CSIRO Intelligent Grid Cluster

End of Year Final Report

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Milestone Report 4 & 5

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1 Introduction

This report presents the work that has been done from August 2009 to August 2010, the second year of the iGRID project. As planned, in this year, the models that we were developing have been completed and 'road tested.' We with the outcomes and what we now have are models that are uniquely able to answer key research questions about a range of different kinds of impacts of distributed energy generation. In the final year of the project we shall be fully utilising these models to provide vital advice to policy makers, both at the federal and State levels as well as relevant industry players.

In chapter 2, we report on our investigations into the possible roles that a carbon price signal and residential based solar PV take-up scheme might play in pursuit of the policy goal of curbing growth in carbon emissions within the National Electricity Market (NEM). To investigate this issue, we have used an agent-based model of the Australian National Electricity Market (NEM) that contains many salient features of the national wholesale electricity market. These features include intra-regional and inter-state trade, realistic transmission pathways and the competitive dispatch of generation based upon Locational Marginal Pricing. The implementation of the residential-based PV scheme is undertaken in terms of its load-shaving capability at nodes containing a high residential load component which, in the current context, is aligned to nodes encompassing Brisbane, Sydney, Melbourne and Adelaide. We found that a demand side policy promoting the take-up PV, when combined with a carbon price signal can potentially enhance many of the desirable impacts associated with the carbon price signal while also serving to mitigate some of the less desirable consequences.

In Chapter 3, we report on progress with the UQ PV Array with which we have been centrally involved over the past year. We have conducted all of the economic analysis and evaluated all bids in the tendering processes. This has been an important learning process form a range of perspectives and a 'live' example of the installation of distributed generation. A full feasibility study was completed in July 2009 and reported in our last Annual Report. A business case had to be prepared to obtain funding for the project from both UQ, the Queensland Government and Energex. We were involved in the preparation of an Expression of Interest (EoI) and learned a great deal about the tendering process in the PV market. Eight submissions were received and assessed. These submissions were evaluated on a number of criteria including cost, required roof area, panel output and contribution to the University's ongoing research activities. Based upon that evaluation, three companies were invited to submit a full tender. Eventually, the tender was awarded to Ingenero, a local Brisbane company with Trina Solar as the panel supplier. The resulting contract for delivery of the 1.2 MW array was signed in June 2010 with a projected completion date scheduled for end December 2010. In the coming year, we shall be monitoring the economics of the array generally and specific aspects of it including, for example, storage battery innovations and costs involved in interfacing effectively with the Grid.

In Chapter 4 we report on our levelised cost analysis of DG. Because of the highly heterogeneous nature of electricity demand, no one individual energy source can effectively be used to serve demand. So an appropriate mix of generation assets is always required. So it is essential to know what the true costs of different generating technologies are. Each country is unique in this regard so it is necessary to provide a unique study of Australia. The platform that we have build has been successfully applied to the expected generation types currently under consideration. We have do this so that we can go on to apply screening curve to establish the optimal plant mix of generation asset types. The intention is to explore how best to embed different types of DG in an optimal mix in the face of assumptions concerning different level of carbon price, or tax.

In Chapter 5 we report the work we have done in understanding better the imopacts of Distributed Generation on the transmission infrastructure of the NEM. In particular, we examined the capacity of DG to defer transmission investments using a purpose built simulation model. This is a transmission expansion model that is formulated as a multi-objective optimization problem with comprehensive technical constraints, such as AC power flow and system security. The case study we selected is the Queensland electricity market. Our simulation results show that, DG has the capacity to reduce transmission investments significantly provided that it is planned appropriately taking existing infrastructure characteristics into account. For example, the location of DG, the network topology, and power system technical constraints are all important. The work that has been done was largely experimental and, in the final year of the project, a comprehensive assessment will be conducted and firm conclusions drawn.

In Chapter 6 we report on our work on the economics of feed-in tariffs. There has been ambivalence and contradictory policy positions in this area in Australia, yet the presence of predictable feed-in tariffs is an essential pre-requisite of a significant switch to DG, particularly in the absence of a significant carbon price or tax. We believe that the case for a gross feed in tariff in Queensland and in all other States is strong and that Federal leadership is necessary in this area. In our study, we focussed on a range of issues that pose obstacles to implementation. These issues have posed a range of reach questions that we shall seek to answer in the coming year. For example, the relative cost of conventional and solar energy sources need to be accurately measured (we identified this at the beginning of the project), we need to understand the interaction of a feed-in tariff regime and the prevailing institutional and regulatory environment in the electricity sector and elsewhere, there are technical issues relating to large scale adoption of DG in a favourable feed-in tariff regime that have to be considered form an economic standpoint, there is the problem of consumer awareness and understanding of tariff systems and, finally, the reactions of various stakeholders to such a regime.

2 An Assessment of the Impact of the Introduction of Carbon Prices and Demand Side PV Penetration

2.1 INTRODUCTION.

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

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

Why load shaving is important is because the level of carbon emission is directly related to the aggregate level of load that has to be served by aggregate generation. Any reductions in aggregate load that has to be served would translate into reductions in carbon emissions because lower levels of aggregate generation output would be needed to service the load. Of course, supply side initiatives such as carbon prices or taxes that promote fuel based switching towards less emissions intensive forms of power generation would further reduce aggregate carbon emissions. However, it is also incontestable that most commentators also believe that cutting or reducing the growth in both peak and aggregate load demand is a crucial part of the process of obtaining deep sustainable cuts in carbon emissions.

However, with any forthcoming move towards a carbon constrained economy, there are many uncertainties over policy settings that are required to achieve the environmental goal of reduced greenhouse gas emissions and about the resulting impact on the National Electricity Industry more generally. A complete understanding of the impacts on the electricity industry of carbon abatement policies requires that new renewable technology proposals be incorporated in a model containing many of the salient features of the national wholesale electricity market.

These features include intra-regional and inter-state trade, realistic transmission and distribution network pathways, competitive dispatch of all generation technologies with price determination based upon marginal cost and branch congestion characteristics.

It is only under such circumstances that the link between carbon emission reductions and generator based fuel switching can be fully explored and the consequences for carbon emission reductions and changes in wholesale and retail electricity prices can be determined.

To capture these linkages, an agent based model of the Australian National Electricity Market (NEM) will be employed in this study that utilizes a heuristic framework that can be viewed as a template for operations of wholesale power markets by Independent System Operators (ISO's) using 'Locational Marginal Pricing' to price energy by the location of its injection into or withdrawal from the transmission grid (Sun, 2007a). The Australian model is called the 'ANEMMarket' model and is a modified and extended version of the 'Agent-Based Modelling of Electricity System (AMES)' model for the American system developed by Sun and Tesfatsion (Sun, 2007b, Sun, 2007a).[1] The modifications were principally made so that the structure of the 'ANEMMarket' model reflects the key structural features of the NEM - structural features which differ in fundamental ways from those found in the USA and which were subsequently included in the 'AMES' model.[2]

[1] Comprehensive information including documentation and Java code relating to the 'AMES' model can be found at: http://www.econ.iastate.edu/tesfatsi/AMESMarketHome.htm.

[2] A summary of the key differences can be found in last year's annual report.

The 'ANEMMarket' modelling framework was developed with the intension of modelling strategic trading interactions over time in a wholesale power market that operated over realistically rendered transmission grid structures (Sun, 2007a). The wholesale market of the NEM is a real time 'energy only' market, and the market for ancillary services is a separate and distinct market. A DC OPF algorithm is used to determine optimal dispatch of generation plant and wholesale prices within the agent based model. The formulation of DC OPF problems require detailed structural information about the transmission grid as well as supply offer and demand bid information from market participants. In principle, the model can also accommodate the supply of ramping capacity which is used principally for frequency support and is a component of the ancillary services market of the NEM. However, given the use of a DC OPF solution (instead of an AC OPF solution) within the model, the ancillary service associated with the supply of reactive power (for voltage support) cannot be modelled.

2.2 PRINCIPAL FEATURES OF THE 'ANEMMARKET' MODEL FRAMEWORK.

In this section, we provide a brief outline of the principal features, structure and agents in the 'ANEMMarket' model. The 'ANEMMarket' wholesale power market framework is programmed in Java using RepastJ, a Java-based toolkit designed specifically for agent base modelling in the social sciences.[3] The 'ANEMMarket' framework currently incorporates in stylized form several core elements that can be associated with key features of the Australian National Electricity Market. Specifically, the elements of the market design that have been incorporated are:

- The 'ANEMMarket' wholesale power market operates over an AC transmission grid for DMax successive days, with each day D consisting of 24 successive hours H = 00, 01, ….., 23;
- The wholesale power market includes an Independent System Operator (ISO) and a collection of energy traders consisting of Load-Serving Entities (LSE's) and generators distributed across the nodes of the transmission grid;
- The 'ANEMMarket' ISO undertakes the daily operation of the transmission grid within a one-settlement system consisting of the Real-Time Market which is settled by means of 'Locational Marginal Pricing';
- For each hour of day D, the 'ANEMMarket' ISO determines power commitments and Locational Marginal Prices (LMP's) for the Spot Market

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

based on generators supply offers and LSE demand bids submitted prior to the start of day D;

- The 'ANEMMarket' ISO produces and posts an hourly commitment schedule for generators and LSE's that is used to settle financially binding contracts on the basis of the day's LMP's for a particular hour; and
- Transmission grid congestion in the spot market is managed via the inclusion of congestion components in the LMP's associated with nodal price variation within an hour when branch congestion is triggered by ISO dispatch instructions to generators.[4]

The organization charged with the primary responsibility of maintaining the security of this power system, and often with system operation responsibilities is the Independent System Operator (ISO).

A Load Serving Entity (LSE) is an electric utility that has an obligation, either under local law, license or long-term contract, to provide electrical power to end-use consumers (residential or commercial) or possibly to other LSE's with end-use consumers. The LSE's are assumed to aggregate individual end-use consumer demands into 'load blocks' for bulk buying at the wholesale level. Generators are assumed to produce and sell electrical power in bulk at the wholesale level.

2.2.1 Transmission Grid Characteristics.

The following assumptions were made in developing the 'ANEMMarket' transmission grid. The transmission grid is an alternating current (AC) grid modelled as a balanced three-phase network with $N \geq 1$ branches and $K \geq 2$ nodes. The transmission grid is assumed to be 'connected' to the extent that it has no isolated components: each pair of nodes k and m is connected by a linked branch path consisting of one or more branches. However, we do not assume complete connectivity implying that node pairs are not necessarily connected directly to each other through a single branch.

As outlined in Sun and Tesfatsion (2007a, p. 5), we make the following additional assumptions:

- The reactance on each branch is assumed to be a total branch reactance, and not a per mile reactance;

[4] It should be noted that 'Locational Marginal Pricing' is the pricing of electrical power according to the location of its withdrawal from, or injection into, a transmission grid, and at any particular node, can be considered the least cost of meeting demand at that node for an additional unit [megawatt (MW)] of power.

- All transformer phase angle shifts are assumed to be 0;
- All transformer tap ratios are assumed to be 1;
- All line-charging capacitances are assumed to be 0; and
- Temperature is assumed to remain constant over time – permitting us to use a constant value for the reactance on each branch.

Base apparent power S_0 is assumed to be measured in three-phase MVA's, and base voltage V_0 in line-to-line KV's. These quantities are used to derive per unit normalisations in the DC OPF solution and also to facilitate conversion between SI and PU unit conventions as required by the model. Real power must be balanced across the entire grid, meaning that aggregate real power withdrawal plus aggregate transmission losses must equal aggregate real power injection.

The key transmission data required for the transmission grid in the model relate to an assumed base voltage value (in KV's) and base apparent power (in MVA's)[5], branch connection and direction of flow information, maximum thermal rating of each transmission line (in MW's) and each line's (SI) reactance value (in ohms). It should be noted that in the current version of the model, there are 72 transmission lines.

The transmission grid has a commercial network consisting of pricing locations for the purchase and sale of electricity power. In this context, a pricing location can be viewed as a location at which market transactions are settled using publicly available LMP's. We assume that the set of pricing locations coincides with the set of transmission grid nodes.

2.2.2 LSE Agents.

The LSE agents purchase bulk power in the wholesale power market each day in order to service customer demand (load) in a downstream retail market – thus linking the wholesale power market and downstream retail market. LSE's purchase power only from generators and are assumed to not engage in production or sale activities in the wholesale power market.

For simplicity, we assume that downstream retail demands serviced by the LSE's exhibit negligible price sensitivity and therefore reduce to daily supplied load

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[5] Base apparent power is set to 100 MVA, an internationally recognized value for this variable. Thermal ratings of transmission lines and SI reactance values were supplied by the QLD, NSW and TAS transmission companies Powerlink, Transgrid, and Transend. For VIC and SA, the authors used values based on the average 'PU-values' associated with comparable branches in the three above states.

profiles. In addition, LSE's are modelled as passive entities who submit daily load profiles (demand bids) to the ISO without strategic considerations (Sun, 2007a). The revenue (and profit) received by LSE's for servicing these load obligations are regulated to be a simple 'dollar mark-up' based retail tariff that is independent of the wholesale cost level. As such, the LSE's have no incentive to submit price-sensitive demand bids into the market.[6] Therefore, just prior to the beginning of each day D each LSE is assumed to submit a daily load profile to the ISO for day D, and this daily load profile represents the real power demand (in MW's) that the LSE has to service in its downstream retail market for each of the 24 successive hours.

The estimates of real power flow and injection/take-off at pre-specified transmission grid nodes as well as spot prices at each node obtained from the DC OPF solution constitute 'quantity' and 'price' variables that are used to calculate respective generator and LSE revenues and costs associated with wholesale market (spot market) transactions and assessments of the need for hedge cover.

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 AEMO for the 'QLD1' and 'NSW1' markets.[7] For the other three states, the regional shares were determined from terminal station load forecasts associated with summer peak demand (and winter peak demand if available) contained in the annual planning reports published by the respective transmission companies Transend (TAS), Vencorp (VIC) and ElectraNet (SA). These regional load shares were then multiplied by the 'TAS1', 'VIC1' and 'SA1' state load time series published by AEMO in order to derive the regional load profiles for TAS, VIC and SA that are used in the model In the current version of the model, there are 53 LSE's.

2.2.3 Generator Agents.

The generator agents are electric power generating units, and each generator is configured with a production technology. It is assumed that generators can sell power only to LSE's and not to each other. In the model, we equate generators with individual generating units typically associated with individual turbines. As such, in the current version of the model, there are 286 generators. These include all thermal (e.g. black and brown coal, natural gas and diesel) and hydro based generation but exclude wind generation.

[6] For example, in Queensland, the state government regulates retail tariffs that are payable by most residential customers. Prior to July 2009, this amount equated to 14.4c/KWh (excl GST) which, in turn, translated into a retail tariff of $144/MWh.

[7] Time series data relating to the AEMO 'QLD1' and 'NSW1' data can be found at: http://www.aemo.com.au/data/price_demand.html.

With regard to production technology, we assume that generators have variable and fixed costs of production and can incur start-up costs. However, they do not incur other costs such as no-load or shutdown costs.

For each generator, technology attributes are assumed, and these attributes refer to the feasible production interval[8], total cost function, total variable cost function, fixed costs [pro-rated to a ($\$/h$) basis] and a marginal cost function. Each generator also faces MW ramping constraints that determine the extent to which real power production levels can be increased or decreased over the next hour within the hourly dispatch process. The production levels determined from application of the ramp up and ramp down constraints must fall within the minimum and maximum thermal MW capacity limits confronting each generator. Therefore, the effective real production levels cannot fall below the minimum stable operating level (if different from zero) or above the maximum thermal MW capacity limit of each respective generator. It should also be recognised that the MW production and ramping constraints are defined in terms of 'energy sent out' because the DC OPF solution is concerned with balancing real power production levels of generators and real power flows on transmission lines with LSE load demand prevailing at and across all nodes within the power grid. As such, the appropriate energy concept is 'energy sent out' – that is, the energy that can be injected into the power grid to serve load.

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, 2007a).[9] 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. The fuel, VO&M and carbon emissions/cost parameterisation of the variable cost (and marginal cost) functions can be determined using data published in (ACIL TASMAN, 2009) for thermal plant and from information sourced from hydro generation companies for hydro generation units.

Over the medium to long term, generators need to cover fixed operating costs while also making contributions to debt servicing and producing acceptable returns to

[8] The feasible production interval refers to the minimum and maximum thermal (MW) rating of each generator. This is defined in terms of both 'energy sent out' and 'energy generated' concepts.

[9] The intercept of the marginal cost function is the linear coefficient of the variable cost function and its slope is given by the quadratic coefficient of the variable cost function.

shareholders. We determine the debt and equity charge component of fixed costs as an amortised costs derived from an overnight capital cost expressed as a per kilowatt (kW) capacity charge across some period of time, typically a year, in order to count these fixed costs against the generator's installed capacity. The amortising formula used is conventional with the cost of debt and return to equity being combined in terms of a discount rate termed the Weighted Average Cost of Capital (WACC). As such, the debt and equity charges are assumed to be amortised over the assumed lifespan of the generation asset at a discount rate given by the WACC value that is also assumed for purposes of analysis (see (Stoft, 2002)). The amortising formula will produce a dollar per annum figure that represents the debt and equity charges which must be met and which, for modelling purpose, are pro-rated to a $(\$/h)$ value.

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

2.2.4 Passive Hedging

Both theory and observation suggest that financial settlements based on spot market operations expose market participants to the possibility of extreme volatility in spot prices encompassing price spike behaviour (typically of short duration) on the one hand and sustained periods of low spot prices on the other. These impacts can pose significant danger to the bottom line of both LSE's and generators respectively, requiring both types of agents to have long hedge cover positions in order to protect their long term financial viability. The protection adopted in the model is in the form of a 'collar' instrument between LSE's and generators which is activated whenever spot prices rise above a ceiling price (for LSE's) or falls below a price floor (for generators) subsequently inducing the activation of long cover for the threatened agent.

It is assumed that both LSE's and generators have to pay a (small) fee (per MWh of energy demanded or supplied) for this long cover irrespective of whether long cover is actually activated. Thus, the small fee acts like a conventional premium payment in real options theory.

If the spot price is greater than the price floor applicable to generator long cover and below the price ceiling applicable for LSE long cover, than no long cover is activated by either generators or LSE's although the fee payable for the long cover is still paid by both types of agents.

2.2.5 DC OPF Solution

The standard AC Optimal Power Flow (OPF) problem involves the minimization of total variable generation costs subject to nonlinear balance, branch flow, and production constraints for real and reactive power. In practice, AC OPF problems are typically approximated by a more tractable DC OPF problem that focuses exclusively on real power constraints in linearized form – see (Sun, 2007a)for more details.

The standard DC OPF problem in per unit *(pu)* form can be represented as a *strictly convex quadratic programming (SCQP) problem*, that is, as the minimization of a positive definite quadratic form subject to linear constraints (Sun, 2007b). Sun and Tesfatsion ((Sun, 2007b) Sections 3.3,and 3.4) demonstrate that the standard DC OPF problem can be implemented using Lagrangian augmentation, while still retaining a SCQP form, so that solution values for LMP's, voltage angles, and voltage angle differences can be directly recovered along with solution values for real power injections and branch flows.

The augmented SCQP problem can be solved using QuadProgJ, a SCQP solver developed by Sun and Tesfatsion [see Section 6 (Sun, 2007b)]. QuadProgJ implements the dual active-set SCQP algorithm developed by (Goldfarb, 1983) and is programmed in Java.

The augmented 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 functions involve 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 (on an 'energy sent out' basis) for each generator and voltage angles for each node.

The equality constraint is a nodal balance condition which requires that at each node, power take-off by LSE's located at that node equals power injection by generators located at that node and net power transfers from other nodes connected to the node in question. The imposition of this constraint across all nodes in the transmission grid will ensure that real power will be balanced across the entire grid by ensuring that aggregate real power withdrawal plus aggregate transmission losses equal aggregate real power injection. Furthermore, on a node by node basis, the shadow price associated with this particular constraint gives the LMP (e.g. 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 thermal limits and the real power produced by each generator (on an 'energy sent out' basis) remains within permitted lower and upper thermal limits while also meeting generator ramp up and ramp down constraints. The algorithm has also been extended to include an aggregate carbon emissions constraint. This is an inequality constraint requiring that aggregate (system wide) carbon emissions remain below some pre-specified target value. If this constraint is violated, it will typically produce a contemporaneous price spike that represents the cost of the emission constraint violation.

2.3 Carbon Price and Residential based PV Penetration Scenario Modelling – Impact on Dispatch, Congestion, Prices and Carbon Emissions for the Month of January 2007.

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

The transmission grid used involved combining the existing QLD, NSW, VIC, SA and TAS modules - see Figures 1-5. The state module linking was via the following Interconnectors: QNI and Directlink Interconnectors linking QLD and NSW; Murray-Dederang Interconnector linking NSW and VIC; Heywood and MurrayLink Interconnectors linking VIC and SA; and the Basslink Interconnector linking VIC and TAS. In accordance with the DC OPF framework that underpins the model, the HVDC Interconnectors Directlink, Murraylink and Basslink are modelled as 'quasi AC' links – that is, power flows are determined by assumed reactance and thermal rating values for each of the above-mentioned HVDC branches.

The solution algorithm that is utilised in the simulations involved applying the 'competitive equilibrium' solution. This means that all generators submitted their true marginal cost coefficients and no strategic bidding was possible. This type of scenario allows assessment of the true cost of generation and dispatch by ruling our cost inflation over their true marginal costs associated with the exploitation of market power linked with strategic bidding. Because the dispatch algorithm employed marginal cost pricing, the competitive equilibrium solution would lead to the discovery of the lowest overall configuration of Locational Marginal Prices' (LMP) consistent with the nodal location of generators and thermal and other constraints on the transmission network connecting the regional nodes. As such, this strategy permits an investigation of the true cost and market operator determined dispatch response of different fuel based generation technologies in response to how their true marginal costs changed with carbon price increases and increased penetration of residential PV on the demand side that can shave load demand.

We assume that all thermal generators are available to supply power during the month. As such, this modelling scenario is an 'as if' scenario. In particular, we did not try to emulate actual generator bidding patterns for the month in question. Our objective, instead, is to investigate how the true cost of power supply changed for the various carbon price/PV scenarios considered, and how the resulting changes in the relative cost of supply influenced dispatch patterns, transmission congestion, regional prices and carbon emission levels when compared to a 'Business-As-Usual' (BAU) scenario involving the absence of a carbon price signal and no PV penetration.

In order to make the model response to the various scenarios more realistic, we take account of the fact that baseload and intermediate coal and gas plant typically have 'non-zero' must run MW capacity levels termed minimum stable operating levels. These plants cannot be run below these specified MW capacity levels without endangering the long term productive and operational viability of the plant itself or violating statutory limitations relating to the production of pollutants and other toxic substances such as N02.

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

Two approaches to modelling gas plant were adopted depending upon whether the gas plant could reasonably be expected to meet intermediate production duties or just peak demand duties. If the gas plant was thought to be capable of meeting intermediate production duties, the plant was assigned a non-zero minimum stable operating capacity. In contrast, peak gas plant was assumed to have a zero minimum stable operating capacity. Furthermore, if the intermediate gas plant was a gas thermal or combined cycle plant, it was assumed to offer to supply power for the complete 24 hour period – thus, the minimum stable operating capacity was applicable for the whole 24 hour period and these plants did not face start-up costs. In contrast, many of the intermediate OCGT plant were assumed to only offer to supply power during the day, i.e. from 07:00 – 19:00 hours. In this case, the minimum stable operating capacities were only applicable for these particular hours of the day and these plants faced the payment of fixed start-up costs upon start-up that was aligned to the first period when the non-zero minimum stable operating capacity constraint became binding. It should be noted, however, that these intermediate OCGT plant can run for more than the required must run daily interval mentioned immediately above if they represent the cheapest source of marginal generation. This is likely to arise when carbon prices are relatively high, and, in this case, fixed start-up costs will be incurred whenever the plant begins to supply power to the grid over the month.

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

Table 2-1 Minimum Stable Operating Capacity Limits for Coal Plant, Assumed Operating Time and Start-up Cost Status

Generation Plant	Minimum Stable Operating Capacity Level	Assumed Operating Time	Start-up Status/Cost	Assumed Start-up Cost
	% of total MW Capacity (sent out basis)	hours	Yes/No	$/MW per start
Black Coal – QLD				
Collinsville	40.00	24	No	$160.00
Stanwell	40.00	24	No	$80.00
Callide B	40.00	24	No	$80.00
Callide C	40.00	24	No	$80.00
Gladstone	31.00	24	No	$90.00
Tarong North	40.00	24	No	$70.00
Tarong	40.00	24	No	$80.00

Kogan Creek	40.00	24	No	$40.00
Millmerran	40.00	24	No	$70.00
Swanbank B	26.00	24	No	$150.00
Black Coal – NSW				
Liddle	40.00	24	No	$50.00
Redbank	40.00	24	No	$150.00
Bayswater	40.00	24	No	$45.00
Eraring	40.00	24	No	$45.00
Munmorrah	40.00	24	No	$80.00
Vales Point	40.00	24	No	$45.00
Mt Piper	40.00	24	No	$45.00
Wallerawang	40.00	24	No	$50.00
Black Coal – SA				
Playford B	40.00	24	No	$150.00
Northern	55.00	24	No	$90.00
Brown Coal – VIC				
Loy Yang A	60.00	24	No	$50.00
Loy Yang B	60.00	24	No	$50.00
Energy Brix	60.00	24	No	$160.00
Hazelwood	60.00	24	No	$95.00
Yallourn	60.00	24	No	$80.00
Anglesea	60.00	24	No	$150.00

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

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

New Osborne	76.00	24	No	$80.00
Torrens Island A	50.00	13 (daytime only)	Yes	$80.00
Torrens Island B	50.00	24	No	$65.00

While all thermal generators were assumed to be available to supply power, certain assumptions were imposed in relation to the availability of hydro generation units. In particular, the following hydro generation units were assumed to be available to supply power during the following hourly time intervals:[10]

Far North QLD (all hydro generation units): 07:00 – 21:00;

Wivenhoe (units 1 and 2): 09:00 – 18:00;

Shaolhaven Scheme (Kangaroo Valley unit 1): 07:00 – 12:00 and 17:00 – 20:00;

Shaolhaven Scheme (Bendeela unit 1): 09:00 – 11:00 and 17:00 – 19:00;

Snowy Mountains Hydro Scheme:

- Blowering: 09:00 – 12:00 and 16:00 – 19:00;
- Tumut 1 (unit 1) and Tumut 2 (unit 1): 07:00 – 21:00;
- Tumut 3 (unit 1): 07:00 – 21:00;
- Tumut 3 (unit 2): 10:00 – 19:00;
- Guthega (unit 1): 10:00 – 19:00;
- Murray 1 (unit 1 and unit 2): 07:00 – 21:00;
- Murray 1 (unit 3): 11:00 – 17:00;
- Murray 2 (unit 1): 07:00 – 21:00; and
- Murray 2 (unit 2): 10:00 – 19:00.

Combined Southern Hydro/Victorian Fleet:

- Hume (unit 1): 11:00 – 17:00;
- Dartmouth: 07:00 – 11:00 and 17:00 – 21:00;
- McKay Creek (unit 1): 11:00 – 17:00;
- West Kiewa (unit 1): 11:00 – 17:00;

[10] The supply offers listed below correspond to the settings associated with weekdays. The structure of supply offers for hydro plant was different for weekends or for public holidays falling within the month of January 2007. The main differences was associated with typically taking second units such as Wivenhoe (unit 2) or Tumut (unit 2) 'offline' and also taking all of the Southern Hydro/native Victorian fleet 'offline'. This was done by having them bid $10,000/MWh for the linear marginal cost coefficient for these respective units, thereby ensuring that they are very expensive and are not dispatched.

- Clover (unit 1): 11:00 – 17:00; and
- Eildon (unit 1): 07:00 – 11:00 and 17:00 – 21:00.

The following Tasmanian hydro generation units are assumed to offer power over the complete 24 hour period: Rowallan, Fisher, Lemonthyme, Wilmot, Cethana, John Butters, Tribute, Reece (unit 1), Trevallyn (units 1-2), Poatina (units 1-5), Liapootah (unit 1), Wayatinah (unit 1), Catagunya (unit 1), Repulse, Butlers Gorge, Lake Echo, Tungatinah (units 1-3), Tarraleah (units 1-3), Meadowbank and Gordon (units 1-3). Additionally, the following hydro generation units are assumed to be available to supply power for the following periods of time:

- Devils Gate: 07:00 – 21:00;
- Paloona: 06:00 – 21:00;
- Mackintosh: 07:00 – 21:00;
- Bastyan: 07:00 – 21:00;
- Reece (unit 2): 07:00 – 21:00;
- Trevallyn (unit 3): 07:00 – 21:00;
- Liapootah (unit 2): 01:00 – 21:00;
- Wayatinah (unit 2): 01:00 – 19:00;
- Catagunya (unit 2): 07:00 – 11:00 and 17:00 – 20:00;
- Cluny: 08:00 – 20:00;
- Tungatinah (unit 4): 10:00 – 20:00;
- Tarraleah (unit 4): 06:00 – 22:00; and
- Tarraleah (unit 5): 07:00 – 12:00 and 16:00 – 21:00.

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

The dispatch of the thermal plant was optimised around the above assumed availability patterns for the specified hydro generation units. For modelling purposes, all other hydro generation units were assumed to not be available to supply power. It should be noted that the availability of 'mainland' hydro generation plant to supply power typically ensures that they would be dispatched at their full thermal (MW) rating because their marginal costs are low in comparison to other competing thermal plant and, importantly, do not change as carbon prices increase and these plant also have very rapid ramping capabilities. Moreover, because we assumed a social (environmental) water cost of $1/ML in deriving the marginal cost of hydro plant, hydro plant that require less water to produce a MW of power will be less costly than generators that have to use more water to produce a MW of power. This social cost consideration will be especially relevant to the dispatch of hydro plant in Tasmania with 'least cost' hydro plant typically being those units which have the highest head such as Poatina, for example. We also assumed that the minimum stable operating capacity for all hydro plant is 0 MW and that no start-up costs are incurred when the hydro plants begin supplying power to the grid.

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

In the next section, we will examine the effects of different levels of residential PV based demand side penetration in the absence of a carbon price signal. In following sections, we will then examine the consequences of combined carbon price/PV penetration scenarios which will enable us to investigate the likely consequences of simultaneously pursuing both supply and demand side initiatives in an attempt to curb carbon emissions accruing from the NEM. Two particular carbon price levels are considered – these being \$30/tC02 and \$60/tC02.

2.4 AN INVESTIGATION OF THE IMPACT OF INCREASED DEMAND SIDE RESIDENTIAL BASED PV PENETRATION IN THE ABSENCE OF CARBON PRICES.

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

The particular PV based load shaving scenarios that were implemented are outlined in Table 2-3.

Table 2-3 Load Shaving Scenarios Associated with Different Levels of Residential PV Penetration

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

22:00	1.000	1.000	1.000	1.000	1.000
23:00	1.000	1.000	1.000	1.000	1.000
24:00	1.000	1.000	1.000	1.000	1.000

It is evident from inspection of Table 2-3 that the load shaving is assumed to begin at 06:00 hours and accelerates over the period 06:00 to 10:00 when the full load shaving capability is assumed to be reached. This full rate of load shaving continues until 15:00 and then begins to taper off over the period 15:00-19:00 at rates equivalent to the rate of increase assumed for the earlier period 07:00-10:00. The various hourly factors listed in Columns 2 to 6 of Table 2-2 are multiplied on an hour-by-hour basis with the actual hourly MW fixed load values determined for the major metropolitan nodes mentioned above. Column 2 is the BAU scenario involving no PV based load shaving. The actual hourly load values used in this scenario are multiplied by unity and thus are unchanged. The factors listed in Columns 3-6 of Table 2-2 for hours 06:00 to 19:00 are less than one in magnitude and are used to implement the load shaving (reduction) associated with the impact of increased residential based PV penetration by reducing the load at the major metropolitan nodes when multiplied with the original (BAU) fixed load values on an hour-by-hour basis.

It will be recognised that the rates of load shaving associated particularly with PV scenarios C and D of 15% and 20% appear quite extreme. These particular scenarios were included to see if any ‘threshold’ effects emerged as the level of PV penetration were increased beyond currently realistic levels and also to determine whether the consequences tended to developed according to a linear or nonlinear scale.

The first set of results associated with the PV scenario implementation is listed in Table 2-4 to Table 2-8and relates to the average monthly price levels and percentage change from BAU, volatility and maximum and minimum monthly prices associated with the BAU and PV scenarios listed in Table 2-3 that were obtained for the various States and NEM as whole.

Table 2-4 Average Monthly Price Levels ($/MWh) Obtained for ($0, BAU) and PV based Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU	17.29	17.55	16.41	17.37	7.52	15.20
$0, PV_A	16.50	16.59	15.40	16.18	7.43	14.41
$0, PV_B	15.93	15.94	14.60	15.23	7.32	13.83

$0, PV_C	15.72	15.48	13.79	14.23	7.22	13.36
$0, PV_D	15.49	15.14	12.95	12.74	7.10	12.85

Table 2-5 Average Percentage (%) Reduction in Average Monthly Price Levels from ($0, BAU) for PV based Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, PV_A	4.58	5.49	6.15	6.85	1.18	5.16
$0, PV_B	7.86	9.18	11.03	12.34	2.64	9.02
$0, PV_C	9.08	11.80	15.98	18.06	4.04	12.07
$0, PV_ D	10.44	13.72	21.10	26.64	5.66	15.42

In Table 2-4 and Table 2-5, the average monthly price level and PV based percentage reductions from BAU are outlined. We can see from inspection of Table 4a that Tasmania has the lowest BAU average price level of $7.52/MWh. This result reflects the prominence of hydro-based power generation in the state which typically has lower marginal costs when compared with thermal based generation. Victoria has the next lowest average price level which reflects the prominence of brown coal fired generation which has lower marginal costs than black coal or gas fired generation (in the absence of a carbon price and carbon cost accounting). Queensland has a slightly lower average price level than NSW which would primarily reflect the fact that the QLD fleet of black coal fired generators, in particular, is generally newer, more thermally efficient and typically has a lower marginal costs associated with lower ($/GJ) black coal fuel costs – especially for the newer black coal plant located at the South West Queensland and Tarong nodes.

It is apparent from examination of Tables 4a and 4b that the average price levels for January 2007 become lower as the level of PV penetration is increased. Thus, increased PV penetration has the general effect of reducing average price levels within each state and across the NEM as a whole. This overall trend reflects the fact that as the PV induced level of load shaving is increased, less aggregate load has to be serviced by aggregate generation and can be accommodated, at the margin, by cheaper forms of generation - typically cheaper coal or gas plant (in the case of SA) that is positioned lower on the generation merit order. The proportionally greater declines listed in Table 4b associated with VIC and SA (see columns 4 and 5) are picking up the higher concentrations of load that is located at the Melbourne/Geelong and Adelaide nodes when compared with the situation in QLD and NSW. Specifically, while load demand in QLD and NSW is prominently located within the greater Brisbane and Sydney nodes, it is also more regionally dispersed in QLD and NSW than is the case with Victoria and SA, in comparison.

In Table 2-6, average price volatility for the BAU and PV scenarios are listed. The values listed in this table were calculated by taking the standard deviation of the spot price time series generated by the model for each node for the month of January 2007 and then averaging these results across the nodes located within each state and across all nodes in the model to obtain the NEM results cited in column 7 of the table. The most discernible feature from inspection of this table is that price volatility generally declines as the level of PV penetration increases except for the results listed for SA, TAS and NEM for the ($0, PV_D) scenario (e.g. the results highlighted in red font in the last row of the table). This latter result is particularly noticeable for SA which would largely be producing the increase in price volatility associated with the NEM as a whole when compared with the results obtained for the ($0, PV_C) scenario. It is certainly the case, however, that for the three largest states (QLD, NSW and VIC), price volatility unambiguously declines as the level of PV penetration is increased when compared with BAU, pointing to price stabilising affects associated with increased PV penetration.

Table 2-6 Average Volatility in State Price Levels Obtained for ($0, BAU) and PV Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU	5.31	8.18	8.83	12.49	3.48	7.29
$0, PV_A	4.56	6.59	7.37	11.21	3.39	6.25
$0, PV_B	4.06	5.64	6.55	10.96	3.34	5.69
$0, PV_C	3.87	5.03	5.92	10.90	3.30	5.36
$0, PV_D	3.72	4.82	5.88	13.56	3.32	5.61

In Table 2-7and Table 2-8, the maximum and minimum ($/MWh) price levels obtained over the month are documented. It is apparent from examination of Table 4d that the maximum price was experienced in NSW- this price outcome being actually associated with price levels occurring at the Lismore node which often experiences branch congestion. The next highest prices are experienced within QLD, followed by SA, VIC and TAS. Note that this pattern matches the average patterns discernable from Table 4a.

