. Indeed, estimates presented in AEMO's 2011 Statement of Opportunities show that there is no material change in the expected order of the LRMC merit order for generators between a zero and $25/tonne carbon price.[44] A generation dispatch benefit resulting from the augmentation would therefore still be expected to be present under lower carbon prices.

Figure 4-1: Assumed carbon price and net market benefit under different scenarios - Option 1b

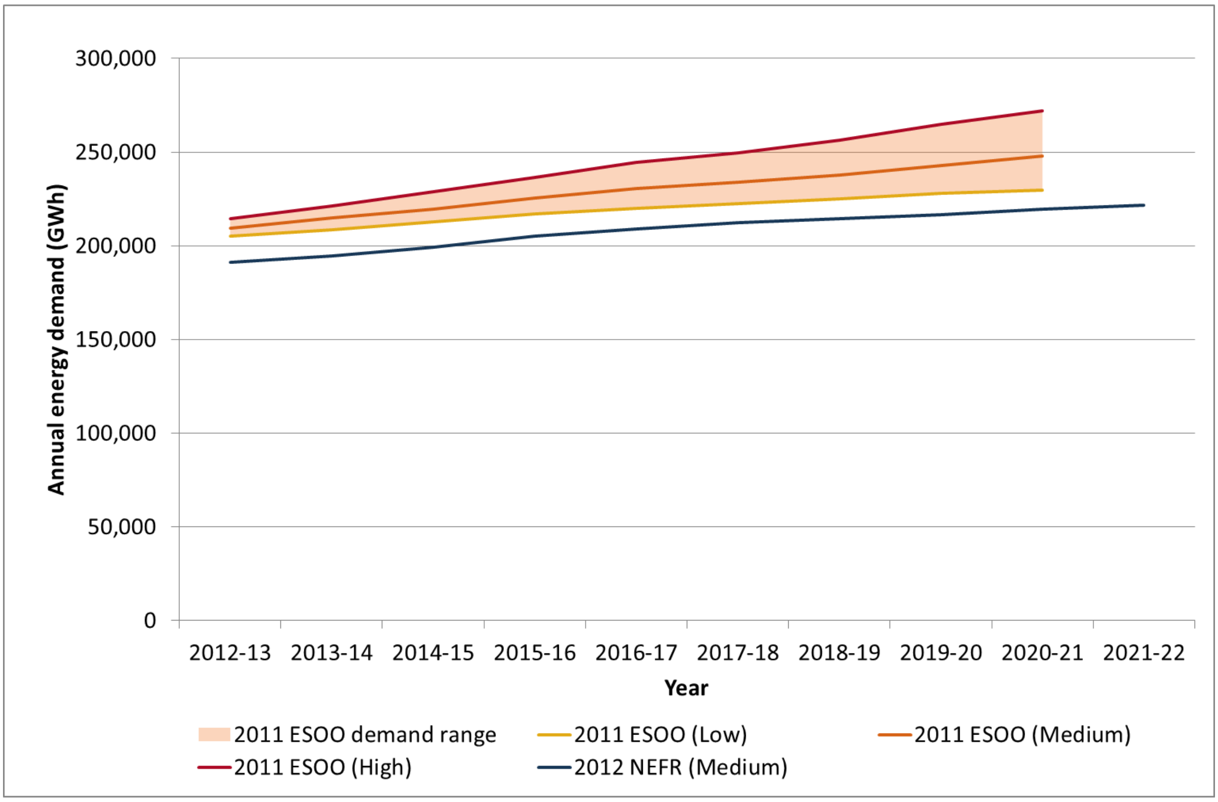


In relation to adding further scenarios to reflect lower levels of demand, ElectraNet and AEMO note that scenario 4 (revised central scenario) already reflects a substantially lower demand forecast, based on AEMO's 2012 NEFR. Figure 4-2 shows the demand range from the 2011 ESOO compared with the 2012 NEFR demand used in the revised central scenario, clearly showing that it is lower than the 2011 demand forecasts.

[43] Appendix H provides further 2020 analysis, also covering an additional snapshot year, 2016.

[44] AEMO 2011 Electricity Statement of Opportunities, Figures 8-11 and 8-12. http://www.aemo.com.au/Electricity/Planning/Reports/Archive-of-previous-Planning-reports/Electricity-Statement-of-Opportunities-2011.

Figure 4-2: 2011 ESOO demand forecasts compared with the 2012 NEFR demand forecasts



The RIT-T analysis shows that under this lower demand forecast, Option 1b continues to provide substantial net market benefits, and to be ranked as the preferred option. As in the case of considering further scenarios with low carbon prices, ElectraNet and AEMO consider that a more proportionate response to assessing the impact of lower demand would be to look at the impact on the RIT-T outcome of applying a higher weighting to the existing low demand scenario (i.e. scenario 4). As discussed above, ElectraNet and AEMO have expanded the sensitivity analysis of scenario weightings in the RIT-T to incorporate this analysis, which is reported in section 6.3.2 and shows that giving a higher weight to scenario 4 results continues to support the identification of Option 1b as the preferred option.

ElectraNet and AEMO do not consider that any substantial reason has been provided for why adopting a lower demand forecast than the 2012 NEFR is either expected to be relevant, or would result in a substantial change in the net market benefits. If 2011/12 observed demand is compared to the 2011/12 NEFR forecast demand, overall variance across the NEM is low (less than 1%).

Figure 4-3 and Figure 4-4 below illustrate the level of demand forecasts in South Australia and Victoria across each scenario (taking 2020 as a ‘snapshot’ year), [45] as well as the net market benefit and historical observed record demand in 2011, for Option 1b.

[45] Appendix H covers additional snapshot years, and different POE assumptions.

Figure 4-3: Assumed South Australia demand and net market benefit under different scenarios - Option 1b

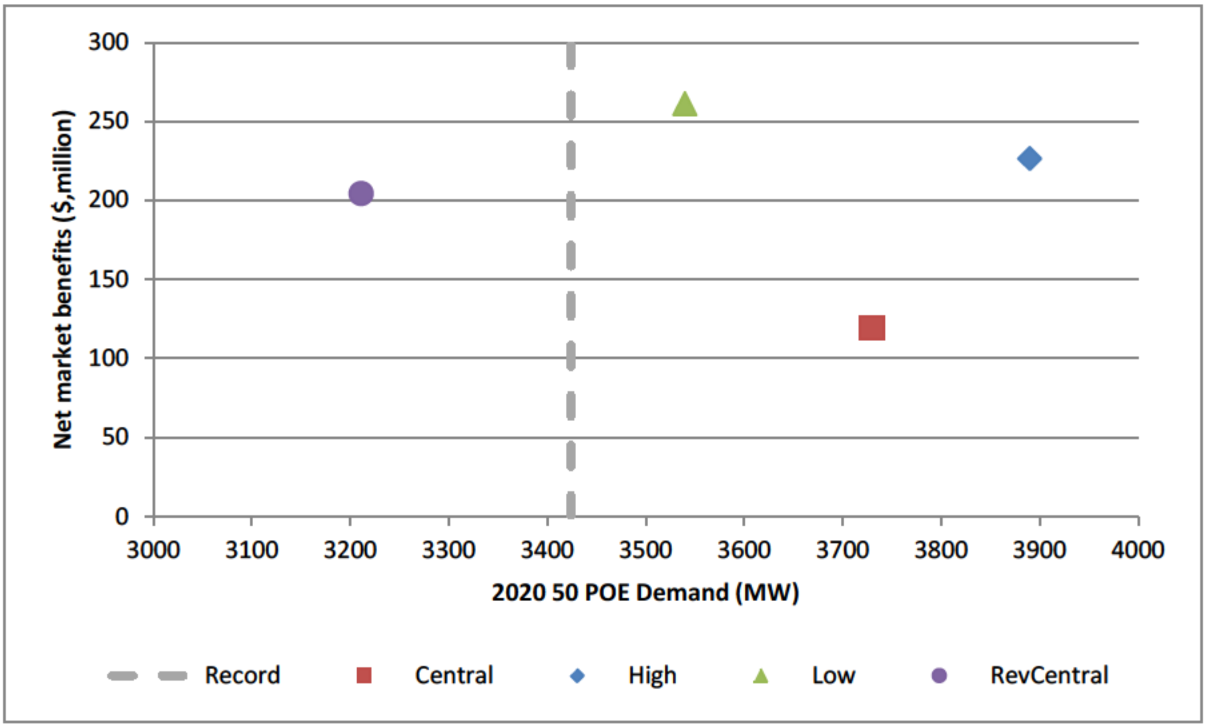
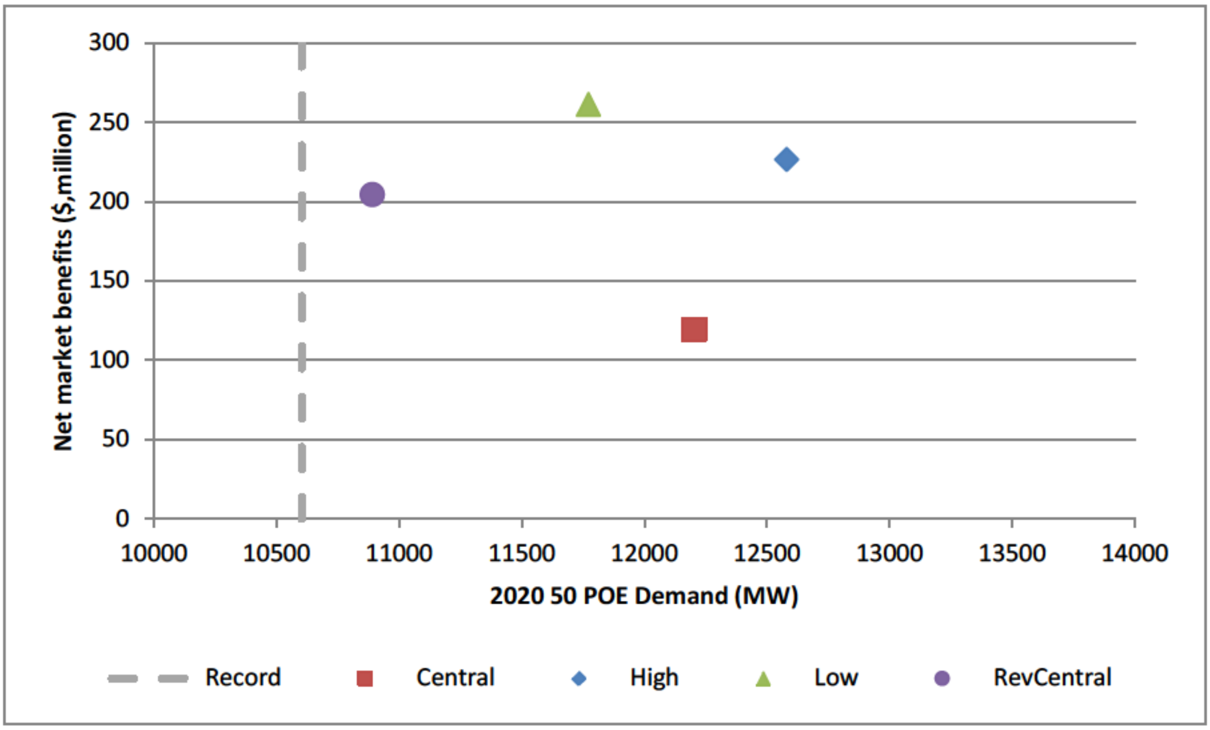


Figure 4-4: Assumed Victoria demand and net market benefit under different scenarios - Option 1b



The figures demonstrate that there is no linear relationship between the assumed demand forecast in these regions and the estimated net market benefit of Option 1b. There is no reason to conclude, a priori, that adding a further scenario with even lower demand will necessarily substantially lower the net market benefits estimated for Option 1b, and alter the RIT-T results. As discussed in section 6.3.1, under the lower demand scenario (scenario 4), the primary source of market benefits are dispatch cost savings from changes in the output of current generation (rather than changes resulting from different patterns of generation investment).

In relation to changing assumptions in relation to the fixed LRET target, ElectraNet and AEMO note that the CCA is recommending no change to the LRET target in its Final Report, and so adopting an alternative assumed target does not appear to be warranted.[46]

4.5 Discount rate and analysis period

Both SACOSS and the NGF suggest that a higher discount rate should be employed as a result of the high degree of uncertainty associated with modelling large and distant benefits. Alternatively, the NGF suggests that the analysis could be restricted to 20 years to compensate for the uncertainty in future benefits.

As discussed above, uncertainty in relation to future outcomes is addressed under the RIT-T framework via the inclusion of different reasonable scenarios. Notwithstanding this point, ElectraNet and AEMO have undertaken additional sensitivity analysis as part of this PACR to address the above points raised in submissions.

ElectraNet and AEMO note that sensitivity analysis reported in the PADR demonstrated that the adoption of a higher (13%) discount rate did not affect the rankings of the options under the RIT-T. In this PACR ElectraNet and AEMO included further sensitivity testing using an even higher discount rate of 16%. The results are reported in section 6.3.2, and demonstrate that the identification of Option 1b as the preferred option with a substantial positive net market benefit remains unchanged if this higher discount rate is assumed.

ElectraNet and AEMO consider that the long-lived nature of the assets involved in the credible options considered for this RIT-T, coupled with the fact that this is a market benefit assessment and the extended period over which benefits are expected to be realised, justify the adoption of a relatively long analysis period. The approach of adopting an extended analysis period, based on the continuation of an assumed end-value, is one which has been adopted in other similar assessments. Notwithstanding this point, ElectraNet and AEMO have conducted a sensitivity analysis using a 20-year analysis period. The results of this analysis are discussed in section 6.3 and demonstrate that the ranking of the credible options (and the identification of Option 1b as the preferred option) would remain unchanged under a 20-year assessment period.

ElectraNet and AEMO's justification for both the analysis period selected and the assumed discount rates are discussed in more detail in section 5.1 and section 5.2, respectively.

[46] Climate Change Authority, (2012), *Renewable Energy Target Review*, Final Report, December 2012, p. vii.

4.6 Basis for identification of the preferred option

The South Australian Minister for Mineral Resources and Energy stated support for Option 1b, i.e. the preferred option outlined in the PADR.

SACOSS and International Power both note that although Option 1b is the preferred option under the NPV ranking presented in the PADR, Option 4 would be the preferred option if a ranking system based on the ratio of benefits to cost were employed.

ElectraNet and AEMO note that the NER establish one of the principles of the RIT-T as follows:

> The purpose of the RIT-T is to identify the option which maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market (the *preferred option*).[47]

ElectraNet and AEMO do not have control over this NER requirement, and selection of the preferred option on an alternative basis (such as the ratio approach proposed by SACOSS and International Power) would not be compliant with the NER.

Moreover, consumers' long-term interests should be furthered by the approach prescribed in the NER as it maximises the *total* net market benefit delivered to the market. In determining the appropriate principles for the regulatory test (now the RIT-T), the AEMC commented that:

> The NEM objective specifies 'efficient investment' as one of the key elements in delivering the long term interests of consumers. By definition, the Regulatory Test seeks to provide incentives for investment that result in the most efficient outcomes, by determining which alternative maximises the net benefit to the market.[48]

In addition, for market benefit assessments the total benefit expected to be delivered to the market is required to outweigh the cost of the investment (i.e. the net benefit must be greater than zero). Under a ratio approach, although the market benefit per dollar of costs may be higher, the total amount of market benefit achieved may well be lower, resulting in market participants realising a lower absolute level of market benefits.

4.7 Consideration of demand management

SACOSS expressed disappointment that the 200 MW demand response capacity offered by EnerNOC was 'so readily dismissed'.

ElectraNet and AEMO do not agree that the demand response capacity has been 'readily dismissed' in the PADR. Rather, the demand response capacity offered by EnerNOC was incorporated into Option 5 in the RIT-T analysis. This option had the same amount of rigour applied to it, and the same consideration in the RIT-T analysis as the other credible options. However, the net market benefit of the demand response option was found not to be as high as those of other credible options, primarily because of the high costs associated with demand response. ElectraNet and AEMO note that the costs of the demand response component of Option 5 were sourced from EnerNOC, who was the proponent for this option.

[47] NER 5.16.1(b).

[48] AEMC 2006, Reform of the Regulatory Test Principles, Final Determination, 30 November 2006, Sydney, p. 53.

4.8 Commercial and technical feasibility of the control scheme

Both Infigen and International Power suggested in their submissions that the control scheme had not received sufficient investigation and should be further explored. Infigen commented that the risks associated with selecting a control scheme solution in preference to adding a third transformer at Heywood noted by ElectraNet and AEMO were not sufficient grounds to cease consideration of the control scheme. Infigen requested that ElectraNet and AEMO comprehensively confirm both the technical and commercial feasibility of a control scheme on Heywood to South East 275 kV transmission lines. Infigen considered that the potential benefits of the control scheme justify further detailed investigation into the feasibility of this option.

ElectraNet and AEMO note that considerable time and costs have been expended to date in analysing the control scheme, which was proposed by Infigen in its submission to the PADR in a high-level conceptual form. In particular ElectraNet and AEMO engaged independent consultants DSA to develop the control scheme proposal to a point where it could be incorporated into the RIT-T analysis.

The RIT-T analysis conducted for the PADR, and the revised analysis conducted for this PACR, show that the combined network and control scheme option (Option 6b) provides positive net market benefits. However the net market benefits associated with Option 6b are not substantially higher than those for Option 1b, whose technical and commercial feasibility is already confirmed. This remains the case, even under a ‘low cost’ assumption for the control scheme, where the $4m cost of the communication scheme is removed. ElectraNet and AEMO consider that Option 6b would need to be expected to provide *materially more benefits* than alternative options in order to justify the additional costs and delay in investment timing that would be necessary in order to conclusively determine the technical and commercial feasibility of this option.

ElectraNet and AEMO further note that proceeding with Option 1b does not preclude consideration of the addition of one or both of the control schemes at a later date (as discussed in section 4.13).

4.9 Uncertainty in relation to additional wind generation

In response to comments in the PADR relating to the uncertainty regarding new wind generators connecting at Krongart suitable to participate in the control scheme, Infigen noted that it recently received development approval for its Woakwine Wind Farm project.

ElectraNet and AEMO note that, even though the Woakwine Wind Farm project has received development approval, there remains significant uncertainty surrounding its eventual development. The Woakwine Wind Farm is classified by AEMO as ‘publically announced only’, meaning that it satisfies less than three of the AEMO commitment criteria and may be removed from the list of proposals at a later time.[49]

4.10 Control scheme costs

Infigen raised a number of points in its submission in relation the costs of the control scheme that has been used in the RIT-T analysis in the PADR. In particular:

[49] 2012 ESOO, Section 2.4.2. Available: http://www.aemo.com.au/Electricity/Planning/Electricity-Statement-of-Opportunities.

- Infigen considered that undue caution has been used for costing and feasibility of the control scheme options and that greater weight should be given to DSA's conclusions on costs over SP AusNet. Infigen noted SP AusNet's interest in the outcome of the process and suggests accordingly that estimates given by independent experts, such as DSA, are more likely to reflect probable costs.
- Infigen noted that the upcoming draft ElectraNet revenue decision by the AER could indicate whether communication costs will form part of ElectraNet's prescribed transmission services or not. Infigen stated that if these costs are included in ElectraNet's prescribed transmission services, they should be excluded from the analysis undertaken in preparing the PACR.

The CEC also submitted that consideration should be given to the interaction between the control scheme costs and ElectraNet's communications infrastructure proposed as part of its regulatory proposal.

ElectraNet and AEMO note that the control scheme costs estimated by DSA included a number of uncertainties and could not include estimates for all cost elements. For example, the DSA estimates were not able to assess the requirements for new protection relays associated with the transformer protection and voltage regulation, as well as modification of existing control schemes associated with the transformers.

The cost estimates provided by SP AusNet were more comprehensive than those estimated by DSA. The SP AusNet costs also made use of alternative control system hardware compared with that proposed by DSA, in order to comply with the standard control scheme design as used at other sites. In combining the DSA costs and the cost estimates provided by SP AusNet, ElectraNet and AEMO took a conservative approach, and adopted the lower end of the cost range provided by SP AusNet.

ElectraNet and AEMO further note that SP AusNet does not have an automatic right to construct the Victorian assets involved in the preferred option. Under the Victorian planning arrangements, the works in Victoria would be subject to a tender process.

The AER's Draft Decision in relation to ElectraNet's Revenue Proposal was released on November 30, including substantial cuts in capital expenditure compared with that proposed by ElectraNet.[50] ElectraNet and AEMO therefore consider it reasonable to assume the full cost of communications equipment as part of the costs of the control scheme.

Notwithstanding the above, ElectraNet and AEMO have incorporated a number of revisions in the analysis presented in this PACR to address the concerns raised by stakeholders:

- The operating costs assumed for the control scheme have been based on the cost estimate provided by DSA (adjusted by 25%) rather than the generic 2% of capital cost assumption used in the PADR.
- Sensitivity analysis has been undertaken to identify the impact on the RIT-T results of (a) excluding the cost for ElectraNet for communications; (b) removing the 25% adjustment made to the DSA cost estimates (both capital and operating costs); and (c) including the higher end of the range of costs from SP AusNet and the higher communications cost estimated by SP AusNet.

The sensitivity analysis is reported in section 6.3.2.

[50] AER Draft Decision, ElectraNet 2012-14 to 2017-18, p. 31. The AER's Final Decision is due by 30 April 2013.

4.11 Accuracy of network cost estimates

Infigen noted that costing information associated with the installation of a third 500/275 kV Heywood transformer, the 500 kV bus tie and associated augmentation of the ElectraNet network depends on inputs from ElectraNet and SP AusNet, both of which have vested interest in the outcome of the RIT-T. They suggest that the costing of these options be independently assured prior to finalisation of the RIT-T assessment. CEC also called for an independent review of network costs, as once a network upgrade is approved the cost of this upgrade is included as an increased use of system charge to consumers for very long time periods.

ElectraNet and AEMO noted in the PADR that ElectraNet's cost estimates have been subject to review by external engineering consultants. Given that at this stage all of the costs incorporated into the RIT-T are necessarily estimates, ElectraNet and AEMO do not consider that there would be substantial value in seeking further review of the network cost estimates. Sensitivity analysis of the impact of differences in network costs on the RIT-T outcome is a more appropriate approach to addressing the uncertainty in relation to network costs. The PADR included a +/- 10% sensitivity analysis in relation to network costs. This sensitivity cost has also been included in this PACR, together with an additional +/- 30% sensitivity test for network costs to address the issue raised by Infigen. These results are reported in section 6.3.2. Both sensitivity tests show that Options 1b and 6b continue to be jointly ranked as the preferred option, with the net market benefit of both being materially indistinguishable.

ElectraNet and AEMO also note that there is a high degree of commonality between the network elements included in different options, such that differences in network cost estimates can be expected to impact many of the options in the same way (with the key exception of the Heywood transformer element, which would not be included in Option 6b). Moreover, in terms of the final impact on consumer prices, the investment undertaken following the completion of the RIT-T process will remain subject to the AER's assessment under the economic regulation provisions in the NER, prior to being reflected in prices.

4.12 Quantification of benefit from reducing impact of major transformer failure at Heywood

Infigen suggested that the market benefits of a prolonged 500/275 kV Heywood transformer outage should be explicitly assessed, rather than being treated as an 'unquantifiable risk'. Infigen also suggested that that a control scheme component applied in conjunction with Option 1b would provide substantial mitigation against the risk of reduction in transfer limits during an outage of a Heywood 500/275 kV transformer, and that this benefit should be taken into account in analysing this option.

The CEC noted that the final recommendations of the PADR are based on the perception of a reduced risk from Option 1b over Option 6b. CEC commented that this risk should not be ignored and needs to be quantified to some extent in the analysis to allow an accurate comparison between options. The CEC stated that it is not clear that the long term reliability benefits of the introduction of a third transformer at Heywood have been fully considered. Specifically, CEC noted that as the existing transformers age, the increased risk of failure could be offset to some degree by the increased N-1 capacity at Heywood and that, in the absence of the third transformer, the loss of one of the transformers represents a significant risk to market efficiency.

SP AusNet requested that the market cost of a major failure of a 500/275 kV Heywood transformer or the cost of a 'cold' spare transformer to mitigate the market impact of a prolonged transformer outage be included in the RIT-T analysis.

In the PADR ElectraNet and AEMO noted that adding a 3rd transformer at Heywood would have the benefit of reducing the risks associated with a prolonged outage of one of the existing transformers, compared with the alternative of adopting the control schemes. Although the probability of a transformer outage is low, if a catastrophic failure of one of the Heywood transformers did occur (for example, due to a failure in the transformer tank) then the replacement time would be in the order of two years. During this period, the interconnector limits would become 460 MW (each way) if there was a third Heywood transformer in place (i.e. Option 1b). However, if the control schemes were to be adopted instead (i.e. Option 6b), the interconnector limits would fall to approximately 250 MW (South Australia to Victoria) and 210 MW (Victoria to South Australia).

In response to the above stakeholder calls for the benefit of the impact of an outage of a Heywood transformer to be explicitly quantified and incorporated in the RIT-T assessment, ElectraNet and AEMO have included details of preliminary analysis undertaken to quantify the potential benefits under different options.

The RIT-T approach of weighting the market benefits across different scenarios means that the additional benefit needs to be multiplied by an expectation of the probability of such an event occurring, in order to be incorporated in the RIT-T analysis. As an input to the preliminary analysis, SP AusNet estimated the probability of a transformer tank fault for the Heywood transformers as being less than 1% per year. As a result, although the extended outage of a transformer at Heywood would have a high cost to the market, the low probability of the event occurring means that the value of this benefit that can be incorporated into the RIT-T analysis is substantially lower. The preliminary analysis shows that options incorporating a 3rd Heywood transformer may be expected to have additional market benefits in the order of $5.6m (probability-adjusted, net present value assuming a 10% discount rate across the assessment period), in the event that there is a two-year outage of one of the existing Heywood transformers, compared to options which do not include a 3rd Heywood transformer.

In light of the RIT-T results presented in section 6.3.2, ElectraNet and AEMO consider that incorporating an additional benefit of this order of magnitude would have an immaterial impact on the outcome of the RIT-T.[51] This immaterial impact means that the costs and time taken to undertake this analysis on a comprehensive basis is not warranted.

ElectraNet and AEMO consider that the impact of a third Heywood transformer in minimising the costs associated with a failure of an existing Heywood transformer is still a relevant factor to consider in terms of selection of the preferred investment, *in the absence of other material differences*.

ElectraNet and AEMO note that an assessment of whether the costs of a major failure of an existing Heywood transformer would justify SP AusNet holding a spare 'cold' transformer is a separate issue to that being addressed in this RIT-T. ElectraNet and AEMO have therefore not incorporated this option in the RIT-T assessment.

[51] This is confirmed by the indicative sensi ivity analysis presented in section 6.3.2.

4.13 Additional/revised credible options

Several submissions propose additional and/or revised credible options. Each of these is discussed in the sections below.

Stand-alone South East control scheme

Infigen proposed that a stand-alone South East control scheme should be considered, both in isolation and in conjunction with other options. This control scheme would be as proposed by DSA for South Australia i.e., a control scheme to manage the constraints due to the South East transformers. Infigen considered that the South East transformer constraint justifies immediate action in the form of implementation of a control scheme.

Infigen has submitted that a stand-alone South East control scheme could be installed ahead of the other components of Option 1b.

ElectraNet has undertaken additional analysis in relation to the potential market benefits that may be associated with adding a control scheme in relation to the South East transformer only, to allow a non-firm increase in the transformer's capability to inject energy into the 275 kV network.

Since July 2012, congestion on the South East transformer has increased from historical levels. The limits on flows across the transformer have been reached for over 200 hours over the first four months of the 2012/13 financial year, specifically: 21 hours in July; 33 hours in August; 119 hours in September and 52 in October. This is on par with annual levels over the preceding two years.

A reduction in demand in the south east of South Australia is leading to greater flows over the South East transformers. This reduction largely reflects reduced load from a single customer, which is likely to further reduce going forward, as the customer is planning to install its own on-site generation.[52]

The existing congestion is predominantly due to South East transformers injecting, while power flows from 132 kV into the 275 kV network. The modelling for this RIT-T assessment has considered in detail the potential for a third transformer at the South East. The market benefits associated with this additional transformer have been shown to not outweigh the costs. A third South East transformer has the potential to deliver benefits in both directions, but the lower demand forecasts are likely to push out the need for additional flows from 275 kV to 132 kV for quite a while.

A control scheme delivers benefits in only a single direction, at lower cost and hence may be a more appropriate solution to this congestion. However ElectraNet also notes that the current congestion is likely to reduce going forward, due to normal demand growth from year to year, and therefore the market benefits may diminish going forward.

ElectraNet set up a reduced network model to explore in more detail the market benefits associated with a control scheme at South East, taking into account the reducing demand situation in the South East region noted above. This analysis (summarised in Table 4-1 below) indicates that under some future demand assumptions the benefits of the control scheme are sufficient to outweigh the costs (and could be estimated to deliver almost $2m of net market benefits). However, in what is currently considered the most probable future (the 'central' demand assumption), the benefits are insufficient to

[52] A generator license application has been lodged with ESCOSA by Kimberly Clark Australia on 6 December, and can be found at http://www.escosa.sa.gov.au/article/newsdetail.aspx?p=16&id=1060

warrant investment at this time (and are estimated to deliver approximately -$360,000 in net market benefits). ElectraNet also notes that the decision is sensitive to a number of uncertainties, including the assumed level of demand, annual operating costs and the value of constrained generation at the time of congestion.

Table 4-1: Net market benefits associated with a control scheme at South East

Demand Assumption	Description	Net Benefits
Central	Assumes the latest growth forecasts received in April 2012 with Snuggery Rural and Kincraig updated in November 2012. Energy consumption is based on the 2011-12 financial year	-$360,902
Lower 10 per cent	Based on the Central demand assumption scenario. Initial annual energy is reduced by 10 per cent (45.9 GWh) based on a 10 per cent reduction in energy consumption at Snuggery. Demand growth is reduced by 10 per cent (5.22 MW) of 2011/12 forecast growth throughout the horizon.	-$64,392
Lower 20 per cent	Based on the Central demand assumption scenario. Initial annual energy is reduced by 20 per cent (91.9 GWh) based on a 10 per cent reduction in energy consumption at Snuggery. Demand growth is reduced by 20 per cent (10.44 MW) of 2011/12 forecast growth throughout the horizon.	$147,764
Rural	Ann extreme future with industrial loads reducing to zero. The scenario is based on the Central demand assumption scenario with energy reduced to 66 GWh.	$1,967,607

The additional analysis undertaken does not support incorporating a control scheme at South East as part of a credible option, since the resulting net market benefit of the overall option would be reduced. However ElectraNet intends to continue to monitor the situation, and will undertake further analysis going forward, as warranted. ElectraNet notes that the investment in a control scheme at South East is one which could be made independently and is not tied to the outcome of this RIT-T analysis. The cost of the control scheme also means that it falls below the RIT-T threshold, and so would not need to be subject to the RIT-T process.

In addition, ElectraNet notes that it is also considering the application of short term ratings to the South East transformers, which may be expected to provide up to 30% additional capacity under favourable environmental conditions (typically low demand, high wind generation and high transformer flows from 132 kV to 275 kV system). ElectraNet is currently in the process of installing monitoring devices to the transformers, which will provide the information required to take a decision on the short term ratings of the transformers.

An expanded South East 132 kV control scheme

In addition to the South East control scheme as proposed by DSA, Infigen suggests that an expanded control scheme could be considered to manage loadings on additional elements of the south east South Australia 132 kV system, to address existing bottlenecks in this region.

ElectraNet and AEMO note that the network options presented in the PSCR and PADR were developed on the basis of analysis to identify the lowest cost options, prior to undertaking the market modelling, as discussed in section 3.1. This assessment of the appropriate 132 kV works in South Australia took into account the potential decommissioning of the 132 kV lines due to asset condition, requiring significant maintenance expense. Retaining these lines was shown not to be the lowest cost option. Removal of these lines and increasing the ratings of the remaining 132 kV to its full design capability is expected to alleviate all line-related thermal constraints in the South East region. ElectraNet and AEMO do not therefore believe that it is necessary to include consideration of retaining these lines at this PACR stage. ElectraNet and AEMO further note that if the existing constraints on the 132 kV network are removed by decommissioning of the lines, then there is no rationale for an additional expanded control scheme, as the only constraint that will remain after the reconfiguration relates to the transformers at South East.

Option 1b (third Heywood transformer) + Option 6a (control scheme)

Infigen proposes full technical and economic evaluation of an option that combines the Heywood transformer and the control scheme. The CEC also submitted that there may be an opportunity to integrate a control scheme into the recommended Option 1b.[53] At a high level, the CEC stated that this scheme could focus on the 132 kV system in South East by tripping participant wind farms when necessary to allow non-firm operation of the Heywood transformers, prior to and following the installation of the third transformer.

ElectraNet and AEMO note that including the control scheme in addition to the third Heywood transformer would potentially substantially increase the available capacity of the interconnector. DSA has estimated this could be up to 1,100 MVA.[54]

ElectraNet and AEMO appreciate that it is possible that the additional capacity provided by the inclusion of the control scheme element may result in additional market benefits, which may outweigh the additional costs of the control scheme. However, as discussed in section 4.10 and in section 6.3.2, the commercial and technical feasibility of the control scheme is not assured at this time, and would require additional costs and a delay in the RIT-T assessment process. This would ultimately delay the timing of the investment works (including the proposed 132 kV works to address congestion in south east South Australia), and delay the time at which the market would realise the net market benefit from the investment.

ElectraNet and AEMO also note that this RIT-T assessment has its origins in the earlier Joint Feasibility Study and subsequent work that indicated that an incremental upgrade to the interconnector capacity may be viable in the short to medium term. A variety of steady state, transient & voltage stability studies have been performed to confirm the technical viability moving from 460 MW to 650 MW (i.e., around a 40% increase in capacity). Options 1b and 6b have each had their benefits modelled from these studies. Inclusion of the control scheme with Option 1b almost doubles the interconnector capability, and means that this would no longer be an incremental upgrade. An increase of this magnitude would require significant additional transient & voltage stability studies as well as small signal studies to determine technical viability, which would require additional transmission elements to be added, adding to cost and again ultimately delay the time at which the market would realise the net market benefit from the recommended investment.

[53] The CEC refer to Option 6b in its submission, but ElectraNet and AEMO have since clarified that the reference should have been to Option 1b (i.e. the preferred option).

[54] DSA Report, Section 5.4 p. 16.

ElectraNet and AEMO consider that 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. This is not the case with this scheme, as it can be added to the proposed solution at a later date. It is important to recognise that addition of the control scheme element can occur at a later date, and is not precluded by undertaking Option 1b first. Given that a delay to the implementation of the preferred option deprives the market of annual benefits in the order of $10m to $30m, ElectraNet and AEMO consider that there is no justification to delay.

1bThe economic benefits of further upgrades to the interconnector capacity will be subject to ongoing review by AEMO and ElectraNet through established national and joint planning processes.

Installation of higher rated transformers at Heywood

Infigen proposed a number of other potential modifications to a combined Option 1b plus control scheme option. Infigen commented that there has been no consideration given to an option to retrofit the existing transformers with short term overloading capability or entirely replacing the transformers with new transformers with a higher rating.

SP AusNet have advised that for the prolonged operation of the South East to Heywood 275 kV transmission lines flows should be kept to below 85% of the continuous rating to avoid long term deterioration of the conductors. This means that with a control scheme and three transformers at Heywood, the transmission line between Heywood and South East would be the limiting factor, and consideration of higher rated transformers is not warranted. SP AusNet has also advised that in situ replacement of the existing transformers to enable higher short term ratings will require long outages and the first transformer will have to be replaced adjacent the existing units to minimise outage times. This will increase the project cost compared with in situ replacement.

ElectraNet and AEMO consider that, based on the feedback provided by SP AusNet, this option does not warrant further investigation.

Additional options to address intra-regional issues in south east South Australia

Alinta expressed the view that a case for augmentation of the intra-regional networks to resolve thermal and voltage stability limits in the south-east of South Australia has not been addressed sufficiently. Alinta stated that the inclusion of intra-regional solutions has occurred on a selective basis, and that they have difficulty reconciling the analysis with their experience of thermal constraints and high wind penetration. Alinta also submitted that there is scope to consider Option 6b in conjunction with other intra-regional options to reduce constraints and alleviate congestion risk that all generators in South Australia continue to regard as inefficient. Alinta commented on the productive work in ElectraNet's APR outlining a number of potential solutions to alleviate constraints, which it considered to be 'no-regrets' pre-conditions to augmentation, and which it didn't consider had been addressed.

