Final Report

ElectraNet-AEMO Joint Feasibility Study

South Australian Interconnector

Feasibility Study

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Executive summary

ElectraNet Pty Ltd (ElectraNet) and the Australian Energy Market Operator (AEMO) have undertaken a joint feasibility study (feasibility study) into transmission development options that will increase the transfer capability between South Australia and other National Electricity Market (NEM) load centres.

The purpose of this feasibility study was to investigate and assess the technical and economic merit of transmission development options that may allow further development of South Australia's renewable resources while supporting South Australian demand, particularly at peak demand times.

A number of options to enhance transmission capability were considered, ranging from incremental upgrades of existing interconnectors to major new high-capacity interconnectors between South Australia and the eastern states.

The feasibility study compared the total costs to the NEM of meeting demand for a base case with no extra interconnection capacity between South Australia and the rest of the NEM, with a number of options to increase that capacity. This assessment was undertaken under a range of market development scenarios describing possible future conditions of economic growth, technological advancement, fuel scarcity, and external policy settings such as an imposed price on carbon emissions.

The study also considered the impact of the Green Grid[1] proposal for large-scale wind generation on the Eyre Peninsula of South Australia. The Green Grid report was published in July 2010 by a consortium funded by the South Australian Government and concluded that a viable business case exists for investment in transmission to unlock large-scale renewable energy generation on the Eyre Peninsula.

Interconnector augmentation options

Table 1 outlines the interconnector options considered, including indicative costs. It includes one incremental option and four new high-capacity augmentation options. Figure 1 shows the indicative routes of the high-capacity augmentation options, but does not attempt to display the actual routes of existing lines or potential new augmentations.

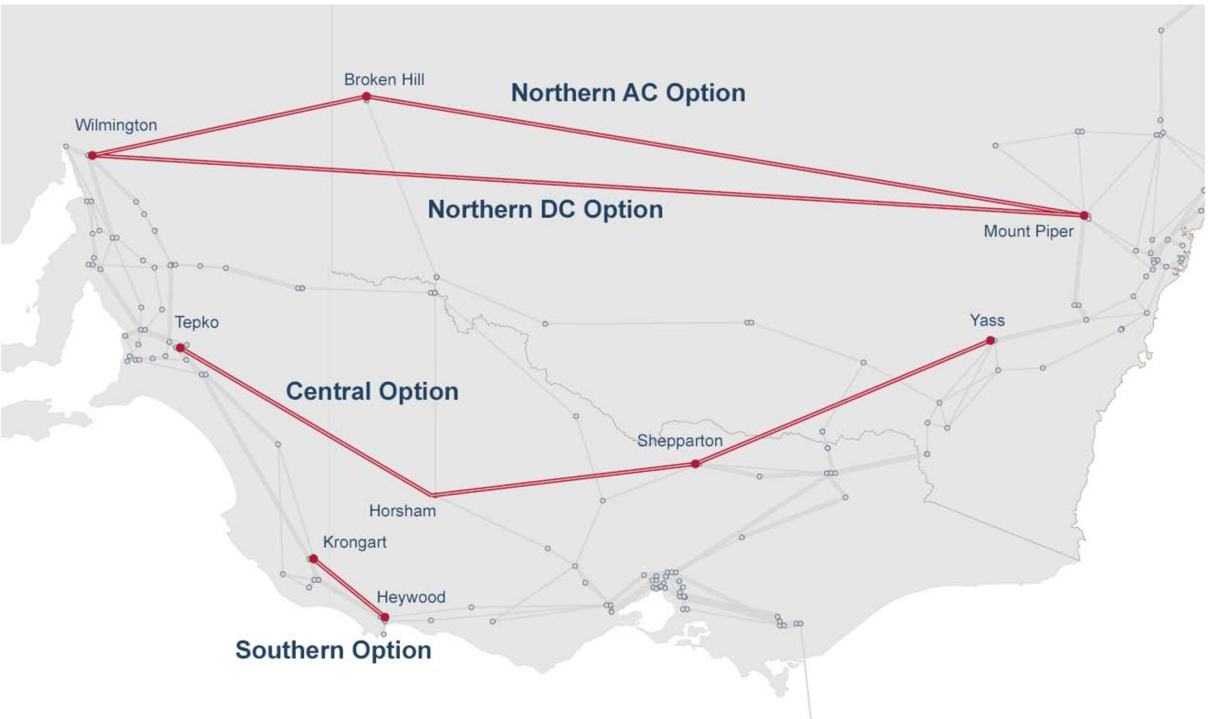
To ensure that the increase in power transfer capability provided by new high-capacity augmentation options was fully realised, a number of supporting projects in South Australia, Victoria and New South Wales were developed and included in the economic feasibility assessment of the interconnector options (for example, the central option included a potential link from Shepparton to the Victorian 500 kV network at Sydenham).

[1] *Green Grid, Unlocking Renewable Energy Resources of South Australia, a feasibility assessment of transmission and generation potential for 2000 MW of wind energy in the Eyre Peninsula*, published by Macquarie Capital Advisors, July 2010.

Table 1 Interconnector augmentation options

Option	Description	Distance (km)	Cost estimate ($ million[2])
Incremental (Heywood)	Add a third 500/275 kV transformer at Heywood in Victoria plus associated minor works in South Australia, increasing the interconnector transfer limit to 650 MW[3]	N/A	38
Northern AC	Wilmington to Mount Piper 2000 MW 500 kV AC double circuit routed via Broken Hill	1,100	3,750
Northern DC	Wilmington to Mount Piper 2000 MW 500 kV HVDC bi-pole	1,100	3,000
Southern	Krongart to Heywood 2000 MW 500 kV AC double circuit	125	530
Central	Tepko to Yass 2000 MW 500 kV double circuit routed via Horsham and Shepparton	1,050	3,500

Figure 1 New high-capacity augmentation options



Market development scenarios

The study was performed under three market development scenarios, comprising a subset of the 2010 National Transmission Network Development Plan (NTNDP)[4] scenarios, which cover a range of potential demand growth paths, fuel prices and policy assumptions:

2 All costs are quoted in real 2010 Australian dollars

3 The ultimate capability of the Heywood interconnector after the installation of a third transformer is an expected figure governed by limitations elsewhere in the system, and is subject to generation and demand patterns and achievement of adequate transmission line ratings (including real-time ratings where used).

4 http://www.aemo.com.au/planning/ntndp.html

- Fast Rate of Change, in which economic and population growth is high, carbon reduction policy and technological and behavioural response to the carbon reduction challenge are both strong;
- Decentralised World, in which economic and population growth is moderate, carbon reduction policy and behavioural response are strong, with an emphasis on decentralisation of energy production technologies;
- Oil Shock and Adaptation, in which economic growth is low, population growth and carbon policy are moderate and behavioural change is weak.

The 2010 NTNDP studies considered two alternate carbon price trajectories for each scenario; this study selected the higher-priced trajectory in each case[5] to create the most favourable conditions for determining whether there is any case for additional interconnection between South Australia and the rest of the NEM.

An implementation of the Green Grid was studied as a sensitivity on the Fast Rate of Change scenario. It examined the benefits of building 2,000 MW of wind power with associated transmission works on South Australia's Eyre Peninsula over the period 2015/16 to 2019/20. This sensitivity is similar to the stage 1 development outlined in the Green Grid proposal.

Study methodology

Market modelling was used to assess the net market benefits[6] of each augmentation option compared with a base case with no upgrade. This was done for all three scenarios and the Green Grid sensitivity.

Two sets of results were obtained:

1. Long-term least-cost expansion modelling results: These results were from simulations based on a least-cost expansion model, which co-optimised transmission and generation investments in the NEM over a 20-year horizon (2014/15 to 2033/34). The analysis yields results that are internally consistent: the co-optimisation approach ensures generation and transmission expansion decisions take account of the impacts of those decisions on operational costs. The model contains a number of simplifications, however, and has limited ability to accurately assess some effects such as:
    - the impacts of wind variability; and
    - changes in system losses arising from network augmentations.
2. Short-term time-sequential modelling results: The time-sequential results are intended to provide additional insight into the impacts of wind variability and network losses. The time-sequential analysis uses more detailed scheduled dispatch modelling which examines hour by hour outcomes. However, the time-sequential modelling only examined every fifth year, and used the generation expansion produced by the least-cost expansion modelling. These results may not be internally consistent. For example, higher losses in the time-sequential results might change or delay the generation expansion plan compared with the least-cost expansion modelling or vice

[5] Fast rate of Change and Decentralised World: \$49.90/tonne in 2013/14 to \$93.50/tonne in 2029/30, Oil Shock and Adaptation: \$33.30/tonne in 2013/14 to \$62.30/tonne in 2029/30

[6] *Market benefits* means the present value of the total benefit of an option to all those who produce, distribute and consume electricity in the National Electricity Market (NEM)

versa. It is thus not possible to compare these results across scenarios as one simulation run may have degraded more from the optimal timing than the other. These results should therefore be viewed as secondary to the least-cost expansion results and treated with caution

The timing of the incremental augmentation option was optimised by the market modelling. For the three market development scenarios considered, the four new high-capacity augmentation options were assessed with staged timing as follows:

- Stage 1 in 2024/25 and stage 2 in 2029/30, or
- Stages 1 and 2 both in 2029/30.

The new high-capacity augmentation options included optimised timing of the incremental option.

The Green Grid sensitivity enters more generation in the first decade and is expected to lead to an earlier need for an augmentation, and consequently the staged timing assessed for this was:

- Stage 1 in 2019/20 and stage 2 in 2024/25, or
- Stage 1 in 2024/25 and stage 2 in 2029/30.

The central high-capacity augmentation option was not analysed in the Green Grid sensitivity as it did not resemble any of the options discussed in the Green Grid report.

Study limitations

The feasibility study is intended to be a preliminary investigation of options only, and is, therefore, necessarily limited in its scope. Study limitations included:

- a limited number of scenarios, all of which assumed at least a medium level of carbon pricing,
- a limited range of capital and operating cost assumptions for generation and transmission assets,
- a limited range of timing for new generation technologies,
- a limited number of transmission augmentation and routing alternatives (for example, options involving multi-terminal HVDC and high voltage AC technologies above 500 kV were not explored).

Furthermore, the least-cost expansion modelling:

- did not cover all classes of market benefits (competition benefits and benefits arising from changes in transmission losses are notable exclusions);
- used simplifying assumptions in the co-optimisation of generation and transmission, including the use of fixed transmission losses[7] and average wind generation profiles; and
- end-effects in net present value calculations were treated conservatively, delivering lower market benefits than would otherwise be the case.

The time-sequential modelling:

- provided some indication of the impacts of wind variability and loss benefits not covered in the least-cost expansion modelling; but

[7] Fixed in the sense that losses did not change as generation and transmission system was altered but was assumed to be equal to the losses of the base run for that particular scenario

- was performed for every fifth year only and relied on interpolation of costs and benefits in the years between; and
- relied on the generation expansion plans from the least-cost expansion modelling results with no feedback to ensure consistency between capital investments and their operational cost impacts.

For these reasons, the time-sequential results are only indicative and should be treated as secondary outcomes.

Key results

Table 2 shows the net market benefits of each option arising from the least-cost expansion results.

Table 2 Net market benefits from least-cost expansion modelling ($ million[8])

Option and timing	Fast Rate of Change	Decentralised World	Oil Shock and Adaptation
Incremental (optimised timing)	26 (2025/26)	28 (2019/20)	22 (2029/30)
Northern AC 2025	-451	-697	-663
Northern AC 2030	-152	-404	-349
Northern DC 2025	-326	-538	-565
Northern DC 2030	-160	-350	-352
Southern 2025	32	-43	-32
Southern 2030	73	-7	7
Central 2025	-554	-531	-707
Central 2030	-240	-270	-396

Option and timing	Green Grid
Incremental	88 (2017/18)
Northern AC 2020	-633
Northern AC 2025	-283
Northern DC 2020	-454
Northern DC 2025	-168
Southern 2020	118
Southern 2025	161

The incremental option (with optimal timing shown) results in a net market benefit under all scenarios. The timing of the incremental option was generally delayed when considered in conjunction with the new high-capacity augmentation options.

The southern option provides higher benefits than the incremental option under the Fast Rate of Change scenario and the Green Grid sensitivity.

The Green Grid sensitivity assumes 2000 MW of new wind generation is connected north and west of Davenport between 2015 and 2020 and exhibits increased benefits compared to the base case Fast

[8] The draft report listed market benefits in 2015 dollars.

Rate of Change scenario, which selected a maximum of approximately 700 MW of new wind generation in the same location. The characteristics of the Fast Rate of Change scenario - high economic growth, high carbon price and the expansion of the Olympic Dam mine in South Australia - are particularly favourable for the Green Grid proposal.

The supplementary time-sequential results indicate that the net market benefits of the high-capacity augmentation options may be higher than indicated in the least-cost expansion results shown in Table 2 because there are significant loss reductions associated with the new high capacity transmission lines. For the northern options in particular (both AC and DC technology) the net market benefits become positive in some scenarios.

The time-sequential results also suggest that the higher flows on the existing transmission system in the incremental upgrade case cause higher losses that might act to delay the optimal timing indicated above. More accurate quantification of these effects is beyond the scope of this feasibility study.

Key conclusions

- The feasibility study has demonstrated that there is potential for augmenting transmission capacity between South Australia and the rest of the NEM, not only to facilitate export of renewable energy out of South Australia, but also to support South Australian peak demand as the level of intermittent generation increases.
- The incremental option to augment the existing Heywood interconnector was shown to be economically feasible as early as 2017/18 under high growth and carbon price conditions and with significant wind investment in South Australia (Green Grid sensitivity). The optimal timing of the incremental option was delayed under less favourable conditions. Changes in system losses not assessed as part of the least-cost expansion results may also delay the incremental option. However, if other market benefits are taken into account (e.g. competition benefits) the timing could be advanced.
- Of the new high-capacity augmentation options assessed the lowest-cost southern option and the northern options appear most likely to be economically feasible in the 2020 to 2030 timeframe.
- The economic feasibility of the interconnector options is sensitive to a number of factors including the future market development scenarios considered, assumptions made about climate change policy settings (e.g. introduction of carbon pricing), and the estimated costs of the options.
- The timing of the new high-capacity augmentation options is expected to advance if additional incentives are provided to the renewable sector, for example extension of the Large-scale Renewable Energy Target (LRET) scheme with stronger targets beyond 2020.
- A new high-capacity interconnector augmentation option could be justified under high growth and carbon price conditions and with significant committed wind investment in South Australia (for example Green Grid sensitivity) as early as 2020 to 2025.