It is evident from inspection of Table 2-8 that both VIC and SA experience negative prices. These prices emerged on Sunday 7/1/2007 (for the hours 06:00-07:00 and 07:00-08:00) and are associated with a situation where combinations of nodal based demand levels within the state of SA was not sufficient to cover the aggregate 'must run' generation capacity levels associated with the minimum stable operating levels of coal and intermediate gas fired plant in SA. This negative price outcome was also transferred to the South West Victorian node via power flows from SA to VIC on the Heywood Interconnector for this two hour period. It should be noted that the nodal price at the Regional Victorian node was not affected because the prevailing level of native load demand at this node significantly exceeded the size of power transfers that could arise on the MurrayLink Interconnector. Thus the incident of negative prices in Victoria was limited solely to the South West Victorian node.

It is also apparent from examination of Table 2-8 that increased PV penetration also tended to exacerbate the magnitude of the negative price levels cited in columns 4, 5 and 7 of the table. Finally, it should also be noted that there was no further incidence of negative spot prices during the month.

Table 2-7 Maximum ($/MWh) State Price Level Obtained for ($0, BAU) and PV Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU	87.05	262.51	59.79	60.72	48.03	262.51
$0, PV_A	81.99	245.33	55.67	57.06	48.03	245.33
$0, PV_B	80.70	240.92	51.33	56.91	48.01	240.92
$0, PV_C	80.70	240.91	49.17	56.89	47.91	240.91
$0, PV_D	80.69	240.90	49.17	56.89	47.91	240.90

Table 2-8 Minimum ($/MWh) State Price Level Obtained for ($0, BAU) and PV Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU	9.12	2.36	-30.25	-192.65	3.00	-192.65
$0, PV_A	9.12	2.36	-30.55	-194.14	3.00	-194.14
$0, PV_B	9.12	2.36	-32.44	-205.84	3.00	-205.84
$0, PV_C	9.11	2.36	-32.58	-206.60	3.00	-206.60
$0, PV_D	9.11	2.36	-33.07	-209.18	3.00	-209.18

Information on aggregate dispatch by state and type of generation is outlined in Table 2-9 to Table 2-12. In particular, in Tables 5a-5d, we present information on dispatch patterns relating to coal, gas and hydro based generation and aggregate state-based generation that was observed in relation to the BAU and PV scenarios considered in this section. Recall that the PV penetration scenarios effectively reduce the level of aggregate load that has to be serviced by aggregate generation by shaving load at key metropolitan nodes. As such, we would expect these scenarios to effectively move the 'marginal' generator required to service this reduced load down the generation merit order, thus displacing more costly plant that might have been previously dispatched at the margin. This plant would typically be gas fired plant or older vintage coal plant.

In determining the values listed in Table 2-9 to Table 2-12, the (MW) values listed in the second row [corresponding to the ($0, BAU) scenario] were determined by summing hourly MW production level time series produced by the model for each individual generator located at a node within each state module over the monthly dispatch horizon. The aggregate generation type and state figures listed in the tables were then obtained by summing the former figures across all relevant generators and generator types located within the state module in order to calculate the aggregate state MW production totals for the month which are measured in MW's. The NEM aggregate (in column 7) was then calculated by totalling the respective state aggregate MW totals by generation type and aggregate production levels.

The percentage change results listed in the latter rows of Table 2-9 to Table 2-12 were calculated by once again calculating state and NEM aggregate production levels for each relevant PV scenario and then expressing this in terms of its percentage change from the BAU levels calculated previously and documented in row 2 of the tables.

In Table 2-9, we present the results for coal fired generation for each state and the NEM as a whole. It is apparent from inspection of this table that increased PV penetration produces a decline in aggregate levels of coal fired production across all states (ignoring TAS) and the NEM. VIC experiences the smallest rate of decline which principally reflects the fact that the brown coal fired plant in VIC has the lowest marginal costs of production (in the absence of carbon cost accounting) when compared with competing black coal and gas fired generation. QLD has the next lowest rates of decline. This outcome reflects the fact that QLD has a newer, more thermally efficient fleet of black coal fired generation which also has lower marginal costs than most competing black coal fired plant in NSW and SA, for example. Thus, the larger decline in production levels in NSW would reflect displacement of more expensive black coal plant by especially brown coal plant from VIC which is exported to NSW via the (NSW-VIC) Interconnector.[11] Furthermore, in the scenarios considered, the marginal cost of brown coal fired production in VIC is much cheaper than the marginal cost of black coal fired generation in SA whose fleet share many similar characteristics with the NSW fleet – older, less thermally efficient and relatively high ($/GJ) black coal fuel costs. In the case of SA, however, the nature of power flows on both the Heywood and Murraylink Interconnectors indicate that the key driver of the reduction in coal fired generation production levels in SA is primarily the reduction in native SA load itself associated with the load shaving arising at the Adelaide node and not exports from VIC – for example, see the last 2 columns of Table 2-15:

Table 2-9 Aggregate State and NEM MW Production for ($0, BAU) Coal Plant and Percentage (%) Reduction in Aggregate MW Production from ($0, BAU) for PV based Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU (MW)	4767564.2	4932544.7	4514466.9	358497.5	0.0	14573073.3
$0, PV_A	0.66	1.63	0.15	1.65	0.00	0.85
$0, PV_B	1.44	3.56	0.34	4.21	0.00	1.89
$0, PV_C	2.23	5.45	0.55	7.44	0.00	2.93
$0, PV_D	3.09	7.45	0.79	9.84	0.00	4.02

In , we present the results for natural gas fired generation for each state and the NEM as a whole. It is apparent from inspection of this table that increased PV penetration produces a decline in aggregate levels of gas fired production across all states (once again ignoring TAS) and for the NEM as a whole. In Table 5b, VIC experiences the largest rate of decline which would principally reflect the displacement of gas fired generation within VIC with much cheaper brown coal generation in VIC in the presence of load shaving arising within VIC associated with the PV scenarios. QLD has the next largest rate of decline and this would also partially reflect the displacement of more expensive gas fired generation with cheaper black coal fired generation (located especially at Tarong and South West QLD nodes) in the presence of PV based load shaving within Greater Brisbane. The declines observed in relation to NSW and SA would also depict similar displacement patterns of gas fired generation associated with load shaving in Sydney and Adelaide with cheaper black coal fired generation in NSW and cheaper forms of gas fired generation within SA primarily located at the Adelaide node.

[11] This outcome is supported by the average power transfers on the (NSW-VIC) Interconnector that are listed in Table 6c (column 4).

Table 2-10 Aggregate State MW Production for ($0, BAU) Gas Plant and Percentage (%) Reduction in Aggregate MW Production from ($0, BAU) for PV based Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU (MW)	333930.8	363063.0	134561.2	679239.5	0.0	1510794.4
$0, PV_A	2.08	1.51	5.55	1.92	0.00	2.18
$0, PV_B	3.21	2.64	8.06	3.06	0.00	3.44
$0, PV_C	3.62	3.21	8.53	3.56	0.00	3.93
$0, PV_D	3.91	3.26	8.53	3.75	0.00	4.10

We present the results for hydro based generation for each state and the NEM as a whole in Table 2-11. For accounting purposes, in determining hydro production levels for NSW and VIC, we have split the hydro plant associated with the Snowy Mountains hydro scheme and allocated all hydro plant located at the Tumut node to NSW and all hydro plant located at the Murray node to VIC. Therefore, NSW hydro plant includes hydro plant located at the Wollongong and Tumut nodes while the VIC hydro plant include all hydro plant located at the Murray and Dederang nodes.

It is evident from inspection of Table 5c that hydro-based generation production levels decline in NSW, VIC and TAS and for the NEM as a whole. Note that SA has no hydro based generation. For QLD, the hydro based production level (particularly associated with Wivenhoe pump storage plant) remains unchanged because the marginal cost of hydro generation in QLD is the cheapest form of generation and will be subsequently dispatched before any other thermal based plant. For the other states (NSW, VIC and TAS as well as the NEM as a whole), aggregate hydro production seems to declines generally in line with the reduction in load demand associated with PV induced load shaving.

Of particular note in Table 2-11 is the decline experienced in aggregate hydro based production in TAS which experiences no direct PV based load shaving. Clearly, some of the hydro based output is geared to export to VIC via the Basslink Interconnector, an observation supported by both the average power flows and duration of these power flows in relation to the Basslink Interconnector. [12] As the level of PV based load shaving increases in VIC, reducing native load demand in VIC, there would be less call on hydro based generation in TAS, effectively moving

[12] We will see latter on in this section that this is indeed the case. Specifically, we will see that the average flows from TAS to VIC will decline in magnitude and duration – e.g. see column 5 of Table 2-15 and Table 2-16.

the 'marginal' hydro generator in TAS down the merit order and thereby producing both the drop in average MW level of power sent from TAS to VIC on Basslink.

Table 2-11 Aggregate State MW Production for ($0,BAU) Hydro Plant and Percentage (%) Reduction in Aggregate MW Production from ($0, BAU) for PV based Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU (MW)	131565.2	265697.6	242753.1	0.00	1035839.6	1675855.4
$0, PV_A	0.00	0.39	0.12	0.00	0.50	0.39
$0, PV_B	0.00	0.89	0.41	0.00	1.33	1.02
$0, PV_C	0.00	1.37	0.96	0.00	2.32	1.79
$0, PV_D	0.00	1.76	1.93	0.00	3.84	2.93

The aggregate MW production levels and declines from BAU for each state and the NEM as a whole are listed in Table 2-12. These results essentially combine all the results listed previously in Table 2-8 to Table 2-11 and broadly match the patterns observed in these tables – especially the patterns appearing in Table 2-8 for QLD, NSW and VIC and in Table 2-10 for SA, reflecting the dominance of coal fired generation in the former states and gas fired generation in SA. Specifically, VIC experiences the smallest rate of decline which principally reflects the location and significant MW capacity of cheap brown coal fired generation within that state. The state with the next smallest rate of decline in production is QLD with this again principally reflecting the location of a newer, more efficient and much cheaper fleet of black coal fired plant located principally at the Tarong and South West QLD nodes. This situation can be contrasted with that confronting NSW and SA which has an older and more costly black coal generation fleet and experiences some displacement of production from increased exports from VIC in the case of NSW in particular. The patterns observed for TAS match those patterns discerned in Table 2-11 in relation to TAS hydro generation.

Table 2-12 Aggregate State MW Production for ($0, BAU) and Percentage (%) Reduction in Aggregate MW Production from ($0, BAU) for PV based Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU (MW)	5233060.1	5561305.3	4891781.2	1037737.0	1035839.6	17759723.2
$0, PV_A	0.73	1.56	0.30	1.82	0.50	0.92
$0, PV_B	1.52	3.37	0.55	3.45	1.33	1.94

$0, PV_C	2.27	5.11	0.79	4.90	2.32	2.91
$0, PV_D	3.07	6.90	1.06	5.86	3.84	3.92

Information about the incidence of branch congestion within each state and between states is listed in the following tables. Table 2-13 provides information on the incidence of branch congestion on native transmission lines located within each state and for the NEM as a whole. It should be noted that we exclude the inter-state Interconnectors from the state results cited in columns 2 to 6 of Table 2-13. However, the NEM results listed in column 7 of Table 2-13 does also include the inter-state Interconnectors.

Table 2-13 Percentage of Time Branch Congestion Arises for ($0, BAU) and PV Based Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
No of Branches	12	21	9	11	13	72
$0, BAU	1.21	8.44	0.85	0.10	17.30	6.44
$0, PV_A	1.14	8.35	0.42	0.00	17.00	6.27
$0, PV_B	0.98	8.44	0.16	0.00	16.67	6.17
$0, PV_C	0.90	8.38	0.10	0.00	16.16	6.03
$0, PV_D	0.65	8.48	0.10	0.00	15.44	5.87

The second row of Table 2-13 lists the number of intra-state transmission branches included in each state module and within the NEM. For example, in QLD, there are 12 ‘native’ branches with this number excluding the QNI and Directlink Interconnectors. For the NEM as a whole, the model contains a total of 72 transmission branches which can be broken down into 66 intra-state transmission lines and 6 inter-state Interconnectors.

Information on branch congestion is listed in Table 2-13. The values within the table are percentage values depicting the percentage of time within the monthly dispatch horizon that branch congestion occurred within each state and across the NEM respectively. These figures were calculated by counting the number of hours within the month that each respective branch line experienced branch congestion. For our purposes, branch congestion is defined to arise when the MW power transfer on the transmission branch (in either a positive or negative direction) is equal to the transmission line’s rated MW thermal limit. For each line within a state module (i.e. excluding inter-state Interconnectors), the count for each line was added to that determined for other transmission branches within each state and aggregated across all intra-state transmission lines within each state module in order to obtain an aggregated state total. To get the percentage values listed in Table 2-13, we then divided this aggregate state number by the total effective number of hours over which power flows occurred on all branches within the state. This latter value was calculated as the total number of hours in the monthly dispatch period multiplied by the number of intra-state branches in each state module.

To determine the overall NEM results recorded in column 7 of Table 2-13 as well as the figures listed in Table 6b relating to individual inter-state Interconnectors, we also performed the same calculations mentioned above for the individual Interconnectors and added them to the state values to derive the overall NEM percentage values listed in the last column of Table 2-13. The percentage results for each Interconnector is reported in Table 2-14.

It is apparent from examination of Table 2-13 that apart from the results for NSW (i.e. column 3), the PV scenarios generally produced reduced incidence of branch congestion in each state and for the NEM as a whole. Thus, the demand side PV initiatives appear to generally lead to reduced branch congestion. It is also apparent from inspection of Table 2-14 that branch congestion only appears on the Basslink and Murraylink Interconnectors. In the former case, the incidence of congestion increases while the incidence of congestion on the Murraylink Interconnector declines as the level of PV penetration is increased.

Table 2-14 Percentage of Time Branch Congestion Arises for ($0, BAU) and PV Based Scenarios on Interconnectors

SCENARIO	QNI	Directlink	NSW-VIC	Basslink	Heywood	Murraylink
$0, BAU	0.00	0.00	0.00	0.72	0.00	12.64
$0, PV_A	0.00	0.00	0.00	0.86	0.00	12.21
$0, PV_B	0.00	0.00	0.00	1.15	0.00	11.78
$0, PV_C	0.00	0.00	0.00	1.58	0.00	10.49
$0, PV_D	0.00	0.00	0.00	2.16	0.00	10.20

Table 2-15 contains the monthly average MW power flow on each respective inter-state Interconnector. The signs of the average power flow indicate, on average, that power flows from QLD to NSW on both QNI and Directlink, from VIC to NSW on the Murray-Dederang (NSW-VIC) Interconnector, from TAS to VIC on Basslink and from VIC to SA on both the Heywood and Murraylink Interconnectors. Inspection of the power flows listed in Table 2-15 also indicates that the power transfers unambiguously decline in magnitude on QNI and Basslink and unambiguously increase in magnitude on the NSW-VIC Interconnector. The evidence for Directlink, Heywood and Murraylink is more mixed in character.

Table 2-15 Average MW Power Flow for ($0, BAU) and PV Based Scenarios on Interconnectors

SCENARIO	QNI	Directlink	NSW-VIC	Basslink	Heywood	Murraylink
$0, BAU	536.70	26.90	-624.92	-392.66	135.27	36.42
$0, PV_A	532.77	26.91	-671.87	-385.28	138.59	37.03
$0, PV_B	530.13	26.94	-727.94	-373.07	139.89	35.73
$0, PV_C	528.38	27.03	-777.84	-358.59	141.54	35.17
$0, PV_D	525.93	27.00	-830.32	-334.35	138.49	30.20

In Table 2-16, we present additional information on the persistence of power flows in the direction indicated by the sign of the average power flow information documented in Table 2-15. This information, as presented in Table 6d, relates to the proportion of time over the month that each Interconnector experienced power flows in the direction implied by the sign associated with the average power flow values listed in Table 6c. For example, for QNI the positive sign associated with the average power flow result listed in column 2 of Table 2-15 indicates average power transfers from QLD to NSW. Examination of column 2 of Table 6d for QNI indicates, additionally, that power flowed in this direction 100 percent of the time. In contrast, for Directlink, power transfers from QLD to NSW occurred around 73% of the time while power flows in the reverse direction (i.e. from NSW to QLD) arose 27% of the time during the month.

Further inspection of the results cited in Table 2-16 indicate that power flows on QNI and Directlink did not change as the level of PV penetration was increased. Power transfers from VIC to NSW on the (NSW-VIC) Interconnector became more prominent while power transfers from VIC to SA (on Murraylink) became marginally more prominent. On the other hand, power transfers from TAS to VIC (on Basslink) declined slightly. The evidence is mixed for power transfers from VIC to SA on the Heywood Interconnector but points to power flows becoming marginally more prominent when compared with BAU, thus qualitatively mirroring power transfers on Murraylink.

Table 2-16 Proportion of Total Time That Dominant Positive (+) or Reverse (-) MW Power Flows Occurred for ($0, BAU) and PV Based Scenarios on Interconnectors

SCENARIO	QNI (+)	Directlink(+)	NSW-VIC(-)	Basslink (-)	Heywood(+)	Murray link(+)
$0, BAU	1.00	0.73	0.77	0.97	0.89	0.63
$0, PV_A	1.00	0.73	0.81	0.97	0.91	0.63
$0, PV_B	1.00	0.73	0.83	0.96	0.92	0.64
$0, PV_C	1.00	0.73	0.85	0.94	0.91	0.64
$0, PV_D	1.00	0.73	0.88	0.92	0.90	0.65

The BAU total monthly level of carbon emissions and percentage change in emissions from BAU associated with the PV scenarios are outlined in Table 2-17. The (tC02) figures listed in the second row [corresponding to the ($0, BAU) scenario] were determined by summing hourly C02 emissions time series produced by the model for each individual dispatched generator located at a node within each state module over the monthly dispatch horizon. The aggregate state figures listed in Table 2-17 were then obtained by summing the former figures across all generators within the state to calculate the state aggregate emission totals for the month which are measured in tC02. The NEM aggregate (in column 7) was then calculated by totalling the aggregate state emission totals.

The percentage change results listed in the latter rows of Table 2-17 were calculated by once again calculating state and NEM aggregate emission levels for each relevant PV scenario and then expressing this in terms of its percentage change from the BAU levels calculated previously and documented in row 2 of Table 2-17.

Table 2-17 Total BAU Carbon Emission Levels (tC02) and Average Percentage (%) Reduction in Carbon Emissions from ($0, BAU) for PV based Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU (tC02)	4152538.3	4466877.9	5596410.6	740726.7	0.00	14956553.5
$0, PV_A	0.74	1.61	0.22	1.79	0.00	0.86
$0, PV_B	1.58	3.51	0.43	3.66	0.00	1.83
$0, PV_C	2.40	5.36	0.64	5.62	0.00	2.78
$0, PV_D	3.26	7.29	0.87	6.96	0.00	3.76

It is apparent from examination of Table 2-17 that the PV scenarios produce both state and NEM level reductions in aggregate carbon emission when compared with the BAU carbon emission levels documented in the table. Thus, demand side initiatives such as residential based PV penetration that has a load shaving effect will actively contribute towards the policy goal of curbing carbon emissions from the power generation sector. This outcome is expected because recall that we observed reductions in MW production levels in coal and gas fired generation as outlined in Tables 5a and 5b, in particular, and which would produce corresponding reductions in carbon emissions.

From inspection of Table 2-17, it is apparent that first, there are no effective carbon emissions produced in Tasmania from power generation. This is because only hydro plant are dispatched in Tasmania for all scenarios considered in this section and hydro generation is assumed to produce no carbon emissions.[13] Second, the lowest rate of decline in emissions is experienced in VIC. This reflects the prominence of brown coal fired generation in this state which has the largest carbon footprint of the competing thermal based generation technology types considered in the model. The rate of emission reductions in QLD is also lower than the corresponding rate in NSW. This reflects the fact that the black coal plant in QLD is newer, cheaper and has superior thermal and carbon footprint characteristics when compared with the older black coal fired generation fleet in NSW. It is therefore likely to be dispatched

[13] While there are some OCGT plant located in Tasmania, these plants have much higher marginal costs than most of the hydro plant located in Tasmania and at zero and relatively low carbon prices, the OCGT plant is not dispatched. In fact, for higher carbon prices, they are essentially dispatched because they become competitive with the brown coal generation plant located in VIC and effectively operate to boost power exports into VIC through power transfers along the Basslink Interconnector from TAS to VIC.

more intensively than the older black coal fleet in NSW which was partially displaced by cheaper power sourced from brown coal fired generation in VIC that was subsequently exported to NSW.[14] Therefore, the larger amounts of displaced capacity in NSW evident in the results presented above have produced the larger emission reductions observed in Table 2-17 for NSW. The larger emission cuts associated with SA would also reflect observed production cuts in black coal and gas fired generation.

The BAU aggregate monthly system-wide total variable cost (TVC) and percentage change in TVC from BAU associated with the PV scenarios are outlined in Table 2-18. The TVC figures listed in the second row of Table 2-18 were calculated by aggregating the hourly system-wide variable costs produced from the model over the monthly dispatch period. These can be regarded as an optimal variable cost measure because they are calculated as part of the DC OPF algorithm and reflect optimal generator dispatch patterns determined by the DC OPF algorithm itself.

Table 2-18 Total ($0, BAU) System Wide Optimal Total Variable Costs (TVC) and Percentage (%) Reduction in TVC for PV based Scenarios

SCENARIO	TVC (S)
$0, BAU	215677500.0
$0, PV_A	1.68
$0, PV_B	3.23
$0, PV_C	4.53
$0, PV_D	5.75

It follows from inspection of Table 2-18 that the PV penetration scenarios reduce the system-wide TVC measure with the rate of decline from BAU being directly related to increases in the rate of PV penetration. This outcome makes intuitive sense because the PV penetration scenarios serve to reduce the amount of aggregate load that has to be serviced by aggregate generation, thus moving the 'marginal' generator down the generation merit order to generators with lower marginal costs.

[14] The more intensive dispatch of QLD black coal generation relative to NSW was clearly indicated in Table 5a with the larger reductions in MW production levels occurring for NSW when compared with MW production cuts in QLD.

2.4.1 An Investigation of the Combined Impact of a ($30/tC02) Carbon Price and Various PV Penetration Scenarios.

The carbon price scenario investigated in this section will involve examining the impact of a 'Business-As-Usual' (BAU) environment involving a ($30/tC02) carbon price signal with no PV penetration. Note that this scenario is indicated by the expression '($30, BAU)' in the analysis below. Subsequently, other scenarios involving a combination of both a carbon price signal of ($30/tC02) and various PV penetration scenarios will also be assessed against the ($30, BAU) scenario mentioned above.

In order to assess the pure effects of the introduction of the ($30/tC02) carbon price, the BAU scenario used in the previous section which involved no carbon price signal (e.g. $0/tC02) and no PV penetration will also be utilised in this section for comparison purposes. This scenario is indicated by the expression '($0, BAU)' in the analysis below.

The first set of results associated with the combined Carbon Price/PV penetration scenarios implementation are listed below and relates to the average monthly price levels and percentage change from ($30, BAU), volatility and maximum and minimum monthly prices for the various States and NEM as whole.

Table 2-19 Average Monthly Price Levels ($/MWh) Obtained for a Carbon Price of ($30/tC02) and Various PV Penetration Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU	17.29	17.55	16.41	17.37	7.52	15.20
$30, BAU	43.89	45.46	46.17	47.09	14.11	38.96
$30, PV_A	43.45	44.75	45.43	46.22	14.05	38.42
$30, PV_B	43.16	44.23	44.85	45.60	14.00	38.02
$30, PV_C	42.85	43.79	44.40	45.04	13.94	37.67
$30, PV_D	42.64	43.44	44.01	44.56	13.90	37.39

Table 2-20 Average Percentage (%) Reduction in Average Monthly Price Levels from BAU for a ($30/tC02) Carbon Price and Various PV Penetration Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$30, BAU	(153.83)	(159.03)	(181.30)	(171.07)	(87.59)	(156.37)
$30, PV_A	1.00	1.57	1.60	1.83	0.41	1.40
$30, PV_B	1.67	2.71	2.86	3.16	0.78	2.42
$30, PV_C	2.38	3.68	3.83	4.34	1.16	3.32
$30, PV_D	2.86	4.45	4.69	5.38	1.47	4.05

It is apparent from inspection of rows 2 and 3 of Table 2-19 that the introduction of a ($30/tC02) carbon price has increased average price levels for each state and the NEM as a whole. For example, for QLD, the average price level increased from $17.29/MWh to $43.89/MWh, an increase of 153.8% on the ($0, BAU) price level outcome which can be discerned from the second row of Table 2-20. It should be noted that the numbers within parentheses that are displayed in red font indicate percentage increases over the ($0, BAU) results.

The results cited in row 2 of Table 2-20 indicates that VIC experiences the largest percentage increase of 181.3% over the ($0, BAU) price level. This would reflect the prominence of brown coal fired generation within this state which will have relatively high marginal carbon costs in the presence of a carbon price signal because of the relatively large carbon footprint this type of generation has when compared to other types of competing thermal based generation.

The other noticeable feature is the relatively modest growth in average price levels in TAS when compared with the other states and the NEM as a whole. Specifically, the growth in average prices in TAS is approximately 56% of the growth experienced in the NEM as a whole. As was the case in the previous section, for a carbon price of ($30/tC02), only hydro generation is dispatched in TAS. As such, no carbon emissions were produced in TAS. However, TAS is linked with the mainland (to VIC) through the Basslink Interconnector. This inter-linkage permits trade and is also responsible for increasing the average prices experienced in TAS. However, the fact that hydro generation is not susceptible to carbon costs ensures that the increase in average prices in TAS is well below that experienced in other states which have forms of generation that are more susceptible to carbon costs such as VIC, for example.

It is also apparent from examination of Table 2-19 and Table 2-20 that the average price levels for January 2007 become lower as the level of PV penetration is increased. Thus, increased PV penetration continues to have the general effect of reducing average price levels within each state and across the NEM as a whole. However, when combined with the introduction of a carbon price signal, this effect is swamped by the upward pressure on average price levels associated with the introduction of the carbon price itself. Therefore, the results cited in Table 2-19 and Table 2-20 indicates that policies that promote PV up-take can be expected to help to partially and slightly mitigate the expected increase in average price levels associated with the introduction of a carbon price.

Table 2-21 Average Volatility in State Price Levels Obtained for a Carbon Price of ($30/tC02) and Various PV Penetration Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU	5.31	8.18	8.83	12.49	3.48	7.29
$30, BAU	4.34	6.15	5.66	6.98	8.90	6.37
$30, PV_A	3.78	4.90	4.46	5.64	8.83	5.51
$30, PV_B	3.45	4.18	3.67	4.92	8.77	4.99
$30, PV_C	3.12	4.29	3.72	5.20	8.78	5.00
$30, PV_D	3.04	4.61	3.96	5.25	8.79	5.13

In Table 2-21, average price volatility for the ($30, BAU) baseline scenario and the various PV penetration scenarios are listed. The most discernible feature in this table is that for all states and the NEM as a whole (except TAS), the introduction of a ($30/tC02) carbon price has reduced average price volatility when compared to the ($0, BAU) results. This broad trend can be contrasted with the case of TAS which experienced an increase in average price volatility with the introduction of the carbon price increasing from 3.48 to 8.90.

In general, average price volatility is further reduced for all states (including TAS) and the NEM as a whole with increased PV penetration when compared with the levels of volatility associated with the ($30, BAU) scenario listed in row 3 of Table 2-21. However, there also appears to be a slight turn around with slight increases in price volatility associated with the PV_C and PV_D scenarios when compared with the level of price volatility associated with the PV_A and PV_B scenarios – for example, see the results highlighted in red font in the last two rows of Table 9c. Overall, the results still support the proposition that the pursuit of policies promoting residential PV take-up can be expected to have a price stabilising affect even when operating in conjunction with a moderately sized carbon price signal.

Table 2-22 Maximum ($/MWh) State Price Level Obtained for a Carbon Price of ($30/tC02) and Various PV Penetration Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU	87.05	262.51	59.79	60.72	48.03	262.51
$30, BAU	105.43	259.34	78.41	78.75	66.73	259.34
$30, PV_A	100.50	243.20	75.40	75.40	66.73	243.20
$30, PV_B	99.23	238.79	71.54	74.74	66.71	238.79
$30, PV_C	99.23	238.79	70.92	74.87	66.69	238.79
$30, PV_D	99.23	238.79	70.92	74.87	66.69	238.79

In Table 2-22 and Table 2-23, the maximum and minimum ($/MWh) price levels obtained over the month for a ($30/tC02) carbon price and various PV penetration scenarios are outlined. Once again, the maximum price was experienced in NSW, with the price levels occurring at the Lismore node. The next highest prices are experienced within QLD, followed by SA, VIC and TAS. Note that this pattern matches the patterns that were discernable in Table 4d in the previous section.

Table 2-23 Minimum ($/MWh) State Price Level Obtained for a Carbon Price of ($30/tC02) and Various PV Penetration Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU	9.12	2.36	-30.25	-192.65	3.00	-192.65
$30, BAU	27.94	4.10	4.10	-2.05	3.00	-2.03
$30, PV_A	27.93	4.09	4.09	-2.61	3.00	-2.61
$30, PV_B	27.92	4.08	4.08	-3.17	3.00	-3.17
$30, PV_C	27.90	4.04	4.04	-21.07	3.00	-21.07
$30, PV_D	27.90	4.04	4.04	-22.37	3.00	-22.37

It is evident from inspection of Table 2-23, however, that there has been a shift around in the results for VIC and SA associated with the ($30, BAU) scenario. Specifically, the lowest price in VIC is now positive (e.g. $4.10/MWh) and is aligned with the incidence of the minimum price recorded in NSW. Furthermore, while SA still continues to experience a negative price, the magnitude of this negative price has diminished significantly (from $-192.65/MWh to$ -2.05/MWh). This contrasts with the ($0, BAU) scenario where both VIC and SA experienced negative prices at the same time – see row 2 of Table 2-23. Of particular note is the divergence of days upon which these lowest prices occur. For VIC, it falls on 1/1/2007 at hour 06:00-07:00 while for SA, it falls on a different day (on 7/1/2007) at hour 07:00-08:00. Moreover, the negative price in SA only occurs at the Riverlands node and other prices in SA are positive for the particular hour in question. This pattern is qualitatively different from the results recorded for SA for the ($0, BAU) scenario which occurred across all SA nodes simultaneously.

It is also apparent from examination of Table 2-23 that increased PV penetration continues to exacerbate the magnitude of the negative price levels cited in columns 4 and 7 of the table.

Information on aggregate dispatch by state and type of generation is outlined in Table 2-24 through Table 2-29 for a carbon price of ($30/tC02) and various PV penetration scenarios. In Table 10a, we present the results for coal fired generation for each state and the NEM as a whole. It should be noted again that the numbers within parentheses and highlighted in red font (i.e. in row 3) indicate percentage <u>increases</u>. It is evident from examination of this table that the introduction of a carbon price of ($30/tC02) led to an overall decline in coal fired generation production in the NEM of 1.02% when compared with the aggregate MW production levels determined for the ($0, BAU) scenario. The impact on state MW productions levels were more varied with <u>increased</u> production being experienced in QLD and NSW of 1.54% and 9.70% respectively when compared with the ($0, BAU) levels. This can be contrasted with the sizeable reductions experienced in VIC and SA of 14.13% and 17.20% respectively from the ($0, BAU) levels for these particular states.

The main drivers of these results is the reduced cost competitiveness of VIC brown coal fired generation when compared with both black coal fired generation located in NSW and QLD and gas fired generation, more generally, in an environment where carbon costs are now incorporated into the marginal cost concept underpinning the competitive dispatch of generators within the broader DC OPF dispatch process. In the case of SA, the reduction in black coal fired generation would principally reflect the loss of competitiveness of this form of generation when compared with competing gas fired generation located with SA in an environment that takes account of the carbon costs of generation.

It is also apparent from examination of Table 2-28 that the PV penetration scenarios have the effect of mitigating the increased productions levels in QLD and NSW (see columns 2 and 3) while reducing further the aggregate MW coal fired generation production levels in VIC and SA (see columns 4 and 5). In particular, for QLD, the implementation of the PV_B scenario almost wipes out the increase in MW coal generation production associated with the introduction of the ($30/tC02) carbon price – the 1.54% increase associated with the latter is almost wiped out by the subsequent 1.53% reduction in output associated with the PV_B scenario. For the NEM as a whole, the PV penetration scenarios have the effect of further reducing aggregate MW coal fired generation production levels – see the last column of Table 10a.

Table 2-24 Aggregate State and NEM MW Production for a Carbon Price of ($30/tC02) for Coal Plant and Percentage (%) Reduction in Aggregate MW Production from ($30, BAU) for Various PV Penetration Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU (MW)	4767564.2	4932544.7	4514466.9	358497.5	0.0	14573073.3
$30, BAU	(-1.54)	(-9.70)	14.13	17.20	0.00	1.02
$30, PV_A	0.72	0.97	0.86	2.21	0.00	0.88
$30, PV_B	1.53	2.39	1.77	4.14	0.00	1.97
$30, PV_C	2.25	3.89	2.69	5.66	0.00	3.05
$30, PV_D	2.97	5.45	3.87	6.34	0.00	4.21

In Table 2-25, we present the results for natural gas fired generation for each state and the NEM as a whole in the presence of a ($30/tC02) carbon price and various PV penetration scenarios. Once again, it should be noted that the numbers within in parentheses and highlighted in red font (i.e. in row 3) indicate percentage increases. It is apparent from inspection of this table that the introduction of a carbon price of ($30/tC02) has increased aggregate MW production from gas fired generation in all states and for the NEM as a whole. From examination of row 3 of Table 10b, for the NEM as a whole, the carbon price has produced a 5.23% increase in aggregate MW power production from gas fired generation. There is some variation among the states with VIC experiencing the smallest increase of 1.74% while SA experiences the largest increase of 7.38% from ($0, BAU) MW production levels.

The smaller rates of increase experienced in VIC and QLD most probably reflects two factors. First, there is a relative paucity of gas plant in VIC that is suited for intermediate production duties when compared to gas plant which is suited to peak production duties. Second, in the case of QLD, the fleet of black coal plant has among the best cost and emissions intensity factors of black coal plant in the NEM. As such, at the prevailing carbon price level of ($30/tC02), a significant proportion of the QLD black coal fleet would still be very competitive when compared with intermediate gas fired plant located in QLD. This would tend to mitigate any expansion in aggregate gas fired production in QLD when compared with other states. These situations contrast with the situation confronting SA where there is a significant intermediate gas fired fleet which would be quite competitive with the older black coal generation fleet in SA particularly after carbon costs have been incorporated into the dispatch process.

It is also apparent from examination of Table 2-25 that the PV penetration scenarios have the effect of mitigating the increased gas fired productions levels in all the states and NEM as a whole as indicated by the numbers in row 3 of Table 2-28. However, apart from VIC, it would take PV penetration rates at levels associated with either the PV_C or PV_D scenarios to completely reverse the observed increase in aggregate MW gas fired production levels in the three largest states QLD, NSW and VIC and the NEM as a whole that was associated with the introduction of a ($30/tC02) carbon price as indicated in row 3 of Table 10b. The level of load shaving associated with these particular scenarios, however, is not thought to be realistic at present.

Table 2-25 Aggregate State MW Production for a Carbon Price of ($30/tC02) for Gas Plant and Percentage (%) Reduction in Aggregate MW Production from ($30, BAU) for Various PV Penetration Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU (MW)	333930.8	363063.0	134561.2	679239.5	0.0	1510794.4
$30, BAU	(-2.34)	(-5.14)	(-1.74)	(-7.38)	0.00	(-5.23)
$30, PV_A	1.34	2.12	5.48	2.39	0.00	2.37
$30, PV_B	2.20	3.75	8.71	3.92	0.00	3.92
$30, PV_C	3.30	4.90	9.72	4.96	0.00	5.00
$30, PV_D	4.53	5.80	9.76	5.97	0.00	5.94

Table 2-26 Aggregate State MW Production for a Carbon Price of ($30/tC02) for Hydro Plant and Percentage (%) Reduction in Aggregate MW Production from ($30, BAU) for Various PV Penetration Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU (MW)	131565.2	265697.6	242753.1	0.0	1035839.6	1675855.4
$30, BAU	0.00	(-1.08)	(-0.97)	0.00	(-2.96)	(-2.14)
$30, PV_A	0.00	0.01	0.00	0.00	0.00	0.00
$30, PV_B	0.00	0.02	0.00	0.00	0.00	0.00
$30, PV_C	0.00	0.03	0.01	0.00	0.00	0.01
$30, PV_D	0.00	0.04	0.10	0.00	0.04	0.04

We present the results for hydro based generation for each state and the NEM as a whole in Table 2-27 for a carbon price of ($30/tC02) and various PV penetration scenarios. As in the case of Table 2-24 and Table 2-25, the numbers encased in parentheses and highlighted in red font (i.e. in row 3) indicate percentage increases. Recall further that for accounting purposes, NSW hydro plant is defined to include hydro plant located at the Wollongong and Tumut nodes while the VIC hydro plant is defined to include all of the hydro plant located at the Murray and Dederang nodes.

