CSIRO Intelligent Grid Cluster

End of Year Final Report

August 2009

Authors

Prof. John Foster,
Dr Liam Wagner,
Dr Phil Wild,
Dr Junhua Zhao,
Dr Lucas Skoufa.
Mr Craig Froome.

Table of Contents

List of Tables

List of Figures

1 Introduction

In the first year of the P2 project, the emphasis has been on building reliable modelling platforms upon which the impacts of distributed generation can be clearly understood now and in the future. In this report, we shall review our progress in developing appropriate methodologies. At the present time, policymakers seem to be unclear about the repercussions of any major shift towards distributed energy generation. There are, for example, clear indications of a 'business as usual' outlook amongst some policymakers. For example, in New South Wales, plans are afoot to spend large amounts of money in upgrading existing transmission networks on the presumption that centralised, coal fired power generation will continue to dominate for a number of decades to come. There appears to have been no serious consideration of the implications of the provision of extensive distributed generation over the coming decades. In particular, there is little or no indication that these decades will be a transition period and that such a transition will have to be managed in a phased manner. The emphasis in our modelling will be to offer explicit guidance as to how this transition can be managed best using sound economic principles.

In Section 2 we discuss methodologies to compare the costs of different generation technologies in an accurate manner. This has been done badly in the past so work of this kind is essential if correct policy decisions are to be made. We discuss what the true costs of different types of power generation actually are, taking all costs into consideration, including opportunity costs. We find that many studies of comparative costs have been incomplete, particularly when comparing costs decades into the future. We adopt the well tried 'real options approach' to better understand how the future can be dealt with in transitional conditions. In Section 3 we outline some of the key principles that should be applied when new technologies, such as solar PV and solar thermal are being developed at a significant rate. There are some quite general trends in relation to falling unit costs that all innovation processes offer – these technologies are no exception. However these falling cost curves present some policy dilemmas in the phase of transition from one technology to another.

Another key cost that has to be taken account in all distributed generation modelling exercises is the future cost of carbon. In Section 4 we discuss a methodology for obtaining a forward carbon curve that can be used to obtain carbon price estimates for modelling purposes.

Another key issue, dealt with in Section 5 in comparing generation technologies is the risk involved. Risks also have to be quantified when comparisons are being made. For example, insufficient attention was given to risk in the early stages of investment in nuclear power in the 1950s and 1960s. Also, many cost evaluations of coal generation neglect the social and environmental risks involved.

In addition to 'micro' issues concerning costing, there are systemic 'macro' issues that need to be investigated to provide guidance to policymakers, particularly in managing the transition to distributed energy systems. The general issues involved are quite well known and have been researched overseas. What we are doing is looking specifically at Australia which is unique in a number of respects and, as such, requires the construction of specific models. We have developed two key modelling strategies. Using the PLEXOS platform (see Section 10), we are investigating the impacts upon the NEM grid of increasing the amount of distributed energy. The novel methodology that we have developed shows what the impacts are across the whole NEM system. We have provided an example of the kind of simulation that can be generated by such modelling and it is clear that it is a very original and powerful tool. Our other modelling strategy (See Section 8) involves a purpose built model of the NEM market designed to examine what the impacts of different carbon price scenarios will be on the viability of different power generation units supplying the grid. For each scenario, different assumptions can be made about the provision of distributed energy generation of different kinds. Using this methodology it is possible to accurately assess which existing power stations remain economic and which don't in a transitional state with carbon trading. To illustrate how this modelling strategy works, we have reported our baseline case.

The preliminary simulations using both modelling methodologies show clearly that we are have a very powerful set of tools for policymakers interested in introducing increasing amounts of distributed energy generation. Later in the project, we shall connect these two modelling methodologies in several ways to allow for interactive simulations. Also, it is hoped that some connection will be forged in the third year of the project with the P4 model to offer an unrivalled set of simulation tools for policymakers to use.

An important issue that is being researched in Project 4 is the extent to which investments in distributed generation will result in the deferral of very expensive investments in transmission infrastructure. We would like, at a later stage, to be able to amend our models to allow for this effect. In Section 9, we outline a methodology to do this. We intend to collaborate with Project 4 researchers in this area.

When attempting to get a clear idea of the costs of distributed generation, it is not sufficient to just compare fixed and variable costs. There are many problems in interfacing with existing power generation, transmission and distribution systems which have all been set up with different priorities in mind. When we are considering small PV units on residential roofs, net inputs into the grid are minor and relatively unproblematic. But the significant shifts in power generation will only come with the installation of PV on commercial roofs (and car parks) which can accommodate 1MW systems. If, for example, all supermarkets in a city the size of Brisbane installed such systems, 100MW could be generated. This does pose possible problems for the grid that need to be researched.

To this end, we have initiated a major project at UQ which is currently close to formal approval: the installation of a new 1.14 MW solar PV generation facility on the multi-storey car park roofs (see Section 7). This will be an ideal case study because such a facility is roughly the size of a typical unit on a commercial roof site, such as a supermarket or a warehouse. From an economic perspective, it is our view that commercial applications, such as these, are superior to small residential applications in a number of respects. Because of its potential to test out PV grid integration, the UQ project has already generated considerable interest amongst both retailers and generators in Queensland and we are now involved in a sequence of workshops that commenced in July with a range of stakeholders. These have been organised by Craig Froome, who is a member of our research group. In Section … we also discuss some of the installation issues faced in adapting the internal UQ grid for the inclusion of a PV system. This will provide valuable cost information to commercial and governmental organisations considering the installation of a PV system of comparable size. In Section 7 we report on the work we have done on the transmission grid more widely, both with regard to the stability issues associated with a varying power generation source such as PV and on the potential savings on transmission investment deferrals because of investment in distributed generation that reduces peak load.

It is somewhat premature to come to any firm conclusions about the economics of distributed energy at this stage. However, there are strong indications that commercial scale PV installations in urban areas and solar thermal installations in rural locations, supplying small towns, mine sites and sites adjacent to existing power stations all seem to make good economic sense in a world of carbon trading. Although, wind and hydro are not generally classified as distributed power generation, it is necessary to take them into account in any simulations of the provision of distributed energy into the future since they have implications for the operation of the grid, particularly in locations such as Tasmania and Victoria. The models show that it is not sensible to look on distributed generation in isolation – it has to be dealt with a part of a portfolio of renewable energy initiatives. Furthermore, decisions made in integrating distributed generation with existing centralised power generation now and in the near future are not the same decisions made concerning the mix of low carbon generation systems two or three decades hence when much of the existing coal-fired capacity has been removed or come to the end of its productive life.

In the transition to low carbon generation, making the distribution network smarter and user systems smarter will be very important. Although we know that the efficiency gains of smarter grids are likely to be substantial, the economic costs and benefits are tricky to calculate. Even though individual cases can be assessed quite easily, once the product costs, installation costs, etc, are arrived at, the macro position is difficult to assess. Also, there are a host of regulatory and safety considerations to be dealt with that have large implications for the economics. But we do note that the cost of smart meters is continuing to fall dramatically and that in some jurisdictions, such as Victoria, a policy decision to install them has already been made. The cost involved in this kind of initiative is blurred by the fact that much of the metering in Australia is very old and needs to be replaced in any event. We have not commenced research in this difficult area yet because we lack reliable data to do so. However, it is possible to make some realistic assumptions about it on the demand side in our models. Future research will be necessary to obtain a firmer understanding of the economics of making both distribution and demand smarter. In this regard, Victoria is a very useful case to investigate over the coming years.

2 Forecasting the future unit costs of distributed energy

In addition to concerns about comparing costs in an accurate way, we also have to face the fact that the unit costs of different technologies vary quite significantly over time. Thus, levelised future costs may be significantly different to current costs. This introduces some important policy issues that have to be dealt with. Here we are most interested in the unit cost of PV since it is likely to be the main distributed energy generation technology installed in urban areas and, because it is a demand reduction technology, not requiring transmission and distribution systems for supply flow, it is likely to become viable in the near future. It will be very important that policymakers take steps to optimise the speed and extent of uptake of certain kinds of PV in the next five years (van Benthem et al., 2008, van den Heuvel and van den Bergh, 2009)

2.1 THE DIFFUSION OF PHOTO-VOLTAICS

A key issue in the assessment of the economic viability of solar photovoltaic energy supply is the trajectory of future cost per kWh (van Benthem et al., 2008). All new technologies follow S-shaped diffusion curves that can usually be tracked by a nonlinear logistic or a Gompertz function. As the volume of adoption rises, unit costs fall, usually log linearly (exponential) to a minimum level. This is due to economies of scale in production, the accumulation of experience in production and marketing, the introduction of incremental innovations and growth in demand for products using the technology. There is a well developed literature on forecasting future diffusion paths based on observations in the early phase of the diffusion curve (see, for example, (Greaker and Sagen, 2006) for a general discussion of the methodology and (Bhandari and Stadler, 2009) for a PV diffusion application). Similarly, forecasts of future unit costs have been forecast using early phase cost data (Alberth, 2008) for a recent study of several cases, including solar.

Universally, unit costs fall significantly but this introduces something of a dilemma for a potential buyer. When is the best time to buy? When production volume is small and unit price is high only ‘enthusiasts’ tend to buy, either for ethical reasons or to impress others as an affluent ‘first mover’ that can afford the high price. So, if the development of a technology is widely viewed as a social or environmental priority, it is vital that, in the early developmental phase, significant subsidies are offered both to encourage purchase of product using the technology and to make producers feel secure enough to invest in expanding production. There is no ‘futures market’ in technologies, so both buyers and sellers have to be compensated for taking their respective risks in what is an uncertain context.

In Figure 1, we have an example of the US Department of Energy forecast of the unit costs of electricity generated by solar in comparison with the wholesale and consumer unit costs of electricity generated by other means in 2007. As is sensible in such studies, ranges rather than point estimates are reported but it is clear that solar becomes viable by about 2012 onwards. This chart also forecasts installed capacity. This is depicted as growing approximately exponentially and this is consistent with the technology remaining in the pre-inflexion growth phase of an S-shaped diffusion curve up to 2020. This is, of course is somewhat heroic given that it is projected out from such small capacity figures up to 2005. However, again, a range is specified rather than one line and there is little doubt that solar technologies will remain in their pre-inflexion range up to 2020. Further diffusion will occur after 2020 as solar technology approaches its mature phase. Typical of this phase, incremental innovations will increase the efficiencies of distributed PV collectors very significantly and unit costs will come to strongly out-perform coal-based power station generated electricity in terms of consumer price. We know that the unit price of coal generated electricity has shown little historical decline in recent years, consistent with it being a mature technology. And, of course, the introduction of a carbon price or a tax would shift the unit cost of coal-based power upwards, bringing the price crossover forward.

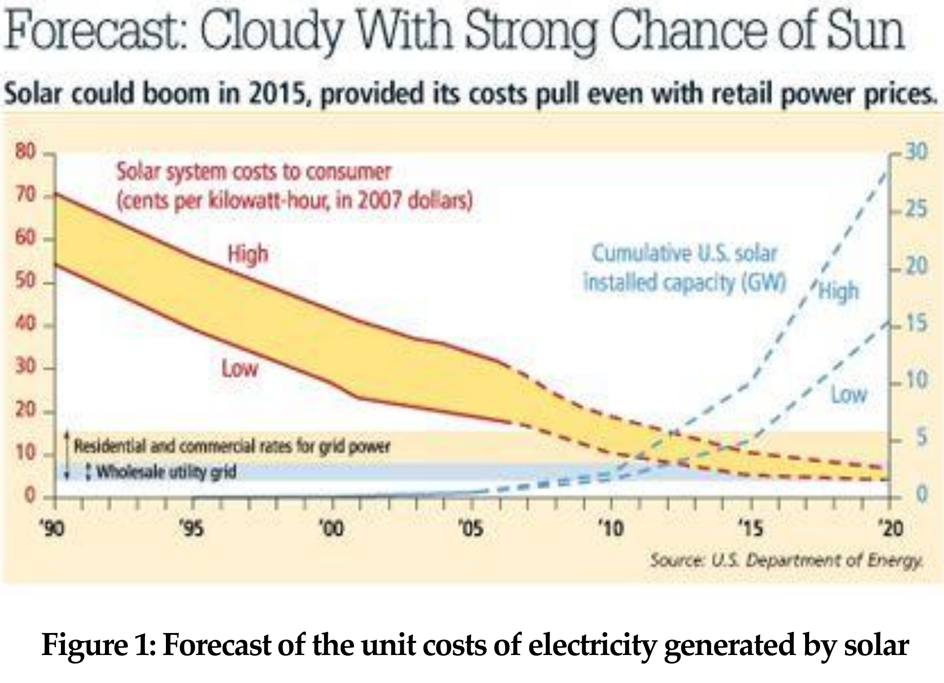


Figure 1: Forecast of the unit costs of electricity generated by solar

The conventional view today is that solar is prohibitively expensive compared to coal but current comparisons are of limited relevance. It is future projections that matter. Already, in 2009, silicon contract prices have fallen by 30% and, if we assume a cost of capital of 6%, we know that PV is now capable of achieving a cost of as little as 17 cents US per kWh and that this is being achieved in some cases. This is already competitive with retail electricity prices in some countries. Also, thin film silicon panels will be cheaper once they begin to flow on to the market in significant volumes from 2010 onwards. New Energy Finance has estimated that 13 cents per kWh is achievable at current silicon prices.

The question arises – can such rapid reduction in price continue or is the dip in the silicon price just a temporary phenomenon because the global downturn has reduced silicon demand by the computer industry? Diffusion curve analysis suggests that price will fall but not at the current fast rate. However, maintenance of a faster rate is possible given that evidence in the past in the energy area suggests that, when the relative prices of energy shift or are expected to shift significantly, technological innovation proceeds rapidly in the development of new energy sources, reducing costs significantly. Reports of a relatively high price elasticity of about one are common in the empirical literature in this area. The very high oil price in 2008, its relatively high recessionary level in 2009, the fear of 'peak oil' and the general expectation that significant carbon prices or taxes will be introduced has resulted in an accelerating innovation impetus in renewable energy technologies. So it is possible that there is a more sustained 'relative price effect' driving down the longer term unit cost of solar energy faster than expected. The fact that PV was being installed for zero cost prior to the end of the solar rebate scheme in June 2009 is a consequence of the significant reduction of the cost of silicon.

The favourable prospects for significant cost reductions due to diffusion curve dynamics has stimulated interest in solar projects in US financial markets. Potential investors have begun to look in detail at the implications of the diffusion process. For example, Stephen O'Rourke has estimated unit cost curves for different PV technologies. His chart is reproduced in Figure 2.

O'Rourke compares high-efficiency crystalline silicon (c-Si), currently most preferred; thin-film copper-indium-gallium-selenium (CIGS), which is just entering the market; thin-film amorphous silicon (α-Si); and thin-film cadmium-telluride (CdTe) on glass. He concludes that all of these technologies will become competitive with conventionally generated electricity prices in the 2013-2016 period which is a similar conclusion to that of the US Department of Energy.

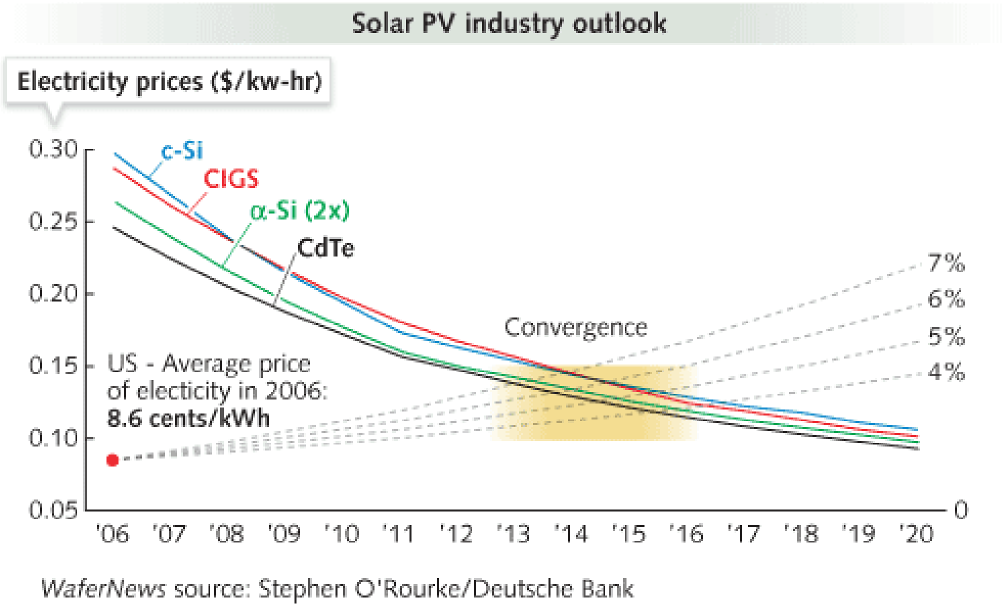


Figure 2: Unit cost curves for different PV technologies

Although solar thermal power stations offer considerable potential in the future it is clear that the most cost effective solar option in the near future is distributed generation using PV both in commercial and domestic applications. This is because electricity generated by solar thermal power stations still has to be fed through expensive transmission and distribution systems where the bulk of the unit cost of electricity is incurred. For example, in Queensland, the wholesale price of electricity has been around 3.5 cents per kWH. However, Ergon's price for domestic consumers in 2008/9 is 16.291 cents per kWH. (plus a supply charge of $6.26 per month or $1,878 over 25 years). The commercial price is 18.249 cents per kWH (plus a supply charge of $11.36 per month or $3,408 over 25 years).

There is little prospect of solar thermal approaching the unit cost of coal generated electricity, even allowing for the impact of carbon pricing, in the foreseeable future but, as has been noted, there is a real prospect that distributed PV will become cheaper than 16.249 cents. Furthermore, the widespread use of PV would reduce pressure on the transmission system, deferring the very significant costs involved in increasing its capacity. This is a further implicit price advantage Also, the coincidence of PV solar collection with the daily peak commercial demand for electricity, when wholesale price peaks, means that the relevant comparison is a price in excess of the average charge of 16.249 cents.

In order to estimate the uptake of PV as its price falls requires a study to estimate the price elasticity of demand of both domestic and commercial consumers. Ultimately it is demand, not supply, that determines diffusion and the consequent cost reductions that are passed into prices. Greentech Media have recently undertaken a major global assessment of current and future demand and supply conditions in 2009 Global PV Demand Analysis and Forecast: The Anatomy of a Shakeout II (Englander, 2009). There is a section on Australia be it is somewhat provisional because it doesn't full account for the impact of recent PV subsidy schemes. Over the past year, there has been a rapid uptake of PV because of the availability of the soar rebate. An assessment of this can provide a better understanding of the price elasticity of demand but this will have to wait until the 2008-9 data become available later in 2009. Also, the fact that this subsidy has been means tested has created a 'natural experiment' in which the responsiveness of consumers with and without a subsidy can be compared.

As of June 10th, 2009, the solar rebate scheme was changes to one involving 'solar credits.' This new scheme is less generous than the old one (which had become far too generous as PV panel prices fell significantly) and is not means tested. Again, this change in the subsidy will provide useful information concerning the price elasticity of demand for PV once it has been in place for a year.

As pointed out earlier, when a new technology is introduced and its development is regarded as a national priority, there must be subsidies to compensate those who invest early when the unit price is still relatively high. This stimulates demand and accelerates diffusion. In Germany, for example, the subsidy has been reduced as unit costs have fallen with no observed adverse effects on the rate of uptake. It is clear that technological diffusion requires an explicit strategy so that a subsidy is varied in an optimal fashion as we move along a diffusion curve. Up until now, the Australian Government doesn't seem to have approached this in a scientific manner. With proper forecasts of technological diffusion, estimated demand elasticities, and anticipated unit cost reductions, it is possible to calculate what a suitable subsidy trajectory should be. This important because wrongly calibrated subsidy schemes readily lead to the misallocation of resources and waste (Taylor, 2006). We can find good recent examples amongst the various subsidy schemes for the domestic installation of water tanks in Australia.

Historically, we know that the production cost of PV panels has fallen by 20% for every doubling of quantity produced (Baker et al., 2009) but, as stated earlier, enjoying this windfall depends critically upon there being a strong expansion of demand. Australian demand constitutes only a small component of global demand and, therefore, it does not have a significant effect on costs and prices. However, it is vitally important, from a carbon abatement perspective, that the uptake of PV is maximised. In a country with very high solar intensity this would seem to be a global climate change priority. But the evidence also suggests that, given this intensity, it will also soon be a cost effective way of generating electricity and easing pressure upon stressed transmission networks. So even without environmental priorities, large scale installation of decentralised PV makes good economic sense.

Without an understanding of the elasticity of demand for PV, it is difficult for a government to know whether targets can be met across any given timescale. If it is the case that the Australian price elasticity of demand is low, then it will be necessary to introduce new regulatory measures, for example, in the construction of new buildings, as the case in Spain, to achieve targets. Australia has a relatively poor track record in the uptake of solar energy but this is possibly because electricity has been so cheap. We can only answer these questions through a better understanding of the price elasticity of demand for PV which will be a central task in the next phase of this project.

3 Levelised Energy Costs

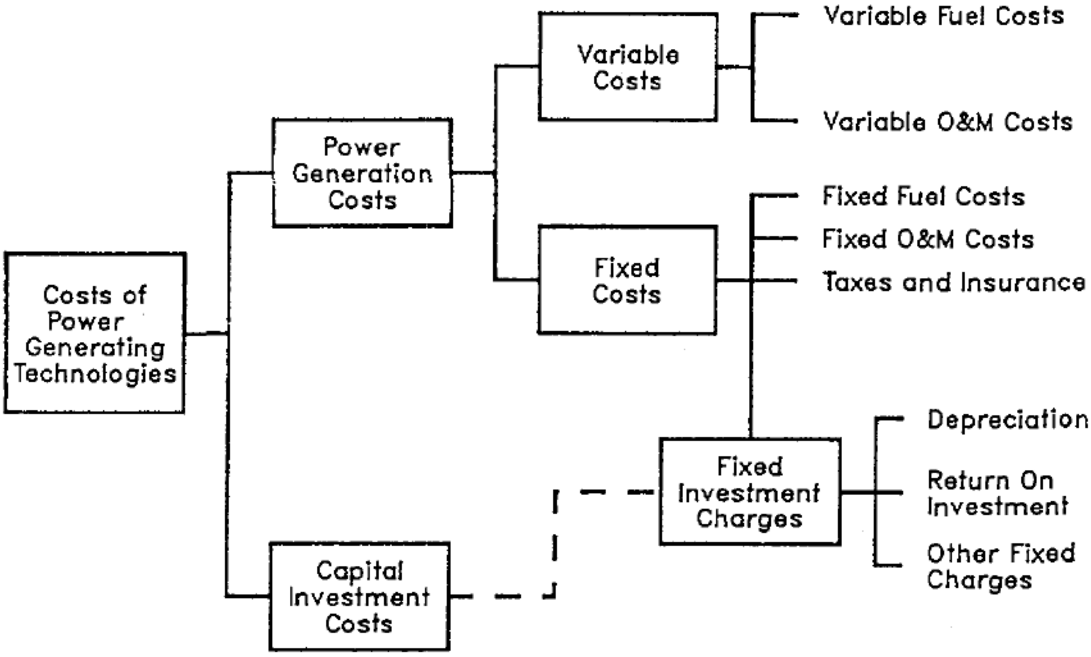
A major problem that is faced in making economic comparisons between different generation technologies is that the costs attributed to existing technologies are not properly measured. For example, much of the infrastructure and capital investment in coal-fired power stations was publicly funded and uncosted. Neither have the environmental or social costs in using a 'dirty' technology been properly costed. The same is true of nuclear power generation. 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 analysis'. Although we can draw upon this literature it is necessary to derive costs that are specifically relevant to Australia to input into our modelling.

3.1 LEVELISED COST ANALYSIS

The article by Bemis and DeAngelis (Bemis and DeAngelis, 1990) stated that "levelised costs are uniform annual costs that determine the estimated annual revenue required to recover all costs over the life of the project. .... These typically include operating and maintenance, fuel, insurance, property taxes, income tax on minimum acceptable rate of return, book depreciation, return on debt and return on equity."

This research also states that decisions "do not require information on financing and cash flow timing" (Bemis and DeAngelis, 1990) but of greater interest is the escalation rate of future costs. Cash flows can very important when analysing different projects as some technologies have high up-front costs, but minimal ongoing costs (and in the case of solar and wind, no fuel costs) compared to some of the more traditional generating plant.

One of the critical points noted from the above is how to determine the lifetime of the project, which may vary upon the preparer of the report. If prepared by a project financier, a shorter lifetime may be assumed by the provider of debt capital compared to the provider of equity capital. Similarly the technical life may be different, as may the economic life, with these both being subject to revision of the project life (McLennan Magasanik Associates, 2008). When looking at alternative measures it is important to factor in the level of planned maintenance during the project life and whether this is general (to ensure smooth operations) or capital (being to extend the life of the equipment). This can be compared with the IAEA analysis which breaks down the cost of generation technology between 'Power Generation Costs' and 'Capital Investment Costs' as shown in figure 1.



Source: (IAEA, 1994)

Figure 3: Cost Analysis Breakdown

Once again they are including depreciation, but ignoring the initial up-front capital costs.

Looking at the variable cost of fuel, whilst supplies are subject to many price fluctuations, coal in particular has remained relatively stable in recent years. Whilst many new plants are utilising gas as a fuel source, the price is expected to be fairly volatile in coming years within Australia, particularly when export opportunities arise.

There have been a number of other methods that have been utilised in evaluating various options similar to the above. In evaluating the feasibility of cogeneration in the plywood industry, (Mujeebu et al., 2009) used the method they described as 'Annualised Life Cycle Cost' (ALCC), which they defined as:

$$ALCC = C_0 * CRF + AOP - (AR + AC)$$

Where C_0 is the initial cost of the equipment, CRF is the capital recovery factor, AOP is the annual operating cost, AR is the annual revenue from power exported to grid and AC is the avoided cost of power purchases. Looking at the CRF, this can be further defined as:

$$\mathrm{CRF} = (1 + d)^n d/[(1 + d)^n - 1]$$

Where d is the discount rate and n is the useful life of the equipment in years.

In (Coventry and Lovegrove, 2003), their analysis of the value of output from domestic solar systems analysed the costs based on a 'levelised cost' arrived at by applying discounted cash flow methodology. The formula they used was expressed as:

NPV = ———

Where n is the life of the project, C_t is the net cash flow generated at time t, k is the discount rate, Δk is the compounding interval and C_0 is the capital cost of the equipment. They then arrived at the levelised cost, being the unit price of energy output that resulted in a zero NPV for the project.

3.2 Real Option Analysis

Another possible method of analysing projects is through the use of real options as they "represent a bridge between strategy and finance" (Gitelman, 2002). The DCF valuation method assumes that the project will hold assets passively; however projects are generally modified, whether this is expansion, abandonment or somewhere in-between (Brealey and Myers, 2003). Real options provides a method of evaluation that considers both uncertainty in asset prices, but also uncertainty in market-based policy measures (Sarkis and Tamarkin, 2008), such as exist within Australia's energy markets today.

The real options approach, like most models has a number of limitations, including that a risk-free portfolio may be applied to all commodity markets, the price process is exogenous and that parameters governing asset price dynamics are constant. The real options approach does allow for factors such as managerial flexibility and volatile fuel prices to be factored into the model (Siddiqui and Marnay, 2008).

In (Sekar, 2005) this method was utilised in evaluating investments in coal-fired plant with the possibility of CCS technology being available in the future. In addition other studies such as (Rothwell, 2006), have evaluated nuclear power, (Laurikka, 2006) IGCC and more recently (Kumbaroglu et al., 2008) have adopted this theory to renewable power generation technology, incorporating the effects of learning curves. Option theory incorporates a value on delaying investment decisions, which can be significant within this sector due to the steep learning curves associated with the technology.

The approach undertaken by (Yang et al., 2008) was to use dynamic programming, where the expected results of investing today are compared with the results of investing at some point in the future, where that future point is determined when the timing is optimal. To determine this optimal point, calculations are solved for the final year and then worked backwards until the optimal point is determined.

On the basis that a project is to go ahead, then the NPV calculations are based on the following formula:

$$V_t^{inv} = \left(\sum_{n=t}^{L} [d(t,n)E[B_n]) - K\right]$$

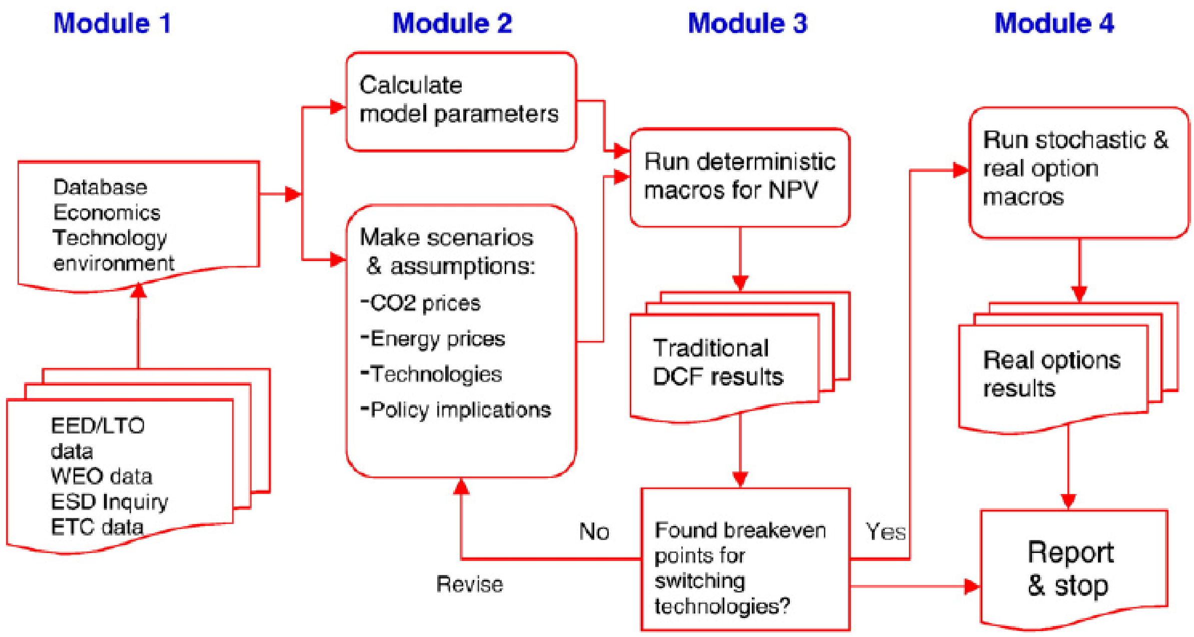
Where L is the project life, K is the capital cost, E is the expectation of cash flow based upon an investment of B and $d(t,n)$ is the discount rate at time t of cash flows at period n. If the decision is made, due to uncertainty in policy, not to invest at this period in time, then the NPV calculation would be based on the following formula:

$$V_t^{cont} = A_t + d(t,t+1)E[V_{(t+1)}^*]$$

In this situation A_t represents the cash flow in period t without the investment and V^* is the optimal NPV of the projects cash flows (Yang et al., 2008).

The amount that the optimal value exceeds the normal NPV is the value of the option of delaying the investment.

The IEA has established modelling methodology, which has been set out in figure 2 and has been used by (Yang et al., 2008) as the basis for their work in evaluating investment in power technology in an uncertain policy environment using real options.



Note: EED -- Energy Efficiency and Environment Division of the IEA, WEO -- World Energy Outlook; LTO -- Long-Term Co-operation and Energy Policy Analysis; ESD -- Energy Statistics Division; ETC -- Energy Technology Collaboration.

Source: (Yang et al., 2008)

Figure 4: IEA's Modelling Methodology

In the above methodology, the NPV is calculated (for module 3) as follows:

$$NPV = \sum_{t=1}^{T} \frac{C([P_c)]_t}{(1+r)^t} - C_0$$

Where P_c is the price of carbon, $C(P_c)_t$ is the cash flow for period t and C_0 is the construction costs of the plant. With this methodology, different electricity prices and carbon costs will provide the points at which a switch in technology could occur.

Within the fourth module, the NPV's for all technologies are again run using the following formula:

$$NPV = \sum_{t=1}^{T} \frac{C(Stochastic\ P_c\ and\ P_e)_t}{(1+r)^t} - C_0$$

4 Estimating future carbon price

At present, we do not know what future carbon prices will be yet it is important to know what these are likely to be in assessing the extent to which significant shifts will occur into low carbon emitting technologies, such as distributed energy generation. It is possible to derive a 'forward carbon curve' that offers a reasonable guide to future prices. In this Chapter we explain the empirical methodology that we are using to obtain estimates of the curve. At the present time, it remains unclear exactly what the Australian emisions trading scheme will look like so it will probably be early 2010 before we can provide sensible estimates of the curve. We have reviewed the various methods that have been used. Clearly, the areas covered go well beyond our concern with distributed energy generation yet all of these wider carbon dioxide production and measurement issues will determine the carbon price that will be relevant to distributed energy generation decisions. Our main concern in this part of the project is to make sure that we use future carbon price estimates that are reasonable and justified.

4.1 THE FORWARD CARBON CURVE MODEL DESCRIPTION

Australia's recent ratification of the Kyoto Protocol introduced a binding commitment to limit greenhouse gas (GHG) emissions at 108 percent of 1990 levels by 2012. Moreover, Australian government has committed to a long term goal of reducing green house gas emission to 60% lower the 2000 level by 2050 (CPRS, 2008).

More proactive measures will be taken to meet the Kyoto commitment and the long term GHG reduction goals. A carbon emission trading scheme is an important part of these measures and will be implemented in the near future as announced by the government. Since the electric power industry is a major GHG emitter in Australia, the introduction of a carbon price will significantly impact power generation costs, thus change the share of different generation technologies. It is therefore important to appropriately model the future carbon price and take it into account in the modelling of distributed generation.

4.1.1 Literature Review

It has been a consensus that international cooperation will be an effective measure to reduce GHG emissions. An international emission reduction scheme will allow the international society to take into account the variations in the abatement costs of different countries due to the differences in their economic and energy system structures. The Kyoto protocol has provided such a cooperation mechanism. Besides domestic reduction efforts, countries can buy and sell their assigned amounts of emission permits through an international emission trading (IET) mechanism. An industrialized country can also implement emission reduction projects in developing countries and gain GHG permits to meet their obligations through the clean development mechanism (CDM). There is also a mechanism called joint implementation (JI) which manages the project-based trades between industrialized countries. Besides Kyoto mechanisms, other regional emission trading schemes have also been introduced, such as the regional greenhouse gas initiative (RGGI) in USA. These efforts have together form an international market of GHG emission permits.

Australian government has announced that a domestic carbon market will be implemented in the near future (Department of Climate Change, 2008). Since currently no limit is expected to be placed on the import of GHG permits, the local carbon price may be significantly impacted by the international carbon price. Therefore, we will not only model the Australian carbon market, but also take into account the international carbon price.

