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Report (EMC00017) to

Impact of the LRET on the costs of FCAS, NCAS and Transmission augmentation

13 September 2011

VERSION HISTORY

Version History				
Revision	**Date Issued**	**Prepared By**	**Approved By**	**Revision Type**
0.9	2011-07-04	Jenny Riesz Joel Gilmore Sam Shiao David Yeowart Richard Bean Matthew Holmes	Ian Rose	Preliminary Draft
1	2011-07-07	Jenny Riesz Matthew Holmes	Ian Rose	Complete
1.1	2011-07-07	Jenny Riesz	Ian Rose	Minor text edits
1.2	2011-09-01	Jenny Riesz	-	Minor text edits - Appendix B and explanation of Badgingarra
1.3	2011-09-13	Jenny Riesz	-	Minor text edits – further explanation of Badgingarra

EXECUTIVE SUMMARY

At the request of the Ministerial Council on Energy, the Australian Energy Market Commission (AEMC) is conducting an assessment of the impact of the Large-scale Renewable Energy Target (LRET) on security of energy supply, the price of electricity and emissions levels from the energy sector.

The AEMC appointed consultants to develop a long-term generation expansion plan for meeting the LRET. Consequently, the 'core' scenarios for the portfolio and geographic distribution of technologies have been determined. ROAM Consulting was subsequently appointed to utilise these scenarios to forecast the cost of Frequency Control Ancillary Services (FCAS), Network Support and Control Ancillary Services (NSCAS) and transmission augmentation associated with the LRET for the National Electricity Market (NEM) and the South West Interconnected System (SWIS).

Many of the outcomes of this study (particularly for FCAS and NCAS) are very strongly driven by the quantity of wind generation assumed to enter in each scenario. As listed in the provided planting schedules, the capacities of wind installed in each scenario in 2019-20 are listed in the Table below.

Table 1 – Wind capacity installed (MW) [1]

		NEM	SWIS
Existing + Committed	2010-11	2280 (1434 existing + 846 committed)	397 (191 existing + 206 committed)
Reference Case (LRET)	2019-20	7884	397
Counterfactual Case (No LRET)	2019-20	2280	397
Carbon Case (LRET + Carbon price)	2019-20	7849	668

For the SWIS, the Reference and Counterfactual scenarios are identical (both feature the committed Collgar wind farm, and no further wind installation). Therefore, the results for these scenarios for the SWIS relating to FCAS, NCAS and transmission augmentation costs are identical.

Frequency Control Ancillary Services (FCAS)

Frequency Control Ancillary Services involve adjusting supply and demand to ensure that they match at all times, and the system frequency remains stable. Two broad categories are identifiable:

1. ***Regulation (Load Following)*** - This is the service of constantly adjusting supply minute to minute to match the variations in the load (or intermittent generation). In the NEM this

[1] Refer to Appendix B) for tables listing the wind farms included.

service is termed "Regulation", and is split into raise and lower components, supplied via the ancillary services market. In the SWIS this service is termed "Load Following", with both raise and lower components supplied by Verve Energy.

2. ***Contingency (Spinning Reserve / Load Rejection)*** - This is the service of adjusting supply in the event of a generator trip (or load trip) such that a large quantity of generation must be suddenly replaced (or removed) from the system to compensate. In the NEM this is split into six services - 6 second raise, 60 second raise, 5 minute raise, and the equivalent lower services. The timeframes refer to how quickly the response needs to be implemented in the event of a contingency. In the SWIS two services are defined - Spinning Reserve relates to the sudden loss of a generating unit (and hence is a raise service), while Load Rejection relates to the sudden loss of a large load (a lower service). Both are provided by Verve Energy, or in some cases by other plant via contractual arrangements.

The LRET is expected to affect the capacity of Regulation service required, since an increase in intermittent generation is likely to increase the magnitude of minute to minute generation deviations. This has been explored extensively in this study.

The LRET is not expected to substantially affect the capacity of Contingency services required, since wind farms consist of many small units. Events such as high wind speed cut-outs have been taken into account in the calculation of Regulation services, and have therefore not been 'double-counted' with the Contingency services. Contingency service requirements have therefore been assumed to remain constant over time.

In both the NEM and the SWIS, Regulation services are considered to simultaneously contribute Slow (5 minute) Contingency services (or Spinning Reserve / Load Rejection in the SWIS). As the capacity of Regulation required increases (with increased wind penetration) this therefore decreases the capacity of Slow Contingency services required, until eventually the Regulation requirement exceeds the Slow Contingency requirement, and no further Slow Contingency service is required. Therefore, in this study the costs of these two services are considered in a combined fashion to allow appropriate comparison from year to year.

Results - FCAS in the NEM

The following major findings relate to Frequency Control Ancillary Services (FCAS) in the NEM:

The Regulation requirement increases substantially in response to the LRET. The Regulation requirement increases from the present value of ±120 MW to around ±800 MW in 2019-20 in scenarios with the LRET. This increase is entirely driven by the projected increase in intermittent wind generation installed. In the absence of the LRET the Regulation requirement increases only slightly to ±200 MW due to demand growth.

Regulation costs increase substantially in scenarios featuring the LRET. In response to the increased Regulation requirement, ancillary service settlements increase from \$10 million pa[2] (for Regulation + Slow Contingency services) to around \$200 million pa in scenarios with the LRET. As

[2] All quoted costs are in real 2011 dollars unless otherwise stated.

the Regulation requirement increases, more expensive FCAS bids must be utilised, increasing FCAS settlements. However, it is noted that if the FCAS market were to increase so substantially it is likely that many generators will change their FCAS bidding strategies in ways that are challenging to predict, so these results should be considered to have a high degree of uncertainty. The application of a carbon price would exacerbate this effect.

In the absence of the LRET, FCAS costs remain close to present levels.

Regulation costs remain small compared with energy settlements. Despite forecast increases, Regulation and Slow Contingency service costs remain small in comparison to anticipated energy settlements of $12 - $20 billion pa ($50 - $80 /MWh) in 2019-20.

Regulation costs could be significant for wind generators. Regulation costs are settled on a causer-pays basis, being paid for by generators or loads when they deviate from their expected dispatch. On this basis, it is anticipated that the majority of the increase in regulation costs will be borne solely by wind generators. This would lead to an increase in regulation costs for wind generators from around $0.40 /MWh at present to $6 - 8 /MWh in 2019-20, in the presence of the LRET. This increase in wind farm costs could have significant implications for the development of new wind projects to meet the LRET. This will apply particularly in the absence of a carbon price, where the LRET shortfall charge is expected to be prohibitively low for new wind farm developments to meet costs, even in the absence of increased FCAS charges.

Results - FCAS in the SWIS

The following major findings relate to Frequency Control Ancillary Services (FCAS) in the SWIS:

The Load Following requirement increases substantially in response to new wind generation. The Load Following requirement increases from the present value of ±60 MW to around ±120 MW with the installation of Collgar[3] (206 MW), or up to ±265 MW with a further 271 MW of wind generation installed (in the Carbon case). The increase is driven primarily by the increase in installed intermittent wind generation.

Load Following costs increase substantially when the Load Following requirement increases. Costs increase from $18 million pa (for Load Following + Spinning Reserve services) in 2009-10 to around $60 million pa in 2019-20 with Collgar installed, and up to around $200 million pa with the additional wind in the Carbon case. The significant increase in costs is driven by two factors - firstly, the increase in the Load Following requirement (in response to more installed intermittent wind). Secondly, the increasing gas price assumed in the modelling (Verve gas prices were assumed to increase from around $4 /GJ at present[4] to $7.65 /GJ in 2019-20). Since Load

[3] For the SWIS, the Reference and Counterfactual scenarios are identical (both feature the committed Collgar wind farm, and no further wind installation). Therefore, the results for these scenarios for the SWIS relating to FCAS, NCAS and transmission augmentation costs are identical.

[4] 2009 Margin_Peak and Margin_Off-Peak Review, Final Report v4.0, MMA report to IMO WA, 10 December 2009.

Following services are provided entirely by Verve gas-fired plant, Verve's gas price has a significant bearing on Load Following costs.

These cost estimates assume that the existing Market Rules continue, with Verve continuing to be the sole provider of Load Following services. If the Rules change as anticipated with the implementation of the new Load Following Ancillary Services (LFAS) Market, increased efficiency from the use of other units in the SWIS may allow costs in the Carbon case to reduce from $200 million pa to $160 million pa.

Load Following costs remain small compared with energy settlements. Despite forecast increases, Load Following costs remain small in comparison to anticipated energy settlements of around $2 billion pa ($80 /MWh) in 2019-20.

Load Following costs could be significant for wind generators. In the SWIS, under the existing Rules Load Following costs are divided between loads and generators on the basis of their metered schedules (MWh). This means that the majority of costs are borne by loads, and leads to Load Following payments by loads and intermittent generators of around $0.42 /MWh at present, increasing to $2 /MWh in 2019-20 with the entry of Collgar wind farm, or $5 - 8 /MWh with the increased wind in the Carbon case in 2019-20. This increase in wind farm costs could have significant implications for the development of new wind projects in the SWIS.

New market rules are under consideration at present that would allocate a much larger proportion of Load Following costs to wind generators, based on a causer-pays principle. Under these new Rules wind generators could be liable for Load Following costs of around $30 /MWh in 2019-20 with the entry of Collgar, or up to $60 - 70 /MWh in 2019-20 with the additional wind in the Carbon case. These additional costs are likely to be prohibitive for the development of new wind generation in the SWIS.

Network Support and Control Ancillary services (NSCAS)

Network Support and Control Ancillary Services (NSCAS) are divided into two categories[5]:

1. ***Reactive Power Ancillary Service (RPAS)*** - Also termed Voltage Control. Used to control the voltage at different points of the electrical network to within the prescribed standards. Generators absorb or generate reactive power and control the local voltage accordingly. RPAS requirements are localised, due to the inefficiencies of transporting reactive power through the network.
2. ***Network Loading Control Ancillary Service (NLCAS)*** - used to control the power flow on interconnectors to within short term physical limits. This involves adjusting the dispatch of generators or loads in the network, achieved through Automatic Generation Control (AGC), in the same manner as regulation frequency control and load shedding.

This study has focused on the first aspect (reactive power and voltage control).

[5] AEMO, Guide to Ancillary Services in the National Electricity Market.
http://www.aemo.com.au/electricityops/0160-0048.pdf

The amount of additional voltage control infrastructure required could vary substantially depending upon the type of wind turbines installed, and the locations of those wind farms. In the best case, wind farms could contribute positively to voltage control, reducing NSCAS costs. In the worst case, the introduction of a large capacity of new wind generation could require substantial new voltage control infrastructure.

When projecting future NSCAS requirements, there are a number of aspects to consider:

1. What are the access standards that new wind farms will need to meet? To meet stringent standards wind farms may need to have effective reactive power and voltage control, which will reduce the additional capacity of these services required to be met by transmission network service providers (reducing NSCAS requirements).
2. What types of wind technologies are likely to be installed, and what reactive power capabilities do they offer? There are a wide range of wind generation technologies available, and they offer a wide range of reactive power and voltage control capabilities. The type of technology that is installed has a significant bearing on the amount of additional NSCAS infrastructure that will be required.
3. What types of infrastructure are available for the management of NSCAS, and how much do they cost?
4. What capacity (and what type) of NSCAS infrastructure will be required to manage NSCAS, in relation to the capacity of wind generation that is installed?

Each of these aspects is addressed briefly below.

The minimum access standard to connect a generator to the NEM does not require any capability to supply or absorb reactive power at the connection point. However, to connect generators must negotiate with the transmission network service provider, and this often leads to more stringent requirements around reactive power. Also, more onerous technical standards have been defined for new wind farms to obtain a license to connect to the network in South Australia.

There are a range of wind generation technologies commercially available, and each contributes differently to reactive power and voltage control. In Australia, DFIG turbines have been popular for development, and offer a relatively high level of reactive power control, with limited voltage control and limited fault ride through capability. The Suzlon S88 DFIG has been a particularly popular choice. This turbine offers a fault ride-through of 0 volts for 0.2 seconds.

A variety of technologies are available for managing reactive power and voltage control in the network. Simpler, fixed or mechanically switched devices (such as capacitor banks) offer a basic level of voltage control, whereas more sophisticated technologies in the class of "Flexible AC Transmission Systems" (FACTS) use additional power electronics or converters to switch the elements in smaller steps or with switching patterns within a cycle of the alternating current.

A number of possible future reactive power infrastructure installations in Australia have published cost estimates. Based on these figures, it is estimated that the cost of Static Var Compensator (SVC) equipment is approximately $0.17 million/MVAr, and the cost of capacitor bank infrastructure is approximately 0.03 million /MVAr.

To provide an estimate of the possible cost of NSCAS, the following assumptions are made:

- ***South Australia*** - Wind generation capacity installed in South Australia is of an advanced technology type, or is accompanied by sufficient infrastructure to maintain local voltages and reactive power requirements (due to the stringent licensing conditions in this region). It is assumed that there will be no further NSCAS requirements related to the entry of wind generation (further NSCAS requirements related to load growth may arise, but are not accounted for in this analysis since they are not related to the cost of the LRET).
- ***Other regions*** -
    - All new installed wind farms are older design fixed-speed induction machines that do not contribute to voltage support;
    - All new installed wind farms are located in very weak parts of the grid where there is insufficient local voltage support;
    - All new installed wind farms therefore require associated Static VAr Compensator (SVC) and capacitor bank infrastructure;
    - 1 MVAr of reactive power is required to support each installed MW of wind capacity (active power). 0.3 MVAr/MW is supplied in a dynamic manner via SVC infrastructure, with the remaining 0.7 MVAr/MW supplied via capacitor banks.

These are extreme assumptions, and therefore are likely to reflect a high estimate. It is very likely that many wind farms will be located in areas where the local voltage support is sufficient, or that some of the installed wind farms will be newer designs that provide some local voltage support.

Results - NSCAS in the NEM

The following major findings relate to Network Support and Control Ancillary Services in the NEM:

NSCAS costs may double due to the entry of new wind farms under the LRET. NSCAS costs in the NEM are projected to increase from $49 million pa[6] to around $100 million pa in 2019-20 in the presence of the LRET. In the absence of the LRET NSCAS costs associated with new wind farms remain close to present levels. This projection only relates to additional NSCAS costs related to increased wind farm penetration; other network factors have not been taken into account.

Due to the assumptions made in this study, the differences in costs between scenarios, and the changes in costs within scenarios, is driven entirely by the capacity of wind installed in each year, in each scenario. This was based upon the provided Oakley Greenwood planting schedules.

NSCAS costs remain small compared with energy settlements. NSCAS costs to consumers are projected to increase from around $0.25 /MWh in 2010-11 to around $0.40 /MWh in 2019-20 in the presence of the LRET. Despite forecast increases, this remains small in comparison to anticipated energy settlements of $50 - $80 /MWh.

NSCAS costs are not likely to be problematic for the liable parties. NSCAS costs are largely borne by transmission and distribution network companies, and passed through to consumers via network tariffs. This means that any additional NSCAS costs are spread over a wide base, and are not likely to be problematic.

[6] Aggregated 2010-11 Reactive Power payments published online weekly by AEMO.

Results - NSCAS in the SWIS

The following major findings relate to Network Support and Control Ancillary Services in the SWIS:

NSCAS costs may increase in response to the installation of more wind generation in the SWIS. NSCAS costs in the SWIS are projected to increase by around $2 million pa with the entry of Collgar wind farm[7], and by around $4 million with the further 271 MW of wind capacity installed in the Carbon case. This projection only relates to additional NSCAS costs related to increased wind farm penetration; other network factors have not been taken into account.

Due to the assumptions made in this study, the differences in costs between scenarios, and the changes in costs within scenarios, are driven entirely by the capacity of wind installed in each year, in each scenario. This was based upon the provided Oakley Greenwood planting schedules.

NSCAS costs remain small compared with energy settlements. NSCAS costs to consumers are projected to increase by around $0.06 /MWh in 2019-20 with the entry of Collgar wind farm, and by around 0.14 /MWh with the additional 271 MW of wind entering in the Carbon case. Despite forecast increases, this remains small in comparison to anticipated energy settlements of $80 /MWh.

NSCAS costs are not likely to be problematic for the liable parties. NSCAS costs are largely borne by transmission and distribution network companies, and passed through to consumers via network tariffs. This means that any additional NSCAS costs are spread over a wide base, and are not likely to be problematic.

Transmission Augmentation

The transmission analysis conducted in this project aimed to identify the extent of any increase in shared transmission costs caused by the LRET. In particular, the study was to determine:

- The likely shared transmission augmentations required (both inter and intra regionally) for meeting the LRET from the present to 2020, while ensuring reliability of supply to consumers is maintained;
- Separately identifying the transmission augmentations needed for meeting demand growth from those specifically required to meet the LRET, and;
- Identifying where there may be congestion bottlenecks occurring as a result of the LRET from the present to 2020 (assuming existing regulatory arrangements continue).

ROAM considered intra-regional and inter-regional network augmentation down to the level of the 16 zones defined in AEMO's NTNDP modelling in the NEM, and in the SWIS, five major zones derived from areas described in Western Power reports.

[7] For the SWIS, the Reference and Counterfactual scenarios are identical (both feature the committed Collgar wind farm, and no further wind installation). Therefore, the results for these scenarios for the SWIS relating to FCAS, NCAS and transmission augmentation costs are identical.

New plant development schedules for the three core scenarios supplied by the AEMC's consultants (Reference Case, Counterfactual and Carbon Case) were split into the zones, and fed into ROAM's least cost model called LTIRP (Long Term Integrated Resource Planner). This model determined the least cost transmission augmentation program to support the new plant schedules. Each possible transmission augmentation was modelled as a 250MW bi-directional upgrade, and costs of $500/kW and $1000/kW (applied consistently across most of the systems[8]) were assessed to provide reasonable bounds on the degree of likely augmentation, given that transmission augmentation costs can vary widely depending on the nature of any particular augmentation. By examining the differences between the Reference Case (or Carbon Case, as both included the LRET), and the Counterfactual (which excluded the LRET) the impact of the LRET policy on transmission costs was evaluated.

Results - Transmission Augmentation in the NEM

The following major findings relate to Transmission Augmentation in the NEM:

Significant investment in transmission augmentation will be required regardless of the LRET. Between 3,750MW and 5,500MW of new transmission capacity was built in the cases and sensitivities studied by 2019-20. This was spread across the NEM but focussed heavily around South-West Queensland through to Central New South Wales, associated with both the influx of low cost gas plant in those areas and also the relatively high forecast rates of load growth in Queensland. At prices of $500/kW of transmission capacity, this level of transmission expenditure would equate to between $194m and $284m pa ($0.8 to $1.20 /MWh) in 2019-20, or double that with pricing of $1000/kW.

There may be a higher level of transmission augmentation necessary without the LRET. The LRET had the effect of reducing the amount of inter and intra regional transmission that would otherwise be required. In the Reference and Carbon cases, around 3,750MW of new transmission capacity was built by 2019-20, compared with 5,500MW in the Counterfactual. This represents around $91m pa more in the Counterfactual in that year. The reasons for this are related to the nature of new plant in the different cases. The Carbon and Reference Cases provided by OGW included more generation capacity overall, and also the bias towards renewable generation in the Reference and Carbon Case meant that generation tended to be located closer to the load (the large thermal plant favoured in the Counterfactual case tends to site near cheap fuel rather than near load). However, it must be noted that this result is dependent on the nature of the planting schemes and could be different if a substantially different planting schedule was adopted. It should also be noted that although the Counterfactual case resulted in higher transmission augmentation costs, the Carbon and Reference Cases would most likely be associated with higher generation costs.

The cost associated with new transmission augmentation is minor compared with energy settlements. Like the Regulation and Slow Contingency service costs, costs associated with new

[8] Some exceptions existed; Latrobe Valley to Tasmania was costed at $1000/kW in all cases, and augmentation was disallowed between South East Queensland and Northern New South Wales.

transmission are relatively small in comparison to the anticipated energy settlements of $12 - $20 billion pa ($50 - $80 /MWh) in 2019-20. Also, transmission costs are spread over all market participants, so costs of this order are unlikely to be problematic.

The LRET does not necessarily increase congestion between the zones comprising the NEM. While the modelling performed for this project did not include detailed network constraint modelling, it was sufficient to provide an indicative congestion assessment. Overall, congestion levels were relatively unchanged in the presence of the LRET (that is, between the Reference/Carbon and Counterfactual cases). However, the LRET will likely shift the locations where congestion tends to occur. The most frequently congested flow paths were Melbourne to Central Victoria and Melbourne to South East South Australia. These flows were associated with the delivery of power from the Latrobe Valley (a bulk supply zone) through the rest of Victoria and into South Australia. Since the model was designed to augment transmission paths where it was economically viable to do so, the outcomes for these flow paths were most likely due to a lack of incentive to upgrade the network in this location, as no augmentation of these flow paths occurred in any of the cases. In the context of this study, a lack of incentive means that an augmentation of the flow path did not result in sufficient fuel cost savings to be justified. The LRET causes congestion over these two flow paths to relax, as the influx of wind generation into South Australia reduces the tendency of South Australia to import power. A carbon price has the same impact; it reduces the cost advantage of base load power in the Latrobe Valley and thus reduces flows from this zone across to South Australia.

It should be noted that if a significantly different planting arrangements were assumed to meet the LRET, then transmission augmentation attributable to the LRET may be significant. The assumed planting scenarios, for example, featured a relatively modest level of wind generation development in South Australia. Should a much larger proportion of wind generation site in South Australia, then significant transmission expansion in that region would be necessary and would be directly attributable to the LRET. However, it is likely this would reduce the need for transmission reinforcement elsewhere.

Results - Transmission Augmentation in the SWIS

Unlike in the NEM, very little transmission augmentation was required in the SWIS cases. The small amount of transmission augmentation observed occurred late in the modelling; after 2019-20. Therefore no augmentation was regarded as directly attributable to the LRET in this timeframe. Furthermore, the new plant assumptions provided for the Reference and Counterfactual cases are identical in the SWIS, and assume the LRET is met via existing and committed plant. The Carbon Case only varies significantly post 2020.

Compared with the NEM, the existing transfer limits between the zones in the SWIS are relatively high for the system size, and the new generation is relatively distributed. In other words, generation in the SWIS tends to be located closer to the load than in the NEM, reducing the need for significant transmission augmentation.

Congestion was minimal in most of the SWIS, except between the East Country and Muja zones, where transmission flows are often at the limit, pushing low cost energy from the Muja zone to the rapidly growing East Country.

Note that the modelling did not examine intra-zonal network issues, which could be significant in the SWIS.

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1) BACKGROUND

The MCE requested on 16 September 2010 that the AEMC assess the likely impact of the enhanced Renewable Energy Target (RET), which took effect from 2011, on security of supply, the price of electricity and emissions levels from the energy sector.

The AEMC expect that installation of a large quantity of intermittent generation under the Large-scale Renewable Energy Target (LRET) will:

1. Increase the variability required to be managed by frequency control ancillary services (FCAS), in particular the services (regulation services) required to match the minute by minute variation of supply and demand on the network.
2. Affect the requirement for Network Support and Control Ancillary Services (NSCAS) on networks, in particular the need for voltage support.
3. Impact upon the development of inter and intra regional networks.

This study aims to quantify the cost of each of these components due to the LRET in the National Electricity Market (NEM) and South-West Interconnected System (SWIS).

2) Scope

Ancillary Services

This study aims to provide analysis of the extent of any increase in ancillary services costs caused by the LRET. In particular:

- The likely cost of FCAS associated with meeting the LRET in 2020 (NEM and SWIS)
- The likely cost of NSCAS associated with meeting the LRET in 2020 (NEM and SWIS)

Transmission Augmentation

This study aims to provide analysis of the extent of any increase in shared transmission costs caused by the LRET. In particular:

- The likely shared transmission augmentations required (both inter and intra regionally) for meeting the LRET from the present to 2020, while ensuring reliability of supply to consumers is maintained.
- Separately identifying the transmission augmentations needed for meeting demand growth from those specifically required to meet the LRET.
- Identifying where there may be congestion bottlenecks occurring as a result of the LRET from the present to 2020 (assuming existing regulatory arrangements continue).

3) SCENARIOS

Other consultants (Oakley Greenwood and NERA) were previously commissioned to develop long-term generation expansion plans for a number of scenarios, including:

1. ***Reference (LRET)*** - no carbon price is applied (carbon uncertainty), but the LRET (20% by 2020) scheme is implemented. The LRET was "forced" to be met, irrespective of the LRET shortfall charge.
2. ***Counterfactual (No LRET)*** - no carbon price is applied (carbon uncertainty), and the LRET scheme is not implemented.
3. ***Carbon price*** - A carbon price is applied, and the LRET scheme is implemented.

ROAM utilised these expansion plans, and developed the regionally aggregated high level results into detailed sets of input assumptions for ROAM's models (including interpreting aggregate specifications into individual generators). In particular, since aggregate wind installed generation capacity by region was specified, ROAM developed this into a detailed planting schedule based upon announced wind projects in each region (supplemented by further hypothetical projects when required). ROAM maintains an extensive database with detailed information on announced renewable (and non-renewable) projects for this purpose.

4) FREQUENCY CONTROL ANCILLARY SERVICES (FCAS)

4.1) INTRODUCTION

Frequency Control Ancillary Services involve adjusting supply and demand to ensure that they match at all times, and the system frequency remains stable. Two broad categories are identifiable:

1. ***Regulation (Load Following)*** - This is the service of constantly adjusting supply minute to minute to match the variations in the load (or intermittent generation). In the NEM this service is termed "Regulation", and is split into raise and lower components, supplied individually via the ancillary services market. In the SWIS this service is termed "Load Following", with both raise and lower components supplied by Verve Energy.
2. ***Contingency (Spinning Reserve / Load Rejection)*** - This is the service of adjusting supply in the event of a generator trip, or load trip, such that a large quantity of generation must be suddenly replaced, or removed, from the system to compensate. In the NEM this is split into six services - 6 second raise, 60 second raise, 5 minute raise, and the equivalent lower services. The timeframes refer to how quickly the response needs to be implemented in the event of a contingency. In the SWIS two services are defined - Spinning Reserve relates to the sudden loss of a generating unit (and hence is a raise service), while Load Rejection relates to the sudden loss of a large load (a lower service). Both are provided by Verve Energy plant, or in some cases by other plant via contractual arrangements.

The LRET is expected to affect the capacity of Regulation service required, since an increase in intermittent generation is likely to increase the magnitude of minute to minute generation deviations. This has been explored extensively in this study.

The LRET is not expected to substantially affect the capacity of Contingency services required. Events such as high wind speed cut-outs have been taken into account in the calculation of Regulation services, and have therefore not been 'double-counted' with the Contingency services. Contingency service requirements have been assumed to remain constant over time.

In both the NEM and the SWIS, Regulation services are considered to simultaneously contribute Slow (5 minute) Contingency services. As the capacity of Regulation required increases (with increased wind penetration) this therefore decreases the capacity of Slow Contingency services required, until eventually the Regulation requirement exceeds the Slow Contingency requirement, and no further Slow Contingency service is required. The settlement equations for these two services are complex and difficult to project into the future. Therefore, in this study the costs of these two services are considered in a combined fashion to allow appropriate comparison from year to year.

4.2) METHODOLOGY

4.2.1) Methodology Summary

The FCAS requirements in 2020 were determined using the methodology summarised below. Each step is expanded upon in more detail in the following section.

1. ***Calculate wind trace -*** A one minute resolution aggregate wind trace for the National Electricity Market (NEM) and the South-West Interconnected System (SWIS) was determined. The outputs of individual wind farms in each minute were forecast from historical wind data from Bureau of Meteorology weather stations (adjusted to produce realistic wind generation profiles at hub height using the Renewable Energy Atlas). The wind traces of individual wind farms were summed to produce one aggregate trace for the NEM, and one aggregate trace for the SWIS.
2. ***Calculate demand trace*** - A one minute resolution demand trace for each of the NEM and SWIS was determined. This was based on an historical reference year (the same year as the wind data was used to ensure accurate correlation between wind and demand). ROAM's Load Trace Synthesizer tool was used to grow this reference trace according to the peak demand and energy targets forecast in each year.
3. ***Calculate demand net of wind trace*** - For each of the NEM and SWIS the wind trace was subtracted from the demand trace to produce the total disturbance in each minute that needed to be met by the regulation raise and lower services.
4. ***System Frequency Modelling -*** ROAM used a system frequency model calibrated individually to each of the NEM and SWIS to calculate the frequency response. For the NEM, the frequency responses were modelled on a minute-to-minute basis for the entire year, while only designated periods were modelled for the SWIS. The difference between the two was due to the difference in frequency regulation requirements. The NEM requires that the frequency is within 0.25Hz at all times[9] for regulation purposes, while the SWIS requires the frequency to be within 0.2Hz for 99.5% of the time[10]. Therefore, rather than simulating the whole year for the SWIS, ROAM examined the distribution of the minute-to-minute changes of demand and wind, and chose periods that represent the bottom (for raise requirement) and top (for lower requirement) 0.25 percentiles to meet the 99.5% target. The model incorporates the expected system inertia and frequency response of each dispatched generator at the time of day under consideration. The amount of regulation raise and lower services applied was increased until the frequency was maintained within the required limits defined by the Rules relevant to each system (NEM and SWIS).
5. ***Co-optimised FCAS market modelling -*** ROAM used a half hourly dispatch model that co-optimises the energy market with the eight ancillary service markets. The increased regulation raise and lower requirements calculated in the previous step with the LRET in 2020 were used as an input to this model. For comparison, the model was run in 2019-20 with the regulation raise and lower requirement that would be required in the absence of the LRET. Historical bids for the FCAS and energy markets were provided as input for the forecasts in 2020.
6. ***Calculate scenario costs*** - The difference in total cost of the two scenarios then gives the cost of providing additional FCAS due to the LRET. Cost differences arise from the fuel and operational costs of units with dispatch changed to accommodate the larger regulation raise and lower requirements in the LRET scenario.

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[9] The "normal frequency operating excursion band" in the frequency operating standards at http://www.aemc.gov.au/Panels-and-Committees/Reliability-Panel/Standards.html#Power%20System%20Standard

[10] "SWIS FREQUENCY OPERATING STANDARDS" at http://www.imowa.com.au/f709,826316/Security.pdf

4.2.2) Detailed FCAS methodology

Step 1 - Determine aggregate wind trace in 2019-20

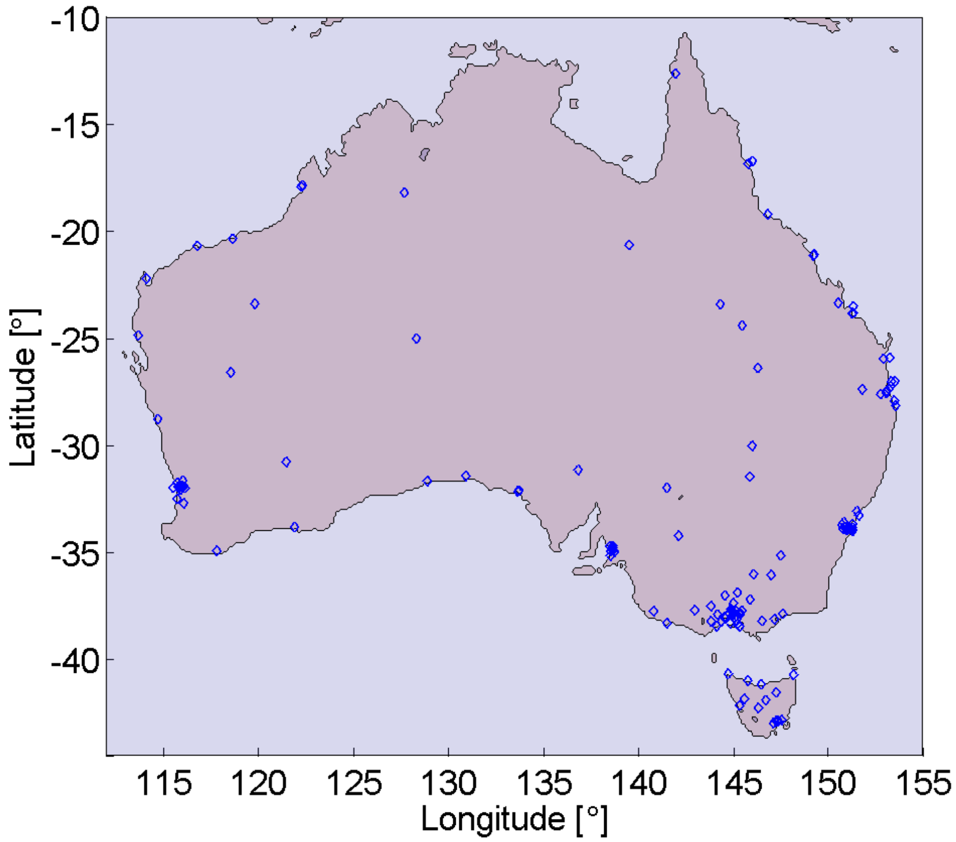
ROAM created wind generation traces for each wind generator in operation in 2019-20 in each scenario. The following methodology was used:

1. A one minute resolution wind generation trace was created for each individual wind farm installed in 2019-20. For each wind farm, the closest Bureau of Meteorology (BOM) weather station with one minute resolution wind data available for the reference year (2009-10) was identified. This wind speed data was converted to wind generation data using ROAM's Wind Energy Simulation Tool, which has been calibrated to the historic operation of existing wind farms. The operation of this tool is outlined in Appendix C).
2. The individual wind farm traces were summed to give an aggregate wind generation trace for each of the NEM and SWIS.

A similar trace was prepared for the reference year 2009-10 for benchmarking purposes.

The existing wind farms and Bureau of Meteorology stations with data available at sufficient resolution for the reference year are illustrated in the figure below.

Figure 4.1 – Bureau of Meteorology Weather Stations with 1-minute data



Step 2 - Determine aggregate load trace in 2019-20

ROAM created a load trace for 2019-20 with one minute resolution for each scenario. To create realistic load forecasts, ROAM uses a proprietary load forecasting tool, the Load Trace Synthesizer (LTS). This software accepts a historical reference load trace and forecast energy and peak demand targets in order to generate load trace forecasts. This tool accurately takes account of the variation in load between weekdays and weekends, public holidays, and seasonal variations, shifting the reference trace as required to accurately replicate the seven days of the week. The model accepts and uses as input data:

- Annual energy targets (sourced from the AEMO 2010 SOO)
- Annual summer peak demand targets (sourced from the AEMO 2010 SOO)
- Annual low load targets (if desired)
- 2010 historical load trace
    - For the NEM, the 5 minute resolution load trace was linearly interpolated to obtain a 1 minute load trace
    - For the SWIS, the 5 minute historical

Step 3 - Determine regulation raise and regulation lower requirements

The wind trace determined in Step 1 was subtracted from the demand trace determined in Step 2 to produce a one minute resolution trace of demand net of wind. ROAM examined this trace in 5 minute intervals (corresponding to the FCAS market interval) using a System Frequency Model. The operation of this model is outlined in Appendix D).

Each five minute interval was modelled with the System Frequency Model and the designated intervals were modelled for the SWIS. A constant system inertia was assumed for the NEM and the SWIS since it was found to have a relatively minor influence on frequency outcomes. In particular, 45,000 MWs of inertia was assumed for the NEM and 24,700 MWs was assumed for the SWIS. These inertia values were chosen to represent a moderately loaded system condition.

Step 4 - Co-optimised FCAS modelling for the NEM

ROAM's 2-4-C market simulation package includes the dispatch and co-optimisation of frequency control ancillary services (FCAS). FCAS modelling using this software has been verified against history through a 'back-cast', simulating past periods with historical demand and bid offers to compare 2-4-C's results to NEMDE. Details of ROAM's FCAS model and example back-cast data are included in Appendix F).

ROAM used the 2-4-C co-optimising model to calculate the dispatch of two scenarios in the year 2019-20:

1. ***Wind regulation requirements*** - All existing and new generators were modelled on a half-hourly basis, including all new wind farms operating on intermittent traces calculated from Bureau of Meteorology wind speed data. The regulation requirement in each half hour was that determined from system frequency modelling.
2. ***No new wind regulation requirements*** - All existing and new generators were modelled on a half-hourly basis, including all new wind farms operating on intermittent traces calculated from Bureau of Meteorology wind speed data. However, the regulation requirement in each half hour was equivalent to that in the present (2011) system, not affected by the new wind (and other intermittent) generation entering to meet the LRET by 2020.

ROAM's FCAS model for the NEM calculates a co-optimised solution for the supply of FCAS services to the aggregate mainland NEM, with Tasmania being treated separately. This replicates the actual operation of the NEM FCAS market. At present, Basslink is the only interconnector for which interconnector limits are considered explicitly in the FCAS dispatch. Other interconnectors within the mainland NEM are allowed to operate outside of their energy market constrained dispatch for the supply of FCAS, under the assumption that these flows will be temporary. Tasmania is considered as a special case, with both local and global FCAS requirements that must be met. The modelling included both the mainland and Tasmanian regions of the NEM.

ROAM used historical FCAS bids as a basis for projected bids in 2019-20. FCAS bids in 2019-20 will be different. However, it is difficult to assess whether they will be higher, because of a shortage of available service providers, or lower, due to a higher level of interest by generators in providing FCAS. The outcomes are indicative of the likely outcomes in 2019-20, assuming no large changes in FCAS bidding behaviour.

Step 5 - Calculation of total cost in each case

The total scenario cost in each case was calculated based upon the dispatch determined by the 2-4-C co-optimised model, and the individual cost parameters of each generator (variable operations and maintenance, fuel costs, fixed operations and maintenance, annualised capital repayments). The difference in cost between the two cases gave the cost of FCAS requirements (particularly the regulation requirement) associated with meeting the LRET in 2019-20 in the NEM.

4.2.3) Market Dispatch modelling for the SWIS (FCAS)

The SWIS does not utilise a market for the dispatch of the load following service. Instead, Verve plant is utilised to provide a constant capacity of load following service in each period throughout the year. ROAM has been previously provided a list of the plant utilised by Verve to provide this service, in order of preference.

ROAM determined which Verve plant will need to be dispatched to provide the load following service in 2019-20. The total load following capacity required was identified in the previous step.

