ROAM CONSULTING
ENERGY MODELLING EXPERTISE

ROAM Consulting Pty Ltd
A.B.N. 54 091 533 621

Report (EMC00008) to AEMC

Network Augmentation and Congestion Modelling

June 2009

VERSION HISTORY

Version History				
Revision	**Date Issued**	**Prepared By**	**Approved By**	**Revision Type**
0.8	2009-05-05	Ben Vanderwaal David Yeowart Richard Bean Jenny Riesz Joel Gilmore Melinda Buchanan Jason Merefield	Ben Vanderwaal	Draft Report
1.0	2009-05-08	Ben Vanderwaal David Yeowart Richard Bean Jenny Riesz Joel Gilmore Melinda Buchanan Jason Merefield	Ben Vanderwaal	Complete Draft Report
1.1	2009-05-22	Ben Vanderwaal David Yeowart Richard Bean Jenny Riesz Joel Gilmore Melinda Buchanan Jason Merefield	Ben Vanderwaal	Final Draft Report
2.0	2009-06-17	Ben Vanderwaal David Yeowart Richard Bean Jenny Riesz Joel Gilmore Melinda Buchanan Jason Merefield	Ben Vanderwaal	Final Report
2.1	2009-06-19	Ben Vanderwaal Melinda Buchanan	Ben Vanderwaal	Minor edits to enhance consistency in terminology
2.2	2009-06-25	Ben Vanderwaal Melinda Buchanan	Ben Vanderwaal	Minor edits after feedback
2.3	2009-06-29	Ben Vanderwaal	Ben Vanderwaal	Final revision

EXECUTIVE SUMMARY

The introduction of the expanded Renewable Energy Target (RET) scheme and the Carbon Pollution Reduction Scheme (CPRS) will have significant impacts on the operation and dispatch of existing generators, as well as investment in both generation and transmission projects. It is important that the transmission network responds optimally to allow an efficient response from the system to these changes.

Scenario modelling

ROAM has conducted extensive modelling to consider the costs of congestion under the CPRS and expanded RET in light of generation locational decisions and network investment responses. The range of scenarios includes:

Scenario (a) **"Non-responsive transmission"** – generators make profit-maximising entry and exit decisions in the knowledge that transmission investment is limited to the bare minimum consistent with meeting mandatory obligations.

Scenario (b) **"Current regime working effectively"** – generators make profit-maximising entry and exit decisions in the knowledge that transmission investment will respond consistent with delivering mandatory and discretionary investment consistent with the National Electricity Rules. Transmission investment reflects benefits to both reliability and efficiency.

Scenario (c) **"Co-optimising central planner"** – a "socially optimal" generation and network investment case that reflects co-optimised investment decisions by generation and transmission businesses from a central-planning perspective. The decision to locate takes account of excess network capacity and the supply-demand balance. This assumes perfect foresight by the central planner and the objective of minimising the total costs of delivering energy services to customers over the analysis period.

Each of these scenarios was modelled with two trajectories of renewable energy development, corresponding to different market responses to the expanded Renewable Energy Target. In the "high banking case", renewable energy developments ramp up quickly, to levels above the NEM-wide targets in early years. The excess Renewable Energy Certificates (RECs) are then banked and sold for surrender in later years, when new development slows. In the "low banking case", growth in renewable development closely follows the minimum annual renewable generation targets. Comparing the high and low banking cases in each scenario yields useful information on the costs of these differing market responses.

Overview of modelling outcomes

The results of this study show that distributed installation of renewable energy around the NEM is preferable to concentrated development in one region. Transmission congestion resulting from concentrated renewables development means that large transmission upgrades (or possibly new lines) would be required to allow export of the energy to other regions.

Across most regions, the difference in renewable resources is not sufficient to justify large transmission augmentations, when more distributed renewable development is possible. However, the scenario modelling shows that South Australia contains sufficient excess renewable resource to justify transmission augmentation within the region and between South Australia and Victoria (or possibly New South Wales). This is partly due to the relative scale of available renewable resources compared with regional demand. In contrast, other regions of the NEM experience sufficient demand to fully utilise their renewable resources. Apart from enhancing export capability from South Australia, significant network augmentation was not found to be justified to facilitate meeting the expanded RET or to accommodate the CPRS.

Rational and informed generation investors are becoming increasingly aware of the influence that network capability has on their business decisions. The modelling shows that generation development for the purpose of maximising profit will deviate from that which might occur under a central planning approach. However, under both planning paradigms there appears to be sufficiently distributed renewable resource available to meet the expanded RET without necessitating significant changes to the current framework.

Modelling

ROAM's Integrated Resource Planning (IRP) model was used to determine the optimal generator and transmission expansion plan for each scenario under high and low banking of RECs, yielding six independent development plans.

This model calculates the full NEM dispatch on an hourly time sequential basis for each year of the study. Generators bid into the market at their short run marginal cost (SRMC), which incorporates their fuel price, variable operation and maintenance costs and carbon pollution permit costs. Each generator's SRMC was updated annually, to reflect yearly changes in fuel and carbon prices. Renewable generators did not incorporate a REC price in their bids, on the grounds that the dispatch merit order and regional pool price outcomes would remain the same (given the modelling methodology applied). The dispatch is calculated for every possible planting combination over the ten year period (that meets the system requirements).

Generator forced outages are included in the model via Monte Carlo seeding (including for hydro generators). The same seed is used for each set of states in each year, to ensure equitable comparison. Thus the model provides full chronological detail, and is fully deterministic with the exception of random generation outages.

To select the optimal development path in Scenario C, the discounted system cost (including variable run costs, fixed operation and maintenance costs, the cost of unserved energy and annual capital repayments) of each planting combination in each year is calculated. Dynamic programming (as the optimisation algorithm behind ROAM's IRP model) is used to find a development path which minimises the cumulative discounted system costs. This optimal development path may include one of four major network upgrades or new line augmentation options (generally referred to as interconnector upgrades).

In Scenarios A and B, the discounted profits (pool price revenue and REC revenue, net of generator costs) of new entry generators are calculated for each planting combination in each year. Dynamic programming is used to find a development plan which maximises the cumulative discounted profit of new entry generators. To do this in Scenario A, only development paths which do not include interconnector upgrades are considered for inclusion in the optimal path.

In Scenario B, each interconnector is considered independently. Development paths are found which maximise new entry generator profit in the knowledge that an interconnector will enter in a fixed year (this is done with the interconnector entering in each year in turn). If the interconnector upgrade is found to be justified (the benefit of reduced system costs exceeds its expenses) then its year of entry is optimised so that total system costs are least. Note that the resulting development plan yields maximum profits for new entry generators, while upgrading transmission to reduce system costs.

Planting outcomes

The table below contains the optimal planting outcomes (including generation and transmission developments) resulting from the modelling for each of the three scenarios (A, B and C) under high and low banking of RECs. Plant names refer to the generator location and type (for example, NSA Wind), with reference to the Annual National Transmission Statement (ANTS) zones[1].

The total capital cost to 2020 for each case is also given in the table below. Throughout this report, all costs are discounted to real 2009 dollars, calculated as net present value, real, pre tax, with a 10% weighted average cost of capital (discount rate), unless otherwise stated.

Summary of planting outcomes[2]
New entry wind, schedulable renewable, gas, committed plant, and transmission augmentations

	Low REC Banking			High REC Banking		
	Scenario A	Scenario B	Scenario C	Scenario A	Scenario B	Scenario C
2010-11	NSA Wind NSW Wind	NSA Wind NSW Wind	NSA Wind TAS Wind	NSA Wind NSW Wind	NSA Wind NSW Wind	NSA Wind TAS Wind

[1] The location of all generators is specified at the ANTS zone level. Where plant location is given as a region rather than a zone, this indicates the level of choice in the model. For example, the model can choose between locating wind farms in New South Wales and elsewhere, but the location of wind farms within New South Wales is specified in advance.

[2] Wind plants are 1000 MW in size, CCGT and OCGT plants are 1000 MW (500 MW in SA), and schedulable renewable plants (geothermal, biomass, sugar cane bagasse) are 500 MW in size.

Summary of planting outcomes[2]
New entry wind, schedulable renewable, gas, committed plant, and transmission augmentations

	Low REC Banking			High REC Banking		
	Scenario A	Scenario B	Scenario C	Scenario A	Scenario B	Scenario C
2011-12	-	-	-	QLD Wind VIC Wind	QLD Wind VIC Wind	NSW Wind VIC Wind
2012-13	SWQ CCGT NCEN OCGT NSW Wind	SWQ CCGT NCEN OCGT NSW Wind	SWQ CCGT NCEN OCGT NSW Wind	SWQ CCGT NCEN OCGT QLD Wind TAS Wind	SWQ CCGT NCEN OCGT QLD Wind TAS Wind	SWQ CCGT NCEN OCGT NSW Wind VIC Wind
2013-14	-	-	-	NSW Wind	NSW Wind	QLD Wind
2014-15	Munmorah retires QLD Bagasse	Munmorah retires QLD Bagasse	Munmorah retires QLD Bagasse	Munmorah retires	Munmorah retires	Munmorah retires
2015-16	VIC Wind MEL CCGT	VIC Wind MEL CCGT	VIC Wind	-	-	-
2016-17	NSA Geoth	SA-VIC Aug NSA Geoth	SA-VIC Aug NSA Geoth	NSA Geoth MEL CCGT	NSA Geoth MEL CCGT	SA-VIC Aug NSA Geoth
2017-18	QLD Biomass	QLD Biomass	MEL CCGT QLD Biomass	-	SA-VIC Aug	MEL CCGT
2018-19	NSW Geoth QLD Geoth	NSW Geoth QLD Geoth	NSW Geoth	SWQ CCGT	SWQ CCGT	SWQ CCGT
2019-20	SA Geoth	SA Geoth	QLD Geoth SA Geoth	-	-	-
Total capacity built	10,000MW	10,000MW	10,000MW	11,500MW	11,500MW	11,500MW
Total wind capacity built	4,000MW	4000MW	4,000MW	7,000MW	7,000MW	7,000MW
Total schedulable renewable capacity	3,000MW	3,000MW	3,000MW	500MW	500MW	500MW
Total capital repayments for new capacity ($2009 mil)	4,627	4,703	4,451	7,747	7,801	7,755

With high levels of RECs banking, a large quantity of wind is installed very early, and no schedulable renewable energy sources (beyond the committed NSA geothermal station) enter the market (because the RET is filled). With low levels of banking a more moderate amount of wind energy enters, and schedulable renewable energy sources are utilised heavily from 2014-15.

Justification of interconnector augmentations

Interconnector augmentations are individually justified on a cost reduction (net benefit) or reliability basis. This may involve demonstrating a combination of benefits, including:

- Sharing of reserve with reductions in overall amount of generating capacity across the combined network
- Reliability benefits
- Production cost reductions
- Ability to build larger more economic plants rather than smaller less economic plants due to sharing of generation capacity across more than one region
- Reduction in transmission losses
- Competition benefits

With the introduction of emissions trading, the value of many of these benefits may be increased. For example, with an emissions cost, transmission losses will become higher cost. Greater reductions in production costs may also result from the displacement of emissions intensive plant by low emissions plant in other regions.

Cost outcomes

The total cumulative cost of each of the scenarios is illustrated in the table below. The total cost can be broken down into the *emissions cost* (the cost of generators purchasing carbon pollution permits to cover their annual emissions at the specified annual carbon price), and the remaining costs (covering generator fuel, fixed and variable operations and maintenance costs, capital repayments and the cost of unserved energy).

The difference in cost between Scenarios A and B (A – B in the table below) tests the network response problem while the difference in cost between Scenarios B and C (B – C in the table below) tests the ability of the current arrangements to deliver timely and economic generator decisions. The difference in cost between Scenarios A and C (A – C in the table below) is also given. High REC banking – Low REC banking in the table refers to the difference in cost between high and low levels of REC banking in each scenario.

Cost comparisons (cumulative cost 2010-11 to 2019-20, $ mil)				
		Total cost	Cost excluding emissions cost	Emissions cost
Low REC banking	Scenario A	67,372	27,832	39,540
	Scenario B	67,223	27,771	39,452
	Scenario C	67,050	27,329	39,721
	A – B	149	61	88
	B – C	173	442	-269
	A – C	322	503	-181
High REC banking	Scenario A	69,442	30,409	39,033
	Scenario B	69,312	30,341	38,971
	Scenario C	69,201	30,260	38,941
	A – B	130	68	62
	B – C	111	81	30
	A – C	241	149	92
High REC banking – Low REC banking	Scenario A	2,070	2,577	-507
	Scenario B	2,089	2,570	-481
	Scenario C	2,151	2,931	-780

Network response problem

The difference in costs between Scenarios A and B is $130 to $149 million, cumulatively over the ten year period 2010-11 to 2019-20 (for the high and low banking cases respectively). Allowing the system to install the SA-VIC interconnector in 2017-18 reduces system costs through increased efficiency of dispatch, although it does not change the investment decisions of new entry generators (Scenarios A and B coincidentally have the same planting outcomes).

Efficiency of current system

The difference in costs between Scenarios B and C is $111 to $173 million, cumulatively over the ten year period 2010-11 to 2019-20 (for the high and low banking cases respectively). Allowing generators to make profit maximising decisions, rather than utilising a central planning approach with complete system knowledge costs the system $111 million over the ten years of the study period.

Impact of the level of REC banking

Low levels of REC banking were found to produce a lower net present cost outcome, by $2,151 million (for Scenario C) over the ten year outlook. Furthermore, this total cost difference is expected to rise over the period 2020 to 2030; the emissions cost in the high REC banking case will be significantly higher than in the low banking case over this period, as the low banking plan includes a much greater capacity and resulting energy supply from renewable generation by 2020.

Interconnector outcomes

The model can choose to build or upgrade at most one transmission augmentation option over the study period. A 400MW SA-VIC interconnector augmentation is justified in a wide range of system conditions, suggesting this augmentation delivers a net benefit to the market consistently.

Two other interconnector upgrades were considered: QNI (400MW bidirectional upgrade) and VIC-NSW (400MW bidirectional upgrade). A 2000MW bidirectional new line between SA and NSW was also investigated. None of these three options provided a net system benefit exceeding their costs in the study timeframe. However, the QNI upgrade and SA-NSW new line approached this threshold by 2020.

The net benefit of the SA-VIC augmentation is obtained by comparing the total system costs with and without this upgrade. The table below breaks down the total cost with the augmentation into generation and transmission costs.

Value of SA-VIC Augmentation in Scenario C (cumulative cost 2010-11 to 2019-20, $ mil)					
		With SA-VIC augmentation		Total cost without SA-VIC augmentation	Net benefit of SA-VIC augmentation
		Generation costs	Transmission costs		
Low REC banking	Scenario A	Augmentation not included			
	Scenario B	67,140	83	67,372	149
	Scenario C	66,967	83	67,198	148
High REC banking	Scenario A	Augmentation not included			
	Scenario B	69,253	59	69,442	130
	Scenario C	69,118	83	69,365	164
				Average:	148

Installation of the SA-VIC interconnector augmentation in 2016-17 produces a lower cost outcome, saving the system $148 to $149 million with low levels of banking, and $130 to $164 million with high levels of RECs banking (cumulatively over the period 2010-11 to 2019-20, but achieved over just the last four years from when the interconnector is installed).

Operational mode of plants

Many plants will undergo a change of operational mode under the CPRS and RET schemes.

Coal fired plant

In the Australian NEM, all coal-fired generators in Victoria operate on brown coal, with all other regions being black coal power stations. Some coal-fired plant (typically the least emissions intensive) maintain close to full capacity generation, even with high penetration of renewable energy generation and the relatively high carbon prices in the late years of the study. Coal-fired generators exhibiting this behaviour in the study included:

- Kogan Creek (QLD)
- Tarong North (QLD)
- Tarong (QLD)
- Bayswater (NSW)
- Loy Yang A (VIC)

Other coal-fired generators exhibit cycling behaviour throughout the day, even during the summer period. This typically occurs for more emissions intensive or older plants. Coal-fired generators exhibiting cycling behaviour in the study included:

- Callide B and C (QLD)
- Eraring (NSW)
- Gladstone (QLD)
- Stanwell (QLD)
- Swanbank B (QLD)
- Liddell (NSW)
- Wallerawang (NSW)
- Loy Yang B (VIC)
- Yallourn (VIC)
- Hazelwood (VIC)

This outcome is driven by relatively small differences in efficiency, fuel cost and emissions factors for each individual plant as sourced from ACIL Tasman data. The outcome may be different if generator costs or efficiencies change into the future or generators behave differently.

CCGT plant

Most CCGT plant has historically taken on the intermediate role in the electricity market due to its relatively higher operating cost compared with coal fired generation. With the introduction of a carbon price, the gap between coal fired and gas fired CCGT generation cost reduces. CCGT plant generally runs at close to full capacity in the studies, depending to some degree on the assumed gas price. CCGT generators exhibiting this behaviour include:

- Darling Downs (QLD)
- Condamine (QLD)

- Swanbank E (QLD)
- Tallawarra (NSW)
- Townsville GT (QLD)

OCGT plant

OCGT plant takes on a peaking role in the electricity market, only operating due to extremely high demands experienced during high or low temperatures or in response to unplanned outages of other generators or transmission lines. OCGT plant typically operates for less than 5% of the time.

With increased penetration of intermittent wind generation and gradual depletion of significant generation reserves due to demand growth over the period, OCGT plant is observed to increase in operation by between two to three times. In absolute cost and energy supply terms this remains relatively small compared to the total cost of the system, however it does highlight the possibility for an increased role for peaking generation capacity to support the higher levels of intermittent (non-schedulable) generation.

Renewable plant

Existing hydro, wind and biomass fuelled generation behaviour and production levels are assumed to remain stable throughout the modelling outlook. These plant will not be significantly influenced by the introduction of CPRS or RET as they have a very low marginal cost and are emissions neutral. Both existing and new entry renewable generation is expected to match generation levels commensurate with their local resource capability unless they are unable to be dispatched to their desired level due to binding transmission limitations.

Transmission congestion in the NEM

Transmission congestion occurs across all regions of the NEM when the limitation of network capability prevents the free flow of energy from low cost supply to meet demand in other parts of the network. The modelling shows that all major interconnectors experience congestion in the order of 5% of the time, but up to 75% in extreme cases. The economic impact of congestion however is not directly related to the percentage of time constrained and depending on the costs associated with alleviating such congestion it may remain lower cost to accept a certain level of persistent congestion.

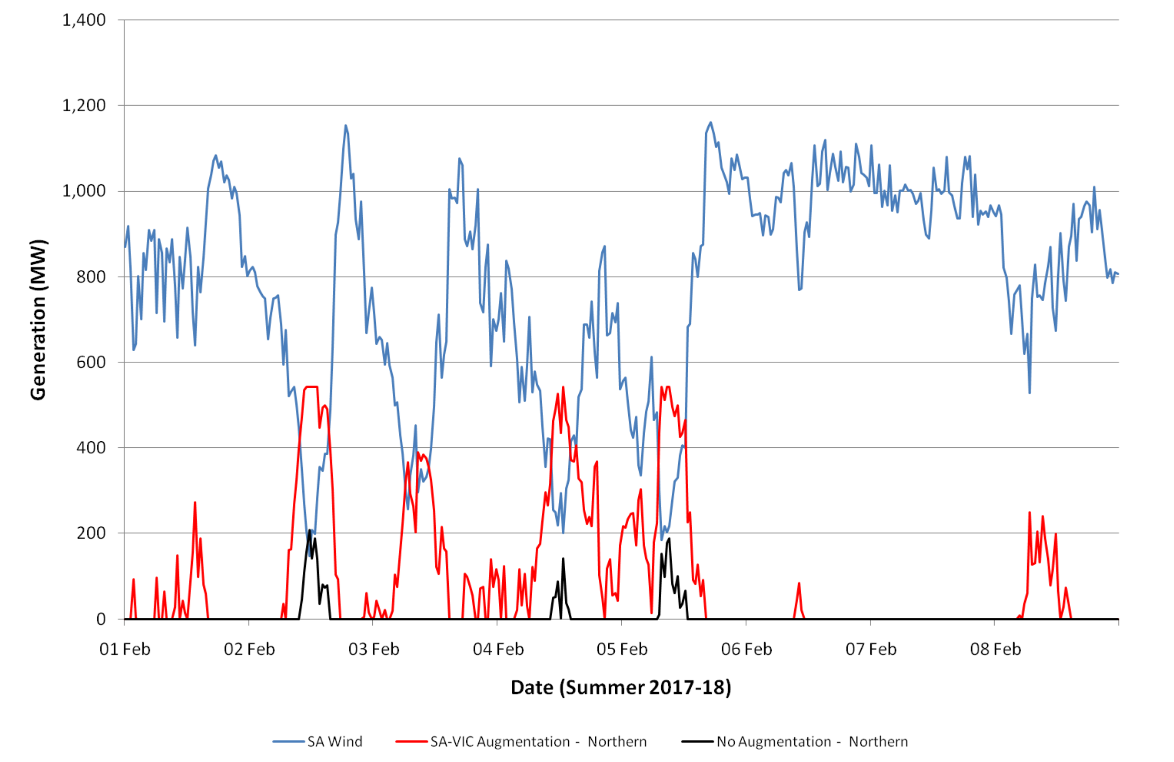
The QNI interconnector experiences congestion in the order or 20% to 30% of the time in the southerly direction throughout the study, however, the cost of augmentation was not found to be justified. Significant transmission congestion was observed within and around the South Australia region, which is discussed in detail below.

Transmission congestion in South Australia

The behaviour of South Australian plant is particularly interesting, given the small load and high proportional penetration of wind generation potential in this region.

Thermal plants in SA are strongly affected. Thomas Playford shows dramatically reduced dispatch not operating even in periods when aggregated SA wind outputs are as low as 200MW. Northern is also strongly affected, as illustrated in the following figure[3]. Northern only operates during periods of low wind, and is barely operational at all in the absence of the SA-VIC interconnector augmentation. This is due to a transmission limit from NSA-ADE, preventing higher cost generators (relative to wind and geothermal) in NSA (such as Northern and Thomas Playford) from supplying the ADE zone. The SA-VIC augmentation option includes a 400MW increase in the transmission limit from NSA to ADE, which allows Northern to increase generation when the SA-VIC augmentation is installed.

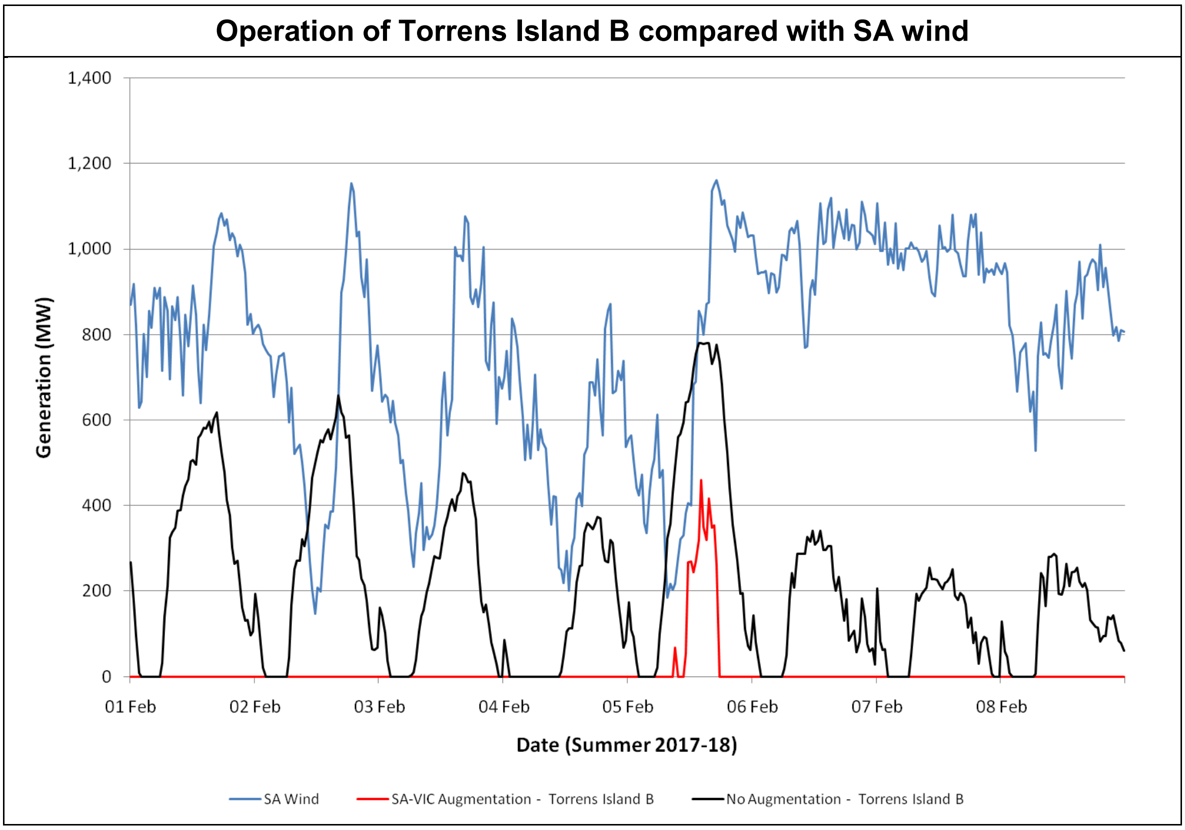
Operation of Northern compared with SA wind



Conversely, Torrens Island B is located in the ADE zone, and therefore exhibits the opposite behaviour, as illustrated in the figure on the following page[4]. Without the SA-VIC augmentation increasing the NSA-ADE limit (plus import capability from Victoria), Torrens Island B is required to operate (in a daily cycling fashion) to supply the ADE load. When the SA-VIC interconnector is installed, increasing the NSA-ADE limit, plants in NSA (such as Northern) and imports from Victoria undercut Torrens Island B, reducing its output.

[3] Results shown are for the low banking case, but are very similar for the high banking case.

[4] Results shown are for the low banking case, but are very similar for the high banking case.



Despite its very low short run marginal cost, even the South Australian geothermal plant (committed in the study in 2016-17) is strongly affected by the wind generation in South Australia, showing strong curtailment at times of high wind generation.

Aside from the economic issues that these fossil-fuel generators in South Australia will face with such dramatic volume reductions, there may be significant technical issues with erratic and reduced dispatch. The implications of dispatch at such low levels must be considered on an individual basis for these fossil-fuel generators, to investigate these technical barriers.

Technical issues for thermal generation and related issues regarding system stability and security resulting from a direct influence of the penetration of wind generation may be considered a cost of the expanded RET and CPRS schemes, and also relate to the transmission system limitations.

Binding transmission constraints

The table below illustrates the Annual National Transmission Statement (ANTS) transmission constraint equations that bound significantly throughout the course of the study. The table gives the name of the constraint, a description of what it is, and a discussion of why the constraint bound.

<table>
<tr><th>Significant binding transmission constraints – Scenario C</th></tr>
<tr><td>Constraint name: S>>V_NIL_BRPA_MNWT</td></tr>
<tr><td>General description: $\text{NSA Generation} - \text{Murraylink} \leq 1000$
Avoid overload of Mintaro to Waterloo 132 kV line on trip of Brinkworth to Para 275kV line</td></tr>
<tr><td>S>>V_NIL_BRPA_MNWT limits transfer across the NSA-ADE flow path by constraining NSA generation and Murraylink. NSA generation primarily consists of Northern power station, Thomas Playford power station, approximately 1000MW of new entry wind farms and 500MW of geothermal from 2016-17 onwards.

The amount of NSA wind generation is such that plant with relatively higher marginal costs (Northern, Thomas Playford and a small quantity of peaking plant) will not be dispatched outside of low wind conditions and are forced into highly intermittent operating patterns that may not be financially viable.

In high wind conditions, even extremely low marginal cost plant in the NSA zone (such as the new entry geothermal) is heavily constrained down without transmission upgrades.

Due to the large volume of low marginal cost plant in the NSA zone, Murraylink is regularly constrained towards SA to increase the maximum export from the NSA zone. This constraint was observed to bind for a very high proportion of time (consistently approximately one third of all hourly dispatch intervals for each year) and is an indication of extreme congestion along this flow path.

The VIC-SA upgrade selected in scenario C increased the maximum allowable export from the NSA zone, but did not reduce the number of binding periods for this constraint. This is a strong indication that a larger NSA-ADE upgrade may be justified if Northern power station continues to operate and considerable renewable new entry occurs in the zone.</td></tr>
<tr><td>Constraint name: V>>S_NIL_BGPA_BRPA, summer formulation</td></tr>
<tr><td>General description: $\text{NSA Generation} + 0.6\text{Murraylink} \leq 360 + 20\% \text{ of SA regional load}$
Limit Murraylink and SA generation to avoid overload of Brinkworth-Para 275 kV line for trip of Bungama to Para 275kV line</td></tr>
<tr><td>Similar to the previous constraint, V>>S_NIL_BGPA_BRPA limits transfer across the NSA-ADE flow path by constraining NSA generation and Murraylink. This constraint is observed to bind for nearly every period in which it is applied.

Outcomes for generation are in line with S>>V_NIL_BRPA_MNWT, albeit potentially more extreme in lower load periods. Murraylink however is forced in the opposite direction to S>>V_NIL_BRPA_MNWT. The two opposing limits on Murraylink combine to ‘set’ the interconnector to a specific value for a large number of periods.

This outcome suggests that multiple transmission elements are being operated at their firm capacities for extended periods of time.</td></tr>
</table>

Significant binding transmission constraints – Scenario C
Constraint name: V>>S_NIL_BGPA_BRPA, not summer formulation
General description: $\text{NSA Generation} + 0.6\text{Murraylink} \leq 760 + 20\% \text{ of SA regional load}$ *Limit Murraylink and SA generation to avoid overload of Brinkworth-Para 275 kV line for trip of Bungama to Para 275kV line*
Similar to the summer formulation this constraint acts to limit NSA generation and in combination with S>>V_NIL_BRPA_MNWT, heavily restrict Murraylink flow. This constraint binds for approximately one fifth of the periods applied.
Constraint name: V::S_NIL
General description: $\text{Heywood} + 0.58 \text{ SESA Wind} \leq \sim 360 - 400$ *Vic to SA Stability limit for loss of one NPS generator following a 2ph to ground fault*
V::S_NIL limits flow on the SESA to ADE flow path to avoid transient instability on the loss of a Northern power station unit. Given the existing installed capacity of SESA wind and the granularity of the IRP candidate wind farms, this constraint considerably constrains economic entry of any further generation capacity in the SESA zone. It is unclear if this constraint is applicable moving further into the future given a significant change in the operating mode of Northern power station but in the absence of more accurate information, V::S_NIL was applied as per the ANTS formulation. The primary driver for V:S_NIL binding in dispatch however, is related more to trade with Victoria than SESA wind. Even after the effects of the CPRS, Victorian brown coal plant is considerably lower cost than most SA thermal plant – the exceptions being Northern power station and Pelican Point. Northern power station is constrained down heavily throughout the study as discussed above, and Pelican Point undergoes a dramatic fuel price increase from 2013-14 based on the ACIL Tasman source data. This leads to importing power from Victoria being lower cost than most local supply options despite network losses, and thus the interconnector is often dispatched to the physical limit. The result is that V::S_NIL binds significantly (approximately one third of hourly dispatch intervals) until the 2013-14 Pelican Point gas price increase, at which point the constraint starts to bind for the majority of dispatch intervals. Following the increase in the CPRS carbon price in 2015-16, Pelican Point becomes considerably more competitive with Victorian coal, and the time binding drops back to approximately a third of all periods, falling to approximately zero when the VIC-SA interconnector is installed.

Summary

The results of this study show that distributed installation of renewable energy around the NEM is preferable compared with concentrated development in one region. Transmission congestion resulting from concentrated renewables development means that large transmission upgrades (or possibly new lines) are required to export the energy to other regions. However, the difference in renewable resources between regions is not sufficient to justify large transmission augmentations when more distributed renewable development is possible.

With this distributed development there is no significant or persistent economic cost associated with transmission congestion between NEM regions, with the exception of South Australia. In South Australia, costs associated with transmission congestion were found to be significant, due to entry of wind and geothermal generation in the NSA zone causing congestion between ADE and NSA[5].

This result assumes that wind projects in all zones experience similar transmission connection costs. If this is not realistic, differences in connection costs may skew renewable development towards a more centralised or concentrated distribution.

Augmentation of the SA-VIC interconnector (NSA to MEL) is suggested to be highly justified on a cost reduction basis in all scenarios analysed, with optimal installation in 2016-17 to 2017-18. This augmentation helps to alleviate the congestion on the NSA-ADE path, which causes significant curtailment of NSA plant. Allowing the system to install the SA-VIC interconnector in 2017-18 reduces system costs by $130-$149 million over ten years (2010-11 to 2019-20) through increased efficiency of dispatch, although it does not change the investment decisions of new entry generators.

Allowing generators to make profit maximising decisions, rather than utilising a central planning approach with complete system knowledge costs the system $111-173 million over ten years (2010-11 to 2019-20).

High or low levels of RECs banking under the RET scheme produce very different outcomes for renewable development, in terms of the type and location of renewable technologies installed. High banking produces a large quantity of wind generation, and excludes schedulable renewable technologies from the scheme. This is far more expensive to the system than allowing a slower rate of installation of renewable technologies, including a moderate amount of wind and allowing schedulable renewable technologies to enter, as in a low banking scenario. The level of REC banking is found to be the most significant differentiating factor in system costs.

[5] As discussed in the previous section, binding intra-regional constraints are a major source of congestion in this study. Addressing these (independent of inter-regional constraints) may have significant impact on congestion outcomes and the resulting pattern of development.

Recommendations

Investigate SA-VIC augmentation further

This study strongly suggests that the SA-VIC augmentation modelled has significant benefits to the NEM under the RET and CPRS, and is likely to be justified on a cost reduction basis. Further investigation of this transmission augmentation should include:

1. Determining the value of each of the individual sections of the augmentation (this study suggests that the NSA-ADE section is very important, but other sections of the full NSA-MEL augmentation may also be critical).
2. Determining the optimal size of the augmentation. This study analysed a 400MW bidirectional upgrade, but the very high value of this suggests that a larger augmentation may be utilised effectively, and be more cost effective.

Investigate SA-NSW augmentation further

This study suggests that a very significant 2000MW bidirectional transmission line between ADE and NCEN could provide substantial benefit to the system, recovering around 70% of its very significant cost. Optimisation of this line may make it entirely cost effective. Further investigation should include:

3. Analysis of the optimal line size, and the cost effectiveness of bigger and smaller line options
4. Analysis of the estimated cost of this line, to determine whether it could be installed for a slightly lower cost, making it cost effective.
5. Analysis of the additional benefits of this line that were not taken into account in this study (such as reductions in transmission losses, and increased market competition benefits).

Investigate retirements

Detailed investigation of retirements was not included in this study due to time limitations. However, the resulting operational mode of many emissions intensive plants suggests that many plants will face significant technical challenges operating in the modelled CPRS and RET environment. These plants may retire unless they are (for example) offered capacity payments to remain available for reliability purposes. Assistance provided to generators under the Electricity Sector Adjustment Scheme[6] may also play a role in the retirement decisions of existing plant.

Further investigation on this extremely important issue should include:

6. Analysing individual plants around the NEM and determining which may retire on the basis of technically infeasible operational modes, and lack of economic justification to remain available.
7. For those plants, determining the impacts of their retirement on the NEM, and examining how reliability can be maintained. This should include investigation and costing of demand side participation options, transmission augmentation options, and generation replacement options.
8. Analysing any regulatory barriers to efficient and timely retirement and replacement of emissions intensive plant.

[6] See the White Paper, Volume 2, December 2008, pp 13-52 to 13-53 for conditionality.

TABLE OF CONTENTS

1) ACRONYMS ... 1

2) BACKGROUND ... 1

3) SCOPE ... 1

3.1) ASSESSING FUTURE CONGESTION PATTERNS AND NETWORK FLOWS ... 1

4) RENEWABLE ENERGY ALTERNATIVES UNDER THE RET ... 3

Inclusion of renewable technologies in the Integrated Resource Planning Model ... 3

4.1) NON-SCHEDULABLE RENEWABLE TECHNOLOGIES ... 4

4.1.1) Wind ... 4

4.1.2) Wave ... 4

4.1.3) Tidal ... 5

4.1.4) Solar ... 5

Solar Photovoltaics – Large scale ... 5

Solar Photovoltaics – Residential scale (embedded) ... 5

Solar water heating ... 5

Solar thermal ... 6

Solar chimneys ... 6

4.2) SCHEDULABLE RENEWABLE TECHNOLOGIES ... 6

Biomass (including sugar cane bagasse) ... 6

Hydro ... 6

Geothermal ... 6

Solar thermal ... 7

5) INPUT ASSUMPTIONS ... 7

5.1) OVERVIEW OF THE IRP MODEL ... 7

Outage modelling ... 7

Dynamic Programming ... 8

5.2) SUMMARY OF INPUT ASSUMPTIONS ... 8

5.3) LOAD FORECAST ... 10

5.4) CARBON POLLUTION REDUCTION SCHEME ... 11

Banking and borrowing under the CPRS ... 12

5.5) GENERATION ... 12

5.5.1) Generator Trading Behaviour ... 12

5.5.2) New Entry Generation Options ... 13

Committed plant ... 13

5.5.3) Retirement of plant ... 14

Committed retirements ... 14

Retirements under the CPRS ... 14

Cost analysis of retirements ... 14

Summary ... 15

5.5.4) Schedulable Renewable projects ... 15

5.5.5) Wind projects ... 16

Existing and committed projects ... 16

New (non-committed) wind farms ... 16

5.6) RENEWABLE ENERGY TARGETS ... 17

Scenario 1: Low banking ... 18

Scenario 2: High banking 18
5.7) THE TRANSMISSION MODEL 19
ANTS Constraints 19
Transmission Augmentation Options 19
Transmission augmentations in the ANTS constraints 20
Segments of augmentations 20
5.8) CALCULATION OF COSTS 21
Discounting 21
Cost components 21
Inclusion of CPRS and RET schemes 22
6) SCENARIO C: CO-OPTIMISING CENTRAL PLANNER 22
Scenario description 22
Scenario treatment in ROAM's IRP model 23
6.1) GENERATION PLANTING SCHEDULE OUTCOMES 23
Planting outcomes 23
Fossil fuel plant 25
Schedulable renewable generation 25
Wind generation 26
Transmission augmentation 26
Renewable Energy Target 26
Energy from plant types 29
Sensitivities 40
Impact of no transmission augmentation on planting outcomes 41
6.2) COSTS 41
Costs in the absence of the interconnector 43
Lowest cost solution 44
6.3) GREENHOUSE EMISSIONS 45
Greenhouse emissions in the absence of the interconnector 46
6.4) UNSERVED ENERGY 46
6.5) INTERCONNECTORS 47
6.5.1) Augmentation Timing 47
6.5.2) Interconnector augmentation costs 48
SA-VIC augmentation 49
SA-NSW new line 53
QNI augmentation 57
VIC-NSW augmentation 58
6.5.3) Interconnector link flows 58
Flows from QLD to NSW 59
Flows from VIC to NSW 59
Flows from TAS to VIC 59
Flows from VIC to SA 60
Interconnector flows without the SA-VIC augmentation 60
Interconnector link flow by time of day 61
6.6) TRANSMISSION CONGESTION 64
Wind farm curtailment 66
Operational mode of plants 69
Transmission congestion in South Australia 74
Binding transmission constraints 78

6.7) RENEWABLE DEVELOPMENT IN SOUTH AUSTRALIA 81
Planting outcomes 81
Costs 83
Augmentation cost effectiveness 83
Operational modes – South Australian fossil fuel plant 84
Implications for this study 86

7) SCENARIO A: NON-RESPONSIVE TRANSMISSION 86

Scenario description 86
Scenario treatment in ROAM's IRP model 86
7.1) RESULTS 88
Planting outcomes 88
Costs 91

8) SCENARIO B: CURRENT REGIME WORKING EFFECTIVELY 92

Scenario description 92
Scenario treatment in ROAM's IRP model 92
8.1) RESULTS 93
Planting outcomes 93
Entry date of the SA-VIC interconnector augmentation 96
Profit maximisation – impacts on planting outcomes 97
8.1.1) Costs 99
Comparison of scenario total cumulative costs 99
Cost components 101
Network response problem 104
Efficiency of current system 104
8.2) INTERCONNECTORS 104
Augmentation timing in Scenario B 104
Augmentation costs – High banking 107
Augmentation costs – Low banking 108
Transmission congestion 108
8.3) GREENHOUSE EMISSIONS 112

9) CONCLUSIONS 116

9.1) RECOMMENDATIONS 117
Investigate SA-VIC augmentation further 117
Investigate SA-NSW augmentation further 117
Investigate retirements 117

APPENDIX A) INPUT ASSUMPTIONS I

A.1) LOAD FORECAST I
Demand side participation I
Significant Non-scheduled Generation I
Reference Load Trace I
A.2) CARBON POLLUTION REDUCTION SCHEME I
A.3) GENERATOR TRADING BEHAVIOUR II
A.4) WIND FARM MODELLING III
Existing wind farms III
Committed wind farms IV
New (non-committed) wind farms V

New wind farm projects .... *VI*
A.5) MODELLING OF WIND FARM GENERATION........ IX
A.6) RENEWABLE ENERGY TARGETS XIII
Case 1: Low banking .... *XIII*
Case 2: High banking .... *XIV*
A.7) THE TRANSMISSION MODEL XIV
ANTS Constraints .... *XIV*

APPENDIX B) INTEGRATED RESOURCE PLANNING: MODELS AND METHODOLOGY XV

B.1) INTRODUCTION XV
B.2) A MATHEMATICAL BASIS FOR INTEGRATED RESOURCE PLANNING XV
Multistage Decision Processes .... *XV*
Developing an expansion planning model .... *XVI*
A graphical representation .... *XVIII*
Costs of a state .... *XIX*
Dynamic programming and the IRP optimisation .... *XXII*
Sensitivities .... *XXV*
Objective Functions for Scenarios A, B and C .... *XXVI*
Strengths of the method .... *XXVII*

LIST OF TABLES

TABLE 5.1 – SUMMARY OF INPUT ASSUMPTIONS 8
TABLE 5.2 – SCHEDULABLE RENEWABLE PROJECTS........ 15
TABLE 5.3 – WIND PROJECTS 17
TABLE 5.4 – TRANSMISSION AUGMENTATION OPTIONS 19
TABLE 5.5 – TRANSMISSION AUGMENTATION COMPONENTS 20
TABLE 6.1 – ASSUMED LONG RUN MARGINAL COSTS OF RENEWABLE TECHNOLOGIES 26
TABLE 6.2 – CAPITAL COST SENSITIVITIES TO SCENARIO C 41
TABLE 6.3 – COST COMPARISONS (CUMULATIVE COST 2010-11 TO 2019-20, $ MIL) 42
TABLE 6.4 – UNSERVED ENERGY AND ASSOCIATED COST........ 47
TABLE 6.5 – TIMING OF SA-VIC INTERCONNECTOR AUGMENTATION 48
TABLE 6.6 – TRANSMISSION AUGMENTATION OPTIONS 48
TABLE 6.7 – SA-VIC INTERCONNECTOR AUGMENTATION 50
TABLE 6.8 – SA-NSW INTERCONNECTOR........ 54
TABLE 6.9 – QNI INTERCONNECTOR AUGMENTATION........ 58
TABLE 6.10 – VIC-NSW INTERCONNECTOR AUGMENTATION........ 58
TABLE 6.11 – INTERCONNECTOR CONGESTION - PERCENTAGE OF TIME CONSTRAINED 65
TABLE 6.12 – INPUT ASSUMPTIONS (LOY YANG A AND B) 72
TABLE 6.13 – SIGNIFICANT BINDING TRANSMISSION CONSTRAINTS – SCENARIO C........ 78
TABLE 6.14 – SUMMARY OF PLANTING OUTCOMES (SCENARIO C, HIGH BANKING) NEW ENTRY WIND, SCHEDULABLE RENEWABLE, GAS, COMMITTED PLANT AND TRANSMISSION AUGMENTATIONS........ 82
TABLE 6.15 – COST COMPARISONS (CUMULATIVE COST 2010-11 TO 2019-20, $ MIL) 83
TABLE 6.16 – SA-VIC INTERCONNECTOR AUGMENTATION (HIGH BANKING)........ 84
TABLE 7.1 – SUMMARY OF PLANTING OUTCOMES (SCENARIO A VS C) NEW ENTRY WIND, SCHEDULABLE RENEWABLE, GAS, COMMITTED PLANT, AND TRANSMISSION AUGMENTATIONS 89
TABLE 7.2 – COST COMPARISONS (CUMULATIVE COST 2010-11 TO 2019-20, $ MIL) 91
TABLE 8.1 – SUMMARY OF PLANTING OUTCOMES NEW ENTRY WIND, SCHEDULABLE RENEWABLE, GAS, COMMITTED PLANT, AND TRANSMISSION AUGMENTATIONS 95
TABLE 8.2 – COST COMPARISONS (CUMULATIVE COST 2010-11 TO 2019-20, $ MIL) 100
TABLE 8.3 – SA-VIC INTERCONNECTOR AUGMENTATION (HIGH BANKING)........ 107
TABLE 8.4 – QNI INTERCONNECTOR AUGMENTATION (HIGH BANKING)........ 107
TABLE 8.5 – SA-VIC INTERCONNECTOR AUGMENTATION (LOW BANKING)........ 108
TABLE 8.6 – LOW BANKING INTERCONNECTOR CONGESTION - % OF TIME CONSTRAINED........ 109
TABLE 8.7 – HIGH BANKING INTERCONNECTOR CONGESTION - % OF TIME CONSTRAINED 111
TABLE A.1 – CARBON PRICE TRAJECTORY II
TABLE A.2 – ROAM CORRECTIONS TO ACIL TASMAN DATA II
TABLE A.3 – EXISTING (OPERATING) WIND FARMS – NON SCHEDULED III
TABLE A.4 – EXISTING (OPERATING) WIND FARMS - SCHEDULED IV
TABLE A.5 – COMMITTED WIND FARMS........ IV
TABLE A.6 – REPRESENTATIVE WIND FARMS VI
TABLE A.7 – LOW BANKING ANNUAL REC LOWER BOUNDS........ XIII
TABLE A.8 – HIGH BANKING ANNUAL REC LOWER BOUNDS........ XIV

List of Figures

Figure 5.1 – ANTS zones 10
Figure 5.2 – Carbon Price under the CPRS 11
Figure 5.3 – RECs produced by new non-committed renewable generators 18
Figure 6.1 – Planting outcome for Scenario C – Low banking 24
Figure 6.2 – Planting outcome for Scenario C – High banking 24
Figure 6.3 – RET outcome for Scenario C – Low banking 27
Figure 6.4 – RET outcome for Scenario C – High banking 28
Figure 6.5 – RET outcome for Scenario C – Mix of technologies (GWh) 28
Figure 6.6 – RET outcome for Scenario C – Distribution by state (GWh) 29
Figure 6.7 – Energy by plant type – Low banking 30
Figure 6.8 – Energy by plant type – High banking 30
Figure 6.9 – South Australia Energy by plant (Low banking) 31
Figure 6.10 – South Australia Energy by plant (High banking) 32
Figure 6.11 – Victoria Energy by plant (Low banking) 33
Figure 6.12 – Victoria Energy by plant (High banking) 34
Figure 6.13 – NSW Energy by plant (Low banking) 35
Figure 6.14 – NSW plant short run marginal costs (without carbon price) 36
Figure 6.15 – NSW plant short run marginal costs (with carbon price) 36
Figure 6.16 – NSW Energy by plant (High banking) 37
Figure 6.17 – QLD Energy by plant (Low banking) 38
Figure 6.18 – QLD Energy by plant (High banking) 39
Figure 6.19 – TAS Energy by plant (Low banking) 40
Figure 6.20 – Cost outcomes (cumulative cost 2010-11 to 2019-20) Scenario C 42
Figure 6.21 – Emissions cost comparison 44
Figure 6.22 – Greenhouse emissions outcomes for Scenario C 45
Figure 6.23 – Greenhouse emissions outcomes 46
Figure 6.24 – Interconnector cost effectiveness (Scenario C) 49
Figure 6.25 – SA-VIC augmentation - Northern (Scenario C) 51
Figure 6.26 – SA-VIC augmentation – Torrens Island B (Scenario C) 52
Figure 6.27 – SA-VIC augmentation - Geothermal (Scenario C) 53
Figure 6.28 – SA-NSW augmentation – Renewable generation (Scenario C) 55
Figure 6.29 – SA-NSW augmentation – Torrens Island B (Scenario C) 56
Figure 6.30 – SA-NSW augmentation - Northern (Scenario C) 57
Figure 6.31 – Average annual interconnector link flows (Scenario C) 59
Figure 6.32 – Average link flow VIC-SA (Scenario C) 60
Figure 6.33 – Average link flow VIC-NSW (Scenario C) 61
Figure 6.34 – NSW-QLD link flow by time of day (Scenario C) 62
Figure 6.35 – VIC-NSW link flow by time of day (Scenario C) 63
Figure 6.36 – VIC-SA link flow by time of day (Scenario C) 64
Figure 6.37 – Wind farm curtailment – Low banking – Scenario C 66
Figure 6.38 – Wind farm curtailment – High banking – Scenario C 67
Figure 6.39 – Wind farm curtailment vs capacity – Low banking – Scenario C 68
Figure 6.40 – Wind farm curtailment vs capacity – High banking – Scenario C 68
Figure 6.41 – Coal-fired plants (full capacity operation) – 2017-18 70

FIGURE 6.42 – COAL-FIRED PLANTS (DAILY CYCLING OPERATION) – 2017-18 71
FIGURE 6.43 – CCGT PLANTS – 2017-18.. 73
FIGURE 6.44 – OPERATION OF NORTHERN COMPARED WITH SA WIND.. 74
FIGURE 6.45 – OPERATION OF TORRENS ISLAND B COMPARED WITH SA WIND 75
FIGURE 6.46 – ANNUAL GENERATION OF SA FOSSIL-FUEL GENERATORS 76
FIGURE 6.47 – OPERATION OF SA GEOTHERMAL PLANT COMPARED WITH NSA WIND 77
FIGURE 6.48 – OPERATION OF SA GEOTHERMAL PLANT 78
FIGURE 6.49 – SHORT RUN MARGINAL COSTS OF SOUTH AUSTRALIAN PLANT (INPUT ASSUMPTIONS).. 81
FIGURE 6.50 –HIGH BANKING REC PRODUCTION TRAJECTORIES 83
(WITH AND WITHOUT NSA PLANT COMMITTED)... 83
FIGURE 6.51 – SUMMER OPERATION OF NORTHERN (HIGH BANKING).. 85
FIGURE 6.52 – SUMMER OPERATION OF TORRENS ISLAND B (HIGH BANKING) 86
FIGURE 7.1 – PLANTING OUTCOME – SCENARIO A (LOW BANKING).. 88
FIGURE 7.2 – PLANTING OUTCOME – SCENARIO A (HIGH BANKING).. 89
FIGURE 7.3 – RENEWABLES DISTRIBUTION BY REGION (GWH) (HIGH BANKING).................................. 91
FIGURE 8.1 – PLANTING OUTCOME – SCENARIO B (LOW BANKING).. 93
FIGURE 8.2 – PLANTING OUTCOME – SCENARIO B (HIGH BANKING).. 94
FIGURE 8.3 – INPUT ASSUMPTIONS – DRIVERS FOR INTERCONNECTOR AUGMENTATION 96
FIGURE 8.4 – INPUT ASSUMPTIONS – CCGT GAS PRICES BY REGION.. 97
FIGURE 8.5 – ANNUALISED PROFIT BY STATION TYPE (LOW BANKING)... 98
FIGURE 8.6 – ANNUALISED PROFIT BY STATION TYPE (HIGH BANKING) 99
FIGURE 8.7 – COST COMPARISON – TOTAL COST 101
FIGURE 8.8 – COST COMPONENTS (SCENARIO C) 102
FIGURE 8.9 – ANNUALISED CAPITAL EXPENDITURE (DISCOUNTED) 102
FIGURE 8.10 – COST COMPARISON – COST EXCLUDING EMISSIONS COST 103
FIGURE 8.11 – COST COMPARISON – EMISSIONS COST... 104
FIGURE 8.12 – SCENARIO B COST VS YEAR OF SA-VIC AUGMENTATION 105
FIGURE 8.13 – SCENARIO B COST VS YEAR OF SA-VIC AUGMENTATION – COMPONENTS (HIGH BANKING).. 106
FIGURE 8.14 – SCENARIO B COST VS YEAR OF SA-VIC AUGMENTATION – COMPONENTS (LOW BANKING) 106
FIGURE 8.15 – GREENHOUSE EMISSIONS (SCENARIO B).. 113
FIGURE 8.16 – GREENHOUSE EMISSIONS (LOW BANKING).. 114
FIGURE 8.17 – GREENHOUSE EMISSIONS (HIGH BANKING) 115
FIGURE A.1 – LOCATIONS OF BOM WEATHER STATIONS..X
FIGURE A.2 – LAKE BONNEY STAGE 2 GENERATION DURATION BENCHMARK XII
FIGURE A.3 – LAKE BONNEY STAGE 2 HALF HOURLY GENERATION BENCHMARK.............................XII
FIGURE B.1 – AN EXAMPLE 3-STAGE DECISION PROCESS..XIX
FIGURE B.2 – RUN AND TRANSITIONAL COSTS XXII
FIGURE B.3 – CALCULATING A LEAST COST PATH...XXV

1) Acronyms

ANTS	Annual National Transmission Statement
BOM	Bureau of Meteorology
CCGT	Combined cycle gas turbine
CCS	Carbon Capture and Storage
CPRS	Carbon Pollution Reduction Scheme. Australia's proposed national emissions trading scheme.
IRP	Integrated Resource Planning
LRMC	Long run marginal cost
M50	NEMMCO load growth forecasts, with medium growth, and a 50% probability of exceedence climatic forecast.
NEM	National Electricity Market – the interconnected electricity grid on the east coast of Australia, incorporating Queensland, New South Wales, Victoria, Tasmania and South Australia.
NEMMCO	National Electricity Market Management Company
NER	National Electricity Rules
OCGT	Open cycle gas turbine
P.O.E.	Probability of exceedence – in the context of peak demand, it represents the probability that the given demand level will be exceeded for at least one half an hour per annum (one trading interval).
(M)RET	(Mandatory) Renewable Energy Target. Australia's proposed expanded renewable energy scheme, which aims to source 20% of Australia's energy from renewable sources by 2020.
SOO	Statement of Opportunities (NEMMCO)
SRMC	Short run marginal cost

2) Background

The introduction of the Renewable Energy Target (RET) scheme and the Carbon Pollution Reduction Scheme (CPRS) will have significant impacts on the operation and dispatch of existing generators, as well as investment in both generation and transmission projects.

3) Scope

3.1) Assessing future congestion patterns and network flows

The purpose of this assignment is to consider the costs of congestion under the CPRS and expanded RET in light of generation locational decisions and network investment responses. Currently, generation locational decisions may be influenced by the likelihood of network businesses "building out congestion" that arises as a result of that generation locational decision. The Assignment is seeking to understand whether improving the locational decisions for new generation may result in better use of the existing network, and, in turn, promote more efficient investment in networks to address congestion as it arises.

For this study, ROAM has modelled the CPRS and expanded RET designs as set out in the Commonwealth Government's White Paper and Exposure Draft of the expanded RET Bill[7], respectively. ROAM has modelled a range of credible scenarios in the NEM that reflect:

- the relative economic costs of different scenarios for the timing and location of the entry and exit of generation under the CPRS and expanded RET, informed by the Commonwealth Treasury CPRS modelling and the National Electricity Market Management Company's (NEMMCO) 2008 Statement of Opportunities (SOO); and
- different transmission investment scenarios.

The range of scenarios includes:

Scenario (a) **"Non-responsive transmission"** – generators make profit-maximising entry and exit decisions in the knowledge that transmission investment is limited to the bare minimum consistent with meeting mandatory obligations.

Scenario (b) **"Current regime working effectively"** – generators make profit-maximising entry and exit decisions in the knowledge that transmission investment will respond consistent with delivering mandatory and discretionary investment consistent with the National Electricity Rules. Transmission investment reflects benefits to both reliability and efficiency.

Scenario (c) **"Co-optimising central planner"** – a "socially optimal" generation and network investment case that reflects co-optimised investment decisions by generation and transmission businesses from a central-planning perspective. The decision to locate takes account of excess network capacity and the supply-demand balance. This assumes perfect foresight by the central planner and the objective of minimising the total costs of delivering energy services to customers over the analysis period.

The different costs between scenarios (a) and (b) test the network response problem while the different costs between scenarios (b) and (c) test the ability of the current arrangements to deliver timely and economic generator decisions.

The modelling also:

- determines the likely congestion patterns and network flow outcomes arising under the range of scenarios; and
- measures and compares the change in dispatch costs and network investment costs under the different scenarios.

7 The Commonwealth released an Exposure Draft of the *Renewable Energy (Electricity) Amendment Bill* in December 2008 to implement the expanded RET together with Commentary on the Exposure Draft. There have been subsequent changes to the proposed CPRS and RET legislation, but the modelling does not reflect these changes.

