Report on the investigation into the impact of wind generation on the National Electricity Market

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Executive Summary

In this submission, we have reported on a detailed investigation of the impact of wind generation in the NEM on the wholesale price of electricity, production trends by state and fuel type, carbon emission outcomes, system-wide total variable costs and transmission network adequacy.

To capture these linkages, we used the agent based ANEM model of the Australian National Electricity Market, incorporating a DC OPF algorithm to determine optimal dispatch of generation plant, power flows on transmission branches and wholesale prices. The wind generation component included in the modelling involved thirteen non-scheduled and thirteen semi-scheduled wind farms with a combined capacity of 2471.8 MW which represents 96.8 per cent of total installed capacity of operational wind farms in the NEM at the end of 2012.

Two broad modelling scenarios were considered. A baseline ‘no-wind’ scenario involved assuming no contributions from wind generation with demand having to be met from thermal and hydro generation. The second scenario incorporated actual half-hourly output traces from operational wind farms and was termed the ‘wind inclusive’ scenario. In this scenario, both semi-scheduled and non-scheduled wind farms were collectively modelled as generators whose supply offers were in the range $3.39/MWh to $4.69/MWh - amongst the cheapest forms of generation incorporated in the modelling. There are a number of broad conclusions:

Wholesale Price Impacts:

All states experience a reduction in average annual wholesale electricity prices associated with the inclusion of operational wind farms with those states with the largest number of operational wind farms experiencing the greatest reductions in average annual prices. The stand-out states are South Australia and Victoria which experience reductions of between 24.9 and 38.9 per cent and 14.5 to 21.6 per cent over the interval 2010-2012, respectively. Reductions in average annual prices also increase over time reflecting the expansion in semi-scheduled wind generation in South Australia, Victoria and New South Wales over the time interval 2010-2012. For the NEM, there was a reduction in average wholesale prices that became particularly evident over the interval 2010-2012, encompassing percentage reductions in the range of 12.3 to 15.5 per cent. For the whole interval 2007-2012, the percentage reduction in average annual prices in the NEM relative to the ‘no wind’ scenario was in the order of 10.2 per cent.

Merit Order Effect - Production Trends:

South Australia and Tasmania experienced the greatest reductions in production from thermal and hydro generation associated with wind generation, with percentage reductions of 3.5 to 9.6 and 4.9 to 11.2 per cent, respectively. In contrast, Queensland and Victoria experience the lowest rates of reduction in thermal and hydro production of between 0.2 and 0.8 per cent, while New South Wales lied between, with percentage reductions in the range of 0.7 to 2.6 per cent. The magnitude of the size of the reductions increased unambiguously over the time interval 2007-2012 in response to the actual expansion in production from wind generation in the NEM.

South Australia experienced relatively high reductions in production from coal-fired generation in the range of 3.7 to 14.6 per cent, whilst, in contrast, Victoria experienced very small reductions in production from coal-fired generation, in a range not exceeding 0.2 per cent. New South Wales, once again, fell in between these two extremes, with a reduction becoming particularly evident over 2010-2012, in the range of 2.3 to 3.9 per cent. For the

NEM as a whole, the percentage reduction in coal-fired production was in the order of 0.4 to 2.1 per cent.

Wind generation also led to significant displacement of gas-fired production from particularly Victoria associated primarily with the displacement of OCGT plant. South Australia also experienced noticeable reductions in output from gas-fired plant, encompassing reductions in production from both NGCC and Gas Thermal plant as well as the sizeable displacement of production from OCGT plant, albeit at slightly lower rates than for Victoria in the case of OCGT plant. Percentage reductions in total gas-fired production of 5.1 to 11.7 per cent and 3.3 to 7.0 per cent were observed for Victoria and South Australia, respectively. Furthermore, percentage reductions in OCGT production of 15.0 to 54.12 per cent and 13.6 to 38.8 per cent were also observed for Victoria and South Australia.

Both Queensland and New South Wales experienced no real impact on production from gas generation. In the case of Tasmania, this state experienced relatively large reductions over 2007-2008 followed by much smaller rates of decline over the remainder of the period under investigation. This pattern was linked to commissioning of the Tamar Valley NGCC plant which had a different operational configuration to the OCGT gas plant operational over 2007-2008.

Tasmania also experienced a relatively stable profile of reductions in production from hydro generation in the range of 0.4 to 5.5 per cent, with the rate of reduction unambiguously increasing in magnitude over 2008-2012. Reductions in hydro generation production in New South Wales and Victoria were more marked and variable in nature, but coming off much lower production levels and also reflecting reasonably close proximity between wind and hydro generation assets in both New South Wales and Victoria. Wind generation had no discernible impact on hydro production in QLD.

The evidence of displacement of production from OCGT plant in Victoria and South Australia and production from hydro generation in Tasmania, and more episodically in Victoria and New South Wales is consistent with what would be expected under high wind penetration regimes to ensure balancing within the network. Specifically, the fast-start/stop and fast ramping capability of OCGT and hydro generation provides the required characteristics needed to help balance the system in the face of significant variations in wind farm output associated with the intermittency of wind power.

Carbon Emissions:

The impact of wind generation in the NEM was to reduce carbon emissions in all states. The stand-out state was South Australia with percentage reductions in carbon emissions in the range of 3.6 to 11.0 per cent. In contrast, the impact on carbon emissions in Victoria was quite marginal, reflecting the very small impact that wind generation had on displacing production from brown coal-fired generation in that state. For this particular state, percentage reductions in carbon emissions were in the range of 0.1 to 0.4 per cent over the interval 2007-2012. New South Wales experienced greater cuts in carbon emissions than Queensland reflecting the partial displacement of production from New South Wales black coal-fired generation. In contrast, the minimal reductions in Queensland primarily reflected the absence of wind generation in that state. The percentage reduction in carbon emissions for New South Wales was in the range of 0.4 to 3.9 per cent while the equivalent range for Queensland was 0.2 to 0.8 per cent.

In the case of Tasmania, larger reductions arose over the 2007-2008 period reflecting displacement of output from OCGT plant by wind power. Much smaller reductions over the period 2009-2012 were associated with the commissioning of Tamar Valley NGCC plant in 2009 and its subsequent dispatch at levels close to its minimum stable operating level, producing relatively stable production and carbon emission time profiles. In the latter period, percentage reductions were in the range of 0.3 to 0.8 per cent, whilst, over the 2007-2008 interval, equivalent reductions were in the range of 15.5 to 17.9 per cent.

For the NEM, percentage reductions in carbon emissions were in the range of 0.4 to 2.1 per cent. More generally, apart from Tasmania, reductions in carbon emissions for other states increased in magnitude over years 2007-2012.

Savings in System-wide Total Variable Costs:

Apart from 2009, reductions in system-wide total variable costs occurred and generally increased in magnitude over the time period 2010-2012 accompanying the expansion in semi-scheduled wind generation in South Australia, New South Wales and Victoria. For this latter period, the annual reductions in system-wide variable costs were between 187.5 and 270.9 million dollars. When considered over the complete period 2007-2012, reduction in system-wide total variable costs was $874.8 million, representing a decline of 2.21 per cent from the equivalent result obtained from the 'no wind' scenario.

Incidence of Negative Prices:

An outcome associated with increased penetration of wind generation has been an emerging perception of the increased incidence of negative price outcomes typically associated with a situation whereby significant wind generation output coincides within periods of low demand such as off-peak periods at night. Under these circumstances, demand is often not sufficient to meet both the output from wind generation and the non-zero minimum stable operating levels of plant with must run characteristics such as coal or gas thermal plant.

We found that negative prices arose under the ‘no wind’ scenario. Evidence also pointed to the increased incidence of negative prices when wind generation was included in the analysis. A possible remedy for removing the incidence of negative price outcomes is to expand the export capability of the affected regions to allow surplus wind generation output to be exported to other regions within the electricity network. In order to investigate this potential remedy, two particular transmission augmentation scenarios were considered. The first, termed the minor transmission augmentation scenario involved doubling the capacity of the transmission branches connecting Mid-North South Australia; Riverlands; Regional Victoria; Dederang; and Melbourne.

The second transmission augmentation scenario involved implementing an augmentation scenario based on the NEMLINK proposal. This entailed adding a double circuit 500 kV transmission branch linking Upper North South Australia-Mid North South Australia-Riverlands-Regional Victoria-Tumut-Yass-Marulan-Sydney; Newcastle-Liddell-Tamworth-Armidale-South West Queensland; Melbourne-Regional Victoria; Bayswater and Liddell and incorporating the existing 500 kV branches linking Marulan-Mt Piper-Bayswater and with a new double circuit 500 kV branch linking Bayswater and Liddell. A new double circuit 220 kV branch connecting Burnie and Sheffield was also added but a second HVDC branch linking Burnie and South West Victoria was excluded.

We found that both transmission augmentation scenarios largely eliminated the incidence of negative prices in the case of the minor transmission augmentation scenario and totally eliminated the incidence of negative prices in the case of the major transmission augmentation scenario. Therefore, our analysis indicated that the incidence of negative price events could be attributed to insufficient export capability of the existing interconnectors notably linking South Australia and Victoria.

Wind Power Spillage Effects:

Wind power spillage effects were investigated by comparing the production results from the transmission augmentation scenarios with those of the 'wind inclusive' scenario which incorporated the existing transmission network structure and operational wind farms. This investigation focused upon examining whether the current transmission structure might have constrained production from wind generation, leading to the spillage of wind power. This case would emerge if wind generation production levels subsequently exceeded the baseline levels under the two particular transmission augmentation scenarios considered, given that all scenarios inherited the same potential maximum wind generation production levels and demand profiles, by construction.

Our results indicated that wind spillage effects occurred particularly in South Australia relative to the results associated with both transmission augmentation scenarios, with spillage effects being slightly larger in extent in the case of the major transmission augmentation scenario. This implied that the major transmission augmentation scenario allowed slightly more wind power to reach market than was the case with the minor transmission augmentation scenario.

More generally, the observed reduction in negative prices and wind power spillage effects pointed to potential benefits associated with transmission network augmentation. However, whether such expansion proposals would be successful under the current transmission network expansion framework encapsulated in the 'RIT-T' Framework (AEMO 2014) remained uncertain. In particular, the 'RIT-T' framework seemed to be well placed to address the more conventional problem of transmission network augmentations to meet peak load demand. However, the problems associated with negative prices and spillage of wind power were essentially off-peak problems associated with insufficient demand relative to must run capacity and wind power which required the spillage of wind and/or thermal power in the absence of sufficient export capacity in order to balance the network. Whether the ‘RIT-T’ framework is suitable or capable of accommodating this type of problem remained an open question.

Introduction

The Renewable Energy Target operates by requiring electricity retailers to buy renewable energy certificates based on their purchases of wholesale electricity. This type of arrangement has been in place since 2001. Specifically, this policy was initially incorporated within the Mandatory Renewable Energy Target (MRET) scheme, which was designed with the intention of supporting additional investment in renewable energy of 9.5 TWh by 2010. Prior to the implementation of the Mandatory Renewable Energy Target in 2001, the only major sources of renewable energy generation were the Tasmanian and Snowy Mountains hydro-electric schemes.

In 2009, the MRET was modified and renamed the Renewable Energy Target (RET) in August 2009. The new scheme had a significantly larger target of 45 TWh of additional renewable generation by 2020. Upon conception, generation from both small-scale renewable energy sources, such as rooftop PVs, and large-scale renewable energy generators were covered by the scheme.

In 2010, amendments were made to the scheme to split the RET scheme into two components:

• Large-scale Renewable Energy Scheme (LRES), which required the surrender of Large-scale Generation Certificates (LGCs); and

• Small-scale Renewable Energy Scheme (SRES).

By the end of calendar year 2012, total generation from large-scale renewable energy sources constructed after 2001 had risen to around 12 TWh (NERA, 2013, Section 2.3). Most of this growth could be attributed to production from wind farms. In particular, hydro plant built prior to 1994/95 could only create RECs/LGS's above a pre-determined base production level initially determined as the average of annual production over the years 1994-1996. These baseline values are determined each year and only that component of total production above the pre-determined annual base value is liable for REC/LGC creation. The only exception in the current portfolio of hydro generation is Bogong Hydro Power Station which was commissioned in 2010. On the other hand, all generation produced by wind farms was liable for REC/LGC creation. Furthermore, currently wind farms are the only viable second generation renewable technology that can be constructed on a sufficient scale to meet the LRET.

