The Impact of Carbon Pricing on Wholesale Electricity Prices, Carbon Pass-Through Rates and Retail Electricity Tariffs in Australia.[1]

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ABSTRACT

The purpose of this article is to investigate the impact that the introduction of a carbon price signal will have on wholesale electricity prices, carbon-pass-through rates and retail electricity rates in the states making up the Australian National Electricity Market (NEM). In order to assess this, we employ an agent based model of the NEM called the ANEM model which contains many of the salient features of the NEM: intra-state and inter-state transmission branches, regional location of generators and load centres and accommodation of unit commitment features. A DC OPF algorithm is used to determine optimal dispatch of generation plant and wholesale prices within the ANEM model. We utilise ANEM model scenario runs to examine the impact of carbon prices on wholesale prices and carbon pass-through rates. This information is then used to assess the impact on retail electricity tariff rates and shares of cost components making up residential retail tariff rate structures for different states in the NEM.

Keywords: carbon pass-through, carbon price, electricity prices, agent-based model, DC OPF Algorithm, Australian National Electricity Market (NEM).

JEL Classifications: C61, C63, D24, L94.

(1). Introduction

There has been significant debate about the potential role that supply side and demand side policy initiatives might exert upon key participants within the National Electricity Market (NEM) in attempts to curb growth in carbon emissions. From the perspective of supply side policy initiatives, most debate and analysis has been focused upon assessing the impact that a óCap-&-Tradeô carbon trading scheme, and more recently, a carbon tax scheme, might have on changing marginal cost relativities in order to promote increased dispatch and investment in less carbon emissions intensive types of generation technologies including gas-fired generation and renewable generation technologies.

However, with any forthcoming move towards a carbon constrained economy, there are many uncertainties over policy settings that are required to achieve the environmental goal of reduced greenhouse gas emissions and about the resulting impact on the National Electricity Industry more generally. A complete understanding of the impacts on the electricity industry of carbon abatement policies requires a model containing many of the salient features of the national wholesale electricity market. These features include intra-regional and inter-state trade, realistic transmission network pathways, competitive dispatch of all generation technologies with price determination based upon variable cost and branch congestion characteristics. It is only under such circumstances that the link between carbon emission reductions and generator based fuel switching can be fully explored and the consequences for carbon emission reductions and changes in wholesale and retail electricity prices can be investigated.

A central plank in assessing the impact of policies that aim to combat carbon emissions growth through the pricing of carbon emissions has been the concept of carbon pass-through. It has been established in the economic literature that this concept will be crucial to understanding and estimating the interaction between the carbon price signal and wholesale electricity prices and assessment of the need, scope and role of industry assistance proposals including partial or complete allocation of free permits (e.g. grandfathering) ï for example, see Reinaud (2007), Chen, Sijm, Hobbs and Lise (2008), Chernyavsõka and Gulli (2008) , Freebairn (2008), Sijm, Hers, Lise and Wetzelaer (2008), Simshauser (2008), Menezes, Quiggin and Wagner (2009), Simshauser and Doan (2009), Kim, Chattopadhay and Park (2010), Nelson, Orton and Kelley (2010) and Sijm, Chen and Hobbs (2011).

In order to investigate the interaction between carbon price levels and wholesale electricity prices and the important issue of carbon pass-through rates, we use an agent based model of the NEM called the ANEM model that utilizes core features of the Wholesale Power Market Platform (WPMP). This platform provides a template for operations of wholesale power markets by Independent System Operators (ISO) using Locational Marginal Pricing (LMP) to price energy by the location of its injection into or withdrawal from the transmission grid, (Sun and Tesfatsion (2007b)). ANEM is a modified and extended version of the American *Agent-Based Modelling of Electricity Systems* (AMES) model developed by Sun and Tesfatsion (2007a, 2007b) [2] and utilises the emerging powerful computational tools associated with Agent-based Computational Economics (ACE).[3] The modifications reflect

[2] Comprehensive information including documentation and Java code relating to the óAMESô model can be found at: http://www.econ.iastate.edu/tesfatsi/AMESMarketHome.htm.
[3] Useful information and computational resources related to ACE modelling can be found at: http://www.econ.iastate.edu/tesfatsi/ace.htm.

the key differences between the Australian and USA wholesale electricity markets, relating more specifically to the different institutional structures of the markets and resulting implications for operational, procedural and legal meanings of day ahead and spot markets in both countries ï see Wild, Bell and Foster (2012), Section 1, for further details.

The wholesale market of the NEM is a real time ónergy onlyô market and a separate market exists for ancillary services (AEMO (2009)). A DC OPF algorithm is used to determine optimal dispatch of generation plant and wholesale prices within the ANEM model. The formulation of DC OPF problems require detailed structural information about the transmission grid as well as supply offer and demand bid information from market participants. This framework will accommodate many features required to model wholesale power markets ï specifically, intra-state and inter-state transmission branches (and power flows), consideration of the regional location of generators and load centres and accommodation of unit commitment features including thermal limits, ramping constraints, start-up costs, minimum stable operating levels and must run requirements of different fuel based generation technologies.

In the next section, we will examine the role that the concept of carbon pass-though plays in assessing the impact of carbon price signals on wholesale electricity prices and the efficacy of claims for industry assistance that commonly emerge in public debate. In Section 3, we will provide a more detailed outline of the ANEM model that is used in this paper to investigate the impact of carbon prices on wholesale and retail electricity prices and carbon pass-through rates. In Section 4, some practical implementation aspects underpinning the model simulation runs will be highlighted. The empirical findings will be presented in Sections 5, 6 and 7, relating to the findings about wholesale price impacts, carbon pass-through rates and retail tariff impacts, respectively. Concluding comments will be offered in Section 8.

(2). The Concept of Carbon Pass-through.

Carbon pass-through can be defined as the incidence of the carbon tax or tradable carbon permit and refers to the proportion of carbon prices (expressed in $/tC02) that are passed through into wholesale electricity spot prices (expressed in $/MWh), (Nelson, Orton and Kelley (2010)). Carbon pass-through is primarily driven by:

- Emissions intensity of the existing capital stock ï high carbon pass-through rates are indicative of a high carbon emissions intensive capital stock ï a situation currently confronting Australia when compared with many European countries, (Simshauser and Doan (2009), Kim, Chattopadhay and Park (2010) and Nelson, Orton and Kelley (2010)).

- Demand and Supply elasticities ï the level of carbon pass-through would be higher the more inelastic is demand and the more elastic is supply, (Chen, Sijm, Hobbs and Lise (2008), Freebairn (2008), Menezes, Quiggin and Wagner (2009), Nelson, Orton and Kelley (2010) and Sijm, Chen and Hobbs (2011)).

- The economics of existing substitutes ï this concerns the extent to which low emissions intensive forms of generation are available for substitution with high emissions intensive form of generation which would be expected to reduce the rate of carbon pass-through, (Simshauser and Doan (2009) and Nelson, Orton and Kelley (2010)).

- The availability of offsets or international credits ï these instruments would serve to increase the domestic rate of carbon pass though by reducing the requirement for domestic substitution of emissions intensive forms of production, (Nelson, Orton and Kelley (2010)).

- Market competition - whether the market is competitive or characterised by oligopolistic or monopolistic structures, (Chernyavsõka and Gulli (2008), Nelson, Orton and Kelley (2010) and Sijm, Chen and Hobbs (2011)).

In theory, most carbon pass-through estimates are obtained by abstracting from such complications as transmission branch congestion, spatial location of generators and demand centres within the transmission grid and assuming perfect competition. When there is no market power and no constraints other than generator capacity limits, least cost production involves first dispatching the generator with lowest marginal cost, followed by the generator with the next lowest marginal cost, and so on, (Sijm, Neuhoff and Chen (2006), Chen, Sijm, Hobbs and Lise (2008) and Sijm, Chen and Hobbs (2011)). However, óout of orderô dispatch can arise when market power is exercised, account is taken of transmission and unit commitment considerations, the level of the carbon price changes the merit order and marginal generator, or when the carbon price signal produces a demand response, (Sijm, Neuhoff and Chen (2006) and Chen, Sijm, Hobbs and Lise (2008)). If the policy of decarbonising the economy in order to combat climate change is successful, we would expect to see the carbon pass-through rate decline over time.

A survey of carbon pass-through rates obtained for Australia is contained in Nelson, Orton and Kelley (2010) ï also see Kim, Chattopadhay and Park (2010). They found that the state emission factors measured in (tC02/MWh) and including contribution of wind generation produced a variable set of outcomes with Victoria having the largest emissions intensity factor of 1.23 while Tasmania had the lowest of 0.32. The emissions intensity factors for QLD and NSW were found to be 0.89 and 0.90 respectively while for SA it was 0.72, reflecting the relatively high concentration of wind generation in that particular state relative to the rest of the NEM. The NEM wide weighted average emissions intensity factor was found to be 0.94. It should be noted that the 0.94 NEM result would imply that a carbon pass-through rate of 0.94 to consumers implying that a $10/tC02 carbon tax would increase the wholesale electricity price by $9.40/MWh, (Nelson, Orton and Kelley (2010)).

It was also demonstrated in Nelson, Orton and Kelley (2010) that existing Australian estimates of carbon pass-through vary significantly ï from 17% to 128% for stable generator bidding strategies. The mean of the studies was found to be 93.4% (e.g. 0.934). Moreover, higher range values were associated with a time frame of investigation relating to the dispatch of the current or existing stock of generators ï e.g. a short term horizon where an assumption of capital stock ófixityô was applied, (Freebairn (2008)). Finally, Australian investigations were based on one of the following modelling frameworks:

- Linear program optimisation modelling.
- Linear program modelling utilising game theory.
- Competitive General Equilibrium Modelling (CGE).
- Dynamic partial equilibrium modelling.

Overseas investigations primarily related to EU ETS indicate that carbon pass-through rates were broadly correlated with average emission intensity levels. A good overview of methods and pass-through estimates can be found in Reinaud (2007), Sijm, Hers, Lise and Wetzelaer (2008), Nelson, Orton and Kelley (2010) and Kim, Chattopadhay and Park (2010)).

The importance of the concept of carbon pass-through reflects the fact that significant levels of carbon pass-through indicate that consumers are bearing a large proportion of the carbon price/tax while a low rate would indicate that producers (e.g. generators) are bearing a high proportion of the incidence of the carbon price/tax. In this context, the level of carbon pass-through can be linked to consideration of who should ultimately bear the costs of combating climate change with a high carbon pass-through rate being consistent with the notion that society, more generally, should contribute to meeting the cost because society, as a whole, also stands to benefit from the successful mitigation of the adverse consequences of climate change, (Nelson, Orton and Kelley (2010)). A high carbon pass-through rate would also mitigate claims of generators for compensation from the introduction of a carbon tax as they pass these increased costs onto consumers in the form of higher wholesale electricity prices, (Freebairn (2008)).

Assuming a competitive least cost dispatch process with no transmission or unit commitment related constraints, comparison of carbon pass-through rates with the emissions intensity factor of individual generators gives an indication of whether the prices increases confronting generators will be sufficient to cover their incremental carbon cost liabilities. Relative to some benchmark óBusiness-As-Usualô (BAU) scenario involving no carbon cost impost, if the carbon pass-though rate confronting a dispatched generator is less than that generatorôs emissions intensity factor, the generator concerned will face a loss of market share and asset value relative to BAU as their profitability will be eroded. At the margin, the incremental increase in revenue associated with the carbon price induced increase in wholesale electricity price will not be enough to offset the incremental increase in variable carbon costs associated with the imposition of the carbon price signal and given the dispatched generatorôs carbon intensity factor. As such, the generator will incur carbon costs that are greater than what can be recovered through the market. This process is likely to be magnified over time to the extent that the rate at which the average emissions intensity (e.g. carbon pass-through rate) declines over time with the decarbonisation of the economy and associated increase in the carbon price/tax level which would combine to further reduce the operating life of the generator as it becomes uneconomic relative to new lower emissions sources. This will further reduce output and market share and shorten the useful economic life and value of the asset, producing further financial losses for existing debt and equity capital investors if the asset is privately owned, (Sijm, Neuhoff and Chen (2006), Simshauser (2008), Simshauser and Doan (2009) and Nelson, Orton and Kelley (2010)). The converse will occur if the dispatched generatorôs emission intensity factor is less than the carbon pass-through rate, pointing to an increase in profitability at the margin relative to BAU. In this case, the growth in revenue attributable to increases in the wholesale price level will outstrip cost increases attributable to the introduction of a carbon price signal and the incurring of a carbon cost liability.

The above reasoning has underpinned academic and public debate about the need, role and potential scope of grandfathering where some provision is made to freely allocate carbon permits to generators whose financial position is adversely affected by the introduction of a carbon price signal ï for example, see Simshauser (2008), Simshauser and Doan (2009) and Nelson, Orton and Kelley (2010). However, Garnaut (2008) argued against this position on the basis that there is no history or precedence of compensating private sector owners of capital for loss of value in asset valuations associated with any other public or regulatory policy. Moreover, concern over climate change has been around since the 1970ôs and the potential use of a carbon pricing mechanisms since the early 1990ôs. Hence, the potential use of a carbon price policy instrument cannot be viewed as being an unanticipated event by investors, (Menezes, Quiggin and Wagner (2009)). This position is supported further when consideration was taken of short and long run elasticity of demand and supply for electricity. Adopting accepted elasticity estimates, Menezes, Quiggin and Wagner (2009) demonstrate that the optimal proportion of freely allocated permits would be below 30%, with most of the cost increase being passed on to consumers ï also see Freebairn (2008) and Lambie (2010). On the whole, this degree of grandfathering tends to be significantly lower than proposals advocated by industry.

In the next section, we provide a detailed outline of the ANEM model that is used in this paper to investigate the impact of carbon prices on wholesale electricity prices and carbon pass-through rates and through this on retail electricity prices.

(3). Principal features of the ANEM Model.

In this section, we provide an outline of the principal features, structure and agents of the ANEM model. The model is programmed in Java using RepastJ, a Java-based toolkit designed specifically for agent base modelling in the social sciences.[4] The core elements of the ANEM model are:

1. The wholesale power market includes an Independent System Operator (ISO) and energy traders that include demand side agents called Load-Serving Entities (LSEôs) 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 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 modelôs ISO determines power commitments and LMPôs for the spot market based on generatorsô supply offers and LSEôs demand bids submitted prior to the start of the day.
6. The ISO produces and posts an hourly commitment schedule for generators and LSEs, which is used to settle financially binding contracts on the basis of the dayôs LMPôs for that particular hour.

[4] RepastJ documentation and downloads can be sourced from the following web address: http://repast.sourceforge.net/repast_3/download.html. A useful introduction to JAVA based programming using the RepastJ package is also located at: http://www.econ.iastate.edu/tesfatsi/repastsg.htm.

7. Transmission grid congestion in the spot market is managed via the inclusion of congestion components in the LMP, which is associated with nodal price variation on an hour-by-hour basis.

3(a). Transmission Grid Characteristics.

The transmission grid is an alternating current (AC) grid modelled as a balanced three-phase network with 72 branches and 53 nodes, which are shown in Figures 1 to 5. The transmission grid has no isolated components so that each pair of nodes is connected by a linked branch path consisting of one or more branches. Base apparent power is assumed to be measured in three-phase MVAôs, and base voltage in line-to-line kVôs. For further discussion, see Sun and Tesfatsion (2007a).

It is apparent from inspection of Figures 1-5 that the transmission grid used involves combining the Queensland, New South Wales, Victoria, South Australia and Tasmanian modules represented in these figures. The state module linking is via the following Interconnectors: QNI and Directlink linking Queensland and New South Wales; Tumut-Murray linking New South Wales and Victoria[5]; Heywood and MurrayLink linking Victoria and South Australia; and Basslink linking Victoria and Tasmania. In accordance with the DC OPF framework underpinning the model, the HVDC Interconnectors Directlink, Murraylink and Basslink are modelled as óquasi ACô links ï that is, power flows are determined by assumed reactance and thermal rating values for each of these branches. The major power flow pathways in the model reflect the major transmission flow pathways associated with 275, 330, 500 and 275/132 KV transmission branches in Queensland, New South Wales, Victoria and South Australia, respectively.

