CSIRO Intelligent Grid Cluster

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Milestones 7 & 8: Combined Report

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Chapter 1: Introduction and Summary

The overall goal of project P2 was to provide a comprehensive understanding of the impacts of distributed energy on the Australian Electricity System. To this end, the Energy Economics and Management Group (EEMG) has constructed a variety of sophisticated models, two of which have been operationalised using supercomputing facilities at both UQ and Monash, to analyse the various impacts of significant increases in Distributed Generation (DG). We believe that the models that we have developed are the most sophisticated of their kind currently available in Australia.

At the present time, we are witnessing dramatic changes in the competitive position of different types of energy generation. Notably, the price of PV panels has been dropping sharply over the past two years as global uptake has increased, spurred on by a range of incentives on offer in different countries. What we are observing is the classic downward trend that is associated with the uptake of a new technology. In this project, we have tended to focus upon PV as our distributed generation case, not because it is the most important form of DG but because it is the one which is currently making the most rapid progress in terms of diffusion and adoption. The models that we have developed use projections of PV growth in simulations but these models can, just as easily, focus upon other forms of DG. For example, we can assess the impacts of smart metering on load demand shaving at the aggregate level. As long as the micro level effects of such innovations can be aggregated, our models can accurately assess the system-wide impacts. Indeed, these models open up an important research agenda beyond this project.

In investing in different forms of power generation, comparisons have to be made of the whole costs and anticipated revenue streams from point of purchase to the scrapping of a system. The conventional way to do this is to calculate net present values and undertake Levelised Cost of Energy (LCOE) analysis. In Chapter 2 we compare DG to a range of alternative forms of power generation using the best information currently available. This is not a new exercise. What is different here is that we explicitly integrate the distribution use of service (DUOS) and transmission use of service (TUOS) charges. This can greatly affect the final cost of electricity to retail customers. W also consider a range of scenarios for discounting factors for particular customers such as mines which access electricity from the high voltage portion of the network.

We have integrated a wide range of technology types considered previously by the CSIRO [15], AEMO [4] for inclusion in the NEM. Our simulations suggest that DG could reduce pressures on retail tariff price rises in Queensland and across the rest of Australia. When we include all the externalities considered in the AEMO NTNDP [4] and DUOS/TUOS into the LCOE it is clear that DG can clearly compete without a DUOS discount against centralised generation so, as was previously reported in our 2009 P2 Annual Report, PLEXOS simulations suggest that DG is a viable option to deliver significant cuts in emissions and reductions in expenditure on the transmission network.

In Chapter 3 we look specifically at the impact DG, not from the perspective of primary power generation but with regard to its load shaving capability at daily peaks. For reasons already discussed, we focus upon PV. Load shaving at peaks can both reduce carbon emissions and can delay transmission and distribution network investments. To investigate this issue, we used a sophisticated agent-based model that contains many salient features of the NEM. These features include intra-regional and inter-state trade, realistic transmission pathways and the competitive dispatch of generation based upon 'locational marginal pricing'. PV is treated as a load shaving capability at nodes containing high residential and commercial load components. The model simulations undertaken encompassed Brisbane, Sydney, Melbourne and Adelaide. We found clear evidence that a demand side policy, promoting the take-up of solar PV, particularly when combined with a carbon price signal, would have significant benefits. However, we did also find that to meet a load shave of 2%, a very large number of residential PV installations would be required and that this, from a policy perspective, could well be infeasible. Thus, the findings point strongly towards the installation of significant commercial PV, in addition to residential PV. Hitherto in Australia, very few incentives have been available for commercial installations, unlike countries such as Germany and Spain, and the upshot is a negligible PV capacity. If serious amounts of peak load shaving are to be achieved, this policy must change radically.

A great deal of research needs to be done before a commercial PV installation program is launched in Australia. In Chapter 4, we discuss the development of a commercial-sized PV installation now operational at UQ. This is a project that has been guided by the EEMG Group throughout P2. We have regarded this as a key part of P2. The economic evaluations that were undertaken have provided valuable insights concerning the viability of commercial PV on different kinds of sites. Now that the PV array is up and running, a range of economic experiments will be conducted to ascertain the feasibility of different kinds of panels, inverters, battery storage systems, etc.. The floods have delayed the full operation of the PV array by several months but, within a relatively short period of time, we shall be able to identify both the economic opportunities and barriers to such investments. Unfortunately, the array will not be fully up and running until early July, so we shall be unable to report the findings of this research before the completion of P2. We strongly believe that this kind of research is essential before investments in commercial scale PV on, for example, supermarkets, shopping centres and warehouses, are undertaken.

For policymakers, we shall be able to scale up our findings in relation to the UQ PV array into a full simulation of the impacts of large scale investments in commercial PV on the NEM. We shall also be able to measure the costs incurred in dealing with voltage instability, either through line and sub-station upgrades or through the use of battery technologies. A research project, due to be undertaken in the second half of 2011, funded by the UQ Global Change Institute, will assess the viability of the latter. This work in P2 also relates to one of the project deliverables, namely, to train PhD students in both the technical and economic aspects of the introduction of DG into the Australian energy system. The UQ PV array, when fully up and running, will offer such opportunities for a number of years to come after this project is completed. An attraction of this work is that it will, inevitably, be multidisciplinary involving integrated studies with both economic and electrical engineering content. Demand for graduates with this kind of training will become very significant the coming decade and UQ will be in a strong position to meet this need.

The load shaving potential of DG through, for example, PV or smart metering, has acknowledged potential to defer transmission investments which are largely driven by peak demand. At the present time, we have a transmission system that is being upgraded at significant expense largely to meet anticipated demand peaks. Surprisingly, very few studies have assessed the impact of DG, such as wind and solar PV, on transmission investments. In Chapter 5, we report our findings concerning such impacts using a sophisticated simulation model that we have specifically developed to answer this question. We have modelled the transmission expansion investment decision as a cost minimization problem subject to system reliability and AC power flow constraints. Power system security constraints, which are also becoming a concern to policymakers, have also been incorporated.

The model was applied to Queensland and the simulation results indicate that, although DG generally can defer transmission investments, it is inappropriate to offer a *general* conclusion about the strength of this effect. In practice, the locations of DG units, the network topology, and the original power flow patterns all have significant impacts on DG's investment deferral effect. In the Queensland market, solar PV was found to have a stronger effect on transmission investment deferral compared to wind power, since it can be deployed evenly in all areas of Queensland, while wind power can only be concentrated in north-eastern areas. Moreover, our simulation results also show that, the investment deferral effects of DG are largely limited by technical constraints, such as voltage and transient stability. We concluded, therefore, that it is important to carefully consider these constraints when evaluating the actual benefits of DG in the context of transmission network investments.

Many of the conclusions drawn here can be applied in other regions of the world. Wind turbines are almost always concentrated in areas with relatively strong wind power and solar generation can usually be spread out geographically. These geographical considerations matter for transmission costs but they have tended to be neglected in discussions of the costs of DG relative to conventional, centralized power generation. Clearly, the evolution of efficient storage systems will be critical in solving transient stability problems. In the case of solar panels and wind turbines, this remains problematic but this is much less so in the case of solar thermal generation where it is a much simpler matter to store heat rather than electricity. We already know that heat storage is much cheaper than electricity storage and a useful topic for further research would be to make a comparison between solar panels and solar thermal generation from the transmission investment perspective. It is also worth stressing that solar thermal can, in many instances, also be classified as DG. We are already very familiar with distributed roof top solar water heaters, but it may well be that isolated communities and mining operations will be able to take advantage of small to medium sized solar thermal power stations with storage. In some cases this might be more cost effective than a large PV array and, being off the NEM, can contribute to deferment of transmission system investments which can be particularly expensive in distant, remote areas.

So, we know that, in some conditions, DG can lead to deferral of transmission investments. However, a very careful assessment of the technical conditions in any region, conducted by electrical engineers, is essential before any firm conclusion can be made. Clearly, further research needs to be done in this area. This is very important. We have to accept that the existing grid structure, constructed over a long period of time with different priorities in mind, will be with us for a long time to come. Replacement of it comes only at a prohibitive cost. This means that, when introducing various kinds of DG, the capability of the local grid has to be assessed very carefully. The location and size of a DG installation, or set of installations, has to be assessed on a case by case basis. Both the economics of a DG project and its safety depend critically on such assessments. And only detailed modelling can tell us what the repercussions will be across the system as a whole. It has been a key goal in P2 to provide the modelling capabilities to do this.

Chapter 2: Economic Viability of DG vs. Centralised Generation

2.1 Introduction

One of the fundamental differences between the current centralised generation paradigm and that of Distributed Generation (DG) is the inclusion of a variety of externalities to the cost of delivered energy. The pricing of future costs of generation assets is usually established via the Levelised Cost of Energy (LCOE) analysis [34], to incorporate all future costs, revenue streams and their associated net present value. What has been lacking however is the integration of the Distribution use of service (DUOS) and Transmission use of service (TUOS) charges which greatly affect the final cost of electricity to retail customers. Furthermore, we are able to include a variety of scenarios for discounting factors to energy for customers such as mines who access electricity from the high voltage portion of the network.

This analysis further builds on the LCOE model delivered in 2010 to develop a platform for assessing a variety of technology types which may be deemed more suitable for deployment with an extensive upgrade to the input variables under assessment.

2.2 Methodology and Analysis

So an important goal of this paper is to ascertain what the true costs of different generating technologies are. This involves what is known in the literature as levelised cost analyses [7]. Although we can draw upon this literature it is necessary to derive costs that are specifically relevant to Australia to input into our modelling. In particular we have relied on a variety of Australian sources for information of generator costs [1,2,5]. To evaluate the likely optimal plant mix for a power system we have to derive the levelised cost of new entrant plant. Below in **Figure 1-2** we provide a schematic which outlines all of the assumptions for the cost of generation model. For the full exploration of this methodology see Project 2 Annual report 2010 section 4. The results presented in this report depart from those presented previously by including the following variables into our LCOE:

- Carbon forward curves as outlined by [4]
- REC prices as outlined by [1,4]
- Retail electricity tariff 11 for Queensland in 2010/2011 minus retail margin
- Gas prices more aligned with analysts' expectations [30]
- A broader range of technology types [4]
- Multi-year start times
- Ability to apply differential discount rates to DUOS/TUOS
- Updated BBB+ credit costs [30]
- Change in Debt Tranche facilities [30,32].

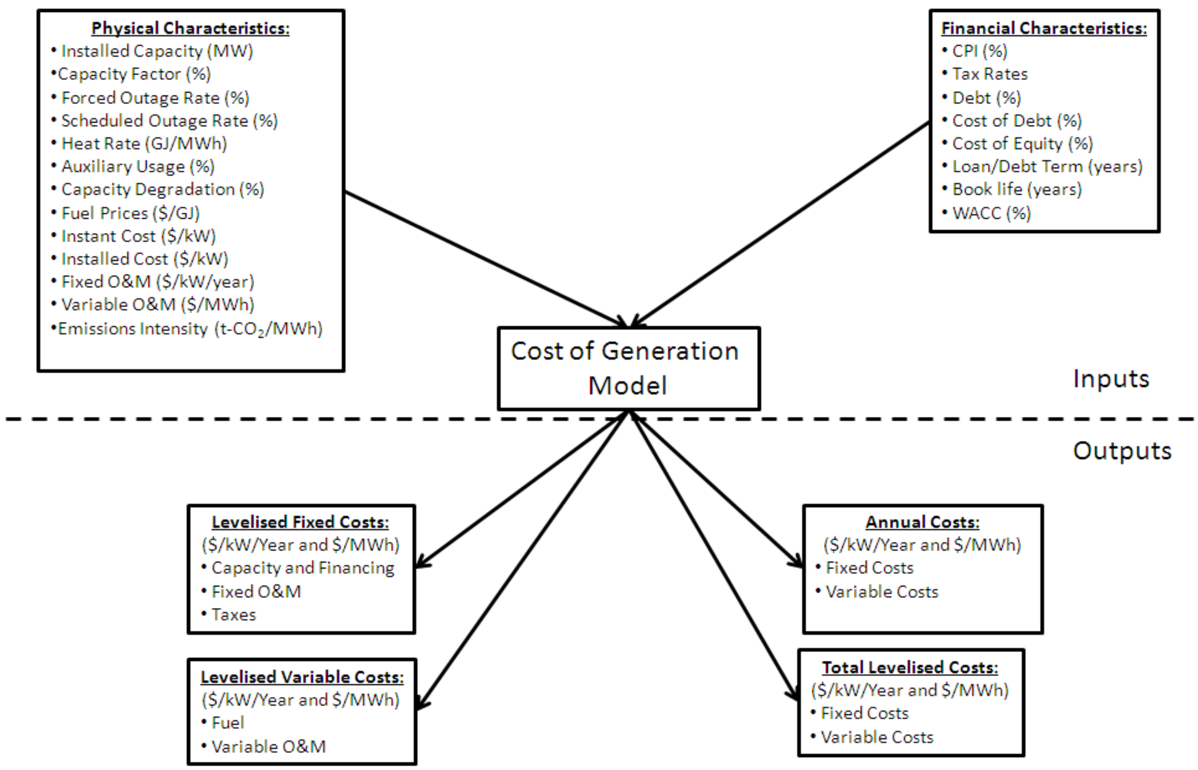

Figure 1-1: Levelised Cost Methodology

2.2.1 Natural Gas Prices

One of the significant departures from those assessed by the market operator AEMO [1,4] is that of natural gas prices. With the prospect of exporting a significant proportion of Australia's natural gas resources to China and Japan, the availability of affordable gas for use by the electricity sector has been put under pressure [32]. The exports of Liquefied Natural Gas (LNG), from Gladstone on Queensland's central coast, could have a variety of consequences for Australia's ability to generator low cost electricity from lower emitting technologies. The exports of LNG from Western Australia have already been observed to have had a detrimental effect on the future investment in gas fired electricity generation [32]. Below in **Figure 1.2**, we present three price forecasts based on AEMO's estimates for the Moomba hub under -5% and -15% emissions reduction scenarios and the EIA reference price for the average delivered price for natural gas to electricity users in the lower 48 states of the US [19]. While many have supported the view that natural gas prices will remain bullish at the Japanese hub to reach $12/GJ (which would result in the free-on-board net-back price at the Gladstone hub reaching $9/GJ) such as the forecasts presented by AEMO [4]. The general view of the Energy Information Agency [18, 19] is that well head prices in the US will remain low until well into 2020. With technical advances in recovery of shale gas in the lower 48 states of the US, well head prices are expected to be much lower than previously forecasted by the EIA and IEA [19, 23]. Production from the US shale fields combined with large supplies being made available from Australia's coal seam gas fields will significantly increase world availability. However, these conflicting views over price forecasts impose a great deal of uncertainty for investors into the electricity supply industry in Australia. While fuel price risk still remains high with recent unrest amongst Middle East and North African states (MENA), and uncertainty over the future of oil supplies, we have made the assumption that natural gas contracts which will remain low at around $3/GJ (given the likely AUD/USD exchange rate forecasts of above $1.05US [30]).

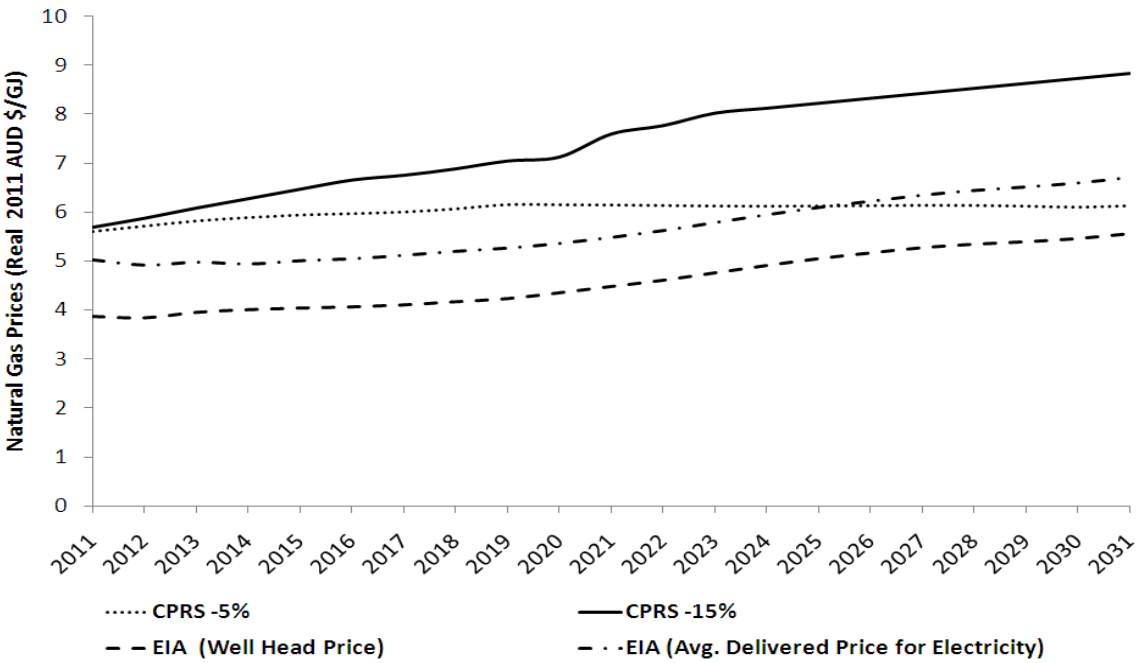

Figure 1-2: Forecasted Natural Gas Prices

2.2.2 Scenarios

When trying to establish the likely outcomes of a range of policy measures and analysis viewpoints for the electricity supply industry, it is best to progress through a number of different scenarios to provide a broad scope of advice to key stake holders. Moreover we will examine a range of carbon abatement trajectories and the centralised vs. end consumers point of view. We will restrict ourselves to the view of retail domestic consumption rather than that of large scale industrial users who may receive a range of discounts on their DUOS and or TUOS costs for deliver energy. The scenarios which we will examine for this report are as follows:

1. **Business-As-Usual (BAU):** in which carbon pricing is not implemented. DUOS and TUOS charges are not implemented into the cost structure of generation in line with current central planning hegemony. Moreover, incentives for deployment of non-centralised generation are removed.

2. **CPRS -5% no DUOS/TUOS:** The CPRS is introduced in combination with the renewable energy target to reach an overall reduction of emissions by 5% below 2000 levels. With DUOS and TUOS charges not implemented.

3. **CPRS -15% no DUOS/TUOS:** The introduction of the CPRS with a deeper emissions abatement pathway is implemented to achieve an overall reduction of emissions of 15% below 2000 levels. With DUOS and TUOS charges not implemented

4. **CPRS -25% no DUOS/TUOS:** The introduction of the CPRS with a dramatically deeper emissions abatement pathway is implemented to achieve an overall reduction of emissions of 25% below 2000 levels. With DUOS and TUOS charges not implemented.

5. **DUOS/TUOS case with no carbon trading:** A second view on the BAU case where we depart from the current paradigm and examine the electricity generation from a end users perspective where the full weight of Distribution and Transmission charges are applied. Looking through the glass from the opposite side can always present one with an un-impeded view of the world one lives in.

6. **CPRS -5% with DUOS/TUOS charges implemented:** The CPRS is introduced in combination with the renewable energy target to reach an overall reduction of emissions by 5% below 2000 levels. With DUOS and TUOS charges implemented.

7. **CPRS -15% with DUOS/TUOS charges implemented:** The introduction of the CPRS with a deeper emissions abatement pathway is implemented to achieve an overall reduction of emissions of 15% below 2000 levels. With DUOS and TUOS charges implemented

8. **CPRS -25% with DUOS/TUOS charges implemented:** The introduction of the CPRS with a dramatically deeper emissions abatement pathway is implemented to achieve an overall reduction of emissions of 25% below 2000 levels, with DUOS and TUOS charges implemented.

2.3 Results

Evaluating the levelised cost of generation is one of the inputs into an extremely complicated process of investment in the electricity supply industry [12]. We will progress through all eight scenarios as outlined above and then present an overview of our findings. In all scenarios the current retail tariff 11 prices for Qld are illustrated to show how different generation costs contributed to the price of deliver energy to households. This tariff price is currently regulated by the Queensland Competition Authority to be ~19c/kWh, with a retail margin of around 7%.

2.3.1 Scenario 1:

This scenario is the current paradigm for central planners, Genco's and other stake holders in the Electricity Supply Industry (ESI) when they evaluate different technological options for inclusion in the generation portfolio. Typically stakeholders would view the world from a top down approach by asking how their investment would perform in the competitive merit order of dispatch for deployment on the NEM.

In this scenario the deployment of further generation into the NEM would certainly come from the lowest cost grouping consisting of mainly gas fired CCGT and OCGT, Supercritical pulverised fuel (SCpf), using black coal as its fuel source. These centralised generation options would be favoured by must stakeholders given the current regulatory regime and the availability of coal and natural gas within all states of the NEM. SCpf stations are currently the leading edge technology for coal fired generation, with Kogan Creek power station as the newest member of the this class to be deployed on the NEM. Its thermal efficiency and lower emissions intensity is also a contributing factor of its lower cost. Surprisingly though the inclusion of some gas fired Combined Heat and Power (CHP), Distributed generation at a minimum installation size of 30MW would also seem to be amongst the desirable candidates for deployment (**Figure 1-3**). A unit of this size would be suitable for scheduled dispatch onto the NEM and could compete in the merit order for dispatch.

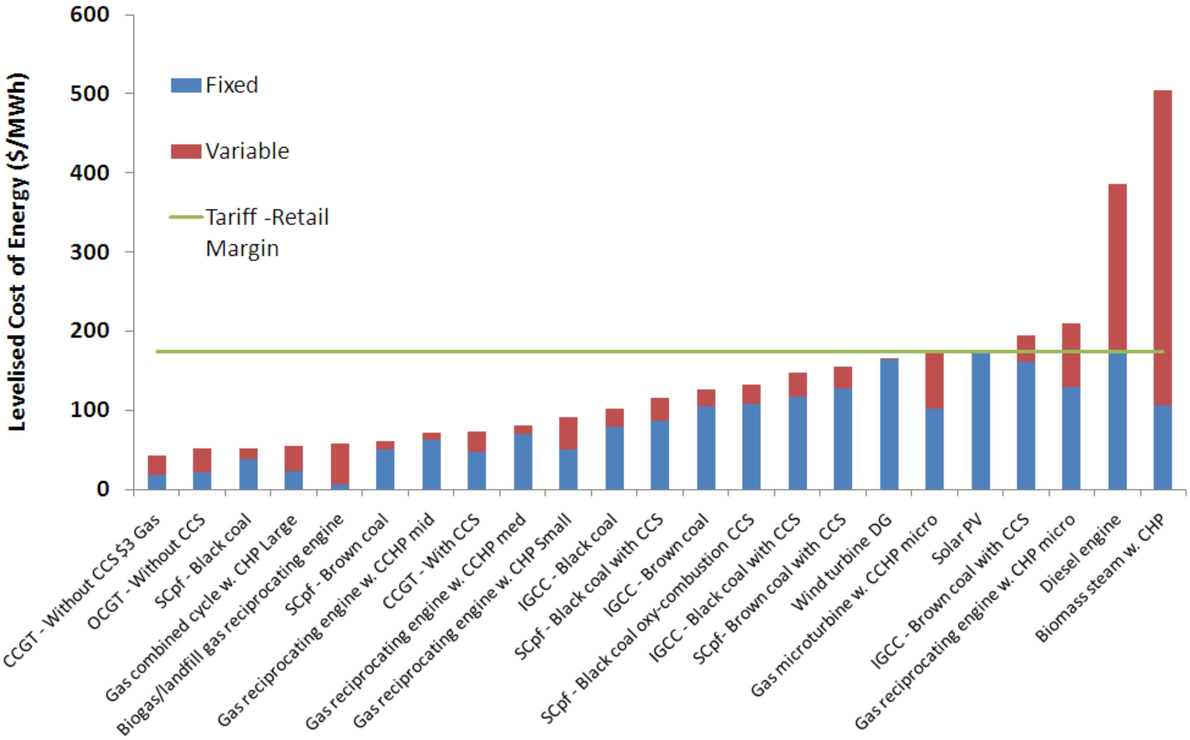

Figure 1-3: Scenario 1, BAU No DUOS/TUOS

2.3.2 Scenario 2

Given the current political landscape in Australia this is the most likely carbon abatement trajectory. The policies announced and proposed before parliament [14], have planned a minimum commitment of a 5% reduction of emissions compared to 2000 levels. The carbon price trajectory remains relatively low to 2020 (\$ 33.7/t-CO_2). Given the low emissions intensity factor of CCGT without CCS as a base load generator compared to SC pf (Black and Brown), it is certainly the most competitive from an LCOE perspective. From a Distributed Generation point of view it is evident that gas fired CHP remains amongst the most suitable for deployment onto the NEM. Furthermore, Gas reciprocating engines fall within the group of likely candidates particularly given its position in comparison to CCS and IGCC technologies. While landfill gas is the 2nd cheapest technology suitable locations and the availability of waste gas is limited (see figure below).