It is evident from inspection of Table 2-25 that with the introduction of a ($30/tC02) carbon price, hydro-based generation production levels increase in NSW, VIC, TAS and for the NEM as a whole when compared to ($0, BAU) aggregate MW production levels – for example, see row 3 of Table 2-25. The biggest increase occurs in TAS with a 2.96% increase in aggregate MW hydro production and the smallest increase was experienced by VIC with a 0.97% increase in aggregate MW hydro production. For the NEM as a whole, the aggregate MW hydro production increase was in the order of 2.14% on the ($0, BAU) aggregate production levels.

In the case of QLD, there was no increase in production over the ($0, BAU) production results. This most likely reflects the fact that the hydro production levels remain unchanged because the marginal cost of hydro generation in QLD is the cheapest form of generation and will be subsequently dispatched before any other thermal based plant.

It is also evident from examination of Table 2-25 that the PV penetration scenarios have an extremely marginal effect of mitigating the increased hydro production levels listed in row 3. Therefore, for the various combined carbon price/PV penetration scenarios, we would expect an aggregate increase in MW hydro production levels in NSW, VIC, TAS and the NEM.

Table 2-28 Aggregate State MW Production for a Carbon Price of ($30/tC02) and Percentage (%) Reduction in Aggregate MW Production from ($30, BAU) for Various PV Penetration Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU (MW)	5233060.1	5561305.3	4891781.2	1037737.0	1035839.6	17759723.2
$30, BAU	(-1.55)	(-8.99)	12.95	1.11	(-2.96)	0.19
$30, PV_A	0.74	1.00	0.96	2.34	0.00	0.93
$30, PV_B	1.54	2.37	1.89	3.98	0.00	1.96
$30, PV_C	2.26	3.78	2.77	5.13	0.00	2.93
$30, PV_D	2.99	5.23	3.84	6.08	0.04	3.96

The aggregate MW production levels and declines from ($30, BAU) for each state and the NEM as a whole are listed in Table 10d for a carbon price of ($30/tC02) and various PV penetration scenarios. These results essentially combine all the results listed previously in Table 2-24 through to Table 2-26and broadly match the patterns observed in these tables – especially the patterns appearing in Table 2-22 Table 10a for QLD, NSW and VIC, Table 2-23 for SA, and Table 2-24 for TAS reflecting the dominance of coal fired generation in the former states, gas fired generation in SA and hydro generation in TAS.

It is apparent from examination of Table 2-26 that the introduction of a carbon price of ($30/tC02) has reduced aggregate MW production from all sources of generation for the NEM by 0.19% from the ($0, BAU) aggregate production level. For QLD, NSW and TAS, there has been aggregate increases of 1.55%, 8.99% and 2.96% from ($0, BAU) baseline MW production levels. In contrast, the states of VIC and SA experienced reductions in aggregate MW production of 12.95% and 1.11% from ($0, BAU) production levels.

The effect of the increased PV penetration is to either further reduce or mitigate any observed increases in MW production levels. Recall that the PV penetration scenarios effectively reduce the level of aggregate load that has to be serviced by aggregate generation by shaving load at key metropolitan nodes, thus moving the marginal' generator required to service this reduced load further down the generation merit order. It is evident from assessment of the last column of Table 10d that the PV penetration scenarios unambiguously leads to additional reductions in aggregate MW productions levels from all sources of generation when compared to aggregate production levels associated with the ($30, BAU) scenario. This broad conclusion can also be extended to the states of VIC and SA (see columns 4 and 5). For the cases of NSW and TAS, the effect of the PV scenarios is to partially mitigate the expansion in production that occurred with the introduction of the ($30/tC02) carbon price – see columns 2 and 6 of Table 2-26. In the case of QLD, significant levels of PV penetration associated, for example, with PV_C and PV_D scenarios are capable of completely offsetting the expansion in aggregate MW output associated with the introduction of the carbon price. However, it should also be recognised that the level of load shaving associated with these particular PV scenarios is not thought to be realistic.

Information about the incidence of branch congestion within each state and between states for a carbon price of ($30/tC02) and various PV penetration scenarios are listed below. Table 2-29 provides information on the incidence of branch congestion on native transmission lines located within each state and for the NEM as a whole. Recall that we have excluded inter-state Interconnectors from the state results cited in columns 2 to 6, but have included them in the NEM results cited in column 7 of Table 11a.

Table 2-29 Percentage of Time Branch Congestion Occurs for a Carbon Price of ($30/tC02) and Various PV Penetration Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU	1.21	8.44	0.85	0.10	17.30	6.44
$30, BAU	1.25	7.73	0.51	0.12	19.96	6.71
$30, PV_A	1.19	7.67	0.24	0.00	19.96	6.62
$30, PV_B	1.08	7.42	0.01	0.00	19.96	6.50
$30, PV_C	0.90	7.36	0.00	0.00	19.94	6.44
$30, PV_D	0.66	7.35	0.00	0.00	19.90	6.38

Recall further that the information on branch congestion cited in Table 11a-11b are percentage values depicting the percentage of time within the monthly dispatch horizon that branch congestion occurred within each state and across the NEM and for each Interconnector, respectively.

It is evident from examination of Table 2-29 that the effect of the introduction of a carbon price of ($30/tC02) on branch congestion has produced mixed results. In the case of QLD, SA and TAS as well as for the NEM overall, the incidence of branch congestion has increased from the ($0, BAU) levels. This situation contrasts with the results for NSW and VIC which indicate a reduction in branch congestion when compared with ($0, BAU) levels – for example, compare row 3 with row 2 in Table 2-29. Examination of Table 2-29 also indicates that the PV penetration scenarios generally produced reduced branch congestion in each state and for the NEM as a whole, matching the results identified in the previous section. Thus, the demand side PV initiatives continue to appear to generally lead to reduced branch congestion, even when introduced in an environment containing a moderately sized carbon price.

In terms of branch congestion on inter-state Interconnectors, it is apparent from inspection of Table 2-30 that branch congestion only arises on the Murraylink Interconnector. This result is qualitatively different from the results cited in Table 6b in the previous section which also pointed to the incidence of branch congestion on the Basslink Interconnector – i.e. see row 2 of Table 2-30. In the case of Murraylink, the introduction of the carbon price produced a jump in the incidence of branch congestion. However, the incidence of congestion on Murraylink also continues to decline as the level of PV penetration is increased – a trend also observed in the previous section.

Table 2-30 Percentage of Time Branch Congestion Occurs for a Carbon Price of ($30/tC02) and Various PV Penetration Scenarios on Interconnectors

SCENARIO	QNI	Directlink	NSW-VIC	Basslink	Heywood	Murraylink
$0, BAU	0.00	0.00	0.00	0.72	0.00	12.64
$30, BAU	0.00	0.00	0.00	0.00	0.00	16.95
$30, PV_A	0.00	0.00	0.00	0.00	0.00	16.81
$30, PV_B	0.00	0.00	0.00	0.00	0.00	16.67
$30, PV_C	0.00	0.00	0.00	0.00	0.00	16.24
$30, PV_D	0.00	0.00	0.00	0.00	0.00	15.23

Table 2-31 contains the monthly average MW power flow on each inter-state Interconnector. The signs of the average power flow indicate, on average, that power flows from QLD to NSW on both QNI and Directlink, from NSW to VIC on the Murray-Dederang (NSW-VIC) Interconnector, from TAS to VIC on Basslink and from VIC to SA on both the Heywood and Murraylink Interconnectors. It is particularly noticeable that the results for the (NSW-VIC) Interconnector represents a complete turn about when compared with the average power flow obtained for the ($0, BAU) scenario which indicated a reversal in terms of average power flowing from VIC to NSW. Note that this implied difference in the direction of average power flow on the (NSW-VIC) Interconnector following the introduction of a ($30/tC02) carbon price is highlighted with red font in column 4 of Table 11c. Examination of the power flows listed in Table 2-29 also indicates that the power transfers unambiguously decline in magnitude on QNI, (NSW-VIC), and Basslink Interconnectors. The evidence for Directlink, Heywood and Murraylink is more mixed in character.

Table 2-31 Average MW Power Flow for a Carbon Price of ($30/tC02) and Various PV Penetration Scenarios on Interconnectors

SCENARIO	QNI	Directlink	NSW-VIC	Basslink	Heywood	Murraylink
$0, BAU	536.70	26.90	-624.92	-392.66	135.27	36.42
$30, BAU	619.26	43.54	(182.41)	-435.08	121.33	67.81
$30, PV_A	614.29	43.37	(171.51)	-435.08	129.11	74.23
$30, PV_B	611.65	43.31	(134.63)	-435.08	130.35	73.54
$30, PV_C	609.80	43.53	(95.17)	-435.07	128.07	69.61
$30, PV_D	608.93	44.00	(62.85)	-434.69	123.86	64.31

In Table 2-31, we present additional information on the persistence of power flows in the direction indicated by the sign of the average power flow information documented in Table 2-31. Note that we have changed the dominate direction for the (NSW-VIC) Interconnector from negative sign associated with the ($0, BAU) scenario to a positive sign which is associated with the ($30, BAU) scenario. Recall that the information presented in Table 2-32, refers to the proportion of time over the month that each Interconnector experienced power flows in the direction implied by the sign associated with the average power flow values listed in Table 2-31. For example, for the ($30, BAU) scenario, examination of column 4 of Table 2-31 for the (NSW-VIC) Interconnector indicates that power flowed from NSW to VIC 68 percent of the time and in the reverse direction 32 percent of the time.

Table 2-32 Proportion of Total Time That Dominant Positive (+) or Reverse (-) MW Power Flows Occurred for a Carbon Price of ($30/tC02) and Various PV Penetration Scenarios on Interconnectors

SCENARIO	QNI(+)	Directlink(+)	NSW-VIC(+)	Basslink(-)	Heywood(+)	Murraylink(+)
$0, BAU	1.00	0.73	0.77	0.97	0.89	0.63
$30, BAU	1.00	0.98	(0.68)	1.00	0.86	0.77
$30, PV_A	1.00	0.98	(0.68)	1.00	0.89	0.78
$30, PV_B	1.00	0.98	(0.65)	1.00	0.90	0.78
$30, PV_C	1.00	0.98	(0.63)	1.00	0.89	0.78
$30, PV_D	1.00	0.98	(0.62)	1.00	0.87	0.79

Inspection of the results cited in Table 2-31 indicate that power flows on QNI, Directlink, and Basslink did not change as the level of PV penetration was increased. Power transfers from NSW to VIC on the (NSW-VIC) Interconnector declined slightly as the level of POV penetration increased while power transfers from VIC to SA (on Murraylink) became marginally more prominent. The evidence was once again mixed for power transfers from VIC to SA on the Heywood Interconnector but pointed to power flows becoming marginally more prominent when compared with the ($30, BAU) scenario, thus qualitatively mirroring power transfers on Murraylink – a conclusion also arrived at in the previous section.

The aggregate monthly level of carbon emissions and percentage change in emissions from the ($30, BAU) baseline scenario associated with the various PV scenarios are outlined in Table 2-33. Recall that the (tC02) figures listed in the second and third rows of Table 12 [corresponding respectively to the ($0, BAU) and ($30, BAU) scenarios] were determined by summing hourly C02 emissions time series produced by the model for each individual dispatched generator located at a node within each state module over the monthly dispatch horizon. The aggregate state figures cited in Table 2-33 were then obtained by summing the former set of figures across all generators within the state in order to calculate the state aggregate emission totals for the month. The NEM aggregate (in column 7) was then calculated by totalling the aggregate state emission totals.

The percentage change results listed in the latter rows of Table 2-33 were calculated by calculating state and NEM aggregate emission levels for each relevant PV scenario and then expressing this in terms of its percentage change from the ($30, BAU) levels calculated previously and documented in row 3 of Table 2-33.

Table 2-33 Total BAU Carbon Emission Levels (tC02) for a Carbon Price of ($30/tC02) and Average Percentage (%) Reduction in Carbon Emissions from ($30, BAU) for Various PV Penetration Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU (tC02)	4152538.3	4466877.9	5596410.6	740726.7	0.00	14956553.5
$30, BAU (tC02)	4213914.8	4841476.1	4736235.1	692059.2	0.00	14483685.3
$30, BAU	(1.48)	(8.39)	15.37	6.57	0.00	3.16
$30, PV_A	0.79	1.02	1.02	2.24	0.00	1.01
$30, PV_B	1.64	2.43	2.04	3.85	0.00	2.14
$30, PV_C	2.40	3.89	3.03	4.94	0.00	3.23
$30, PV_D	3.15	5.39	4.26	5.71	0.00	4.38

It is evident from inspection of Table 2-33 that the introduction of a ($30/tC02) carbon price has produced an overall 3.16% cut in aggregate carbon emission when compared to the level of carbon emission associated with the ($0, BAU) scenario – the baseline scenario considered in the previous section. The results for each state are more variable with both QLD and NSW actually experiencing an increase in aggregate carbon emissions of 1.48% and 8.39% on the ($0, BAU) levels, respectively – see row 4 of Table 2-33. This would principally be being driven by the expansion in both coal, gas fired and aggregate MW generation production for both of these states as indicated above. This trend can be contrasted with the sizeable carbon emission reductions in VIC and SA of 15.37% and 6.57% from ($0, BAU) levels, respectively. These latter results would be principally driven by the reductions in MW coal fired and aggregate generation production that were highlighted previously.

The effects of the various PV scenarios produce both state and NEM level reductions in aggregate carbon emission when compared with the ($30, BAU) carbon emission levels documented in row 4 of the Table 2-33. In the case of QLD and NSW, the additional carbon emission reductions associated with the PV scenarios would help to partially or completely mitigate the increase in carbon emission associated with the introduction of the carbon price itself. Therefore, demand side initiatives such as residential based PV penetration that has a load shaving effect will continue to actively contribute towards the policy goal of curbing carbon emissions from the power generation sector when combined with a carbon price signal.

The aggregate monthly system-wide total variable cost (TVC) and percentage change in TVC from the ($30, BAU) scenario associated with the introduction of a ($30/tC02) carbon price and the various PV scenarios are outlined in Table 2-34. Recall that the TVC figures listed in the second and third rows of Table 2-34 were calculated by aggregating the optimal hourly system-wide variable costs produced from the model over the monthly dispatch period.

Table 2-34 Total System Wide Total Variable Costs for a Carbon Price of ($30/tC02) and Percentage (%) Reduction in TVC for Various PV Penetration Scenarios from ($30, BAU)

SCENARIO	TVC ($)
$0, BAU	215677500.0
$30, BAU	659713740.0
$30, BAU	(205.88)
$30, PV_A	1.19
$30, PV_B	2.43
$30, PV_C	3.57
$30, PV_D	4.75

It is apparent from examination of Table 2-34 that the introduction of a ($30/tC02) carbon price produces a significant increase in system wide variable costs – amounting to an increase of 205.88% over the aggregate cost level associated with the ($0, BAU) baseline scenario utilized in the previous section. This increase in total variable costs is primarily picking up the additional carbon costs associated with coal fired generation, and to a less extent, gas fired generation.

It also follows from further inspection of Table 2-34 that the PV penetration scenarios reduce the system-wide TVC measure with the rate of decline from ($30, BAU) being directly related to increases in the rate of PV penetration. This result also matches the findings determined in the previous section. This result makes intuitive sense because the PV penetration scenarios serve to reduce the amount of aggregate load that has to be serviced by aggregate generation, thus moving the 'marginal' generator down the generation merit order to generators with lower marginal costs.

2.4.2 An Investigation of the Combined Impact of $60/tC02 Carbon Price and PV Penetration Scenarios.

The carbon price scenario being investigated in this section will involve examining the impact of a 'Business-As-Usual' (BAU) environment involving a ($60/tC02) carbon price signal with no PV penetration. This particular scenario will be indicated by the expression '($60, BAU)' in the analysis below. Other scenarios involving a combination of both a carbon price of ($60/tC02) and various PV penetration scenarios defined in accordance with Table 3 will also be assessed against the ($60, BAU) scenario mentioned above.

In order to assess the pure effects of the introduction of the ($60/tC02) carbon price, the BAU scenario used in Section 4 which involved no carbon price signal and no PV penetration will also be utilised in this section for comparison purposes. As was the case in the previous section, this scenario is indicated by the expression '($0, BAU)' in the analysis below.

The first set of results associated with the combined Carbon Price/PV penetration scenarios implementation are listed below in the following tables, and relates to the average monthly price levels and percentage change from ($60, BAU), volatility and maximum and minimum monthly prices for the various states and NEM as whole.

Table 2-35 Average Monthly Price Levels ($/MWh) Obtained for a Carbon Price of ($60/tC02) and Various PV Penetration Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU	17.29	17.55	16.41	17.37	7.52	15.20
$60, BAU	70.53	73.08	74.78	74.62	19.85	62.00
$60, PV_A	70.18	72.47	74.04	73.86	19.79	61.51
$60, PV_B	69.84	71.80	73.21	72.99	19.71	60.98
$60, PV_C	69.53	71.31	72.62	72.33	19.65	60.58
$60, PV_D	69.36	70.82	71.91	71.48	19.58	60.16

Table 2-36 Average Percentage (%) Reduction in Average Monthly Price Levels from BAU for a ($60/tC02) Carbon Price and Various PV Penetration Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$60, BAU	(307.90)	(316.41)	(355.56)	(329.57)	(163.97)	(307.91)
$60, PV_A	0.50	0.85	0.99	1.03	0.31	0.79
$60, PV_B	0.98	1.76	2.10	2.19	0.71	1.64

$60, PV_C	1.42	2.42	2.89	3.07	1.01	2.29
$60, PV_D	1.66	3.09	3.84	4.20	1.36	2.97

It is evident from examination of rows 2 and 3 of Table 2-37 that the introduction of a ($60/tC02) carbon price has increased average price levels for each state and the NEM as a whole. For example, for NSW, the average price level increased from $17.55/MWh to $73.08/MWh, an increase of 316.41% on the ($0, BAU) price level outcome which can be discerned from the second row of Table 14b. As was the case in the previous section, numbers enclosed within parentheses that are displayed in red font indicate percentage increases over the ($0, BAU) results.

The results cited in row 2 of Table 2-38 indicates that VIC experiences the largest percentage increase of 355.56% over the ($0, BAU) price level. This result is consistent with the findings in the previous section and would reflect the prominence of brown coal fired generation within this state which has relatively high marginal carbon costs in the presence of a carbon price signal when compared to other types of competing thermal based generation.

The other noticeable feature is the relatively modest growth in average price levels in TAS when compared with the other states and the NEM as a whole. Specifically, the growth in average prices in TAS is approximately 53% of the growth experienced in the NEM as a whole – an outcome that was also found to arise in the previous section.

It is also evident from examination of Table 2-37 and Table 2-38 that the average price levels for January 2007 become lower as the level of PV penetration is increased. Thus, increased PV penetration continues to have the general effect of reducing average price levels within each state and across the NEM as a whole. However, these mitigating affects on average price levels associated with increased PV penetration are swamped by the upward pressure that is exerted on average price levels associated with the introduction of the ($60/tC02) carbon price itself. Therefore, the results cited in Table 2-37 and Table 2-38 indicates that policies that promote PV up-take can be expected to help to slightly mitigate the expected increase in average price levels associated with the introduction of a carbon price in the range of ($60/tC02).

Table 2-37 Average Volatility in State Price Levels Obtained for a Carbon Price of ($60/tC02) and Various PV Penetration Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM

$0, BAU	5.31	8.18	8.83	12.49	3.48	7.29
$60, BAU	4.24	6.41	6.70	7.39	14.67	7.85
$60, PV_A	3.90	5.76	5.98	6.89	14.63	7.40
$60, PV_B	3.60	5.32	5.47	6.56	14.58	7.07
$60, PV_C	3.21	5.06	5.20	6.42	14.55	6.85
$60, PV_D	3.10	5.92	5.70	7.01	14.59	7.24

Average price volatility for the ($60, BAU) baseline scenario and the various PV penetration scenarios are listed in Table 2-37. The most discernible feature from assessment of this table is that for all states except TAS, the introduction of a ($60/tC02) carbon price has reduced average price volatility when compared to the ($0, BAU) results. This broad trend can be contrasted with the case of TAS which experienced an increase in average price volatility 3.48 to 14.67 – see the numbers highlighted in red font in the third row of Table 14c. This result represents an increase in the level of volatility experienced in TAS from the level associated with the ($30/tC02) carbon price considered in the previous section. The results for the NEM as a whole indicate a slight increase in volatility although this outcome would be especially influenced by the large jump in volatility experienced by TAS.

Average price volatility is unambiguously reduced in all states and the NEM as a whole with increased PV penetration when compared with the levels of average price volatility associated with the ($60, BAU) scenario listed in row 3 of Table 14c. Overall, the results strongly support the proposition that the pursuit of policies promoting residential PV take-up can be expected to have a price stabilising affect when operating in conjunction with a carbon price in the range of ($60/tC02).

Table 2-38 Maximum ($/MWh) State Price Level Obtained for a Carbon Price of ($60/tC02) and Various PV Penetration Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU	87.05	262.51	59.79	60.72	48.03	262.51
$60, BAU	123.78	256.01	104.45	104.45	87.69	256.01
$60, PV_A	121.79	249.44	99.03	94.90	87.62	249.44
$60, PV_B	120.10	244.13	98.47	92.78	87.44	244.13
$60, PV_C	120.87	246.18	97.36	92.77	87.41	246.18

$60, PV_D	120.87	249.88	90.88	92.77	87.41	249.88

In Table 2-38 and Table 2-39, the maximum and minimum ($/MWh) price levels obtained over the month for a ($60/tC02) carbon price and various PV penetration scenarios are outlined. The maximum price was experienced in NSW, with the price levels occurring, once again, at the Lismore node. The next highest prices are experienced within QLD, followed this time by VIC, SA, and TAS. Note that this pattern does not exactly match the pattern observed in the previous two sections with VIC and SA interchanging positions.

Table 2-39 Minimum ($/MWh) State Price Level Obtained for a Carbon Price of ($60/tC02) and Various PV Penetration Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU	9.12	2.36	-30.25	-192.65	3.00	-192.65
$60, BAU	44.87	4.23	4.23	4.23	3.00	3.00
$60, PV_A	44.86	4.21	4.21	4.21	3.00	3.00
$60, PV_B	42.67	4.16	4.16	4.16	3.00	3.00
$60, PV_C	42.24	4.14	4.14	4.14	3.00	3.00
$60, PV_D	42.24	4.14	4.14	4.14	3.00	3.00

It is apparent from examination of Table 2-39 that there has been a further shift in the results for VIC and SA associated with the ($60, BAU) scenario. Specifically, the lowest prices experienced in both VIC and SA are now positive (e.g. $4.23/MWh) and are also aligned with the incidence of the minimum price recorded in NSW. For all three states, this price occurs on 7/1/2007 at hour 07:00-08:00 and occurs simultaneously across all nodes in the three states. This contrasts qualitatively with the results that were observed for all three states in the previous two sections. It is also evident from inspection of Table 14e that increased PV penetration tends to reduce the magnitude of the lowest prices observed during the month when compared with lowest price level associated with the ($60, BAU) scenario as reported in row 3 of Table 2-39.

In Table 2-40 to Table 2-43, details on aggregate dispatch by state and type of generation is documented for a carbon price of ($60/tC02) and various PV penetration scenarios. In Table 15a, we present the results for coal fired generation for each state and the NEM as a whole. Recall that numbers enclosed within parentheses and highlighted in red font (i.e. in row 3) indicate percentage increases. It is evident from examination of this table that the introduction of a carbon price of ($60/tC02) led to an overall decline in coal fired generation production in the NEM of 6.02% when compared with the aggregate MW production levels determined for the ($0, BAU) scenario. The impact on state MW productions levels were more varied with increased production being experienced in NSW of 11.54% when compared with the ($0, BAU) levels. This can be contrasted with the sizeable reductions experienced in VIC and SA of 28.55% and 17.43% respectively and a more modest decrease in QLD of 2.2% from the ($0, BAU) levels for these particular states.

Table 2-40 Aggregate State and NEM MW Production for a Carbon Price of ($60/tC02) for Coal Plant and Percentage (%) Reduction in Aggregate MW Production from ($60, BAU) for Various PV Penetration Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU (MW)	4767564.2	4932544.7	4514466.9	358497.5	0.0	14573073.3
$60, BAU	2.20	(-11.54)	28.55	17.43	0.00	6.09
$60, PV_A	0.67	0.94	1.11	1.62	0.00	0.90
$60, PV_B	1.44	2.25	2.19	3.35	0.00	1.98
$60, PV_C	2.15	3.71	3.12	4.82	0.00	3.06
$60, PV_D	2.99	5.25	4.16	5.91	0.00	4.24

The main drivers of these results is the marked reduction in the cost competitiveness of VIC brown coal fired generation when compared with both black coal fired generation located in NSW and gas fired generation, more generally, in an environment where carbon costs are now incorporated into the marginal cost concept underpinning the competitive dispatch of generators. In the case of VIC, most of the brown coal fired generation plant would be dispatched at MW production levels that are equal to or close to the minimum stable operating (e.g. must run) capacity levels of this type of plant. Similar arguments could also be extended to SA as well because the black coal fleet in SA is of an older vintage. In the case of QLD, the reduction in black coal fired generation would principally reflect the loss of competitiveness of especially of older and medium vintage plant when compared with competing gas fired generation located in both states in an environment that takes increasing account of the carbon costs of generation.

In terms of the expansion of coal fired generation in NSW, a key factor driving this result is this state's 'close' proximity to VIC. In particular, as the cost competitiveness of brown coal diminishes relative to other forms of generation including to black coal, cheaper power will be exported from NSW to VIC and additional power will have to be internally generated from within NSW to cover the increased power withdrawal from NSW.

It is also apparent from inspection of Table 2-40 that the PV penetration scenarios have the effect of mitigating the increased productions levels in NSW (see columns 3) while unambiguously reducing further the aggregate MW coal fired generation production levels in QLD, VIC and SA (see columns 2, 4 and 5). For the NEM as a whole, the PV penetration scenarios have an unambiguous effect of further reducing aggregate MW coal fired generation production levels – see the last column of Table 15a.

The results for natural gas fired generation for each state and the NEM as a whole in the presence of a ($60/tC02) carbon price and various PV penetration scenarios are presented in Table 15b. It is apparent from inspection of this table that the introduction of a carbon price of ($60/tC02) has significantly increased aggregate MW production from gas fired generation in all states and for the NEM as a whole. From inspection of row 3 of Table 2-41, for the NEM as a whole, the carbon price has produced a 51.49% <u>increase</u> in aggregate MW power production from gas fired generation. There is some variation among the states with SA experiencing the smallest increase of 35.39% while QLD experiences the largest increase of 75.98% from the ($0, BAU) MW production levels.

It should also be recognised that for a carbon price of ($60/tC02), there is now some dispatch of gas plant occurring in TAS. The number of 8595.3 listed in row 3 of Table 2-41 for TAS seems very large in magnitude but this actually reflects the low (i.e. zero) base from which it is coming from. The figure actually also refers to the monthly aggregate MW level of gas fired generation in TAS. In this context, this figure could be legitimately compared with the (MW) figures listed in row 2 of Table 2-41. Seen in this context, the TAS figure indicates that gas fired generation in TAS was still quite marginal, even when the carbon price level was in the range of ($60/tC02).

Table 2-41 Aggregate State MW Production for a Carbon Price of ($60/tC02) for Gas Plant and Percentage (%) Reduction in Aggregate MW Production from ($60, BAU) for Various PV Penetration Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU (MW)	333930.8	363063.0	134561.2	679239.5	0.0	1510794.4

$60, BAU	(-75.98)	(-51.99)	(-64.30)	(-35.39)	(-8595.2)	(-51.49)
$60, PV_A	0.82	0.43	8.65	1.33	31.10	1.80
$60, PV_B	1.61	0.54	16.06	2.30	61.04	3.25
$60, PV_C	2.34	0.64	21.47	3.03	80.94	4.35
$60, PV_D	2.74	0.76	25.90	3.81	92.15	5.26

The smaller rates of increase observed for SA and NSW most likely reflect two facts. First, for SA, most of the intermediate gas fired generation fleet had been dispatched previously at levels closer to their maximum thermal rated MW capacity limit then similar plant located in other states which faced much 'stiffer' competition from black coal fired generation, in particular for lower carbon prices. Moreover, this expansion is also coming from a much larger base than is the case of the other states – for example, compare the ($0, BAU) MW production levels cited in row 2 of Table 2-41. In the case of NSW, in relative terms, there is a more limited penetration of gas fired generation when compared with the other states. These two factors would operate to constrain the potential for increased dispatch of intermediate gas fired plant, in particular, which would be very cost competitive with existing black coal based generation for carbon prices in the range of ($60/tC02).

This situation would contrast with that confronting VIC and QLD. In the case of VIC, gas fired generation would be extremely cost competitive with brown coal fired generation when carbon prices are in the range of ($60/tC02) with the increased dispatch of gas reflecting this. It is also the case that the expansion in VIC is coming from a much smaller base when compared with the other states – for example, compare the ($0, BAU) MW production levels cited in row 2 of Table 2-41. In the case of QLD, there is a significant intermediate gas fired fleet that would have largely been dispatched at minimum stable operating capacities for carbon prices in the range of ($30/tC02) as considered in the previous section. With the onset of higher carbon prices in the range of ($60/tC02), this plant would be quite competitive with older and medium vintage black coal fired generation plant in both QLD and NSW and would subsequently now being dispatched at MW capacity values significantly above their must run stable operating MW capacity levels. These effects would produce the more marked increase in gas fired MW production observed in VIC and QLD when compared with the other states for carbon prices in the range ($60/tC02).

It is also apparent from examination of Table 2-41that the PV penetration scenarios have the effect of partially mitigating the increased gas fired productions levels in all the states and NEM as a whole as indicated by the numbers in row 3 of Table 2-41.

This would particularly be the case for VIC and TAS. However, it is also apparent that for QLD, NSW, VIC, SA and for the NEM as a whole, the mitigation effect is slight in magnitude and we would expect unambiguous and significant increases in state based gas fired generation for all scenarios combining the ($60/tC02) carbon price with PV penetration.

In Table 2-42 we present the results for hydro based generation for each state and the NEM as a whole for a carbon price of ($60/tC02) and various PV penetration scenarios. Recall that NSW hydro plant is defined to include hydro plant located at the Wollongong and Tumut nodes while the VIC hydro plant is defined to include all of the hydro plant located at the Murray and Dederang nodes.

Table 2-42 Aggregate State MW Production for a Carbon Price of ($60/tC02) for Hydro Plant and Percentage (%) Reduction in Aggregate MW Production from ($60, BAU) for Various PV Penetration Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU (MW)	131565.2	265697.6	242753.1	0.0	1035839.6	1675855.4
$60, BAU	0.00	(-1.14)	(-0.97)	0.00	(-2.97)	(-2.16)
$60, PV_A	0.00	0.00	0.00	0.00	0.00	0.00
$60, PV_B	0.00	0.01	0.00	0.00	0.00	0.00
$60, PV_C	0.00	0.03	0.00	0.00	0.00	0.01
$60, PV_D	0.00	0.03	0.08	0.00	0.03	0.04

It is evident from inspection of Table 2-42 that with the introduction of a ($60/tC02) carbon price, hydro-based generation production levels increase in NSW, VIC, TAS and for the NEM as a whole when compared to ($0, BAU) aggregate MW production levels. The biggest increase occurs in TAS with a 2.97% increase in aggregate MW hydro production and the smallest increase was experienced by VIC with a 0.97% increase in aggregate MW hydro production. For the NEM as a whole, the aggregate MW hydro production increase was in the order of 2.16% on the ($0, BAU) aggregate production levels.

The aggregate MW production levels and percentage change from ($60, BAU) for each state and the NEM as a whole, for a carbon price of ($60/tC02) and various PV penetration scenarios considered. As was the case in the previous section, these results essentially combine all the results listed previously in Tables 15a-15c and broadly match the patterns observed in these tables – especially the patterns appearing in Table 2-41 for QLD, NSW and VIC, Table 2-43 for SA, and Table 2-42 for TAS reflecting the dominance of coal fired generation and increased dispatch of gas fired generation in the former states, gas fired generation in SA and hydro generation in TAS.

Table 2-43 Aggregate State MW Production for a Carbon Price of ($60/tC02) and Percentage (%) Reduction in Aggregate MW Production from ($60, BAU) for Various PV Penetration Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU (MW)	5233060.1	5561305.3	4891781.2	1037737.0	1035839.6	17759723.2
$60, BAU	(-2.84)	(-13.68)	24.53	(-17.14)	(-3.80)	0.41
$60, PV_A	0.67	0.86	1.49	1.40	0.25	0.93
$60, PV_B	1.42	2.01	2.87	2.56	0.49	1.96
$60, PV_C	2.12	3.28	4.01	3.46	0.65	2.93
$60, PV_D	2.89	4.64	5.19	4.32	0.77	3.96

It is apparent from inspection of Table 2-43 that the introduction of a carbon price of ($60/tC02) has reduced aggregate MW production from all sources of generation for the NEM by 0.41% from the ($0, BAU) aggregate production level. For QLD, NSW, SA and TAS, there has been aggregate increases of 2.84%, 13.68%, 17.14% and 3.80% from the ($0, BAU) baseline MW production levels. These results principally reflect significant expansions in gas fired production in the states of QLD and SA and an expansion in both gas and black coal fired generation in NSW. In contrast, VIC experienced a reduction in aggregate MW production of 24.53% from the ($0, BAU) production levels, with this results primarily reflecting large reductions in brown coal generation production.

The effect of the increased PV penetration is to either further reduce (in the case of VIC and NEM) or mitigate any observed increases in MW production levels (in the case of QLD, NSW, SA and TAS). It is apparent from assessment of Table 2-43 that increased PV penetration can produce a partial mitigation of aggregate production increases in the cases of NSW, SA and TAS while possibly producing a complete mitigation of the expansion observed in the case of QLD, although at levels of PV induced load shaving that is thought at present to be realistic.

Information about the incidence of branch congestion within each state and between states for a carbon price of ($60/tC02) and various PV penetration scenarios are listed in the tables below. Information on the incidence of branch congestion on native transmission lines located within each state and for the NEM as a whole are contained in Table 2-44.

Table 2-44 Percentage of Time Branch Congestion Occurs for a Carbon Price of ($60/tC02) and Various PV Penetration Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU	1.21	8.44	0.85	0.10	17.30	6.44
$60, BAU	0.85	7.28	0.18	0.01	20.21	6.49
$60, PV_A	0.83	7.20	0.14	0.00	20.21	6.45
$60, PV_B	0.67	6.94	0.13	0.00	20.21	6.33
$60, PV_C	0.44	6.90	0.13	0.00	20.21	6.27
$60, PV_D	0.38	6.92	0.13	0.00	20.17	6.26

It is evident from examination of Table 2-44 that the effect of the introduction of a carbon price of ($60/tC02) on branch congestion has produced mixed results. In the case of TAS as well as for the NEM overall, the incidence of branch congestion has increased from the ($0, BAU) levels. This situation contrasts with the results for QLD, NSW, VIC and SA which indicate a reduction in branch congestion when compared with ($0, BAU) levels – compare rows 2 and 3 in Table 16a. Examination of Table 16a also indicates that the PV penetration scenarios generally produced reduced branch congestion in each state and for the NEM as a whole, matching the results identified in the previous section. Thus, the demand side PV initiatives continue to generally lead to reduced branch congestion, even when introduced in an environment containing a moderately sized carbon price in the range of ($60/tC02).

In terms of branch congestion on inter-state Interconnectors, it is apparent from inspection of Table 16b that branch congestion arises on the (NSW-VIC), Basslink and Murraylink Interconnector. This result is qualitatively different from the results cited in Tables 6b and 11b in the previous two sections where branch congestion only occurred on the Basslink and Murraylink and Murraylink Interconnectors, respectively – i.e. see row 2 of Table 2-45. It is evident from assessment of row 3 of Table 2-45 that the introduction of a ($60/tC02) carbon price produced a jump in the incidence of branch congestion on both the (NSW-VIC) and Basslink Interconnectors when compared with the ($0, BAU) figures cited in the table – that is, jumps of 2.73% and from 0.72% to 4.89% respectively. This contrasts with the case of Murraylink which experienced a reduction in the incidence of branch congestion from the ($0, BAU) levels – e.g. from 12.64% to 11.35%.

Table 2-45 Percentage of Time Branch Congestion Occurs for a Carbon Price of ($60/tC02) and Various PV Penetration Scenarios on Interconnectors

SCENARIO	QNI	Directlink	NSW-VIC	Basslink	Heywood	Murraylink
$0, BAU	0.00	0.00	0.00	0.72	0.00	12.64
$60, BAU	0.00	0.00	2.73	4.89	0.00	11.35
$60, PV_A	0.00	0.00	2.59	1.87	0.00	11.93
$60, PV_B	0.00	0.00	2.30	0.86	0.00	12.64
$60, PV_C	0.00	0.00	1.58	0.29	0.00	12.93
$60, PV_D	0.00	0.00	1.01	0.14	0.00	14.08

Further assessment of Table 2-45 also indicates that the incidence of branch congestion on both the (NSW-VIC) and Basslink Interconnectors declines as the level of PV penetration is increased while the reverse occurred on the Murraylink Interconnector with branch congestion in this latter case increasing with PV penetration.

