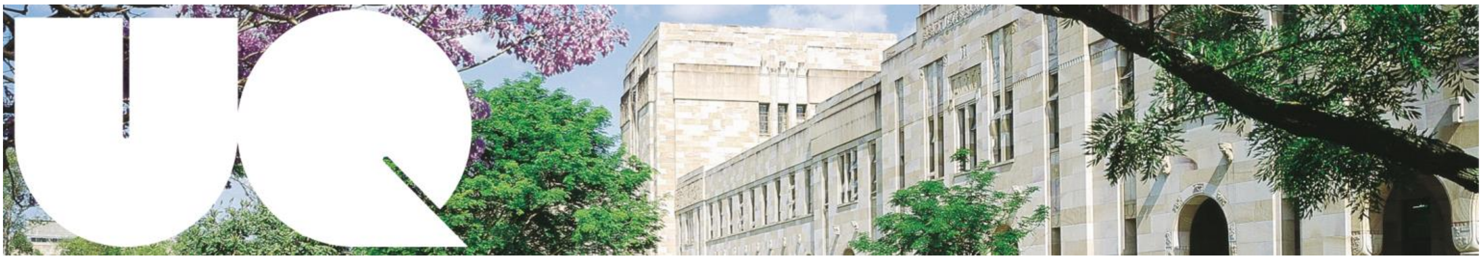

Impact of Operational Wind Generation in the Australian National Electricity Market over 2007-2012.

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ABSTRACT

This paper investigates the effect of wind generation in the states comprising the Australian National Electricity Market (NEM). The methodology utilize an agent based model, which contains many features salient to the NEM including intra-state and inter-state transmission branches, regional location of generators and load centres and accommodation of unit commitment features. The model uses a Direct Current Optimal Power Flow (DC OPF) algorithm to determine optimal dispatch of generation plant, power flows on transmission branches and wholesale prices. We present results of the impact of wind generation on wholesale prices, dispatch patterns, carbon emissions and transmission network adequacy within the NEM.

Keywords: carbon emissions, electricity prices, agent-based model, DC OPF Algorithm, wind generation, Australian National Electricity Market.

JEL Classifications: C61, C63, D24, L94.

Executive Summary

In this article, 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. It was argued that in order to address this, a model of the national electricity market is required that 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.

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 termed the 'wind exclusive' 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 (Section 4.1):

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 9.1 to 11.9 per cent.

Similar trends were also observed in nodal prices. This reflected the observation that close proximity to the location of wind farms seems to matter in reaping the greatest benefits from reductions in average wholesale prices. For example, Brisbane and Sydney experienced more modest reduction in average nodal prices than was the case with nodes located in Victoria and South Australia. Of the Tasmanian nodes considered (e.g. Launceston, Burnie and Hobart), both Launceston and Burnie experiencing greater reductions in average nodal prices than Hobart which was located further away from Woolnorth wind farm. In the case of Victoria and South Australia, the degree of reduction in average nodal prices was slightly larger in magnitude in South Australia when compared with Victoria, reflecting a greater degree of wind penetration in the former state when compared with the latter. For the period 2010-2012, percentage reductions in the range of 15.5 to 26.3 per cent and 21.5 to 42.1 per cent were identified for nodes located in Victoria and South Australia, respectively.

Accompanying the reduction in average wholesale electricity prices, wind generation tended to reduce price volatility in the high wind penetration states of Victoria, South Australia and Tasmania. For the interval 2010-2012, percentage reductions in average price volatility in the range of 7.1 and 30.1 per cent, 12.8 and 45.5 per cent and 11.3 to 22.3 per cent were experienced by these three states, respectively. Wind generation also tended to decrease the incidence of negative price outcomes in VIC but increased their incidence in SA, particularly over the interval 2011-2012.

Production Trends (Section 4.2):

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.

Results also pointed to wind generation impacting more heavily on old and medium vintage plant. The locational proximity of coal-fired plant to wind farms was another contributing factor affecting coal plant production outcomes in South Australia, and to a less extent, in Victoria.

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 is 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 VIC 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 NSW and VIC were more marked and variable in nature, but coming off much lower production levels and also reflecting reasonably close locational 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 (Section 4.3):

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 old and medium vintage 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 2007-2012.

System-wide Total Variable Costs (Section 4.4):

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 variable cost estimates 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 'wind exclusive' (no wind) scenario.

Transmission Network Adequacy (Section 4.5):

Wind generation reduced the magnitude of average power flows from Queensland to New South Wales on QNI, New South Wales to Victoria on Tumut-Regional Victoria interconnector and from Victoria to South Australia on the Heywood interconnector. Wind generation also increased the magnitude of average power flows from New South Wales to Queensland on Directlink and South Australia to Victoria on the Murraylink interconnector. For the Tumut-Murray and Tumut-Dederang interconnectors, the impact of wind generation was to significantly increase average power flows from Victoria to New South Wales. Finally, for the Basslink interconnector, the impact of wind generation increased the magnitude of average power flows from Victoria to Tasmania.

Our modelling also indicated that wind generation tended to ameliorate congestion on QNI, Tumut-Regional Victoria, Heywood, Sheffield-Palmerston and Waddamana-Tarraleah transmission branches while increasing congestion on the Directlink and Basslink interconnectors. It significantly increased congestion on the Murraylink interconnector.

More generally, in assessing transmission adequacy, we also investigated whether the inclusion of wind generation in the modelling made the task of obtaining an optimal solution a more easier or difficult task when running the ANEM model. The results indicated that year 2009 produced the most problematic half hourly dispatch intervals and the inclusion of wind generation had a stabilising (e.g. beneficial) effect in terms of obtaining optimal solutions. This suggested, overall, that the transmission network can adequately support the current penetration of wind generation within the NEM.

(1). Introduction

Analysis and action by Governments, policy-makers and the academic community in Australia aimed at combating the adverse consequences of climate change by reducing Greenhouse gas emissions have centred on two main policy instruments. The first instrument called the Renewable Energy Target (RET), targets the electricity industry and requires electricity retailers to purchase a prescribed amount of their total electricity requirements from renewable energy sources each year with this amount increasing annually until 2020. The RET was expanded in scope and split between small and large scale renewable energy systems (DIICCSRTE 2013a)[2]. The second major policy instrument is a broad based carbon pricing mechanism (DIICCSRTE 2013b)[3]. The first round impacts of carbon pricing on the economy acts through the electricity generation sector by changing marginal cost relativities and dispatch from generation with high carbon intensity rates to generation with lower carbon intensity rates.

Over the last decade, there has been considerable investment in wind farms in the NEM, with this investment being primarily stimulated by policies supporting renewable energy such as the RET scheme mentioned above. A complete list of wind farms included in the modelling are listed in Appendix A. This includes thirteen non-scheduled wind farms with a combined capacity of 1267.9 MW and thirteen semi-scheduled wind farms with a combined capacity of 1203.9 MW. Note further that all the semi-scheduled wind farms were commissioned on or after 2009. Finally, adding the two MW capacity figures mentioned above for both non-scheduled and semi-scheduled wind farms produces an aggregate wind generation capacity of 2471.8 MW. This aggregate capacity figure represents 96.8 per cent of total installed capacity of operational wind farms in the NEM up to the end of 2012.[4] An

[2] 'DIICCSRTE' is an acronym for Department of Industry, Innovation, Climate Change Science, Research and Tertiary Education.

[3] A fixed carbon price of $23/tC0_2$ was introduced on 1 July 2012 by the Gilliard Labour Government. However, with the more recent election of the Abbott Coalition Government in late 2013, it is the intention of this Government to repeal this mechanism.

[4] The source of this slight discrepancy relates to a number of small non-scheduled wind farms that have been excluded from the modelling. These wind farms are listed in Panel (C) of Appendix A. They were excluded from the modelling because AEMO did not have any data relating to the output of these wind farms because they did not appear to have appropriate SCADA connections with AEMO.

overview and analysis of recent developments in wind generation in the NEM can also be found in AEMO (2013c).

We use an agent-based model of the NEM called the Australian National Electricity Market (ANEM) model to estimate the impact of operational wind farms in the NEM. ANEM's methodology 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). The ANEM model fully reflects the differences between the institutional structures of the Australian and USA wholesale electricity markets.[5]

The wholesale market of the NEM is a real time, 'energy only' market and a separate market exists for ancillary services (AEMO 2010). The ANEM model uses a DC OPF algorithm to determine optimal dispatch of generation plant, power flows on transmission branches and wholesale prices. The ANEM model accommodates: intra-state and inter-state power flows; regional location of generators and load centres; demand bid information; accommodation of unit commitment features including variable generation costs, thermal limits, ramping constraints, start-up costs and minimum stable operating levels. In the ANEM model simulations, we assume that no carbon price has been implemented and the years range from 2007 to 2012.

The goal of this article is to understand and answer some key questions concerning the impacts that operational wind farms have had on wholesale electricity prices, dispatch pattern (i.e., fuel switching impacts), carbon emissions outcomes and transmission network adequacy to accommodate both wind and other forms of generation in the NEM. The potential effects on the electricity generation sector are important because it produces around 35 per cent of all $C0_2$ emissions in Australia (Simshauser 2008, Simshauser and Doan 2009, Nelson *et al.* 2010).

Note that our focus is on investigating the impact of wind generation within the current structure of the NEM while also outlining the nature and limitations of any carbon emission reductions that might emerge. Importantly, our focus is not on the potential fuel mix

[5] See Wild et al. 2012a, Section 1, for further details.

and investment patterns that might emerge over the medium to long term, which are largely speculative at this stage. In particular, wind, solar PV and solar thermal generation technologies are the only second generation renewable energy technologies that have been proven commercially. Furthermore, there currently exists enormous uncertainty about both the future prospects of emerging renewable technologies and the need for, status and timing of both thermal and renewable energy projects slated for development, against a backdrop of declining average and peak demand in the NEM. Specifically, the medium AEMO (2013b) reserve deficit projection is zero until 2022-23 with the exception of Queensland at 159MW in 2019-20. This implies an oversupply of generation capacity to meet demand, requiring no investment in new thermal plant until at least 2022-23. Compounding this is continued regulatory uncertainty over the status and target levels associated with the large scale component of the RET which is crucial for the viability of large scale renewable energy projects slated for potential development over the period to 2020.

The next section provides an outline of the ANEM model. Section 3 discusses implementation issues of the ANEM model. Section 4 will present the findings of our modelling on the impact of wind generation on the NEM. These results will relate to the wholesale electricity prices, production trends by state and fuel type, carbon emission outcomes, system-wide total variable costs and the adequacy of the transmission network. Section 5 offers conclusions.

(2). Principal features of the ANEM Model.

In this section, we provide an outline of the core features of the ANEM model which are:

1. The wholesale power market includes an ISO and energy traders that include demand side agents called Load-Serving Entities (LSE's) and generators distributed across the nodes of the transmission grid.
2. The transmission grid is an alternating current (AC) grid modelled as a balanced three-phase network.
3. The ANEM wholesale power market operates using increments of one half-hour.
4. The ANEM model ISO undertakes daily operation of the transmission grid within a single settlement system, which consists of a real time market settled using LMP.

5. For each hour of the day, the ANEM model's ISO determines power commitments and LMP's for the spot market based on generators' supply offers and LSE's demand bids which are used to settle financially binding contracts.
6. Transmission grid congestion in the spot market is managed via the inclusion of congestion components in the LMP.

The transmission grid contains 68 branches and 52 nodes covering QLD, NSW, VIC, SA and TAS where the States are linked by the following interconnectors: QNI and Directlink linking QLD and NSW; Tumut-Murray connecting NSW and VIC; Heywood and MurrayLink linking VIC and SA; and Basslink linking VIC and TAS. See Figures 1 to 5 for details.