The key transmission data required for the transmission grid within the model relate to an assumed base voltage value (in kVôs) and base apparent power (in MVAôs), branch connection and direction of flow information as well as the maximum thermal rating of each transmission branch (in MWôs), together with an estimate of its reactance value (in ohms). Base apparent power is set to 100 MVA, an internationally recognized value for this variable. Thermal ratings of transmission lines and reactance values were supplied by the Queensland, New South Wales and Tasmania transmission companies Powerlink, Transgrid, and Transend. For Victoria and South Australia, the authors used values based on the average values associated with comparable branches in the three above states.

3(b). LSE Agents.

A Load Serving Entity (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 (load) in a downstream retail market ï thus, they link the wholesale power market and the downstream retail market.

[5] Note that we adopt the regional boundaries adopted by AEMO and allocate Tumut to New South Wales and Murray to Victoria notwithstanding the positioning of Murray in the New South Wales module as outlined in Figure 2 which represents the original boundaries linking the previous Snowy Mountains Region to Victoria via the Murray-Dederang Interconnector.

For simplicity, we assume that downstream retail demands serviced by the LSEôs exhibit negligible price sensitivity and hence reduce to daily supplied load profiles which represents the real power demand (in MWôs) that the LSE has to service in its downstream retail market for each hour of the day. In addition, LSEôs are modelled as passive entities who submit daily load profiles (i.e. demand bids) to the ISO without strategic considerations (Sun and Tesfatsion (2007b)). The revenue received by LSEôs for servicing these load obligations are regulated to be a simple ódollar mark-upô based retail tariff.

The hourly regional load data for Queensland and New South Wales required by the model was derived using regional load traces supplied by Powerlink and Transgrid. This data was then re-based to the state load totals published by AEMO for the óQLD1ô and óNSW1ô markets which are located at: http://www.aemo.com.au/data/price_demand.html. For the other three states, the regional shares were determined from terminal station load forecasts associated with summer peak demand (and winter peak demand if available) contained in the annual planning reports published by the transmission companies Transend (Tasmania), Vencorp (Victoria) and ElectraNet (South Australia). These regional load shares were then interpolated to a monthly based time series using a cubic spline technique and these time series of monthly shares were then multiplied by the óTAS1ô, óVIC1ô and óSA1ô state load time series published by AEMO in order to derive the regional load profiles for Tasmania, Victoria and South Australia and which are also available at the web address mentioned above.

3(c). Generator Agents.

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 cost function, total variable cost function, fixed costs [pro-rated to a $(\$/h)$ basis] and a marginal cost function. Depending upon plant type, a generator may also have start-up costs but are assumed not to incur other costs such as no-load or shutdown costs. The feasible production interval refers to the minimum and maximum thermal (MW) rating of each generator. This is defined in terms of both ónergy sent outô and ónergy generatedô. Each generator also faces MW ramping constraints that determine the extent to which real power production levels can be increased or decreased over the next hour within the hourly dispatch horizon. The production levels determined from the ramp up and ramp down constraints must fall within the minimum and maximum thermal MW capacity limits confronting each generator. Note that if the generatorôs minimum MW thermal limit is non-zero, it is said to have a non-zero minimum stable operating capacity.

The MW production and ramping constraints are defined in terms of ónergy sent outô because the DC OPF solution is concerned with balancing real power production levels of generators and real power flows on transmission lines with LSE load demand prevailing at and across all nodes within the power grid. In contrast, variable costs and carbon emissions are calculated from the ónergy generatedô power production concept. This later concept includes energy sent out plus a typically small amount of additional energy that is produced internally as part of the general power production process.

Variable costs of each generator are modelled as a quadratic function of hourly real energy produced by each generator on an ónergy generatedô basis. The marginal cost function is calculated as the partial derivative of the quadratic variable cost function with respect to

hourly energy produced, producing a marginal cost function that is linear in hourly real energy production of each generator (Sun and Tesfatsion (2007b). The intercept of the marginal cost function is the linear coefficient of the variable cost function and its slope is given by the quadratic coefficient of the variable cost function.

The variable cost concept underpinning each generatorôs variable cost as well as the system-wide variable cost incorporates fuel, variable operation and maintenance (VO&M) costs and carbon cost components. In this context, it should be recognised that generators fully incorporate carbon cost liabilities in their supply offers. As such, in the terminology of Sijm, Neuhoff and Chen (2006), the óadd-onô rate of generators with a carbon cost liability is 100%. The fuel, VO&M and carbon emissions/cost parameterisation of the variable and marginal cost functions can be determined using data published in ACIL Tasman (2009) for thermal plant and from information sourced from hydro generation companies for hydro generation units. A formal derivation of the various total and marginal cost components is outlined in Appendix A of Wild, Bell and Foster (2012).

Over the medium to long term, generators need to cover fixed operating costs while also making contributions to debt servicing and producing acceptable returns to shareholders. We determine the debt and equity charge component of fixed costs as an amortised costs derived from an overnight capital cost expressed as a per kilowatt (kW) capacity charge across a year in order to count these fixed costs against the generatorôs installed capacity. The amortising formula used is conventional with the cost of debt and return to equity being combined in terms of a discount rate termed the Weighted Average Cost of Capital (WACC).[6] Thus, the debt and equity charges are assumed to be amortised over the assumed lifespan of the generation asset at a discount rate given by the WACC value, (Stoft (2002)). The amortising formula will produce a dollar per annum figure that represents the debt and equity charges which must be met and which are pro-rated to a $(\$/h)$ value.

The second component is Fixed Operation and Maintenance (FO&M) charges which are assumed to be some per annum dollar amount that will grow over time at the inflation rate assumed for cost components. This per annum value is also pro-rated to a $(\$/h)$ basis. Thus, the total fixed cost for each generator is defined as the sum of the FO&M and debt and equity charge and is defined on a $(\$/h)$ basis.

3(d). Hedging

Both theory and observation suggest that financial settlements based on óGross Poolô spot market operations expose market participants to the possibility of extreme volatility in spot prices encompassing price spike behaviour (typically of short duration) on the one hand and sustained periods of low spot prices on the other. These impacts can pose significant danger to the bottom line of both LSEôs and generators respectively, requiring both types of agents to have long hedge cover positions in order to protect their long term financial viability.

The protection adopted in the model is in the form of a ócollarô instrument between LSEôs and generators which is activated whenever spot prices rise above a ceiling price (for LSEôs) or falls below a price floor (for generators) subsequently inducing the activation of long cover for the threatened agent. Note that if the price floor applicable to generators is set equal to

[6] This rate was assumed to be 11.93%.

their long run marginal (i.e. ólevelisedô) cost, than generator long run revenue recovery can be implemented through the implementation of the hedge cover. It is assumed that both LSEôs and generators pay a (small) fee (per MWh of energy demanded or supplied) for this long cover, irrespective of whether long cover is actually activated.

3(e). DC OPF Solution

Tesfatsion and Sun (2007a) develop a representation of the standard DC OPF problem as a *strictly convex quadratic programming (SCQP) problem*, that is, as the minimization of a positive definite quadratic form subject to linear equality and inequality constraints.[7] They provide an augmentation of the standard DC OPF problem that still retains the SCQP form, but which also allows the full set of solution values for LMPôs, voltage angles, and voltage angle differences to be directly recovered along with solution values for real power injections and branch flows. The óaugmentationô involves the implementation of a version of the standard DC OPF problem that makes use of Lagrangian augmentation and entails utilising the following DC OPF objective function:

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

where A_i and B_i are the linear and quadratic cost coefficients from each generatorôs variable cost function, P_{G_i} is real (MW) power production level of generator óiô and δ_k and δ_m are the voltage angles at nodes ókô and ómô (measured in radians). Parameter π is a positive soft penalty weight on the sum of squared voltage angle differences, (Tesfatsion and Sun (2007a, Sections 3.4)). Note that the objective function of the augmented SCQP involves quadratic and linear variable cost coefficients and bus admittance coefficients as indicated in (1). 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.[8]

The augmented SCQP problem can be solved using QuadProgJ, a Java based SCQP solver developed by Sun and Tesfatsion (2007a, Section 6) which implements the dual active-set SCQP algorithm developed by Goldfarb and Idnani (1983). One potential limitation is that the QuadProgJ Java code implementing the algorithm does not incorporate sparse matrix techniques and is not designed for large-scale problems for which speed and efficiency of computation become critical limiting factors.

To overcome this limitation, we used the Mosek Optimisation Software which utilises a convex quadratic programming algorithm based on interior point method and sparse matrix techniques.[9] This resulted in very significant reductions in runtime when compared with

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[7] Note that Sun and Tesfatsion (2007a) formally demonstrate how the conventional AC OPF power flow equations can be derived from Ohmôs law and how the DC OPF problem can be formally derived from the AC OPF power flow equations.

[8] Note that one voltage angle is eliminated by setting its value equal to zero. This is a normalisation condition so solution values are actually determined for voltage angles of óK-1ô nodes.

[9] The web-address for Mosek is: http://www.mosek.com/. We ran the software under a free academic license available from Mosek ï see http://mosek.com/resources/trial/ , utilizing the java API: http://mosek.com/products/product-overview/mosek/java-api/.

equivalent runtimes obtained using QuadprogJ for the same underlying problem. The complete representation of the augmented (SCQP) DC OPF algorithm outlined in (Tesfatsion and Sun (2007a, Section 3.4)), but with modification for implementation in Mosek takes the form:

- **Minimize Generator-reported total variable cost**

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

with respect to real-power production levels and voltage angles $P_{G_i}, i = 1,...,I;\ \delta_k, k = 2,...,K,$ subject to

- **Real power balance (equality) constraint for each node** $k = 1,...,K$ **(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 ókô and ómô).

- **Real power thermal (inequality) constraints for each branch** $km \in BR$ $k = 1,...,K$ **(with** $\delta_1 \equiv 0$**):**

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

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

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

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

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

where

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

and

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

Note that F_{km}^{UN} and F_{km}^{UR} are the (positive) MW thermal limits associated with real power flows in the ónormalô and óreverseô direction on each transmission branch.

The equality constraint is a nodal balance condition which requires that at each node, power take-off (by LSEôs located at that node) equals power injection (by generators located at that node) and net power transfers from other nodes connected to the node in question by óconnectedô transmission branches. The imposition of this constraint across all nodes means that real power will be balanced across the entire grid by ensuring that aggregate real power withdrawal plus aggregate power transfers on transmission branches equal aggregate real power injection. Furthermore, on a node by node basis, the shadow price associated with this constraint gives the LMP (i.e. regional wholesale spot price) associated with that node.

The inequality constraints ensure that real power transfers on connected transmission branches remain within permitted ónormalô and óreverseô direction thermal limits and the real power produced by each generator remains within permitted lower and upper thermal MW capacity limits while also meeting generator hourly MW ramp up and ramp down production constraints.

In the next section, we will address aspects relating to the practical implementation of the scenario runs performed using the ANEM model in order to provide the empirical results which will be examined in later sections of the paper.

(4). Practical Implementation Considerations

The solution algorithm employed in all simulations involves applying the ócompetitive equilibriumô solution. This means that all generators submit their true marginal cost coefficients and no strategic bidding is possible. This type of scenario permits assessment of the true cost of generation and dispatch by ruling out cost inflation over true marginal costs associated with the exploitation of market power linked to strategic bidding.

We assume that all thermal generators are available to supply power during the whole period under investigation.[10] Therefore, the methodological approach underpinning model scenario runs clearly produce óas ifô scenarios. In particular, we do not try to emulate actual generator bidding patterns for the years in question. Our objective is to investigate how the true cost of power supply changes for the various carbon prices considered, and how the resulting changes in the relative cost of supply influences dispatch patterns, transmission congestion, regional prices and carbon emission levels when compared to a Business-As-Usual (BAU) scenario involving no carbon price.

In order to make the model response to the various scenarios more realistic, we have taken account of the fact that baseload and intermediate coal and gas plant typically have ónon-zeroô minimum stable operating levels. These plants cannot be run below these specified MW capacity levels without endangering the long term productive and operational viability of the plant itself or violating statutory limitations relating to the production of pollutants and other toxic substances.

Because of the significant run-up time needed to go from start-up to a position where coal-fired power stations can actually begin supplying power to the grid, all coal plant was assumed to be synchronized with the grid so they can supply power. Thus, their minimum stable operating limits were assumed to be applicable for the whole period being investigated and they do not face start-up costs. Gas plant, on the other hand, has very quick start-up characteristics and can be synchronized with the grid and be ready to supply power typically within a half hour period of the decision to start-up. In this case, the start-up decision and fixed start-up costs can accrue within the dispatch period being investigated.

Two approaches to modelling gas plant were adopted depending upon whether the gas plant could reasonably be expected to meet baseload or intermediate production duties or just peak load duties. If the gas plant was capable of meeting baseload or intermediate production duties, the plant was assigned a non-zero minimum stable operating capacity. In contrast, peak gas plant was assumed to have a zero minimum stable operating capacity. Furthermore, if the baseload/intermediate gas plant was a combined cycle (NGCC) plant, it was assumed to offer to supply power for a complete 24 hour period ï thus, the minimum stable operating capacity was applicable for the whole 24 hour period and these plants did not face start-up costs. In contrast, many of the intermediate Open Cycle Gas Turbine (OCGT) and Gas Thermal plant were assumed to only offer to supply power during the day, i.e. from 07:00 ï 19:00 hours.[11] In this case, the minimum stable operating capacities were only applicable for those particular hours of the day and these plants faced the payment of fixed start-up costs upon start-up.

Details of the minimum stable operating capacities assumed for coal and intermediate gas plant are listed in Table 1 and Table 2, respectively, together with details about their assumed operating time, whether start-up costs were liable and what values were assumed for these particular costs.

[10] Note that allowing for planned outages or unscheduled outages in thermal generators would be expected to increase costs and prices above what is produced when all thermal plant is assumed to be available to supply power because it acts to constrain the least cost supply response available to meet prevailing load demand.
[11] An exception was Torrens Island B which was assumed to meet baseload duties and was dispatched in a manner similar to NGCC plant in the model.

While all thermal generators were assumed to be available to supply power, certain assumptions were imposed in relation to the availability of hydro generation units. The dispatch of thermal plant was optimised around the assumed availability patterns for the hydro generation units.[12] The nature of hydro plant supply offers on the mainland was structured to meet peak load production duties. However, because of the prominence of hydro generation in Tasmania, hydro units were assumed to offer capacity over the whole year with some account being taken of the ability of hydro plant to meet baseload, intermediate or peak load production duties. For further details, see Wild, Bell and Foster (2012), Section 3.

For pump-storage hydro units such as Wivenhoe and the Shoalhaven units (i.e. the Bendeela and Kangaroo Valley hydro units located at the Wollongong node ï see Figure 2), the pump mode was activated in the model by setting up a pseudo LSE located at the Morton North and Wollongong nodes, respectively ï also consult Wild, Bell and Foster (2012), Section 3, for further details. Note that pump actions are assumed to occur in off-peak periods when the price (cost to hydro units) of electricity should be lowest. Furthermore, pump storage hydro unit supply offers were based upon short run marginal costs to ensure that dispatch occurred in a synchronised manner with pump actions. For all remaining hydro plant, supply offers were based on long run marginal costs which will have larger magnitudes than corresponding short run marginal costs.

In the case of mainland hydro plant (except pump-storage plant), supply was tailored to peak load production. Thus, long run marginal cost estimates were obtained for much lower annual capacity running factors (ACF) than would be associated with hydro plant fulfilling baseload or intermediate production duties, thus producing higher long run marginal costs. Moreover, the ACF was reduced for each successive turbine comprising a hydro plant resulting in an escalating series of supply offer bids for each successive turbine. In general, the lowest supply offer (for the first turbine) shadowed peak load gas plant while the other turbines supply offer bids could be significantly in excess of cost coefficients associated with more expensive peak load gas and diesel plant, for example.