Next steps

Based on the outcomes of this feasibility study, AEMO and ElectraNet intend to undertake further work in 2011 that is focussed on clarifying the costs, benefits and timing of the lower cost incremental augmentation option (including a more accurate assessment of the impact of changes in system losses).

This further work is not intended to involve a formal application of the regulatory investment test for transmission (RIT-T), but will better inform when a formal regulatory assessment may be needed. The outcomes of this work will be reported in future South Australian and Victorian Annual Planning Reports and the National Transmission Network Development Plan.

The new high-capacity augmentation options assessed in this feasibility study will be kept under review as part of the annual planning processes that result in publication of Annual Planning Reports and the National Transmission Network Development Plan.

Consultation

On 19 November 2010, ElectraNet and AEMO issued a draft report in relation to this feasibility study and held a stakeholder forum on 30 November 2010 to brief market participants and other interested parties on the outcomes of the study. A number of submissions from stakeholders were received and these have been taken into account in finalising this report. A response to key issues and questions raised in stakeholder submissions is included as an attachment to this report.

1 Introduction

ElectraNet Pty Ltd and the Australian Energy Market Operator (AEMO) have conducted a joint feasibility study of transmission development options that could economically increase interconnector transfer capability between South Australia and other National Electricity Market (NEM) load centres.

The purpose of the study was to assess the economic benefits gained from increasing the transfer capability between South Australia and the rest of the NEM. Furthermore, increased interconnector transfer capability is expected to enable further development of South Australia's extensive renewable resources while also providing South Australia with improved access to reliable thermal generation in the rest of the NEM, particularly at peak demand times.

The feasibility study involved:

- developing a range of technically feasible transmission development options,
- determining reasonable cost estimates for each of the options proposed,
- selecting a reasonable set of market development scenarios covering a range of potential future conditions, and
- using simulation techniques to assess the market benefits generated by each option under each scenario.

The feasibility study was a preliminary, high-level study aimed at identifying which augmentation options would be likely to satisfy the Regulatory Investment Test for Transmission (RIT-T), not an attempt to apply the RIT-T. In doing this, the study selected market development scenarios that favour renewable generation (with all scenarios imposing a price on carbon emissions), and assessed only a limited range of market benefits and cost sensitivities.

This report details the study's approach and conclusions.

1.1 Purpose

This study arose from ongoing questions about the potential development of South Australia's extensive renewable energy resources and how limits on South Australia's energy export capability may limit the extent to which these resources can be developed. The study also addresses the need to investigate future South Australian transmission system congestion identified in AEMO's 2009 National Transmission Statement.

The main purpose of the feasibility study was to assess the economic benefits gained from increasing transfer capability between locations with promising renewable energy resources in South Australia and other NEM load centres, enabling these renewable resources to help meet the challenges of climate change and a future of low carbon intensity for Australia.

In July 2010, a consortium funded by the South Australian Government issued the Green Grid report, which studied the feasibility of locating a significant amount of wind generation on South Australia's

Eyre Peninsula[9]. The report concluded that a viable business case exists for investment in transmission and generation to unlock large-scale renewable energy generation in the Eyre Peninsula. This feasibility study included a Green Grid sensitivity to assess outcomes under similar assumptions of generation development to those used in the Green Grid report.

1.2 Scope

The specific objectives and scope of the feasibility study were to:

- develop a range of transmission investment options that are:
  - compatible with existing national transmission networks,
  - considered feasible from an approvals and construction perspective,
  - capable of increasing the transmission transfer capability to and from South Australia, covering a range of potential solutions from inexpensive incremental enhancements to large high-capacity augmentation increases,
- determine reasonable cost estimates for each of the options identified,
- apply reasonable market development scenarios to explore a range of potential future conditions,
- use simulation techniques to assess the market benefits provided by each investment option, and
- analyse and report on the technical and economic feasibility of the option outcomes.

1.3 Approach

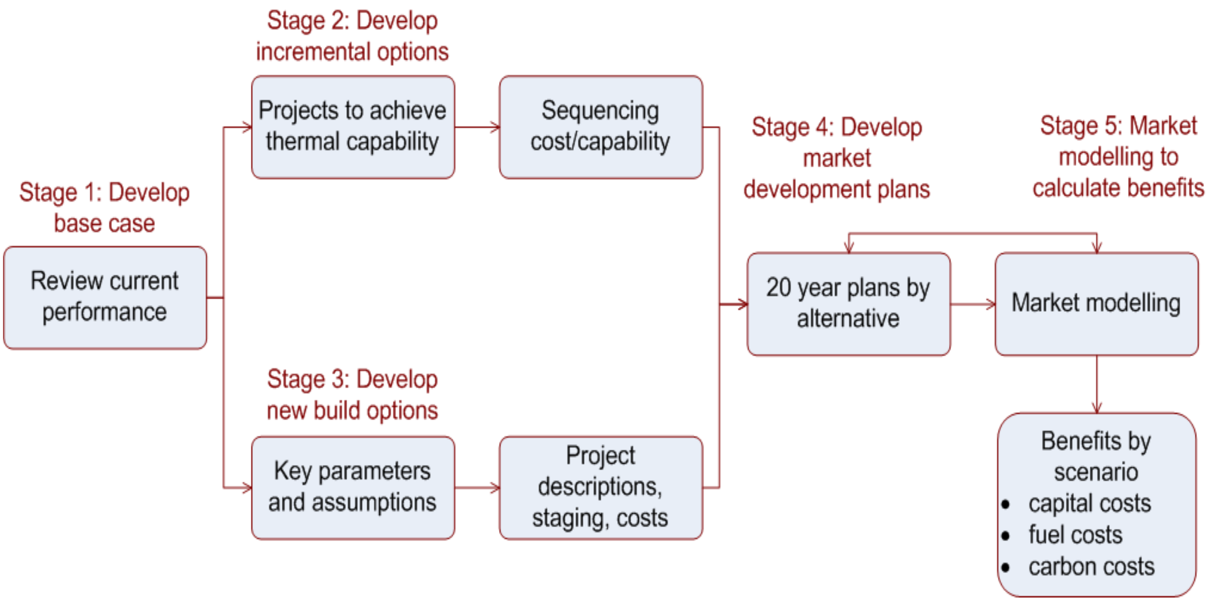
The feasibility study compared the total costs to the NEM of meeting demand for a base case with no extra interconnection capability between South Australia and the rest of the NEM against a number of options that would increase that capability.

The cost comparison was made over a 20-year period from 2014/15 to 2033/34 under a range of market development scenarios describing possible future conditions of economic growth, technological advancement, fuel scarcity, and external policy settings such as an imposed price on carbon emissions.

The study consisted of several stages as shown in Figure 2.

[9] Macquarie (2010) report: “Green Grid - Unlocking Renewable Energy Resources in South Australia” available from: http://www.renewablessa.sa.gov.au

Figure 2 Study stages



In detail, the stages of development were:

Stage 1: develop a base case for comparison with the augmented cases, including an assessment of the historical performance of existing interconnectors and the associated transmission network, and identification of current constraints and operational practices that restrict transfer capability.

Stage 2: develop incremental augmentations of existing interconnectors to raise transfer capability to thermal limits.

Stage 3: develop new high-capacity interconnector options by identifying transmission capacity requirements over the planning horizon and performing preliminary design, staging and costing.

Stage 4: develop detailed 20-year network development plans that deliver a secure and operable power system through refinement of the technical requirements of the augmentation options and identification of other intraregional transmission upgrades that may be required.

Stage 5: develop a reduced network market model containing detailed capital and operating cost assumptions and use the model to assess the benefits of each augmentation option.

Stages 4 and 5 were performed in parallel, with the generation expansion resulting from the market modelling informing the network analysis work and the network analysis work being used to validate the operational outcomes of the market modelling.

The study was conducted in an open manner involving other Jurisdictional Planning Bodies as required, in particular TransGrid in relation to potential developments within New South Wales.

A stakeholder briefing, open to all interested parties was held in Adelaide in April 2010 to invite feedback on the intended approach to the study and the augmentation options and market development scenarios being considered.

On 19 November 2010, ElectraNet and AEMO issued a draft report and held a stakeholder forum on 30 November 2010 to brief market participants and other interested parties on the outcomes of the study. A number of submissions from stakeholders were received and these have been taken into account in finalising this report. A response to key issues and questions raised in stakeholder submissions accompanies this report.

An independent peer reviewer, Greg Thorpe, from the consultancy Oakley Greenwood, was engaged to review input data sources, assumptions, methods and outcomes of the analysis.

Furthermore, ElectraNet and AEMO engaged McLennan Magasanik Associates (now SKM-MMA) to assist with development of the market model and Sinclair Knight Merz (SKM) to provide independent cost estimates for the transmission investment options considered.

The peer review report and the SKM cost estimate report are available along with this report on ElectraNet's and AEMO's websites[10].

1.4 Report outline and additional information

This report provides a high-level summary of the approach, methodology, key assumptions and conclusions of the feasibility study. The report is structured as follows:

- **Section 2, Market Development Scenarios**, provides an overview of the scenarios used, how they were developed and the key drivers in each one.
- **Section 3, Network Options**, includes information on the development of the augmentation options, a summary of their technical details and their estimated costs.
- **Section 4, Cost-Benefit Evaluation**, includes information on the cost benefit analysis undertaken, including the market modelling approach used, key assumptions made and the modelling results.
- **Section 5, Key Conclusions**, summarises the conclusions that can be drawn from the cost-benefit analysis.
- **Section 6, Next steps**, provides information on the next steps that ElectraNet and AEMO intend to pursue on completion of this feasibility study.

This report supersedes the draft report issued by AEMO and ElectraNet in November 2010. Apart from editorial changes, the key changes in this report are:

- various amendments to take into account issues and comments raised by interested stakeholders in their submissions; and
- results of additional time sequential modelling undertaken following the release of the draft report have been added.

[10] ElectraNet: http://electranet.com.au; AEMO: http://www.aemo.com.au

This report is accompanied by the following:

- the Joint Feasibility Study Network Modelling Report, which details the approach, methodology, and assumptions behind the network analysis that was undertaken for this feasibility study,
- the Joint Feasibility Study Market Modelling Report which details the approach, methodology and the assumptions behind the market modelling work undertaken for this feasibility study,
- the External Peer Review Report, prepared by Greg Thorpe of Oakley Greenwood,
- the AEMO-ElectraNet Feasibility Study Estimates Final Report Rev2 which details the cost estimates of the interconnector augmentation projects, prepared by SKM,
- the Joint Feasibility Study response to submissions, and
- a supplementary results data package.

All reports and the data package are available at:

- www.electranet.com.au
- www.aemo.com.au.

2 Market development scenarios

This section presents information about the market development scenarios used in the feasibility study.

2.1 Scenario development background

In 2009, AEMO developed a series of scenarios in conjunction with the Department of Resources, Energy and Tourism (DRET), and in consultation with a Stakeholder Reference Group (SRG) made up of industry experts with a diverse range of experience and interests[11]. The SRG's input was synthesised into a common strategic framework for long-term energy modelling. Five market development scenarios were developed by combining the principal energy sector and national transmission network development drivers identified by the framework.

Each market development scenario describes the Australian stationary energy sector in the year 2030, and explores a series of credible outcomes in the presence of uncertainties that include:

- the introduction of measures that place a cost on carbon emissions which are expected to lead to changes in consumption patterns and generation sources, and
- energy and maximum demand forecasts driven by changes in the economy and demographic patterns.

To ensure consistency between AEMO's planning documents and studies, these scenarios were also applied to the 2010 NTNDP, Victorian Annual Planning Report (VAPR), South Australian Supply-Demand Outlook (SASDO), Electricity Statement of Opportunities (ESOO), and Gas Statement of Opportunities (GSOO).

2.2 Scenario descriptions

The five scenarios consider distinct socio-economic futures designed to capture a diverse range of potential developments. Each scenario is analysed under a base carbon price and an alternative carbon price trajectory. The five scenarios are each characterised by a core theme:

- The Fast Rate of Change scenario describes a world where relatively strong emission reduction targets have been agreed internationally by both developed and developing countries, and there is high sustained economic growth in Australia. Successful adaptation to a carbon-constrained world is partly possible, due to government and industry investment in the development of new technologies.

[11] Australia Pipeline Industry Association (APIA), Australian Academy of Technological Science of Engineering, Australian National Low Emission Coal Research And Development, Australian Petroleum Production & Exploration Association (APPEA), Clean Energy Council, CSIRO, Domgas Alliance, Energy Networks Australia (ENA), Energy Retailers Association of Australia (ERAA), Energy Supply Association of Australia, Energy Users Association of Australia (EUAA), Grid Australia, Major Energy Users, Minerals Council of Australia, National Generators Forum

- The Uncertain World scenario describes a world characterised by carbon policy uncertainty both internationally and domestically, creating barriers for emerging technologies, and is coupled with high economic growth in Australia.
- The Decentralised World scenario describes a world where Australia's energy network becomes highly decentralised by 2030, with significant investment in demand-side technologies. Moderate emission targets are coupled with medium economic and population growth, and all sectors of the Australian economy do well.
- The Oil Shock and Adaptation scenario describes a world characterised by low reserves of oil coupled with internationally agreed emissions targets. Weak economic growth and moderate levels of population growth are observed.
- The Slow Rate of Change scenario describes a world characterised by low economic growth coupled with internationally agreed low emission targets. Weak economic growth and low levels of population growth are observed. Boosting economic activity becomes a priority.

2.2.1 Scenario drivers and emissions targets

Two alternative carbon prices (and therefore emissions targets) are associated with each scenario, providing a total of 10 cases. Table 3 lists the drivers and emission targets for each scenario. All scenarios included the Large-scale Renewable Energy Target (LRET) scheme.

Table 3 Scenario drivers and emissions targets

Scenario	Economic growth	Population growth	Global carbon policy	Centralised supply-side response	Decentralised supply-side response	Demand-side response	Emission targets below year 2000 levels[12]
Fast Rate of Change	high	high	strong	strong	strong	strong	-25% (sensitivity -15%)
An Uncertain World	high	high	weak	strong	weak	weak	-5% (sensitivity no carbon price)
Decentralised World	medium	medium	strong	weak	strong	strong	-15% (sensitivity -25%)
Oil Shock and Adaptation	low	medium	moderate	moderate (renewable)	weak	weak	-15% (sensitivity -5%)
Slow Rate of Change	low (mixed)	low	weak	moderate	weak	weak	-5% (sensitivity no carbon price)

12 Australia's Low Pollution Future – the Economics of Climate Change Mitigation, 30 October 2008

2.3 Scenarios considered for the feasibility study

Three of the five scenarios were selected for the joint feasibility study:

- Fast Rate of Change, under the -25% carbon emissions target,
- Decentralised World, under the -25% carbon emissions target, and
- Oil Shock and Adaptation, under the -15% carbon emissions target.