ROAM used the 2-4-C model (without FCAS co-optimisation) to calculate the dispatch of two cases for each scenario in the year 2019-20:

1. **Wind regulation requirements** - All existing and new generators were modelled on a half-hourly basis, including all new wind farms operating on intermittent traces calculated from Bureau of Meteorology wind speed data. The regulation requirement in each half hour was the amount determined via system frequency modelling.
2. **No wind regulation requirements** - All existing and new generators were modelled on a half-hourly basis, including all new wind farms operating on intermittent traces calculated from Bureau of Meteorology wind speed data. However, the regulation requirement in each half hour was removed.

In the Carbon case a third simulation was also conducted to explore the implications of a pending Rule change that will implement a market for Load Following:

3. **Altered wind regulation requirements** - All existing and new generators were modelled on a half-hourly basis. The regulation requirement in each half hour was supplied by Verve and new generators such that the most efficient peaking units supplied the load following requirement.

Plant providing the load following service was forcibly dispatched to a mid-point between minimum and maximum load.

The total scenario cost in each case was calculated based upon the dispatch determined by the 2-4-C model, and the individual cost parameters of each generator (variable operations and maintenance, fuel costs, fixed operations and maintenance, and annualised capital repayments). The difference in cost between the two cases gave the cost of FCAS requirements (particularly the regulation requirement) associated with meeting the LRET in 2019-20 in the SWIS.

4.3) Results and Discussion

4.3.1) NEM

Regulation Requirements

ROAM determined the capacity of regulation service required to maintain the system frequency operating standards in the NEM during the 2019-20 year. This process was also benchmarked against the reference year (2009-10) ensuring that historical results are accurately reproduced. A summary of ROAM's system frequency modelling outcomes for the NEM is shown in the table below.

Table 4.1 – Forecast Regulation Requirements (NEM)

	Regulation Raise (MW)	Regulation Lower (MW)	Installed wind capacity (MW)[11]
Existing (2009-10)[12]	120	120	1434
Reference Case (2019-20)	840	700	7884
Counterfactual Case (2019-20)	200	200	2280
Carbon Case (2019-20)	800	700	7849

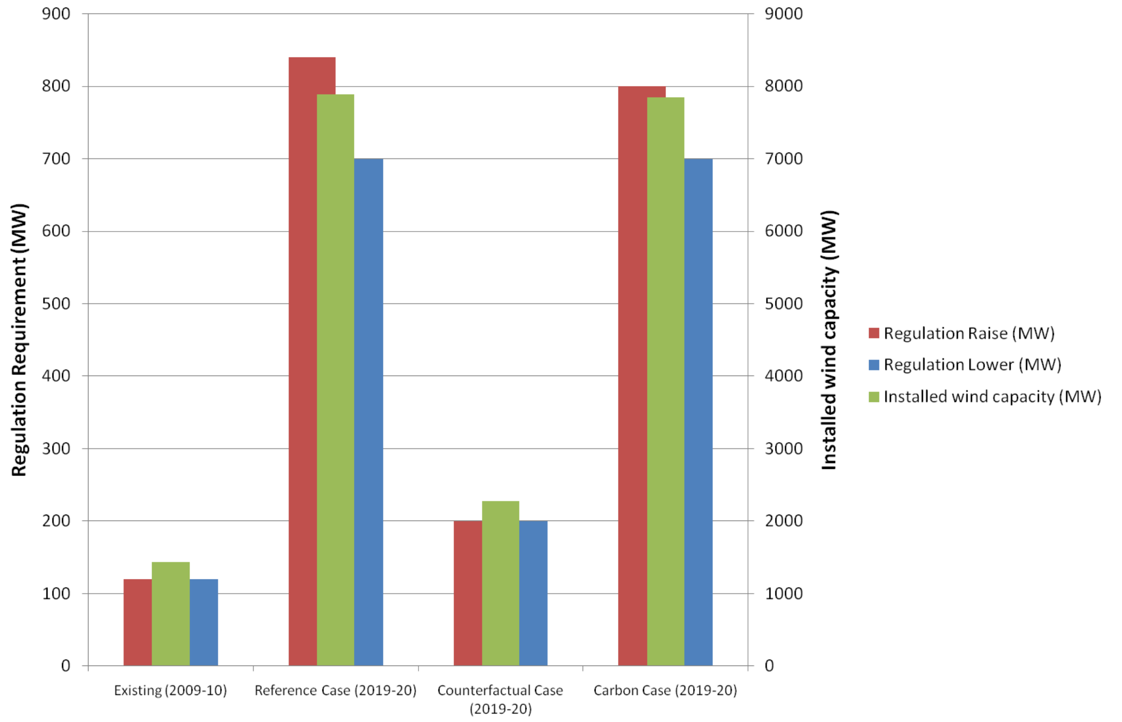
All cases feature significant increases in regulation requirements versus the currently available levels. The Reference Case and the Carbon Case require far more regulation service than the Counterfactual Case, which is directly attributable to the large amount of wind plant present in the former two cases, resulting from the presence of the enhanced RET scheme. In the Counterfactual, the growth in regulation requirement is associated with demand growth between 2009-10 and 2019-20, as well as the impact of existing and committed wind farms.

Figure 4.2 shows the growth in wind farm capacity in the three cases, and the corresponding calculated Regulation requirements. Note that the Counterfactual by design has no new wind generation installed by 2019-20, beyond committed wind farms (currently under construction). Regulation requirements are observed to scale closely with the installed wind farm capacity, although there is an additional (smaller) contribution from the growth in demand.

[11] Refer to Appendix B) for tables listing the wind farms included in the modelling.

[12] Model outcomes for 2009-10 closely matched the present regulation requirements for the NEM.

Figure 4.2 – Regulation requirements and installed wind capacity (NEM)



Regulation Costs

Naturally, with the significant increases in Regulation requirement in the NEM by 2019-20, one would expect that Regulation costs would also face significant increases. This is found to be the case. The results of ROAM's 2-4-C FCAS modelling are shown in Table 4.2. The wholesale energy costs are also derived by the modelling, and are included in the table for comparison with the FCAS costs. Despite the large increase in FCAS costs associated with the enhanced RET, as seen in the data for the Reference and Carbon cases, FCAS costs remain relatively small in comparison to wholesale energy costs. FCAS costs are 35-40 times higher in the enhanced RET cases than they are in the Counterfactual case, even though the relative wind capacity is only four times greater. This and the observations made earlier suggest that wind capacity and regulation requirement is relatively proportional, but the relationship between wind capacity and FCAS costs is non-linear. This occurs as the marginal generator for Regulation moves up the bid stack to higher priced bands, in order to dispatch the larger Regulation requirement.

Table 4.2 – FCAS and wholesale energy costs in the NEM (2019-20)
Real 2011 dollars
(based on demand PoE weighted Medium growth forecasts)

		Total Regulation and Slow Contingency settlements	Energy Settlements
$ millions pa	Existing (2010-11)	$10	$6,900
	Reference Case (2019-20)	$204	$12,418
	Counterfactual (2019-20)	$5	$17,853

Table 4.2 – FCAS and wholesale energy costs in the NEM (2019-20) Real 2011 dollars (based on demand PoE weighted Medium growth forecasts)			
		Total Regulation and Slow Contingency settlements	Energy Settlements
	Carbon Case (2019-20)	$177	$20,347
$/MWh	Existing (2010-11)	$0.05	$35.25
	Reference Case (2019-20)	$0.84	$51.00
	Counterfactual (2019-20)	$0.02	$73.32
	Carbon Case (2019-20)	$0.72	$83.03

It should be noted that these outcomes are based upon the assumption that historical FCAS market bids by existing generators in the NEM were projected forward (and applied similarly to new entrant generators). However, with such a large increase in the Regulation requirement this market will undergo a dramatic change. This means that generator bidding strategies relating to FCAS are likely to change. The manner in which they will change is extremely difficult to predict, particularly given that there is little transparency around historical bidding strategies. With the growth in the market size more generators may participate more actively, seeking ways to provide these services more efficiently. Alternatively, the growth in the market may allow generators more market power, giving them the ability to bid high prices in many periods and increase FCAS costs.

Regarding energy settlements, electricity prices are found to be lower on average in the Reference case (than the Counterfactual case) due to the large increase in installed wind. These renewable generators have very low short run marginal costs and are therefore expected to bid low prices into the market. This tends to decrease the electricity price. A large quantity of wind also enters in the Carbon case, but the depression of the pool price is offset by the application of the carbon price. Carbon prices act to inflate the electricity price, as this cost is passed onto consumers via the market.

Average pool prices in all cases are projected to increase from 2010-11 levels. This is due to a number of factors:

1. There is currently an oversupply of generation capacity in the NEM, which leads to low average prices. These prices are likely to be too low for a stable long term outcome (many generators, particularly combined cycle gas turbines, are unlikely to be making sufficient revenue at present to cover costs).
2. 2010-11 could be considered to have been a very mild weather year, having low peak demands. This leads to an absence of very high priced periods which are a significant driver of average prices.
3. The scenarios provided for this modelling projected very high demand growth, particularly in Queensland. This was not matched by a correspondingly high growth in installed generating capacity, such that unserved energy exceeding the reliability standard was observed in some regions. To counteract the effect of this on prices ROAM installed sufficient open cycle gas turbines (OCGTs) to reduce unserved energy to levels that meet the reliability standard. However, this means that OCGTs would operate (and set prices)

for significant periods of time (this is observed for up to 40% of the time in the model). This will cause pool price to rise to the short run marginal cost of an OCGT for significant periods of time, and cause high average pool prices.

FCAS settlements decline over time in the Counterfactual for two reasons:

1. Load relief increases substantially (because the load increases over the timeframe), so the slow contingency requirement is reduced, and;
2. This modelling does not include many possible contingency events (such as transmission contingencies), so exceptionally high priced periods are not included. This makes ROAM's forecast at the low end of the spectrum of possibilities.

Allocation of Regulation costs

In the NEM the recovery of payments for Regulation Services is based on the 'causer pays' methodology. Under this methodology, the response of measured generation and loads to frequency deviations is monitored and used to determine a series of causer pays factors. These factors are calculated each four seconds, averaged to 5 minute intervals.

For this analysis, ROAM has assumed that since the entry of new wind generation is the driver of increases in the Regulation requirement, wind generators are likely to bear the majority of the increase in Regulation costs. It was assumed that half of the existing Regulation costs are borne by wind generators (with the other half being borne by loads and other generators). The proportion borne by other Market Participants (non-wind farms) was projected to continue at a constant level, while the entire increase in Regulation costs is borne by the installed capacity of wind farms. These assumptions allow an upper estimate of the Regulation costs for which wind generators could be liable. The resulting cost estimates are listed in Table 4.3.

Table 4.3 – Regulation cost liability for wind generators in the NEM (2019-20)
Real 2011 dollars

	Regulation cost liability for wind generators ($/MWh)
Existing (2010-11)	$0.40
Reference Case (2019-20)	$8.30
Counterfactual (2019-20)	$0.17
Carbon Case (2019-20)	$6.18

In cases featuring the LRET (Reference and Carbon) these costs constitute a significant increase in Regulation costs for wind generators. The addition of these costs to the long run marginal costs of wind generators could have significant implications for whether sufficient wind generation is installed for the LRET to be met (especially in scenarios that do not feature a carbon price, and the LRET shortfall charge is not increased).

4.3.2) SWIS

Load Following Requirements

ROAM determined the capacity of Load Following service required to maintain the system frequency operating standards in the SWIS during the 2019-20 year. This process was also benchmarked against the reference year (2009-10) ensuring that historical results are accurately reproduced. A summary of ROAM's system frequency modelling outcomes for the SWIS is shown in the table below.

Table 4.4 – Forecast Load Following Requirements (SWIS)

	Load Following Raise (MW)	Load Following Lower (MW)	Installed wind capacity (MW)[13]
Existing (2009-10)[14]	60	60	191
Reference Case (2019-20)	120	120	397
Counterfactual Case (2019-20)	120	120	397
Carbon Case (2019-20)	265	265	668

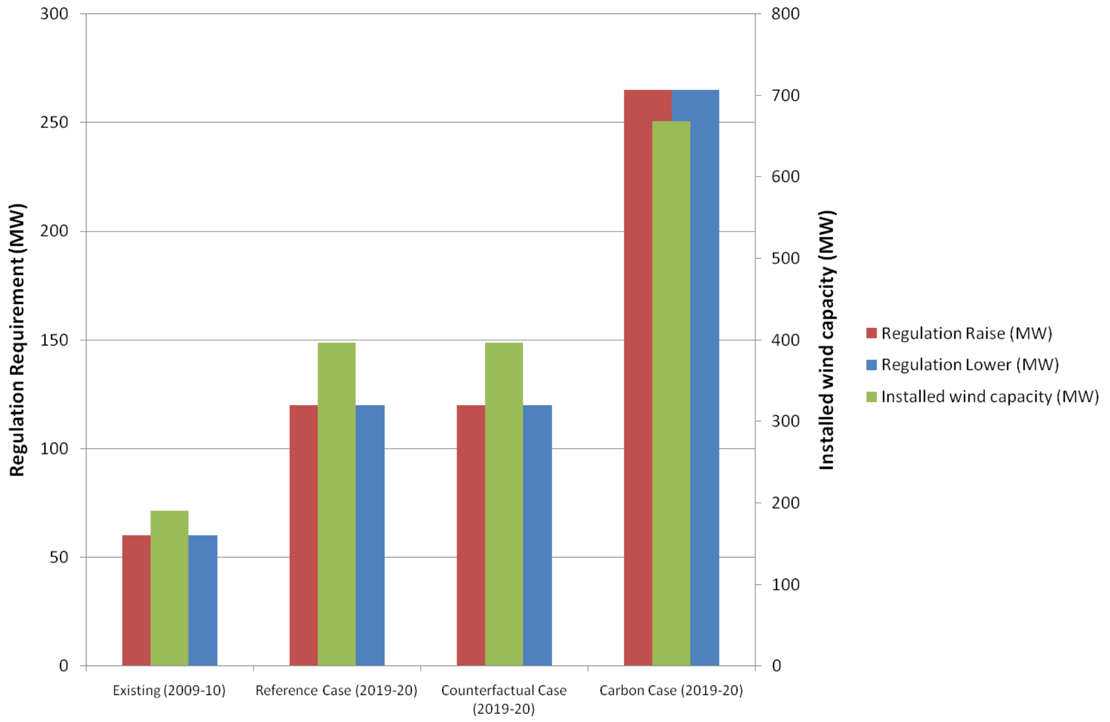
All cases feature significant increases in Load Following requirements versus the currently available levels. The Carbon Case requires far more Load Following service than the other cases, which is directly attributable to the large amount of wind generation present in the Carbon case, driven by the carbon price.

Figure 4.2 shows the growth in wind farm capacity in the three cases, and the corresponding calculated Load Following requirements. Note that the Reference and Counterfactual cases are identical for the SWIS, with the entry of the committed Collgar wind farm being sufficient to meet the share of the LRET allocated to the SWIS. As in the NEM, Load Following requirements are observed to scale closely with the installed wind farm capacity, although there is an additional (smaller) contribution from the growth in demand.

[13] Refer to Appendix B) for tables listing the wind farms included in the modelling.

[14] Model outcomes for 2009-10 closely matched the present regulation requirements for the NEM.

Figure 4.3 – Load Following requirements and installed wind capacity (SWIS)



Load Following Costs

As for the NEM, Load Following costs increase significantly as the Load Following Requirement increases. The results of ROAM's 2-4-C FCAS modelling are shown in Table 4.5. The wholesale energy costs are also derived by the modelling, and are included in the table for comparison with the FCAS costs. Despite the large increase in FCAS costs associated with an increase in wind generation, FCAS costs remain relatively small in comparison to wholesale energy costs.

Table 4.5 – FCAS and wholesale energy costs in the SWIS (2019-20)
Real 2011 dollars
(based on demand PoE weighted Medium growth forecasts)

		Total Load Following and Spinning Reserve settlements	Energy Settlements
$ millions pa	Existing (2009-10)	$18	-
	Reference Case (2019-20)	$58	$1,964
	Counterfactual (2019-20)	$58	$1,964
	Carbon Case (2019-20)	$203	$1,923
	Carbon Case (2019-20) - With LFAS Market[15]	$160	$2,097
$/MWh	Existing (2009-10)	$1.04	-
	Reference Case (2019-20)	$2.36	$79.72
	Counterfactual (2019-20)	$2.36	$79.72
	Carbon Case (2019-20)	$8.23	$78.09
	Carbon Case (2019-20) - With LFAS Market	$6.49	$85.16

The large increase in FCAS costs for the SWIS is due to several factors:

1. ***Increased Load Following requirement*** - The increased Load Following requirement means that a larger capacity of gas-fired plant must be operated at a midpoint to provide sufficient raise and lower capacity. This increases the cost.
2. ***Increased Verve gas price*** - The gas price assumed for Verve in the existing settlement calculations is around $4 /GJ. However, it is likely that Verve will need to negotiate new gas contracts prior to 2019-20, and will face significantly higher gas prices. For this modelling, ROAM has assumed a gas price of $7.60 in the SWIS in 2019-20. This significantly increases the cost to Verve of operating the gas-fired plant required to provide fast-acting Load Following services.
3. ***Carbon price*** - In the Carbon case, the applied carbon price increases the cost of Verve's gas-fired generation that is operating to provide Load Following. This increases the cost of Load Following services.

As for the NEM, these results suggest that wind capacity and Load Following requirement is relatively proportional, but the relationship between wind capacity and FCAS costs is non-linear. This occurs as less efficient plant must be utilised for Load Following service as the requirement increases.

[15] Load Following Ancillary Services (LFAS) Market. This scenario is identical to the Carbon case, except that the most efficient gas-fired generators were used for the provision of Load Following service (regardless of whether they were Verve plant or Independent Power Producers).

A Rule change process is currently underway in the SWIS to create a Load Following Ancillary Services (LFAS) market. This would facilitate plant other than Verve owned generators providing Load Following. This should enable more efficient plant to provide this service, reducing costs. To investigate the potential magnitude of the effect of this Rule change, ROAM re-calculated the dispatch for the Carbon case utilising the most efficient gas-fired plant for Load Following service, regardless of whether it was owned by Verve or not. This resulted in a substantial reduction in Load Following costs from $203 million to $160 million pa. It is also possible that Verve may invest in more plant similar to the soon-to-be-commissioned High Efficiency Gas Turbines (HEGT), designed to deliver services such as Load Following at low cost. This would reduce Load Following costs further.

Regarding energy settlements, electricity prices are inflated by the carbon price in the Carbon case, but this is offset by the significant quantity of additional wind that enters in this case.

Allocation of Load Following costs

In the SWIS the recovery of payments for Load Following Services is divided equally according to the metered schedules (MWh) consumed and generated by loads and intermittent generators. On this basis, wind generators (and loads) could expect Load Following costs similar to those listed in Table 4.6 in the first column ("Existing Rules"). Costs would likely be reduced below this, since some of the liability would be paid for under Spinning Reserve services.

Table 4.6 – Load Following cost liability for wind generators in the SWIS (2019-20) ($/MWh) Real 2011 dollars

	Existing Rules	Proposed Rule Change ("Full Load, Marginal Generation")
Present (2010-11)	$0.42	$5.75
Reference Case (2019-20)	$2.24	$29.17
Counterfactual (2019-20)	$2.24	$29.17
Carbon Case (2019-20)	$7.51	$72.86
Carbon Case (2019-20) - With LFAS Market	$5.92	$57.47

However, a Rule Change process is currently underway in the SWIS that will change the settlement equations for Load Following. A "Full Load, Marginal Generation" allocation methodology is being pursued. This method estimates the capacity of Load Following that would be required to meet the variability of loads (in the absence of intermittent generation), and attributes that proportion of the Load Following cost to Loads. Intermittent generators are then liable for the remaining cost. Since the majority of the increase in Load Following requirement is due to the entry of new wind generation, this means that wind generators will bear the majority of the increase in Load Following costs.

In 2009-10 the fluctuations caused by loads alone lead to a Load Following requirement of -32/+26 MW. This is anticipated to increase gradually in response to load growth. A value of 40 MW is assumed for 2019-20. Allocating the remaining proportion of Load Following costs to wind generators leads to the costs listed in the right column in Table 4.6. These costs constitute a very significant increase in Load Following costs for wind generators. The addition of these costs to the long run marginal costs of wind generators is likely to be prohibitive of any further wind generation is installation in the SWIS, in the absence of substantial additional subsidies.

Treatment of Badgingarra Wind Farm (SWIS)

It has been identified that in constructing the planting schedules used for this study, Oakley Greenwood considered Badgingarra Wind Farm (130 MW) to be committed for installation in the SWIS. However, ROAM did not ascribe this status to the Badgingarra proposed wind development, and therefore did not model this wind farm explicitly in any of the scenarios included in this modelling.

Based upon simple projections of the results of this study, rough estimates can be made of the effect on Load Following costs of including Badgingarra. The proposed Badgingarra wind farm is relatively close to Emu Downs (an 80 MW existing wind farm), which means that their output is likely to be relatively strongly correlated. This would exacerbate wind disturbances at Emu Downs, increasing the FCAS requirement. This modelling suggests that in the SWIS, 30-40% of the added capacity of wind is likely to be required as an increase to the Load Following requirement. This suggests that the Load Following requirement may to need to be increased by around 40 - 50 MW with the addition of Badgingarra wind farm.

Load Following service was projected to cost $0.5 million/MW in the Reference and Counterfactual cases, or up to $0.8 million/MW in the Carbon case ($0.6 million/MW if an LFAS market is introduced). Projecting these average costs linearly suggests that the addition of Badgingarra wind farm is likely to add on the order of $20-25 million pa in the Reference and Counterfactual cases, or around $30-40 million pa in the Carbon case ($20-30 million pa if an LFAS market is introduced) in 2019-20.

With the application of the existing settlement rules, this could further increase FCAS costs to wind generators in 2019-20 by around $0.80 - $1.20 /MWh. This corresponds to total costs to wind generators in 2019-20 being around $3/MWh in the Reference and Counterfactual cases, $8.70/MWh in the Carbon case, or $6.80 in the Carbon case with an LFAS market.

If the proposed rule change (“Full Load, Marginal Generation”) is applied, this would mean that the addition of Badgingarra wind farm is likely to increase Load Following costs to wind generators in 2019-20 in the range $1.50 - $6.00 /MWh. This corresponds to total costs to wind generators in 2019-20 being around $35/MWh in the Reference and Counterfactual cases, $75/MWh in the Carbon case, and $59/MWh in the Carbon case with an LFAS market.

5) NETWORK SUPPORT AND CONTROL ANCILLARY SERVICES (NSCAS)

Unlike the other parts of this study (FCAS and transmission augmentation), NSCAS projections were not approached with a detailed modelling exercise. Reactive power and voltage control typically need to be provided locally, and this means that requirements can depend very much on the unique aspects of each individual location. ROAM has therefore applied a more general research and literature review approach, allowing some broad generalisations and calculations.

Because of the different nature of the approach used for this part of the study, this part of the report is structured somewhat differently. This chapter is arranged in the following way:

- **Section 5.1)** - An overview of the treatment of NSCAS in the Rules in the NEM and the SWIS
- **Section 5.2)** - An overview of the connection requirements for new wind farms, relating to reactive power requirements.
- **Section 5.3)** - A review of published forecasts of NSCAS requirements from various sources
- **Section 5.4)** - A summary of the various wind generation technologies commercially available, and their implications for NSCAS requirements. This includes an assessment of the wind technologies installed in Australia to date, and anticipated future installations (and the implications for NSCAS requirements)
- **Section 5.5)** - A summary of the various technologies available for the management of reactive power, including their relative effectiveness and costs
- **Section 5.6)** - Calculation of the NSCAS requirements under the LRET that are likely to result, given assumptions based upon the assessments made in previous sections.

5.1) NSCAS IN THE RULES

NEM Rules

Until recently, a network control ancillary service (NCAS) was defined in the Rules[16] as:

> A service identified in clause 3.11.4(a) which provides *AEMO* with a capability to control the real or *reactive power flow* into or out of a *transmission network* in order to:
>
> (a) maintain the *transmission network* within its current, voltage, or stability limits following a credible contingency event; or
>
> (b) enhance the value of *spot market* trading in conjunction with the *central dispatch* process.

A recent Rule Change[17] has introduced a new defined term "NSCAS" to replace the current definition for NCAS. A network support and control ancillary service or NSCAS is now defined in the Rules[18] as:

[16] National Electricity Rules, Version 43, Chapter 10, Glossary, Page 1020.

[17] Australian Energy Market Commission, Rule Determination, National Electricity Amendment (Network Support and Control Ancillary Services) Rule 2011. 7 April 2011.

http://www.aemc.gov.au/Media/docs/Final%20Rule%20Determination-99d83c06-e2d1-43c8-be98-31e102670ec1-0.PDF

A service with the capability to control the *active power* or *reactive power* flow into or out of a *transmission network* to address an *NSCAS need.*

An NSCAS need is defined as:

Network support and control ancillary service required to:

(c) maintain *power system security* and reliability of *supply* of the *transmission network* in accordance with the *power system security and reliability standards*; and

(d) maintain or increase the *power transfer capability* of that *transmission network* so as to maximise the present value of net economic benefit to all those who produce, consume or transport electricity in the *market*.

Types of NSCAS defined in the NEM

Network Support and Control Ancillary Services (NSCAS) are divided into two categories[19]:

3. ***Reactive Power Ancillary Service (RPAS)*** - Also termed Voltage Control. Used to control the voltage at different points of the electrical network to within the prescribed standards. Generators absorb or generate reactive power and control the local voltage accordingly. RPAS requirements are localised, due to the inefficiencies of transporting reactive power through the network. RPAS services can be subdivided into two categories:
   a. ***Synchronous Compensator*** - a generating unit that can generate or absorb reactive power while not generating energy in the market.
   b. ***Generation Mode*** - a generating unit that can generate or absorb reactive power while generating energy in the market.
4. ***Network Loading Control Ancillary Service (NLCAS)*** - used to control the power flow on interconnectors to within short term physical limits. This involves adjusting the dispatch of generators or loads in the network, achieved through Automatic Generation Control (AGC), in the same manner as regulation frequency control and load shedding.

NSCAS Payments in the NEM

NSCAS is provided to the market under long term ancillary service contracts negotiated between AEMO (on behalf of the market) and the participant providing the service[20]. Generation Mode Voltage Control services are paid for via availability payments (made for every trading interval that the service is available), whereas Synchronous Compensator services and Network Loading Control services are paid for via enabling payments (made only when the service is specifically enabled). These payments are recovered from market customers only (not generators).

[18] Australian Energy Market Commission, National Electricity Amendment (Network Support and Control Ancillary Services) Rule 2011 No. 2.

http://www.aemc.gov.au/Media/docs/Rule%20as%20Made-f18c6bb4-8dd1-4169-b23b-f05915c3916f-0.PDF

[19] AEMO, Guide to Ancillary Services in the National Electricity Market.

http://www.aemo.com.au/electricityops/0160-0048.pdf

[20] AEMO, Guide to Ancillary Services in the National Electricity Market.

http://www.aemo.com.au/electricityops/0160-0048.pdf

5.2) CONNECTION REQUIREMENTS FOR REACTIVE POWER CAPABILITY

5.2.1) NEM

The automatic access standard is a generating system operating at any level of active power output and any voltage at the connection point varying by no more than 10 percent above or below its normal voltage, provided that the reactive power flow and the power factor at the connection point is within the corresponding limits set out in the connection agreement. Under this standard, generators must be capable of supplying and absorbing continuously at their connection point an amount of reactive power of at least the amount equal to the product of the rated active power of the generating system and 0.395.

However, the minimum access standard to connect a generator to the NEM does not require any capability to supply or absorb reactive power at the connection point.

The Electricity Supply Industry Planning Council (ESIPC) has indicated that the National Electricity Rules applying in the NEM do not yet deal adequately with the treatment of reactive power from wind generators[21]. While this issue is of minimal significance in regions with very little wind generation connected, it is important in higher penetration wind regions (such as South Australia). The Essential Services Commission of South Australia (ESCOSA) therefore applies more onerous technical standards (particularly relating to reactive power) for the connection of new wind farms to the South Australian network.

South Australia

In 2005 ESCOSA identified that there were likely to be issues related to voltage control in the South Australian network under the minimum access standards for the NEM. They therefore defined more onerous technical standards for new wind farms to obtain a license to connect to the network in South Australia. These standards were reviewed in 2010 in light of changes in the NEM Rules, but were deemed to remain necessary for the continued secure and reliable operation of the South Australian network.

The existing standards applying in South Australia for the connection of new wind farms, relating to voltage control and reactive power include the following[22]:

1. ***Fault Ride Through Capability*** - As a minimum, generators must meet the NER automatic access standards for:
    a. Generating system response to disturbances following contingency events (S5.2.5.5.(b)(1) and S5.2.5.5.(b)(2) of the NER); and
    b. Generating system response to voltage disturbances (S5.2.5.4 of the NER)

    (with a number of specific exemptions).

[21] Appendix 1, ESCOSA Licence conditions for wind generators, Draft Decision, June 2009. http://www.escosa.sa.gov.au/library/090616-WindGenerationLicenceConditions-DraftDecision.pdf

[22] The Essential Services Commission of South Australia, Licence Conditions for Wind Generators, Final Decision, May 2010.

2. ***Reactive Power Capability -*** The generator must be capable of continuous operation at a power factor of between 0.93 leading and 0.93 lagging at real power outputs exceeding 5 MW. At least 50% of this reactive power must be available on a dynamically variable basis, with the balance of reactive power provided on a non-dynamic basis. At generation levels below full rated output, the generator must be capable of absorbing and delivering reactive power at a level at least pro-rata to that of full output.

These additional requirements must be met by wind farm developers in order to obtain a license to connect to the South Australian network. These conditions were considered by ESCOSA to be sufficient to ensure voltages on the network could be managed, and voltage stability maintained.

These conditions place the responsibility for voltage control with wind farm developers (rather than on Transmission Network Service Providers or AEMO), such that the future NSCAS requirements due to wind farms connecting in South Australia are likely to be minimal.

5.2.2) SWIS

In the SWIS, the minimum steady state voltage must be 90% of nominal voltage and the maximum steady state voltage must be 110% of nominal voltage. Each generating unit, and the power station in which the generating unit is located, must be capable of continuously providing its full reactive power output within this full range of steady state voltages.

Reactive power requirements differ depending upon the type of generator, and wind generation technologies can fall into several types. The reactive power requirements of each are[23]:

- ***Synchronous generating units*** must be capable of supplying reactive power equal to the product of rated active power and 0.750, and absorbing reactive power equal to the product of rated active power and 0.484. At the maximum active power output, this equates to operating at any power factor between 0.8 lagging and 0.9 leading.
- ***Induction generating units*** must be capable of supplying or absorbing an amount of reactive power of at least equal to the product of the rated active power output and 0.329. When producing at the maximum active power output, this equates to operation at any power factor between 0.95 lagging and 0.95 leading.
- ***Inverter coupled generating units*** or ***converter coupled generating units*** must be capable of supplying reactive power such that the lagging power factor is less than or equal to 0.95 and must be capable of absorbing reactive power at a leading power factor less than or equal to 0.95.

5.3) Published Forecasts of NSCAS Requirements

NSCAS Rule Change

A recent Rule Change[24] requires AEMO to identify any gaps between the Network Support and Control Ancillary services (NSCAS) needs of the NEM power system and the NSCAS that is

[23] Western Power, Technical Rules for the South West Interconnected Network, 26 April 2007.

anticipated to be acquired by the network service providers (NSPs), including the trigger date when the NSCAS gap arises and the NSCAS tender date by AEMO would need to act by if it considered it necessary to acquire the NSCAS. This will occur as a part of the National Transmission Network Development Plan (NTNDP) publication.

Under this Rule Change, transmission network service providers (TNSPs) have the primary responsibility for meeting the NSCAS needs in the NEM, but AEMO will consult with the TNSPs to determine whether the NSCAS remains unmet and, in the case of NSCAS required for power system security or reliability of supply, seek tenders from NSCAS providers to meet this gap. The costs for NSCAS acquired by AEMO should be recovered from Market Customers in benefiting regions on the basis of the regional benefit ancillary services procedures, while NSCAS costs incurred by the TNSPs are recovered from network users through the TNSPs' regulated transmission charges.

Power System Adequacy - Two Year Outlook

AEMO's Power System Adequacy - Two Year Outlook report[25], released in late 2010, analysed historical data to examine potential voltage fluctuations at a number of locations. No clear trends in historical voltage fluctuations were identified which would suggest any emerging issues with voltage control.

AEMO identified a number of locations where voltage fluctuations may increase under certain operating conditions, creating power system security issues. Several locations were identified in Tasmania (particularly Georgetown) where voltage fluctuations have occurred in the past, and are considered possible in the future. Additionally, possible voltage control issues were identified at Beaconsfield West in New South Wales and Moorabool in Victoria. However, voltage control at these locations was not expected to deteriorate significantly over the next two years, and increased wind generation capacity was judged unlikely to significantly exacerbate any current voltage control problems.

Results were identical in the sensitivity scenario, which included the unplanned retirement of 995 MW of older generating units across the NEM. Both scenarios only considered existing and committed wind farms expected to enter over the two year outlook period, with analysis of the impacts of high and low generation at those facilities.

2010 NTNDP

AEMO reported on anticipated future NSCAS requirements over the next five years (2010-11 to 2014-15) in the 2010 NTNDP. Key issues were identified (issues that are currently being managed by existing NSCAS contracts, or may not have been sufficiently addressed by the relevant TNSP in its latest Annual Planning Report). The resulting five year forecast of NSCAS requirements in each region of the NEM is summarised in Table 5.1.

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[24] Australian Energy Market Commission, Rule Determination, National Electricity Amendment (Network Support and Control Ancillary Services) Rule 2011. 7 April 2011.

http://www.aemc.gov.au/Media/docs/Final%20Rule%20Determination-99d83c06-e2d1-43c8-be98-31e102670ec1-0.PDF

[25] http://www.aemo.com.au/electricityops/0410-0051.pdf

Table 5.1 – NSCAS requirements identified in the 2010 NTNDP						
		2010-11	**2011-12**	**2012-13**	**2013-14**	**2014-15**
QLD	**NLCAS**	0	0	0	0	0
	Supplying RPAS	0	0	0	0	0
	Absorbing RPAS	0	0	0	0	0
NSW	**NLCAS**	0	0	0	0	0
	Supplying RPAS	650 MVAr	650 MVAr 150 MVAr	650 MVAr 150 MVAr	650 MVAr	650 MVAr
	Absorbing RPAS	650 MVAr	650 MVAr	650 MVAr	650 MVAr	650 MVAr
VIC	**NLCAS**	260 MW	260 MW	260 MW	260 MW	260 MW
	Supplying RPAS	0	0	0	0	200 MVAr
	Absorbing RPAS	0	0	0	0	0
SA	**NLCAS**	0	0	0	0	0
	Supplying RPAS	20 MVAr 35 MVAr	0	0	0	0
	Absorbing RPAS	0	0	0	0	0
TAS	**NLCAS**	0	0	0	0	0
	Supplying RPAS	0	0	0	0	0
	Absorbing RPAS	0	0	0	0	0

The details of these identified NSCAS requirements are described below:

- New South Wales
  - Supplying RPAS requirement to ensure acceptable voltage quality and sufficient voltage stability margins for supplying major load centres in Sydney
  - Absorbing RPAS requirement to manage voltage quality in the Snowy area under light load conditions
- Victoria
  - NLCAS requirement to increase power transfers from NSW to VIC over the 330 kV Murray-Dederang lines
  - RPAS requirement at Rowville to avoid voltage collapse
- South Australia
  - RPAS requirement at Mount Barker and Dorrien in 2010-11. Can also be managed under existing load shedding schemes.

These projections were for an "expected" scenario, including existing and committed renewable projects. Intermittent generation was assumed to be operating either at its maximum or minimum, depending upon whichever requires the most NSCAS.

Wind generation assumptions in the 2010 NSCAS studies were shown to have little or no bearing on the assessed NSCAS reactive power support requirements because most of the identified reactive power issues are associated with supplying load centres, significant distances away from existing and committed wind farms.

2011 NTNDP

The consultation paper[26] for the 2011 NTNDP identifies the anticipated increase in wind generation in the NEM to be an area of focus for NSCAS modelling. It is identified that under some load conditions, wind generation far from the load centres may replace the conventional generation near the load centres, creating a deficit in the supply of reactive power support required for maintaining voltage quality at load centres. The 2011 NTNDP aims to explore operational scenarios that will allow assessment of the impact of increasing wind power generation on NSCAS requirements.

5.4) WIND GENERATION TECHNOLOGIES

There are a range of wind generation technologies commercially available, and each contributes differently to reactive power and voltage control.

Fixed Speed Induction Wind Turbine

These turbines are simple and robust, with a fixed speed stall regulated turbine coupled via a gearbox to an induction generator. The comparatively low cost of these turbines has made them ubiquitous for small, distribution connected wind installations (commonly installed in the previous decade around Europe).

Up to a point, induction machines tend to reduce voltage imbalance on local networks, providing an intrinsic benefit to the network. However, they inherently absorb reactive power, which can lead to voltage excursions outside statutory limits, and significantly increase electrical losses. They also do not provide control over their reactive power consumption, and therefore do not provide fault ride-through capability on their own, except for brief voltage dips. Auxiliary reactive compensation equipment is therefore typically required for these installations.

Dual Speed Generator Wind Turbine

The dual speed generator wind turbine type is similar to the simple fixed speed induction generator, but utilises two induction generators (a small generator with a high efficiency at low wind speeds, and a larger generator with high efficiency at higher wind speeds). The wind turbine switches between the two induction generators as the wind speed varies, providing greater efficiency, but maintaining the simple and robust qualities of the fixed speed generator. This technology type is typically used for smaller turbines (less than 2 MW), and is particularly effective at sites with modest wind resources.

[26] AEMO, National Transmission Network Development Plan: Consultation Paper 2011, 31 January 2011. http://www.aemo.com.au/planning/0418-0009.pdf

This technology provides limited control of active and reactive power - more than the fixed speed induction design, but not as much as the variable speed synchronous technologies. It does not provide sufficient fault-ride through capability to meet typical grid codes, or comprehensive reactive power control without additional infrastructure.