The major power flow pathways in the model reflect the major transmission pathways associated with 275, 330, 500, 275 and 220 kV transmission branches in QLD, NSW, VIC, SA and TAS, respectively. Key transmission data required for the transmission grid relate to an assumed base voltage value in kilovolts (kV), base apparent power in three-phase megavoltamperes (MVA), branch connection and direction of flow information, maximum thermal rating of each transmission branch in megawatts (MW) and transmission branch reactance in ohms (Sun and Tesfatsion 2007a, Section 2.2). Base apparent power is set to 100 MVA, an internationally recognized value. Thermal ratings of transmission lines was constructed from data contained in AEMO (2013d) using the detailed grid diagrams in AEMO (2013e) to identify transmission infrastructure relevant to the transmission grid structure used in the ANEM model.[6] Reactance data was obtained from AEMO load flow data provided to the authors on a confidential basis.

A LSE is an electric utility that has an obligation to provide electrical power to end-use consumers (residential, commercial or industrial). The LSE agents purchase bulk power in the wholesale power market each day in order to service customer demand in a downstream retail market. We assume that retail demands exhibit negligible price sensitivity reducing to daily supplied load profiles (Sun and Tesfatsion 2007b).

[6] The ratings data in AEMO (2013d) are defined in terms of MVA. We assumed a power factor of unity to convert to MW values, which then, by assumption, correspond exactly to the MVA values listed in AEMO (2013d).

Half-hourly regional load data for QLD and NSW was derived using regional load traces supplied by Powerlink and Transgrid. This data was then re-based to the state demand totals published by AEMO for the 'QLD1' and 'NSW1' markets (AEMO 2013a). For the other three states, regional shares were determined from terminal station load forecasts contained in the annual planning reports published by the transmission companies Transend (TAS), Vencorp (VIC) and ElectraNet (SA). These regional load shares were then interpolated to a monthly time series using a cubic spline technique and then multiplied by the 'TAS1', 'VIC1' and 'SA1' state demand time series published in AEMO (2013a) to derive regional load profiles for TAS, VIC and SA.

The "demand" published in AEMO (2013a) is termed 'scheduled demand', which is 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 2012b). The only major type of 'non-hydro' renewable generation not netted from gross demand is semi-scheduled wind generation which only emerged as a generation category in April 2009.

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.[7] 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.

[7] 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.

Generators are assumed to produce and sell electrical power in bulk at the wholesale level. Each generator agent is configured with a production technology with assumed attributes relating to feasible production interval, total variable and marginal cost functions and fixed costs. Depending upon plant type, start-up costs might also be incurred. Each generator also faces MW ramping constraints that determine the extent to which real power production levels can be increased or decreased within the half-hourly dispatch horizon. Production levels determined from the ramp up and ramp down constraints must fall within the minimum and maximum thermal MW capacity limits of each generator.

The MW production and ramping constraints are defined in terms of ‘energy sent out’ – i.e. energy available to service demand. In contrast, variable costs and carbon emissions are calculated from the ‘energy generated’ production concept which is defined to include energy sent out plus a typically small amount of additional energy that is produced internally as part of the power production process. Variable costs of each generator are modelled as a quadratic function of hourly real energy produced by each generator (Sun and Tesfatsion 2007b). The variable cost concept employed incorporates fuel, variable operation and maintenance (VO&M) costs and carbon cost components. Fuel, VO&M and carbon emissions/cost parameterisation was determined using data published in ACIL Tasman (2009) for thermal plant and from information sourced from hydro generation companies for hydro generation plant.[8]

Wind farms are assumed to construct supply offers for their output based upon their variable costs. As such, they are assumed to operate as semi-scheduled plant. The notional allocation of operating costs to fixed and variable categories is controversial. The main components of operating expenses relate to:

- Warranty and Non-Warranty Scheduled and Unscheduled Operations and Maintenance (O&M) on a per Wind Turbine Generator (WTG) basis – e.g. an individual wind turbine basis;
- Insurance costs on a WTG basis;
- Balance of Plant O&M;
- Audit and Regulatory expenses per WTG; and

[8] A derivation of the various cost components is outlined in Appendix A of Wild et al. 2012a.

- Transmission Connection Fees.

In relation to the first component, the warranty period usually relates to the first five years of the WTG's life, with the non-warranty period corresponding to the remainder of its life (usually a fifteen to twenty year period). The time profile of WTG O&M incurs escalation during the post warranty period of around 30% every five years to account for increased expenditure associated with wear and tear over the WTG's operational life. Increases in non-warranty period Balance of Plant O&M and WTG insurance costs also occur over and above equivalent costs incurred during the warranty period. The magnitude of the transmission connection fees depends upon the Transmission Network Service Provider (TNSP), existing infrastructure and the underlying voltage of the transmission connection. In principle, it will be cheaper to connect to an existing substation than to one built particularly for the wind farm, and it will also be cheaper to connect to a lower voltage substation (e.g. 132 kV) than a higher voltage substation (e.g. 500 kV).

As mentioned above, the categorisation of operational expenses into fixed and variable components attracts some controversy. This principally surrounds whether the treatment of WTG O&M can be classified as a fixed or variable cost, with this categorisation also potentially depending upon whether this expenditure arises in the warranty or post warranty period. Because WTG O&M during the post warranty period can be directly linked to operating hours and practices, this would seem to more closely reflect a variable cost. However, expenditure relating to WTG O&M during the warranty period is much more regulated in nature, with its schedule being determined by the agreement between the wind farm operator and WTG supplier, thereby more closely approximating a fixed cost. Whatever the classification adopted, the higher the variable cost component, the higher will be the ($/MWh) supply offer coefficient that is bid by the wind farm operator when basing supply offers on variable costs.

In this paper, we assume that 85% of total operating costs of wind farms are fixed costs whilst the remaining 15% are variable costs. Note that this split is likely to be significantly different if most of the WTG O&M was classified as a variable cost. Total operating costs were calculated using a representative ($/kw) value determined from data associated with the AGL Hallett wind farms portfolio. This representative ($/kw) value was then used to estimate total operating costs for the other operational wind farms, taking into account their MW capacities.

In order to calculate the short run supply offer coefficients, we calculated the $m pa total variable operating costs from the $m pa total operating expenses and then divided this by the annual output of the wind farm. This latter concept was calculated as the product of each wind farms capacity factor, number of hours in the year and total MW capacity of each wind farm. For example, for a fictional wind farm, assume operational expenses of $6.75m pa producing fixed and variable splits of $5.74m and $1.01m pa respectively assuming the split of 0.85/0.15 for fixed and variable expenses as mentioned above. The assumed capacity factor for this wind farm is 0.39 and its maximum MW capacity is 90.5MW. Thus, assuming 365 days in the year, the output for this wind farm is calculated as 8760 hours multiplied by 0.39 multiplied by 90.5MW, giving 309184.2 MWh per year or 309.18 GWh per year. Therefore dividing the dollar variable cost expense component of $1,012,500 by the output of 309184.2 MWh produces a variable cost coefficient of $3.27/MWh which is assumed to be offered by the wind farm when bidding its output in the wholesale market.

The assumptions about the split between fixed and variable costs above ensured that supply offers by wind farms were towards the bottom of the merit order ensuring a high probability of dispatch when compared to other competing types of generation. Moreover, the higher the capacity factor of the wind farm, the lower would be the supply coefficient. In general, the ($/MWh) supply offers of wind farms used in the modelling was in the range of $3.39/MWh to $4.69/MWh, and are amongst the cheapest forms of generation incorporated in the modelling.

Optimal dispatch, wholesale prices and power flows on transmission branches are determined in the ANEM model by a DC OPF algorithm. The DC OPF algorithm utilised is that developed in Tesfatsion and Sun (2007a) and involves representing the standard DC OPF problem as an augmented strictly convex quadratic programming (SCQP) problem, involving the minimization of a positive definite quadratic form subject to linear equality and inequality constraints. The solution values are the real power injections and branch flows associated with the energy production levels for each generator and voltage angles for each node.

In order to utilise computational speed and efficiencies that are often needed for large-scale or complex problems, we used the Mosek Optimisation Software which exploits direct sparse matrix methods and utilises a convex quadratic programming algorithm based on the interior point algorithm to solve the DC OPF problem within the model.[9] The DC OPF algorithm employed in the model, incorporating the constraint format used by Mosek for the inequality constraints, is:

- Minimize Generator-reported total variable cost and nodal angle differences

$$\sum_{i=1}^{I}\left[A_i P_{G_i} + B_i P_{G_i}^2\right] + \pi\left[\sum_{I_m \in BR}\delta_m^2 + \sum_{km \in BR,\, k\geq 2}[\delta_k - \delta_m]^2\right],$$

  with respect to real-power production levels and voltage angles

$P_{G_i},\ i = 1,\ldots,I;\ \ \delta_k,\ k = 2,\ldots,K,$ subject to

- Real power balance (equality) constraint for each node $k = 1,\ldots,K$ (with $\delta_1 \equiv 0$):

  $0 = PLoad_k - PGen_k + PNetInject_k$,

where

  - $PLoad_k = \sum_{j \in J_k} P_{L_j}$ (e.g. aggregate power take-off at node k),
  - $PGen_k = \sum_{i \in I_k} P_{G_i}$ (e.g. aggregate power injection at node k),
  - $PNetInject_k = \sum_{km \text{ or } mk \in BR} F_{km}$,

- $F_{km} = B_{km}\left[\delta_k - \delta_m\right]$ [e.g. real power flows on branches connecting nodes ‘k’ and ‘m’ (Sun and Tesfatsion 2007a, Section 3.1)].
- Real power thermal (inequality) constraints for each branch $km \in BR$ $k = 1,\ldots,K$ (with $\delta_1 \equiv 0$):

  $F_{km} \geq -F_{km}^{UR}$, (lower bound constraint: reverse direction MW branch flow limit)

  $F_{km} \leq F_{km}^{UN}$, (upper bound constraint: normal direction MW branch flow limit).

[9] The web-address for Mosek is: http://www.mosek.com/. We ran the software under a free academic license available from Mosek – see http://mosek.com/resources/trial/.

- Real-power production (inequality) constraints for each Generator $i = 1, \ldots, I$:

$P_{G_i} \geq P_{G_i}^{LR}$, (lower bound constraint: lower hourly MW thermal ramping limit)

$P_{G_i} \leq P_{G_i}^{UR}$ (upper bound constraint: upper hourly MW thermal ramping limit),

where

$P_{G_i}^{LR} \geq P_{G_i}^{L}$, (lower hourly thermal ramping limit $\geq$ lower thermal MW capacity limit)

and

$P_{G_i}^{UR} \leq P_{G_i}^{U}$ (upper hourly thermal ramping limit $\leq$ upper thermal MW capacity limit).

'U' = upper limit and 'L' = lower limit, A_i and B_i are linear and quadratic cost coefficients of the variable cost function. P_{G_i} is real (MW) power production level of generator 'i'. δ_k and δ_m are the voltage angles at nodes 'k' and 'm' (measured in radians). Parameter π is a positive soft penalty weight on the sum of squared voltage angle differences. Variables F_{km}^{UN} and F_{km}^{UR} are MW thermal limits associated with real power flows in the 'normal' and 'reverse' direction on each connected transmission branch $km \in BR$.

The linear equality constraint refers to a nodal balance condition which requires that, at each node, power take-off (by LSE's located at that node) equals power injection (by generators located at that node) and power transfers from other nodes on 'connected' transmission branches. On a node by node basis, the shadow price associated with this constraint gives the LMP associated with that node, i.e. regional wholesale electricity spot price. The linear inequality constraints ensure that real power transfers on transmission branches remain within thermal limits and the real power produced by each generator remains within lower and upper thermal limits while also meeting hourly ramping production limits.

It should be recognised that the ANEM model differs in significant ways from many of the wholesale electricity market models used to investigate the Australian electricity industry. First, the nodal structure of the ANEM model is more disaggregated than the structure underpinning many of the other wholesale market models. Depending upon the treatment of Snowy Mountains Region in the NEM, the grid structures associated with wholesale market models used previously often involve five or six nodes (corresponding to each state region in the NEM) and six or seven inter-state interconnectors – see MMA (2006), ROAM (2008, Appendix A, p. II), SKM-MMA (2011, p. 62) and ACIL Tasman (2012, Section B.2). In contrast, the ANEM model contains 52 nodes and 68 transmission branches, including eight inter-state interconnectors and 60 intra-state transmission branches – see Figures 1-5.