This report is intended to fulfil the following criteria:

- develops a range of credible scenarios of future generation and demand for each region under the CPRS during the period July 2010 to July 2020. These scenarios shall be based on the Commonwealth Government's White Paper design of the CPRS and the Exposure Draft of the Bill to implement the expanded RET. This also presents the scope of other modelling assumptions, including generation offer assumptions, transmission investment assumptions, central planning assumptions, etc. The scenarios were discussed with the AEMC before modelling;
- advises on the likely changes in the location of generation in each region resulting from the changing generation mix under the CPRS;
- advises on the likely location decisions of renewable generation under the expanded RET;
- discusses how the operation and dispatch of increased renewable generation (under the expanded RET) and the changing generation plant mix (under CPRS) influences the patterns of congestion compared to the current patterns;
- advises on the likely inter-regional and intra-regional network flows under each credible scenario;
- identifies and measures the resulting congestion under each scenario (covering both inter-regional and intra-regional constraints). The measures of congestion must reflect both the duration and economic cost of the constraint binding;
- identifies areas where congestion could be persistent and material, if efficient network developments cannot be achieved; and
- provides commentary and observations about how to improve the current incentives that inform generation entry and exit decisions and network investment decisions, where the dispatch and network investment costs under the different scenarios differ substantively.

4) Renewable Energy Alternatives under the RET

This section provides an overview of the types of renewable technologies considered likely to enter the market to meet the Renewable Energy Target (RET).

Inclusion of renewable technologies in the Integrated Resource Planning Model

To limit the number of scenarios and allow modelling within a manageable timeframe, ROAM modelled renewable technologies in two categories:

1. Non-schedulable renewable technologies (largely wind)
2. Schedulable renewable technologies (including geothermal, landfill gas, sugar cane bagasse and other forms of biomass)

This categorisation allows reasonably accurate modelling of the operational mode of the various renewable technologies, whilst limiting computational time. The capital and ongoing costs input into the model for these technologies are representative of the most mature and least expensive of the alternatives under that category, on the expectation that the costs of the less mature technologies will decrease to competitive levels, if they are preferentially installed. Capital costs can be varied by sensitivity analysis following completion of the Base Case outcomes, in order to explore the relationship between capital cost and new entrant generation for any generation type.

Following is a brief overview of the various types of renewable technologies available, and how likely they are considered to contribute to the RET.

4.1) NON-SCHEDULABLE RENEWABLE TECHNOLOGIES

4.1.1) Wind

Wind is the most mature and least expensive form of renewable generation[8]. Australia has excellent wind resources in South Australia, Victoria, Tasmania and Western Australia, and moderate resources in Queensland and New South Wales.

With wind development beyond 20% of the local load in a region, further wind development becomes expensive and technically more challenging. South Australia is already approaching this limit. This means that in order to meet the 20% by 2020 RET, it may be necessary to distribute wind development around the country, either by increasing the incentives for development in other regions or by expanding interconnection capacities.

Given the short timeframe of the RET (to 2030) ROAM expects that the majority of the RET will be met with wind generation, as the most mature and commercially available technology[9]. Other technologies are likely to contribute more significantly beyond the timeframe of the RET.

Wind generation has been explicitly modelled on an hourly basis in this study and ROAM has included specific announced wind projects in the model. Further details on the wind modelling is included in Section 5.5.5) and Appendix A).

4.1.2) Wave

Wave technologies show great promise, most particularly the CETO sea-bed piston type technology proposed by Carnegie. However, these technologies are currently very expensive, and are at the early pilot project stage. For these reasons, ROAM considers wave energy unlikely to contribute to the RET in the same quantities as wind generation prior to 2020, and therefore has not considered it an option in this study.

---

[8] Aside from hydroelectricity. Opportunities for further development in hydroelectricity in Australia are very limited, with the main remaining potential located in environmentally sensitive locations.

[9] Although this will depend on the market response to the policy. If renewable development grows in line with the RET (a low amount of REC banking is observed) then other technologies will make a larger proportionate contribution. Nevertheless, wind farms will generate the majority of RECs before 2020, as they will be installed earlier than plant of less mature technologies, and hence produce RECs for a longer period of time. This is borne out by the modelling in this study.

4.1.3) Tidal

Australia has some limited potential for tidal energy, particularly in northern Queensland. It is not expected to be a wide scale energy resource in the NEM, and therefore has not been considered as an option in this study.

4.1.4) Solar

Australia has a world class solar resource. There are a variety of types of solar technology under serious consideration for development in the NEM. All are significantly more expensive than wind or biomass:

1. Photovoltaics (mature technology, very high cost)
    a. Large scale installation
    b. Residential installation (small generating units)
2. Solar water heating (residential)
3. Thermal (Pilot stage, high cost)
4. Chimneys (Hypothetical, unknown cost)

The various solar thermal technologies all show promise. Solar thermal technologies are discussed in the following section (schedulable renewable technologies) since the direct storage of heat allows schedulability.

Solar Photovoltaics – Large scale

Solar PV technologies are relatively mature and commercially available. However, they are very expensive by comparison with other renewable technologies. Given the maturity of the technology, large cost reductions are unlikely. There is likely to be some investment in solar PV in residential and commercial areas as a form of distributed energy to offset distribution system augmentations (and because the technology is favoured by the general public), but it is unlikely to be a wide scale contributor to the RET. ROAM has therefore not included this technology as an option in this study.

Solar Photovoltaics – Residential scale (embedded)

Due to the very high expense of widespread installation of solar photovoltaics on residential buildings compared with other renewable alternatives, ROAM does not expect this to be a substantial contributor to the RET. ROAM has therefore not included this technology as an option in this study.

Solar water heating

Residential solar water heating units are eligible to create RECs for their lifetime of operation at the point of installation. This was a substantial contributor to RECs production under the previous MRET scheme.

In this study ROAM has assumed that solar water heating units continue to be installed (and contribute to the RET) at a similar rate to in recent past years. New buildings are likely to utilise solar water heating, and there will be some continued exchange of old electric units for new solar water heating units.

Solar thermal

Solar thermal technologies can be installed with direct large scale heat storage, and hence be schedulable. Despite the additional capital cost of including storage facilities, this increases the profitability of solar thermal plants, because they can operate through peak demand periods in the late afternoon and early evening. It is therefore anticipated that most solar thermal units installed will be of a schedulable nature. Solar thermal technologies are therefore included in the following section for discussion.

Solar chimneys

Solar chimneys are currently at a very early pilot stage, and therefore have not been included as an option in this study.

4.2) SCHEDULABLE RENEWABLE TECHNOLOGIES

Biomass (including sugar cane bagasse)

Biomass, including wood chip waste, sugar cane bagasse, landfill gas and other waste biomass represents a significant renewable energy source. Despite being a mature and viable technology, current development of this resource has been inhibited by the fulfilment of the very modest existing MRET (causing RECs prices to be insufficient for new bagasse projects). With the introduction of the significantly expanded RET in 2009, and the CPRS raising electricity prices from 2010 biomass generation should become more cost effective and a valuable energy resource for the NEM. ROAM expects biomass to be an important contributor to the RET in significant volumes from around 2014-15.

Historically, sugar cane bagasse has not been utilised as a fully schedulable renewable technology due to limitations with storage of the bagasse throughout the year (the crushing season covers only half the year). However, recent advances in bagasse storage techniques now mean that bagasse generators can operate almost constantly throughout the year, providing genuine schedulable renewable energy.

Hydro

Hydroelectricity is currently the most cost effective form of renewable energy. There are unused hydroelectricity resources in the NEM, but most are located in areas of high environmental sensitivity. It is unlikely that there will be opportunities for substantial further hydroelectricity development in Australia. In this study ROAM has modelled the current hydroelectricity generators with appropriate energy limitations, but further development in hydroelectricity has not been included as an option.

Geothermal

Geothermal power is a promising technology that may prove to be an important source of energy for the NEM in the longer term. However, it is at a very early pilot stage, and has many significant issues that will need to be overcome before this technology becomes commercially viable and enters the market large scale. Based on advice provided for this assessment, geothermal plant is assumed to be available in significant volumes from 2016-17.

This study allows for a number of 500MW geothermal stations to enter by 2020. They are modelled as the hot fractured rock technology, with identical costs and efficiencies across all regions.

Solar thermal

Solar thermal technologies show great promise as a large scale energy resource for the NEM, but are currently immature and expensive. However, as a favoured technology for long term development (due to anticipated cost reductions with investment in pilot projects), solar thermal pilot projects are likely to receive substantial funding to support their introduction to the market.

Solar troughs are the most mature of the solar thermal technologies, although solar towers show great promise. Parabolic dish technologies are also worth consideration in the longer term.

With incentives, solar thermal energy could contribute to the RET, but will not be competitive with wind energy until pilot project funding is sourced. ROAM expects only small scale pilot plants to be built before 2020, and hence it has not been included in this study as an option.

5) INPUT ASSUMPTIONS

This chapter outlines the broad input assumptions utilised in this study. Much more detailed input assumptions are outlined in Appendix A and B.

5.1) OVERVIEW OF THE IRP MODEL

ROAM's Integrated Resource Planning model was used to determine the optimal planting outcomes for each scenario. This model calculates the full NEM dispatch on an hourly time sequential basis for the full ten years of the study. The dispatch is calculated for every possible planting combination over the ten year period (that meets the system requirements). The optimal path is then determined by selecting the path that maximised profits, or minimised costs (as desired).

Outage modelling

Generator maintenance plans (unique to each generator) are included, in addition to partial and full forced outages. Generator forced outages are included in the model via Monte Carlo seeding (including for hydro generators). The same seed is used for each generator in each set of states in each year, and each generator has a unique seed, to ensure equitable comparison. Thus the model provides full chronological detail, and is fully deterministic with the exception of random generation outages.

Dynamic Programming

In more detail, ROAM's Integrated Resource Planning model implements Dynamic Programming. The dynamic program:

- Develops a planning study covering 2010-11 to 2019-20. This ensures that the optimal long term planning outcome is captured such that the right planning decisions can be assessed in the near term;
- Applies an ANTS constraints dispatch engine with hourly solution intervals;
- Allows for sufficient new entry generation technology types to meet demand and energy growth whilst also satisfying the RET;
- Allows for major transmission augmentations which enable changes in transmission congestion leading to increased dispatch from constrained out generation, reducing unserved energy and lowering overall cost of energy supply.

In the first instance least cost planning[10] outcomes are extracted from the IRP study. The outcome of the IRP is then tested with sensitivity analysis and a range of alternative Dynamic Program constraints to investigate various scenarios.

More details of the operation of the IRP are included in Appendix B.

5.2) SUMMARY OF INPUT ASSUMPTIONS

Table 5.1 gives a summary of the input assumptions for this study.

Table 5.1 – Summary of input assumptions	
Timeframe	2010/11 to 2019/20
Demand and Energy	M50 projections from NEMMCO's 2008 Statement of Opportunities
Renewable Energy Target (RET)	Sufficient renewable energy generators are available to meet the expanded RET. The model can choose whether to install non-schedulable wind, or schedulable renewable generation (such as geothermal or biomass) and can choose which areas they should be installed in. Two levels of RECs banking have been investigated: 1. High banking – renewable technologies are installed as rapidly as possible, exceeding the annual RET targets in early years of the scheme and banking the additional certificates for surrender against the liability of later years 2. Low banking – renewable technologies are installed as slowly as possible, only just meeting the annual RET targets.

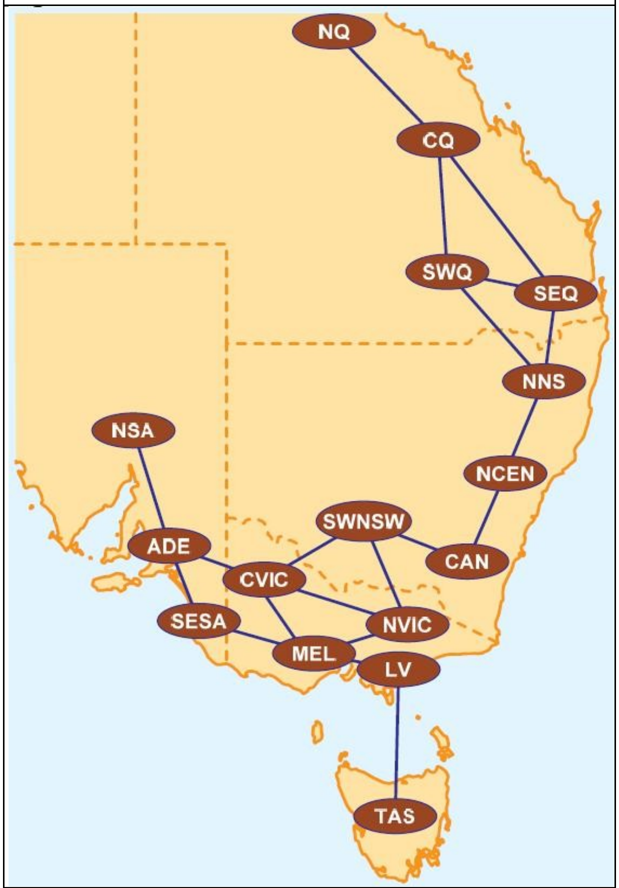
[10] For this assessment, the modelling is based on SRMC bidding by generators leading to the lowest cost of supply, subject to reliability, emissions/carbon price, energy limitations and other constraints.

Table 5.1 – Summary of input assumptions	
Carbon Pollution Reduction Scheme (CPRS)	The price of carbon pollution permits under the CPRS is a trajectory calculated from the Treasury modelling -5% and -15% price trajectories. The AEMC specified a -5% trajectory initially, changing to a -15% trajectory from 1st July 2015 for the rest of the period being modelled. The prices used are in real 2009 dollars, calculated by applying the multiplier of 1.136652 to the Australian Treasury report data (provided in 2005 dollars). This affects the dispatch order of existing and new plants in the NEM, according to their individually calculated increased costs under the CPRS. It also affects new planting decisions.
Fuel price	Fuel costs used were as given in the ACIL Tasman report “Fuel resource, new entry and generation costs in the NEM: draft report” of 13 February 2009.
Generator trading behaviour	Generators bid into the market at their short run marginal cost, which incorporates their fuel costs, variable operation and maintenance costs and emissions costs.
Generator connection costs	Connection costs have not been modelled explicitly.
New generator location	The sites for new generation are specified at the level of ANTS zones. The ANTS zones are illustrated in Figure 5.1 for reference.
Carbon Capture and Sequestration (CCS)	CCS technologies are not considered to be available in significant quantities throughout the study period.
Gas generation	The model can choose to install CCGT and/or OCGT generation to meet additional demand, once the RET requirements have been satisfied and to meet economic and reliability of supply requirements.

Inter-regional transmission augmentation	The model can choose to construct any of the following upgrades at any time:
	• ADE to NCEN link
	  o 2000MW HVDC or controllable AC link, in addition to removing all South Australian intra-regional constraints (NSA-ADE, ADE-SESA)
	• NSA to MEL upgrade
	  o an extra 400MW capability in both directions between NSA and MEL, through ADE and SESA
	• MEL to SWNSW upgrade
	  o an extra 400MW capability in both directions between MEL and SWNSW, through NVIC
	• NNS to SWQ upgrade
	  o An extra 400MW capability in both directions
	where the upgrades are between ANTS zones. The ANTS zones are illustrated in Figure 5.1 for reference.

Table 5.1 – Summary of input assumptions	
Inter-zonal transmission augmentation	The inter-regional upgrades include upgrades to some inter-zonal flow paths. The model could not choose to upgrade any inter-zonal flow path independent of the upgrade of an inter-regional line.
Retirements (Fixed)	Munmorah retires in 2014-15 (announced, presumed committed) in all scenarios. Further retirements under the CPRS were not included in this study.

Figure 5.1 – ANTS zones



5.3) Load Forecast

The demand and energy forecast applied in the modelling forms the basis for all modelling outcomes and is the driver for generation and transmission development. Peak demand drives the need for generation and transmission 'capacity' development to meet reliability of supply for short periods of time. Energy requirements underpin the relative 'shape' of load throughout the day and year providing a key determining factor for the optimal timing and type of generation technology and transmission augmentation to meet the overall load at least cost.

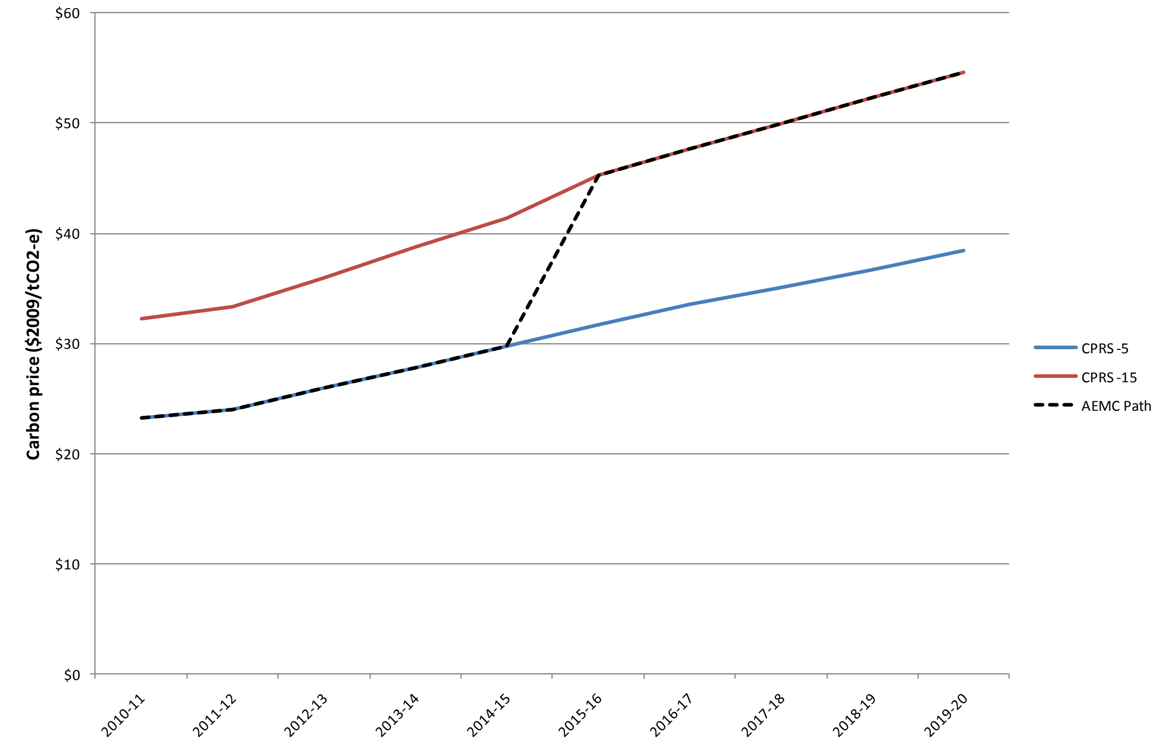
In this study the regional Winter/Summer peak demand and annual energy growth for the NEM is based on M50[11] projections from NEMMCO's 2008 Statement of Opportunities[12].

[11] Medium economic growth with 50% probability of exceedence forecast

5.4) CARBON POLLUTION REDUCTION SCHEME

The Carbon Pollution Reduction Scheme (CPRS) was included as a carbon price trajectory applied to the costs of each generator, according to their individual emissions factors and generation each year. This influences the bids of each generator (at their SRMC), and hence their dispatch. The AEMC provided the carbon price trajectory used for this study, illustrated in Figure 5.2.

Figure 5.2 – Carbon Price under the CPRS



The assumed CPRS price trajectory is based upon the Australian Treasury modelling[13] of the -15% and -5% targets at real 2009 price levels. This is the -5% trajectory initially, changing to the -15% trajectory from 1st July 2015. This could occur if a strong international agreement is reached in 2015-16, and auction prices increase in response to lower anticipated targets in later years (with banking permitted).

This carbon price trajectory is applied to all generation bids for the duration of the study, to reflect the potential changes to the dispatch resulting from the introduction of the scheme.

[12] It is noted that a wide range of studies have been completed and are currently underway which put a significant emphasis on the demand side of the electricity market in response to the CPRS. Alternative assumptions may provide for a significant reduction in demand, and certainly energy growth into the future. The NEMMCO demand and energy forecast are for the most part developed by NIEIR for the TNSPs and NEMMCO and do include some reduction in growth in response to an assumed emissions value, albeit relatively mild compared with other study assumptions.

[13] Australia's Low Pollution Future, The Economics of Climate Change. Australian Government, Treasury, 2008.

Banking and borrowing under the CPRS

In the policy described in the CPRS White Paper, unlimited banking of permits will be allowed (except those accessed under the price cap or fixed price arrangements). This means that permit holders may choose to reduce emissions in the short term and retain permits to retire against emissions in later years. This has the effect of increasing the price of permits in the short term, if much more stringent targets are expected in the future. It also has the effect of smoothing the permit price over time. The step change in the permit price illustrated in Figure 5.2 could therefore be in response to the announcement of much more stringent targets in future, as might occur if a strong international agreement is reached in that year.

Some limited borrowing is allowed under the CPRS scheme, in the short term. Borrowing will take the form of allowing liable entities to discharge up to a certain percentage of their obligations by surrendering carbon pollution permits dated from the following year. This may be done for up to 5% of a liable entity's obligations. This is intended only as a short term mechanism to allow flexibility and price stability. Borrowing is not explicitly allowed for in these studies.

5.5) *GENERATION*

Existing and committed generation was included in the dispatch model. Trading behaviour has been based on estimated SRMC values, but modified for the impact of a carbon pollution permit price on each generator following implementation of the CPRS.

5.5.1) Generator Trading Behaviour

The emissions cost for each generator (in \$/MWh) is given by each generator's emissions factor (tCO_2/MWh), multiplied by the cost of carbon pollution permits. Since the electricity market in Australia is not (substantially) internationally trade exposed, it is anticipated that generators will largely increase their bids by the amount of their respective emissions costs. This will alter the dispatch merit order in favour of lower emission generators such as gas fired plant. Wind generators have the lowest marginal cost and will not curtail output unless faced with a transmission limitation.

Many thermal generators do not currently bid their short run marginal costs (SRMCs). When carbon prices are applied, it is anticipated that higher polluting plants will be forced to bid closer to their short run marginal costs in order to recover emissions costs.

Short run marginal costs (SRMC) for each generator in each year are calculated based on:

- The carbon price in that year;
- The emissions factor of the generator;
- The fuel price for the generator;
- The efficiency of the generator; and
- Variable operations and maintenance costs of each generator.

Existing and new thermal generators were bid into the market at their sent-out SRMC (inclusive of their emissions cost), calculated as follows:

Sent-out SRMC = (as-generated SRMC excluding carbon costs)* (1-auxiliary factor) + (emissions factor * carbon price)

Each generator's as-generated SRMC excluding carbon costs, auxiliary factor and emissions factor was sourced from Tables 29, 12 and 17-22 respectively (in the case of existing generators) and Tables 49, 31 and 40 (in the case of new entrant generators) of the ACIL Tasman report, "Fuel resource, new entry and generation costs in the NEM: draft report" of 13 February 2009. Further details on generator bids can be found in Section A.3) of Appendix A).

Wind farms are bid into the market at $0/MWh. The bids of renewable generators do not incorporate the REC price.

5.5.2) New Entry Generation Options

New entry generation development options available for selection are based on the following categories:

- Combined Cycle Gas Turbine (CCGT)[14];
- Open Cycle Gas Turbine (OCGT);
- Non-schedulable renewables (wind farms);
- Schedulable renewables (geothermal, biomass, sugar cane bagasse).

Committed plant

In addition to the known committed generators, as provided for on the NEMMCO generator information page, sufficient advanced proposals allow for commitment of the following plant in the IRP study:

- 2012-13: 1000MW of CCGT plant in South West Queensland;
- 2012-13: 1000MW of OCGT plant in Central New South Wales.

ROAM also assumed the following plant to be sufficiently likely to be "committed" in the model:

- 2010-11: 1000MW of wind in NSA;
- 2016-17: 500MW of geothermal in NSA.

[14] CCGT generation and coal-fired generation with CCS would have a similar impact on congestion and CCGT is used as a surrogate for both. CCS plant is widely considered to be a candidate for large scale development only after 2020.

5.5.3) Retirement of plant

Committed retirements

Munmorah retires in 2014-15 (announced, presumed committed) in all scenarios.

Retirements under the CPRS

Under the CPRS, the most emissions intensive plants in each region are likely to experience significantly reduced dispatch. This is not an immediate effect of the CPRS; rather an outcome of the increase in their SRMC due to the carbon price, and their resulting displacement by lower cost, less emissions intensive plant. For many generators, this is likely to make them uneconomic to keep in service, in the absence of capacity payments, reserve contracts, cap contracts or other market mechanisms to allow them to recover their costs. Even with the implementation of mechanisms of this nature, many generators that typically operate in a baseload fashion will experience technical challenges with erratic dispatch.

Plant retirements (beyond Munmorah) were not included in this study, even if plant became unprofitable to operate under the CPRS. This is on the assumption that over the short term, such plant will be required to remain available to maintain reliability standards, and market mechanisms will be introduced to allow this to occur. Over the longer term, retirement of these generators will be essential for achieving emissions reductions and will become possible with the entry of schedulable renewable technologies such as biomass and geothermal energy, and increased use of demand side participation.

Cost analysis of retirements

Whether or not a plant becomes unprofitable to run under the CPRS, retirement and replacement of existing plant is a very expensive option that is unlikely to be the most cost effective result under a cost minimisation central planning regime.

Another study by ROAM that explicitly included retirement of plant as an option found that retirements were not selected by the model since they were not cost effective under the carbon prices modelled by Treasury to 2019-20. In that study, Hazelwood was allowed to be retired and replaced by a 500MW CCGT and a 500MW OCGT. This retirement and replacement produced a saving on Fixed O&M of $50 million per year, and a saving on emissions costs of $170 to $200 million per year. However, the cost of capital repayments on the new plant was found to be $112 million per year, and with increased future gas prices the additional cost in fuel was more than $170 million per year[15]. This means that at these carbon prices, the retirement and replacement of Hazelwood with gas plant only recovers 27% of its cost in 2015-16. This increases to 45% cost recovery in 2019-20 with the increased carbon price of $45 /t$CO_2$, but is still insufficient to justify the retirement. The carbon price needs to reach $55 /t$CO_2$ before retirement and replacement of Hazelwood is cost effective. Under Treasury modelling this is not forecast to occur until 2020-21 under a CPRS-15% scenario, and 2029-30 under a CPRS-5% scenario. This would mean that in this study for the AEMC, a retirement may have been cost effective in the final year (2019-20), but is very unlikely to have been utilised by the model prior to that.

[15] All costs listed here are in real 2009 dollars.

This analysis will change depending upon the type of plant that is used for replacement. Schedulable renewables will have a substantially higher capital cost, but much lower fuel costs. Optimisation of the proportion of CCGT to OCGT plant may also lower associated costs. However, from a cost minimisation perspective, these results strongly suggest that the introduction of market mechanisms to allow unprofitable plant to remain available for peak periods would produce an efficient outcome. Hence this approach has been taken within this study.

Summary

Although retirements have not been included as an option in this study, ROAM considers them a very significant issue that should be analysed in detail in future studies.

5.5.4) Schedulable Renewable projects

Schedulable renewable stations have been included for selection by the model, representing biomass, sugar cane bagasse, or geothermal technologies. These have been planted in 500MW blocks. As only small scale solar thermal projects are expected to be installed before 2020, not reaching 500MW installation in any single region, it was not included explicitly as a possible renewable, although it could be considered as contributing to another schedulable unit, particularly in Queensland.

An assessment of the resource of each schedulable renewable technology was made, in each ANTS zone. The earliest possible dates of entry of each plant type were estimated based upon market research, and an order of entry was determined based upon the relative costs and maturities of the technologies. The resulting options available for planting are shown in the Table below.

Table 5.2 – Schedulable Renewable Projects

Type	Station #	Location	Technology type	Earliest entry date
QLD schedulable	1	QLD, NQ	Sugar cane bagasse	2014-15
	2	QLD, SEQ	Biomass	2016-17, and after QLD Station #1
	3	QLD, SWQ	Geothermal	2017-18, and after QLD Stations #1 and #2
Geothermal SA/NSW	1	SA, NSA	Geothermal	COMMITTED in 2016-17
	2	NSW, NCEN	Geothermal	2017-18, and after Station #1
	3	SA, NSA	Geothermal	2018-19, and after Stations #1 and #2

Victoria has insufficient resources to justify a 500MW schedulable renewable unit by 2020. Landfill gas was also considered an insufficient resource to justify a new 500MW unit by 2020.

5.5.5) Wind projects

Existing and committed projects

The larger existing wind farms are modelled explicitly in the IRP, so that their effect on transmission has been correctly included. Committed wind farms have also been included by ROAM in every scenario.

A further 1000MW of wind is assumed to be installed in NSA by the commencement of the study in 2010-11, as at least this capacity is required to meet the expanded Renewable Energy Target and ROAM's research suggests NSA is the most likely zone for the first 1000MW.

New (non-committed) wind farms

Wind farms are planted in 1000MW blocks, which are assumed to contribute 15% of their capacity (150MW) to peak demand. Their energy contribution is derived by simulating each wind farm based on recorded data from the nearest BOM site throughout 2007/08, to be consistent with the use of the 2007/08 demand profile as the reference profile for producing forecast load traces.

The quality of the wind resource available in each zone is assessed based on announced (proposed) wind farms, and on wind resource maps from the Australian Renewable Energy Atlas[16]. In each zone, half-hourly generation traces (and hence the capacity factors) of each proposed wind farm are calculated using WEST, ROAM's Wind Energy Simulation Tool. WEST uses data from the Bureau of Meteorology and the Australian Renewable Energy Atlas to develop dispatch traces of wind farms based on geographical location and turbine specifications.

Average wind farm capacity factors are expected to decrease as the number of installed wind farms increases, and less attractive sites are utilised. This is modelled by including multiple "tiers" of wind farms in each zone:

- ***Tier 1:*** The capacity factor for the first tier is averaged from the best 600-1000MW of proposed projects. This represents the best available wind resource in a region or zone.
- ***Tier 2:*** Average capacity factor of the next best projects (up to 1000MW).
- ***Tier 3:*** In zones with potential capacity of 3000MW, the third tier is expected to utilise the same resource (same capacity factor) as Tier 2.

Wind plant is constrained to enter sequentially by Tier, such that the Tier 1 wind farms (the highest capacity factor locations) in each region must enter first. However, the model has freedom to install wind farms sequentially in whichever order by region it finds to be cost minimising (or profit maximising).

For Queensland, Victoria and New South Wales, wind farms are planted sequentially across zones according to the best available (highest capacity factor) blocks, adjusted by ROAM's research on the feasibility of planting schedules. Zones with limited wind

[16] http://www.environment.gov.au/settlements/renewable/index.html

resources are not modelled (LV, NVIC, NNS, SWNSW, SEQ, CQ, ADE). Wind farms in South Australian zones NSA and SESA are allowed to enter independently, due to the more significant congestion issues in this area and available resource. The first NSA station is assumed to be committed, for operation in 2010-11, as the most likely new renewable generation to meet the expanded Renewable Energy Target.

The resulting wind farm options available for planting by the IRP are shown in the table below.

Table 5.3 – Wind Projects

Region / Zone	Station # (Tier)	ANTS zone	Capacity Factor
QLD	1	SWQ	29.89%
	2	NQ	30.63%
	3	SWQ	27.05%
NSW	1	CAN	30.70%
	2	NCEN	28.83%
	3	CAN	25.77%
	4	NCEN	24.94%
	5	CAN	25.77%
	6	NCEN	24.94%
VIC	1	MEL	31.11%
	2	CVIC	29.88%
	3	MEL	26.99%
	4	MEL	26.99%
	5	CVIC	25.88%
	6	CVIC	25.88%
TAS	1	TAS	36.30%
SA (NSA)	1 (Committed 2010-11)	NSA	38.30%
	2		30.95%
	3		29.98%
	4		26.35%
SA (SESA)	1	SESA	32.26%
	2		26.43%

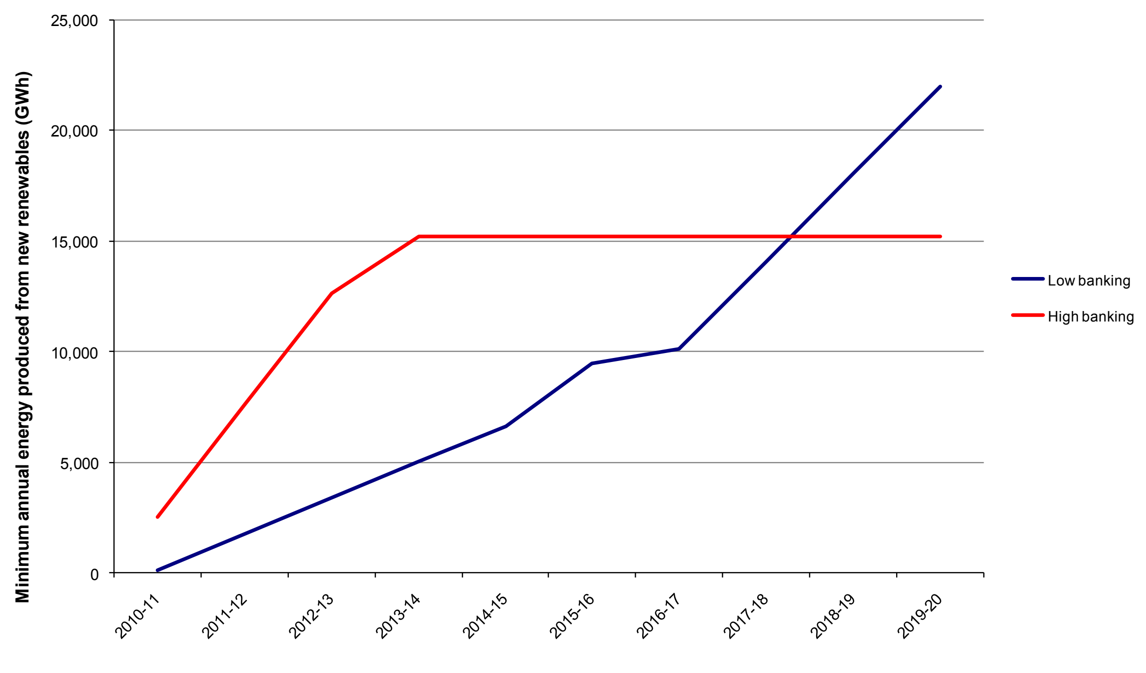
5.6) RENEWABLE ENERGY TARGETS

Two independent scenarios are analysed, to evaluate the effects on transmission of early renewable investment (and consequent banking of renewable energy certificates (RECs)) versus an investment trajectory that closely matches the legislated annual REC trajectory (with minimal banking).

At the carbon prices used in this modelling study, ROAM considers it highly unlikely that significant renewable projects will enter the market to produce RECs in excess of the cumulative RET before 2020. Production of RECs over the cumulative target will result in an oversupply and subsequent drop in the REC price, and pre-2020 carbon prices alone are insufficient to drive investment in renewable projects, ahead of conventional (gas) generation.

The annual REC trajectories for each scenario are plotted in Figure 5.3. The figures used in this chart are discussed below.

Figure 5.3 – RECs produced by new non-committed renewable generators



Scenario 1: Low banking

In this scenario, the annual RECs produced must meet the Australia-wide targets in each year. This equates to 60,000GWh of renewable energy in 2020 in Australia. ROAM scales the annual Australia-wide amount by 86% to include only renewable projects in the NEM (since WA and NT are not being modelled in this case. 14% of the load in Australia is located outside of the NEM, and it is assumed that renewable development will be largely in line with this proportion). This means that the target is just over 52,000GWh of renewable energy in the NEM by 2020. The component of this that is required to be met by new entry generation from 2010-11 to 2019-20 is illustrated in Figure 5.3. (That is, Figure 5.3 has netted off renewable energy from existing and committed generators).

Scenario 2: High banking

In this scenario, there is significant investment above the NEM-wide targets of Scenario 1 in early years, and less investment in later years. The excess RECs produced in the early years can be banked and surrendered in later years of the study. Thus, after an early flurry of investment and a rapid ramp-up in REC production, the number of RECs produced annually settles to a constant amount. This is realistic under the assumption that the carbon price alone will be insufficient to support renewable investment beyond that required by the RET.

We note that new renewable generators available for selection by the model are either 1000MW wind farms (of varying capacity factors) or 500MW schedulable renewable generators. The model must build renewable generators to meet or exceed the annual RECs required; thus on average the model will exceed the targets over the course of the study. Furthermore, the coarse investment blocks mean that the “excess” RECs produced above the required targets may be significant. However explicit modelling of REC banking and resulting REC price is not included in the modelling (beyond that implicit in the high banking annual targets).

5.7) THE TRANSMISSION MODEL

ANTS Constraints

The dispatch model for the IRP implements the NEMMCO ANTS constraint equations as supplied by NEMMCO with the annual Statement of Opportunities. These constraint equations define intra- and interconnector flow limits in terms of generation, demands and flows.

Transmission Augmentation Options

Given the time constraints allowed for completion of this planning study, ROAM has allowed for a few major transmission augmentations as selectable options to limit the scale of the problem and resulting simulation time. The transmission augmentations allow for a significant upgrade to the capability of the main grid backbone throughout the NEM as illustrated in Table 5.4.

Table 5.4 – Transmission augmentation options

Upgrade name	Upgrade Path	Capacity Increase	Change to IRLFs	Change to ANTS equations
SA-VIC	NSA to MEL (upgrade)	400MW bidirectional	New line would be needed; path losses (i.e. resistance terms) in IRLF equations would be reduced in proportion to increase in transfer capacity	Alleviate all relevant ANTS constraints by amount of notional upgrade
VIC-NSW	MEL to SWNSW (upgrade)	400MW bidirectional	No change – upgrades would not likely involve new transmission conductors	Use proposed ANTS constraint upgrades as a basis – alleviate relevant ANTS constraints by amount of notional upgrade
QNI	NNS to SWQ (upgrade)	400MW bidirectional	No change – series capacitor installation – no change to line loss equations	Already included as a selectable upgrade in ANTS equations
SA-NSW	ADE to NCEN (new)	2000MW bidirectional	New flow path; modelled as generator-load pair without resistance or losses	ANTS constraint equations modified to allow export from NSA/ADE zone to increase by 2000MW bidirectional and injection points for Supply-Demand balance

To maintain a tractable simulation time, at most one transmission augmentation option can be selected in a development plan.

The impact of each network augmentation on the set of constraint equations was modelled through applying offsets to the right hand side of the appropriate sub-set of equations. The selection of constraints was guided by the information provided in the ANTS.

Transmission augmentations in the ANTS constraints

New sets of ANTS constraint equations were defined for each interconnector augmentation option, such that the alternative sets of constraint equations were invoked when an augmentation was installed. This meant that a variety of constraints could change when an interconnector was installed, allowing the system to fully utilise the new capability of the interconnector augmentation.

Segments of augmentations

The transmission augmentations modelled include a variety of segments that can be modelled separately for future studies. Table 5.5 breaks down each augmentation into its component flow paths.

Table 5.5 – Transmission augmentation components

Upgrade name	Component flow paths
SA-VIC	NSA to ADE (400MW bidirectional) ADE to SESA (400MW bidirectional) SESA to MEL (400MW bidirectional)
VIC-NSW	MEL to NVIC (400MW bidirectional) NVIC to SWNSW (400MW bidirectional)
QNI	NNS to SWQ (400MW bidirectional)
SA-NSW	ADE to NCEN (2000MW bidirectional) NSA to ADE (2000MW bidirectional) ADE to SESA (2000MW bidirectional)

Due to time limitations, these parts could not be modelled separately, and the model was constrained to install all components of a transmission augmentation option at the same time, or none at all. This means that the selection of an option may be driven solely by one part of the augmentation (for example, congestion on the NSA-ADE flow path may drive selection of the SA-VIC upgrade).

Future studies could investigate combinations that appear cost effective in more detail, allowing the various parts of the augmentation to enter separately, and providing cost analysis of each part on an individual basis.

5.8) Calculation of costs

To determine the minimum cost planting outcome, full scenario costs were calculated. These costs (and components of it) are provided throughout this report.

A summary of the methodology for calculating costs is provided here; for a complete description refer to Section B.2 of the Appendix.

Discounting

All costs are expressed in real 2009 dollars, discounted where appropriate using a real, pre-tax discount rate of 10%. Capital costs for both generation and transmission plant are annualized applying a 30 year lifetime and a 10% real, pre-tax weighted average cost of capital (WACC).

Cost components

Costs were calculated in the components as follows:

1. Total run cost, which includes:
    - Variable O&M
    - Fuel costs
    - Emissions costs
2. Capital repayments
    - Annual net present value repayments for all new plant (does not include existing plant, or committed plant)
    - This includes capital repayments on transmission augmentations
3. Fixed O&M
    - Annual net present value O&M for all new plant (does not include existing plant)
    - This includes fixed O&M for transmission augmentations

Existing plant were not determined to contribute to capital repayments since these costs will be the same across every state, and hence can be ignored (in the absence of retirements). They are also not determined to contribute to fixed O&M payments for the same reason.

Run costs were calculated on an hourly basis, determined by the hourly dispatch of each plant. These were discounted to net present values for determination of the total scenario cost.

Start up and shut down costs were not included, and could be significant given the cycling behavior of many plants under the CPRS that typically operate in a ‘baseload’ fashion.

Inclusion of CPRS and RET schemes

The cost of the CPRS scheme is directly included as a carbon pollution permit liability for all emitting generators. These generators must acquire a permit for every tonne of emissions, at the permit price for that year[17]. This is directly added to their short run marginal costs. The Electricity Sector Adjustment Scheme is assumed to not impact on generator behaviour, except to incentivise generators to remain available despite declining generation volumes. The payments under this scheme are independent of ongoing operation (only requiring plant to be available), and will therefore not affect short run marginal costs.

The cost of the RET scheme is directly included through inclusion of the capital repayments for renewable generators. RET costs to retailers are not included in the cost calculation, since the RET scheme simply provides monetary redistribution within the energy sector to support the capital expenditure on renewable generation via REC payments from retailers and consumers. Accurate inclusion of the actual costs of the RET to the system therefore requires calculation of the actual capital repayments, rather than the "costs" of RECs to retailers.

6) Scenario C: Co-optimising central planner

Scenario description

> *A "socially optimal" generation and network investment case that reflects co-optimised investment decisions by generation and transmission businesses from a central-planning perspective.*

The decision to locate takes account of excess network capacity and the supply-demand balance. This assumes perfect foresight by the central planner with the objective of minimising the total costs of delivering energy services to customers over the analysis period. Within the constraints placed on development (meeting the RET, minimum reserve levels etc.) this provides a global least cost path for generator and transmission investment. Allowing the central planner to have perfect foresight over the study period means that the true value of decisions can be assessed; decisions which in the short term appear costly but in the long-term are efficient will be excluded in a more short-sighted model.

This implementation is limited by the coarse generator investment blocks (500 to 1000MW plants) and four transmission augmentation options available for selection by the model. However, these concessions were made to allow a greater amount of time to be spent on detailed estimation of production costs. A model which studies finer levels of investment necessarily includes coarser estimation of costs. ROAM's model focuses on the desire to maintain very credible dispatch to yield an excellent estimate of production costs. In particular this yields accurate information on transmission congestion and generator operation used in this study.

---

[17] Banking will allow generators more flexibility in how they procure carbon pollution permits, allowing a potentially smoother carbon price path.

Scenario treatment in ROAM's IRP model

ROAM's IRP model is naturally suited to determining a socially optimal generation and network investment case, since it determines the least cost central planning outcome. To create this scenario, the IRP was run with high and low levels of REC banking (under the RET) to determine the least cost solution. The model was allowed to install any one candidate network augmentation at any time.

6.1) *GENERATION PLANTING SCHEDULE OUTCOMES*

Planting outcomes

Figure 6.1 and Figure 6.2 illustrate the outcomes of ROAM's IRP model, for a least cost central planning scenario[18]. Figure 6.1 illustrates the least cost outcome if a low level of RECs banking occurs in the Renewable Energy Target scheme, and Figure 6.2 illustrates the least cost outcome if a high quantity of RECs banking occurs in the Renewable Energy Target scheme.

Of these two cases, the low banking case is the lowest cost, and is therefore ROAM's proposed solution to Scenario C. Results from the high banking case are also included for comparison, to illustrate the impacts to the system if the drivers under the RET scheme produce a high banking outcome, regardless of holistic cost minimisation.

[18] In the planting outcome charts, the capacity of each plant shown is its contribution (in MW) to peak demand. 1000MW wind farm developments are attributed 150MW contribution to peak demand due to their intermittent nature. All other plant in this study is assumed to be fully schedulable and therefore able to provide their full capacity at time of peak demand.

Figure 6.1 – Planting outcome for Scenario C – Low banking

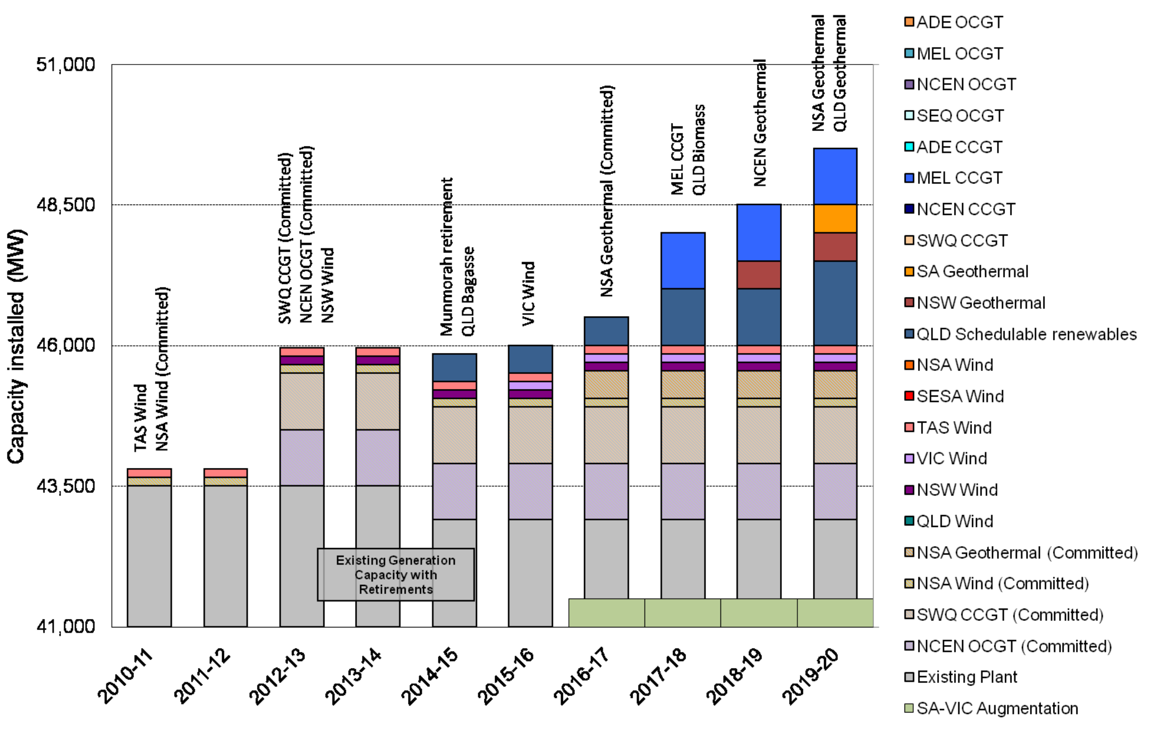
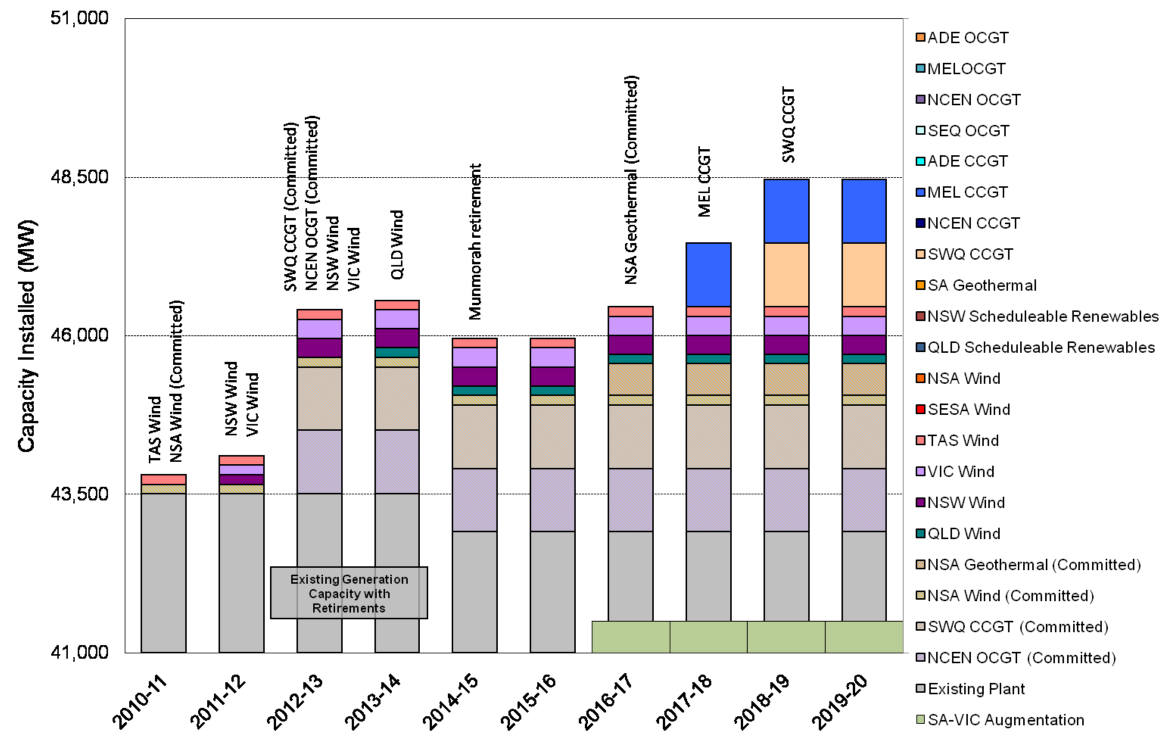


Figure 6.2 – Planting outcome for Scenario C – High banking



Fossil fuel plant

In both scenarios (high and low banking), a CCGT is installed in the SWQ zone in Queensland, and an OCGT is installed in NCEN in 2012-13 (this is committed plant). A second CCGT is constructed in the MEL zone in Victoria in 2017-18. The lack of schedulable renewable generation in the high banking scenario brings in an additional CCGT plant in the SWQ zone in Queensland in 2018-19.

Schedulable renewable generation

The biggest difference between the two scenarios (high and low banking) is in the outcomes for schedulable renewable generation. With high levels of banking, the RET is largely filled by wind generation by 2013-14, before schedulable renewable sources are commercially available. This means that all schedulable renewable sources are excluded in the high banking scenario, with the exception of a single committed geothermal plant in South Australia.

With low levels of banking in the RET, schedulable renewable generators are strongly incentivised, with every schedulable renewable plant available in the IRP being installed by the completion of the study. The construction of these is heavily weighted to the later parts of the timeline, because the technologies are not commercially viable in the early parts of the study.

With low levels of banking, the first schedulable renewable plant is installed in Queensland (sugar cane bagasse) in 2014-15 (likely due to the high level of load growth in Queensland). The second plant is the committed geothermal station in South Australia (2016-17). This is rapidly followed by:

1. A second schedulable renewable plant (SEQ biomass) in Queensland (2017-18)
2. A geothermal plant in NSW (2018-19)
3. A third plant in Queensland (SWQ geothermal) (2019-20)
4. A geothermal plant in SA (2019-20)

ROAM limited the amount of schedulable renewable plant available to the model according to fundamental limitations on the amount of resource available within the timeframe. These results suggest that if more resource were available, then more schedulable renewables could be effectively utilised to meet the RET at lowest cost. This provides strong incentives for developing schedulable renewable options, such as geothermal, biomass, and solar thermal (with storage).

The strong incentives to install schedulable renewable generation stem from the assumed low cost of these technologies (when taking into account operational modes) compared with wind energy. The input assumptions used for this study amount to long run marginal costs illustrated in Table 6.1 (LRMCs vary depending upon capacity factors, and will have been different for each station in each scenario in the modelling reported. However, the numbers illustrated here give an indication). Under these assumptions, wind is consistently more expensive than either biomass or geothermal technologies, incentivising the model to install as much schedulable renewable energy as possible, in place of wind generation.

Table 6.1 – Assumed long run marginal costs of renewable technologies					
	Long run marginal cost (LRMC) ($/MWh) [19]			Capacity Factor	
	2008	2010	2020	Assumed by ACIL Tasman	From ROAM's modelling
Wind	93.31	97.62	83.87	35%	30%
Biomass	70.34	70.34	70.88	75%	90%
Geothermal	87.42	86.65	82.89	85%	80%

Significantly, this result is heavily dependent upon the relative costing of these technologies, and will vary if the relativity of these costs changes. Predictions of future costs of new technologies have very high levels of uncertainty, and a cross over in costs is not infeasible.

Wind generation

In both the high and low banking scenarios, wind is initially constructed in Tasmania, and the NSA zone in South Australia. These are the best wind resources in the nation. Wind is then installed progressively in NSW and VIC.

More wind is installed in the high banking scenario (due to the early renewable development). Additional wind is installed in NSW, VIC and QLD in the high banking scenario.

Transmission augmentation

In both cases (high and low banking), the SA-VIC interconnector upgrade is installed in 2016-17, as part of the lowest cost way of meeting demand and the RET requirements. The model did not choose any other interconnector to be built or upgraded. A full analysis of all the interconnector options in this scenario is explored further in a later section.

Renewable Energy Target

Figure 6.3 and Figure 6.4 illustrate the composition and pathway of the Renewable Energy Target (RET) scheme for Scenario C, with high and low levels of RECs banking.

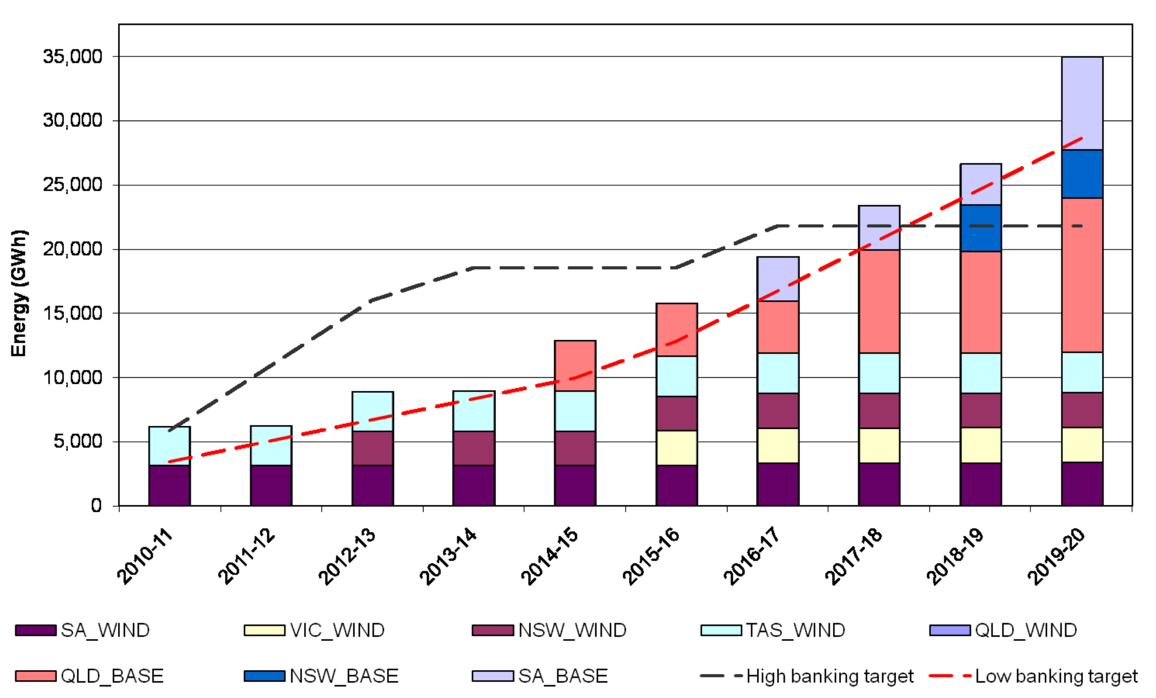
These figures illustrate the entry of renewable energy into the market, and show how it contributes to the Renewable Energy Target (RET) scheme. Two different targets were used – low banking (red dashed line) and high banking (black dashed line). To ensure that the modelled scenarios were consistent with the RET scheme, capacity factors for each renewable generator were estimated and used to determine planting combinations that would meet or slightly exceed the annual RET targets for each of the high and low banking cases. The actual capacity factors of these generators may vary slightly from the initial estimates (typically being higher for schedulable renewable generators due to higher

[19] ACIL Tasman, Projected energy prices in selected world regions – The estimation of energy prices for existing and new technologies in a number of regions around. Prepared for the Department of the Treasury, May 2008.

than anticipated dispatch, or lower for wind generators, due to curtailment under transmission congestion). For this reason, the actual renewable energy generated in each case slightly exceeds the annual RET targets. If significant transmission curtailment had occurred, the amount of renewable energy generated would have been slightly below the annual targets.