Variable Slip Wind Turbine

In this design, a variable resistor is connected in series with the induction machine's rotor circuit. This is used to adjust the speed at which the generator operates at maximum efficiency for a given power output. This allows efficient operation for a range of wind speeds. Like the dual generator wind turbine technology, variable slip wind turbines are typically used for smaller turbines (less than 2 MW), and are particularly effective at sites with modest wind resources.

Like the dual generator technology, variable slip technology provides limited control of active and reactive power - more than the fixed speed induction design, but not as much as the variable speed synchronous technologies. It does not provide sufficient fault-ride through capability to meet typical grid codes, or comprehensive reactive power control without additional infrastructure.

Doubly Fed Induction Generator (DFIG) Wind Turbine

The design of DFIG turbines is based on an induction machine, but incorporates sophisticated power electronics to present an arbitrarily adjustable voltage and frequency to one of the machine's windings. This permits operation over a greater speed range than earlier induction generator designs.

A significant advantage of DFIG designs is that they allow control over the absorption or supply of reactive power. The DFIG can therefore provide a voltage control function if required. The control capabilities are limited by the size of the converter (typically 30% of the nominal rating of the generator). DFIG turbines provide sufficient reactive power support and voltage control to meet typical grid code requirements. Overvoltage ride-through has not been an issue due to their fast voltage control capability, and in some instances DFIGs have been observed to aid in locally reducing the worst case system over-voltages, providing a slight improvement to the system[27].

DFIGs cannot provide sufficient fault ride-through capability during a local, solid three-phase fault, when the voltage at the low-voltage generator bus can sometimes dip slightly below the ride-through capability of the generator.

The DFIG design has proven popular for more recent wind farm installations, providing an attractive trade-off between the cost competitiveness of a fixed speed generator and the high performance and controllability of a variable speed generator.

Variable Speed Synchronous Wind Turbine

This turbine design is based upon a synchronous generator in combination with sophisticated power electronics. The electrical design is more complicated than the design based on an

[27] CIGRE Working Group C6.08, Grid Integration of Wind Generation, Holger Mueller, Markus Poeller, David Jacobson, Transient Stability. February 2011.

induction generator, but it provides must greater flexibility. In particular, this turbine has the capability to control both active and reactive power over the full range of turbine output. Therefore, no additional reactive compensation equipment is typically required.

This generator type is capable of providing some degree of ride-through capability for symmetrical faults, but it has a low tolerance of phase imbalance, and so provides only very limited capability to ride-through asymmetrical faults.

These generators tend to be more expensive, require heavier foundation works, and often require filtering equipment to manage harmonic distortions caused by the large power converters (which further increase the installation cost of this technology). Nevertheless, their higher efficiency and more desirable qualities for grid integration allow this technology to compete with the simpler fixed speed induction type turbines. Variable speed turbines of this type are in use in Australia, including at the 21.6 MW Albany wind farm (Western Australia).

Summary of technologies

The various wind turbine technologies are summarised in Table 5.2, with their capabilities relating to reactive power and voltage control summarised in Table 5.3.

Table 5.2 – Wind turbine technologies overview[28]

Wind turbine type	Details
Fixed Speed Induction	• Fixed speed stall regulated turbine coupled via a gearbox to an induction generator
Dual Speed Generator	• Asynchronous • Employs two induction generators: a small generator with a high efficiency at low wind speed, and a larger generator with high efficiency at nominal wind speed • Wind turbine switches between the small to the large generator depending on the prevailing wind speed
Variable Slip	• Asynchronous • A variable resistor is connected in series with the induction machine's rotor circuit. By changing the rotor resistance of the induction generator, the torque/speed characteristic is modified. This affects the speed at which the generator operates at maximum efficiency for a given power output. This allows the generator to operate at near maximum efficiency for a range of speeds above the nominal wind speed. • At speeds below the rated wind speed, the generator behaves like a fixed speed machine.

[28] Modified from Econnect report, South West Interconnected System (SWIS), Maximising the Penetration of Intermittent Generation in the SWIS. Econnect Project No. 1465, prepared for Office of Energy, Western Australia. December 2005.

Table 5.2 – Wind turbine technologies overview[28]	
Doubly Fed Induction Generator (DFIG)	• The design is based on an induction machine, but it incorporates the use of power electronics to present an arbitrarily adjustable voltage and frequency to one of the machine windings. • The traditional squirrel cage rotor is replaced by a three phase rotor winding; electrical connections are made to this winding via slip rings and connected to the grid via an AC-DCAC converter, in parallel with the conventional stator connection.
Variable Speed Synchronous	• Synchronous generator in combination with sophisticated power electronics. • Mechanical system comprises a direct drive pitch-regulated wind turbine, with blade angle control used to control the shaft speed rather than a gearbox interposed between blades and generator. • The stator (stationary part) of the synchronous generator is connected to the grid via an AC-DC-AC converter, which transforms the variable-frequency variable-voltage generator output into a constant frequency constant-voltage output that can be synchronised and transmitted into the grid.

Table 5.3 – Reactive power control capabilities of wind farm technologies[29]

Wind turbine type	Reactive Power Control	Voltage Control	Fault Ride Through Capability
Fixed Speed Induction	No	No	No
Dual Speed Generator	Limited	No	No
Variable Slip	Limited	No	No
Doubly Fed Induction Generator (DFIG)	Yes	Limited	Limited
Variable Speed Synchronous	Yes	Yes	Limited

5.4.1) Wind technologies installed in Australia

Information on the turbine choice in wind project development is not typically publicly available. However, the turbine selections at a variety of installations in Australia are summarised in Table 5.4 below. It is clear that DFIG turbines have been popular for development in Australia.

[29] Reproduced from Econnect report, South West Interconnected System (SWIS), Maximising the Penetration of Intermittent Generation in the SWIS. Econnect Project No. 1465, prepared for Office of Energy, Western Australia. December 2005.

Table 5.4 – Wind farm technologies installed in Australia				
Wind Farm	**Capacity**	**Location**	**Turbine**	**Turbine Type**
Capital	141 MW	NSW	Suzlon S88, 2.1MW	DFIG
Brown Hill (Hallett 1)	95 MW	SA	Suzlon S88, 2.1MW	DFIG
North Brown Hill (Hallett 4)	132 MW	SA	Suzlon S88, 2.1MW	DFIG
Hallett Hill (Hallett 2)	71 MW	SA	Suzlon S88, 2.1MW	DFIG
Clements Gap	57 MW	SA	Suzlon S88, 2.1MW	DFIG
Woolnorth Studland Bay	75 MW	TAS	Vestas V90, 3 MW	DFIG
Lake Bonney Stage 2	159 MW	SA	Vestas V90, 3 MW	DFIG
Lake Bonney Stage 3	39 MW	SA	Vestas V90, 3 MW	DFIG
Lake Bonney Stage 1	80.5 MW	SA	Vestas V66, 1.75 MW	DFIG
Woolnorth Bluff Point	60.5 MW	TAS	Vestas V66, 1.75 MW	DFIG
Mt Millar	70 MW	SA	Enercon E70, 2.3 MW	Variable speed synchronous
Oaklands Hill (under construction)	65 MW	VIC	Suzlon S88, 2.1MW	DFIG
Crookwell 2 (under construction)	92 MW	NSW	Vestas V90, 2 MW	DFIG
Macarthur (under construction)	420 MW	VIC	Vestas V112, 3 MW	Full scale converter, permanent magnet generator, gearbox[30]

The Suzlon S88 DFIG has been a particularly popular choice. This turbine offers a fault ride-through of 0 volts for 0.2 seconds.

Vestas is also now offering a variety of 2-3MW turbines utilising "GridStreamer" technology, which uses a permanent magnet generator, with a full scale converter and a gearbox. Since this technology utilises a back-to-back converter, it offers reactive power and voltage control capabilities at least as good as the variable speed synchronous generators. Vestas claims that this technology delivers a power factor of +/-0.9 at full power and is capable of a low voltage ride-through down to 0 volts for 0.5 seconds.

[30] This turbine has reactive power and voltage control properties similar or superior to a variable speed synchronous generator. It can operate at a voltage range of 0.9-1.1 pu, with a power factor range of 0.9 capacitive/0.83 inductive (HV transformer). It provides reactive current injection, and zero voltage ride through for 0.5 seconds.

The experience in many European countries (such as Denmark) has been that generous feed in tariffs combined with mandatory grid connection of new projects has incentivised the development of a large number of embedded small wind farms at the distribution level. This type of development favours the simpler fixed speed induction wind turbines.

By contrast, the Australian regulatory regime appears to incentivise much larger wind projects, often connected at the transmission level. Participation in the Renewable Energy Certificate market necessitates the negotiation of Power Purchase Agreements, and grid connection must be negotiated for each project. This creates significant economies of scale for wind farm developers, and makes the implementation of small projects challenging. Larger wind farm developments of this nature appear to favour more sophisticated wind generation technologies, such as DFIGs and variable speed synchronous turbines. Since these more advanced technologies offer more voltage support and reactive power control to the local network, there are likely to be fewer issues with NCAS in Australia than may have appeared elsewhere.

5.5) Technologies for the Management of Reactive Power

A variety of technologies are available for managing reactive power and voltage control in the network. Simpler, fixed or mechanically switched devices (such as capacitor banks) offer a basic level of voltage control, whereas more sophisticated technologies in the class of "Flexible AC Transmission Systems" (FACTS) use additional power electronics or converters to switch the elements in smaller steps or with switching patterns within a cycle of the alternating current.

Capacitor banks

Capacitor banks provide the simplest and most inexpensive form of reactive power compensation. These act as a fixed source of reactive power suitable for counteracting the steady-state reactive power absorbed by fixed speed induction wind turbines (for example). In many wind farm installations, capacitor banks are installed at the generator terminals, the wind farm substation terminals, or both, in order to satisfy power factor requirements.

Some basic switching control can be used with capacitor banks to vary the reactive power output depending upon the wind farm active power output. However, this can only be achieved in steps. Capacitor bank switching has a comparably slow response time, and is therefore typically insufficient to provide fault ride-through capability for fixed speed wind generators.

Capacitor bank reactive supply varies proportionally to the square of the voltage, and hence capacitor banks can only assist in supply of reactive power if the voltage is stable.

Static VAr Compensators (SVCs)

SVCs use power electronics to provide fast acting reactive power compensation, and provide smoother and more precise control than mechanically switched compensation. If the power system load is capacitive (leading), they use reactors (usually thyristor-controlled reactors) to consume reactive power from the system (lowering the system voltage). If the power system load is inductive (lagging), the SVC individually switches in capacitor banks to increase the system voltage (these can also be switched by thyristors for smoother control and more flexibility). The automated switching ability of SVCs provides near instantaneous response to changes in system voltage.

To provide sufficient fault ride-through capability for a medium to large wind farm to meet typical grid codes (including in the NEM) usually requires the installation of SVCs equivalent to 20-40% of the wind farm's installed capacity[31]. SVCs are relatively expensive, compared with simpler capacitor bank technology.

SVC technology is effective for mitigating undamped voltage oscillations and preventing voltage collapse. However, SVCs can only produce a reduced VAR output during low voltage, which makes them less effective for mitigating violation of certain voltage limits immediately following fault recovery.

STATCOMs

Similarly to SVCs, STATCOMs use power electronics to provide fast acting reactive power compensation. They are inverters based on forced-commutated switches (with full, continuous control of the reactive power).

STATCOMs are more expensive than SVCs, but are generally considered to have better characteristics. When the system voltage drops sufficiently to force the STATCOM output to its ceiling, its maximum reactive power output will not be affected by the voltage magnitude. Therefore, it exhibits constant current characteristics when the voltage is low under the limit. In contrast the SVC's reactive output is proportional to the square of the voltage magnitude. This makes the provided reactive power decrease rapidly when voltage decreases, thus reducing its stability. Therefore STATCOMs are better than SVCs for managing post-disturbance undervoltage conditions, and can improve power quality against dips and flickers[32]. However, they may not be as effective as SVCs at damping voltage oscillations[33].

Synchronous condensers

Synchronous condensers were used to manage power factor compensation prior to the invention of the SVC. They are large rotating machines, identical to a synchronous motor whose shaft is not connected to anything but spins freely. A voltage regulator allows the unit to either generate or absorb reactive power in a continuously adjustable manner. Synchronous condensers are typically more expensive, lower capacity, slower and less reliable than SVCs, but their use was common through the period prior to the invention of SVCs. Many existing peaking generators, particularly hydro and OCGTs with clutches, have synchronous condenser capability. Some fossil fuel generators are converted to synchronous condenser mode in their later lives, by decoupling the turbines and synchronising them using small motors. However, the windage losses of synchronous condensers tends to make them expensive to operate, particularly in support of renewable generators.

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[31] Econnect, South West Interconnected System (SWIS), Maximising the Penetration of Intermittent Generation in the SWIS. Econnect Project No. 1465, prepared for Office of Energy, Western Australia. December 2005.

[32] Xiao-Ping Zhang, Christian Rehtanz and Bikash Pal, Flexible AC Transmission Systems: Modelling and Control. Power Systems. Springer, 2006.

[33] Holger Mueller, David Jacobson, Jerome Duval, Reactive Power Control and Voltage Control Capability. CIGRE Working Group C6.08, Grid Integration of Wind Generation, February 2011.

5.6) NSCAS REQUIREMENTS UNDER THE LRET

As discussed above, the amount of additional voltage control infrastructure required could vary substantially depending upon the type of wind turbines installed, and the locations of those wind farms. In the best case, wind farms could contribute positively to voltage control, reducing NSCAS costs. In the worst case, the introduction of a large capacity of new wind generation could require substantial new voltage control infrastructure.

To provide an estimate of the possible cost, we can make the following assumptions:

- ***South Australia*** - Wind generation capacity installed in South Australia is of an advanced technology type, or is accompanied by sufficient infrastructure to maintain local voltages and reactive power requirements (due to the stringent licensing conditions in this region). It is assumed that there will be no further NSCAS requirements related to the entry of wind generation (further NSCAS requirements related to load growth may arise, but are not accounted for in this analysis since they are not related to the cost of the LRET).
- ***Other regions*** -
    - All of the new installed wind farms are older design fixed-speed induction machines that do not contribute to voltage support;
    - All of the new installed wind farms are located in very weak parts of the grid where there is insufficient local voltage support;
    - All of the new installed wind farms therefore require associated Static VAr Compensator (SVC) infrastructure;
    - 1 MVAr of reactive power is required to support each installed MW of wind capacity (active power). 0.3 MVAr/MW is supplied in a dynamic manner via SVC infrastructure, with the remaining 0.7 MVAr/MW supplied via capacitor banks.

These are extreme assumptions. It is very likely that many wind farms will be located in areas where the local voltage support is sufficient, or that some of the installed wind farms will be newer designs that provide some local voltage support.

A number of possible future reactive power infrastructure installations in Australia have published cost estimates:

- A +280/-120 MVAr SVC at Dederang in Victoria, estimated to cost $75 million[34].
- A 330 kV SVC at Armidale in NSW, to increase QNI stability limits, estimated to cost $50 million[35].
- A 200 MVAr SVC at Heywood in Victoria, estimated to cost $30 million[36].
- 120 MVAr capacitor bank at Belmont 275kV substation, and a 50 MVAr capacitor bank at the South Pine 110 kV substation, estimated to cost $5.2 million[37].

[34] AEMO, 2010 National Transmission Network Development Plan (NTNDP). Quoted cost of $73 million has been adjusted for inflation, and is listed here in real March 2011 dollars.

[35] AEMO, 2010 National Transmission Network Development Plan (NTNDP) and Powerlink Annual Planning Report 2011, p143.

[36] 2009 AEMO National Transmission Statement. Quoted cost of $28 million has been adjusted for inflation, and is listed here in real March 2011 dollars.

[37] 2009 AEMO National Transmission Statement. Quoted cost of $4.9 million has been adjusted for inflation, and is listed here in real March 2011 dollars.

- Two 120 MVAr capacitor banks on Millmerran-Middle Ridge 330kV circuits, and 200 MVAr capacitor bank at Millmerran 330kV substation, estimated to cost $10.9 million[38].
- A 150 MVAr capacitor bank at Wodonga, estimated to cost $5.4 million[39].

These cost estimates are recognised as indicative only, having uncertainty estimates between ±25% and ±50%. Cost estimates have increased substantially over recent years; for example the Dederang SVC was originally quoted at $30 million, and the Armidale SVC at $38 million in 2008. Costs are likely to have increased in response to a variety of external drivers, such as increases in the price of steel, aluminium and other fundamental components, as well as increases in the cost of labour. Based on these figures, we can estimate that the cost of SVC equipment is approximately $0.17 million/MVAr.

Table 5.5 – Assumptions for estimate of NCAS costs **(Real 2011 dollars)**	
Cost of SVC infrastructure	$0.17 million / MVAr
Cost of capacitor bank infrastructure	$0.03 million / MVAr
Reactive power requirement	0.3 MVAr of SVCs (dynamic) per MW of wind + 0.7 MVAr of capacitor banks (static) per MW of wind
Lifetime of SVC equipment	30 years
WACC	9.70 %

5.6.1) Results - NEM

Based upon the wind installation levels in each scenario considered in this study, and the assumptions listed in Table 5.5, this produces the estimate of reactive power equipment costs listed in Table 5.6. For comparison, AEMO published reactive power costs[40] of $47 million in 2009-10 and $49 million in 2010-11. All other factors remaining constant, this implies a doubling of reactive power costs in 2019-20 in the presence of the LRET, due to the increased wind capacity.

In the absence of the LRET NSCAS costs associated with new wind farms remain close to present levels. This projection only relates to additional NSCAS costs related to increased wind farm penetration; other network factors have not been taken into account.

[38] 2009 AEMO National Transmission Statement. Quoted cost of $10.3 million has been adjusted for inflation, and is listed here in real March 2011 dollars.

[39] 2008 AEMO Statement of Opportunities, Annual National Transmission Statement. Quoted cost of $5 million has been adjusted for inflation, and is listed here in real March 2011 dollars.

[40] http://www.aemo.com.au/electricityops/883.html

Due to the assumptions made in this study, the differences in costs between scenarios, and the changes in costs within scenarios, is driven entirely by the capacity of wind installed in each year, in each scenario. This was based upon the provided Oakley Greenwood planting schedules.

Table 5.6 – NCAS costs associated with wind generation (NEM)
(Real 2011 dollars)

		2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
New installed wind (MW) (includes committed)	Reference	3117	275	0	0	250	706	1036	1066
	Counterfactual	846	0	0	0	0	0	0	0
	Carbon	3117	275	0	250	250	437	1028	1059
Capital cost of reactive power equipment ($millions)	Reference	$223	$20	$0	$0	$18	$51	$74	$76
	Counterfactual	$61	$0	$0	$0	$0	$0	$0	$0
	Carbon	$223	$20	$0	$18	$18	$31	$74	$76
Annualised cost of reactive power equipment ($million pa)	Reference	$23	$25	$25	$25	$27	$32	$40	$48
	Counterfactual	$6	$6	$6	$6	$6	$6	$6	$6
	Carbon	$23	$25	$25	$27	$29	$32	$40	$47
Additional NSCAS cost due to LRET (No CO2 price) ($million pa)		$17	$19	$19	$19	$21	$26	$34	$41

Utilising the energy projections provided with the scenarios, this implies the estimate of costs (in $/MWh) listed in Table 5.7. NSCAS costs remain small compared with energy settlements. Despite forecast increases in NSCAS costs, they are likely to remain small in comparison to anticipated energy settlements of $50 - $80 /MWh.

NSCAS costs are largely borne by transmission and distribution network companies, and passed through to consumers via network tariffs. Due to the wide base for these payments, NSCAS costs are therefore not likely to be problematic for the liable parties.

Table 5.7 – NSCAS costs associated with wind generation as a proportion of energy (NEM) (Real 2011 dollars)									
		2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Energy projection (GWh)	Refence & Counterfactual	204,923	209,789	213,664	217,869	222,926	229,301	236,657	243,487
	Carbon	207,654	212,413	216,107	220,225	225,145	231,377	238,483	245,066
Cost of NSCAS ($/MWh)	Reference	$0.11	$0.12	$0.12	$0.12	$0.12	$0.14	$0.17	$0.20
	Counterfactual	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03
	Carbon	$0.11	$0.12	$0.12	$0.12	$0.13	$0.14	$0.17	$0.19

The differences in costs between scenarios, and the changes in costs within scenarios, are driven entirely by the capacity of wind installed in each year, in each scenario. This was based upon the provided Oakley Greenwood planting schedules.

5.6.2) Results - SWIS

Based on an equivalent analysis, the numbers listed in Table 5.8 and Table 5.9 were calculated for the SWIS.

NSCAS costs in the SWIS are projected to increase by around $2 million pa with the entry of Collgar wind farm[41], and by around $4 million with the further 271 MW of wind capacity installed in the Carbon case. This projection only relates to additional NSCAS costs related to increased wind farm penetration; other network factors have not been taken into account.

Due to the assumptions made in this study, the differences in costs between scenarios, and the changes in costs within scenarios, are driven entirely by the capacity of wind installed in each year, in each scenario. This was based upon the provided Oakley Greenwood planting schedules.

Table 5.8 – NCAS costs associated with wind generation (SWIS) (Real 2011 dollars)									
		2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
New installed wind (MW) (includes committed)	Reference	206	0	0	0	0	0	0	0
	Counterfactual	206	0	0	0	0	0	0	0
	Carbon	206	0	0	0	0	0	81	191

[41] For the SWIS, the Reference and Counterfactual scenarios are identical (both feature the committed Collgar wind farm, and no further wind installation). Therefore, the results for these scenarios for the SWIS relating to FCAS, NCAS and transmission augmentation costs are identical.

Table 5.8 – NCAS costs associated with wind generation (SWIS)
(Real 2011 dollars)

Capital cost of reactive power equipment ($millions)	Reference	$15	$0	$0	$0	$0	$0	$0	$0
	Counterfactual	$15	$0	$0	$0	$0	$0	$0	$0
	Carbon	$15	$0	$0	$0	$0	$0	$6	$14
Annualised cost of reactive power equipment ($million pa)	Reference	$2	$2	$2	$2	$2	$2	$2	$2
	Counterfactual	$2	$2	$2	$2	$2	$2	$2	$2
	Carbon	$2	$2	$2	$2	$2	$2	$2	$4
Additional NSCAS cost due to LRET (No CO2 price) ($million pa)		$0	$0	$0	$0	$0	$0	$0	$0

As illustrated in Table 5.9, NSCAS costs to consumers are projected to increase by around $0.06 /MWh in 2019-20 with the entry of Collgar wind farm, and by around 0.14 /MWh with the additional 271 MW of wind entering in the Carbon case. Despite forecast increases, this remains small in comparison to anticipated energy settlements of $80 /MWh.

NSCAS costs are largely borne by transmission and distribution network companies, and passed through to consumers via network tariffs. This means that any additional NSCAS costs are spread over a wide base, and are not likely to be problematic.

Table 5.9 – NSCAS costs associated with wind generation as a proportion of energy (SWIS)
(Real 2011 dollars)

		2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Energy projection (GWh)[42]		19,321	21,041	22,006	22,478	22,999	23,785	24,219	24,630
Cost of NSCAS ($/MWh)	Reference	$0.08	$0.07	$0.07	$0.07	$0.07	$0.06	$0.06	$0.06
	Counterfactual	$0.08	$0.07	$0.07	$0.07	$0.07	$0.06	$0.06	$0.06
	Carbon	$0.08	$0.07	$0.07	$0.07	$0.07	$0.06	$0.09	$0.14

Actual reactive power requirements could vary depending upon the type of wind generation technology installed, and the grid connection points of new wind farms.

Treatment of Badgingarra Wind Farm (SWIS)

It has been identified that in constructing the planting schedules used for this study, Oakley Greenwood considered Badgingarra Wind Farm (130 MW) to be committed for installation in the

[42] AEMO, 2010 Electricity Statement of Opportunities.

SWIS. However, ROAM did not ascribe this status to the Badgingarra proposed wind development, and therefore did not model this wind farm explicitly in any of the scenarios included in this modelling.

Based upon the methodology applied in this study, the inclusion of Badgingarra wind farm would have the following impacts upon NSCAS costs:

- The wind capacity installed in the SWIS in 2019-20 would increase by 130 MW
- This would increase the cost of reactive power equipment associated with wind by $9 million in each case.
- This would increase the cumulative annualised cost of reactive power equipment associated with wind in the SWIS from $1.5 million pa to $2.5 million pa (in the Reference and Counterfactual cases) and $3.5 million pa to $4.5 million pa (in the Carbon case).
- This would increase the cost of NSCAS associated with wind in the SWIS in 2019-20 from around $0.06/MWh to $0.10/MWh (in the Reference and Counterfactual cases), and from around $0.14/MWh to $0.18/MWh (in the Carbon case).

6) TRANSMISSION AUGMENTATION

6.1) *METHODOLOGY*

ROAM employed the use of its Long Term Integrated Resource Planning (LTIRP) software package to develop the modelling necessary to understand the possible impact of the LRET on future transmission developments. The LTIRP software has been designed specifically to meet the challenges of generation and transmission development co-optimisation problems. It uses Mixed Integer Linear Programming (MILP) techniques to determine the least cost economic expansion plan by minimising the cost of serving the energy demanded for each year. Other key features include:

- The model uses a subset of the half hourly periods, with weightings assigned to each period such that an accurate representation of the load duration curve is modelled.
- Includes the capability to limit:
  - Fuel availability (particularly important for energy limited generators such as hydro plant)
  - Build rates of generation technologies
  - Availability dates for generation technologies
  - RET and carbon emissions targets
  - Banking and borrowing of RECs
- Other features include:
  - Full accounting of existing generation plant
  - Carbon pricing
  - Fuel supply and demand price curves
  - Economic, age and capacity factor based retirements

Appendix H) provides more detail on the LTIRP model.

Network augmentation

Intra-regional and inter-regional network augmentation was considered down to the level of the sixteen zones defined in AEMO's NTNDP modelling in the NEM. The SWIS network was defined in terms of five main zones derived from areas described in Western Power documentation.

Figure 6.1 and Figure 6.2 show the NEM and SWIS zone diagrams. For the SWIS, the ROAM "Muja" zone is the Western Power "Country South" zone, and the ROAM "NC" zone is the Western Power "Country North" zone.

Figure 6.1 – NEM zone diagram (from AEMO NTNDP)

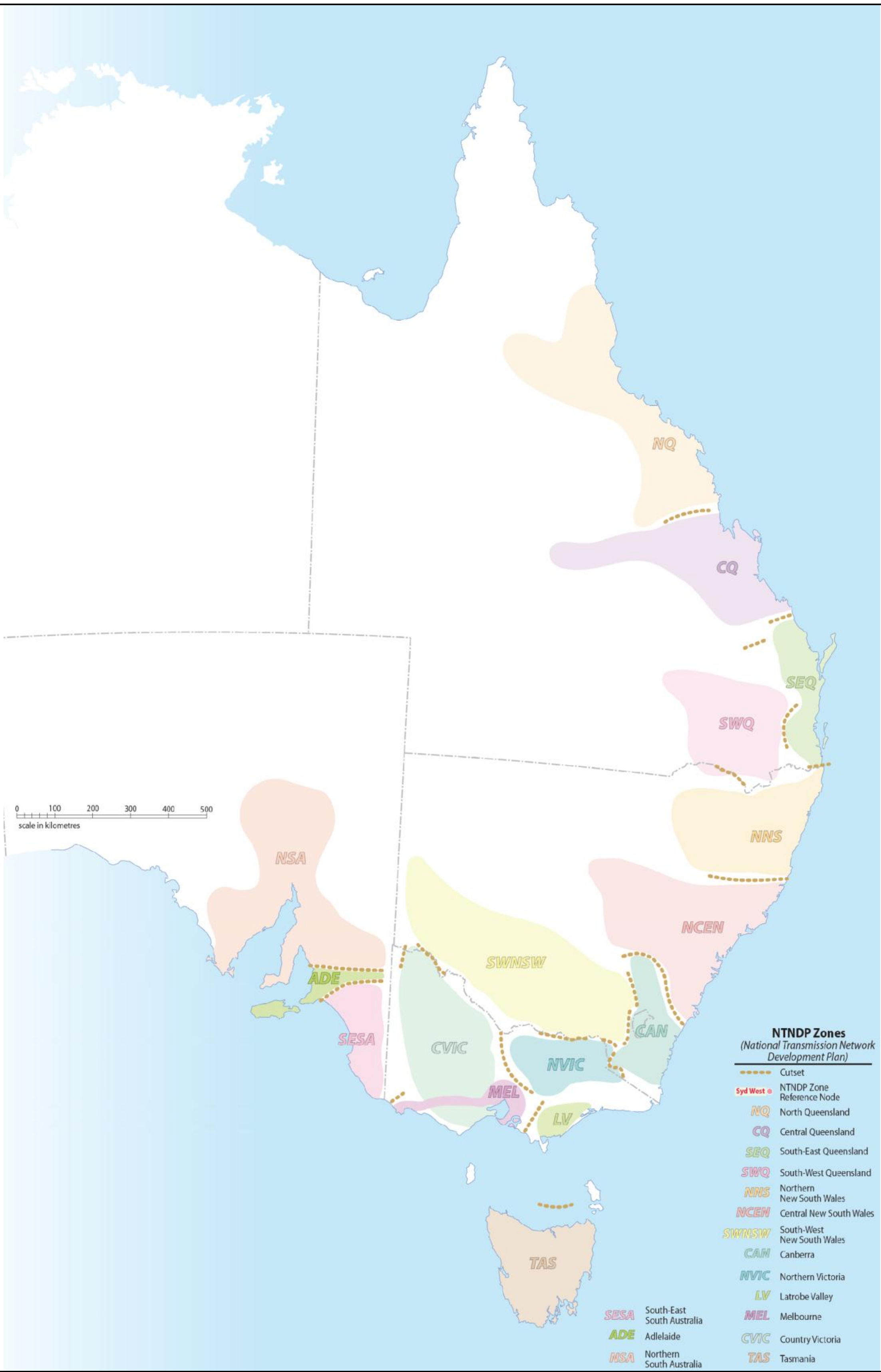
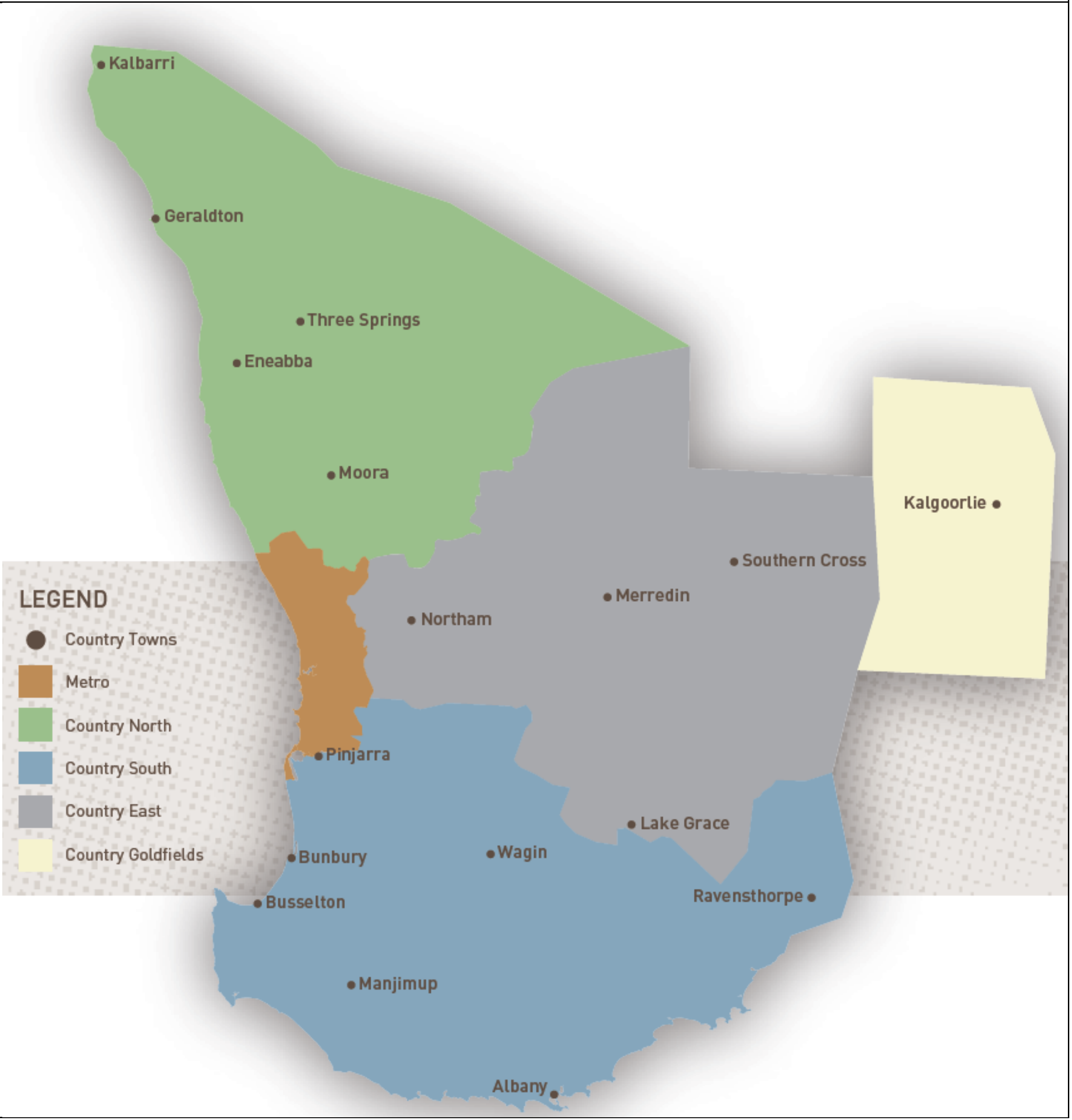


Figure 6.2 – SWIS zone diagram (from Western Power APR)



Network flows - Congestion Analysis

Following the LTIRP modelling, network flows between the NTNDP zones were evaluated in each load block to produce an indicative flow duration curve for each line, in each year from the present to 2020. Where interconnectors were found to be operating at their nominal limits they were considered to be constrained. This data was analysed to provide an indication of the magnitude, location and frequency of network congestion in the NEM from the present to 2020. However the model will tend to alleviate congestion by adding link upgrades where these are found to provide the overall least cost option. Excerpts from these flow duration projections are provided in a subsequent section.

Timeframe

While the study scope called for analysis up to and including 2020, ROAM calculated the least cost network development plan from the present to 2030. This allows for a ten year window to minimise end effects and produce a reliable result for 2020.

General assumptions concerning the NEM and SWIS models

ROAM was provided with an initial plant build on a regional basis for the NEM and SWIS markets by Oakley Greenwood. These planting schedules were provided separately for the three cases studied in this scope of works; the reference case, the counterfactual case, and the carbon pricing case. ROAM's directive was to use these build schedules in the transmission modelling. This required that the new plant described in the planting schedules be distributed between the zones comprising each region. These generation planting schedules are provided in Appendix B).

For each of the three cases, ROAM distributed new biomass generation within each region of the NEM between all of the region's zones equally and placed all gas generation in those zones in each region where gas prices were cheapest (according to the fuel cost data taken from Scenario 3 of the 2010 AEMO NTNDP data). The applicable zones selected were SWQ in Queensland, NNS in New South Wales, LV in Victoria and SESA in South Australia.

In the SWIS, the Oakley Greenwood CCGTs were distributed in the Perth and Muja zones in a 1:1 ratio and the OCGTs were distributed in the Muja, NC and Perth zones in a 4:1:5 ratio. These ratios were estimated referenced on the distribution of existing gas plant in the SWIS; most plant tends to site near the chief load centre (Perth), or in the major generation hub, Muja. A small amount of plant is located in the northern area of the system. The other zones (for example, Goldfields) were assumed to be mostly supplied by the other zones where fuel and transmission is more readily available.

Distribution of the wind farms, as the most widespread LRET technology by far, was an important factor. ROAM maintains an up-to-date database of future committed and potential wind developments, and has used this information in assigning the wind farms to the various zones comprising the NEM. That is, ROAM has where possible linked the regional wind capacity numbers from the Oakley Greenwood data with actual announced projects in each zone. Some observations on this are as follows:

- In Queensland, wind generation is split evenly between NQ and SEQ;
- In New South Wales, wind generation is predominantly located in the CAN and SWNSW zones, with some also in NNS;
- In Victoria, wind generation is predominantly located in CVIC and MEL, with some also in LV;
- In South Australia, wind generation is split evenly between NSA and SESA, and;
- In Tasmania, all wind generation is located in the single TAS zone.

In allocating the assumed new wind generation to the zones of the SWIS, only the Carbon Case needed consideration, as the Reference and Counterfactual Cases only included existing and committed wind farms. The additional wind capacity in the Carbon Case (totalling 2,142MW by 2030) was split evenly between North Country, East Country and Muja, based on ROAM's knowledge of the location of existing and announced wind farms in Western Australia and the available wind resource in the state.

ROAM's modelling accounted for the intermittency and variability in wind generator output, an important factor in evaluating the impact of large scale wind penetration. A description of the methodology used to capture this impact is given in Appendix H).

ROAM's LTIRP was permitted to install plant over and above that specified by Oakley Greenwood if this reduced the total cost objective[43]. To limit any distorting influences, ROAM elected to only allow this additional NEM plant to site in the cheapest zone of each region (plus Adelaide in SA)[44], and the only option available was open cycle gas plant. In the SWIS modelling, additional open cycle gas plant was permitted only in the Perth zone.

The Counterfactual case provided by Oakley Greenwood assumes the LRET is discontinued, and the only technologies appearing in the future generation plans are gas fuelled open cycle and combined cycle plants.

Demand forecasts were provided for the NEM in the reference/counterfactual and carbon price models by Oakley Greenwood (i.e. the same numbers used in their analysis) and for the SWIS by the Expected growth 10% Probability of Exceedence forecasts in the IMO's 2010 Statement of Opportunities report.

Data concerning fuel costs, auxiliary rates, station capacities, heat rates and emissions factors were taken from the 2010 NTNDP Scenario 3 assumptions.

New gas entrant heat rates were selected from the NTNDP data based on the year designated in the name assigned to them by Oakley Greenwood (for example, 2012, 2015 or 2020 vintage OCGTs or CCGTs).

