Authors

Prof. John Foster

Dr Liam Wagner

Dr Phil Wild

Mr Craig Froome

Dr William Paul Bell

Dr Junhua Zhao

INTELLIGENT GRID
RESEARCH CLUSTER - PROJECT 2

Market & Economic Modelling of the Impacts of Distributed Generation

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iGrid
intelligent grid
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Energy Economics and Management Group

Postal address:	School of Economics, The University of Queensland
	St Lucia, Brisbane QLD 4072, Australia
Phone:	+61 7 33460594 or +61 7 33656780
Fax:	+61 7 3365 7299
E-mail:	webeemg@uq.edu.au
Website:	http://www.uq.edu.au/eemg/

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1. EXECUTIVE 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) constructed a variety of sophisticated models, two of which have been implemented using supercomputing facilities at both University of Queensland (UQ) and Monash University, 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. 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 Section 2 we compare different types of DG to a range of centralised power generation options using the best information currently available via explicitly integrating 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. We also consider different carbon abatement scenarios. We have integrated a wide range of technology types considered previously by the CSIRO (CSIRO, 2009), AEMO (AEMOb 2011) for inclusion in the NEM. Our simulations suggest that DG could reduce pressures on retail tariff price rises across Australia and across the rest of Australia. When we include all the externalities considered in the AEMO NTNDP (AEMOb 2011) 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 and in the case study discussed in this Report, PLEXOS simulations suggest that DG is a viable option to deliver significant cuts in emissions and reductions in expenditure on the transmission network. The results are conclusive: including DG in the generation asset portfolio is rational from an investment appraisal perspective in the coming years. What the mix will be will, of course, depend upon the carbon policy selected and the adaptive capability of the regulatory/institutional environment that determines how energy is supplied and demanded.

Section 3 looks 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 (ANEM) 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 from a policy perspective, this could well be infeasible. Thus, the findings point strongly towards the installation of significant commercial PV, in addition to residential PV. 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. Section 4 discusses 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 Project 2. 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 operational, a range of economic experiments have commenced to ascertain the feasibility of different kinds of panels, inverters, battery storage systems, etc. We strongly believe that this kind of ‘hands on’ economic 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. This work in Project 2 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. This finding is supported by the research work conducted by project 4 of the research cluster- Institutional Barriers, Stakeholder Engagement and Economic Modelling. 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 Section 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 Alternating Current (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. 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 when they are below 30MW in size. 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.

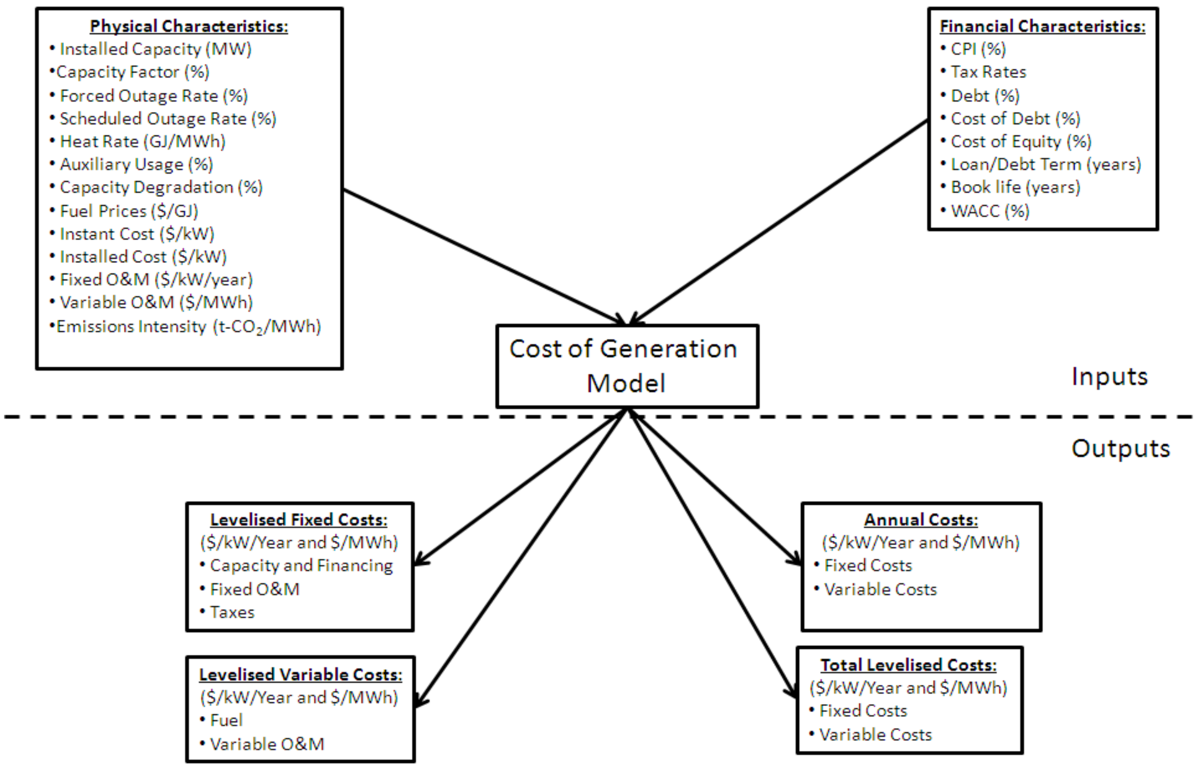
So, we know that, in some conditions, DG can lead to deferral of transmission investments. However, a very careful assessment of the technical conditions in any region, conducted by electrical engineers, is essential before any firm conclusion can be made. Clearly, further research needs to be done in this area. 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 high 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 Project 2 to provide the modelling capabilities to do this. Similarly, Project 3 of the iGrid cluster- Optimal siting and dispatch of Distributed Generation reaches similar conclusions.

2. THE ECONOMIC VIABILITY OF DG VERSUS CENTRALISED GENERATION

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 in the latter. The pricing of generation assets is usually established via levelised cost of energy (LCOE) analysis (Thumann & Woodruff 2005). This incorporates all future costs, revenue streams and their associated net present value. What has been lacking, however, is the integration of distribution use of service (DUOS) and transmission use of service (TUOS) charges which greatly affect the final cost of electricity to retail customers. So our goal is to determine what the true costs of different generating technologies are. Although we can draw upon an international literature on LCOE, it is necessary to derive costs that are specifically relevant to Australia to input into our modelling. We have relied on a variety of Australian sources for information on generator costs (ACIL Tasman 2009a, AEMC 2008a, AER 2009).

In order 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**,** we provide a schematic which outlines all of the assumptions for the cost of generation model (for a full exposition of this methodology, see Project 2 Annual Report 2010, Section 4).

Figure 1: Levelised Cost Methodology



2.1 Scenarios

When trying to establish the likely outcomes of a range of policy measures, it is best to progress through a number of different scenarios to provide broad advice to key stake holders. Moreover we can examine a range of carbon abatement trajectories from the centralised versus end consumer point of view. We restrict ourselves to retail domestic consumers rather than large scale industrial users who may receive a range of discounts on their DUOS and or TUOS costs for delivered energy.

The scenarios which we examine are as follows:

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

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

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

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

DUOS/TUOS case with no carbon trading: An alternative BAU case where we depart from the current paradigm and examine electricity generation from a end users perspective. Thus, distribution and transmission charges are applied.

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

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

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

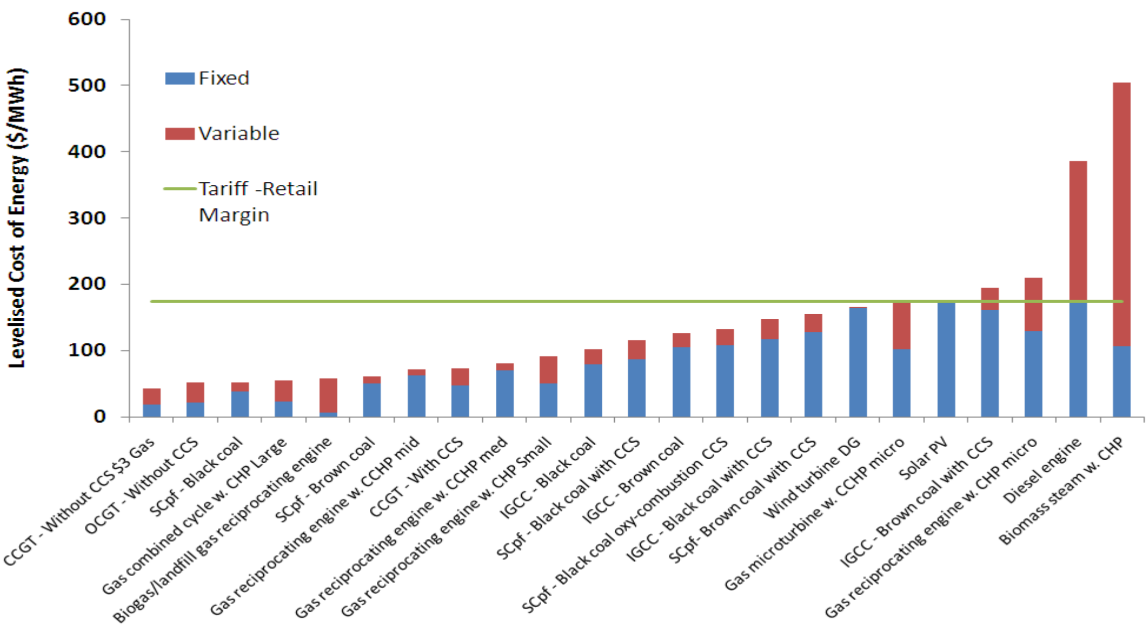
2.2 Results

Evaluating the levelised cost of generation is one input into an extremely complicated process of investment in the electricity supply industry (California Energy Commission, 2009). We progress through all eight scenarios and then present an overview of our findings. In all scenarios the current retail tariff 11 prices for Queensland are used for illustrative purposes to show how different generation costs contribute to the price of delivered 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%.

2.2.1 Scenario 1

This scenario reflects the current practice of central planners, generators and other stake holders in the electricity supply industry (ESI) when they evaluate different technological options for inclusion in the a generation portfolio. Typically, stakeholders view the system from 'top down' by asking how their investment would perform given the competitive merit order of dispatch on the NEM. In this scenario deployment of further generation into the NEM would almost certainly come from lowest cost generation, mainly gas fired CCGT or OCGT and supercritical pulverised fuel (SCpf), using black coal as its fuel source. These centralised generation options would be favoured by most stakeholders given the current regulatory regime and the availability of coal and natural gas within all states of the NEM. SCpf is currently the leading edge technology for coal fired generation, with Kogan Creek power station the newest member of this class to be deployed on the NEM. Its higher thermal efficiency and lower emission intensity are also contributing factors to its lower cost. Surprisingly, 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 2). A unit of this size would be suitable for scheduled dispatch onto the NEM and could compete in the merit order for dispatch.

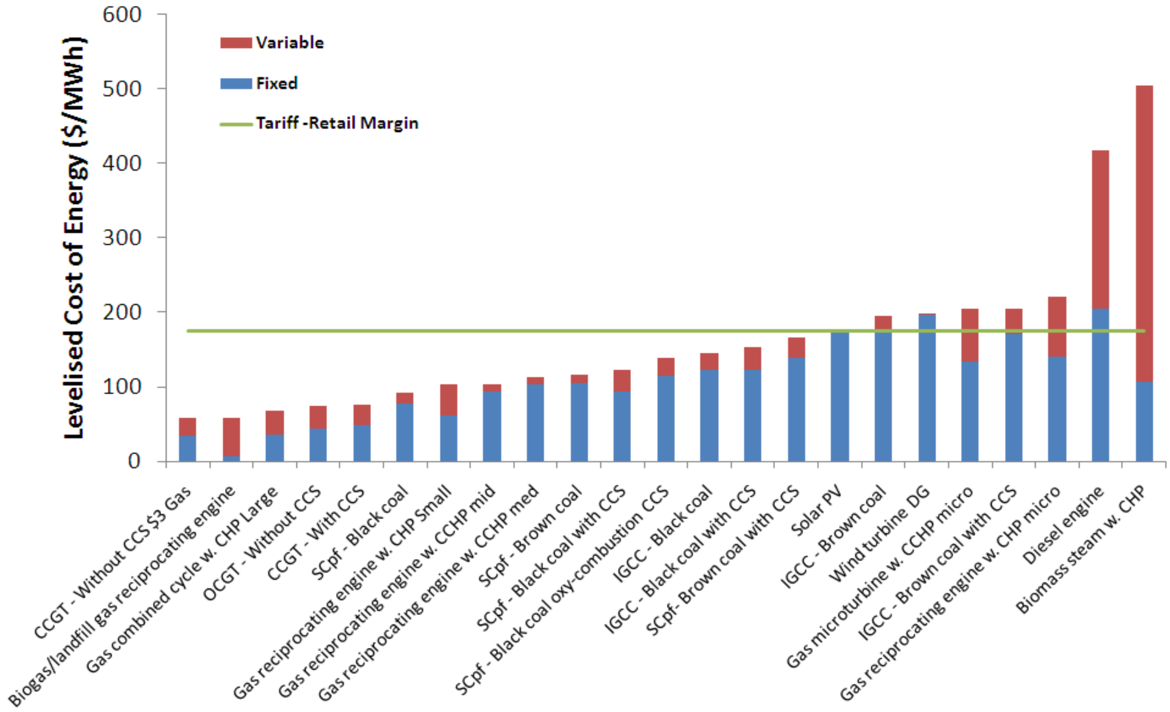
Figure 2: Scenario 1, BAU No DUOS/TUOS



2.2.2 Scenario 2

Given the current political landscape in Australia this scenario contains the most likely carbon abatement option. The policies announced and proposed before Federal Parliament (Commonwealth of Australia 2008), 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, it is certainly the most competitive base load generator from an LCOE perspective. So we can expect a significant shift toward gas generation, rather than the deployment of significant DG, if the 5% target is adopted.

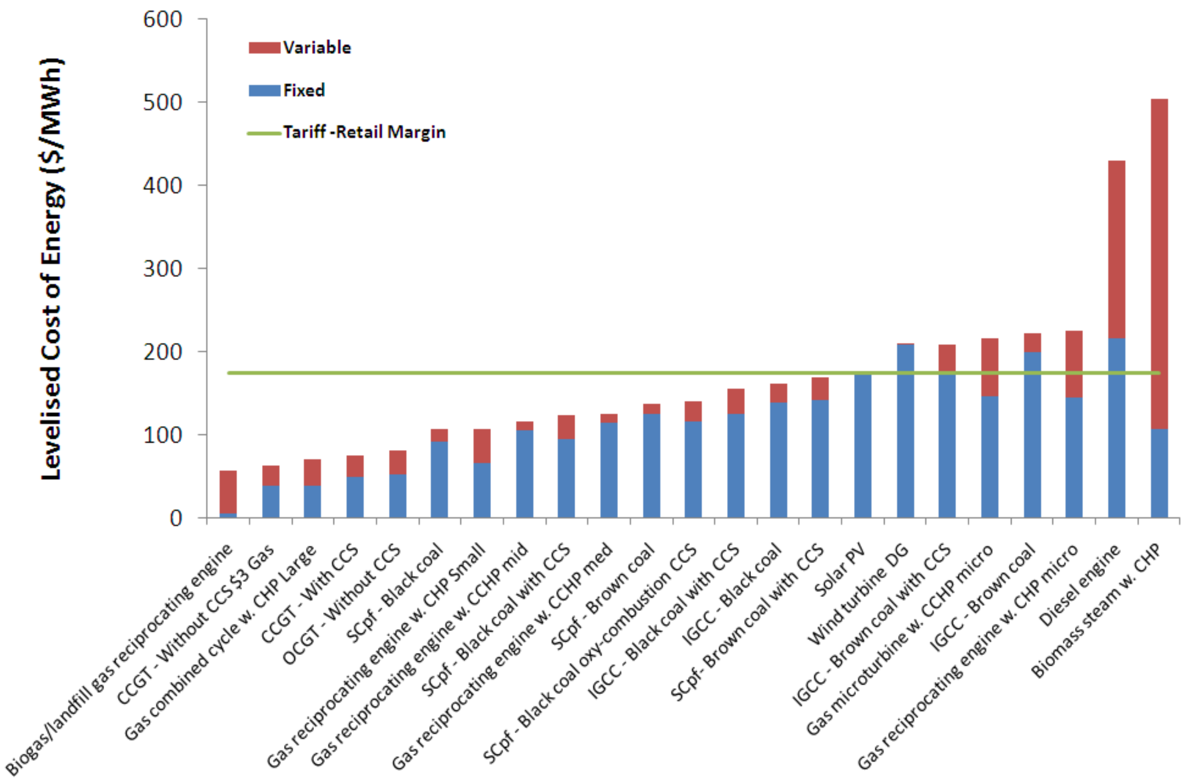
Figure 3: Scenario 2, CPRS - 5% no DUTO/TUOS



2.2.3 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, it remains a possible aspirational target that is still physically and technically possible once a carbon trading regime is established. CCGT without CCS was found to be the most competitive up to a gas price of $3/GJ. SCpf black coal remains viable during the planning horizon out to 2025.

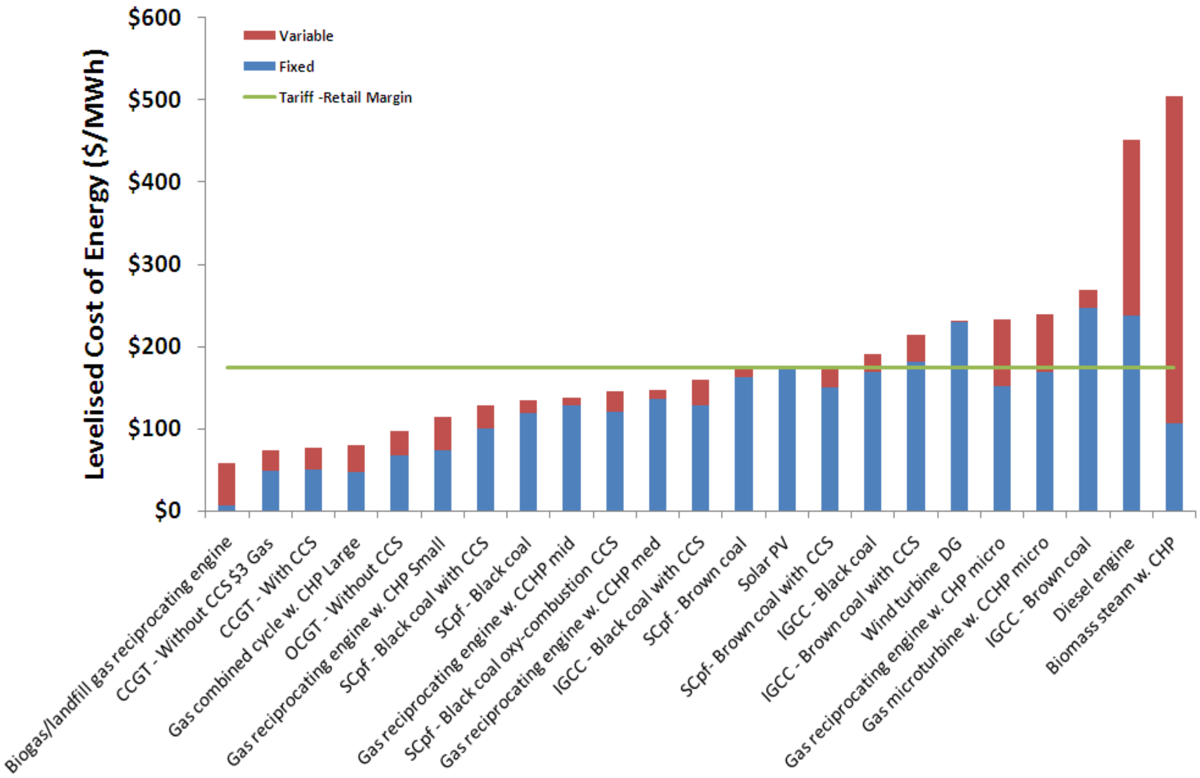
Figure 4: Scenario 3, CPRS - 15% no DUTO/TUOS



2.2.4 Scenario 4

While the prospect of a 25% cut to emissions may seem very remote at the time of writing this report, it should be considered as a possibility given previous commitments of the Federal Government to global agreements on abatement. The long term carbon price trajectory chosen by Treasury (Commonwealth of Australia 2008), is applied 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. While CCS technologies appear to be desirable, given the high carbon price, they are very unlikely to be able to be deployed at any significant scale until after 2015 (AEMO 2011b). It is striking that, even at a high carbon price, DG still does not feature as an attractive option. This underlines the seriousness of omitting DUOS and TUOS from LCOE calculations.

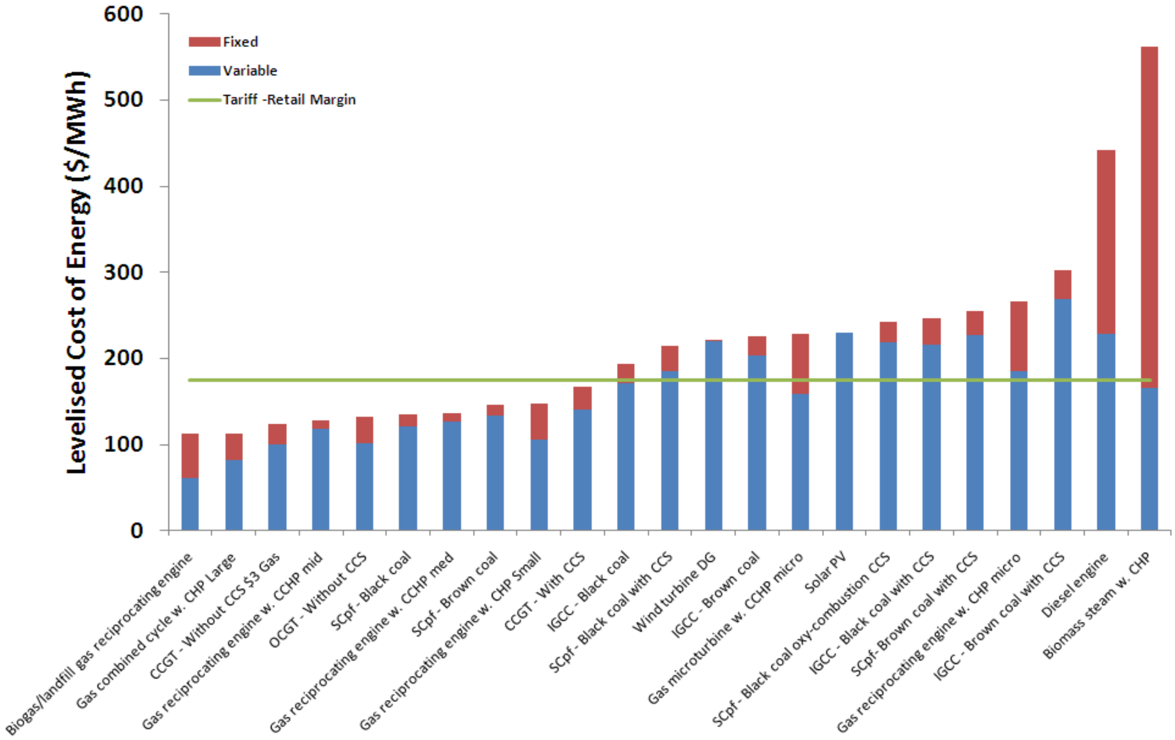
Figure 5: Scenario 4, CPRS - 25% no DUTO/TUOS



2.2.5 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. DG options begin to become much more competitive, even in the BAU case.