[12] In determining the availability patterns for hydro plant, we are assuming that water supply to hydro plant is not an issue. If water supply issues, or in fact, hydro unit availability were constraining factors, as was the actual case in 2007, then this would increase the cost and prices obtained from simulations runs in a potentially significant way as the supply offers of hydro plant would be expected to increase significantly.

Table 1. Minimum Stable Operating Capacity Limits for Coal Plant, Assumed Operating Time and Start-up Cost Status

Generation Plant	Minimum Stable Operating Capacity Level	Assumed Operating Time	Start-up Status/Cost	Assumed Start-up Cost
	% of total MW Capacity (sent out basis)	Hours	Yes/No	$/MW per start
Black Coal – QLD				
Collinsville	40.00	24	No	$160.00
Stanwell	40.00	24	No	$ 80.00
Callide B	40.00	24	No	$ 80.00
Callide C	40.00	24	No	$ 80.00
Gladstone	31.00	24	No	$ 90.00
Tarong North	40.00	24	No	$ 70.00
Tarong	40.00	24	No	$ 80.00
Kogan Creek	40.00	24	No	$ 40.00
Millmerran	40.00	24	No	$ 70.00
Swanbank B	26.00	24	No	$150.00
Black Coal – NSW				
Liddle	40.00	24	No	$ 50.00
Redbank	40.00	24	No	$150.00
Bayswater	40.00	24	No	$ 45.00
Eraring	40.00	24	No	$ 45.00
Munmorrah	40.00	24	No	$ 80.00
Vales Point	40.00	24	No	$ 45.00
Mt Piper	40.00	24	No	$ 45.00
Wallerawang	40.00	24	No	$ 50.00
Black Coal – SA				
Playford B	40.00	24	No	$150.00
Northern	55.00	24	No	$ 90.00
Brown Coal – VIC				
Loy Yang A	60.00	24	No	$ 50.00
Loy Yang B	60.00	24	No	$ 50.00
Energy Brix	60.00	24	No	$160.00
Hazelwood	60.00	24	No	$ 95.00
Yallourn	60.00	24	No	$ 80.00
Anglesea	60.00	24	No	$150.00

Table 2. Minimum Stable Operating Capacity Limits for Intermediate Gas Plant, Assumed Operating Time and Start-up Cost Status

Generation Plant	Minimum Stable Operating Capacity Level	Assumed Operating Time	Start-up Status/Cost	Assumed Start-up Cost
	% of total MW Capacity (sent out basis)	Hours	Yes/No	$/MW per start
QLD				
Townsville	50.00	24	No	$100.00
Braemar 1	50.00	13 (daytime only)	Yes	$100.00
Braemar 2	50.00	13 (daytime only)	Yes	$100.00
Condamine	50.00	24	No	$50.00
Swanbank E	50.00	24	No	$ 50.00
NSW				
Smithfield	60.00	24	No	$100.00
Tallawarra	50.00	24	No	$ 40.00
Uranquinty	50.00	13 (daytime only)	Yes	$ 90.00
VIC				
Newport	65.00	13 (daytime only)	Yes	$ 40.00
SA				
Ladbroke Grove	50.00	13 (daytime only)	Yes	$110.00
Pelican Point	50.00	24	No	$ 70.00
New Osborne	76.00	24	No	$ 80.00
Torrens Island A	50.00	13 (daytime only)	Yes	$ 80.00
Torrens Island B	50.00	24	No	$ 65.00

In the following sections, we will examine the empirical findings obtained from ANEM model scenario runs. In the next section we will investigate the implications for wholesale price levels, followed then by the implications for carbon pass-through rates in the following section (e.g. Section 6). This will be followed by the assessment of the implications for retail electricity prices which will be presented in Section 7.

(5). Wholesale Electricity Price Impacts.

Given the high carbon intensity of Australia Electricity Generation Sector (by international standards) and the resulting overall importance of the electricity generation sector in accounting for around 35% of all C02 emissions in Australia, of particular interest is the potential upward impact that the introduction of a carbon price signal might have upon wholesale electricity prices, see Simshauser (2008) and Simshauser and Doan (2009). This issue is examined in this section.

The first set of results associated with the carbon price scenarios investigated in this paper is documented in Figures 6a-6c and relates to the average annual price levels obtained for the various states and NEM for carbon prices in the range of $10/tC02 to $100/tC02, with escalation according to a rate of $10/tC02 and for calendar years 2007, 2008 and 2009, respectively.

Figure 6a. 2007 Average Yearly Spot Prices By State

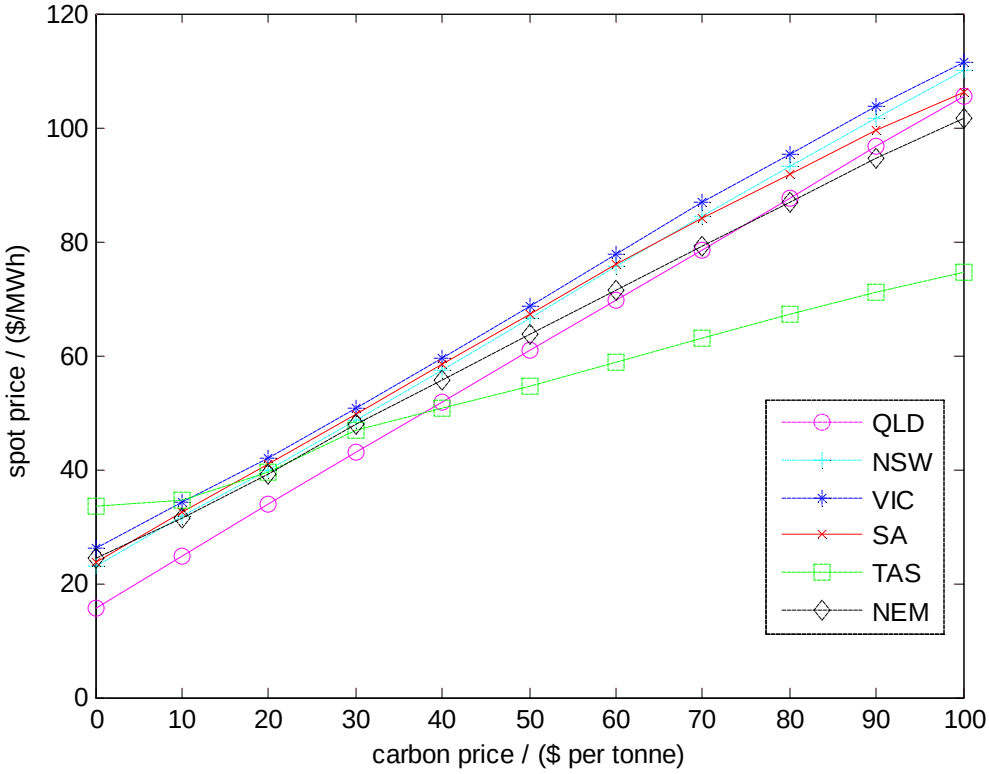


Figure 6b. 2008 Average Yearly Spot Prices By State

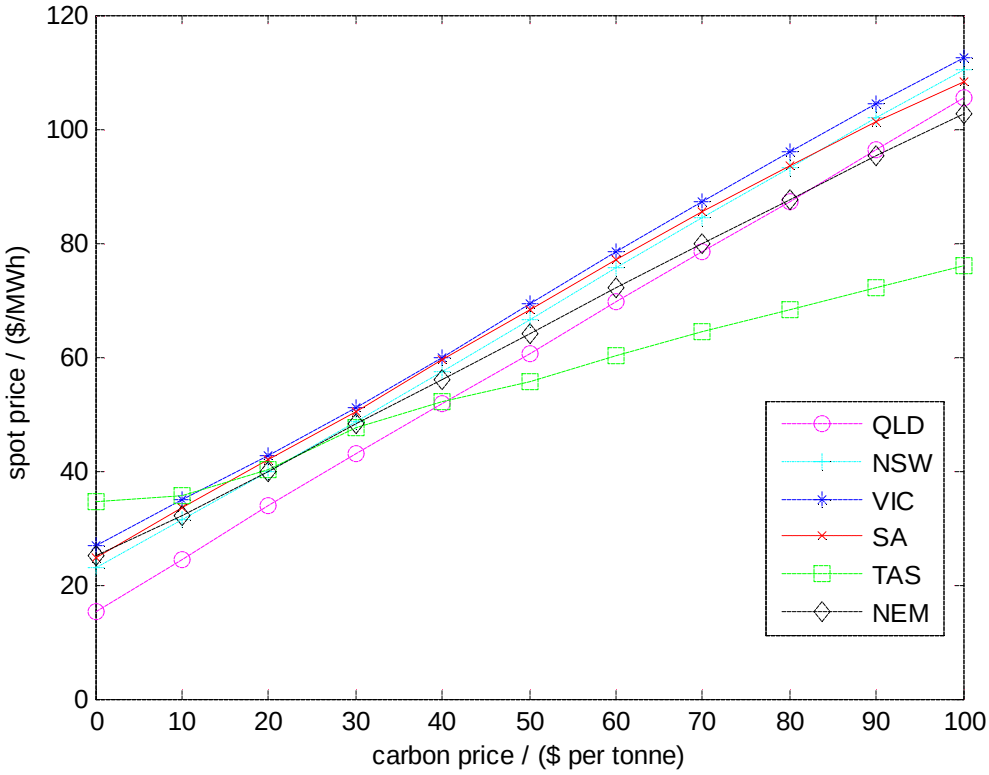
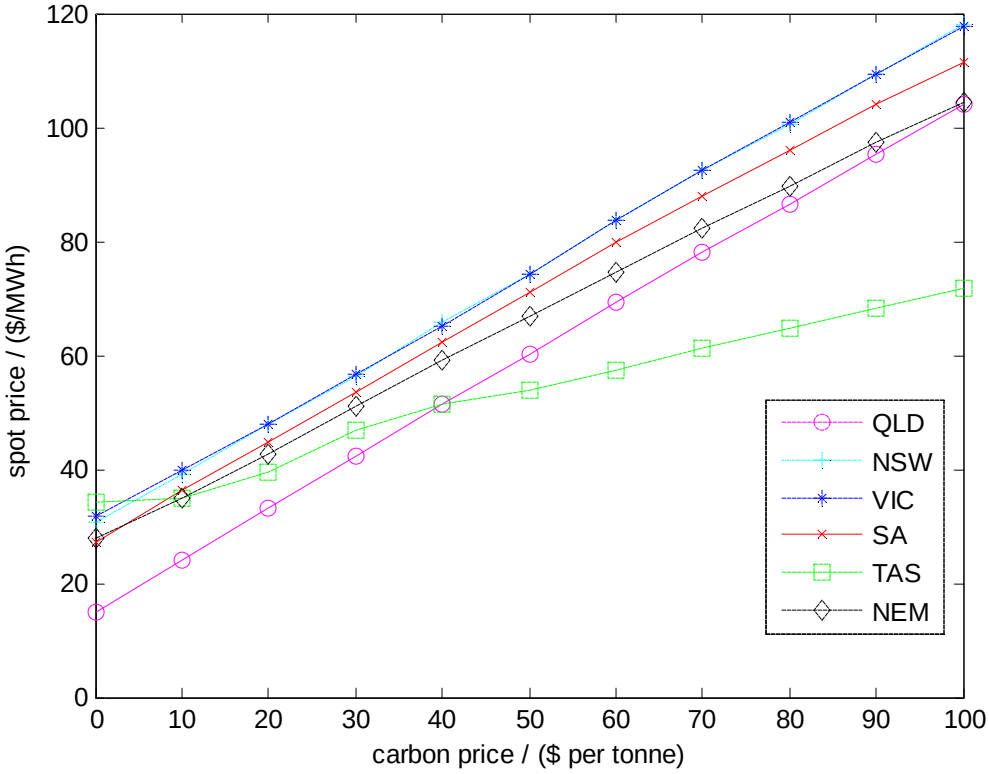


Figure 6c. 2009 Average Yearly Spot Prices By State



The average price results cited in Figures 6a-6c reflect both a spatial and temporal dimension. Specifically, for each hourly dispatch interval in a given year, an average state price level was obtained by averaging across all the relevant nodal prices within each state as indicated by the nodal structure contained in each state module outlined in Figures 1-5. The average annual price for each state was then obtained by averaging across the number of hours in each respective year.[13] The average annual price for the NEM was then calculated by averaging across the five state average annual prices obtained for each of the three years being investigated. It should also be noted that all averaging operations performed involved simple arithmetic averaging and not some weighted average scheme, particularly in relation to obtaining the NEM averages.

It is evident from inspection of Figures 6a-6c that all three graphs display very similar qualitative results. The most notable result for each year relates to average price results obtained for Tasmania. Specifically, Tasmania experiences higher averages price levels for BAU and lower carbon price levels when compared with the other states although this narrowed considerably in 2009 when compared with 2007 and 2008 ï compare Figure 6c with Figures 6a and 6b. This outcome can be attributed to the fact that supply offers of predominantly Tasmanian hydro plant is based on long run marginal costs instead of short run marginal costs. The resulting marginal cost structure is higher than comparable marginal cost structures of thermal plant on the mainland for these particular carbon price levels, thus producing higher average price levels in Tasmania when compared with equivalent average price levels obtained for the mainland states.

[13] For 2007 and 2009, this corresponds to 8760 hours. For 2008, the number of hours was 8784, reflecting the fact that there was 366 days in the 2008 calendar year.

The second key outcome is the relatively more modest growth in average price levels experienced in Tasmania when compared with the growth in average price levels of other states as the carbon price level increases. The growth experienced in Tasmania is related predominantly to the possibility of trade with the mainland (i.e. into Victoria) via the Basslink Interconnector which gives Tasmania exposure to cost structures and price levels prevailing in Victoria which will promote the increased dispatch of gas plant located at the George Town node, in particular, as the carbon price is increased. However, this growth is moderated by the fact that the predominantly hydro based generation fleet in Tasmania is not susceptible to carbon costs, thus ensuring that the increase in average prices is well below that experienced in other states which have forms of generation that are much more susceptible to carbon cost imposts following the introduction of a carbon price signal.

For the other states, Queensland consistently has the lowest average price levels, followed by South Australia and then New South Wales. In the case of Queensland, this most likely reflects the availability of relatively new vintage coal fired plant located at the Tarong and South West Queensland nodes which are among the newest vintage, cheapest and most emissions friendly forms of coal-fired generation available in the country. Furthermore, significant intermediate OCGT (and emerging NGCC) plant is located in the South West Queensland nodal region that can be dispatched to meet peak load demand arising within the Greater Brisbane region (i.e. Moreton North and Moreton South regional zones), in conjunction with the NGCC Swanbank E and Wivenhoe pump-storage hydro power stations located within the Moreton South and Moreton North nodes, respectively. [14] These latter types of plant have the ramping capabilities to be able to meet incremental load changes associated with peak load demand conditions while incurring fuel and carbon costs that are significantly lower than would be associated with conventional OCGT peak load plant, for example.

A similar type of argument can also be applied to the case of New South Wales although the New South Wales coal fleet is, on average, of older vintage, marginally more costly and has slightly higher carbon emission intensity rates when compared to the Queensland coal plant located specifically in the Tarong and South West Queensland nodes.[15] Furthermore, in the case of New South Wales, key NGCC and pump-storage hydro plant is also located in the Sydney and Wollongong nodes which would be well placed to incrementally ramp up production in order to meet peak demand conditions arising in the Central Coast/Sydney/Wollongong areas in particular, thereby potentially playing a similar role identified above in relation to Swanbank E and Wivenhoe power stations in Queensland. That is, the NGCC plant could become marginal generators while the dispatch of the pump-storage plant in Wollongong would push the cheaper coal generation units further up the merit order.[16]

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[14] Recall that Wivenhoe power station, being a pump-storage hydro plant, is bid at short-run marginal costs instead of long run marginal costs. This would have the effect of moving cheaper coal fired plant up the merit order of dispatch, thus reducing system costs and average price levels at the margin when Wivenhoe power station is dispatched.