Second, the solution algorithm used in the ANEM model is very different conceptually from the linear programming algorithms used in many of the other wholesale market models. In the ANEM model, quadratic programming is employed to minimise both nodal angle differences and generator variable costs subject to network limits on transmission branches and generation. Optimal power flows on transmission branches are determined from optimised nodal angle differences, which, in turn, depend on transmission branch adjacency and bus admittance properties determined from the transmission grid's structure and branch reactance data (Sun and Tesfatsion 2007a, Section 4). Accounting for power flows in the equality constraints of the DC OPF algorithm allows the incorporation of congestion components in regional wholesale spot prices, which can produce divergence in regional spot prices associated with congestion on intra-state transmission branches.

In contrast, the linear programming algorithms do not explicitly optimise power flows as part of the optimisation process, directly capture the impact of branch congestion on spot prices or account for any impact associated with congestion on intra-state transmission branches. Moreover, intra-state regional spot prices are not typically defined in these models.

(3). Focus and Practical Implementation Considerations

The solution algorithm employed involves applying the ‘competitive equilibrium’ solution. This means that all generators submit their true marginal cost coefficients and no strategic bidding is allowed, thus permitting assessment of the true cost of generation and dispatch. We also assume that all thermal generators are available to supply power during the whole period under investigation. This assumption avoids the effect that planned or unscheduled outages of thermal generators would have on increasing costs and prices by constraining the least cost supply response available by all generation to meet demand. Thus, our objective is to investigate, in an *ideal* setting, how the true cost of power supply changes when operational wind generation was included in the analysis compared to a baseline scenario involving no wind generation in dispatch.

The implementation details relating to unit commitment features and dispatch of thermal and hydro plant are the same as outlined in (Wild et al. 2012a, Section 3) and also discussed in Wild and Bell (2013). While all thermal generators were assumed to be available to supply power, the dispatch of thermal plant was optimised around assumed availability patterns for hydro generation units where water supply is unconstrained. If water supply and hydro unit availability were constraining factors, this would increase costs and prices by constraining the least cost supply response available of all generation to meet demand. This follows because the supply offers of hydro plant would be significantly higher than the case where water supply did not constrain hydro generation availability.

Hydro generator supply offers were based on long run marginal costs. This approach reflected the assumption that hydro plant supply offers on the mainland was assumed to shadow peak load gas plant. Annual capacity factors obtained were consistent with the provision of peak load production duties by mainland hydro plant (Wild et al. 2012a, Section 4.3). Supply offers of TAS hydro generation plant were also based on long run marginal costs. However, account was taken of the ability to provide baseload, intermediate or peak production duties when determining the long run marginal costs of TAS hydro plant. Annual capacity factors for TAS hydro generation were consistent with this approach. See (Wild et al. 2012a, Section 4.3) for further details.

The approach adopted for modelling Hydro generation gives greater emphasis to generators with larger storages such as Poatina and Gordon power stations in TAS, especially when considered with the assumption that prevailing water supply does not constrain hydro generation availability. This reflects the fact that the larger storages provide the capacity of such hydro plant to operate, in the conventional sense, as baseload generators – e.g. operate for significant periods of time each year potentially over a number of years. Plant with medium sized storages can potentially operate as intermediate plant but these storages can be run down significantly over a period of a year. Run-of-River plant tends to have much lower storages that can be potentially depleted within hours, days or a week and cannot therefore be depended upon to operate in the conventional baseload context, but instead, may operate as a peak or seasonal based intermediate plant during the wet season.

In contrast, many hydro generation companies act in a different way in practice. During periods of significant rainfall, Run-of-River plant will tend to be dispatched first to avoid spillage of water in their smaller storages. Plant with medium sized storages will then tend to be dispatched next with the expectation of these storages being replenished within a yearly time horizon, and also possibly to avoid spillage during the wet season. Finally, plant associated with very large storages are dispatched last in an attempt to conserve this resource so that it is available during times of drought conditions to meet both electricity generation and environmental flow requirements. See Hydro Tasmania (2000, pp. 20-21)

As such, the assumed behaviour and dispatch patterns of hydro generation plant in the model might potentially deviate substantially from the operational practice of hydro generation companies. How to incorporate more realistic supply offers of hydro generation linked to real time water storage and flow information into the model is an area of ongoing research.

Both non-scheduled and semi-scheduled wind generation operational over the period 2007 to 2012 was incorporated in the modelling.[10] Note however that the output of the wind farms in the modelling are incorporated as aggregated nodal wide entities calculated by summing the output of all non-scheduled and semi-scheduled wind farms located within a particular node. Thus, we are not modelling the individual wind farms themselves but are aggregating their output within a node to derive an aggregated nodal based wind generation source. Moreover, we are restricting attention to those nodes that contain operating wind farms. As such, we have not included assessment of the impact of proposed wind farms

[10] Note that the data contains quite constrained output from Macarthur wind farm which was in the process of being commissioned in the latter half of 2012 and not running anywhere near full capacity.

located at nodes that do not contain operational wind farms such as Armidale, Marulan, Wellington and Yass in NSW.

The default setting adopted for modelling purposes is for wind generation not to be dispatched. This is implemented by specifying a default supply offer containing a zero minimum stable operating level, a maximum MW capacity calculated by summing the maximum MW capacities of all operational wind farms located in the node and utilising a supply offer coefficient equal to the '*Value-of-Lost-Load*' (VOLL).[11] Under these default settings, the nodal based wind generation source would not be dispatched, representing one of the most expensive types of available generation.

This default setting is overridden when the output of the nodal based wind generation source exceeds 10MW. This output value was determined by summing the half-hourly traces associated with both non-scheduled and semi-scheduled wind farms located in each node. Note that this output, in the case of non-scheduled wind farms, was used to augment the 'scheduled' demand concept mentioned in the previous section. Half-hourly output traces for semi-scheduled wind farms were also calculated in the same way as for non-scheduled generation from five minute semi-scheduled wind farm output traces obtained from AEMO.[12] Thus, the only parameter changes from the default setting is a new (lower) maximum MW capacity limit corresponding to the actual output of the wind farms and use of short run marginal cost coefficients obtained by averaging across the equivalent coefficients of all wind farms located in the node instead of VOLL. Recall from the discussion in the previous section that these coefficient values lie in the range of \$3.39/MWh to \$4.69/MWh. Furthermore, the minimum stable operating level remains the same (i.e. set to 0 MW's).

(4). Main Impact of Wind Generation in the NEM over the period 2007-2012

This section examines the effect of wind generation in the NEM over the period 2007-2012 using the actual output of operational wind farms over this period of time. The impact of wind generation is compared with a scenario in which we assume that no wind generation was available but the demand corresponded to our augmented net demand concept discussed

[11] In the modelling, VOLL was set to \$10,000/MWh.

[12] Note that the name and nodal locations of the semi-scheduled wind generators are listed in Panel (B) of Appendix A.

in Section 2. Thus, under this particular scenario, demand has to be met by thermal and hydro generation.

Our focus in this section will be on examining how the additional output from wind generation influenced:

- Wholesale electricity prices;
- Dispatch patterns (e.g. fuel substitution effects);
- Carbon emissions;
- System-wide total variable costs; and
- Transmission network adequacy

when compared against the outcomes associated with the scenario involving no contribution from wind generation in satisfying demand.

(4.1) Wholesale Price Impacts

Average wholesale price outcomes reflect both a spatial and temporal dimension. 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 average price data obtained from the baseline 'no-wind' scenario termed the 'wind exclusive' scenario and the scenario incorporating the actual half-hourly output traces from operational wind farms, termed the 'wind inclusive' scenario. 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 'wind exclusive' scenario. Negative percentage change values would indicate that the inclusion of wind generation has reduced average wholesale prices relative to the baseline 'wind exclusive' scenario.

The percentage change values are reported in Panel (A) of Table 1. 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 1. 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.[13] A number of observations can be drawn from the results in Table 1. First, those states with the largest number of operational wind farms experience the greatest reductions in average annual prices. The stand-out states are clearly SA and VIC 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 'wind exclusive' scenario. Second, reductions in average annual prices tend to broadly increase over time reflecting, in particular, the expansion in semi-scheduled wind farms in SA, VIC and NSW over the 2010-2012 time frame. The trend in TAS 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 reported in the last column of Panel (A) particularly over years 2010-2012 accompany the expansion in wind capacity mentioned above. Specifically, annual average prices in the

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

NEM decline relative to the 'wind exclusive' 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, as reported in Panel (C) of Table 1. Note that the results reported in Panel (C) are the percentage change in scheduled demand reported in AEMO (2012b, 2013a), aggregated over each year for each state. Therefore, the first row denotes the percentage change in state scheduled demand in 2008 relative to the totals observed in 2007.

Table 1. 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

Panel (C): Year-on-Year Percentage Change in Aggregate Scheduled Demand by State

Year	QLD	NSW	VIC	SA	TAS	NEM
2008	1.21	0.55	0.94	0.49	2.28	0.89
2009	0.77	-1.69	-2.27	0.05	-5.11	-1.28

2010	-0.55	-0.44	0.03	0.90	2.73	-0.11
2011	-2.29	-0.86	-1.99	-3.34	-1.29	-1.70
2012	0.16	-5.17	-0.88	-0.86	-3.64	-2.38

For the overall interval 2007-2012, the average rate of percentage reduction in annual average wholesale prices relative to the baseline 'wind exclusive' scenario attributable to wind generation in the NEM is given in the last row of Panel (A) of Table 1. These results indicate percentage reductions relative to the 'wind exclusive' 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 'wind exclusive' scenario is in the order of 10.2 per cent over the five year period.

A key conclusion from Table 1 is that close proximity to the location of wind farms seems to matter in reaping the benefits associated with reductions in average wholesale prices. 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 1 except that the calculation was applied to average annual nodal prices from both scenarios and not to average annual state price outcomes as in the case of Table 1. The percentage change results for the selected nodes are reported in Table 2.

Table 2. Percentage Change in Volume Weighted Annual Average Prices By State Associated with Operational Wind Farms: Selected Regional Results

Panel (A)[14]

Year	BRIS	SYD	MELB	SW VIC	REG VIC	SE SA
Node	10	19	32	33	34	35
2007	-0.08	-0.25	-6.94	-7.65	-7.54	-8.65
2008	-0.13	-0.42	-11.12	-12.00	-9.67	-13.10
2009	-0.30	-0.98	-15.26	-16.24	-17.36	-15.66
2010	-0.30	-1.61	-27.86	-28.27	-25.72	-28.48
2011	-0.41	-2.38	-28.62	-30.38	-26.20	-36.00
2012	-0.23	-3.93	-22.64	-25.93	-21.38	-32.66
Average	-0.24	-1.60	-18.74	-20.08	-17.98	-22.42

Panel (B) [15]

[14] In Panel A, the column headings respectively refer to the following nodes: Brisbane (Moreton South), Sydney, Melbourne, South West VIC, Regional VIC and South East SA.

Year	ADEL	RIVERL	MN SA	LAUNC	BURNIE	HOBART
Node	37	38	39	42	44	51
2007	-9.13	-9.75	-9.35	-3.23	-3.48	-2.86
2008	-11.23	-9.37	-9.87	-4.74	-5.74	-3.11
2009	-11.08	-2.14	-4.60	-5.32	-6.43	-3.79
2010	-25.96	-25.38	-25.02	-6.14	-7.20	-4.04
2011	-34.89	-34.36	-33.33	-6.01	-7.05	-4.64
2012	-35.16	-38.43	-36.50	-5.91	-6.48	-5.48
Average	-21.24	-19.90	-19.78	-5.23	-6.06	-3.99

In Panel (A), Brisbane and Sydney experience more modest reduction in average nodal prices than is the case with the other nodes, and more particularly, those located in VIC and SA. In increase in magnitude of the percent reductions over years 2010-2012 in Sydney are of the order to 1.6 to 3.9 per cent and reflect the significant increase in wind generation output in NSW associated with the commissioning of Cullerin Range, Gunnings Range and Woodlawn wind farms during this period. For the interval 2007-2012, the average rate of percentage reduction in annual average wholesale prices in Brisbane and Sydney relative to the baseline 'wind exclusive' scenario are 0.2 and 1.6 per cent, respectively.