As noted in Section 3.1 above, the network options presented in the PSCR and PADR were developed on the basis of analysis to identify the lowest cost options, prior to undertaking the market modelling. This analysis identified the 132 kV works included in the options assessed under the RIT-T as the most effective solution to address constraint issues in the 132 kV network. It alleviates all the thermal constraints in the system, except for the South East transformer constraint. There are some emerging issues upstream of Tailem Bend towards Tungkillo, which will continue to be reviewed and, where appropriate, investments to address these issues will be considered as part of a separate RIT-T process, as described in Section 3.1.

As noted earlier, ElectraNet is also considering the application of short term ratings to the South East transformers, and is currently in the process of installing measuring devices to the transformers which will provide the information required to take a decision on the short term ratings of the transformers. This work is evidence of the continued consideration of the potential solutions identified in the APR, as commented on by Alinta. ElectraNet will also continue to monitor and assess the potential benefits of a South East control scheme, which could be undertaken as a separate investment to this RIT-T.

Infigen and the CEC stated that further consideration should be made to making full use of the existing 132 kV assets by applying dynamic ratings and considering if low cost asset replacement within the South East 132 kV substations could be undertaken for limiting assets. Infigen also proposed the adoption of dynamic ratings for the Heywood to South East 275 kV transmission line.

ElectraNet is presently considering the implementation of Dynamic Line Ratings across its network. At this stage, weather stations are being installed at various locations. Any Dynamic Line Rating consideration will be based on the roll-out of a Dynamic Rating Strategy across the network, which considers a number of factors including risk assessment. Therefore the Dynamic Line Ratings have not been explicitly considered. However, the development of the proposed solution does not preclude the implementation of Dynamic Line Ratings at a later stage.

Consideration of a staged approach for 132 kV configuration works

Both Infigen and Alinta proposed fast tracking the reconfiguration of the 132 kV line in advance of other network investments.

ElectraNet and AEMO note that within Option 1b it would not be possible to stage the timing of the 132 kV works ahead of the Heywood transformer component. The main reason for this is that switching out the 132 kV lines compromises the voltage and transient stability and will reduce interconnector capability by 10-15%. The series compensation is required to restore this reduced capability, besides providing the capability for expansion of the interconnector capability.

Consideration of a staged approach to defer costs

SACOSS suggested that Option 4 could be the first stage to deliver Option 1b at a later date.

ElectraNet and AEMO note that the difference in reactive support components of Option 1b (series compensation) and Option 4 (capacitor bank) implies that a staged approach could result in inefficient outcomes and too much reactive support, as the capacitor bank in Option 4 does not appear as an element in Option 1b. Therefore, it is not possible to develop Option 4 first and subsequently develop Option 1b as a next step.

Maintenance of existing interconnector capacity

Alinta stated that it is unclear how ElectraNet and AEMO have responded to its earlier submission that the maintenance of the existing interconnector capacity could to some degree diminish the need for the proposed upgrade.

ElectraNet and AEMO note that any investment in network assets in order to maintain the capacity of the Heywood interconnector would be subject to the RIT-T process, and would need to demonstrate a net market benefit. That is, there is no automatic provision that would allow ElectraNet or AEMO to undertake investment to maintain interconnector capacity, separate from the general provisions in the NER regarding network investment.

Option 4 was included in the PADR in response to the earlier submissions from Alinta and the private generators in relation to maintaining the 460 MW capacity of the Heywood interconnector on a firmer basis, by addressing network congestion in the South Australia. The RIT-T analysis has demonstrated that this is not the preferred option under the RIT-T, i.e., options which enhance the capacity of the interconnector also result in higher net market benefits.

Option 4 plus third South East transformer

International Power stated concern that decommissioning lines in the 132 kV network may worsen congestion in and around South East. To this end, they requested consideration of a variant of Option 4 with the inclusion of a third transformer at South East. Alinta queried why the analysis of the third South-East transformer option coupled with Option 4 had not been presented in the PADR.

ElectraNet and AEMO note that the RIT-T results from the options that were analysed with and without the third South East transformer (i.e. Option 2a compared to Option 1a) indicate that the inclusion of the third transformer at South East has a negative impact on overall net market benefits. That is, the incremental costs of adding the 3rd transformer at South East substation under Option 2a was not offset by the additional market benefits.

Given this finding, and also in the light of the fact that Option 4 is ranked substantially below other credible options in the RIT-T analysis, ElectraNet and AEMO consider that the additional costs required to include the proposed variant of Option 4 would not be justified, as it would not change the outcome of the RIT-T analysis. As discussed earlier, ElectraNet has considered a control scheme at South East as a more cost-effective means of managing the South East transformer constraint, in response to submissions. Although the analysis indicates that a control scheme would not have sufficient benefits, ElectraNet intends to keep this issue under review. In addition, as mentioned earlier, ElectraNet is also exploring the possibility of adopting short-term ratings on transformers, which has the potential to alleviate the South East transformer constraint to a large extent.

In its submission SACOSS refers to earlier submissions from generators to the PSCR questioning the additional value of 3rd Heywood Transformer. ElectraNet and AEMO note that the earlier generator submissions led directly to the inclusion in the PADR of Option 4, which does not include the 3rd Heywood transformer. The RIT-T analysis has shown that this option does not have a higher net market benefit than options which include the 3rd Heywood transformer. ElectraNet and AEMO therefore consider that this point has been directly addressed by modelling Option 4 in the RIT-T analysis.

ElectraNet and AEMO note that there appears to be some potential confusion between the Heywood and South East transformers in the SACOSS submission. Specifically, in a discussion of the need for a 3rd transformer at Heywood, the SACOSS submission mentions “that at page 60, ElectraNet notes a 3rd transformer is likely to be needed at some future point to address reliability issues (possibly around 2020-25) anyway”. This reference in the PADR is in fact discussing the South East transformer, rather than the 3rd Heywood transformer. The 3rd South East transformer is likely to be needed at some point in the future for reliability purposes.

4.14 Modelling assumptions

A number of issues were raised in submissions in relation to various modelling assumptions employed in the RIT-T analysis. These issues are discussed below.

Minimum Loading Levels

International Power and Alinta questioned the adjustment in minimum generation levels for the Yallourn, Loy Yang A and B, Anglesea and Northern power stations. In particular, they considered that the assumed minimum generation levels at Northern and Loy Yang B are too low.

Minimum stable generation output for some generating units was modelled at values lower than those used for the 2012 NTNDP (see Appendix D.3). Modelled minimum generation levels reflect not only the physical limitations of generating plant (for example water hammer or furnace stability), but also the desire for base load generation to avoid shutdowns and start-ups during short periods where variable costs are not met by the spot price.

In practice, it is expected that generators with low ramp rates that are frequently marginal in dispatch will not maintain all units at operational levels all the time, preferring instead to partially shut down the plant by taking individual units off-line. Due to the complexity of the market model and the unpredictability of outcomes, such operational responses to the market cannot be incorporated directly into the modelling. Reduction of minimum generation levels allows the model to select a lower output, at the station level, in a way that mimics this operational response (for example two units operating at 100 MW are equivalent in the model to a single unit operating at 200 MW with the other unit off-line). In practice, the modelling shows that these units were usually running well above the assumed minimum generation levels (i.e. they are not running at the low levels very often in the model).

If minimum generation levels were maintained at higher values, the consequence is that the model will select the next most expensive generating unit to meet dispatch targets. When network augmentations allow either less expensive generation in remote regions to be imported, or excess generation in the local region to be exported, higher minimum generation levels can be accommodated, leading to a reduction in overall cost. The higher the minimum generation levels are, the more impact network augmentations can have on reducing cost, because higher cost generation would otherwise have been dispatched more frequently in the augmentation's absence. It is therefore expected that, if the minimum generation levels were raised in the modelling, it would increase, rather than decrease the market benefits, further supporting the preferred option.

ElectraNet and AEMO have discussed the minimum generation assumptions with those stakeholders who raised concerns in relation to this issue, and have not been made aware of any information which would imply that the outcome of the RIT-T assessment would be materially different if the assumptions were changed.

Playford switching to open cycle gas turbine (OCGT)

International Power, Alinta, and the NGF questioned the assumption that Playford power station will be running as an OCGT plant from 2012/13.

ElectraNet and AEMO note that this assumption was initially made for consistency with inputs and results for the 2011 NTNDP.

However the materiality of this assumption has also been explicitly tested in scenario 4 (revised central scenario), which does not assume this conversion for Playford. Option 1b is shown to still create substantial market benefits and to be the most favourable option under this scenario.

Furthermore, for the other scenarios the assumption that Playford converts to OCGT is imposed consistently across all of the options considered, and so should not be material to the ranking of the options under these scenarios.

As a consequence, ElectraNet and AEMO are comfortable that changing the assumptions made in relation to Playford converting to an OCGT plant are not material to the outcome of this RIT-T assessment.

Contract for closure assumptions

International Power asserted in their submission that the assumptions regarding the retirement of two units at Hazelwood power station are invalid. They noted that contract for closure is no longer being sought by the federal government and that Hazelwood has not indicated intent to close in the assumed timeframe. International Power stated they believe this assumption falsely removes 1,600 MW from the Victorian system over a decade and materially impacts modelling results.

Similarly, the NGF stated that the assumptions regarding the retirement of Hazelwood should be revised. Alinta also noted that the assumed removal of significant quantities of thermal generation in Victoria appeared to be an issue with the PADR modelling assumptions.

ElectraNet and AEMO note that scenario 4 (revised central scenario) has specifically tested the significance of the assumptions relating to the early closure of coal-fired plant. Specifically, under scenario 4 there is no forced retirement of any plant. Rather the model is allowed to choose the date for retirement of Hazelwood, which does not occur over the assessment period. Under this scenario Option 1b is shown to still create substantial market benefits and to be the most favourable option. This demonstrates that, contrary to the assertion in some submissions, the assumption of Hazelwood's retirement is not material to the outcome of the RIT-T.

The cost of gas generation exported into South Australia

Alinta questioned the assumptions relating to the costs of gas generation that is exported into South Australia. The CEC noted that following release of the Federal Government's Energy White Paper, consideration should be given to trends in gas prices and the impact of parity with the international gas price.

The modelling conducted for this RIT-T has used the latest information available at the time when it was conducted. The gas price assumptions used in the RIT-T assessment come from those used in the 2011 NTNDP.[55] The gas price assumptions made as part of this RIT-T are also further discussed in Appendix C. ElectraNet and AEMO note that the Federal Government's Energy White Paper was released after the consultation closure date for the PADR.

Uncertainty in relation to future gas prices is addressed via including different gas price assumptions across the different reasonable scenarios modelled for this RIT-T, as discussed in section 5.4.

ElectraNet and AEMO are open to further sharing of fuel costs to improve modelling outcomes going forward. The NTNDP consultation process is the appropriate forum for interested parties to take forward their concerns on the cost of gas.

[55] See the NTNDP Modelling Assumptions – Supply Input Spreadsheets file, available at: http://www.aemo.com.au/Electricity/Planning/Reports/Archive-of-previous-Planning-reports/2010-NTNDP/2010-NTNDP-Data-and-Supporting-Information/~/media/Files/Other/planning/2010ntndp_cd/downloads/NTNDPdatabase/NTNDPoutpu info/Input%20Assumption%20Tables%20zip.ashx.

Inclusion of additional network costs

Both the NGF and Alinta suggested that the construction of the Moorabool/Mortlake to Heywood 500 kV line should be included as part of the RIT-T assessment, given their view that it would be required to justify expansion of the interconnector.

ElectraNet and AEMO note that the construction of the Moorabool/Mortlake to Heywood 500 kV line is not required under both the revised central scenario (scenario 4) and the low scenario (scenario 2). It is required late in the time horizon for the central scenario (scenario 1) and high scenario (scenario 3). However, under both of these scenarios the augmentation was applied in the base and upgraded cases at the same time in the modelling, and hence was not a cost to be considered by any of the network options (including the Krongart option).

Overall, this line is not required by the interconnector but is a result of the generation build in the base case. ElectraNet and AEMO modelled all generation expansion plans prior to the assessment of any of the credible options, and so the need for the Moorabool/Mortlake to Heywood 500 kV line is not predicated on a particular option.

Level of South Australia network upgrades required to transfer additional flows from Victoria

The NGF requests that the level of South Australia network upgrades required to transfer additional Victoria to South Australia flows be verified along with their costs.

ElectraNet and AEMO note that there were no additional network components modelled apart from those required to enable the interconnector upgrade. While aware of some emerging upstream congestion (as described in section 3.1), ElectraNet and AEMO note that corresponding additional network components have not been explicitly considered, except for Option 3.

Specific assumptions that have been made in relation to network developments which may impact flows over the Heywood interconnector can be found in section D.5 of the PADR.

South East 132 kV system capabilities

Infigen proposed that the South East 132 kV system be comprehensively reviewed with a view to releasing full capability of the assets in the area.

ElectraNet and AEMO note that this was undertaken as part of the PADR and is reproduced in Table D.2 of the PACR.

Technology market entry timings

The CEC submitted that the modelling inputs regarding technology market entry timings need to be updated, given they were based on the draft report prepared by Worley Parsons for AEMO's 2012 NTNDP. Specifically, the CEC note that this work has since been updated following release of the Federal Government's Energy White Paper.

In addition, the CEC note that where carbon capture and storage has been considered based on the draft Worley Parsons report the accompanying assumptions on carbon transport have not been provided.

The modelling conducted for this RIT-T has used the latest information available at the time when it was conducted. ElectraNet and AEMO note that the Federal Government's Energy White Paper was released after the consultation closure date for the PADR. ElectraNet and AEMO do not consider that it would be a proportionate approach to re-run all of the modelling on the basis of this recent update of technology timings.

It is expected that the location of new entry technologies will have more of an impact on the results than the timing, which will interact with the discount rates, which we have conducted a number of sensitivities on.

The Bureau of Resource and Energy Economics (BREE) technology inputs were an extension of the earlier Worley Parsons work done for AEMO. Modifications of technology timing were minimal. Significant differences between Worley Parsons timings and BREE timings in the Energy White Paper were not observed:

- BREE solar thermal from 2012, Worley Parsons solar thermal from 2015: a solar thermal plant cannot be built before 2015, so this difference is immaterial.
- BREE geothermal 2030, Worley Parsons geothermal 2025: geothermal doesn't enter under the modelling conducted for the RIT-T until 2026/27, and so these timing differences are not likely to be material.

Carbon transport and storage costs are assumed to be shared by adjacent generators, in both the BREE modelling and the 2012 NTNDP, and so cannot be assigned to any one generator. BREE performed post-processing on modelled outcomes to incorporate carbon transport costs. Similar post-processing was not performed for the generation expansions developed for this RIT-T because it is not able to modify investment decisions and so has no material outcome.

Use of 2009/10 demand and wind traces

The NGF requested details on the sensitivities to different load traces, why these base years were chosen as well as load diversity ratings for each year over the past decade.

The CEC commented in its submission that the 2009/10 demand and wind traces align with the El Nino weather pattern and suggested that atypical demand and wind profiles would have been recorded. The CEC stated that some comparison should be made with a typical or high demand and wind period to ensure that the modelling results are robust. Additionally, the CEC requests that a detailed analysis be provided as to why sensitivities were conducted using 2005/06 and 2007/08 load traces (as opposed to other years) as well as why 2009/10 was chosen as the base year.

In determining a base year, ElectraNet and AEMO note that a balance needed to be made between the inclusion of the number of options and scenarios, and the resources available to model. 2009/10 was chosen as the base year as it had typical load diversity between Victoria and South Australia, and also had the most average wind output across all locations. The load diversity ratings are published as part of AEMO's ESOO and Historic Market Information Reports.[56] NTNDP's wind diversity study shows that most of the wind locations had a fairly average capacity factor that year.[57]

[56] For 2012, see: Table 2-3 of the Historical Market Information Report (http://www.aemo.com.au/Electricity/Planning/Related-Information/Historical-Market-Information-Report); For 2011: Tables A3-3 and A3-4 of the ESOO (at: http://www.aemo.com.au/Electricity/Planning/Reports/Archive-of-previous-Planning-reports/Electricity-Statement-of-Opportuni ies-2011).

[57] http://www.aemo.com.au/Electricity/Planning/Related-Information/~/media/Files/Other/planning/0400-0057%20pdf.ashx See Table 5-1 on page 7.

Using load traces for 2005/06 and 2007/08 tested a range of different environmental conditions. 2005/06 had a lower than average wind capacity factor across the board, whilst 2007/08 had a slightly higher capacity factor (except for Tasmania). However preliminary analysis indicated that different base years did not materially alter the magnitude of market benefits or the preferred option.

Expansion of wind generation in South Australia

The CEC stated that the PADR did not make clear whether the potential expansion of the Eyre Peninsula system in providing opportunities for significant expansion of wind generation in South Australia had been considered.

Appendix D.5 in the PADR and in this PACR detail those network developments which have been assumed in the modelling for this RIT-T assessment.

Network expansion in the Eyre Peninsula has not been included in the input assumptions for the modelling. Augmentation of the transmission network in the Eyre Peninsula remains subject to a separate RIT-T process, and is expected to be dependent on the commitment of additional mining load on the Peninsula. However these additional Eyre Peninsula loads have been captured in the high demand growth scenario (scenario 3).

Ratings of 275 kV Heywood – South East lines

The CEC stated that SP AusNet and ElectraNet currently apply different ratings to their respective sections of the 275 kV Heywood – South East lines and, instead, uniform ratings should be applied based on asset capability. Infigen also commented on the different ratings by ElectraNet and SP AusNet for their sections of the Heywood to South East transmission lines, and proposed that the whole of the lines should be rated in accordance with its design capabilities.

ElectraNet and AEMO note that the existing line ratings are based on asset capability, and both SP AusNet and ElectraNet use the same methodology to determine ratings. Differences in ratings are due to differences in the treatment and assumptions in relation to wind speed at peak periods.

ElectraNet and SP AusNet have had discussions in relation to these ratings. However AEMO and ElectraNet do not have control over SP AusNet’s policy or decisions in relation to risk management.

Re-run modelling assuming 500 MW new wind generation in south east South Australia

Infigen requested that for Option 1b, the additional capital cost and associated market benefits for a scenario in which a control scheme is applied in conjunction with 500 MW of new wind generation connected to the ElectraNet 275 kV transmission system at or around South East substation be modelled.

ElectraNet and AEMO note that the modelling conducted for the PADR included 600 MW of additional wind generation in South East South Australia, in the vicinity of Krongart. It is therefore unlikely that re-running the modelling with the 500 MW of additional wind proposed by Infigen would lead to materially different results to those already modelled.

4.15 Interconnector augmentation and generation investment

The NGF requested details on how the 190 MW increase in the interconnector supports larger changes to generator investment.

ElectraNet and AMEO note that the NGF is assuming a linear relationship between interconnector augmentation and new generation investment. This may not be the case in reality. Appendix G provides a detailed discussion on this point.

ElectraNet and AEMO believe the generation builds included as part of this RIT-T are reasonable.

4.16 Request for details of power flow studies and congestion

International Power made the following requests in their submission:

- Details of the power flow studies to show that the removal of the 132 kV circuits does not worsen transmission congestion around South East network in South Australia.
- Modelling data to show that the increase in transfer capability on the Heywood interconnector from 460 MW to 650 MW from South Australia to Victoria will not be restricted by congestion on the South Morang transformers.
- Evidence to support the claim made in the PADR that the Keith to Tailem Bend 132 kV lines are the limiting factor for the Victoria to South Australia limit on the Heywood interconnector.

ElectraNet and AEMO undertook extensive load flow studies to determine the new constraints including in the market modelling. ElectraNet and AEMO are confident that these new constraints capture all of the relevant congestion. Table D-3 and D-4 highlight that the Snuggery-Keith and Keith-Tailem Bend #1 132 kV lines are the limiting elements for a number of potential contingencies in this part of the 132 kV network, after the 40% upgrade to the interconnector capacity. With these two network elements no longer in service, these existing constraints will be removed.

The series compensation on the 275 kV lines also reduces the influence of interconnector flows on the remaining circuits. Modelling results do not highlight increased levels of congestion due to the 132 kV network reconfiguration, apart from congestion due to the South East 275/132 kV transformers under low demand and high wind farm output conditions.

Table 4-2 captures the most important constraints in the base case and the preferred option (i.e., Option 1b) and demonstrates the expected reduction in congestion that is expected to occur following the augmentation. ElectraNet and AEMO's modelling indicates that current constraints will be significantly reduced as a result of the augmentation. ElectraNet and AEMO also have no information to suggest that access to the network for any particular generator would be adversely impacted by the augmentation. ElectraNet and AEMO will continue to examine the impacts of the augmentation as the project enters into detailed design phase. ElectraNet and AEMO - through the APR and NTNPD - will continue to keep the market informed of the likely impacts of the augmentation during the detailed design phase and prior to commissioning.

The data in Table 4-2 is drawn from the Revised Central scenario (i.e., scenario 4) and is a snap shot of results from 2016. Limits have been categorised according to the interconnector they impact and the direction of flow. Where a constraint is predominately an 'intra-regional' constraint, this has been separately categorised. Note that where a limit is categorised as 'Heywood', this does not preclude the constraint from also impacting on Murraylink. This is not a complete summary of all congestion on the Heywood and Murraylink interconnectors. Rather, the table focusses on those constraints that are generally caused by limitations on the ElectraNet network or limits from the SP AusNet network that have been specifically addressed by the preferred option (i.e., Option 1b). Constraints around South Morang and the 330 kV network in Victoria have not been included. These constraints remain significant limits on flows in South Australia.

Table 4-2: Reduction in network constraints associated with the preferred option

Classification	Network limitation	Notes	Reduction (from base case)
Heywood Interconnector (Victoria to South Australia)	Tailem Bend to Cherry Gardens 275 kV line	Existing	40%
	VIC to SA thermal rating SE-HYTS lines	Existing	
	South East transformer	Existing	
	Heywood transformer limit	Improved	
	South East voltage stability	Removed	
	Snuggery to Keith 132 kV line	Removed	
Heywood Interconnector (South Australia to Victoria)	Heywood transformer limit	Improved	25%
Murraylink Interconnector (Victoria to South Australia)	Murraylink 220 MW	Existing	70%
Murraylink Interconnector (South Australia to Victoria)	Robertstown transformer #1	Existing	31%
	Robertstown to Morgan Whyalla Pipeline 3 132 kV line 1	Existing	
	North West Bend to Robertstown 132 kV line	Existing	
Intra-regional	Templers to Para 275 kV line	Existing	20%

Comparison between congestion in the base case and the preferred option is complicated by shifting bottle necks. For example in the base case, the most significant constraint was the voltage stability limits in the south east. It is expected that series compensation should entirely remove this limitation for the near term.[58] Upon removal of this limit, the model has identified the next most significant limit as being the thermal limits on the line between Tailem Bend and Cherry Gardens. This is an entirely different limitation. This limitation currently exists, but due to the lower limits elsewhere in the network it does not often affect actual dispatch.[59] Importantly, limits across the Tailem Bend to Cherry Garden line under summer ratings will likely limit imports into metropolitan Adelaide across the 275 kV network to below the limit due to the Heywood-South East 275 kV lines. Flows south under peak wind conditions are less likely to be limited by these lines, due to higher ratings that may be applied under these conditions.

Congestion on flows from the 132 kV network will be removed for the foreseeable future with the removal of the “weak” 132 kV Keith to Snuggery line and improvements to the capacity of the stronger, remaining 132 kV Keith to Tailem Bend line.

With respect to congestion on the South Morang transformers, ElectraNet and AEMO note that the relevant consideration under the RIT-T is whether total 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. ElectraNet and AEMO note that specific augmentations may adversely affect individual proponents, where enhanced access for lower cost generation is provided through the augmented transmission network. However this forms part of the current accepted operating environment of all generators in the NEM.

In relation to the Keith to Tailem Bend 132 kV lines being the limiting factor for the Victoria to South Australia limit on the Heywood interconnector, this is a limiting factor that appears in the 2011 Constraint Report.[60] Specifically it is reflected through constraint V>>S_NIL_SETB_KTB with a Marginal Cost of Constraint (MCC)[61] of $544,000 and 18 hours. This highlights the short duration of this constraint (i.e. time of peak) but also the high market impact, noting that the duration of the constraints will increase further after a 40% upgrade to interconnector capacity. The modelling conducted for this RIT-T shows this limit becomes more important into the future. ElectraNet and AEMO note that the RIT-T is a planning mechanism and should address constraints where it is expected to become efficient to do so. This may or may not relate to the appearance of constraints in current real time dispatch, as the planning studies assess the future system with higher power transfer capability.

[58] It is noted that some load and generation changes may see this limit re-assert itself as a significant bottle neck. The preferred op ion does not guarantee that this limit will never re-appear going forward.

[59] Limits on flows across the Tailem Bend to Cherry Gardens lines did impact on exports from South Australia on 27 November 2012.

[60] AEMO, (2011), *The NEM Constraint Report 2011*, Table 6 Top 20 Market impact constraint equations, p. 23.
Further, ElectraNet and AEMO note that this limit does not appear in 2010 Constraint Report, but only just missed the top 20 list. It is represented in Appendix 1: Top 20 market impact constraint equations in 2009 as constraint V>>S_NIL_KHTB2_KHTB1 with a MCC value of $753,000 and 18 hours – see: AEMO, (2010), *The NEM Constraint Report 2010*, p. 46.

[61] The MCC for an individual constraint equation is calculated using a MCC rerun of the market dispatch engine, with the violating constraint equation removed or the binding constraint equation relieved by one megawatt. This shows how much the cost of generation (based on generator bids) will be reduced at the margin.

Further, ElectraNet and AEMO note that the constraint set for Option 1b are available online.[62]

4.17 Requests for further information

In addition to the information requests discussed elsewhere in this section, the NGF also made the following requests for further information:

- Details of both the baseline and revised USE outcomes.
- The revised generation build and dispatch data results on a sub-regional basis.
- Price forecasts, in order to determine the financial viability of potential entrants.

ElectraNet and AEMO note that the changes in USE are very low and are represented by the reliability benefits reported in the RIT-T results. Figures 6-1 and 6-2 included in both the PADR and this PACR show the level of USE, and also highlight that it is immaterial compared with the other categories of market benefit. The actual changes in USE can be extracted from the reliability benefits included in Appendix I.

ElectraNet and AEMO note that the generation build data on a sub-regional basis have been provided following the NGF's request. However ElectraNet and AEMO are of the view that this level of detail does not aid assessment of the PADR results, and is not material.

ElectraNet and AEMO note that the price forecasts included in the modelling are cost (i.e. spot) prices and not market prices, based on SRMC modelling (as per the AER's RIT-T Guidelines). Therefore, these price forecasts would not be of any use in determining the financial viability of potential entrants and as a consequence have not been provided to the NGF.

4.18 Wind farm licence conditions

The CEC raised questions in relation to AEMO's position on wind farm licence conditions imposed by ESCOSA in South Australia.

The CEC referred to AEMO previously recommending that ESCOSA retain stringent reactive power and fault ride through capabilities and that AEMO's position was based on the expectation that the minimum access standard will prevail for all new connecting wind farms, therefore placing voltage stability at risk. The CEC requests that AEMO undertakes, and makes public, this analysis as a matter of priority so that the wind industry can have confidence that their investments are efficient and consumers can have confidence that renewable energy is being developed efficiently.

This matter is out of scope for this RIT-T, which has taken the current policy as the default approach in the analysis. However, ElectraNet and AEMO note that the SCER has directed the AEMC to undertake a review of the technical standards, which is due to commence in 2013.[63] This matter is relevant to that review.

[62] Constraint data is available from: http://www.aemo.com.au/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission-RITTs/Heywood-Interconnector-RIT-T.

[63] http://www.scer.gov.au/files/2012/06/MCE-Response_AEMC-Extreme-Weather-Evernts-Review_8-June-2012.doc.

4.19 Submissions to the PSCR

In addition to the above submissions in relation to the PADR, ElectraNet and AEMO received six submissions to the earlier PSCR, from:

- Origin Energy.
- Alinta.
- Private Generators (AGL Energy, Alinta Energy, Energy Brix, International Power GDF-Suez, Origin Energy, TRUenergy).
- EnerNOC.
- Infigen.
- The National Generators Forum (NGF).

The key issues raised in these submissions were discussed in Section 4 of the earlier PADR, and have also been incorporated as Appendix F in this PACR.

5 Description of methodology

This section provides a summary of the methodology adopted for the RIT-T assessment, including a description of the approach used for the market dispatch modelling, a description of the reasonable scenarios considered and a summary of key assumptions.

Section 6 provides a further description of the approach adopted to quantifying each of the material categories of market benefits.

5.1 Analysis period

The RIT-T analysis has been undertaken over a period from 2013/14 to 2054/55.

Specifically, the market modelling discussed in section 5.3 below has been undertaken for the period 2013/14 to 2039/40. The period selected for the market modelling was sufficiently long to cover ten years following the end of the Large-scale Renewable Energy Target (LRET) scheme. ElectraNet and AEMO consider that this is important in order to reflect the impact of each network option on the NEM, once the specific LRET driver for increased investment in renewable generation has been removed.

However ElectraNet and AEMO do not consider that an extension of the period for the market modelling beyond 2039/40 is either credible or warranted.[64] Instead, in order to capture the 'end-effects' associated with the life of the network assets extending beyond 2039/40, the market benefits calculated for the final five years of the modelling period (i.e. 2035/36 to 2039/40) have been averaged, and this average value has been assumed to be indicative of the annual market benefit that would continue to arise under that credible option in the future. This annual average value of the market benefit has been assumed to apply for a further 15 years, following the end of the modelling period, in calculating the overall net market benefit associated with that option, together with the annualised cost of that option.

The length of analysis period was a factor raised by the NGF in its submission to the PADR. The NGF suggested that either a 20 year analysis period should be adopted (with no end effects), or a higher discount rate assumed.

The NER and the AER's RIT-T Guidelines leave open the choice of analysis period. The AER notes that 'the duration of modelling periods should take into account the size, complexity and expected life of the relevant credible option to provide a reasonable indication of the market benefits and costs of the credible option. This means that by the end of the modelling period, the network is in a 'similar state' in relation to needing to meet a similar identified need to where it is at the time of the investment.'[65] The AER also states that 'in the case of very long-lived and high-cost investments, it may be necessary to adopt a modelling period of 20 years or more'.

ElectraNet and AEMO consider that the long-lived nature of the assets involved in the credible options considered for this RIT-T, coupled with the fact that this is a market benefit assessment and the extended period over which benefits are expected to be realised, justify the adoption of a relatively

[64] ElectraNet and AEMO note that the expansion plan modelling was conducted out to 2045, in order to minimise distortions in modelled generator planting decisions in the final years of the main modelling period.

[65] AER, RIT-T Application Guidelines, June 2010, p. 41.

long analysis period. In addition, one of the credible options (i.e. Option 3, construction of a new Krongart-Heywood 500 kV interconnector) involves substantial investment in 2025 and 2030. Adoption of a shorter analysis would therefore not ensure that the network was in a 'similar state' following this option, compared to other credible options. The approach of adopting an extended analysis period, based on the continuation of an assumed end-value, is one which has been adopted in other similar assessments.[66]

Notwithstanding the above, ElectraNet and AEMO have conducted a sensitivity analysis using a 20-year analysis period. The results of this analysis are discussed in section 6.3. In addition, ElectraNet and AEMO have continued to consider the impact of adopting a 13% discount rate, and have included further sensitivity testing using an even higher discount rate of 16%, discussed below. Both of these sensitivity tests confirm that there would be no impact on the outcome of the RIT-T analysis of adopting either a shorter assessment period, or a different discount rate.

5.2 Discount rate

A discount rate of 10% (real, pre-tax) has been adopted in undertaking the NPV analysis, for all credible options. This discount rate represents a reasonable commercial discount rate, appropriate for the analysis of a private enterprise investment in the electricity sector, as required by the RIT-T.[67]

ElectraNet and AEMO have tested the sensitivity of the results to changes in this discount rate assumption. Several submissions to the PADR[68] commented that the uncertainty associated with future parameters (such as the level of demand and the carbon price) should be reflected in the adoption of a higher discount rate. As a consequence, ElectraNet and AEMO have considered as an additional sensitivity the adoption of a 16% discount rate, in addition to the 13% discount rate sensitivity incorporated in the earlier PADR.

Specifically sensitivity tests have incorporated a lower bound discount rate of 6.13%, as reflective of the regulatory weighted average cost of capital (WACC)[69] and higher discount rates of 13% and 16%. The sensitivity of the RIT-T results to the discount rate assumption is discussed further in section 6.3.

5.3 Market modelling

The RIT-T requires that in estimating the magnitude of market benefits, a market dispatch modelling methodology must be used, unless the TNSP can provide reasons why this methodology is not relevant.[70] ElectraNet and AEMO consider that a market dispatch modelling methodology is relevant for this RIT-T application, and as a consequence have adopted this approach in order to calculate the market benefits associated with the credible options included in the RIT-T analysis.

The RIT-T requires many of the categories of market benefit to be calculated by comparing the 'state of the world' in the base case (where no action is undertaken by ElectraNet or AEMO) with the 'state

[66] See for example: Powerlink and TransGrid, Final Report – Queensland/New South Wales Interconnector upgrade, 24 July 2008. The total assessment period for this analysis was 30 years.

[67] AER, Final Regulatory Investment Test for Transmission, June 2010, version 1, paragraph 14, p. 6.

[68] Specifically, the SACOSS and NGF submissions – see section 4.5 above.

[69] This is the lower bound scenario for he discount rate, specified in the RIT-T paragraph (15)(g). The estimate of the regulatory WACC (real, pre-tax) that would apply to ElectraNet is based on the AER's April 2012 final determination for Powerlink. http://www.aer.gov.au/node/7945.

[70] AER, Final Regulatory Investment Test for Transmission, June 2010, version 1, paragraph 11, p. 6.

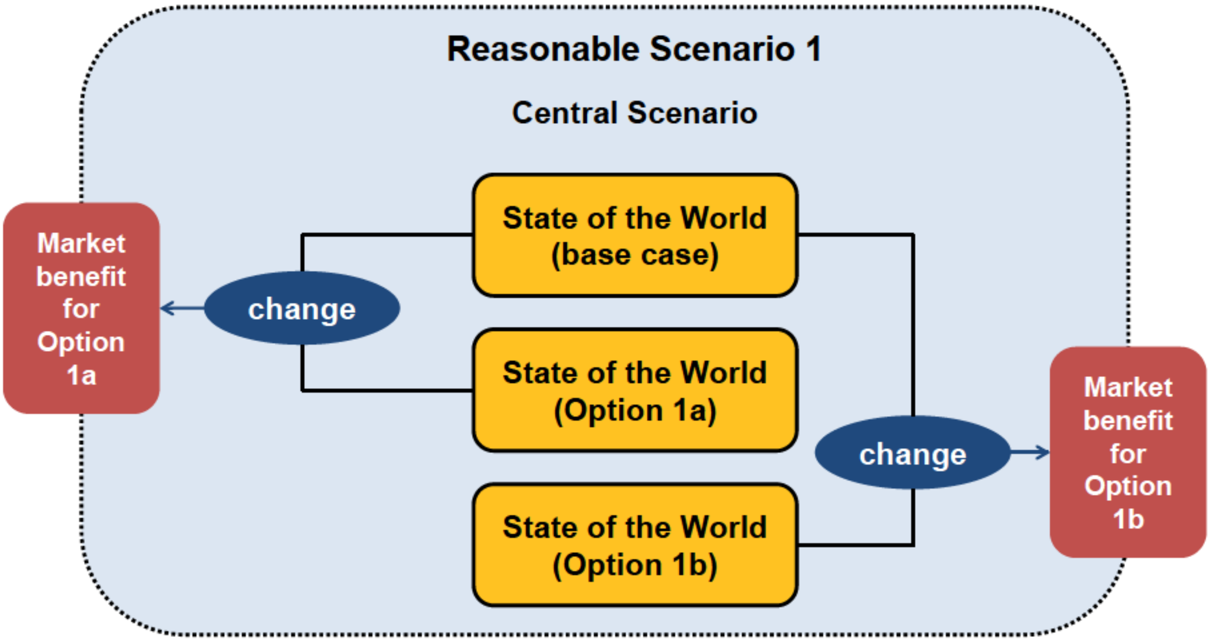
of the world' with each of the credible options in place. The 'state of the world' is essentially a description of the NEM outcomes expected in each case,[71] and includes the type, quantity and timing of future generation investment as well as the market dispatch outcomes over the assessment period. The approach to calculating market benefits by comparing the states of the world 'with' and 'without' each credible option is depicted in Figure 5-1.

In the case of this RIT-T assessment, the complexity of the impact of each of the credible options on the operation of and outcomes in the NEM is such that the relevant comparison between the states of the world with and without each of the options can only be estimated using market dispatch modelling.

In addition, the uncertainty associated with future NEM development and therefore the future 'state of the world' is addressed under the RIT-T by considering a number of 'reasonable scenarios' (discussed further in section 5.4).