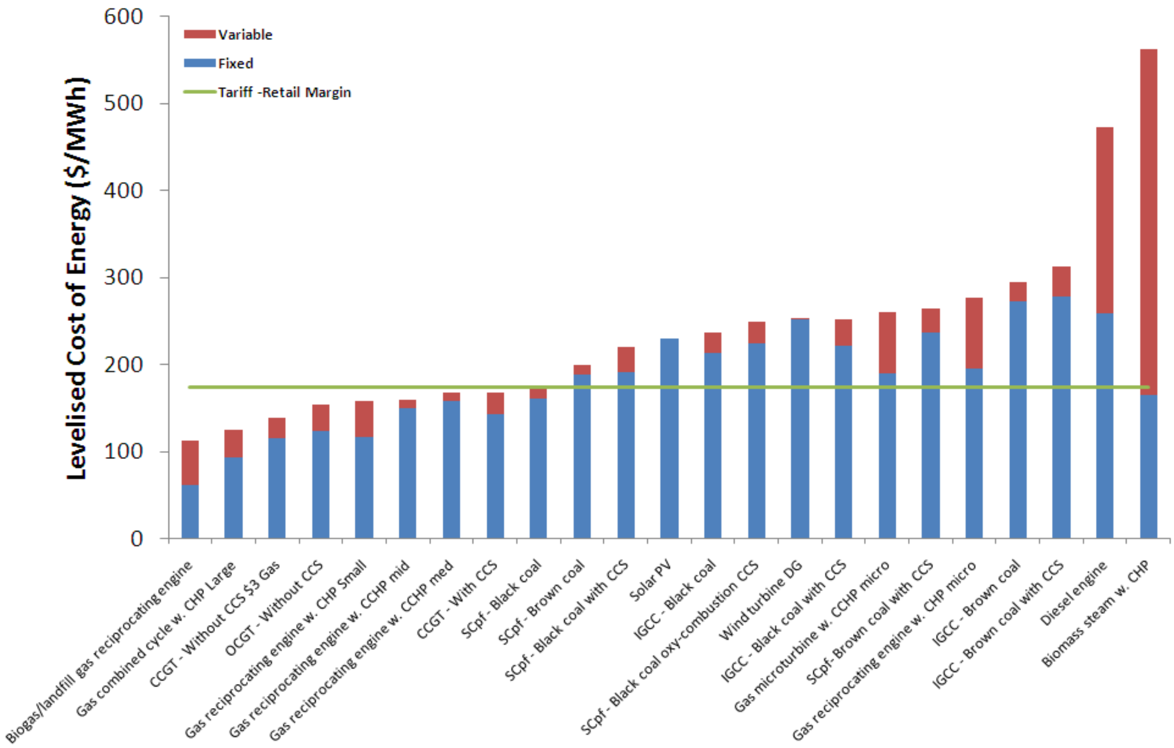
Figure 6: Scenario 5, No CPRS with DUTO/TUOS



2.2.6 Scenario 6

With the introduction of a CPRS with a 5% reduction in emissions and a $33/t-$CO_2$ carbon price, a significant rearrangement of the possible generation mix is apparent. The continued presence of biogas/landfill gas technology can be greatly attributed to its eligibility under the Renewable Energy Target (RET) scheme, and its zero net emissions intensity factor. But, 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 their lower price relative to the current retail tariff.

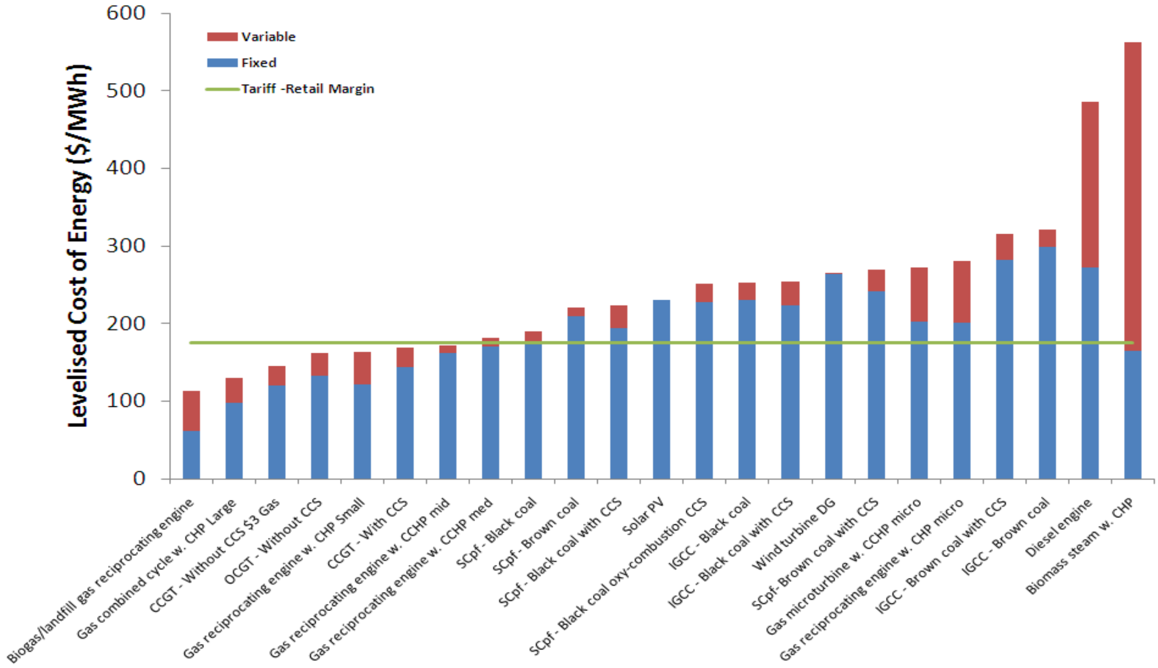
Figure 7: Scenario 6, CPRS - 5% with DUTO/TUOS



2.2.7 Scenario 7

The imposition of a 15% reduction in emissions and DUOS/TUOS continues to push conventional technologies further away as 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. CCS is still a less than desirable option given that it's soonest construction is 2015 (AEMO 2011b).

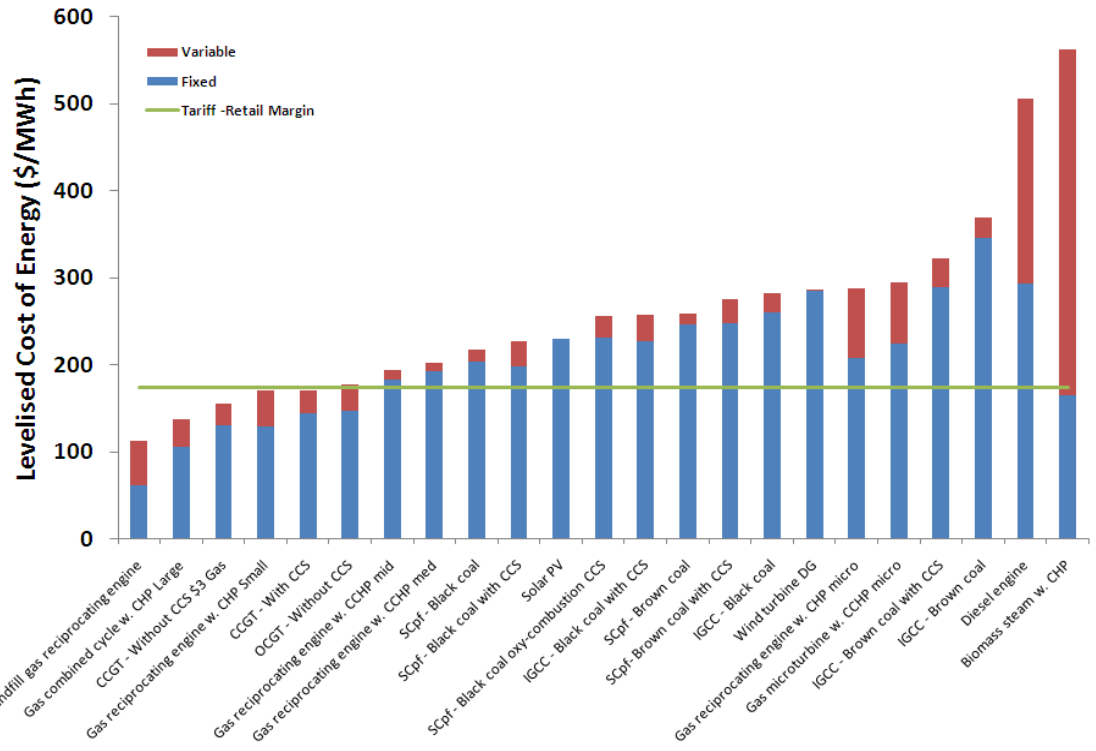
Figure 8: Scenario 7, CPRS - 15% with DUTO/TUOS



2.2.8 Scenario 8

The final scenario involves a 25% cut in emissions with the inclusion of DUOS/TUOS. The broad scale deployment of Combined Heat and Power (CHP) 30MW (i.e. cogen) is the most cost effective technology with such a high carbon price given the availability of its fuel source. The town gas that this technology would be primarily using, at roughly $9/GJ, certainly takes advantage of being inside the distribution network.

Figure 9: Scenario 8, CPRS - 25% with DUTO/TUOS



2.3 Conclusions

With the inclusion of all the externalities considered in the AEMO National Transmission Network Development Plan [AEMO 2011b] and DUOS/TUOS in the LCOE, it is quite clear that DG can compete without a DUOS discount against centralised generation. As has been previously reported in the Project 2 Annual Report (2009), using PLEXOS simulations, DG is an option which can help deliver significant cuts in emissions and reduce expenditure on the transmission and distribution networks. This study integrates a wide range of technology types considered previously by the CSIRO (CSIRO 2009), AEMO (AEMO 2011b) 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. It also the case that this study has not taken full account of the fact that the unit cost of solar PV panels has been falling rapidly. Thus, it is likely that LCOE calculations in the coming years will begin to show that this DG technology is much more competitive than in the scenario simulations presented here.

3 THE IMPACT OF DG DEPLOYMENT: A CASE STUDY APPLYING PLEXOS MODELLING

In the P2 Project, PLEXOS modelling has been applied extensively to assess the impact of significant deployments of DG on wholesale electricity prices, emissions and investment in network and centralised generation assets. The results of this modelling have been presented in the Project 2 Annual Reports. The Energy Economics and Management Group (EEMG) at the University of Queensland (UQ), in collaboration with the CSIRO, prepared a case study on the impacts of significant deployment of Distributed Generation (DG) throughout the NEM. Five policy scenarios were simulated. These varied in terms of energy demand, fuel costs, carbon prices and the scale and scope of installed technology types.

Developing forecasts for energy market behaviour out to 2020 presents many challenges given the uncertain regulatory environment. Furthermore, forecasting the composition of generation asset types, network topology and demand require a significant reliance on the assumptions prepared for this project as a part of UQ's NEM database. The development of an analytical framework that can model the NEM and capture price variation associated with the rollout of DG energy can provide significant support to decision makers seeking emissions reduction via both technological improvements and alternative investment prioritisation. This requires a range of modelling inputs with respect to demand and supply in the NEM that can provide half hourly electricity market simulations over an annual planning horizon.

3.1 Modelling Distributed Generation

PLEXOS is a commercially available optimisation theory based electricity market simulation platform. At its core is the implementation of rigorous operation algorithms and tools such as linear programming (LP) and mixed integer programming (MIP). PLEXOS takes advantage of these tools in combination with an extensive input database of regional demand forecasts, inter-regional transmission constraints and generating plant technical data to produce price, generator and demand forecasts by applying the SPD (scheduling, pricing and dispatch) engine used by NEMMCO to operate the NEM (known as the NEMDE). PLEXOS has been used extensively by Australian market participants to provide forecasts of NEM variables to guide their generation strategies. It is also used by publicly listed Australian generators to provide detailed market performance analysis for their annual audit reporting requirements.

Modelling the NEM central dispatch and pricing for the Regional Reference Nodes (RRN), is achieved by determining the generators that need to be included for each five-minute dispatch interval in order to satisfy forecasted demand. To adequately supply consumer demand, PLEXOS examines which generators are currently online or are capable of being turned on to generate for the market at that interval. This centralised dispatch process uses the LP dispatch algorithm SPD to determine the generators in the dispatch set in the given trading interval, taking into account physical transmission network losses and constraints. Each day consists of 48 half hour trading periods, and market scheduled generators have the option to make an offer to supply a given quantity (MW) of electricity at a specific price ($/MWh) across 10 bid bands. For each band, the bid price/quantity pairs are then included into the Regional Reference Node (RRN) bid stack.

PLEXOS can produce market forecasts, by taking advantage of one of the following three generator bidding behavioural models:

- Short Run Marginal Cost Recovery (SRMC, also known as economic dispatch)
- User defined market bids for every plant in the system
- Long Run Marginal Cost Recovery (LRMC).

The suitability of PLEXOS for modelling the inclusion of DG into the NEM is one of the main reasons UQ has pursued this platform. A variety of technology types can be easily represented in the main PLEXOS:

- Small CCGT with Combined Heat and Power (CHP) or Cogeneration
- Gas micro-turbines with CHP
- Gas reciprocating engine with and without CHP
- Biomass steam with CHP
- Solar PV (as negative load)
- Diesel engines
- Small wind turbines
- Biomass/Landfill gas reciprocating engine
- Gas fuel cells
- Gas reciprocating engine with Combined Cooling Heat and Power (CCHP) or Tri-generation

Battery storage units can be implemented for any of these tech types.

Combining large scale centralised generation with small units which are distributed throughout the network enables analysis of how DG will affect market prices and emissions. All combustive DG units installed in the NEM for this study are treated as market scheduled generators which are placed in the merit order of dispatch for market clearing. The treatment of wind and solar in this study has been performed by examining forecasts derived from climate data obtained from the Bureau of Meteorology to produce half hourly energy production traces for each year which are then subtracted from forecasted demand.

The modelling presented in this report required a range of assumptions regarding the composition of the NEM to portray the roll out of DG. Key assumptions which have been implemented within UQ's NEM database include:

- Electricity demand forecasts
- Thermal plant fuel prices
- Distributed Generator technology specification
- Policy options with respect to greenhouse gas abatement pathways

Existing and committed generating assets in all states are distributed across their respective portfolios as outlined in the 2008 NEMMCO SOO (NEMMCO 2008).

New installed centralised generation capacity output by CSIRO's ESM is attributed to new generic companies for each region.

3.2 The Scenarios

The five scenarios examined were developed in partnership with the CSIRO and provide a snap shot of estimated future effects of the deployment of DG across the NEM. The focus is on three landmark years: 2020, 2030 and 2050. The five policy frameworks modelled are as follows:

Business-As-Usual (BAU) case with no carbon trading: the CPRS is not implemented. Load growth is met by significant investment in large centralized generation assets such as base load coal, combined cycle gas turbine's (CCGT), solar thermal, geo-thermal (hot fractured rocks) and wind turbines.

CPRS -15%, no DG: The CPRS is introduced in combination with a renewable energy target to reach an overall reduction of emissions of 15% below 2000 levels. The price of emissions permits reaches ~$50 t/$CO_2$. Demand growth is reduced compared to the reference case because of the increase in energy costs following the implementation of the CPRS.

Garnaut 450ppm, no DG: The introduction of the CPRS with a deeper emissions abatement pathway is implemented to achieve an overall reduction of emissions of 25% below 2000 levels. Emissions permit price reaches ~$61 t/$CO_2$ which places more pressure to achieve further energy efficiency and lower emissions technology deployment across the NEM.

CPRS -15% with DG: Following the introduction of the CPRS, emissions permit prices stimulate the deployment of small scale distributed generation technologies. The roll out of small scale de-centralised generation allows for the further cut in emissions than the corresponding CPRS -15% case study.

Garnaut 450ppm with DG: With the implementation of deeper cuts to emissions following the introduction of a 25% target via the CPRS, higher permit prices stimulate a variety of alternative distributed generation options for deployment across the NEM. Furthermore, with increased pressure from permit prices reducing demand, results in the decreasing reliance over time for centralized higher emitting generation types.

3.3 Results

The modelled results are presented for:

- Installed capacity for each scenario
- Average prices for each state
- Price distribution and premium of flat price caps
- Inter-regional price spreads as a proxy measure of transmission congestion
- Greenhouse gas (GHG) emissions and the Emissions Intensity Factor (EIF) of electricity generation
- Effects on centralised generation assets.

It should be noted that the installed capacity provided by the CSIRO, is based on output from their ESM. Integrating these results into our modelling presents several challenges due do the fact that the ESM is a partial equilibrium model which simulates yearly demand with some peak information. In contrast, PLEXOS is a full chronological simulation platform which can deal with dispatches on a half hourly basis to meet demand across a multi-node interconnected network. The amount of installed capacity provided is extremely close to the actual peak demand, which in some circumstances may contribute to the predicted need for upgrading the transmission interconnector limits. Furthermore, transmission congestion, which is normally represented as the number of hours binding, is zero for all scenarios. Analysis of transmission congestion can still be performed by examining the inter-regional price spread as an indicator of constrained capacity.

One of the standard ways to represent the relative volatility of price on the NEM is to provide a price distribution based on the pricing of premiums for standard cap contracts for difference (CFDs). The relative cap price is calculated by using the frequency of prices exceeding each cap price barrier. The sum of all of these cap premiums is equal to the time weighted average price of the price trace considered. The representation of relative GHG emissions to compare the five scenarios with each other is more effectively performed by using the EIF which is the number of emitted tonnes of CO_2 per MWh produced. Due to the change in demand and installed capacity provided by the CSIRO, the raw GHG emissions data are misleading in representing the relative emissions changes observed across the simulations.

The relative generation mix is represented for each scenario by calculating the percentage contribution each technology type makes to the total demand as sent out in MW. This establishes the relative performance of each technology type with respect to changing demand and installed capacity.

It should also be mentioned that solar PV, solar thermal and wind energy production is represented as negative demand rather than dispatched generation. In some instances, the supply of renewable generation exceeds the demand for that given half hour. The higher incidence of zero demand accounts for the frequency of prices at or below $0/MWh. One advantage of increasing the transmission interconnector limits is that excess renewable generation can be included in the optimal power flow solution to clear demand in other States at a lower price.

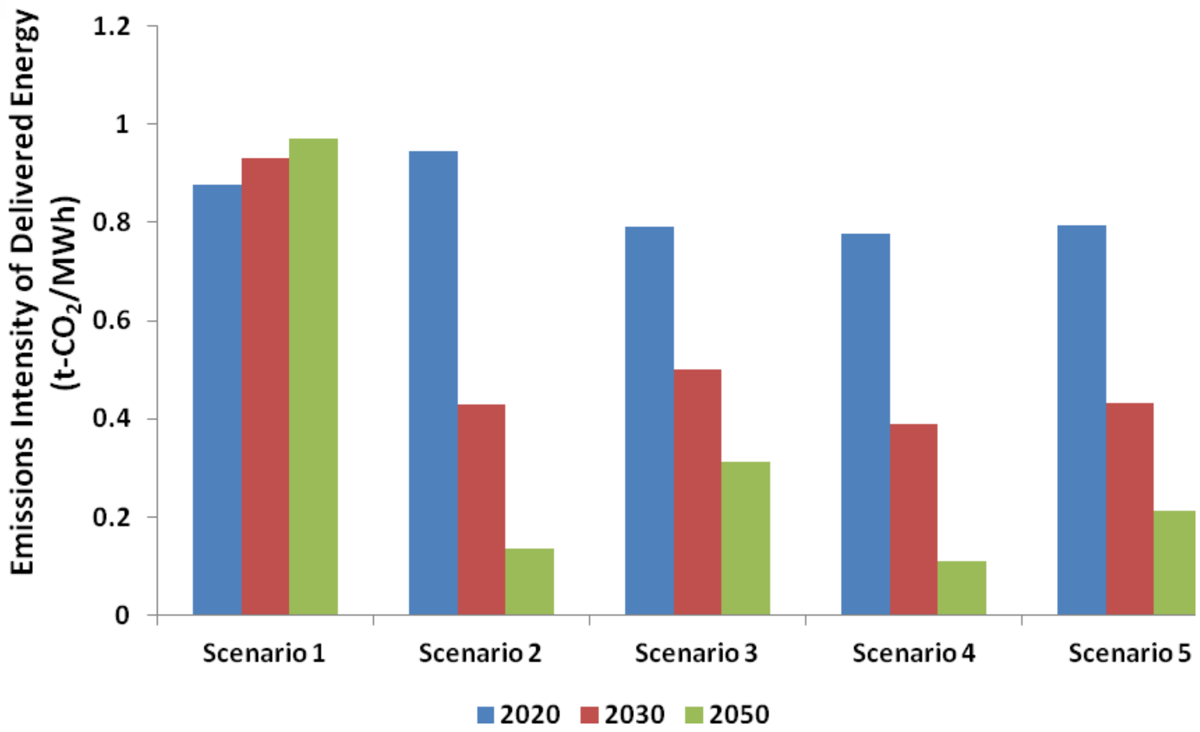
3.3.1 Effects on Emissions

EEMG's modelling found that the Emissions Intensity Factor (EIF in t-CO_2/MWh) of delivered energy throughout the NEM is significantly reduced across all three years and under both emissions reduction scenarios, when distributed generation is introduced. The EIF was chosen as the benchmark for analysis to better reflect emissions behaviour, given the different rates of load growth across all scenarios. In Table 1, the EIF's of delivered energy across the NEM show significant market structural changes with respect to the emissions profile, demonstrating that DG could have a large impact on curtailing CO_2 production.