Extensive research has been conducted to model the emerging international carbon market. The existing models can be broadly divided into the following categories:

- *Integrated Assessment Models* - this kind of models study both the physical and social processes, and aim at providing detailed analysis of the climate change problem. They focus on not only the carbon market, but also pay attention to human activities, atmospheric composition, climate and sea level changes, and ecosystems. This kind of models include AIM (Kainuma, 1998), GRAPE (Kurosawa, 1999) and RICE (Nordhaus, 2001).
- *Computable General Equilibrium Models* – CGE models can be employed to obtain the new equilibrium of an economic system after an exogenous disturbance. In the context of carbon trading modelling, the disturbance will generally be the introduction of an emission reduction scheme including the implementation of the carbon market. These models are usually called "top-down" models because they employ the aggregate data on all sectors of the economy. The main strength of CGE models is their ability to study the interactions between the carbon market and other industry sectors, as well as the impacts of energy policies. However, they are usually based on the assumption of perfect markets, which is claimed to be their main disadvantage. Moreover, they lack the ability to clearly describe the transition path to the new equilibrium and thus cannot accurately estimate the transition cost. Existing CGE models include EPPA (Ellerman and Wing, 2000), GEM-E3 (Capros, 1999) and GREEN (Burniaux, 2000).
- *Emission Trading Models* – Emission trading models usually employ *marginal abatement cost* (MAC) curve to analyse the effects of carbon trading. The MAC curve is usually generated by running a CGE model under emission

constraints (Klepper, 2006, Holtsmark and Maestad, 2002). The carbon abatement cost will be calculated as the shadow price, which is a function of the abatement level. The MAC curve can also be estimated with econometric methods (Lanza et al., 2001) or with sector specific analysis (McKinsey&Co., 2008).

- *Neo-Keynesian Macroeconomic Models* – similar to CGE models, this kind of models also belong to the "top-down" models. However different from CGE, they will consider monetary policies and allow for imperfect competition and unemployment (Grubb et al., 1993).
- *Energy System Models* – these models are usually categorized as "bottom-up" models because they employ disaggregated data and model the energy sector in a much more detailed level than CGE models. Energy system models will determine an optimal energy technology profile by performing an optimization process. Examples of these models include MARKAL (Chen, 2005) and POLE (Criqui, 2000). The main advantage of energy system models is their unique ability to provide detailed analysis of the energy sector. On the other hand, they also have several shortcomings. For example, they usually assume the energy demand is independent of the energy price. Moreover, they usually cannot properly model the interactions between the energy sector and the rest of the economy.
- *Econometric Models* – both discrete and continuous time econometrics models have been applied to empirically study the dynamics of carbon spot and future prices. Existing models include GARCH type model (Paolella and Taschini, 2008), regime-switching model (Benz and Truck, 2009) and continuous time stochastic processes (Daskalakis et al., 2009). Most of these studies focus on EU ETS market, because it is currently the largest, most liquid and most developed emission trading market.

Several studies have been conducted to specifically investigate the emerging Australian carbon market, such as (Garnaut, 2008, Treasury, 2008). The results of these studies will be important information sources for our modelling.

4.1.2 Domestic Marginal Abatement Cost Curve

Constructing a marginal abatement cost (MAC) curve for Australia is the basis for estimating the future carbon price in the domestic market. The MAC curve expresses the abatement cost as a function of the potential abatement level. If we consider the carbon emission permit as a commodity, the MAC curve provides detailed supply side information. Given an emission reduction target, which represents the carbon demand; an equilibrium price of carbon can be obtained as illustrated in the following figure. In Figure 5, Q1 represents the emission reduction target and the corresponding marginal cost P is the carbon price. Q0 is the emission reduction level that can be achieved with no cost.

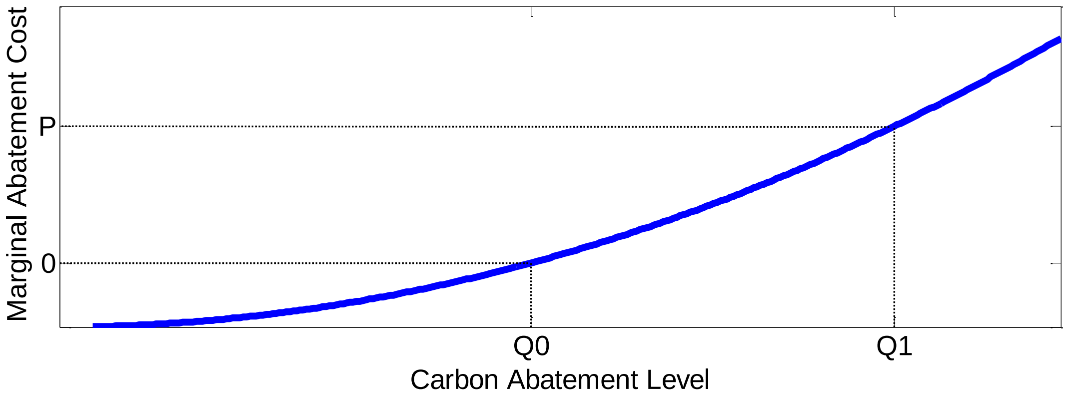


Figure 5: Marginal Cost Abatement Curve

To obtain a domestic MAC curve, we will conduct detailed analysis of the abatement opportunities in different sectors. The results will then be aggregated to form the MAC curve.

Energy Sector

The energy sector contributes more than 40% of GHG emissions in Australia. Significant abatement opportunities therefore exist in this sector. We will consider several abatement options in our modelling, including carbon capture and storage (CSS), wind power, solar power and geothermal.

Since currently fossil fuels based power plants contribute more than 80% of the generation capacity in Australia, the *carbon capture and storage* technology is an option with significant abatement potential. Since the CSS technology is still under development and immature, great uncertainty remains about its future market share. We will model the uncertainty by assuming two scenarios. In the CSS scenario, the CSS technology is assumed to be developed successfully and deployed in large scale. It is assumed that 2/3 of coal fire plants will install CSS devices by 2030. Moreover, we assume that the CSS technology is able to capture 90% of emissions, which follows the assumption in (Garnaut, 2008). In the non-CSS scenario, it is assumed that the commercial development of CSS technology fails and no CSS will be available in Australia. The carbon prices under these two scenarios will be compared to understand the impacts of CSS.

Besides hydroelectric power, *wind* power is currently the most cost competitive renewable energy in Australia. In our modelling, we assume that the hydro power has no potential for significant growth. We also assume that the wind power will remain relatively competitive compared with other renewable technologies till 2030.

Moreover, we will mainly consider onshore wind power in our modelling, since offshore wind power will incur higher maintenance and power transmission costs (McKinsey&Co., 2008).

Solar power has large room to grow, since Australia is one of the regions that have the best solar resources. In our modelling both solar thermal and solar PV will be taken into account. Today solar power is still relatively cost ineffective. The solar thermal currently has a levelized cost of around 110$/MWh compared with the 30$/MWh of coal and 80$/MWh of wind (McKinsey&Co., 2008). Therefore in some other studies it is assumed that most of renewable energy growths will not be contributed by solar power (Treasury, 2008). We will conduct technological learning analysis to determine the future costs of solar power and thus estimate its potential market share.

Other power generation options to be modelled include *geothermal* and *biomass*. The geothermal power is projected to constitute around 8% of the generation capacity by 2030 (McKinsey&Co., 2008). The biomass is also expected to account for around 14% of additional renewable capacity by 2020 (Treasury, 2008). The potential impacts of these two options on the carbon price will also be studied.

Nuclear power is an important option for emission reduction. However there are strong barriers for its large scale deployment in Australia because of political and environmental considerations. Considering the difficulty of getting regulatory approval for nuclear power, we assume that it will not be available by 2030.

Two way interactions exist between the carbon and electricity markets. The carbon price will influence the generation cost and thus change the market share of different technology. On the other hand, a different technology profile will change the MAC curve and thus impact the carbon price. It is therefore necessary to model the carbon and electricity markets with an integrated model. We propose to model the interactions between carbon and electricity markets in the following way:

i. Following (Garnaut, 2008), a fixed carbon price (20$/MWh) will be assumed till 2012.
ii. The carbon price in year t will be used to represent the carbon cost of power generation in year t+1.
iii. The market simulation tools (PLEXOS) based on optimal power flow, as discussed in previous sections, will be employed to simulate the NEM-wide generation investment behaviours and determine the market shares of different generation technologies in year t+1.
iv. Using the results of step iii and employing the methodology discussed in the following sections, the carbon price will be determined for year t+1.

v. The above process is repeated till the end of our modelling horizon and generates the carbon forward curve.

Transport Sector

The introduction of emission trading will cause significant transformation in the transport sector. The main abatement opportunities associated with the transport sector include:

i. *Fuel Efficiency Improvement* – a number of measures can be taken to improvement fuel efficiency improvement. For example, *lightweight materials* can be used to reduce the vehicle weights. Further improvement of *aerodynamics performance* is another possible measure. *New engine and transmission technologies* have already been applied now and have to potential to yield substantial emission reductions.
ii. *Alternative Fuels* – possible alternative fuel types include *biofuels, natural gas, hydrogen, fuel cells* and *electricity*. The abatement potentials of these alternative fuel types will be investigated.
iii. *Transport Mode Shift* – further emission reductions can be achieved by changing the transport mode such as improving the *public transport* infrastructure and changing to *non-motorized transport*.

Forestry and Agriculture

The forestry and agriculture sectors account for around 200 Mt of abatement opportunities by 2030 (McKinsey&Co., 2008). In the forestry sector, *avoiding deforestation* is a measure that has big reduction potential and can be implemented immediately. Another possible option is *replanting* on marginal crop and grazing land. In the agriculture sector, main abatement options include changes in *tillage*, improvement in *fertilization* techniques and *methane capture* from landfills.

Industry sector

A wide range of technologies have the potential for reducing industrial GHG emissions. These technologies can be grouped into the following categories:

i. *Management Practices* – management tools are helpful for reducing emissions. Possible options include *energy audit and management systems* and *GHG management systems*.
ii. *Improving Energy Efficiency* - large amounts of energy can be saved and CO2 emissions avoided by strict adherence to carefully designed operating and maintenance procedures. Methods of improving the efficiency of electric motor-drive systems include the use of control mechanisms more sensitive to variations in load, which are thus more energy efficient. The efficiency of boilers, furnaces and process heaters can also be further improved.

iii. *Fuel Switching* – many industries that use fuels for steam generation or process heat, have the options to change their fuels to the ones with lower carbon intensities. (Metz and Intergovernmental Panel on Climate Change. Working Group III., 2001), concludes that the fuel switches can reduce the CO2 emissions by 10-20%.
iv. *Heat and Power Recovery* – Heat is used and generated at specific temperatures and pressures and discarded afterwards. The discarded heat can be re-used in other processes onsite, or used to preheat incoming water and combustion air. Power can be recovered from processes operating at elevated pressures using even small pressure differences to produce electricity through pressure recovery turbines. Examples of pressure recovery opportunities are blast furnaces, fluid catalytic crackers and natural gas grids.
v. *Fugitive Emission Reductions* – measures for fugitive emission reductions include recovering methane from mines, and replacing or upgrading those technologies which account for significant quantities of methane leakage in their normal practice.

The abatement opportunities discussed above and the corresponding costs will be taken into account in the MAC modelling. The abatement opportunities will be sorted in an ascending order according to their costs. The abatements costs will then be aggregated to form the MAC curve. The potential abatement volumes and costs of different opportunities will be collected from a variety of sources such as (Treasury, 2008, Garnaut, 2008, McKinsey&Co., 2008). For the opportunities in the energy sector, we will employ a simulation based approach to estimate their abatement volumes and costs as discussed previously.

4.2 MODELLING INTERNATIONAL CARBON TRADING

To model the future carbon price in Australia, we should not only consider the domestic demand and supply, but also take into account the impacts of international carbon markets. In our study, two approaches will be employed to model international carbon markets. Firstly, since several international carbon markets have already been in operation, continuous time stochastic processes can be employed to model carbon prices based on the historical data of these markets. Secondly, a variety studies have been conducted to estimate the MAC curves for main regions in the world. Based on these international MAC curves and the domestic MAC curve, an equilibrium model can be used to estimate the international equilibrium price of carbon. We will implement both of these two approaches and compare their performances.

4.3 STOCHASTIC PROCESSES FOR THE CARBON PRICE

Currently a number of national and regional carbon markets have been established in which a variety of specialized financial instruments are traded. However, Europe has emerged as a leader in emissions trading. The *European Union Emission Trading Scheme* (EU ETS) is currently the world's largest single market for CO2 emission allowances, accounting for approximately 98% of the global transactions for 2007. Due to its unique role in emission trading, we will focus our modelling on the EU carbon market. However, the approach can be easily extended to other emerging carbon markets to account for their impacts.

The EU ETS is mainly performed through three different markets, namely the *European Climate Exchange* (ECX), the *Bluenext*, and the *Nordic Nord Pool*. In each of these markets, two different permits, the *European Union Allowance* (EUA) and the *Certified Emission Reduction* (CER) are being traded. They are both designed to be equivalent to the *Assigned Allocation Unit* (AAU) defined by the Kyoto Protocol, and therefore can be used to meet the Kyoto commitment. For each permit (EUA or CER) in a specific market, a continuous time stochastic process will be derived. These models will be used together with the domestic MAC curve to determine the Australian carbon price.

The spot price of a commodity can usually be modelled by a *mean reverting* process (Hull, 2006) Considering that jumps can usually be observed in energy prices, a jump-diffusion process may also be applicable in our problem. We propose to model the carbon price with the following three processes:

Mean reverting square root process:

$$dS_t = k(\theta(t) - S_t)dt + \sigma\sqrt{S_t}\,dW_t \qquad (1)$$

Mean reverting logarithmic process:

$$d\ln(S_t) = k(\theta(t) - \ln(S_t))dt + \sigma dW_t \qquad (2)$$

Mean reverting jump diffusion process:

$$dS_t = k(\theta(t) - S_t)dt + \sigma\sqrt{S_t}\,dW_t + (y-1)S_t dq_t \qquad (3)$$

In Equations (1)-(3), S_t is the carbon price at time t; W_t is a standard Wiener process; k represents the speed of mean reversion; $\theta(t)$ is the long run mean conditional on time; and σ is the volatility. In Equation (3), the jump size y follows an asymmetric double exponential distribution (Dotsis et al., 2007):

$$f(y) = pn_1 e^{-n_1 y} 1_{\{y \geq 0\}} + qn_2 e^{n_2 y} 1_{\{y<0\}} \tag{4}$$

where $p > 0, q > 0$, and $p + q = 1$. $1/n_1, 1/n_2$ represent the mean sizes of upward and downward jumps.

The parameters of Equations (1)-(3) can be estimated with the Maximum Likelihood Estimation (MLE) method. Since dW_t is normally distributed, the price increment dS_t in (1) and (2) follows a normal distribution as well. Given an observed carbon price series $\{\hat{S}_t\}, t = 0..T$, the conditional likelihood function of (1) can be derived as:

$$L(\{S_t\};\Theta\} = \prod_{t=1}^{T} \frac{1}{\sigma\sqrt{2\pi\hat{S}_{t-1}}} e^{-\frac{(\hat{S}_t - (\hat{S}_{t-1} + k(\theta - \hat{S}_{t-1})))^2}{2\sigma^2 \hat{S}_{t-1}}} \tag{5}$$

where $\Theta = (k, \theta, \sigma)'$. Similarly, the conditional likelihood function of (2) can be given as:

$$L(\{S_t\};\Theta\} = \prod_{t=1}^{T} \frac{1}{\sigma\sqrt{2\pi}} e^{-\frac{(\ln \hat{S}_t - (\ln \hat{S}_{t-1} + k(\theta - \ln \hat{S}_{t-1})))^2}{2\sigma^2}} . \tag{6}$$

To derive the ML estimator for (3), we follow the approach described in [Singleton, 01]. Denote $\phi_{S_t}(u,\Theta)$ as the Fourier transform of the density function of S_t conditional on S_{t-1}:

$$\phi_{S_t}(u,\Theta) = \int_{R^N} f(S_t \mid S_{t-1};\Theta) e^{-juS_t} dS_t . \tag{7}$$

The conditional log likelihood function of (3) can then be given as:

$$L(\{S_t\};\Theta\} = \sum_{t=1}^{T} \log(\frac{1}{\pi^N} \int_{R_+^N} \mathrm{Re}[e^{-juS_t} \phi_{S_t}(u,\Theta)] du) \tag{8}$$

An Equilibrium Model for International Carbon Price

The main advantage of stochastic process based models is that they are based on historical market data. However, they may not be able to capture the interactions between Australian and international markets. Therefore, we will also employ an equilibrium model for the international carbon price. The model will be based on the MAC curves of the countries that are involved in the international carbon trading. The MAC curves of Annex B countries have been derived in several existing studies (Metz, 2007, Eyckmans et al., 2002, Lanza et al., 2001). Based on these MAC curves and the domestic MAC curve discussed in above sections, the equilibrium of the international carbon market will be obtained. Other main emitters such as China and India can also be included in our modelling if their abatement data are available.

Denote $GDP(i)$ as the GDP of country i, which can be expressed as:

$$GDP(i) = GDP_{BAU}(i) - C(i, Q_i) \qquad (9)$$

where $GDP_{BAU}(i)$ represents the projected GDP of country i under the BAU scenario without large-scale abatements; $C(i, Q_i)$ is the abatement cost function of country i; and Q_i stands for the emission abatement level. The actual emission of country i can be given as the BAU emission minus the emission abatement:

$$E_i = E_{BAU}(i) - Q_i \qquad (10)$$

For mathematical convenience, we assume that $C(i, Q_i)$ is twice continuously differentiable, strictly increasing and strictly convex.

In an international emission trading scheme, each participant country will be assigned an amount of emission permits P_i. P_i can also represent the voluntary abatement target introduced by the government of country i. The GDP of country i can then be changed to:

$$\begin{aligned} GDP(i) &= GDP_{BAU}(i) - C(i, Q_i) + S \times (P_i - E_i) \\ &= GDP_{BAU}(i) - C(i, Q_i) + S \times (P_i - E_{BAU}(i) + Q_i) \qquad (11) \end{aligned}$$

where S represents the international carbon price. Assume that there are no constraints on carbon import/export. Then theoretically each country can maximize its GDP by reducing its emissions to the level where its MAC is equal to the carbon price:

$$\frac{dC(i, Q_i)}{dQ_i} = S \qquad (12)$$

Define the excessive supply for permits as:

$$X_i(S) = P_i - E_i \qquad (13)$$

The sign of $X_i(S)$ indicates whether country i is importing or exporting carbon. Then as discussed in (Eyckmans et al., 2002), a perfect market equilibrium of the international carbon market is the price S^* that makes the total excessive supply nonnegative:

$$\sum X_i(S) \geq 0 \qquad (14)$$

Under the assumption of no import/export constraints, the equilibrium price S^* will also be the Australia carbon price.

In practice, a country cannot import or export unlimited amount of carbon permits. As stated in the Article 17 of the Kyoto Protocol, the Annex B parties can meet their Kyoto obligations through emission trading as long as the trading is "supplemental" to domestic abatement efforts. Although what can be defined as "supplemental" is unclear in the Kyoto Protocol, the effects of "supplementarity" should be considered in the modelling since it will change the uniform carbon price under the no-trading-constraints scenario. When import/export constraints are placed, Australia may be forced to implement some abatement measures whose costs are higher than the international carbon price. The domestic carbon price will then be driven up.

We can introduce import/export constraints as follows:

$$IE_{i,\min} \leq X_i(S) = P_i - E_i \leq IE_{i,\max} \qquad (15)$$

where $IE_{i,\min}$ and $IE_{i,\max}$ are respectively the import and export constraints. Note that $IE_{i,\min}$ should be non-positive.

5 Renewable Energy Certificate Model Description

5.1 BACKGROUND

Considering the relatively higher capital costs and longer payback periods, it is difficult to obtain financing for renewable energy projects in the electricity market. A mechanism to tackle these obstacles for renewable energy investments is to establish a green certificate market. In this market, renewable energy producers can obtain additional payments for the green electricity generated.

In Australia, The federal government has set up the Mandatory Renewable Energy Target (MRET) scheme to provide financial incentives for renewable energy. The MRET will increase additional 9,500 GWh of renewable energy supply by 2010, which will help reduce greenhouse gas emissions. The MRET scheme places obligations on electricity retailers and large consumers to purchase a portion of their power from renewable sources. Establishing a Renewable Energy Certificate (REC) market is a component of the scheme.

The Renewable Energy Certificate is an electronic form of currency initiated by the Renewable Energy (Electricity) Act 2000. It can be created by eligible parties for each MWh of eligible renewable electricity generated or deemed to have generated. RECs are eventually surrendered to demonstrate liability compliance against the requirements of the Australian Government's MRET or voluntary surrender. It can be traded separately from the physical electricity in a REC market. The aim of the REC market is to enables the renewable energy targets to be met at minimum cost.

The MRET scheme has been implemented with a high penalty for non-performance of $40/MWh. This penalty is not indexed to CPI. In addition, the penalty is not tax deductible, meaning that under current company tax rates, a liable party would be indifferent between paying the penalty or purchasing certificates at a price of around $57/MWh. This essentially sets a price cap for RECs.

In our study, a deterministic equilibrium model will be employed to model the REC market and project future REC prices. The details of the REC model are discussed in following sections.

5.2 THE MODEL OF REC PRICES

Existing studies on REC price modelling are rare (IES, 2007, Jensen and Skytte, 2002, SBC, 2008), mainly because green certificate markets are just emerging and it is difficult to obtain reliable market data. Our REC model will be built based on the ideas of these models.

5.2.1 Model Setting

We consider only the Australia domestic REC market in our model. In other words, no international trading will be taken into account. We assume that the REC market is liberalized and perfect competition exists. The REC price can therefore be determined by obtaining equilibrium between demand and supply. The demand for RECs is mandatorily set by the MRET. The supply is determined by the installed capacity of renewable power units. We assume that besides the MRET obligation, additional RECs will give no benefit to the electricity customer, it will therefore purchase exactly the amount specified by MERT.

In the electricity market, all customers are assumed to be indifferent; they can therefore be combined to form a representative customer. The representative customer's utility function is assumed to be increasing and concave for mathematical convenience. Two types of generators, fossil-fuel generators and renewable generators will be treated differently in the model. Each generator has its unique cost function which is assumed to be increasing and convex.

Following (IES, 2007), we will also take into account the "Investment Phase" and "Post Investment Phase" in our model. The investment phase represents the period in which existing renewable power capacity is not sufficient for meeting MRET obligations. New investments of renewable energy capacity will be made. In this situation, the REC price will be strongly influenced by the costs of new renewable power plants.

Model Description

In the model, the representative customer selects the optimal power consumption d by solving the following benefit optimization problem:

$$\text{Max} \quad u(d) - (p_e + p_c k)d \qquad (1)$$

$$\text{Subject to} \quad d \geq 0 \qquad (2)$$

where $u(d)$ represents the utility function depending on d. p_e, p_c represent the power and REC price respectively. k is the percentage of total power consumption that must come from renewable sources as specified by MRET. To simplify the analysis, the marginal utility is assumed to be linear, positive but decreasing. The utility function is therefore assumed to have the following form:

$$u(d) = \begin{cases} \delta d^2 + \eta d + \lambda & d \leq -\dfrac{\eta}{2\delta} \\ -\dfrac{\eta 2}{4\delta} + \lambda & otherwise \end{cases} \qquad (3)$$

For a fossil fuel generator *i*, we assume that it aims at maximizing its benefits as follows:

$$\text{Max} \quad \pi_i(q_i) = p_e q_i - c_i(q_i)\,,\ i \in G^F$$

$$\text{Subject to} \quad q_i \geq 0 \tag{4}$$

where q_i is the power generated by generator *i*; $c_i(q_i)$ represents the cost function of generator *i*; G^F is the set of fossil fuel generators. The cost function of a fossil fuel generator is assumed to have the following quadratic form:

$$c_i(q_i) = \alpha_i q_i^2 + \beta_i q_i + \gamma_i \tag{5}$$

where $\alpha_i, \beta_i > 0$. This implies that marginal generation costs are increasing.

For the renewable generator *j*, the benefit maximization problem will change to:

$$\text{Max} \quad \pi_j(q_j) = (p_e + p_c)q_j - c_j(q_j)\,,\ j \in G^R$$

$$\text{Subject to} \quad q_j \geq 0 \tag{6}$$

where G^F is the set of all renewable generators in the market. Similarly, the cost function of renewable generator *j* can be defined as:

$$c_j(q_j) = \alpha_j q_j^2 + \beta_j q_j + \gamma_j \tag{7}$$

The marginal cost is also assumed to be increasing.

The total supply should be greater than or equal to the demand in equilibrium. Therefore, the equilibrium in the electricity can be formulated as follows:

$$\sum q_i + \sum q_j \geq d \tag{8}$$

For the REC market, the equilibrium will be given as:

$$\sum q_j \geq dk \tag{9}$$

A general optimization algorithm will be needed to solve the model and thus obtain the equilibrium price of RECs.

6 Risk Management and Distributed Generation

Distributed generation (DG) is becoming seen to be a viable alternative to the traditional centralised bulk electricity supply system, for several reasons apart from reducing GHG emissions. A concise definition by Ackermann, Andersson and Soder (Anderson et al., 2008), stated that … "Distributed generation is an electric power source connected directly to the distribution network or on the customer site of the meter". Furthermore, DG power output ratings can range from 1 W to 300 MW and cover a range of renewable technologies including micro- and combustion-turbine, internal combustion engines, and hydro, solar, biomass, wind and fuel cell (Anderson et al., 2008). DG encompasses three classes of technology:

(1) Combined heat and power (CHP),
(2) Distributed renewable energy generators, and
(3) Distributed non-renewable energy generators (Sovacool, 2008).

DG will itself not replace the traditional centralised electricity supply system; it will complement the centralised system to provide a hybrid more of operation that will be secure, safe and more clean (Bouffard and Kirschen, 2008).

DG systems may accommodate for electricity demand growth and future obsolescence of an existing centralised electricity supply system. Current power generation assets that face impending obsolescence are those at the higher end of CO_2 emissions intensity (i.e., brown and black coal). The increasing impetus for using DG stems from the vulnerability and question of the future viability of centralised electricity supply. Several points with respect to this include (Bouffard and Kirschen, 2008, Carley, 2009), Cost – the centralised electricity supply system includes the generation, high-voltage transmission and low-voltage distribution of power, the investment in this system requires large amounts of capital investment and on-going operating and maintenance costs.

Security – a large power station presents a large target for potential terrorist activity and if these are attacked then the whole supply chain would be disrupted, for months even years in an extreme case.

Ageing of the electricity infrastructure – power stations, transmission and distribution networks are in cases reaching the end of their useful operating lives. Replacement with newer facilities would be costly.

Climate change – DG can replace an existing area's traditional centralised electricity supply system with a lower emissions solution that might be able to provide similar quality and reliability as that from the centralised system.

In some jurisdictions in the European Union (EU) DG has a very large share of the total electricity production (Cossent et al., 2009). For example, Denmark has just over 45% of total electricity production from DG, whilst Germany, The Netherlands, Spain and Sweden have 15%-20% of their electricity production via DG (Cossent et al., 2009). European Commission and EU directives and policies support DG amongst other instruments (i.e., the EU ETS) to reduce GHG emissions and also energy usage (Bouffard and Kirschen, 2008, Cossent et al., 2009).

According to Dyner, Larsen and Lomi (Dyner, 2003), there are three broad categories of risk facing companies involved with electricity supply (specifically the generation sector); *organisational risks, market risks, and regulatory risks*. These risks would also face any company that desires to invest into DG. *Organisational risks* are those mainly associated with inertia within an organisation, that is, the tendency of established companies to resist change (both the content of the change and the process by which it is done). *Market risks* are those related to issues brought on by competition such as customer choice, price volatility, asymmetric information, new and possibly aggressive new entrants to the industry, and variable rates of return. *Regulatory risks* come about because even after restructuring and deregulation regulatory body/bodies have been established to oversee the electricity supply industry. Regulatory bodies have to choose how to balance controls on such issues as prices, anti-competitive behaviour and now with climate change and greenhouse gas emissions being of importance there will be uncertainty in policy and regulations and thus increased risk. Another way to view the major risks facing investors in power generation sectors is shown below in Figure 6.

Plant Risk	Market Risk	Regulatory Risk	Policy Risk
Construction costs	Fuel cost	Market design	Environmental standards
Lead time	Demand	Regulation of competition	CO_2 constraints
Operational cost	Competition	Regulation of transmission	Support for specific technologies (renewables, nuclear, CCS)
Availability/ performance	Electricity price	Licensing and approval	Energy efficiency

Figure 6: Major Risk Factors for Investors in Power Generation (Nguyen, 2007)

In the above figure some of the risks may actually present an opportunity for DG investors. One example is that policy risk - supporting specific technologies (i.e., wind and/or solar) may provide the economic/financial incentive for DG investment within a particular jurisdiction. However, to rely on the one DG technology would not be prudent from a corporate-level risk perspective. In other words, DG investors need to diversify away asset-specific risk (Roques et al., 2008). For instance, if the primary DG asset is wind-powered then additional and more reliable assets (e.g., small scale gas turbine and solar) would be needed to supplement the variability of wind flows at the DG site.

One approach for valuing a portfolio of generation assets for DG is Portfolio Theory. Awerbuch and Berger (Awerbuch, 2008), applied portfolio theory to generation assets in the European Union and emphasised that the portfolio-based approach should be used to evaluate alternative generation asset portfolios. Unlike the traditional planning approach for electricity generation investment (i.e., least cost basis) a portfolio approach means that an asset is evaluated on how it effects the generating costs of the portfolio relative to how it effects the risk of the portfolio (Awerbuch, 2008). Thus, portfolio approach has shown that the addition of wind and solar PV to a portfolio of conventional generation assets reduces the overall portfolio cost and risk, even if the stand-alone generating cost of some assets could be higher (Awerbuch, 2008).

Other studies by Roques (Roques et al., 2006, Roques et al., 2008) studied optimal portfolio for generators in the UK. Electricity price risk and where applicable, CO_2 price risk, are relevant in determining the optimal generation portfolio. Roques (Roques, 2008) found that the current UK electricity industry framework is unlikely to reward a diversified fuel mix portfolio. That is, private investors' generation choices are unlikely to be aligned with a socially optimal fuel mix such as that potentially available in using DG. One possible solution could be the use of long-term power purchase agreements, in this way private investment into socially optimal DG would be less risky.

Real Option Theory can also be utilised in determining the appropriate DG technology portfolio mix when the future is risky/uncertain. The theory of Real Option in essence states that when the future is uncertain it is prudent to have an availability of a broad range of options that have the flexibility to be exercised as required. Thus, Real Option Theory is useful for analysing the optimal DG technology portfolio. Two attributes of renewable technologies can improve their value to investors and society (Roques et al., 2008). First, generation costs of renewable technologies are not sensitive to coal/gas and CO_2 prices so over time rising coal/gas and CO_2 prices will make renewable more competitive against coal- and gas-fired plants. Second, investment into renewables via DG is a hedge against the volatility of coal/gas and CO_2 prices, the actual uncertainty of the evolution of coal/gas and CO_2 prices means there is an option value. This option value is associated with the ability of being able to choose between renewable DG and fossil fuel technologies in the future.

One way to understand generation portfolio risk is to construct a cost-risk diagram, an example is shown in Figure 7 below. This example is based on work by Neuhoff and Twomey (Neuhoff, 2008).

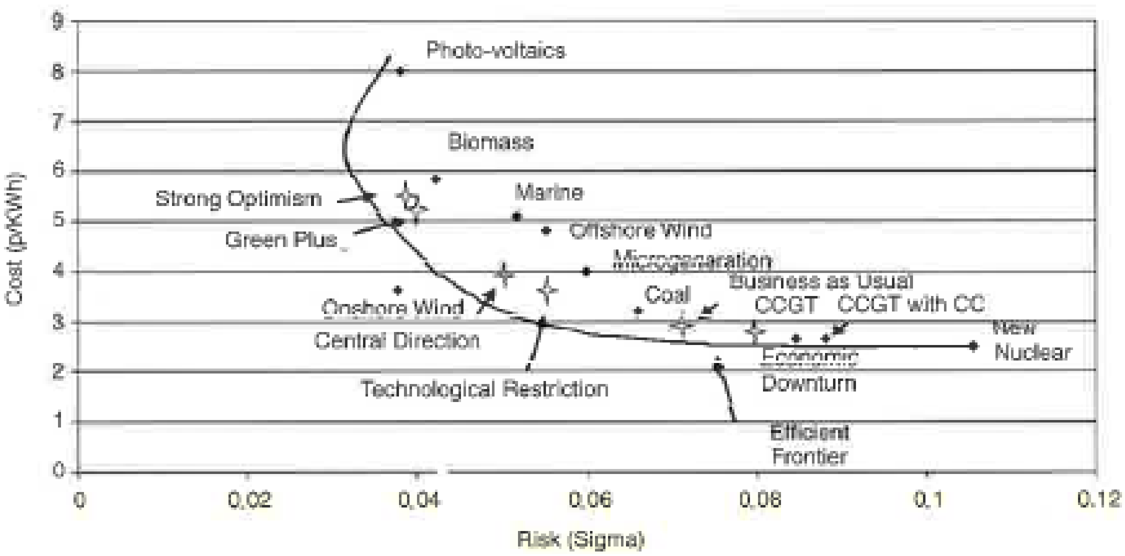


Figure 7: A Cost-Risk Efficient Frontier Example – UK Electricity Generation

Source: (Neuhoff, 2008) *Will the market choose the right technologies?* p. 262

The above figure shows the costs and risks for pure portfolios (100%) of a given generation technology and also an efficient frontier line. Any portfolio that lies toward the left-hand corner of the diagram and below the efficient frontier line is an example of the benefits of diversifying generation technology, that is, lower costs and lower risk (Neuhoff, 2008).

7 UQ PV Project

Although various modelling methodologies can enable us to better understand the impacts of distributed energy generation, much of this knowledge remains hypothetical because it has to be based upon assumptions concerning systems that do not yet exist. Thus, it is essential to conduct 'live' experiments. The UQ PV Project will do just this. The scale of the installation is similar to that on a commercial building, such as a supermarket of a warehouse, introducing a range of questions that do not arise with small residential PV units. Many of these questions are economic and regulatory and, indeed, may pose greater difficulty than technical issues. The research group has maintained close involvement in this project from the outset and will continue to do so, documenting all aspects of project planning, development, installation and system management.

7.1 THE SOLAR RESOURCE IN BRISBANE

Australia has one of the world's best solar energy resources. Measured annually, the Brisbane region has an annual average daily solar exposure on a horizontal plain of around 18 MJ/m^2, rising for locations inland from the coastline.

7.1.1 General PV mounting and orientation

In principle, the yearly average solar energy captured by a plane surface such as an array of PV modules can be maximised by facing the plane of the modules due north, inclined to the horizontal at the angle of the location's latitude. The annual averaged daily solar exposure at Brisbane for this orientation is approximately 20 MJ/m^2, or 5.5 peak sun hours. According to the tables, for an array facing due north, any inclination of between 20 and 40 degrees from horizontal will capture greater than 99% of the maximum possible available solar energy. As the tilted plane of PV modules is rotated away from true north, the average available solar energy falls. A PV array inclined at ten degrees from the horizontal captures 95%of the maximum possible insulation for an optimally oriented fixed plane, and greater than 89% for any orientation from due east to due west. Careful examination shows a small bias for westward (afternoon sun) vs. eastward (morning sun) azimuth rotations. Even though total output is slightly reduced, westward rotated planes will also produce their maximum output in the afternoon, rather than the middle of the day, which is a better match for most commercial peak demand load shapes.

