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Intelligent Grid

A value proposition for distributed energy in Australia

CSIRO Report ET/IR 1152

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1. INTRODUCTION

In response to climate change, Australia is developing a suite of options aimed at delivering more efficient and sustainable low emissions energy. One solution is distributed energy (DE; collectively demand side management, energy efficiency and distributed generation) which provides solutions near the point of use rather than at remote locations.

The Low Emissions and Distributed Energy (LEDE) theme of CSIRO's Energy Transformed Flagship is developing local solutions through a range of initiatives. These include intelligent control and aggregation of household and commercial appliances, optimisation of loads and generation in minigrid systems, development of an innovative household solar based air conditioner, construction of a zero emissions home and production of novel generation devices.

Wide scale deployment of distributed energy will require a revolution in engineering design, practice and regulation. To facilitate this change, CSIRO has investigated economic, social, environmental and technical barriers and enablers for wide scale adoption of DE. Results of these investigations are contained within this Intelligent Grid report which provides evidence of the critical role distributed energy can play in Australia's Energy future.

Realising the value of DE requires understanding and addressing the complex issues affecting key stakeholders including government, electricity and gas network businesses, energy retailers, small to medium enterprises, large energy users and domestic consumers. Critically important issues include the effects of DE on short and long term economic drivers; the effects of DE on networks through introduction of local grid connected devices; environmental sensitivities resulting from the change in technology type and the location of generation; the acceptance of DE by all forms of society; and the complex interaction with policy and regulation. By dealing with these issues, this report will help stakeholders understand the vital role DE can play in ensuring an affordable low emissions future.

2. SUMMARY

This report examines the economic, environmental and social aspects of using distributed energy technologies as an alternative to further centralised generation. Distributed energy is a term that describes technologies and systems which provide local generation of electrical power (distributed generation), energy efficiency and demand management functions. Distributed energy is a collection of technologies and systems that supply or substitute electrical power at the point of consumption close to load, with more efficient devices or systems that optimise and reduce the use of electricity thus reducing carbon emissions and improving infrastructure utilisation. This summary details the findings from the report that identify the potential contribution distributed energy can make to reduce greenhouse gas emissions in Australia, and how that potential can be realised.

2.1 Understanding distributed energy

Distributed energy describes a number of technologies that can significantly reduce the nation's greenhouse gas emissions. These reductions result from reduced network losses by using generation near the point of consumption, through maximising the use of cleaner fuel sources such as natural gas, solar and wind, and through more efficient conversion of fuels to useful energy services, including recovering heat otherwise wasted.

Distributed generation (DG), sometimes referred to as embedded generation is generally connected to the electricity grid at low voltage (< 22 kV). Internal combustion reciprocating engines (ICE) are the most mature prime movers for DG applications. Advantages include comparatively low installed cost, high efficiency (up to 45% for larger units), suitability for intermittent operation, high part-load efficiency, high-temperature exhaust streams for combined heat and power (CHP) and are easily serviced. These units have been popular for peaking, emergency, and base-load power generation. The units can run on a variety of fuels including diesel, natural gas, compressed natural gas and petrol. DG units connect to the grid as synchronous machines, asynchronous machines and/or inverter generators depending on the primary source of energy. Synchronous generators are commonly used with engines and turbines. Asynchronous generators are commonly employed on medium and large wind turbines while solar photovoltaics and small wind turbines utilise DC/AC inverters to connect to the grid.

Cogeneration (see Figure 2.1) is a process where the heat generated by combustion of a fuel for electricity production is used for a secondary purpose rather than being a waste product. The heat is most often used to create hot water or steam but can also be used for cooling purposes through an adsorption cycle. Where heat can be used for cooling as well as heating, it is referred to as combined cooling and heating power (CCHP) or trigeneration. The value of co/trigeneration can be influenced by the type of technology, its reliability, the timing and size of the heating and cooling demand in respect to electrical needs, and the type of system the waste heat equipment is replacing or substituting.

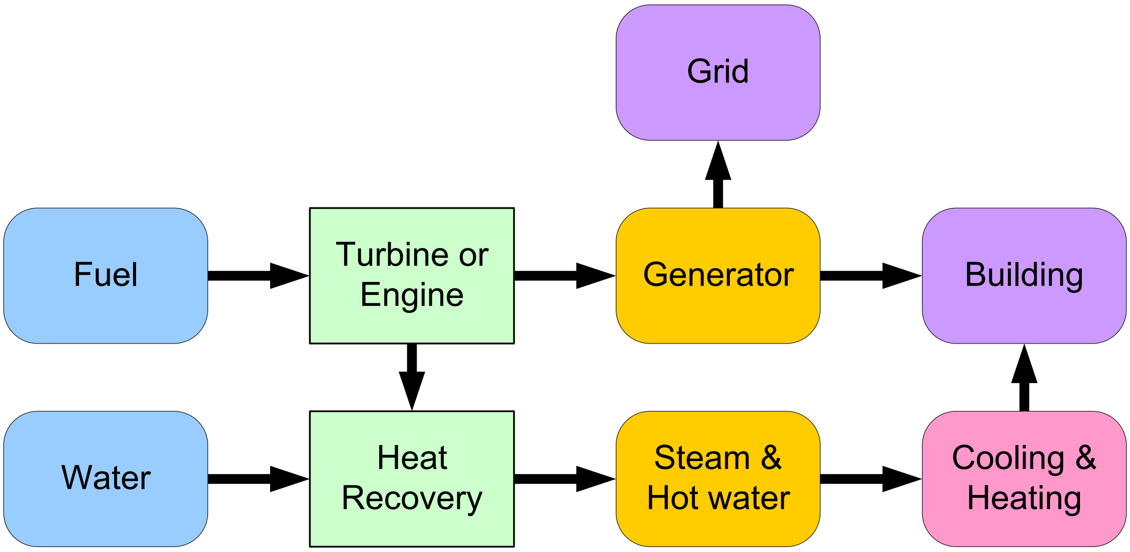


Figure 2.1: Schematic representation of a CHP system

Demand management refers to a suite of technologies and techniques used to actively alter demand profiles over time. While these measures may reduce total energy use, they are primarily employed to smooth or shift peaks in demand. By controlling peak energy patterns, demand management may provide substantial financial savings to consumers by reducing the need to build generation and network infrastructure required to service this peak demand for only a small number of hours each year.

A number of technologies are important for demand management. These are generally storage devices such as batteries, compressed air and thermal materials, or communication and control technologies that allow controlled cycling of appliances such as compression cycles in air conditioners or discretionary loads such as pool pumps to be turned off.

Storage devices take a variety of forms and can be used for many applications including maximising the value of intermittent, but predictable clean energy such as wind and solar power or mitigating the cost of peak demand at the distribution or transmission level. They do this by storing any energy produced at times of low demand and releasing it at times of high demand (see Figure 2.2). Storage options can include coordinating refrigeration cycles in large cold stores so that temperatures are dropped at times of low demand or high solar/wind output, and allowed to rise at times of high demand or low solar/wind output. Optimising the integration of low cost storage devices with alternative forms of generation and discretionary heat and power loads are likely to be critical to realising high penetrations of renewable and distributed energy in a cost effective way.

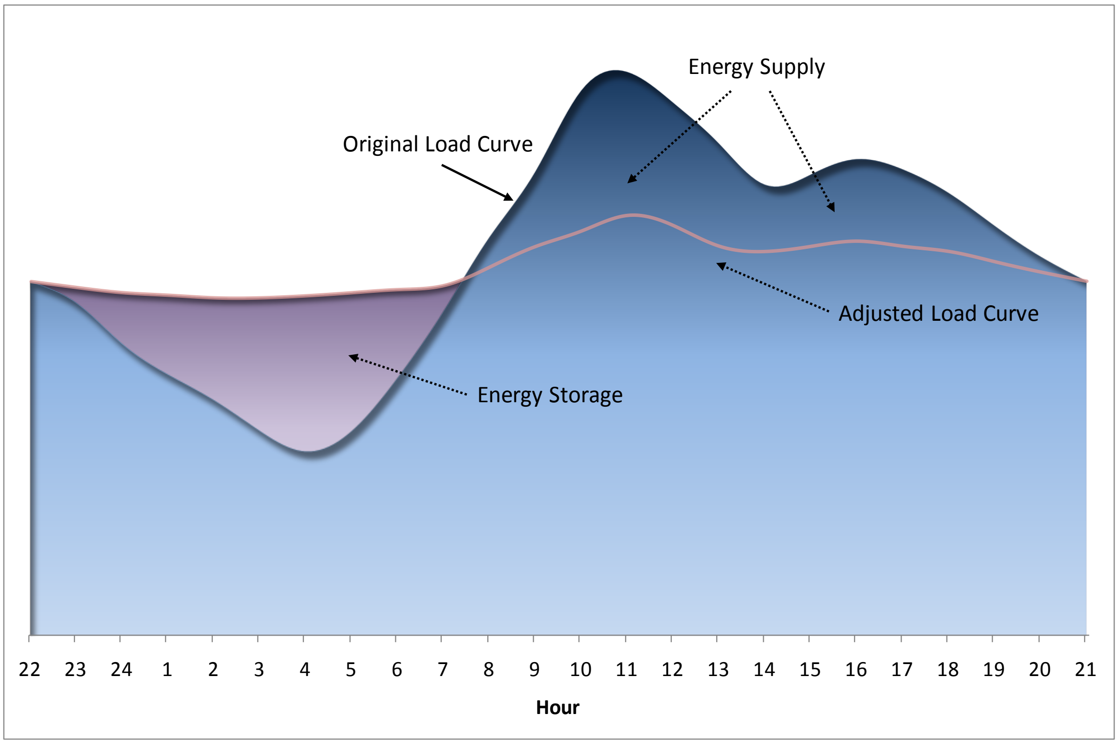


Figure 2.2: A hypothetical daily demand profile including storage

Energy efficiency can be thought of in a number of ways. In one sense, it is a reduction in energy demand as a result of changes in performance efficiency of individual devices or the substitution of one form of energy for another more efficient version (using solar energy for heating water for instance). In another sense, improvements to system efficiency are a form of energy efficiency. This could include the reduction of network losses by generating energy close to the point of consumption, or improving the utilisation of a fuel by capturing more of the energy available as occurs through cogeneration and trigeneration. Improving system efficiency can help reduce greenhouse gas emission and energy costs, but can also mitigate against fuel scarcity risks by creating better use of a limited quantity of fuel.

Energy efficiency is often seen as the easiest and most cost effective way to reduce greenhouse gas emissions in the short term. It is important to note that the value of energy efficiency is not only determined by the quantity of energy that can be saved, but the timing of those energy savings as energy market costs vary significantly over the course of the day with costs typically highest when demand peaks.

While all energy efficiency measures reduce energy consumption, or maximise the value of a given unit of available energy, their economic merit can vary depending upon the timing at which the efficiency gain is made. For example, solar hot water systems heat up during the day and store hot water in tanks. The greenhouse gas savings for these systems are greatest when replacing off-peak electric hot water units, as these units would otherwise draw on grid based electricity that is primarily coal fired. However this off-peak hot water system was developed to remove load from the network during the day when it is most stressed and to allow large coal-fired generators to operate continuously, thereby maximising their thermal efficiency. In this way, off-peak electric hot water provides a service to the electricity industry which results in reduced energy prices.

The value of substituting off-peak electric hot water with a solar hot water system can be contrasted with a solar based cooling system. In this process, fresh (outside) air is dehumidified in a rotary desiccant wheel (see Figure 2.3). In this adiabatic drying process, the air is unavoidably warmed. A heat recovery heat exchanger is used to cool the warm dry air back down to near ambient temperature. The resulting pre-cooled, dry air stream is then further cooled to temperatures below ambient using an evaporative cooling process before it is introduced into the occupied space to provide the desired space conditioning.

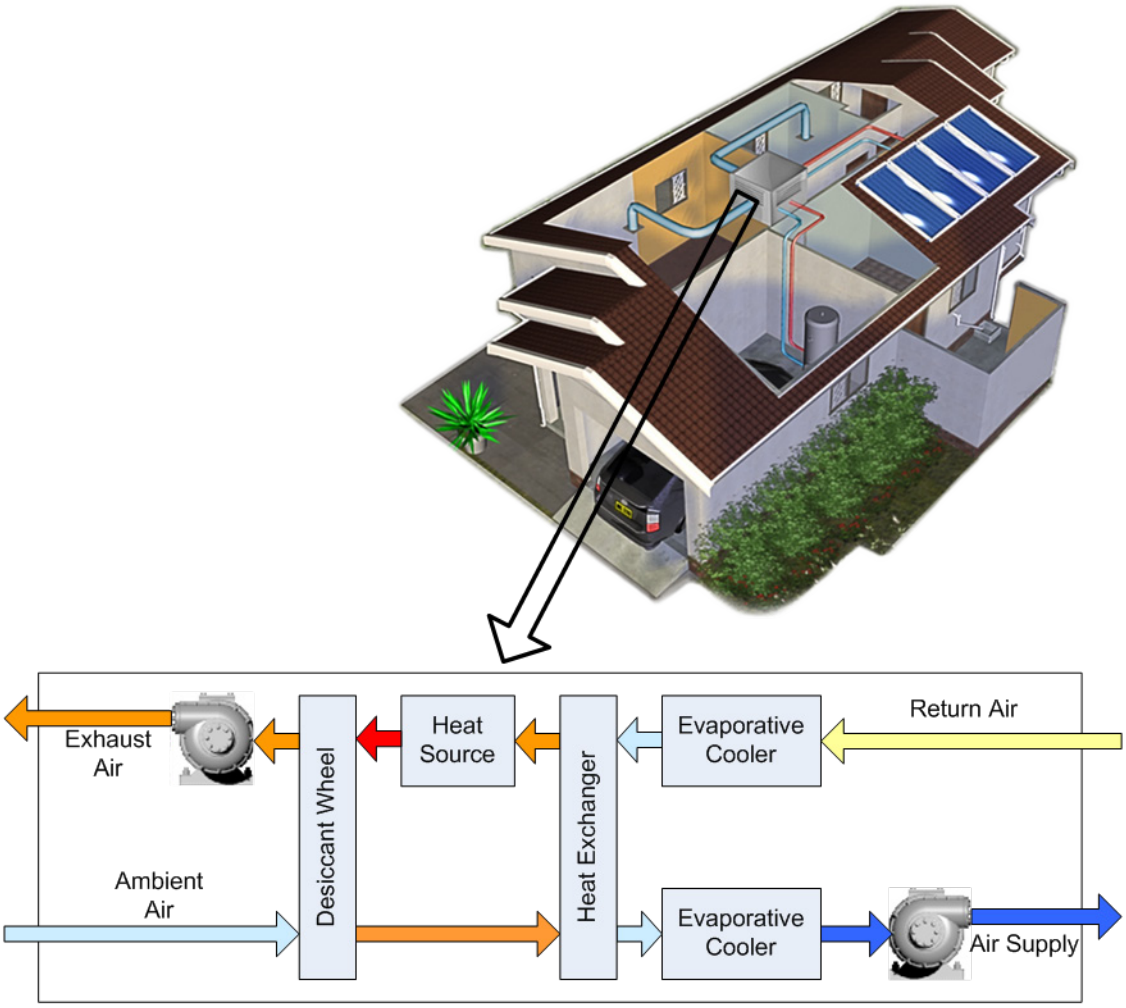


Figure 2.3: Schematic representation of a solar based air conditioning system.

There is an increasing acceptance that Australia's energy supply system needs to evolve in order to meet the dual challenges of energy security and climate change. Smart grids which incorporate distributed energy solutions with large scale renewables and information infrastructure are expected to provide a future system able to meet the growing demand for energy while ensuring low emissions and high levels of security.

2.2 Distributed energy as an early action response to climate change

Four carbon mitigation scenarios were analysed using CSIRO's Energy Sector Model (ESM), a bottom-up model of the electricity and transport sectors in Australia. It has a detailed representation of the electricity generation sector with substantial coverage of DG technologies.

Scenarios tested were based on different policy proposals that have been considered in public debate, including those currently being considered by the Australian Government. In brief, these scenarios are as follows:

CPRS -5: A carbon pollution reduction scheme is adopted, commencing in 2010, with an emissions allocation that leads to a reduction in emissions of 5 per cent on 2000 levels by 2020 and 60 per cent below 2000 levels by 2050.

CPRS -15: A carbon pollution reduction scheme is adopted, commencing in 2010, with an emissions allocation that leads to a reduction in emissions of 15 per cent on 2000 levels by 2020 and 60 per cent below 2000 levels by 2050.

Garnaut 550ppm: An Australian emission trading scheme is adopted, commencing in 2013, with an emissions allocation that leads to a reduction in emissions of 10 per cent on 2000 levels by 2020 and 80 per cent below 2000 levels by 2050 for stabilisation at 550 ppm.

Garnaut 450ppm: An Australian emission trading scheme is adopted, commencing in 2013, with an emissions allocation that leads to a reduction in emissions of 25 per cent on 2000 levels by 2020 and 90 per cent below 2000 levels by 2050 for stabilisation at 450 ppm.

Results from the ESM modelling show that distributed energy has a significant role to play in a carbon constrained future. On the basis of technology characteristics and cost competitiveness, the economic modelling indicates that DG can significantly increase its share of energy supply in the near-term, decreasing the need for additional centralised generation and reducing the emission intensity of energy supply. The estimated technology uptake suggests that DG has a bridging role in transitioning from the current coal dominated system while large-scale renewable and near-zero emission carbon capture and storage technologies are either too expensive or unproven. In this way, distributed energy is found to be an attractive early action response to climate change.

To develop a sense of the welfare gain provided by distributed energy, we compared two scenarios. The base case is Garnaut 450ppm with baseline growth in electricity accounting for energy efficiency and structural economic change, distributed generation included as an option, and demand endogenous in the model, so affected by price elasticity of demand for different end users. The alternative case is Garnaut 450ppm, with baseline growth in electricity demand set at business as usual (BAU) levels, DG not included as an option, and demand fixed (perfectly inelastic).

The difference between the two gives a measure of the value (welfare gain) of energy efficiency, demand management, distributed generation and structural change in the economy. The model cannot distinguish between energy efficiency and structural change in the economy.

Over the period 2006-2050, the undiscounted value of energy efficiency, demand management, distributed generation and structural change is around $800b (currently Gross Domestic Product in real terms is around $1,100b). This saving is calculated by measuring the difference in weighted average prices multiplied by energy consumed between scenarios modelled. The present value of the welfare gain is around $130b discounted at 7% pa. Ultimately, these benefits are shared by all consumers of electricity.

Figure 2.4 below illustrates how this value accrues over time. The blue line represents total energy costs where distributed energy is excluded as an option in the model, the red line represents total energy costs where distributed energy.

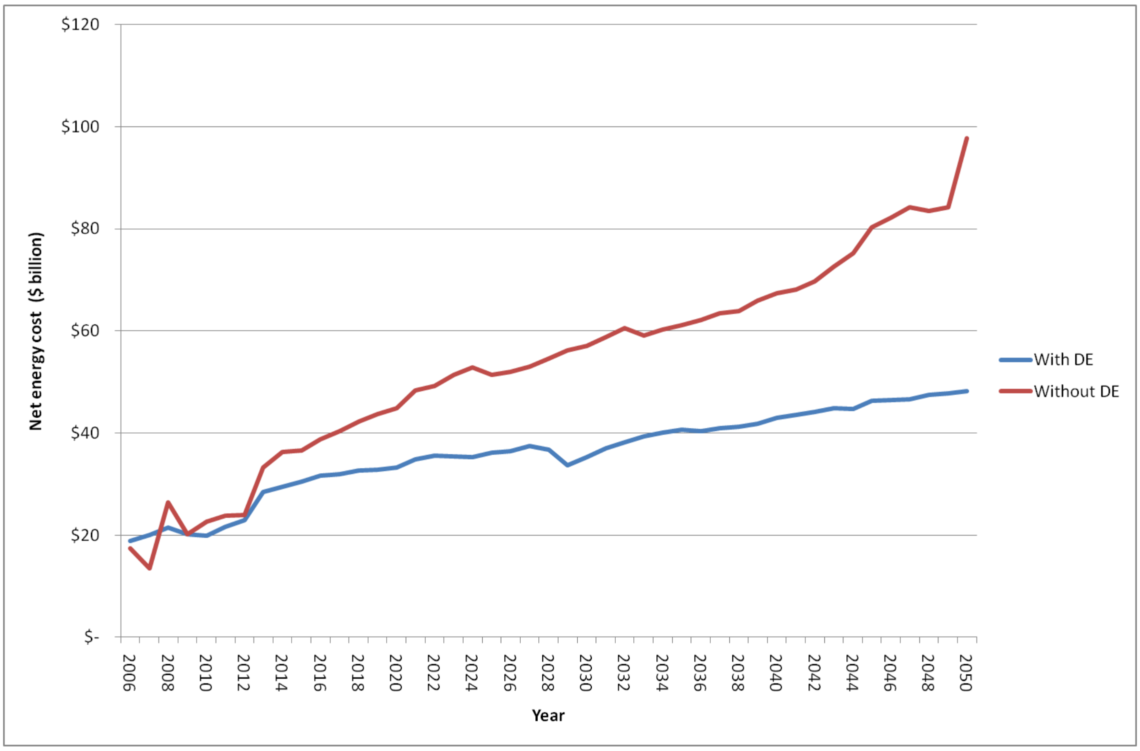


Figure 2.4: Comparison of energy costs with and without DE

It is important to note that the only major cost the ESM doesn’t account for is the cost of structural change in the economy over time. Costs associated with transforming the energy supply chain are built into the model and so can effectively be considered zero. The model optimises by requiring a 7% rate of return on energy assets over their lifetime.

Fully valuing distributed energy based on avoided or delayed spending on network and generation infrastructure is a complex exercise that is not fully captured by the ESM. The ESM captures avoided spending on peak generation infrastructure, and transmission networks to a degree, but imperfectly due to modelling limitations. Previous attempts have been made to quantify the market value of demand management specifically excluding network benefits, with estimates ranging from $363M - $954M over the period 2007 – 2025 (Hoch et al. 2006).

Water savings are also made in the Garnaut 450ppm scenario through a mix of distributed energy and renewables, with approximately 200 gigalitres saved per annum in 2030 and 375 gigalitres saved in 2050. While this appears relatively small compared to Australia wide water consumption (around 1%), it significantly reduces the exposure of energy wholesale markets to potential water shortages, with an approximate 66% reduction in water intensity of electricity supply by 2030 and 83% by 2050. This is likely to have significant risk management value, potentially resulting in lower prices for consumers, but also competitive advantage for suppliers and consumers of distributed energy where they compete with mains grid supply. We note water shortages in 2007 helped drive an approximate doubling of wholesale prices.

In all scenarios modelled, the relative contribution each technology makes to emission reductions remains relatively constant with the main difference being the timing of technology deployment and the increase in electricity demand caused by the emergence of plug-in hybrid and fully electric vehicles. For example, in the Garnaut 450ppm scenario, it is estimated by 2050 these vehicles will account for over half of road kilometres travelled. Mild hybrids which generate their electricity on board rather than drawing on the electricity grid, are projected to account for another 20 per cent of the fleet, leaving internal combustion vehicles accounting for around 17 per cent of kilometres travelled. The electricity generation mix projected in the Garnaut 450ppm scenario is presented below.

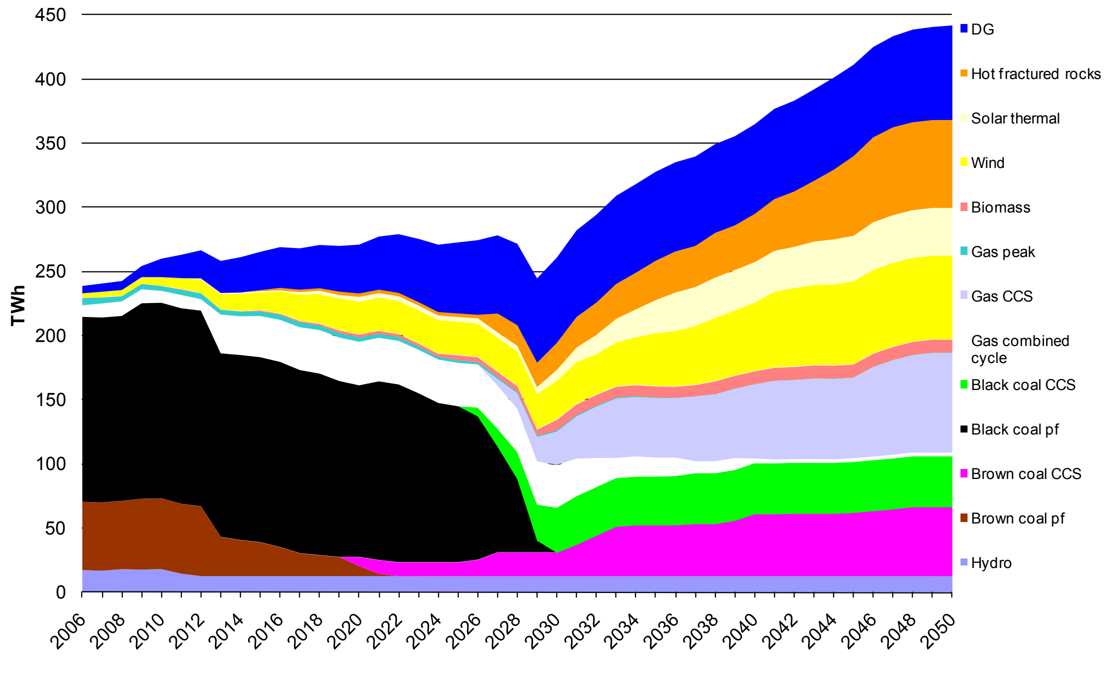


Figure 2.5: National electricity generation under Garnaut 450ppm, 2006-2050

It is of interest to note the drop in demand that occurs around 2030 as black coal is phased out and replaced by low-emission technologies (Figure 2.5). This negative demand shock may be less severe under real world conditions, but it highlights the difficulty in meeting aggressive emission cuts through the supply-side without constraining demand in some way. It is worth noting the model does incorporate significant levels of energy efficiency, detailed in Figure 2.7.

Figure 2.6 represents the breakdown of distributed generators forecast under the Garnaut 450ppm scenario by the model. It can be seen that initially, biomass and gas fired combined heat and power systems are most prevalent, with trigeneration in commercial buildings coming online in the vey short term, before solar PV systems dominate growth in DG from 2018 onwards. It is important to recognise this type of scenario forecasting is not a prediction of real world events, but indicative of how they may play out should a certain scenario eventuate.

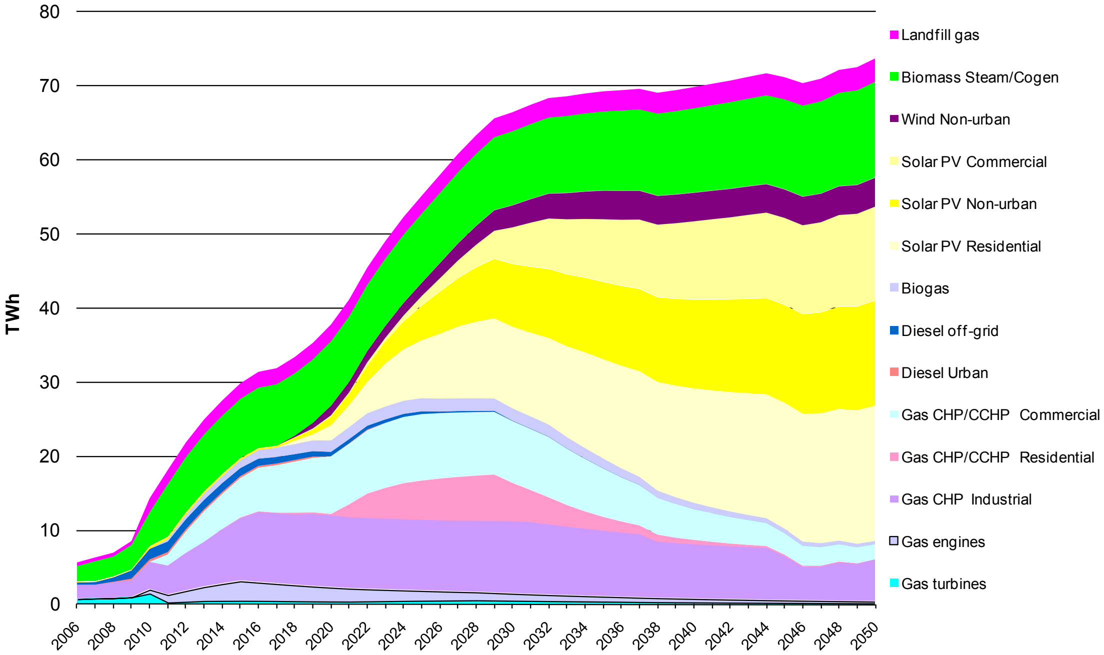


Figure 2.6: Distributed generation under Garnaut 450ppm, 2006-2050

An important feature of the model results is the relative contribution to emission reductions achieved by the mix of technologies, including energy efficiency. It can be seen that DG has a greater role to play in the near-term before other low emission technology options are competitive or available (Figure 2.7). However, as expected, energy efficiency remains a very important contributor to emission reductions in the short and long term.

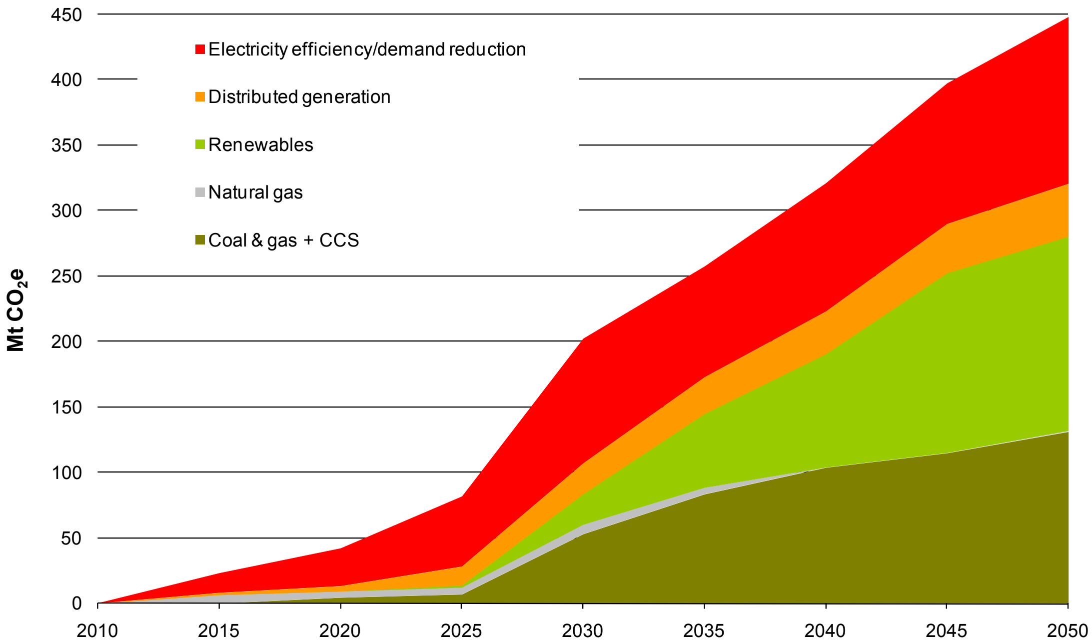


Figure 2.7: Electricity sector greenhouse gas abatement, Garnaut 450ppm

A number of sensitivity analyses were conducted to determine variations that may result from a future in which carbon capture and storage technologies are unavailable; where capital costs of alternative options are higher or lower than expected, and where the deployment of DG technologies can roll out faster than expected. Figure 2.8 which shows the range in distributed energy that can result from different modelling assumptions highlights the importance of ensuring a portfolio of technologies are developed that can be integrated within energy market constraints.

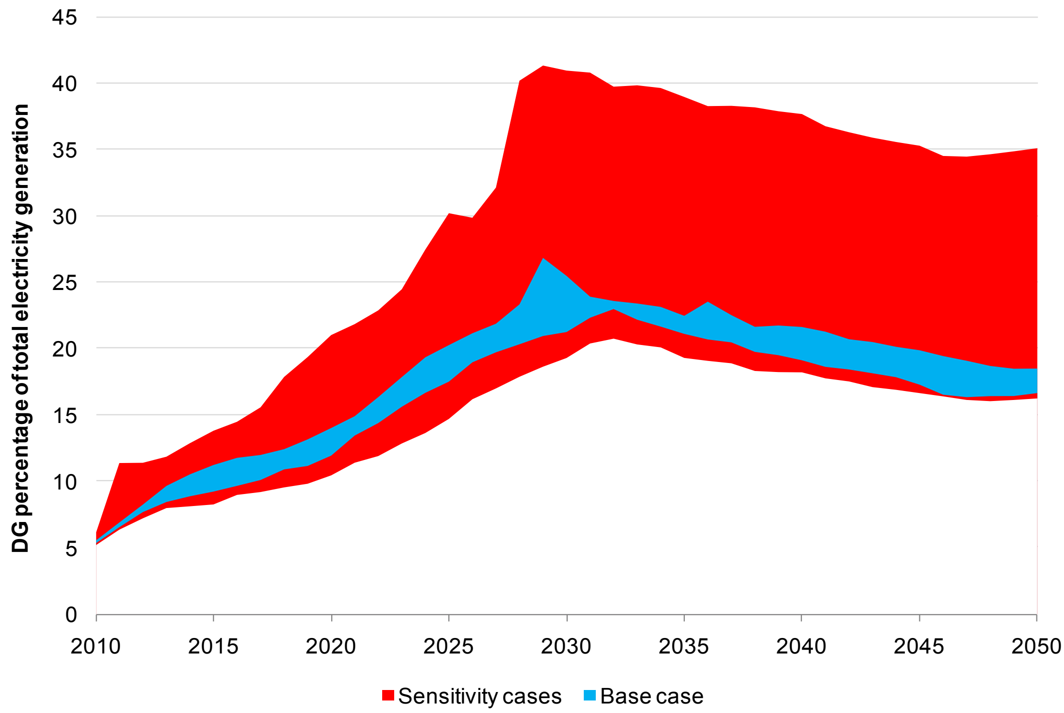


Figure 2.8: Sensitivity of DG uptake

In general, DG appears to be an effective early action greenhouse gas mitigation option for Australia when it is considered within a portfolio of other mitigation options. This is principally due to a number of factors:

- There are numerous low-emission DG technology options that are commercially available
- There are DG technologies which utilise waste heat that is lost in centralised electricity generation, increasing overall fuel energy efficiency
- DG options have less lead time in comparison to brown- or green-field expansions of centralised plant
- DG options are modular and can be tailored to individual end-user requirements
- Some DG options utilise fuel that is uneconomic for large centralised plant (e.g., landfill gas, waste streams, some forms of biomass)
- DG options are more able to match growing demand by installing smaller more appropriately sized units while centralised technologies result in large stepwise additions of supply
- DG options provide a mechanism to reduce electrical losses in transmission and distribution by locating the units close to the point of end use.

More specifically, the results indicate that:

- In the near-term, co- or trigeneration technologies using natural gas or biomass/biogas appear to be the most cost effective options, especially in the industrial (natural gas, waste gas, coal seam methane), commercial (natural gas and biogas) and rural (biomass) sectors. They provide a vital bridge towards a low carbon future
- Landfill gas and waste gas reciprocating engines are competitive but are limited by fuel availability
- Small scale wind turbines are more competitive in non-urban areas where alternatives are more expensive or better wind resources are available
- In the medium-term, there is potential for significant deployment of photovoltaic (PV) technology in the residential, rural and commercial sectors. The estimated uptake has implications for employment
- In conjunction with energy efficiency and demand reduction, DG is the most cost effective greenhouse gas mitigation option in the near- to medium-term contributing between 4 to 18 Mt of abatement in 2020 and 23 to 40 Mt of abatement in 2030
- Sensitivity analyses indicated that the more rapidly DG technologies can get down the cost curve (i.e., technological breakthrough, imported learning) the more competitive these options are to other alternatives
- Should large scale low emission technologies prove unworkable or too expensive there appears to be some scope for DG to lessen negative impacts such as higher electricity prices
- Significant co-benefits resulting from the deployment of distributed energy solutions can be found in reduced water consumption and pollutant emissions such as NO_X, SO_2 and PM_{10}.

The modelling results need to be interpreted with some caution. Some key limitations of the modelling include:

- The modelling framework considers cost effectiveness and a limited set of constraints in projecting technology uptake. In reality community concerns and many other non-price factors not included in the modelling will influence the future technology choices individuals and businesses make
- Not all DG technologies are included in the modelling because of the difficulty of establishing a future price(e.g., mini-hydro and Stirling CHP)
- Assumed capacity factors for each technology are fixed and only partially account for spatial variation.

2.3 The impacts and benefits of distributed energy on the NEM

The commercial software package PLEXOS (http://www.plexossolutions.com/) was used to examine the impacts of distributed energy on the National Electricity market (NEM) for a future in which distributed energy plays a large and significant role in reducing Australia's greenhouse emissions. The modelling performed by the University of Queensland (UQ; Wagner, 2009) examined the outcomes on the NEM resulting from installed capacities of DG technologies predicted by ESM for the CPRS-15 and Garnaut 450 ppm scenarios.

The effects of distributed energy in the NEM were considered by running five case studies representing policy frameworks in three landmark years, namely 2020, 2030 and 2050.

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

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 reaches 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

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 reaches 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

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 will allow for additional cuts in emissions than the corresponding CPRS -15% case study

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

Modelling performed with PLEXOS indicates that the Emissions Intensity Factor (EIF; t-CO_2/MWh) of delivered energy throughout the NEM is significantly reduced across all three years, and under both emissions reduction scenarios, when DG has been considered. The EIF was chosen as the benchmark for analysis to better reflect emissions behaviour given the different rates of load growth across all scenarios. Table 2.1 features the EIF's of delivered energy across the NEM and shows significant structural change with respect to the emissions profile, demonstrating that DG could have a significant impact on curtailing CO_2 emissions.

Table 2.1: Emissions Intensity Factor (EIF; t-CO_2/MWh)

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
2020	0.878	0.944	0.791	0.776	0.795
2030	0.932	0.429	0.500	0.390	0.433
2050	0.970	0.140	0.310	0.110	0.210

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

For example the installed capacity of low-cost coal-fired generation in the reference case will ensure that energy prices remain relatively low especially with brown coal generators having a LRMC of less than $30/MWh. Conversely the increased cost of the generation types such as Combined Cycle Gas Turbines (CCGT) contributes greatly to the observed average price. Furthermore, the difference in prices between Scenario 2 and 3 (see Table 2.2), are due to the lower demand and generation mix changes due to the higher carbon price observed for a 25% carbon abatement pathway.

Table 2.2: NEM average spot prices ($/MWh)

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

The modelling indicates that the role out of DG will have a significant impact on the average spot price of electricity throughout the NEM. The drop in average spot prices for each of the DG scenarios indicates that investment in new technology stimulated by the CPRS will lower the delivered energy cost across the NEM.

The modelling indicates that another benefit of the roll out of DG is lower volatility of observed prices on the wholesale market. Lower volatility of spot price behaviour also provides significant benefits from a risk management perspective and reduces the cost of serving the retail consumer base. Valuing the premium on a $100/MWh base cap product is a simple method of measuring market participant's exposure to high and volatile prices (see Table 2.3).

Table 2.3: Premium price of a $100/MWh Base cap

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

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

2.4 Impacts and benefits of distributed energy on distribution networks

A study performed with Senergy Econnect examined the impact of a high DG penetration on distribution networks (Senergy Econnect, 2009). A quantitative analysis was performed using power system modelling techniques on four real-world distribution feeders (data provided by SP Ausnet). The feeder case studies are assumed to be typical of the class they represent and have the following characteristics:

Feeder 1: Urban established commercial feeder, supplying predominantly commercial zones in an established urban area

Feeder 2: Urban established residential feeder, supplying predominantly residential load in a long-established urban area (to account for incremental network augmentation in response to evolving electrical applications over a period of decades)

Feeder 3: Urban green-field residential feeder, supplying developing residential subdivisions. This feeder will contain some rural and semi-rural load including some Single Wire Earth Return (SWER) circuitry but be evolving toward predominantly urban use

Feeder 4: Rural feeder, containing a combination of three-phase and SWER circuits.

Detailed power system analyses for large DG penetrations on the four feeder networks found that:

- DG is of benefit in reducing distribution network losses and improving voltage profiles
- DG is of some value in postponing network upgrades where thermal limits are a critical factor, although attention must be given to the effective capacity contribution under peak loading conditions. Network upgrades may be necessary in any case due to reliability considerations (value of lost energy), but depending on DG characteristics it may be possible to upgrade feeders with lighter conductors than would otherwise be necessary
- Under the investigated scenarios to 2050, DG is unlikely to pose widespread issues with fault current capacity of existing equipment, or to raise issues with protection coordination through displacement of conventional generation leading to reduced fault levels
- The envisaged embedded generator technologies are not considered to be a significant source of voltage flicker, rapid voltage change or phase imbalance. Harmonic emissions from inverter-connected generators such as PV are expected, but are unlikely to result in harmonic distortion on feeders in excess of regulatory limits
- The opportunity for power from DG to result in a power flow reversal across zone substation MV busbars is limited due to the fact the embedded generators have a tendency to generate at times of human activity and so energy consumption. As such it is considered unlikely to be a problem
- High-level investigations indicate that DG is unlikely to pose issues due to steady-state voltage stability, frequency stability, rotor angle stability or small-disturbance (oscillatory) stability. However, these investigations are limited and more detailed investigations are warranted in future to confirm these results

- Fault ride-through capabilities have been found to be desirable for DG but not necessary at the present or prior to 2050 given the high level assessment applied here.

A qualitative analysis considering the impact of policy and regulation found that:

- Currently, due diligence assessment of each individual embedded generator connection is required by the distribution network service provider (DNSP), if the DNSP foresees the potential for adverse network impacts. This could become impractical as the rate of connection requests increases. It is suggested that in future, an aggregated due diligence assessment might be undertaken instead based on an anticipated penetration of embedded generators. This would establish a level of DG that could connect without further assessment before network limits are reached
- The safety standards which are currently in place to achieve safe operation of distribution feeders are considered to remain appropriate for DG into the future. However, the protection philosophies and settings of existing equipment may need reconsideration, and some equipment may need to be upgraded, as embedded generator installations increase in number
- DG at present largely falls outside the scope of the National Electricity Rules generator technical requirements. There is some technical justification for extending some of these requirements to embedded generators as penetration increases toward 2050
- Given the level of interaction suggested between DNSPs, local electricity retailers, and embedded generators of all types, it can be expected that a myriad of contractual arrangements may be required between parties. It is suggested that arrangements should prioritise system security.
- Islanded operation of distribution networks is in principle highly effective in realising the full value from embedded generation. However, the technical and commercial barriers to such operation remain formidable and will require substantial work to address. It is reasonable to expect that islanded operation of networks will become feasible prior to the 2050 time horizon used in this study.

2.5 Impacts and benefits of distributed energy on transmission networks

The effects of DE on transmission systems were considered by examining the impact of passive DG installations within an Institute of Electrical and Electronics Engineers (IEEE) standardised transmission test grid (Figure 2.9). While the IEEE test grid is used extensively in gauging the performance of power system models, it is important to recognise this test grid is not based on real conditions of any Australian electricity grids. As such, the results are indicative of the behaviour of transmission networks to the installation of passive DG rather than a measure of impact in Australian grids to specific installations of DE.

The study examined the impact of passive constant DG on the economic dispatch of units within the system to determine the effects on the transmission systems using a full AC power flow model. Three simple case studies were used to examine the impact from increasing amounts of passive DG installed within the system. In two cases the DG was installed at isolated buses (transmission connection points) within the grid (Alder and Arne) and in the third case DG was spread throughout the entire network.

Modelling performed in this study found that adding constant passive DG to the IEEE test grid results in reduced congestion and a moderation of the price of electricity. Somewhat surprisingly, the modelling found that system wide transmission losses could increase. Changes to demand were found to significantly alter the merit order of the bids in the dispatch process. In some cases this results in electricity being routed through longer transmission lines or lines with different ratings. This can result in increased losses compared to the base case.

In general, capacity utilisation and net energy benefit were affected by the addition of DG, there were however some notable exceptions:

- The utilisation of nuclear, hydroelectric, and the largest coal units remained largely unaffected by DG. However, as electricity prices decline markedly once DG capacity is installed, the net energy benefit realised by these units decreased
- In most scenarios, the utilisation of the #6 fuel-oil conventional steam units at Arne is higher with DG installed. And, this increase is more than sufficient to offset the lower electricity prices; units at Arne are often more profitable with DG installed in the system than without it.

Further findings from the modelling include that:

- Adding even small amounts of DG can have dramatic impacts on the power flows and economics of an electricity system. For example the modelling found that 20 MW_e of DG; a small amount (approximately 0.6% of total system capacity), installed at one location can reduce the average electricity price by 12%
- The effects of adding DG aren't limited to the bus at which the capacity is installed. They are felt by pre-existing generation units both near and far and, from generators' perspectives, can be positive or negative
- The effects of adding DG may depend more upon where the DG is added than on how much

- The effects of adding DG depend quite heavily upon specific characteristics of the target electricity system (e.g., disposition of sources and sinks relative to one another, types of generation units in the system, electricity demand).

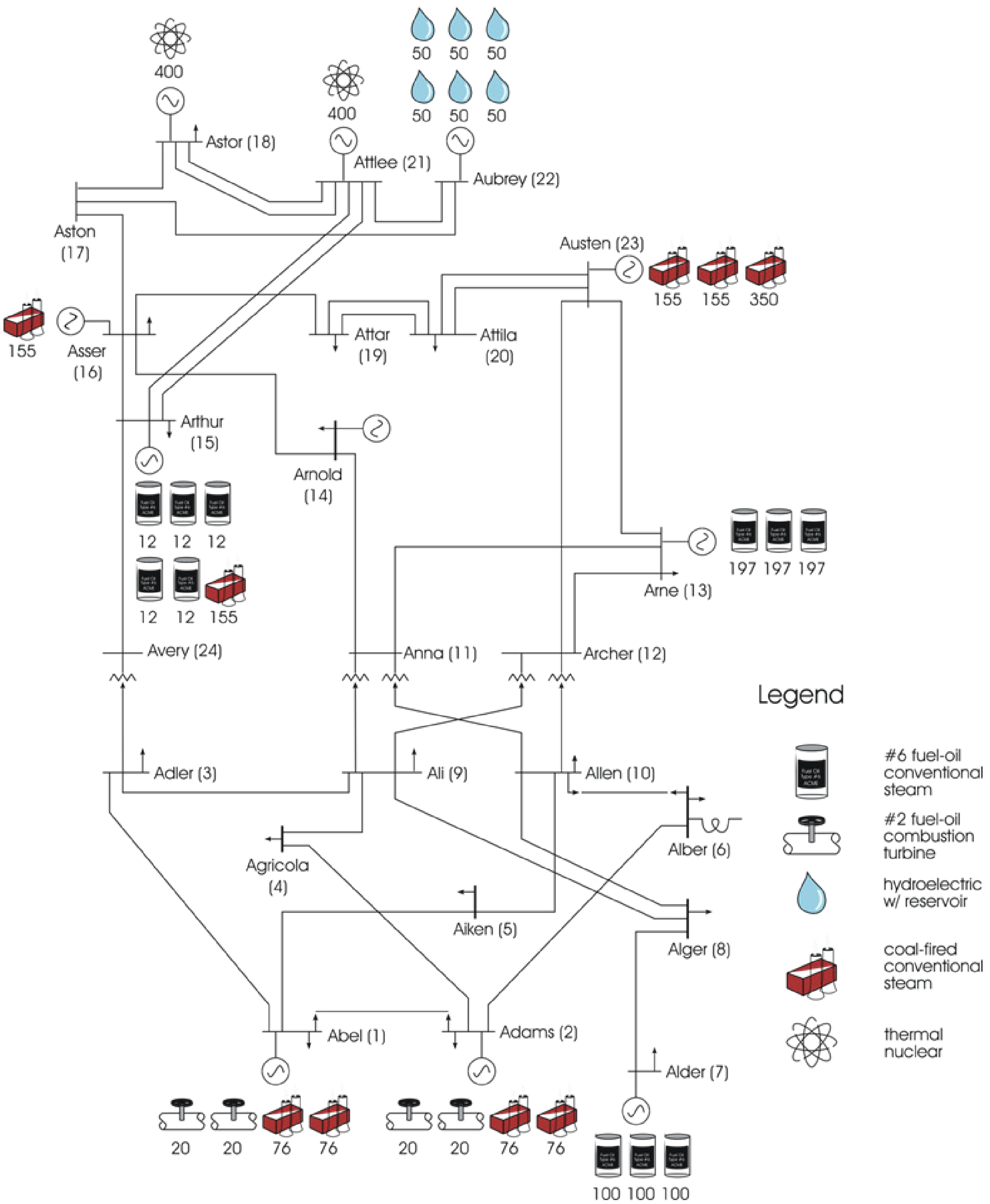


Figure 2.9: One-line diagram of IEEE RTS '96

2.6 Integrating distributed energy with the electricity grid

Realising the value of distributed energy can be achieved through many system configurations. One concept that is being increasingly accepted is that the electricity grid may need to evolve in order to meet the dual challenges of energy security and climate change. “Smart grids” which incorporate distributed energy solutions with large scale renewables and information infrastructure are expected to provide a future system able to meet the growing demand for energy with large elements of intermittent renewables and high levels of security.

In Australia and abroad, there is a growing movement which advocates that smart grids are the logical progression which will allow the electricity network to function in the most efficient economic manner, while supporting environmental and social needs. A smart grid optimally delivers electricity (and potentially other resources such as natural gas, water, heat etc) from suppliers to consumers using digital technology to save energy, reduce cost and increase reliability. As such, it is a way of addressing energy security and/or global warming issues by:

- Accommodating all forms of energy generation and storage
- Enabling new energy services
- Providing high power quality
- Optimising asset utilisation
- Anticipating and responding to system disturbances, and
- Operating resiliently against attack and natural disaster.

Figure 2.10 provides a conceptual model of a smart grid which incorporates minigrids. The minigrid is one of a number of available concepts that allows better integration of local devices through control and aggregation of technologies without requiring substantial change to existing infrastructure. It does this by connecting to the wider grid through a single point of common coupling. The larger grid is isolated from the interaction of devices and loads within the minigrid which are controlled locally. The figure shows a backbone of large scale electricity generation, transmission and distribution together with distributed energy resources and communication technologies which enable local supply, load control, asset optimisation and system resilience. The high voltage grid remains important in Australia to support the introduction of centralised renewable options such as geothermal and wind power, which are located at considerable distance from the major population centres. The inclusion of distributed energy resources and communications are the two defining features that set apart the smart grid from the current system.

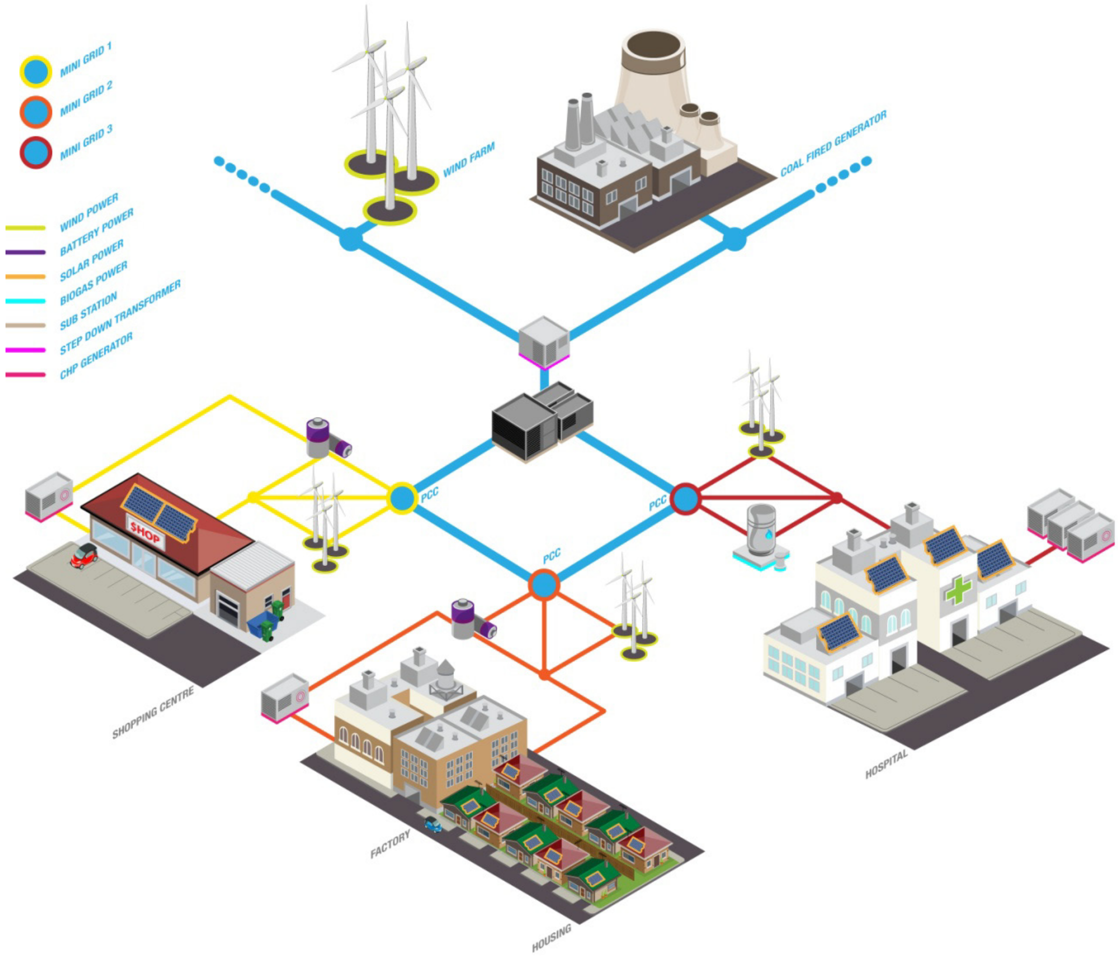


Figure 2.10: A conceptual model of a "smart grid" containing minigrid elements

Some of the key technical considerations when trying to incorporate high levels of distributed energy into the network are issues relating to the connection of generators, and the effect DG can have on network performance.

In Australia, network service providers (NSPs) operate, maintain and upgrade their infrastructure based on forecast growth over a five-year cycle. These forecasts are used to determine the amount of spend required to meet demand and are subject to regulatory checks. Previously these economic checks were performed by State based entities, but are now performed by a national authority; the Australian Energy Regulator (AER).

The AER determines how much DNSPs can receive in revenue by setting a price or revenue cap for electricity sales. This cap represents the regulator's view on what is reasonable for DNSPs to charge customers for the delivery of electricity. This revenue forms part of the total electricity bill and is known as the distribution use of system charge (DUoS). The price or revenue cap is set at the beginning of each five-year determination.

A vital component of the AER's determination is a prediction of peak and base demand provided by the DNSP. Any changes to the network demand within a regulatory cycle that results from activities such as demand management or DG can affect this determination and shortfalls in forecast throughput may operate as a real or perceived penalty for the business under the price or revenue capping regulation. Similarly, the introduction of a large load mid-cycle could lead to significant concerns for the DNSP if their system does not have sufficient redundancy built in.

The effect of unplanned demand management on distribution business revenue is a contested issue. In its stage 2 draft report into barriers to demand side participation, the Australian Energy market Commission (AEMC) effectively takes a position that any loss of revenue felt by a distribution business acts to discipline them only to provide efficient demand management. Their rationale appears to be that demand management entails a customer foregoing energy consumption, and so lost network revenue reflects the social cost of not consuming.

The process for connecting distributed generation and allocating costs is currently being reviewed as part of a number of parallel processes including the energy market reform process. It is likely that any changes driven by this reform will take time to resolve due to the complex nature of the issue.

A contentious point in the connection of distributed generation has been the allocation of “shallow” or “deep” connection costs. This issue has been raised in many submissions to government authorities in reviews, both locally and internationally. At present there is no standardised definition across Australia in this regard. It appears that only Victoria has formally defined the difference in their Electricity Industry Guideline No. 15 (connection of embedded generation). In this document, the cost of connecting a local generator to the nearest point in a network is referred to as a “shallow” connection charge. A circuit breaker used exclusively by the generator for instance would fall into this category. This cost might not fully reflect system reinforcement upstream that may be required to allow the safe implementation of the device. These additional costs are considered by some as “deep costs” and in some areas may be passed onto the connecting generator. Guideline 15 states that in Victoria, shallow costs for the connection are those associated with connection assets and any augmentation of the distribution system up to and including the first transformation in the distribution system. Furthermore, the guideline states that deep costs beyond this point cannot be allocated to the local generator. A National framework for the allocation of shallow and deep connection costs is subject to current review and remains important to resolve.

While the Victorian example of a connection process appears reasonably simple in design, costs can vary depending upon the timing of connection. Consider a number of proponents that wish to connect to a network over time. The first proponent may find that the system can easily cater for their introduction. At a later time, a second proponent may wish to connect to the network. In this case, the DNSP’s ability to cater for their introduction will have been altered by connection of the first proponent. In this case, they may find that their proposed connection requires changes in the network such as replacement of a circuit breaker at the next highest voltage level due to increased fault levels. These costs which fall within the definition of a shallow charge may have been avoidable by the second proponent if for instance, they had connected first, and if their addition did not require augmentation for the earlier network state. Additionally, a third proponent may now find that adding to a network requires only standard costs because of changes induced by the second proponent.

In its current review of “energy market design in light of climate change,” the AEMC is developing a process for connecting multiple generation units to the transmission network. It is our understanding that efforts will be made to apply this framework to distribution connections also. However, details have not been worked through. The difference between connection frameworks for centralised and distributed generators is potentially an important source of competitive advantage and so remains a vital issue to be resolved.

Dealing with these connection costs is an area of considerable and complex debate. In some cases, connection costs are seen as a barrier for introducing local generation. Connection costs are seen by some as contentious in part because most energy assets were built at a time of Government owned infrastructure, with costs shared across customers and taxpayers. Given these assets are now ‘sunk’, any historical distortion of cost allocation is naturally impossible to undo. However, it is important to recognise the origins of the energy market structure, to realise that a centralised supply model dominates by virtue of historical circumstance. Perhaps what is most important today is that the process and methodology for calculating connection costs faced by all new generators connecting to distribution or transmission networks are consistent, and cognisant of the potential for distortions to occur due to information or negotiating power asymmetry.

Furthermore, issues around reliability and safety are a significant concern for network operators who are responsible for the performance of their network and who are penalised for failing to meet reliability and service standards. Addition of generation (or demand reduction) within their network and outside their scope of control can lead to risk. Valuing the change (positive or negative) that local generation (or demand management) provides for the network is difficult to determine, is location specific and has no currently available standardised method for evaluation.

In Australia, these issues are being considered via the Ministerial Council on Energy (MCE) review on “Network Incentives for Demand Side Response and Distributed Generation” and the AEMC review of “Demand Side Participation in the National Electricity Market.” A number of similar processes are underway abroad, one of the most relevant being those under taken by the Office of the Gas and Electricity Markets (Ofgem) in the United Kingdom (see Ofgem, 2009).

2.7 Enabling large scale uptake of distributed energy

Realising the value of distributed energy in an efficient way depends on many conditions being met, not just an effective integration of generation and the network. To inform our understanding of these issues we conducted a series of stakeholder interviews and undertook a meta literature review of perceived barriers to distributed energy. We also conducted distributed energy case studies, and used insights gathered from social science conducted for this project and related work.

Indicatively, based on interviews with 47 industry and Government stakeholders, research conducted by CSIRO (2009) suggests a hierarchy of conditions that need to be met before distributed energy achieves wide scale uptake. The following hierarchy is adopted from the report:

- Distributed energy needs to be a commercially viable alternative to mains grid supply before it will have widespread uptake
- For distributed energy to be commercially viable, policy and regulation needs to allow proponents to capture the value of distributed energy where it reduces emissions or costs that are otherwise socialised - primarily seen as costs of peak demand infrastructure
- Policy and regulation must also have long term certainty to give distributed energy proponents and investors the confidence to implement distributed energy
- Consumers, industry and governments all need to be educated on the value of distributed energy and how it works to overcome cultural bias towards mains grid energy supply. This is also needed to inform appropriate policy and regulation development
- Technology and market development needs to be focussed on reducing cost and improving reliability.

A literature review of barrier studies broadly corroborated these findings and allowed a more fine grain understanding of issues to evolve. From these findings, a summary of key enablers (outcomes which should lead to an efficient deployment of distributed energy technologies and systems) were developed. They are as follows:

- A long term policy horizon with firm targets and commitments for uptake of distributed energy that have widespread support across the political spectrum. Implicitly, that distributed energy is a highly visible and important policy deliverable, and that the market has improved certainty about how distributed energy is valued
- Data that allows more accurate valuation of different forms of distributed energy incorporating real time market costs and a full suite of environmental and social externalities
- The use of a widely accepted, accurate, transparent, efficient and equitable distributed energy valuation methodology across government agencies when developing distributed

energy related policies, programs and regulation including building standards, appliance standards, product rebates, feed in tariffs and so on

- Accurate, transparent pricing methodologies, accounting for time and location specific environmental and social externalities, for energy exported by DG and/or when DG is used for demand management that allows value to be easily captured by a full range of market participants (small to large, with various technologies)
- Full and efficient access to markets for services provided by distributed generation including the ability to easily aggregate small generating or load reduction units into wholesale markets
- A regulatory and policy framework and environment that effectively aligns the incentive of companies in the supply chain, or encourages business model innovation, to provide efficient energy services to consumers, including conducting research, trials, and continued innovation. These incentives must be compatible with market competition, have broad support, be we well understood and followed
- An efficient, transparent process for connecting distributed generators, standardised as far as possible and coupled with effective low cost dispute resolution. Processes are needed for connecting multiple units and aggregating the costs based on aggregate impacts of connections
- A well informed, trained/accredited, skilled workforce that understands the value of distributed energy and can sell its benefits to consumers of all types using insights provided by decision making science
- Improved information provision and framing of costs and benefits to consumers to allow easy and accurate valuations of distributed energy options
- Tax, rebate and/or financing schemes that enable widespread access to cost effective distributed energy that would otherwise not be taken up due to high capital costs or lack of access to capital. That this be done by providing efficient, easily recoverable financial incentives and reframing decision making biases (sticky budgets, incorrect weighting of probable outcomes, inefficiently high hurdle rates). This includes access to assistance for low income and small business market segments
- A comprehensive research and development program that allows for overcoming technology lock-in at a scale in line with the need for efficient uptake of distributed energy and complementary policies/programs structured to move technologies efficiently through their development lifecycle
- A system of State and local planning and environmental controls that allows for a full consideration of issues, and ensures distributed energy is not blocked without robust justification
- Education of relevant service sectors (designers, architects, engineers, builders, tradespeople, manufacturers) on the value of distributed energy, and methods for better aligning their service incentives with long term, efficient supply of energy
- Continued and bolstered support for minimum performance standards (appliances, buildings), improved information provision (future energy prices, probable savings over time etc)

- Targeted, efficient incentives for landlords – structures for recovering cost savings from energy efficiency. Minimum efficiency standards can be stretched for the more expensive end of products/services
- Effective education around smart meters, tariff structures, how best to manage energy, processes that provide real time feedback and rewards (internal and external) to customers for effective behaviour
- A policy and regulatory environment where experimentation can take place, but where best practice is quickly adopted consistently across the nation.

It is important to note that many of these enablers are either in place, or being worked towards by current and ongoing policy, regulatory, commercial and academic processes. These enablers should not be seen as a list of outcomes that either have not, or will not be achieved. Rather they can serve as a checklist for policy makers, regulators, industry and researchers to guide their actions as the market for distributed energy evolves.

It is important to note that due to the disaggregated centralised energy supply chain in Australia, no one business in this supply chain can capture the full value of distributed energy. This acts to dilute the incentive to invest, and has the potential to result in significant investments that do not achieve socially efficient energy supply. How this can be best overcome is not simple, but ultimately, enabling distributed energy is likely to require the bringing together of many complementary policies. Split incentives, access to finance, renewable energy policies, energy prices, skill and industry capacity, from architects, through to builders and trades people, can all impact on the uptake of distributed energy and must be addressed simultaneously.

2.8 Distributed energy and policy making

It is clear that policy outcomes are critical to the transformation of industry, in this case the energy industry. The policy development process is highly mediated by diverse stakeholder interests. The relationship between policy decision makers and the various layers that seek to influence them is a complex dynamic. The policy making process occurs at State and Federal levels, sometimes with significant overlap. Policy making and the programs, instruments, environmental and planning controls that come out of policy decisions are in a constant state of flux.

An analysis of policies and programs related to distributed energy shows the uptake of distributed energy sometimes overlaps and competes within or between jurisdictions. There is sometimes uncertainty over the longevity of programs, which can make it difficult to map the framework comprehensively, but more importantly, may make it difficult for those trying to implement distributed energy to plan their activities.

For this reason, rather than policy outcomes, we see the process of policy making as critical to realising the value of distributed energy, recognising this is an emerging market and that it takes time for the new institutional relationships required to realise the value of distributed energy to evolve.

Best practice policy making is the subject of considerable research and attention. Evidence based policy making is an approach that ‘helps people make well informed decisions about policies, programmes and projects by putting the best available evidence from research at the heart of policy development and implementation' (Davies, 2004). Explicitly, it aims to avoid the use of ‘best hunches’ and ‘educated guesses’ in the policy development process.

Evidence based policy making includes the use of various research and analytical methods to test economic, scientific, environmental or ethical considerations to be considered in the policy making process. It can be used to identify issues to be addressed by policy makers and to guide the design of policy interventions.

Evidence based policy development has an intuitive logic, but implementing it is not always easy. Research by Campbell et al. (2007) in the UK point to issues such as the demands of political cycles, inadequate resources and political culture that can undermine the use of evidence based research in policy development. In the United States, research by Allison, 2005, has highlighted the importance of policy networks in shaping public policy relating to distributed generation. Ostrom et al. (1990) in Allison (2005) state that:

> *“Policy networks coordinate public and private actors who are increasingly bound by shared values, common discourse and dense exchanges of information…”*

In this way, policy networks can be used to overcome some of the difficulties of implementing evidence based policy development by ensuring a degree of continuity across political cycles and by encouraging sharing of resources and collaboration across institutions.

With relevance to distributed energy specifically, Research by Haas et al. (2004) and Allen et al. (2008), reinforce the need for complementary and targeted policies that can help emerging technologies develop through their lifecycle from immaturity to broad market uptake. This requires specific policies depending on the stage of technology development. and as the technology matures through a standard S curve from research and development through to commercial deployment. Specifically, technologies first require R&D support, subsidies that allow them to be demonstrated and deployed while pre commercial, limited support as their commercial uptake is increased and finally competition policies that help drive down their costs as they are deployed at commercial scale.

In designing markets, policy interventions and/or regulatory change, it is important to consider decision making complexity. Research into decision making highlights the limitation of assuming information is processed rationally, and that decision makers will act in their best financial interest. For instance, decision making can be affected by internal (values, beliefs, etc.) and external (social norms, financial rewards, etc.) factors, and also in more subtle ways such as the way information is presented, who presents it, the ordering of words, the choice of words with only superficial differences in meaning, or whether information is provided to groups or individuals.

Because of this, research has challenged the legitimacy of traditional cost benefit analysis (CBA) in establishing the need for policy intervention, as well as the design of the policy intervention itself, recognising that decision making is often subject to anomalies. Relying on rational CBA theory to guide environmental policy only makes sense if citizens make, or act as if they make, consistent and systematic choices toward both certain and risky events (Friedman and Savage (1948) in Hanley et al., 2005).

From a policy perspective, the most important finding from Hanley (2005) is that there is potential for analytical bias to influence the interpretation of results of cost benefit analysis. Consequently, there is the potential for these biases to under or over value policy intervention and so distort the efficacy of policy design.

To overcome the potential for bias to distort efficient policy interventions, multi-criteria decision making analysis (MCDA) can be used. MCDA allows sharing of data, concepts and opinions across those involved in the policy making process including members of the public, consultants, policy agencies, and elected officials. Through iteration and reflection, MCDA allows sources of decision making anomalies such as incomplete information, misallocation of risk, or the framing of problems to be worked through and resolved (Kiker et al., 2005).

Essentially, MCDA allows a CBA to occur, but has inbuilt processes to ensure the analysis has legitimacy from objective and subjective viewpoints. MCDA is broadly consistent with the idea of policy networks discussed previously in that a well functioning policy network can facilitate the MCDA process. To an extent, work presented in this report reflects this process where insights from engineering, economics, social science and other disciplines have been incorporated to develop a more comprehensive view on the value of distributed energy.

2.9 Decision making, consumers and distributed energy

In ensuring efficient levels of distributed energy, one of the complexities policy makers must manage is determining when distributed energy is socially efficient, considering full lifecycle inputs and outputs. This is an inherently difficult task and there is a complex trade off between the cost and benefit of a policy or regulatory intervention to ensure a socially efficient decision occurs. Original CSIRO modelling in this report goes some way to informing efficient levels of distributed energy considering social and economic factors, and a range of environmental externalities. In a sense, this creates an upper bound to the quantity of distributed energy that could emerge should all decision makers act rationally.

While modelling presented at this stage does not capture the full complexity of time and location specific conditions that affect the value of distributed energy, it helps inform an aggregated view on what an efficient level of distributed energy may look like. Our work on this is evolving to incorporate fine grain detail including weather conditions, network constraints and social preferences with the potential to develop powerful decision making tools for government, industry and the community alike.

To a degree, the ability to realise the value of distributed energy is affected by the nature of decision making at many levels. Consumers, energy companies, policy makers, regulators and others all make decisions that fundamentally impact on the uptake of distributed energy. Each individual or group of decision makers faces distinct conditions that affect their decision making. At the customer level, implementing distributed energy where it is socially efficient requires the ability to understand and process a large amount of information relating to real time energy prices, location specific network and emission constraints, their expected energy consumption demand, the cost of implementing distributed energy and even changes to energy prices in the future that may affect expected returns. In theory, efficient price signals would enable efficient decisions about distributed energy. However as described previously, individuals do not systematically process information in a rational way.

As well as informing policy development, insights from decision making science can be used to increase the uptake of distributed energy more directly by affecting consumer decision making and aligning incentives towards a particular objective. For instance, regulatory intervention in appliance markets is driven by the recognition that competitive markets do not have sufficient incentive to improve efficiency of appliance performance over time. Essentially, it is a split incentive problem where action taken by one party has benefits that cannot be captured by that party. Regulatory intervention can essentially be two fold – standards for energy efficiency or better information provided to consumers at the point of sale. Decision making science can inform the latter option.