Under current LRET target settings, significant future investment in renewable generation is expected in order to meet the existing target of 41,850 GWh in 2020. In general terms, an additional 8 to 9 GW of wind generation capacity would be expected to be required to meet the LRET target in 2020 (NERA, 2013, Section 2.3.1). Thus the current configuration of the LRET is seen as underpinning the potential for considerable investment and expansion in wind farm capacity up to 2020.

In general, the financial viability of wind farms rests on revenue earned from both the sale of electricity in the wholesale market as well as revenue earned from the creation and sale of LGCs to demand side participants with a LRET liability. Without this additional source of revenue, wind farms would not earn sufficient revenue to cover costs. Moreover power purchase agreements with energy retailers typically include provisions relating to both revenue streams. Power purchase agreements are typically needed to obtain project funding from banks or other financial institutions.

Once wind farms are constructed, they are characterised as having very low marginal costs of generation. As such, in a competitive dispatch process based upon marginal costs, wind farms would be expected to be dispatched ahead of thermal generation. Competitive dispatch is linked closely with the notion of the merit order of dispatch. The merit order of dispatch can be defined as the ordering of generation based upon short run marginal cost in an ascending order. As such, the generation with the lowest marginal costs will lie at the *bottom* of the merit order while the most expensive generators (e.g. those with the highest marginal costs) will be located at the *top* of the merit order. Thus, in the case of wind generation, this additional cheap capacity will enter at the bottom of the merit order and shift all other generation up the merit order and, at the margin, displace more costly types of generation located at the top of the merit order.

This process in called the ‘merit order effect’ and will place downward pressure on wholesale spot prices. For example, short run marginal costs of wind generation are typically in the range of $3/MWh to $6/MWh whereas conventional peaking plant’s short run marginal costs typically exceed $60/MWh and can even exceed $400/MWh for diesel generation. In the absence of branch congestion, under nodal pricing employed in the modelling, the short run marginal cost of the last dispatched unit (e.g. the ‘marginal’ generator) sets the wholesale price for all other cheaper previously dispatched generation that is located below the marginal generator in the merit order. It is the subsequent displacement of more expensive types of generation at the top of the merit order with the entry of the cheaper generation at the bottom of the merit that locks in the wholesale price reductions associated with expansion in production from wind generation. Furthermore, as more wind farms are constructed in order to meet the LRET, the additional energy that they supply to the market will also act to further reduce wholesale spot electricity prices. Furthermore, to the extent that domestic gas input prices rise in the future with the advent of sea-bound LNG exports, than this effect is likely to be larger in magnitude as the marginal costs of gas generation including peak OCGT plant increase significantly in the future.

However, the additional revenue earned by wind farms through the creation and sale of LGCs must ultimately be recovered by liable retailers who pass on the costs of compliance onto their customers. Thus, if these 'LRET costs' exceed any reduction in wholesale electricity purchase costs, then the net effect of the LRET will be to increase costs to consumers.

In this submission, we report on the key results obtained from a detailed investigation of the impact of operational wind generation in the NEM over the period 2007-2012. The aim of this research is to investigate the nature of any merit order affects operating in the wholesale electricity market that can be attributed to wind generation operating in the NEM over the period 2007-2012. This will help inform debate about the net benefits that are likely to occur with investment in wind generation and other renewable energy sources under the current LRET configuration. In this submission, we address the impact on a restricted number of key metrics including wholesale electricity price impacts, carbon emission outcomes and savings in system-wide total variable cost impacts. We will also conduct an investigation of the net benefit of the RET/LRET scheme in terms of its impact on household retail tariff by assessing the impact of the direct costs of compliance as well as the nature of any reductions in wholesale electricity prices associated with the merit order effect alluded to above.

Modelling Issues

To address the issues raised in the previous section pertaining to the merit order effect, a model of the national electricity market is used which contains many realistic features of what is a complex, networked system. Such features include intra-regional and inter-state trade, realistic transmission network pathways and the competitive dispatch of all generation with price determination based upon marginal cost and transmission branch congestion characteristics.

In order to capture these linkages, we used the agent based ANEM model of the Australian National Electricity Market, incorporating a DC OPF algorithm to determine optimal dispatch of generation plant, power flows on transmission branches and wholesale prices. The methodology underpinning the ANEM model assumes an Independent System Operator (ISO) and uses Locational Marginal Pricing (LMP) to price energy by the location of its injection into, or withdrawal from, the transmission grid. ANEM is based on the American *Agent-Based Modelling of Electricity Systems* (AMES) model (Sun and Tesfatsion 2007a, 2007b) with appropriate modifications to reflect the differences between the institutional structures of the Australian and USA wholesale electricity markets. Further information can be found in Wild *et al.* 2012, Section 1.

The version of the ANEM model used to conduct the simulations for this submission contains 52 nodes, 68 transmission branches and 315 generating units (including wind generators). The wind generation component included in the modelling involved thirteen non-scheduled and thirteen semi-scheduled wind farms with a combined capacity of 2471.8 MW which represents 96.8 per cent of total installed capacity of operational wind farms in the NEM at the end of 2012. A detailed list of the wind farms that were included and excluded from the modelling in contained in Appendix A and the schematic representation of the transmission network including location of regional nodes, generators and transmission branches are outlined in Figures 1 to 5. More detailed information about the application of the ANEM model to the investigation of the wind generation in the NEM can be found in Wild *et al.* (2014).

In investigating the impact of operational wind farms in the NEM, two broad modelling scenarios were considered. A baseline 'no-wind' scenario involved assuming no contributions from wind generation with demand having to be met by thermal and hydro generation. The second scenario incorporated actual half-hourly output traces from operational wind farms and was termed the 'wind inclusive' scenario. In this scenario, both semi-scheduled and non-scheduled wind farms were collectively modelled as generators whose supply offers were based upon short run marginal costs in the range \$3.4/MWh to \$4.7/MWh - amongst the cheapest forms of generation incorporated in the modelling.

The "demand" concept utilised in the modelling is based upon that published in AEMO (2013) which is termed 'scheduled demand'. This demand concept is calculated utilising the fact that in electricity networks, supply and demand must match instantaneously, and scheduled demand is defined to equal the output of scheduled and semi-scheduled generation, transmission losses and large independent loads directly connected to the transmission grid. As such, this is a net demand concept calculated from gross demand, after contributions from small scale solar PV and wind and large scale non-scheduled generation (including wind, hydro and bagasse generation) has been netted off to produce the net demand concept (AEMO 2012).

The actual demand concept employed in the modelling is a grossed up form of scheduled demand which was obtained by adding the output of large-scale non-scheduled generation to the scheduled demand data. Five minute non-scheduled generation output data for the period 2007 to 2012 was obtained from AEMO and averaged across six five minute intervals to obtain half-hourly output traces.[1] This data was then summed across all non-scheduled generators located within a node and added to the nodal based scheduled demand to determine the nodal based augmented demand concept used in the modelling. Therefore, the demand concept employed in the modelling equates to the sum of the output of scheduled and semi-scheduled generation, non-scheduled generation, transmission losses and large independent loads directly connected to the transmission grid. It does not include the contributions from small scale solar PV and wind and, as such, still represents a net demand concept.

Wind Generation Penetration Levels by State

To obtain an idea of the scope of penetration of actual wind generation by state based upon actual dispatch records from ANEM model simulations, we calculated the ratio of aggregate MW wind generation production to total aggregate MW production from all sources of generation (including wind generation), by state. These results are presented in Table 1. In terms of state production share, South Australia has the largest penetration of wind generation, accounting for 17.7 per cent of total production in South Australia in 2012, increasing from 6.0 per cent in 2007. The state with the next highest penetration is Tasmania, corresponding to 6.7 per cent of total state production in 2012, increasing from 4.2 per cent in 2007. This is followed by Victoria and then New South Wales with production shares of 2.4 and 1.0 per cent in 2012. For the NEM, the production share has increased steadily over the 2007-2012 period, from 0.7 of a per cent in 2007 to around 2.5 per cent in 2012.

[1] Note that the name and nodal locations of the non-scheduled wind generators are listed in Panel (A) of Appendix A while a list of the other non-scheduled generators and their nodal location are reported in Panel (D) of Appendix A.

Table 1. Penetration of Actual Wind Generation over 2007-2012: Proportion of Total Production

Year	NSW	VIC	SA	TAS	NEM
2007	0.000	0.004	0.060	0.042	0.007
2008	0.000	0.004	0.064	0.056	0.007
2009	0.003	0.013	0.117	0.064	0.015
2010	0.006	0.018	0.133	0.060	0.018
2011	0.009	0.020	0.169	0.064	0.022
2012	0.010	0.024	0.177	0.067	0.025

Wholesale Price Impacts

Average wholesale price outcomes reflect both a spatial and temporal dimension. Average prices were calculated by a two-step procedure. First, volume weighted averaging was applied across all relevant nodes to produce a volume weighted annual nodal average price for each year in the 2007-2012 interval, with the quantity variable being half-hourly nodal demand and the price variable being half-hourly nodal prices. As such, generation only nodes were dropped from the averaging process which applied to the Bayswater and Murray nodes. Second, we then applied a demand weighted averaging scheme to produce annual state average wholesale prices for each of the years 2007-2012 from the volume weighted annual average nodal prices determined in step one. Finally, average annual prices for the NEM as a whole was determined by applying a state demand weighted averaging process to the state annual average prices calculated above. The weights in the averaging scheme were determined by aggregating each states total demand over each year and expressing that as a proportion of the total demand determined by summing across the five state totals for each year in the interval 2007-2012. Note also that the same demand weighting scheme was applied to the two scenarios being investigated.

This averaging process was applied to the nodal price data obtained from both the baseline ‘no-wind’ scenario and the ‘wind inclusive’ scenario that incorporates wind generation in the analysis utilising actual half-hourly output traces from operational wind farms. To investigate the impact of wind generation in the NEM, for each year in the period 2007-2012, we calculated the percentage change in average annual prices associated with the ‘wind inclusive’ scenario relative to the average price outcomes associated with the baseline ‘no wind’ scenario. Negative percentage change values would indicate that the inclusion of wind generation has reduced average annual wholesale prices relative to the baseline ‘no wind’ scenario.

The percentage change values are reported in Panel (A) of Table 2. Note that the average annual price outcomes for the NEM are listed in the last column in Panel (A) using the demand weighted averaging process mentioned above and the demand weights used for each year being reported in Panel (B) of Table 2. It should be noted that the weighting scheme gives relatively more weight to New South Wales and Queensland than would be forthcoming if a simple arithmetic averaging process was used, and if relatively larger reductions in prices were observed in Victoria, South Australia and Tasmania associated with greater penetration of wind generation in those particular states.

It is evident from Panel (A) that all states experience a reduction in average annual prices associated with the inclusion of operational wind farms in the modelling, including Queensland which has no operational wind farms in the modelling.[2] A number of observations can be drawn from the results presented in Table 2. First, those states with the largest number of operational wind farms experience the greatest reductions in average

[2] While Windy Hill wind farm is a small operational wind farm in Northern Queensland, no output data was available in the data we obtained from AEMO and therefore its contribution was excluded from the modelling.

annual prices. The stand-out states are clearly South Australia and Victoria which experience reductions in average annual wholesale prices in the range of 9.1 to 35.2 per cent and 7.1 to 28.2 per cent relative to the baseline ‘no wind’ scenario. Second, reductions in average annual prices tend to broadly increase over time reflecting, in particular, the expansion in semi-scheduled wind farms in South Australia, Victoria and New South Wales over years 2010-2012. The trend in Tasmania is more moderate reflecting the fact that the Woolnorth wind farm was fully commissioned in 2007 and no new wind farms were commissioned over the remainder of the period under investigation.

The increase in the magnitude in percentage reductions in average annual prices in the NEM are reported in the last column of Panel (A) with this trend becoming particularly evident over years 2010-2012, accompanying the expansion in wind capacity mentioned above. Specifically, annual average prices in the NEM decline relative to the ‘no wind’ scenario by between 3.5 and 8.6 per cent over years 2007-2009 before the magnitude of the percentage reduction increases to 15.5 per cent in 2010, before declining in magnitude over years 2011-2012 to 12.3 per cent in 2012. An important factor contribution to the decline over years 2011-12 relative to year 2010 is the fall in demand experienced over the period 2011-12 relative to the level of demand prevailing in 2010.

For the overall interval 2007-2012, the average rate of percentage reduction in annual average wholesale prices relative to the baseline ‘no wind’ scenario attributable to wind generation in the NEM is given in the last row of Panel (A) of Table 2. These results indicate percentage reductions relative to the ‘no wind’ scenario of 21.2, 18.6, 5.0, 1.6 and 0.3 per cent in South Australia, Victoria, Tasmania, New South Wales and Queensland, respectively. For the NEM, the average rate of percentage reduction relative to the ‘no wind’ scenario is in the order of 10.2 per cent over the five year period.