7.1.2 Expected PV electrical energy output

As the power output of a PV array is nearly directly proportional to the solar insulation, the daily, monthly and annual outputs of the array can be calculated from their corresponding solar insulation. The rating of PV modules is conducted under standard test conditions (STC) of 25°C cell temperature and 1,000 W/m² (1 Sun) illumination. In practice, three factors reduce the power delivered to the AC grid – soiling of the module glass surface, temperature rise of the solar cells, and the losses of the grid connect inverter and associated wiring. Dirt and dust will accumulate on the surface of the module over time, but is washed off whenever sufficient rain falls. For this reason, modules should not be mounted truly horizontal, or they do not effectively self clean. The loss of power output from the modules can easily be over 10% in a dirty environment with infrequent rain but on average is between 4 and 7%.

Most PV modules produce less electricity as they get hotter – a natural function of being exposed to the sun. Mono-crystalline and polycrystalline silicon modules generally lose 0.5% of their rated power per °C temperature rise. With a typical operating temperature of 47°C, this equates to an 11% drop in power output. Amorphous silicon modules generally lose less power (0.2%/°C) which is one of their quoted advantages. The value of 11% power loss due to module temperature rise has been used in this study.

Grid connect PV inverters are by design very efficiency because of the high value of the energy they process. Peak efficiencies vary between 93% for small string inverters of 1 kW rating, 95-96% for large 5 kW multi-string inverters, to over 96% (including transformer) for large 100 kW three phase central inverters. It is important to calculate and where necessary oversize the DC and AC cabling, since a normally acceptable 2% cable voltage drop is the equivalent of 2% power loss. The cost of PV modules usually makes over sizing cable economic.

The overall efficiency has been estimated to be about 80%. This means that for a daily average insulation of 5.5 kWh/m², a 1 kWp array would generate 5.5 * 1.0 * 0.80 = 4.4 kWh of electricity at the output of the inverter on average each day. Assuming that there is negligible cable loss, this will also be the power recorded at the point of metering and exported to the grid. Applying these conversion efficiencies to a nominal 1000 kWp PV array using a daily average insulation of 19.8 MJ/m² for Brisbane generates 1600 MWh of electricity each year.

Effects of shading

When a single PV cell is shaded, its output current drops very significantly, to perhaps only 10% of its unshaded neighbour. However, because all PV cells in a PV module are wired in series, a single shaded cell could reduce the output of the entire module. In practice, to minimise the impact of this problem, a bypass diode is connected in parallel with a substring of 24 cells, and is active when a cell in that substring is shaded. The diode allows the full current generated by the remainder of that module and other series connected modules to flow around (bypass) the shaded cell. Each 72 cell module contains three bypass diodes and may only produce one thirds or two thirds of its unshaded power depending on the extent of shading of the module. The diodes also serve an important function of protecting the shaded cells from "hot spot damage", which would otherwise occur from excessive power dissipation in a shaded cell. Even with bypass diodes, shading of even a single row of six cells in a 72 cell PV module can reduce its output to near zero. As far as practical, shading of a PV installation should be avoided. Shading analysis is thus one of the more important steps in the design process. Surrounded buildings, vegetation, poles and other structures including neighbouring PV modules than may cast a shadow should be taken into account in the analysis. Where shading cannot be avoided different module technologies or arrangement of PV array strings should be considered. Because of the arrangement of substrings and diodes within a (6 x 12) 72 cell module, the "portrait" or "landscape" orientation of PV modules may make a significant difference. If shading is unavoidable, the modules that are shaded should be connected in the same string to reduce the overall system loss. Multiple small string inverters can also minimises the impact of shading. Because of the layout of their cells and their parallel connection in strings, amorphous modules are less affected than crystalline modules when partially shaded and should be considered if the installation is in an area of partial shading or uneven sunlight.

Maintenance of PV arrays

Photovoltaic modules require very little maintenance. However they should be kept clean otherwise operating efficiencies will be reduced. A rainfall event of greater than 5mm is generally sufficient to wash away any dust build up on the modules. However, other deposits to take into consideration that may not be washed away by rainfall and may require the modules to be manually cleaned include:

- Fallen debris from trees and sap from gum trees
- Bird and bat faeces
- Dirt or contamination from construction dust
- Sulphuric fumes from building exhausts

An inspection and cleaning regime should be implemented for a minimum of one per year initially, with monitoring of power output to assess if more frequent cleaning is justified. PV arrays should be installed so they are accessible for cleaning and inspection.

7.1.3 Existing installation at UQ – GP North

During 2008, a 10 kWp PV array was installed on the roof of the General Purpose North 4 building at University of Queensland, St Lucia campus. The array was initiated at a late stage of construction of the building and was not as integrated as it may otherwise have been. The PV array serves a number of purposes for the

University. It provides a source of real data and is a potential research facility for academics, thesis students and the university properties and facilities group, to compare energy generation between the different technologies and tilt angles. The array installation has also allowed the properties and facilities group to better understand some of the practical issues involved in a grid connected array, such as metering and monitoring. The array will also reduce the energy consumed from the electricity grid for the GPN4 building. The array consists of six PV strings mounted in two rows. The inclination of the front row is 22 degrees, while the back row is tilted at 26 degrees. Three different PV technologies are also represented in the six strings, mono-crystalline, polycrystalline and amorphous Si.

7.1.4 Linked with Research and Development arrays

In any site chosen for research and development, compliant and equitable access will be provided. Therefore these areas would be able to be accessed by all, under supervision. There is an attraction in making visible to the public experimentation, research and development and the like. It has the potential to be more revealing, and take the educational aspect of this element to a much higher level. Conversely, there would need to be appropriate supervision of visitors of all types in and around experimental works. No doubt there would need to be controls in place to enable some areas to be off limits. This option may require a dedicated information centre space amid the possibly ever changing and evolving experimentation.

Whilst this option is attractive in many ways, its viability would ultimately be informed by the academic staff that would have an opinion on the workability of the research/public interface.

Linked with the large arrays

There is an attraction in enabling visitors to be able to view a vast field of PV panels so that their physicality can be understood in conjunction with their energy capabilities. The two most likely sites for this are Building 98A and 98B and the UQ Centre. Either of these options could accommodate visitor drop off or parking. Depending upon the resultant design, both could provide suitably impressive views across the roofs to take in the full extent of the panels. In addition to the view south view across the panels, the view to the north across the green space with Highgate Hill beyond has an amenity suitable for this function. The most desirable solution is to provide an accessible platform which offers a south view of the panels. This will mean generally the viewer is looking away from the glare and will see the face of the panel. In addition to the view, the facility may have a visitor centre with data, sample panels, evolving technologies and the like. A roof over the platform would enable the view and learning experience to occur in the shade. Whilst it may shade some panels at some times of the day particularly in winter, the roof itself may be a site for PV, even exhibiting some new technology in small portions. Illustrated below is an example of how this might manifest itself as a separate viewing platform adjacent to the multi-storey car parks.

7.2 CONNECTION WITH THE DISTRIBUTION NETWORK

An Embedded Generator is an electricity generator that is connected to the local electricity distribution network rather than the transmission network. As such, any urban grid connected PV systems will almost certainly fall into the category of an embedded generator. For the UQ St Lucia Campus, and indeed all University of Queensland campuses in the South East Queensland region, the distribution network service provider is ENERGEX Ltd.

7.2.1 Technical requirements

ENERGEX has guidelines for the network connection of Inverter Energy Systems, however these "outline the requirements for small installations in residential or small business environments, where the total power of the generator system does not exceed 30 kilo-volt amperes (kVA)." This size matches the upper limit for which AS4777 applies. For these smaller residential and commercial grid connect PV systems, a standard "boilerplate" network connection agreement is used. However, note that if considered a single installation, the larger UQ PV installations will exceed this size. The University of Queensland St Lucia campus already operates with a network connection agreement as an individually calculated customer (ICC), connected via a number of dedicated 11 kV circuits. Even with 1 MWp of installed PV, no electricity will actually be exported, so the current UQ network connection agreement may be sufficient, with some modifications if necessary. Meetings with the ENERGEX asset manager and networks agreement manager have been organised to discuss this.

Energex requires small (< 30 kVA) PV grid connect systems to meet a number of conditions for connection to their network:

- The design and installation of your IES must be carried out by an installer accredited by the Australian Business Council for Sustainable Energy (BCSE).
- The equipment installed at your premises, including the inverter, *must* comply with:

– Australian Standard AS/NZS 3000:2000 – SAA Wiring Rules;
– Australian Standard AS/NZS 4777:2005 Grid Connection of Energy Systems;
– Any other applicable Australian Standards, current as at the date of installation;
– The requirements of the ENERGEX Electricity Connection and Metering Manual.

These requirements give an indication of ENERGEX's expectations for a large grid connected PV system.

7.2.2 Connection with the distribution network

The connection of a large amount of embedded generation at the customer connection point shared with the customer's load has the potential to reduce the capacity requirement of the network service provider (ENERGEX) at the connection point. This has potential value for ENERGEX, as it may defer the need for network augmentation by ENERGEX. While this would normally be reasonably straightforward, it is made much more complex by the non-dispatchable nature of the PV resource.

7.3 CONNECTION AS A GENERATOR

According to the Business Council for Sustainable Energy (BCSE) Guide for the Connection of Embedded Generation in the National Electricity Market [section ref: 7-2], "Generators who form part of an end-use customer connection (e.g. cogeneration) where all the power produced is consumed on site are not required to register as a generator, provided that interlocks are provided so as to ensure that the site never acts as a net generator or that the generator is less than 30 MW and exports are rare as set out in NEMMCO's exemptions." The 30 minute maximum electricity demand at the St Lucia campus never dropped below 9 MVA during 2008, and peaked at 22.7 MVA (Midday, 11 Dec 2008). A PV array with 1 MW peak capacity will never generate more than a maximum of 1 MW due to the ratings of the grid connect inverters. The University of Queensland could only export power from the campus under very unusual circumstances, and the export can never be greater than 1 MW. Based on this, The University of Queensland will not be required to register as an embedded generator. Confirming this, according to NEMMCO's guidelines, UQ's proposed PV system is classified as a very small, non-scheduled and non-market generator and hence, it is exempted from registration. Indeed, NEMMCO has a standing exemption for generating systems with nameplate rating of less than 5 MW. Non-Scheduled is defined as "A generating unit with a nameplate rating of less than 30 MW or a group of generating units connected to common connection point with a combined nameplate rating of less than 30 MW." Non-Market is defined as "A generating unit from which the sent out electricity is purchased in its entirety by the Local Retailer or by a Customer located at the same connection point."

In this situation, UQ itself is the customer located at the same connection point. Although UQ is not required to register as an embedded generator, it may choose to do so at a later date so that it can sell its electricity in the National Electricity Market

(NEM) as a non-scheduled market generator. Registration with NEMMCO incurs participation and registration fees. Participating in the NEM may or may not lead to a better financial return, and the ability to participate is limited given the PV array is non-scheduled. Generators may also be required to register for a generation licence from their state government. In Queensland, "Under section 130 of the Electricity Regulation 2006, a person who operates generating plant with a capacity of 30 MW or less is deemed to have a Special Approval to connect the generating plant to a transmission grid or supply network and sell electricity generated by that plant. In such a circumstance, the person operating the generating plant does not need a Generation Authority and may rely on the 'deemed' Special Approval."

7.3.1 Sale of electricity under alternative tariffs

The Queensland Government Solar Bonus Scheme pays households and other small customers at a higher tariff of 0.44 $/kWh for the surplus electricity generated from roof-top solar photovoltaic (PV) panel systems, that is exported to the Queensland electricity grid (nett generation). To be eligible to receive the solar bonus, among other requirements, customers must consume no more than 100 megawatt hours (MWh) of electricity a year (the average household uses 10 MWh a year), and have solar PV systems with a capacity of up to 10kVA for single phase power and 30kVA for three-phase power. Apart from the lack of nett electricity export at the connection point, on the basis of these two requirements, UQ's proposed grid connected PV system does not qualify for existing Feed in tariff.

7.3.2 Renewable energy certificates (RECs)

As explained in the previous section, The University of Queensland will never be a nett exporter of electricity at its current connection point for the size of grid connected PV array envisaged. Revenue grade metering installed at output of the PV array grid connect inverters will allow "gross" metering – the separate measurement of the PV array power output prior to its consumption internally within the University's electricity distribution network. Gross metering is important for the accounting of Renewable Energy Certificates (RECs) and to allow the sale of the "greenness" of the power generated by the PV modules. Each 1 MWh of renewably generated electricity also allows the creation of 1 REC, which can then be sold, otherwise traded, or retired. The Australian Government's Mandatory Renewable Energy Target Scheme (MRET), which commenced in April 2001, requires the sourcing of 9,500 GWh of extra renewable electricity per year by 2010 through to 2020. The target applies nationally, and is implemented through the Renewable Energy (Electricity) Act 2000 [section ref:7-6]. According to the Department of Climate Change website, "On 30 April 2009, Council of Australian Governments' (COAG) agreed the design of the expanded national Renewable Energy Target (RET) scheme, to implement the Government's commitment that 20 per cent of Australia's electricity supply comes from renewable energy sources by 2020.

The RET scheme expands on the existing Mandatory Renewable Energy Target (MRET) scheme and absorbs State and Territory renewable energy targets into a single national scheme. The RET scheme includes a legislated target of 45 000 gigawatt-hours in 2020, which is more than four times larger than the current target." [section ref: 7-7] If this legislation is successfully put in place, this larger target will provide greater certainty for the future value of RECs. The MRET imposes an obligation on electricity retailers and large consumers to purchase a percentage of their power requirements from renewable sources. They are required to submit a legislated number of RECs in proportion to their electricity purchases in each year. In 2008, this requirement was 3.14% - for every 100 MWh of energy consumed, 3.14 MWh of renewable energy (3.14 RECs) were required to be sourced. Non compliance of the target is underpinned by a $40 per MWh shortfall charge (prior to 2010) and it will be indexed to the CPI between 2010 and 2020. Under current company tax rates (30%) applicable for a profitable liable party would on a purely financial basis, be indifferent between purchasing RECs of around $57 or paying the shortfall charge. To facilitate this objective, qualifying renewable energy generators including solar PV who are accredited by the Office of the Renewable Energy Regulator are permitted to create tradable Renewable Energy Certificates (RECs) for each MWh of renewable electricity generated. Renewable energy from projects commencing after 2005 receive RECs for a period of 15 years. It is important to understand that although the sale of RECs generates an income stream, the seller has effectively "sold" the "greenness" (zero emissions nature) of their renewable energy. They cannot claim they have lowered their emissions, since by selling their RECs; they have sold that right to another emitter. The seller may be able to purchase emissions offsets in some other form at a lower price and fulfil their obligations while still turning a profit. As part of the purchase of electricity, the University will be already purchasing RECs either directly or indirectly to meet its MRET obligation. It may be possible to reduce the number of RECs purchased due to the RECs created in-house. This may be a potential source of income in the same manner that the reduction in electricity consumption effectively creates an income source.

7.4 CONNECTION WITH THE GRID – SIMPLIFIED ECONOMIC ANALYSIS

A preliminary economic analysis has been undertaken to help understand the costs and returns of a grid connected PV system. This simple analysis estimates an installation cost, an annual income and hence a simple payback period. It will be necessary to undertake a more complex analysis to get a more accurate estimate of the payback period. The analysis was undertaken for a potential 384 kWp PV array which could be mounted on one of the multi-storey car parks, and for the combined 1.1 MWp PV array which could be achieved with both carparks and the UQ centre. The combined 1145 kWp array is estimated to generate 4786 kWh/day energy, or 1747 MWh annually. At an estimated installed cost of between $8/Wp to $9/Wp, the array will have a capital cost of approximately $9 million to $10 million. The energy generated by the PV array displaces electricity which would otherwise need to be bought. This saving in energy represents an income stream for the PV array. UQ's electricity tariff is relatively low due to the large volumes of electricity it purchases and this lowers the value of the energy generated. As the cost of electricity rises (as it is predicted to do), this income will rise. Two tariffs are used – the existing 2008 tariff and the quoted 2012 tariff – using the peak rate for weekdays and the off-peak rate for weekends. The annual savings in purchased electricity amount to approximately $94,000 using 2008 rates, and $169,000 using 2012 rates. The RECs generated by the PV array are also assumed to be able to displace RECs which the University would otherwise be obliged to purchase. RECs have been valued at approximately $40 which is a conservative value, lower than the rate at which they are currently trading. The creation of RECs will generate another $70,000 each year for the combined PV array. Using a range of assumptions, a preliminary estimate of the full payback period is approximately 20 years.

7.4.1 Greenhouse gas abatement

One motivation for the installation of renewable energy generation is to reduce the generation of greenhouse gases through the displacement of electricity that would otherwise be generated by conventional power stations with their associated greenhouse emissions. Greenhouse gas emissions are measured in tonnes of carbon dioxide equivalent (t CO2-e) which accounts for other greenhouse gases such as methane. Generating 1747 MWh of electricity annually from a grid connected Photovoltaic system will displace 1817 tonnes of CO2-e per year.

7.4.2 Public relations and research value

Potential publicity benefits include:

- Provided 1.1 MWp is targeted, claiming the largest photovoltaic installation in Australia (based on current knowledge)
- A demonstration of the University's commitment to renewable energy
- An educational visitor centre for University students, school students and the wider community
- An online educational tool
- Research opportunities

Assessing the value of these PR benefits is ultimately at the discretion of UQ. These benefits may take precedence over the expected cost payback period. By establishing a world leading photovoltaic research platform, UQ can accelerate research in this area.

8 Modelling the Future Composition of Electricity Supply

The process of increasing distributed energy generation has important implications for the existing national generation capacity. The shifting pattern of generation will dictate carbon emissions and, importantly, policymakers need to know which coal-fired power stations should be shut down first and how much gas-fired capacity will be necessary to introduce while distributed energy generation and other non-carbon emitting sources of supply are built up. Without detailed guidance concerning the implications of shifts to significant distributed energy generation, it will be difficult for policymakers to plan an orderly restructure of the power generation system. Also, it will be impossible to do this without taking into account the impacts of carbon pricing and trading. It is necessary to assess just how high the carbon price has to be to provide a significant incentive for large substitutions of low carbon emitting technologies. Distributed energy generation, such as PV, can be expected to become viable sooner than other technologies because it doesn't use the transmission and distribution system for flow, having mainly a reduction in demand effect instead of increasing transmittable supply. However, until cost effective power storage can be introduced, these technologies will continue to rely upon the grid as the implicit storage medium if power generation doesn't match peak demand.

We have constructed a modelling methodology that will answer key questions concerning the shifts in generation that will occur as we move into a low carbon emissions environment. This will enable policymakers to be able to identify where subsidies to assist closures will be required. This will reduce the extent to which coal-fired generators will obstruct policies to encourage significant shifts to low carbon emission technologies. The model of the NEM used is a 'state of the art' agent-based model suited to modelling complex economic systems.

8.1 Rationale and Design Issues Underpinning the Development of Agent Based Electricity Model.

The agent based modelling framework developed for the Australian National Electricity Market (NEM) was a modified and extended version of the 'Agent-Based Modelling of Electricity System (AMES)' model for the USA system developed by Sun and Tesfatsion (Sun, 2007a, Sun, 2007b).[1] The Australian model is called the 'ANEMMarket' model.

The heuristic framework underpinning the development of the USA model by Sun and Tesfatsion was the Wholesale Power Market Platform (WPMP) which was adopted by the USA Federal Energy Regulatory Commission in April 2003. The WPMP was a complicated market design that was recommended for common adoption by all USA wholesale power markets. As such, it could 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, 2007b).

The WPMP market design had a high degree of complexity which led to difficulty in undertaking economic and physical reliability studies of the design using standard statistical and analytical tools (Sun, 2007b). This overriding degree of complexity suggested the applicability of the emerging powerful computational tools associated with the analysis of complexity based upon Agent-based Computational Economics (ACE) as developed, for example, in (Sun, 2007b).[2]

ACE is a computational study of economic processes modelled as a dynamic system of interacting agents. Thus, both the 'AMES' and 'ANEMMarket' modelling frameworks were developed with the intension of modelling strategic trading interactions over time in a wholesale power market that was organized in accordance with core WPMP features and that operated over realistically rendered transmission grid structures (Sun, 2007b). In ACE, strategic behaviour is often modelled by adaptive learning built around reinforced learning or emergent learning and knowledge creation from genetic algorithms.

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. Therefore, a DC OPF algorithm was used to determine optimal dispatch of generation plant and wholesale prices within the agent based model. In principle, formulation of DC OPF

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 Useful information and computational resources related to ACE modelling can be found at: http://www.econ.iastate.edu/tesfatsi/ace.htm.

problems require detailed structural information about the transmission grid as well as supply offer and demand bid information from market participants.

In order to formulate the DC OPF problem, it was necessary to modify the structure of the 'AMES' program in important ways in order to capture the key differences existing between the wholesale markets in Australia and the USA. The most important structural difference related to the institutional structure of the market in Australia which differed fundamentally from that in the USA. Specifically, in Australia, a 'Gross Pool' market structure was implemented whereas a 'Net Pool' market structure was implemented widely in the USA. This meant that the spot market and potential role of the 'day ahead' market had fundamentally different operational, procedural and legal meanings in the context of wholesale market operations in both countries.

In Australia, the spot market is the principal market in which transactions to sell and buy physical quantities of power are made with resulting financial settlements that reflect spot market outcomes. Moreover, while day ahead bidding by generators frequently occurs and forms an important part of pre-dispatch forecasts released by the national ISO (i.e. AEMO) prior to current spot market operations, this bidding does not constitute a formal legally binding market operation with implied financial settlement protocols. The day ahead bidding helps AEMO determine and inform market participants of the 'state-of-play' with respect to the balancing of supply with demand in relation to prospective spot market operations but generators can leave their day ahead bids unchanged or change them just prior to dispatch within the operation of the spot market itself (AEMO, 2009). As such, the day ahead bidding facilitates spot market operations but does not constitute, in and of itself, a formal 'day ahead' market operation with binding legal and financial implications for participants. Because of the gross pool structure underpinning the Australian market, the spot market is the key binding market legally and financially. As such, the onus for ensuring supply matches demand ultimately rests with generators who are legally required to exactly follow dispatch instructions issued by AEMO in order to match the supply of power with the demand for power in a real time setting. Because of the marked possibility of considerable spot price volatility, hedging by wholesale market participants is crucial for their long term financial viability. These characteristics were implemented in the 'ANEMMarket' program.

8.2 PRINCIPAL FEATURES OF THE 'ANEMMARKET' MODEL FRAMEWORK.

We now give a brief outline of the principal features, structure and agents in the 'ANEMMarket' model framework. 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 of the WPMP market design that can be associated with key features of the Australian National Electricity Market. Specifically, the elements of the WPMP market design that have been incorporated into the 'ANEMMarket' framework 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;[4]
- 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 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.[5]

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

4 A node in the grid is a point on the transmission grid where power is injected or withdrawn.

5 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. The locational marginal price (LMP) at any particular node can be considered the least cost of meeting demand at that node for an additional unit [megawatt (MW)] of power.

- 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). The ISO is an independent organization and is assumed to have no conflicts of interest in carrying out these responsibilities.

- 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.

8.3 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.[6] We do not assume complete connectivity, however, implying that node pairs are not necessarily connected directly to each other through a single branch.

In common with the design features outlined in (Sun, 2007b), 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;[7]
- 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.

6 If two nodes are directly connected to each other, it is assumed to be at most by one branch thereby ruling out explicit consideration of branch groups.

7 This means that the branch length is already taken into account.

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. 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.

They key transmission data required for the transmission grid within the model relate to an assumed base voltage value (in KV's) and base apparent power (in MVA's)[8], branch connection and direction of flow information as well as the maximum thermal rating of each transmission line (in MW's), together with an estimate of its (SI) reactance value (in ohms).

In accordance with the WPMP power design, the transmission grid has a commercial network consisting of 'pricing locations' for the purchase and sale of electricity power.[9] We assume that the set of pricing locations coincides with the set of transmission grid nodes.

8.3.1 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, they link the wholesale power market and the downstream retail market. LSE's purchase power only from generators because they are assumed to not engage in production or sale activities in the wholesale power market. In principle, at each node there can be zero, one or more LSE's.

For simplicity, it is assumed that downstream retail demands serviced by the LSE's exhibit negligible price sensitivity and hence reduce to daily supplied load profiles. In addition, LSE's are modelled as passive entities who submit daily load profiles (i.e. demand bids) to the ISO without strategic considerations (Sun, 2007b). 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. Therefore, in the current set-up, LSE's have no incentive to

8 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 and NSW transmission companies 'Powerlink' and 'Transgrid'.

9 A pricing location is a location at which market transactions are settled using publicly available LMP's.

submit price-sensitive demand bids into the market.[10] Therefore, we assume that just prior to the beginning of each day D each LSE submits 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.[11]

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.

8.3.2 Generator Agents.

The 'ANEMMarket' generator agents are electric power generating units, and each generator is configured with a production technology. In principle, zero, one or more generators can be located at each node in the transmission grid. It is assumed further that generators can sell power only to LSE's and not to each other.

With regard to production technology, it is assumed that generators have variable and fixed costs of production, but do not incur other costs such as no-load, start-up, or shutdown costs. At this stage, we also assume that they do not face ramping constraints (Sun, 2007b).

For each generator, technology attributes are assumed, and these attributes refer to the feasible production interval[12], total cost function, total variable cost function, fixed costs [pro-rated to a $(\$/h)$ basis] and a marginal cost function. 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

10 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.

11 The regional load data 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. Time series data relating to the AEMO 'QLD1' and 'NSW1' data can be found at: http://www.aemo.com.au/data/price_demand.html.

12 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.

respect to hourly energy produced, yielding a marginal cost function that is linear in hourly real energy production of each generator (Sun, 2007b).[13]

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 (ACILTASMAN, 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 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.

Passive Hedging

Both theory and observation suggest that financial settlements based on 'Gross Pool' 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.

13 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.

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.

A key decision for both sets off agents is when to activate long cover in order to protect their bottom lines from the consequences of consistently high (low) spot prices – a key determinant of 'excessively' high costs ('excessively' low revenues) faced by LSE's and generators respectively that could potentially pose problems for their continued market solvency. 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.[14]

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). This payment constitutes a partial profit transfer back to generators (LSE's) on the part of LSE's (generators) seeking long cover. Thus, the small fee acts like a conventional premium payment in 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.

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.[15]

14 If the price floor applicable to generators is set equal to the generators long run marginal (i.e. 'levelised') cost, then generator long run revenue recovery can be implemented through the implementation of hedge cover.

15 SUN, J. A. L. T. (2007a) DC Optimal Power Flow Formulation and Solution Using QuadProgJ. *ISU Economics Working Paper No. 06014.* Department of Economics, Iowa State University, IA 50011-1070. formally demonstrate how the conventional AC OPF power flow equations can be derived from Ohm's law and how the DC OPF problem can be formally derived from the AC OPF power flow equations, [see SUN, J. A. L. T. (2007a) DC Optimal Power Flow Formulation and Solution Using

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. The solution of this standard DC OPF problem as a SCQP problem directly provides solution values for real power injections. However, solution values for locational marginal prices (LMP's), voltage angles, and real power branch flows have to be recovered indirectly by additional manipulations of solution values ((Sun, 2007b), Sections 3.2)).

Tesfatsion and Sun (Sun, 2007b), Sections 3.3) demonstrate that the standard DC OPF problem can be augmented, 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. However, in its standard form, voltage angle substitution eliminates the nodal balance constraints and hence the ability to directly generate solution values for LMP's, which are the shadow prices for the nodal balance constraints. Therefore, the 'augmentation' requires an implementation of an alternative version of the standard DC OPF problem that makes use of Lagrangian augmentation. This augmented DC OPF problem can directly generate solution values for LMP's, voltage angles, and voltage angle differences as well as real power injections and branch flows while retaining the numerically desirable SCQP form, [see (Sun, 2007a), Sections 3.4)].

The augmented SCQP problem can be solved using QuadProgJ, a SCQP solver developed by Sun and Tesfatsion [see (Sun, 2007a), Section 6)]. The program platform QuadProgJ implements the dual active-set SCQP algorithm developed by Goldfarb and Idnani (1983) and is programmed in Java. The advantage of the SCQP formulation is its highly desirable properties from the standpoint of stable numerical solution properties. [16]

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

---

QuadProgJ. *ISU Economics Working Paper No. 06014.* Department of Economics, Iowa State University, IA 50011-1070. pp. 8-10].

16 The SCQP algorithm has two potential limitations. The first is the requirement that the QP objective function be a strictly convex function. The second is that the JAVA code implementing the algorithm does not incorporate sparse matrix techniques, and as a consequence, is not designed for large-scale problems for which speed and efficiency of computation become critical limiting factors.

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.[17]

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 via 'connected' transmission grid branches. 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 constraint give the LMP (i.e. 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 energy produced by each generator (on an 'energy sent out' basis) remains within permitted lower and upper thermal limits. The algorithm has also been extended to include an aggregate carbon emissions constraint. This is an inequality constraint requiring that aggregate (i.e. 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.

8.4 AN APPLICATION OF THE 'ANEMMARKET' MODEL: CARBON PRICE MODELLING SCENARIO – IMPACT OF VARIOUS CARBON PRICE SCENARIOS ON DISPATCH, CONGESTION, PRICES AND CARBON EMISSIONS ON 23/1/2007.

To demonstrate the type of analysis that can undertaken by the 'ANEMMarket' model, we investigated a number of carbon price scenarios for regional load profiles associated with 23/1/2007, which contained a number of hourly peak demand periods for the Sydney node for the 2006-07 financial year.

The transmission grid used involved combining both the existing QLD and NSW modules - see Figures 1 and 2. The state module linking was via the 'QNI' and 'Directlink' Interconnectors which enabled the transfer of power between QLD and NSW, thereby enabling trade between the two states.

---

17 One voltage angle is eliminated by setting its value equal to zero. This is a normalisation condition so solution values are actually determined for voltage angles of 'K-1' nodes.

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 scenario allowed 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 associated 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 permitted 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.

It was assumed that all thermal generators were available to supply power during the day. As such, this modelling scenario is an 'as if'' scenario. In particular, we did not try to emulate actual generator bidding patterns for the particular day in question. Our objective, instead, is to investigate how the true cost of power supply changed for the various carbon price 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' scenario involving the absence of a carbon price signal.

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:

- 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; and
- Murray 1 (unit 1) and Murray 2 (unit 1): 07:00 – 21:00.

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 hydro generation plant to supply power effectively 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.

In general, two fuel substitution effects were evident in the scenarios considered in response to increases in the carbon price. The first was a general substitution of gas fired generation for coal fired generation as the carbon price was increased. The second substitution was the substitution of newer coal fired plant for older coal fired plant. This reflected the fact that the newer plant had better thermal and lower emission intensities than older coal plant. These broad trends can be discerned from inspection of the following four tables. These tables display the average dispatch levels as a percentage of total portfolio capacity (in terms of energy generated) over the 24 hour period for various carbon price scenarios considered.

Table 1: Average Daily Dispatch (as a Percentage of Total Portfolio Capacity) of Gas Fired Generator Portfolios for Various Carbon Price Scenarios

23/1/2007							
SCENARIO	**Townsville**	**Barcaldine**	**Braemar**	**Swanbank E**	**Smithfield**	**Tallawara**	**Uranquinty**
$0/tC02 BAU	0.0	0.0	3.41	37.07	22.49	24.80	10.85
$10/tC02	0.0	0.0	3.41	37.07	22.75	26.94	10.85
$20/tC02	0.0	0.0	3.41	47.15	22.98	38.49	11.09
$30/tC02	1.90	0.0	3.41	73.60	35.97	69.86	12.97
$50/tC02	100.00	0.00	48.26	100.00	99.23	100.00	15.04
$70/tC02	100.00	96.13	99.11	100.00	100.00	100.00	15.04
$100/tC02	100.00	100.00	100.00	100.00	100.00	100.00	23.81

Table 1 displays the results for gas fired thermal portfolios. Inspection of this table indicates that the dispatch patterns did not change much for carbon prices in the range of $0/tC02 to $20/tC02. The slightly larger percentages for Swanbank E reflects the fact that the landed gas prices for this plant is relatively cheaper when compared to other gas plant and this plant is primarily 'competing' against the relatively old coal fired plant of Swanbank B which has relatively poor thermal and carbon emission intensity factors when compared with newer coal fired plant located at the Tarong and South West Queensland nodes. As the carbon prices increases, Swanbank E essentially displaces the capacity of Swanbank B that was dispatched at lower carbon prices.

In the carbon price range of $30/tC02 to $50/tC02, the relative cost of gas fired plant is approaching or has become less than the relative cost of most of the coal fired plant fleet commissioned between 1965 and 1995. This leads to the full dispatch of Townsville, Swanbank E, Smithfield and Tallawara gas portfolios and the Braemar portfolio to a slightly less extent. The lower dispatch percentages for Braemar reflect the fact that it is located at the same node as Kogan Creek and Millmerran coal fired portfolios which are amongst the cheapest and most thermally and carbon efficient coal fired plant in Australia.[18]

At a carbon price of $100/tC02, all gas portfolios apart from Uranquinty are fully dispatched. The results for Uranquinty reflect the fact that it is located at the same node (Tumut) as a significant proportion of the Snowy Mountain hydro generation plant which is dispatched at very lower marginal cost which does not change as carbon prices are increased. Therefore, some of this hydro generation plant dispatch would be potentially displacing dispatch that might have emerged for Uranquinty as the price of carbon increased.[19]

The key result to emerge from the results cited in Table 1 is that a carbon price in the range of $50/tC02 to $70/tC02 seems to be needed to induce significant substitution of gas fired generation for existing coal fired generation.

The dispatch results for coal fired plant commissioned between 1965 and 1976 are displayed in Table 2. Inspection of this table generally demonstrates the substitution of other generation sources for the 'old' coal fired fleet where alternative sources of supply exist within the nodal structure of the transmission grid. First, it should be noted that the Collinsville fleet is never dispatched – the cheaper and more carbon efficient hydro generation plant in the Far North Queensland Node and well as 'newer' coal fleet in the Central West Queensland Node effectively displace it as a viable source of supply. There is a slight reduction in the percentage dispatch of the Gladstone Fleet but its nodal position in servicing the sizeable industrial load associated with the Gladstone regional area and the absence of alternative competing generators at this node ensures its continued dispatch at significant levels. The same nodal positioning argument also applies to Wallerawang.

The other coal fired generation portfolios listed in Table 2 display significant reduction in their percentage dispatch figures. This would principally reflect substitution of gas for these coal fired generators as well as substitution from newer cheaper coal fired plant. For Swanbank B, the key driver would be displacement by Swanbank E as carbon prices make Swanbank E more competitive relative to the coal fired Swanbank B portfolio. For the Liddle and Munmorah portfolios, they key

18 Inspection of Table 1 indicates that carbon prices in excess of $70/tC02 would be required to equalize the relative cost of power generation of Braemar with that of Kogan Creek and Millmerran coal fired Portfolios.

19 If a Victorian module was introduced, Uranquinty would be particularly well placed to supply power to Victoria in response to scenarios involving carbon price increases which would disadvantage the largely brown coal fired generation plant prominently located in Victoria.

sources of displacement are substitution of cheaper coal fired dispatch (particularly from Bayswater) plus the export of cheaper power sourced from South West Queensland as well as the increased dispatch of the Smithfield and Tallawara gas fired portfolios (as the carbon price is increased).