[15] Note that the coal plant we are referring to in New South Wales is the coal plant located in the Liddell, Bayswater, Central Coast and Mt Piper nodes.

[16] It is also worth noting that both Queensland and New South Wales gas fleet have a higher proportion of plant (both NGCC and OCGT) capable of meeting baseload or intermediate production duties than does Victoria and to a less extent South Australia.

In the case of South Australia, there is NGCC and Gas Thermal plant located in the Greater Adelaide nodal region that is well suited to meet incremental changes in load demand corresponding to peak load conditions in the Adelaide area. This plant includes Pelican Point, New Osbourne and Torrens Island A and B power stations. This plant has the capacity to both set price as marginal units during peak demand periods and also partially replace the reduced production from coal generation plant in South Australia as the carbon price level increases.[17] This type of gas plant has lower fuel and carbon costs than more conventional OCGT peak gas plant.

Victoria consistently has the highest average price levels for each year and across all carbon price levels considered although the gap between New South Wales and Victoria which was observable in Figures 6a and 6b for years 2007 and 2008 narrowed significantly in Figure 6c for 2009. Victoria has a óclassicalô generation structure with the brown coal fired generation fleet being used for baseload and peak load duties being meet primarily by OCGT peak gas plant as well as hydro plant located in the Murray and Dederang nodes ï See Figure 3. It should be noted in this context that the brown coal generation fleet, in the absence of a carbon price signal, is amongst the cheapest forms of generation in the country while the OCGT gas and hydro costs structures in Victoria is more expensive than the NGCC, Gas Thermal and intermediate OCGT plant located in Queensland, New South Wales and South Australia. As such, with the incidence of peak load conditions in Victoria, to the extent that the marginal generator is a gas or hydro based generator in Victoria, it is likely to have a higher marginal cost structure than comparable units in Queensland, New South Wales and South Australia. This would tend to escalate the rate of increase in wholesale price levels relative to those emerging in the other mainland states of the NEM.

We now proceed to examine the implication for carbon pass-through which will be undertaken in the next section.

(6). Carbon Pass-Through Rates.

As discussed in the Introduction of this paper, an issue of particular interest is the extent to which the full carbon price is passed through to average annual prices. Recall from this discussion that this phenomenon refers to the concept of carbon pass-through. It should be noted that the carbon pass-through estimates presented in this section represent, in the terminology of Sijm, Nuehoff and Chen (2006), ówork-onô rates. As such, they indicate given each generatorôó add-onô rates and the merit order of dispatch, how much of the carbon price signal is óworked-onô the wholesale electricity prices. Moreover, in the presence of branch congestion and other constraints associated with unit commitment features, the merit order can diverge from the purely competitive merit order identified in much of the literature and will also most likely produce spatial divergence, in terms of marginal generators, wholesale spot price outcomes and carbon pass-through rates.

The rate of carbon pass-through is calculated in a two-step process. First, the price differential between average annual prices associated with a carbon price and the baseline BAU scenario is calculated. This price differential is then divided by the carbon price level

[17] Recall that the coal fired plant face non-zero minimum stable operating levels which are approached as the carbon price level is increased. These were set to 40% and 55% of nameplate capacity for Playford B and Northern power stations respectively ï see Table 1.

itself. If the resulting proportion is less than unity, then there is less than complete pass-through of the carbon price into average annual prices. If the proportion equals unity, then there is complete pass-through ï the difference between the price levels is exactly equal to the carbon price level. If the proportion is greater than unity, there is more than complete pass-through. In this case, the carbon price would have a ómagnifiedô affect on average annual prices.

We calculated these proportions for all carbon price scenarios considered and the results are listed in Table 4, Panels (A)-(C), for years 2007, 2008 and 2009, respectively. To see how sensitive the NEM average results are to the averaging operation adopted (e.g. arithmetic averaging), we have also derived a second set of NEM averages which utilises a different averaging operation based on the state production shares listed in Table 1 of Nelson, Orton and Kelley (2010). As such, we have two separate set of NEM averages in Table 4. The first is listed in column 7 and was calculated by taking the simple arithmetic average of the preceding state results. The second set of NEM results, termed óNEM*ô in Table 4 is a state production share weighted average of the preceding state results as mentioned above. This latter weighting scheme operates to give higher relative weight to the results from Queensland, New South Wales and Victoria while reducing the relative weight attached to the results from South Australia and Tasmania when compared to the implicit weighting scheme involved in the arithmetic averaging process. It is evident from inspection of all three panels of Table 4 that the state production weighted average results (in column 8) are greater in magnitude than the equivalent results obtained from the simple arithmetic averaging process (in column 7) of Table 4, Panels (A)-(C).

It is apparent from inspection of Panels (A)-(C) that there is less than complete pass-through ï all proportions are strictly less than unity. This indicates that carbon costs are not being totally passed onto consumers in the form of higher wholesale prices and that some of the carbon cost obligations are being absorbed the generators with carbon cost liabilities.

A noticeable result is that the carbon pass-through rate for Tasmania is much lower than for the other states in the NEM. Specifically, from inspection of Panels (A)-(C), it is evident that carbon price pass-through in Tasmania is around half of the values associated with the other states. With the prominence of hydro generation in Tasmania and the much lower carbon footprint of generation in that state, there is a much lower pass-through of carbon prices and costs into average annual prices in Tasmania. This particular state also experiences a sharp increase in carbon pass-through for carbon prices in the range $10/tC02-$30/tC02, followed by a slight decline over higher carbon price levels. This increase is associated with the relatively larger average wholesale price level increases relative to BAU experienced for carbon prices in this particular band, producing a relatively larger change in average wholesale prices relative to BAU in the first part of the pass-through rate calculations. This price increase is primarily associated with increased dispatch of relatively more expensive Tasmanian hydro plant at the expense of imported production from Victoria via the Basslink Interconnector. The fact that little further growth in the carbon pass-through rate occurs in Tasmania for carbon prices greater than $30/tC02 indicates a relatively constant rate of growth in average wholesale prices levels for this state for carbon prices in this band. This would reflect, in turn, very little change in hydro generator dispatch patterns in meeting native Tasmanian demand and thermal limits on some intra-state transmission branches although some further expansion in exports to Victoria continue to emerge for higher carbon price levels, reflecting the increased dispatch of gas plant at the George Town node, albeit from a very small base ï see Wild, Bell and Foster (2012) , Section 4.2, for further details.

The other surprising result is the relatively lower levels of carbon pass-though experienced in Victoria. Specifically, from inspection of Table 4, Panels (A)-(C), the carbon pass-though rates experienced in Victoria are smaller in magnitude than those experienced in New South Wales, South Australia and Queensland. This is a surprising result given the higher state carbon emissions intensity factor identified in Nelson, Orton and Kelley (2010), for example, when compared to equivalent rates for the other three states. This outcome broadly indicates that carbon costs are being internally absorbed to a larger extent by Victorian brown coal generators when compared to coal generators located in New South Wales, South Australia and Queensland.

For carbon prices in the band $30/tC02 to $100/tC02, the carbon pass-through rate increases in Victoria from 0.806 to 0.855, see Column 4 of Table 4, Panels (A)-(C). This indicates that carbon costs are being passed into average wholesale prices to a greater degree than occurred at lower carbon price levels. This occurs against a backdrop of significant reductions in production from brown coal generation plant in Victoria, and increased dispatch of gas plant in Victoria, and imports of power from Tasmania, South Australia and New South Wales ï see Wild, Bell and Foster (2012), Sections 4.2 and 4.3. In fact, over the carbon price band $50/tC02 to $80/tC02, the carbon pass-through rates of Victoria, New South Wales and South Australia become reasonably close to each other in magnitude before beginning to diverge somewhat at higher carbon price levels. The former outcome would be expected to occur when no significant branch congestion arises between the states and they possibly share the same marginal generator in setting wholesale price levels. The latter outcome (e.g. price divergence), however, occurs against the backdrop of increased incidence of congestion on the Murraylink Interconnector linking Victoria and South Australia and to a less extent on the ôNSW-VICô Interconnector linking Victoria and New South Wales ï see Wild, Bell and Foster (2012), Section 4.5, for further details. This increased incidence of branch congestion would promote divergence between wholesale price levels and carbon pass-through rates between these three states. Of interest to this latter context is the transmission branch path most directly linking New South Wales, Victoria and South Australia via the branches connecting Tumut and Murray (i.e. the NSW-VIC Interconnector), Murray, Dederang and Regional Victoria (i.e. intra-state Victorian transmission branches) and Regional Victoria and Riverlands (i.e. the Murraylink Interconnector linking Victoria and South Australia) ï e.g. see Figures 2, 3 and 4.

Queensland has the highest level of carbon pass-through for all carbon price levels and years considered. This particularly reflects the prominence and nodal location of the coal generation plant within the Tarong and South West regions to meet the residential, commercial and industrial demand coming from the Moreton North, Moreton South and Gold Coast regions. To a less extent, it would also reflect the production contribution of the coal generation plant located in the Central West and Gladstone nodes which are available to service the largely industrial load in Gladstone as well as the loads in northern Queensland. The high carbon rates pass-through rates observed for Queensland relative to the other states indicate that carbon costs are passed into wholesale prices to the largest extent observed of any state in the NEM.

The carbon pass-through rate of South Australia is generally higher for small to moderate carbon price levels but becomes lower for higher carbon price levels than the comparable carbon price pass-through rates of New South Wales and Victoria. This trend would generally reflect the substitution of production from gas generation in South Australia for production from coal generation plant in South Australia and also Victoria as higher carbon prices reduce

production levels from coal generation plant in both states towards each coal generation plantôs minimum stable operating level and promotes the export of power from South Australia to Victoria (especially for carbon prices of $40/tC02 and higher) ï see Wild, Bell and Foster (2012), Sections 4.2, for further details. It should be noted that the levels of carbon pass-through obtained for South Australia exceed the carbon emission intensity rate value of 0.72 that was cited in Nelson, Orton and Kelley (2010). One reason for this is that the contribution of wind generation has been ignored in the analysis undertaken in this paper. Specifically, all thermal and hydro plant is available for dispatch but wind generation has been excluded. This is likely to lead to an overstatement of carbon pass-through rates in South Australia which has a significant wind generation capacity relative to other state markets in the NEM. A similar argument might also be extended to Victoria although the degree of overstatement would be much less than in the case of South Australia because the contribution of wind generation is much smaller in Victoria when compared with the available thermal and hydro fleet in that particular state.

For Queensland and South Australia, the level of carbon pass-through generally declines as the carbon price level is increased. This again reflects the substitution of production from gas fired generation at the margin for production from coal generation as fuel switching from coal to gas becomes more prominent in an environment of rising carbon price levels. In the case of Queensland, it also reflects the substitution of production from newer vintage black coal generation plant for production from older vintage plant that have more costly fuel and carbon cost structures and whose production levels are driven towards minimum stable operating levels as the carbon price level increases ï see Wild, Bell and Foster (2012), Section 4.3.

The experience for New South Wales is more mixed. New South Wales generally experiences a slight decline in carbon pass-through with the move from BAU to $10/tC02, followed by an increase until around a carbon price level of $70/tC02, followed by a slight decline over the range of $80/tC02 to $100/tC02. In qualitative terms, it matches the pattern observed for Victoria, albeit at a higher rate than was the case for Victoria. This indicates, on average, that carbon costs are passed into average wholesale electricity prices to a slightly higher degree in New South Wales than in Victoria and with brown coal and gas generation in Victoria absorbing a slightly greater share of carbon costs than is the case for coal and gas generators in New South Wales. It should be recognised that this all occurs against a backdrop of higher levels of export of power from New South Wales to Victoria for carbon prices in the band $40/tC02 to $100/tC02 and with relatively low incidence of branch congestion on the Interconnector linking New South Wales and Victoria. These conditions would operate to ensure the broad linking of wholesale prices movements in New South Wales and Victoria thus producing the similarity, in qualitative terms, in the carbon pass-through rates as a function of carbon price level as mentioned above.

Table 4. Carbon Price Pass Through: (Proportion of Annual Average Price Level)

Panel (A): 2007

Carbon Price	QLD	NSW	VIC	SA	TAS	NEM	NEM*
$10/tC02	0.9170	0.8561	0.8079	0.8846	0.0946	0.7063	0.7969
$20/tC02	0.9164	0.8421	0.7947	0.8685	0.2940	0.7392	0.7966
$30/tC02	0.9144	0.8560	0.8203	0.8747	0.4435	0.7789	0.8089
$40/tC02	0.9066	0.8601	0.8321	0.8748	0.4349	0.7787	0.8129
$50/tC02	0.9028	0.8687	0.8492	0.8761	0.4211	0.7805	0.8213
$60/tC02	0.9032	0.8744	0.8616	0.8717	0.4247	0.7845	0.8271
$70/tC02	0.8973	0.8760	0.8657	0.8628	0.4218	0.7827	0.8261
$80/tC02	0.8985	0.8742	0.8621	0.8550	0.4206	0.7805	0.8252
$90/tC02	0.8991	0.8734	0.8597	0.8444	0.4171	0.7779	0.8237
$100/tC02	0.8995	0.8700	0.8535	0.8278	0.4126	0.7728	0.8198

Panel (B): 2008

Carbon Price	QLD	NSW	VIC	SA	TAS	NEM	NEM*
$10/tC02	0.9198	0.8436	0.7913	0.8762	0.1000	0.7005	0.7947
$20/tC02	0.9183	0.8372	0.7847	0.8575	0.2870	0.7336	0.7917
$30/tC02	0.9167	0.8478	0.8059	0.8624	0.4376	0.7718	0.8037
$40/tC02	0.9090	0.8564	0.8247	0.8667	0.4401	0.7769	0.8108
$50/tC02	0.9040	0.8672	0.8447	0.8713	0.4231	0.7794	0.8195
$60/tC02	0.9048	0.8743	0.8596	0.8710	0.4263	0.7847	0.8268
$70/tC02	0.9002	0.8749	0.8628	0.8670	0.4255	0.7838	0.8267
$80/tC02	0.8997	0.8750	0.8624	0.8590	0.4227	0.7820	0.8261
$90/tC02	0.9003	0.8741	0.8597	0.8496	0.4187	0.7793	0.8245
$100/tC02	0.9008	0.8716	0.8549	0.8358	0.4144	0.7752	0.8216

Panel (C): 2009

Carbon Price	QLD	NSW	VIC	SA	TAS	NEM	NEM*
$10/tC02	0.9164	0.8519	0.8101	0.8912	0.0663	0.7003	0.8027
$20/tC02	0.9148	0.8706	0.8040	0.8751	0.2574	0.7418	0.8004
$30/tC02	0.9138	0.8581	0.8253	0.8781	0.4204	0.7759	0.8131
$40/tC02	0.9082	0.8749	0.8365	0.8770	0.4246	0.7821	0.8168
$50/tC02	0.9028	0.8698	0.8508	0.8765	0.3907	0.7749	0.8219
$60/tC02	0.9033	0.8837	0.8634	0.8739	0.3873	0.7800	0.8277
$70/tC02	0.8996	0.8826	0.8661	0.8677	0.3851	0.7781	0.8274
$80/tC02	0.8941	0.8747	0.8657	0.8602	0.3815	0.7729	0.8251
$90/tC02	0.8908	0.8731	0.8630	0.8511	0.3778	0.7694	0.8224
$100/tC02	0.8903	0.8750	0.8580	0.8396	0.3729	0.7664	0.8191

The implications for retail electricity prices will now be addressed.

(7). Retail Tariff Impacts.

There are two main retail electricity markets in Australia. The first is the market servicing industrial and commercial retail customers. The second market is that servicing residential (e.g. household) retail demand.