Table 2. Percentage Change in Volume Weighted Nodal Annual Average Prices Associated with Operational Wind Farms

Panel (A): State Results

Year	QLD	NSW	VIC	SA	TAS	NEM
2007	-0.10	-0.27	-7.06	-9.14	-3.14	-3.48
2008	-0.14	-0.44	-10.92	-11.20	-4.29	-6.30
2009	-0.32	-1.04	-15.68	-10.68	-5.10	-8.56
2010	-0.31	-1.64	-27.47	-26.04	-5.72	-15.47
2011	-0.41	-2.38	-28.25	-34.79	-5.79	-14.82
2012	-0.29	-3.94	-22.53	-35.19	-5.89	-12.27
Average	-0.26	-1.62	-18.65	-21.17	-4.99	-10.19

Panel (B): State Based Weighting Scheme to Calculate NEM Average Annual Prices

Year	QLD	NSW	VIC	SA	TAS
2007	0.2512	0.3817	0.2525	0.0650	0.0496
2008	0.2520	0.3804	0.2526	0.0648	0.0503
2009	0.2572	0.3788	0.2501	0.0656	0.0483
2010	0.2560	0.3775	0.2504	0.0663	0.0497
2011	0.2545	0.3807	0.2497	0.0652	0.0499
2012	0.2611	0.3699	0.2535	0.0662	0.0492

A key conclusion from Table 2 is that close proximity to the location of wind generation seems to matter in reaping the greatest benefits associated with reductions in annual average wholesale prices. This outcome, more generally, also appears to be the case for the states of South Australia and Victoria. However, in Table 1, we saw that the degree of wind penetration is significantly different between these two states. For example, in 2012 South Australia has a penetration rate of 17.7 per cent whilst Victoria has a penetration rate of 2.4 per cent. Therefore, it is of particular interest to establish what factors are producing the similar average wholesale spot price outcomes in both states given the significant differences in wind generation penetration rates in both states. To investigate this issue further, we also present the percentage change in selected average nodal prices. The percent change values were calculated in the exact same way as for Table 2 except that the calculation was applied to volume weighted average annual nodal prices from both scenarios instead of the average annual state price outcomes as in the case of Table 2. The percentage change results for the selected nodes are reported in Table 3.

Table 3. Percentage Change in Annual Average Prices Associated with Operational Wind Farms: Selected Regional Results[3]

Year	MELB	SW VIC	REG VIC	SE SA	ADEL	RIVERL	MN SA
Node	32	33	34	35	37	38	39
2007	-6.94	-7.65	-7.54	-8.65	-9.13	-9.75	-9.35
2008	-11.12	-12.00	-9.67	-13.10	-11.23	-9.37	-9.87
2009	-15.26	-16.24	-17.36	-15.66	-11.08	-2.14	-4.60
2010	-27.86	-28.27	-25.72	-28.48	-25.96	-25.38	-25.02
2011	-28.62	-30.38	-26.20	-36.00	-34.89	-34.36	-33.33
2012	-22.64	-25.93	-21.38	-32.66	-35.16	-38.43	-36.50
Average	-18.74	-20.08	-17.98	-22.42	-21.24	-19.90	-19.78

In Table 3, we can see that all the selected nodes experience significant percentage reductions in average nodal prices. Comparison of the Victorian and South Australian results indicate that the degree of reduction in average nodal prices is of a slightly larger magnitude in South Australia than in Victoria especially over years 2010-2012, reflecting the greater degree of wind penetration in the former state when compared with the latter. The results associated with the South West Victorian and South East South Australian nodes together appear to provide a link between price dynamics operating in both South Australia and Victoria. In particular, both average nodal prices appear to be linear combinations of spot price outcomes occurring in both states, however, with greater weight given to Victorian outcomes in the case of the South West Victorian node and greater weight given to South Australian outcomes in the case of the South East South Australian node. In contrast, the degree of nodal price separation between the Regional Victoria and Riverlands nodes

[3] In Panel A, the column headings respectively refer to the following nodes: Melbourne, South West Victoria, Regional Victoria, South East South Australia, Adelaide, Riverlands, and Mid-North South Australia.

especially over years 2011-2012 indicates a more fundamental difference in nodal price determination between these two nodes.

These trends can be linked to the degree of branch congestion occurring on both the Heywood and Murraylink interconnectors. Specifically, in nodal pricing based upon DC OPF analysis, nodal price equalisation would be expected to arise between two interconnected nodes when there is no branch congestion on transmission lines connecting the two nodes. Conversely, if branch congestion does arise, nodal price divergence would be expected to occur. In this latter case, the congestion islands of the two nodes from each other with different marginal generators setting prices at the two nodes, thus producing nodal price divergence.

Information on transmission branch congestion on these two interconnectors is presented in Table 4. The values in Panel (A) of this table are proportion values depicting the amount of time (e.g. total number of half-hours) within the yearly dispatch horizon that branch congestion occurred on each indicated transmission branch. Branch congestion is defined as arising when the MW power transfer on the transmission branch is equal to the transmission line's rated MW thermal limit. The results associated with the 'no wind' scenario are reported in Panel (A) of Table 4 while the results associated with the 'wind inclusive' scenario are reported in Panel (B).

The results in Panel (A) indicate very low levels of congestion on Heywood, amounting to 1 per cent or less. In the case of Murraylink, however, branch congestion is more apparent, with congestion rates in the range of 7.5 to 9.2 per cent. When wind generation is included in the analysis, branch congestion on Heywood actually declines further relative to the 'no wind' scenario while congestion on Murraylink increases significantly with congestion rates now in the order of 13.8 to 43.2 per cent. Moreover, in the case of Murraylink, the congesting rates especially increase over the years 2011-2012.

One reason for the tendency for greater congestion on Murraylink is linked to its interconnection with the Regional Victorian node. This node has sizeable load that can exceed 1000 MW's and very limited generation located at this node. As such, power will tend to flow towards this node and the cheap generation from the wind farms located in Mid-North South Australian node, in particular, is well placed geographically to supply power into this region, via the Murraylink interconnector.

Low rates of congestion on the Heywood interconnector would be expected to promote nodal price equalisation between Victorian and South Australian nodes as suggested by the above-mentioned price outcomes arising at the South West Victorian and South East South Australian nodes. On the other hand, the higher rates of branch congestion on Murraylink would be expected to promote more nodal price divergence between South Australia and South Australia. This outcome is particularly seen in nodal price differences reported in Table 3 over years 2011-2012 which also coincides with rising branch congestion on Murraylink as also identified in Panel ((B) of Table 4. More generally, these considerations clearly demonstrate the importance of capacity and congestion effects on transmission branches which are capable of either propagating or islanding off wholesale price effects between different nodes and even states.

Table 4. Congested Transmission Branches

Panel (A) Proportion of Time Congested: Baseline No Wind Scenario.

Year	HW	ML
2007	0.004	0.085
2008	0.005	0.077
2009	0.009	0.075
2010	0.006	0.092
2011	0.010	0.092
2012	0.009	0.079

Panel (B) Proportion of Time Congested: Wind Inclusive Scenario.

Year	HW	ML
2007	0.001	0.149
2008	0.003	0.138
2009	0.002	0.221
2010	0.001	0.292
2011	0.000	0.394
2012	0.000	0.432

Displacement Effects Associated With the Merit Order Effect

In the previous section, significant reductions in annual average wholesale prices were observed to accompany the inclusion of wind generation in the modelling. In the introductory section of this submission, this possibility was associated with a merit order effect whereby cheap power from wind generation entered the merit order at its base, shifting other generation further up the merit order and displacing more costly forms of generation located at the top of the merit order. This merit order effect can be confirmed by observing how the inclusion of wind generation affected production from other types of competing generation.

To obtain an overall picture of the aggregate impact by state, the impact of wind generation on state production trends in other competing thermal and hydro generation is presented in Table 5. In this table, these trends are expressed in terms of percentage change in the ‘wind inclusive’ scenario’s production levels relative to the productions levels associated with the baseline ‘no wind’ scenario. Once again, negative values indicate that the production levels associated with the ‘wind inclusive’ scenario have decreased relative to the equivalent production levels associated with the baseline ‘no wind’ scenario.

It is apparent from Table 5 that South Australia and Tasmania experience the greatest reduction in production from thermal and hydro generation, with percentage reductions in the order of 3.5 to 9.6 and 4.9 to 11.2 per cent, respectively. Both Queensland and Victoria experience the lowest rates of reduction with results in the range of 0.2 to 0.8 per cent. New South Wales lies between these upper and lower ranges with percentage reductions in the range of 0.4 to 3.8 per cent. For the NEM as a whole, the percentage reduction in production from thermal and hydro generation is in the order of 0.7 to 2.6 per cent. The magnitude of the size of the reduction increases unambiguously years 2007-2012 in response to the expansion in production from wind generation in the NEM over this time interval. Perhaps the most surprising result is the relatively small impact on total production from non-wind generation in Victoria.

Table 5. Percentage Change in Annual Production from Thermal and Hydro Generation Associated with Operational Wind: State Results

Year	QLD	NSW	VIC	SA	TAS	NEM
2007	-0.26	-0.44	-0.20	-3.54	-4.95	-0.68
2008	-0.22	-0.50	-0.24	-3.62	-6.12	-0.75
2009	-0.49	-1.52	-0.30	-6.91	-8.70	-1.50
2010	-0.52	-2.24	-0.51	-7.88	-9.19	-1.89
2011	-0.67	-3.11	-0.47	-9.64	-9.75	-2.33
2012	-0.76	-3.78	-0.59	-9.30	-11.25	-2.61

The impact on coal-fired generation by state is documented in Table 6. There are two noticeable outcomes in Table 6. The first is the relatively high percentage reductions in production from coal-fired generation experienced in South Australia with percentage reductions in the range of 3.7 to 14.6 per cent over the period 2007-2012. The other striking result is the very low percentage reductions in production from coal-fired plant in Victoria, with percentage reductions in the range of 0.0 to 0.2 per cent. The results for Victoria reflect the very low marginal costs associated with brown coal-fired generation that are around or slightly higher than the marginal costs associated with wind generation. Thus, whilst the inclusion of wind generation moves brown coal generation slightly higher up the merit order of dispatch, this type of generation still remains one of the cheapest types of generation in the NEM. Furthermore, given the current level of penetration of wind generation in Victoria, and in the absence of a policy mechanism that changes the existing marginal cost relativities, brown coal generation is largely unaffected when compared with other more expensive forms of generation.

The other state experiencing some reduction in coal-fired generation production is New South Wales with this reduction becoming particularly evident over the interval 2010-2012 with percentage reductions in the range of 2.3 to 3.9 per cent. The other clear trend is that the magnitude of percentage reduction also increases over the time interval 2007-2012, and especially over years 2009-2012 which accompanied the role out of wind generation capacity particularly in South Australia and New South Wales. The percentage reduction in production from coal-fired generation in the NEM is in the range 0.4 to 2.1 per cent.

Table 6. Percentage Change in Annual Production from Coal Generation Associated with Operational Wind Farms: State Results

Year	QLD	NSW	VIC	SA	NEM
2007	-0.28	-0.44	0.00	-3.98	-0.36
2008	-0.24	-0.51	0.00	-3.68	-0.36
2009	-0.54	-1.58	-0.01	-9.33	-1.00
2010	-0.61	-2.33	-0.06	-9.61	-1.34
2011	-0.79	-3.23	-0.08	-14.57	-1.86
2012	-0.90	-3.94	-0.23	-13.78	-2.14

The second fuel type we investigate is gas-fired generation by state which is presented in Table 7. There are two main results evident in Table 7. The first is the relatively larger reductions in production from gas-fired generation in Victoria when compared to the other states except for Tasmania over the period 2007-2008. Reductions in Victoria are in the order of 5.1 to 11.7 per cent, with the largest percentage reductions arising over the 2010-2012 period which also corresponds to the period during which there was significant expansion in wind capacity in South Australia, Victoria and New South Wales. The second key outcome is that there is no real impact of production from gas generation in either Queensland or New South Wales with this result being notable given the expansion in wind farms in New South Wales occurring over years 2011-2012. The percentage reductions experienced in South Australia are between these two extremes, being in the order of 3.3 to 7.0 per cent. Finally, in the case of Tasmania, there were relatively large reductions in production from gas generation over the 2007-2008 period followed by much smaller rates of decline over the remainder of the period under investigation. This qualitative change is linked to the commissioning of the Tamar Valley NGCC plant which has different operational configuration to the OCGT gas plant that was operational over the time interval 2007-2008.