Table 2: Average Daily Dispatch (as a Percentage of Total Portfolio Capacity) of 'Old Vintage' Coal Fired Generator Portfolios for Various Carbon Price Scenarios

23/1/2007						
SCENARIO	Collinsville	Gladstone	Swanbank B	Liddle	Munmorah	Wallerawang
$0/tC02 BAU	0.00	65.66	55.98	81.37	68.40	49.52
$10/tC02	0.00	66.26	55.45	52.96	66.64	53.07
$20/tC02	0.00	67.06	46.61	45.12	44.92	61.44
$30/tC02	0.00	63.62	39.51	37.03	25.48	57.38
$50/tC02	0.00	58.69	11.08	18.40	24.40	45.82
$70/tC02	0.00	55.07	11.08	9.47	24.40	45.82
$100/tC02	0.00	54.29	11.08	10.07	14.78	44.18

In Table 3, the average daily percentage dispatch patterns for coal fired plant commissioned between 1977 and 1995 are displayed. The only portfolio displaying a significant reduction in average dispatch levels is the Callide B portfolio which would reflect displacement by the Townsville gas portfolio for carbon prices in excess of $30/tC02.[20] The contribution of the Bayswater portfolio increases as it displaces the older coal fired Liddle portfolio. The declines in average daily dispatch percentages for the Eraring and Vales Point portfolios most likely reflect the partial displacement by the increased dispatch of the Smithfield and Tallawara gas portfolios which can directly service the Sydney node.

Table 3: Average Daily Dispatch (as a Percentage of Total Portfolio Capacity) of 'Medium Vintage' Coal Fired Generator Portfolios for Various Carbon Price Scenarios

23/1/2007							
SCENARIO	**Stanwell**	**Callide B**	**Tarong**	**Bayswater**	**Eraring**	**Vales Point**	**Mt Piper**

20 The fuel cost and emissions intensity of Callide B is slightly higher than the corresponding results for Stanwell which is the key reason why the Callide B Portfolio is both dispatched less intensively and displaced more extensively than the Stanwell Portfolio.

$0/tC02 BAU	94.88	76.82	100.00	61.56	94.53	100.00	75.23
$10/tC02	100.00	73.30	100.00	82.72	89.44	100.00	88.51
$20/tC02	100.00	78.96	100.00	86.69	84.97	100.00	98.64
$30/tC02	100.00	81.53	100.00	92.66	82.92	99.59	100.00
$50/tC02	100.00	68.47	100.00	97.57	77.89	97.05	100.00
$70/tC02	99.87	50.69	100.00	97.57	80.08	96.14	100.00
$100/tC02	100.00	50.69	99.38	97.57	81.57	94.22	100.00

In Table 4, the average daily percentage dispatch patterns for coal fired plant commissioned after 1995 are displayed. The only portfolio displaying a significant reduction in average daily dispatch is the Redbank portfolio. This displacement reflects the high carbon emission intensity of the tailing (i.e. coal waste) fuel source which induces it to be totally displaced for carbon prices of $30/tC02 or higher. This would reflect partial displacement by cheaper power supplied from South West Queensland and cheaper power being supplied from the Bayswater coal fired generators. All other generators are dispatched fully reflecting their superior thermal, fuel cost and emission intensities factors when compared with other existing coal fired plant, even in the presence of significantly rising carbon prices.

Table 4: Average Daily Dispatch (as a Percentage of Total Portfolio Capacity) of 'Latest Vintage' Coal Fired Generator Portfolios for Various Carbon Price Scenarios

23/1/2007					
SCENARIO	**Callide C**	**Tarong North**	**Kogan CK**	**Millmerran**	**Redbank**
$0/tC02 BAU	100.00	100.00	100.00	100.00	100.00
$10/tC02	100.00	100.00	100.00	100.00	20.83
$20/tC02	100.00	100.00	100.00	100.00	6.32
$30/tC02	100.00	100.00	100.00	100.00	0.00
$50/tC02	100.00	100.00	100.00	100.00	0.00
$70/tC02	100.00	100.00	100.00	100.00	0.00
$100/tC02	100.00	100.00	100.00	100.00	0.00

Carbon emissions reduction from the 'Business-As-Usual (BAU)' (i.e. no carbon price) scenario reflects the dispatch patterns observed above. The observed emission reductions are driven by the substitution of gas for coal fired plant and the substitution of newer coal plant with lower cost and emission intensities for older coal fired plant with higher cost and emission intensities.

Table 5: Carbon Emission Levels and Percentage Reductions from 'BAU' Associated with Various Carbon Price Scenarios

SCENARIO	Carbon Emissions (tC02)	% Change from BAU
$0/tC02 BAU	347474.5	
$10/tC02	345500.3	-0.57
$20/tC02	343338.6	-1.19
$30/tC02	339021.5	-2.43
$50/tC02	328665.3	-5.41
$70/tC02	325469.1	-6.33
$100/tC02	324786.7	-6.53

The results cited in Table 5 shows both the level of carbon emissions and percentage reduction from the 'BAU' levels associated with the various carbon price scenarios. It is clear that the increase in the carbon price to a level of $100/tC02 has effected a reduction in aggregate (i.e. system wide) carbon emission levels from the BAU level of 6.53 percent. Apart from the dispatch of more hydro generation plant from the Snowy Mountain nodes of Tumut and Murray in NSW, it is difficult to see how carbon emissions could be reduced much further with the existing fleet of generators. The cheapest, most carbon efficient coal fired plant are being fully dispatched together with most of the gas turbine fleet apart from the Uranquinty portfolio. The most expensive and carbon emission intensive coal plant's dispatch has been effectively displaced to a large extent so additional capacity capable of eating into the aggregate carbon footprint seems very limited, apart from the remaining hydro generation units mentioned above.[21] Moreover, the remaining peak

21 Complicating the dispatch of hydro generation units in the Snowy Mountains Hydro scheme is the fact that water releases are determined as part of the management of irrigation releases into the Murray and Murrumbidgee River systems.

plant that has not been dispatched is the diesel based fleet which face marginal costs in the order of $300/MWh and do not have a large aggregate MW capacity in any case. They also have higher carbon emission intensities than natural gas fired generation plant that has been largely dispatched (apart from the Uranquinty).

Therefore, if the above pattern of emission reduction is indicative given the existing structure and nodal location of thermal plant and binding constraints on hydro generation, then in order to obtain further deep emission cuts, two possible and interrelated approaches would seem to be necessary. On the supply side, significant investment in additional capacity based on proven low emission intensity technologies such as NGCC or OCGT technologies would be needed, especially if renewable supply side proposals based on clean coal, geothermal, solar thermal and wind prove problematical for base load and intermediate production duties. Second, demand side initiatives that focus on reducing the aggregate load that has to be serviced by generators will also reduce carbon emissions especially if the load reduction is fulfilled by renewable technologies. Such options might relate to the use of solar PV technologies, thermal heating and air-conditioning, smart metering which manages and reduces load during peak demand periods as well as improved energy efficiency associated with the uptake of improved construction standards and techniques.

Plots of the optimal system variable costs (defined in terms of $000's/h) determined from the DC OPF algorithm used to determine dispatch and regional prices is shown in Figure 10. It is apparent from inspection of this figure that the variable cost profiles shift upward with increases in the carbon price. The shape of each profile also indicates that more costly generation plant has to be dispatched to meet peak daily demand. For lower carbon prices, this would be associated with the more intense dispatch of more expensive gas fired generation. For higher carbon prices, this would reflect the continued need to dispatch coal fired generation to service load demand in an environment where their relatively higher emission intensity factors (when compared with gas plant) translate into higher relative variable carbon costs.

The upward shift in the system variable cost functions documented in Figure 10 will translate into upward shifts in the average wholesale price of electricity. This can be discerned by inspecting Figure 11. It is evident from inspection that the average price profile shifts upwards as the carbon price (and system variable costs) increase. For low carbon prices (in the range $0/tC02-$30/tC02) the shape of the average price profile remains the same and the magnitude of the upward shift remains approximately the same. This reflects the fact that the carbon price has been increased in increments of $10/tC02. The other noticeable observation is that the small plateau effect associated with hours 13:00-18:00 at lower carbon prices narrows and becomes more pronounced for higher carbon prices in the range $70/tC02 to $100/tC02. It is over these hours that the remaining dispatch of 'old' coal fired plant (notably the Swanbank B, Liddle and Munmorah portfolios) still occurs at significant capacity levels and the high carbon intensities of these plant, together with the higher carbon prices, have the effect of driving up the marginal cost of dispatch in these hours in relative terms which is subsequently reflected in the average price profile.

Nodal based price variations within a state and between states is possible when branch congestion arises on one or more transmission lines. This is possible, in the current setting, if the introduction of a carbon price causes the dispatch patterns to change significantly from the 'BAU' dispatch patterns. To investigate this issue, we present a brief profile of the transmission lines experiencing congestion for the BAU scenario and the $100/tC02 carbon price scenario. This information is documented in Table 6 and Table 7, respectively, together with QNI and Directlink Interconnector (MW) flows between the two state modules[22].

It is apparent from inspection of Table 6 that for the 'BAU' scenario, congestion occurs on the 'Central West QLD – Tarong' (line 5) branch, 'Lismore to Armidale' (line 15) branch, 'Bayswater to Sydney' (line 20) branch, and episodically on the 'Sydney to Mt Piper' (line 24) branch. For the $100/tC02 scenario, it is apparent from Table 7 that congestion continues on branch lines 5 and 15 although the extent of congestion on line 15 has diminished as power flow on Directlink has increased, thus reducing the need for power from the Liddle and Bayswater based generators in order to service load demand in northern regions of New South Wales. Congestion on branch line 20 has also diminished possibly in response to the increased dispatch of gas fired Smithfield and Tallawara portfolios and the Mt Piper generators which has increased congestion on branch line 24. There is also episodic evidence of some congestion on branch lines 16 ('Armidale to Tamworth') and on line 19 ('Liddle to Newcastle'). The source of generation underpinning these power flows largely originates from South West Queensland with the power transfer being exported from Queensland along the QNI Interconnector into New South Wales. For example, compare the second last columns of Tables 6 and 7 respectively to see the increased power transfer along the QNI Interconnector associated with the $100/tC02 carbon price scenario over the levels associated with the 'BAU' scenario.

---

22 It should be noted that the positive MW values in the last two columns of Tables 6 and 7 indicate power transfers from Queensland to New South Wales. Negative signed power flows, on the other hand, represent power transfers from New South Wales to Queensland.

In order to demonstrate the nature of regional (nodal) price variation produced by the branch congestion, we present graphs containing plots of the hourly average, minimum and maximum nodal prices for a selection of the carbon price scenarios. These plots are documented Figure 12 to Figure 16, respectively. These figures indicate that there is a substantial difference between the minimum and maximum nodal price for all selected scenarios considered. For the 'BAU' scenario (Figure 12), the maximum nodal prices during the peak demand period (12:00 to 20:00 hours) are in excess of $100/MWh while the corresponding average price level is in a range between $40/MWh to $55/MWh prices. The corresponding minimum prices are in quite a narrow price range encompassing $35/MWh to $38/MWh.

The pattern discerned above in relation to the 'BAU' scenario continues for all other selected carbon price scenarios listed in Figure 13 to Figure 16. The main difference is an overall upward shift in the price series as the carbon price level is increased reflecting the upward shift in variable and marginal costs. The narrowing and increasing prominence of the plateau observed previously for average hourly price levels (i.e. see Figure 11) emerges in both the plots of average and maximum prices around hours 15:00 to 1800 as the carbon price is increased – for example, see Figures 5c to 5e. It is clear that the price trends at the upper end of the price range is driving this outcome – in this particular case, the incidence of peak hourly demand arising at the Sydney node is causing the relative jump in the nodal price at the Sydney node that is subsequently producing the more pronounced plateau affect observed in Figure 14 to Figure 16.

Table 6: Incidence of Branch Congestion and Power Transfers on QNI and Directlink Interconnector for $100/tC02 Carbon Price Scenario

Hour	Line 5	Line 15	Line 16	Line 19	Line 20	Line 24	QNI	Directlink
1:00			X				1198	136
2:00			X				1168	126
3:00				X			1108	111
4:00				X			1090	107
5:00			X				1149	120
6:00			X				1182	133
7:00							924	94
8:00	X						930	101
9:00	X				X		985	120
10:00	X				X		781	88
11:00	X	X			X		761	88
12:00	X	X			X	X	774	93
13:00	X	X			X	X	790	99
14:00	X	X			X	X	793	101
15:00	X	X			X	X	805	106
16:00	X	X			X	X	801	103
17:00	X	X			X	X	768	90
18:00	X	X			X		754	85
19:00	X	X			X		713	73
20:00	X	X			X		715	74
21:00	X				X		704	63
22:00	X				X		971	98
23:00							1033	106
0:00							910	84

Table 7: Incidence of Branch Congestion and Power Transfers on QNI and Directlink Interconnector for \$100/tC02 Carbon Price Scenario

Hour	Line 5	Line 15	Line 20	Line 24	QNI	Directlink
1:00		X	X		306	7
2:00		X	X		247	-9
3:00		X	X		202	-22
4:00		X	X		191	-25
5:00		X	X		218	-17
6:00		X	X		289	3
7:00		X	X		384	25
8:00	X	X	X		469	48
9:00	X	X	X		536	69
10:00	X	X	X		567	81
11:00	X	X	X		587	88
12:00	X	X	X		599	93
13:00	X	X	X		630	99
14:00	X	X	X		679	101
15:00	X	X	X	X	690	106
16:00	X	X	X	X	630	103
17:00	X	X	X		593	90
18:00	X	X	X		580	85
19:00	X	X	X		542	73
20:00	X	X	X		540	74
21:00	X	X	X		488	55
22:00	X	X	X		416	28
23:00		X	X		361	15
0:00		X	X		321	7