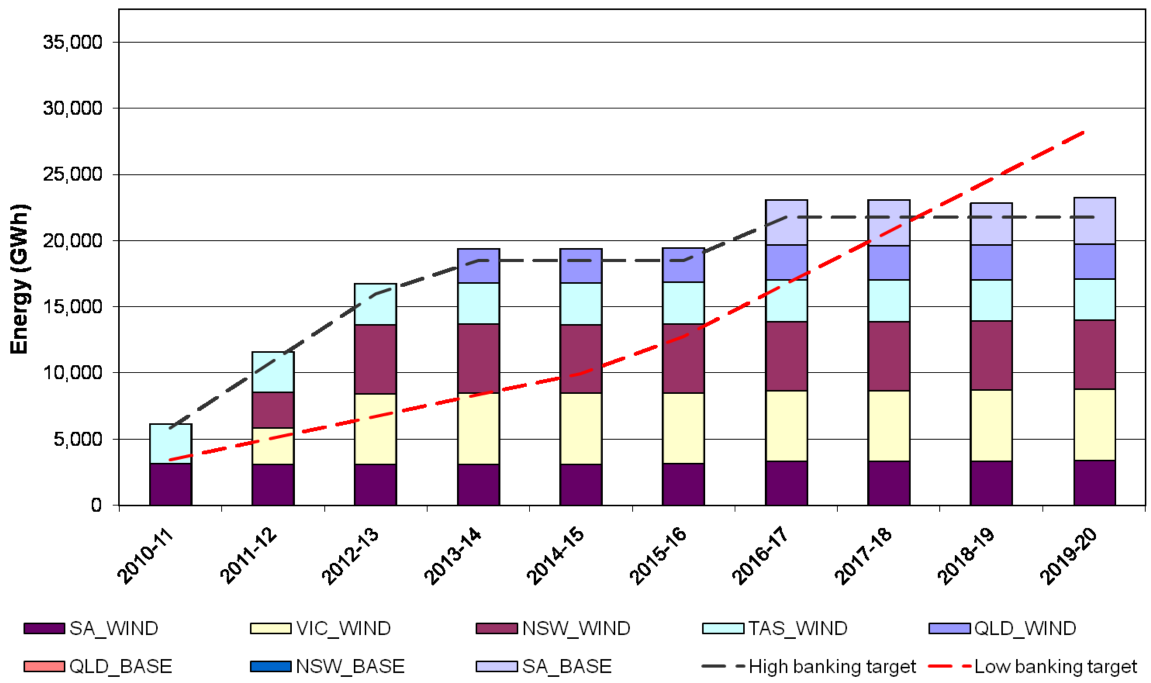
With low banking, 34,985GWh of renewable energy is generated in 2020 in the NEM from new renewable sources (illustrated by the blue line in Figure 6.3). This exceeds the amount of renewable energy required to meet the RET (illustrated by the dashed red line).

Figure 6.3 – RET outcome for Scenario C – Low banking



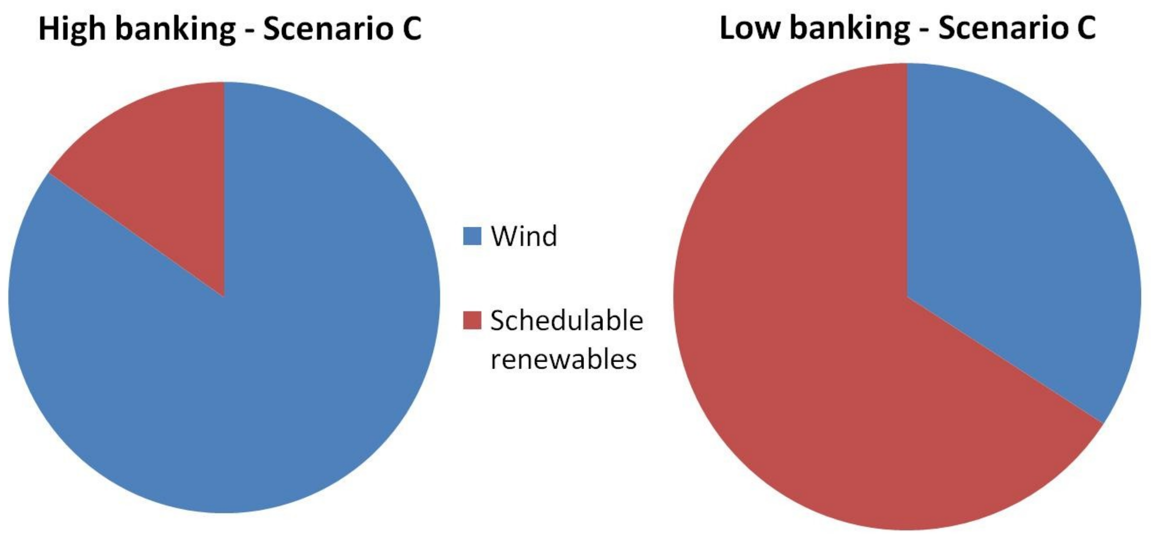
By comparison, with high levels of banking (Figure 6.4), only 23,259GWh of renewable energy is generated in 2020 in the NEM from new renewable sources (illustrated by the blue line in Figure 6.4). Although this meets the requirements of the Renewable Energy Target scheme (as currently designed), it is more than 11,000GWh short of the 60,000GWh government policy target . This suggests that the allowance of unlimited banking in the RET may mean that the scheme is not successful in achieving 20% renewable energy by 2020.

Figure 6.4 – RET outcome for Scenario C – High banking



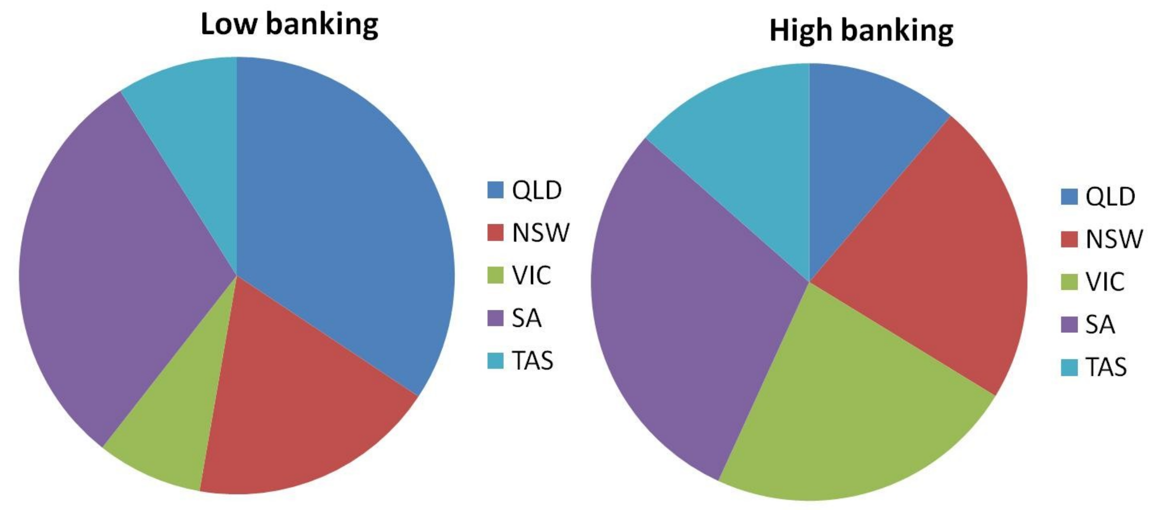
Banking has very significant implications for the mix of renewable energy resulting from the RET scheme, as discussed earlier. With high levels of banking, 85% of the renewable energy in 2020 is sourced from wind, with only 15% from schedulable renewable sources. With low levels of banking, 66% is from schedulable renewable sources, with only 34% of renewable energy in 2020 sourced from wind.

Figure 6.5 – RET outcome for Scenario C – Mix of technologies (GWh)



This also affects the distribution of renewable energy across the NEM, as illustrated in Figure 6.6. With high levels of banking, Queensland achieves a much smaller share of renewable energy, whereas Victoria and Tasmania achieve much higher levels (due to the greater wind resources in those states, incentivised under a high banking scenario).

Figure 6.6 – RET outcome for Scenario C – Distribution by state (GWh)



Energy from plant types

The energy produced by each plant type is illustrated in the figures below, for the two banking cases.

In both cases, energy from coal sources reduces marginally under the CPRS, and energy from gas-fired generation increases (most notably upon entry of new units). Renewable generation also increases substantially, generating much of the increase in total energy required over the study period.

In the low banking case (Figure 6.7), Queensland renewable generators contribute much more, in place of Queensland gas generation in the high banking case (Figure 6.8). In the high banking case, much more energy is sourced from Victorian renewable generation (wind) over the course of the study.

Figure 6.7 – Energy by plant type – Low banking

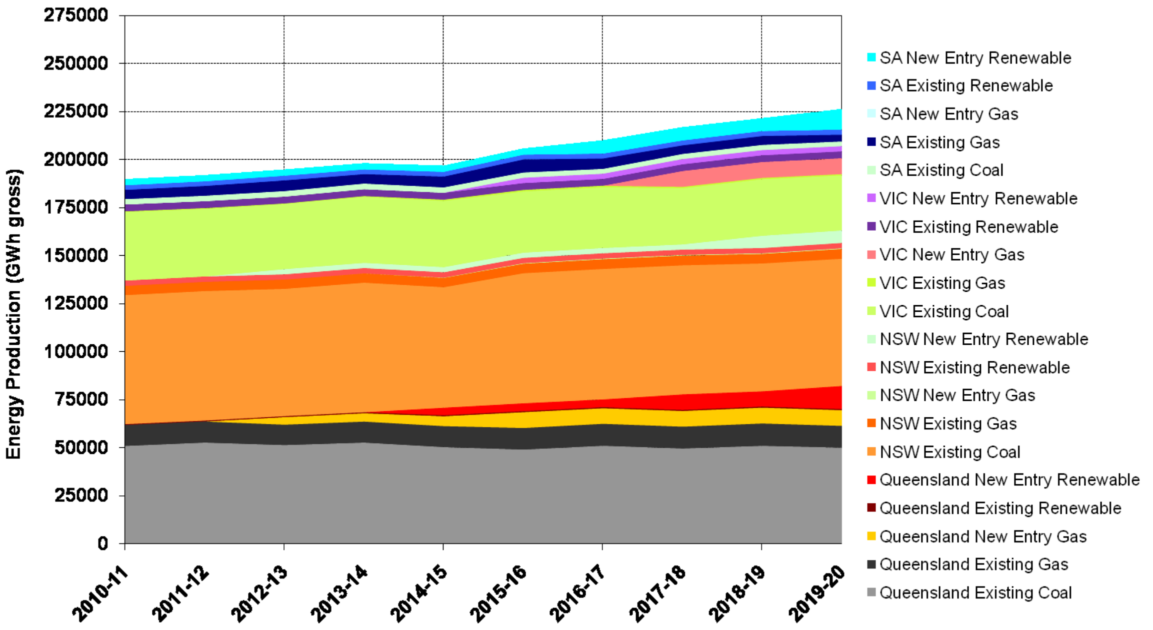
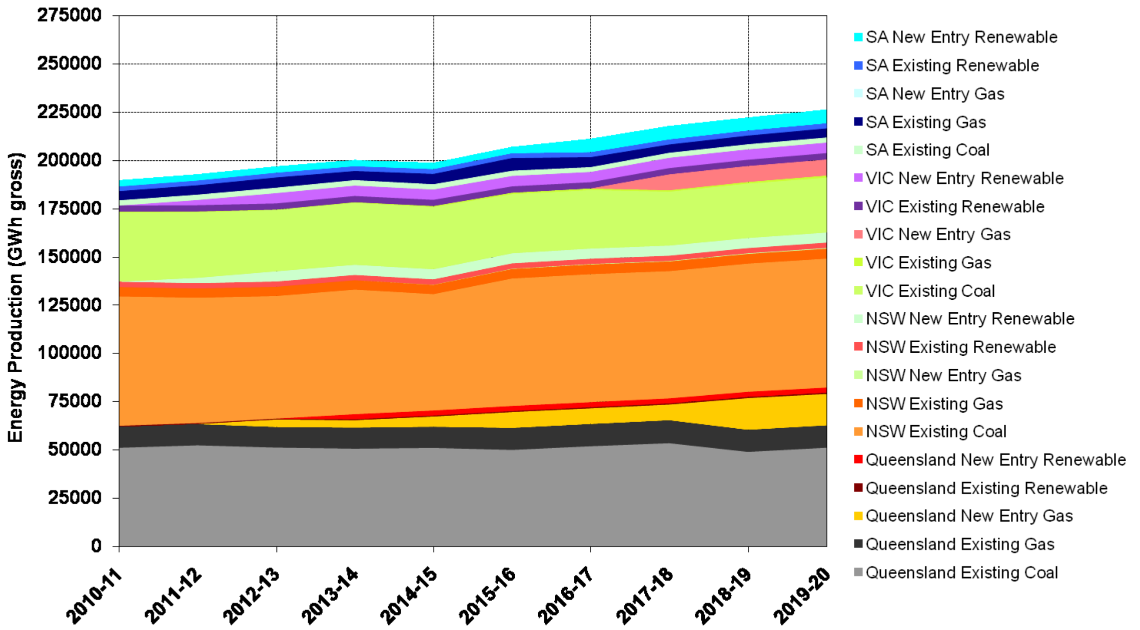


Figure 6.8 – Energy by plant type – High banking

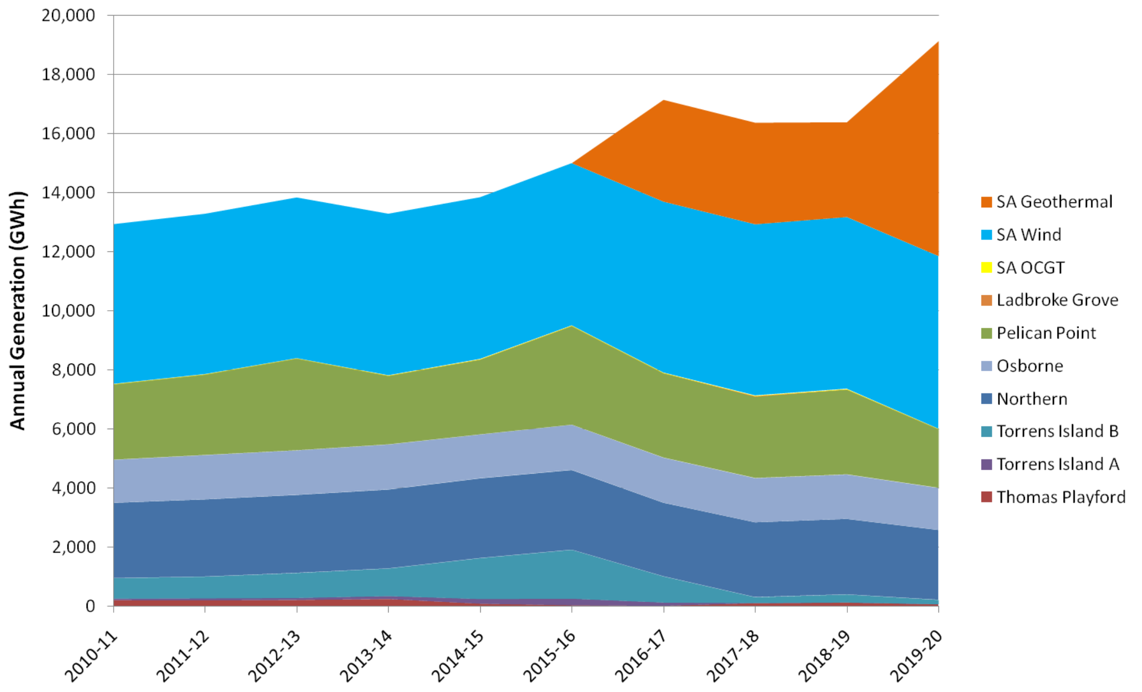


This data is illustrated by region in the figures below, showing the impacts of the CPRS on individual plants.

In South Australia (Figure 6.9), renewable sources contribute proportionally very large amounts of energy. Wind contributes a very large proportion from the beginning of the study, due to the large amount of existing and committed wind in South Australia (including the 1000MW of wind plant committed from the first year in this study). The SA geothermal plant also makes a significant contribution when it enters in 2016-17, and expands in 2019-20. This large quantity of wind generation contributes substantially to emissions reduction from business as usual levels, by displacing more emissions intensive plant.

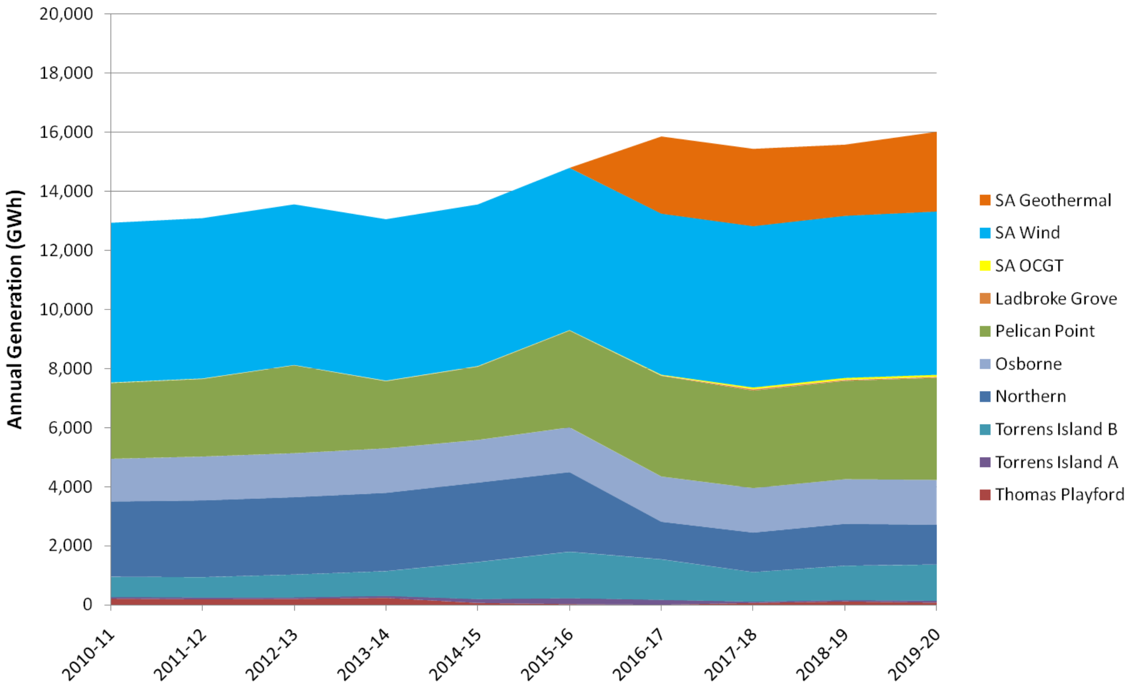
Other plants in South Australia show a reduction in volume for a combination of reasons; they are squeezed out of the market by the large quantity of renewable generation in South Australia, suffer transmission congestion (causing periods of curtailment), experience increasing fuel prices (Pelican Point), and increasing carbon prices (causing increased competition from lower emissions generators).

Figure 6.9 – South Australia Energy by plant (Low banking)



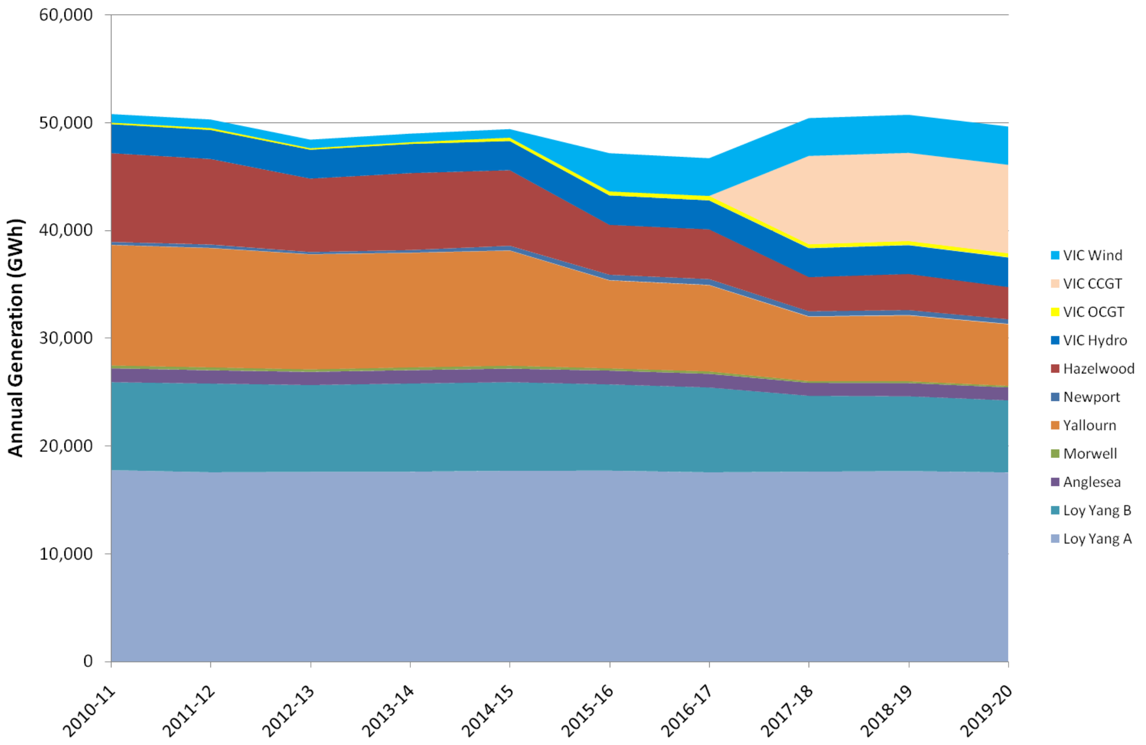
The high banking scenario (Figure 6.10) does not include the second SA Geothermal plant in the final year, which causes reductions in volume of the existing fossil-fuel fired plants in South Australia in the low banking case.

Figure 6.10 – South Australia Energy by plant (High banking)



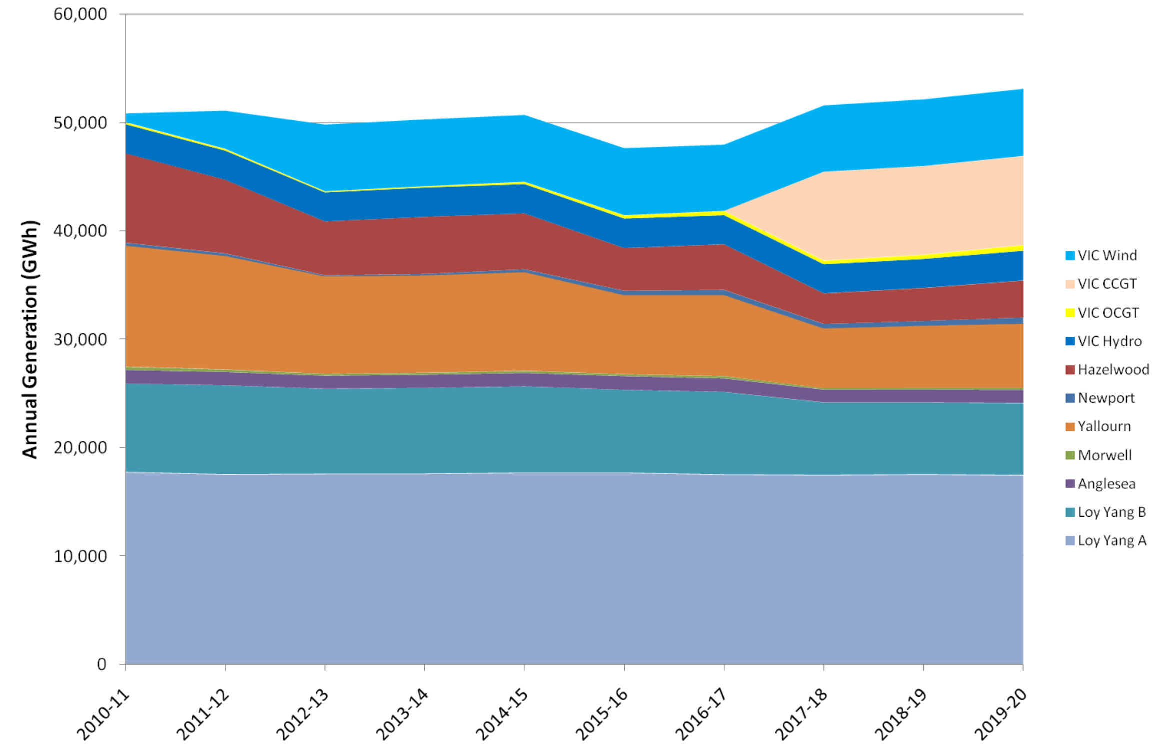
In Victoria (Figure 6.11), large amounts of energy are sourced from wind generation by the end of the study, with a dramatic increase in 2017-18. Yallourn and Hazelwood exhibit very large reductions in volume, due to their inability to compete with an carbon price. This effect is particularly notable from 2015-16 onwards, when the carbon price increases dramatically. Other brown coal plants manage to maintain volumes despite their relatively high emissions factors (compared to other regions in the NEM), due to limitations on interconnectors to Victoria, and the requirement that the demand within Victoria be consistently met.

Figure 6.11 – Victoria Energy by plant (Low banking)



In the high banking case (Figure 6.12) there is a great deal more wind installed in Victoria, causing a marginal reduction in volume at most of the brown coal generators due to increased competition.

Figure 6.12 – Victoria Energy by plant (High banking)



In NSW (Figure 6.13) the black coal plants exhibit differing behaviour depending upon their relative emissions factors. The lower emissions plants manage to maintain volumes (Bayswater, Mt Piper), whereas higher emissions plants lose significant volume (Liddell). Vales Point and Wallerawang substantially increase volumes in 2014-15, while Eraring loses volume in the same year. This interaction is due to the varying short run marginal costs (and hence bids) of the NSW thermal plants primarily due to changes in fuel cost assumptions.

Figure 6.13 – NSW Energy by plant (Low banking)

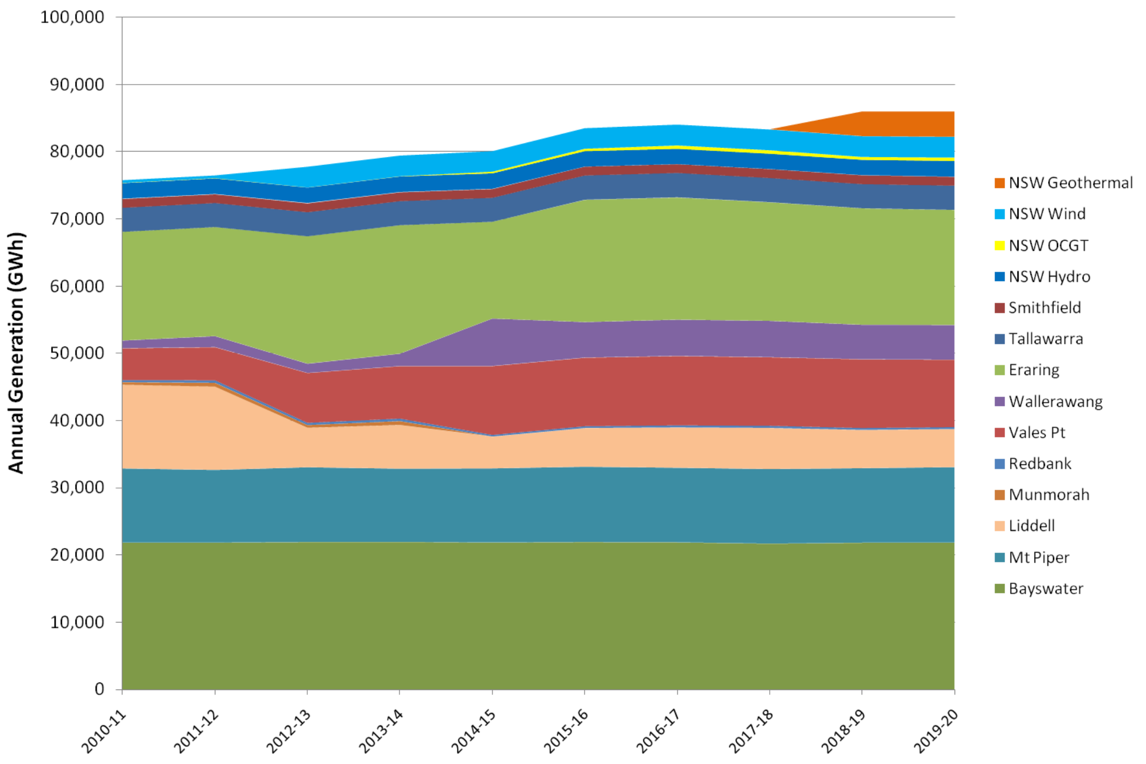


Figure 6.14 illustrates the variation in the short run marginal costs (SRMC) of NSW plants throughout the study. Most reduce over time, due to reducing fuel costs. Fuel costs at Wallerawang and Mt Piper reduce dramatically in 2014-15.

Adding on the annual emissions costs (multiplied appropriately by each station's emissions factor), yields the total short run marginal cost of each plant, illustrated in Figure 6.15. The apparent step change in costs in 2014-15 is a result of both the significant change in the carbon price (changing from -5% trajectory to -15% trajectory) in that year, as well as changes in generator fuel costs[20]. Between 2013-14 and 2015-16 a number of plants cross over; notably Mt Piper undercuts Bayswater (due to reduced fuel costs), and Wallerawang shifts from being the second most expensive coal-fired plant in NSW, to being the third lowest cost. A number of plants have extremely close SRMCs, meaning that they will lie extremely close in the bid stack (Liddell, Eraring, Vales Pt, Wallerawang). The shifts in volumes between these plants illustrated in Figure 6.13 will therefore be extremely sensitive to small changes in costs. This highlights the value in incremental efficiency improvements at these stations.

[20] These changes in fuel price, and hence SRMC are based on data in the ACIL Tasman report "Fuel resource, new entry and generation costs in the NEM: draft report", 13 Feb 2009.

Figure 6.14 – NSW plant short run marginal costs (without carbon price)

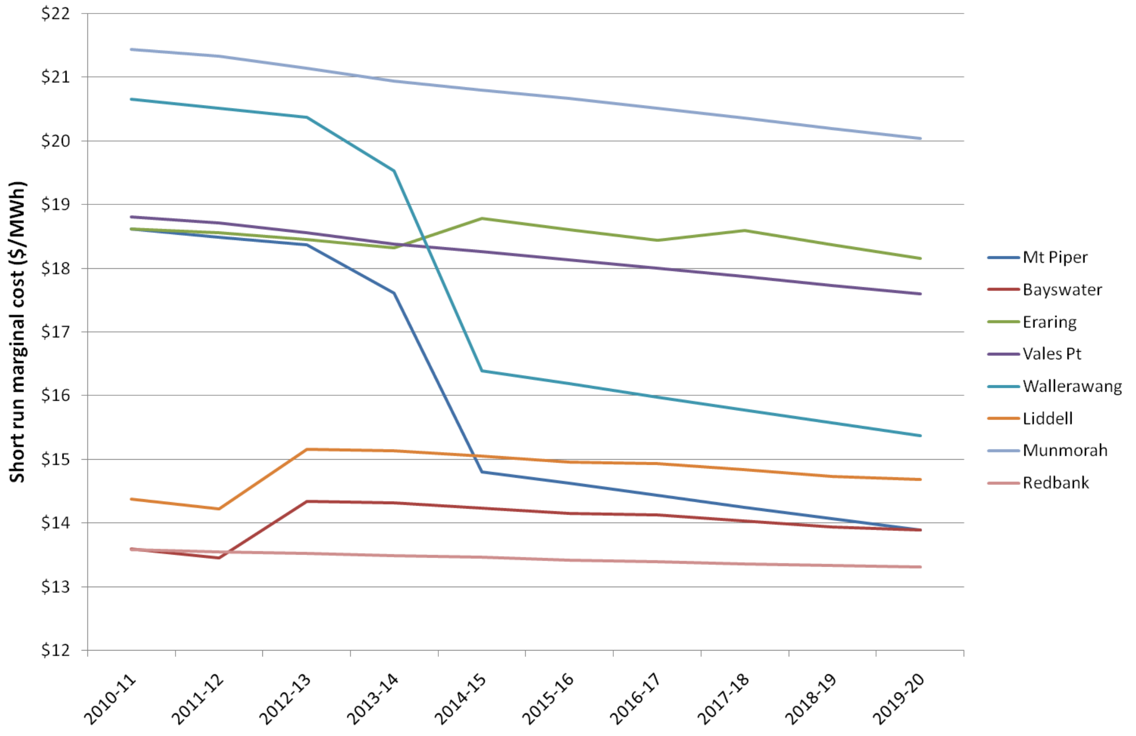
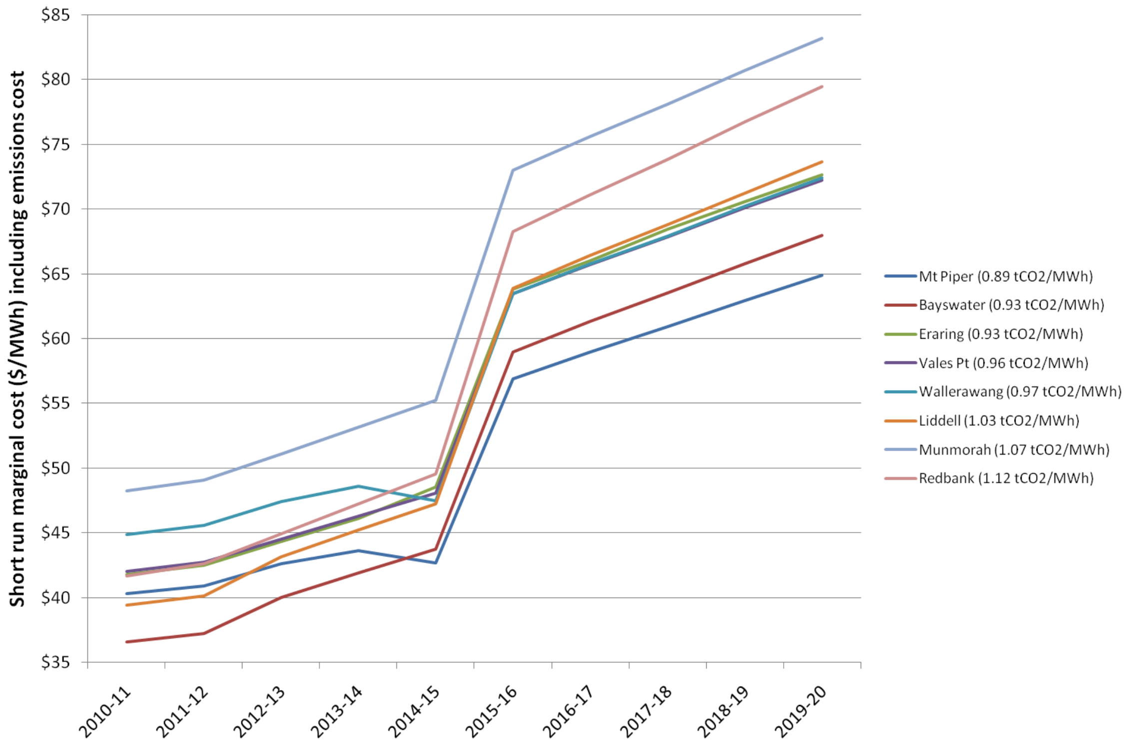
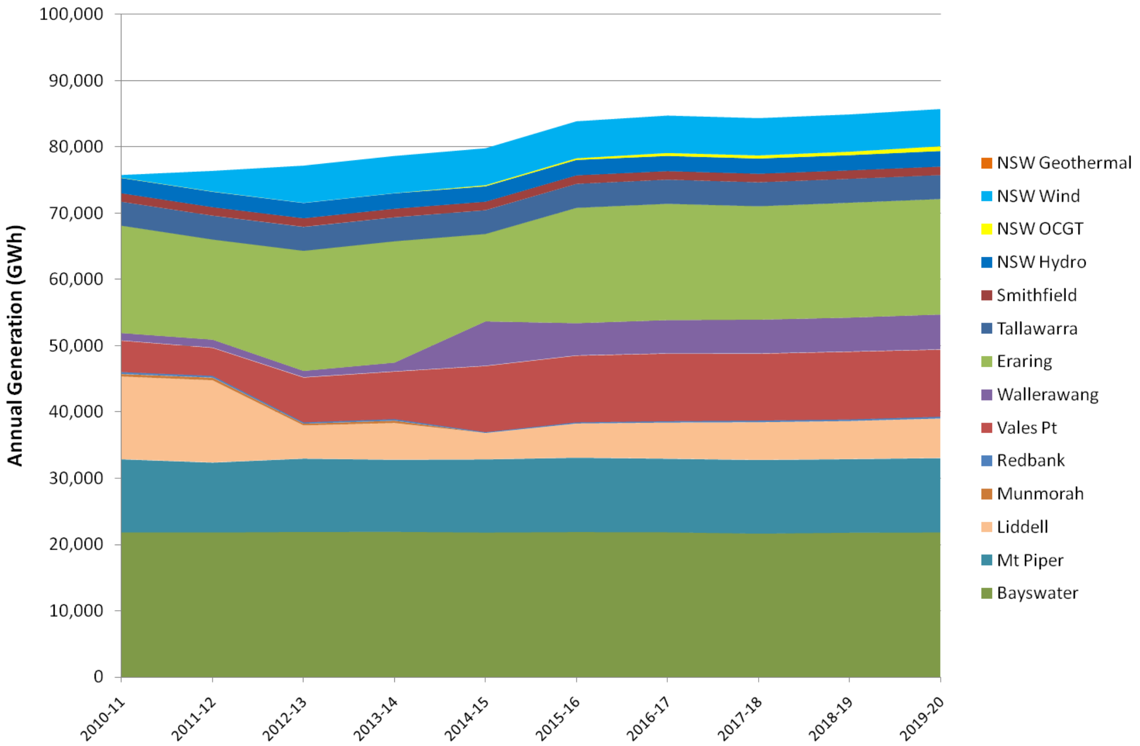


Figure 6.15 – NSW plant short run marginal costs (with carbon price)



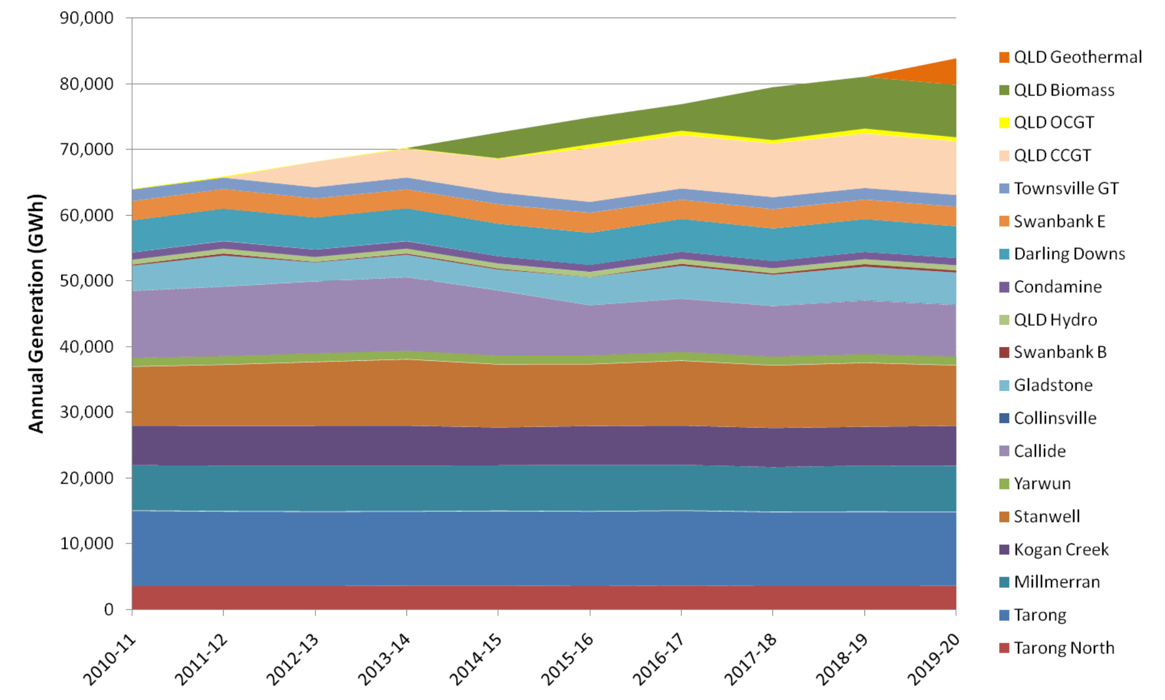
In the high banking case (Figure 6.16), the larger quantity of wind in early years depresses the output of the NSW black coal generators marginally more than in the low banking case.

Figure 6.16 – NSW Energy by plant (High banking)



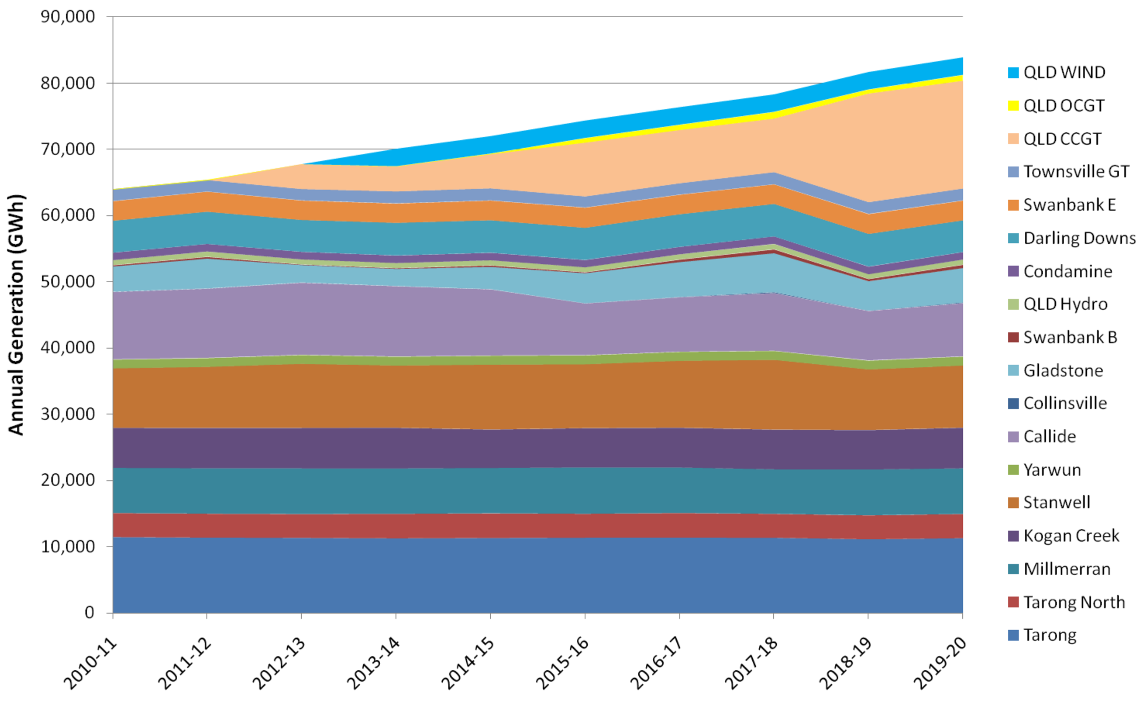
With low levels of banking (Figure 6.17), Queensland experiences high growth in biomass generation from 2014-15, and the installation of a geothermal plant in 2019-20. Queensland black coal generators show relatively unchanged volumes, due to the strong load growth and lack of wind installation in Queensland. There is also substantial investment in CCGT generation.

Figure 6.17 – QLD Energy by plant (Low banking)



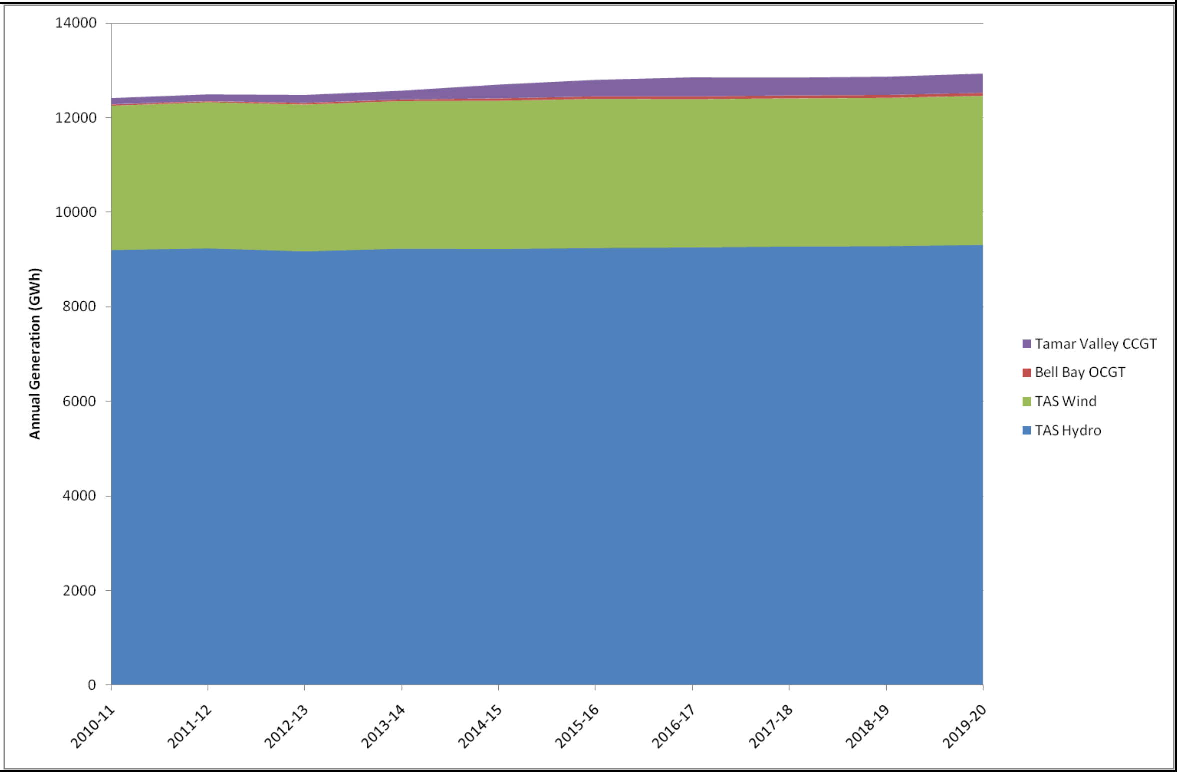
With high levels of banking (Figure 6.18), Queensland experiences a very different outcome. Biomass and geothermal energy are squeezed out of the market by wind installation in other regions, and a small amount of wind generation located in Queensland. The strongest growth is in CCGT generation.

Figure 6.18 – QLD Energy by plant (High banking)



In both high and low banking cases, Tasmanian generation is a mix of roughly 70-75% hydro-electricity and 24% wind generation. Gas-fired production increases gradually from around 1% of supply to 4% of supply by the end of the study. This break-down is shown for the low banking case in Figure 6.19.

Figure 6.19 – TAS Energy by plant (Low banking)



Sensitivities

ROAM conducted a variety of sensitivity cases to Scenario C, to determine the sensitivity of the outcome to various parameters. Table 6.2 describes the sensitivities to capital cost[21] which were tested. The results were extremely robust, as explained in the table.

Further to these cost sensitivities, ROAM also investigated the least cost generator planting outcome and associated costs if no interconnectors are upgraded or built (noting that the least cost outcome includes the SA-VIC augmentation from 2016-17 under both high and low banking). To do this, the model is restricted to only choosing states which include no augmentations or new lines, and an optimal, least-cost path through these states is found. This is a particularly useful sensitivity, as it quantifies the system benefit of the SA-VIC interconnector compared with least-cost development outcomes in its absence. This sensitivity is referred to as the 'no augmentations' case in each scenario.

In a similar fashion, the system benefits of each network augmentation option have been quantified relative to least-cost development outcomes in their absence. This is done by comparing the yearly costs of optimal expansion plans including the augmentation and those of the optimal expansion plan without the augmentation. The results of these studies are included in Section 6.5.2). We note that the difference between the costs of cases with and without an interconnector upgrade is the economic cost of congestion on that line.

[21] Capital costs in the base case were sourced from the ACIL Tasman report "Fuel resource, new entry and generation costs in the NEM: draft report" of 13 Feb 2009.

Table 6.2 – Capital Cost Sensitivities to Scenario C	
Parameter	**Sensitivity outcome**
CCGT capital cost	CCGT plant capital costs were varied from 80% of the initial cost, to 120% of the initial cost. There was no change in the lowest cost planting outcome, suggesting high robustness of results to the capital costs of CCGT plant.
OCGT capital cost	OCGT plant capital costs were varied from 80% of the initial cost, to 120% of the initial cost. There was no change in the lowest cost planting outcome, suggesting high robustness of results to the capital costs of OCGT plant.
Wind capital cost	The capital cost of all new wind farms was varied from 80% of the initial cost, to 120% of the initial cost. There was no change in the lowest cost planting outcome, suggesting high robustness of results to the capital costs of wind plant.
Capital cost of wind generation in South Australia	The capital cost of all new wind farms in South Australia was varied from 80% of the initial cost to 120% of the initial cost. This investigated the benefits of concentrating wind development in South Australia, which appears to be likely from the number of projects proposed for South Australia. This sensitivity had no impact on the lowest cost planting outcome, suggesting high robustness of results to the capital costs of wind generation in SA.

Impact of no transmission augmentation on planting outcomes

The planting outcomes from the IRP model with no significant transmission augmentations were not changed from the base case of Scenario C when high banking of RECs occurred. Despite the absence of the SA-VIC augmentation installation in 2016-17, no generator entry decisions were affected.

With low banking of RECs, a CCGT plant in the MEL zone was installed one year earlier than in Scenario C, being installed in 2016-17 (in the absence of the SA-VIC interconnector which was installed in 2016-17 in Scenario C). Without the interconnector, this plant is necessary one year earlier to meet the lower reserve margin in Victoria.

Aside from this minor change in the low banking case, generation entry decisions were unaffected by the absence of significant interconnector upgrades. This may change if the capacities of new entrant generators were smaller, but it is indicative that there are not significant differences in generator entry decisions, dependent upon transmission augmentation alternatives, when those augmentations occur relatively late in the outlook period.

6.2) Costs

The difference in renewable plantings between the high and low banking cases has implications for the cumulative costs[22] of the scenario, as illustrated in Table 6.3 and Figure 6.20.

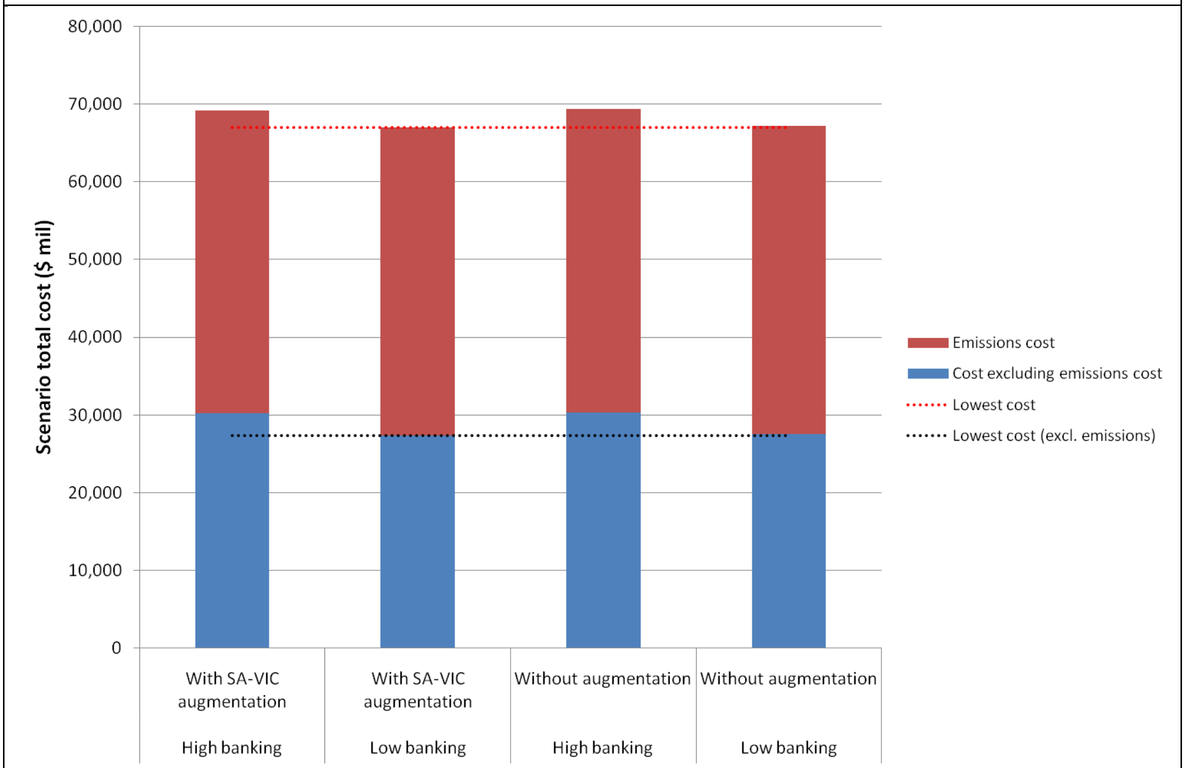
[22] Costs throughout this report are calculated as net present value, real, pre tax, with a 10% WACC.

Low banking produces a lower cumulative cost by 2019-20 (excluding the cost of carbon pollution permits under the CPRS) of $27,329 million (compared with $30,260 million for the high banking case).

Table 6.3 – Cost comparisons (cumulative cost 2010-11 to 2019-20, $ mil)

		With SA-VIC augmentation (Scenario C)	Without SA-VIC augmentation
Low banking	Total cost of scenario	67,050	67,198
	Cost excluding emissions cost	27,329	27,547
	Emissions cost	39,721	39,651
High banking	Total cost of scenario	69,201	69,365
	Cost excluding emissions cost	30,260	30,340
	Emissions cost	38,941	39,025

Figure 6.20 – Cost outcomes (cumulative cost 2010-11 to 2019-20) Scenario C



The high banking scenario has a marginally lower emissions cost under the CPRS, because the early construction of a large quantity of wind generation displaces more fossil fuel fired plant, earlier in the study, producing lower cumulative emissions from 2010 to 2020. In the high banking case, 185,090GWh of energy is produced from renewable sources over the study period (2010 to 2020), compared with 163,113 in the low banking case.

It is important to note that this effect is dependent upon the length of the study period under analysis. If the period 2020 to 2030 were also included in the analysis, the low banking case is expected to have a substantially lower emissions cost than the high banking case, because of the following two complementary effects:

1. Despite producing a lower cumulative amount of GWh of renewable energy from 2010 to 2020, the low banking case will produce a significantly larger quantity of GWh than the high banking case from 2010 to 2030. The amount of renewable energy generated in 2020 is much higher in the low banking case (necessary to meet the RET in that year, in the absence of significant banking). Since renewable generators will not be retired, this means that the number of RECs required in the later parts of the scheme (to 2030) will far exceed the decreasing targets (much more than in the high banking case). With a larger quantity of renewable GWh produced in the low banking case over the whole period (2010 to 2030), the total emissions (and hence the emissions cost) will be much lower.
2. In the low banking case, a much higher proportion of the renewable energy is generated in the later parts of the study, when the emissions cost is much higher. This means that the renewable energy generated in the low banking case will generally be displacing emissions at a much higher cost, hence reducing the total emissions cost over the whole study period (2010 to 2030) even further below that for the high banking case.