In the case of the NEM, the percentage reduction in production from gas-fired generation is in the range 2.6 to 3.7 per cent. Moreover, the magnitude of the reductions continue to increase broadly over the time interval 2007-2012, although declining slightly over the 2011-2012 period relative to 2010.

Table 7. Percentage Change in Annual Production from Gas Generation Associated with Operational Wind Farms: State Results

Year	QLD	NSW	VIC	SA	TAS	NEM
2007	0.00	0.01	-5.13	-3.31	-15.48	-2.63
2008	0.00	0.02	-5.97	-3.59	-17.88	-2.94
2009	0.01	0.00	-8.07	-5.65	-0.40	-3.35
2010	0.01	-0.02	-11.67	-6.97	-0.87	-3.70
2011	0.00	-0.08	-11.22	-7.02	-0.62	-3.54
2012	0.00	0.00	-11.05	-6.98	-0.42	-3.46

Detailed results for gas-fired generation by type of plant are reported in Tables 8 and 9 for NGCC/Gas Thermal (GT)[4] and OCGT[5] plant, respectively. In Table 8, South Australia experiences the greatest percentage decline in production from NGCC/GT plant with reductions in the range of 2.7 to 5.0 per cent while smaller reductions arise in both Victoria and Tasmania. It should be noted in the latter context that both Victoria and Tasmania only have one power station associated with this category of plant type – namely, Newport and Tamar Valley (commissioned in 2009), respectively.[6] This contrasts with the situation in South Australia which has a number of NGCC and GT power stations and a larger aggregate capacity for this category of plant type than is the case in Victoria or Tasmania. The other noticeable feature of Table 8 is no appreciable impact on production from NGCC plant in either New South Wales or Queensland.

For the NEM, the percentage reduction in production from NGCC/GT plant falls in the range 1.8 to 2.2 per cent, with the magnitude of the percentage reductions continuing to increase broadly over the time interval 2007-2012, although declining slightly over the 2011-2012 period relative to 2010.

[4] NGCC plant is defined to include Townsville, Condamine, Darling Downs and Swanbank E power stations in QLD; Smithfield and Tallawara power stations in NSW; and Pelican Point and New Osbourne power stations in SA; and Tamar Valley NGCC Power Station in TAS. Gas Thermal plant include Newport in VIC and Torrens Island A and B power stations in SA.

[5] OCGT plant to include Barcaldine, Roma, Oakey and Braemar power stations in QLD; Uranquinity Power Station in NSW; Valley Power, Jeeralang A and B, Bairnsdale, Somerton and Laverton North power stations in VIC; Ladbroke Grove, Quarantine, Dry Creek, Mintaro and Hallett power stations in SA; and Bell Bay, Bell Bay Three and Tamar valley OCGT power stations in TAS.

[6] Note that the ‘na’ values in Table 6 for Tasmania over the 2007-2008 time period signifies that no production occurred under each scenario because the Tamar Valley NGCC plant was not commissioned until 2009.

Table 8. Percentage Change in Annual Production from NGCC/Gas Thermal Generation Associated with Operational Wind Farms: State Results

Year	QLD	NSW	VIC	SA	TAS	NEM
2007	0.01	0.01	-0.72	-2.70	na	-1.77
2008	0.00	0.02	-0.70	-2.91	na	-1.91
2009	-0.01	0.02	-1.04	-4.06	-0.40	-2.15
2010	0.00	-0.03	-1.34	-5.02	-0.87	-2.20
2011	0.00	-0.07	-1.13	-5.01	-0.62	-2.14
2012	0.00	0.00	-1.30	-5.05	-0.42	-2.15

It is apparent from Table 9 that there are much larger impacts on production from OCGT plant. This is particularly the case for Victoria and South Australia who experience percentage reductions in production from OCGT plant in the range of 15.0 to 53.1 per cent and 13.6 to 38.8 per cent, respectively. Both New South Wales and Queensland experience much smaller (if any) impacts on production from OCGT plant while Tasmania experiences reductions of between 15.5 and 17.8 per cent over the 2007-2008 period before experiencing no change over the period 2009 to 2012 because no OCGT plant in Tasmania was dispatched over this latter period during ANEM model simulations. This latter situation also arose in New South Wales in 2007-2008 because no OCGT plant was commissioned at that time and in 2012 because no OCGT plant was subsequently dispatched in ANEM model simulations. These results are represented by the ‘na’ values included in Table 9 for New South Wales.

For the NEM as a whole, the percentage reduction in production from OCGT plant lies in the range 7.4 to 12.3 per cent, with the magnitude of the percentage reductions broadly increasing over the time interval 2007-2012, although declining slightly in 2012 relative to 2011.

The larger reductions in production from OCGT plant in South Australia and Victoria reflects a number of different factors. First, OCGT plant typically have significantly higher fuel costs than NGCC or GT plant which translates into higher marginal costs that underpin the supply offers of these types of generation plant. Second, a significant portion of the OCGT fleet in South Australia is located in closer proximity to sources of wind generation including plant located directly at the Mid-North South Australia and South East South Australian nodes – see Figure 4 for further details. NGCC and GT plant, on the other hand, are located in Adelaide. Third, in Victoria, the greater extent of displacement of output from OCGT plant attributable to wind generation would reflect the OCGT's plants cost disadvantages (e.g. higher fuel costs when compared to other competing forms of thermal generation), its greater capacity (e.g. availability), as well as its close proximity to wind generation in Victoria.

More generally, the higher reduction rates associated with production from OCGT plant is consistent with what would be expected to eventuate under high wind penetration regimes as a combination of wind and peak gas is used to ensure balancing within the network. In this context, both the fast-start and fast ramping capability of OCGT plant provide the required start-up and ramp up capacity to balance the system when wind power drops off while also providing the shutdown and fast ramp down capability when wind power ramps up (Holttinen *et al.*, 2009).

Table 9. Percentage Change in Annual Production from OCGT Generation Associated with Operational Wind Farms: State Results

Year	QLD	NSW	VIC	SA	TAS	NEM
2007	-0.04	na	-15.00	-13.56	-15.48	-7.44
2008	0.00	na	-17.46	-14.59	-17.88	-8.71
2009	0.05	-2.33	-26.35	-27.11	na	-9.13
2010	0.03	1.32	-36.08	-31.55	na	-12.24
2011	0.01	-1.39	-46.48	-38.44	na	-12.28
2012	0.00	Na	-53.12	-38.80	na	-11.99

The third fuel type we investigate is hydro generation by state which is presented in Table 10. There are two main results discernible from this table. The first is the relatively stable profile of percentage reductions in production from Tasmania hydro which are in the range of 0.4 to 5.5 per cent and which unambiguously increase in magnitude over the period 2008-2012. Second, the percentage reductions in hydro generation in New South Wales and Victoria, on the other hand, are more marked and variable in extent but are coming off a much lower production levels. It is also clear that wind generation has no discernible impact on hydro production trends in Queensland. The percentage reduction in production from hydro generation in the NEM is in the range 0.4 to 5.5 per cent. Furthermore, the magnitude of the percentage reduction in hydro production in the NEM continues to increase unambiguously over the time period 2008-2012. It also closely tracks the trend associated with Tasmania which indicates the prominence of Tasmanian hydro within aggregate hydro generation fleet in the NEM.

In common with OCGT peaking plant, the higher reduction rates associated with production from hydro plant especially in New South Wales and Victoria is also consistent with what would be expected under high wind penetration regimes as a combination of wind and hydro is used to ensure balancing within the network. This relates to both the fast-start and fast ramping capability of hydro plant that provides the required characteristics needed to help balance the system in the face of intermittency associated with wind power.

Table 10. Percentage Change in Annual Production from Hydro Generation Associated with Operational Wind Farms: State Results

Year	QLD	NSW	VIC	TAS	NEM
2007	-0.01	-8.59	-11.23	-0.65	-0.66
2008	na	-4.26	-14.24	-0.38	-0.43
2009	na	-11.63	16.95	-2.75	-2.67
2010	-0.04	-37.84	-11.57	-3.77	-3.80
2011	-0.01	-13.70	-33.24	-4.01	-4.06
2012	0.00	na	Na	-5.48	-5.48

Carbon Emission Outcomes

Carbon emission outcomes reflect the merit order effects identified in the previous section. To assess the implications of wind generation on carbon emission in the NEM, we calculated the total level of carbon emissions of each generation plant during each year over the time interval 2007-2012. To obtain state-specific results, we then aggregated the results across the relevant categories of plant located in each state. NEM wide results were then determined by summing across state results. This process was done for both the baseline ‘no wind’ scenario as well as the ‘wind inclusive’ scenario. We then calculated the percentage change in carbon emissions associated with the ‘wind inclusive’ scenario relative to the baseline ‘no wind’ scenario for each year in the interval 2007 to 2012. These results for each state and the NEM are reported in Table 11, where negative values, once again, indicate that wind generation has reduced carbon emission levels relative to levels prevailing under the baseline ‘no wind’ scenario.

The negative entries in Table 11 indicate that wind generation in the NEM has reduced carbon emissions in all states relative to the baseline ‘no wind’ scenario. The stand-out state is clearly South Australia with reductions in carbon emissions relative to the baseline scenario in the range of 3.6 to 11.0 per cent. This, in turn, reflects the more significant penetration of wind generation in this state and the greater substitution of wind generation for the more carbon emission intensive coal-fired generation that was identified in Table 6 in the previous section. The other noticeable result is the marginal size of reductions in Victoria which are in the order of 0.1 to 0.4 of a per cent. This reflects the much smaller level of wind penetration in Victoria when compared to the size of thermal capacity in that state and the fact that wind generation in this state appeared to primarily displace generation from less carbon emission intensive OCGT plant and not materially reduce production (and carbon emissions) from brown coal generation – e.g. see Table 6.[7] Thus, we see much smaller carbon emission reduction impacts in Victoria than in South Australia where a greater displacement of coal generation by wind power occurs.

The percentage reduction in carbon emissions is of a much smaller magnitude in Queensland than in New South Wales particularly over the period 2009-2012 as wind generation in the latter state commissioned over this period begins to displaces some production from black coal generation plant, as also identified in Table 6 in the previous section. In contrast, the minimal reductions in Queensland primarily reflect the fact that there was no wind generation operating in Queensland over the period of investigation available to displace other sources of power production in Queensland.

In the case of Tasmania, the larger reductions arising over the 2007-2008 period that are in the range of 15.5 to 17.9 per cent reflect displacement of output from OCGT plant by wind power as indicated in Tables 7 and 9 in the previous section. The production and carbon emissions outcomes are related to the marginal dispatch of OCGT gas plant in Tasmania to meet episodes of peak demand and are actually coming off of a small OCGT production and emission base for these two particular years. The much smaller percentage reductions over the period 2009-2012 are associated with the commissioning of Tamar Valley NGCC plant in 2009 and its subsequent dispatch at levels close to its minimum stable operating levels over extended periods of time, together with no dispatch of Tasmanian OCGT plant. As such, the production and carbon emission time profile of Tasmania becomes much larger in magnitude, but also more constant, producing much smaller variations in percentage change terms.

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[7] Note that the large Macarthur wind farm was in the process of being commissioned in the latter half of 2012 and production levels were well below its maximum MW capacity.

Table 11. Percentage Change in Annual Carbon Emissions Associated with Operational Wind Farms: State Results

Year	QLD	NSW	VIC	SA	TAS	NEM
2007	-0.27	-0.44	-0.10	-3.69	-15.53	-0.45
2008	-0.23	-0.51	-0.11	-3.65	-17.94	-0.46
2009	-0.51	-1.57	-0.14	-7.55	-0.34	-1.09
2010	-0.53	-2.30	-0.25	-8.28	-0.80	-1.42
2011	-0.68	-3.12	-0.24	-10.96	-0.54	-1.85
2012	-0.82	-3.90	-0.38	-10.54	-0.42	-2.13

More generally, apart from Tasmania, the percentage reduction in carbon emissions relative to the baseline 'no wind' scenario for all the other states increases in magnitude as time progresses in the interval under investigation. This reflects the fuel substitution impacts identified in the previous section associated with the significant expansion in operational semi-scheduled wind generation particularly after 2009. For the NEM, there is an unambiguous reduction in aggregate carbon emissions relative to the baseline scenario commencing with reductions of 0.4 and 0.5 of a per cent in 2007 and 2008, then ramping up over the 2009 to 2012 period with percentage reductions in the order of 1.1 to 2.1 per cent, respectively.