The Perth zone in this study is the aggregation of all the Western Power "metro" zones.

Assumptions concerning transmission links in NEM and SWIS

The LTIRP model was permitted to upgrade each of the existing inter and intra regional links (except for the underground NNS-SEQ link, that is, the HVDC Directlink interconnector) in increments of 250 MW up to four times in each simulation year. While assessment of the cost and capacity of many different potential upgrades was performed[45], ROAM came to the view that due

[43] The objective here was to allow the unserved energy to be alleviated, if economic, without altering the Oakley Greenwood scenarios more than was necessary.

[44] Adelaide was added as an option in later modelling runs as early runs showed a sizable need for interconnection between SESA and ADE.

[45] For example Powerlink lists 44 different potential upgrades for consideration in the Powerlink Annual Planning Report 2011 in relation to the NTNDP and other planning processes (Section 5.3 Strategic Planning)

to the large variance in augmentation capability and cost, it was far more even handed to apply a constant augmentation size and pricing model across the network for this long term study. The capacity of 250MW was judged to be a worthwhile increment while not being too large in relation to existing link capacities and zonal demands.

The link upgrades were priced at two levels; either $500 or $1,000 / kW, covering the bulk of the range of prices observed in the example augmentation options described in the Electranet-AEMO joint feasibility study for the South Australian Interconnector[46] and Appendix F of the 2011 Powerlink Annual Planning Report[47]. The price range selected can be further justified by considering that a peaking generator could be installed for approximately $1000/kW; this was assumed to be an upper bound on interconnector cost, since otherwise it would be cheaper to install a generator in any zone that was short of capacity. Conversely, the maximum an interconnector can be possibly be "worth" to a system in reliability terms is twice its capacity; that is, its capacity is fully exploitable on both ends of the links, due to diversity between the occurrence of peak demand periods and/or generation failures. Hence it was assumed that the lower bound on interconnector cost would be half the upper bound of the approximate cost of a peaking generator. In this case the lower bound is like a peaking generator on the boundary between two zones which is fully effective in both zones.

Basslink was an exception; it was always assumed to be priced at $1,000 / kW, in recognition of the fact that any significant upgrade would involve costly new HVDC infrastructure. Furthermore, it was assumed that upgrades to the SEQ-NNS flow path would be too costly relative to other upgrades to be viable, due to this flow path being in urban South-East Queensland and relatively pristine environmental areas of Northern NSW. It was therefore omitted from the available upgrade options. The distance between zones is roughly similar and so this uniform pricing policy (high or low cost) has been applied across all zones. Upgrades have only been allowed along existing transmission paths. Further evaluations of options could be considered following a complete review of costs of all upgrade paths of interest, including those which are not presently connected, such as the proposed South Australia to New South Wales lines previously considered by AEMO and ElectraNet.

An assumption of 5% average losses has been made across all links. This level of transmission losses is in line with typical networks, and is comparable to loss figures used by other organisations, such as AEMO (an example may be found in AEMO's "Network Extensions to Remote Areas – Innamincka Case Study").[48]

Table 6.1 and Table 6.2 contain the capacities for the existing links between each of the NEM and SWIS zones.

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[46] http://www.electranet.com.au/assets/Uploads/interconnectorfeasibilitystudyfinalnetworkmodellingreport.pdf

[47] http://www.powerlink.com.au/asp/index.asp?sid=5056&page=Corporate/Documents&cid=5250&gid=661

[48] http://www.aemo.com.au/planning/0400-0005.pdf

The NEM flow path capabilities have been taken from Scenario Modelling for the Energy White Paper[49] and are derived from Grid Australia work. The SEQ-SWQ value of 5500 MW was suggested by Powerlink. In comparison, the footnote to table F. 1 of the 2011 Powerlink Annual Planning Report states 5400 MW.[50]

In the SWIS, there is little visibility of the underlying network constraints compared with the NEM. The SWIS is not separated into regions for the purposes of running the market, and there is no representation of the transmission network in the market dispatch systems. Therefore it was necessary to estimate all inter-zonal limits. ROAM derived these from a combination of analysis of line limits in a system network snapshot of the SWIS (a PSS/E file), along with estimations based on work previously performed for Western Power and other SWIS participants. To begin with, for each flow path, ROAM defined the set of major lines adjoining the connected zones. The MVA flow limits of these lines were then inspected in the network snapshot. In the first instance, ROAM added all of these limits, and then subtracted the limit of the largest line (where duplicate lines existed in the flow path). This was regarded as a reasonable approximation of the typical approach of limiting transmission flows such that the loss of the single most significant line resulted in acceptable network flows. However, this analysis only considers thermal transmission constraints, and so ROAM reduced the limits on some flow paths to values reflecting known voltage limitations. For example, the thermal limit based analysis yielded a flow limit of approximately 339 MW for the East Country to Goldfields line, however due to the extreme length of the line, ROAM reduced the transfer limit to 100 MW based on knowledge of the voltage stability limitations affecting the line.

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[49] http://www.aemo.com.au/planning/0418-0004.pdf

[50] http://www.powerlink.com.au/asp/index.asp?sid=5056&page=Corporate/Documents&cid=5250&gid=661

Table 6.1 – NEM existing flow path limits (MW)		
Connected regions	**Import capacity**	**Export capacity**
CQ-NQ	1400	1400
SWQ-CQ	2100	2100
SEQ-CQ	2100	2100
SEQ-SWQ	5500	5500
NNS-SWQ	1250	450
NNS-SEQ	230	70
NCEN-NNS	1150	880
CAN-NCEN	2000	2000
CAN-SWNSW	2700	2700
NVIC-SWNSW	1650	1650
CVIC-SWNSW	250	250
NVIC-CVIC	265	265
MEL-NVIC	1410	1410
MEL-CVIC	265	265
LV-MEL	9450	9450
TAS-LV	500	600
MEL-SESA	460	460
CVIC-ADE	200	200
SESA-ADE	500	500
ADE-NSA	1000	1000

Table 6.2 – SWIS existing flow path limits (MW)		
Connected regions	**Import capacity**	**Export capacity**
Perth to NC	323	323
Perth to East	200	200
East to Gold	100	100
East to Muja	100	100
Perth to Muja	2000	2000

Assumptions concerning demand

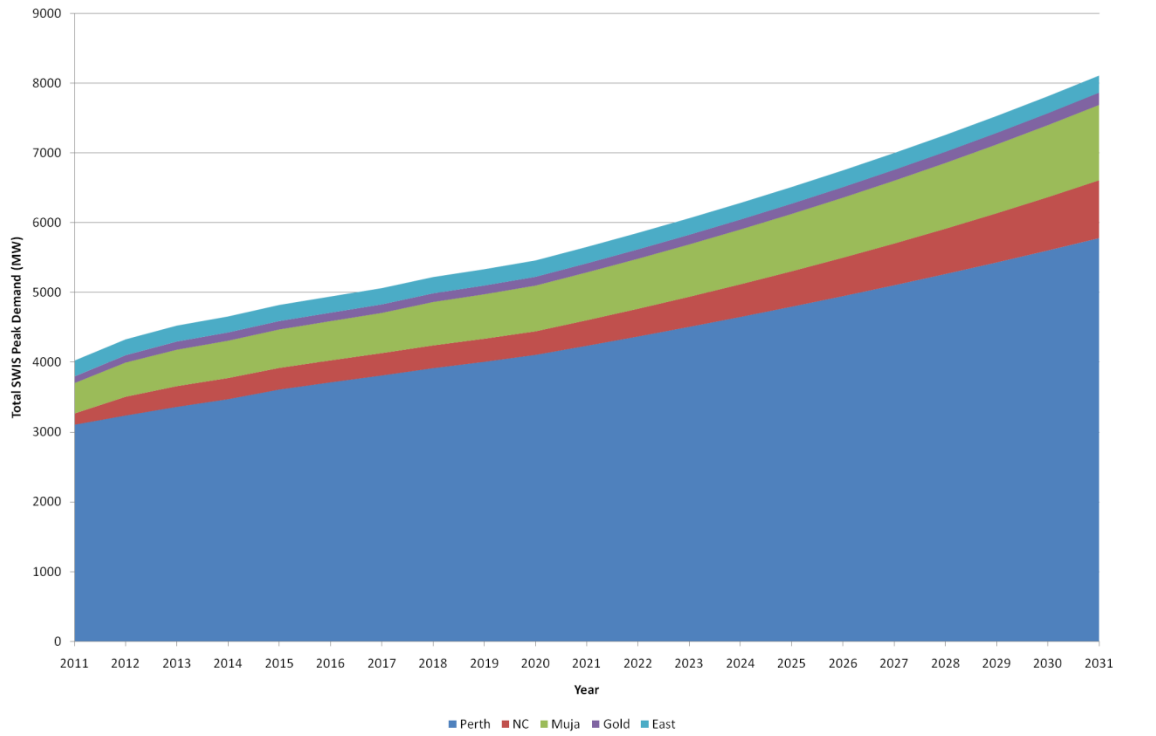
NEM demand was scaled from the regional values provided by Oakley Greenwood to zonal level using the following load distribution factors in Table 6.3, from the Energy White Paper Scenario Modelling performed by ROAM in 2010. In addition to the data presented in this table, it was assumed that there was a 600 MW flat load in south western Victoria associated with the industry in that area, and this has been added to the MEL zone. These assumptions are all based on previous work undertaken for Grid Australia.

Table 6.3 – Zone Load Distribution Factors

Region	NTS Zone	Distribution Factor
QLD	NQ	15%
	CQ	20%
	SWQ	5%
	SEQ	60%
NSW	NNS	8%
	NCEN	81%
	CAN	5%
	SWNSW	6%
VIC	CVIC	7%
	NVIC	6%
	LV	9%
	MEL	78%
SA	SESA	6%
	ADE	80%
	NSA	14%
TAS	TAS	100%

SWIS demand was scaled using load distribution factors calculated from peak demand figures in the Western Power APR. Specifically, the peak demand figures come from Table 4-2 "Central MW Load Forecast PoE10 for Summer Peak Load Demand in years 2011 to 2020." Post-2020, the growth rate for each region has been extrapolated using the average growth rate from 2011 to 2020. A key point is that the NC zone has a higher growth rate than the SWIS as a whole, and this serves to reduce the need to upgrade transmission out of this zone, even with high levels of new wind assumed to enter the zone, based on Oakley Greenwood generation data.

Figure 6.3 – SWIS peak demands extrapolated to 2030



6.2) Results - Transmission Augmentation Outcomes and Costs

Noting the limitations and constraints of the modelling, this study has found that significant new transmission capacity is built in all cases, but somewhat higher levels are seen in the Counterfactual case than in the Reference or Carbon cases.

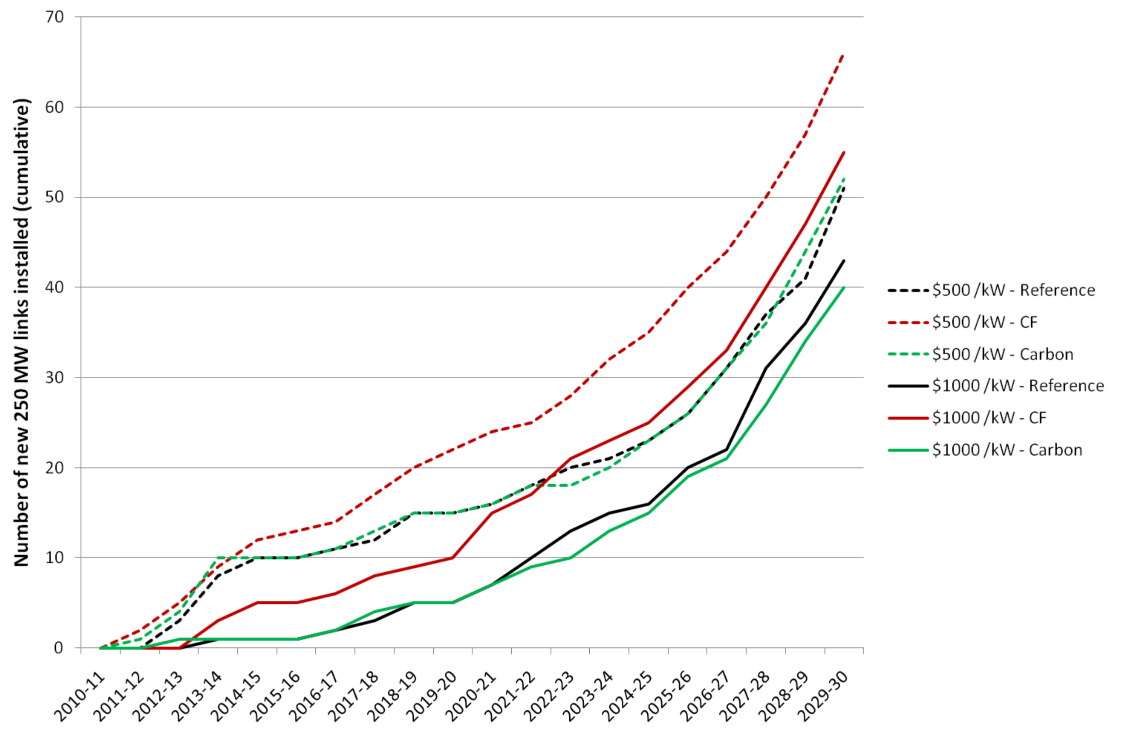
Between 3,750MW and 5,500MW of new transmission capacity was built by 2019-20, expanding to between 10,000MW to 16,000MW by 2030. New transmission capacity was spread across the NEM but focussed heavily around South-West Queensland through to Northern Central New South Wales. This was associated with both the influx of low cost gas plant in those areas (these were assumed to have the cheapest cost of supply in the NEM) and the relatively high assumed rates of load growth in Queensland. At prices of $500/kW of transmission capacity, this level of transmission expenditure would equate to between $194m and $284m pa ($0.8 to $1.20 /MWh) in 2019-20, or double that with pricing of $1000/kW.

The higher level of augmentation seen in the Counterfactual suggests that transmission costs attributable directly to the LRET are comparable or lower than would otherwise occur, at least when considered down to the inter-zonal level. This outcome is largely dependent on the distribution of the generation in the three cases. In the Reference and Carbon Cases, generation is more distributed throughout the NEM, as the wind farms and biomass plants are spread around the zones. In contrast, the Counterfactual case features a future of gas plant only, which was not only in larger ‘chunks’, but also was assumed to be located where the cheapest fuel exists, which was usually remote from major load centres. Distributed generation such as wind farms have a tendency to be closer to load, which reduces the need for bulk transmission capacity, while large scale thermal generation tends to be more remote from load due to both fuel and land availability. It should be noted however that distributed generation may require significant investment in intra-zonal augmentation (for example, to connect wind farms to local lines and reinforce the area to support the power injection), which is not considered in this assessment.

Another important factor to note is that gas pipeline development may influence the location of new gas plant significantly. For example, major new gas infrastructure may see gas plant located in different areas. However, this may not reduce the need for transmission augmentation by a large amount but rather alter the location.

Figure 6.4 shows a plot of the cumulative number of 250MW bi-directional flow path augmentations built in the NEM and the SWIS to the end of the study. As might be expected, in each case more transmission capacity is built in the $500/kW sensitivity than in the $1,000/kW sensitivity, since the installation of new transmission capacity in the context of this study is typically to reduce the cost of fuel by allowing cheaper generation to be more fully utilised; when the transmission cost is high, more substantial fuel savings are required to overcome the cost. These transmission cost sensitivities set reasonable bounds on the degree of augmentation that might be required. Note that there is very little difference between the Reference and Carbon Cases, but significantly more transmission in the Counterfactual.

Figure 6.4 – Cumulative number of 250MW augmentations in the NEM and SWIS to 2029-30



In this study, the LRET had the effect of reducing the amount of inter and intra regional transmission that would otherwise be required. In the Reference and Carbon cases, around 3,750MW of new transmission capacity was built by 2019-20, compared with 5,500MW in the Counterfactual. This represents around $91m pa more in the Counterfactual in that year. Note that although the Counterfactual case resulted in higher transmission augmentation costs, the Carbon and Reference Cases would most likely be associated with higher generation costs, so the overall cost relativity between the cases will differ to the situation described by transmission costs only.

Figure 6.5 shows the cumulative capital cost of transmission augmentation in the NEM and SWIS combined for two sample periods; 2010-11 to 2019-20 and 2010-11 to 2029-30. These charts again show how the transmission costs associated with the Reference and Carbon cases are similar, while the Counterfactual case is significantly more expensive.

Figure 6.5 – Cumulative cost of flow path augmentation in NEM and SWIS

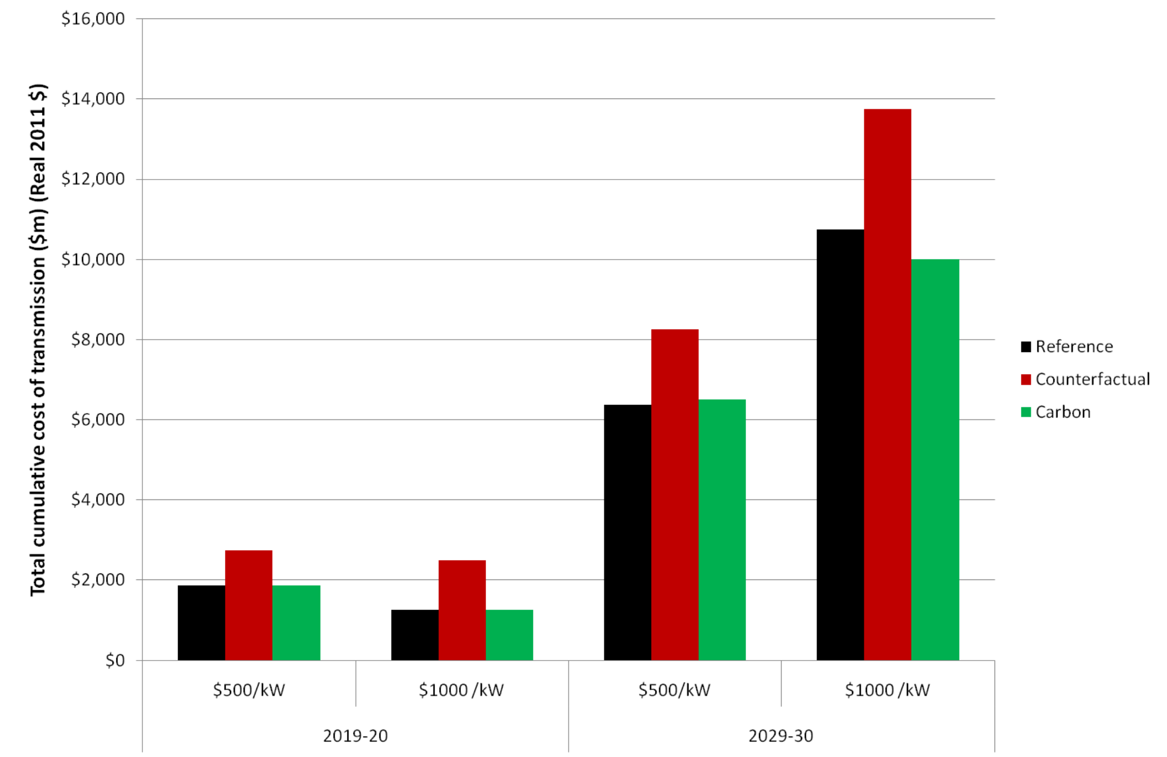
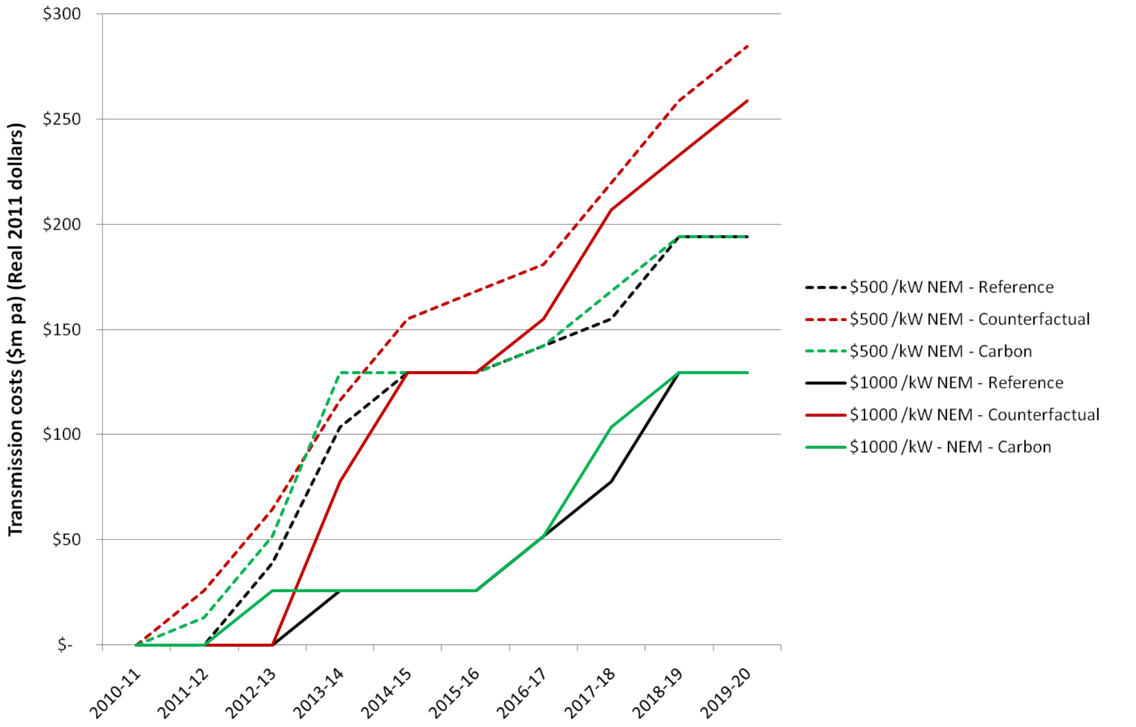


Figure 6.6 shows a plot of the cumulative cost associated with flow path augmentation in the NEM only to 2019-20 for each of the cases modelled (note that no augmentation is built in the SWIS before this date). The transmission cost sensitivities are shown separately. Given the uniform pricing of augmentation assumed, the cost curve exhibits the same shape as the chart displaying the cumulative number of installed augmentations. Note that the transmission costs in the $500/kW sensitivities are consistently higher than the costs in the $1000/kW sensitivities, despite the lower cost per augmentation. This is due to the significantly greater level of transmission augmentation in the $500/kW sensitivities. While the transmission capacity costs in these sensitivities are greater, they are offset via savings in expenditure on new additional capacity (in excess of the Oakley Greenwood planting assumptions) and fuel cost savings resulting in removing transmission congestion and thus allowing greater usage of cheaper plant.

Figure 6.6 – Cumulative cost of flow path augmentation in NEM to 2019-20



These costs, when converted to a $/MWh equivalent, equate to between $0.53 /MWh and $0.80 /MWh in the Reference or Carbon Case, and $1.06 /MWh to $1.17 /MWh in the Counterfactual for the year 2019-20. Like the Regulation and Slow Contingency service costs, costs associated with new transmission are relatively small in comparison to the anticipated energy settlements of $12 - $20 billion pa ($50 - $80 /MWh) in 2019-20. Also, transmission costs are spread over all market participants.

In the SWIS, transmission costs were not influenced by the RET to 2019-20, as no further transmission augmentation was required to carry the assumed level of plant.

6.2.1) Transmission Augmentation by Flow Path in the NEM

Table 6.4 and Table 6.5 show the numbers of 250MW bi-directional augmentations along existing flow paths in the $500 / kW and $1000 / kW sensitivities. Figure 6.7 and Figure 6.8 show the same information in graphical form. If further investigations show that augmentation options at lower than $500 / kW can be found, this would help to justify more transmission capacity. It is important to note that this study examines the impact of just one development 'path' under each future scenario (reference, counterfactual and carbon pricing). Should the allocation of the regional plant schedules to the individual zones be substantially different, the outcomes for the individual flow paths could be substantially impacted. However, it is likely that for most plausible future development scenarios, the general trend of major upgrades between the key areas of low priced fuel and the load centres would be present.

Table 6.4 – Number of $500/kW augmentations by flow path			
	Reference	Counterfactual	Carbon
CQ-NQ	3	3	3
SWQ-CQ	2	2	1
SEQ-CQ	-	-	-
SEQ-SWQ	20	22	21
NNS-SWQ	5	3	4
NNS-SEQ	-	-	-
NCEN-NNS	15	13	13
CAN-NCEN	-	2	-
CAN-SWNSW	-	4	-
NVIC-SWNSW	-	-	-
CVIC-SWNSW	-	4	1
NVIC-CVIC	-	1	-
MEL-NVIC	2	3	4
MEL-CVIC	-	-	-
LV-MEL	-	4	-
TAS-LV	-	-	-
MEL-SESA	-	-	-
CVIC-ADE	-	3	2
SESA-ADE	2	-	-

Figure 6.7 shows how despite the significant differences between the Counterfactual and Reference or Carbon Cases, the general trends remain similar. They key difference is that the Counterfactual features augmentation of more of the flow paths than the other cases. This echoes the reasoning stated earlier:

- The cases with the LRET (Reference and Carbon Cases) tend to favour more de-centralized generation, meaning load is supplied from more points in the system;
- The Counterfactual favours large scale, centralized generation, which has the flow-on effect of requiring broader strengthening of the transmission system to ship power from the major supply zones to all of the other zones.

Figure 6.7 – Number of $500/kW augmentations by flow path

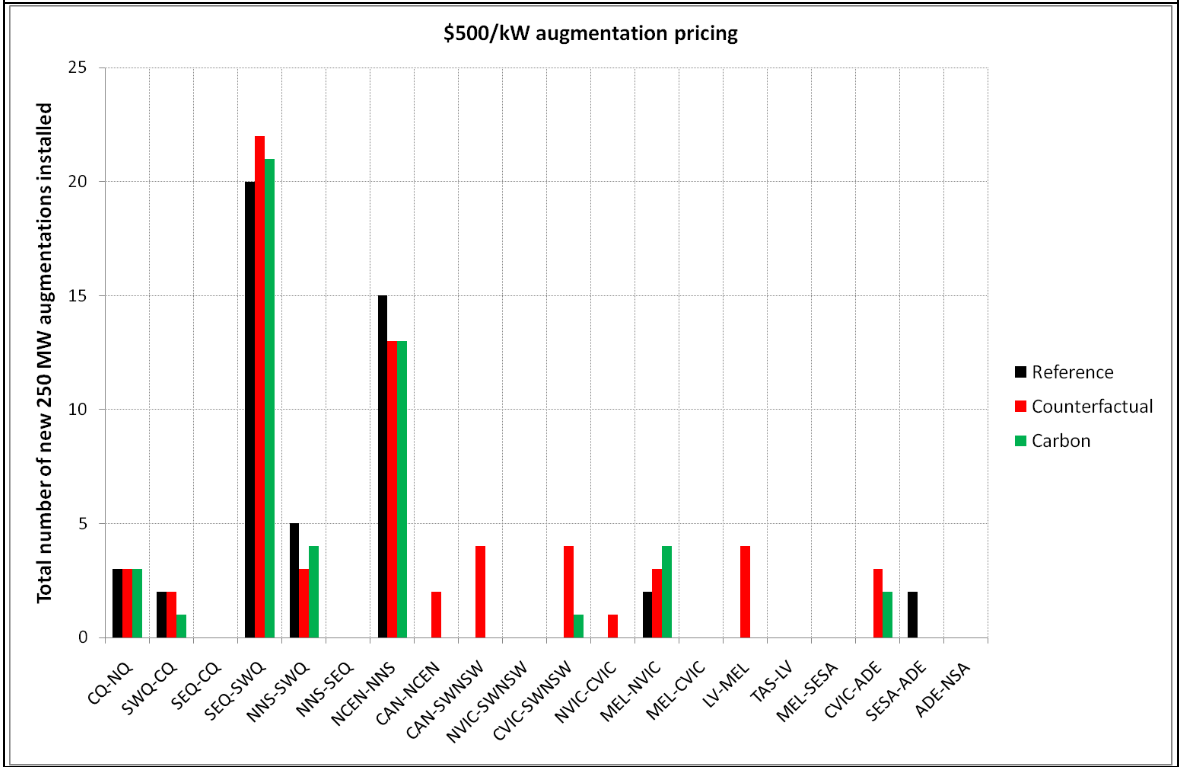
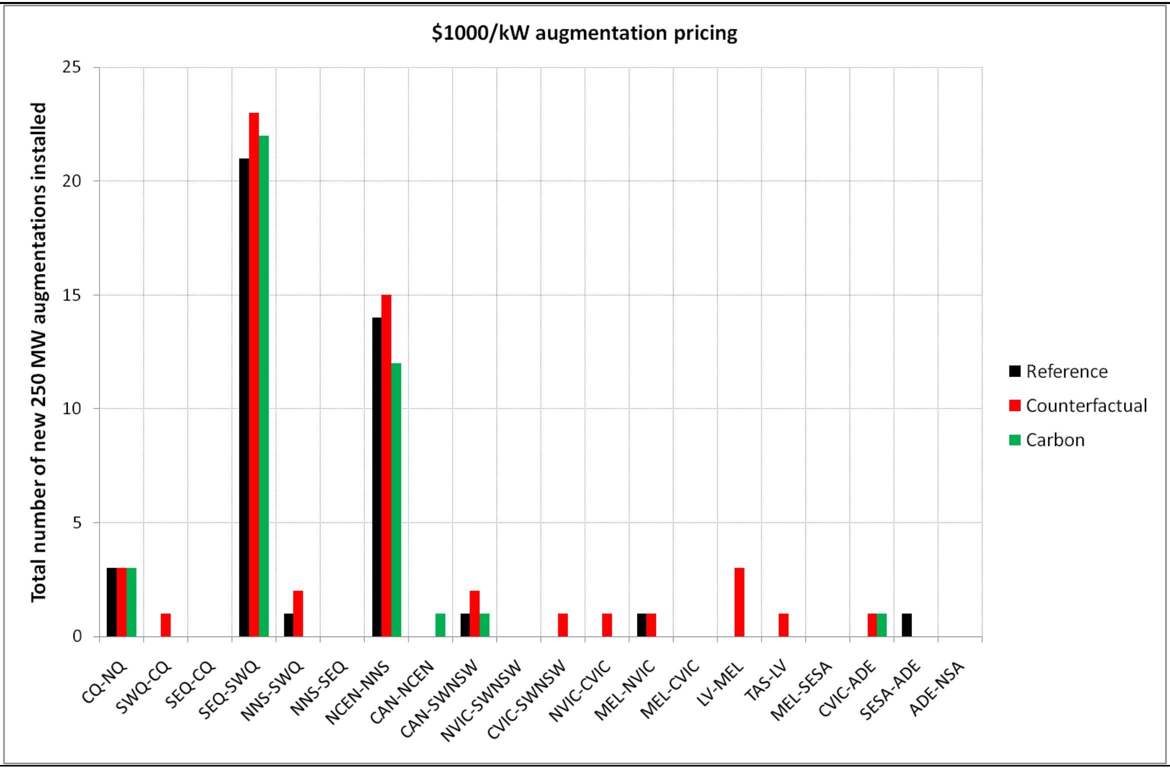


Table 6.5 – Number of $1,000 / kW augmentations by flow path

	Reference	Counterfactual	Carbon
CQ-NQ	3	3	3
SWQ-CQ	-	1	-
SEQ-CQ	-	-	-
SEQ-SWQ	21	23	22
NNS-SWQ	1	2	-
NNS-SEQ	-	-	-
NCEN-NNS	14	15	12
CAN-NCEN	-	-	1
CAN-SWNSW	1	2	1
NVIC-SWNSW	-	-	-
CVIC-SWNSW	-	1	-
NVIC-CVIC	-	1	-
MEL-NVIC	1	1	-
MEL-CVIC	-	-	-
LV-MEL	-	3	-
TAS-LV	-	1	-
MEL-SESA	-	-	-
CVIC-ADE	-	1	1
SESA-ADE	1	-	-

Figure 6.8 – Number of $1000/kW augmentations by flow path



The most significant degree of augmentation observed in all cases occurred over the SEQ-SWQ and NCEN-NNS flow paths. This is largely due to the assumption that all future gas generation would be installed in the cheapest zone of the region (that is, these zones are the ‘gas hubs’ for those regions). In QLD and NSW, these zones (SWQ and NNS respectively) are adjacent to the major load in each region (SEQ and NCEN respectively). The NNS to SWQ link augmentations help deliver energy to both the major load centres. In the counterfactual case, additional augmentation in NSW (along the CAN-NCEN and CAN-SWNSW flow paths) is driven by the new gas generation in the NNS zone.

A further significant driver is that load growth in QLD is high relative to the other regions. The growth in peak demand in the load forecasts is 3.55% per year on average to 2030 and 4.44% per year on average to 2020, and the energy growth is 3.26% per year on average to 2030 and 4.08% per year on average to 2030. These figures are in line with the growth published in the 2011 Powerlink Annual Planning Report. This level of growth is much higher than forecast elsewhere in the NEM, and is largely associated with a large amount of LNG infrastructure for export to international destinations. The CQ-NQ and SWQ-CQ flow paths also require upgrading in order to ensure that SWQ generation can service CQ and NQ load, since CQ and NQ load remains at 20% and 15% of the regional load during the study.

In comparison, the Latrobe Valley to Melbourne flow path already has a high capacity (9,450 MW bi-directional) and no augmentation here was observed except in the Counterfactual case, where all new Victoria generation is gas plant located in the Latrobe Valley zone.

Upgrades in the South Australia region differ between the cases, but in general, in the Reference Case the SESA to ADE flow path is preferred in order to allow new OCGTs to connect to the load in Adelaide, while in the other two cases expanding the CVIC to ADE flow path was the most economic option. This is affected by Latrobe Valley having lower marginal production cost than SESA (attributable to both the presence of low cost base load coal plant, and also to somewhat cheaper delivered gas), meaning the Latrobe Valley plant will operate in preference to the SESA plant where possible due to cost advantages. In these two cases, the gas generation growth in Latrobe Valley and the biomass (equally distributed through the three SA zones) helps meet the load growth in the Adelaide region.

The Tasmania to Latrobe Valley flow path (Basslink) was upgraded only in the $1,000/kW Counterfactual case (noting this flow path was priced at $1,000/kW in all cases). The tradeoff here in the model falls between augmenting Basslink or building new generation in Latrobe Valley (where gas prices are lower than in Tasmania) or in Tasmania. The Oakley Greenwood cases also tend to provide self sufficiency in generation in Tasmania, reducing any justification for transmission augmentation.

The scope of the modelling did not include the assessment of intra-zonal upgrades. Hence there may be zones which have a large requirement for augmentations, such as the NCEN zone, where generation developments are likely to be on the perimeter of the zone, with further need for major lines into the Sydney area. Such further detailed modelling would be feasible but would require further disaggregation of load, and definition of intra-zonal links.

6.2.2) Transmission Augmentation by Flow Path in the SWIS

Compared with the NEM, little transmission augmentation was observed in the SWIS modeling. Table 6.6 and Table 6.7 show the number of augmentations in each of the cases for the $500 / kW and $1,000 / kW transmission pricing sensitivities respectively. The few transmission augmentations that were observed appeared late in the study from around 2024 onwards. There are several reasons for this. Firstly, the new generation allocated in the SWIS was quite distributed, with capacity going in to several of the zones, allowing the generation and load to be more evenly matched within the various zones than in the NEM. The major generation hub in the SWIS currently is the Muja area, where all of the coal generation is; however, the assumed planting schedule did not feature any new coal capacity. This means generation is more likely to site near the load. The second factor in the SWIS modeling was that the more important flow paths in the SWIS have relatively high transfer capabilities relative to the size of the system (when compared with the NEM). Finally, the size of the upgrades, that is 250 MW, represents a far more significant upgrade in the relatively small SWIS than it would in the NEM.

In the Reference and Counterfactual cases, the Perth to North Country flow path is upgraded to carry more power into the rapidly growing North Country load. In the Carbon case however, this flow path is not selected, as more local plant is available in North Country to service the load. Similar reasoning applies to the East to Muja upgrade observed in the $500 / kW sensitivity. In the Carbon case, two augmentations were observed in the $500 / kW case, whereas the $1,000 / kW sensitivity saw none. This was due to a tradeoff between building transmission and building/utilizing generation. Upgrading the Muja to Perth flow path allows increased utilization of the cheap baseload assets in the Muja area, which saves fuel costs, but these savings are not sufficient to overcome the barrier of transmission pricing at $1,000 / kW.

Table 6.6 – Number of $500/kW augmentations by flow path

Flow path	Reference / Counterfactual	Carbon
Perth to NC	1	-
Perth to East	-	1
East to Gold	-	-
East to Muja	1	-
Perth to Muja	-	2

Table 6.7 – Number of $1000/kW augmentations by flow path

Flow path	Reference / Counterfactual	Carbon
Perth to NC	1	-
Perth to East	-	1
East to Gold	-	-
East to Muja	-	-
Perth to Muja	-	-

Treatment of Badgingarra Wind Farm (SWIS)

It has been identified that in constructing the planting schedules used for this study, Oakley Greenwood considered Badgingarra Wind Farm (130 MW) to be committed for installation in the SWIS. However, ROAM did not ascribe this status to the Badgingarra proposed wind development, and therefore did not model this wind farm explicitly in any of the scenarios included in this modelling.

The results of this study suggest that the addition of Badgingarra Wind Farm would be unlikely to significantly change transmission outcomes. It is unlikely that additional transmission would be justified on a least cost basis if Badgingarra Wind Farm had been included in the modelling. It is even possible that the addition of Badgingarra Wind Farm (located in the North Country area) would assist in avoiding the need for the transmission upgrade installed in the Base Case from Perth to North Country, since the load growth in North Country would be met locally. This was observed in the Carbon Case, where the Perth to NC augmentation was avoided by the inclusion of additional generation in the NC area.