Table 1: Emissions Intensity Factor t-CO2/MWh)

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
2020	0.878	0.944	0.791	0.776	0.795
2030	0.932	0.429	0.500	0.390	0.433
2050	1.641	0.137	0.313	0.110	0.212

Figure 10: Emissions Intensity Factor



3.3.2 Effects on Average Electricity Prices

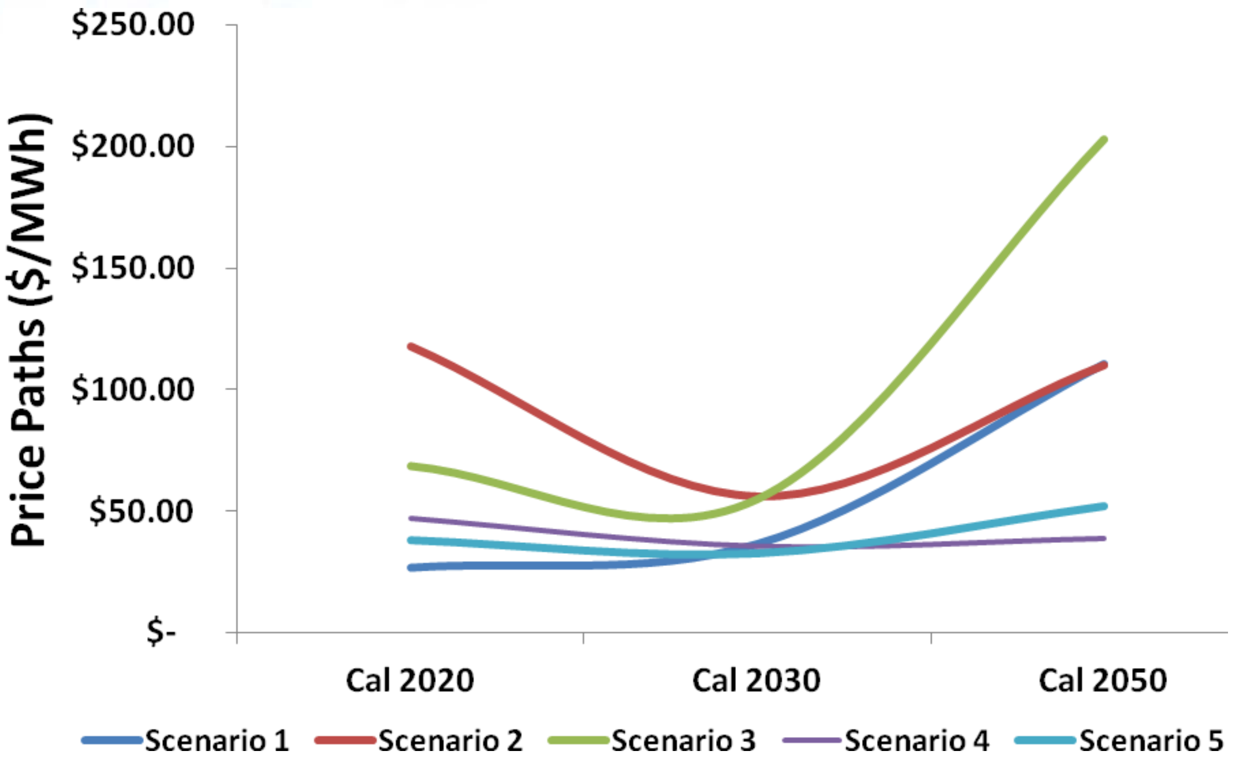
With the introduction of the CPRS, wholesale electricity prices are set to increase to meet the marginal cost increase imposed by a carbon price. Consequently modelling results indicate that the marginal increase in electricity price will vary depending on the price setting generating unit. While there is a significant increase in electricity prices for Scenario 2 (compared to the reference case), it should be noted that there is also a significant shift in installed generating assets.

For example, the installed capacity of low cost coal fired generation in the reference case ensures that energy prices remain relatively low, especially with brown coal generators having a LRMC of less than $30/MWh. Conversely, the increased cost of the installation of high cost generation types, such as Combined Cycle Gas Turbines, contribute greatly to the observed average price. Furthermore, the difference in prices between Scenario 2 and 3 (see Table 2), are due to the lower demand and generation mix changes due to the increase carbon price observed in a 25% carbon abatement pathway.

Table 2: Average spot prices ($/MWh)

NEM	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
2020	$26.92	$104.72	$68.68	$47.21	$37.94
2030	$36.66	$55.87	$54.97	$35.46	$32.40
2050	$110.74	$110.10	$203.17	$38.67	$52.20

Figure 11: Summary of Price Paths



The roll out of DG will have a significant impact on the average price of energy throughout the NEM. The drop in average prices for each of the DG scenarios indicates that investment in new technology stimulated by the CPRS will lower the delivered energy cost across the NEM. Furthermore, the generation mix outlined in the body of this report will shift significantly away from centralized generation assets and further improving energy costs on the wholesale market over the planning horizon modelled.

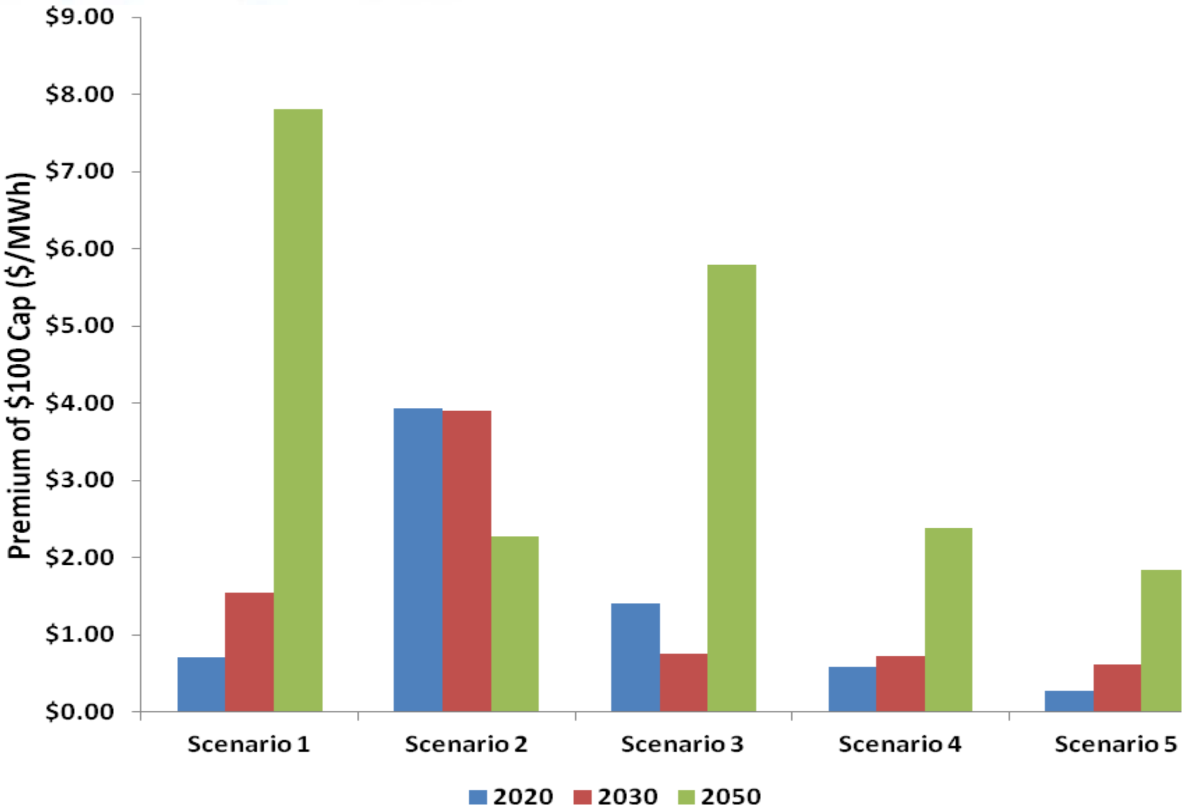
3.3.3 Effects on Spot Price Volatility

Following the discussion of average price, another benefit of the roll out of distributed generation is the lowered volatility of observed prices on the wholesale market. Lower volatility of spot price behaviour also provides significant benefits from a risk management perspective and reduces the cost of serving the retail consumer base. Valuing the premium on a $100 base cap product is a simple way of measuring a market participant's exposure to high and volatile prices (see Table 3).

Table 3: Premium Price of a $100/MWh Base Cap

NEM	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
2020	$25.75	$64.19	$68.00	$39.18	$26.77
2030	$24.69	$52.04	$54.96	$35.40	$32.38
2050	$44.79	$30.70	$53.56	$29.36	$40.09

Figure 12: Spot price volatility represented by the premium on a $100/MWh Cap product



With the deployment of distributed generation there is a decrease in the incidence of prices above $100 throughout each simulated year. In the NEM, the frequency and severity of high prices has been observed in previous years. This has resulted in adverse structural consequences for the viability of retailers to recover the price of wholesale electricity from consumers. Lower spot market price volatility results in lower tariff price increases over the planning horizon and the deferral of investment in expensive higher emitting peaking generator plant.

3.4 Conclusions

Through the modelling of distributed generation using PLEXOS, the EEMG was able to demonstrate the benefits of the large scale deployment of distributed generation technology across the NEM. DG has been shown to significantly improve the likelihood that there will be a reduction of electricity prices and emissions in the long term. The drop in average price and volatility with respect to both carbon price scenarios presents many opportunities for market participants to reduce their exposure to uncertainty in the wholesale electricity market. As a result, the decrease in the emissions intensity factor for generated energy would be of enormous benefit in relation to the CPRS, placing Australia at the forefront of cleaner and more renewable technology deployment.

4 ASSESSING THE ECONOMIC IMPACT OF DG USING THE ANEM MODEL

The Australian National Electricity Market (ANEM) model is an agent-based model of Australia's NEM, which is based on Sun and Tesfatsion's (2007a, 2007b) Agent-Based Modelling of Electricity Systems (AMES). AMES (Tesfatsion 2011) models American electricity systems, so the ANEM model has been extensively modified to incorporate the structure of Australia's NEM. Both models are programmed in Java using a Java toolkit called Repast (Altaweel et al. 2011) that is specifically designed for agent base modelling in the social sciences. Additionally, both models use a Direct Current Optimal Power Flow (OPF) algorithm to determine the optimal dispatch of generation and wholesale market price at each node in the transmission grid. This algorithm is further discussed later in this section.

The ANEM model framework incorporates seven core elements that correspond with key features of the Australia's National Electricity Market, which are discussed below. The wholesale power market includes an Independent System Operator (ISO) and energy traders that include Load-Serving Entities (LSE's) and generators distributed across the nodes of the transmission grid. The transmission grid is an alternating current (AC) grid modelled as a balanced three-phase network. The grid is modelled as consisting of nodes and branches as shown in Figure 13 to Figure 17. The transmission grid has no isolated components, so any pair of nodes is connected by a path consisting of one or more branches. The ANEM wholesale power market operates using increments of one hour.

The ANEM model's ISO undertakes daily operation of the transmission grid within a single settlement system, which consists of a real time market settled using Locational Marginal Pricing (LMP) that is the wholesale price for injection into or withdrawal from each node in the grid (Sun & Tesfatsion 2007b, p. 2). For each hour of the day, the ANEM model's ISO determines power commitments and LMP's for the spot market based on generators' supply offers and LSE's demand bids submitted prior to the start of the day. The ISO produces and posts an hourly commitment schedule for generators and LSEs, which is used to settle financially binding contracts on the basis of the day's LMP's for a particular hour. Transmission grid congestion in the spot market is managed via the inclusion of congestion components in the LMP, which is associated with nodal price variation within any hour. Figure 13 to Figure 17 shows the ANEM's transmission grids of QLD, NSW, VIC, SA and TAS respectively. 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 inter-state interconnectors Directlink, Murraylink and Basslink are high voltage direct current (HVDC) while all other intra-state and inter-state transmission lines are AC. The optimal power flow solution used in ANEM is a DC OPF solution. Hence, in accordance with this solution methodology, optimal power flows on both AC and HVDC transmission lines are modelled using reactance and thermal rating values (Sun & Tesfatsion 2007a, sec. 3.1, 3.3 and 3.4).

ANEM models 72 transmission lines in this report of which 66 are intra-state branches and 6 are inter-state interconnectors. The ANEM model requires the following data for each branch of the transmission grid: base voltage (kV), base apparent power (MVA), branch connection and direction of flow information, maximum thermal rating (MW) and reactance (ohms). The study uses the internationally recognised unit for base apparent power of 100 MVA. The QLD, NSW and TAS transmission companies called Powerlink, Transgrid, and Transend respectively supplied the reactance and thermal ratings of the transmission lines in their state. The values for VIC and SA were calculated using comparable branches in QLD, NSW and TAS.

ANEM models 53 Load-Serving Entities (LSEs) in this Report. LSEs are demand side agents who purchase bulk power in the wholesale power market each day in order to service customer demand (load) in the downstream retail market. For simplicity, we assume that downstream retail demands serviced by the LSEs exhibit negligible price sensitivity and each LSE supplies a load profile. The LSEs' revenue is based on 'dollar mark-up' and is independent of the wholesale cost level (Sun & Tesfatsion 2007b, p. 11).

The regional load data for QLD and NSW was derived using regional load traces supplied by Powerlink and Transgrid. This data was then re-based to the state load totals published by the Australian Energy Market Organisation (AEMO 2011) for the 'QLD1' and 'NSW1' markets. For the other three states, the regional shares were determined from terminal station load forecasts associated with summer peak demand and winter peak demand if available, which were published in the annual planning reports of the transmission companies called Transend, Vencorp and ElectraNet for TAS, VIC and SA, respectively. These regional load shares were then multiplied by the 'TAS1', 'VIC1' and 'SA1' state load time series published by AEMO (2011) in order to derive the regional load profiles for TAS, VIC and SA, which are used in the model.

ANEM models 286 generators that include all hydro and thermal based generation such as black and brown coal, natural gas and diesel but exclude wind generation. In ANEM, each generator has a given production technology. Specifically, we assume that generators have variable and fixed costs of production and can incur start-up costs. For each generator, technology attributes are assumed, and these attributes refer to the feasible production interval, total cost function, total variable cost function, fixed costs based on a pre-determined pro rata dollar per hour amount and a marginal cost function. The minimum and maximum bounds of the feasible production interval of each generator define its minimum and maximum MW production limits. In addition each generator faces MW ramping constraints that determine the extent to which real power production levels can be increased or decreased over the next hour. The lower and upper MW bound associated with the hourly ramping constraint of each generator must also fall within its feasible production interval that is within its minimum and maximum MW production limit.

Variable costs of each generator are modelled as a quadratic function of hourly real energy produced by each generator on an 'energy generated' basis. The marginal cost function is calculated as the partial derivative of the quadratic variable cost function with respect to hourly energy produced, yielding a marginal cost function that is linear in hourly real energy production of each generator (Sun & Tesfatsion 2007b, p. 12). The variable cost concept underpinning each generator's variable cost as well as the system-wide variable cost incorporates fuel, variable operation and maintenance (VO&M) costs and carbon cost components. ACIL Tasman (2009) provides data to calculate the fuel, VO&M and carbon emissions/cost parameterisation of the variable and marginal cost functions.

4.1 The Optimal Power Flow Algorithm

To calculate the optimum power flow, ANEM uses the DC OPF algorithm, which is a *strictly convex quadratic programming (SCQP) problem* (Sun & Tesfatsion 2007a, sec. 3.3 and 3.4). The SCQP problem involves the minimization of a positive definite quadratic form subject to a set of linear constraints in the form of equality and inequality constraints. The objective function involves quadratic and linear variable cost coefficients and bus admittance coefficients. The solution values are the real power injections and branch flows associated with the energy production levels for each generator and voltage angles for each node. The SCQP problem is solved using 'QuadProgJ', a JAVA based SCQP solver developed by (Sun & Tesfatsion 2007a, sec. 6). QuadProgJ implements the dual active-set SCQP algorithm developed by Goldfarb and Idnani (1983).

The equality constraints implement a nodal balance condition which requires that at each node, power taken off by LSEs located at that node equals power injection by generators located at that node and net power transfers from other nodes connected to the node in question. On a node by node basis, the shadow price associated with this particular constraint gives the LMP which can be interpreted as a regional or nodal wholesale spot price associated with that node.

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

4.2 Practical Implementation Considerations

The solution algorithm utilised in all simulations involves applying the 'competitive equilibrium' solution. This means that all generators submit their true marginal cost coefficients without strategic bidding. We assume that all thermal generators are available to supply power during the year. The following additional assumptions are also made to make ANEM's response to the various scenarios more realistic. First, base load and intermediate coal and gas plant have non-zero minimum stable operating levels. Second, coal and natural gas combined cycle plant are assumed to be synchronized with the grid at the commencement of each simulation and do not face start-up costs. Within the ANEM model, these types of generation plant provide base load production duties. Third, all other thermal generation plant is assumed to face start-up costs.

The dispatch of thermal plant was optimised around assumed availability patterns for specified hydro generation units. In general, 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 base load, intermediate or peak load production duties.

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 Load Serving Entity (LSE) located at the Morton North and Wollongong nodes, respectively. 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. In both cases, the pump actions are assumed to occur in off-peak periods. 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, and, thus, are more closely aligned with the provision of peak load production duties.