System-wide Total Variable Costs Savings

In previous sections we have seen that one impact of including operational wind generation was to change dispatch patterns, partially displacing coal production in South Australia and New South Wales, hydro production in Tasmania and OCGT production in South Australia and Victoria. This essentially operates because wind generation has a lower marginal cost structure than these other competing forms of generation. The changed dispatch patterns are also likely to affect the system-wide total variable costs associated with the changes in dispatch of the NEM-wide generation fleet in response to production from wind generation.

As implied above, the system-wide total variable cost is the aggregated variable costs of generation calculated across all generators within the network and all dispatch intervals within a given year in order to determine the total variable cost for the system as a whole for a given year. The variable cost components are restricted to fuel and variable Operation and Maintenance (O&M) costs, and the aggregate system-wide total variable cost (STVC) can be calculated as:

$$STVC = \sum_{h=1}^{Nh}\left(\sum_{i=1}^{I}\left[\alpha_i \times P_{G_{i,h}}\right] + \left[\beta_i \times \left\{P_{G_{i,h}} \times P_{G_{i,h}}\right\}\right]\right). \qquad (1)$$

Variable Nh is the number of half-hours in the year (i.e. dispatch intervals); I is the number of generators in the network (e.g. the NEM); α_i and β_i are the linear and quadratic cost coefficients in the variable and marginal cost functions of generator $'i'$ relating to fuel and variable O&M costs; $P_{G_{i,h}}$ is the dispatched power production of generator $'i'$ at dispatch interval (e.g. half-hour) $'h'$. Note that parameters i and h are looped over all $i \in I$ and all $h \in Nh$ in order to derive the aggregate annual system-wide total variable cost estimate, expressed in millions of dollars ($m).

System-wide total variable costs associated with the baseline 'no wind' and 'wind inclusive' scenarios are calculated from (1) for each year in the interval 2007-2012 and are listed in Table 12. In this table, the second column titled 'NWS' corresponds to the 'no wind' scenario whereas the third column titled 'WIS' denotes the 'wind inclusive' scenario. The second last column is a difference metric calculated as 'NWS' minus 'WES'. A negative value indicates a reduction in system-wide total variable costs associated with the incorporation of wind generation in the analysis when compared with the baseline 'no wind' scenario. In the final column, we express this monetary difference as the percentage change in system-wide total variable costs associated with the 'wind inclusive' scenario relative to the ‘no wind’ scenario. Once again, a negative value signifies that the system-wide variable costs associated with the ‘wind inclusive’ case have declined relative to the system-wide total variable costs associated with the baseline ‘no wind’ scenario. The last row of Table 12 contains the aggregate results for years 2007-2012 obtained by totalling the values in columns 2 and 3 of the table and then applying the difference and percentage change calculations to these two aggregated values.

It is apparent from Table 12 that, apart from 2009, reductions in system-wide total variable costs accompany the inclusion of contributions from wind generation, and generally have increased in magnitude over the 2010-2012 period with the expansion in semi-scheduled wind generation in South Australia, New South Wales and Victoria. For this latter period, the magnitude of the reductions is between 187.5 and 270.9 million dollars. When considered as a whole, over the complete period 2007-2012, the reduction in system-wide total variable costs in the order of $874.8m, representing a decline of 2.21 per cent from the equivalent result obtained under the ‘no wind’ scenario. Thus, when viewed from the perspective of the NEM as a whole, it is clear that wind generation has produced a considerable monetary savings in terms of reduced expenditure by market participants on variable costs by displacing, on a marginal cost basis, more costly types of generation.

Table 12. System-wide Variable Costs ($m)

Year	NWS	WIS	Diff	% Diff
2007	6140.1	6061.8	-78.3	-1.28
2008	6333.6	6215.4	-118.2	-1.87
2009	6663.5	6680.9	17.4	0.26
2010	6866.5	6678.9	-187.5	-2.73
2011	6831.1	6560.3	-270.9	-3.96
2012	6729.7	6492.4	-237.3	-3.53
Total	39564.5	38689.7	-874.8	-2.21

The Issue of Negative Prices

A feature of interest associated with wind generation has been an emerging perception of the increased incidence of negative price outcomes typically associated with a situation whereby significant wind generation output coincides within periods of low demand such as off-peak periods at night. Under these circumstances, demand is often not sufficient to meet both the output from wind generation and the non-zero minimum stable operating levels of plant with must run characteristics such as coal or gas thermal plant. A complicating factor here is that this latter type of plant cannot easily stop production because of the significant amount of time needed to shut down and then start up, or operate below non-zero minimum stable operating MW capacities. Under these circumstances, the LMP at affected nodes will be negative signifying that the marginal cost of meeting an additional incremental MW of demand is in fact negative which also implies that that generators must pay the market operator to avoid having to shut down. Of course, negative prices also mean negative revenue streams and profits, potentially placing strain on the financial position of operating plant and dampening the prospects of additional investment in new capacity if such events become commonplace.

The results associated with the incidence of negative prices under both scenarios are reported in Table 13. In Panel (A), we document the proportion of time in each year that negative prices were obtained for the baseline ‘no wind’ scenario. The proportion values reported in Panel (A) were determined by calculating for each node the number of half-hourly dispatch intervals over which negative prices were obtained and then dividing this by the total number of half hours in each year. This same process was also applied to the ‘wind inclusive’ scenario and the percentage change in these values relative to the baseline ‘no wind’ scenario is reported in Panel (B) of Table 13. Note that in both panels of Table 13, the results are only reported for nodes containing negative prices. In this context, it is of particular note that no negative prices were obtained for the Regional Victorian node (e.g. node 34), although negative prices were obtained for nodes neighbouring this particular node in South Australia.

Table 13. Incidence of Negative Prices Associated with Operational Wind Farms: Selected Regional Results

Panel (A): Wind Exclusive Case: Proportion of Time Containing Negative Prices

Year	SW VIC	SE SA	ADEL	RIVERL	MN SA
Node	33	35	37	38	39
2007	0.016	0.028	0.028	0.029	0.029
2008	0.009	0.020	0.020	0.022	0.020
2009	0.011	0.024	0.024	0.026	0.024
2010	0.008	0.020	0.020	0.022	0.021
2011	0.010	0.030	0.030	0.031	0.030
2012	0.018	0.038	0.039	0.039	0.039

Panel (B): Percentage Change in the Incidence of Negative Prices

Year	SW VIC	SE SA	ADEL	RIVERL	MN SA
Node	33	35	37	38	39
2007	-2.94	1.80	2.20	8.00	2.20
2008	-3.03	1.14	1.41	0.52	1.12
2009	-10.33	-0.09	1.80	7.62	1.32
2010	-6.33	-0.91	-0.32	-1.58	-2.79
2011	-13.98	4.58	5.65	20.58	5.65
2012	-19.81	9.20	11.61	23.04	11.59

The first observation to note is that negative prices did arise under the 'no wind' scenario. It is apparent that the proportion of time outlined in Panel (A) during which negative prices occurred increases overtime. For example, in 2012, the 0.018 value associated with South West Victoria represents 308 half hours during which negative prices were recorded in 2012 at that node. The 0.018 proportion value can also be interpreted as signifying that negative prices arose at this node around 1.8 per cent of the time in 2012. Similarly, the value 0.039 recorded for Adelaide represents 689 half hours in the calendar year 2012 during which negative prices were recorded at the Adelaide node – equivalently, around 3.9 per cent of the time in 2012 at the Adelaide node. Note that in 2012, there were 17,568 half hours in the year. One explanation for the increasing trend observed in Table 13, Panel (A) especially over period 2011-2012 was the effect of declining demand. Specifically, must run requirements of baseload plant, in particular, had to be set against a demand base that was declining in magnitude over years 2011-2012.

In Panel (B) of Table 13, the negative entries for the South West Victoria node indicate that the inclusion of wind generation had the effect of actually reducing the number of half hours with negative prices when compared against the ‘no wind’ scenario. This contrasts with the situation in South Australia with the predominance of positive entries indicating, across all relevant nodes, an increase in the incidence of negative prices. This increase in magnitude of the positive results also indicates that this effect becomes more prominent over the period 2011-2012, coinciding with the expansion of wind farm capacity especially in the Mid North South Australian node and, to a less extent, in the South East South Australian node.

The increased incidence of negative prices is particularly noticeable in its impact on the Riverlands node, which is especially interesting given that no occurrence of negative prices arose in the Regional Victoria node. For this nodal price separation to occur between these two inter-connected nodes, the periods of negative prices in Riverlands must also have coincided with periods of congestion on the Murraylink interconnector. Note that evidence in support of branch congestion on Murraylink was reported in Table 4, Panel (B). The converse, however, seems to arise between the South West Victoria and South East South Australia nodes. For South West Victoria to experience a relatively high incidence of negative prices in contrast to the other Victorian nodes, this must mean that the South West

Victorian and South East South Australian nodes have the same marginal price setting generator which is different from that associated with other nodes in Victoria during the incidence of negative price events. This can only arise if these periods of negative prices coincide with periods in which there is no congestion on the Heywood interconnector. Evidence pointing to very low levels of branch congestion on Heywood was also reported in Table 4. Moreover, these considerations once again clearly demonstrate the importance of capacity and congestion effects on transmission branches which are capable of propagating negative price outcomes on the one hand or islanding off regions from the impact of negative prices, on the other.

One possible remedy for removing the incidence of negative price outcomes is to expand the export capability of the affected regions - see Holttinen *et al.*, (2009). In this case, the expansion of reverse direction export capacities of the Heywood and Murraylink interconnectors would enable the export of surplus South Australian wind (and thermal) power to Victoria which has a greater capability to absorb this extra generation output without unduly affecting must run generation located in that state given its much larger demand base. This would also have the added advantage of alleviating the need to spill wind power to balance the network in low demand periods in South Australia because of insufficient export capability.

To investigate this possible remedy further, two particular transmission augmentation scenarios are considered. The first relates to the ‘smaller’ augmentation of the baseline transmission branches connecting Dederang-Regional Victoria; Melbourne-Regional Victoria; South West Victoria-South East South Australia (Heywood interconnector); Regional Victoria-Riverlands (Murraylink interconnector); and Riverlands-Mid North South Australia – see Figures 3-4 for details. These smaller transmission augmentations amount to doubling the existing MW capacity of these transmission branches, and is subsequently termed the ‘minor transmission augmentation scenario’.

A larger transmission augmentation scenario considered involved incorporating a version of the NEMLINK proposal into the transmission grid structure – see AEMO (2010, 2010a, 2011, 2011a) for further details. This involved adding a double circuit 500 kV transmission branch into the existing baseline transmission branch structures linking Upper North South Australia-Mid North South Australia-Riverlands-Regional Victoria-Tumut-Yass-Marulan-Sydney; Newcastle-Liddell-Tamworth-Armidale-South West Queensland. It should be noted that this transmission structure also includes the existing 500 kV branches linking Marulan-Mt Piper-Bayswater and with a new double circuit 500 kV branch linking Bayswater and Liddell. This larger augmentation scenario also has a double circuit 500 kV branch linking Melbourne and Regional Victoria and a new double circuit 220 kV branch connecting Burnie and Sheffield. It does not, however, include the second HVDC branch linking Burnie and South West Victoria as has been proposed in the NEMLINK proposal. This particular scenario is termed the ‘major transmission augmentation scenario’.

It should be noted that both transmission augmentation scenarios considered involve some degree of expansion in the export capability from South Australia to Victoria. The results associated with the incidence of negative prices under the two above transmission augmentation scenarios are reported in Table 14. In Panel (A), we document the proportion of time in each year that negative prices were obtained for the ‘wind inclusive’ scenario considered above which incorporates the underlying baseline transmission network structure. The proportion values reported in Panels (A)-(C) of Table 14 were calculated in the same way as discussed in relation to Panel A of Table 13. This process was also applied to the two transmission augmentation scenarios mentioned above and the results are reported in Panels

(B) and (C) of Table 14 for the minor and major transmission augmentations scenarios, respectively. Note that in all panels of Table 14, the results are only reported for nodes containing negative prices.