In strictly rational terms, it shouldn't matter whether a customer receives financial savings at the time of purchase, or over time, so long as the net present value of each option is equal. However insights from behavioural economics indicate decision making is influenced not just by the quantity of gain or loss that can be made from a decision, but by the certainty of gain or loss (Kahneman and Tversky, 1981). Decision makers can also show a preference for avoiding loss, as opposed to seeking gain (Tversky and Kahneman, 1986). In the case of energy efficiency, potential gains from reduced operating costs over time are uncertain[1] while the cost of the more efficient appliance is certain. So a consumer is likely to prioritise minimising the certain loss, as opposed to maximising the uncertain potential gain. In addition, as noted previously, there are real limits to the extent to which an individual can understand the full lifecycle impacts of decisions they make. In essence, consumers act with bounded rationality.

Achieving energy efficiency is also subject to the split incentive involving landlords and tenants, where neither landlord nor tenant can capture sufficient value from investing in more efficient appliances (where the tenant pays the energy bill), or changing consumption behaviour (where the landlord pays the energy bill).

Simplistically, incentives will not be aligned where one party cannot capture the benefit of their action, or do not perceive that the benefit of their action will accrue to them sufficiently to justify that action. Aligning incentives is therefore a function of payment arrangements, but also the certainty of those arrangements. For instance, a landlord may not upgrade the efficiency of their property from 3 star to 6 star, to the extent they are unsure whether they will realise the benefits through higher rent, as opposed to whether or not they can increase rent.

Perhaps due to the complexity of this issue, the split incentive problem has not been readily addressed in many jurisdictions around the world. Regulating building standards and requiring building information disclosure are two common regulatory approaches to addressing the landlord/tenant split incentive; however this does not strictly align incentives.

Our understanding of the full complexity of decision making is still evolving, and the limitations of the rational utility maximising customer are further challenged by social science. These insights are particularly important when considering how to motivate decisions that incorporate some element that can't be, or are difficult to monetize.

In earlier work, Gardner and Ashworth (2007) developed a framework for the societal acceptance of the Intelligent Grid (see Figure 2.11). An underlying premise of the framework is that people's values, attitudes and beliefs will drive their intentions, subsequent action and eventual long-term acceptance of distributed energy and reductions in consumption. Although a wide array of psychological research supports this central premise, it is important to acknowledge that people's decisions are made within a broader context, where a range of external influences also have an impact. These external influences include economic factors and the costs of implementing distributed energy; physical/technological factors, such as the development of and access to technology; and societal factors, such as community support for low emission technology, government incentives and industry reactions. The impact of societal factors on the adoption of distributed energy is particularly relevant, since some distributed energy technology is likely to be implemented at the community level, rather than in individual households (Gardner and Ashworth, 2007). This model is described below:

[1] The consumer would need to calculate the amount of energy used by the appliance over time, the price they pay for energy and any potential future change to this price, and the operating lifetime of the appliance. They still then have to weigh up the time taken to pay off their investment against any other spending they may value (i.e. opportunity cost).

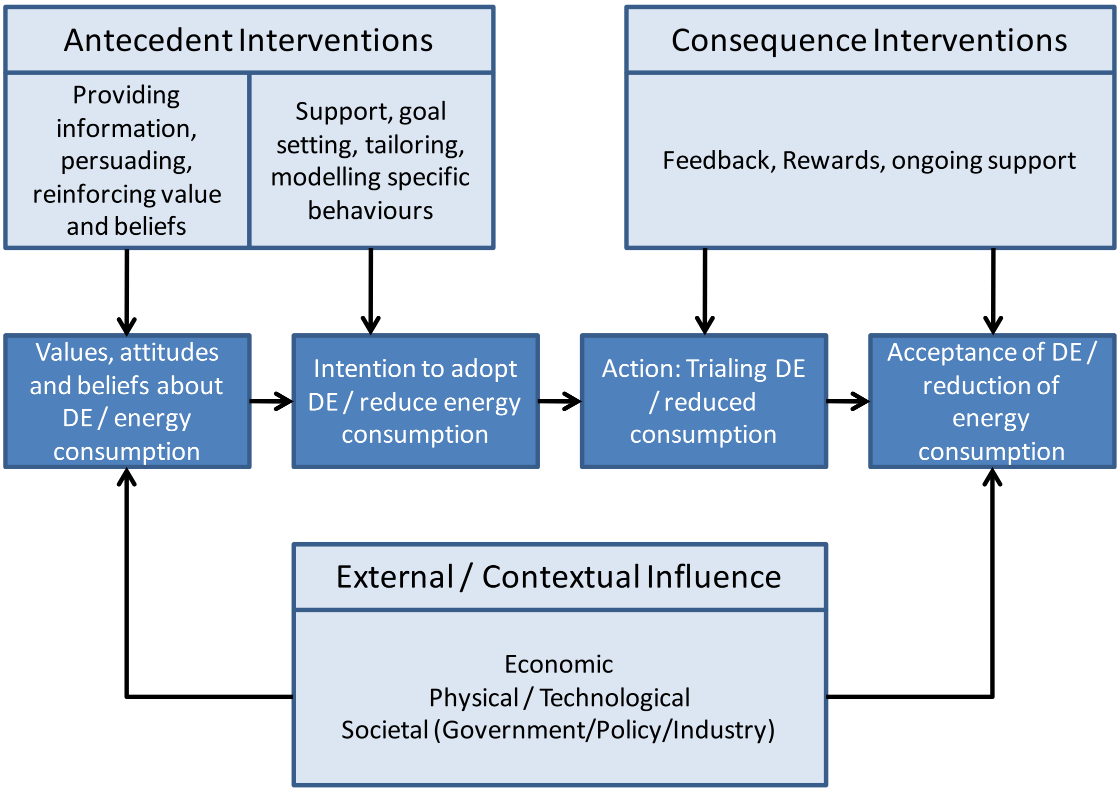


Figure 2.11: A conceptual framework for the Intelligent Grid

To develop a sense of demographic variables that affect the uptake of distributed energy, a survey was conducted across four states of Australia. The initial survey was developed with reference to psychological theory of environmental concern (Fransson and Garling, 1999; Xiao and Dunlap, 2007) and consumer technology adoption (Davis, 1989; Rogers, 1995). The survey was pilot tested in focus groups with members of the general public. As a result of this feedback some adjustments were made to improve readability and clarity. To reduce the length of the survey, two different versions were produced. One version included questions relating to demand management, and the alternate version included questions relating to DG.

Overall the survey contained four sections:

Section One: assessed knowledge and beliefs about energy sources and environmental issues

Section Two: assessed household energy use

Section Three: assessed reactions to local energy generation (in one version) and demand management (in the other version)

Section Four: assessed demographic details about the individual and their household

At the individual and household level, we find education, income levels, household size and age were most commonly the most powerful demographic variables affecting: intention to reduce electricity consumption; acceptance of demand management technology and acceptance of DG technology. Specifically, those with higher levels of education, higher incomes, smaller household size and of lower age reported higher levels of intent to reduce consumption, accept demand management and accept distributed generation.

Where individuals report positive beliefs about environmental protection, preference environmental over economic outcomes, positive attitudes towards reducing energy consumption and perceive positive norms about reducing consumption, they typically report higher intentions to reduce energy consumption and adopt demand management and distributed generation technologies. The only counter intuitive finding was that knowledge of energy and the environment sometimes polarised people's attitudes towards reducing consumption.

Distributed energy also has important applications for large commercial applications. Based on research conducted for this report, Australian organisations most likely to adopt demand management or distributed generation technology are relatively large, and so have large energy consumption. However many small businesses also appear likely to adopt distributed energy. Therefore targeting large energy users may help maximise the impact of distributed energy, but the distributed energy market is not likely to be limited to large energy users. While financial payback periods have some influence on organisational decision making, safety, efficiency and reliability were typically the most important features of demand management and distributed generation technology.

2.10 Distributed energy business models

There is a natural interplay between business models for the delivery of energy and the ability to align consumer decision making with efficient energy service outcomes. A business that can capture the full value of social and environmental externalities associated with energy consumption and production has naturally aligned incentives to deliver private and socially efficient levels of distributed energy.

A relatively successful example of directly aligning the incentives across a range of functions that affect energy outcomes often referred to is the Woking Borough Council (WBC) energy service company model in the U.K. In this model, WBC sought to accelerate emission reductions in its jurisdiction through setting up a Special Purpose Vehicle (SPV) called Thameswey Ltd in 1999. The company's purpose was to form public/private partnerships to deliver projects targeting the Council's broader climate change strategy, including providing clean energy, tackling fuel poverty, water security, waste minimisation and clean transport. Generated revenues are channelled back to the council to reinvest in specific projects, such as improvements to housing, retrofitting solar PV and heating systems for low income families (WBC, 2009). By 2006, WBC had achieved 33% energy efficiency and 21% emissions reduction on residential property, against a 1991 benchmark (Resource Smart, 2008).

The success of the model is that it aligns environment, social and economic objectives, delivered through a single entity that can capture the full benefit of its action either directly through revenue recovery, or indirectly through socialised value it provides to the community. Significantly, the vehicle is also empowered to deploy a full suite of distributed energy options and is resourced with the necessary technical capability. The entity also aligns incentives that are often weakened due to disaggregation between generators, network companies and retailers, and the regulatory and market structures within which they operate.

In this way, WBC was able to overcome many overlapping and related barriers that typically impede a wide range of distributed energy options. The business model also allows a number of key enablers identified in this chapter to be realised because it does not have to directly recover the value of social and environmental externalities that it reduces, as the value is spread across the community.

Ultimately, it is likely to be a policy choice whether such a business model can be deliberately constructed by Government jurisdictions in Australia, for example by local governments, or whether through policy, market settings and regulation, such models are encouraged for others to develop and implement.

Another model for maximising the uptake of distributed energy where it is efficient includes community collaborations. The Maine's Power project was initiated by a local community and environment group (Mount Alexander Sustainability Group; MASG) who discussed the project concept with the four businesses (referred to within as Sites 1-4). With the help of representatives from the CSIRO Sustainable Communities Initiative (SCI), MASG gathered together external expertise and facilitated external funding through government funding agencies. The businesses and other project participants discussed an ambitious goal of 30% greenhouse gas reductions by 2010. This was selected based on what the businesses believed they could achieve, and to match the same target set by the local council.

The project was developed as a non legal partnership model to enable four businesses to work together with government agencies, peak industry bodies, energy retailers, distribution network owner operators and environmental organisations to achieve an ambitious 30 per cent reduction in greenhouse gas emissions by 2010.

This partnership model was advantageous in two ways. First, it helped facilitate and guide business decisions, particularly for those businesses not directly employing an energy and operation specialist. While energy costs may be significant to most businesses, in general the cost is considerably smaller than other processes such as labour and material costs. Second, the partnership model allows government agencies to continue their skill development, to retain information learnt, and to collate and pass on relevant knowledge to businesses and the community in the future.

In consultation with CSIRO, MASG developed a general project plan based on a three stage approach. The first stage was to analyse the energy landscape of the local region and more specifically for the four businesses. The second stage was the identification of options to meet the project reduction goals knowing the energy use patterns.

During the first stage, a project partner was identified to undertake energy efficiency audits as an in-kind contribution. Unfortunately, the partner moved from their business and their in-kind contribution was not able to be filled by remaining participants. In response, the businesses were asked to pay for an external audit of their sites (with financial assistance from SV) by an accredited company. It was thought appropriate that each business contributed financially to this task in the belief it was something they should undertake as part of their normal operations.

Given the timelines of the audit process it is recommended that this action is taken at the very beginning of the project and is preferably carried out by an external party unless contingencies are available for those contributing on an in-kind basis. This allows both a thorough understanding of the business operations and energy landscape as well as a more considered project goal to be established.

While the energy audits are vital, it should be noted that the process only informs action but does not ensure action is carried out. For example it was found one of the businesses had undertaken an audit in 1998 as part of the Federal Government greenhouse gas challenge with little action taken as a result. The partnership model undertaken in this study can help facilitate information exchange and dialogue which can increase the chance of implementing audit recommendations.

Surveys were also conducted at the beginning of the work program to establish the perceptions, understandings and goals of the diverse group of participants in the study. A number of interviewees expressed a wish that the solutions proposed included new and innovative ideas. In general, these innovations were considered primarily in a technological sense.

The surveys revealed that when attributing their funds to projects Government agencies aim to encourage the uptake of technologies or policies they believe have merit for their core agency values. In this case, the agencies involved were primarily driven by the environment and rural community development. Second, the agencies provide funds in the hope of developing new and novel ways of dealing with often common problems.

The businesses surveyed had interest in the project for similar reasons, those being an interest in improving their environmental performance and in fostering ties with the community. While the public sector may contribute funds to the development of innovative solutions, it is the businesses that bear the greatest financial impost and risk when adopting change in their operation. This is not an unreasonable position as it is the businesses who gain from efficiency improvements.

In a sense, the public sector can be a vital source of information, skills and sometimes funds to ensure that changes to the business as usual approach can be tackled with minimal risk. The partnership model used in this project provides an excellent structure to improve project outcomes for future community driven projects. While technologies may play a significant role in innovation, there are potentially more gains to be had in developing new business and engagement models that allow risk and gains to be spread across all participants. Ultimately this is needed to overcome reluctance to deploy technology.

The project highlighted that the local network businesses are vital stakeholders when trying to reduce consumption in the stationary energy sector. It is their asset base which allows the flow of energy and it is their asset in which local generation or demand reduction activities may be located. Network businesses are highly regulated and subject to severe penalties when their service falls below specified standards. As such, these businesses have a propensity to adopt well understood practices, as opposed to continually innovate, to ensure their business operates within regulated guidelines. However new regulatory incentives are helping to change this.

For example, an energy recovery method for reducing high transient loads in the local network was identified as a potential project for Site 2. Figure 2.12 displays an example of the large intermittent peaks from this business. Realisation of this method would involve Powercor (the local DNSP) taking a risk based on the engineering knowledge, skills and information provided by Site 2 staff. If Powercor were to take this risk, they would need to retrain their staff or buy in the services of Site 2 personnel to ensure the system was well maintained and operated within regulatory requirements. However the recently proposed demand management Incentive Scheme (DMIS) by the Australian Energy Regulator (AER) provides a means for Powercor to consider trialling this option as a new and innovative technique to reducing the largest single source of transient peaks in the local network. While the adaptation of the technology used in this scenario is somewhat innovative (similar systems are used elsewhere such as in desalinisation plants for instance), the real innovation comes from changing business processes.

An alternative method for potentially alleviating peak load issues from Site 2 caused by equipment testing was also considered in discussion with the other project partners. At Site 1, large cold stores that have a high thermal inertia are used. The business could install simple switch gear that could coordinate a demand response that minimises network demand during the start-up of Site 2 tests by switching off compressors to the refrigeration system. This application could be used for small periods of time (say 10s of minutes) at minimal cost and with minimal disruption to Site 1 activities. Again, the innovation could only be realised through the partnership model.

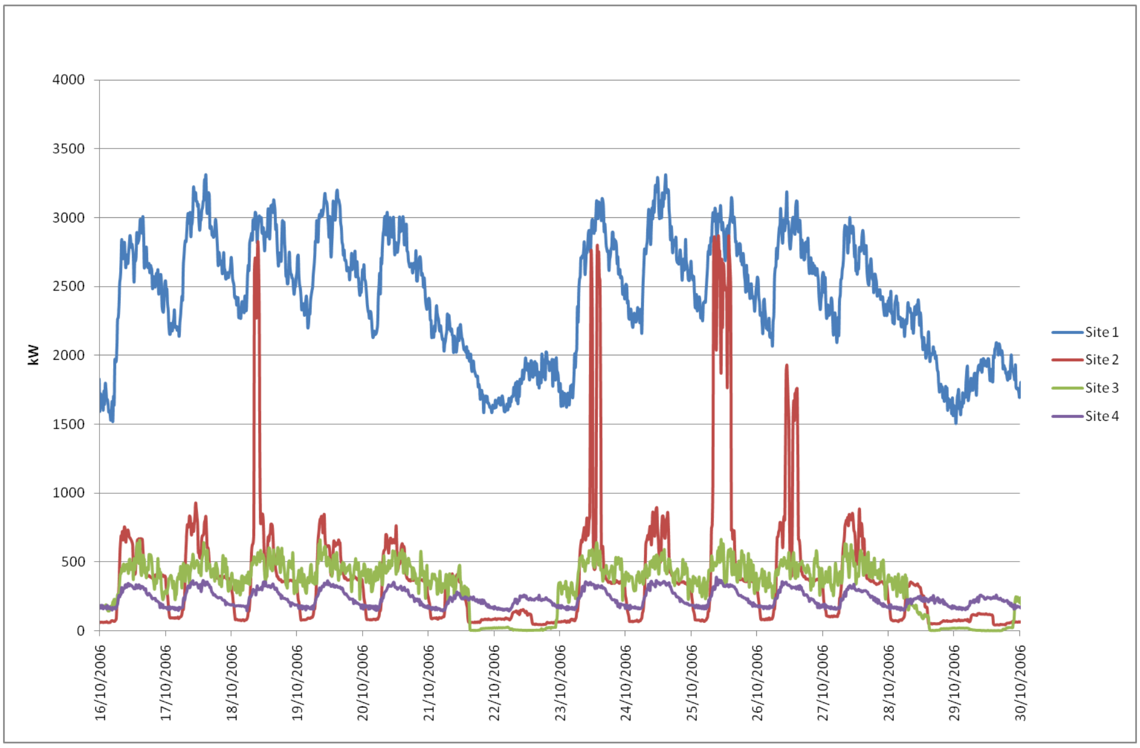


Figure 2.12: 15 minute average power (kW) consumption for a two week period in the base line year from the four businesses in the Maine's power study

2.11 Integrating distributed energy with energy markets

When considering business models for energy delivery, how they can effectively align incentives within the energy supply chain, and across property and appliance ownership structures, it is useful to consider commercial and institutional structures that influence Australia's energy markets.

The Australian NEM has relatively formal governance, commercial, security and technical decision making regimes. In summary, these organisations have the following roles:

- The Council of Australian Governments (COAG) brings together Federal and State governments in a forum to coordinate policy development, and set policy principles at a high level
- The Ministerial Council on Energy (MCE) coordinates Federal and State policy and has oversight for rule and regulation development
- Uniform industry-specific legislation, the National Electricity Law (NEL) defines decision-making constraints for the electricity industry including commercial, technical, security and regulatory arrangements. The specific details of these arrangements are set out in the National Electricity Rules
- The AEMC manages the National Electricity Rules, and the rule change process by which they can be further developed
- The AER enforces regulatory requirements and manages particularly regulatory processes such as the review and approval of network investment plans. It also monitors compliance with the National Electricity Rules by market participants as well assessing the overall effectiveness of these rules
- The Australian Energy Market Operator (AEMO) is both the market and system operator and thus has responsibility for implementing and managing both the security regime and the short-term aspects of the commercial regime.

The institutional and legislative framework of the NEM has been developed over many years and has been reinforced by the dominant centralised supply model. Small scale energy and demand management have fulfilled relatively niche roles and in some instances have been used to reinforce the dominance of the centralised supply model, for example, the use of off peak electric resistance hot water systems.

It is important to note there are processes underway that will enable better integration of distributed energy into the NEM, including potential rule changes to allow aggregated generation and load participation in wholesale market operations.

Design of regulation to meet environmental or social objectives and integration of this regulation with energy market operation is relatively new and integrating them with the market is not always easy. Environmental and social objectives are not always immediately compatible with business models that operate in the existing energy supply chain. For example, very generally, various sources of cost and value for solar hot water and PV may impact on different businesses in the supply chain as follows:

Baseload generators: could be negatively affected by solar hot water at significant levels of deployment

Peaking generators: could be negatively affected by PV (at significant levels of deployment) to the extent that it correlates with times of network-wide peak demand

Network companies: could be negatively affected by reduced energy volumes if they result in demand growth slower than forecast as part of their network investment plans. Or could benefit from PV to the extent it provides network support, reduced losses and power quality benefits that outweigh any unrecovered connection costs

Retailers: the net impact may vary depending on any generation assets owned, exposure to peak wholesale prices, or even levels of integration into solar PV and hot water markets.

Supply-side participants in the energy market are generally large, well resourced, focussed almost exclusively on the electricity industry and have considerable shared interests. End-users are far more diverse, typically less well resourced and may have interests beyond electricity itself. In this environment, effective representation of end-user interest in NEM Governance and broader policy decision making is a difficult process. Formal governance processes must be able to manage these asymmetries between supply and demand-side stakeholders in order to represent environmental and social interests in NEM design and operation.

Ultimately, successful introduction of any new technology into the NEM requires the effective support of these institutional decision makers as well as supporting organisational infrastructure. In the case of distributed energy, this includes not only the organisations and people directly involved with the technology such as designers, retailers, installers, but also those who have to manage the impacts of that technology on the rest of society. This support infrastructure does not automatically emerge in response to market signals and so highlights a role for government, not only in education and training but in developing the necessary institutional decision making structures. This is an important consideration for policy makers seeking to harness the value of distributed energy.

Integrating and valuing new technology, specifically distributed energy into the NEM, also requires explicit, transparent methodologies for signalling, motivating and optimising end-user participation to facilitate effective decision making. Active participation by the majority of end-users (residential and commercial) will require that the uncertain time and location varying value of energy is better reflected in the prices these end-users see, or that end users and/or third parties will be able to capture the value of distributed energy where it supplies energy services below time and location specific costs. The use of interval meters coupled with price deregulation goes some way to achieving this. However, it must be recognised price is a limited tool if used in isolation. Without access to information, financial support and potentially specialist skills to facilitate behaviour change as well as new physical infrastructure, customers may have a limited response to price signals. This decision making complexity highlights the potentially important role of energy service companies that can optimise delivery of energy services to customers.

Investment decision making is also a critical component of the NEM. Forward looking prices and planning documents can help signal where future investment are needed. For example, investment in centralised generation is largely driven by the Statement of Opportunities (SOO) report. Released by the market operator (AEMO), it details historical demand, demand projections and projections in energy shortfalls. Efforts are being made to replicate a comparable process at a distribution network level, with distribution companies required to release network planning details and signal opportunities for demand side proponents to offer alternatives to network building. However signalling for investment in distributed energy is naturally a more complex process due to the fine grain nature of location and price signals it can be driven by, as well as the sometimes competing interests of the energy supply chain and distributed energy proponents. Furthermore, to capture a full suite of distributed energy opportunities, these decision making signals must incorporate the intersection between natural gas and electricity, a potentially significant issue given the relative immaturity of natural gas markets and the predicted impacts of natural gas based technologies.

Demand management, one important element of distributed energy, relies heavily on energy market structures to realise value. This is because it primarily operates to resolve time specific network or generation constraints. Demand management refers to a suite of technologies and techniques used to alter demand profiles over time. Active control measures can smooth or shift demand peaks, or substitute local generation for centralised generation. Passive control measures such as energy efficiency can reduce total demand over time. Figure 2.13 provides an illustrative demand profile, indicative of a network area dominated by commercial energy demand and hence a midday peak in summer. In this example, the blue curve shows demand ramping up from 6am when people begin to wake and get ready for work. Demand grows during the day peaking before lunch as air conditioning demand grows in commercial buildings. The demand then drops off slowly briefly peaking again in the late afternoon as people return home.

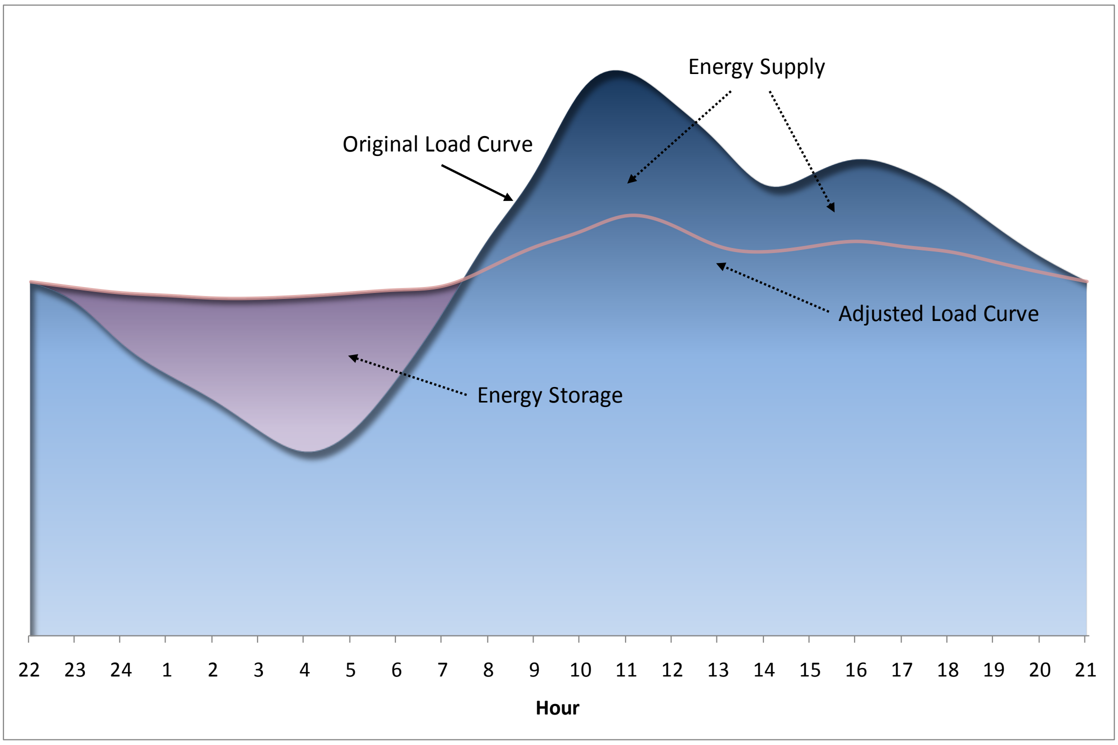


Figure 2.13: A hypothetical daily demand profile including storage

Demand management offers potential value to network companies, energy retailers, energy customers and the market operator. Most simply, it can defer spending on network assets for network companies, reduce wholesale prices particularly at peak times and reduce retailer exposure to wholesale market price volatility. However, it can also offer more complex services, for instance controlling loads in emergency situations (such as power shortages or outages), providing frequency control and ancillary services, or managing customer exposure to generation or network charges according to stated preferences. By way of example, Read et al. (1998) in Ackerman et al. (2000), found that ancillary service costs were reduced by 75% in the first year that interruptible load was allowed to participate in the New Zealand energy market.

One mechanism recently developed to facilitate demand management is the demand management incentive scheme for network businesses. In acknowledgement of the complexity facing demand side solutions, the AER have developed Demand Management Incentive Schemes (DMIS) for distribution businesses. At this stage, the DMIS in each State differs slightly to reflect State based regulation, prior to National regulation. The AER intends to deliver a national version once national policy settings such as CPRS and reviews such as AEMC's demand side participation are understood.

The objective of the DMIS is to provide incentives for DNSPs to implement efficient non-network alternatives or to manage expected demand for standard control services in some other way. It is not designed to be the primary source of funding for demand management expenditure which is based on the approved forecasts of operating and capital expenditure in the AER's determination for a particular DNSP.

The scheme will provide a demand management innovation allowance (DMIA) which allows the DNSP to recover funds allocated to these non network solutions through two mechanisms; an annual ex-ante (before the event) allowance in the form of a fixed amount of additional revenue, and a forgone revenue recovery scheme.

It is important to note that demand management led by distribution network businesses is only one model. Demand management could be performed by retailers or third parties, to the extent they can capture the value of doing so and thereby make a commercial return.

In New Zealand, demand side participation has been effectively used to manage network constraints. In November 2008, New Zealand's energy grid network management company Transpower, released a Report entitled "Demand-Side Participation (DSP) Trial 2008" detailing outcomes of a DSP trial conducted from June to August in 2008 across a limited network corridor of northern New Zealand.

Eleven organisations were interviewed as a case study for this report in order to understand their experience of the Trial, and ultimately what influences the degree to which businesses can engage in demand management in response to market signals.

Organisations interviewed generally show a high degree of satisfaction with the Trial, being able to achieve financial savings that outweighed business disruptions. They support the concept of demand side participation as a short to medium term measure for managing supply side issues. However in the long term, they indicate a preference for managing supply issues directly through building transmission network and/or generation capacity.

While some organisations were new to the concept of demand side participation, they were able to overcome initial issues by developing strategies for optimising their demand response. They highlighted a need for developing automated processes, and receiving immediate feedback on the success of their response to improve their ability to manage their demand in the future.

Financial incentives were deemed an important motivator for participation. However along with financial considerations, participants noted the importance of assurances of minimal disruption to day to day business activities and therefore the low risk participation in the Trial. Some participants indicated they were assured by the opt out clause. This meant they could ‘give the Trial a go’, but pull out if it wasn’t working for them. Related to this assurance, several organisations noted the communication structure implemented during the Trial as a contributing factor in the decision to be involved.

The majority of interviewees indicated that in the short term, DSP was a viable and effective tool for mitigating supply issues during peak periods, however that its use should be short term. Long term, DSP was not considered to provide the answer to New Zealand’s ongoing energy supply issues and it was felt it should not be used to deliberately avoid upgrading the network where this was necessary. Concern was raised in relation to placing the onus on industry for ensuring uninterrupted supply through DSP, commenting that industry should not have to “bear the brunt of poor investment decisions.”

These preferences are broadly compatible with the intended use of DSP. That is, it is not intended to replace capital expenditure on grid infrastructure, rather complement it or delay it if necessary, to ensure reliable supply at peak times until new infrastructure can be built. However the concerns raised highlight the importance of ensuring network companies, or others, do not have an incentive to use DSP as a long term, ongoing measure to avoid network building, unless the benefits of doing so outweigh the costs in the long run.

Demand management is also being used in Australia at the domestic customer level. Data from a domestic trial conducted by ENERGEX, analysed as part of this report, supported an overall conclusion that participation was primarily driven by two factors: the confidence customers had in the trial, and by the sense of community contribution and connection they associated with the trial. Those who has experience with earlier trials (continuers) reported the most confidence in the trial, and had the strongest sense of contribution and connection. Levels of confidence and sense of contribution/connection were moderate for trial newcomers, and were lowest for eligible non-participants. Positive outcomes, including positive evaluation of the trial, positive word of mouth, and intentions to participate in future trials, all tended to be higher for people with higher levels of confidence and connection/contribution. These conclusions are best represented in the illustration below (Figure 2.14).

Based on the initial qualitative data and previous research into consumer choice and decision-making, a preliminary model of potential drivers and barriers to trial participation was identified. Each major element in the model was tested in the survey.

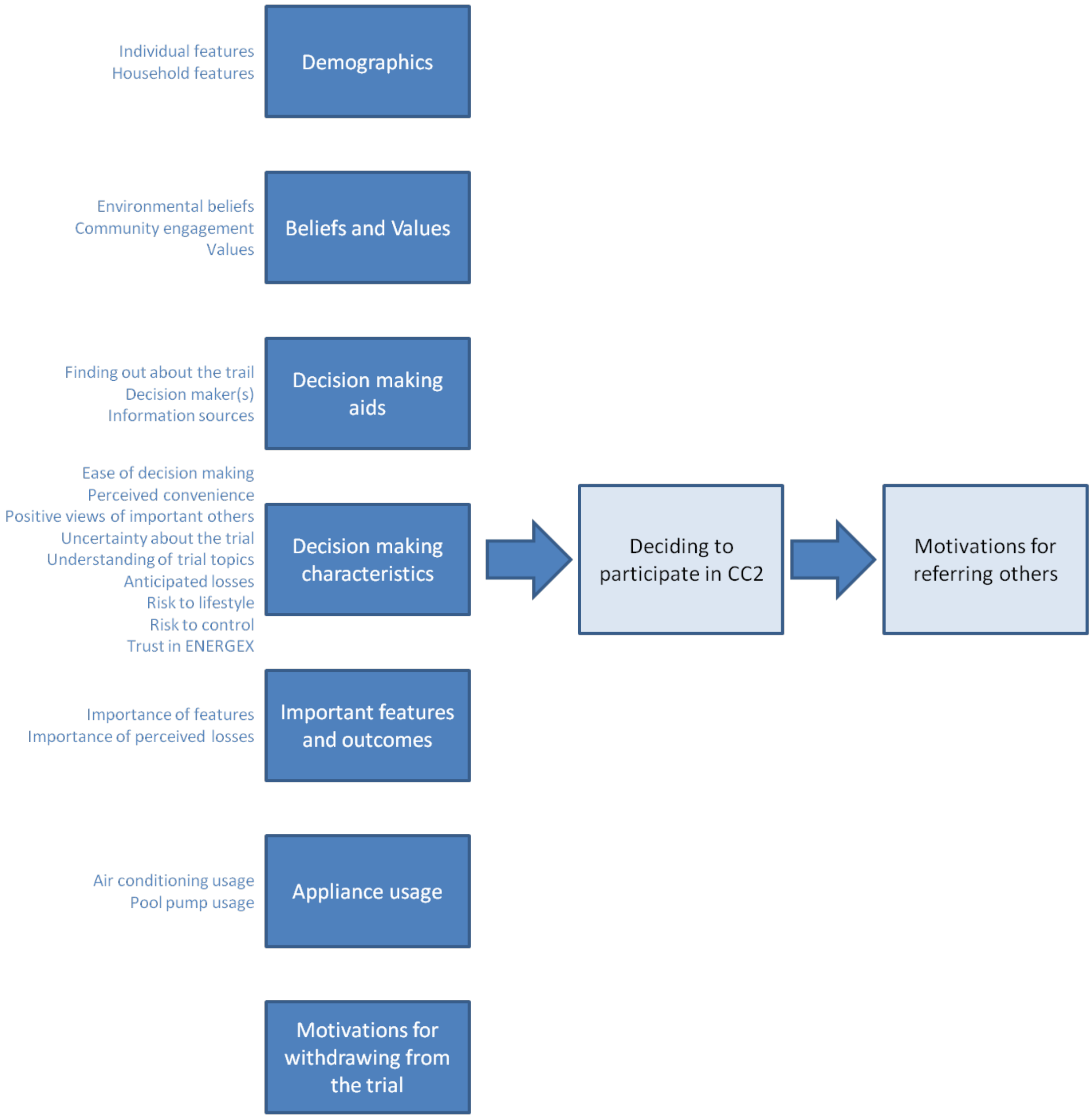


Figure 2.14: Potential barriers and drivers to participating in CC2

Positive word of mouth and supportive opinions of others in the household appear to have been very important in encouraging people to participate in the trial. This effect is consistent with previous research which shows that people are more likely to trust and accept something if it has been tried or supported by people that they know, or by people who are similar to them in some way (including living nearby). When the trial is expanded, it may be most effective to expand to neighbouring suburbs first, rather than suburbs in a completely different area, because the former will benefit more from existing awareness and from the reassurance that people similar to them are already involved.

2.12 Global trends in distributed energy

It is difficult to make global comparisons about distributed energy penetration due to the wide range of variables that affect its uptake including: availability and cost of centralised energy; geographic characteristics; climate; population density; energy market structure; economic structure; policy; and regulation. However it is reasonable to assume the market for distributed energy in Australia will be affected by global trends, as technology development and new system design configurations overseas will influence technology and system development in Australia.

Distributed energy can be deployed anywhere thermal energy or electrical power is needed. Figure 2.15 from the World Survey of Decentralised Energy (WADE, 2006), illustrates the extent to which DG is deployed (at 2006) in various countries.

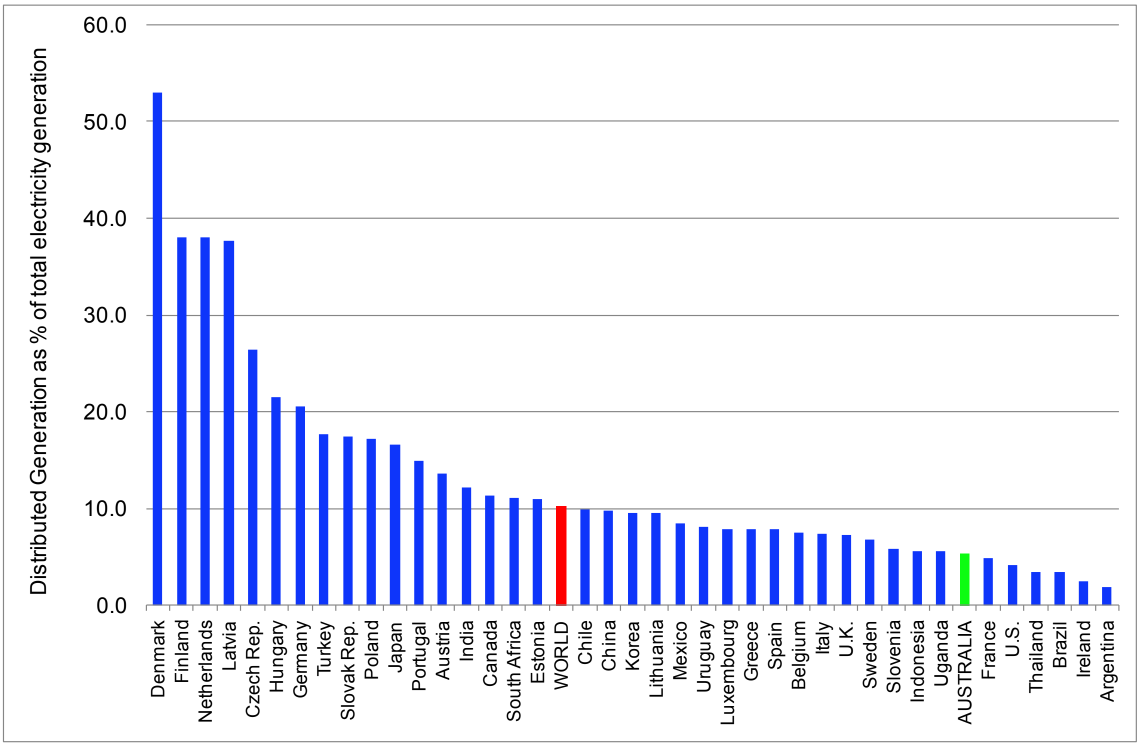


Figure 2.15: Proportion of electricity from DG (WADE, 2006). Reproduced with permission from WADE

Evident from this figure is the below average deployment of distributed energy in Australia when compared to the world average. Generally speaking, countries with high proportions of distributed energy tend to have the following characteristics:

- Relatively cold climates
- Highly urbanised, densely populated cities
- Industrial sectors that account for a large share of economic activity
- Concerns over energy supply security and fuel scarcity, and
- Focused government policy on electricity and heat supply.

European countries generally have greater proportions of distributed energy than other countries, primarily due to the above criteria. However various distributed energy applications are suited for both industrialised countries and emerging economies. The flexibility of distributed energy as a power source is perhaps highlighted by the penetration of distributed energy in China and India being approximately average by global standards, despite having significantly different economic structures to high ranking countries.

Although the United States has relatively low levels of distributed energy, energy security concerns and a changing political landscape for renewable energy, is likely to drive an increase in distributed energy, enabled by smart grids.

For Australia, the experience around the world suggests there may be considerable untapped distributed energy potential, most probably constrained historically by the low cost and abundance of centralised energy supply and Australia's climatic conditions. However, with many of Australia's centralised supply infrastructure assets either in need of, or in the process of renewal, growing recognition of the importance of greenhouse gas pollution reductions and technological development that allows the use of heat for cooling, Australia is well positioned to increase its penetration of distributed energy and secure the benefits it can provide.

When compared to nations of comparable economic development, China and India are two countries with relatively high levels of DG by global standards. They share similar economic, demographic and geographic characteristics with large rural populations, fast growing urbanised populations, rapid industrialisation and a range of renewable energy resources, albeit not yet fully developed. Both countries are using targeted programs to electrify rural areas and improve access to other forms of energy in remote areas including heating and lighting, which may be conducive to distributed energy.

Table 2.4 shows that in 2006, around 70% of Indian electricity production came from coal, with 15% from hydro and 8% natural gas. Wind, solar, and biomass energy make up less than 2% of all electricity generation.

Table 2.4: Electricity production sources in India (IEA, 2009a)

INDIA	Energy Production (GWh)	Technology Mix (%)
Production from:		
- coal	508,362	68%
- oil	31,475	4%
- natural gas	62,092	8%
- biomass	1,930	0%
- waste	0	0%
- nuclear	18,607	3%
- hydro*	113,599	15%
- geothermal	0	0%
- solar PV	19	0%
- solar thermal	0	0%
- wind	7,994	1%
- tide	0	0%
- other sources	0	0%
Total Production	744,078	

Table 2.5 shows that China has a similar energy production profile to India with 80% coming from coal, 15% from hydro, and the remained primarily from oil and nuclear. Almost all of its biomass energy is used in residential applications, most probably in rural communities. As shown below, this is not yet a significant source of energy in China.

Table 2.5: Electricity production sources in China (IEA, 2009b)

CHINA	Energy Production (GWh)	Technology Mix (%)
Production from:		
- coal	2,301,402	80%
- oil	51,469	2%
- gas	14,217	0%
- biomass	2,514	0%
- waste	0	0%
- nuclear	54,843	2%
- hydro*	435,786	15%
- geothermal	0	0%
- solar PV	105	0%
- solar thermal	0	0%
- wind	3,868	0%
- tide	0	0%
- other sources	0	0%
Total Production	2,864,204	

However the quantity of installed renewable energy is expected to significantly change in China over the next decade. The Government has established targets for the development of various sources of renewable energy up to 2020, requiring 10% of total energy consumption by 2010 and 15% by 2020 to be renewable. An investment of ¥CNY 2 trillion (approximately $US 263 billion) before 2020 on renewable energy development in China is envisaged to reach this goal. By 2020, the plan calls for the development of a total of (IEA, 2009c):

- 300,000 MW of hydropower
- 30,000 MW of wind power
- 30,000 MW of biomass
- 1,800 MW of solar power
- 300 million m^2 coverage of solar hot water heaters
- 44 billion m^3 of methane gas per year
- 50 million tonnes of biofuel.

Table 2.6 details the current penetration of different forms of energy within India, including distributed and decentralised systems. In total 14,224 MW of grid interactive renewable power capacity was installed at the end of January 2009 representing around 10% of total installed generation.

Table 2.6: Current installations of renewable and distributed energy sources in India (MNRE, 2009)

Sources / Systems	**Cumulative capacity (as of 31.01.2009)**
Grid-interactive renewable power	
Biomass Power (Agro residues)	683.30 MW
Wind Power	9755.85 MW
Small Hydro Power (up to 25 MW)	2344.67 MW
Cogeneration-bagasse	1033.73 MW
Waste to Energy	58.91 MW
Solar Power	2.12 MW
Off-grid/Distributed Renewable Power (including Captive/CHP plants)	
Biomass Power / Cogen.(non-bagasse)	150.92 MW
Biomass Gasifier	160.31 MWeq
Waste-to- Energy	31.06 MWeq
Solar PV Power Plants and Street Lights	3.00 MWp
Aero-Generators/Hybrid Systems	0.89 MW
Decentralized Energy Systems	
Family Type Biogas Plants	4,090,000
Home Lighting Systems	434,692
Solar Lanterns	697,419
Solar PV Pumps	7,148
Solar Water Heating - Collector Area	2,600,000 m^2
Solar Cookers	637,000
Wind Pumps	1,347

Note : MW = Megawatt
MWeq = Megawatt equivalent
MEp = Megawatt peak

Their experience points to the significant potential for distributed energy where there is a relative lack of centralised supply infrastructure. This is because distributed energy is often low cost, modular, and renewable, making it a logical choice particularly where centralised alternatives have not yet been developed. The importance of highlighting their experience is because trends for distributed energy in Australia or globally, may largely depend on innovations developed for specific regions of the world. It is reasonable to suggest that as China and India manufacture distributed energy solutions for large scale deployments in their own regions, this could have significant impacts on the cost of distributed energy solutions globally.

2.13 Distributed energy in Australia

Many of Australia's centralised supply infrastructure assets are either in need, or in the process of renewal. Combined with growing recognition of the importance of reducing greenhouse gas pollution, emission intensive centralised generation will become increasingly more expensive. With technological development that allows the use of heat for cooling, well suited to the Australian climate, Australia is well positioned to increase its penetration of distributed energy as an alternative to centralised generation.

Australia's energy supply system was developed at a time when large scale, centralised generation plant close to fossil fuel resources, was the optimal supply model. It allowed economies of scale, and took advantage of the relative efficiency of transporting electricity, as opposed to transporting coal or gas.

Today, the imperative to address climate change and technological change is challenging the dominance of this central supply model. Small scale generation close to load creates significant efficiencies, allowing for the useful recovery of heat, otherwise wasted in the generation of electricity. It can reduce electrical losses on transmission and distribution network infrastructure, particularly in rural areas and can improve power quality while imposing minimal additional costs and risks to network assets.

Advances in emerging technologies such as solar photovoltaics has the potential to make clean energy generation at the point of consumption viable with grid supplied electricity. Advances in communications and control devices has the potential to facilitate smart grids, where the supply and consumption of energy can be seamlessly optimised, maximising the potential to integrate clean renewable energy generation with grid infrastructure. Combined with building design optimisation and efficient heating and cooling systems, distributed energy systems are currently reducing, and offer significant potential to reduce greenhouse gas emissions cost effectively in the future.

This new energy supply model, with decentralised generation, decentralised decision making, and active consumer input has the potential to create highly resilient energy supply systems, reducing the cost of high impact, low probability events such as power outages caused by bushfires. Naturally this type of resilience comes at a cost, requiring network islanding and sophisticated control systems. However as climate change heightens the risk of extreme weather events such as bush fire and high wind speeds, decentralised energy supply models offer risk mitigation, by removing the reliance on vulnerable transmission and distribution infrastructure. While detailed modelling of costs and benefits of this type of supply model have not been undertaken here, it may be a field of future research.

This imperative of transitioning to a decentralised energy supply model is heightened by the need to mitigate the risk of clean central supply technologies failing to emerge from concept to reality, highlighted by economic modelling work which shows distributed energy playing an even greater role in emission reductions should carbon capture and storage technology not evolve.

A distributed energy system may naturally evolve over time without intervention from Governments as communities take unilateral action to reduce their emissions from stationary energy. There is a movement across Australia at the community level working towards distributed energy solutions which is important to acknowledge. However a full and efficient transition of the energy supply chain is likely to require the union of many complementary policies. This is because of significant social and environmental costs associated with energy use that remain unpriced, and the current centralised supply system showing characteristics of inefficient technology lock-in, with modelling consistently demonstrating the significant untapped potential of distributed energy, and in this report, energy efficiency and DG in particular.

Overcoming technology lock-in requires targeted policy support for new technologies that allows them to emerge from a market niche to maturity. Technology support starts with research and development funding, creates subsidies for emerging technologies, then as the technology matures, makes use of market based and competition policies to drive efficiency improvements.

The majority of clean energy research and development priorities in Australia to date have focussed on addressing emissions caused by large scale generation. While this remains very important, modelling in this report shows that an efficient reduction of emissions requires a mix of technologies, with the role of distributed energy heightened by scenarios where promising future technologies such as carbon capture and storage fail to be deployed commercially. To mitigate the risk of stranded energy assets, more support for development of distributed energy technologies and systems may be required.

Policies are also needed to address systemic issues created by the dominance of the central supply model. Systemic issues include the lack of a pervasive skills base required to deliver distributed energy, the inability to capture the value of distributed energy solutions due to incomplete energy prices, and the decision making bias of customers.

A lack of skills is largely caused by the complex and disaggregated chain of businesses involved in designing and building the infrastructure that determines how we consume energy. From property developers, energy retailers, architects and network companies, no one business can capture all the value of distributed energy, therefore their incentive to pursue DG, energy efficiency or demand management is diluted. The flow on effect is a lack of commercial imperative to develop training and education that supports skills other than those required to perpetuate existing business models. To address this lack of skill development, policy is needed to signal the value of distributed energy, and create frameworks that allow its value to be captured. This will create innovation within the existing supply chain, but also ensure a competitive market for energy service delivery, with new energy supply models likely to emerge.

Policy and regulatory frameworks that start to address these issues have emerged in Australia including the use of energy white certificates to target energy efficiency at the household level through energy retailers, demand management incentive schemes for network companies to seek alternatives to network building, Smart Grid funding for a large scale demonstration of distributed energy technologies, building and appliance regulation, and the planned rollout of interval meters coupled with the potential for price deregulation to signal opportunities for more efficient energy services.

However there remains scope to refine those frameworks and in some cases expand their scope to allow the full value of distributed energy to be realised. To support this, better methodologies are required for valuing various distributed energy measures and incorporating them into policy and regulation including the value of time specific energy costs that distributed energy may avoid or substitute the value of environmental externalities and the value of enhanced energy system security and reliability that distributed energy can bring.

Systemic decision making bias in the energy supply chain appears to be caused by the interplay of inherent human decision making characteristics, the delivery model for centralised and decentralised energy and a lack of effective price signals for energy consumption. Consumers appear to systemically prefer to avoid loss as opposed to seek gain, and make imperfect trade offs between incurring costs today to securing benefits in the future. This decision making bias complements the central energy supply model which uses highly geared companies to finance capital intensive infrastructure, paid off over long time periods, resulting in low operating costs for energy. The low, flat tariff price signal encourages consumers to seek cheap, inefficient energy appliances, building design options and sub optimal energy supply options.

The decentralised model of high efficiency and local infrastructure ownership can entail high capital costs. This can affect the uptake of distributed energy as consumers typically lack access to cheap finance and inherently place high discount rates on their decisions. Consumer uptake may also be suppressed from uncertain payback periods that result from a combination of not knowing future energy prices, and not knowing how their energy demand may change over time.

Customers may also lack the ability to augment the infrastructure required to facilitate distributed energy, for instance they may not own the building they live or work in. They may also face significant information asymmetries and split incentives when integrating distributed energy with the grid, including navigating the grid connection process, and the inability to recover the time specific value of energy they avoid consuming, or substitute with a local alternative.

Addressing these systemic decision making biases can be achieved in a number of ways. Innovative models for delivering distributed energy can change the price signal seen by customers. Existing examples include bulk supply of technologies to reduce up front costs, or leasing models where distributed energy equipment is leased to customers for an annual fee or installed for no cost but paid for by energy cost savings.

They can also be addressed by using information and/or financial incentives, helping consumers make better decisions considering the true cost of operating energy consuming appliances. For example, decisions at the point of sale of energy appliances can be influenced, by providing efficient rebates for more efficient appliances. Rebates can be calculated to consider the time specific value of avoided energy costs not factored into energy prices, reflecting the significant cost difference between suppling base load power and temperature sensitive peak demand. Refining information disclosure requirements on buildings and appliances can also help consumers make better decisions about energy, for example by giving them clear guidance on likely avoided costs and paypack periods, not just avoided consumption.

In part, because of the differing characteristics of centralised and decentralised supply models, distributed energy can often compete with the central supply model in green-field developments and where customers are forced to contribute significant capital costs up-front for infrastructure building. This is particularly evident in developing countries where centralised energy supply infrastructure has yet to be established. This should be considered an important signal as to the future value of distributed energy, with significant economic growth, and energy demand, likely to be driven by emerging economies such as China and India.

Importantly, distributed energy has significant potential in developed urban areas although capturing its value is made difficult because of the lack of clear price signals. As opposed to rural or green-field sites where the price signal for trade offs between centralised and decentralised energy models is often clear, in dense urban areas, upgrade and renewal of infrastructure is an ongoing processes with costs allocated across diverse customer bases. Coordinating decisions required to capitalise on avoiding asset renewal and upgrading is a difficult process, particularly if an optimal distributed energy solution is being sought across a network zone, as opposed to a single distributed energy solution such as DG to meet a very specific network constraint. Processes are underway to develop such signals through the AEMC and it will be important for policy makers and regulators to observe how the distributed energy market responds to these signals, and to refine signals where necessary.

Insights from social science can also help overcome some of decision making biases. Distributed energy product retailers and service providers can use social science to target consumers who are more likely to adopt distributed energy technologies and systems. Using insights documented in this report, awareness raising, education and messaging campaigns can be tailored to overcome a reluctance to adopt distributed energy, and help promote the values and attitudes that make consumers more likely to adopt distributed energy.

Fundamentally, in order to bring about the market transformation required to realise the value of distributed energy, long term policy with firm targets and commitments are required to give the market confidence about developing and deploying distributed energy solutions. The use of formal policy networks, where policy research, ideas and intentions can be shared, can help create the collaborative environment needed to transform the energy supply chain. These policy networks must involve multiple parties and be inter disciplinary in nature to capture the diverse range of stakeholders that influence energy supply options. Most importantly, policy networks need to bring together the complementary disciplines of economics, engineering and science so that decisions can be optimised considering a full diversity of variables.

Undoubtedly, transforming how energy is generated and consumed is one of the great challenges facing societies around the world. It is a challenge we believe distributed energy will play a major role in meeting.

3. UNDERSTANDING DISTRIBUTED ENERGY

Distributed energy refers to a collection of small local generation technologies (distributed or embedded generation) that can be combined with active load management and energy storage systems (demand management) along with passive measures (energy efficiency) to improve the quality and/or reliability of the electricity system and mitigate the cost of peak demand. This chapter provides an overview of current practice in Australia's energy system, a description of distributed energy resources and a brief discussion of smart grids, which are considered by many as a future system which will deliver energy services to the benefit of consumers and utilities by minimising greenhouse gas emissions, losses and price.

3.1 Key findings

Distributed energy describes a number of technologies that can significantly reduce the nation's greenhouse gas emissions. These savings result from reduced network losses by using generation near the point of consumption, through maximising the use of cleaner fuel sources such as natural gas, solar and wind, and through more efficient conversion of fuels to useful energy services, including recovering heat otherwise wasted in centralised generators.

Distributed generation (DG), sometimes referred to as embedded generation is generally connected to the electricity grid at low voltage (< 22 kV). Internal combustion reciprocating engines (ICE) are the most mature prime movers for DG applications. Advantages include comparatively low installed cost, high efficiency (up to 45% for larger units), suitability for intermittent operation, high part-load efficiency, high-temperature exhaust streams for CHP and are easy servicability. These units have been popular for peaking, emergency, and base-load power generation. The units can run on a variety of fuels including diesel, natural gas, compressed natural gas and petrol. DG units connect to the grid as synchronous machines, asynchronous machines and/or inverter generators depending on the primary source of energy. Synchronous generators are commonly used with engines and turbines. Asynchronous generators are commonly employed on medium and large wind turbines while solar photovoltaics and small wind turbines utilise inverters. Where DG is reliably available at peak times, or where multiple units provide a degree of firm supply at peak times, it has the potential to mitigate peak demand and so reduce network costs.

Cogeneration is a process where the heat generated by combustion of a fuel for electricity production is used for a secondary purpose rather than being a waste product. The heat is most often used to create hot water or steam but can also be used for cooling purposes through an adsorption cycle. Where heat can be used for cooling as well as heating, it is referred to as combined cooling and heating power (CCHP) or trigeneration. The value of co/trigeneration can be influenced by the type of technology, its reliability, the timing and size of the heating and cooling demand in respect to electrical needs, and the type of system the waste heat equipment is replacing or substituting.

Demand management (DM) refers to a suite of technologies and techniques used to alter demand profiles over time. While these measures may reduce total energy use, they are primarily employed to smooth or shift peaks in demand. By controlling peak energy patterns, demand management may provide substantial financial savings to consumers by reducing the need to build network infrastructure required to service this high demand for only a small number of hours each year.

Energy efficiency is the passive reduction in demand as a result of changes in performance efficiency of individual devices or the substitution of one form of energy for another more energy efficient version, for example passive solar design in buildings. Energy efficiency is often seen as the easiest and most cost effective way to reduce emissions in the short term. It is important to note that the value of energy efficiency is not only determined by the quantity of energy that can be saved, but the timing of those energy savings as energy market costs vary significantly over the course of the day with costs typically highest when demand peaks.

There is an increasing acceptance that the energy system needs to evolve in order to meet the dual challenges of energy security and climate change. Smart grids which incorporate distributed energy solutions with large scale renewables and information infrastructure are expected to provide a future system able to meet the growing demand for energy while ensuring low emissions and high levels of security.

DE may be able to play a role in generation and ancillary marketsbut this will be affected by market structure and rules. In Australia, the largest market, the National Electricity Market (NEM) services the eastern states. It is a spot market in which generators are paid only for energy produced and a high price cap is meant to provide incentive to invest in generation capacity and/or establish efficient demand side response. DE may provide a role in decreasing price spikes through better resource utilisation or if used for active demand management and integrated with the market bid and dispatch process. In Western Australia there is an energy market and a capacity market. The capacity market is meant to provide incentive to meet peak demand by providing sufficient revenue for different ways of meeting capacity requirements regardless of how often an option is deployed and so without the market experiencing volatile prices.

3.2 Australia's current energy system

3.2.1 Electricity

In simple terms, electricity is a form of energy produced by the flow of electrons along a conductor such as copper or aluminium. It is a secondary source of energy produced by the conversion of other energy sources such as chemical or mechanical energy. It can be readily converted into heat and light and used to power plant, equipment and appliances. It can also be transported with relative ease. A unit of power is referred to as a watt (W) and is equivalent to one joule of work per second (J/s). Both the voltage (V; analogous to electrical pressure) and the current (A; the number of electrons flowing) determine the rate of electrical energy flow (NEMMCO, 2008).

In Australia, more than 90 per cent of electricity production comes from the burning of the fossil fuels, coal, natural gas and oil. The chemical energy stored in these fuels is used to heat water and produce steam. The steam is then forced through a turbine that drives a generator to produce electricity. The complete process involves the conversion of chemical energy first to kinetic energy then to electrical energy. In a similar way, the kinetic energy of falling water drives turbine blades to produce electrical energy at a hydro-electricity plant, and the kinetic energy of wind drives the blades of a wind turbine to produce electricity (NEMMCO, 2008).

When an appliance is switched on, power is transmitted near the speed of light through a sequence of specific events (see Figure 3.). First, a transformer converts the electricity produced at a generation plant from low to high voltage to enable its efficient transport within the high voltage (e.g. 132 kV) transmission network (red and blue lines). The energy passes through a step down transformer to a lower voltage (e.g. 66 kV, yellow line) for supply into the wider distribution network (orange line). The energy then travels along distribution line to the point of use. In this step, it travels through a substation which reduces the voltage to a lower level (e.g. 22/11/6.6 kV) which may be used by large businesses. For domestic consumers, the energy undergoes a final voltage reduction which converts the electricity to a voltage compatible with household appliances (240/415 V)

In Australia, electricity is generated and supplied in this fashion into three markets: the National Electricity Market (NEM) which services the Eastern States of Australia, the Wholesale Electricity Market (WEM) in the South West Interconnected System (SWIS) of Western Australia and the Darwin and Katherine Interconnected System (DKIS) servicing the Northern Territory. These markets are explored in this section including a brief analysis of the difference in structure of each market.

Figure 3.1: A simplified view of electricity generation and transfer

The National Electricity Market (NEM)

The National Electricity Market (NEM) commenced operation in December 1998 as a wholesale market for electricity supply in the Australian Capital Territory and the states of Queensland, New South Wales, Victoria and South Australia. Tasmania joined the NEM in 2005 and was physically interconnected to the NEM in April 2006. The NEM delivers electricity to market customers via an interconnected power system that stretches more than 4,000 km from Port Douglas in Queensland to Port Lincoln in South Australia, and includes a sea-bed cable between Victoria and Tasmania. The NEM comprises five regions that are based on the State boundaries. An overview of the NEM regions is provided in Figure 3.2.

Establishment of the NEM resulted from disaggregation of the vertically integrated government-owned electricity industry into separate generation, transmission, distribution and retail sales sectors in each State. Private ownership has grown significantly since the disaggregation. In 2008, NEMMCO reported private ownership of 61% for generation, 40% for transmission networks, 47% for distribution networks and 62% for retail entities.

The electrical generation capacity and demand in the NEM is indicated in Table 3.1. All measures of scale are assessed against capacity and demand that is "scheduled" – that is, measured by the operation of generation that is centrally controlled through the processes managed by the Australian Energy Market Operator (AEMO) which began operation on 1 July 2009. Prior to this date, the market was operated by the National Electricity Market Management Company (NEMMCO).

Some energy generated is not traded through AEMO systems because the generators involved have a size (nameplate rating) less than 30 MW. However, there are some generators larger than 30 MW that are exempt from this requirement because the energy they export to the grid is below 30MW as the energy is used on-site. Generators below 30 MW nameplate rating can choose to be scheduled.

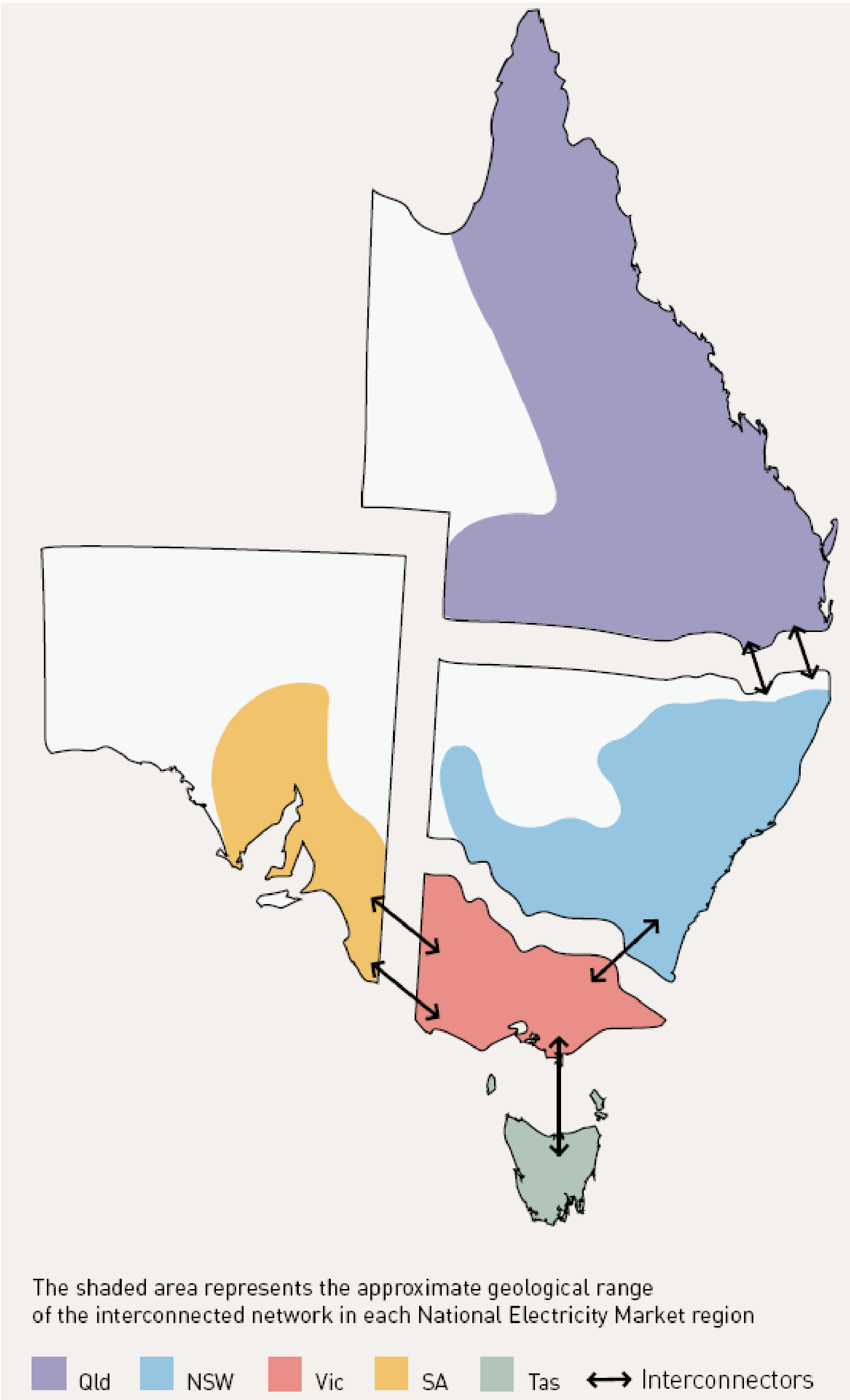


Figure 3.2: Regions of the National Electricity Market (AER, 2008). Reproduced under licence from AER.

Table 3.1: Generating capacity, peak demand and energy demand by NEM region

Region	**Scheduled generating capacity [a] (MW, summer 2008-09)**	**Record peak demand (MW)**	**Scheduled energy demand [b] (GWh, 2007-08)**
New South Wales	15,670	14,289 (winter 2008)	74,310
Queensland	11,100	8,611 (summer 2006-07)	48,134
Victoria	9,786	10,494 (summer 2008-09)	47,819
South Australia	3,754	3,383 (summer 2008-09	12,704
Tasmania	2,455	1,736 (winter 2007)	10,020
NEM total	**42,765**	**34,416 (winter 2008)**	**192,987**

[a] Nameplate rating of generating units that are registered as "scheduled".
[b] Sent-out energy from scheduled generating units.
Source: NEMMCO (2008).

Trading between electricity producers and electricity consumers occurs through a gross pool spot market where the output from all generators is aggregated and scheduled to meet demand through a centrally-coordinated dispatch process operated by AEMO on a five-minute (dispatch interval) cycle. At the start of each dispatch interval, the National Electricity Market Dispatch Engine (NEMDE) determines the least cost combination of generation to meet forecast demand for the forthcoming five-minute period taking account of, amongst other things:

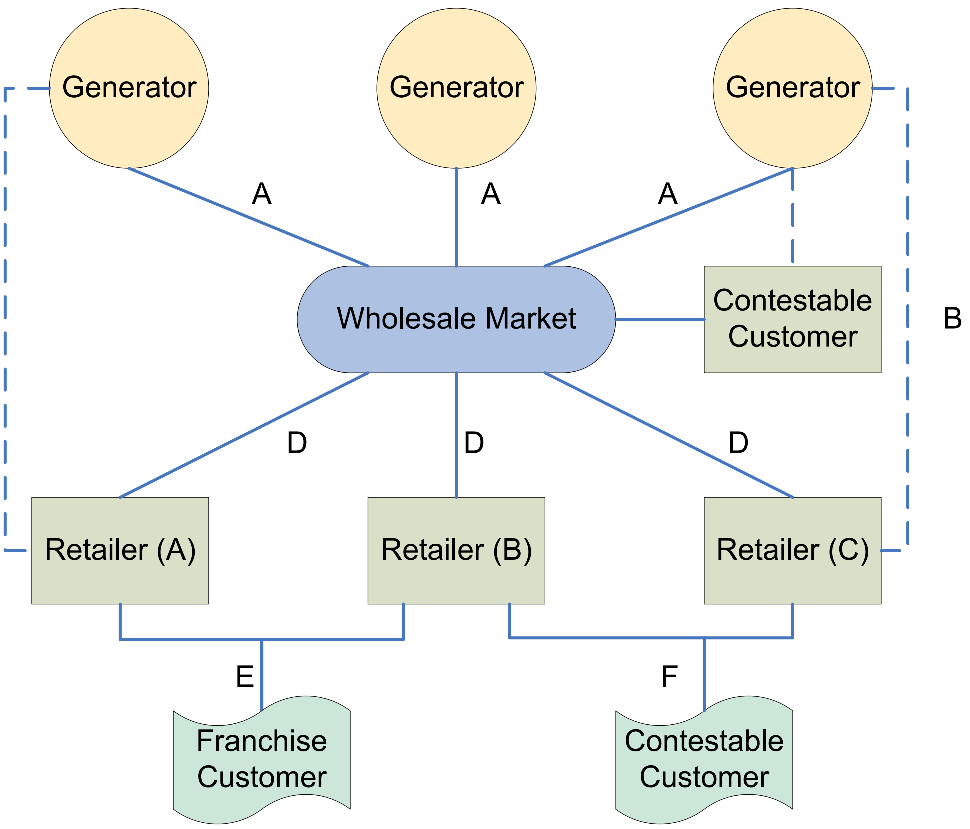
- The latest offers (MWs and $/MWh) to generate energy from all scheduled generators
- The ability of each generating unit to change its MW output – that is, ramp rates (the rate of change the technology can reliably provide expressed in MW/min)
- The ability of the transmission network to manage power flows – that is, network constraints, and
- Electrical losses created by the transport of energy based on predetermined loss factors in the transmission (MLF) and distribution systems (DLF).

Prices for energy are determined on a region-by-region basis every five-minutes. The spot price is defined as the marginal cost of supplying an additional unit of energy to a designated reference point in the region; the regional reference node (RRN) – that is, the next unit of energy not taken. Settlement of energy market obligations is on the basis of liabilities accrued over a 30-minute trading interval that comprises the six five-minute dispatch intervals ending on the hour and the half-hour. The price for energy in a trading interval, the RRP, is determined as the arithmetic average of the six dispatch interval spot prices. Metered energy delivered and consumed in each trading interval is multiplied by the RRP to determine settlement liabilities. AEMO will collect money from retailers and forward payment to generators on this basis.

Because the spot price can be volatile, market participants – generators, retailers and direct wholesale customers (e.g. smelters) – manage their exposure to spot market prices by entering into "hedge" contracts. These contracts can be of many different forms (e.g., swaps, caps, options or a combination of the three). Trading in contracts is not centrally managed and is considered to be off-market or over-the-counter (OTC). The combination of the spot and contract markets provide market participants with the necessary flexibility to manage their operations, and incentives for investors to commit capital to the development of new generating capacity.

All NEM regions except Tasmania have full retail contestability. From 1 July 2009, the only customers in Tasmania that are not contestable will be those whose energy usage is below 150 MWh/year. The mainland experience of retail contestability has been quite favourable with reasonably strong rates of "churn" (transfer from one franchise area retailer to a competitor). However, given the homogenous nature of energy, churn is often driven by passive, rather than active choice and so is sometimes considered an imperfect measure of market competition.

A summary of the energy trading arrangement detailed above are provided in Figure 3.3.



A – Energy from the centralised generators bid into the wholesale market and transmitted via the tranmission network
B – Bilateral financial contracts between generators and retailers
C – Bilateral financial contracts between generators and contestable customers (licensed participants in the NEM)
D – Retailers or contestable customers purchasing in the wholesale market
E – Retailers supplying monopoly customers via regulated distribution networks
F – Retailers competing for contestable customers via access to regulated distribution networks

Figure 3.3: NEM energy and financial flows (South Australian Government, 2009). Reproduced with permission from the South Australian Government, Annual Report for the Year ended 30 June 1998 - Audit Overview, Part A.4, Pg A.4 - 30

Management of the trading of energy is only part of the challenges of operating an electricity market and a power system. Separate mechanisms are in place to manage security and reliability within the power system and the market.

The security of the power system largely depends on the management of a range of ancillary services that control power system voltage, power system frequency and network loading. These services are deployed in a manner that complements the operation of the dispatch process. Relevant ancillary services are as follows:

Voltage control: The National Electricity Rules (NER) define the voltage standards within which the power system is to be operated, with control of voltage effected through the deployment of sources of reactive power. Network Service Providers (NSPs) source reactive power through: a) generator performance standards and connection agreements; and b) Network Service Provider (NSP) owned infrastructure. AEMO can also procure additional reactive power ancillary service from generators.