6.3) Results - Indicative congestion outcomes

Included in the scope of works was the directive to provide an assessment of the degree of transmission congestion that may be associated with the RET. In the context of ROAM's transmission assessment, indicative congestion outcomes were derived from the LTIRP modelling by inspecting the flow duration of all of the inter and intra-regional flow paths in the two systems. Flow paths operating at their nominal limits were considered to be experiencing congestion. And thus provide an indication of the magnitude, location and frequency of network congestion. In assessing these measures, the following should be noted:

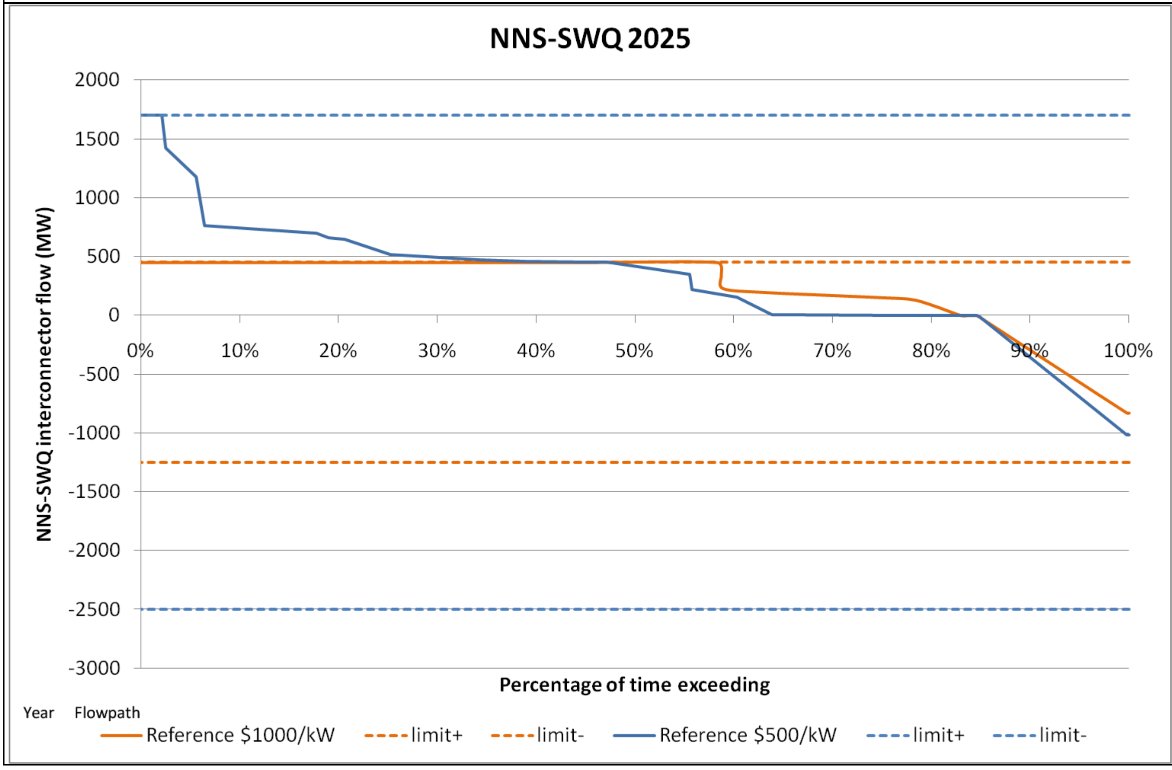
- The model will tend to alleviate congestion where it is the least cost development option through the addition of link upgrades;
- The long-term model does not include detailed security-constrained transmission constraints, as these require a level of detail incompatible with such long term models;
- As it does not consider transmission impacts down to the sub-zonal level, potential transmission congestion *within* a zone is not captured.

6.3.1) Congestion in the NEM

ROAM has attempted to draw out the major conclusions regarding congestion over each flow path in the NEM. Congestion varies year to year and between all the cases, but the following highlights the most interesting observations:

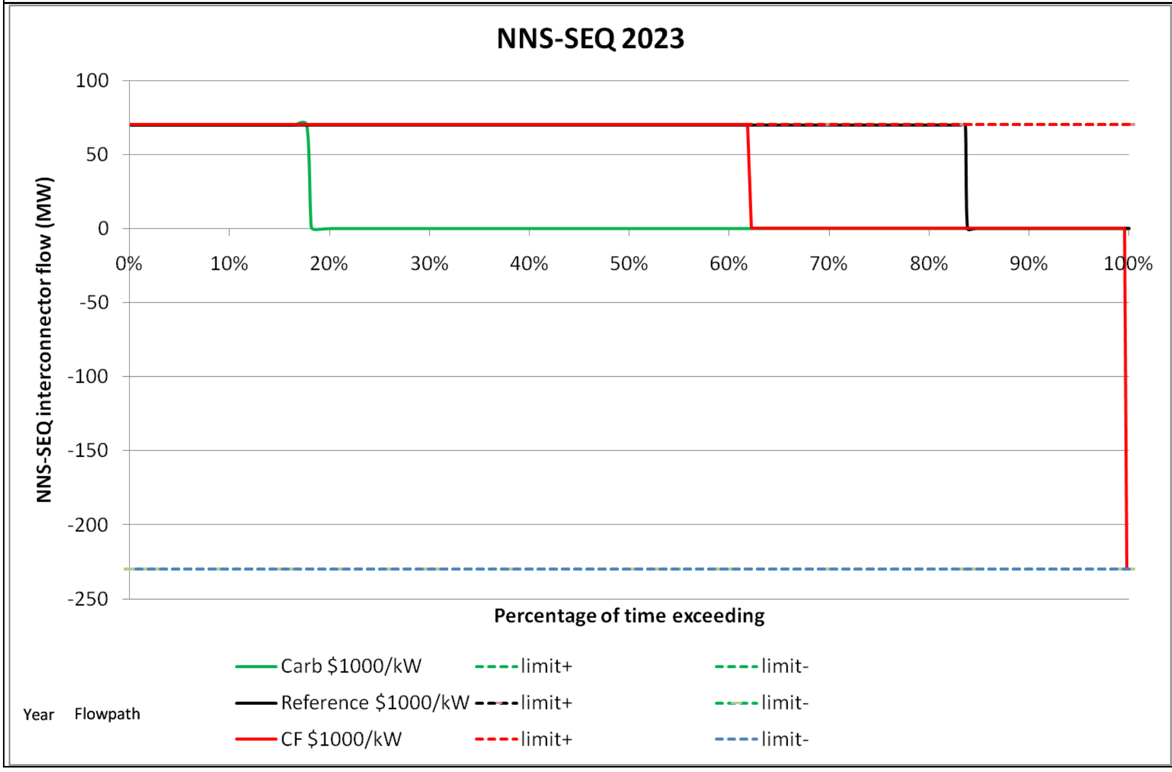
- **CQ-NQ:** Little congestion observed.
- **SWQ-CQ:** Little congestion observed.
- **SEQ-CQ:** Low to moderate congestion observed towards South-East Queensland, particularly in the Carbon case.
- **SEQ-SWQ:** Low to moderate congestion observed towards South-East Queensland. This flow path sees significant augmentation in all cases, reducing the likelihood of congestion.
- **NNS-SWQ:** The congestion observed over this flow path is related to the cost of transmission, indicating a trade off is occurring. In the $500 / kW sensitivity, only low levels of congestion towards SWQ were observed, but when the transmission price is $1,000 / kW, the levels of congestion are significantly higher. In this Reference case, for example, five of the 250MW nominal upgrades of the flow path occur when the price is $500 / kW, but just one upgrade is selected with the higher price of $1,000 / kW. In this way, the model trades the cost associated with the congestion off against the cost of upgrading the transmission system. Figure 6.9 demonstrates this difference in transmission flows associated with the upgraded and non-upgraded flow path.

Figure 6.9 – Flow duration curve: NNS-SWQ flow path in 2024-25



- **NNS-SEQ:** This flow path begins at only low levels of congestion, but by 2020 has significant congestion towards South East Queensland. This is associated with the high demand growth in the Queensland region. Congestion is most pronounced in the Reference case. Note that augmentation of this flow path was disallowed (as described in section 6.1). Figure 6.10 shows the variation in flows and the proportion of time flows are at the limits between the three cases for a selected example year.

Figure 6.10 – Flow duration curve: NNS-SEQ flow path in 2022-23

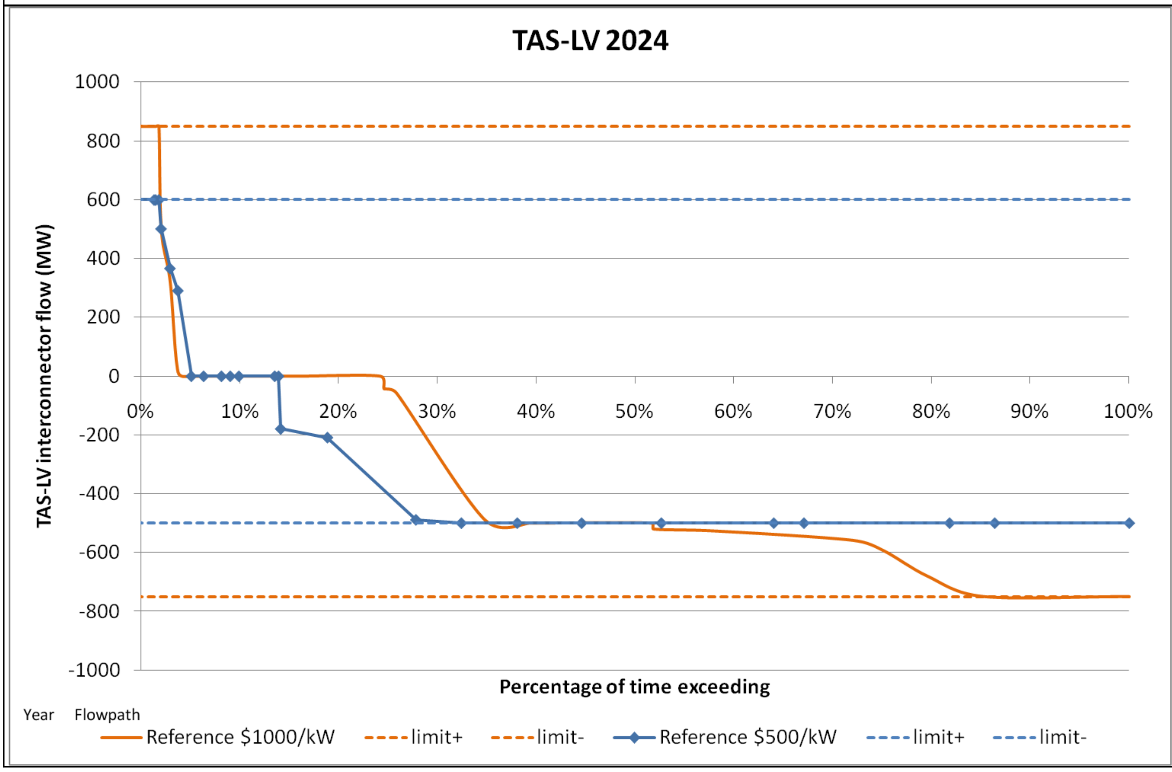


- **NCEN-NNS:** Low to moderate levels of congestion towards NNS. Levels are slightly lower in the Counterfactual case.
- **CAN-NCEN:** Little congestion observed except in the Counterfactual case, where congestion towards CAN is quite high. This is associated with the large amount of plant installed in NNS and SWQ in the Counterfactual cases, being the locations selected as having the cheapest fuel available. This results in significantly increased flows from North to South throughout NSW, loading up this flow path.
- **CAN-SWNSW:** Little congestion observed.
- **NVIC-SWNSW:** Little congestion observed.
- **CVIC-SWNSW:** Moderate levels of congestion towards CVIC in Reference and Carbon cases; high levels of congestion in the Counterfactual case (particularly the $1,000 / kW transmission price sensitivity). This was associated with the much lower level of installed plant in Victoria and New South Wales assumed in the Oakley Greenwood planting schedule, as no new wind farms were installed in either region. With much less plant, both regions import heavily at times to support their load.
- **NVIC-CVIC:** Moderate congestion observed towards CVIC in all cases. In the Carbon case, some congestion is also observed in the opposite direction, but only for a short period around 2020.
- **MEL-NVIC:** Low levels of congestion
- **MEL-CVIC:** High levels of congestion towards CVIC in Reference and Counterfactual cases, which improves significantly around the early 2020's but increases again towards the end of the study. In the Reference and Carbon cases the influx of renewable plant in South Australia associated with the LRET reduces the level of power imported from elsewhere (particularly the Latrobe Valley in Victoria). However, in the Counterfactual, congestion

remains at moderate to high levels as South Australia continues to import large amounts of power from Victoria due to the cost advantage of the Latrobe Valley.

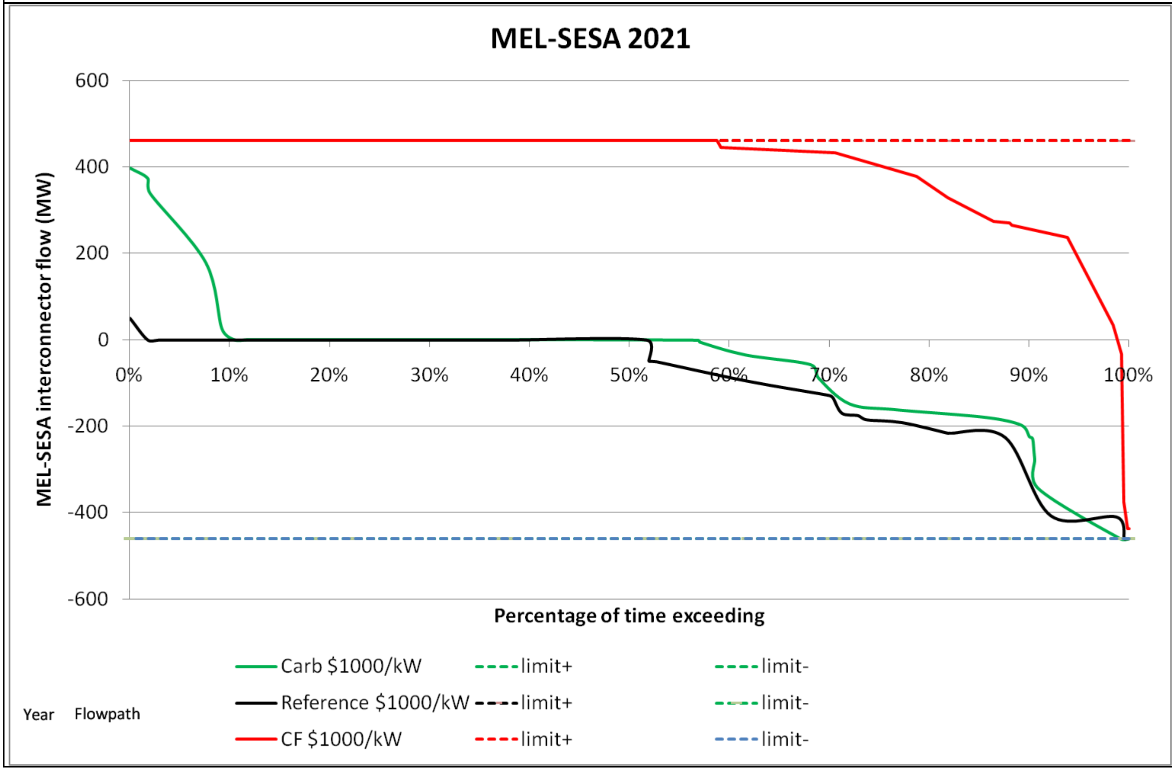
- **LV-MEL:** Little congestion observed.
- **TAS-LV:** Tasmania's link to the mainland has a tendency to run up to its limits in both directions at times. This operational behaviour continues in the modelling in all cases, with congestion particularly increasing towards Tasmania, particularly in the Counterfactual case with $500 / kW transmission pricing. The levels are much lower in the $1,000 / kW sensitivity, as the model upgrades the flow path. From 2020 in the Carbon case, the congestion tails off, as the Oakley Greenwood new entry schedule assumes that significantly more capacity is built in Tasmania in this case. Figure 6.11 demonstrates this difference in transmission flows associated with the upgraded and non-upgraded flow path.

Figure 6.11 – Flow duration curve: TAS-LV flow path in 2023-24



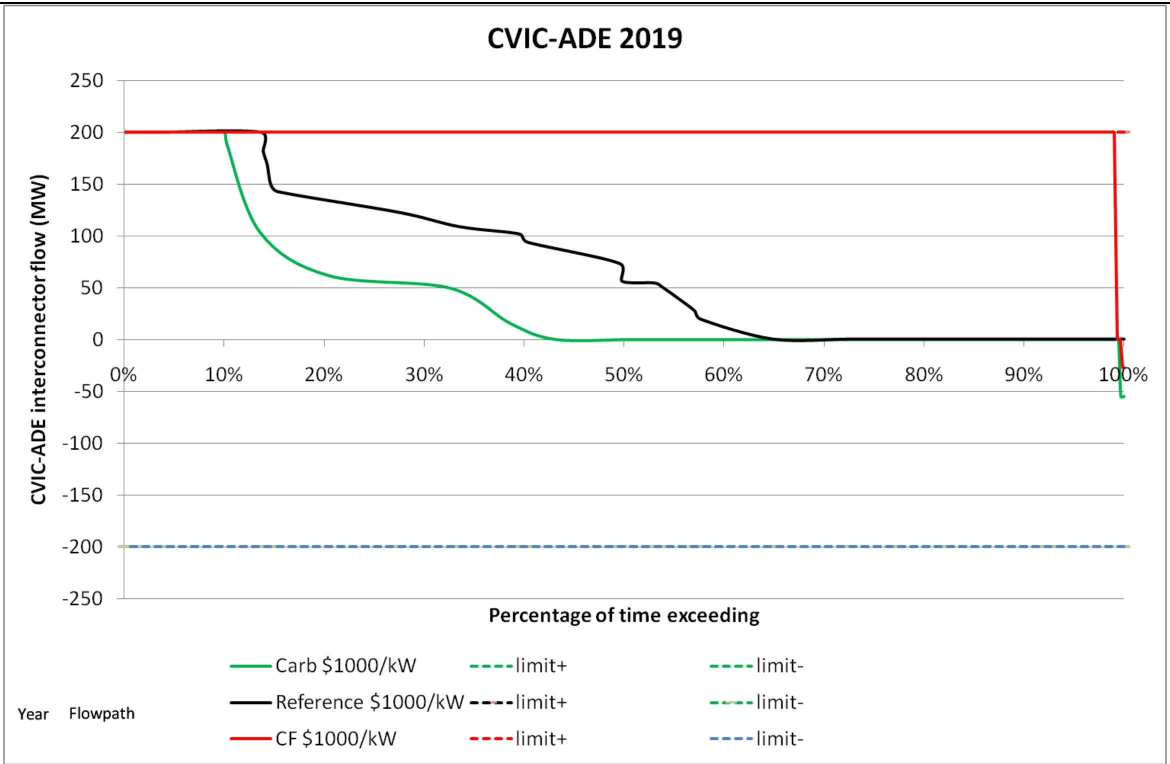
- **MEL-SESA:** Moderate levels of congestion towards SESA at beginning of study. In Reference and Carbon cases, this fades away around 2015-16, as the influx of renewable plant in South Australia reduce the level of power imported from elsewhere (particularly the Latrobe Valley in Victoria). However, in the Counterfactual, congestion remains at moderate to high levels as South Australia continues to import large amounts of power from Victoria due to the cost advantage of the Latrobe Valley. Figure 6.12 shows the variation in flows and the proportion of time flows are at the limits between the three cases for a selected example year.

Figure 6.12 – Flow duration curve: MEL-SESA flow path in 2020-21



- **CVIC-ADE:** Moderate levels of congestion were observed towards Adelaide in the Reference and Carbon cases and high levels of congestion in the Counterfactual case. This was associated with the much lower level of installed plant in South Australia assumed in the Oakley Greenwood planting schedule, as no new wind farms were installed in the region. The result of this is markedly increased flows from Victoria into South Australia. Figure 6.13 shows the variation in flows and the proportion of time flows are at the limits between the three cases for a selected example year.

Figure 6.13 – Flow duration curve: CVIC-ADE flow path in 2018-19



- **SESA-ADE:** Although this flow path starts out with very little congestion, over the course of a few years, congestion builds to moderate levels particularly in the Reference case. Congestion is in the direction of Adelaide and associated with the influx of new plant into the SESA zone.
- **ADE-NSA:** Mildly congested towards Adelaide in Reference and Carbon cases, but not in the Counterfactual case.

Indicative congestion in 2019-20

The following tables show the proportion of time each flow path was utilised at its limit in the 2019-20 year (for the $500 / kW and $1,000 / kW transmission pricing sensitivities). As before, these numbers are only indicative due to the lack of detailed network constraint analysis in this scope of works. However, this shows the relative loading of the various flow paths across the NEM and the large degree of variation between the Reference, Counterfactual and Carbon cases. Note that the Counterfactual tends to feature more of the 'extremes' in these congestion numbers, owing to the relative lack of diversity in the location of generation in that case. Also note that more links show congestion in the $1,000 / kW transmission pricing sensitivity, owing to the lower degree of transmission augmentation resulting from the substantially higher cost.

Table 6.8 – Percent time constrained: $500 / kW augmentations by flow path

	Reference		Counterfactual		Carbon	
Flow path	+ve	-nve	+ve	-nve	+ve	-nve
CQ-NQ	0%	0%	2%	0%	0%	0%

Table 6.8 – Percent time constrained: $500 / kW augmentations by flow path

	Reference		Counterfactual		Carbon	
SWQ-CQ	0%	0%	0%	0%	0%	0%
SEQ-SWQ	0%	3%	0%	1%	0%	7%
SEQ-CQ	0%	6%	0%	0%	0%	2%
NNS-SWQ	0%	0%	0%	0%	0%	0%
NNS-SEQ	37%	0%	70%	0%	46%	0%
NCEN-NNS	5%	0%	4%	0%	18%	0%
CAN-NCEN	5%	0%	0%	26%	1%	0%
CAN-SWNSW	0%	0%	0%	0%	0%	0%
NVIC-SWNSW	0%	0%	0%	0%	0%	0%
CVIC-SWNSW	0%	0%	0%	17%	0%	7%
NVIC-CVIC	13%	0%	1%	0%	7%	1%
MEL-NVIC	5%	0%	0%	0%	0%	9%
MEL-CVIC	38%	0%	0%	0%	0%	2%
LV-MEL	0%	0%	0%	0%	0%	0%
TAS-LV	4%	19%	11%	59%	7%	14%
MEL-SESA	0%	0%	21%	0%	0%	0%
CVIC-ADE	1%	0%	46%	0%	14%	0%
SESA-ADE	25%	0%	5%	0%	8%	0%
ADE-NSA	0%	16%	0%	0%	0%	9%

Table 6.9 – Percent time constrained: $1,000 / kW augmentations by flow path

	Reference		Counterfactual		Carbon	
Flow path	+ve	-nve	+ve	-nve	+ve	-nve
CQ-NQ	0%	0%	2%	0%	0%	0%
SWQ-CQ	0%	0%	0%	0%	0%	0%
SEQ-CQ	0%	14%	0%	0%	0%	0%
SEQ-SWQ	0%	3%	0%	3%	0%	2%
NNS-SWQ	0%	0%	4%	0%	3%	0%
NNS-SEQ	37%	0%	72%	0%	46%	0%
NCEN-NNS	26%	0%	14%	0%	25%	0%
CAN-NCEN	3%	0%	0%	53%	0%	0%
CAN-SWNSW	0%	0%	0%	0%	0%	0%
NVIC-SWNSW	0%	0%	0%	0%	0%	0%
CVIC-SWNSW	0%	1%	0%	50%	0%	16%
NVIC-CVIC	13%	0%	7%	0%	7%	10%
MEL-NVIC	5%	0%	0%	2%	0%	9%
MEL-CVIC	21%	0%	0%	0%	0%	3%
LV-MEL	0%	0%	0%	0%	0%	0%
TAS-LV	6%	15%	3%	44%	8%	14%

Table 6.9 – Percent time constrained: $1,000 / kW augmentations by flow path

	Reference		Counterfactual		Carbon	
MEL-SESA	0%	0%	24%	0%	0%	0%
CVIC-ADE	17%	0%	90%	0%	9%	0%
SESA-ADE	25%	0%	10%	0%	8%	0%
ADE-NSA	0%	9%	0%	0%	0%	5%

6.3.2) Congestion in the SWIS

ROAM has attempted to draw out the major conclusions regarding congestion over each flow path in the SWIS. Congestion levels are quite low in the SWIS compared with some flow paths in the NEM, owing to the relative size of the flow paths compared with the size of the system, and also the somewhat higher correlation in the SWIS between the location of load and generation. Note that in the SWIS, the Reference and Counterfactual cases are equivalent, and therefore this section simply refers to the two as Reference/Counterfactual. Also, the Carbon case differs very little from the other case to 2020, as the new plant assumptions are the same until 2017-18 where they begin to diverge. Therefore prior differences are mainly attributable to the effect of the carbon price uplift on generator costs, which is not present in the Reference/Counterfactual case. The following highlights key observations for each flow path:

- **East Country to Goldfields:** Only low levels of congestion observed. Congestion is slightly higher towards Goldfields in the Carbon case, owing to the additional wind farms.
- **East to Muja:** This is the only heavily congested flow path in the SWIS, with moderately high levels of congestion towards East Country right from the beginning of the study. Congestion levels are virtually the same until around 2017-18, when the new plant assumptions diverge, resulting in rapidly receding congestion in the Carbon case, compared with continuing high levels of congestion in the Reference/Counterfactual case. This behaviour is largely associated with the rapid load growth in the East Country; in the Carbon case, new local generation (particularly wind farms) help support this growth, but in the Counterfactual, there is much less new generation assumed in the Oakley Greenwood planting schedules, and what plant there is tends to be located more in Muja and Perth rather than East Country. Figure 6.14 and Figure 6.15 show this change in circumstances; note how in the second chart, which depicts 2020-21, the difference between the flow curves is much more dramatic as the flow in the Carbon case is much less biased towards East Country.

Figure 6.14 – Flow duration curve: East Country to Muja flow path in 2017-18

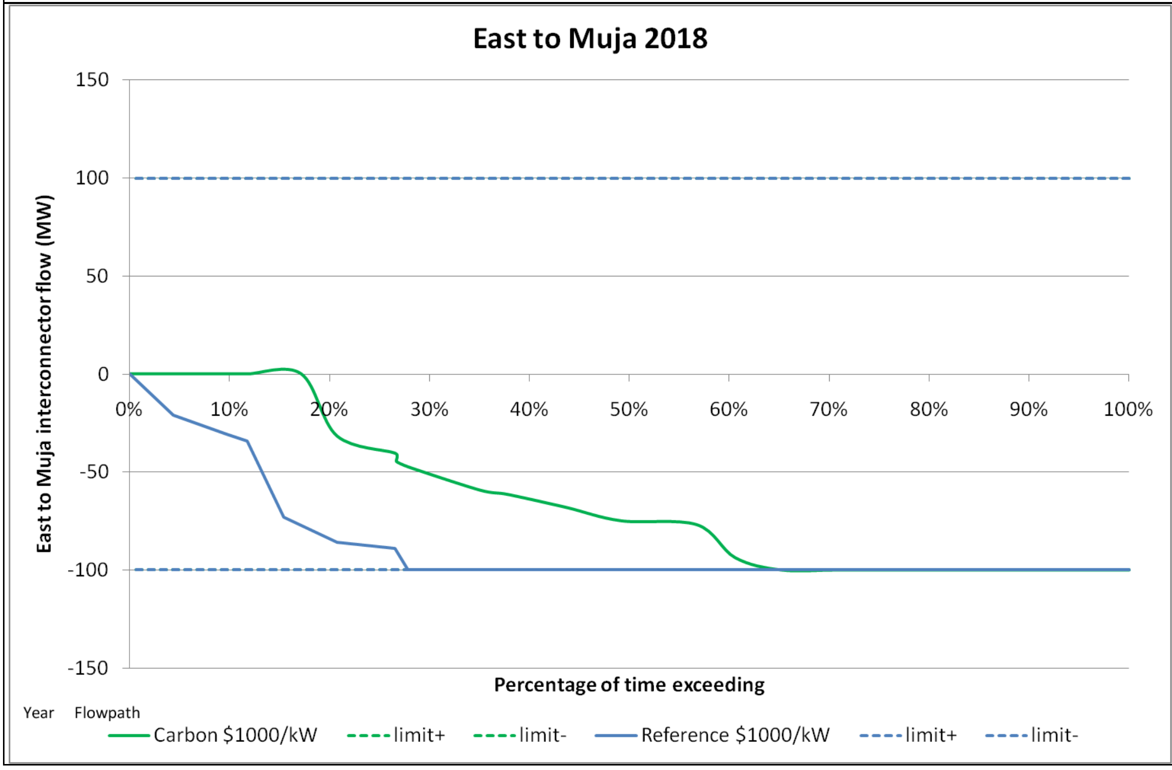
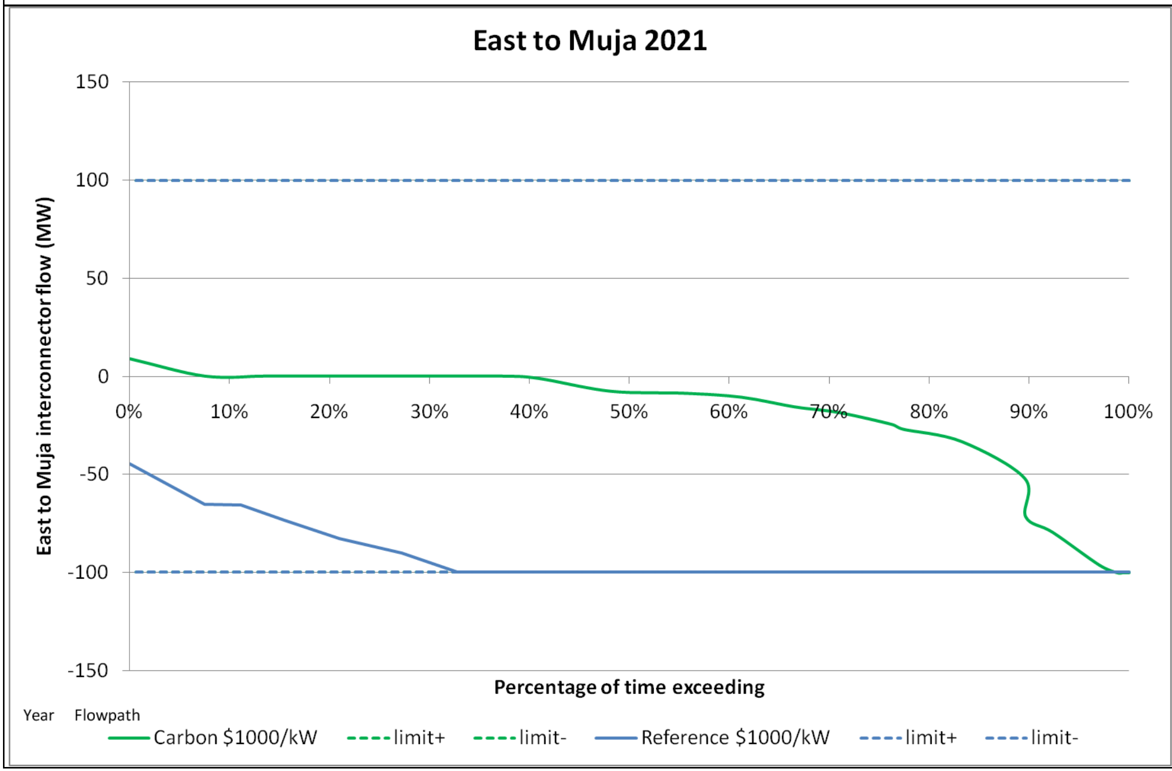
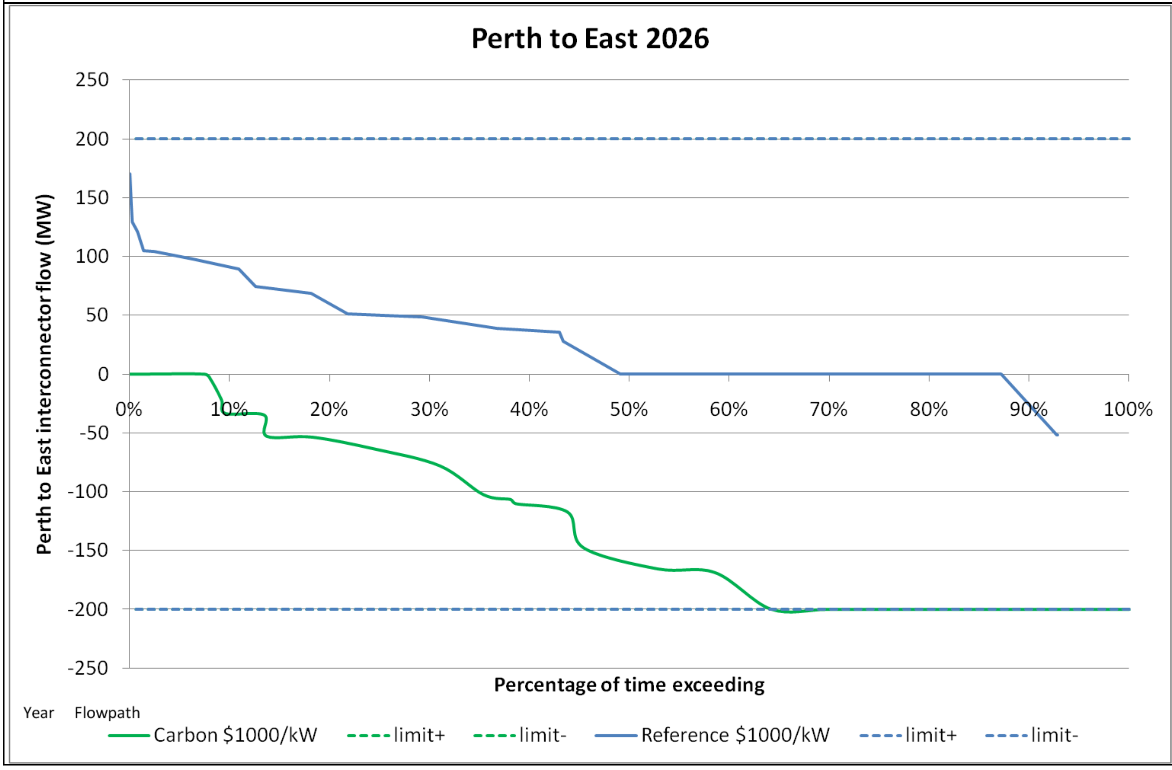


Figure 6.15 – Flow duration curve: East Country to Muja flow path in 2020-21



- **Perth to East Country:** The Perth to East Country flow path starts out quite neutral, with virtually no congestion. However, the Carbon case sees significant congestion towards Perth, growing from 2020 onwards as lots of additional plant is installed in East Country. Figure 6.16 shows the difference in flows and congestion for the year 2025-26.

Figure 6.16 – Flow duration curve: Perth to East Country flow path in 2025-26



- **Perth to Muja:** Very minor levels of congestion were observed towards Perth in the late years of the study.
- **Perth to North Country:** Some minor congestion towards North Country was observed in the Reference/Counterfactual case in the late years of the study (2025-26 onwards). North Country has a rapidly growing load, and this congestion is not seen in the Carbon case due to the additional plant (including wind farms), installed in the late part of the study.

Indicative congestion in 2019-20

The following tables show the proportion of time each flow path was utilised at its limit in the 2019-20 year. Due to the similarity between the $500 / kW and $1,000 / kW transmission pricing sensitivities, only the $1,000 / kW results are shown. As before, these numbers are only indicative due to the lack of detailed network constraint analysis in this scope of works. Note that in 2019-20, only the East to Muja flow path in the direction of East Country has significant congestion, with levels much higher in the Reference/Counterfactual case owing to the relative lack of plant located in the East Country zone in that case.

Table 6.10 – Percent time constrained: $1000/kW augmentations by flow path				
	Reference/Counterfactual		Carbon	
Flow path	+ve	-nve	+ve	-nve
East to Gold	0%	0%	0%	0%
East to Muja	0%	56%	0%	17%
Perth to East	0%	0%	0%	0%
Perth to Muja	0%	0%	0%	0%
Perth to NC	0%	0%	0%	0%

7) CONCLUSIONS

7.1) FREQUENCY CONTROL ANCILLARY SERVICES (FCAS)

7.1.1) NEM

The Regulation requirement increases substantially in response to the LRET. The Regulation requirement increases from the present value of ±120 MW to around ±800 MW in 2019-20 in scenarios with the LRET. This increase is entirely driven by the projected increase in intermittent wind generation installed. In the absence of the LRET the Regulation requirement increases only slightly to ±200 MW due to demand growth.

Regulation costs increase substantially in scenarios featuring the LRET. In response to the increased Regulation requirement, ancillary service settlements increase from $10 million pa[51] (for Regulation + Slow Contingency services) to around $200 million pa in scenarios with the LRET. As the Regulation requirement increases, more expensive FCAS bids must be utilised, increasing FCAS settlements. However, it is noted that if the FCAS market were to increase so substantially it is likely that many generators will change their FCAS bidding strategies in ways that are challenging to predict, so these results should be considered to have a high degree of uncertainty. The application of a carbon price would exacerbate this effect.

In the absence of the LRET, FCAS costs remain close to present levels.

Regulation costs remain small compared with energy settlements. Despite forecast increases, Regulation and Slow Contingency service costs remain small in comparison to anticipated energy settlements of $12 - $20 billion pa ($50 - $80 /MWh) in 2019-20.

Regulation costs could be significant for wind generators. Regulation costs are settled on a causer-pays basis, being paid for by generators or loads when they deviate from their expected dispatch. On this basis, it is anticipated that the majority of the increase in regulation costs will be borne solely by wind generators. This would lead to an increase in regulation costs for wind generators from around $0.40 /MWh at present to $6 - 8 /MWh in 2019-20, in the presence of the LRET. This increase in wind farm costs could have significant implications for the development of new wind projects to meet the LRET. This will apply particularly in the absence of a carbon price, where the LRET shortfall charge is expected to be prohibitively low for new wind farm developments to meet costs, even in the absence of increased FCAS charges.

7.1.2) SWIS

The Load Following requirement increases substantially in response to new wind generation. The Load Following requirement increases from the present value of ±60 MW to around ±120

[51] All quoted costs are in real 2011 dollars unless otherwise stated.