Table 14. Incidence of Negative Prices Associated with Operational Wind Farms: Selected Regional Results

Panel (A): Wind Inclusive Scenario: Proportion of time containing negative prices

Year	SW VIC	REG VIC	SE SA	ADEL	RIVERL	MN SA
Node	33	34	35	37	38	39
2007	0.015	0.000	0.029	0.029	0.031	0.029
2008	0.009	0.000	0.020	0.020	0.022	0.021
2009	0.010	0.000	0.024	0.025	0.028	0.025
2010	0.008	0.000	0.020	0.020	0.022	0.020
2011	0.009	0.000	0.031	0.032	0.037	0.032
2012	0.014	0.000	0.041	0.044	0.048	0.044

Panel (B): Minor transmission augmentation: Proportion of time containing negative prices

Year	SW VIC	REG VIC	SE SA	ADEL	RIVERL	MN SA
Node	33	34	35	37	38	39
2007	0.000	0.003	0.000	0.000	0.003	0.000
2008	0.000	0.001	0.000	0.000	0.000	0.000
2009	0.000	0.001	0.000	0.000	0.000	0.000
2010	0.000	0.001	0.000	0.000	0.000	0.000
2011	0.000	0.001	0.000	0.000	0.000	0.000
2012	0.000	0.000	0.000	0.000	0.000	0.000

Panel (C): Major transmission augmentation: Proportion of time containing negative prices

Year	SW VIC	REG VIC	SE SA	ADEL	RIVERL	MN SA
Node	33	34	35	37	38	39
2007	0.000	0.000	0.000	0.000	0.000	0.000
2008	0.000	0.000	0.000	0.000	0.000	0.000
2009	0.000	0.000	0.000	0.000	0.000	0.000
2010	0.000	0.000	0.000	0.000	0.000	0.000
2011	0.000	0.000	0.000	0.000	0.000	0.000
2012	0.000	0.000	0.000	0.000	0.000	0.000

It is apparent that the proportion of time outlined in Panel (A) of Table 14 during which negative prices occurred varies somewhat over years 2007-2010 before increasing unambiguously over years 2011-2012 accompanying the significant expansion in wind farms located particularly in the Mid-North South Australian node. Specifically, in 2012, the 0.014 value associated with South West Victoria represents 247 half hours or 1.4 per cent of the time in 2012. Similarly, the value 0.044 recorded for Adelaide represents 769 half hours in the calendar year 2012 or occurring around 4.4 per cent of the time in 2012 at the Adelaide node.

Inspections of Panels (B) and (C) demonstrate that the augmentation of the export capacity from South Australia to Victoria in both transmission augmentation scenarios has largely eliminated the incidence of negative prices in the case of the minor scenario [e.g. in Panel (B)] and has totally eliminated the incidence of negative prices in the case of the major augmentation scenario [e.g. in Panel (C)]. In the case of the minor transmission augmentation scenario, negative prices are restricted to the Regional Victorian and Riverlands nodes. In this context, a qualitative change has emerged relative to the 'wind inclusive' scenario results cited in Panel (A) [and in Table 13] in that there was no incidence of negative prices recorded at this node in the former case – see Panel (A) of Table 14 and Table 13. Moreover, the situation in Panel (B) can only arise if there is no congestion on the Murraylink interconnector during these negative price events. This situation is also qualitatively different to the situation underpinning the results listed in Table 13 and Table 14, Panel (A) which indicated congestion on Murraylink had the effect of islanding off the Regional Victoria node from the negative price events arising in South Australia.

In Panel (B), those nodes containing negative prices are shaded in red. In order to obtain some scope of the magnitudes involved, the result for Regional Victoria (REG VIC) in

2007 of 0.3 per cent corresponds to negative prices arising over 53 half- hourly dispatch intervals while the number of half hours corresponding to Riverlands node in 2007 corresponds to 44 half-hourly dispatch intervals – the difference in values being explained through the rounding employed in Table 14. Note that these two values constitute the years containing the largest incidence of negative prices for these two nodes. Similarly, the lack of red shading in Panel (C) demonstrates the finding that there is no incidence of negative prices at any of the nodes listed in Panel (C) in the case of the major transmission augmentation. Thus our analysis indicates that the incidence of negative price events in South Australia could be attributed to insufficient export capability of the existing interconnectors linking South Australia and Victoria.

Transmission Network Adequacy: Spillage Impacts

In the modelling, wind generation was assumed to be dispatched with supply offers based upon short run marginal costs and with the maximum capacity of wind generation offered to the market also being linked to observed production levels. However, actual dispatch of wind generation might be constrained to be less than the maximum production available depending upon prevailing demand, assumptions made about generation production constraints, unit availability and must-run characteristics as well as transmission network limits. By comparing the production results from the transmission augmentation scenarios with those of the ‘wind inclusive’ scenario which incorporates the existing transmission network structure and operational wind farms, we can examine the extent to which the current transmission structure might have constrained production from wind generation, leading to the spillage of wind power. This case would emerge if wind generation production levels subsequently exceeded the baseline levels under the two particular transmission augmentation scenarios considered, given that all scenarios inherit the same potential maximum wind generation production levels and demand profiles, by construction.

To investigate the scope for the possible spillage of wind power because of 'diminished' capacity of the existing transmission network, we divided the baseline 'wind inclusive' state wind generation productions levels by those state production levels associated with the two transmission augmentation scenarios. If the value of the ratio is less than one, this implies a wind spillage effect because the baseline wind generation production levels are less than the relevant transmission augmentation scenario's wind generation production levels. Conversely, a proportional value greater than unity implies that the production levels associated with the baseline scenario are larger when compared with the relevant transmission augmentation scenario's wind generation production level. Finally, a proportional value of unity implies that the production levels under the baseline and transmission augmentation scenario coincide.

These results for the minor and major augmentation scenarios are outlined in Panels (A) and (B) of Table 15, respectively. Note that proportional values less than unity are shaded in green while proportional values greater than unity are shaded in blue. It is evident from Panel (A) that spillage effects arise in South Australia and these effects tend to increase with time in the interval 2007-2012, accompanying the expansion in wind generation production in that state. Specifically, the increased spillage of wind power is denoted by the reduction in the magnitude of the values reported for South Australia in column four of Panel (A) of Table 15, which records a fall from 0.96 in 2008 to 0.78 in 2012. Moreover, the spillage effects in South Australia are large enough to more than compensate for increases in production observed in Victoria, producing an overall net spillage effect in wind power over the NEM as a whole – e.g. see the last column of Panel (A) of Table 15. Therefore, this result suggests that the minor transmission augmentation would allow, in aggregate, more wind power especially sourced from South Australia to get to market, however, at the expense of some production from especially Victoria.

Table 15. Spillage of wind power relative to Baseline 'Wind Inclusive' Scenario

Panel (A): Minor transmission augmentation scenario

Year	NSW	VIC	SA	TAS	NEM
2007	na	1.01	0.95	1.00	0.97
2008	na	1.01	0.96	1.00	0.98
2009	1.00	1.06	0.88	1.00	0.94
2010	1.00	1.07	0.85	1.00	0.93
2011	1.00	1.09	0.79	1.00	0.89
2012	1.01	1.07	0.78	1.00	0.89

Panel (B): Major transmission augmentation scenario

Year	NSW	VIC	SA	TAS	NEM
2007	na	0.99	0.94	1.00	0.96
2008	na	0.99	0.96	1.00	0.98
2009	1.00	1.00	0.88	1.00	0.93
2010	1.01	1.00	0.85	1.00	0.92
2011	1.01	1.00	0.78	1.00	0.87
2012	1.02	1.00	0.77	1.00	0.87

In the case of the major transmission augmentation scenario, it is evident from Panel (B) that spillage effects arise in South Australia and also Victoria (over years 2007-2008) with the effects in South Australia also tending to increase with time over the interval 2007-2012. These reductions are large enough in magnitude to more than compensate for slight increases in production arising in New South Wales over years 2010-2012. This produces a net spillage effect in wind power over the NEM as a whole as reported in the last column of Panel (B), which broadly increases over years 2007-2012. Therefore, this result suggests that the major transmission augmentation would allow, in aggregate, more wind power sourced especially from South Australia and, to a less extent Victoria, to get to market, however, at the (very slight) expense of some production from New South Wales from 2010. Finally, comparison of the last columns in Panel (A) and (B) of Table 15 also indicate slightly larger spillage effects associated with the major transmission augmentation scenario, when compared with the spillage rates associated with the minor transmission augmentation scenario. That is, the major transmission augmentation scenario allows slightly more wind power to reach market than is the case with the minor transmission augmentation scenario.

The key message from Table 15 points to the benefits of transmission augmentation in allowing more wind generation output sourced from South Australia and, to a less extent, from Victoria to get to market than is apparent from simulations utilising the current transmission network. However, whether such expansion proposals would be successful under the current transmission network expansion framework encapsulated in the 'RIT-T' Framework (AEMO 2014) is uncertain.

One reason for this is that the current test framework seems to be aligned towards the more conventional problem of transmission network augmentations to meet peak load demand. However, as mentioned in relation to the issue of negative prices, our concern is with a situation that is likely to reflect insufficient demand relative to must run capacity and wind power which requires the spillage of wind or thermal power in the absence of sufficient export capacity in order to balance the network. This is likely to be prevalent during off-peak periods. Thus, the transmission expansion scenarios mentioned above were not introduced with the intention to meet peak load demand conditions, but in handling potential adverse consequences arising in the case of insufficient demand during off-peak periods that could lead to negative prices and the spillage of wind power. Whether the RIT-T framework is suitable to accommodate this type of problem remains an open question.

Summary of Results

In this submission, we have reported on a detailed investigation of the impact of wind generation in the NEM. To accomplish this, we used the agent based ANEM model of the Australian National Electricity Market, incorporating a DC OPF algorithm to determine optimal dispatch of generation plant, power flows on transmission branches and wholesale prices. The wind generation component included in the modelling involved thirteen non-scheduled and thirteen semi-scheduled wind farms with a combined capacity of 2471.8 MW which represents 96.8 per cent of total installed capacity of operational wind farms in the NEM at the end of 2012.

Two broad modelling scenarios were considered. A baseline ‘no-wind’ scenario involved assuming no contributions from wind generation with demand having to be met from thermal and hydro generation. The second scenario incorporated actual half-hourly output traces from operational wind farms and was termed the ‘wind inclusive’ scenario. In the latter scenario, wind generation was modelled according to short run marginal costs and was one of the cheapest forms of generation incorporated in the modelling. There are a number of broad conclusions:

Wholesale Price Impacts:

All states experience a reduction in average annual wholesale electricity prices associated with the inclusion of operational wind farms with those states with the largest number of operational wind farms experiencing the greatest reductions in average annual prices. The stand-out states are South Australia and Victoria. Reductions in average annual prices also increase over time reflecting the expansion in semi-scheduled wind generation in South Australia, Victoria and New South Wales over the time interval 2010-2012.

Merit Order Effect - Production Trends:

South Australia and Tasmania experienced the greatest reductions in production from thermal and hydro generation associated with wind generation. Queensland and Victoria experienced the lowest rates of reduction in thermal and hydro production with New South Wales lying between these two extremes The magnitude of the size of the reductions also increased unambiguously over the time interval 2007-2012 in response to the actual expansion in production from wind generation in the NEM.

South Australia experienced relatively high reductions in production from coal-fired generation, whilst, in contrast, Victoria experienced very small reductions in production from coal-fired generation, with New South Wales, once again, fallingl in between these two extremes.

Wind generation also led to significant displacement of gas-fired production from particularly Victoria associated primarily with the displacement of OCGT plant. South Australia also experienced noticeable reductions in output from gas-fired plant, encompassing reductions in production from both NGCC and Gas Thermal plant as well as the sizeable displacement of production from OCGT plant. Queensland and New South Wales, in contrast, experienced no real impact on production from gas generation. In the case of Tasmania, this state experienced relatively large reductions over 2007-2008 followed by much smaller rates of decline over the remainder of the period under investigation. This pattern was linked to commissioning of the Tamar Valley NGCC plant which had a different operational configuration to the OCGT gas plant operational over 2007-2008.

Tasmania also experienced a relatively stable profile of reductions in production from hydro generation which declined unambiguously over years 2008-2012. Reductions in hydro generation production in New South Wales and Victoria were more marked and variable in nature, but coming off much lower production levels. Wind generation had no discernible impact on hydro production in QLD.

The evidence of displacement of production from OCGT plant in Victoria and South Australia and production from hydro generation in Tasmania, and more episodically in

Victoria and New South Wales was consistent with what would be expected under high wind penetration regimes to ensure balancing within the network. Specifically, the fast-start/stop and fast ramping capability of OCGT and hydro generation provides the required characteristics needed to help balance the system in the face of significant variations in wind farm output associated with the intermittency of wind power.