Frequency control: Power system frequency is managed in accordance with standards established by the Australian Energy Market Commission (AEMC) Reliability Panel and is maintained within control bands by the matching of supply and demand. Any imbalance in supply and demand is corrected through the deployment of frequency control ancillary services (FCAS), which are delivered to the NEM via a market managed by AEMO. There are two broad categories of FCAS:

- **Regulation FCAS** – recruited to manage, within a five-minute dispatch interval, the effects of: a) load forecasting error; or b) dispatch error by scheduled units, and
- **Contingency FCAS** – recruited to be deployed following credible contingency events to (as required): a) arrest the change in frequency; b) stabilise the frequency; and c) aid the recovery of frequency to the normal operating band.

Each of the above services would be procured in the form of “frequency raise” (energy injection) and “frequency lower” (energy withdrawal). FCAS markets operate on a five-minute cycle and the dispatch of frequency control services are co-optimised with the dispatch of the energy spot market – that is generators can simultaneously provide both energy and frequency control service. The dispatch process finds the most cost effective way of simultaneously meeting all energy and frequency control requirements for each five-minute dispatch interval. FCAS markets are priced and settled in a manner similar to that of the energy spot market.

Network loading control: In order to ensure network elements are always managed within their technical limits, NSPs and AEMO can procure services that inject or withdraw energy from specific points within the power system to avoid the overloading of network elements.

An important part of the structure of the NEM is the mechanism by which the market ensures energy supply is able to meet energy demand at all times. The market has been deliberately designed to provide incentives for investors to develop new generating capacity. “Energy-only market” design means that generation is remunerated only for the provision of energy and is not remunerated for having capacity in reserve for deployment at peak times.

In an energy-only market, the risk of failure of supply is managed by retailers’ response to their exposure to high price events. In the NEM, the price cap is currently set at $10,000/MWh and is scheduled to increase to $12,500/MWh from 1 July 2010. The greater the duration, frequency and magnitude of high price events, the higher the value of spot market revenue during peak times and the higher the risk to retailers that buy on the spot market and sell at fixed rates. By setting the market price cap sufficiently high, the value of spot market trade at peak times is sufficiently large to encourage either:

- Retailers to enter into off-market contracts that will underwrite investment in generation (base-load, mid-merit or peaking as appropriate), or
- Investors to develop generation that will earn sufficient revenue during peak (and other operating times) times to recover the capital and operating costs of the relevant plant.

Retailers will make their own assessments of the optimal level of contracting consistent with their views on price and demand volatility and the value of unhedged energy to which they might be exposed. The greater the value of unhedged energy to which a retailer might be exposed, the more inclined they will be to seek an energy contract that reduces their exposure and hence underwrite additional generation capacity. Where overall contracted generation capacity exceeds system needs, the cost of that capacity will be passed through to customers who seek fixed price contracts for their energy.

Because of this, it is sometimes said that an energy only market relies on, among other things, low levels of vertical integration and high levels of contract liquidity to ensure incentives are not distorted.

Proponents of an energy-only market believe that market participants are best placed to establish the most efficient form of risk management and, hence, to minimise the amount of the premium ultimately added to energy prices charged to customers who seek fixed price contracts.

Although the NEM is notionally an “energy-only” market with no payment for capacity, if the market fails to deliver sufficient capacity such that there is a high probability of the market breaching the standard for a maximum level of unserved energy (currently set at 0.002% of annual energy system consumption), AEMO could intervene in the market to contract directly with additional sources of energy.

Parties that participate in the NEM’s systems for spot market settlement and dispatch are required to be formally registered. The registration process is the mechanism by which AEMO ensures that each relevant party complies with requirements for:

- Operating plant within appropriate technical limits
- Maintaining the ability to respond, with acceptable accuracy and timeliness, to dispatch instructions associated with energy and FCAS targets
- Metering the delivery and use of energy
- Management of financial obligations and operation within approved credit limits.

By becoming registered, parties are automatically bound by relevant provisions of the NER which are subject to enforcement by the Australian Energy Regulator (AER).

Planning of transmission network development is a function of the newly formed National Transmission Planner (NTP) within AEMO. The primary objective of the NTP function is to produce an annual National Transmission Network Development Plan (NTNDP) that is to be strategic and long term, looking out 20 years at a minimum. The scope of the NTNDP includes all transmission elements that are part of, or materially affect, the energy transfer capacity in key transmission corridors. The NTNDP is required to map out development strategies under a range of scenarios for the efficient delivery of transmission capability across those corridors. Network development strategies to be recommended may involve a combination of physical network augmentation and non-network solutions (forms of ancillary service).

The NTNDP and the shorter-term investment planning activities of the TNSPs (generally with a five-year horizon) are expected to work to complement each other in promoting efficient outcomes for consumers.

Planning of network development at the distribution level is managed by Distribution Network Service Providers (DNSPs) but is subject to regulatory oversight from the AER.

The Wholesale Electricity Market (WEM) in the South West Interconnected System (SWIS)

Due to its large geographical size, industry and demographics, Western Australia's electricity is served from several distinct systems (see Figure 3.4), those being the South West Interconnected system (SWIS), the North West Interconnected system (NWIS) and 29 regional isolated power systems (AER, 2008).

In 2006, the Western Power Corporation which supplied electricity in the southern region of Western Australia was restructured into four separate corporations (westernpower, 2009) those being:

- Synergy - responsible for the sale of electricity within the SWIS - the area bound by Kalbarri, Kalgoorlie and Albany
- Horizon Power - the regional business responsible for the generation, transport and sale of electricity in areas outside of the SWIS
- Verve Energy - responsible for power generation within the SWIS, and
- Western Power - responsible for operating, maintaining and expanding the electrical transmission and distribution network in the SWIS.

The Wholesale Electricity Market (WEM) operates in the SWIS and covers the shaded area shown in Figure 3.4. The SWIS began its transition to the WEM in 2004, with the full market rules applying from September 2006.

The NWIS remains a vertically integrated system for transmission, distribution and retail run by Horizon Power. Generation capacity in the region is around 400 MW.

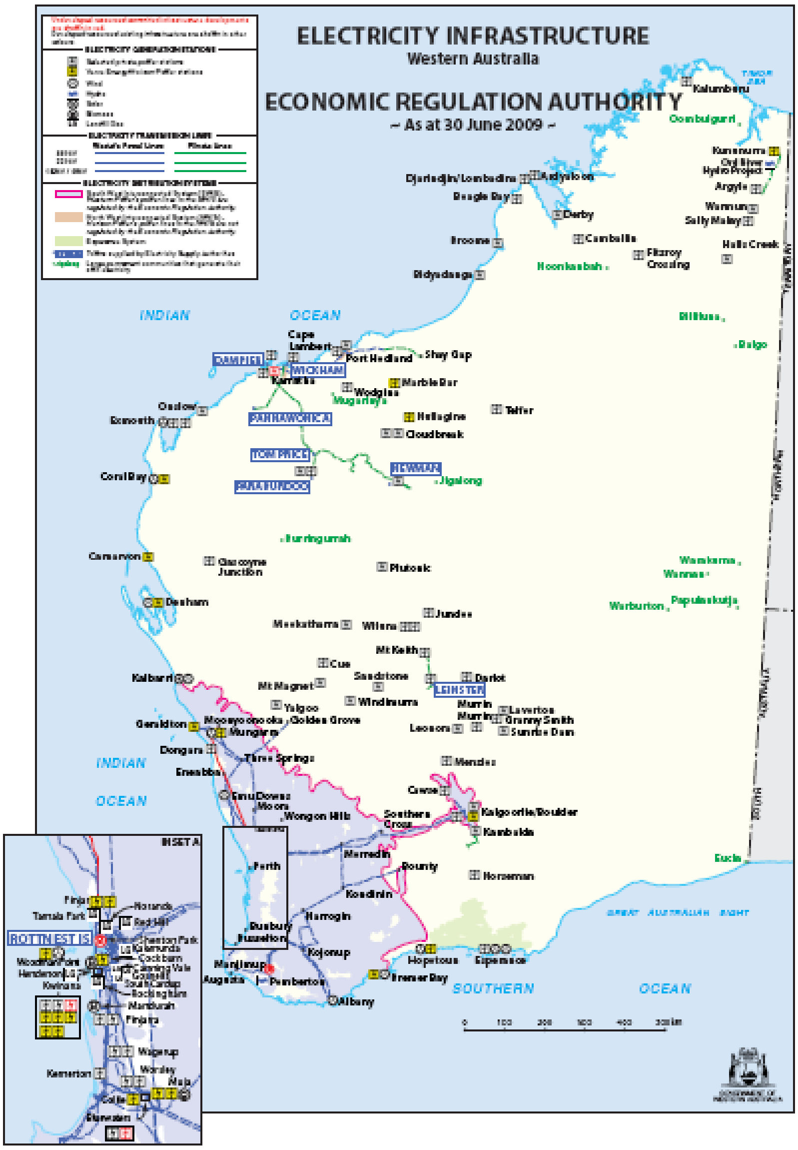


Figure 3.4: Electricity infrastructure in Western Australia (ERA, 2009). Reproduced with permission from the Western Australian Land Information Authority. www.landgate.wa.gov.au

The electrical generation capacity and demand of the WEM is outlined in Table 3.2. The market is clearly much smaller than the NEM but considerably larger than the NWIS.

Table 3.2: Generating capacity, peak demand and energy demand in the WEM (Western Australia)

Installed generating capacity (MW, June 2009)	Record peak demand (MW)	Sent-out energy (GWh, 2007-08)
4,486	3,515 (summer 2008-09)	16 ,441

Sources: IMOWA (2009a), IMOWA (2009b)

Trading of energy in the WEM is effectively separated by: bilateral long-term contracting; a formal market based trading in the short term; and a balancing mechanism.

Long-term contracting: Market participants (i.e., generators and retailers) will conduct bilateral trades for energy for each 30-minute trading interval potentially years ahead of dispatch. Bilateral contracts comprise around 95 per cent of all energy traded. Trading of this nature is not regulated and counterparties to bilateral contracts are responsible for financial settlement. However, contract positions must be advised to the Independent Market Operator (IMO) as formal "resource plans" as an input to the balancing mechanism.

Short term energy market (STEM): The IMO operates the STEM as a formal mechanism for market participants to shape contract positions for each 30-minute trading interval of the forthcoming scheduling day. Each day, participants will advise the IMO of their bilateral contract position via their resource plans and make bids to buy and offers to sell electricity in each trading interval on the following day relative to its bilateral position. For example:

- A generator may offer to supply increasing quantities into the market, beyond its contractual position, as the price rises. It may also bid to purchase energy where the price is less than its own production cost, and
- A retailer may bid to purchase increasing quantities as the price moves lower or less if the price increases.

The IMO will combine all of the offers and bids for all participants in the form of supply and demand curves to establish a market clearing STEM price for each 30-minute trading interval. STEM trades comprise somewhere between 0 and 4 per cent of energy traded. Settlement of trades through the STEM is managed by the IMO.

Balancing mechanism: After positions from all long term contracts and STEM trades have been compiled, the IMO operates a balancing mechanism that takes account of:

- The inevitable real-time variations in generation and customer demand, and
- Intermittent generation, such as wind farms, whose power output is not required to follow a production schedule.

Market participants submitting resource plans must specify pay-as-bid balancing prices to be used as the basis for compensation if asked by System Management – a financially ring-fenced part of the network operator (westernpower) – to deviate from their resource plans. System Management will schedule resources from the government owned generator (Verve Energy) around advised resource plans, but it may issue dispatch instructions to other market generators and to curtailable or dispatchable loads if it cannot otherwise maintain security and reliability. After the trading day, the IMO will determine "administrative" balancing prices to apply for unscheduled deviations from schedules, with those non-Verve Energy facilities given dispatch instructions being settled (to the extent they obey) at their pay-as-bid balancing prices.

In January 2005, Western Australia extended retail contestability to electricity customers using at least 50 MWh per year. Customers below this threshold who are connected to the SWIS are served by Synergy, the State-owned energy retailer. Most customers outside the SWIS are served by Horizon Power. Currently, around 60 per cent by volume of the Western Australian market is contestable.

The Western Australian Government has not set an implementation date for full retail contestability in electricity. The *Electricity Corporations Act 2005* requires the Minister for Energy to undertake a review in 2009 to consider a further extension of contestability. While full contestability has not commenced, there has been some degree of retailer switching by large market customers.

The System Management function in the WEM is required to procure voltage control and frequency control services sufficient to maintain the secure management of the power system. The forms of these services are very similar to those described above as applying in the NEM.

Dispatch support: This service ensures voltage levels around the power system are maintained – analogous to reactive power ancillary service in the NEM – and includes services required to support the security and reliability of the power system that are not covered by other ancillary services

Load following: Corrects any moment-to-moment imbalance in supply and demand – analogous to regulation FCAS in the NEM

Spinning reserve: This service holds capacity in reserve to respond rapidly should another unit experience a forced outage – analogous to contingency "raise" FCAS in the NEM. The capacity would include on-line generation capacity, dispatchable loads and interruptible loads (i.e., loads that respond automatically to frequency drops)

Load rejection reserve: This service requires that generators be maintained in a state in which they can rapidly decrease their output should a system fault result in the loss of load – analogous to contingency "lower" FCAS in the NEM. This service is particularly important overnight when most generating units in the system are operating at minimum loading and have no capability to decrease their output in the time frame required.

An important feature of the WEM is the reserve capacity mechanism – that is, the WEM operates as a "capacity market" compared to the NEM "energy-only market". Rather than retailers making their own decisions on how to most efficiently deliver reserve to manage their exposure to volatile market prices (with a high cap), the capacity-based mechanism in the WEM imposes a reserve margin that is likely to be larger than that which would occur in an "energy-only market". In this case, overall market costs are likely to be higher with a capacity mechanism, however the system reliability is generally better. Capacity-based markets typically have a low price cap because they do not need price volatility to encourage investment (IMOWA, 2006). The STEM currently has a price cap of $286/MWh.

In the WEM, the annual reserve capacity requirements (RCRs) will be specified by the IMO based on an annual "statement of opportunities" that considers the capacity requirements of the SWIS for the next 10 years. Each market customer (retailer) will be allocated a share of the RCR, and will be required to secure "capacity credits" to cover that requirement. A capacity credit is effectively installed capacity or interruptible load registered with the IMO. A market customer can either procure capacity credits bilaterally from qualifying capacity credit suppliers, or it can purchase them from the IMO. The IMO may run an annual auction to procure capacity credits for on-sale to market customers if the requirement for capacity credits is not met through bilateral trade.

Proponents of capacity markets believe that the regulated reserve margin provides an assurance that customers will not be faced with loss of supply due to the possible failure of the market to: a) effectively plan to deliver the capacity the market requires for reliable day-to-day operation; or b) have reserve capacity in place should major system events remove some capacity from the market.

The WEM has a similar process for registration of, and compliance by, rule participants as applies in the NEM, but with regulatory oversight provided by the Economic Regulation Authority.

Each year the IMO prepares a *Statement of Opportunities* outlining projected capacity requirements for the SWIS and projected capacity shortfalls for each of the next ten years. This report indicates opportunities for supply and demand augmentations that would improve the security and reliability of the power system. The IMO does not consider transmission planning, as Western Power (the network owner) will address this, but the *Statement of Opportunities* may make use of transmission planning information provided by Western Power.

To develop the *Statement of Opportunities*, the IMO has authority to request information from rule participants pertaining to their expected future system usage and available generation, demand side and transmission capacities. The IMO also takes into account probable new projects where appropriate.

The IMO will determine the capacity required in each year so as to:

- Meet the forecast peak demand after the outage of the largest generation unit and while maintaining some residual frequency management capability (e.g., 30 MW), in nine years out of ten
- Limit energy shortfalls to 0.002% of annual energy system consumption.

Network control services are services provided by distributed generation or demand side management that can be substitutes for an upgrade to a transmission or distribution network. Under the *Electricity Networks Access Code 2004*, network operators will inform the IMO where such opportunities exist and the IMO will run a competitive tender for procurement of the services. Where the tender response of a distributed generation or demand side management option is less expensive than the transmission upgrade, the IMO will enter into a ten-year contract with the successful tender respondent, and will recover the costs of the contract from the network operator where the normal market processes do not provide sufficient revenue.

The network control service contract allows system management to issue real-time dispatch instructions to the facility as required, within the capacity and availability limits of the contract. For its part, the facility providing network control service receives guaranteed minimum revenue and is not precluded from participating in the energy market. The rules do require, however, that any facility contracted to provide network control service must seek certification for reserve capacity. The reserve capacity rules ensure that to the extent such a facility is certified, it will be issued capacity credits and settled at the prevailing reserve capacity price. This feature means that to the extent that reserve capacity payments are made to the facility, the network control service payment required of the network operator can be reduced.

The Darwin and Katherine Interconnected System (DKIS)

The Northern Territory's electricity industry is small, reflecting its population of around 215,000. There are three relatively small regulated systems: Darwin-Katherine, Alice Springs and Tennant Creek (Figure 3.5).

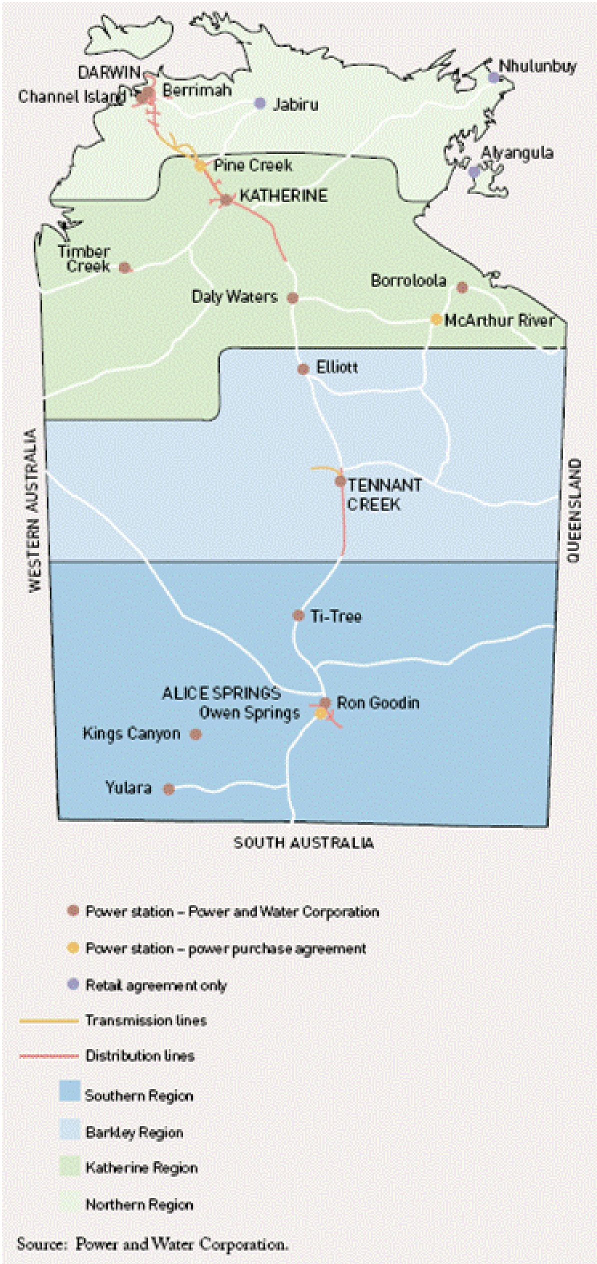


Figure 3.5: The Darwin and Katherine interconnected system (AER, 2008). Reproduced under licence from AER

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Given the scale of the Northern Territory market (see Table 3.3), it has not been considered feasible to establish a wholesale electricity spot market. Rather, the Territory uses a 'bilateral contracting' system in which generators are responsible for dispatching the power their customers require.

Table 3.3: Generating capacity, peak demand and energy demand Northern Territory system

Region	**Generating capacity (MW, June 2008)**	**Peak demand (MW, 2007-08)**	**Energy demand (GWh, 2007-08)**
Darwin – Katherine	356.5	261	1,416
Alice Springs	71.1	54	229
Tennant Creek	16.4	7	80

Source: NTUC (2009)

The industry is dominated by a government-owned corporation, Power and Water, which owns the transmission and distribution networks. Currently, Power and Water is the monopoly retail provider and generator and is also responsible for power system control. There are six independent power producers in the resource and processing sector that generate their own requirements and also generate electricity for the market under contract with Power and Water.

Retail competition is scheduled to be introduced from April 2010.

The Utilities Commission of the Northern Territory (NTUC, 2009) has indicated that it is not satisfied with the existing policy framework and has recently stated:

> *The policy framework within which Power and Water operates contains basic contradictions; Power and Water is structured as a commercial, return-oriented business entity, but has implicit obligations to operate as if it were still a public authority, responsible for deciding matters of public policy interest. While it is important to acknowledge that in practice it is impossible to fully separate commercial and public policy interests (it is more in the nature of a continuum), nevertheless, the point of separation should be explicit and transparent, and be capable of answering the key public interest questions, such as what level of reliability is considered to be satisfactory, how this is expressed in operational power system terms, and who is accountable and by what means. … The central question is – does the current institutional and regulatory environment within which Power and Water operates support and incentivise good management practices? In the Commission's view the answer is – not as well as it could.* NTUC (2009)

In light of this position, it appears that change to current arrangements is likely. However, the Northern Territory Government has yet to indicate the direction, extent or timing of any change.

Market comparison

The previous sections outlined the market structures of the NEM, WEM and DKIS. In summary, the NEM is a gross pool in which the sale of all wholesale electricity occurs in a spot market. NEM participants also enter into hedge contracts to manage spot market risk. Generators are paid only for the energy sent out and a high price cap is meant to provide incentive to invest in generation capacity and/or establish demand side responses (AER, 2008).

In contrast, energy in the WEM is mainly traded through bilateral contracts outside the pool. These may be entered into years, weeks or days prior to supply. Before the trading day, generators must inform the IMO of the quantity of energy to be sold under bilateral contracts and to whom it will be sold so the IMO can schedule that supply. The WEM includes both an energy market (STEM) and a capacity market. The capacity market is meant to provide incentive to meet peak demand by providing sufficient revenue without the market experiencing high or volatile prices (AER, 2008).

3.2.2 Natural gas

Wholesale gas markets involve the sale of gas by producers, mainly to energy retailers that on-sell it to business and residential customers. In addition, some major industrial, mining and power generation customers buy gas directly from producers in the wholesale market.

In Australia, wholesale gas is mostly sold under confidential, long-term *take or pay* contracts. These clauses require the purchaser to pay for a minimum quantity of gas each year regardless of the actual quantity used. Prices may be reviewed periodically during the life of the contract. Between reviews, prices are typically indexed (often to the consumer price index). Contract prices therefore do not tend to fluctuate on a daily or seasonal basis. There is however considerable scope for significant price differentials between contracts due to variations in term, volume, volume flexibility and penalties associated with failure to supply (AER, 2008).

Wholesale market arrangements must take account of the physical properties of natural gas and transmission pipelines:

- Unlike electricity, gas takes time to move from point to point. In Victoria, gas is typically produced and delivered within 6 – 8 hours because most demand centres are within 300 kilometres of gas fields. But gas delivered from the Cooper Basin into Sydney, or from the Carnarvon Basin into Perth, can take 2 – 3 days because the gas must be transported over much longer distances
- Natural gas is automatically stored in pipelines (known as *linepack*). It can also be stored in depleted reservoirs or in liquefied form, which is economic only to meet peak demand or for use in emergencies
- Natural gas pipelines are subject to pressure constraints for safety reasons. The quantity of gas that can be transported in a given period depends on the diameter and length of the pipeline, the maximum allowable operating pressure and the difference in pressure between the two ends.

These features make it essential that daily gas flows are managed. In particular, deliveries must be scheduled to ensure that gas produced and injected into a pipeline system remains in approximate balance with gas withdrawn for delivery to customers. To achieve this, gas retailers and major users must estimate requirements ahead of time and nominate these to producers and pipeline operators, subject to any pre-agreed constraints on flow rates and pipeline capacity (AER, 2008).

Each day, producers inject the nominated quantities of gas into the transmission pipeline for delivery to customers. There are typically short-term variations between a retailer's nominated injections and their actual withdrawals from the system, creating imbalances. A variety of systems operate in Australia for dealing with physical imbalances, as well as financial settlements to address imbalances between the injections and withdrawals of particular shippers (AER, 2008).

In most jurisdictions, physical balancing is managed by pipeline operators, while financial settlements for system imbalances are managed by independent system operators: VENCorp (Victoria and Queensland), REMCo (South Australia and Western Australia) and the Gas Market Company (New South Wales and the ACT). On 1 July 2009, these responsibilities were transferred to AEMO.

Victorian wholesale gas market

In Victoria, AEMO operates a gas spot market to manage system imbalances and constraints on a daily basis. Participants bid into the spot market on a daily basis via a bulletin board. Bids may range from $0 per GJ (the floor price) to $800 per GJ (the price cap).

Market participants (mostly retailers) inform AEMO of their nominations for gas one and two days ahead of requirements. At the beginning of each day, schedules are drawn up that set out the hourly gas injections into and withdrawals from the system. The schedules rely on information from market participants and AEMO, including demand forecasts, bids, conditions or constraints affecting bids, hedge nominations and AEMO's modelling of system constraints.

At the beginning of each day, AEMO stacks supply offers and selects the least cost bids to match demand across the market. This establishes a spot market clearing price. As the Victorian market is a net market, this price applies only to net injections or withdrawals (the difference between contracted and actual amounts).

Overall, gas traded at the spot price accounts for around 10 to 20 per cent of wholesale volumes in Victoria, with the balance sourced via bilateral contracts or vertical ownership arrangements between producers and retailers.

In effect, the spot market provides a clearing house in which prices reflect short-term supply – demand conditions, while underlying long-term contracts insulate parties from price volatility. Nevertheless, a comparison of the likely spot market price with underlying contract prices allows a retailer to choose to take a position to modify its own injections of gas and then trade gas at the spot price.

Until 2007, a single price applied in each 24-hour period without reference to system constraints or unforeseen events. Reforms to the gas market in February 2007 introduced rescheduling and rebidding at five defined time intervals over the day. The reforms aim to enhance flexibility, create incentives to respond to the spot price and provide clearer and more certain pricing signals. They also bring the gas market into closer alignment with the NEM.

Occasionally, AEMO needs to schedule additional injections of gas (typically LNG) that have been offered at above market price to alleviate short-term constraints. Market participants that inject the higher priced gas receive ancillary payments. These are recovered from uplift charges paid, as far as practicable, by those market participants whose actions resulted in a need for injections. A user's authorised maximum interval quantity (AMIQ) is a key allocation factor in determining who must contribute uplift payments to pay for this gas (AER, 2008).

In particular, market participants that exceed their AMIQ on a day when congestion occurs may face uplift charges, which provides price signals to gas users to adjust their usage patterns.

Market participants with AMIQ credits also have higher priority access to the pipeline system if congestion requires the curtailment of some users to maintain system pressure. This has not been necessary in recent years as sufficient gas (including LNG) has been available to support all users on the system. Nevertheless, in the event of severe congestion, those users without AMIQ must reduce their usage ahead of authorised users. A party can acquire AMIQ certificates by injecting gas into the Victorian system at Longford or by entering a contract with the Victorian Transmission System (VTS) owner, GasNet (AER, 2008).

Short-term trading market

The MCE intends to extend transparent wholesale markets to other States, initially to New South Wales and South Australia in mid-2010. The proposed market is intended to facilitate daily trading by establishing a mandatory price-based balancing mechanism at defined gas hubs.

The rationale for the market stems from concerns that the current gas balancing mechanisms in New South Wales and South Australia present barriers to retail market entry and impede gas supply efficiency. In particular, the current mechanisms create substantial financial exposures that are disproportionate to underlying costs. New entrants have faced difficulties acquiring appropriate hedging to manage these risks. The issues are especially pertinent for Sydney and Adelaide, which are sourced by multiple transmission pipelines (AER, 2008).

A daily market clearing price will be determined at each hub based on bids by gas shippers to deliver additional gas. The difference between each user's daily deliveries and withdrawals of gas will then be settled by the market operator at the clearing price. The mechanism is aimed at providing price signals to shippers and users to stimulate trading — including secondary trading — and demand-side response by users.

The short-term trading market is intended to operate in conjunction with longer-term gas supply and transportation contracts. It will provide an additional option for users to buy or sell gas on a spot basis without needing to enter delivery contracts in advance. It will also allow contracted parties to manage short-term supply and demand variations to their contracted quantities (AER, 2008).

Australian Energy Market Operator (AEMO)

It is envisaged that the AEMO will operate both the gas market bulletin board and the short-term trading market. It is also envisaged that the AEMO will publish an annual Gas Statement of Opportunities (GSOO) — a National gas supply and demand statement — of a similar nature to the annual Statement of Opportunities currently published for electricity (AER, 2008).

The GSOO is intended to provide information to assist gas industry participants in their planning and commercial decisions on infrastructure investment. The Gas Market Leaders Group commenced work on the design of the GSOO in 2008 (AER, 2008).

3.2.3 Retail prices

Electricity

The previous two subsections detailed the mechanisms which determine the wholesale price of electricity and gas. With the exception of some large energy users, most end users buy their electricity from an energy retailer. The retailer buys electricity at the price determined by the wholesale market (ignoring strategies to reduce their exposure to market fluctuations) and on-sells the electricity to the end users. The retailer pays the transmission and distribution companies' for use of system charges (TUoS and DUoS) and the generator for the electricity produced, it also pays AEMO charges associated with being a retailer. The generator transactions are settled through AEMO, while the distributors are paid directly by the retailer.

Because the distribution companies are essentially monopoly operators, their revenue is determined through the setting of price or revenue caps depending on the State in which they operate. Table 3.4 details which States operate under which regime. The caps are determined by the AER which has recently taken over the role of economic regulation from State based entities.

Weighted average price caps set a ceiling on a weighted average of distribution tariffs. The DNSP can adjust individual tariffs as long as the weighted average remains below the ceiling. There is no cap on total revenue which is governed by the total throughput of energy supplied to end users (AER, 2008).

Revenue caps set the maximum revenue that a network business can earn during a regulatory period. The tariff price can vary so long as the total revenues do not exceed the cap. This method is used to regulate transmission networks (AER, 2008).

A maximum average revenue cap sets a ceiling on the average revenues during the regulatory cycle. Total revenue is capped each year at the average revenue allowance multiplied by the actual energy sales. Tariffs are required to be set to comply with this constraint (AER, 2008).

An average revenue control links the amount of revenue for a DNSP with the volume of electricity sold. Revenue is not capped and may vary in proportion to energy sales. Tariffs can vary provided that total revenues do not exceed the average (AER, 2008).

Table 3.4: Use of system charging methods

State / Territory	DUoS pricing method	Regulator (*Prior to AER)
Queensland	Revenue Cap	Queensland Competition Authority*
New South Wales	Weighted Average Price Cap	Independent Pricing and Regulatory Tribunal*
Australian Capital Territory	Maximum Average Revenue Cap	Independent Competition and Regulatory Commission*
Victoria	Weighted Average Price Cap	Essential Services Commission Victoria*
South Australia	Average Revenue Control	Essential Services Commission of South Australia*
Tasmania	Revenue Cap	Office of the Tasmanian Energy Regulator*
Western Australia	Revenue Cap	Economic Regulation Authority
Northern Territory	Weighted Average Price Cap	Utilities Commission

The transmission and distribution prices are set for five-year periods referred to as "determinations". At the end of each cycle, the distribution companies submit to the regulator (AER for the NEM based States) a proposal for energy charges for the next cycle which provides them with a revenue that accounts for a margin after expenditure to operate, maintain and upgrade their systems. The regulators review and amend these submissions as necessary and set a final price it believes reflects the operation of the business as if it had operated in a contestable market.

For small to medium end users the retailer sets a fixed price generally for peak and off-peak periods. Some retailers may also have a price set for shoulder periods (on the peak margins). The price is formed from a combination of the regulated DUoS and TUoS fees, retail margin and operation and the wholesale price. The total price may be regulated for consumers who are on non-contestable tariffs but in general they vary by retailer as part of full retail contestability.

Figure 3.6 provides an illustrative break down of the retail cost on average (noting variations in percentage occur from the price set by the wholesale market) for the NEM. It is apparent from this figure that the transmission and distribution charges form the largest component (approximately 60%) of the cost. This reflects the large capital expenditure (see Table 3.5) required to provide the 57,200 km of transmission cables and 827,700 km of distribution lines in Australia (ESAA, 2008). As a comparison, around $10.2 billion is traded in electricity on the NEM each year (NEMMCO, 2008).

Avoiding these transmission and distribution costs is one potential major source of value for distributed energy. It can do this by either decreasing or potentially bypassing the need for network augmentation.

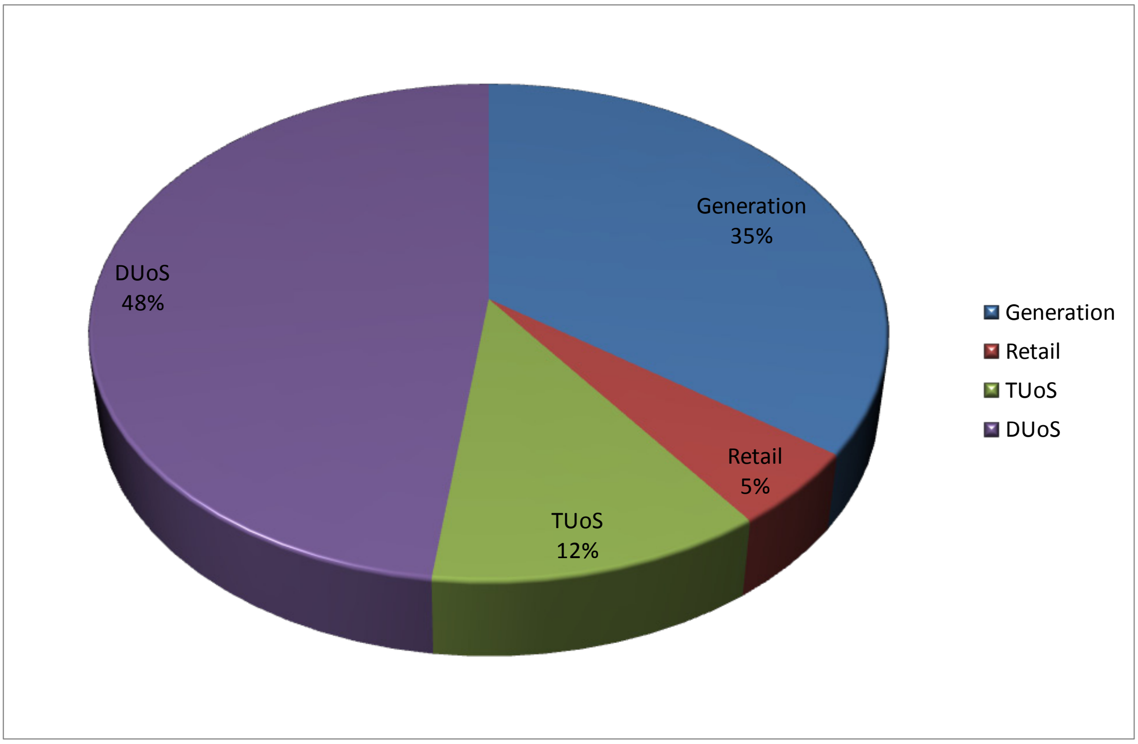


Figure 3.6: Illustrative components of an electricity bill (South Australian Government, 2009). Reproduced with permission from the South Australian Government (2009), Annual Report for the Year ended 30 June 1998 - Audit Overview, Part A.4, Pg A.4 - 30

Table 3.5: Financial value of Australian electricity and natural gas networks (ENA, 2009)

Sector	Number of Businesses	Regulated asset base ($b)	Capital expenditure ($b/yr)	Operational expenditure ($b/yr)
Electricity distribution	15	45.0	4.5	3.1
Electricity transmission	7	15.0	1.6	0.7
Gas distribution	10	7.4	0.5	0.4
Gas transmission	10	2.6	0.1	0.2
Total	42	70.0	6.7	4.4

Natural gas

Similar to electricity, gas retail prices paid by end-users cover the costs of a bundled product made up of gas, transport through transmission and distribution pipelines, and retail services.

While all jurisdictions have introduced full retail competition, New South Wales, Victoria, South Australia and Western Australia continue to regulate gas retail prices for small customers. Typically, host retailers must offer standing contracts to sell gas at default prices based on some form of regulated price cap or oversight. These contracts apply to customers who have not switched to a market contract. Retail gas prices are not regulated in Queensland, Tasmania, the ACT or the Northern Territory.

In setting default prices, jurisdictions take into consideration gas purchase costs, pipeline charges, retailer operating costs and a retail margin. The approach varies between jurisdictions:

- In New South Wales, prices under standing offer contracts are controlled through voluntary agreements with host retailers that limit annual price increases
- Since 2003, the Victorian Government has entered into agreements with host retailers on a pricing structure for default retail prices for households and small businesses. Default arrangements ceased to apply to small businesses from 1 January 2008 and ceased for residential customers from 1 January 2009
- The South Australian regulator (ESCOSA) sets default prices for the host retailer by considering the costs that a prudent retailer would incur in delivering the services
- In Western Australia, gas retail prices for the major distribution systems are capped by regulations. During 2008, the Office of Energy reviewed the level and structure of regulated retail prices.
- The AEMC is reviewing the effectiveness of competition in electricity and gas retail markets to determine whether it is appropriate to remove retail price caps in each jurisdiction.

Figure 3.7 illustrates the components of retail residential gas prices in the mainland State capital cities for typical residential customers in those locations. Total prices range from around $15.50 per GJ in Melbourne to almost $28 per GJ in Brisbane.

Upstream costs associated with the extraction and production of the gas itself account for a relatively small proportion of total cost — between 11 and 21 per cent. Transportation through the high pressure transmission system is the smallest contributor to delivered costs for residential consumers in the capital cities (2 to 7 per cent). The total upstream and midstream costs therefore account for only around 15 per cent of delivered cost to residential customers. For larger industrial users, this proportion rises steadily with scale as the fixed costs associated with downstream services are spread across much larger gas supply volumes.

By far the highest proportion of total cost is associated with the low pressure distribution system (38 to 58 per cent) reflecting the high capital cost to service each customer. The proportionate cost associated with distribution is greatest in Queensland, where average gas consumption per customer is lowest, and conversely, is lowest in Victoria, where average gas consumption per customer is highest. Retailing typically accounts for around 30 per cent of total costs and is relatively uniform across the regions, ranging from $5.50 to $8.00 per GJ.

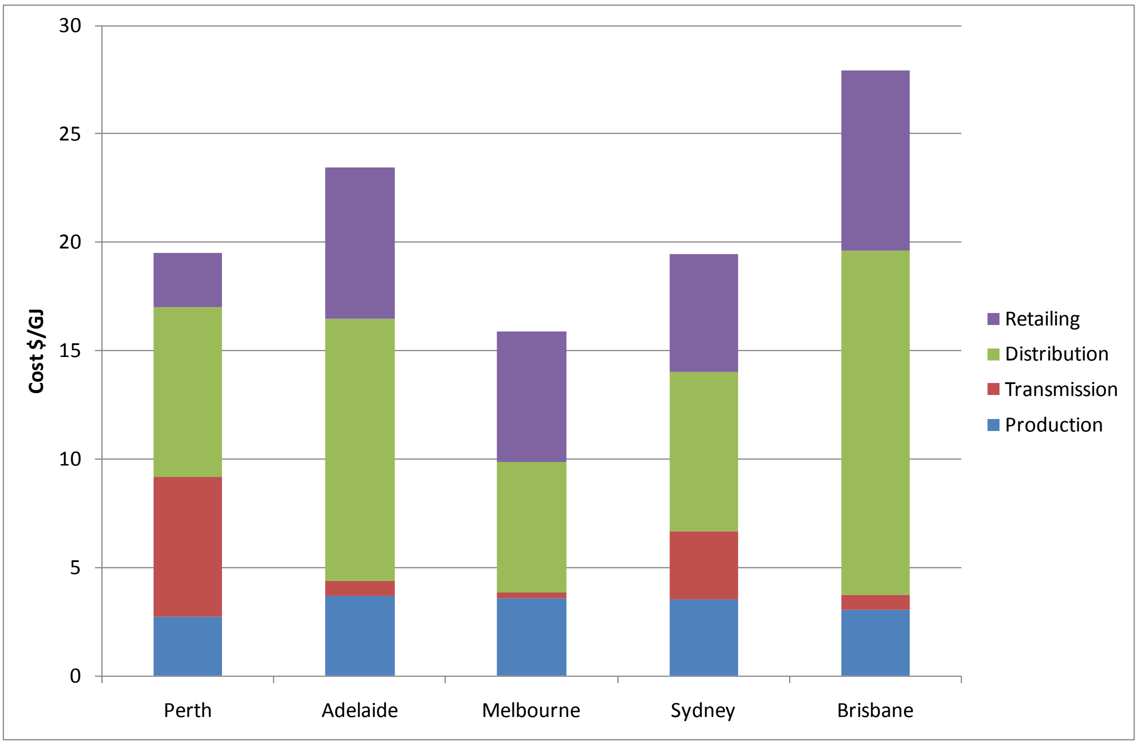


Figure 3.7: Components of retail residential natural gas prices (ACIL Tasman, 2008). Reproduced under licence from AER.

3.3 Smart grids

In Australia and abroad there is a growing movement which believes “smart grids” are the logical progression which will allow the electricity network to function in the most efficient economic manner while supporting environmental and social needs. The Australian Government has recently announced funding for a trial and demonstration of the smart grid concept.

The move towards smart grids is a relatively new concept and was not specifically considered at the outset of this project. However research conducted for this report is relevant to the smart grid concept and we believe the move to smart grids may offer some additional benefits.

A smart grid optimally delivers electricity (and potentially other resources such as natural gas, water, heat etc) from suppliers to consumers using digital technology to save energy, reduce cost and increase reliability. As such, it is a way of addressing energy security and/or global warming issues by:

- Accommodating all forms of energy generation and storage
- Enabling new energy services
- Providing high power quality
- Optimising asset utilisation
- Anticipating and responding to system disturbances, and
- Operating resiliently against attack and natural disaster.

It is important to note distributed energy and smart grids are related but have some fundamental differences. Distributed energy in its most basic form can be implemented without the need for additional communications, metering and network infrastructure. In advanced forms of DE however, additional communications and metering may be used to allow aggregates of DM or DG to be controlled and dispatched which shares a commonality with the smart grid concept. Other network specific measures of a smart grid such as fault detection, isolation and recovery (FDIR), integrated voltage control, and conservation voltage reduction are requirements of a smart grid irrespective of the installation of DE. It should be noted however that their addition may enhance the addition DE to the distribution network.

When considering the value of increased network reliability that smart grids may facilitate, it is useful to consider the cost to businesses caused by supply outages. While somewhat outdated, It is worth noting the reverse situation which is applicable for demand management where load is curtailed, as opposed to supplied with an alternative, local source of generation. For those businesses in the top of the table, the value of not consuming is significantly more than the base value of supply making load curtailment more difficult to justify. However, businesses at the bottom of the table may be more willing to curtail load as the cost of an outage is less. In this way, the table demonstrates how different types of distributed energy may be of more or less value for different types of business. Specifically, for the businesses at the top of the table, a local generation option that ensures supply may be more advantageous, whereas a demand management option where the consumer is compensated for consuming less may be more appropriate for those businesses at the bottom of the table.

Table 3.6 provides an indication of cost (i.e. loss of income) for various types of industry for each dollar spent on electricity, helping to describe the potential value increased energy security can offer. The table clearly shows that maintaining supply is vitally important to a number of industries where the value of the product created is a significantly higher than the value of the energy purchased.

It is worth noting the reverse situation which is applicable for demand management where load is curtailed, as opposed to supplied with an alternative, local source of generation. For those businesses in the top of the table, the value of not consuming is significantly more than the base value of supply making load curtailment more difficult to justify. However, businesses at the bottom of the table may be more willing to curtail load as the cost of an outage is less. In this way, the table demonstrates how different types of distributed energy may be of more or less value for different types of business. Specifically, for the businesses at the top of the table, a local generation option that ensures supply may be more advantageous, whereas a demand management option where the consumer is compensated for consuming less may be more appropriate for those businesses at the bottom of the table.

Table 3.6: Indicative industry costs ($US/kWh) of power outages (Willis and Scott, 2000)

Industry type	**Cost (USD)**
silicon integrated chip manufacturing	16.25
air traffic control	11.09
hosiery weaving (robotic loom)	8.22
packaging	5.02
bulk plastics refining	4.34
carpet filament manufacturing plant	3.37
air compressor/bottling	2.60
weaving	1.94
catalogue distribution centre	1.37
cement factory	0.91
scrap metal recycling	0.34

Figure 3.8 provides a conceptual model of a smart grid which incorporates minigrids. The minigrid is one of a number of concepts available that allows better integration of local devices through control and aggregation of local technologies without requiring substantial change to existing infrastructure. It does this by connecting to the wider grid through a single point of common coupling (PCC). The larger grid is isolated from the interaction of devices and loads within the minigrid which are controlled locally.

The figure shows a backbone of large scale electricity generation, transmission and distribution together with distributed energy resources and communication technologies which enable local supply, load control, asset optimisation and system resilience. The large scale grid remains important in Australia to support the introduction of centralised renewable options such as geothermal and wind power, which are located at considerable distance from the major end users. The inclusion of distributed energy resources and communications are the two defining features that set apart the smart grid from the current system.

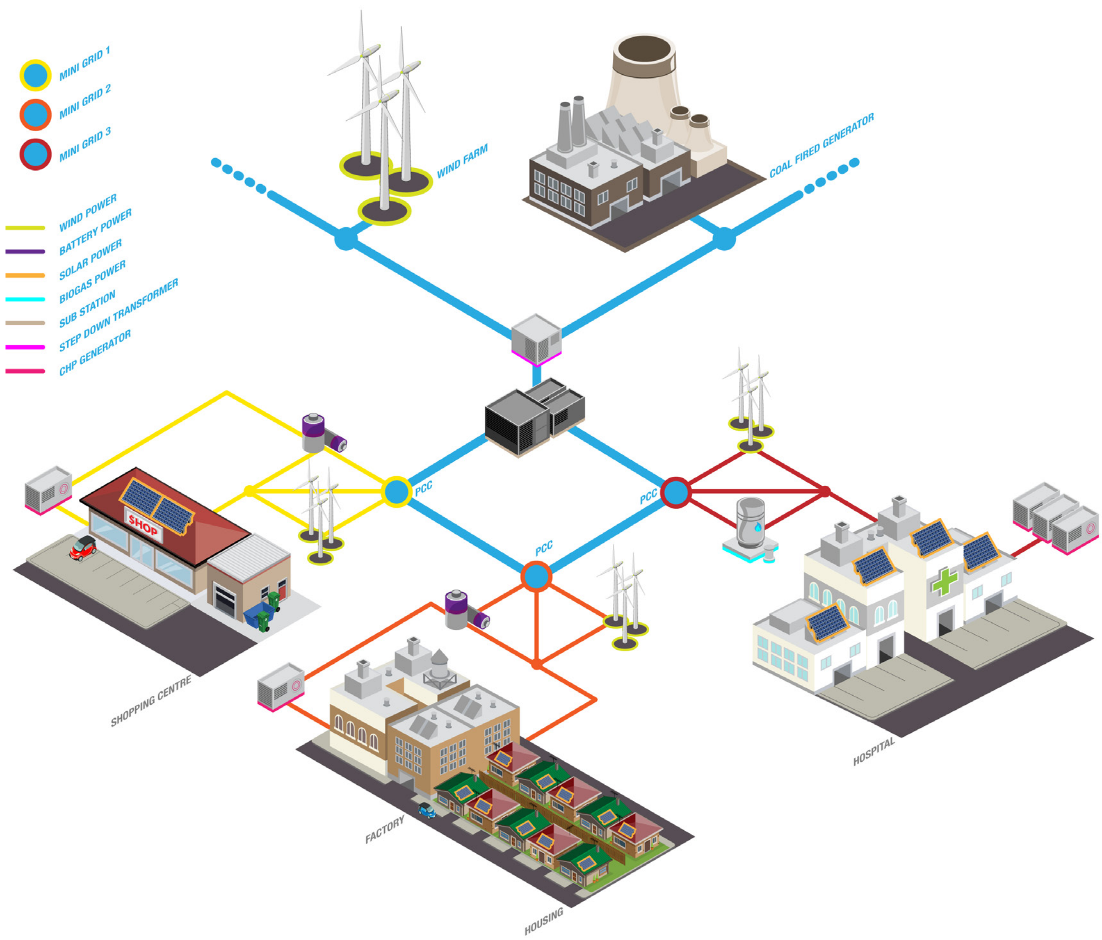


Figure 3.8: A conceptual model of a "smart grid" containing mini grid elements

In this report, we consider the value that distributed energy offers with a particular emphasis on its ability to reduce greenhouse gas emissions. While it is acknowledged that there are significant issues in the communication and security aspects of the smart grid, in this report we focus on the issues required to understand the impacts and benefits of a future grid with large scale introduction of distributed energy resources, as opposed to a smart grid per se.

3.4 Distributed generation

Distributed generation refers to technologies generating electricity that are located in the distribution network. These technologies are sometimes referred to as embedded generation. Generally, the technologies are connected at low voltage (< 22 kV) and in a number of cases may provide additional energy in the form of hot or cool water for a variety of applications. This section provides a general description of the major distributed generation technologies and discusses the process of connecting them to the grid.

3.4.1 Cogeneration and trigeneration

One of the key benefits of using distributed generation over centralised generation is the ability to capture heat generated during the production of electricity for useful applications. This process is known as combined heat and power (CHP) or cogeneration. When using the waste heat for cooling purposes as well, it is commonly called combined cooling, heat and power (CCHP) or trigeneration. Centralised generators typically reject this heat to the atmosphere where its energy value is lost.

Figure 3.9 provides a schematic representation of a CHP installation for an engine (see Section 3.4.2) or turbine (see Section 3.4.4) system. Around 30% of the fuel's energy is directly converted to electricity. The actual electrical efficiency varies considerably by engine type and fuel source. Generally, larger diesel units have the highest electrical efficiency. The remainder of the fuel's energy is discharged as heat where it can be captured by a heat exchanger and used for useful applications.

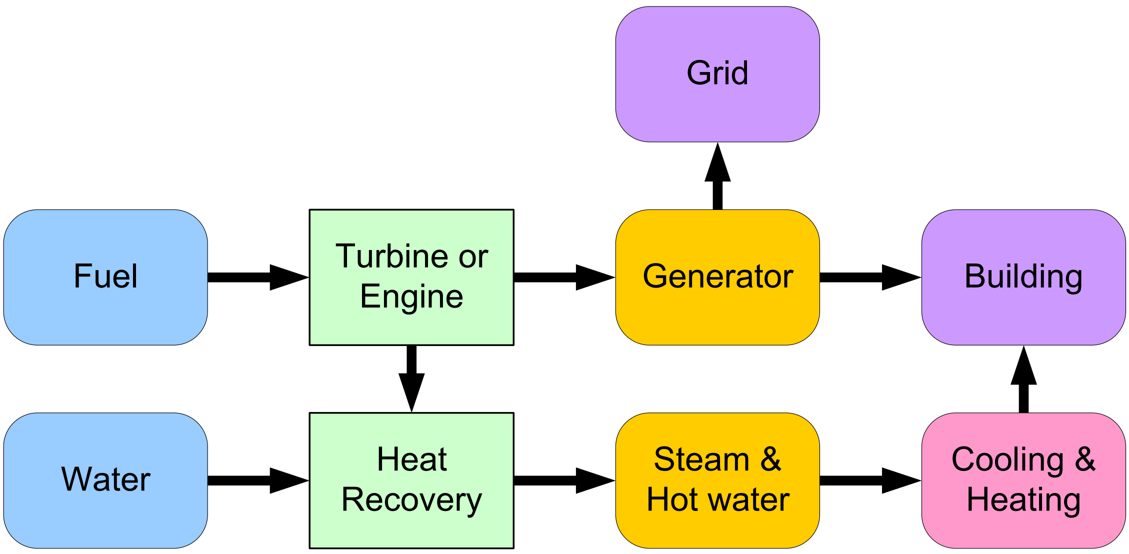


Figure 3.9: Schematic representation of a CHP system

While there are many types of heat exchangers, the basic concept is that a cool liquid (generally water but others such as oil may be more efficient) is passed through the unit (through say a series of coils) which the hot fluid passes over. Heat is exchanged from the hot fluid to the colder one. The amount of heat exchanged depends on the design of the unit, the available specific heat capacity of the media and the temperature gradient between the two media. The captured heat may be used for other purposes such space heating and/or cooling or steam production. By capturing and using the waste heat, the overall performance of the system can increase substantially to 70% or more. This increase in efficiency provides a substantial benefit in reduced greenhouse gas emissions and cost compared with centralised generation.

When capturing waste heat, the usefulness (or efficiency) of the waste stream is influenced by the system or source of energy it replaces. For example, in industrial applications, a CHP system might replace a gas fired boiler used to generate steam or hot water. In this case, the waste heat from the system can act as a one to one replacement of a boiler. The degree to which it can completely replace a boiler typically depends on the degree to which the timing of heat and electrical loads correlate, or whether the value of exporting excess electrical power to the grid is sufficient to justify electrical production in excess of electrical demand at the site where the generator is installed.

It is also determined by the source of the waste heat. In an engine based system (Section 3.4.2), the waste heat resides in the exhaust stream and in the cooling jacket water. The cooling jacket water may be useful for providing low grade hot water. The hot exhaust is better suited to steam generation. The amount of heat in the exhaust and the jacket water is roughly 50:50 in an engine based system. Accordingly, the usefulness of the waste heat stream is highly dependant on the type of heating application and the engineering design employed. Combustion turbines (Section 3.4.4) are more useful for steam generation as a larger component of their waste heat is contained in their hot exhaust stream.

Evaluating the benefit of trigeneration is a more complicated process. Electrical cooling systems use a refrigerant compression heat pump to convert electrical energy into cooling work. The amount of cooling work created is defined by a parameter known as the coefficient of performance (COP). For a system with a COP of 1, the amount of cooling delivered is equal to the amount of electrical energy consumed. For domestic air conditioners, the COP is generally around 2 to 3, meaning that the cooling work from the system is 2 to 3 times higher than the electrical energy supplied. For large commercial units the COP is higher, say 6 to 7.

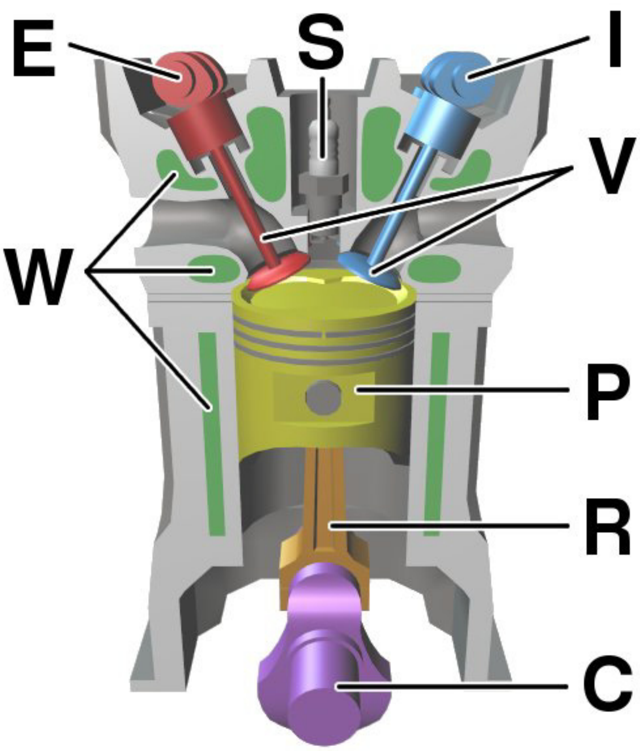
Systems using waste heat for cooling generally employ absorption chillers which typically have COP's around 1. When replacing a conventional electrical chiller, the difference between the COP values needs to be considered. If the waste heat system (with an assumed COP of 1) was able to capture and convert 80% of the waste heat from a system with an electrical efficiency of 40% (i.e. 60% is wasted as heat), then the unit could create 0.48 kW of cooling work for each kW of fuel energy. Creating an identical amount of cooling work from a commercial grade electrical chiller with a COP of 6, would require 0.06 kW of additional electricity. Therefore, a unit with 46% electrical efficiency that did not use its waste heat could provide an equal amount of system performance (electricity and cooling). In this case, system flexibility (i.e., the timing of electrical and cooling needs) and simple economics become the major drivers for considering which option is more viable.

Finally, for those implementing cogeneration and trigeneration systems, the value of doing so will depend on the extent to which the value of displacing energy from the grid, or supplying energy to the grid, is reflected in the avoided and received tariffs respectively. Calculating and capturing this value is a complex task which is explored in more detail in Chapters 6,7 and 8.

3.4.2 Reciprocating internal combustion engines

Among distributed generation technologies internal combustion engines (ICE) are the most mature prime movers having been in production since the 1800s. Advantages include: comparatively low installed cost, high efficiency (up to 45% for larger units), suitability for intermittent operation, high part-load efficiency, high-temperature exhaust streams for CHP and due to their common place are readily serviceable. These units have been popular for peaking, emergency, and base-load power generation. The units can run on a variety of fuels including diesel, natural gas, compressed natural gas, petrol, biogas or landfill gas. The size of the units can vary from a few kilowatts to megawatts. A small emergency generator may be around 2 kW (electrical) for instance while a marine diesel engine may be 30 MW (electrical) or more.

Reciprocating engines operate by combusting a mixture of air and fuel in a combustion chamber (see Figure 3.10). The forces created by combustion force the piston downwards exerting a force on the crankshaft. In electrical applications, the crankshaft is connected (directly or via a gearbox) to the generator set which produces electrical output.



Where,
E is the exhaust camshaft
I is the intake camshaft
S is a spark plug
V are the valves
P is the piston
R is the connecting rod
C is the crankshaft
W is the water jacket for coolant flow

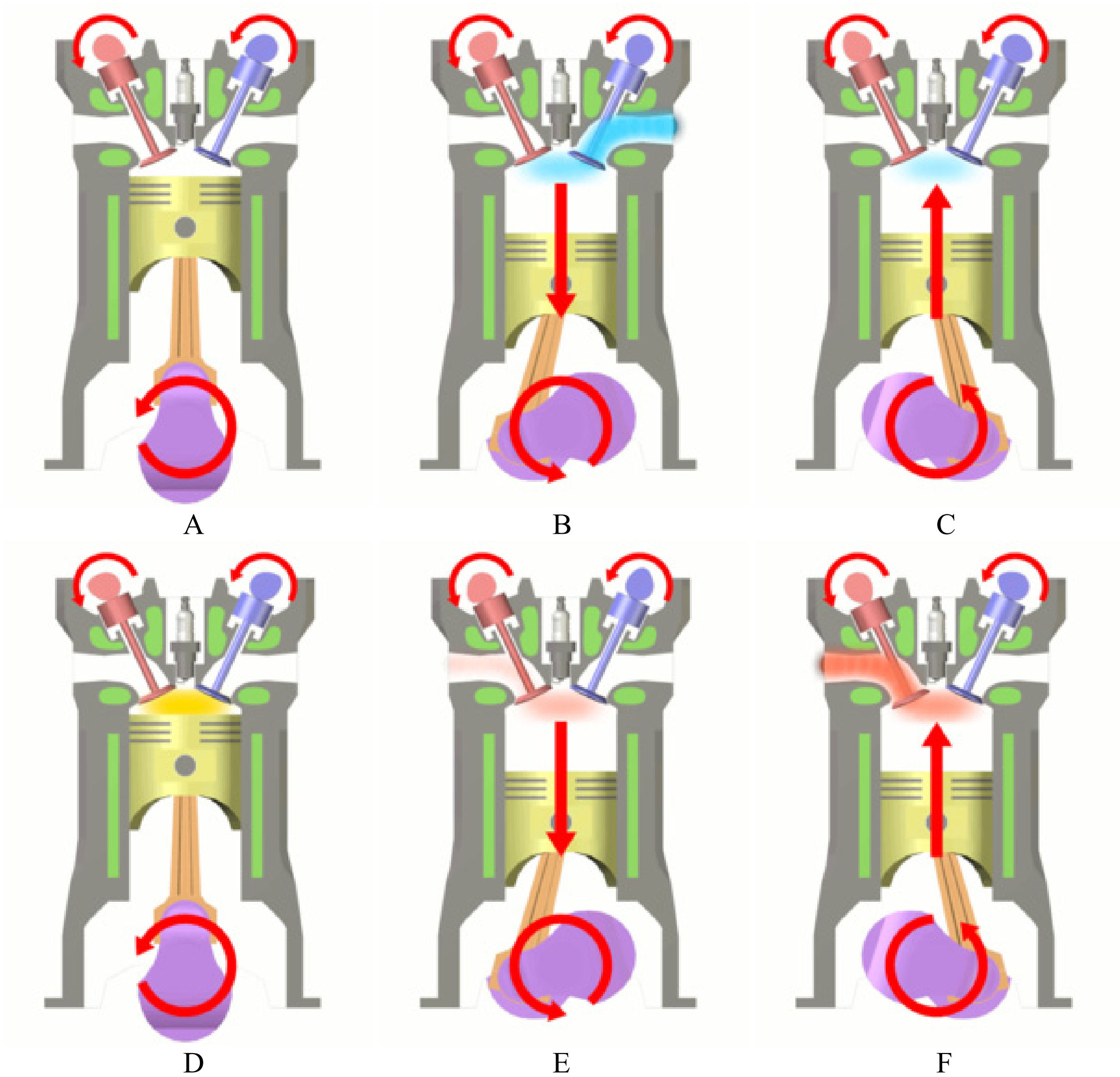
Figure 3.10: Schematic representation of an ICE (Wikimedia, 2009a)

The operation of an ICE is primarily performed with either a four-stroke (see Figure 3.11) or two-stroke cycle. A four stroke spark ignition engine (or Otto cycle) operates through four discrete processes those being adiabatic compression (C in Figure 3.11), heat addition at constant volume (D in Figure 3.11), adiabatic expansion (E in Figure 3.11) and rejection of heat at constant volume (F in Figure 3.11). An adiabatic process is a thermodynamic process in which there is no heat transfer into or out of the system. It is generally obtained through insulation or through a rapid process in which there is little time for a significant heat transfer to occur.

In the Otto cycle shown in Figure 3.11, the combustion of the air and fuel mixture drawn into the cylinder is initiated by an electrical charge from the spark plug. The exothermic reaction from the oxidation of the fuel in air heats and expands the gas which exerts a force on the face of the piston. The piston travels downwards transferring its vertical momentum into rotational energy at the crankshaft. For DE applications the crankshaft is connected to an electrical generator either directly or via a gearbox to create electricity.

In a modern four stroke diesel engine, air is brought into the engine and fuel is directly injected into the cylinder as it approaches the top of its compression cycle. The heat formed from compression of the air ignites the fuel. This process is often referred to as self ignition. In general the compression ratio (the ratio of the volume at the bottom of the stroke with the volume at the top of the stroke) of a diesel engine is substantially higher than an Otto cycle engine. Compression ratios in Otto cycle engines are intentionally kept low to stop self ignition of the air and fuel mixture during compression. The higher compression of a diesel engine generally results in a higher combustion temperatures and greater efficiency. Most new diesel engines rely on electronic systems that control the combustion process to increase efficiency and reduce emissions. A major difference between an Otto and a diesel engine is the amount of gas in the cylinder. In a diesel engine a full cylinder of air is drawn in every stroke. The power is varied by the amount of fuel injected. As such the air/fuel ratio can vary quite significantly across the range which affects performance and emissions. In an Otto cycle, the amount of gas brought into the cylinder is throttled and because the air and fuel are premixed the air fuel ratio remains essentially constant resulting in potentially better part load performance. Dual fuel systems which generally use a small charge of diesel to ignite a fuel and air mixture are also a widely available technology primarily as a result of retrofitting diesels for natural gas use.

A two-stroke engine is an ICE which completes the thermodynamic cycle in two movements of the piston. In this case, the compression stroke and the end of the combustion stroke perform the exhaust and intake functions. These engines are often used in lightweight applications such as chainsaws and are also used with diesel cycles in larger applications such as ships and locomotives. A number of varying designs exist for the control of the intake and exhaust including piston controlled inlet ports, reed inlet valves, rotary inlet valves, cross flow scavenged engines and loop scavenged engines. A six-stroke engine captures the waste heat from the four-stroke Otto cycle and creates steam, which simultaneously cools the engine while providing a free power stroke which increases the efficiency over a standard Otto cycle.



Where,
A is the start of the cycle (top dead centre; TDC)
B is the intake of the fresh air/fuel mix brought through the inlet valves
C is the compression of the air and fuel in the engine cylinder by the piston
D is the combustion of the fuel
E is the power stroke caused by the expansion of the gas
F is the exhaust cycle where the hot gases exit through the exhaust valves

From the start of the cycle a homogenous mixture of air and fuel is drawn into the engine through the inlet valves (B). At the bottom of the stroke the exhaust valves close. The piston then travels up the cylinder compressing the trapped air (C). A spark plug initiates combustion (D) which heats and expands then air in an exothermic reaction. This forces the piston downwards (E) forming the power stroke. The vertical momentum of the piston is transferred into rotational energy via the crankshaft. Having completed the power stroke, the piston travels upwards again during which time the exhaust valve opens to the exhaust the spent air (F).

Figure 3.11: Schematic representation of a combustion cycle for a four stroke petrol (Otto cycle) engine (Wikimedia, 2009b)

Emissions from internal combustion engines can vary substantially depending on the type of fuel and combustion cycle. In general, oxides of nitrogen (NOx) and particulate matter emissions are higher from diesel engines. The NOx emissions are formed from the high combustion temperatures of a diesel engine (from higher compression ratios) while particles are generally formed from the heterogeneous combustion of the injected fuel. Particle emissions can be controlled through filtration or secondary combustion. NOx emissions can be controlled through catalytic conversion and through engine management techniques including retarded injection timing and injection of water. The methods used depend on a variety of issues including location and cost and are complicated by the variation that can occur depending on the species of interest. Table 3.7 displays an example of the variation in emissions that can occur from control techniques for four pollutants emitted from a diesel engine.

Table 3.7: General effects of engine speed and load on selected emissions from diesel engines

Engine Speed ↑	**HC**	**Particle Formation**	**Particle Oxidation**	**NO/NO_2 Formation**	**NO_2 Survival**
Mixing Rates ↑	↑	↓	↑	↓	↑
Cycle Temperature ↑	↓	↑	↑	↑	↓
Ignition Delay ↓	↓	↑	--	--	--
Reaction Time ↓	↑	--	↓	--	↑
Overall Effect	↑	↑	↑	↓	↑
Engine Load ↑	**HC**	**Particle Formation**	**Particle Oxidation**	**NO/NO_2 Formation**	**NO_2 Survival**
Cycle Temperature ↑	↓	↑	↑	↑	↓
Equivalence Ratio ↑	↑	↑	↓	↓	↓
Overall Effect	↓	↑	↓	↑	↓

Source: Campbell et al. (1986)

Where;
↑ indicates an increase
↓ indicates a decrease
HC are hydrocarbons
NO is nitrogen oxide
NO_2 is nitrogen dioxide.

For DE applications, ICEs can be used in a stand-alone operation (commonly as emergency backup generators in commercial buildings and as network support in constrained locations) where they are generally used for a small number of hours per year. Alternatively, they can be used in CHP applications which may offer a more economic proposition given the right load profiles. Table 3.8 shows that the efficiency and cost of reciprocating engines depends to a large extent on the fuel and end use types. Diesel engines have lower capital costs due to the large volumes created for the automotive and industrial sectors. Because these technologies are well established and created in large numbers, their capital cost (in real terms) and efficiencies are not expected to change over time (see Figure 3.24). Incorporation of CHP or trigeneration facilities adds significantly to capital cost. The cost of CHP versions are expected to fall from increased production.

3.4.3 External heat engines

Stirling cycle

The Stirling engine converts heat energy into mechanical power by compressing and expanding a fixed quantity of gas (usually air and known as the working fluid) using a piston in cylinder engine. The system is a closed cycle meaning that the air trapped in the cylinder remains within it for its lifetime. Energy is supplied externally from a heat source. Any heat source can be used but in general it is provided by the combustion of a fuel such as natural gas or biomass (Figure 3.12). In recent years, renewable sources such as the heat from a solar parabolic dish collector (Figure 3.13) have been developed to provide heat to Stirling engines.

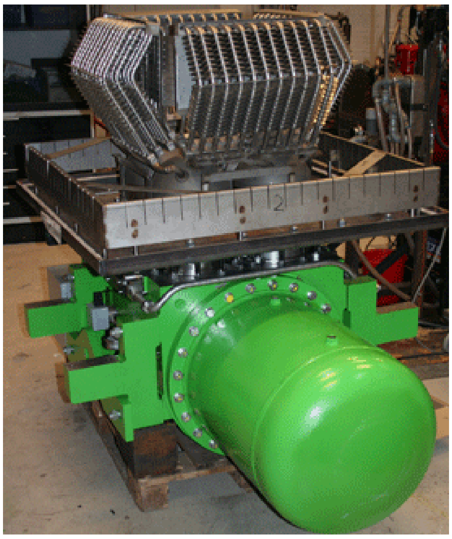


Figure 3.12: Picture of a biomass Stirling engine (WADE, 2009). Reproduced with permission from WADE

Figure 3.13: Picture of a solar parabolic dish to provide heat to a Stirling generator (Wikimedia, 2009c)

The Stirling engine comes in a variety of designs. Figure 3.14 describes the process of operation using a conceptual Alpha type engine. The Alpha engine uses independent cylinders. Beta and Gamma engines use single cylinder dual piston arrangements. This simple schematic representation does not include internal heat exchangers and regenerators; it is simply designed to show the process of a Stirling cycle. The cycle consists of four thermodynamic processes acting on the working fluid: isothermal expansion, constant volume heat removal, isothermal compression and constant volume heat addition. Theoretically, a Stirling engine can obtain the highest efficiency of a heat engine. In current operation however, their efficiencies are around 12% to 20% (WADE, 2009) due to material and design limitations.

While Stirling engines are a well known technology, their limited production means that their costs are high. The California Energy Commission (2009) suggest a cost between $US 2,000-50,000 per kW for instance. A New Zealand manufacturer of residential Stirling based micro CHP systems (www.whispergen.com) estimates a capital cost for their residential unit around $AUD 8,000. The unit provides up to 1 kW (at around 12% efficiency) of electricity and between 7.5 and 14 kW of thermal energy for a total efficiency approaching 92%. Given the high heat output of the unit, the product has been naturally aimed at the European market to replace boilers (Personal communication, Gary Whitfield - whispergen). If products such as the whispergen residential CHP unit are successful, they should provide market credibility leading to a drop in price over time through mass production. In this case, the learning curve could be expected to show a similar trend to those expected for relatively new technologies such as fuel cells (see Figure 3.24).