These scenarios were selected because they provide a diverse range of potential developments and, with their higher carbon price trajectories, the most favourable conditions for new renewable generation and thus additional interconnection between South Australia and the rest of the NEM.

The following sections describe each selected scenario in more detail.

2.3.1 Fast Rate of Change

The Fast Rate of Change scenario describes a world in which relatively strong emission reduction targets have been agreed internationally by both developed and developing countries. The scenario assumes targets have been set to achieve a global carbon dioxide equivalent (CO2-e) emission concentration not exceeding 450 parts per million (ppm) by 2050. Domestic and overseas governments have successfully introduced policy frameworks to implement the targets, and by 2030 all interim emission targets have been met. The transition to a carbon constrained future has been smooth.

Government and industry investment in low emissions technology such as carbon capture and sequestration (CCS) means that these technologies are cheaper than expected. The strong emphasis on research and development (R&D) and pilot and large-scale technology demonstration has meant that new demand and supply-side options have moved rapidly down learning curves, and have been successfully developed on a commercial scale. The process of R&D has also grown the domestic skill base required to efficiently install and operate new energy technologies.

Geothermal, solar and wind are available for commercialisation on a large scale. Coal and gas generation can be fitted with CCS to enable continued operation in traditional generation locations.

In this scenario, underlying demand for electricity is likely to be high due to factors such as high economic growth, sustained population growth, water desalination and the high uptake of electric plug-in vehicles. However, diversification of energy sources, emission reductions from new technologies, improvements in energy efficiency and other types of demand-side participation (DSP) have been sufficient to enable the strong emission reduction targets to be met.

Under this scenario, carbon prices range from $49.90/tonne in 2013/14 to $93.50/tonne in 2029/30[13].

[13] All costs are quoted in real 2010 Australian dollars

2.3.2 Decentralised World

Under a Decentralised World, Australia's energy network is highly decentralised by 2030 and there has been significant new investment in demand-side technologies. The scenario assumes that moderate emission reduction targets aimed at restricting CO2-e emission concentration to less than 500 ppm have been implemented and met, both in Australia and internationally.

Demand-side technologies and distributed generation emerge as lower cost alternatives to new centralised supply-side options, such as geothermal generation or CCS. The emergence of fuel cells in homes, coupled with the high uptake of commercial and industrial cogeneration and tri-generation, increases domestic demand for gas.

New low-emission, base-load power sources, such as geothermal and CCS technologies, have proven more expensive than first thought, depressing large-scale uptake. The renewable energy target provides incentives for strong growth in wind generation and small-scale renewable generation.

In this scenario, underlying demand for electricity is likely to be moderate due to medium-level economic and population growth. Carbon prices range from $49.90/tonne in 2013/14 to $93.50/tonne in 2029/30.

2.3.3 Oil Shock and Adaptation

Oil Shock and Adaptation represents a world in which oil reserves are in short supply, resulting in low global economic growth. Nonetheless, the scenario assumes there is international agreement that a carbon policy is essential to combat climate change. The scenario assumes that emission reduction targets are set to limit CO2-e emission concentration to 500 ppm by 2050.

After reaching agreement on a global carbon emissions policy, the international economy is challenged by a global oil shortage, putting upward pressure on oil and gas prices and leading to low economic growth both internationally and domestically. Higher than expected CCS costs and fossil fuel prices lead to greater reliance on centralised renewable energy options.

Weak economic growth but a moderate level of population growth leads to moderate to low underlying demand for electricity in all sectors of the economy. This has moderated the rate of increase in CO2-e emissions. However, demand-side initiatives and CCS have proven to be more costly than first anticipated, which has made meeting the CO2-e emission target more challenging.

Under this scenario, carbon prices range from $33.30/tonne in 2013/14 to $62.30/tonne in 2029/30.

2.4 Green Grid sensitivity

In addition to the three scenarios, a Green Grid sensitivity analysis was included in the feasibility study. This sensitivity on the Fast Rate of Change scenario examined the merits of the different augmentation options assuming that 2,000 MW of new wind generation is built on the Eyre Peninsula within the next 10 years. This wind generation assumption is similar to stage 1 of the Green Grid proposal.

The assumptions for the Green Grid sensitivity include:

- 400 MW per year of additional wind at various locations on the Eyre Peninsula from 2015/16 to 2019/20 (2,000 MW in total), and
- new generation is connected via double-circuit 275 kV lines to Davenport.

The costs of development of this new generation and its connection to Davenport were included in the cost-benefit assessment. All other generation developed (within and outside South Australia) was least-cost optimised by the market modelling to meet capacity, energy and LRET targets.

The sensitivity follows the Fast Rate of Change assumptions in all other regards.

3 Network Options

This section provides a summary of the capability of the existing interconnectors between South Australia and Victoria and information on the development of the augmentation options assessed in the feasibility study.

3.1 Existing interconnector capability

The two existing interconnectors between South Australia and the rest of the NEM are:

- the Heywood interconnector, with a dispatch limit of 460 MW, and
- the Murraylink HVDC interconnector with a rating of 220 MW.

Before considering potential interconnector augmentation options, ElectraNet and AEMO reviewed the capability and performance of the two existing interconnectors under system normal conditions.

3.1.1 Heywood interconnector

- For flows from Victoria to South Australia, the Heywood transfer limit can vary between 0 MW and 460 MW in response to local network thermal ratings, voltage and reactive power limits, system demand and generation in south east South Australia.
- For flows from South Australia to Victoria, the Heywood transfer limit can vary between 150 MW and 460 MW in response to local network thermal ratings, voltage and reactive power limits, system demand and generation in south east South Australia.

3.1.2 Murraylink interconnector

- In the South Australia to Victoria direction, thermal limits on the 132 kV transmission system in South Australia's Riverland region restrict flows on Murraylink to less than 180 MW (with runback schemes in place).
- In the Victoria to South Australia direction at times of low demand, Murraylink flows can be limited by transient stability constraints in Victoria, or by thermal limits on the South Morang 500/330 kV transformer. At times of peak demand, Murraylink flows can be limited to less than 50 MW by voltage collapse constraint equations applied to Victoria.

3.1.3 Combined Heywood and Murraylink interconnector limits

In the market dispatch systems there are multiple constraint equation sets that limit the combined transfer capability of the Heywood and Murraylink interconnectors.

Oscillatory stability limit

An oscillatory stability constraint equation limits power transfer from South Australia to Victoria on both Heywood and Murraylink to a total of 580 MW[14]. For the purposes of this feasibility study this limit was ignored[15] and the thermal capacity of the interconnectors was considered as fully available.

Transient stability limit

The Victorian transient stability export limit restricts power transfer from Victoria to New South Wales and South Australia, with the export limit to New South Wales increasing as export to South Australia decreases and vice versa. This transient stability limit restricts flows to New South Wales and South Australia from Victoria (limits may be raised economically by increasing flow on Basslink into Victoria or increasing dispatch of Victorian hydroelectric generation). The transient stability limit was not included in this feasibility study. AEMO is currently reviewing this limit as part of its annual planning process.

Transformer thermal limit

The South Morang 500/330 kV transformer thermal constraint equation can limit flows from South Australia to Victoria when demand in Victoria is low and power transfer to New South Wales is high. The impact of this constraint equation is to increase Victorian generation (and potentially the Victorian prices). The requirement to upgrade this transformer was assessed as part of the feasibility study.

3.2 Incremental augmentation options

Incremental options are relatively inexpensive augmentations that allow the full thermal capability of existing assets to be used, without requiring construction of new transmission line circuits.

3.2.1 Incremental augmentation of the Heywood interconnector

A third 500/275 kV transformer at the Heywood terminal station and associated minor works in South Australia would allow increased transfers to and from South Australia as the existing transformer capacity is currently the limiting factor on this interconnector.

This option has previously been identified by ElectraNet and AEMO as a low-cost interconnector augmentation which will release additional transfer capacity on the Heywood interconnector.

Power flow through the Heywood transformers, in the absence of broader system transient stability, voltage collapse or oscillatory constraints, is limited by the N-1 post-contingent rating of a single transformer. Each transformer is rated at 370 MVA for continuous operation, and limited to 460 MW for post-contingent short term operation.

14 This limit was increased from 420 MW on 6 January 2011.

15 Addition of new interconnectors, particularly between New South Wales and South Australia, would require significant review of constraint equations currently applied to the NEM. Stability constraint equations may no longer apply in their present form.

Addition of a third 370 MVA (continuous) transformer increases the total N-1 post-contingent rating to a sum of the post-contingent rating of the two remaining transformers, or a dispatch limit of 920 MW. This increase brings the post-contingent rating of the transformer bank to a value above the post-contingent transfer capability of the South East-to-Heywood 275 kV lines, which have a maximum winter rating of 675 MVA. These lines then become the limiting factor for the interconnector, meaning that the interconnector's capability can be increased from 460 MW to 650 MW (the post-contingent transfer capability of the 275kV lines).

Detailed assessment was undertaken to identify any other works that would be required to support the increased transfers between South Australia and Victoria with the third transformer in place. The assessment identified the following requirements:

- 100 MVAr shunt capacitor bank at South East 275 kV substation,
- dynamic line rating for the Tailem Bend-to-South East 275 kV lines, and
- dynamic line rating of the 132 kV lines in the south east region of South Australia.

3.2.2 Incremental augmentation of the Murraylink interconnector

The Murraylink HVDC link does not easily allow for incremental upgrades. The owner of Murraylink, Australian Pipeline Trust (APA), has advised that there is potential to implement a short term overload capability (adding an additional 5% to maximum capability), or to build a parallel link. Due to the cost involved with a parallel link, it has not been considered as an incremental upgrade for the purpose of the feasibility study.

The option to implement a short term overload capability could be further considered once future reinforcement of the Riverland network in South Australia occurs.

Currently, the network in Victoria allows up to the maximum import and export of 220 MW to be transferred on Murraylink, however thermal and voltage limitations reduce this capacity at high demand periods.

Murraylink includes extensive runback schemes to extend the range of its operation, and there is little scope to increase the transfer capability without additional work between Red Cliffs and the load centres of Victoria or New South Wales. Potential upgrades on the Ballarat-Bendigo 220 kV and Ballarat-Moorabool 220 kV lines within regional Victoria will be assessed under a RIT-T application within the next five years[16].

Installation of dynamic line rating for the Robertstown-Monash 132 kV lines, along with some reactive support at Monash in South Australia, has been identified by ElectraNet as an augmentation option to allow for increased South Australia to Victoria flows, up to thermal capability of the interconnector (220 MW), under favourable environmental conditions. The cost of the augmentation (installation of a 132 kV 30 MVAr shunt capacitor bank at Monash and installation of weather stations and dynamic line rating of Robertstown-Monash 132 kV lines) was estimated by ElectraNet at $5 million. This relatively low-cost upgrade was included in the base case of the feasibility study, as well as all

[16] 2010 Victorian Annual Planning Report.

upgrade scenarios. As such the feasibility study did not assess the benefits of the Murraylink incremental upgrade, but instead treated it is a committed project.

3.2.3 Incremental upgrade option summary and costs

Table 4 shows the incremental augmentation considered for the feasibility study. The indicative costs for this option were provided by SP AusNet and ElectraNet.

Table 4 Incremental augmentation

Description	Augmented capacity (MW)	Indicative cost ($ million)
▪ 3rd transformer at Heywood	650[17]	33
▪ 100 MVAr capacitor bank at South East 275 kV ▪ dynamic line rating of Tailem Bend to South East to Heywood 275 kV lines		5

3.3 New high-capacity augmentation option development

The new high-capacity augmentation options assessed under this feasibility study were identified at a workshop attended by ElectraNet, AEMO and a representative from TransGrid. Existing interconnector capabilities were analysed in combination with potential locations of future generation development to guide decisions about the location and size of new interconnectors. The potential locations of future generation were based on ElectraNet's and AEMO's current connection activity, AEMO's 2009 National Transmission Statement and the Commonwealth Government's National Energy Scenarios Modelling[18].

3.3.1 New high-capacity augmentation option path development

A significant driver in the identification of new high-capacity augmentation development was potential generation and demand locations in the South Australian power system. While the north and south regions of the state have significant renewable generation development potential, the central region is where demand is concentrated. Interconnector options terminating within each of the north, south and central regions of South Australia were selected to ensure that the transmission requirements due to different generation locations could be compared. Furthermore, under the market development scenarios considered it appeared likely that generation in South Australia would be competitive in either Victoria or New South Wales.

[17] Based on N-1 post-contingent thermal ratings of the two South East-Heywood 275 kV lines.

[18] See www.ret.gov.au

The working group developed:

- a northern option, connecting northern South Australia directly to New South Wales,
- a southern option to improve existing links between South Australia and Victoria, and
- a central option between South Australia and New South Wales, passing through northern Victoria.

For the northern option, Mount Piper was chosen as a connection point in New South Wales due to ongoing 500 kV network developments providing a strong connection to load centres in New South Wales[19]. The South Australian end connects to 275 kV lines between Davenport and the Hallett wind farms, nominally at Wilmington.

For the southern option, Heywood was chosen as a connection point in Victoria for its existing 500 kV links. A new connection point at Krongart connects the new interconnector to the South Australian 275 kV network.

Routing of the central option was chosen by taking into consideration possible future 500 kV network developments in regional Victoria, and allowing for the future connection of renewable generation in this region[20]. The South Australian connection point at Tepko provides access to the major load in Adelaide. The interconnector is routed via Horsham and Shepparton in Victoria, and terminates at Yass, having access to the load centre of Canberra and proximity to existing 500 kV assets at Bannaby.

When selecting line routes, detailed assessment of easement availability was not undertaken, however the location of existing national parks was considered.

3.3.2 New high-capacity augmentation option technology

The new high-capacity augmentation options were primarily developed as AC solutions. A lower cost point to point HVDC option was developed as a second northern option.

For the AC augmentation options, 500 kV AC transmission solutions were chosen because 500 kV is the highest AC voltage currently used in Australia, and would have sufficient capacity to transfer the required power levels over the distances considered. Lower voltages were not considered feasible over the distances considered.

Consideration was also given to higher transmission voltages, but these were excluded from this feasibility study to limit the number of options to be assessed.

Similarly for the HVDC augmentation option, 500 kV was selected as the solution to study. Higher transmission voltages or application of multi-terminal technology were not considered in the analysis to limit the number of options under consideration.

[19] See TransGrid Strategic Network Development Plan: http://www.transgrid.com.au/aboutus/pr/Documents/Strategic Development Network Plan 2008.pdf

[20] See VenCorp Vision 2030 document: http://www.aemo.com.au/planning/2030.html

The northern AC augmentation option was routed via Broken Hill to allow for the possible connection of large-scale renewable projects in this area.