Carbon Emissions:

The impact of wind generation in the NEM was to reduce carbon emissions in all states. The stand-out state was South Australia. In contrast, the impact on carbon emissions in Victoria was quite marginal, reflecting the very small impact that wind generation had on displacing production from brown coal-fired generation in that state. New South Wales experienced greater cuts in carbon emissions than Queensland reflecting the partial displacement of production from New South Wales black coal-fired generation. In the case of Tasmania, larger reductions arose over the 2007-2008 period reflecting displacement of output from OCGT plant by wind power. Much smaller reductions over the period 2009-2012 were associated with the commissioning of Tamar Valley NGCC plant in 2009 and its subsequent dispatch at levels close to its minimum stable operating level, producing relatively stable production and carbon emission time profiles.

Savings in System-wide Total Variable Costs:

Apart from 2009, reductions in system-wide total variable costs occurred and generally increased in magnitude over the time period 2010-2012 accompanying the expansion in semi-scheduled wind generation in South Australia, New South Wales and Victoria. When considered over the complete period 2007-2012, reduction in system-wide total variable costs was $874.8 million, representing a decline of 2.21 per cent from the equivalent result obtained from the ‘no wind’ scenario.

Incidence of Negative Prices and Wind Spillage Effects:

The possibility of increased incidence of negative prices accompanying the expansion in wind generation was also canvassed. This possibility was associated with a situation whereby significant wind generation output coincided with periods of low demand such as off-peak periods at night. Under these circumstances, demand is often not sufficient to meet both the output from wind generation and the non-zero minimum stable operating levels of plant with must run characteristics such as coal or gas thermal plant.

We found that negative prices arose under the ‘no wind’ scenario. Evidence also pointed to the increased incidence of negative prices when wind generation was included in the analysis. A possible remedy for removing the incidence of negative price outcomes was to expand the export capability of the affected regions to allow surplus wind generation output to be exported to other regions within the electricity network. We examined this option using two particular transmission augmentation scenarios. The first termed the minor transmission augmentation scenario involved doubling the capacity of the transmission branches connecting Mid-North South Australia; Riverlands; Regional Victoria; Dederang; and Melbourne. The second involved augmenting the existing network structure with a major high voltage backbone based on the NEMLINK proposal which involved interconnecting South Australia, Victoria, New South Wales and Queensland.

We found that both transmission augmentation scenarios largely or completely eliminated the incidence of negative prices. Our modelling also showed that when compared to the transmission augmentation results, wind spillage effects were associated with the current network. This was related especially to significant spillage effects occurring in South Australia. More generally, the observed reduction in negative prices and wind power spillage effects pointed to potential benefits associated with transmission network augmentation.

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Appendix A. List of non-scheduled and semi-scheduled generation included in the modelling

Panel (A). Non-scheduled wind farms

Wind Farm	Nodal Location	Capacity (MW)
Capital	Canberra	140.7
Cullerin Range	Canberra	30.0
Yambuk	South West VIC	30.0
Portland	South West VIC	102.0
Waubra	Regional VIC	192.0
Challium Hills	Regional VIC	52.5
Canundra	South East SA	46.0
Lake Bonney 1	South East SA	80.5
Starfish Hill	Adelaide	34.5
Wattle Point	Mid-North SA	90.8
Mount Millar	Eyre Peninsula	70.0
Cathedral Rock	Eyre Peninsula	66.0
Woolnorth	Burnie (TAS)	139.8
Total		1267.9

Panel (B). Semi-scheduled wind farms

Wind Farm	Nodal Location	Capacity (MW)
Gunnings Range	Canberra	46.5
Woodlawn	Canberra	48.3
Oaklands Hill	South West VIC	67.2
Macarthur	South West VIC	420.0
Lake Bonney 2	South East SA	159.0
Lake Bonney 3	South East SA	39.0
Snowtown 1	Mid-North SA	98.7
Hallett 1	Mid-North SA	94.5
Hallett 2	Mid-North SA	71.4
Clements Gap	Mid-North SA	56.7
Waterloo	Mid-North SA	111.0
North Brown Hill	Mid-North SA	132.3
The Bluff	Mid-North SA	52.5
Total		1203.9
Combined Total		2471.8

Panel (C). Excluded smaller non-scheduled wind farms

Wind Farm	Nodal Location	Capacity (MW)
Windy Hill	Far North QLD	12.0
Crookwell	Marulan (NSW)	4.8
Blayney	Mt Piper (NSW)	9.9
Toora	Morwell (VIC)	21.0
Wonthaggi	Morwell (VIC)	12.0
Codrington	South West VIC	18.2
Hepburn	Regional VIC	4.1
Total		82.0
Proportion of Total Wind Capacity		0.032 (or 3.2%)

Panel (D). Non-scheduled generation other than wind farms

Name	Nodal Location	Generation Type
Butlers Gorge	Tarraleah (TAS)	Hydro
Clover	Dederang (VIC)	Hydro
Cluny	Liapootah (TAS)	Hydro
Broken Hill GT 1	Tumut (NSW)	Diesel
Broken Hill GT 2	Tumut (NSW)	Diesel
Invicta Mill	Ross (QLD)	Sugar Cane (Bagasse)
Paloona	Sheffield (TAS)	Hydro
Pioneer Mill	Ross (QLD)	Sugar Cane (Bagasse)
Repulse	Liapootah (TAS)	Hydro
Rowallan	Sheffield (TAS)	Hydro
Rubicon	Melbourne	Hydro
Warragamba	Sydney	Hydro
Rocky Point	Moreton South (QLD)	Biomass (Bagasse/Wood Chips)
Callide A	Central West QLD	Coal
Angaston 1	Mid-North SA	Diesel
Angaston 2	Mid-North SA	Diesel

Figure 1. QLD 11 Node Model - Topology

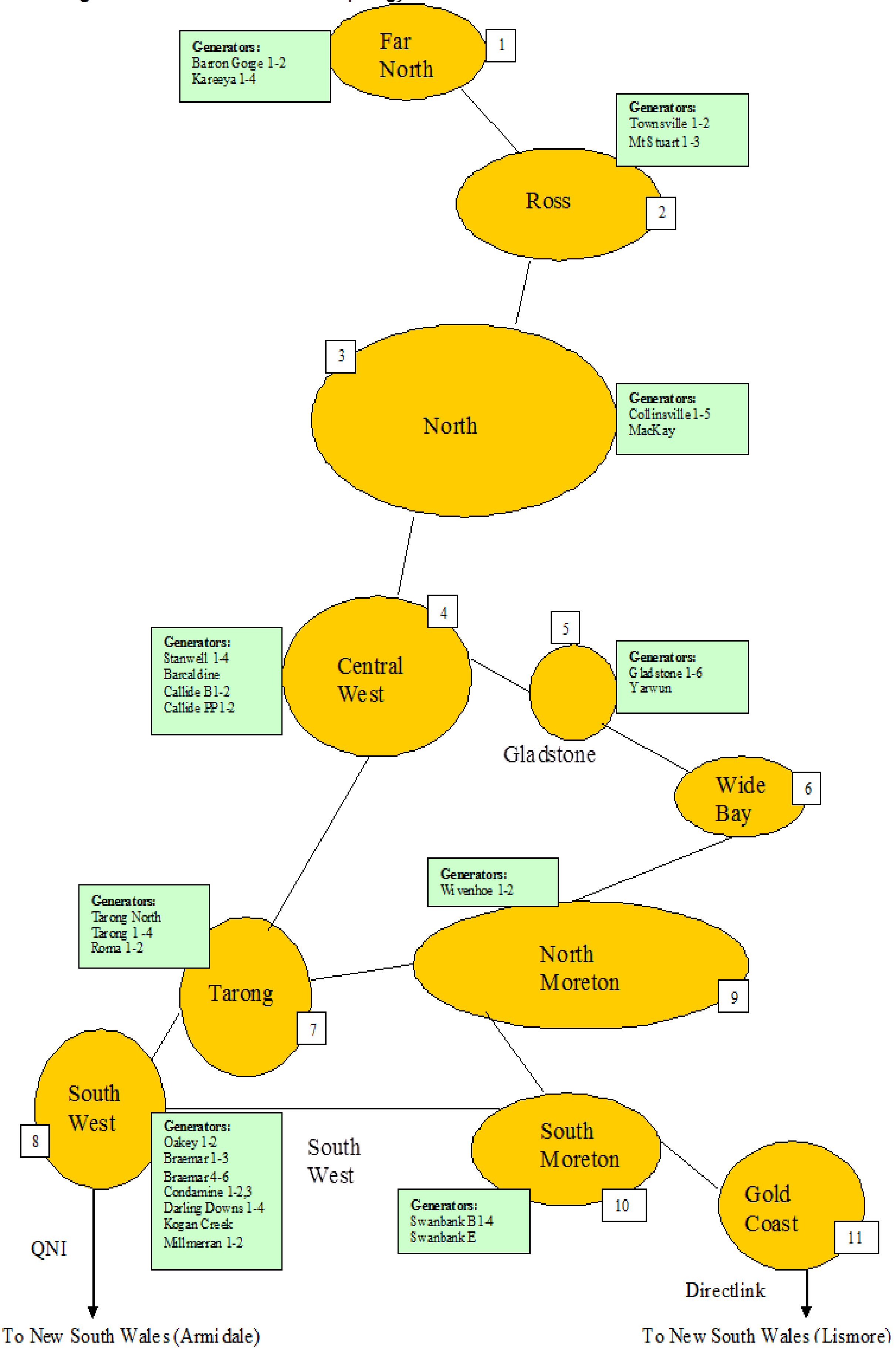
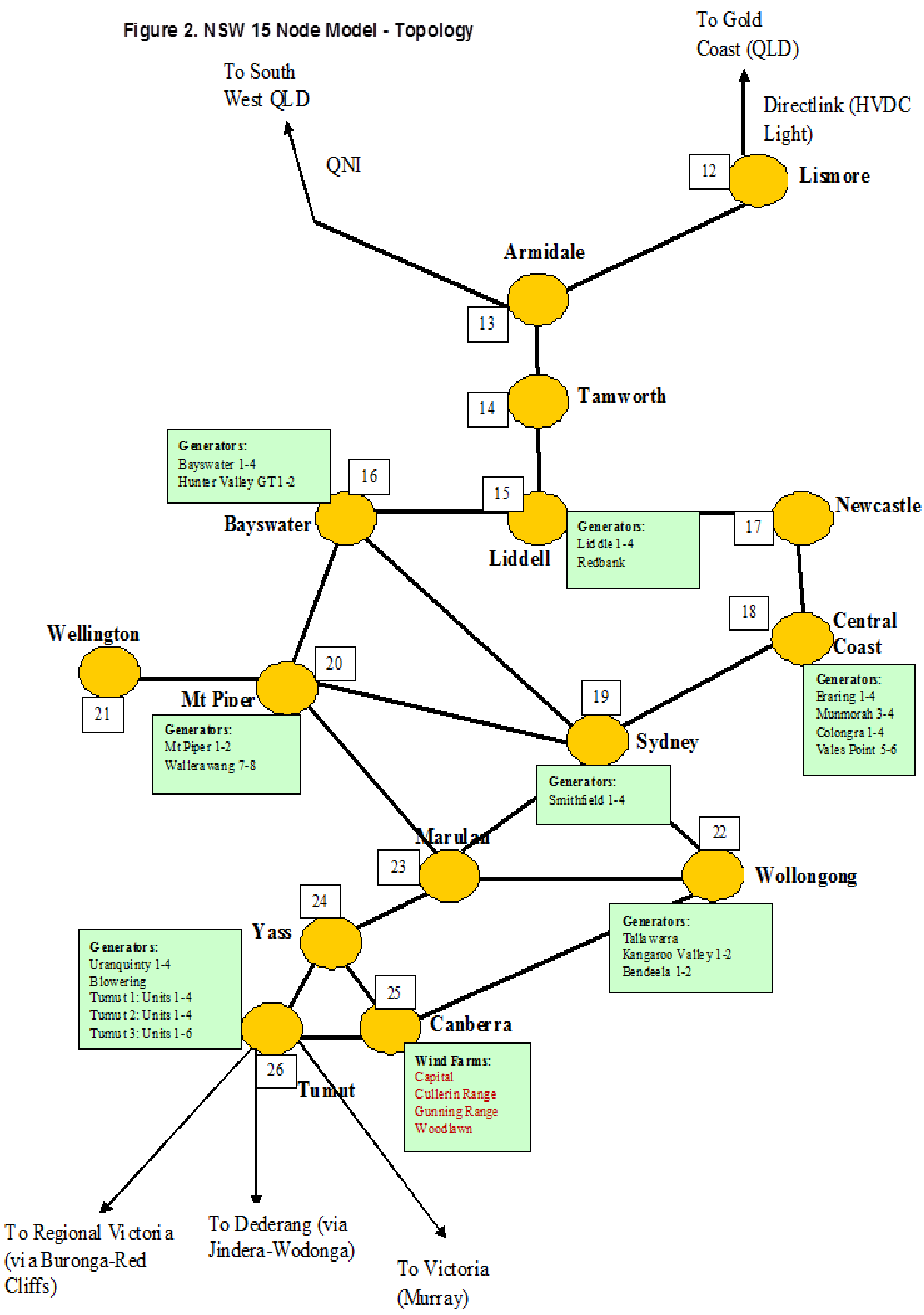