Referring to Figure 3.14, in Stage A, most of the working gas is in contact with the hot cylinder walls. This heat is continually provided by an external source. The expansion of the gas pushes the upper piston to the bottom of its travel. In Stage B, the working fluid is at its greatest volume. The hot cylinder pushes the gas into the cold cylinder where it cools dropping the working fluid's pressure. Heat is exchanged to the external cool fluid. This process can be used to generate hot water in CHP applications. In Stage C, almost all of the air is in the cool cylinder and the cool piston begins to compress the gas. In Stage D, the gas reaches its minimum volume contained primarily within the hot cylinder. The heat in the cylinder walls begins heating the working fluid driving the hot piston and producing linear momentum which is converted to rotational energy on the crankshaft.

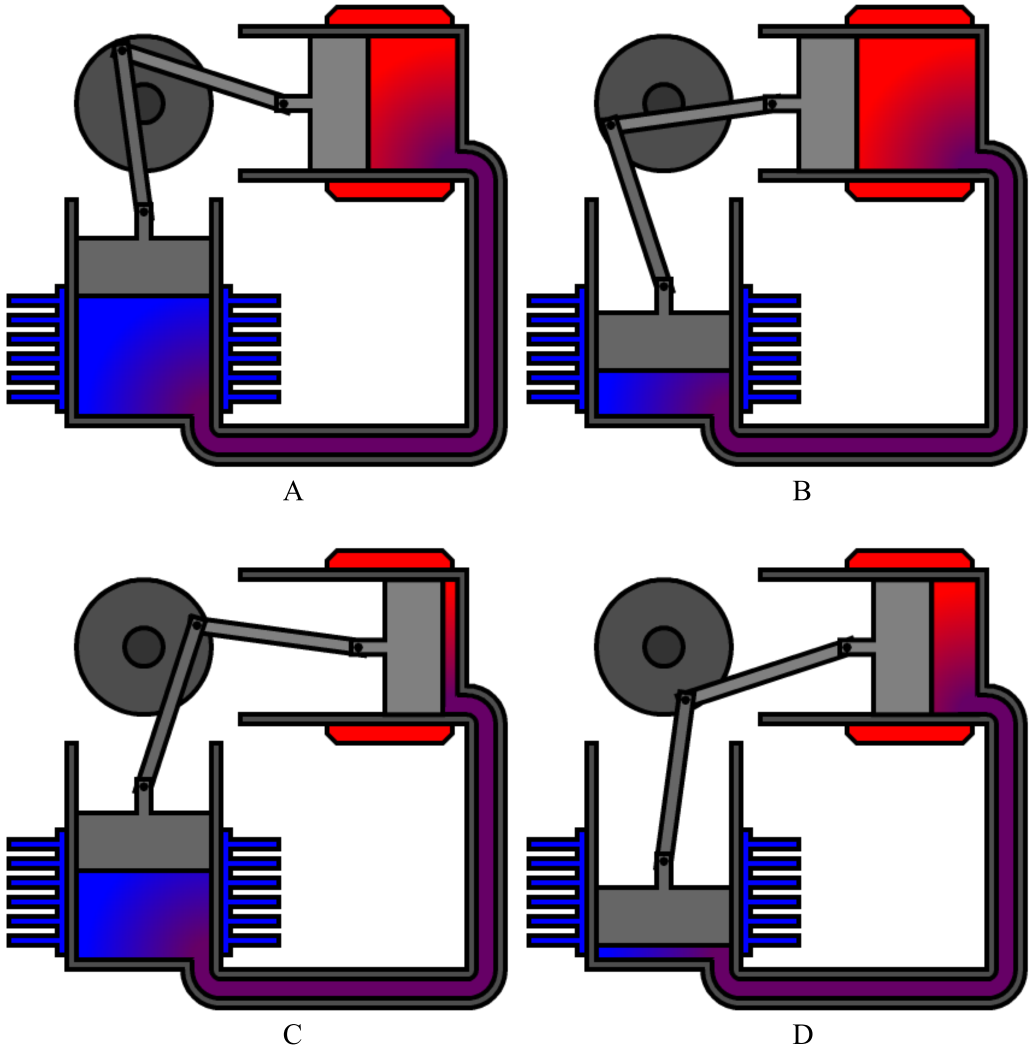


Figure 3.14: Example of an alpha type Stirling engine cycle (Wikimedia, 2009d)

Rankine cycle

The Rankine cycle is used in most of the world's power generation primarily through the use of natural gas and coal-fired steam generation. Figure 3.15 shows a schematic representation of the system. A basic Rankine Cycle involves circulation of a volatile working fluid. Heat is used to vaporise the working fluid into a high pressure vapour. The vapour passes through an expander to create useful mechanical work. The cycle is completed by condensing the vapour back to a liquid and pumping it through the heat source again.

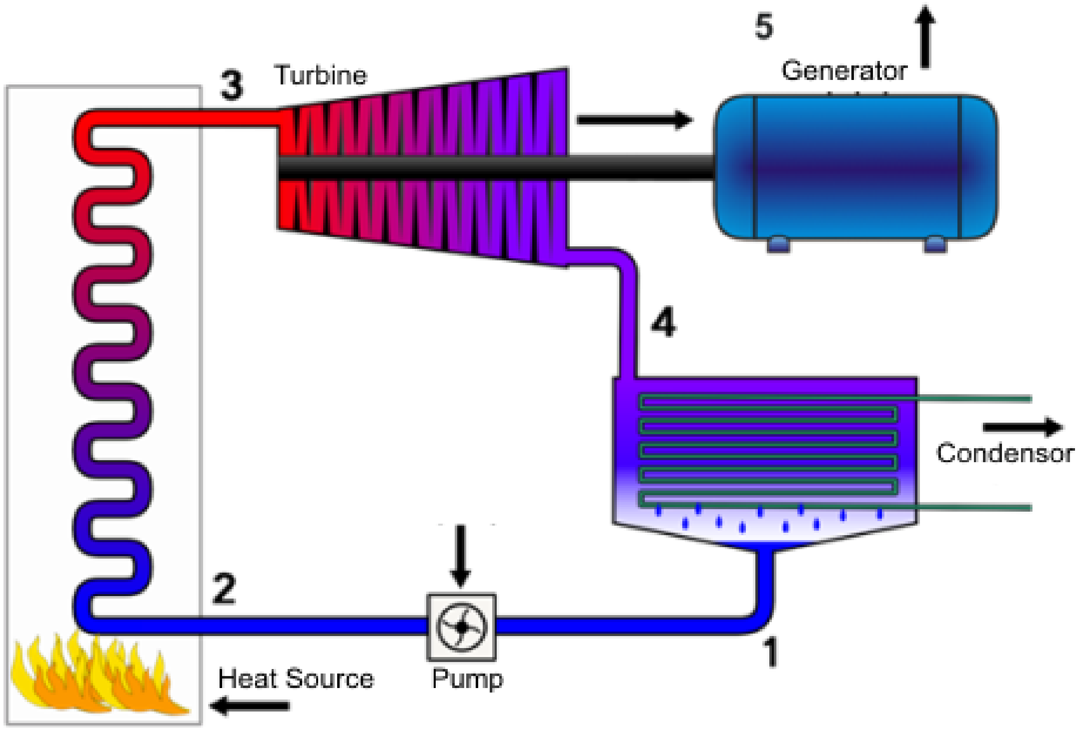


Figure 3.15: Example of a Rankine engine cycle (Wikimedia, 2009e)

Water is used to generate steam in most Rankine cycle applications through the use of high temperature heat sources such as the burning of coal, natural gas or biomass. While water is the most widely used working fluid, volatile organics with lower boiling temperatures such as Toluene can be used in place of water to allow the capture of lower grade heat sources albeit at lower efficiencies. Table 3.8 shows that the capital cost of a biomass Rankine (steam plant) cycle CHP unit is more expensive than a natural gas reciprocating engine with CHP but cheaper than a gas fired microturbine CHP unit . Like reciprocating engines, the steam Rankine cycle is a well established high production technology. Steam plants are usually large and for DE applications we consider smaller CHP units. In this case, the costs expected to drop in real terms (see Figure 3.24) as mass production increases.

3.4.4 Combustion turbines

Combustion turbines range in size from 10's of kilowatts to hundreds of megawatts. Smaller (25 kW to 500 kW) units are commonly referred to as microturbines (a registered trademark of Capstone Turbine Corporation) while the larger units (250 kW to 500 MW) are generally referred to as gas turbines although they can use a variety of fuel types such as diesel, biogas and kerosene. A combustion turbine consists of three main parts (Figure 3.16): a gas compressor, a mixing/combustion chamber and a turbine expander. They operate using the Brayton cycle. Firstly, air is drawn into the engine and compressed isentropically (this is the ideal state in which no energy is added and no losses occur from friction or dissipative effects). Fuel is added and mixed with the compressed air which is then burnt at constant pressure. The hot gas is then expanded isentropically over a turbine creating useful work.

The units can use single shaft (common on smaller turbines and becoming more prevalent on larger turbines) where the compressor and turbine are directly coupled or dual/split shaft arrangements (Figure 3.24). The dual shaft systems show better part-load performance because the load does not affect the rotational speed of the inlet compressor and hence the energy output from the burner. In most instances, the shaft from the turbine is attached to a gearbox which then drives a synchronous generator (see Section 3.3.1). Some of the smaller microturbines have generators directly coupled to the main shaft which can spin at speeds around 100 000 rpm. This creates a high frequency AC output which is converted to DC and then inverted back to AC at 50 Hz.

On some units a recuperator captures some of the waste heat to improve efficiency by preheating the fluid entering the combustion chamber. This directly offsets fuel use and wastes less heat. A Rankine cycle (see Section 3.3.3.2) can be added to form what are known as combined cycle gas turbines (CCGT). Since the waste heat is of high quality, it can be readily used in CHP applications. Because the exhaust has relatively high levels of oxygen it can undergo secondary burning to raise the exhaust temperature. This is useful where higher temperature steam is required.

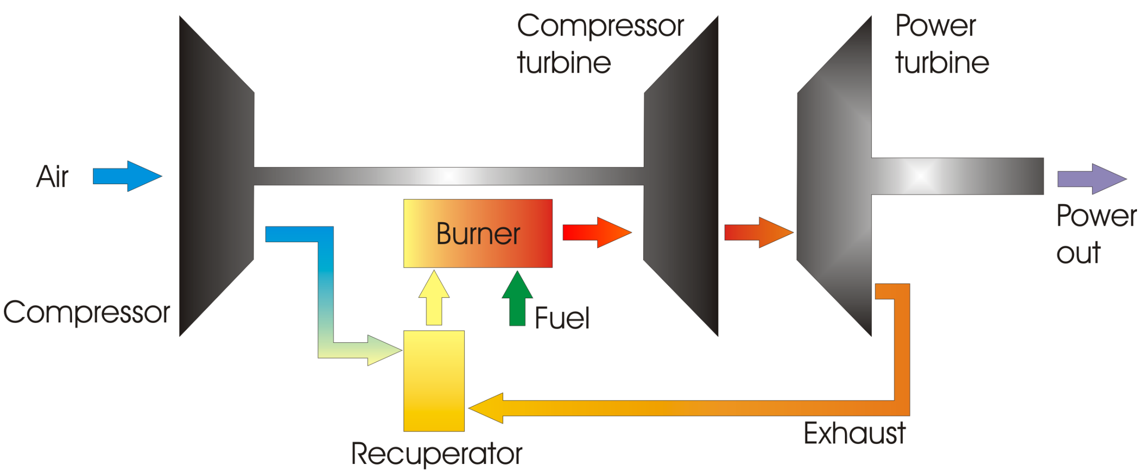


Figure 3.16: Schematic diagram of the operational principles of a combustion turbine

Table 3.8 shows that the cost of large turbines is much cheaper than their smaller (microturbine) counterparts. Electrical efficiencies of the smaller units are considerably less than reciprocating engines but the waste heat source is higher grade (hotter) which can be advantageous depending on the needs of the waste heat stream. The cost of microturbines is expected to decrease moderately over time particularly for CHP units as production volumes increase. The cost of larger scale turbines is expected to remain constant although combined cycle units are expected to become cheaper as economies of scale become more favourable.

Generally turbines are clean burning engines (see Appendix C for details). Steam can be injected into the combustion chamber to improve electrical efficiency and reduce NOx emissions. Selective catalytic reduction (SCR) can be added to the exhaust stream to reduce NOx levels further if required.

Arrays of mirrors or lenses may be used to construct concentrating solar thermal systems that may use a Brayton cycle for direct power production. The concentrated energy of the sun is used to heat a fluid like water, air, liquid metals, or molten salts which can be used to drive a turbine. Storage may be incorporated using molten salt tanks. The hot fluid heats up the compressed air substituting or lowering the amount of fuel needed to heat up the air in the combustion chamber for power generation. The systems can be used in a hybrid form (i.e., having standard gas fired backup) to ensure continuous operation.

3.4.5 Wind turbines

The are two main types of wind turbine commercially available for converting the kinetic energy in wind into useful electrical energy, those being the traditional horizontal axis wind turbines (HAWTs; Figure 3.17-A) and newer vertical axis wind turbines (VAWTs; Figure 3.17-B shows a Darrieus type turbine). Vertical axis turbines are not as efficient but have some benefits including greater tolerance to turbulence and high wind speeds.

A B

Figure 3.17: Example horizontal (A; Wikimedia, 2009f) and vertical (B Wikimedia, 2009g) wind turbines

As wind travels over the blade it creates a lifting force (the exception are Savonius VAWTs which use drag). This force is translated into rotational energy via a shaft connecting to the blades (see Figure 3.18). Generally the shaft then connects to a gear box which operates a secondary shaft at higher speeds. This secondary shaft provides rotational energy generally to an asynchronous generator (see Section 3.4.9).

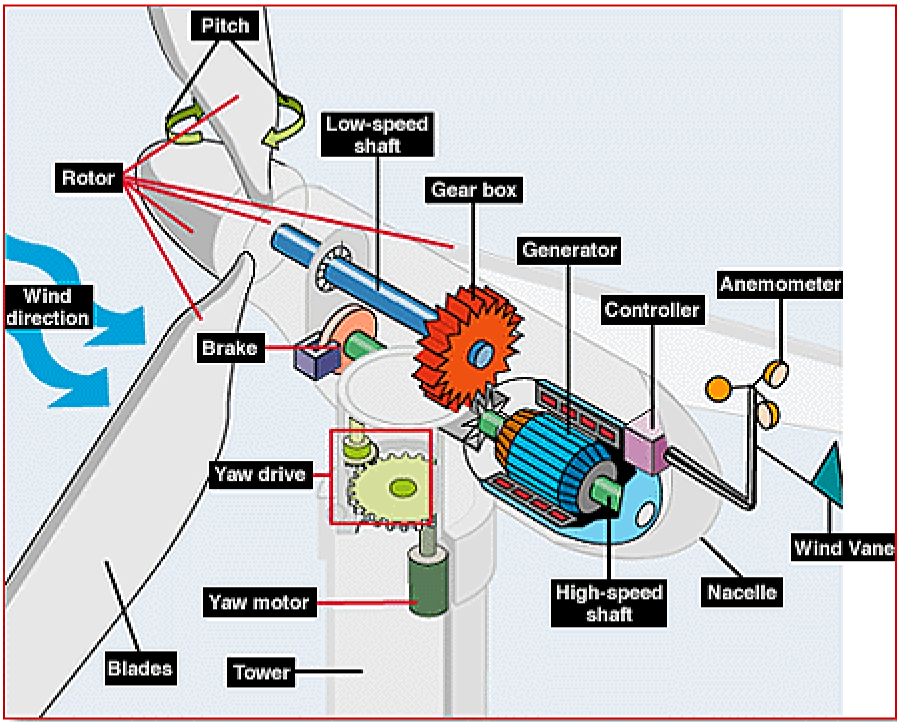


Figure 3.18: Schematic representation of the components in a horizontal wind turbine (Wikimedia, 2009h)

Figure 3.19 shows an example wind speed distribution over time. Wind speed distributions are often well approximated by a Weibull distribution (Equation 3.1). In this example, the shape factor (k) has been set at 2 while the magnitude factor (c) has been set at 5. Figure 3.19 illustrates that on average, wind speed is low to moderate and that high wind speeds occur infrequently.

$$f(u) = \frac{k}{c}\left(\frac{u}{c}\right)^{k-1} e^{-\left(\frac{u}{c}\right)^{k}} \qquad 0 < u < \infty \qquad 3.1$$

Wind turbines are designed for cheap production by operating them in the low to moderate range of wind speeds where they are most economically viable. They are not designed to capture fast infrequent winds which put considerable strain on the unit. To compensate, a number of protection mechanisms are available.

On a pitch controlled wind turbine, an electronic controller checks turbine output several times per second. When the output becomes too high, it pitches (turns) the rotor blades out of the wind. A stall on the blade is created by turbulence slowing the rotational speed of the unit. Some wind turbines have blades that are rigidly mounted but are designed to create turbulence when the wind speed becomes too high. Some older units employ an aileron (flap at the back of the blade) to control the power. Some units may employ a yaw control which moves the blades away from a direction perpendicular to the wind. This can decrease the amount of wind experienced by the blades but can also create additional bending stresses by having one section of the rotor experience a larger force than the rest of the rotor.

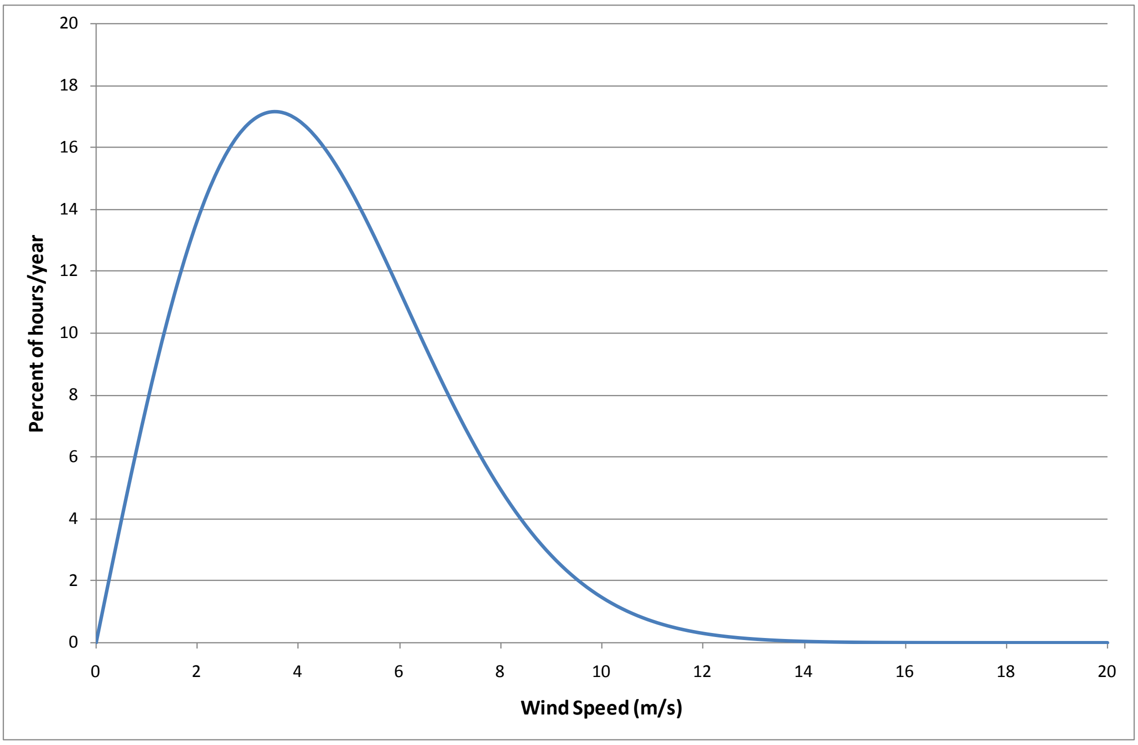


Figure 3.19: Example Weibull distribution with k=2, c=5.

Table 3.8shows that wind turbines are the cheapest renewable based generation technology. The economics is highly dependent on the location and installation. The power of a wind turbine can be approximated by Equation 3.2. This shows that the power is a cubic function of the wind speed. Wind speed increases with height above the ground as the frictional effects of the earth's surface become reduced. Figure 3.20 illustrates this point. The graph shows the output of Equation 3.3 (assuming z_0=0.2 and u_{10} = 5). This equation provides a function of wind speed with height for a neutral atmosphere (a condition in the atmosphere where isolated air parcels do not have a tendency to rise or sink as they are the same temperature as the air that surrounds them). This chart clearly illustrates the importance of the rotor mounting height, with careful consideration required to balance the output of the turbine against the capital cost for installation. Perhaps more importantly, the geographical location for installation has to weigh factors such as the cost to connect against variations in wind speed from local climatic and geographical factors.

$$P = \frac{\rho A u^3}{2} \qquad 3.2$$

Where,
P is the power
ρ is the air density
A is the swept area
u is the wind speed.

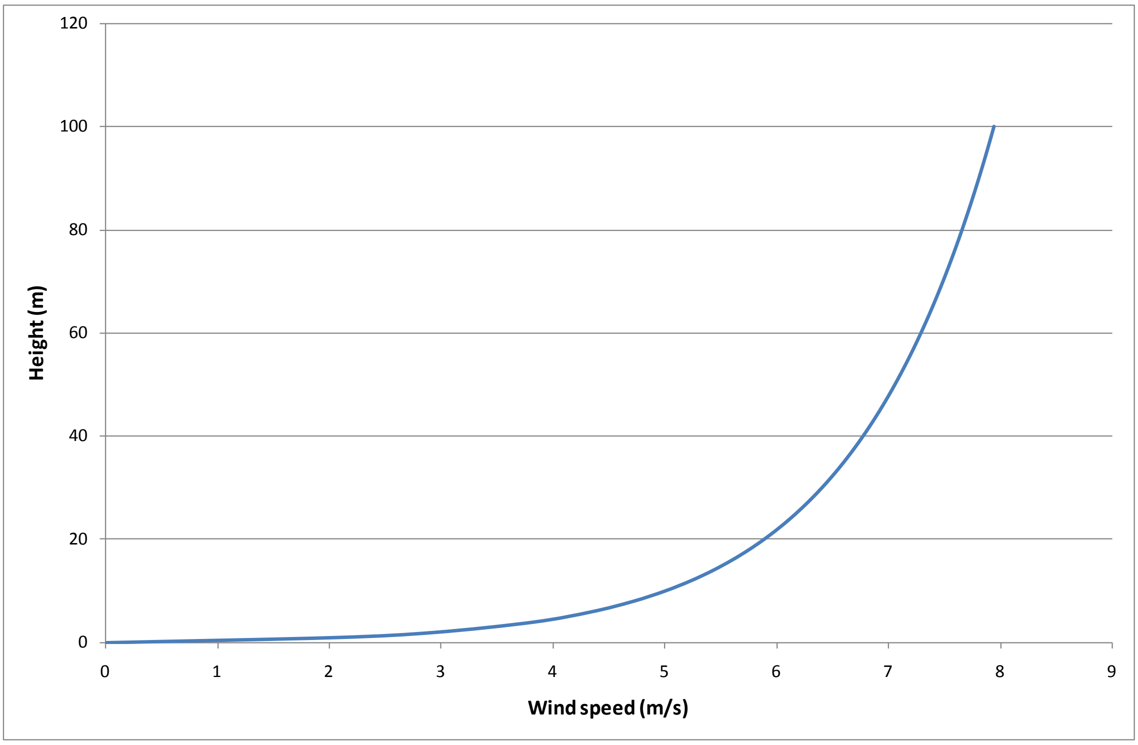


Figure 3.20: Graph showing wind power is a cubic function of wind speed

$$u_z = u_{10}\left(\frac{ln\left(\frac{z}{z_0}\right)}{ln\left(\frac{z_{10}}{z_0}\right)}\right) \qquad 0 < u < \infty \qquad 3.3$$

Where,
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.

Table 3.8 shows that the cost of small and medium sized turbines is relatively high being comparable to or more expensive than a microturbine with CHP. Lifetimes of the turbines are relatively poor compared to other distributed generation technologies. Costs are expected to drop as unit numbers grow.

3.4.6 Photovoltaic

Solar photovoltaic (PV) cells generate power through the absorption of solar radiation into a semi-conductor material producing an electrical current via the photoelectric effect. A solar cell contains a thin wafer of a semiconductor which is treated to form an electric field, positive on one side and negative on the other. Most common cells use a single junction to create the electric field. When a photon of light hits the cell electrons are released from the semiconductor. These electrons can then flow between the positive and negative sides forming an electric current. The electric current is in DC form and so requires an inverter to create AC when connecting to the grid or when running normal household devices in stand-alone operation. Like wind turbines, the output from these devices can be sporadic due primarily to the effect of clouds. The amount of power produced also varies by time of day and time of year as the sun moves through the sky.

The modular design of solar cells allows them to be easily scaled to meet a particular energy demand and makes them well suited to supplying power in remote areas where access to grid infrastructure is expensive. While there output is intermittent, when coupled with storage devices or integrated in a system with reliable back up power, they can be a cost effective source of clean reliable energy. They are noiseless, reliable and only require surface cleaning for maintenance, making them popular with domestic consumers.

Commercial photovoltaic cells may have efficiencies between 10-17% in ordinary sunshine and can produce 1 to 1.5 kWh/m^2 per day. In clear sky conditions, the efficiency can be affected by the installation angle and ambient conditions. In some instances, the cells may be installed in a tracking unit which allows the cells to follow the path of the sun. Ambient conditions affect the solar cell output through temperature degradation. Equation 3.4 shows a typical drop-off for a solar cell indicating a loss of around 0.4% per degree increase in temperature (Mills, 2001).

$$P = R_{in}\left[1 - \left(\left. 0.4\big(PT + (AT - 25)\big) \middle/ 100 \right.\right)\right] \tag{3.4}$$

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.

Figure 3.24 shows that PV is currently one of the most costly distributed generation technologies. Like wind, its output is highly variable and intermittent. Capacity factors depend greatly on location and installation. There has been considerable change in the price and efficiency of PV over the last decade. It is expected that the price will drop more dramatically than any other DG technology as production increases. Some observers consider that this group of technologies holds promise for a step change in price due to advances in areas such as printing technology for instance.

Currently there are four main types of commercially available solar cells:

Monocrystalline: These cell types (Figure 3.21) were once the most efficient commercially available cells and typically have a peak output of 120-140W/m^2.

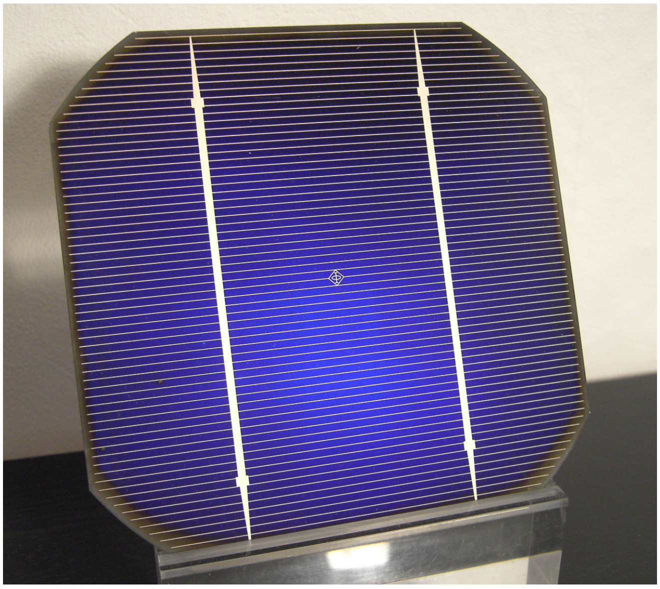


Figure 3.21: Example of a monocrystalline panel (Wikimedia, 2009i)

Polycrystalline: These cells (Figure 3.22) offer considerable cost saving during the manufacturing process by using polycrystalline materials. Typically, this type of cell can produce peak output of approximately 110-130W/m^2. However, due to the slightly lower efficiencies, the actual energy yield (total kWh) maybe less than for equivalent monocrystalline systems.

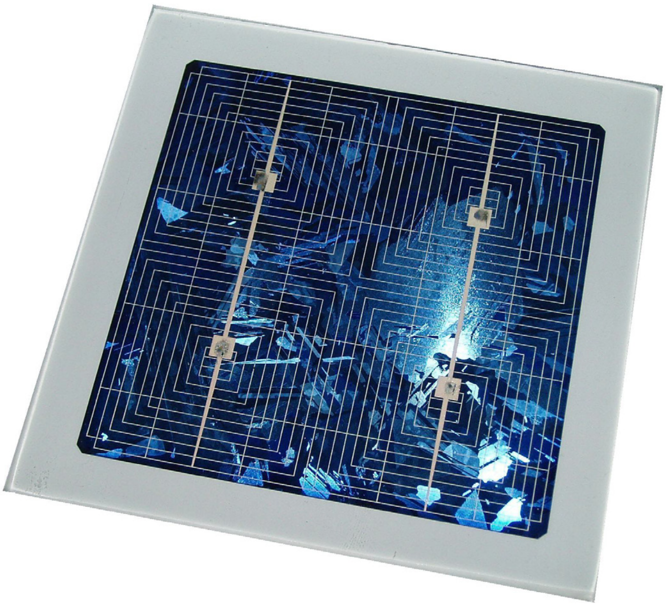


Figure 3.22: Examples of polycrystalline panel (Wikimedia, 2009j)

Amorphous: Amorphous cells have been developed with the aim of low cost production and their efficiencies are lower than other types (in the order of 10%), therefore requiring almost double the surface area of polycrystalline cells to produce the same amount of power. They are typically seen in smaller applications such as calculators and garden lights; a number of building related products are only now beginning to emerge.

Thin film triple junction cells: These cells use multiple layers of material to provide cells with specific design aspects such as flexible materials or improved performance in diffuse light situations. Efficiencies for these cells are around 10% and they are relatively new to the market.

3.4.7 Fuel cells

A fuel cell is an electrochemical device that converts chemical energy into electricity and thermal energy. It produces electricity from the reaction of a fuel (on the anode side) with an oxidant (on the cathode side) in the presence of an electrolyte. Fuel cells differ from batteries as they require a fuel source that must be replenished. The fuel substitutes electricity used for recharging in a battery device. Fuel cells range in size from a few kilowatts to megawatts and can use a variety of fuel sources.

Figure 3.23 provides a schematic representation of a polymer exchange membrane fuel cell (PEMFC). This fuel cell works by catalysis, separating the component electrons and protons (H+ ions) of the reactant fuel. The electrolyte allows the flow of protons and forces the electrons to travel through an external circuit creating electricity. An inverter is required to convert the DC current into AC power (see Section 3.3.1). A further catalytic process combines electrons back with the protons and oxidant to form waste products (water in this case). The hydrogen fuel cell pictured requires a flow of pure hydrogen. In some instances, this flow could be formed from an electrolytic reaction which breaks water into its constituent parts for later use. More commonly, a reformer is used to process a fuel such as natural gas into hydrogen creating carbon dioxide and water as waste materials. The reformer may use waste heat from the exothermic reaction. Alternatively, the waste heat can be used in CHP applications where applicable.

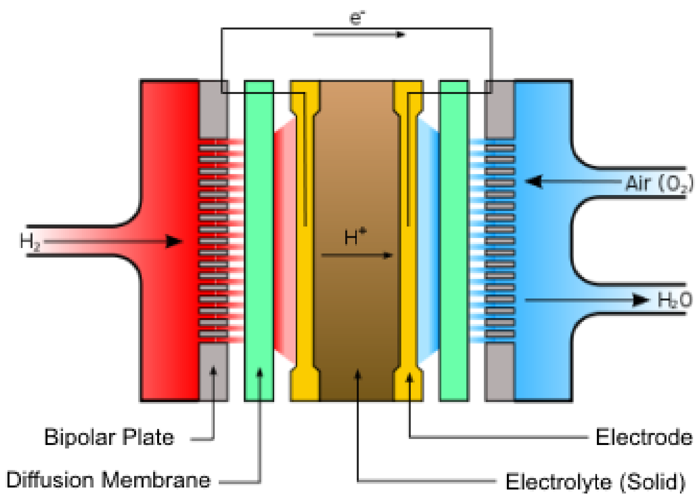


Figure 3.23: Schematic diagram of a PEM fuel cell (Wikimedia, 2009k)

Figure 3.24 shows that fuel cells are somewhat cheaper than wind and solar technologies. In this example, the fuel cell runs on natural gas using a reformer to create hydrogen. Like solar photovoltaic and wind technologies, fuel cells have little market penetration. As such, the price in real terms is expected to drop considerably over time with mass production. There are a number of fuel cells in development, and four of these are described briefly below.

Polymer Exchange Membrane Fuel Cell (PEM): A PEMFC can be constructed of plastic, metal or carbon and uses air or oxygen as an oxidant which reacts which H^+ ions transferred through a solid electrolyte (see above). Electrical efficiencies are expected to be around 30-40%. Overall efficiency can be improved by utilising waste heat. In these units, operational temperatures are around 65-85°C which could be useful for low grade applications (EPRI, 2004).

Phosphoric Acid Fuel Cell (PAFC): A PAFC is typically constructed of carbon or ceramic material and uses air (or oxygen enriched air) as an oxidant which reacts which H^+ ions transferred through a phosphoric acidic electrolyte. Electrical efficiencies are expected to be around 35-45%. Overall efficiency can be improved by utilising waste heat. In these units, operational temperatures are around 190-210°C which could be useful for higher grade applications than a PEMFC (EPRI, 2004).

Molten Carbonate Fuel Cell (MCFC): In a MCFC, charge is carried via CO_3^{2-} ions. They are typically built from high temperature metals and ceramics. They use air as an oxidant and operate at 650-700°C and have expected electrical efficiencies of around 40-50% (EPRI, 2006).

Solid Oxide Fuel Cell (SOFC): A SOFC uses O^{2-} ions as the charge carrier and air as an oxidant. They run at high temperatures (750-1000°C) and are built from ceramic and high temperature metals. In 2005, predicted electrical efficiencies where around 45-55% (EPRI, 2004). In 2008, an Australian company (Ceramic Fuel Cell Limited) reported an electrical efficiency of a micro-CHP unit at 60% (http://www.cfcl.com.au/Electrical_Efficiency/). With heat recovery, the total efficiency can approach 85%.

Emissions from these technologies are lower than other fuel based distributed generation technologies (see Appendix C). While the oxidation process producing electricity is clean (creating water), the reforming process can produce NOx, CO, hydrocarbons and CO_2. Add-on emission controls can be used if required.

3.4.8 Summary of distributed generation technologies

Table 3.8: Characteristics of distributed generation technologies (in 2010 and as used in ESM modelling, Section 9.1).

Technology name	End-user	Fuel	Indicative size	O&M cost ($/MWh)	Capital Cost ($/kW)	Electrical Efficiency (% HHV)	Maximum Total Efficiency (% HHV)	Fuel transport cost ($/GJ)	Economic life (years)	Capacity factor (%)
Combined cycle CHP	Industrial	Gas	30 MW	35	1935	45	81	1.35	20	65
Fuel cell CHP	Residential	Gas	2 kW	70	3476	58	79	11.20	15	80
Microturbine CCHP	Commercial	Gas	60 kW	15	4268	28	78	5.85	15	43
Microturbine CHP	Commercial	Gas	60 kW	10	3734	28	78	5.85	15	18
Rankine CHP	Rural	Biomass	30 MW	30	3169	28	56	24.60	25	65
Reciprocating engine	Industrial	Gas	5 MW	5	1265	40	N/A	1.35	20	1
Reciprocating engine	Commercial	Gas	500 kW	2.5	1265	38	N/A	5.85	20	3
Reciprocating engine	Residential	Gas	5 kW	2	919	36	N/A	11.20	20	1
Reciprocating engine	Commercial	Diesel	500 kW	5	460	45	N/A	1.55	15	3
Reciprocating engine	Commercial	Biogas	500 kW	0.5	2068	38	N/A	0.50	20	80
Reciprocating engine CCHP	Residential	Gas	5 MW	15	4439	40	84	1.35	20	80
Reciprocating engine CCHP	Commercial	Gas	500 kW	10	2497	38	80	5.85	20	43
Reciprocating engine CCHP	Residential	Biogas	5 MW	15	4439	40	84	0.50	20	80
Reciprocating engine CCHP	Commercial	Biogas	500 kW	10	2497	38	80	0.50	20	43
Reciprocating engine CHP	Industrial	Gas	1 MW	7.5	1776	40	84	1.35	20	65
Reciprocating engine CHP	Commercial	Gas	500 kW	5	1998	38	80	5.85	20	18
Solar PV	Commercial	Solar	40 kW	0.5	7027	N/A	N/A	N/A	25	variable
Solar PV	Residential	Solar	1 kW	0.5	8384	N/A	N/A	N/A	25	variable
Wind turbine	Commercial	Wind	10 kW	0.5	6090	N/A	N/A	N/A	15	variable
Wind turbine	Residential	Wind	1 kW	0.5	4964	N/A	N/A	N/A	10	variable

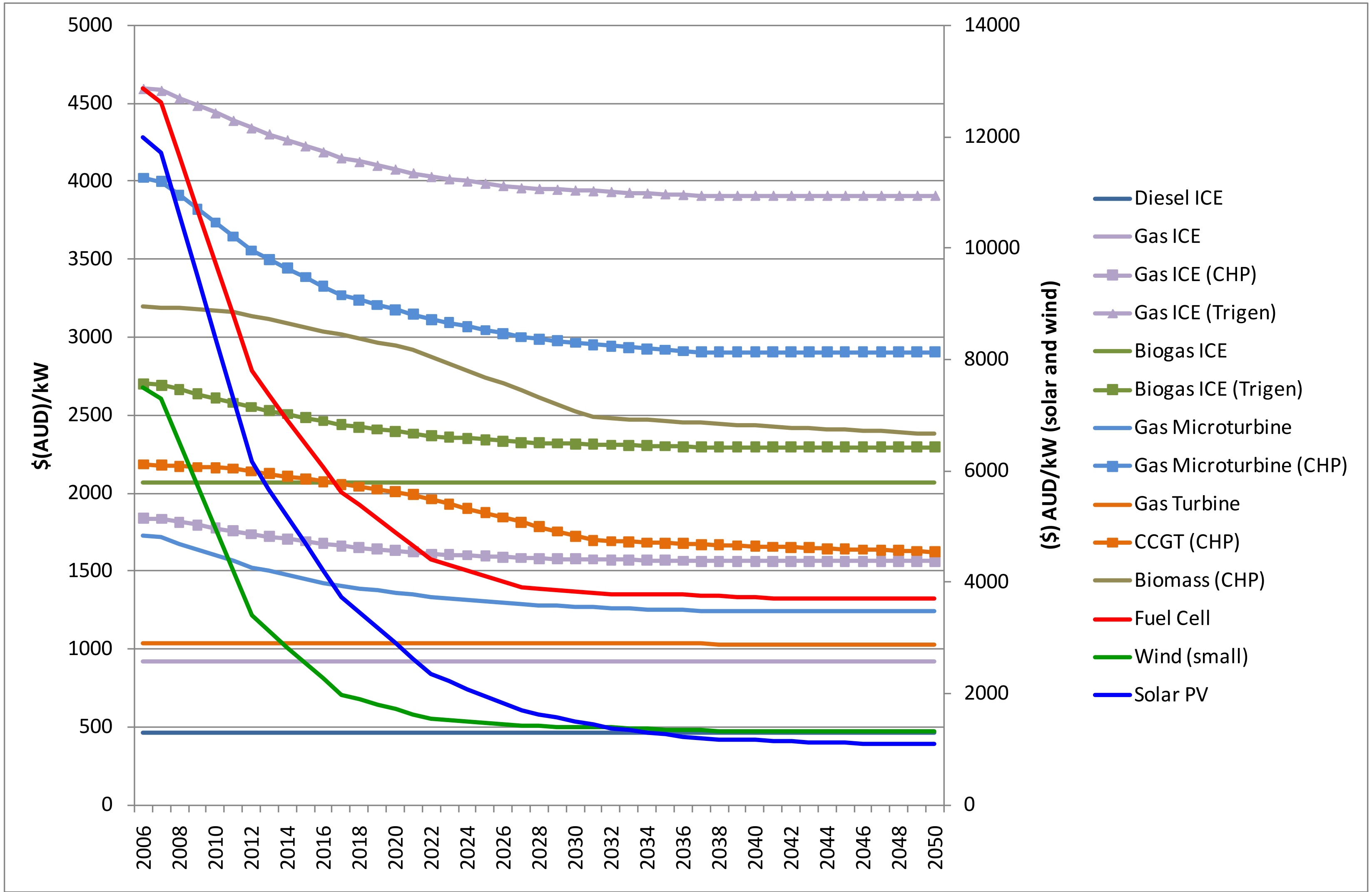


Figure 3.24: Assumed cost curves for DG technologies as used in ESM modelling (see Section 9.1).

3.4.9 Grid connection

The process of connecting generators to the distribution network is in part influenced by the type of generator itself. The devices essentially fall into three classes of generator: synchronous machine, induction machine and inverter-connected generators.

The synchronous electrical machine is the backbone of electricity generation throughout the world. It converts mechanical energy from a device such as an engine into electrical energy whose output frequency is determined by the rotational shaft speed and the number generator poles. Synchronous machines have the capacity to deliver and sustain fault currents[2] which can exceed the rated current by several orders of magnitude. This makes it an ideal machine for connecting to the distribution grid.

Asynchronous (or induction) machines (AMG) can be operated at a range of speeds. The rotor in this case must be driven at a speed higher than the grid frequency in order to deliver power to a network. The capacity to generate at variable speeds lends the AMG to renewable energy applications where the primary energy source is variable, large wind turbines are an example technology utilising AMGs.

AMGs require an external supply to provide excitation. Depending on the speed of the rotor, the excitation flux will either consume power (as a motor) or deliver power at the synchronous frequency (as a generator). For a grid connected device, the excitation flux current is supplied from the network which results in the generator requiring reactive power. The requirement of real power from the network is a cost that needs to be factored into consideration. Since these generators do not have self-excitation they are incapable of delivering sustained fault currents but their making current needs to be accounted for.

For devices that output a direct current (DC) such as a photovoltaic cell, an inverter is required to transform the output to an alternating current (AC) when connecting to the wider grid. A power converter interfaces the generator's variable DC output to the fixed AC grid signal. An inverter will use a pair (or more) of transistors to continually switch the direction of the voltage. In Australia, the switching or oscillation occurs 50 times a second (50 Hz). It does this by running the DC it into a pair (or more) of power switching transistors which are rapidly switched on and off and feed to opposite sides of a transformer. This forms an alternating DC input which the transformer converts to an AC output. Depending on the quality of the inverter, it may output a square wave, a modified (or quasi) sine wave or a true sine wave. If connected to the grid, the inverter requires a sample of the mains voltage for synchronisation.

At larger scales, AC rotating machines are used operating at variable speed and a power converter is used to interface the variable-frequency, variable-voltage AC signal with the fixed AC grid. Like induction machines, inverters do not deliver steady state fault currents. Both will

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[2] A fault current is an abnormal current in a circuit due to a fault (usually a short circuit). The maximum (or making) fault current occurs in the first 20 ms while the steady state fault current follows after approximately 40-60 ms. To protect a circuit, the fault current must be high enough to operate a protective device as quickly as possible and the protective device must be able to withstand the fault current. A calculation of fault currents in a system determines the maximum current at a particular location and this value determines the appropriate rating of breakers and fuses.

deliver 'making' fault current - in the case of inverters, at a similar level to normal operation, in the case of induction machines, at a similar level to locked rotor start-up (say six times normal current; westernpower, 2008).

Grid connection costs

In Australia, network service providers (NSPs) operate, maintain and upgrade their infrastructure based on forecast growth over a five-year cycle. These forecasts are used to determine the amount of spend required to meet demand and are subject to regulatory checks. Previously these economic checks were performed by State based entities. For instance, in Victoria, the Essential Services Commission in Victoria (ESCV) provided economic regulation of network businesses. From 1 January 2009, economic regulation of distribution businesses was transferred to a National authority; the Australian Energy Regulator (AER). The AER is now the economic regulator of all networks businesses in the NEM (see Section 3.2).

The AER determines how much DNSPs can receive in revenue by setting a price or revenue cap for electricity sales (see Table 3.4). This cap represents the regulators view on what is reasonable for DNSPs to charge customers for the delivery of electricity including maintenance, operation and system reinforcement, and includes a profit margin for distribution businesses. This revenue forms part of the total electricity bill and is known as the distribution use of system charge (DUoS). The price or revenue cap is set at the beginning of each five-year determination.

A vital component of the AER’s determination is a prediction of peak and base demand provided by the DNSP. Any changes to the network demand within a regulatory cycle that results from activities such as demand management or distributed generation can affect this determination and shortfalls in forecast throughput effectively operate as a penalty for the business under the price capping scheme. Similarly, the introduction of a large load mid-cycle could lead to significant concerns for the DNSP if their system does not have sufficient redundancy built in.

The effect of unplanned demand management on distribution business revenue is a contested issue. In its stage 2 draft report into barriers to demand side participation, the AEMC state that any loss of revenue felt by a distribution business acts to discipline the market only to provide efficient demand management. Their rationale is that demand management entails a customer foregoing energy consumption, and so lost network revenue reflects the social cost of not consuming. This contention is considered further in Chapter 6 of this report.

The determination of connection costs is considered here with reference to Victoria as an example. Previously, under the ESCV the cost of new and upgraded connections in Victoria was determined by the “Electricity Industry Guideline, No 14: Provision of Services by Electricity Distributors” (ESCV, 2004a). The guideline facilitates the determination of customer contributions to the capital cost of new works and augmentation, the contestability of connection and augmentation works, and the provision for excluded services. Embedded generation (distributed or local generation in this study) falls under the excluded services in Guideline 14 and is guided further by the “Electricity Industry Guideline, No 15: Connection of Embedded Generation” (ESCV, 2004b). Guideline 15 is meant to provide clarity in the manner in which DNSPs negotiate and set charges with distributed generation proponents and in determining payment of avoided use of system charges (DUoS and TUoS). As noted earlier, the AER is now responsible for the economic determinations for distributors in each Australian State. In transferring functions to the National level, the AER inherited these guidelines and is responsible for their implementation and future development.

The process for connecting distributed generation and allocating costs is currently being reviewed as part of the energy market reform process, discussed in some detail in Chapter 5. It is likely that any changes driven by this reform will be some time away due to the complex nature of the issue. As such, it is expected that State specific guidelines will remain relevant in their current form for some time.

A contentious point in the connection of distributed generation has been the allocation of “shallow” or “deep” connection costs. This issue has been raised in many submissions to government authorities in reviews both locally and internationally. The cost of connecting a local generator to the nearest point in a network is referred to as a “shallow” connection charge. A circuit breaker used exclusively by the generator for instance would fall into this category. This cost might not fully reflect system reinforcement upstream that may be required to allow the safe implementation of the device. These additional costs are considered by some as “deep costs” and in some areas may be passed onto the connecting generator. Guideline 15 states that in Victoria, shallow costs for the connection are those associated with connection assets and any augmentation of the distribution system up to and including the first transformation in the distribution system. Furthermore, the guideline states that deep costs beyond this point cannot be allocated to the local generator. Again, a National framework for the allocation of shallow and deep connection costs is subject to current review.

While the connection process appears reasonably simple in design, costs can vary depending upon the timing of connection. Consider a number of proponents that wish to connect to a network over time. The first proponent may find that the system can easily cater for their introduction. At a later time, a second proponent may wish to connect to the network. In this case, the DNSPs ability to cater for their introduction will have been altered by connection of the first proponent. In this case, they may find that their proposed connection requires changes in the network such as replacement of a circuit breaker at the next highest voltage level due to increased fault levels for instance. These costs which fall within the definition of a shallow charge may have been avoidable by the second proponent if for instance, they had connected first, and if their addition did not require augmentation for the earlier network state. Additionally, a third proponent may now find that adding to a network requires only standard costs because of changes induced by the second proponent.

In its current review of “energy market design in light of climate change”, the AEMC is developing a process for connecting multiple generation units to the transmission network. It is our understanding that this framework will be applied to distribution connections also. However, details of the connection process facilitation have not been worked through.

Clearly, connection costs and how they impact on network companies, and so the connection process itself, is a complex issue determined by a number of factors including:

- The number and timing of proposed additions to a network
- The demand forecast estimates used in the current regulatory determination
- The size and type of the proposed connecting generator, and
- The network characteristics at and upstream from the point of connection.

It is worth noting here a distinction between adding generation to a network and undertaking local energy efficiency measures. Adding local generation will require connection to the grid which incurs a connection cost. In contrast, energy efficiency measures provide a reduction in demand (equivalent to increased generation) that does not incur extra network costs. Both mechanisms can reduce sales volume and potentially profit margins to retailers and DNSPs (those regulated by a price cap) through reduced volumes of energy.

Dealing with these connection costs is an area of considerable and complex debate. In some cases, connection costs are seen as a barrier for introducing local generation (see Chapter 6). Connection costs are seen by some as contentious in part because most energy assets were built at a time of Government owned infrastructure, with costs shared across customers and tax payers. Given these assets are now ‘sunk’, any historical distortion of cost allocation is naturally impossible to undo. However, it is important to recognise the origins of the energy market structure, to realise that a centralised supply model dominates by virtue of historical circumstance as much as any inherent virtue. Perhaps what is most important today is that the process and methodology for calculating connection costs faced by all new generators connecting to distribution or transmission networks are consistent, and cognisant of the potential for distortions to occur due to information or negotiating power asymmetry.

Furthermore, issues around reliability and safety are a significant concern for network operators who are responsible for the performance of their network and who are penalised for failing to meet reliability and service standards. Addition of generation (or demand reduction) within their network and outside their scope of control can lead to risk. Valuing the change (positive or negative) that local generation (or demand management) provides for the network is difficult to determine, is location specific and has no currently available standardised method for evaluation.

In Australia, connection issues are being considered via the Ministerial Council on Energy (MCE) review on “Network Incentives for Demand Side Response and distributed generation” and the AEMC review of “Demand Side Participation in the National Electricity Market” and “Review of Energy Market Frameworks in light of Climate Change Policies”. A number of similar processes are underway abroad one of the most relevant being those under taken by Office of the Gas and Electricity Markets (Ofgem) in the United Kingdom (see Ofgem, 2009).

3.5 Demand management

Demand management (DM) refers to a suite of technologies and techniques used to alter demand profiles over time. Active control measures can smooth or shift demand peaks, or substitute local generation for centralised generation. Passive control measures such as energy efficiency can reduce total demand over time, or the maximum demand drawn at any given time. Figure 3.25 provides an illustrative demand profile, indicative of a network area dominated by commercial energy demand and hence a midday peak in summer. In this example, the blue curve shows demand ramping up from 6am when people begin to wake and get ready for work. Demand grows during the day peaking before lunch as air conditioning demand grows in commercial buildings. The demand then drops off slowly briefly peaking again in the late afternoon as people return home.

The goal of demand management is to smooth the demand profile over time, reducing spending on expensive network and peak generation assets which would otherwise be required to supply energy infrequently, and for short periods of time. In this way, significant financial savings can be made. The techniques used to manage demand may also reduce total demand over time, although this is not always the objective.

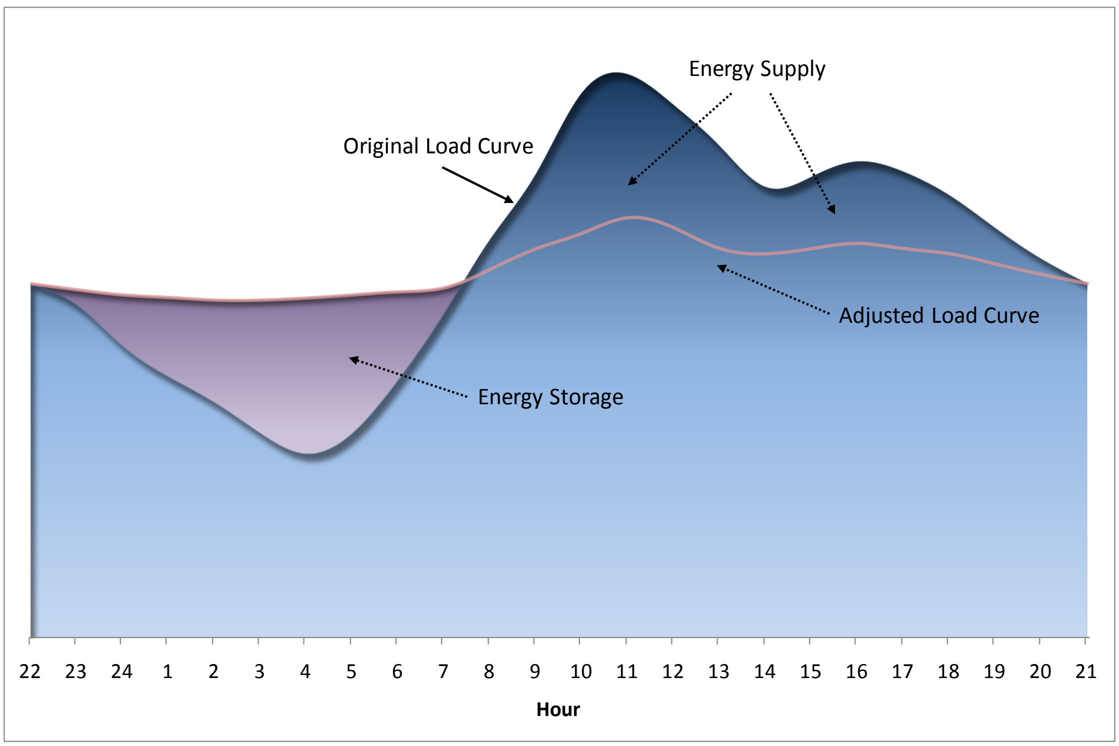


Figure 3.25: A hypothetical daily demand profile including storage

A number of technologies are important for demand management. These are generally storage devices such as batteries, compressed air and thermal materials, or communication and control technologies that allow controlled cycling of appliances such as compression cycles in air conditioners or discretionary loads such as pool pumps to be turned off.

Storage devices take a variety of forms and can be used for many applications including maximising the value of intermittent, but predictable clean energy such as wind and solar power or mitigating the cost of peak demand at the distribution or transmission level. They do this by storing any energy produced at times of low demand and releasing it at times of high demand. Storage options can include coordinating refrigeration cycles in large cold stores so that temperatures are dropped at times of low demand or high solar/wind output, and allowed to rise at times of high demand or low solar/wind output. Optimising the integration of low cost storage devices with alternative forms of generation and discretionary heat and power loads are likely to be critical to realising high penetrations of renewable and distributed energy in a cost effective way.

A simple example of low-cost storage is the thermal inertia of a building such as a commercial office block. An office block constructed of concrete may be cooled overnight using energy supplied at off peak times when demand is low. The concrete will trap the cooling potential in the thermal inertia of the building material. As the building heats during the daytime, the cool concrete can absorb heat from the surrounding air offsetting the need for electricity use, and so reducing daytime peak demand on the network. Figure 3.25 illustrates this concept. In this case, storage of some type is activated overnight when electricity prices are low. The storage is then called upon during peak hours. This process smoothes demand as shown by the pink line in the figure above. While the total energy remains more or less the same, the total expenditure on electricity is dramatically reduced by decreasing energy purchases during peak times. If such measures prove reliable and repeatable, then in the long run prices could fall by such practices providing a measure to reduce spending on network infrastructure which is sized to meet peak demand.

A relatively new storage concept is plug-in electric vehicles. The vehicles contain significant storage potential in their electrochemical batteries. These batteries could be charged slowly overnight during times of low demand, or could be used to store energy created from renewable sources such as wind and solar which may be producing at non critical times. It is possible that these batteries could discharge during peak times, either when parked in an office block or in the driveway at home, to shave peak demand. Operating in this manner, the economics of owning and operating a vehicle may alter as it adds value in the two energy domains of transport and electricity. The economics will depend significantly on battery costs in the vehicle, whether battery capacity additional to driving needs are required, the ability to capture the value of time specific energy prices, and the costs of system integration including integration with the National Energy Market if desirable. The effect on the stationary energy sector would be governed by the location and timing of recharging and the growth in demand for vehicles over time.

Demand management offers potential value to network companies, energy retailers, energy customers and the market operator. Most simply, as noted above it can defer spending on network assets for network companies, reduce wholesale energy prices particularly at peak times and so reduce retailer and customer exposure to wholesale market price volatility. However, it can also offer more complex services, for instance controlling loads in emergency situations (such as power shortages or outages), providing frequency control and ancillary services, or managing customer exposure to generation or network charges according to stated preferences. By way of example, Read et al. (1998) in Ackerman et al. (2000), found that ancillary service costs were reduced by 75% in the first year that interruptible load was allowed to participate in the New Zealand energy market.

Capturing the value of undertaking demand management is not always simple and is related to the nature of the energy market, policies and regulation in the jurisdiction in which it is deployed. As described in Section 3.2.1, the National Electricity Market (NEM) is an energy-only market, which means generators receive payments for the production of energy, not the provision of reserve capacity. Amongst other things, an energy-only market typically aims to meet additional demand with additional supply rather than demand management.

Different jurisdictions in the NEM also have different market structures with varying levels of private and public ownership, and price deregulation in Victoria only. Price regulation interacts with demand management, as prices are necessary to signal the need, and value of a demand management option. Where price structures are flat, the signal for demand management is dampened. We note that the degree to which price reflects the true cost of supply is necessarily limited by the need to ensure that social objectives such as energy affordability are met.

The interplay of market structure, policy and regulation impacts on the incentive to undertake demand management and this is explored in more detail in Chapters 6 and 7, in a review of literature detailing barriers to DE and a discussion of DE enablers.

Demand Management Incentive Schemes (DMIS)

In acknowledgement of the complexity facing demand side solutions, the AER have developed Demand Management Incentive Schemes (DMIS) for distribution businesses. At this stage, the DMIS in each State differs slightly to reflect State based regulation, prior to National regulation. The AER intends to deliver a National version once National policy settings such as CPRS and reviews such as AEMC's demand side participation are understood. Further discussion of the DMIS below relates specifically to the final Victorian determination (AER, 2009) as an example.

The objective of the DMIS is to provide incentives for Victorian DNSPs to implement efficient non-network alternatives or to manage expected demand for standard control services in some other way. It is not designed to be the primary source of funding for demand management expenditure which is based on the approved forecasts of operating and capital expenditure in the AER's determination for a particular DNSP.

The scheme will provide a demand management innovation allowance (DMIA) which allows the DNSP to recover funds allocated to these non network solutions through two mechanisms. Part A of the DMIS allows:

> *"an annual, ex-ante (before the event) allowance in the form of a fixed amount of additional revenue at the commencement of each regulatory year of the regulatory control period". "In the second regulatory year of the subsequent regulatory control period, when results for regulatory years one to five are known, a single adjustment will be made to return the amount of any underspend on unapproved amounts to customers" to ensure the scheme remains neutral. "The total amount recoverable under the DMIA within a regulatory control period will be capped at an amount based on the AER's understanding of typical demand management project costs, and is scaled to the relative size of each DNSPs average annual revenue allowance in the previous regulatory control period" (AER, 2009)*

Part B of the DMIS allows the DNSP to:

> *"recover forgone revenue resulting from a reduction in the quantity of energy sold for a DNSP", "whose direct control services are subject to a form of control whereby recovery of the annual revenue is at least partially dependent on energy sold." "The reduction in energy sold must be directly attributable to the implementation of a non-tariff demand management program approved under part A of the DMIS. Approved forgone revenue will be provided to a DNSP in the second regulatory year of the subsequent regulatory control period, as an addition to the innovation allowance adjustment in that regulatory year, to offset the disincentives associated with certain forms of control." "Recovery under this part B is limited to revenue forgone as a result of non-tariff demand management projects or programs approved by the AER under the DMIA" (AER, 2009).*

It is important to note that demand management led by distribution network businesses is only one model. Demand management could be performed by retailers or third parties, to the extent they can capture the value of doing so and thereby make a commercial return. Impediments to demand management are discussed in more detail in Chapter 6, while Chapter 7 details how the benefits of demand management can be realised.

3.6 Energy efficiency

Energy efficiency can be thought of in a number of ways. In one sense, it is a reduction in energy demand as a result of changes in performance efficiency of individual devices or the substitution of one form of energy for another more efficient version (using solar energy for heating water for instance). In another sense, improvements to system efficiency are a form of energy efficiency. This could include the reduction of losses by generating energy close to the point of consumption, or improving the utilisation of a fuel by capturing more of the energy available as occurs in cogeneration and trigeneration. Improving system efficiency can help reduce greenhouse gas emission, reduce energy costs, but can also mitigate against fuel scarcity risks by creating better use of a limited quantity of fuel.

Energy efficiency is often seen as the easiest and most cost effective way to reduce greenhouse gas emissions in the short term. There are many consultants available who specialise in the measurement of energy use and detailing replacement or upgrade options. Alternatively, government authorities such as the Department of Energy, Water, Heritage and the Arts (DEWHA) provide audit tools so that staff can easily examine their energy use and determine least cost solutions for energy reduction. The audit tools provide guidance on categories including indoor and outdoor lighting, chillers, boilers and steam systems, heating and ventilation equipment and insulation.

While all energy efficiency measures reduce energy consumption, or maximise the value of a given unit of available energy, their economic merit can vary depending upon the timing at which the efficiency gain is made. For example, solar hot water systems heat up during the day and store hot water in tanks. The greenhouse gas savings for these systems are greatest when replacing off-peak electric hot water units, as these units would otherwise draw on grid based electricity that is primarily coal fired. However this off-peak hot water system was developed to remove load from the network during the day when it is most stressed and to allow large coal-fired generators to operate continuously, thereby maximising their thermal efficiency. In this way, off-peak electric hot water provides a service to the electricity industry which results in reduced energy prices.

The value of substituting off-peak electric hot water with a solar hot water system can be contrasted with a solar based cooling system. In this process, fresh (outside) air is dehumidified in a rotary desiccant wheel (see Figure 3.26). In this adiabatic drying process, the air is unavoidably warmed. A heat recovery heat exchanger is used to cool the warm dry air back down to near ambient temperature. The resulting pre-cooled, dry air stream is then further cooled to temperatures below ambient using an evaporative cooling process before it is introduced into the occupied space to provide the desired space conditioning.

Regeneration of (moisture removal from) the desiccant wheel is required to ensure a continuous drying process. Regeneration is achieved by passing hot air through one side of the desiccant wheel. Moisture removed from the desiccant wheel is exhausted with the regeneration air stream exiting the desiccant wheel.

Regeneration air can be sourced from the occupied space (return air) or from outside ambient (fresh air). Regeneration air is first evaporatively cooled before it is pre-heated in the heat recovery heat exchanger. This minimises the supply air temperature before the supply air evaporative cooling process and maximises the regeneration air temperature before it is further heated in a heating coil with externally supplied heat.

External heat could be obtained, inter alia, from solar collectors, a cogeneration unit or from a fossil fuel burner. In a current CSIRO research project (REDECool), the desiccant cooling process is being adapted to run off low temperature heat from a common flat plate domestic hot water system. In this way, the full REDECool product aims to supply domestic hot water, winter space heating and summer space cooling.

If commercialised, these units will allow a significant reduction in energy during peak hours by substituting solar energy for an electrical chiller, using much of the same technology as a solar hot water system. However, because the unit reduce temperature sensitive energy demand, it has significantly more value to the energy market and network than a solar hot water unit.

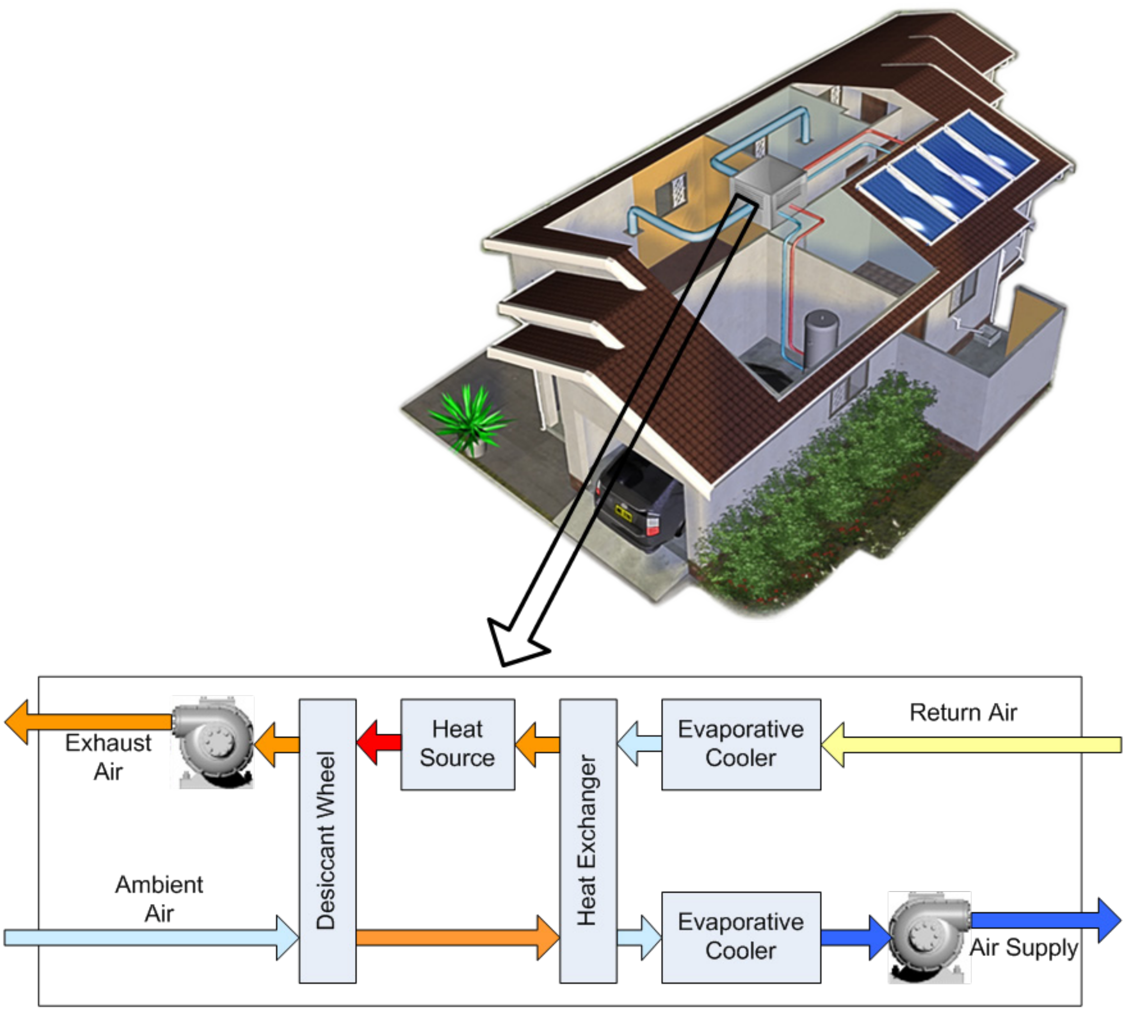


Figure 3.26: Schematic representation of a solar based air conditioning system.

That the value of energy efficiency is not only determined by the quantity of energy that can be saved, but the timing of those energy savings, has important implications for how the value of energy efficiency is determined by policy makers, regulators, consumers and businesses. Many energy efficiency programs are designed to reduce greenhouse gas emissions at least cost. However, costs of emission reductions are typically calculated based on the relatively flat tariff structure that consumers experience. This has guided the principle behind market based energy efficiency schemes in various states such as white certificate schemes. However, as noted above, the cost of reducing emissions is a function of both the quantity of emissions reduced, and the timing of their reduction. Consider the following example.

The West Australian Office of Energy aimed to quantify the cost of building generation and network infrastructure required to supply air conditioners. To do this, they estimated that the infrastructure required to supply the top 20% of demand, where air conditioners were most likely to be operating at full capacity, was around \$3000/kW of capacity (WA Office of Energy, 2004). If we assume that generation and network infrastructure has a lifetime of 30 years, and an air conditioner a lifetime of 10 years, ignoring the time weighted cost of money, we can say that reducing air conditioning by 1 kW has a value of \$1000 in Western Australia.

The following figures compare the costs, and so potential savings, of addressing peak demand and reducing emissions through energy efficient air conditioning. The horizontal axis represents the demand reduction due to energy efficiency measures. The "Emissions" series represents emission savings and the "Infrastructure" series represents reduced infrastructure costs. The "Total" series provides a sum of emission and infrastructure savings. In these illustrative figures, the emissions are priced at \$20/t, and the emissions intensity of electricity is assumed to be 1000 kg/MWh. Figure 3.27 charts the value of an appliance operating for 10,000 hours, while Figure 3.28 provides an estimate for an appliance operating for 49,000 hours.

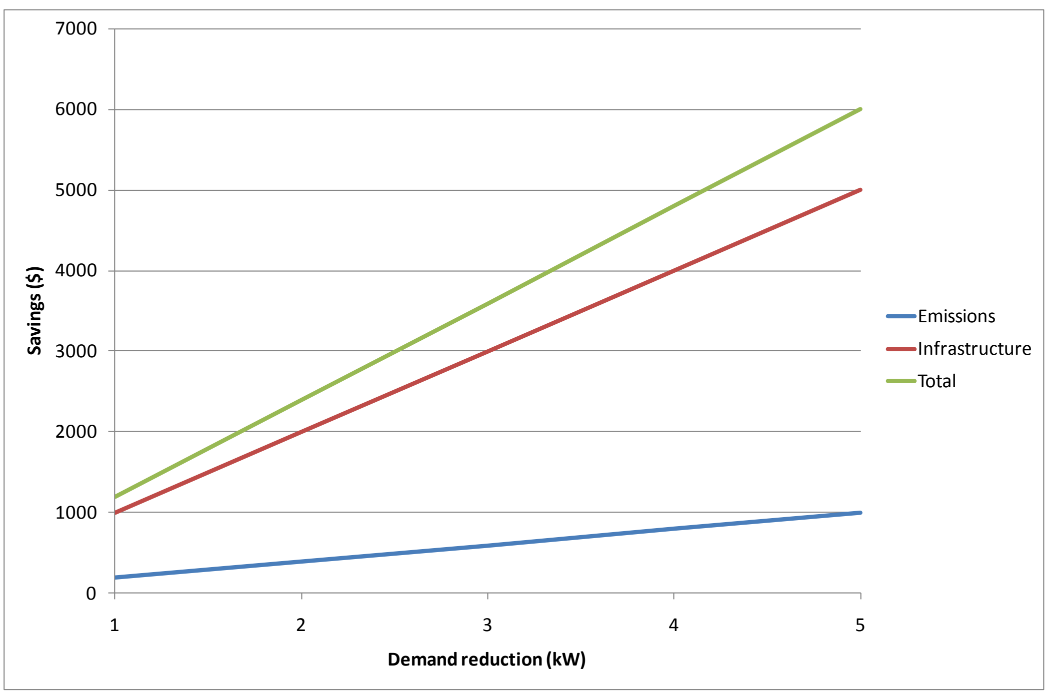


Figure 3.27: Saving estimate for demand reductions for a device operating for 10,000 hours.