Figure 13: Stylised QLD transmission line topology of 11 nodes

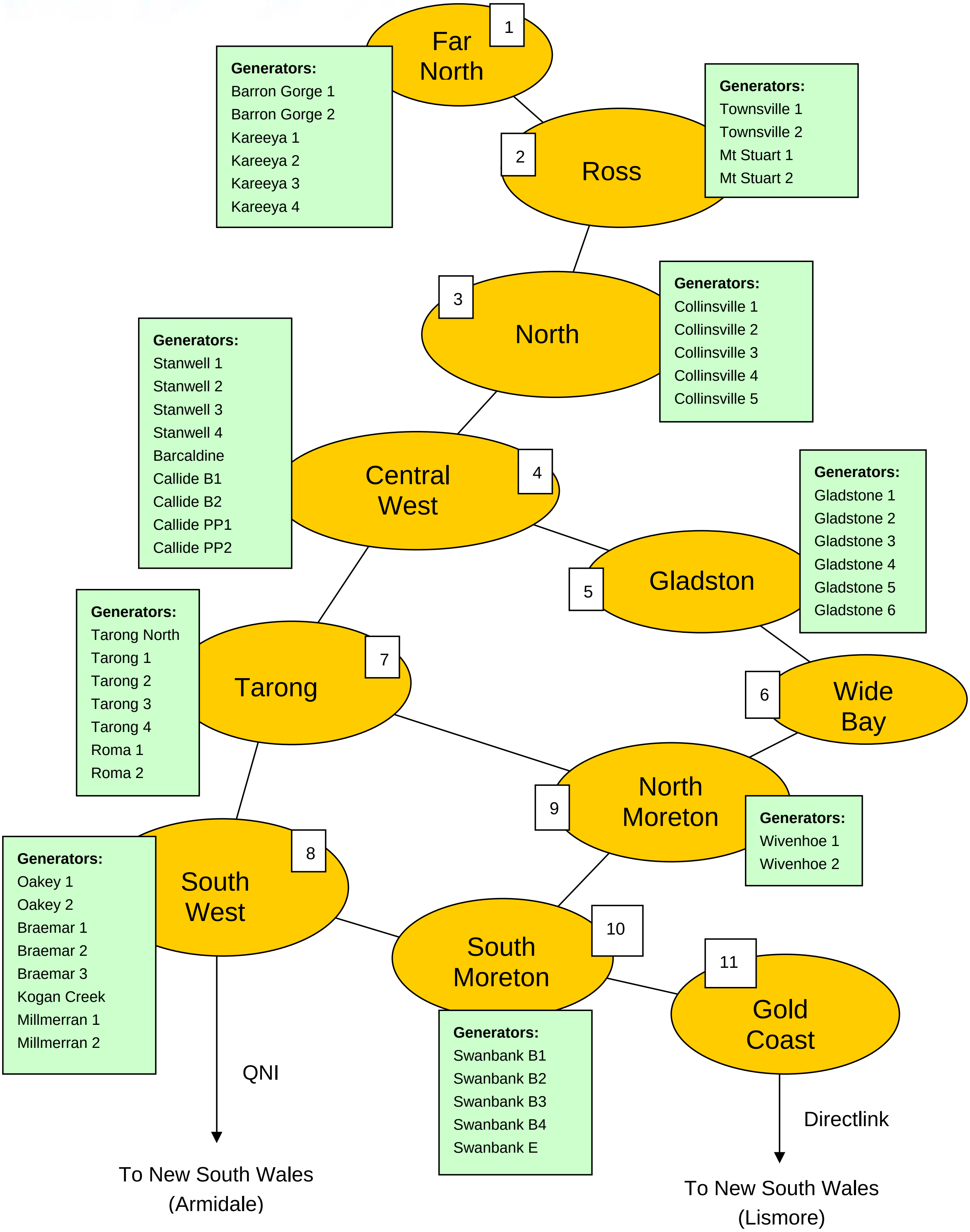


Figure 14: Stylised NSW transmission line topology of 16 nodes

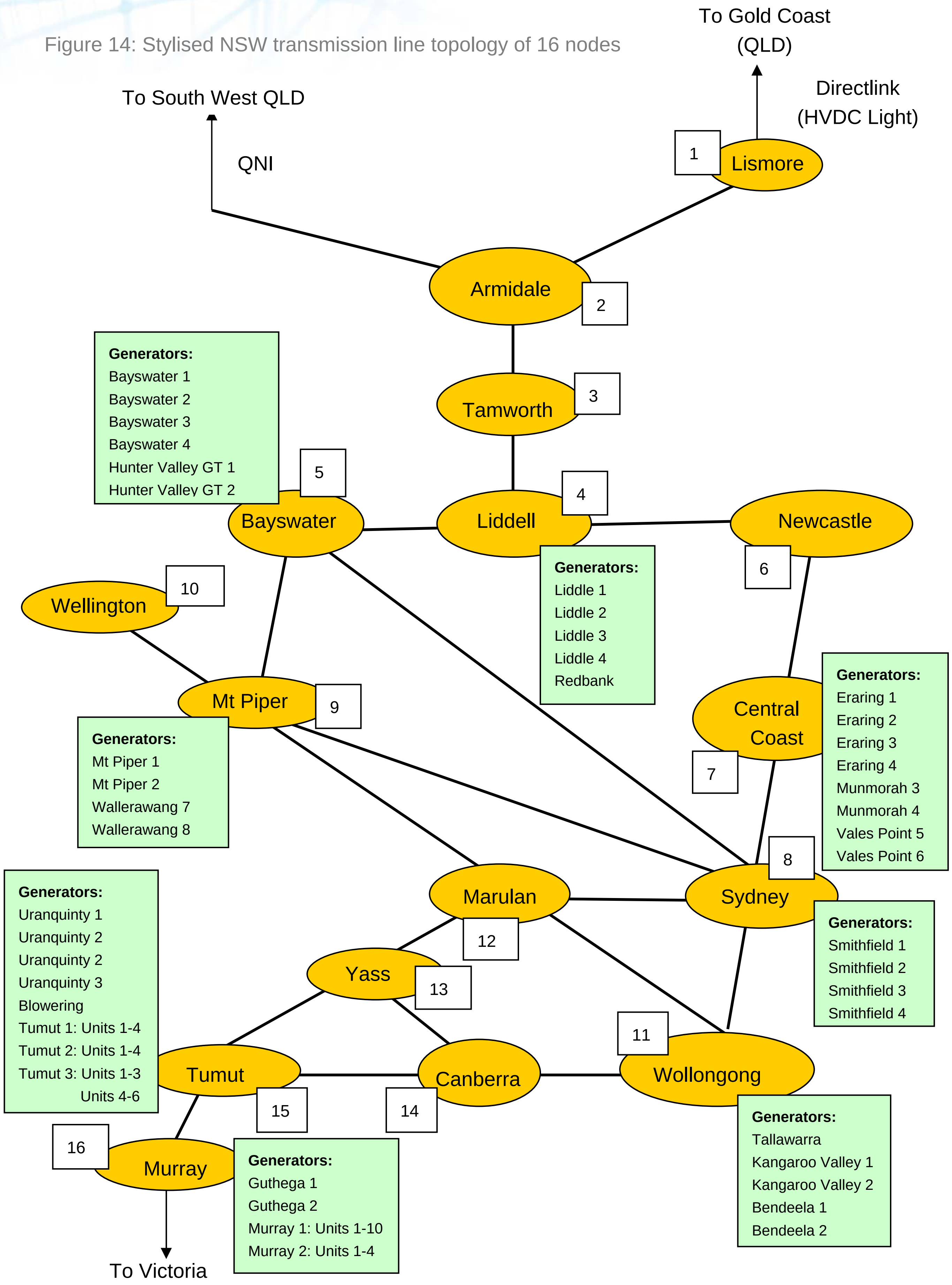


Figure 15: Stylised VIC transmission line topology of 8 nodes

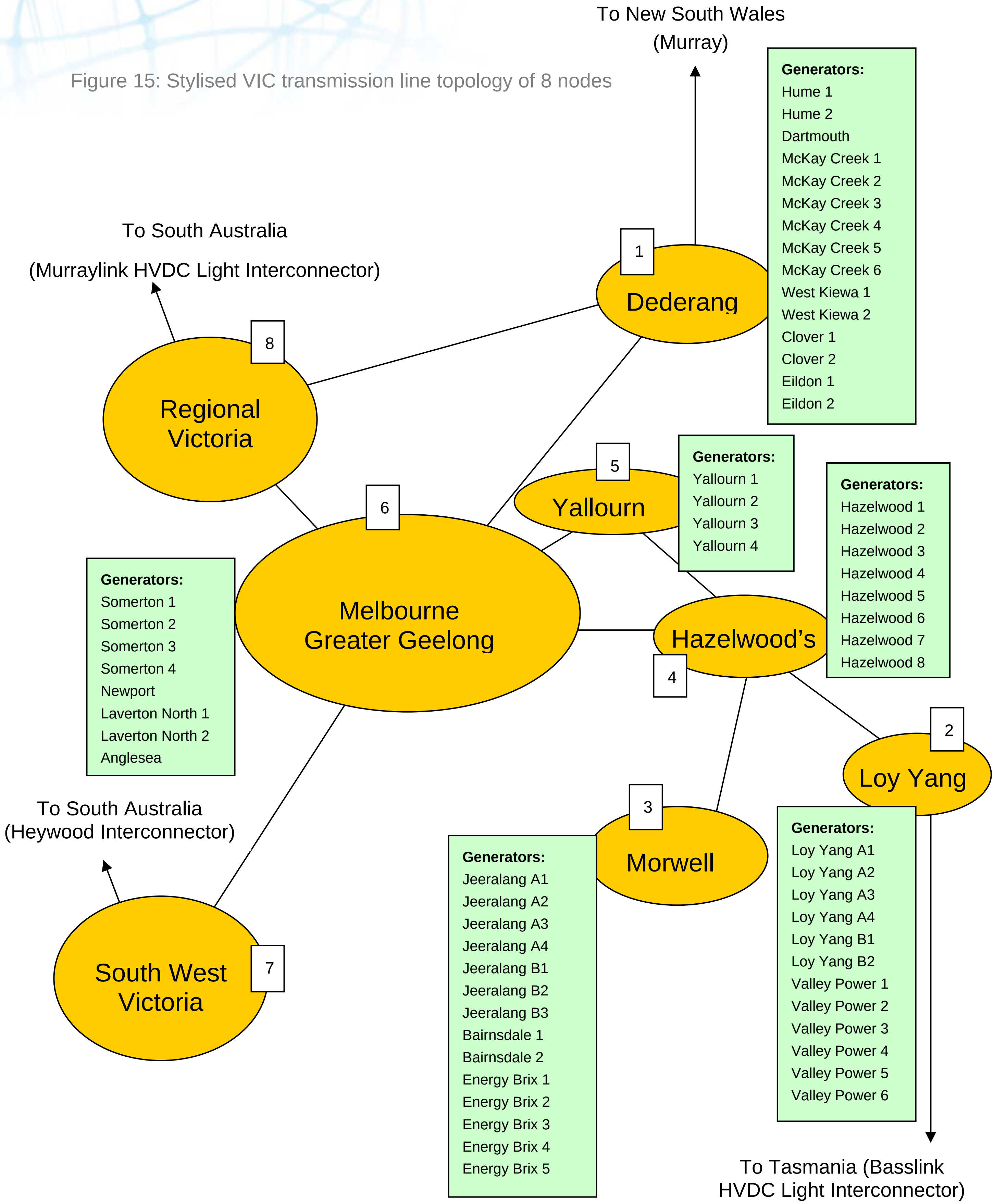


Figure 16: Stylised SA transmission line topology of 7 nodes

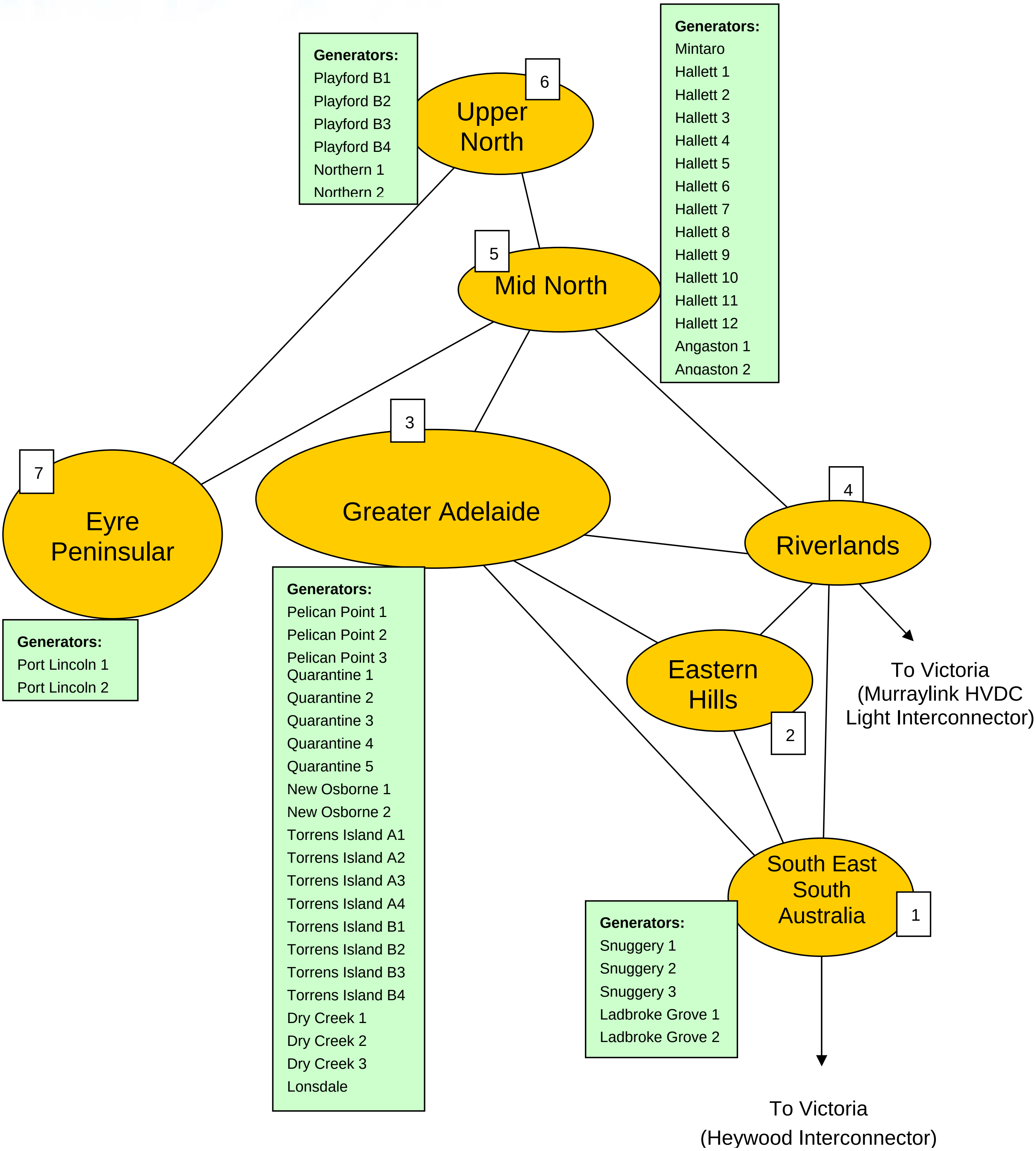
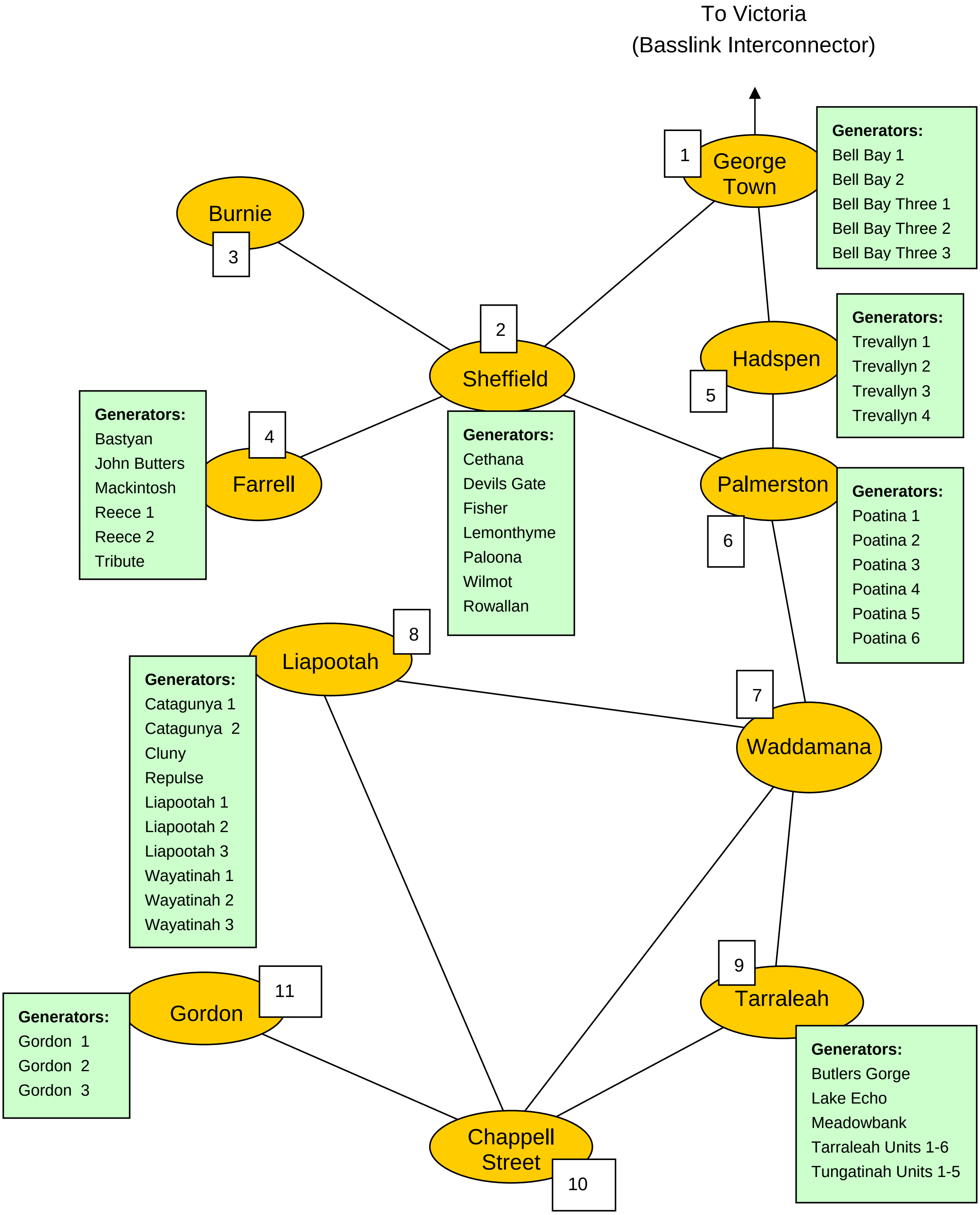


Figure 17: Stylised TAS transmission line topology of 11 nodes



4.3 Results

The objective was to model the economic consequences of large scale investment in distributed energy (DE) in conjunction with carbon pricing. The methods used include a load shaving profile in the ANEM model. The DE modelled relates to residential and commercial PV that can produce load shaving profiles on nodes of the ANEM model that could support a high level of residential or commercial PV penetration. The nodes chosen that meet this criteria are Moreton North and Moreton South (Greater Brisbane), Sydney, Melbourne/Geelong and Adelaide.

Four economic impacts of DE are examined: spot price, energy generated, carbon emissions and transmission line congestion. The results section is organised in the following way. Section 1 discusses the load shaving methodology used throughout the scenarios in Sections 2, 3 and 4, that discuss the economic consequences of three load shaving and carbon pricing combinations that are load shaving without carbon pricing, carbon pricing without load shaving and carbon pricing with load shaving, respectively.

4.3.1 Using load shaving profiles to model PV penetration

This section discusses the load shaving profile method used to model PV penetration. This method can be readily applied to other DE such as Solar thermal and wind generation.

Figure 18 shows the summer and winter versions of the six load shaving profiles that are analysed in this study, which include 0%, 2%, 5%, 10%, 15% and 20%. The 0% profile is the business as usual (BAU) scenario with regards to load shaving.

Figure 18 shows that the load shaving profiles are well suited to modelling solar based applications where load shaving commences early in the morning, gradually increasing over mid-morning and reaching a maximum around midday before tailoring off during mid-afternoon and completing dying out during late afternoon. Comparing the summer and winter load shaving profiles shows that the load shaving potential in winter is compressed in both extent and duration.

This study is conducted over Calendar year 2007 and summer is defined as the periods from 1 January to 21 May 2007 and from 17 September to 31 December 2007. The six load shaving profiles are used to calculate the load adjusted for PV penetration on an hour-by-hour basis by multiplying the unadjusted load for the major metropolitan nodes by unity less the percentage load shaving for that hour according to the profiles in Figure 18.

For example, consider calculating load shaving for the zero percentage load shaving or BAU scenario. The hourly load adjusted for PV penetration is the same as the unadjusted load because the multiplicative factor used is unity less zero percent. However for the non-zero percentage profiles the multiplicative factor values are less than unity in magnitude, which produces a reduction in load relative to BAU.

This study investigates the effect of the six PV load shaving profiles on four factors, spot price, energy generated, carbon emissions and branch flow congestion under four different carbon prices of 0, 30, 50 and 70 dollars per carbon dioxide tonne ($/tCO2).

Figure 18: The summer load shaving profiles

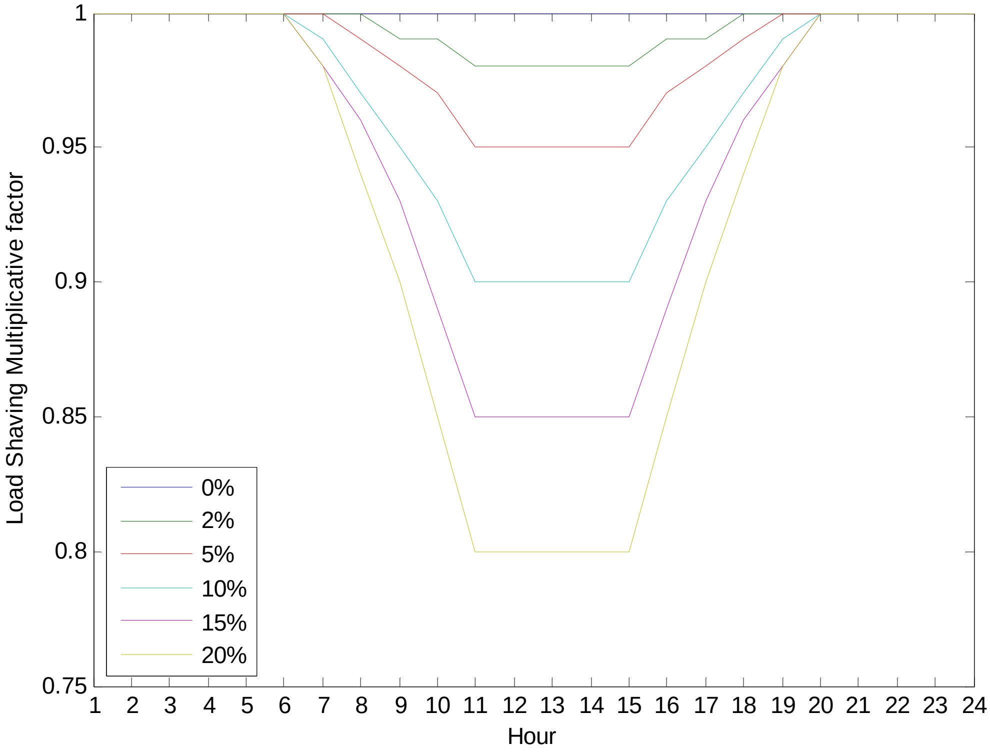
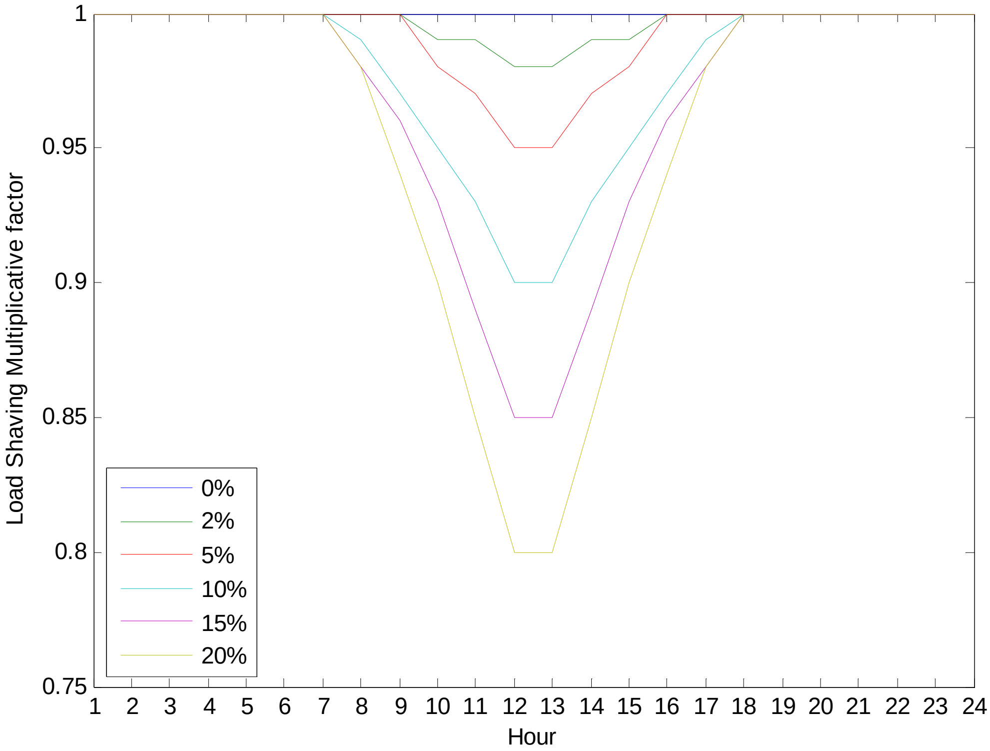