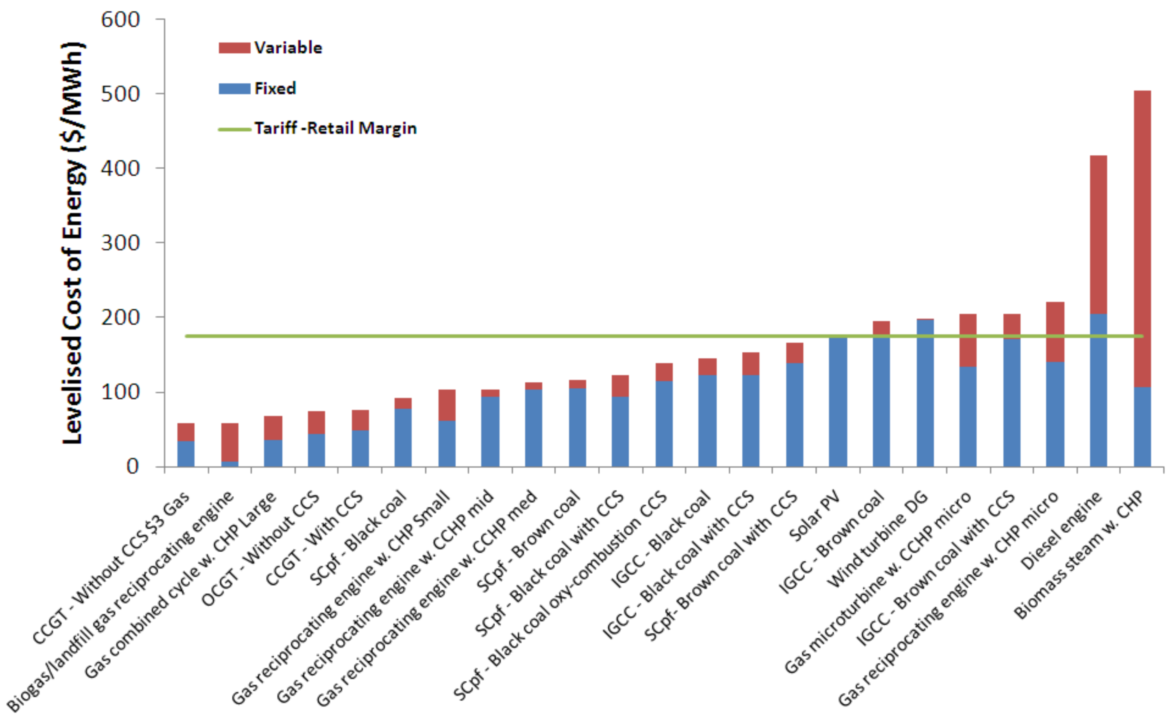

Figure 1-4: Scenario 2, CPRS -5% no DUTO/TUOS

2.3.3 Scenario 3

While the probability of the introduction of a 15% reduction in emissions by 2020 would seem remote given the timing and the current political landscape, however the aspirational target is still physically and technically possible. CCGT without CCS was found to be the most competitive up to a gas price of $3/GJ with entry of SC pf Black coal is still viable during the planning horizon out to 2025. Once again CHP based technologies could be considered on a locational basis for inclusion into the generation mix when the unit size is above 30MW (**Figure 1-5**). The likely forward deployment rates of SC pf with CCS is significantly questioned given its immaturity and the first industrial scale generator not ready for commissioning until 2015 [4].

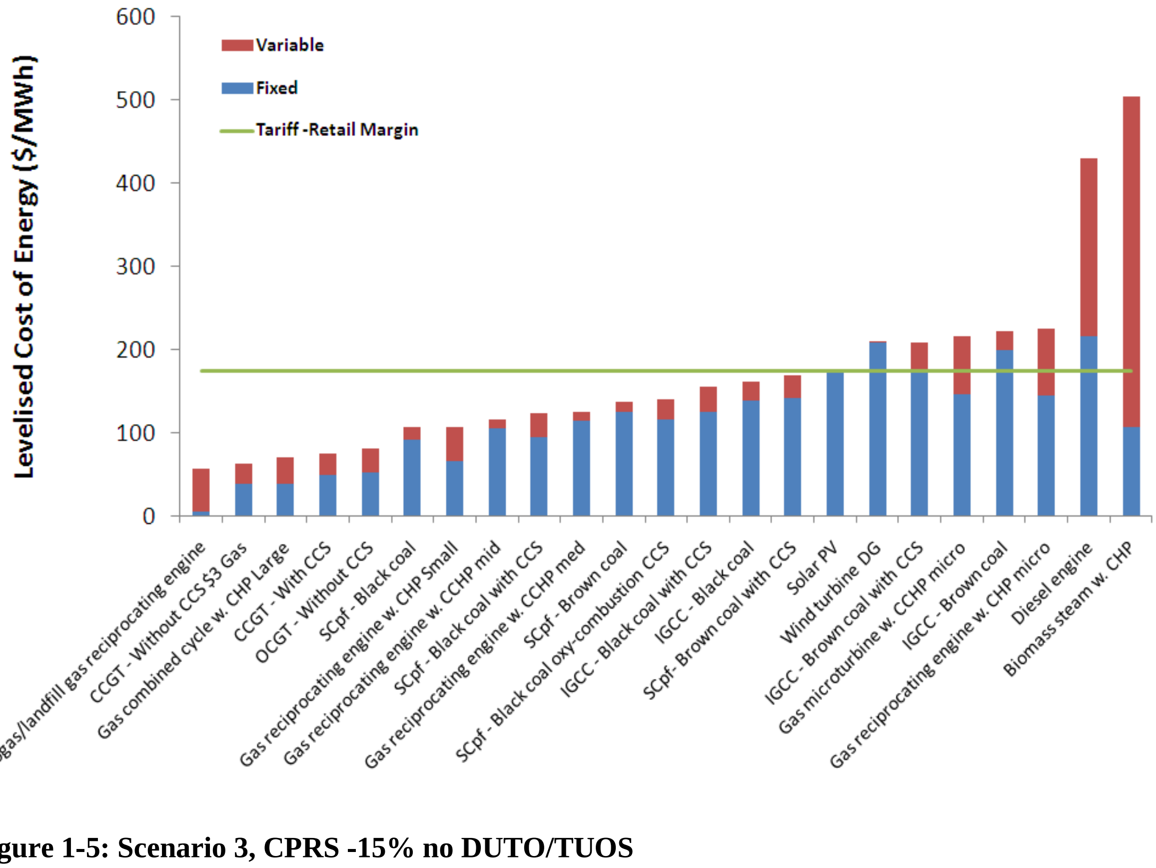

Figure 1-5: Scenario 3, CPRS -15% no DUTO/TUOS

2.3.4 Scenario 4

While the prospect of a 25% cut to emissions may seem remote at the time of writing this report, it should be considered given previous commitments of the federal government should world agreement on a cut in abatement be required. The long term carbon price trajectory outlined previously by the Treasury [14], has been implemented with a price in 2020 of \$70.3/t-CO_2. With deeper cuts in emissions expected in this scenario DG CHP 30MW and CCGT without CCS are the most likely candidates for investment (**Figure 1-6**). While CCS technologies appear to be desirable given high carbon price they are unlikely to be able to be deployed till after 2015 [4].

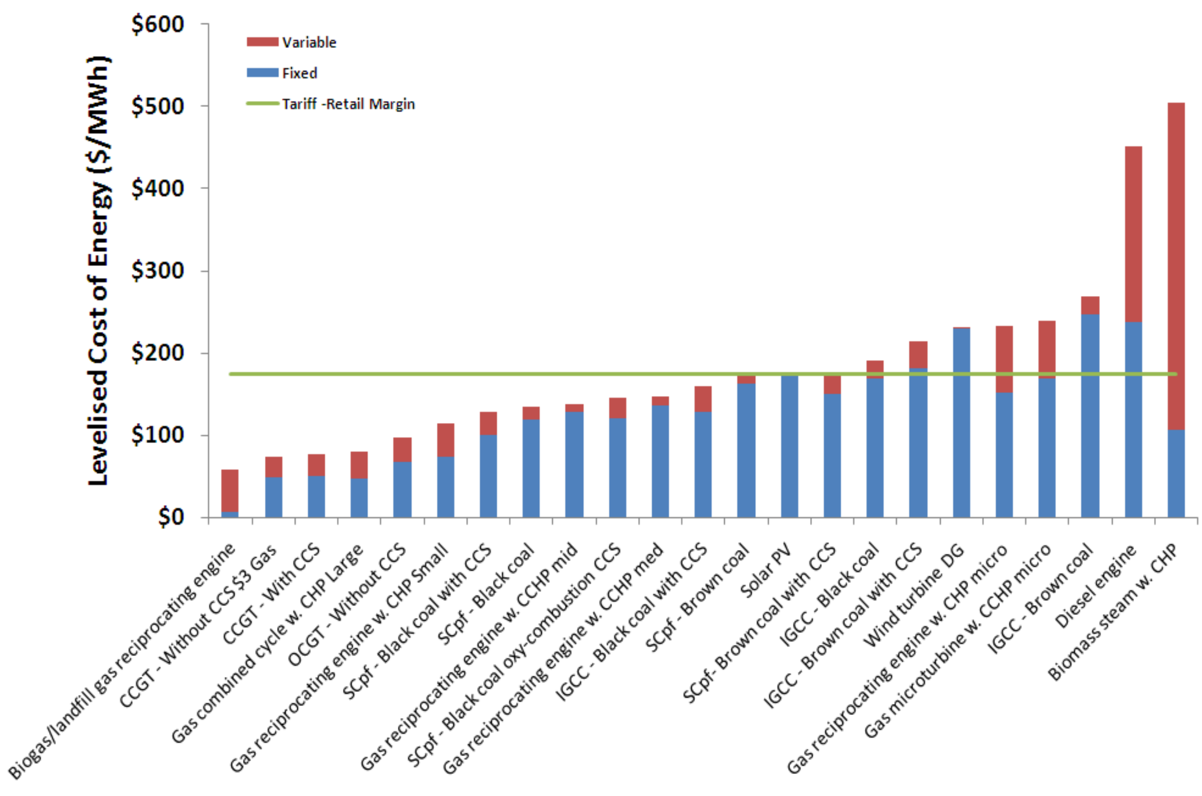

Figure 1-6: Scenario 4, CPRS -25% no DUTO/TUOS

2.3.5 Scenario 5

With the inclusion of DUOS and TUOS into the delivered cost of energy from each technology types we begin to see how the viable options change swiftly in comparison with the previous scenarios.

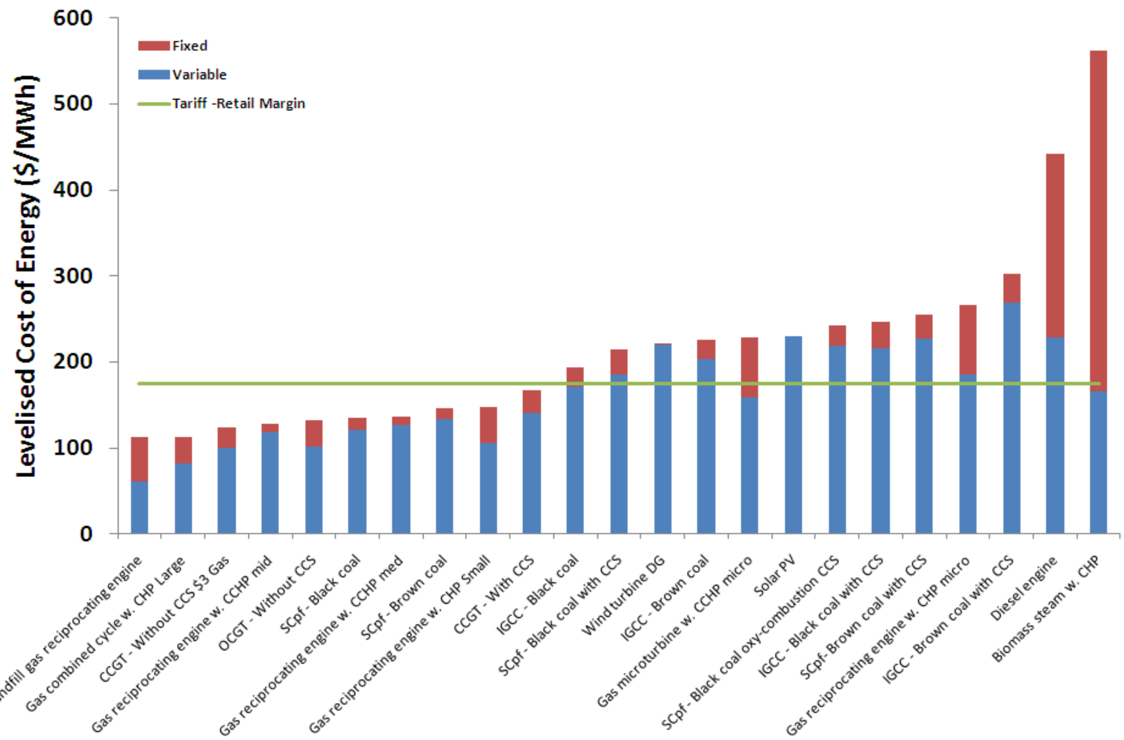

Figure 1-7: Scenario 5, No CPRS with DUTO/TUOS

2.3.6 Scenario 6

Clearly with the introduction of the CPRS with a 5% reduction in emissions and a \$33/t-CO_2 carbon price the rearrangement of the suitable candidates into the possible generation mix is apparent (**Figure 1-8**). The continued presence of biogas/landfill gas technology can be greatly attributed to its eligibility under the Renewable Energy Target (RET), and its zero net emissions intensity factor. Once again its viability is solely dependent on the location of a suitable fuel source. CHP 30MW and CCGT continue to be the best options given the assumptions elucidated previously. Some reciprocating engines would also be expected to be deployed given its lower price relative to the current retail tariff.

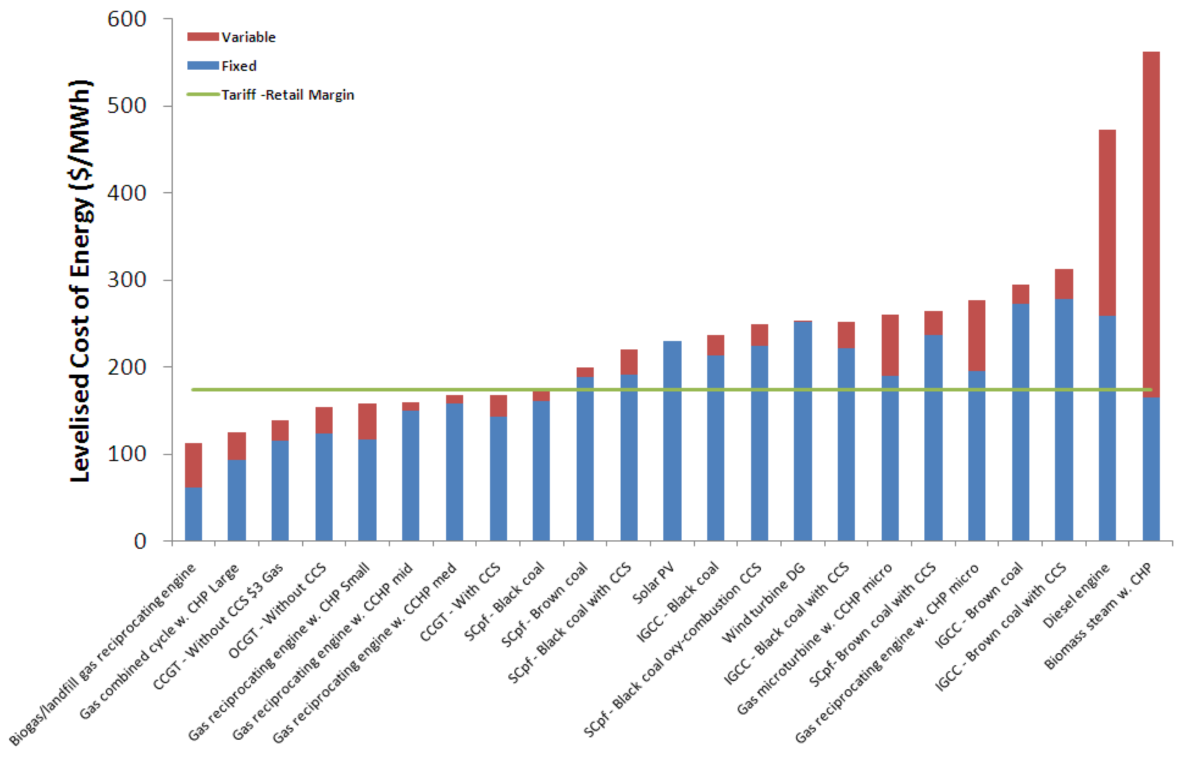

Figure 1-8: Scenario 6, CPRS -5% with DUTO/TUOS

2.3.7 Scenario 7

The imposition of a 15% reduction in emissions and DUOS/TUOS continues to push conventional technologies further away from the interior solution of suitable candidates for deployment. CHP 30MW, Biogas/Landfill Gas, CCGT, OCGT and reciprocating engines move to be the top 5 on possible options for the NEM (**Figure 1-9**). CCS is still a less than desirable option given that it's soonest construction is 2015 [4].

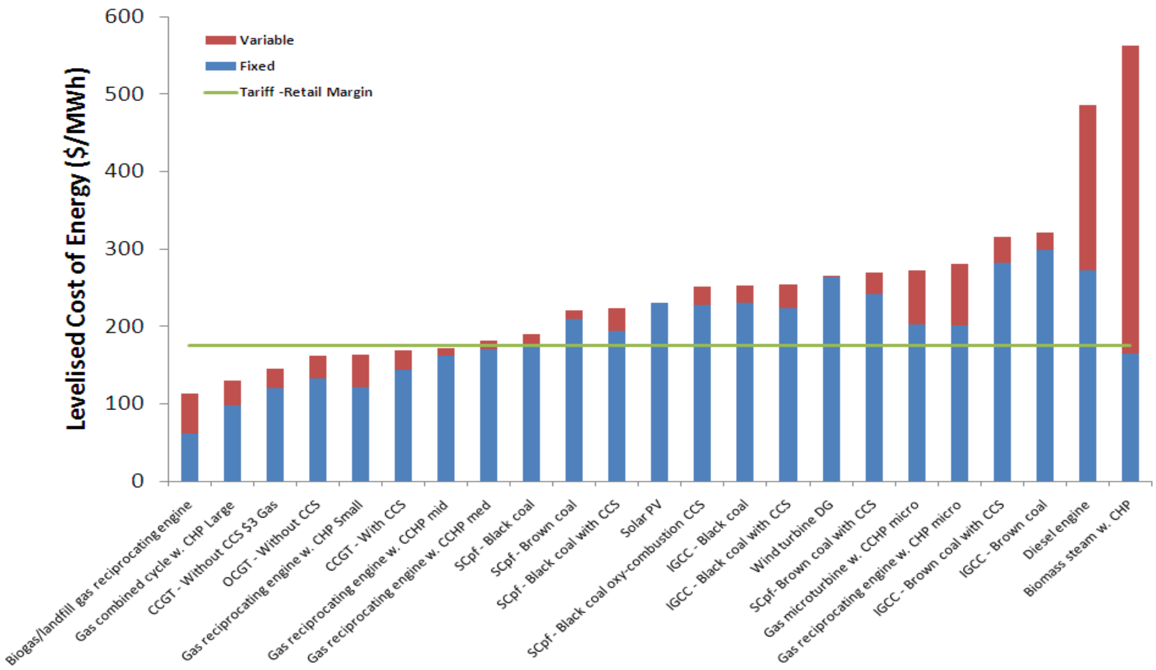

Figure 1-9: Scenario 7, CPRS -15% with DUTO/TUOS

2.3.8 Scenario 8

The final scenario investigates the 25% cut in emissions with the inclusions of DUOS/TUOS and its effects on pricing suitable technology types. The broad scale deployment of CHP 30MW is certainly the most cost effective technology with such a high carbon price (**Figure 1-10**) given the availability of its fuel source. While town gas which this technology would be primarily using at roughly $9/GJ, it certainly takes advantage of being inside the distribution network.

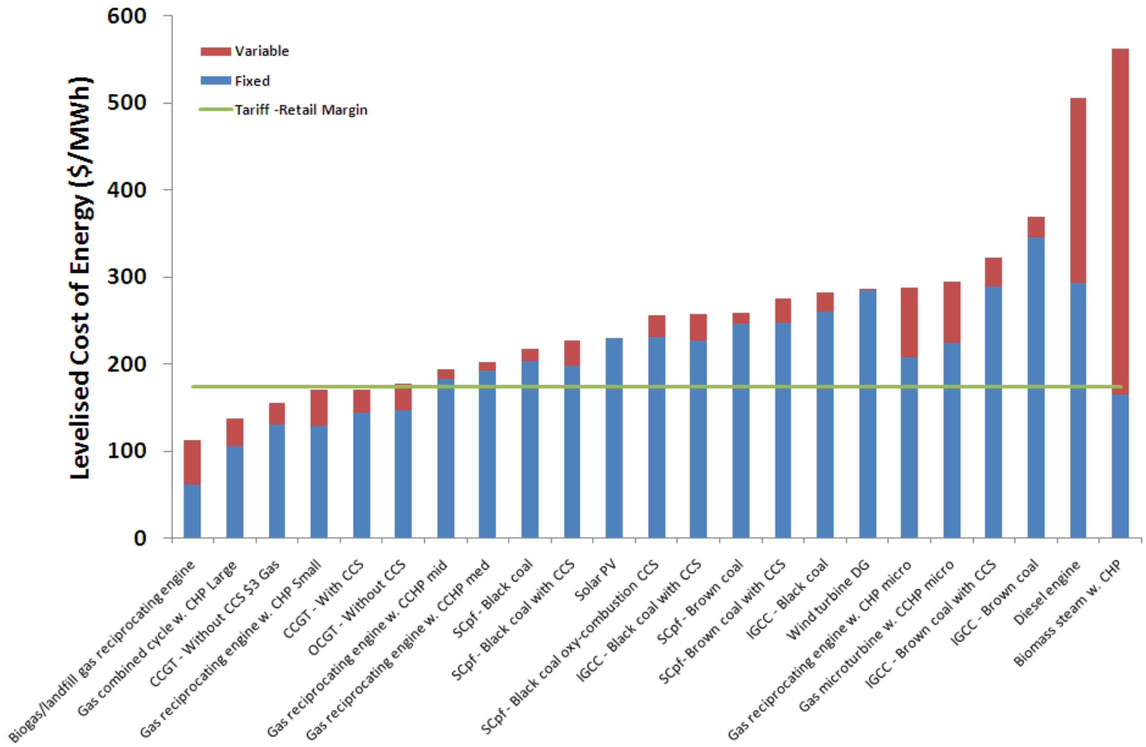

Figure 1-10: Scenario 8, CPRS -25% with DUTO/TUOS

2.4 Conclusion

With the inclusion of all externalities considered in the AEMO NTNDP [4] and DUOS/TUOS into the LCOE it is quite clear that Distributed Generation can clearly compete without a DUOS discount against centralised generation. As has been previously reported in the 2009 Project 2 annual report via Plexos simulations DG is certainly an option which can help deliver significant cuts in emissions and reduce expenditure on transmission network.

This study integrates a wide range of technology types considered previously by the CSIRO [15], AEMO [4] for integration into the NEM. It is quite clear that DG can reduce pressures on retail tariff price rises in Queensland and across the rest of Australia. Further to this study a variety of distribution charge discount rates could be applied to a range of locations to show how DG could be better deployed to meet demand across the NEM.

2.5 References

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Chapter 3: An Assessment of the Impact of the Introduction of Carbon Prices and Demand Side PV Penetration for Calendar year 2007 using the 'ANEMMarket' model of the Australian National Electricity Market (NEM).

3.1 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 of a 'Cap-&-Trade' carbon trading scheme, and more recently, a carbon tax scheme. Many policy initiatives of both the Commonwealth and various state governments in Australia have also promoted the adoption of demand side energy efficiency measures. Among state governments, solar based programs have been particularly prominent, relating principally to measures promoting residential based installation of solar hot water and PV systems through either direct subsidies to households or appropriate residential based gross and net feed-in tariff arrangements. The main effect of many of these demand side initiatives is to effectively shave load during the day.

Why load shaving is important is because the level of carbon emission is directly related to the aggregate level of load that has to be served by aggregate generation. 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 that new renewable technology proposals be incorporated in a model containing many of the existing 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 marginal cost and branch congestion characteristics.

To capture these linkages, an agent based model of the NEM will be employed in this study that utilizes a heuristic framework that can be viewed as a template for operations of wholesale power markets by Independent System Operators (ISO's) using 'Locational Marginal Pricing' to price energy by the location of its injection into or withdrawal from the transmission grid (Sun and Tesfatsion (2007b, p.2)). The Australian model is called the 'ANEMMarket' model and is a modified and extended version of the

'Agent-Based Modelling of Electricity System (AMES)' model of the American system developed by Sun and Tesfatsion (2007a, 2007b).[1]

The 'ANEMMarket' modelling framework was developed with the intension of modelling strategic trading interactions over time in a wholesale power market that operated over realistically rendered transmission grid structures. The wholesale market of the NEM is a real time 'energy only' market, with the market for ancillary services being a separate and distinct market. A DC OPF algorithm is used to determine optimal dispatch of generation plant and wholesale prices within the agent based model. A detailed description of agents and network structures encapsulated within the ANEMMarket model is contained in previous reports and interested readers are particularly directed to CSIRO (2010) for further discussion of these issues.

3.2 Carbon Price and PV Penetration Scenario Modelling – Impact on Dispatch, Congestion, Prices and Carbon Emissions for Calendar year 2007.

In this and following sections, we will use the 'ANEMMarket' model to investigate the consequences of a number of carbon price/PV penetration scenarios for regional load profiles associated with calendar year 2007.

The transmission grid used involved combining the existing QLD, NSW, VIC, SA and TAS modules - see Figures 1-5. The state module linking was via the following Interconnectors: QNI and Directlink linking QLD and NSW; Murray-Dederang linking NSW and VIC; Heywood and MurrayLink linking VIC and SA; and the Basslink linking VIC and TAS. In accordance with the DC OPF framework that underpins the model, the HVDC Interconnectors Directlink, Murraylink and Basslink are modelled as 'quasi AC' links – that is, power flows are determined by assumed reactance and thermal rating values for each of the above-mentioned HVDC 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 QLD, NSW, VIC and SA respectively. The nodal based breakup of load demand, however, often involves splitting up, in geographical terms, aggregative elements of existing distribution networks – for example, the regional based load profiles implied in the nodal structure of the Queensland module would represent the breaking up of the aggregative distribution networks of Ergon and Energex into smaller regional based configurations. However, currently it is not possible to model congestion at the distribution level of the network within the ANEMMarket model. In order to model at the distribution network level, we would require a

[1] Comprehensive information including documentation and Java code relating to the 'AMES' model can be found at: http://www.econ.iastate.edu/tesfatsi/AMESMarketHome.htm. Key differences between the Australian and US models can be found in last year's annual report. Also see AEMO (2009).

significant amount of additional information/data from network service providers such as Energex and Ergon Energy. Furthermore, from the perspective of economic modelling of dispatch/price determination in the wholesale power market, proceeding down to the distribution network level does not make a lot of sense. On the other hand, if the focus is more on engineering based power flow analysis, than going down to the distribution network level would make more sense. However, in this case, a full AC OPF model would need to be used instead of the DC OPF algorithm underpinning the ANEMMarket model and the gresulting power flow analysis investigating such things as transient and steady-state stability would proceed quite differently from the market modelling analysis performed in this Chapter.

The solution algorithm utilised in all simulations involves applying the 'competitive equilibrium' solution. This means that all generators submit their true marginal cost coefficients and no strategic bidding is possible. This type of scenario allows 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, thus leading to the discovery of the lowest overall configuration of Locational Marginal Prices' (LMP) consistent with the nodal location of generators, thermal and other constraints on the transmission network connecting the regional nodes. This strategy directly permits investigation of the true cost and market operator determined dispatch response of different fuel based generation technologies in response to how their true marginal costs changed with carbon price increases and increased penetration of PV on the demand side that is capable of shaving load demand.