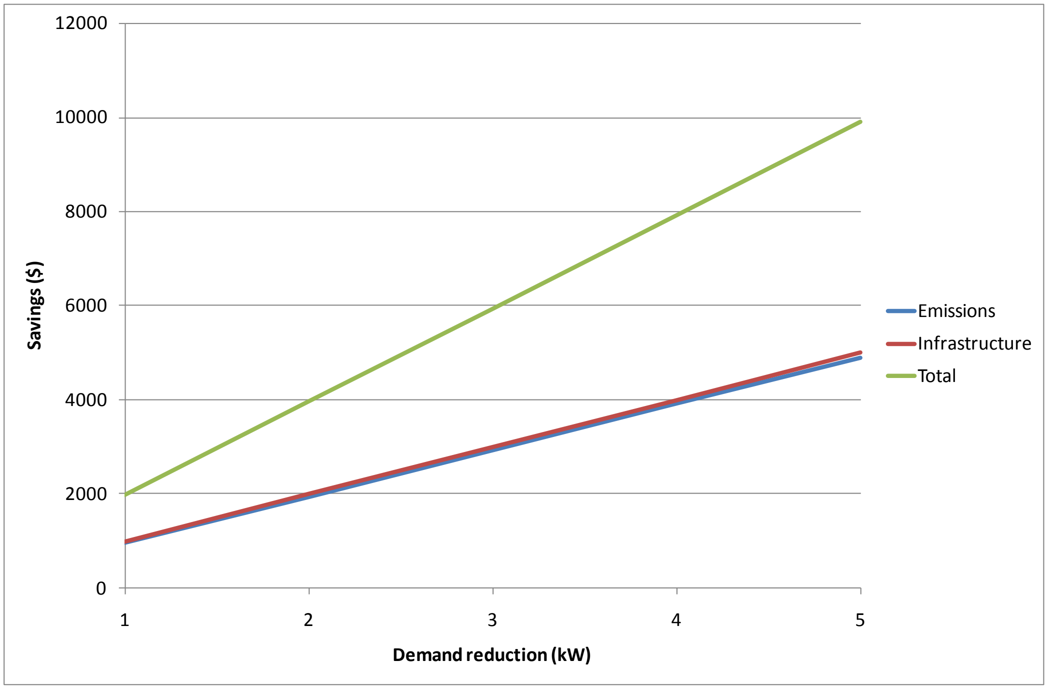


Figure 3.28: Saving estimate for demand reductions for a device operating for 49,000 hours.

The figures highlight that for each kW of capacity reduced through air conditioning energy efficiency, the value of infrastructure savings outweigh the value of emissions savings, unless the appliance is operated in excess of approximately 50,000 hours over its lifetime. Considering an air conditioner may operate for less than 1,000 hours a year, this cost difference is significant. It is important to note that if the price of emissions was set at a higher rate, say $100/t, then at 10,000 hours lifetime, the value of emission and peak infrastructure savings are equal for this example.

This simple example highlights the importance of better methodologies for calculating the value of energy efficiency policies and regulation. This is considered again in Chapters 6 and 7.

4. DISTRIBUTED ENERGY MARKET PENETRATION

4.1 Key findings

It is difficult to make global comparisons about distributed energy penetration due to the wide range of variables that affect its uptake including: availability and cost of centralised energy; geographic characteristics; climate; population density; energy market structure; economic structure; policy; and regulation. However it is reasonable to assume the market for distributed energy in Australia will be affected by global trends, as technology development and new system design configurations overseas will influence technology and system development in Australia.

When considering export opportunities for Australian companies, or potential influencing factors on Australian market development, it is important to note the experience of China and India, where distributed energy is relatively well utilised when compared to nations of comparable economic development, often in the rural context. Due to the relative lack of reliable centralised supply infrastructure, the rate of energy demand outstripping generation capacity, and significant air quality issues, the modular, clean nature of many distributed energy options makes it a logical, low cost option, mitigating significant environmental and social health costs.

For Australia, the experience around the world suggests there may be considerable untapped distributed energy potential, most probably constrained historically by the low cost and abundance of centralised energy supply and Australia's climatic conditions. However, with many of Australia's centralised supply infrastructure assets either in need of, or in the process of renewal, growing recognition of the importance of greenhouse gas pollution reductions and technological development that allows the use of heat for cooling, Australia is well positioned to increase its penetration of distributed energy and secure the benefits it can provide. The extent of these benefits and the potential large scale uptake of distributed energy are explored in Chapter 9.

4.2 Background

Distributed energy can be deployed anywhere thermal energy or electrical power is needed. Figure 4.1 from the World Survey of Decentralised Energy (WADE, 2006), illustrates the extent to which distributed generation is deployed (at 2006) in various countries.

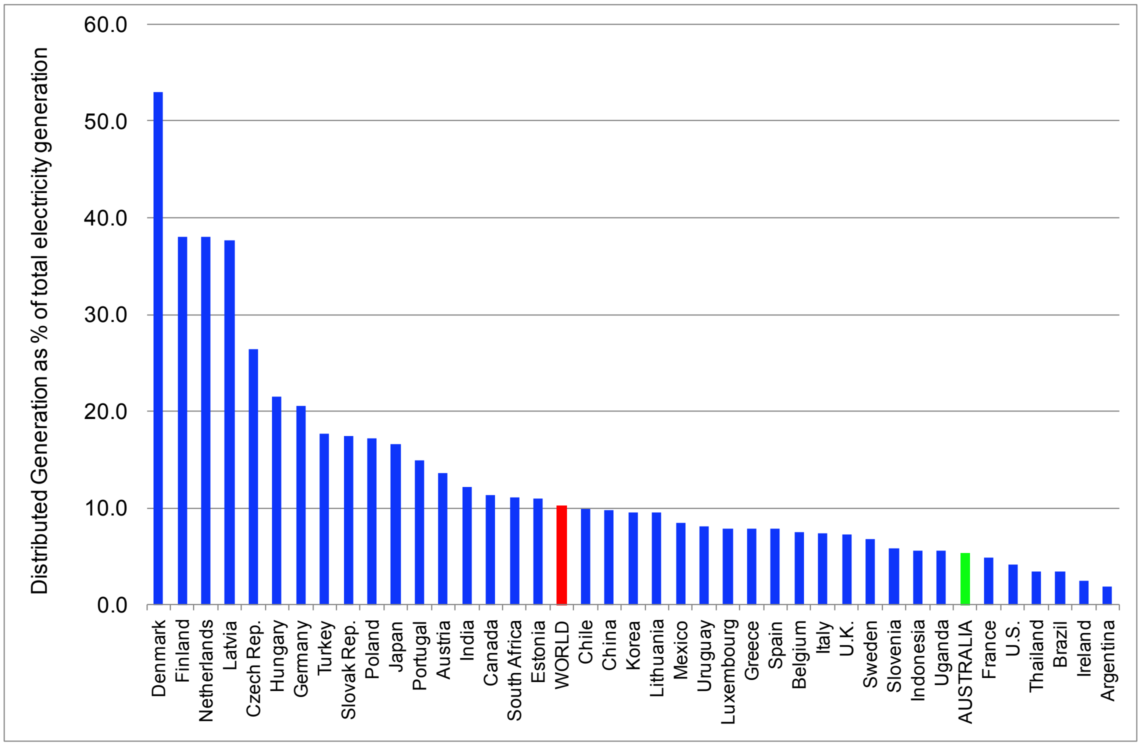


Figure 4.1: Proportion of electricity from distributed generation (WADE, 2006). Reproduced with permission of WADE.

Evident from this figure is the below average deployment of DE in Australia when compared to the world average. Generally speaking, countries with high proportions of DE tend to have the following characteristics:

- Relatively cold climates
- Highly urbanised, densely populate cities
- Industrial sectors that account for a large share of economic activity,
- Concerns over energy supply security and fuel scarcity, and
- Focused government policy on electricity and heat supply.

European countries generally have greater proportions of DE than other countries. However various DE applications are suited for both industrialised countries and emerging economies. The flexibility of DE as a power source is perhaps highlighted by the penetration of DE in China and India being approximately average by global standards, despite having significantly different economic structures to high ranking countries.

Although the United States of America has relatively low levels of DE, energy security concerns and a changing political landscape for renewable energy, is likely to drive an increase in DE, enabled by smart grids.

The following subsections contain more specific discussion on the deployment of DE in Australia as well as Europe, United States and the developing countries of China and India as a comparison.

4.3 Australia

In most regions of the country, Australians have typically enjoyed a low cost reliable supply of grid delivered electricity. In 2006-07, coal-fired generation accounted for around 81 per cent of National electricity generation (ESAA, 2008). The dominance of coal as a source of energy in Australia is driven by:

- Its relative abundance domestically
- Economies of scale in its extraction and use for power
- The absence of a price for negative externalities associated with its use, such as greenhouse gas emissions and,
- The nature of price regulation in Australia which has kept energy prices relatively stable and low.

The dominance of centralised electricity supply means that DG currently accounts for around 9% of total capacity in Australia (note this is somewhat different than the earlier WADE estimates for 2006). Table 4.1 and Table 4.2 provide detail on installed capacity of non-renewable and renewable DG respectively.

Table 4.1: Capacity of non-renewable distributed generation (MW) at 31 December 2006 (ESAA, 2008)

Plant type	**Fuel type**	**NSW / ACT**	**VIC**	**QLD**	**SA**	**WA**	**TAS**	**NT**	**AUST**
Steam	Coal	11.00		7		135.00	13.00		229.00
	Natural gas		19.20	54.50	8.00	522.50			604.20
	Oil					2		133.00	157.00
	Waste gas	80.35	57.40		6	6.50			204.25
Gas turbine	Natural gas	6.00	104.78	0.35	17.10	1320.50		16.55	1,465.28
	Oil			29.00		43.90	1		82.90
Combined cycle	Natural gas			26.50		196.00			222.50
	CSM			32.00					32.00
Reciprocating engine	Natural gas	17.77	9.11	39.34	8.71	88.76			163.69
	Oil			6.40	2	91.09	6.00	22.90	146.40
	CSM			12.00					12.00
	CWM	111.80		12.00					123.80
	LPG	0.09	0.65	0.75	0.10				1.59
Fuel cell	Natural gas	0.45							0.45
Total		414.16	285.54	303.26	115.81	2,454.35	36.65	172.45	3,782.23

Notes: CSM: coal seam methane; CWM: coal waste methane; LPG: liquid petroleum gas.

Table 4.2: Capacity of renewable distributed generation (MW) at 31 December 2006 (ESAA 2008)

Fuel type	NSW & ACT	VIC	QLD	SA	WA	TAS	NT	AUST
Hydro	186.71	94.40	20.41	1.90	30.10	3.65		337.18
Bagasse	15.50		354.75		6.00			376.25
Biomass	5.25	0.22	36.50	3.50	1.00			46.47
Black liquor	2	54.50	2.00					76.50
Landfill gas	36.48	33.60	16.57	20.93	21.70	2.76	1.10	133.15
Sewage gas	3.50	3.76	4.50	5.45	1.80	0.14		19.14
Solar[1]	1.46	0.24	0.07	0.32	0.34		1.03	3.46
Wave	0.50							0.50
Wind	16.66	133.77	12.46	387.90	176.81	2.54	0.08	730.22
Total	286.06	320.49	447.27	420.00	260.35	73.84	2.21	1,810.21

1. Excludes off-grid PV or hybrid diesel-PV systems.

Industrial cogeneration represents over 60% of DG capacity (2.5 GWe), with much of it used in heavy industries such as metals, paper and chemicals (see Figure 4.2). Eighteen percent of the country's 151 cogeneration projects are renewable, mostly bagasse-fired. Cogeneration and trigeneration in the residential and commercial sectors are limited when compared to the prevalence of district heating and cooling (DHC) systems in some European countries. In addition to the low cost of grid electricity, these systems have been hampered by Australia's relatively mild weather conditions and low density housing stock. Despite this, there is potential for significantly more cogeneration in Australia, in Sydney for instance a preliminary study indicated a potential for 330 MW of installed natural gas-fired cogeneration by 2030 (Sydney Council, 2009)

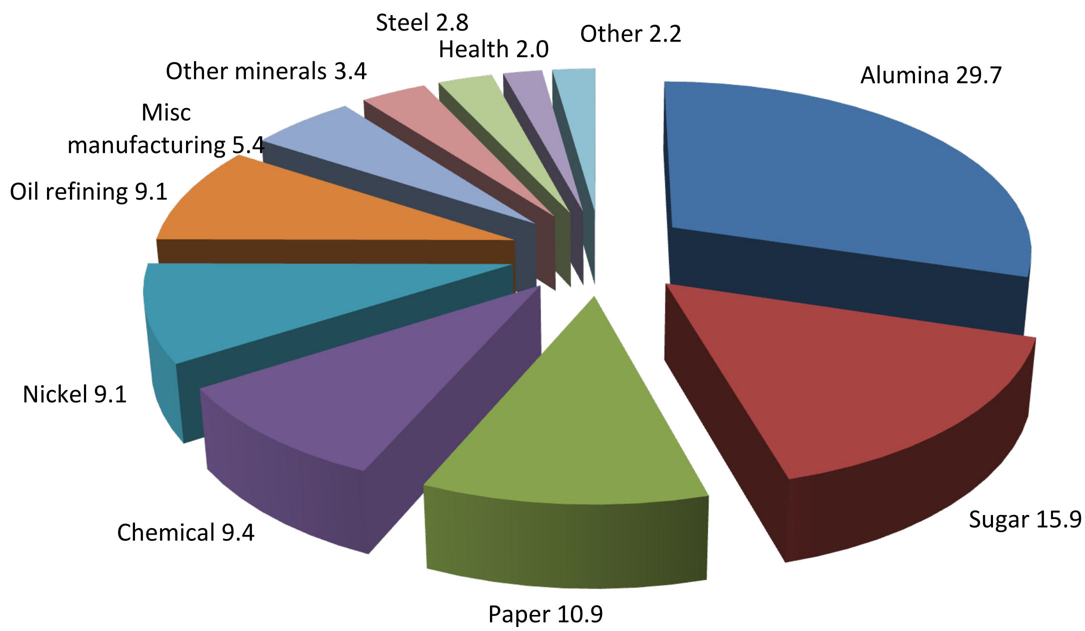


Figure 4.2: Cogeneration in Australia by host industry, 31 December 2006 (BCSE, 2007)

Installation of solar technologies has been steadily rising (see Figure 4.3), and reached 70.3 MW in December 2006, 84% of which was off-grid (Watt, 2007). The off-grid market will remain important for PV in Australia, since little additional grid extension is likely and the country has many extremely remote locations in need of reliable power. With an increased reliance on imported diesel, likely continued diesel price increases over the long term, as well as the constant problems of fuel delivery to remote locations, PV remains a cost-effective option (IEA, 2008a).

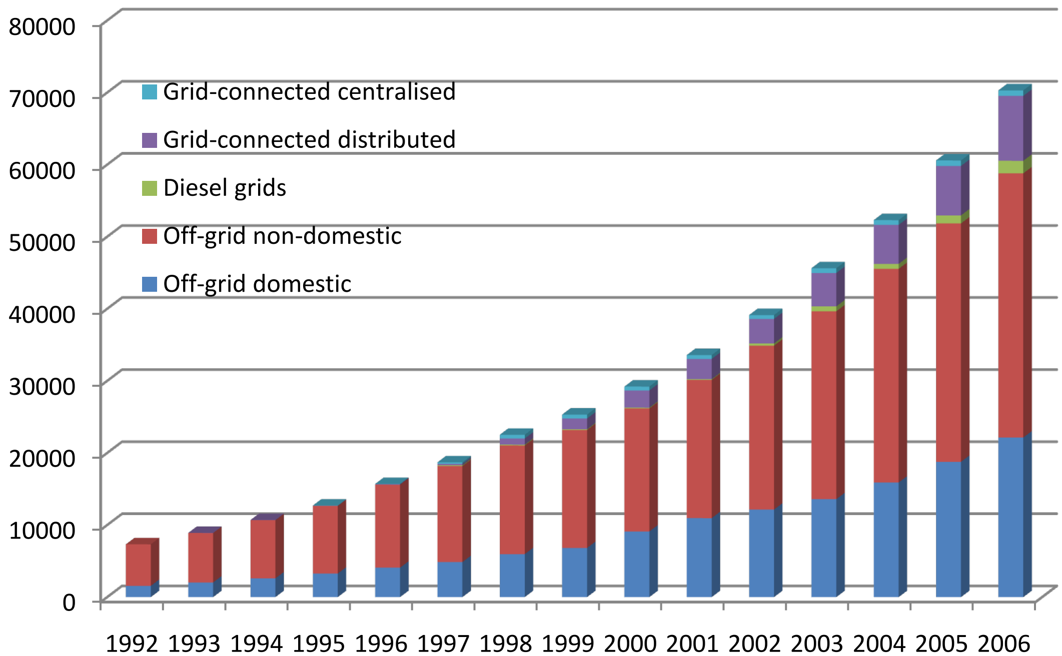


Figure 4.3: Cumulative installed PV power by sub-market, Australia, 1992-2006 (Watt, 2007)

The most abundant DE technology currently deployed in Australia are solar water heaters (SWH) and heat pumps that are now installed in 7% of households with annual sales approaching around 100,000 units (Perger, 2009). Table 4.3 shows the installed capacity of SWH by State and Territory. Following the effective banning of electric water heaters in new homes and prohibiting them as replacements from 2012, combined with government rebates, sales of these systems are expected to grow substantially in the near-term.

Table 4.3: Installed Solar Water Heaters (SWH) in 2008

	NSW & ACT	**VIC**	**QLD**	**SA**	**WA**	**TAS**	**NT**	**AUST**
Number of units (‘000)	134.6	53.1	137.5	N/A	177.6	5.1	33.1	587.8
Proportion of total dwellings (%)	5.0	2.6	8.5	N/A	21.5	2.5	54.3	7.1

Source: ABS (2008).

4.4 Europe

In the European Union (EU-27), total renewable energy capacity increased by almost 40% during the last decade mainly due to the development of wind and biomass technologies (Eurostat, 2009). Out of the 55 MW total growth, 36 MW is attributed to wind energy while the combined capacity growth of wood, biogas and municipal solid waste (MSW) was 10 MW. However, hydro power remains the largest sector, with a 70% share in 2005 followed by wind energy with a 20% share. Within EU-27, there is significant divergence around the average, with Norway generating an excess of renewable energy in 2007, and some nations generating none. This probably reflects the significant divergence in geographic, demographic and policy characteristics of each nation. Only Norway and Denmark are net exporters of energy, with Norway by far the biggest exporter due to its significant oil and natural gas reserves.

In 2005, Germany further increased its lead in photovoltaic capacity, reaching 1,508 MW and 89% of EU-27 total photovoltaic capacity. Germany and Spain lead the wind sector, with 69% of the total EU-27 wind capacity. Finland and Sweden, on the other hand, have 44% of the wood burning power plants. Italy with a 98% share of geothermal capacity is almost the sole player in the sector.

Combined heat and power systems provide just fewer than 11% of all electricity consumed in EU-27 with more than 40% of electricity in Denmark and Latvia coming from CHP. Finland and the Netherlands both generate more than 30% of their electricity from CHP (Eurostat, 2009) These high levels of CHP are generally attributed to, cheap accessible gas supplies, suitable climatic conditions and strong policy support. Not surprisingly, these nations also have the highest penetration of distributed generation in the world.

However despite the significant CHP penetration, uptake trends have slowed recently, largely due to rising National gas prices and falling electricity prices, although recent electricity price trends are expected to reverse. The exposure to natural gas prices and availability may highlight the importance of developing alternative renewable fuels to power CHP units, as well as policy measures required to capture environmental externalities from energy production (European Environment Agency, 2009).

4.5 United States

Similar to Australia, the bulk of electricity supply in the U.S. is sourced from coal-fired generation. In 2006, coal-fired generation accounted for around 50 per cent of National electricity generation (DOE/EIA, 2009). Also similar to Australia, the majority of installed DE in the U.S. are CHP systems.

Based on 2006 data, there is around 85 GW of existing CHP generation capacity at over 3,300 sites which represents over 8% of total U.S. power generation capacity. CHP represents over 12% of annual U.S. power generation, reflecting the longer operating hours of CHP assets. The majority of CHP capacity (over 80%) is employed in industrial applications, primarily providing power and steam to large industries such as chemicals, paper, refining, food processing and metals (see Figure 4.4). CHP in commercial and institutional applications is currently limited (12% of existing capacity) but growing in use, providing power, heating, and, in many cases, cooling to hospitals, schools, university campuses and office and apartment complexes (IEA, 2008b).

Natural gas is the most common fuel at 72% of CHP capacity. Coal and process wastes make up the remaining fuel mix (14% and 8% respectively), followed by biomass, wood, oil, and other waste fuels. There has been increased interest in biomass and waste fuels in recent years as policymakers and consumers seek to use more renewable fuel sources.

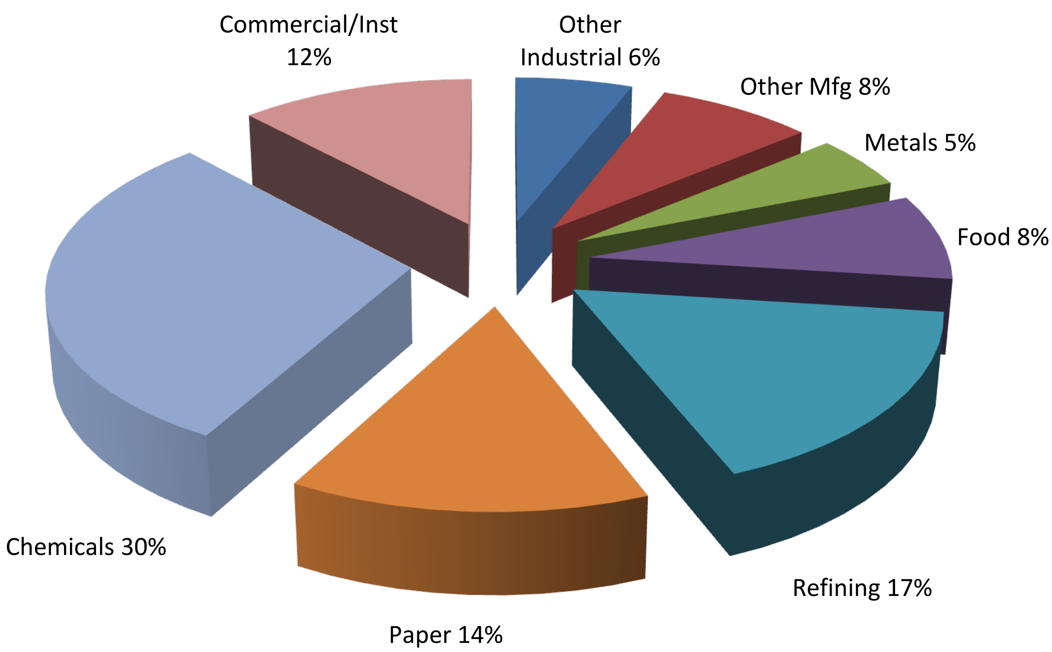


Figure 4.4: Existing U.S. CHP Capacity by Host Industry (IEA, 2008b). Redrawn from Figure 4, CHP/DHC Country Scorecard: United States © OCED/IEA 2009

The prominent use of natural gas as a fuel for CHP in the U.S. is driven by the extensive use of gas turbine and combined cycle (gas turbine/steam turbine) systems as displayed in Figure 4.5.

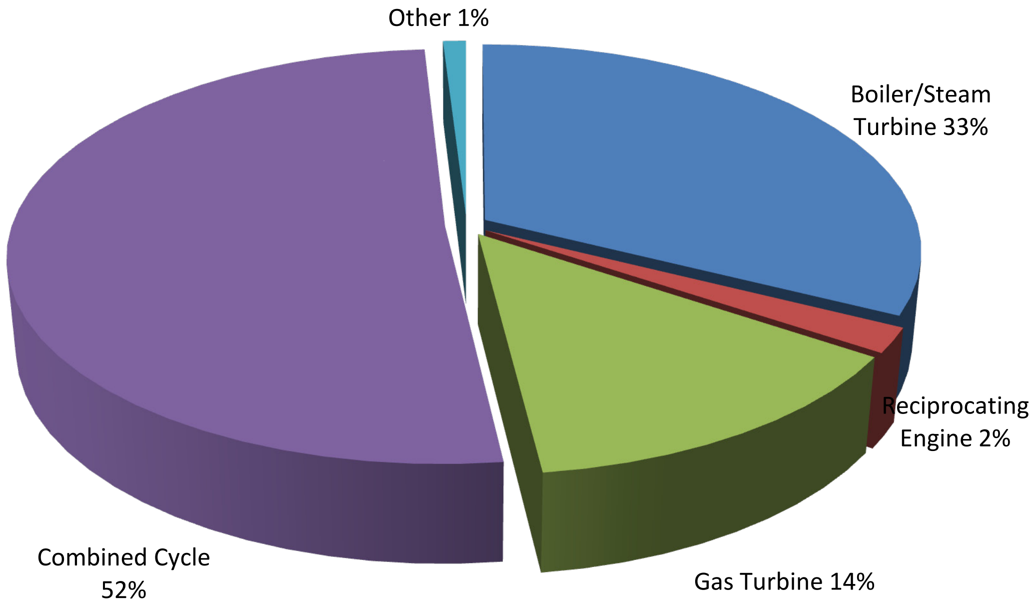


Figure 4.5: Existing U.S. CHP capacity by technology (IEA, 2008b). Redrawn from Figure 5, CHP/DHC Country Scorecard: United States © OCED/IEA 2009

Figure 4.6 shows that combined cycles and gas turbines represent 52% and 14% of existing CHP capacity respectively. Boiler/steam turbine systems represent 33% of total CHP capacity and are fuelled by solid fuels such as coal and wood waste. Reciprocating engines, primarily fuelled by natural gas, represent only 2% of CHP capacity in the U.S. Together, microturbines (small, recuperated gas turbines in the 60 to 250 kW size range), fuel cells and other technologies such as organic Rankine cycles represent less than one percent of installed CHP capacity.

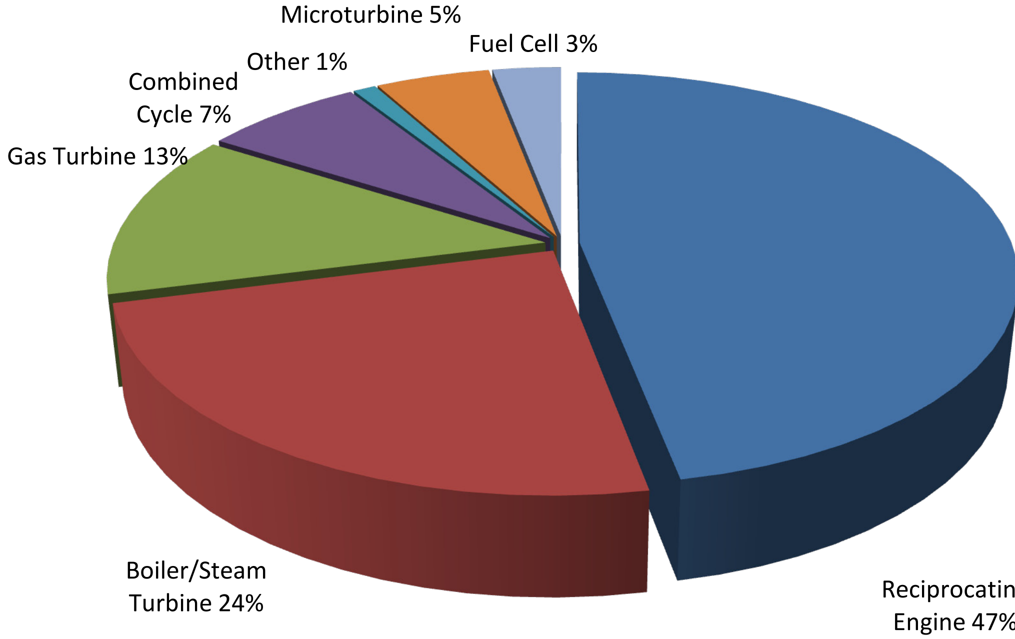


Figure 4.6: U.S. CHP Sites by Technology (IEA, 2008b). Redrawn from Figure 6, CHP/DHC Country Scorecard: United States © OCED/IEA 2009

Figure 4.6 shows the market share of CHP technologies based on the number of installations. Reciprocating engines are the primary technology of choice, used in 47% of existing CHP systems in the U.S. Emerging technologies such as fuel cells and microturbines are used in 8% of existing CHP systems in the United States.

The U.S has a long history of using Combined Heat and Power (CHP), and 8% of US electricity generation is provided by 85 GW of installed CHP capacity at over 3,300 facilities. The large-scale district energy systems are located in many major cities and 330 university campuses use district energy systems as a low-carbon, decentralised energy solution. The large base of installed capacity in the US is the result of supportive federal policies in the 1970s and 80s, including PURPA, the Public Utilities Regulatory Policy Act, which required utilities to purchase electricity from CHP plants at a set rate. A number of US States, including California, New York and other States in the Northeast, also provide incentives and recognition in environmental regulations for CHP, which has supported new development. However, the partial repeal of PURPA, as well as a wide diversity in State support, has resulted in a patchwork of CHP markets.

4.6 China and India

China and India are two developing countries with relatively high levels of distributed generation compared to other nations at comparable stages of economic development. They share similar economic, demographic and geographic characteristics with large rural populations, fast growing urbanised populations, rapid industrialisation and a range of renewable energy resources, albeit not yet fully developed. Both countries are using targeted programs to electrify rural areas and improve access to other forms of energy in remote areas including heating and lighting, which may be conducive to distributed energy.

Table 4.4 shows that in 2006, around 70% of Indian electricity production came from coal, with 15% from hydro and 8% natural gas. Wind, solar, and biomass energy make up less than 2% of all electricity generation.

Table 4.4: Electricity production sources in India (IEA, 2009a)

INDIA	Energy Production (GWh)	Technology Mix (%)
Production from:		
- coal	508,362	68%
- oil	31,475	4%
- natural gas	62,092	8%
- biomass	1,930	0%
- waste	0	0%
- nuclear	18,607	3%
- hydro*	113,599	15%
- geothermal	0	0%
- solar PV	19	0%
- solar thermal	0	0%
- wind	7,994	1%
- tide	0	0%
- other sources	0	0%
Total Production	744,078	

Table 4.5 shows that China has a similar energy production profile to India with 80% coming from coal, 15% from hydro, and the remained primarily from oil and nuclear. Almost all of its biomass energy is used in residential applications, most probably in rural communities. As shown below, this is not yet a significant source of energy in China.

Table 4.5: Electricity production sources in China (IEA, 2009b)

CHINA	Energy Production (GWh)	Technology Mix (%)
Production from:		
- coal	2,301,402	80%
- oil	51,469	2%
- gas	14,217	0%
- biomass	2,514	0%
- waste	0	0%
- nuclear	54,843	2%
- hydro*	435,786	15%
- geothermal	0	0%
- solar PV	105	0%
- solar thermal	0	0%
- wind	3,868	0%
- tide	0	0%
- other sources	0	0%
Total Production	2,864,204	

The quantity of installed renewable energy is expected to significantly change in China over the next decade. The Government has established targets for the development of various sources of renewable energy up to 2020, requiring 10% of total energy consumption by 2010 and 15% by 2020 to be renewable. An investment of $CNY 2 trillion (approximately $USD 263 billion) before 2020 on renewable energy development in China is envisaged to reach this goal. By 2020, the plan calls for the development of a total of (IEA, 2009c):

- 300,000 MW of hydropower
- 30,000 MW of wind power
- 30,000 MW of biomass
- 1,800 MW of solar power
- 300 million m^2 coverage of solar hot water heaters
- 44 billion m^3 of methane gas per year, and
- 50 million tonnes of biofuel.

Table 4.6 details the current penetration of different forms of energy within India, including distributed and decentralised systems. In total 14,224 MW of capacity was installed at the end of January 2009 representing around 10% of total installed generation.

Table 4.6: Current installations of renewable and distributed energy sources in India (MNRE, 2009)

Sources / Systems	**Cumulative capacity (as of 31.01.2009)**
Grid-interactive renewable power	
Biomass Power (Agro residues)	683.30 MW
Wind Power	9,755.85 MW
Small Hydro Power (up to 25 MW)	2,344.67 MW
Cogeneration-bagasse	1,033.73 MW
Waste to Energy	58.91 MW
Solar Power	2.12 MW
Off-grid/Distributed Renewable Power (including Captive/CHP plants)	
Biomass Power / Cogen.(non-bagasse)	150.92 MW
Biomass Gasifier	160.31 MWeq
Waste-to- Energy	31.06 MWeq
Solar PV Power Plants and Street Lights	3.00 MWp
Aero-Generators/Hybrid Systems	0.89 MW
Decentralized Energy Systems	
Family Type Biogas Plants	4,090,000
Home Lighting Systems	434,692
Solar Lanterns	697,419
Solar PV Pumps	7,148
Solar Water Heating - Collector Area	2,600,000 m^2
Solar Cookers	637,000
Wind Pumps	1,347

Note: MW = Megawatt
MWeq = Megawatt equivalent
MEp = Megawatt peak

5. POLICY AND REGULATION FOR DISTRIBUTED ENERGY

This chapter provides insight into the policy and regulatory structures relevant to DE in Australia. An analysis of these structures allows an enriched understanding of DE in its current state and allows a consideration of impediments and enablers that are either being addressed or are yet to be considered.

5.1 Key findings

Policy outcomes are critical to the transformation of an industry where it imposes costs on society that are not factored into prices, in this case the energy industry. The policy development process is highly mediated by diverse stakeholder interests. The relationship between policy decision makers and the various layers that seek to influence them is a complex dynamic and generally has less formal structures than regulation. To ensure policy outcomes are achieved in the interest of distributed energy, it is very important that policy decision making is representative, and can transparently account for different stakeholder views.

Policy making that affects DE primarily occurs at State and Federal levels, sometimes with significant overlap. Policy making and the programs, instruments, environmental and planning controls that come out of policy decisions are in a constant state of flux. The policy framework for supporting the uptake of DE sometimes overlaps and competes within or between jurisdictions. There is sometimes uncertainty over the longevity of programs, which can make it difficult to map the framework comprehensively, but more importantly, may make it difficult for those trying to implement DE to plan their activities. Long term policy certainty, for both policy objectives and the frameworks for realising those objectives, are fundamentally important to realising the benefits of distributed energy in an efficient way.

State and Local Government regulation can also affect the uptake of DE, without always explicitly aiming to do so. This influence includes, but is not limited to controls over emission to air standards and heritage controls over urban developments. These regulations affect the uptake of natural gas fired cogeneration, urban PV and wind systems in particular. Importantly, the location specific cost and value of DE, such as cogeneration, energy efficiency, solar or wind power, may depend to a degree on the existence of issues relating to air quality.

Energy market regulation, market reform and rule making processes are important to understand because of the significant interaction between how rules affect the incentive of energy market participants which in turn affects levels of DE. Market reform is driven by the Ministerial Council on Energy and the departments represented by those Ministers, while the Australian Energy Market Commission oversees changes and development of market rules. Market reform and rule change decision making, in comparison to policy making, is characterised by a more formal, rigid process guided by the National Electricity Objective. The Australian Energy Regulator is responsible for economic regulation of energy companies and enforcing market rules.

5.2 Policy making process

The development and deployment of distributed energy technologies and systems is influenced by government policy objectives and subsequent program and regulatory design. The formation of policies and how they manifest in government programs and regulation is a complex process, influenced by many layers of stakeholders. The following model provides a description of this process for energy:

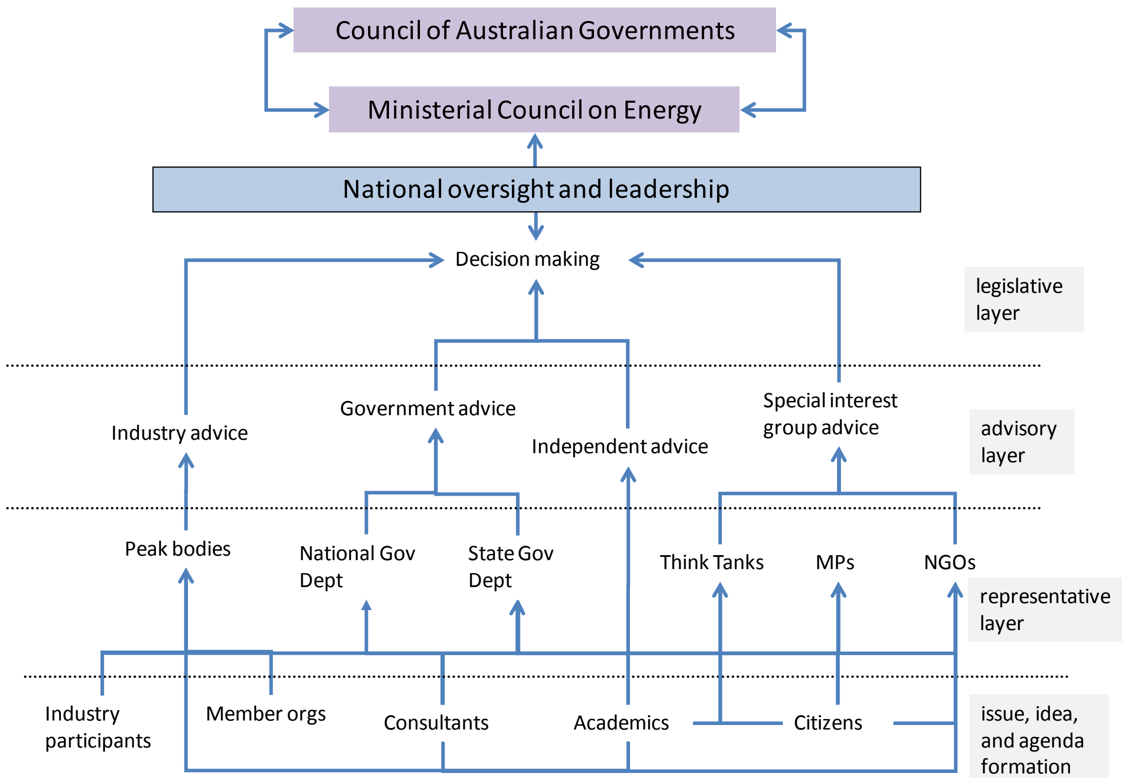


Figure 5.1: Stylised description of the governance process for energy in Australia.

The model should be considered as a stylised democratic governance model. The diagram shows that the process by which ideas and agendas (IAA) are manifest in government decisions is highly mediated. Of course, the genesis of IAA is not necessarily a bottom-up process as the model suggests. IAA may be formed in any of the four layers represented in the model.

The relationship between decision makers and the various layers that seek to influence them is a complex dynamic. Where IAA are in conflict, decision makers in any layer have incentive to influence and shape the thinking of the individuals and organisations in order to control the actual or perceived legitimacy behind the decisions they implement.

5.2.1 Funding and implementation of DE

This policy making process occurs at State and Federal levels, sometimes with significant overlap. Policy making and the programs, instruments, environmental and planning controls that come out of policy decisions are in a constant state of flux. Table 5.1 aims to summarise the latest data available that is relevant to the funding and implementation of DE by providing a list of current policies and programs related to DE at a National and State level[3]. Included are details of recently ended or amended programs, to help provide a sense of the policy context over time. Appendix B provides a schematic representation of current (at the time of writing) National and State policies and the organisations responsible for them. Details of programs have been taken from Government websites and care has been taken to ensure information provided is up to date. However, due to the difficulty of ensuring all information is accurate and complete, the reader should clarify details of any information provided before taking any action based on this information. When considering barriers to distributed energy in Chapter 6, a cross check against policies is provided to determine where barriers may remain, or have been addressed over time

Both the table and appendix diagrams show the complexity of how policies and programs are developed but also the complexity of the policy and program framework itself with sometimes overlapping or competing policies within or between jurisdictions. There is sometimes uncertainty over the longevity of programs, which can make it difficult to map the framework comprehensively, but more importantly, may make it difficult for those trying to implement DE to plan their activities.

Following Table 5.1, a description is provided of some of the State and Local Government environmental and planning controls that affects distributed energy is provided using NSW and Victoria as specific case studies for detailing these controls. A summary of policies and programs relevant to DE is presented below.

Federal Government:

- Smart grid
- Energy innovation fund
- Renewable energy equity fund
- Renewables Australia
- Carbon pollution reduction scheme
- Mandatory renewable energy target
- Energy efficiency opportunities
- Solar cities
- Clean Business Australia
- Clean Energy Enterprises Connect Centre
- Green loans

[3] Note that initiatives underway in Tasmania, The Australian Capital Territory or the Northern Territory are not included. As such the table should not be considered exhaustive, but is indicative of what action is being taken and the diversity across jurisdictions.

- Low emission and technology abatement fund
- Renewable and remote power program
- Solar credit program
- Solar hot water rebate program
- National strategy on energy efficiency
- R&D tax credit

New South Wales:

- Energy savings scheme
- Greenhouse gas reduction scheme
- Feed in tariff
- Low income household refit program
- Small business energy efficiency program
- Energy efficiency community awareness program
- Clean business program
- Energy savings fund
- Residential rebate program
- Renewable energy development program

Queensland:

- Feed in tariffs
- Solar hot water plan
- Smart energy savings fund
- Queensland renewable energy fund

South Australia:

- Feed-in tariff
- Residential energy efficiency scheme
- Solar got water program

Victoria:

- Energy efficiency target
- Standards feed-in tariff
- Premium feed-in tariffs
- Sustainability fund
- Smart energy zones
- Zero emission neighbour-hoods
- Centre for energy and greenhouse technologies
- Sustainable energy R&D grants program
- Solar hot water rebate

Western Australia:

- SEDO grants program
- Household renewable energy scheme (to be replaced with net feed-in tariff)
- Renewable energy water pumping program

Table 5.1: Federal and State policies and programs relevant to distributed energy.

Jurisdiction	Name	Type	Fund Size	Technology	Description	Dept responsible	End date
National	Smart Grid	Commercialisation fund	$100M	Grid management	The Government will provide up to $100 million in 2009-10 for the National energy efficiency Initiative to develop an innovative smart-grid energy network. Funding will be provided to a consortium of State and Local government, public and private energy companies and other private sector investors for the large scale demonstration of integrated smart grid technologies.	Department of Energy, Water Heritage and the Arts (DEWHA)	
National	Energy Innovation fund	Commercialisation fund	?	Renewables - Multiple	The Energy Innovation Fund has been established by the Australian Government to provide $150 million over four years to support the development of clean energy technologies - $100 million for research into concentrating solar thermal energy and solar photovoltaic technologies, $50 million for the Clean Energy Program to provide competitive grants for research and development in clean energy technologies. It is unclear if this fund will continue to exist, with the 2009/10 budget indicating $200 million from this fund will be rolled into the $1.5 billion Solar Flagship fund	Department of Resources, Energy and Tourism (DRET)	?
National	Renewable energy equity fund	Commercialisation fund	$25M	Renewables - Multiple	REEF can provide venture capital for small innovative renewable energy companies. This includes companies which are commercialising direct or enabling renewable energy technologies and services, such as manufacturers of PV cells or the inverters to convert this to useful electricity, providing there is an innovative development being commercialised.	Department of Energy, Water Heritage and the Arts (DEWHA)	closed (July 2009)

Jurisdiction	Name	Type	Fund Size	Technology	Description	Dept responsible	End date
National	Renewables Australia	Commercialisation fund	$465M	Renewables - Multiple	To support leading-edge technology research and bring it to market, including new funding of $100 million. The body will advise governments and the community on the implementation of renewable energy technologies, and support growth in skills and capacity for domestic and international markets. The funding was taken from the Renewable Energy Fund. which is now divested, its remaining $135 million going to large scale solar projects under the $1.5 billion solar flagship program	TBA	
National	Carbon Pollution Reduction Scheme	Market Instrument		Multiple	The design of the scheme is not finalised and therefore legislation is yet to be passed. Importantly for DE, revenue raised by the scheme will also be used to encourage energy efficiency in trade exposed industries as well as business and the community more generally through the Climate Change Action Fund	Department of Climate Change (DCC)	N/A
National	Mandatory renewable energy target	Market Instrument		Renewables - Multiple	To help ensure the Government achieves its goal of a 20 percent share for renewable energy in Australia's electricity supply by 2020, the Government committed to increasing the MRET from 9,500 gigawatt-hours to 45,000 gigawatt-hours in 2020. The expanded measure is to be phased out between 2020 and 2030 as emissions trading matures	Department of Climate Change (DCC)	2020-2030
National	Energy Efficiency Opportunities	Program		Energy efficiency - Business	Participants in the program are required to assess their energy use and report publicly on the results of the assessment and the business response. Decisions on energy efficiency opportunities remain at the discretion of the business. The energy efficiency	Department of Resources, Energy and Tourism (DRET)	

Jurisdiction	Name	Type	Fund Size	Technology	Description	Dept responsible	End date
					Opportunities program is designed to accommodate a wide range of business circumstances, making it possible to integrate energy efficiency Opportunities into normal business processes and become an effective tool to assist participants to improve their energy efficiency.		
National	Solar Cities	Program	fully funded	Multiple	Each Solar City will integrate a unique combination of energy options such as energy efficiency measures for homes and businesses, the use of solar technologies, cost reflective pricing trials to reward people who use energy wisely, and community education about better energy usage in an increasingly energy-reliant world. The information will be analysed to see how different members of a community can best reduce energy consumption, and how governments, industries and individuals can support wise energy use.	Department of Energy, Water Heritage and the Arts (DEWHA)	fully allocated
National	Clean Business Australia	Program	$240M	Multiple - Business	The Australian Government has allocated $240 million over four years to establish Clean Business Australia (CBA) a partnership with Australian business and industry for tackling climate change. CBA will support a range of activities aimed at improving our energy and water efficiency and increasing sustainability, with a focus on productivity and innovation. It consists of Climate Ready, Re-tooling for Climate Change and the Green Building Fund	Department of Innovation, Industry, Science and Research (DIISR)	2013
National	Clean Energy Enterprise	Program	$20M over 4	Multiple -	The centre will provide strategic assistance to business including but not limited to potential areas for business	Department of Innovation, Industry,	2008-2012

Jurisdiction	Name	Type	Fund Size	Technology	Description	Dept responsible	End date
	Connect Centre		years	Business	improvement areas for growth, improve products and manufacturing processes, access to specialist facilities and advice to turn innovative ideas into new products or to test products for new markets, help identify export markets and understanding relevant regulatory, cultural and market issues.	Science and Research (DIISR)	
National	Green loans	Program	$300M over 5 years	Multiple - Domestic	Provides $300 million over five years for low interest green loans of up to $10,000 to assist families to install solar, water, and energy efficient products. Provides participating households with a Green Renovation Pack and a sustainability assessment identifying potential energy and water efficient actions, complete with estimated savings to electricity and water bills and environmental benefits.	Department of Energy, Water Heritage and the Arts (DEWHA)	2009-2014
National	Low emission and technology abatement fund	R&D	$26.9M	Multiple	The Low Emissions Technology and Abatement (LETA) initiative is a $26.9 million measure to reduce greenhouse gas emissions over the longer term by supporting the identification and implementation of cost effective abatement opportunities and the uptake of small scale low emission technologies in business, industry and local communities.	Department of Energy, Water Heritage and the Arts (DEWHA)	closed (July 2009)
National	Renewable and remote power program	Rebate Program		Renewable - off and fringe grid	The Australian Government's Renewable Remote Power Generation Program (RRPGP) provides financial support to increase the use of renewable generation in remote parts of Australia that presently rely on fossil fuel for electricity supply. The Program has funding available to 30 June 2011.	Department of Energy, Water Heritage and the Arts (DEWHA)	closed (July 2009)

Jurisdiction	Name	Type	Fund Size	Technology	Description	Dept responsible	End date
National	Solar credit program	Rebate Program		Solar PV - domestic	In 2009 the Australian Government will introduce legislation for an expanded Mandatory Renewable Energy Target (RET) of an additional 45,000 gigawatt-hours of renewable electricity in 2020. As part of the Government's commitment to an expanded RET, purchasers of eligible small generation units, such as roof top solar systems, will receive Solar Credits to assist with the upfront cost of installing the systems. Rooftop solar systems will generate solar credits equal to 15 years in advance, redeemable up-front based on the potential generation over the life of the system. From 1 July 2009 until June 2012, the number of solar credits received will be multiplied by five, enabling householders an increased return from their generation. From June 2012, the amount of credits will be reduced annually until 2016. The new system will apply to the first 1.5 kilowatts of system capacity.	Department of Climate Change (DCC)	2016
National	Solar hot water rebate program	Rebate Program		Solar Water Heater - domestic	To be eligible for the rebate, a hot water system must: replace an electric storage hot water system; be purchased and installed on, or after 18 July 2007; be a solar or heat pump hot water system that is eligible for at least 20 Renewable Energy Certificates (RECs) at the time and place of installation, be installed by a suitably qualified person (for example an electrician or plumber). Eligible households - The dwelling where the hot water system is installed must be a principal place of residence; The applicant's taxable family income must have been less than $100,000 in the most recent tax year as lodged	Department of Energy, Water Heritage and the Arts (DEWHA)	2012

Jurisdiction	Name	Type	Fund Size	Technology	Description	Dept responsible	End date
					with the Australian Taxation Office.		
National	National strategy on energy efficiency – including an expansion of the Minimum Energy Performance Standards	Regulatory instrument	$64.6 million	Energy efficiency	The Government will invest $64.6 million over four years as part of its contribution to the National Strategy on energy efficiency to help Australians choose more energy efficient appliances, homes and buildings, and make residential and commercial buildings more energy efficient. This includes: $8.7 million over four years for increasing energy efficiency requirements for residential buildings, $7.8 million over four years for disclosure of energy performance of residential buildings, $5.3 million over four years for disclosure of commercial building energy efficiency, $3.3 million over four years for improvements to the Building Code of Australia requirements for commercial buildings, $2.6 million over four years for commercial building rating tools, $2.0 million over three years for improvements in heating, ventilation and air conditioning systems, $18.3 million over four years for implementing enhanced energy efficiency labelling, $16.6 million over four years for an expansion of minimum performance standards for appliances and equipment.	N/A	
National	R&D tax credit	Tax incentive		Multiple	The Government will simplify and enhance the Research and Development (R&D) Tax Concession in a bid to boost business investment. From 2010-11, the Government will replace the complex R&D Tax Concession with a simplified R&D Tax Credit which cuts red tape and provides a better incentive for	Australian Tax Office (ATO)	

Jurisdiction	Name	Type	Fund Size	Technology	Description	Dept responsible	End date
					business to invest in research and innovation.		
National	Advanced electricity storage program	Program	$20.4M	Electricity storage	The Australian Government has provided $20.4 million to the Advanced Electricity Storage Technologies program, which supports the development and demonstration of efficient electricity storage technologies for use with variable renewable generation sources such as wind and solar.	Department of Resources, Energy and Tourism (DRET)	closed July 2009
National	Energy efficiency homes package	Program	$3.9b	Insulation, hot water	Australian Government's Energy Efficient Homes Package is a $3.9 billion package to improve the energy rating of Australian homes - cutting their energy waste, making them more comfortable and helping households save up to 40 per cent on their electricity bills. Under this program the Australian Government is offering: ceiling insulation worth up to $1,600 to all Australian home owner-occupiers with limited or no ceiling insulation or a $1,600 rebate on the costs of installing a solar hot water system, with a rebate for landlords and tenants on the costs of insulating rental properties.	Department of Energy, Water Heritage and the Arts (DEWHA)	
NSW	Energy Savings Scheme	Market instrument	N/A	Energy efficiency	On 27 February 2009, the NSW Government announced the target for the Energy Savings Scheme (the Scheme). The Energy Savings Scheme is a NSW based mandatory energy efficiency scheme for electricity retailers and other liable parties under the Scheme. Trade-exposed industries that are particularly intensive users of electricity will be exempt from the Scheme. The Scheme will commence on 1 July 2009 with an energy	Department of Water and energy (DWE)	2009-2020

Jurisdiction	Name	Type	Fund Size	Technology	Description	Dept responsible	End date
					efficiency target of 0.4 per cent of total electricity sales which will increase to 4 per cent in 2014.		
NSW	Greenhouse Gas reduction scheme	Market instrument	N/A	Multiple	GGAS establishes annual state-wide greenhouse gas reduction targets, and then requires individual electricity retailers and certain other parties who buy or sell electricity in NSW to meet mandatory benchmarks based on the size of their share of the electricity market. If these parties, known as benchmark participants, fail to meet their benchmarks, then a penalty is assigned.	Department of Water and energy (DWE)	Legislation introduced to end in July 2009
NSW	Feed-in tariff	Market instrument	N/A	Solar PV	The NSW Government has announced its intention to introduce a Feed-in Tariff (FiT) scheme for small scale, grid connected, solar PV systems and has established a taskforce to determine an appropriate design for the FiT.	Department of Water and energy (DWE)	2009-?
NSW	Low income household refit program	Program	$63M	Energy efficiency – domestic	The $63 million Low Income Household Refit Program will provide energy assessments and saver kits to 220,000 low income households across NSW. Funded through the NSW Climate Change Fund, the program is part of the NSW Government's energy efficiency Strategy to help households, government and business reduce their energy bills and greenhouse gas emissions. The program will apply to low income households who are currently eligible for the NSW Government's Energy Rebate.	Department of Environment, Climate Change and Water (DECCW)	

Jurisdiction	Name	Type	Fund Size	Technology	Description	Dept responsible	End date
NSW	Small business energy efficiency program	Program	$15M	Energy efficiency – small business	This $15-million program will provide on-site advice for 6,000 small and medium businesses. It will offer rebates to assist measures such as lighting upgrades and improvements to air-conditioning and refrigeration. As a result, the average small business is expected to save $7,850 on power bills over 10 years.	Department Environment, Climate Change and Water (DECCW)	
NSW	Energy efficiency community awareness program	Program	$15M	Energy efficiency	$15 million has been allocated to a community awareness program which will provide practical advice on how to save energy at home and work.	Department Environment, Climate Change and Water (DECCW)	
NSW	Green business program	Program	$30M	Energy efficiency, cogeneration	The NSW Green Business Program provides $30 million over five years for projects that will save water and energy in business operations in NSW.	Department Environment, Climate Change and Water (DECCW)	?
NSW	Energy Savings Fund	Program	$40M pa	Energy efficiency, Renewables	The purpose of the Energy Savings Fund is to: reduce overall electricity consumption in NSW and related greenhouse gas emissions, reduce peak electricity demand, stimulate investment in innovative measures, and increase public awareness in energy savings.	Department Environment, Climate Change and Water	2010

Jurisdiction	Name	Type	Fund Size	Technology	Description	Dept responsible	End date
						(DECCW)	
NSW	Residential rebate program	Program	$100M	Insulation, water tanks, solar hot water, washing machine, fridge	More than 50,000 rebates have been claimed by NSW householders, saving more than 1 billion litres of water and 50,000 tonnes of greenhouse gas emissions a year. Applications for the rebates occur after the purchase and installation is complete. Hot water systems, insulation or rainwater tanks installed to comply with BASIX (the Building Sustainability Index) for new homes and major renovations are not eligible for a rebate. Rainwater tank rebate - up to $1,500 for rainwater tanks connected to toilets and washing machines. Hot water system rebate - up to $1,200 to switch from electric to solar, heat pump or gas hot water systems. Ceiling insulation rebate - half the cost of installing ceiling insulation in your home, to a maximum of $300. Washing machine rebate - $150 for buying a 4.5 star or higher WELS rated washing machine. The Residential Rebate Program also supports: Fridge Buyback - $35 to have a second fridge removed from your home	Department Environment, Climate Change and Water (DECCW)	?
NSW	Renewable energy development program	Program	$40M over 5 years	Renewables	The Renewable Energy Development Program is open for Expressions of Interest for any renewable energy project which will generate electricity or displace grid electricity use in NSW for stationary energy purposes. Renewable energy is defined as energy which is naturally occurring and which is theoretically inexhaustible, such as energy from the sun or wind. It includes energy sourced from hydro, wind, solar, wave, tide and ocean,	Department Environment, Climate Change and Water (DECCW)	2009 - 2014, round 1 closed, $27M allocated

Jurisdiction	**Name**	**Type**	**Fund Size**	**Technology**	**Description**	**Dept responsible**	**End date**
					food waste and biomass.		
QLD	Feed-in tariffs	Market Instrument		Solar PV - domestic	To be eligible to receive the solar bonus, customers must: consume no more than 100 megawatt hours (MWh) of electricity a year (the average household uses 10 MWh a year); purchase and install a new solar power (photovoltaic) system (not solar hot water system) or operate an existing system that is connected to the Queensland electricity grid; generate surplus electricity that is fed into the Queensland electricity grid; ensure they have an agreement in place with their electricity distributor (Ergon Energy or ENERGEX) to have adequate metering installed.	Queensland Office of Clean Energy (OCE)	2028 (reviewed in 2018)
QLD	Solar hot water plan	Rebate program			To make the most of electricity cost savings and greenhouse gas emission reductions, this offer is only open to Queenslanders who have an existing electric hot water system installed in their home. The Queensland Government is entering into agreements with solar and heat pump hot water suppliers to supply and install high quality systems at competitive prices under the Program. The Federal Government is offering a $1600 rebate to help with the cost of installation. Before installation, under the Queensland Solar Hot Water Program an eligible participant will pay $500, or $100 for pensioner or low income earners, to receive a standard solar or heat pump hot water system professionally installed, with warranty, in a principal place of residence. Upon installation,	Queensland Office of Clean Energy (OCE)	

Jurisdiction	Name	Type	Fund Size	Technology	Description	Dept responsible	End date
					the purchaser will receive an additional invoice for $1,600, equivalent to the Federal Government rebate the purchaser will be applying for. The invoice needs to be paid once the rebate is received. Also under this Program the right to create and trade Renewable Energy Certificates (RECs) to the hot water system are transferred to the Contractor responsible for installing the hot water system. RECs are issued when a complete solar or heat pump hot water system is installed. The number of RECs issued varies with each hot water system.		
QLD	Smart energy savings fund	Program	$50M	Energy efficiency	The Smart Energy Savings Fund (SESF) is a $50 million funding program to assist Queensland businesses to invest in commercial energy saving projects. The fund encourages Queensland businesses to identify and implement cost-effective energy improvements to their buildings, appliances and industrial processes. The fund offers grants and loans to support businesses that may have difficulty funding the energy efficiency projects internally or by accessing traditional funding sources.	Queensland Office of Clean Energy (OCE)	Not defined
QLD	Queensland Renewable energy fund	Program	$50M	Renewables	The Queensland Renewable Energy Fund (QREF) is a $50 million funding program that supports the development and deployment of renewable energy generation technologies in Queensland. Funds are allocated annually as grants and loans to	Queensland Office of Clean Energy (OCE)	Not defined

Jurisdiction	Name	Type	Fund Size	Technology	Description	Dept responsible	End date
					support proven renewable energy technologies State wide.		
SA	Feed-in Tariff	Market Instrument		Solar PV - Domestic	'Small electricity customers' in South Australia – that is a household, small business, community building, church or other facility that consumes less than 160 MWh of electricity per annum – that have installed or intend to install, a solar photovoltaic (PV) electricity system on their premises, are able to receive a premium price for any excess electricity returned to the electricity grid at 44c/kWh	Department of Transport, Energy and Infrastructure (DTEI)	2008 - 2028
SA	Residential energy efficiency scheme	Market Instrument		Energy efficiency – domestic	The REES is intended to benefit all types of households, whether owner-occupied or rented. It has a particular focus on low income families who are most vulnerable to rising energy costs. Energy providers are required to make sure they meet at least one third of their targets in low income households. They must also deliver 13,000 energy audits to low income households over the next three years (2009 to 2011).	Department of Transport, Energy and Infrastructure (DTEI)	2009-2011
SA	Solar Hot Water Program	Rebate Program		Solar Hot Water - Domestic	The rebate covers gas/solar, electric/solar and heat pump systems and is available to new and existing homes. Electric/solar and heat pumps are not eligible on new homes where there is mains gas. On existing homes, these systems only attract a rebate where they replace a more greenhouse intensive water heater	Department of Transport, Energy and Infrastructure (DTEI)	not defined
VIC	Energy efficiency target	Market instrument		Energy efficiency - domestic	The target itself is called the Victorian energy efficiency Target (VEET) and is a legislative requirement placed on energy retailers through the Victorian energy efficiency Target Act	Department of Primary Industries	

Jurisdiction	Name	Type	Fund Size	Technology	Description	Dept responsible	End date
					2007. The scheme will help families reduce greenhouse gas emissions and cut their power bills. The Energy Saver Incentive sets a target for energy savings, initially in the residential sector, and requires energy retailers to meet their own targets through energy efficiency activities, such as providing households with energy saving products and services at little or no cost.	(DPI) and Victorian Essential Services Commission (ESCV)	
VIC	Standard feed-in tariff	Market Instrument	N/A	Renewables	An offer must: (a) specify that the retailer will pay or credit the customer, for electricity; supplied by the customer under a feed-in contract, at a rate not less than the rate the customer pays to buy electricity from the retailer; and (b) use as the basis for this calculation the cost of the bill received by the customer, excluding the service to property charge and government charges. Offer must be 'fair and reasonable'	Department of Primary Industries (DPI)	Ongoing
VIC	Premium feed-in tariffs	Market instrument	N/A	Solar PV - domestic	The premium feed-in tariff will be available for households with small-scale solar photovoltaic systems (up to 3.2 kilowatts) and paid at 60c/kWh for exported electricity	Department of Primary Industries (DPI)	2009-2024
VIC	Sustainability fund	Program	funded by landfill levy	Multiple	The Sustainability Fund is designed to support projects that foster sustainable resource use and have economic and social benefits for Victorians. The successful applicants will deliver practical and affordable solutions to tackle climate change and help Victoria reduce its environmental impact. The projects incorporate a strong partnership focus, have significant in-kind support and have detailed project plans for tackling sustainability across a number of different sectors.	Sustainability Victoria (SV)	Ongoing
VIC	Smart energy zones	Program	$4M	Multiple	Smart Energy Zones will demonstrate the benefits of integrating multiple technologies in one location, for greater energy efficiency and security. A zone could include: Small-scale, community based energy creation, known as "micro-generation", will not only have low greenhouse impact but will directly engage people in solutions to climate change. The aim of the Smart Energy Zones program is to demonstrate that by combining supply and demand solutions and developing local	Sustainability Victoria (SV)	2012

Jurisdiction	Name	Type	Fund Size	Technology	Description	Dept responsible	End date
					energy opportunities, communities can dramatically and cost-effectively reduce their greenhouse intensity.		
VIC	Zero emission neighbour-hoods	Program	$6M	Multiple	The program will showcase innovative water, waste, transport and energy solutions, such as local renewable energy supply, sustainable master planning and design, onsite recycled water and smart meters to help manage energy usage.	Sustainability Victoria (SV)	Not defined
VIC	Centre for energy and greenhouse technologies	R&D	$29M	Multiple	The Centre for Energy and Greenhouse Technologies (CEGT) is an investment and service provider focussing exclusively on the development of new sustainable energy and greenhouse gas reductions technologies. CEGT is a private company managing a pool of funds allocated to it by the Victorian Government through the Energy Technology Innovation Strategy. By identifying and attracting development projects that require investment to reach the demonstration or commercialisation stage the Centre, in conjunction with co-investors, aims to generate commercial returns by meeting the growing Australian and global demand for these technologies.	Department of Primary Industries (DPI)	Ongoing
VIC	Sustainable energy R&D grants program	R&D	Fully funded	Multiple	The Victorian Government has provided up to $10 million over three years for the Sustainable Energy Research and Development (SERD) Grants Program. The program complements the Government's Our Environment Our Future Sustainability Action Statement 2006, and seeks to drive new technologies in the sustainable energy sector to the commercial stage. The program is to facilitate industry development in niche fields of renewable energy, energy efficiency, clean distributed generation and enabling technologies.	Department of Primary Industries (DPI)	Fully funded
VIC	Solar hot water rebate	Rebate Program		Solar hot water	The Solar Hot Water Rebate program provides rebates for installations in Victoria that: Replace a natural gas or LPG water heater with a gas-boosted solar system; Add solar to an to an existing natural gas or LPG water heater by installing a solar system as a reheater; and Add solar to an existing electric water heater by installing a retrofit kit. Rebates range from $480-$1,500 per system	Sustainability Victoria (SV)	Not defined

Jurisdiction	Name	Type	Fund Size	Technology	Description	Dept responsible	End date
WA	SEDO grants program	Program	up to $50k per grant	Multiple	The program provides grants of up to $50,000 for community-based sustainable energy projects and sustainable energy research and development projects. Community-based projects: To help householders to reduce fossil fuel energy use; To raise community awareness of ways to reduce energy use and increase the use of renewable energy. Research and development projects: To assist the research and development of innovative sustainable energy products, services, installations and practices; To support the development of the Western Australian sustainable energy industry. All projects: To lead to the long-term reduction of greenhouse gas emissions in Western Australia.	Sustainable Energy Development Office (SEDO)	Not defined
WA	Household renewable energy scheme – to be replaced by net feed-in tariff by July 2010	Rebate program	$13.5M	Solar PV	The Household Renewable Energy Scheme (HRES) will provide three annual payments to owners of eligible renewable energy systems to assist in recovering the capital cost of their purchase. A homeowner who had a renewable energy system installed between 6 September 2008 and 2 June 2009, and are a customer of the Renewable Energy Buyback Scheme (offered through Synergy or Horizon Power) are likely to be eligible to receive the HRES payments. System owners with pending applications for the Renewable Energy Buyback Scheme, and who have systems installed within the eligibility dates may also apply. The Government will provide $13.5 million in payments to eligible system owners. The amount paid to each recipient will depend on the system size and the applicant's receipt of other Government rebates. However, the value of each annual payment cannot be determined with full accuracy until the application processed has closed	Sustainable Energy Development Office (SEDO)	
WA	Solar schools program	Program	$5.1M	Solar PV	The Solar Schools Program supports solar (PV) systems installed on Western Australian State Government schools. The $5.1 million program will see over 350 metropolitan and regional schools harness the power of the sun by 2010. The program will help students to learn about renewable energy and	Sustainable Energy Development Office (SEDO)	2010

Jurisdiction	Name	Type	Fund Size	Technology	Description	Dept responsible	End date
					energy efficiency and the importance of reducing greenhouse gas emissions. Schools must contribute a minimum of $1,000 towards the cost of the system. The Sustainable Energy Development Office will contribute up to $12,500 in metropolitan areas and $13,000 in regional areas.		
WA	Renewable energy water pumping program	Rebate Program	$4.8M	Renewable energy pumps	General eligibility criteria - The applicant must be a business, government agency or incorporated organisation that is registered for the GST, and the proposed renewable energy pump must serve a purpose that is essential to the operation of the applicant; The proposed renewable energy pump must replace an existing diesel pump or must be used where a diesel pump would otherwise have been used; Renewable energy pumps on which a rebate is sought must be new, must be complete systems and must be purchased and installed after a pre-purchase application has been approved; Proposed renewable energy pumps must be guaranteed of delivering a minimum annual average of 8,000 litres per day at a total static head of 20 metres (or equivalent); Sufficient resources must be available for the implementation of projects and system suppliers and installers must be capable and sufficiently qualified.	Sustainable Energy Development Office (SEDO)	Closed

5.2.2 State, Territory and Local Government controls

State and Local Government regulation can affect the uptake of DE, without always explicitly aiming to do so[4]. This influence includes, but is not limited to controls over emission to air standards and heritage controls over urban developments. These regulations affect the uptake of natural gas-fired cogeneration, urban PV and wind systems in particular.

Emissions to air are typically regulated by State Government. This usually involves measuring and monitoring air quality across the relevant jurisdiction against some benchmark standard, reporting on any breaches of standards, investigating breaches and taking enforcement action where necessary. As far as possible, benchmark setting is coordinated nationally to ensure that minimum best practice is implemented across jurisdictions.

While minimum standards for air quality may be set at a National level, how each jurisdiction meets and enforces these standards is managed at a jurisdictional level. This is driven by the need for jurisdiction specific management plans that can take account of the specific configuration of industry, transport, air flows and other variables in any jurisdiction.

Two main outcomes that State Governments seek to manage are photochemical smog and fine particulate emissions. These outcomes are influenced by a range of emissions to air, a subset being criteria pollutants which include, but are not limited to: carbon monoxide; nitrogen dioxide; and sulfur dioxide. Of relevance to distributed energy, specifically fossil fuel fired distributed co/trigeneration, are oxides of nitrogen (in particular nitrogen oxide, NO, and nitrogen dioxide, NO_2, which is in itself an irritant) and particulate emissions. Nitrous oxide (N_2O) can also be produced in small amounts (relative to NO and NO_2) but has a global warming potential 298 times higher than carbon dioxide. Emission rates both current and predicted for DE technologies are provided in Appendix C. These values are used to determine total emission fluxes for the future predicted technology mixes provided in Chapter 9.

Ozone (O_3) is a secondary pollutant which can be problematic in the major capital cities of Australia. It is formed by a series of complex chemical reactions involving oxides of nitrogen and volatile organic compounds in the presence of sunlight. At ground level, ozone is a pollutant that can cause respiratory irritation, particularly for asthmatics.

The importance of controlling emissions in the urban environment from distributed generation is highlighted by the Department of Environment, Climate Change and Water (DECCW) in NSW. They note the City of Sydney targets the use of 330 MW of gas fired cogeneration in their 2030 plan, and that this would result in an emission of 660 kg/h NOx. However Sydney has consistently breached the National Environment Protection Measure for Ambient Air Quality (NEPM) for ozone on a small number of hours each year. This has resulted in a DECCW requirement to reduce NOx levels by 25%, equating to a reduction of 2600 kg/h (DECCW, 2009). In short, meeting the City of Sydney target for cogeneration could result in increasing NOx levels by around 6%, while they need to be reduced by 25%. Since emissions

[4] It is important to note that while we do not detail current or historic attempts by State or Local Governments to regulate, or set targets for the release of carbon dioxide, this can and has been done.

are released from a variety of sources including motor vehicles (the predominant source), industry and commercial premises, control standards and techniques that weigh the cost and benefits of all emission sources need to be thoroughly evaluated and considered.