The Tasmanian nodes listed in Panel (B) (e.g. Launceston, Burnie and Hobart) experience slightly larger reductions in average prices than does Sydney although the results over time experience less variation reflecting the fact that no additional wind farms were commissioned in Tasmania over the 2008 to 2012 time frame. In general, the percentage reductions are in the range of 2.9 to 7.2 per cent and are larger in magnitude over years 2009-12 when compared with years 2007-08. The proximity argument is evident in the case of the Tasmania with both Launceston and Burnie experiencing greater reductions in average nodal prices than Hobart which is located further away geographically than either Burnie or Launceston from Woolnorth wind farm. For example, the percentage reductions fall within the range of 3.5 to 7.2 per cent for Burnie and are of a slightly lower magnitude in Launceston, in the order of 3.2 to 6.1 per cent. In the case of Hobart, however, the percentage reductions are even smaller in magnitude, being in the range of 2.9 to 5.5 per cent. Furthermore, for the interval 2007-2012, the average rate of percentage reduction in annual

[15] In Panel B, the column headings respectively refer to the following nodes: Adelaide, Riverlands, Nid-North SA, Launceston (GeorgeTown), Burnie and Hobart (Chappell Street).

average wholesale prices in Launceston, Burnie and Hobart, relative to the baseline ‘wind exclusive’ scenario are 5.2, 6.1 and 4.0 per cent, respectively.

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. For example, for the interval 2010-2012, the average rate of percentage reduction in annual average wholesale prices associated with the Victorian nodes is in the range of 21.4 to 30.4 per cent. In the case of the South Australian nodes, the equivalent range is slightly higher, falling in the range of 25.0 to 38.4 per cent, relative to the results obtained from the ‘wind exclusive’ scenario. Note further that the average nodal prices obtained for the five year period under investigation fall in the range of 18.0 to 20.1 per cent for the Victorian nodes and in the range of 19.8 to 22.4 per cent in the case of the South Australian nodes. These results are all reported in the last rows of Panels (A) and (B) of Table 2.

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 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.

We will see in Section 4.4 that wind generation increased the incidence of congestion on Murraylink while reducing it on the Heywood interconnector. The 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 Panel (B) of Table 2 over years 2011-2012 which also coincides with rising branch congestion on Murraylink. 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.

Wholesale price volatility is an important variable in formulating risk management strategies for both demand and supply side agents as well as in the cost of serving retail electricity demand. It is of interest to observe whether the inclusion of wind generation in the analysis has served to increase or decrease spot price volatility. To investigate this issue, we calculated the percentage change in price volatility relative to the 'wind exclusive' scenario which is documented in Table 3 for each of the six years being investigated. Note that the values listed in this table were calculated for each year by taking the standard deviation of the spot price time series generated by the model for each node and then averaging these results across nodes located within each state and across all nodes in the model to obtain the NEM results reported in column 7 of this table. Therefore, the percentage change for each year was calculated in a similar way to how the values listed in Tables 1 and 2 were calculated, except now applying the calculation to standard deviation results instead of average annual prices.

Table 3. Percentage Change in Average Price Volatility Associated with Operational Wind Farms: State Results

Year	QLD	NSW	VIC	SA	TAS	NEM
2007	0.19	-1.02	-3.47	-2.90	-4.70	-2.71
2008	-0.24	-2.45	-11.88	-17.06	-2.72	-12.26
2009	0.01	1.04	-10.12	56.14	-10.86	6.98
2010	0.15	1.48	-33.43	-59.64	-11.44	-38.04
2011	0.58	-0.38	-44.57	-53.44	-17.16	-44.02

2012	0.34	14.47	-15.58	-12.80	-22.30	-11.43
Average	0.17	2.19	-19.84	-14.95	-11.53	-16.92

The inclusion of wind generation in the analysis tends to reduce price volatility in VIC, SA and TAS, apart from a very noticeable positive spike arising in 2009 for both VIC and SA. In all other years, the impact of including wind generation is to reduce price volatility relative to the volatility levels associated with the 'wind exclusive' scenario. The importance of this result becomes more noticeable when account is taken of the fact that VIC and SA are the states with the largest number of operational wind farms. The results in QLD and NSW are more mixed in nature and generally of a lower order of magnitude than when compared to the other three states. In broad terms, price volatility has increased marginally in QLD, and reduced marginally in NSW except for a noticeable positive jump in 2012 in the case of NSW. For the NEM, the results in column 7 indicate that, apart from 2009, the inclusion of wind generation has reduced price volatility.

The time average of the percentage change values reported in Table 3, calculated over the complete 2007-2012 period are reported in the last row of Table 3. It is apparent from these results that spot price volatility increases relative to BAU in QLD and NSW with percentage increases of 0.2 and 2.2 per cent, respectively. In contrast, VIC, SA and TAS experience percentage declines in volatility relative to BAU over the whole interval of 19.8, 14.9 and 11.5 per cent. The larger magnitudes associated with the latter three states also produces an overall reduction in spot price volatility in the NEM of 16.9 per cent.

Another feature of interest associated with wind generation has been an emerging perception of 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 farms 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 type of plant cannot easily stop production because of the significant amount 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 that all generators earn a negative revenue stream and profits, 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 are reported in Table 4. In Panel (A), we document the proportion of time in each year that negative prices were obtained for the baseline 'wind exclusive' 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 process was also applied to the 'wind inclusive' scenario and the percentage change in these values relative to the 'wind exclusive' scenario is reported in Panel (B) of Table 4. Note that in both panels of Table 4, 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 VIC node (node 34), although negative prices were obtained for nodes neighbouring this particular node in SA.

Table 4. 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

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 VIC 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, the incidence of negative prices occurred around 3.9 per cent of the time in 2012 at the Adelaide node. Finally, note that in 2012, there were 17,568 half hours in the year.

In Panel (B), the results for the South West VIC node indicate that the inclusion of wind generation has the effect of actually reducing the number of half hours with negative prices when compared against the 'wind exclusive' scenario. This contrasts with the situation in South Australian with all relevant nodes generally experiencing increased incidence of negative prices, with this becoming more prominent over the period 2011-2012, coinciding with the expansion of wind farm capacity especially in the Mid North SA node and, to a less extent, in the South East SA 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 VIC node. For this nodal price separation to occur between these two inter-connected nodes, the periods of negative prices in Riverlands must also coincide with periods of congestion on the Murraylink Interconnector.[16] The converse seems to happen between the South West VIC and South East SA nodes. For South West VIC to experience a relatively high incidence of negative prices in contrast to the other VIC nodes, this must mean that the South West VIC and South East SA nodes have the same marginal price setting generator which is different from that associated with other nodes in VIC during the incidence of negative price events. This can only arise if these periods of negative prices

[16] Support for this can be found in Table 17, Section 4.4 where congestion increases on the Murraylink interconnector when wind generation is included.

coincide with periods in which there is no congestion on the Heywood Interconnector.[17] More generally, these considerations 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 hand.

(4.2) Fuel Substitution Effects

Information about changes in dispatch patterns associated with increasedwind generation will provide a measure of fuel substitution amongst different generation technologies. To investigate this, we calculated the total level of production for each generation plant during each year for both the ‘wind exclusive’ (e.g. no wind) and ‘wind inclusive’ scenarios. To obtain state-specific results by plant type, we totalled the results across the relevant categories of plant located in each state. NEM results were obtained by aggregating across state results.

To obtain an idea of the scope of penetration of actual wind generation by state, 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 5. In terms of state production share, SA has the largest penetration of wind generation, accounting for 17.7 per cent of total production in SA in 2012, increasing from 6.0 per cent in 2007. The state with the next highest penetration is TAS, corresponding to 6.7 per cent of total state production in 2012, increasing from 4.2 per cent in 2007. This is followed by VIC and then NSW 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.

Table5. Penetration of Actual Wind Generation over 2007-2012: Proportion of Total Production

Year	NSW	VIC	SA	TAS	NEM

[17] Support for this can also be found in Table 17, Section 4.4 where congestion on the Heywood interconnector is shown to decline when wind generation is included.

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

The impact of wind generation on state production trends in other competing thermal and hydro generation is presented in Table 6. In this table, these trends are expressed in terms of percentage change in the ‘wind inclusive’ scenario’s production trends relative to the baseline ‘wind exclusive’ scenario. Once again, a negative value indicates that the production levels associated with the ‘wind inclusive’ scenario have decreased relative to the equivalent production trends associated with the ‘wind exclusive’ scenario. SA and TAS experience the greatest reductions 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 QLD and VIC experience the lowest rates of reduction with results being in the range of 0.2 to 0.8 per cent. NSW lies between these upper and lower ranges with percentage reductions in the range of 0.4 to 3.8 per cent. For the NEM, 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 over the time interval 2007-2012 in response to the actual expansion in production from wind generation in the NEM.

The other noticeable feature is that the magnitude of percentage reduction also increases over the interval 2007-2012, reflecting the role out of wind generation in SA, VIC and NSW over the period 2009-2012, in particular. Overall, the most striking outcomes are the relatively small impact arising in VIC and the relatively large impact arising in TAS. We will now investigate these impacts in more detail looking at reductions by fuel and technology type and age of plant.

Table 6. 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 first fuel type we consider is coal-fired generation by state which is presented in Table 7. There are two noticeable outcomes in Table 7. The first is the relatively high percentage reductions in production from coal-fired generation experienced by SA 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 experienced in VIC, with percentage reductions in the range of 0.00 to 0.23 per cent. The other state experiencing some reduction in coal-fired generation production is NSW with this reduction becoming particularly evident over the interval 2010-2012. The reductions experienced in QLD are of a smaller order of magnitude when compared with NSW. The other clear trend is that the magnitude of percentage reduction also increases over the 2007-2012 time period, and especially over the 2009-2012 period associated with the role out of wind generation particularly in SA and NSW.

Table 7. 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 percentage reduction in production from coal-fired generation in the NEM is in the range 0.4 to 2.1 per cent. This range is slightly lower than the overall production trend listed in Table 5. In common with Table 5, the magnitude of the size of the reduction increases unambiguously over the time interval 2008-2012 in response to the expansion in production from wind generation.

In order to understand the trends identified in Table 7 in more detail, we present more detailed results for coal-fired generation by age and type of plant. These results are reported in Table 8 for NSW (grouped by age of plant) and for SA (by plant). It is clear from Table 8 that the inclusion of wind generation impacts more heavily on old and medium vintage coal-fired plant in NSW with per cent reductions in the range of 0.5 to 4.2 per cent when compared with newer vintage plant with equivalent range of -0.1 to -1.6 per cent. In SA, the impact is greater on Playford B with percentage reductions in the range 5.8 to18.9 per cent when compared to Northern Power Station with percentage reductions in the range of 2.9 to 12.9 per cent. Note that Playford B is an old vintage plant while Northern is a medium vintage plant.

One factor influencing these results is that both Playford B and Northern are located in close proximity to wind generation located in the Mid-North SA node while the NSW wind farms located in the Canberra node are located quite a distance geographically and transmission-wise from NSW coal-fired generation located in the Newcastle and Blue Mountains regions of NSW. Another key driver of the results is that the old vintage coal-fired plant typically has higher fuel costs and less efficient thermal features which places them at a competitive disadvantage to other forms of generation including newer vintage coal plant. This argument can be extended, to a less degree, to medium vintage coal plant when compared with new vintage coal plant. Therefore, the larger percentage reductions in production associated with old and medium vintage plant identified in Table 8 reflects the poor competitive position, in relative terms, confronting such plant when compared with newer coal-fired generation plant, in response to increased competition from wind generation.