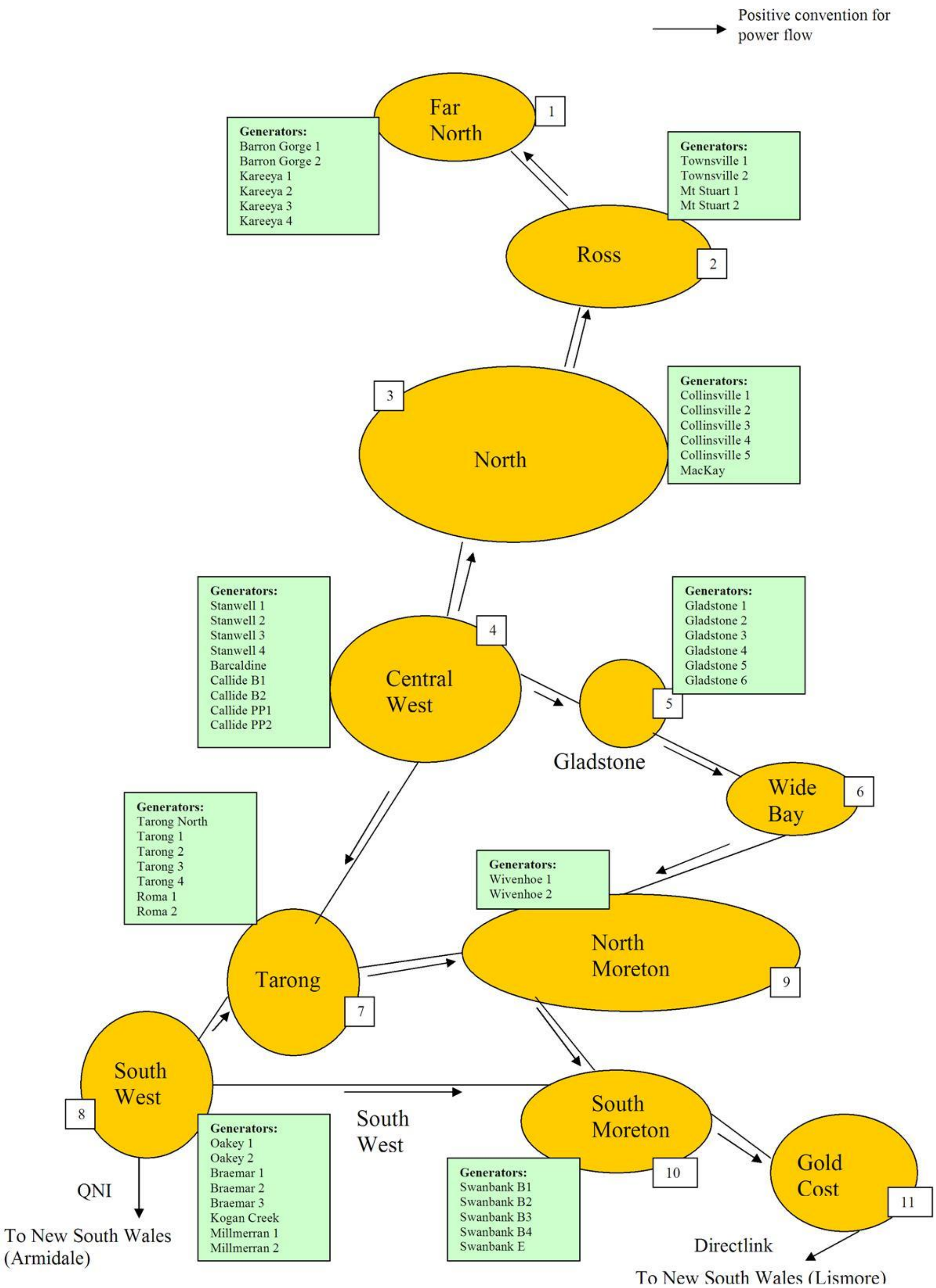


Figure 8: QLD 11 Node Model - Topology

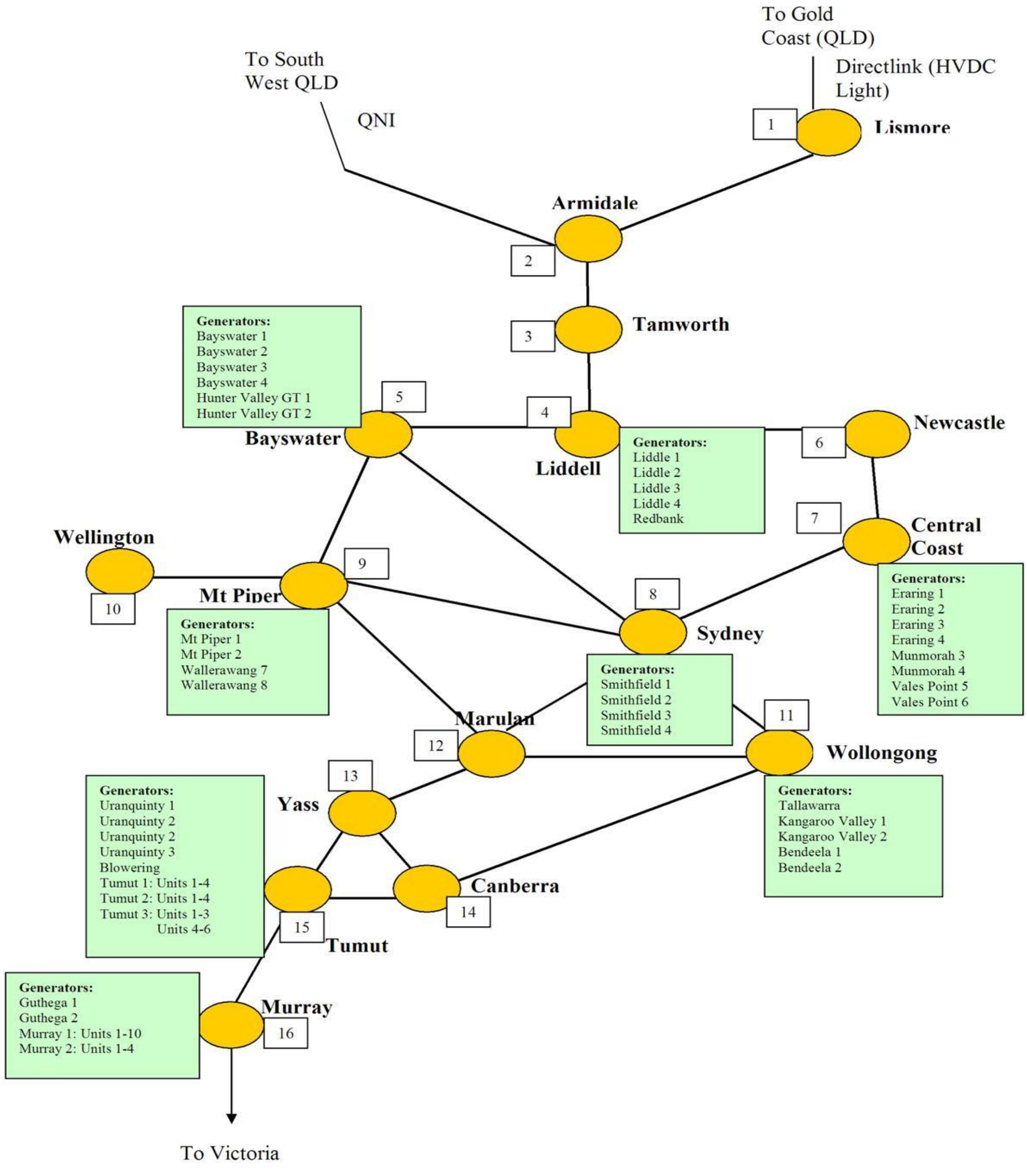


Figure 9: NSW 16 Node Model - Topology

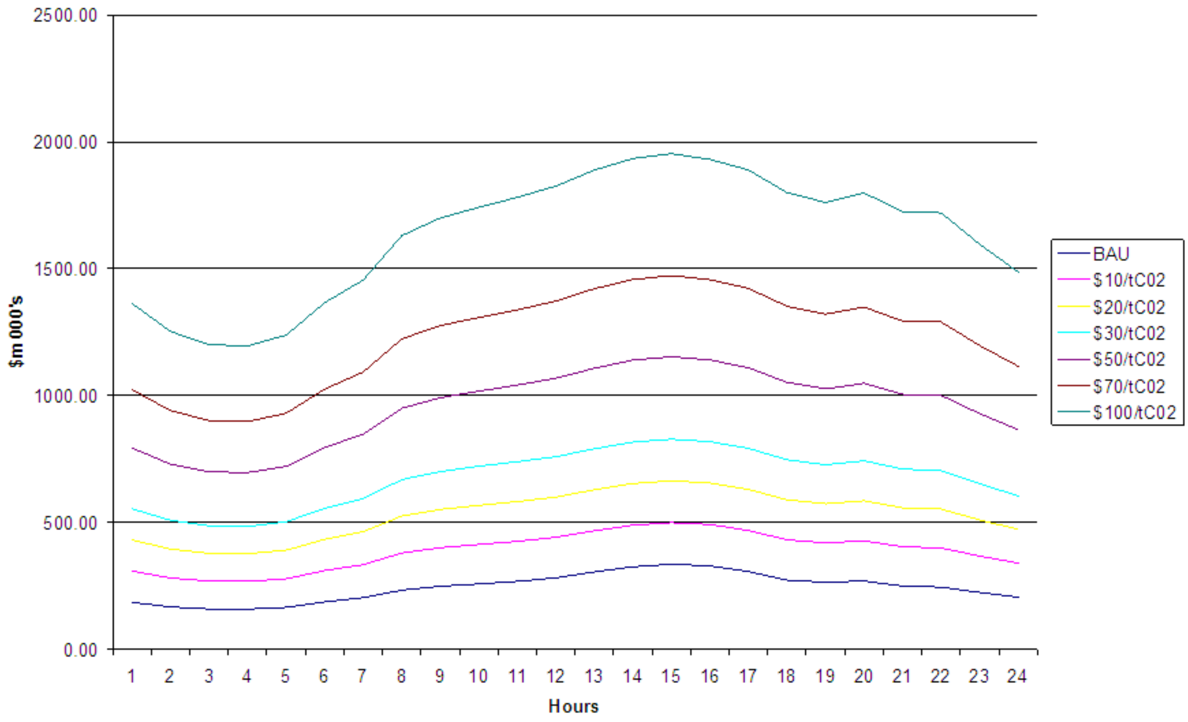


Figure 10: Plot of Optimal Hourly System Variable Cost

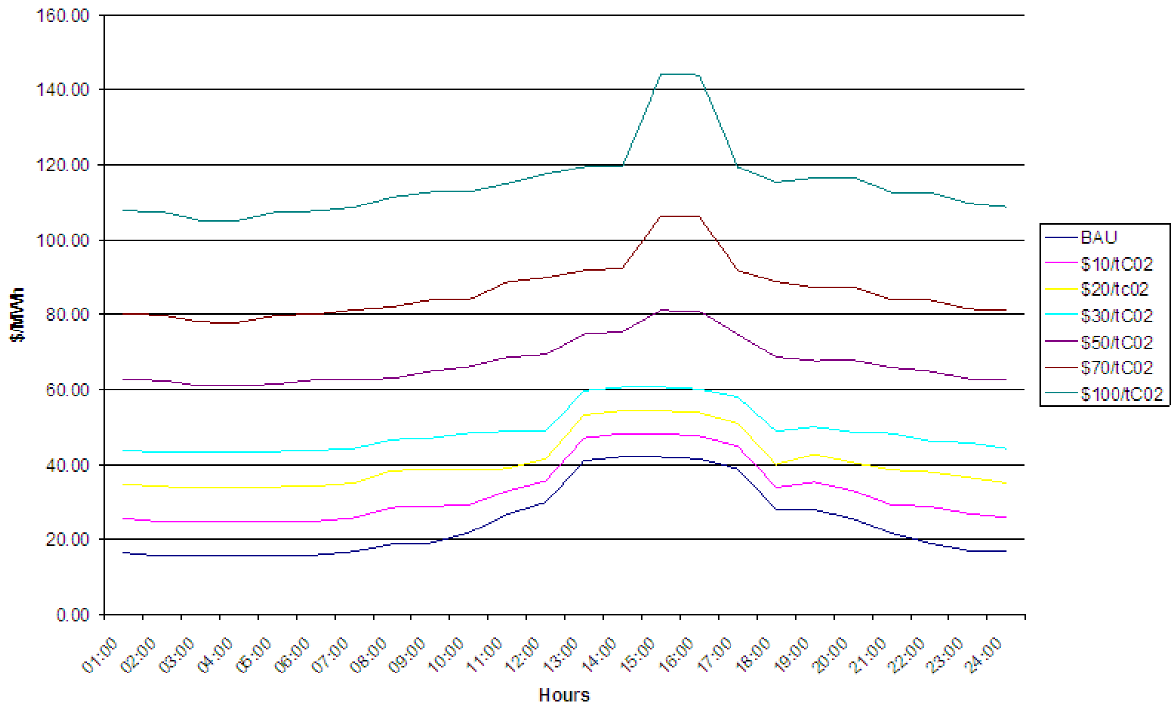


Figure 11: Average Hourly Electricity Prices for Various Carbon Price Scenarios

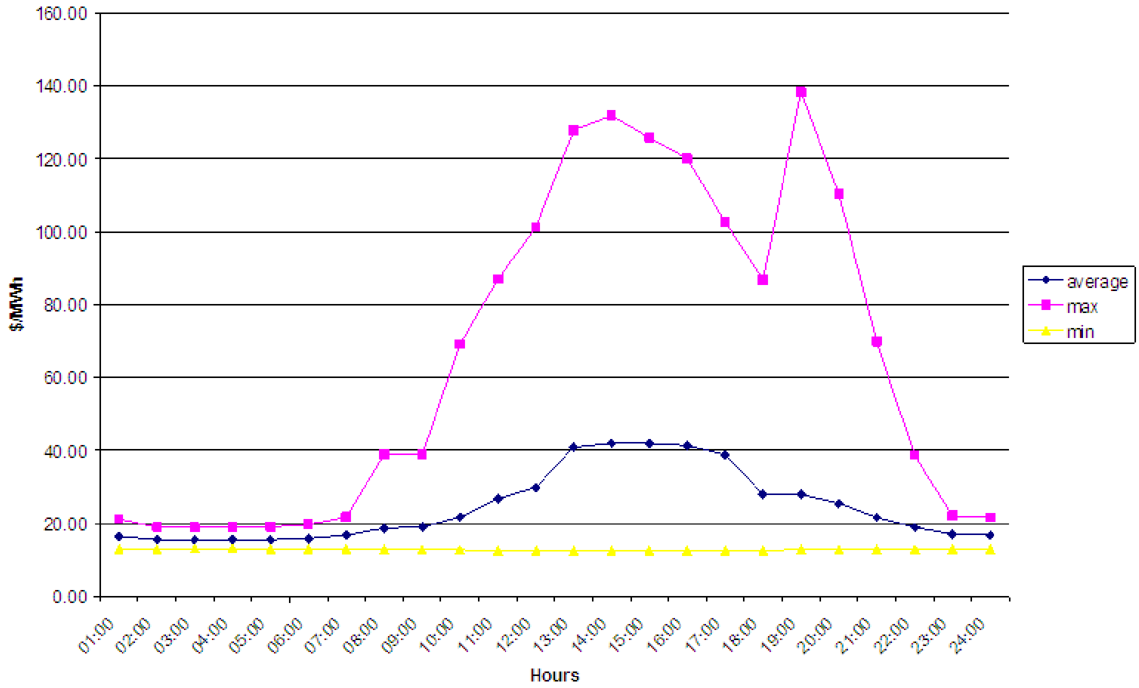


Figure 12: Average Hourly Price Variation for 'BAU' ($0/tCO2) Scenario

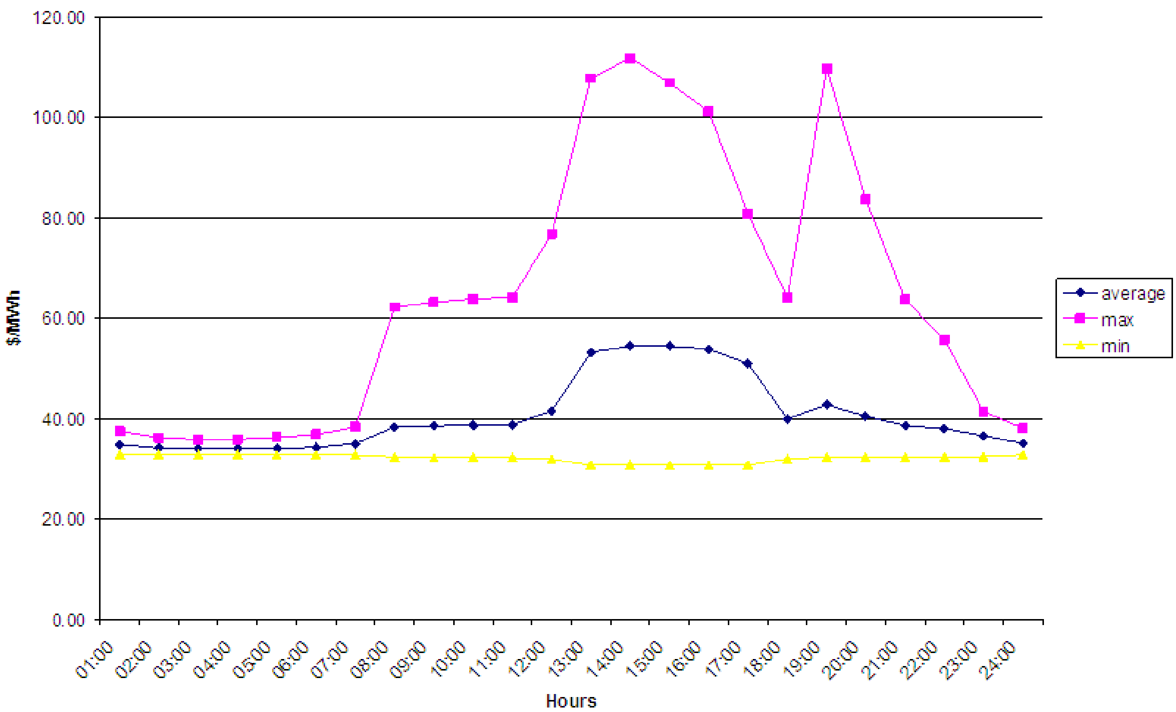


Figure 13: Average Hourly Price Variation for 'BAU' ($20/tCO2) Scenario

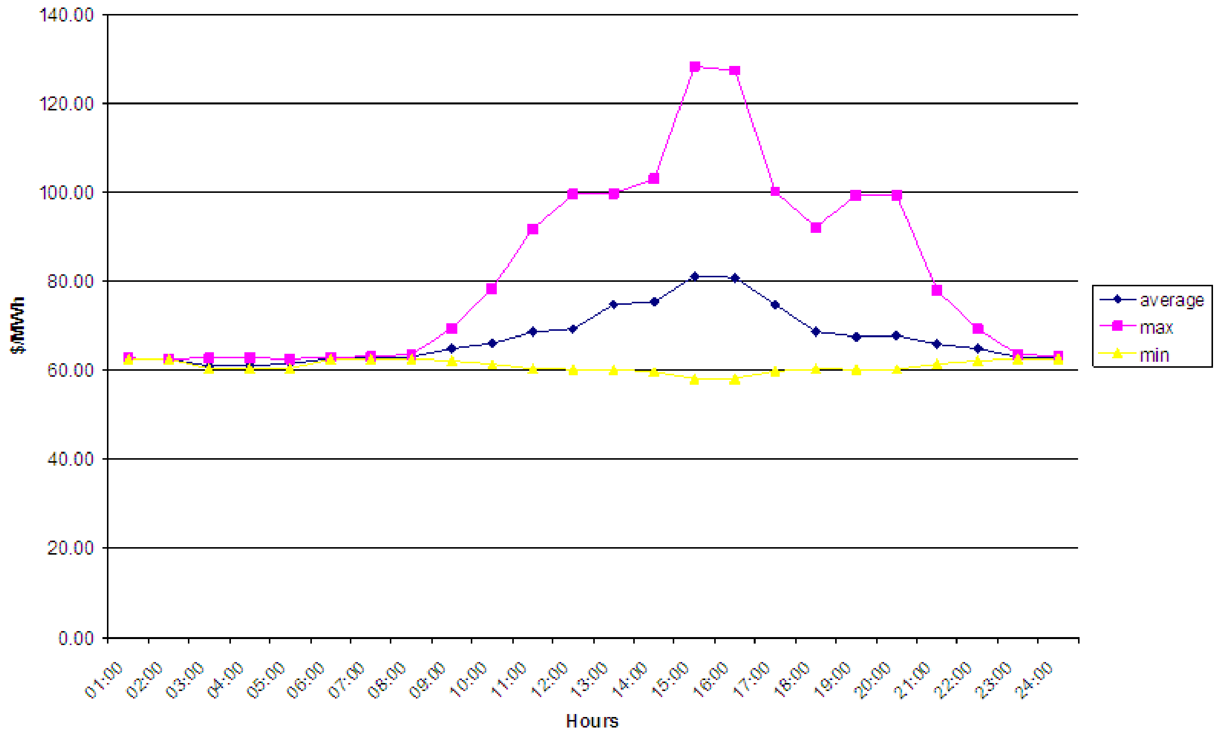


Figure 14: Average Hourly Price Variation for 'BAU' ($50/tCO2) Scenario

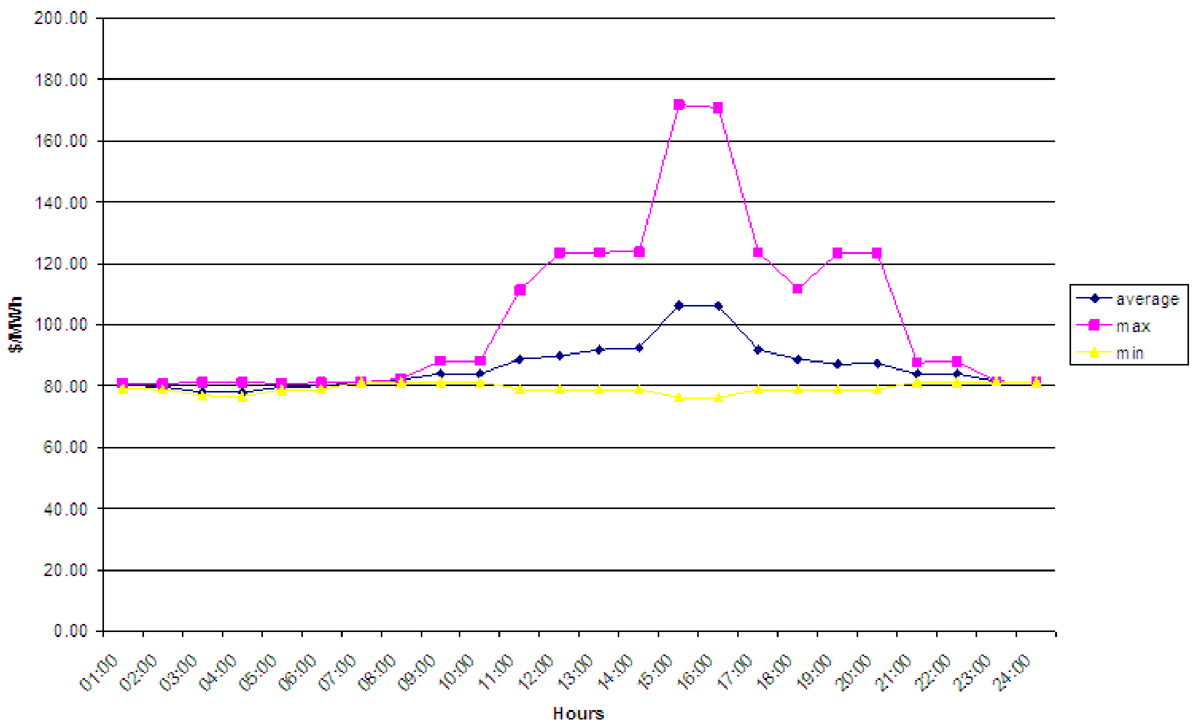


Figure 15: Average Hourly Price Variation for 'BAU' ($70/tCO2) Scenario

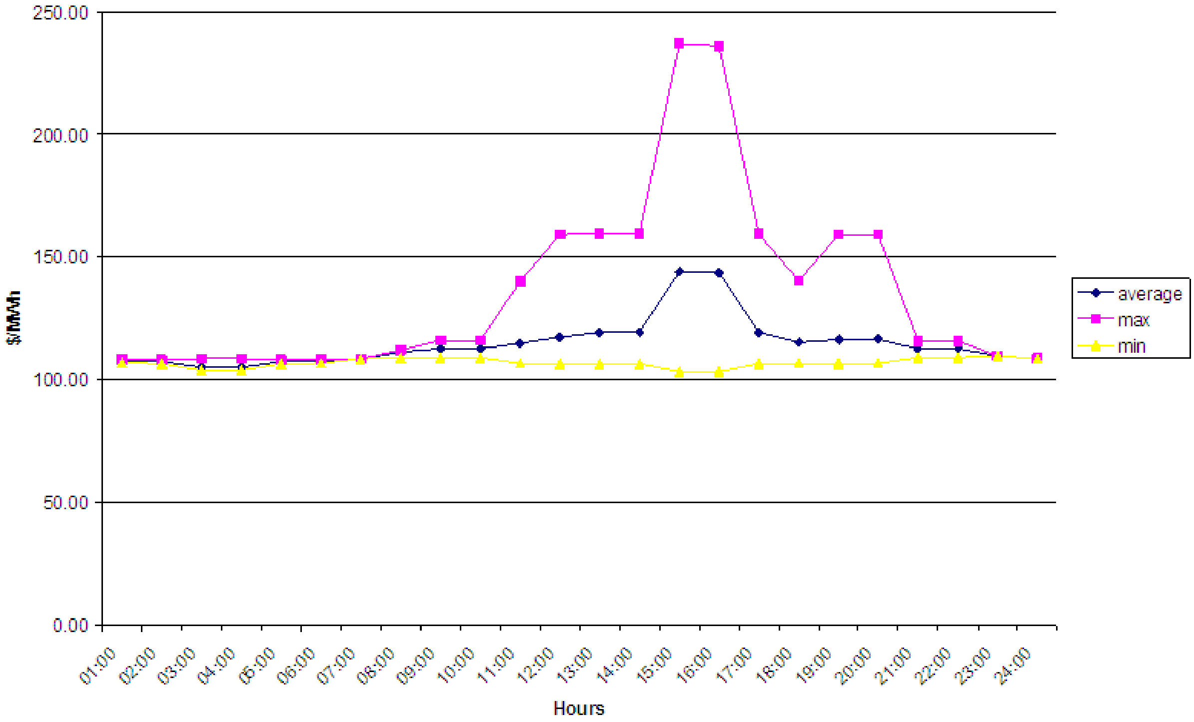


Figure 16: Average Hourly Price Variation for 'BAU' ($100/tCO2) Scenario

9 Dealing with the Impacts of Distributed Generation on Transmission Network Planning

The restructure and deregulation of the global power industry have introduced fundamental changes to the practices of power system planning. Traditionally, generation expansion and transmission expansion are sub-tasks of a power system planning process performed by the regulated power utility. In the new market environment however, transmission expansion planning is performed separately by *transmission network service providers (TNSPs)*, while generation expansion becomes the task of generation companies or investors. These changes have imposed new objectives and uncertainties for transmission planners and make the transmission planning problem much more difficult.

Generally speaking, *transmission expansion planning (TEP)* aims at addressing the problem of expanding the power transmission network to better serve the growing electricity demand while satisfying a number of economical and technical constraints (Choi, 2005). In the regulated environment, the problem can be formulated as minimizing the expansion cost subject to the reliability and other system constraints. In the deregulated environment, the situation becomes more complicated since transmission planners have to take into account the preferences of all market players, and try to simultaneously satisfy several different planning objectives. The possible planning objectives include (Buygi et al., 2004): facilitating market competition; providing non-discriminatory access to cheap generation for all customers; enhancing reliability and maintaining sufficient capacity reserves; enhancing system security, etc. Some of these objectives can be conflicting with each other.

Another challenge is the increasing uncertainty involved in the planning process. In the new environment, although generation planning is considered in the process, transmission planning is no longer coordinated with generation planning by a single planner. It is therefore difficult for the transmission planner to access information concerning generation expansion. Therefore, future generation capacities and system load flow patterns become more uncertain. Other possible sources of uncertainty include (Buygi et al., 2006):

- System load;
- Bidding behaviours of generators;
- Availability of generators, transmission lines and other system facilities;
- Installation/closure/replacement of other transmission facilities;
- Carbon prices and other environmental costs;
- Market rules and government policies.

An important issue not listed above is the potential large-scale penetration of *distributed generation (DG)* technologies. Traditionally, the global power industry has been dominated by large, centralized generation units which are able to exploit significant economies of scale. In recent decades, however, the centralized generation model has been criticized for its costs, security vulnerability and environmental impacts, while DG is expected to play an increasingly important role in the future provision of sustainable electricity supply. Large-scale implementation of DG will cause significant changes in the power industry, and also deeply influence the transmission planning process. For example, DG can reduce local power demand and, thus, it can potentially defer investments in the transmission and distribution sectors. On the other hand, when the penetration of DG in the market reaches a certain level, its suppliers will have to get involved in the spot market and trade the electricity through the transmission and distribution networks, which may need to be further expanded. Reliability of some types of DGs is also of a concern for the transmission and distribution network service providers (TNSPs and DNSPs). Therefore, it is important to investigate the impacts of DG on transmission planning and take into account the uncertainty it brings to the planning process.

In this paper, a novel approach to transmission network expansion planning is proposed. Two stochastic processes, namely *Geometric Brownian motion* and a *mean reverting* process, are employed to model system load and market price. Based on these stochastic models, the risk neutral valuation technique is applied to obtain the values of different generation investment options in different locations. The estimated investment values are then used to generate future generation scenarios. A multi-objective optimization model is introduced to model the TEP problem. A Monte Carlo based approach is employed to simulate a transmission company's behavior over a given planning horizon and to assess the flexibility of a given transmission expansion plan. The results of comprehensive case studies to assess the performance of the propose method are reported. The proposed method is then applied to investigate the potential impacts of DG on transmission planning.

The rest of this section is organized as follows: a comprehensive literature review is provided in Section II. In Section III, the proposed planning method is discussed in more detail. Comprehensive case studies are presented in Section IV. In particular, the impacts of DG on transmission planning are assessed, using the proposed method. Section V contains our conclusions.

9.1 LITERATURE REVIEW

In recent years, extensive research has been conducted on transmission planning due to its importance in electricity market operation. The literature of transmission planning roughly falls into the following three areas:

1. **Optimization Methods** – since TEP involves an optimization problem, extensive studies have been conducted on applying different optimization techniques to obtain appropriate expansion plans. These methods can be further classified into two types: mathematical optimization and heuristic optimization. The mathematical optimization models find an optimum expansion plan by using a calculation procedure that solves a mathematical formulation of the TEP problem. This approach includes linear programming (Chanda and Bhattacharjee, 1994), dynamic programming (Dusonchet and El-Abiad, 1973), nonlinear programming (Youssef and Hackam, 1989), mixed-integer programming (Bahiense et al., 2001, Seifu et al., 1989), benders (Binato et al., 2001) and hierarchical decomposition (Romero and Monticelli, 1993). In Contrast heuristic methods select optimum expansion plans by performing local searches with the guidance of some logical or empirical rules (Latorre et al., 2003). Heuristic optimization techniques that have been applied to solve the TEP problem include sensitivity analysis models (Pereira and Pinto, 1985), genetic algorithms (da Silva et al., 1999), simulated annealing (Gallego et al., 1996), 1997), fuzzy set theory (Choi et al., 2005), differential evolution (Zhao et al., 2009) and the TS algorithm (da Silva et al., 2001). Moreover, since TEP is usually modelled as a multi-objective optimization problem, several multi-objective optimization techniques have also been applied, such as the weighted sum method (Xu et al., 2006), the weighted sum metric method (Xu et al., 2006), and multi-criteria decision making (Linares, 2002).
2. **Static and Dynamic Planning** – transmission planning can be categorized as static or dynamic based on the manner in which the planning horizon is treated. Static planning (Latorre et al., 2003), aims at identifying the size and location of the optimal expansion plan at a certain time point. On the other hand, dynamic planning (Bahiense et al., 2001) considers a planning horizon of several years and, besides the size and location, it also determines when to implement an expansion plan.
3. **Modelling Uncertainties** – a main challenge of TEP in the deregulated environment is the increasing uncertainty involved in the planning process. A number of probabilistic approaches (Buygi et al., 2004, Miranda and Proenca, 1998) have been proposed to handle the random uncertainties (Buygi et al., 2004) such as the uncertainties of load, generation

capacities and generator availability. Decision analysis (Fang and Hill, 2003) can be applied to take into account non-random uncertainties. Stochastic programming (Jirutitijaroen and Singh, 2008) can be employed to find some policy that is feasible for all (or almost all) the possible data instances and maximizes the expectation of some function that includes both decisions and random variables. In contrast to the above methods, we propose in this paper that an expansion plan should be selected on the basis of its flexibility (Zhao et al., 2009). The most flexible plan is defined as the plan that can adapt to any potential scenario at minimum adaptation cost.

The flexibility criterion is chosen because probabilistic and decision analysis methods do not consider the possible consequences of implementing an expansion plan. In a deregulated market, transmission planning usually has to simultaneously satisfy a number of different planning objectives such as: enhancing market competition, improving reliability and security, etc. Since the implementation of an expansion plan will usually take several years, the optimal plan that is identified by probabilistic or decision analysis methods may not be able to satisfy the planning objectives after implementation due to significant market uncertainties. Further expansion will then become necessary and this cost should be taken into account and used to measure the value of flexibility. Thus, we can establish a framework for flexible transmission planning and further develop the method to handle more complicated cases.

It is expected that large scale penetration of DG will significantly change the power industry. Therefore, increasing efforts have been made recently to investigating the impacts of DG on all aspects of the power market. Generally speaking, *distributed generation* is defined as the generation units that are connected to the power grid either on the customer side or at from the distribution network (Carley, 2009). The size of a typical DG system usually ranges from 1 KW to 5 MW, while a large DG system can reach a capacity up to 300MW (Carley, 2009). DG can be categorized as renewable, such as wind or solar power, or non-renewable, such as the internal combustion engine (ICE) and micro-turbines.

Since the market penetration of DG is still low in most countries, a number of studies (Dondi et al., 2001, Johnston, 2005) have been conducted to investigate the barriers to DG penetration and the factors that can contribute to DG 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) has been conducted to investigate the impacts of DG on distribution network planning. These studies usually focus on determining the optimal size and location of DG units in the distribution network from the distribution company's point of view. Some studies

(Neto, 2006, Zhu et al., 2006) also have been performed to understand the impacts of DG on the system side, such as on reliability, system security and power quality.

Currently, little research has been done to investigate the impacts of DG on the transmission network. When its market share is still small, DG can be modelled as negative load in the system. However when the market penetration of DG reaches a certain level and the electric utilities implement DGs as standard investments in generation capacity (Carley, 2009), then they will have to get involved in the spot market and sell the power through the transmission network, which will possibly require modifications to the current market dispatch mechanism (Ummels et al., 2007). To investigate the potential of large impacts of DG on the transmission network, comprehensive quantitative analysis will need to be performed. In this paper, the proposed planning model will be employed to study this problem.

9.2 THE PROPOSED PLANNING APPROACH

In this section, the proposed method is introduced in more detail. We firstly introduce the main idea of the approach and then the main steps of the proposed method are introduced in subsections.

9.2.1 Overview of the Proposed Planning Method

The main idea is to firstly evaluate generation investment options in different locations of the network. These options include both traditional generation techniques and DG. The future generation scenarios are based on the investment valuation results. A multi-objective optimization model is formulated to find several expansion plans that are quasi-optimal at the beginning of the planning horizon. To take into account market uncertainties, a Monte Carlo simulation is performed to generate *N* market scenarios over the entire planning horizon. Each scenario consists of different generation capacity, system load and market price paths and different market rules such, as different fit-in-tariff (FIT). It is checked whether the planning objectives have been satisfied during the entire planning horizon and re-expansion is performed if the objectives are not met. The re-expansion costs of *N* iterations form a distribution of adaptation costs for a given candidate plan, which measures the plan’s flexibility.

The major steps of this proposed method are listed as follows and illustrated in Figure 17:

1 Building models for system load and market price at different locations in the market. These models are used in the following steps when doing investment valuation and market simulation.

2 Evaluating potential investment options and selecting several options that are relatively attractive.
3 Employing the multi-objective optimization model to generate several candidate expansion plans.
4 For each candidate plan, perform Monte Carlo simulation to generate N market scenarios.
5 For each plan under a scenario, re-expand the network if planning objectives are not reached and calculate the adaptation cost.
6 Obtain a probability distribution of the adaptation cost of each candidate plan and select the optimal expansion plan based on its flexibility.

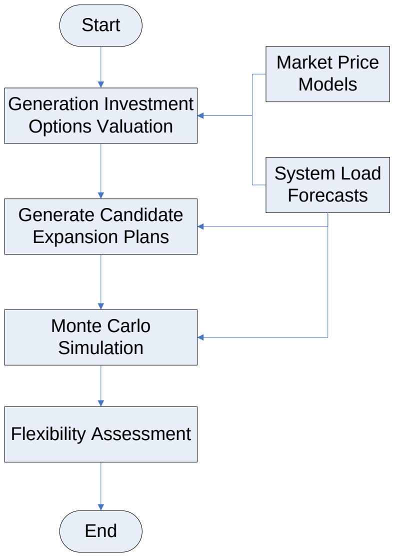


Figure 17 The Procedure of the Proposed Planning Approach

9.2.2 Models for System Loads and Market Prices

Two stochastic processes are proposed to model the system load and the nodal price at each bus of the system. Investment valuation and market simulation are based on these two models. For each bus i in the system, the load is modelled by the widely used *Geometric Brownian motion (GBM)* process (Eydeland, 2003) as follows:

$$dP_{Di} = u_{Di} P_{Di} dt + \sigma_{Di} P_{Di} dX \qquad (1.1)$$

$$dX \sim N(0, dt) \qquad (1.2)$$

where P_{Di} represents the power demand at bus i; dX is the standard *Wiener process* (Eydeland, 2003), which essentially follows a normal distribution with zero mean and a variance of dt.

For each bus i, the nodal price can be modelled by the *mean-reverting* (Eydeland, 2003) process, which is widely recognized to be an appropriate model for energy prices (Eydeland, 2003). The model can be written as follows:

$$\frac{dZ_i}{Z_i} = k_i(u_{Zi} - Z_i)dt + \sigma_{Zi}dX \quad (2)$$

Here Z_i is the nodal price at bus *i*; u_{Zi} and σ_{Zi} are long term mean and variance of the process; k_i represents the mean reversion rate. The price Z_i probabilistically tends to increase if it is below u_{Zi}, and decrease if it is above. The mean reversion rate k determines the speed with which Z_i converges to the long term mean. u_{Zi} is usually assumed to be a function of time. Since the market price generally tends to increase in the long term, we assume that u_{Zi} is a function of the bus load P_{Di}. This function relationship can be estimated using a statistical regression technique.

The parameters of models (1) and (2) can be estimated with the *Maximum Likelihood Estimation (MLE)* method. The essential idea of MLE is to select the parameters that make the observed data most likely to occur.

To obtain the ML estimators, the likelihood functions of the models should be derived first. Assume that a historical load series $\hat{P}_{Di}(t), t = 0,1\ldots T$ has been observed. Transform model (1) into the discrete form we have:

$$P_{Di}(t) = P_{Di}(t-1) + u_{Di} \times P_{Di}(t-1) + \varepsilon_t \quad (3.1)$$

$$\varepsilon_t \sim N(0, (\sigma_{Di}P_{Di}(t-1))^2) \quad (3.2)$$

Obviously $P_{Di}(t)$ is conditionally normal as well, with mean $P_{Di}(t-1) + u_{Di} \times P_{Di}(t-1)$ and variance $(\sigma_{Di}P_{Di}(t-1))^2$. The likelihood function of model (3) given observed data $\hat{P}_{Di}(t), t = 0,1\ldots T$ can therefore be calculated as:

$$\begin{aligned} L(\{\hat{P}_{Di}(t)\}_1^T; \vec{\theta}) &= f_1(\hat{P}_{Di}(1) \mid \hat{P}_{Di}(0); \vec{\theta}) \times f_2(\hat{P}_{Di}(2) \mid \hat{P}_{Di}(1); \vec{\theta}) \ldots\ldots \\ &\quad \times f_T(\hat{P}_{Di}(T) \mid \hat{P}_{Di}(T-1); \vec{\theta}) \\ &= \prod_{t=1}^{T} \frac{1}{\sigma_{Di}\hat{P}_{Di}(t-1)\sqrt{2\pi}} e^{-\frac{(\hat{P}_{Di}(t) - (\hat{P}_{Di}(t-1) + u_{Di} \times \hat{P}_{Di}(t-1)))^2}{2(\sigma_{Di}\hat{P}_{Di}(t-1))^2}} \end{aligned} \quad (4)$$

where $\vec{\theta} = (u_{Di}, \sigma_{Di})'$.

Similarly, assume that a historical nodal price series $\hat{Z}_i(t), t = 0,1\ldots T$ has been observed. The likelihood function of model (2) can be given as:

$$L(\{\hat{Z}_i(t)\}_1^T; \vec{\vartheta}) = \prod_{t=1}^{T} \frac{1}{\sigma_{Zi}\hat{Z}_i(t-1)\sqrt{2\pi}} e^{-\frac{(\hat{Z}_i(t) - \hat{Z}_i(t-1) - k_i(u_{Zi} - \hat{Z}_i(t-1)) \times \hat{Z}_i(t-1))^2}{2(\sigma_{Zi}\hat{Z}_i(t-1))^2}} \quad (5)$$

where $\vec{\vartheta} = (u_{Zi}, \sigma_{Zi})'$.

The ML estimators of parameters $\vec{\theta} = (u_{Di}, \sigma_{Di})'$ and $\vec{\vartheta} = (u_{Zi}, \sigma_{Zi})'$ can finally be obtained by maximizing likelihood functions (4) and (5) respectively. This optimization problem can be easily solved with a nonlinear optimization algorithm, such as an evolutionary algorithm.

9.2.3 Generation Options Valuation

Generation capacity is a major uncertain factor that can significantly affect transmission planning decisions. In a deregulated market, the transmission company is not involved in the decision process leading to generation investments, although TNSPs may conduct studies when potential generators request a connection point to the existing network (AEMC, 2009). It is therefore difficult for the TNSPs to take into account the future generation capacity in the planning process. We solve this problem by comparing the investment values of different generation technologies at different locations of the network and selecting the generation options with relatively higher values to construct future generation scenarios.

The value of an investment in a generation plant usually is measured by its *net present value (NPV)*. The calculation process takes into account the *capital cost*, the *operation and maintenance (O&M) cost*, the *fuel cost* and the nodal price to calculate the cash flows for the entire life cycle of the plant (Eydeland, 2003). NPV is obtained by summing the discounted cash flows. The generation options with higher NPVs are considered to be more attractive for investors and, thus, more likely to occur in the market. The generation options with *M* highest NPVs are selected for constructing future generation scenarios. We employ this method to evaluate traditional generation technologies such as coal fire and gas plants.

DG units can be valued in two different ways. When the market share of DG is small, a DG unit is usually modelled as a negative load in the distribution network and the distribution company implements it only if its cost is lower than the cost of buying power from the market and it expands the distribution network correspondingly (Haffner et al., 2008). When the penetration of DG reaches a certain level, a DG can be considered as a standard generation plant and its value can be determined by the NPV method discussed below.

We calculate the value of building a generation plant with technology *j* at bus *i* as follows:

1 Derive the *risk neutral process* (Eydeland, 2003) from model (2). This process can be given as:

2 $$\frac{dZ_i}{Z_i} = (k_i(u_{Zi} - Z_i) - \sigma_{Zi}\lambda_i)dt + \sigma_{Zi}dX \qquad (6)$$

3 where λ_i is the *market price of risk* (Eydeland, 2003) of the nodal price Z_i.

4 Employ model (6) to generate a market price path of *T* consecutive years, where *T* is the life cycle of the plant.

5 Calculate the cash flow CF_t of plant *j* at year *t*, CF_t as:

6 $$CF_t = (Z_i(t) - C_{VO\&M} - C_{fuel}) \times f_{cap} \times 8760 - C_{FO\&M} \qquad (7)$$

7 where $C_{VO\&M}, C_{FO\&M}, C_{fuel}$ are the variable operation and maintenance cost, the fixed operation and maintenance cost, and the fuel cost of technology *j* respectively. f_{cap} represents the typical *capacity factor* (Eydeland, 2003) of technology *j*.

8 The NPV can be calculated as:

9 $$NPV_{i,j} = C_{cap} + \sum_{t=1}^{T}(CF_t \times e^{-rt}) \qquad (8)$$

10 where *r* is the *risk-free interest rate* (Eydeland, 2003) and C_{cap} is the capital cost of technology *j*.

11 Repeat steps (2)-(4) for *N* iterations, obtain the average value of NPVs.

The above procedure is based on the *risk neutral valuation* (Eydeland, 2003) approach. Generally speaking, risk-neutral valuation assumes that electricity markets are risk-neutral. All investments will therefore yield an identical return of the risk free interest rate. Theoretically the risk-neutral assumption is equivalent to a 'no arbitrage' assumption. In electricity markets however, the non-storability of electricity weakens the non-arbitrage assumption. The market price of risk should therefore be introduced to adjust the drift rate of the risk-neutral process.

9.2.4 Transmission Expansion Planning Model

A transmission expansion planning model is proposed in this sub-section. The main idea of the model is to minimize the expansion investment subject to power flow and other system constraints. As discussed in the introduction, TEP in the deregulated environment may need to consider several different objectives. We handle multi-objectives by adding a constraint into the model for each objective. For example, to consider reliability, we will add a constraint that the expansion plan must reach a minimum reliability requirement. The model is as follows:

Minimize

$$O = C^T \eta \tag{9.1}$$

Subject to

$$P_{Gi} - P_{Di} = \sum_{n=1}^{N} |Y_{in} V_i V_n| \cos(\theta_{in} + \delta_n - \delta_i)$$

(9.2) $Q_{Gi} - Q_{Di} = \sum_{n=1}^{N} |Y_{in} V_i V_n| \sin(\theta_{in} + \delta_n - \delta_i)$

(9.3)

$$S_{ij}^{f} \le S_{ij}^{\max}$$

(9.4)

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

(9.5)

$$P_{Gi}^{\min} \le P_{Gi} \le P_{Gi}^{\max}$$

(9.6)

$$Q_{Gi}^{\min} \le Q_{Gi} \le Q_{Gi}^{\max}$$

(9.7)

$$Y_{ij} = -(y_{ij}^{0} + \eta_{ij}\tau_{ij}), (i \ne j)$$

(9.8)

$$Y_{ii} = y_{i0} + \sum (y_{ij}^{0} + \eta_{ij}\tau_{ij}), (i \ne j)$$

(9.9)

$$O_k \ge O_k^{\min}, k = 1 \ldots K$$

(9.10)

Where

P_{Gi}, Q_{Gi} Real and reactive power outputs of generator *i*;

P_{Di}, Q_{Di} Real and reactive power demands at bus *i*;

Y Bus admittance matrix of the system;

θ_{in} Angle of elements Y_{in} in Y;

τ_{ij} New circuit admittance between of branch $i-j$;

O_k Measure of objective k after expansion;

$O_{\min}$ Minimum planning requirement for objective k;

In model (9), the objective (9.1) represents the expansion investments. Constraints (9.2)-(9.7) correspond to the typical AC power flow. Equations (9.8) and (9.9) set the new admittance matrix after expansion. Constraint (9.10) ensures that the system satisfies the minimum planning requirements for all k objectives after expansion. The model aims to minimize the expansion investment while satisfying all the pre-defined expansion objectives. In this paper, two main objectives, enhancing reliability and market competition, are considered. Other objectives can also be added into the model in a similar way, which makes the model highly flexible for being applied in practice.

Model (9) is a constrained nonlinear optimization problem which is highly complex. To solve this problem, a *particle swarm optimization (PSO)* algorithm (del Valle et al., 2008) is employed. Particle swarm optimization is a stochastic population based algorithm based on social-psychological principles. A problem is given, and some way to evaluate a proposed solution to it exists in the form of a fitness function. A communication structure or social network is also defined, assigning neighbours for each individual to interact with. Then a population of individuals defined as random guesses at the problem solutions is initialized. These individuals are candidate solutions. They are also known as the particles, hence the name particle swarm. An iterative process to improve these candidate solutions is set in motion. The particles iteratively evaluate the fitness of the candidate solutions and remember the location where they had their best success. The individual's best solution is called the particle best or the local best. Each particle makes this information available to their neighbours. They are also able to see where their neighbours have had success. Movements through the search space are guided by these successes, with the population usually converging, by the end of a trial, on a problem solution better than that of non-swarm approach using the same methods. It should be noted that other *evolutionary computation (EC)* methods can be used here as well. Since the main purpose of this paper is not on application and choice of ECs, discussions on this aspect is not included in greater details. Assessing the Flexibility of Expansion Plans

As discussed above, the market environment is highly uncertain and somewhat unpredictable. Since the implementation of an expansion plan usually takes several years, during which the market situation may have changed significantly; the planning objectives may not be met after the expansion. Flexibility in an expansion plan is therefore very important. The flexible expansion plan should ensure that, if unexpected future scenarios occur, further expansion can be done in a timely and cost-effective way.

We have proposed that the flexibility of an expansion plan can be measured by its maximum re-expansion cost, given all possible future scenarios (Zhao et al., 2009). In practice however, this approach may become computationally infeasible for a large system due to the very large number of potential scenarios. In this paper, we tackle this problem by employing Monte Carlo simulation to obtain an approximate value for the maximum re-expansion cost. Moreover, the distribution of the re-expansion costs given by the simulation also provides valuable information for flexibility assessment.

In the simulation, random and non-random uncertainties are treated differently. Random uncertainties, such as the system load and the market price, are modelled with the stochastic processes introduced in previous sections; and future scenarios consist of the load and price paths generated with these processes. Non-random uncertainties are modelled by assuming each possible event is equally likely. For example, we can select M generation investment options with the method described in Section III.C. Then, in each year of a scenario, we can randomly select one investment to implement and study its impacts. Changes in market rules can also be modelled in this way. For example, over the planning horizon we can randomly select a year, in which a fit-in-tariff (FIT) schema is introduced. The procedure of the simulation is illustrated in **Figure 18**.

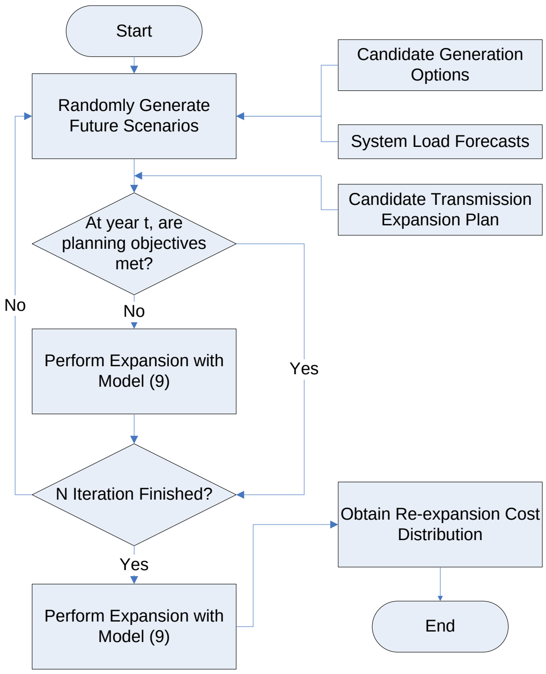


Figure 18 The Procedure of Employing Monte Carlo Simulation for Flexibility Assessment

9.2.5 Reliability Assessment

Maintaining system reliability is a core task in transmission planning. Reliability can be seen as the degree of assurance in providing customers with continuous service of satisfactory quality. In this paper, the system reliability is measured by the expected unserved energy (EUE) (Shahidehpour, 2002). This is the expected amount of power that is not supplied due to the inadequate generation and transmission capacities. In the Australian NEM planning process, EUE is used to measured the reliability costs by multiplying it with Value of Customer Reliability (VCR) for involuntary load shedding, (AEMC, 2009, AER, 2009). Given a market scenario, as formulated in the above section, a Monte Carlo simulation can be used to randomly generate different system load levels and AC optimal power flow (OPF) (Zhao et al., 2009) can be calculated to find the amount of unsupplied energy. By calculating the average of the unsupplied energy in the simulation the EUE can be finally obtained.

9.2.6 Market Competition

A core task of the transmission network is to provide non-discriminatory access to generation resources and enhance competition among market participants. Theoretically, the nodal prices at all buses in the system will be equal if the system has infinite transmission capacity. Insufficient transmission capacity will cause congestion and give large generators opportunities to exercise market power and raise the spot price (Buygi et al., 2004). Therefore, an important objective of transmission planning is to mitigate congestion and enhance market competition.

In light of the above consideration, congestion cost can be employed to assess the impacts of new expansion plans on market competition. The congestion cost of a transmission line is defined as:

$$C_i = (price_{i2} - price_{i1}) \times P_{i1,i2} \tag{10.1}$$

where C_i is the congestion cost of line *i*, $price_{i2}, price_{i1}$ are the locational prices of end buses of line *i*, and $P_{i1,i2}$ is the power transferred through line i. The total congestion cost of the system is:

$$C = \sum_{i \in N} C_i \tag{10.2}$$

9.2.7 CASE STUDIES

The proposed planning approach is tested on the IEEE 14 bus system (Zhao et al., 2009). The diagram of the system is given in

. The system data of generators and loads are set as Table 8 and Table 9. The total generation capacity of the system is 952.4 MW, while the total system load is 638 MW. The EUE and congestion cost of the base case is calculated as 28948 MWh and 4393.7 $/Hour respectively. We assume that all new transmission lines will have a nominal voltage of 345 KV and a capacity of 50 MVA. The construction cost is assumed to be 45-50 M$/100km. The construction time is proportional to the length of the line.

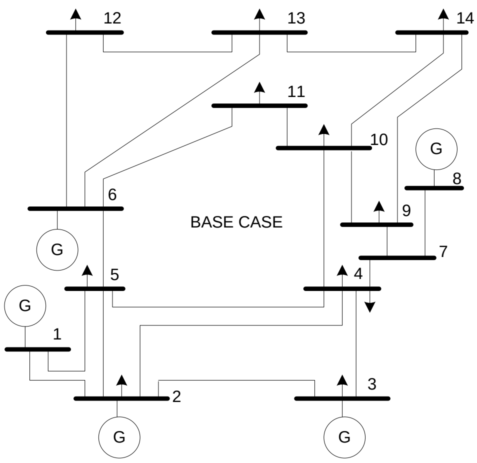


Figure 19 IEEE 14 Bus System - Base Case

Table 8 Generators Data

Bus No.	P_{max} (MW)	P_{min} (MW)	Q_{max} (MVAR)	Q_{min} (MVAR)
1	332.4	0	10	0
2	200	0	50	-40
3	140	0	40	0
6	140	0	54	-6
8	140	0	54	-6

Table 9 Loads Data

Bus No.	P_d (MW)	Q_d (MVAR)
2	21.7	12.7
3	194.2	29
4	47.8	-13.9
5	157.6	11.6
6	30.2	17.5
9	119.5	16.6
10	9	5.8
11	3.5	1.8
12	26.1	11.6
13	13.5	5.8
14	14.9	5

In our case studies, four generation technologies are considered, including a black coal fire plant, a combined cycle gas turbine (CCGT) plant and two distributed generation technologies – concentrated solar thermal (CST) and wind power. We assume possible generation investment options and their technical parameters as specified in Table 10. The cost data were obtained from (Wibberley, 2006, ACILTASMAN, 2009, Global Environment Facility, 2005). We firstly conduct simulations without considering distributed generation, and investigate the performance of our approach. The approach is then employed to study the impacts of DG on the network.

Table 10 New Generator Characteristics

Technology	Capital Cost (M$/MW)	Fixed Generation Cost ($/MW/Year)	Variable Generation Cost ($/MWh)	Life Cycle (Year)	Capacity (MW)	Capacity Factor (%)
Black Coal Fire	2.239	7200000	17.02	40	200	85
CCGT	1.314	1550000	38.21	30	150	60
CST	4.9	-	45.5	25	20×5	56
Wind	2.8	600000	-	25	20×5	40

A. Case 1 - Flexibility Assessment

We firstly test the proposed method by assuming that only the coal fire plant and CCGT are implemented in the market. The planning horizon T is set as 10 years. By applying the investment valuation method discussed in above, the 8 investment options with highest values are listed in Table 14. Based on the data in Table 13, the coal fire plant is generally more attractive than CCGT for investors, which matches the real market situation. Moreover, it can be observed that building new generators in buses 2, 3, and 6 are relatively more economical, while bus 1 is not preferable since it already has a high generation capacity.