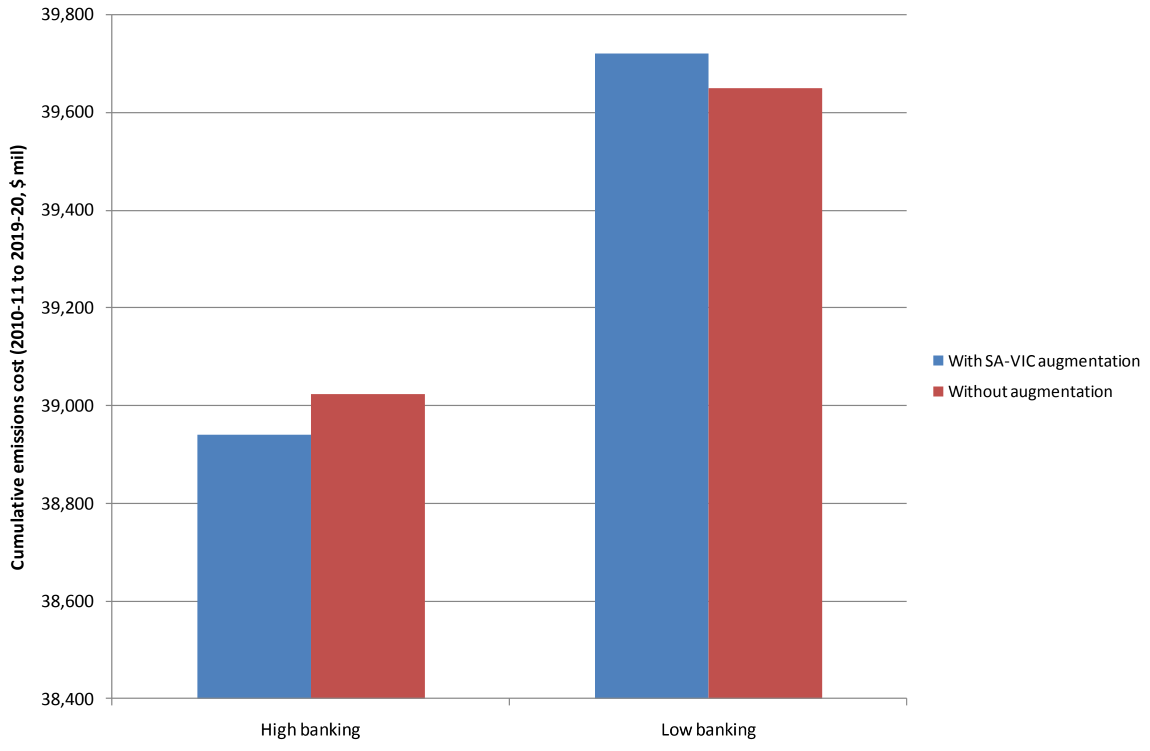
Costs in the absence of the interconnector

When the SA-VIC interconnector is excluded, the costs are increased slightly, for both the low and high banking cases. This is consistent with the fact that the model chose to install the interconnector to develop the lowest cost “central planning” planting solution. However, this effect is much smaller than the impact of a high banking scenario, vs a low banking scenario.

Costs are increased more significantly in the low banking case, due to the necessity of bringing forward the MEL CCGT plant one year. For the high banking case, the costs differ by a smaller margin, since the cost differences are just due to dispatch changes in the absence of the interconnector augmentation.

Emissions costs through the CPRS scheme are illustrated in Figure 6.21, comparing Scenario C with and without the SA-VIC transmission augmentation. As with the augmentation (discussed earlier), the emissions cost is consistently lower for the high banking case, due to the larger cumulative amount of renewable energy generated over the outlook period (displacing fossil fuel plant).

Figure 6.21 – Emissions cost comparison



In the high banking case, emissions costs are higher without the augmentation due to the less efficient dispatch in the absence of the SA-VIC interconnector augmentation.

In the low banking case, emissions costs are lower without the augmentation, due to the earlier introduction of the MEL CCGT plant, which primarily displaces emissions intensive brown coal generation. This more than offsets the effect of the less efficient dispatch of plant in the absence of the SA-VIC interconnector augmentation.

Lowest cost solution

The low banking scenario is the lower cost solution to Scenario C, and therefore is ROAM's suggested scenario for analysis. However, it should be noted that only the upper and lower bound banking paths (high banking and low banking) were considered in the model; intermediate banking paths are possible, and may ultimately be lower cost.

In addition, the drivers for banking may not be entirely economic in nature, with political and meteorological influences having had a large impact on the RECs market in the past.

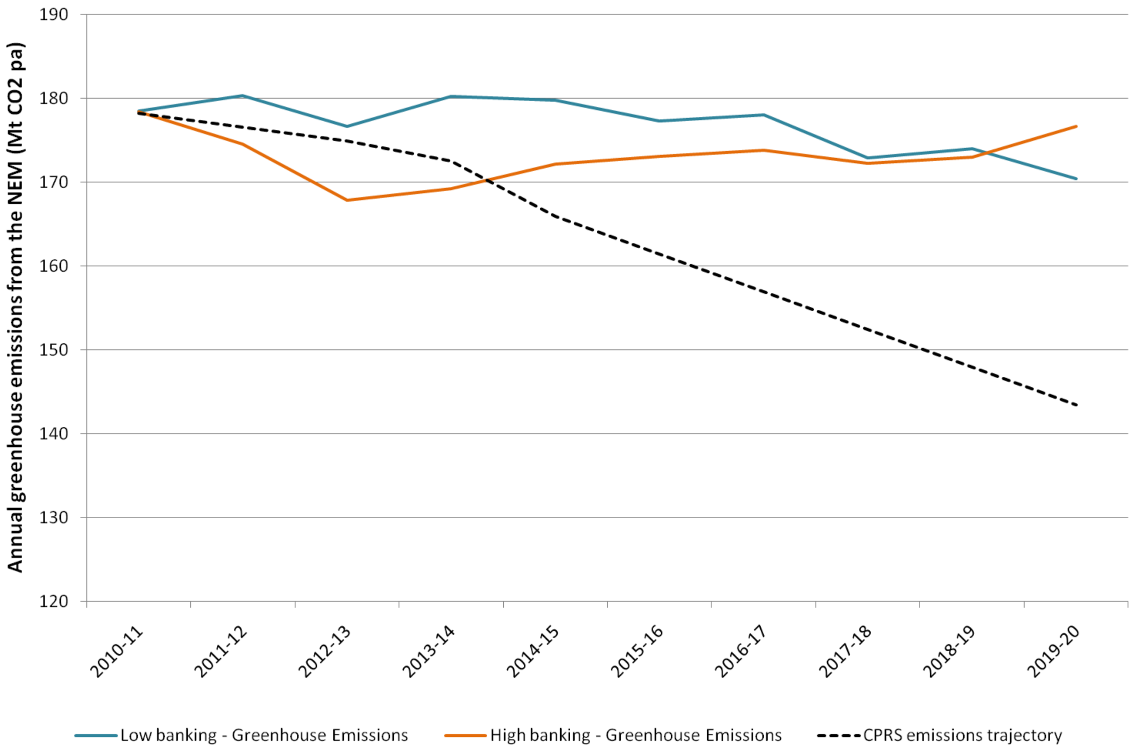
ROAM has therefore analysed both the high and low banking scenarios throughout this report, to capture the possible differences in outcomes due to this important factor. If it is necessary to choose one outcome for final analysis at any stage, the low banking scenario should be chosen in preference (due to its lower overall cost).

6.3) GREENHOUSE EMISSIONS

The greenhouse emissions in Scenario C for the high and low banking cases are illustrated in Figure 6.22. In the low banking case emissions gradually reduce over the course of the study, as renewable energy is gradually introduced into the market. Emissions in the final year are lower than in the high banking scenario, due to the much larger quantity of renewable generation that ultimately results in the low banking case.

By comparison, the high banking case shows a large initial reduction in emissions due to the large quantity of wind generation entering the market in early years. In later years, the introduction of renewable generation slows substantially, and energy growth is met with the installation of new gas plant, causing a slow increase in emissions for the later parts of the study.

Figure 6.22 – Greenhouse emissions outcomes for Scenario C



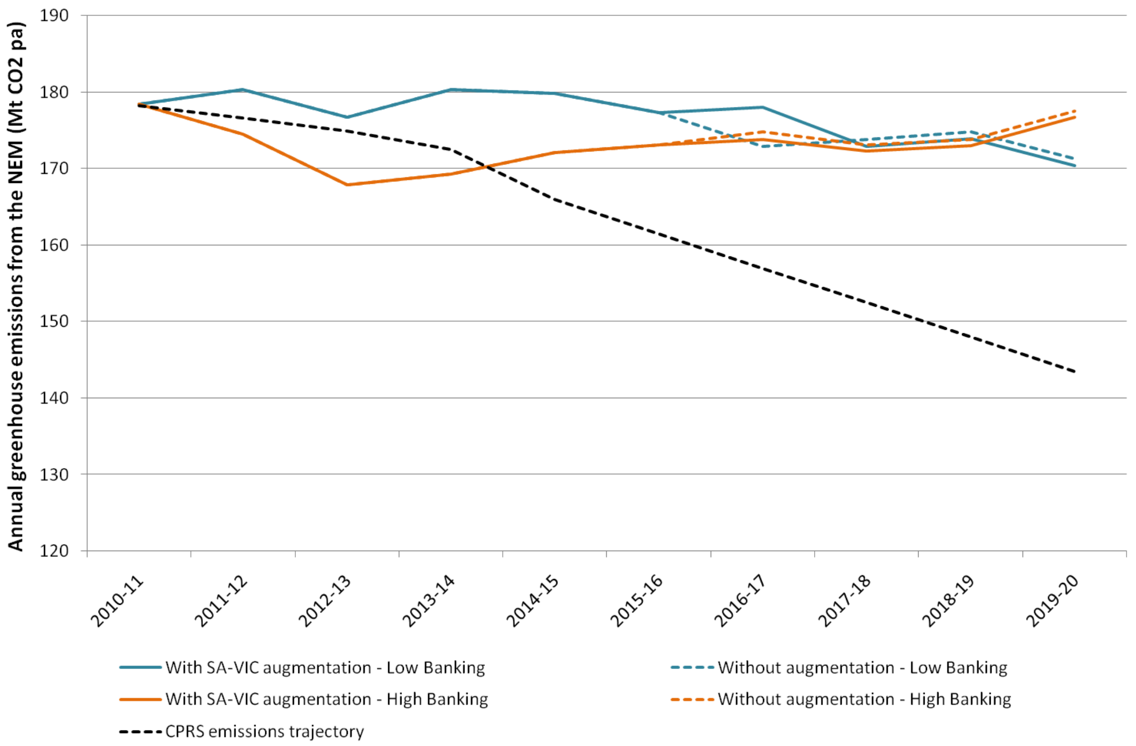
The black dotted line in Figure 6.22 illustrates the emissions targets announced for the CPRS scheme, assuming an initial -5% by 2020 target, moving to a -15% by 2020 target in 2015-16 (as assumed in the generator bids). These targets are for the whole Australian economy, and have been translated here to targets for just the NEM, based upon emissions levels from the NEM in the year 2000. The electricity sector may ultimately play a larger or smaller proportionate role towards meeting the national targets.

This target is determined against emissions levels from the NEM in the year 2000, as announced in the CPRS scheme white paper. It is coincidental that there is agreement between the target in 2010-11 and the emissions modelled to originate from the NEM in that year. Significantly, a 1000MW wind farm is committed for installation in NSA in the first year of the study, which acts to displace fossil fuel generation and reduce emissions to the level of the CPRS target in that year. In the absence of this NSA wind generator, emissions from the NEM in 2010-11 would exceed the target.

Greenhouse emissions in the absence of the interconnector

The greenhouse emissions outcomes with and without the interconnector augmentation are compared in Figure 6.23 below. In the low banking case, emissions are substantially reduced in 2016-17 when the MEL CCGT is installed a year earlier in the absence of the augmentation. However, inefficient dispatch in the absence of the SA-VIC interconnector augmentation beyond 2016-17 causes slightly higher emissions for both the high and low banking cases in every year.

Figure 6.23 – Greenhouse emissions outcomes



6.4) *UNSERVED ENERGY*

The unserved energy (USE) and associated discounted costs observed in Scenario C for the high and low banking cases are reported in Table 6.4. Unserved energy has been costed at $12,500/MWh. The annual discounted cost of unserved energy in the development plan has been included for comparison. We note that these estimates are the outcome of only one detailed simulation of each year. It is understood that a much larger sample (in the order of 100 Monte Carlo simulations) of each state are required to adequately capture the likelihood of random generator outages and transmission congestion causing unserved energy[23]. Nevertheless, the cost of unserved energy that has been observed in the modelling is captured in the optimisation.

Table 6.4 – Unserved energy and associated cost

		2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Cumulative Cost
Low banking	USE (GWh)	0	0	0	0	0	0	0.14	0	0	3.84	3.98
	Cost ($ mil)	0	0	0	0	0	0	0.94	0	0	19.41	20.35
	Total annual cost ($ mil)	6971	6555	6469	6282	6132	7565	7177	6905	6642	6352	67050
High banking	USE (GWh)	0	0	0	0	0	0	0.48	2.05	0.04	4.44	7.01
	Cost ($ mil)	0	0	0	0	0	0	3.23	12.54	0.22	22.44	38.43
	Total annual cost ($ mil)	6971	6817	6829	6704	6453	7737	7327	7066	6794	6503	69201

6.5) INTERCONNECTORS

6.5.1) Augmentation Timing

The model chooses to implement the SA-VIC interconnector upgrade in 2016-17, as the lowest cost central planning option. The main driver for installing the interconnector is likely the fact that it includes a 400MW increase in the limit from NSA to ADE, which experiences very significant congestion (discussed in section 6.6).

Sensitivities were conducted to analyse the sensitivity of this interconnector upgrade to the cost of the upgrade. Table 6.5 illustrates the results.

[23]See Peard and Vanderwaal, “Calculation of minimum reserve levels and their application to maintain reliability of supply in the NEM”, EESA conference, Melbourne, 16-18 August 2006, available at www.roamconsulting.com.au/about_papers.html

Table 6.5 – Timing of SA-VIC interconnector augmentation		
	Low Banking	**High Banking**
SA-VIC interconnector at 50% of capital cost	2010-11	2010-11
SA-VIC interconnector at 80% of capital cost	2013-14	2013-14
Base scenario C (SA-VIC interconnector at 100% of capital cost)	2016-17	2016-17
SA-VIC interconnector at 120% of capital cost	2016-17	2016-17

When the capital cost of the SA-VIC interconnector is reduced to 50% of the original cost, the interconnector upgrade is installed in 2010-11 (the first year of the study). With a slightly higher capital cost (80% of initial), its entry is delayed until 2013-14, when transmission congestion is higher (increasing its value), and the discounted cost of the upgrade is lower.

If the cost of the upgrade is increased to 120% of its initial cost it is still installed in 2016-17, suggesting a high value of this upgrade to the system, and a high degree of robustness of the modelling results to the cost of the augmentation.

6.5.2) Interconnector augmentation costs

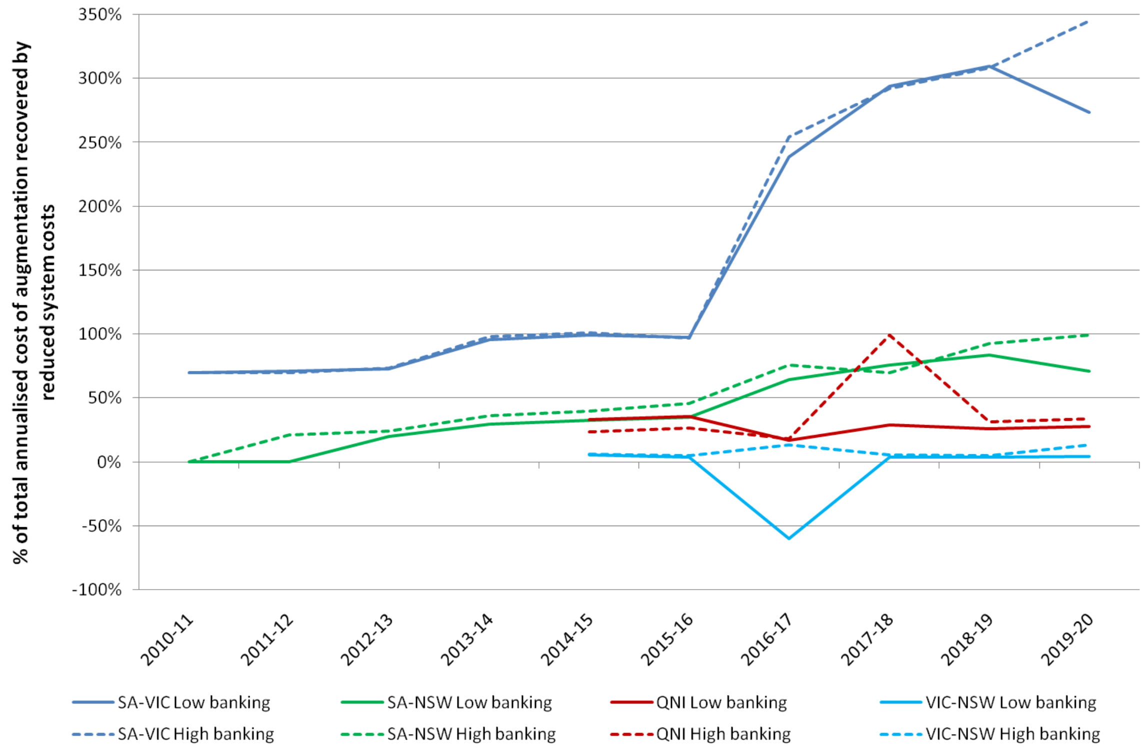
The interconnector augmentation alternatives available to the model are listed in Table 6.6. Of these, the SA-VIC interconnector was the only one that was justified on the basis of reduced costs. However, a year-by-year analysis of annualised costs and benefits of each interconnector augmentation reveals the relative cost effectiveness of each interconnector, as discussed further below.

Table 6.6 – Transmission augmentation options			
Upgrade	**Path**	**Capacity Increase**	**Capital cost**
SA-VIC	NSA to MEL (upgrade)	400MW bidirectional	\$400 mil
VIC-NSW	MEL to SWNSW (upgrade)	400MW bidirectional	\$247 mil
NSW-QLD (QNI)	NNS to SWQ (upgrade)	400MW bidirectional	\$220 mil
SA-NSW	ADE to NCEN (new)	2000MW bidirectional	\$2,310 mil

The annual cost of each interconnector was calculated in each year, including an annualised capital cost (discounted appropriately to recover the net present value), in addition to the annual operations and maintenance cost (1% of capital cost for each interconnector augmentation). This cost was compared to the benefit of installing the interconnector in each year, where the benefit was determined by comparison of the total system costs to a base scenario that did not include the interconnector, corrected for any differences in the capital expenditure between the scenarios.

The resulting percentages are illustrated in Figure 6.31, and discussed in the sections below.

Figure 6.24 – Interconnector cost effectiveness (Scenario C)



SA-VIC augmentation

The most cost justified transmission augmentation of those studied is the SA-VIC augmentation of a 400MW bidirectional upgrade from ADE to MEL, costing $400 million. The percentage of the total annualised cost of this augmentation that is recovered by reduced system costs (from more efficient dispatch and delayed generation entry) is shown on an annual basis in Table 6.7 below.

To evaluate the cost effectiveness of the interconnectors, the yearly costs with each interconnector installed were compared to the costs in the no augmentation case. The differences between costs were evaluated as a fraction of the expenditure (capital cost repayments plus fixed O&M) on the interconnector in that year, and are shown in the tables below. A value above 100% means the cost of the interconnector in that year was more than offset by savings elsewhere in the NEM (e.g., delayed the requirement for new plant, reduced emission costs, etc). A value between 0-100% represents a portion of costs being recovered, while a negative value would indicate that the interconnector actually incurred additional costs to the system beyond its capital and O&M (for example, by delaying new, cleaner plant from entering for supply-demand reasons).

Table 6.7 – SA-VIC interconnector augmentation		
	Percentage of total annualised cost of augmentation recovered by reduced system costs	
	Low banking	High banking
2010-11	70.1%	70.1%
2011-12	71.1%	70.2%
2012-13	73.2%	73.8%
2013-14	95.8%	98.5%
2014-15	99.5%	101.5%
2015-16	97.9%	97.2%
2016-17	238.6%	254.0%
2017-18	293.9%	291.8%
2018-19	309.3%	308.4%
2019-20	273.4%	344.7%

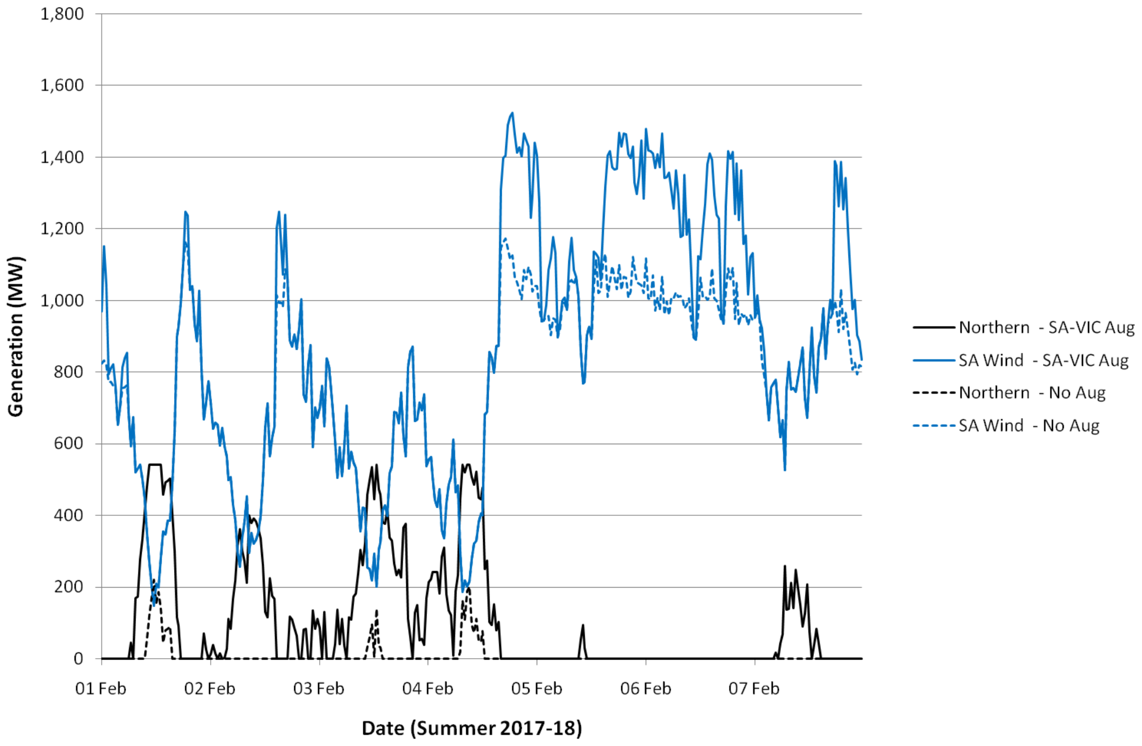
The SA-VIC augmentation is highly justified from 2016-17, recovering almost 240-250% of its annual costs in that year. This rises to 270-345% by the end of the study (depending upon the level of RECs banking). The interconnector is close to justified in earlier years, recovering approximately 70% of its costs from 2010-11 to 2012-13, and approximately 95% from 2013-14 to 2015-16.

The large jump in the value of the interconnector in 2016-17 is likely due to the entry of the committed geothermal plant in South Australia (NSA) in that year.

The SA-VIC augmentation had minimal impacts on the operational behaviour of coal-fired plant (both those running at close to full capacity, and those exhibiting cycling behaviour). CCGT operation was similarly unaffected, since most CCGTs are running at full capacity even in the absence of any interconnector augmentation.

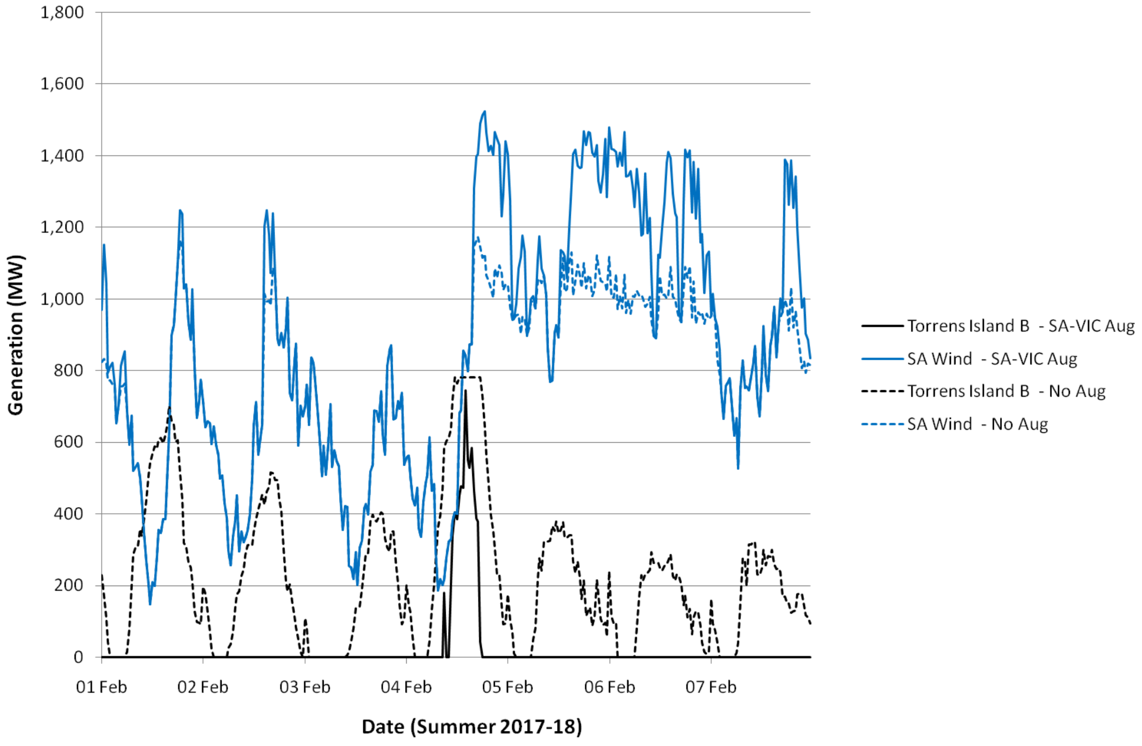
The most dramatic impacts of the augmentation were on South Australian plant. Northern exhibits significantly increased dispatch with the SA-VIC augmentation, as does the South Australian wind generators at times of high wind (Figure 6.25).

Figure 6.25 – SA-VIC augmentation - Northern (Scenario C)



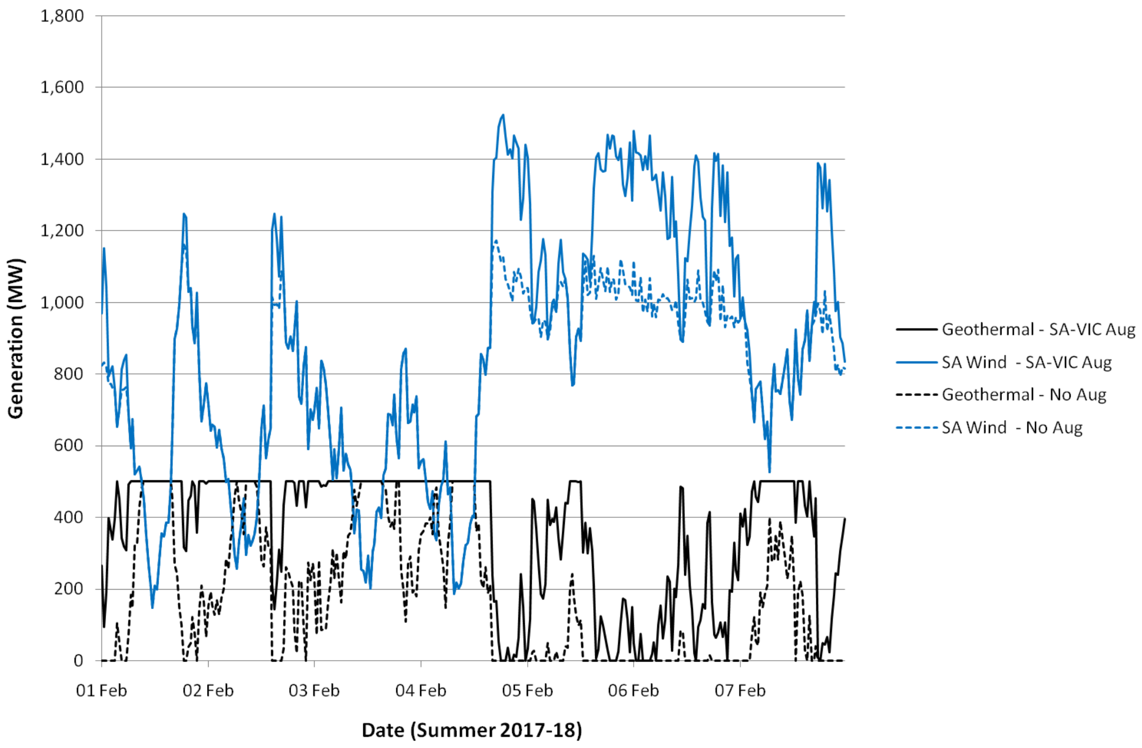
Torrens Island B exhibits reduced dispatch with the installation of the SA-VIC augmentation, since it has a higher short run marginal cost (SRMC) than most other plant (Figure 6.26). Its operation is required in the absence of the augmentation, to meet the demand in the ADE zone (where Torrens Island B is located). With the SA-VIC augmentation, it is no longer 'protected' by transmission congestion into ADE, and is undercut by Northern and other lower SRMC plant, exhibiting reduced dispatch.

Figure 6.26 – SA-VIC augmentation – Torrens Island B (Scenario C)



The NSA geothermal plant also exhibits significantly increased dispatch with the SA-VIC augmentation, since it can be exported from the NSA zone (along with the NSA wind generation) (Figure 6.27).

Figure 6.27 – SA-VIC augmentation - Geothermal (Scenario C)



SA-NSW new line

Surprisingly, the next most beneficial interconnector augmentation of those studied is the SA-NSW new line of 2000MW (bidirectional), at a cost of $2,310 million. Despite the very high cost of this augmentation, this interconnector is 70-90% justified over the later years of the study, as illustrated in Table 6.8 below. Particularly with high levels of RECs banking, this interconnector may be justified for entry around 2020 (especially when the value of avoided transmission losses is taken into account in a more detailed fashion)[24]. Significantly, this study did not attempt to optimise the size of this interconnector, and a smaller (less expensive) line may be sufficiently justified on a cost reduction basis. Further study should analyse this augmentation option further.

[24] This augmentation and the SA-VIC augmentation are, however, exclusive of each other in this modelling, so only one is indicated to proceed by 2020.

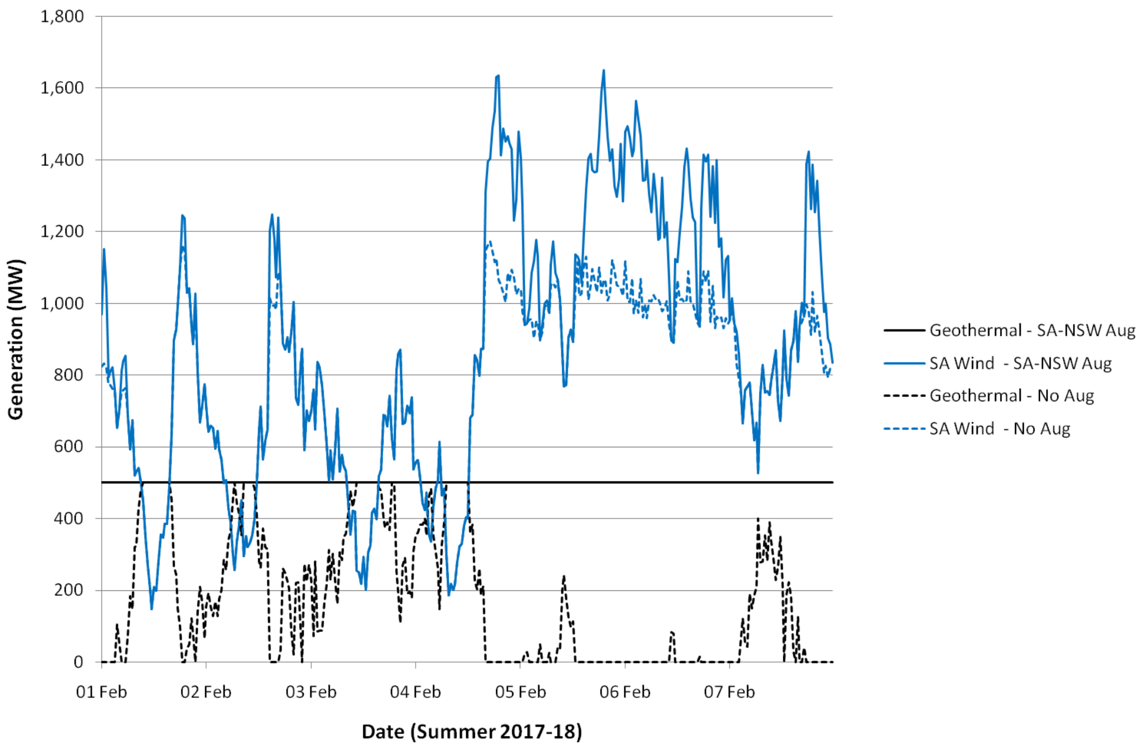
Table 6.8 – SA-NSW interconnector		
	% of total annualised cost of augmentation recovered by reduced system costs	
	Low banking	**High banking**
2011-12	-	20.8%
2012-13	20.0%	24.3%
2013-14	29.4%	35.8%
2014-15	32.6%	39.7%
2015-16	34.8%	45.5%
2016-17	64.0%	75.6%
2017-18	75.6%	69.8%
2018-19	83.5%	92.4%
2019-20	70.9%	99.2%

Similar to the SA-VIC augmentation, the SA-NSW augmentation had minimal impacts on the operational behaviour of coal-fired plant (both those running at close to full capacity, and those exhibiting cycling behaviour). CCGT operation was similarly unaffected, since most CCGTs are running at full capacity even in the absence of any interconnector augmentation.

More dramatic impacts are observed on South Australian plant than for the SA-VIC augmentation. The SA-NSW new line augmentation option included upgrades to remove constraints within South Australia, from NSA to ADE to SESA. In addition, it included a large new line from ADE to NCEN. The impact of this is to allow the model to utilise low SRMC renewable generation in South Australia more completely (without curtailment), and to completely prevent usage of high SRMC plant in South Australia (instead utilising lower cost plant in NSW).

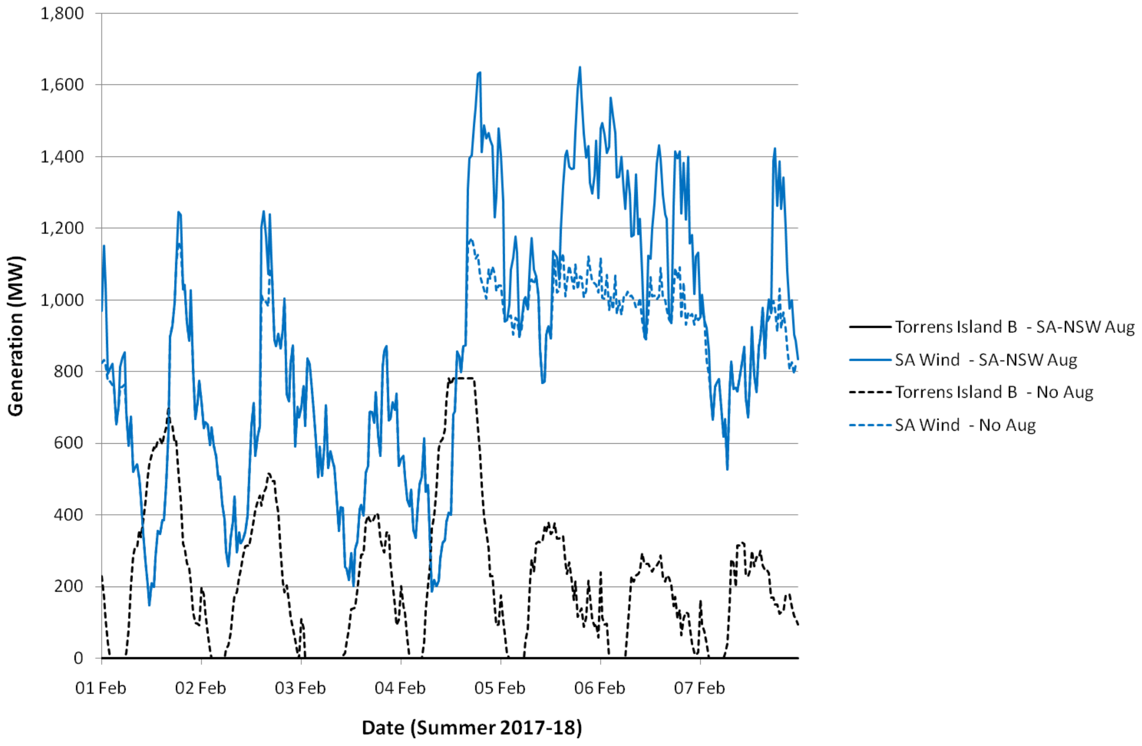
For example, the NSA geothermal plant and wind farms show no curtailment and full capacity operation when the SA-NSW augmentation is installed (Figure 6.28). By contrast, the SA-VIC augmentation increased dispatch of the geothermal station, but curtailment remained evident at times of high wind operation.

Figure 6.28 – SA-NSW augmentation – Renewable generation (Scenario C)



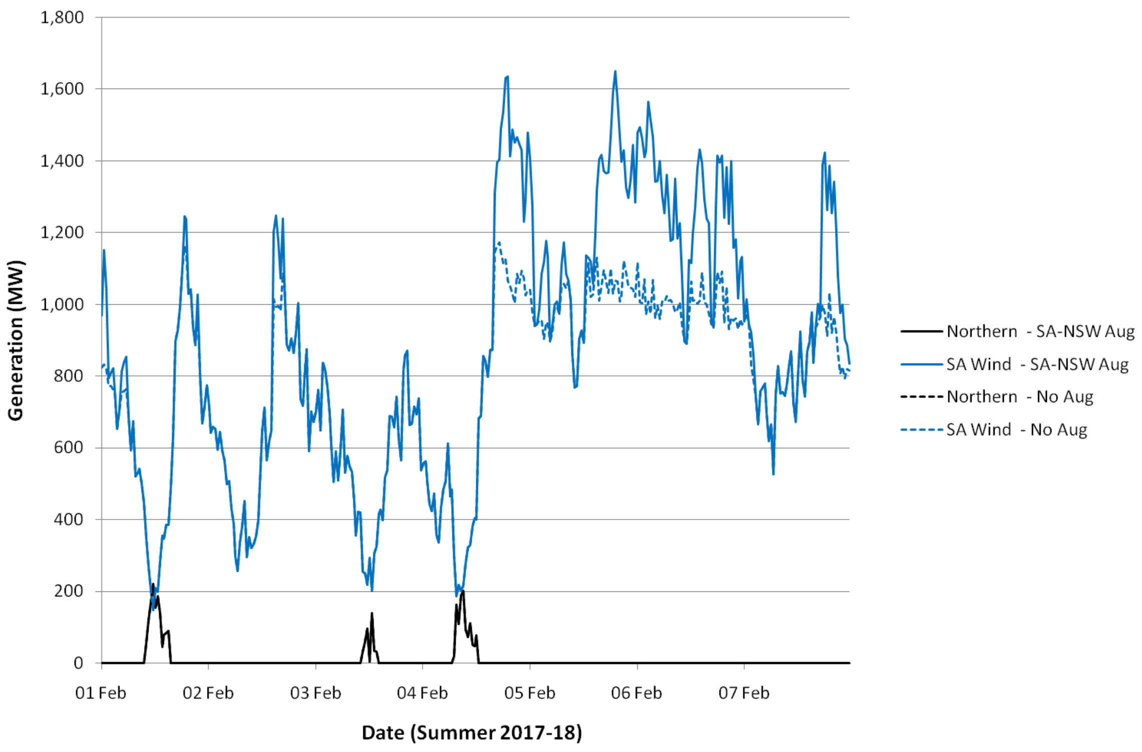
Torrens Island B does not operate at all in the week under analysis, being undercut by lower cost plant in other parts of the NEM (Figure 6.29). By contrast, the SA-VIC augmentation still required the operation of Torrens Island B in the high demand period on the 4th February, to meet ADE demand.

Figure 6.29 – SA-NSW augmentation – Torrens Island B (Scenario C)



Northern is unaffected by the SA-NSW augmentation, operating only in periods of very low wind operation, to meet the local demand (Figure 6.30). Despite the augmentation between NSA and ADE, the ADE demand is met by lower cost plant in NSW, removing the opportunity for increased dispatch at Northern. We note that the supply of coal to Northern power station from the Leigh Creek coal mine will be limited by 2017-18, and hence this production decrease may occur independently of the CPRS and RET drivers.

Figure 6.30 – SA-NSW augmentation - Northern (Scenario C)



These factors illustrate the increased benefit of the SA-NSW line, and demonstrate how it can potentially be justified on a cost reduction basis despite the very high capital cost of this option.

QNI augmentation

The QNI upgrade of 400MW (bidirectional) from NNS to SWQ, at a cost of $220 million, is not well justified by the model, recovering only 30% of its costs throughout the study. It is almost justified in 2017-18 in the high banking case, but the benefit of the interconnector is removed by the installation of a CCGT in SWQ in 2018-19. In the low banking case, a large quantity of schedulable renewable generation is installed in Queensland, reducing the value of the QNI interconnector augmentation in most years.

Table 6.9 – QNI interconnector augmentation		
	% of total annualised cost of augmentation recovered by reduced system costs	
	Low banking	High banking
2014-15	33.7%	23.2%
2015-16	35.9%	26.4%
2016-17	17.1%	18.0%
2017-18	29.0%	99.5%
2018-19	25.9%	31.5%
2019-20	28.0%	33.8%

VIC-NSW augmentation

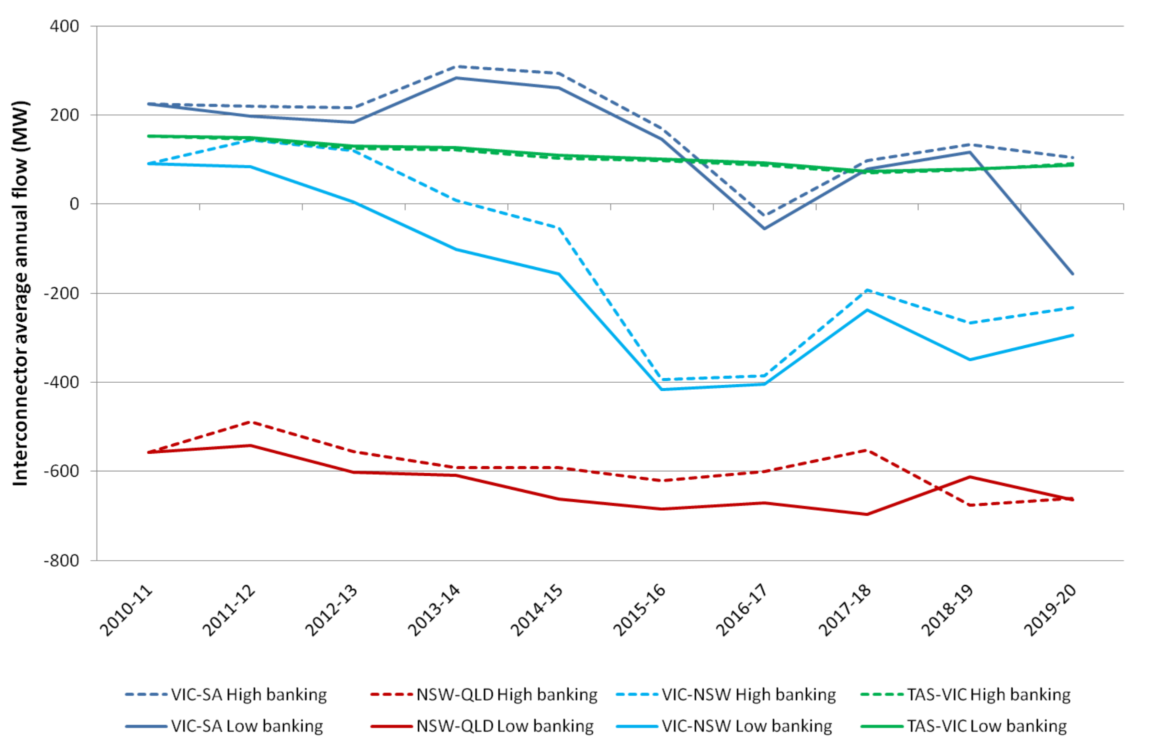
The VIC-NSW interconnector augmentation of 400MW (bidirectional), from MEL to SWNSW at a cost of $247 mil is the least justified of all the options considered, recovering only 3-10% of its costs over the study period. A negative benefit is recorded in 2016-17 due to an aberration in emissions costing, due to the delay of the installation of a CCGT plant in MEL in the case where the VIC-NSW interconnector is augmented in 2016-17. This causes a large emissions penalty from installing the augmentation, because the CCGT plant is not available for 2016-17 to displace more emissions intensive brown coal generation in Victoria. This effect is not observed in the high banking case, because the CCGT plant is not delayed (the generation entry schedule is identical).

Table 6.10 – VIC-NSW interconnector augmentation		
	% of total annualised cost of augmentation recovered by reduced system costs	
	Low banking	High banking
2014-15	5.6%	6.3%
2015-16	3.8%	5.1%
2016-17	-59.9%	13.6%
2017-18	3.5%	5.4%
2018-19	3.8%	5.0%
2019-20	4.1%	13.5%

6.5.3) Interconnector link flows

The average annual interconnector link flows are shown in Figure 6.31 for the high and low banking base cases.

Figure 6.31 – Average annual interconnector link flows (Scenario C)



Flows from QLD to NSW

Flows from QLD to NSW are relatively unchanged during the study, increasing slightly over time. The installation of a QLD CCGT in 2018-19 in the high banking case increases the flows to NSW, while in the low banking case flows to NSW decrease with the installation of a NSW geothermal plant in 2018-19.

Flows from VIC to NSW

The VIC-NSW interconnector initially has average flows into NSW, but reverses after 2012-13 in the low banking case and 2013-14 in the high banking case. The increasing exports from NSW to VIC are due to the displacement of Victorian brown coal by NSW black coal, driven by the increasing carbon price over the course of the study. This is evident in the sharp increase in exports from NSW to VIC in 2015-16, when the higher carbon price is implemented. This causes a large reduction in volume at most of the Victorian brown coal generators (Figure 6.11 and Figure 6.12).

The installation of a 1000MW Victorian CCGT in 2017-18 reduces imports from NSW in the later parts of the study. This effect is somewhat mitigated in the low banking case with the installation of a 500MW NSW geothermal plant one year later.

Flows from TAS to VIC

From the beginning of the study, Tasmania has become a net exporter, due to the installation of the high capacity factor Tasmanian wind farm in the first year. However, exports decrease marginally in later years due to increasing Tasmanian demand.

Flows from VIC to SA

Initially, VIC is a net exporter to SA, but this changes direction temporarily in 2016-17 with the installation of the SA-VIC interconnector augmentation, and the SA geothermal plant, driving low short run marginal cost energy into Victoria.

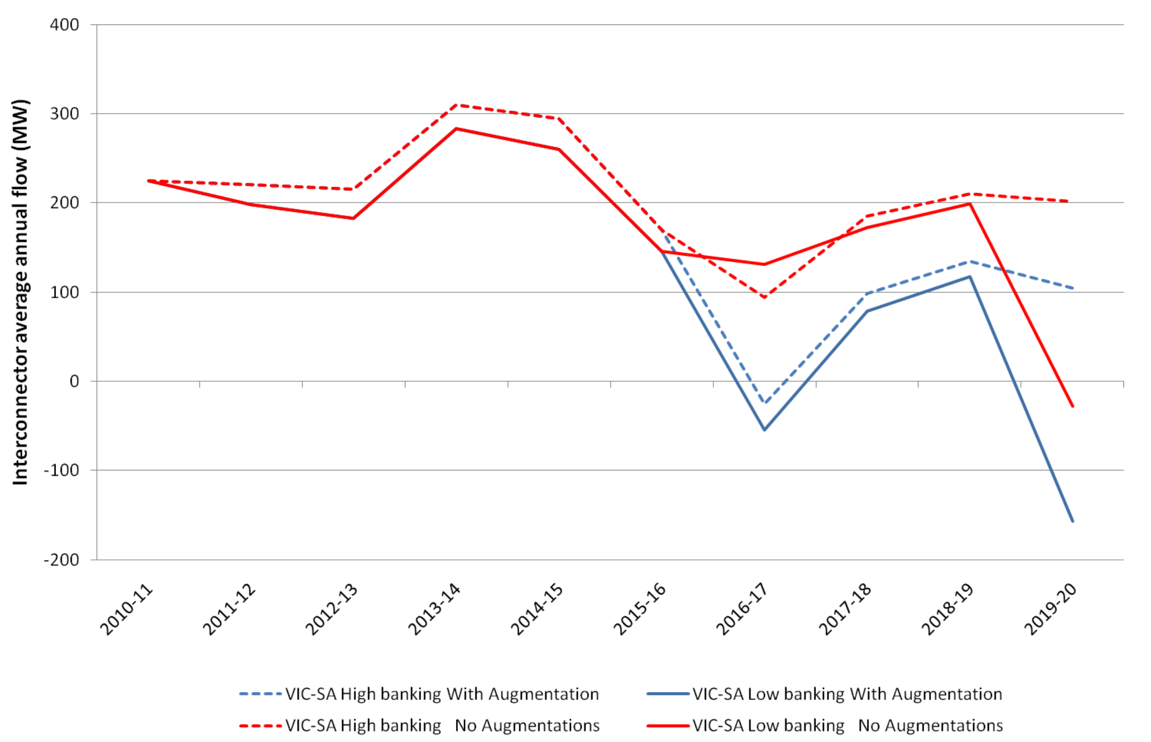
In 2017-18, flows return to VIC exporting to SA on average, with the installation of a Victorian CCGT under both high and low banking scenarios. The installation in 2019-20 of the second SA geothermal plant drives the final reversal of flow to SA exporting to VIC in the low banking case.

Interconnector flows without the SA-VIC augmentation

In the absence of the SA-VIC interconnector augmentation, most link flow annual trends remain very similar. Two that exhibit some difference are the flows on the SA-VIC interconnector (since it is not augmented) (Figure 6.32), and the flows from VIC to NSW (Figure 6.33).

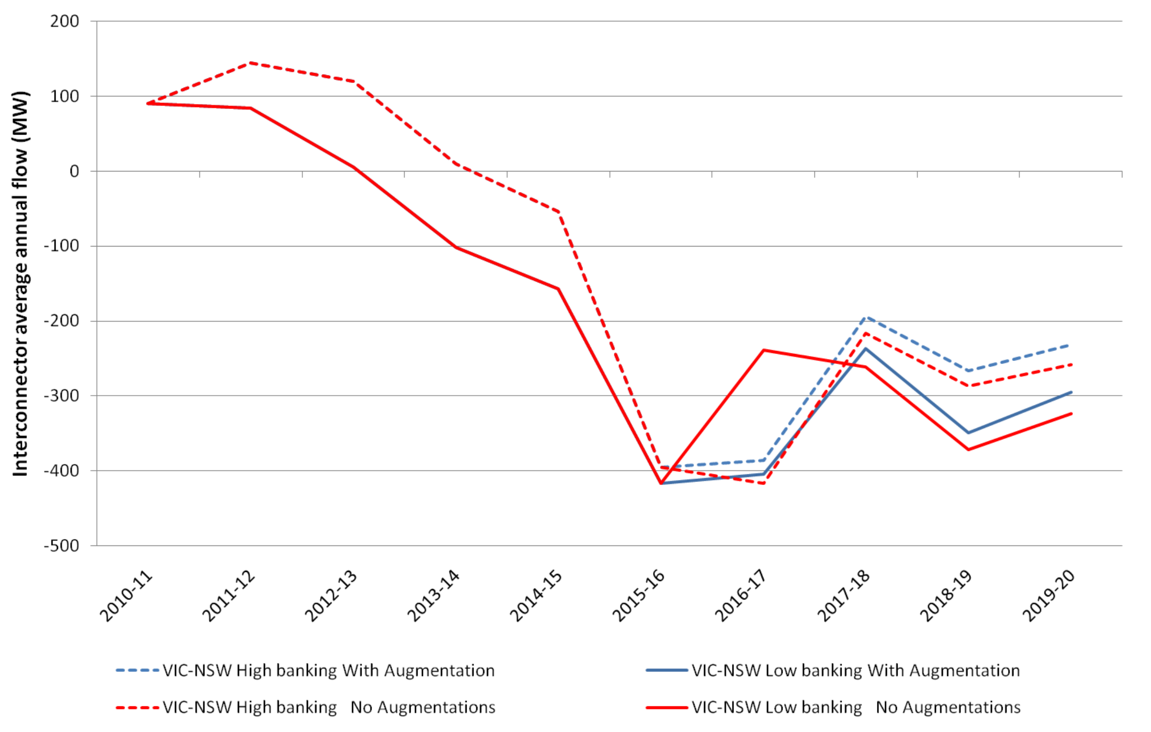
In the absence of the SA-VIC interconnector augmentation, the VIC to SA interconnectors continue to flow towards SA on average at levels similar to the early parts of the study, as illustrated in Figure 6.32. In the low banking case, the installation in 2019-20 of a second SA geothermal plant means that flows reverse and SA exports to VIC in this final year.

Figure 6.32 – Average link flow VIC-SA (Scenario C)



In the absence of the SA-VIC interconnector augmentation, a Victorian CCGT is installed one year earlier in 2016-17 in the low banking case. This drives the reduction in flows from NSW to VIC in that year, seen in Figure 6.33.

Figure 6.33 – Average link flow VIC-NSW (Scenario C)

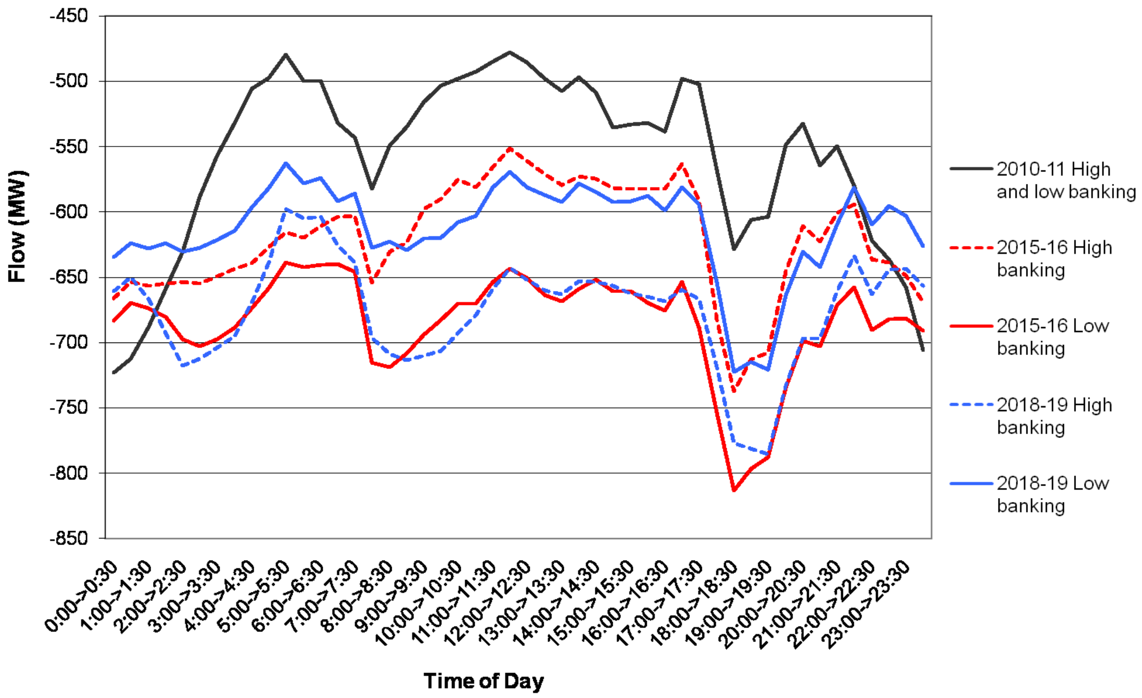


Interconnector link flow by time of day

Interconnector link flows exhibit the same overall trends illustrated in the annual average flow figure (Figure 6.31). The charts below compare the time of day flows from 2010-11 (the beginning of the study) with daily average flows in 2015-16 (immediately preceding the installation of the SA-VIC interconnector augmentation), and in 2018-19 (near the end of the study, with high carbon prices and high quantities of renewable energy).