Table 8. Percentage Change in Annual Production from NSW and SA Coal-fired Generation Associated with Operational Wind Farms: By Age of Plant (Vintage) and Selected Plant[18]

Year	OLD VINT	MED VINT	NEW VINT	PLAY B	NORTH
2007	-0.53	-0.46	-0.10	-6.35	-3.05
2008	-0.56	-0.55	-0.11	-5.79	-2.86
2009	-1.67	-1.66	-0.84	-12.78	-7.99

[18] Note that the column headings in columns 2 to 4 of Table 8 refer to old vintage, medium vintage and new vintage black coal-fired plant located in NSW. Older vintage coal plant includes Liddell, Munmorah and Wallerawang C power stations. Medium vintage plant includes Bayswater, Eraring and Vales Point power stations. New vintage NSW coal plant includes Mt Piper and Redbank power stations. The last two columns in Table 8 refer to Playford B and Northern power stations located in SA.

2010	-2.58	-2.38	-1.29	-13.53	-8.08
2011	-3.41	-3.33	-2.12	-18.89	-12.94
2012	-4.16	-4.21	-1.59	-17.50	-12.39

The situation confronting VIC brown coal generation is outlined in Table 9. The results in this table indicate that three of the largest brown coal-fired plant are unaffected – these being Loy Yang A, Hazelwood and Yallourn. Three generators Loy Yang B, Energy Brix and Anglesea appear to experience slight reductions in production particularly over the interval 2010-2012. In the case of Loy Yang B, the key factor driving this outcome is its relatively high fuel costs when compared to the lower fuel costs of Loy Yang A, Hazelwood and Yallourn. In the case of Energy Brix and Anglesea, it is a combination of relatively high fuel costs, lower thermal efficiencies (related to age of plant) as well as locational proximity to wind generation sources located in the South West VIC and Regional VIC nodes and even South East SA – see Figures 3 and 4 for details.

Therefore, in overall terms, the production trends identified in relation to Tables 7 to 9 reflect higher fuel costs and greater thermal inefficiencies linked to the age of plant as well as locational proximity to operational wind generation. In general, the older the coal-fired generation plant, the greater its fuel cost or the closer it is located to operational wind farms, the more likely its production will be adversely affected by wind generation.

Table 9. Percentage Change in Annual Production from Victorian Brown Coal Generation Associated with Operational Wind Farms: Selected Power Stations[19]

Year	LY A	LY B	ENG BRX	HAZELW	YALL	ANGLS
2007	0.00	0.00	-0.16	0.00	0.01	-0.02
2008	0.00	-0.01	-0.11	0.00	0.00	-0.04
2009	0.00	-0.03	-0.40	0.01	0.02	-0.11
2010	0.00	-0.23	-0.78	0.01	0.02	-0.48
2011	0.00	-0.30	-1.08	0.00	0.03	-0.52
2012	0.00	-1.06	-1.90	0.01	0.05	-1.36

The second fuel type we investigate is gas-fired generation by state which is presented in Table 10. There are two main results evident in Table 10. The first is the relatively larger

[19] In Table 9, the column headings of columns 2 to 7 refer to Loy Yang A, Loy Yang B, Energy Brix, Hazelwood, Yallourn and Anglesea power stations.

reductions in production from gas generation in VIC when compared to the other states except for TAS over the period 2007-2008. Reductions in VIC are in the order of 5.1 to 11.7 per cent. The second key outcome is that there is no real impact of production from gas generation in either QLD or NSW with this result being particularly striking given the expansion in wind farms in NSW occurring over the 2011-2012 time interval. The percentage reductions experienced in SA are between these two extremes, being in the order of 3.3 to 7.0 per cent. Finally, in the case of TAS, 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 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.

Table 10. 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

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. This range is above the total and coal-fired generation production trends reported in Tables 6 and 7 respectively. Moreover, the magnitude of the reductions continue to increase broadly over the time interval 2007-2012, although tailing off slightly over the 2011-2012 period relative to the 2010 result.

To investigate the trends discussed above in Table 10 in more detail, we present more detailed results for gas-fired generation by type of plant. These results are reported in Tables 11 and 12 for NGCC/Gas Thermal (GT)[20] and OCGT[21] plant, respectively.

[20] 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

In Table 11, SA experiences the greatest percentage decline in production from NGCC/GT plant while smaller reductions arise in both VIC and TAS. Note in the latter context that both VIC and TAS only have one power station associated with this category of plant type – namely, Newport and Tamar Valley (commissioned in 2009), respectively. [22] This contrasts with SA which has a number of NGCC and GT power stations and a larger aggregate capacity for this category of plant type than does VIC or TAS. The other noticeable feature of Table 11 is no appreciable impact on production from NGCC plant in either NSW or QLD.

Table 11. 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 clear from Table 12 that there are much larger impacts on production from OCGT plant. This is particularly the case for VIC and SA 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 NSW and QLD experience much smaller (if any) impacts on production from OCGT plant while TAS 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 TAS was dispatched over this latter period during ANEM model simulations. This latter situation also arose in NSW in 2007-2008 because no OCGT plant

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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.

[21] 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.

[22] Note that the 'na' values in Table 11 for TAS 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.

was commissioned at that time and in 2012 because no OCGT plant was dispatched in ANEM model simulations. These results are also represented by the 'na' values in Table 12 for NSW.

The larger reductions in production from OCGT plant in SA and VIC 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 bid by these plants in the ANEM model. Thus, in a similar way that old and medium vintage coal-plant have a competitive disadvantage to new vintage coal plant, OCGT are at a competitive disadvantage to NGCC/GT plant and their production is more susceptible to displacement from competing generation including wind generation. Second, a significant portion of the OCGT fleet in SA is located in closer proximity to sources of wind generation including plant located directly at the Mid-North SA and South East SA nodes. NGCC and GT plant, on the other hand, are located in Adelaide. Third, in VIC, the OCGT fleet has a higher capacity than the NGCC/GT fleet which, as mentioned previously, corresponds to a single power station in VIC – namely Newport Power Station. Furthermore, a significant portion of the OCGT fleet is located in the Melbourne and South West VIC nodes, in close proximity to VIC wind generation located in South West VIC and Regional VIC nodes. Therefore, the reduction in output from OCGT plant in VIC from wind generation would reflect the OCGT's plants cost disadvantages (when compared to other competing forms of thermal generation), its capacity (e.g. availability), as well as its locational proximity to wind generation sources in VIC.

More generally, the higher reduction rates associated with production from OCGT plant is consistent with what would be expected 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 ramp up capacity to balance the system when wind power drops off while also providing the fast ramp down capability when wind power ramps up. Thus, the significant reductions in output from OCGT plant in response to increased output from wind generation would be something we would expect to see and a sign that the system is potentially well placed to handle intermittency problems associated with wind power.

Table 12. 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 13. There are two main results discernible from this table. The first is the relatively stable profile of percentage reductions in production from TAS 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 NSW and VIC, on the other hand, are more marked and variable in extent but are coming off a much lower production levels. Note that the 'na' values recorded in the table are associated with no dispatch of hydro plant under both scenarios considered. It is also clear that wind generation has no discernible impact on hydro production trends in QLD. The percentage reduction in production from hydro generation in the NEM is in the range 0.4 to 5.5 per cent. Over the period 2009-2012, the range, in particular, is above the equivalent rates associated with the total, coal and gas generation production trends listed in Tables 6, 7 and 10, respectively. Furthermore, the magnitude of the percentage reduction in hydro production in the NEM continues to increase unambiguously over the time period 2007-2012. They also very closely match the trend associated with TAS which indicates the prominence of the TAS hydro within the NEM.

A key aspect of interest, given the results in Table 13 for NSW and VIC, are the transmission linkages between regions containing hydro and wind generation assets in both NSW and VIC. Specifically, NSW hydro generation is located at the Wollongong and Tumut nodes that are directly connected to the Canberra node which contains the NSW wind farms. In the case of VIC, hydro generation sources located within the Dederang and Murray nodes are connected to the Regional VIC node and potentially the South West node via Regional VIC and Melbourne nodes. For VIC, this situation mirrors the linkages with OCGT plant, and, in both states, stands in contrast with the situation confronting coal-fired generation which tends to be located further away from nodes containing operational wind farms – see Figures 2 and 3 for further details.

In common with OCGT peaking plant, the higher reduction rates associated with production from hydro plant in NSW and VIC 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. Once again, in this context, both the fast-start and fast ramping capability of hydro plant provides the required characteristics needed to help balance the system in the face of intermittency associated with wind power.

Table 13. 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

(4.3) Carbon Emission Outcomes.

To investigate carbon emission outcomes associated with operational wind farms, we calculated the total level of carbon emissions of each generation plant during each year for the time interval 2007-2012. To obtain state-specific results, we 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 ‘wind exclusive’ (e.g. 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 ‘wind exclusive’ scenario for each year in the interval 2007 to 2012. These results for each state and the NEM are reported in Table 14. Note that when interpreting the values in Table 14, negative values indicate that wind generation has reduced carbon emission levels relative to baseline ‘wind exclusive’ scenario.

The negative entries in Table 14 indicate that wind generation in the NEM has reduced carbon emissions in all states relative to the baseline scenario. The stand-out state is clearly SA with reductions in carbon emissions relative to the baseline (no wind) scenario in the range of 3.6 to 11.0 per cent. This, in turn, reflects the more significant penetration of wind generation in SA and the greater substitution of wind generation for the more carbon emission intensive coal generation that was identified in the previous section. The other noticeable result is the marginal size of reductions in VIC. This reflects the much smaller wind penetration in VIC when compared to the size of thermal capacity and the fact that wind generation in this state appears to primarily displace generation from less carbon emission intensive OCGT plant and not materially reduce production (and carbon emissions) from brown coal generation in VIC.[23] Thus, we see much smaller carbon emission reduction impacts in VIC than in SA where a greater displacement of coal generation by wind power occurs. The reduction in carbon emissions is of a much smaller magnitude in QLD than NSW particularly over the period 2009-2012 as wind generation in NSW commissioned over this period displaces some production from old and medium vintage black coal generation plant, as also demonstrated in the previous section. In contrast, the minimal reductions in QLD primarily reflect the fact that there was no wind generation operating in QLD over the period of investigation.

In the case of TAS, the larger reductions arising over the 2007-2008 period reflect displacement of output from OCGT plant by wind power. The production and carbon emissions 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 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 this extended period of time, together with no dispatch of TAS OCGT plant. As such, the production and carbon emission time profile of TAS becomes much larger and more constant, reflecting the must run characteristics assumed for the NGCC plant and operating levels obtained (i.e. close to minimum stable operating level). Hence, the displacement patterns

[23] Recall also 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.

associated with wind generation also become reasonably constant and of a similar order of magnitude under these particular circumstances.

Table 14. 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 TAS, 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 0.45 and 0.46 per cent in 2007 and 2008, then ramping up over the 2009 to 2012 period with percentage reductions in the order to 1.0 to 2.1 per cent.

(4.4) System-wide Total Variable Costs

In Section (4.2), we saw that one impact of including operational wind generation was to change dispatch patterns, partially displacing coal production in SA and NSW, hydro production in TAS and OCGT production in SA and VIC. 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 changed dispatch of the NEM-wide generation fleet.

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 O&M costs, and the aggregate system-wide total variable cost (STVC) can be represented as:

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

where 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. 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 and $P_{G_{i,h}}$ is the dispatched power production of generator $'i'$ at dispatch interval (e.g. half-hour) $'h'$, where i and h are looped over all $i \in I$ and all $h \in Nh$ 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 'wind exclusive' (i.e. no wind) and 'wind inclusive' scenarios are calculated from (1) for each year in the interval 2007-2012 and are listed in Table 15. In this table, the second column titled 'WES' corresponds to the 'wind exclusive' scenario whereas the third column titled 'WIS' denotes the 'wind inclusive' scenario. The second last column is a difference metric calculated as 'WIS' minus 'WES'. A negative value indicates a reduction in system-wide total variable costs associated with the 'wind inclusive' scenario when compared with the 'wind exclusive' 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 'wind exclusive' 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 'wind exclusive' scenario. The last row of Table 15 contains the aggregate results for the interval 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 15 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 SA, NSW and VIC. For this latter period, the magnitude of the reductions are 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 from the 'wind exclusive' scenario. Thus, when viewed from the perspective of the NEM as a whole, it is clear that wind generation has produced a considerable monetary gain (e.g. savings) in terms of reduced expenditure by market participants on total variable costs by displacing, on a marginal cost basis, more costly forms of generation.