MW with the installation of Collgar[52] (206 MW), or up to ±265 MW with a further 271 MW of wind generation installed (in the Carbon case). The increase is driven primarily by the increase in installed intermittent wind generation.

Load Following costs increase substantially when the Load Following requirement increases. Costs increase from $18 million pa (for Load Following + Spinning Reserve services) in 2009-10 to around $60 million pa in 2019-20 with Collgar installed, and up to around $200 million pa with the additional wind in the Carbon case. The significant increase in costs is driven by two factors - firstly, the increase in the Load Following requirement (in response to more installed intermittent wind). Secondly, the increasing gas price assumed in the modelling (Verve gas prices were assumed to increase from around $4 /GJ at present[53] to $7.65 /GJ in 2019-20). Since Load Following services are provided entirely by Verve gas-fired plant, Verve's gas price has a significant bearing on Load Following costs.

These cost estimates assume that the existing Market Rules continue, with Verve continuing to be the sole provider of Load Following services. If the Rules change as anticipated with the implementation of the new Load Following Ancillary Services (LFAS) Market, increased efficiency from the use of other units in the SWIS may allow costs in the Carbon case to reduce from $200 million pa to $160 million pa.

Load Following costs remain small compared with energy settlements. Despite forecast increases, Load Following costs remain small in comparison to anticipated energy settlements of around $2 billion pa ($80 /MWh) in 2019-20.

Load Following costs could be significant for wind generators. In the SWIS, under the existing Rules Load Following costs are divided between loads and generators on the basis of their metered schedules (MWh). This means that the majority of costs are borne by loads, and leads to Load Following payments by loads and intermittent generators of around $0.42 /MWh at present, increasing to $2 /MWh in 2019-20 with the entry of Collgar wind farm, or $5 - 8 /MWh with the increased wind in the Carbon case in 2019-20. This increase in wind farm costs could have significant implications for the development of new wind projects in the SWIS.

New market rules are under consideration at present that would allocate a much larger proportion of Load Following costs to wind generators, based on a causer-pays principle. Under these new Rules wind generators could be liable for Load Following costs of around $30 /MWh in 2019-20 with the entry of Collgar, or up to $60 - 70 /MWh in 2019-20 with the additional wind in the Carbon case. These additional costs are likely to be prohibitive for the development of new wind generation in the SWIS.

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[52] For the SWIS, the Reference and Counterfactual scenarios are identical (both feature the committed Collgar wind farm, and no further wind installation). Therefore, the results for these scenarios for the SWIS relating to FCAS, NCAS and transmission augmentation costs are identical.

[53] 2009 Margin_Peak and Margin_Off-Peak Review, Final Report v4.0, MMA report to IMO WA, 10 December 2009.

7.2) Network Support and Control Ancillary Services (NSCAS)

7.2.1) NEM

NSCAS costs may double due to the entry of new wind farms under the LRET. NSCAS costs in the NEM are projected to increase from $49 million pa[54] to around $100 million pa in 2019-20 in the presence of the LRET. In the absence of the LRET NSCAS costs associated with new wind farms remain close to present levels. This projection only relates to additional NSCAS costs related to increased wind farm penetration; other network factors have not been taken into account.

Due to the assumptions made in this study, the differences in costs between scenarios, and the changes in costs within scenarios, is driven entirely by the capacity of wind installed in each year, in each scenario. This was based upon the provided Oakley Greenwood planting schedules.

NSCAS costs remain small compared with energy settlements. NSCAS costs to consumers are projected to increase from around $0.25 /MWh in 2010-11 to around $0.40 /MWh in 2019-20 in the presence of the LRET. Despite forecast increases, this remains small in comparison to anticipated energy settlements of $50 - $80 /MWh.

NSCAS costs are not likely to be problematic for the liable parties. NSCAS costs are largely borne by transmission and distribution network companies, and passed through to consumers via network tariffs. This means that any additional NSCAS costs are spread over a wide base, and are not likely to be problematic.

7.2.2) SWIS

The following major findings relate to Network Support and Control Ancillary Services in the SWIS:

NSCAS costs may increase in response to the installation of more wind generation in the SWIS. NSCAS costs in the SWIS are projected to increase by around $2 million pa with the entry of Collgar wind farm[55], and by around $4 million with the further 271 MW of wind capacity installed in the Carbon case. This projection only relates to additional NSCAS costs related to increased wind farm penetration; other network factors have not been taken into account.

Due to the assumptions made in this study, the differences in costs between scenarios, and the changes in costs within scenarios, are driven entirely by the capacity of wind installed in each year, in each scenario. This was based upon the provided Oakley Greenwood planting schedules.

NSCAS costs remain small compared with energy settlements. NSCAS costs to consumers are projected to increase by around $0.06 /MWh in 2019-20 with the entry of Collgar wind farm, and

[54] Aggregated 2010-11 Reactive Power payments published online weekly by AEMO.

[55] For the SWIS, the Reference and Counterfactual scenarios are identical (both feature the committed Collgar wind farm, and no further wind installation). Therefore, the results for these scenarios for the SWIS relating to FCAS, NCAS and transmission augmentation costs are identical.

by around 0.14 /MWh with the additional 271 MW of wind entering in the Carbon case. Despite forecast increases, this remains small in comparison to anticipated energy settlements of $80 /MWh.

NSCAS costs are not likely to be problematic for the liable parties. NSCAS costs are largely borne by transmission and distribution network companies, and passed through to consumers via network tariffs. This means that any additional NSCAS costs are spread over a wide base, and are not likely to be problematic.

7.3) TRANSMISSION AUGMENTATION

7.3.1) NEM

Significant investment in transmission augmentation will be required regardless of the LRET. Between 3,750MW and 5,500MW of new transmission capacity was built in the cases and sensitivities studied by 2019-20. This was spread across the NEM but focussed heavily around South-West Queensland through to Central New South Wales, associated with both the influx of low cost gas plant in those areas and also the relatively high forecast rates of load growth in Queensland. At prices of $500/kW of transmission capacity, this level of transmission expenditure would equate to between $194m and $284m pa ($0.8 to $1.20 /MWh) in 2019-20, or double that with pricing of $1000/kW.

There may be a higher level of transmission augmentation necessary without the LRET. The LRET had the effect of reducing the amount of inter and intra regional transmission that would otherwise be required. In the Reference and Carbon cases, around 3,750MW of new transmission capacity was built by 2019-20, compared with 5,500MW in the Counterfactual. This represents around $91m pa more in the Counterfactual in that year. The reasons for this are related to the nature of new plant in the different cases. The Carbon and Reference Cases provided by OGW included more generation capacity overall, and also the bias towards renewable generation in the Reference and Carbon Case meant that generation tended to be located closer to the load (the large thermal plant favoured in the Counterfactual case tends to site near cheap fuel rather than near load). However, it must be noted that this result is dependent on the nature of the planting schemes and could be different if a substantially different planting schedule was adopted. It should also be noted that although the Counterfactual case resulted in higher transmission augmentation costs, the Carbon and Reference Cases would most likely be associated with higher generation costs.

The cost associated with new transmission augmentation is minor compared with energy settlements. Like the Regulation and Slow Contingency service costs, costs associated with new transmission are relatively small in comparison to the anticipated energy settlements of $12 - $20 billion pa ($50 - $80 /MWh) in 2019-20. Also, transmission costs are spread over all market participants, so costs of this order are unlikely to be problematic.

The LRET does not necessarily increase congestion between the zones comprising the NEM. While the modelling performed for this project did not include detailed network constraint modelling, it was sufficient to provide an indicative congestion assessment. Overall, congestion levels were relatively unchanged in the presence of the LRET (that is, between the

Reference/Carbon and Counterfactual cases). However, the LRET will likely shift the locations where congestion tends to occur. The most frequently congested flow paths were Melbourne to Central Victoria and Melbourne to South East South Australia. These flows were associated with the delivery of power from the Latrobe Valley (a bulk supply zone) through the rest of Victoria and into South Australia. Since the model was designed to augment transmission paths where it was economically viable to do so, the outcomes for these flow paths were most likely due to a lack of incentive to upgrade the network in this location, as no augmentation of these flow paths occurred in any of the cases. In the context of this study, a lack of incentive means that an augmentation of the flow path did not result in sufficient fuel cost savings to be justified. The LRET causes congestion over these two flow paths to relax, as the influx of wind generation into South Australia reduces the tendency of South Australia to import power. A carbon price has the same impact; it reduces the cost advantage of base load power in the Latrobe Valley and thus reduces flows from this zone across to South Australia.

It should be noted that if a significantly different planting arrangements were assumed to meet the LRET, then transmission augmentation attributable to the LRET may be significant. The assumed planting scenarios, for example, featured a relatively modest level of wind generation development in South Australia. Should a much larger proportion of wind generation site in South Australia, then significant transmission expansion in that region would be necessary and would be directly attributable to the LRET. However, it is likely this would reduce the need for transmission reinforcement elsewhere.

7.3.2) SWIS

Unlike in the NEM, very little transmission augmentation was required in the SWIS cases. The small amount of transmission augmentation observed occurred late in the modelling; after 2019-20. Therefore no augmentation was regarded as directly attributable to the LRET in this timeframe. Furthermore, the new plant assumptions provided for the Reference and Counterfactual cases are identical in the SWIS, and assume the LRET is met via existing and committed plant. The Carbon Case only varies significantly post 2020.

Compared with the NEM, the existing transfer limits between the zones in the SWIS are relatively high for the system size, and the new generation is relatively distributed. In other words, generation in the SWIS tends to be located closer to the load than in the NEM, reducing the need for significant transmission augmentation.

Congestion was minimal in most of the SWIS, except between the East Country and Muja zones, where transmission flows are often at the limit, pushing low cost energy from the Muja zone to the rapidly growing East Country.

Note that the modelling did not examine intra-zonal network issues, which could be significant in the SWIS.

7.4) Treatment of Badgingarra Wind Farm (SWIS)

It has been identified that in constructing the planting schedules used for this study, Oakley Greenwood considered Badgingarra Wind Farm (130 MW) to be committed for installation in the SWIS. However, ROAM did not ascribe this status to the Badgingarra proposed wind development, and therefore did not model this wind farm explicitly in any of the scenarios included in this modelling.

FCAS

Based upon simple projections of the results of this study, rough estimates can be made of the effect on Load Following costs of including Badgingarra. This modelling suggests that in the SWIS, 30-40% of the added capacity of wind is likely to be required as an increase to the Load Following requirement. This suggests that the Load Following requirement may to need to be increased by around 40 - 50 MW with the addition of Badgingarra wind farm.

Load Following service was projected to cost $0.5 million/MW in the Reference and Counterfactual cases, or up to $0.8 million/MW in the Carbon case ($0.6 million/MW if an LFAS market is introduced). Projecting these average costs linearly suggests that the addition of Badgingarra wind farm is likely to add on the order of $20-25 million pa in the Reference and Counterfactual cases, or around $30-40 million pa in the Carbon case ($20-30 million pa if an LFAS market is introduced) in 2019-20.

With the application of the existing settlement rules, this could further increase FCAS costs to wind generators in 2019-20 by around $0.80 - $1.20 /MWh. This corresponds to total costs to wind generators in 2019-20 being around $3/MWh in the Reference and Counterfactual cases, $8.70/MWh in the Carbon case, or $6.80 in the Carbon case with an LFAS market.

If the proposed rule change ("Full Load, Marginal Generation") is applied, this would mean that the addition of Badgingarra wind farm is likely to increase Load Following costs to wind generators in 2019-20 in the range $1.50 - $6.00 /MWh. This corresponds to total costs to wind generators in 2019-20 being around $35/MWh in the Reference and Counterfactual cases, $75/MWh in the Carbon case, and $59/MWh in the Carbon case with an LFAS market.

NSCAS

Based upon the methodology applied in this study, the inclusion of Badgingarra wind farm would increase the cost of NSCAS associated with wind in the SWIS in 2019-20 from around $0.06/MWh to $0.10/MWh (in the Reference and Counterfactual cases), and from around $0.14/MWh to $0.18/MWh (in the Carbon case).

Transmission

The results of this study suggest that the addition of Badgingarra Wind Farm would be unlikely to significantly change transmission outcomes. It is unlikely that additional transmission would be justified on a least cost basis if Badgingarra Wind Farm had been included in the modelling. It is even possible that the addition of Badgingarra Wind Farm (located in the North Country area) would assist in avoiding the need for the transmission upgrade installed in the Base Case from Perth to North Country, since the load growth in North Country would be met locally. This was observed in the Carbon Case, where the Perth to NC augmentation was avoided by the inclusion of additional generation in the NC area.

Appendix A) Glossary

ADE	Adelaide
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
APR	Annual Planning Report
CAN	Canberra
CCGT	Combined Cycle Gas Turbine
CF	Counterfactual
CQ	Central Queensland
CVIC	Country Victoria
DFIG	Doubly Fed Induction Generator
ESCOSA	Essential Services Commission of South Australia
FCAS	Frequency Control Ancillary Services
HEGT	High Efficiency Gas Turbine
IMO WA	Independent Market Operator, Western Australia
LFAS	Load Following Ancillary Services (Market)
LNG	Liquid Natural Gas
LRET	Large-scale Renewable Energy Target
LRMC	Long Run Marginal Cost
LTIRP	Long Term Integrated Resource Planning (ROAM model)
LV	Latrobe Valley
MCE	Ministerial Council on Energy
MEL	Melbourne
NC	North Country (Western Australia, Country North)
NCAS	Network Control Ancillary Services
NCEN	Central New South Wales
NEM	National Electricity Market
NLCAS	Network Loading Control Ancillary Service
NNS	Northern New South Wales
NQ	North Queensland
NSA	Northern South Australia
NSCAS	Network Support and Control Ancillary Services
NSP	Network Service Provider
NSW	New South Wales
NTNDP	National Transmission Network Development Plan
NVIC	Northern Victoria
OCGT	Open Cycle Gas Turbine
PoE	Probability of Exceedence

QLD	Queensland
REC	Renewable Energy Certificate
RET	Renewable Energy Target
ROAM	ROAM Consulting
RPAS	Reactive Power Ancillary Service
SA	South Australia
SEQ	South-East Queensland
SESA	South East South Australia
SRMC	Short Run Marginal Cost
SVC	Static Var Compensator
SWIS	South-West Interconnected System
SWNSW	South-West New South Wales
SWQ	South-West Queensland
TAS	Tasmania
TNSP	Transmission Network Service Provider
VIC	Victoria
WA	Western Australia
WEST	Wind Energy Simulation Tool (ROAM model)

Appendix B) PLANTING SCHEDULES

The following planting schedules were provided by Oakley Greenwood as the basis for this modelling. Only new plant is included in Table B.1, Table B.2 and Table B.3 below; existing and committed plant are additional to these numbers. The existing and committed plant included by ROAM is listed in Table B.4. It should be noted that ROAM and Oakley Greenwood independently made decisions around existing and committed plant; in particular, Badgingarra wind farm (130 MW) was assumed to be committed for installation in the SWIS by Oakley Greenwood, but was not ascribed this status by ROAM (and therefore was not modelled in ROAM's study).

Some wind plant was not modelled explicitly by ROAM, but instead was included via netting off the demand traces. This is most appropriate in the case of non-scheduled wind farms that are not included explicitly in any NTNDP constraint equations. The operation of these wind farms has already been netted off the historical demand reference traces used for the modelling, so to avoid "double counting" they are not added explicitly. The wind plant modelled in this manner by ROAM is listed in Table B.5.

Table B.1 – Oakley Greenwood Planting Schedule: Reference Case (Cumulative MW)

FY ending:	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
NSW Biomass	86	186	186	186	186	186	186	186	186	186	186	186	186	186	186	186	186	186	186
NSW CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	545	1125	1290	1518
NSW OCGT	0	0	0	0	0	457	1490	1925	2201	2705	2885	3129	3252	3252	3252	3252	3257	3832	4075
NSW Wind	1105	1105	1105	1105	1105	1105	1387	2203	2649	2649	2649	2649	2649	2649	2649	2649	2649	2649	2649
QLD Biomass	14	14	114	214	314	414	514	614	697	697	697	697	697	697	697	697	697	697	697
QLD CCGT	0	0	0	0	0	0	0	0	278	573	973	1146	1146	2148	2988	3437	3681	4101	4633
QLD OCGT	0	0	0	871	1697	2472	2475	2500	2819	2866	2866	2993	3323	3323	3323	3394	3810	3983	4283
QLD Wind	266	266	266	266	266	266	266	266	532	532	532	532	532	532	532	532	532	532	532
SA Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SA OCGT	0	0	0	0	0	0	274	549	549	549	549	549	664	664	664	664	664	664	799
SA Wind	150	300	300	300	450	600	750	900	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050
TAS Biomass	0	0	0	0	0	0	0	0	16	23	29	36	42	49	55	62	68	75	81
TAS CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	84	133
TAS Wind	100	200	200	200	300	400	500	600	700	700	700	700	700	700	700	700	700	700	700
VIC CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	106	598	1362	1989	2164	2439
VIC OCGT	0	0	0	0	0	0	608	1122	1122	1375	1773	2313	2744	2744	2744	2744	2752	3101	3167
VIC Wind	650	675	675	675	675	1131	1635	1635	2285	2285	2285	2285	2285	2285	2285	2285	2285	2285	2285
WA Biomass											21	30	30	30	30	30	30	30	30
WA OCGT	135	231	481	660	864	1094	1284	1472	1472	1663	1838	2031	2237	2237	2251	2378	2486	2602	2721
WA CCGT	0	0	0	0	0	0	0	0	186	186	186	186	186	398	602	699	819	939	1061
WA Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WA Biomass											21	30	30	30	30	30	30	30	30

Table B.2 – Oakley Greenwood Planting Schedule: Counterfactual Case (Cumulative MW)																			
FY ending:	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
NSW Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NSW CCGT	0	0	0	0	0	0	0	0	0	254	280	588	817	817	817	817	817	817	817
NSW OCGT	0	0	0	0	63	544	1727	2491	2491	2491	2491	2491	3206	3206	3206	3206	3491	4198	4821
NSW Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
QLD Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
QLD CCGT	0	0	0	0	0	193	193	351	1088	1601	2176	2440	2453	2833	3707	4802	5783	6346	7057
QLD OCGT	0	0	114	669	1869	2663	2663	2663	2663	2663	2663	2663	2677	2677	2677	2677	2677	2677	2677
QLD Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SA Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SA OCGT	0	0	0	0	0	0	227	712	712	712	712	712	739	739	739	739	739	739	824
SA Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TAS Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TAS CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12	182	286	438	496
TAS Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VIC CCGT	0	0	0	0	0	0	226	226	893	1245	1640	1903	1903	2651	3120	3557	4092	4636	5014
VIC OCGT	0	0	0	0	0	234	898	898	898	898	898	1168	1189	1189	1189	1189	1189	1189	1189
VIC Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WA Biomass											21	30	30	30	30	30	30	30	30
WA OCGT	135	231	481	660	864	1094	1284	1472	1472	1663	1838	2031	2237	2237	2251	2378	2486	2602	2721
WA CCGT	0	0	0	0	0	0	0	0	186	186	186	186	186	398	602	699	819	939	1061
WA Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WA Biomass											21	30	30	30	30	30	30	30	30

Table B.3 – Oakley Greenwood Planting Schedule: Carbon Case (Cumulative MW)																			
FY ending:	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
NSW Biomass	0	0	0	100	200	300	300	300	300	300	300	300	300	300	300	300	300	300	300
NSW CCGT	0	0	0	0	0	0	0	0	0	0	0	0	290	290	290	290	368	435	435
NSW OCGT	0	0	0	305	387	823	1485	1903	1903	2334	2334	2739	2808	2808	2808	2808	2808	3403	3849
NSW Wind	1105	1105	1105	1105	1105	1105	1233	1918	2363	2363	2363	2363	2363	2363	2363	2363	2363	2363	2363
QLD Biomass	0	0	0	0	0	0	100	200	200	200	200	200	200	200	200	200	200	200	200
QLD CCGT	0	0	0	0	76	76	76	76	806	1181	1890	1984	1984	2848	3712	4765	5724	6419	7127
QLD OCGT	0	0	317	1293	1875	2276	2606	2606	2606	2606	2606	2606	2606	2606	2606	2606	2606	2606	2606
QLD Wind	266	266	266	266	266	266	266	266	532	532	532	532	532	532	532	532	532	532	532
SA Biomass	100	200	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
SA OCGT	0	0	0	0	0	0	0	291	291	291	291	291	291	291	291	291	291	291	291
SA Wind	150	300	300	450	600	750	900	1050	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200
TAS Biomass	0	0	0	0	0	0	0	0	100	106	113	125	225	225	225	288	300	300	300
TAS CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	27	63
TAS Wind	100	200	200	300	400	500	600	700	800	800	800	800	800	800	800	800	800	900	1000
VIC CCGT	0	0	0	0	0	0	0	0	0	0	0	408	464	771	1164	1947	2690	2889	3359
VIC OCGT	0	0	0	0	55	423	1291	1724	1724	1957	2163	2269	2556	2556	2556	2556	2556	2815	2849
VIC Wind	650	675	675	675	675	861	1511	1635	2285	2285	2285	2285	2285	2285	2285	2285	2285	2285	2285
WA Biomass	0	0	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100
WA OCGT	135	231	481	660	864	994	1168	1318	1435	1582	1762	1963	2169	2198	2342	2453	2628	2707	2791
WA CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	73	179	179	335	493
WA Wind	0	0	0	0	0	0	81	271	615	836	918	918	918	1836	1836	1868	2142	2142	2142
WA Biomass	0	0	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100

Table B.4 – Existing and Committed wind plant explicitly modelled by ROAM			
Region	**Status**	**Project Name**	**Capacity (MW)**
NSW	Existing	Capital	141
		Cullerin Range	30
	Committed	Crookwell 2	92
		Gunning	47
		Woodlawn	42
SA	Existing	Brown Hill (H1)	95
		Canunda	46
		Cathedral Rocks	66
		Clements Gap	57
		Hallett Hill (H2)	71
		Lake Bonney	81
		Lake Bonney stage 2	159
		Lake Bonney stage 3	39
		Mt Millar	70
		Snowtown Stage I	99
		Starfish Hill	35
		Waterloo	111
		Wattle Point	91
	Committed	Bluff Range (H5)	50
		N Brown Hill (H4)	132
VIC	Existing	Challicum Hills	53
		Waubra	192
	Committed	Macarthur	420
		Oaklands Hill	63
		Total (NEM):	1434
WA	Existing	Albany	21
		Emu Downs	80
		Walkaway	90
	Committed	Collgar	206
		Total (SWIS):	397

Table B.5 – Existing wind plant not explicitly modelled by ROAM (included via netting off demand traces)		
Region	**Project Name**	**Capacity**
NSW	Blayney	9.9
	Crookwell	4.8
	Hampton	1.32
QLD	Windy Hill	12
TAS	Woolnorth Bluff Point	60.5
	Woolnorth Studland Bay	75
VIC	Cape Bridgewater	58
	Cape Nelson (South)	44
	Codrington	18.2
	Toora	21
	Wonthaggi	12
	Yambuk	30
	Total (NEM):	347
WA	Bremer Bay	0.6
	Coral Bay	0.825
	Denham	0.69
	Hopetoun	0.6
	Kalbarri	1.7
	Nine Mile Beach	3.6
	Rottnest Island	0.6
	Ten Mile Lagoon	2.025
	Total (SWIS):	11

Appendix C) WIND ENERGY SIMULATION TOOL (WEST)

The outputs of wind farms were forecast utilising ROAM's WEST software.

WEST (ROAM's proprietary Wind Energy Simulation Tool) calculates generation traces for wind farms based on historical data from the Bureau of Meteorology, location specific wind speed simulations from the Australian Renewables Atlas, historical or forecast capacity factors and manufacturer provided turbine power curves. These are routinely used as input to ROAM's electricity market models for explicit modelling of wind farm generation and transmission congestion with high quantities of renewable energy.

WEST requires as input the average wind speed at the wind farm site for each one minute period. Historical data is sourced from automatic weather stations around Australia from the Bureau of Meteorology.

The wind data from the Bureau of Meteorology (BOM) weather stations is 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 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 shows this to be the case, as illustrated in the figures below).

In this study, wind speeds were scaled up in an iterative fashion such that the final generation achieved a targeted capacity factor for each wind farm. For existing wind farms, average historical capacity factors over the life of the project were targeted, while for new projects the tiered capacity factors for each location provided in the 2010 NTNDP data set were used.

ROAM's WEST program then applies a turbine power curve to convert the wind speeds into actual generation for input into 2-4-C, ROAM's market dispatch system, or for other modelling purposes (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). ROAM is therefore able to accurately determine an aggregated wind profile for both the SWIS and the NEM, correctly taking these correlations into account.

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

C.1) *Calibration of WEST*

WEST has previously been calibrated to 1-minute, 5-minute and 30 minute historical generation data in both the SWIS and NEM. Backcast generation profiles are produced and compared to the historical generation, and a higher correlation is observed.

C.1.1) Time of day calibration

Due to the height of wind turbines above the ground, wind data collected at weather stations often does not accurately reproduce the correct time of day averages for wind farm outputs. Weather stations, being closer to the ground, will tend to be affected by daily wind patterns that are not experienced at a higher height. To account for this, ROAM applies a time of day average generation adjustment to the output of WEST, which is calibrated by the average historical output of existing wind farms.

C.1.2) Smoothing of wind data

Wind is typically more "gusty" than the output of a wind farm due to the inertia of the turbines, the geographical distribution of turbines across the farm and smoothing due to the height of the turbines above the ground. Additionally, rounding issues with the Bureau of Meteorology wind speed data sometimes causes larger than appropriate 1-minute changes.

It was therefore necessary to apply a smoothing to the output of WEST. Previous studies by ROAM have provided calibration of WEST against actual wind farm output on the 1-minute and 5-minute timescales. Calibration was performed differently in the SWIS compared to the NEM, due to the different Rules – in the NEM, calibration was performed to ensure that the periods of greatest minute-to-minute change were captured by the modelling, while in the SWIS the calibration focuses on the 99.9% highest change periods. Limited publicly available data, however, particularly at the 1-minute resolution, means that the forecast traces contain some uncertainty.

For the NEM, the smoothing applied was:

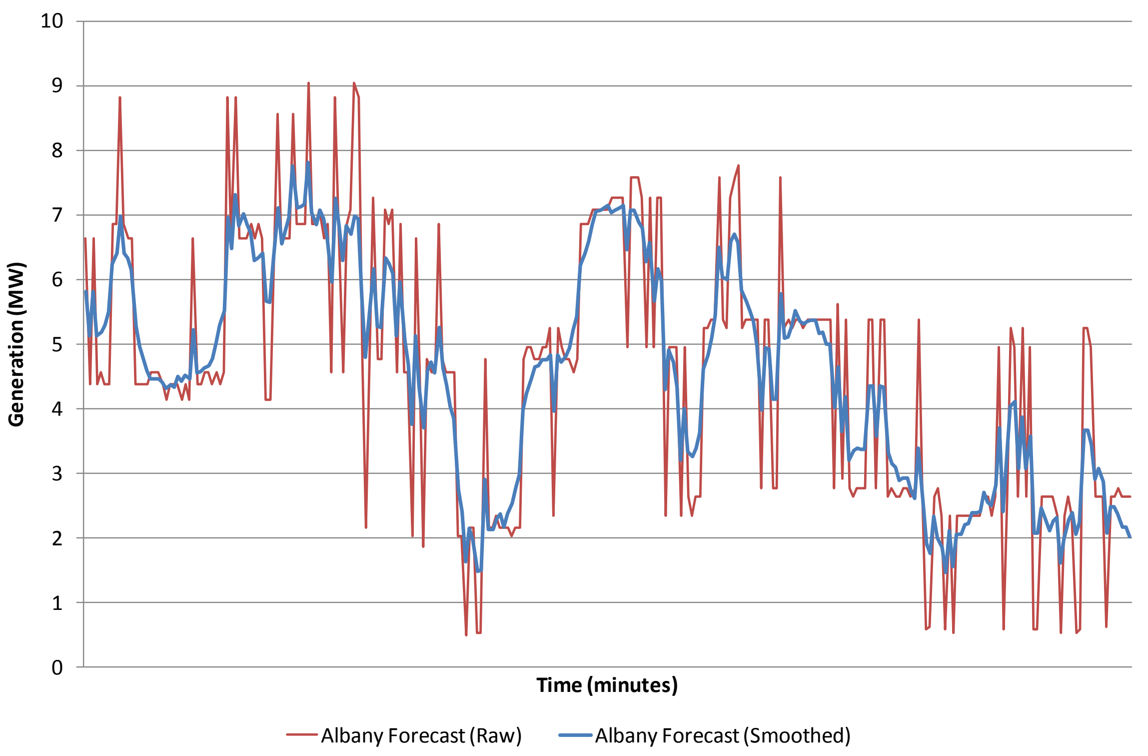
$$W_i^s = 0.3W_i + 0.7\langle W_{i-2}: W_{i+2}\rangle$$

For the SWIS, the smoothing applied was:

$$W_i^s = 0.3W_i + 0.7\langle W_{i-10}: W_{i+10}\rangle$$

An example of the smoothing methodology applied is shown in the figure below for Albany Wind Farm in the SWIS.

Figure C.17 – Example of WEST smoothing - Albany Wind Farm



Appendix D) SYSTEM FREQUENCY MODEL

System frequency models were developed to model the amount of frequency regulation required in both the NEM and the SWIS. The theories applied to develop these models and their structural construction are outlined and discussed in this section.

D.1) *GENERATOR AND LOAD MODEL*

For a single generator supplying power to a load, the rate of change in electrical frequency due to a difference between the power supplied and the power consumed by the load can be calculated as

$$\frac{df(t)}{dt} = \frac{f_s \cdot (P_{Gen}(t) - P_{Load}(t))}{2H_{Gen}} \tag{1}$$

where $P_{Gen}(t)$ and $P_{Load}(t)$ is the output of the generator and load, respectively, f_s is the nominal frequency (50Hz), and H_{Gen} is the inertia of the generator, turbine and all other connecting plant (in units of *MWs*). This is known as the Swing Equation[56].

For a system with *M* generators and *N* loads, if we are only interested in the average system dynamics (ignoring the inter-machine oscillations), we can model the system as a single-machine[57] and apply the Swing Equation accordingly by summing the contribution of each generator and load. That is,

$$\frac{df(t)}{dt} = \frac{f_s \cdot \left(\sum_{i=1}^{M} P_{Gen_i}(t) - \sum_{j=1}^{N} P_{Load_j}(t)\right)}{2\sum_{i=1}^{M} H_{Gen_i}} = \frac{f_s \cdot (P_G(t) - P_L(t))}{2H} \tag{2}$$

where $P_G(t)$ and $P_L(t)$ is the system generation and load, respectively, and H is the centre of inertia (COI) of the system supplied by active generators. Expressing the Swing Equation in terms of a transfer function in the *s*-domain gives

$$\frac{F(s)}{P_G(s) - P_L(s)} = \frac{f_s}{2H \cdot s} \tag{3}$$

which is used to form the basis of the generator model after replacing absolute values $P_G(s)$, $P'_L(s)$, and $F(s)$ with small signal representations $\Delta P_G(s)$, $\Delta P_L(s)$ and $\Delta F(s)$.

[56] H. Saadat, "Power System Analysis", *International Editions*, McGrill-Hill, 1999.

[57] A. Li and Z. Cai, "A Method for Frequency Dynamics Analysis and Load Shedding Assessment Based on the Trajectory of Power System Simulation", *Electric Utility Deregulation and Restructuring and Power Technologies Conference*, April 2008.

Power system loads consists of a variety of electrical devices. For resistive loads, such as lighting and heating loads, the electrical power is independent of frequency. Motor loads, however, are sensitive to changes in frequency. The amount of sensitivity depends on the composite of the speed-load characteristics of all the driven devices. Here, we model speed-load characteristic of a composite load as

$$P_L(t) = P_L'(t) \cdot \left(\frac{f(t)}{f_s}\right)^m \tag{4}$$

where $P_L'(t)$ is the total system load in the absence of frequency deviation and m is the load-frequency index.

To make sure that correct generator inertia values were applied in ROAM's modelling of the NEM and the SWIS, ROAM requested and obtained generator inertia data from AEMO and Western Power, respectively, and applied those accordingly in the modelling. The load-frequency index for the NEM was set to 1.7 based on the modelling data provided by AEMO. The load-frequency index for the SWIS, however, was difficult to obtain as advised by Western Power. ROAM nominated a value of 1.5 for m as it was shown to give good benchmark outcomes of historic contingence events.

D.2) *Governor-Turbine Models*

Equipments such as the speed governor controller and the governor itself cannot respond instantaneously in the presence of system frequency change. Instead, exponential responses governed by time-constants, or time delay responses, or in some cases more complex response types are to be expected. Similarly, components associated with the turbine such as fuel controllers, valve positioning devices and temperature controllers also inhibit those characteristics. The combination of different responses from governors and turbines can have a significant influence on the system frequency response.

Ideally, every generator governor and turbine should be modelled accordingly in the system model. However, ROAM was not able to obtain governor and turbine models for all of the generators in both the NEM and the SWIS, as data was either unavailable or were not able to be extracted.

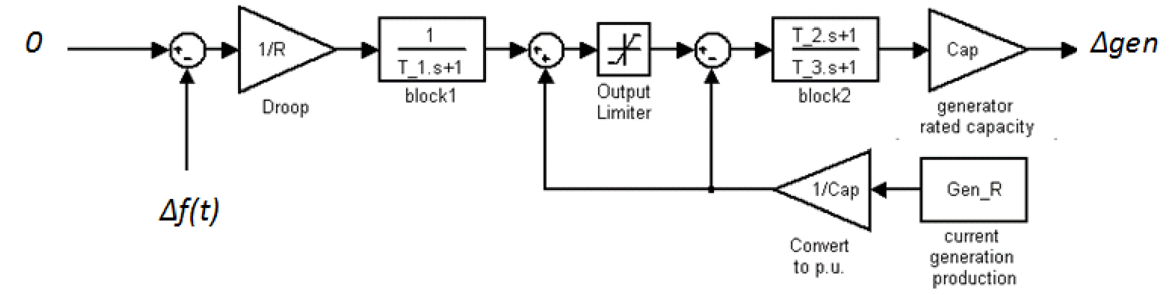
D.2.1) NEM

The majority of frequency regulation in the NEM is provided by large thermal generators. After careful examination of the data provided by AEMO, two governor-turbine models were identified as the most prominent models for the NEM. In addition, one of the models was found to have significantly different parameters settings, which resulted in a total of three distinct models using the same governor-turbine modelling layout. This gave a total of four governor-turbine models in the NEM. However, it was later found through the calibration process that the frequency response corresponding to a slow-changing system supply-demand imbalance was almost identical when using just one of the four governor-turbine models with appropriate parameters applied. As a result of this, a single governor-turbine model was employed at the end to model the aggregated response of governors and turbines (of generators that are providing frequency regulation) in the NEM. Details of the resulting aggregated governor-turbine model are outlined below. In addition, details of the four governor-turbine models initially identified for the NEM are also outlined below for completeness.

The TGOV1 Model

One of the two governor-turbine models identified is the TGOV1 model. This model is a standard steam turbine-governor model and the block diagram outlining its structure is shown in the figure below.

Figure D.18 – TGOV1 Governor/Turbine Model



Analysis of the dataset provided by AEMO indicated that the TGOV1 models can be grouped into three subsets based on the different settings for the droop characteristic (*R*) and the time constants (T_1, T_2 and T_3). The difference in the parameter settings are outline din the table below.

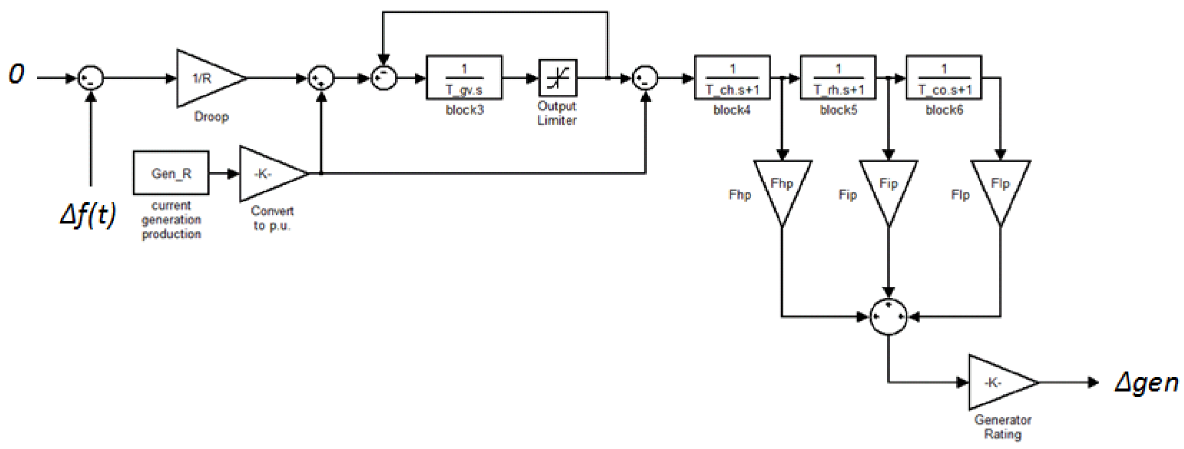
Table D.1 – TGOV1 Model Parameters

Parameter	Group A	Group B	Group C
R	0.12	0.02	0.05
T1 (seconds)	5.0	5.0	5.0
T2 (seconds)	2.7	2.7	1.5
T3 (seconds)	9.0	9.0	9.0

The TGOV7 Model

In addition to the TGOV1 model, the TGOV7 model was also identified in dataset provided. The block diagram outlining its structure is shown in the figure below.

Figure D.19 – TGOV1 Governor/Turbine Model



The aggregated governor-turbine model

The aggregated governor-turbine model employed is based on the standard TGOV1 model with parameters set to resemble historic frequency responses observed for slow-varying system supply-demand imbalances. The modelling parameters was obtained through calibration and are outlined in Table D.1.