Figure 19: The winter load shaving profiles



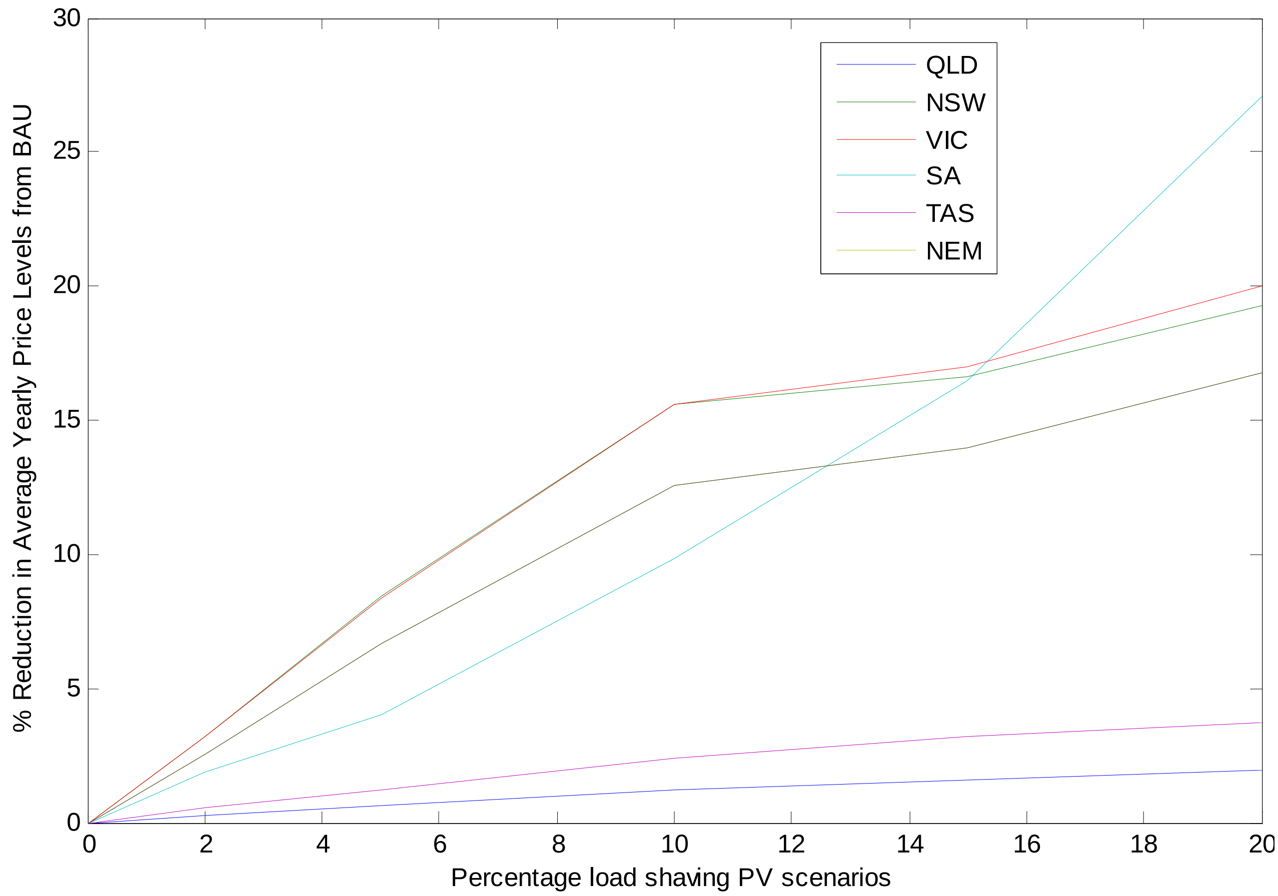
4.3.2 Evaluating the impact of load shaving without carbon pricing

This section discusses the effect of load shaving on the four factors for a carbon price of $0/tCO2 to provide a baseline for the study. The following baseline results are discussed.

The 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. See Foster et al. (2011) for further details.

Figure 20 shows that increased PV penetration has the general effect of reducing average price levels within each state and across the NEM as a whole.

Figure 20: The percentage reduction in the average yearly price from BAU for six load shaving profiles for a carbon price of $0/tCO2



Figures 21, 22, 23 and 24 show for all fuel types, coal, gas fired and hydro respectively that increased PV penetration produces a decline in aggregate levels of generation across all the relevant states and the NEM. This reflects the fact that load shaving has reduced the level of aggregate load demand that has to be serviced by the aggregate generation fleet producing an overall reduction in energy generated by all types of generation.

Figure 21: The percentage reduction in energy generated by all fuel types for six load shaving profiles for a carbon price of $0/tCO2

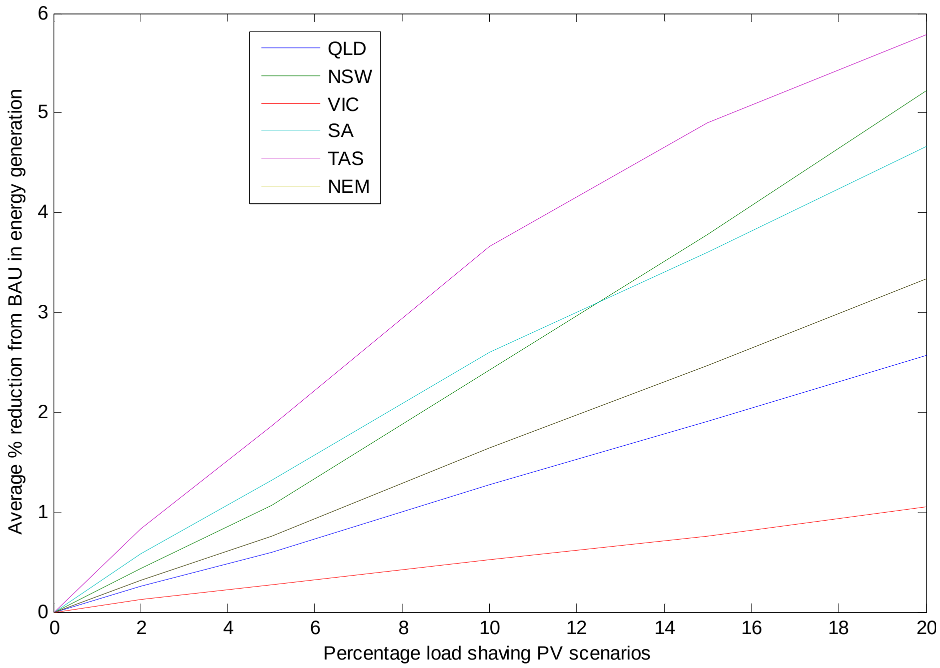


Figure 22: The percentage reduction in energy generated by coal generators for six load shaving profiles for a carbon price of $0/tCO2

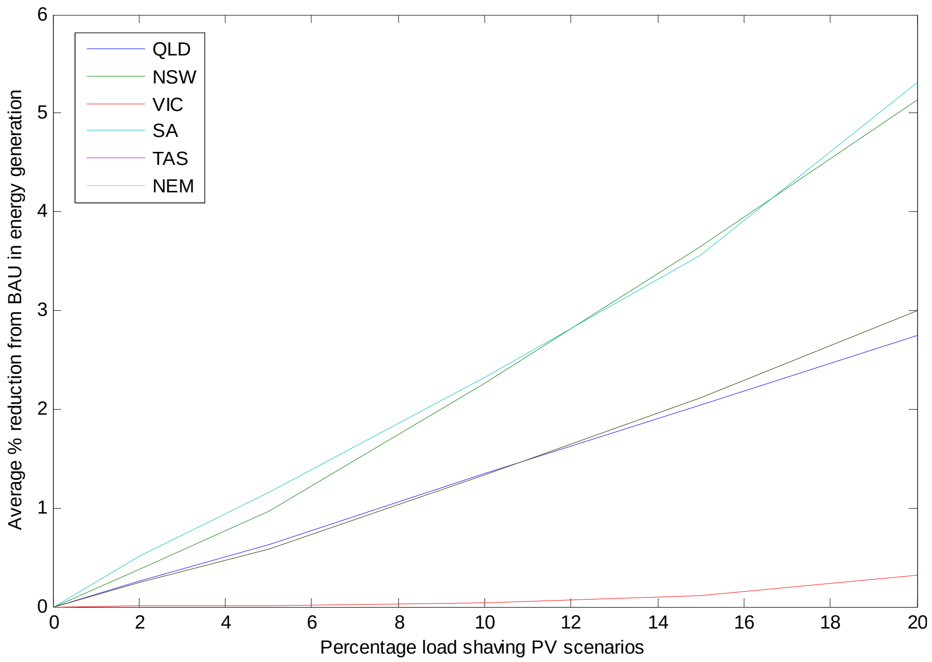


Figure 23: The percentage reduction in energy generated by gas generators for six load shaving profiles for a carbon price of $0/tCO2

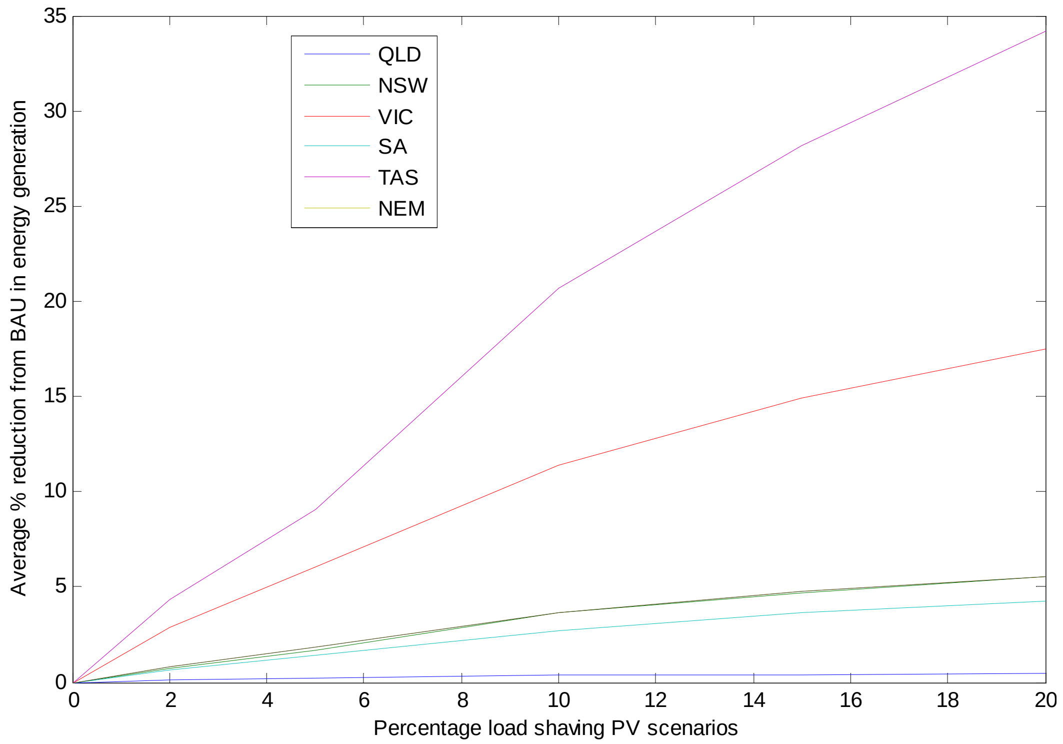


Figure 24: The percentage reduction in energy generated by hydro generators for six load shaving profiles for a carbon price of $0/tCO2

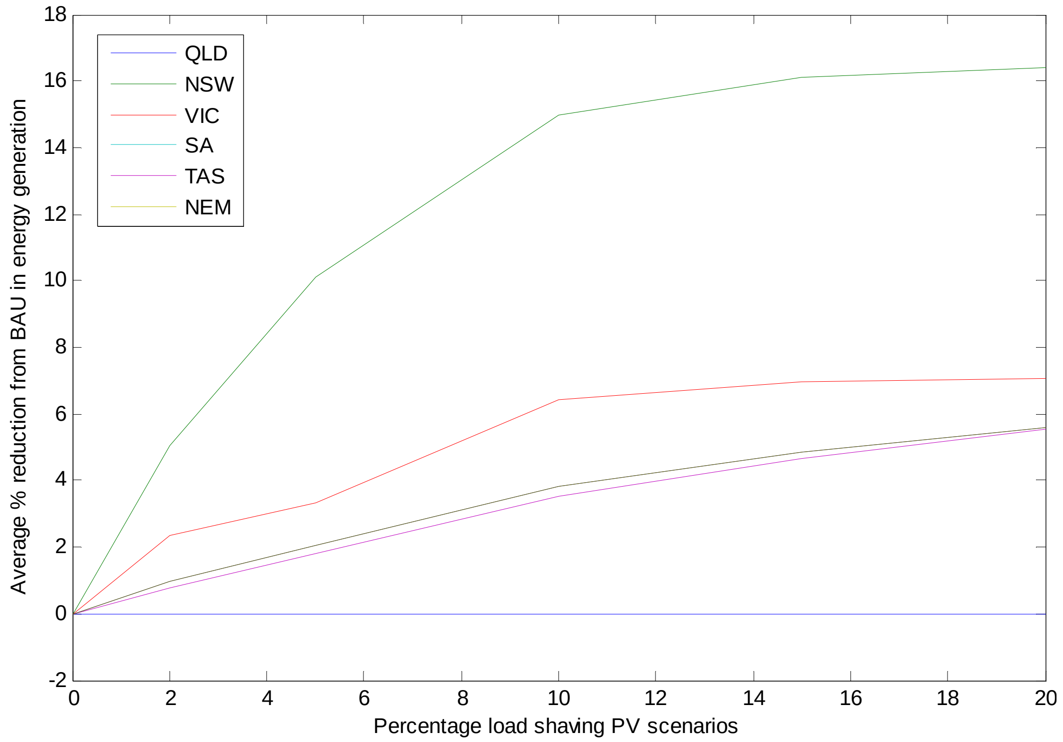


Figure 25 shows that increased PV penetration produces both state and NEM wide reductions in aggregate carbon emission thereby contributing to the policy goal of curbing carbon emissions from the power generation sector.

Note that the significant reduction in carbon emissions experienced by Tasmania are coming off of a small base result linked to the dispatch of some gas fired plant during 2007.

Figure 25: The percentage reduction in carbon emission for six load shaving profiles for a carbon price of $0/tCO2

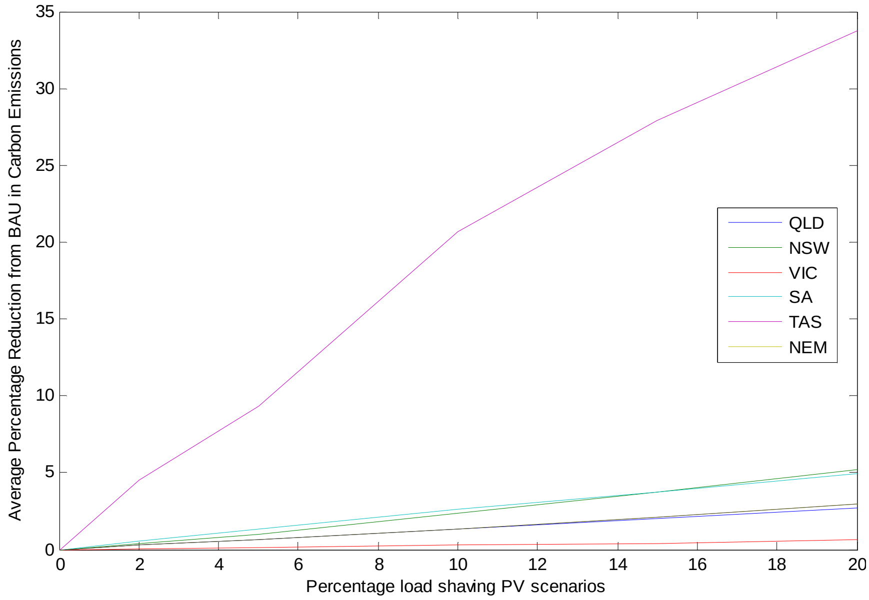


Figure 26 shows that increased PV penetration produces a slight amelioration in the incidence of branch congestion across each state and NEM as a whole.

Figure 26: The percentage of time that branch flow is at maximum for six load shaving profiles for a carbon price of $0/tCO2

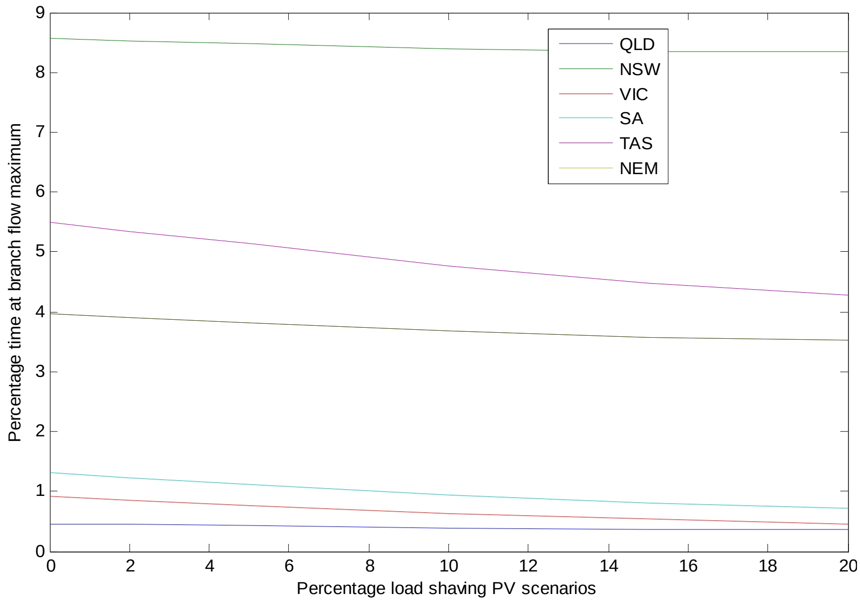
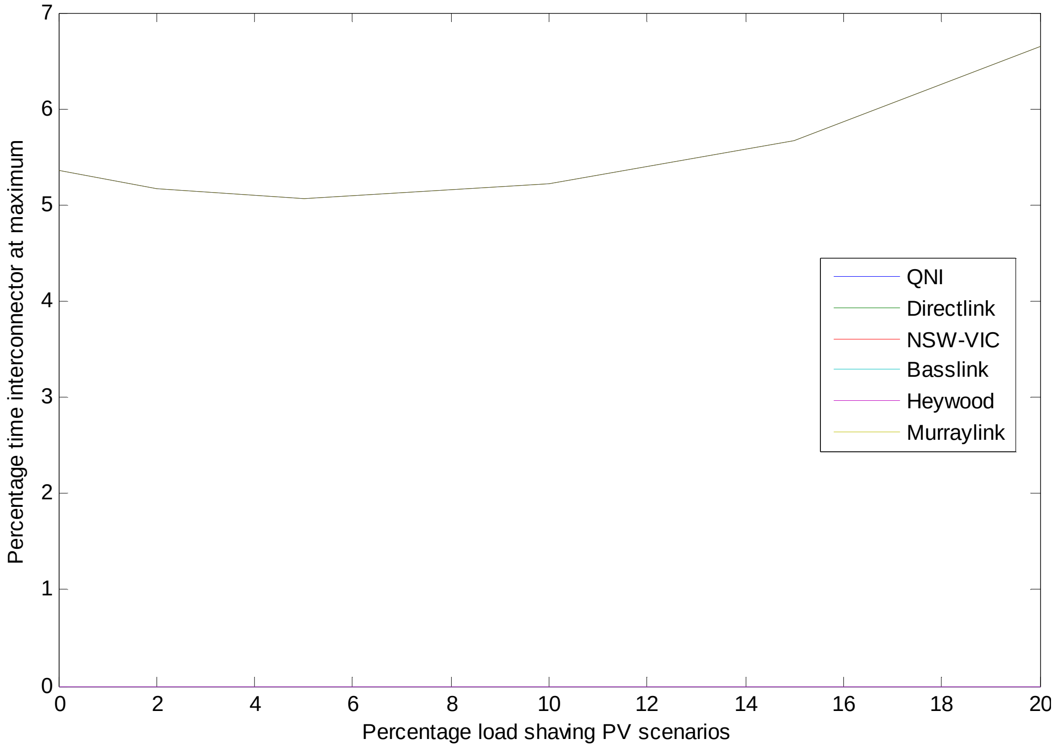


Figure 27 shows that increased PV penetration produced slight increase in branch congestion on the Murraylink Interconnector while the incidence of branch congestion on other Interconnectors was unchanged.

Figure 27: The percentage of time that interconnectors are at maximum for six load shaving profiles for a carbon price of $0/tCO2



Analysis indicated that hundreds of thousands or even millions of residential PV installations would be required to achieve a load shaving profile of between 10% and 20%. See Foster et al. (2011) for further details. This analysis clearly indicates a severe limitation to residential PV installations to provide deep cuts in load. So, if deep cuts are desired to curb growth in load demand and carbon emissions using PV then commercial scale PV installations or embedded solar PV or thermal generation would be required.

This section analysed the effect of the six PV load shaving profiles on four factors, the spot price, energy generated, carbon emissions and branch flow congestion under a carbon price of $0/tCO2. This provides a baseline for the remainder of the study that discusses the effect of the six load shaving profiles on the four factors under carbon prices of 30, 50 and 70 dollars per carbon dioxide tonne. However before combining load shaving and carbon pricing, carbon pricing without load shaving is discussed.

4.3.3 Evaluating the impact of carbon pricing without load shaving

To isolate the ‘pure’ impact of the introduction of the carbon pricing, three additional baselines or BAU scenarios are used, which involve a carbon price without load shaving. The three scenarios are termed ($30, BAU), ($50, BAU) and ($70, BAU), and are compared with the original ($0, BAU) baseline scenario to investigate the impact of carbon pricing without PV take-up. The main conclusions arising from these comparisons are:

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. See Foster et al. (2011) for details. This reflects the predominance of hydro generation in this state whose cost structure and pass through into spot prices is not affected by carbon prices.

Table 4 shows that the introduction of a carbon price signal leads to significant jumps in average annual price levels across all states and for the NEM.

Note that the larger average percentage increases recorded for QLD and SA cited in Table 4 are coming from a lower base when compared with NSW and VIC which experience smaller average percentage increases associated with the carbon prices.