Table 2-46 contains the monthly average MW power flow on each inter-state Interconnector. The signs of the average power flow indicate, on average, that power flows from QLD to NSW on both QNI and Directlink, from NSW to VIC on the Murray-Dederang (NSW-VIC) Interconnector, from TAS to VIC on Basslink and from SA to VIC on both the Heywood and Murraylink Interconnectors. It is particularly noticeable that the results for both the Heywood and Murraylink Interconnectors represent a complete turn about when compared with the average power flow obtained for both the ($0, BAU) and ($30, BAU) scenarios in the previous two sections which pointed to average power transfers from VIC to SA. The results cited in row 3 of Table 16c, however, point instead to a reversal in average power flows from SA to VIC. Moreover, we also continue to detect average power flow from NSW to VIC that was observed in the previous section in relation to a ($30/tC02) scenario but was not present for the ($0, BAU) baseline scenario as indicated by the result in row 2 of Table 2-45.

Table 2-46 Average MW Power Flow for a Carbon Price of ($60/tC02) and Various PV Penetration Scenarios on Interconnectors

SCENARIO	QNI	Directlink	NSW-VIC	Basslink	Heywood	Murraylink

$0, BAU	536.70	26.90	-624.92	-392.66	135.27	36.42
$60, BAU	698.67	56.23	(645.73)	-445.23	(-39.35)	(-41.39)
$60, PV_A	697.07	56.73	(647.78)	-441.93	(-38.21)	(-40.13)
$60, PV_B	694.02	57.08	(627.46)	-438.71	(-39.95)	(-42.44)
$60, PV_C	692.03	57.70	(593.58)	-436.89	(-42.60)	(-46.30)
$60, PV_D	689.29	58.02	(558.32)	-435.53	(-46.35)	(-51.30)

Note that the implied difference in the direction of average power flow from the ($0, BAU) levels on the Heywood, Murraylink and (NSW-VIC) Interconnectors following the introduction of a ($60/tC02) carbon price is highlighted with red font in Table 2-46. Additional examination of the power flows listed in Table 2-46 indicates that the power transfers decline in magnitude on QNI and (NSW-VIC), and Basslink Interconnectors, while increasing in magnitude on Directlink, Heywood and Murraylink Interconnectors as the level of PV penetration increases.

In Table 2-47, we present additional information on the persistence of power flows in the direction indicated by the sign of the average power flow information documented above. Note that we have changed the dominate direction for the (NSW-VIC), Heywood and Murraylink Interconnector from negative sign associated with the ($0, BAU) scenario to a positive sign which is associated with the ($60, BAU) scenario. For example, from examination of Table 2-47 for the ($60, BAU) scenario, assessment of column 6 indicates that for the Heywood Interconnector, power flowed from SA to VIC 63 percent of the time and in the reverse direction 37 percent of the time.

Table 2-47 Proportion of Total Time That Dominant Positive (+) or Reverse (-) MW Power Flows Occurred for a Carbon Price of ($60/tC02) and Various PV Penetration Scenarios on Interconnectors

SCENARIO	QNI(+)	Direct link(+)	NSW-VIC (+)	Bass link(-)	Heywood (+)	Murray link(+)
$0, BAU	1.00	0.73	0.77	0.97	0.89	0.63
$60, BAU	1.00	0.99	(0.94)	1.00	(0.63)	(0.64)
$60, PV_A	1.00	1.00	(0.95)	1.00	(0.64)	(0.65)
$60, PV_B	1.00	1.00	(0.93)	1.00	(0.64)	(0.65)

$60, PV_C	1.00	0.99	(0.91)	1.00	(0.65)	(0.65)
$60, PV_D	1.00	0.99	(0.88)	1.00	(0.65)	(0.66)

More generally, inspection of the results documented in Table 2-47 indicate that power flows on QNI, Directlink, Basslink, Heywood and Murraylink remained pretty constant as the level of PV penetration was increased. Power transfers from NSW to VIC on the (NSW-VIC) Interconnector declined slightly as the level of POV penetration increased.

The aggregate monthly level of carbon emissions and percentage change in emissions levels from the ($60, BAU) baseline scenario associated with the various PV scenarios are outlined in Table 2-48. It is evident from inspection of Table 2-48that the introduction of a ($60/tC02) carbon price has produced an overall 7.00% cut in aggregate carbon emission when compared to the level of carbon emission associated with the ($0, BAU) scenario. The results for each state are more variable with both QLD, NSW and SA experiencing increases in aggregate carbon emissions of 0.05%, 11.51% and 3.78% on the ($0, BAU) levels, respectively – e.g. see row 4 of Table 2-48. This would principally be being driven by the expansion in aggregate generation occurring in all three states reflecting the significant expansion in gas fired generation as well as black coal fired generation in the case of NSW. This trend can be contrasted with the sizeable carbon emission reductions in VIC of 28.52% from ($0, BAU) levels. These latter result are principally be driven by the reductions in brown coal fired and aggregate generation production that were highlighted for this particular state.

Of further note is the carbon emission now coming from TAS that is associated with the dispatch of gas fired generation arising in that state following the introduction of a ($60/tC02) carbon price signal. However, aggregate carbon emissions from this source are quite small in magnitude when compared, for example, with the level of carbon emission being produced in SA – compare columns 5 and 6 of row 3 of Table 2-48.

The effects of the various PV scenarios produce both state and NEM level reductions in aggregate carbon emission when compared with the ($60, BAU) carbon emission levels documented in row 4 of the Table 2-48. In the case of QLD, NSW and SA, the additional carbon emission reductions associated with the PV scenarios would help to partially or completely mitigate the increase in carbon emission associated with the introduction of the carbon price itself. Therefore, demand side initiatives such as residential based PV penetration that has a load shaving effect will continue to contribute towards the policy goal of curbing carbon emissions from the power generation sector by enhancing the level of carbon emission reduction that would be produced with the introduction of a carbon price signal, in the absence of any PV uptake.

Table 2-48 Total BAU Carbon Emission Levels (tC02) for a Carbon Price of ($60/tC02) and Average Percentage (%) Reduction in Carbon Emissions from ($60, BAU) for Various PV Penetration Scenarios

SCENARIO	OLD	NSW	VIC	SA	TAS	NEM
$0, BAU (tC02)	4152538.3	4466877.9	5596410.6	740726.7	0.00	14956553.5
$60, BAU (tC02)	4154518.1	4980965.0	4000540.1	768750.2	4765.1	13909538.5
$60, BAU	(0.05)	(11.51)	28.52	(3.78)	0.00	7.00
$60, PV_A	0.73	0.94	1.31	1.52	31.10	1.02
$60, PV_B	1.55	2.20	2.53	2.81	61.04	2.15
$60, PV_C	2.29	3.59	3.54	3.82	80.94	3.23
$60, PV_D	3.13	5.06	4.58	4.70	92.15	4.35

In Table 2-49, we present information on the aggregate monthly system-wide total variable cost (TVC) and percentage change in TVC from the ($60, BAU) scenario associated with the introduction of a ($60/tC02) carbon price and various PV scenarios.

Table 2-49 Total System Wide Total Variable Costs for a Carbon Price of ($60/tC02) and Percentage (%) Reduction in TVC for Various PV Penetration Scenarios from ($60, BAU)

SCENARIO	TVC ($)
$0, BAU	215677500.0
$60, BAU	1086587900.0
$60, BAU	(403.80)
$60, PV_A	1.12
$60, PV_B	2.32
$60, PV_C	3.44
$60, PV_D	4.59

It is evident from inspection of Table 2-49 that the introduction of a ($60/tC02) carbon price has produced a significant increase in system wide variable costs – amounting to an increase of 403.8% over the aggregate TVC level associated with the ($0, BAU) baseline scenario. This increase in total variable costs is primarily picking up the additional carbon cost inflation associated with the use of a higher carbon price and with subsequent increase in carbon costs associated with coal and gas fired generation.

It also follows from further inspection of Table 2-49 that the PV penetration scenarios BAU) being directly related to increases in the rate of PV penetration. This result matches the findings presented in the previous two sections.

2.4.3 Concluding Remarks.

In this chapter, we have focused our analysis on investigating the possible roles that key supply side and demand side policy initiatives currently available to Governments might play in pursuit of the policy goal of curbing growth in carbon emissions within the National Electricity Market (NEM). These policy instruments were the introduction of a carbon price signal and residential based solar PV take-up whose principal effect is to shave load during the day.

It was argued that to address the consequences of such policy initiatives on key participants within the NEM would require a model containing many of the salient features of the national wholesale electricity market. Such features would include intra-regional and inter-state trade, realistic transmission and distribution network pathways and the competitive dispatch of all generation with price determination based upon marginal cost and branch congestion characteristics.

In order to capture these linkages, we used an agent based model of the Australian National Electricity Market (NEM) called the 'ANEMMarket' model. The 'ANEMMarket' model was developed with the intension of modelling strategic trading interactions over time in a wholesale power market that operated over realistically rendered transmission grid. The particular model that was used contained 286 generators, 72 transmission lines including six inter-state Interconnectors and 53 regional nodes/demand centres.

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

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

The solution algorithm that was utilised in the simulations involved applying the 'competitive equilibrium' solution. This meant that all generators submitted their true marginal cost coefficients and no strategic bidding was possible. This type of solution permitted assessment to be made of the true cost of generation and dispatch. Moreoever, in order to make the model response to the various scenarios more realistic, we took explicit account of that fact that baseload and intermediate coal and gas plant have 'non-zero' must run MW capacity levels termed minimum stable operating levels. The dispatch of the thermal plant was also optimised around assumed availability patterns for specified hydro generation units.

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

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

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

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

- Price volatility generally declined as the level of PV penetration was increased, pointing to a price stabilising affect;
- Increased PV penetration produced a decline in aggregate levels of coal, gas fired and hydro generation production across relevant states and the NEM;
- Increased PV penetration generally reduced the incidence of branch congestion in each state and for the NEM as a whole;
- On average, power flowed from:
    - QLD to NSW on both QNI and Directlink Interconnectors;
    - VIC to NSW on the Murray-Dederang (NSW-VIC) Interconnector;
    - TAS to VIC on the Basslink Interconnector; and
    - VIC to SA on both the Heywood and Murraylink Interconnectors.
- Increased PV penetration produced both state and NEM wide reductions in aggregate carbon emission thereby contributing to the policy goal of curbing carbon emissions from the power generation sector; and
- Increased PV penetration reduced system-wide total variable costs.

A second broad set of scenarios were implemented involving the joint application of a carbon price signal together with the same set of PV scenarios mentioned above. Two particular carbon prices levels were investigated – a ($30/tC02) and a ($60/tC02) carbon price. To isolate the 'pure' impact of the introduction of both carbon price signals, two additional baseline (BAU) scenarios were utilized which involved the employment of no PV penetration – these scenarios were termed '($30, BAU)' and '($60, BAU)', respectively. These two scenarios could be compared with the original ($0, BAU) baseline scenario in order to investigate the impact of the introduction of the carbon price signals in an environment containing no PV take-up. Similarly, these two scenarios could also be used as benchmarks that could be used to net out the 'pure' affect of the carbon price signal from more complicated scenarios involving the combined use of both the carbon price signal and residential based PV take-up.

A number of broad conclusions are available from this broad set of scenarios. The first set of conclusions relate to the pure impact associated with the introduction of the carbon price signals in the absence of PV take-up that is discernible from comparing the results associated with the ($30, BAU) and ($60, BAU) benchmark scenarios with the original ($0, BAU) scenario. These main conclusions arising from these comparisons are:

- The introduction of a carbon price signal led to significant jumps in average price levels across all states and for the NEM as a whole: for the NEM, increases of the order of 156.4% and 307.9% from ($0, BAU) for ($30/tC02) and ($60/tC02) carbon prices were obtained, respectively;

- Reductions in average price volatility for all states except Tasmania;

- A decline in aggregate levels of coal fired generation production across the NEM of 1.02% and 6.09% for carbon prices of ($30/tC02) and ($60/tC02), respectively. State based changes were more variable:

    - Unambiguous declines in VIC and SA;

    - Unambiguous expansion in NSW;

    - Mixed results for QLD – a small increase of 1.54% for a carbon price of ($30/tC02) and a small decline of 2.20% for a carbon price of ($60/tC02).

- Gas fired generation production increased across all relevant states and for the NEM as a whole of 5.23% and 51.49% for carbon prices of ($30/tC02) and ($60/tC02), respectively;

- Modest increase in hydro generation across the NEM of 2.14% and 2.16% for carbon prices of ($30/tC02) and ($60/tC02);

- Changes in aggregate MW generation production of each state:

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

    - Decrease in aggregate MW production for VIC;

    - Mixed results for SA – a 1.11% reduction and 17.14% increase in aggregate MW production for carbon prices of ($30/tC02) and ($60/tC02), respectively;

- Implications for branch congestion were mixed:

    - For a carbon price of ($60/tC02), there was reduced branch congestion for all states except TAS;

- For a ($30/tC02) carbon price, evidence was more mixed with reduced branch congestion occurring for NSW and VIC but greater congestion occurring for QLD, SA and TAS.

➢ Implications for branch congestion on inter-state Interconnectors were quite mixed and variable:

- For a carbon price of ($60/tC02), branch congestion emerged on the NSW-VIC, Basslink and Murraylink Interconnectors;

- For a ($30/tC02), branch congestion only appeared on the Murraylink interconnector.

➢ Some changes in the <u>direction</u> of average power transfers were experienced on certain inter-state Interconnectors when compared with the ($0, BAU) results:

- For a ($30/tC02) carbon price, average power flowed from NSW to VIC on (NSW-VIC) Interconnector;

- For a ($60/tC02) carbon price, average power flowed from NSW to VIC on (NSW-VIC) Interconnector and from SA to VIC on both the Heywood and Murraylink Interconnectors;

➢ Introduction of carbon prices led to NEM based reductions in aggregate carbon emissions of 3.16% and 7.00% from ($0, BAU) levels for carbon prices of ($30/tC02) and ($60/tC02), respectively. State based aggregate carbon emission results were more variable in nature:

- For a ($30/tC02) carbon price, reductions in aggregate carbon emission of 15.37% and 6.57% were obtained for VIC and SA while increases of 1.48% and 8.39% were obtained for QLD and NSW when compared against the corresponding ($0, BAU) state levels;

- For a ($60/tC02) carbon price, reductions in aggregate carbon emission of 28.52% were obtained for VIC but increases of 0.05%, 11.51% and 3.78% were obtained for QLD, NSW and SA, when compared against the corresponding ($0, BAU) state levels.

➢ Introduction of carbon prices led to a significant jump in system-wide total variable costs which now incorporated variable carbon costs – the increases were in the order of 205.88% and 403.80% on ($0, BAU) levels for carbon prices of ($30/tC02) and ($60/tC02), respectively.

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

- Increased PV penetration helps to partially and slightly 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 dominant.

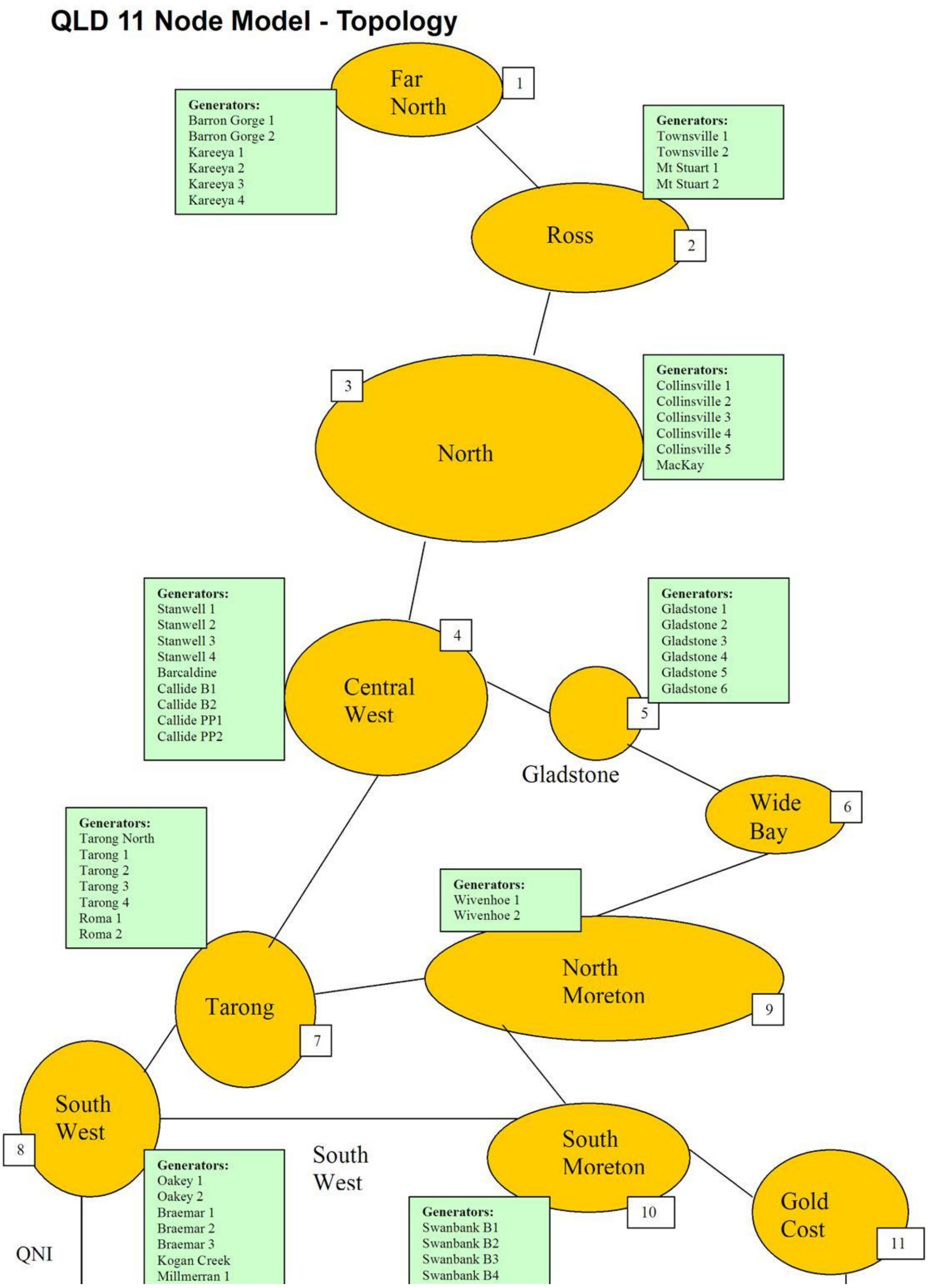
- Price volatility declines as the level of PV penetration was increased, pointing to a price stabilising affect;

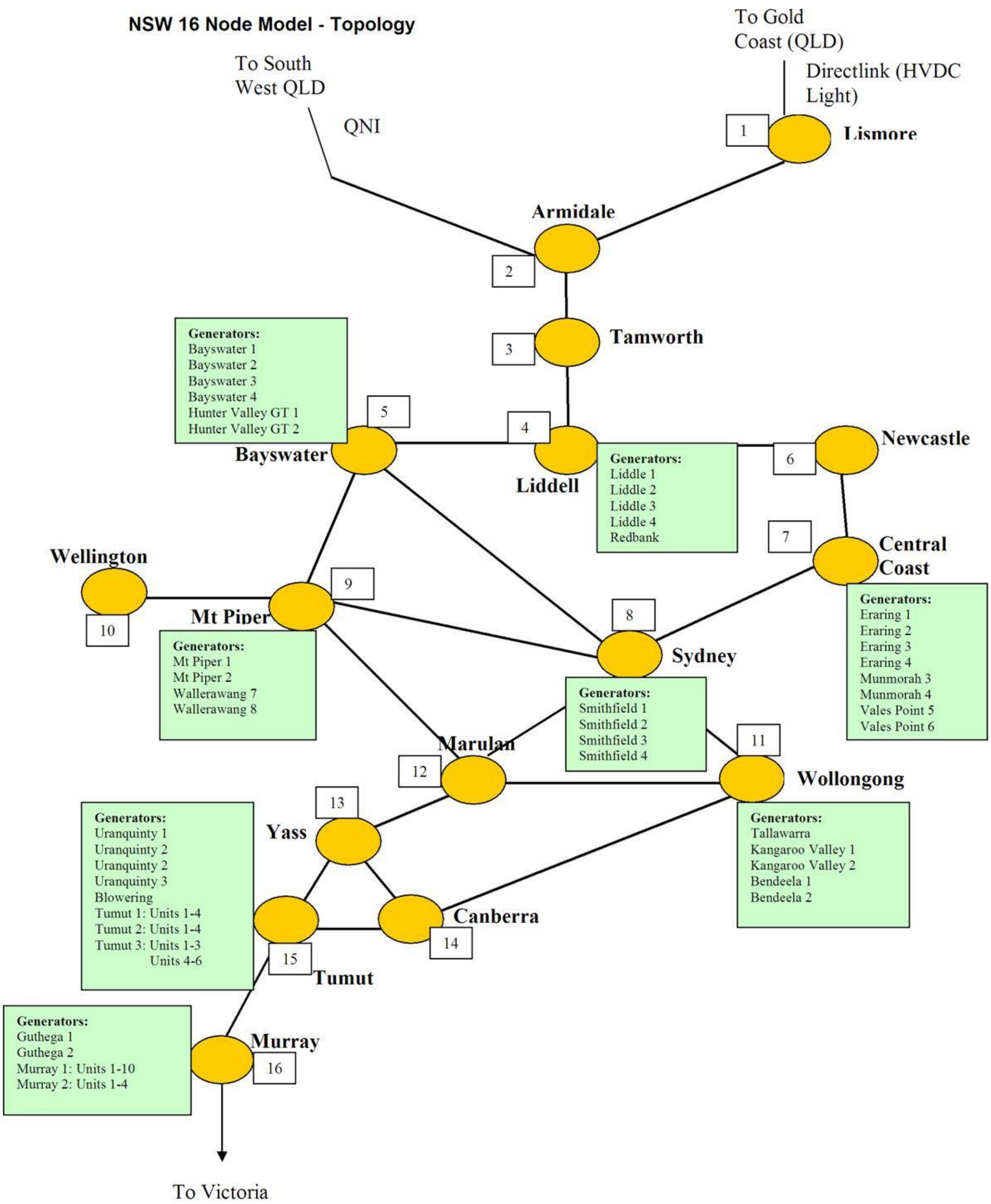
- Increased PV penetration tends to reinforces any decline or mitigates against any expansion in aggregate levels of coal, gas fired and hydro generation production levels across relevant states and the NEM that were experienced with the introduction of carbon prices;

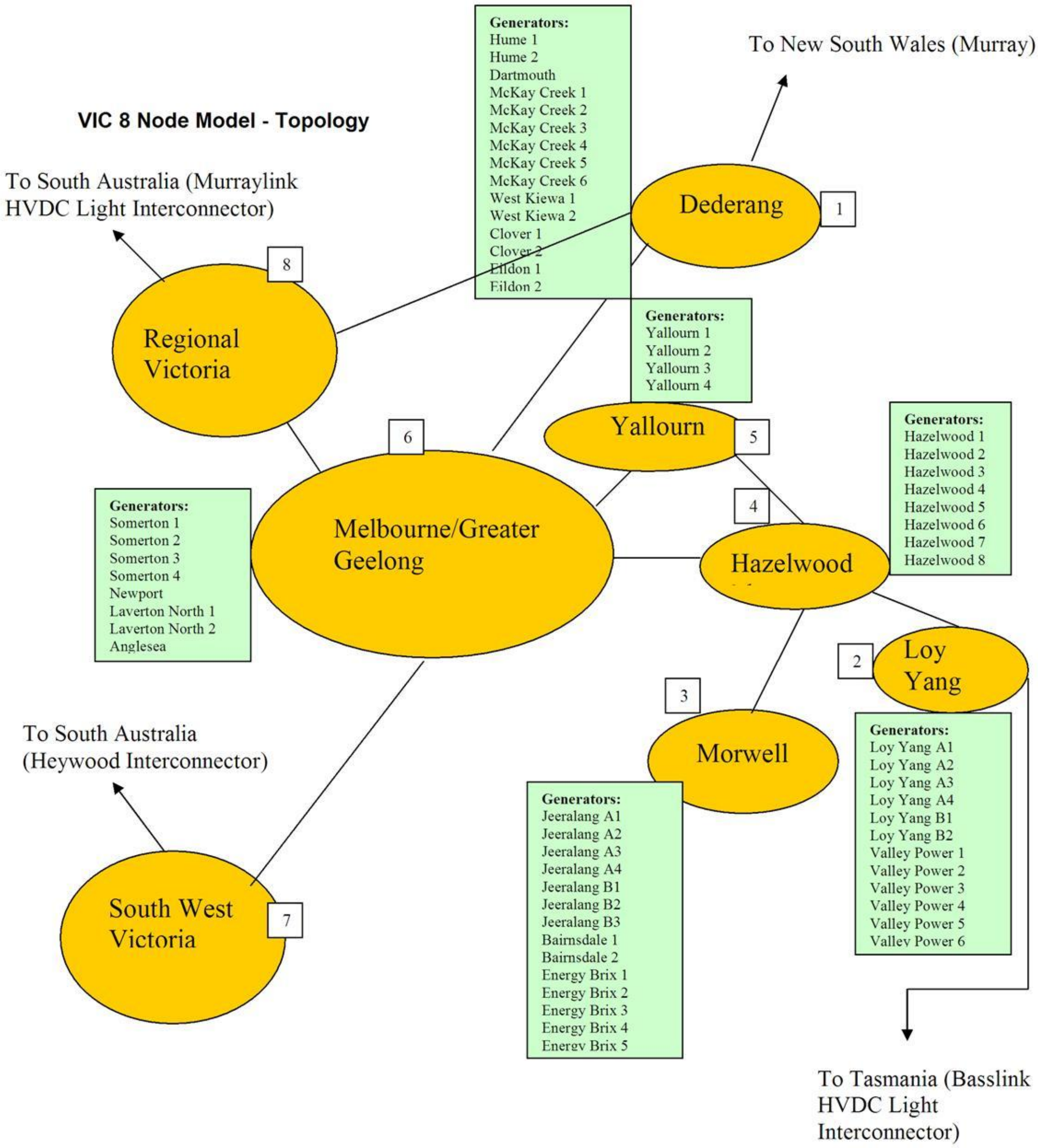
- Increased PV penetration generally reduced the incidence of branch congestion in each state and for the NEM as a whole that may have been produced following the introduction of a carbon price signal;

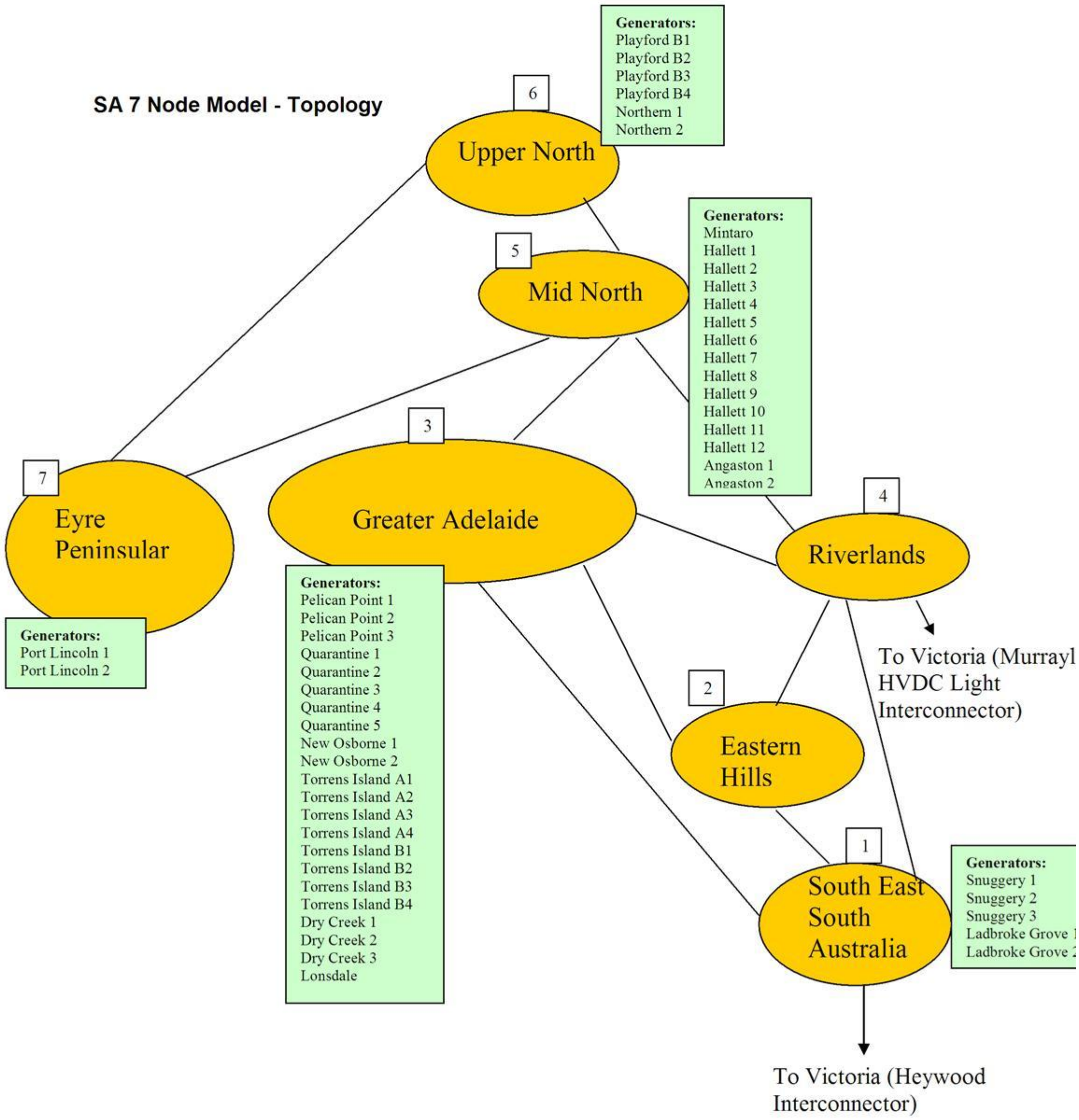
- Increased PV penetration tends to reinforces any reduction or mitigates against any increase in aggregate carbon emission experienced by the states and NEM as a whole, thereby contributing to the policy goal of curbing carbon emissions from the power generation sector by enhancing the effects produced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

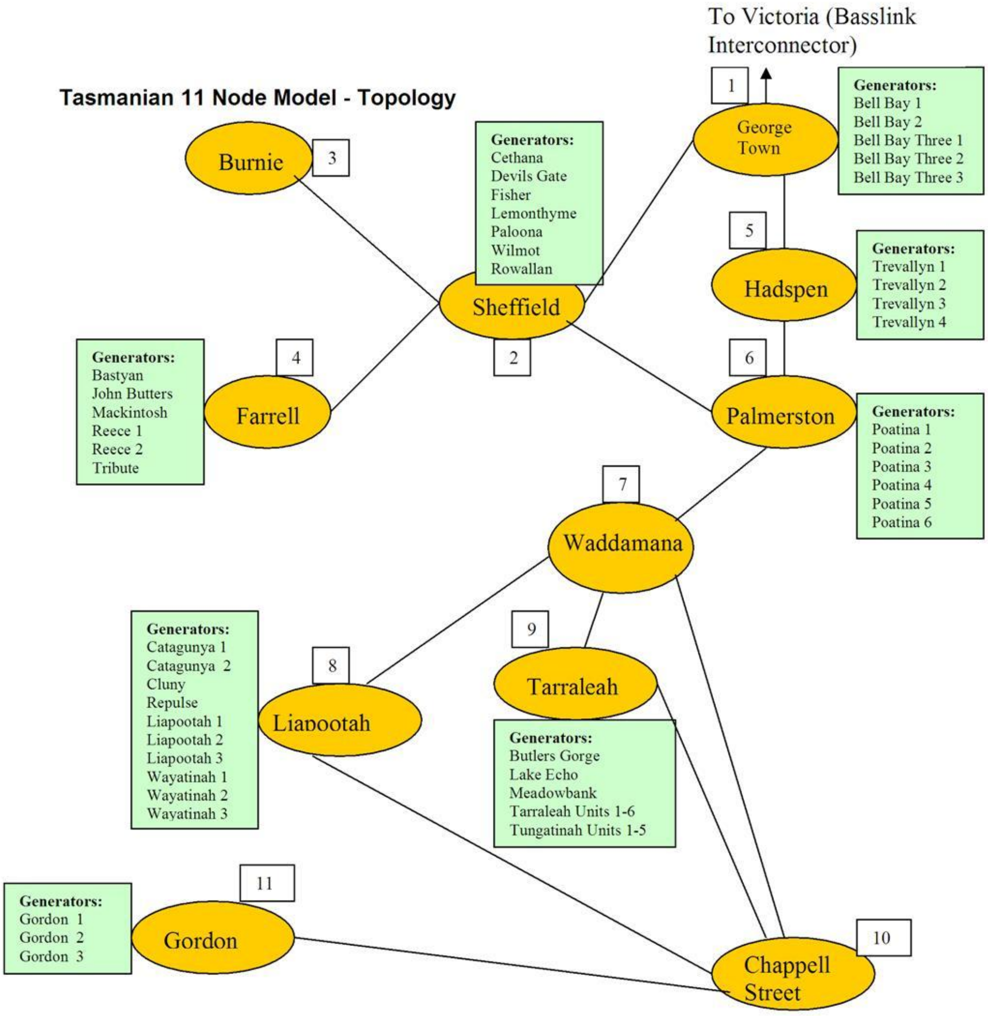
- Increased PV penetration helps to partially and slightly mitigate the increase in system-wide total variable costs associated with the introduction of a carbon price signal. However, the increase in total variable costs produced by the introduction of a carbon price signal is once again very dominant for carbon prices in the range of ($30/tC02) or ($60/tC02).