We assume that all thermal generators are available to supply power during the year. Therefore, the methodological approach underpinning model scenario runs clearly produce 'as if' scenarios. In particular, we do not try to emulate actual generator bidding patterns for the year in question. Our objective is to investigate how the true cost of power supply changes for the various carbon price/PV scenarios 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 the absence of both a carbon price signal and PV induced load shaving.

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 'non-zero' must run MW capacity levels termed 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 such as N02.

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 year being investigated and they therefore 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. Therefore, 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 gas thermal or combined cycle plant, it was assumed to offer to supply power for a complete 24 hour period – 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 OCGT plant were assumed to only offer to supply power during the day, i.e. from 07:00 – 19:00 hours. 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. It should be noted, however, that these intermediate OCGT plant can run for more than the required must run daily interval mentioned immediately above if they represent the cheapest source of marginal generation. This is likely to arise when carbon prices are relatively high.

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

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. In general, offers by hydro generators could differ depending upon whether the day in question was either a weekday or weekend and whether it arose in summer or winter. The mainland hydro plant was assumed to principally offer capacity in summer. Some plant was also assumed to offer capacity in winter – notably Shoalhaven and some units of Snowy Mountains Hydro in order to be capable of meeting winter peak demand occurring in NSW at night. 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. An example of the assumed availability of hydro plant for weekdays in summer was listed in last year's report, see CSIRO (2010).

The nature of hydro plant supply offers associated with summer weekdays were changed for summer weekends, and for winter. In particular, for summer weekends, the main differences from the summer weekday patterns was associated with typically taking second units such as Wivenhoe (unit 2) or Tumut (unit 2) 'offline' and also taking all of the Southern Hydro/native Victorian fleet 'offline'. For winter weekdays, the QLD and Victorian hydro plant was assumed to be 'offline' while Snowy Mountains operated at greatly reduced capacity, with a few units offering to meet genuine peak demand by bidding

[2] Note that all tables cited in the text will be documented in Appendix A.

capacity at $1000/MWh during winter weekdays. Shoalhaven plant was also assumed to offer capacity between 17.00 and 21:00 hours during winter weekdays in order to help meet winter peak demand arising principally in the Sydney/Wollongong/Canberra areas. For days falling on weekends during winter, all mainland hydro plants were assumed to be offline – e.g., offer their capacity at $10000/MWh.

The following Tasmanian hydro generation units are assumed to meet baseload production duties: Rowallan, Fisher, Lemonthyme, Wilmot, Cethana, John Butters, Tribute, Reece (unit 1), Trevallyn (units 1-2), Poatina (units 1-5), Liapootah (unit 1), Wayatinah (unit 1), Catagunya (unit 1), Repulse, Butlers Gorge, Lake Echo, Tungatinah (units 1-3), Tarraleah (units 1-3), Meadowbank and Gordon (units 1-3). Other units offer backup to this baseload configuration. An example of the assumed availability of

Tasmanian hydro plant for weekdays in summer was listed in last year's report, see CSIRO (2010). Similar types of offer patterns were also adopted for winter week days and with some reduction in offered capacity occurring for summer weekends and winter weekends.

For pump-storage hydro units such as Wivenhoe and the Shoalhaven units, the pump mode was activated in the model by setting up a pseudo LSE located at the Morton North and Wollongong nodes, respectively. In the case of Wivenhoe, each unit can generate power for up to 10 hours and then has to implement pump action for 14 hours in a 24 hour period. This was implemented by having each hydro unit act as a pseudo LSE and demand (purchase) 240MW of power per hour over a fourteen hour period in the 24 hour period. The combined load requirements for pump actions of all Wivenhoe and Shoalhaven hydro units were combined into a single load block for each respective pseudo LSE. For the Shoalhaven scheme, the pump action requirements matched the generation patterns. In both cases, the pump actions are assumed to occur in off-peak periods when the price (cost to hydro units) of electricity should be lowest.

It should also be noted that pump storage hydro unit supply offers was based upon short run marginal cost coefficients to ensure that dispatch occurred in a synchronised manner with pump actions. For all remaining hydro plant, hydro generator supply offers were based on long run marginal cost coefficients. These coefficients take into account the need to meet fixed costs including capital and operational expenses and are often significantly larger in magnitude than corresponding short run marginal cost coefficients. For example, estimates of long run marginal cost for hydro plant range from around $18/MWh to over $70/MWh, thus broadly lying in a range that shadows the short run marginal costs coefficients used in supply offers of coal, intermediate and even peak gas plant.

A key consideration in the decision to use long run marginal cost coefficients to underpin supply offers of hydro generation plant also reflects the large predominance of such generators operating in Tasmania. With the absence of other major forms of thermal based generation in Tasmania, limited native load demand and export capability into Victoria, it was likely that nodal pricing based on short run marginal costs in Tasmania at nodes other than George Town would not be sufficient to cover operational and capital expenditure confronting generators, on average. Supply offers based on long run marginal costs, however, should ensure that average price levels are sufficient to cover these costs over the lifetime of the hydro plant's operation.

We also assumed a social (environmental) water cost of $1/ML in deriving both short and long run marginal costs of hydro plant. Thus, hydro plant that requires less water to produce a MW of power will be less costly than competing hydro generators that have to use more water to produce a MW of power. This social cost consideration will be especially relevant to the dispatch of hydro plant in Tasmania with 'least cost' hydro plant typically being those units which have the highest head such as Poatina, for example. We also assumed that the minimum stable operating capacity for all hydro plant is 0 MW and that no start-up costs are incurred when the hydro plants begin supplying power to the grid. Hydro plant is also assumed to have very fast ramping capability.

The dispatch of thermal plant was optimised around the above assumed availability patterns for the specified hydro generation units. For modelling purposes, all other hydro generation units were assumed to not be available to supply power (e.g. were 'offline').

In the next section, we will briefly outline how we modelled the impact of increased PV penetration within the NEM, focusing particularly on the load shaving consequences of this penetration and implications for dispatch and price determination within the wholesale electricity market.

3.3 Design Implementation of Modelling Increased PV Penetration.

The implementation of the PV scenarios outlined in this section is modelled in terms of their potential to generate the shaving of load at particular nodes containing a capacity to both support a high level of residential or commercial based PV penetration as well as having a significant load component in their own right. Because of the favourable treatment given in many Australian States to residential based PV take-up when compared, for example, to commercial based PV take-up, we have applied different load shaving scenarios to the major metropolitan nodes in the model – namely, Moreton North and Moreton South (Greater Brisbane), Sydney, Melbourne/Geelong and Adelaide. We have not applied these load shaving scenarios to nodes containing large industrial load components such as Gladstone and Newcastle.

It should be noted that in implementing the scenarios, no explicit account was taken of the cost of the PV panels and associated systems. This decision reflects the fact that the demand side participants modelled in the ANEMMarket model are LSE's who submit aggregated regional or nodal based load profiles representing power purchased from generators in the wholesale market and who then sell (supply) power purchased in wholesale market to downstream residential, commercial or industrial customers. In the Australian context, such agents would include AGL and Origin, for example. It is the downstream residential or possibly commercial customers of companies such as AGL or Origin who would be responsible for meeting the costs of PV system installation. Because these retail based agents are not explicitly modelled, these PV related costs are not explicitly examined. Thus, while the profit position of LSE's would be affected by such things as 'feed-in-tariff' liabilities, partial or full extinguishing of REC's liabilities and payments received from customers from fixed term re-payment schemes for PV system installation, the direct costs of PV installation will not affect the LMP's in the model per se. However, the extent of load shaving produced by the level of PV penetration would. The load to be served, generator marginal costs, thermal limits, ramping constraints of generators and thermal constraints on branch flows principally affect LMP's in model scenario runs.

The particular summer and winter PV based load shaving scenarios that were implemented in the various scenarios are outlined in Table 3, Panel A and B, Appendix A.[3] It is evident from inspection of Table 3, Panel A that in summer the load shaving is assumed to begin at 06:00 hours and accelerates over the period 06:00 to 10:00 when the full load shaving capability is assumed to be reached. This full rate of load shaving continues until 15:00 and then begins to taper off over the period 15:00-19:00 at rates equivalent to the rate of increase assumed for the earlier period 06:00-10:00. The assumed pattern is somewhat different for winter. In this case, it is evident from inspection of Table 3, Panel B that in winter the load shaving is assumed to begin at 07:00 hours and accelerates over the period 07:00 to 10:00 when the full load shaving capability is assumed to be reached. This full rate of load shaving continues until 14:00 and then begins to taper off over the period 14:00-17:00 at rates equivalent to the rate of increase assumed for the earlier period 07:00-10:00. Thus, load shaving potential in winter is characterised, when compared to summer, as starting later and finishing earlier and with the full load shaving potential occurring for a smaller number of hours over the middle of the day. Thus, the load shaving potential has been compressed in both extent and duration.

The various hourly factors listed in Columns 2 to 7 of both panels of Table 3 are multiplied on an hour-by-hour basis with the actual hourly MW fixed load values determined for the major metropolitan nodes mentioned above. Column 2 is the BAU scenario involving no PV based load shaving. The actual hourly load values used in this scenario are multiplied by unity and thus are unchanged. The factors listed in columns 3-7 of both panels for hours 06:00 to 19:00 and 07:00 to 17:00 respectively, are less than one in magnitude and are used to implement the load shaving (reduction) by reducing the load at the major metropolitan nodes when multiplied with the original (BAU) fixed load values.

It will be recognised from inspection of Table 3 that the load shaving takes a particular form that is thought to be well suited to solar based applications, whether solar PV or solar thermal. This follows because of the particular shape of load shaving potential - load shaving commences early in the morning, gradually increasing over mid-morning and then reaches it maximum potential over the middle portion of the day before tailoring off during mid-afternoon and completing dying out during late afternoon. This pattern is well linked to expected solar insolation and temperature patterns observed during the day.

While the values listed in Tables 3 are hypothetical, they display the general shape that would be expected. Furthermore, we can also expect a direct relationship between the load value and temperature/brightness during the day that would be linked to increased levels of power demand for particularly refrigeration and cooling within both the residential and commercial sectors. Thus, in

[3] For purposes of model scenario runs, summer is defined to occur from 1 January to 21 may 2007 and from 17 September to 31 December 2007.

summer, in particular, conditions leading to higher levels of load demand could also be expected, in principle, to be conducive to generation of solar power whether by PV or solar thermal technologies. The converse is also the case. During particularly cloudy or rainy days, the overall level of power demand would be expected to be lower because of the reduced power requirements needed to support refrigeration and cooling activities. In this case, the temperature/insolation characteristics would also produce lower solar power generation. Therefore, applying the load shaving factors in Table 3a to higher (lower) levels of demand would similarly produce higher (lower) levels of load shaving that would be automatically well matched to the underlying solar power generation potential. This relationship would become less clear during winter when increased power levels during the day could also reflect increased power demand for heating (instead of refrigeration) which would be expected to be inversely related to current solar power generation potential. However, it should also be recognised that peak demand during winter would be expected to fall at night and be associated with the demand for heating.

If actual time series insolation and temperature data were available together with data on actual PV take-up in major urban areas and appropriate PV or solar thermal efficiency curves, then, in principle, it would be possible to calculate the actual extent of load shaving that would occur. This value would equate with the amount of power that is being generated on a gross output basis. For net output determination for net feed-in-tariff scheme calculations, further assumptions would have to be made about auxiliary load (e.g. internal power usage).

In the simulations, the shape or incidence of load shaving is the key. In principle, if other load control or energy efficiency measures could replicate this shape during the day, then their consequences could also be reflected in model results. However, to the extent that other direct load control, energy efficiency or other demand side measures produce a different shape than that implied in Table 3, then their consequences will not be captured by model results. This will be the case, for example, where the impact of load control or deferrable efficiency measures is to shift load from day to off peak periods at night, as associated, for example, with conventional 'ripple control' systems.

It will also be recognised that the rates of load shaving associated particularly with PV scenarios D and E of 15% and 20% appear quite extreme and are most likely beyond levels that could be attributed to a purely residential based PV scheme. In order to get a better perception of this possibility, the hourly MW values associated with load shaving was recorded during the scenario runs and both the average and maximum hourly MW level of load shaving for 2007 was identified for each load shaving scenario identified in Table 3. Our objective is to determine the number of representative PV systems that would be needed to achieve both the average and maximum levels of hourly load shaving under each load shaving scenario. The representative system chosen for the residential PV system is a 1.5KW system and we investigate the number of such units that would have to be installed for assumed average output levels for the PV system ranging from 800 watts to 1600 watts in increments of 200 watts. These results are listed in Table 4, Panels A-E for average hourly MW load shaving values and in Table 5, Panels A-E for maximum hourly MW load shaving values obtained for Calendar year 2007 - see Appendix A

The information contained in these tables can be interpreted as follows. The second row in each table gives the MW value of average or maximum hourly level of load shaving identified by the program for each respective load shaving scenario for Calendar year 2007. Note that the average value was calculated over non-zero load shaving values – zero load shaving values associated with night, for example, were excluded when calculating the average value. In the third row, this MW value is converted to a watts basis by multiplying the MW value in row two by one million. The last five entries in the first column (e.g. 800 to 1600) refer to the assumed average watt output of the representative residential PV system (i.e. 1.5KW system) and denote 800 watts to 1600 watts in increments of 200 watts. For tables relating to the maximum hourly load shaving results (e.g. Table 5), we restrict the assumed average watt output to the range 1200 to 1600 watts because the incidence of this result would occur when conditions are very

conducive to solar power generation and would be associated with PV system output levels at the upper end of the assumed range adopted in Table 4 for average load shaving values.

The number of PV units (systems) that have to be installed to achieve the MW level of load shaving is then calculated for each capital city by dividing the watt output values listed in row three by the assumed average watt output of the PV system listed in the last five entries of column 1 in Panel A of Table 4, for example. Therefore, in Table 4, Panel A, corresponding to '2% PV_A' load shaving scenario, and assuming an average output of 800 watts for the representative residential PV system, the number of PV systems that would need to be installed in Brisbane to meet the load shaving level is 40,481 which is determined by dividing 32384533 by 800. Similarly, for an assumed average PV system output of 1400 watts, the number of representative 1.5KW PV systems that would need to be installed in Melbourne to meet the load shaving value of 53.77 MW is 38,405 units, being calculated as 53766559/1400.

It is apparent from inspection of all panels in Table 4 that very large numbers of representative residential PV systems would be needed to be installed to even meet the rather modest 2% load shaving values listed in Table 4, Panel A. For example, for Brisbane, depending upon the assumed output of the representative PV system, we would need between 20,240 and 40,481 installed PV systems. These figures are even larger for Sydney and Melbourne/Geelong which need between 33,309 and 67,208 systems to meet average MW load shaving values of 53.29 MW and 53.77 MW, respectively. Because of the smaller load base, Adelaide would need between 9,143 and 18, 287 installed representative PV systems.

It is also apparent from inspection of Panels A to E of Table 4 that the number of individual representative PV systems that need to be installed grows significantly as the level of load shaving is increased with the move from PV_B (5%) through to the PV_E (20%) load shaving scenario. For example, for scenario PV_B (Panel B), for Brisbane, the range of numbers of installed systems have increased from 20,240 – 40,481 associated with PV_A (Panel A) to the range 50,647 – 101,294. Similarly, for scenarios PV_D (15%) and PV_E (20%) listed in Panels D and E of Table 4, for Melbourne/Geelong, the range of numbers of installed systems have increased from 33,604 – 67,208 associated with PV_A (Panel A) to 256,937 – 513,873 for PV_D (Panel D) and 347,397 – 694,794 for PV_E (Panel E). This reflects the marked increase in the MW value of average hourly load shaving which increased from 53.77 MW associated with PV_A (Panel A_) to 411.10 MW for PV_D (Panel D) and 555.83 MW associated with scenario PV_E (Panel E) of Table 4.

In the case of maximum hourly load shaving results obtained for 2007 that are cited in Table 5, the number of PV systems becomes even larger. In the case of the PV_A(2%) scenario for Brisbane, there has been an increase from the range 20,240 – 40,481 associated with average hourly load shaving results in Table 4, Panel A to a range of 50,045 to 66,727 installed PV systems for maximum hourly load shaving case listed in Table 5, Panel A. This reflects the increase in MW value of the average hourly load shaving from 32.38 MW in Table 4, Panel A to an observed maximum hourly MW load shaving value in 2007 of 80.07 MW cited in Table 5, Panel A. Assessment of results listed in Table 5, Panels A-E show a marked increase in required number of installed PV systems when compared with the comparable figures in Table 4, Panels A-E, with these results being produced by the increase in MW values associated with maximum hourly values listed in Table 5 when compared against the smaller MW values associated with average hourly load shaving values reported in Table 4.

It is clearly evident that required numbers of installed residential type PV systems in the hundreds of thousands or even millions (e.g. see results in Panel E of Table 5) associated particularly with Scenarios PV_C (10%) – PV_E (20%) clearly indicate the severe limitations that residential based PV schemes will exhibit in driving deep cuts in load demand as represented in the load shaving scenarios. If deep cuts are desired and are to be obtained in an attempt to curb growth in electricity demand and carbon emissions, then it is evident that commercial scale PV installation or embedded solar PV or thermal generation would be needed. To investigate this issue, we have investigated a scenario where residential PV is only depended upon to achieve 10% of the MW load shaving values implied in both the average and maximum hourly values underpinning the results cited in Tables 4 and 5 above. The remaining 90% is assumed to be obtained from commercial scale PV installation. Our representative commercial scale PV system is assumed to be a 1 MW PV system that would be capable of being installed on large commercial buildings such as factories and shopping centres, for example. Note that the modelling proceeds in the same way as in the case of the representative residential PV system except that now we assume that the average output levels for the commercial scale PV system ranges from 0.8 to 1.2 MW in increments of 0.2 MW. These results are listed in Table 6, Panels A-E for average hourly MW load shaving values and in Table 7, Panels A-E for maximum hourly MW load shaving. These tables are also listed in Appendix A.

It is apparent from inspection of Table 6, Panel A – Residential PV, that for the PV_A (2%) scenario, the total load shaving MW values that are to be met by residential PV has been reduced significantly. For example, there has been a reduction from 53.29 MW for Sydney in Panel A, Table 4 to 5.33 MW in Table 6, Panel A. Closer examination of row 2 in both Panels indicate similar reductions for the other cities listed in these tables. This has produced a marked reduction in the number of installed residential PV systems that are needed to achieve the reduced MW load shaving values. For example, the range recorded for Brisbane in Table 6, Panel A is now of the order of 2,024 to 4,048 installed units, instead of the range 20,240 to 40,481 units listed in Table 4, Panel A. Similar types of reductions have also occurred for Sydney and Melbourne, falling from ranges of 33,309 – 66,617 and 33,604 - 67,208 respectively in Panel A, Table 4 to ranges in the order of 3,331 – 6,662 and 3,360 – 6,721 in Table 6, Panel A.

This particular trend has also continued in relation to the other load shaving scenarios as indicated in Panels B-E, Table 6 – Residential PV tables. For example, in relation to PV_D (15%) and PV_E(20%) scenarios, the MW value of the load shaving has declined from 407.15, 411.10, 550.53 and 555.83 MW respectively for Sydney and Melbourne (see row 2, Panels D and E, Table 4) to 40.71, 41.11, 55.05 and 55.58 MW (see row 2, Table 6, Panels D and E). This produced falls in the required number of installed PV units for Sydney for scenario PV_D from the ranges of 254,468 – 508,936 to 25,447 – 50,894 and from 344,084 – 688,168 to 34,408 – 68,817 for scenario PV_E, respectively. The large fall in the number of required residential PV systems to be installed from hundreds of thousands to tens of thousands makes this option more of a realistic proposition. This conclusion also broadly extends when maximum hourly load shaving values are substituted for average hourly MW load shaving values that underpin the results cited in Table 7, Panel A-E. For example, in the cases of scenarios PV_D and PV_E cited in Table 7, Panels D and E – Residential PV, for Sydney, the reduction in number of installed PV systems has fallen to the range encompassing 59,210 – 78,946 and 78,946 – 105,261. While these numbers are still quite large in magnitude, they are nowhere near the extremely large values cited in Table 5, Panels D and E which broadly fall in the range of half a million to million installed units in Sydney alone.

With the large fall in the number of required residential PV systems, it then falls on commercial PV to achieve the bulk of the load shaving with average hourly MW values confronting commercial POV being in the order of 13.17MW for Adelaide to 48.39 MW for Melbourne for scenario PV_A – see row 2, Panel A of Table 6 - Commercial PV. It is evident from inspection of this table that it takes a much smaller number of commercial PV units to achieve the load shaving results because of the larger output of the commercial scale representative 1 MW PV system. Depending upon the assumed output of the commercial array, for Brisbane, the number of commercial units is in the range of 24 to 36. Similarly, for Sydney and Melbourne, the number of installed commercial PV systems needed to achieve load shaving of 47.96 MW and 48.39 MW are in the range of 40 – 60 commercial PV units. These numbers increase with the degree of load shaving, but even in the case of the more aggressive load shaving scenarios corresponding to PV_D and PV_E scenarios, the required load shaving in the range of around 370 MW and 500 MW, for Melbourne, for example, can be broadly met by a number of commercial scale PV systems in the range of 308 to 462 and 417 to 625 units – see Panels D and E of Table 6. These range of numbers increase when the analysis is based on maximum instead of average hourly load shaving values. For example, it is evident from assessment of Panels D and E of Table 7, for Melbourne, we get an increased range of 711 to 1,066 and 947 to 1,421 installed units to meet the increased hourly load shaving values of 877MW and 1169MW respectively, depending upon assumption made about the output of the commercial PV system.

While we have couched our analysis of commercial scale response in terms of PV systems, other potential solar based responses would also be possible within this framework. In particular, apart from small scale commercial PV involving 1 MW PV systems, broader scale solar PV or thermal based generation, perhaps embedded within appropriate distribution networks, could also play a similar role to that envisaged being played by small scale commercial PV systems. Given the relatively large MW values associated with the PV_C, PV_D and PV_E scenarios encompassing values for Sydney and Melbourne in the range 568 MW to 1170 MW, when based on maximum hourly load shaving values, a combination of embedded large scale solar PV or thermal generation and small scale commercial PV take-up could work together to achieve these more ambitious targets in conjunction with residential based PV.

It will certainly be the case, however, that some combination of embedded solar based generation and/or commercial PV take-up would be needed to achieve the large degree of load shaving associated with the PV_C to PV_E load shaving scenarios, in particular. It is also very clear that residential based PV cannot be expected to achieve significant load shaving affects in its own right.

In subsequent sections, we examine the consequences of various carbon price/PV penetration scenarios on dispatch patterns, average spot prices, branch congestion, system wide variable costs and reductions in carbon emissions when compared against a 'business-as-usual' (BAU) baseline scenario involving no carbon prices or PV based load shaving.

3.4 Investigation of the Impact of Increased PV Penetration in the Absence of Carbon Prices.

In this section, we will examine the effects of different levels of PV based demand side penetration in the absence of a carbon price signal. In following sections, we will examine the consequences of combined carbon price/PV penetration scenarios which will enable us to investigate the likely consequences of simultaneously pursuing both supply and demand side initiatives in an attempt to curb carbon emissions accruing from the NEM.

The first set of results associated with the PV scenario implementation is listed in Table 8, Panel A and Table 9, Panel A, Appendix A and relates to the average annual price levels and percentage change from BAU associated with the BAU and PV scenarios listed in Table 3 that were obtained for the various states and NEM as whole.

In Tables 8 and 9, the average annual price level and PV based percentage reductions from BAU are outlined. The most noticeable feature of Table 8, Panel A is the marked difference in average price levels in NSW and VIC when compared to the other states.[4] Victoria has the highest annual average BAU price level of $88.89/MWh, followed by NSW with $85.13/MWh - average annual BAU price levels which are significantly higher than the average annual price levels of the other states. Inspection of the table indicates that Queensland has the lowest BAU average annual price level of $16.36/MWh, followed by South Australia with $23.87/MWh and then Tasmania with $33.60/MWh – see row 2 of Panel A, Table 8. Note the higher average price level for Tasmania in this study when compared with those cited in CSIRO(2010) which can be attributed to the assumption made in this current study to base the supply offers of Tasmanian hydro plant on long run marginal costs instead of short run marginal costs. The BAU

[4] Of course, these results depend crucially upon modelling assumption adopted. In this context, increasing ramping capability of coal plant within the model, for example, could potentially affect model results significantly.

average annual price level for the NEM as a whole of $52.71/MWh is influenced by the relatively high average annual price levels obtained for NSW and VIC.

The significantly larger average price levels reported for both NSW and VIC point to the power systems of these two states facing the dispatch of more costly forms of generation, at the margin, to meet load demand. For example, the average price results cited in row 2, Panel A of Table 8 indicate that on average over Calendar year 2007, the cost of meeting the last MW of power demanded in NSW and VIC was over five times more expensive than in QLD, was over three and a half times more expensive than in SA and over two and a half times more expensive than in Tasmania. This broad finding was also found to not be conditional on the decision to dispatch the hydro plant located at the Tumut, Murray and Dederang nodes in accordance with their long run marginal costs.

It is apparent from examination of Panel A of Tables 8 and 9 that the average annual price levels for Calendar year 2007 become lower as the level of PV penetration is increased. Therefore, increased PV penetration has the general effect of reducing average price levels within each state and across the NEM as a whole. This overall trend reflects the fact that as the PV induced level of load shaving increases, less aggregate load has to be serviced by aggregate generation and can be accommodated, at the margin, by competing forms of cheaper generation positioned lower on the generation merit order.

It is evident from examination of Table 9, Panel A that greater declines in average annual price levels occur for NSW, VIC and SA (see columns 3, 4 and 5). For example, examination of the last row of this table indicates that the PV_E(20%) load shaving scenario produced a reduction in annual average prices from BAU of 19.28% for NSW, 20.01% for VIC and 27.12% for SA. This contrasts with the much smaller rates of decline of 1.94% and 3.75% experienced in QLD and TAS. For the NEM as a whole, the PV_E scenario produced an overall decline in average annual prices from BAU of 16.78% - a sizeable reduction. In some respects, these outcomes reflect the higher concentrations of load (and subsequent reduction in load) associated with the Melbourne/Geelong and Adelaide nodes when compared with the situation in QLD and NSW. Specifically, load demand in QLD and NSW is more regionally dispersed than is the case with Victoria and SA, in comparison. Furthermore, given the more costly generation that seems to be required, at the margin, to serve load in NSW and VIC, greater potential benefits are likely to accrue to these states with load shaving inducing some amelioration of these cost pressures. For example, the results cited in row 6 of Table 8, Panel A indicate that the PV_E (20%) scenario has resulted in the cost of meeting the last MW of power demanded in NSW and VIC dropping to under four and a half time more expensive than in QLD, increasing slightly to being just over four times more expensive than in SA and dropping to be just above two times more expensive than in Tasmania – improvements over BAU in the competitive position of NSW and VIC relative to QLD and TAS, but a slight deterioration relative to SA. The latter result for SA is not unexpected given that this state recorded the largest overall percentage decline in average annual prices relative to BAU for the PV_E scenario although not necessarily for the other load shaving scenarios. For the other scenarios, both NSW and VIC experienced greater percentage declines in average annual prices than SA.