Table 4: The average percentage increase in average annual price levels from BAU for three carbon prices without load shaving for 2007

Scenario	QLD	NSW	VIC	SA	TAS	NEM
$30, BAU	171.19	30.63	27.73	107.97	39.73	44.68
$50, BAU	283.30	47.60	43.63	181.03	63.24	71.70
$70, BAU	392.45	73.34	68.44	251.38	90.11	105.36

Table 5 shows 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 $\$30/tCO_2$, $\$50/tCO_2$ and $\$70/tCO_2$, respectively. State based changes were more variable. There are unambiguous declines in VIC and SA with mixed results for QLD and NSW.

Note that in all the following Tables results that are encased in parentheses indicate that percentages are increases.

Table 5: The percentage reduction in aggregate MW production from BAU for coal plant for three carbon prices without load shaving

Scenario	QLD	NSW	VIC	SA	TAS	NEM
$30, BAU	(1.87)	(1.22)	9.77	25.71	0.00	2.57
$50, BAU	1.57	2.39	23.31	25.26	0.00	8.98
$70, BAU	3.03	2.06	31.61	29.60	0.00	11.87

Table 6 shows that gas fired generation production increased across all relevant states (except for VIC for carbon price of $30/tCO_2$) and for the NEM as a whole of 4.05%, 34.51% and 61.65% for carbon prices of $30/tCO_2$, $50/tCO_2$ and $70/tCO_2$, respectively.

Table 6: The percentage reduction in aggregate MW production from BAU for gas plant for three carbon prices without load shaving

Scenario	QLD	NSW	VIC	SA	TAS	NEM
$30, BAU	(1.36)	(6.38)	12.87	(9.11)	50.93	(4.05)
$50, BAU	(68.80)	(34.68)	(12.97)	(25.06)	(90.03)	(34.51)
$70, BAU	(143.26)	(40.93)	(68.11)	(32.23)	(526.13)	(61.65)

Table 7 shows 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 $30/tCO_2$, $50/tCO_2$ and $60/tCO_2$. This reflects the lack of pass through of carbon costs into the cost of hydro generation relative to other competing forms of thermal based generation. This means, in turn, that hydro generation becomes increasingly competitive against other forms of thermal based generation in an environment of rising carbon prices.

Table 7: The percentage reduction in aggregate MW production from BAU for hydro plant for three carbon prices without load shaving

Scenario	QLD	NSW	VIC	SA	TAS	NEM
$30, BAU	(0.14)	(24.41)	(0.38)	0.00	(55.50)	(48.45)
$50, BAU	(0.07)	(250.64)	11.51	0.00	(98.16)	(97.05)
$70, BAU	(32.55)	(422.97)	(1.62)	0.00	(100.16)	(111.35)

Table 8 shows the changes in aggregate MW generation production of each state, where there are:

- increases in aggregate MW production for QLD, NSW and TAS,
- decrease in aggregate MW production for VIC and
- mixed results for SA.

Table 8: The percentage reduction in aggregate MW production from BAU for three carbon prices without load shaving for 2007

Scenario	QLD	NSW	VIC	SA	TAS
$30, BAU	(1.82)	(1.68)	9.90	3.56	(54.53)
$50, BAU	(2.95)	(1.44)	21.75	(6.73)	(98.09)
$70, BAU	(6.78)	(3.13)	27.32	(9.72)	(104.07)

Table 9 shows the 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 $\$30/tCO_2$, $\$50/tCO_2$ and $\$70/tCO_2$, respectively. State based aggregate carbon emission results were more variable in character.

For a $\$30/tCO_2$ carbon price, reductions in aggregate carbon emission were obtained for VIC, SA and TAS while increases were obtained for QLD and NSW when compared against the BAU state levels.

For a $\$50/tCO_2$ carbon price, reductions in aggregate carbon emissions were obtained for NSW, VIC and SA but increases were obtained for QLD and TAS, when compared against the corresponding BAU state levels.

For a $\$70/tCO_2$ carbon price, reductions in aggregate carbon emission were obtained for NSW, VIC and SA but increases were obtained for QLD and TAS, when compared against the corresponding BAU state levels.

The BAU levels for TAS are very small in magnitude – big increases in carbon emissions observed for TAS are coming from a very small base and reflect increased dispatch of gas-fired plant in TAS in response to the decline in the competitive position of the VIC brown coal fleet relative to TAS hydro and gas generation fleet.

Table 9: The percentage reduction in aggregate carbon emissions from BAU for three carbon prices without load shaving for 2007

Scenario	QLD	NSW	VIC	SA	TAS	NEM
$30, BAU	(1.65)	(0.05)	11.01	11.61	51.37	4.16
$50, BAU	(0.58)	2.16	23.87	5.61	(97.88)	9.48
$70, BAU	(1.79)	2.09	30.61	4.99	(560.19)	11.48

Table 10 shows that evidence relating to the impact on branch congestions is mixed.

Unambiguous reduction in branch congestion in QLD and TAS.

For carbon prices in range of $\$30/tCO_2$ to $\$50/tCO_2$, reductions in incidence of branch congestion in NSW, VIC and SA and for the NEM as a whole.

For carbon price of $\$70/tCO_2$, increase in branch congestion in NSW and VIC when compared to the results obtained for a carbon price of $\$50/tCO_2$.

For carbon price of $\$70/tCO_2$, increase in branch congestion in SA and NEM as a whole when compared with results obtained for carbon prices of $\$30/tCO_2$ and $\$50/tCO_2$, respectively.

Table 10: The percentage of time branch congestion arises for three carbon prices without load shaving for 2007

Scenario	QLD	NSW	VIC	SA	TAS	NEM
$0, BAU	0.57	9.22	7.28	0.58	19.11	7.45
$30, BAU	0.50	8.60	1.17	0.25	20.78	6.72
$50, BAU	0.37	8.02	0.82	0.28	20.79	6.59
$70, BAU	0.24	8.31	0.96	0.52	20.79	6.74

Table 11 shows that evidence relating to the impact on Interconnector branch congestions is mixed. However there are unambiguous increases in incidence of branch congestion on NSW-VIC, Basslink and Murraylink Interconnectors with increases in carbon price level.

Directlink shows increased incidence of congestion for carbon prices in range of \$30/tCO_2-\$50/tCO_2. However, for a carbon price of \$70/tCO_2, there is a reduction in congestion when compared to the results obtained for a carbon price of \$50/tCO_2.

Murraylink experiences the most congestion, with noticeable increases also occurring for NSW-VIC and Basslink Interconnectors for carbon price of \$70/tCO_2 when compared with other carbon price levels.

Table 11: The percentage of time branch congestion arises on interconnectors for three carbon prices without load shaving for 2007

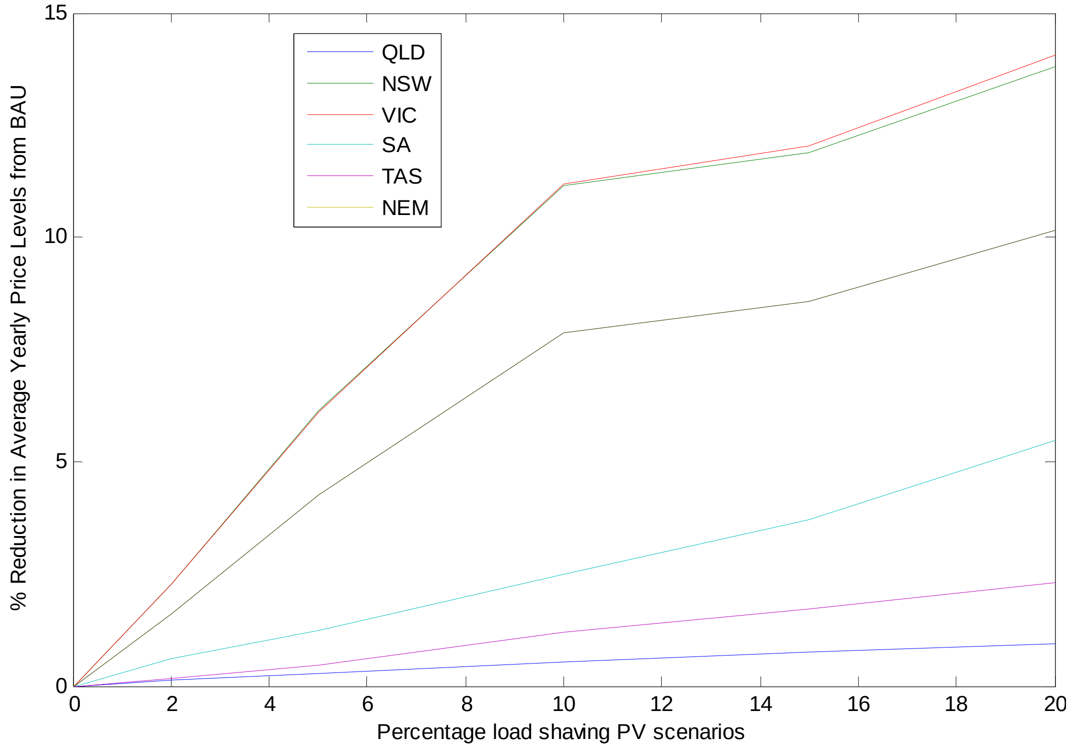
Scenario	QNI	Direct link	NSW-VIC	Bass link	Heywood	Murray link
$0, BAU	0.00	0.00	0.06	0.00	0.00	8.51
$30, BAU	0.00	0.05	0.07	0.01	0.00	12.33
$50, BAU	0.00	2.20	0.88	0.11	0.00	16.83
$70, BAU	0.00	0.42	2.28	5.81	0.00	19.78

4.3.4 Evaluating the impact of carbon pricing with load shaving

This section discusses the effect of the six PV load shaving profiles on four factors, spot price, energy generated, emissions and branch flow congestion under three carbon prices of $30/tCO2, $50/tCO2 and $70/tCO2.

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 still very dominant. See Table 4 for details. Figure 28 provides an indication of the type of reduction in average price levels obtained from load shaving for a carbon price of $30/tCO2.

Figure 28: The percentage reduction in price levels from ($30, BAU) for six load shaving profiles for a carbon price of $30/tCO2



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. See Foster et al. (2011) for details. Figure 29, Figure 30, Figure 31, and Figure 32 provide a good depiction of the type of additional reinforcement/mitigation effects that the PV based load shaving profiles can contribute over and above the impacts associated with the introduction of the carbon price signal itself.

Figure 29: The percentage reduction in energy generated by coal plant from ($30, BAU) for six load shaving profiles for $30/tCO2

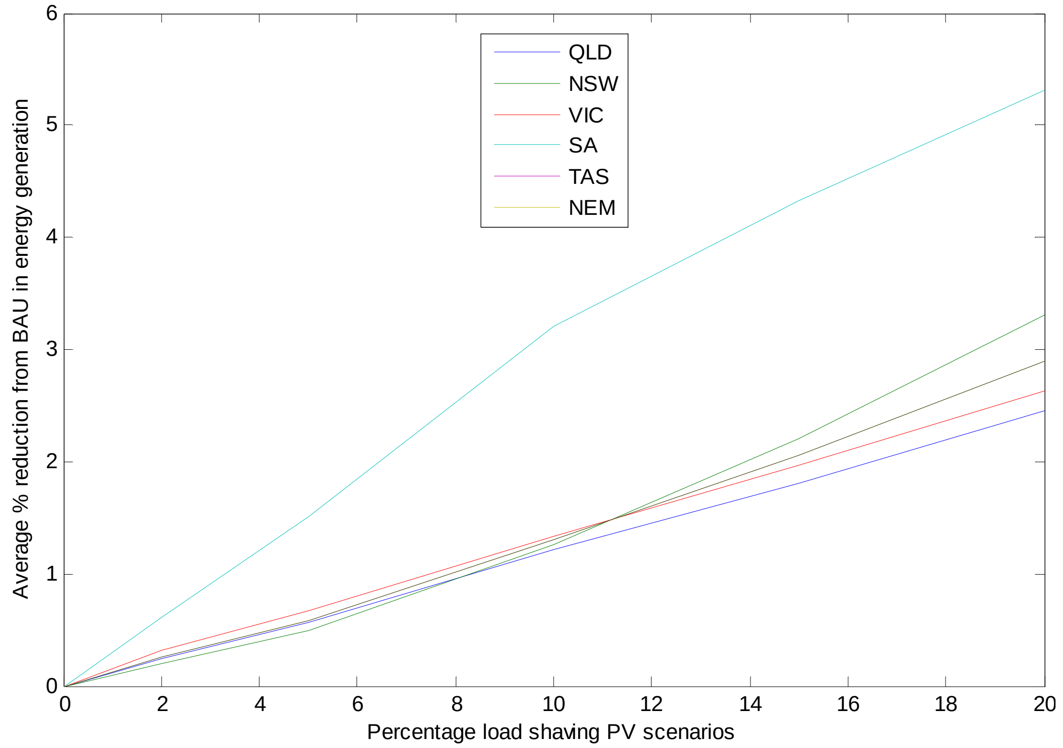


Figure 30: The percentage reduction in energy generated by gas plant from ($30, BAU) for six load shaving profiles for $30/tCO2

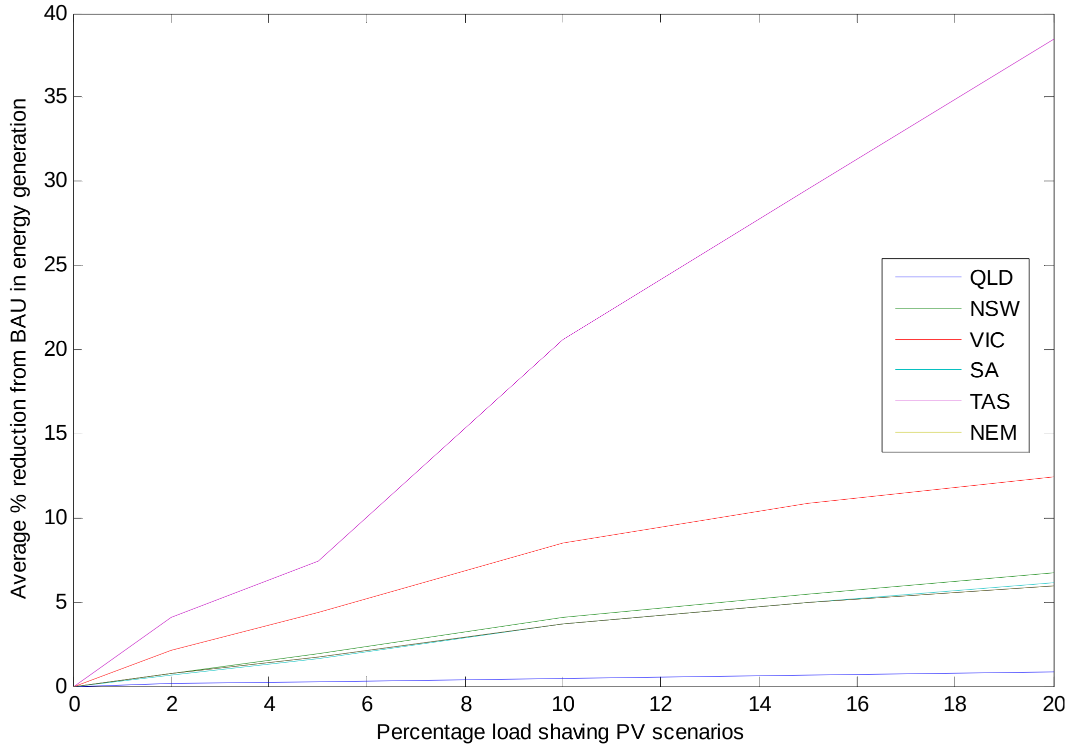


Figure 31: The percentage reduction in energy generated by hydro plant from ($30, BAU) for six load shaving profiles for $30/tCO2

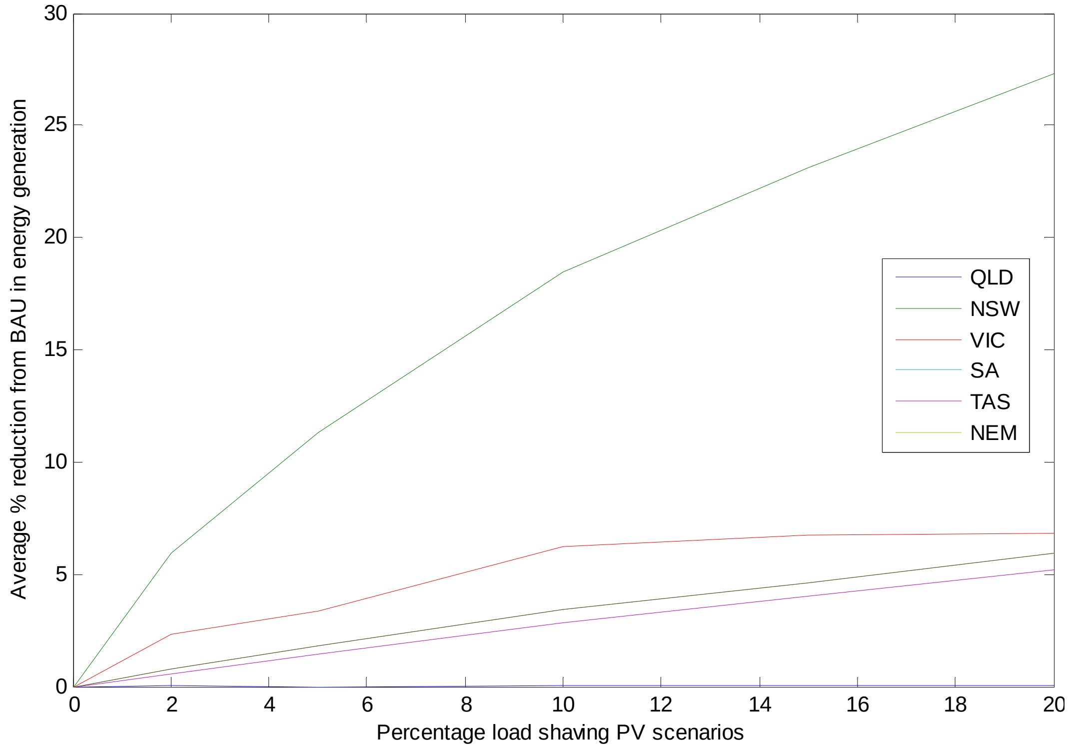
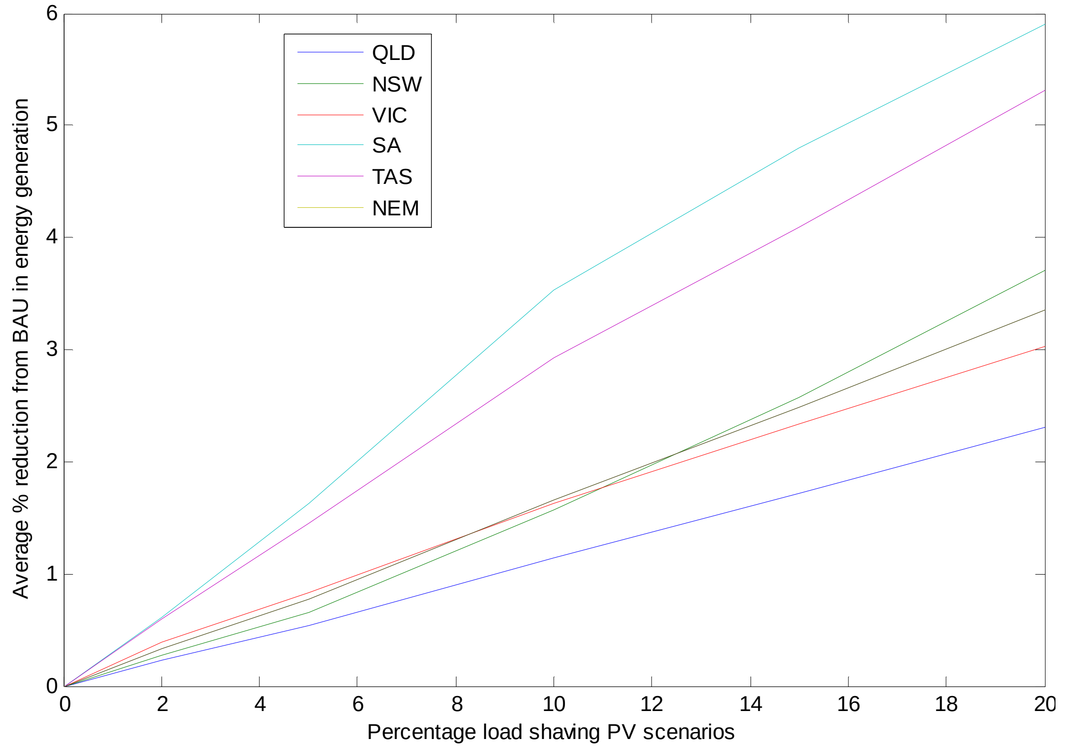
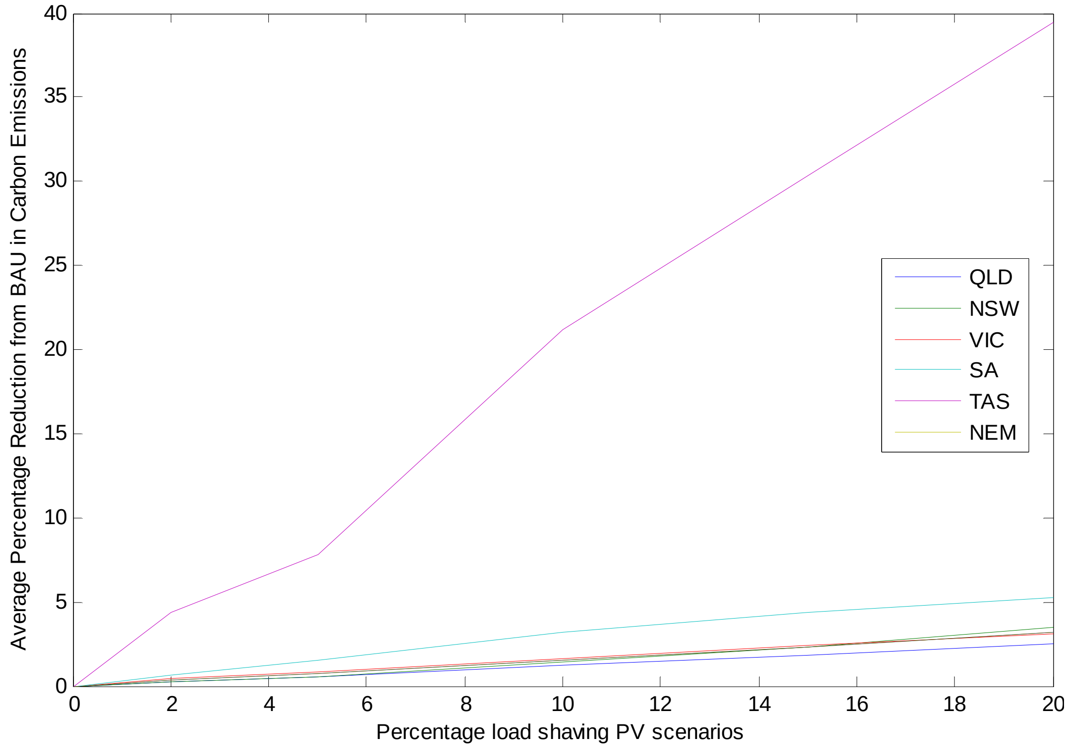


Figure 32: The percentage reduction in energy generated by all types of plant from ($30, BAU) for six load shaving profiles for $30/tCO2



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 further enhancing the effects produced by the carbon price signal itself. Figure 33 provides a depiction of the type of additional carbon emission reductions that might be available (over and above what was obtained from the $30/tC02 carbon price itself) when PV based load shaving is combined with the carbon price signal. Note that the large reduction experienced for TAS is once again coming from a low base.