QLD 11 Node Model - Topology
Far North
1
Generators:
Barron Gorge 1
Barron Gorge 2
Kareeya 1
Kareeya 2
Kareeya 3
Kareeya 4
Generators:
Townsville 1
Townsville 2
Mt Stuart 1
Mt Stuart 2
Ross
2
3
North
Generators:
Collinsville 1
Collinsville 2
Collinsville 3
Collinsville 4
Collinsville 5
MacKay
Generators:
Stanwell 1
Stanwell 2
Stanwell 3
Stanwell 4
Barcaldine
Callide B1
Callide B2
Callide PP1
Callide PP2
4
Central West
Generators:
Gladstone 1
Gladstone 2
Gladstone 3
Gladstone 4
Gladstone 5
Gladstone 6
5
Gladstone
Wide Bay
6
Generators:
Tarong North
Tarong 1
Tarong 2
Tarong 3
Tarong 4
Roma 1
Roma 2
Generators:
Wivenhoe 1
Wivenhoe 2
North Moreton
9
Tarong
7
South West
8
South Moreton
10
Gold Cost
11
Generators:
Oakey 1
Oakey 2
Braemar 1
Braemar 2
Braemar 3
Kogan Creek
Millmerran 1
South West
Generators:
Swanbank B1
Swanbank B2
Swanbank B3
Swanbank B4
QNI


NSW 16 Node Model - Topology
To South West QLD
QNI
To Gold Coast (QLD)
Directlink (HVDC Light)
1
Lismore
Armidale
2
3
Tamworth
Generators:
Bayswater 1
Bayswater 2
Bayswater 3
Bayswater 4
Hunter Valley GT 1
Hunter Valley GT 2
5
4
Bayswater
Liddell
Generators:
Liddle 1
Liddle 2
Liddle 3
Liddle 4
Redbank
6
Newcastle
7
Central Coast
Generators:
Eraring 1
Eraring 2
Eraring 3
Eraring 4
Munmorah 3
Munmorah 4
Vales Point 5
Vales Point 6
Wellington
10
9
Mt Piper
Generators:
Mt Piper 1
Mt Piper 2
Wallerawang 7
Wallerawang 8
8
Sydney
Generators:
Smithfield 1
Smithfield 2
Smithfield 3
Smithfield 4
Marulan
12
11
Wollongong
Generators:
Tallawarra
Kangaroo Valley 1
Kangaroo Valley 2
Bendeela 1
Bendeela 2
13
Yass
Generators:
Uranquinty 1
Uranquinty 2
Uranquinty 2
Uranquinty 3
Blowering
Tumut 1: Units 1-4
Tumut 2: Units 1-4
Tumut 3: Units 1-3
Units 4-6
Canberra
14
15
Tumut
Generators:
Guthega 1
Guthega 2
Murray 1: Units 1-10
Murray 2: Units 1-4
Murray
16
To Victoria


VIC 8 Node Model - Topology
To South Australia (Murraylink HVDC Light Interconnector)
To New South Wales (Murray)
Generators:
Hume 1
Hume 2
Dartmouth
McKay Creek 1
McKay Creek 2
McKay Creek 3
McKay Creek 4
McKay Creek 5
McKay Creek 6
West Kiewa 1
West Kiewa 2
Clover 1
Clover 2
Eildon 1
Eildon 2
Dederang
1
8
Regional Victoria
Generators:
Yallourn 1
Yallourn 2
Yallourn 3
Yallourn 4
Yallourn
5
6
Generators:
Hazelwood 1
Hazelwood 2
Hazelwood 3
Hazelwood 4
Hazelwood 5
Hazelwood 6
Hazelwood 7
Hazelwood 8
4
Hazelwood
Generators:
Somerton 1
Somerton 2
Somerton 3
Somerton 4
Newport
Laverton North 1
Laverton North 2
Anglesea
Melbourne/Greater Geelong
2
Loy Yang
3
Morwell
Generators:
Loy Yang A1
Loy Yang A2
Loy Yang A3
Loy Yang A4
Loy Yang B1
Loy Yang B2
Valley Power 1
Valley Power 2
Valley Power 3
Valley Power 4
Valley Power 5
Valley Power 6
To South Australia (Heywood Interconnector)
Generators:
Jeeralang A1
Jeeralang A2
Jeeralang A3
Jeeralang A4
Jeeralang B1
Jeeralang B2
Jeeralang B3
Bairnsdale 1
Bairnsdale 2
Energy Brix 1
Energy Brix 2
Energy Brix 3
Energy Brix 4
Energy Brix 5
South West Victoria
7
To Tasmania (Basslink HVDC Light Interconnector)


SA 7 Node Model - Topology
6
Upper North
Generators:
Playford B1
Playford B2
Playford B3
Playford B4
Northern 1
Northern 2
5
Mid North
Generators:
Mintaro
Hallett 1
Hallett 2
Hallett 3
Hallett 4
Hallett 5
Hallett 6
Hallett 7
Hallett 8
Hallett 9
Hallett 10
Hallett 11
Hallett 12
Angaston 1
Angaston 2
3
Greater Adelaide
Generators:
Pelican Point 1
Pelican Point 2
Pelican Point 3
Quarantine 1
Quarantine 2
Quarantine 3
Quarantine 4
Quarantine 5
New Osborne 1
New Osborne 2
Torrens Island A1
Torrens Island A2
Torrens Island A3
Torrens Island A4
Torrens Island B1
Torrens Island B2
Torrens Island B3
Torrens Island B4
Dry Creek 1
Dry Creek 2
Dry Creek 3
Lonsdale
7
Eyre
Peninsular
Generators:
Port Lincoln 1
Port Lincoln 2
4
Riverlands
To Victoria (Murrayl
HVDC Light
Interconnector)
2
Eastern
Hills
1
South East
South
Australia
Generators:
Snuggery 1
Snuggery 2
Snuggery 3
Ladbroke Grove
Ladbroke Grove
To Victoria (Heywood
Interconnector)


Tasmanian 11 Node Model - Topology
To Victoria (Basslink Interconnector)
1
George Town
Generators:
Bell Bay 1
Bell Bay 2
Bell Bay Three 1
Bell Bay Three 2
Bell Bay Three 3
Burnie
3
Generators:
Cethana
Devils Gate
Fisher
Lemonthyme
Paloona
Wilmot
Rowallan
Sheffield
2
5
Hadspen
Generators:
Trevallyn 1
Trevallyn 2
Trevallyn 3
Trevallyn 4
Generators:
Bastyan
John Butters
Mackintosh
Reece 1
Reece 2
Tribute
4
Farrell
6
Palmerston
Generators:
Poatina 1
Poatina 2
Poatina 3
Poatina 4
Poatina 5
Poatina 6
7
Waddamana
Generators:
Catagunya 1
Catagunya 2
Cluny
Repulse
Liapootah 1
Liapootah 2
Liapootah 3
Wayatinah 1
Wayatinah 2
Wayatinah 3
8
Liapootah
9
Tarraleah
Generators:
Butlers Gorge
Lake Echo
Meadowbank
Tarraleah Units 1-6
Tungatinah Units 1-5
Generators:
Gordon 1
Gordon 2
Gordon 3
11
Gordon
10
Chappell Street

3 UQ Solar PV Array

The University of Queensland has many faculties working on a range of projects within the renewable energy sector, but with little overall co-ordination, As a result in February 2009 the University formed the *Renewable Energy Technical Advisory Group* (RETAC) to gain an understanding of what research was being conducted, with an emphasis at looking at what technology could be deployed within our various campuses and research stations. The School of Economics *Energy Economics and Management Group* (EEMG) has been involved on this committee from the outset and current projects will benefit greatly from the infrastructure currently being established.

The first project being rolled out is the deployment of 1.2 MW of flat panel PV at the St Lucia Campus, with a project cost of $7.75 million. This array will produce approximately 6% of the University's peak demand and as the University can monitor all electricity on site; this project will therefore allow for detailed modelling of the effect that intermittent renewable generation will have within a distribution network. It is also proposed to expand this project through the introduction of 400 kW of battery storage, extending the modelling on the distribution network. EEMG will be working closely with the School of ITEE on this project to maximize both research opportunities and benefits.

3.1 PROJECT TIMELINE

The project commenced in March 2009 with a review of the options available within the renewable energy technologies that were available and could be deployed. It was decided that solar PV was the most mature technology that could be deployed within the current confines of the St Lucia Campus and should be investigated further, resulting in preliminary feasibility studies being undertaken by both University academic and facilities management staff, with a subsequent brief being undertaken by external architects and consulting engineers. A full structural and shading analysis was undertaken on all University buildings and they were ranked in order of preference for siting the array based on suitability and structural ability to withhold the array weight.

The full feasibility study was completed in July 2009 and a business case prepared to obtain both funding for the project and permission to mount the panels on the selected buildings. An Expression of Interest (EoI) was prepared for review by the University's Legal Department and a list of potential panel manufacturers and suppliers was drawn up.

The EoI was subsequently issued to a limited number of interested parties in December 2009 following lengthy discussions with all major PV panel manufacturers, with eight submissions being received by the closing date in January 2010. These submissions were evaluated on a number of criteria including cost, required roof area, panel output and contribution to the University's ongoing research activities. Based upon that evaluation, three companies were invited to submit a full tender.

None of the tenders subsequently received met the University's tender and budget criteria, although all of them contained areas of value to the University. After again evaluating based on similar criteria to that used during the EoI process, the tender was awarded to Ingenero, a local Brisbane company with Trina Solar as the panel supplier. The resulting contract for delivery of the 1.2 MW array was signed in June 2010 with panels arriving on Campus in July 2010 and the project practical completion date being scheduled for prior to 31st December 2010.

3.2 THE CHALLENGES IN CREATING A 1.2MW SOLAR ARRAY

Whilst the technologies considered for this project are all technically mature, they are still not economic when compared to fossil fuel based generation. However as these emerging technologies are gaining economies of scale and increasing their market penetration, how they may be integrated into our existing distribution network and the effects that they may have on existing infrastructure is of importance to electricity retailers and distributors alike. This array, which may meet approximately 5% of the University's peak power demand, will allow for research and modelling to be undertaken to answer many of the questions being asked.

The array not only contains the best-in-class PV technology but also will include state-of-the-art monitoring and control systems, and a purpose-built control room and education / visitor centre. Multiple research groups across UQ have been involved in the development of the array concept including power systems engineering, next generation solar cell development and energy economics. UQ's Property and Facilities section also plays a central role in the array deployment – an innovative example of how the research community and engineering / infrastructure services can combine to create world-class multi-user capacity at a University. Furthermore, a large number of external stakeholders in government, the energy industry and technology providers have been consulted throughout the concept design. By far the greatest challenge has been to raise the finance to construct the array, which has been met through a $1.5 million contribution from the Queensland State Government, an equivalent funding contribution from our suppliers with the balance of costs being met by the University.

The array will be the largest flat panel PV array of its kind in Australia and would position UQ as a distinctive provider of research, training and education in solar energy within this country. The array provides unprecedented opportunities for solar research partners to test multiple facets of PV technology (panels; mobile and static storage; smart grid and metering; demand management and pricing optimisation; inverter and BoS technologies; hybridisation; etc.) and to gain first-hand experience of the issues of MW-scale deployment of renewable energy infrastructure into an urban grid environment.

3.3 DEVELOPING A MICRO-GRID TO PROVIDE RENEWABLE ENERGY FOR THE UNIVERSITY

UQ has a number of significant solar energy research activities largely based at the main St Lucia campus. These activities range from fundamental next generation solar cell development, through systems engineering, network integration and smart grids, to energy economics, energy markets, energy pricing and policy development. We also have a major new Queensland Geothermal Energy Centre of Excellence which has strong interest in the efficient use of hot water from geothermal sources – this activity has clear resonances with solar thermal technology. The deployment of the 1.2 MW array is only phase 1 of the roll-out of renewable energy and energy efficiency programs within the University with a number of other projects already being discussed with potential partners. The next phase currently being discussed is the deployment of energy storage followed by solar cooling/air-conditioning.

UQ has already constructed a number of smaller grids as set out in Table 1 with all data being logged for research purposes. Eventually all of these smaller grids will be part of the overall micro-grid with the data being centrally collected. Whist greatly assisting research, much of this information will also be publically available through a public website and will be displayed within a number of public areas within each Campus.

Table 3-1 - UQ PV Arrays

Location	Size (kW)
Hawken Building – St Lucia Campus	0.6
Sir Llew Edwards Building – St Lucia Campus	12.25
Electrical Sub-Station – Gatton Campus	25
Research Station – Herron Island	53

The above arrays contain a number of different technologies including monocrystalline, polycrystalline, amorphous and CIGS.

Figure 3-1 - Gatton 25kW Array Source: The University of Queensland

Figures 3-2 and 3-3 show the layout of the panels together with how the array will look on the two multi-level carpark structures once completed. Although the pitch of the roof is sloped away from the preferred northerly aspect, the front panels facing north will be mounted flat, whilst those at the back will be mounted with a ten degree tilt.

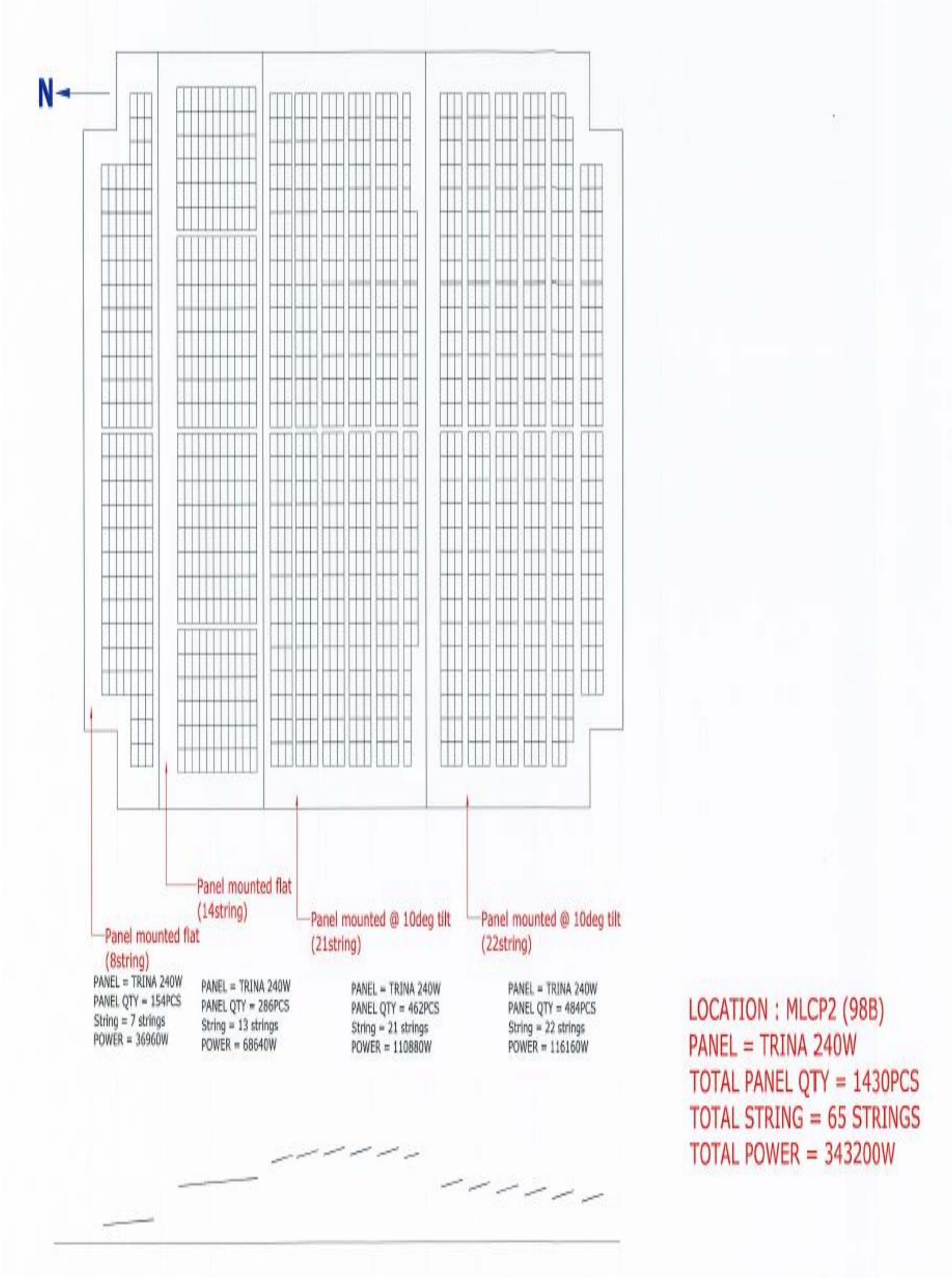


Figure 3-2 - Multi-Level Car Park Panel Placement

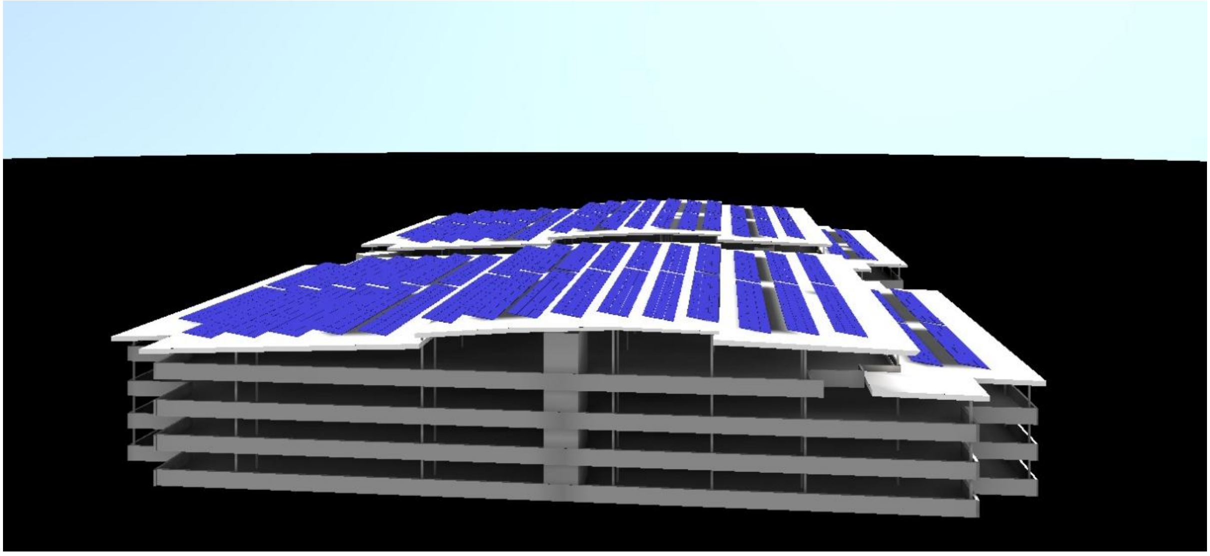


Figure 3-3 - Multi-Level Car Parks

Source: The University of Queensland/Aurecon

The first stage of the project will also include the deployment of an 8kW concentrating solar array as shown in figure 4. Whilst this is a ground-based system, it will allow for data collection and comparison between concentrating solar and PV systems. This system also tracks the sun and will therefore provide comparative data between tracking and non-tracking systems, with them again being located within direct line of site of each other.

Figure 3-4 - SolFocus Concentrating Solar System Source: Ingenero/SolFocus (2010)

The University has a number of Campuses and Research Centres that are located where large-scale deployment of this technology may be a viable alternative, particularly in facilities where there is an abundance of land but a lack of suitable roof-space.

3.4 POTENTIAL APPLICATIONS OF THE TECHNOLOGIES EMPLOYED

The technologies that are currently being deployed are focussing on electricity generation from renewable resources. With the introduction of battery storage during phase two of the project we will be able to model the effect that storage has on both the reduction on intermittency factors and reduction on peak demand through load shifting.

The two multi-level car park buildings are identical in size and construction and will both have identical arrays in size and layout as shown earlier in Figures 2 and 3. When the project is progressed to phase 2, 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.

As noted earlier, given the size of the array it will contribute to approximately 5% 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.

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 large scale solar penetration particularly 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 solar and other renewable energy source integration (micro-grid level also).

This includes the study of voltage regulation and development of control methods and compensation techniques to overcome any instability issues. Analysis of frequency regulation, spinning reserve and investigation of advanced islanding monitoring and control schemes due to faults in the existing protection systems is also under investigation. Existing and planned UQ 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.

3.5 BUILDING RESEARCH PARTNERSHIPS AND CAPACITY

Clear economic synergies will emerge when Distributed Generation is considered in conjunction with a successful demand-side management model. In order to understand the financial and economic impacts of distributed generation and demand side management, system simulations must to be coupled to electricity market simulations. This is the focus of a major UQ research program by the Energy Economics and Management Group, based in the School of Economics, to understand the economic impacts of distributed energy on Australian electricity generation, distribution and demand (CSIRO funded). The Group also has a three year Australian Research Council Linkage Grant to assess the impacts of emission trading scenarios and renewable energy generation subsidies on the growth of distributed energy supply. Particular attention is being given to the economic benefits that stem from deferring new network infrastructure and the corresponding availability of funding for new investment in low carbon emitting generation technologies and measures to increase the efficiency of energy use. In the ARC Linkage Project, the Group is also investigating the flow-on effects of distributed energy deployment on the greater economy, using a new econometric input- output model of the Australian Economy. One of the great strengths of the UQ solar research portfolio is the connectivity between technical and economic/policy aspects of solar energy development and deployment. This connectivity and broad multi-disciplinary skill-base would be valuable assets in any solar research consortium.

When the University undertook the 1.2 MW array project one of the key evaluation criteria in both the expression of interest and the subsequent tender was the ongoing relationship between the University and successful parties. As previously noted, the objectives of the array were to not only generate renewable energy and reduce our carbon footprint, but to also provide a base for future teaching and research opportunities.

With the sale of BP Solar's manufacturing plant in Sydney, remains the only PV manufacturing operation within Australia. On the world stage this would be considered unusual, particularly looking at a recent MIT study that indicated that if the whole world was linked as one huge electricity network it could be powered by solar energy, with 28% of that generation coming from Australia.

One of UQ's objectives is to create a research environment for solar technologies within an area that has significant solar resources. By requiring research partnerships as part of both the EoI and tender process this objective has been able to achieve a level of commitment from the industry to work within this region.

Figure 5 provides an overview of some of the additional data acquisition equipment that will be included within the arrays which will provide for generation output to be modelled against solar and other climatic conditions.

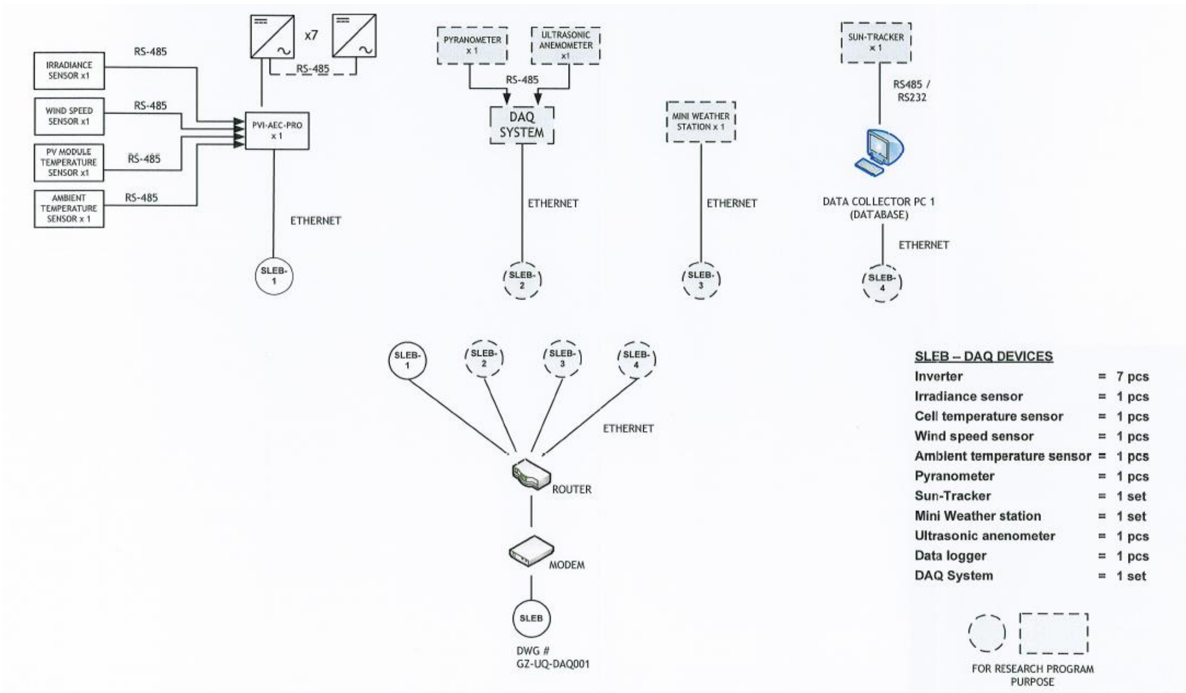


Figure 3-5 - Research Data Collection Schematic

Source: Trina Solar

The next phase of the project where storage will be introduced will also involve domestic and possible international collaborations. Internationally, solar research facilities are fairly scarce, with many being located in regions with considerably less solar resource than Queensland. This will also provide opportunities for international collaborations where similar data can be compared to differing regions.

4 The Levelised Cost of Electricity: Centralised versus DG

The demand for electricity is highly heterogeneous with respect to seasonality, time of day, and location. As a consequence of this variability, no one individual energy source can effectively be used to serve demand and an appropriate mix of generation assets is required. So an important goal in this project is to ascertain what the true costs of different generating technologies are. This involves what is known in the literature as levelised cost analyses (Alonso et al., 2006). Although we can draw upon this literature it is necessary to derive costs that are specifically relevant to Australia to input into our modelling. In particular we have relied on a variety of Australian sources for information of generator costs (AER, 2009, AEMC, 2008a, ACIL TASMAN, 2009)

4.1 INTRODUCTION

There a great number of factors to consider when deciding to invest in a particular generation asset type for participants in the electricity supply industry (Thumann, 2005). One of the difficulties in providing an estimate of the true cost of each technology type is estimating its cost of production over its economic life and how it relates to future uncertainties in policy formation. For this reason a Levelised Cost of Energy model has been developed to address some of the following issues when considering what type, and where to install a particular generation asset class:

I. Network position (grid connected or distributed generation)

II. Fuel source costs ($/GJ, including possible transport charges)

III. Fuel source costs (periodicity and variability)

IV. Interment renewable energy sources (i.e. wind, solar and run of the river hydro)

V. Availability (%)

VI. Reliability (%)

VII. Flexibility (i.e. ramp rates (MW/min), rapid start (time to full capacity)

VIII. Fixed/Marginal cost ratio (%)

IX. Outage patterns (hours to repair and frequency of outages)

X. Emissions intensity (t-CO_2/MWh)

XI. Unit Size (MW)

4.2 OUTLINE OF THE MODEL

To evaluate the likely optimal plant mix for a power system we have to derive the levelised cost of new entrant plant. To model this plant mix we need to discuss this framework and the assumptions which this model relies on. Below in Figure 4-1 we provide a schematic which outlines all of the assumptions for the cost of generation model.

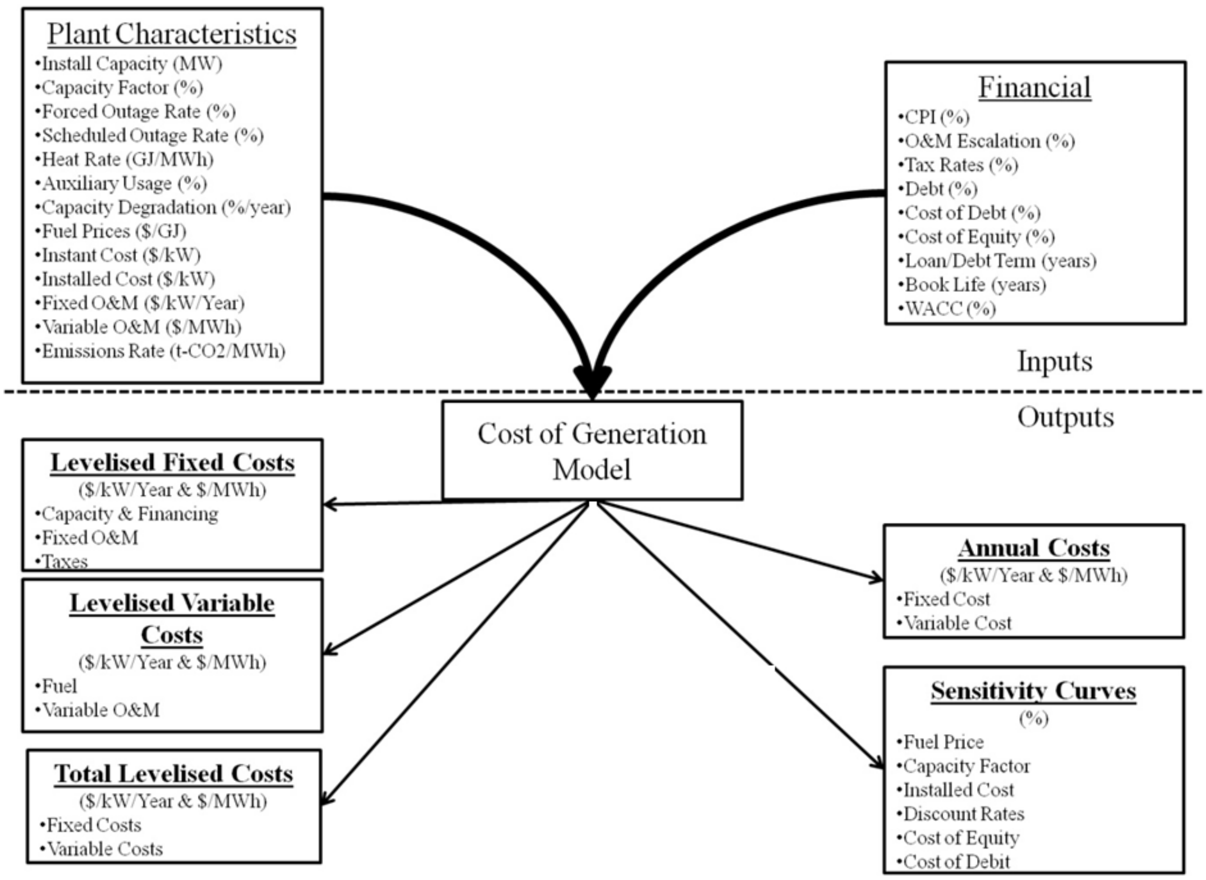


Figure 4-1 Cost of Generation Model Inputs and Results

4.2.1 Assumptions

The following assumptions have been included into our framework of the levelised cost model for establishing the future viability of centralised and distributed generation projects. Time t is defined to be a discrete time period such that where N corresponds to the economic life of the technology being considered. Each technology types are denoted by j. We shall now more on to describe in detail our list of assumptions as outlined in Figure 4-1.

Inflation (CPI)

The pass through of inflation (ρ), throughout this modelling will be considered to be ρ_R=75% for revenue streams and ρ_C=100% for non-finance related operating costs.

Operations and maintenance (O&M) costs escalation will be at the rate of in accordance with the aforementioned cost stream pass through rate(Simshauser and Wild, 2009).

Tax Rates (%)

When applying a discounted cash flow model such the levelised cost of energy methodology the effects on taxation rates should be accounted for. Currently in Australia corporate taxation is currently set at 30%. When tax shields are implemented the effects of deductibility of interest payments and imputation credits have been calculated by a number of analysts such as in (ACIL TASMAN, 2009, The Allen Consulting Group, 2005, NECG, 2003) and the effective corporate tax effective rates is assumed to be 22.5%

Cost of Capital

The Weighted Average Cost of Capital has been used for a significant number of regulatory decisions and has generally determined one of the hurdle rates for investment in capital infrastructure in Australia (IPART, 2002). This modelling has been implemented with standard principles for the Australian electricity supply industry and the Weighted Average Cost of Capital calculation is certainly another example of maintaining those principles.

Initially we must establish the cost of equity using the Capital Asset Pricing Model (CPAM) as used by a variety of regulators in Australia.

One of the most common applications of the CAPM model is to establish the cost of equity, with the assumption that capital markets are completely independent(IPART, 2002). This application is certainly one that is not applied in this work, where international prices of debt based on the increasing debt basis point premium on BBB+ credit are included into establishing a more appropriate cost of capital (The Allen Consulting Group, 2009). The recognition by some regulators (IPART, 2002), that ownership of electricity supply assets will dictate the all investment hurdle rates, highlights the need to act in a conservative manner when calculating the cost of capital. This modelling assumes the cost of capital will be for private investment rather than any further development by government owned corporations. The use of international observations for credit ratings data and lending premiums have been sourced from (Reuters, 2010). All of the assumed values for the WACC calculations are presented in Table 4-1 below.

Table 4-1 WACC components

Component	Symbol	Assumed Value
Liabilities	V	100%
Debt	D	60%
Equity	E	40%
Risk free rates as observed by the market[15]	R_f	6%
Market Risk Premium	R_{mp}	6%
Market Rate of Return	R_m	12%
Corporate Tax		30%
Effective Tax Rate	T	22.5%
Debt basis point premium	R_p	200
Cost of Debt	R_d	8%
Gamma	Γ	0.5
Asset Beta	β_a	0.8
Debt Beta	β_d	0.16
Equity Beta	β_e	1.75
Return on equity	R_e	16.50
Inflation	CPI	3.0%

[15] Data acquired from REUTERS 2010. Data Stream. Thompson Reuters.

We have used the post-tax real Officer WACC in a similar fashion as proposed in (ACIL TASMAN, 2009) as a conservative proxy for investment decision hurdle rate for electricity market modelling. The post-tax WACC has been applied due to the effects of depreciation for capital intensive generation assets.

The Fisher equation allows for the conversion of the WACC into real terms, which accounts for inflation effects over the economic life of the project.

Installed Capacity (MW)

The unit size for available generation installed capacity varies widely across different technology types which we will denote as . While the need for investment in generation assets grows over time, more often than not it is not possible to installed fractions of a unit of any particular asset type. The number of units which can be considered for inclusion within the optimal plant mix solution has been considered on an incremental integer basis. Within our model we consider uniform unit sizes within each technology types as potential candidates to meet demand and energy policy objectives. Typical unit sizes have been sourced from (ACIL TASMAN, 2009).

Generation and Capacity Factor (%)

Each generation technology type has different modes of operation which dictate its typical energy output over time. More formally the Capacity Factor ( ) is the ratio of total energy generated by a generating unit for a particular time scale to its maximum possible energy it could have produced if it was operated at its maximum capacity rating for that time period (Stoft, 2002). Furthermore, the capacity factor reflects a particular technology type's ability to recover its long run marginal costs over a year. This typical operation behaviour will also dictate its potential candidacy for inclusion in the optimal plant mix to serve demand. Typical operating behaviours for taken from (AEMO, 2010) historical data and product specifications for distributed generations units which are detailed by (CSIRO, 2009). The sent out ($SO(t)_j$) energy for each generating technology j is calculated as follows:

The revenue stream version of the sent out energy calculation , is found by applying the assumed revenue inflation escalation rate to the output generated by each representative generation asset type. This is given by the following calculation:

Forced and Scheduled Outage Rates (%)

There are two types of outage patterns/rates which have been considered for inclusion in this levelised cost/optimal generation mix model, namely forced and scheduled outages. The first of which is a Forced Outage Rate (FOR), which mainly incorporates the likely timing and length of unexpected removal from service availability of a generating unit. Scheduled outages/patterns are typical of maintenance of plant to maintain optimal operation and long term viability of a plant. Typical acceptable standard outage rates have been incorporated from the IEEE standards (IEEE, 2007) into the expected capacity factor for technology type j.

Heat Rate (GJ/MWh)

For the electricity generation sector heat rate is a direct indicator of efficiency of energy production. The lower the heat rate the less fuel is required to generate power. Typically heat rate improvements over time have facilitated the deployment of more fuel efficient and lower carbon emitting assets. Furthermore, some of the technology types considered in this modelling will have evolving heat rates as better technology is developed (i.e. Ultra Super Critical black coal fired generation (ACILTASMAN, 2009)).

Auxiliary Usage (%)

The internal use of energy to enable a generation asset to operate normally referred to as auxiliary usage ( ), is also a factor that must be considered. Typically generation technology types have improved their internal usage factors considerably over time (ACIL TASMAN, 2009). However the imposition of carbon capture and storage (ACIL TASMAN, 2009), has had an appreciable effect on generator efficiency rates will plays a significant role as to whether this type of technology is suitable for the Australian electricity generation sector. Higher energy internal use rates are expected to have a detrimental effect on the probability of inclusion in the interior solution of the screening curve analysis.

Capacity Degradation (%/year)

The ability of any electricity generation asset to maintain peak performance over time is also an internal optimisation constraint on future performance. The technical reliability of each electricity generation technology type is considered in our modelling framework and is explicitly associated with sent out energy over time (Stoft, 2002). To avoid the long term effects of capacity degradation capital maintenance programs are performed via a variety of inspection types. These inspections and their associated costs have been implemented directly into the operations and maintenance costs (ACIL TASMAN, 2009, ESAA, 2008).

Fuel Prices ($/GJ)

Accessing cheap, reliable and abundant primary fuel supply sources is of extreme importance for central planners and GENCO's to not only bank and develop a project but to also operate effectively. Fuel prices are examined explicitly by incorporating fuel prices forecasts from a variety of sources (EIA, 2010, ACIL TASMAN, 2009, IEA, 2009) and our internal energy market modelling capability. Furthermore, primary fuel source pricing has a dramatic effect on the potential positioning of an asset's bids within the Dutch auction performed on pre-dispatch in the NEM. Total fuel costs for each generator technology type , are given via the following equation,

Capital Costs (Instant or Installed Costs ($/kW))

The cost of deployment for each generation asset technology type has been explicitly included into the cost structure of our modelling. While installed cost can vary marginally for different locations we have constructed this model from a central planning perspective and will rely on a generalised price for each technology type (ACIL TASMAN, 2009, Klein, 2009). Instant cost, also referred to as the overnight cost, is the initial capital expenditure. The instant costs do not normally include the costs incurred during the construction phase (i.e. installed cost). Instant costs include all costs: the component cost, land cost, development cost, regulatory compliance costs, connection charges and environmental compliance costs (Klein, 2009). A comparison of technology types we are currently considering is detailed in Figure 4-2.

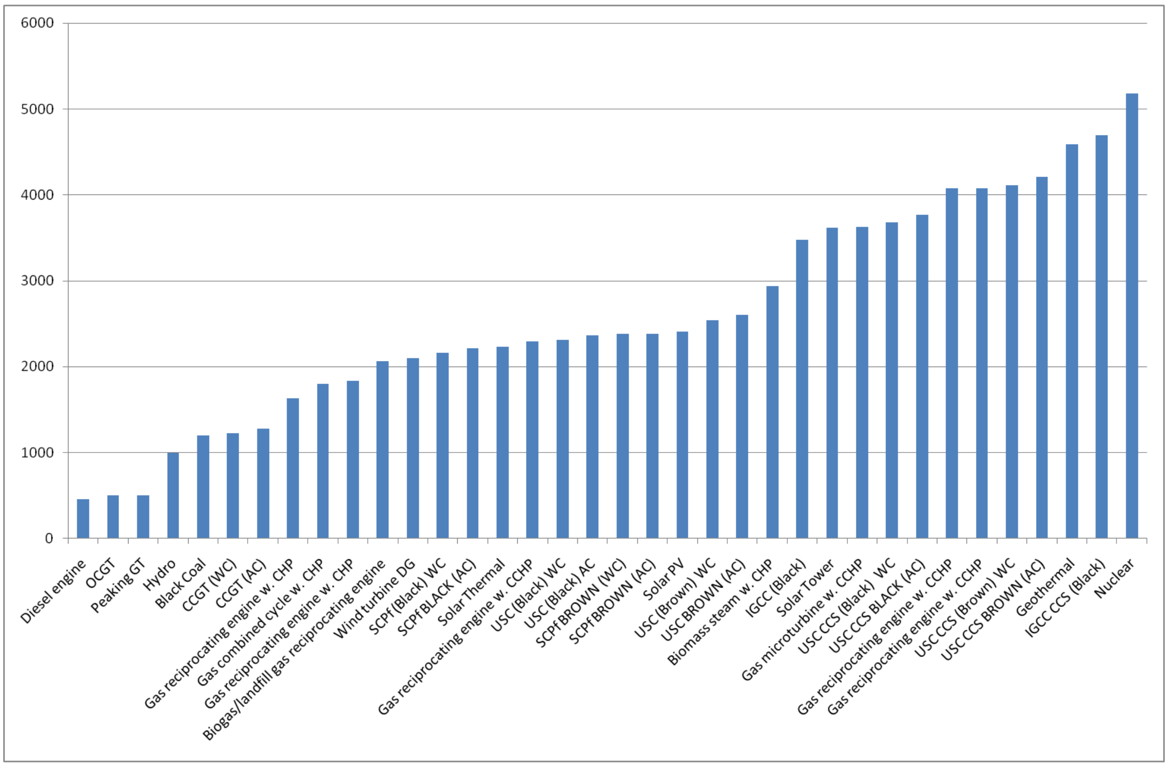


Figure 4-2 Capital cost for each centralised generation type considered

FO&M ($M/year or $/MWh)

The Fixed Operations and Maintenance costs $FOM(t)_j$, are conceptually composed of the costs incurred regardless of whether the station generates electricity. The costs included in this category are not always consistent from one assessment to the other but always include labour and the associated overhead costs. Other costs that are not consistently included are equipment (and leasing of equipment), regulatory compliance, and miscellaneous direct costs. We shall adopt these conventions which have been previous implemented by the Californian Energy Commission(Klein, 2009) and the (IEA, 2009).