Information on aggregate annual dispatch by state and type of generation is outlined in Panels A of Tables 10-13, Appendix A. In these tables, we present information on dispatch patterns relating to coal, gas and hydro based generation and aggregate state-based generation that was observed in relation to the BAU and PV scenarios considered in this section. Recall that the PV penetration scenarios effectively reduce the level of aggregate load that has to be served by aggregate generation by shaving load at key metropolitan nodes. As such, we would expect these scenarios to effectively move the 'marginal' generator required to serve this reduced load down the generation merit order, thus displacing more costly plant that might have been previously dispatched at the margin.

In determining the values listed in the tables, the (MW) values listed in Panel A in the second row [corresponding to the ($0, BAU) scenario] were determined by summing hourly MW production level time series produced by the model for each individual generator located at a node within each state module over the yearly dispatch horizon. The aggregate generation type and state figures listed in the tables were then obtained by summing the former figures across all relevant generators and generator types located within the state module in order to calculate the aggregate state MW production totals for the year. The NEM aggregate (in column 7) was then calculated by totalling the respective state aggregate MW totals by generation type and aggregate production levels.

The percentage change results listed in the latter rows of Panel A, Tables 10-13 were calculated by once again calculating state and NEM aggregate production levels for each relevant PV scenario and then expressing this in terms of its percentage change from the BAU levels calculated previously and documented in row 2 of the tables.

In Table 10, we present the results for coal fired generation for each state and the NEM as a whole. It is apparent from inspection of Panel A of this table that increased PV penetration produces a decline in aggregate levels of coal fired production across all states (ignoring TAS) and the NEM. VIC experiences the smallest rate of decline, followed by QLD, then NSW and finally SA. This matches the findings presented in last year's report although the rates of decline cited in Panel A of Table 10 are of a lower order of magnitude than those cited in the previous year's report, see CSIRO (2010).

In Panel A of Table 11, we present the results for natural gas fired generation for each state and the NEM as a whole. It is apparent from inspection of this table that increased PV penetration produces a decline in aggregate levels of gas fired production across all states and for the NEM as a whole. Inspection of Panel A indicates that TAS experiences the biggest decline, albeit from a very small base. VIC experiences the next largest rate of decline followed by NSW, SA and then QLD. In the case of VIC and NSW, the decline would principally reflect the displacement of gas fired generation with cheaper coal fired generation in the presence of load shaving arising in both the Sydney and Melbourne nodes associated with the PV scenarios. The decline observed in relation to SA would also depict similar displacement patterns of gas fired generation associated with load shaving at the Adelaide node with cheaper forms of gas fired generation within SA primarily located at the Adelaide node.

We present the results for hydro based generation for each state and the NEM as a whole in Table 12. For accounting purposes, in determining hydro production levels for NSW and VIC, we have split the hydro plant associated with the Snowy Mountains hydro scheme and allocated all hydro plant located at the Tumut node to NSW and all hydro plant located at the Murray node to VIC.

It is evident from inspection of Panel A of Table 12 that hydro-based generation production levels decline in NSW, VIC and TAS and for the NEM as a whole. Note that SA has no hydro based generation. For QLD, the hydro based production level (particularly associated with Wivenhoe pump storage plant) remains unchanged. For the other states (NSW, VIC and TAS as well as the NEM as a whole), aggregate hydro production seems to declines generally in line with the reduction in load demand associated with PV induced load shaving. The greater degrees of decline associated particularly with NSW and to a less extent VIC is related to the decision to dispatch hydro plant located in the Tumut and Murray nodes according to long run marginal costs. This had the effect of moving them up the generation merit order. With the subsequent reduction in load to be served in both NSW and VIC that is associated with the load shaving scenarios, then these generators are likely to be dispatched much less intensively.

The aggregate MW production levels and declines from BAU for each state and the NEM as a whole are listed in Table 13, Panel A. These results essentially combine all the results listed previously in Panel A of Tables 10-12 and broadly match the patterns observed in these tables – especially the patterns appearing in Table 10 for QLD, NSW and VIC and in Table 11 for SA, reflecting the dominance of coal fired generation in the former states and gas fired generation in SA. Specifically, VIC experiences the smallest rate of decline which principally reflects the location and significant MW capacity of cheap brown coal fired generation within that state, in the absence of a carbon price. The state with the next smallest rate of decline in production is QLD with this again principally reflecting the location of a newer, more efficient and much cheaper fleet of black coal fired plant. This situation can be contrasted with that confronting NSW and SA which has an older and more costly black coal generation fleet and experiences some displacement of production from increased exports from VIC in the case of NSW in particular. The patterns observed for TAS match those patterns discerned in Table 12 in relation to TAS hydro generation.

The percentage change in emissions from BAU levels associated with the PV scenarios are outlined in Panel A, Table 14, Appendix A. The BAU baseline was determined by summing hourly C02 emissions time series produced by the model for each individual dispatched generator located at a node within each state module over the yearly dispatch horizon. The aggregate state figures were then obtained by summing the former figures across all generators within the state to calculate the state aggregate emission totals for the year. The NEM aggregate was then calculated by totalling the aggregate state emission totals.

The percentage change results associated with the PV scenarios are listed in the latter rows of Table 14, Panel A and were calculated by once again calculating state and NEM aggregate emission levels for each relevant PV scenario and then expressing this in terms of its percentage change from the BAU levels calculated previously. It is apparent from examination of Table 14, Panel A that the PV scenarios produce both state and NEM level reductions in aggregate carbon emission when compared with the BAU carbon emission levels. For example, for the NEM as a whole, it is evident that PV_A, PV_B, PV_C, PV_D and PV_E scenarios produce percentage reductions in total carbon emissions of 0.26%, 0.62%, 1.37%, 2.11% and 2.93%, respectively – see the last column of Table 14, Panel A. Thus, demand side initiatives promoting the take-up of PV that has a demonstrable load shaving effect will actively contribute towards the policy goal of curbing carbon emissions from the power generation sector. This outcome is expected because of the reductions in MW production levels in coal and gas fired generation outlined in Tables 10 and 11, in particular, and which would produce corresponding reductions in carbon emissions.

From inspection of Table 14, it is apparent that first, there are some carbon emissions produced in Tasmania from gas fired power generation. Second, the lowest rate of decline in emissions is experienced in VIC. This reflects the prominence of brown coal fired generation in this state which has the largest carbon footprint of the competing thermal based generation technology types considered in the model.

The rate of emission reductions in QLD is also lower than the corresponding rate in NSW. This reflects the fact that the black coal plant in QLD is newer, cheaper and has superior thermal and carbon footprint characteristics when compared with the older black coal fired generation fleet in NSW. The larger emission cuts associated with SA would also reflect observed production cuts in black coal and gas fired generation listed in Tables 10 and 11 for SA.

3.5 Investigation of the Combined Impact of a Various Carbon Price and PV Penetration Scenarios.

A number of carbon price scenarios will be investigated in this section with the scenarios involving \$30/tC02, \$50/tC02 and \$70/tC02 carbon prices. The carbon price scenarios investigated will also involve examining the impact of a 'Business-As-Usual' (BAU) environment involving a carbon price but with no PV penetration. For example, for a carbon price of \$30/tC02, the 'carbon price but no PV penetration' scenario will be indicated by the expression '(\$30, BAU)' in the analysis below. Subsequently, other scenarios will be examined that involve a combination of both a carbon price signal one of the various PV penetration scenarios that were defined in Table 3. These will be indicated by the expression (\$cp, PV_A).[5] For example, the combined scenario involving a \$30/tC02 carbon price and PV_B load shaving scenario would be expressed as (\$30, PV_B). These combined scenarios will be assessed against the (\$cp, BAU) scenario mentioned above in order to identify the impact of load shaving at the given carbon price level.

In order to assess the pure effects of the introduction of the carbon price signal, the (\$cp, BAU) scenario will be assessed against the BAU scenario used in the previous section which involved no carbon price signal (e.g. \$0/tC02) and no PV penetration. This latter scenario is indicated by the expression '(\$0, BAU)' in the analysis below.

[5] Note that the term \$cp equates to the following carbon price scenario options: \$30/tC02, \$50/tC02 and \$70/tC02.

The first set of results associated with the combined carbon price/PV penetration scenarios implementation are listed in Table 8, Panels B-D and Table 9, Panel B-D and relates to the average annual price levels and percentage change from ($cp, BAU) for the various States and NEM as whole.

It is apparent from inspection of rows 2 and 3 of Panels B-D of Table 8 that the introduction of the various carbon price signals has increased average price levels for each state and the NEM as a whole. For example, for QLD, the average price level increased from $16.36/MWh to $44.36/MWh, an increase of 171.19% on the ($0, BAU) price level outcome which can be discerned from inspection of Panel B of Table 8 and the second row of Table 9, Panel B, following the introduction of a $30/tC02 carbon price. It should be noted that the numbers within parentheses in Table 9 that are displayed in red font indicate percentage increases over the ($0, BAU) results.

For all carbon prices considered, QLD consistently experiences the largest percentage increase from the baseline ($0, BAU) price level. For carbon prices of $30/tC02, $50/tC02 and $70/tC02, the percentage increases for QLD are 171.19%, 283.30% and 392.45% respectively, see row 2, Panels B-D of Table 9. These price changes encapsulate increases in the average annual price levels to $44.36/MWh, $62.70.MWh and $80.55/MWh respectively, from the BAU price level of $16.36/MWh, see row 2, Panels B-D of Table 8. Examination of these rows in these tables, more generally, indicate that SA experiences the second largest percentage increase from BAU price levels, followed by TAS, NSW and then VIC. For the NEM as a whole, the percentage increases are of the order of 44.68%, 71.70% and 105.36%, which represent actual increases in average annual price levels to $76.26/MWh, $90.50/MWh and $108.24/MWh respectively, from the BAU price level of $52.71/MWh.

Of particular note in the above-mentioned results is that those states with the highest ($0, BAU) average annual price levels (e.g., VIC and NSW) experience the smallest percentage increase in average price levels accompanying the introduction of the respective carbon prices. Similarly, those states with the lowest ($0, BAU) average annual price levels (e.g., QLD, SA and TAS) experience the largest percentage increases in average price levels following the introduction of the carbon prices. Notwithstanding these trends, it is still the case, however, that the average annual price levels of QLD, SA and TAS are significantly below the average annual price levels in NSW and VIC at each carbon price considered. The other noticeable feature is the relatively modest growth in average price levels in TAS when compared with growth in prices in the NEM as a whole. The growth experienced is related to the possibility of trade with the mainland (to VIC) through the Basslink Interconnector which gives TAS exposure to price levels prevailing in VIC. However, this growth is moderated by the fact that the predominant hydro based generation in TAS is not susceptible to carbon costs, thus ensuring that the increase in average prices in TAS is well below that experienced in other states which have forms of generation that are more susceptible to carbon costs following the introduction of carbon prices.

It is also apparent from examination of Table 8 and 9, Panels B - D that the average annual price levels decline as the level of PV penetration is increased. As was the case in the previous section, those states with the highest BAU prices – notably VIC and NSW – experience the greatest degree of decline in average annual price levels associated with increased PV penetration, for example, see columns 3 and 4 of

Table 9, Panel B – D. It is evident from inspection of these panels that VIC experiences a slightly larger percentage decline when compared to NSW for all PV and carbon price scenarios considered. The other noticeable feature from inspection of Table 9 is the more moderate rates of decline in average annual prices experienced in SA for all PV scenarios following the introduction of carbon prices when compared against the BAU response outlined in column 6 of Table 9, Panel A. More generally, for each state and the NEM as a whole, the rates of percentage decline in average annual prices for all scenarios involving considered involving both carbon prices and PV based load shaving are of a lower order of magnitude than those associated with the BAU scenario considered in Section 4 and whose results are cited in Panel A of Table 9.

Thus, increased PV penetration has continued to have the general effect of reducing average price levels within each state and across the NEM as a whole. However, when combined with the introduction of a

carbon price signal, this effect is swamped by the upward pressure exerted on average annual price levels associated with the introduction of the carbon price itself. Therefore, the results cited in Tables 8 and 9 indicates that policies that promote PV up-take can be expected to help to partially mitigate the expected increase in average price levels associated with the introduction of a carbon price signal.

Another issue of potential interest is the extent to which the full carbon price is passed through to average annual prices. This can be calculated in a two-step process. First, the price differential between average annual prices associated with a carbon price scenario and the baseline BAU scenario is calculated. This price differential is then divided by the carbon price 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 – the difference between the price levels is exactly equal to the carbon price itself. If the proportion is greater than unity, there is more than complete pass-through. In this case, the carbon price would have a 'magnified' affect on average annual prices.

We calculated these proportions for all carbon price/PV scenarios considered. The results for a carbon price of \$30/tC02, %50/tC02 and \$70/tC02 are documented in Panels A-C, Table 15, Appendix A, respectively. It is apparent from inspection of all three panels that there is less than complete pass-through – all proportions are strictly less than unity. For QLD and SA, the level of pass-through declines as the carbon price level is increased. The experience for NSW, VIC and TAS is mixed. All three states experience a decline in pass-through with the move from a \$30/tC02 to \$50/tC02 carbon price. However, with the move from \$50/tC02 to \$70/tC02, the level of carbon price pass-through increases. NSW and VIC achieves pass-through rates very close to, if not above, those associated with the \$30/tC02 carbon price while TAS generally remain at rates below those associated with the \$30/tC02 carbon price. The other noticeable feature is the significantly smaller values associated with TAS. Specifically, from inspection of Table 18, it is evident that carbon pass-through in TAS is around half of the values associated with the other states and the NEM generally. With the prominence of renewable hydro based generation in TAS and the much lower resulting carbon footprint of generation, there is a much smaller pass- through of carbon prices and costs into average annual prices in TAS. More generally, in absolute terms, the level of pass-through is also generally higher for QLD and SA than for NSW, VIC and TAS.

Information on aggregate dispatch by state and type of generation is outlined in Tables 10-13, Panels B-D for a carbon price of \$30/tC02, \$50/tC02 and \$70/tC02 and various PV penetration scenarios. In Table 10, we present the results for coal fired generation for each state and the NEM as a whole. It should be noted again that the numbers within parentheses and highlighted in red font (i.e. in row 2 of Table 10, Panel B) indicate percentage increases. It is evident from examination of Panels B-D of this table that the introduction of the carbon prices lead to an overall decline in coal fired generation production in the NEM of 2.57%, 8.98% and 11.87% when compared with the aggregate MW production levels determined for the (\$0, BAU) scenario. The impact on state MW productions levels were more varied with increased production being experienced in QLD and NSW of 1.87% and 1.22% respectively for a carbon price of \$30/tC02 when compared with the (\$0, BAU) levels. This can be contrasted with the sizeable reductions experienced in VIC and SA of 9.77% and 25.71% respectively from the (\$0, BAU) levels for these particular states at that carbon price. For higher carbon prices, coal fired production unambiguously

declines in each state with quite small reductions arising in QLD and NSW and much larger reductions occurring in both VIC and SA. These latter trends would reflect the high carbon intensity and carbon cost impact on brown coal fired generation in VIC following the introduction of a carbon price and loss of competitiveness of this form of generation when compared with competing gas fired generation located in SA.

It is also apparent from examination of Table 10 that the PV penetration scenarios have the effect of mitigating the increased productions levels in QLD and NSW (see columns 2 and 3) while reducing further the aggregate MW coal fired generation production levels in VIC and SA (see columns 4 and 5). In particular, for QLD, the implementation of the PV_D scenario almost wipes out the increase in MW coal generation production associated with the introduction of the (\$30/tC02) carbon price – the 1.87% increase associated with the latter is almost wiped out by the subsequent 1.81% reduction in output associated with the PV_B scenario. For the NEM as a whole, the PV penetration scenarios have the effect of further reducing aggregate MW coal fired generation production levels – see the last column of Table 10, Panels B-D.

In Table 11, Panels B-D, we present the results for natural gas fired generation for each state and the NEM as a whole in the presence of a carbon prices and PV penetration scenarios. Once again, it should be noted that the numbers within in parentheses and highlighted in red font (i.e. in row 2) indicate percentage increases. It is apparent from inspection of Panel B of this table that the introduction of a carbon price of \$30/tC02 has increased aggregate MW production from gas fired generation in most states and for the NEM as a whole. From examination of row 2 of Table 11, Panel B, for the NEM as a whole, the carbon price has produced a 4.05% increase in aggregate MW power production from gas fired generation. There is some variation amongst the states with VIC and TAS actually experiencing declines of 12.87% and 50.93% respectively while SA experiences the largest increase of 9.11% from (\$0, BAU) MW production levels, followed by NSW and QLD. The most likely cause of the large reduction in TAS is because the main competing form of generation in TAS is hydro generation which is unaffected by the introduction of the carbon price. Thus, the competitive position of gas-fired plant in TAS deteriorates with the introduction of the carbon price relative to competing hydro generators located in TAS and the carbon price has not increased enough to induce displacement of VIC brown coal generation by TAS gas fired generation.

With further increases in the carbon price levels, gas fired production in each state and the NEM as a whole unambiguously increases by a substantial amount. For example, from inspection of Panel D, Table 11, a $70/tC02 carbon price produced a 143.26%, 40.93%, 68.11%, 32.23% and 526.13% increase in gas fired production levels in QLD, NSW, VIC, SA and TAS respectively, over the BAU production levels. The large increase recorded for TAS would principally reflect production for export to VIC to displace some of the production coming from the VIC brown coal generation fleet. The large increase in gas fired production in QLD would be aimed at export opportunities into NW and NE NSW from the South West QLD node as well as the natural displacement of production from older vintage black coal generation plant in QLD.

For the NEM as a whole, the three carbon prices produced an increase in gas fired production of 4.05%, 34.51% and 61.65%, respectively – see Panels B-D of Table 11. These results indicate that a carbon price closer to $50/tC02 rather than $30/tC02 might be needed to induce significant switching from coal to gas fired generation. It is also apparent from examination of Table 11 that the PV penetration scenarios have the effect of mitigating the increased gas fired productions levels in all the states and NEM as a whole. However, for carbon price levels of $50/tC02 or greater, this mitigation is quite minor in extent apart from the case of VIC for a carbon price of $50/tC02.

We present the results for hydro based generation for each state and the NEM in Table 12, Panels B-D for the various carbon price and PV penetration scenarios considered. As in the case of Tables 10 and 11, the numbers encased in parentheses and highlighted in red font (i.e. in row 3) indicate percentage increases. Recall further that for accounting purposes, NSW hydro plant is defined to include hydro plant located at the Wollongong and Tumut nodes while the VIC hydro plant is defined to include all of the hydro plant located at the Murray and Dederang nodes.

It is apparent from inspection of Table 12 that with the introduction of the carbon prices, hydro-based generation production levels increase very significantly in NSW, significantly in TAS while varying somewhat for VIC but remaining relatively small in magnitude. For the NEM as a whole, hydro production increases significantly by 48.45%, 97.05% and 111.35% when compared to ($0, BAU) aggregate MW production levels cited in the second row of Table 12, Panel A. This significant expansion would have the added environmental benefit of curbing carbon emissions as well. In the case of QLD, there was no increase in production over the ($0, BAU) production results.

It is also evident from examination of Table 12 that the PV penetration scenarios have a marginal effect of mitigating the increased hydro production levels for NSW and TAS and especially at the two higher carbon price levels of $50/tC02 and $70/tC02. Therefore, for the various combined carbon price/PV penetration scenarios, we would expect an aggregate increase in MW hydro production levels in NSW, TAS and the NEM as a whole.

The percentage aggregate MW production levels reductions from BAU for each state and the NEM as a whole are listed in Table 13, Panels B-D for the various carbon price and load shaving scenarios. These results essentially combine all the results listed previously in Tables 10-12 and broadly match the patterns observed in these tables – especially the patterns appearing in Table 10 for QLD, NSW and VIC, Table 11 for SA, and Table 12 for TAS reflecting the dominance of coal fired generation in the former states, gas fired generation in SA and hydro generation in TAS.

It is apparent from examination of Table 13, Panels B-D that the introduction of the various carbon prices has increased aggregate production in QLD, NSW and TAS in the respective range of 1.82% to 6.78%, 1.44% to 3.13% and 54.53% to 104.07%, respectively. The record is more mixed for SA with a decline of 3.56% being experienced for a carbon price of \$30/tC02, followed by increases in aggregate production of 6.73% and 9.72% for the two higher carbon prices. For all three carbon prices considered, VIC experienced an unambiguous decline in aggregate production in the range of 9.90% to 27.32%.

The effect of the increased PV penetration is to either further reduce or partially or completely mitigate any observed increases in MW production levels. Recall that the PV penetration scenarios effectively reduce the level of aggregate load that has to be serviced by aggregate generation by shaving load at key metropolitan nodes, thus moving the 'marginal' generator required to service this reduced load further down the generation merit order. It is evident from assessment of the last column of Table 13, Panels B-D that the PV penetration scenarios unambiguously leads to additional reductions in aggregate MW productions levels from all sources of generation when compared to aggregate production levels associated with the (\$cp, BAU) scenario.

The percentage change in the aggregate annual level of carbon emissions from BAU are outlined in Table 14. It is evident from inspection of Panels B-D of Table 14 that in the absence of load shaving, the introduction of the carbon prices produced overall cuts in emissions from BAU of 4.16%, 9.48% and 11.48%, respectively. The results for each state are more variable with both QLD and TAS experiencing increases in aggregate carbon emissions relative to BAU levels in the range of 0.58% to 1.79% for QLD and 97.88% to 560.19% for TAS for the two higher carbon price levels. It should be noted that the increases experienced by TAS are coming from a very small base when compared with the other states. After a small increase of 0.05% in the case of NSW for the \$30/tC02 carbon price, this state recorded reductions in emissions of the order of 2.09% to 2.16% for the two higher carbon prices. South Australia also experienced reductions in emission from BAU, although at a diminishing rate as the level of the carbon price was increased. The state experiencing the largest decline is VIC with the percentage reduction from BAU levels being in the range of 11.01% to 30.61%, mirroring the significant reductions observed in aggregate production from VIC brown coal generation fleet.

The effects of the various PV scenarios produce both state and NEM level reductions in aggregate carbon emission when compared with the (\$cp, BAU) carbon emission levels as documented in rows 3 to 7 of Table 14, Panels B-D. In the case of QLD and TAS, the additional carbon emission reductions associated with the PV scenarios help to partially or completely mitigate the increase in carbon emission associated with the introduction of the carbon price itself. Therefore, demand side initiatives such as residential based PV penetration that has a load shaving effect will continue to actively contribute towards the policy goal of curbing carbon emissions from the power generation sector when combined with a carbon price signal.

3.6 Concluding Remarks.

In this chapter, we have focused our analysis on investigating the possible roles that key supply side and demand 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 were the introduction of a carbon price signal and residential based solar PV take-up whose principal effect is to shave load during the day.

In order to capture these linkages, we used an agent based model of the Australian National Electricity Market (NEM) called the 'ANEMMarket' model. The particular model that was used contained 286

generators, 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.

The solution algorithm that was utilised in the simulations involved applying the 'competitive equilibrium' solution whereby all generators submit their true marginal cost coefficients and no strategic bidding is allowed. 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 'non-zero' 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.

The implementation of the PV scenarios involved exploiting the potential that PV technologies have to shave load at particular nodes containing a high residential and commercial load components. We applied different load shaving scenarios to the major metropolitan nodes in the model – namely, the nodes that collectively encompassed Brisbane, Sydney, Melbourne and Adelaide.

We investigated a number of different types of scenarios. The first broad set related to implementing the PV based scenarios in an environment that did not contain a carbon price signal. We implemented five particular PV scenarios that encompassed increased rates of PV take-up that was capable of producing greater rates of load shaving at the major metropolitan nodes mentioned above. The 'Business-As-Usual' (BAU) scenario employed for comparative purposes for this set of scenarios involved no carbon price and no PV penetration – the so-called '($0, BAU)' scenario.

A number of broad conclusions are available from this set of scenarios when compared with the ($0, BAU) baseline result:

- We found that average annual prices in VIC and NSW were significantly higher than in QLD, SA and TAS pointing to the use, at the margin, of more costly generation to meet incremental demand in VIC and NSW when compared to QLD, SA and TAS.

- BAU cost of meeting the last MW of power demand in NSW and VIC was over five times more expensive than in QLD, was over three and a half times more expensive than in SA and over two and a half times more expensive than in Tasmania.

- The results depend crucially upon model assumption including ramping rates for coal fired generation.

- Increased PV penetration had the general effect of reducing average price levels within each state and across the NEM as a whole.

- Increased PV penetration produced a decline in aggregate levels of coal, gas fired and hydro generation production across relevant states and the NEM.

- Increased PV penetration produced both state and NEM wide reductions in aggregate carbon emission thereby contributing to the policy goal of curbing carbon emissions from the power generation sector.

A second broad set of scenarios were implemented involving the joint application of a carbon price signal together with the same set of PV scenarios mentioned above. Three particular carbon prices were examined – a $30/tC02, $50/tC02 and $70/tC02 carbon price. To isolate the 'pure' impact of the introduction of the carbon price signals, three additional baseline (BAU) scenarios were utilized which involved the employment of a carbon price but no PV penetration – these scenarios were termed '($30, BAU)', '($50, BAU)' and '($70, BAU)', respectively. These three scenarios could be compared with the original ($0, BAU) baseline scenario in order to investigate the impact of the introduction of the carbon price signals in an environment containing no PV take-up. Similarly, these three scenarios could also be used as benchmarks that could be used to net out the 'pure' affect of the carbon price signal from more complicated scenarios involving the combined use of both the carbon price signal and PV based load shaving.

A number of broad conclusions are available from this broad set of scenarios. The first set of conclusions relate to the pure impact associated with the introduction of the carbon price signals in the absence of PV take-up that is discernible from comparing the results associated with the ($30, BAU), ($50, BAU) and ($70, BAU) benchmark scenarios with the original ($0, BAU) scenario. The main conclusions arising from these comparisons are:

- The introduction of a carbon price signal led to significant jumps in average annual price levels across all states and for the NEM.