In the case of the central augmentation option, only an AC option was considered as the intention was to be able to connect generation at different points along the line route.

A HVDC option was not considered for the southern augmentation option as the shorter distance of this option would make the HVDC option substantially higher in cost than the AC option.

3.3.3 Staging of options

To reduce cost through deferral of capital expenditure, design of the augmentation options allowed for division of the new interconnector capacity into two 1,000 MW stages.

- For the AC options, the first stage consists of a new double-circuit 500 kV line. The second stage involves installation of additional transformer capacity and series compensation needed to achieve the maximum design capacity of the interconnector.
- For the DC option, the first stage is a twin-conductor line, operated as a HVDC monopole. The second stage involves the installation of extra converters to convert the monopole into a bi-pole.

3.3.4 Specification and costing of options

ElectraNet and AEMO, with assistance from TransGrid, developed technical scopes for each of the new high-capacity augmentation options, including transformer requirements and static and dynamic reactive power requirements including series compensation. These technical specifications were developed with requirements for secure and reliable operation of the network taken into account. The design for the northern AC option was based on previous studies undertaken by TransGrid.

SKM was engaged to provide cost estimates for each of the new high-capacity augmentation options.

To allow a consistent comparison between the options the following standard design blocks were adopted:

- breaker and a half bus arrangements,
- quad Orange conductors for 500 kV lines,
- twin Sulphur conductors for 275 kV lines,
- twin Olive conductors for 330 kV lines,
- quad Sulphur conductors for HVDC lines,
- duplicate high-speed communication paths,
- static var compensators (SVCs) to assist with system stability,
- 50% series compensation where applicable, and
- 1,000 MVA transformers.

Should any option progress to design stage, parameters such as conductor size and equipment rating would be optimised to take account of factors such as losses and expected future utilisation.

3.3.5 Augmentation option summary and costs

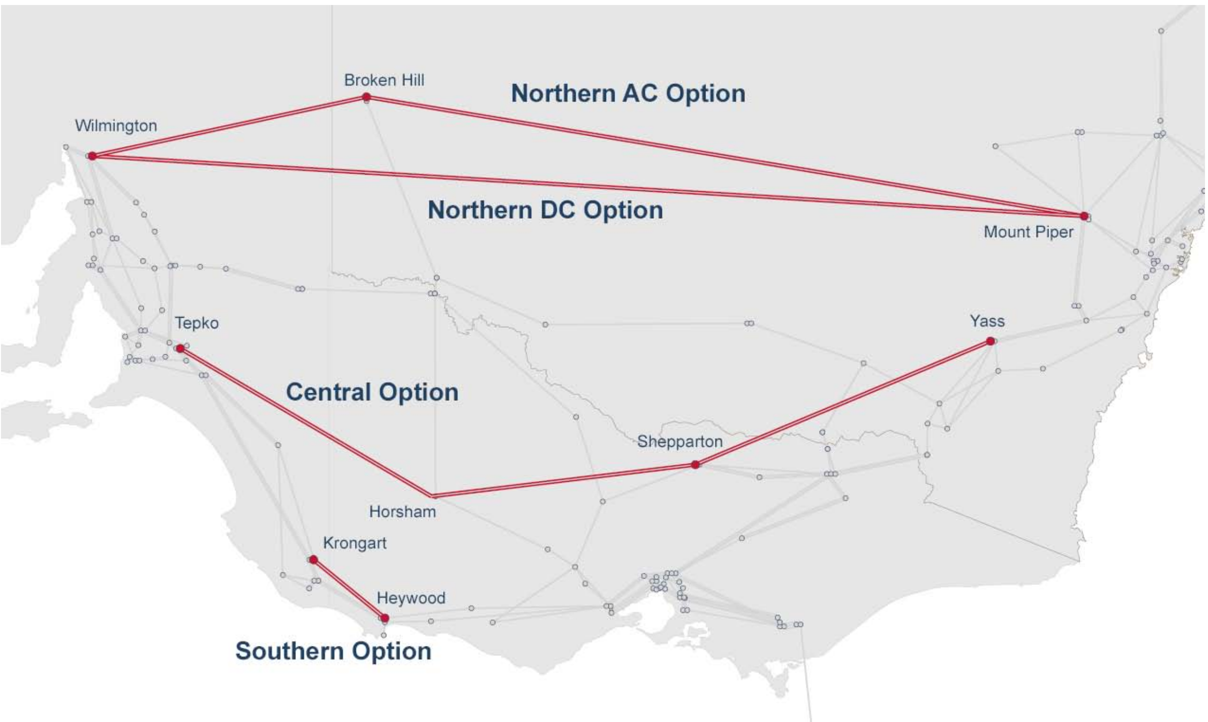
Table 5 shows a summary of the augmentation options studied. The indicative cost estimates for the new high-capacity augmentations were supplied by SKM.

Figure 3 shows an indicative transmission path for each of the new high-capacity augmentation options but does not attempt to display the actual routes of existing lines or potential new augmentations.

Table 5 Augmentation options summary

Option	Description	Distance (km)	Cost estimate ($ million)
Incremental (Heywood)	Add a third 500/275 kV transformer at Heywood in Victoria plus associated minor works in South Australia, increasing the interconnector transfer limit to 650 MW	N/A	38
Northern AC	Wilmington to Mount Piper 2000 MW 500 kV AC double circuit routed via Broken Hill	1,100	3,750
Northern DC	Wilmington to Mount Piper 2000 MW_500 kV HVDC bi-pole	1,100	3,000
Southern	Krongart to Heywood 2000 MW 500 kV AC double circuit	125	530
Central	Tepko to Yass 2000 MW 500 kV double circuit routed via Horsham and Shepparton	1,050	3,500

Figure 3 Indicative paths of new high-capacity augmentation options



3.4 Supporting augmentation projects

To fully realise the value of the new high-capacity interconnector augmentation options, a number of supporting transmission augmentations are potentially required to transfer power from generators to the interconnector, or from the interconnector to load centres. The following major support projects were included in the feasibility study:

- To support generation in northern South Australia, and the southern and central augmentation options, a rebuilding of the Davenport-Brinkworth-Para line to a high-capacity double circuit line. A second double circuit 275 kV transmission line was identified to connect Tepko near Adelaide with Krongart in the south east of South Australia.
- A 500 kV link between Yass and Bannaby in New South Wales, to connect the central option to the existing 500 kV transmission system around Sydney, and through it the large generation base west of Newcastle.
- A 500 kV link between Sydenham and Shepparton in New South Wales, to connect the central option to existing 500 kV transmission around Melbourne, and through it the large generation base in the Latrobe Valley.
- To support the southern option, augmentation of the Victoria-New South Wales interconnector through Albury-Wodonga, consisting of a third 330 kV line between South Morang and Dederang, a second line between Dederang and Wagga Wagga passing through Jindera and a new line between Wagga Wagga and Bannaby. TransGrid has noted that this option would require the replacement of single-circuit 330 kV lines with double-circuit 330 kV lines, and that a new site would likely be required for the Jindera substation works. For the purposes of this study the environmental impact of these developments has not been assessed, and TransGrid has advised that a similar development further west may be a more feasible route. Given this uncertainty, sensitivity studies were also undertaken with higher costs for this support option, and these studies showed that the increased costs did not have a material impact on the results.

The technical scopes for the supporting augmentation options were developed using similar processes and assumptions as for the new high-capacity augmentation options, with SKM again providing cost estimates.

Table 6 summarises the supporting augmentation options included in the feasibility study. Figure 4 shows the indicative paths of the supporting augmentation options but does not attempt to show actual routes of existing or potential new lines.

Table 6 Major supporting augmentation options and indicative costs

Key	Region	Description	Transfer capability (MW)	Distance (km)	Cost estimate ($ million)
1	SA	Rebuild Davenport-Brinkworth-Para 275 kV line as a double circuit with twin conductors	1,200	280	250
2	SA	Krongart-Tepko 275 kV double circuit with twin conductors	1,200	340	305
3	NSW	Bannaby-Yass 500 kV double circuit	3,000	120	380
4	VIC	Sydenham-Shepparton 500 kV double circuit	3,000	170	530
5	VIC-NSW	South Morang-Dederang-Jindera-Wagga-Bannaby 330 kV single circuit	900	660	490

Figure 4 Indicative paths of the supporting augmentations

3.5 Generic augmentation options

Although ElectraNet and AEMO attempted to identify specific transmission augmentations that would be required to support each new high-capacity augmentation option, it was recognised that the development required would depend heavily on where new generation would be located by the market modelling.

For example, while the 500 kV lines between Heywood and Moorabool currently have considerable spare thermal capacity to accept or supply the new southern augmentation option, a number of additional transmission augmentations will be required if there are a large number of new generation connections in this part of the network.

To allow for additional transmission investment over the 20-year study period, a set of generic augmentation costs were developed as input to the market model. These costs allowed the market model to select transmission lines or transformers for augmentation when it was economic to do so. This process is discussed further in Section 4.1.2.

The generic augmentation option costs, developed by AEMO for the NTNDP, are shown in Table 7.

Table 7 Generic transmission augmentation costs

Augmentation option	Indicative costs ($ million)
500 kV double-circuit transmission line (2,500 MW per circuit)	2.5/km
220 kV, 275 kV or 330 kV double-circuit transmission line (800 MW, 1,100 MW and 1,300 MW per circuit respectively)	1/km
220 kV double-circuit transmission line (500 MW per circuit)	0.75/km
132 kV double-circuit transmission line (150 MW per circuit)	0.5/km
1500 MVA 500/275 kV or 500/330 kV transformer with associated switchgear	45
1000 MVA 500/220 kV transformer with associated switchgear	36
400 MVA 330/220 kV transformer with associated switchgear	20
700 MVA 330/220 kV transformer with associated switchgear	25
375 MVA 275/110 kV transformer with associated switchgear	18

4 Cost-Benefit Evaluation

This section provides a summary of the cost-benefit evaluation undertaken to assess the feasibility of each augmentation option.

The cost-benefit evaluation was undertaken using the PLEXOS market modelling software, which simulates the development and operation of the NEM and provides both a least-cost development plan of generation and transmission over the long-term along with hourly generation dispatch and transmission utilisation.

Each augmentation option was assessed under the three market development scenarios outlined in Section 2. The study's implementation of the Green Grid was examined as a sensitivity on the Fast Rate of Change scenario and considered all but the central option. The total cost to the NEM, including generation and transmission capital costs and operational costs including fuel, fixed and variable costs, were calculated for each option and scenario to identify the most economically feasible option over a broad range of market conditions.

4.1 Market modelling process

The market modelling is undertaken as a six-step process:

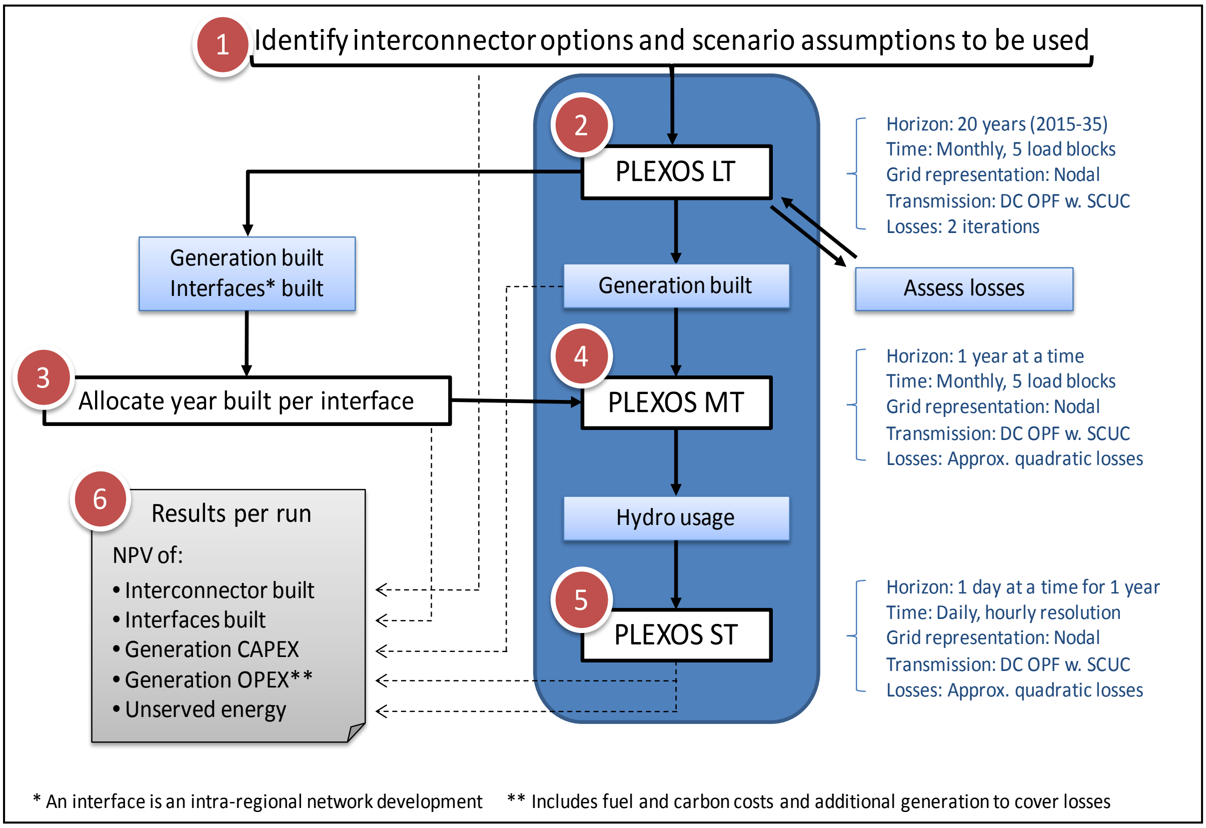
1. Set up and validate the market model.
2. Solve the model in the long term (20 years at approximately weekly intervals) to obtain a least-cost expansion of co-optimised generation and transmission assets.
3. Validate the generation and transmission expansion using a more detailed physical model of the NEM and express transmission expansion as actual projects.
4. Solve the model in the medium term (1 year at daily intervals) to assess power system adequacy and hydroelectric generation inflow limits.
5. Solve the model in the short term (1 year at hourly intervals) to obtain time-sequential detailed generation dispatch and transmission network utilisation.
6. Perform net present value calculations of all systems costs to determine benefits to the NEM for each augmentation option in each scenario.

The primary results presented in the report are based on the least-cost expansion modelling and skip steps 4 and 5.