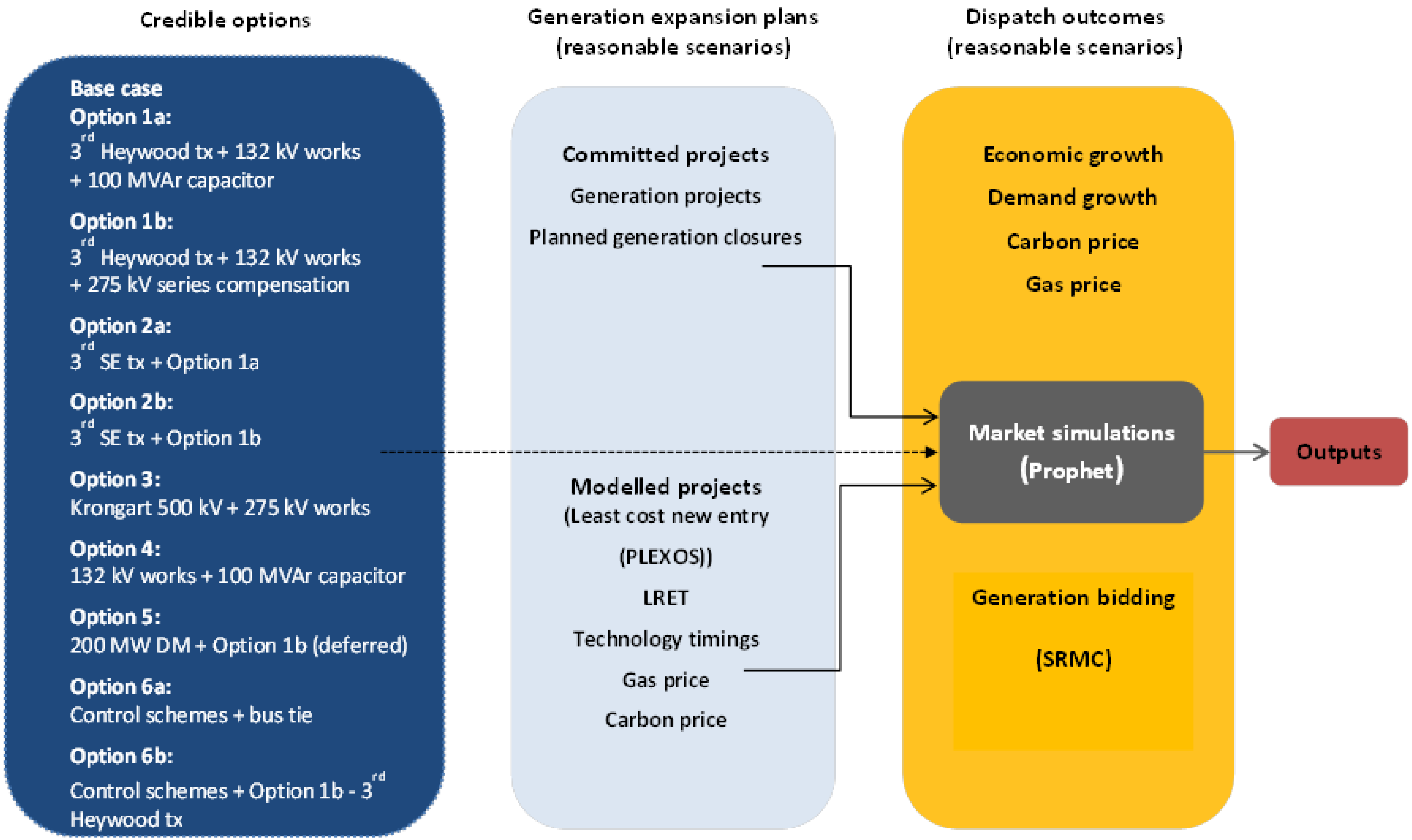
Figure 5-2 provides an overview of the modelling approach adopted by ElectraNet and AEMO for this RIT-T assessment. The following sub-sections provide a further description of the specific models used for this assessment.

Figure 5-1: Market benefits are calculated by comparing outcomes in different states of the world



[71] The AER describes the 'state of the world' in its RIT-T Application Guidelines as being a detailed description of all of the relevant market supply and demand characteristics and conditions likely to prevail if a credible option proceeds or in the base case, if the credible op ion does not proceed (AER, RIT-T Application Guidelines, June 2010, p. 15).

Figure 5-2: Approach to calculating market benefits



5.3.1 Generation expansion plans: modelled projects

ElectraNet and AEMO have modelled the generation expansion plans under each of the four reasonable scenarios considered in this RIT-T assessment.[72]

Committed generation projects are based on those projects identified by AEMO in the 2011 Electricity Statement of Opportunities (ESOO) as 'committed'. The generation expansion plans also reflect assumptions about potential future generation retirements, including the expected closure of some high-emission generators as part of the Federal Government's Clean Energy Package, which are varied across the reasonable scenarios considered in the RIT-T. Further details in relation to the specific assumptions made about committed generation projects and generator retirements are set out in section 5.5.

The generation expansion plans also include modelled generation projects, which have been derived by ElectraNet and AEMO using a model (Long Term (LT) Plan) developed utilising the PLEXOS software.[73] Consequently, these modelled projects were developed on a least-cost basis, consistent with the requirement of the RIT-T.[74] The expansion plan model adopts a number of build limits in order to ensure that the modelled generation build profile is realistic. It also adopts the same new entrant cost assumptions for different generation technologies as used in the NTNDP.[75] In modelling the expansion plan, ElectraNet and AEMO have assumed that the LRET is met. It has therefore been taken as a 'hard constraint' in the modelling. The model also reflects assumptions about the timing of availability of new technologies (including geothermal), which are varied across the reasonable scenarios considered in the RIT-T (see section 5.4).

Generation expansion plans have been modelled for the base case for each scenario, and for each credible option (with the exception of Option 6a (stand-alone control schemes) which was considered to be of such a small scale that it would not affect wider generator investment decisions in the NEM). Modelling of the expansion plans for Options 1a, 1b, 2a, 2b, 4 and 6b highlighted the sensitivity of the expansion plans to the detailed specification of various network constraints. AEMO and ElectraNet consider that differences in the expansion plans under these options reflect these sensitivities, rather than fundamental differences in how the options would in reality impact generation investment decisions. As a consequence the same expansion plans have been adopted for these six options in the RIT-T analysis. ElectraNet and AEMO do not consider that this approach will materially affect the outcome of the RIT-T. A different expansion plan has been modelled for Option 3 (new Krongart-Heywood 275 kV interconnector + 275 kV works), for scenarios 1, 2 and 3. The greater capacity of this option means that it would be expected to influence generation investment decisions in a different way to the smaller capacity options. The results of the modelling also show that the overall market benefit of Option 3 is increased, if this expansion plan is used. For scenario 4, although a different expansion plan was again modelled for Option 3, overall market benefits were found to be higher if the expansion plan for the smaller scale options was used (i.e. the expansion plan for Options 1a, 1b,

[72] AEMO notes that the least cost expansion plans developed for this RIT-T are not directly comparable with the forecasts of future generation requirements presented in the ESOO. In particular the ESOO projections consider only a single period of demand per year and do not allow for any uncommitted retirement of plant.

[73] ElectraNet and AEMO have not identified any 'anticipated' genera ion projects which are expected to materially impact the results.

[74] AER, Final Regulatory Investment Test for Transmission, June 2010, version 1, paragraph 21, pp. 8-9.

[75] http://www.aemo.com.au/en/Electricity/Planning/2010-National-Transmission-Network-Development-Plan-Consultation. These costs have been escalated by CPI to June 2011 dollars.

2a, 2b, 4 and 6b).[76] The smaller-scale expansion plan was therefore used for Option 3 under scenario 4.

In the case of Option 5 (DM + deferred Option 1a), under scenarios 1 (central), 2 (low) and 3 (high) the modelling has assumed the deferral of 200 MW of OCGT plant in South Australia as a consequence of the introduction of the DM capability, in addition to the impact of the network augmentation component of that option on the underlying generation expansion plan. ElectraNet and AEMO note that further market modelling would need to be undertaken in order to determine whether in reality all of this 200 MW of OCGT investment would be deferred; however this is considered a reasonable assumption for the purposes of this RIT-T assessment. Under scenario 4 (revised central), the amount of additional OCGT plant built in South Australia in the base case (i.e., without any option in place) is below 200 MW, which reduces the amount of generation investment deferral which can be achieved by the DM capability. Under scenario 4, the generation deferral associated with DM falls to zero for the first three years of the program, followed by a two year deferral of 87 MW of OCGT plant in South Australia. The costs of the DM program are still assumed to be the same as in the other scenarios, as the DM program would need to be robust to all scenario outcomes.[77]

5.3.2 Market dispatch model

In order to calculate dispatch outcomes in the relevant 'state of the world', ElectraNet and AEMO have undertaken market simulations using a market model which incorporates generation dispatch and market clearing processes to replicate the operation of the NEM. The model used for this RIT-T is the Prophet model.[78]

The market dispatch modelling methodology adopted is consistent with the further requirement in the RIT-T that the model must incorporate both:

- A realistic treatment of plant characteristics, including for example minimum generation levels and variable operating costs.
- A realistic treatment of the network constraints and losses.

The modelling uses the NTNDP database with a full set of NEMDE pre-dispatch system normal constraints so that all intra-regional constraints are captured. The assumptions used in the modelling also capture minimum load assumptions for generators which are in general consistent with those used in the NTNDP.[79]

ElectraNet and AEMO note that a number of submissions to the PADR commented on the assumptions used in the market dispatch model, including in relation to minimum generation levels. Responses to the points made in submissions are contained in section 4.14. However in brief ElectraNet and AEMO do not consider that changing the assumptions raised in submissions would materially affect the outcome of the RIT-T assessment.

[76] This is considered to be due to differences between the assumptions and level of granularity used in the PLEXOS and Prophet modelling, leading PLEXOS to select an expansion plan which on the basis of the Prophet modelling does not appear to be optimal for Option 3 in this scenario.

[77] It may be possible to stagger the introduction of the DM program over several years. However in this case the benefits assumed under scenarios 1 (central), 2 (low) and 3 (high) would also be staggered.

[78] The Prophet model was one of the models used by AEMO for its analysis in relation to the 2010 NTNDP.

[79] http://www.aemo.com.au/en/Electricity/Planning/2010-National-Transmission-Network-Development-Plan-Consultation. Appendix D highlights where the assumptions adopted differ from those used in the NTNDP.

The Prophet model has been run using load and wind traces from 2009/10 and based on an assumption of SRMC bidding behaviour of generators.

5.4 Description of reasonable scenarios

The RIT-T analysis needs to incorporate a number of different reasonable scenarios, which are used to estimate market benefits. The RIT-T states that the number and choice of reasonable scenarios must be appropriate to the credible options under consideration. The choice of reasonable scenarios must reflect any variables or parameters that:[80]

- Are likely to affect the ranking of the credible options, where the identified need is reliability corrective action.
- Are likely to affect the ranking of the credible options, or the sign of the net economic benefits of any of the credible options, for all other identified needs.

Several of the submissions to the PADR raised the issue of uncertainty in relation to the future environment facing the investment options being considered.[81] In particular, factors such as the future level of the carbon price, future demand, any changes in the LRET policy and changes in assumptions made about the closure of brown coal generators may fundamentally affect the level of market benefits associated with the expansion of the Heywood interconnector capacity.

The adoption of a higher discount rate is one way of addressing such uncertainty (by 'discounting' the future value of market benefits, to reflect the greater degree of uncertainty associated with future developments), as discussed above (see section 5.2). However conducting the analysis over a range of different future scenarios is an equally important step in ensuring that the results of the RIT-T assessment remain robust to different potential future outcomes.

ElectraNet and AEMO have adopted the following four scenarios in undertaking the RIT-T analysis:[82]

- Scenario 1: Central scenario.
- Scenario 2: Low scenario.
- Scenario 3: High scenario.
- Scenario 4: Revised central scenario.

These four scenarios reflect a broad range of different assumptions in relation to factors such as growth in electricity demand, the future carbon price and future gas prices, which were considered to have the potential to affect the market modelling outcomes under this RIT-T. They also reflect different assumptions in relation to the closure of brown coal plant, and the conversion of Playford.

ElectraNet and AEMO continue to consider that these four scenarios adequately capture a sufficiently wide range of parameter outcomes such that they address the concerns about uncertainty raised in some submissions.[83] Inevitably, there will be a continuing evolution of expectations around future developments, particularly in heavily policy-related areas such as the future level of carbon price.

[80] AER, Final Regulatory Investment Test for Transmission, June 2010, version 1, paragraph 16, p. 7.

[81] For example, NGF, SACOSS and International Power.

[82] These scenarios remain unchanged from those adopted in the RIT-T assessment presented in the PADR.

[83] The issue of incorporating additional scenarios is discussed further in section 4.4, in response to submissions.

However, it is also important to recognise that the scenarios adopted in this RIT-T cover a forty year assessment period, and so must be reflective of a plausible range of long-term expectations.

ElectraNet and AEMO do not consider that adding further variants of these scenarios would provide substantial additional insight into the factors affecting the RIT-T outcome, given the robustness of the RIT-T outcome already demonstrated across these four scenarios. The additional cost and time required to expand the number of scenarios considered would not be proportionate, as it would not materially affect the outcome of the assessment. ElectraNet and AEMO also note that, given the long-term nature of the investment being considered, it is important that the outcome is robust to a range of future potential outcomes, and that current policy debates and current circumstances are not the only focus.

As an alternative to adding more scenarios into the analysis, ElectraNet and AEMO have provided the net market benefit results for each of the four scenarios individually, as well as conducting a further sensitivity analysis which substantially increases the weighting given to scenario 4 (revised central scenario), compared to the other scenarios. Scenario 4 reflects a low carbon price and low demand and does not assume the closure of Hazelwood or the conversion of Playford power station. As such, scenario 4 already captures the key features which some stakeholders have called to be reflected in additional scenarios. Increasing the weighting for scenario 4 can therefore be expected to provide a similar outcome to incorporating these additional scenarios into an expanded analysis. The results of this sensitivity are discussed in section 6.3.2, but in brief confirm the view that giving additional weight to low carbon, low demand scenarios does not materially impact the RIT-T outcome.

The first three scenarios adopted for this RIT-T largely reflect scenarios developed by AEMO for the 2010 and 2011 NTNDP, with some of the parameters updated where relevant to reflect more recent information.[84] ElectraNet and AEMO have also made a number of modifications to the NTNDP scenarios, where these are considered to make them 'fit for purpose', given the situation being assessed under this RIT-T. Specifically, scenario 1 represents central values of each of the relevant parameters, largely based on the 2010 and 2011 NTNDP. Scenario 2 reflects parameters that would be associated with a slower rate of economic development than in scenario 1, such as lower electricity demand and low domestic gas prices. Scenario 3 reflects parameters associated with a faster rate of economic development, such as higher electricity demand (including additional mining loads on the Eyre Peninsula and at Olympic Dam[85] in South Australia) and high domestic gas prices. Scenarios 1 to 3 also assume the forced retirement of Hazelwood power station, as well as the conversion of Playford, as set out in section 5.5.

Scenario 4 is based on the medium demand forecasts from AEMO's 2012 National Electricity Forecasting Report (NEFR),[86] which are lower than the 2010 forecasts used for the 2010 NTNDP, together with a low carbon price assumption. Scenario 4 does not assume the closure of Hazelwood or the conversion of Playford power station.

[84] For instance, scenarios 1, 2, and 3 use 2011 ESOO demand forecasts; scenario 3 used core Treasury carbon pricing; and scenario 4 used the low carbon pricing in the Prophet modelling to ensure consistency with announcements on carbon price at the time these assumptions were made.

[85] ElectraNet and AEMO note both BHP Billiton's announcement in August 2012 that it is not progressing the Olympic Dam expansion, and its subsequent statement (November 2012) that it continues to be 'serious' about an eventual Olympic Dam expansion. ElectraNet and AEMO therefore consider that it remains appropriate for he scenarios used for this RIT-T to cover both of these potential outcomes.

[86] http://www.aemo.com.au/en/Electricity/Forecasting.

The modelling of both generation expansion plans and dispatch outcomes in the base case (i.e. with none of the credible options in place) and for each credible option has been undertaken for each of the four reasonable scenarios.

The parameters adopted under each of these scenarios are summarised in Table 5.1.

In particular:

- **Scenario 1 (the 'central' scenario**) is equivalent to the 'Decentralised World' scenario used in AEMO's 2010 NTNDP, updated to reflect the most recent core Treasury carbon price and updated assumptions about earliest timings for new technology.
- **Scenario 2 (the 'low' scenario)** is equivalent to the 'Independent Climate Action' scenario used in AEMO's 2010 NTNDP, updated to reflect the most recent high Treasury carbon price and updated assumptions about timings for new technology. This scenario incorporates a high carbon price, as one of the contributors to the low overall rate of economic growth. The 'low' scenario used in this RIT-T is modified from the NTNDP scenario in that a low gas price has been assumed for the RIT-T scenario, based on the low gas price assumption in the NTNDP 'Uncertain World' scenario.
- **Scenario 3 (the 'high' scenario)** is equivalent to the 'Uncertain World' scenario used in AEMO's 2010 NTNDP, modified to reflect increased electricity demand in South Australia due to increased mining activity in the Eyre Peninsula and the expansion of Olympic Dam, and updated to reflect the most recent core Treasury carbon price and updated assumptions about timings for new technology. The 'high' scenario used in this RIT-T is modified from the NTNDP scenario in that a high gas price has been assumed for the RIT-T scenario, based on the high gas price assumption in the NTNDP 'Fast Rate of Change' scenario.
- **Scenario 4 (the 'revised central' scenario)** includes the recent 2012 demand assumptions contained in AEMO's 2012 NEFR. The 2012 NEFR also includes a higher penetration of solar PV, which changes the demand profile. Scenario 4 also includes a lower carbon price assumption than in the other three scenarios, specifically three years of a fixed carbon price and the legislated carbon floor continuing beyond 2017.[87] This recognises the continuing evolution in expectations around the level of future carbon prices, with many commentators pointing to carbon prices being below the core Federal Treasury forecasts. Scenario 4 assumes moderate adoption of demand-side technologies, consistent with the 2012 NEFR. Scenario 4 also uses the 2012 NTNDP wind contribution to peak demand assumptions, since the shift of new generation from NSW to South Australia was considered relevant to the RIT-T. The other scenario parameters are as per scenario 1.

Appendix C provides a more detailed summary of the specific assumptions made in relation to each of the parameters included in the RIT-T scenarios.

[87] ElectraNet and AEMO note the Federal Government's announcement on 28 August 2012 that it intends to remove the floor price under the Carbon Price scheme. This could mean that future carbon prices fall below the level assumed in his scenario.

Table 5-1: Summary of parameters under each reasonable scenario

	Scenario 1: Central Scenario	Scenario 2: Low Scenario	Scenario 3: High Scenario	Scenario 4: Revised Central Scenario
Economic growth	Medium	Low	High	2012 NEFR Medium
Demand growth	Medium	Low	High plus Eyre Peninsula and Olympic Dam	2012 NEFR Medium
Carbon price	Core Treasury price	High Treasury price	Core Treasury price	Low carbon price[88]
Technology timings and cost	Central view of timings for new technologies	Timings delayed 2 years (compared with central view)	Timing brought forward by 2 years (compared with central view)	Central view of timings for new technologies
Gas prices	Business as usual: medium published gas prices as per 2010 NTNDP	Surplus domestic supply: low domestic prices	High international demand: high domestic prices	Business as usual: medium published gas prices as per 2010 NTNDP
Wind contribution to peak demand	2011 NTNDP	2011 NTNDP	2011 NTNDP	2012 NTNDP[89]
Demand-side technologies (Electric vehicles; scale storage)	Low adoption	No adoption	High adoption	2012 NEFR moderate adoption
LRET	Hard target (moderate uptake of greenpower)	Hard target (low uptake of greenpower)	Hard target (moderate uptake of greenpower)	Hard target (moderate uptake of greenpower)
Closure of Hazelwood	Forced retirement	Forced retirement	Forced retirement	No forced retirement
Conversion of Playford	Assumed 2012/13	Assumed 2012/13	Assumed 2012/13	No forced conversion

5.4.1 Weights applied to each scenario

ElectraNet and AEMO acknowledge that the weights applied to the various reasonable scenarios is reliant on making an assessment of the likelihood of different future paths for factors such as the carbon price, economic growth and future gas prices.

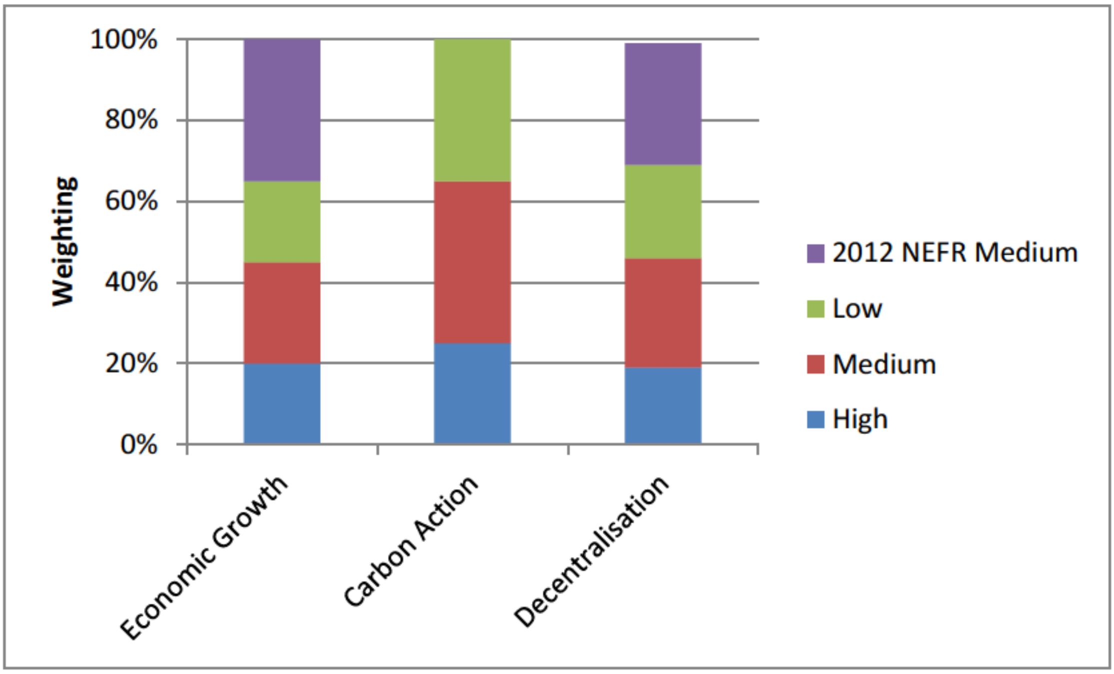
The scenario weights adopted in this RIT-T have been derived by firstly considering the likelihood that the assumptions used in the scenario definitions would be achieved for: future economic growth; the extent of action taken to address carbon emissions; and the degree of decentralisation of generation. These scenario parameters represent the underlying drivers of many of the assumptions. Each of

88 See Appendix C, Section C.2.

89 See Appendix C, Section C.5.

these parameters was assigned a probability against the scenario assignments so that the probabilities summed to 100% as shown in Figure 5-3.

Figure 5-3: Weightings of scenario parameters



The scenario drivers have then been 'mapped' onto the reasonable scenarios used in this RIT-T (the scenario definition in Table 5-1 determined which of these weightings were combined to derive the scenario weighting). Table 5-2 presents the mapping of scenario drivers to each scenario.

Table 5-2: Mapping of Scenario Drivers to the RIT-T Scenarios

	Scenario			
Scenario Parameters	**Central**	**Low**	**High**	**Revised Central**
Economic growth	Medium	Low	High	2012 NEFR Medium
Carbon Action	Medium	High	Medium	Low
Decentralisation	Medium	Low	High	2012 NEFR Medium

Mapping the assumptions in relation to whether the scenario drivers are high, medium or low (Table 5-2) with the probabilities assigned to each scenario driver (Figure 5-3) results in the weightings for the four RIT-T reasonable scenarios set out in Table 5-3.

Table 5-3: Weightings for RIT-T reasonable scenarios

	RIT-T reasonable scenarios			
	Central	**Low**	**High**	**Revised Central**
Scenario weightings	29%	13%	17%	41%

ElectraNet and AEMO have also considered the impact on the RIT-T outcome of adopting alternative scenario weightings, including increasing the weight given to the revised central scenario (which has a low carbon price and low demand, together with no forced closure assumptions for brown coal generators).

5.5 Assumptions on committed new generator entry and forced closures

The generation expansion plans developed for the RIT-T reflect the following committed new generation entrants, as identified by AEMO in the 2011 ESOO. In relation to South Australia and Victoria, these generators include:

- 566 MW new OCGT entry in Melbourne from 2011/12 (Mortlake Stage 1).
- 67 MW new wind in Victoria from 2011/12 (Oakland Hills).
- 420 MW new wind in Victoria from January 2013 (Macarthur Wind Farm).

In addition, the following assumptions have been made in relation to the closure/conversion of generating plant for the market modelling under scenarios 1, 2 and 3, using inputs and results from the 2011 NTNDP:

- Hazelwood: retirement of two units (400 MW) in each of 2016/17, 2017/18, 2018/19 and 2019/20.[90]
- Playford assumed to convert to 258 MW OCGT in 2012/13 in scenarios 1, 2 and 3.

In scenario 4, no assumption about forced closures of generation has been made, as well as no assumption in relation to the conversion of Playford. Rather, the model is allowed to choose the retirement date for both Hazelwood and Playford.[91]

5.6 Classes of market benefits not expected to be material

ElectraNet and AEMO have identified that the following classes of market benefit are unlikely to be material for this RIT-T analysis:

- Changes in ancillary services costs.
- Option value.
- Changes in penalties for not meeting the LRET.

[90] The assumed retirement timings were based on 2011 NTNDP sensitivity modelling.

[91] ElectraNet and AEMO note that in this scenario he model decides to retire Playford in July 2015.

- Changes in unrelated transmission investment.

The reasons for this assessment are set out below.

ElectraNet and AEMO note that no stakeholders have disputed the identification of these categories of market benefit as being not material for this RIT-T assessment.[92]

Changes in ancillary services costs

The cost of Frequency Control Ancillary Services (FCAS) may rise as a result of increased wind generation associated with the network options. However, the cost of frequency control services is not likely to be material in the selection of the preferred option.

FCAS costs are typically less than 1% of the total electricity market costs. Further, the inclusion of all, or some, of the FCAS markets as part of the market modelling under the RIT-T would lead to substantial increase in the complexity and cost of the RIT-T assessment. Such increased complexity is not warranted given that changes in FCAS costs will not have a role in determining the preferred option.

There is no expected change to the costs of Network Control Ancillary Services (NCAS) and System Restart Ancillary Services (SRAS) as a result of the options being considered. These costs are therefore not material to the outcome of the RIT-T assessment.

Option value

ElectraNet and AEMO note the AER's view that option value is likely to arise in situations where the following three conditions are all met:

- There is uncertainty regarding future outcomes.
- The information that is available in the future is likely to change.
- The credible options considered by the TNSP are sufficiently flexible to respond to that change.[93]

ElectraNet and AEMO also note the AER's view that appropriate identification of credible options and reasonable scenarios captures any option value, thereby meeting the NER requirement to consider option value as a class of market benefit under the RIT-T.

For this RIT-T assessment, the estimation of any option value benefit over and above that already captured via the scenario analysis would require a significant modelling assessment, which would be disproportionate to any additional option value benefit that may be identified. ElectraNet and AEMO have not therefore estimated any additional option value market benefit for this RIT-T assessment.

[92] Origin Energy agreed in its submission to the PSCR that changes in ancillary services costs and option value are not material for this RIT-T assessment.

[93] AER, Final Regulatory Investment Test for Transmission Application Guidelines, June 2010, p. 39 and p. 75.

Penalties for not meeting the LRET

One of the categories of market benefit identified under the RIT-T is 'the negative of any penalty paid or payable for not meeting the LRET'.

As noted earlier, one of the assumptions that have been made in conducting this RIT-T assessment is that the LRET target is met. As such it is a 'hard target'. As a consequence, there are no market benefits (or market costs) in relation to changes in the penalties paid for not meeting the LRET as a result of any of the credible options.

Differences in the timing of unrelated transmission investment

ElectraNet and AEMO have not identified any unrelated transmission investment which would be affected by the credible options being assessed under this RIT-T. This is therefore not a material category of market benefit for this RIT-T.

6 Detailed option assessment

This section sets out the results of the NPV analysis for each of the credible options discussed in section 3.

The NER requires that the PACR set out a detailed description of the methodologies used in quantifying each class of material market benefit and cost, together with the results of the NPV analysis, and accompanying explanatory statement regarding the results. This section therefore discusses how each of the costs and material categories of market benefits have been calculated, before presenting and discussing the results of that analysis across all of the credible options.

6.1 Quantification of costs for each credible option

The total capital costs for each credible option are set out in Table 6-1. The present value of these costs are set out in Table 6-3 in section 6.3.2.

The capital costs for the network options have been developed by ElectraNet and SP AusNet. ElectraNet's cost estimates have been based on a range of factors including historical data from actual projects and ElectraNet's substation and line design manuals. ElectraNet's cost estimates have also been subject to review by external engineering consultants. SP AusNet's cost estimates have been based on in-house estimation. Operating costs for the network options have been assumed to be 2% of the capital costs.

The indicative cost of the DM component of Option 5 has been based on estimates provided by EnerNOC, who earlier identified themselves as a proponent for this option. In addition to the total availability fee of $120m (i.e. $24m a year for a five year program), there would also be a dispatch fee estimated at around $750/MWh.

The capital cost of the control schemes included in Options 6a and 6b has been estimated by independent consultants (DSA). These costs were adjusted based on an indicative estimate received from SP AusNet. Operating costs have also been based on adjusted DSA estimates of a total cost of $3.87m across both control schemes). No costs have been included to reflect participation fees that may be required by generators.

ElectraNet and AEMO note that Infigen submission suggested that the network cost estimates used in the RIT-T should be subject to independent review, and that the capital cost estimates should be based on the DSA costings, rather than being adjusted.[94] ElectraNet and AEMO note that at the RIT-T stage, cost estimates are necessarily of a relatively high-level nature. ElectraNet and AEMO therefore believe that the level of external review of cost estimates that has been undertaken to date is appropriate, and that sensitivity testing is a more relevant means of assessing the impact of the cost estimates on the RIT-T outcome. The sensitivity analyses conducted in relation to both general network costs and the control scheme costs in particular is discussed in section 6.3.2.

[94] The issues raised by Infigen in relation to the control scheme costs are discussed in more detail in section 4.10.

Table 6-1: Costs of each credible option (2011/12 $m)

	Components	Component costs	Total capital cost ($m)
Option 1a	3rd 500/275 kV Heywood transformer and 500 kV bus tie (Victoria)	$45.0m	$78.0m
	Reconfiguration of 132 kV network (South Australia)	$28.6m	
	Installation of 100 MVAr capacitor (South Australia)	$4.4m	
Option 1b	3rd 500/275 kV Heywood transformer and 500 kV bus tie (Victoria)	$45.0m	$107.7m
	Reconfiguration of 132 kV network (South Australia)	$28.6m	
	Series compensation of the Tailem Bend to South East 275 kV double circuit lines at Black Range (South Australia)	$34.1m	
Option 2a	Works as per Option 1a	$78.0m	$95.4m
	3rd transformer at South East and associated works (South Australia)	$17.4m	
Option 2b	Works as per Option 1b	$107.7m	$125.1m
	3rd transformer at South East and associated works (South Australia)	$17.4m	
Option 3	**Krongart Stage 1 Works:** New switching station at Krongart (South Australia) New 500 kV double circuit line from Krongart to Heywood (operated at 275 kV) (Victoria) 500/275 kV transformers at Heywood (Victoria) 275 kV works Tailem Bend to Tungkillo (South Australia)	$417.3m	$888.8m
	Krongart Stage 2 works: Create a 500 kV switchyard at Krongart (South Australia) 500/275 kV transformers at Krongart (South Australia) Re-connect the Heywood end line termination to the 500 kV side of the Heywood substation (Victoria) 275 kV works Tailem Bend – Krongart (South Australia)	$471.5m	
Option 4	500 kV bus tie (Victoria)	$7.6m	$40.6m
	Reconfiguration of 132 kV network (South Australia)	$28.6m	
	Installation of 100 MVAr capacitor (South Australia)	$4.4m	

Option 5	200 MW DM	$120.0m (availability fee)	$233.2m
	Option 1b	$113.2m	
Option 6a	Heywood control scheme (Lake Bonney wind farms only)	$12.0m	$21.6m
	South East control scheme	$1.0m	
	Adding additional wind generation at Krongart	$1.0m	
	500 kV bus tie	$7.6m	
Option 6b	Heywood control scheme (Lake Bonney wind farms only)	$12.0m	$84.3m
	South East control scheme	$1.0m	
	Adding additional wind generation at Krongart	$1.0m	
	Option 1b minus 3rd 500/275 kV Heywood transformer	$70.3m	

6.2 Quantification of classes of material market benefit for each credible option

The purpose of the RIT-T is to identify the credible option that maximises the present value of the net economic benefits to all those who produce, consume and transport electricity in the market.[95]

To measure the increase in net market benefit, ElectraNet and AEMO have analysed the classes of market benefit required for consideration under paragraph 5 of the RIT-T, with the exception of those categories which are not considered material for this RIT-T assessment (see section 5.6).

The remaining classes of market benefit which have been quantified for this assessment are:

- Changes in generator fuel consumption arising through different patterns of generation dispatch (including changes in carbon costs).
- Changes in voluntary load curtailment.
- Changes in involuntary load shedding.
- Changes in costs for parties, other than the TNSP.
- Changes in network losses.

There have been no additional categories of market benefit identified as relevant for this RIT-T assessment, outside of those specified in the RIT-T itself.[96]

As noted earlier, many of the material categories of market benefit for this RIT-T are calculated by comparing the 'state of the world' in the base case (where no action is undertaken by ElectraNet or AEMO) with the 'state of the world' with each of the credible options in place.

[95] NER 5.16.1(b).

[96] RIT-T para (5)(k).

Competition benefits have not been included in the results reported in section 6.3. Studies undertaken by ElectraNet indicate that, for this particular RIT-T assessment, the magnitude of competition benefits is expected to be low and would not materially affect the RIT-T outcome. Key findings from ElectraNet's analysis of competition benefits are discussed in section 6.4.

6.2.1 Changes in fuel consumption

ElectraNet and AEMO have calculated the fuel consumption costs (including the costs associated with the carbon price) and the variable operating costs arising under the base case, for each of the scenarios considered in the RIT-T analysis. Fuel costs (including carbon costs) and variable operating costs have been calculated on the basis of the generator dispatch pattern resulting from the Prophet dispatch market modelling, taking into account the difference in generation expansion plans associated with each scenario.

For each scenario, the fuel consumption cost (including emissions costs) and variable operating cost estimated under the base case has then been compared with the fuel consumption cost and variable operating cost predicted by Prophet if each of the credible options were in place. For example, using the Prophet model ElectraNet and AEMO have calculated the fuel consumption costs and variable operating cost under scenario 1 (central scenario) for the base case and then taken the difference between this cost and the fuel consumption costs estimated by Prophet under scenario 1 if Option 1a is in place (i.e. the 3rd transformer at Heywood + 100 MVAr capacitor + 132 kV works). A positive difference represents a *reduction* in fuel costs resulting from the credible option (a market benefit), whilst a negative difference represents an *increase* in fuel costs resulting from the credible option (a market cost).

The differences in dispatch costs have been calculated across the NEM as a whole, and therefore also reflect market benefits that arise outside of South Australia and Victoria.

6.2.2 Changes in voluntary load curtailment

Voluntary load curtailment is when customers agree to reduce their load, once pool prices in the NEM reach a certain threshold. Customers usually receive a payment for agreeing to reduce load in these circumstances. Where the implementation of a credible option affects pool price outcomes, and in particular results in pool prices reaching higher levels in some trading intervals than in the base case, this may have an impact on the extent of voluntary load curtailment.[97]

The Prophet modelling incorporates voluntary load curtailment as part of its suite of dispatch options. As a consequence, the market benefit associated with changes in voluntary load curtailment is already reflected in the difference in dispatch cost outcomes discussed under section 6.2.1.

ElectraNet and AEMO note that the level of voluntary load curtailment currently present in the NEM is limited.

[97] It is also noted that the frequency of high price periods will be limited in the SRMC analysis, and therefore voluntary load curtailment is likely to be underestimated. However, this is not expected to have a material impact on results.