- For the NEM, increases of the order of 44.68%, 71.70% and 105.36% from ($0, BAU) for $30/tC02, $50/tC02 and $70/tC02 carbon prices were obtained.

- There was less than complete pass-through of carbon prices into average annual prices. TAS had a much lower level of carbon pass-through when compared to the other states and NEM as a whole.

- A decline in aggregate levels of coal fired generation production across the NEM of 2.57%, 8.98% and 11.87% for carbon prices of $30/tC02, $50/tC02 and $70/tC02, respectively. State based changes were more variable:

    - Unambiguous declines in VIC and SA; and

    - Mixed results for QLD and NSW – a small increase of 1.87% and 1.22% for a carbon price of $30/tC02, reductions of 1.57% and 2.39% for a carbon price of $50/tC02 and reductions of 3.03% and 2.06% for a carbon price of $70/tC02.

- Gas fired generation production increased across all relevant states (except for VIC for carbon price of $30/tC02) and for the NEM as a whole of 4.05%, 34.51% and 61.65% for carbon prices of $30/tC02, $50/tC02 and $70/tC02, respectively.

- Big increases in hydro generation particularly in NSW and TAS and across the NEM of 48.45%, 97.05% and 111.35% for carbon prices of $30/tC02, $50/tC02 and $60/tC02. This has the added environmental benefits of further curbing carbon emissions.

- Changes in aggregate MW generation production of each state:

    - Increases in aggregate MW production for QLD, NSW and TAS;

    - Decrease in aggregate MW production for VIC; and

    - Mixed results for SA – a 3.56% reduction followed by 6.73% and 9.72% increase in aggregate MW production for carbon prices of $30/tC02, $50/tC02 and $70/tC02, respectively.

- Introduction of carbon prices led to NEM based reductions in aggregate carbon emissions of 4.16%, 9.48% and 11.48% from ($0, BAU) levels for carbon prices of $30/tC02, $50/tC02 and $70/tC02, respectively. State based aggregate carbon emission results were more variable in nature:

    - For a $30/tC02 carbon price, reductions in aggregate carbon emission of 11.01%, 11.61% and 51.37% were obtained for VIC, SA and TAS while increases of 1.65% and 0.05%

were obtained for QLD and NSW when compared against the corresponding ($0, BAU) state levels;

- For a $50/tC02 carbon price, reductions in aggregate carbon emission of 2.16%, 23.87% and 5.61%, were obtained for NSW, VIC and SA but increases of 0.58% and 97.88% were obtained for QLD and TAS, when compared against the corresponding ($0, BAU) state levels;

- For a $70/tC02 carbon price, reductions in aggregate carbon emission of 2.09%, 30.61% and 4.99% were obtained for NSW, VIC and SA but increases of 1.79 and 560.19% were obtained for QLD and TAS, when compared against the corresponding ($0, BAU) state levels; and

- The ($0, BAU) levels for TAS are very small in magnitude – big increases in emissions observed for TAS for $50/tC02 and $70/tC02 carbon prices are coming from a very small base.

The second set of conclusions relate to the impact that increased PV penetration will have when combined with a carbon price signal. The main conclusions are:

- Increased PV penetration helps to partially mitigate the increase in average price levels associated with the introduction of a carbon price. However, the increase in average prices associated with the carbon price itself is very dominant.

- Increased PV penetration tends to reinforce any decline or mitigate any expansion in aggregate levels of coal, gas fired and hydro generation production levels across relevant states and the NEM that were experienced with the introduction of the carbon prices.

- Increased PV penetration tends to reinforce any reduction or mitigate any increase in aggregate carbon emissions experienced by the states and NEM as a whole, thereby contributing to the policy goal of curbing carbon emissions from the power generation sector by enhancing the effects produced by the carbon price signal.

- If deep levels of load shaving are desired and are to be obtained in an attempt to curb growth in electricity demand and carbon emissions, then it is evident that commercial scale PV installation or embedded solar PV or thermal generation would be needed.

3.7 References

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3.8 Appendix A. Tables

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	50.00	13 (daytime only)	Yes	$100.00
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

Table 3. Load Shaving Scenarios Associated with Different Levels of PV Penetration for Calendar Year 2007

Panel A: Summer

Hour Ending	BAU	PV Scenario A (2%)	PV Scenario B (5%)	PV Scenario C (10%)	PV Scenario D (15%)	PV Scenario E (20%)
01:00	1.000	1.000	1.000	1.000	1.000	1.000
02:00	1.000	1.000	1.000	1.000	1.000	1.000
03:00	1.000	1.000	1.000	1.000	1.000	1.000
04:00	1.000	1.000	1.000	1.000	1.000	1.000
05:00	1.000	1.000	1.000	1.000	1.000	1.000
06:00	1.000	1.000	1.000	1.000	1.000	1.000
07:00	1.000	1.000	0.995	0.990	0.980	0.980
08:00	1.000	0.995	0.990	0.970	0.960	0.940
09:00	1.000	0.990	0.980	0.950	0.930	0.900
10:00	1.000	0.985	0.965	0.930	0.890	0.850
11:00	1.000	0.980	0.950	0.900	0.850	0.800
12:00	1.000	0.980	0.950	0.900	0.850	0.800
13:00	1.000	0.980	0.950	0.900	0.850	0.800
14:00	1.000	0.980	0.950	0.900	0.850	0.800
15:00	1.000	0.980	0.950	0.900	0.850	0.800
16:00	1.000	0.985	0.965	0.930	0.890	0.850
17:00	1.000	0.990	0.980	0.950	0.930	0.900
18:00	1.000	0.995	0.990	0.970	0.960	0.940
19:00	1.000	1.000	0.995	0.990	0.980	0.980
20:00	1.000	1.000	1.000	1.000	1.000	1.000
21:00	1.000	1.000	1.000	1.000	1.000	1.000
22:00	1.000	1.000	1.000	1.000	1.000	1.000
23:00	1.000	1.000	1.000	1.000	1.000	1.000
24:00	1.000	1.000	1.000	1.000	1.000	1.000

Panel B: Winter

Hour Ending	BAU	PV Scenario A (2%)	PV Scenario B (5%)	PV Scenario C (10%)	PV Scenario D (15%)	PV Scenario E (20%)
01:00	1.000	1.000	1.000	1.000	1.000	1.000
02:00	1.000	1.000	1.000	1.000	1.000	1.000
03:00	1.000	1.000	1.000	1.000	1.000	1.000
04:00	1.000	1.000	1.000	1.000	1.000	1.000
05:00	1.000	1.000	1.000	1.000	1.000	1.000
06:00	1.000	1.000	1.000	1.000	1.000	1.000
07:00	1.000	1.000	1.000	1.000	1.000	1.000
08:00	1.000	1.000	1.000	0.990	0.980	0.980
09:00	1.000	0.995	0.995	0.970	0.960	0.940
10:00	1.000	0.990	0.980	0.950	0.930	0.900
11:00	1.000	0.985	0.965	0.930	0.890	0.850
12:00	1.000	0.980	0.950	0.900	0.850	0.800
13:00	1.000	0.980	0.950	0.900	0.850	0.800
14:00	1.000	0.985	0.965	0.930	0.890	0.850
15:00	1.000	0.990	0.980	0.950	0.930	0.900
16:00	1.000	0.995	0.995	0.970	0.960	0.940
17:00	1.000	1.000	1.000	0.990	0.980	0.980
18:00	1.000	1.000	1.000	1.000	1.000	1.000
19:00	1.000	1.000	1.000	1.000	1.000	1.000
20:00	1.000	1.000	1.000	1.000	1.000	1.000
21:00	1.000	1.000	1.000	1.000	1.000	1.000
22:00	1.000	1.000	1.000	1.000	1.000	1.000
23:00	1.000	1.000	1.000	1.000	1.000	1.000
24:00	1.000	1.000	1.000	1.000	1.000	1.000

Table 4. Number of Residential Based PV Systems needed to be Installed to Achieve Average Hourly MW Load Shaving Values

Panel A: PV Scenario PV_A (2%)

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	32.38	53.29	53.77	14.63
Watt Output	32384533	53293764	53766559	14629247
800	40,481	66,617	67,208	18,287
1000	32,385	53,294	53,767	14,629
1200	26,987	44,411	44,805	12,191
1400	23,132	38,067	38,405	10,449
1600	20,240	33,309	33,604	9,143

Panel B: PV Scenario PV_B (5%)

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	81.03	133.12	134.42	36.62
Watt Output	81034816	133115734	134417479	36616591
800	101,294	166,395	168,022	45,771
1000	81,035	133,116	134,417	36,617
1200	67,529	110,930	112,015	30,514
1400	57,882	95,083	96,012	26,155
1600	50,647	83,197	84,011	22,885

Panel C: PV Scenario PV_C (10%)

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	164.99	271.48	274.11	74.49
Watt Output	164994679	271475113	274110874	74491729
800	206,243	339,344	342,639	93,115
1000	164,995	271,475	274,111	74,492
1200	137,496	226,229	228,426	62,076
1400	117,853	193,911	195,793	53,208
1600	103,122	169,672	171,319	46,557

Panel D: PV Scenario PV_D (15%)

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	247.40	407.15	411.10	111.71
Watt Output	247404327	407148453	411098778	111709769
800	309,255	508,936	513,873	139,637
1000	247,404	407,148	411,099	111,710
1200	206,170	339,290	342,582	93,091
1400	176,717	290,820	293,642	79,793
1600	154,628	254,468	256,937	69,819

Panel E: PV Scenario PV_E (20%)

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	334.52	550.53	555.83	151.04
Watt Output	334517169	550534426	555834877	151037685
800	418,146	688,168	694,794	188,797
1000	334,517	550,534	555,835	151,038
1200	278,764	458,779	463,196	125,865
1400	238,941	393,239	397,025	107,884
1600	209,073	344,084	347,397	94,399

Table 5. Number of Residential Based PV Systems needed to be Installed to Achieve Maximum Hourly MW Load Shaving Values

Panel A: PV Scenario PV_A (2%)

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	80.07	126.31	129.86	41.63
Watt Output	80072200	126313600	129860000	41628200
1200	66,727	105,261	108,217	34,690
1400	57,194	90,224	92,757	29,734
1600	50,045	78,946	81,163	26,018

Panel B: PV Scenario PV_B (5%)

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	200.18	315.78	324.65	104.07
Watt Output	200180500	315784000	324650000	104070500
1200	166,817	263,153	270,542	86,725
1400	142,986	225,560	231,893	74,336
1600	125,113	197,365	202,906	65,044

Panel C: PV Scenario PV_C (10%)

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	400.36	631.57	649.30	208.14
Watt Output	400361000	631568000	649300000	208141000
1200	333,634	526,307	541,083	173,451
1400	285,972	451,120	463,786	148,672
1600	250,226	394,730	405,813	130,088

Panel D: PV Scenario PV_D (15%)

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	600.54	947.35	973.95	312.21
Watt Output	600541500	947352000	973950000	312211500
1200	500,451	789,460	811,625	260,176
1400	428,958	676,680	695,679	223,008
1600	375,338	592,095	608,719	195,132

Panel E: PV Scenario PV_E (20%)

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	800.72	1263.14	1298.60	416.28
Watt Output	800722000	1263136000	1298600000	416282000
1200	667,268	1,052,613	1,082,167	346,902
1400	571,944	902,240	927,571	297,344
1600	500,451	789,460	811,625	260,176

Table 6. Number of Residential and Commercial Based PV Systems needed to be Installed to Achieve Average Hourly MW Load Shaving Values with 10%-90% split in favour of Commercial PV

Panel A: PV Scenario PV_A (2%) – Residential PV

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	3.24	5.33	5.38	1.46
Watt Output	3238453	5329376	5376656	1462925
800	4,048	6,662	6,721	1,829
1000	3,238	5,329	5,377	1,463
1200	2,699	4,441	4,481	1,219
1400	2,313	3,807	3,840	1,045
1600	2,024	3,331	3,360	914

Panel A: PV Scenario PV_A (2%) – Commercial PV

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	29.15	47.96	48.39	13.17
Watt Output	29146079	47964387	48389903	13166322
800000	36	60	60	16
1000000	29	48	48	13
1200000	24	40	40	11

Panel B: PV Scenario PV_B (5%) – Residential PV

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	8.10	13.31	13.44	3.66
Watt Output	8103482	13311573	13441748	3661659
800	10,129	16,639	16,802	4,577
1000	8,103	13,312	13,442	3,662
1200	6,753	11,093	11,201	3,051
1400	5,788	9,508	9,601	2,615
1600	5,065	8,320	8,401	2,289

Panel B: PV Scenario PV_B (5%) – Commercial PV

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	72.93	119.80	120.98	32.95
Watt Output	72931335	119804160	120975731	32954931
800000	91	150	151	41
1000000	73	120	121	33
1200000	61	100	101	27

Panel C: PV Scenario PV_C (10%) – Residential PV

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	16.50	27.15	27.41	7.45
Watt Output	16499468	27147511	27411087	7449173
800	20,624	33,934	34,264	9,311
1000	16,499	27,148	27,411	7,449
1200	13,750	22,623	22,843	6,208
1400	11,785	19,391	19,579	5,321
1600	10,312	16,967	17,132	4,656

Panel C: PV Scenario PV_C (10%) – Commercial PV

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	148.50	244.33	246.70	67.04
Watt Output	148495211	244327602	246699787	67042556
800000	186	305	308	84
1000000	148	244	247	67
1200000	124	204	206	56

Panel D: PV Scenario PV_D (15%) – Residential PV

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	24.74	40.71	41.11	11.17
Watt Output	24740433	40714845	41109878	11170977
800	30,926	50,894	51,387	13,964
1000	24,740	40,715	41,110	11,171
1200	20,617	33,929	34,258	9,309
1400	17,672	29,082	29,364	7,979
1600	15,463	25,447	25,694	6,982

Panel D: PV Scenario PV_D (15%) – Commercial PV

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	222.66	366.43	369.99	100.54
Watt Output	222663894	366433608	369988900	100538792
800000	278	458	462	126
1000000	223	366	370	101
1200000	186	305	308	84

Panel E: PV Scenario PV_E (20%) – Residential PV

Node/City	**BRISBANE**	**SYDNEY**	**MELBOURNE**	**ADELAIDE**
MW Output	33.45	55.05	55.58	15.10
Watt Output	33451717	55053443	55583488	15103768
800	41,815	68,817	69,479	18,880
1000	33,452	55,053	55,583	15,104
1200	27,876	45,878	46,320	12,586
1400	23,894	39,324	39,702	10,788
1600	20,907	34,408	34,740	9,440

Panel E: PV Scenario PV_E (20%) – Commercial PV

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	301.07	495.48	500.25	135.93
Watt Output	301065452	495480983	500251389	135933916
800000	376	619	625	170
1000000	301	495	500	136
1200000	251	413	417	113

Table 7. Number of Residential and Commercial Based PV Systems needed to be Installed to Achieve Maximum Hourly MW Load Shaving Values with 10%-90% split in favour of Commercial PV

Panel A: PV Scenario PV_A (2%) – Residential PV

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	8.01	12.63	12.99	4.16
Watt Output	8007220	12631360	12986000	4162820
1200	6,673	10,526	10,822	3,469
1400	5,719	9,022	9,276	2,973
1600	5,004	7,895	8,116	2,602

Panel A: PV Scenario PV_A (2%) – Commercial PV

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	72.06	113.68	116.87	37.47
Watt Output	72064980	113682240	116874000	37465380
800000	90	142	146	47
1000000	72	114	117	37
1200000	60	95	97	31

Panel B: PV Scenario PV_B (5%) – Residential PV

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	20.02	31.58	32.47	10.41
Watt Output	20018050	31578400	32465000	10407050
1200	16,682	26,315	27,054	8,673
1400	14,299	22,556	23,189	7,434
1600	12,511	19,737	20,291	6,504

Panel B: PV Scenario PV_B (5%) – Commercial PV

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	180.16	284.21	292.19	93.66
Watt Output	180162450	284205600	292185000	93663450
800000	225	355	365	117
1000000	180	284	292	94
1200000	150	237	243	78

Panel C: PV Scenario PV_C (10%) – Residential PV

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	40.04	63.16	64.93	20.81
Watt Output	40036100	63156800	64930000	20814100
1200	33,363	52,631	54,108	17,345
1400	28,597	45,112	46,379	14,867
1600	25,023	39,473	40,581	13,009

Panel C: PV Scenario PV_C (10%) – Commercial PV

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	360.32	568.41	584.37	187.33
Watt Output	360324900	568411200	584370000	187326900
800000	450	711	730	234
1000000	360	568	584	187
1200000	300	474	487	156

Panel D: PV Scenario PV_D (15%) – Residential PV

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	60.05	94.74	97.40	31.22
Watt Output	60054150	94735200	97395000	31221150
1200	50,045	78,946	81,163	26,018
1400	42,896	67,668	69,568	22,301
1600	37,534	59,210	60,872	19,513

Panel D: PV Scenario PV_D (15%) – Commercial PV

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	540.49	852.62	876.56	280.99
Watt Output	540487350	852616800	876555000	280990350
800000	676	1,066	1,096	351
1000000	540	853	877	281
1200000	450	711	730	234

Panel E: PV Scenario PV_E (20%) – Residential PV

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	80.07	126.31	129.86	41.63
Watt Output	80072200	126313600	129860000	41628200
1200	66,727	105,261	108,217	34,690
1400	57,194	90,224	92,757	29,734
1600	50,045	78,946	81,163	26,018

Panel E: PV Scenario PV_E (20%) – Commercial PV

Node/City	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
MW Output	720.65	1136.82	1168.74	374.65
Watt Output	720649800	1136822400	1168740000	374653800
800000	901	1,421	1,461	468
1000000	721	1,137	1,169	375
1200000	601	947	974	312

Table 8. Average Annual Price Levels ($/MWh) Obtained for Various Carbon Price Scenarios and PV Scenarios for Calendar Year 2007

Panel A: Carbon price of $0/tC02 – 'Business-As-Usual' (BAU)

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$0, BAU	16.36	85.13	88.89	23.87	33.60	52.71
$0, PV_A	16.31	82.43	86.06	23.41	33.41	51.35
$0, PV_B	16.26	77.96	81.45	22.90	33.18	49.18
$0, PV_C	16.16	71.89	75.00	21.52	32.78	46.08
$0, PV_D	16.10	71.00	73.77	19.94	32.52	45.35
$0, PV_E	16.04	68.72	71.11	17.39	32.34	43.86

Panel B: Carbon Price of $30/tC02

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$0, BAU	16.36	85.13	88.89	23.87	33.60	52.71
$30, BAU	44.36	111.20	113.54	49.63	46.95	76.26
$30, PV_A	44.30	108.68	110.97	49.32	46.87	75.04
$30, PV_B	44.24	104.38	106.62	49.01	46.73	73.00
$30, PV_C	44.13	98.79	100.84	48.39	46.39	70.26
$30, PV_D	44.03	97.99	99.89	47.80	46.14	69.72
$30, PV_E	43.94	95.83	97.58	46.91	45.86	68.53

Panel C: Carbon Price of $50/tC02

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$0, BAU	16.36	85.13	88.89	23.87	33.60	52.71
$50, BAU	62.70	125.65	127.67	67.07	54.85	90.50
$50, PV_A	62.64	122.87	124.83	66.74	54.77	89.15
$50, PV_B	62.58	118.55	120.44	66.37	54.67	87.10
$50, PV_C	61.85	112.44	114.45	65.71	54.46	84.08
$50, PV_D	61.75	111.84	113.70	65.09	54.29	83.64
$50, PV_E	61.66	109.61	111.28	64.04	54.11	82.41

Panel D: Carbon Price of $70/tC02

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$0, BAU	16.36	85.13	88.89	23.87	33.60	52.71
$70, BAU	80.55	147.56	149.73	83.86	63.87	108.24
$70, PV_A	80.49	144.80	146.91	83.52	63.79	106.90
$70, PV_B	80.44	140.57	142.62	83.13	63.70	104.90
$70, PV_C	79.73	135.60	137.77	82.41	63.49	102.38
$70, PV_D	79.64	133.84	135.82	81.56	63.31	101.38
$70, PV_E	79.56	131.70	133.45	79.08	63.11	99.99

Table 9. Average Percentage (%) Reduction in Average Annual Price Levels from BAU for Various Carbon Price and PV Scenarios for Calendar Year 2007

Panel A: Carbon price of $0/tC02 – 'Business-As-Usual' (BAU)

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$0, PV_A	0.26	3.17	3.18	1.91	0.56	2.57
$0, PV_B	0.61	8.42	8.37	4.04	1.25	6.69
$0, PV_C	1.20	15.56	15.63	9.83	2.43	12.57
$0, PV_ D	1.56	16.59	17.01	16.44	3.20	13.96
$0, PV_ E	1.94	19.28	20.01	27.12	3.75	16.78

Panel B: Carbon Price of $30/tC02

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$30, BAU	(171.19)	(30.63)	(27.73)	(107.97)	(39.73)	(44.68)
$30, PV_A	0.13	2.27	2.26	0.62	0.17	1.60
$30, PV_B	0.27	6.13	6.09	1.25	0.46	4.27
$30, PV_C	0.52	11.16	11.19	2.50	1.19	7.86
$30, PV_D	0.74	11.88	12.02	3.70	1.73	8.57
$30, PV_E	0.95	13.82	14.05	5.48	2.31	10.14

Panel C: Carbon Price of $50/tC02

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$50, BAU	(283.30)	(47.60)	(43.63)	(181.03)	(63.24)	(71.70)
$50, PV_A	0.09	2.21	2.22	0.50	0.15	1.49
$50, PV_B	0.18	5.65	5.66	1.04	0.33	3.75
$50, PV_C	1.34	10.51	10.35	2.03	0.71	7.10
$50, PV_D	1.51	10.99	10.94	2.94	1.02	7.57
$50, PV_E	1.65	12.77	12.84	4.52	1.34	8.94

Panel D: Carbon Price of $70/tC02

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$70, BAU	(392.45)	(73.34)	(68.44)	(251.38)	(90.11)	(105.36)
$70, PV_A	0.07	1.87	1.88	0.40	0.13	1.24
$70, PV_B	0.14	4.74	4.75	0.87	0.28	3.09
$70, PV_C	1.02	8.11	7.99	1.72	0.60	5.41
$70, PV_D	1.13	9.30	9.29	2.74	0.88	6.34
$70, PV_E	1.23	10.75	10.87	5.70	1.20	7.62

Table 10. Percentage (%) Reduction in Aggregate MW Production from BAU For Coal Plant For Various Carbon Price and PV Scenarios for Calendar Year 2007

Panel A: Carbon price of $0/tC02 – 'Business-As-Usual' (BAU)

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$0, BAU (MW)	57075000	72287000	56877000	5146100	0	191380000
$0, PV_A	0.27	0.38	0.00	0.50	0.00	0.24
$0, PV_B	0.63	0.96	0.01	1.15	0.00	0.59
$0, PV_C	1.35	2.27	0.04	2.33	0.00	1.33
$0, PV_D	2.04	3.65	0.12	3.56	0.00	2.12
$0, PV_E	2.75	5.14	0.32	5.31	0.00	3.00

Panel B: Carbon Price of $30/tC02

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$30, BAU	(1.87)	(1.22)	9.77	25.71	00.0	2.57
$30, PV_A	0.24	0.20	0.31	0.61	0.00	0.25
$30, PV_B	0.57	0.49	0.68	1.52	0.00	0.59
$30, PV_C	1.21	1.26	1.34	3.21	0.00	1.31
$30, PV_D	1.81	2.21	1.97	4.33	0.00	2.06
$30, PV_E	2.45	3.31	2.62	5.31	0.00	2.89

Panel C: Carbon Price of $50/tC02

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$50, BAU	1.57	2.39	23.31	25.26	0.00	8.98
$50, PV_A	0.24	0.28	0.41	0.52	0.00	0.31
$50, PV_B	0.60	0.71	0.92	1.22	0.00	0.74
$50, PV_C	1.22	1.78	1.76	2.94	0.00	1.62
$50, PV_D	1.74	3.03	2.48	4.05	0.00	2.50
$50, PV_E	2.37	4.30	3.20	4.97	0.00	3.41

Panel D: Carbon Price of $70/tC02

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$70, BAU	3.03	2.06	31.61	29.60	0.00	11.87
$70, PV_A	0.19	0.25	0.42	0.48	0.00	0.28
$70, PV_B	0.45	0.59	1.13	1.00	0.00	0.68
$70, PV_C	0.98	1.41	2.44	1.85	0.00	1.52
$70, PV_D	1.51	2.45	3.33	2.46	0.00	2.34
$70, PV_E	2.09	3.69	4.21	3.09	0.00	3.27

Table 11. Percentage (%) Reduction in Aggregate MW Production from BAU For Gas Plant For Various Carbon Price and PV Scenarios for Calendar Year 2007

Panel A: Carbon price of $0/tC02 – 'Business-As-Usual' (BAU)

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$0, BAU (MW)	3953700	5026200	2556400	8987900	63032	20587000
$0, PV_A	0.11	0.75	2.87	0.63	4.34	0.85
$0, PV_B	0.22	1.71	6.08	1.41	9.08	1.86
$0, PV_C	0.36	3.62	11.36	2.74	20.70	3.62
$0, PV_D	0.41	4.69	14.93	3.62	28.19	4.75
$0, PV_E	0.45	5.54	17.51	4.28	34.15	5.58

Panel B: Carbon Price of $30/tC02

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$30, BAU	(1.36)	(6.38)	12.87	(9.11)	50.93	(4.05)
$30, PV_A	0.15	0.71	2.10	0.61	4.10	0.71
$30, PV_B	0.27	1.91	4.40	1.66	7.41	1.76
$30, PV_C	0.47	4.08	8.48	3.64	20.60	3.69
$30, PV_D	0.65	5.46	10.88	4.96	29.56	4.93
$30, PV_E	0.82	6.70	12.48	6.13	38.52	5.99

Panel C: Carbon Price of $50/tC02

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$50, BAU	(68.80)	(34.68)	(12.97)	(25.06)	(90.03)	(34.51)
$50, PV_A	0.04	0.21	2.60	0.33	6.55	0.50
$50, PV_B	0.07	0.44	5.86	0.76	13.44	1.10
$50, PV_C	0.21	0.74	11.48	1.50	26.88	2.15
$50, PV_D	0.29	0.94	15.04	2.02	35.72	2.84
$50, PV_E	0.32	1.24	17.93	2.52	42.91	3.46