Table 15. System-wide Variable Costs ($m)

Year	WES	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

(4.5) Transmission Network Adequacy

To the extent that wind farm generation produces changes in dispatch patterns, it can also potentially cause both intra-state and inter-state power flows on transmission branches to change significantly from outcomes associated with the baseline 'wind exclusive' scenario. In the context of changed inter-state power flows, this could show up as changes in both the *magnitude* and *direction* of average power flows on inter-state interconnectors. Recall that for the NEM as a whole, the ANEM model contains a total of 68 transmission branches which can be broken down into 60 intra-state transmission branches and eight inter-state interconnectors.

In this section**,** we examine how wind generation might have influenced trade (e.g. power flows) between states by assessing how wind generation might have affected the magnitude and direction of power flows on inter-state interconnectors. In undertaking this, we will examine the adequacy of the transmission network to accommodate operational wind generation together with other forms of generation operating within the NEM. This aspect will particularly focus on the issue of transmission branch congestion. Branch congestion is defined to arise when the MW power transfer on the transmission branch (in either a positive or negative direction) is equal to the transmission branches rated MW thermal limit. Note that in this study our focus in assessing branch congestion is strictly associated with MW limits associated with thermal limits, and not related, for example, to limits associated with voltage or oscillatory stability limits. Thus, we are concerned with assessing the adequacy of the transmission network from the viewpoint of its thermal transfer capabilities.

In assessing transmission adequacy, one metric of interest is the extent to which the ANEM model had difficulties in achieving an optimal solution during model simulations. The definition of optimal here relates to the actual status of the solution process arising from the MOSEK optimisation software where, within MOSEK, the solution is deemed to be optimal if it is primal and dual feasible. As part of the model output, we record the number of dispatch intervals in which the model experienced problems in achieving an optimal solution. In such cases, typically, either a generation constraint, or more likely, a transmission constraint will be inconsistent with obtaining the property of primal and dual feasibility. Often, this means that either the generation or transmission limit would have to be increased in order to achieve an optimal solution.

The number of half-hourly intervals during which solution problems emerged for each year is reported in Table 16. In this table, the second column titled 'WES' corresponds to the 'wind exclusive' (i.e. no wind) scenario whereas the third column titled 'WIS' denotes the 'wind inclusive' scenario. The final column is a difference metric calculated as 'WIS' minus 'WES' and negative values indicate a reduction in the number of problematic half hours associated with the 'wind inclusive' scenario when compared with the 'wind exclusive' scenario. It is apparent from Table 16 that 2009 poses the most problematic half hourly intervals for both scenarios and, more generally, the baseline 'wind exclusive' scenario produces more problematical intervals than does the 'wind inclusive' scenario. Thus, in broad terms, the inclusion of wind generation has had a stabilising effect in terms of obtaining optimal solutions to the underlying DC OPF problem. This is seen particularly by the negative numbers in the last column of Table 16 indicating less problematic dispatch intervals under the 'wind inclusive' scenario.

Table 16. The Number of Problematic Dispatch Intervals (Half Hours)

Year	WES	WIS	Diff

2007	0	0	0
2008	0	0	0
2009	33	18	-15
2010	7	0	-7
2011	2	0	-2
2012	0	0	0

Average MW power flows on inter-state interconnectors for each year are reported Panel (A) of Table 17. These results were calculated by determining the average MW power flow for each calendar year on each inter-state interconnector for both the baseline 'wind exclusive' and 'wind inclusive' scenarios being investigated. The results listed in Panel (B) of Table 17 are the percentage change in average MW power flows associated with the 'wind inclusive' scenario relative to average power flows reported in Panel (A) of Table 17 corresponding to the 'wind exclusive' scenario.

It should be noted that average power flow values with a positive sign ('+') in the second row of both panels of Table 17 indicates power flows from QLD to NSW on QNI and Directlink (DL) interconnectors; from NSW to VIC on Tumut-Murray (T-M), Tumut-Dederang (T-D) and Tumut-Regional VIC (T-RV) interconnectors; from VIC to TAS on the Basslink (BL) interconnector; and from VIC to SA on Heywood (HW) and Murraylink (ML) interconnectors. Negative signs ('-') signify power flows in the reverse direction.

Under the baseline 'wind exclusive' scenario, inspection of Panel (A) of Table 17 indicates that QLD exports power to NSW on QNI but imports power from NSW on DL. Furthermore, the magnitude of these average power flows broadly increases over the interval 2007-2012, although tails off on QNI in 2012 compared to the two previous years.

Average MW power transfers from NSW to VIC are more variable in character. The magnitude of the average power flows on both the T-M and T-D branches are very small and the sign tends to flip around between different years. It is only on the T-RV branch that definitive directional flow emerges – from NSW to VIC. In this latter case, the magnitude of average power flow also broadly declines, from 164.1 MW in 2007 to 146.4 MW in 2012.

Table 17. Average MW Power Flows on Inter-State Interconnectors

Panel (A) Baseline Wind Exclusive Scenario.

Year	QNI	DL	T-M	T-D	T-RV	BL	HW	ML

	+	-	+/-	+/-	+	+	+	-
2007	781.32	14.57	1.55	3.94	164.15	388.75	139.92	-92.90
2008	971.30	-1.97	7.99	19.71	168.86	400.21	131.93	-90.71
2009	967.04	-49.69	-0.22	2.37	160.29	369.92	148.83	-86.27
2010	1029.10	-68.72	2.12	6.81	162.82	372.42	138.39	-92.59
2011	1027.12	-65.32	-4.51	-8.35	152.37	403.72	151.81	-87.76
2012	997.17	-89.33	-8.54	-18.11	146.45	395.69	165.21	-82.47

Panel (B) Percentage Change Associated with Wind Inclusive Scenario relative to the Wind Exclusive Scenario

Year	QNI	DL	T-M	T-D	T-RV	BL	HW	ML
	+	-	-	-	+	+	+	-
2007	-1.50	-41.15	-687.35	-576.00	-12.67	1.55	-20.16	20.35
2008	-1.06	265.44	-139.33	-121.92	-12.97	0.92	-23.55	24.02
2009	-2.42	23.77	12157.1	-2393.95	-33.74	5.53	-37.63	45.51
2010	-2.37	17.39	-1540.6	-1020.13	-41.72	7.97	-47.21	49.35
2011	-2.99	22.87	969.90	1116.25	-56.73	7.31	-54.88	73.61
2012	-3.45	18.75	603.59	603.59	-67.70	9.63	-55.88	93.17

In the case of VIC, this state exports power to TAS on BL with the average amount of power exported remaining fairly constant, between the range of 369.9 and 403.7 MW's. A similar situation also emerges on HW with VIC exporting power to SA on this interconnector. Whilst there is some variation from year to year, the magnitude of average power flow on this interconnector generally increases in magnitude and especially over the interval 2011-2012. More generally, the magnitudes of the average MW power flows are in the range of 131.9 to 165.2 MW's for the period 2007-2012.

In contrast, the sign of the average power flows on the ML interconnector indicates that VIC imports power from SA, with the magnitude of such power flows generally diminishing over the interval 2007-2012. For example, the average power flow was 92.9 MW in 2007, declining to 82.5 MW's in 2012.

Details about the impact of wind generation on average MW power flows on inter-state interconnectors are listed in Panel (B) of Table 17. The first thing to note is that the signs of the power flows have remained the same as Panel (A) of Table 17 for QNI, DL, T-RV, BL, HW and ML interconnectors. Furthermore, the sign on average power flows have become more definite in nature in the case of T-M and T-D with the negative signs now indicating average power flows from VIC to NSW on these interconnectors. In the case of average power flows with positive signs in the second rows of Table 17, negative percentage change values in Panel (B) indicate that wind generation has reduced the magnitude of average power flows on interconnectors. This occurs for QNI, T-RV and HW interconnectors.

The converse occurs for the BL interconnector – the positive percentage growth results in Panel (B) together with the positive signs on the direction of power flow implies that average MW power flows from VIC to TAS increased when wind generation was included in the analysis. More generally, a key factor driving power flows on Basslink in the direction from VIC to TAS is that the cost of generation at Loy Yang (e.g. brown coal) is much cheaper in relative terms than that at GeorgeTown (e.g. NGCC or OCGT plant). Moreover, Loy Yang acts as a type of source in terms of having a higher 500 kV transmission transmission backbone and also significant excess generation relative to load while George Town acts as a sink (having a lower 220 kV transmission backbone and excess demand). Under these circumstances, power would generally be expected to flow from VIC to TAS in the absence of something like a carbon price to equalize out the relative differences in marginal costs of generation located at the two nodes. In support of this latter proposition, we found in other modeling that carbon prices in the range of \$30/tC02 to \$40/tC02 were broadly sufficient to turn around the direction of average power flows to TAS to VIC, suggesting that relative marginal cost differences between the two nodes is very important in determining the direction and magnitude of average power flows. See Wild et al. (2012a, Section 4.5, Table 17) for further details.

An important contributing factor is that the supply offers of TAS hydro generation are based on Long Run Marginal Costs (LRMC) and not Short Run Marginal Costs (SRMC) [as is also the case for mainland hydro]. This also means more generally that TAS hydro costs are higher in relative terms than generation costs at Loy Yang (especially Loy Yang A). Using SRMC's for TAS hydro supply offers could potentially change the direction of power flows on Basslink in favour of power transfers from TAS to VIC, but also potentially expand production from TAS hydro to such an extent to generate congestion on some TAS intra-state branches producing islanding effects within TAS and nodal prices in the range \$3/MWh to \$8/MWh at many TAS nodes. Thus, while basing TAS hydro supply offers around SRMC would be expected to significantly turn around the extent and direction of power flows on Basslink, realistic water storage and flow constraints would be needed to ensure that ‘excessive’ production is not sourced from TAS hydro plant under this circumstance.

Research addressing how to incorporate real time water storage and flow information and SRMC bidding on the part of hydro generation agents in the model is currently ongoing.

For interconnectors with negative power flows in the second rows, positive results in Panel (B) indicate an increase in the magnitude of negative MW power flows in response to the incorporation of wind generation in the analysis. This occurs for the DL and ML interconnectors. The impact of wind generation on power flows on the T-M and T-D interconnectors has been to significantly increase the magnitude of negative average power flows on these two interconnectors, especially over the interval 2009-2012, pointing to larger power transfers from VIC to NSW. Note also that the large percentage change values reported in Panel (B) for these two particular branches should also be reconciled against the extremely small magnitudes of average power flows listed for these two branches in Panel (A) of Table 17. Thus, we can conclude given the sign of average power flows and percentage change results reported in Panel (B) of Table 17 that:

- Wind generation reduces the magnitude of average MW power flows from QLD to NSW on QNI, NSW to VIC on T-RV and from VIC to SA on HW interconnectors. Moreover, the magnitude of this reduction effect increases over 2007-2012;

- Wind generation increases the magnitude of average MW power flows from NSW to QLD on DL and SA to VIC on ML interconnectors. In the case of DL, this trend becomes reasonably constant over the period 2009-2012 after being quite variable for prior years. For ML, the above trend unambiguously increases over 2007-2012;

- For the T-M and T-D interconnectors, the impact of wind generation is to significantly increase average power flows from VIC to NSW with the trend becoming particularly evident over the 2009-2012; and

- For the BL interconnector, the impact of wind generation is to increase the magnitude of average MW power flows from VIC to TAS, with this trend broadly increasing over the interval 2007-2012.

Information on transmission branch congestion is presented in Table 18. 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. [24] Note that only transmission branches experiencing congestion are included in Table 18. The values listed in Panel (B) of Table 18 are the percentage change in congestion rates associated with the ‘wind inclusive’ scenario relative to the congestion rates cited in Panel (A) of Table 18 associated with the ‘wind exclusive’ scenario.