Model (9) is then employed to select the candidate expansion plans which can be implemented at the beginning of the planning horizon ($t = 0$). As observed in Table V, plan 4 has the minimum construction cost. Since model (9) has ensured all five plans satisfy the planning objectives, given the information at $t = 0$, plan 4 should therefore be optimal if future uncertainties are not considered.

Table 11 Generation Valuation Results for Case 1

Technology	Bus No.	Capacity (MW)	NPV (M$)
Black Coal Fire	3	200	1435.56
Black Coal Fire	2	200	1372.39
Black Coal Fire	6	200	1214.61
Black Coal Fire	8	200	933.68
Black Coal Fire	1	200	458.48
CCGT	3	150	183.3
CCGT	2	150	155.11
CCGT	6	150	91.13

Table 12 Candidate Expansion Plans

Plan No.	Transmission Lines	Construction Cost (M$)	Construction Time (Year)
1	(1,3) (2,3)	450	4
2	(1,3) (6,11)	396	6
3	(1,4) (3,9)	330	4
4	(6,11) (8,14)	306	4
5	(1,4) (6,9) (6,11)	411	3

However, we can now employ the flexibility assessment approach discussed in above Table 13 to obtain the distributions of the re-expansion costs of five candidate plans. As shown in Table 13, in the assumed planning horizon, plan 4 needs at most 2095 M$ of further expansion cost to satisfy planning objectives, which is much higher than the maximum re-expansion costs of 1288 M$ and 1395 M$ of candidate plans 1 and 2. The mean re-expansion cost of plan 2 is also significantly less than plan 4, while plan 1 has a similar mean re-expansion cost to plan 4.

Table 13 Re-expansion costs of Candidate Plans

Plan No.	Maximum Re-expansion Cost (M$)	Minimum Re-expansion Cost (M$)	Mean Re-expansion Cost (M$)
1	1288	550	817
2	1395	396	648.7
3	1965	330	876.5
4	2095	456	782.2
5	1848	411	889

Plotting the empirical *cumulative distribution functions (CDF)* of plans 1, 2 and 4 gives us a clearer idea about their flexibilities. As clearly observed in Figure 20 through to Figure 22, if plan 1 is implemented initially, there is only around 10% probability that the further expansion cost will exceed 1000 M$. This probability is less than 5% for plan 2. For plan 4, however, the probability is around 20%. Taking into account both the distributions and maximum re-expansion costs, plans 1 and 2 are much more flexible than plan 4, although it has the minimum initial cost.

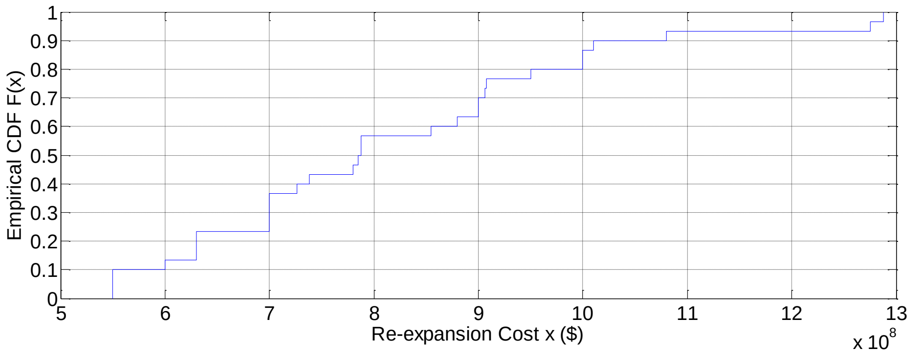


Figure 20 Empirical CDF of Plan 1

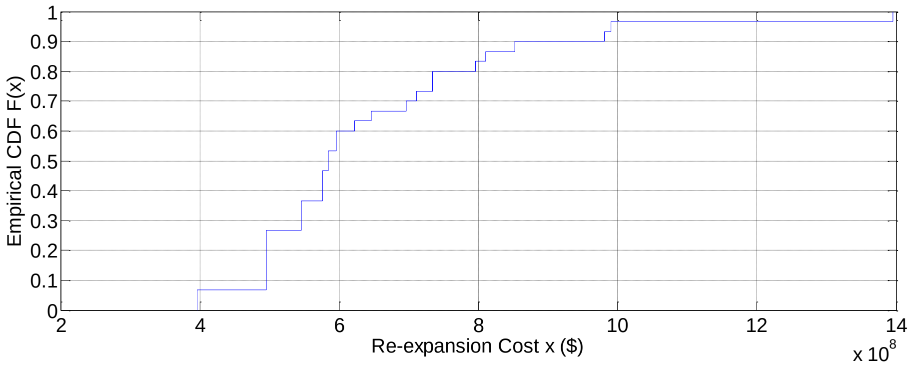


Figure 21 Empirical CDF of Plan 2

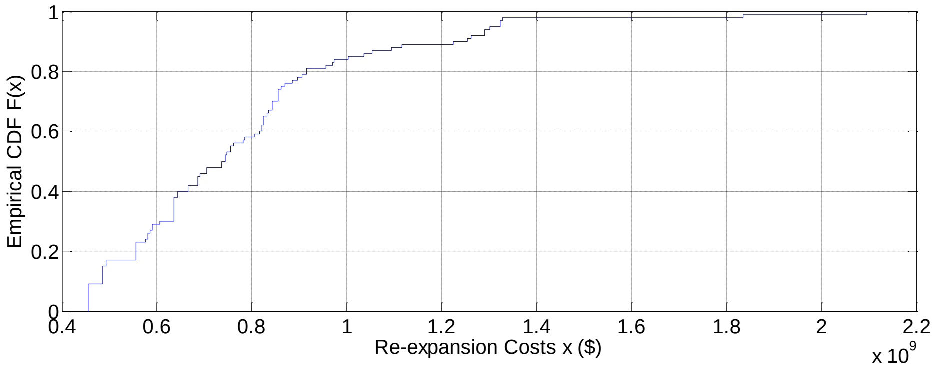


Figure 22 Empirical CDF of Plan 4

B. Case 2 – Distributed Generation

In the second case, DG will be taken into account. We assume that CST and wind power plants are only built at load buses (Buses 4, 5, 7, 9, 10-14). Similarly, the generation valuation method is applied firstly to determine the generation options with highest values in the market. To consider possible government policies for encouraging the adoption of renewable energy, a *fit-in tariff (FIT)* factor is assumed for solar and wind power. The prices of solar and wind will be the spot market price multiplied by their specific FIT factors. The candidate generation options given different FIT factors can then be calculated, as given in Table 14 and Table 15. As observed, wind power can replace CCGT if a 2 times fit-in tariff is introduced, while CST can become competitive with CCGT only if a 3 times fit-in tariff is implemented. CST can start to replace coal fire after its FIT factor reaches 4. These results clearly indicate that the two renewable technologies are not competitive enough yet with fossil fuel generation technologies, given their current costs. Strong government support is still necessary for promoting their market penetration.

Table 14 Generation Valuation Results (FITwind = 2, FITsolar = 2)

Technology	Bus No.	Capacity (MW)	NPV (M$)
Black Coal Fire	3	200	1435.56
Black Coal Fire	2	200	1372.39
Black Coal Fire	6	200	1214.61
Black Coal Fire	8	200	933.68
Black Coal Fire	1	200	458.48
CCGT	3	150	183.3
Wind	14	100	163.21
Wind	9	100	155.2

Table 15 Generation Valuation Results (FITwind = 2, FITsolar = 3)

Technology	Bus No.	Capacity (MW)	NPV (M$)
Black Coal Fire	3	200	1435.56
Black Coal Fire	2	200	1372.39
Black Coal Fire	6	200	1214.61
Black Coal Fire	8	200	933.68
Black Coal Fire	1	200	458.48
CST	9	100	356.6
CST	14	100	356.4
CST	4	100	354.9

Table 16 Generation Valuation Results (FITwind = 4, FITsolar = 4)

Technology	Bus No.	Capacity (MW)	NPV (M$)
Black Coal Fire	3	200	1435.56
Black Coal Fire	2	200	1372.39
Black Coal Fire	6	200	1214.61
Black Coal Fire	8	200	933.68
CST	13	100	744.4
CST	14	100	735.72

CST	9	100	735.71
CST	7	100	735.6

The proposed approach is then applied to study the impacts of DG on transmission planning. Unlike case 1, in this study no initial expansion plans are implemented at $t = 0$. After candidate generation options are selected, the approach illustrated in Figure 21 is performed directly to simulate transmission expansion actions and obtain the expansion cost distribution. Higher expansion costs indicate stronger needs for network expansion. The expansion cost distribution in the base case without DG units installed is given in Figure 23. Several different scenarios of DG penetration are then considered. In these scenarios, DG units are built to replace coal fire plants, while the total generation capacity remains identical. In scenario 1, DG units constitute around 10% of the system capacity (100MW), but we assume that DG units are non-dispatchable and their electricity is only consumed locally. They are therefore modelled as negative loads. The expansion cost distribution is illustrated in Figure 21. Clearly, the maximum expansion cost of scenario 1 (350M$) is much lower than the base case (1400M$). Moreover, based on Figure 25 and Figure 26, there is a 70% probability that the expansion cost of scenario 1 is lower than the base case. These results strongly support the hypothesis that the introduction of DG can defer investments in transmission expansion.

Figure 23 CDF of the Expansion Cost - No DG Installed

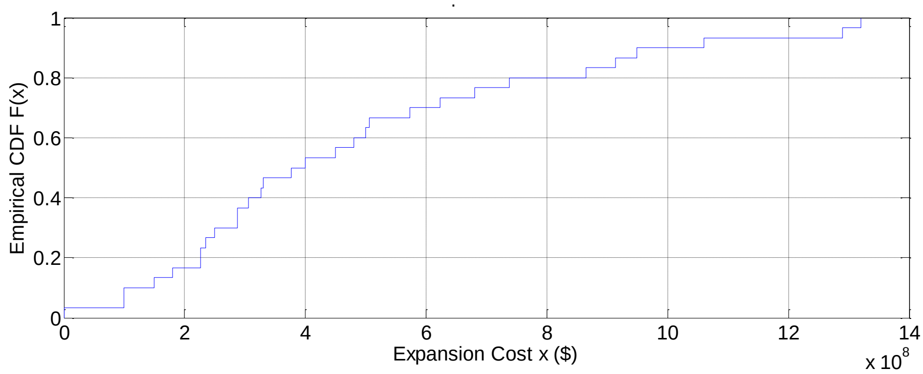


Figure 24 CDF of the Expansion Cost – scenario 1 (10% Non-dispatchable DG Penetration)

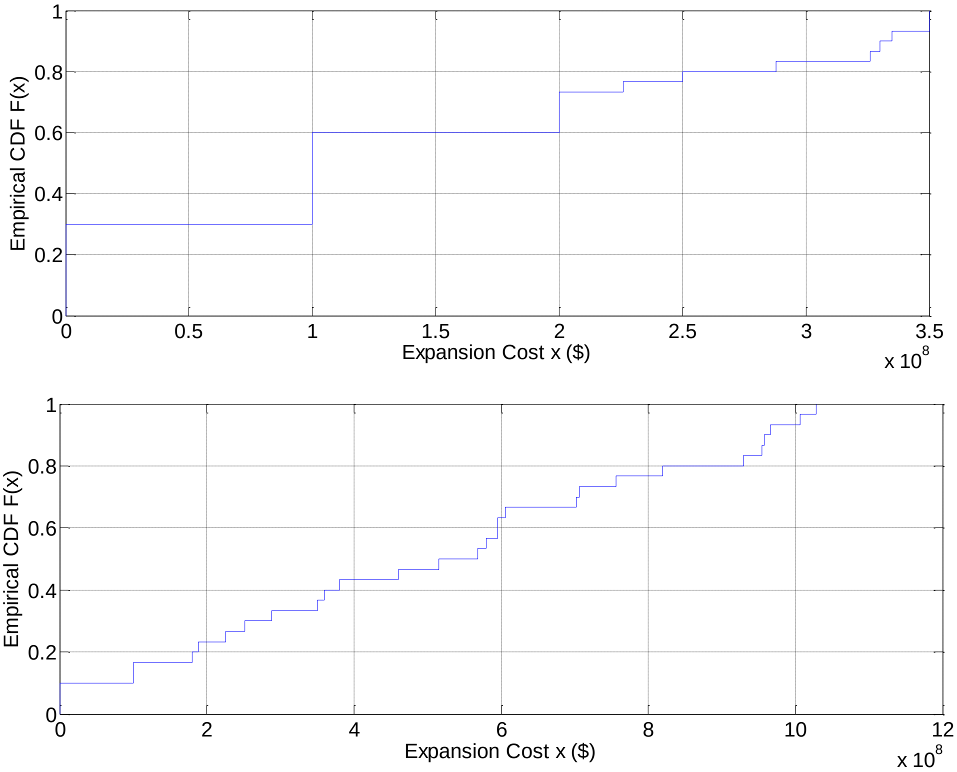


Figure 25 The Expansion Cost - Scenario 2 (10% Dispatchable Wind Power Penetration)

Four different scenarios are also studied. In these scenarios, we assume only wind or solar power will be implemented so as to investigate their specific performances in the market. Similarly, DG units replace coal fire plants but keep the total generation capacity unchanged. Unlike scenario 1, DG units are assumed to be dispatchable and will be traded through the spot market. In practice, involving DG units in the spot market may need modifications to the existing market dispatch process. The expansion costs of four scenarios are given in Figure 25, Figure 26 and Figure 27.

As observed, a 10% market share of dispatchable wind power and CST can still reduce future network expansion costs. However, the cost reductions are much lower than the non-dispatchable case. These results are reasonable because when the DG units are involved in the dispatch process, their electricity will be traded through the transmission network, which potentially can cause network congestion and provide incentives for network expansion. However, compared with the base case, a 10% penetration level of DG can still defer transmission investments to some extent since most of their power is consumed locally. On the other hand, a 20% of CST will not defer transmission investments, while a 20% of wind power can even increase the transmission expansion cost in some situations. These results can largely be attributed to the relatively lower capacity factors of DG (especially wind power) compared with coal fire plants. When DG units are unavailable, most power will be generated by the coal fire plants located in a few generator buses, which will worsen network congestion.

To better understand the impacts of DG, the simulated paths of congestion costs and EUE for different DG penetration levels are plotted in Figure 26 and Figure 27. As observed, the base case without DG installed has a congestion cost ranging from 1000 to 5000. After DG units are built to replace coal fire plants, although the congestion cost still remains at the same level in most situations, DG does increase the probability of high congestion costs. This is especially the case for wind power (30% capacity factor). Since some coal fire plants have been replaced by DG units, the system relies on the remaining coal fire plants when wind power units are unavailable. This however increases the power flows on nearby transmission lines and hence worsen the congestion. Another possible explanation is that DG units will increase the nodal prices, which can also contribute to high congestion costs.

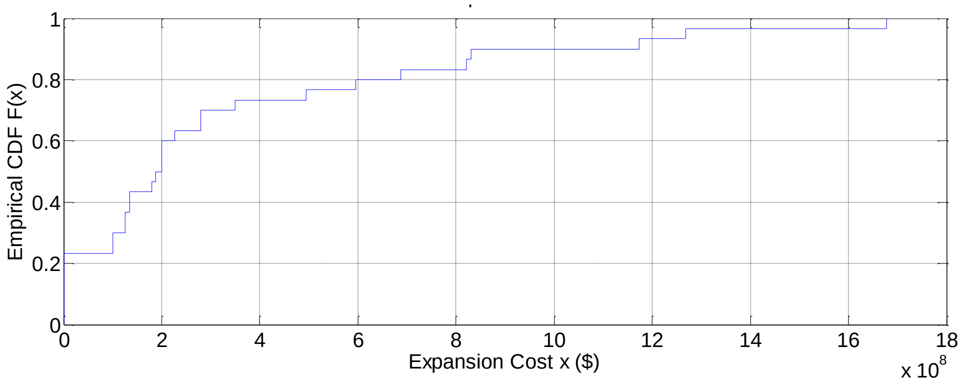


Figure 26 The Expansion Cost - Scenario 3 (20% Dispatchable Wind Power Penetration)

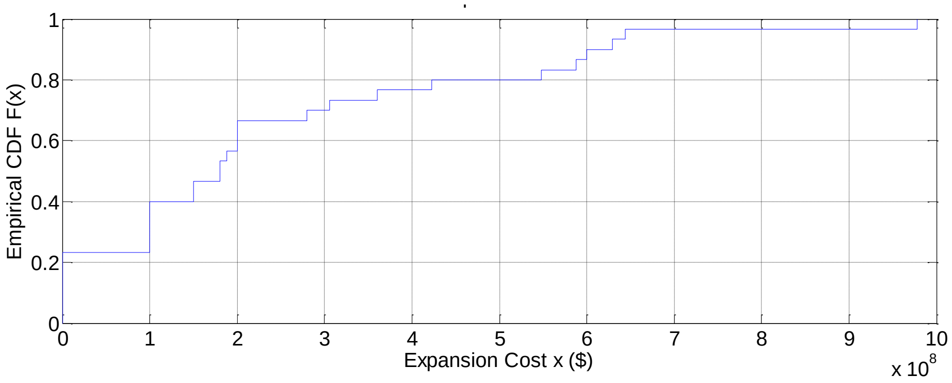
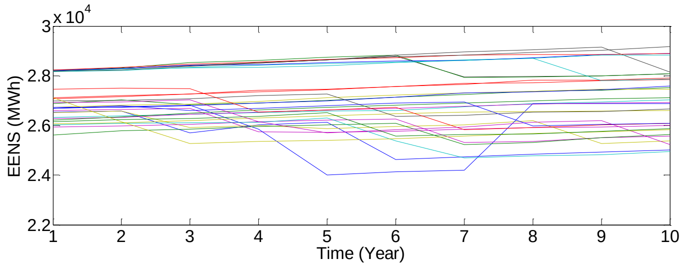
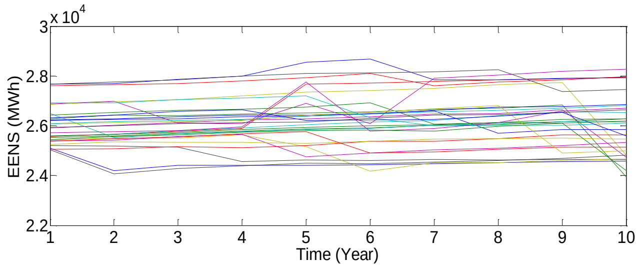


Figure 27 The Expansion Cost - Scenario 4 (10% Dispatchable CST Penetration)

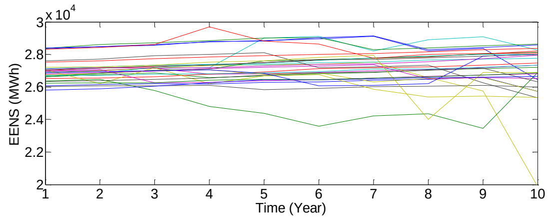
The EUS and EENS of different scenarios, as plotted in Figure **29** and



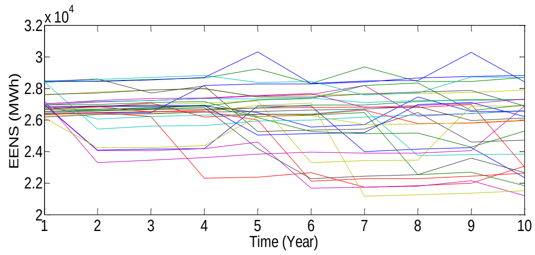
Base Case without DG



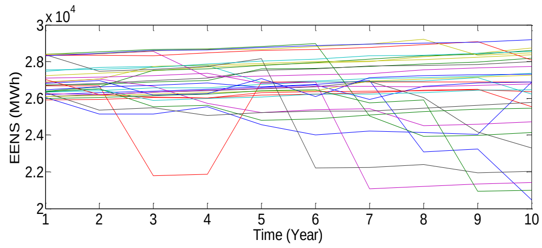
10% CST Penetration



20% CST Penetration



10% Wind Power Penetration



20% Wind Power Penetration

Figure **30**, are also compared. Surprisingly, it can be observed that the installation of DG units has not caused significant impacts on system reliability. This may be attributed to the sufficient generation capacity reserve. It should also be noted that, by connecting DG units, the number of devices in the system also increases significantly. The probability of device failure will contribute to the overall system reliability. Such impact need to be analyzed by detailed reliability assessment in the actual planning process. Generally, to mitigate the impacts of DG on system reliability, it is necessary to build backup generators so as to maintain a sufficient generation reserve level. Under the rules (AEMC, 2009), building proper generation is one of the options available for TNSPs and/or DNSPs in their network planning practice. This allows more mechanisms for the network service providers in their expansion process considering the impact of aggregated DGs in the system.

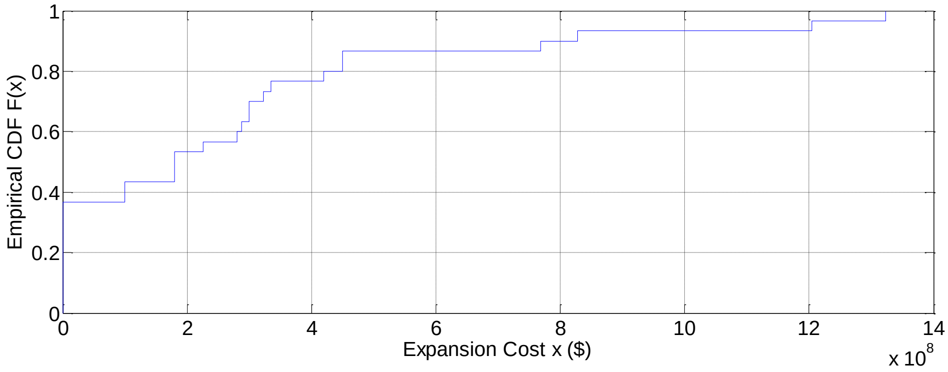
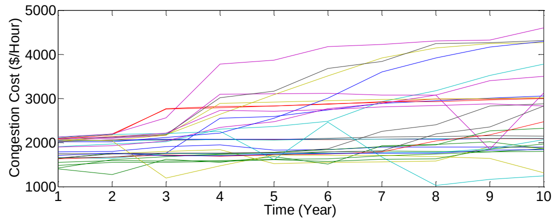
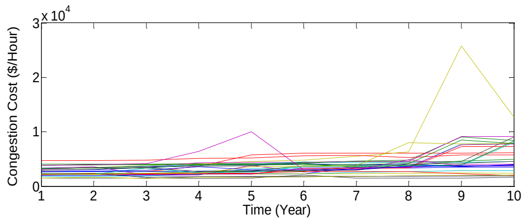


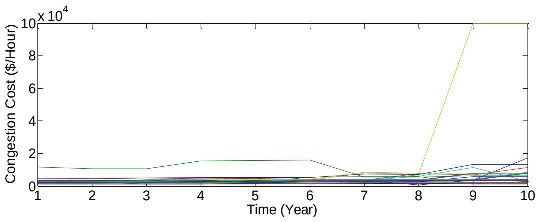
Figure 28 The Expansion Cost - Scenario 5 (20% Dispatchable CST Penetration)



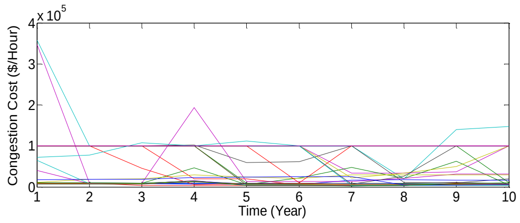
Base Case without DG



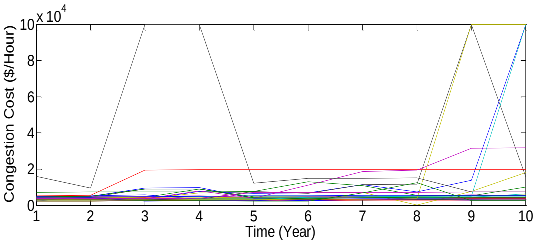
10% CST Penetration



20% CST Penetration

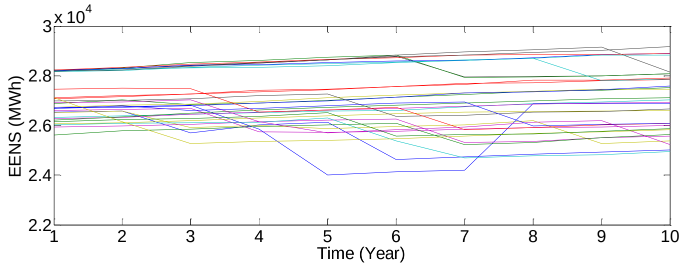


10% Wind Power Penetration

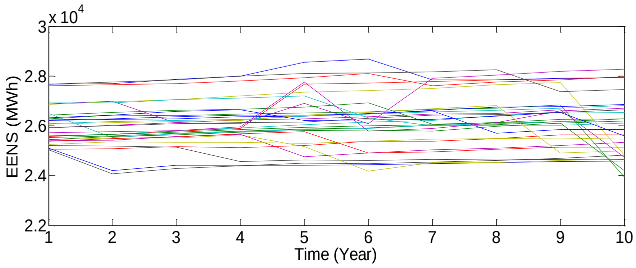


20% Wind Power Penetration

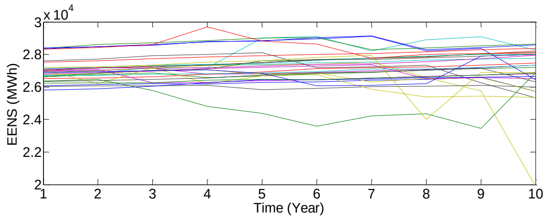
Figure 29: Congestion Costs for Different DG Penetration Levels



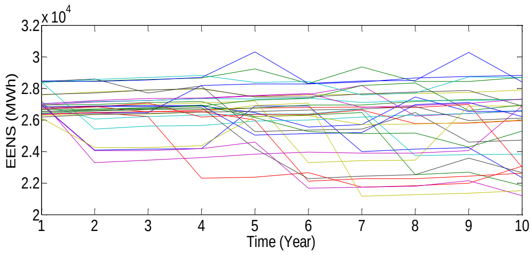
Base Case without DG



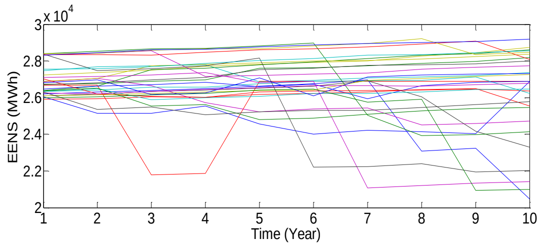
10% CST Penetration



20% CST Penetration



10% Wind Power Penetration



20% Wind Power Penetration

Figure 30: EENS for Different DG Penetration Levels

9.3 CONCLUSION

How to expand the transmission network is an essential problem in the electricity market. In this paper, a novel method of transmission expansion planning is proposed. The method employs two stochastic processes to model system loads and market prices. The values of different generation options in the network are calculated using load and price models. The generation options with higher values are selected to form a candidate generation options set on which generation uncertainty can be modelled. A transmission planning model based on AC OPF is introduced. A novel method based on Monte Carlo simulation is proposed to assess the flexibility of a candidate expansion plan and simulate transmission expansion behaviours under different market settings.

The proposed method is applied to investigate the impacts of distributed generation (DG) on transmission planning. Based on our results, DG can significantly defer transmission investments when it is not involved in the spot market. However, when DG reaches a high penetration level, its effect of deferring transmission investments is reduced. Moreover, a high level of DG penetration may increase the probability of network congestion, which might eventually lead to more transmission investments.

10 Modelling Platform: PLEXOS for Power Systems

PLEXOS is a commercially available optimisation theory based electricity market simulation platform. At its core is the implementation of rigorous operation algorithms and tools such as Linear Programming (LP) and Mixed Integer Programming (MIP). PLEXOS takes advantage of these tools in combination with an extensive input database of regional demand forecasts, inter-regional transmission constraints and generating plant technical data to produce price, generator and demand forecasts by applying the SPD (scheduling, pricing and dispatch) engine used by NEMMCO to operate the NEM (known as the NEMDE).

PLEXOS has been used extensively by current Australian market participants to provide forecasts of the NEM for their generation operations in the market. It is also used by publicly listed Australian generators to provide detailed market performance analysis for their annual audit reporting requirements. Furthermore, this platform has recently been utilised by:

- The Irish electricity market operator to act as its SPD engine
- Californian utilities to examine transmission planning, requiring a 100 000 node representation of their network
- Market participants in the U.S. to present regulatory compliance filings to the FERC.

10.1 Simulation Engine

The PLEXOS modelling platform breaks down the simulation of the NEM into a number of phases ranging from year-long planning and constraints, security and availability of supply, and network expansion, to half hourly dispatch and market clearing. The operation of the interaction between these modelling phases is shown in Figure 31. In this discussion of the mechanisms required to model the NEM, we outline the phases in simulating the market.

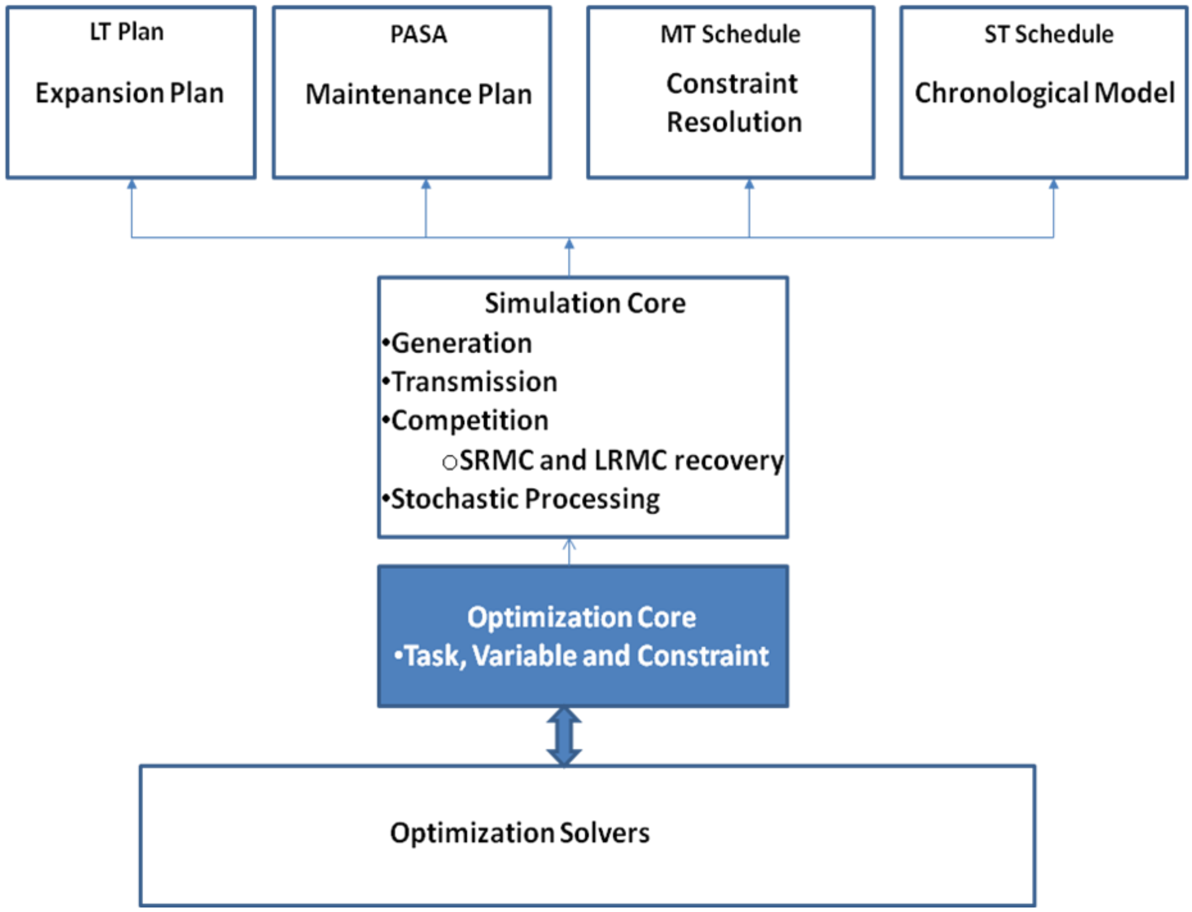


Figure 31: PLEXOS Engine Design

Optimal Power Flow Solution

The solution to the Optimal Power Flow (OPF), is one of the core functions of the PLEXOS simulation engine. The OPF utilizes a linear version of the DC approximation of the optimal power flow problem to model transmission congestion and marginal losses, Therefore Locational Marginal Prices (LMP) reflect transmission marginal loss factors as well as congestion. It does not perform any pre-computation or impose any restrictions on how dynamic the network data can be, thus it can model transmission augmentations and transmission outages dynamically. PLEXOS optimizes the power flows using a linearized approximation to the AC power flow equations. This model is completely integrated into the mathematical programming framework. As a result, generator dispatch, transmission line flows and nodal pricing are jointly optimized with the AC power flow.

LT Plan

The Long Term (LT) Plan establishes the optimal combination of new entrant generation plant, economic retirements, transmission upgrades that minimises the Net Present Value (NPV) of the total costs of the system over a long-term planning horizon. The following types of expansions/retirements and other planning features are supported within the LT Plan:

- Building new generation assets
- Retiring existing generation plant
- Multi-stage generation projects
- Building or retiring DC transmission lines
- Multi-stage transmission projects
- Upgrading the capacity of existing transmission lines
- Acquiring new physical generation contracts
- Acquiring new load contracts.

PASA

The Projected Assessment of System Adequacy (PASA) schedules maintenance events such that the optimal share of generation capacity distributed across and between interconnected regions. It is also a model of discrete and distributed maintenance and random forced outage patterns for generators and transmission lines.

MT Schedule

The Medium Term (MT) Schedule is a model based on Load Duration Curves (LDC) that can run on a day, week or month resolution which includes a full representation of the generation and transmission system and major constraint equations, but without the complexity of individual unit commitment.

The MT Schedule models constraint equations including those that span several weeks, or months of a year. These constraints may include:

- Fuel off-take commitments (i.e. gas take-or-pay contracts)
- Energy limits
- Long term storage management taking into account inflow uncertainty
- Emissions abatement pathways.

Each constraint is optimised over its original timeframe and the MT to ST Schedule's bridge algorithm converts the solution obtained (e.g. a storage trajectory) to targets or allocations for use in the shorter step of the ST Schedule. The LDC blocks are designed with more details in peak and off-peak load times and less in average load conditions, thus preserving some of the original volatility. The solver will schedule generation to meet the load and clear offers and bids inside these discrete blocks. All system constraints are applied, except those that define unit commitment and other inter-temporal constraints that imply a chronological relationship between LDC block intervals. The LDC component of the MT Schedule maintains consistency of inter-regional load profiles which ensures the coincident peaks within the simulation timeframe are captured. This method is able to simulate over long time horizons and large systems in a very short time frame. Its forecast can be used as a stand-alone result or as the input to the full chronological simulation ST Schedule.