A set of results based on the time sequential modelling (i.e. adding steps 4 and 5) are provided as secondary information.

A high level outline of the process used to assess the benefits of augmentation is shown in Figure 5. The following sections provide more detail about each step.

Figure 5 Overview of feasibility study modelling approach



4.1.1 Market model set-up and validation

In this step, simplifying assumptions are made to reduce the problem to be computationally tractable. A reduced-detail representation of the NEM was developed and validated using a full power system analysis.

The key market modelling assumptions are discussed here and are also documented in the accompanying detailed market modelling report. Details of the reduced network model are documented in the accompanying network modelling report.

4.1.2 Long-term least-cost expansion modelling

The least-cost expansion modelling provides a co-optimised set of new entrant generation, transmission network augmentation and generation retirement across the NEM for the next 20 years. This expansion plan provides an indication of the optimal combined technology, location, timing, and capacity of future generation and transmission developments.

Simplifications in the long-term model include:

- relatively large time steps, with demand averaged according to load duration curves,

- approximate transmission losses, and
- a relaxed integer approach – allowing the model to build generation and transmission in continuous blocks

Load duration curve approach

Long-term models cannot generate precise co-optimised solutions over horizons like those used in this study without requiring prohibitive amounts of time and computing hardware. To reduce model solve times, demand growth is typically expressed as a load-duration curve. In this particular case, the model split each year into months, with each month represented by 5 load blocks, for a total of 60 time segments per year. The load blocks were automatically calculated by the model based on hourly load profiles. Wind generation outputs for the hours assigned to each load block were averaged and assumed to be the output from wind generation in that load block.

Time-sequential hourly dispatch modelling is subsequently used to assess the impact of diversity in demand and available wind energy.

Transmission loss treatment

Losses were assessed for the base case (with no interconnector options built) for each scenario and added to demand for all simulations with the interconnector options active. This approach was taken because losses can be approximated only and the noise from differences in losses may distort the ranking of options. Maintaining the same loss approximations across options for the long-term runs reduced the risk of inconsistent results.

The actual losses of higher capacity or lower resistance lines are assessed with greater accuracy in the time-sequential modelling.

Relaxed integer approach

To model generator units or transmission upgrades as discrete unit sizes in an optimisation model, the model must use integer constraints. These integer constraints increase the time required to solve the optimisation exponentially.

To avoid this exponential growth in solve-time, the feasibility study “relaxed” these discrete variables to continuous variables, maintaining the model as a linear problem. As result, new generator capacity and new supporting transmission capability can take on any value, even when that value does not correspond to the capacity of a typical real generating unit or a specific transmission upgrade project.

4.1.3 Generation and transmission validation

This step converted the partial generation units and partial transmission reinforcements from the least-cost expansion into discrete projects.

To model maintenance outages adequately, new generation was split into a number of units corresponding to the size of a typical modern unit of that type, and entered step-wise.

For new transmission capability, partial reinforcements were converted into discrete projects which were enabled based on the benefit the investment would provide to the market each year, or to relieve unserved energy (USE) observed in the time-sequential modelling. Power system analysis was used to match identified transmission projects in the various Jurisdictional Planning Bodies' (JPBs) 2009 Annual Planning Reports (APRs) to the transmission reinforcements in the market model outcomes.

4.1.4 Annual simulation with a daily time-step

This step involves a yearly simulation taking the generation entry from step 2 and transmission projects identified in step 3. It allocates hydroelectric generation to individual days based on annual inflows, reservoir sizes and hydroelectric plant operational constraints to optimise the use of water throughout the year.

4.1.5 Annual simulation with an hourly time-step

With energy generated from hydroelectric plant pre-allocated, a full year of time-sequential generation dispatch modelling is performed using hourly resolution. It uses hourly demand defined at each node in the model, and hourly generation output for wind and solar plant defined by location. Losses are modelled by approximating quadratic loss functions for each transmission line component. Scheduled generators bid capacity to the market according to their short-run marginal cost (SRMC). This process provides a better estimate of actual generation dispatch and power flows, which can be used to validate the long-term modelling outputs from step 2.

Power system load flow analysis is also used in this step to validate the market modelling outcomes by comparing hourly snapshots with various demand, export and import conditions from the market model with the load flow analysis outcomes.

4.1.6 Net present value calculations

In this step, the net present value (NPV) of the total market costs are calculated for each scenario and transmission augmentation option. The total market costs are the sum of interconnector costs, other transmission costs, generation capital costs (including connection costs), fixed costs and variable operating costs (including fuel and emission costs).

The variable operating costs are either based on the least-cost expansion modelling only (from step 2) as the primary set of results or from the time sequential modelling (step 5) as supplementary information.

Interconnector augmentation options are ranked based on these total costs.

Given that the new high-capacity augmentation options are likely to be built towards the end of the planning horizon, the way in which end-effects are calculated is important. Most of the market benefits of new high-capacity augmentation options will be realised after the modelling horizon, and a strategy for capturing these benefits is required.

This study assumes that the state of the market in the last simulated year would be representative of years beyond the modelling horizon. This assumption is likely to result in a conservative estimate of market benefits of the new high-capacity augmentation options, as demand, carbon price and fuel costs are expected to continue to increase. Carbon price and fuel cost are strong drivers for additional renewable generation and, particularly for intermittent sources, additional transmission capability.

4.2 Interconnector option timing

4.2.1 New high-capacity augmentations

For the market modelling, each new high-capacity augmentation option could be entered in two stages, as described in Section 3.3.3. Staged entry increases the economic viability of the projects by allowing capital costs to be deferred to a time when the extra capacity is needed.

The market benefits associated with the new high-capacity options were assessed by entering each option, either staged or all at once, at predetermined times.

For the three market development scenarios considered, the four new high-capacity augmentation options were assessed with staged timing as follows:

- Stage 1 in 2024/25 and stage 2 in 2029/30
- Stages 1 and 2 both in 2029/30

The new high-capacity augmentation options included optimised timing of the incremental option.

The Green Grid sensitivity enters more renewable generation in the first decade and is expected to lead to an earlier need for an augmentation. Consequently, the staged timing assessed for this was:

- Stage 1 in 2019/20 and stage 2 in 2024/25
- Stage 1 in 2024/25 and stage 2 in 2029/30

The central high-capacity augmentation option was not analysed in the Green Grid sensitivity as it did not resemble any of the options discussed in the Green Grid report.

Entering options at predetermined times prevents the relaxed linear model from attempting to partially build an interconnector. A partial interconnector with optimised timing provides little information about when the full project will be required, or the benefits of advancing or deferring the project's entry.

4.2.2 Incremental option

Due to its relatively small size, the model was allowed to optimise the timing of the incremental option by building additional capacity as required. The incremental option was assessed both alone and in combination with each new high-capacity augmentation.

4.3 Market modelling network assumptions

The market model utilises a reduced nodal model[21] to represent significant load/generation centres and transmission links. The nodal representation was developed by ElectraNet, AEMO, and TransGrid.

The physical network was reduced to represent the transmission backbone only (with radial lines generally not explicitly represented):

- South Australia (SA) – 275 kV and 132 kV nodes only
- Victoria (VIC) – 500 kV, 330 kV and 220 kV nodes only
- New South Wales (NSW) – 500 kV, 330 kV and 220 kV nodes only
- Queensland (QLD) – for simplicity, treated as one 330 kV node only
- Tasmania (TAS) – for simplicity, treated as one 220 kV node only

The nodal network and resultant power flow outputs from the reduced network representation in the market model were validated in a load flow analysis using PSS/E with a full network representation.

4.3.1 Interconnector capability

The feasibility study market modelling enforces a maximum transfer capability in each direction on each interconnector. Table 8 describes these assumed capabilities.

For the purposes of this feasibility study, existing and new interconnectors were assumed to be capable of contributing their full capability towards meeting the minimum reserve levels (MRL) in each of their connecting NEM regions. This approach represents a simplification of the actual MRL adequacy assessment employed in the NEM.

Table 8 Assumed interconnector capabilities

Interconnector	Forward direction	Forward summer/winter (MW)	Reverse summer/winter (MW)
Queensland New South Wales interconnector (QNI)	Into QLD	1,180	1,180
Terranora	Into QLD	220	200
VIC-NSW effective N-1	Into NSW	1,638	1,638
Murray-Lower Tumut	Into NSW	715/857	715/857
Murray-Upper Tumut	Into NSW	715/857	715/857
Wodonga-Jindera	Into NSW	995/1,008	995/1,008
Heywood	Into SA	460	460
Murraylink	Into SA	220	180
Basslink	Into VIC	600	480

[21] More details on the reduced nodal model, including a diagram, can be found in the accompanying Joint Feasibility Study Network Modelling report.

4.3.2 Line thermal ratings

Seasonal line ratings were applied to lines in South Australia (based on advice from ElectraNet) and Victoria (based on advice from AEMO). The thermal ratings of the conductors were used under the assumption that any other limiting equipment can be upgraded as required.

Static summer line ratings were applied in New South Wales based on TransGrid advice. Post-contingent ratings were also used where provided (on some lines/transformers in Victoria and New South Wales).

Where control schemes are present to deal with post-contingent overloads, the post-contingent ratings have been used to reflect the additional headroom. Short-term ratings have not been used in the modelling.

4.3.3 Constraint equations

Thermal limitations are explicitly managed by the model via the security constrained unit commitment (SCUC) feature of PLEXOS. This feature enforces the lowest cost dispatch (unit commitment) that ensures post-contingency (N-1) network flows are not violated, updating automatically as transmission and generation assets are entered into or removed from the model.

With the exception of a South Australian minimum inertia constraint, no other non-thermal (stability) limitations have been considered. For the purpose of the feasibility study modelling, it was assumed that the imposed South Australian minimum inertia constraints[22] would be sufficient to represent stable system operation under very high wind generation and low load conditions, with an underlying assumption that any transient, voltage, or other stability limits can be fixed at a relatively low cost.

4.4 Market modelling generator assumptions

Generator operating cost assumptions and technology development assumptions for new generators used in this study are consistent with those supplied by ACIL Tasman for the 2010 NTNDP, described in the 2010 NTNDP Consultation Paper.

The NTNDP consultation and associated input data can be found on the following website:

- http://www.aemo.com.au/planning/ntndp.html

4.4.1 Generator cost assumptions

Cost assumptions for new and existing generators were supplied by ACIL Tasman for use in the NTNDP. These costs include:

[22] Two constraints, one for Adelaide and one for the northern zone, specify a minimum of 500 MW of conventional generation to be online at all times.

- capital costs,
- fuel costs,
- fixed operating and maintenance costs, and
- variable operating and maintenance costs (other than fuel).

Generation dispatch in the feasibility study was based on the generator's SRMC (calculated using the fuel and emissions costs and thermal efficiency of individual units) and therefore does not account for possible competitive strategies or the exercise of market power. This approach finds the most cost-efficient pattern of dispatch, but may not represent actual market outcomes.

Generation connection costs

Generic generation connection costs were also included in the market modelling. These generic connection costs were developed by AEMO, except in the case of the Green Grid generation connection cost to Davenport, which was developed by ElectraNet.

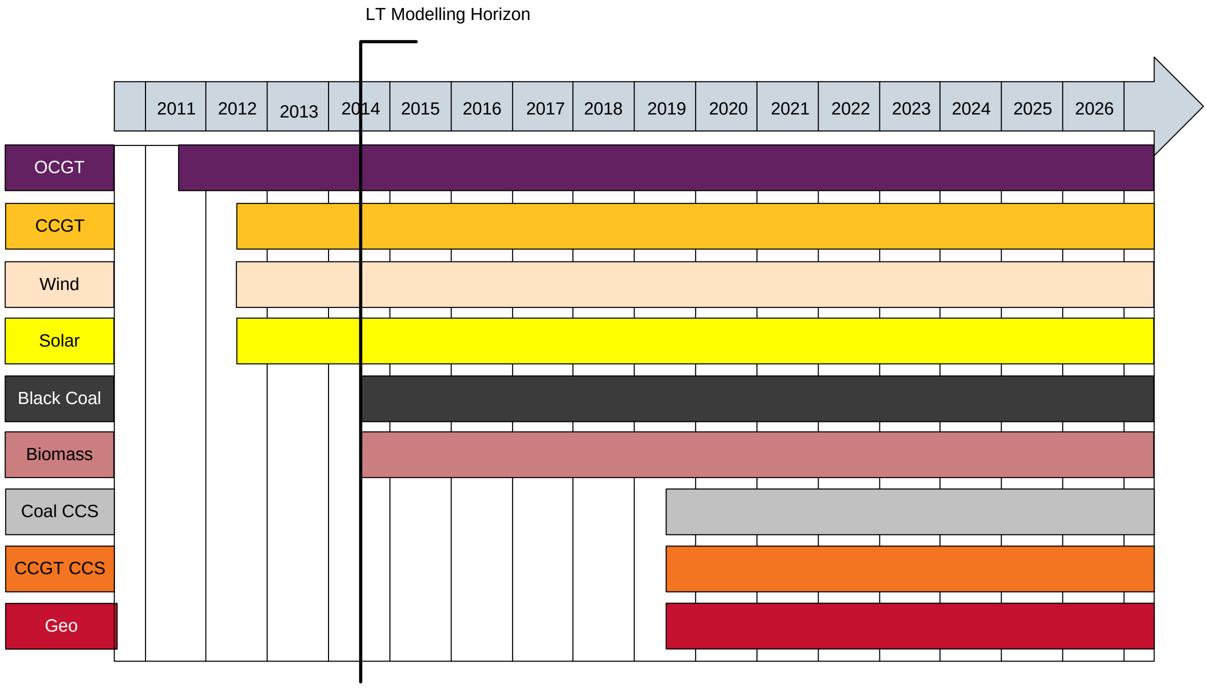
4.4.2 New generator technologies

The market model incorporates assumptions about the future development, testing, and construction timings of various generation technology types. These assumptions are consistent with the NTNDP modelling work, with the exception of carbon capture and sequestration (CCS) and geothermal technologies. These technologies have been delayed (by increasing build costs) to reflect a less favourable, more realistic view of the time required to bring these technologies to a commercially available state. Figure 6 shows the earliest date at which new build of each generation type was assumed to be available, taking into account both development of generation technology and construction times.

Other new generation technology assumptions incorporated from the NTNDP include:

- new unit capacity,
- heat rates,
- auxiliary load, and
- emission factors.

Figure 6 Technologies and timings for new generators



4.5 Market modelling demand assumptions

The at-node demand forecasts used in the feasibility study were aligned with the regional energy and peak demand projections used in the NTNDP studies.