Panel D: Carbon Price of $70/tC02

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$70, BAU	(143.26)	(40.93)	(68.11)	(32.23)	526.13)	(61.65)
$70, PV_A	0.19	0.17	2.00	0.51	4.26	0.58
$70, PV_B	0.42	0.33	4.57	1.06	10.43	1.28
$70, PV_C	0.86	0.61	9.60	2.05	21.35	2.60
$70, PV_D	1.25	0.73	13.40	2.90	29.45	3.63
$70, PV_E	1.66	0.81	16.44	3.61	36.01	4.49

Table 12. Percentage (%) Reduction in Aggregate MW Production from BAU For Hydro Plant For Various Carbon Price and PV Scenarios for Calendar Year 2007

Panel A: Carbon price of $0/tC02 – 'Business-As-Usual' (BAU)

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$0, BAU (MW)	774640	440790	865	0	6810200	8026500
$0, PV_A	0.00	5.03	2.35	0.00	0.80	0.95
$0, PV_B	0.00	10.09	3.34	0.00	1.80	2.08
$0, PV_C	0.00	14.96	6.43	0.00	3.51	3.80
$0, PV_D	0.00	16.10	6.99	0.00	4.68	4.86
$0, PV_E	0.00	16.41	7.05	0.00	5.52	5.59

Panel B: Carbon Price of $30/tC02

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$30, BAU	(0.14)	(24.41)	(0.38)	0.00	(55.50)	(48.45)
$30, PV_A	0.00	5.96	2.34	0.00	0.58	0.79
$30, PV_B	0.00	11.33	3.32	0.00	1.43	1.79
$30, PV_C	0.01	18.48	6.24	0.00	2.87	3.40
$30, PV_D	0.01	23.14	6.74	0.00	4.01	4.63
$30, PV_E	0.01	27.34	6.81	0.00	5.22	5.90

Panel C: Carbon Price of $50/tC02

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$50, BAU	(0.07)	(250.64)	11.51	0.00	(98.16)	(97.05)
$50, PV_A	0.01	2.35	2.66	0.00	0.01	0.24
$50, PV_B	0.01	5.61	3.77	0.00	0.02	0.56
$50, PV_C	0.05	12.52	7.27	0.00	0.04	1.26
$50, PV_D	0.06	18.50	7.89	0.00	0.06	1.86
$50, PV_E	0.09	27.13	7.96	0.00	0.13	2.77

Panel D: Carbon Price of $70/tC02

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$70, BAU	(32.55)	(422.97)	(1.62)	0.00	(100.16)	(111.35)
$70, PV_A	0.00	2.35	2.30	0.00	0.00	0.32
$70, PV_B	0.00	5.02	3.27	0.00	0.00	0.68
$70, PV_C	0.00	9.17	6.26	0.00	0.01	1.25
$70, PV_D	0.00	12.83	6.29	0.00	0.02	1.76
$70, PV_E	0.01	15.31	6.71	0.00	0.12	2.18

Table 13. Percentage (%) Reduction in Aggregate MW Production from BAU For Various Carbon Price and PV Scenarios for Calendar Year 2007

Panel A: Carbon price of $0/tC02 – 'Business-As-Usual' (BAU)

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$0, BAU (MW)	61803000	77754000	59434000	14140000	6873300	220000000
$0, PV_A	0.25	0.43	0.13	0.58	0.83	0.32
$0, PV_B	0.59	1.07	0.27	1.32	1.86	0.76
$0, PV_C	1.27	2.42	0.53	2.60	3.67	1.64
$0, PV_D	1.91	3.79	0.75	3.60	4.90	2.46
$0, PV_E	2.57	5.23	1.06	4.66	5.79	3.34

Panel B: Carbon Price of $30/tC02

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$30, BAU	(1.82)	(1.68)	9.90	3.56	(54.53)	
$30, PV_A	0.23	0.27	0.39	0.61	0.59	0.32
$30, PV_B	0.54	0.66	0.83	1.63	1.45	0.77
$30, PV_C	1.15	1.57	1.63	3.53	2.92	1.65
$30, PV_D	1.71	2.57	2.34	4.79	4.09	2.48
$30, PV_E	2.31	3.70	3.03	5.91	5.32	3.36

Panel C: Carbon Price of $50/tC02

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$50, BAU	(2.95)	(1.44)	21.75	(6.73)	(98.09)	
$50, PV_A	0.22	0.32	0.55	0.38	0.06	0.33
$50, PV_B	0.54	0.78	1.23	0.88	0.14	0.77
$50, PV_C	1.10	1.90	2.36	1.87	0.28	1.66
$50, PV_D	1.57	3.15	3.26	2.55	0.38	2.50
$50, PV_E	2.13	4.48	4.11	3.15	0.51	3.37

Panel D: Carbon Price of $70/tC02

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$70, BAU	(6.78)	(3.13)	27.32	(9.72)	(104.07)	
$70, PV_A	0.19	0.30	0.58	0.51	0.12	0.33
$70, PV_B	0.44	0.69	1.47	1.05	0.30	0.77
$70, PV_C	0.95	1.56	3.15	2.01	0.61	1.66
$70, PV_D	1.45	2.59	4.33	2.80	0.85	2.49
$70, PV_E	2.00	3.77	5.43	3.50	1.13	3.37

Table 14. Percentage (%) Reduction in Aggregate Carbon Emissions from BAU For Various Carbon Price and PV Scenarios for Calendar Year 2007

Panel A: Carbon price of $0/tC02 – 'Business-As-Usual' (BAU)

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$0, PV_A	0.27	0.41	0.06	0.58	4.48	0.26
$0, PV_B	0.63	1.02	0.14	1.31	9.32	0.62
$0, PV_C	1.36	2.36	0.27	2.59	20.69	1.37
$0, PV_D	2.04	3.75	0.40	3.72	27.90	2.11
$0, PV_E	2.74	5.24	0.63	4.98	33.71	2.93

Panel B: Carbon Price of $30/tC02

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$30, BAU	(1.65)	(0.05)	11.01	11.61	51.37	4.16
$30, PV_A	0.25	0.23	0.39	0.59	4.35	0.31
$30, PV_B	0.58	0.56	0.84	1.51	7.79	0.71
$30, PV_C	1.23	1.39	1.65	3.21	21.14	1.52
$30, PV_D	1.83	2.35	2.38	4.33	30.33	2.32
$30, PV_E	2.47	3.45	3.10	5.27	39.45	3.16

Panel C: Carbon Price of $50/tC02

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$50, BAU	(0.58)	2.16	23.87	5.61	(97.88)	9.48
$50, PV_A	0.24	0.29	0.49	0.43	6.81	0.35
$50, PV_B	0.59	0.72	1.09	0.99	13.94	0.81
$50, PV_C	1.20	1.77	2.08	2.16	27.59	1.74
$50, PV_D	1.71	2.97	2.88	2.92	36.38	2.60
$50, PV_E	2.31	4.20	3.64	3.56	43.54	3.48

Panel D: Carbon Price of $70/tC02

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$70, BAU	(1.79)	2.09	30.61	4.99	(560.19)	11.48
$70, PV_A	0.19	0.26	0.48	0.53	4.36	0.32
$70, PV_B	0.46	0.60	1.23	1.09	10.69	0.78
$70, PV_C	0.99	1.41	2.62	2.05	21.91	1.69
$70, PV_D	1.52	2.41	3.58	2.80	30.12	2.54
$70, PV_E	2.10	3.60	4.48	3.47	36.65	3.45

Table 15. Carbon Price Pass-Through for Calendar Year 2007: Proportion of Carbon Price

Panel A: Carbon Price of $30/tC02

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$30, BAU	0.9334	0.8691	0.8217	0.8589	0.4449	0.7850
$30, PV_A	0.9329	0.8751	0.8302	0.8638	0.4486	0.7894
$30, PV_B	0.9327	0.8807	0.8389	0.8702	0.4516	0.7940
$30, PV_C	0.9322	0.8969	0.8613	0.8957	0.4536	0.8060
$30, PV_ D	0.9309	0.8996	0.8708	0.9285	0.4538	0.8125
$30, PV_ E	0.9299	0.9038	0.8825	0.9840	0.4508	0.8222

Panel B: Carbon Price of $50/tC02

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$50, BAU	0.9268	0.8104	0.7756	0.8640	0.4250	0.7558
$50, PV_A	0.9265	0.8089	0.7753	0.8665	0.4271	0.7560
$50, PV_B	0.9265	0.8118	0.7798	0.8693	0.4297	0.7585
$50, PV_C	0.9139	0.8111	0.7890	0.8838	0.4335	0.7599
$50, PV_D	0.9130	0.8167	0.7986	0.9030	0.4354	0.7659
$50, PV_E	0.9125	0.8178	0.8035	0.9328	0.4355	0.7709

Panel C: Carbon Price of $70/tC02

SCENARIO	QLD	NSW	VIC	SA	TAS	NEM
$70, BAU	0.9170	0.8919	0.8691	0.8570	0.4325	0.7933
$70, PV_A	0.9168	0.8911	0.8692	0.8587	0.4340	0.7935
$70, PV_B	0.9168	0.8945	0.8738	0.8604	0.4359	0.7960
$70, PV_C	0.9081	0.9102	0.8967	0.8699	0.4387	0.8043
$70, PV_D	0.9077	0.8977	0.8864	0.8803	0.4399	0.8005
$70, PV_E	0.9074	0.8997	0.8906	0.8812	0.4395	0.8018

Figure 1. QLD 11 Node Model - Topology

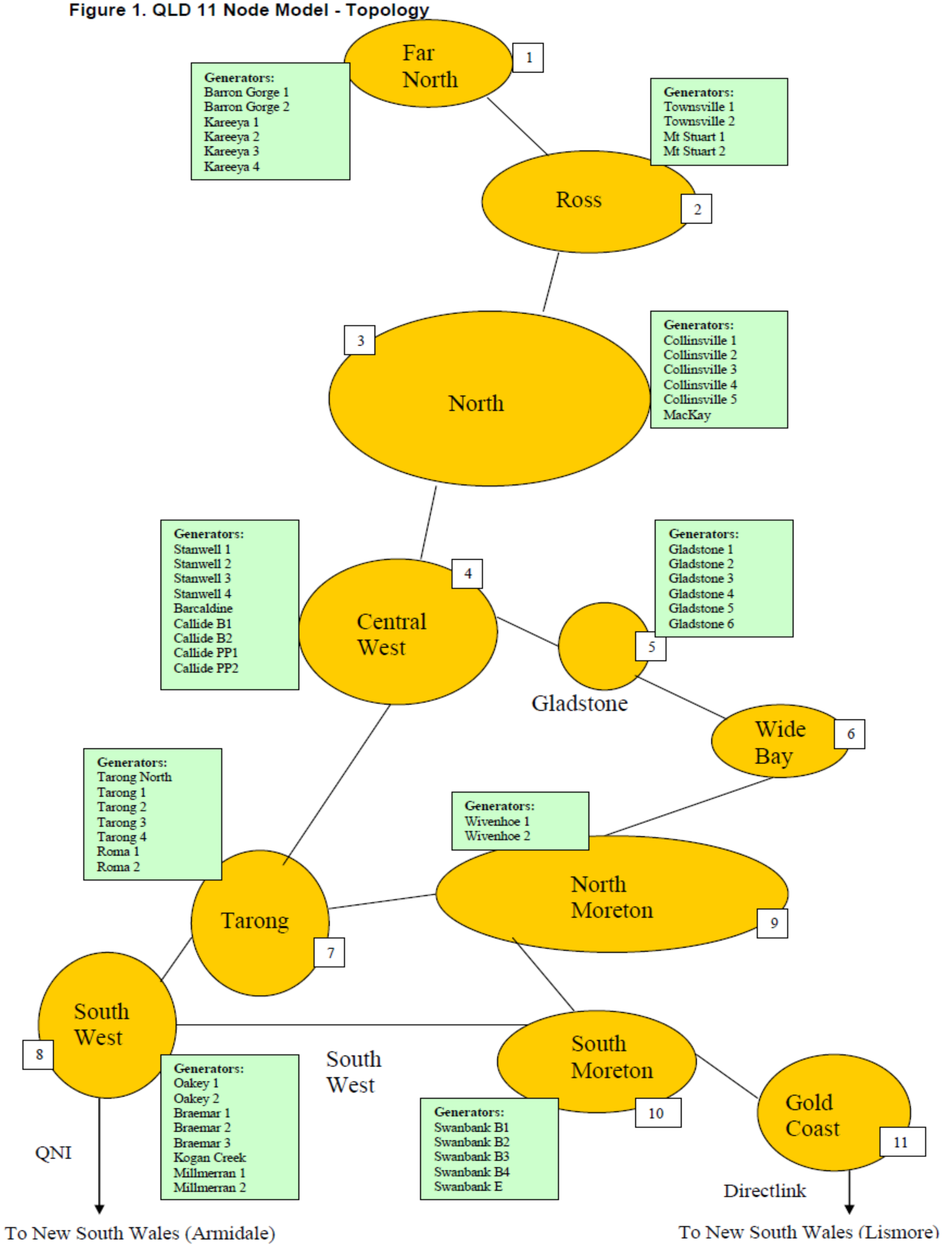
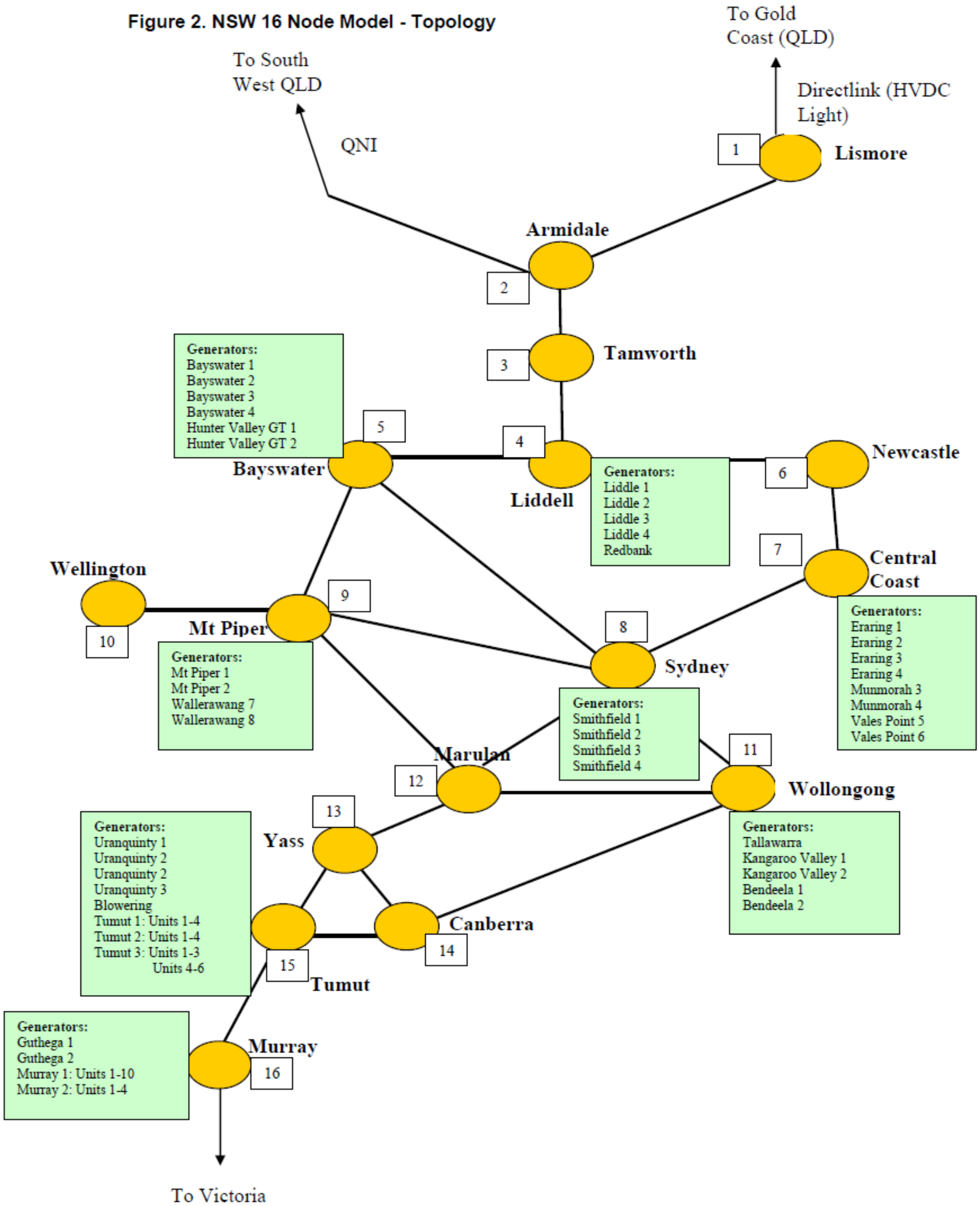


Figure 2. NSW 16 Node Model - Topology



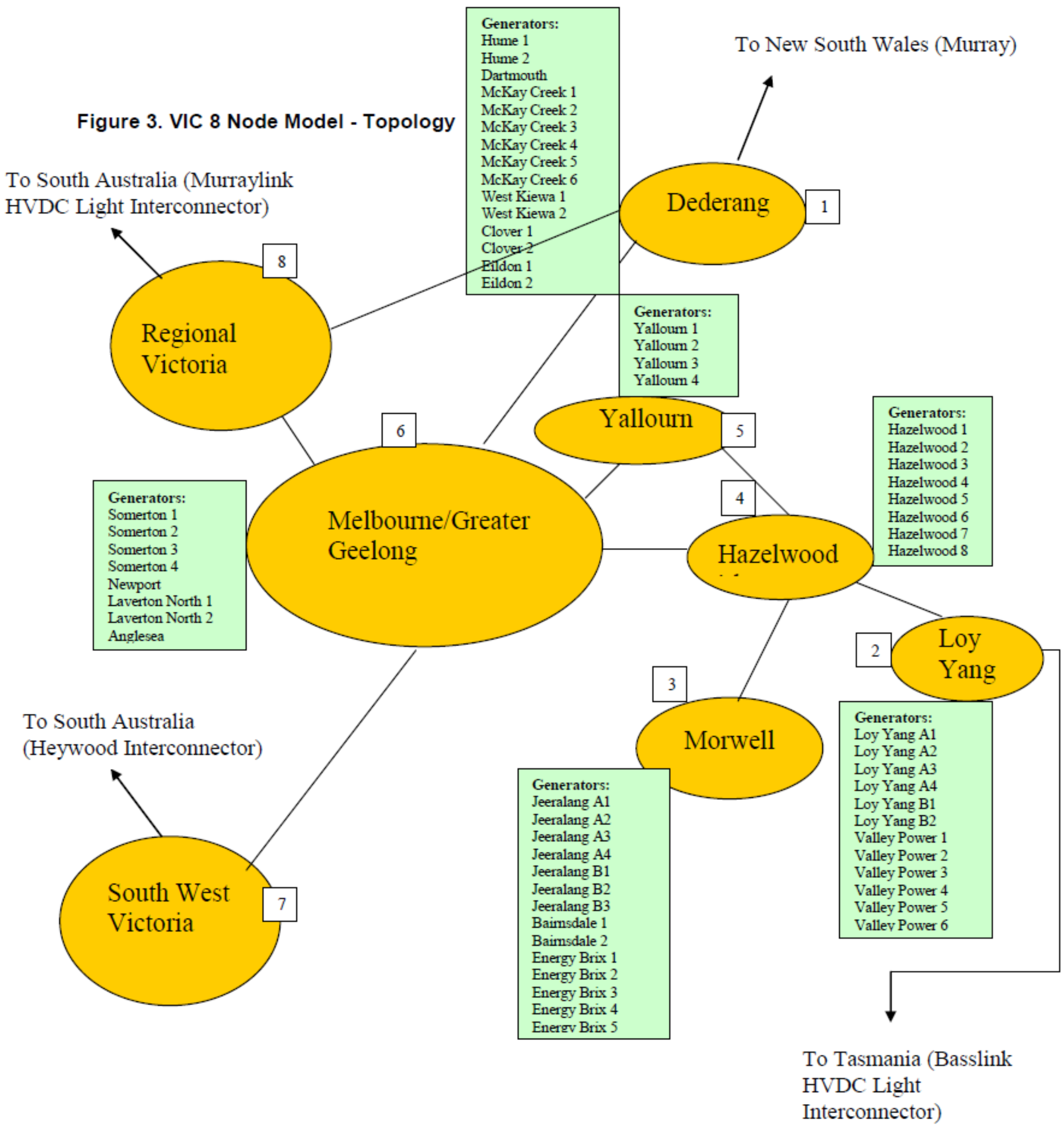


Figure 3. VIC 8 Node Model - Topology

Figure 4. SA 7 Node Model - Topology

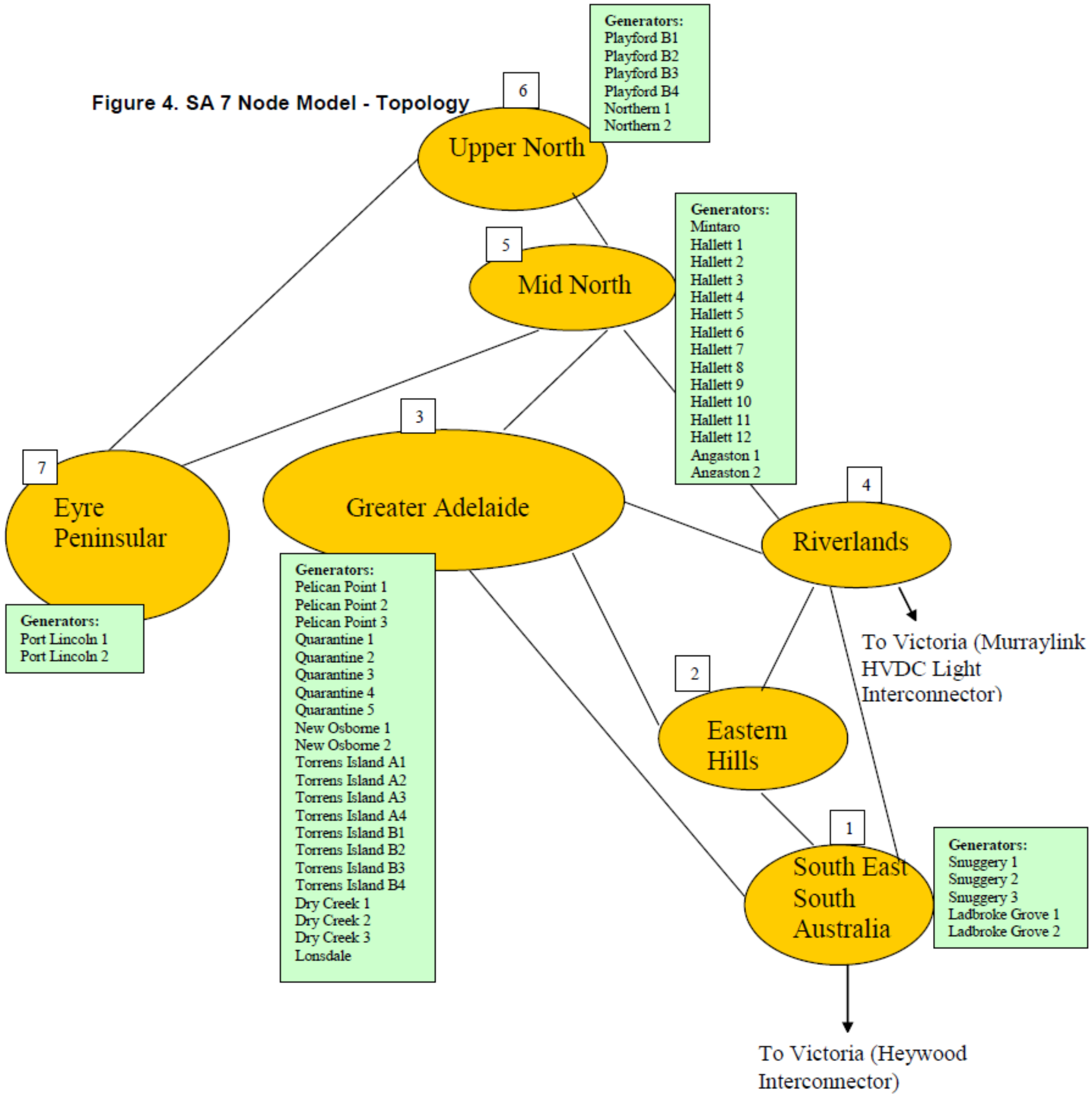
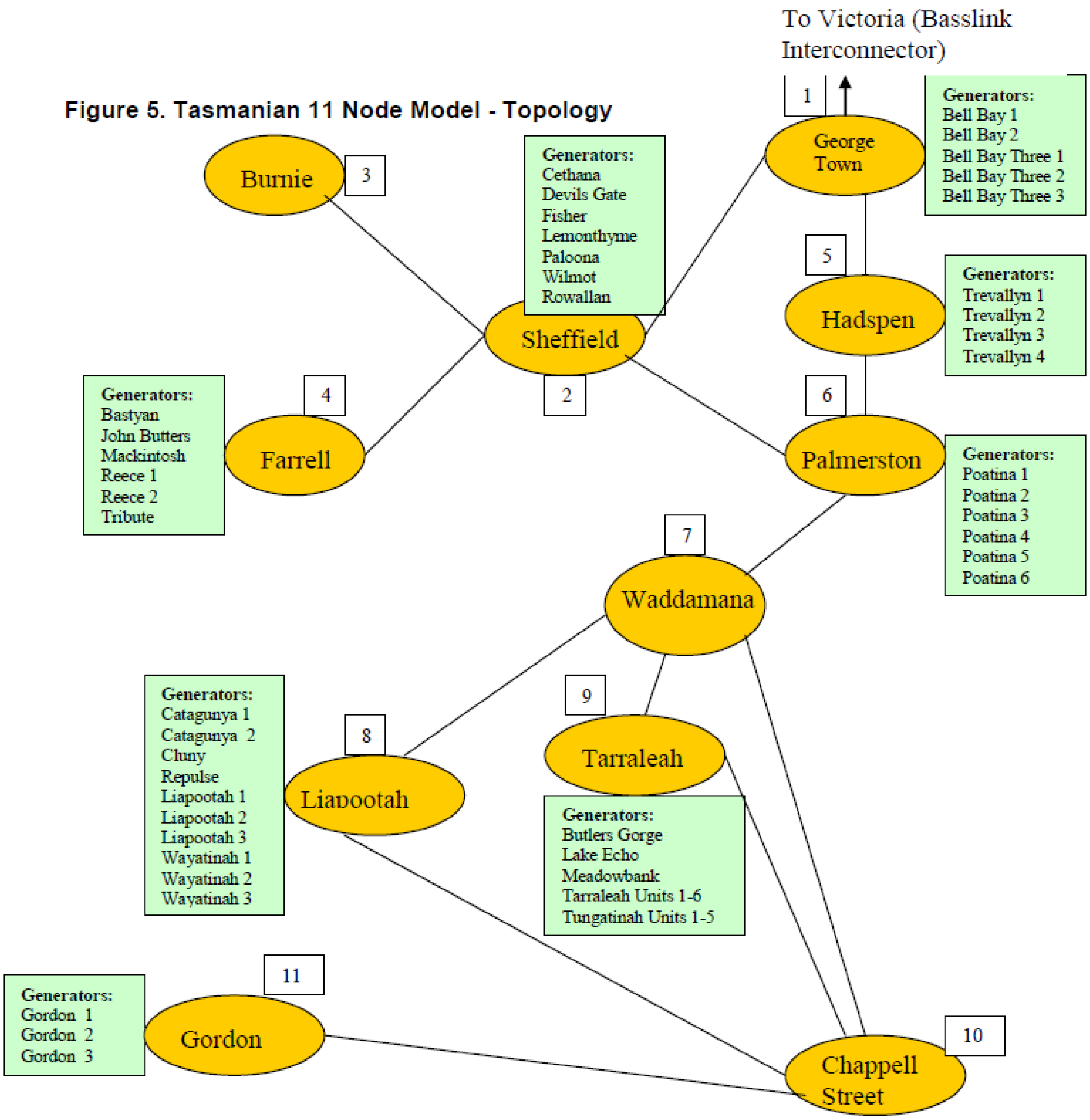


Figure 5. Tasmanian 11 Node Model - Topology



Chapter 4: The Development of a Commercial Scale Experimental PV Array: the Case of UQ

One of the key project deliverables was the training of PhD students who understand both the technical and economic aspects of the Australian energy system. UQ has taken the ‘learning by doing’ approach by creating an electricity Micro-Grid across multiple campuses through a number of research projects. The Micro-Grid concept has been developed and eventually will contain multiple sources of renewable and alternative energy forms (solar PV, solar thermal, micro-turbines, etc.) and would be designed to achieve a number of emission reduction, research, education and policy development, deployment learning and training objectives.