6.2.3 Changes in involuntary load shedding

Raising the import capacity of the Heywood Interconnector increases the generation supply availability from Victoria to meet demand in South Australia. This will provide greater reliability for South Australia by reducing the potential for supply shortages and the consequent risk of involuntary load shedding. At the same time, increasing the export capability from South Australia provides greater reliability for the Victorian region.

ElectraNet and AEMO have quantified the impact of changes in involuntary load shedding associated with the implementation of each credible option via the Prophet market modelling. Specifically, the Prophet modelling estimates the MWh of unserved energy (USE) in each trading interval over the modelling period, and then applies a Value of Customer Reliability (VCR, expressed in $/MWh) to the estimated level of USE. The VCR adopted for this RIT-T analysis varies for each jurisdiction, and reflects the regional VCR estimates presented in AEMO's 2012 National Value of Customer Reliability study.[98]

The differences in USE have been calculated across the NEM as a whole, and therefore also reflect market benefits that arise outside of South Australia and Victoria.

6.2.4 Changes in costs for other parties

Changes in costs to other parties reflects the differences in the value of generation investment between the base case 'state of the world' and the 'state of the world' arising from the implementation of each of the credible options.

Differences in generation investment can relate to the type, timing and quantity of generation investment between the base case (in which no action is undertaken by ElectraNet and AEMO) and each credible option. In particular, differences in generator capital and fixed costs between the base case and with the credible option in place could arise due to:

- A deferral of the need to build new generation investment, arising from an increased ability to share generation resources across the expanded interconnector capacity (for the network options), or a reduction in peak demand (for the DM option).
- A difference in the type of generation investment, given the change in market opportunities represented by the expanded interconnector capacity, and/or modified demand conditions (for the DM option). In particular, expansion of the interconnector may provide increased opportunities to invest in generation technologies with high capital costs but low fuel cost and low emission generation, such as wind and geothermal.
- Changes in the location of new wind generation prior to 2020 to meet the LRET target, to higher-efficiency wind locations, resulting in an overall decrease in the MW of wind generation required.

The generation expansion plan in the base case and under each option[99] for each scenario has been derived on the basis of the PLEXOS modelling described earlier (section 5.3.1). The exception is for the DM component of Option 5, where an assumption of a five year deferral of 200 MW of OCGT

[98] AEMO, January 2012, National Value of Customer Reliability, p. 4. For example, the VCR applied for South Australia is $44,300/MWh whilst that for Victoria is $57,290/MWh.

[99] As noted earlier, Option 6a (stand-alone control scheme) is not expected to impact generation investment decisions, due to its relatively small scale, and so there is no impact on the base case expansion plan for this option.

investment in South Australia compared with the base case has been made in scenarios 1, 2 and 3, and a two year deferral of 87 MW of OCGT in South Australia in scenario 4.

Differences between the base expansion plan and the expansion plan resulting with the credible option in place have then been identified, and the difference in capital costs and fixed operating costs under the two expansion paths has been calculated. A positive difference between the generation capital costs in the base case and the generation capital costs with the credible option represents a *reduction* in overall capital costs resulting from the credible option (i.e. a market benefit), whilst a negative difference represents an *increase* in capital costs resulting from the credible option (i.e. a market cost). The differences in generator capital and fixed operating costs have been calculated across the NEM as a whole, and therefore also reflect market benefits that arise outside of South Australia and Victoria.

6.2.5 Changes in network losses

The market modelling undertaken by ElectraNet and AEMO has taken into account the change in network losses that may be expected to occur as a result of the implementation of any of the credible options, compared with the level of network losses which would occur in the base case, for each scenario.

An increase in network losses represents a negative market benefit (i.e. a market cost), whilst a reduction in losses represent a positive market benefit.

The market benefits of the change in losses have been quantified by a direct calculation of the likely MWh impact on losses in each trading interval for each year of the modelling horizon. Specifically, losses on the interconnectors have been modelled explicitly based on loss equations from the NTNDP, with the Heywood equations updated to take into account the proposed augmentations. Intra-regional losses have been modelled using the generator marginal loss factors for 2011/12. These MWh figures for losses have then been multiplied by the value of those losses, as measured by the Pool Price applicable in each trading period, taken from the Prophet dispatch modelling.

The differences in network losses have been calculated across the NEM as a whole, and therefore also reflect market benefits that arise outside of South Australia and Victoria.

6.3 Net Present Value results

This section summarises the results of the net present value (NPV) analysis. Appendix I sets out the full NPV results for each of the credible options, under each of the three scenarios. The full NPV analysis shows separately the costs for each option, and each class of material market benefit.

6.3.1 Gross market benefits

Table 6.2 summarises the gross market benefit, in NPV terms, for each of the nine credible options included in the RIT-T analysis. The gross market benefit is the sum of each of the individual categories of material market benefit (both positive and negative), as quantified on the basis of the approach set out in the preceding section.

As discussed earlier, the gross market benefit of each option has been calculated for four reasonable scenarios. The results for each option under each scenario have then been weighted together in order to derive the overall market benefit for each option.

A detailed breakdown of the gross market benefit for each credible option, under each scenario is provided in Appendix I. The remainder of this section discusses some high-level observations in relation to the key drivers of market benefits for each option, and how these differ between the individual scenarios.

Key categories of market benefit

A review of the results of the gross market benefit quantification highlights that the two main categories of market benefit which are material for this RIT-T are changes in fuel consumption and changes in costs for other parties (i.e. changes in generator investment costs). Losses and changes in involuntary load shedding (unserved energy) form only a very minor part of the total gross market benefit calculated for any of the nine options.

This conclusion holds across all four of the reasonable scenarios. In general terms, the market benefit associated with each of the options arises from the ability of that option to facilitate the increased output of lower operating cost generation (including emissions costs), across the NEM as a whole.

The precise pattern of market benefits and the relative breakdown between changes in fuel consumption and changes in generator investment costs differs across scenarios. The most notable difference is that under the revised central scenario (scenario 4) changes in fuel costs form a higher proportion of the overall market benefit of each option, compared to the other three scenarios where changes in generation investment costs (and notably an *increase* in those costs) are also significant.

The one outlier in terms of the nine credible options considered is Option 6a (the stand-alone control scheme option). The market benefits for this option predominantly relate to changes in fuel costs since the expansion plan used for this option is no different from the base case, so there are no changes in generator investment costs. Whilst this option has a positive market benefit, the size of that benefit is orders of magnitude different to the other options included in the assessment. Appendix I provides the detailed breakdown of the market benefits for this option. However given that it is a clear outlier, Option 6a is not discussed further in this section.

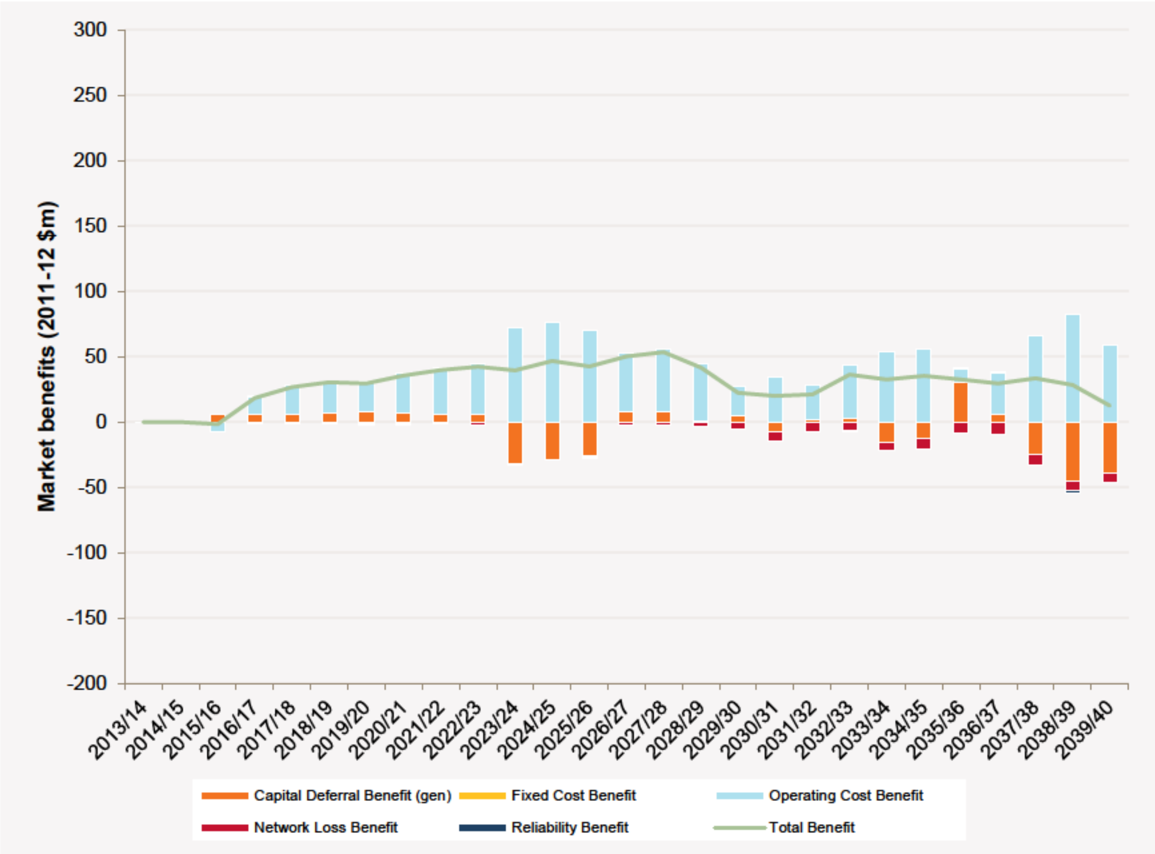
Table 6-2: Gross market benefit for each credible option (PV, $m)

		Scenario 1: Central Scenario	Scenario 2: Low Scenario	Scenario 3: High Scenario	Scenario 4: Revised Central Scenario	Market Benefit (weighted)
Scenario weights		29%	13%	17%	41%	
Option 1a	3rd Heywood transformer + 100 MVAr capacitor + 132 kV works	144.6	308.8	264.5	232.0	222.2
Option 1b	3rd Heywood transformer + series compensation + 132 kV works	199.1	340.8	306.2	284.0	270.5
Option 2a	Option 1a + 3rd South East transformer	151.6	308.7	272.7	236.8	227.5
Option 2b	Option 1b + 3rd South East transformer	199.2	340.5	304.9	284.2	270.4
Option 3	New Krongart-Heywood 500 kV interconnector + 275 kV works	290.8	444.7	350.0	247.2	303.0
Option 4	132 kV works + 100 MVAr capacitor	85.9	176.6	173.4	190.8	155.6
Option 5	200 MW DM + Option 1b	261.5	411.7	372.6	271.6	304.1
Option 6a	Control schemes + 500 kV bus tie	19.9	48.8	8.5	12.1	18.5
Option 6b	Control schemes + Option 1b minus 3rd Heywood transformer	176.0	342.9	295.4	261.6	253.1

Figure 6-1 shows the breakdown of gross market benefits for Option 1b (3rd Heywood transformer + 100 MVAr capacitor + 132 kV works), under scenario 1 (central scenario). It is clear from the figure that the main positive category of market benefit for this option under this scenario is the reduction in generator operating costs (which comprise mainly fuel and carbon costs) resulting from the implementation of the option. In the earlier years of the assessment period, and in some subsequent years, there is also a limited benefit in terms of reduced generation investment costs. However, from

2023/24 onwards, generation investment costs in several years actually *increase* as a result of implementation of the option, indicating additional investment in capital-intensive generation in order to realise dispatch cost benefits.

Figure 6-1: Option 1b (3rd Heywood Transformer + series compensation + 132 kV works) – gross market benefits, central scenario (2011/12 $m)



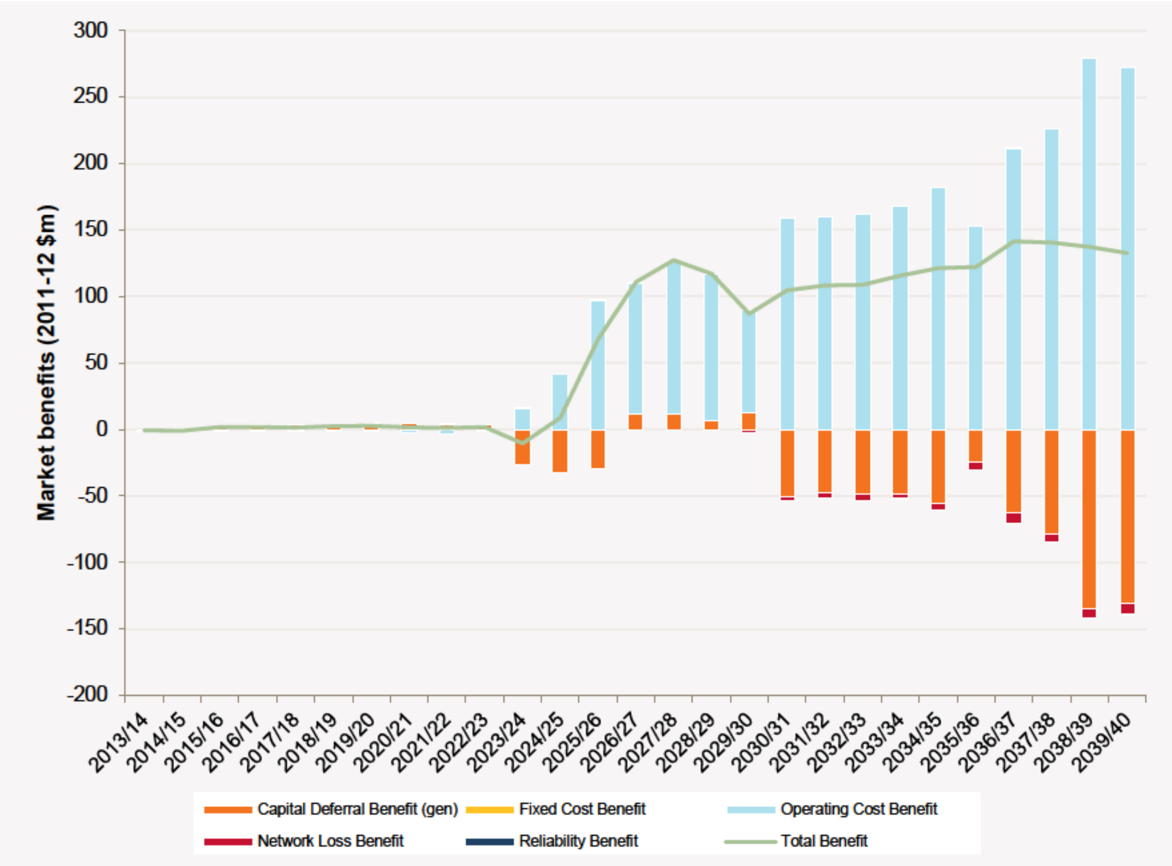
The overall pattern and breakdown of gross market benefits under the central scenario is very similar for Options 1a, 2a, 2b, 4, 5 and 6b. However the following differences are worth noting:

- The magnitude of the differences in fuel costs and generator investment is slightly lower for Option 1a compared with Option 1b. This is because Option 1a (which includes the capacitor) results in lower voltage stability limits over the interconnector (for both flow directions) compared with Option 1b (which include series compensation). These voltage stability limits begin to become significant during the later years of the assessment period for Victoria to South Australia flows, limiting flows below those which are possible under Option 1b.
- The options which include the 3rd South East transformer (i.e. Options 2a and 2b) have only slightly higher overall gross market benefits than the corresponding options without the South East transformer (i.e. Options 1a and 1b). The re-arrangement of the 132 kV network leads to higher flows on the parallel 275 kV network compared to the base case, which in turn results in lower parallel flow through the South East transformers due to interconnector flows, and reduces the scope for market benefits.

- Option 4, which does not include the 3rd Heywood transformer, has a lower overall magnitude of market benefits due to the lower interconnector limits (+/- 460MW) without the transformer.
- Option 5 has the additional capital deferral benefit associated with the 5-year DM program deferring the need for 200 MW of new OCGT plant in South Australia.

The pattern of market benefits is different for Option 3 (new Krongart – Heywood 500 kV interconnector + 275 kV works). Under the central scenario, this option shows benefits occurring later than for the other options, but being of a greater magnitude. However, the key benefit categories remain operating cost savings and generation capital deferral, with the latter representing a negative benefit in most years (i.e. an increased cost of generation investment following the augmentation).

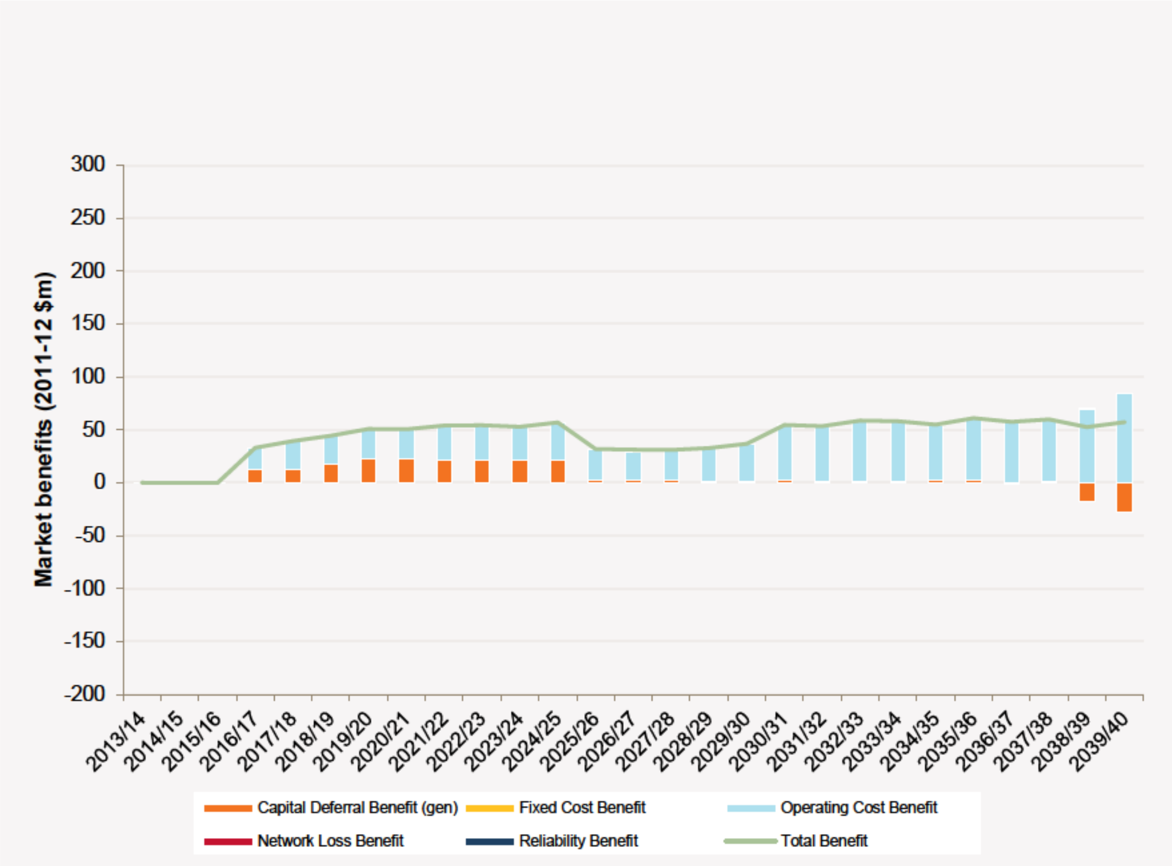
Figure 6-2: Option 3 (New Krongart 500 kV interconnector + 275 kV works) – gross market benefits, central scenario (2011/12 $m)



The pattern and breakdown of market benefits for scenario 2 (low scenario) and scenario 3 (high scenario) are similar to that for the central scenario. In scenario 2, which has a higher carbon price, there is a greater degree of additional investment in low operating cost and low emission generation, in order to realise dispatch cost benefits.

Scenario 4 (revised central scenario) shows a slightly different breakdown of benefits, in that fuel cost benefits are realised without additional generation investment until much later in the period, due to low demand forecasts and fewer coal-fired generator retirements. Figure 6-3 shows the breakdown of market benefits for Option 1b under scenario 4.

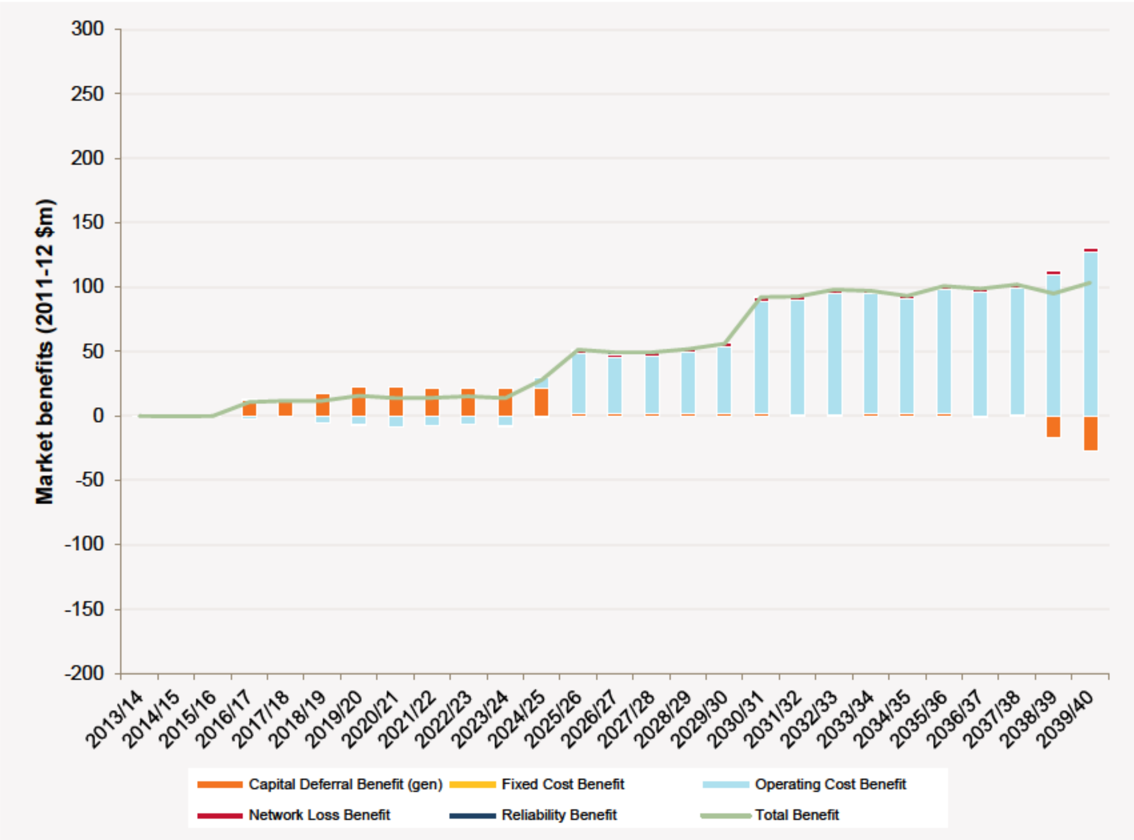
Figure 6-3: Option 1b (3rd Heywood Transformer + series compensation + 132 kV works) – gross market benefits, revised central scenario (2011/12 $m)



This breakdown remains similar for Options 1a, 2a, 2b, 4, 5 and 6b under this scenario, subject to the relativities discussed earlier.

The breakdown of benefits for Option 3 (new Krongart 500 kV interconnector) is also somewhat different under scenario 4, as shown in Figure 6-4. Again, under this scenario substantial benefits in relation to fuel consumption are achieved, without a corresponding increase in the level of investment in low operating cost generation. This reflects an increase in imports into South Australia, as lower operating cost generation outside of South Australia is substituted for higher operating cost generation in South Australia.

Figure 6-4: Option 3 (New Krongart 500 kV interconnector + 275 kV works) – gross market benefits, revised central scenario (2011/12 $m)



Changes in fuel costs

The change in fuel costs represents the biggest category of positive market benefit associated with each of the options. This is the case across all of the options and for each of the scenarios considered, although the underlying changes in fuel costs differ between scenarios. A detailed breakdown of the impact of each option on generation output for each jurisdiction, under each scenario, is provided in Appendix I.

Changes in fuel costs reflect the change in generation dispatch, which is facilitated by each of the credible options, compared to the base case in each scenario. Differences between scenarios reflect the impact of the different assumptions between scenarios (such as the assumed carbon price, which will directly affect the relative costs of different generation sources). It will also reflect different base case generation expansion plans associated with the different scenarios. For example, in scenario 1 (central scenario), substantial additional generation (particularly wind generation) is assumed in the base case generation expansion plan, compared with scenario 4 (revised central scenario).

Figure 6-5 and Figure 6-6 show the changes in the source of generation output that arise from Option 1b, compared to the base case, for the central scenario. Specifically Figure 6-5 highlights the five sources of generation which have the largest increases[100] in output (in GWh) together with the remaining overall increase in generation output across all other remaining generation sources. Figure 6-6 presents the same breakdown, but in relation to the main sources of decreases in generation.

[100] Where the increase is measured by adding he annual GWh changes over the modelling period.

Figure 6-5: Option 1b (3rd Heywood Transformer + series compensation + 132 kV works) - top five increases in NEM generator dispatch (GWh), central scenario

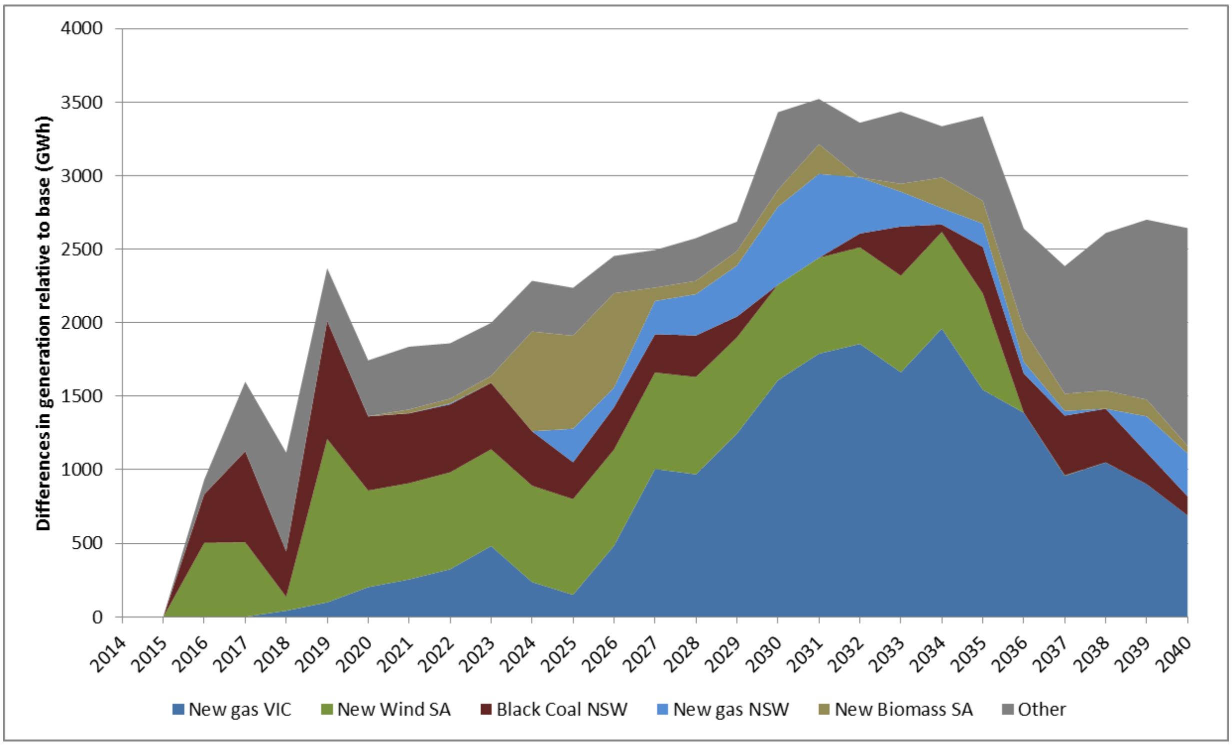
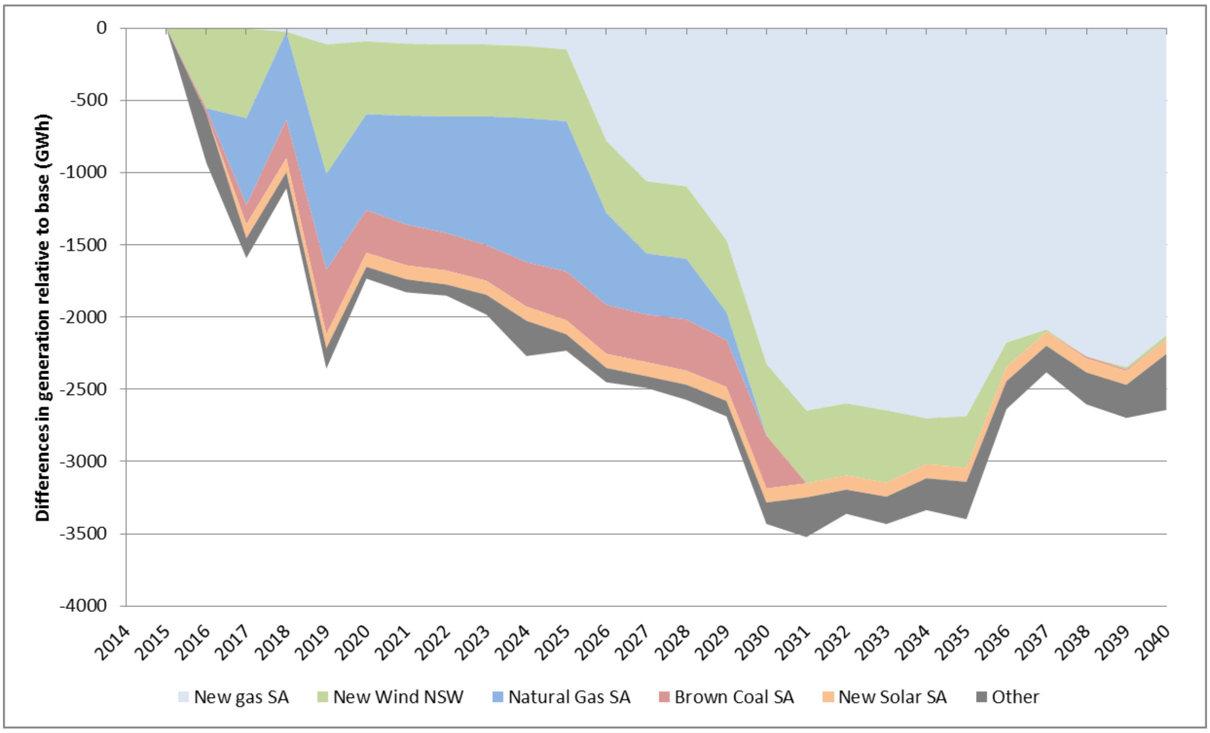


Figure 6-6: Option 1b (3rd Heywood Transformer + series compensation + 132 kV works) - top five decreases in NEM generator dispatch (GWh), central scenario



From the figures it is clear that a key impact of Option 1b under the central scenario is the increase it enables in the output of new wind generation in South Australia from 2015 and, later in the period, the increase in the output of new gas-fired generation in Victoria. Increases in these sources of generation displace higher fuel cost generation from new and existing gas-fired generators in South Australia, and from new wind generation in NSW, which would otherwise have occurred in the base case. The fuel cost benefit for Option 1b reflects the differences in generation operating cost (including carbon costs) associated with this changed pattern of dispatch.

A similar change in dispatch patterns is evident for the majority of other options in this scenario. The pattern of redispatch under Option 3 (new Krongart – Heywood 500 kV interconnector + 275 kV works) is slightly different in that it shows increased output of new gas generation in Victoria, together with new geothermal generation in South Australia, predominantly displacing the output of new gas plant in South Australia. The changes in generation output under Option 3 are shown in Figure 6-7 and Figure 6-8.

Under the revised central scenario (scenario 4), the dispatch of generation resulting in lower fuel costs (including emission costs) remains the key component of market benefit under each of the options. However, the specific changes in generation redispatch differ to that under the central scenario. Figure 6-9 and Figure 6-10 show the top five changes in the source of generation output (in GWh) that arise from Option 1b (3rd Heywood Transformer + series compensation + 132 kV works), compared to the base case, for the revised central scenario.

The figures show that under the revised central scenario (scenario 4) a key impact of Option 1b is the increase it enables in the output of new biomass generation in South Australia, displacing the need to build OCGTs in South Australia to meet reserve requirements. With an increase in biomass investment in South Australia, less biomass is required to be built in NSW to meet the LRET, and NSW biomass generation is replaced by existing black coal generation in New South Wales. To a lesser extent, there is also increased output of existing wind generation in South Australia. Increases in these sources of generation displace higher fuel cost generation from new and existing gas-fired generation in South Australia, which would otherwise have occurred in the base case. Again, this revised dispatch pattern reflects a lower overall dispatch cost (including carbon cost).

In relation to the remaining scenarios:

- Under the low scenario (scenario 2), Option 1b (3rd Heywood Transformer + series compensation + 132 kV works) results in an increase in the output of new geothermal generation in South Australia together with new gas generation in Queensland. These increases displace new gas-fired generation in South Australia and New South Wales, and new solar generation in South Australia.

- Under the high scenario (scenario 3), Option 1b (3rd Heywood Transformer + series compensation + 132 kV works) results in an increase in new wind generation in South Australia, in addition to new geothermal generation in South Australia and new gas generation in Victoria. These increases predominantly displace generation which would otherwise have been provided from new gas-fired generation in South Australia.

As noted earlier, the differences in generation redispatch between the central, revised central, high and low scenarios reflects differences in the modelled expansion plans and input assumptions between scenarios. What is consistent across all scenarios is that market benefits are being driven by the increased dispatch of low operating cost and low emission generation sources.