VO&M ($/MWh)

Variable O&M, , is a function of the generating assets operational behaviour and it is composed of the following (IEEE, 2007, Klein, 2009, ACIL TASMAN, 2009, AEMC, 2008a):

- Scheduled outage and maintenance including the three main inspection types which is by far the largest expenditure
- Forced outage patterns

- Availability of water supplies

Emissions Rates (Emissions Intensity Factor (EIF), t-CO_2/MWh)

The emissions intensity of any generation technology type , will become of prime significance over the next ten years. With a carbon pollution reduction scheme on the horizon (at some point in time), higher emitting generation assets will struggle to have their power dispatched at a meagre carbon price , of $30. The emissions intensity factor (see Figure 4-3 for a comparison of different technology types), has been explicitly included to account for future carbon liability under some sort of emissions reduction plan. The emissions liability (and the total cost of that liability , for each generation technology type j, is defined as follows:

Renewable Energy

The consequences of the renewable energy target will have on different generation asset types is also of importance when considering which plant types to invest in. Many of the assets which we have included in our modelling are eligible for payments under the renewable energy scheme. Account for these payments is performed by the following equation:

Where is the renewable energy certificate price in time t, and is the eligibility of a particular generation asset to be awarded those certificates.

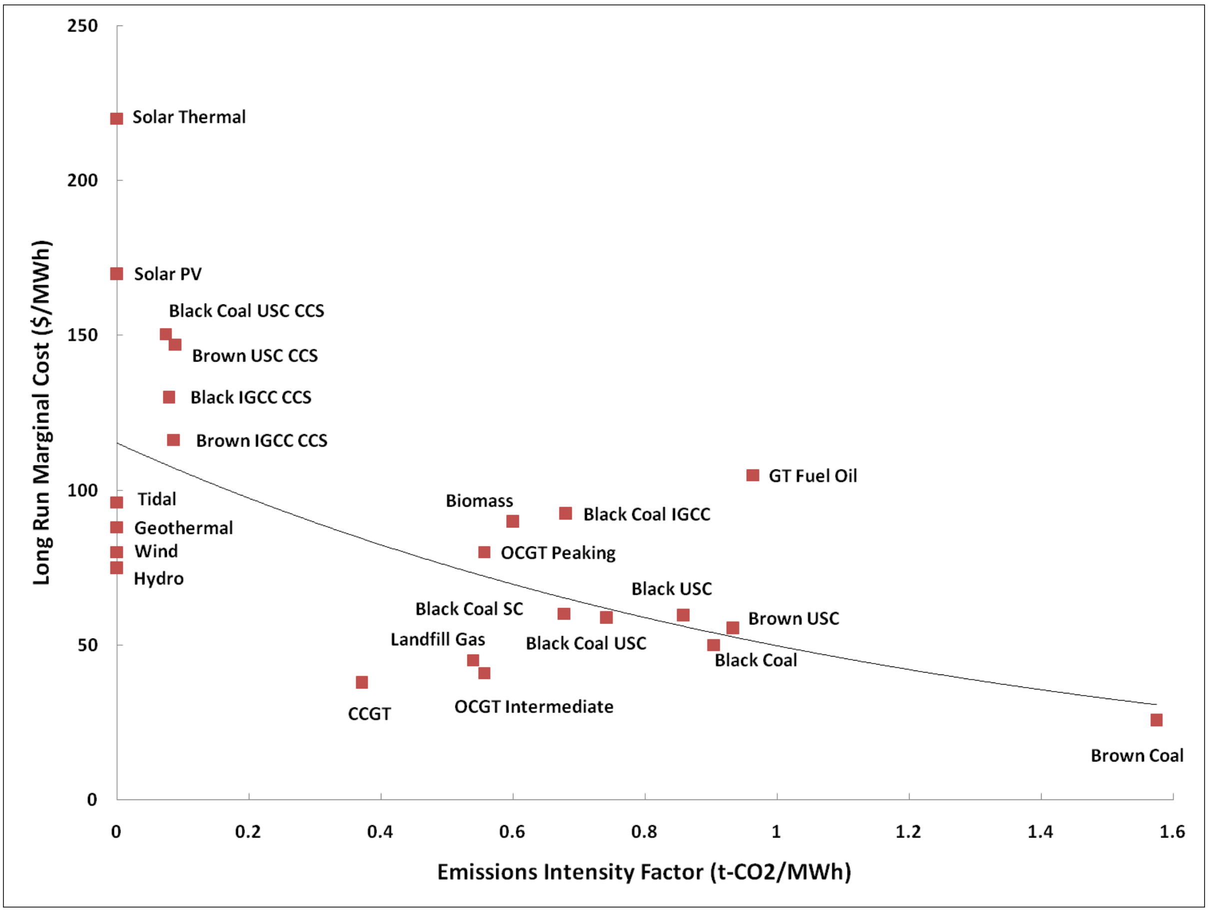


Figure 4-3 Emissions intensity of centralised generators (t CO2/MWh)

4.3 CALCULATING THE LEVELISED COST OF ENERGY

Establishing the levelised cost of electricity generation from a central planning/economies of scale perspective will allow for the integration of deployed asset types into our whole market model in PLEXOS. Understanding the long term effects that a variety of policy structures will have on the composition of the electricity market will allow for further development of the case for deploying distributed generation to avoid transmission infrastructure capital expenditure. The total costs associated with operations and maintenance and the total operational costs , associated with generation are follows:

To calculate the levelised cost of energy we have applied the following standard formula from (Klein, 2009, IEA, 2010, Yang et al., 2008), Having established the levelised cost formula we shall move on to three scenarios to examine how the likelihood of investment options will change with respect to policy and fuel cost view points. In Table 4-3 and Table 4-4 we provide a comprehensive list of assumptions of technological specifications for both centralised and distributed generation assets.

Table 4-2 Technological Specification of Centralised Generation

Generation technology	Capex ($/kW)	Unit size (MW)	VO&M ($/MWh)	FO&M ($M pa)	Useful life (years)	Heat rate (GJ/MWh)	Fuel cost ($/GJ)	Emissions (t/MWh)	Capacity Factor (%)
Hydro	1000	300	1.05	72	50	0	0	0	50%
Black Coal	1200	500	1.6	20	40	9.2	1.20	0.85	85%
SCPf (Black)	2162	500	1.25	24	40	7.93	1.40	0.8	85%
IGCC (Black)	3481	500	4.1	25	40	7.46	1.40	0.82	85%
USC (Black)	2314	500	1.25	24	40	7.44	1.40	0.74	85%
USC CCS (Black)	3679	500	2.4	40	40	8.18	1.40	0.07	85%
IGCC CCS(Black)	4699	500	5.15	37.5	40	8.73	1.40	0.07	85%
USC (Brown)	2545	500	2.4	46	40	9.31	1.40	0.07	85%
USC CCS (Brown)	4114	500	2.4	46	40	9.31	1.40	0.06	85%
SCPf BROWN	2379	500	1.25	27.5	40	9.58	0.57	0.99	85%
Nuclear	5182	1000	5.9	84	50	9.74	0.83	0.02	85%
CCGT (WC)	1224	400	1.05	12.4	30	6.82	2.00	0.567	85%
OCGT	918	150	7.7	1.95	30	11.5	2.00	0.66	45%
Peaking GT	500	150	7.5	2	30	10.26	15.00	0.896	3%
Solar Tower	3622	200	0	9.132	30	0	0	0	73%
Geothermal	4585	500	3	35	30	0	0	0	80%
Solar Thermal	2230	200	0	10	20	0	0	0	25%

Table 4-3 Technological Specification of Distributed Generation

Generation technology	Capital cost ($/kW)	Unit size (MW)	Variable O&M ($/MWh)	Fixed O&M ($M pa)	Useful life (years)	Heat rate (GJ/MWh)	Fuel cost ($/GJ)	Emissions (t/MWh)	Capacity Factor (%)
CCGT w. CHP	1796	30	1.25	2.69	20	7.9	3.35	0.35	65%
Gas recipro. engine w. CHP	1630	1	7.5	0.08	20	8.75	3.35	0.35	65%
Gas recipro. engine w. CHP	1834	0.5	7.5	0.04	20	8.75	7.85	0.35	18%
Biomass steam w. CHP	2942	30	30	3.53	20	12.41	1.5	0	65%
Solar PV	2407	0.04	0	-	20	0	0	0	18%
Diesel engine	459	0.5	1	0.0025	20	8	16.55	1	3%
Wind turbine DG	2098	0.01	0.001	-	20	0	0	1	10%
Biogas/landfill gas recipro. Engine	2068	0.5	1.25	0.0003	20	9.23	2	1	80%
Gas microturbine w. CCHP	3630	0.06	70	0.007	20	12.4	7.85	1	43%
Gas recipro. engine w. CCHP	4077	5	10	0.57	20	8.7	3.35	1	80%
Gas recipro. engine w. CCHP	2293	0.5	10	0.05	20	9.2	7.85	1	43%
Gas recipro. engine w. CHP	4077	5	10	0.57	20	8.7	2.5	1	80%

4.4 Results: The evaluation of the costs of Centralised versus Distributed generation technology types

Evaluating the levelised cost of generation is one of the inputs into a extremely complicated process of investment in the electricity supply industry (Harris, 2006). Firstly we will examine a base case or Business as usual scenario where we only consider the power system from a centralised perspective.

Scenario 1 Business as usual

To establish the effectiveness of this modelling framework we should firstly test our assumptions. Our initial iteration of this model does not include the current energy policy progress, renewable energy targets or DG as a viable option. The system wide assumptions for input into our levelised cost model are listed below in Table 4-4.

Table 4-4 Scenario 1 Business as Usual Assumptions

Gas Price $/GJ	$2.50
Carbon Price $/t-CO2	$0.00
REC Price $/MWh	$0.00
GEC Price $/MWh	$0.00
Biomass Price $/GJ	$4.03
Diesel Price $/GJ	$20.00
PV CF%	18%
Solar Thermal CF%	35%
Wind Central CF%	39%
Wind DG CF%	19%
CCGT CF%	80%
OCGT CF%	45%

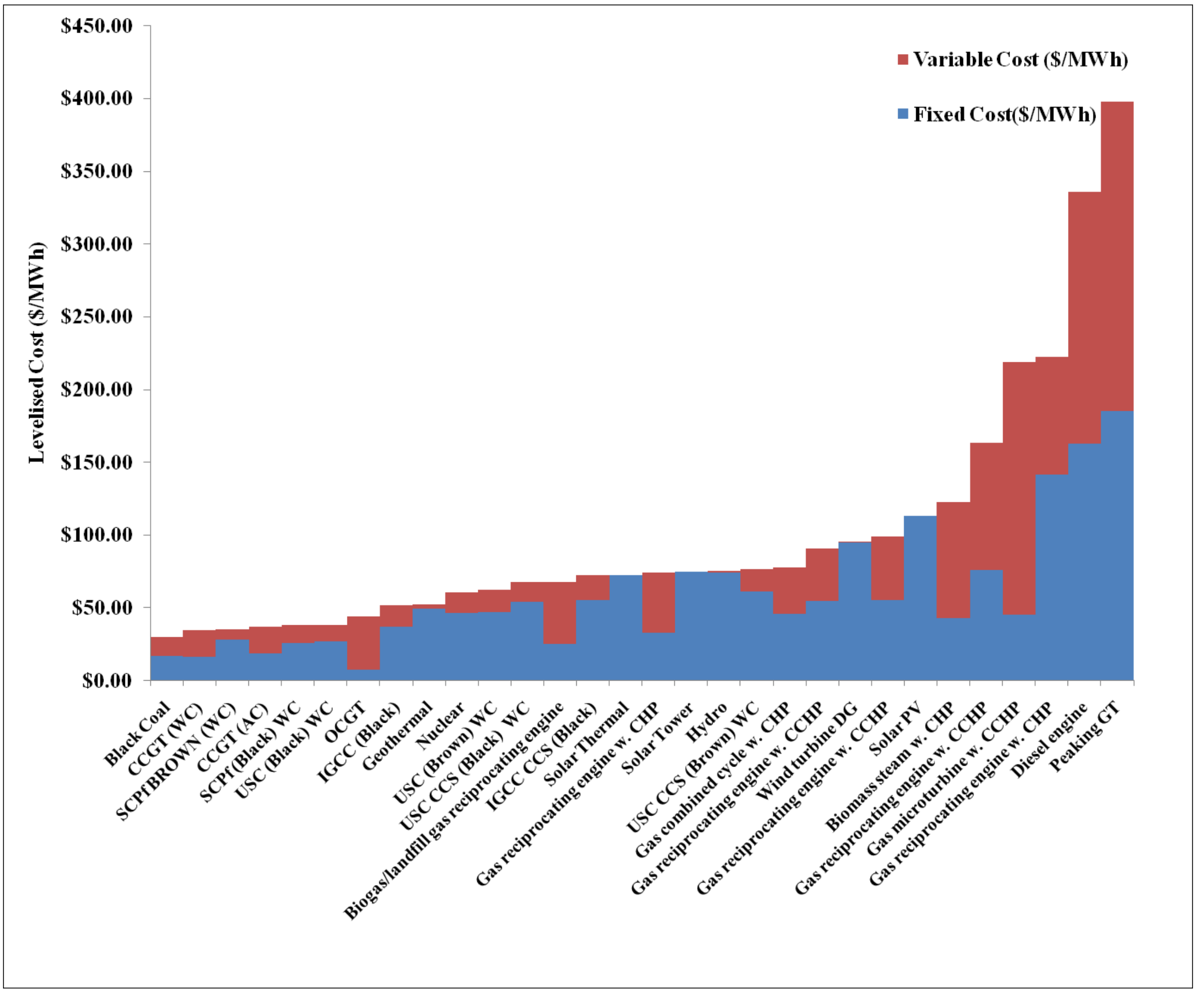


Figure 4-4 Scenario 1 Business as Usual Levelised Costs

The results shown in Figure 4-4 detail the application of the levelised cost model and technology types are fairly typical of levelised energy costs reported in (Simshauser and Wild, 2009, CSIRO, 2009). Centralised generation is at a distinct advantage from a short run and long run marginal cost point of view over distributed generation. Distributed generation doesn't appear in the first group of assets below a $50/MWh levelised cost. Typically when centralised generation firms assess the viable options for investment the above set of results form one of the first criteria for decision makers (Simshauser, 2002).

Scenario 2: Renewable Energy Target

Inclusion of a $40/MWh REC price which is consistent with artificial price floor imposed on the REC market by the split of the large and small segments of the target provide the motivation of our second scenario. From initial analysis Biogas/Landfill gas has a negative fixed cost due to the application of the REC price. The way that this payment has been applied is consistent with the design of the levelised cost curve analysis in (Simshauser, 2002, Stoft, 2002). Only two generation types which are of a distributed generation asset type are under the $50/MWh price threshold. While this isn't surprising given the fact that no capacity payments have been applied for DG nor TUOS/DUOS payment has been implemented to centralised generation. The application of these types of payments/liability is within the capability of this model, the results of those simulations are still under development.

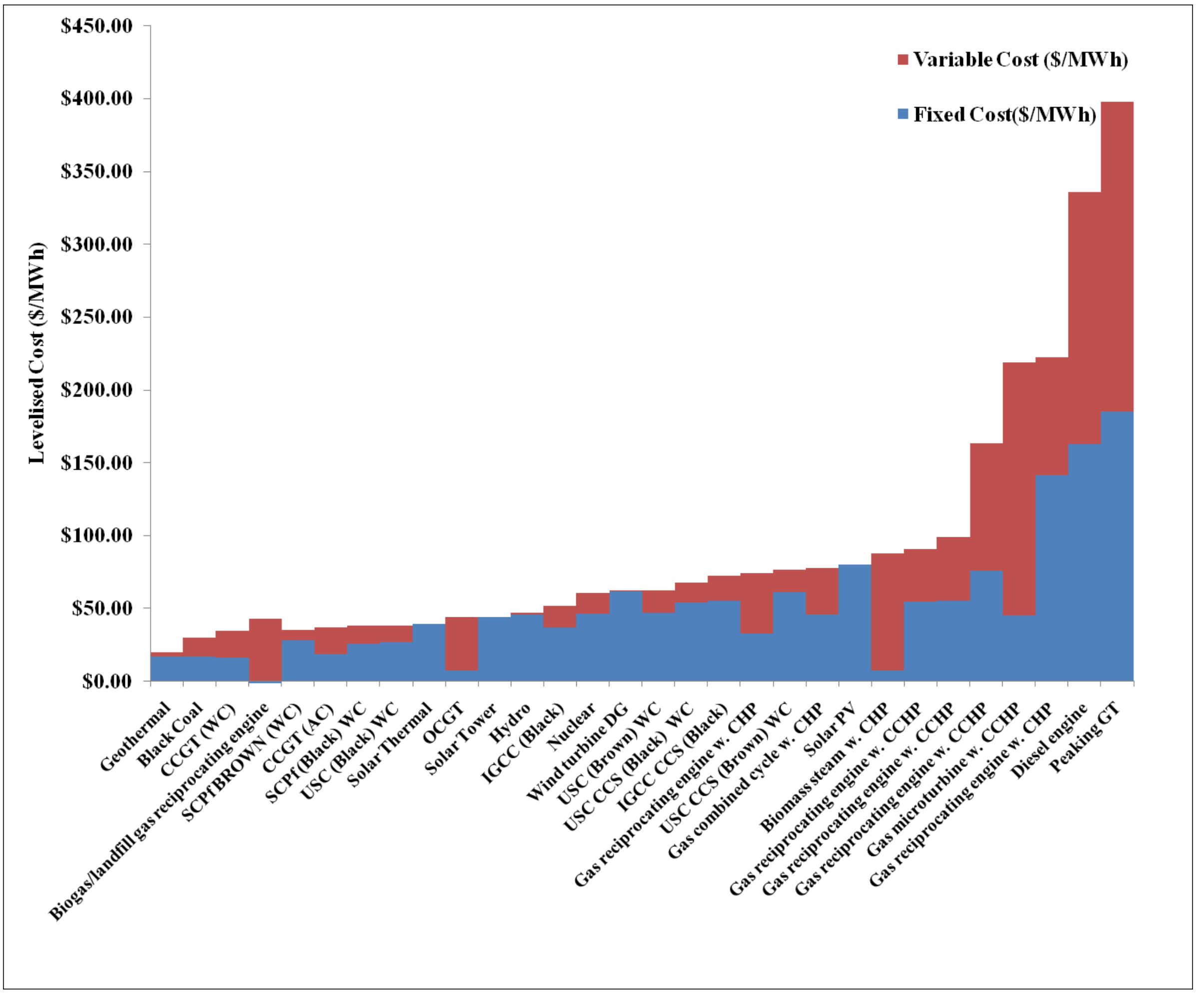


Figure 4-5 Scenario 2 Renewable Energy Policy Levelised Costs

4.5 CONCLUSION

The application of the levelised cost modelling platform has been successfully applied to the expected generation types currently under consideration for the methodological candidates. This model has been developed in such a way that we can consider in the future the deployment of the screening curve analysis (Boiteux, 1949, Berrie, 1967) to establish the optimal plant mix of generation asset types. This next step in the modelling will improve our understanding of the cost structures involved in helping decision makers implement judgement on the appropriate installation of new capacity.

5 Assessing the Impacts of Distributed Generation on Transmission Expansion Cost with an Australian Case Study

5.1 INTRODUCTION

Originally, the electricity industry consisted of generation units that were deployed in a dispersed manner with little or no interconnection. The situation soon evolved and, by 1930s, centralized operation became the dominant feature of the industry because of significant economies of scale and technical advantages. Nowadays, the power industry is still characterized by large-scale centralized generation and an extensive transmission and distribution infrastructure. However, this centralized power generation model has been challenged in recent years. Large-scale base load generators are frequently criticized for causing environmental damage. Moreover, along with continually increasing size and complexity, the security of large power transmission/distribution networks is also questioned. The question then arises: can distributed generation (DG) technologies offer viable alternatives and can they play a significant role in the foreseeable future?

Distributed generation can be defined as generation units that are connected at the distribution network level and close to end-users (Ackermann et al., 2001). Based on this definition, DG is not necessarily green power generation. However, the renewable DG technologies (wind turbine, solar photovoltaic, biomass, etc) tend to be more preferred options due to their environmental benefits. Another important benefit claimed by the proponents of DG is that it can potentially defer large investments in the transmission/distribution infrastructure. However, only a few studies (Borenstein, 2008, Kahn, 2008, Beach, 2008) have been conducted to investigate how significant the effect might be. Moreover, existing studies usually ignore system technical constraints, which can have large impacts on the conclusions of such studies.

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

The rest of this paper is organized as follows: a review of relevant research is provided in section 5.2. In Section 5.3, the proposed model for simulating transmission expansion behaviors is discussed in detail. Transmission expansion is formulated as a multi-objective optimization problem. The technical constraints, including AC power flow, voltage stability and transient stability, are also discussed. The "areas of influence" method is then introduced to determine what portion of transmission investments can be reduced by the installation of DG. The simulation results are provided in Section IV. Finally in Section V, we present some concluding remarks.

5.2 REVIEW OF RELEVANT RESEARCH

Economic and engineering questions concerning the implementation of distributed generation technologies have been the subjects of increasing amounts of research in recent years; and rapid progress has been made. Research has been firstly devoted to the definition and classification of DG technologies (Ackermann et al., 2001, Carley, 2009). Although, strictly speaking, DG can be either renewable or non-renewable, in this paper we focus on renewable DG technologies only. Therefore we use "distributed generation" and "renewable distributed generation" inter-changeably.

Since the market penetration of DG is still low in most countries, a number of studies (Dondi et al., 2002, Johnston, 2005) have been conducted to investigate the barriers to DG penetration and the factors that can contribute to its deployment. A number of economic analyses (Gulli, 2006, Abu-Sharkh et al., 2006) have also been conducted to study the market performance of DG systems. In addition, since DG is usually connected at the distribution level, extensive research (Haffner et al., 2008, Sharma and Bartels, 1997, Ball et al., 1997) has been conducted to investigate the impacts of DG on distribution network planning. These studies usually focus on determining the optimal sizes and locations of DG units in the distribution network from a distribution company's point of view. Other studies (Neto et al., 2006, Zhu et al., 2006) have also been performed to understand the impacts of DG from a power system side, such as on reliability, system security and power quality.

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

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

After the optimization objectives and constraints are formulated, the transmission network expansion problem can be solved by applying different optimization techniques to obtain appropriate expansion plans. Optimization techniques can be classified into two types: mathematical optimization and heuristic optimization. Mathematical optimization models can be used to find an optimum expansion plan by using techniques such as linear programming (Chanda, 1994), dynamic programming (Dusonchet, 1973), nonlinear programming (Youssef and Hackam, 1989), mixed-integer programming (Bahiense et al., 2001) and benders (Binato et al., 2001). In contrast, heuristic methods can be used to select optimum expansion plans by performing local searches applying logical or empirical rules (Latorre et al., 2003). These heuristic optimization techniques include genetic algorithms (Silva et al., 2005), simulated annealing (Gallego et al., 1997), differential evolution (Zhao et al., 2009) and the TS algorithm (Silva et al., 2005).

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

5.3 THE TRANSMISSION EXPANSION SIMULATION MODEL

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

5.4 THE TRANSMISSION NETWORK EXPANSION MODEL

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

We make the following assumptions:

1) Transmission network expansion is conducted solely by the transmission

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

2) The market operator determines the generation schedules by minimizing overall system generation cost. This assumption matches the policy of the Australian national electricity market (NEM).
3) All generators bid into the market at their short-run marginal costs.
4) The mandatory renewable energy target (MRET) and the renewable energy certificate (REC) market in Australia provides policy incentives that are strong enough for the large-scale deployment of wind and solar power. In other words, we assume that the costs of wind and solar PV will fall to levels where they are no longer barriers to their penetration.

Based on the above assumptions, a transmission expansion model can be developed follows.

The first optimization objective is to minimize the total expansion investment cost:

$$\text{Minimize } O_{invest} = C^T \eta \tag{5.1}$$

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

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

$$\text{Minimize } O_{gen} = \sum_{i \in G} f_i(P_{G,i}) \tag{5.2}$$

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

The following two constraints set up the relation between the injected power, the voltages and network parameters:

$$\text{Subject to} \quad P_{G,i} - P_{D,i} = \sum_{n=1}^{N} |Y_{in} V_i V_n| \cos(\theta_{in} + \delta_n - \delta_i) \tag{5.3}$$

$$Q_{G,i} - Q_{D,i} = \sum_{n=1}^{N} |Y_{in} V_i V_n| \sin(\theta_{in} + \delta_n - \delta_i) \tag{4}$$

Here $P_{G,i}, P_{D,i}$ are, respectively, the real power output and demand of node i; $Q_{G,i}, Q_{D,i}$ are the reactive power output and demand of node i; $P_{G,i} - P_{D,i}$ and $Q_{G,i} - Q_{D,i}$ represent the real and reactive power injected into node i. Y_{in} is an element of the admittance matrix Y, which can be easily calculated from transmission line impedances, as discussed in (Saadat, 1999). θ_{in} is the angle of Y_{in} and can be given as $\theta_{in} = \arctan(\mathrm{Im}(Y_{in}) / \mathrm{Re}(Y_{in}))$. V_i is the complex voltage at node i, and δ_i is the angle of V_i

$(\delta_i = \arctan(\mathrm{Im}(V_i)/\mathrm{Re}(V_i)))$.

Constraints (5) – (8) specify the limits of line flows, node voltages, generators' active power outputs and reactive power outputs:

$$S_{ij} \le S_{ij}^{\max} \tag{5.5}$$

$$V_i^{\min} \le V_i \le V_i^{\max} \tag{5.6}$$

$$P_{G,i}^{\min} \le P_{G,i} \le P_{G,i}^{\max} \tag{5.7}$$

$$Q_{G,i}^{\min} \le Q_{G,i} \le Q_{G,i}^{\max} \tag{5.8}$$

where S_{ij} represents the apparent power flowing through line $i-j$, which can be calculated as $S_{ij} = \sqrt{P_{ij}^2 + Q_{ij}^2}$. Objective (2) and constraints (3)-(8) together formulate the standard OPF equations.

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

$$EUE \le EUE_{\max}, \tag{5.9}$$

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

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

$$VSI \ge VSI_{\min} \tag{5.10}$$

$$TSM \ge TSM_{\min} \tag{5.11}$$

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

In summary, the solution to model (1)-(11) gives the optimal transmission network expansion plan. In this study, we have divided the market simulation into N stages and assumed that the transmission network operator will solve model (1)-(11) at each stage and implement the optimal expansion plan.

In practice, system reliability can only be maintained by simultaneously expanding the transmission network and investing in new generation capacities. Therefore, generation investments were also simulated. Since we are interested in the impacts of large-scale penetration of DG, we assumed that strong policy incentives exist in the market so that DG units are investment priorities. Two scenarios are assumed: DG reaches 20% and 40% penetration levels at the end of the simulation. If the added DG capacity is not enough to satisfy the minimum reliability requirement, the insufficient generation capacity is met by building traditional coal-fire plants. These new coal fire plants are built in the nodes with higher nodal prices. The nodal prices can be obtained from the OPF calculation. Summarizing our discussion, the simulation procedure is depicted in Fig. 1.

5.5 Reliability Assessment

Power system reliability can be seen as offering a degree of assurance to customers that continuous service of satisfactory quality will be maintained. In this study, the widely used *expected unserved energy* (EUE) (AEMC, 2008b) 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. Different markets have different standards of reliability. In the Australian NEM, the EUE is limited within 0.002% of the overall energy traded in the market (AEMC, 2008b).

The EUE can be calculated with OPF and Monte Carlo simulation. Before calculating the EUE, probability distributions should be firstly assumed to model load levels and the availabilities of all generators in the market. Load levels are usually assumed to follow normal distributions. The maximum outputs of wind turbine and solar PV are determined by the wind speed and solar irradiation, which can be modeled respectively with Weibull (Celik, 2004) and normal distributions (Kaplanis and Kaplani, 2007). In each iteration of a Monte Carlo simulation, load levels and the maximum outputs of generators are randomly generated. OPF is then calculated to determine the generation schedule. If all loads can be met, the unserved energy is zero. After N iterations of the Monte Carlo simulation, the EUE can be calculated as the average unserved energy of all N iterations.

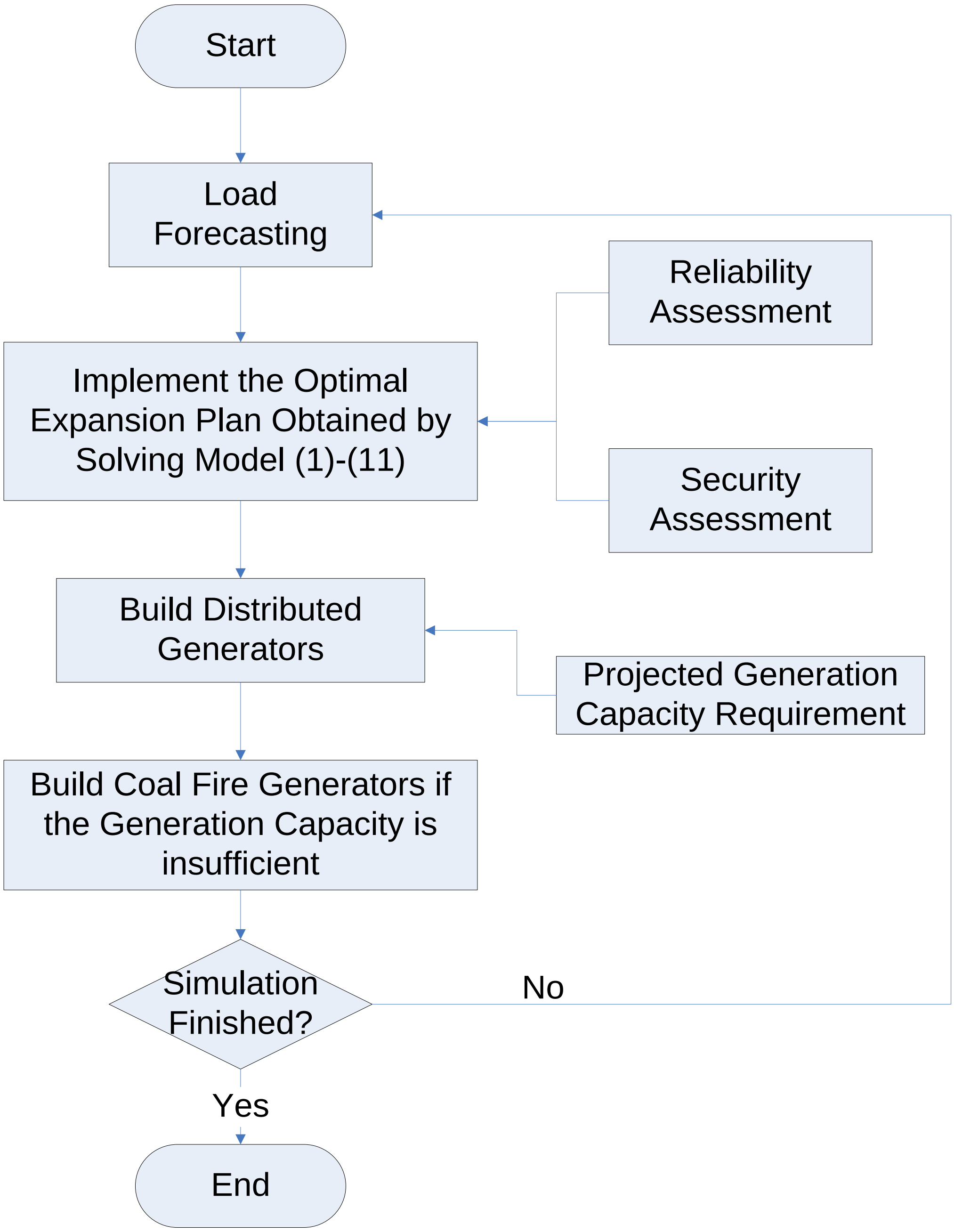


Figure 5-1 Procedure of the Transmission Network Expansion Simulation

5.6 Security Assessment

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

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

$$\bar{J} = \begin{pmatrix} \partial\vec{P}/\partial\vec{\theta}, & \partial\vec{P}/\partial\vec{V} \\ \partial\vec{Q}/\partial\vec{\theta}, & \partial\vec{Q}/\partial\vec{V} \end{pmatrix} = \begin{pmatrix} \frac{\partial P_1}{\partial\theta_1},\ldots,\frac{\partial P_n}{\partial\theta_n}, & \frac{\partial P_1}{\partial V_1},\ldots,\frac{\partial P_n}{\partial V_n} \\ \frac{\partial Q_1}{\partial\theta_1},\ldots,\frac{\partial Q_n}{\partial\theta_n} & \frac{\partial Q_1}{\partial V_1},\ldots,\frac{\partial Q_n}{\partial V_n} \end{pmatrix} \tag{5.12}$$

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

$$\bar{J} = \bar{U} \cdot \bar{\Sigma} \cdot \bar{V}^T = \sum_{i=1}^{n} \sigma_i \vec{u}_i \vec{v}_i^T \tag{5.13}$$

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

$$\bar{\Sigma} = \begin{pmatrix} \sigma_1 & 0\ldots & 0 \\ \vdots & \ddots & \vdots \\ 0 & 0\ldots & \sigma_n \end{pmatrix} \tag{5.14}$$

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

Another security index is the transient stability margin (TSM). Transient stability is the ability of all generators in the system to maintain synchronization subject to disturbances. The transient stability margin gives us an indicator of the distance to the transient stability limit. In our study, the widely used *extended equal area criterion* (EEAC) (Xue et al., 1989) method is employed to obtain TSM. EEAC firstly can be used to divide all generators into two groups, based on their characteristics. Each group is then aggregated to form an equivalent generator. The accelerating and decelerating energy of the system are then calculated to determine whether the two equivalent generators will lose synchronization and obtain TSM. The EEAC method is well-known for its superior computational efficiency and therefore has been widely applied in the power industry.

5.7 Transmission Expansion Cost Allocation

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

Based on power flow increases in transmission lines, it is possible to calculate a participation factor FPN for each generator for using a line

$$FPN_{ik} = \frac{P_{G,i}\dfrac{\partial P_k}{\partial P_{G,i}}}{\sum_{j=1}^{J} P_{G,j}\dfrac{\partial P_j}{\partial P_{G,j}}}\text{, if } \frac{\partial P_k}{\partial P_{G,i}} > 0 \tag{5.7}$$

$$FPN_{ik} = 0\text{, if } \frac{\partial P_k}{\partial P_{G,i}} \leq 0 \tag{5.8}$$

J is the number of system nodes, whose areas of influence include transmission line k. Areas of influence can also be computed by means of distribution factors, based on power flow equations. Finally, transmission expansion costs are calculated proportionally to participation factors.

5.8 Case Study Results

5.8.1 Case Study Setting

The proposed simulation model is applied in the Queensland market, which is one of the six regions of the Australia national electricity market (NEM). In our study, the Queensland system is divided into 11 regions. The one line diagram of the Queensland network before simulation is given in Figure 5.2. The overview of the Queensland system information before simulation is provided in Table 5.1.