The results in Panel (A) indicate that for the baseline ‘wind exclusive’ scenario, congestion on QNI increases markedly between 2007 and 2008 from 18.1 per cent to 61.2 per cent and then varies from year to year within the range 58.1 to 72.2 per cent, with evidence of a slight tailing off over the period 2010-2012. In the case of DL, there is a significant reduction in branch congestion between years 2007 and 2008, declining from 25.3 per cent to 5.7 per cent. For the remainder of the period under investigation, congestions rates vary from year to year but are within the range of 5.4 per cent to 13.4 percent. In the case of T-RV, the congestions rates are within the range of 48.3 to 54.7 per cent, although the rates decline over the interval 2010-2012 from 54.4 per cent to 48.3 per cent. For BL, the congestions rates are reasonably constant, in the range 62.4 to 69.7 per cent. The congestions rates, however, do increase over the period 2010-2012 from 62.4 to 69.7 per cent. The results for both HW and ML indicate relatively small amounts of congestion on both of these interconnectors (particularly so for HW) under the baseline wind exclusive case. For HW, the congestions rates are not more than 1 per cent and for ML fall within the range of 7.5 to 9.2 per cent. Finally, two TAS intra-state branches experience some branch congestion. These are the Sheffield-Palmerston (S-P) and Waddamana-Tarraleah (W-TL) transmission branches which experience congestion rates of between 9.0 and 23.3 per cent and 2.2 and 6.0 per cent, respectively. Moreover, the extent of congestion also diminishes on both branches especially over the 2010-2012 time interval.

Table 18. Congested Transmission Branches

Panel (A) Proportion of Time Congested: Baseline Wind Exclusive Scenario.

Year	QNI	DL	T-RV	BL	HW	ML	S-P	W-TL
2007	0.181	0.253	0.543	0.673	0.004	0.085	0.137	0.060
2008	0.612	0.057	0.547	0.695	0.005	0.077	0.200	0.044

[24] Recall that 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.

2009	0.581	0.091	0.525	0.640	0.009	0.075	0.220	0.048
2010	0.722	0.054	0.544	0.624	0.006	0.092	0.233	0.036
2011	0.716	0.056	0.517	0.687	0.010	0.092	0.163	0.022
2012	0.614	0.134	0.483	0.697	0.009	0.079	0.090	0.024

Panel (B) Percentage Change In Average MW Power Flows Associated with Wind Inclusive Scenario relative to the Wind Exclusive Scenario

Year	QNI	DL	T-RV	BL	HW	ML	S-P	W-TL
2007	-2.52	2.48	-7.95	5.71	-64.71	75.96	-28.52	-5.90
2008	-3.29	19.68	-8.21	2.87	-47.62	78.33	-56.46	-10.72
2009	-7.42	37.32	-22.88	17.24	-77.18	195.69	-50.93	-5.98
2010	-9.81	79.68	-22.21	18.45	-87.63	218.03	-56.21	-24.71
2011	-12.33	88.39	-36.87	19.93	-95.27	328.14	-57.96	-32.91
2012	-18.49	78.87	-42.79	20.84	-98.19	443.05	-57.77	-32.32

The impact of wind generation on transmission congestion rates are outlined in Panel (B) of Table 18. Recall that the data in this panel are the percentage change in branch congestion rates associated with the 'wind inclusive' scenario relative to the results reported in Panel (A) associated with the baseline 'wind exclusive' scenario. Note that negative percentage change results in Panel (B) would be indicative of wind generation reducing the incidence of branch congestion relative to the congestion rates obtained from the 'wind exclusive' scenario. Therefore, from Panel (B), it is clear that wind generation has reduced congestion on QNI, T-RV, HW, S-P and the W-TL transmission branches. Moreover, the extent of the reduction in congestion on these branches has increased in magnitude over the time period 2009-2012, as discernible from the increase in the magnitude of the negative percentage change results reported in Panel (B) of Table 18.

In contrast, the DL, BL and ML interconnectors all experience increased branch congestion as represented by the positive percentage change values in Panel (B). In particular, note the sizable percentage change values associated with the ML interconnector over the period 2009-2012 which fall within the range of 195.7 and 443.0 per cent – a period of time during which there was considerable expansion in wind farm capacity in the Mid-north SA node. Furthermore, the extent of the increase in branch congestion associated with wind generation generally increases over time for all three transmission branches, and particularly so for ML. This can be discerned by the increased magnitudes of the positive percentage change results listed in Panel (B) of Table 18 for these specific transmission branches. Therefore, in summary, the incorporation of wind generation in the modelling has tended to ameliorate congestion on QNI, T-RV, HW, S-P and W-T branches while increasing congestion on the DL and BL interconnectors and significantly increasing congestion on the ML interconnector.

(5). Concluding Remarks

In this article, 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 and transmission network adequacy. It was argued that in order to address this, a model of the national electricity market is required that 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.

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. 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 SA and VIC. Reductions in average annual prices also increase over time reflecting the expansion in semi-scheduled wind farms in SA, VIC and NSW 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. Similar trends were also observed in nodal prices.

Accompanying the reduction in average wholesale electricity prices, wind generation tended to reduce price volatility in the high wind penetration states of VIC, SA and TAS. Wind generation also tended to decrease the incidence of negative price outcomes in VIC but increased their incidence in SA particularly over the interval 2011-2012.

Production Trends:

SA and TAS experienced the greatest reductions in production from thermal and hydro generation associated with wind generation. QLD and VIC experience the lowest rates of reduction in thermal and hydro production with NSW lying between. SA experienced relatively high reductions in production from coal-fired generation whilst, in contrast, VIC experiences very small reductions in production from coal-fired generation. NSW, once again, fell in between these two states, with this reduction becoming particularly evident over 2010-2012. Results also pointed to wind generation impacting more heavily on old and medium vintage plant.

Wind generation also led to significant displacement of gas-fired production from particularly VIC associated primarily with displacement of OCGT plant. SA also experienced noticeable reductions in output from gas-fired plant, encompassing reductions is production from both NGCC and Gas Thermal plant as well as sizeable displacement of production from OCGT plant, albeit at slightly lower rates than for VIC in the case of OCGT plant. Both QLD and NSW experienced no real impact on production from gas generation. In the case of TAS, 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.

TAS experienced a relatively stable profile of reductions in production from hydro plant, with the rate of reduction unambiguously increasing in magnitude over 2008-2012. Reductions in hydro generation production in NSW and VIC were more marked and variable in nature, but coming off of much lower production levels. Wind generation had no discernible impact on hydro production in QLD.

Carbon Emissions:

The impact of wind generation in the NEM was to reduce carbon emissions in all states. The stand-out state was clearly SA. In contrast, the impact on carbon emissions from VIC was quite marginal, reflecting the very small impact that wind generation had on displacing production from brown coal-fired generation in that state. NSW experienced greater cuts in carbon emissions than QLD reflecting the partial displacement of production from NSW old and medium vintage black coal-fired generation. In contrast, the minimal reductions in QLD primarily reflected the absence of wind generation in that state.

In the case of TAS, 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.

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

System-wide Total Variable Costs:

Apart from 2009, reductions in system-wide total variable costs arose, and generally increased in magnitude over the time period 2010-2012 with the expansion in semi-scheduled wind generation in SA, NSW and VIC. When considered as a whole over the period 2007-2012, reduction in system-wide total variable costs was in the order of 2.21 per cent from the equivalent result obtained from the no-wind 'wind exclusive' scenario.

Transmission Network Adequacy:

Wind generation reduced the magnitude of average MW power flows from QLD to NSW on QNI, NSW to VIC on Tumut-Regional VIC and from VIC to SA on Heywood interconnectors. Wind generation also increased the magnitude of average power flows from NSW to QLD on Directlink and SA to VIC on the Murraylink interconnector. For the Tumut-Murray and Tumut-Dederang interconnectors, the impact of wind generation was to significantly increase average power flows from VIC to NSW. Finally, for the Basslink interconnector, the impact of wind generation increased the magnitude of average power flows from VIC to TAS.

Our modelling also indicated that wind generation tended to ameliorate congestion on QNI, Tumut-Regional VIC, Heywood, Sheffield-Palmerston and Waddamana-Tarraleah transmission branches while increasing congestion on the Directlink and Basslink interconnectors. It significantly increased congestion on the Murraylink interconnector.

More generally, in assessing transmission adequacy, we also investigated whether the inclusion of wind generation in the modelling made the task of obtaining an optimal solution more easier or more difficult when running the ANEM model. The latter situation would usually occur if a generation or transmission constraint was inconsistent with obtaining a feasible solution and would typically require either the generation or transmission limit be augmented to achieve an optimal solution. The results indicated that year 2009 produced the most problematic half hourly dispatch intervals and the inclusion of wind generation had a stabilising (e.g. beneficial) effect in terms of obtaining optimal solutions. This suggested, overall, that the transmission network could adequately support the current penetration of wind generation within the NEM.

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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