It is important to consider that the location specific cost and value of distributed energy, such as cogeneration, energy efficiency, solar or wind power, may depend on the existence of issues relating to air quality. In Sydney, as detailed above, due to already high levels of NOx, new measures are being considered for ensuring the NOx impact of cogeneration is minimised at least cost to industry, in order to balance potential greenhouse gas benefits against air quality impacts. This will make cogeneration relatively more expensive to install in Sydney compared to locations that are not as significantly impacted by air quality issues. However, it also means the benefits of energy efficiency, solar and wind, to the extent they reduce emissions otherwise released to the Sydney airshed, may be greater than in other locations. The significance of this potential is highlighted by the estimated annual cost of current levels of air pollution in the greater metropolitan area: $4.7 billion, or $893 per head of population (DECCW, 2009). The extent to which air quality issues are a constraint on the implementation of DE in the Sydney region is being considered in a comprehensive modelling study by CSIRO linked to this “Intelligent Grid” program of work. The project is due for completion in June 2011.

Local Government controls can also affect distributed generation. In interviews conducted by CSIRO (2009), heritage and planning controls were identified by some stakeholders as a barrier to distributed energy. For example, heritage controls can impede residents installing solar hot water or PV systems where their north facing roof space also faces the street. Heritage controls may also affect upgrades to building facades required to take advantage of passive solar gain.

Many local councils have recognised these issues and have begun taking steps to remove unnecessary barriers, or improve processes to allow full consideration of both heritage and sustainability concerns. For example the City of Port Phillip in Melbourne, Victoria, revisited planning processes and now waives the application fee associated with obtaining a planning permit for various sustainability measures such as PV panels. Sustainability measures are also fast tracked for processing.

Again, the presence or lack of such controls can influence the uptake of different distributed energy measures, and may make implementing distributed energy less problematic in green-field developments. However given the relative slow turnover time of old building stock, with rates typically being 2-3% pa (Brown et al., 2005), it is important that local council planning controls are fully cognisant of different distributed energy measures, and have processes in place to ensure they are considered appropriately.

5.3 Energy market regulatory reform and rule making

Energy market reform and rule making processes are important to understand in the context of DE. Primarily, this is because of the significant interaction between how rules affect the incentive of energy market participants which in turn affects levels of distributed generation, and other forms of demand management. For example, distributed generation depends on being connected to distribution networks and so how network businesses are regulated will affect how they interact with distributed generators.

What follows is a description and brief discussion of the current market reform process followed by a description of rule making processes and enforcement.

The reform process is useful to understand as it provides context for current and future regulation. The objectives of National reform are primarily driven by economic efficiency goals, in part forseen to be delivered by harmonisation of regulatory frameworks across the country. The following diagram provides a stylised description of the market reform process as it relates to DE at the time of writing.

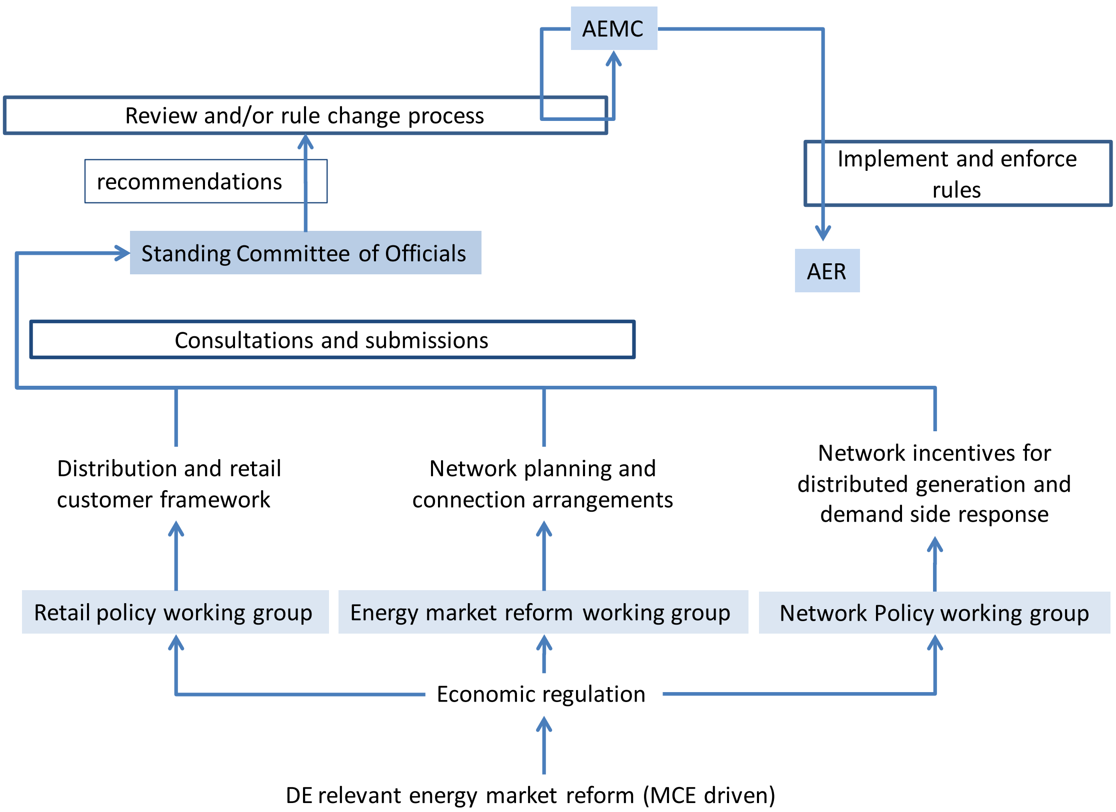


Figure 5.2: Indicative current energy reform processes in Australia relevant to DE

This model is stylised and takes a bottom up approach. In this model, the Ministerial Council on Energy (MCE) leads and manages the reform process. Of particular relevance to DE, the energy market reform working group and the network policy working group have commissioned reports on network planning and connection arrangements and on network incentives for distributed generation (DG) and demand side response (DSR) respectively. These two working groups have been analysing existing regulation to determine what incentives networks have to undertake DG and/or DSR and how any barriers to DG and DSR can be overcome.

The retail policy working group also has influence over distributed generation by shaping the regulatory framework that guides how retail and distribution companies interact with customers. Amongst other things, this includes setting distributor obligations to provide connection services and defining contractual obligations between the distributor and embedded generators.

Working groups commission research and conduct consultations, out of which are developed recommendations to the standing committee of officials (SCO). SCO can then initiate rule change through the Australian Energy Market Commission (AEMC). This makes working groups central to reform outcomes.

The composition of working groups reflects the composition of the MCE, which is made of Energy Ministers from all State, Territory and Federal jurisdictions. Accordingly, working groups and consultations are typically driven by State and Federal departments that report to these Ministers. The Commonwealth department primarily active in consultation processed affecting distributed energy has been the Department Resources, Energy and Tourism (DRET) while different State energy departments have been involved to varying degrees in working groups. Some of the relevant State departments include:

- Department of Water and Energy (NSW)
- Department of Mines and Energy (QLD)
- Department of Primary Industries (VIC)
- Western Australia Office of Energy (WA)
- Department for Transport, Fisheries and Energy (SA)
- Department of Primary Industries, Mines and Energy (NT)
- Tasmania Department of Infrastructure, Energy & Resources (TAS)
- Energy Policy Unit, Territory and Municipal Services (ACT)

The outcome of the reform process will not represent a final state of the National Electricity Market. The AEMC regularly conducts reviews into market performance and can propose and make rule changes as required. Rule changes can be initiated by anyone, but the AEMC may only initiate the Rule making process without a request if:

- It considers the Rule corrects a minor error in the Rules, or
- It considers the Rule involves a non-material change

The rule change process consists of the following stages:

Stage 1: Initiation and preliminary assessment of a Rule change proposal

Stage 2: Consultation on a proposed Rule change

Stage 3: Draft Rule determination and further consultation

Stage 4: Final determination and making of an amending Rule.

In the context of DE, the manner in which the AEMC manages consultations on rule changes and makes determinations out of this process is critical. Regulation shapes the incentives and disincentives faced by energy market participants. At the time of writing, the AEMC is conducting two reviews of particular relevance to DE. These are a review of demand side participation and a review of distribution network planning and expansion arrangements.

While not analysed here, Chapter 6 of this report presents a literature review of barriers to distributed energy, and locates these barriers in the Australian context with reference to policy and regulatory reviews and outcomes, such as those being undertaken by the AEMC.

Depending on their scope and significance, rule change processes can act as micro versions of the reform process with the AEMC as the managing agent, as opposed to working groups. For instance, rule change is likely to involve consultants, peak bodies, government departments, NGOs and other interested parties, all developing their respective cases for or against a rule change and seeking to influence the change process through formal and informal channels. Where a rule change has the potential to create market winners and losers, this process will naturally be contested by interested parties.

It is important to note that market regulation consists of law, rules and guidelines. Laws provide long term stability and consistency to the market based on fundamental principles, captured in the National Electricity Objective which is:

To promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to –

- Price, quality, safety, reliability, and security of supply of electricity, and
- The reliability, safety and security of the National electricity system.

Market rules and guidelines are progressively more flexible and can be changed over time to meet the particular circumstance of a jurisdiction through a derogation, or if a change is deemed beneficial for market operation, considering the market objective.

As described above, the rule change process is overseen by the AEMC and the law and rules are enforced by the Australian Energy Regulator (AER). The AER has the power to develop and amend guidelines.

6. IMPEDIMENTS TO DISTRIBUTED ENERGY: A REVIEW OF BARRIER STUDIES

In this chapter the impediments to wide scale uptake of DE are considered by reviewing barrier studies from Australia and abroad. The review attempts to disaggregate the barriers into those specific to Energy Efficiency (EE), Demand Management (DM) and Distributed Generation (DG). A mix of formal research, as well as insights from case studies and reports is included to identify each barrier by category and provide a brief discussion of the barrier including its potential significance in the Australian context today with reference to current or recently completed Government reviews. In this way, we build a picture of what work has been done, is being done and what work may remain to be done, to ensure the benefits of DE can be efficiently maximised.

Research presented here should not be viewed as a formal literature review tracing the antecedents of barriers identified in the literature, rather a useful resource which documents a comprehensive list of potential barriers. It is important to note this literature review while comprehensive, is not exhaustive.

6.1 Key findings

Removing impediments to DE is likely to require new policy and/or regulation, or changes to existing policy and/or regulation. It can be said that in general, government develops policy interventions to achieve changes to energy market performance where there is a desired policy outcome that cannot be delivered efficiently or effectively through changes to market law, rules and guidelines, or that won't occur naturally or efficiently in line with government objectives as a market develops.

Determining when DE is efficient, considering full lifecycle inputs and outputs, is difficult to do but important to understand when considering barriers and enablers. Original CSIRO modelling work presented in Chapter 9 goes some way to informing efficient levels of distributed energy considering social and economic factors, and a range of environmental externalities. While this type of modelling cannot capture the full complexity of time and location specific conditions that affect the value of DE, it helps inform an aggregated view on what an efficient level of DE may look like.

Terminology used for understanding different forms of distributed energy is not always consistent and sometimes overlaps. We note in particular that energy efficiency and distributed generation can be used as forms of demand management. The lack of consistent terminology makes it difficult to develop a hierarchy, or sense of the importance of different barriers discussed in literature.

Indicatively, based on interviews with 47 industry and government stakeholders, research conducted by CSIRO (2009) suggests a hierarchy of issues to be addressed before DE achieves wide scale uptake. The following hierarchy of issues is adopted from the report:

- DE needs to be a commercially viable alternative to mains grid supply before it will have widespread uptake
- For DE to be commercially viable, policy and regulation needs to allow proponents to capture some portion of the value of DE where it reduces emissions or costs that are otherwise socialised - primarily seen as costs of peak demand infrastructure
- Policy and regulation must also have long term certainty to give DE proponents and investors the confidence to implement DE
- Consumers, industry and governments all need to be educated on the value of DE and how it works to overcome cultural bias towards mains grid energy supply. This is also needed to inform appropriate policy and regulation development
- Technology and market development needs to be focussed on reducing cost and improving reliability.

This is not a complete hierarchy, however in combination with literature reviewed in the remainder of this chapter, it informs key DE enablers identified in Chapter 7.

6.2 Background

The deliberate shaping of how markets supply and consume energy occurs through energy market law, rules, and guidelines, or through policy initiatives such as those outlined in Chapter 5. For this reason, removing impediments to DE is likely to require new policy and/or regulation, or changes to existing policy and/or regulation.

It can be said that in general, government develops policy interventions to achieve changes to energy market performance where there is a desired policy outcome that cannot be delivered efficiently or effectively through changes to market law, rules and guidelines, or that won't occur naturally line with government objectives as a market develops.

The process by which market law, rules and guidelines are developed and changed is distinctly different from the process by which policy initiatives are developed and implemented. At a high level, both types of intervention can be guided by Federal or State Government policy objectives. However market laws, rules and regulations are developed strictly in accordance with the National Electricity Objective which provides stability, predictability and consistency to market design over time.

As described previously, market rules are developed and changed by an independent authority - the Australian Energy Market Commission (AEMC) and enforced by an economic regulator - the Australian Energy Regulator (AER). Neither entity reports directly to an elected Minister, although the AEMC reports to the Ministerial Council on Energy (MCE), made up of Energy Ministers from all jurisdictions. The AER reports to an independent board. Changes to the National Electricity Law are by nature lengthy processes subject to significant consultation and oversight. Rules, regulations and guidelines can be adapted more readily, but are still subject to consultation and oversight.

Policy initiatives are typically driven by government departments, either top down by the relevant Minister, or bottom up through the department, community, industry and various stakeholders. Government departments have a broader scope for influencing energy markets because they are not bound by a static objective or law. In very simple terms, government departments are primarily bound by the acceptability of policy to stakeholders, which provides discipline.

The link between policy, regulation and barriers is an important one. Barriers are typically defined with regard to economic efficiency. That is, a barrier is typically seen as legitimate if it impedes an economically efficient transaction and the cost to remove the barrier is outweighed by the benefits of doing so. Indicatively, this approach is adopted by the AEMC in its review of demand side participation and by agencies such as the Productivity Commission (PC). However, sometimes a barrier is defined as a hybrid between economic and engineering efficiency. For instance, Sorrell et al. (2000) state a barrier is a postulated mechanism that inhibits investment in technologies that are both energy efficient and (apparently) economically efficient. Barriers can also be split between market barriers and market failures, as is typically done by the International Energy Agency (IEA).

In the literature review that follows, we have tried not to exclude or screen barriers based on whether they may or may not impede a strictly efficient transaction, in economic or engineering terms, or based on the likely cost and benefit of addressing them. We do this in part due to the difficulty of determining when an action may be efficient, considering full life cycle inputs and outputs, but primarily in recognition that broadly supported policy or regulatory intervention needs to be cognisant of a wide range of stakeholder interests that cannot be captured by the analysis of one or two disciplines.

This position reflects trends in best practice policy making principles, which encourage the use of multi-criteria decision making analysis (MCDA) as a policy development tool. MCDA allows sharing of data, concepts and opinions across those involved in the policy making process including members of the public, consultants, policy agencies, and elected officials (Kiker et al., 2005). Through iteration and reflection, MCDA allows sources of decision making anomalies such as incomplete information, misallocation of risk, or the framing of problems to be worked through and resolved (Kiker et al., 2005). Essentially, MCDA allows a cost benefit analysis to occur, but has inbuilt processes to ensure the analysis has legitimacy from objective and subjective viewpoints.

This literature review looks at various studies into barriers to DE in Australia and internationally to develop a comprehensive range of potential barriers. It then compares the barriers identified through literature, with action that has been, and is being taken by government and its independent agencies. In this way, we aim to identify barriers that are yet to be resolved, providing guidance for future work.

Terminology used for understanding different forms of distributed energy is not always consistent and sometimes overlaps. In this literature review, we have separated categories of distributed energy into energy efficiency, demand management and distributed generation. We recognise significant overlap in the literature between these terms and the interchangeable use of other terminology such as demand side participation or demand side response. We note in particular that energy efficiency and distributed generation can be used as forms of demand management.

The lack of consistent nomenclature makes it difficult to develop a hierarchy, or sense of the importance of different barriers discussed in literature. Furthermore, the use of discipline specific language makes it likely that barriers need to be described and discussed in a way that is tailored to the intended target. For instance, economists and engineers may use different language to discuss the same issue.

However indicatively, based on interviews with 47 industry and government stakeholders, research conducted by CSIRO (2009) suggests a hierarchy of issues to be addressed before DE achieves wide scale uptake. The following hierarchy of issues is adopted from the report:

- DE needs to be a commercially viable alternative to mains grid supply before it will have widespread uptake
- For DE to be commercially viable, policy and regulation needs to allow proponents to capture some portion of the value of DE where it reduces emissions or costs that are otherwise socialised - primarily seen as costs of peak demand infrastructure
- Policy and regulation must also have long term certainty to give DE proponents and investors the confidence to implement DE

- Consumers, industry and governments all need to be educated on the value of DE and how it works to overcome cultural bias towards mains grid energy supply. This is also needed to inform appropriate policy and regulation development
- Technology and market development needs to be focussed on reducing cost and improving reliability.

For ease of understanding across a wide audience, we have defined different types of barriers identified into generic categories, recognising that in many instances, the same barrier may sit across a number of categories. Category types have been chosen to create a degree of consistency with previous research, but this is made difficult by the absence of consistency in the literature.

We have identified the following barrier categories common to all forms of distributed energy:

- Policy/regulatory
- Financial costs (energy prices, market access and equipment costs)
- Decision making
- Energy market structure and capacity (includes service providers, manufacturers, suppliers etc)
- Information
- Technological.

Section 9.4 explicitly deals with technological issues through an analysis of the large scale uptake of DE on power systems and as such it is not repeated here.

We recognise that a barrier relating to energy efficiency or distributed generation may also relate to demand management and vice versa. As far as possible, we have tried to ensure that where a barrier is specific to energy efficiency or distributed generation, it is considered as such. Where the barrier may apply more generically, or in circumstances where energy efficiency or distributed generation is being used explicitly as a form of demand management, it is included under demand management. For clarity, we treat energy efficiency as passive reduction of load with the only active element being the appliance purchase decision, as opposed to demand management which typically involves active reduction of load at specific times either by a third party, or by the appliance user.

The reader should note that inevitably, some barriers are repeated across the different categories or have a high degree of relatedness. For instance, it is likely that some information barriers relate to or cause decision making biases.

6.3 Australian reviews

While there is a significant amount of information available on potential barriers to energy efficiency, formal, or evidence based research into this issue, specific to the Australian context, appears relatively limited. We have tried to capture a mix of formal research, as well as insights from case studies and reports. In this section, we have included research by Vine et al. (2003) that reviews barriers in a number of jurisdictions including Australia.

Barriers to distributed energy have been subject to a number of parallel and overlapping government reviews and independent research in Australia and internationally. In this complex and constantly evolving environment, it is necessary to monitor changes to market frameworks that affect distributed energy, cross check against barriers, and ensure legitimate barriers are either being removed, or plan to be removed. Industry participants need to be able to understand current frameworks, but also understand how they are evolving so they can plan future activity.

In the sections that follow, we identify each barrier by category and provide a brief discussion of the barrier including its potential significance in the Australian context today with reference to current or recently completed government reviews. In this way, we build a picture of what work is being done and what work may remain to be done, to ensure the benefits of DE can be efficiently maximised.

6.3.1 Energy efficiency

Barriers to energy efficiency identified through a review of studies either specifically in the Australian context, or that consider the Australian context are as follows:

Policy/regulatory

- *Short term policy horizon (Crossley, 1999), (Vine et al., 2003).*

A short term policy horizon refers to the lack of, or difficulty in setting policy frameworks that have a consistent long term objective. A long term objective, and ideally the coherent, predictable policy framework that follows creates a degree of certainty, and so confidence, for market participants to plan and implement their objectives efficiently. In any jurisdiction, efforts need to be made across all policy stakeholders to ensure long term objectives are understood by market participants. This can be assisted by use of best practice policy making principles, including the use of policy networks, and multi criteria decision making analysis – discussed in more detail in Chapter 7.

- *Lack of understanding by policy makers of the value of energy efficiency (Crossley, 1999), (Vine et al., 2003).*

This barrier makes it difficult to set policy that fully harnesses the value of energy efficiency. In part it may be driven by a lack of data on the value of energy efficiency, considering all externalities, but is also driven the by effectiveness of communicating that data in a way which is readily understandable by policy makers. It is difficult to determine the extent to which this is a barrier without undertaking thorough consultation with a range of government agencies. It is sufficient to say here that understanding of the value of energy efficiency can be improved by using best practice policy making principles, including the use of policy networks, and multi criteria decision making analysis – discussed in more detail in Chapter 7.

- *Separation of energy policy from social and environmental policy (Crossley, 1999), (Vine et al., 2003).*

This barrier is closely related to the previous in that the separation of social and environmental policy objectives from energy policy objectives makes it difficult, if not impossible to fully account for the value of energy efficiency in energy policy decisions. This barrier may be in part driven by the nature of policy making structures where government departments are split across energy, environment and social issues, although we recognise within these departments there can be teams dedicated to improving interdepartmental collaboration and dialogue.

- *The extent to which market compatible policies are developed reflecting social and environmental objectives, such as energy efficiency policy. These need to internalise social and environmental benefits (Outhred and MacGill, 2006).*

Again, this barrier is closely related to previous barriers, albeit that it explicitly describes the policy outcome that acts as a barrier, as opposed to previous barriers that relate to the process of achieving a policy outcome. Attempts are being made in Australia to recognise environmental and social externalities in energy prices through the development of an emissions trading scheme, retail price deregulation in some jurisdictions and reforms to network pricing. However the reforms are in process and have not been finalised. A recent paper released by the Australian Academy of Technological Science and Engineering has called for more research into externalities associated with energy (ATSE, 2009). The paper extrapolates social health and environmental costs associated with energy generation in Australia based on European research.

- *Lack of political will/attention – energy efficiency typically has low visibility (Crossley, 1999), (Vine et al., 2003).*

This barrier relates back to the process of policy making, and the difficulty of raising the profile of energy efficiency sufficiently to ensure its benefits are acknowledged and facilitated where necessary through policy. In part, it may be driven by the relatively abstract nature of energy as a product in that it is relatively homogenous, excites low consumer involvement, and for the majority of people may have no immediate direct visual or physical impact. While this barrier and its cause is difficult to prove empirically, stakeholders seeking to promote the benefits of energy efficiency should note this barrier.

Financial costs (energy pricing, market access and equipment costs):

- *Low cost of energy (Crossley, 1999), (Vine et al., 2003).*

This barrier relates specifically to Australia in that relative to many other nations, Australia has abundant cheap energy; so long as environmental externalities are not fully accounted for. Implicitly, this reduces the financial driver to undertake energy efficiency as it makes financial paybacks longer. The extent to which the cost of energy is low is difficult to address. What can be addressed is the extent to which the price of energy does not reflect externalities, or time specific market costs.

- *Potential for high capital cost of efficiency measures (Crossley, 1999), (Vine et al., 2003).*

This relates to the previous barrier in that high capital costs are a barrier to the extent they reduce the rate of return on any investment in energy efficiency. As a barrier, it can also be exacerbated where there is limited low cost finance, or where the finance available for energy efficiency measures comes at a higher cost than finance available for energy generation.

High capital costs can be addressed using an efficient subsidy that enables the purchaser of an energy efficient device to capture value that may otherwise be socialised as costs. For example, Sustainability Victoria recently developed a discount at the point of sale promoting efficient appliance purchases (Resource Smart, 2009). The discount was only available for a short time and may have been implemented as a trial. This approach has not been widely used specifically in relation to energy efficiency in Australia as yet, although the green loans scheme, a low interest loan scheme to address capital barriers for low income households, has been developed by the DEWHA and this scheme will facilitate a range of DE measures.

Another approach to overcome capital costs barriers is to implement market based white certificate schemes that target the uptake of certain energy efficient products. This can drive economies of scale and bring down installation costs. Designing market based schemes can be complex and realising efficiency gains is not always straight forward.

- *Price of energy does not reflect its true cost (Crossley, 1999), (Green and Pears, 2003), (Energetics, 2008), (PC, 2008).*

This barrier is highly related to policy barriers previously mentioned in that the price of energy will reflect its true cost without policy intervention. It is important to note that energy also has time specific costs relating to the supply/demand balance in the energy market and the cost of building network infrastructure to supply energy at peak times. Attempts are being made in Australia to recognise environmental and social externalities in energy prices through the development of an emissions trading scheme, retail price deregulation in some jurisdictions and reforms to network pricing. As described above, many reforms are in process and have not been finalised. A recent paper released by the Australian Academy of Technological Science and Engineering has called for more research into externalities associated with energy (ATSE, 2009). The paper extrapolates social health and environmental costs associated with energy generation in Australia based on European research.

Decision making bias:

- *Habits and custom are not developed in energy efficiency manifesting in a number of barriers, those being (Crossley, 1999), (Vine et al., 2003).*
    - *Lack of certainty with regards to efficacy of decisions*
    - *Lack of history of successful projects/energy efficiency improvements*
    - *Reluctance to change equipment and/or work/living patterns*
    - *Fear of routine disruption.*

This collection of barriers are referred to as decision making bias in that they relate to the way individuals and organisations inherently make decisions, but they are not fixed. Typically organisational habit and custom can be changed through deliberate change management including education, targeted incentives and positive reinforcement. These barriers will be perceived as legitimate to the extent that they result in inefficient decisions, and that the benefits of changing habits outweigh the costs. It cannot be assumed any failing to secure energy efficiency gains is inefficient, for instance while energy efficiency may have a net benefit for a business, the time and cost in securing that benefit may be better spent on other business activities with higher returns.

These barriers are likely to be best addressed through education, including education of tradespeople, engineers, designers, but also more generic education on the benefits of energy efficiency to households and business to raise its profile. Significant efforts have been made in Australia to provide web based information and case studies on the benefits of energy efficiency through Federal and State departments. The extent to which provision of information, education and other behaviour change programs should be re designed or increased to deliver energy efficiency is unclear. However, studies such as the McKinsey cost curve (Figure 6.1) for abatement in Australia (2008), have generally pointed to significant untapped, cost effective energy efficiency potential in Australia. This suggests more work is required to ensure these cost effective gains are realised.

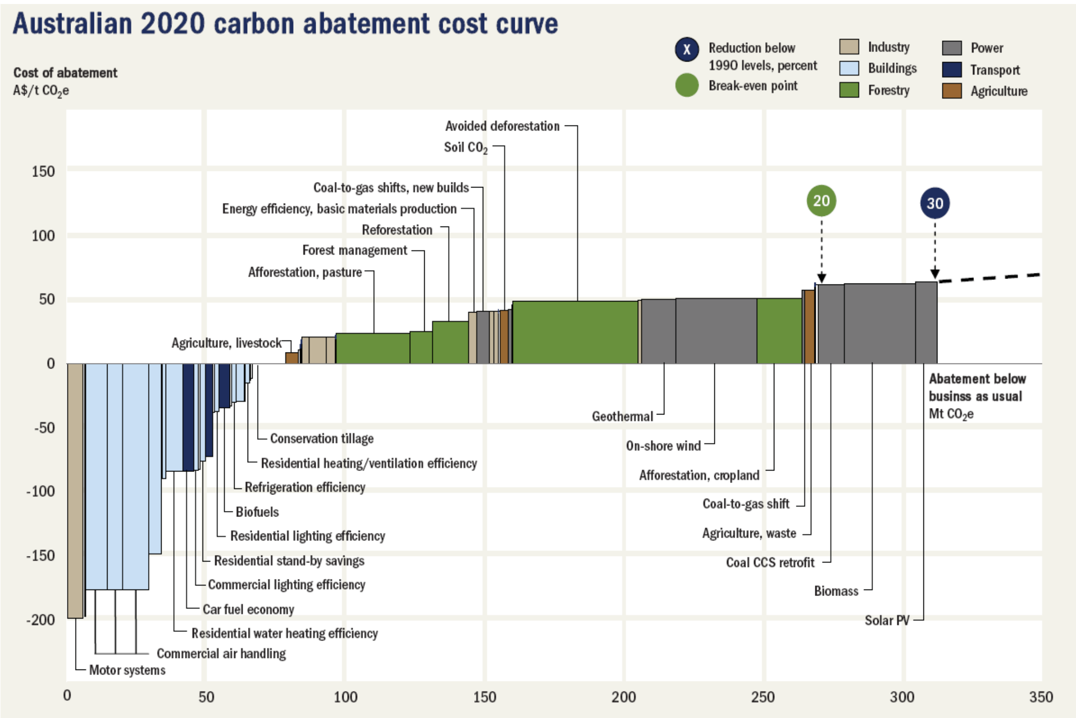


Figure 6.1: McKinsey Australian abatement cost curve (base case assumes no nuclear power and international CDM credits; McKinsey and Company 2009). Reproduced with permission from McKinsey and Company.

- *Prioritisation of certain capital savings up front, rather than uncertain operating savings (Kahneman and Tversky,1981), (IEA,2005 in Garnaut, 2008).*

This is considered a decision making bias because the research shows people will consistently make decisions that preference certain outcomes over uncertain outcomes, where the probabilistic value of either outcome is equivalent. This finding has not been linked explicitly to decision making on energy efficiency through empirical research, although the finding is commonly applied in behavioural economics.

This barrier could be addressed by having more certain information on operating savings that can be made by purchasing a more efficient appliance at the point of sale, or by providing an efficient rebate at point of sale. The potential for addressing this barrier in Australia has not been fully exploited, with information provided at point of sale not detailing cost savings (this information is available on web tools), and limited experience with point of sale rebates.

- *Pre-determined, and sticky budgets can limit appropriation of efficiency gains in higher cost appliances (Thaler, 1999 in Garnaut, 2008).*

This barrier relates to the process of decision making and highlights that people may inadvertently lock out an efficient optimal decision before the time at which their final decision is made. This highlights the importance of using education and information in a way that reaches decision makers while they are forming their intent to purchase an appliance, not just at the time of purchasing.

- *Hurdle rates (minimum acceptable rate of return) for energy efficiency investments (Green and Pears, 2003), (Energetics, 2008).*

This has been classed a decision making barrier in that high hurdle rates for energy efficiency will only be a barrier to the extent they are set unreasonably, or irrationally high. For instance, a business may set a hurdle rate of 14% for upgrading manufacturing systems, but 20% for upgrades specifically designed to improve energy efficiency, all other variables being comparable. To an extent, high hurdle rates may be driven by other barriers such as uncertainty over potential efficiency gains.

Energy market structure and capacity (includes service providers, manufacturers, suppliers etc):

- *Lack of access to equipment, infrastructure and skilled people in the industry, (Green and Pears, 2003), (Vine et al., 2003), (Garnaut, 2008).*

It is difficult to determine the extent to which this barrier may be symptomatic of other barriers to energy efficiency or causal. That is, if pricing, policy and decision making barriers were worked through, this may create a demand for energy efficiency that builds market capacity. Regardless, it is an important barrier in that any lack of market capacity may increase transaction costs for consumers and businesses or reduce the confidence decision makers have in energy efficiency.

To an extent, a sign of this barrier being addressed is evident in the latest COAG announcement on energy efficiency which includes a commitment to targeted outreach, education and training (COAG, 2009).

- *Market structure and regulation - level of privatisation, unbundling, competition interact in complex ways and can impact on incentives for energy efficiency. (Crossley, 1999), (Vine et al., 2003).*

This is a legitimate barrier to the extent that cost effective efficiency gains in energy service delivery are not realised considering all social and environmental externalities. The barrier is difficult to surmise, but crudely it relates to the extent to which businesses in the energy supply chain have incentive to improve the efficiency of energy consumed by customers. If incentives are not aligned with end use efficiency, or other DE measures, there may be perverse incentive for the energy supply chain to maximise throughput of energy, or to not use DE where it is efficient. For instance, it is sometimes said that deterministic planning standards limit the ability for distribution networks to value the aggregated affects of distributed generation.

In its draft report on barriers to demand side participation, the AEMC note that end use energy efficiency is best dealt with through policy intervention, as opposed to amending market structure or regulation. An example of this at a State level has been the development of policy interventions that require energy retailers to facilitate improvements in end use efficiency. Examples of these interventions have been described in Chapter 5.

- *Excess supply capacity (Crossley, 1999), (Vine et al., 2003).*

This is classed as a barrier due to market structure, but largely manifests itself as low energy prices which in turn reduce the relative financial gains that can be made through energy efficiency. It may also limit the extent to which individuals and organisations plan for energy efficiency in that if energy supply is expected to be abundant into the future, less attention may be spent on harnessing efficiency gains.

This is potentially less of a barrier today in Australia than it may have been at the time of research as supply/demand conditions are relatively tight now, particularly at peak times. Networks are also in a state of renewal, and new renewable generators will be brought on line, driven by regulation. This could be a driver for DE to the extent the benefit of deferring or substituting capital expenditure on supply infrastructure can be captured.

- *Incentive of supply chain not aligned with energy efficiency (Crossley, 1999).*

This barrier is explicit in that it suggests the energy supply chain does not have the incentive to improve energy efficiency. Given how market structures change over time it is difficult to say this barrier applies today in the same way it did at the time of the research undertaken. Nevertheless, it is important to acknowledge it as a potential barrier that may warrant further analysis.

This is a complex barrier, and one which the AEMC, in its review of barriers to demand side participation, suggests is best dealt with through policy intervention, as opposed to changes to regulatory frameworks or market rules. It is classed here as a barrier caused by energy market structure, but equally could be thought of as a regulatory or policy barrier.

- *Inadequate competition (Crossley, 1999), (Vine et al., 2003).*

Again, this is a relatively time specific barrier with market characteristics such as the level of competition changing over time. It is reasonable to assume that as levels of competition decrease, the incentive to further improve the efficiency of energy services provided may decrease also.

Reform processes in Australia are aimed at deregulating the energy industry and encouraging competition. However barriers may remain if providers of efficiency products and services do not face competition. As far as possible, it is important for regulators and policy makers to ensure barriers to efficient market entry are removed.

- *Split or misplaced incentives, also referred to as principal agent problems (Crossley 1999), (Vine et al., 2003), (PC, 2008), (IEA, 2005 in Garnaut, 2008).*

This barrier describes a situation where a decision maker is not exposed to the full costs and benefits of their action, and so does not necessarily have the incentive to maximise benefits and minimise costs efficiently. Split incentives occur in many instances that affect energy efficiency, from decisions made by building designers and builders, to decisions made by landlords and investors.

This could be considered a decision making bias, because in some regards split incentives should not inherently preclude appropriation of efficiency gains, but may do so because decision makers have not, or are unwilling, to overcome uncertainty relating to appropriating the gains of energy efficiency. For example, a landlord may not pursue efficiency gains because they are unsure they will recoup their costs through higher rent. However here it is considered a market structure issue, as changing the structure of markets that affect energy efficiency would directly help align incentives. Overcoming split incentives is discussed in more detail in Chapter 7.

- *Customer instability (Crossley, 1999), (Vine et al., 2003).*

Customer instability can affect the incentive an energy provider has to improve efficiency at any given location. This is because any investment in improved efficiency may only be recoverable in a relatively short period of time from a specific customer. This is a relatively difficult barrier to address, but is useful to note for market participants.

- *Inseparability of product features – you can't choose differences in energy efficiency as an add on/option (Crossley, 1999), (Vine et al., 2003).*

This is a subtle barrier that means the value and cost of efficiency upgrades tends to be bundled with other product options. For example, a customer may want a more fuel efficient car, but it may only come with other standard upgrades that a customer does not want such as more expensive wheels. This could dampen the incentive to choose a more efficient model.

Without strict regulation, this is a difficult barrier to resolve. To an extent, it is being addressed in the appliance and housing markets by creating minimum energy efficiency performance standards (MEPS) and providing consumer information. This barrier may be addressed by manufacturers to the extent they see demand for energy efficient products, and so in part this barrier can be overcome by consumer education and information provision, creating social norms and so on.

- *Lack of time and resources (internally) for developing and implementing energy efficiency (Energetics, 2008).*

This barrier was identified through a survey of consumers taking part in the Australia Federal Government Energy Efficiency Opportunity Program and so relates to large energy users specifically. This barrier is likely to have a degree of relatedness to market capacity as a mature market for energy efficiency services should overcome any lack of resources a company may have internally.

Implicitly, this may be a failing of providers of energy efficiency services, and so attributed to market capacity. Ultimately, service providers need to find ways of reducing search and implementation costs by improving business models and/or sales techniques. This barrier may also relate to habitual technology lock-in, where the historical priorities, and so habitual decision making in an organisation, does not fully account for the value of energy efficiency and so decision makers systematically under invest in developing and implementing energy efficiency.

Information barriers

- *Energy users can have difficulty understanding tariff structures (Green and Pears, 2003).*

This barrier is important for a number of reasons, but particularly because prices are often thought of as an important signal to customers to consume less energy, or consume energy more efficiently. This barrier highlights that even with tariff structures that better reflect the true time specific cost of energy, customers may not respond as expected. Education and information may be needed to better facilitate this.

Tariff structures may get more complicated with the introduction of ‘smart meters’ in Australia. Effective in-home communications may help resolve this, but it is likely to take time and effort for households to learn how new pricing structures affect them. It will be important that customer education programs are designed and implemented to address this.

- *Energy users may have insufficient feedback/understanding about their energy use (implicitly, that they don’t understand how to use energy efficiently or identify and deploy energy efficient measures) (Crossley, 1999), (Green and Pears, 2003), (Vine et al., 2003), (Garnaut, 2008).*

This barrier relates to the degree to which customers understand how to use energy more efficiently. Limitations in understanding may result in consumers responding imperfectly to price signals, or other incentives that may be used to change their behaviour.

Again, this can be resolved to an extent through effective in home display and communication tools, but it is likely that households need to be engaged in a way that encourages development of habit which reduces transaction costs that result from constant evaluation of energy consumption decisions.

- *Accessing information can be difficult and/or costly (Crossley, 1999), (Green and Pears, 2003), (Vine et al., 2003), (Garnaut, 2008), IEA (2005).*

- *This can result in an information asymmetry and potential for adverse product selection (Garnaut, 2008).*

There is a degree of relatedness between this barrier and previously mentioned barriers in that it impacts on the degree to which other barriers are realised such as market capacity barriers and decision making biases. It will also affect other information barriers, such as the degree to which customers understand their energy consumption and how to improve efficiency in a cost effective way.

Various websites now exist, privately and publicly run, that convey information on energy efficiency and its benefits, including case studies. To some extent, this barrier may be less relevant today, however findings made by Energetics (2008) suggest large companies may still not be able to commit the time and resources to search for and implement energy efficiency. This may suggest a need for rethinking and reworking how information on energy efficiency is provided to domestic and commercial customers.

6.3.2 Demand management

As stated above, we have categorised barriers to demand management consistently with barriers to energy efficiency and distributed generation, recognising some barriers may apply across categories. Barriers identified most specifically relating to demand management are as follows.

Policy/regulatory:

- *Time lag and uncertainty when DNSP recovering costs of DM trials (Dunstan et al., 2008).*

This barrier was identified specifically in relation to NSW distribution businesses in a review of the demand management code of practice, but is broadly applicable given the Australian Energy Regulator (AER) has also developed demand management incentive schemes for other jurisdictions. Time lag and uncertainty around cost recovery means distribution businesses may not commit fully to DM trials, or explore their full potential.

The AER has developed some mechanisms to improve certainty such as providing clear guidelines ex ante (before the event) on requirements that must be met in order to have spending approved. However, the effectiveness of this will be unknown until the scheme has operated for some time.

- *Time lag between DM trials and reporting requirements slows the learning process for DNSPs (Dunstan et al., 2008).*

This is a more specific version of the barrier above, specifically relating to the speed at which distribution business learn, and apply what they learn, following demand management trials. The demand management incentive scheme proposed by the AER will operate on a five year basis with yearly reviews. However the AEMC is also in the process of developing a requirement for distribution businesses to develop and implement a demand management strategy that will be reviewed and updated on a three year basis. This may help increase the speed at which learning takes place within distribution businesses.

- *Dispute resolution process does not allow for low cost access for small DM proponents (Szatow, 2008).*

Access to dispute resolution was found to be a barrier specifically for small customers trying to connect generators to the distribution network and/or secure some network support payments. This barrier relates to the negotiating power imbalance between a small customer and the monopoly distribution businesses. The AEMC is in the process of developing dispute resolution procedures relating to the regulatory investment test for distribution.

- *Regulatory test may not accurately consider value of DG, particularly the value of avoided emissions (Szatow, 2008).*

This barrier is speculative to the extent that the regulatory test is worded in a way that is open to a degree of interpretation. For example, for transmission network investments, 'market benefits' must be considered, and there is a degree of interpretation as to how this is applied. However the barrier highlights the need for the regulatory test to account for externalities resulting from different investment options, not just costs priced in the energy market. For transmission investments, the test has recently been changed while the regulatory test for distribution is being redesigned. This makes it difficult to determine the extent to which this may be a barrier in the future.

- *Network incentives do not encourage uptake of DM activity on long timeframes, encourages DM as a solution to short term network constraints. DM on long timeframes includes new building design and efficient appliance installation. (Dunstan et al., 2008), (CSIRO, 2009).*

This is a relatively complex barrier and relates to the ability for either those companies in the energy supply chain, or those companies that influence the efficiency of energy consumption, to capture the value of avoided network spending that energy efficiency provides. The AEMC in its review of demand side participation notes the potential of this barrier and suggests it is best dealt with through policy intervention such as building and appliance standards. However, there is still the potential for a gap between the cost incurred from upgrading the efficiency of a building or appliance, and the degree to which the benefits of those decisions can be captured. This relates to the absence of time specific costs for energy consumption, and costs that fully reflect the scale and timing of network investment. However, we note that time and location specific prices for energy will not automatically resolve this issue due to decision making complexity, discussed in more detail in Chapter 7.

- *The extent to which market compatible policies and/or regulation are developed reflecting social and environmental objectives, such as energy efficiency policy. These need to internalise social and environmental benefits (Vine, 2003), (Outhred and MacGill, 2006), (CSIRO, 2009).*

This barrier was noted as a barrier to energy efficiency but is equally applicable to demand management more generally and so has been included here also.

- *Uncertain recovery of DM spending means DNSP management may be averse to spending on DM (SKM, 2003), (Dunstan et al., 2008), (CSIRO, 2009).*

This barrier relates to how distribution businesses recover costs undertaken as part of their regulated business operations. As described in Chapter 3 of this report, distribution businesses are regulated in a way that requires them to forecast spending over five years and have those budgets approved by a regulator. Spending on demand management is generally classed as operational expenditure which is subject to less certain recovery than capital expenditure on network building, therefore network businesses may invest less time and effort developing demand management options as part of their forecasts, and ultimately implementing sub optimal levels of demand management.

- *Network businesses do not have regulatory incentive aligned with investment in and/or facilitation of efficient DG/DM (SKM, 2003), (Szatow, 2008).*

This barrier has a high degree of relatedness to the previous barrier, but also affects the ability for third parties to access the network, and so provide competitive demand management services. The barrier suggests that networks will not undertake efficient DM, or will block third parties undertaking efficient DM, because this can reduce their revenue. This barrier has been largely rejected by the AEMC in its review on barriers to demand side participation and so may require further analysis, although the AEMC acknowledged the efficiency carry over mechanism may provide some incentive asymmetry towards network building.

The AEMC rationale for rejecting this barrier appears to hinge on the assumption that any loss of revenue by undertaking DSP reflects the loss of value experienced by customers from not consuming. However some forms of demand management may not necessarily entail a consumer not consuming energy, rather being supplied energy in a more efficient way, or by an alternative to the grid.

Financial costs (energy pricing, market access and equipment costs):

- *No equitable transparent valuation of DG and/or uncertain payment arrangements for DG (Outhred and MacGill, 2006), (CSIRO, 2009), (Szatow, 2008).*

Distributed generation has the potential to provide a number of benefits to different market participants and typically has to negotiate with larger companies in the supply chain to capture the value of these benefits. For this reason, it is often difficult for a DG operator to capture all the value they provide and trying to do so can involve significant transaction costs.

To ensure DM, including the use of DG, is not excluded from certain markets, AEMC work on barriers to demand side participation has looked at ways to improve access to wholesale markets and ancillary service markets. Initiatives include a better process for registering DG units, and allowing aggregating load to provide frequency control and ancillary services (FCAS). These changes appear likely to be driven by the AEMO, and are likely to go through a rule change process in the near future.

However, there is still potential for value provided to go unrewarded, particularly where it can address costs associated with peak demand and environmental externalities.

- *Pricing does not reflect true cost of supply at peak times, and hence the value of avoided consumption (SKM, 2003), (Outhred and MacGill, 2006), (Szatow, 2008).*

Smart meters and price deregulation in Australia is aiming to address this, but it may not result in a ‘true cost’ price signal. It is more likely that time of use prices will represent a fraction of the real cost, albeit a more accurate tariff shape than currently used. SKM (2003) contemplate the potential of congestion pricing to improve price signals, but note the severity of accurate prices may deter policy makers or regulators from pursuing such an option.

- *Limited funds for capital expenditure (CRA, 2001 in EFA, 2002).*

This issue is difficult to overcome and has been discussed in relation to energy efficiency. Intervention may not be efficient or equitable to the extent public money is being used to deliver otherwise privately cost effective gains.

Decision making bias:

- *Scale of network investment that appears necessary in the near term creates pressure on networks to allocate resources to plan and build networks according to their strength, rather than seek alternatives such as DM (Dunstan et al., 2008).*

This is a subtle barrier, in that it relates to the perceived need for investment, rather than the actual need for investment – hence it is classified as a decision making bias. AEMC work on distribution planning and expansion arrangements may address this through the requirement to develop a non network strategy. This may help networks identify DE opportunities, on longer timeframes, and so help overcome any inherent organisational or cultural decision making bias.

- *High discount rates (CRA, 2001 in EFA, 2002).*

This barrier has been discussed with regards to energy efficiency, and the same discussion applies here.

- *Perception that DM will result in loss of amenity. (CRA, 2001 in EFA, 2002).*

This barrier specifically relates to the perception that DM will result in lost production, business operation and/or amenity caused by the interruption of supply. It is likely this barrier is best overcome through education and trials. A specific trial of demand management which was able to overcome these issues is discussed in Chapter 9.

- *Low priority given to DM (CRA, 2001 in EFA, 2002).*

This barrier has been discussed in relation to policy/regulatory decision making on energy efficiency. The extent to which it is a legitimate barrier relates to the extent to which the benefits of demand management remain untapped, and that benefits outweigh the cost of securing them. It is an important barrier to consider when trying to increase the uptake of demand management in that it cannot be assumed customers will be interested in demand management and/or the savings to them will outweigh the opportunity cost of participating in demand management

Energy market structure and capacity (includes service providers, manufacturers, suppliers etc):

- *The role of energy service companies (ESCO) is curtailed – end users need to be actively engaged in decisions about distributed resource options. ESCO model limited by lack of accurate and timely price signals, including the ability of distributed generators to be integrated with the NEM through spot markets and ancillary services markets (Outhred and MacGill, 2006).*

This is considered a barrier caused by market structure because fundamentally, price signals and market access would be irrelevant to the development of ESCOs to the extent the supply chain was aggregated. That is, an aggregated supply chain allows all the benefits of demand management to be captured, without having to rely on price signals.

As discussed previously, pricing issues are being addressed by the move to roll-out smart meters in Australia, and the move to deregulate prices in some jurisdictions. Reforms are likely to be subject to jurisdictional appetite for full cost pass through to consumers. Integrating demand management into spot and ancillary service markets is likely to be addressed to some extent through reforms to be undertaken by the AEMO.

The degree to which Energy Service Companies evolve is likely to be driven by both market innovation and deliberate policy and regulator intervention.

- *Manufacturers need to be included in developing and marketing solutions (Outhred and MacGill, 2006).*

The extent to which manufacturers are engaged in developing and marketing DM solutions in Australia is unclear and difficult to determine. However the MEPS program does provide this link in the appliance market.

- *Lack of resources to undertake DM. (CRA, 2001 in EFA, 2002).*

As discussed previously, recent COAG announcements indicate an appetite for building industry capacity with regards to energy efficiency. However efforts may be needed to broaden this to include building industry capacity to undertake other demand management activities. This is occurring to an extent, with the Australian Energy Regulator designing demand management incentive schemes for distribution network companies (discussed in chapter 3) and the Federal Government committing $100 million towards the development of a 'Smart Grid' demonstration which should help build resources and capacity for undertaking DM.

Information barriers:

- *Consumers, industry and governments all need to be educated on the value of DE and how it works to overcome cultural bias towards mains grid energy supply. This is also needed to inform appropriate policy and regulation development (CSIRO, 2009).*

This barrier is likely to be behind many other barriers including decision making biases and policy/regulatory barriers. To a large degree, overcoming this barrier is the subject of this report.

- *Lack of information on the costs and benefits of DM. (CRA, 2001 in EFA, 2002).*

This barrier naturally has a high degree of relatedness to the barrier above, and has been discussed in relation to energy efficiency. Information on the costs and benefits of DM needs to fully account for social and environmental externalities that may not be reflected in energy prices.

- *Lack of information about DM techniques and technologies. (CRA, 2001 in EFA, 2002).*

This relates closely with market capacity barriers and reinforces the need for education and demonstration projects that allow knowledge sharing. To an extent, this is a barrier inherent in the development of any new technology, but its effect can be reduced through processes for knowledge sharing and collaboration.

- *The market (energy users, companies, tradespeople, designers etc) do not have sufficient information and knowledge about demand management (Crossley, 2002).*
    - *Service providers don't always have the skill to sell the value of operating savings from higher upfront costs.*

As discussed previously, it is important that efforts are made to develop and implement information, training and education packages that help the market build capacity to undertake a full suite of demand management activities, and not solely focus on one or two forms of demand management such as energy efficiency and distributed generation.

6.3.3 Distributed generation

Again, we have categorised barriers to distributed generation consistently with barriers to energy efficiency and demand management, recognising some barriers may apply across categories. Barriers identified most specifically relating to distributed generation are as follows:

Policy/regulatory:

- *Building block form of regulation (for network businesses): (ESC submission to VCEC inquiry, 2009).*
    - *Does not create strong incentives for dynamic cost efficiency, because it links returns directly to the regulated asset base (RAB), or the value of the assets used to provide regulated services. Networks have little to gain from an effective demand response or investments in distributed generation.*

As discussed in Chapter 3, regulation of distribution businesses has varied across jurisdictions, however a common approach used by regulators to determine prices (where price cap regulation is in place) to be charged by a network business is the building block method. This is a detailed approach requiring the regulator to calculate and verify all expenditure items, then setting prices that allow a return on efficient investment.

In its review of barriers to demand side participation, the AEMC does not deal with this issue in relation to distributed generation specifically, but as noted previously under barriers to demand management, they effectively discount the form of regulation as a barrier to efficient demand side participation. Given conflicting results, this is a barrier worth further consideration and analysis.

It is worth noting the AEMC is currently reviewing the potential to use total factor productivity for the regulation of network businesses and that based on submissions, there is considerable debate about the relative benefits and disadvantages of this form of regulation (AEMC, 2009a).

- *Creates the need to determine RAB which can raise cost allocation issues, particularly if networks are providing regulated and non-regulated services.*

As discussed above, the AEMC does not address this barrier in their review of demand side participation.

- *Requires regulators to determine efficient investment levels, which will become more complicated as renewable and distributed generation become more common.*

To an extent, the AER is trying to address this issue by developing demand management incentive schemes that reveal information about efficient demand management, and implicitly distributed generation. This does not address the barrier directly, but can help overcome it.

- *May discourage investment in distributed generation if it reduces the network's overall RAB because the incremental cost of distributed generation is less than the incremental cost of network expansion.*

This barrier is discussed more generally in relation to demand management (or demand side participation) by the AEMC in its review of demand side participation. The AEMC position appears to be that networks will only inefficiently build capital expenditure (Capex), implicitly avoiding spending efficient operating capital (Opex), if their weighted average cost of capital (WACC) is set too high.

- *Results in capital markets inevitably establishing highly geared (i.e. leveraged through debt), risk-averse business models and management styles.*

Capital market barriers have been discussed previously. However, it is posited here that high levels of gearing and subsequent institutional lock-in of risk adverse practice is caused by the form of network regulation. It should also be noted that highly geared companies will apply different discount rates to those relying on equity, typically equity being higher cost than debt. This may affect investment hurdle rates, and so also act as a barrier to otherwise efficient DG. It will be a legitimate barrier to the extent companies building centralised supply infrastructure can secure cheaper finance than those building DG, or other forms of DE, where all other variables are comparable. Implicitly, guaranteed rates of return provided to regulated businesses may result in artificially low discount rates for investment, artificially low prices, and so aversion to otherwise efficient DE spending by other market participants and consumers.

- *Technology specific incentives can create an artificial technology 'winner' (Szatow, 2008).*

Technology specific rebates or subsidies exist, as outlined in Chapter 5, and may result in weakened incentive to improve technology performance over time, or artificial lock out of competing technologies. This barrier was identified specifically in relation to distributed generation, but could apply more generally.

- *Policy and regulation needs to have long term certainty to give market confidence (CSIRO, 2009).*

This barrier has been discussed previously as a barrier to demand management.

- *Lack of process and technical standardisation can impede efficient connection (Outhred et al., 2002), (Szatow, 2008).*

MCE/SCO is currently developing connection processes at a distribution level, as is the AEMC at a transmission level. The extent to which this may remain a barrier is yet to be determined. In its review of market design in light of climate policies, the AEMC has proposed a new connection processes for connecting remote generation that allows for cost sharing and planning optimisation. The extent to which this process will be reflected at the distribution level is uncertain.

- *Rebate delays create cash flow problems for technology installers (Szatow, 2008).*

Government rebates for PV have ended and will be replaced by subsidies delivered through the Mandatory Renewable Energy Target. This issue may remain for other products that attract rebates such as solar hot water.

Financial costs (energy pricing, market access and equipment costs):

- *No equitable, transparent valuation of DG and/or uncertain payment arrangements for DG (Outhred and MacGill, 2006), (Garnaut, 2008), (Szatow, 2008), (CSIRO, 2009).*

The value of DG is either captured by substituting for mains grid supply, or by exporting power to the grid for some price. Unless the price of mains grid power is fully cost reflective, and any power exported to the grid is priced to fully reflect the value of this, it is very difficult for DG to capture its full potential value. As discussed previously, mains grid energy remains incompletely priced.

For some forms of DG, price regulation of power exported to the grid has been developed through feed-in tariffs (see Chapter 5 for details on this), but for most forms of DG the price paid for exported power is negotiated with energy retailers. Other value the DG operator may provide such as network support is also subject to negotiation. Furthermore, the aggregated effects of multiple DG operators may be different to an individual operator, and there is no methodology for pricing aggregated effects of DG, although reforms are underway to improve access to FCAS markets as discussed previously.

This means that for anyone planning DG, there is a relatively uncertain revenue stream, and significant complexity in capturing all value provided, and so the potential for incentives to be diluted. It should be noted that DG may not need to capture all the value it provides to be viable, but naturally, this would help ensure it is implemented where it is efficient.

Decision making bias:

None identified specifically relating to DG, although significant overlap with barriers to demand management and energy efficiency is likely.

Energy market structure and capacity (includes service providers, manufacturers, suppliers etc):

- *Monopoly power of networks affects ability to connect and secure network support payments (Szatow, 2008).*

This barrier was rejected by the AEMC in its review of DSP, and was originally identified in relation to relatively small scale DG. By nature, the existence of the barrier is difficult to prove, but may highlight the importance of effective guidelines for connection and/or dispute resolution as discussed previously.

- *Lack of access to equipment, infrastructure and/or skilled people (Outhred and MacGill, 2006), (Dunstan et al., 2008), (Szatow, 2008).*

It is difficult to determine to what extent this is the nature of an emerging market, or a barrier that can be efficiently addressed through deliberate strategy by market participants and/or government. As described in Chapter 5, various government initiatives exist to stimulate market activity, but it is unclear to what extent this can be increased, while still delivering efficient outcomes.

Information barriers:

- *Connection of multiple generators competing for access to the network needs to be optimised without breaching confidentiality issues (Szatow, 2008).*

A new connection framework is being developed in parallel between the AEMC and MCE/SCO, with the AEMC looking for ways to optimise connection of multiple generators at a transmission level. It is not clear if this process will be, or can be replicated at a distribution level.

- *Network planning process and market information provision not effective, or as effective as it could be, in signalling for distributed generation (Szatow, 2008).*

The process for communication distribution network planning and expansion information to the market is being examined by the AEMC at the time of writing.

6.4 International reviews

The extent to which findings from studies undertaken overseas are relevant to Australia is determined by differences in market structures, energy resources, geographic distribution of energy users and other variables such as the presence of domestic industries and cultural norms. Here we present barriers identified in international reviews and try to determine the relevance of these barriers to the Australian context. It is important to note this literature review while comprehensive, is not exhaustive.

Table 6.1: International barriers in energy efficiency

Barrier – Energy efficiency	Type	Identified by	Relevance to current Australian policy and regulatory context
Tax incentives may favour increasing operating expenditure over increasing capital expenditure. Most efficiency measures require greater capital spending and less operating spending	Policy/regulatory	Brown (2001)	A complete review of the tax system is naturally beyond this report and so the extent to which this barrier applies in Australia is difficult to determine. We note the Henry review is currently being conducted and will examine issues such as how tax incentives impact on incentives to reduce environmental harm. For example, in its submission to the review, the Clean Energy Council point out that replacing equipment when 'like for like' is treated as a tax deduction, but upgrading equipment as it wears out, for instance to a more efficient product, is considered an investment and so only depreciates over time.
Unpriced public goods can misalign investment signals. Public goods can include education, training and research – which is essential when trying to transform an industry, such as energy.	Policy/regulatory [international]	Brown (2001), IEA, (2007)	This barrier relates closely to the concept of technology lock-in – discussed in more detail in Chapter 7, but where use of a potentially inefficient technology becomes locked in by social structures including education systems and organisational culture. It is unclear to what extent research, education and training locks in centralised energy supply where distributed energy may be more efficient.
Costs (externalities) related to energy use/consumption may remain unpriced	Policy/regulatory	IEA (2007)	This barrier is identified in Australian literature and referred to previously.
Capital market barriers can inhibit efficiency purchases, particularly in certain market segments (low income households, small business, and highly geared companies).	Financial costs (energy pricing, market access and equipment costs)	Sorrell et al. (2000), Brown (2001), IEA (2007)	The green loans scheme targeting low income households has been discussed previously, however in small business there is no such assistance available. Lack of capital in highly geared companies may be a more acute issue in the short term given the current global financial crises.
Incomplete or mispricing of fuels can distort markets (including incentives for fuel search and extraction, and a variety of environmental externalities).	Financial costs (energy pricing, market access and equipment costs)	Brown (2001)	This barrier and efforts to address it have been discussed to some extent previously, although importantly, incentive that impacts on search and exploration cost is identified here. In Australia, tax incentives do exist for fossil fuel exploration, for instance through the petroleum resource rent tax. However determining the extent to which they may be inappropriate, or advantage fossil fuels over alternative fuels is difficult. There are significant unpaid social costs of travel. For example, in 2005 the road sector alone imposed $9.6 billion in congestion and local pollution costs (BITRE, 2008).
Fee structure of services can impede efficiency – fees based on % of costs provide incentive to minimise the ratio of design effort/capital cost. Therefore little incentive	Decision making bias	Brown (2001)	While this type of barrier may be real in Australia, it is difficult to see how it could be efficiently overcome directly, i.e. by restructuring fee for service models across industries. Regulation of product standards and improved access to information and/or education and training is likely to help align incentives of

Barrier – Energy efficiency	**Type**	**Identified by**	**Relevance to current Australian policy and regulatory context**
for designers to innovate due to search costs.			clients and service providers. Targeted education to service sectors about how to sell the value of efficient design may also assist.
'Principal agent problem' – an agent has the authority to act on behalf of a consumer, but does not, or cannot reflect the consumers' best interest (e.g. architects, engineers and builders, landlords).	Decision making bias	Sorrell et al. (2000), Brown (2001), IEA, (2007), Levine et al. (2007)	This is very similar to the barrier identified above. In some instances, the causal barrier may well be the fee structure of service providers, and the 'principal agent' problem a symptom of the fee structure. Again, a mix of standards, information and education can help align incentives and this is the approach that has been taken to date in Australia, principally through building codes and the minimum energy performance standards (MEPS) program.
Uncertainty over future energy prices and technology development can be a barrier	Decision making bias	Brown (2001)	This barrier is likely to overlap and/or drive previously identified decision making barriers, to the extent people tend to favour certain outcomes over uncertain outcomes, even if probabilistically, both outcomes have the same value. Uncertainty over future energy prices must be factored into information and education campaigns. Ideally, future cost curves based on probabilistic assessments could be used to provide more certain estimates of potential savings.
Return on investment hurdle rates, or other investment criteria (implicitly, that they may be set irrationally high)	Decision making bias	Sorrell et al. (2000)	This barrier has been identified and discussed above in relation to Australian specific research.
Lack of routine, habit and/or culture at individual and/or organisational level, combined with behavioural impediments to change	Decision making bias	Sorrell et al. (2000), IEA (2007)	This barrier has been identified and discussed above in relation to Australian specific research.
Decision makers may not trust the source of information	Decision making bias	Sorrell et al. (2000)	This barrier may be difficult to overcome on a case by case basis, but it highlights the importance of education, training and certification to avoid this becoming a systemic barrier.
Decision makers may not value all benefits of energy efficiency	Decision making bias	Sorrell et al. (2000), IEA (2007)	This barrier can be overcome to an extent through more accurate pricing of energy considering environmental and social externalities, as well as its time specific costs. It can also be addressed through generic education and information provision on the benefits of energy efficiency, including establishing social norms – this is discussed in more detail in Chapter 7.
Intermediaries in the purchase of energy consuming devices can distort decision making. For example automobile design caters for new car buyers, who may be	Energy market structure and capacity (includes service providers,	Brown (2001)	Again, this is a difficult barrier to address without strict regulation, but can be resolved to an extent by creating minimum performance standards and/or stretch targets for industry It may be beneficial to create more stringent targets on more expensive product ranges, acknowledging those consumers are most likely to

Barrier – Energy efficiency	**Type**	**Identified by**	**Relevance to current Australian policy and regulatory context**
relatively wealthy, but who represent a small percentage of total car owners (many buy second hand). These wealthier new car buyers typically have lower incentive for fuel efficiency.	manufacturers, suppliers etc)		afford energy efficiency improvements. . Referring to the automotive example, it is worth noting for instance that the US Government has recently announced new standards for fuel consumption in motor vehicles
Markets for energy efficiency are often incomplete. For instance, different car models don't have fuel efficiency levels as an optional item. This cost gets bundled with other optional items.	Energy market structure and capacity (includes service providers, manufacturers, suppliers etc)	Brown (2001), IEA (2007)	This barrier is comparable with that identified by Vine et al. (2003), as discussed previously.
Decision makers may lack the necessary authority and/or power to prioritise energy efficiency	Energy market structure and capacity (includes service providers, manufacturers, suppliers etc)	Sorrell et al. (2000), IEA, (2007)	This barrier is unlikely to be resolved other than through targeted education, information provision and efficient incentives for industry that can raise the profile of energy efficiency benefits, particularly amongst senior decision makers.
Transaction costs can impede energy efficiency, not easy for consumers to work out what costs and benefits will be of different investment options. Markets may lack incentive to provide this information.	Information barriers	Sorrell et al. (2000), Brown (2001) , IEA (2007)	This barrier relates closely to decision making biases previously discussed. governments have, and can mitigate this barrier by mandating standards and information provision. However scope may remain to improve the level of certainty consumers have over potential savings from energy efficiency through information provision at the point of sale.
How information is presented can lead to decision making bias	Information barriers	Sorrell et al. (2000)	This barrier must be considered when designing information and education campaigns around energy efficiency. For instance, research has indicated people tend to prefer avoiding losses than securing gains (Tversky and Kahneman, 1986)

Table 6.2: International barriers in demand management

Barrier – Demand management	Type	Identified by	Relevance to current Australian policy and regulatory context
Regulations need to ensure DGs and interruptible load can access ancillary service markets. For example in NZ, ancillary service costs were reduced by 75% in the first year of allowing interruptible loads	Policy/regulatory	Ackerman et al. (2000)	AEMC work on barriers to demand side participation has looked at ways to improve aggregated DM access to wholesale markets and ancillary service markets. Initiatives include better process for registering DG units, and allowing aggregating load to provide frequency control and ancillary services (FCAS). These changes will be driven by the AEMO and are likely to go through a rule change process in the near future.
Treating intermittent generators (wind, solar) as single units, and imposing penalty payments can limit their value. Each unit may have fluctuations in generation, but amongst a disperse group of generators, their fluctuation may be smoothed out. Regulations must allow for pooling net generation (for bidding purposes, but also for assessing any penalty payments) from dispersed group of intermittent generators.	Policy/regulatory	Ackerman et al. (2000)	As noted previously, work is underway to improve aggregated DG and load access to markets.
Distributed generation project proponents frequently felt that existing rules did not give them appropriate credit for the contributions they make to meeting power demand, reducing transmission losses, or improving environmental quality.	Policy/regulatory	Galdo et al. (2000)	Again, this barrier is being addressed to some extent, as discussed above, by improving access to FCAS and wholesale markets. However the extent to which other value can be captured, such as avoided losses and improved environmental outcomes, remains uncertain. To the extent these costs are internalised and accounted for in energy prices in a time specific way, DG will capture value where it supplies a customer. But where it supplies the grid, DG is likely to face uncertain recovery of value where price paid is subject to negotiation.
Uncertainty over future policy and regulatory decisions	Policy/regulatory	Hirst (2002)	To an extent, a degree of policy uncertainty is inevitable. But policy and regulatory agencies must be cognisant of the real barrier this creates and ensure processes are in place to reduce market uncertainty as far as possible. Policy networks could assist with this – this is discussed in more detail in Chapter 7.
Lack of coordination between State and Federal jurisdictions	Policy/regulatory	Hirst (2002)	Chapter 5 outlines the many different State and Federal based policies and programs relating to DE. To some extent, divergence is positive in that it allows for experimentation and learning. However where best practice is identified, it is important that consistency is quickly established. Policy networks could assist with this as discussed in more detail in Chapter 7.

Barrier – Demand management	**Type**	**Identified by**	**Relevance to current Australian policy and regulatory context**
Lack of incentive for distribution businesses to incorporate DG in the planning and operation of networks and use as an active control element	Policy/regulatory	Ropenus (2007)	A very similar barrier was identified in the domestic literature, and this has been discussed previously. Work is being done to ensure distribution businesses plan for and use DG as a legitimate alternative to network building where it is a feasible alternative.
Fee structures for market participation can act as a barrier – large fixed fees can disadvantage small generators.	Financial costs (energy pricing, market access and equipment costs)	Ackerman et al. (2000)	Fee structures for market participation have not been identified as a barrier in Australia. Based on research available, it is unclear if this is a material barrier for the Australian market.
Prices may not reflect time specific costs	Financial costs (energy pricing, market access and equipment costs)	Hirst (2002)	This barrier repeats and affirms the same barrier identified in domestic research.
The extent to which customer operations are perceived to be inflexible, where they may not be.	Decision making bias	Hirst (2002)	It is likely that this barrier can only be addressed through information, education and training, particularly by for service providers.
Low prices at any time may impede the development of demand management activities, even if high prices are highly probable in the future.	Decision making bias	Hirst (2002)	This barrier may relate to decision making bias discussed with relevance to energy efficiency, in that customers may fail to make efficient decisions due to inaccurate price forecasting and/or weighting of the probability of different future price scenarios. Better information provided by the market and service providers may help alleviate this barrier.
Most customers equate price volatility with higher bills, failing to recognise the potential for low prices to offset high prices, or to shift demand to make savings	Decision making bias	Faruqui et al. (2002), in Hirst (2002)	As discussed above, this can only really be overcome by providers of demand management services.
Incumbents in the supply chain who believe they stand to make economic losses, or face decreased returns from demand management, may block efforts to encourage it.	Decision making bias	Hirst (2002)	This is considered a decision making bias, but could easily fit as a policy/regulatory barrier and/or a market structure barrier. It is a decision making bias caused by the extent to which there is a perceived misalignment of incentive created by regulation, policy, lack of competition, or some other factor, as opposed to a real misalignment of incentive.
The extent to which market, or system operators can integrate many small units of generation or load into market operation.	Energy market structure and capacity (includes service providers, manufacturers, suppliers etc)	Hirst (2002)	Again, this barrier has been identified in the National context and work is being conducted by the AEMO to resolve it.

Barrier – Demand management	**Type**	**Identified by**	**Relevance to current Australian policy and regulatory context**
Limited availability of low cost, standard/off the shelf systems for end use energy management and control.	Energy market structure and capacity (includes service providers, manufacturers, suppliers etc)	Hirst (2002)	This is a difficult barrier to address directly, but is useful for DM service and technology providers to be aware of. It is likely to be overcome as the DM market develops and increased levels of investment occur in technology development and marketing.
Lack of resources within companies to search for and implement solutions, and limited timeframes to do so.	Energy market structure and capacity (includes service providers, manufacturers, suppliers etc)	Dyer et al. (2008)	This barrier has been identified with regards to energy efficiency specifically, and the discussion applies to demand management more generally. It may be that COAG initiatives need to be broadened to include forms of demand management other than energy efficiency.
Lack of expertise resulting from workforce rationalisation.	Energy market structure and capacity (includes service providers, manufacturers, suppliers etc)	Dyer et al. (2008)	Barriers caused by lack of industry expertise have been discussed above, albeit the causal nature of the barrier described here is more explicitly. The degree to which they may apply in Australia is difficult to determine.
Customers don't always have the means to receive price and consumption data.	Information barriers	Hirst (2002), Dyer et al. (2008)	This barrier has been discussed with regards to energy efficiency. The discussion applies more generally to other forms of demand management.
Information to make decisions when upgrading or replacing equipment is not always readily available.	Information barriers	Dyer et al. (2008)	This is a subtle barrier and points to the need for very targeted information and education campaigns, but also the importance of having a skilled industry where sound advice is readily available.
Incomplete or inaccurate analysis of data.	Information barriers	Dyer et al. (2008)	Again, this is a subtle barrier, and points to the importance of having a skilled industry where sound advice and analysis is readily available.

Table 6.3: International barriers in distributed generation

Barrier – Distributed generation	Type	Identified by	Relevance to current Australian policy and regulatory context
Regulatory inconsistency across jurisdictions can impede developers of new technology	Policy/regulatory	Brown (2001)	National market reform is in the process of addressing regulatory inconsistency where possible. Policy inconsistency remains, particularly a diverse range of rebates and subsidies for renewable energy technologies, and in some case, energy efficiency. Policy diversity can be a strength where it allows for testing of different policy measures. However, where best practice is identified, it is important that National consistency is quickly developed.
Unpriced public goods can misalign investment signals. Public goods can include education, training and research – which is essential when trying to transform an industry, such as energy.	Policy/regulatory	Brown (2001)	As noted under barriers to energy efficiency, COAG has taken measures to address some of these issues for energy efficiency, but whether enough is being done on distributed generation specifically is unknown. A combination of funding through solar cities, smart grids and network companies undertaking DM activity may address this to an extent.
Any requirements for distributed generators to sell into distribution networks at fixed prices, as opposed to wholesale markets, can limit opportunities for receiving peak prices.	Policy/regulatory	Ackerman et al. (2000)	Smart meters and price deregulation are being used to address this, with energy sold to the grid subject to negotiation unless export from the DG system is covered by regulation. This barrier may remain where price regulation remains – DG may not be able to fully capture benefits it provides. Issues may also come about if retailers do not reflect tariff shapes of network companies, or use negotiating power to block DG operators securing a fair price.
There is no National consensus on technical standards for connecting equipment, necessary insurance, reasonable charges for activities related to connection, or agreement on appropriate charges or payments for distributed generation.	Policy/regulatory	Galdo et al. (2000)	Similar barriers are identified by Szatow (2008) and Outhred et al. (2002), identified previously. This highlights the importance of work being done by MCE/SCO, AEMC and other initiatives designed to improve connection processes and the degree to which DG operators can access markets such as FCAS. However given the significant complexity of negotiating payment arrangements, there is still likely to be a degree of uncertainty and so may remain a barrier.