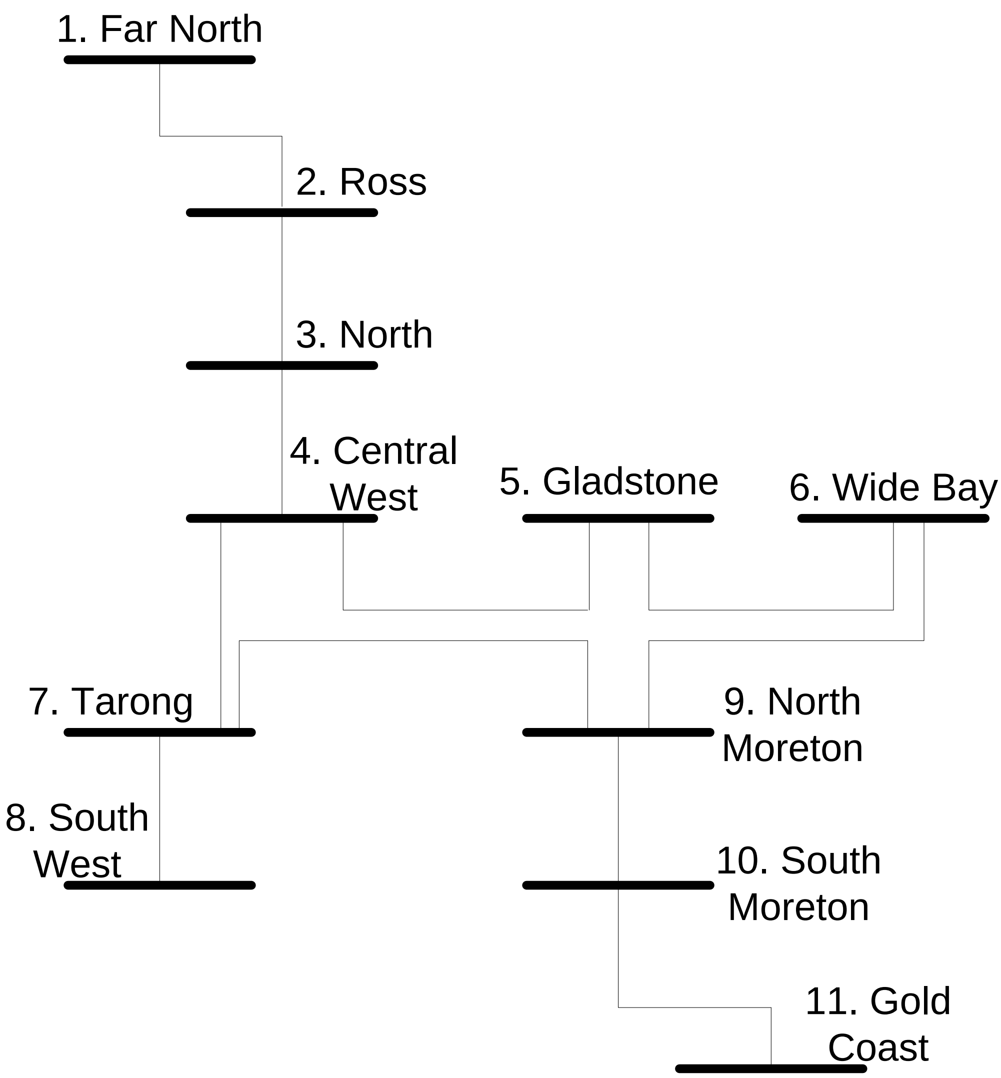


Figure 5-2 One Line Diagram of the Queensland Network

Table 5-1 Queensland System Information

Nodes	11
Generators	53
Overall Load Level (MW)	6861.6
Overall Generation Capacity (MW)	9248
Overall Transmission Capacity (MVA)	25600

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 5-2. 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 behaviors 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.

Table 5-2 6 Simulation Scenarios

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

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

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

5.8.2 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 5.3. As observed, the transmission investments are relatively small in the first three years, largely due to the sufficient transmission capacity at the beginning of the simulation. From Figure 5.3 we can also observe that, since the reliability is a constraint rather than an objective in our model, the EUE generally is increasing.

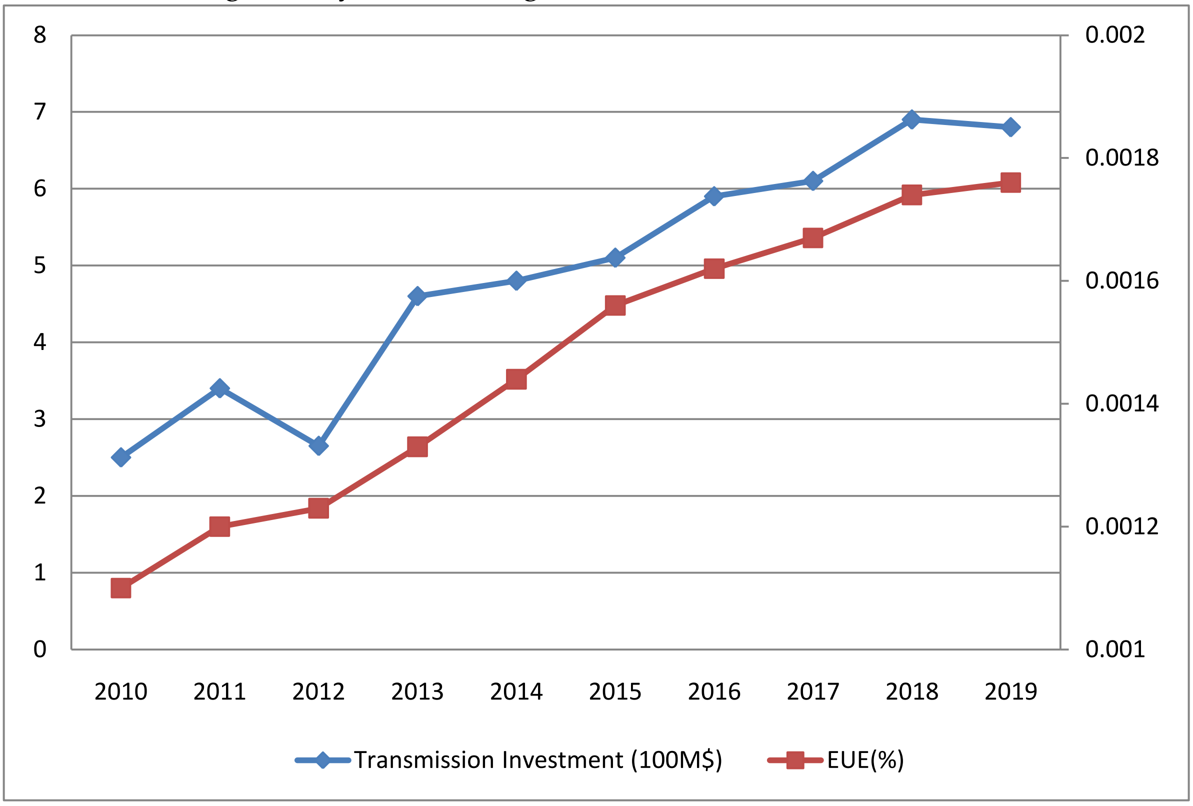


Figure 5-3 Transmission Investments of Base Case Scenario

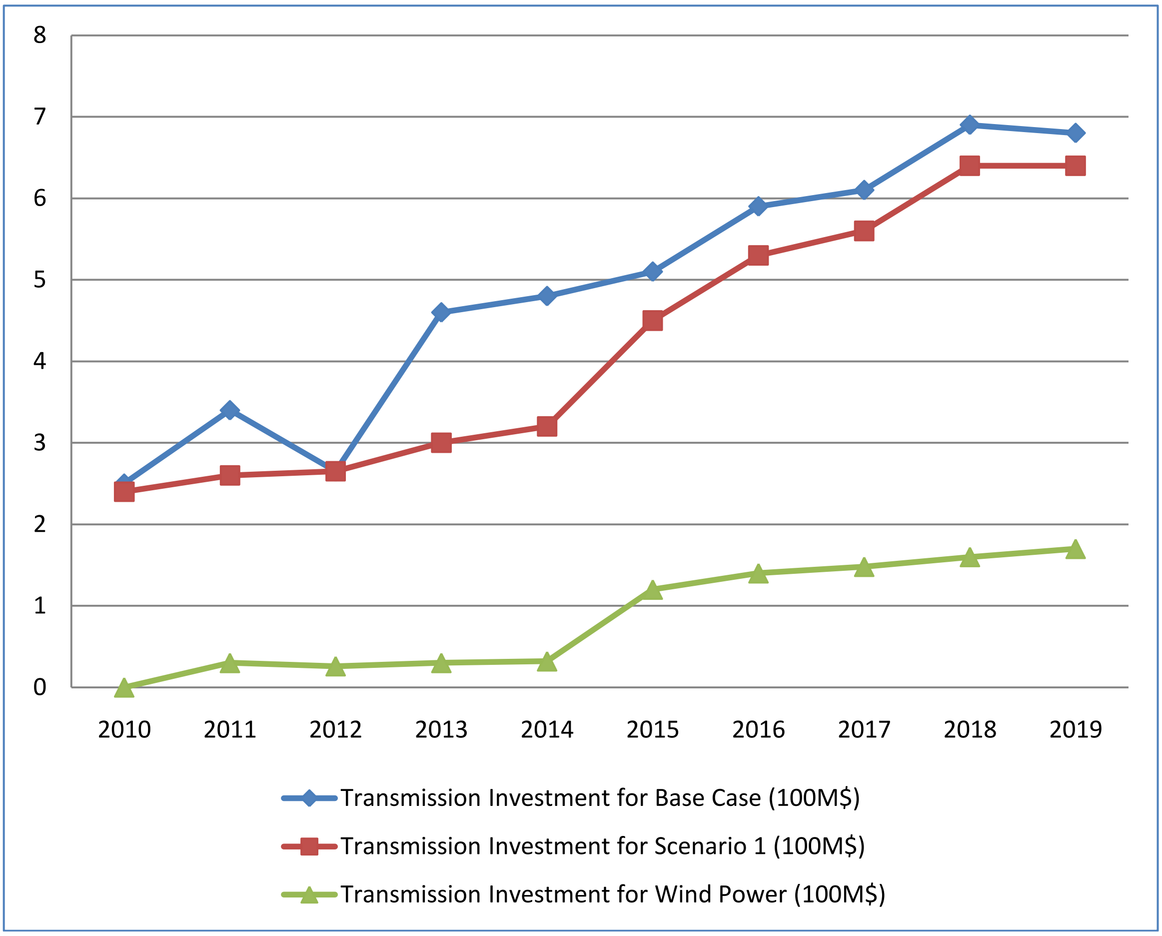


Figure 5-4 Transmission Investments of Scenario 1 (20% Wind Turbine with SIG)

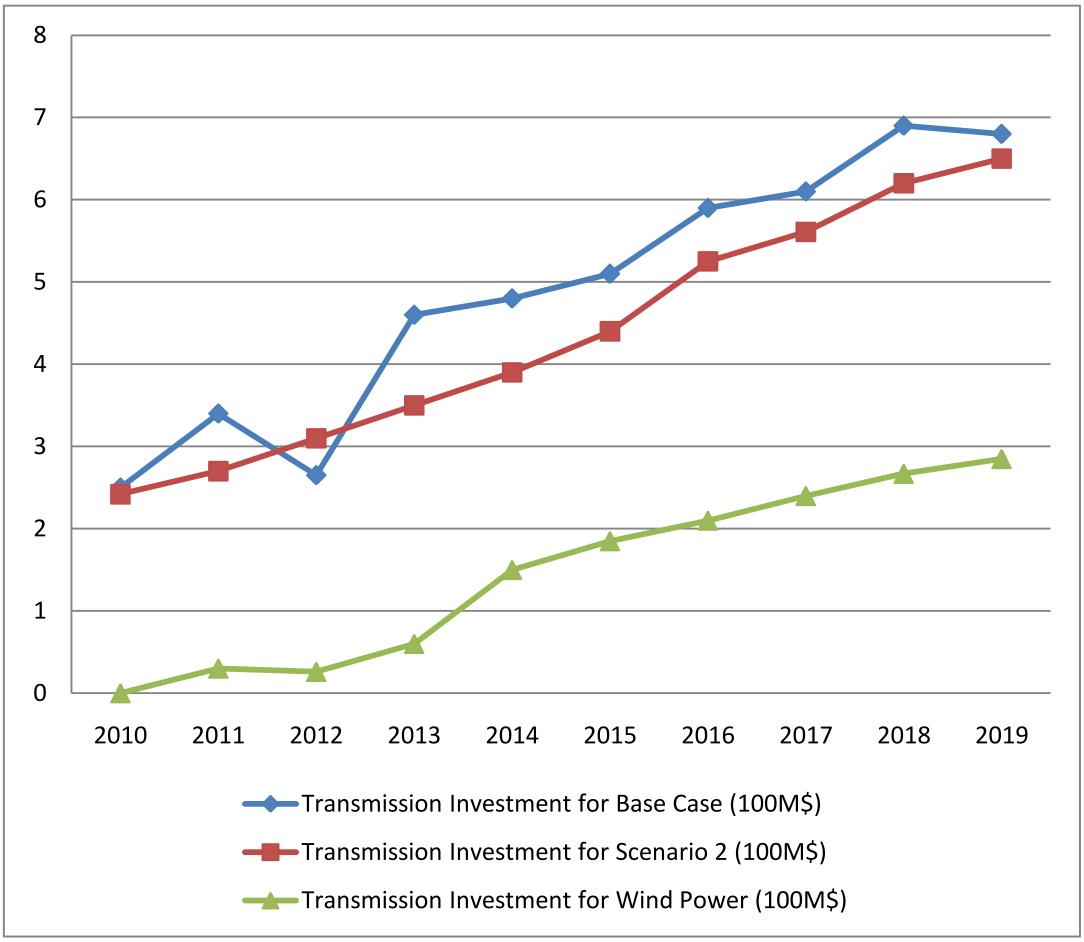


Figure 5-5 Transmission Investments of Scenario 2 (40% Wind Turbine with SIG)

The simulation results of scenario 1 are plotted in Figure 5.4. As observed, wind turbines do have a strong effect on transmission investment deferral in 2013 and 2014, because in the early stage of wind power penetration, it satisfies local demands and thus reduces transmission congestions in North Queensland. After 2014 however, 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 significantly from 2015. Moreover, the overall transmission investments from 2015 to 2019 are still lower than in the base case, but the reduced investments are much smaller compared to 2013-14. 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.

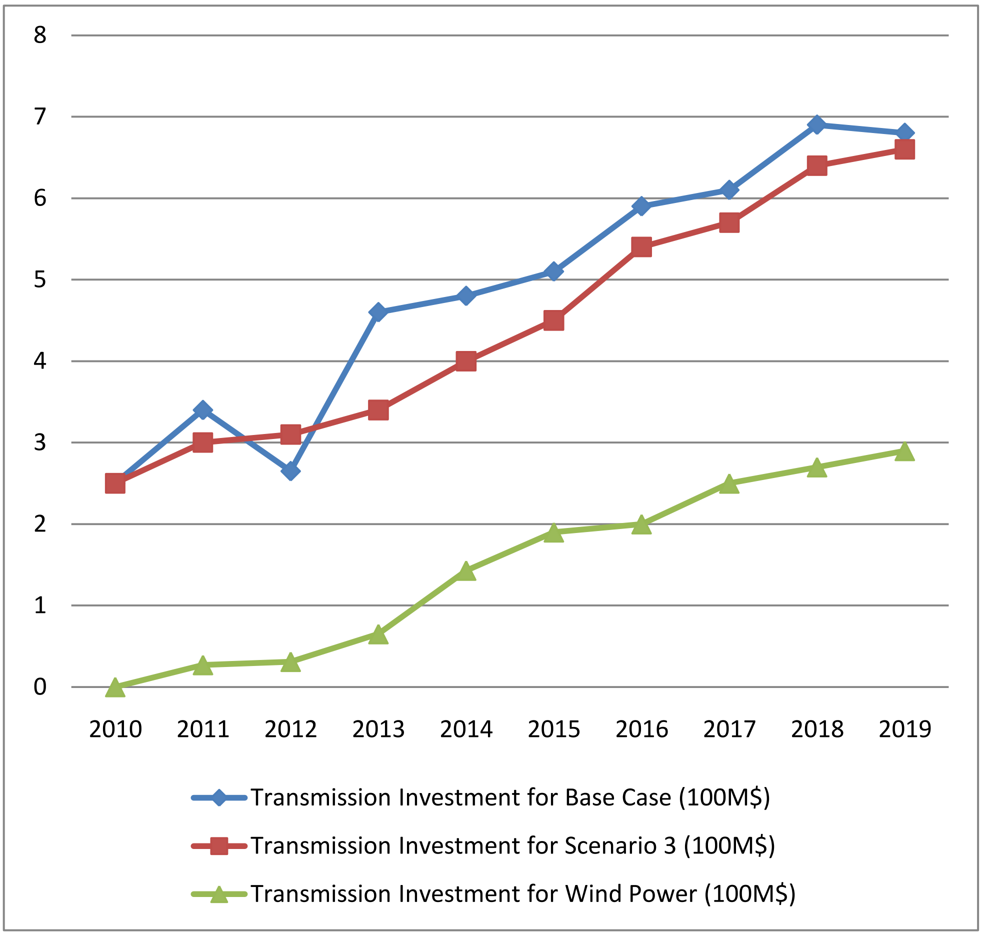


Figure 5-6 Transmission Investments of Scenario 3 (40% Wind Turbine with DFIG)

For scenarios 2 and 3, the transmission investment deferral effects are even smaller. As seen in Figure 5.5 and 5.6, investments caused by wind power start to increase in 2013. This is because, in scenarios 2 and 3, wind power increases at a higher speed and exceeds the local demands of Far North and Ross in 2012, two years earlier than scenario 1. 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.

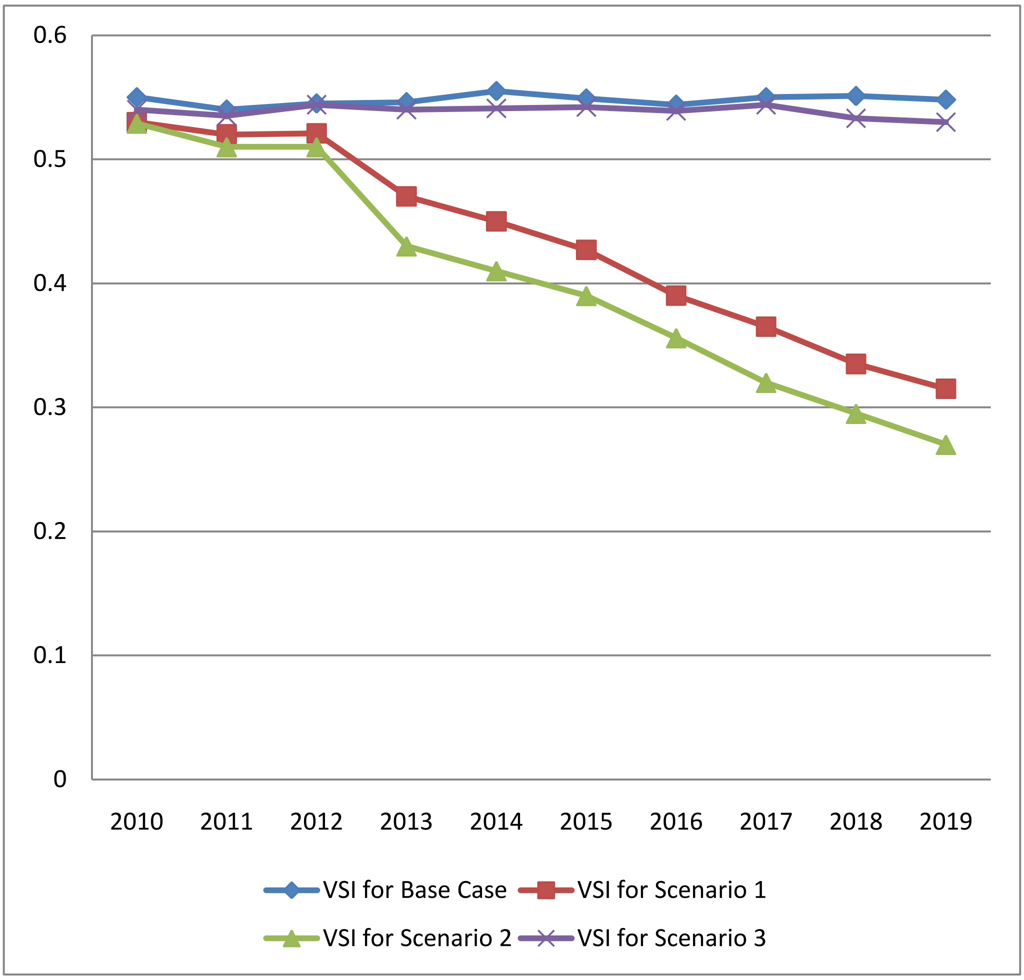


Figure 5-7 VSI for Wind Power Scenarios

The VSIs of three wind power scenarios are also plotted in Figure 5.7. As observed, in scenarios 1 and 2, the penetration of wind power significantly worsens voltage stability compared to the base case. This is because the wind turbines equipped with SIG cannot generate reactive power. The reactive power is usually drawn from local sources because the line loss of reactive power transmission is much greater than real power. Traditionally, coal fire plants are main reactive power sources. In scenarios 1 and 2 however, there are insufficient reactive power capacities in Far North and Ross areas since only wind turbines are added into these areas. On the other hand, in scenario 3 the voltage stability remains at a reasonable level, since the wind turbines with DFIG can supply reactive power if necessary. To maintain voltage stability, voltage support facilities, such as capacitor banks, must be installed in areas with high wind capacities. In practice, the transmission network operator is responsible for investing in voltage support facilities - the cost of voltage support is also considered as a part of transmission investment. Therefore, the wind turbine with DFIG is a better DG option since it can reduce the voltage support cost.

5.8.3 Solar PV Scenario

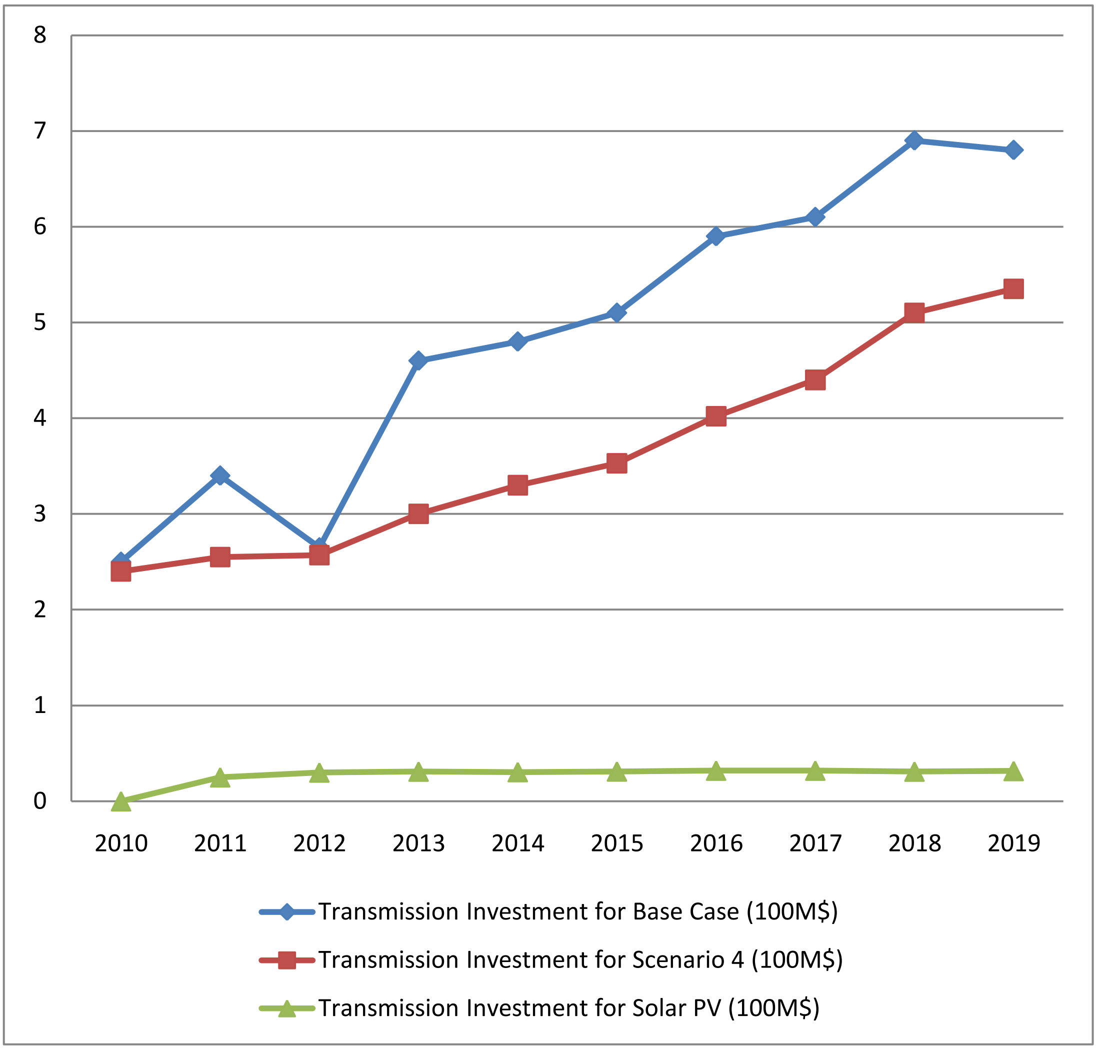


Figure 5-8 Transmission Investments of Scenario 4 (20% Solar PV)

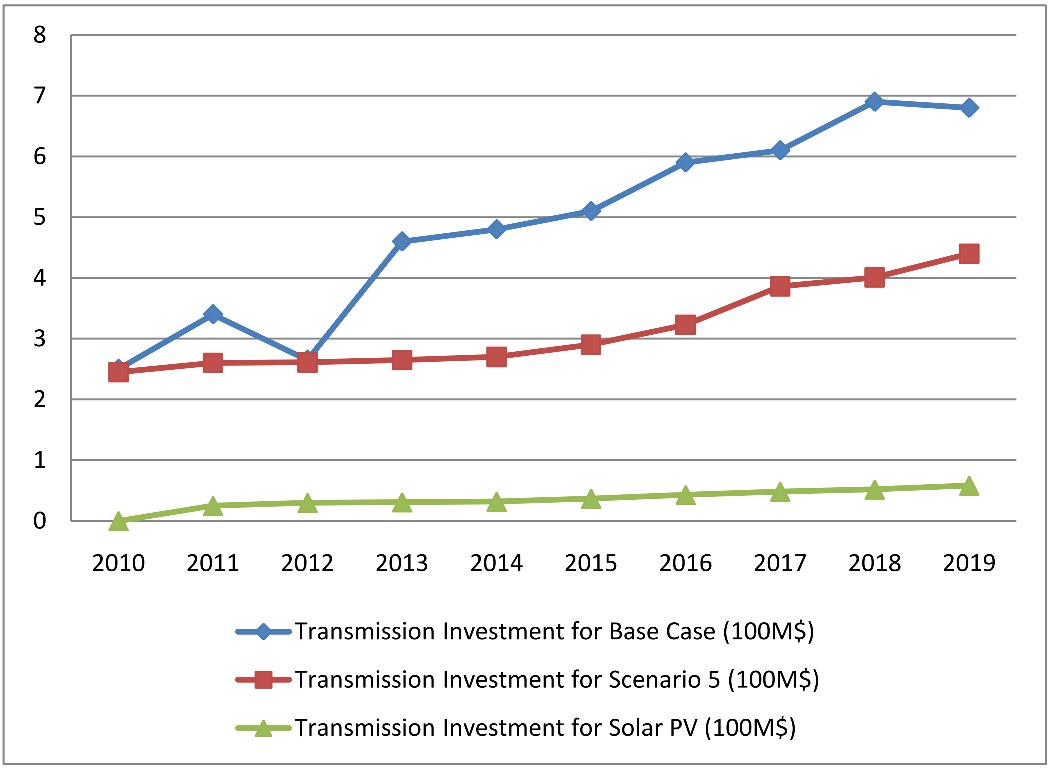


Figure 5-9 Transmission Investments of Scenario 5 (40% Solar PV)

In scenarios 4 and 5, we assume that solar PVs are evenly deployed in all 11 areas of the Queensland market. The transmission investments of two solar PV scenarios are illustrated in Figure 8 and 9. As observed, in both scenarios, solar PV has a strong effect in reducing transmission investments. Moreover, the investment for transferring solar power in scenario 4 is almost negligible. In scenario 5, the transmission investment for solar PV slightly increases, but is still small compared with the overall transmission investments. The reason behind these observations is that if solar PVs are spread evenly over the market, most of the solar power is therefore consumed by local demand. This mitigates network congestion and consequently reduces transmission investments. Compared with scenarios 1-3, we again confirm that the location of DG is an important factor in determining its impacts on transmission expansion.

The voltage stability indices (VSI) of scenarios 4 and 5 are also plotted in Figure 5.10. Solar PV panels worsen voltage stability since most solar PV panels are operated at a power factor of one. They therefore cannot act as reactive power sources. At the beginning stages (2010-2013), VSI drops slowly, mainly because solar PVs are distributed evenly in all nodes, in which reactive power capacities (coal fire plants) are still sufficient. From 2014 however, voltage stability has also worsened. Compared to scenarios 1 and 2, the negative effect of solar PV panels on voltage is smaller than wind turbines with SIG, since in scenarios 1 and 2, wind turbines are all placed in Far North and Ross, which do not have sufficient reactive power capacities. However, local voltage support is still necessary for solar PV, through the use of either capacitor banks or traditional fossil fuel generators.

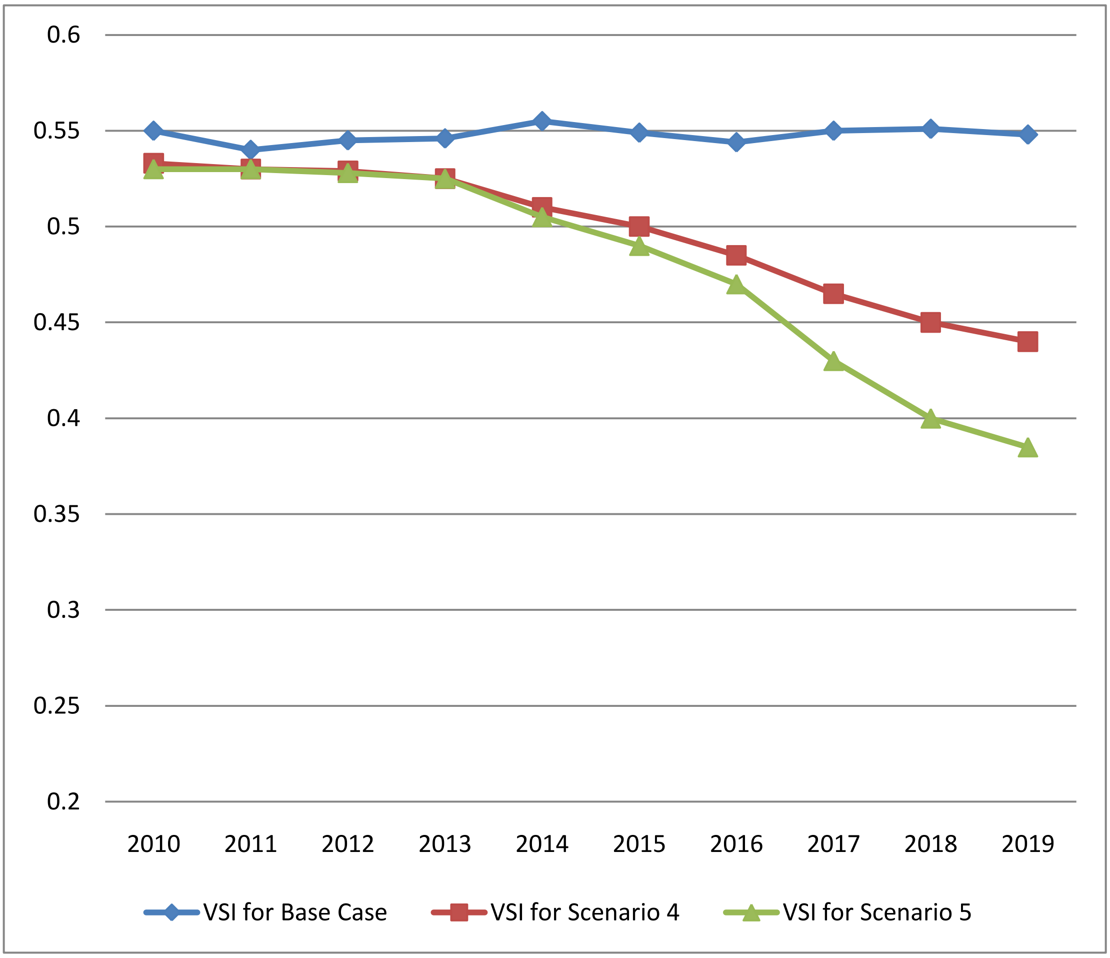


Figure 5-10 VSI for Solar PV Scenarios

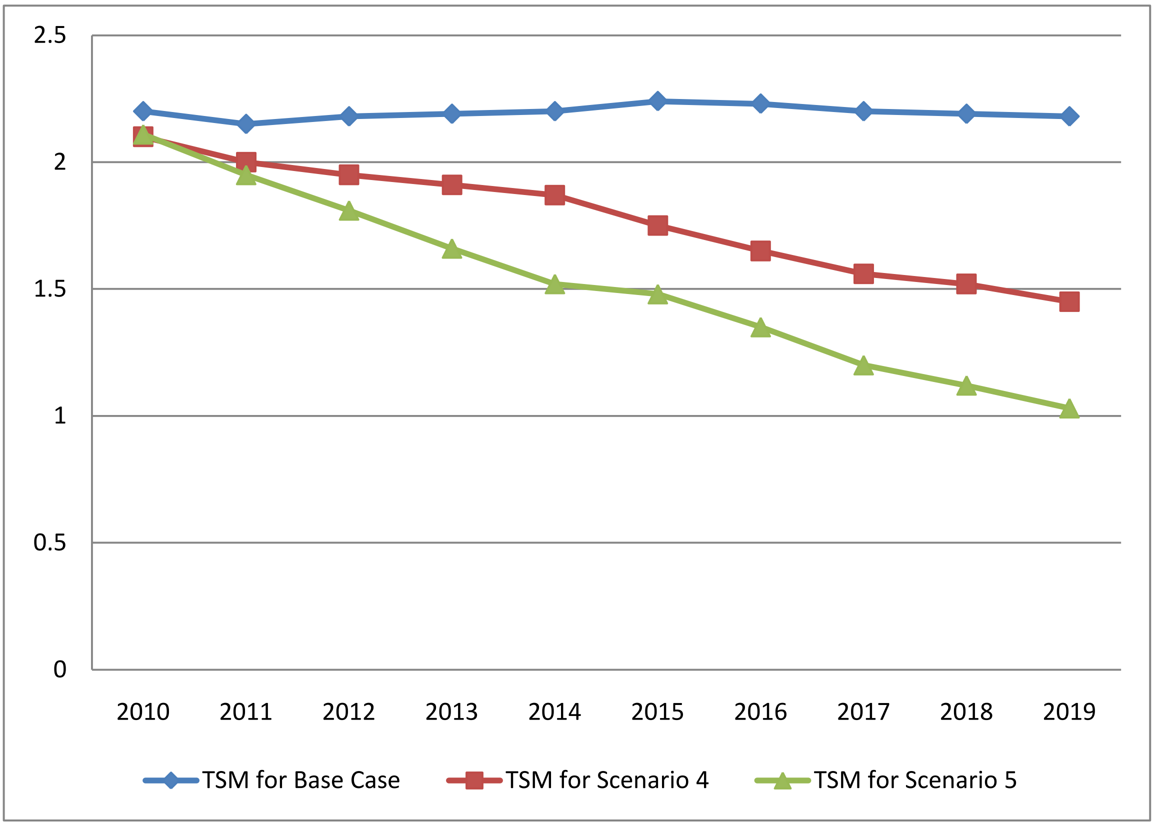


Figure 5-11 TSM for Scenario 5

The transient stability margin (TSM) for scenarios 4 and 5 is also depicted in Figure 5.11. As is shown, the 20% penetration of solar PV already has a clear negative effect on the transient stability. Moreover, after solar PV achieves a 40% penetration level, the TSM drops nearly below 1, which indicates that the transient stability of the system has reached a dangerous level. In other words, from the viewpoint of system security, a 40% penetration of solar PV may not be feasible. Transient security concerns can, thus, weaken the extent to which solar PV can reduce transmission investments.

Summarizing the discussions above, we have following observations:

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

5.9 CONCLUSION

In this paper, 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 electricity market in Australia to study the impacts of two DG technologies, wind turbine and solar PV panel.

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

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

6 Feed-in Tariffs for Commercial Solar Power Generation within Queensland

Renewable energy within Australia has stalled due to a number of issues, but primarily due to delays in establishing policies aimed at increasing its deployment. Whilst the Federal Government has settled on the policy measures to be introduced, being a Carbon Pollution Reduction Scheme (CPRS) and increasing the current Mandatory Renewable Energy Target (MRET) from 9,500 MW in 2010 to 45,000 MW in 2020, most of the legislation and associated regulations have been delayed, with the new Renewable Energy Target (RET) being passed in August and the CPRS legislation being finalised before being resubmitted to Parliament. This provides an air of uncertainty as to whether the measures can be ready for implementation within the timeframes provided.