In the case of the first market relating to retail commercial and industrial customers, the bulk of electricity is mainly determined by contract (rather than spot market) prices and the net effect of participantsô contract and spot market exposures through hedge instrument or óself-insuranceô through their own physical plant or Power Purchase Agreements, (Outhred (2000), Energy Consumersô Council (2003) and AEMO (2009)). As such, the contract price tends to be very important. If energy traders use the óOver-The-Counterô (OTC) market, there is a standard clause that links the forward price to some agreed on strike price relating to expected energy cost plus a carbon cost component. This latter provision equates to the carbon price times the average carbon intensity (ACI) rate which references the whole of NEM carbon intensity (e.g. carbon pass-through) rate. It should be noted that the ACI concept does not attempt to capture the implications of differences in carbon pass-through rates of different states, thus allowing for the possibility of windfall gains (by retailers) by inflating contract price if a states carbon pass-through rate is less than the ACI rate and losses (by retailers) by understating the contract price if the states carbon pass-through rate is greater than the ACI rate.

In order to investigate this issue further, we have listed the average carbon pass-through rates obtained for the period 2007-2009 in Table 5.[18] Recall that the NEM average results listed in column 7 were obtained by taking the simple arithmetic average of the preceding state results. The second set of NEM average results cited in column 8 (e.g. NEM*) is a state production share weighted average of the preceding state results utilising the productions shares contained in Table 1 of Nelson, Orton and Kelley (2010). The first thing to note from examination of Table 5, Panel (A) is that the carbon pass-through rates vary from state to state and also across carbon price levels. Panel (B) of Table 5 contains the incremental carbon cost that would correspond to the carbon cost component in the OTC standard clause contract price mentioned above. However, in this case, we have substituted the ACI component with the various carbon pass-through rates listed in Panel (A) of Table 5. As such, the values cited in Panel (B) were derived by multiply each carbon price level by the carbon pass-through rates listed in Panel (A) and then converting from a ($/MWh) basis to a (c/kWh) basis.

Now suppose we assume that either of the carbon pass-through rate associated with the óNEMô or óNEM*ô columns in Panel (A) become the ACI for purposes of standard clause OTC contract price calculations. Then any state which has a carbon pass-through rate less than the ACI will experience a windfall profit because its incremental carbon cost component would be less than the carbon cost component calculated according to the OTC ACI criteria. The case in point here is Tasmania. It is evident from examining column 6 with columns 7 and 8 of Panel (B), Table 5 that Tasmaniaôs incremental carbon cost is less than the ACI credited amount. If we assume a strike price of 20c/kWh, then the ACI credited contract price

[18] The results in Table 5 were obtained by taking the arithmetic average of the pass-through rates documented in Panels (A)-(C) of Table 4 in the previous section of the paper.

would be in the range of 21.48c/kWh to 21.59c/kWh for a carbon price of $20/tC02 and depending upon whether the óNEMô or óNEM*ô carbon cost components are used in Panel (B). On the other hand, using Tasmaniaôs assessed incremental carbon cost in Panel (B), we get 20.56c/kWh which is smaller than the ACI accredited contract price levels. As such, Tasmanian retailers experience inflation in OTC contract prices of between 0.92c/kWh and 1.02c/kWh over and above what they would have got if the ACI was based on the Tasmanian carbon pass-through rate listed in Panel (A) of Table 5.

A similar exercise can also be undertaken to show that states with a carbon pass-through rate in excess of the ACI stand to lose as their true incremental carbon cost is greater than the ACI accredited cost. For this reason, their standard clause OTC contract price would understate the true incremental carbon cost confronting them and thereby understate the required contract price. As an example of this, take the case of Queensland. For a carbon price of $20/tC02, the OTC contract price would once again be in the range 21.48c/kWh to 21.59c/kWh. In the case of Queensland, using Queensland assessed incremental carbon cost produces a contract price of 21.83c/kWh (i.e. 20 + 1.83) for a carbon price of $20/tC02. This contract price is above the range associated with the ACI contract prices. Therefore, the ACI accredited OTC contract price would understate the required contract price level when account is taken of the Queensland carbon pass-through rates. In this circumstance, Queensland retailers would face losses in the range of 0.24c/kWh to 0.35c/kWh because OTC contract prices do not fully reflect the carbon costs confronting Queensland retailers.

In order to see how crucial the ACI carbon pass-through rate is, we included an additional column in Panel (B), column 9 (termed óNEM**ô) in which NEM incremental carbon costs were calculated assuming an ACI of 0.9492 which corresponds to the weighted average NEM carbon intensity rate derived in Nelson, Orton and Kelley (2010). It is apparent from examination of all the state incremental carbon cost results listed in Panel (B) of Table 5 that no state has an incremental carbon cost component that is greater than or equal to the óNEM**ô incremental carbon cost associated with a carbon pass-through rate of 0.9492. In this case, all states would potentially obtain windfall gains as the OTC standard clause contract price would be greater than comparable state contract prices calculated using each states respective carbon pass-through rate listed in Panel (A) of Table 5.

These examples have demonstrated the complexities that might emerge when account is taken of possible variations in carbon pass-through rates across states and across carbon price levels when taken in the context of OTC standard clause contracts.

Table 5. Implications For OTC Contract Prices Of Variations In Carbon Pass-Through Rates By State And Carbon Price Level

Panel (A). 2007-2009 Average Carbon Pass Through Rates (Proportion).

Carbon Price	QLD	NSW	VIC	SA	TAS	NEM	NEM*
$10/tC02	0.9177	0.8470	0.7994	0.8838	0.0869	0.7070	0.7981
$20/tC02	0.9165	0.8419	0.7944	0.8669	0.2794	0.7399	0.7963
$30/tC02	0.9150	0.8529	0.8160	0.8717	0.4338	0.7779	0.8086
$40/tC02	0.9079	0.8591	0.8304	0.8728	0.4332	0.7807	0.8135
$50/tC02	0.9032	0.8686	0.8483	0.8746	0.4116	0.7813	0.8209
$60/tC02	0.9038	0.8748	0.8615	0.8722	0.4128	0.7850	0.8272
$70/tC02	0.8996	0.8750	0.8639	0.8664	0.4114	0.7833	0.8267
$80/tC02	0.8974	0.8747	0.8634	0.8581	0.4083	0.7804	0.8254
$90/tC02	0.8967	0.8735	0.8608	0.8484	0.4045	0.7768	0.8235
$100/tC02	0.8969	0.8706	0.8554	0.8344	0.4000	0.7715	0.8202

Panel (B). Incremental Carbon Cost (c/kWh).

Carbon Price	QLD	NSW	VIC	SA	TAS	NEM	NEM*	NEM**
$10/tC02	0.92	0.85	0.80	0.88	0.09	0.71	0.80	0.95
$20/tC02	1.83	1.68	1.59	1.73	0.56	1.48	1.59	1.90
$30/tC02	2.74	2.56	2.45	2.62	1.30	2.33	2.43	2.85
$40/tC02	3.63	3.44	3.32	3.49	1.73	3.12	3.25	3.80
$50/tC02	4.52	4.34	4.24	4.37	2.06	3.91	4.10	4.75
$60/tC02	5.42	5.25	5.17	5.23	2.48	4.71	4.96	5.70
$70/tC02	6.30	6.12	6.05	6.07	2.88	5.48	5.79	6.64
$80/tC02	7.18	7.00	6.91	6.86	3.27	6.24	6.60	7.59
$90/tC02	8.07	7.86	7.75	7.64	3.64	6.99	7.41	8.54
$100/tC02	8.97	8.71	8.55	8.34	4.00	7.71	8.20	9.49

In contrast to OTC contracts, futures contracts do not have a carbon clause. In this context, the expected energy plus carbon cost can be viewed as the price of the futures contract but which also carries a political risk attached to it ï e.g. that the carbon pricing mechanism is repealed or never in fact implemented.

In the case of the second retail market relating to retail household demand, retail tariffs are regulated in most states except Victoria. In jurisdictions where the retail market has been deregulated, two broad types of contracts exist. The first is a ósanding offer contractô which contains terms and conditions that must be approved by the relevant jurisdictional regulation authority. Prices for such contracts can be set by retailers or the relevant regulation authority if retail price regulation is in place and are usually published. Currently, the price associated with standing offer contracts are regulated in all states except for Victoria (AEMC (2011)).

The main methods used to determine standard offer regulated tariff rates usually allocate wholesale cost components according to the long run marginal cost of supply. In this context, it should be recognized that, historically, the wholesale cost allocation component has been around 30-40% of the price (tariff) paid by domestic consumers for electricity supply. Additional retail based charges include mark-ups associated with the costs of network usage, retail charges associated with providing customer services such as billing and call centre services, profit mark-up, goods and services taxes (GST), obligations to purchase renewable energy certificates and fulfil feed-in tariff liabilities associated with small scale solar pv installations, (Outhred 2000, 5-6, Energy Consumersô Council 2003, 21-23, NEMMCO 2005, 7, Simshauser, Nelson and Doan (2011), and AEMC (2011)).

The second type of contract is called a ómarketô contract, which is a negotiated contract which will have divergence from standard offer contracts often in terms of discounted prices or other incentives. In Victoria, most residential customers are on market contracts often at contract prices that are discounted to published standing offer contract tariff rates (AEMC (2011)). Thus, in the case of Victoria, the conventional modelling approaches based upon standard offer contract price determination might not provide a good indication of the actual prices arising in Victoria but should provide some indication of price trends in relation to the introduction of a carbon price and likely impact on retail residential demand.

Deriving these cost components can be a very difficult and time consuming exercise. This is because there are hundreds of regulated customer tariffs which can vary by use and structure (Simshauser, Nelson and Doan (2012)). In this study, we utilise the baseline ócost stackô cited in AEMC (2011) for representative households in each state of the NEM and also extrapolated for a representative household for the Nation as a whole. Note that the baseline year used in AEMC (2011) is financial year 2010-2011. For our óBusiness-As-Usualô (BAU) baseline case, we adopted the 2010/11 (c/kWh) prices (i.e. tariff rates) for Queensland, New South Wales, Victoria, South Australia, Tasmania and the National jurisdictional categories that were outlined in AEMC (2011) and which are represented in Figure 7. Note that the baseline case has no carbon price. We also utilised for the baseline case the component cost allocations for these jurisdictions that was also outlined in AEMC (2011). The cost share and (c/kWh) values are outlined in Panel (A) and Panel (B) of Table 6, respectively.

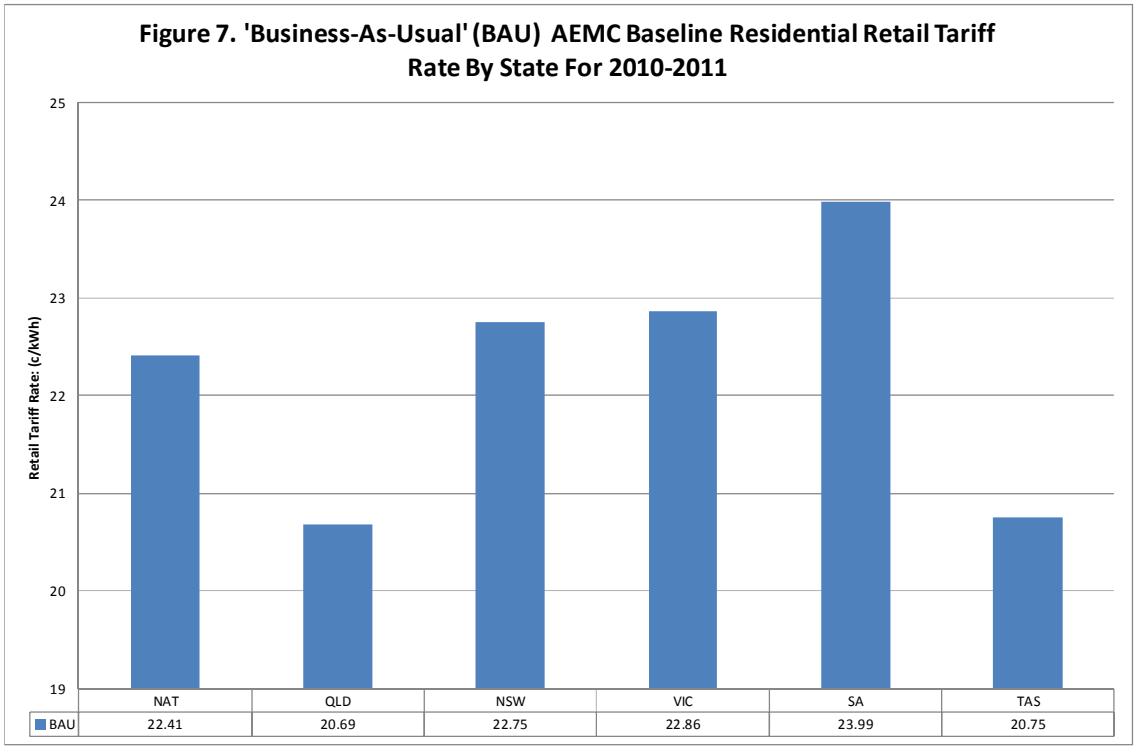


Table 6. 'Business-As-Usual' (BAU) Baseline Retail Tariff Rate Component Breakdown for 2010/11

Panel (A): Component Share (Proportion)

Cost Component	NAT	QLD	NSW	VIC	SA	TAS
Transmission	0.077	0.088	0.077	0.056	0.098	0.173
Distribution	0.373	0.461	0.473	0.255	0.347	0.306
Wholesale	0.345	0.273	0.330	0.320	0.398	0.407
Retail Margin	0.150	0.144	0.109	0.257	0.126	0.080
Other	0.055	0.034	0.011	0.113	0.032	0.034
'Other' Comprises:						
Feed-in tariff	0.001	0.001	0.000	0.001	0.005	0.000
Renewable Certificates	0.019	0.027	0.008	0.024	0.017	0.034
Energy Efficiency/ Demand Management	0.025	0.000	0.003	0.088	0.010	0.000
Other State Schemes	0.010	0.006	0.000	0.000	0.000	0.000

Panel (B): Component Value (c/kWh)

Cost Component	NAT	QLD	NSW	VIC	SA	TAS
Transmission	1.73	1.83	1.76	1.27	2.35	3.59
Distribution	8.35	9.53	10.75	5.82	8.32	6.35
Wholesale	7.74	5.65	7.51	7.31	9.54	8.45
Retail Margin	3.36	2.98	2.47	5.88	3.02	1.65
Other	1.23	0.70	0.26	2.58	0.76	0.71
'Other' Comprises:						
Feed-in tariff	0.02	0.02	0.00	0.03	0.13	0.00
Renewable Certificates	0.43	0.56	0.19	0.54	0.40	0.71
Energy Efficiency/ Demand Management	0.56	0.00	0.08	2.01	0.23	0.00
Other State Schemes	0.23	0.12	0.00	0.00	0.00	0.00

The empirical work reported in this section relates to using the above data as baseline (BAU) values and then factoring in the impact of the introduction of a carbon price signal on the retail tariff rates and component cost shares. The carbon price levels considered relate to the introduction of a $10/tC02, $20/tC02, $30/tC02, $40/tC02 and $50/tC02 carbon price. The (c/kWh) increase in the wholesale cost component was determined by multiplying the average carbon pass-through rates determined for the period 2007-2009 from ANEN model runs by each respective carbon price level mentioned above and then converting from a ($/MWh) basis to a (c/kWh) basis. We then added this incremental (c/kWh) value to the baseline (BAU) óWholesaleô (c/kWh) values outlined in Table 6, Panel (B) in order to calculate the new carbon price inclusive wholesale cost component. The incremental wholesale (c/kWh) values as a function of carbon price level are cited in Table 7, Panel (A).