Figure 33: Carbon emissions percentage reduction from ($30, BAU) for a carbon price of $30/tCO2



Increased PV penetration produced slight amelioration in the incidence of branch congestion across each state and NEM as a whole. Figure 34 and Figure 35 provides a depiction of the slight amelioration in branch congestion that can be generally attributed to the PV based load shaving over and above the results that can be attributed to the impact of the $30/tC02 carbon price as outlined in Table 10. See Figure 34 and 35. Figure 34 provides a depiction of incidence of branch congestion obtained for carbon prices of $50/tCO2 and $70/tCO2. Once again, the impact of the PV based load shaving is to slightly ameliorate branch congestion in addition to the carbon price signal.

Figure 34: The percentage of time that branch flow is at maximum for six load shaving profiles for a carbon price

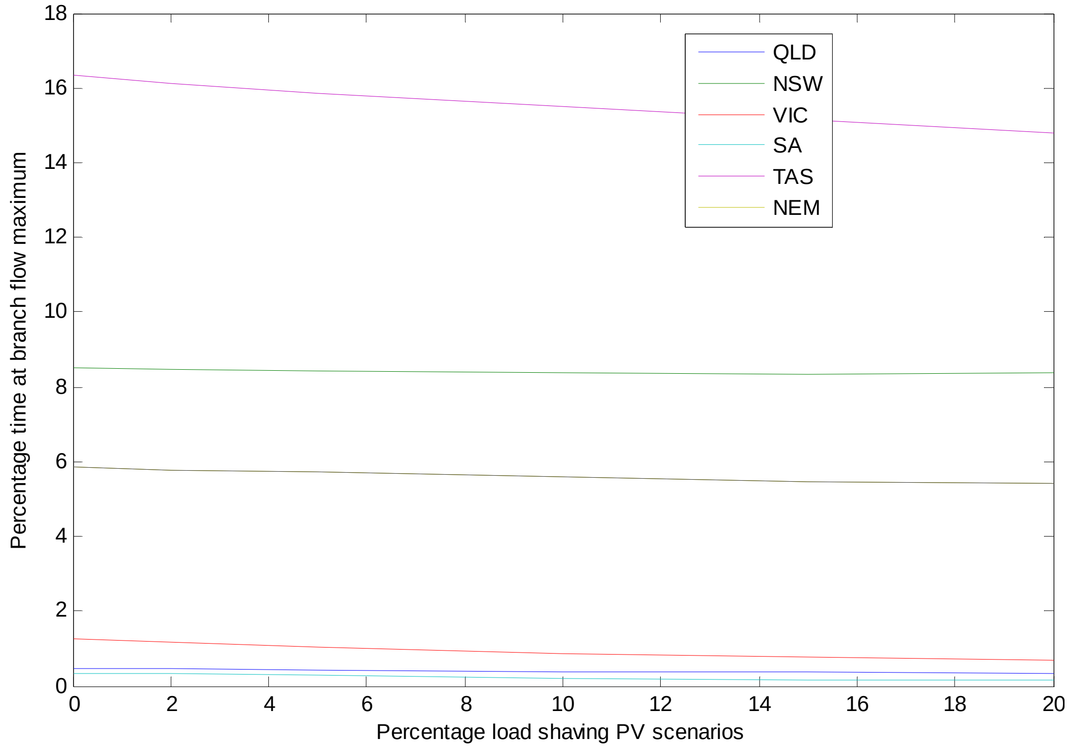


Figure 35: The percentage of time that branch flow is at maximum for six load shaving profiles for a carbon price

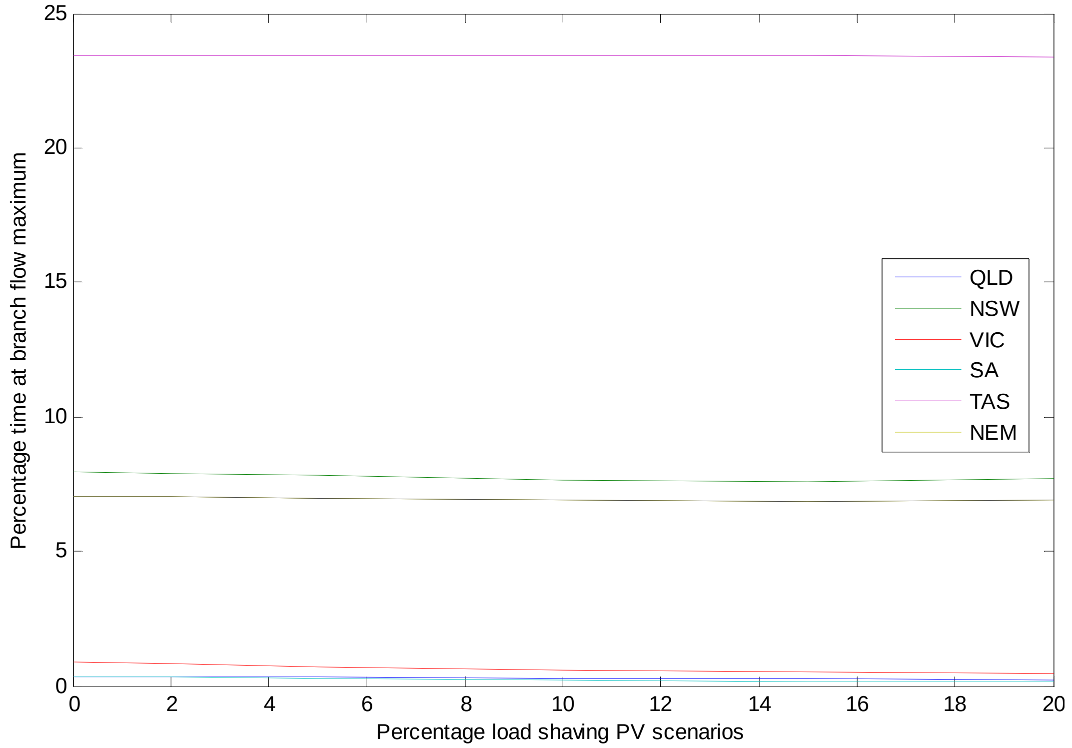


Figure 36, Figure 37 and Figure 38 display the incidence of congestion on the Interconnectors for carbon prices of $30/tCO2, $50/tCO2 and $70/tCO2 respectively. The following results are apparent from inspection of these figures.

For carbon prices in the range of $50/tCO2 to $70/tCO2, the incidence of branch congestion on especially Murraylink, Directlink and Basslink became much more pronounced than was evident for carbon prices in the range of $0/tCO2 to $30/tCO2. Increased PV penetration produced slight increase in branch congestion on the Murraylink Interconnector. Except for Murraylink and to a less extent Directlink, the effect of PV based load shaving is to generally ameliorate congestion on the other Interconnectors.

Figure 36: The percentage of time that interconnectors are at maximum for six load shaving profiles for a carbon

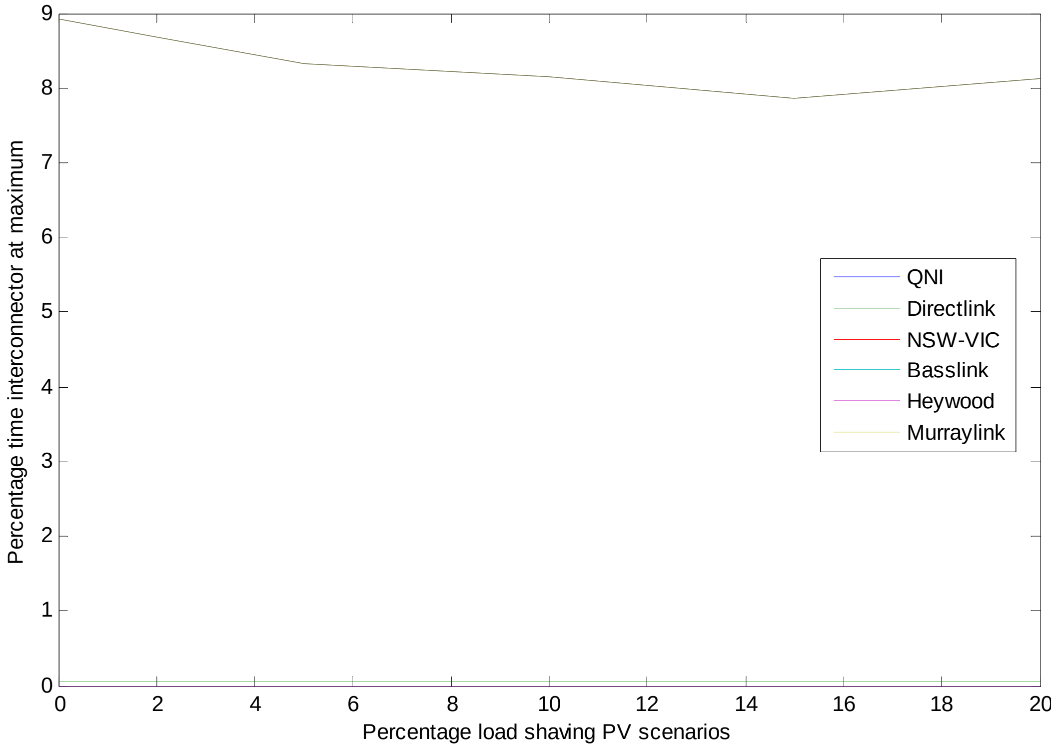


Figure 37: The percentage of time that interconnectors are at maximum for six load shaving profiles for a carbon

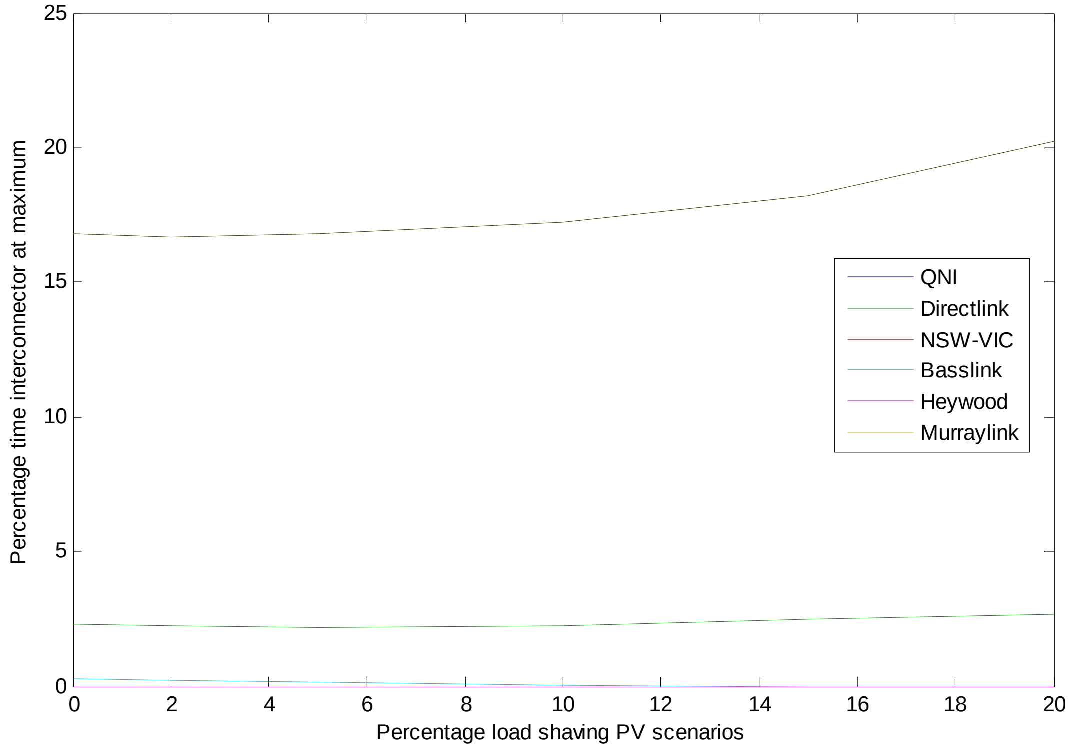
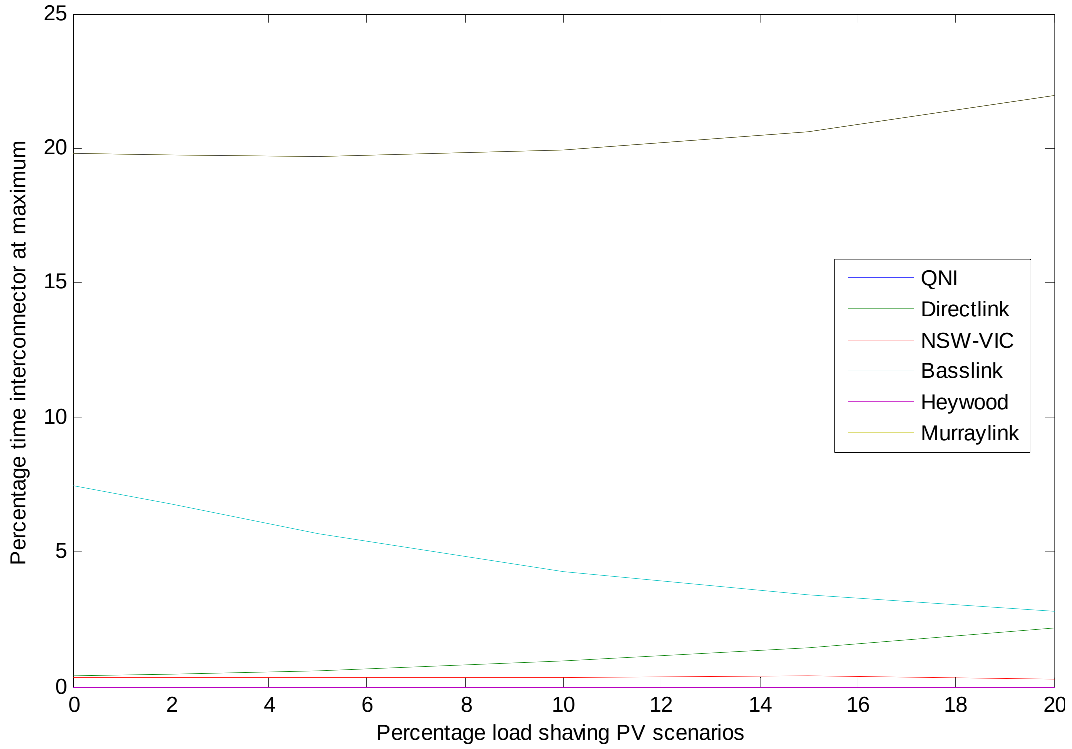


Figure 38: The percentage of time that interconnectors are at maximum for six load shaving profiles for a carbon price of $70/tCO_2$



4.4 Conclusions

The results are based on the thermal and hydro based generation structure existing in 2007. In the simulations performed, account is taken of the fact that coal and gas-fired base load/intermediate plant is modelled as having minimum stable operating levels. This precludes the possibility of driving production output of particularly coal fired plant to zero. Instead, in response to increases in carbon prices, production levels of coal fired plant will be driven to the minimum stable operating level. This will put an effective ceiling on the level of carbon emission reductions that can be secured.

Second, a large portion of the existing gas-fired generation fleet is designed for peak load production duties. This reflects the historical development of the national generation fleet which saw coal fired generation as being predominantly responsible for supplying base load power while the gas fired fleet was seen as predominantly being available to supply peak load production duties. In practice, engineering features, pipeline capacity and gas storage capacity of much of the existing peak load gas fleet will prevent this plant from being able to switch from peak to base load or intermediate production duties for any extended period of time without significant additional pipeline infrastructure construction. However, the current version of the ANEM model does not accommodate this practical consideration and subsequent dispatch of gas plant relative to other competing plant will only reflect relative cost differentials and not the engineering efficacy of the resulting dispatch patterns. As such, it is possible (and likely for higher carbon prices) that some (cheaper) peak load plant will be dispatched in a manner analogous to intermediate or even base load plant.

Third, the results obtained depend crucially on model assumptions including ramping rates used for coal fired generation which could have influenced the price outcomes obtained for NSW and VIC, in particular.

Thus, the emission reductions obtained from the model for carbon prices in the range of $50/tC02 and $70/tC02, in particular, should be interpreted with care for these three reasons. Deep sustained cuts in carbon emissions within the NEM are unlikely to be obtained in practice until a significant portion of the existing black and brown coal fleet can be retired or mothballed. This will not be possible, however, until either new plant is constructed or the existing plant is retro-fitted to a more carbon emissions friendly form of production technology which can also meet base load production duties. In the short to medium term and in an environment containing carbon prices in the range $30/tC02 to $70/tC02, the technology of choice, ignoring the nuclear option and further expansion in hydro generation, on both cost and carbon emissions grounds would be Natural Gas Combined Cycle plant. Given the aforementioned implementation problems for gas to meet base load demand, DG has an important role in helping transform the energy industry to reduce carbon emissions. Research into the efficacy of policies promoting the construction of new base load gas plant as well as the cost of converting existing generators into base load gas generators would help inform this debate.

5 THE DEVELOPMENT OF A COMMERCIAL SCALE EXPERIMENTAL PV ARRAY: THE CASE OF UQ

One of the key Project 2 deliverables was the training of PhD students who understand both the technical and economic aspects of the Australian energy system. Also, it was imperative that the economic research in this project, which was predominantly modelling, should be balanced by ‘hands on’ involvement in the actual implementation of a DG installation. Thus, the three of the researchers in the project were centrally involved in the planning and implementation of the UQ PV Array which became fully operational in July 2011. This was very much a ‘learning by doing’ exercise, the result being the creation of an electricity Micro-Grid across multiple campuses. This has resulted in a number of spin off research projects for both PhD students and experienced researchers. Some of these projects are already ongoing and funded. The Micro-Grid concept is an important development in the implementation of DG. The current driver at UQ is the new PV Array but the goal is to eventually incorporate multiple sources of renewable and alternative energy forms (solar PV, solar thermal, micro-turbines, etc.). A number of emission reduction, research, education and policy development, deployment learning and training objectives will then become feasible.

The first Micro-Grid sub-project, the St Lucia PV Array, is 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. All of the economic evaluations of this project were undertaken as part of Project 2. The St Lucia Array will be the largest PV array of its kind in Australia and is approximately the size of a shipping centre or supermarket installation. Thus, it is an ideal test bed for investigating the economics of commercial PV and its impacts.

The Array will initially focus research activity on the costs of dealing with an intermittent DG technology. The current array size will produce approximately 6% 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.

The array itself is 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.

The research projects and contracts that have already been negotiated are 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;

These projects will allow the development of a range of different modelling scenarios[1].

[1] 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)

Figure 39: University of Queensland Centre PV Array

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 40), having 120 kWh 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 occupies 15% of the footprint, with the balance being set-up as a demonstration room with monitoring equipment to monitor system performance.

This unit is to be replaced 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. 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 40: CPV Array - St Lucia Campus

As noted earlier, the array will contribute 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 41: Red Flow 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 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.[2]

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.

[2] 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)

6 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 (Beach 2008; Borenstein 2008; Kahn 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 modelled 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.

6.1 A brief introduction to the modelling methodology and assumptions

The model employed is based on the 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:

- 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.
- 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).
- All generators bid into the market at their short-run marginal costs.
- 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 cost related barriers to their penetration.

Based on the above assumptions, the two optimization objectives of the proposed transmission network expansion model are respectively minimizing the total expansion investment cost and overall system generation cost. 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.

Besides the AC power flow constraints, the power system reliability and security constraints will also be taken into account in the proposed model. 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.

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, the *voltage stability index (VSI)* is employed to measure system security. Voltage stability is the ability of the power system to maintain voltage levels, subject to disturbances. In this paper, the voltage stability index is calculated by performing power flow calculation and singular vector decomposition (SVD) (Lof et al. 1992).

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 the proposed model 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-fired plants.

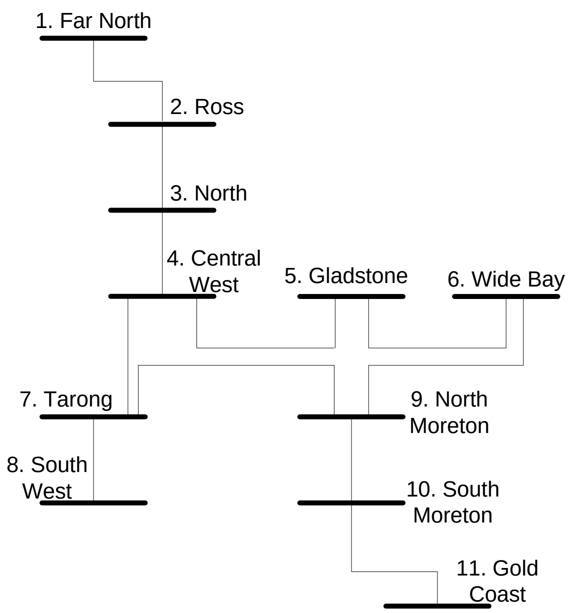
We employ the *areas of influence method* (Reta, Vargas & Verstege 2005) to allocate transmission expansion cost. This method is also based on power flow calculations. It can be employed to determine the contribution of each market participant to the overall expansion cost. The transmission cost allocation 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 added into each bus successively. Based on power flow increases in transmission lines, it is possible to calculate a *participation factor* (Reta, Vargas & Verstege 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.