Figure 2. NSW 15 Node Model - Topology



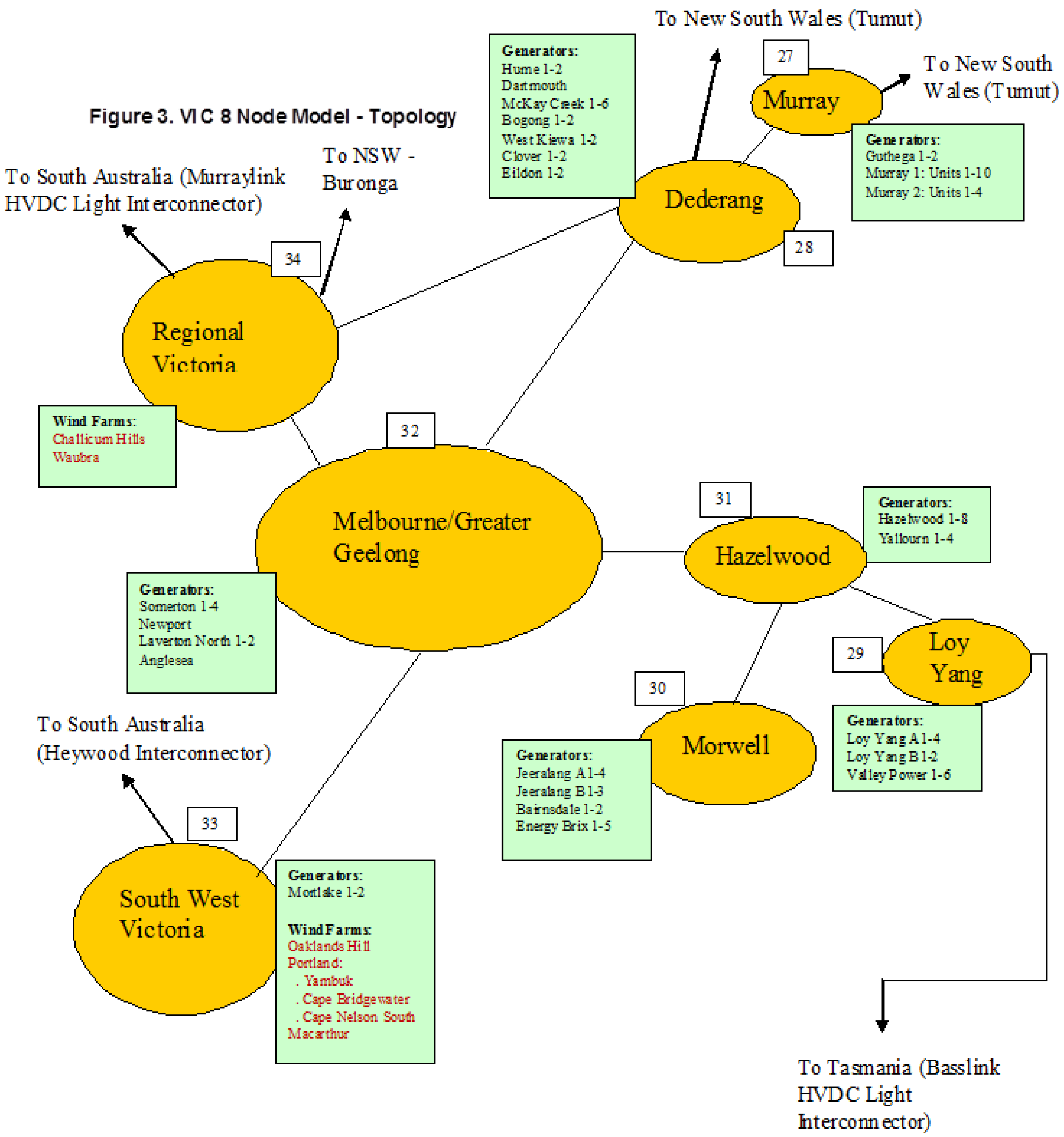


Figure 3. VIC 8 Node Model - Topology

To New South Wales (Armidale)

Figure 4. SA 7 Node Model - Topology

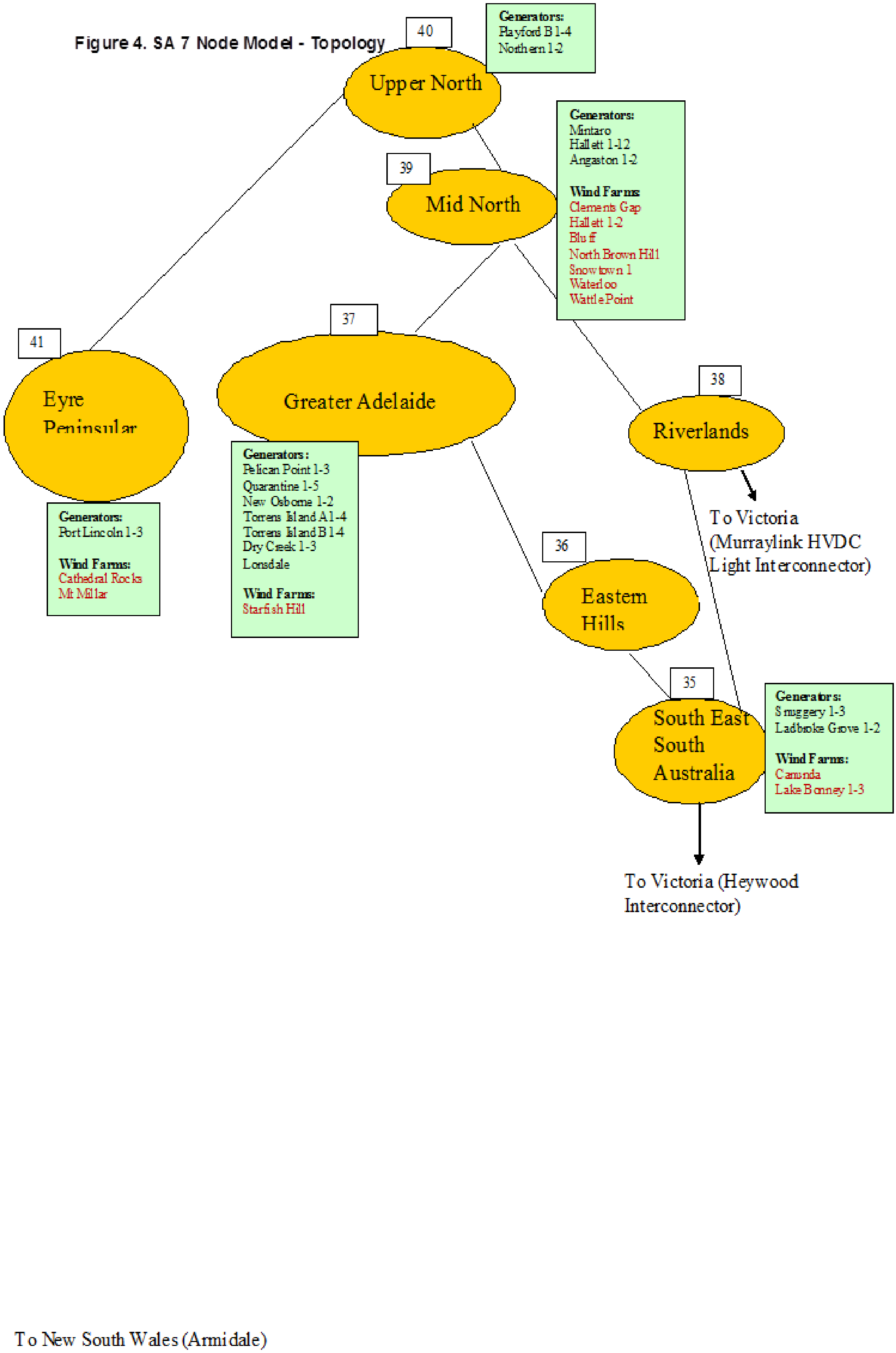
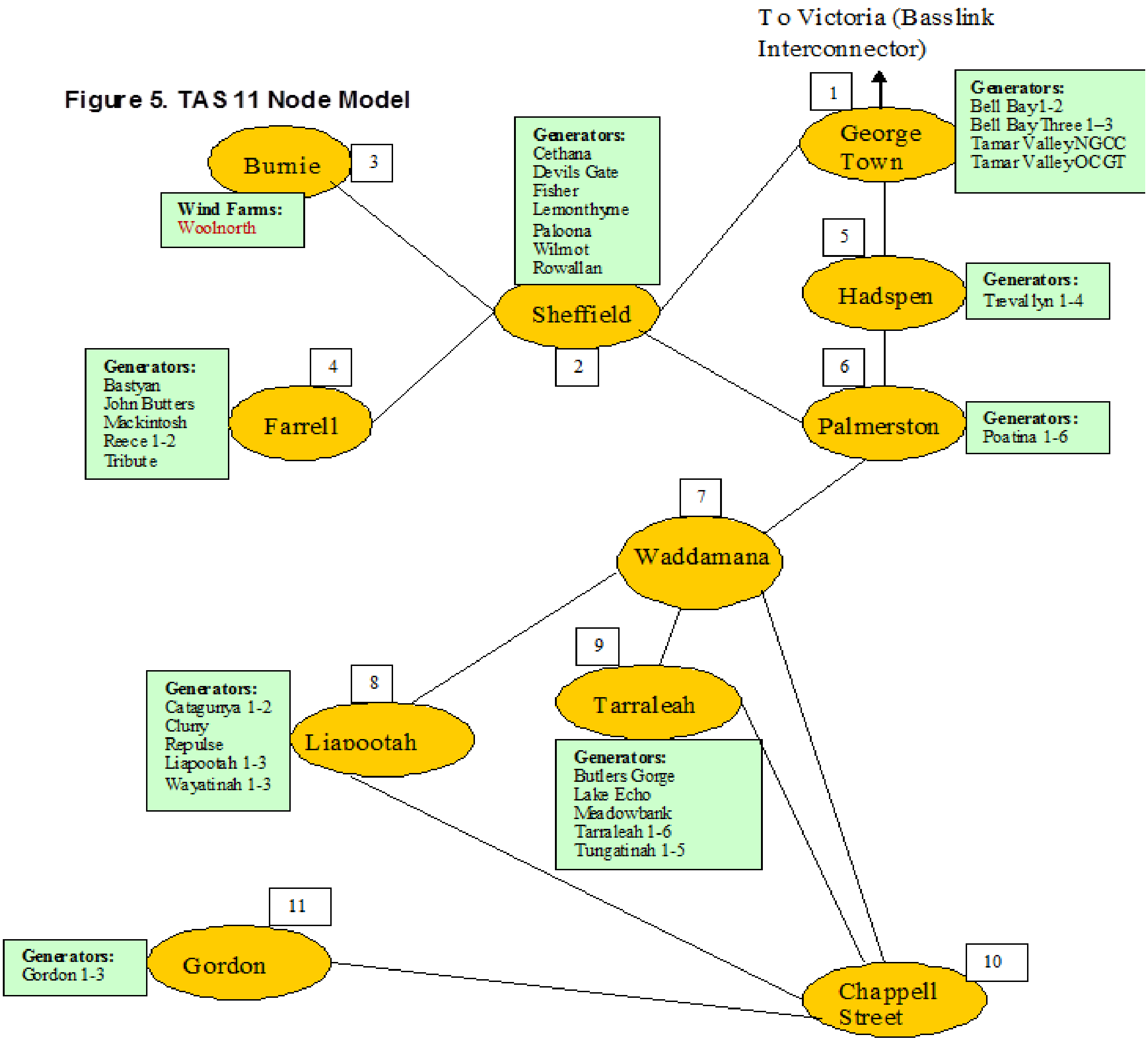


Figure 5. TAS 11 Node Model



To New South Wales (Armidale)