The first Micro-Grid sub-project is the St Lucia PV Array – a 1.22 MW photovoltaic flat panel deployment at the St Lucia campus containing both standard and next generation technologies, state-of-the-art monitoring and control systems, and a purpose-built control room and education / visitor centre. The “heart” of the array (control room and visitor centre) is to be housed in the new Global Change Institute as UQ’s renewable energy centre-piece (located in the Steele Building but connected directly to Level 2 of GCI). The GCI Building itself will form part of the micro-grid, utilising a number of renewable energy technologies and energy efficiency measures. Multiple research groups across UQ are involved in the development of the St. Lucia PV Array involving power systems engineering, next generation solar cell development and energy economics. Multiple external stakeholders in government and the energy industry have been consulted in concept design. The St Lucia Array will be the largest PV array of its kind in Australia and will position Queensland (The Sunshine State) as a unique provider of research, training and education in renewable energy globally. The State Government has also raised the idea of establishing a Queensland Solar Institute including a number of other research institutions with the array being the centrepiece for research activity.

The array will initially focus research activity on looking at the impact that deployment of intermittent technology will have in a distribution environment. The current array size will produce approximately six percent of the St Lucia Campus peak demand and will be fed directly into the internal grid. In addition the introduction of storage at the point of generation will also provide the opportunity to model the effects of load shifting from both an economic and power systems perspective.

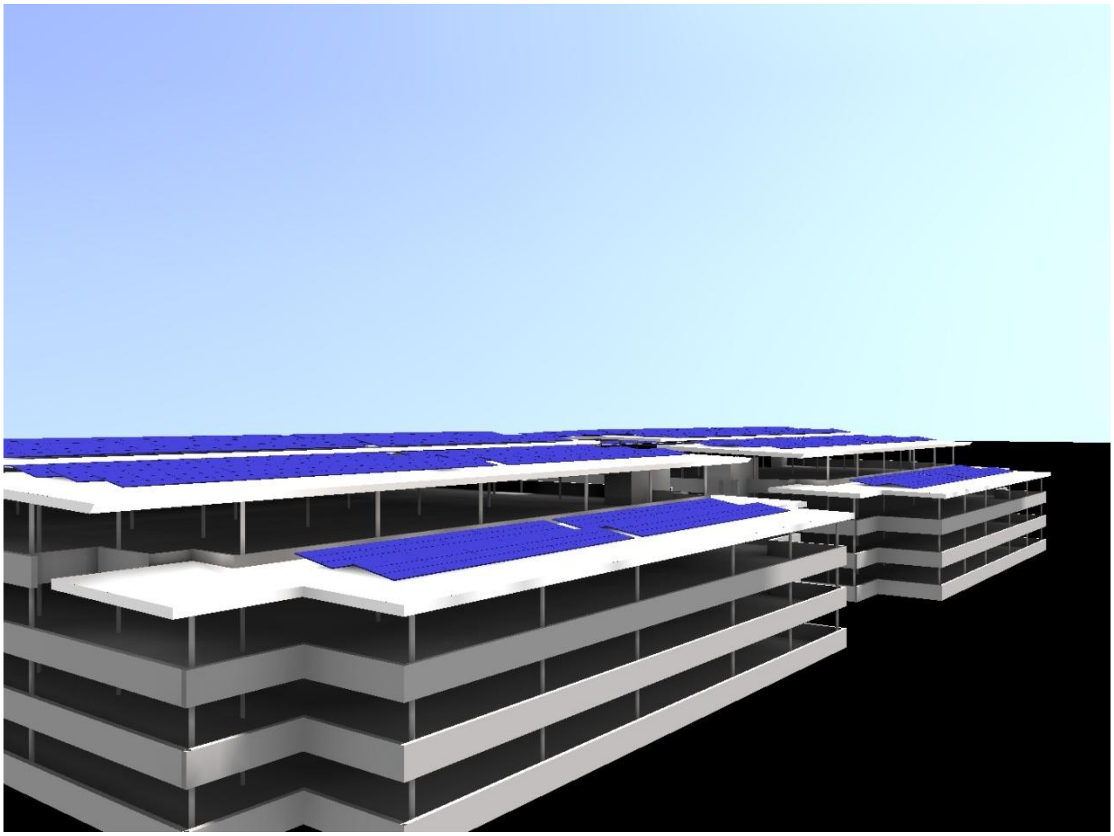


Figure 1 - Engineers Drawings for Multi-Level Car Parks

The array itself is to be deployed over four buildings, being the Multi-Level Car Parks, UQ Centre and Sir Llew Edwards Building, with a focus on micro-grid and distributed generation research.

Research projects and contracts have already been negotiated with: -

- RedFlow – Battery Storage;
- Energex – Power Stability and Quality;
- Trina Solar – Next Generation Solar Panels;
- Tritium – Next Generation Inverters;
- SolarMagic – Shading Analysis and Smart Modules;

with this providing for the development of a range of different modelling scenarios[6].

Figure 2 - UQ Centre (Dec 2010)

The battery storage project will see a 400 kWh zinc bromine battery (with a 200 kWh discharge rate) connected to one of the multi-level car parks. The arrays on both car parks (approximately 370 kW) are identical providing both a test and BAU situation.

The battery system being used is based on RedFlow's zinc-bromine flowing electrolyte battery module with the unit installed in April 2011 (see Figure 4), having 120 kHh storage capacity with power electronics rated at 30 kW. The system is packaged in a 20 foot Hi-Cube shipping container, but the current system only occupier 15% of the footprint, with the balance being set-up as a demonstration room with monitoring equipment to monitor system performance.

[6] Details of Building Research Partnerships and Data Acquisition systems to be used were included in Chapter 3.5 of Milestone Report 4 & 5 (July 2010)

This unit will be replaced mid-year with the larger 400 kWh model which will remain on-site for at least two years, with research projects currently being established.

The two multi-level car park buildings are identical in size and construction and will both have identical arrays in size and layout as shown earlier in Figure 1. Battery storage will be initially added to the western array only and a number of scenarios will be modelled looking at various load shifting options and the effect that this may have on the peak load. The ability to model two identical large-scale arrays under identical climatic conditions, one with storage and the other without, will provide considerable research data that is not currently available.

In addition to the flat-panel array, a seven-metre by six-metre 8.4 kilowatt high-efficiency, concentrating PV (CPV) array that tracks the sun has also been installed and is operational. Whilst only small in size, it has been located adjacent to the Flat-panel PV arrays and again will produce important comparative research data.

Figure 3 - CPV Array – St Lucia

As noted earlier, the array it will contribute to approximately 6% of the St Lucia Campus peak power demand. This will provide a good base to model the introduction of a large-scale renewable energy generator within a distribution network. Whilst the technology itself is not new or innovative, how it can be deployed within a micro-grid and the benefits that may be obtained on the larger distribution network are still to be quantified.

Figure 4 - RedFlow Battery (April 2011)

Significant penetration of solar and other renewable energy sources into the national grid will highlight a number of operational concerns over maintaining system power balance. With the proliferation of wind and large scale solar penetration into the grid, electricity networks will become two-way power flow systems. Sudden changes of climatic conditions can cause a big power fluctuation within a few seconds. Because the conventional generation has to be uncommitted to allow usage of solar and other energy sources, the sudden power deficit may not be easy to compensate quickly. This will result in power system instability and poor power quality problems having an impact on operating reserve, imbalance in energy, and voltage and frequency regulation of the grid. Therefore, these technical issues need to be addressed within the existing distribution network systems. Research in this area focuses on comprehensive power system stability issues that will arise due to massive wind, solar and other renewable energy source integration (micro-grid level also). This includes the study of voltage regulation and development of control methods and compensation techniques to overcome any instability issues. Analysis of frequency regulation, spinning reserve and investigation of advanced islanding monitoring and control schemes due to faults in the existing protection systems is also under investigation. Existing and planned research projects will help the distribution utilities to redesign the existing distribution network and provide timely solutions to customers and also help maintain the security of the grid. These issues are uppermost in many utility-scale and network providers' minds and this extensive power system engineering program has immediate and clear synergies with implementing solar research projects.

Future major projects being considered include the use of solar thermal generation to meet part of the air-conditioning load of buildings. The initial system is planned to be located within the Advanced Engineering Building, with construction scheduled to commence in mid-2011.

Planning for this project is still in the early stages, but would again create a number of research opportunities within the distributed generation environment, relying on intermittent technologies.

Smaller solar arrays are also being planned for other campuses to provide for interregional comparisons as well as creating a 'virtual' micro-grid. Negotiations are also underway to source data from other large Australian sites (such as the Adelaide Showground) to supplement internally generated data.[7]

4.1 Solar Flagships Program

The Federal Government intends to provide partial funding to build up to 1GW of utility-scale solar power generation plant in 4 projects to 2020 (2 x solar PV and 2 x concentrating solar thermal). This program (the Solar Flagships Program) will be in two stages – in the first stage 8 projects were shortlisted of which 7 have submitted final bids (December 2010). It is a requirement of each project to engage with a research provider and develop a project specific research program under the Education Investment Fund (EIF). UQ has been selected as Lead Research Organisation in 2 of the 7 submissions (AGL PV bid and Solar Dawn CST bid).

If the PV bid is successful, massive solar and power systems research infrastructure will be deployed across a number of States (including UQ and partner UNSW). This includes pilot power plants and laboratories. In particular, the AGL project is based around a large 3.75MW PV plant at UQ's Gatton Campus. This will further increase the ability to model the impact of distributed generation within a local environment as this project would meet most of the Campus load as well as feed back into the local grid

The Solar Dawn project will deploy most research infrastructure on the main power plant site at Kogan Creek. This project is being partnered with ANU to take advantage of their experience in this area.

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[7] There are already a number of existing arrays on other campuses and research stations and details of these were included in Chapter 3.3 of Milestone Report 4 & 5 (July 2010)

If either of the bids is successful substantial and globally significant research programs will be initiated in both distributed and utility-scale renewable generation which will change the local landscape dramatically.

4.2 Next Generation Technology and the Grid

The Centre for Organic Photonics & Electronics (COPE) hosts a major research initiative in next generation organic solar cells. This work encompasses multiple aspects of materials development and new architectures across the two main types of organic solar cells, namely thin-film solid-state and dye sensitized solar cells. COPE has state-of-the-art materials synthesis, cell fabrication and testing infrastructure as well as the capacity to scale materials production and prototype device fabrication. The centre is a cross-disciplinary organisation with Chemists, Physicists and Engineers working on the organic solar cell problem from both fundamental and applied perspectives. The COPE OPV program is supported by the Australian Research Council and includes a new joint research program with the National Renewable Energy Laboratory in the United States. Furthermore, the program was further boosted by the award of an Australian Solar Institute Grant ($1.95M program).

The application of the OPV technology could allow for an even greater deployment of renewable technology within distribution networks as the engineering requirements would be minimal, particularly looking at weight loads on existing (older) structures.

The Power Engineering Systems Group's (PES) focus has been working towards the development of new tools (software and hardware), suitable for future power systems. In the context of renewable energy, the group has been actively investigating how to reliably integrate decentralized power sources into the distribution grid and estimate the cost/benefit of such systems in a deregulated market environment. This includes the integration of wind and photovoltaic power to the Grid, and geothermal power, which is located far away from the Grid.

Each of the renewable energy sources comes with unique challenges for integration. For example, wind power has challenges in voltage-VAR management and stability issues. For photovoltaic power, bidirectional power flow, voltage profile and subsequent control schemes are major issues. And for geothermal located far away from the national grid, stability and control issues are the main issues here. To date we have developed the following:

- Analytic tools for voltage stability analysis in static and dynamic analysis and large scale blackout issues.

- Advanced analytical tools in assessing the conditions required for secure and stable operation of the Grid.

With regard to cost/benefit analysis, we have been actively investigating the new generation entry problem in a deregulated market environment. We have also investigated the contribution internal interconnectivity makes by comparing the reliability of similar loaded meshed and extended transmission systems in the Australian environment. Our experience with reliability tools is helping to develop new algorithms for different renewable energy sources, in particular with the foreseeable carbon pricing scheme. We have also extensively worked on electricity demand and price analysis in a deregulated market, where a number of new tools and techniques have been developed in this area.

The future paradigm shifts in this area of research are as follows: -

- New tools and techniques developed in power systems stability and security that is compliant for renewable energy integration into the grid.

- Changes to planning and regulatory frameworks required for successful implementation of demand side management (DSM) activities, including demand response (DR) in future smart grids. Currently, many researches are being conducted on technological challenges associated with demand response and smart grids. However, deep research on regulatory modifications to facilitate the large scale utilization of demand response resources are vital and have not been address properly yet.

- New tools for voltage profile using energy storage systems, voltage control management of renewable energy sources and the injection of renewable energy into the power grid in conjunction with transmission technologies to mitigate frequency deviation and strengthen weak systems.

- The adaptation of smart grid communication standards, such as IEC61850, to automate the connection of renewable power sources to the Grid.

Finally, increasing concerns over the diminishing supply and climate change effects of conventional fossil fuels have led to greater efforts directed towards the development of alternative energy and sustainable environmental technologies. Innovative materials for energy conversion hold the key for renewable energy production. The School of Chemical Engineering and ARC Centre of Excellence for Functional Nanomaterials are now designing a variety of functional materials, aiming to develop innovative material systems that underpin emerging technologies for clean fuel production, water/air pollutant removal, low cost solar cells and anti-reflective self-cleaning coatings. The expected outcomes in the next five years include: -

- Cost effective technologies for hydrogen production from water splitting using solar energy;

- A suite of new materials for efficiently harvesting solar energy to remove the pollutants in wastewater and air;

- New generation solar cells based on low cost metal oxide thin films to generate electricity; and

- Anti-reflective and self-cleaning coatings for solar cell devices.

Again, the effective deployment of any of these technologies will rely heavily on the economic ability to integrate into the grid of the future.

Chapter 5: Investigating the Impact of Distributed Generation on Transmission Network Investment Deferral

Nowadays, the power industry is still characterized by large-scale centralized generation and an extensive transmission and distribution infrastructure. Along with continually increasing size and complexity, the security of large power transmission/distribution networks is being questioned. An important benefit claimed by the proponents of distributed generation is that it can potentially defer large investments in the transmission/distribution infrastructure. However, only a few studies [Borenstein, 2008; Kahn, 2008; Beach, 2008] have been conducted to investigate how significant the effect might be. Moreover, existing studies usually ignore system technical constraints, which can have large impacts on the conclusions of such studies.

To answer this important question, we use a simulation model to investigate the impacts of distributed wind and solar generation on transmission network expansion costs. The transmission network expansion problem is modeled as a cost minimization problem subject to system reliability and AC power flow constraints. Generation investments are implemented using the nodal prices obtained from power flow studies. Power system security constraints, which are also becoming a concern to policymakers, are also carefully considered in our model. The model is applied to the Queensland market, and the simulation results will be presented.

5.1 Literature Review

Economic and engineering questions concerning the implementation of distributed generation technologies have been the subjects of increasing amounts of research in recent years; and rapid progress has been made. Although, strictly speaking, DG can be either renewable or non-renewable, in this chapter we focus on renewable DG technologies only. Therefore we use "distributed generation" and "renewable distributed generation" inter-changeably.

Since the market penetration of DG is still low in most countries, a number of studies [Dondi, 2002; Johnston, 2005] have been conducted to investigate the barriers to DG penetration and the factors that can contribute to its deployment. A number of economic analyses [Gulli, 2006; Abu-Sharkh, 2006] have also been conducted to study the market performance of DG systems. In addition, since DG is usually connected at the distribution level, extensive research [Haffner, 2009; Sharma, 1997; Ball, 1997] has been conducted to investigate the impacts of DG on distribution network planning. These studies usually focus on determining the optimal sizes and locations of DG units in the distribution network from a distribution company's point of view. Other studies [Neto, 2006; Zhu, 2006] have also been performed to understand the impacts of DG from a power system side, such as on reliability, system security and power quality.

The high costs of wind and solar generation have been the most important barriers for their market penetration. Until 2006, the capital cost of wind power was still 4 times higher than coal-fired power in Australia [Wibberley, 2006]. The capital cost of solar PV was even higher. However, since then, these costs have been falling in real terms, particularly in the case of solar, and we can expect these to continue to fall in the future as technological diffusion proceeds. What are frequently ignored in cost comparisons are, firstly, the reductions in transmission losses when DG power is supplied directly to consumers and, secondly, the saving in transmission infrastructure costs that significant investments in DG can potentially bring. With regard to the latter, there is, as yet, no agreement in the literature whether this cost saving effect is significant. [Borenstein, 2008] concludes that, the PV systems in California have had no significant effect on reducing transmission investments, and are unlikely to do so in other areas, due to the fact that PV systems are not specifically deployed in transmission-constrained areas. However, this study has been challenged by proponents of solar PV [see Kahn, 2008; Beach, 2008]. Studies have also been conducted to investigate the impacts of wind power on transmission expansion costs with mixed conclusions [Dale et al, 2004]. A common problem with these studies is that many technical constraints of the power system, especially security constraints, are largely ignored, leading to potentially biased conclusions.

There is a well-developed literature on transmission network expansion that can be drawn upon to augment such studies. Transmission network expansion planning is always conducted by power utilities and is usually modeled as an optimization problem that aims at minimizing expansion investments, subject to system reliability and other technical constraints [Zhao, 2007]. Deregulation and the creation of wholesale electricity markets have changed priorities in the power industry. Transmission network expansion may also involve other objectives, such as enhancing market competition, minimizing network congestion and facilitating the integration of renewable energy sources [Buygi, 2006]. In these new conditions, a number of technical constraints have to be carefully incorporated into transmission expansion models. The most fundamental ones are power flow constraints [Zhao, 2009], which involve physical laws that transmission systems must obey. System security constraints [de.J. Silva, 2005] are also essential to consider in the more fluid market environment, since violating security constraints can potentially cause large scale blackouts and huge economic and social damage.

A number of transmission cost allocation methods have been proposed in the literature to measure the impact of DG on transmission network expansion. Two methods, the postage-stamp rate method and the contract path method [Shahidehpour, 2002], have been widely used in the power industry due to their simplicity. These methods do not consider actual power flows but, instead, they allocate transmission costs based on assumed usage of the transmission network. In practice the usages assumed by researchers applying these two methods tend to differ significantly from actual network usages. Other methods, based on power flow calculations, are available, such as the power flow tracing method [Shahidehpour, 2002] and the influence areas method [Reta, 2005]. The latter has a range of attractions and is the method used in this study to determine the transmission expansion cost saving caused by increasing the supply of power from distributed generators.

5.2 The Transmission Expansion Simulation Model

In this section, we introduce our model for simulating transmission investment behaviour in a regional electricity market. Firstly, we discuss the assumptions and the formulation of the model. Since reliability is a main constraint in transmission expansion, we employ a probabilistic method for reliability assessment. We also employ two security assessment methods for formulating security constraints in the model. Finally the influence areas method is introduced and used to allocate transmission investments.

5.2.1. The Transmission Network Expansion Model

The model employed in this chapter is based on AC optimal power flow (OPF) calculation. This is the most common power network analysis tool. Given the network topology, network device parameters (e.g. line resistance and reactance), generators' information (e.g. capacity and cost) and projected system load levels, the OPF calculation can provide the voltage profiles of all nodes in a network, the power flows of all transmission lines, and the power outputs of all generators. In other words, an OPF calculation can determine how the generators and the transmission network should be operated, subject to the physical constraints of the network.

We make the following assumptions:

1. Transmission network expansion is conducted solely by the transmission network operator. This assumption is valid for any of the regional electricity markets in Australia since, currently, private investors can only invest in the transmission lines between two regional transmission networks.

2. The market operator determines the generation schedules by minimizing overall system generation cost. This assumption matches the policy of the Australian national electricity market (NEM).

3. All generators bid into the market at their short-run marginal costs.

4. The mandatory renewable energy target (MRET) and the renewable energy certificate (REC) market provides policy incentives that are strong enough for the large-scale deployment of wind and solar power. In other words, we assume that the costs of wind and solar PV will fall to levels where they are no longer barriers to their penetration.

Based on the above assumptions, a transmission expansion model can be developed as follows. The first optimization objective is to minimize the total expansion investment cost:

Minimize $O_{invest} = C^T \eta$ (1)

where C is vector of the construction costs of all added transmission lines; η_{ij} is a integer indicating whether a new transmission line will be added in transmission route $i - j$.

The second optimization objective is to minimize the overall generation cost:

Minimize $O_{gen} = \sum_{i \in G} f_i(P_{G,i})$ (2)

where G is the set of all generators in the system; $P_{G,i}$ is the scheduled real power output of generator i; $f_i(\bullet)$ represents the generation cost of generator i.

The major technical constraints considered in the model are the AC power flow constraints, which specify the relationships between bus injected power, bus voltages and network parameters. The limits of line flows, node voltages, generators' active power outputs and reactive power outputs are also taken into account in the model.

As mentioned above, enhancing the system reliability is the basic objective of network expansion. In practice, the transmission network operator will ensure that a minimum reliability level is reached after the network expansion:

$EUE \le EUE_{\max}$ (3)

where EUE denotes expected unserved energy, a widely-used reliability index.

Besides reliability, system security is another important issue to consider in transmission expansion. In our model, we considered two security indices, the *voltage stability index (VSI)* and *transient stability index (TSI)* in our model:

$VSI \ge VSI_{\min}$ (4)

$TSM \ge TSM_{\min}$ (5)

We shall briefly discuss how to calculate EUE, VSI and TSI in the following sections.

In summary, the solution to the proposed model gives the optimal transmission network expansion plan. In this study, we have divided the market simulation into *N* stages and assumed that the transmission network operator will solve model (1)-(5) at each stage and implement the optimal expansion plan.

In practice, system reliability can only be maintained by simultaneously expanding the transmission network and investing in new generation capacities. Therefore, generation investments were also simulated. Since we are interested in the impacts of large-scale penetration of DG, we assumed that strong policy incentives exist in the market so that DG units are investment priorities. Two scenarios are assumed: DG reaches 20% and 40% penetration levels at the end of the simulation. If the added DG capacity is not enough to satisfy the minimum reliability requirement, the insufficient generation capacity is met by building traditional coal-fire plants.

5.2.2 Reliability Assessment

Power system reliability can be seen as offering a degree of assurance to customers that continuous service of satisfactory quality will be maintained. In this study, the widely used expected unserved energy (EUE) [AEMC, 2008] is employed as the index of reliability. The EUE is defined as the expected amount of energy that is not supplied due to the inadequate generation and transmission capacity. In NEM, the EUE is limited within 0.002% of the overall energy traded in the market [AEMC, 2008].

The EUE can be calculated with OPF and Monte Carlo simulation. Before calculating the EUE, probability distributions should be firstly assumed to model load levels and the availabilities of all generators in the market. Load levels are usually assumed to follow normal distributions. The maximum outputs of wind turbine and solar PV are determined by the wind speed and solar irradiation, which can be modeled respectively with Weibull [Celik, 2003] and normal distributions [Kaplanis, 2007]. In each iteration of a Monte Carlo simulation, load levels and the maximum outputs of generators are randomly generated. OPF is then calculated to determine the generation schedule. If all loads can be met, the unserved energy is zero. After *N* iterations of the Monte Carlo simulation, the EUE can be calculated as the average unserved energy of all *N* iterations.

5.2.3 Security Assessment

Power system security is its ability to withstand certain level of disturbances without losing stability. Losing stability can potentially cause blackouts and consequently cause severe economic and social damages. In this study, two indices, the *voltage stability index* and the *transient stability index*, are employed to measure system security.