The use of the average carbon pass-through rates for the period 2007-2009 should give a reasonable indication of carbon price impacts on retail tariffs. In particular, the generation set remained fairly constant between 2009 and the 2010-2011 period with additions being Darling Downs NGCC (South West Queensland node in 2010), Colongra Peak OCGT (Central Coast node, New South Wales in 2010), Bogong hydro (Dederang Node, Victoria in 2010) and Mortlake Peak OCGT (South West Victorian node in 2011). Furthermore, two units of Swanbank B (Moreton South node, Queensland) were retired in 2010 and another unit was retired in 2011. The average carbon pass-through rates used are those listed in Table 5, Panel (A) for carbon prices in the range $10/tC02 to $50/tC02. Note further that we used the óNEMô results (e.g. column 7 of Panel (A), Table 5) for the national (e.g. óNATô) carbon pass-through rates. Recall that these values were obtained by taking the simple arithmetic average of the state carbon pass-through rates.

Table 7. Carbon Price Inclusive Cost Component Adjustments

Panel (A). Incremental Wholesale Cost Component: (c/kWh)

Carbon Price	NAT	QLD	NSW	VIC	SA	TAS
$10/tC02	0.71	0.92	0.85	0.80	0.88	0.09
$20/tC02	1.48	1.83	1.68	1.59	1.73	0.56
$30/tC02	2.33	2.74	2.56	2.45	2.62	1.30
$40/tC02	3.12	3.63	3.44	3.32	3.49	1.73
$50/tC02	3.91	4.52	4.34	4.24	4.37	2.06

Panel (B). Multiplicative Factor Applied to (BAU) Retail Margins Component

Carbon Price	NAT	QLD	NSW	VIC	SA	TAS
$10/tC02	1.0071	1.0092	1.0085	1.0080	1.0088	1.0009
$20/tC02	1.0148	1.0183	1.0168	1.0159	1.0173	1.0056
$30/tC02	1.0233	1.0274	1.0256	1.0245	1.0262	1.0130
$40/tC02	1.0312	1.0363	1.0344	1.0332	1.0349	1.0173
$50/tC02	1.0391	1.0452	1.0434	1.0424	1.0437	1.0206

Panel (C). Multiplicative Factor Applied to (BAU) Renewable Certificates Component

Carbon Price	NAT	QLD	NSW	VIC	SA	TAS
$10/tC02	0.9929	0.9908	0.9915	0.9920	0.9912	0.9991
$20/tC02	0.9852	0.9817	0.9832	0.9841	0.9827	0.9944
$30/tC02	0.9767	0.9726	0.9744	0.9755	0.9738	0.9870
$40/tC02	0.9688	0.9637	0.9656	0.9668	0.9651	0.9827
$50/tC02	0.9609	0.9548	0.9566	0.9576	0.9563	0.9794

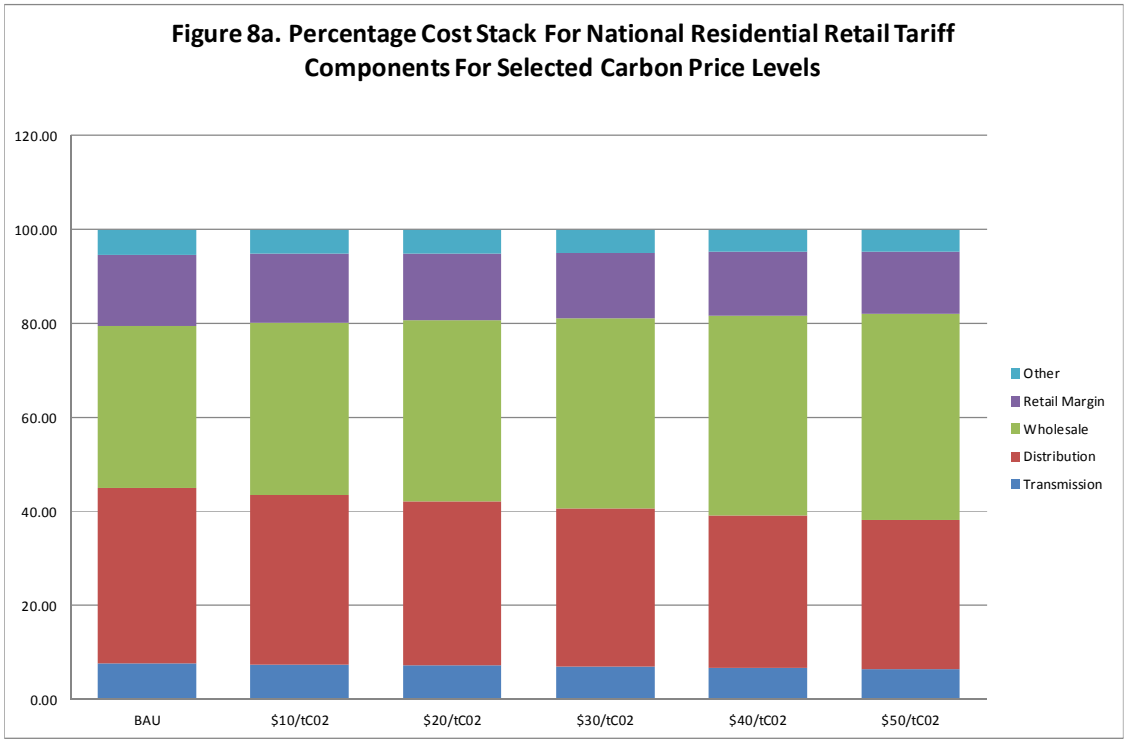
In accordance with the methodology used in AEMC (2011), we also assumed that the introduction of a carbon price signal will exert a direct impact on retail margins and renewable energy certificate components. We assume further that this occurs in direct proportion to the incremental change arising in the wholesale cost component attributable to the carbon price level.

For retail margins, we assume that the increased wholesale cost of electricity also directly flows into retail costs. This is modelled by use of a multiplicative factor calculated as ó1+(wcc/100)ô where ówccô are the respective values listed in Table 7, Panel (A). Note that the calculated values produce a multiplicative factor greater than unity, thereby producing an increase in this cost component relative to BAU when multiplied by the relevant BAU óRetail Marginô (c/kWh) values listed in Table 6, Panel (B). These multiplicative values are listed in Table 7, Panel (B). Note from inspection of this panel that the magnitude of the multiplicative factor increases with carbon price level ï higher carbon prices produce greater levels of cost inflation in the retail margin relative to BAU.

In a competitive market, the renewable energy certificate price can be viewed as the difference between the long run marginal cost of the marginal renewable energy asset and the average wholesale electricity price. The long run marginal costs of existing mature second generation renewable assets such as wind generation, solar pv and solar thermal generation will be significantly higher than average wholesale price levels because of their high capital costs (on an overnight ($/kW) basis) and relatively poor (e.g. low) annual capacity running factors. However, the long run marginal cost of such assets is not affected by carbon prices as these assets have a zero carbon emission intensity rate and are therefore not susceptible to carbon costs. Therefore, to the extent that carbon prices increase average wholesale electricity prices while leaving the long run marginal cost of renewable assets unchanged, then the gap between the long run marginal costs and the higher average wholesale price levels (i.e. the renewable certificate price) will decline.

This aspect is modelled also by utilising a multiplicative factor calculated as ó1-(wcc/100)ô where ówccô is once again the respective values listed in Table 7, Panel (A). Note that the calculated values produce a multiplicative factor less than unity, thereby producing a decrease in this cost component relative to BAU when multiplied by the relevant BAU óRenewable Certificateô (c/kWh) values listed in Table 6, Panel (B). These multiplicative values are listed in Table 7, Panel (C). Note from examination of this panel that the magnitude of the multiplicative factor decreases with increases in the carbon price level ï higher carbon prices produce greater levels of cost deflation in the renewable certificate component relative to BAU.

The cost stacks for retail tariffs for each state and nationally were calculated using the data displayed in Tables 6 and 7 respectively for the five carbon prices mentioned above as well as the baseline BAU (i.e. zero carbon price) scenario. These results are listed in Figures 8a-8f. In Figure 8a, the cost stack associated with the national case is presented. Two main features are evident from inspection of this figure. First, the wholesale cost componentôs share increases with the carbon price level ï this can be seen by the increase in the size of the area with green shading in this diagram as the carbon price level increases ï e.g. moving from left to right in the figure. It should be noted that this also occurs for all states considered and can be also discerned in a similar manner from inspections of Figures 8b-8f. The second observation relates to the slight decline in relative terms of the cost share that can be attributed to the distribution network component (e.g. óDistributionô). This can be seen by examining the reduction in the size of the region with red shading as a function of increasing carbon price levels. It should also be noted that the same thing has also happened to the transmission network component but it is less evident because of the overall smaller cost share of this component when compared to the distribution and wholesale cost components. These trends can also be similarly discerned from inspecting Figures 8b-8f. The main reason for the results relating to distribution and transmission cost components is that we have assumed that the introduction of a carbon price will have no direct impact on these two particular cost components. This assumption was also employed in AEMC (2011).



The results for Queensland and New South Wales are displayed in Figures 8b and 8c respectively. It is evident from inspection of Figures 8b and 8c that the distribution cost component is more significant in both states when compared to the national result cited in Figure 8a. The reduction in the size of the cost share of the distribution component with increasing carbon price is also more evident in Figures 8b and 8c when compared to the national case outlined in Figure 8a. The other noticeable result is the relatively small size of the ñOtherô component listed in Figure 8c relating New South Wales when compared to the national case and other states. However, it should be noted that the Small Scale Renewable Energy Scheme (SRES) component and New South Wales feed-in-tariff scheme was not included in the pricing determination by the New South Wales regulatory authority IPART which was, in turn, used by AEMC in deriving their baseline cost component allocations outlined in Table 6. As such, for New South Wales, the óOtherô componentôs cost share would be understated, (AEMC (2011)).

Figure 8d contains the results for Victoria. There are a few noticeable features pointing to differences from other states. First, the retail margin allocation is substantially larger than comparable costs shares of other NEM states. This reflects the fact that all retail electricity suppliers in Victoria have been privatised. It should also be recognised that the retail component listed in Table 6 for Victoria is based on standard offer contracts. However, most households in Victoria are on market contracts and no data is available on the retail cost component of such contracts. It is possible, however, that the retail component applicable to market contracts will be lower than the estimate provided in Table 6 which was noted also in AEMC (2011). Second, the transmission and distribution components appear to be relatively smaller in size than is the case for other states in the NEM. Third, the óOtherô category is relatively larger in size with the key factor driving this result being the cost impost associated with the roll out of smart meters which was included in the óenergy efficiency/demand managementô category in Table 6, Panel (A).

The results for South Australia are documented in Figure 8e. The most noticeable feature of this figure is the relatively smaller share that is attributed to the óOtherô component, reflecting the lower contribution from renewable energy certificate cost component relative to other states -see Table 6, Panel (A).

The results for Tasmania are listed in Figure 8f. The most noticeable feature is the relatively smaller size of the óOtherô component which is being driven by an absence of a feed-in tariff scheme and energy efficiency/demand management component. The other noticeable feature is the relatively larger size of the transmission component compared with other states. This was attributed to an increase in replacement expenditure, increases in Tasmanian reliability standards for transmission and higher input costs, (AEMC (2011)). The distribution component, however, appears to be within the lower range of cost share values, appearing similar to the results obtained for South Australia and greater than the share allocation determined for Victoria.

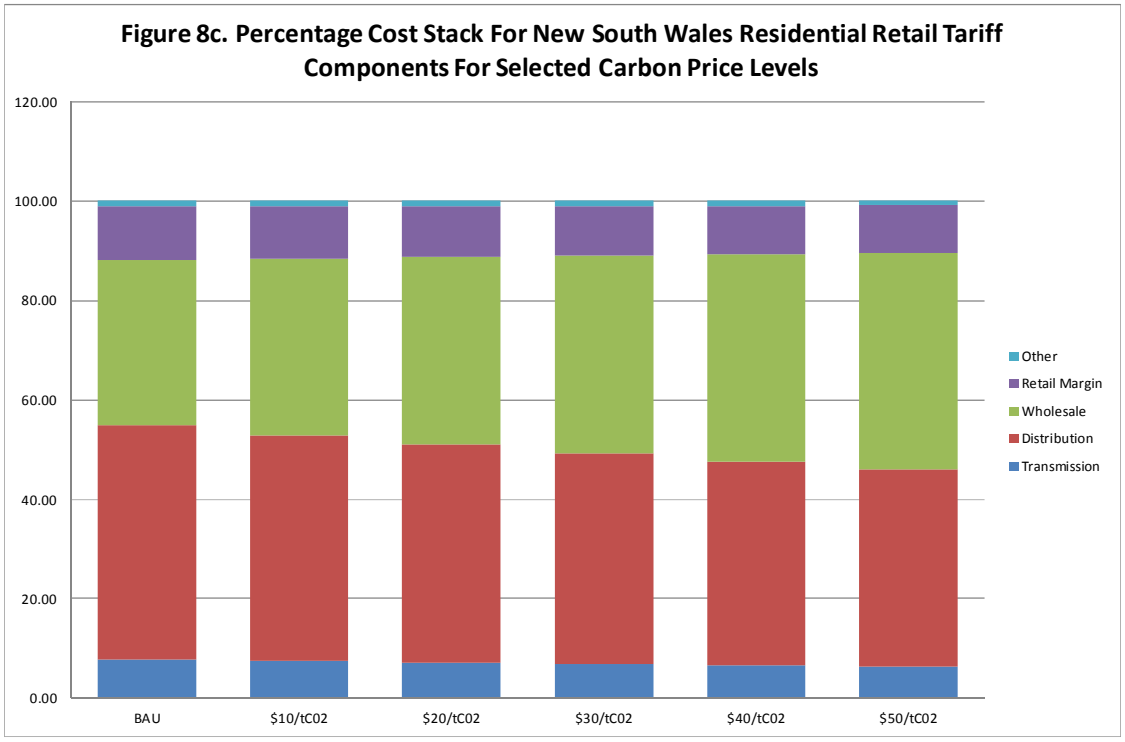


Figure 8c. Percentage Cost Stack For New South Wales Residential Retail Tariff Components For Selected Carbon Price Levels
120.00
100.00
80.00
60.00
40.00
20.00
0.00
BAU
$10/tC02
$20/tC02
$30/tC02
$40/tC02
$50/tC02
Other
Retail Margin
Wholesale
Distribution
Transmission