Distribution factors and relative growth rates were used to split the regional demand and energy projections down to a terminal station basis. Terminal stations represent entry and exit points for the transmission network. The apportioning factors were based on data in the Jurisdictional Planning Bodies' 2009 Annual Planning Reports.

For the long term market development modelling, the model uses the NTNDP's 10% probability of exceedence (POE) demand forecasts, where a 10% POE demand forecast is one that is expected to be exceeded in one year of every ten. For the time-sequential phase the model uses the NTNDP's 50% POE demand forecasts, where a 50% POE demand forecast is one that is expected to be exceeded in one year of every two.

Hourly demands were represented in the model using reference traces based on the 2005/06 year for all terminal stations where sufficient data was available. The 2005/06 reference year was chosen as it is considered to represent a drought-free and average POE year across all NEM regions.

The expansion of the Olympic Dam mine in South Australia has been included in the Davenport node profile for the Fast Rate of Change studies, in line with regional forecasts. This expansion has not been included in the other two scenarios with lower economic growth assumptions.

4.6 Policy inputs

Two major renewable energy policy inputs are applied to the market model: an imposed price on carbon emissions, and the Commonwealth Government's Large-scale Renewable Energy Target (LRET) [23].

Carbon pricing

The feasibility study explores market development scenarios which include various carbon emissions pricing assumptions. These assume additional costs are placed on generators in proportion to their measured CO2-e (carbon dioxide equivalent) emissions. The market model calculates emissions costs based on an assumed carbon price trajectory and the fuel use, fuel type and thermal efficiency of individual generating units.

Two carbon price trajectories are studied, designed to result in either a 15% or a 25% reduction in CO2-e emissions below year 2000 levels by 2020. Table 9 lists the annual carbon price applied under the three scenarios.

Table 9 Carbon price assumptions ($/tonne CO2-e)

Year	Fast Rate of Change Decentralised World	Oil Shock and Adaptation
2010/11	0	0
2011/12	0	0
2012/13	0	0
2013/14	49.9	33.3
2014/15	51.9	34.6
2015/16	54.0	36.0
2016/17	56.2	37.4
2017/18	58.4	38.9
2018/19	60.7	40.5
2019/20	63.2	42.1
2020/21	65.7	43.8
2021/22	68.3	45.6
2022/23	71.1	47.4
2023/24	73.9	49.3
2024/25	76.9	51.2
2025/26	79.9	53.3
2026/27	83.1	55.4
2027/28	86.5	57.6
2028/29	89.9	59.9
2029/30	93.5	62.3

[23] http://www.orer.gov.au/publications/lret-sres-basics.html

Large-scale Renewable Energy Target

The (LRET) was applied on January 1, 2011 to encourage entry of new renewable generation. The scheme requires 41,000 GWh of stationary energy generated by the year 2020 to originate from renewable sources[24], increasing from 10,400 GWh in 2011.

Table 10 lists the annual Australia-wide LRET targets.

Table 10 Large-scale renewable energy target (LRET) – Australia wide

Year	LRET target (GWh)
2011	10,400
2012	12,300
2013	14,200
2014	16,100
2015	18,000
2016	22,600
2017	27,200
2018	31,800
2019	36,400
2020-2030	41,000

The market model does not include generation in Western Australia or the Northern Territory. Australia-wide targets were uniformly scaled by 87% under a continuing assumption of 13% of total Australian generation occurring in these two regions[25].

4.7 Cost-benefit assumptions

For this feasibility study, market benefits are defined as the total benefit of an option to all those who produce, distribute and consume electricity in the NEM.

The net market benefit of an option is calculated as the present value of the total cost to the market without the option present minus the present value of the total cost to the market with the option present.

Changes in total cost to the market occur when a reconfiguration of the network results in changes to the cost of:

- generation capital costs, including cost of connection to the network,
- capital costs incurred in constructing or providing a new interconnector augmentation option,

[24] The LRET target is over and above existing renewable energy generation, referenced to a baseline developed from generation in 1994 to 1996. This baseline is incorporated into the market model to allow Tasmanian and Snowy hydroelectric generators to contribute to the LRET when they generate above the baseline.

[25] http://www.abare.gov.au/interactive/energyUPDATE08/excel/Table_I_08.xls

- generator operating and maintenance costs over the operating life of the option, including fixed, variable, fuel and emissions costs and reduced generation arising from increased transmission efficiency,
- transmission capital costs for new transmission capability required to support the option, and
- costs incurred by consumers when demand cannot be met (unserved energy).

Benefits not assessed in this feasibility study included:

- benefits arising from changes in ancillary services costs,
- competition benefits (the change in net market benefits arising from the impact of the augmentation option on participant bidding behaviour),
- secondary operational benefits such as improved equipment reliability, and
- resilience to high impact, low probability events.

4.8 Economic assumptions

As part of the NTNDP scenario development process, the implications on the cost of capital under the different scenarios were discussed, along with considerations on exchange rates and economic growth. It was agreed that scenarios assuming high uncertainty for investors or ill-functioning financial markets were likely to lead to higher financing costs for investors, and as a result, the weighted average cost of capital (WACC) for generation would differ across the scenarios, so that:

- Fast Rate of Change uses a WACC of 8.78%, and
- Decentralised World and Oil Shock and Adaptation use a WACC of 9.79%.

Along with the assumed economic life of generation investments, the WACC is used to calculate annual payments required for each investment. Only annual payments within the modelled horizon are taken into account in the modelling. This ensures generation expansion in the latter years is not distorted by the so-called “end-effect”. This is where the model stops investing in capital intensive generation such as wind turbines, and only invests in low capital cost generation towards the end of the simulation horizon (the longer term benefit achieved from the low operational costs of the wind turbine is outside the horizon and not captured by the model).

The cost benefit analysis was to consider a minimum of 20 years. The period 2014/15-2033/34 was selected, as none of the augmentation options considered are likely to be needed before 2015. Investments in generation and transmission required between 2010 and 2015 are entered in 2015. This expands the period covered by the modelling by exploiting knowledge of the near future. As transmission investments typically last 40 years or more, it was furthermore decided to assume that the last year’s costs and benefits continued to perpetuity. This will capture some of the benefits arising beyond the modelled horizon, but typically not all as the benefits of augmentations tend to increase as demand increases.

For each year, the cash flow using annual payments to cover capital costs, fuel costs, carbon costs, and so on were discounted to a net present value (NPV) using an 8.82% discount rate[26].

4.9 Market modelling results

This section presents the results from the market modelling by market development scenario.

- Section 4.9.1 discusses the flow characteristics that result from each interconnector augmentation option for each of the different scenarios considered,
- Sections 4.9.2 to 4.9.7 present the primary results of the least-cost expansion modelling, and
- Section 4.9.8 presents the secondary results from time sequential modelling.

Compared with the draft report, results are presented in 2010 dollars, rather than 2015 dollars. Furthermore, the transmission costs are based on annuities to be consistent with the way generation costs are treated in the PLEXOS model.

4.9.1 Flow characteristics, import and export

The new interconnector augmentation options exhibit specific patterns of use that depend on the scenario under study. The degree of utilisation of an interconnector is a direct consequence of providing access to generation at lower cost, and is a chief indicator of the origin of cost benefits.

Northern options

The two northern options exhibit similar characteristics. The Fast Rate of Change scenario models high demand growth rates, which are most pronounced in Queensland and New South Wales. As a result, the northern options serve primarily as energy exporters from South Australia. This, and the presence of the Olympic Dam expanded load in that scenario, results in reduced congestion on the South Australian network. South Australia generally imports energy from Victoria on the Heywood interconnector when the northern interconnectors are in place - the relationship is one of increased magnitude of flows at decreased frequency, indicating South Australia's increasing dependence on its interconnectors to manage increasing intermittency in local supply.

In the Oil Shock and Adaptation scenario the northern interconnectors operate as true two-way links, with energy import to and export from South Australia relatively balanced. This scenario exhibits similar amounts of new entry wind generation to the Fast Rate of Change scenario, driven by the LRET, but lacks the high demand growth. Consequently, a larger proportion of the generation fleet is wind generation, and South Australia uses its link with base load generation in New South Wales for reliability.

A large amount of wind generation enters South Australia in the Decentralised World scenario. With its moderate growth in demand, this scenario presents fewer opportunities to South Australian generation for export to New South Wales, and the large wind generation fleet is used primarily to

[26] Australian Energy Regulator (2009): “Final decision - Electricity transmission and distribution network service providers - Review of the weighted average cost of capital (WACC) parameters”

meet local demand. These conditions lead to suppression of new gas generation in South Australia and an increased reliance on the new interconnectors for importing energy during low wind periods.

The high utilisation of the northern options leads to significant NEM-wide operating cost reductions, however their high cost (each one would span over 1,000 km), prevents achievement of a positive net market benefit.

Central option

The same flow characteristics as above (export from South Australia in Fast Rate of Change, import in Decentralised World and a balance in Oil Shock and Adaptation) are observed with the central option in place. The central option operates much like a link between South Australia and New South Wales, with little interaction with Victorian supply or demand. This behaviour results in lower cost-benefit performance compared to the northern options, which provide a direct, low loss link between renewable generation in South Australia and thermal generation in New South Wales.

This option resembles the NEMLink project presented in AEMO's 2010 NTNDP[27], but with significant differences. The feasibility study did not consider new interconnectors between Queensland and New South Wales, or Victoria and Tasmania that were considered as part of NEMLink. Estimated project costs for NEMLink were lower on a component by component basis than those used in this study. Optimised timing of individual components of NEMLink was not studied as part of the NTNDP. Any direct comparisons with NEMLink must be treated with caution, and conclusions on the viability of the central option based on its resemblance to NEMLink cannot be made based on this work.

Southern options

The incremental option and the southern option facilitate South Australian energy export in all scenarios.

The incremental option increases flow between South Australia and Victoria, but does not introduce a significant change in the operation of the Heywood interconnector or cause significant relocation of generation. Congestion is eased on the transformers at Heywood and peak flows are increased, however the interconnector continues to experience frequent congestion due to limits on the transmission lines between South East and Heywood.

The southern option reaches 80% to 90% of its capability at peak, with an approximate average utilisation of 30%. Between 2015 and 2020, driven by the LRET and favourable conditions for renewable generation in South Australia, the frequency of South Australia to Victoria flow increases from 30% to 80% of the time, though average flow rates remain low. By 2030 the interconnector is used almost exclusively for export from South Australia. While this option's full capability is not as well utilised as the northern options, its low cost allows it to achieve net positive market benefits under some scenarios.

The presence of the Green Grid wind generation exaggerates the flow characteristics observed above. Because it is location-correlated, the Green Grid generation increases the intermittency of South Australian supply and increases South Australia's reliance on its interconnectors. This

[27] http://www.aemo.com.au/planning/ntndp.html

increased utilisation has the potential to increase the benefits of the new interconnectors, particularly the northern options. However, costs due to increased losses, placement of new generation without least-cost optimisation and system stability considerations that were not modelled may become significant and affect the magnitude of reported benefits.

4.9.2 Fast Rate of Change

Generation build

The Fast Rate of Change scenario combines high demand growth with an ambitious carbon emission reduction target. By 2030 over 41 GW of new generation enters in this scenario, shown in Table 11.

Renewable generation constitutes a large portion of new generation up to 2019/20, driven by the LRET. Intermittent wind and solar generation is supported by significant investments in OCGT generation for peak capacity, with CCGT units providing base load supply.

After the LRET plateaus in 2020, gas powered generation enters exclusively, meeting growth in demand and offsetting retirement of brown coal generation. By the late 2020s, with carbon prices approaching $90/MWh, renewable generation becomes cost-competitive in its own right and enters in larger amounts.

Table 11 Fast Rate of Change – generation expansion in the base case (MW)

Technology	2014/15	2017/18	2020/21	2023/24	2026/27	2029/30
Black coal	0	0	0	0	0	750
Brown coal	-316	-316	-316	-810	-915	-1,099
CCGT	3,630	6,220	8,863	13,088	16,608	18,164
OCGT	3,208	5,563	7,828	9,360	10,896	12,205
Biomass	550	950	950	950	950	950
Geothermal	0	0	955	955	955	2,800
Solar	0	200	200	200	200	1,143
Wind	845	3,291	4,411	4,411	4,411	6,473
Net new capacity	**7,916**	**15,908**	**22,890**	**28,154**	**33,105**	**41,387**

Least-cost expansion market benefit assessment

Table 12 summarises the present value (PV) of the total market costs with each transmission option based on the least-cost expansion model. See Section 4.9.6 for calculations that account for operating costs from the time-sequential modelling.

Table 12 Fast Rate of Change present value of total market costs ($ million)

Option	Total cost (PV)	Gross benefit (PV)	Augmentation cost (PV)	Net benefit (PV)
Base	185,917	0	0	0
Incremental	185,891	26	0[28]	26
Northern AC 2025	185,419	497	948	-451
Northern AC 2030	185,433	484	635	-152
Northern DC 2025	185,515	402	727	-326
Northern DC 2030	185,570	346	506	-160
Central 2025	185,575	341	895	-554
Central 2030	185,562	355	594	-240
Southern 2025	185,756	160	128	32
Southern 2030	185,753	163	90	73

The southern AC option with stage 1 built in 2024/25 provides $160 million in gross benefits compared to the base case. Once the present value of the capital costs of the augmentation ($128 million) have been accounted for, the southern AC option shows a net market benefit of $32 million.

The net market benefits for the southern AC option with both stages built in 2029/30 are $73 million; more than double the benefits with the staged 2024/25 and 2029/30 timing.

The northern and central augmentation options provide significant gross market benefits. The high cost to build them, however, prevents achievement of a net market benefit. The central option is the least cost-effective, providing lower gross benefits than the northern options at a similar build cost.

The northern options generally provide the highest gross benefits of all the new high-capacity augmentation options, however they are also the most costly. The DC option has lower build costs than the AC option and shows the greater benefits of the two under the early timing. The AC option, however, shows greater benefits over the longer term because it enables the connection of wind generation at Broken Hill, which becomes economic around 2029/30.

Timing of incremental option

Apart from the southern option, the only other option providing a net market benefit is the incremental option with net market benefits of around $26 million. When built alone, the optimal entry timing of the option is 2025/26. The augmentation is generally delayed when high-capacity interconnector augmentations, which reduce flow on the Heywood interconnector, are entered early. Entry timing in conjunction with each high-capacity augmentation is shown in Table 13.

[28] Augmentation costs for the incremental option are included in the total cost due to the least-cost optimised timing of its entry.