ST Schedule

The Short Term (ST) Schedule is a fully featured, chronological unit commitment model, which solves the actual market interval time steps and is based on mixed inter programming. Some examples of how one can use the ST Schedule are:

- Market clearing dispatch and pricing problem based on generator bid pairs
- Large scale transmission study (via the Optimal Power Flow solution)
- Traditional thermal unit commitment and coordination simulation
- Market participant portfolio optimisation.

The ST Schedule generally executes in daily steps and receives information from the MT Schedule which allows PLEXOS to correctly handle long run constraints over this shorter time frame.

10.2 PLEXOS Dispatch Algorithm

Modelling the NEM central dispatch and pricing for the Regional Reference Nodes (RRN), is achieved by determining the generators which need to be included for each five-minute dispatch interval in order to satisfy forecasted demand. To adequately supply consumer demand, PLEXOS examines which generators are currently online or are capable of being turned on to generate for the market at that interval. This centralised dispatch process uses the LP dispatch algorithm SPD to determine the generators in the dispatch set in the given trading interval, taking into account the physical transmission network losses and constraints.

Each day consists of 48 half hour trading periods, and market scheduled generation assets have the option to make an offer to supply a given quantity (MW) of electricity at a specific price ($/MWh) across 10 bid bands. For each band, the bid price/quantity pairs are then included into the RRN bid stack.

Following the assembly of the generator bid pairs for each band, the LP algorithm begins with the least cost generator and stacks the generators in increasing order of their offer pairs at the RRN, taking into account the transmission losses. The LP algorithm then dispatches generators successively, from the least cost to the highest cost until it dispatches sufficient generation to supply the forecasted demand with respect to the inter-regional losses. The price that PLEXOS dispatches the marginal generating unit to the market determines the marginal price of electricity at the RRN for that given trading period. The algorithm executes this process for all six five-minute intervals in the half hourly trading period, and then averages these prices to determine the spot price of electricity for the period. It should be noted that this dispatch process has the following important properties:

1. The dispatch algorithm calculates separate dispatch and markets prices for each RRN in the NEM
2. The prices that determine the merit order of dispatch are the generator offer pairs which are adjusted with respect to relevant marginal loss factors due to notional trading occurring at each RRN
3. The market clearing price is the marginal price, not the average price of all dispatched generation
4. Price differences across regions are calculated using inter-regional loss factor equations as outlined by NEMMCO's SOO 2008 (NEMMCO, 2008).

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

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

10.3 The Short Run Marginal Cost Recovery Algorithm

The core capability of any electricity market model is to perform the economic dispatch or Short Run Marginal Cost (SRMC) recovery based simulations of generating units across a network to meet demand at least cost. PLEXOS' core platform performs economic dispatch under perfect competition where generators are assumed to bid faithfully their SRMC into the market. While simulations such as these will never result in a price trace which would match historical market data from an observed competitive market, they provide a lower bound representative of a pure competitive market.

10.4 User defined market bids for every plant in the system

Historical patterns of bid behaviour are more often than not poor indicators of medium-term future bidding strategies, particularly as they do not account for the following changes in market conditions:

- Growth in load
- New generator entry
- Transmission congestion/expansion
- Short term simulated events such as outages
- Major policy shifts.

Furthermore, bids based on historical data cannot easily target the level of fixed cost recovery required for portfolio optimisation seen on a day to day basis within the NEM. To address these concerns, PLEXOS can model fixed cost recovery in a dynamic and automatic manner, which accounts for natural rents derived across a long simulation horizon such as a fiscal year. This cost recovery is also optimised over all system constraints and opportunities that arise due to outages, shifts in demand and portfolio optimisation.

10.5 Long Run Marginal Cost Recovery

PLEXOS has implemented a heuristic Long Run Marginal Cost (LRMC) recovery algorithm that develops a bidding strategy for each generating portfolio such that it can recover the LRMC for all its power stations. It should be noted that the actual dispatch algorithm is still an LP based protocol in contrast to other commercial tools which use much slower heuristic rule based algorithms to solve for LRMC recovery. This price modification is dynamic and designed to be consistent with the goal of recovering fixed costs across an annual time period. The cost recovery algorithm runs across each MT Scheduled time step. The key steps of this algorithm are as follows:

1. Run MT Schedule with 'default' pricing (i.e. SRMC offers for each generating units).
2. For each firm (company), calculate total annual net profit and record the pool revenue in each simulation block of the LDC
3. Notionally allocate any net loss to simulation periods using the profile of pool revenue (i.e. periods with highest pool revenue are notionally allocated a higher share of the annual company net loss)
4. Within each simulation block, calculate the premium that each generator inside each firm should charge to recover the amount of loss allocated to that period and that firm equal to the net loss allocation divided by the total

generation in that period – which is referred to as the 'base premium'

5. Calculate the final premium charged by each generator in each firm as a function of the base premium and a measure how close the generator is to the margin for pricing (i.e. marginal or extra marginal generators charge the full premium, while infra-marginal generators charge a reduced premium)
6. Re-run the MT Schedule dispatch and pricing with these new premium values
7. If the ST Schedule is also run, then the MT Schedule solution is used to apply short-term revenue requirements for each step of the ST Schedule and the same recovery method is run at each step. Thus, the ST Schedule accounts for medium-term profitability objectives while solving in short steps.

In using PLEXOS, UQ has set the LRMC recovery algorithm to run three times for each time step to produce price trace forecasts with sufficient volatility and shape as recommended by the software's vendor, Energy Exemplar. This will ensure that under normal demand conditions, generating units will bid effectively to replicate market conditions as seen in the NEM.

10.6 Modelling Distributed Generation

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

- Small CCGT with Combined Heat and Power (CHP) or Cogeneration
- Gas micro-turbines with CHP
- Gas reciprocating engine with and without CHP
- Biomass steam with CHP
- Solar PV (as negative load)
- Diesel engines
- Small wind turbines
- Biomass/Landfill gas reciprocating engine
- Gas fuel cells
- Gas reciprocating engine with Combined Cooling Heat and Power (CCHP) or Trigeneration
- Battery storage units can be implemented for any of these tech types.

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

10.7 CASE STUDY

In collaboration with the Commonwealth Scientific and Industrial Research Organisation (CSIRO), the University of Queensland (UQ), prepared a case study on the implications of significant deployment of Distributed Generation (DG) throughout the National Electricity Market (NEM), to gauge its impacts on wholesale electricity prices, emissions and investment in network and centralised generation assets.

The impacts of installing DG across the NEM were modelled using five policy scenarios which varied in terms of energy demand, fuel costs, carbon prices and the scale and scope of installed technology types. Developing forecasts for energy market behaviour out to 2020 presents many challenges given the uncertain regulatory environment. Furthermore, forecasting the composition of generation asset types, network topology and demand require a significant reliance on the assumptions prepared for this project as a apart of UQ's NEM database.

In the previous section we have outlined the modelling platform PLEXOS and the algorithms which we shall employ to perform the analysis of the role out of distributed generation. The methodology and assumptions used in estimating the benefits of installing DG within the NEM used in this modelling report are provided in section 10.8. Assumptions implemented in this modelling with respect to the operational environment encountered by market participants, while appropriate give the policy frameworks currently under review, could change significantly given the uncertainty as to their future implementation.

The development of analytical modelling frameworks that can model the NEM and represent price signals with respect to the role out of distributed energy will provide significant support to decision makers in the pursuit of emissions reduction via technological improvement and alternate investment prioritisation.

The examination of the effects and benefits of the roll out of DG requires a range of modelling inputs with respect to demand and supply side participation to provide half hourly electricity market simulations for 2020 represents one year in the planning horizon. The five scenarios presented in this report were developed in partnership with the CSIRO to provide a snap shot of the future effects of the deployment of DG across the NEM. The scenarios are as follows:

1. **Business-As-Usual (BAU) case with no carbon trading:** in which carbon pricing is not implemented. Load growth is met by significant investment in large centralised generation assets such as base load coal, combined cycle gas turbines (CCGT), solar thermal, geothermal (hot fractured rocks) and wind turbines.
2. **CPRS -15% no DG:** The CPRS is introduced in combination with the renewable energy target to reach an overall reduction of emissions by 15% below 2000 levels. The price of emissions permits is set to reach approximately \$50 t/CO_2 in 2020. Demand growth is reduced compared to the reference case given the increase in energy costs following the implementation of the CPRS. Increased renewable generation asset deployment is observed in this scenario compared to the BAU reference case.
3. **Garnaut 450ppm no DG:** The introduction of the CPRS with a deeper emissions abatement pathway is implemented to achieve an overall reduction of emissions of 25% below 2000 levels. The emissions permit price is set to reach around \$61 t/CO_2 in 2020 which will place more pressure to achieve further energy efficiency and lower emissions technology deployment across the NEM.
4. **CPRS -15% with DG:** Following the introduction of the CPRS, emissions permit prices stimulate the deployment of small scale DG technologies. The roll out of small scale decentralised generation may allow for further cuts in emissions than the corresponding CPRS -15% scenario.
5. **Garnaut 450ppm with DG:** With the implementation of deeper cuts to emissions following the introduction of a 25% target via the CPRS, higher permit prices stimulate a variety of alternative DG options for deployment across the NEM. Furthermore, with increased pressure from permits prices, demand declines, decreasing reliance over time on centralised higher emitting generation types.

10.8 ASSUMPTIONS AND METHODOLOGY

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

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

* Existing and committed generating assets in all states are distributed across their respective portfolios as outlined in the 2008 NEMMCO SOO (NEMMCO, 2008).
* New installed centralised generation capacity output by CSIRO's ESM is attributed to new generic companies for each region.

10.9 DEMAND

Yearly energy demand forecasts were initially provided by the CSIRO for inclusion as a key modelling input (see Table 17). For inclusion in the UQ NEM database, peak demand forecasts were taken from the 2008 NEMMCO SOO (NEMMCO, 2008), which allowed for the appropriate load growth parameters to be applied to historical as generated demand curves. The yearly load curves were then included in the database for the modelling presented in this report. From the data presented in Table 17, each of the four scenarios that include carbon trading exhibit a significant reduction in demand compared to the BAU case due to higher energy costs. Increasing energy costs over time will enable technological innovation in energy efficiency and behavioural change, consistent with estimated long term elasticities of demand, NIEIR (NIEIR, 2004).

Table 17: Demand Forecast

Demand (TWh)	**2020**	**2030**	**2050**
BAU	270	331	481
CPRS -15%	246	241	328
Garnaut 450ppm	230	198	324
CPRS -15% with DG	252	270	344
Garnaut 450ppm with DG	245	256	344
Change from BAU	**2020**	**2030**	**2050**
CPRS -15%	-8.8%	-27.2%	-31.8%
Garnaut 450ppm	-15.0%	-40.2%	-32.5%
CPRS -15% with DG	-6.7%	-18.6%	-28.4%
Garnaut 450ppm with DG	-9.2%	-22.7%	-28.4%

10.9.1 Peak Demand

To provide a forecast of the load profile which represents consumer demand behaviour on the NEM, UQ has used the peak energy values for summer and winter peaks presented in 2008 NEMMCO's SOO (NEMMCO, 2008), for the business as usual case. Peak demand for the other four scenarios was derived from the yearly load forecasts supplied by the CSIRO and incremental load growth from historical data (see Table 18 and Table 19).

Table 18: Winter Peak Demand (MW)

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
2020	44 232	36 979	34 635	36 979	36 838
2030	54 152	33 214	32 583	36 603	37 470
2050	82 920	33 214	32 583	36 603	39 153

Table 19: Summer Peak Demand (MW)

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
2020	48 734	40 353	37 669	40 353	40 185
2030	59 641	34 827	34 206	38 197	39 164
2050	91 375	34 827	34 206	38 197	38 525

10.10 FUEL PRICES

Natural gas prices for this modelling were provided by the CSIRO based on analysis by the Treasury and MMA for the examination of the impacts of the CPRS on generator revenues (see Figure 32). The price data provided represents a city node price for gas in each State rather than each individual generation site. We have not changed the value of gas for peaking or CCGT plant as this may distort the assumptions that the CSIRO has used in their ESM which provides estimates of installed capacity and electricity generation used in this modelling. Furthermore, the same natural gas prices were used for all of the scenarios considered in this report.

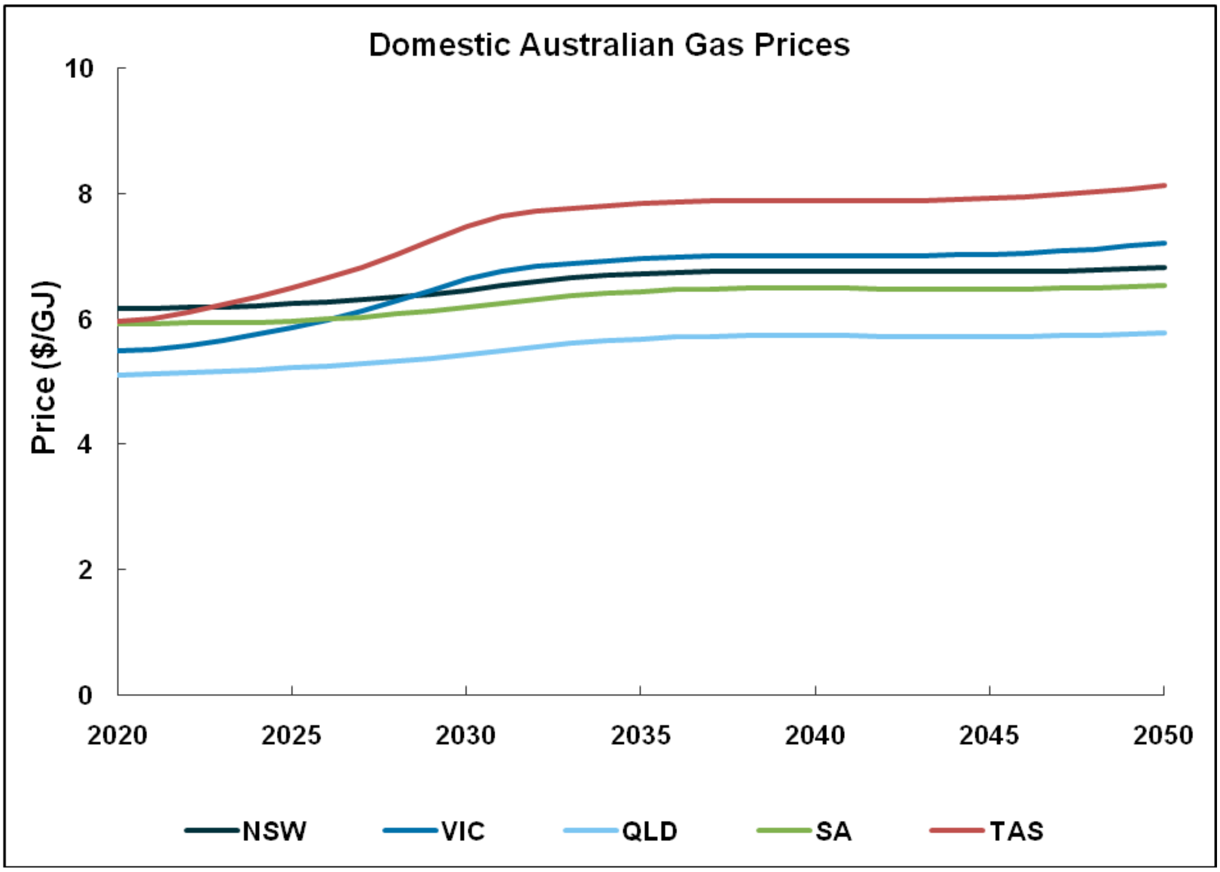


Figure 32: Trends in Natural Gas Prices in NEM States

The price of Biomass fuel prices (excluding transport costs) were provided by the CSIRO as an output shadow price from their ESM. The results of this output are presented in Table 20 for completeness.

Table 20: Biomass Fuel Prices ($/GJ)

	2020	**2030**	**2050**
NSW	$4.03	$4.03	$4.03
VIC	$1.92	$1.92	$1.92
QLD	$5.10	$5.10	$5.10
SA	$7.29	$1.5	$1.5
TAS	$8.14	$1.5	$4.98

The price of black and brown coal was derived from ACIL Tasman's modelling (ACILTASMAN, 2009) , these results will be used by the new Australian Energy Market Operator (AEMO), to perform transmission and infrastructure planning for their 2009 Annual National Transmission Survey. The prices presented in the aforementioned report range out to 2025, and to overcome this shortfall in the data horizon, UQ applied the average growth rate of fuel prices in the original data set to provide suitable values.

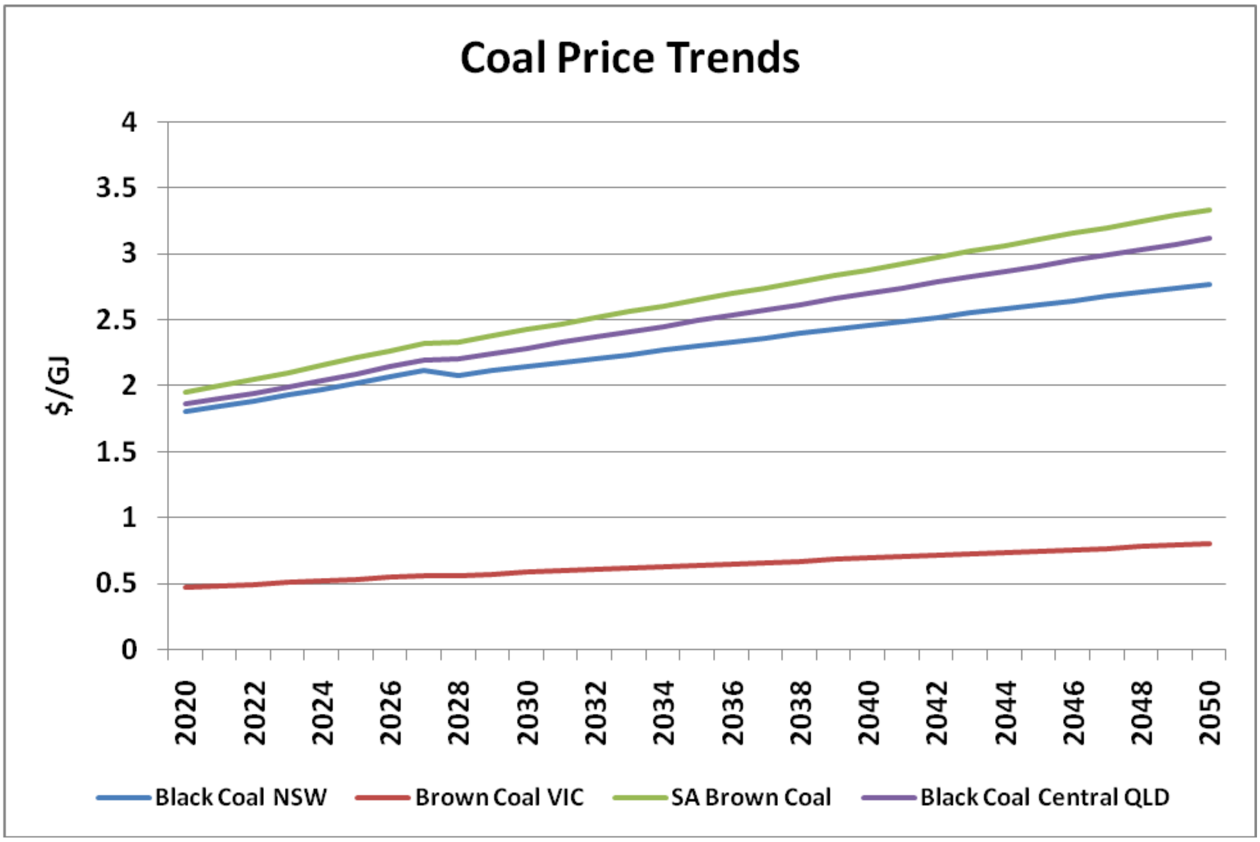


Figure 33: Trend in Coal Prices in NEM States

10.11 TECHNOLOGY SPECIFICATION AND COSTS

The installation of new generation assets into the NEM provides many advantages for Australia's proposed carbon abatement pathway and renewable energy target. The CSIRO in commissioning this report has provided UQ with a variety of new technology types to implement across the NEM to estimate the impacts of large scale deployment of DG. The installed capacity of each technology type for each scenario will be discussed in the modelling results section. From a centralised generation perspective, the development of Carbon Capture and Storage (CCS), hot fractured rocks, solar thermal and Integrated Gasification Combined Cycle (IGCC) are included in the deployment of new generation.

Alternatively, DG technology types are also considered in this modelling to estimate the impacts of large scale deployment of the following technology types:

- Gas micro-turbines with Combined Heat and Power (CHP) or Cogeneration

- Reciprocating engines with and without CHP
- Biomass steam with CHP
- Solar PV (has been included as negative load)
- Small wind turbines
- Biomass/Landfill gas reciprocating engine
- Gas reciprocating engine with Combined Cooling Heat and Power (CCHP) or Trigeneration

Table 21: New Centralised Generation Plant Data (ACILTASMAN, 2009).

Technology	Typical new entrant size (MW)	Minimum stable generation level (%)	Auxiliary load (%)	Thermal efficiency HHV (GJ/MWh) sent-out	FOM ($/MW/year) for 2009-10	VOM ($/MWh sent-out) for 2009-10	Emission intensity (tonnes CO_2-e per MWh sent-out)
CCGT	400	40%	4.0%	7.20	31,000	1.05	0.40
OCGT (Peaking)	100	0%	1.0%	11.61	13,000	7.70	0.66
SC BLACK	500	50%	9.5%	9.00	48,000	1.25	0.88
Geothermal	500	50%	2.5%	5.14	35,000	2.05	0
IGCC	500	50%	15.0%	8.78	50,000	4.10	0.86
IGCC – CCS	500	50%	20.0%	10.91	75,000	5.15	0.14
USC CCS BLACK	500	50%	26.0%	11.61	80,000	2.40	0.15
USC CCS BROWN	500	50%	26.0%	12.86	92,000	2.40	0.06

Table 22: Distributed Generation Plant Data

Technology name	Indicative size	O&M cost ($/MWh)	Fuel transport cost ($/GJ)	Aux. power usage (%)	Capacity factor (%)	Thermal efficiency HHV (GJ/MWh) sent-out	Power to heat ratio
Gas combined cycle w. CHP	30 MW	35	1.35	5	65	7.45	0.8
Gas microturbine w. CHP	60 kW	10	5.85	1	18	12.15	2.8
Gas reciprocating engine (Large)	5 MW	5	1.35	0.5	1	8.57	na
Gas reciprocating engine (Medium)	500 kW	2.5	5.85	0.5	3	9	na
Gas reciprocating engine (Small)	5 kW	2	11.2	0.5	1	9.4	na
Gas reciprocating engine w. CHP	1 MW	7.5	1.35	1	65	8.57	1.1
Gas reciprocating engine w. CHP (Small)	500 kW	5	5.85	1	18	9	1.1
Biomass steam w. CHP	30 MW	30	24.6	6.5	65	12.15	1
Solar PV (Large)	40 kW	0.5	na	na	na	na	na
Solar PV (Small)	1 kW	0.5	na	na	na	na	na
Diesel engine	500 kW	5	1.55	0.5	3	8	na
Wind turbine (Large)	10 kW	0.5	na	na	na	na	na
Wind turbine (Small)	1 kW	0.5	na	na	na	na	na
Biogas/landfill gas reciprocating engine	500 kW	0.5	0.5	0.5	80	9	na
Gas fuel cell w. CHP	2 kW	70	11.2	na	80	5.2	0.36
Gas microturbine w. CCHP	60 kW	15	5.85	1.5	43	12.15	2.8
Gas reciprocating engine w. CCHP (Large)	5 MW	15	1.35	1.5	80	8.57	1.1
Gas reciprocating engine w. CCHP (Small)	500 kW	10	5.85	1.5	43	9	1.1

10.11.1 Renewable Generation

Climate data from the Bureau of Meteorology (BoM) for each capital city in the NEM were used to estimate the energy production from wind and solar generation. The 1min average wind data were converted to half hourly averages for use with the PLEXOS model. The 30 minute wind speed data were then scaled for the height of the wind turbine (70 metres) using Equation 1. Power produced by the wind turbines was determined by fitting the adjusted wind speed data to the turbine output profile displayed in Figure 4.

It should be noted that solar and wind power production was treated as negative load in this modelling. These resources are uninterruptable and would naturally be bid in at full capacity with a $0 dollar price. To provide a half hourly trace of the availability of these resources, UQ has performed the following analysis. Where,

$$u_z = u_{10}\left(\frac{ln\left(\frac{z}{z_0}\right)}{ln\left(\frac{z_{10}}{z_0}\right)}\right) \qquad 0 < u < \infty \qquad (1)$$

u_z is the wind speed at height z

u_{10} is the wind speed at a reference height (z_{10}), in this case 10 metres

z_{10} is the surface roughness length determined by land use.

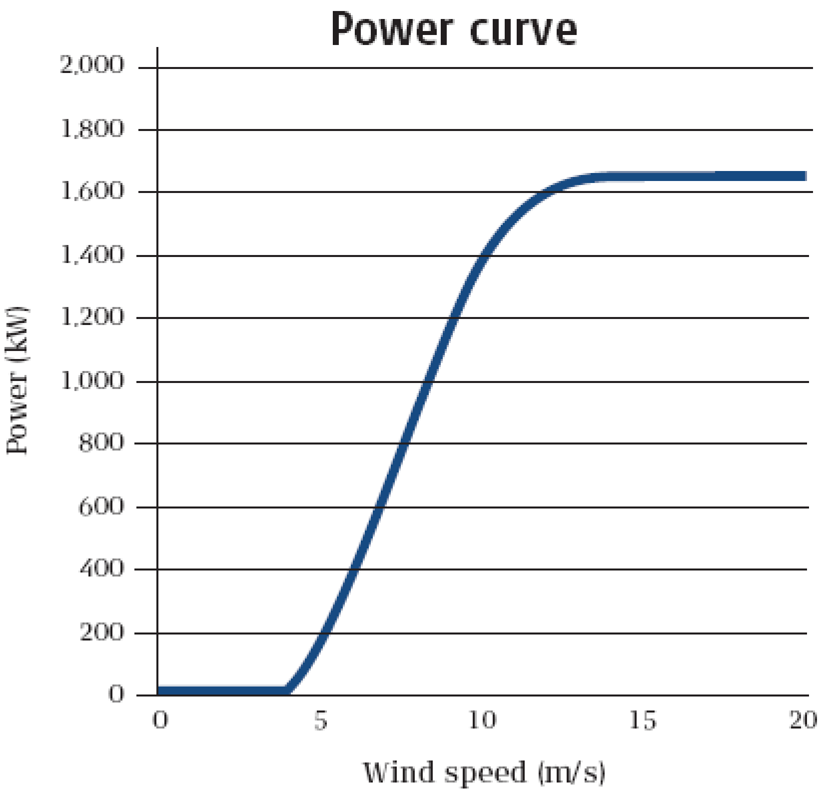


Figure 34: Power Curve for a Vestas V82 wind turbine

BoM solar radiation and temperature data were converted to 30 minute averages to determine the output from a solar thermal or photovoltaic (PV) system. The output from a 1 kW solar PV panel is derived from Equation 2 (Mills, 2001). The PV panel was assumed to produce 1 kW for a shortwave radiation solar flux of 1000 W/m^2 at an ambient temperature of 25ºC. A temperature correction factor was applied assuming the panel was operating at 30ºC above ambient and had a loss of 0.4% per degree increase in ambient temperature.

$$P = R_{in}\left[1 - \left({0.4\left(PT + (AT - 25)\right)}/{100} \right)\right] \qquad (2)$$

Where,

P is the output of the solar cell (W)

R_{in} is the short wave radiation flux over one square metre,

PT is the panel operating temperature above ambient and,

AT is the ambient temperature.

10.11.2 Hydro Storage Levels

The Snowy, Tasmanian and Southern Hydro reservoir storage levels were detailed within the UQ PLEXOS database to their levels during pre-drought periods. These levels are assumed to be the inflows into reservoirs as outlined in the 2008 SOO NEMMCO (NEMMCO, 2008). It should also be noted that the impacts of possible droughts were not considered in the availability of hydro generation during the planning horizon.

10.12 CARBON PRICES

With the proposed introduction of the Australian CPRS, major structural change is expected in the NEM. The two carbon price forecasts for a 15% (CPRS -15%) and 25% (Garnaut 450ppm) reduction targets that have been implemented within the modelling presented were obtained from (Treasury, 2008).

Table 23: Carbon Price Forecasts

	CPRS-15%	**Garnaut 450ppm**
2020	50.02	61.06

10.13 MANDATORY RENEWABLE ENERGY TARGET

The Mandatory Renewable Energy Target (MRET), was introduced in the Australian environmental policy framework in 2001 to encourage investment in a renewable energy industry within the electricity market. The initial target set out in the legislation was 9500 GWh per annum by 2010 and to remain at this level until 2020.

Under further amendments initiated by the current Federal Government, MRET will be raised to approximately 20% or 45 000GWh of Australian electricity production. The expanded MRET has been included in this modelling for all four scenarios which include carbon trading by installing the prescribed generation mix estimated by CSIRO's ESM. While the cost of Renewable Energy Certificates (RECs) has not been explicitly included in the modelling input data, the modelling horizon begins in the last year of the MRET and from analysis of the ESM outputs the 45 000GWh target is predicted to be met.

10.14 Transmission Network Topology

The NEM region model used within PLEXOS contains 5 regional reference nodes and the main NSW to VIC interconnection (the Snowy) which includes inter-regional transfer limits (see Figure 35). The interconnector limits are currently modelled as static limits with marginal loss factors. These static limits for 2020 were based on NEMMCO's regional boundary and loss factors as published in the 2008 SOO (NEMMCO, 2008).

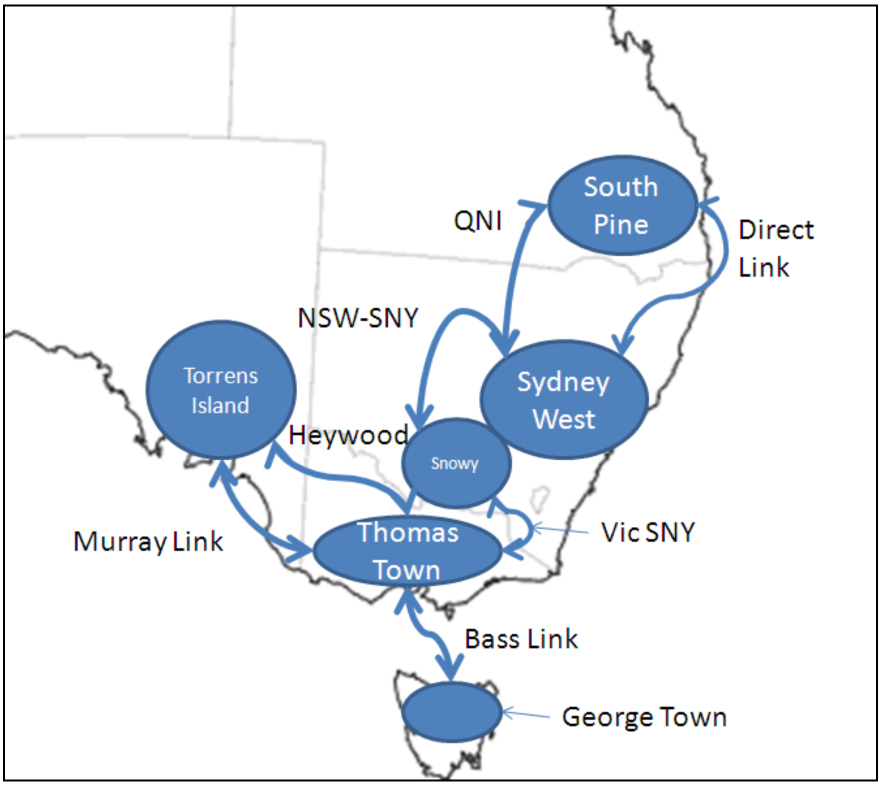


Figure 35: NEM Network Topology

Upgrades to inter-regional line limits were introduced incrementally during the testing phase for each milestone year within the planning horizon (see Table 24 below). Initially, PLEXOS was run over a 24-hour settlement period to test for

Unserved Energy (USE) within the network over the year-long simulation. Due to the proximity of the available generation capacity and the forecasted demand provided by CSIRO, the optimal power flow solution should not include USE more than 0.002% of yearly demand, which is consistent with AEMO's own planning criteria. Therefore, the major constraint to solving the optimal power flow is inter-regional line flow limits.

To improve the flow of energy and maintain the our forecast of energy supply and demand balance, after each testing simulation if USE existed in the solution, then the line limit was upgraded by the peak amount of USE. In doing so, it was found that upgrades to the line limit between at the 2020 milestone were fairly modest. Line losses, outage and repair pattern timings of the interconnectors where consistent with those currently observed in the NEM.

Table 24: NEM Interconnector Line Limits (MW)

Link Name	**From**	**To**	**2020**
QNI	NSW	Qld	600
QNI	Qld	NSW	1200
Direct Link (DC)	NSW	QLD	100
Direct Link (DC)	Qld	NSW	180
Murray Link (DC)	Vic	SA	220
Murray Link (DC)	SA	Vic	120
Heywood	Vic	SA	460
Heywood	SA	Vic	300
Basslink (DC)	Tas	Vic	630
Basslink (DC)	Vic	Tas	480
Snowy NSW	NSW (Snowy)	NSW Sydney West 330KV	3200
Snowy NSW	NSW Sydney West 330KV	NSW (Snowy)	1150
Snowy Vic –NSW	Vic	NSW	1200
Snowy Vic –NSW	NSW	Vic	1900

10.15 RESULTS

In the methodology section for the market simulation of the 5 cases studies was provided. In this Section the results of the analysis is given with particular emphasis provided to quantify the impacts of DG in the NEM

The modelled results are presented for:

1. Installed capacity for each scenario based on input assumptions provided by the CSIRO
2. Average prices for each state
3. Price distribution and premium of flat price caps
4. Inter-regional price spreads as a proxy measure of transmission congestion
5. Greenhouse gas (GHG) emissions and the Emissions Intensity Factor (EIF) of electricity generation
6. Effects on centralised generation assets.

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

One of the standard ways to represent the relative volatility of price on the NEM is to provide a price distribution based on the pricing of premiums for standard cap contracts for difference (CFDs). The relative cap price is calculated by using the frequency of prices exceeding each cap price barrier. The sum of all of these cap premiums is equal to the time weighted average price of the price trace considered.

The representation of relative GHG emissions to compare the five scenarios with each other is more effectively performed by using the EIF which is the number of emitted tonnes of CO_2 per MWh produced. Due to the change in demand and installed capacity provided by the CSIRO, the raw GHG emissions data are misleading in representing the relative emissions changes observed across the simulations.

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

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

10.16 SIMULATION RESULTS FOR 2020

The first year within the planning horizon begins with forecasting the effects of DG in the NEM in the last year of the current renewable energy target and the first target proposed for the CPRS. The installed capacity used for this time step is represented in Figure 36. The greatest structural changes observed are the decrease in the amount of brown coal generation and an increase in Brown coal IGCC plant.

Effects on average prices

Scenario 1 (S1), represents the business as usual case which exhibits a low average price with no carbon price uplift due to any increase in the SRMC of combustive units. Scenarios 2 and 3 (S2 and S3 respectively) represent a significant increase in average price across all States resulting in some reduction in demand in 2020. Furthermore, the average price experienced in QLD for S2 is largely due to the close proximity of supply to balance demand. Across every State in S4 and S5 a large decrease in the time weighted average price is observed.