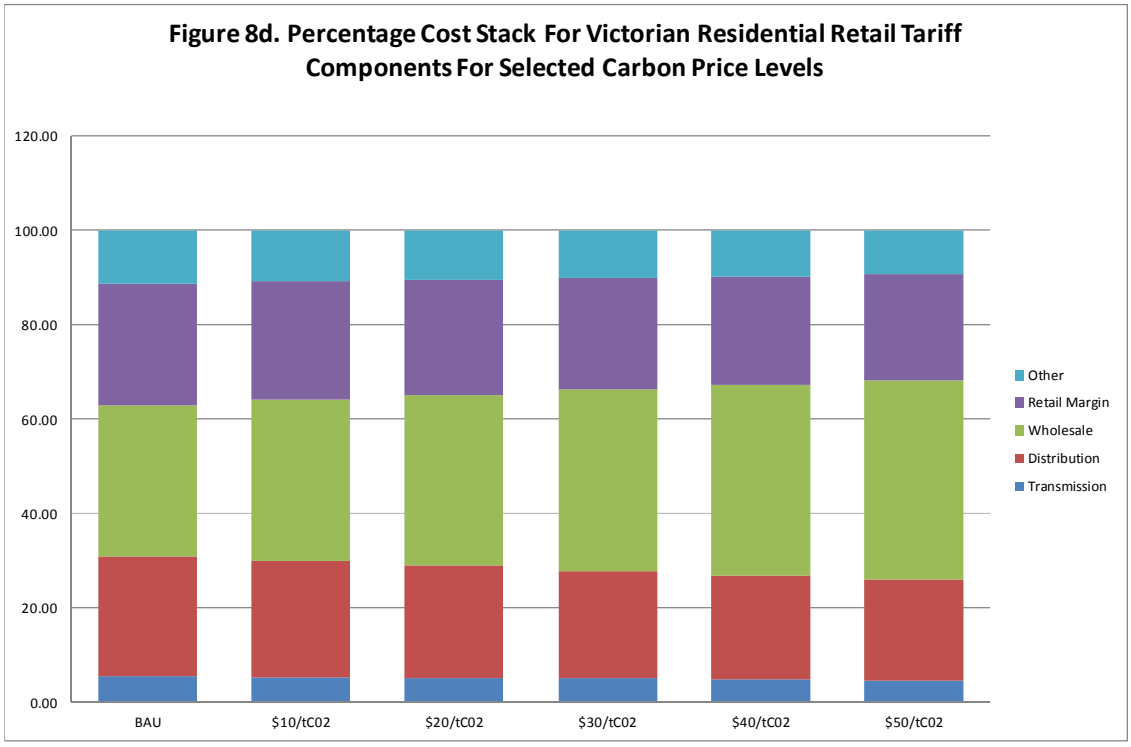
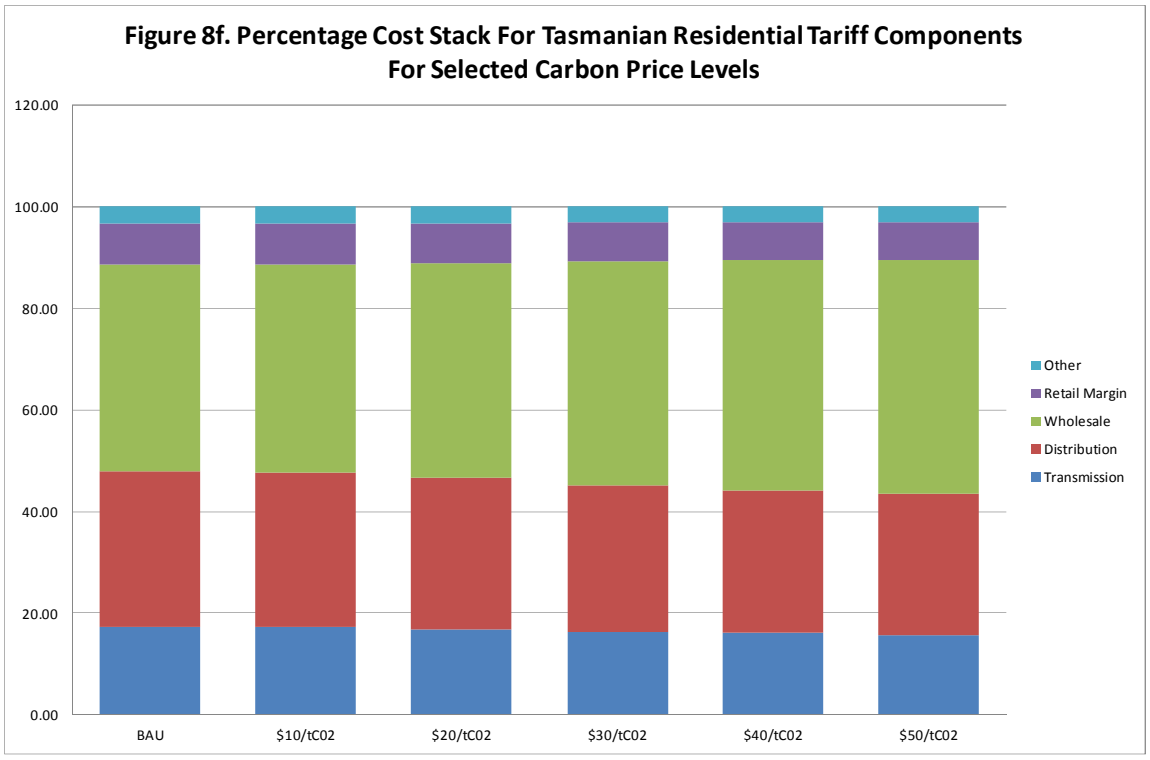
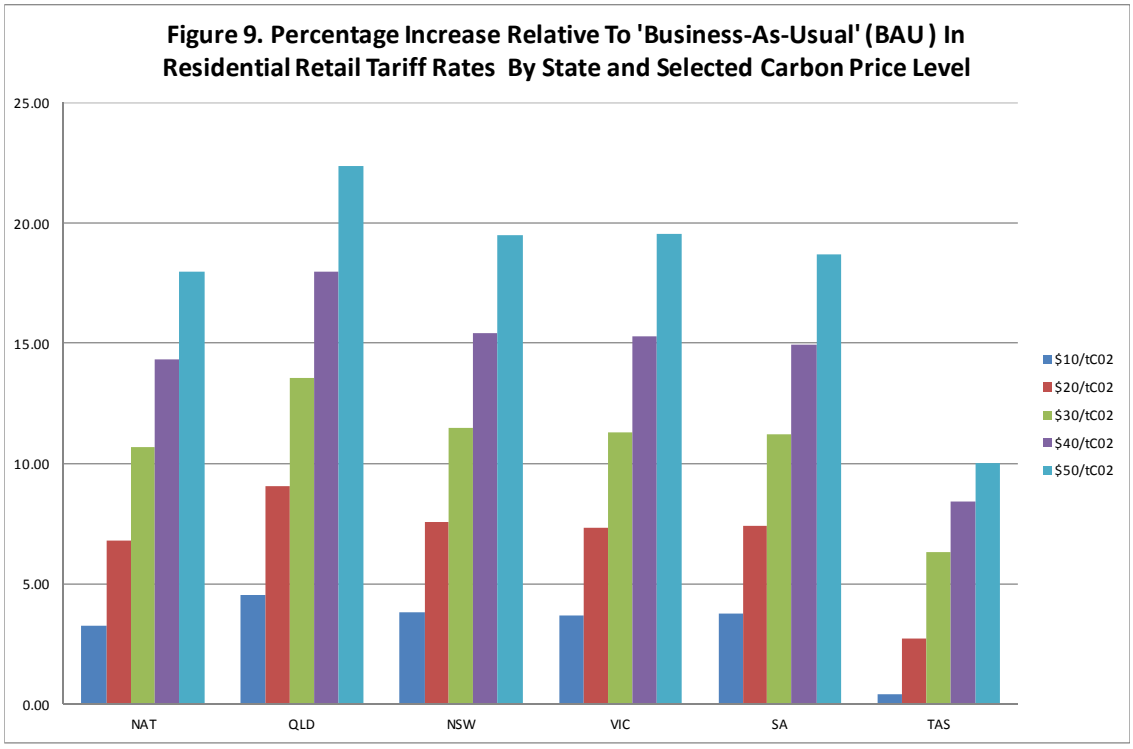


Figure 8d. Percentage Cost Stack For Victorian Residential Retail Tariff Components For Selected Carbon Price Levels
120.00
100.00
80.00
60.00
40.00
20.00
0.00
BAU
$10/tC02
$20/tC02
$30/tC02
$40/tC02
$50/tC02
Other
Retail Margin
Wholesale
Distribution
Transmission



The above analysis examined how core components making up regulated retail tariff structures might be expected to change from BAU with the introduction of a carbon price. Another area of interest is in discerning how the percentage growth (increase) in the retail tariff itself might be affected by the introduction of carbon prices. In assessing this aspect, we define the percentage increase relative to the BAU tariff levels documented in Figure 7. The

percentage growth in retail tariff rates relative to the BAU levels in response to the different carbon prices are documented in Figure 9 for each state and nationally.



It is evident from examination of Figure 9 that Tasmania experiences the smallest rate of increase in retail tariffs rates relative to BAU levels at all carbon price levels. This is followed (in ascending order) by South Australia, New South Wales, Victoria and finally Queensland. The national results appear to closely match those associated with South Australia, in qualitative terms.

For completeness, summary information relating to both the (c/kWh) level and (c/kWh) incremental increase in retail tariffs relative to BAU are also documented in Table 8, Panel (A) and Panel (B), respectively. It is apparent from Table 8, Panel (A), that Tasmania has the lowest retail tariff rates followed (in ascending order) by Queensland, New South Wales, Victoria and finally South Australia. This outcome is interesting in the case of Queensland because this particular state also experiences the greatest rate of incremental increase in retail tariff rates relative to BAU of any state as documented in Table 8, Panel (B). The state experiencing the next highest rate of incremental increase in retail tariff rates relative to BAU is South Australia, followed then New South Wales, Victoria and Tasmania (in descending order).

Table 8. Carbon Price Inclusive Cost Component Adjustments

Panel (A). Retail Tariffs Rates: (c/kWh)

Carbon Price	NAT	QLD	NSW	VIC	SA	TAS
BAU	22.41	20.69	22.75	22.86	23.99	20.75
$10/tC02	23.14	21.63	23.62	23.70	24.89	20.84
$20/tC02	23.93	22.56	24.47	24.53	25.77	21.32
$30/tC02	24.81	23.50	25.37	25.44	26.68	22.06
$40/tC02	25.62	24.41	26.27	26.36	27.57	22.50
$50/tC02	26.43	25.32	27.19	27.33	28.47	22.83

Panel (B). Incremental Increase in Retail Tariffs Relative To BAU Tariff Rates: (c/kWh)

Carbon Price	NAT	QLD	NSW	VIC	SA	TAS
$10/tC02	0.73	0.94	0.87	0.84	0.90	0.09
$20/tC02	1.52	1.87	1.72	1.67	1.78	0.57
$30/tC02	2.40	2.81	2.62	2.58	2.69	1.31
$40/tC02	3.21	3.72	3.52	3.50	3.58	1.75
$50/tC02	4.02	4.63	4.44	4.47	4.48	2.08

We will now offer concluding comments in the next section.

(8). Concluding Remarks

In this paper, we have focused our analysis on investigating the possible roles that key supply side policy initiatives currently available to Governments might play in pursuit of the policy goal of curbing growth in carbon emissions within the National Electricity Market (NEM). These policy instruments aim to combat carbon emissions growth through the pricing of carbon emissions. A survey of the literature demonstrated that the concept of carbon pass-through is crucial to understanding and estimating the interaction between a carbon price signal and wholesale electricity prices, assessment of the need, scope and role of industry assistance proposals relating to partial or complete allocation of free permits and examining the impact of carbon prices on retail electricity tariffs.

It was argued that to address the consequences of such policy initiatives on key participants within the NEM would require a model containing many of the salient features of the national wholesale electricity market. Such features would 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 branch congestion characteristics.

In order to capture these linkages, we used an agent based model of the Australian National Electricity Market (NEM) called the ANEM model. The particular model that was used contained 286 generators (increasing to 292 generators in 2009), 72 transmission lines including six inter-state Interconnectors and 53 regional nodes/demand centres.

A DC OPF algorithm was used to determine optimal dispatch of generation plant and wholesale prices within the agent based model. This algorithm employed an augmented SCQP problem involving the minimization of a positive definite quadratic form subject to a set of linear constraints in the form of equality and inequality constraints. The objective functions involve quadratic and linear variable cost coefficients and bus admittance coefficients. The solution values were the real power injections and branch flows associated with the energy production levels for each generator and voltage angles for each node.

The equality constraint is a nodal balance condition which ensured that at each node, power take-off by demand side participants located at that node equalled power injection by generators located at that node and net power transfers from other connected nodes. The shadow price associated with this constraint gave the LMP (or spot price) associated with that node. The inequality constraints ensure that real power transfers on connected transmission branches remained within permitted MW thermal limits and that real power produced by each generator remained within permitted lower and upper MW thermal limits while also meeting MW hourly ramp up and ramp down constraints.

The solution algorithm utilised in the simulations involved applying the ócompetitive equilibriumô solution. This meant that all generators submitted their true marginal cost coefficients and no strategic bidding was possible. This type of solution permitted assessment to be made of the true cost of generation and dispatch. Moreover, in order to make the model response to the various scenarios more realistic, we took explicit account of that fact that baseload and intermediate coal and gas plant have ónon-zeroô must run MW capacity levels termed minimum stable operating levels. The dispatch of the thermal plant was also optimised around assumed availability patterns for specified hydro generation units. Wind generation, however, was not included in the modelling.

A number of broad conclusions are available from this set of scenarios when compared with the óBusiness-As-Usualô (BAU) baseline results. First, Tasmania experienced higher averages price levels for BAU and lower carbon price levels when compared with the other states while also experiencing relatively more modest growth in average price levels compared with other mainland states as the carbon price level increased. This result was linked to how the hydro generators in Tasmania were assumed to offer supply. For the mainland states, Queensland consistently had the lowest average price levels, followed by South Australia and then New South Wales. Victoria consistently has the highest average price levels for each year that was investigated.

For all states and all years considered, we found that there was less than complete carbon pass-through of carbon price into average wholesale prices. Tasmania was found to have a much lower rate of carbon pass-through than the other mainland states. The rate of carbon pass-through was highest for Queensland whilst the pass-through rate for New South Wales, Victoria and South Australia, as a function of carbon price, was more variable in scope. Specifically, South Australia has higher pass-though rates than New South Wales and Victoria for small to moderate carbon price levels but experienced lower pass-through rates for higher carbon price levels than the comparable pass-through rates of New South Wales and Victoria.

In assessing the implications for retail electricity tariffs of carbon prices, we distinguished between the markets for commercial and industrial customers and the market for residential

(household) demand. We also examined the impact of $10/tC02, $20/tC02, $30/tC02, $40/tC02 and $50/tC02 carbon prices on retail electricity tariffs.

In the case of the first market relating to retail commercial and industrial customers, contract prices were crucial together with the net effect of participantsô contract and spot market exposure through hedge instrument or óself-insuranceô through their own physical plant or Power Purchase Agreements. Over-The-Counter (OTC) market contract prices had a standard clause linking the forward price to a strike price relating to expected energy cost plus a carbon cost component. The carbon cost component was calculated by multiplying the carbon price by an average carbon intensity rate linked to the whole of NEM carbon intensity rate. It was noted that the average carbon intensity rate did not attempt to capture the implications of differences in carbon pass-through rates of different states. This permitted the possibility of windfall gains by inflating contract price if a states carbon pass-through rate was less than the OTC average rate and losses by understating the contract price if the states carbon pass-through rate is greater than the OTC average rate. Our analysis more generally demonstrated the complexities that might emerge when account was taken of possible variations in carbon pass-through rates across states and across carbon price levels when taken in the context of OTC standard clause contracts.

In the case of retail residential demand, the empirical analysis employed in the paper utilised existing retail tariff rates and component cost shares published by the AEMC for a baseline year of 2010-11. This baseline also excluded a carbon price and thus represented a óBusiness-As-Usualô (BAU) scenario for the purpose of assessing the impact of carbon prices. The main methods used to determine standard offer regulated tariff rates typically allocated wholesale cost components according to the long run marginal cost of supply as well as additional retail based charges including mark-ups associated with the costs of network usage, retail charges associated with providing customer services, profit mark-up, goods and services taxes (GST), and obligations to purchase renewable energy certificates or meet feed-in tariff liabilities.

The impact of carbon prices on retail residential rates mainly emerged through the impact on the wholesale cost component. This impact was modelled by multiplying the relevant carbon pass-through rate by the carbon price and converting from a ($/MWh) to (c/kWh) basis which was then added onto the baseline (BAU) wholesale cost component.

In the analysis we used the average carbon pass-through rates for the period 2007-2009 determined from ANEM model scenario runs. This would provide a reasonable indication of carbon price flow on impacts on retail tariffs because the generation set remained fairly constant between 2009 and the 2010-2011. In addition we also allowed for an impact of carbon prices on the retail margin and renewable energy certificate price cost components of the retail tariff cost structure. All other components including transmission and distribution components were assumed to not be affected by carbon prices.

In terms of the impact of carbon prices on the relative share of different retail tariff cost components, we found that the wholesale cost componentôs share increased with the carbon price level for all states and the nation as a whole. A slight decline in relative terms of the cost shares attributable to distribution and transmission network cost components was also observed.