Figure 6-7: Option 3 (New Krongart 500 kV interconnector + 275 kV works) - top five increases in NEM generator dispatch (GWh), central scenario

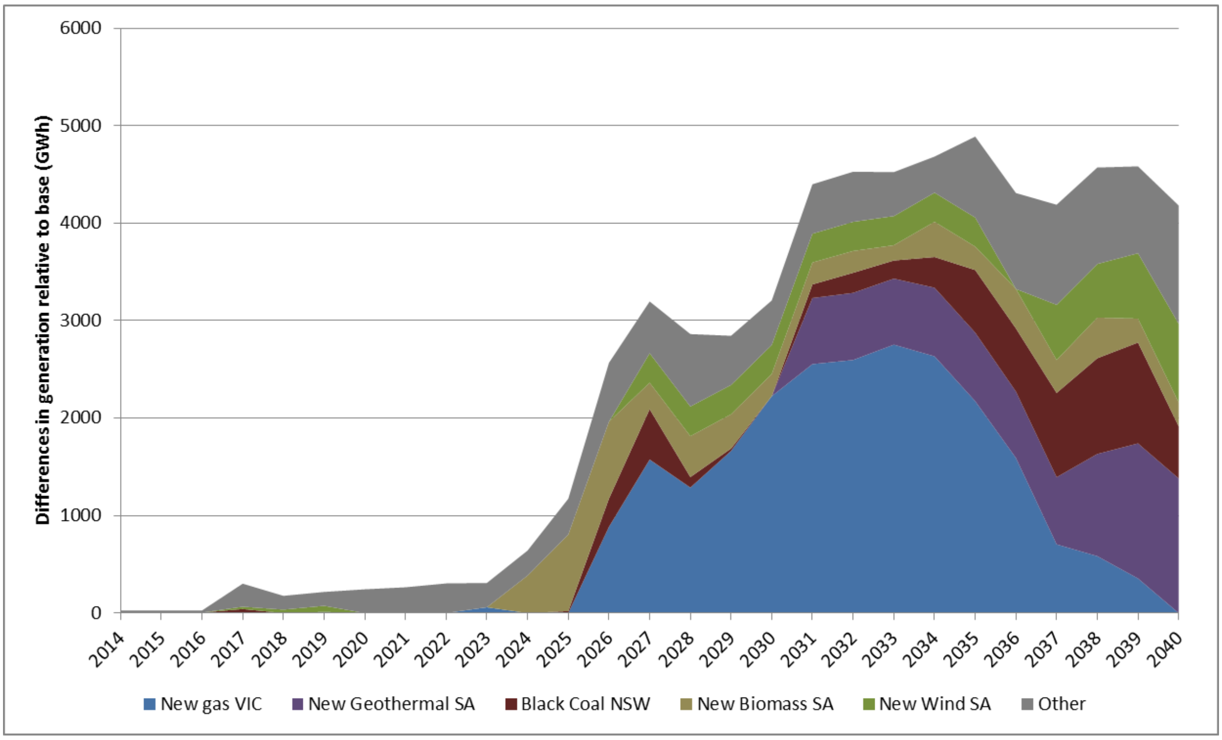


Figure 6-8: Option 3 (New Krongart 500 kV interconnector + 275 kV works) - top five decreases in NEM generator dispatch (GWh), central scenario

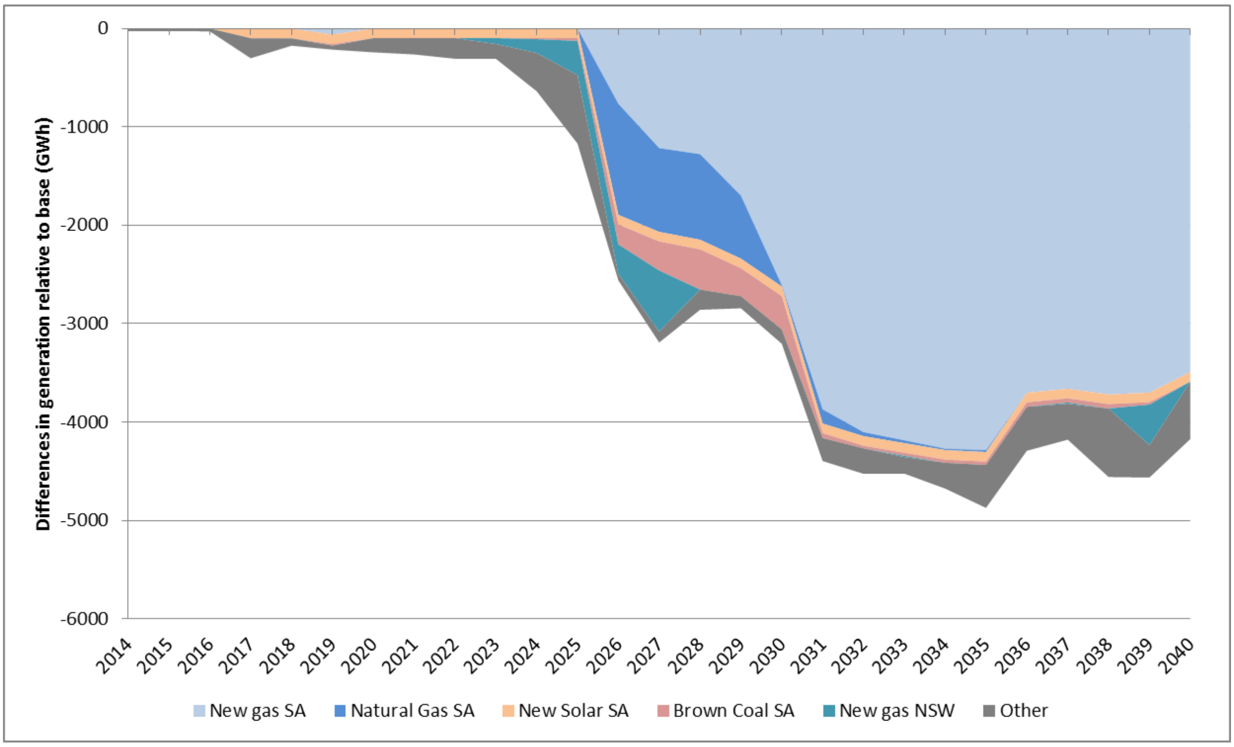


Figure 6-9: Option 1b (3rd Heywood Transformer + series compensation + 132 kV works) - top five increases in NEM generator dispatch (GWh), revised central scenario

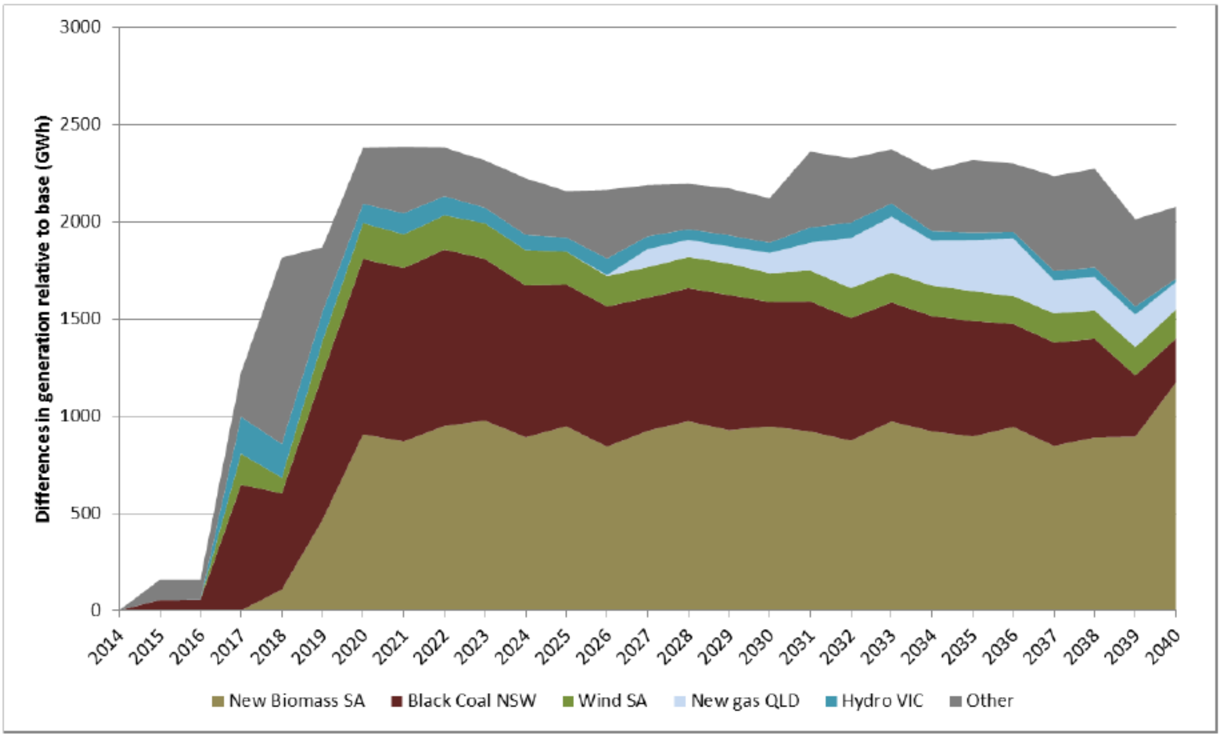
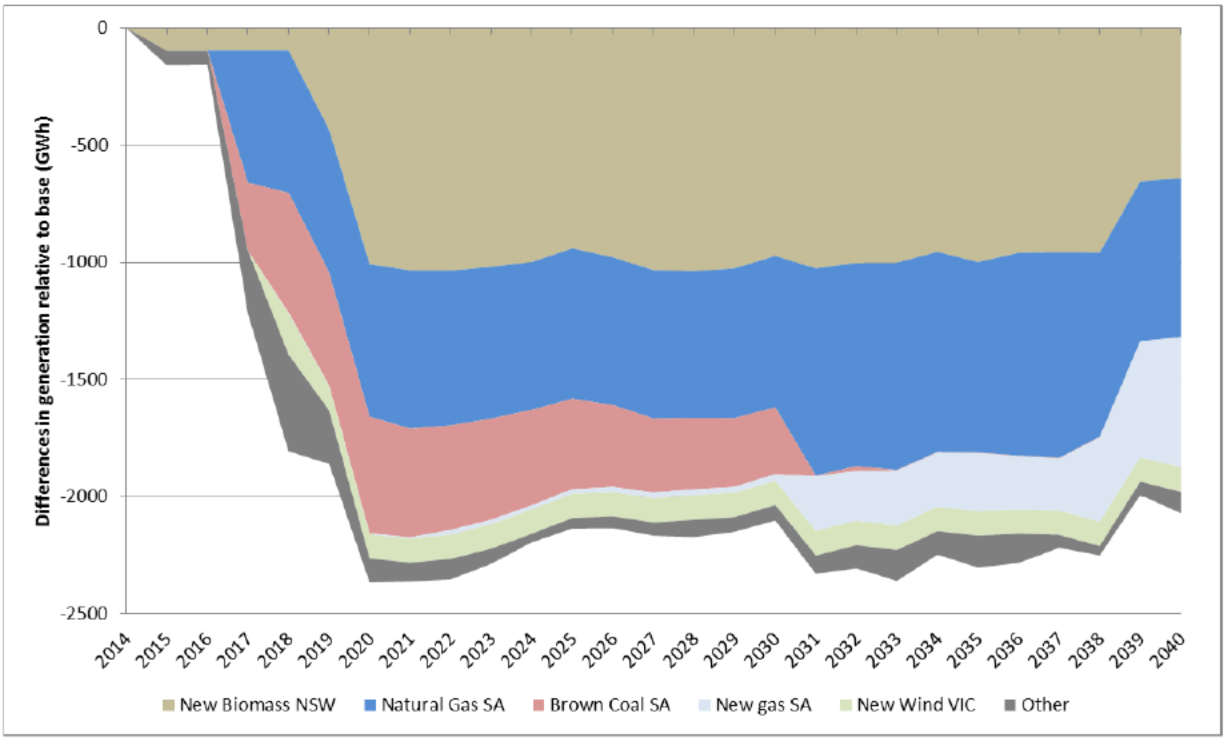


Figure 6-10: Option 1b (3rd Heywood Transformer + series compensation + 132 kV works) - top five decreases in NEM generator dispatch (GWh), revised central scenario



Changes in generation investment

It is evident from the preceding discussion that for scenarios 1 (central scenario), 2 (low scenario) and 3 (high scenario), a substantial proportion of the change in fuel costs resulting from the different credible options is related to changes in the output of new (modelled) generation, as well as existing generation. The modelling results indicate that the different credible options considered each, to varying extents, enable additional investment in low fuel cost sources of generation, compared with the base case. This includes (but is not limited to), new gas-fired generation in Victoria displacing new gas-fired generation in South Australia and new wind generation in South Australia displacing wind generation in NSW.

The impact on gross market benefit of the change in generation investment pattern will depend on the relative costs of the additional generation, compared to the generation displaced. The modelling results highlight that for scenarios 1 (central scenario), 2 (low scenario) and 3 (high scenario) there is an overall increase in the cost of generation investment under each option, compared to the base case, representing a negative market benefit. However, this negative benefit is outweighed by the positive market benefit resulting from the overall reduction in dispatch costs resulting from the increased presence of low-cost generating sources (discussed above). This impact does not occur to the same extent under scenario 4 (revised central scenario) due to the relatively low demand growth and fewer coal-fired generation retirements.

A detailed breakdown of the change in generation investment by jurisdiction is provided in Appendix I, across all scenarios.

As an illustration, Figure 6-11 and Figure 6-12 summarise the five largest changes in the type of generation investment across the NEM as a whole (cumulative MW over the overall assessment period) under the central scenario for Options 1a, 1b, 2a, 2b, 4 and 6b.[101] For Option 5 (200 MW DM + Option 1b) an additional impact of the deferral of 200 MW of OCGT investment in South Australia by five years from 2013/14 has also been assumed under the central scenario.

Figure 6-13 and Figure 6-14 show the equivalent key changes in the generation expansion plan associated with Option 3 (new Krongart-Heywood 500 kV interconnector + 275 kV works), under the central scenario.

[101] As discussed in section 5.3.1, the impact of these six options on the generation expansion plan was found to be materially identical, and so the same expansion plan was adopted across all of these options.

Figure 6-11: Options 1a, 1b, 2a, 2b, 4 and 6b - top five increases in NEM generation investment (MW), central scenario

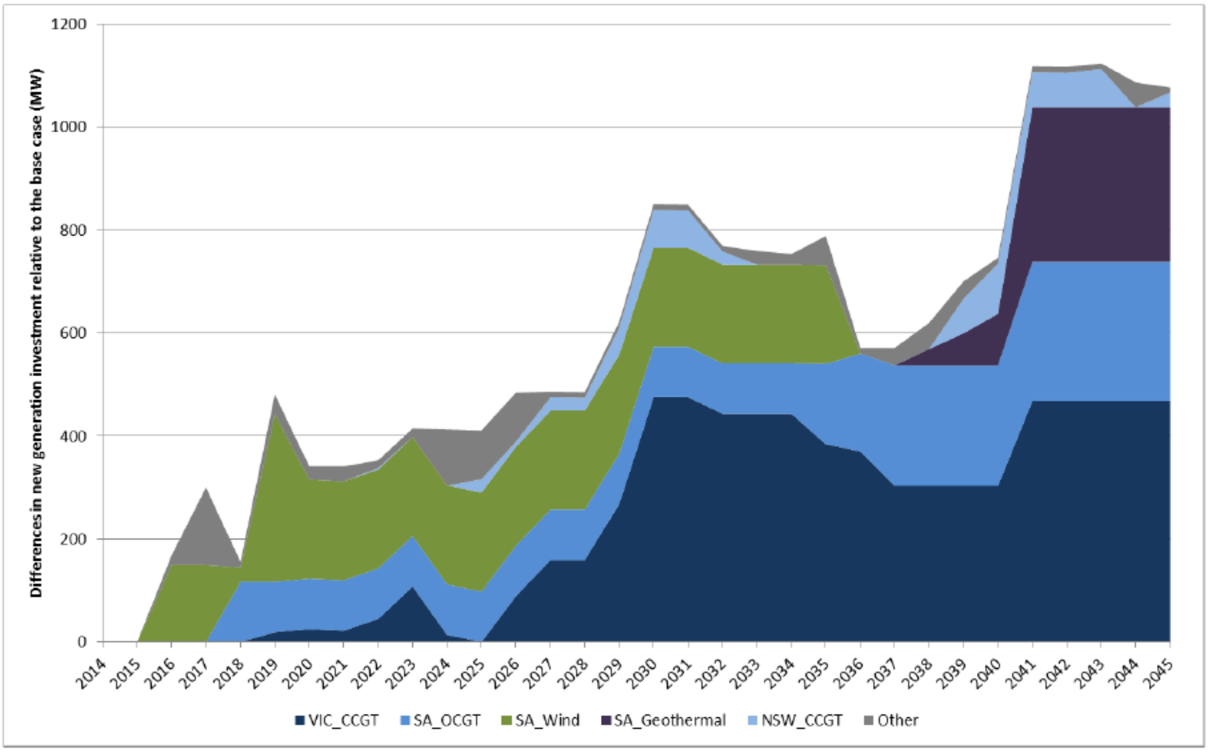


Figure 6-12: Options 1a, 1b, 2a, 2b, 4 and 6b - top five decreases in NEM generation investment (MW), central scenario

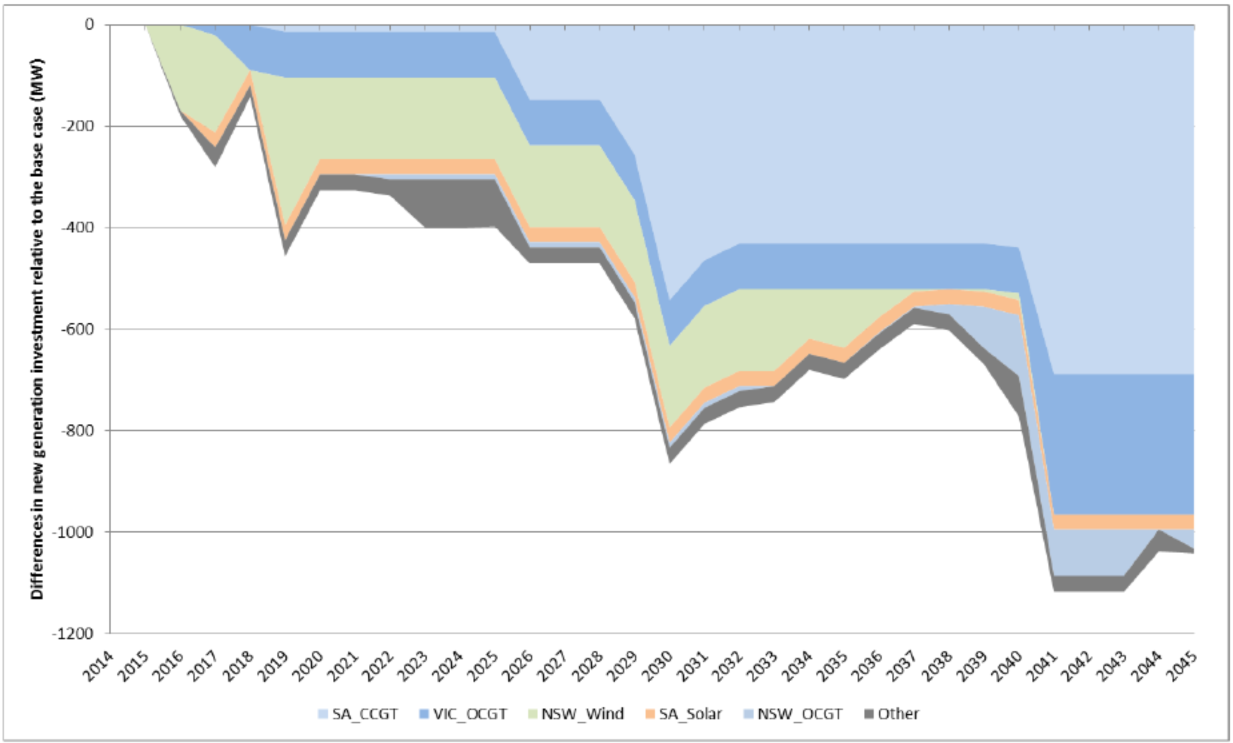


Figure 6-13: Option 3 (New Krongart-Heywood 500 kV interconnector + 275 kV works) - top five increases in NEM generation investment (MW), central scenario

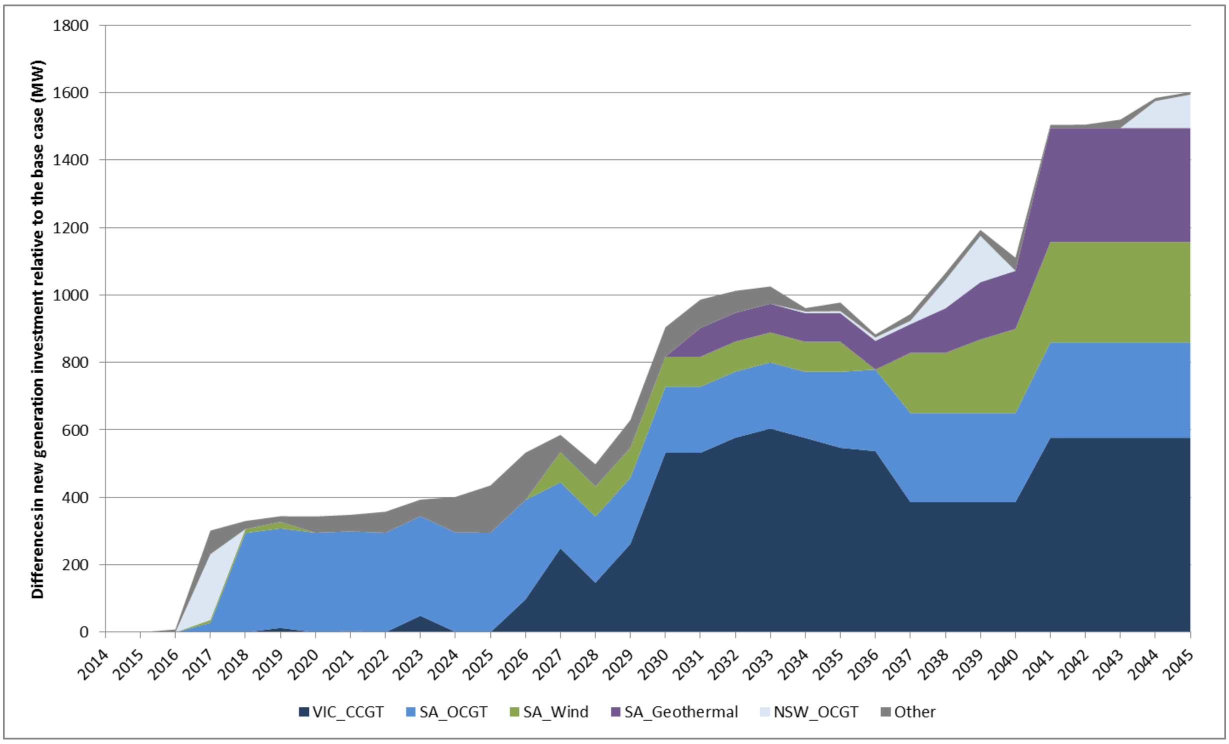
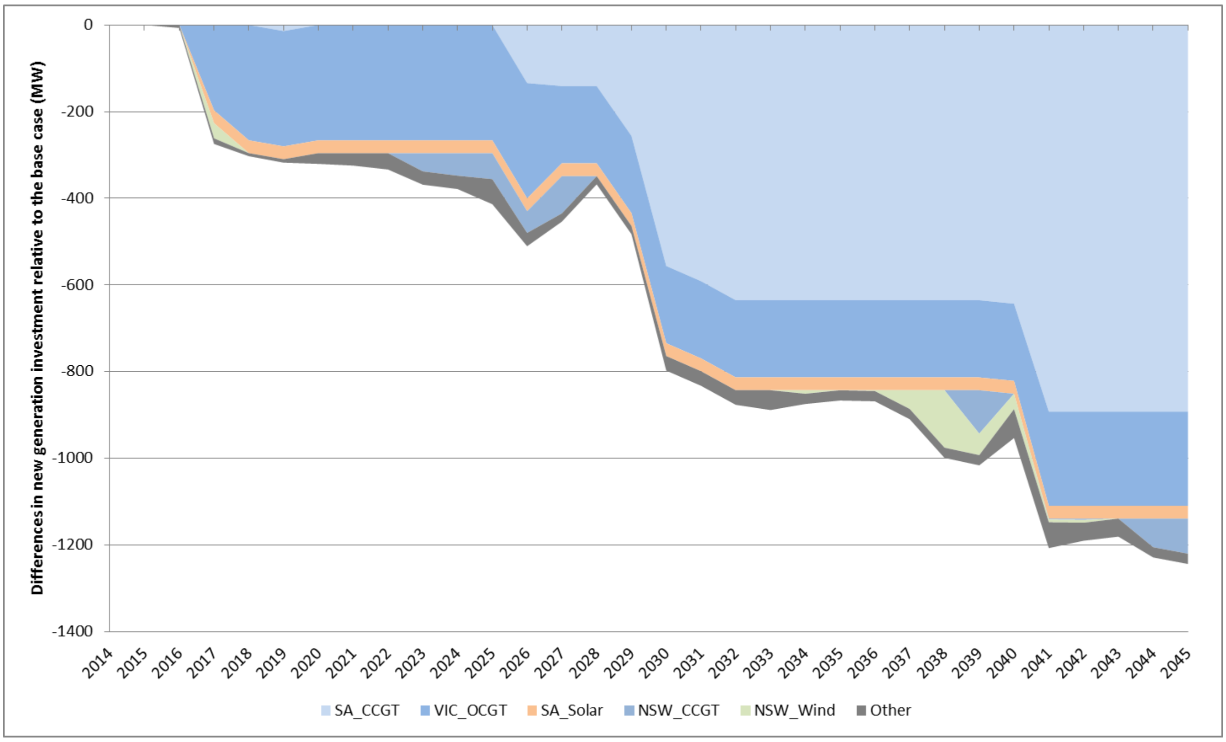


Figure 6-14: Option 3 (New Krongart-Heywood 500 kV interconnector + 275 kV works) - top five increases in NEM generation investment (MW), central scenario



6.3.2 Net market benefits

Table 6.3 summarises the net market benefit in NPV terms for each credible option. The net market benefit is the gross market benefit, weighted across all scenarios (as set out in Table 6.2), minus the costs of each option, all in present value terms.

The table also shows the corresponding ranking of each option under the RIT-T, with the options ranked from 1 to 9 in order of descending net market benefit.

Table 6-3: Net market benefit for each credible option (PV, $2011/12m)

		Costs	Market benefit	Net market benefit	Ranking under RIT-T
Option 1a	3rd Heywood transformer + 100 MVAr capacitor + 132 kV works	57.8	222.2	164.4	4
Option 1b	3rd Heywood transformer + series compensation + 132 kV works	79.8	270.5	190.8	=1
Option 2a	Option 1a + 3rd South East transformer	70.7	227.5	156.8	6
Option 2b	Option 1b + 3rd South East transformer	92.7	270.4	177.7	3
Option 3	New Krongart-Heywood 500 kV interconnector + 275 kV works	212.2	303.0	90.8	8
Option 4	132 kV works + 100 MVAr capacitor	30.6	155.6	125.0	7
Option 5	200 MW DM + Option 1b	147.1	304.1	156.9	5
Option 6a	Control schemes + 500 kV bus tie	16.7	18.5	1.8	9
Option 6b	Control schemes + Option 1b minus 3rd Heywood transformer	63.1	253.1	190.0	=1

Table 6.3 shows that all of the credible options considered have a positive net market benefit. As a consequence, all of the options are ranked higher than the 'do nothing' option, and could be expected to result in an overall net benefit to the market.

Option 6a (Stand-alone control schemes + bus tie) is a clear outlier in terms of net market benefit, with an overall net market benefit orders of magnitude below other credible options. Even with the control scheme in place, which can theoretically increase the thermal limits for the interconnector flows to 690 MW from South Australia to Victoria with future generation added at Krongart (up to 570 MW with existing generation), voltage stability issues would limit this to less than 550 MW. Without the 132 kV network re-arrangements or increased reactive compensation, interconnector flows were found to be frequently limited by other 132 kV network limitations not covered by the control scheme, which in turn limits the benefits associated with this stand-alone option. Further, flows from Victoria to South Australia are not improved in any way under the stand-alone control scheme option, compared to the 'do nothing' option.

It is also evident from the results that the higher costs of Option 3 (new Krongart-Heywood 500 kV interconnector + 275 kV works) are not outweighed by substantially higher benefits, compared to the other options, resulting in the overall net market benefit for this option being materially below that of other options. Similarly, the results show that the lower costs for Option 1a (which includes a 100 MVAr capacitor) do not offset the lower market benefits of this option, compared with Option 1b (which include series compensation), resulting in Option 1a having a lower net market benefit than Option 1b.

The RIT-T assessment also shows that the incremental costs of adding the 3rd transformer at South East substation under Options 2a and 2b are not offset by the additional market benefits. As noted earlier, the re-arrangement of the 132 kV network leads to higher flows on the parallel 275 kV network compared to the base case. This results in lower parallel flow through the South East transformers due to interconnector flows, which reduces the potential scope for additional market benefits from adding the 3rd transformer at South East. Although there are additional benefits available from installing a 3rd transformer under Option 2a, the cost of this transformer was found to outweigh these benefits. However ElectraNet notes that a 3rd transformer at South East is likely to be needed at some point in the future (in the mid-2020s) in order to address reliability concerns. It would therefore be subject to a separate RIT-T at that time.

The results also demonstrate that there are additional net benefits with including the 3rd Heywood transformer (i.e. Options 1a and 1b) compared with only undertaking the 132 kV works in South Australia and installing a 100 MVAr capacitor (i.e. Option 4). The assessment also shows that the additional market benefit associated with including a DM component (i.e. Option 5) is outweighed by the higher cost of that option compared with the network component alone.

Notwithstanding the above conclusions, it is also clear from Table 6.3 that Option 1b (3rd Heywood transformer + series compensation + 132 kV works) and Option 6b (Control schemes + Option 1b minus 3rd Heywood transformer) have the highest net market benefit, but cannot be materially distinguished on this basis alone. Although Option 1b has the greatest net market benefit, the difference between this option and Option 6b is only $0.8m, or 0.39%.

Sensitivity tests

ElectraNet and AEMO have performed a series of sensitivity tests in relation to these results. These sensitivity tests have been expanded from those included in the earlier PADR in order to address specific concerns raised in submissions in relation to the:

- Adoption of a higher discount rate, to address uncertainty.
- Time period adopted for the analysis.
- Accuracy of the network cost assumptions.

- Assumed control scheme costs.
- Quantification of the risks associated with a prolonged outage of a Heywood transformer.

The results of these sensitivity tests are presented and discussed in turn below. In each case, the option with the highest net market benefit is shown in the table in bold print. In summary, given the closeness of the results, the relative ranking of Options 1b and 6b are sensitive to changes in some of these assumptions. However, none of these sensitivity tests resulted in a material difference emerging between the net market benefit of these two options. The ranking of the other options relative to Options 1b and 6b were not sensitive to these tests.

Table 6-4 presents the sensitivity test in relation to the adoption of different discount rates in the NPV analysis. This sensitivity analysis has been expanded from that in the PADR in order to include a further 'high' sensitivity test of 16%, as suggested in some submissions as a means of reflecting the uncertainty of future outcomes. Given the closeness of the results, the relative ranking of Options 1b and 6b are sensitive to changes in the discount rate applied. However the ranking of the other options relative to Options 1b and 6b are not sensitive to these changes, and in no case were these latter options found to have a higher net market benefit than Options 1b and 6b. Moreover, Options 1b and 6b continue to have positive net market benefits, even under a high (16%) discount rate assumption.

Table 6-4: Sensitivity to different discount rates (PV, $m)

Sensitivity	Option 1a	Option 1b	Option 2a	Option 2b	Option 3	Option 4	Option 5	Option 6a	Option 6b
Base: 10% discount rate	164.4	**190.8**	156.9	177.7	90.8	124.9	156.9	1.9	190.0
If 6.13% discount rate applied	328.4	381.9	314.1	358.2	206.4	243.2	338.2	10.9	**383.6**
If 13% discount rate applied	106.0	**122.8**	101.1	113.9	53.3	82.1	94.3	(0.6)	121.4
If 16% discount rate applied	72.8	**84.1**	69.5	77.8	33.6	57.2	59.8	(1.5)	82.6

In response to submissions received on the PADR, ElectraNet and AEMO also investigated whether a shorter assessment period would impact the results of this RIT-T. Specifically, a 20 year assessment period was considered, and was found to have no impact on selection of the preferred option, as shown in Table 6-5. Again, with the exception of Option 6a (stand-alone control scheme), all options were still found to have a positive net market benefit. This is not surprising, given the estimated profile of net market benefits over time, which shows for all options except Option 6a that almost all years post-commissioning return a net market benefit.

Table 6-5: Net market benefit for each credible option assuming a 20 year assessment period (PV, $m)

Sensitivity	Option 1a	Option 1b	Option 2a	Option 2b	Option 3	Option 4	Option 5	Option 6a	Option 6b
Base assessment period	164.4	**190.8**	156.9	177.7	90.8	124.9	156.9	1.9	190.0
20 year assessment period	108.3	**124.5**	101.0	112.6	39.5	86.0	92.5	(3.8)	124.4

Table 6-6 presents the sensitivity analysis in relation to changes in the capital cost estimates used for the network components of each option. The sensitivity test in relation to the network costs has been expanded from that in the PADR and include a +/- 30% change in network costs, in addition to a +/- 10% change. This addresses the concern raised in submissions as to the accuracy of the network costs, and the impact this may have on the identification of the preferred option. Given the closeness of the results, the relative ranking of Options 1b and 6b are sensitive to changes in the assumed network capital costs. However the ranking of the other options relative to Options 1b and 6b are not sensitive to these changes, and in no case were these latter options found to have a higher net market benefit than Options 1b and 6b.

Table 6-6: Sensitivity to different network capital cost assumptions (PV, $m)

Sensitivity	Option 1a	Option 1b	Option 2a	Option 2b	Option 3	Option 4	Option 5	Option 6a	Option 6b
Base	164.4	**190.8**	156.9	177.7	90.8	124.9	156.9	1.9	190.0
If network capital cost estimates increased by 10%	158.6	182.8	149.8	168.5	69.6	121.9	149.7	0.3	**183.8**
If network capital cost estimates decreased by 10%	170.2	**198.8**	163.9	187.0	112.0	128.0	164.1	3.4	196.2
If network capital cost estimates increased by 30%	147.1	166.8	135.7	149.9	27.1	115.7	135.3	(2.9)	**171.3**
If network capital cost estimates decreased by 30%	181.7	**214.7**	178.1	205.5	154.4	134.1	178.5	6.6	208.7

ElectraNet and AEMO also examined what effect different control scheme cost assumptions would have on the relative ranking of Options 1b and 6b, in response to concerns raised in submissions. Specifically, ElectraNet and AEMO examined the following sensitivities for the control scheme costs:

- Exclusion of the communications costs.[102]
- Exclusion of the 25% upward adjustment to DSA costs (both capex and opex).
- Adoption of the high set of control scheme cost assumptions estimated by SP AusNet.

[102] Note that since the $4.5m cost estimate included $500,000 for a second communications path that is required in the low-cost option provided by SP AusNet, only $4m was removed from this sensitivity.

The relative ranking of Options 1b and 6b is shown to be dependent on these assumptions, as shown in Table 6-7 below. However, it is again difficult to materially distinguish a preferred option under each sensitivity i.e., under the low sensitivity, Option 6b has net market benefits 1.36% greater than Option 1b and, under the high sensitivity, Option 1b has net market benefits 2.8% greater than Option 6b.

Table 6-7: Sensitivity to different control scheme cost assumptions (PV, $m)

Sensitivity	Option 1a	Option 1b	Option 2a	Option 2b	Option 3	Option 4	Option 5	Option 6a	Option 6b
Base	164.4	**190.8**	156.9	177.7	90.8	124.9	156.9	1.9	190.0
Low: Excluding $4m communications costs	164.4	190.8	156.9	177.7	90.8	124.9	156.9	5.3	**193.4**
Exclusion of upward adjustment to DSA costs	164.4	190.8	156.9	177.7	90.8	124.9	156.9	4.0	**192.1**
High: SP AusNet high cost assumptions	164.4	**190.8**	156.9	177.7	90.8	124.9	156.9	(2.6)	185.6

Finally, as discussed in section 4.12, preliminary analysis conducted by ElectraNet and AEMO in relation quantifying the market impact of an outage of one of the Heywood transformers, indicates that options involving a 3rd transformer at Heywood could be expected to have an additional probability-weighted market benefit in the order of $5.6m (probability-adjusted, net present value across the assessment period, assuming a 10% discount rate). Whilst recognising that this preliminary analysis was based on an earlier data set, ElectraNet and AEMO note that allowing for an additional benefit of this order of magnitude for Option 1b would increase the amount by which this option is ranked ahead of Option 6b (which does not involve a 3rd Heywood transformer, and so would not realise this benefit). The results of this sensitivity analysis are shown in Table 6-8 below. Again, it remains difficult to materially distinguish a preferred option under each sensitivity, i.e. under the low sensitivity, Option 1b has net market benefits 0.42% greater than Option 6b and, under the high sensitivity, and Option 1b has net market benefits 3.37% greater than Option 6b.

Table 6-8: Sensitivity to additional benefit resulting from a Heywood transformer outage (PV, $m)

Sensitivity	Option 1a	Option 1b	Option 2a	Option 2b	Option 3	Option 4	Option 5	Option 6a	Option 6b
Base	164.4	**190.8**	156.9	177.7	90.8	125.0	156.9	1.9	190.0
Including additional $5.6m benefit	170.0	**196.4**	162.5	183.3	na*	125.0	162.5	1.9	190.0

** Note that the HILP analysis was not conducted for option 3.*

Scenario weightings

ElectraNet and AEMO have also assessed the sensitivity of the results (and in particular the relative ranking of Options 1b and 6b) to the assumed weighting of the reasonable scenarios adopted for the RIT-T analysis.

The following table presents the net market benefit (and ranking) for each credible option across each of the four reasonable scenarios investigated on a standalone basis. The table highlights that Option 1b is ranked 1st under both the central scenario, and the revised central scenario (i.e., the scenario with the lowest demand forecast and the lowest carbon price assumptions). Option 6b is ranked 1st under scenarios 2 and 3.

Table 6-9: Net market benefits estimated under each scenario (PV, $m)

	Scenario 1: Central Scenario		Scenario 2: Low Scenario		Scenario 3: High Scenario		Scenario 4: Revised Central Scenario	
	Net Market Benefit	Rank	Net Market Benefit	Rank	Net Market Benefit	Rank	Net Market Benefit	Rank
Option 1a	86.8	5	251.0	4	206.8	5	174.3	4
Option 1b	**119.3**	1	261.0	3	226.5	2	**204.3**	1
Option 2a	81.0	6	238.0	6	202.0	6	166.1	5
Option 2b	106.6	4	247.9	5	212.3	4	191.5	3
Option 3	78.6	7	232.5	7	137.8	8	35.0	8
Option 4	55.3	8	145.9	8	142.7	7	160.2	6
Option 5	114.3	2	264.6	2	225.5	3	124.4	7
Option 6a	3.2	9	32.2	9	(8.2)	9	(4.5)	9
Option 6b	112.9	3	**279.8**	1	**232.3**	1	198.5	2

The RIT-T assessment is based on a weighting of the gross market benefits across the different scenarios Table 6-10 below shows the difference in the NPV of net market benefit and the relative ranking of Options 1b and 6b under a set of alternative scenario weightings. As discussed in section 4 above, a number of submissions requested that a further reasonable scenario be included in the analysis to reflect a low carbon price as well as low demand. ElectraNet and AEMO note that scenario 4 (i.e. the revised central scenario) includes these assumptions. To this end, ElectraNet and AEMO have included a sensitivity where scenario 4 is given a greater weighting (70%) relative to the other three scenarios and it is shown that these revised weightings do not affect the RIT-T outcome.