Table 13 Fast Rate of Change incremental option timing

Option	Build year
Incremental	2025/26
Northern AC 2025	2028/29
Northern AC 2030	2025/26
Northern DC 2025	2026/27
Northern DC 2030	2026/27
Central 2025	2028/29
Central 2030	2026/27
Southern 2025	2029/30
Southern 2030	2025/26

4.9.3 Decentralised World

Generation build

The Decentralised World scenario includes the same high carbon emission reduction target as Fast Rate of Change, with slower growth in demand and lower cost for wind generation technology.

The moderate demand growth results in lower overall new generation capacity compared to Fast Rate of Change (34 GW in 2029/30 compared to 41 GW), with geothermal, solar and OCGT technologies showing reduced new entry. High costs for geothermal generation discourage that technology. To meet the LRET, additional wind is built to offset the reductions in solar and geothermal generation. A disproportionately large amount of the new wind generation enters in South Australia in this scenario (2,900 MW in 2029/30 compared to 900 MW at the same time in Fast Rate of Change), two thirds of which is in the north. High costs for geothermal generation discourage that technology, and CCGT generation operates as base load supply.

Table 14 Decentralised World generation expansion in base case (MW)

Technology	2014/15	2017/18	2020/21	2023/24	2026/27	2029/30
Black coal	0	0	0	0	0	0
Brown coal	0	-493	-849	-849	-980	-1,958
CCGT	3,200	7,035	9,475	10,992	14,236	19,181
OCGT	2,259	2,962	5,344	7,382	7,753	8,729
Biomass	550	950	950	950	950	950
Geothermal	0	0	827	827	827	827
Solar	0	0	0	0	0	0
Wind	835	3,444	4,900	4,900	4,900	6,292
Net new capacity	**6,844**	**13,897**	**20,648**	**24,202**	**27,686**	**34,022**

Least-cost expansion market benefit assessment

Table 15 shows the present value of benefits for each augmentation option under the Decentralised World scenario, based on the results of the least-cost expansion. The incremental option is the only augmentation to provide a net market benefit under this scenario

The southern option is marginally uneconomic due to lower export from South Australia compared to Fast Rate of Change, particularly toward the end of the modelling horizon. The central option shows less negative net market benefits compared to the northern options. Unlike the other scenarios, under Decentralised World the northern and central options encourage energy import into South Australia. Imports to South Australia from New South Wales are relatively costly, leading to reduced gross benefits for the northern options. For all new high-capacity augmentation options the later timing (with both stages entered in 2029/30) is preferred over the earlier timing (with stage 1 entered in year 2024/25).

See Section 4.9.6 for calculations that account for operating costs from time-sequential modelling.

Table 15 Decentralised World present value of total market costs ($ million)

Option	Total cost (PV)	Gross benefit (PV)	Augmentation cost (PV)	Net benefit (PV)
Base	162,144	0	0	0
Incremental	162,116	28	0	28
Northern AC 2025	161,893	252	948	-697
Northern AC 2030	161,913	231	635	-404
Northern DC 2025	161,955	189	727	-538
Northern DC 2030	161,989	155	506	-350
Southern 2025	162,059	85	128	-43
Southern 2030	162,061	84	90	-7
Central 2025	161,779	365	895	-531
Central 2030	161,820	325	594	-270

Timing of incremental option

The large amount of new wind generation entered in South Australia in this scenario, combined with low demand growth leads to a higher proportion of the South Australian generation fleet being intermittent. Without high-capacity augmentation, this intermittency is managed locally by new gas powered generation, but is still strongly supported by existing interconnectors. The need for support increases the value of the incremental option and advances its timing.

When new high-capacity augmentation options are considered, the least cost expansion prefers to augment the Heywood connector in addition to the new interconnector option, and enters less new gas generation in South Australia.

Table 16 Decentralised World incremental option timing

Option	Build year
Incremental	2019/20
Northern AC 2025	2022/23
Northern AC 2030	2019/20
Northern DC 2025	2022/23
Northern DC 2030	2019/20
Central 2025	2020/21
Central 2030	2019/20
Southern 2025	2019/20
Southern 2030	2019/20

4.9.4 Oil Shock and Adaptation

Generation build

The Oil Shock and Adaptation scenario models a world with lower electricity demand growth, lower carbon prices and higher gas prices than the other scenarios. Reflecting the lower demand growth, this scenario builds the least amount of new generation, entering around 24 GW by 2029/30, as shown in Table 17.

Table 17 Oil Shock and adaptation generation expansion in base case (MW)

Technology	2014/15	2017/18	2020/21	2023/24	2026/27	2029/30
Black coal	0	0	0	1,679	4,127	6,030
Brown coal	0	0	0	0	0	0
CCGT	1,827	1,892	2,412	2,412	2,412	2,412
OCGT	2,227	4,580	6,789	7,236	7,476	7,692
Biomass	550	950	950	950	950	950
Geothermal	0	0	957	957	957	1,471
Solar	0	614	614	614	614	614
Wind	845	2,825	3,942	3,942	3,942	5,430
Net new capacity	**5,448**	**10,862**	**15,664**	**17,790**	**20,477**	**24,600**

High gas prices, moderate carbon prices and low peak demand allow new coal with CCS generation to displace gas powered generation compared to other scenarios. The LRET drives similar renewable energy new entry to the other scenarios, leading to a proportionally higher intermittent supply. New OCGT capacity is used to manage the intermittency in the base case. Lower carbon prices and the high gas price discourage new CCGT generation in the Latrobe Valley and allow brown coal generation to remain viable in the least cost expansion.

Least-cost expansion market benefit assessment

In most cases, the benefits of the various options under Oil Shock and Adaptation are comparable with those observed under Decentralised World. Table 18 shows the gross and net market benefits for each option.

The northern and central options operate as balanced two-way links under Oil Shock and Adaptation, unlike Fast Rate of Change which exports energy from South Australia, and Decentralised World which imports energy to South Australia. The southern option continues to be primarily used for export of energy from South Australia.

Of the new high-capacity augmentation options, only the southern option entered in 2029/30 provides a net market benefit, and this benefit is marginal at only $7 million. The incremental option is the most favourable under this scenario, providing a $22 million net benefit.

Higher value is attributed to an interconnector augmentation when the spot price differential between the sending and the receiving region is high. The northern and central options' low flow, balanced import-export operation indicates that spot price differences are lower under the Oil Shock and Adaptation scenario, and a correspondingly lower value is placed on the interconnector. Likewise, though the southern option continues to operate in a South Australian export mode, flows are lower more often, reducing the option's gross benefit.

Table 18 Oil shock and adaptation present value of total market costs ($ million)

Option	Total cost (PV)	Gross benefit (PV)	Augmentation cost (PV)	Net benefit (PV)
Base	137,493	0	0	0
Incremental	137,471	22	0	22
Northern AC 2025	137,208	285	948	-663
Northern AC 2030	137,207	286	635	-349
Northern DC 2025	137,331	162	727	-565
Northern DC 2030	137,340	154	506	-352
Southern 2025	137,397	96	128	-32
Southern 2030	137,397	97	90	7
Central 2025	137,305	188	895	-707
Central 2030	137,295	198	594	-396

Timing of the incremental option

Table 19 shows the entry timing of the incremental option under the Oil Shock and Adaptation scenario. Lower power transfers between Victoria and South Australia or New South Wales and South Australia reduce the value of the augmentation and delay its timing. Entry is deferred further when combined with the southern option.

Table 19 Oil Shock and Adaptation incremental option timing

Option	Build year
Incremental	2029/30
Northern AC 2025	2022/23
Northern AC 2030	2028/29
Northern DC 2025	2031/32
Northern DC 2030	2031/32
Central 2025	2022/23
Central 2030	2028/29
Southern 2025	2032/33
Southern 2030	after 2033/34

4.9.5 Green Grid sensitivity

Generation build

The Green Grid sensitivity enters 2,000 MW of wind generation on the Eyre Peninsula between 2015/16 and 2019/20. All other input assumptions are the same as the Fast Rate of Change scenario, and all other new entry generation is optimised by the model.

Including the 2,000 MW of Green Grid generation, more new wind generation is installed in the Green Grid sensitivity than under the Fast Rate of Change scenario. With new renewable generation developments driven by the LRET up to 2019/20, the inclusion of the Green Grid wind generation defers entry of other renewable technologies like geothermal and solar, despite the higher assumed costs of wind generation in this scenario.

The result is a very high proportion of wind generation in the total South Australian supply, clustered in a single location and consequently operating in a relatively correlated fashion. Such conditions accentuate the intermittency of wind generation and increase the value of interconnector augmentation options.

Table 20 shows new generation NEM-wide under the Green Grid sensitivity. More than 1,000 MW additional capacity enters compared to the Fast Rate of Change scenario.

Table 20 Green Grid sensitivity generation expansion in base case (MW)

Technology	2014/15	2017/18	2020/21	2023/24	2026/27	2029/30
Black coal	0	0	0	0	0	750
Brown coal	-301	-301	-301	-821	-915	-1,129
CCGT	3,621	6,264	9,029	13,151	16,667	18,105
OCGT	3,203	5,660	7,982	9,638	11,169	12,660
Biomass	550	950	950	950	950	950
Geothermal	0	0	758	758	758	2,438
Solar	0	0	0	0	0	1,016
Wind	845	3,515	5,075	5,075	5,075	7,734
Net new capacity	**7,918**	**16,088**	**23,493**	**28,751**	**33,704**	**42,525**

Least-cost expansion market benefit assessment

Table 21 shows the market benefits of each augmentation option under the Green Grid sensitivity. The incremental option and the southern option both provide a net market benefit compared to the base case.

The net benefits under the Green Grid sensitivity are significantly larger than those observed under Fast Rate of Change, despite advancing interconnector capital expenditure by five years.

The concentration of wind generation in one area defers generation elsewhere and increases the value of interconnector augmentation options. New high capacity interconnector augmentations operate at very high flows out of South Australia compared to other scenarios. Table 21 shows that the highest benefits are achieved by connecting the Green Grid directly to New South Wales. Lower benefits are achieved by improving interconnection with Victoria, but only the low-cost incremental and southern options are able to achieve a high enough utilisation to justify the cost of augmentation.

Table 21 Green Grid sensitivity present value of total market costs ($ million)

Option	Total cost (PV)	Gross benefit (PV)	Augmentation cost (PV)	Net benefit (PV)
Base	186,076	0	0	0
Incremental	185,988	88	0	88
Northern AC 2020	185,261	815	1448	-633
Northern AC 2025	185,410	665	948	-283
Northern DC 2020	185,419	656	1110	-454
Northern DC 2025	185,516	559	727	-168
Southern 2020	185,763	313	195	118
Southern 2025	185,787	289	128	161

When comparing the Green Grid results with the Fast Rate of Change, Green Grid gross benefits are slightly higher for most options. However, the results do not give the complete picture needed for a comparison across the scenarios. In particular, the differences in losses between the scenarios are not captured by the least cost expansion.

The Green Grid sensitivity was modelled under favourable conditions. The high growth, high carbon price input assumptions result in high energy export from South Australia. The Green Grid adds to these conditions and raises the value of interconnector augmentation.

Timing of the incremental option

Table 22 shows the timing of the incremental option under the Green Grid sensitivity. Early entry of generation in South Australia and its displacement of new renewable generation elsewhere increases the value of interconnector augmentation and advances entry timing. Timing is not delayed by the entry of new high-capacity interconnector options, indicating continuing high utilisation of the Heywood interconnector even with additional transfer capability between South Australia and New South Wales or Victoria.

Table 22 Green Grid sensitivity incremental option timing

Option	Build year
Incremental	2017/18
Northern AC 2020	2017/18
Northern AC 2025	2017/18
Northern DC 2020	2017/18
Northern DC 2025	2017/18
Southern 2020	2017/18
Southern 2025	2017/18

4.9.6 Summary of least-cost expansion modelling

Table 22 shows the net market benefits for each augmentation option under each scenario. The Green Grid sensitivity displays the highest net market benefits for a range of augmentation options, with the southern augmentation, with the later build date of year 2025, having the highest benefits under this scenario. Overall, the two options that show the highest benefits are the incremental option and the southern new high-capacity augmentation option.

Table 23 Net market benefits ($ million)

Option and timing	Fast Rate of Change	Decentralised World	Oil Shock and Adaptation
Incremental (optimised timing)	26 (2025/26)	28 (2019/20)	22 (2029/30)
Northern AC 2025	-451	-697	-663
Northern AC 2030	-152	-404	-349
Northern DC 2025	-326	-538	-565
Northern DC 2030	-160	-350	-352
Southern 2025	32	-43	-32
Southern 2030	73	-7	7
Central 2025	-554	-531	-707
Central 2030	-240	-270	-396

Option and timing	Green Grid
Incremental	88 (2017/18)
Northern AC 2020	-633
Northern AC 2025	-283
Northern DC 2020	-454
Northern DC 2025	-168
Southern 2020	118
Southern 2025	161

The timing of the incremental option was optimised as part of the market modelling. The optimal timing of this option when built alone is set out in Table 24. When considered in addition to the new high-capacity augmentation options, the timing of the incremental option was typically delayed.

Table 24 Incremental option timing (when built alone)

	Fast Rate of Change	Decentralised World	Oil Shock and Adaptation	Green Grid
Timing	2025/26	2019/20	2029/30	2017/18

The significant development of wind generation in South Australia assumed in the Green Grid sensitivity caused the incremental option to be economically viable as early as 2017/18. Similar conditions under Decentralised World caused the incremental option to be required in 2019/20, significantly earlier than under Fast Rate of Change and Oil Shock and Adaptation.

Substantial wind generation development also occurred in South Australia in Fast Rate of Change, however the higher demand growth in South Australia in this scenario allowed more of this additional wind generation to be used within South Australia, delaying the need for additional export capacity. The incremental option was delayed until 2029/30 under Oil Shock and Adaptation. While utilisation of interconnectors continues to be frequent in this scenario, flow rates are lower and the value of augmentation is reduced.

The benefits assessed in the feasibility study represent a reduced set of the possible benefits expected to arise with a new interconnector. Notably competition benefits and loss benefits were excluded. The impact of losses may be significant as indicated by the time sequential modelling.

Table 25 shows the ratio of the net present value of the gross benefits under each of the new high-capacity augmentation options to the net present value of the capital costs of the options. This ratio gives a measure of how significant the shortfall in benefits is under each option, or in other words, how significant the benefits are in relation to the costs for those options that display net market benefits.