Voltage stability is the ability of the power system to maintain voltage levels, subject to disturbances. Around the world, a number of large blackouts have been proven to be caused by voltage collapse [Lof, 1992]. A convenient method for voltage stability assessment is to employ singular value decomposition (SVD) [Lof, 1992]. For a power system with n nodes, denote $\bar{J}$ as the power flow Jacobian matrix [Lof, 1992], which contains the first derivatives of the real power and reactive power of all nodes in the system with respect to voltage magnitudes $\vec{V}$ and angles $\vec{\theta}$:

$$\bar{J} = [\begin{matrix} \partial\vec{P}/\partial\vec{\theta}, & \partial\vec{P}/\partial\vec{V} \\ \partial\vec{Q}/\partial\vec{\theta}, & \partial\vec{Q}/\partial\vec{V} \end{matrix}] = [\begin{matrix} \frac{\partial P_1}{\partial\theta_1},...,\frac{\partial P_n}{\partial\theta_n}, & \frac{\partial P_1}{\partial V_1},...,\frac{\partial P_n}{\partial V_n} \\ \frac{\partial Q_1}{\partial\theta_1},...,\frac{\partial Q_n}{\partial\theta_n} & \frac{\partial Q_1}{\partial V_1},...,\frac{\partial Q_n}{\partial V_n} \end{matrix}] \quad (6)$$

The smallest singular value of a matrix is a measure of distance between this matrix and the set of all rank-deficient matrices [Lof, 1992], the smallest singular value of $\bar{J}$ therefore can be seen as the distance to the voltage stability limit. If we perform singular value decomposition of $\bar{J}$ we have:

$$\bar{J} = \bar{U} \cdot \bar{\Sigma} \cdot \bar{V}^T = \sum_{i=1}^{n} \sigma_i \vec{u}_i \vec{v}_i^T \quad (7)$$

where $\bar{U}, \bar{V}$ are two orthogonal matrices; $\vec{u}_i, \vec{v}_i$ are the columns of $\bar{U}, \bar{V}$. $\bar{\Sigma}$ is a diagonal matrix with

$$\bar{\Sigma} = [\begin{matrix} \sigma_1 & 0... & 0 \\ \vdots & \ddots & \vdots \\ 0 & 0... & \sigma_n \end{matrix}] \quad (8)$$

where $\sigma_1 ... \sigma_n$ are the singular values. The smallest σ_i will be selected as the voltage stability index (VSI).

Another security index is the transient stability index (TSI). Transient stability is the ability of all generators in the system to maintain synchronization subject to disturbances. The transient stability index gives us an indicator of the distance to the transient stability limit. In our study, the TSI is calculated by performing time domain simulation, which is well-known for its superior accuracy. Time domain simulation takes into account the detailed models of all major generators in the system, and calculates the system behaviour trajectories step by step. The transient stability of the system can then be determined by comparing the trajectories of different generators. A number of potential system contingencies (e.g. failure of a major generator, sudden decrease of solar radiation and wind speed) will be considered in the study. The TSI will be calculated as the probability that the system maintains the stability subject to these potential contingencies.

5.2.4 Transmission Expansion Cost Allocation

We employ the *areas of influence method* [Reta, 2005] to allocate transmission expansion cost. This method is also based on power flow calculations. It can be employed to determine the contribution of each market participant to the overall expansion cost. The transmission cost allocation is based on the marginal use of the network. The power flow is firstly calculated for a typical system load setting as the base load flow case. A single generator is then be added into each bus successively. The area of influence of a specific node is defined as the transmission lines in which the power flow increases, compared to the base case.

Based on power flow increases in transmission lines, it is possible to calculate a *participation factor* [Reta, 2005] for each generator for using a line. The participation factor measures the power flow change in a line caused by a specific generator. Finally, transmission expansion costs are allocated to each generator proportionally to their participation factors.

5.3 Case Study Results and Findings

5.3.1 Case Study Setting

The proposed simulation model is applied in the Queensland market. In our study, the Queensland system is divided into 11 regions. The one line diagram of the Queensland network before simulation is given in Fig. 1.

In our study, 6 different scenarios are created from the combination of two factors: DG technologies and maximum DG penetration levels. The overview of the 6 scenarios is given in Table I. The 20% penetration level is identical to the mandatory renewable energy target (MRET) of Australia government, while the 40% penetration level indicates a more aggressive market expansion of DG. In each scenario, the transmission expansion behaviours from 2010 to 2019 were simulated. We assumed that the penetration level of DG increases at a constant speed and reaches the maximum level at 2019.

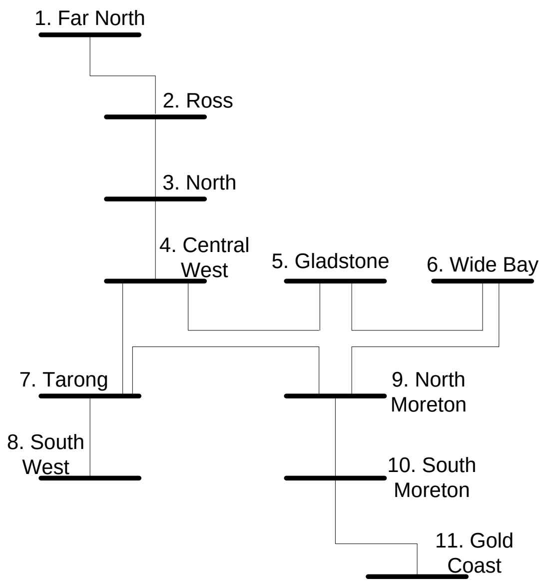

Figure 1 One Line Diagram of the Queensland Network

The projected load levels were assumed to grow at a constant rate of 3.6%/year, which is identical to the medium growth scenario in the report of Australian Energy Market Operator (AEMO) [AEMO, 2009]. AEMO also provides the required generation capacities for ensuring the system reliability objective (0.002%) from 2010 to 2019. In the base case scenario, the required generation capacity was met only by coal fire plants. In the other 5 scenarios, generation capacity was met by investing firstly in DG units, then in coal fire plants.

Table I 6 Simulation Scenarios

Scenarios	**DG Technology**	**Maximum DG Penetration Level**
Base Case	No DG installed	0%
1	Wind turbine with simple induction generator (SIG)	20%
2	Wind turbine with SIG	40%
3	Wind turbine with doubly fed induction generator (DFIG)	40%
4	Solar PV Panel	20%
5	Solar PV Panel	40%

We assume that all new transmission lines have a nominal voltage of 275 KV and a capacity of 250 MVA. The construction cost was assumed to be 50 M$/100km.

5.3.2 Wind Power Scenarios

The simulation results of the base case and three wind power scenarios are reported in this section. In the simulations, we assumed that wind turbines can only be installed in Far North and Ross areas (nodes 1 & 2). This is because in Queensland, only the North-east coast line area has high wind power potential [Outhred, 2006]. The simulated transmission expansion investments and the EUEs for the base case scenario are plotted in Fig. 2. As observed, the transmission investments are relatively small in the first several years, largely due to the sufficient transmission capacity at the beginning of the simulation. From Fig. 2 we can also observe that, the transmission expansion generally can maintain the EUE within 0.0015%, which is a reasonable level.

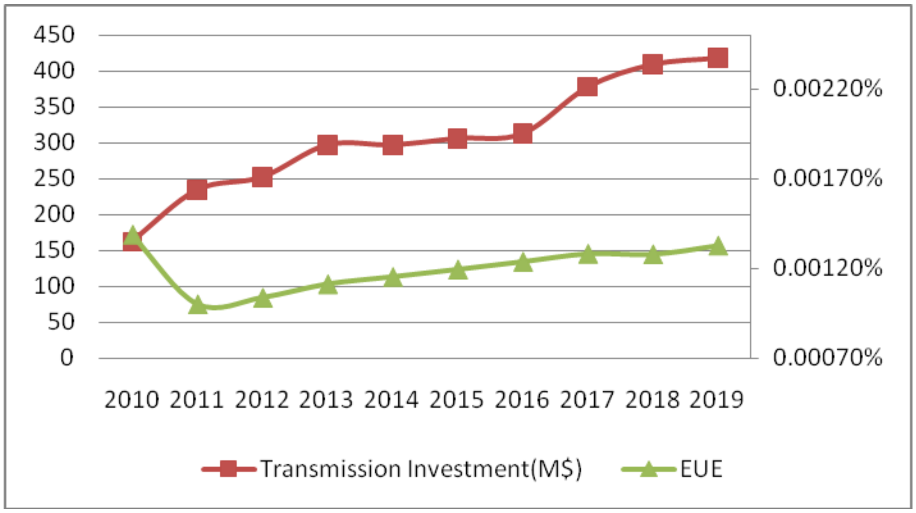

Figure 2 Transmission Investments of Base Case Scenario

The simulation results of scenario 1 are plotted in Fig. 3. As observed, wind turbines do have a clear effect on transmission investment deferral in 2011-2012 and 2014-2015, because in the early stage of wind power penetration, it satisfies local demands and thus reduces transmission congestions in North Queensland. We can also observe that, the transmission investments caused by wind power in 2011-2013 are higher than 2014-2015. This is because the wind turbine equipped with simple induction generator absorbs reactive power, and the reactive power capacities in Far North and Ross areas are insufficient. Transmission expansion is therefore needed for voltage support purposes.

After 2015, the wind power capacity has exceeded local demand and starts to be traded to other areas in the market. We therefore observe that the transmission investments caused by wind power rise again from 2015. Moreover, the overall transmission investments from 2016 to 2019 are relatively close to the base case. This is largely because wind turbines have very small short-run marginal costs. Therefore, all wind turbines can be dispatched and can sell power to South Queensland, which is a highly populated area with high load levels. This trend significantly changes original power flow patterns, causing congestions between North and South areas, triggering transmission investments.

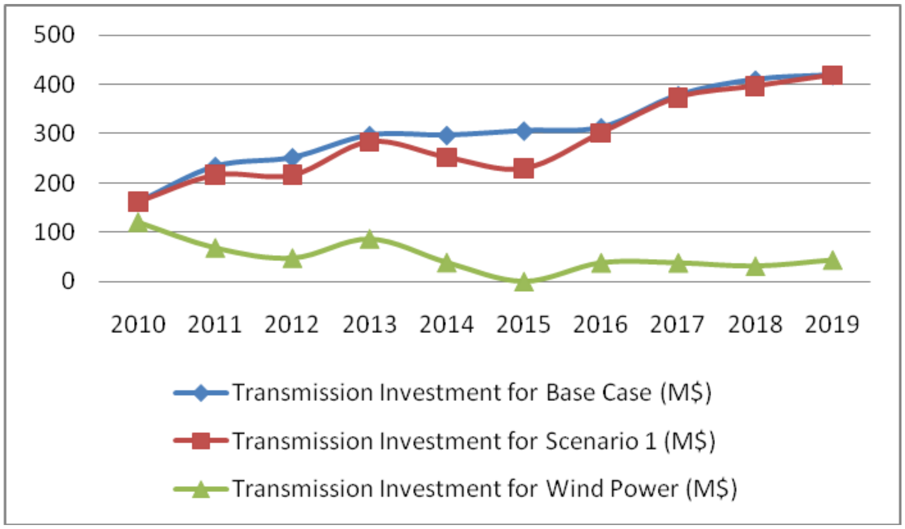

Figure 3 Transmission Investments of Scenario 1 (20% Wind Turbine with SIG)

For scenarios 2 and 3, the transmission investment deferral effects are even smaller. As seen in Figs. 4 and 5, wind power generally does not reduce the transmission investment significantly. For scenario 2, wind power even increases the transmission investment in 2012. From the three wind power scenarios it can be observed that, whether or not DG can reduce transmission investments is largely determined by location and network topology. Placing DG units in inappropriate areas significantly weakens the deferral effect.

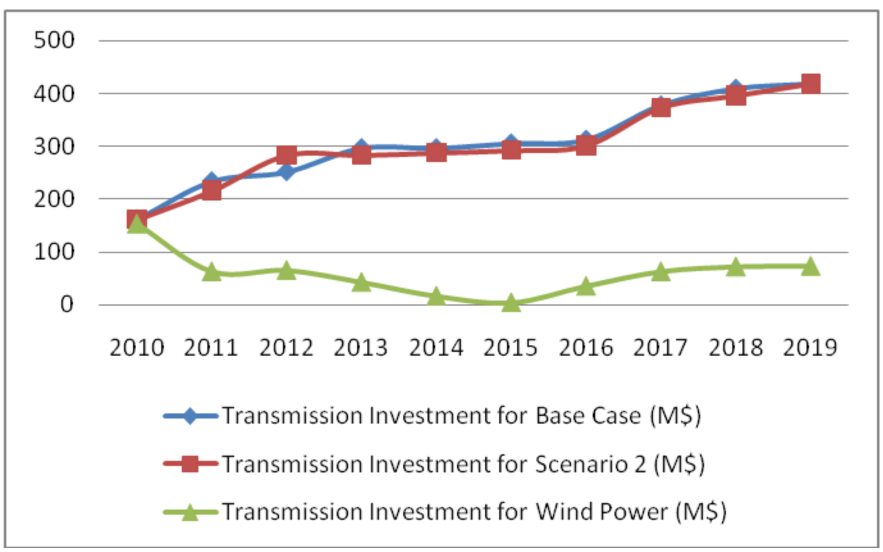

Figure 4 Transmission Investments of Scenario 2 (40% Wind Turbine with SIG)

The VSIs of three wind power scenarios are also plotted in Fig. 6. As observed, in scenarios 1 and 2, the penetration of wind power significantly worsens voltage stability compared to the base case. This is because the wind turbines equipped with SIG cannot generate reactive power. The reactive power is usually drawn from local sources because the line loss of reactive power transmission is much greater than real power. Traditionally, coal fire plants are main reactive power sources. In scenarios 1 and 2 however, there are insufficient reactive power capacities in Far North and Ross areas since only wind turbines are added into these areas. On the other hand, in scenario 3 the voltage stability remains at a reasonable level, since the wind turbines with DFIG can supply reactive power if necessary. To maintain voltage stability, voltage support facilities, such as capacitor banks, must be installed in areas with high wind capacities. In practice, the transmission network operator is responsible for investing in voltage support facilities **-** the cost of voltage support is also considered as a part of transmission investment. Therefore, the wind turbine with DFIG is a better DG option since it can reduce the voltage support cost.

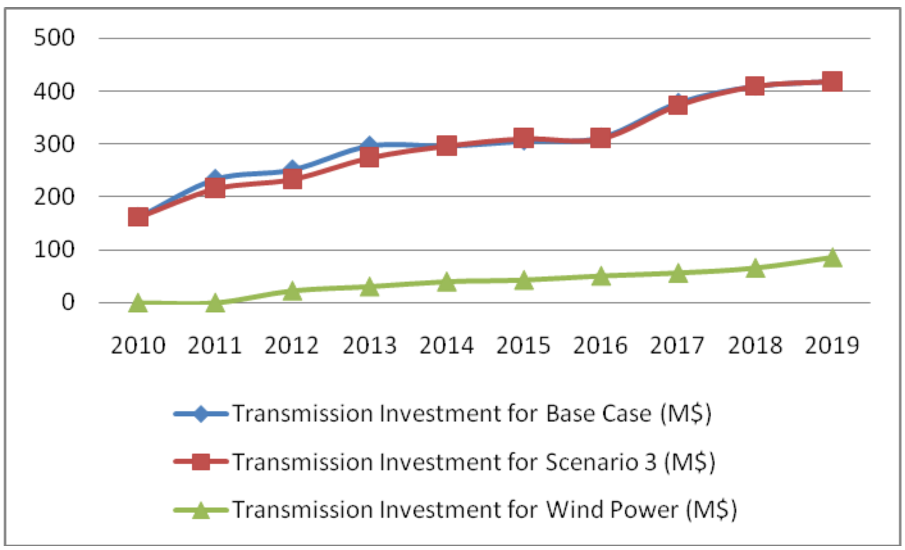

Figure 5 Transmission Investments of Scenario 3 (40% Wind Turbine with DFIG)

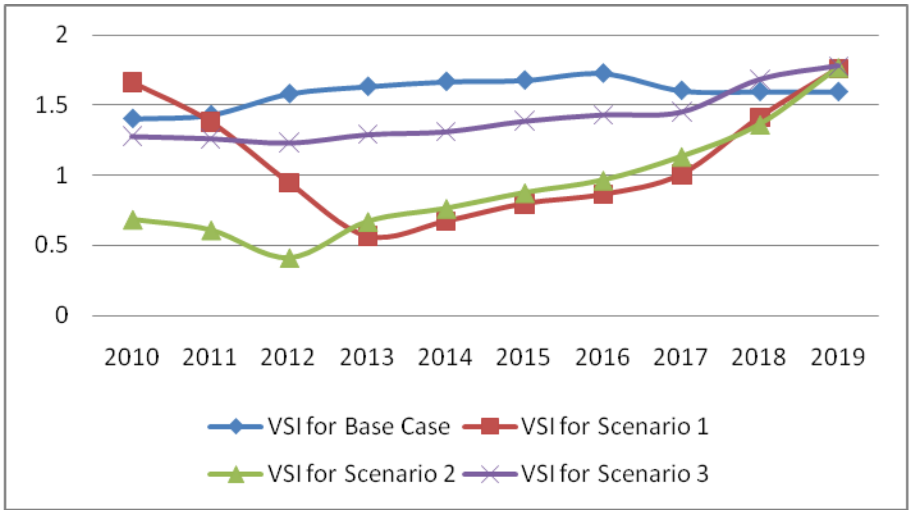

Figure 6 Voltage Stability Index for Wind Scenarios

5.7.3 Solar PV Scenario

In scenarios 4 and 5, we assume that solar PV panels are evenly deployed in all 11 areas of the Queensland market. The transmission investments of two solar PV scenarios are illustrated in Figs. 7 and 8. As observed, in both scenarios, solar PV has a clear effect in reducing transmission investments. Moreover, the investment for transferring solar power in scenario 4 and 5 are small compared with the overall transmission investments. The reason behind these observations is that solar PVs are spread evenly over the market. Most of the solar power is therefore consumed by local demand. This mitigates network congestion and consequently reduces transmission investments. Compared with scenarios 1-3, we again confirm that the location of DG is an important factor in determining its impacts on transmission expansion.

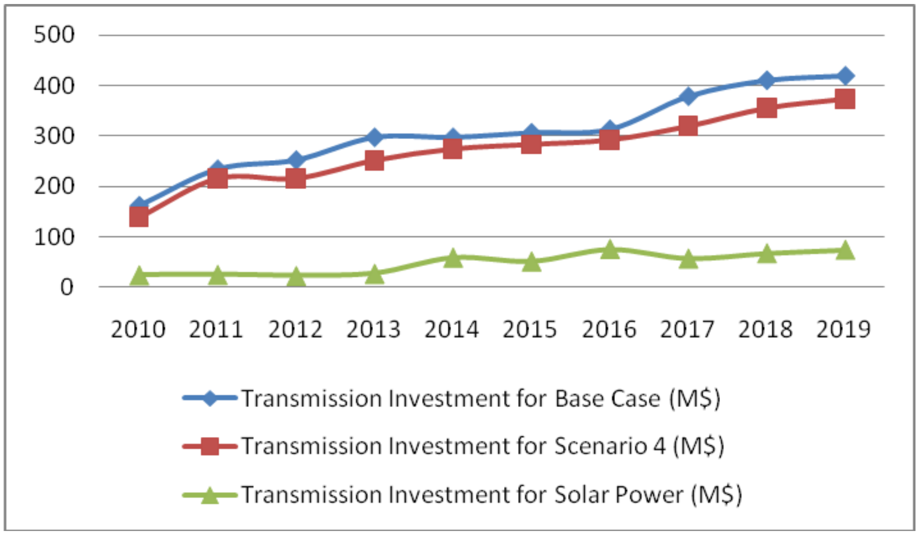

Figure 7 Transmission Investments of Scenario 4 (20% Solar PV)

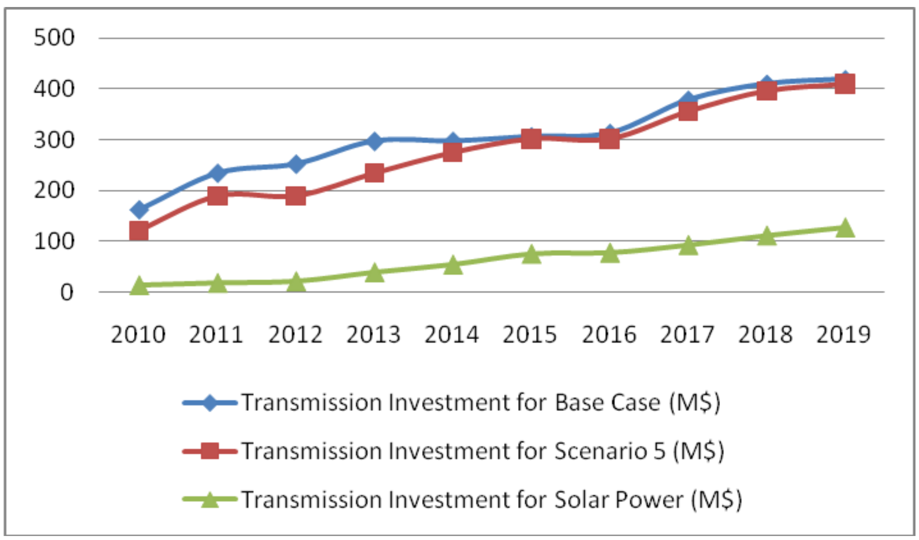

Figure 8 Transmission Investments of Scenario 5 (40% Solar PV)

The voltage stability indices (VSI) of scenarios 4 and 5 are also plotted in Fig. 9. As observed clearly, Solar PV panels can improve voltage stability. This is because solar PV panels are deployed in all areas of the market, they therefore can reduce the local active and reactive power demands, consequently help maintain the voltage level.

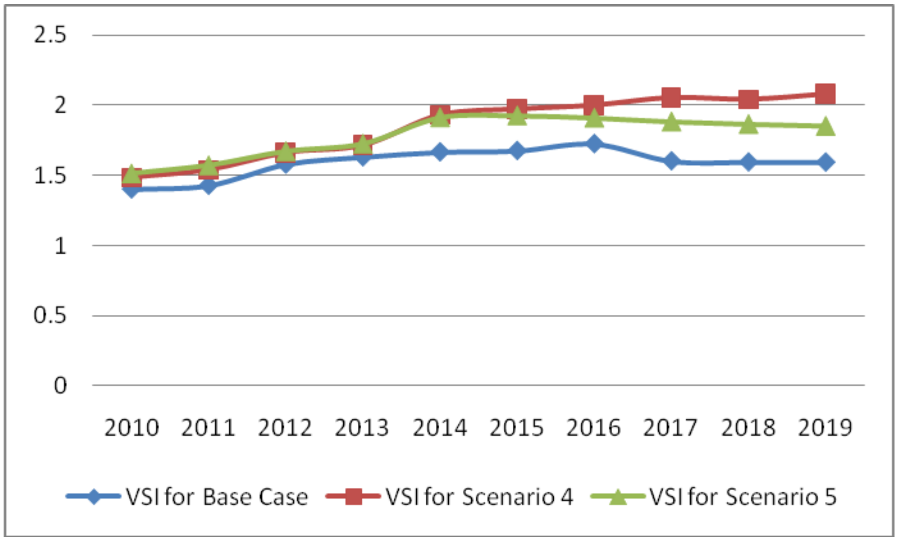

Figure 9 Voltage Stability Index for Solar Scenarios

The transient stability index (TSI) for scenarios 4 and 5 is also depicted in Fig. 10. As is shown, the 20% penetration of solar PV already has a clear negative effect on the transient stability. Moreover, after solar PV achieves a 40% penetration level, the TSI drops even below 75%, which indicates that the transient stability of the system has reached a dangerous level. In other words, from the viewpoint of system security, a 40% penetration of solar PV may not be feasible. Transient security concerns can, thus, weaken the extent to which solar PV can reduce transmission investments.

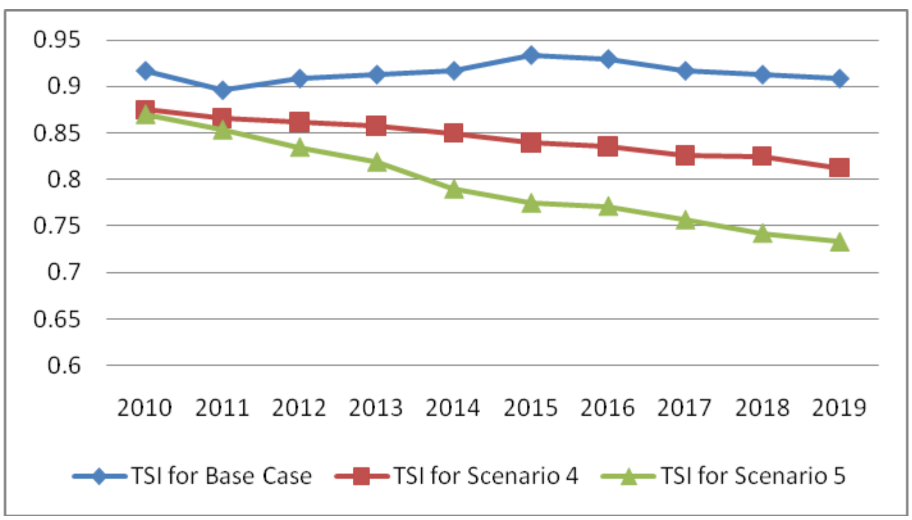

Figure 10 Transient Stability Index (TSI) for Solar Scenarios 4 and 5

Summarizing the discussions above, we have following observations:

1. In general, both solar PV and wind power can defer transmission investments;
2. Whether the deferral effect is significant is determined by a number of complex factors, such as the locations of DG units, network topology and original power flow patterns;
3. The deployment and the corresponding investment deferral effect of DG are also limited by technical constraints. For example, insufficient reactive power capacity will limit the deployment of wind turbine with SIG. Transient stability will limit the deployment of solar PV.

5.8 Conclusion

In this chapter, we have conducted a quantitative analysis of the factors that determine whether DG can significantly reduce transmission investments. We implemented a transmission expansion simulation model, which was formulated as a multi-objective optimization problem with AC OPF and system security constraints. The model was then applied to the Queensland market to study the impacts of two DG technologies, wind turbine and solar PV panel.

The simulation results indicate that, although DG generally can defer transmission investments, it is inappropriate to offer a general conclusion about the strength of this effect. In practice, the locations of DG units, the network topology, and the original power flow patterns all have significant impacts on DG’s investment deferral effect. In the Queensland market, solar PV would have a stronger effect on transmission investment deferral compared to wind power, since it can be deployed evenly in all areas of Queensland, while wind power can only be concentrated in North-east areas. Moreover, our simulation results also show that, the investment deferral effects of DG are largely limited by technical constraints, such as voltage and transient stability. It is therefore important to carefully consider these constraints when evaluating the actual benefits of DG.

Many of the conclusions drawn here can be applied in other regions of the world. Wind turbines are almost always concentrated in areas with relatively strong wind power and solar generation can usually be spread out geographically. These geographical considerations matter from transmission costs but they have tended to be neglected in discussions of the costs of DG relative to conventional, centralized power generation. Clearly, the evolution of efficient storage systems will be critical in solving transient stability problems. In the case of solar panels and wind turbines this remains problematic but this is much less so in the case of solar thermal generation where it involves the much simpler matter of storing heat rather than electricity. We already know that heat storage is much cheaper than electricity storage and a useful topic for further research would be to make a comparison of solar panels and solar thermal from the transmission investment perspective.

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