Whilst Australia is considered a developed country, our uptake of renewable energy is similar to developing countries. Shafiei *et al.* noted that with renewable energy, developing countries simultaneously undertook three activities, being (Shafiei et al., 2009): -

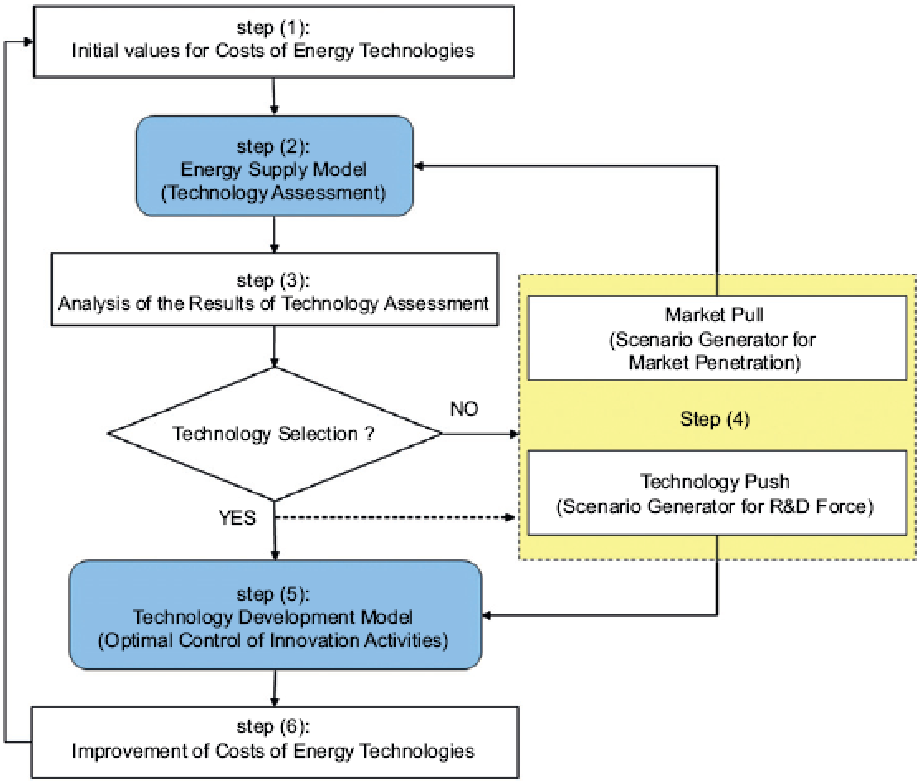
1. Investing in research and development on renewable energy technologies.
2. Absorbing knowledge from developed countries on the technologies under consideration, on the basis of following paths of existing deployment.
3. Absorbing knowledge on similar new technologies that may create competitive advantages.

The choice of which technology to adopt will be dependent upon the resources of the proposed location, however can be assessed using the decision path set out in Figure 6-1.

The Federal policies noted above need to be accompanied by State policies which will target those technologies or resources which are most abundant within their area.

Looking specifically at solar technologies a number of different policies have been proposed including tax rebates, cash rebates, government guaranteed loans, portfolio standards by technology or resource group as well as feed-in tariffs (Fthenakis et al., 2009a).

Figure 6-1 - Technology decision Path analysis



Source: (Shafiei et al., 2009)

The use of feed-in tariffs for PV electricity generation within Queensland was formally recognised in the ClimateSmart 2050 (Queensland Government, 2007) initiatives. However the announcement of this initiative was limited to domestic installations and has subsequently resulted in the current Queensland Government Solar Bonus Scheme. This scheme, which is now administered by the Office of Clean Energy, is limited to customers that consume less than 100 MWh per annum with the current feed-in tariff (which is based on the amount of surplus electricity that is exported to the grid) being $0.44 per kWh (Energex Limited, 2009).

Currently use of existing PV technology to meet peak demand requirements of many small to medium size businesses has been ignored. Many of these operate in flat-roofed structures which can easily be utilized to hold PV panels. The need to greatly expand the use of existing renewable technologies is important if Queensland is to meet their share of the proposed MRET.

This will create opportunities for both solar thermal generation as well as commercial roof-top PV applications. Policy needs to be implemented to act as a driver for the research, development and deployment of these technologies.

To meet the State's obligations under the proposed Renewable Energy Target (RET), it is important to recognise that some locations may have poor renewable energy resources whilst others may be plentiful. Planning should therefore reflect the need to harness those resources where they are both plentiful and cost effective (Dodd, 2008).

In the case of Queensland, the major renewable resources, such as bagasse and hydro have all been fully utilised. Whilst some opportunities for wind generation exist, they are limited. Solar generation provides the greatest opportunity as it is the one resource in great abundance within the State.

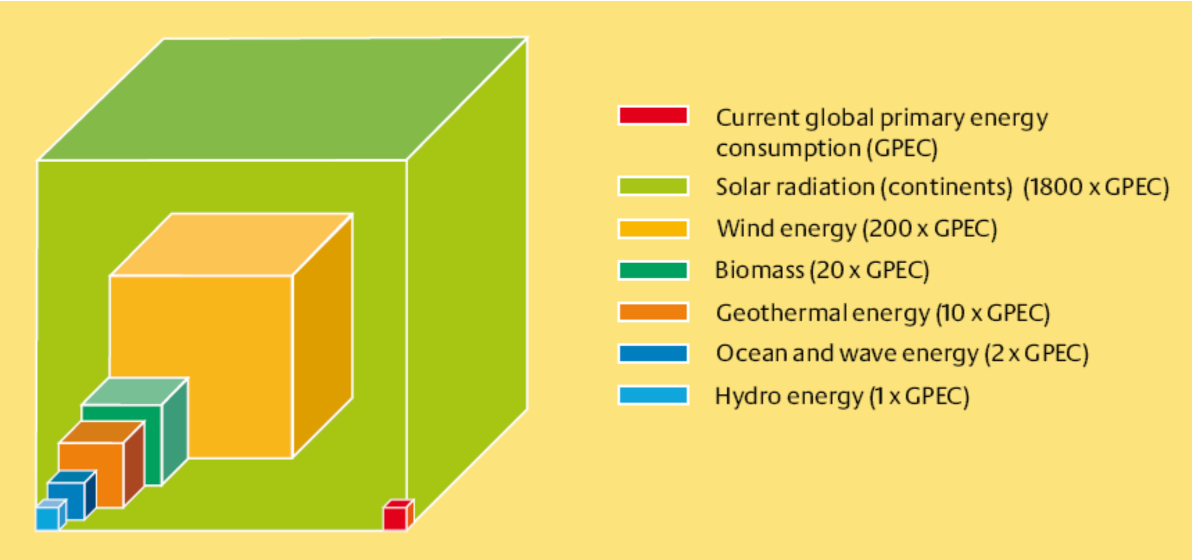
There are also opportunities for geothermal generation, however the technology is still to be proven and there are a number of transmission issues to be resolved.

6.1 RESOURCE AVAILABILITY

Solar energy is the renewable resource with the greatest potential to meet our energy needs, but like other intermittent resources will need reliable storage options to be developed if greater reliance is to be placed upon it.

Figure 6-2 shows the overall potential of solar power compared to other forms of renewable energy and current global energy consumption.

Figure 6-2 - renewable energy potential



Source: (IRENA, 2008)

The total land area required to replace all fossil fuels, including uranium, utilising solar technologies at an efficiency rate of 15% would be equal to the size of France (Marchie van Voorthuysen, 2008)

Like most renewable sources, the geographic location plays an important role in the actual amount of power that can be generated. A European report found that utilising only adequate roof area in settlement areas, that at mid-day on a cloudy autumn day, there is the potential to meet almost half of the demand (Krewitt, 2008). The areas that have the greatest potential within Australia can better be shown in Figure 6-3.

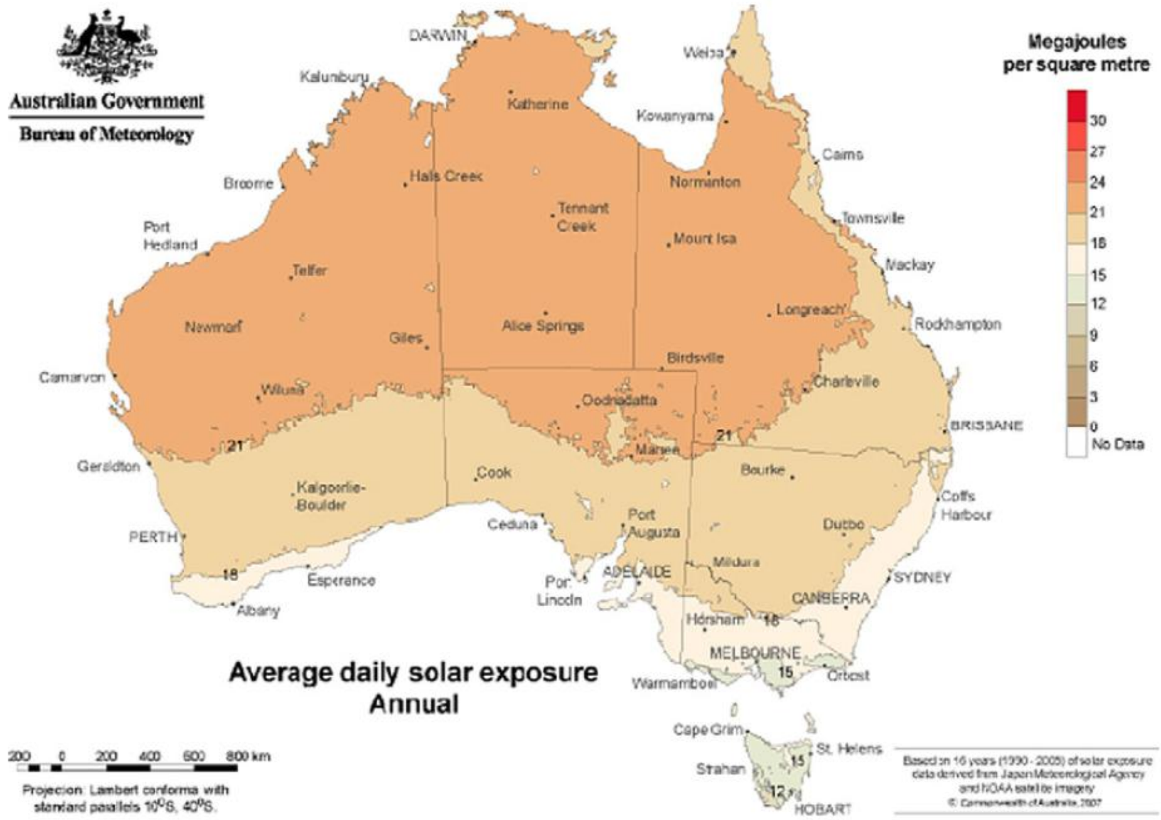


Figure 6-3 Australia's solar resources

Source: (Zahedi, 2008)

Looking specifically at Queensland, this indicates that those areas that are best suited to solar power are outside of the major urban areas (located on the coast), being where demand for electricity is high, however the levels received within the major population areas, particularly in the South East Queensland Region are still suitable for electricity generation. As noted above, there is the need to utilise available resources where they are found in abundance.

6.2 ENVIRONMENTAL ISSUES

From an environmental impact, photovoltaic cells have no environmental impact as they produce neither noise nor emissions. However, their production involves a high embedded energy cost and the use of a number of noxious chemicals. There are also a number of metals required for the production of PV cells including zinc, cadmium, indium, germanium and gallium (Fthenakis et al., 2009b). The availability of these metals over extended periods is an issue that requires further research.

Most large-scale solar plants are located in deserts or steppes where there is low population base, however they do require vast amounts of land which must be flattened and compacted making it susceptible to soil erosion (Kaltschmitt et al., 2007). This will also have possible implications for local plant and wildlife although this would be considered negligible.

Given the controlled environment in which they are produced, the overall environmental impact from chemical spills is considered low. The actual payback period for the embedded energy is approximately 3 – 4 years; however the life expectancy is in excess of 20 years (Twidell and Weir, 2006) with minimum maintenance requirements. In the short to medium term, the deployment of the technology is expected to be limited to roof-top PV systems, which will have minimal environmental impact.

6.3 Social Issues

The 'not in my backyard' syndrome or 'NIMBY' has been one of the major barriers to many planned renewable energy projects, particularly those proposing to use wind, biomass and municipal wastes as fuel sources. However, it does not only affect the renewable energy sector, with many proposed generating facilities utilising fossil fuels receiving the same attention.

The basis of this proposition is that members of society support the aims and objectives of a particular project or development, as long as it is not located in their immediate area.

It is those communities that have the greatest political and economic resources that are able to prevent unwanted development. In considering these developments the initial question that will be asked by the community is 'why is this development needed?' The value of the development to the community will extend past the value of the energy generated, creation of jobs, effect on electricity prices, sustainability of resources or localised control and will include external effects such as (Bergmann et al., 2006): -

- Projects must be aesthetically pleasing
- Renewable energy projects must have a low environmental impact
- Wildlife should not be harmed

When considering roof-top mounted PV systems, this is the one renewable energy source that already has community acceptance, local planning approval and will not create any public opposition as there is no impact on the external factors noted above.

6.4 POLICY MEASURES

When looking at policy measures, a distinction needs to be drawn between customer generators and independent power producers (Hughes and Bell, 2006). Customer generators can then be further broken down between domestic (household) and commercial (business) customers. Currently within Queensland the PV scheme has targeted only domestic customers, but with proposed portfolio legislation and the PV potential within the State, there is scope to review current policy. The potential of extending the current scheme to commercial customers and potentially independent power producers needs to be considered.

When considering regulations as policy measures, economists have classified them into two broad categories being 'command and control' or 'incentive-based' regulations. Incentive-based regulations, such as emission taxes or tradeable permits, will reduce with a performance improvement in the outcome or objective being sought. This may be compared to command and control regulations, such as emission permits which set maximum levels, with penalties payable for exceeding these limits.

As the purpose of the Government's current policy is to look at the promotion of renewable energy alternatives, incentive based regulations will be more beneficial as they would act as a stimulus to seek alternatives which will not incur the costs imposed by the regulators.

In the case studies undertaken by Gan *et al.*(2007) on policy measures and their implementation in Germany, Sweden, The Netherlands and the US it was noted that the US had lagged behind the others in developing a clear national policy as most of their policies and their implementation is undertaken at state and local level. The same can be said of the Australian position.

The Federal Government is currently implementing an expanded national Renewable Energy Target (RET), replacing those already legislated or proposed by the individual States, together with a proposed Carbon Pollution Reduction Scheme (CPRS). Within Queensland, whilst no portfolio scheme is currently in place, a 'clean energy' policy was adopted, with the 13% Gas Scheme, with current proposals to increase this to 18%.

Before looking at the US market, a positive example of policy action can be drawn from the German wind industry. The policy measures that were introduced included (Jacobson and Johnson, 2000): -

i. Subsidies introduced in 1989;

ii. Legislation effective from 1991 guaranteeing a relatively high (and fixed) price for grid supplied electricity; and
iii. The government ensured that sufficient land was allocated for use by wind turbines.

When the legislation was originally enacted, the electricity sector considered wind turbines as an experimental exercise, paying it little attention. This view changed once the market share of electricity generated by this source increased (to over 10% of market share), with the traditional sectors of the market lobbying the government to repeal the existing policy measures. As the industry grew, so did its contribution to the economy, particularly in employment growth in regional areas resulting, after much debate, in the government voting in 1997 to retain the existing policies (Jacobson and Johnson, 2000).

An interesting point that can be observed from the German (and French) feed-in tariff schemes was that the actual tariff paid was linked to the amount of generation from the site, with lower tariffs for more efficient sites. From an investor's viewpoint, total revenue was still greater than less efficient sites, resulting in an overall higher profit from the investment (Huber et al., 2007).

As the US markets are very similar to our own, we should be able to learn from their experiences. Deregulation in the US commenced in 1996 and within four years sixteen percent of generating capacity had been sold or transferred to unregulated entities (Menz, 2005). Whilst California has been one of the more active states in the renewable energy field, they were forced to pull back their policies due to escalating wholesale electricity prices caused by "a severe curtailment of generating capacity and a poorly designed deregulation policy that:

i. Forced all utilities to divest themselves of their generation assets;
ii. Capped electricity prices until all assets were divested; and
iii. Forced utilities to buy power on spot markets rather than with long term contracts." (Menz, 2005)

In the case of California all of the transmission and distribution of electricity remained regulated whilst the generation facilities were divested. In Queensland, the generation, transmission and distribution has remained predominately State owned, whilst they have divested themselves of the retail sales activities.

There is still the need for the introduction of long-term policy measures that promote renewable energy as well as more efficient energy use. Lund (2007) undertook a study of the IEA database and found over 30 different policies and measures in use that generally fell into one of the following five categories: -

i. Legislative and regulatory policies
ii. Research and technology development
iii. Fiscal measures
iv. Information dissemination and awareness raising
v. Other voluntary measures

The purpose of this paper is to focus on the legislative and regulatory policies available to promote commercial solar power within Queensland. The Government has already created a Solar Bonus Scheme (feed-in tariff) and an extension of this scheme to provide incentives to larger installations is seen as a natural policy progression to drive investment within this sector.

6.5 Feed-in Tariffs

Feed-in tariffs have been the major policy measure adopted in Europe to drive the deployment of renewable energy technologies. Currently twenty countries in Europe have feed-in tariffs for PV systems. Of this group, fourteen countries are using the tariff with additional policy measures such as net metering, renewable energy certificates, capital subsidies, grants or rebates (Campoccia et al., 2008).

In the European Union policy measures similar to Australia's RET were favoured, however many have been replaced with by feed-in tariffs due to the certainty of income to the investor and the ability to integrate them with other policy measures, such as capital subsidies, grants or rebates (Campoccia et al., 2008).

The utilisation of feed-in tariffs to solve some of these policy issues has been widely discussed, with a number of advantages and disadvantages being identified. The advantages include long-term return for investors, simple to implement and different technologies can have different tariff rates, whilst the disadvantages include the need for transparency and monitoring systems, may not be cost effective and they may not ensure that long term goals are met (Gan et al., 2007, Menz, 2005).

In addition to the benefit of the long-term return for investors, there is the associated benefit of guaranteed returns for financiers. Apart from internal funds, there is lower investment risk providing for lower cost of borrowed funds. This in turn will reduce overall costs and provide market incentives (Mendonça, 2007).

Huber *et al.* (2007)looked at the possibility of feed-in tariffs in Ireland in combination with a portfolio requirement for 2020, similar to that proposed within Australia. The design of their system provided for different tariffs for different technologies, with the tariffs decreasing on an annual basis for new contracts to discourage the postponement of investment decisions. The modelling concluded that the technology specific feed-in tariff resulted in the use of less mature technologies at a higher public cost in the early years, but when the portfolio target was due to be met (in 2020), there was more widespread use of the technology at a lower cumulative public cost than non-specific technology policy measures.

The German model has proven to be one of the most successful, with the current legislation having been in place since 2000. The legislation mandates that electricity from renewable generation has priority access to the grid and during this period electricity from renewable energy has increased from 37 TWh to 87 TWh in 2007, representing 14.2% of the gross electricity consumption (Langniß et al., 2009). Another reason for the success of the German model is the regular review and amendment of the legislation. Although the current model was enacted in 2000, it has been subsequently reviewed in 2004, 2006 and 2008 (Mendonça, 2007, Langniß et al., 2009). These reviews ensure that the incentives being offered will obtain the results required.

In Italy the feed-in tariff is paid for all electricity generated by the system, with an additional payment for any electricity exported to the grid (Campoccia et al., 2008).Greece has recently announced new PV feed-in tariffs, guaranteeing the tariff for 20 years and providing for the tariff rate to be indexed annually based on the inflation rate (Renewable Energy Focus, 2009b). Looking at the major proactive European countries, the current feed-in tariffs are set out in table 1.

Table 6-1 - European pv feed-in tariffs

Country	Description	Rate (€/kWh)	Rate ($AUD[16]/kWh)
France	Non-integrated PV	0.400	0.976
	Bonus for Building Integrated PV	0.150	0.366
Germany	Field installation	0.421	1.027
	Roof mounted ≤ 30 kW	0.545	1.329
	Roof mounted 30 – 100 kW	0.519	1.266
	Roof mounted > 100 kW	0.513	1.251
	Bonus for Façade integration	0.050	1.220
Italy	Field installation ≤ 3 kW	0.400	0.976

[16] Based on an exchange rate of one $AUD is equivalent to €0.41

	Field installation 3 – 20 kW Field installation > 20 kW Partially integrated ≤ 3 kW Partially integrated 3- 20 kW Partially integrated > 20 kW Building integrated ≤ 3 kW Building integrated 3 – 20 kW Building integrated > 20 kW	0.380 0.360 0.440 0.420 0.400 0.490 0.400 0.380	0.927 0.878 1.073 1.024 0.976 1.195 0.976 0.927
Spain	≤ 100 kW – first 25 years > 100 kW – first 25 years ≤ 100 kW – following years > 100 kW – following years (RAT – reference average tariff)	575% of RAT 460% of RAT 300% of RAT 240% of RAT	0.805[17] 0.644 0.420 0.336

Source: Adapted from (Campoccia et al., 2008)

As shown in Table 6-1, the rate of payment can vary for a number of reasons. Looking again at the German model, the payment is fixed for 20 years, but although reference has only been made to solar technology, other rates are payable for other renewable based generation. The payment is primarily derived based on technology cost and plant capacity (Langniß et al., 2009), which can be set out as follows: -

$$P_{tvi} = P_{Ti}(1-d_i)^{v-T} + k_i$$

In the above, P is revenue per kWh; t is the year of payment; T is the base year; v is the year that operations commenced; i is the type of renewable technology; k is the additional payment for innovation and d is the digression rate (Langniß et al., 2009).

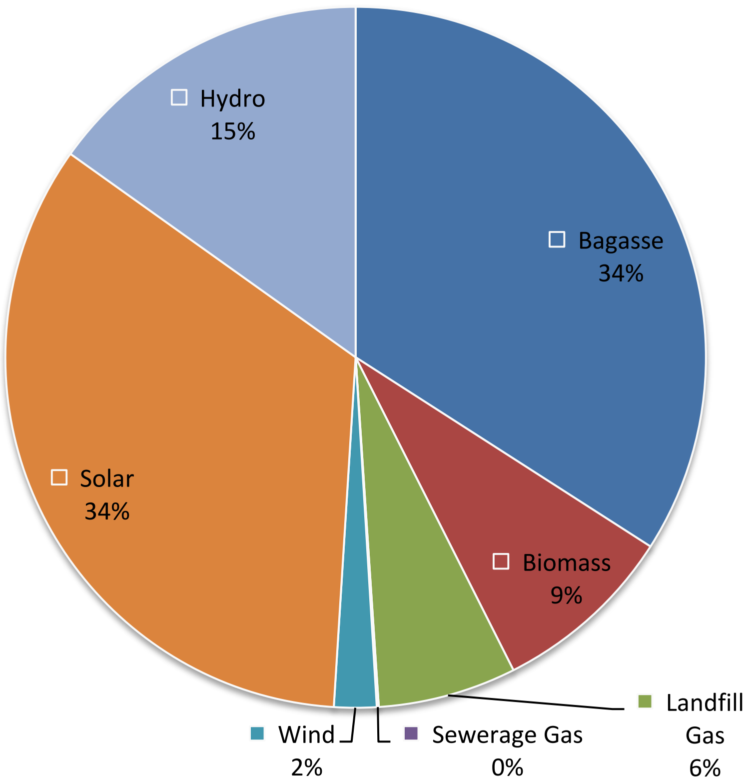
In the case of Italy, further promotion of PV systems has occurred with the Government integrating PV systems in public places, particularly adjacent to school

[17] The calculations in this section are based on a reference average tariff of $0.14

buildings where the 'shelters' have been used for vehicle and cycle covers (Aste et al., 2007).

Solar generation already receives some level of Government support through the current MRET scheme. Figure 6-4 highlights the fact that one third of the current REC's are generated through solar technology, however the majority of these relate to solar hot water systems (HWS). To provide some indication of the take-up of this technology, it is equivalent to the REC's generated by the sugar industry (bagasse) which was expected to be the major renewable energy contributor within the State when the legislation was enacted. The design options for the expanded RET have considered removing the eligibility of HWS, favouring technologies that generate rather than just displace electricity.

Figure 6-4 - Queensland rec's (2007)



Source: (Office of Renewable Energy Regulator, 2008)

With the introduction of the Solar Bonus Scheme, the contribution of solar is expected to increase. Australia is one of the few countries in the world to have adopted a net feed-in tariff, with the schemes currently in operation set out in Table 6-2. It is anticipated that whilst this scheme will promote the technology, the rate of uptake would be greater if the payment was based on gross electricity generated rather than the net amount exported to the grid.

Table 6-2 - Australian feed-in tariff schemes

State/Territory	Net/Gross	Limitations	Rate ($/kWh)
Queensland	Net	< 10kVA single phase < 30kVA three phase	44c/kWh
South Australia	Net	< 10kVA single phase < 30kVA three phase	44c/kWh
Victoria	Net	<=5kW (from 2009)	60c/kWh (Credit only)
New south Wales	Net	<=10kW	60c/kWh
Tasmania	Net	TBA	20c/kWh
Western Australia	Net	TBA	TBA – commence 1st July 2010
ACT	Gross	Up to 10kW Up to 30kW	50.05c/kWh 40.04c/kWh
Northern Territory (Applies to Alice Springs Solar Cities Project only)	Gross		45c/kWh

Source: Adapted from (The Senate Standing Committee on Environment Communication and the Arts, 2008, Renewable Energy Focus, 2009a)

In relation to the ACT, they are also proposing a feed-in tariff for large-scale generation, with details to be released in June, with a proposed commencement date of July 1, 2009 (Renewable Energy Focus, 2009a).

6.6 Gross v Net

The gross feed-in tariff is considered the more appropriate method as many external costs of generation, such as network augmentation benefits, peak-pricing benefits and reduced transmission losses are applicable to every unit of electricity, not just those exported to the grid (Access Economics, 2008).

Feed-in tariffs were also considered by The Garnaut Climate Change Review (Garnaut, 2008), which also favoured the gross schemes. The report stated that quantification of external costs may result in a lower cost than is currently paid, however this must be weighed up with the incentive to drive deployment of the technology.

The cost of the tariff is generally apportioned over all users, with the German system having estimated that the total cost to consumers amounted to 3% of the total retail cost. The cost is passed on as a levy to residential and commercial consumers only, with large industry and railways being exempt (Alternative Technology Association, Undated).

The network augmentation benefits may be substantial, with Access Economics (2008) modelling suggesting that 3,000 MW of solar capacity could defer approximately 500 MW of other generation capacity. In addition to the network benefits, the delay will provide opportunities for other renewable or emission neutral technologies that are not currently commercially available to mature and become available for deployment.

It was noted earlier that one of the major advantages of the gross schemes are that they provide an income stream which can be estimated with some degree of certainty. Given the current cost of PV systems, this provides some level of comfort to financiers, with finance almost certainly being required for any commercial system.

The main argument in support of the net schemes is that they promote energy efficiency. The more efficient the customer, the more electricity exported to the grid and hence greater revenue. From an economic viewpoint, the incentive to consume less should come through the retail electricity tariff, which will affect all consumers, not just those exporting their net generation (The Senate Standing Committee on Environment Communication and the Arts, 2008).

6.7 Technology Availability

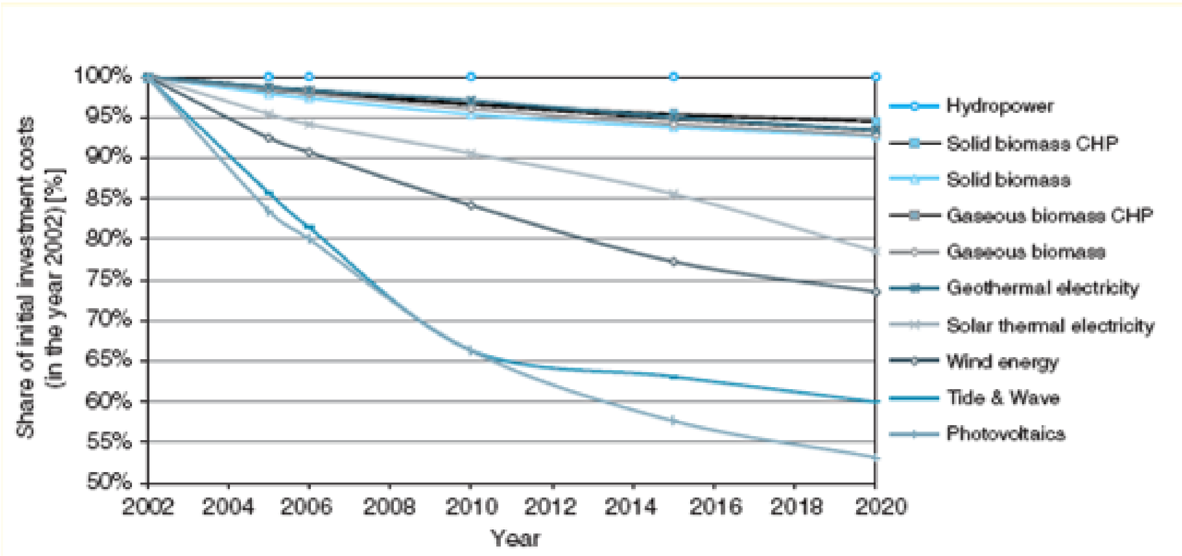
A recent Federal Government Research Paper (Needham, 2008) identified that long-term potential for commercial PV systems existed should costs reduce. This comment was limited to roof-top systems, with the belief that off-roof systems would not be competitive for another twenty years and therefore outside current proposed portfolio targets.

This Research Paper (Needham, 2008) also identified that policy measures such as subsidies and level of feed-in tariffs could significantly increase the rate of uptake of this technology and its contribution to the National Electricity Markets (NEM).

Large-scale deployment will need to see the introduction of solar thermal plants, with three technologies currently considered mature, being parabolic troughs, solar towers and dish-sterling systems (Al-Soud and Hrayshat, 2009).

It is the policy measure selected by the government that will determine the extent of the innovation effect on the market. The greater the driver for alternative energy products, the greater the movement in the production frontier curve. Estimates have been made in relation to those technologies that are either ready or near ready for commercial deployment.

Figure 6-5 - Renewable energy learning curves



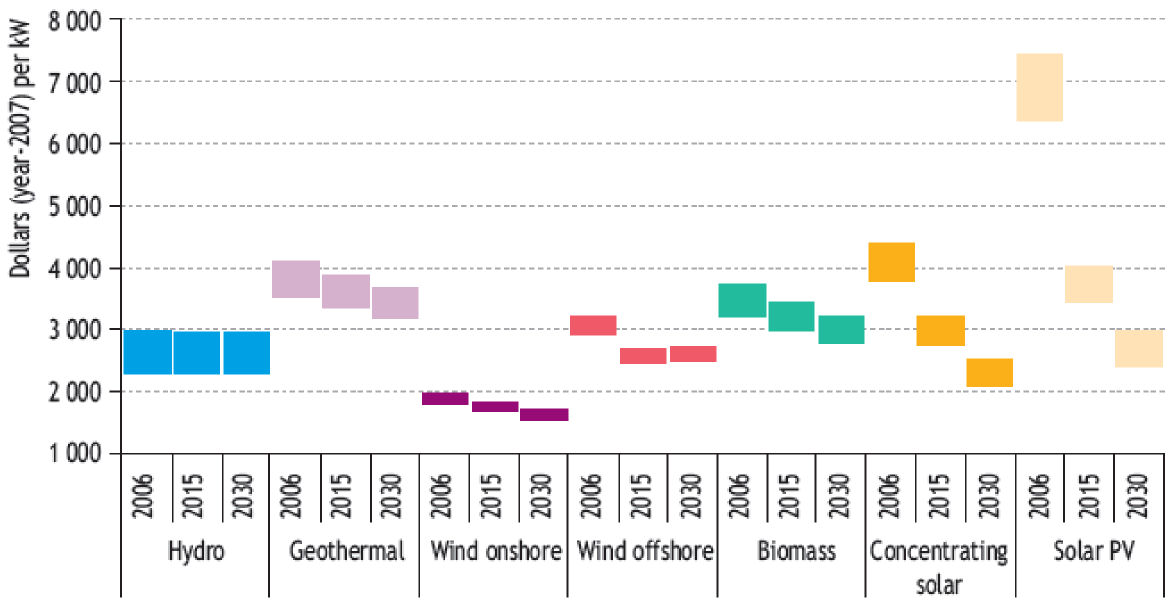
Source: (Walz, 2006)

Figure 6-5 shows the potential future savings expected to be achieved through innovation and the ability to capitalise on learning effects and economies of scale. As expected, this indicates that those technologies that are near or at the commercialisation stage of their development have the least amount of scope for future cost savings.

The above assessment indicates that the greatest cost reductions will be made in the photovoltaic area, with substantial savings achievable in geothermal, solar thermal, wind, tide and wave technologies (Walz, 2006). These cost savings together with price increases in the conventional energy generation technologies (due to the introduction of the CPRS) should act as a driver for further development and deployment of PV systems.

This has further been confirmed in a recent IEA Report as indicated in Figure 6-6, which shows that the cost of solar PV will reduce by over 50% over the next 20 years.

Figure 6-6 - Investment costs of renewable technologies



Source: (IEA, 2008)

The extent of the savings that can be achieved through innovation will have a direct impact on whether there will be any significant ongoing increase in employment, as the greater the innovation savings the greater the demand for the product and therefore the greater the demand for labour. This will result in an economic stimulus, irrespective of whether systems are locally manufactured or just installed and maintained.

In addition, solar power stations located in coastal areas can also be combined with desalination plants (Marchie van Voorthuysen, 2008), creating useable water rather than utilising what is now becoming a scarce resource like tradition fossil fuel based plants.

6.8 CONCLUSION

Whilst the need for further policy measures to help drive the deployment of solar and PV technologies is accepted and should be the subject of further discussion, there are also a number of other issues that also need to be considered including (Menz, 2005): -

- Relative cost of conventional and solar energy sources
- Institutional and regulatory environment for the electricity sector
- Other public policy (i.e. environmental laws)
- Technical issues (i.e. transmission of renewable energy)
- Consumer access to and awareness of green electricity products
- Stakeholders (e.g. industry associations)

Further research and public debate is needed to further progress the deployment of this technology which will result in meeting GHG emission reductions and other climate change objectives.

7 Research Group Profile

Prof. John Foster
Project Leader: School of Economics
Professor Foster's research interests lie in the following fields; modelling the macroeconomics as a complex adaptive system, the application of self organisation theory to statistical and economical modelling in the presence of structural change. As well as modelling, the diffusion of innovations with special reference to the emergence of low carbon emission power generation technologies and the empirics of evolutionary economic growth with special reference to the role of energy generation and distribution systems. More recently John has been involved in modelling the impact of climate change on the entire economy with specific reference to the power generation sector.

Dr Liam Wagner, Research Fellow: School of Economics
Liam Wagner is a Research Fellow at the University of Queensland. He was awarded his PhD thesis in 2008 in mathematics at the University of Queensland examining a variety of topics in mathematical physics. He has previously worked as a Trading Analyst in the energy industry, providing advice on risk, while also trading an Open Cycle Gas Turbine power station. While in the energy industry Liam also performed analysis on the impending carbon economy and its effects on electricity generators. His current research interests include analysis of the National Emissions Trading Scheme and the deployment of Distributed Generation.

Dr Phillip Wild, Research Fellow: School of Economics
Dr Phillip Wild will be conducting research at the University of Queensland and will bring agent based modelling capability to projects 1 'Control Methodologies of Distributed Generation' and project 2 'Market and Economic Modelling of the impacts of Distributed

Generation'. Phillip's previously research experience has been in the areas of econometric modelling of National Energy Market (NEM) spot price and load time series data and 'levelised cost' and 'agent based' modelling of the NEM. Dr Wild has a PhD from the University of Queensland specializing in the field of macro-economic modelling.

Dr Junhua Zhao, Research Fellow: School of Economics

Dr Zhao is a Research Fellow with the School of Economics and brings extensive experience in transmission and distribution system modelling. During his PhD studies Dr Zhao examine transmission problems in the National Electricity Market in the School of Information Technology and Electrical Engineering. Formally Dr Zhao was an analyst with Suncorp Banking on the quantitative analysis desk.

Mr Craig Froome, Research Officer and PhD student: School of Chemical Engineering

Craig has extensive consulting experience and has undertaken a number of projects looking at renewable energy scenarios including the preparation of a discussion paper, *SEQ Regional Study of Renewable Energy* on behalf of the Queensland Department of Infrastructure and Planning. He has recently been appointed to The University of Queensland's *Renewable Energy Technical Advisory Committee*, which will look at renewable energy projects that may be implemented within the University's campuses for the purposes of not only energy generation, but looking at research and teaching opportunities.

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