Barrier – Distributed generation	Type	Identified by	Relevance to current Australian policy and regulatory context
Distributed generation project proponents faced with technical requirements, fees, or other burdensome barriers are often able to get those barriers removed or lessened by protesting to the utility, to the utility's regulatory agency, or to other public agencies. However, this usually requires considerable time, effort, and resources. • Official judicial or regulatory appeals were often seen as too costly for relatively small scale distributed generation projects.	Policy/regulatory	Galdo et al. (2000)	This barrier relates in part to the ability of connection applicants having access to dispute resolution, identified previously in the Australian context. It also suggests there may be barriers in terms of time and effort spent by connection applicants trying to investigate/qualify connection requirements and costs, but also to change rules and regulations through engaging with policy and/or regulatory agencies. For larger companies, typically incumbents, affecting policy and regulatory outcomes is less of a relative burden and so there may be lobbying power asymmetry.
Insufficient public funds for R&D – significant downtrend in OECD from 1974 – 2004. The Stern report (Stern et al., 2006) called for a doubling of R&D.	Policy/regulatory	Allen et al. (2008)	R&D funding is available in Australia and some tax incentives exist also. However it is unclear whether the level of R&D in Australia is sufficient to enable a full and efficient uptake of DE. It is worth noting that R&D spending within the energy sector in Australia is being reviewed as part of the development of an Energy White Paper by the Department of Energy, Resources and Tourism.
Complementary Policy needed to support innovation through different stages of the technology development cycle	Policy/regulatory	Allen et al. (2008)	This is a potential barrier where the suite of policy tools deployed does not address the different stages of the technology development lifecycle. This is discussed in more detail in Chapter 7.
Stable long term policy frameworks needed to send clear investment inducing signals such as firm targets for renewables well into the future.	Policy/regulatory	Allen et al. (2008)	This barrier is to some extent likely to be inherent in any democracy where policy frameworks may be subject to change depending on the party elected at any given time. To ensure policy is stable in the long term, efforts have to be made to achieve broad support across the political spectrum.
Long and complex procedures for network connection	Policy/regulatory	Ropenus (2007), UK Gov. (2007)	Again, this has been identified in domestic specific studies and is in the process of being addressed through work being conducted by MCE/SCO and the AEMC.
Difficulty of accessing any policy or regulatory incentives for export of energy	Policy/regulatory	UK Gov. (2007)	While not explicitly a barrier identified by domestic research, cash flow issues for installers of technologies relying on rebates was identified as a barrier for DG. Australia's rebate system for small scale PV is being restructured, with subsidies to be delivered through the renewable energy target scheme. The barrier suggests efforts must be made to ensure claims for renewable energy certificates (RECs), including the REC multiplier, can be quickly and easily processed.
Difficulty of obtaining planning permissions	Policy/regulatory	UK Gov. (2007)	This barrier has not been identified in literature reviewed in Australia specifically, and to some extent, planning permissions are subject to substantive process for legitimate reasons. Planning issues have been discussed briefly in Section 5.2.2.

Barrier – Distributed generation	Type	Identified by	Relevance to current Australian policy and regulatory context
			For any difficulty caused by the planning process to be a legitimate barrier, it would need to be shown to be unnecessary.
Lack of time of use pricing, or access to time specific market prices can impede distributed generation	Financial costs (energy pricing, market access and equipment costs)	Brown (2001)	Smart meters and price deregulation are being used to address this in Australia, but as discussed previously, the extent to which prices may reflect true costs may vary depending on the method of implementation.
Connection charges, particularly when based on deep connection costs – potential for market discrimination	Financial costs (energy pricing, market access and equipment costs)	Ropenus (2007)	The latest position of the MCE/SCO work on connection arrangements proposes deep connection costs for DG. AEMC work has found that deep connection costs are appropriate where output of DG is not restricted. Reforms in this area are incomplete, making it difficult to determine the relevance of the barrier.
DG can involve high capital costs	Financial costs (energy pricing, market access and equipment costs)	UK Gov. (2007)	To a degree, when read as a standalone barrier, this is not a legitimate barrier. However where DG is efficient, but blocked by high capital costs because of decision making bias or some flaw in capital markets, it may be. This has been discussed previously.
Price paid for energy exported to grid may not reflect its true value	Financial costs (energy pricing, market access and equipment costs)	UK Gov. (2007)	Again, this issue has previously been discussed, but here it has been identified relating to distributed generation specifically. It is important that market structure changes, policy and regulation is cognisant of the range of DG technologies available, or coming to market, and can allow these technologies to capture their full value when exporting energy to the grid.
Many barriers in today's marketplace occur because utilities have not previously dealt with small-project or customer-generator interconnection requests.	Decision making bias	Galdo et al. (2000)	This barrier is likely to be a function of experience, the lack of experience creating decision making bias and potentially mispricing connections, and/or mispricing risk associated with connections. In the Australian context, some of these issues have been worked through, but work remains to qualify connection costs and benefits. This is in part the function of this report and related work.
Market participants can influence price.	Energy market structure and capacity (includes service providers, manufacturers, suppliers etc)	Ackerman et al. (2000)	As above, the monopoly power of network companies has been discounted by the AEMC as a barrier to demand side participation. For some forms of DG, the price is regulated by feed-in tariffs – this varies across State jurisdictions. It is unclear if Retailers are exerting market power to keep any unregulated prices for DG low. Further research may be required on this issue.

Barrier – Distributed generation	**Type**	**Identified by**	**Relevance to current Australian policy and regulatory context**
Market barriers exist for certain participants, exacerbated as most markets are designed to accommodate large generators, not small ones.	Energy market structure and capacity (includes service providers, manufacturers, suppliers etc)	Ackerman et al. (2000)	This is a barrier that can only be interpreted quite generally. In Australia, many processes are underway or completed that have aimed to address this issue – i.e. markets are being reconfigured to accommodate small generation. This includes work being done by the AEMO, the AEMC, and others, as discussed above.
Restrictions on market access	Energy market structure and capacity (includes service providers, manufacturers, suppliers etc)	Ropenus (2007)	As far as we are aware, this is not a barrier in Australia. What may be a barrier in Australia are the terms on which access is available. How this is resolved may depend to an extent on work being conducted by the MCE/SCO and AEMC on connections, the AEMO on market access, and policy/regulation relating pricing (externalities, and time specific costs). This work has been discussed above.
Lack of market transparency.	Energy market structure and capacity (includes service providers, manufacturers, suppliers etc)	Ropenus (2007)	This may be a barrier in Australia, specifically around connection costs and information on planned network building. A comparable barrier has been identified above relating to demand management, as opposed to distributed generation specifically. Again, work being done by the MCE/SCO and the AEMC will be important for addressing any potential barriers caused by a lack of market transparency.
Fulfilment of technical market operation requirements, authorisation problems and high power trading fees.	Energy market structure and capacity (includes service providers, manufacturers, suppliers etc)	Ropenus (2007)	Work by the AEMC and the AEMO is aiming to improve integration of DG into market operations, but it is not yet clear if this will be sufficient to allow DG to compete with centralised generation on an equal footing.
Concentration of market power can make it difficult for small DG units to establish a market.	Energy market structure and capacity (includes service providers, manufacturers, suppliers etc)	Ropenus (2007)	It is unclear how this may affect small DG units in Australia, although it does highlight the role of creating a market niche where new technologies competing with established technologies that may be 'locked in' such that the new technology has an opportunity to develop.
Lack of accredited, and/or trustworthy suppliers of services.	Energy market structure and capacity (includes service providers, manufacturers,	UK Gov. (2007)	Processes are in place in the Australian market to train and certify installers of DG equipment; however gaps may remain in relation to conducting network studies, or providing other niche services relating to DG. These barriers were identified by Szatow (2008) specifically in the Australian context.

Barrier – Distributed generation	**Type**	**Identified by**	**Relevance to current Australian policy and regulatory context**
	suppliers etc)		
Not all market participants have full information about the market	Information barriers	Ackerman et al. (2000)	This barrier is similar to the market transparency barrier identified previously, and is also identified as a barrier to energy efficiency and demand management. It can relate to a number of issues, for instance: time specific value of energy; when new investments are planned; the value of DG, or other DE solutions etc. As noted previously, a mix of better pricing information and information about planned network investments is being developed for Australian markets, and may address this barrier to a degree.
Technical barriers include grid-integration, planning permission and licensing. A study has found PV penetration up to 30% can occur with negligible impact on the network	Information barriers	Allen et al. (2008)	This is classed as an information barrier, because in the Australian context, a lack of real data has limited the ability to accurately price the network impact of DG. This study is largely corroborated by work recently commissioned by CSIRO, and completed by Senergy-Econnect (see Section 9.4)
Lack of transparency around calculation of charges	Information barriers	Ropenus (2007)	This issue is being addressed by the MCE in developing connection processes, but it is acknowledged that standardisation above a relatively low threshold (5-10kW) is difficult. It may be that this issue is best dealt with by encouraging competitive service provision, information transparency and effective dispute resolution processes.

7. ENABLERS FOR DISTRIBUTED ENERGY

In this chapter, we aim to distil findings from research detailed in Chapter 6 and with relevance to the Australian context, provide a detailed set of outcomes and processes to achieve those outcomes, to enable a large scale, efficient take up of distributed energy in Australia.

7.1 Key findings

Enabling distributed energy requires a coming together of many complementary policies. Split incentives in the property sector and within the energy supply chain, access to finance, renewable energy policies, energy prices, skill and industry capacity, from architects, through to builders and trades people, can all impact on the uptake of distributed energy and must be addressed simultaneously.

Based on research by CSIRO (2009) and literature reviewed in Chapter 6, key enablers for distributed energy are:

- A long term policy horizon with firm targets and commitments for uptake of DE that have widespread support across the political spectrum. Implicitly, that distributed energy is a highly visible and important policy deliverable, and that the market has improved certainty about how DE is valued
- Data that allows more accurate valuation of different forms of distributed energy incorporating real time market costs and a full suite of environmental and social externalities
- The use of a widely accepted, accurate, transparent, efficient and equitable DE valuation methodology across government agencies when developing DE related policies, programs and regulation including building standards, appliance standards, product rebates, feed in tariffs and so on
- Accurate, transparent pricing methodologies, accounting for time and location specific environmental and social externalities, for energy exported by DG and/or when DG is used for demand management that allows value to be easily captured by a full range of market participants (small to large, with various technologies)
- Full and efficient access to markets for services provided by DG including the ability to easily aggregate small generating or load reduction units into wholesale markets
- A regulatory and policy framework and environment that effectively aligns the incentive of companies in the supply chain, or encourages business model innovation, to provide efficient energy services to consumers, including conducting research, trials, and continued innovation. These incentives must be compatible with market competition, have broad support, be we well understood and followed
- An efficient, transparent process for connecting distributed generators, standardised as far as possible and coupled with effective low cost dispute resolution. Processes are needed for connecting multiple units and aggregating the costs based on aggregate impacts of connections

- A well informed, trained/accredited, skilled workforce that understands the value of DE and can sell its benefits to consumers of all types using insights provided by decision making science
- Improved information provision and framing of costs and benefits to consumers to allow easy and accurate valuation of DE options
- Tax, rebate and/or financing schemes that enable widespread access to cost effective DE that would otherwise not be taken up due to high capital costs or lack of access to capital. That this be done by providing efficient, easily recoverable financial incentives and reframing decision making biases (sticky budgets, incorrect weighting of probable outcomes, inefficiently high hurdle rates). This includes access to assistance for low income and small business market segments
- A comprehensive R&D program that allows for overcoming technology lock-in at a scale in line with the need for efficient uptake of DE and complementary policies/programs structured to move technologies efficiently through their development lifecycle
- A system of State and local planning and environmental controls that allows for a full consideration of issues, and ensures DE is not blocked without robust justification
- Education of relevant service sectors (designers, architects, engineers, builders, tradespeople, manufacturers) on the value of DE, and methods for better aligning their service incentives with long term, efficient supply of energy
- Continued and bolstered support for minimum performance standards (appliances, buildings), improved information provision (future energy prices, probable savings over time etc)
- Targeted, efficient incentives for landlords – structures for recovering cost savings from energy efficiency. Minimum efficiency standards can be stretched for the more expensive end of products/services
- Effective education around smart meters, tariff structures, how best to manage energy, processes that provide real time feedback and rewards (internal and external) to customers for effective behaviour
- A policy and regulatory environment where experimentation can take place, but where best practice is quickly adopted consistently across the nation.

7.2 Enablers for distributed energy

Research conducted by CSIRO (2009) provides a useful, albeit incomplete framework for thinking about how to best ensure an efficient, large scale take up of DE opportunities. The hierarchy of issues identified in the report is repeated below, and can be thought of as outcomes leading to the uptake of DE:

- DE needs to be a commercially viable alternative to mains grid supply before it will have widespread uptake
- For DE to be commercially viable, policy and regulation needs to allow proponents to capture some portion of the value of DE where it reduces emissions or costs that are otherwise socialised - primarily seen as costs of peak demand infrastructure
- Policy and regulation must also have long term certainty to give DE proponents and investors the confidence to implement DE
- Consumers, industry and governments all need to be educated on the value of DE and how it works to overcome cultural bias towards mains grid energy supply. This is also needed to inform appropriate policy and regulation development
- Technology and market development needs to be focussed on reducing cost and improving reliability.

The hierarchy is incomplete as a framework in that it does not include and prioritise a large subset of issues identified in the CSIRO interviews. Amongst the hierarchy and subset of issues is significant overlap with barriers identified in Chapter 6 of this report. By testing the hierarchy and subset of issues against barriers identified in Chapter 6, we aim to corroborate or reject findings made in the respective bodies of work.

To do this, barriers identified have been collapsed into one category – barriers to distributed energy. Comparable or related barriers have been amalgamated where possible and any barriers that are specific to one form of distributed energy have been isolated. Each barrier has then been rephrased as an outcome that would remove or overcome that barrier – an enabler. Literature has then been drawn upon to determine the best process by which to arrive at the desired outcome.

It is important to note with reference to efficient building design, which typically involves utilising a full suite of DE opportunities, research by Levine et al. (2007) highlights the importance of a coming together of many complementary policies. Levine et al. (2007) argue that split incentives, access to finance, renewable energy policies, energy prices, skill and industry capacity, from architects, through to builders and trades people, can all impact on building design and that policy makers must address these issues simultaneously. This is an important finding to consider when thinking about how to harness the benefits of distributed energy.

What follows is a table detailing specific enablers, the form of DE to which they apply, the degree of corroboration evident in literature reviewed, and specific processes that are likely to ensure key enablers are implemented. Where the degree of corroboration around enablers is discussed, references are made to the Australian context in order to provide a richer understanding of what remains to be done to ensure the benefits of DE are realised. We note that enabling processes we describe may be underway in some form. Where this is so, our comments should be seen as helping to inform those processes, as opposed to implying these processes are deficient.

A number of barriers remain that appear difficult to resolve, unlikely to cause significant impact and/or useful to be mindful of as opposed to able to be directly addressed. These have been included in a separate table below the enablers.

Table 7.1: Enablers for distributed energy technologies

Enabler	DE type	Degree of Corroboration	Process required to achieve the enabler
Long term policy horizon with firm targets and commitments for uptake of DE that have widespread support across the political spectrum. Implicitly, that distributed energy is a highly visible and important policy deliverable, and that the market has improved certainty about how DE is valued.	ALL	Policy and regulatory uncertainty and/or bias is identified as the most important barrier in CSIRO (2009). Policy certainty was highlighted as the key enabler including clear commitment to DE and targets. A lack of policy certainty was also commonly cited as a barrier to DE in the literature reviewed, with policy certainty highlighted as one of the key enablers of efficient DG uptake (Haas et al., 2004), (Allen et al., 2008). While it is difficult to say this is the most critical enabler, the weight of evidence suggests it is significant and should be addressed as a priority.	Achieving this enabler requires a coordinated policy development process with inter departmental, multi stakeholder involvement, potentially with independent brokering and/or establishment of formal policy networks for ongoing learning and collaboration across institutions. Given the diversity of stakeholders that influence distributed energy, it is important policy networks are represented by a full diversity of stakeholder interests. An effective way of establishing and working towards long term policy objectives is through backcasting. This process, and the use of policy networks is discussed in more detail in Section 7.3
Data that allows more accurate valuation of different forms of distributed energy incorporating real time market costs and a full suite of environmental and social externalities. The use of a widely accepted, accurate, transparent, efficient and equitable DE valuation methodology across government agencies when developing DE related policies and programs. Accurate, transparent pricing methodologies, accounting for	ALL	These enablers are closely related to each other, but also policy certainty, in that policy certainty is unlikely to come about unless the value of DE is well understood and accepted. A lack of understanding of the value of DE was identified as the 2nd most important barrier identified by CSIRO (2009). Variations on the theme of these enablers are repeated frequently and consistently in the literature suggesting a high degree of corroboration, with many references to environmental and market costs either not being factored into energy prices (and so not into the value of avoiding consumption), but also benefits not being captured, or difficult to capture when DG exports to the grid. Issues such as information asymmetry and/or negotiating power are often cited.	More research may be required to quantify the specific and potential value of different DE measures/technologies. However the network study and analysis detailed in Chapter 9 in this document goes someway to achieving a more accurate valuation of DE. Findings such as these are vital to inform policy making, regulation and any explicit or implicit methodologies used for valuing DE. Ultimately, they can assist to inform accurate valuation, fair pricing methodologies and easy market access to ensure DE proponents can capture the value of their activity.

Enabler	DE type	Degree of Corroboration	Process required to achieve the enabler
environmental and social externalities, for energy exported by DG and/or when DG is used for demand management that allows value to be easily captured by a full range of market participants (small to large, with various technologies). Full and efficient access to markets for services provided by DG including the ability to easily aggregate small generating or load reduction units into wholesale electricity markets.		Again, while difficult to say these are the most critical enablers, they are likely to be very significant and should be addressed as a priority. It is likely that addressing these barriers would help overcome related barriers such as the separation of environmental policy goals from energy policy goals. It is instructive to note that Chapter 5 of this report details a myriad of programs and policies that implicitly, through rebates, or explicitly through feed-in tariffs, value DE. However there does not appear to be a consistent methodology for how this is done across jurisdictions.	Policy networks can be used to develop and promote valuation methodologies that incorporate social health and environmental outcomes as well as real time market costs. In using policy networks to improve valuation and access to markets, energy policies that increase the uptake of distributed energy typically affect energy market operation, and the businesses involved in the energy supply chain. Policy makers must be cognisant of this and where possible, ensure incentives and disincentives of policy, market design and market operation work together to deliver outcomes that optimise social, environmental and economic objectives. Policy networks can be used to research and implement reform to better align incentives throughout the supply chain and improve signals for DE.
A regulatory and policy framework and environment that effectively aligns the incentive of companies in the supply chain, or encourages business model innovation, to provide efficient energy services to consumers, including conducting research, trials, and continued innovation. These incentives must be compatible with market competition, have broad support, be we well understood and followed.	ALL	The 2nd most important enabler identified by CSIRO (2009) was the aligning of distribution network company's incentives with planning/undertaking DM such that the value of DM is recognised as part of the network planning process. This was related to policy/regulatory uncertainty, identified as the most important barrier. Again, there is a high degree of corroboration in the literature around the need for aligning incentives within energy markets but also within energy related service industries, to ensure incentives encourage efficiency gains, as well as social and environmental externalities to be minimised. This enabler therefore has a degree of relatedness to the need for better data and pricing methodologies outlined above.	Policy networks can be used to research and implement reform to better align incentives throughout supply chain and improve signals for DE. Energy policies that increase the uptake of distributed energy typically affect energy market operation, and the businesses involved in the energy supply chain. Policy makers must be cognisant of this and where possible, ensure incentives and disincentives of policy, market design and market operation work together to deliver outcomes that optimise social, environmental and economic objectives.

Enabler	DE type	Degree of Corroboration	Process required to achieve the enabler
			There are some suggestions that efforts could be made to direct market innovation towards an Energy Service Company (ESCO) model – an energy and service provider that can capture the benefits of DE. Energy service companies will require the ability to measure, and capture the difference between the true cost of energy supply and more efficient supply. This model is discussed in more detail in Section 7.3 and Chapter 8.
An efficient, transparent process for connecting distributed generators, standardised as far as possible and coupled with effective low cost dispute resolution. Processes are needed for connecting multiple units and aggregating the costs based on aggregate impacts of connections.	DG	CSIRO (2009) found connection issues to be the 3rd equal most significant barrier. To a degree, distribution network companies were seen as the driver of this barrier, with DG seen as a threat to their revenue base. Resolving connection issues was seen as the equal 3rd most important enabler. The importance of connection processes was corroborated in domestic and international literature, including the potential for bargaining power and information asymmetry to block DG, particularly where DG pays for shared network augmentation costs. However these barriers are largely rejected by the AEMC in its review of barriers to demand side participation. MCE/SCO are currently developing connection processes at a distribution level, as is the AEMC at a transmission level, so the extent to which this may be a barrier in the future is uncertain. The AEMC are also developing dispute resolution processes.	Existing processes are underway to improve network connection arrangements and are being managed by the MCE/SCO. It is important that policy networks are leveraged to identify how network connections can be designed and managed most efficiently. Technical issues relating to the impact of connecting DG to distribution networks are explored in more detail in Chapter 9.

Enabler	DE type	Degree of Corroboration	Process required to achieve the enabler
A well informed, trained/accredited, skilled workforce that understands the value of DE and can sell its benefits to consumers of all types using insights provided by decision making science. Improved information provision and framing of costs and benefits to consumers to allow easy and accurate valuations of DE options.	ALL	Educating customers on the value of DE was found to be the 4th most important enabler by CSIRO (2009). A comparable barrier identified was a lack of industry skills/knowledge and the link between this and industry/cultural bias. This was the 3rd equal most important barrier. These enablers also have a high degree of corroboration in the literature and are most probably related to industry capacity and a number of decision making biases including irrationally high discount rates and incorrect weighting of probable outcomes. It is necessarily difficult to determine the appropriate level of support for industry capacity building, and so difficult to determine the degree to which existing programs will realise these enablers.	Public and privately operated training regimes may need revision and updating/upgrading where deemed necessary to incorporate new and emerging knowledge about DE. More generally, there needs to be broad promotion of findings relating to the value of distributed through messaging tailored to specific industry segments including product manufacturers, tradespeople, and those more directly engaged in energy markets. Further decision making research on DE may be needed to improve information framing and market signals used to promote DE. This is explored in some detail in Section 7.3. Findings from such research will assist industry participants, service providers, policy makers and regulators.
Tax, rebate and/or financing schemes that enable widespread access to cost effective DE that would otherwise not be taken up due to high capital costs or lack of access to capital. That this be done by providing efficient, easily recoverable financial incentives and reframing decision making biases (sticky budgets, incorrect weighting of probable outcomes, inefficiently high hurdle rates). This includes access to assistance for low income and small business market segments.	ALL	Capital cost issues were identified as a relatively minor subset issue in CSIRO (2009) research. However it is identified in a number of papers reviewed, suggesting it is a barrier that should be addressed, but that it may be less urgent than those discussed above. We qualify this by saying programs to address capital market barriers may be more urgent for particular consumer segments depending on government policy objectives. To a degree, this barrier is in the process of being addressed, with substantial commitments made to support insulation and hot water specifically across Federal and State jurisdictions, as well as the green loans program which will target a range of DE measures on a means tested basis. Chapter 5 details the range of programs being implemented. It appears as though the market segment that remains to be addressed is small business.	Not all barriers caused by capital costs are legitimate in that some DE measures may be more expensive than centralised alternatives that deliver comparable outcomes. Care must be taken to ensure inefficient DE measures are not encouraged through subsidies or rebates, or that DE measures are subsidised inefficiently. This requires that overcoming barriers caused by capital costs must be carefully researched and implemented to ensure barriers are legitimate and policy networks can help achieve this. It is also important to consider decision making science to help inform efficient

Enabler	DE type	Degree of Corroboration	Process required to achieve the enabler
			solutions to this barrier such as reframing cost/benefits of different purchasing decisions, allowing for more accurate weighting of options.
A comprehensive R&D program that allows for overcoming technology lock-in at a scale in line with efficient uptake of DE and complementary policies/programs structured to move technologies efficiently through their development lifecycle.	ALL	Insufficient R&D was identified as a minor subset issue in CSIRO (2009) research and has some corroboration in literature reviewed. Related is the finding that best practice policy making requires complementary policy to support innovation through different stages of the technology development cycle. This is discussed in more detail in Section 7.3. While there is a significant amount of R&D conducted in Australia, with some funding programs detailed in Chapter 5, the degree to which it is sufficient is uncertain.	Policy networks can be used to improve coordination and targeting of public R&D funding where possible and to establish efficient levels of public R&D funds.
A system of State and local planning and environmental controls that allows for a full consideration of issues, and ensures DE is not blocked without robust justification.	DG	This was identified as a minor subset issue in CSIRO (2009) research and has some corroboration in literature reviewed. Specifically, heritage controls were raised as an issue, while controls over air borne emissions from cogeneration in urban environments have also been identified as a potential barrier if set unreasonably high. These issues have been discussed in Section 5.2.2.	State and local planning agencies and/or associations need to be engaged through policy networks to identify and overcome any planning or environmental controls caused by misunderstanding DE.
Education of relevant service sectors (designers, architects, engineers, builders, tradespeople, manufacturers) on the value of DE, and methods for better aligning their service incentives with long term, efficient supply of energy.	ALL	The barrier corresponding to this enabler is not identified in CSIRO (2009), but is identified explicitly and implicitly by literature reviewed. While related to previously mentioned barriers, the enabler is a more targeted solution to a particular market segment that has significant decision making control over the extent to which DE is implemented.	Targeted research and messaging is needed to raise the profile of DE solutions within this audience. Training and capacity building is also needed through existing education programs, as well as new training and certification programs where necessary.
Continued and bolstered support for minimum performance standards (appliances, buildings), improved information provision (future energy prices, probably savings over time etc). Targeted, efficient incentives for	ALL	Again, the barrier corresponding to this enabler is not identified in CSIRO (2009), but is corroborated by literature reviewed, particularly principal agent problems. It relates to previously mentioned enablers in that effective policy and regulation is dependent on better data and valuation methodologies for DE that ultimately determines the	Use of policy networks to ensure policy/regulatory design maximises efficiency and effectiveness of regulatory intervention, particularly regulation of efficiency standards for buildings. Research may be needed on alternative or

Enabler	DE type	Degree of Corroboration	Process required to achieve the enabler
landlords – structures for recovering cost savings from energy efficiency. Minimum efficiency standards can be stretched for the more expensive end of products/services		cost/benefit of regulating building and/or appliance standards. COAG has taken steps to introduce disclosure of energy performance for rental properties and tighten building standards for new homes, and we understand there is a commitment to continue expanding and tightening the MEPS program.	complementary ways to overcome principal agent problems.
Effective education around smart meters, tariff structures, how best to manage energy, processes that provide real time feedback and rewards (internal and external) to customers for effective behaviour	ALL	While not identified in CSIRO (2009), this enabler has some explicit and implicit recognition in literature reviewed. Due to the relative lack of widespread complex tariff structures in the residential and small business market, this enabler has limited relevance today, although is likely to become increasingly relevant if proposed reforms to pricing are realised in the near future.	Messaging and education for consumers should be implemented as part of smart meter rollout. This will assist customers to understand the implications of the meters, potential tariff structures, and how they can change their usage patterns to take advantage of lower prices. Additionally feedback from the meters may be vital in educating the consumer on the environmental outcomes of their usage behaviour
A policy and regulatory environment where experimentation can take place, but where best practice is quickly adopted consistently across the nation	ALL	The need for consistent regulatory environments across jurisdictions is noted in the literature. However it is also recognised divergence can allow a degree of experimentation that can be positive. This means that convergence to best practice once identified is important.	Policy networks can be used to promote a level of experimentation, shared learning and where possible, convergence around best practice.

Table 7.2: Barriers to be aware of but difficult to resolve, or likely to be resolved over time with minimal impact:

Barrier	**Discussion of potential solution**
Excess supply capacity	Policy makers should be cognisant that the value of DE is in part contingent on the need/timing for investment in mains grid infrastructure. Naturally this is not a barrier that can be resolved directly but inefficient redundant supply capacity should not be encouraged.
Inseparability of product features – you can't choose differences in energy efficiency as an add on/option	This barrier may be more of academic interest in that it would be difficult for policy makers to resolve without significant market intervention/regulatory control in the manufacturing and sales process. This barrier can be indirectly resolved by creating minimum performance standards and incentives to improve efficiency.
Incomplete or mispricing of fuels can distort markets (including incentives for fuel search and extraction, and a variety of environmental externalities).	Public funding for the development of energy resources must necessarily balance government policy objectives where they are in competition, and this is most probably likely to occur in the short run where trade offs exist between maintaining fuel security and transitioning to clean, renewable fuels. However in the long run, the objectives of clean, renewable, low cost, secure energy supplies converge and so incentives should be reviewed and updated where necessary to enable this transition efficiently.
Uncertainty over future energy prices and technology development can be a barrier	It is uncertain if there is a role for government to play in addressing this. Suffice to note that where possible, decision makers that affect energy consumption need to be aware of future price trends and incorporating them into their decision making.
Intermediaries in the purchase of energy consuming devices can distort decision making. For example automobile design caters for new car buyers, who may be relatively wealthy, but who represent a small percentage of total car owners (many buy second hand). These wealthier new car buyers typically have lower incentive for fuel efficiency.	The impact of a product is in part determined by its longevity, and its efficiency will in part depend on the market it is designed for. So where the consumer of a new products does not value efficiency, there may be merit in requiring minimum efficiency standards. For example, if car designers and manufacturers do not feel new car buyers value energy efficiency, there may be merit in regulating minimum efficiency standards in new cars. This is particularly important where products are likely to have more than one owner, as the consumer of second hand product may value efficiency highly.

Barrier	Discussion of potential solution
Decision makers may lack the necessary authority and/or power to prioritise energy efficiency	Energy efficiency investment will naturally compete with other forms of investment. Government intervention cannot affect this directly but through measures such as education and incentives as described in the enabler table, it can be assisted.
The network Regulatory test may not accurately consider value of DG, particularly the value of avoided emissions	The network Regulatory test would need to explicitly require the valuation of greenhouse gas emissions, but also other social and environmental externalities associated with energy production and use. As it reads, it appears to do this implicitly. This is a reasonably complex barrier and may be subject to the interpretation of the wording by the authority applying the regulatory test. Policy makers could require a particular interpretation in order to ensure emissions are explicitly valued.
Manufacturers need to be included in developing and marketing solutions.	This is done in the appliance market through MEPS, but there does not appear to be a similar structure in distributed generation or demand management products. A government program could be established to manage integration between the development of DM products, DG, energy market operations, and energy policy objectives. Alternatively existing programs could be adapted to this purpose.
Limited availability of low cost, standard/off the shelf systems for end use energy management and control.	This is simply a barrier for product manufacturers to be aware of. Again, programs like MEPS, or a similar program for DM or DG products need to be engaged with policy objectives, and where required, educated on the need for ‘plug and play’ type products where possible
Information needed to make decisions when upgrading or replacing equipment is not always readily available.	This can be addressed through industry capacity building, a more targeted use of information for instance at point of sale and/or broader public messaging to ensure information provision is timely. This is potentially addressed by a combination of the enablers discussed in the table above.
Technology specific incentives can create an artificial technology ‘winner’.	Policy makers need to ensure policy design does not unduly lock out technologies, or artificially create technology winners. This is more a barrier to be aware of when developing policies, or reviewing existing policies. Where possible, policies should motivate and reward technology outcomes, not specific technologies.

7.3 Leveraging policy networks to achieve best practice

Policy and program design and implementation are key tools for government in shaping social, economic and environmental outcomes. In the context of distributed energy, as demonstrated by the nature of the key enablers identified in this chapter, government policy and regulation is critical to ensure the value of DE can be realised. While policy outcomes are important, assuming a desirable outcome without a thorough process for defining that outcome has the potential to limit the solution adopted. For this reason, we focus on the process of policy development and how this can be optimised. In the table above (Table 7.1) the concept of policy networks was introduced as a process to allow the realisation of key enablers. Here, the concept of policy networks is explored further.

Best practice policy making is the subject of considerable research and attention. Evidence based policy making is an approach that 'helps people make well informed decisions about policies, programmes and projects by putting the best available evidence from research at the heart of policy development and implementation' (Davies, 2004). Explicitly, it aims to avoid the use of 'best hunches' and 'educated guesses' in the policy development process.

Evidence based policy making includes the use of various research and analytical methods to test economic, scientific, environmental or ethical considerations to be considered in the policy making process. It can be used to identify issues to be addressed by policy makers and to guide the design of policy interventions.

Evidence based policy development has an intuitive logic, but implementing it is not always easy. Research by Campbell et al. (2007) in the UK point to issues such as the demands of political cycles, inadequate resources and political culture that can undermine the use of evidence based research in policy development. In the United States, research by Allison, 2005, has highlighted the importance of policy networks in shaping public policy relating to distributed generation. Ostrom et al. (1990) in Allison (2005) state that:

> *"Policy networks coordinate public and private actors who are increasingly bound by shared values, common discourse and dense exchanges of information…"*

In this way, policy networks can be used to overcome some of the difficulties of implementing evidence based policy development by ensuring a degree of continuity across political cycles and by encouraging sharing of resources and collaboration across institutions. In the context of energy, collaboration across government departments can help ensure environmental and social considerations are factored into energy policy making, one of the key enablers identified above. It must be recognised a policy network that doesn't use evidence based research, or doesn't represent a diversity of economic, scientific, environmental or ethical views, may have the potential to undermine effective policy making.

When thinking about how to achieve best practice policy making processes, it is also useful to consider risks to effective policy making specifically in the context of technology development/and or large scale structural change required to deal with environmental problems, and how policy networks can help overcome those risks.

One risk is technology lock-in. Technology lock-in occurs when the dependence of a particular technology is reinforced by the market it is used in through positive feedback. Examples include standardisation of rail gauges, dominance of VHS technology over Betamax and the monopoly of the QWERTY keyboard layout. Not all technology lock-in will have negative affects, but it can limit the speed and efficiency of technological change.

When trying to drive improved sustainability of resource use, a risk is that policies can inadvertently reinforce the status quo albeit with marginal efficiency improvements, or marginal pollution reductions. By reinforcing the status quo, competing technologies may be locked out and remain immature or underdeveloped, yet those technologies that are locked out may be necessary to make the transition to a desired, long term policy objective. In this way, locking out necessary technology development may have adverse impacts in the long run and undermine the efficient transition of an economy to a new equilibrium.

Cowan, (1990) in Kline (2001), details one example of technology lock-in:

> *"… the U.S. Government sponsored research and development that led to the development of light-water reactors for powering nuclear submarines. Light-water reactors were arguably the right choice for the sub-marine application, given all the technical and strategic considerations. After they were chosen for use in submarines, light-water reactor designs dominated the nuclear market for utility power generation by virtue of the experience of manufacturers in producing them for the Navy. This outcome represented the technology path of least resistance. Many have argued that other nuclear designs are better suited to the utility power market, but light-water reactors are now locked in."*

Kline (2001) also notes technology can become locked in when new infrastructure investment occurs with a low emissions price, but is at risk of being made prematurely redundant, or difficult to dislodge, by a high emission price in the future.

To overcome technology lock-in, it is best to use a suite of complementary polices (Kline, 2001). This can help ensure a smooth, efficient transition to a desired outcome. For instance, in the case of stationary energy, research and development can be directed at a range of technologies that may be cost effective for niche applications such as off grid or remote energy supply, or have significant future promise such as zero emission heating and cooling technologies. Overtime, these technologies may develop sufficiently to gain large scale market acceptance for on grid applications, or may result in technology improvements that can be applied in centralised generation.

Research by Haas et al. (2004) and Allen et al. (2008), reinforce the need for complementary and targeted policies that can help emerging technologies develop through their lifecycle from immaturity to broad market uptake. This requires specific policies depending on the stage of technology development and as the technology matures through a standard S curve from research and development through to commercial deployment. Specifically, technologies first require R&D support, subsidies that allow them to be demonstrated and deployed while pre commercial, limited support as their commercial uptake is increased and finally competition policies that help drive down their costs as they are deployed at commercial scale.

Policy networks can help ensure that such targeted and complementary policies are achievable and implemented by allowing for: research collaboration; data sharing; experimentation; coordinated action across jurisdictions; and adoption of best practice where it is identified.

Another policy development technique that can be used in parallel with policy networks is backcasting. Backcasting is the process of envisioning a desired future objective based on need, and then working out what is required to get there. Whereas forecasting attempts to determine future scenarios based on information and data analysis today, backcasting attempts to determine what change is necessary to achieve a desired future scenario (Jansen, 2001). This thinking dominated the development of the Dutch Sustainable Technology Development Programme in the 1990’s and led to models for strategic planning that were applied across Government and the private sector.

Backcasting is useful for policy making in that it helps policy makers think in terms of what is necessary to meet some important future objective, not what appears possible given today’s circumstance, and so can stimulate creative new thinking and problem solving. In the Dutch context, backcasting has been coupled with interdisciplinary partnerships between Government, private enterprise, financiers, research and education institutions and end users of technology. By involving a range of stakeholders in policy development in this way, policy becomes more than just a consultative process to determine the detail of policy delivery, it can galvanise a collective strategy based on a shared policy objective (Van de Meulen, 1999).

This collective engagement in policy objectives, as opposed to engagement in policy design, is compatible with the creation and use of policy networks outlined previously, and in keeping with best practice policy development principles.

7.3.1 Informed decision making

A common theme throughout barrier studies is the role information plays as a causal barrier behind many other barriers. For instance, it is often implied that policy barriers, decision making bias, or a lack of incentive to undertake efficient DE, is caused by a lack of information and data, or difficulty accessing and interpreting that information and data in a meaningful way. The way information is presented can also influence the extent to which barriers to DE are overcome.

For this reason, a key enabler for DE is seen to be the process of data gathering, developing messages that relay important content, and educating sectors of the market through information transfer and demonstration. While this process is relatively constant and ongoing, research reviewed suggests there are specific issues that may need to be addressed as a priority.

Importantly, data that does not appear to be available, or at least in widespread use, is the time specific, aggregated value of DE incorporating all social and environmental externalities. As alluded to in earlier sections of this report, the value of DE is conditional upon a wide variety of factors that may include: the time at which it operates; its predictability and/or ability to be dispatched; the level of greenhouse gas emissions it can reduce; the level of other air borne emissions, such as NOx, that it emits; the degree to which air borne emissions are a health issue in the location DE is deployed; and even the degree to which the public values any loss of visual amenity DE, or its alternatives, may cause. The analysis in Chapter 9 of this report aims to value DE using best available data. Section 8.5 highlights the value by showcasing case studies where DE provides efficient alternative to standard centralised options for energy supply.

The price of energy, and so the price of avoided energy consumption, as well as the value of energy exported to the grid by various technologies in various locations is not subject to a clear, transparent and accurate pricing methodology that incorporates all time and location specific externalities. While this is a barrier in itself, it can only be overcome by first quantifying the true value of DE. This value then needs to be expressed in a way which allows decision makers to consider it when generating or consuming energy.

For instance, if twenty independently operated 200 kW CHP units generate power within a network zone reliably at peak times, over time they may reduce costs associated with supplying energy to that network zone, particularly network costs and peak generation. However no one generator will be able to capture the full value they provide as no methodology exists for valuing the collective effect of this type of configuration. As noted in the discussion of barriers, this is driven in part by deterministic network planning standards, as opposed to probabilistic ones.

It may be that over time savings accrue to consumers in the network zone through reduced network expenditure, but this acts as a highly diluted benefit due to benefits being shared across customers within the network, even assuming network prices are rebalanced perfectly across network zones. Without a methodology for calculating the value of this and a mechanism for allowing distributed generators to capture this value, decisions around locating and sizing generation is likely to be sub optimal.

The lack of quantified and priced costs associated with energy also impacts on decisions around energy consumption, for instance where a consumer purchases an air conditioning unit and faces a choice between different star ratings. Consumers do not face the true cost of installing and operating appliances, and therefore can make a highly imperfect trade off between operating costs and purchasing costs. The same could be said for decisions about building fabric and/or design features such as awnings or double glazing.

It is important to consider that more accurate, time specific prices for energy consumed will not rectify all these issues due to the potential mismatch between energy prices, and prices paid for energy exported to the grid, but also decision making imperfections as people make trade offs between certain capital costs today, and uncertain operating costs into the future. Fully cost reflective prices may also be incompatible with social objectives such as energy affordability.

For this reason, it is important for policy makers and regulators to explore ways to inform better decision making, not just through market driven price signals or rating schemes, but through transparent pricing methodologies, for example for energy exported to the grid, or through better comparative tools that allow decision makers to better evaluate the full cost and benefit of choosing more efficient buildings or appliances.

Feed-in tariffs offer a conceptual framework for more accurately pricing the value of energy exported to the grid, and if treated on a probabilistic basis, could account for the aggregated benefits that a collection of distributed generation units may offer. It is also possible to apply rebates or other financial incentives to energy efficiency measures, and this is being done in some jurisdictions including Victoria and Western Australia where consumers choose a higher star rating appliance. However providing comparative information at the point of sale for appliances, or when buildings are being sold or let, such as forecast operating costs, savings a more efficient option may entail, or even the rate of return those savings translate to, may help create more informed decision making.

7.3.2 End user decision making, policy and aligning incentives

To a degree, the ability to realise the value of distributed energy is affected by the nature of decision making. Consumers, energy companies, policy makers, regulators and others all make decisions that fundamentally impact on the uptake of DE. Each individual or group of decision makers faces distinct conditions that affect their decision making.

In designing markets, policy interventions and/or regulatory change, it is important to consider decision making complexity. Research into decision making highlights the limitation of assuming information is processed rationally, and that decision makers will act in their best financial interest. For instance, decision making can be affected by internal (values, beliefs etc) and external (social norms, financial rewards etc) factors , and also in more subtle ways such as the way information is presented, who presents it, the ordering of words, the choice of words with only superficial differences in meaning, or whether information is provided to groups or individuals.

Research has challenged the legitimacy of traditional cost benefit analysis (CBA) in establishing the need for policy intervention, as well as the design of the policy intervention itself, recognising that decision making is often subject to anomalies. Relying on rational CBA theory to guide environmental policy only makes sense if citizens make, or act as if they make, consistent and systematic choices toward both certain and risky events (Friedman and Savage (1948) in Hanley and Shogren., 2005).

As outlined in Hanley and Shogren (2005), anomalies in results given by CBA challenge its legitimacy. Hanley and Shogren (2005) cites an example in the UK of policy makers trying to value the cost of pollution. In theory, pollution should be valued consistently by the same person. Therefore, regardless of being compensated for a level of pollution, or paying to reduce pollution by some amount, the unit value of pollution should be consistent. However individuals nominate significantly different values of pollution depending on whether they would be compensated for existing levels of pollution, or pay to reduce pollution. Specifically, they nominated far higher levels for compensation than willingness to pay, and many respondents refused to nominate a value for compensation.

This type of result is subject to various explanations and intuitively is not entirely unexpected. If someone earns an income that doesn’t allow basic shelter and health costs to be met, it is unlikely they will be willing to pay to reduce a pollutant, the effect of which they don’t understand. In the example above, high level policy advice was to seek conservative values where there are differing contingent valuations, and so the lower value, determined by willingness to pay, was selected (Hanley and Shogren, 2005).

From a policy perspective, the most important finding from Hanley and Shogren (2005) is that there is potential for analytical bias to influence the interpretation of results of cost benefit analysis. Consequently, there is the potential for these biases to under or over value policy intervention and so distort the efficacy of policy design.

To overcome the potential for bias to distort efficient policy interventions, multi-criteria decision making analysis (MCDA) can be used. MCDA allows sharing of data, concepts and opinions across those involved in the policy making process including members of the public, consultants, policy agencies, and elected officials. Through iteration and reflection, MCDA allows sources of decision making anomalies such as incomplete information, misallocation of risk, or the framing of problems to be worked through and resolved (Kiker et al., 2005).

Essentially, MCDA allows a CBA to occur, but has inbuilt processes to ensure the analysis has legitimacy from objective and subjective viewpoints. MCDA is broadly consistent with the idea of policy networks discussed previously in that a well functioning policy network can facilitate the MCDA process.

Insights from decision making science can also be used to increase the uptake of DE more directly by affecting consumer decision making and aligning incentives towards a particular objective. For instance, regulatory intervention in appliance markets is driven by the recognition that competitive markets do not have sufficient incentive to improve efficiency of appliance performance over time. Essentially, it is a split incentive problem where action taken by one party has benefits that cannot be captured by that party. Regulatory intervention can essentially be two fold –standards for energy efficiency or better information provided to consumers. Decision making science can inform the latter option.

In strictly rational terms, it shouldn't matter whether a customer receives financial savings at the time of purchase, or over time, so long as the net present value of each option is equal. However insights from behavioural economics indicate decision making is influenced not just by the quantity of gain or loss that can be made from a decision, but by the certainty of gain or loss (Kahneman and Tversky, 1981). Decision makers can also show a preference for avoiding loss, as opposed to seeking gain (Tversky and Kahneman, 1986). In the case of energy efficiency, potential gains from reduced operating costs over time are uncertain[5] while the cost of the more efficient appliance is certain. So a consumer is likely to prioritise minimising the certain loss, as opposed to maximising the uncertain potential gain.

In Australia, appliance labelling is designed to correct this type of decision making bias to an extent by providing an estimate of how much energy an appliance will use in a typical operating year and a star rating which allows consumers to rank the efficiency of different appliances. However it is possible that a refined consumer information strategy could improve decision making, specifically by providing an estimate of annual operating costs and/or administering a

[5] The consumer would need to calculate the amount of energy used by the appliance over time, the price they pay for energy and any potential future change to this price, and the operating lifetime of the appliance. They still then have to weigh up the time taken to pay off their investment against any other spending they may value (i.e. opportunity cost).

rebate to the customer that reflects to some degree any value of energy efficiency they can't capture through operating savings alone – that is, provide consumers with a certain gain, framed in a way that it becomes a certain loss should the more efficient appliance not be chosen.

For instance, choosing an energy efficient air conditioner reduces temperature sensitive network demand, and reduces retailer exposure to peak wholesale generation costs. However the full value of both benefits is not reflected in time specific operating costs and so can't be captured by the customer. A proxy value for $/kW capacity saved by upgrading star ratings and reflected in product rebates to some degree, could be used to encourage a more socially efficient purchasing decision. This may be preferable, or complementary, to using time specific prices to encourage more efficient consumption.

Achieving energy efficiency is also subject to the split incentive involving landlords and tenants, where neither landlord nor tenant can capture sufficient value from investing in more efficient appliances (where the tenant pays the energy bill), or changing consumption behaviour (where the landlord pays the energy bill).

Simplistically, incentives will not be aligned where one party cannot capture the benefit of their action, or do not perceive that the benefit of their action will accrue to them sufficiently to justify that action. Aligning incentives is therefore a function of payment arrangements, but also the certainty of those arrangements. For instance, a landlord may not upgrade the efficiency of their property from 3 star to 6 star, to the extent they are unsure whether they will realise the benefits through higher rent, as opposed to whether or not they can increase rent.

Perhaps due to the complexity of this issue, the split incentive problem has not been readily addressed in many jurisdictions around the world. Regulating building standards and requiring building information disclosure are two common regulatory approaches to addressing the landlord/tenant split incentive; however this does not strictly align incentives.

However, a relatively successful example of directly aligning the incentives across a range of functions that affect energy outcomes often referred to is the Woking Borough Council (WBC) energy service company model in the U.K. In this model, WBC sought to accelerate emission reductions in its jurisdiction through setting up a Special Purpose Vehicle (SPV) called Thameswey Ltd in 1999. The company's purpose was to form public/private partnerships to deliver projects targeting the Council's broader climate change strategy, including providing clean energy, tackling fuel poverty, water security, waste minimisation and clean transport. Generated revenues are channelled back to the council to reinvest in specific projects, such as improvements to housing, retrofitting solar PV and heating systems for low income families (WBC, 2009). By 2006, WBC had achieved 33% energy efficiency and 21% emissions reduction on residential property, against a 1991 benchmark (Resource Smart, 2008).

The success of the model is that it aligns environment, social and economic objectives, delivered through a single entity that can capture the full benefit of its action either directly through revenue recovery, or indirectly through socialised value it provides to the community. Significantly, the vehicle is also empowered to deploy a full suite of DE options and is resourced with the necessary technical capability. The entity also aligns incentives that are often weakened due to disaggregation between generators, network companies and retailers, and the regulatory and market structures within which they operate.

In this way, WBC was able to overcome many overlapping and related barriers that typically impede a wide range of DE options identified in Chapter 6. The business model also allows a number of key enablers identified in this chapter to be realised because it does not have to directly recover the value of social and environmental externalities that it reduces, as the value is spread across the community.

Ultimately, it is likely to be a policy choice whether such a business model can be deliberately constructed by Government jurisdictions in Australia, for example by Local Governments, or whether through policy, market settings and regulation, such models are encouraged for others to develop and implement.

7.3.3 Energy market decision making

The Australian NEM has relatively formal governance, commercial, security and technical decision making regimes. These structures and commercial decision making regimes have been described in part in Chapters 3 and 5. In summary, these organisations have the following roles:

- The Council of Australian Governments (COAG) brings together Federal and State governments in a forum to coordinate policy development, and set policy principles at a high level
- The Ministerial Council on Energy (MCE) coordinates Federal and State policy and has oversight for rule and regulation development
- Uniform industry-specific legislation, the National Electricity Law (NEL) defines decision-making constraints for the electricity industry including commercial, technical, security and regulatory arrangements. The specific details of these arrangements are set out in the National Electricity Rules
- The AEMC manages the National Electricity Rules, and the rule change process by which they can be further developed
- The AER enforces regulatory requirements and manages particularly regulatory processes such as the review and approval of network investment plans. It also monitors compliance with the National Electricity Rules by market participants as well assessing the overall effectiveness of these rules
- The AEMO is both the market and system operator and thus has responsibility for implementing and managing both the security regime and the short-term aspects of the commercial regime.

Here, we seek to discuss these regimes in more detail and specifically in relation to distributed energy. In this way, we help describe in more detail some of the barriers that have been touched on above.

Importantly, as noted in Chapter 5, policy making is a distinct and separate process from developing market rules and regulation. These processes are governed and influenced by particular institutional relationships, structures and decision making process.

The institutional and legislative framework of the NEM has been developed over many years and has been reinforced by the dominant centralised supply model. Small scale energy and demand management have fulfilled relatively niche roles and in some instances have been used to reinforce the dominance of the centralised supply model, for example, the use of off peak electric resistance hot water systems.

Design of regulation to meet environmental or social objectives and integration of this regulation with energy market operation is relatively new and integrating them with the market is not always easy. Environmental and social objectives are not always immediately compatible with business models that operate in the existing energy supply chain. For example, very generally, various sources of cost and value for solar hot water and PV may impact on different businesses in the supply chain as follows:

Baseload generators: could be negatively affected by solar hot water at significant levels of deployment

Peaking generators: could be negatively affected by PV (at significant levels of deployment) to the extent that it correlates with times of network-wide peak demand

Network companies: could be negatively affected by reduced energy volumes if they result in demand growth slower than forecast as part of their network investment plans. Or could benefit from PV to the extent it provides network support, reduced losses and power quality benefits that outweigh any unrecovered connection costs

Retailers: the net impact may vary depending on any generation assets owned, exposure to peak wholesale prices, or even levels of integration into solar PV and hot water markets.

Supply-side participants in the energy market are generally large, well resourced, focussed almost exclusively on the electricity industry and have considerable shared interests. End-users are far more diverse, typically less well resourced and may have interests beyond electricity itself. In this environment, effective representation of end user interest in NEM Governance and broader policy decision making is a difficult process. Formal governance processes must be able to manage these asymmetries between supply and demand-side stakeholders in order to represent environmental and social interests in NEM design and operation.

Ultimately, successful introduction of any new technology into the NEM requires the effective support of these institutional decision makers as well as supporting organisational infrastructure. In the case of DE, this includes not only the organisations and people directly involved with the technology such as designers, retailers, installers, but also those who have to manage the impacts of that technology on the rest of society. This support infrastructure does not automatically emerge in response to market signals and so highlights a role for government, not only in education and training but in developing the necessary institutional decision making structures. This is an important consideration for policy makers seeking to harness the value of distributed energy.

Integrating and valuing new technology, specifically DE into the NEM, also requires explicit, transparent methodologies for signalling, motivating and optimising end-user participation to facilitate effective decision making. Active participation by the majority of end-users (residential and commercial) will require that the uncertain time and location varying value of energy is better reflected in the prices these end-users see, or that end users and/or third parties, will be able to capture the value of DE where it supplies energy services below time and location specific costs. The use of interval meters coupled with price deregulation goes some way to achieving this. However, it must be recognised price is a limited tool if used in isolation.

Without access to information, financial support and potentially specialist skills to facilitate behaviour change as well as new physical infrastructure, customers may have a limited response to price signals.

Investment decision making is also a critical component of the NEM. Forward looking prices and planning documents can help signal where future investment are needed. For example, investment in generation for the centralised supply chain is largely driven by the Statement of Opportunities (SOO) report. Released by the market operator (AEMO), it details historical demand, demand projections and projections in energy shortfalls. As touched on in this report, efforts are being made to replicate a comparable process at a distribution network level, with distribution companies required to release network planning details and signal opportunities for demand side proponents to offer alternatives to network building. However signalling for investment in distributed energy is naturally a more complex process due to the fine grain nature of location and price signals it can be driven by, as well as the sometimes competing interests of the energy supply chain and distributed energy proponents. Furthermore, to capture a full suite of DE opportunities, this decision making signals must incorporate the intersection between natural gas and electricity, a potentially significant issue given the relative immaturity of natural gas markets and the predicted impacts of natural gas based technologies detailed in Section 9.1

Perhaps more challenging are the complex realities of end-user behaviour. Standard economic models characterise energy end-user demand in terms of rational preferences that optimise personal economic wellbeing. Encouraging end-user participation is thus seen as a combination of providing appropriate price signals, education, and removing barriers to the satisfaction of rational preferences. However, human behaviour is not simply an expression of rational economic ‘preferences’ but a more complex function of routines, habits and practices shaped by factors such as socio-economic status, ethnicity, geography and values.

In order to facilitate DE where it is efficient, and fully account for end user decision making complexity, the concept of energy service companies are sometimes promoted. In Australia, this concept has been developed and promoted by authors such as Hugh Outhred, for example, (see Outhred and MacGill, 2006). Broadly speaking, energy services companies take on contracts to deliver energy to customers, taking on financial risk, and leveraging energy efficiency or other measures to capture the value between flat tariffs and fluctuating wholesale and network tariffs. The ESCO model is discussed in more detail in case studies in Chapter 8.

7.3.4 Enabling DE for cooling loads: a worked example

The following details a hypothetical worked example of how policy makers could enable the efficient and cost effective supply of temperature sensitive energy demand, in this case cooling, by distributed energy. We incorporate insights from the enablers as discussed above. It is very important to note we have used basic data assumptions on the value of cooling loads for the purpose of demonstrating a worked example. Data quoted here should not form the basis of policy unless it has been verified by independent research.

Firstly, long term policy objectives and a clear commitment to improve the efficiency of supply of temperature sensitive demand are needed. This could involve setting targets for reducing the rate of peak demand growth, targets for reducing peak energy use in residential and commercial buildings, or even targets for improved efficiency of cooling systems. Ultimately, the long term objective should reflect a desirable outcome, such as cost effective zero emission cooling. Targets would require the implicit or explicit support of key industry stakeholders including the property industry, equipment manufacturers and businesses in the energy supply chain. A process of backcasting could enable this.

These objectives and commitment would need to be backed by programs and policies that support the objective. Programs and policies would need to be developed with a broad range of industry and community stakeholder input, and informed by decision making science which provides insights into how individuals and organisations make decisions that affect cooling demand.

In designing the policies and programs that may reward the purchase of more efficient, or less emission intensive cooling systems, and so the production of those systems, a key consideration is the cost of temperature sensitive energy demand and who bears it. In general terms, we can say that based on a study by the Western Australia Office of Energy (WA Office of Energy, 2004), the cost of air conditioning is around \$3,000/kW_e of capacity. We have not qualified this figure through empirical research and naturally it should not be applied in other jurisdictions which are likely to have significantly different cost structures.

This cost is cross-subsidised by all energy users through energy prices and so costs are not necessarily in proportion to the cost of supplying a particular energy user. This infrastructure cost is recovered over time by generators, network companies and retailers over the lifetime of their assets and incorporates a margin. If we assume research showed that on average, the \$3,000/kW_e was recovered by the energy supply chain over a period of 30 years and the lifetime of a typical cooling unit is ten years, then in simple terms, each time a consumer purchases an air conditioning unit it is cost effective to subsidise the purchase by \$1,000 so long as that subsidy reduces the capacity of the unit they otherwise would have bought by over 1 kW. There are also operating costs associated with this infrastructure including fuel costs and maintenance costs. Let us also assume that fuel, operation and maintenance costs associated with generating and transporting electricity for cooling loads are \$0.1/kWh.

Operating cooling load also comes at a cost not factored into energy prices as yet. This could include the cost of greenhouse gas emissions and the social health costs associated with particulate emissions that result from energy production. Policy makers face a choice on how to value those emissions, and this could be somewhere between valuing them based on the current cost of reducing them (i.e., through a market mechanism), or valuing them based on the cost to society (a tax based system). Valuation of pollution is not a simple process and has been discussed briefly in Section 7.1.2 above.

Let us assume the pollution associated with operating electric cooling has a cost of \$0.02/kWh and that the average annual operating hours for the cooling system is 300. Over a ten year life time, the device will consume 3MWh per kilowatt of capacity, and impose an unfunded cost to society of \$60, so long as those emissions are not priced into energy operating costs. A table of typical operating hours is presented below and taken from the Western Australian Office of Energy (SEDO, 2009).

Table 7.3: Typical operating hours for cooling and heating across Australia

City	Cooling	Heating
Adelaide	200	250
Brisbane	600	100
Canberra	150	500
Darwin	2,000	-
Hobart	50	450
Melbourne	100	350
Perth	300	150
Sydney	180	200

In reality, the time and location specific costs of supplying cooling loads is likely to vary significantly and depend on the timing of energy infrastructure investment and the shape of energy demand. That is, the more extreme the peaks and the greater the contribution of cooling demand to those peaks, the greater the cost of supplying cooling loads.

It is important to recognise that some distributed energy measures can meet cooling and heating demand using the same device. This may not change the value of avoided infrastructure building, for instance if heating and cooling demand is supplied by the same electrical infrastructure, and where cooling demand capacity is greater than heating (i.e. peak demand is caused by cooling). However, it will change the value of avoided pollution and fuel costs caused by operating the heating or cooling device.

One policy option to motivate more efficient cooling is to rely on time and location specific prices, enabled by metering and price deregulation. However, decision making science discussed earlier highlights individuals make highly imperfect trade offs between capital costs incurred today and operating savings made in the future. Subsequently, pricing energy based on operating costs is not likely to be sufficient to motivate efficient supply of cooling loads.

Before a policy intervention is designed, the potential value of the intervention, or cost of not intervening must be known. If we assume the average coefficient of performance (COP) for air conditioning systems is 2.5, we could say it costs \$1,000 to build the infrastructure required to supply 2.5 kW_{th} of cooling demand in today's dollars where this is met by the average electric air conditioning unit and so the aggregated infrastructure cost of meeting a kilowatt of cooling demand is \$400. If this cooling load is met through an electrically powered air conditioner, it will operate for 300 hrs a year over 10 years incurring \$300 of fuel, operation and maintenance costs and \$60 of unfunded externalities.

Policy makers may also decide to incorporate values for home comfort and energy affordability into the cost of supplying cooling loads. For example, it may be determined the value of a cool home is actually far higher than consumers willingness or capacity to pay for it. This could particularly be the case where children, the elderly or those with temperature sensitive health conditions incur negative health impacts due to excessive heat but don't have the means to pay for the cooling they need. Arbitrarily, let us assume this value creates a 10% premium on the total infrastructure, fuel, operation and maintenance cost.

Now, policy makers have two benchmarks to value an intervention. If peak cooling demand can be reduced by a kilowatt thermal and we assume the demand would otherwise be supplied by a typical electrical air conditioning appliance, this has a value of $836/kW$_{th}$ i.e. (($400+$300+60)x1.1) including the value to society of avoiding unfunded externalities and value to a customer from avoiding operating costs. This type of benchmark could be used to value passive design measures such as improved building fabric performance or orientation that reduces the thermal load of a building.

If the electrical demand used to supply the cooling load can be reduced by a kilowatt electrical, it has a value of $1,496/kW$_{e}$ i.e. (($1000+300+60)x1.1) including the value to society of avoiding unfunded externalities and value to a customer from avoiding operating costs. This could be used to value the upgrade of existing appliances, substitution of electric for alternative cooling systems, or as a basis to influence the efficiency of a new appliance purchase through a rebate.

Another benchmark for valuing DE could be the cost of the average peak cooling load of a new home met by the average cooling system in a new home. For example, the average peak cooling load might be 15kW$_{th}$ and be met by one or more systems with a COP of 2.5, therefore requiring an electrical load of 6kW to be drawn at peak times. Any new home that can reduce the electrical load for cooling by a kilowatt through better design, more efficient appliances, or alternative cooling devices that do not use mains electricity, could be valued at $1496/kW$_{e}$. This value could be used as an incentive for property developers, consumers, or some combination to produce or purchase homes with more efficient cooling systems respectively.

Naturally, fully valuing cooling loads is beyond this simple example, and the difference between funded and unfunded externalities associated with cooling demand has not been fully detailed. But the discussion helps provide insight to how valuing the supply of more efficient cooling loads could be done and the complexity of doing so. In practice, policy makers need to incorporate insights from economics, engineering, social science, health sciences and other disciplines to establish a view on the value of policy intervention.

Having set benchmark costs for reducing cooling loads, or supplying those loads with clean alternatives to the grid, policy makers have to find the most cost effective way to reduce, manage and/or meet cooling loads using the established benchmark value of reducing peak loads. Based on public information, policy options that address this issue currently being pursued or considered, include, but are not limited to:

- Minimum standards for electrical appliances
- Minimum standards for buildings
- Labelling programs for appliances and buildings
- Minimum standard for rental properties
- Demand management incentive schemes for distribution businesses
- Social awareness and education programs that help individuals and businesses make better decisions about meeting their cooling requirements
- Research and development funding for alternative cooling solutions.

Other policy options could include:

- Providing rebates to customers who purchase cooling appliances that reduce costs otherwise socialised and the value of which can't be captured. This can help overcome decision making bias at the point of sale
- Providing tax incentives to reduce cooling demand of buildings and/or the efficiency of cooling supply. This could help align split incentives
- Providing minimum standards for cooling demand/m^2 of building footprint and/or minimum standards for electricity consumed to supply cooling demand including targets for their reduction. This could help align split incentives
- Redesigning white certificate schemes for energy efficiency to incorporate a value for reducing peak loads, not just emissions.

Where there are competing options for addressing cooling demand, and policy makers are unclear on the best way to proceed, the use of policy networks, and inter jurisdictional collaboration can help through information sharing, collaboration and potentially policy trials. Ideally, jurisdictions would move to best practice where it is identified. Using the value of meeting cooling demand or supplying a kilowatt of electricity at peak times as a benchmark, policy makers can then decide on the cost and benefit of different policy options.

8. DISTRIBUTED ENERGY IN SOCIETY: CONSUMERS, BUSINESS AND CASE STUDIES

This chapter details how distributed energy interacts with people and organisations by exploring consumer research and case studies of distributed energy. This brings to life some of the real world impacts of barriers, and the importance of the enablers as discussed in Chapters 6 and 7 respectively.

8.1 Key findings

Once psychological and contextual drivers relevant to DE are understood, a range of interventions can be designed to either directly or indirectly promote uptake and acceptance of DE and reduction in energy consumption at the individual and household level. Literature suggests such interventions would be best informed by a combination of social theories implemented via participatory action research.

At the individual and household level, education, income levels, household size and age are commonly the most powerful demographic variables affecting: intention to reduce electricity consumption; acceptance of demand management technology and acceptance of distributed generation technology.

Beliefs about the environment, economic values, attitudes towards consumption and subjective norms about consumption typically showed significant positive relationships with intentions to reduce energy consumption and adopt demand management and distributed generation technologies. The only counter intuitive finding was that knowledge of energy and the environment sometimes polarised people's attitudes towards reducing consumption.

Internal motivations for early adoption of DE appear to be self-sufficiency and energy-independence; the opportunity to demonstrate environmental values in consumption choices; and the prospect of catalysing social change through political statements which challenge dominant assumptions. Tentatively, we suggest that those who tend towards the 'self-sufficiency and energy-independence' end of the internal motivation continuum are more influenced by external motivators, whereas those who tend towards the 'catalysing social change' end of the internal motivation continuum are less influenced by these external motivators.

Australian organisations most likely to adopt demand management or distributed generation technology are relatively large, and so have large energy consumption. However many small businesses also appear likely to adopt DE. Therefore targeting large energy users may help maximise the impact of DE, but the DE market is not likely to be limited to large energy users. While financial payback periods have some influence on organisational decision making, safety, efficiency and reliability were typically the most important features of demand management and distributed generation technology.

Case studies presented in this chapter point to the value of innovative models for implementing DE, and complementary efficiency gains that can be secured by engaging in alternative methods of energy supply. Business collaborations to resolve common, local energy constraints can help identify energy supply options that optimise solutions and reduce barriers to implementation by reducing search costs and spreading risk. Using bulk buy schemes for technologies can help drive down transaction costs associated with identifying customers and carrying out installations. Structured trials of new energy management processes such as demand management, not only demonstrate its inherent value, but can help businesses identify opportunities for process improvement.

8.2 Societal acceptance of distributed energy

As discussed in previous chapters, consumer behaviour and how consumers make decisions about their energy supply influences the adoption and support for large scale deployment of DE technology. By understanding attitudes and behaviours that can reduce energy demand and increase the acceptance of DE systems, various interventions can be implemented to help maximise technology diffusion and the likelihood of DE technology uptake.

In earlier work, Gardner and Ashworth (2007) developed a framework for the societal acceptance of the Intelligent Grid (see Figure 8.1). An underlying premise of the framework is that people's values, attitudes and beliefs will drive their intentions, subsequent action and eventual long-term acceptance of DE and reductions in consumption. Although a wide array of psychological research supports this central premise, it is important to acknowledge that people's decisions are made within a broader context, where a range of external influences also have an impact. These external influences include economic factors and the costs of implementing distributed energy; physical/technological factors, such as the development of and access to technology; and societal factors, such as community support for low emission technology, government incentives and industry reactions. The impact of societal factors on the adoption of distributed energy is particularly relevant, since some DE technology is likely to be implemented at the community level, rather than in individual households (Gardner and Ashworth, 2007).

Once the psychological and contextual drivers relevant to DE are understood, a range of interventions can be designed to either directly or indirectly promote uptake and acceptance of DE and reduction in energy consumption. Such interventions might provide information about potential economic and environmental benefits, provide examples of specific types of DE uptake, or provide feedback about particular levels of energy usage in a household or a broader community/organisation. The literature suggests such interventions would be best informed by a combination of social theories implemented via participatory action research. Evaluation and ongoing tracking of these interventions will help to identify what mix of DE is acceptable to Australian society, and what methods of promotion are liable to be effective in the long term.

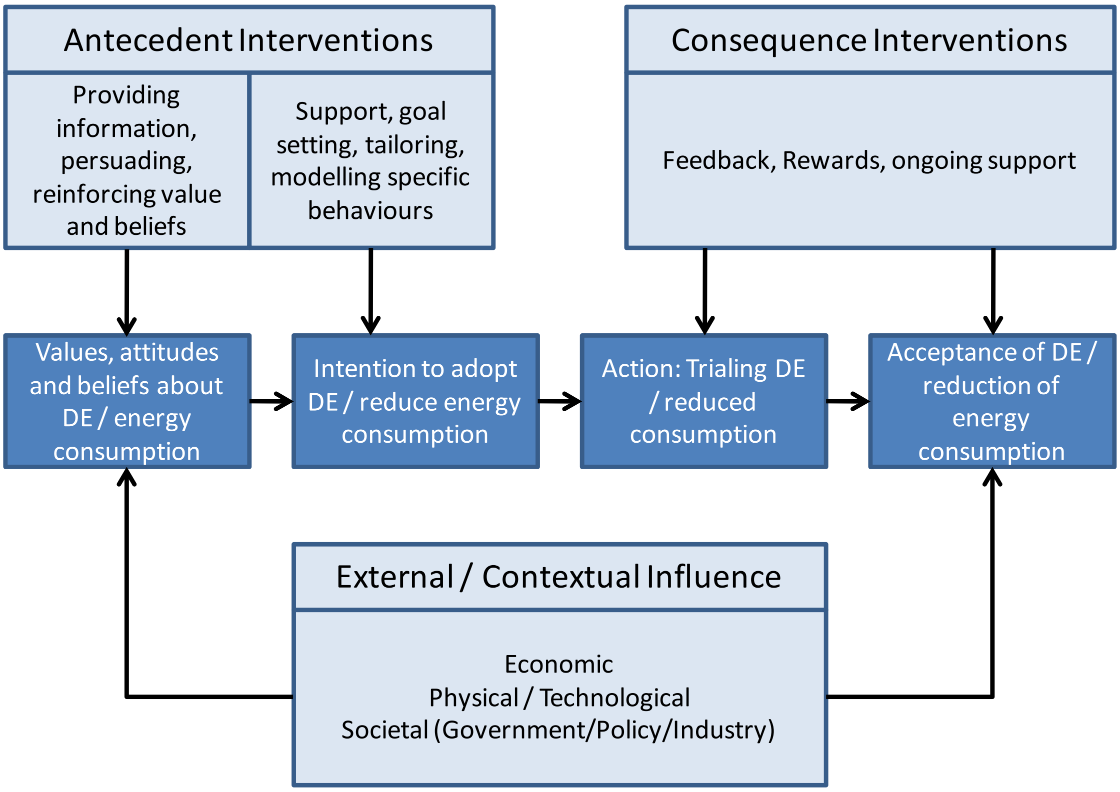


Figure 8.1: A conceptual framework for the Intelligent Grid

8.2.1 Survey sample

To understand the likelihood for individual consumers to accept DE, a survey was conducted across four states of Australia. The initial survey was developed with reference to psychological theory of environmental concern (Fransson and Garling, 1999; Xiao and Dunlap, 2007) and consumer technology adoption (Davis, 1989; Rogers, 1995). The survey was pilot tested in focus groups with members of the general public. As a result of this feedback some adjustments were made to improve readability and clarity. To reduce the length of the survey, two different versions were produced. One version included questions relating to demand management, and the alternate version included questions relating to distributed generation.