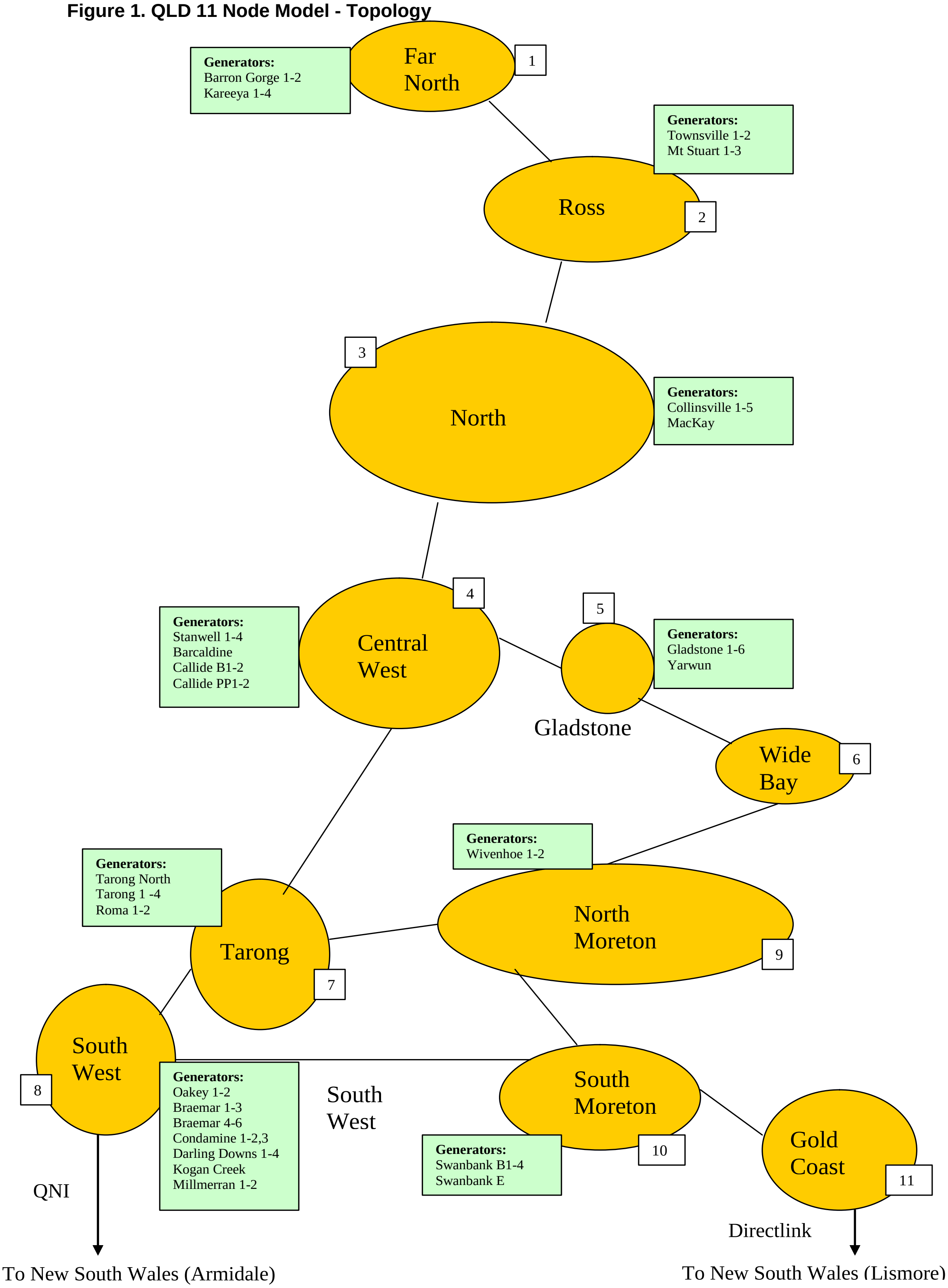


Figure 2. NSW 15 Node Model - Topology

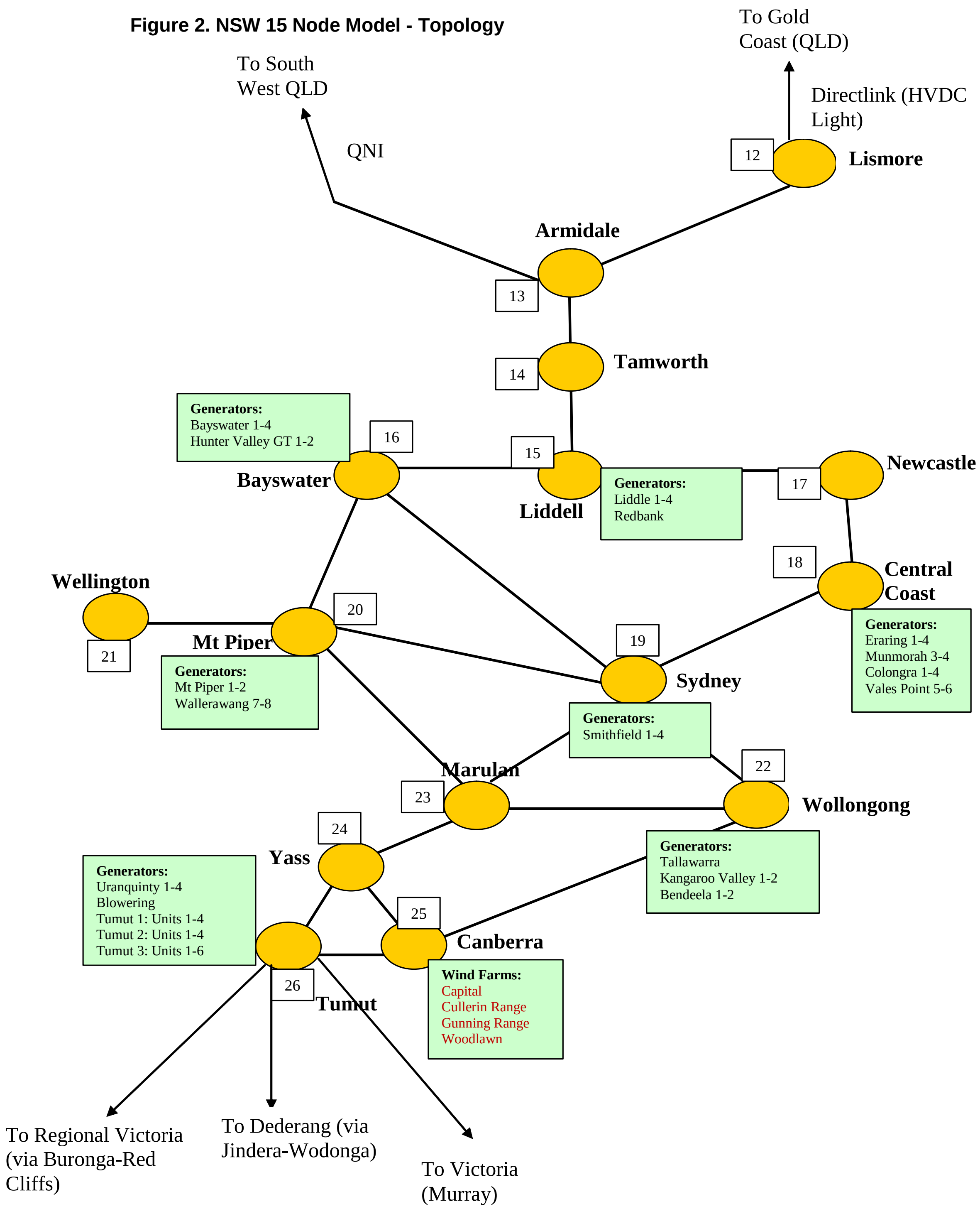
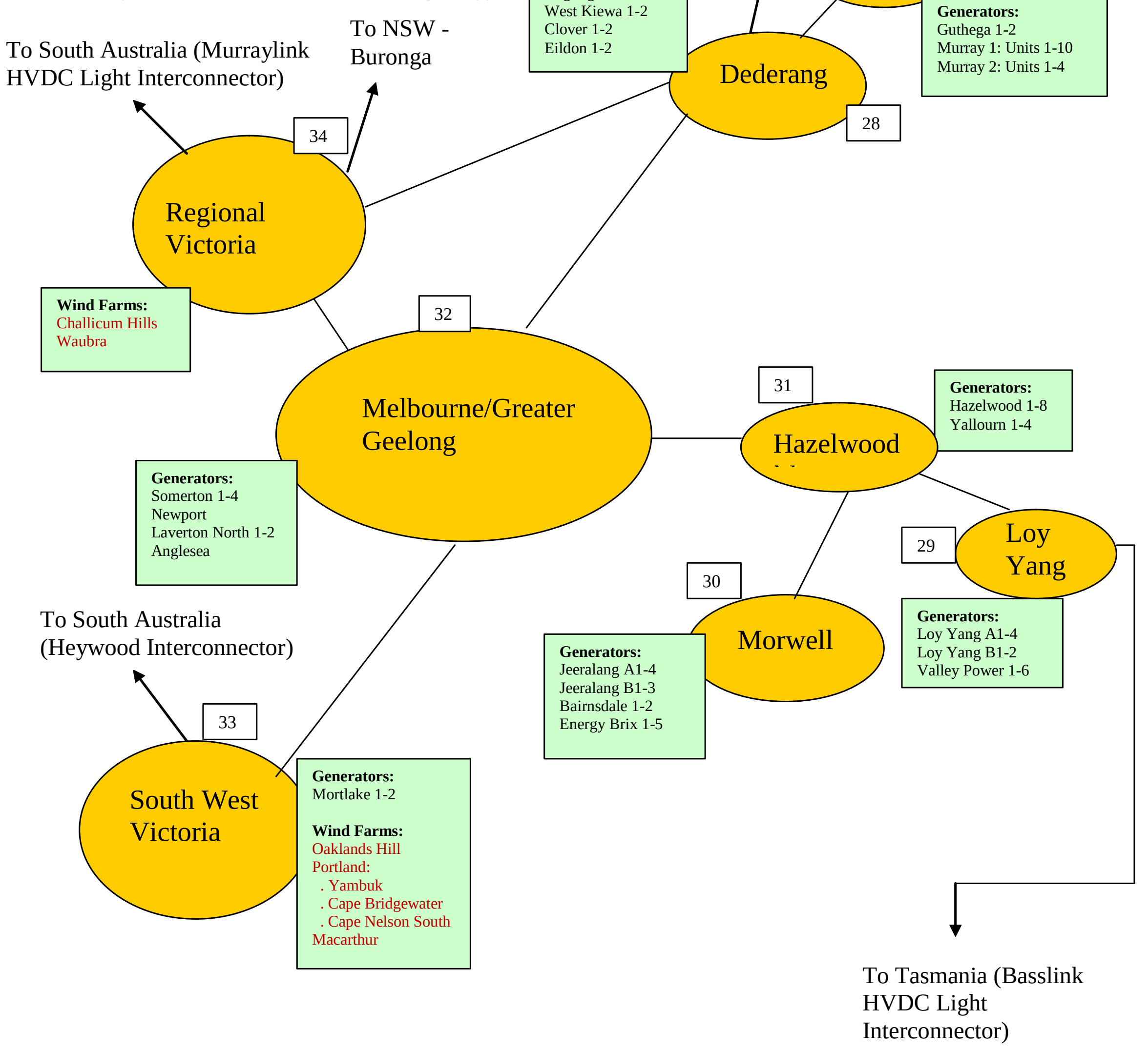
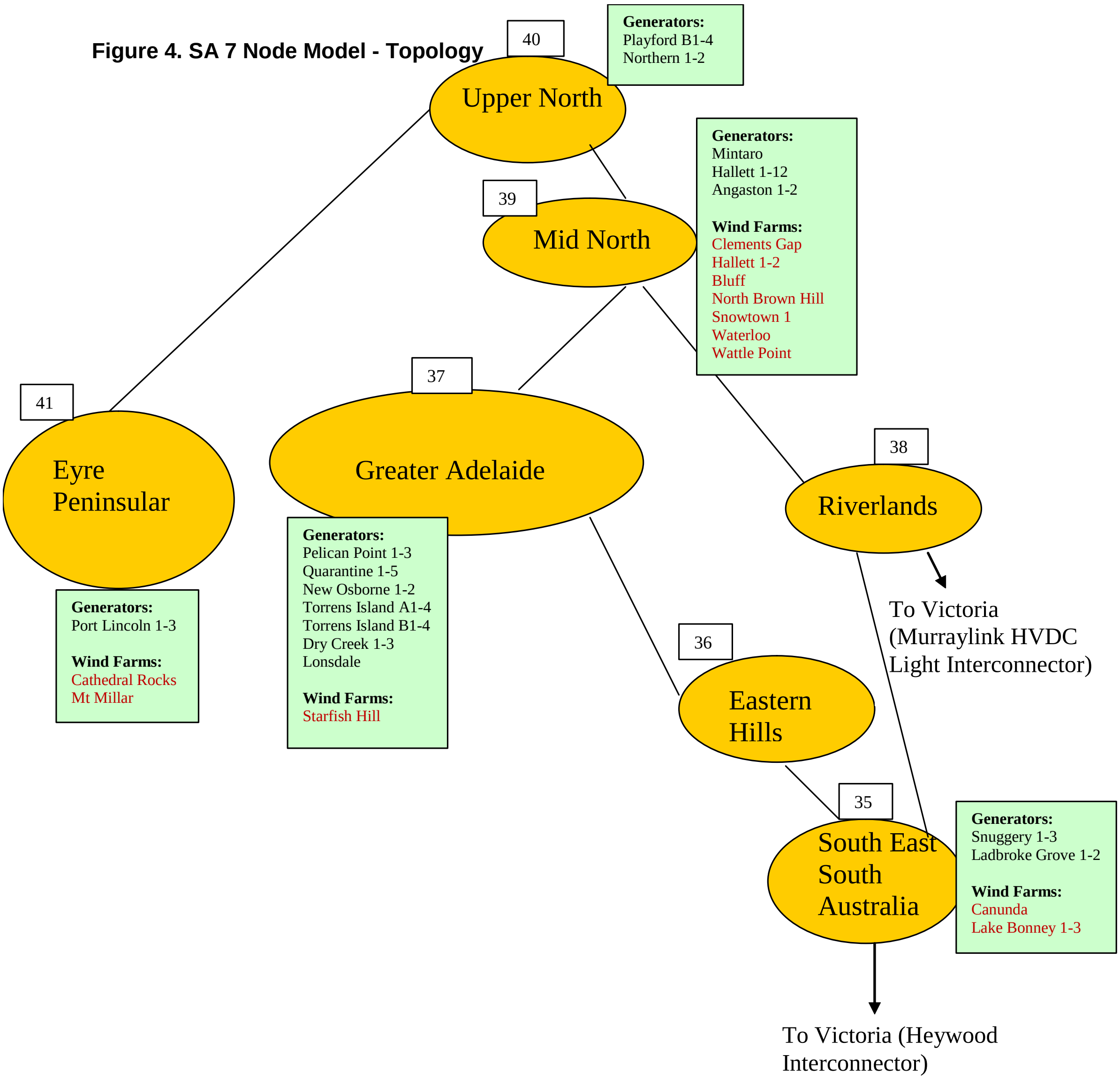


Figure 3. VIC 8 Node Model - Topology



To New South Wales (Armidale)

Figure 4. SA 7 Node Model - Topology



To New South Wales (Armidale)

Figure 5. TAS 11 Node Model