Table 25 Ratio of gross benefits to capital costs of the options

Option and timing	Fast Rate of Change	Decentralised World	Oil Shock and Adaptation	Green Grid
Northern AC 2020				56%
Northern AC 2025	52%	27%	30%	70%
Northern AC 2030	76%	36%	45%	
Northern DC 2020				59%
Northern DC 2025	55%	26%	22%	77%
Northern DC 2030	68%	31%	30%	
Central 2025	38%	41%	21%	
Central 2030	60%	55%	33%	
Southern 2020				160%
Southern 2025	125%	66%	75%	225%
Southern 2030	181%	93%	107%	

4.9.7 Augmentation costs sensitivity analysis

The costs of each new high-capacity interconnector option was estimated on a high-level building block basis. As a result, cost estimates are indicative only and include significant uncertainty. The following tables show net present value of total system costs for transmission cost variations of 25% and 50% higher and lower than the costs used throughout this study. The sensitivity analysis is based on the results of the least-cost expansion modelling only.

The tables show that under a range of market development conditions, only the southern option consistently shows a net positive market benefit. Positive benefits are not conclusive, however, and will not be achieved under scenarios with less than high demand growth or when project costs prove to be higher than those estimated for this study.

Table 26 Fast Rate of Change cost sensitivities (PV $ million)

Option	Net benefits PV				
	-50% costs	-25% costs	Base costs	+25% costs	+50% costs
Northern AC 2025	23	-214	-451	-688	-925
Northern AC 2030	166	7	-152	-311	-469
Northern DC 2025	38	-144	-326	-508	-690
Northern DC 2030	93	-33	-160	-286	-413
Central 2025	-106	-330	-554	-778	-1,002
Central 2030	58	-91	-240	-388	-537
Southern 2025	96	64	32	0	-32
Southern 2030	118	95	73	50	28

Table 27 Decentralised World cost sensitivities (PV $ million)

Option	Net benefits PV				
	-50% costs	-25% costs	Base costs	+25% costs	+50% costs
Northern AC 2025	-223	-460	-697	-934	-1,171
Northern AC 2030	-86	-245	-404	-563	-722
Northern DC 2025	-175	-357	-538	-720	-902
Northern DC 2030	-98	-224	-350	-477	-603
Central from 2025	-83	-307	-531	-754	-978
Central from 2030	27	-121	-270	-418	-567
Southern 2025	21	-11	-43	-75	-107
Southern 2030	39	16	-7	-29	-52

Table 28 Oil Shock and Adaptation cost sensitivities (PV $ million)

Option	Net benefits PV				
	-50% costs	-25% costs	Base costs	+25% costs	+50% costs
Northern AC 2025	-189	-426	-663	-900	-1,137
Northern AC 2030	-32	-190	-349	-508	-667
Northern DC 2025	-202	-384	-565	-747	-929
Northern DC 2030	-99	-226	-352	-479	-605
Central 2025	-259	-483	-707	-931	-1,155
Central 2030	-99	-248	-396	-545	-693
Southern 2025	32	0	-32	-64	-96
Southern 2030	52	29	7	-16	-39

4.9.8 Time-sequential modelling results

Since the publication of the draft report, time-sequential, hourly dispatch modelling was undertaken to supplement the results shown in Sections 4.9.2 to 4.9.5. Hourly dispatch modelling provides a better indication of the impacts of wind variability and transmission losses than long-term least-cost expansion modelling. The resulting variable costs are higher than those observed in least-cost expansion modelling, as the latter will underestimate losses during times of high power flow. The reported present value of the total costs presented below is therefore higher than the values presented for the least-cost expansion based modelling.

Time-sequential modelling was undertaken at 5 year intervals, with results obtained for 2014/15, 2019/20, 2024/25 and 2029/30. Between these years, interpolation was used to determine approximate costs. Beyond 2029/30 the least-cost expansion results were used, and scaled to match those of the time-sequential 2029/30 run. This simplification may have some impacts on the findings and as result, these are presented as secondary to the least-cost expansion results rather than superseding them.

Analysis of results is presented for Fast Rate of Change, Decentralised World and Oil Shock and Adaptation scenarios.

Fast Rate of Change

Table 29 shows the present value (PV) of the total cost to the NEM for each augmentation option, with operating costs (fuel costs, variable operating costs and emission costs) based on the time-sequential modelling. Fixed operating costs and generation and transmission build costs continue to be based on the least-cost expansion modelling.

Table 29 Fast Rate of Change alternate present value of total market costs ($ million)

Option	Total cost (PV)*	Gross benefit (PV)	Augmentation cost (PV)	Net benefit (PV)
Base	197,901	0	0	0
Incremental	198,000	-98	0	-98
Northern AC 2025	197,476	426	936	-510
Northern AC 2030	197,148	754	627	127
Northern DC 2025	197,679	223	718	-495
Northern DC 2030	197,518	383	499	-115
Central 2025	197,808	94	884	-790
Central 2030	197,630	271	586	-315
Southern 2025	197,590	311	126	185
Southern 2030	197,496	405	89	316

** excluding cost of the interconnector option*

The ranking of the augmentation options is generally consistent with the least cost expansion results. Unlike under the least cost expansion, the incremental option shows negative net market benefits. The incremental option enters more than 400 MW more wind generation in (northern) South Australia compared to the base case, and moves OCGT generation away from Adelaide to other regions. The results indicate that increasing wind generation in South Australia while removing its local intermittency support introduces a loss penalty that was not modelled in the least cost expansion.

The least-cost expansion modelled the same losses regardless of the presence of new transmission augmentation options. The high-capacity interconnector options reduce losses, however, by introducing new, low-impedance flow paths to the network. The reduced losses result in higher market benefits than those observed in the least cost expansion. Later entry timing continues to be preferred for these options.

Table 30 shows a division of the total costs shown in Table 26.

Table 30 Fast Rate of Change division of total costs (PV $ million)

Option	Generation			Transmission		Total
	Fixed*	Variable**	Emissions	Augmentation	Other	costs***
Base	63,299	49,769	84,600	0	234	197,901
Incremental	63,507	49,632	84,622	0	239	198,000
Northern AC 2025	65,316	48,653	83,271	936	235	198,412
Northern AC 2030	65,331	48,570	83,011	627	236	197,775
Northern DC 2025	64,997	48,918	83,554	718	210	198,397
Northern DC 2030	65,023	48,803	83,480	499	212	198,017
Central 2025	64,909	49,020	83,592	884	288	198,691
Central 2030	65,074	48,891	83,390	586	275	198,217
Southern 2025	64,886	48,347	84,108	126	248	197,716
Southern 2030	64,956	48,216	84,077	89	247	197,585

** includes capital costs and fixed operating and maintenance costs*

*** includes fuel and variable operating and maintenance costs, but not emission costs*

**** includes cost of the interconnector augmentation option*

Transmission costs are minor compared to generation costs accumulated over a 20 year period. Of the generation costs, emission costs increase to become the largest component, creating a strong incentive for low-emission new entry generation. By improving support for intermittent generation, the new high capacity interconnector options allow larger amounts of renewable generation to enter, increasing fixed costs but decreasing both variable and emission costs.

Decentralised World

Table 31 presents the present value (PV) of the total cost to the NEM of each option under the Decentralised World scenario, with operating costs based on the time-sequential modelling.

Table 31 Decentralised World alternate present value of total market costs ($ million)

Option	Total cost(PV)*	Gross benefit (PV)	Augmentation cost (PV)	Net benefit (PV)
Base	180,177	0	0	0
Incremental	180,395	-218	0	-218
Northern AC 2025	179,754	424	936	-512
Northern AC 2030	179,848	330	627	-297
Northern DC 2025	179,899	279	718	-439
Northern DC 2030	180,033	144	499	-355
Central 2025	180,535	-358	884	-1,242
Central 2030	180,360	-183	586	-769
Southern 2025	180,006	172	126	45
Southern 2030	179,933	245	89	156

** excluding cost of the interconnector option*

The Decentralised World results are consistent with the time-sequential results for Fast Rate of Change: the southern option provides the highest benefits and a positive net market benefit, with later timing preferred.

When compared to the least-cost expansion results in Table 15, the southern option improves from being slightly negative to positive and the incremental option shows negative benefits. Both changes occur for the same reasons as under Fast Rate of Change.

A detailed division of costs is shown in Table 32.

Table 32 Decentralised World division of total costs (PV $ million)

Option	Generation			Transmission		Total
	Fixed*	Variable**	Emissions	Augmentation	Other	costs***
Base	51,120	50,246	78,462	0	349	180,177
Incremental	51,258	50,245	78,541	0	351	180,395
Northern AC 2025	51,307	49,945	78,154	936	347	180,690
Northern AC 2030	51,097	50,160	78,229	627	361	180,475
Northern DC 2025	50,970	50,401	78,181	718	347	180,617
Northern DC 2030	50,987	50,451	78,232	499	363	180,532
Central from 2025	51,434	50,083	78,589	884	429	181,419
Central from 2030	51,269	50,172	78,478	586	440	180,946
Southern from 2025	51,999	49,624	78,040	126	343	180,132
Southern from 2030	52,064	49,547	77,976	89	345	180,022

** includes both capital costs and fixed operating and maintenance costs*

*** includes fuel and variable operating and maintenance costs, but not emission costs*

**** includes cost of the interconnector augmentation option*

Oil Shock and Adaptation

Table 33 presents the present value (PV) of the total cost to the NEM of each option under Oil Shock and Adapatation, with operating costs based on the time-sequential modelling.

Table 33 Oil Shock and Adaptation alternate present value of total market costs ($ million)

Option	Total cost(PV)*	Gross benefit (PV)	Augmentation cost (PV)	Net benefit (PV)
Base	152,869	0	0	0
Incremental	152,614	256	0	256
Northern AC 2025	152,071	798	936	-138
Northern AC 2030	152,145	724	627	97
Northern DC 2025	152,019	850	718	132
Northern DC 2030	152,118	751	499	253
Central 2025	152,264	606	884	-278
Central 2030	152,289	581	586	-6
Southern 2025	152,332	537	126	411
Southern 2030	152,122	747	89	658

** excluding cost of the interconnector option*

As observed under the other scenarios, the southern option, entered towards the end of the modelling horizon, is the preferred option. The incremental option, the northern DC option and the northern AC option with later timing also providing a positive net market benefit.

When compared to the least-cost expansion results, most options are now economic and the northern DC option entered in 2029/30 provides similar net market benefits to the incremental option.

Contrary to the other two scenarios, the incremental option remains positive in this case. The incremental option enters in 2029/30 under this scenario. Because the timing of entry corresponds to the last year for which time sequential modelling was done, it does not capture the impact on losses as new generation is built in the following years to utilise the augmentation. For the previous two scenarios, a later time sequential run captured this impact

Table 34 shows the division of costs under Oil shock and Adaptation.

Table 34 Oil Shock and Adaptation division of total costs (PV $ million)

Option	Generation			Transmission		Total
	Fixed*	Variable**	Emissions	Augmentation	Other	costs***
Base	49,294	27,119	76,287	0	170	152,869
Incremental	49,506	26,965	75,970	0	174	152,614
Northern AC 2025	50,324	26,725	74,858	936	165	153,007
Northern AC 2030	50,264	26,776	74,938	627	167	152,772
Northern DC 2025	49,894	26,884	75,081	718	161	152,737
Northern DC 2030	49,942	26,844	75,161	499	172	152,617
Central 2025	49,893	26,940	75,238	884	193	153,148
Central 2030	49,988	26,919	75,187	586	194	152,875
Southern 2025	50,299	26,601	75,258	126	175	152,459
Southern 2030	50,556	26,393	75,074	89	100	152,211

** includes both capital costs and fixed operating and maintenance costs*

*** includes fuel and variable operating and maintenance costs, but not emission costs*

**** includes cost of the interconnector augmentation option*

5 Key conclusions

The feasibility study has demonstrated that:

- There is potential for augmenting transmission capacity between South Australia and the rest of the NEM, not only to facilitate export of renewable energy out of South Australia, but also to support South Australian peak demand as the level of intermittent generation increases.
- The incremental option to augment the existing Heywood interconnector could be economically feasible as early as 2017/18 under high growth and carbon price conditions and with significant wind investment in South Australia (Green Grid sensitivity). The optimal timing of the incremental option was delayed under less favourable conditions. Changes in system losses not assessed as part of the least-cost expansion results may also delay the incremental option. However, if other market benefits are taken into account (e.g. competition benefits) the timing could be advanced.
- Of the new high-capacity augmentation options assessed the lowest-cost southern option and the northern options appear most likely to be economically feasible in the 2020 to 2030 timeframe.
- The economic feasibility of the interconnector options is sensitive to a number of factors including the future market development scenarios considered, assumptions made about climate change policy settings (e.g. introduction of carbon pricing), and the estimated costs of the options.
- The timing of the new high-capacity augmentation options is expected to advance if additional incentives are provided to the renewable sector, for example extension of the Large-scale Renewable Energy Target (LRET) scheme with stronger targets beyond 2020.
- A new high-capacity interconnector augmentation option could be justified under high growth and carbon price conditions and with significant committed wind investment in South Australia (for example Green Grid sensitivity) as early as 2020 to 2025.

The key conclusions are drawn within the context of the limitations of the study, which include:

- a limited number of scenarios, all of which assumed at least a medium level of carbon pricing,
- a limited range of capital and operating cost assumptions for generation and transmission assets,
- a limited range of timing for new generation technologies,
- a limited number of transmission augmentation and routing alternatives (for example, options involving multi-terminal HVDC and high voltage AC technologies above 500 kV were not explored).

Furthermore, the least-cost expansion modelling:

- did not cover all classes of market benefits (competition benefits and benefits arising from changes in transmission losses are notable exclusions);
- used simplifying assumptions in the co-optimisation of generation and transmission, including the use of fixed transmission losses[29] and average wind generation profiles; and
- end-effects in net present value calculations were treated conservatively, delivering lower market benefits than would otherwise be the case.

The time-sequential modelling:

- provided some indication of the impacts of wind variability and loss benefits not covered in the least-cost expansion modelling; but
- was performed for every fifth year only and relied on interpolation of costs and benefits in the years between; and
- relied on the generation expansion plans from the least-cost expansion modelling results with no feedback to ensure consistency between capital investments and their operational cost impacts.

6 Next steps

Based on the outcomes of this feasibility study, AEMO and ElectraNet intend to undertake further work in 2011 that is focussed on clarifying the costs, benefits and timing of the lower cost incremental augmentation option (including a more accurate assessment of the impact of changes in system losses).

This further work is not intended to involve a formal application of the regulatory investment test for transmission (RIT-T), but will better inform when a formal regulatory assessment may be needed. The outcomes of this work will be reported in future South Australian and Victorian Annual Planning Reports and the National Transmission Network Development Plan.

The new high-capacity augmentation options assessed in this feasibility study will be kept under review as part of the annual planning processes that result in publication of Annual Planning Reports and the National Transmission Network Development Plan.

[29] Fixed in the sense that losses did not change as generation and transmission system was altered but was assumed to be equal to the losses of the base run for that particular scenario