Table D.1 – TGOV1 Aggregated Model Parameters

Parameter	Value
R	0.05
T1	5.0
T2	1.5
T3	9.0

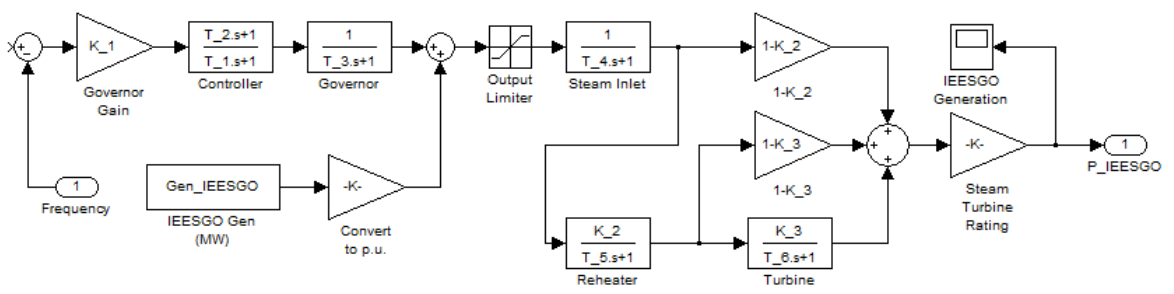
D.2.2) SWIS

Since not all of the generator governor and turbine were available and significant amount of similarities were observed in the modelling parameters, ROAM decided that it was sufficient to model the governors and turbines based on their relevant types. In particular, a total of four governor-turbine models, namely IEESGO (Slow), IEESGO (Fast), GAST2A and IEEEG1, were employed.

The IEESGO Model

The IEESGO governor-turbine model is used for modelling the majority of steam turbine generators. A block diagram representation of this model is outlined in Figure D.20.

Figure D.20 – IEESGO Governor/Turbine Model



The model parameters provided by Western Power suggested that generators modelled by the IEESGO model can be subdivided into two distinct classes as significant differences in the time-constant for the Reheater was observed. In particular, some time-constants are in the range of 0.1 seconds while the rest around 10 seconds. Therefore, ROAM subdivided generators modelled by the IEESGO into IEESGO (Fast) and IEESGO (Slow) classes. Table D.1 summarises the parameters assigned for each of the two classes. ROAM will repeat this analysis for the NEM, based upon data for that system (this will need to be provided by AEMO).

Table D.1 – IEESGO Model Parameters

Parameter	Description	Slow	Fast
T_1	Controller time-constant (s)	0.1	0.46
T_2	Controller lead compensation (s)	0	0.3
T_3	Governor time-constant (s)	0.2	0.23
T_4	Steam inlet time-constant (s)	0.13	0.21
T_5	Reheater time-constant (s)	10.07	0.15
T_6	Turbine time-constant (s)	1	0
K_1	Inverse of Governor Droop[58]	20	20
K_2	Constant gain	0.73	0.28
K_3	Constant gain	0.67	0

The GAST2A Model

The GAST2A governor-turbine model is used for modelling gas turbines generators. A block diagram representation of this model is outlined in Figure D.21, with the associated parameters outlined in Table D.2.

[58] Governor droop is normally 4% for most units. In addition, there are some times when the governors are set on isochronous control to manage frequency.

Figure D.21 – GAST2A Governor-Turbine Model

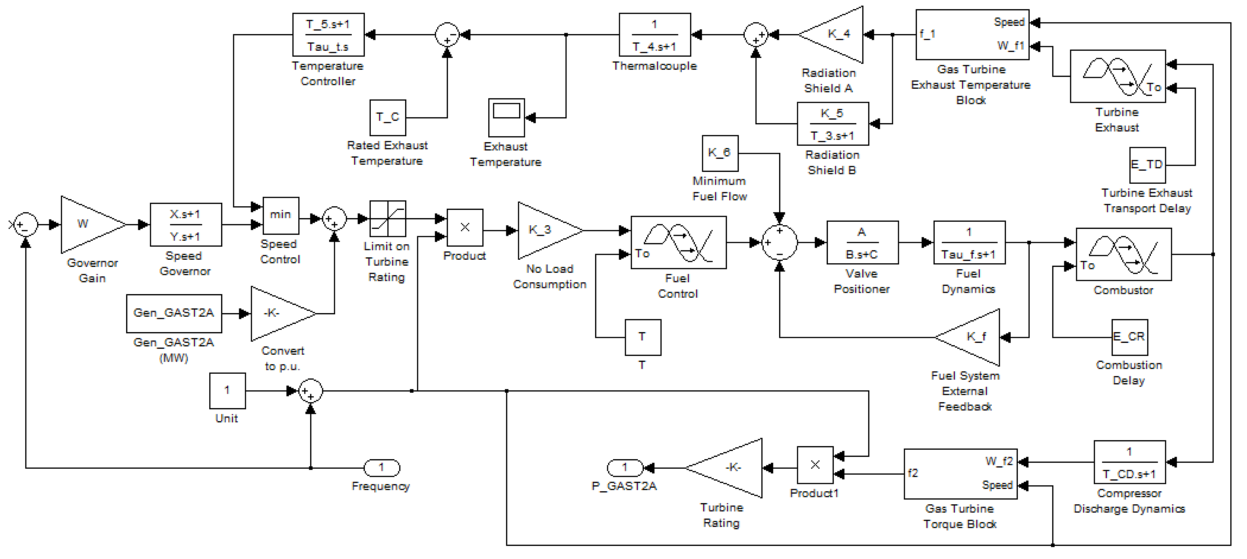


Table D.2 – GAST2A Model Parameters

Parameter	Description	Value
W	Inverse of governor droop	20
X	Controller lead compensation (s)	0
Y	Governor time-constant (s)	0.05
E_{TD}	Turbine and Exhaust transport delay (s)	0.04
T_{CD}	Compressor discharge time-constant (s)	0.2
T	Fuel control delay (s)	0.12
E_{CR}	Combustor delay (s)	0.01
K3	Fuel control gain	0.77
A	Valve positioner gain	1
B	Valve positioner time-constant (s)	0.05
τ_f	Fuel system time-constant (s)	0.4
K_5	Radiation shield gain	0.2
K_4	Radiation shield gain	0.8
T_3	Radiation shield time-constant (s)	15
T_4	Thermalcouple time-constant (s)	2.5
τ_t	Temperature control (°F)	450
T_5	Temperature controller time-constant (s)	3.3
A_{f1}	Gas turbine exhaust temperature block parameter (°F)	700
B_{f1}	Gas turbine exhaust temperature block parameter (°F)	550

Table D.2 – GAST2A Model Parameters		
Parameter	Description	Value
A_{f2}	Gas turbine torque block parameter	-0.3
B_{f2}	Gas turbine torque block parameter	1.3
C_{f2}	Gas turbine torque block parameter	0.5
T_R	Rated temperature (°F)	972
K_6	Minimum fuel flow	0.23
T_C	Rated exhaust temperature (°F)	838

The IEEEG1 Model

The IEEEG1 governor-turbine model is an alternative model for steam turbine generators. This model is used to model the steam turbine component of CCGTs and inhibits a very fast response time. A block diagram representation of this model is outlined in Figure D.22, with the associated parameters outlined in Table D.3.

Figure D.22 – – IEEEG1 Governor-Turbine Model

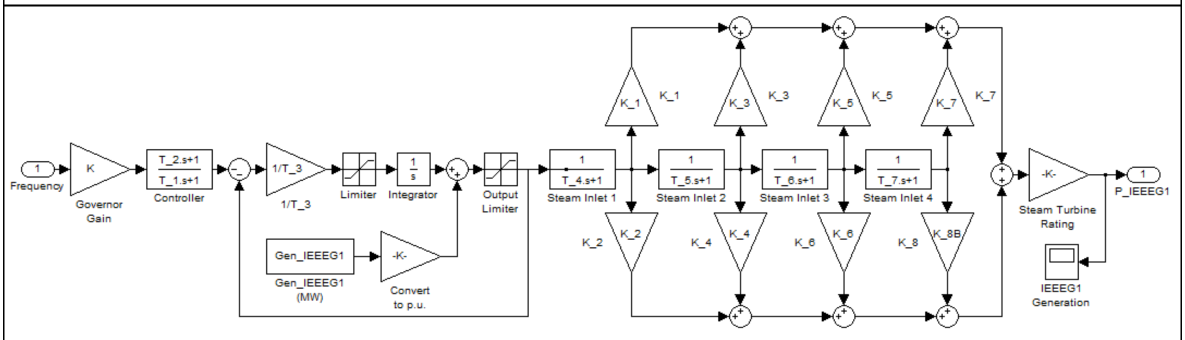


Table D.3 – IEEEG1 Model Parameters		
Parameter	Description	Value
K	Inverse of governor droop	22
T_1	Controller time-constant (s)	0
T_2	Controller lead time compensation	0
T_3	Constant gain	0.15
T_4	Steam inlet 1 time-constant (s)	0.4
K_1	Constant gain	1
K_2	Constant gain	0
T_5	Steam inlet 2 time-constant (s)	0
K_3	Constant gain	0

Table D.3 – IEEEG1 Model Parameters		
Parameter	Description	Value
K_4	Constant gain	0
T_6	Steam inlet 3 time-constant (s)	0
K_5	Constant gain	0
K_6	Constant gain	0
T_7	Steam inlet 4 time-constant (s)	0
K_7	Constant gain	0
K_8	Constant gain	0

D.3) *Calibrating the System Frequency Model*

D.3.1) NEM

Although there are numerous governor models for different generators in the NEM, ROAM has identified that most of the baseload power stations were setup in AEMO's simulation data to employ the TGOV1 model, with a scarce number of generators in South Australia employing the TGOV7 model. The frequency model was initially setup to include all of the governor-turbine models identified, and was benchmarked against a contingency event occurred on 21st January 2010.

The contingency involved a generator outage, which resulted in a generation shortfall of approximately 700MW. To benchmark against the contingency event, the base load generators employing the identified governor-turbine models were set to generate at their actual dispatches prior to the contingency. Changes in system supply leading up to the contingency (observed from the dataset provided by AEMO) were also encapsulated in the model. In particular, a MW increase in system supply was observed over a 22 second interval prior to the contingency. Table D.4 is a summary of the generators and their associated Governor-Models setup in the frequency model.

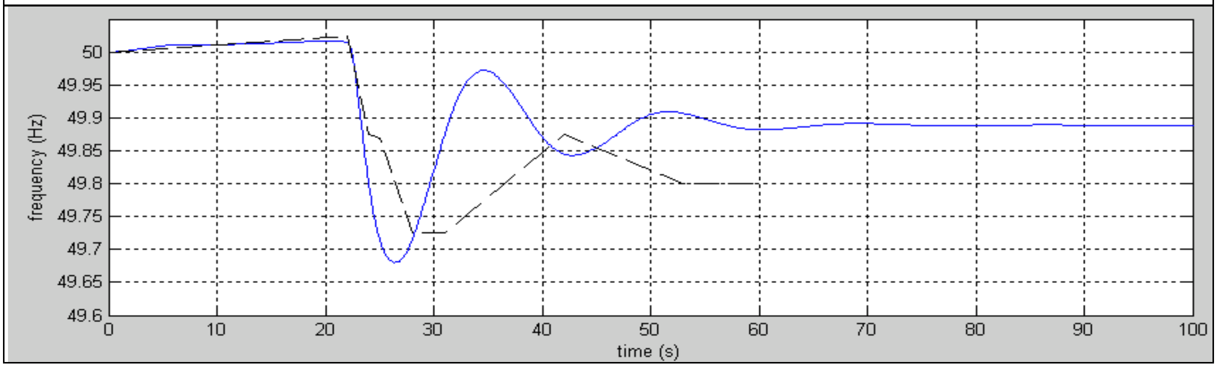
Table D.4 – Generators in the NEM providing Regulation Service					
Region	Generator	Governor Model	Generation prior to contingency event	Generation Capacity (of units online)	Generation available for frequency response (excluding units offline)
Victoria	Liddell	TGOV1 (A)	1725	2000	275
	Loy Yang	TGOV1 (A)	2200	2200	0
	Yallourn	TGOV1 (A)	1400	1450	50
	Hazelwood	TGOV1 (A)	1350	1600	250
	Eraring	TGOV1 (A)	1710	2640	930

Table D.4 – Generators in the NEM providing Regulation Service

Region	Generator	Governor Model	Generation prior to contingency event	Generation Capacity (of units online)	Generation available for frequency response (excluding units offline)
	Mt. Piper	TGOV1 (A)	1380	1400	20
	Wallerawang	TGOV1 (A)	840	1000	160
Queensland	Callide B	TGOV1 (B)	502	700	198
	Gladstone	TGOV1 (B)	1380	1560	180
	Stanwell	TGOV1 (B)	1000	1050	50
	Swanbank B	TGOV1 (B)	60	120	60
	Tarong	TGOV1 (B)	907	1400	493
New South Wales	Bayswater	TGOV1 (C)	2640	2640	0
	Liddell	TGOV1 (C)	1725	2000	275
	Murray	TGOV1 (C)	790	950	160
South Australia	Torrens Island A	TGOV7	108	120	12
	Torrens Island B	TGOV7	435	800	365
	Northern	TGOV7	319	520	201

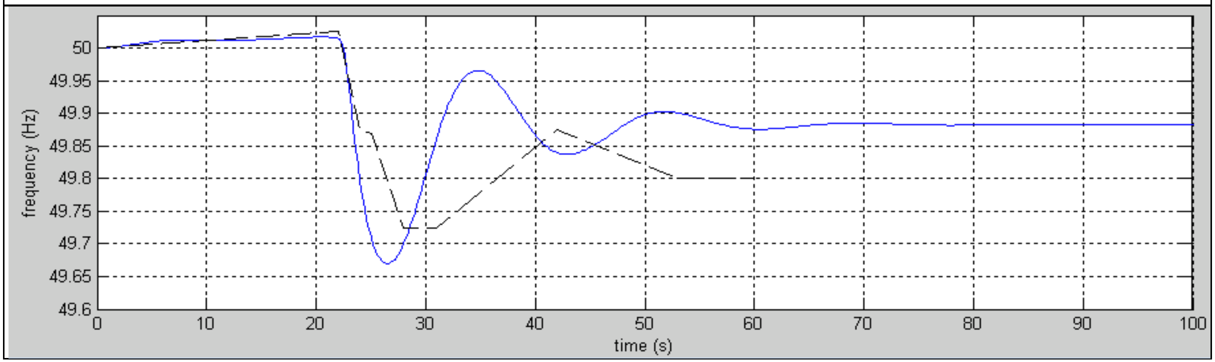
Both the lead up and the contingency were modelled and the outcome of the simulation is shown in the figure below

Figure D.23 – Simulated NEM System Frequency Response



The outcome shows that although the simulated frequency response starts to deviate from what actually happened after the 25 seconds, the frequency response during the "build up" period and the initial drop in system frequency immediately after the contingency line up very well. This shows that the frequency model is adequate for modelling slow changes in system supply-demand balance, which is more relevant for assessing frequency regulation requirements since frequency regulation is applied in the absence of contingencies.

Figure D.24 – Simulated NEM System Frequency Response



D.3.2) SWIS

Using the system frequency and generation dispatch data corresponding with past generator tripping events provided by Western Power, ROAM benchmarked the system frequency model against several cases in the SWIS.

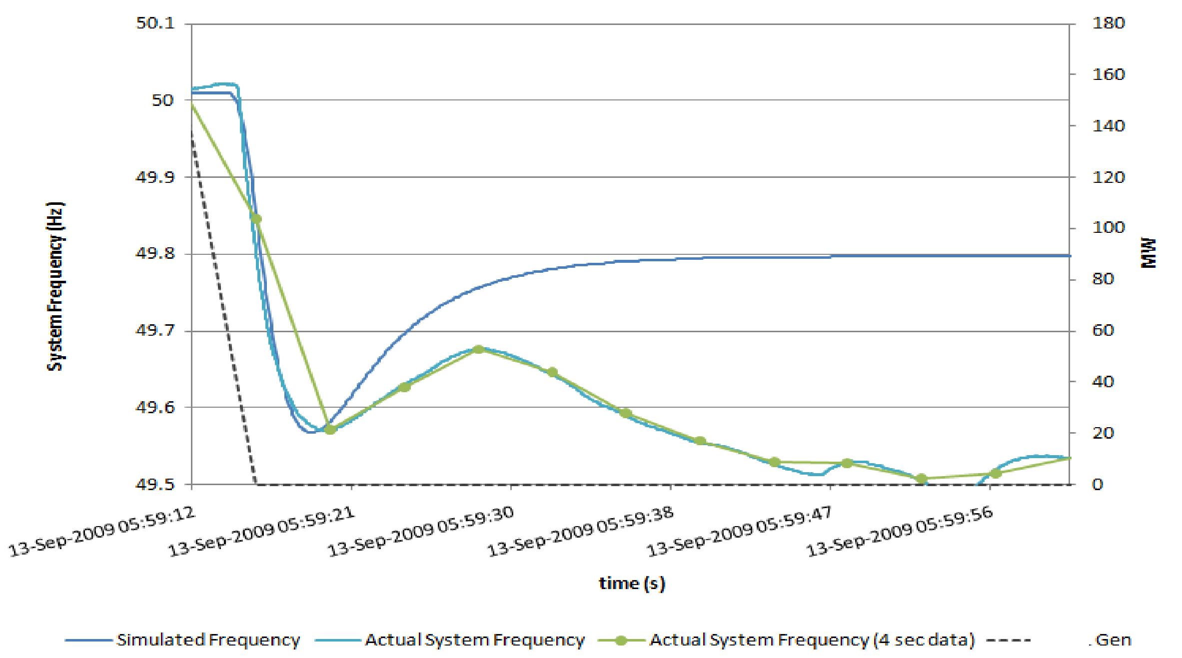
Contingency 1

The contingency event occurred on 13 September 2010 at 5:59:20 AM 2009, and involved tripping of a single unit of a coal-fired generator, which resulted in a loss of 150MW in the overall system supply. The system load at the time was around 1,720MW. From the historic system data provided by Western Power, ROAM approximated the system inertia provided by active generators immediately after the unit went offline to be around 12,529MWs. Furthermore, ROAM also derived the most likely responsive generation mix (grouped by the governor-turbine type) to arrest the frequency decline immediately after 150MW of supply was lost. This is summarised in Table D.5 and was used in ROAM's model to simulate the system frequency response. Figure D.25 is a comparison between the simulated frequency response and the actual system frequency.

Table D.5 – SWIS Generation Dispatch of Responsive Generators

Governor-Turbine Type	Generation (MW)	Capacity (MW)
IEESGO (Slow)	699.1	1295
IEESGO (Fast)	0	0
GAST2A	225.7	351
IEEEG1	0	0

Figure D.25 – Simulated and Actual System Frequency Response for contingency



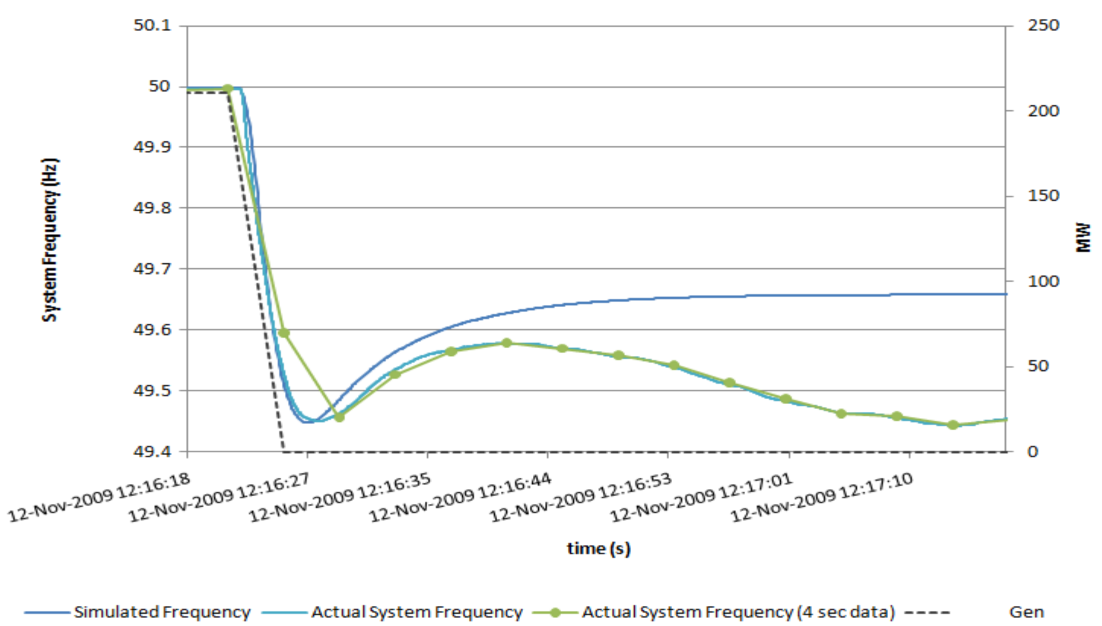
It can be observed from Figure D.25 that the simulated system frequency closely aligns with the actual system frequency within 8 seconds immediately after the contingency. This indicates a similar rate of change in frequency decay between ROAM's system model and the SWIS system, which justified the applied system inertia. Furthermore, the frequency bottoming out at around 49.57Hz also conforms to the observed system frequency. This indicates a similar amount of governor response was present at the time of contingency in ROAM's system model and the SWIS system. The agreement of the two frequency responses, however, starts to disappear beyond 8 seconds. ROAM believes that this is due to a large number of factors which was not captured in ROAM's model. These include generators detuning their governors, generators pulling back or shutting off due to excessive generation and/or over heating (as suggested by the second decline in frequency observed 16 seconds after the contingency) and external factors such as instructions given by the operators. Having said that, these factors are difficult to model and considered to be long-term effects. ROAM believes that for the purpose of assessing system frequency response with varying intermittent generation levels, the focus should be on how the frequency varies with fast varying disturbance introduced by intermittent generation, and the long-term effects outline above can be considered to have a small impact on the modelling outcome.

Contingency 2

This contingency event occurred on 12 November 2010 12:16:32 PM 2009 involved tripping of a unit of a coal-fired generator, which resulted in a lost of 211MW in the overall system supply. The system load at the time was around 2,500MW. From the historic system data provided by Western Power, ROAM approximated the system inertia provided by the active generators (tripped unit excluded) to be around 14,345MWs. Furthermore, ROAM also derived the most likely responsive generation mix (grouped by the governor-turbine type) to arrest the frequency decline immediately after 211MW of supply was lost. This is summarised in Table D.6 and was used in ROAM's model to simulate the system frequency response. Figure D.26 is a comparison between the simulated frequency response and the actual system frequency.

Table D.6 – SWIS Generation Dispatch of Responsive Generators		
Governor-Turbine Type	Generation (MW)	Capacity (MW)
IEESGO (Slow)	1081.1	1231
IEESGO (Fast)	0	0
GAST2A	289.6	475.4
IEEEG1	0	0

Figure D.26 – Simulated and Actual System Frequency Response for contingency



Similar to the simulation outcome for the first contingency discussed in the previous section, it can be observed from Figure D.26 that the simulated system frequency closely aligns with the actual system frequency within 8 seconds immediately after the unit trips. This again indicates similar rate of change in frequency decay between ROAM's system model and the SWIS system, which justified the applied system inertia. Furthermore, the frequency bottoming out at around 49.46Hz also conforms to the observed system frequency. For periods beyond 8 seconds, the agreement in frequency starts to disappear due to similar reasoning discussed earlier for the first contingency event.

D.4) *Final System Frequency Model Layout*

The layout of the frequency model developed for the NEM and SWIS are outline in Figure D.27 and Figure D.28 respectively.

Figure D.27 – System Frequency Model for the NEM

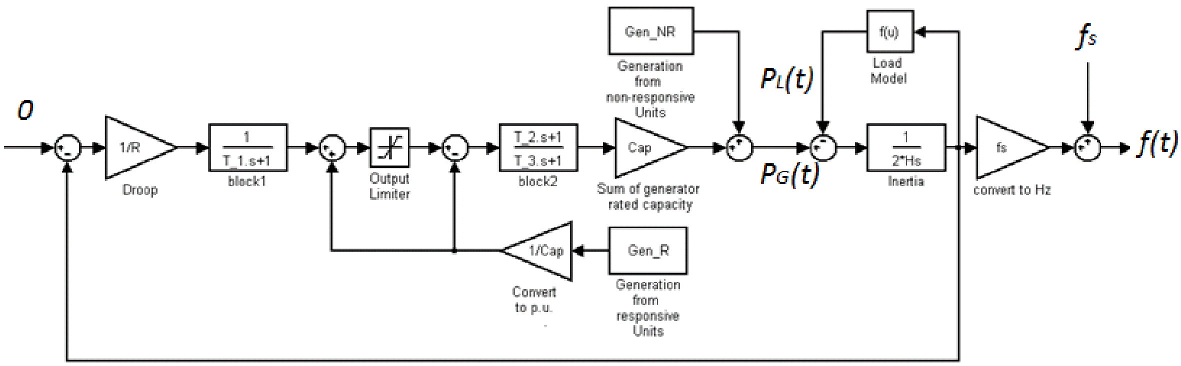
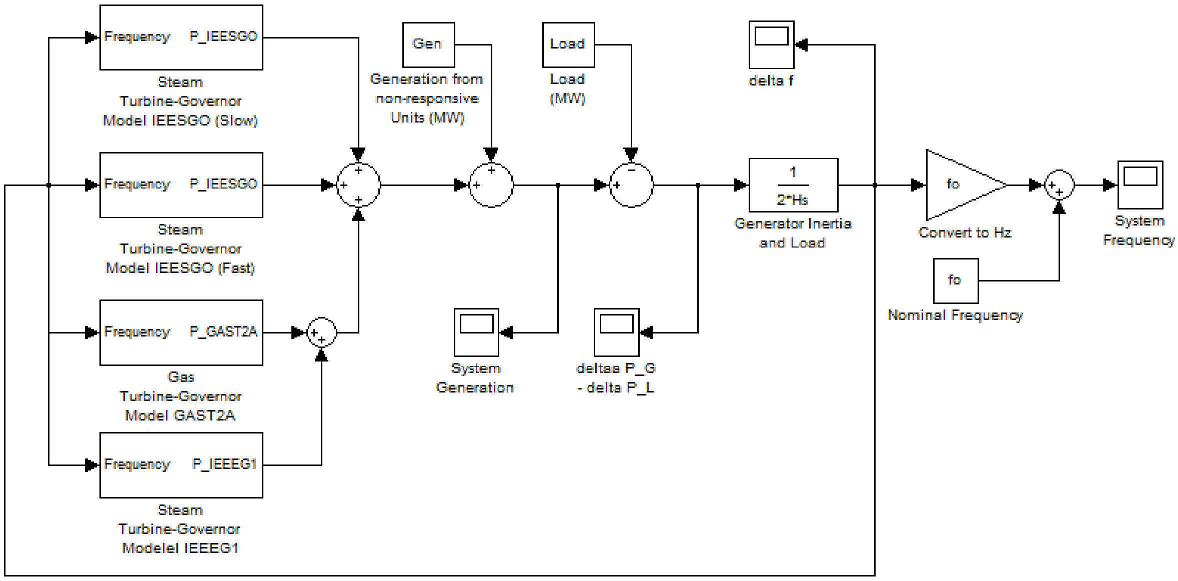


Figure D.28 – System Frequency Model for the SWIS



Appendix E) Modelling with 2-4-C

E.1) *Forecasting with 2-4-C*

2-4-C is ROAM's flagship product, a complete proprietary electricity market forecasting package. It was built to match as closely as possible the operation of the AEMO Market Dispatch Engine (NEMDE) used for real day-to-day dispatch in the NEM. However, it is capable of modelling any electricity network, and is in use to model small systems such as the North-West Interconnected System (NWIS) of Western Australia, and the enormous 4000 bus CalISO system of California.

2-4-C implements the highest level of detail, and bases dispatch decisions on generator bidding patterns and availabilities in the same way that the real NEM operates. The model includes modelling of forced full and partial and planned outages for each generator, including renewable energy generators and inter-regional transmission capabilities and constraints.

ROAM continually monitors real generator bid profiles and operational behaviours, and with this information constructs realistic 'market' bids for all generators of the NEM. Then any known factors that may influence existing or new generation are taken into account. These might include for example water availability, changes in regulatory measures, or fuel availability. The process of doing this is central to delivering high quality, realistic operational profiles that translate into sound wholesale price forecasts.

2-4-C has been used on behalf of AEMO (previously NEMMCO) since 2004 to estimate the level of reliability in the NEM and consequently set the official Minimum Reserve Levels for all regions of the NEM.

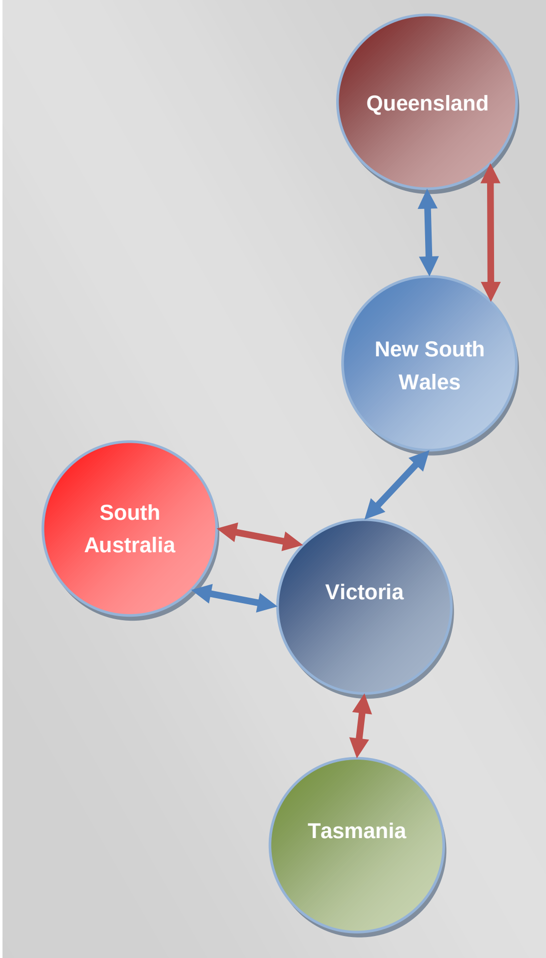
E.2) *THE 2-4-C MODEL*

The multi-node model used by ***2-4-C*** is shown in Figure E.1. This nodal arrangement features a single node per region of the NEM, the same as the regional configuration used by NEMDE.

This network representation means that there is no direct visibility of intra-regional network capabilities. In order to model these important aspects of the physical system, AEMO employs the use of constraint equations that transpose intra-regional network issues to the visible parts of the network; that is, the inter-connectors joining the regions of the NEM. These constraint equations consist of several hundred mathematical expressions which define the interconnector limits in terms of generation, demand and flow relationships. ***2-4-C*** implements these constraint equations within its LP engine in fully co-optimised form.

Modelling major transmission lines and constraint equations delivers an outcome consistent with the real operation of the NEM under normal system conditions. Additionally, the occurrence of congestion in the network is the primary factor that drives out-of-merit dispatch outcomes and hence price volatility. These important aspects of the NEM would not be seen in a more simplistic model.

Figure E.1- 2-4-C NEM Representation



Blue bi-directional arrows signify the AC interconnectors between the regions of the NEM, while the red arrows signify High-Voltage DC Links.

E.3) *MODELLING THE TRANSMISSION SYSTEM*

ROAM's ***2-4-C*** dispatch model implements the full set of AEMO NTS constraints as supplied by AEMO with the annual Statement of Opportunities. These constraint equations define 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

E.4) *Key Parameters used by the Model*

Data contained within the ***2-4-C*** model is a combination of the best information sources within information available in the public domain including:

- All released AEMO Statements of Opportunity through to the present, together with half-hourly historical load profiles by region;
- Annual Planning Statements by Network Service Providers:
    - All published Powerlink statements, together with half hourly historical load profiles by zone;
    - All published TransGrid statements;
    - All published Vencorp statements;
    - All published ESIPC statements, and;
    - All published Transend statements.
- Corporate Annual Reports for many market participants (generators, retailers and network service providers), and;
- General reports from market participants.

Appendix F) FCAS MODELLING WITH 2-4-C

Modelling the contingency FCAS markets requires calculating the amount of FCAS required to be enabled to cover a 'credible single contingency' (typically loss of the largest generation unit or load). This calculation is of the form:

Contingency requirement = largest single load/generation unit at risk – load relief

Regulation FCAS is not related to any specific contingency and is calculated differently.

F.1) *LOAD RELIEF*

Load relief represents the response of an AC system to a change in system frequency. Many devices are sensitive to power system frequency and their power consumption is proportional to it. For example, the rotational speed of a synchronous motor is linked to system frequency; a synchronous motor will slow down when system frequency falls and thus consume less power. The opposite is also true, when the system frequency rises synchronous motors will speed up and consume more power.

This effect will always oppose any change in system conditions, reducing FCAS requirements. Load relief is represented as a percentage change in load per percentage change in frequency ratio. It has been determined to be approximately 1.5% for mainland regions, and 1.0% for Tasmania[59].

The reduction in FCAS requirements due to load relief is defined as the allowable change in frequency due to the disturbance * the load relief factor * the present load.

For example, the mainland frequency standard states that the allowable frequency band for six seconds after the loss of the largest generator is 49.5-50.5Hz. The load relief for a frequency drop then becomes, 1%[60] * 1.5% * the current mainland load.

Load relief varies with respect to both the timeframe of the FCAS service considered and the type of contingency event, but will always reduce the FCAS service requirement.

F.2) *FCAS BID OFFERS*

FCAS bid offers are similar to energy bid offers in that they consist of 10 price/quantity pairs and a maximum quantity available that define a generator's willingness to provide a service. FCAS bid offers also include an 'FCAS trapezoid' that defines the generator's capabilities to provide FCAS based on their energy dispatch.

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[59] As determined by NEMMCO, 'Operating procedure: Frequency control ancillary services'

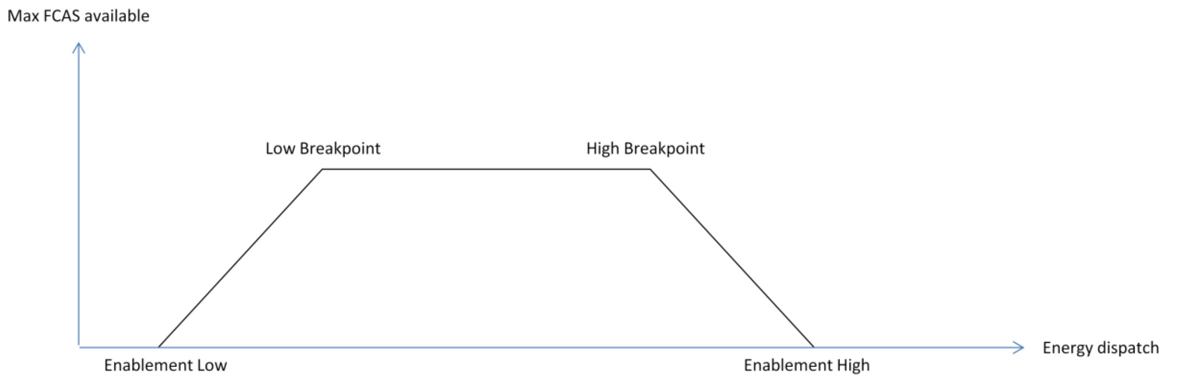
[60] 1% is the percentage change in frequency, (0.5/50).

An FCAS trapezoid features five points that define the relationship between energy dispatch and available FCAS:

1. Enablement low, which defines the lowest energy dispatch at which an FCAS service may be provided;
2. Low breakpoint, which defines the lowest energy dispatch at which the maximum quantity of FCAS bid may be provided;
3. High breakpoint, which defines the highest energy dispatch at which the maximum quantity of FCAS bid may be provided; and
4. Enablement high, which defines the maximum energy dispatch at which an FCAS service may be provided.
5. Maximum available, which defines the maximum FCAS dispatch between the low and high breakpoints.

The FCAS trapezoid is pictured in graphical form in the figure below.

Figure F.1 – FCAS Trapezoid



FCAS trapezoids link FCAS and energy offers through the design and implementation of the NEMDE linear program formulation. The formulation shares common elements in the parallel energy and FCAS markets (such as generation units) and is referred to as co-optimisation.

F.3) *Modelling FCAS Trapezoids*

FCAS trapezoids are nonlinear, and cannot be directly implemented in a linear programming optimisation. 2-4-C determines whether a generator is enabled to provide FCAS based on the outcome of the previous dispatch period.

A linear model approximating the FCAS trapezoids has been developed that is equivalent within the range of enablement low to enablement high. Outside these limits, the model is not valid and leads to distorted outcomes, thus a methodology to address this is required. ROAM's solution is that if a unit was within its enablement limits in the previous period and has a nonzero maximum FCAS availability, its energy target is restricted to be within the enablement limits in the current dispatch interval, the FCAS trapezoid model is applied for that unit and the unit may provide

FCAS. If a unit does not meet these conditions, its output is not restricted to the enablement range and it is not eligible to provide the FCAS service in question.

This can lead to suboptimal outcomes as units enabled for FCAS can only be dispatched within their trapezoid in the energy market regardless of the FCAS market outcomes (NEMMCO refers to this outcome as being 'trapped' by the FCAS bid). ROAM understands however, that NEMDE has similar limitations and this difficulty is not avoidable in a linear program.

As units enabled for FCAS service provision can be 'trapped' between their enablement limits in the energy market, a mechanism is needed to allow units to 'escape', otherwise units will always be constrained on to at least their enablement low. ROAM allows units to escape their trapezoid by only enabling a unit for an FCAS market if the previous energy target was *above* the enablement low (if the enablement low is nonzero). NEMMCO requires participants to rebid to escape trapezoids. ROAM believes the approach chosen is consistent with NEMDE, and observes that NEMDE is documented to share many of the same limitations.

F.4) *BASSLINK*

Each interconnector in the NEM has a nominated flow direction convention. The convention is generally for positive flow values to be towards the north and west. Basslink operates typically between approximately 600MW towards the mainland and 480MW towards Tasmania. Its operating range as defined by NEMMCO is -478MW to 594MW.

Basslink has several unique properties that make it pivotal in both the mainland and Tasmania NEM FCAS markets. Although a DC link and therefore asynchronous, Basslink has the capability to rapidly vary its power transfer in response to changes in frequency. This allows limited transfer of FCAS between the mainland and Tasmania, restricted by the 'headroom' remaining on Basslink.