The relative ranking of Options 1b and 6b are shown to be dependent on the scenario weightings adopted. If higher weights are given to the high and low scenarios, this increases the weighted market benefit of Option 6b, relative to Option 1b. However, even if the weights of the high and low scenario were increased to 25% each,[103] Option 6b would only have a net market benefit 1.7% higher than Option 1b. ElectraNet and AEMO consider such high weights for the high and low scenarios to be unrealistic, particularly in the light of the announcements in relation to the deferral of the expansion of BHP Billiton's Olympic Dam project and the removal of the floor price under the carbon trading

[103] This calculation assumes that the weights assumed for the other scenarios are also changed to 25% for scenario 1 (central scenario) and 25% for scenario 4 (revised central scenario).

scheme.[104]

If the weighting of the high scenario is decreased to reflect the Olympic Dam announcement, concurrent with increasing the weighting on the revised central scenario to reflect the Federal Government's announcement of the removal of the floor price under the carbon trading scheme, Option 1b would have a 1.5% higher net market benefit than Option 6b.

Table 6-10: Sensitivity to different scenario weightings (PV, $m)

	Net market benefit ($m)		Scenario weighting			
	Option 1b	Option 6b	Central	Low	High	Revised Central
Using current scenario weightings	**190.8**	190.0	29%	13%	17%	41%
50% combined weighting of high and low scenarios	202.8	**205.9**	25%	25%	25%	25%
High scenario decreased and revised central scenario increased	**187.7**	185.8	30%	13%	7%	50%
Increased weighting to revised central scenario	**203.7**	201.5	10%	10%	10%	70%

ElectraNet and AEMO note that sensitivities conducted in relation to the weightings applied to each of the scenarios indicate that the RIT-T outcome is robust to a wide-range of alternative weightings.

Other sensitivities

ElectraNet and AEMO have performed further analysis in relation to Options 1b and 6b to investigate whether adoption of a different reference year for the load traces used in the dispatch modelling[105] would materially affect the relative net market benefits of these two options. This analysis showed that adopting a different reference year does not help to distinguish between the two options.

Similarly, studies conducted in relation to the potential competition benefits associated with these options (discussed in section 6.4) also indicated that the quantification of competition benefits would not provide a robust basis on which to distinguish between these options.

Conclusions

In light of the results discussed above, ElectraNet and AEMO consider that the net market benefit of Option 1b and Option 6b are essentially equal. Neither option emerges as materially ahead of the other under any of the sensitivity analyses, or across any of the scenarios.

ElectraNet and AEMO note that there are core investment elements which are common to both Option 1b and Option 6b, namely reconfiguration of the 132 kV network between Snuggery-Keith and Keith-Tailem Bend (South Australia), 275 kV series compensation in South Australia and the installation of a bus tie at Heywood. These investment components therefore clearly form part of the preferred option.

[104] BHP Billiton's announcement in August 2012 that it has deferred the expansion of its Olympic Dam project would potentially support applying a lower weight to the high scenario in the RIT-T. The Federal Government's announcement of he removal of the floor price under the carbon trading scheme (also in August 2012) would potentially support applying a higher weight to the revised central scenario, which is the scenario which incorporates the lowest carbon price assumption.

[105] As set out in sec ion 5.3.2, the Prophet model has been run using load traces from 2009/10. Sensitivity of the results for Options 1a and 6b to the adoption of load traces for 2005/6 and 2007/8 were also conducted, as noted above.

The question is therefore whether these 'core' network components should be coupled with a 3rd transformer at Heywood (i.e. Option 1b) or network control schemes (i.e. Option 6b).

In relation to Option 6b, ElectraNet and AEMO note that the inclusion of series compensation and 132 kV re-arrangements as part of this option overcomes the voltage and thermal limitations discussed above in relation to the stand-alone control scheme option (i.e. Option 6a), to allow the control scheme to fully utilise the non-firm ratings of the Heywood transformers and South East to Heywood lines. The series compensation also improves the voltage stability limits for Victoria to South Australia when compared to the base case. Although still limited to 460 MW Victoria to South Australia, this full 460 MW is able to be better utilised, so realising benefits for additional flows in this direction.

The impact of the control schemes is to expand the export capacity from South Australia at lower cost than under the 3rd Heywood transformer. Option 6b therefore has greater market benefits under those scenarios in which there is substantial investment in renewable generation (particularly geothermal generation) in South Australia, i.e. the high and low scenarios. In contrast, adding a 3rd transformer at Heywood increases both the import and export capability of the interconnector. It therefore enables additional exports from South Australia, albeit at a lower level that is facilitated by the control schemes, whilst also enabling increased imports of lower cost generation into South Australia. The market benefits associated with this option (i.e. Option 1b) continue to be present (and indeed increase) in scenarios of low demand and low carbon pricing (i.e. scenario 4).

ElectraNet and AEMO note that there is substantial uncertainty in relation to the commercial feasibility of the control schemes, as issues relating to liabilities and associated indemnities would need to be worked through. It is anticipated that significant further work would be required, with an uncertain outcome, since initial investigation of commercial issues indicates that the commercial issues are not straightforward. The issue of technical feasibility would also need to be subject to further detailed investigation, particularly in relation to issues of wider system security and the overload ratings of the Heywood transformers.

ElectraNet and AEMO also note the higher transfer capacity associated with Option 6b is predicated on there being additional wind generation locating near Krongart. However, there remains substantial uncertainty surrounding these developments, with no proposals for new generation currently nearing committed status. ElectraNet and AEMO note that Infigen's Woakwine Wind Farm, which is located near Krongart, is currently classified by AEMO as 'publically announced only', meaning that it satisfies less than three of the AEMO commitment criteria.

Given that the RIT-T analysis has not shown that there would be substantial additional benefits associated with adopting the control scheme rather than a 3rd Heywood transformer, ElectraNet and AEMO do not consider that the additional time and costs taken to conclusively address the uncertainties identified above would be warranted. Undertaking this assessment would delay the finalisation of the current process, and the time at which the investment could be implemented. The RIT-T analysis has shown that Option 1b is expected to deliver market benefits from the year in which it is commissioned. Delay in making an investment decision would deprive the market of these benefits.

ElectraNet and AEMO note that proceeding with Option 1b does not preclude the potential addition of either or both of the Heywood and South East transformer control schemes. However deferring development of these components represents a prudent staged approach to augmenting the Heywood interconnector capability.

In light of the uncertainties associated with selecting the control scheme component in preference to adding a 3rd transformer at Heywood, ElectraNet and AEMO have determined that the preferred option for investment is Option 1b: installation of a 3rd transformer at Heywood and 500 kV bus tie, plus 275 kV series compensation in South Australia and reconfiguration of the 132 kV network between Snuggery-Keith and Keith-Tailem Bend (South Australia).

ElectraNet and AEMO consider that this is a prudent decision, taking into account the RIT-T assessment and the additional uncertainty associated with Option 6b. The transformer is a lower risk option that performs equally as well in the assessment of market benefits and satisfies the RIT-T.

The economic benefits of further expanding interconnector capacity will be subject to ongoing review by AEMO and ElectraNet through established national and joint planning processes.

6.4 Competition benefits

Competition benefits are defined in the RIT-T as 'net changes in market benefit arising from the impact of the credible option on participant bidding behaviour'. [106]

A lack of competition between generators can lead to one or more of the following outcomes:

- Non-optimal dispatch: cheap generation may be withheld, and replaced by more expensive peaking generation.
- Reduced consumption: higher electricity prices as a result of non-competitive outcomes lead to less consumption and therefore lower utility for electricity consumers, whether residential or commercial/industrial.
- Over investment in generation: inflated prices may bring forward unnecessary investments in generation that would have been uneconomic under a competitive market.

Where a credible option results in changes in participant bidding behaviour, market benefits can arise as a result of improvements in each of the above areas.

Changes in bidding behaviour can also lead to substantial wealth transfers between market participants. However wealth transfers between participants in the NEM are not counted as a market benefit under the RIT-T.

There are substantial challenges with quantifying competition benefits, as it requires assumptions about current and future generator contracting levels, future ownership of generating plant and the price elasticity of demand for electricity. The results are likely to be sensitive to these assumptions and any comprehensive study would need to cover a wide range of sensitivities, reflecting a range of possible futures, in order to derive a robust value. In addition, the complexity of the modelling requires approximate methods to be used, which leads to an uncertainty band around the results.

Due to the complexity of the modelling, quantifying competition benefits is therefore likely to be disproportionate to the scale, size and potential benefits of each credible option considered in the RIT-T analysis, unless competition benefits are expected to be significant and to materially affect the outcome of the RIT-T assessment. [107]

6.4.1 Competition benefit studies

ElectraNet and AEMO have explored a limited number of futures in order to test the likely magnitude of the competition benefits that may be associated with the credible options considered in relation to this RIT-T. This modelling has focussed on estimations of the consumer surplus benefits attributable to changes in consumption.

[106] AER (2010): *Regulatory Investment Test for Transmission*, June 2010, para (5)(h).

[107] The RIT-T requires a TNSP to calculate all classes of market benefits in a RIT-T assessment, unless it can provide reasons why a par icular class of market benefit is not likely to materially affect the RIT-T outcome, or where the estimated cost of undertaking the analysis the quantify the market benefit is likely to be disproportionate to the scale, size and potential benefits of each credible option considered in the analysis (NER 5.16.1(c)(6)). For the purposes of the RIT-T, a class of market benefits is judged to be material if it would alter the ranking of alternative op ions or if it would change he sign of the preferred option's net benefit.

The studies used the Nash-Cournot algorithm in Energy Exemplar's PLEXOS modelling software. Extensive testing was undertaken to ensure that the results from the PLEXOS model were comparable with the outputs from AEMO's Prophet model.

ElectraNet made the following assumptions as part of its initial quantification of competition benefits:

- The Price Elasticity of Demand (PED) estimates published by AEMO in its 2012 NEFR were used. The price elasticity published in this report applies to retail electricity prices. ElectraNet scaled these values by forty per cent to reflect the contribution of the spot price to the retail price.[108]
- New entrant generation was assumed to be unattached to any existing portfolio. The implication of this assumption is that competition benefits will reduce over time. As a consequence, ElectraNet has focussed on the first 10 years of the proposed augmentation's life.
- Generation contracting levels have been assumed to be at 90%.

An idealised network model was used which incorporates nominal interconnector limits between the regions but does not enforce the full range of network constraints on dispatch. Testing comparing this idealised model to the outcomes from AEMO's Prophet model indicated that use of the idealised model did not significantly affect results.

Competition benefits were tested only for the central scenario. Given that there was no prior expectation that a particular scenario would drive any more or less competitive outcomes, use of the central scenario was considered appropriate for this exercise.

The studies performed have shown that the magnitude of competition benefits associated with the credible options considered in this RIT-T is very low. Competitive bidding under the Nash-Cournot algorithm led to higher prices when compared to SRMC pricing. These higher prices in turn led to a reduction in consumption. With the credible options in place, prices were lower, and consumption higher. However, the change in the regions expected to be most influenced by the augmentation (Victoria and South Australia) were small, and hence changes in consumption and consumer surplus in these regions were also small. Price impacts did extend beyond these regions; however these were found to be smaller again. Further, changes in consumption were found to be volatile over the years, demonstrating a high level of variability in outcomes.

ElectraNet and AEMO note that the finding that competition benefits are relatively small in the context of this RIT-T is unsurprising. NERA[109] suggests the two following conditions as necessary for competition benefits to arise:

1. There must exist non-competitive bidding strategies in at least one of the relevant spot markets (or, to the extent that intra-regional transmission constraints exist, in some subsets of that spot market) which result in prices being above marginal cost for a sustained period; and
2. There must be some change in either the outcome of the non-competitive bidding strategy or in the bidding strategy itself as a result of the option being considered, such that spot market prices fall closer to marginal costs.

[108] That the values in the AEMO report are comparable to he PED values published by Monash University for South Australia.

[109] NERA (2011): *Assessing Competition Benefits under the RIT-T*, May 2011.

In relation to the first condition, the AEMC's draft determination on market power in the NEM[110] has studied evidence in relation to the extent of sustained market power in the NEM. Referring to several consultants' reports, the AEMC concludes that:

> *In consideration of the lack of evidence from NERA's analysis supporting the existence of substantial generator market power, and the lack of firm evidence from CEG's analysis supporting the existence of significant barriers to entry, the Commission considers that there are insufficient grounds to conclude the existence of substantial market power and to assume the likely future exercise of substantial market power by generators in the NEM.*

This suggests the competition benefits, if any, are likely to be moderate at best for many RIT-T assessments.

The second condition requires that the options considered in the RIT-T must be able to affect the outcome of generator bidding behaviour. This suggests that competition benefits are more likely to occur for larger upgrades. Incremental upgrades may have no significant impact on the ability of generators to exercise market power, meaning that competition benefits are likely to be more limited for such upgrades. In the case of this RIT-T, many of the credible options represent incremental upgrades of capacity. The exception is Option 3 (new Krongart-Heywood 500 kV interconnector + 275 kV works), but even for this option ElectraNet's analysis indicates that the extent of market benefits is of an order of magnitude that would not affect the ranking of this option against the other credible options.

Given the findings from the competition benefit studies, ElectraNet and AEMO have concluded that competition benefits are not material for this RIT-T, and that the quantification required would be disproportionate to the expected level of such benefits. Of the two top-ranked options from the analysis excluding competition benefits, Option 1b (which includes the 3rd Heywood transformer) would be expected to have greater competition benefits than Option 6b (which includes the control schemes), as Option 1b increases the capacity of the interconnector in both directions. However, both of the two top-ranked options relate to relatively small incremental increases in capacity, and therefore the magnitude of competition benefits associated with these options would be relatively low. The significant uncertainty band surrounding any quantification of competition benefits, coupled with this relatively low magnitude, therefore means that it would not be reasonable to distinguish between the two options on this basis alone.

[110] AEMC (2012): *Draft Rule Determination - Potential Generator Market Power in the NEM*, June 2012.

7 Proposed preferred option

The previous section has presented the results of the NPV analysis conducted for this RIT-T assessment.

The NER requires the PACR to include the identification of the preferred option under the RIT-T.[111] This should be the option with the greatest net market benefit and which is therefore expected to maximise the present value of the net economic benefit to all those who produce, consume and transport electricity in the market.

The RIT-T analysis (discussed in section 6.3.2) indicates that Option 1b (3rd Heywood transformer + 275 kV series compensation + 132 kV works) and Option 6b (Control schemes plus Option 1b, minus 3rd Heywood transformer) have the same net market benefit, and are ranked substantially ahead of all other credible options.

ElectraNet and AEMO note that there are core investment elements which are common to both Option 1b and Option 6b, namely reconfiguration of the 132 kV network between Snuggery-Keith and Keith-Tailem Bend (South Australia), 275 kV series compensation in South Australia and the installation of a bus tie at Heywood.

There are a number of additional uncertainties associated with selecting the control scheme component in addition to the above core elements in preference to adding a 3rd transformer at Heywood, predominantly in relation to the commercial and technical feasibility of this component. Given that the RIT-T analysis has not indicated that the control scheme component would result in substantial additional market benefits, compared to the 3rd Heywood transformer, ElectraNet and AEMO have determined that the additional cost of confirming the commercial and technical feasibility of this option would not be warranted. The 3rd Heywood transformer has therefore been selected in preference to the control schemes, as the additional component of the preferred option.

The preferred option for investment is therefore Option 1b: installation of a 3rd transformer at Heywood and 500 kV bus tie, plus 275 kV series compensation in South Australia and reconfiguration of the 132 kV network between Snuggery-Keith and Keith-Tailem Bend (South Australia). This option has a positive net market benefit and satisfies the RIT-T.

The estimated commissioning date for this option is July 2016. The total capital cost of the option is estimated at $107.7m ($2011/12, equating to $79.8m in present value terms), reflecting $45.0m investment in Victoria and $62.7m in South Australia. The net market benefits of this option are more than $190 million (in present value terms) over the life of the project with positive net benefits commencing from the first year of operation.

The technical characteristics of this option have been set out in section 3. In compliance with the NER provisions,[112] ElectraNet and AEMO note that this option is likely to have a material inter-regional impact between South Australia and Victoria only.

[111] NER 5.16.4(k)(8).

[112] NER 5.16.4(k)(9)(iii).

Appendix A. Checklist of compliance clauses

This section sets out a compliance checklist which demonstrates the compliance of this PACR with the requirements of clauses 5.16.4(v) and 5.16.4(k) of the NER version 54.

NER clause	Summary of requirements	Relevant section in PACR
5.16.4(v)	The project assessment conclusions report must set out: • the matters detailed in the project assessment draft report as required under paragraph (k) • a summary of, and the Transmission Network Service Provider's response to, submissions received, if any, on the project assessment draft report.	See below 4
5.16.4(k)	A Transmission Network Service Provider must prepare a project assessment draft report, which must include:	
	• a description of each credible option assessed;	3
	• a summary of, and commentary on, the submissions to the *Project Specification Consultation Report*;	4
	• a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each *credible option*;	3 6.1 6.2 Appdx H
	• a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	5 6.2
	• the reasons why the TNSP has determined that a class or classes of market benefit are not material, where relevant;	5.6
	• the identification of any class of market benefit estimated to arise outside the TNSP's region and quantification of the aggregate value of such market benefit;	6.2.1 6.2.2 6.2.3 6.2.4
	• the results of an NPV analysis of the net market benefit of each *credible option* and accompanying explanatory statements regarding the results;	6.3 Appdx H

NER clause	Summary of requirements	Relevant section in PACR
5.16.4(k)	• the identification of the proposed *preferred option* and a statement that the *preferred option* satisfies the RIT-T: - details of the technical characteristics; - the estimated construction timetable and commissioning date; - if the option is likely to have a material inter-regional network impact; and - an augmentation technical report (if the TNSP has received such a report from AEMO).	7

Appendix B. Definitions

All laws, regulations, orders, licences, codes, determinations and other regulatory instruments (other than the Rules) which apply to Registered Participants from time to time, including those applicable in each participating jurisdiction as listed below, to the extent that they regulate or contain terms and conditions relating to access to a network, connection to a network, the provision of network services, network service price or augmentation of a network.

A comprehensive list of applicable regulatory instruments is provided in the NER.

Applicable regulatory instruments	
AEMO	Australian Energy Market Operator
Base case	A situation in which no option is implemented by, or on behalf of the transmission network service provider.
Commercially feasible	An option is commercially feasible under clause 5.15.2(a)(2) of the Electricity Rules if a reasonable and objective operator, acting rationally in accordance with the requirements of the RIT-T, would be prepared to develop or provide the option in isolation of any substitute options. This is taken to be synonymous with 'economically feasible'. Costs are the present value of the direct costs of a credible option.
Credible option	A credible option is an option (or group of options) that: • address the identified need; • is (or are) commercially and technically feasible; and • can be implemented in sufficient time to meet the identified need.
Economically feasible	An option is likely to be economically feasible where its estimated costs are comparable to other credible options which address the identified need. One important exception to this general guidance applies where it is expected that a credible option or options are likely to deliver materially higher market benefits. In these circumstances the option may be "economically feasible" despite the higher expected cost. This is taken to be synonymous with 'commercially feasible'.
Identified need	**Identified need** means the objective a *Network Service Provider* (or in the case of a need identified through joint planning under clause 5.14.1(d)(3) or clause 5.14.2(a), a group of *Network Service Providers*) seeks to achieve by investing in the *network*.
Market benefit	Market benefit must be: (a) the present value of the benefits of a credible option calculated by:

Applicable regulatory instruments	
	(i) comparing, for each relevant reasonable scenario: (A) the state of the world with the credible option in place to (B) the state of the world in the base case, **And** (ii) weighting the benefits derived in sub-paragraph (i) by the probability of each relevant reasonable scenario occurring. (b) a benefit to those who consume, produce and transport electricity in the market, that is, the change in producer plus consumer surplus.
Net economic benefit	Net economic benefit equals the market benefit less costs.
Preferred option	The preferred option is the credible option that maximises the net economic benefit to all those who produce, consume and transport electricity in the market compared to all other credible options. Where the identified need is for reliability corrective action, a preferred option may have a negative net economic benefit (that is, a net economic cost).
Reasonable scenario	Reasonable scenario means a set of variables or parameters that are not expected to change across each of the credible options or the base case.

Appendix C. Reasonable scenario assumptions

This appendix provides further information in relation to key parameters incorporated in the reasonable scenarios adopted for the RIT-T analysis and discussed in section 5.4 of this report.

C.1 Electricity demand projections

Demand projections used in the 2010 NTNDP scenarios were based on the 2009 ESOO projections.

For this RIT-T, new load profiles have been grown using the 2009/10 base year, and the following ESOO 2011 demand projections:

- Scenario 1 – based on 2011 ESOO medium economic growth demand projections.
- Scenario 2 – based on 2011 ESOO low economic growth demand projections.
- Scenario 3 – based on 2011 ESOO high economic growth demand projections.

Varying assumptions around electric vehicle uptake and the potential for additional new step-loads in South Australia (Olympic Dam/Eyre peninsula) have then been imposed on these base demand forecasts, as discussed below.

For scenario 4, the electricity demand projections are based on the medium forecasts in the 2012 NEFR.

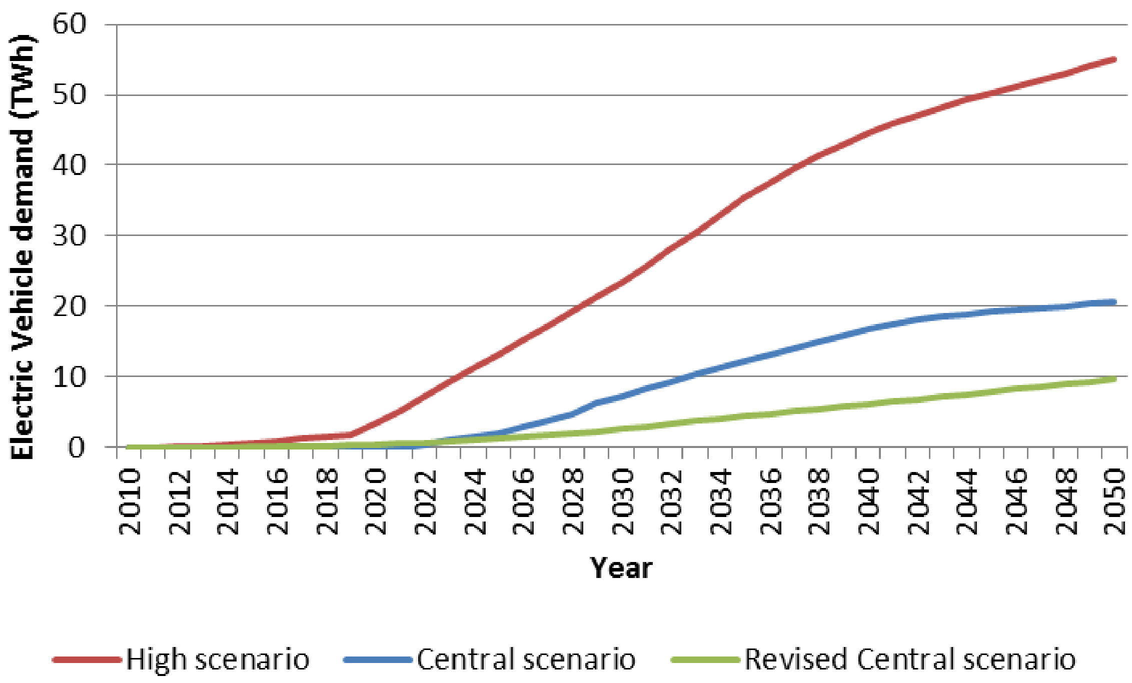
Electric vehicles

New electric vehicle assumptions have recently been derived by CSIRO for AEMO for the five NTNDP scenarios.

The electric vehicle demand projections for the central and high scenarios are summarised in Figure C-1 below. In the low scenario, no electric vehicle uptake is assumed.

For the revised central scenario, a moderate adoption of electric vehicle uptake has been assumed, consistent with the 2012 NEFR.

Figure C-1 : Proposed electric vehicle uptake per scenario



Additional Eyre Peninsula/Olympic Dam demand

The 'high scenario' also reflects additional electricity demand in South Australia as a result of developments at Olympic Dam and on the Eyre Peninsula.

Specifically, assumptions have been made in relation to the expected increase in mining load on the Eyre Peninsula, based on connection enquiries which ElectraNet has received to date. Whilst the precise details of these connection enquiries are confidential, for the purposes of this RIT-T ElectraNet and AEMO have made the following indicative assumptions in relation to the mining and supporting loads:

- 192 MW, 1 July 2015.
- 180 MW, 1 July 2016.

In addition, the high scenario assumes an expansion of the existing Olympic Dam mine. While recent announcements indicate that this expansion is unlikely in the short term, under a scenario with high economic growth, it may still be a plausible option.

Currently Olympic Dam uses 125 MW, supplied by a 275 kV line from Davenport. A 132 kV transmission line from Pimba is used for stand-by capacity.[113]

Operational post expansion loads are expected to increase by approximately 641 MW in South Australia. The table below presents data from BHP Billiton included in the Environmental Impact Statement, highlighting types of loads, location, energy and maximum demand forecasts. In

[113] Olympic Dam Environmental Impact Assessment Section 5.8.1 page 156.

addition there is a 250 MW cogeneration facility that is expected to grow at the same rate as the loads below.

Table C-1: BHP Billiton energy and demand forecasts

Description	Location	Maximum demand	Annual energy	Load factor
Open pit mine	Open pit mine	95	283	34%
New concentrator	Flat	300	2365	90%
New hydrometallurgical	Flat	40	315	90%
Expanded smelter	Flat	3	24	91%
Expanded refinery	Flat	12	95	90%
New on-site admin	Variable	4	18	51%
Acid plant	Flat	42	331	90%
Process infrastructure	Flat	20	158	90%
TOTAL ON-SITE		**516**		
Desalination plant	Flat	35	245	80%
Water supply pipeline	Flat	22	154	80%
Transmission losses	Removed	7	61	99%
Pimba intermodal	Variable	3	16	61%
Port – Darwin	Removed	5	26	59%
Port – Outer Harbour	Variable	5	26	59%
Land facility	Variable	2	11	63%
Airport	Variable	1	4	46%
Roxby Downs	Variable	42	184	50%
Hiltaba Village	Variable	8	35	50%
TOTAL OFF-SITE		**130**		

These loads have been grouped into three categories: flat loads, variable loads and the open pit mine. This information has been summarised as follows in figures 2 for maximum demand. This summary has been used to simplify the above data to assist in identifying the relevant load shapes for fitting.

Table C-2: Load characteristics to be modelled

Summary	Capacity	Energy	Load Factor
Flat	474	3687	89%
Cogeneration facility*	(250)	(2,081)	95%
TOTAL	224	1,607	
Variable	65	294	52%
Open pit mine	95	283	34%
NET	384	2,184	

* Cogeneration assumptions are presented in Table C-3 below.

Modelling of the 224 MW flat load additions have been based on the load shapes at Olympic Dam. Specifically Olympic Dam West 275 kV and 132 kV transformers 1 and 2 (S179) have been chosen. This is a flat load profile with a load factor that is 84 per cent, which is close to the 89 per cent across the flat loads.

The 65 MW variable loads are scattered over a wide geographical area leading to the potential for local weather effects. It is noted that most variable loads are centred on Roxby Downs. There is no comparable load shape currently at Roxby Downs. Further, some of the loads represent different electrical usage patterns. Loads with the same usage characteristics (such as time of day) are not known and are unlikely to lead to sufficient value in separating the credible options to develop.

The load at Playford has been selected as the best proxy. It has similar load factor characteristics to BHP Billiton's forecasts at 44 per cent. It is likely to experience weather effects similar to Roxby Downs. It is, however, much smaller than the loads being modelled.

There is not a load shape that reasonably fits with the load characteristics of the open pit mine, with a large maximum demand of 95 MW but a relatively low load factor of 34 per cent. A load trace that matches these characteristics is still under development.

The timing of this load is subject to three stages as identified in the Olympic Dam EIS. These steps occur at year 6, 9 and 11 representing the mine reaching 20, 40 and 60 million tonnes of ore per annum. The cogeneration unit is assumed to grow at the same rates as the loads. Year 1 is taken as starting on 1 July 2012. Table C-3 presents the timing and size of the additional loads.

Table C-3: Timing of energy and demand increases

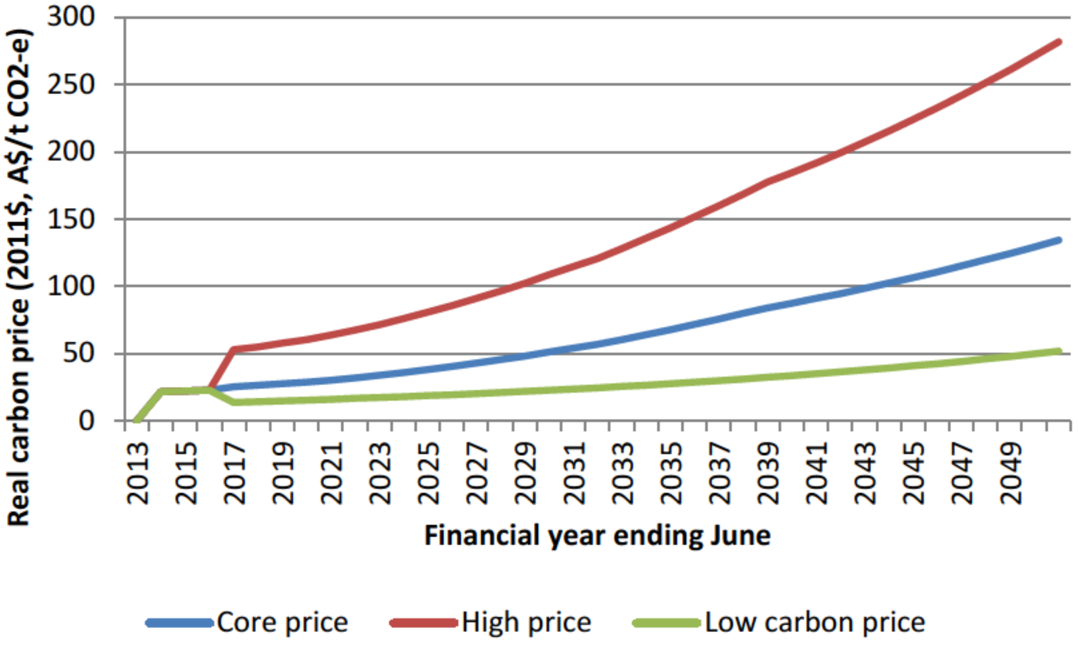
Timing	2018		2021		2023	
Percentage	33%		66%		100%	
	Capacity (MW)	Energy (MWh)	Capacity (MW)	Energy (MWh)	Capacity (MW)	Energy (MWh)
Flat	74	530	148	1,060	224	1,607
Variable	21	97	43	194	65	294
Open pit mine	31	93	63	187	95	283
Total	**126**	**720**	**254**	**1,441**	**384**	**2,184**

C.2 Carbon price

The carbon price assumed in the Prophet modelling for each scenario is consistent with Federal Government's Clean Energy Policy, as shown in Figure C-2 below.

The figure also shows the 'carbon floor' price path included in the fourth scenario (Revised central scenario). The carbon floor price path reflects three years of a fixed carbon price, and the current legislated carbon floor continuing beyond 2017 (assumed to be $15/tonne rising annually at 4%).

Figure C-2: Carbon prices assumed



Source: Clean Energy Policy, http://archive.treasury.gov.au/carbonpricemodelling/content/chart_table_data/chapter5.asp

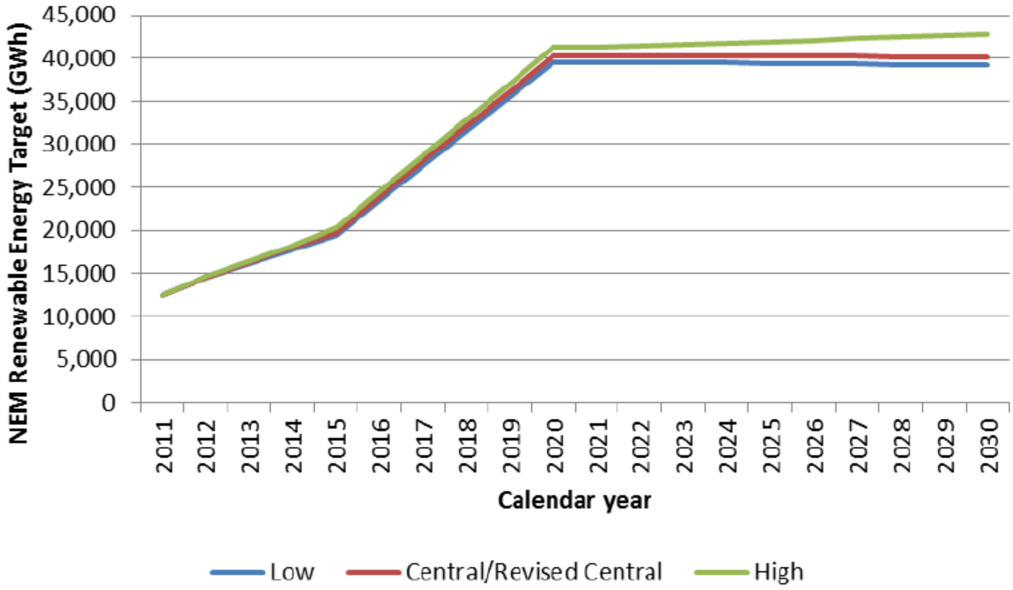
C.3 Renewable Energy Target

For the purpose of the RIT-T analysis, the percentage of the national LRET apportioned to the NEM has been based on the ratio of NEM energy relative to the total energy consumption in Australia which, in 2009/10, was 0.89.[114] Therefore, the assumed NEM share of the LRET is 89%.

The NEM equivalent renewable energy target consists of a portion of the national large-scale renewable energy target (LRET), projections of GreenPower sales, and commitments from desalination plant in South Australia and New South Wales to purchase energy from renewable generation sources. This target differs slightly for each of the Heywood RIT-T scenarios, as shown in Figure C-3, with the main difference being attributed to variations in projections of GreenPower sales. The target for scenario 1 (central) and scenario 4 (revised central) are the same. In scenario 4, the renewable energy target also includes commitments from the Olympic Dam desalination plant to purchase energy from renewable generation sources.

[114] ABARE: "Australian Energy Statistics - Energy update 2011". 2009/10 reflects the most recent information available at the time at which the modelling for this RIT-T was undertaken.

Figure C-3: NEM renewable energy target assumed for each scenario.



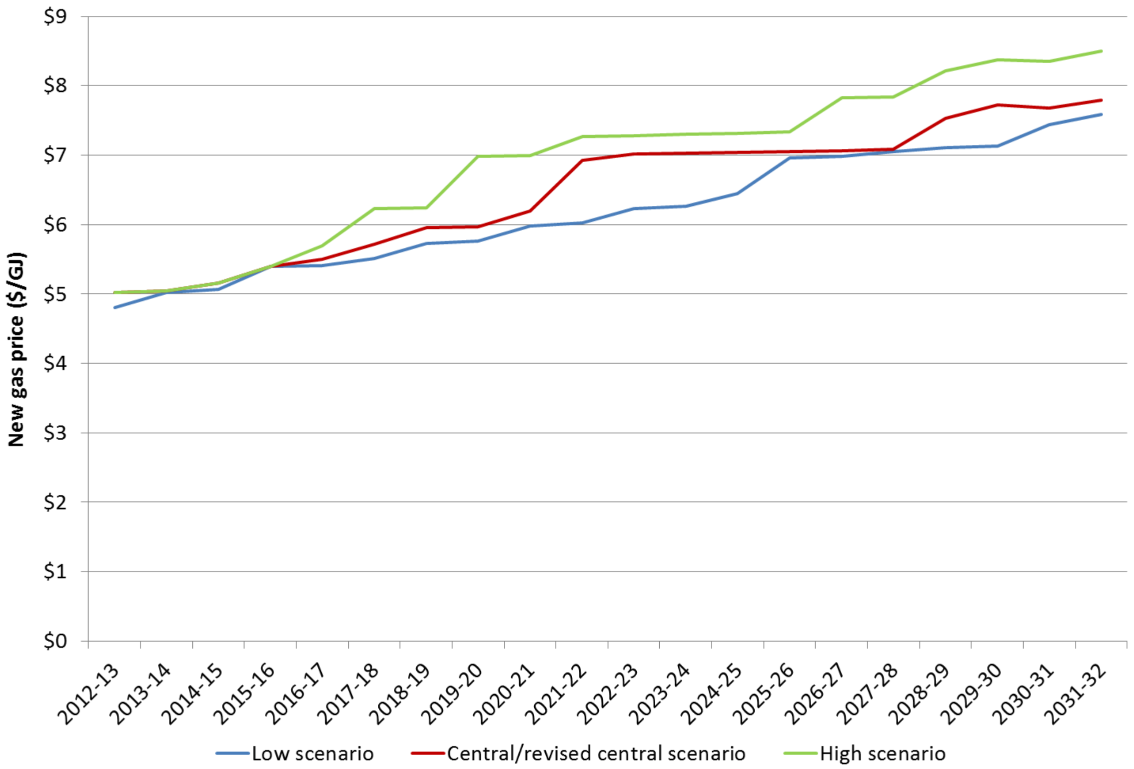
C.4 Gas prices

The following NTNDP scenarios have been used for the fuel price assumptions:

- Scenario 1 (central scenario) and Scenario 4 (revised central scenario) – using gas and coal prices from the Decentralised World.
- Scenario 2 (low scenario) – using gas and coal prices from Uncertain World.
- Scenario 3 (high scenario) – using gas and coal prices from Fast Rate of Change.