6.2 Case Study Results and Findings

6.2.1 Case Study Setting

The 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 network before simulation is given in Figure 42.

Figure 42: One Line Diagram of the Queensland Network



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 12. 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. 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.

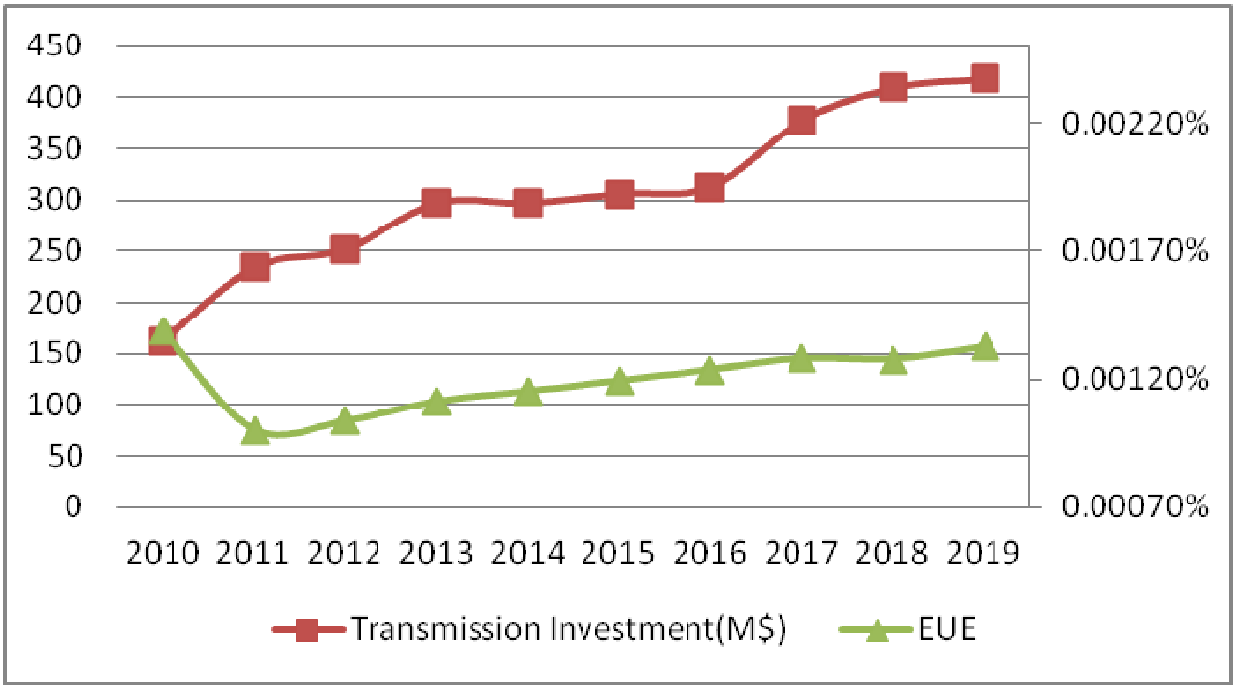
Table 12: Simulation Scenarios

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%

6.2.2 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 Figure 43. 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 Figure 43 we can also observe that, the transmission expansion generally can maintain the EUE within 0.0015%, which is a reasonable level.

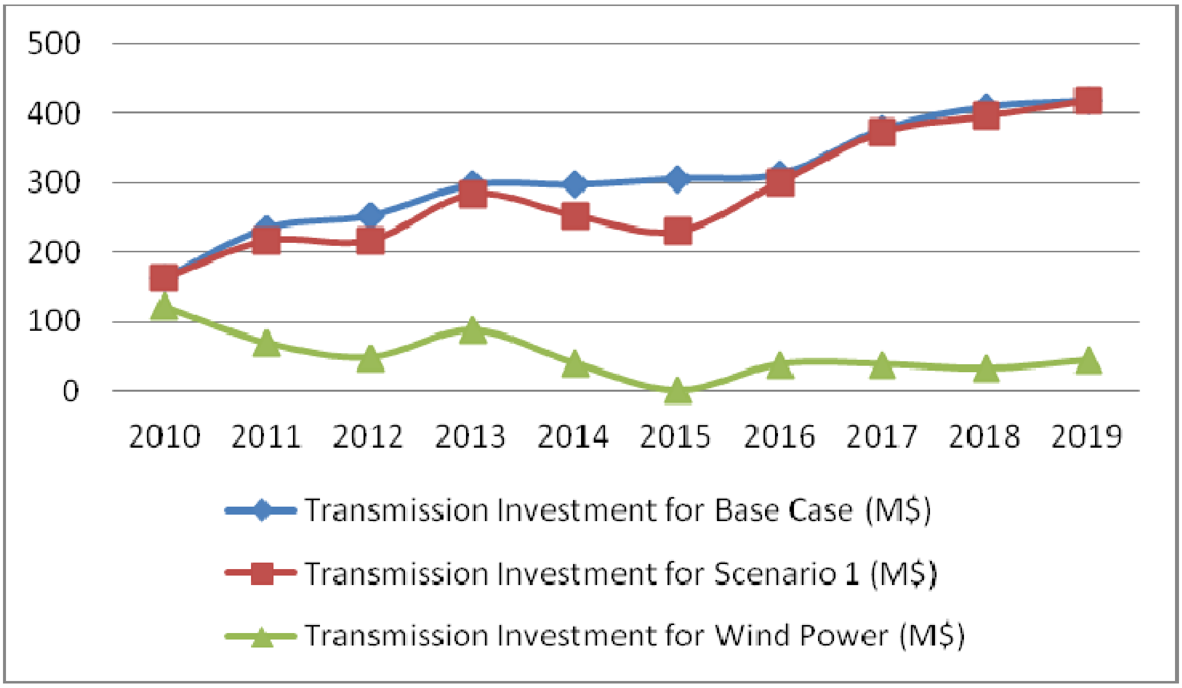
Figure 43: Transmission Investments of Base Case Scenario



The simulation results of scenario 1 are plotted in Figure 44. 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 44: 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 Figure 45 and 46, 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 45: Transmission Investments of Scenario 2 (40% Wind Turbine with SIG)

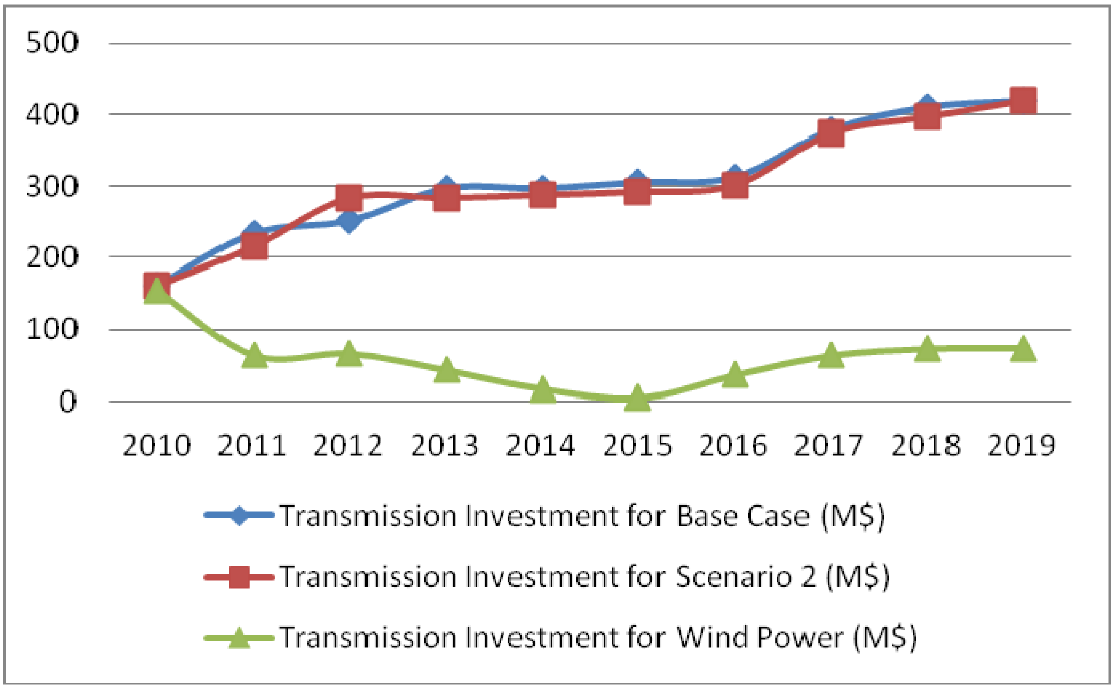
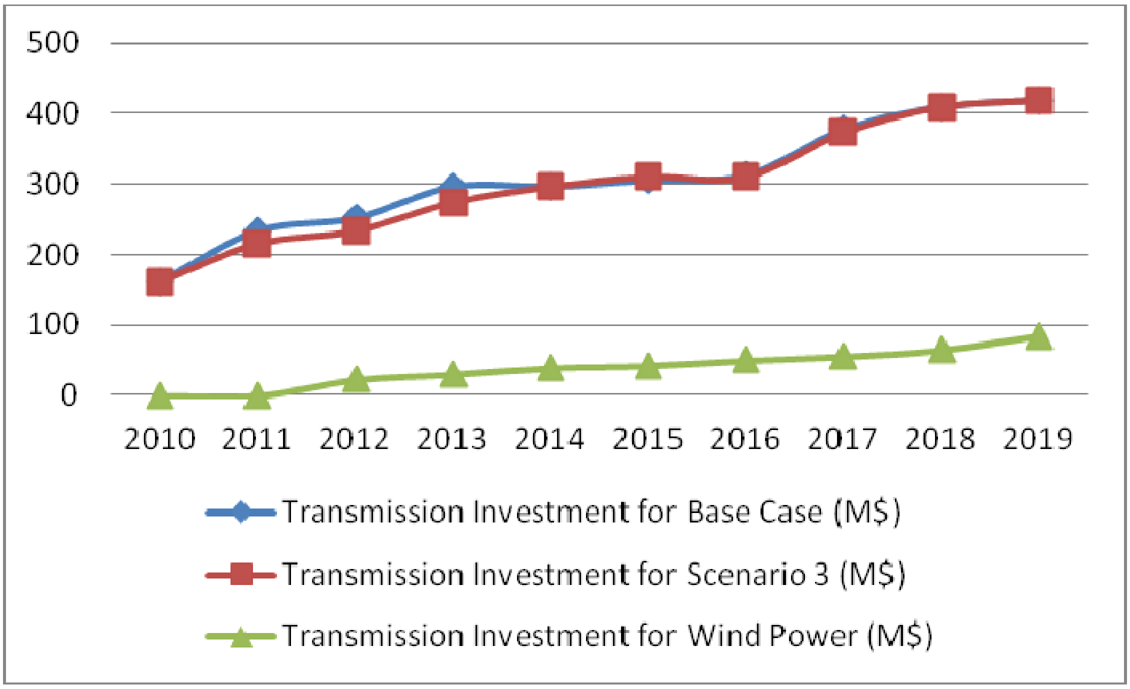
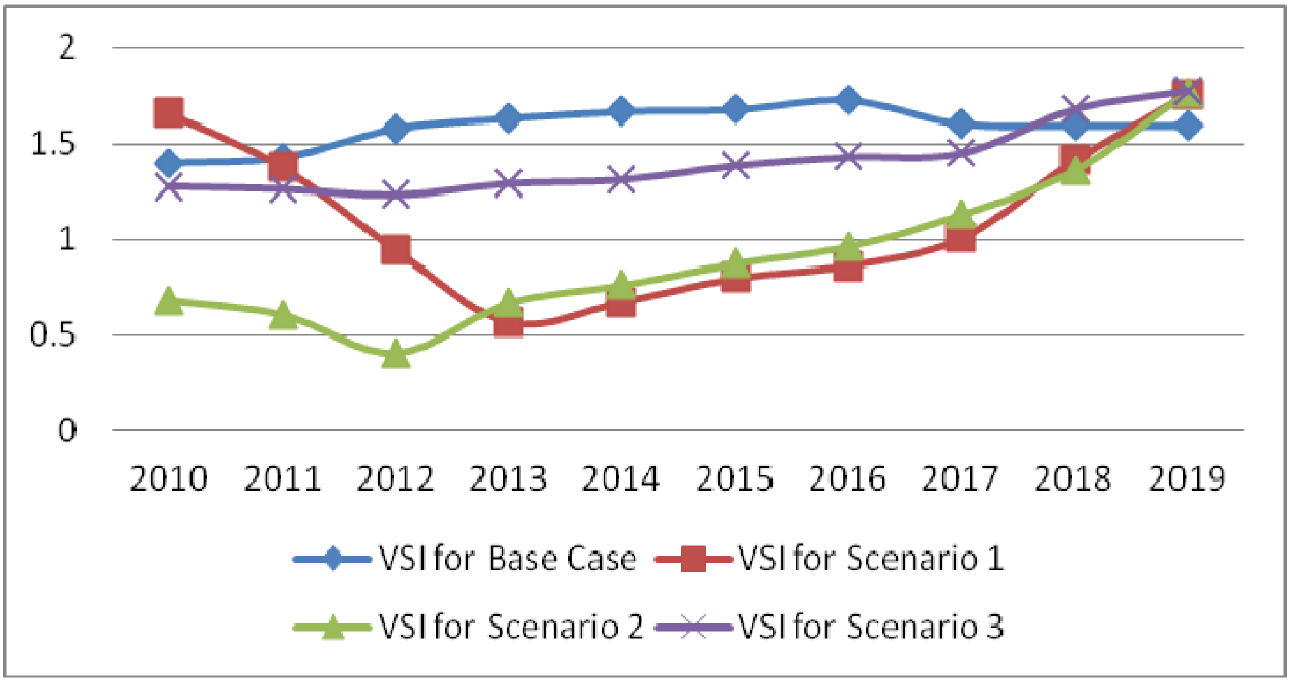


Figure 46: Transmission Investments of Scenario 3 (40% Wind Turbine with DFIG)



The VSIs of three wind power scenarios are also plotted in Figure 47. 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 the 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 47: Voltage Stability Index for Wind Scenarios



6.2.3 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 Figure 48 and 49. 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 demand, consequently help maintain the voltage level.

Figure 48: Transmission Investments of Scenario 4 (20% Solar PV)

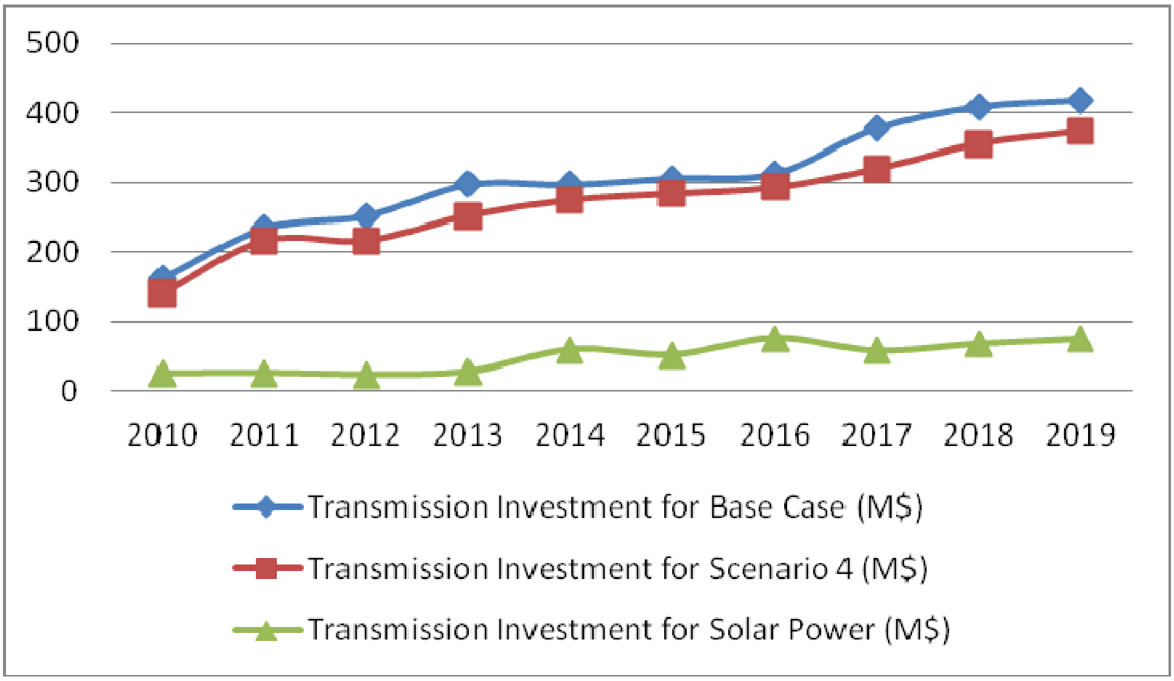


Figure 49: Transmission Investments of Scenario 5 (40% Solar PV)

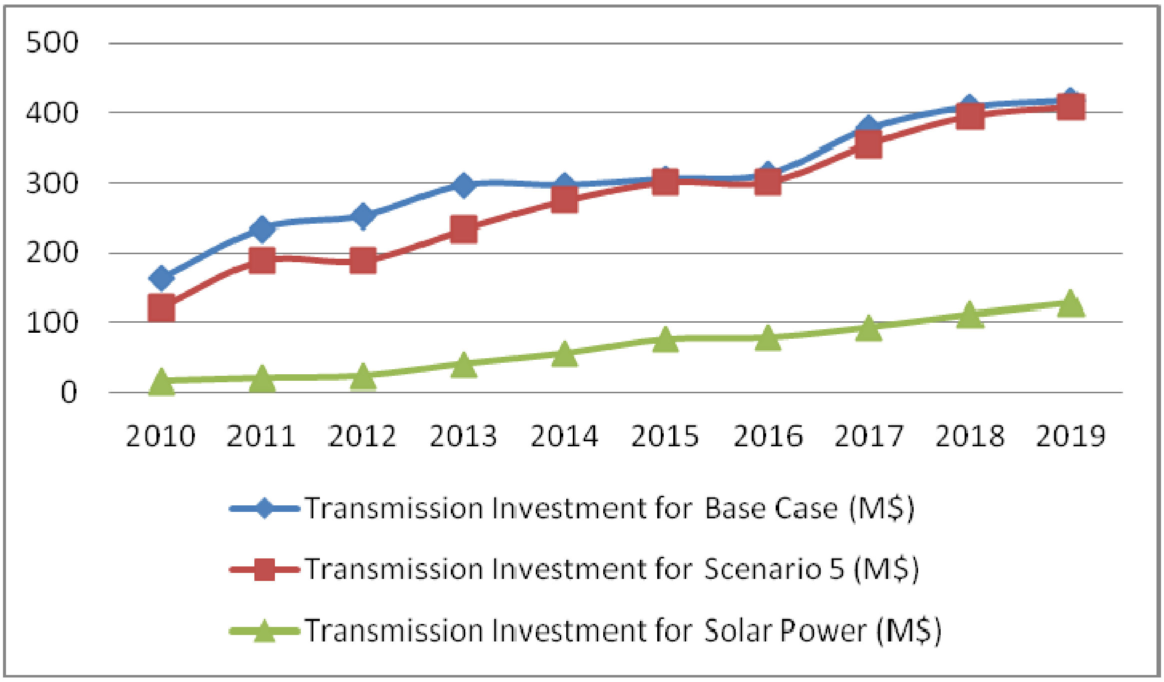
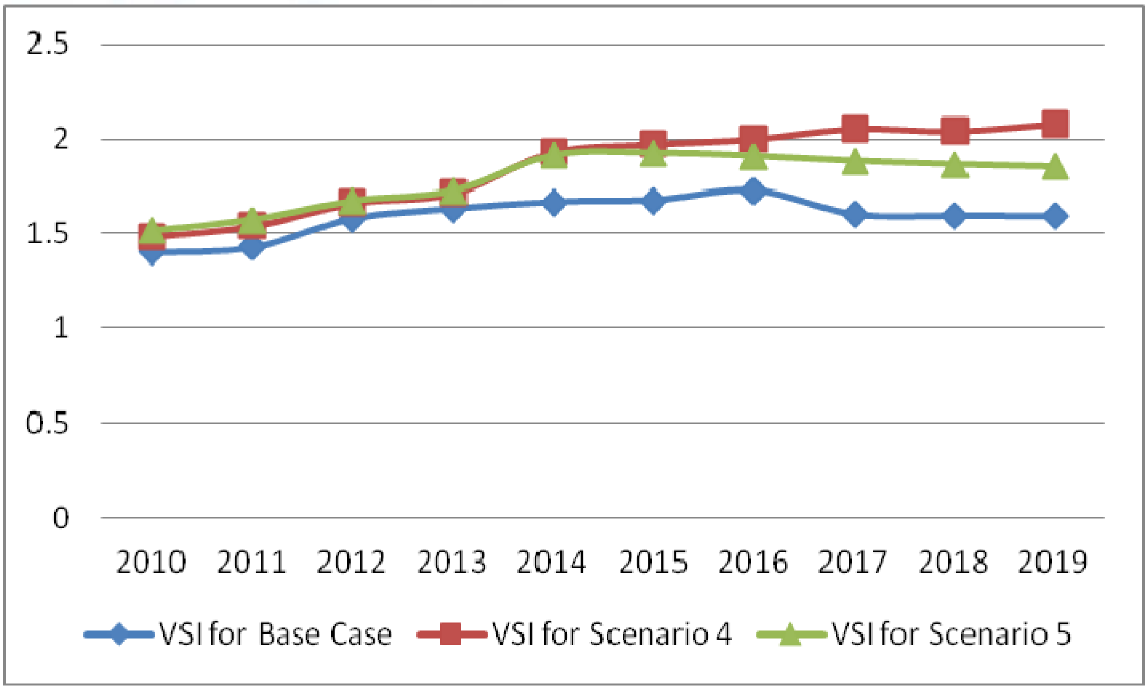


Figure 50: Voltage Stability Index for Solar Scenarios



6.3 Conclusions

In this section, 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 turbines and solar PV panels.

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 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 reliability and security 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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