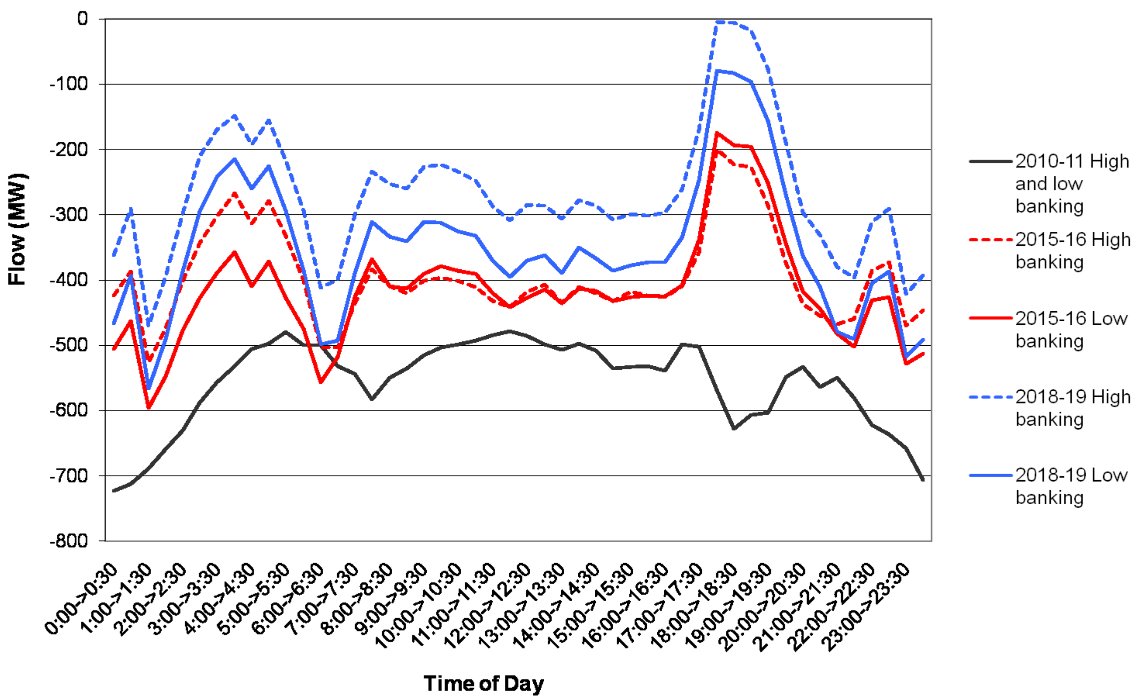
Flows on the NSW-QLD interconnector remain relatively unchanged by time of day (Figure 6.34).

Figure 6.34 – NSW-QLD link flow by time of day (Scenario C)



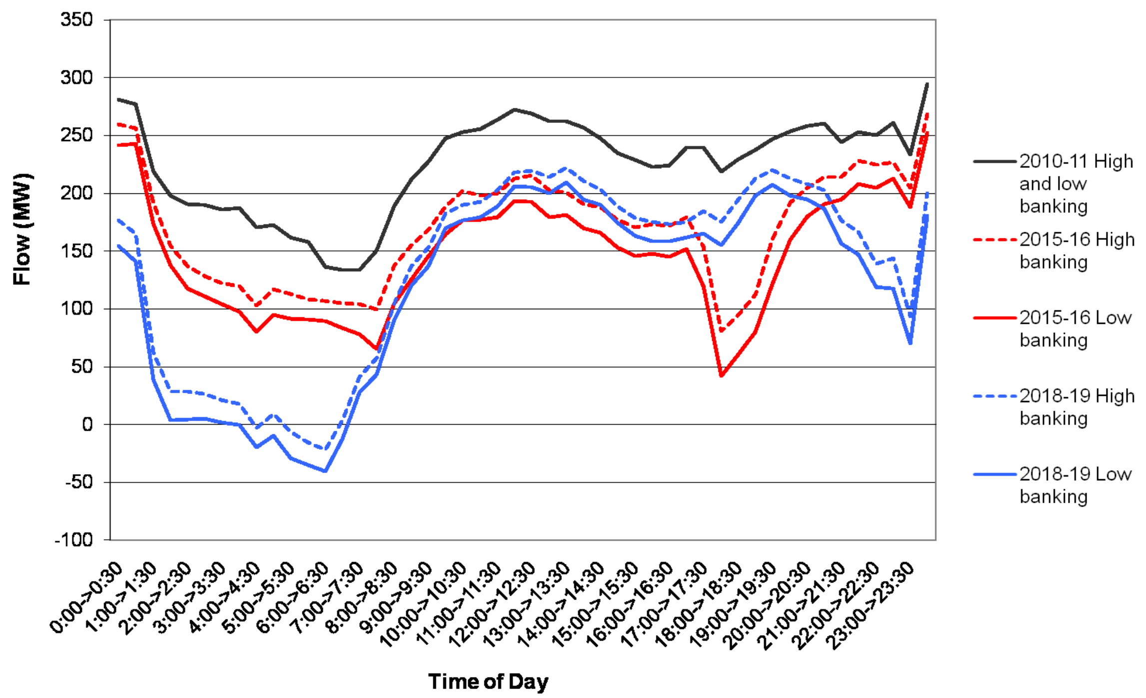
Flows from VIC to NSW (Figure 6.35) change the most in the overnight period, shifting from negative flow (NSW to VIC) at the beginning of the study, to positive flow (VIC to NSW) by 2015-16, likely due to overnight wind in Victoria exceeding the low demand at that time of day, and undercutting NSW plant. By the end of the study, flows return to net export from NSW (perhaps due to higher carbon prices forcing Victorian brown coal to cycle overnight), but do not return to the same levels as at the beginning of the study.

Figure 6.35 – VIC-NSW link flow by time of day (Scenario C)



Similarly, flows from VIC to SA are most affected during the overnight period (Figure 6.36). Initially, an increase in exports from VIC to SA is observed. After the interconnector augmentation is installed, these overnight flows are dramatically decreased, as the SA wind and geothermal in NSA is less constrained and able to supply the Adelaide zone and Victoria.

Figure 6.36 – VIC-SA link flow by time of day (Scenario C)



6.6) TRANSMISSION CONGESTION

The amount of transmission congestion on major NEM interconnectors is illustrated in Table 6.11. This table shows the percentage of time that major interconnectors were found to be limited by a constraint equation in Scenario C, for the high and low banking cases. The interconnector name is followed by a reference to the direction of flow in which the limitation occurred. QNI, Terranora, VIC-NSW and Basslink run north-south, while Heywood and Murraylink run east-west.

Similar patterns of congestion are observed for the high and low banking cases, with substantial periods of constraint between South Australia and Victoria on Murraylink and Heywood (towards South Australia). Significant periods of constraint were also found on Murraylink in both directions, and on QNI towards NSW.

Table 6.11 – Interconnector congestion - percentage of time constrained

		2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Scenario C – Low Banking	QNI (north)	2%	4%	1%	1%	1%	1%	2%	1%	3%	3%
	QNI (south)	30%	28%	13%	15%	21%	27%	23%	27%	22%	28%
	Heywood (west)	40%	35%	36%	68%	65%	33%	1%	3%	3%	2%
	Heywood (east)	3%	3%	3%	2%	3%	4%	1%	0%	0%	2%
	Basslink (north)	13%	12%	11%	11%	10%	9%	9%	8%	8%	8%
	Basslink (south)	10%	9%	10%	10%	12%	8%	6%	8%	8%	8%
	Terranora (north)	2%	4%	1%	1%	1%	1%	2%	1%	3%	2%
	Terranora (south)	2%	2%	3%	4%	10%	9%	8%	8%	5%	7%
	Murraylink (west)	51%	51%	47%	59%	60%	47%	42%	43%	42%	39%
	Murraylink (east)	30%	32%	33%	33%	34%	37%	44%	42%	41%	40%
	VIC-NSW (north)	7%	6%	5%	6%	7%	4%	3%	3%	2%	3%
	VIC-NSW (south)	5%	4%	5%	5%	4%	3%	3%	2%	3%	2%
Scenario C – High banking	QNI (north)	2%	4%	1%	1%	1%	2%	3%	5%	3%	3%
	QNI (south)	30%	28%	13%	16%	18%	21%	16%	14%	29%	27%
	Heywood (west)	40%	36%	40%	75%	74%	37%	2%	4%	4%	4%
	Heywood (east)	3%	2%	2%	2%	1%	3%	1%	0%	0%	0%
	Basslink (north)	13%	12%	11%	11%	9%	9%	8%	8%	8%	8%
	Basslink (south)	10%	8%	12%	13%	14%	10%	7%	8%	8%	8%
	Terranora (north)	2%	4%	1%	1%	1%	2%	3%	5%	2%	2%
	Terranora (south)	2%	1%	2%	2%	6%	6%	5%	4%	7%	8%
	Murraylink (west)	51%	49%	49%	60%	61%	48%	42%	43%	42%	44%
	Murraylink (east)	30%	30%	31%	30%	32%	36%	43%	41%	41%	43%
	VIC-NSW (north)	7%	5%	7%	9%	10%	5%	3%	4%	3%	5%
	VIC-NSW (south)	5%	4%	3%	3%	3%	3%	3%	2%	3%	3%

The economic cost of this congestion on each major interconnector is the difference in system costs between this case and a case where the interconnector is upgraded (and consequently congestion levels are insignificant). These economic costs have been discussed for the significant lines (QNI, Heywood/SA-VIC and the new SA-NSW line) in Section 6.5.2).

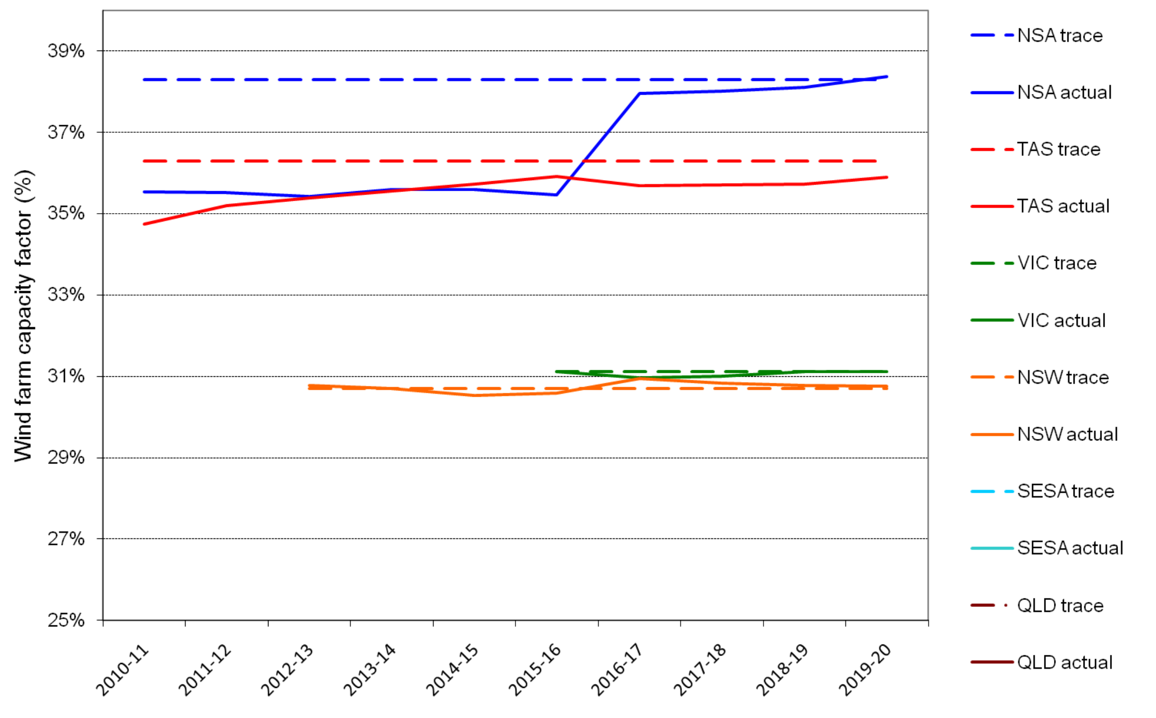
Wind farm curtailment

The curtailment of wind farms gives an indication of transmission congestion, since the very low short run marginal cost of these generators means that they should be dispatched before other plant. Any reduction in their capacity factor (from the maximum available) is therefore due to transmission congestion.

The figures below illustrate the amount of wind farm curtailment occurring throughout the study. Curtailment is significant in NSA and TAS, but negligible in other zones. The curtailment in NSA is largely addressed by the SA-VIC interconnector augmentation in 2016-17.

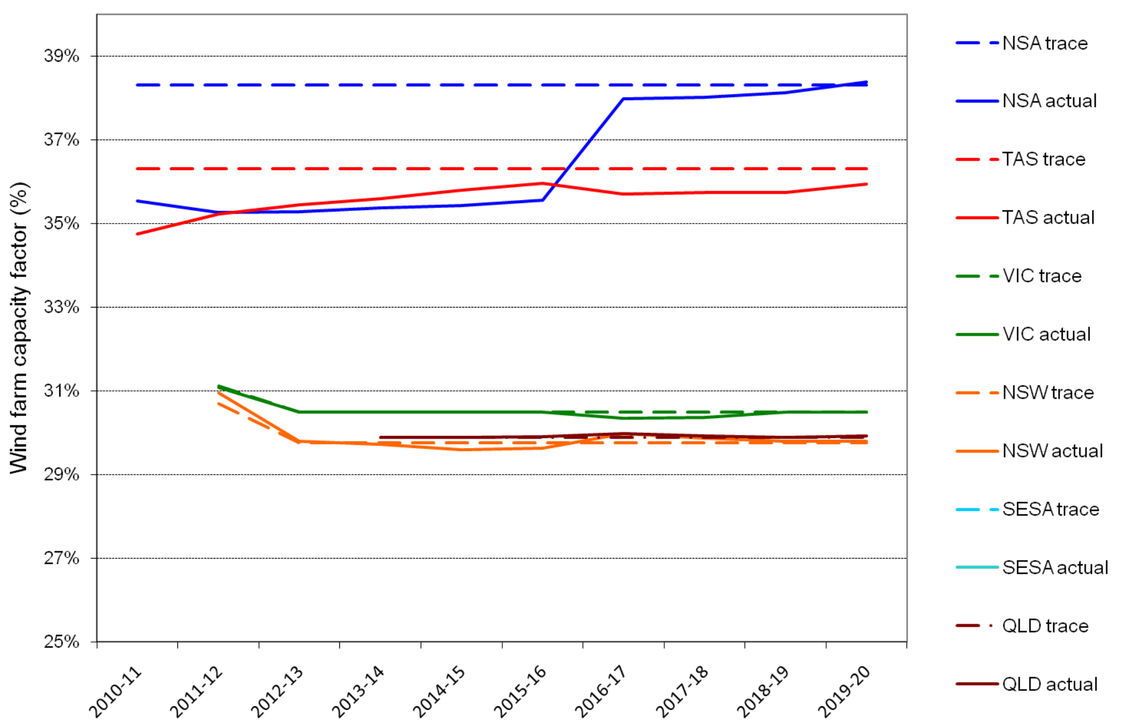
The amount of curtailment is largely independent of the amount of RECs banking.

Figure 6.37 – Wind farm curtailment – Low banking – Scenario C



Where there are multiple new entry wind farms in a zone over the study period, the capacity factor is the average of all wind farms in the zone that have entered.

Figure 6.38 – Wind farm curtailment – High banking – Scenario C



The figures below illustrate the change in wind farm congestion over the course of the study, with comparison to the amount of renewable energy that is installed. As increasing amounts of wind in each zone enter the market, wind farm capacity factors are depressed. This is offset by growing load in each zone. The SA-VIC transmission augmentation in 2016-17 also causes a dramatic increase in capacity factor for NSA wind farms, illustrating the value of this interconnector.

Figure 6.39 – Wind farm curtailment vs capacity – Low banking – Scenario C

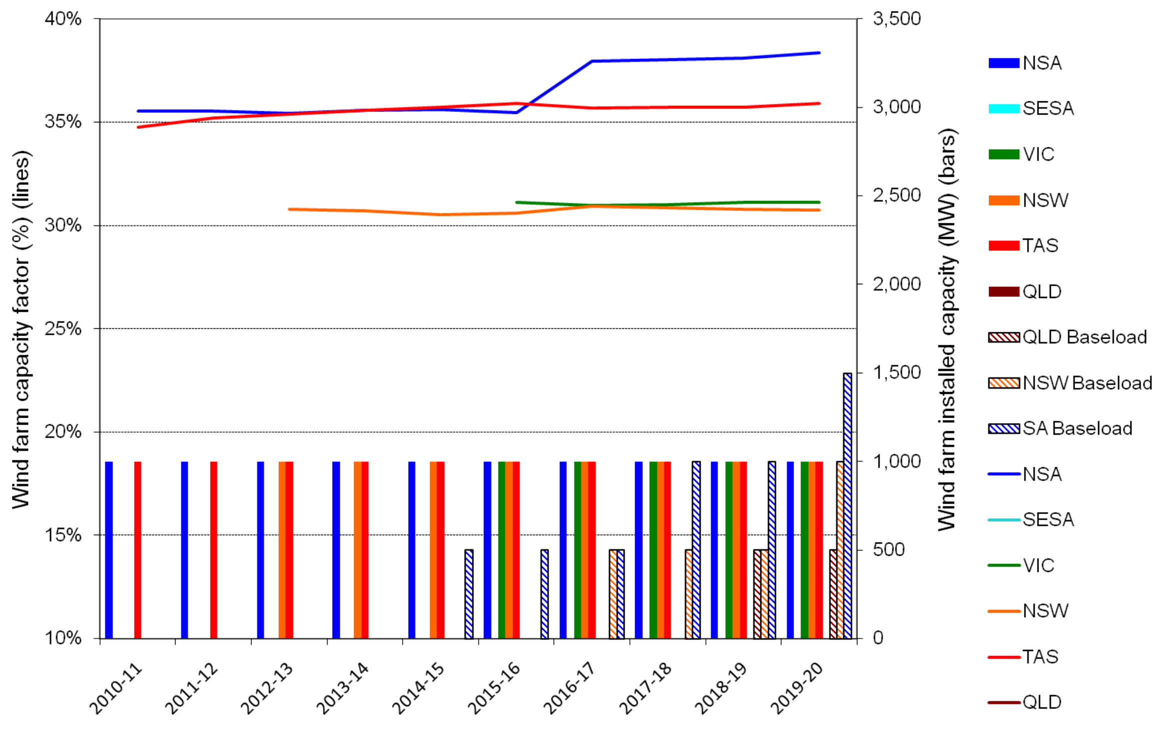
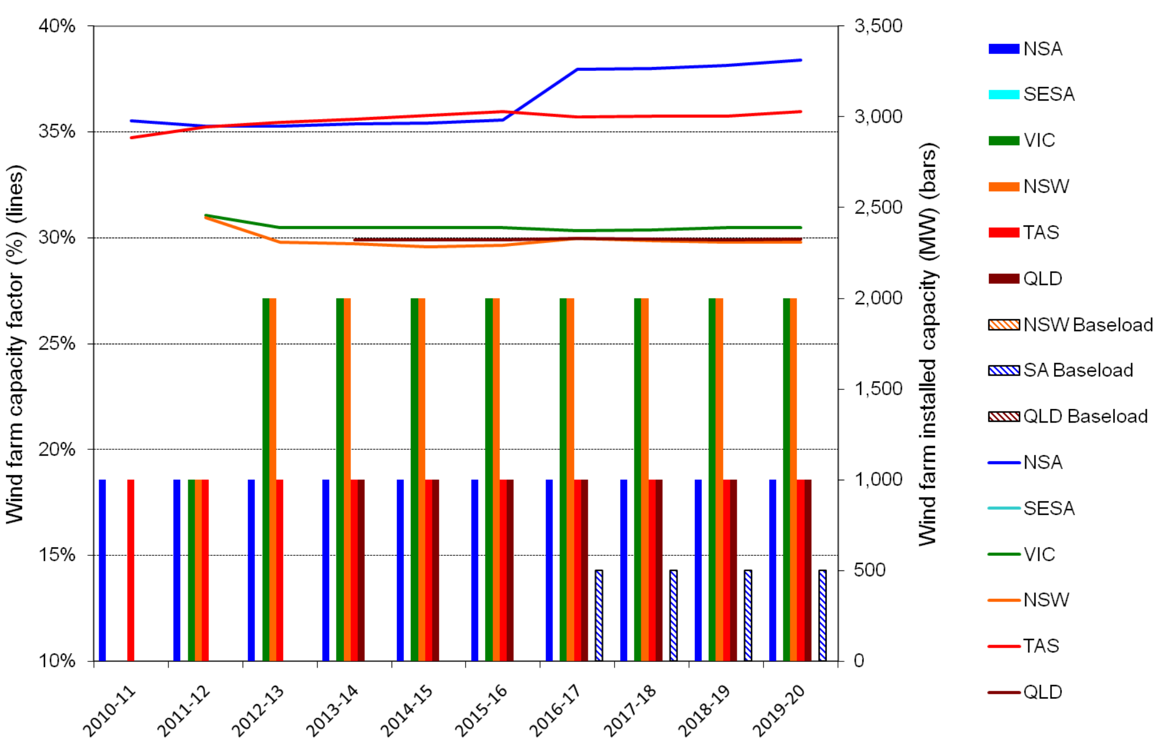


Figure 6.40 – Wind farm curtailment vs capacity – High banking – Scenario C



Operational mode of plants

Many plants are expected to undergo a change of operational mode under the CPRS and RET schemes. An analysis of ROAM's modelling outcomes on a time sequential basis in a late year of the study (2017-18) over the summer period (high demands) yielded the operational details described below.

These charts illustrate a single week from the summer of 2017-18, but the full time sequential data is available. The modelling reported here included time sequential modelling at hourly intervals for the full ten year period.

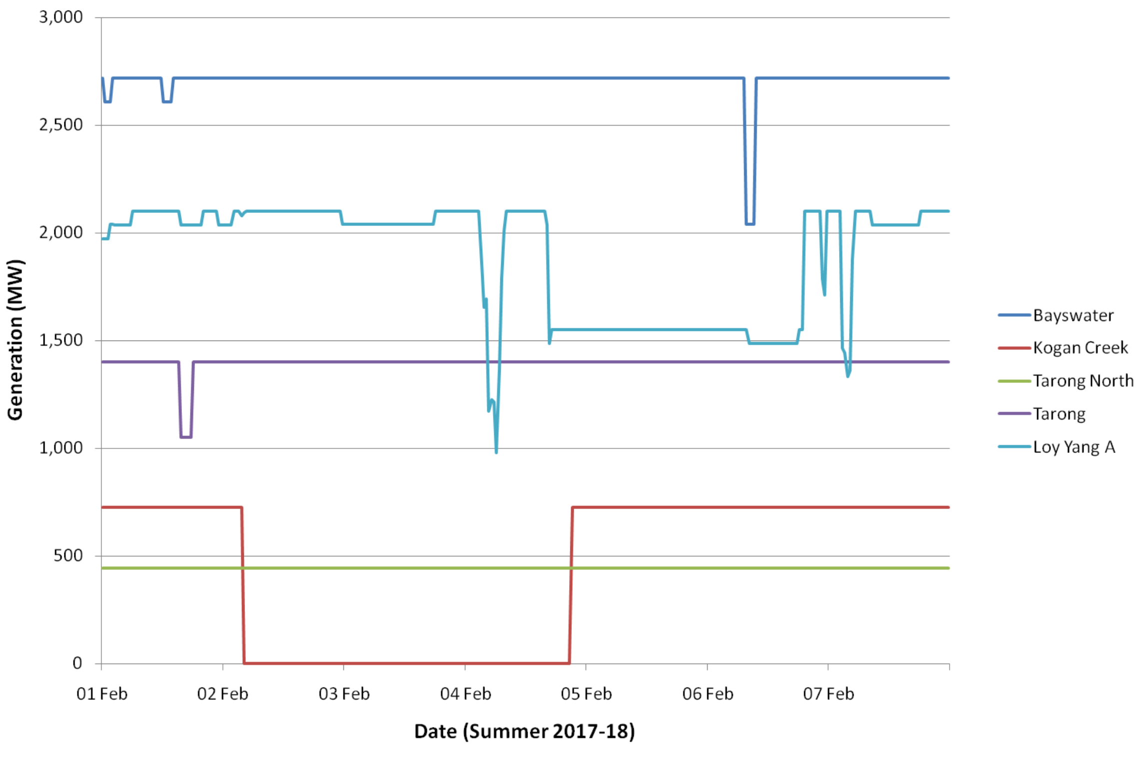
Coal fired plant

In the Australian NEM, all coal-fired generators in Victoria operate on brown coal, with all other regions being black coal power stations. Some coal-fired plant (typically the least emissions intensive) maintain close to full capacity generation, even with high penetration of renewable energy and the relatively high carbon prices in the late years of the study. Coal-fired generators exhibiting this behaviour in the study included:

- Bayswater (NSW)
- Kogan Creek (QLD)
- Tarong North (QLD)
- Tarong (QLD)
- Loy Yang A (VIC)

The time sequential operation of these plants over a week in the summer of 2017-18 is illustrated in Figure 6.41. The data show is for the high banking case (Scenario C), but is very similar for all cases and scenarios considered in this study, due to the similar modelling of the CPRS scheme across all scenarios and cases.

Figure 6.41 – Coal-fired plants (full capacity operation) – 2017-18



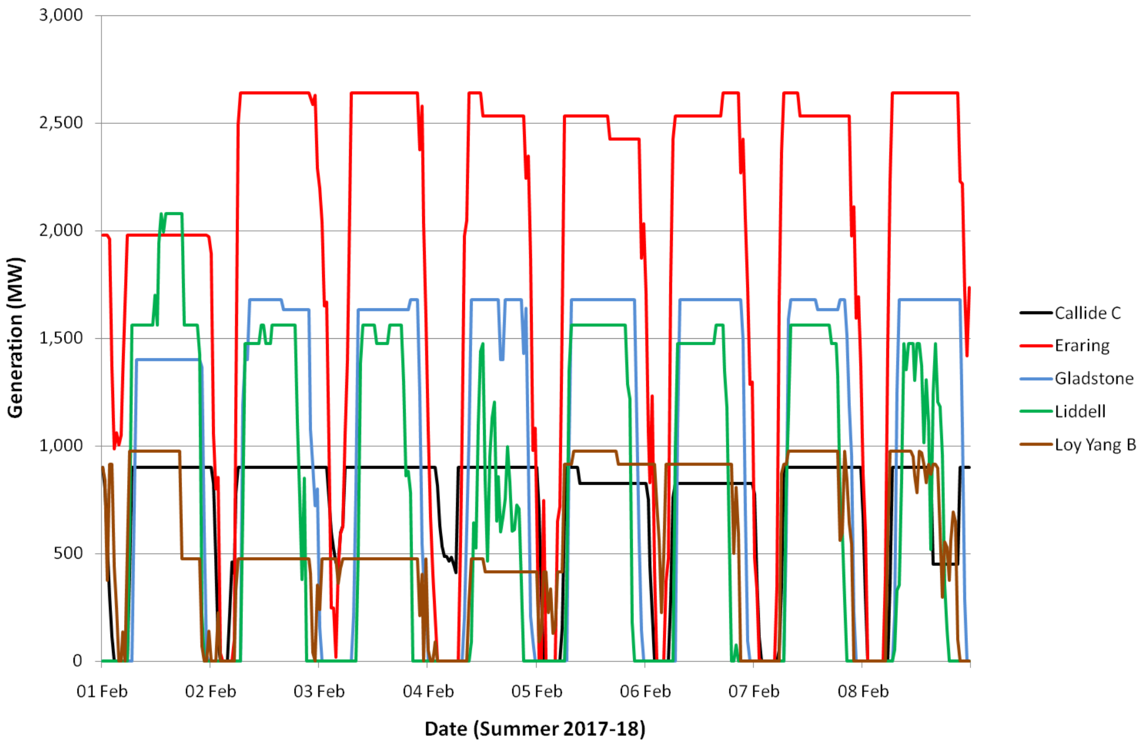
Kogan Creek experiences a forced outage during this period. Of the plants illustrated in Figure 6.41, Loy Yang A is the most impacted in operation by the CPRS and RET, due to its higher emissions factor (being a brown coal plant), and the high quantity of wind installed in Victoria over the course of the study (especially in the high banking case). Nevertheless, since it is one of the lowest emissions baseload plants in Victoria, it maintains high volumes (especially over the summer period).

Other coal-fired generators exhibit cycling behaviour throughout the day, even during the summer period. This typically occurs for more emissions intensive or older plants. Coal-fired generators exhibiting cycling behaviour in the study included:

- Callide B and C (QLD)
- Gladstone (QLD)
- Stanwell (QLD)
- Swanbank B (QLD)
- Eraring (NSW)
- Liddell (NSW)
- Wallerawang (NSW)
- Loy Yang B (VIC)
- Yallourn (VIC)
- Hazelwood (VIC)

A selection of generators which cycle are illustrated in Figure 6.42 below.

Figure 6.42 – Coal-fired plants (daily cycling operation) – 2017-18



Loy Yang A fares better than Loy Yang B due to a combination of relatively small differences in generator data, as illustrated in Table 6.12 below The higher fuel cost, fixed O&M and emissions factor at Loy Yang B produce a measurably higher short run marginal cost, leading to reduced dispatch compared with Loy Yang A.

Table 6.12 – Input assumptions (Loy Yang A and B)[25]			
		Loy Yang A	**Loy Yang B**
Auxiliary Factor	(%)	9%	7.5%
Heat Rate	(GJ/MWh)	12.04	12.52
Fuel cost	($/GJ)	0.08	0.37
Fixed O&M	($/MWh)	1.08	1.10
Emissions factor	(tCO_2/MWh)	1.11	1.15
SRMC (2010-11)	($/MWh)	30.46	34.97
SRMC (2014-15)		38.47	43.16
SRMC (2019-20)		68.58	73.94

CCGT plant

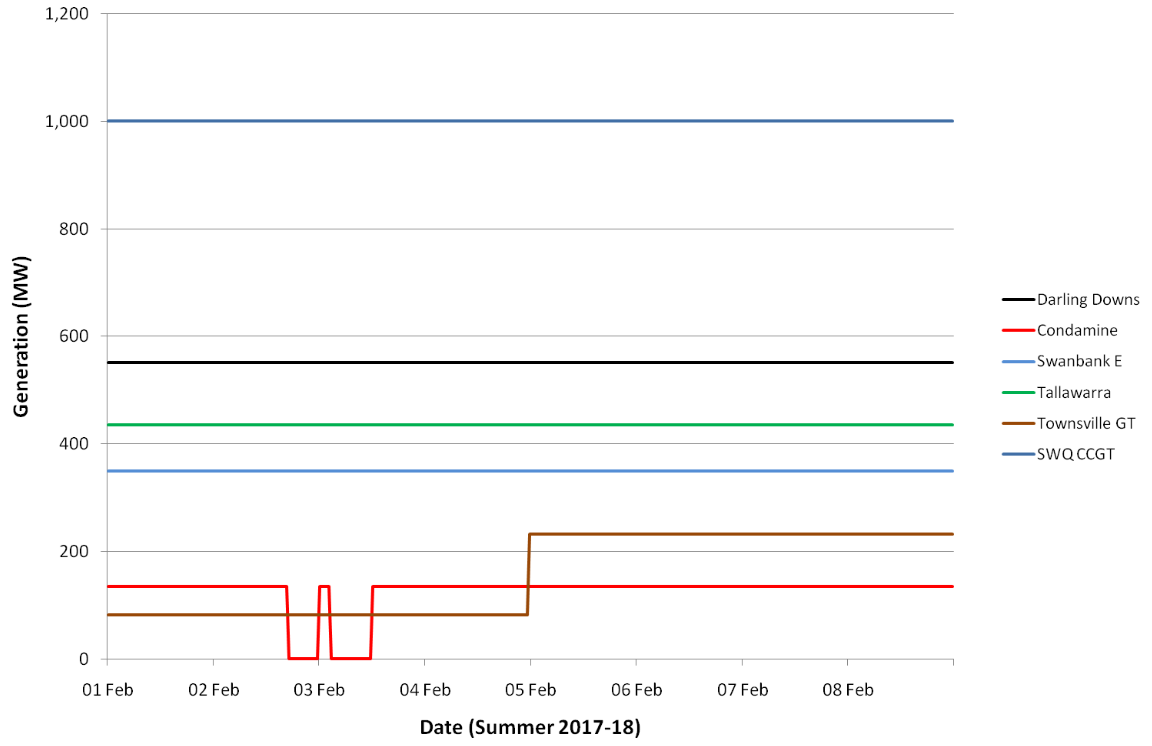
Most CCGT plant runs at close to full capacity generation. CCGT generators exhibiting this behaviour include:

- Darling Downs (QLD)
- Condamine (QLD)
- Swanbank E (QLD)
- Tallawarra (NSW)
- Townsville GT (QLD)
- SWQ CCGT (QLD) (new plant)

These are illustrated in Figure 6.43 below.

[25] Sourced from ACIL Tasman, “Fuel resource, new entry and generation costs in the NEM: draft report”, 13 Feb 2009.

Figure 6.43 – CCGT plants – 2017-18



OCGT plant

OCGT plant takes on a peaking role in the electricity market, only operating due to extremely high demands experienced during high or low temperatures or in response to unplanned outages of other generators or transmission lines. OCGT plant typically operates for less than 5% of the time.

With increased penetration of intermittent wind generation and gradual depletion of significant generation reserves due to demand growth over the period, OCGT plant is observed to increase in operation by between two to three times. In absolute cost and energy supply terms this remains relatively small compared to the total cost of the system, however it does highlight the possibility for an increased role for peaking generation capacity to support the higher levels of intermittent (non-schedulable) generation.

Renewable plant

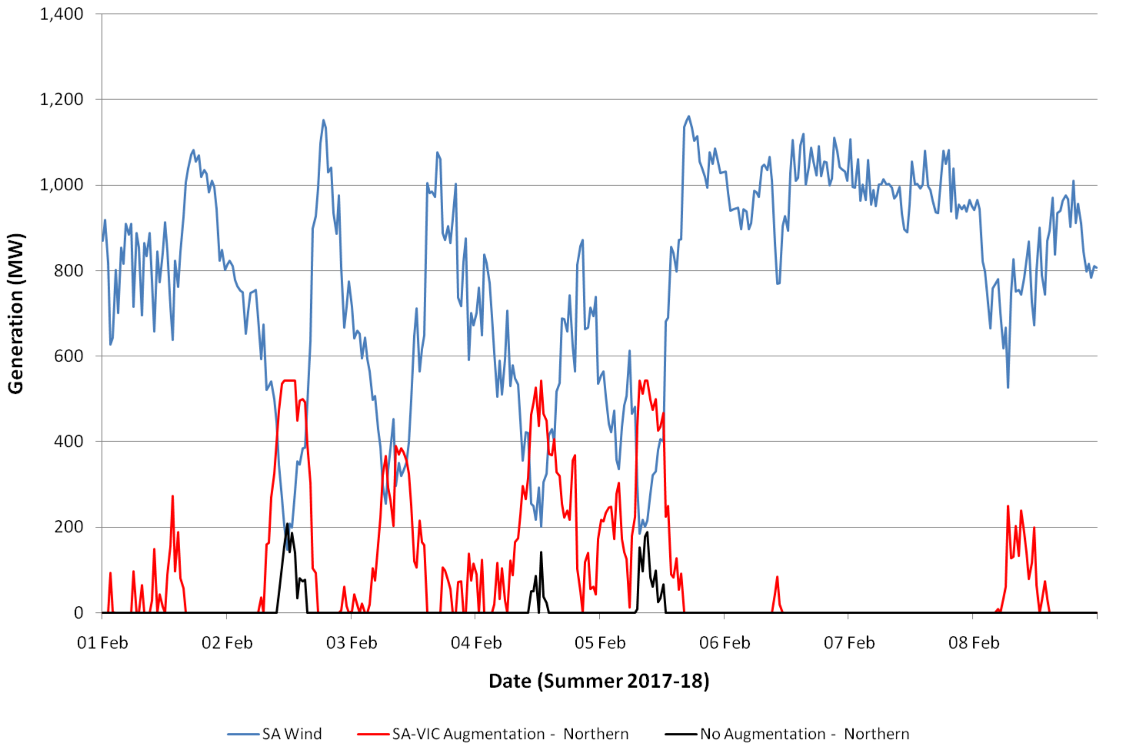
Existing hydro, wind and biomass fuelled generation behaviour and production levels are assumed to remain stable throughout the modelling outlook. These plant will not be significantly influenced by the introduction of CPRS or RET as they have a very low marginal cost and are emissions neutral. Both existing and new entry renewable generation is expected to match generation levels commensurate with their local resource capability unless they are unable to be dispatched to their desired level due to binding transmission limitations.

Transmission congestion in South Australia

The behaviour of South Australian plant is particularly interesting, given the small load and high proportional penetration of wind in this region.

Thermal plant in SA is strongly affected. Thomas Playford and Torrens Island A do not operate at all in the summer week under analysis, despite aggregated SA wind outputs as low as 200MW during some periods. (Their short run marginal costs exceed $100/MWh in this year, making them uncompetitive against SA geothermal and Victorian imports) Northern is also strongly affected, as illustrated in Figure 6.44. Northern only operates during periods of low wind, and is barely operational at all in the absence of the SA-VIC interconnector augmentation. This is due to a transmission limit from NSA-ADE, preventing generators in NSA (such as Northern and Thomas Playford) from supplying the ADE zone. The SA-VIC interconnector augmentation includes a 400MW increase in the transmission limit from NSA to ADE, which allows Northern to increase generation when the SA-VIC augmentation is installed.

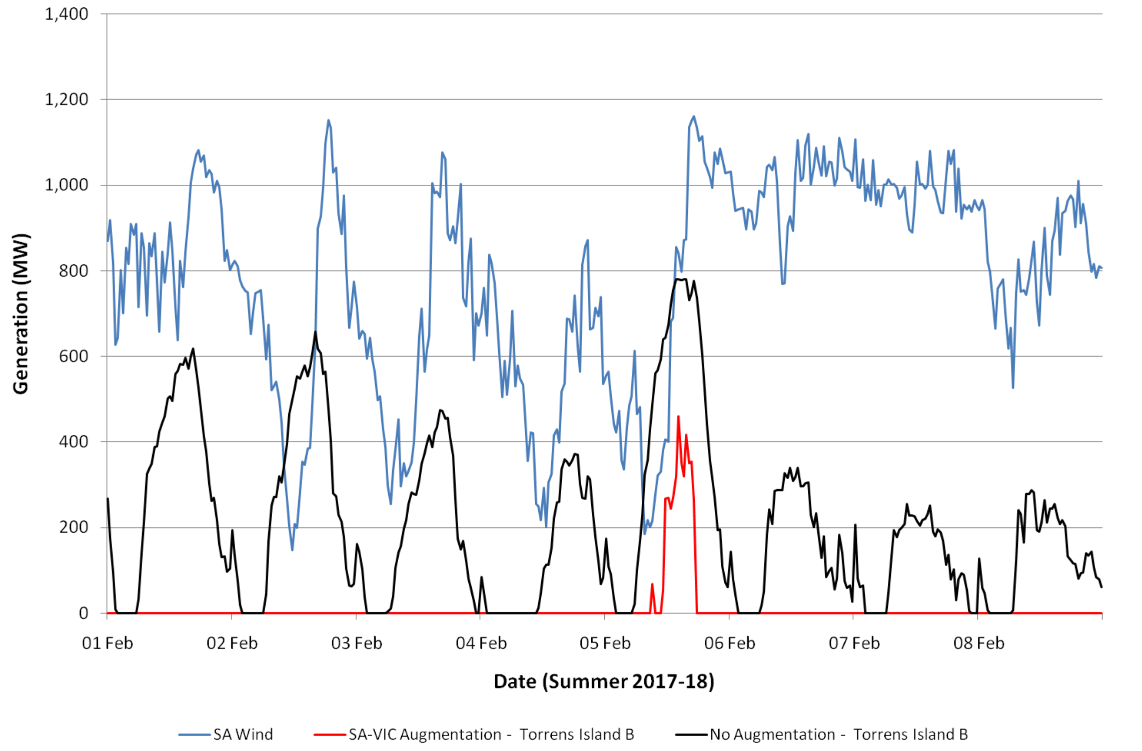
Figure 6.44 – Operation of Northern compared with SA wind[26]



Torrens Island B is located in the ADE zone, and therefore exhibits the opposite behaviour, as illustrated in Figure 6.45. Without the SA-VIC augmentation increasing the NSA-ADE limit, Torrens Island B is required to operate (in a daily cycling fashion) to supply the ADE load. When the SA-VIC interconnector is installed, increasing the NSA-ADE limit, plants in NSA (such as Northern) undercut Torrens Island B, reducing its output.

[26] Results shown are for the low banking case.

Figure 6.45 – Operation of Torrens Island B compared with SA wind[27]

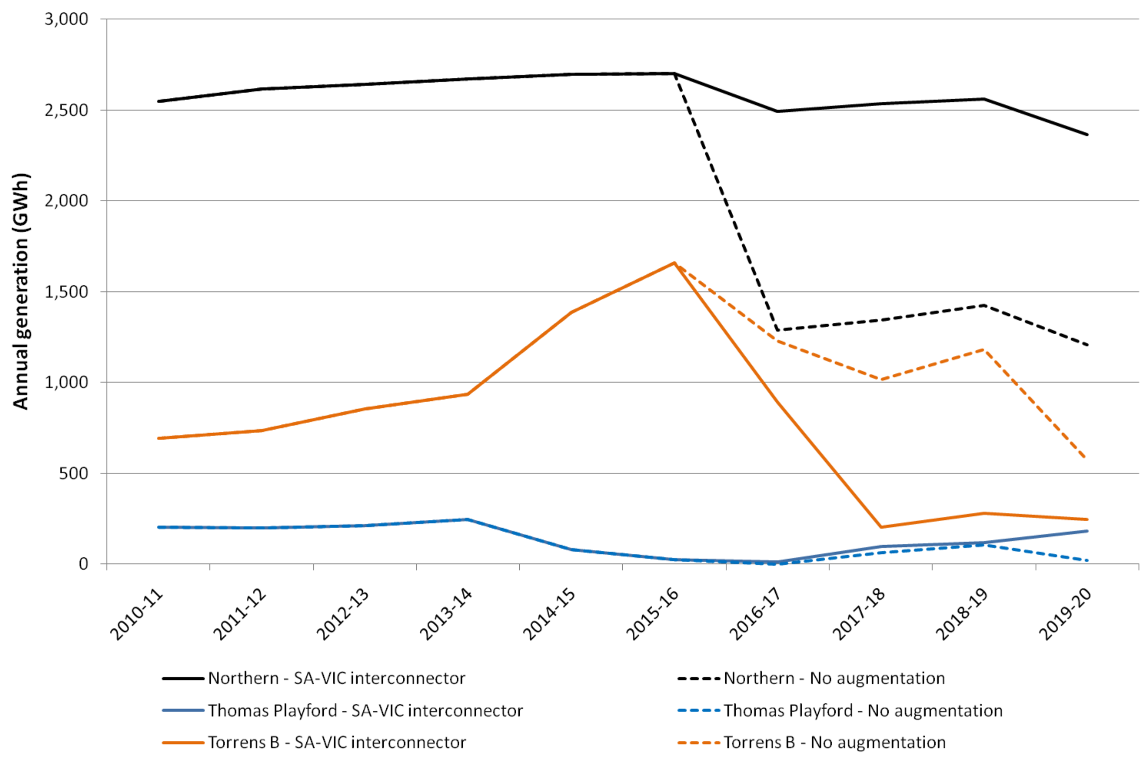


These behaviours are illustrated in annual generation terms in Figure 6.46. In the absence of the SA-VIC interconnector augmentation, generation at Northern plummets in 2016-17, due to the installation of the 500MW geothermal plant in NSA. The very low short run marginal cost of the geothermal generation undercuts the fossil fuel generators located in NSA (Northern and Thomas Playford). Torrens Island B exhibits the opposite behaviour, being located in the ADE zone, and therefore achieving significantly higher volumes in the absence of the SA-VIC interconnector, since it cannot be undercut by lower cost generators in NSA due to intra-regional transmission constraints.

Aside from the economic issues that these fossil-fuel generators in South Australia will face with such dramatic volume reductions, there may be significant technical issues with erratic and reduced dispatch. The implications of dispatch at such low levels must be considered on an individual basis for these fossil-fuel generators, to investigate these technical barriers.

[27] Results shown are for the low banking case.

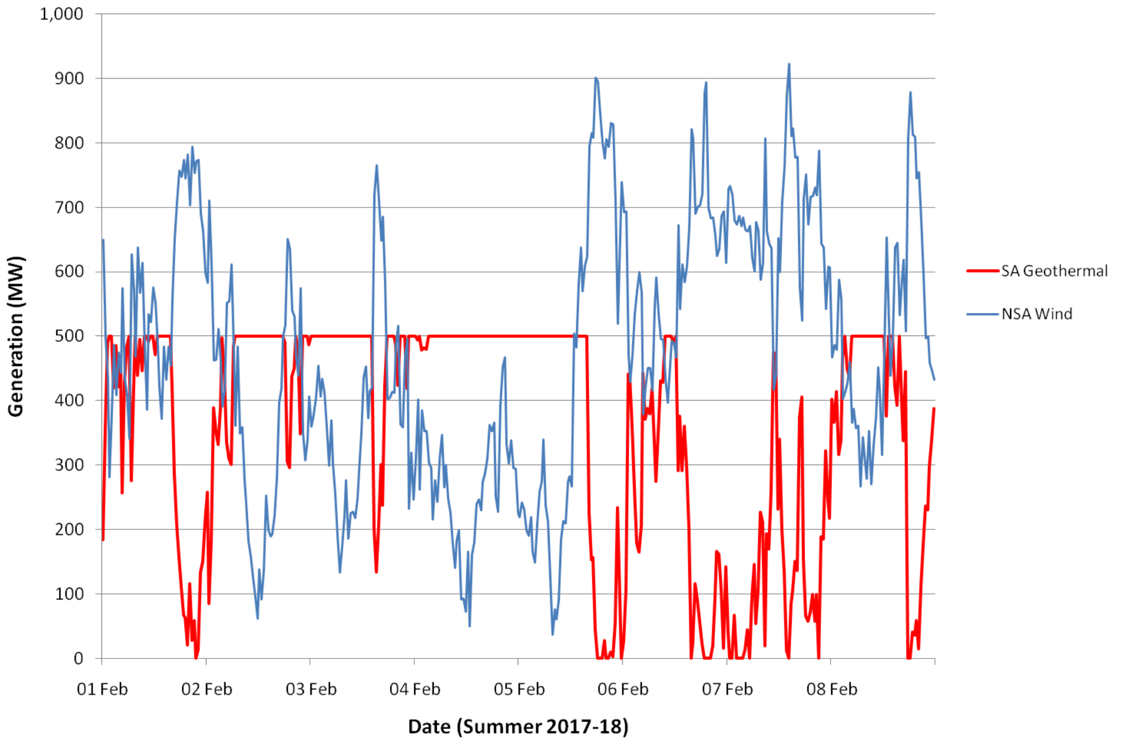
Figure 6.46 – Annual generation of SA fossil-fuel generators[28]



Despite its very low short run marginal cost, even the South Australian geothermal plant (committed in the study in 2016-17) is strongly affected by the wind generation in South Australia, showing strong curtailment at times of high wind generation, as illustrated in Figure 6.47.

[28] Results shown are for the low banking case.

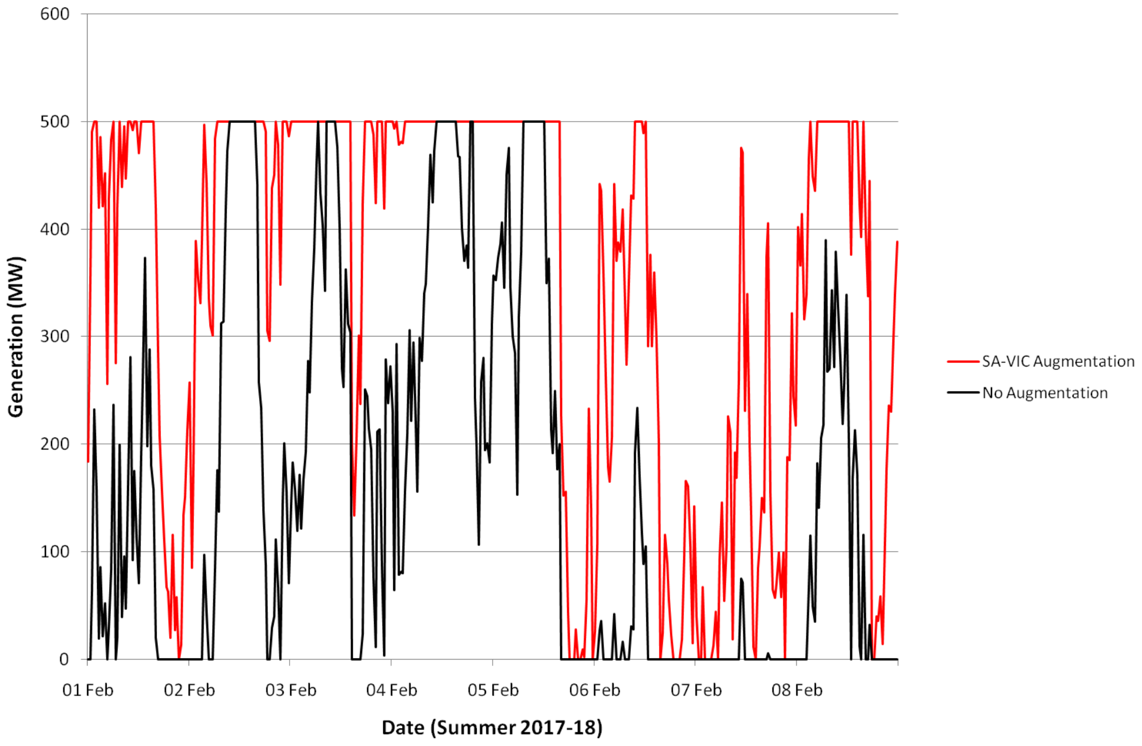
Figure 6.47 – Operation of SA Geothermal plant compared with NSA wind[29]



In the absence of the SA-VIC interconnector augmentation, the curtailment of the SA geothermal plant (located in NSA) is much more severe, similar to the operational impacts on Northern. This is illustrated in Figure 6.48, and demonstrates the value of the SA-VIC interconnector upgrade.

[29] Results shown are for the low banking case.

Figure 6.48 – Operation of SA geothermal plant[30]



Binding transmission constraints

This section investigates the ANTS transmission constraint equations that bound significantly throughout the course of the study for Scenario C. The table below gives the name of the constraint, a description of what it is, and a discussion of why the constraint bound.

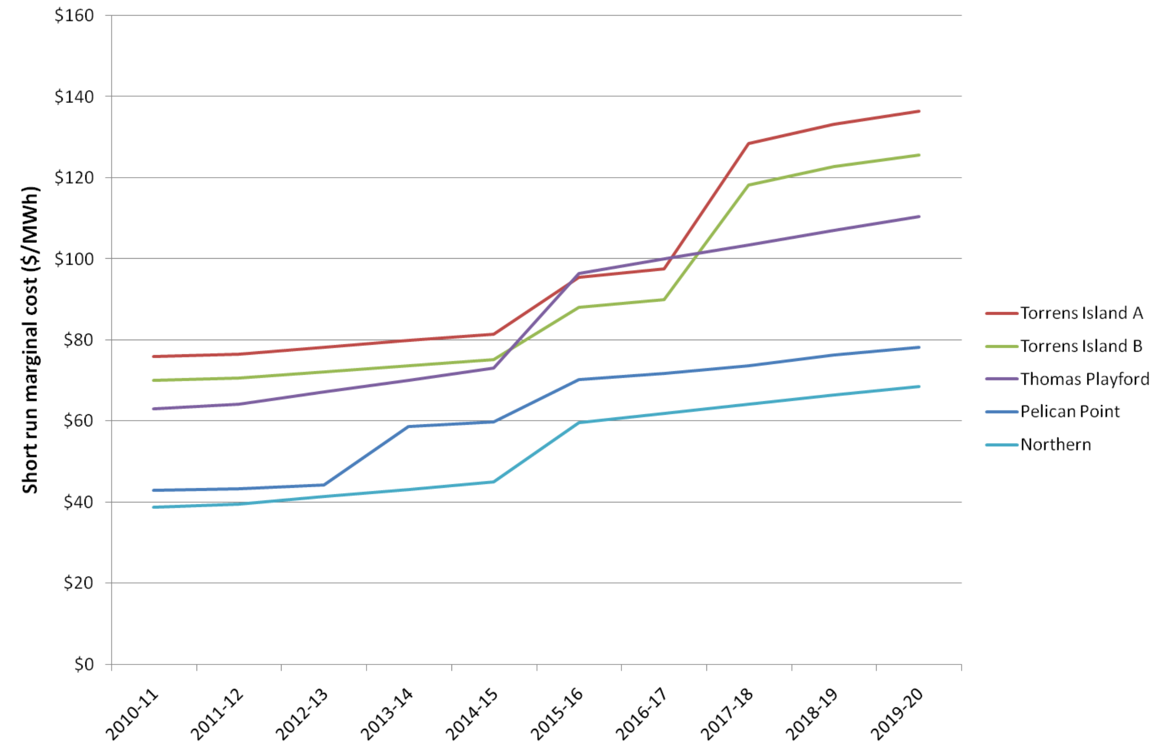
Table 6.13 – Significant binding transmission constraints – Scenario C
Constraint name: S>>V_NIL_BRPA_MNWT
General description: $\text{NSA Generation} - \text{Murraylink} \leq 1000$ *Avoid overload of Mintaro to Waterloo 132 kV line on trip of Brinkworth to Para 275kV line*
S>>V_NIL_BRPA_MNWT limits transfer across the NSA-ADE flow path by constraining NSA generation and Murraylink. NSA generation primarily consists of Northern power station, Thomas Playford power station, approximately 1000MW of new entry wind farms and 500MW of geothermal from 2016-17 onwards.   The amount of NSA wind generation is such that plant with relatively higher marginal costs (Northern, Thomas Playford and a small quantity of peaking plant) will not be dispatched outside of low wind conditions and are forced into highly intermittent operating patterns that may not be financially viable.

30 Results shown are for the low banking case, but are very similar for the high banking case.

Table 6.13 – Significant binding transmission constraints – Scenario C
In high wind conditions, even extremely low marginal cost plant in the NSA zone (such as the new entry geothermal) is heavily constrained down without transmission upgrades. Due to the large volume of low marginal cost plant in the NSA zone, Murraylink is regularly constrained towards SA to increase the maximum export from the NSA zone. This constraint was observed to bind for a very high proportion of time (consistently approximately one third of all hourly dispatch intervals for each year) and is an indication of extreme congestion along this flow path. The VIC-SA upgrade selected in scenario C increased the maximum allowable export from the NSA zone, but did not reduce the number of binding periods for this constraint. This is a strong indication that a larger NSA-ADE upgrade may be justified if Northern power station continues to operate and considerable renewable new entry occurs in the zone.
Constraint name: V>>S_NIL_BGPA_BRPA, summer formulation
General description: $\text{NSA Generation} + 0.6\text{Murraylink} \leq 360 + 20\% \text{ of SA regional load}$ *Limit Murraylink and SA generation to avoid overload of Brinkworth-Para 275 kV line for trip of Bungama to Para 275kV line*
Similar to the previous constraint, V>>S_NIL_BGPA_BRPA limits transfer across the NSA-ADE flow path by constraining NSA generation and Murraylink. This constraint is observed to bind for nearly every period in which it is applied. Outcomes for generation are in line with S>>V_NIL_BRPA_MNWT, albeit potentially more extreme in lower load periods. Murraylink however is forced in the opposite direction to S>>V_NIL_BRPA_MNWT. The two opposing limits on Murraylink combine to 'set' the interconnector to a specific value for a large number of periods. This outcome suggests that multiple transmission elements are being operated at their firm capacities for extended periods of time.
Constraint name: V>>S_NIL_BGPA_BRPA, not summer formulation
General description: $\text{NSA Generation} + 0.6\text{Murraylink} \leq 760 + 20\% \text{ of SA regional load}$ *Limit Murraylink and SA generation to avoid overload of Brinkworth-Para 275 kV line for trip of Bungama to Para 275kV line*
Similar to the summer formulation this constraint acts to limit NSA generation and in combination with S>>V_NIL_BRPA_MNWT, heavily restrict Murraylink flow. This constraint binds for approximately one fifth of the periods applied.

Table 6.13 – Significant binding transmission constraints – Scenario C
Constraint name: V::S_NIL
General description: $\text{Heywood} + 0.58\ \text{SESA Wind} \leq {\sim}360 - 400$ *Vic to SA Stability limit for loss of one NPS generator following a 2ph to ground fault*
V::S_NIL limits flow on the SESA to ADE flow path to avoid transient instability on the loss of a Northern power station unit. Given the existing installed capacity of SESA wind and the granularity of the IRP candidate wind farms, this constraint considerably constrains economic entry of any further generation capacity in the SESA zone. It is unclear if this constraint is applicable moving further into the future given a significant change in the operating mode of Northern power station but in the absence of more accurate information, V::S_NIL was applied as per the ANTS formulation. The primary driver for V:S_NIL binding in dispatch however, is related more to trade with Victoria than SESA wind. Even after the effects of the CPRS, Victorian brown coal plant is considerably lower cost than most SA thermal plant – the exceptions being Northern power station and Pelican Point. Northern power station is constrained down heavily throughout the study as discussed above, and Pelican Point undergoes a dramatic fuel price increase from 2013-14 based on the ACIL Tasman source data. This leads to importing power from Victoria being lower cost than most local supply options despite network losses, and thus the interconnector is often dispatched to the physical limit. The result is that V::S_NIL binds significantly (approximately one third of hourly dispatch intervals) until the 2013-14 Pelican Point gas price increase, at which point the constraint starts to bind for the majority of dispatch intervals. Following the increase in the CPRS carbon price in 2015-16, Pelican Point becomes considerably more competitive with Victorian coal, and the time binding drops back to approximately a third of all periods, falling to approximately zero when the VIC-SA interconnector is installed.