To demonstrate the range of gas prices covered in these three scenarios, Figure C-4 shows the gas prices assumed for new CCGT plant locating in central Victoria.

Figure C-4: New gas prices for new central Victorian CCGT



C.5 Technology timings and contribution of wind to peak demand

The following assumptions reflect the 'central view' of the availability of new technologies. In some cases these reflect updated assumptions from those used in the 2010 NTNDP:

- Based on the Worley Parsons technology assumptions draft report prepared for AEMO for the 2012 NTNDP,[115] the first year available for geothermal construction in South Australia is 2015, with a five year construction period. Therefore, the earliest date for geothermal generation in South Australia is assumed to be July 2020.
- For Victoria, given that the projects are not as far advanced in this region, it is assumed that nothing of scale is constructed prior to the commissioning of the first units in South Australia. Therefore, the earliest date for geothermal generation in Victoria and all other states is July 2025.
- 200 MW annual geothermal build limit per State, as per Worley Parson's draft report.
- Earliest date of operation for carbon capture and storage (CCS) technologies is assumed to be 1 July 2024, based on the draft Worley Parson's report.
- Size of new CCGTs reduced from 700 MW per unit to 250 MW per unit in South Australia and Tasmania and to 350 MW per unit in the other regions.
- CCS cost and efficiency parameters have been revised, and Victorian IGCC with CCS is now included as an option for consideration in the study.

[115] The draft report was the most recent report available at the time at which the modeling for this RIT-T assessment was undertaken. http://www.aemo.com.au/en/Electricity/Planning/2012-National-Transmission-Network-Development-Plan-Consultation

- Limit solar thermal new entry in the first round of the Solar Flagship Program to 400 MW total, and only allow units to be built in NSW and Queensland. Relax this limit to 1,000 MW and allow other states to participate in the second round of funding from 1 July 2016.

For scenarios 1, 2 and 3, the assumptions made in relation to the contribution of wind generation to peak demand are consistent with the 2011 NTNDP assumptions.

In scenario 4 the 2012 NTNDP assumptions have been used, which reflect an increased contribution. Preliminary analysis in the 2012 NTNDP has shown that, using the new peak contribution factors, there is a shift of new wind generation investment from NSW to South Australia. Since this may impact on the RIT-T outcome, it was decided to use these new figures in market modelling runs for scenario 4.

Appendix D. Modelling inputs

This appendix provides additional information in relation to some of the assumptions used in the market modelling described in section 5.3. In general, inputs have come from the 2010 NTNDP. This appendix documents those assumptions that have diverged from the 2010 NTNDP assumptions.

D.1 Base years

Wind and demand profiles for the long term simulation are using profiles based on the 2009/10 financial year. Wind output is scaled so that the average capacity factor per tranche is equal to the ACIL Tasman assumptions provided for the 2010 NTNDP.

The 2009/10 wind profiles lie close to the average capacity factor for all wind bubbles over the range 2002/03 to 2009/10 and are hence the most suitable for the expansion plan.

To test the sensitivity of market benefits to base profile used, for the two preferred options time sequential runs have also used 2005/06 profiles and 2007/08 profiles with equal weighting across the three base years. These profiles have also been scaled, using the same scalars as for the 2009/10 profiles. The three years experienced a range of demand conditions with respect to peak demand across the south east of Australia. The 2009/10 year has relatively high NSW and SA demand at time of Victorian peak demand. The 2005/06 year has relatively low SA and NSW demand at time of Victorian peak demand, and the 2007/08 year falls somewhere in the middle with high SA demand but relatively low NSW demand at time of Victorian peak demand. Additionally all three years are relatively recent, maintaining as close as reasonable relationship with current demand patterns.

D.2 Probability of exceedance (POE)

Demand traces have included both 50 POE and 10 POE peak demand conditions with weightings of 69.6 per cent and 30.4 per cent respectively.[116]

[116] The 2010 NTNDP consultation paper, appendix B, details these weightings (p. 5): http://www.aemo.com.au/en/Electricity/Planning/~/media/Files/Other/planning/0418-0004%20pdf ashx. They are also repeated in the 2012 NTNDP consultation methodology and assumptions paper (p.10): http://www.aemo.com.au/en/Electricity/Planning/~/media/Files/Other/planning/2418-0002%20pdf ashx.

D.3 Minimum generation levels

Some minimum generation levels have been reduced from the 2010 NTNDP. The table below identifies only those assumptions that have changed.

Table D-1: Minimum generation levels (variations from 2010 NTNDP)

Station	Capacity (MW)	Minimum generation assumed in RIT-T (MW)
Yallourn 1	350	216
Yallourn 2	350	216
Yallourn 3	350	228
Yallourn 4	350	228
Loy Yang B1	500	262.5
Loy Yang B2	500	262.5
Anglesea	150	79
Loy Yang A1	560	435
Loy Yang A2	500	397.5
Loy Yang A3	560	435
Loy Yang A4	560	435
Northern 1	273	60*
Northern 2	273	60*

***** Based on observed behaviour***

D.4 New entry costs

The market modelling uses cost assumptions for all generators as per the ACIL Tasman data for:

- Capital costs.
- Fuel costs.
- Fixed operating and maintenance costs.
- Variable operating and maintenance costs.

Connection costs for wind generation were based on the assumptions used in the 2010 NTNDP. Two alternative sets of connection costs were also developed: one set assuming that the same size generator connects at all voltages and the other set assuming that larger generators connect at the higher voltage. Sensitivity tests indicated that the resulting changes in the modelled planting schedules relatively small, and that the 2010 NTNDP assumptions were therefore fit for purpose.

D.5 Network modelling

The following assumptions have been made in relation to network developments which may impact flows over the Heywood interconnector:

Murraylink:

- A new Ballarat-Moorabool 220 kV line upgrade occurs in 2016/17 (RIT-T currently in progress).
- The existing Ballarat-Bendigo 220 kV line is uprated in 2016/17 (RIT-T currently in progress).
- New 275 kV supply to Riverland area in SA in 2025/26 (as per ElectraNet APR).

Heywood:

- New Moorabool-Mortlake/Heywood 500 kV line when new generation along line exceeds 2500 MW (as per NTNDP and VAPR).

The following tables provide a summary of ratings of selected circuits, a description of impacted constraints and the impact of selected existing constraints.

Table D-2: Summary of ratings of selected circuits

Element	Continuous rating (MVA)	Post contingent rating (MVA)	Notes
Heywood 500/275 kV transformers	370	525	Post contingent reactive flows require a 460 MW limit for these transformers
Heywood-South East 275 kV lines	591-675 503-644	 591-772	Seasonal ratings for South Australian side Temperature dependant rating for Victorian side
South East-Tailem Bend 275 kV lines	591-675	-	Seasonal ratings
Tailem Bend - Keith #1 132 kV line	60-97	-	Seasonal ratings
Tailem Bend - Keith No 2 132 kV line	178-221	-	Seasonal ratings
Keith – Snuggery 132 kV line	60-97	97*	Seasonal ratings
South East 275/132 kV transformers	160	-	
Heywood-Moorabool/Mortlake 500 kV lines	2,043	-	Protection limit

* Some of the line ratings on the South Australian side are design ratings and would require plant and protection upgrades to get to the ratings shown above.

Table D-3: Description of selected impacted constraints

Constraint	Description
S:V_580	Combined Murraylink and Heywood limit for export from South Australia to Victoria due to oscillatory stability
S>V_NIL_HYTX_HYTX	Prevent overload of a Heywood 500/275 kV transformer for the trip of the parallel transformer, with flow South Australia to Victoria
V>S_460	Prevent overload of a Heywood 500/275 kV transformer for the trip of the parallel transformer, with flow Victoria to South Australia
S>>V_NIL_SETX_SETX	Prevent overload of a South East 275/132 kV transformer for the trip of the parallel transformer, with flow South Australia to Victoria
V^^S_NIL_MAXG_AUTO	Voltage stability limit to cater for a trip of the largest generator in the South Australia region, limits flow for flow Victoria to South Australia
V>>S_NIL_NIL_SGKHC	Prevent overload of the Snuggery-Keith 132 kV line with flow Victoria to South Australia
V>>S_NIL_KHTB2_KHTB1	Prevent overload of the Keith-Tailem Bend #1 132 kV line for the trip of the Keith-Tailem Bend no.2 132 kV line, with flow Victoria to South Australia
V>>S_NIL_NIL_KHTB1	Prevent overload of the Keith-Tailem Bend #1 132 kV line for flow Victoria to South Australia
V>>S_NIL_PWKN_SGKH	Prevent overload of the Snuggery-Keith 132 kV line for the trip of the Penola West-Kincraig 132 kV line with flow Victoria to South Australia
V>>S_NIL_SETB_KHTB	Prevent overload of the Keith-Tailem Bend #1 132 kV line for the trip of a South East-Tailem Bend 275 kV line, with flow Victoria to South Australia
V>>S_NIL_SETB_SGKH	Prevent overload of the Snuggery-Keith 132 kV line for the trip of a South East-Tailem Bend 275 kV line, with flow Victoria to South Australia
V>>S_NIL_SGBL_SGKH	Prevent overload of the Snuggery-Keith 132 kV line for the trip of the Snuggery-Blanche 132 kV line, with flow Victoria to South Australia

S>>V_NIL_TBSE_KHSG	Prevent overload of the Snuggery-Keith 132 kV line for the trip of a South East-Tailem Bend 275 kV line, with flow South Australia to Victoria
S>>V_NIL_TBSE_TBKH1	Prevent overload of the Keith-Tailem Bend #1 132 kV line for the trip of a South East-Tailem Bend 275 kV line with flow South Australia to Victoria
S>>V_NIL_NIL_SGKHC	Prevent overload of the Snuggery-Keith 132 kV line with flow South Australia to Victoria
S>>V_NIL_PWSE_SGKHC	Prevent overload of the Snuggery-Keith 132 kV line for the trip of the Penola West-South East 132 kV line, with flow South Australia to Victoria
V::N_NILQx_BL_R V::N_NILVx_BL_R	Victorian Export Transient stability limit for a South Morang to Hazelwood 500 kV line fault

Table D-4: Impact on selected existing constraints

Constraint								
	Option 1a 132 kV works, Heywood tx[c], 100 MVAr capacitor	Option 1b 132 kV works, Heywood tx, series compensation	Option 2a 132 kV works, Heywood tx, 100 MVAr capacitor, SE tx	Option 2b 132 kV works, Heywood tx, series compensation, SE tx	Option 3 Krongart 500 kV circuits	Option 4 132 kV works, 100 MVAr capacitor	Option 6a Control scheme only	Option 6b 132 kV works, series compensation, control scheme
S:V_580[a]	+290.	+290.	+290.	+290.	Remove.	+290.	+290.	+290
S>V_NIL_HYTX_HYTX	+460[d].	+460.	+460.	+460.	+1940	No change [e]	+ 0 to 230[b]	+ 0 to 230
V>S_460	Remove.[d]	Remove.	Remove.	Remove.	+1940	No change.[e]	No change.[e]	No change.[e]
S>>V_NIL_SETX_SETX	+ 5 to 20	+ 15 to 30	+165 to 180	+175 to 190	Remove.	+5 to 20	+ 0 to 140	+ 15 to 140
V^^S_NIL_MAXG_AUTO	+130	+350	+130	+350	Remove.	+130	No change.	+350
V>>S_NIL_NIL_SGKHC	Remove[f].	Remove.	Remove.	Remove.	Remove.	Remove.	No change.	Remove.
V>>S_NIL_KHTB1_KHTB2	Remove[f].	Remove.	Remove.	Remove.	Remove.	Remove.	No change.	Remove.
V>>S_NIL_NIL_KHTB1	Remove[f].	Remove.	Remove.	Remove.	Remove.	Remove.	No change.	Remove.
V>>S_NIL_PWKN_SGKH	Remove[f].	Remove.	Remove.	Remove.	Remove.	Remove.	No change.	Remove.

V>>S_NIL_SETB_KHTB	Remove[f].	Remove.	Remove.	Remove.	Remove.	Remove.	No change.	Remove.
V>>S_NIL_SETB_SGKH	Remove[f].	Remove.	Remove.	Remove.	Remove.	Remove.	No change.	Remove.
V>>S_NIL_SGBL_SGKH	Remove[f].	Remove.	Remove.	Remove.	Remove.	Remove.	No change.	Remove.
S>>V_NIL_TBSE_KHSG	Remove[f].	Remove.	Remove.	Remove.	Remove.	Remove.	No change.	Remove.
S>>V_NIL_TBSE_TBKH1	Remove[f].	Remove.	Remove.	Remove.	Remove.	Remove.	No change.	Remove.
S>>V_NIL_NIL_SGKHC	Remove[f].	Remove.	Remove.	Remove.	Remove.	Remove.	No change.	Remove.
S>>V_NIL_PWSE_SGKHC	Remove[f].	Remove.	Remove.	Remove.	Remove.	Remove.	No change.	Remove.

a. Previous studies by ElectraNet and AEMO which assessed the increase of the South Australian Oscillatory Export limit from 420 MW to 580 MW were extended to examine the works required to increase this limit to 870 MW. These studies concluded that this increased level of export can be achieved, but will require the retuning of existing power system stabilisers.

b. Dependant on generation available for tripping.

c. tx = transformer.

d. Heywood –South East 275 kV line ratings will limit flows prior to the transformers with 3 installed.

e. Heywood 500 kV bustie overcomes uneven loadings that can currently occur for these transformers.

f. New thermal constraints still required for remaining Keith-Tailem Bend and Keith to South East 132 kV lines.

Note: Indicative changes shown. Constraints reformulated for the market modelling so actual increases are dependent on system conditions.

Appendix E. Summary of submissions to the PADR

This appendix provides a summary of the issues raised in the submissions received to the PADR, by submitter. It also details specifically where ElectraNet and AEMO have responded to each particular issue.

Table E-1: SACOSS submission

Request	ElectraNet/AEMO response
Change preferred option to option 4 based on cost-benefit ratio.	Section 4.6
Consider a staged approach for 132 kV reconfiguration works.	Section 4.13
Concerned that the DSM option was dismissed.	Section 4.7
Discount rates.	Section 4.5
Some potential confusion between transformers.	Section 4.13
Optional Firm Access might provide a more market-based and efficient driver for network investment; also notes the uncertainty created by the current high number of review processes.	Section 4.3
SACOSS expressed that investment should be delayed to ensure the need holds given the flux and levels of uncertainty in the NEM regulatory environment.	Section 4.2

Table E-2: Infigen submission

Request	ElectraNet/AEMO response
Suggested that the market benefits of a prolonged outage of the 500/275 kV Heywood transformer be explicitly assessed.	Section 4.12
Consider fast-tracking the 132 kV works.	Section 4.13
Comprehensively confirm the technical feasibility of non-firm transformer operation/control scheme.	Section 4.8
Assess an expanded control scheme for the 132 kV network in SA to be assessed in isolation and in conjunction with other options.	Section 4.13
Enhance option 1b – replace existing transformers with higher rated units instead of third unit, also allowing for higher non-firm ratings with a control scheme in future.	Section 4.13
Consider 1b (third Heywood transformer) with a control scheme.	Section 4.13
Consider SE transformer control scheme on its own.	Section 4.13
Re-run modelling assuming 500 MW wind around South East substation (+ comments on their Woakwine wind development) to estimate benefits for a scenario with 500 MW new wind generation in SE.	Section 4.14
Considers undue caution has been used for costing and feasibility of the control scheme options – use most probable costs. Requests that greater weight be given to DSA's conclusions on costs over SP AusNet.	Section 4.10
Comments on its Woakwine Wind Farm project.	Section 4.9

Table E-3: International Power submission

Request	ElectraNet/AEMO response
Requested load flow study results to show that the removal of the 132 kV circuits does not compound transmission congestion in the South East.	Section 4.16
Demonstrate that the preferred option does not create congestion in other parts of the network. Specifically the South Morang Transformers.	Section 4.16
Show Keith-Tailem Bend lines are a limiting factor on the VIC-SA limit as constraint reports don't highlight this as an issue.	Section 4.16
Requests that we explain why the minimum generation levels for Yallourn, Loy Yang, Anglesea and Northern have been run at such low levels.	Section 4.14
Request review of: - Playford as an OCGT; and - Hazelwood closure. And update the modelling.	Section 4.14
Suggested delay of PACR and review of modelling assumptions in relation to carbon price, and LRET once LRET review is completed.	Section 4.2
Request the modelling of an additional option. (option 4 + third SE transformer).	Section 4.13
Should perform more due diligence on control scheme option (confirm commercial feasibility) due to lower cost.	Section 4.8

Table E-4: NGF submission

Request	ElectraNet/AEMO response
Request review of: - Playford as an OCGT; and - Hazelwood closure. And update the modelling.	Section 4.14
Suggested suspending PACR process until the release of AEMO's 2013 National Energy Forecast Report (NEFR).	Section 4.2
Timeframes for analysis – should only consider first 20 years, and no end effects. Use of a higher discount rate if dependant on long term benefits.	Section 4.5
Show/release details of USE (MWh or %).	Section 4.17
Provide sub-regional generation builds.	Section 4.17
Appendix E shows increases in VIC CCGT of 450MW, and 450MW decrease in SA. Please explain these results when the upgrade is an additional 190 MW.	Section 4.17
Provide load diversity sensitivities for each year over last decade, and explain choice of reference year used (09/10).	Section 4.14
Include cost of Heywood to Moorabool upgrade. Considers that the increase of Heywood interconnector capability requires the 500 kV upgrade.	Section 4.14
Verify level of SA network upgrades required to transfer additional Victoria to SA flows, and include costs.	Section 4.15
Request release of RRP data.	Section 4.17
Discount rates.	Section 4.5

Table E-5: Alinta Power submission

Request	ElectraNet/AEMO response
Requests to explain why the minimum generation levels for Yallourn, Loy Yang, Anglesea and Northern have been run at such low levels.	Section 4.14
Request review of: - Playford as an OCGT; - Hazelwood closure; and - Costs of gas generation expected into SA. And update the modelling.	Section 4.14
Include cost of Heywood to Moorabool upgrade. Considers that the increase of Heywood interconnector capability requires the 500 kV upgrade.	Section 4.14
Requests further clarity on what weight is given to submissions.	Section 4.1
View that a case for augmentation of the intra-regional networks to resolve thermal and voltage stability limits in the south-east of SA has not been addressed sufficiently. The inclusion of intra-regional solutions has occurred on a selective basis, and that they have difficulty reconciling the analysis with their experience of thermal constraints and high wind penetration.	Section 4.13
Clarify how AEMO and ElectraNet have responded to the view that maintenance of existing interconnections would to some degree diminish the need for the proposed upgrade.	Section 4.13
Thinks that the process may have benefitted from the establishment of a stakeholder reference group or similar to canvass options and issues.	Section 4.1
Consider fast tracking the reconfiguration of the 132 kV line in advance of other network investments.	Section 4.13

Table E-6: SP AusNet submission

Request	ElectraNet/AEMO response
Requested that the market cost of a major failure of a 500/275 kV transformer or the cost of a cold spare transformer to mitigate the market impact of a prolonged transformer outage be included in the RIT-T analysis.	Section 4.12

Table E-7: CEC submission

Request	ElectraNet/AEMO response
Consider a staged approach for 132 kV configuration works.	Section 4.13
Include quantitative impact of a prolonged loss of the Heywood Transformer.	Section 4.12
Delay RIT-T and include update 2013 NEFR demand forecasts	Section 4.2
Provide load diversity sensitivities for each year over last decade, and explain choice of reference year used (09/10).	Section 4.14
Consider 1b (third Heywood transformer) with a control scheme.	Section 4.13
Consideration should be given to the interaction between the control scheme costs and ElectraNet's proposed communications infrastructure.	Section 4.10
PACR to show/consider results from AERs determination on communication costs.	Section 4.10
Consideration (at the time of commissioning) should be made for any differences in technology market entry timings as a result of the White Paper since the WP report.	Section 4.14
Include more detail in the PACR on the carbon transport assumptions where CCS has been considered.	Section 4.14
Consider gas price trends as per the White Paper.	Section 4.14
Make clear in the PACR whether ElectraNet's potential expansion of the Eyre Peninsula system has been considered in the modelling.	Section 4.14
Considers that uniform rating should be applied to the 275 kV Heywood-SE lines based on asset capability.	Section 4.14
Request quantification of the risk of option 6b to enable a more accurate comparison between options.	Section 4.12
Consider whether dynamic ratings can be applied to the 132 kV assets and whether low-cost replacements could be undertaken within the SE substations for limiting assets.	Section 4.13
Concerns in relation to wind farm licence conditions.	Section 4.18
An independent review of network costs	Section 4.11

Appendix F. Submissions to the Project Specification Consultation Report

ElectraNet and AEMO received six submissions[117] to the PSCR, from:

- Origin Energy.
- Alinta.
- Private Generators (AGL Energy, Alinta Energy, Energy Brix, International Power GDF-Suez, Origin Energy, TRUenergy).
- EnerNOC.
- Infigen.
- The National Generators Forum (NGF).

The key issues raised in these submissions are discussed in this appendix.

F.1. Importance of interconnector capacity

The submission from the private generators noted that interconnector limits have a profound impact on market operation. The decrease in the Heywood Interconnector capacity has reduced both the reserve margin available to South Australia from other NEM regions and South Australia's ability to access lower cost interstate power. The generators further noted that from a commercial perspective this undermines confidence in inter-regional trading, as parties are not able to effectively manage basis risk. This in turn reduces contract liquidity and overall competition in the market. The generators are therefore supportive of the process ElectraNet and AEMO are pursuing to evaluate possible enhancements of interconnector capacity.

F.2. Alleviation of South Australia intra-state network constraints

Alinta Energy and the private generators expressed the view in their submissions that action to address thermal and voltage stability limits in south-east South Australia is justified independent of any Heywood interconnector upgrade.

Alinta suggested that AEMO and ElectraNet evaluate intra-regional issues affecting South Australia separate to the case for various interconnector options. Alinta also commented that the progression of works to maintain the existing capacity of the Heywood Interconnector remains critical going forward.

The private generators further noted that they would be against a proposal that would improve capability between Heywood substation in Victoria and South East substation in South Australia but leave the 'upstream' issues in and around south-east South Australia unresolved. They would prefer that the option to add a 3rd 275/132 kV transformer at South East be included as part of the network options evaluated, rather than being left to a sensitivity study.

ElectraNet and AEMO note that the credible network options set out in section 3 include re-configuration of the 132 kV network between Snuggery–Keith and Keith–Tailem Bend, which currently

117 PSCR submissions can be accessed at: http://www.aemo.com.au/en/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission-RITTs/Heywood-Interconnector-RIT-T.

cause some of the existing thermal limitations on Heywood transfer capacity, as well as reactive power compensation which will alleviate voltage/stability constraints.

ElectraNet and AEMO have also investigated the market benefits which may be expected as a result of intra-regional investment in South Australia to address constraints around the south-east, not coupled with a 3rd transformer being installed at Heywood. An option which includes re-configuration of the 132 kV network and installation of a 100 MVAr capacitor, but does not include a 3rd transformer at Heywood has been included as a credible option in the RIT-T analysis (Option 4).

ElectraNet and AEMO further note that consideration of other investments to address particular intra-regional constraints (outside of the scope of this RIT-T assessment) would still need to be subject to a separate RIT-T assessment. This would include investments to address network limitations in and around the Robertstown transformer which may impact the Murraylink interconnector capacity. The issue of network limitations around Robertstown was raised in Alinta's submission, but is considered outside the purview of this current RIT-T.

F.3. Non-network options

Two additional non-network options were proposed in response to the PSCR:

- A DM option proposed by EnerNOC and for which EnerNOC has identified itself as a proponent.
- A control scheme for wind generators in south-east South Australia and south-west Victoria, proposed by Infigen to increase South Australia to Victoria export capability.

EnerNOC requested some additional details in relation to the characteristics that a DM option would need to meet, in order to enable it to estimate the details of its DM proposal and the cost of that option. This information was provided to EnerNOC and also posted on AEMO and ElectraNet's websites in order to be accessible to all interested parties.

Both of the non-network options proposed in submissions have been subject to further specific assessment and evaluation, and have been included as a component of potential credible options in the RIT-T analysis.

Alinta and the private generators expressed support for consideration of as many technically feasible options as possible, within reason, in the RIT-T, including the control scheme proposed by Infigen. The private generators note that this option is far more credible as a non-network option compared to the two non-network options set out in the PSCR (demand management and utility scale storage). ElectraNet and AEMO note that they have considered a substantial number of potential alternative credible options as part of this RIT-T process.

F.4. Market benefits included in the RIT-T assessment

In its submission, EnerNOC referred to a number of categories of market benefits which may be associated with a DM option. These include fuel cost benefits associated with both the avoidance of the dispatch of high cost generation in South Australia as a result of peak demand reduction, and an increase in curtailable load that can increase its demand to better utilise available wind generation in South Australia. EnerNOC also notes that there may be capital expenditure deferral benefits (both generation and network capital expenditure), and competition benefits associated with a DM option, as a non-network option can be highly competitive to a non-network solution. ElectraNet and AEMO note that each of these categories of market benefit has been considered as part of the assessment of the DM option under the RIT-T, where they have been assessed as material.

In addition, EnerNOC refers to the following benefits from a DM option:

- A downward pressure on energy prices for the entire market.
- The increased time made available for a major augmentation.
- Improvement in reliability and security.
- Reduction in greenhouse gas emissions.

In relation to these four categories of benefit, ElectraNet and AEMO note that all but the first benefit has been included in the assessment of the DM option (i.e. Option 5) under the RIT-T. The RIT-T does not take into account changes in NEM prices as a category of market benefit, since this represents a transfer between producers and consumers, rather than an overall net benefit to the market.

In relation to the other categories of benefit, the modelling has included the impact on unserved energy (USE) associated with the DM option (i.e. the improvement in reliability and security), as well as the impact on greenhouse gas emissions (since generator short run marginal cost (SRMC) has been calculated inclusive of the associated carbon emission level for that generator and the assumed carbon price[118]). The DM option assessed has also considered the lower cost (in present value terms) associated with a deferral of the time at which a network augmentation is undertaken, as this option explicitly includes a two year deferral of network augmentation.

F.5. RIT-T analysis to be sufficiently transparent and robust

The submission received from the NGF highlighted its view of the importance of the analysis by AEMO and ElectraNet being rigorous and robust, as well as sufficiently transparent to facilitate detailed analysis by third parties.

In particular the NGF highlighted a number of assumptions which it considered should be made transparent in the PADR, such as those made about wind farm output in South Australia at times of peak demand, any assumptions made in relation to the Federal Government's Contract for Closure (CFC) Program, the minimum generation levels assumed for South Australian generators and the additional generating capacity assumed in the 2011 Electricity Statement of Opportunities to be required in both South Australia and Victoria by 2014/15.

Infigen commented in relation to the network options included in the PSCR that it is important that the costs of each option are provided at suitable granularity to allow detailed feedback by industry participants and/or third party engineering review. Infigen also noted that the assumption of what the new entrant wind energy price will be at the time of commissioning the proposed additions would be a materially significant assumption, and could be influenced by the rapid pace of change in the industry and the entrance of new, cheaper manufacturers of wind turbines. Infigen also commented that network connection costs for wind generators would be greater for 500 kV sites in Victoria relative to 275 kV connected sites in south-east South Australia, and suggested that actual connection costs for advanced wind farms be used, using nominal 132 kV circuits.

[118] This is consistent with the AER RIT-T Application Guidelines in relation to the inclusion of the carbon price in the RIT-T analysis. See AER, RIT-T Applica ion Guidelines, June 2010 p. 21-25.

ElectraNet and AEMO note that the NER requires the PADR to include a detailed description of the methodologies used in quantifying each class of material market benefit and cost.[119] The NER also require the PADR to contain the results of a net present value (NPV) analysis of each credible option and accompanying explanatory statement regarding the results.[120] Key assumptions adopted for the market modelling component of the RIT-T assessment are discussed in section 5 of the PADR. The results of the NPV analysis for all credible options are presented and discussed in section 6.3 of the PADR. Greater detail in relation to both the assumptions adopted in the analysis and the NPV results are contained in Appendices C, D and E of the PADR.[121]

In addition, ElectraNet and AEMO note that the main cost estimates for the network component of the credible options has been subject to independent review by external engineering consultants, as discussed in section 6.1 of the PADR.

ElectraNet and AEMO further note that the RIT-T assessment is one which compares the relative ranking of alternative options against each other, and against the option of no investment. Assumptions are material to the extent that they affect this *relative* ranking, rather than simply where they affect the value calculated for the net market benefit. ElectraNet and AEMO have conducted a number of sensitivity tests as part of the modelling assessment, in order to gauge the importance of particular assumptions in affecting the rankings between the different options. The results of this analysis are discussed in section 6.3 of the PADR.

[119] NER 5.16.4(k)(4).

[120] NER 5.16.4(k)(7).

[121] Please note that Appendix E to he PADR is a separate spreadsheet available on the ElectraNet and AEMO websites.

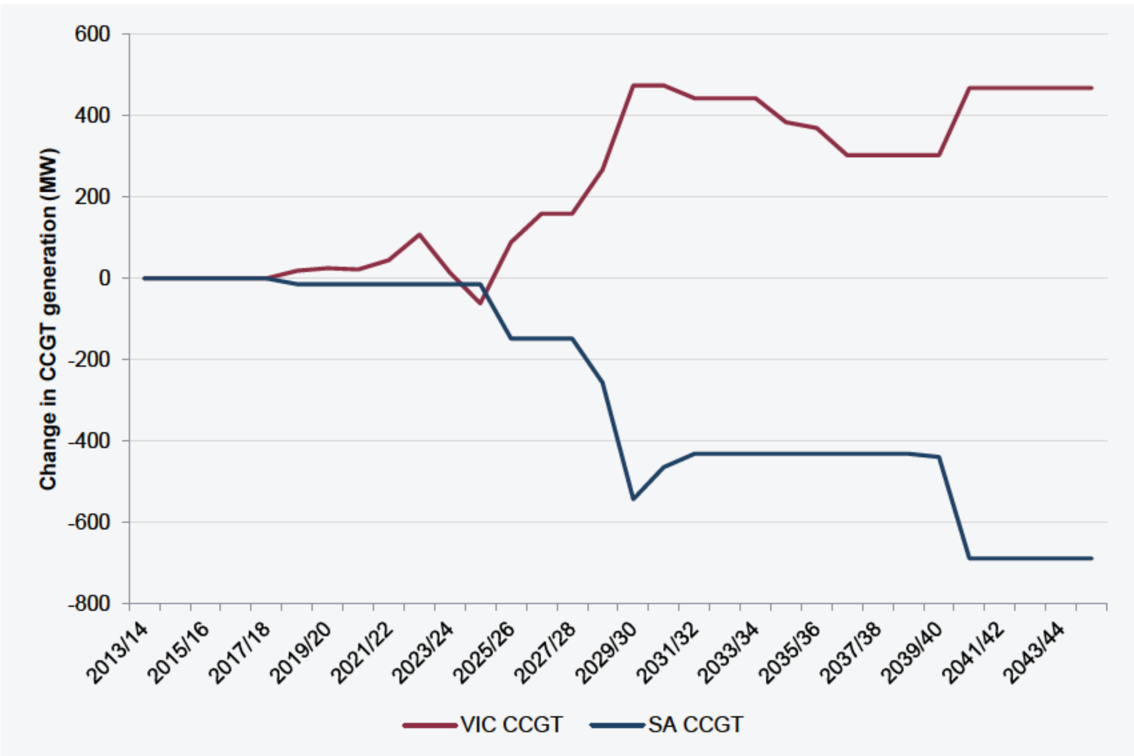
Appendix G. Relationship between additional interconnector capacity and changes in generation investment

The augmentation of the Heywood interconnector moves new investment in CCGT generation from South Australia to Victoria, in excess of the increase of the interconnector limit.

The NGF's submission to the PADR requested details on how the 190 MW increase in the interconnector supports larger changes to generator investment. This appendix discusses reasons why the relationship between the augmentation of interconnector capacity and changes in generation investment need not be linear.

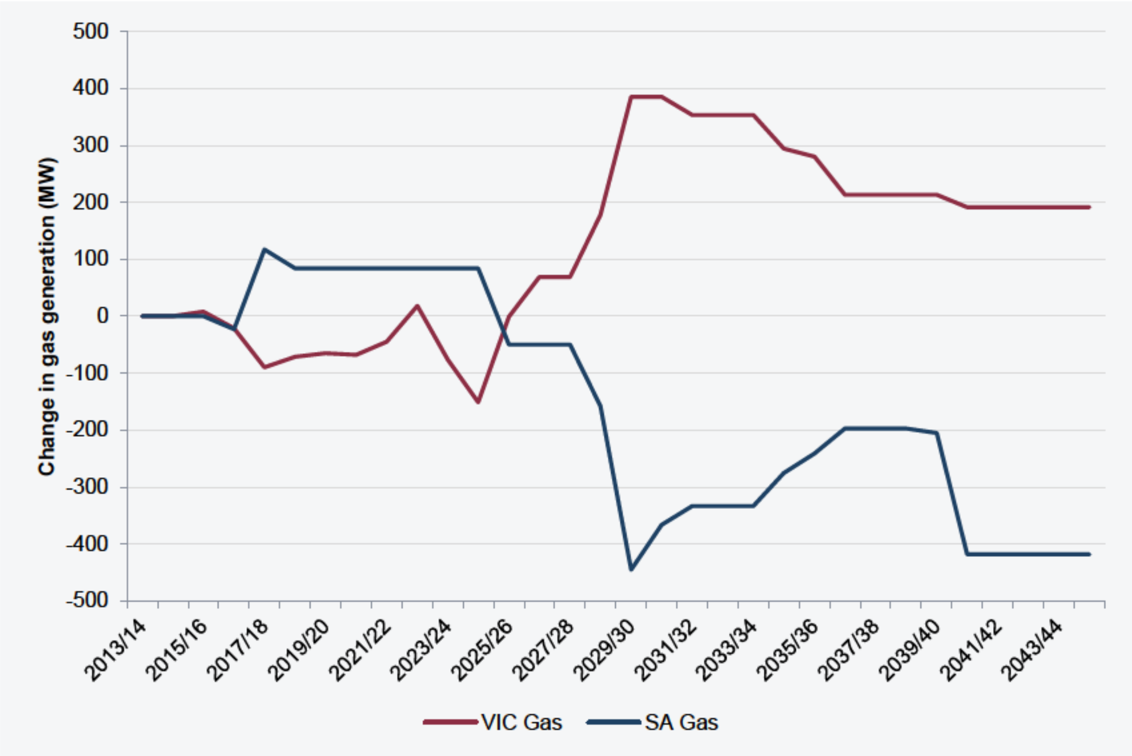
In the Central scenario, the change in CCGT generation in Victoria and South Australia is as shown in Figure G-1, where a positive change indicates more generation being established in the presence of the augmentation. A clear transfer of CCGT generation from South Australia to Victoria is exhibited, although the exchange is not one-for-one. The exchange is also in excess of the 190 MW increase in interconnector capability that is provided by the augmentation.