F.5) *HEADROOM*

AC interconnector transfer capacity in NEMDE is primarily limited by 'N-1' contingency requirements (the requirement for no network element to exceed a firm limit after any single credible contingency), and thus they are rarely operated to their physical limits. In practice this means that they may be treated as able to transfer FCAS without limitation.

Basslink, due to being both a controllable network element and the unique arrangements for loss of link (FCSPS, NCSPS) is able to be dispatched at close to the firm capacity of the link in the energy market. This leads to a limit on the amount of FCAS that may be transferred across Basslink. The minimum power transfer characteristic of Basslink also limits FCAS transfer with the mainland NEM regions.

Headroom is the difference between Basslink's energy dispatch target and the minimum/maximum flows possible. For example, with a dispatch target of 200MW, the headroom available for Tasmania to import raise FCAS is 150MW (current flow – lowest possible flow [50MW in exporting zone]).

The need to maintain headroom to permit FCAS transfer can 'trap' Basslink in periods of FCAS scarcity into a specific flow direction, which may result in counter-price flows in the energy market.

F.6) *FCSPS*

Due to the magnitude of Basslink transfers in relation to the size of the Tasmanian AC system, a dedicated protection scheme was required to avoid requiring operation of the Tasmanian load shedding schemes on loss of link. The frequency control system protection scheme (FCSPS) involves contracted loads and generation armed for immediate tripping in response to a loss of Basslink. FCSPS is designed to limit the contingency FCAS requirement to avoid placing unrealistic demands on the Tasmanian system following the tripping of Basslink.

When inadequate load or generation is armed for FCSPS action to maintain full dispatch, Basslink energy transfer is restricted to limit the 'effective' contingency.

F.7) *DEADZONE*

Due to technical characteristics of materials used in its design, Basslink has a minimum sustainable transfer level of approximately 50MW. NEMMCO models this by dividing Basslink flow into three operating 'zones' (as observed 'in Tasmania') as follows:

1. The importing zone is Basslink flow < -50, in this zone the link may be dispatched to any point <= -50.
2. The exporting zone is Basslink flow > 50, in this zone the link may be dispatched to any point >= 50.
3. The 'deadzone' is -50 <= Basslink flow <= 50, in this zone Basslink may be dispatched at any point >= -125 and <= 125. FCAS transfer capability is not available in the dead zone.

During transitions between zones, Basslink becomes unavailable for FCAS transfer. This is consistent with the Basslink model used in NEMDE, as summarised in the table below.

Table F.1 – Basslink Operating Zones

Initial Flow	Valid Targets	FCAS transfer available?
Basslink < -50MW	<= -50MW	Yes
Basslink > 50MW	>= 50MW	Yes
-50MW <= Basslink <= 50MW	-125MW <= Basslink <= 125MW	No

F.8) *REGULATION FCAS*

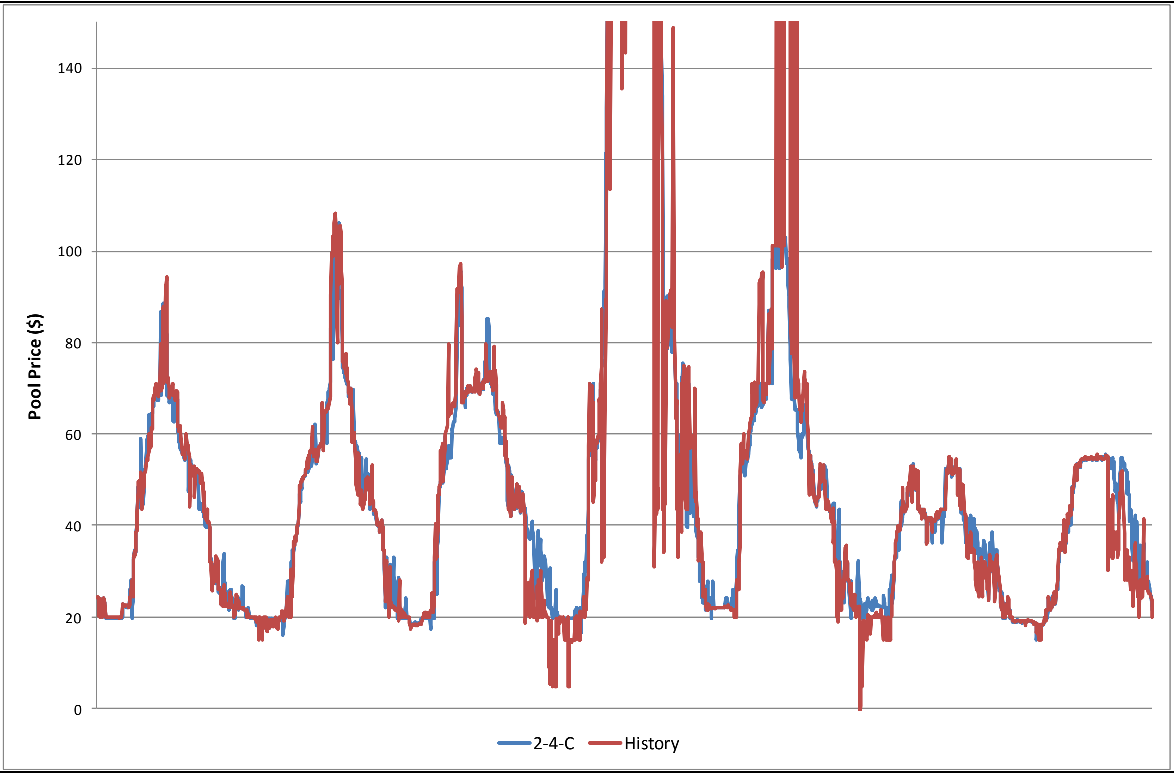
Regulation FCAS is enabled to control variations in frequency resulting from small supply-demand imbalances such as demand forecast errors. As this is not in response to any particular contingency, there is no analytical approach available to calculate the required amount of regulation FCAS and NEMMCO's approach historically has been based on empirical observation.

F.9) *BACK-CASTING*

Back-casting with FCAS modelling in 2-4-C is generally very consistent with historical energy price outcomes. The following figure illustrates the performance of the 2-4-C back-cast simulation versus historically observed energy market prices in Queensland (for example). Notable differences are primarily observed during periods that historically featured significant network outages.

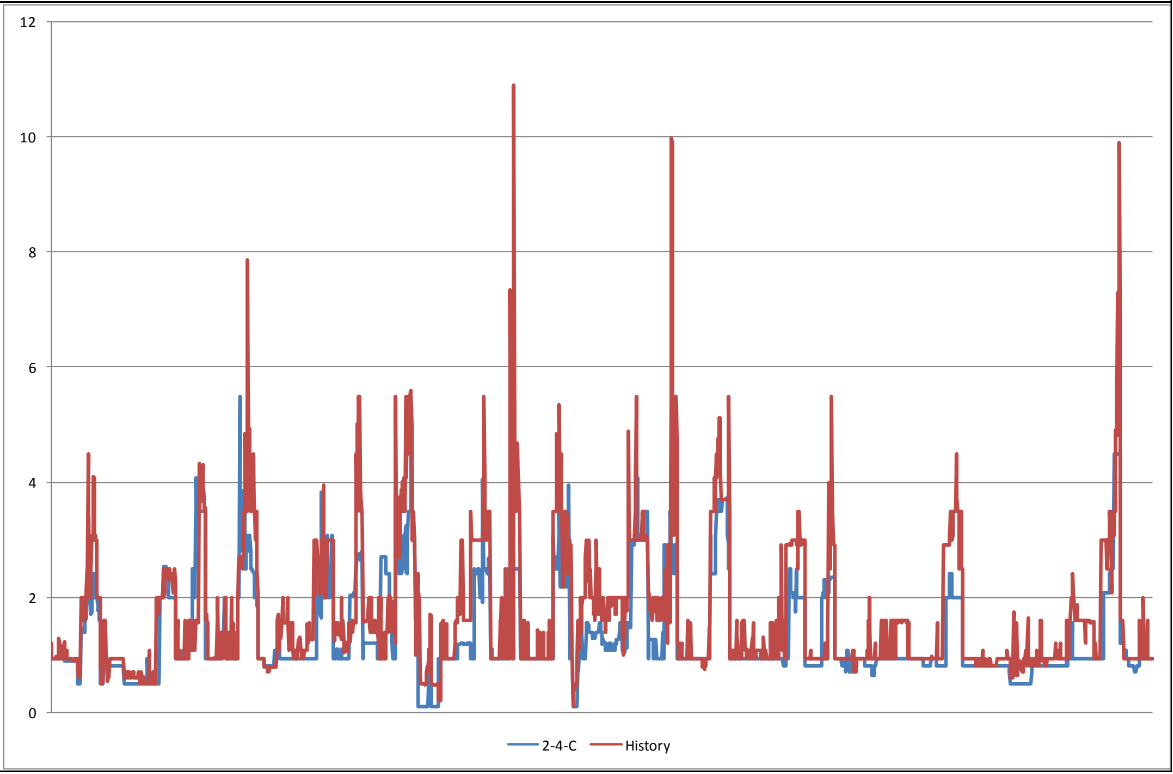
Despite multiple non system normal conditions, the back-cast pool price outcome for Queensland compares extremely well with history, deviating slightly due to partial QNI and Terranora outages not replicated in 2-4-C.

Figure F.2 – Queensland Energy Price



Back-casting is also able to consistently replicate historical mainland ancillary services price outcomes. For example, mainland regulation price outcomes are illustrated in the figure below. These differ slightly in some period from history due to historical non-conformance and network outage conditions. ROAM considers this unavoidable and the back-cast output is otherwise clearly consistent with history.

Figure F.3 – Mainland RReg FCAS Price



Appendix G) MODELLING ASSUMPTIONS

G.1) *DEMAND SIDE ASSUMPTIONS*

G.1.1) Demand and energy forecasts

To account for sensitivities to the load, ROAM considers a variety of load forecasts, as supplied annually by AEMO. These include:

- M10 case - Medium load growth, 10% P.O.E.
- M50 case - Medium load growth, 50% P.O.E.
- L10 case – Low load growth, 10% P.O.E.
- L50 case – Low load growth, 50% P.O.E.

where P.O.E. is the probability of exceedence.

The 10% P.O.E. case represents an extreme weather year resulting in demand levels exceeded only 1 year in 10. The 50% P.O.E. case represents a reasonably mild weather year (exceeded 1 year in 2).

These 10% and 50% P.O.E. cases represent upper and lower bounds. To show the 'likely' case, ROAM calculates a 'weighted' value for all properties. This weighted value is calculated as 30% of the 10% P.O.E. value and 70% of the 50% P.O.E. value.

The regional load trace forecasts (that is, the half-hourly load data) have been developed using the actual recorded 2009-10 financial year load traces for each region as the reference year.

G.1.2) Inclusion of customers

At each region, a bulk load consumption facility has been included to represent the cumulative, time-sequential, load consumption profile anticipated at each of the five regions used in the study.

G.1.3) Regional load profiles

Load data for each bulk consumption facility has been derived directly from historical load profiles for each region, and grown to meet the energy and demand forecasts published in the most recent energy and demand projections from AEMO.

G.1.4) Demand-side participation

The vast majority of demand in the wholesale market currently operates as a series of aggregated loads for the purposes of schedule and dispatch. Though some individual customers may be responsive to price, the majority of end-consumers are shielded from short-term price fluctuations through retail contracts. Thus, incentives to reduce demand during high-price periods are dissipated.

In this study, as detailed in AEMO's 2010 Statement of Opportunities, DSP is captured as part of the actual measured demand and therefore inherently part of the demand forecast.

G.1.5) New base loads

No new base loads are included in this study, aside from those included in the AEMO demand projections.

G.1.6) Hydroelectric pump storage loads

The ***2-4-C*** version used for this study includes a hydroelectric model, including pump storage loads. The pumping loads for the following hydroelectric facilities have been included in the load profile:

- Wivenhoe power station;
- Shoalhaven power station
- Snowy Mountains Scheme: Tumut 3 power station.

G.2) *SUPPLY SIDE ASSUMPTIONS (GENERATION ASSETS)*

G.2.1) Existing projects

These market forecasts take into account all existing market scheduled generation facilities. In addition, the likely commissioning schedule (beginning typically three months prior to commercial operation) for new generators has been taken into account.

G.2.2) Individual unit capacities and heat rates

Details of unit capacities and heat rates (for thermal plants) have been collated and included on the basis of information available in the public domain.

G.2.3) Unit emissions intensity factors

Emissions Intensity Factors have been collated from public sources and along with heat rates are the basis for determining the uplift in Short Run Marginal Cost (and hence market bids) for each generator under Carbon Pricing Schemes.

G.2.4) Unit operational constraints

Information on unit minimum load and ramp rate constraints is included in the ***2-4-C*** database. This database has been developed based on pre-market information, moderated with information being currently supplied to the market. Such information is taken into consideration in the simulation of market operation (to ensure that an infeasible solution is not simulated).

G.2.5) Forecast station outage parameters

2-4-C utilises independent schedules for each unit of:

- Planned maintenance, and
- Randomised forced outage (both full and partial outage) distribution.

These schedules have been constructed based on information in the public domain and historical generator availabilities - in particular, the following six key parameters are used in the development of outage schedules and are detailed in the table below.

Table G.1 – Generator outage modelling assumptions	
Full Forced Outage Rate:	Proportion of time per year the unit will experience full forced outages.
Partial Forced Outage Rate:	Proportion of time per year the unit will experience partial forced outages.
Number of Full Outages:	The frequency of full outages per year.
Number of Partial Outages:	The frequency of partial outages per year.
Derated Value:	Proportion of the unit's maximum capacity that the unit will be derated by in the event of a partial outage.
Full Maintenance Schedule:	Maintenance schedule of planned outages (each planned outage has a start and end date between which the unit will be unavailable).

G.3) *GENERATOR BIDDING STRATEGIES*

Generator bids are based on analysing past bid profiles for all generators across the NEM and taking into account any known factors that may influence existing or new generation, for instance in response to water availability. In the case of base load generators, these are generally bid at negative price levels up to their minimum operating levels and then at marginal costs for the remainder of the capacity. These base load generators are referred to as 'price-takers' in the market. In the case of intermediate plants, these are bid as price-takers for the peak periods of the day and may be started at other periods in response to a high price signal. Peaking generators are generally bid at or above their marginal costs and start when prices reach these values due to low generator reserve margins caused by high demand intervals or periods of generator failures. Since prices may be set at different times by base, intermediate and peaking plant, depending on load levels and simulated failures of generating units, the simulation faithfully replicates the price variability in the real market.

G.3.1) Generation commercial data

In the development of the chosen trading strategy for each generator across the NEM, key commercial data is used, including:

- The intra-regional Marginal Loss Factor (MLF);
- Operations and maintenance cost;
- Fuel cost, which has been computed with reference to:
    - Unit heat rate;
    - Fuel heating value, and;
    - Fuel unit price;
- Emission factors for greenhouse gas production.

G.3.2) Applying a carbon price

The carbon cost for each generator (in $/MWh) is given by each generator's emissions factor (tCO_2/MWh), multiplied by the cost of emissions permits. Since the electricity market in Australia is not internationally trade exposed, it is anticipated that generators will largely increase their bids by the amount of their respective carbon costs. Hence, the effects of a carbon price on the NEM was modelled by adding the carbon cost ($/MWh) to the bids of each generator. Once these uplifts were applied to all bid bands of all generators, the competitive dispatch was recalculated for each half hourly interval.

G.3.3) SRMC vs historical bidding

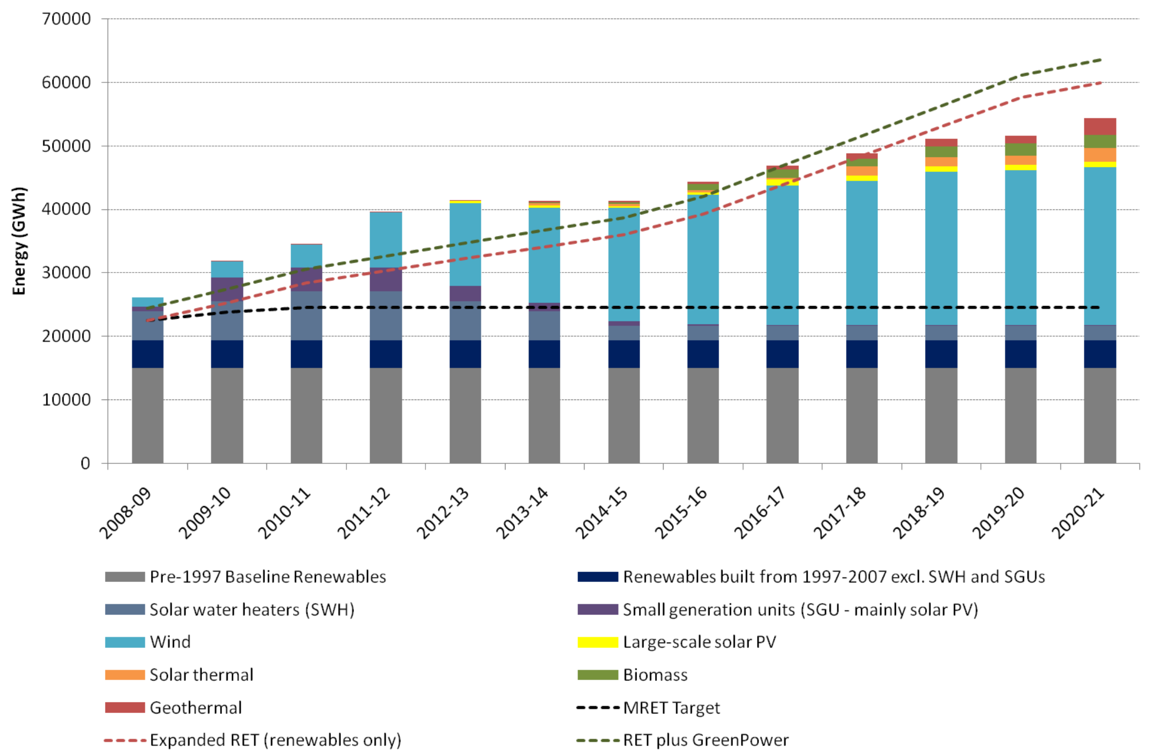
Many generators do not currently bid prices consistent with their short run marginal costs (SRMCs). When carbon prices are applied, it is expected that more polluting plants will be forced to bid closer to their short run marginal costs in order to remain competitive. This means that applying a carbon price uplift to historical (current) bids is not necessarily an accurate representation of the bidding strategy of plants under an emissions trading regime, particularly for high carbon prices.

To account for this, ROAM has used the short run marginal costs (SRMCs) of plants to adjust negative bids (which are clearly not representative of costs). Any bids found to be below the SRMC of a particular plant are lifted to the SRMC (with the impacts of the carbon price applied). This approach takes account of relative changes in the bidding order, by ensuring that gas generation will undercut coal generation (for example) when the carbon price is sufficiently high that the two overlap.

G.4) *MODELLING OF RENEWABLE GENERATION*

Sufficient renewable generation was planted to meet the expanded 20% by 2020 renewable energy target, as shown in the figure below. The structure of the scheme, which allows for 'banking' of renewable energy certificates (RECs), means that the shortfall in annual generation in later years is covered by banked RECs created in earlier years.

Figure G.1 – Renewable energy planting to meet the RET



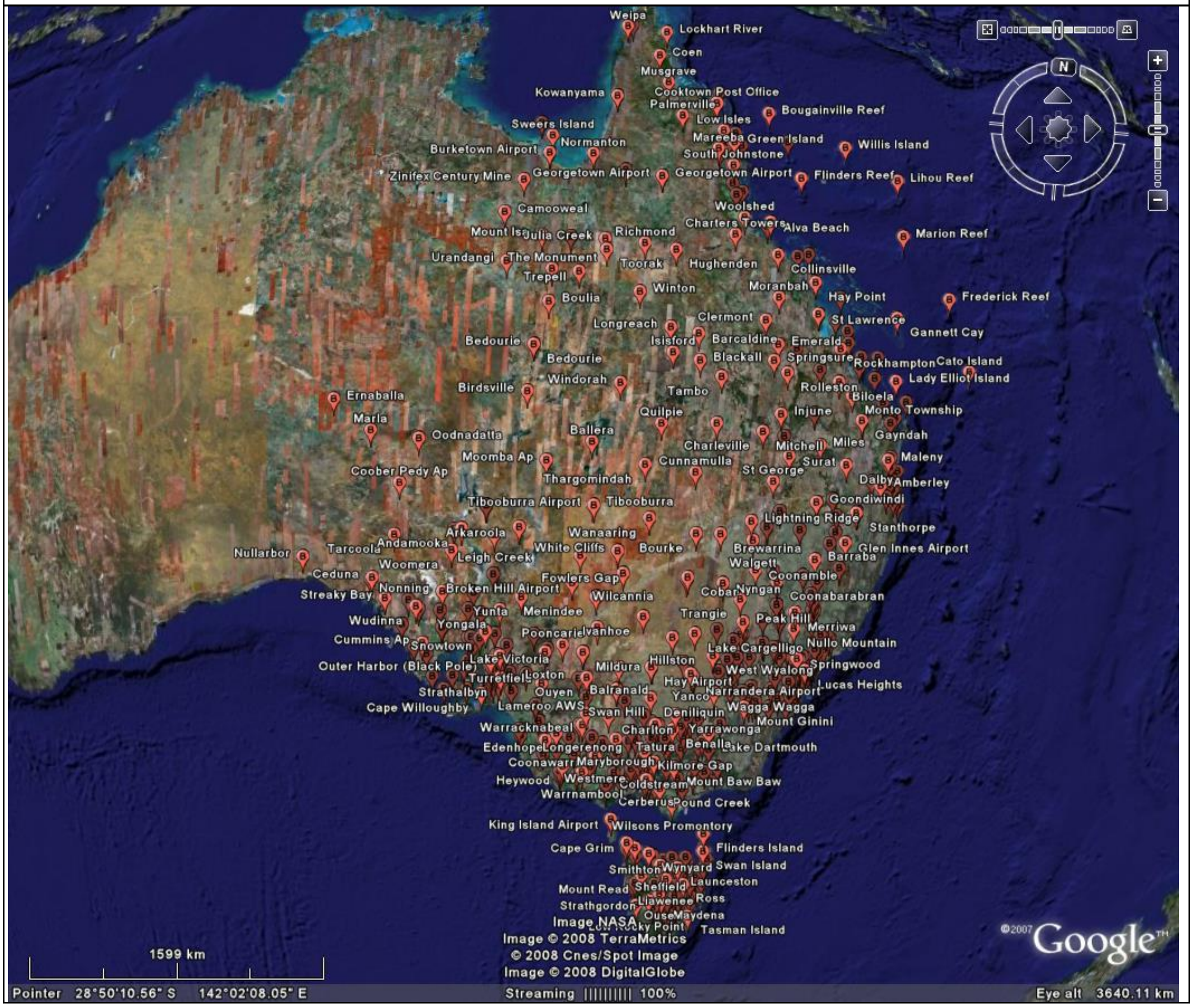
G.4.1) Wind modelling

Individual announced wind farm projects are planted in their announced locations around the grid to make up the target, and are included in transmission congestion calculations on a half hourly basis.

To model the output of wind farms, the average wind speed at the wind farm site is required for each half hourly period, which can then be converted into generator output using turbine power curves.

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 G.2 – 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).

Therefore, the wind speed at a weather station perhaps 30km distant from a wind farm is likely to be correlated strongly in time with the wind at the site of the turbines, but the absolute scaling of the speeds is highly uncertain. 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[61]. The Atlas contains modelling data provided by Windlab Systems giving the 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 historic data from existing wind farms.

A turbine power curve is then applied to convert the wind speeds into actual generation (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.

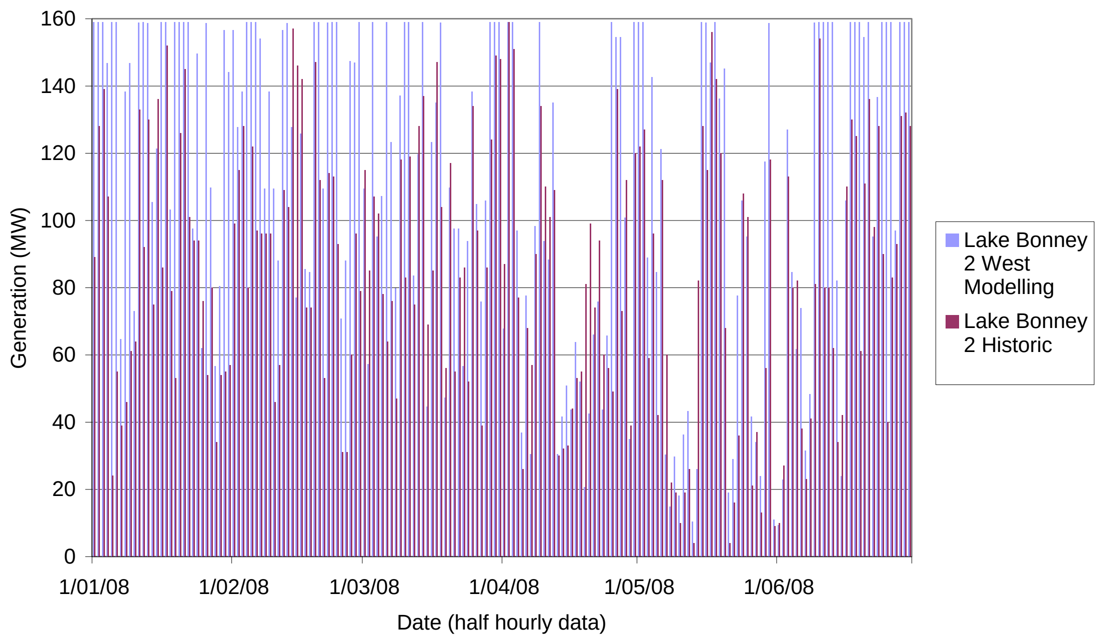
This method captures the daily and seasonal variation of wind at different sites, and also the likely correlation in the operation of nearby wind farms, which is highly material for assessing likely transmission congestion.

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[62] as described above. The results are shown in a graphical form presented in Figure G.3. The nearest weather station to Lake Bonney is the Mount Gambier weather station, of which the wind data from 1 January 2008 to 30 June 2008 was used to develop the generation profile shown in Figure G.3 – Lake Bonney Stage 2 Generation Benchmark. The capacity factor of the historic generation data was found to be 24.5%, compared to 25.6% predicted by ROAM's modelling. The modelled generation provides a very good approximation to the historic generation profile, with a strong correlation of 0.56.

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

[62] WEST is ROAM's Wind Energy Simulation Tool. WEST converts wind profiles (either actual or simulated wind data) to energy production from manufacturers design data for input to 2-4-C and then AC power flow for congestion, stability and MLF forecasting.

Figure G.3 – Lake Bonney Stage 2 Generation Benchmark



Wind farms were bid into the market at $0, with volumes based upon their unit trace outputs in each half hour period.

G.4.2) Solar photovoltaic and solar thermal modelling

ROAM's modelling uses a detailed meteorological model to produce solar availability traces that vary by time of day, by time of year and by location.

The clear sky solar radiation incident on a location in the absence of any atmospheric effects is modelled by a solar model used by the National Oceanic and Atmospheric Administration (NOAA), part of the United States Department of Commerce. This models the position of the sun and incident radiation on Earth's atmosphere for any given date and location, and takes into account the local elevation.

ROAM then uses an atmospheric model developed by Bird and Hulstrom[63] that estimates the incident solar radiation, both direct (line of sight to the sun) and diffuse (sunlight reflected from the ground or from clouds), based on a number of atmospheric parameters (including type of local terrain, ozone thickness, water vapour present in the atmosphere and atmospheric pollutants). This produces a "clear sky" (no cloud) solar insolation trace, at the half hour level, that takes into account local atmospheric effects.

[63] *A Simplified Clear Sky model for Direct and Diffuse Insolation on Horizontal Surfaces*, R.E. Bird and R.L Hulstrom, SERI Technical Report SERI/TR-642-761, Feb 1991. Solar Energy Research Institute, Golden, CO

However, solar plant is significantly affected by cloud cover and this must be taken into account in the final model. Ideally, data at the hourly level (at least) would be obtained for each specific site of interest for a full calendar year. Unfortunately, relatively few sites have to date been monitored in Australia, and those that have been are not located ideally for solar plant.

Instead, ROAM has obtained data from the Bureau of Meteorology (BOM) on the total daily (global) solar radiation received each day at weather monitoring stations around Australia. This data is obtained from cloud cover satellite imagery and uses a sophisticated computer model estimate daily solar exposure. Calibration tests by BOM have shown it to be accurate to within 7% on sunny days and within 20% on cloudy days.

The BOM data is used to calibrate ROAM's model by introducing periods of partial or total cloud cover during each half hourly period of each day until the reported daily total global incident radiation is reached.

From this method, ROAM produces a half hourly global solar radiation trace. An empirical model of diffuse solar radiation is employed to separate out the diffuse and direct beam components, calibrated by sites where detailed half hourly data is available.

Solar PV generation

A detailed geometric model is employed to calculate the portion of the direct and global solar insolation on the PV plate. Only the direct component is used by concentrating solar PV plant, while both the direct and diffuse components are utilised by flat panel solar PV.

The name plate capacity of the cells is assumed to correspond to Standard Testing Conditions (STC) which correspond to 1000W/m2 incident radiation (either beam or global as appropriate) and an operating temperature of 25°C. A derating factor of 78% (in the form of a reduction in output energy) is applied to solar PV to account for the losses in conversion from DC to AC current.

Solar PV cells display a generally linear response to incident radiation. However efficiency decreases at high temperatures. A simplified model[64] is used to estimate the cell temperature based on incident radiation and ambient temperature (obtained from BOM), and a further derating factor of 0.44%/°C is applied.

Solar Thermal generation

Solar thermal parabolic trough power stations are modelled as having a single axis tracking system, while full two axis tracking is assumed for solar tower plants. A minimum incident radiation of 200 W/m2 is assumed to be required for operation (in the absence of storage) and

[64] *Photovoltaic Array Performance Model*, David L. King, William E. Boyson, Jay A. Kratochvil, Sandia National Laboratories 2004

the start up time is assumed to be 60-90 minutes to reach full capacity. Both these quantities can vary from plant to plant, but are representative parameters for near term plant[65].

A simplified model of storage is applied where no "strategic" generation decisions are utilised – the power station generates at its maximum possible generation in every period, and uses its stored energy in the same way.

G.4.3) Bidding of renewable generators

Schedulable renewable generation (geothermal and biomass/bagasse) were bid into the market at prices which reflect their fuel and variable operation and maintenance costs, while intermittent generators were bid at $0/MWh.

Figure G.4 – Renewable generator bidding

Plant type	**Bid price**
Biomass / Bagasse	$29.77/MWh
Geothermal	$2.05/MWh
Solar PV and solar thermal	$0/MWh
Wind	$0/MWh

G.5) *TRANSMISSION AND DISTRIBUTION SYSTEM ASSUMPTIONS*

G.5.1) Transmission losses

Losses are modelled commercially in either of two ways, in accordance with existing market rules. Treatment is as follows:

Inter-regional losses

Inter-regional losses over AC interconnectors are modelled using dynamic loss equations supplied by AEMO.

Intra-regional losses

Intra-regional losses are modelled by static, but periodically adjusted, marginal loss factors (MLF) in relation to a Regional Reference Node (RRN). These MLF's are published annually by AEMO (and assumed for new stations).

Market forecasting has been completed on a gross basis. Therefore, the energy profiles assumed for each node have incorporated allowance for (transmission and distribution) losses and generator auxiliary energy.

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[65] See for example *Potential for Renewable Energy in the San Diego Region, Appendix E*, prepared by National Renewable Energy Laboratory (http://www.renewablesg.org/docs/Web/AppendixE.pdf)

G.5.2) Transmission limits

For each of the links between the nodes defined in the ***2-4-C*** model, bi-directional limits are dynamically calculated based on the most recent publicly available set of transmission limit equations. This data has been added on the basis of information provided within the relevant planning documentation listed as references in the previous section.

G.5.3) Transmission asset development

The NTNDP constraint equations supplied by AEMO assume some limited transmission asset development over time, accounting for minor upgrades. However, they do not include significant transmission development that will be necessary over longer modelling timeframes. To account for this, in longer studies ROAM may 'switch off' a given constraint equation at the point in the study where a significant transmission upgrade is clearly required. From that point onwards, notional transmission limits are applied to the various inter-regional transmission network flow paths.

G.5.4) Terranora (Gold Coast to Armidale interconnector)

Terranora is modelled as a regulated market scheduled interconnector. As the HVdc link is controllable it will be dispatched to maximise inter-regional competition if this is the optimal dispatch outcome.

G.5.5) Murraylink (Melbourne to South Australia interconnector)

Murraylink is modelled as a regulated market scheduled interconnector. Murraylink is dispatched in a similar way to Terranora as described above.

G.5.6) Basslink (Latrobe Valley to Tasmania interconnector)

Basslink is modelled as a bi-directional interconnector. The bidding profile allows for transfers of energy from Tasmania to Victoria during peak times and from Victoria to Tasmania during off-peak times.

G.6) *MARKET DEVELOPMENT ASSUMPTIONS*

Several assumptions are made about the development of the market.

G.6.1) Market Price Cap

The Market Price Cap (MPC) was set to $12,500/MWh based on the recommendations of the Australian Energy Market Commission Reliability Panel's *Review of VoLL 2008*[66].

G.7) *ASSUMPTIONS WITH REGARD TO MARKET EXTERNALITIES*

There are numerous externalities that will impact on the operation of the competitive energy market. Several of these are outlined below.

[66] http://www.aemc.gov.au/pdfs/reviews/VoLL%202008%20Review/reliability/000Reliability%20Panel%20Review%20of%20VoLL%202008%20Draft%20Determination.pdf

G.7.1) Inflation

All monetary figures provided in this report are listed in equivalent July 2011 dollars (net of the impact of inflation).

G.7.2) The impact of the Goods and Services Tax

Wholesale market prices are quoted exclusive of the Goods and Services Tax (GST). Hence, projections of the wholesale spot price are provided net of GST.

Appendix H) THE LTIRP MODEL

ROAM's LTIRP software has been designed specifically to meet the challenges of generation and transmission development co-optimisation problems. It uses Mixed Integer Programming (or linear programming) techniques to determine the least cost economic expansion plan by minimising the cost of serving the energy demanded for each year. Other key features include:

- The model uses a subset of the half hourly period, with weightings assigned to each period such that an accurate representation of the load duration curve is modelled.
- Includes the capability to limit:
  - Fuel availability (particularly important for energy limited generators such as hydro plant)
  - Build rates of generation technologies
  - Availability dates for generation technologies
  - LRET and carbon emissions targets
  - Banking and borrowing of RECs
- Other features include:
  - Full accounting of existing generation plant
  - Carbon pricing
  - Fuel supply and demand price curves
  - Economic, age and capacity factor based retirements

Network augmentation

The model co-optimises generation and network augmentation. For this study, the generation plan was provided as a fixed input to the model. The LTIRP could then select to install further OCGT plant, or transmission augmentation, to find the least cost solution.

An assessment was be made as to likely losses on new interconnectors (calculated as a percentage of line flow in each time block).

H.1) *IMPORTANT ASPECTS OF THE LTIRP*

ROAM's LTIRP model is the most sophisticated of its kind available. However, like all models it has limitations. A full understanding of these limitations is essentially for accurate interpretation of model results.

The most important aspects of the LTIRP model for clear understanding of results are:

Load Blocks

The LTIRP model is not time-sequential. The model utilises "load blocks", which are determined based upon the load duration curve. Each load block is simulated only once, and the results from each load block are weighted according to the load duration curve to produce realistic annual outcomes. This approach significantly reduces the amount of simulation time required, allowing a much larger number of variable parameters to be co-optimised. However, it is not time sequential in nature, and this means that certain features of the market are captured through averages only. For example, generator forced outages are captured as a reduction in availability spread across all load blocks (generator scheduled outages are included via annual maximum capacity factors for each station such that maintenance can be scheduled during the most appropriate load blocks).

If desired, ROAM also utilises an alternative Integrated Resource Planning (IRP) model that is time sequential. However, this model has much longer simulation times. For this reason most consultants offer non time sequential models (this includes MARKAL and Plexos).

Intermittent generation

Due to the non time sequential nature of the LTIRP model (and all similar models) the modelling of intermittent generation is a key challenge. Many previous modelling studies (utilising models such as MARKAL and Plexos) have assumed a constant average output from intermittent generators in all load blocks. This dramatically over estimates the contribution of intermittent generation to reliability. ROAM's approach, by contrast, is as follows:

1. Determine load blocks from the load duration curve.
2. Determine the generation duration curve for wind farms in each NTNDP zone.
3. Use the previously defined load blocks to split up the intermittent generation duration curve into equivalently weighted blocks. These are forced to be in a different order to the load blocks to ensure diversity (and ensure that the model doesn't always have high wind at times of high demand, and low wind at times of low demand).
4. The wind is considered to contribute these varying amounts in each load block. This means that wind contributes a large quantity of energy in some load blocks, and very little in other blocks, and the weighting of periods is determined from actual wind farm output data. This forces the model to include sufficient other firm capacity when it is economical to do so (to avoid the cost of unserved energy in periods where there is no contribution from wind).

This methodology appears to effectively capture the intermittency of wind and its impacts upon market and network operation. It is a large improvement over previous modelling approaches that utilise a constant output from intermittent generators.

Network granularity

This modelling will only capture network augmentations between the 16 NTNDP zones, but will not capture network augmentation within these zones. If a smaller degree of granularity is required further zones can be modelled, with a corresponding increase in model complexity (increasing set-up and simulation times).

Integer solutions

For this study ROAM used a Mixed Integer Programming (MIP) approach. This allows only integer solutions (interconnectors cannot be installed incrementally), for realistic modelling of the 'blocky' nature of network investments.

For simulations with a larger number of degrees of freedom (higher complexity), the MIP may not solve to completion, and a linear programming approach is used instead. This will allow incremental upgrade of the network (installation of small pieces). Often the network is augmented in response to a new generator or other market development, in which case interconnector augmentations will enter in realistic capacities. However, in some cases small increments can be installed in each year, which is not realistic. This can be addressed through the application of additional constraints in a follow-up iteration.