Figure 6.49 – Short run marginal costs of South Australian plant (input assumptions)



6.7) Renewable Development in South Australia

Throughout this study, 1000MW of wind was committed in the NSA zone from 2010-11, and a 500MW geothermal station was committed in NSA from 2016-17. This was found to cause significant transmission congestion and fossil fuel plant curtailment in South Australia, and the model did not choose to install any further renewable generation in the NSA zone. For this reason, ROAM conducted a sensitivity where these plants were not committed. Due to time constraints this was only possible for the high banking case, but it provides a comparison to indicate the impact of committing this plant.

It should be noted that these plants were committed because they are considered highly likely in light of the announcements by wind and geothermal proponents. These plants are considered likely to enter the market regardless of transmission congestion issues, although further renewable development beyond those will be heavily dependent upon transmission augmentation in that region.

Planting outcomes

The change in planting outcomes that occurs when the NSA wind and geothermal plants are not committed is illustrated in Table 6.14. The NSA wind farm is still installed in 2010-11, indicating that the very high quality wind resource in this zone leads to sufficiently high capacity factors to drive wind investment in that zone. This is sufficient to offset the reductions in capacity factor due to transmission congestion. ROAM therefore considers the commitment of this plant throughout this study to be justified on an economic basis, in addition to being likely due to proponents announcements.

Table 6.14 – Summary of planting outcomes (Scenario C, High banking)[31]
New entry wind, schedulable renewable, gas, committed plant and transmission augmentations

	With NSA plants committed	Without NSA plants committed
2010-11	NSA Wind TAS Wind	NSA Wind TAS Wind
2011-12	NSW Wind VIC Wind	NSW Wind VIC Wind
2012-13	SWQ CCGT NCEN OCGT NSW Wind VIC Wind	SWQ CCGT NCEN OCGT NSW Wind QLD Wind
2013-14	QLD Wind	QLD Wind VIC Wind
2014-15	Munmorah retires	Munmorah retires QLD Bagasse
2015-16	-	-
2016-17	SA-VIC Aug NSA Geothermal	SA-VIC Aug
2017-18	MEL CCGT	MEL CCGT
2018-19	SWQ CCGT	-
2019-20	-	SWQ CCGT

The NSA geothermal plant committed in 2016-17 is not installed in the case where it is not committed. Instead, a Queensland biomass plant enters in 2014-15. This is because a slightly higher level of banking is possible when the NSA geothermal plant is not committed, allowing earlier entry of an additional wind farm, and the QLD bagasse plant. This makes the installation of the NSA geothermal plant impossible, due to the modelling constraints, without exceeding the RET scheme requirements (economically unviable).

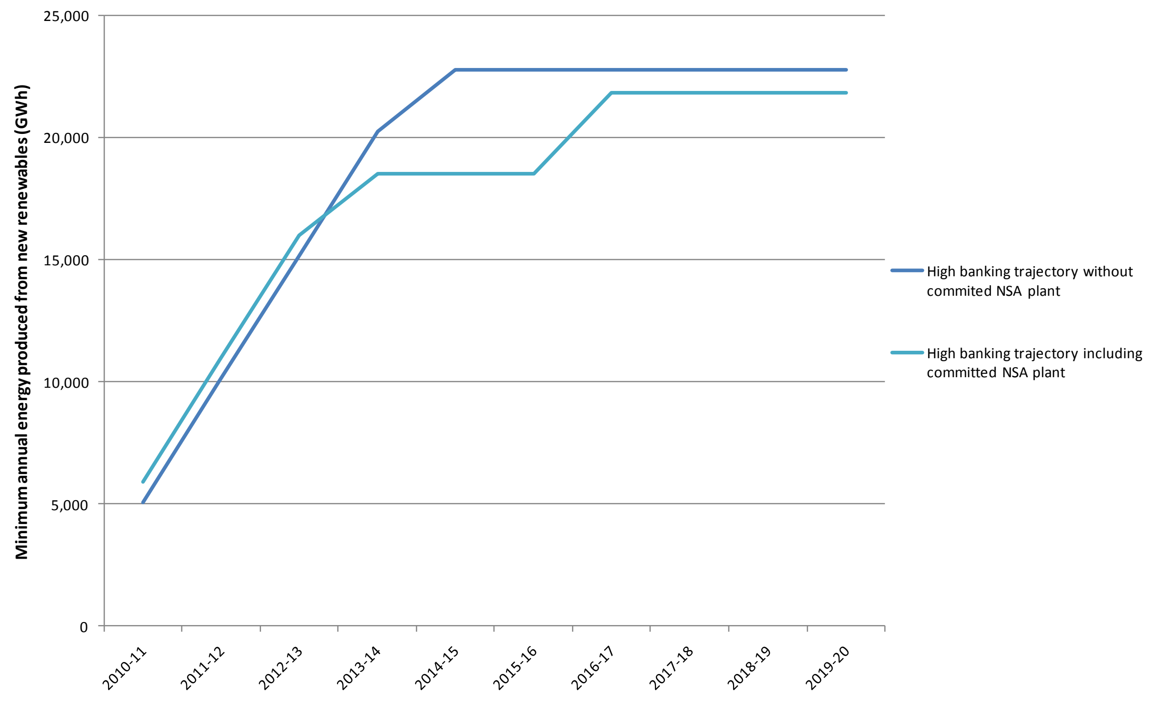
Because the schedulable renewable plant enters in Queensland (instead of the NSA geothermal plant) the SWQ CCGT can be delayed by one year (to reduce costs).

---

[31] Wind plants are 1000 MW in size, CCGT and OCGT plants are 1000 MW (500 MW in SA), schedulable renewable plants are 500 MW.

Figure 6.50 below shows the minimum GWh of energy produced by new renewable generators in the model, with and without the NSA plant being committed.

Figure 6.50 –High banking REC production trajectories (with and without NSA plant committed)



Costs

The higher levels of REC banking investigated when the NSA plant is not committed costs the system $377 mil over the study period. Despite emissions costs being reduced by $429 mil, this is insufficient to make up for the additional capital expenditure (at the carbon prices in the model). The breakdown of this cost difference is given in Table 6.15.

Table 6.15 – Cost comparisons (cumulative cost 2010-11 to 2019-20, $ mil)

		Difference in cost between Scenario C cases with and without committed NSA plant
High banking	Total cost of scenario	377
	Cost excluding emissions cost	807
	Emissions cost	-429

Augmentation cost effectiveness

Despite the fact that the NSA geothermal plant is not installed, the SA-VIC interconnector augmentation is still installed in 2016-17. This suggests that the SA-VIC interconnector augmentation is cost effective even without the 500MW geothermal plant in NSA.

The cost effectiveness of the SA-VIC augmentation in the absence of the committed NSA geothermal plant is illustrated in Table 6.16, compared with the case where the NSA geothermal plant is committed in 2016-17. The value of the augmentation is clearly significantly larger when the NSA geothermal plant is installed, but is cost effective from 2016-17 even in its absence.

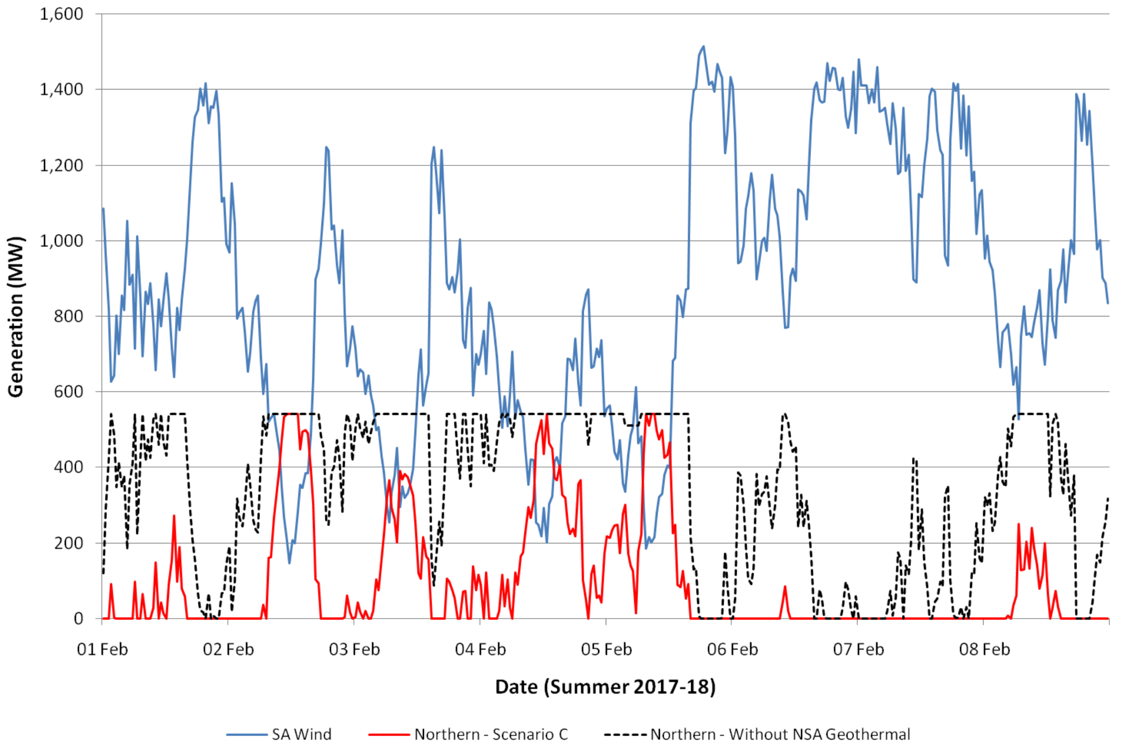
Table 6.16 – SA-VIC interconnector augmentation (high banking)		
% of total annualised cost of augmentation recovered by reduced system costs		
	Without committed NSA plant	Scenario C, with committed NSA plant
2010-11	-	70.1%
2011-12	-	70.2%
2012-13	-	73.8%
2013-14	-	98.5%
2014-15	-	101.5%
2015-16	-	97.2%
2016-17	137.9%	254.0%
2017-18	155.0%	291.8%
2018-19	159.3%	308.4%
2019-20	163.0%	344.7%

The cost analysis results throughout this report should be interpreted on the understanding that if this geothermal plant is not installed, the cost effectiveness of the SA-VIC augmentation may vary. However, these results suggest that the augmentation is justified, even in the absence of committed NSA plant.

Operational modes – South Australian fossil fuel plant

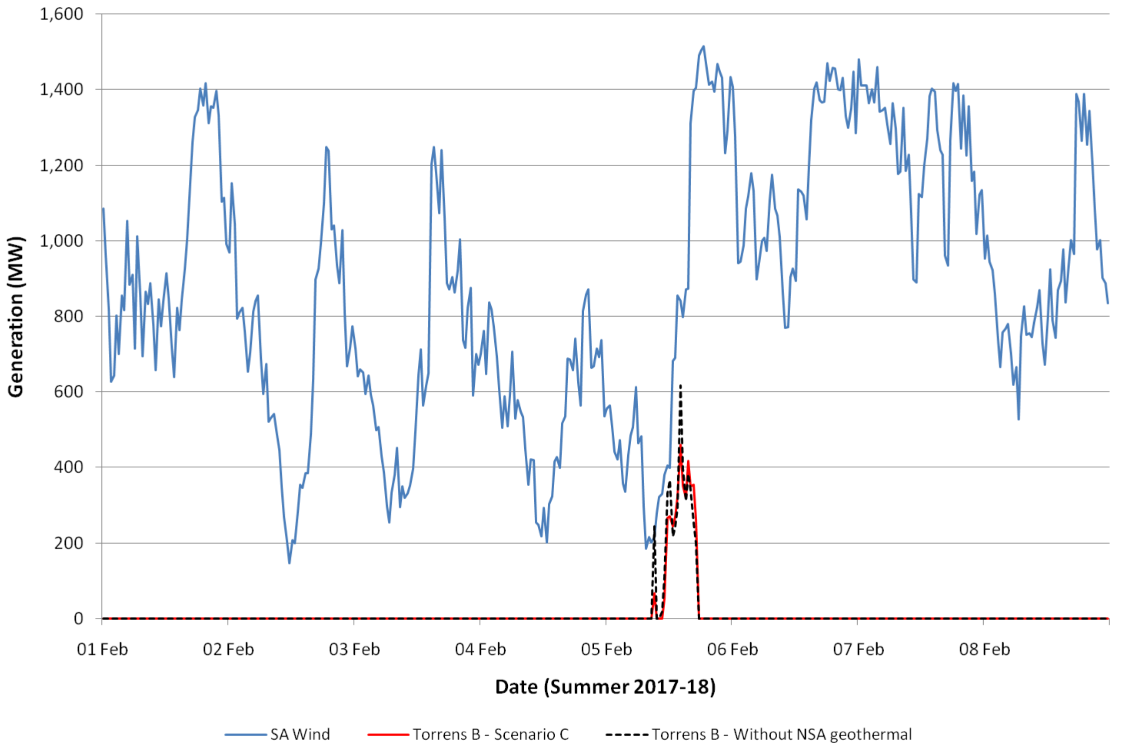
The figures below illustrate the impacts of the absence of the NSA geothermal plant on the summer operation of fossil fuel plants in South Australia. Northern (Figure 6.51) shows increased generation, since it is no longer being undercut by the NSA geothermal plant. The SA-VIC interconnector augmentation (also present in Scenario C) assists further by relieving congestion between NSA and ADE, and allowing NSA plant to undercut more expensive plant in ADE. Notably, Northern still exhibits erratic dispatch in response to the South Australian wind profile, and even in this case may experience technical difficulties with operating in this fashion.

Figure 6.51 – Summer operation of Northern (high banking)



The operation of Torrens Island B (Figure 6.52) is heavily dependent upon the SA-VIC augmentation, and hence is very similar to the Scenario C case (regardless of the presence of the NSA geothermal plant). With the SA-VIC augmentation it can be undercut by all the lower SRMC plant in NSA, so the presence or absence of the NSA geothermal plant is not relevant to Torrens B.

Figure 6.52 – Summer operation of Torrens Island B (high banking)



Implications for this study

The changed planting result when the NSA geothermal plant is not committed has implications for the interpretation of the results in this study. If the NSA geothermal plant is likely to be installed regardless of transmission congestion issues (perhaps as a demonstration plant for the technology), then the results may be interpreted as presented. However, if transmission congestion issues are likely to prevent the entry of the NSA geothermal plant, or cause it to connect to the transmission grid in another zone, then the cost analysis of transmission augmentations, most particularly those located in South Australia, will be affected. Nevertheless, under the assumptions in this study, the SA-VIC interconnector provides a net positive benefit from 2016-17 to the end of the study, independent of the commitment of the NSA geothermal plant.

7) Scenario A: Non-responsive transmission

Scenario description

Generators make profit-maximising entry and exit decisions in the knowledge that transmission investment was limited to the bare minimum consistent with meeting mandatory obligations. The level of transmission investment reflects the bare minimum required to continue meeting NEM demand and the expanded RET targets.

Scenario treatment in ROAM's IRP model

This scenario was modelled in ROAM's IRP by determining the path which maximises over the study period the total profit of new entry, non-committed generators within the constraints placed on installed capacity and renewable capacity. The total profit is given by the sum of the following for each new entry, non-committed generator:

$$\text{Pool price revenue} + \text{REC price} \times \text{Renewable generation} - (\text{Fixed O\&M} + \text{Run cost} + \text{Annualised capital costs})$$

The REC price was assumed to be \$40/MWh throughout the study, and was only applied to renewable generators. Sensitivity to REC price was investigated; prices in the range \$40 to \$60/MWh did not impact on the planting results. The outcome is therefore considered to be reasonably robust to RECs price.

It should be noted that under both high and low banking, the amount of renewable generation is tightly constrained to meet or just exceed the relevant REC trajectory. Thus the inclusion of the REC price in the calculation of profit is used to trade-off pool price revenue against REC revenue for renewable projects. For instance, this is used to compare the relative merits of a high capacity factor wind farm located in a region with low pool prices against a lower capacity factor wind farm in a region with high pool prices. It neither incentivises nor discourages renewable generators to enter the market above or below the target REC trajectory; the amount of renewable generation is specified by the pre-defined constraints placed on development paths.

It should also be noted that this profit maximisation methodology maximises total profit from a holistic point of view. Decision making remains from the point of view of a central planner with perfect foresight, who seeks to maximise total profits of new entry, non-committed plant (rather than minimise total system costs, as for Scenario C). Alternatively, this approach can be interpreted as all new entry, non-committed plant belonging to a single new investment portfolio, which is seeking to maximise its profits at the expense of existing and committed plant. This is not a likely pattern of investment, and it is likely to produce a different outcome to a methodology where individual stations make entry decisions to maximise their individual profits, or where they are built as part of existing portfolios. Furthermore, the assumption that agents have perfect foresight over the study period is unrealistic.

It was found that major interconnector augmentations were not necessary to meet mandatory obligations, NEM demand or the expanded RET targets over the study timeframe. In this scenario, the model could not choose any interconnector augmentations (to reflect this "non-responsive transmission"). New-entry non-committed generator profits were maximised with knowledge that transmission would not be upgraded.

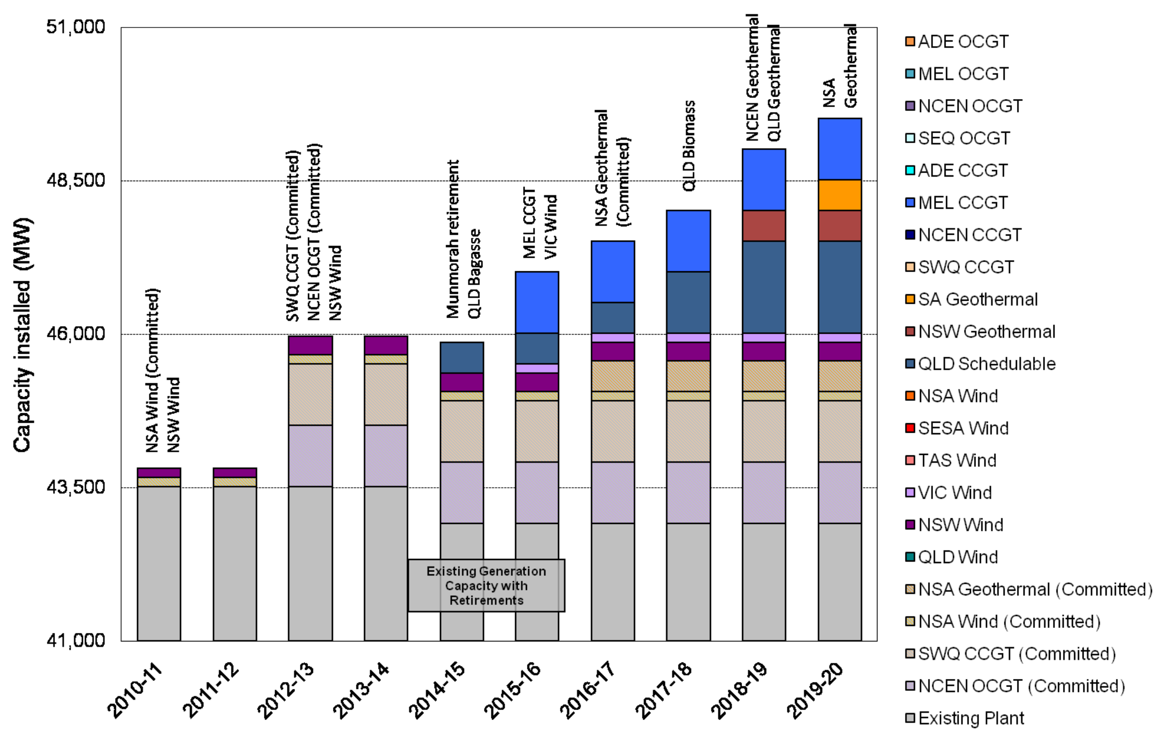
7.1) RESULTS

Planting outcomes

Applying this methodology to the IRP yields the planting outcome for Scenario A shown in Figure 7.1 (low banking) and Figure 7.2 (high banking)[32]. These are tabulated in Table 7.1, compared with Scenario C.

Of these two cases, the low banking case produces the maximum profit, and is therefore ROAM's proposed solution to Scenario A. Results from the high banking case are also included for comparison, to illustrate the impacts to the system if the drivers under the RET scheme produce a high banking outcome, regardless of holistic profit maximisation.

Figure 7.1 – Planting outcome – Scenario A (Low banking)



---

[32] In the planting outcome charts, the capacity of each plant shown is its contribution (in MW) to peak demand. 1000MW wind farm developments are attributed 150MW contribution to peak demand due to their intermittent nature. All other plant in this study is assumed to be fully schedulable and therefore able to provide their full capacity at time of peak demand.

Figure 7.2 – Planting outcome – Scenario A (High banking)

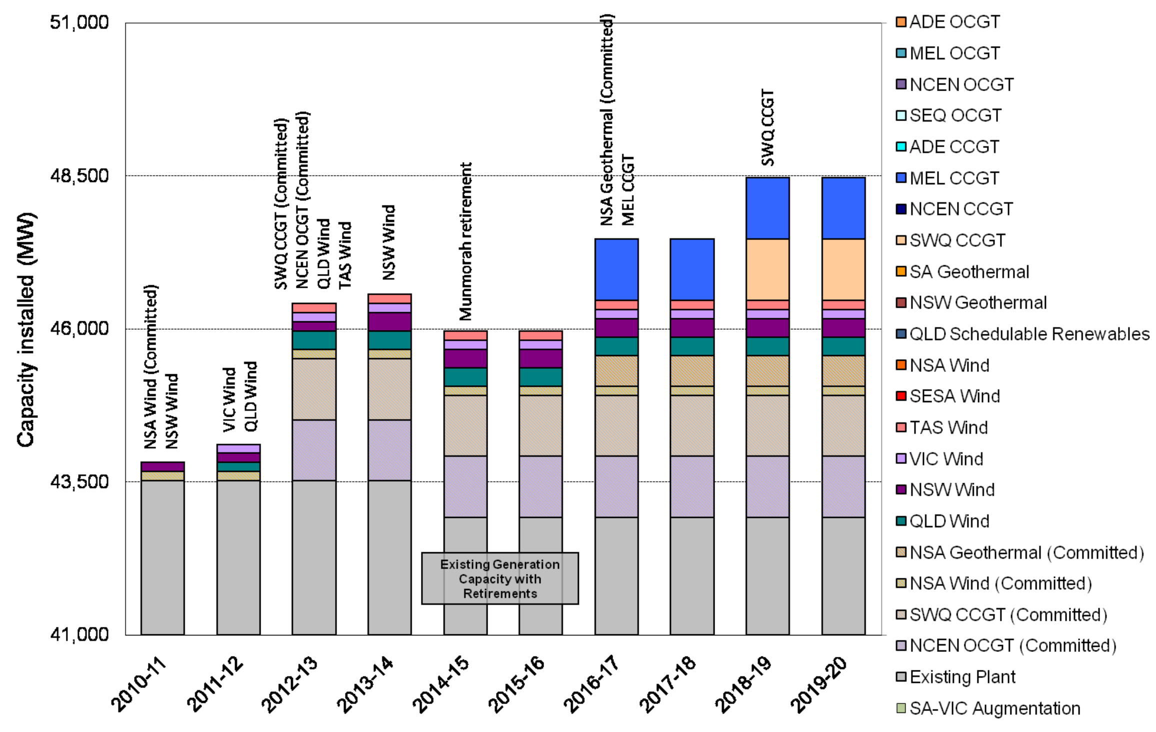


Table 7.1 – Summary of planting outcomes (Scenario A vs C)[33]
New entry wind, schedulable renewable, gas, committed plant, and transmission augmentations

	Low Banking		High Banking	
	Scenario A	Scenario C	Scenario A	Scenario C
2010-11	NSA Wind NSW Wind	NSA Wind TAS Wind	NSA Wind NSW Wind	NSA Wind TAS Wind
2011-12	-	-	QLD Wind VIC Wind	NSW Wind VIC Wind
2012-13	SWQ CCGT NCEN OCGT NSW Wind	SWQ CCGT NCEN OCGT NSW Wind	SWQ CCGT NCEN OCGT QLD Wind TAS Wind	SWQ CCGT NCEN OCGT NSW Wind VIC Wind
2013-14	-	-	NSW Wind	QLD Wind

[33] Wind plants are 1000 MW in size, CCGT and OCGT plants are 1000 MW (500 MW in SA), schedulable renewable plants (geothermal, biomass, sugar cane bagasse), and are 500 MW in size.

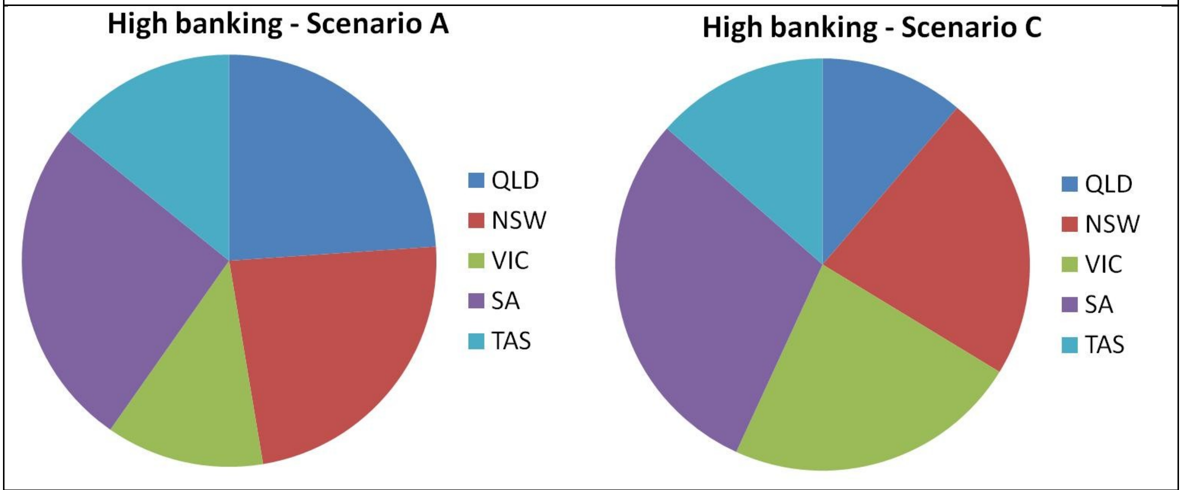
Table 7.1 – Summary of planting outcomes (Scenario A vs C)[33]
New entry wind, schedulable renewable, gas, committed plant, and transmission augmentations

	Low Banking		High Banking	
	Scenario A	Scenario C	Scenario A	Scenario C
2014-15	Munmorah retires QLD Bagasse	Munmorah retires QLD Bagasse	Munmorah retires	Munmorah retires
2015-16	VIC Wind MEL CCGT	VIC Wind	-	-
2016-17	NSA Geothermal	SA-VIC Aug NSA Geothermal	NSA Geothermal MEL CCGT	SA-VIC Aug NSA Geothermal
2017-18	QLD Biomass	QLD Biomass MEL CCGT	-	MEL CCGT
2018-19	NSW Geothermal QLD Geothermal	NSW Geothermal	SWQ CCGT	SWQ CCGT
2019-20	SA Geothermal	SA Geothermal QLD Geothermal	-	-

For the high banking cases, the outcomes for Scenario A are very similar to Scenario C, except for the distribution of wind. More wind is installed in Queensland overall, and earlier, in Scenario A, and wind development in Tasmania is delayed several years. Victoria develops less wind in Scenario A. This is illustrated in Figure 7.3.

When interpreting these results it should be kept in mind that profits are maximised as if all new plant belongs in the same portfolio. Thus it is beneficial for the portfolio to forego the high capacity factor Victorian wind farms in favour of wind farms in other states, so that the highly profitable MEL CCGT can be installed one year earlier. (The entry of thermal plant is limited so that it is only built when required by growth in demand. Installing Victorian wind delays the need for thermal plant in Victoria.)

Figure 7.3 – Renewables distribution by region (GWh) (High banking)



For the low banking cases, Tasmanian wind is not installed at any point in the study in Scenario A (compared with installation in the first year in Scenario C, due to the very high capacity factors of Tasmanian wind). NSW wind is favoured instead. As in the high banking case, this allows the earlier installation of the profitable MEL CCGT (the TAS wind farm is modelled as contributing to meeting Victoria's minimum reserve level, through support from Basslink). The same schedulable renewable plants are installed, but where allowed by the model, they are installed earlier. We note that the low cost and high capacity factor of the schedulable renewables (compared to wind) mean that they are highly profitable at the REC prices modelled. Thus earlier installation increases the total profit of the new entry portfolio.

Costs

The cumulative costs of Scenario A (over the study period) are illustrated in Table 7.2 compared with Scenario C. A detailed comparison of the costs of all three scenarios (A, B and C) is included in the following chapter (Section 8.1.1).

Table 7.2 – Cost comparisons (cumulative cost 2010-11 to 2019-20, $ mil)

		Scenario A	Scenario C
Low banking	Total cost of scenario	67,372	67,050
	Cost excluding emissions cost	27,832	27,329
	Emissions cost	39,540	39,721
High banking	Total cost of scenario	69,442	69,201
	Cost excluding emissions cost	30,409	30,260
	Emissions cost	39,033	38,941

8) Scenario B: Current regime working effectively

Scenario description

Generators make profit-maximising entry and exit decisions in the knowledge that transmission investment will respond consistent with delivering mandatory and discretionary investment consistent with the National Electricity Rules (NER). The level of transmission investment reflects both reliability and market benefits driven investments to continue meeting NEM demand and the expanded RET targets. This case reflects the investment decisions that can be made under the current framework.

Scenario treatment in ROAM's IRP model

As for Scenario A, this scenario was modelled in ROAM's IRP by determining the path which maximises over the study period the total profit of new entry generators, where total profit is given by the sum of the following for each generator:

$$\text{Pool price revenue} + \text{REC price} \times \text{Renewable generation} - (\text{Fixed O\&M} + \text{Run cost} + \text{Annualised capital costs}$$

The REC price was assumed to be \$40/MWh throughout the study, and was only applied to renewable generators. Sensitivity to REC price was investigated; prices in the range \$40 to \$60 /MWh did not impact on the planting results. The outcome is therefore considered to be reasonably robust to RECs price.

It should be noted that this profit maximisation methodology maximises total profit from a holistic point of view. Decision making remains from the point of view of a central planner with perfect foresight, who seeks to maximise total system profits (rather than minimise total system costs, as for Scenario C). This may produce a different outcome to a methodology where individual stations make entry decisions to maximise their individual profits, and in the absence of perfect foresight.

Significant transmission augmentations were assessed on a cost minimisation basis. Where a transmission augmentation would reduce total system costs, it was allowed to enter in the year in which it minimised system costs the most. Residual benefits (benefits from reduced variable costs beyond the study timeframe) have not been accounted for in this analysis.

8.1) RESULTS

Planting outcomes

Applying this methodology to the IRP yields the planting outcomes for Scenario B shown in Figure 8.1 (low banking) and Figure 8.2 (high banking).

Of these two cases, the low banking case produces the maximum profit, and is therefore ROAM's proposed solution to Scenario B. Results from the high banking case are also included for comparison, to illustrate the impacts to the system if the drivers under the RET scheme produce a high banking outcome, regardless of holistic profit maximisation.

Figure 8.1 – Planting outcome – Scenario B (Low banking)

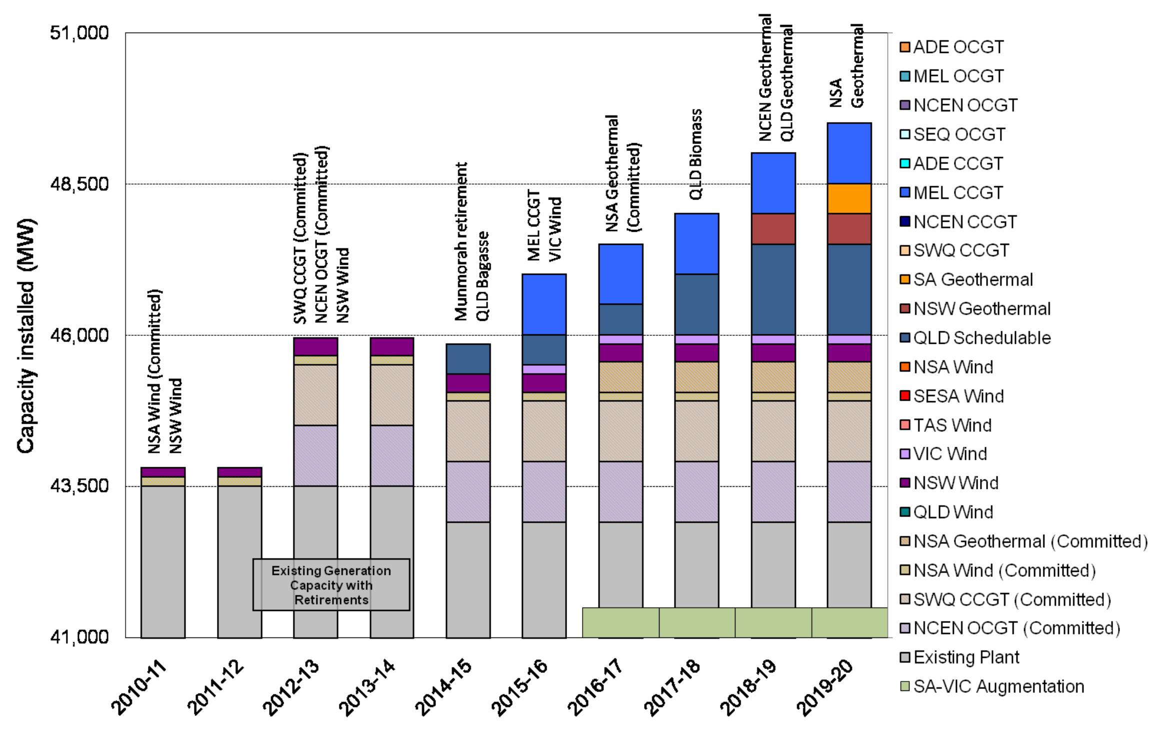
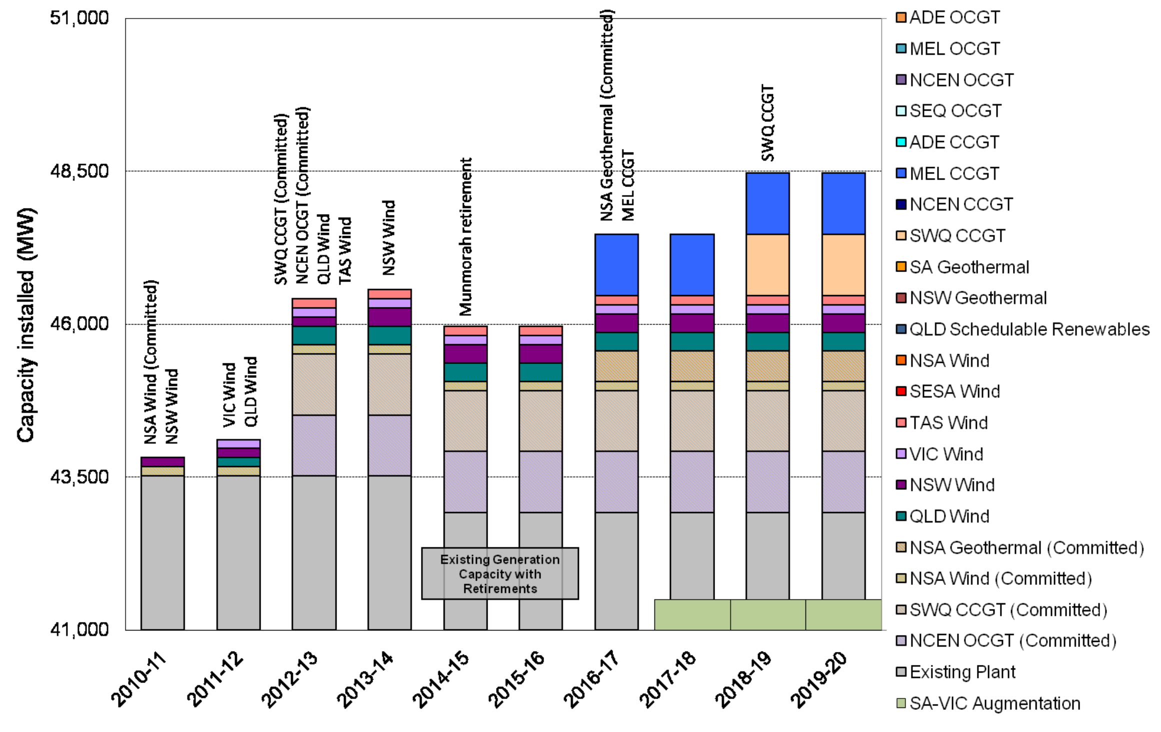


Figure 8.2 – Planting outcome – Scenario B (High banking)



For the high banking case, the planting outcome for Scenario B is identical to Scenario A, but includes the SA-VIC transmission augmentation in 2017-18 (this does not influence the profit maximising planting schedule). Similarly, the planting outcome for the low banking case is identical for Scenario A and Scenario B (with the exception of the SA-VIC interconnector entering in 2016-17 in Scenario B).

Table 8.1 – Summary of planting outcomes[34]
New entry wind, schedulable renewable, gas, committed plant, and transmission augmentations

	Low Banking			High Banking		
	Scenario A	Scenario B	Scenario C	Scenario A	Scenario B	Scenario C
2010-11	NSA Wind NSW Wind	NSA Wind NSW Wind	NSA Wind TAS Wind	NSA Wind NSW Wind	NSA Wind NSW Wind	NSA Wind TAS Wind
2011-12	-	-	-	QLD Wind VIC Wind	QLD Wind VIC Wind	NSW Wind VIC Wind
2012-13	SWQ CCGT NCEN OCGT NSW Wind	SWQ CCGT NCEN OCGT NSW Wind	SWQ CCGT NCEN OCGT NSW Wind	SWQ CCGT NCEN OCGT QLD Wind TAS Wind	SWQ CCGT NCEN OCGT QLD Wind TAS Wind	SWQ CCGT NCEN OCGT NSW Wind VIC Wind
2013-14	-	-	-	NSW Wind	NSW Wind	QLD Wind
2014-15	Munmorah retires QLD Bagasse	Munmorah retires QLD Bagasse	Munmorah retires QLD Bagasse	Munmorah retires	Munmorah retires	Munmorah retires
2015-16	VIC Wind MEL CCGT	VIC Wind MEL CCGT	VIC Wind	-	-	-
2016-17	NSA Geoth	SA-VIC Aug NSA Geoth	SA-VIC Aug NSA Geoth	NSA Geoth MEL CCGT	NSA Geoth MEL CCGT	SA-VIC Aug NSA Geoth
2017-18	QLD Biomass	QLD Biomass	MEL CCGT QLD Biomass	-	SA-VIC Aug	MEL CCGT
2018-19	NSW Geoth QLD Geoth	NSW Geoth QLD Geoth	NSW Geoth	SWQ CCGT	SWQ CCGT	SWQ CCGT
2019-20	SA Geoth	SA Geoth	QLD Geoth SA Geoth	-	-	-

[34] Wind plants are 1000 MW in size, CCGT and OCGT plants are 1000 MW (500 MW in SA), schedulable renewable plants (geothermal, biomass, sugar cane bagasse), and are 500 MW in size.

Entry date of the SA-VIC interconnector augmentation

The SA-VIC interconnector augmentation is strongly driven by the entry of the NSA geothermal plant in 2016-17. Without the augmentation, this geothermal plant is strongly constrained due to the transmission limitation from NSA-ADE. The SA-VIC augmentation therefore becomes very cost effective from 2016-17 onwards in all scenarios.

The single exception to this is the Scenario B high banking case, where the lowest cost entry date for the SA-VIC interconnector is one year later, in 2017-18. This is due to the interplay between wind farm revenues by region, and the amount of benefit that can be extracted from the interconnector with different planting outcomes.

Potential drivers for the SA-VIC interconnector augmentation are illustrated in Figure 8.3 and Figure 8.4. The carbon price undergoes a significant step change in 2015-16, one year prior to the entry of the SA-VIC augmentation. The augmentation coincides with the entry of the 500MW NSA geothermal plant, which could be a strong driver for the augmentation. However, it is not the sole driver, as illustrated in section 6.7). Table 6.16 shows that the entry of the geothermal plant very much increases the cost effectiveness of the augmentation, but the augmentation is viable for entry from 2015-16 even in its absence.

Figure 8.3 – Input assumptions – drivers for interconnector augmentation

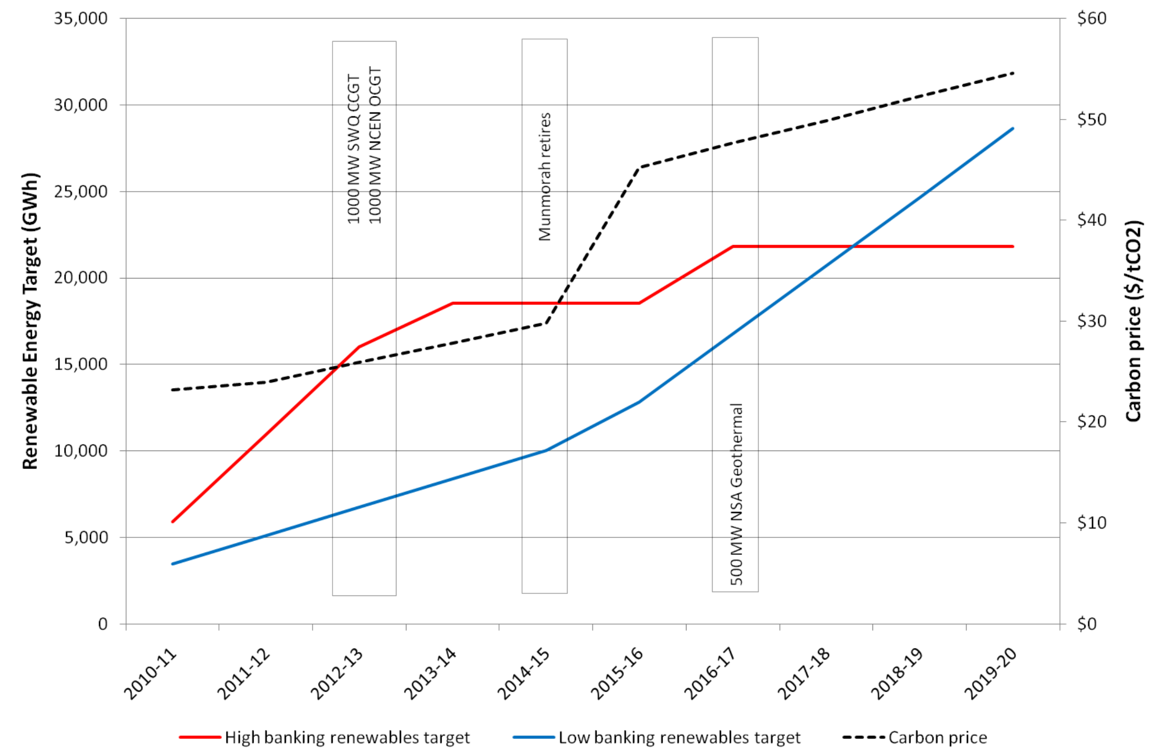
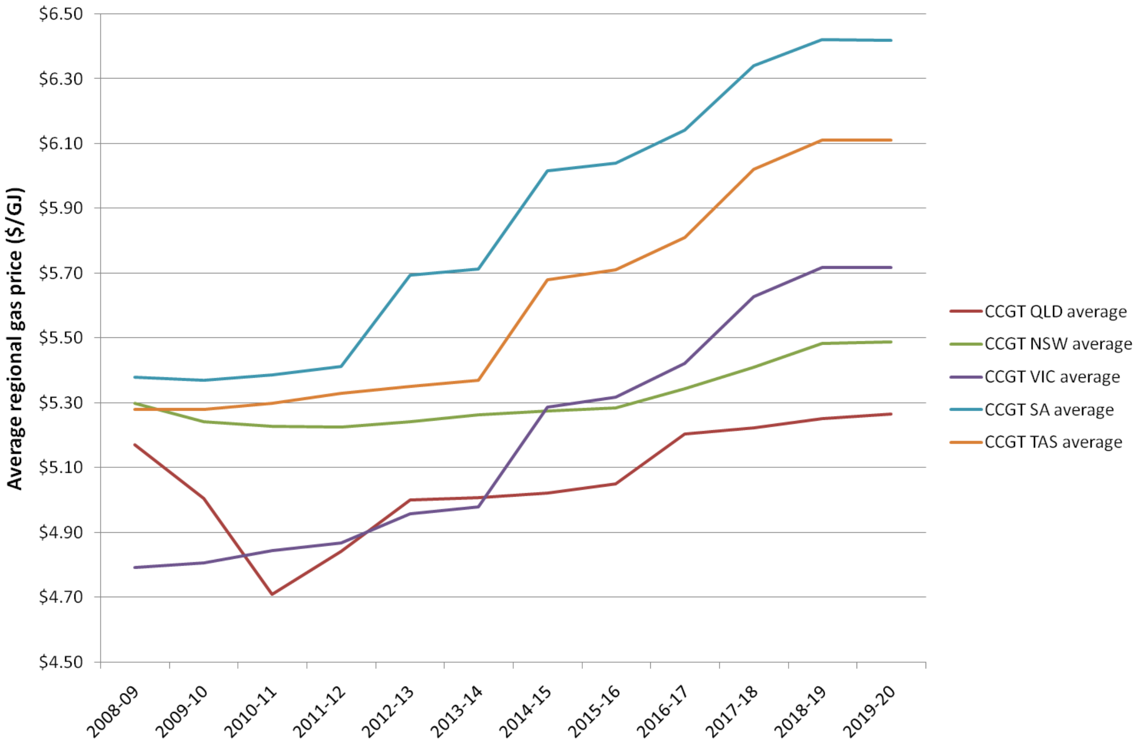


Figure 8.3 shows a step increase in the RET target for the high banking case in 2016-17, although this is to allow for the entry of the committed NSA geothermal plant in that year.

Gas prices also change over time, as illustrated in Figure 8.4, and could be a significant driver. However, there are no significant changes in 2016-17 that might drive the SA-VIC interconnector augmentation.

Figure 8.4 – Input assumptions – CCGT gas prices by region



Profit maximisation – impacts on planting outcomes

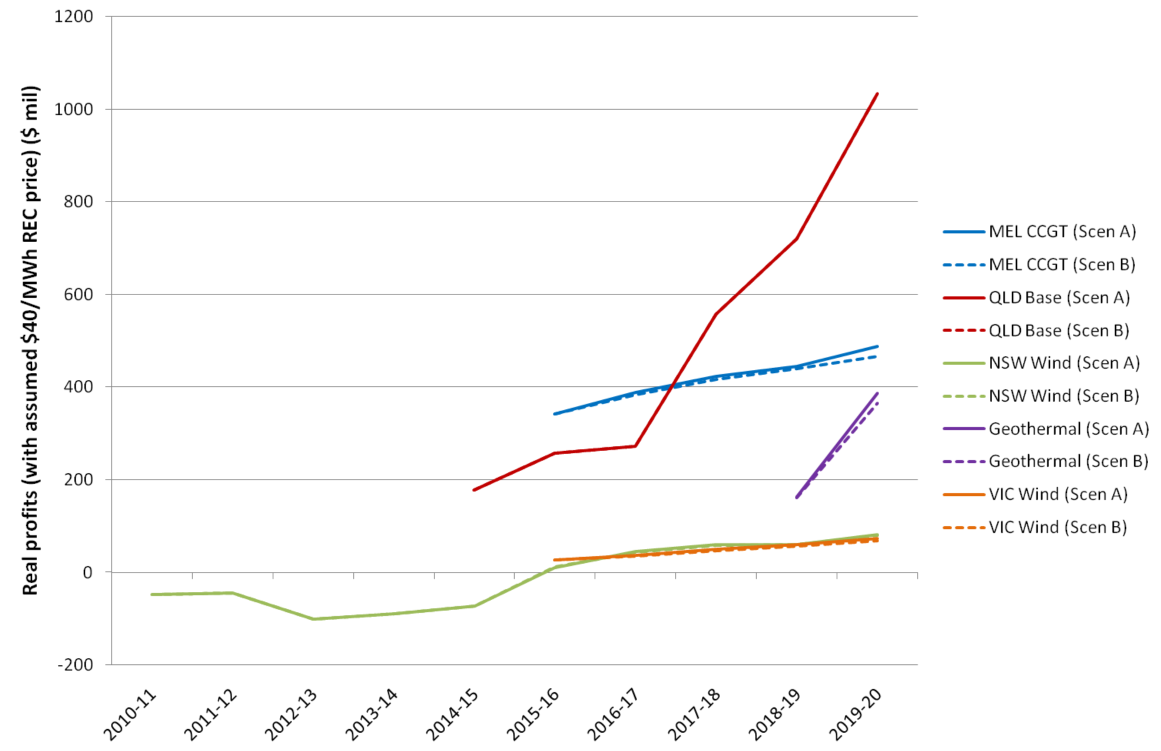
The profit maximisation methodology produces a different planting outcome to the cost minimisation methodology (used to determine Scenario C). The main difference between the two profit maximising scenarios (A and B) and the cost reduction scenario (Scenario C) is the locations of the wind planted. This is driven by differences in pool price between regions (in Scenarios A and B) rather than small differences in wind farm capacity factor (in Scenario C). In Scenario C, small variations in capacity factor (due to differences in the underlying wind resource quality in different regions) vary the long run marginal costs of wind generators, incentivising installation of wind farms in the highest resource areas. This effect also increases wind farm profit, but in Scenarios A and B competes with varying pool prices across regions to produce a different outcome.

In the low banking case, Tasmanian wind does not enter at all, and is replaced by a second NSW wind farm.

In the high banking case, to maximise profits, more wind is installed in Queensland, and less in Victoria. The Tasmanian wind station is also installed much later.

Figure 8.5 illustrates the profit of each station type in the low banking case, for Scenarios A and B, on an annual basis (not discounted). The very high profitability of schedulable renewable plants is illustrated. Wind farms are far less profitable, not being self sustaining until 2015-16 (they enter the market to meet the RET requirements). These results are calculated using a constant REC price of $40/MWh, and the analysis suggests that a significantly higher REC price will be required in early years of the RET to support the required entry of renewable generation (or a higher market pool price driven by increased peak demand or generator gaming).

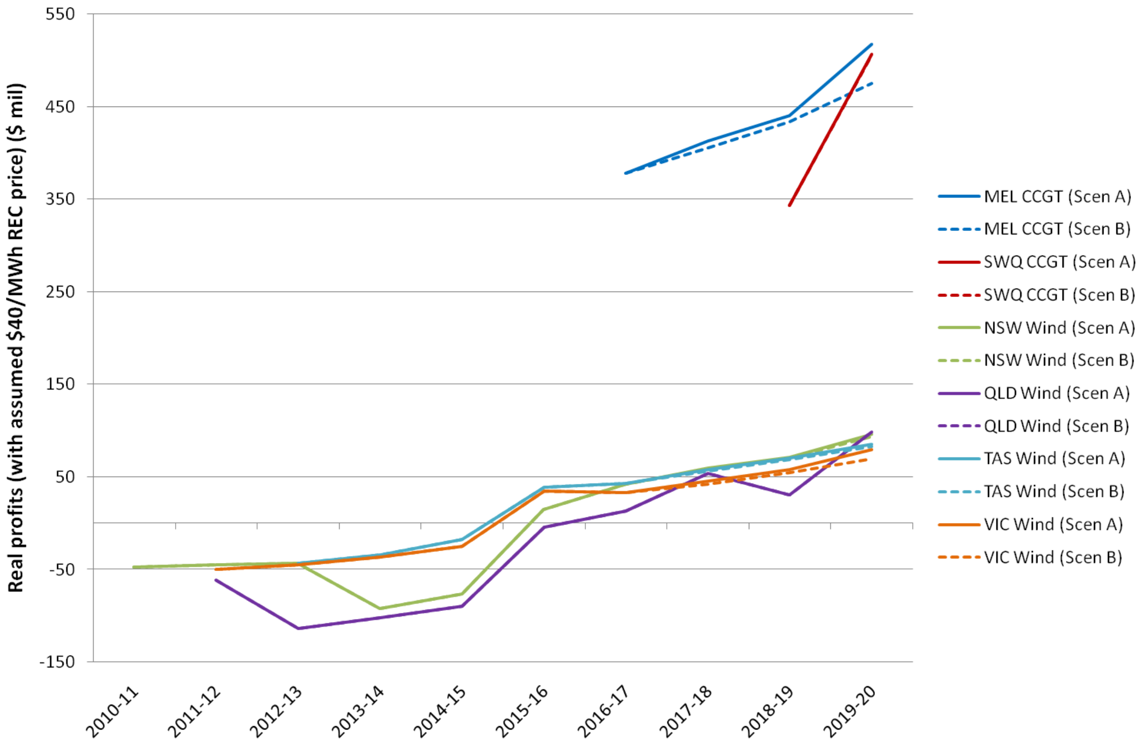
Figure 8.5 – Annualised profit by station type (Low banking)[35]



For comparison, Figure 8.6 illustrates the profit of each station type in the high banking case, for Scenarios A and B, on an annual basis (not discounted). The larger quantity of wind installed in the high banking case illustrates why the low banking case maximises profit more than the high banking case. The MEL CCGT has slightly lower profitability in Scenario B, since the SA-VIC interconnector allows inter-regional plant to undercut this CCGT plant more often, and otherwise mitigate pool price volatility.

[35] To determine the model outcome that maximises profit, discounting is applied to these profits (all values calculated as net present value, real, pre tax, with a 10% WACC.).

Figure 8.6 – Annualised profit by station type (High banking) [36]



8.1.1) Costs

Comparison of scenario total cumulative costs

Cost outcomes for all three scenarios are compared in Table 8.2.

[36] To determine the model outcome that maximises profit, discounting is applied to these profits (all values calculated as net present value, real, pre tax, with a 10% WACC.).

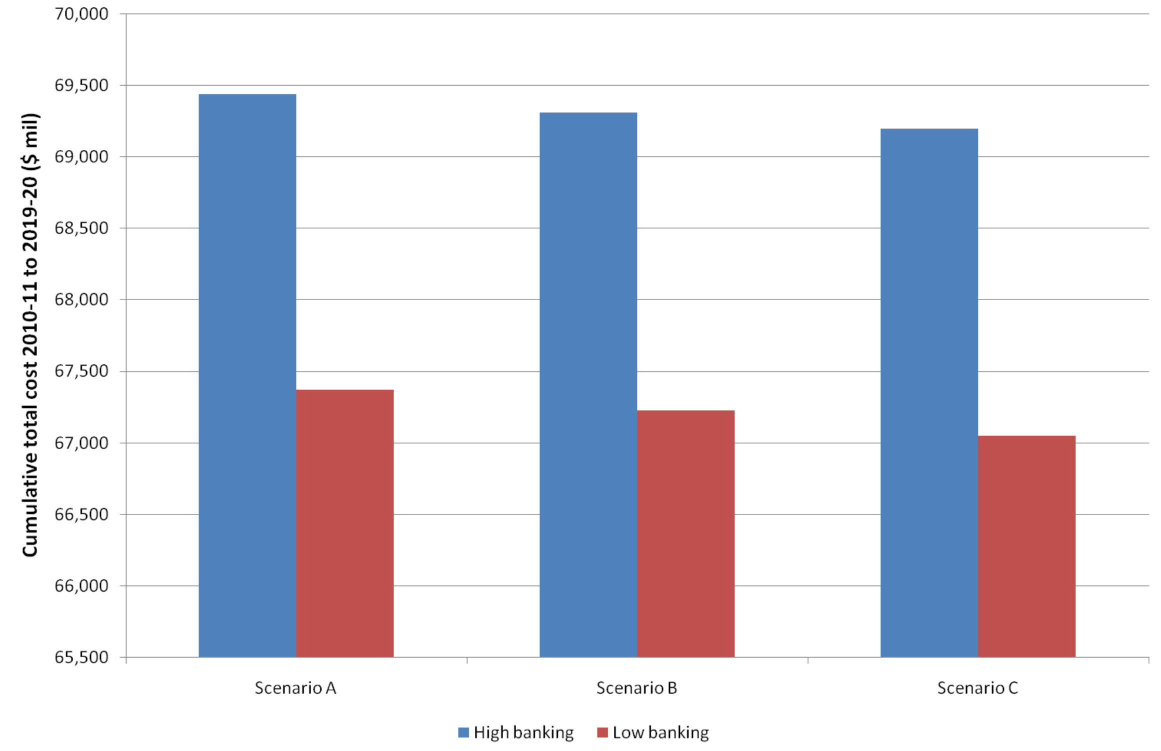
Table 8.2 – Cost comparisons (cumulative cost 2010-11 to 2019-20, $ mil)

		Total cost	Cost excluding emissions cost	Emissions cost
Low banking	Scenario A	67,372	27,832	39,540
	Scenario B	67,223	27,771	39,452
	Scenario C	67,050	27,329	39,721
	A – B	149	61	88
	B – C	173	442	-269
	A – C	322	503	-181
High banking	Scenario A	69,442	30,409	39,033
	Scenario B	69,312	30,341	38,971
	Scenario C	69,201	30,260	38,941
	A – B	130	68	62
	B – C	111	81	30
	A – C	241	149	92
High banking – Low banking	Scenario A	2,070	2,577	-507
	Scenario B	2,089	2,570	-481
	Scenario C	2,151	2,931	-780

Consistent with the methodology requirements, Scenario A produces the highest cost solution, and Scenario C the lowest cost.