Figure G-1: Change in CCGT generation (MW) in Victoria and South Australia – Central scenario



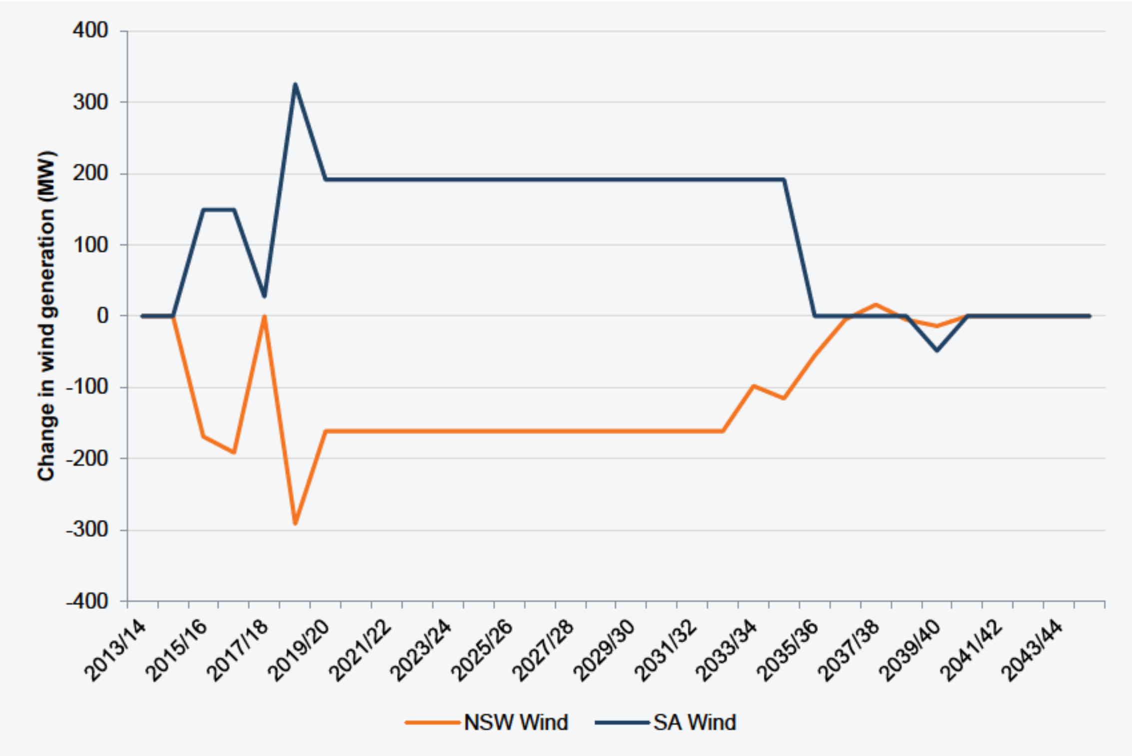
When the change in OCGT generation is also considered, the magnitude of the exchange is decreased, as shown in Figure G-2.

Figure G-2: Change in total gas-fired generation (MW) in Victoria and South Australia – Central scenario



The differences between the generation investment patterns may be due to the relative differences in gas prices between Victoria and South Australia. It is noted, however, that there is also an exchange of wind generation between New South Wales and South Australia, despite there being no direct transmission augmentation between the two, as shown in Figure G-3.

Figure G-3: Change in wind generation (MW) in New South Wales and South Australia – Central scenario

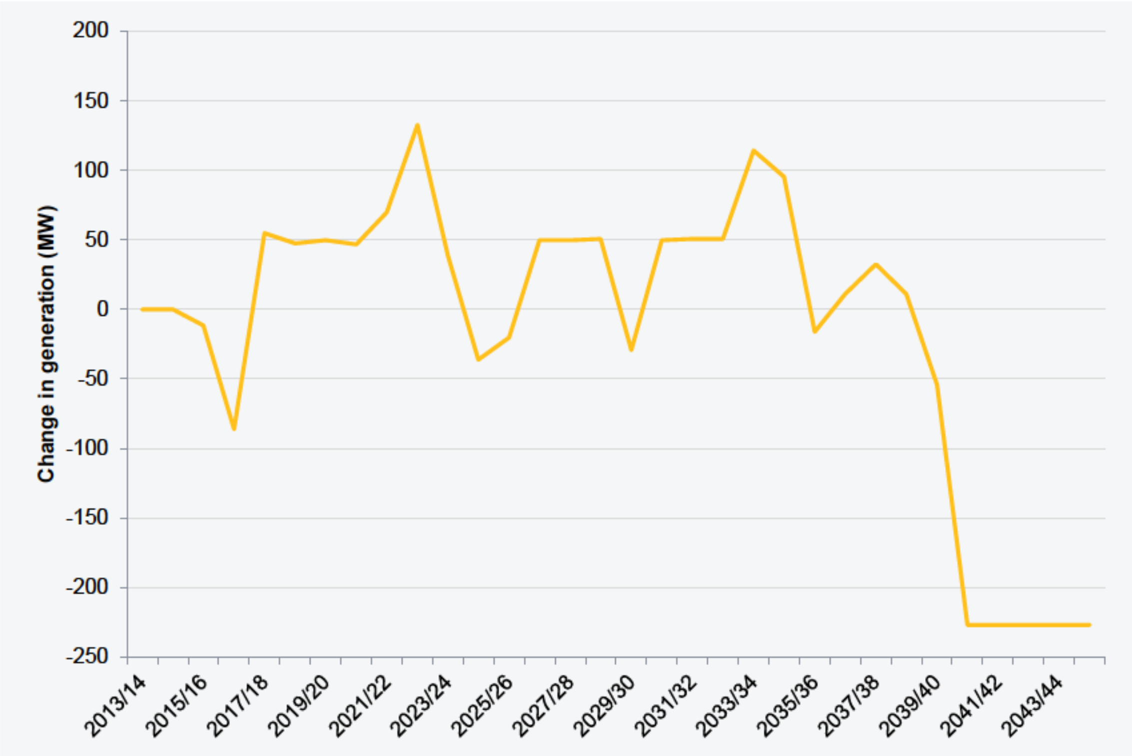


When South Australian wind and gas generation, Victorian gas generation and New South Wales wind generation are considered together, generation capacity exchange resulting from the augmentation becomes less clear-cut, as shown in Figure G-4. These three generation types together represent the majority of change introduced by the augmentation in this scenario.

The movement of wind generation from New South Wales to South Australia in the presence of the augmentation is able to occur because the augmentation has two effects in the model: a transfer capability increase; and a change in electricity losses across the interconnector. The first effect increases the maximum amount of energy that can be transferred between Victoria and South Australia, while the second makes transfer of energy across the interconnector less expensive. The first effect activates during times of peak flow, while the second effect can impact generation investment decisions during all time periods, regardless of flow. This second effect is able to change the times at which specific types of generation in specific locations are dispatched, with economic benefits accruing at times other than during peak flow.

For example, in one period without the augmentation the interconnector may not be flowing. With the augmentation in place, the cost of energy in a remote region is effectively reduced. This may result in a reshuffling of the merit order across the two regions. The reshuffle may increase the flow to the limit of the marginal generator in the remote region. In extreme circumstances, this change may be as large as the sum of the interconnector's transfer limits in either direction.

Figure G-4: Change in South Australian wind and gas generation, Victorian gas generation and New South Wales wind generation – Central scenario



The following simplified and hypothetical example seeks to demonstrate the point. Consider a system with two regions and a 500 MW interconnector between the two. Both regions contain generators and load. Prior to the augmentation, losses are 10 per cent and the capacity of the interconnector is 500 MW. After the augmentation losses are 5 per cent, the capacity remains unchanged.

Dispatch of this simplified market results in all of Generator A from Region One being dispatched and 1000 MW from Generator B. Generator C from Region Two is dispatched to 1500 MW. The price in Region One is $21.50/MWh, and in Region Two it is $20/MWh. The interconnector is not utilised as the effective price of Generator C in Region One is $22/MWh which is greater than Region One's price of $21.50/MWh. Likewise the price of generator A in Region 2 is $22/MWh.

After the augmentation, the effective price of Generator C in Region 1 is now $21/MWh. This is cheaper than Generator B. The new dispatch will see Generator A unchanged. Generator C will meet its local demand and export 500 MW to Region One, delivering 476 MW after losses.

Figure G-5: Before Augmentation

Region One

Demand: 6000 MW

Price: $21.50/MWh

Merit order

Generator	Capacity	Dispatch	SRMC
Generator A	5000 MW	5000 MW	$20.00/MWh
Generator B	2000 MW	1000 MW	$21.50/MWh

Zero flow

Interconnector
Max capability: 500 MW
Flow: zero
Losses: 10%

Region Two

Demand: 1500 MW

Price: $21.50/MWh

Merit order

Generator	Capacity	Dispatch	SRMC
Generator C	2000 MW	1500 MW	$20.00/MWh
Generator A (imported)	476 MW	0 MW	$22.00/MWh
Generator B (imported)	476 MW	0 MW	$23.65/MWh

After Augmentation

Region One

Demand: 6000 MW

Price: $21.50/MWh

Merit order

Generator	Capacity	Dispatch	SRMC
Generator A	5000 MW	5000 MW	$20.00/MWh

500 MW

Interconnector
Max capability: 500 MW
Flow: 500 MW
Losses: 5%

Region Two

Demand: 1500 MW

Price: $20/MWh

Merit order

Generator	Capacity	Dispatch	SRMC
Generator C	2000 MW	2000 MW	$20.00/MWh
Generator A (imported)	476 MW	0 MW	$21.00/MWh
Generator B (imported)	476 MW	0 MW	$22.58/MWh

It is important to note that these benefits may not manifest as a reduction in losses and hence a market benefit attributable to losses. These benefits may be realised through capital deferral and operating cost benefits. In the above example, losses actually come through as a cost to the system of $476 (24 MW * $20/MWh), whilst operating cost benefits are $714 (476 * 1.50/MWh) for a net benefit of $238.

Figure G-3 indicates that investment in wind generation in South Australia is increased by the augmentation, but that the effect is active only temporarily, between 2015-16 and 2035-36. Positive net market benefits exhibited by the majority of augmentations considered by the modelling indicate that the increased wind generation in South Australia over a twenty year period is sufficient to justify interconnector augmentation. After 2035-36 other interregional imbalances become the primary means of market benefit accrual.

In particular, the NGF submission has highlighted that the expansion of the interconnector only delivers a 16 MW reduction in net investment in wind farms in the central scenario.[122] If that deferral becomes evident immediately and persists in perpetuity, it represents a future reduction in capital expenditure in the order of $ 40 million. Whilst 16 MW is not large in the context of the NEM, the $40 million saved in capital expenditure contributes to the augmentation justification.

ElectraNet and AEMO acknowledge that the examination of results provides interesting or even unexpected insights into future investment and operational decisions. This is the reason a wide range of reasonable scenarios are explored. ElectraNet and AEMO invested considerable resources into developing scenarios that would test a diverse range of futures and challenge the robustness of the RIT-T outcome.

[122] As highlighted in the NGF PADR submission, pg. 5, Table 1.

Appendix H. Net market benefits of Option 1b and assumed Demand and Carbon Prices forecasts

This appendix provides further details of the different carbon price assumptions and demand assumptions included in each scenario, and highlights that there is no linear relationship with the overall net market benefit for Option 1b.

Figure H-1: Assumed carbon price and net market benefit under different scenarios - Option 1b, 2020

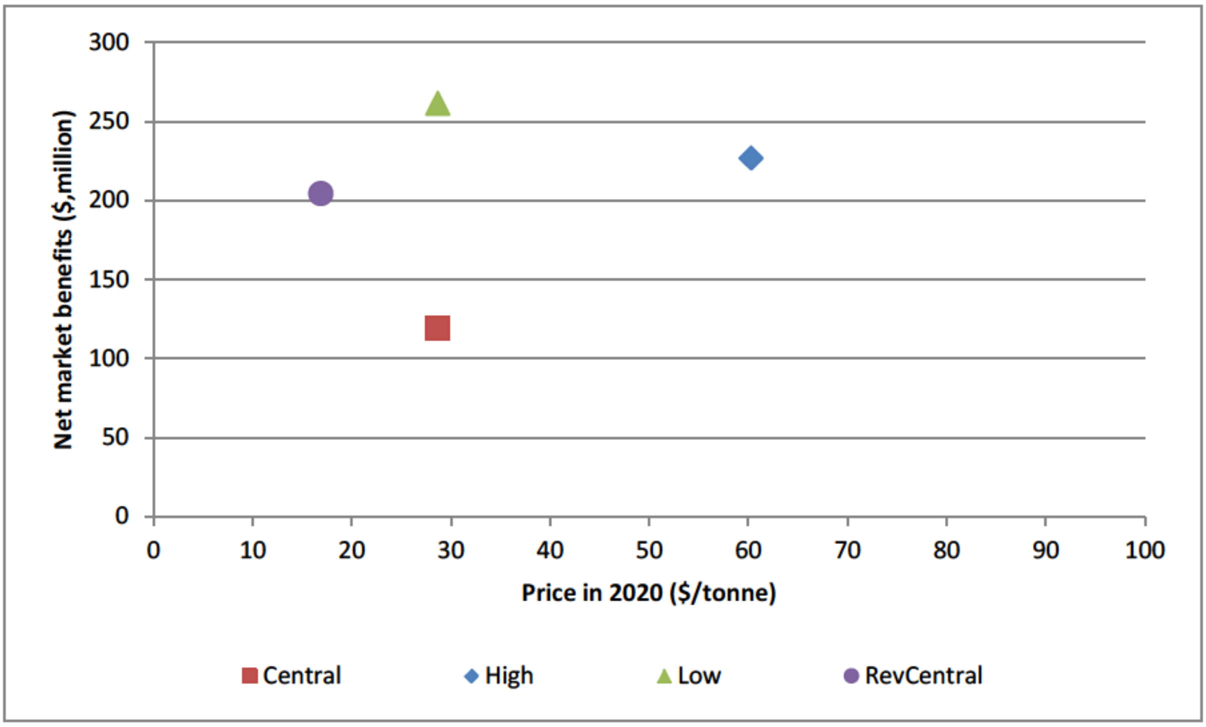


Figure H-2: Assumed carbon price and net market benefit under different scenarios - Option 1b, 2030

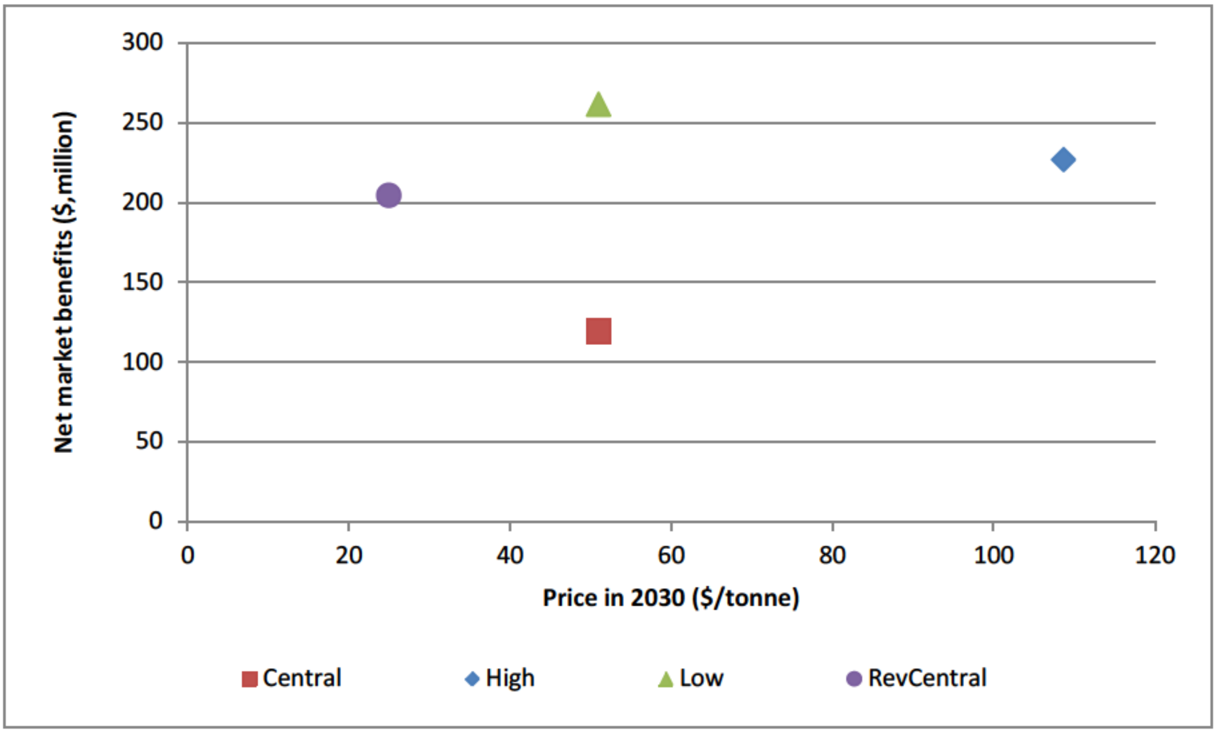


Figure H-3: Assumed South Australia demand and net market benefit under different scenarios - Option 1b, 2016 10% POE

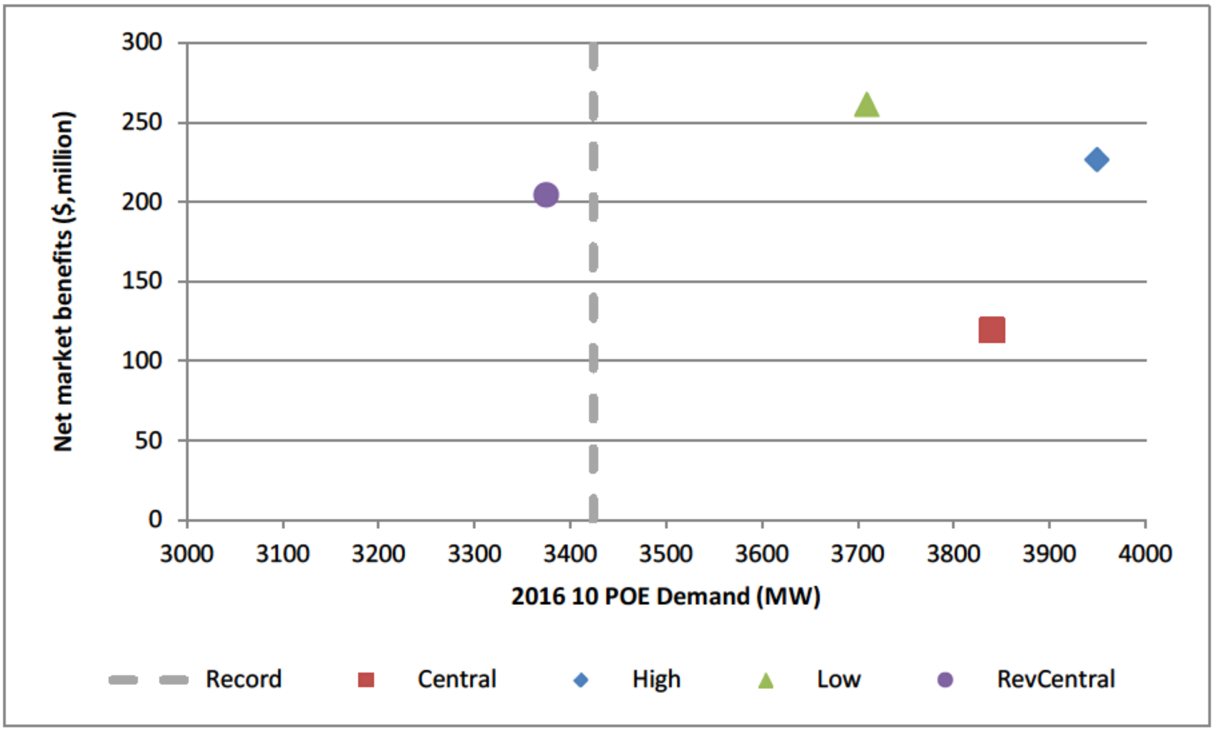


Figure H-4: Assumed South Australia demand and net market benefit under different scenarios - Option 1b, 2020 10 % POE

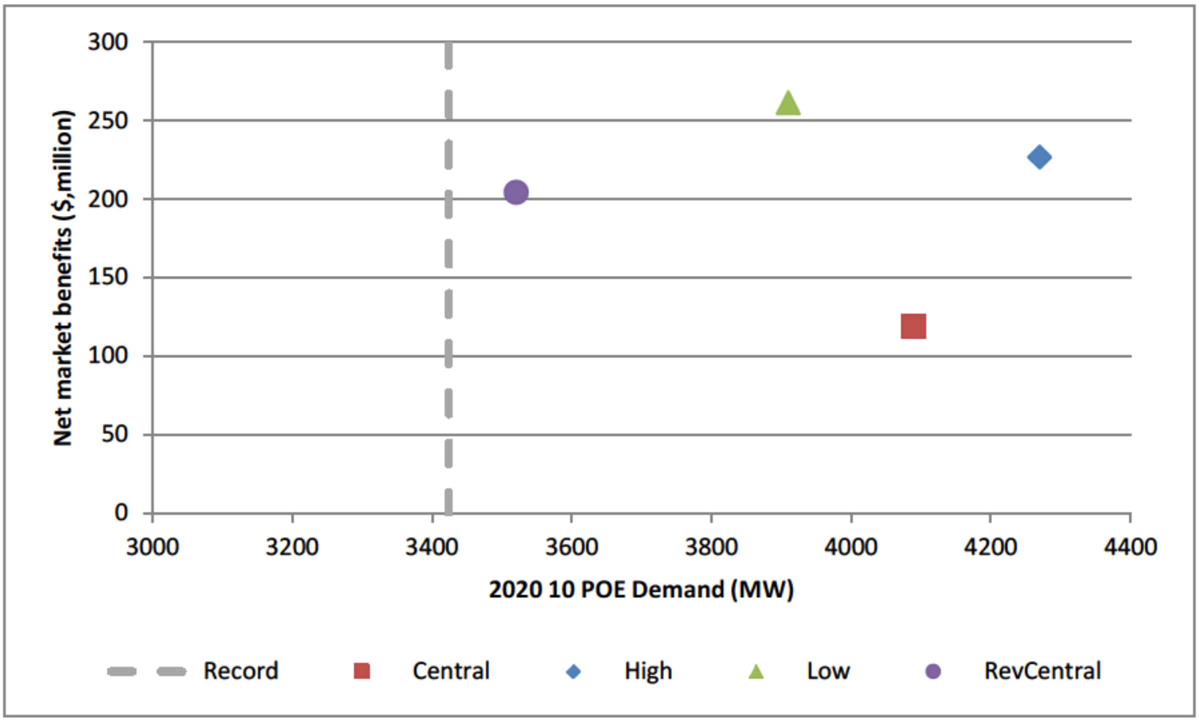


Figure H-5: Assumed South Australia demand and net market benefit under different scenarios - Option 1b, 2016 50 % POE

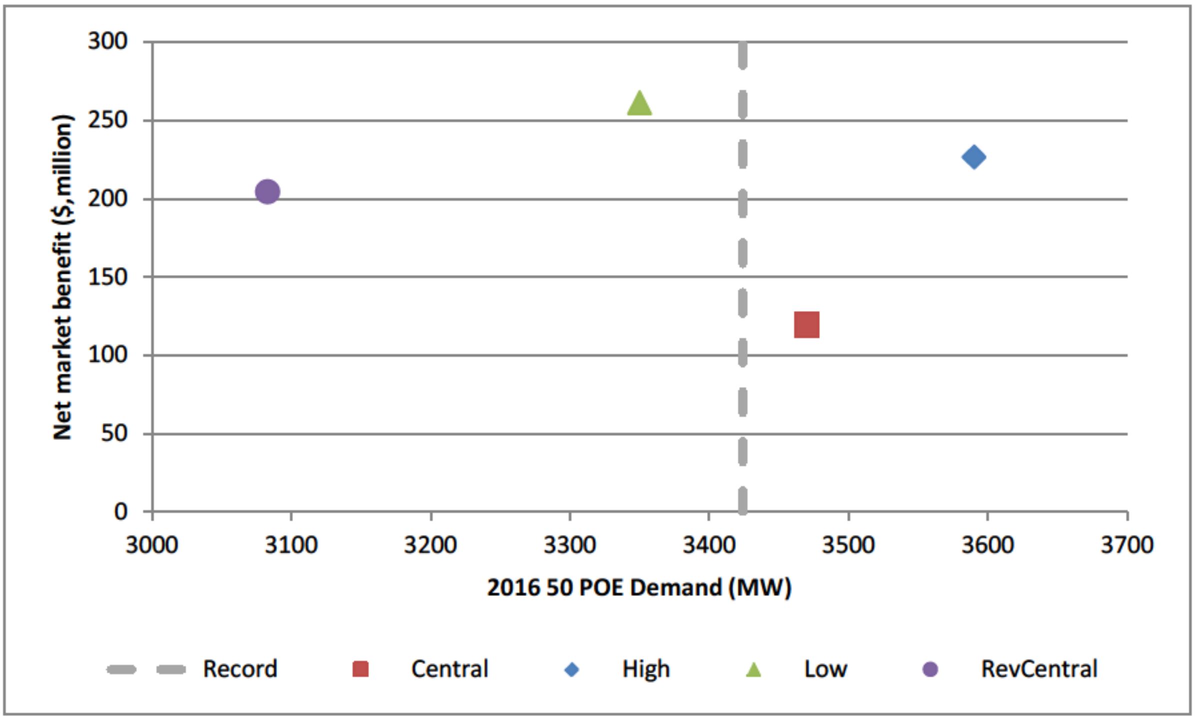


Figure H-6: Assumed South Australia demand and net market benefit under different scenarios - Option 1b, 2020 50 % POE

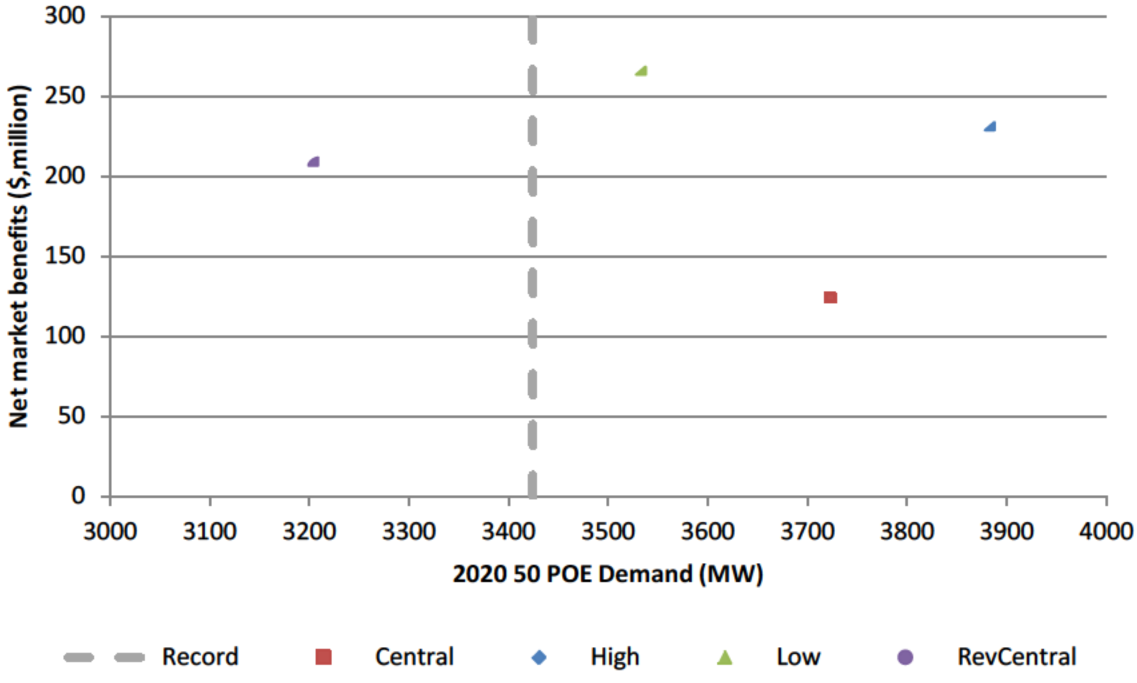


Figure H-7: Assumed Victoria demand and net market benefit under different scenarios - Option 1b, 2016 10 % POE

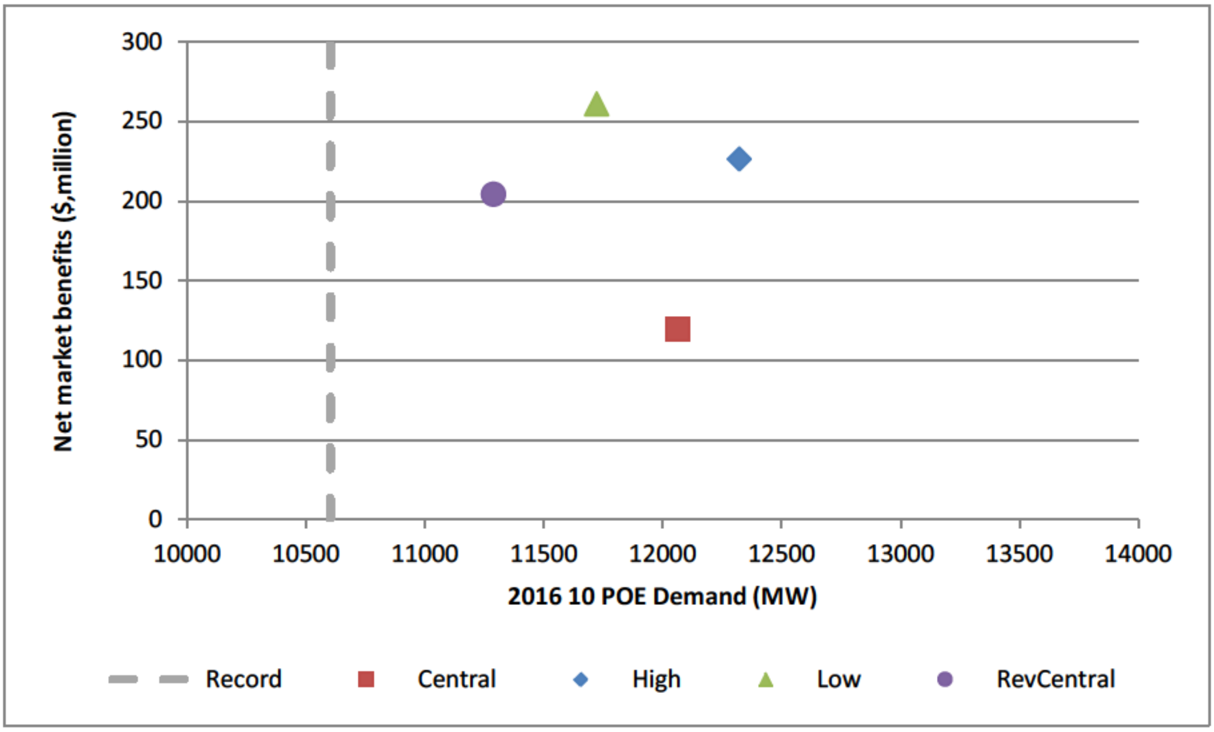


Figure H-8: Assumed Victoria demand and net market benefit under different scenarios - Option 1b, 2020 10 % POE

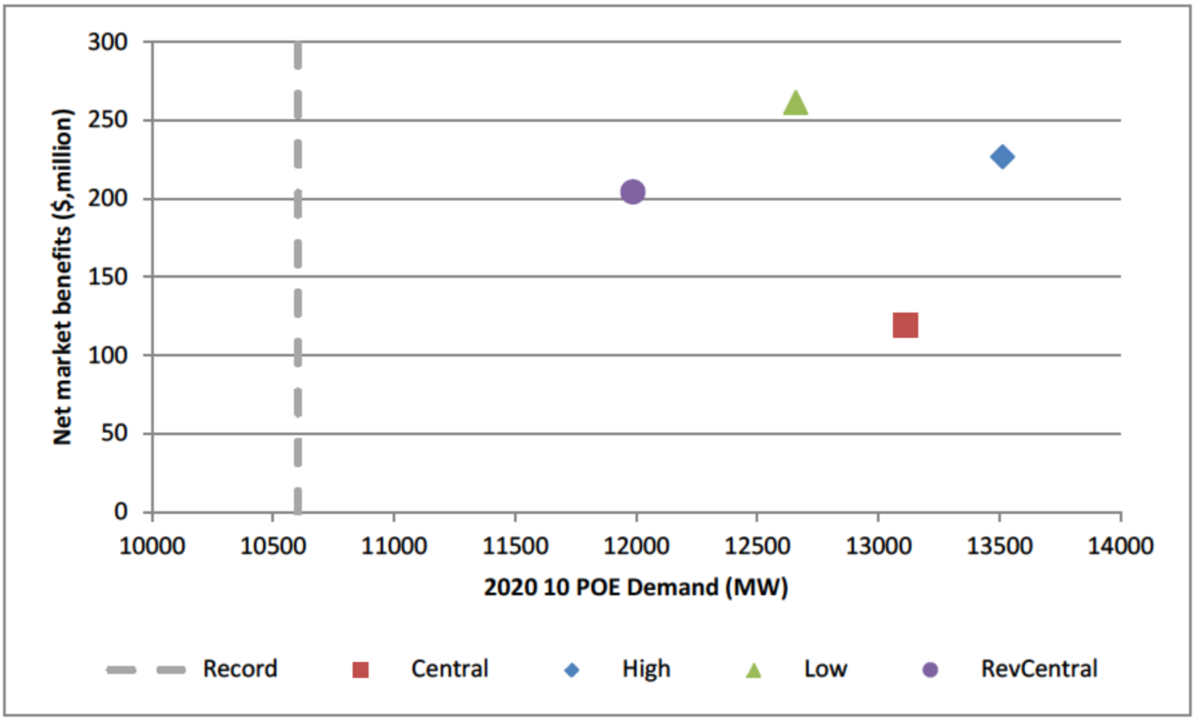


Figure H-9: Assumed Victoria demand and net market benefit under different scenarios - Option 1b, 2016 50 % POE

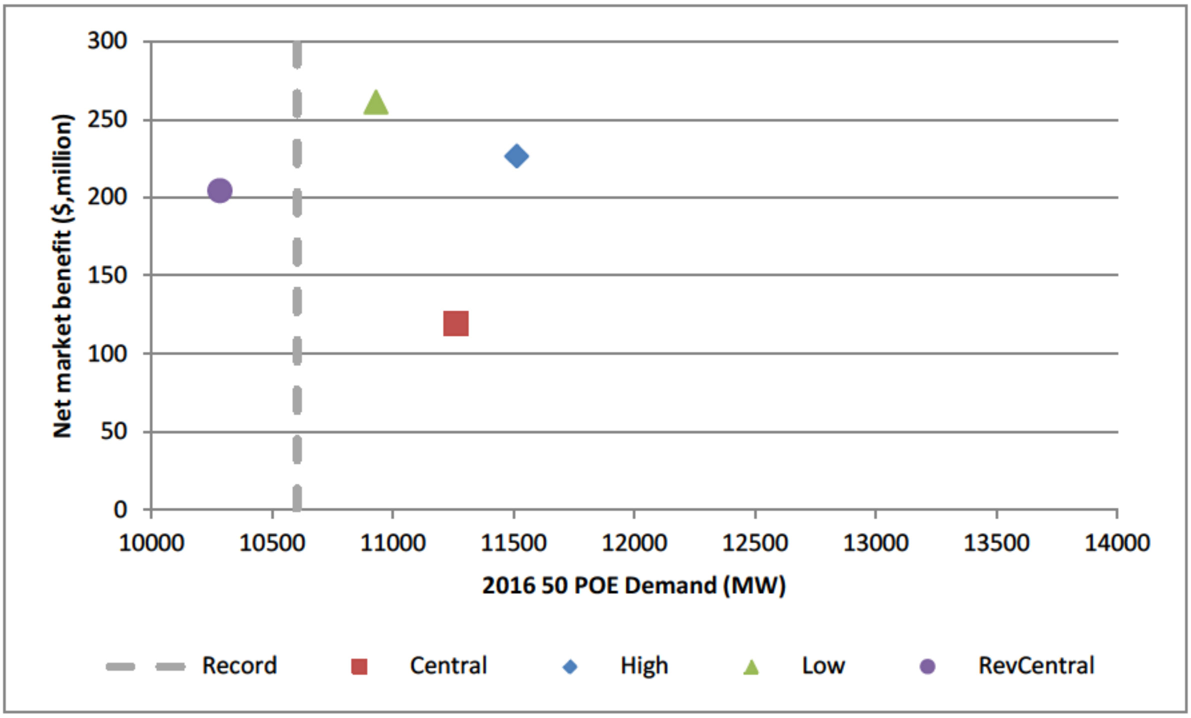


Figure H-10: Assumed Victoria demand and net market benefit under different scenarios - Option 1b, 2020 50 % POE