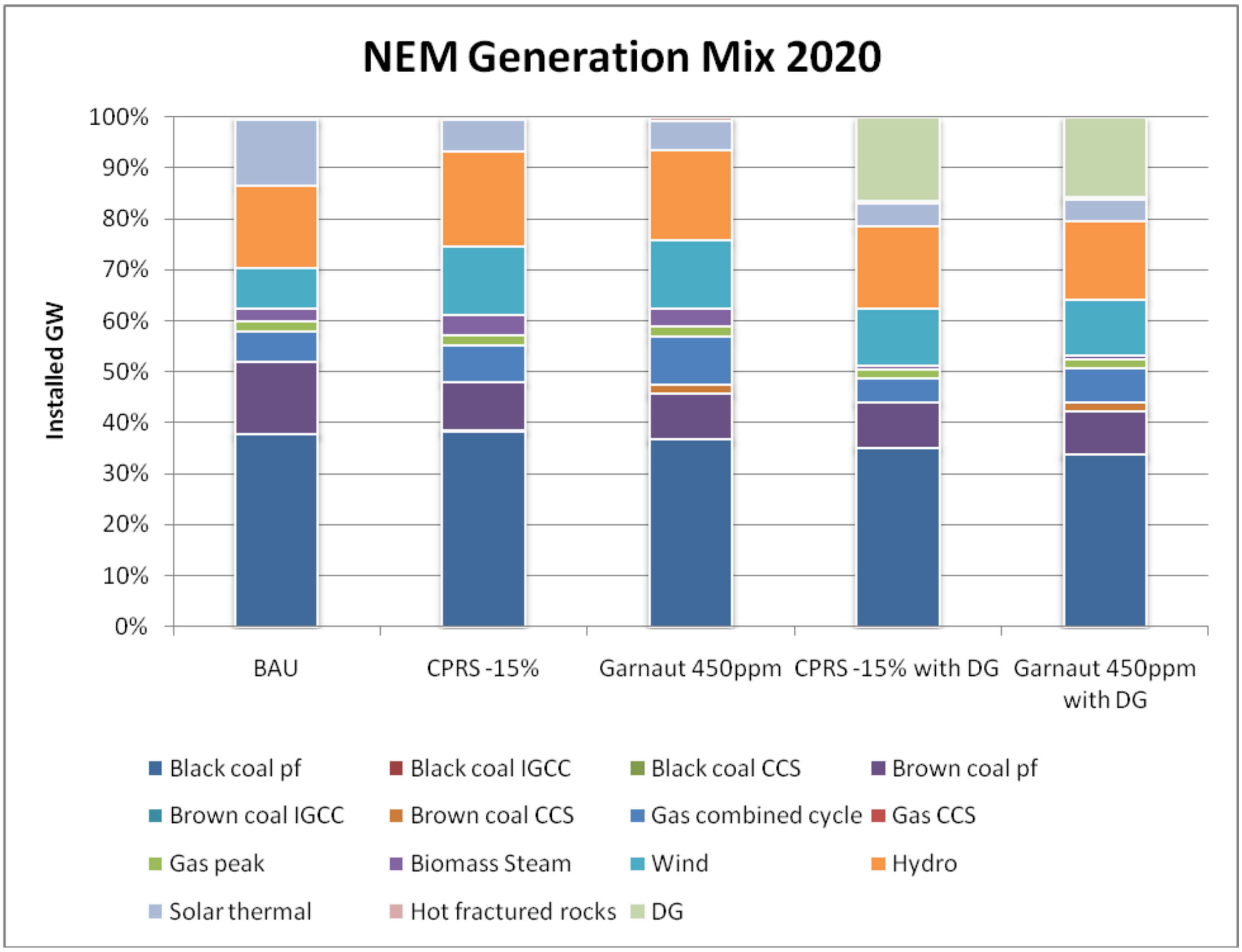


Figure 36: NEM 2020 Installed Generation Mix

Table 25: Average Prices 2020 ($/MWh)

	NSW	QLD	SA	TAS	VIC
Scenario 1	$28.20	$26.59	$37.13	$15.60	$24.76
Scenario 2	$80.92	$165.54	$70.38	$68.52	$68.54
Scenario 3	$81.61	$71.71	$62.01	$62.01	$49.48
Scenario 4	$39.54	$36.13	$67.65	$67.65	$66.11
Scenario 5	$35.95	$35.06	$39.78	$39.78	$31.51

Effects on the volatility of prices

The premiums on all of the caps below $300/MWh are significantly higher in all scenarios which do not include DG. The ability of small generation assets such as DG to address changes in peak demand appears to be one of the advantages of their installation. The slight increase in prices above $300/MWh in S4 and S5 represents a small shift in volatility which does make a significant contribution to the average price. Volatility above the $300 price cap is accounted for by examining the proximity of supply and demand. The breakdown of cap premium prices is provided in Table 26. The Base value represents the sum of premium values up to and including the $100 cap which represents a benchmark hedge position generally observed on the NEM.

Table 26: Price Distribution 2020

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Premium on Cap: $0	$19.01	$20.00	$20.00	$19.99	$17.45
Premium on Cap: $20	$3.68	$10.00	$10.00	$6.30	$5.82
Premium on Cap: $30	$1.65	$18.75	$19.65	$5.75	$2.95
Premium on Cap: $50	$0.69	$11.51	$16.95	$6.57	$0.28
Premium on Cap: $100	$0.71	$3.93	$1.40	$0.58	$0.27
Premium on Cap: $300	$0.86	$7.28	$0.64	$1.80	$0.84
Premium on Cap: $1,000	$0.31	$33.25	$0.04	$6.23	$10.53
Total	$26.92	$104.72	$68.68	$47.21	$38.14
Base	$25.75	$64.19	$68.00	$39.18	$26.77

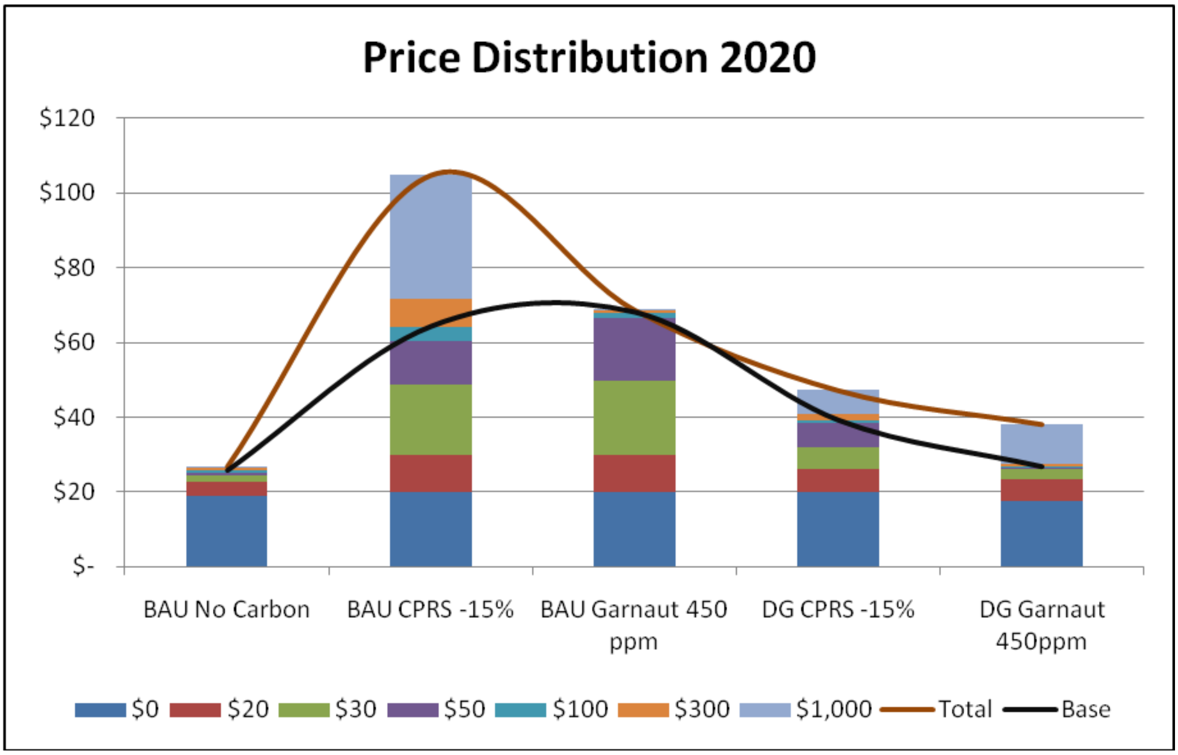


Figure 37: Price Distribution for 2020 Simulations

Effects on Transmission Congestion

As mentioned earlier, evaluating transmission congestion in this modelling will be performed by examining the inter-regional price spread. The observed spread between prices for each of the scenarios in this time step is consistent with the proximity of demand and maximum available supply (see Table 27, i.e. S2 NSW-QLD). In each scenario the spreads which raise the most questions as to the future adequacy of the NEM to cope with future demand are represented by constant higher prices in SA compared to Victoria. The transmission congestion observed in SA and VIC, by our use of the proxy measure of interregional price spreads is behaviour that may have been a result of insufficient home state generation asset deployment provided in the CSIRO ESM data. The spread across NSW-VIC in S4 represents the increased flow of energy from NSW to QLD and Tasmania's increased export to Victoria. Increased prices in Victoria are also attributed to the marginal cost increase experience by brown coal generation assets.

Table 27: Interregional Price Spread 2020

	NSW - QLD	NSW - VIC	VIC - SA	TAS-VIC
Scenario 1	$1.61	$3.44	-$12.37	-$9.16
Scenario 2	-$84.63	$12.38	-$1.84	-$0.02
Scenario 3	$9.90	$32.13	-$12.53	$12.53
Scenario 4	$3.41	-$26.57	-$1.54	$1.54
Scenario 5	$0.89	$4.44	-$8.27	$8.27

Effects on Greenhouse Gas Emissions

The relative drop in GHG emissions and the delivered EIF is a significant outcome from the deployment of DG across the NEM. While there is a small increase in the EIF for S5 compared to its non-DG counterpart S3, electricity sector GHG emissions are 2 million tonnes lower.

Table 28: Greenhouse Gas Emissions 2020

	GHG Emissions (MT/year)	Emissions Intensity Factor (tCO_2/MWh)
Scenario 1	229.566	0.878
Scenario 2	223.731	0.944
Scenario 3	201.205	0.791
Scenario 4	199.952	0.776
Scenario 5	199.196	0.795

Effects on Centralised Generation

According to the modelling results, the deployment of DG across the NEM results in a moderate reduction in the use of brown coal-fired assets. The main observation which can be made from the results presented in Table 29, is that the share of demand served by centralised generation is lower causing a loss in revenues relative to those experienced in S1. Table 29 shows significant structural change in the electricity generation sector by 2020.

Table 29: Percentage of 2020 Demand Met by Technology Type

	2020				
	Scenario 1	**Scenario 2**	**Scenario 3**	**Scenario 4**	**Scenario 5**
Brown coal pf	23.22%	14.88%	3.49%	11.53%	3.50%
Brown coal IGCC	0.03%	0.03%	0.03%	0.03%	0.03%
Brown coal CCS	0.00%	0.00%	2.99%	0.00%	2.81%
Black coal pf	48.89%	51.70%	53.16%	48.02%	47.43%
Black coal IGCC	0.08%	0.09%	0.09%	0.08%	0.09%
Black coal CCS	0.00%	0.00%	0.00%	0.00%	0.00%
Gas combined cycle	7.41%	10.27%	15.38%	6.41%	11.12%
Gas CCS	0.00%	0.00%	0.00%	0.00%	0.00%
Gas peak	0.56%	0.99%	0.84%	0.36%	0.67%
Biomass Steam	2.65%	4.31%	4.63%	0.86%	0.88%
Wind	4.27%	7.87%	8.68%	7.06%	7.36%
Hydro	4.66%	5.06%	5.44%	4.98%	5.12%
Solar thermal	7.33%	3.96%	4.06%	2.96%	2.93%
Hot fractured rocks	0.90%	0.84%	1.20%	1.10%	1.13%
Centralised Generation	**100.00%**	**100.00%**	**100.00%**	**83.38%**	**83.07%**
DG	**0.00%**	**0.00%**	**0.00%**	**16.62%**	**16.93%**

10.17 CONCLUSION

The electricity market modelling of DG has demonstrated some benefits of the large scale deployment of DG across the NEM. DG has been shown to significantly improve the long-term reduction of wholesale electricity prices and GHG emissions. Reductions in average spot prices and volatility with respect to both carbon price scenarios, may present opportunities for market participants to reduce their exposure to the wholesale electricity market. The results show that analyses which do not factor in DG, may underestimate the potential of the electricity generation sector to reduce its GHG emissions over time.

11 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.

Dr Lucas Skoufa, Lecturer: UQ Business School

Lucas Skoufa is a lecturer in Energy and Carbon Management at UQ Business School. He completed his PhD in Strategic Management, and also has a Master of Business Administration, a Bachelor of Business and a Bachelor of Engineering (Mechanical). His current research looks at (1) power generation technology trajectories, (2) developing a planetary sustainability index, and (3) carbon and emissions trading schemes as they relate to the electricity sector and how these firms can operate and be strategically competitive in a carbon constrained world. Recent papers in this area include the *Impact of environmental costs on competitiveness of Australian Electricity Generation technologies*. In summary Lucas is interested in making a contribution to de-carbonising the energy sector. Originally from an engineering background, Lucas historically worked in the electricity industry as both a business manager and engineer. At AUSTA Electric (Queensland Government power-generating corporation in 1995 – 1997) he was part of a team that conducted a feasibility study on a $800 million power station, which is now Callide "C" Power Station. Prior to that he served as a Marine Engineering Officer in the Royal Australian Navy which included the role of Project Manager for the major overhaul of HMAS SUCCESS (a major Naval surface ship).

Dr Ariel Liebman, Honorary Research Consultant: School of Economics and Director Policy, Regulation and Analysis, Energy Users Association of Australia.

Dr. Ariel Liebman is an energy market specialist and has recently joined the EUAA. With more than 10 years in the field, Ariel has a breadth of experience in the market and has worked for power generation companies, energy retailers and economic research organisations. In that time he has been involved in identifying and evaluating renewable energy opportunities, analysis retail contracts, developing trading policies, portfolio risk management frameworks, and market simulators. As a researcher at the University of Queensland his research focused on emissions trading, generation project investment risk, and the economics of demand management. During his time at the University of Queensland Ariel was part of the University of Queensland's team of experts appointed to the Federal Department of Climate Change's consulting panel on the Emission Trading Scheme. Ariel retains his close association with the University of Queensland through his position as Honorary Research Consultant in its School of Economics.

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.

12 References

ABU-SHARKH, S., ARNOLD, R. J., KOHLER, J., LI, R., MARKVART, T., ROSS, J. N., STEEMERS, K., WILSON, P. & YAO, R. (2006) Can microgrids make a major contribution to UK energy supply? *Renewable & Sustainable Energy Reviews,* 10**,** 78-127.

ACILTASMAN (2009) Fuel resource, new entry and generation costs in the NEM.

AEMC, A. E. M. C. (2009) The National Electricity Rules.

AEMO (2009) An Introduction to Australia's National Electricity Market.

AER, A. E. R. (2009) Proposed Regulatory Test Version 3.

ALBERTH, S. (2008) Forecasting technology costs via the experience curve - Myth or magic? *Technological Forecasting and Social Change,* 75**,** 952-983.

ANDERSON, K., BOWS, A. & MANDER, S. (2008) From long-term targets to cumulative emission pathways: Reframing UK climate policy. *Energy Policy,* 36**,** 3714-3722.

AWERBUCH, S. A. B., M., (2008) Energy Security and Diversity in the EU: A Mean-Variance Portfolio Approach. *IEA Working Paper.* IEA, Paris.

BAHIENSE, L., OLIVEIRA, G. C., PEREIRA, M. V. F., GRANVILLE, S. & IEEE, I. I. (2001) A mixed integer disjunctive model for transmission network expansion. Sydney, Australia, Ieee.

BAKER, E., CHON, H. W. & KEISLER, J. (2009) Advanced solar R&D: Combining economic analysis with expert elicitations to inform climate policy. *Energy Economics,* 34**,** S37-S49.

BEMIS, G. R. & DEANGELIS, M. (1990) Levelized Cost of Electricity Generation Technologies. *Contemporary Policy Issues,* 8**,** 200-214.

BENZ, E. & TRUCK, S. (2009) Modeling the price dynamics of CO2 emission allowances. *Energy Economics,* 31**,** 4-15.

BHANDARI, R. & STADLER, I. (2009) Grid parity analysis of solar photovoltaic systems in Germany using experience curves. *Solar Energy,* 83**,** 1634-1644.

BINATO, S., PEREIRA, M. V. F. & GRANVILLE, S. (2001) A new benders decomposition approach to solve power transmission network design problems. *Ieee Transactions on Power Systems,* 16**,** 235-240.

BOUFFARD, F. & KIRSCHEN, D. S. (2008) Centralised and distributed electricity systems. *Energy Policy,* 36**,** 4504-4508.

BREALEY, R. A. & MYERS, S. C. (2003) *Principles of Corporate Finance,* New York, McGraw-Hill/Irwin.

BURNIAUX, J. M. (2000) A Multi-Gas Assessment of the Kyoto Protocol. OECD, Economics Department.

BUYGI, M. O., BALZER, G., SHANECHI, H. M. & SHAHIDEHPOUR, M. (2004) Market-based transmission expansion planning. *Ieee Transactions on Power Systems,* 19**,** 2060-2067.

BUYGI, M. O., SHANECHI, H. M., BALZER, G., SHAHIDEHPOUR, M. & PARIZ, N. (2006) Network planning in unbundled power systems. *Ieee Transactions on Power Systems,* 21**,** 1379-1387.

CAPROS, P. (1999) European Emission Mitigation Policy and Technological Evolution: Economic Evaluation with the GEM-E3 model: Final Report. Athens, Greece, National Technical University of Athens, Institute of Communication and Computer Systems, E3M-Lab. .

CARLEY, S. (2009) Distributed generation: An empirical analysis of primary motivators. *Energy Policy,* 37**,** 1648-1659.

CHANDA, R. S. & BHATTACHARJEE, P. K. (1994) APPLICATION OF COMPUTER SOFTWARE IN TRANSMISSION EXPANSION PLANNING USING VARIABLE LOAD STRUCTURE. *Electric Power Systems Research,* 31**,** 13-20.

CHEN, W. Y. (2005) The costs of mitigating carbon emissions in China: findings from China MARKAL-MACRO modeling. *Energy Policy,* 33**,** 885-896.

CHOI, J., EL-KEIB, A. A. & TRAN, T. (2005) A fuzzy branch and bound-based transmission system expansion planning for the highest satisfaction level of the decision maker. *Ieee Transactions on Power Systems,* 20**,** 476-484.

COSSENT, R., GOMEZ, T. & FRIAS, P. (2009) Towards a future with large penetration of distributed generation: Is the current regulation of electricity distribution ready? Regulatory recommendations under a European perspective. *Energy Policy,* 37**,** 1145-1155.

COVENTRY, J. S. & LOVEGROVE, K. (2003) Development of an approach to compare the 'value' of electrical and thermal output from a domestic PV/thermal system. *Solar Energy,* 75**,** 63-72.

CPRS (2008) Carbon Pollution Reduction Scheme: Australia's Low Pollution Future. IN CHANGE, D. O. C. (Ed.). Canberra, Department of Climate Change.

CRIQUI, P. V., L. (2000) Kyoto and technology at world level: costs of CO2 reduction under flexibility mechanisms and technical progress. *International Journal of Global Energy Issues,* 14**,** 155-168.

DA SILVA, E. L., GIL, H. A., AREIZA, J. M. & IEEE, I. (1999) Transmission network expansion planning under an Improved Genetic Algorithm. Santa Clara, Ca, Ieee.

DA SILVA, E. L., ORTIZ, J. M. A., DE OLIVEIRA, G. C. & BINATO, S. (2001) Transmission network expansion planning under a Tabu Search approach. *Ieee Transactions on Power Systems,* 16**,** 62-68.

DASKALAKIS, G., PSYCHOYIOS, D. & MARKELLOS, R. N. (2009) Modeling CO2 emission allowance prices and derivatives: Evidence from the European trading scheme. *Journal of Banking & Finance,* 33**,** 1230-1241.

DEL VALLE, Y., VENAYAGAMOORTHY, G. K., MOHAGHEGHI, S., HERNANDEZ, J. C. & HARLEY, R. G. (2008) Particle swarm optimization: Basic concepts, variants and applications in power systems. *Ieee Transactions on Evolutionary Computation,* 12**,** 171-195.

DEPARTMENT OF CLIMATE CHANGE (2008) Carbon Pollution Reduction Scheme: Australia's Low Pollution Future. IN CHANGE, D. O. C. (Ed.). Canberra, Department of Climate Change.

DONDI, P., BAYOUMI, D., HAEDERLI, C., JULIAN, D. & SUTER, M. (2001) Network integration of distributed power generation. London, England, Elsevier Science Bv.

DOTSIS, G., PSYCHOYLOS, D. & SKLADOPOULOS, G. (2007) An empirical comparison of continuous-time models of implied volatility indices. *Journal of Banking & Finance,* 31**,** 3584-3603.

DUSONCHET, Y. P. & EL-ABIAD, A. (1973) Transmission Planning Using Discrete Dynamic Optimizing. *Power Apparatus and Systems, IEEE Transactions on,* PAS-92**,** 1358-1371.

DYNER, I., LARSEN, E.R. AND LOMI, A., (2003) Simulation for Organisational Learning in Competitive Electricity Markets. IN KU, A. (Ed.) *Risk and Flexibility in Electricity: Introduction to the Fundamentals and Techniques.* London, Risk Books.

ELLERMAN, A. D. & WING, I. S. (2000) Supplementarity: An invitation to monopsony? *Energy Journal,* 21**,** 29-59.

ENGLANDER, D. B., T. (2009) Global PV Demand Analysis and Forecast: The Anatomy of a Shakeout II. GTM Research.

EYCKMANS, J., VAN REGEMORTER, D. & VAN STEENBERGHE, V. (2002) Is Kyoto Fatally Flawed? An Analysis with MacGEM. *SSRN eLibrary*.

EYDELAND, A., AND WOLYNIEC, K. (2003) *Energy and Power Risk Management. New developments in Modeling, Pricing and Hedging.*, Hoboken, New Jersey, John Wiley & Sons, Inc.

FANG, R. S. & HILL, D. J. (2003) A new strategy for transmission expansion in competitive electricity markets. *Ieee Transactions on Power Systems,* 18**,** 374-380.

GALLEGO, R. A., ALVES, A. B. & MONTICELLI, A. (1996) Parallel simulated annealing applied to long term transmission network expansion planning. Baltimore, Md, Ieee-Inst Electrical Electronics Engineers Inc.

GARNAUT, R. (2008) *The Garnaut Climate Change Review: Final Report,* Port Melbourne, Cambridge University Press.

GITELMAN, G. (2002) Use of Real Options in Asset Valuation. *The Electricity Journal,* 15**,** 58-71.

GLOBAL ENVIRONMENT FACILITY (2005) Assessment Of The World Bank/GEF Strategy For The Market Development Of Concentrating Solar Thermal Power. *report prepared for World Bank. .*

GREAKER, M. & SAGEN, E. L. (2006) Explaining experience curves for new energy technologies: A case study of liquefied natural gas. Hanover, NH, Elsevier Science Bv.

GRUBB, M., EDMONDS, J., TENBRINK, P. & MORRISON, M. (1993) THE COSTS OF LIMITING FOSSIL-FUEL CO2 EMISSIONS - A SURVEY AND ANALYSIS. *Annual Review of Energy and the Environment,* 18**,** 397-478.

GULLI, F. (2006) Small distributed generation versus centralised supply: a social cost-benefit analysis in the residential and service sectors. *Energy Policy,* 34**,** 804-832.

HAFFNER, S., PEREIRA, L. F. A., PEREIRA, L. A. & BARRETO, L. S. (2008) Multistage model for distribution expansion planning with distributed generation - Part I: Problem formulation. *Ieee Transactions on Power Delivery,* 23**,** 915-923.

HOLTSMARK, B. & MAESTAD, O. (2002) Emission trading under the Kyoto Protocol - effects on fossil fuel markets under alternative regimes. *Energy Policy,* 30**,** 207-218.

HULL, J. (2006) *Options, Futures and Other Derivatives*, Pearson US Imports & PHIPEs.

IAEA (1994) Expansion Planning for Electrical Generating Systems: A Guidebook. Vienna, Austria, International Atomic Energy Agency.

IES, I. E. S. (2007) Modelling the Price of Renewable Energy Certificates under The Mandatory Renewable Energy Target: A report submitted to the Office of the Renewable Energy Regulator.

JENSEN, S. G. & SKYTTE, K. (2002) Interactions between the power and green certificate markets. *Energy Policy,* 30**,** 425-435.

JIRUTITIJAROEN, P. & SINGH, C. (2008) Reliability constrained multi-area adequacy planning using stochastic programming with sample-average approximations. *Ieee Transactions on Power Systems,* 23**,** 504-513.

JOHNSTON, L., TAKAHASHI, K., WESTON, F., MURRAY, C. (2005) Rate Structure for Customers with Onsite Generation: Practice and Innovation. *NREL Report #NREL/SR-560-39142.* Golden, CO., National Renewable Energy Laboratory.

KAINUMA, M., MATSUOKA, Y., AND MORITA, T., (1998) Analysis of Post-Kyoto Scenarios: The AIM Model *OECD Workshop on the "Economic Modelling of Climate Change".* PARIS, FRANCE, ORGANISATION FOR ECONOMIC CO-OPERATION AND DEVELOPMENT.

KLEPPER, G. P., S. (2006) Marginal abatement cost curves in general equilibrium: The influence of world energy prices. *Resource and Energy Economics,* 28**,** 1-23.

KUMBAROGLU, G., MADLENER, R. & DEMIREL, M. (2008) A real options evaluation model for the diffusion prospects of new renewable power generation technologies. *Energy Economics,* 30**,** 1882-1908.

KUROSAWA, A. Y., H. ZHOU, W. TOKIMATSU, K. YANAGISAWA, Y. (1999) Analysis of Carbon Emission Stabilization Targets and Adaptation by Integrated Assessment Model. *ENERGY JOURNAL,* 20**,** 157-176

LANZA, A., CIORBA, U. & PAULI, F. (2001) Kyoto Protocol and Emission Trading: Does the US Make a Difference? *SSRN eLibrary*.

LATORRE, G., CRUZ, R. D., AREIZA, J. M. & VILLEGAS, A. (2003) Classification of publications and models on transmission expansion planning. *Ieee Transactions on Power Systems,* 18**,** 938-946.

LAURIKKA, H. (2006) Option value of gasification technology within an emissions trading scheme. *Energy Policy,* 34**,** 3916-3928.

LINARES, P. (2002) Multiple criteria decision making and risk analysis as risk management tools for power systems planning. *Ieee Transactions on Power Systems,* 17**,** 895-900.

MCKINSEY&CO., D., L., GÖRNER, S., LEWIS, A., MICHAEL, J., SLEZAK, J., & WONHAS, A (2008) An Australian Cost Curve for Greenhouse Gas Reduction. Sydney, Mckinsey & Company.

MCLENNAN MAGASANIK ASSOCIATES (2008) Installed capacity and generation from geothermal sources by 2020. South Melbourne, Australian Geothermal Energy Association.

METZ, B., INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE. WORKING GROUP III. (2007) *IPCC Fourth Assessment Report: Mitigation of Climate Change,* Cambridge, Cambridge University Press.

METZ, B. & INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE. WORKING GROUP III. (2001) *Climate change 2001 : mitigation : contribution of Working Group III to the third assessment report of the Intergovernmental Panel on Climate Change,* Cambridge ; New York, Cambridge University Press.

MILLS, D. (2001) Assessing the potential contribution of renewable energy to electricity supply in Australia. *University of Queensland.*

MIRANDA, V. & PROENCA, L. M. (1998) Why risk analysis outperforms probabilistic choice as the effective decision support paradigm for power system planning. *Ieee Transactions on Power Systems,* 13**,** 643-648.

MUJEEBU, M. A., JAYARAJ, S., ASHOK, S., ABDULLAH, M. Z. & KHALIL, M. (2009) Feasibility study of cogeneration in a plywood industry with power export to grid. *Applied Energy,* 86**,** 657-662.

NEMMCO (2008) Statement of Oppurtunities. National Electricity Market Management Company, Victoria.

NETO, A. C., DA SILVA, M.G., RODRIGUES, A.B. (2006) Impact of Distributed Generation on Reliability Evaluation of Radial Distribution Systems Under Network Constraints. *PMAPS conference 2006.*

NEUHOFF, K. A. T., P., (2008) Will the market choose the right technologies? IN GRUBB, M., JAMASB, T., POLLITT, M.G. (Ed.) *Delivering a Low-Carbon Electricity System.* Cambridge, UK

Cambridge University Press.

NGUYEN, F., STRIDBAEK, U., VAN HULST,N., (2007) Tackling Investment Challenges in Power Generation: In IEA Countries. Paris, OECD/IEA.

NIEIR (2004) *The price elasticity of demand for electricity in NEM regions:* a report to the National Electricity Market Management Company, Victoria.

NORDHAUS, W. D. (2001) Climate change - Global warming economics. *Science,* 294**,** 1283-1284.

PAOLELLA, M. S. & TASCHINI, L. (2008) An econometric analysis of emission allowance prices. *Journal of Banking & Finance,* 32**,** 2022-2032.

PEREIRA, M. V. F. & PINTO, L. (1985) APPLICATION OF SENSITIVITY ANALYSIS OF LOAD SUPPLYING CAPABILITY TO INTERACTIVE TRANSMISSION EXPANSION PLANNING. *Ieee Transactions on Power Apparatus and Systems,* 104**,** 381-389.

ROMERO, R. & MONTICELLI, A. (1993) A HIERARCHICAL DECOMPOSITION APPROACH FOR TRANSMISSION NETWORK EXPANSION PLANNING. Columbus, Oh, Ieee-Inst Electrical Electronics Engineers Inc.

ROQUES, F. A. (2008) The benefits of fuel diversity mix. IN GRUBB, M., JAMASB, T., POLLITT, M.G. (Ed.) *Delivering a Low-Carbon Electricity System.* Cambridge, UK

Cambridge University Press.

ROQUES, F. A., NEWBERY, D. M. & NUFFALL, W. J. (2008) Fuel mix diversification incentives in liberalized electricity markets: A Mean-Variance Portfolio theory approach. *Energy Economics,* 30**,** 1831-1849.

ROQUES, F. A., NUTTALL, W. J., NEWBERRY, D. M., DE NEUFVILLE, R. & CONNORS, S. (2006) Nuclear Power: A Hedge against Uncertain Gas and Carbon Prices? *Energy Journal,* 27**,** 1-23.

ROTHWELL, G. (2006) A Real Options Approach to Evaluating New Nuclear Power Plants. *The Energy Journal,* 27**,** 37.

SARKIS, J. & TAMARKIN, M. (2008) Real options analysis for renewable energy technologies in a GHG emissions trading environment. IN ANTES, R., HANSJURGENS, B. & LETMATHE, P. (Eds.) *Emissions Trading: International Design, Decision Making and Corporate Strategies.* New York, Springer.

SBC, S. C. C., LLC) (2008) Renewable Energy Credit Prices - the Market Signal from the State Renewable Portfolio Standard Program: A report prepared for the New York State Energy Research and Development Authority.

SEIFU, A., SALON, S. & LIST, G. (1989) OPTIMIZATION OF TRANSMISSION-LINE PLANNING INCLUDING SECURITY CONSTRAINTS. *Ieee Transactions on Power Systems,* 4**,** 1507-1513.

SEKAR, C. (2005) Carbon Dioxide Capture from Coal-Fired Plants: A Real Options Analysis. Cambridge, MA, Massachusetts Institute of Technology, Laboratory for Energy and the Environment.

SHAHIDEHPOUR, M., YAMIN, H., LI, Z. (2002) *Market Operations in Electric Power Systems: Forecasting, Scheduling and Risk Management,* New York, Wiley - Interscience.

SIDDIQUI, A. S. & MARNAY, C. (2008) Distributed generation investment by a microgrid under uncertainty. *Energy,* 33**,** 1729-1737.

SOVACOOL, B. K. (2008) Distributed Generation (DG) and the American Electric Utility System: What is Stopping It? *Journal of Energy Resources Technology,* 130**,** 012001-8.

STOFT, S. (2002) *Power Systems Economics: Designing Markets for Electricity,* New York, IEEE Computer Society Press, John Wiley & Sons.

SUN, J. A. L. T. (2007a) DC Optimal Power Flow Formulation and Solution Using QuadProgJ. *ISU Economics Working Paper No. 06014.* Department of Economics, Iowa State University, IA 50011-1070.

SUN, J. A. L. T. (2007b) Dynamic testing of Wholesale power Market Designs: An Open-Source Agent Based Framework. *ISU Economics Working Paper No. 06025.* Department of Economics, Iowa State University, IA 50011-1070.

TAYLOR, M. (2006) Beyond technology-push and demand-pull: Lessons from California's solar policy. Hanover, NH, Elsevier Science Bv.

TREASURY, C. D. O. (2008) Australia's Low Pollution Future: The Economics of Climate Change Mitigation. Canberra.

UMMELS, B. C., GIBESCU, M., PELGRUM, E., KLING, W. L. & BRAND, A. J. (2007) Impacts of wind power on thermal generation unit commitment and dispatch. *Ieee Transactions on Energy Conversion,* 22**,** 44-51.

VAN BENTHEM, A., GILLINGHAM, K. & SWEENEY, J. (2008) Learning-by-doing and the optimal solar policy in California. *Energy Journal,* 29**,** 131-151.

VAN DEN HEUVEL, S. T. A. & VAN DEN BERGH, J. C. J. M. (2009) Multilevel assessment of diversity, innovation and selection in the solar photovoltaic industry. *Structural Change and Economic Dynamics,* 20**,** 50-60.

WIBBERLEY, L., COTTRELL, A., PALFREYMAN, D., SCAIFE, P., BROWN, P. (2006) Techno-Economic Assessment of Power Generation Options for Australia. Cooperative Research Centre for Coal in Sustainable Development.

XU, Z., DONG, Z. Y. & WONG, K. P. (2006) A hybrid planning method for transmission networks in a deregulated environment. *Ieee Transactions on Power Systems,* 21**,** 925-932.

YANG, M., BLYTH, W., BRADLEY, R., BUNN, D., CLARKE, C. & WILSON, T. (2008) Evaluating the power investment options with uncertainty in climate policy. *Energy Economics,* 30**,** 1933-1950.

YOUSSEF, H. K. & HACKAM, R. (1989) NEW TRANSMISSION PLANNING-MODEL. *Ieee Transactions on Power Systems,* 4**,** 9-18.

ZHAO, J. H., DONG, Z. Y., LINDSAY, P. & WONG, K. P. (2009) Flexible Transmission Expansion Planning With Uncertainties in an Electricity Market. *Ieee Transactions on Power Systems,* 24**,** 479-488.

ZHU, D., BROADWATER, R. P., TAM, K. S., SEGUIN, R. & ASGEIRSSON, H. (2006) Impact of DG placement on reliability and efficiency with time-varying loads. *Ieee Transactions on Power Systems,* 21**,** 419-427.