The difference in cost between the three scenarios is very small, much less than the difference between the two banking cases considered. This is due to the fact that the profit maximisation methodology (Scenarios A and B) incentivises very similar plant to cost reduction (Scenario C) with similar entry timing. By comparison, high RECs banking produces a much more rapid, early installation of renewable plant, whereas low RECs banking produces a significantly lower rate of installation, allows entirely different plant types to enter the market. This highlights the importance of creating a well designed RET scheme that incentivises efficient market responses. The high banking case is consistently more than $2 billion more expensive than the low banking case, suggesting that allowing unlimited banking in the RET scheme may not be the most efficient RET scheme design.

Figure 8.7 – Cost comparison – Total cost[37]

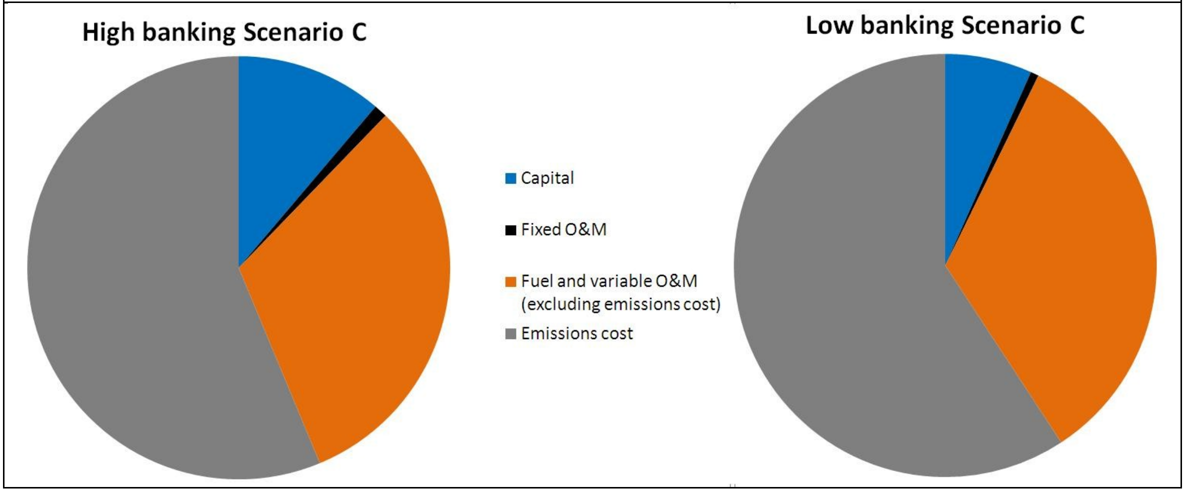


Cost components

The breakdown of cost by component was found to be very similar between Scenarios A, B and C, but varied more significantly between high and low banking cases. The break down comparison for Scenario C is illustrated in Figure 8.8. In the high banking case proportionally more is spent on capital, whereas in the low banking case, proportionally more is spent on emissions costs under the CPRS (due to the slower ramp-up of renewable technologies, and the therefore smaller amount of displaced fossil fuel plant over the study period).

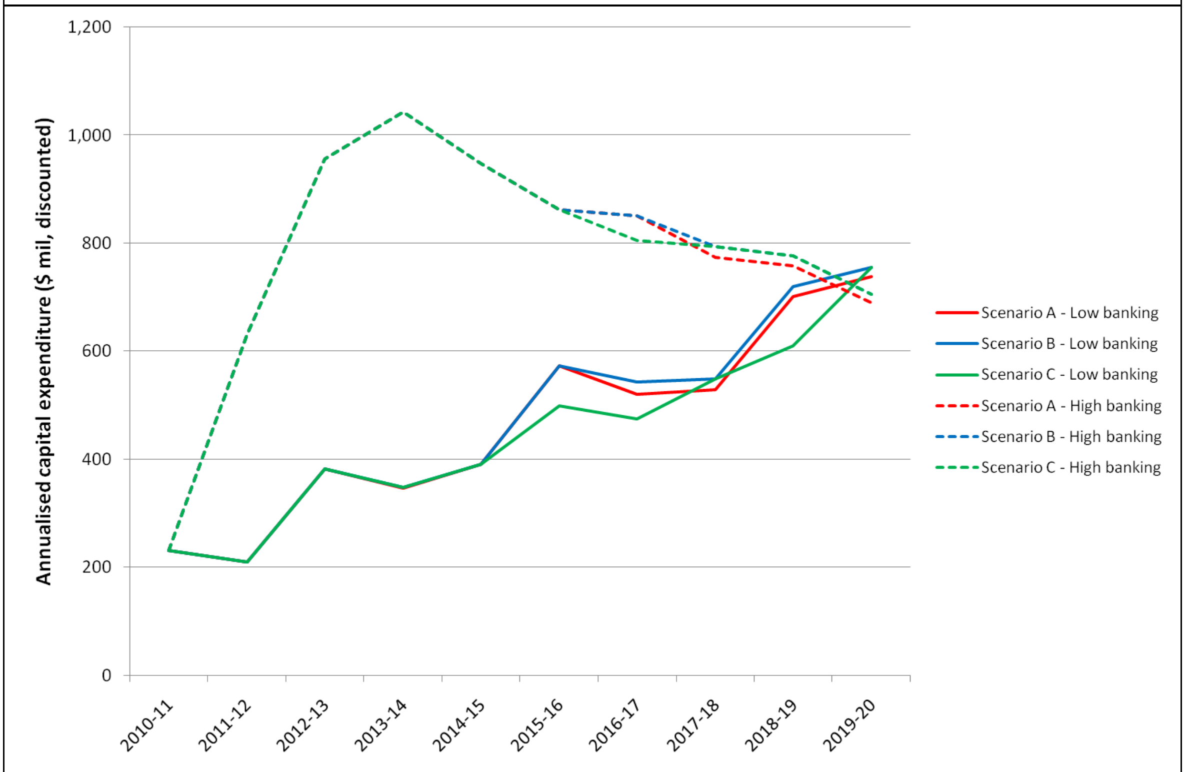
[37] Components included in this cost are detailed in section 5.8)

Figure 8.8 – Cost components (Scenario C)



Capital expenditure on an annualised basis is illustrated in Figure 8.9 The large difference in expenditure patterns between the high and low banking cases is evident. The high banking case shows an initial rapid increase due to the large quantity of installed wind. The low banking case shows a steady moderate increase in capital expenditure, as renewable technologies are gradually installed over the period.

Figure 8.9 – Annualised capital expenditure (discounted)



A comparison of the total costs excluding emissions costs between Scenarios A, B and C is illustrated in Figure 8.10. The pattern follows that of the total cost.

Figure 8.10 – Cost comparison – Cost excluding emissions cost

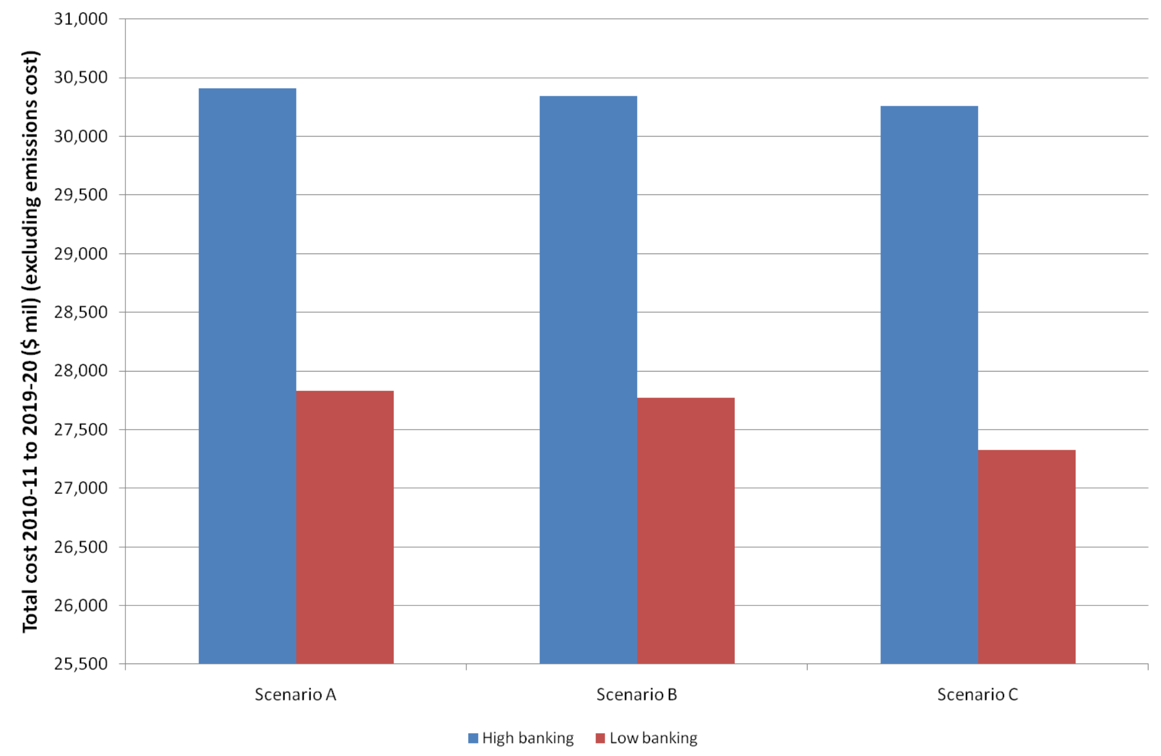
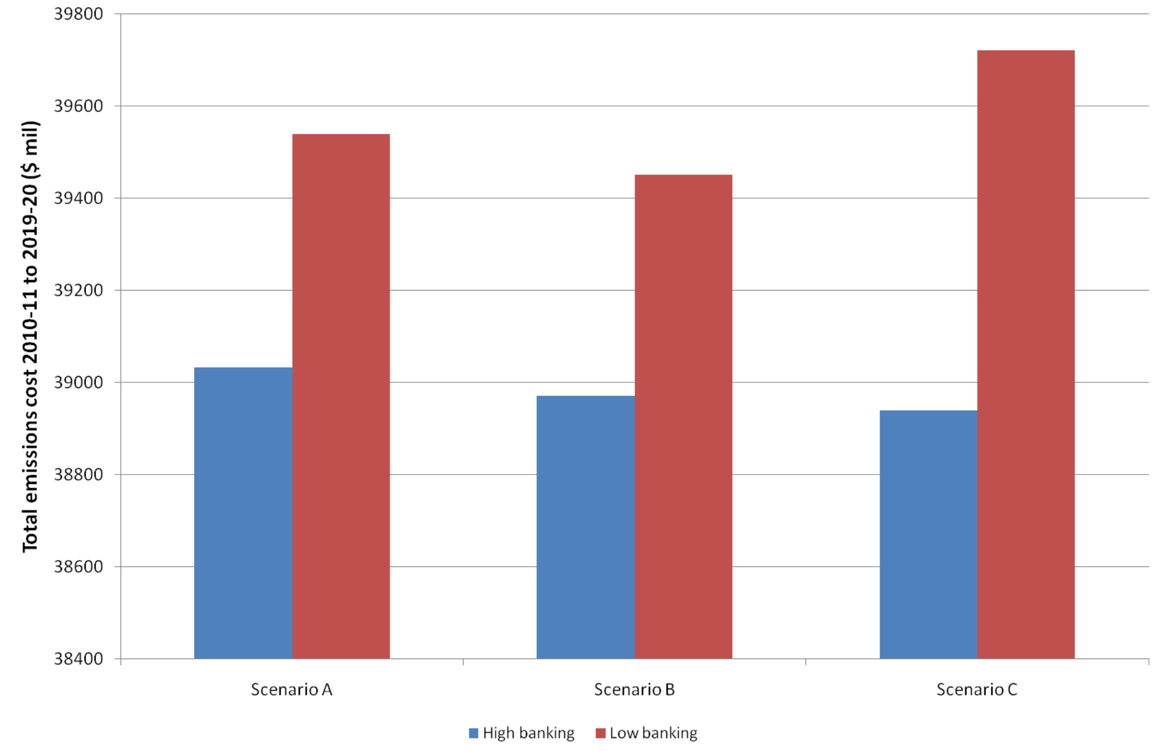


Figure 8.11 illustrates the differences in emissions costs across the scenarios and cases. Scenario C has the highest emissions cost of the three in the low banking case, but the lowest emissions cost in the high banking case. It should be noted that these results are heavily dependent upon the length of the study period chosen; a longer outlook to 2030 would yield significantly different results (as discussed in section 6.3).

Figure 8.11 – Cost comparison – Emissions cost



Network response problem

The difference in costs between Scenarios A and B is $130 to $149 million, cumulatively over the ten year period 2010-11 to 2019-20 (for the high and low banking cases respectively). Allowing the system to install the SA-VIC interconnector in 2017-18 reduces system costs through increased efficiency of dispatch, although it does not change the investment decisions of new entry generators (Scenarios A and B coincidentally have the same planting outcomes).

Efficiency of current system

The difference in costs between Scenarios B and C is $111 to $173 million, cumulatively over the ten year period 2010-11 to 2019-20 (for the high and low banking cases respectively). Allowing generators to make profit maximising decisions, rather than utilising a central planning approach with complete system knowledge costs the system $111 million over the ten years of the study period. This is much less than the difference in cost between the high and low banking cases in Scenario C, indicating that correct system design for the Renewable Energy Target scheme is of very high importance, to ensure efficient incentivisation under the scheme.

8.2) INTERCONNECTORS

Augmentation timing in Scenario B

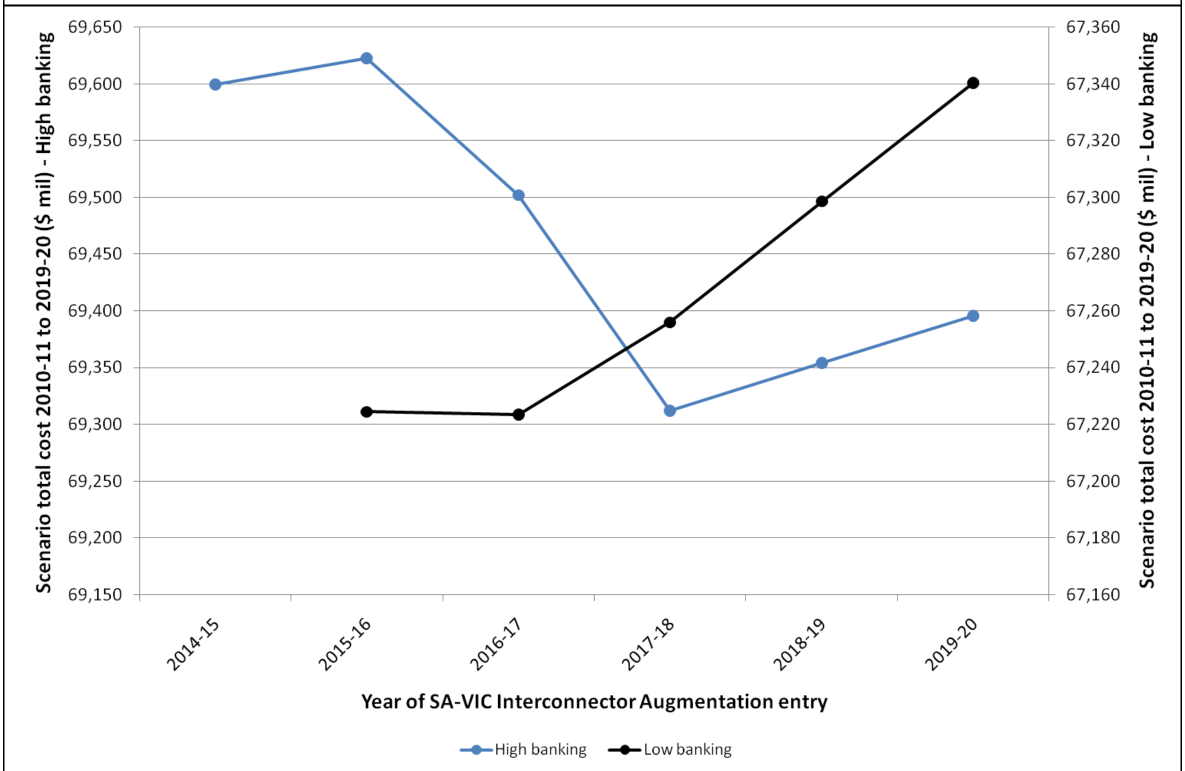
Within an environment where generators are making profit maximizing decisions, interconnector augmentations will still be installed at the point where they minimize system costs. Therefore a purely profit maximizing solution is not the required solution to Scenario B.

To determine the optimal planting schedule for Scenario B, ROAM implemented the profit maximizing algorithm, with the SA-VIC interconnector being installed in each year of the study. This process was as follows:

1. The profit maximizing planting schedule was determined with the interconnector being installed in 2014-15. Generators made profit maximizing decisions in the knowledge that the interconnector was going to be installed in 2014-15.
2. The total cumulative system cost was determined for this case.
3. Steps 1 and 2 were repeated with the interconnector entering in 2015-16 (and for each later year of the study).
4. The interconnector augmentation entry year producing the lowest cost outcome was determined to be the desired solution to Scenario B.

The lowest cost year of entry for the SA-VIC interconnector augmentation under generator profit maximizing decisions was found to be 2017-18. The cumulative scenario costs are illustrated in Figure 8.12 and Figure 8.13, with the augmentation entering in each year of the study. Installation in 2017-18 produces the lowest total cumulative cost, and the lowest cost excluding greenhouse emissions cost.

Figure 8.12 – Scenario B cost vs year of SA-VIC augmentation



Emissions costs are a minimum with the interconnector augmentation installed in 2016-17, but the difference is not enough to offset the much lower cost in other aspects of the system (Figure 8.13).

Figure 8.13 – Scenario B cost vs year of SA-VIC augmentation – components (High banking)

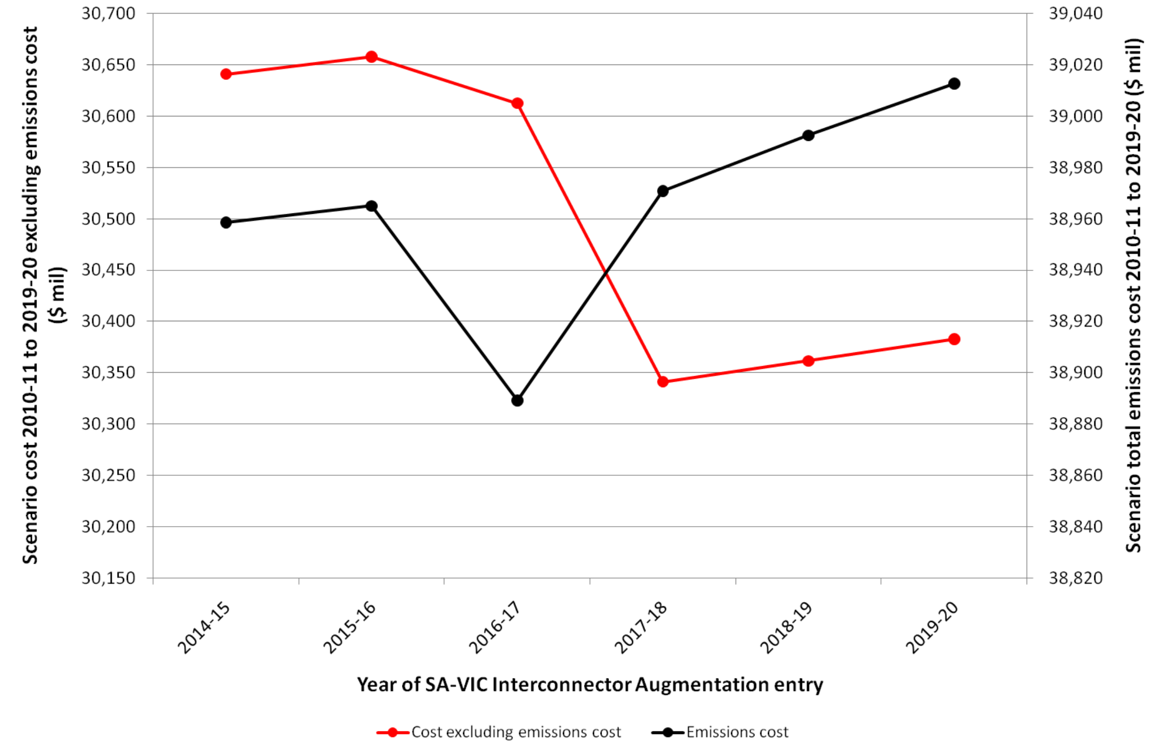
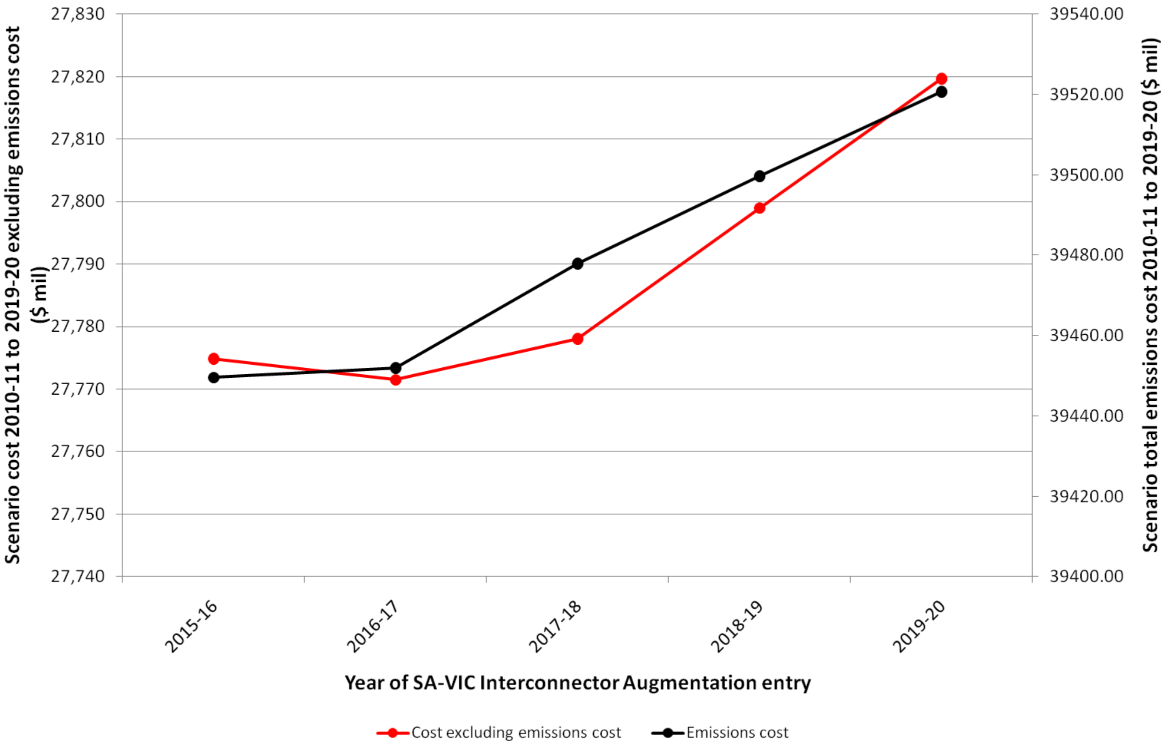


Figure 8.14 – Scenario B cost vs year of SA-VIC augmentation – components (Low banking)



Augmentation costs – High banking

The percentage of the total annualised cost of the SA-VIC interconnector that is recovered by reduced system costs (due to more efficient dispatch) is illustrated in Table 8.3 for the high banking case. This is dependent upon the year in which the interconnector is installed, since generators respond in a profit maximising fashion with changed entry decisions when the interconnector entry date is varied. This means that a variety of different planting outcomes result. Identical planting outcomes result if the interconnector is installed the last three years of the study (2017-18, 2018-19 or 2019-20), meaning that the percentage of the cost recovered is identical for these three outcomes. Similarly, augmentation installation in 2014-15 and 2015-16 produces identical planting outcomes.

Table 8.3 – SA-VIC interconnector augmentation (high banking)

Year of augmentation entry:	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
% of total annualised cost of augmentation recovered by reduced system costs						
2014-15	18.4%	-	-	-	-	-
2015-16	-78.8%	-78.8%	-	-	-	-
2016-17	-8.7%	-8.7%	70.1%	-	-	-
2017-18	38.1%	38.1%	34.9%	292.8%	-	-
2018-19	45.6%	45.6%	183.0%	309.8%	309.8%	-
2019-20	123.0%	123.0%	173.9%	353.8%	353.8%	353.8%

If the SA-VIC interconnector augmentation is installed in 2014-15 or 2015-16 it only recovers its costs in the final year of the study. Later installation in 2016-17 means that changed generator entry decisions make the augmentation profitable in the last two years of the study. Augmentation installation in 2017-18 means that the interconnector recovers its annualised cost from the first year of installation by almost 300%, and continues to recover 300 to 350% of its cost in each of the remaining years of the study.

The QNI augmentation was also considered for Scenario B, but was found to be almost as unjustified (on a cost basis) as for Scenario C. The percentage of cost recovered in each year is illustrated in Table 8.4, for an installation year of 2014-15 (compared with Scenario C).

Table 8.4 – QNI interconnector augmentation (high banking)

	% of total annualised cost of augmentation recovered by reduced system costs	
	Scenario C	**Scenario B**
2014-15	23.2%	23.9%
2015-16	26.4%	29.8%
2016-17	18.0%	16.6%
2017-18	99.5%	84.6%
2018-19	31.5%	40.3%
2019-20	33.8%	44.0%

Augmentation costs – Low banking

Unlike the high banking case, the installation of the SA-VIC interconnector in any year does not change the planting result that maximises scenario profit. When the NSA geothermal plant enters in 2016-17 the SA-VIC interconnector augmentation becomes immediately very cost effective, recovering more than 200% of its annualised cost in every year for the remainder of the study (very similar to the outcome for Scenario C). The cost effectiveness of the SA-VIC augmentation is illustrated in Table 8.5 (for the low banking case).

Table 8.5 – SA-VIC interconnector augmentation (low banking)

	% of total annualised cost of augmentation recovered by reduced system costs	
	Scenario C	**Scenario B**
2010-11	70.1%	69.9%
2011-12	71.1%	70.8%
2012-13	73.2%	74.0%
2013-14	95.8%	95.0%
2014-15	99.5%	98.8%
2015-16	97.9%	96.1%
2016-17	238.6%	235.9%
2017-18	293.9%	296.1%
2018-19	309.3%	310.8%
2019-20	273.4%	276.5%

Transmission congestion

The percentage of time that major interconnectors were constrained in the three scenarios under low banking is illustrated in Table 8.6. Patterns of congestion are similar between the three cases. The interconnector name is followed by a reference to the direction of flow in which the limitation occurred. QNI, Terranora, VIC-NSW and Basslink run north-south, while Heywood and Murraylink run east-west.

Table 8.6 – Low banking interconnector congestion - % of time constrained

		2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Scenario C – Low Banking	QNI (north)	2%	4%	1%	1%	1%	1%	2%	1%	3%	3%
	QNI (south)	30%	28%	13%	15%	21%	27%	23%	27%	22%	28%
	Heywood (west)	40%	35%	36%	68%	65%	33%	1%	3%	3%	2%
	Heywood (east)	3%	3%	3%	2%	3%	4%	1%	0%	0%	2%
	Basslink (north)	13%	12%	11%	11%	10%	9%	9%	8%	8%	8%
	Basslink (south)	10%	9%	10%	10%	12%	8%	6%	8%	8%	8%
	Terranora (north)	2%	4%	1%	1%	1%	1%	2%	1%	3%	2%
	Terranora (south)	2%	2%	3%	4%	10%	9%	8%	8%	5%	7%
	Murraylink (west)	51%	51%	47%	59%	60%	47%	42%	43%	42%	39%
	Murraylink (east)	30%	32%	33%	33%	34%	37%	44%	42%	41%	40%
	VIC-NSW (north)	7%	6%	5%	6%	7%	4%	3%	3%	2%	3%
	VIC-NSW (south)	5%	4%	5%	5%	4%	3%	3%	2%	3%	2%
Scenario A – Low banking	QNI (north)	2%	4%	1%	1%	1%	1%	2%	1%	2%	3%
	QNI (south)	36%	33%	15%	16%	22%	20%	17%	25%	29%	25%
	Heywood (west)	41%	37%	36%	66%	63%	41%	25%	35%	40%	15%
	Heywood (east)	3%	4%	3%	3%	4%	2%	3%	3%	2%	11%
	Basslink (north)	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Basslink (south)	22%	23%	26%	27%	29%	26%	23%	24%	23%	23%
	Terranora (north)	2%	4%	1%	1%	1%	1%	2%	1%	1%	2%
	Terranora (south)	2%	2%	3%	3%	9%	5%	5%	8%	6%	6%
	Murraylink (west)	54%	53%	34%	33%	34%	46%	69%	71%	72%	61%
	Murraylink (east)	31%	33%	34%	33%	34%	36%	80%	72%	67%	79%
	VIC-NSW (north)	11%	10%	7%	9%	10%	3%	3%	4%	3%	4%
	VIC-NSW (south)	8%	7%	7%	7%	7%	1%	1%	4%	7%	5%

Table 8.6 – Low banking interconnector congestion - % of time constrained											
		2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Scenario B – Low banking	QNI (north)	2%	4%	1%	1%	1%	1%	2%	2%	2%	3%
	QNI (south)	36%	33%	15%	16%	22%	20%	16%	24%	28%	24%
	Heywood (west)	41%	37%	36%	66%	63%	41%	1%	3%	3%	3%
	Heywood (east)	3%	4%	3%	3%	4%	2%	0%	0%	0%	2%
	Basslink (north)	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Basslink (south)	22%	23%	26%	27%	29%	26%	23%	24%	23%	22%
	Terranora (north)	2%	4%	1%	1%	1%	1%	2%	2%	1%	2%
	Terranora (south)	2%	2%	3%	3%	9%	5%	4%	7%	6%	6%
	Murraylink (west)	54%	53%	49%	61%	62%	46%	41%	43%	42%	40%
	Murraylink (east)	31%	33%	34%	33%	34%	36%	42%	42%	42%	41%
	VIC-NSW (north)	11%	10%	7%	9%	10%	3%	2%	2%	1%	2%
	VIC-NSW (south)	8%	7%	7%	7%	7%	1%	1%	3%	6%	4%

Comparing scenarios B and C under low banking, the patterns of congestion are very similar except for on Basslink. Scenario B shows 14 to18% more periods constrained on Basslink than Scenario C towards Tasmania, and 8 to 13% fewer periods constrained on Basslink towards Victoria. This is likely because Scenario C includes a 1000MW wind farm in Tasmania, whereas Scenario B distributed the wind elsewhere due to the profit maximisation methodology.

Comparing scenarios A and B, the SA-VIC augmentation in 2016-17 reduces congestion on Heywood (east) and Murraylink (east and west) by 20-40%. There are otherwise only very minor differences between the congestion patterns in the two scenarios.

Table 8.7 gives the percentage of time that each interconnector is constrained in each scenario under high banking. Scenarios B and C display similar patterns of congestion, differing significantly only in years 2010-11 and 2011-12 on Basslink and in 2016-17 on Murraylink and Heywood. The earlier installation of a 1000MW Tasmanian wind farm in scenario C reduces congestion by 12 to 14% into and out of Tasmania in 2010-11 and 2011-12. The reduced congestion between Victoria and South Australia in 2016-17 in scenario C is due to the earlier augmentation of the SA-VIC interconnector in that year.

As in the low banking case, the SA-VIC augmentation in 2016-17 accounts for the reduced congestion on Murraylink and Heywood in scenario B, compared to scenario A.

Table 8.7 – High banking interconnector congestion - % of time constrained

		2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Scenario C – High Banking	QNI (north)	2%	4%	1%	1%	1%	2%	3%	5%	3%	3%
	QNI (south)	30%	28%	13%	16%	18%	21%	16%	14%	29%	27%
	Heywood (west)	40%	36%	40%	75%	74%	37%	2%	4%	4%	4%
	Heywood (east)	3%	2%	2%	2%	1%	3%	1%	0%	0%	0%
	Basslink (north)	13%	12%	11%	11%	9%	9%	8%	8%	8%	8%
	Basslink (south)	10%	8%	12%	13%	14%	10%	7%	8%	8%	8%
	Terranora (north)	2%	4%	1%	1%	1%	2%	3%	5%	2%	2%
	Terranora (south)	2%	1%	2%	2%	6%	6%	5%	4%	7%	8%
	Murraylink (west)	51%	49%	49%	60%	61%	48%	42%	43%	42%	44%
	Murraylink (east)	30%	30%	31%	30%	32%	36%	43%	41%	41%	43%
	VIC-NSW (north)	7%	5%	7%	9%	10%	5%	3%	4%	3%	5%
	VIC-NSW (south)	5%	4%	3%	3%	3%	3%	3%	2%	3%	3%
Scenario A – High banking	QNI (north)	2%	3%	0%	1%	1%	1%	2%	3%	2%	2%
	QNI (south)	36%	35%	17%	15%	17%	25%	19%	19%	34%	33%
	Heywood (west)	41%	37%	37%	72%	69%	34%	26%	36%	40%	38%
	Heywood (east)	3%	3%	2%	2%	2%	3%	3%	2%	2%	2%
	Basslink (north)	0%	0%	11%	11%	10%	9%	8%	8%	8%	8%
	Basslink (south)	22%	22%	9%	10%	11%	8%	7%	8%	9%	9%
	Terranora (north)	2%	3%	0%	1%	1%	1%	2%	3%	1%	2%
	Terranora (south)	2%	2%	3%	3%	7%	7%	5%	5%	9%	10%
	Murraylink (west)	54%	52%	47%	58%	59%	47%	69%	71%	72%	76%
	Murraylink (east)	31%	32%	32%	31%	32%	37%	79%	71%	67%	71%

Table 8.7 – High banking interconnector congestion - % of time constrained

		2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
	VIC-NSW (north)	11%	8%	4%	5%	6%	3%	3%	4%	3%	5%
	VIC-NSW (south)	8%	5%	4%	4%	4%	3%	1%	3%	4%	4%
Scenario B – High banking	QNI (north)	2%	3%	0%	1%	1%	1%	2%	3%	2%	2%
	QNI (south)	36%	35%	17%	15%	17%	25%	19%	19%	34%	33%
	Heywood (west)	41%	37%	37%	72%	69%	34%	26%	36%	40%	38%
	Heywood (east)	3%	3%	2%	2%	2%	3%	3%	2%	2%	2%
	Basslink (north)	0%	0%	11%	11%	10%	9%	8%	8%	8%	8%
	Basslink (south)	22%	22%	9%	10%	11%	8%	7%	8%	9%	9%
	Terranora (north)	2%	3%	0%	1%	1%	1%	2%	3%	1%	2%
	Terranora (south)	2%	2%	3%	3%	7%	7%	5%	5%	9%	10%
	Murraylink (west)	54%	52%	47%	58%	59%	47%	69%	71%	72%	76%
	Murraylink (east)	31%	32%	32%	31%	32%	37%	79%	71%	67%	71%
	VIC-NSW (north)	11%	8%	4%	5%	6%	3%	3%	4%	3%	5%
	VIC-NSW (south)	8%	5%	4%	4%	4%	3%	1%	3%	4%	4%

8.3) GREENHOUSE EMISSIONS

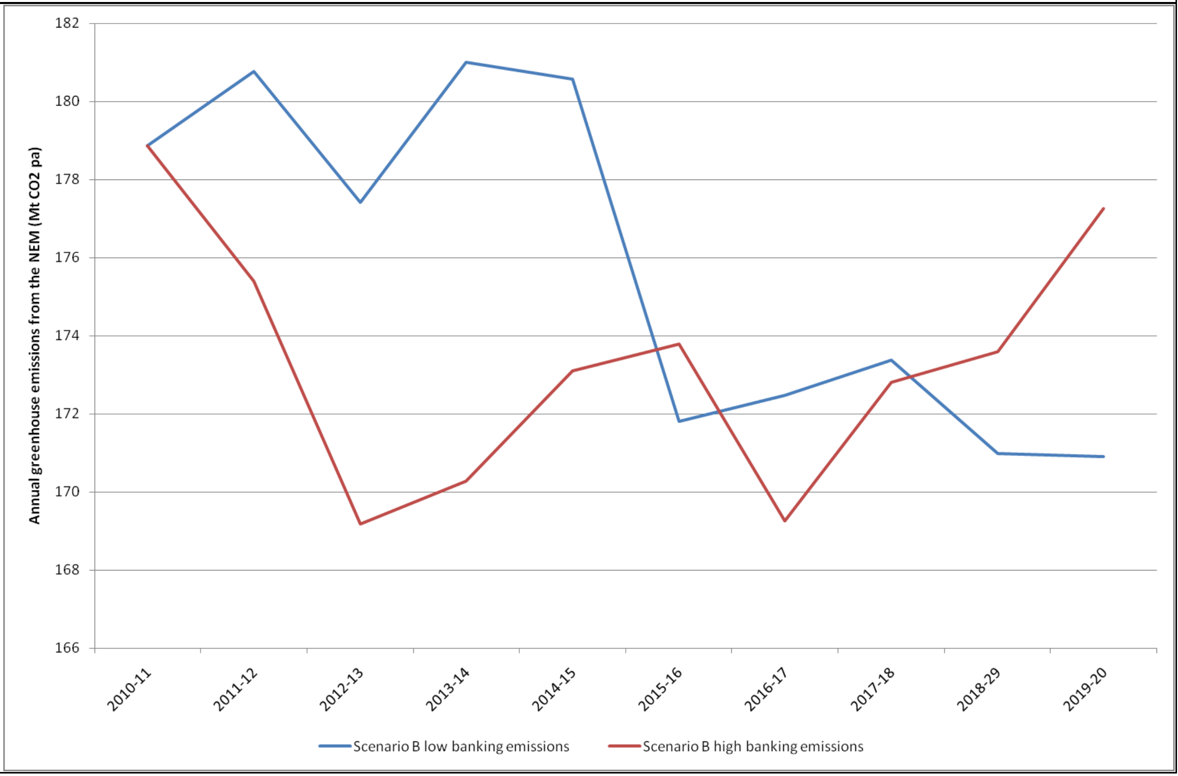
Figure 8.15 compares the annual greenhouse emissions in Scenario B under high and low levels of REC banking.

In the high banking case, emissions rapidly drop from their 2010-11 levels with the installation of 4000MW of wind generation and 2000MW of gas-fired generation. Emissions drop again in 2016-17 when the NSA geothermal plant and MEL CCGT are installed. In all other years, emissions increase with growth in demand.

In the low banking case, emissions reduce significantly in 2012-13, 2015-16 and 2018-19 when large generator installations occur.

While the annual emissions at the end of the study are higher in the high banking case, the cumulative emissions to 2020 for the high banking case are around 25 Mt CO_2 lower than the cumulative emissions in the low banking case. Nevertheless, given the greater amount of renewable generation installed in the low banking case, it is expected that beyond 2020, the low banking planting will produce significantly less emissions going forward.

Figure 8.15 – Greenhouse emissions (Scenario B)



Greenhouse emissions for the three scenarios under low banking are compared in Figure 8.16. Scenario A has slightly higher emissions than Scenario C, with the exception of years 2015-16 and 2016-17 (due to the earlier entry of the MEL CCGT plant) and 2018-19 (due to the earlier entry of the QLD geothermal plant). Scenario C has slightly lower emissions than Scenario A throughout the rest of the study due to the slightly higher capacity factor of wind farms selected in Scenario C, causing more displacement of fossil fuel fired generation.

Scenario B has very similar emissions to Scenario A, but slightly reduced from 2017-18 due to the increased efficiency of dispatch due to the installation of the SA-VIC interconnector augmentation in that year.

Figure 8.16 – Greenhouse emissions (Low banking)

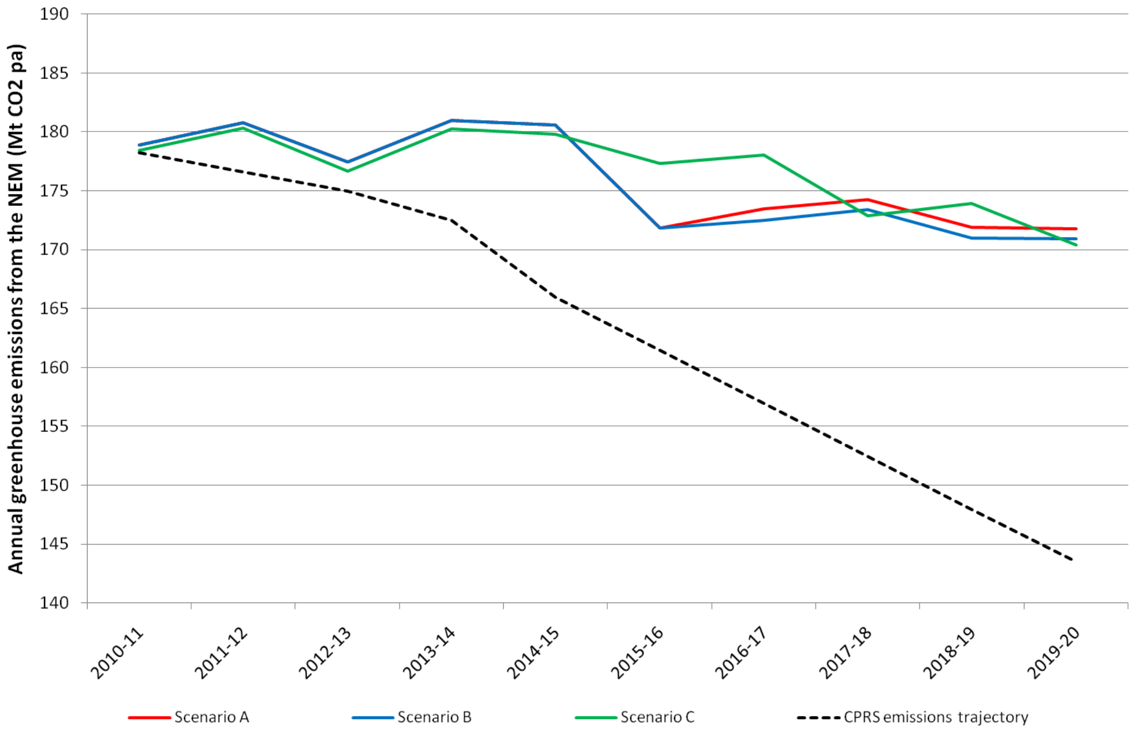
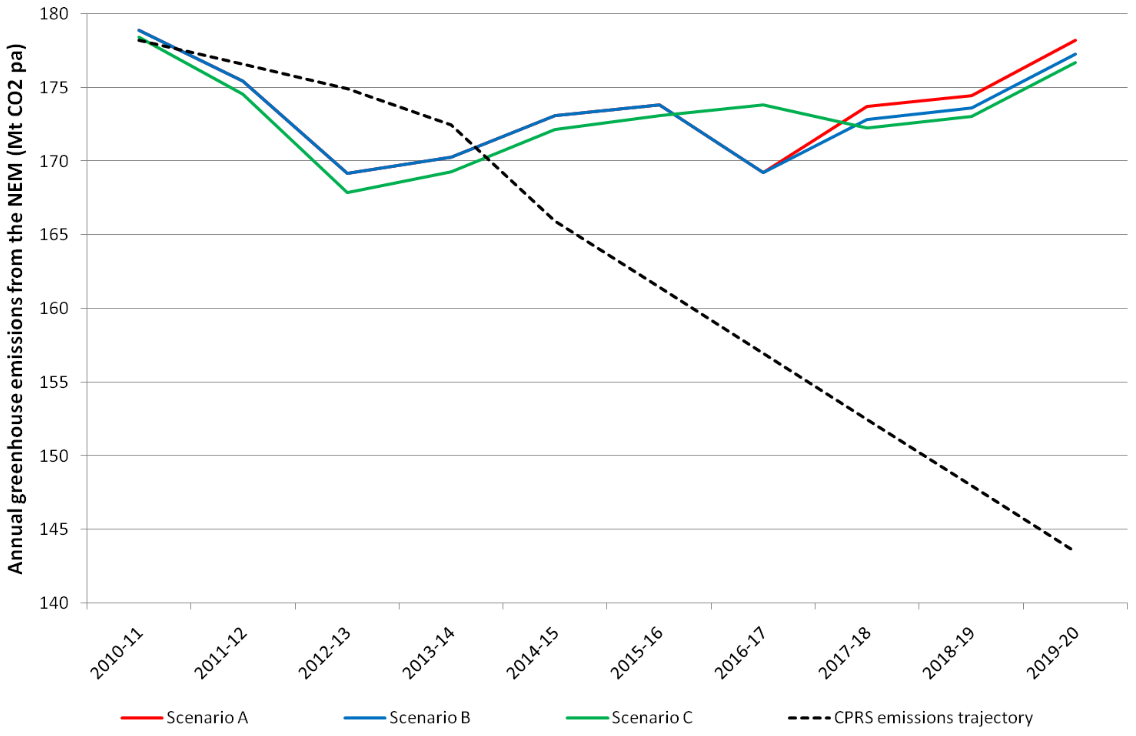


Figure 8.17 illustrates the emissions across the three scenarios for the high banking case for comparison.

Figure 8.17 – Greenhouse emissions (High banking)



9) CONCLUSIONS

Distributed installation of renewable energy around the NEM is preferable to concentrated development in one region with transmission augmentations to facilitate export of the energy to other regions. The difference in the renewable resource between regions is not sufficient to justify large transmission augmentations when more distributed renewable development is possible. With this distributed development there is no significant or persistent transmission congestion between NEM regions, with the exception of South Australia. In South Australia, transmission congestion was found to be significant, due to entry of wind and geothermal generation in the NSA zone causing congestion between ADE and NSA.

Augmentation of the SA-VIC interconnector (NSA to MEL) is suggested to be highly justified on a cost reduction basis in all scenarios analysed, with optimal installation in 2016-17 to 2017-18. This augmentation helps to alleviate the congestion on the NSA-ADE path, which causes significant curtailment of NSA plant. Allowing the system to install the SA-VIC interconnector in 2017-18 reduces system costs by $130-$149 million over ten years (2010-11 to 2019-20) through increased efficiency of dispatch, although it does not change the investment decisions of new entry generators.

Allowing generators to make profit maximising decisions, rather than utilising a central planning approach with complete system knowledge costs the system $111-173 million over ten years (2010-11 to 2019-20).

High or low levels of RECs banking under the RET scheme produces very different outcomes for renewable development, in terms of the type and location of renewable technologies installed. High banking produces a large quantity of wind generation, and excludes schedulable renewable technologies from the scheme. This is far more expensive to the system than allowing a slower rate of installation of renewable technologies, including a moderate amount of wind and allowing schedulable renewable technologies to enter, as in a low banking scenario. High or low banking is found to be the largest determining factor in system costs, indicating that correct system design for the Renewable Energy Target scheme is of very high importance to ensure efficient incentivisation under the scheme.

9.1) RECOMMENDATIONS

Investigate SA-VIC augmentation further

This study strongly suggests that the SA-VIC augmentation modelled has significant benefits to the NEM under the RET and CPRS, and is likely to be justified on a cost reduction basis. Further investigation of this transmission augmentation should include:

1. Determining the value of each of the individual sections of the augmentation (this study suggests that the NSA-ADE section is very important, but other sections of the full NSA-MEL augmentation may also be critical).
2. Determining the optimal size of the augmentation. This study analysed a 400MW bidirectional upgrade, but the very high value of this suggests that a larger augmentation may be utilised effectively, and be more cost effective.

Investigate SA-NSW augmentation further

This study suggests that a very significant 2000MW bidirectional transmission line between ADE and NCEN could provide substantial benefit to the system, recovering around 70% of its very significant cost. Optimisation of this line may make it entirely cost effective. Further investigation should include:

3. Analysis of the optimal line size, and the cost effectiveness of bigger and smaller line options
4. Analysis of the estimated cost of this line, to determine whether it could be installed for a slightly lower cost, making it cost effective.
5. Analysis of the additional benefits of this line that were not taken into account in this study (such as reductions in transmission losses, and increased market competition benefits).

Investigate retirements

Detailed investigation of retirements was not included in this study due to time limitations. However, the resulting operational mode of many emissions intensive plants suggests that many plants will face significant technical challenges operating in the modelled CPRS and RET environment. These plants may retire unless they are offered capacity payments to remain available for reliability purposes.

Further investigation on this extremely important issue should include:

6. Analysing individual plants around the NEM and determining which may retire on the basis of technically infeasible operational modes, and lack of economic justification to remain available
7. For those plants, determining the impacts of their retirement on the NEM, and examining how reliability can be maintained. This should include investigation and costing of demand side participation options, transmission augmentation options, and generation replacement options.
8. Analysing any regulatory barriers to efficient and timely retirement and replacement of emissions intensive plant.

Appendix A) Input assumptions

A.1) Load Forecast

In this study the regional Winter/Summer peak demand and annual energy growth for the NEM is based on M50[38] projections from NEMMCO's 2008 Statement of Opportunities[39].

Demand side participation

Demand side participation has not been explicitly modelled in this study. However, the use of M50 demand projections gives a moderate outcome that is consistent with some use of DSP in the NEM, compared with traditional planning which requires meeting the 10% POE demand forecast.

Significant Non-scheduled Generation

The NEMMCO load forecasts are projections for Market Scheduled load, net of the impact of the NMS generators. In this assessment, the modelling has explicitly included significant NSM wind generation as this is seen to be a key determining factor in transmission utilisation. The existing and committed non scheduled wind farms are explicitly modelled and therefore their expected production has been added back on to the M50 targets.

Reference Load Trace

The NEMMCO M50 demand and energy projections were applied in conjunction with the 2007/08 half hourly load trace as a reference to forecast future load traces using ROAM's Load Trace Synthesiser application. Selecting a recent historic load trace provides the best indication of the underlying trends in system load including minimum levels of demand, embedded generation and demand side participation. The impacts of weather on short term peak demand are normalised during the load trace forecasting process.

A.2) Carbon Pollution Reduction Scheme

The carbon price trajectory used was in real 2009 dollars, calculated from 2005 dollars (as given in the Australian Treasury modelling) with a multiplier for conversion of 1.136652, as illustrated in the table below.

[38] Medium economic growth with 50% probability of exceedence forecast

[39] It is noted that a wide range of studies have been completed and are currently underway which put a significant emphasis on the demand side of the electricity market in response to the CPRS. Alternative assumptions may provide for a significant reduction in demand, and certainly energy growth into the future. The NEMMCO demand and energy forecast are for the most part developed by NIEIR for the TNSPs and NEMMCO and do include some reduction in growth in response to an assumed emissions value, albeit relatively mild compared with other study assumptions.

Table A.1 – Carbon price trajectory					
	2005 AUD		2009 AUD		
	CPRS -5	CPRS -15	CPRS -5	CPRS -15	AEMC Path
2010-11	20.4	28.4	23.19	32.28	**23.19**
2011-12	21.1	29.3	23.98	33.30	**23.98**
2012-13	22.8	31.6	25.92	35.92	**25.92**
2013-14	24.5	34.1	27.85	38.76	**27.85**
2014-15	26.2	36.4	29.78	41.37	**29.78**
2015-16	27.9	39.8	31.71	45.24	**45.24**
2016-17	29.5	41.9	33.53	47.63	**47.63**
2017-18	30.9	43.9	35.12	49.90	**49.90**
2018-19	32.3	46.0	36.71	52.29	**52.29**
2019-20	33.8	48.0	38.42	54.56	**54.56**

A.3) Generator trading behaviour

The price data used in this study was taken from the ACIL Tasman report "Fuel resource, new entry and generation costs in the NEM: draft report" of 13 February 2009, from the NEMMCO National Transmission Statement webpage. ROAM corrected some known mistakes for Queensland generators in this data, but otherwise the data has been used as-is. The data includes assumptions about fuel prices on a generator by generator basis across the NEM, which change over time, and all values are in real 2009-10 dollars. We note that in this report, it is assumed that fuel costs for gas plants reach export parity levels over time.

Table A.2 – ROAM corrections to ACIL Tasman Data				
	Emissions Factor (tCO_2e/MWh)		Capacity / Type	
	ACIL	ROAM	ACIL	ROAM
Condamine	0.56	0.39	-	-
Darling Downs	0.53	0.39	-	-
Barcaldine	0.49	0.66	55MW / CCGT	34MW / OCGT

For the cogen stations Yarwun, Osborne, and Smithfield, we adjusted ACIL Tasman's HHV to 4.5GJ/MWh in line with the value given in the Parliamentary Library research note "Cogeneration-Combined Heat and Power (Electricity) Generation. The fuel price for Townsville (CCGT) was modified such that its SRMC was in line with Swanbank E power station.

ROAM also used ACIL Tasman values from the document "Projected energy prices in selected world regions" for the SRMC of biomass plants. ROAM assumed that the schedulable biomass plants had an SRMC of $27.38/MWh (in 2009-10 dollars) and a zero carbon emissions factor. Based on advice received through the AEMC for this assessment, all geothermal plant had an assumed SRMC of $10.50/MWh. Wind farms are bid into the market at $0/MWh. The bids of renewable generators do not incorporate the RECs price.

The SRMC bids of the generator are uplifted by the emissions cost to the generator ($/MWh), equal to the carbon pollution permit price ($/t$CO_2$) multiplied by the emissions factor of the generator (tCO_2/MWh). In this way, the carbon price is incorporated into the strategic bidding of existing generators. As generators are paid only for sent-out generation, the bids must also take the auxiliary factor of each generator into account so that generators can recover all of the carbon price impost.

In order to minimise possible generator cycling during off-peak periods, the prices for generators with multiple units are adjusted by small amounts (from $0.01 to $0.09) so that large generators do not turn on and off all at once. As the market simulation only takes generated SRMCs into account this measure is employed to avoid such uneconomic outcomes.

A.4) Wind farm modelling

Existing wind farms

The larger existing wind farms are modelled explicitly in the IRP, so that their effect on transmission has been correctly included. Non scheduled wind farms that are currently in operation and are modelled explicitly are listed in the table below. These wind farms are typically netted off demand forecasts, and so must be added onto the demand forecasts when modelled explicitly. To do this, ROAM creates the generation trace for the wind farm using WEST, ROAM's Wind Energy Simulation Tool. The resulting energy production from the non scheduled wind farms is then added onto the scheduled energy forecast, and contribution to peak demand added onto the peak demand forecast for creating the regional half hourly load forecasts.

Table A.3 – Existing (operating) wind farms – Non scheduled

Wind farm	Capacity (MW)	ANTS zone	Contribution to peak demand (MW)	Classification	Status
Canunda	46	SESA	7	Non-scheduled	Operating
Cathedral Rocks	66	NSA	10	Non-scheduled	Operating
Lake Bonney	80.5	SESA	12	Non-scheduled	Operating
Mt Millar	70	NSA	11	Non-scheduled	Operating

Market Scheduled[40] wind farms that are currently in operation (and are modelled explicitly by ROAM) are listed in the table below.. These wind farms are not typically netted off demand forecasts, and therefore are not added onto the load traces.

[40] Market Scheduled wind farms are non-schedulable, but use wind forecasting tools to bid their expected generation into the market.

Table A.4 – Existing (operating) wind farms - Scheduled					
Wind farm	**Capacity (MW)**	**ANTS zone**	**Contribution to peak demand (MW)**	**Classification**	**Status**
Snowtown	99	NSA	15	Scheduled	Operating
Lake Bonney stage 2	159	SESA	24	Scheduled	Operating
Hallett (Brown Hill)	94.5	NSA	14	Scheduled	Operating

Committed wind farms

The table below lists the committed wind farms that have been included by ROAM in every scenario. These committed non-scheduled wind farms have been explicitly modelled and accommodated into the regional load trace forecast development as described above. Forecast production from non scheduled wind farms is added onto demand and energy forecasts as described previously.