More generally, Tasmania was found to experience the smallest rate of percentage growth in retail tariffs rates relative to BAU levels at all carbon price levels. This was followed (in

ascending order) by South Australia, New South Wales, Victoria and finally Queensland. The national result appeared to closely match the results associated with South Australia. In terms of the (c/kWh) retail tariff rate levels, Tasmania had the lowest retail tariff rates followed (in ascending order) by Queensland, New South Wales, Victoria and finally South Australia. In terms of the (c/kWh) incremental increase in retail tariffs relative to BAU, Queensland experienced the greatest rate of incremental increase, followed by South Australia, New South Wales, Victoria and Tasmania (in descending order).

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Figure 1. QLD 11 Node Model - Topology

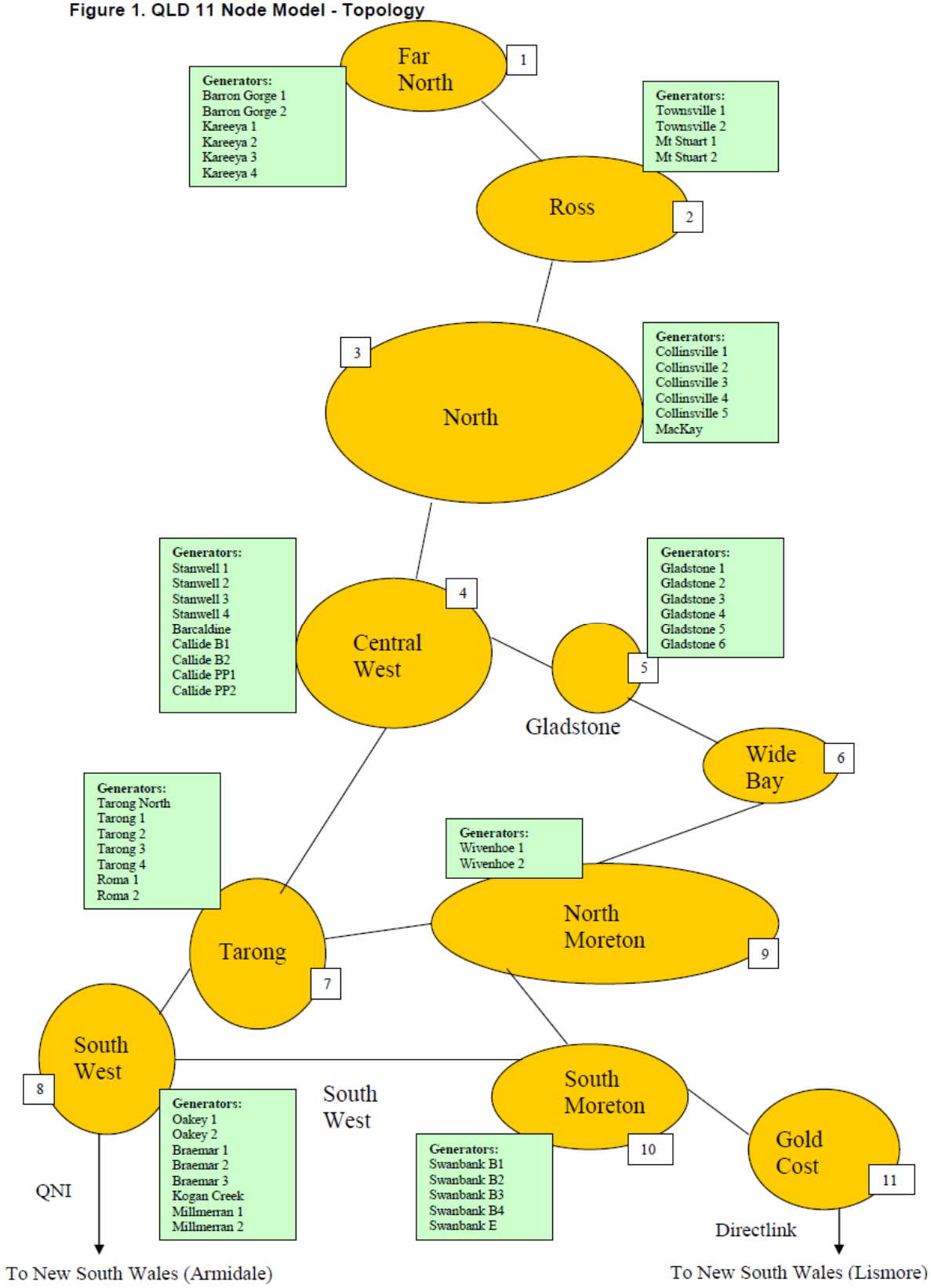

Figure 2. NSW 16 Node Model - Topology

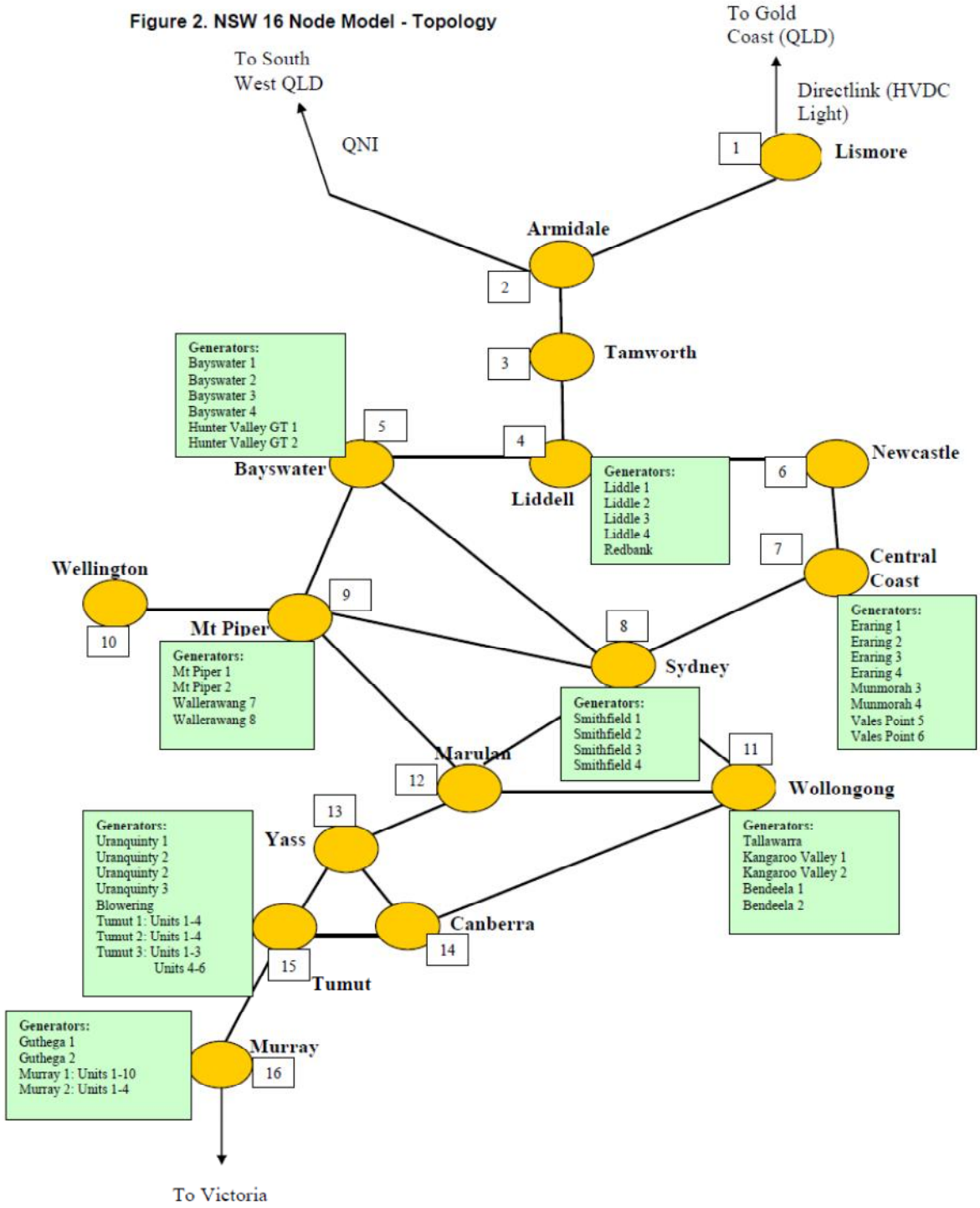

Figure 3. VIC 8 Node Model - Topology

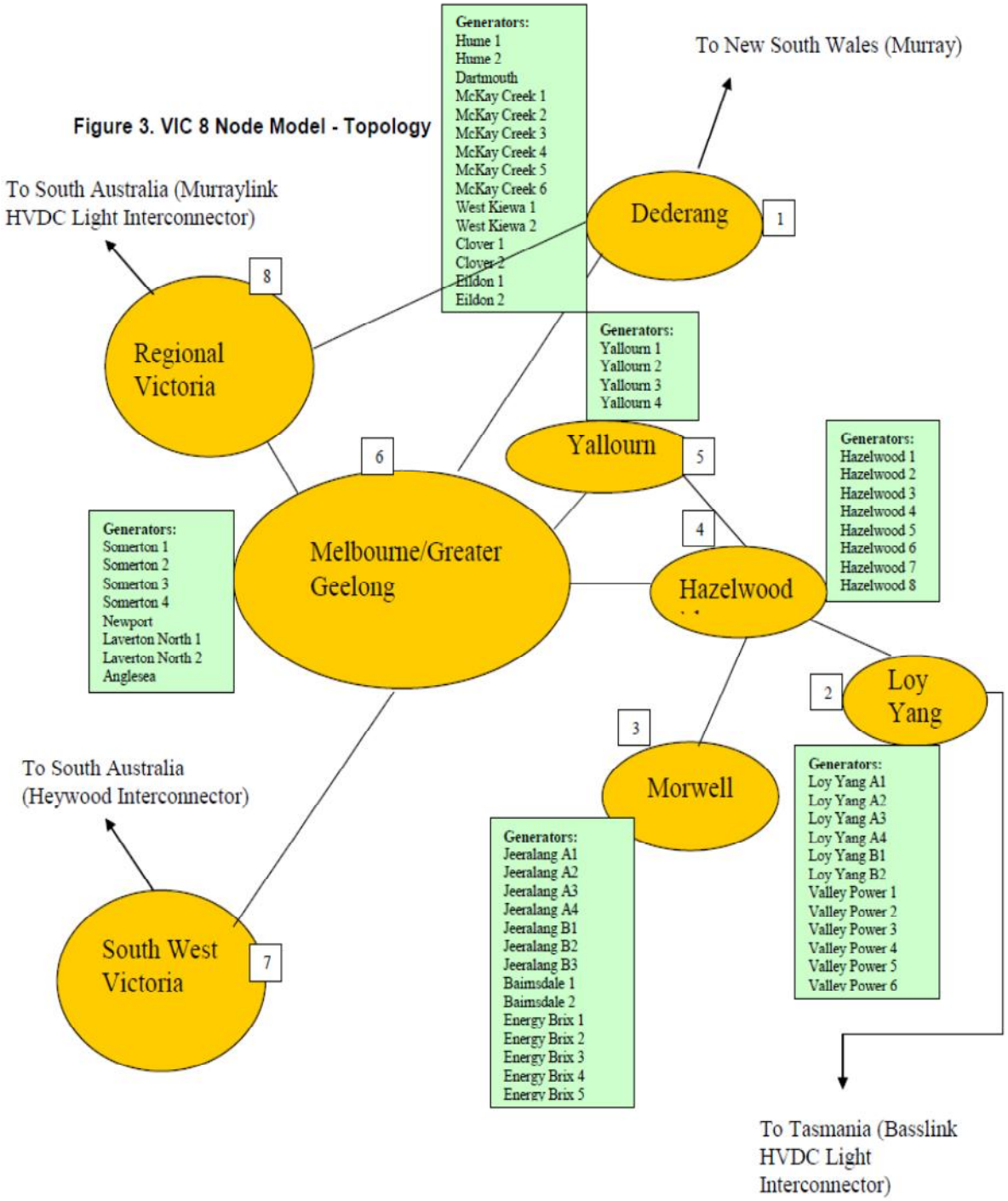

Figure 4. SA 7 Node Model - Topology

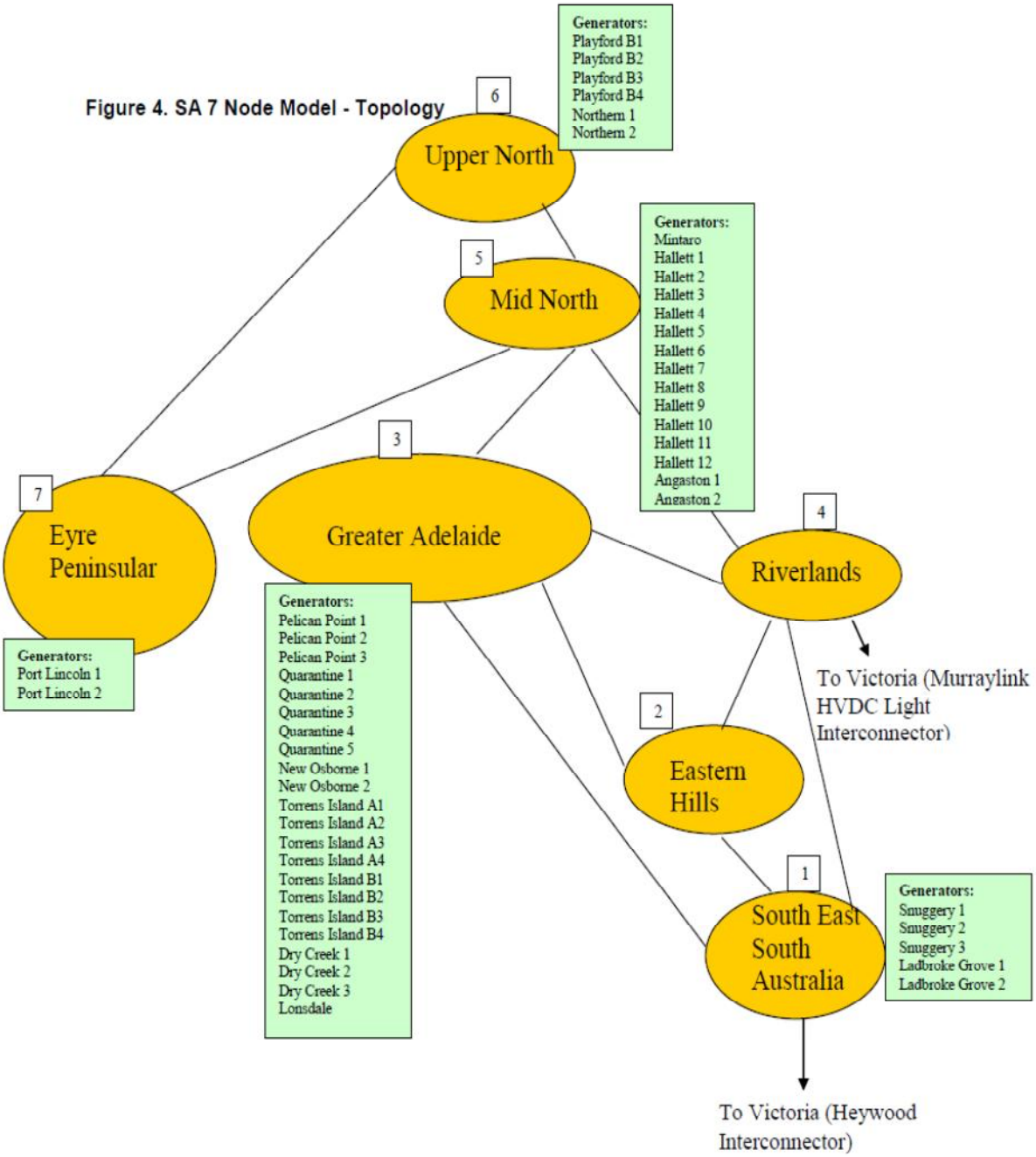

Figure 5. Tasmanian 11 Node Model - Topology