Table A.5 – Committed wind farms					
Wind farm	**Capacity (MW)**	**ANTS zone**	**Contribution to peak demand (MW)**	**Classification**	**Status**
Cape Bridgewater (Portland Stage 2)	58	MEL	9	Non-scheduled	Committed
Cape Nelson South (Portland Stage 3)	44	MEL	7	Non-scheduled	Committed
Capital Bungendore	132	CAN	19	Non-scheduled	Committed
Cullerin Range	30	CAN	5	Non-scheduled	Committed
Waubra	192	CVIC	29	Non-scheduled	Committed
Clements Gap	57	NSA	9	Non-scheduled	Committed, commissioning 2010
Hallett Stage 2 (Hallett Hill)	71	NSA	11	Scheduled	Committed, commissioning 2009/10
Lake Bonney Stage 3	39	SESA	6	Scheduled	Committed, commissioning 2010

A further 1000MW of wind is assumed to be installed in NSA by the commencement of the study in 2010-11, as at least this capacity is required to meet the expanded Renewable Energy Target and ROAM's research suggests NSA is the most likely zone for the first 1000MW. The capacity factor and make-up of this block (NSA Wind Station 1) is described below.

New (non-committed) wind farms

Wind farms are planted in 1000MW blocks, which are assumed to contribute 15% of their capacity (150MW) to peak demand. The actual contribution is derived by simulating each wind farm based on recorded data from the nearest BOM site throughout 2007/08, to be consistent with the use of the 2007/08 demand profile as the reference profile for producing forecast load traces.

The quality of the wind resource available in each zone is assessed based on announced (proposed) wind farms, and on wind resource maps from the Australian Renewable Energy Atlas[41]. In each zone, half-hourly generation traces (and hence the capacity factors) of each proposed wind farm are calculated using WEST, ROAM's Wind Energy Simulation Tool. WEST uses data from the Bureau of Meteorology and the Australian Renewable Energy Atlas to generate generation traces of wind farms based on geographical location and turbine specifications.

Average wind farm capacity factors are expected to decrease as the number of installed wind farms increases, and less attractive sites are utilised. This is modelled by including multiple "tiers" of wind farms in each zone:

- ***Tier 1:*** The capacity factor for the first tier is averaged from the best 600-1000MW of proposed projects. This represents the best available wind resource in a region or zone.
- ***Tier 2:*** Average capacity factor of the next best projects (up to 1000MW).
- ***Tier 3:*** In zones with potential capacity of 3000MW, the third tier is expected to utilise the same resource (same capacity factor) as Tier 2.

In zones with insufficient projects to fill 1000MW, projects in these zones are divided into two Tiers representing the best resource (Tier 1) and next best resource (Tier 2), thus allowing for future unannounced developments.

In the event that average capacity factors are not in line with ROAM's initial estimates (based on external factors, such as overall wind resources), slight adjustments to the above procedure are carried out (e.g. removing outliers, such as poorly performing wind farms not considered to be representative of the true resource of the region).

For Queensland, Victoria and New South Wales, wind farms are planted sequentially across zones according to the best available (highest capacity factor) blocks, adjusted by ROAM's research on the feasibility of planting schedules. Zones with limited wind resources are not modelled (LV, NVIC, NNS, SWNSW, SEQ, CQ, ADE). Wind farms in South Australian zones NSA and SESA are allowed to enter independently, due to the more significant congestion issues in this area and available resource. The first NSA station is assumed to be committed, for operation in 2010-11, as the most likely new renewable generation to meet the expanded Renewable Energy Target.

[41] http://www.environment.gov.au/settlements/renewable/index.html

New wind farm projects

The specific wind farm locations used to produce the capacity factor and generation traces for each tier/zone are given in the table below. It should be noted that the wind farms do not add up to the 1000MW block included in the IRP model in most cases. This is to allow for new projects that may fall within that tier/zone. The first tier generally includes a larger number of announced projects, since it will be constructed first in the IRP and should consist of the more advanced projects. Later tiers allow for a larger number of new, as yet unannounced, projects at that lower resource quality level.

The total generation capacity, and hence the generation in each half hourly period, for each block is then scaled up to 1000MW, maintaining the predicted capacity factor.[42]

The wind farms listed below are used to produce the aggregate generation traces for each zone/tier, but should be used as an indicative guide to the resource in each zone only; not all listed projects will necessarily be constructed.

Table A.6 – Representative wind farms

Region	ANTS Zone	Tier	Wind farm	Capacity (MW)	Capacity Factor
QLD	SWQ	1	Coopers Gap	500	30.17%
			Crows Nest	124	28.50%
	NQ	2	Archer Point	120	31.44%
			Crediton	30	27.27%
	SWQ	3	High Road[43]	40	28.26%
			North Stradbroke	15	23.63%
NSW	CAN	1	Snowy Plains	10	35.36%
			Crookwell II	92	33.29%
			Evandale Goulburn	30	31.17%
			Woodlawn Tarago	50	31.17%
			Gullen Range	150	31.17%
			Conroys Gap Yass	30	30.44%
			Goulburn	10	29.84%
			Gurrundah	35	29.84%
			Gunning	62	29.20%
			Molonglo	120	29.20%
			Snowy Plains	10	35.36%

[42] All wind generation data is prepared at half hourly intervals. The modelling is then dispatched hourly (due to time constraints for this project).

[43] Due to the limited proposed resources in SWQ but higher perceived capacity, ROAM has used proposed SEQ wind farms to generate the third tier for QLD. However, ROAM expects that if a third (1000MW) block is produced, it would be in SWQ, and hence has planted the wind in SWQ zone.

Table A.6 – Representative wind farms					
Region	**ANTS Zone**	**Tier**	**Wind farm**	**Capacity (MW)**	**Capacity Factor**
		2	Anembo	150	25.90%
			Woodlawn 2	150	25.90%
	NCEN	1	Taralga	105	30.37%
			Black Springs	20	28.16%
			Paling Yards	90	27.53%
			Spring Hill	10	27.21%
		2	Silverton	1150	25.02%
VIC	MEL	1	Cape Nelson 2	66	35.62%
			Cape Wililiam Grant	66	35.62%
			Woorndoo	26	31.54%
			Point Lonsdale	5	30.58%
			Stockyard Hill	200	30.55%
			Lal Lal	160	30.36%
			Ballan	90	30.36%
			Salt Creek	30	29.32%
			Drysdale Purnim	30	28.54%
			Woolsthorpe	25	28.54%
		2	Breamlea Black Rock	2	28.00%
			Baynton	50	27.97%
			Macarthur	329	27.56%
			Sidonia Hills	120	27.12%
			Science Works	2	26.34%
			Pipers Creek	150	25.85%
	CVIC	1	Nirranda South	50	35.43%
			Hawkesdale	62	34.52%
			Newfield	22.5	34.29%
			Naroghid	42	32.71%
			Morton's Lane	30	31.75%
			Berrimal	24	30.60%
			Leonards Hill	4	30.36%
			Dean	20	30.36%
			Mt Mercer	160	29.24%
			Bald Hills	104	28.20%
			Lexton	28.5	28.20%
			Pyrenees	200	28.20%

Table A.6 – Representative wind farms					
Region	**ANTS Zone**	**Tier**	**Wind farm**	**Capacity (MW)**	**Capacity Factor**
			Hepburn Daylesford	4	28.20%
			Oaklands Hill	30	27.53%
		2	Yaloak	105	27.21%
			Crowlands Glenlofty	140	26.70%
			Mount Gellibrand	232	26.23%
			Mortlake 1	100	25.20%
			Mortlake 2	164	25.20%
			Tuki	28.5	25.14%
TAS	TAS	1	Mussleroe	130	37.67%
			Flinders Island	3.4	36.66%
			Granville Harbour	30	35.49%
			Robbins Island	100	34.93%
SA	NSA	1	H5 Bluff Range	50	44.34%
			H4 (N Brown Hill)	132	43.37%
			Elliston Stage 1	55	37.28%
			Elliston stage 2	65	37.28%
			Loch Well Beach	54	37.28%
			Sheringa Beach	100	37.28%
			Tungketta hill	49.5	37.28%
			Willogoleche Hill	52	36.67%
			Troubridge Point	25	35.76%
		2	H3 Mount Bryan	60	44.34%
			Robertstown	100	30.98%
			Worlds End	200	30.98%
			Uley	160	30.67%
			Mt Millar extn	60	29.60%
			Eyre Peninsula	100	28.40%
			Lincoln Gap	123.9	28.30%
		3	Barunga	170	33.21%
			Collaby Hill	120	28.50%
			Lochiel	200	28.50%
		4	Barn Hill	120	27.45%
			Shea Oak Flat	59	24.55%
	SESA	1	Cape Jaffa	200	34.01%
			Mount Benson	130	34.01%
			Lake Eliza	50	30.66%

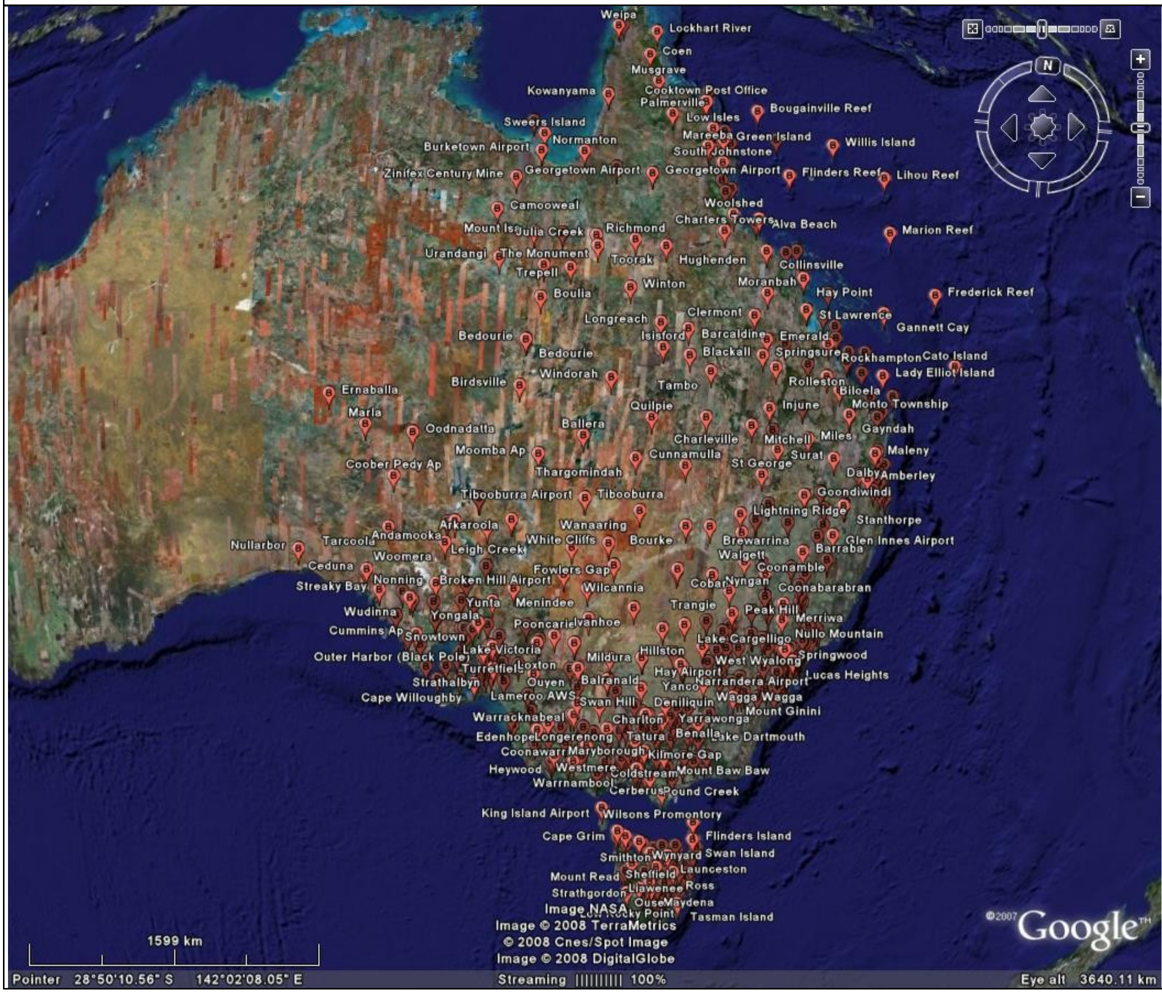
Table A.6 – Representative wind farms					
Region	**ANTS Zone**	**Tier**	**Wind farm**	**Capacity (MW)**	**Capacity Factor**
			Lake George	120	30.66%
			Lake Hamilton	110	30.21%
		2	Woakwine	100	27.61%
			Kongorong	30	25.74%
			Green Point	44	24.71%

A.5) Modelling of Wind Farm Generation

Wind modelling is performed using WEST, ROAM's Wind Energy Simulation Tool. WEST generates half hourly generation traces for wind farms based on historical data from the Bureau of Meteorology, location specific wind speed simulations from the Australian Renewables Atlas and manufacturer provided turbine power curves. These are used as input to the IRP for explicit modelling of wind farm generation and transmission congestion modelling.

WEST requires as input the average wind speed at the wind farm site for each half hourly period. Historical data was sourced from automatic weather stations around Australia from the Bureau of Meteorology. The locations of the weather stations in eastern Australia are shown in the figure below.

Figure A.1 – Locations of BOM weather stations



The wind data from the Bureau of Meteorology (BOM) weather stations was taken at a variety of elevations (from 1m off the ground to 70m above the ground), and elevation strongly affects wind speeds. The wind at the height of a turbine hub (from 50m to 80m) will be much faster than the wind at ground level, and the amount of the increase in speed is strongly dependent upon many factors, including the type of ground cover (rock, grass, shrubs, trees) and the nature of the weather pattern causing the wind. In addition, the local topography affects wind speeds very strongly (winds tend to be focused by flowing up hillsides, for example).

However, it is reasonable to assume that the wind speeds at the weather station will be very highly correlated in time with the wind speeds at the turbine site (analysis of existing wind farm generation profiles compared with the BOM weather station data has shown this to be the case).

To provide the absolute scaling, ROAM uses data from the Renewable Energy Atlas of Australia[44]. The Atlas contains modelling data provided by Windlab Systems giving the

[44] http://www.environment.gov.au/settlements/renewable/

mean annual wind speeds, at a typical turbine height of 80m, at 3km resolution for most of Australia. The mean wind speed at the wind farm site is used to scale the data from the closest weather station to provide an estimate of the wind speed time series at turbine height.

Finally, the wind speeds are adjusted (reduced) to account for turbulence and shading across the wind farm (the “park effect”), calibrated by historical generation from existing wind farms and historical wind speeds from the BOM.

ROAM’s WEST program then applies a turbine power curve to convert the wind speeds into actual generation for input into 2-4-C (this accounts for the fact that the efficiency of turbines varies strongly with wind speed). As a final check, the annual time of day average generation is compared to historic data, and the output adjusted if necessary to achieve an appropriate time of day average generation curve. This accounts for qualitative differences between time of day wind speed distributions at hub height versus the BOM stations.

This method captures the daily and seasonal variation of wind at different sites, and also the likely correlation between the output of nearby wind farms (which is highly material for transmission congestion).

There is very good agreement between the results of this method and the known output of existing wind farms. As a benchmarking exercise, ROAM compared the historic generation profile of Lake Bonney Stage 2 with a generation profile developed with the WEST as described above. The figure below shows that the average annual generation duration curve for the wind farm forecast using the WEST is very close to the 2008 historic year, while Figure A.3 demonstrates that on a half-hourly basis (here a week-long generation trace) historic and forecast generation levels are highly correlated. The nearest weather station to Lake Bonney is the Mount Gambier weather station. The 2008 capacity factor of the historic generation data was found to be 27.0%, compared to 25.6% predicted by ROAM’s modelling. The modelled generation provides a very good approximation to the historic generation profile on a half hourly basis, with a strong correlation of 0.56.

ROAM is therefore confident that this methodology produces wind generation output traces that are a good approximation for the half hourly output of wind turbines, capturing intermittency, ramp rates and capacity factors accurately.

Figure A.2 – Lake Bonney Stage 2 Generation Duration Benchmark

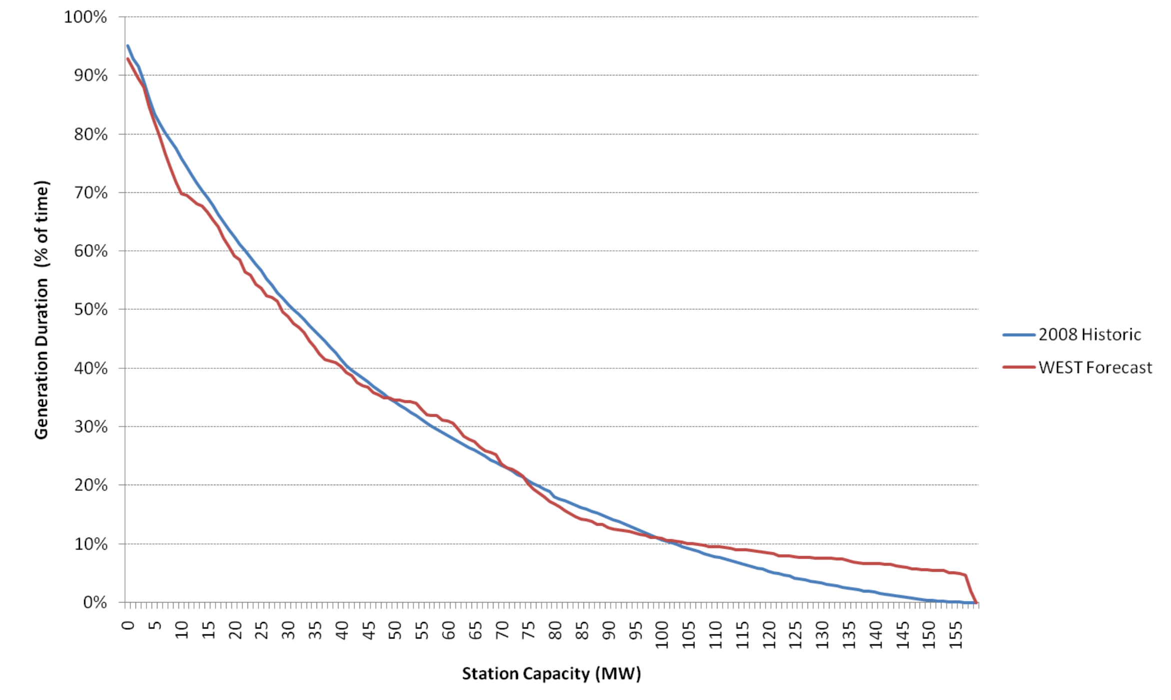
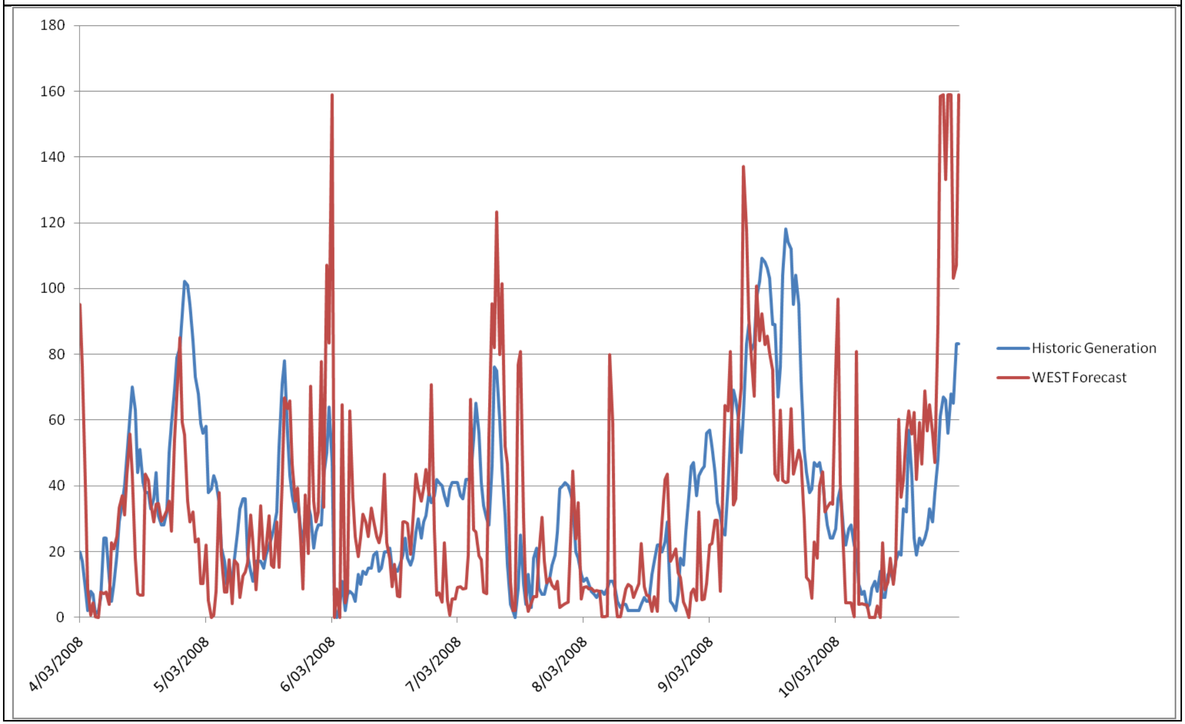


Figure A.3 – Lake Bonney Stage 2 Half Hourly Generation Benchmark



A.6) Renewable Energy Targets

Two independent cases are analysed, to evaluate the effects on transmission of early renewable investment (and consequent banking of renewable energy certificates (RECs)) versus an investment trajectory that closely matches the legislated annual REC trajectory (with minimal banking).

In both cases, ROAM assumes that existing renewable projects (both pre- and post-1997) will continue to contribute energy as they have historically. ROAM assumes that new wind farms will contribute towards meeting this target with the capacity factors listed in Section 5.5.5), and that schedulable renewable generators will contribute 75% capacity factors. Committed wind farm projects are also included, as well as the first tier wind farm block in NSA and the geothermal plant in NSA, which are assumed to be committed in the model.

At the carbon prices used in this modelling study, ROAM considers it highly unlikely that significant renewable projects will enter the market to produce RECs in excess of the cumulative RET before 2020. Production of RECs over the cumulative target will result in an oversupply and subsequent drop in the REC price, and pre-2020 carbon prices alone are deemed insufficient to drive investment in renewable projects, ahead of conventional (gas) generation.

Case 1: Low banking

In this case, the annual RECs produced must meet the Australia-wide targets in each year. This equates to 60,000GWh of renewable energy in 2020 in Australia. ROAM scales the annual Australia-wide amount by 86% to include only renewable projects in the NEM (since WA and NT are not being modelled in this case. 14% of the load in Australia is located outside of the NEM, and it is assumed that renewable development will be largely in line with this proportion). This means that the target is just over 52,000GWh of renewable energy in the NEM by 2020.

The figures in the table below are the RECs which must be produced by new plant, in addition to the RECs which will be produced by existing and committed renewable plant.

Table A.7 – Low banking annual REC lower bounds

Year	Annual GWh which must be produced from new renewable sources
2010-11	116
2011-12	1750
2012-13	3384
2013-14	5018
2014-15	6652
2015-16	9447
2016-17	10118
2017-18	14074
2018-19	18030
2019-20	21986

A state in a given year is modelled in this case provided that new generators produce at least the number of RECs given in the table in that year.

Case 2: High banking

In this case, there is significant investment above the NEM-wide targets of Case 1 in early years, and less investment in later years. The excess RECs produced in the early years can be banked and surrendered in later years of the study. Thus, after an early flurry of investment and a rapid ramp-up in REC production, the number of RECs produced annually settles to a constant amount. This is realistic under the assumption that the carbon price alone will be insufficient to support renewable investment prior to 2020.

The table below gives the RECs which must be produced by new plant, in addition to the RECs which will be produced by existing and committed renewable plant under the significant banking scenario. These numbers were chosen taking into account estimated maximum renewable build rates.

Table A.8 – High banking annual REC lower bounds

Year	Annual GWh which must be produced from renewable sources
2010-11	2530
2011-12	7590
2012-13	12650
2013-14	15180
2014-15	15180
2015-16	15180
2016-17	15180
2017-18	15180
2018-19	15180
2019-20	15180

A state in a given year is modelled under this case provided that new generators produce at least the number of RECs given in the table in that year.

A.7) The Transmission Model

ANTS Constraints

The dispatch model for the IRP implements the 2008 NEMMCO ANTS constraints as supplied by NEMMCO with the annual Statement of Opportunities. These constraint equations define intra- and interconnector flow limits in terms of generation, demands and flows. A constraint equation for an interconnector is defined in a particular direction and is of the following form:

$$X * Flow_{InterconnectorA_{DirectionB}} + Y * Output_{GenA} \leq$$
$$Constant + Z * Demand_{RegionA} + P * Output_{GenA} + Q * Output_{GenB} + R * Flow_{InterconnectorB_{DirectionA}}$$

$where:\ X, Y, Z, P, Q$ are constants

Appendix B) Integrated Resource Planning: Models and Methodology

B.1) Introduction

ROAM's Integrated Resource Planning Suite (IRP) can be used to find cost-effective generation and transmission expansion plans for any power system, given client-specified parameters and constraints. IRP takes into account existing supply, forecast demand, and financial and regulatory considerations, to produce an optimal new entry generation development, retirement, and transmission upgrade schedule over the duration of the study. One advanced feature of IRP is its capacity to deal with systems separated into disparate yet interconnected nodes, and to find solutions satisfying both nodal and global constraints.

The scope of an IRP study is limited only by available computing power, or equivalently, the time available to run the program. Given a fixed amount of computing power, the scope of an IRP study can be traded off against the study's duration.

The IRP methodology is in accordance with world's best practice, and applies an underlying model and solution algorithm similar to that employed by the WASP (Wien Automatic System Planning) program developed by the International Atomic Energy Agency. WASP is currently one of the most widely used models for power system planning.

ROAM's IRP has been used since 2001 to assist clients with their long-term planning decisions. The IRP suite undergoes continual in-house development, to model a broadening range of industry and government constraints and regulations.

B.2) A Mathematical Basis For Integrated Resource Planning

The mathematical theory underpinning IRP is well-established and has application across a diverse range of problems. In this section we outline the techniques employed by ROAM's IRP model.

Multistage Decision Processes

A *multistage decision process* is a process that can be separated into a number of sequential steps or stages, which may be completed in one or more ways. The options for completing the stages are called *decisions*. A *policy* is a sequence of decisions, one for each stage of the process. The condition of the process at a given stage is the *state* at that stage.

We shall be concerned with multistage decision processes which are *finite* (there is a finite number of stages, and at each stage there is a finite number of associated states) and *deterministic* (the state produced by a decision is known exactly). The states at which the system can arrive at the end of a multistage decision process are the *terminal states.*

Typically, multistage decision processes have costs or benefits associated with each decision, which depend upon both the state and stage of the process. The cost (or benefit) of a policy is the sum of the costs (or benefits) associated with each of its decisions. The objective in analysing such processes is to determine an *optimal policy*, namely one which results in the best possible return (for example, a minimal cost or maximal benefit).

Developing an expansion planning model

Power system expansion planning is a textbook example of a deterministic, multi-stage decision process. The *stages* of the process are typically the years in the study's timeline. The *starting state* consists of the combination of generators and transmission assumed to exist at the start of the study. In general, *states* are the configurations of existing and new candidate generators (of various types, in various locations) and transmission augmentations, which can be reached from the starting state by building and retiring plant according to the specified constraints. For convenience we refer to both generator and transmission augmentation options as *stations*.

If there are x candidate stations for installation and y candidate stations for retirement, then there are 2^{x+y} states. However, IRP studies have fewer than this maximum number of states, to reflect real-world and computational constraints. For example,

- energy security regulations and
- limits to annual capital expenditure

contain the states at each stage. Nevertheless, trade-offs must be made between the accuracy of the estimation of costs, and the percentage of the state space explored. ROAM's approach focuses on the desire to maintain very credible dispatch, taking into account transmission limitations and time sequential hourly dispatch, to yield an excellent estimate of production costs. Thus, we introduce additional computation constraints to narrow down the search space. These computation constraints determine the quality of the solution produced by IRP; if they are poorly chosen, then the global optimum schedule will lie (wholly or partially) outside the space searched by IRP.

The following constraints have been applied to the states.

- A *lower bound on installed capacity*: In each year and region, the installed capacity is at least the sum of the region's forecast M50 peak demand for that year and the region's (2009) minimum reserve level.

  Interconnectedness of the system is one of the key factors affecting the computation of minimum reserve levels. If a network upgrade between regions is selected, the minimum reserve levels of the regions at either end of the upgrade are reduced by 25% of the total capacity of the link. However, as unserved energy is valued at the market cap, this does not mean that installed capacity will reduce, but rather that the search space will be expanded to allow capacity growth to slow if that is an economic decision.
- *Maximum build rate*: In any year, two candidate generators of the same type (CCGT, OCGT, wind, base load renewable) cannot be installed in the same ANTS zone.
- A *REC trajectory (high or low banking)*: Based on the features of the proposed Renewable Energy Target, we define two trajectories of REC production, reflecting different market responses to the legislation (high vs low banking). The specific REC production trajectories in these scenarios are discussed in Section 5.6). Let C

be the set of new and existing stations in year y, let R(C) be the set of new renewable generators (built in years 1 to y of the study) and let R(C,y) be the set of renewable generators built in year y (so $R(C,y) \subseteq R(C)$). Then C satisfies the low (high) banking scenario REC trajectory provided that

- generators in R(C) together produce at least the RECs required in year y by the low (high) banking REC production trajectory; and
- for each *x* in R(C,y), the generators other than *x* in R(C) produce less than the RECs required in year y by the low (high) banking REC production trajectory. That is, renewable generators are built to 'only just' meet the low (high) banking REC production trajectory.

For technical reasons associated with the recording of transitions between states, the current IRP suite cannot deal with cumulative constraints. For this reason, two annual REC trajectories, rather than a single cumulative REC target were applied. The ability to deal with cumulative constraints is currently under development.

- A *thermal upper bound*: Let *A* be a region, let $\text{Demand}_y(A)$ be the forecast demand for region *A* in year *y* and let MRL(*A*) be region *A*'s (2009) minimum reserve level. We consider a configuration *C* of new and existing plant in year *y* and let
  - C_A be the set of plant installed in region *A*; and
  - T_A be the set of thermal plant built in year *y* in region *A*.

We split the conditions for satisfying the thermal upper bound in region *A* into three mutually exclusive cases:

Case 1: T_A is empty.

In this case, *C* immediately satisfies the thermal upper bound for region *A*.

Case 2: T_A is non-empty and *C* contains no interconnector upgrades with *A* as an end-node.

In this case, *C* satisfies the thermal upper bound in region *A* provided that for each *x* in T_A,

$$\text{Capacity}(C_A) - \text{Capacity}(x) \leq \text{Demand}_y(A) + \text{MRL}(A)$$

That is, all newly-built thermal plant in a region not affected by any interconnector upgrades must be required to meet the lower bound in that region.

Case 3: T_A is non-empty and *C* contains interconnector upgrade(s) with *A* as an end-node, with a total capacity of m_A MW and providing a total support of s_A MW to region *A*.

Method 1 – applied to the low banking scenario.

In this case, *C* satisfies the thermal upper bound in region *A* provided that for each *x* in T_A

$$\text{Capacity}(C_A) - \text{Capacity}(x) \leq \text{Demand}_y(A) + \text{MRL}(A) - 0.25m_A$$

That is, all newly-built thermal plant in a region affected by interconnector upgrade(s) must be required to meet the adjusted lower bound in that region.

Method 2: - applied to the high banking scenario.

In this case, *C* satisfies the thermal upper bound in region *A* provided that for each *x* in T_A

$$\text{Capacity}(C_A) - \text{Capacity}(x) \leq \text{Demand}_y(A) + \text{MRL}(A) + s_A$$

This allows the interconnector benefit to be fully explored; configurations without upgrades and expanded local capacity can be compared with those with an upgrade and displaced or reduced capacity. Ideally, Method 2 would be applied to both high and low banking scenarios; however, the huge number of states under the low banking scenario precluded the use of Method 2 given the time constraints of the project.

A state must satisfy the thermal upper bound in *every* region.

It is assumed that new renewable generators will be built in the best location, regardless of the local supply-demand balance, as their bids (at their short-run marginal cost) will undercut the bids of existing thermal generation. The maximum build rate is the only location-specific bound applied to the capacity of newly-built renewable generators.

The number of states grows from hundreds in earlier stages, to hundreds of thousands in later stages of a study.

A graphical representation

It is often helpful to visualise a multistage decision process as a flow chart or directed graph. Time (in stages) is indexed from left to right, with states at each stage represented by a vertex (or node) in the graph. (We shall not distinguish between a state and its corresponding vertex in the graph.) A state's decisions are the endpoints of the arrows from that state.

We consider the following illustrative 3-year multistage decision process.

There are three candidate wind stations, TAS, QLD and VIC, with annual capital costs and capacity factors resulting in annual RECs generation as follows.

Wind farm	Yearly REC contributions
TAS	3000
QLD	2500
VIC	2800

The states at each stage and their decisions obey the following constraints.

- At most one wind farm can be built per year.
- Once built, a wind farm cannot be retired.
- The RECs produced each year by new candidate wind generators must meet or exceed the numbers given in the following table.

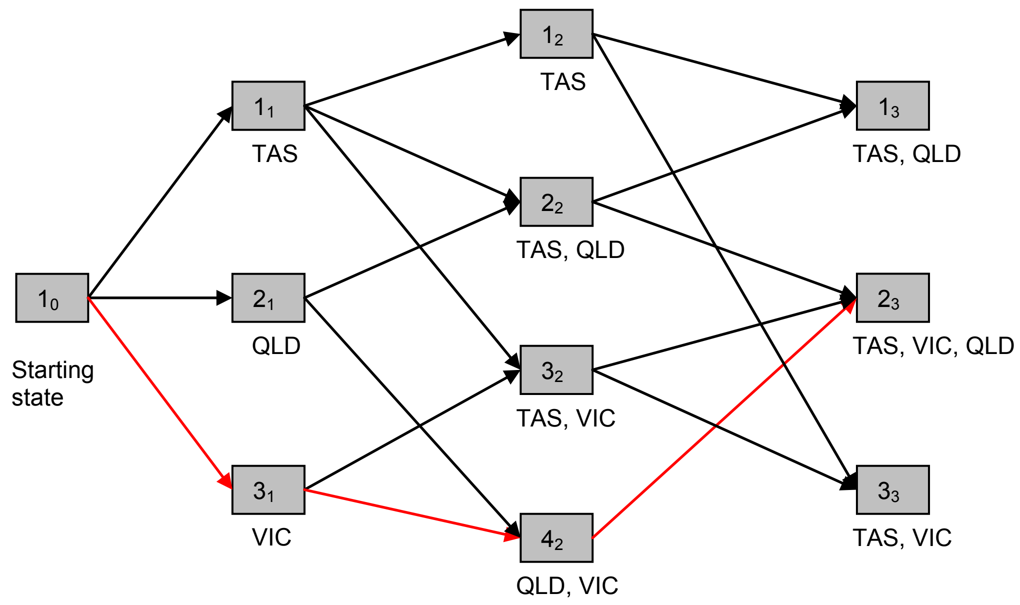
Year of study	REC target
1	800
2	3000
3	5500

The graph depicting states which satisfy these constraints at each year and their decisions is given in Figure B.1. Let m_t denote the number of states at time t. We label the states at time t by 1_t, $2_{t, \dots ,}$ m_t (so for example, the unique starting state is labelled 1_0).

Note that this example does not capture the typically combinatorial growth in states at each stage, due to the limited number of candidate plants and tight constraints.

One policy is the sequence of states (in order from left to right) given by the red path. In the next section, we discuss the assignment of costs to each vertex (the state's run cost) and each edge (the state's capital and fixed O&M costs).

Figure B.1 – An example 3-stage decision process



Costs of a state

The total cost associated with each state is the sum of:

- the net present value of the variable operating costs (fuel, operation and maintenance (O&M), carbon emissions);
- the net present value of the fixed O&M costs; and
- the net present value of the annual capital repayments.

We now discuss in more detail each of these summands.

Run cost

Let Run(s, y) be the real sent-out run cost in \$/MWh of station s in year y. Then

$$\text{Run}(s, y) = f(s,y)h(s) + e(s)h(s)p(y) + v(s)$$

where

- f(s,y) is the real fuel price (in \$/GJ) of station s in year y;
- h(s) is the real sent-out heat rate of station s (in GJ/MWh);
- e(s) is the real sent-out carbon emissions factor of station s (in T/GJ),
- p(y) is the real carbon price (in \$/T) in year y; and
- v(s) is the real sent-out variable O&M of station s (in \$/MWh).

To accurately estimate the generation of each station in a state, the corresponding configuration of generation and transmission is input into ROAM's state-of-the-art electricity market forecasting package, ***2-4-C®***. Generators bid into the market at their sent-out short-run marginal cost, at hourly dispatch intervals, and the generation and revenue of each generator in each state is recorded.

Simulation of the states at each stage occupies the majority of time in a study. However, important aspects of the NEM that determine factors such as the expected unserved energy of a state would not be seen in a more simplistic model.

Let

- ς_y be a state in the y^{th} year of the study;
- DVar(s, ς_y) be the discounted variable cost of station s in state ς_y;
- Gen(s, ς_y) be the generation in MWh of station s in state ς_y (obtained from ***2-4-C®***);
- Run(s, ς_y) be the real run cost in \$/MWh of station s in state ς_y; and
- let *i* be the discount rate (nominally 10% weighted average cost of capital (WACC)).

Then

$$\mathrm{DVar}(s, \varsigma_y) = \mathrm{Run}(s, \varsigma_y)\mathrm{Gen}(s, \varsigma_y)(1+i/100)^{-(y-0.5)}$$

(The run costs are assumed to be paid mid-year and are discounted accordingly, to approximate expenditure throughout the year).

Let U(ς_y) be the amount of unserved energy (in MWh) in state ς_y, and let VoLL (equal to the market cap) be the cost of unserved energy (in \$/MWh). Let *S* be set of all stations. The discounted *run cost of* ς_y is given by

$$U(\varsigma_y)\mathrm{VoLL}(1+i/100)^{-(y-0.5)} + \sum_{s \in S} \mathrm{DVar}(s, \varsigma_y)$$

Annual capital costs and fixed O&M – transitional costs

In each year, the annual capital repayments and fixed O&M of existing stations are constant across all states (as in this study there are no retirements). As such, they are not included in the calculation of the total cost of a state. The real total capital cost and real annual fixed O&M of new entry generators is based on ACIL Tasman data prepared for NEMMCO. Interconnector capital costs and fixed O&M have been provided by TNSPs.

Let RCap(s,ς_y) be the real annual capital cost of station s in state ς_y and let TCap(s,y) be the total real capital cost of building station s in year y. A learning curve is currently not applied to capital costs, so TCap(s,y) is constant over all y.

Then RCap(s,ς_y)=0 if station s is not installed in state ς_y. Otherwise,

$$\mathrm{RCap}(s, \varsigma_y) = \mathrm{TCap}(s,y)i/(1-(1+i/100)^{-n})$$

where i is the discount rate (nominally 10% WACC[45]) and n is the lifetime of the annuity (nominally 30 years)[46]. We note that since the lifetime of the annuity is longer than the duration of the study, no capital costs of new entry plant will be sunk in the study. No retirements have been considered in this study; nevertheless, in general, plant which has ongoing capital repayments is never a candidate for retirement. Let

- DCap(s, ς_y) be the discounted annual capital cost of station s in state ς_y;
- DFix(s, ς_y) be the discounted annual fixed O&M of station s in state ς_y; and
- RFix(s, ς_y) be the real annual fixed O&M of station s in state ς_y.

Then

$$\mathrm{DCap}(s, \varsigma_y) = \mathrm{RCap}(s, \varsigma_y)(1+i/100)^{-y}$$

$$\mathrm{DFix}(s, \varsigma_y) = \mathrm{RFix}(s, \varsigma_y)(1+i/100)^{-(y-0.5)}$$

(Fixed O&M is assumed to be paid mid-year, whereas capital costs are paid at year-end, as in an ordinary annuity). Note that if s is an existing station then RCap(s, ς_y) = RFix(s, ς_y) = 0 for each year y and state ς_y.

The discounted *transitional cost to* ς_y is given by

$$\sum_{s\in S} (\mathrm{DCap}(s, \varsigma_y) + \mathrm{DFix}(s, \varsigma_y))$$

Total cost

The total cost of state ς_y is the sum of the run cost of ς_y and the transitional cost to ς_y. That is, the total cost is given by

$$\sum_{s\in S} (\mathrm{DVar}(s, \varsigma_y) + \mathrm{DCap}(s, \varsigma_y) + \mathrm{DFix}(s, \varsigma_y)) + U(\varsigma_y)\mathrm{VoLL}(1+i/100)^{-(y-0.5)}$$

Example

Returning to the example depicted earlier, we assign annual capital and fixed O&M costs to each wind farm as follows.

Wind farm	Annual capital and fixed O&M costs ($mil real)
TAS	260
QLD	254
VIC	250

The run cost ($mil real) associated with a state is given next to its vertex in Figure B.2. This is assigned arbitrarily in this example; in the IRP study, this is an outcome of the ***2-4-C***® simulation of the state.

[45] A 10% discount rate is used in both net present value and capital cost calculations.

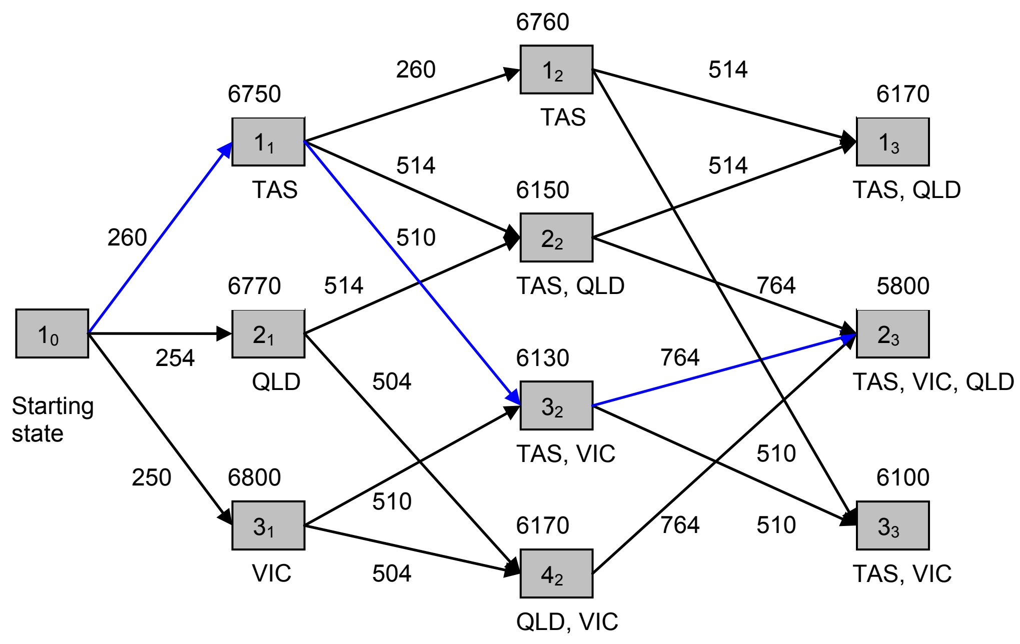
[46] Recall that a *station* is a generator or transmission augmentation. This annuity is applied to obtain annualised capital costs for both types of investment.

The transitional cost to a state is given on the edges to that state. For convenience, in this example we do not apply a discount rate. Note that the transitional cost is the same across all edges into a vertex, and is the sum of the discounted annual capital and fixed O&M of generation and transmission in that state (where these are set at zero for existing plant).

For example, the transitional cost to state 2_2 is the sum of 254 and 260, the annual capital and fixed O&M costs of the new entry TAS and QLD wind farms that exist in that state (no discounting is applied here), whether built in that year, or a prior year. Once built, plant cannot be retired. Thus these annualised costs are carried through and are incorporated as part of the transitional costs to the decisions of state 2_2. (In fact, they are carried through the transitional costs to any decision which can be reached from state 2_2, within the bounds of the study or the 30-year annuity.)

A least cost policy is shown by the blue path. In the next section, we discuss fast computation methods for finding such an optimal policy.

Figure B.2 – Run and transitional costs



Dynamic programming and the IRP optimisation

Dynamic programming is a mathematical method for fast computation of an optimal policy for a multistage decision process. It involves calculation of the optimised returns (for example, minimised costs or maximised benefits) associated with reaching the states at each stage of the process. The solution to these sub-problems can be used to quickly construct an optimal solution to the original problem. The IRP algorithm for finding an optimal policy is a deterministic decision analysis technique based on dynamic programming.

We first discuss the cost-minimising algorithm and introduce some notation. Let m_t denote the number of states at time t and label the states at time t by 1_t, $2_{t, \ldots,}$ m_t (so for example, the starting state is labelled 1_0). A *predecessor* of a state s_t at time t is a state ς_{t-1} such that s_t is a decision of ς_{t-1}.

Let $tc(s_t)$ be the discounted transitional cost to s_t and let $rc(s_t)$ be the discounted run cost of state s_t. Let $opc(s_t)$ denote the minimum (discounted) total cost over all paths leading to s_t from 1_0. Finally, let $n(s_t)$ be a predecessor of s_t, specified in Algorithm 1 below. Algorithm 1 describes the steps for finding a lowest cost policy.

Algorithm 1:

1. For each state s_1 in year 1

   {

   Set $opc(s_1) = rc(s_1) + tc(s_1)$

   Set $n(s_1) = 1_0$

   }

2. For $t = 2, 3, \ldots, T$

   {

   For each state s_t at time t

   {

   Set $opc(s_t) = rc(s_t)+tc(s_t) + \min(\{opc(\varsigma_{t-1}): \varsigma_{t-1}$ is a predecessor of $s_t\})$

   Set $n(s_t)$ to be the predecessor of s_t which yielded this *opc*.

   }

   }

Thus, the problem of computing the total cost of the optimal path is broken down into sub-problems that exhibit the structure of the original, and which reduce to a trivial computation (in this case the *opc* of each state at $t = 1$).

For each terminal state (at time T), its *opc* is the cost of the cheapest path to reach that state. The terminal state with least *opc* is the end state of the least cost path, and we reconstruct the optimal path of states, $p(0), p(1), \ldots, p(T)$, as using Algorithm 2.

Algorithm 2:

1. $p(T)$ is the state with least *opc* at time T
2. For $i = 1, 2, \ldots, T - 1$,

   $p(T - i) = n(p(T - i + 1))$
3. $p(0) = 1_0$

One of the strengths of the method is the ability to modify the objective function without altering the steps of the overall process. It is straightforward to adapt Algorithms 1 and 2 to finding a path yielding maximum benefits (profits). Let $b(s_t)$ denote the discounted profit associated with state s_t and let $opb(s_t)$ denote the maximum discounted profit over all paths leading to s_t from the starting state. Algorithm 3 is used to find an optimal policy.

Algorithm 3:

1. For each state s_1 in year 1
   {
   Set $opb(s_1) = b(s_1)$
   Set $n(s_1) = 1_0$
   }
2. For $t = 2, 3, \dots, T$
   {
   For each state s_t at time t
   {
   Set $opb(s_t) = b(s_t) + \max(\{opb(\varsigma_{t-1})$: ς_{t-1} is a predecessor of $s_t\})$
   Set $n(s_t)$ to be the predecessor of s_t which yielded this *opb*.
   }
   }

We reconstruct the optimal path of states, $p'(0), p'(1), \dots, p'(T)$, as follows.

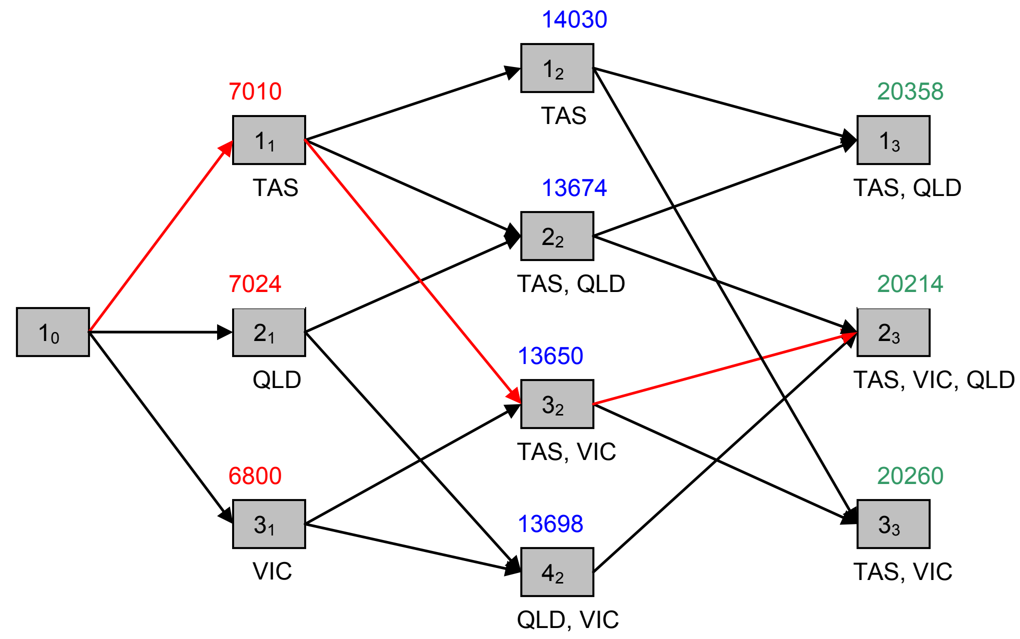
Algorithm 4:

1. $p'(T)$ is the state with greatest *opb* at time T
2. For $i = 1, 2, \dots, T - 1$,
   {
   $p'(T - i) = n(p'(T - i + 1))$
   }
3. $p'(0) = 1_0$

We now illustrate Algorithms 1 and 2, applying them in order to the example 3-stage decision process depicted in Figure B.2. We iteratively calculate the cost of the least cost path to reach each state from the starting state.

For each state s_1 at $t = 1$, $opc(s_1) = tc(s_1) + rc(s_1)$, and these values are recorded in red next to the states. For a state at time $t = 2$, this is the sum of the run cost associated with that state, the transitional costs to reach that state and the minimum of the cost of the least cost path to each of its predecessors (so $opc(s_2) = rc(s_2) + tc(s_2) + \min(\{opc(s'_1)$: s'_1 is a predecessor of $s_2\})$.These *opc* values are recorded in blue in Figure B.3. This step is repeated for $t = 3$, with the resulting *opc* values recorded in green in Figure B.3.

Figure B.3 – Calculating a least cost path



To reconstruct a least cost path, we find a terminal state with least *opc* and label this state *p*(3). Then *p*(2) is a predecessor of *p*(3) with minimal *opc*. Finally, *p*(1) is a predecessor of *p*(2) with minimal *opc*. The path through these states is shown in red in Figure B.3.

Sensitivities

Two classes of sensitivity studies can be run:

- *cost sensitivities*; and
- *state sensitivities*.

Since the calculation of costs is separate from the determination of the optimal path, the optimisation can be rerun as required with differing cost components. The robustness of the original solution can be examined by altering variables such as capital costs, fixed O&M or connection costs to all or certain stations. Factors affecting the run cost, such as fuel price and carbon cost can be varied within a narrow range, consistent with maintaining the dispatch merit order.

State sensitivities restrict the state space in which the solution can lie. For example, all states which include interconnector upgrades can be excluded from the solution space, and the optimal path through the resulting states found. Similarly, options can be 'locked in' from a specified year; that is, from that year only states containing the chosen options can be part of the optimal path. Comparison of these state-restricted solutions with the global optimal path allows benefits and costs of options to be accurately quantified.

The effect of all these sensitivity studies is to vary the optimum development plan to achieve the lowest cost (or highest profit) outcome consistent with the change in assumptions. Each sensitivity study delivers a new policy, optimal under the new set of constraints or assumptions.

Objective Functions for Scenarios A, B and C

The Scenario C *cost-minimising objective function* B_j of an expansion plan *j* is defined as follows:

$$B_j = \sum_{t=1}^{T} (DCap_{j,t} + DFix_{j,t} + DVar_{j,t} + U_{j,t})$$

where

- *T* is the duration of the study and *t* is the time index;
- $DCap_{j,t}$ represents the discounted annual capital investment costs expended on new stations in year *t*;
- $DFix_{j,t}$ represents the discounted fixed operation and maintenance costs expended on both existing and new stations in year *t*;
- $DVar_{j,t}$ represents the discounted run cost of both existing and new generators in year *t* (including fuel costs, variable O&M and carbon emission costs); and
- $U_{j,t}$ represents the discounted cost of unserved energy in year *t*.

To solve Scenario C, the IRP package uses Algorithms 1 and 2 with the objective function above. All paths are searched to find the expansion plan *j* such that $B_j \leq B_i$ for every *i*.

The Scenario A *profit-maximising objective function* P_j of an expansion plan *j* is defined as follows:

$$P_j = \sum_{t=1}^{T} (R_{j,t} - Cap'_{j,t} - Var'_{j,t} - Fix'_{j,t})(1 + i/100)^{-(t-0.5)}$$

where

- *T* is the duration of the study and *t* is the time index;
- $R_{j,t}$ represents the real revenue earned by new generation in year *t*. This includes pool price revenue and RECs revenue for new renewable generators (assuming a constant RECs price);
- $Cap'_{j,t}$ represents the real annualised capital investment costs expended on new generation in year *t*;
- $Var'_{j,t}$ represents the real run cost of new generators in year *t* (including fuel costs, variable O&M and carbon emission costs); and
- $Fix'_{j,t}$ represents the real fixed operation and maintenance costs expended on new generation in year *t*.

We note that this maximises the profits of new entry generators possibly at the expense of existing generators. Furthermore, it assumes that investors have perfect foresight over the duration of the study, and that investors work cooperatively to maximise the profits of all new entry plant.

To solve Scenario A, the IRP package uses Algorithms 3 and 4 with the profit-maximising objective function. All paths which exclude interconnector upgrades are searched, to find the expansion plan j such that $P_j \geq P_i$ for every i.

In Scenario B, generators make profit-maximising entry in the knowledge that transmission will enter if benefits outweigh costs. Given the results for Scenario C, interconnectors which are deemed likely to be cost-effective in the time frame of the study are investigated under profit-maximising generator entry. To solve Scenario B, we apply Algorithms 3 and 4 to find the profit-maximising path when an interconnector is installed in each year iteratively.

The yearly benefit of each interconnector is defined to be the yearly reduction in system costs, when compared with the Scenario A baseline costs. An interconnector will be upgraded in the earliest (critical) year that its benefits exceed its expenses (annual capital costs, fixed O&M). The Scenario B planting schedule is the schedule arising from profit-maximising entry with the interconnector committed in the critical year.

Further sensitivities are run to analyse the robustness of the planting schedule under differing constant REC prices. Due to time constraints, the effect of a variable REC price trajectory has not been investigated.

Strengths of the method

In summary, the IRP program comprises several modules, which perform distinct steps in the analysis.

1. IRP identifies states which satisfy the specified constraints.
2. Generation dispatch is simulated for each state at each stage. The output for each of these scenarios contains station production levels and revenue, system reliability and carbon emissions, and wholesale pool price outcomes.
3. The optimal expansion plan (based on the chosen objective of minimal cost or maximal benefit) is calculated. The optimisation considers every possible development path, discarding uneconomic paths during the process.
4. Having found the least cost plan under the initial assumptions, Step 3 may be repeated many times to develop a wide range of sensitivity studies to various parameters.

The data at each step is recorded, which allows for exploration of the state space beyond the states contained in the least cost path. For example:

- The objective function used in step 3 can be altered and the results from Step 2 (production costs, revenue etc. for each state) do not need to be recomputed. Thus the optimal expansion plans for Scenarios A and B (profit-maximising) and C (cost-minimising) are determined from the same set of simulation data, allowing direct comparison of costs and benefits across scenarios.
- The algorithm for finding the optimal path records the least cost/maximum benefit (as specified by the objective function) to reach each terminal state. Thus we can compare the differences in costs/benefits of the best paths to each terminal state (the best path to each is not recorded, but can be determined by sensitivity analysis).

- The robustness of the original solution to variation in capital and other transitional costs can be quickly tested, by repeating Step 3 with the desired changes in costs. Steps 1 and 2 are not repeated.
- Optimal expansion plans on restricted sets of states can be found quickly. For example, the least-cost expansion plan with no interconnector upgrades is found by applying the cost-minimising (Scenario C) objective function and limiting the states considered in Step 3. In doing this, Steps 1 and 2 are not repeated. Similarly, base load renewables may not be commercially available by the dates assumed in the study, and sensitivities delaying the entry of these stations until a later date can be performed.
- Stations which are optional in the initial set of assumptions can be 'committed' from a certain date, and the resulting optimal path found. For example, interconnectors can be 'locked in' from a certain date to analyse the benefit in reduced production costs as compared to capital expenditure. This feature is used to solve Scenario B.
- To answer the problem posed in Scenario B, it is necessary to both maximise profits (of generators) while minimising costs (by upgrading transmission). This is possible with clever use of the profit-maximising objective function and the commitment of interconnectors from each year of interest. The yearly benefits of the interconnector can then be quantified relative to the Scenario A (no augmentations) outcome, and the minimal cost solution chosen. This dual-optimisation arises naturally from the dynamic-programming style algorithm employed.