Overall the survey contained four sections:

Section One: assessed knowledge and beliefs about energy sources and environmental issues

Section Two: assessed household energy use

Section Three: assessed reactions to local energy generation (in one version) and demand management (in the other version)

Section Four: assessed demographic details about the individual and their household.

Survey recipients were identified from a commercially-purchased mailing list of adult consumers of energy. The survey was printed and posted in April/May 2007 to 8000 people across Queensland, New South Wales, Victoria and South Australia. Two thousand surveys were posted to each State.

Of the 8,000 surveys posted, 1,821 usable surveys were returned by post. A further 201 usable surveys were returned via a web-based version, representing an overall response rate of 25.3%. This response rate is extremely high for a survey of the general population. Details of responses from each State are shown in Table 8.1. Overall the responses were evenly distributed across the states.

Table 8.1: Survey responses and response rates for each State

	NSW	QLD	SA	VIC	Postcode not specified	Total
Surveys sent	2,000	2,000	2,000	2,000	-	8,000
Paper surveys returned	401	463	467	456	34	1,821
Web surveys completed	73	53	8	42	25	201
Total completed	474	516	475	498	59	2,022
Response rate	23.7%	25.8%	23.7%	24.9%	-	25.3%

The age and gender profile of people in the survey sample was compared to the profile of the relevant population from the four states that were surveyed (see Table 8.2). In the survey sample, people aged 20-39 are underrepresented, and people aged 60 and over are overrepresented. This skew towards older respondents is to be expected for a self-completed survey sent to homes: older people are more likely to have time available to complete the survey, and are more willing to participate. Hence, the sample collected is less representative of younger Australians. Overall, the sample represented a wide range of income levels, sizes and types of household, education levels, employment statuses and occupations.

Table 8.2: Age and gender percentages in the survey sample and in population statistics.

Age Group	Population Statistics[6]			Survey Sample		
	Females	**Males**	**Total**	**Females**	**Males**	**Total**
20-29 years	9.1	9.4	18.5	3.0	2.3	5.3
30-39 years	10.2	10.0	20.2	6.5	6.7	13.2
40-49 years	10.1	10.0	20.1	10.8	10.0	20.8
50-59 years	5.7	5.6	17.0	10.8	10.5	21.4
60-69 years	5.7	5.6	11.3	8.4	10.6	19.0
70-79 years	4.4	3.8	8.2	6.3	7.5	13.8
80+ years	3.0	1.7	4.7	3.3	3.3	6.6

[6] Statistics shown are derived from Australian Bureau of Statistics 2004 figures for the combined populations of Queensland, NSW, Victoria and South Australia (Australian Bureau of Statistics, 2006).

Of the two versions of the questionaries, the missing response patterns for each version were similar. Within the returned questionaries that measured reactions to demand management, the rate of missing responses, for most questions ranged between 0.3% (n=3) to 6.1% (n=61). The rate of missing responses to versions of the questionnaire that assessed distributed generation, ranged mostly between 0.7% (n=7) to 7.9% (n=79). However, on both questionnaires the rate of missing responses to questions that assessed the importance of the technology features was higher; for demand management the rate increased to 15.1% (151) and for distributed generation 14.6% (146). Consequently, it was concluded that the overall level of missing responses and the mostly random nature of these responses, could be effectively substituted (Hair et al., 1998).

8.2.2 Variables measured

The analyses used a range of demographic variables and psychological variables to predict three outcome measures:

- Intention to reduce household electricity consumption
- Acceptance of demand management technology, and
- Acceptance of distributed generation technology.

The demographic variables were State, age group, electricity consumption, gender, education, employment type, household income, household size and household type. These variables are described in Appendix B of Gardner and Ashworth, 2007.

The psychological variables were knowledge of energy/environment, pro-environmental beliefs, pro-environmental behaviours, pro-economic values, attitude to reduced consumption, and subjective norms about reduced consumption. Appendix C of Gardner and Ashworth, 2007 describes these variables.

Because this research aimed to describe the characteristics of people with particular attitudes, analyses were conducted on pairwise relationships, rather than more complex multivariate methods. Pairwise analyses used bivariate correlations and one-way analysis of variance, as appropriate. A conservative significance level of $p < .01$ was adopted, to counteract the increased error rate caused by conducting multiple tests across the same group of variables.

8.2.3 Household consumption

The survey used a single item to assess people's intention to reduce their household energy consumption. Overall, 40.0% (Table 8.3) of the sample reported a strong intention to reduce consumption, although it is possible that a bias towards social desirability has contributed to this strong response.

Table 8.3: Intention to reduce consumption

Which of the following best reflects your intentions for the next year?	**Frequency**	**Percent**
I will definitely not try to reduce my household energy consumption	12	0.7
It is unlikely that I will try to reduce my household energy consumption	86	4.9
There is a 50/50 chance I will try to reduce my household energy consumption	334	19.0
It is likely that I will try to reduce my household energy consumption	621	35.4
I will definitely try to reduce my household energy consumption	702	40.0
Total	1,755	100.0

Note: 66 people did not answer this question.

To identify variables that might predict this response, relationships between the outcome and demographic characteristics were examined, to create a profile of people who are more likely to intend to reduce consumption. Significant relationships were found for the following variables:

- Electricity consumption – people with lower electricity bills were more likely to intend to reduce consumption
- Gender – females were more likely to intend to reduce consumption.

The inverse relationship between electricity consumption and intention to reduce consumption is provocative, suggesting that households who consume more electricity are least motivated to change their behaviour. This clearly has important implications for programs designed to promote reduced consumption: households specifically targeted to reduce their consumption may be least willing to do so.

Psychological predictors of intention to reduce consumption were also assessed with the same methods. Significant relationships were found for the following variables:

- Pro-environmental beliefs – people with more pro-environmental beliefs were more likely to intend to reduce consumption
- Pro-environmental behaviours – people who reported more pro-environmental behaviours in the past were more likely to intend to reduce consumption
- Pro-economic values – people who valued the economy over the environment were less likely to intend to reduce consumption
- Attitudes towards consumption – people with more positive attitudes towards reduced consumption were more likely to intend to reduce consumption
- Subjective norms about consumption – people who perceived more positive norms about reduced consumption were more likely to intend to reduce consumption
- Knowledge of energy/environment – a non-linear relationship was found, such that people with higher levels of knowledge tended to polarise, reporting either a very high or very low intention to reduce consumption.

Overall, these findings support predictions made in theoretical work previously conducted for the Intelligent Grid project; it was expected that these attitudes, beliefs and values would successfully predict intentions to change behaviour.

The non-linear relationship between knowledge and intention was unexpected, but is similar to a relationship found in previous research (Centre for Low Emission Technology, 2006), and may reflect the tendency for people who are better informed to hold more extreme positions about environmental issues. Further investigation is required to understand the nature of this effect.

8.2.4 Demand management technology

Predictors of acceptance of demand management technology

Acceptance of demand management technology[7] was assessed by providing a generalised description of an "energy manager" (see Appendix A of Gardner and Ashworth, 2007 for details) and then asking for reactions to the following four items, rated on a 7-point Likert scale:

- The technology sounds like a good idea
- Typical Australian households are likely to support it
- I would consider installing this in my home
- This sort of technology is not suitable for my home (reverse scored).

Responses on these items were averaged to form a single acceptance measure, which ranged from 1 (low acceptance) to 7 (high acceptance). Overall levels of acceptance were high, with 50% of respondents providing average scores above 5. Clearly it is inappropriate to translate a response to a hypothetical description into a predictable willingness to purchase an actual product, but the general attitudes toward this technology are positive.

To identify variables that might predict this response, the demographic variables (Appendix B of Gardner and Ashworth, 2007) and psychological variables (Appendix C of Gardner and Ashworth, 2007) were assessed for relationships with the acceptance measure.

Amongst the demographics, significant relationships were identified for the following variables:

- Age group – younger people reported higher levels of acceptance of demand management
- Education – people with higher levels of education reported higher levels of acceptance
- Employment – people in the workforce reported higher levels of acceptance than those at home
- Household size – people in households of 3, 4, or 5 people reported higher levels of acceptance than people in either smaller or larger households
- Household type – group households and couples with children reported higher levels of acceptance than other households

[7] Only one version of the survey included questions relating to demand management technology. Thus the results described in this section are based on 910 cases, 50% of the full sample.

- Income – households with higher incomes tended to report higher levels of acceptance.

In summary, younger, better educated, working people with moderate size households and higher income levels were more likely to accept demand management technology.

Amongst the psychological variables, significant relationships were identified as follows:

- Knowledge of energy/environment – people with higher levels of knowledge reported higher acceptance of demand management
- Pro-environmental beliefs – people with more pro-environmental beliefs reported higher acceptance
- Pro-environmental behaviours – people who reported more pro-environmental behaviours in the past reported higher acceptance
- Pro-economic values – people who valued the economy over the environment reported lower acceptance
- Attitudes towards consumption – people with more positive attitudes towards reduced consumption were more likely to intend to reduce consumption
- Subjective norms about consumption – people who perceived more positive norms about consumption were more likely to intend to reduce consumption.

Overall, psychological variables successfully predicted the acceptance of demand management, as expected.

Preferences related to demand management

To understand preferences related to the automatic control of appliances used in demand management, a survey question asked people to identify what appliances they would be willing to have automatically controlled. Nine options were presented, and people selected all that applied (see Table 8.4). It is recognised that not all of these appliances would actually be controlled by a demand management system, but it was useful to include a range of appliances for reference. For example, electric hot water is already automatically controlled in the large majority of homes.

It was assumed that people who actually owned the various appliances would give a more meaningful response about whether they would allow it to be automatically controlled. In the table, the first column shows the percentage of all respondents who were willing to have the appliance controlled automatically, and the second column shows the percentage of willing people amongst those who actually owned each appliance type.

Table 8.4: Willingness to have various appliances automatically controlled

	Percent (all responses)	Percent (owners only)
Air conditioner	51.0	59.2
Refrigerator [a]	44.6	-
Electric hot water system	53.2	72.2
Pool pump	35.1	81.7
Clothes dryer	45.2	63.3
Dishwasher	43.7	64.5
Washing machine [a]	48.4	-
Deep freezer	31.0	48.7
Electric heater	38.4	50.4

Note: 21 people did not answer these questions.
[a]Ownership was not measured.

Only 72.2% of people with an electric hot water system indicated that they would be willing to have it controlled automatically. This response probably reflects a lack of understanding of the electric hot water control already applied in most homes. In actual demand management applications, air conditioners and pool pumps are the two appliances most likely to be controlled. Owners of pool pumps were generally willing to have them controlled (81.7%), and owners of air conditioners were somewhat less willing (59.2%).

Utility of demand management features

To understand the relative importance or utility that people placed on various features of demand management technology, nine features were assessed using best-worst scaling. The features, which were developed via a review of technical features and adjusted in focus group work, were:

- Cost to install
- Ease of installation
- Ease of use
- Reduction in my carbon emissions
- Level of control I have
- Interruptions to my electricity
- Reliability and durability
- Safety levels
- Savings over time.

Sets of these features were presented to respondents, and they were asked to choose the "most important" and the "least important" feature from each set.

Utilities are calculated by subtracting the number of times each feature is chosen as "least important" from the number of times it is chosen as "most important". Each feature appears in four different choice sets. Thus, utilities can range from -4 (always chosen as least important) to +4 (always chosen as most important).This value is averaged across respondents.

Based on the measure of acceptance described above, respondents were split into three equal groups reflecting low, moderate and high acceptance of demand management technology. In the figure below, the utilities for the nine features of the technology are charted separately for these three acceptance groups.

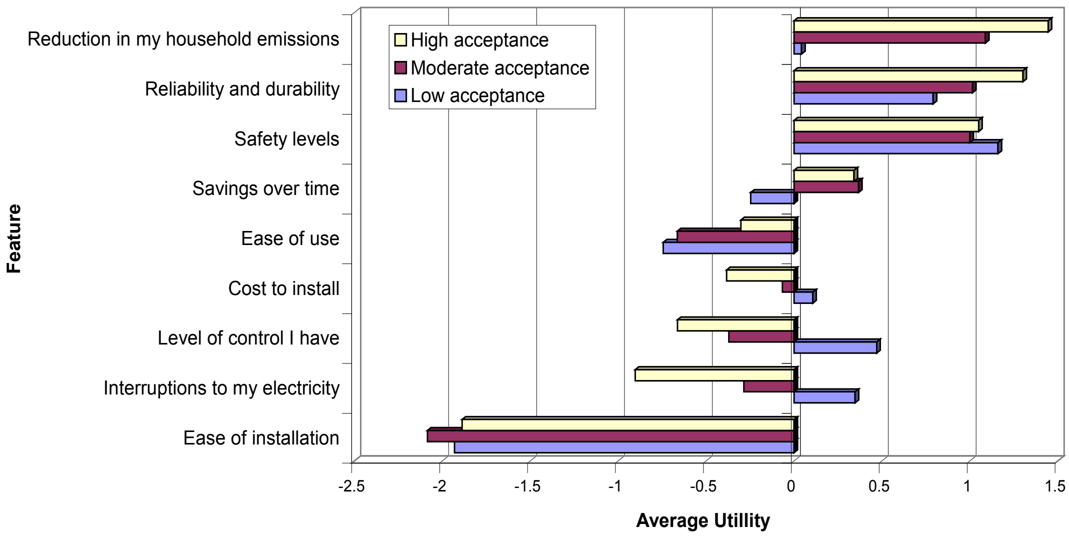


Figure 8.2: Relative utilities of demand management features by levels of acceptance

Compared to people with low acceptance, people who were more prepared to accept demand management placed a lower utility on cost to install, levels of control and interruptions to electricity, and a higher utility on reduction in emissions and savings over time.

8.2.5 Distributed generation technology

Predictors of acceptance of distributed generation

Acceptance of distributed generation technology[8] was assessed by providing a generalised description of a "household electricity generator" (see Appendix A of Gardner and Ashworth, 2007for details) and then asking for reactions to the same four items used to assess acceptance of demand management.

Responses on the four items were averaged to form a single acceptance measure, which ranged from 1 (low acceptance) to 7 (high acceptance). Overall levels of acceptance were high, with 50% of respondents providing average scores above 5. Again, expressed attitudes toward this technology are positive.

[8] Only one version of the survey included questions relating to distributed generation technology. Thus the results described in this section are based on 911 cases, 50% of the full sample.

To identify variables that might predict this response, the demographic variables (Appendix B of Gardner and Ashworth, 2007) and psychological variables (Appendix C of Gardner and Ashworth, 2007) were assessed for relationships with the acceptance measure.

Amongst the demographics, significant relationships were identified for the following variables:

- Age group – younger people reported higher levels of acceptance of distributed generation
- Education – people with higher levels of education reported higher levels of acceptance
- Employment – people in the workforce reported higher levels of acceptance than those at home (retired, home duties)
- Household type – families with children reported higher levels of acceptance than other households
- Income – households with higher incomes reported higher levels of acceptance, although this effect was only marginally significant.

In summary, younger, better educated, working people with children and higher income levels were more likely to accept distributed generation technology.

Amongst the psychological variables, significant relationships were identified as follows:

- Knowledge of energy/environment – people with higher levels of knowledge reported higher acceptance
- Pro-environmental beliefs – people with more pro-environmental beliefs reported higher acceptance
- Pro-environmental behaviours – people who reported more pro-environmental behaviours in the past reported higher acceptance
- Pro-economic values – people who valued the economy over the environment reported lower acceptance
- Attitudes towards consumption – people with more positive attitudes towards reduced consumption were more likely to intend to reduce consumption
- Subjective norms about consumption – people who perceived more positive norms about consumption were more likely to intend to reduce consumption.

Overall, psychological variables successfully predicted the acceptance of distributed generation, as expected.

Preferences related to distributed generation

To understand preferences related to the type of energy source used for distributed generation, a survey question asked people to identify what energy sources they would be willing to use for the example household generator. Five options were presented, and people selected all that applied to them (see Table 8.5).

Table 8.5: Willingness to use various energy sources

	Frequency	**Percent**
Diesel/petrol	46	5.1
Natural gas	361	39.9
Wind power	553	61.1
Solar panels	767	84.8
Biofuel	386	42.7
Total	905	

Note: 6 people did not answer these questions.

Of the energy sources, solar was most preferred (84.8% of the sample), followed by wind (61.1%) and biofuel (42.7%) and natural gas (39.9%). Only a very small proportion of respondents (5.1%) were willing to use a diesel- or petrol-powered generator.

Utilities of distributed generation features

To understand the relative importance or utility that people placed on various features of distributed generation technology, nine features were assessed using best-worst scaling. The features, which were developed via a review of technical features and adjusted in focus group work, were:

- Cost to install
- Ease of installation
- Ease of use
- Reduction in my carbon emissions
- Potential exhaust fumes
- The generator's energy source
- Reliability and durability
- Safety levels
- Savings over time.

Note that these features are slightly different to the features used to assess demand management technology. Utilities were calculated in the same manner as described previously.

Based on the measure of acceptance described above, respondents were split into three equal groups reflecting low, moderate and high acceptance of distributed generation technology. In the figure below, the utilities for the nine features of the technology are charted separately for these three acceptance groups.

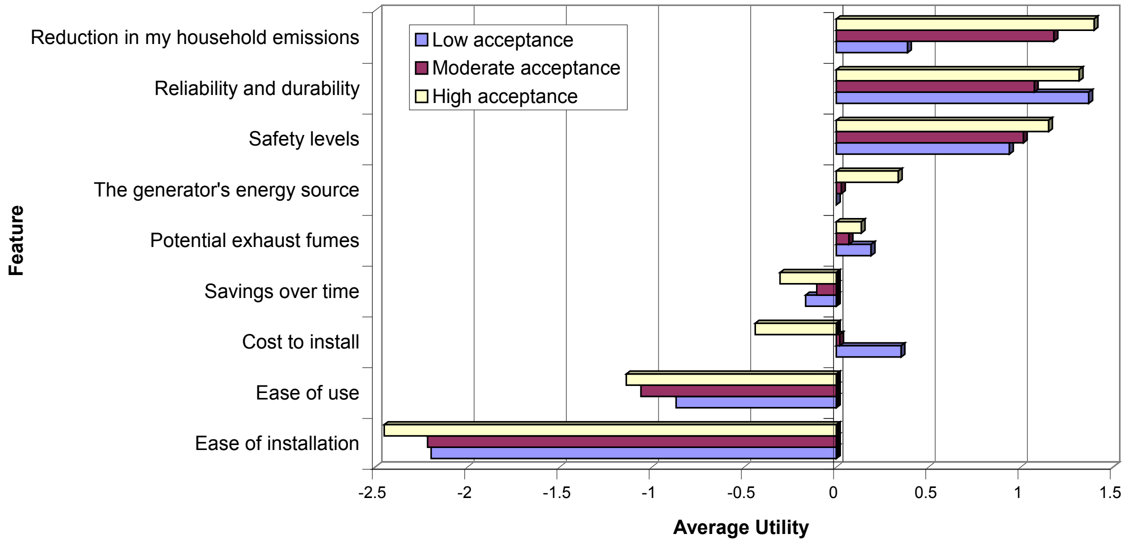


Figure 8.3: Relative utilities of distributed generation features by levels of acceptance

A high utility was placed on reduction in household emissions, reliability/durability and safety, and a low utility was placed on ease of use and ease of installation. People who were more prepared to accept distributed generation placed a lower utility on cost to install and a higher utility on reduction in emissions.

8.2.6 Public orientations to distributed energy

There were two sets of analyses performed, one for data collected through the questionnaire that measured reactions toward demand management and a second on the data collected through the questionnaire that measured reactions toward distributed generation. The sample size of the demand management test was in total 1,020, where as the sample size of the distributed generation test was 1,002. Examination of the orientations, identified by the self-organised map analysis, revealed that the given orientations were substantively the same across each data set and could be best be described as: 1) ‘Informed Environmentalists’, 2) ‘Balance Focused’, 3) ‘Solution Focused’, 4) ‘Uninformed’ and 5) ‘Sceptical’.

The orientations were found to be generated by a similar proportion of individuals from each of the states surveyed - New South Wales, Queensland, South Australia and Victoria (please refer to Appendix C of Gardner and Ashworth, 2007). However membership numbers to each orientation was not consistent across the two data sets. Table 8.6 presents a breakdown of the percentage of respondents that are classed under each orientation, within the data that included reactions to demand management and the data that included reactions to distributed generation.

The greatest proportion of the demand management sample, 26.5%, was classified as having a ‘Sceptical’ orientation, closely followed at 24.0%, by the ‘Balance Focused’ orientation. ‘Informed Environmentalist’ and the ‘Sceptical’ orientations represented the greatest proportion of individuals in the distributed generation data: 21.8% and 21.9% respectively. Within the demand management data, membership to the ‘Uninformed’ orientation represented the smallest proportion of individuals, 13.3'%. Membership of the 'Informed Environmentalist' and 'Solution Focused' orientations was similar: respectively 17.7% and 18.3%. Membership to the 'Balance Focused' orientation, within the distributed generation data represented the smallest proportion of individuals, 16.9%. Similarly, membership of the 'Solution Focused' and 'Uninformed' orientations was respectively 19.6% and 20.0%. Following the table is a summary of the responses that characterised each orientation.

Table 8.6: Orientation membership across the data sets.

Orientations	**Membership within the demand management Data**		**Membership within the distributed generation Data**	
	Count	**Percent**	**Count**	**Percent**
1) 'Informed Environmentalists'	181	17.7	218	21.8
2) 'Balance Focused'	245	24.0	169	16.9
3) 'Solution Focused'	187	18.3	196	19.6
4) 'Uninformed'	136	13.3	200	20.0
5) 'Sceptical'	271	26.6	219	21.9
Total	1,020	100	1,002	100

'Informed Environmentalists'

Individuals represented by the 'Informed Environmentalists' orientation generally reported high acceptance of distributed energy. These individuals' also reported mostly positive attitudes toward renewable energy alternatives and placed high importance on reduction in emissions, which is a potential feature of distributed energy technology. Furthermore, these individuals rated the importance of climate change highly and supported a swift response to the issue. Strong environmental values and beliefs, high to moderate practice of environmental behaviours, and positive attitudes toward reducing energy consumption, characterised 'Informed Environmentalists'. Furthermore, the 'Informed Environmentalists' perceived themselves as being informed about energy and the environment and had the highest scores when tested on climate change and energy facts.

'Balance Focused'

The individuals making up the 'Balance Focused' orientation tended to report a high potential acceptance of distributed generation and a moderate willingness to accept demand management. Similar to the 'Informed Environmentalists', the 'Balance Focused' respondents placed high importance on the reduction in emissions feature of distributed energy, strongly supported renewable energy alternatives and viewed climate change as a highly important issue. However, the 'Balance Focused' respondents differed from the 'Informed Environmentalists' in that they strongly supported carbon-capture and storage and were not in favour of a swift response to climate change. Furthermore, individuals within this orientation valued the environment and economy equally, were moderately informed about climate change and energy, and practiced a moderate level of pro-environmental behaviour. Most individuals with a 'Balance Focused' orientation were in favour of reducing energy consumption.

'Solution Focused'

Individuals within the 'Solution Focused' orientation tended to be either moderate or unsure in their attitude toward distributed energy. These individuals were concerned about the cost to install distributed generation and the cost saving overtime associated with distributed generation. In relation to demand management, they were concerned about the level of control offered by the technology and potential safety issues. Similar to the 'Balance Focused' respondents, the 'Solution Focused' respondents considered climate change to be important issue, reported positive attitudes toward renewable energy alternatives and carbon capture and storage; and viewed reducing energy consumption positively. However, the 'Solution Focused' respondents differed from the 'Balance Focused' respondents in that gave higher priority to the economy over the environment and reported low to moderate participation in pro-environmental activities. Like the 'Balance Focused', 'Uninformed' and 'Sceptical' respondents, these individuals were moderately informed about climate change and energy, though in addition these individuals perceived themselves to be knowledgeable about climate change and energy.

'Uninformed'

Individuals who were classified within the 'Uninformed' orientation reported themselves as being unsure about their acceptance of distributed energy. These individuals considered the cost to install and cost savings to be important features of distributed generation, and safety to be an important issue for demand management. Similar to individuals with a 'Balance Focused' and 'Solution Focused' orientation, individuals within the 'Uninformed' orientation had positive reactions toward renewable energy alternatives and carbon-capture and storage. The 'Uninformed' orientation was also characterised by agreement about the importance of climate change and a moderate score on climate change, though individuals reported mixed attitudes toward the rate of responses to climate change. However, 'Uninformed' individuals were different in that they were more unsure of their knowledge of climate change and energy alternatives. 'Uninformed' individuals did acknowledge the importance of the environment but valued the economy more. Further more these individuals had a low to moderate level of pro-environmental behaviour and were mostly unsure about their view of reducing energy consumption.

'Sceptical'

Individuals who were classified within the 'Sceptical' orientation were less likely to accept distributed energy. These respondents rated cost to install and cost savings as important issues relating to distributed energy and were concerned about level of control and interruption to electricity in relation to demand management. Whereas respondents within the other orientations reported positive reactions toward renewable energy and generally carbon-capture and storage, respondents within the 'Sceptical' orientation reported positive reactions towards coal instead. Most notably, these respondents did not view climate change as an important issue and were not in favour of a swift response to the issue. Furthermore, these respondents reported pro-economic values and anti-environmental beliefs, were unlikely to have engaged in environmental behaviours and were either unsure or held a negative attitude toward reducing energy consumption.

While the above descriptions provide an overview of the different orientations towards distributed energy, the next section of the report describes each orientation's profile on key dimensions of the questionnaire: technology acceptance and preference, psychological reactions toward energy and the environment, and demographic profiles.

8.2.7 Technology acceptance and preferences

Overall, three of the five orientations represented participants who indicated that they would accept both distributed generation and demand management: 'Informed Environmentalists', 'Balance Focused', 'Solution Focused'. The 'Uninformed' and 'Sceptical' orientations represented participants who were either unwilling to accept distributed generation and demand management or unsure in their acceptance towards these technologies. In this section, the levels of potential acceptance for demand management and distributed generation, and preferred features of these technologies for each orientation are reported on in further detail.

Potential acceptance of demand management

Before assessing respondents' acceptance of demand management, we provided a generalised description of an "energy manager" technology in the questionnaire. The technology was described as involving direct control of grid-connected high-load appliances (for example air conditioners) via communication from the energy supplier. After reading this description, respondents were asked to rate the following four items: "the technology sounds like a good idea", "typical Australian households are likely to support it", "I would consider installing this in my home" and "this sort of technology is not suitable for my home" (reverse scored). The measure of potential acceptance of demand management was created by averaging respondents' responses to these four items and this scale ranged from 1 (low acceptance) to 7 (high acceptance). Figure 8.4 visually depicts the five orientations to DE in terms of this measure. The colour represents both the responses commonly reported by members of each orientation, and also demonstrates the variability in responses across the orientations, and within the orientations.

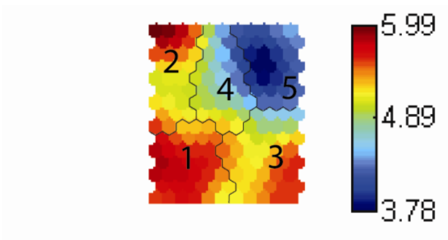


Figure 8.4: Potential acceptance[1] of demand management for each orientation[2]

1: Acceptance ranged from: very low acceptance (blue), unsure (green), to very high acceptance (red). 2: Each colour region represents an orientation: 1) 'Informed Environmentalists'; 2) 'Balance Focused'; 3) 'Solution Focused'; 4) 'Uninformed'; and 5) 'Sceptical'.

Approximately 60.6% of respondents reported that they would accept the demand management technology (these respondents are represented as orientations with red colouring in Figure 8.4). Specifically, respondents from the 'Informed Environmentalists' orientation (region 1) reported high acceptance of demand management.

The other orientations consisting of individuals that reported high acceptance were the 'Balance Focused' (region 2) and 'Solution Focused' (region 3). These orientations were characterised by mainly high potential acceptance and some individuals that were unsure of their willingness to accept.

Members of the 'Uninformed' (region 4) orientation were mostly likely to report to be unwilling to accept the technology or unsure of their acceptance. Members of the 'Sceptical' (region 5) orientation were mostly likely to report to be unwilling of demand management (please refer to the dark blue in Figure 8.4.

Importance of demand management features

To understand the relative importance or utility that people placed on various features of demand management technology, nine features were assessed using best-worst scaling. The features, which were developed via a review of technical features and adjusted in focus group work were: 1) cost to install, 2) ease of installation, 3) ease of use, 4) reduction in my carbon emissions, 5) level of control I have, 6) interruptions to my electricity, 7) reliability and durability, 8) safety levels, and 9) savings over time.

Sets of these features were presented to respondents, and they were asked to choose the "most important" and the "least important" feature from each set. This approach is known as best-worst scaling (Auger et al., 2007). Utilities are calculated by subtracting the number of times each feature is chosen as "least important" from the number of times it is chosen as "most important". Each feature appears in four different choice sets. Thus, utilities could range from -4 (always chosen as least important) to +4 (always chosen as most important).This value is averaged across respondents. In preparation for the SOM analyses these scores were recoded to range from 0-always chosen as least important to (blue colours) to 8-always chosen as most important (red colours).

Figure 8.5 colour codes the perceived importance of each feature within each orientation group. Following is a summary of the features that are of high importance to each orientation:

Members of the 'Informed Environmentalists' orientation (region 1) considered the reduction in carbon emissions to be of high importance as did the other pro-environmental orientation - 'Balance Focused' (region 2)

'Solution Focused' (region 3), is characterised by individuals with a moderately high willingness to accept demand management or unsureness of their acceptance. These individuals considered level of control and safety to be highly important features of demand management

The individuals from the 'Uninformed' (region 4) and 'Sceptical' (region 5) orientations were either unwilling to accept or unsure about demand management. 'Uninformed' (region 4) individuals were most concerned about the safety feature of demand management, whereas 'Sceptical' individuals were most concerned about level of control and interruption to electricity

Ease of installation was considered to be of low to very low importance for all orientations, as indicated by the primarily blue coding on this feature map, indicating relatively low scores across all orientations.

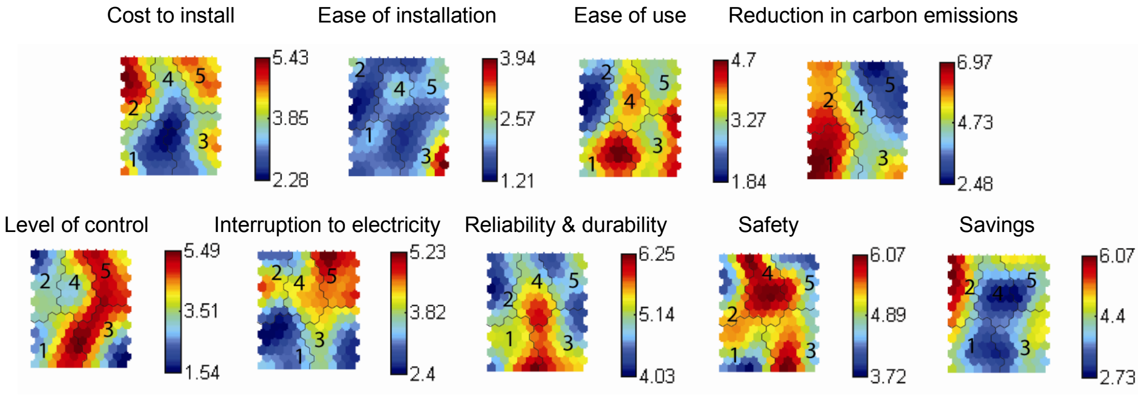


Figure 8.5: Importance[1] of demand management features for each orientation[2]

1: Importance ranged from: least important (blue colours) to most important (red colours).

2: Each region represents an orientation: 1) 'Informed Environmentalists'; 2) 'Balance Focused'; 3) 'Solution Focused'; 4) 'Uninformed'; and 5) 'Sceptical'.

Respondents were asked to indicate, from a list in the questionnaire, which appliances they would be willing to have controlled through demand management. Overall, more support was reported for the centralised control of air-conditioners (53.89%), electric hot water systems (56.63%) and washing machines (51.21%). The lowest support was reported for the control of pool pumps (39.54%) and deep freezers (36.16%). 'Informed Environmentalists' (region 1) and 'Balance Focused' (region 2) tended to nominate more appliances to be controlled. The nominations were made by individuals that both owned and did not own the appliances. Listed in Table 8.7 is breakdown of each orientation's support for control of various appliances.

Table 8.7: Percentage of support for the control of appliance using demand management.

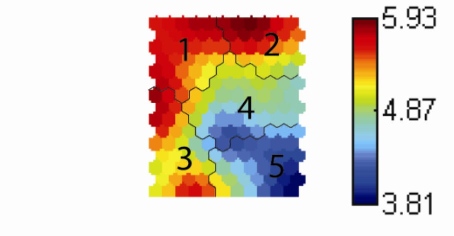
Appliances that could be controlled:	'Informed Environ-mentalists'	'Balance Focused'	'Solution Focused'	'Uninformed'	'Sceptical'	Total
Air-conditioner	56.65	59.15	42.86	51.52	56.42	53.89
Refrigerator	50.86	66.97	32.00	37.88	46.48	48.18
Electric hot water system	61.80	63.96	42.61	52.24	58.59	56.63
Pool pump	39.20	45.16	34.66	39.69	38.31	39.54
Clothes dryer	54.07	51.18	38.29	51.16	45.85	47.87
Dishwasher	48.85	53.11	40.34	45.04	45.74	46.84
Washing machine	60.47	57.08	42.61	43.85	49.81	51.21
Deep freezer	36.78	47.49	26.40	27.61	37.26	36.16
Electric heater	43.10	49.55	31.25	44.36	44.27	42.92

Support for each appliance was significantly different between orientations, at <0.05 significance, except for the pool pump.

Potential acceptance of distributed generation

Acceptance of distributed generation technology was assessed by providing a generalised description of a "household electricity generator" (see Appendix A of Gardner and Ashworth, 2007) and then asking for reactions to the same four items used to assess acceptance of demand management. Figure 8.6 visualises the potential acceptance reported for distributed generation. The colour represents both the responses commonly reported by members of each orientation, and also demonstrates the variability in responses across and within the orientations.

Figure 8.6: Potential acceptance [1] of distributed generation for each orientation [2].



1: Acceptance ranged from: low acceptance (blue), unsure (green), and very high acceptance (red).
2: Each region represents an orientation: 1) 'Informed Environmentalists'; 2) 'Balance Focused'; 3) 'Solution Focused'; 4) 'Uninformed'; and 5) 'Sceptical'.

Approximately three orientations (58.3% of the sample) reported they would accept distributed generation (these respondents are represented by the red colouring in Figure 8.6). Orientations that reported potential acceptance where: ‘Informed Environmentalists’ (region 1), ‘Balance Focused’ (region 2), and ‘Solution Focused’ (region 3).

Members of the ‘Informed Environmentalists’ (region 1) and ‘Balance Focused’ (region 2) orientations were most accepting of distributed generation. Members of the ‘Solution Focused’ (region 3) orientation either reported high potential acceptance or where unsure of their acceptance.

Individuals from the ‘Uninformed’ (region 4) orientation tended to be unwilling to accept distributed generation or unsure in their attitude toward distributed generation. Individuals from the ‘Sceptical’ orientation (region 5) were the most unwilling to accept distributed generation (as indicated by the blue colouring associated with this orientation in Figure 8.6).

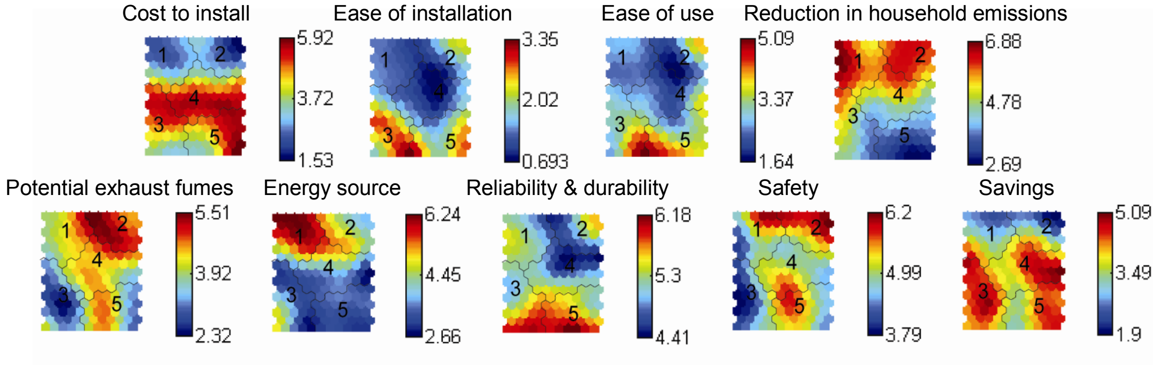
Importance of distributed generation features

To understand the relative importance or utility that people placed on various features of distributed generation technology, nine features were assessed using best-worst scaling. The features, which were developed via a review of technical features and adjusted in focus group work, were: 1) Cost to install, 2) ease of installation, 3) ease of use, 4) reduction in my carbon emissions, 5) potential exhaust fumes, 6) the generator’s energy source, 7) reliability and durability, 8) safety levels, and 9) savings over time.

These features were slightly different to the features used to assess demand management technology. Utilities were calculated in the same manner as described previously. In preparation for the SOM analyses these scores were recoded to range from 0-always chosen as least important to (blue colours) to 8-always chosen as most important (red colours).

The importance each orientation assigned to the features is depicted in Figure 8.7. Following is a summary of the importance each orientation assigned to the features:

- The orientations that were most willing to accept distributed generation (1-’Informed Environmentalists’ and 2-’Balance Focused’), reported the reduction in household emissions as the most important feature of distributed generation
- Members of the ‘Solution Focused’ (region 3), ‘Uninformed’ (region 4) and ‘Sceptical’ (region 5) orientations considered the cost to install and cost savings over times as the most important features of distributed generation.



1: Importance ranged from: least important to (blue colours) to most important (red colours).
2: Each region represents an orientation: 1) 'Informed Environmentalists'; 2) 'Balance Focused'; 3) 'Solution Focused'; 4) 'Uninformed'; and 5) 'Sceptical'.

Figure 8.7: Importance [1] of distributed generation features for each orientation [2].

In addition to the importance of the technology's features, respondents were asked to nominate their support for a range of power sources for the technology. The breakdown for support is presented in Table 8.8. All the orientations reported high support for using solar panels as a distributed generation source, while low support was reported for using diesel (or petrol). These results are consistent with other international research findings about public attitudes towards energy generation technologies (Curry et al., 2006; Shackley et al., 2007; Sola et al., 2007).

Table 8.8: Percentage of support for generator power source

Preferred fuel source:	**Informed Environ-mentalists'**	**'Balance Focused'**	**'Solution Focused'**	**'Uninformed '**	**'Sceptical'**	**Total**
Diesel/petrol	7.8	2.47	9.44	4.4	3.9	5.71
Natural gas	46.7	39.52	46.2	39.77	39.05	42.37
Wind power	63.08	69.82	46.45	81.73	58.88	63.97
Solar panels	85.19	91.12	75.66	95.96	82.95	86.05
Biofuel	45.97	53.29	29.51	63.07	36.36	45.14

Preference for each fuel source was significantly different between orientations, at <0.05 significance, except for natural gas.

8.2.8 Psychological characteristics

This section includes details of the psychological characteristics of each orientation. First, the measures for each of the psychological variables are described. Second, the similarities and differences between the orientations in terms of these psychological variables are summarised. Finally, a summary of the psychological characteristics associated with each orientation group is provided.

Measures for psychological characteristics

Each orientation was defined, in part, by the psychological reactions individuals reported toward energy and the environment. Specifically, respondents were asked to describe their:

- Perceived importance of each technology's features
- Attitudes toward and self-rated knowledge of climate change and energy alternatives
- Attitudes toward their energy consumption and the consumption of others (subjective norms)
- Environmental beliefs, behaviours and values, and
- Knowledge of facts relating to climate change and energy.

In Appendix D and Appendix E of Carr-Cornish et al. (2008), the results from analysing these psychological characteristics are listed, including the self-organised map.

To measure attitudes toward climate change and energy alternatives, respondents were asked to rate their reactions to six statements. The six statements were: "Climate change is an important issue for Australia"; "Australia shouldn't make a rushed response to climate change"; "Australia should continue using coal-powered generation for electricity production"; "Australia should consider using carbon capture and storage (storing CO_2 underground) to reduce emission from coal-powered generators"; and "Australia should consider using renewable energy sources (wind, solar, hydro-electric) for electricity production". The respondents rated their reactions on a Likert scale where 1 was strongly disagree, 4 was unsure and 7 was strongly agree.

Self-rated knowledge about climate change and energy was measured by asking respondents to report their level of agreement with the following three statements: "I am well informed about climate change"; I am well informed about fossil fuels (coal, oil, natural gas)"; and "I am well informed about renewable energy sources (solar, wind, hydro-electric)". Responses were rated on a Likert scale with 1 representing strongly disagree, 4 unsure and 7 strongly agree.

The four items assessing attitudes toward reduced household energy consumption (e.g. "Reducing my household's energy consumption would help protect the environment") were rated on a 5-point scale from 1 = strongly disagree to 5 = strongly agree). One negatively worded item was reverse-scored, and then the items were averaged to produce a single measure, ranging from 1 to 5. Higher scores reflected more positive attitudes.

Four items assessing subjective norms regarding reduced household energy consumption (e.g. "People I know have taken steps to reduce their household energy consumption") were rated on a 5-point scale from 1 = strongly disagree to 5 = strongly agree). The items were averaged to produce a single measure, ranging from 1 to 5. Higher scores reflect more positive subjective norms.

Respondents reported their perceptions of the energy efficiency of their house in comparison to similar houses by rating if their house was 1 = less efficient; 3 = about the same and 5 = much more efficient than similar houses. The willingness to reduce their household energy was measured as 1- I will definitely not try, 3- there is a 50/50 chance I will try, 5- I will definitely try. The willingness of respondents to pay extra for an energy efficient house was measured from one item where 1 - represented up to 10% extra, 2 - up to 5% extra, 3 - up to 2% extra, 4- up to 1% extra, 5- not being prepared to pay more. This measure was reverse coded for the analyses.

Pro-environmental beliefs were measured using the New Environmental Paradigm scale (Dunlap et al., 2000), consisting of fifteen statements (e.g. “we are approaching the limit of the number of people the earth can support”) answered on a five point scale (strongly disagree to strongly agree). Negatively worded items were reverse-scored, and scores were then averaged to form a single measure ranging from 1 (anti-environmental beliefs) to 5 (pro-environmental beliefs).

Pro-environmental behaviours were assessed by asking respondents to identify (from list of ten behaviours which reflect environmental impact, e.g., “I pay extra for ‘green’ electricity”) how many of the behaviours they practiced. Positive responses to positive behaviours and negative responses to negative behaviours were summed, to produce a single measure of pro-environmental behaviour ranging from 1-low environmental impact to 10-high environmental impact. These scores were reversed for the SOM analyses, consequently lower scores represented high environmental impact and higher scores represented low environmental impact.

A single item was used to measure the extent to which respondents valued the environment above the economy (“Many environmental issues involve difficult trade-offs with the economy. Which of the following statements best describes your view?”). Response options ranged from 1 (“The highest priority should be given to protecting the environment, even if it hurts the economy”) to 5 (The highest priority should be given to economic considerations, even if it hurts the environment). In preparation for the SOM analyses these scores were reversed, therefore 1 was “The highest priority should be given to economic considerations even if it hurts the environment” and 5 was “The highest priority should be given to protecting the environment, even if it hurts the economy”.

To assess respondents’ knowledge of energy and the environment respondents were tested on facts about climate change and energy. Seven questions were used (e.g. “Most of the air pollution in Australian cities is caused by motor vehicles”), which were answered on a five-point scale (definitely false, likely to be false, uncertain, likely to be true, definitely true). Responses were scored on a sliding scale from -2 for an incorrect answer about which the respondent was “definite”, through to +2 for a correct answer about which the respondent was “definite”. Scores were summed across all seven items, yielding a total knowledge score which could range from -14 to +14. In order use this variable in the SOM analyses, the variable was re-coded to range from -0 to +28.

Similarities and differences of each orientations’ psychological characteristics

Although two data sets were analysed, the orientations generated were substantively the same and have been presented as one set of orientations toward distributed energy. Some of the measures that characterised the orientations were measures of psychological reactions toward energy and the environment.

‘Informed Environmentalists’ and ‘Balance Focused’ orientations were mostly defined by high potential acceptance of the technologies. These orientations were also characterised by stronger pro-environmental qualities and the most positive attitudes toward reducing energy consumption. The distinction between these two pro-environment and pro-energy reducing orientations, was that slightly higher scores on facts about climate change and energy, and slightly stronger environmental qualities were reported by the 'Informed Environmentalists' rather than the 'Balance Focused'.

Although the 'Solution Focused' orientation was also characterised by mostly high acceptance and some unsureness, members of this orientation typically reported few pro-environmental qualities. The 'Uninformed' and 'Sceptical' orientations were typified by low acceptance or were unsure about accepting the technologies, and overall these orientations had less pro-environmental qualities and more negative attitudes toward reducing energy consumption. These orientations all perceived that they had little, or where unsure of, their knowledge of climate change and energy, although like the rest of the orientations scored moderately on the test of climate change and energy facts. Overall, climate change was identified as an important issue by each orientation, with the 'Sceptical' orientation being the exception.

Summary of each orientation's psychological characteristics

Following, each orientation's psychological reactions toward energy and the environment are summarised.

'Informed Environmentalists':

- Had the strongest pro-environmental qualities and most positive reactions toward reducing energy consumption
- Were most likely to agree that climate change is an important issue and should be responded to swiftly
- Scored highest on a test of climate change and energy facts
- Were most are likely to perceive their knowledge of climate change and energy as high
- Reported strong support for renewable energy alternatives.

'Balance Focused':

- Had strong pro-environmental beliefs
- Reported behaviours with a moderate environmental impact
- Valued the environment and the economy equally
- Had positive attitudes toward reducing energy consumption
- Saw climate change as an important issue but did not support a rushed response to climate change
- Scored moderately on a test of climate change and energy facts
- Rated their knowledge of climate change and energy as low or alternatively reported to be unsure of their knowledge
- Reported strong support for the use of renewable energy alternatives and carbon-capture and storage.

‘Solution Focused’:

- Valued the economy more highly than the environment
- Reportedly exhibited behaviours with a moderate to high environmental impact
- Reported to be mostly uncertain about their environmental beliefs
- Had positive attitudes toward reducing energy consumption
- Saw climate change as an important issue but had a mixed opinion about the rate of response required
- Scored moderately on the test of climate change and energy facts
- Strongly supported the use of renewable energy sources and carbon-capture and storage.

‘Uninformed’:

- Valued the economy more highly than the environment, were uncertain of their environmental beliefs and reported to carryout behaviours with a high environmental impact
- Were unsure in their attitudes toward reducing energy consumption
- Perceived climate change to be an important issue but had mixed opinions about responding swiftly
- Scored moderately on the test of climate change and energy facts
- Were unsure about their knowledge about climate change and energy
- Strongly supported the use of renewable energy sources and carbon-capture and storage.

‘Sceptical’:

- Reported to value the economy even if it hurt the environment, anti-environmental beliefs and behaviours with a high environmental impact
- Had negative or unsure attitudes toward reducing energy consumption
- Did not perceive climate change to be an important issue and saw no need for a rushed response to climate change
- Scored moderately on the test of facts about climate change and energy
- Were unsure of their knowledge about climate change and energy
- Strongly supported the use of coal based energy while indicating some support for all other energy sources.

8.2.9 Demographic characteristics

This section described the demographic characteristics of each orientation, which can be used to understand the capacity of each orientation to adopt the technologies. First, the measures for each of the demographic variables are introduced. Second, the similarities and differences between the orientations are summarised. Third, the demographic characteristics of each orientation are described in detail.

Demographic measures

In total, nine demographic variables were assessed through questions that required either tick box or 'open-ended' responses. The demographic variables were age, gender, education level, employment, household income, quarterly electricity bill, household size and household type and occupation

After the respondents had been classified into orientations (based on the psychological measures), analyses were carried out to determine whether there were reliable differences in the demographic characteristics of respondents within each orientation. The results of these tests are reported in Appendix F and Appendix G of Carr-Cornish et al. (2008). Appendix F includes the results from testing the demographic associated with acceptance of demand management. Appendix G includes the results of testing the demographic characteristics associated with acceptance of distributed generation.

The two sets of self-organized map analyses (one based on data from the demand management version of the questionnaire and one based on data from the distributed generation version of the questionnaire) produced orientations with slightly different demographic profiles. Furthermore, the measures of household income and quarterly electricity bill did not differentiate the orientations in the distributed generation dataset, though they did in the demand management dataset.

Having different demographic profiles for demand management and distributed generation does not detract from there being five distinctly different orientations toward distributed energy. Rather, the demographic differences indicate that although there are five common orientations toward these technologies, people sharing the same orientation can have different demographic features.

The technologies had different features, for instance demand management calls for a householder to release some control of their energy consumption, whereas distributed generation calls for the householder to financially invest and exercise more control. Demographics are an indicator of the capacity of individuals to act (Dunlap et al., 2000; Fransson and Garling, 1999), thus given the difference in the features of each technology it is highly plausible the demographic features associated with each orientation differ in the context of each technology. Following the demographic profile for each orientation, in the context of both demand management and distributed generation is summarised.

Similarities and differences of each orientations' demographic characteristics

Orientations that maintained a similar demographic profile for both technologies were the 'Balance Focused' and 'Solution Focused'. The 'Balance Focused' orientation tended to consist of females, aged between 20-59 years and living as a couple in a household with a child or children. The 'Solution Focused' was characterised by individuals that were older, males, either retired or on the pension and living as in a single person household or in couple with no children. The 'Solution Focused' individuals had a range of educational backgrounds.

However, the demographic profile of the 'Informed Environmentalists', 'Uninformed' and 'Sceptical' orientations differed for the demand management dataset and the distributed generation dataset. Nevertheless, there were some consistent demographic characteristics associated with the 'Informed Environmentalists', 'Uninformed' and 'Sceptical' orientations. In the analysis of the distributed generation dataset, the individuals in the 'Informed Environmentalist's' orientation tended to be older males, whereas this same orientation, in the demand management data set, consisted of mostly females between 30-49 years.

Individuals that reported the 'Uninformed' orientation in relation to distributed generation were mostly individuals that were males, 20-59 year olds, working full-time and tertiary educated. Whereas the ''Uninformed'' orientation, in relation to demand management was mostly reported by individuals that were females, aged either 20-39 years or 50 to 69 years, retired or on the pension, and have either a year 10 or 11 pass or hold a trade or apprenticeship qualification.

The individuals that reported a 'Sceptical' orientation in relation to distributed generation, were most likely to be females, between 20-59 years, and employed in a full-time position or a part-time/casual position. Individuals that reported this 'Sceptical' orientation in relation to demand management were more likely to be males, 60 years or over and retired or on the pension.

Summary of each orientations' demographic characteristics

Summaries of the demographic profiles of each orientation are provided in tables below (Table 8.9 to Table 8.13).

Table 8.9: Demographic profile of 'Informed Environmentalists'

Demographics	Profile for demand management	Profile for distributed generation
Age	24.6% between 30-49 years	54.4% over 50 years
Gender	56.2% were females	70.6% were males
Education level	Junior high school educations or diplomas	Varied across the range
Employment situation	Most were employed full-time (39.0%) or employed part-time/casual (19.2%)	Were most likely to be retired (42.5%)
Household income and quarterly electricity bill#	18.3% reported <$10,000 - $19 999 31.5% reported $30,000 - $59,999 29.1% reported $70,000 - $124,999	47.5% reported < $10,000 - $39,000
Household size and type	Single person household (21.2%) or couple with children (39.6%)	Smallest s number of occupants at 2.28 people Most likely occupy houses as a single person (25.2%) or a couple with no children (39.0%)
Occupations	Were most likely to be either: manager, Technician/trade worker, clerical/ administrative worker, or sales worker	Were most likely to be out of paid employment (39.5%)

Household income and quarterly electricity bill were not significant descriptors in the demographic profiling of distributed generation.

Table 8.10: Demographic profile of 'Balance Focused'

Demographics	Profile for demand management	Profile for distributed generation
Age *	74% reported to be between 20 -59 years	88.4% between 20 to 69 years old
Gender*	52.9% female	59.3% females
Education level	Most reported to have a tertiary education (50.6%)	Some high school education or a diploma
Employment situation	Most likely to be employed full-time (44.0%), part-time or casual (18.1%)	Were most like to be engaged in home duties (7.2%) or part-time (or casual) work (19.2%)
Household income and quarterly electricity bill#	Most reported to earn $50,000 or greater (71.1%). Reported to have the lowest average electricity bill per a quarter: $243.89	Most reported to have moderately low incomes: $20,000 to $69,999 (49.8%)
Household size and type*	Average of 2.78 people (largest) Couple with children (40.3%)	Most likely to be in households that consisted of a couple with children (32.3%)
Occupations	Were most likely to be a professional, community service worker (personal service worker) or machinery operator (or driver)	Were most likely to be a professional, clerical (or administration) worker, sales worker, machinery operator (or driver) or labourer

* Profile characteristic was similar for distributed generation and demand management.
# Household income and quarterly electricity bill were not significant descriptors in the demographic profiling of distributed generation.

Table 8.11: Demographic profile of 'Solution Focused'

Demographics	Profile for demand management	Profile for distributed generation
Age*	Were more likely to be 50-59 years (21.2%) or 70 years and over (16.2%)	53.5% were 60 years or older
Gender*	More likely to be male (55.9%)	Were most likely to be males (53.4%)
Education level*	Varied across the range	Varied across the range
Employment situation*	Were likely to be retired (40.4%)	Were more likely to be retired (42.0%)
Household income and quarterly electricity bill#	Were most likely to earn $10,000 - $49,999 (57.7%) or $150,000 - $249,999 (8.4%)	Distributed across the range from low ($10,000 - $19,999) to high ($150,000 - $249,999)
Household size and type*	Most likely to occupy households as singles (21.9%) or a couple with no children (38.8%) Reported to have the lowest average number of household occupants (2.44 people)	Reported to most likely be occupants of single person households (21.6%) or couples with no children (39.5%)
Occupations*	Were more likely to be out of paid employment (28.2%)	Were most likely to be out of paid employment (29.2%)

* Profile characteristic was similar for distributed generation and demand management.
# Household income and quarterly electricity bill were not significant descriptors in the demographic profiling of distributed generation.

Table 8.12: Demographic profile of 'Uninformed'

Demographics	Profile for demand management	Profile for distributed generation
Age	20-39 years (21.1%) or 50 to 69 years (42.9%)	21.8% between 20 to 59 years old
Gender	Were most likely to be females (50.4%)	Were most likely to be males (54.6%)
Education level	Were likely to hold a year 10 or 11 pass (28.1%) or trade certificate/ apprenticeships (19.3%)	Most likely to have a tertiary education (43.1%)
Employment situation	Were most likely to be retired or pension recipients (34.1%)	Were more likely to be engaged in full-time work (39.9%)
Household income and quarterly electricity bill#	Reported to have the highest average electricity bill per quarter ($353.11) Household incomes varied from <$10,000 to $124,999	$247.62 the lowest average electricity bill per quarter Most reported to earn moderately low or moderately high household incomes: $30,000-$49,999 (18.8%) and $90,000-$149,000 (30.2%)
Household size and type	Were most likely to be occupants of single person households (20.3%), couples with children (29.3%) or without (36.8%)	Reported to have the highest average number of household occupants (2.89) Were most likely to be couples with children (36.5%)
Occupations*	Most were out of paid employment (29.6%) If they reported an occupation they were more likely to be managers, technicians (trade workers), clerical workers (administration workers), sales workers, or machinery operators (drivers)	Were most likely to be a professional, technician (trade worker), community worker (personal service worker) or labourer.

Household income and quarterly electricity bill were not significant descriptors in the demographic profiling of distributed generation.

Table 8.13: Demographic profile of 'Sceptical'

Demographics	Profile for demand management	Profile for distributed generation
Age	60 years or older (52.0%)	20 and 59 years old (67.2%)
Gender	Were most likely to be males (60.1%)	Were most likely to be females (59.1%)
Education level	High school at year 10 (12.0%) High school at year 12 (13.1%) Trade certificate/apprenticeship (17.0%)	Primary school (5.1%) Year 9 or below (6.5%) Year 10, 11, 12 (39.2%) Trade/apprenticeship (13.1%)
Employment situation	Were most likely to be retired or pension recipients (45.5%)	Were more likely to be employed full-time (34.1%) or part-time or casual (15%)
Household income and quarterly electricity bill#	Reported to have household incomes that varied from low ($10,000) to high ($250,000 or greater)	At $291.34 reported to have the highest average electricity bill Were most likely to earn low, or medium to high household incomes: less than $10,000 to $19,999 (30, 19.6%) or $40,000 to $124,999 (55.9%)
Household size and type	Were most likely to occupy single person households (20.0%), couple with no children (40.4%)	Were most likely to be occupants of one parent with children households (18.9%) or couples with children (31.5%)
Occupations	Were most likely to be out of paid employment (32.3%), if in employment were likely to be a machinery operator (or driver), labourer or clerical worker (administration workers)	Were most likely to be a manager, community worker (personal service worker), clerical (or administration) worker, or machinery operator (or driver) or a labourer

Household income and quarterly electricity bill were not significant descriptors in the demographic profiling of distributed generation.

8.3 Early adopters of PV

In early research for the IG project, Gardner and Ashworth (2007) proposed a conceptual model arising from a literature review that links knowledge, beliefs and attitudes, intention to act, actual behaviour, longer-term acceptance and uptake, and external physical, social, economic and political influences. The review drew particularly on Ajzen's Theory of Planned Behaviour (Ajzen, 1989; Ajzen and Fishbein, 2005), which extended the Theory of Reasoned Action (Ajzen and Fishbein, 1980). Gardner and Ashworth (2007) interpreted these theories, proposing that a person's likelihood of adopting a DE technology will increase if:

- They hold a positive attitude towards the technology
- They perceive support for the technology from within their community, and
- They feel they possess the capability and opportunity to adopt the technology.

In particular, the conceptual model allows for highly complex inter-relationships between values, attitudes and behaviours. It also identified two types of social-psychological intervention: firstly, ‘antecedent interventions’, designed to increase knowledge and promote positive attitudes and intentions towards DE generation; and secondly, ‘consequence interventions’, based around incentives to increase the likely uptake of specific distributed energy technologies (see Figure 8.1). The premise of this model is that people’s values, attitudes and beliefs will drive their intentions, subsequent action and eventual long-term acceptance of DE and reductions in energy consumption, and that their decisions are made within a broader context of external influences.

8.3.1 Method

To shed light on this model, case study interviews were conducted. Participants were asked to reflect on both internal motivations (e.g., values, attitudes and beliefs) and external motivations (e.g., financial incentives, social networks, societal norms). To help tease out these motivations further, participants were also asked to describe their ideal energy scenarios, at both personal and societal levels. From a theoretical perspective, ‘internal motivations’ can be seen as psychological factors driving DE implementation, while ‘external motivations’ can be seen as contextual factors.

The interviews were held face-to-face during May and June 2007. Potential participants were identified through existing contacts, and by following up subsequent leads. Eligible participants were those who had installed, or were considering installing, some kind of DE system. Participants were sent interview questions in advance, and these were used in a semi-structured manner to guide the interviews.

Those who participated were fairly diverse demographically (Table 8.14), ranging in age from their thirties to retirement age, and in household size from one to seven residents. Four live in south-east Queensland, two in north-east New South Wales, and two in south-east New South Wales. Five live in rural communities, two in regional towns, and one in an ‘eco-village’; thus, further studies might focus on the motivations of urban residents. Participants had undertaken, and/or were considering undertaking, a range of DE initiatives. Mostly, these involved harnessing solar energy. In many cases, participants also had made concerted efforts to reduce energy consumption, and/or had designed their homes along solar-passive principles, to reduce energy needs. However, these initiatives are not recorded in the table below.

Table 8.14: Details of case study participants

Participants	Region	Type of Location	Approx. Age	Household size	Current/Planned DE Initiatives
Ivor & Anthea	NE NSW	Regional town	70s	2	Photovoltaic panels (grid-connected) *Planning to install solar hot water*
Greg	NE NSW	Rural community	40s	1	Photovoltaic panels (stand-alone) Gas-powered fridge
Ian & Sascha	SE Qld	'Eco-village'	30s	3	Solar hot water *Planning to install photovoltaic panels and electricity, gas and water monitoring system*
David & Sara	SE Qld	Rural community	40s	2	Solar hot water Photovoltaic panels (awaiting installation)
John & Judy	SE Qld	Rural community	50s	5	Photovoltaic panels (stand-alone)
Ken	SE Qld	Rural community	40s	7	Solar hot water
Matthew	SE NSW	Regional town	40s	5	Photovoltaic panels (grid-connected) *Planning to install solar hot water and a wind turbine*
Richard & Cindy	SE NSW	Rural community	30s	4	Solar hot water

Note: Permission was gained to use participants' first names in this report.

Of these eight participant households, five also completed the household survey. Comparing their responses with those of all survey respondents provides initial evidence of how the motivations of case study participants might differ from those of the general population. Survey questions designed to assess pro-environmental behaviour, for example, found that these five participants averaged 5.2 on a 7-point scale, compared to 4.8 for survey respondents as a whole. Four reported in the survey that their households are "much more efficient than similar households", and the other responded as "a bit more efficient"; just over three-quarters of survey respondents gave one of these two responses. Three (60%) also affirmed, "I will definitely try to reduce my household energy consumption for the following year", compared to 40% for survey respondents as a whole. Additionally, questions testing knowledge of energy and environment issues suggested that, on average, these five participants have greater knowledge of these issues than do survey respondents as a whole. These comparisons provide some evidence to support the designation of these participants as innovators and early adopters of DE technology, rather than as representative of the entire population.

8.3.2 Internal motivations

The household survey included various questions relating to values, beliefs and attitudes. In a summary measure of pro-environmental beliefs, the five case study participants who also completed the survey averaged 4.09 out of 5, compared to 3.77 for survey respondents as a whole. Four interview questions, therefore, aimed to elaborate further on participants' internal motivations for implementing DE initiatives:

- Broadly speaking, why was/is the idea attractive to you?
- In what way did/might your own values influence your decision?
- What would be your ideal energy scenario personally?
- What kind of system would be appropriate more generally in other households?

Responses to these questions suggest that participants are influenced by a range of internal motivations. For some, the predominant motivator is a desire for self-sufficiency and energy-independence. For others, DE offers the opportunity to demonstrate an environmental value system. Meanwhile, others are motivated by the view that making sustainable energy choices can catalyse social change. However, participants cannot be categorised exclusively into one category and may have multiple motivations.

Self-sufficiency and energy independence

Some participants expressed their values in terms of the objective of self-sufficiency, via energy-independence. Ian and Sascha, for example, identified their ideal energy scenario as never having to pay for power, and putting energy back into the grid. Energy-independence is also an internal motivation for Ken, who expressed a desire to avoid having to rely on external sources for his power. However, in both cases currently, this is an aspiration only. Moreover, Ian and Sascha intend to install a grid-connected solar system, meaning that they would be never truly independent of the grid. Conversely, the self-sufficiency motivation is most strongly evident for David and Sara, and for John and Judy.

David and Sara appear to be largely motivated by a perceived need to insure themselves and their family against perceived external threats, and they see energy-independence as their insurance policy:

> *"I find myself increasingly selfish; I care less about other people and more about my family. I started to think about the enormity of the problems, and decided there's nothing I can do… When the terrorists blow up the power stations, we'll still have power."*

When John and Judy moved from the U.S. to Australia 25 years previously,

> *"It was a survival thing… We didn't want to have to rely on power companies."*

and now:

> *"If something goes wrong [with grid power], we won't be the ones struggling to survive."*

This motivation, then, suggests a relatively individualistic perspective. Participants here prioritise personal independence from external energy suppliers as their objective. Their emphasis is on protecting themselves and their families from future energy crises, rather than on a perceived need for collective or social action. This apparently individualistic focus does not, however, exclude a broader motivation. David and Sara stressed that they also have wider social concerns, and that their approach to energy use is also motivated by environmental values:

> *"You do it because it's right; to be a role model."*

Environmental values

The sense that their actions are "right", more for social than individual reasons, was the most common factor that participants cited as influencing their decisions to implement DE initiatives. This perspective appeared to be based upon a value system which emphasises ecological sustainability. Ian and Sascha, for example, suggested that a deeply-held environmental ethic drove their decision to move to the eco-village, a move they see as an example of taking personal responsibility for the future. John and Judy, as well as aspiring to energy-independence, also articulated a wider sense of environmental responsibility:

> *"We have a moral obligation to minimise our impact… We wanted to walk as lightly as we could. We wanted to think about the future for everyone."*

Greg saw his own environmental values as a significant motivator of his energy choices. Inspired by Gavin Gilchrist's *The Big Switch* (1994), he sensed that generating his own power, without using fossil fuels, was environmentally "the right thing to do". Ivor and Anthea, similarly, expressed a concerned awareness of the environment and climate change, and perceived a personal responsibility to "do the right thing" in the interests of future generations. Anthea translated this perceived responsibility into a determination to take what action they could as consumers:

> *"We have a wonderful planet, and we should be nurturing it… I'd like to be part of remedying the situation."*

Ken's motives, meanwhile, stem from a Christian ethic, which endows him with environmental values of stewardship:

> *"You own a block of land, you're supposed to look after it... God created all these beautiful things, so we've got a responsibility to look after them."*

The motivational factor for those espousing environmental values appears to be the opportunity to take remedial action as responsible consumers. Purchasing and installing DE systems constitutes a public demonstration of their environmental values, beyond the individualised focus on self-sufficiency and energy-independence. However, this motivation generally still focuses on what each participant could do within the confines of their own households. For some, conversely, motivation for DE goes beyond simply demonstrating social values through consumption decisions, towards a critical focus on how they perceive wider structural forces in society constrain sustainable living and exacerbate climate change.

Catalysing social change

The household survey findings suggest that, on average, respondents as a whole value the environment and the economy almost equally. In comparison, of the five case study participants who completed the survey, four said that they valued the environment more highly than the economy, and one answered that both are equally important. This highlights that early adopters of DE may not necessarily make decisions based on economic considerations and so product manufacturers and distributors need to appeal to other variables that drive early uptake.

Some interviews participants, when discussing their internal motivations, spoke of an inherent ‘unsustainability’ within the dominant economic paradigm in Australia. They conceived their energy choices partly as constituting a political statement challenging this paradigm, and thus potentially catalysing social change. Through their choices, they are not only “doing the right thing”, but also implicitly critiquing conventional assumptions, particularly the perceived prioritisation of economic objectives over social and environmental considerations. Ian and Sascha, for example, see their decision as a statement about contemporary Australian society, urging a need to curb consumerism and materialism:

> *“[Ecological values] made our decision; it’s what we believe in 100%, rather than having holidays. We get a lot more happiness out of living sustainably than out of consumer items. Why is the economy the overriding God?... People think they’re going to be happy in their big palaces, but they end up lost and lonely.”*

Ken argued that society needs to differentiate between what we *need* and what we *want*. An over-emphasis on fulfilling needless desires has led to a materialistic society, he reflected, in which:

> *“We’re building palatial-looking homes [where] we live to excess”.*

Greg, meanwhile, argued that the competitive spirit of the monetary system is incompatible with the cooperative values required to achieve sustainability. For Richard, similarly, a wasteful approach to energy use is embedded in, and exacerbated by, the western socio-economic paradigm:

> *“Social change is about slowing the process of consumerism… Growth is about people having fatter pockets.”*

The most explicit example of DE as catalysing social change was provided by Matthew, who is motivated by the perceived need to take action against climate change at a community, and ultimately a National level. The project he founded, *Clean Energy for Eternity*, is unusual in that it represents a community-level effort to tackle climate change, rather than relying solely on individual decisions to implement DE initiatives. Matthew is keen to portray himself as an ‘ordinary’ citizen and to distance himself from ‘greenies’. His focus, therefore, is on disseminating the message of urgency regarding climate change to mainstream society, to protect the environment for future generations:

> *“It’s all about my kids, at my age, being confident that their kids, at their age, can have a sustainable future.”*

Thus, his principal motivation for implementing DE initiatives at home is neither to be self-sufficient nor to demonstrate his own values, but to catalyse the rapid uptake of renewable energy systems in his community and beyond. To illustrate, his solar panels already generate more energy than his family needs, yet he now plans to install a 400 W wind turbine – at a height of 7 m above his roof. Since he lives on a main road, he will be making a public statement through the turbine's conspicuous presence. His activism has already motivated several other domestic consumers, including Richard and Cindy, as well as some small organisations locally, to install DE systems and reduce energy consumption.

From this perspective, implementing DE initiatives is not only "the right thing to do" as a responsible consumer, but also implicitly a political act designed to draw attention to the perceived need for rapid social change. Participants here appear to be motivated by the potential for their own actions to catalyse such change.

8.3.3 External motivations

As noted above, the theoretical model for this project includes a recognition that decisions are made within a broader context of external influences. Four interview questions, therefore, aimed to shed light, directly and indirectly, on participants' external motivations for implementing DE initiatives:

- In what way did/might financial incentives influence your decision?
- In what way did/might those around you (family, friends, neighbours, work colleagues) influence your decision?
- In what way did/might general social expectations influence your decision?
- In what way did/might the design of the technology itself influence your decision?
- Is there anything else that influenced, or might influence, your decision?

The following discussion of external motivations, therefore, is divided into consideration of three possible influences: economic factors, social and societal factors, and physical and technological factors.

Economic factors

For seven of the eight participants, economic factors appear to be a secondary consideration, or completely irrelevant, in their decisions to implement DE initiatives. David and Sara, for example, received a rebate for their solar hot water system, but said they would have installed this anyway, without a rebate. A common sentiment, therefore, was that any rebate was "a bonus" which did not alter intentions.

"I don't think government rebates influenced us; it was just a bonus." (Sascha)

While this may lead the effectiveness of rebates to be questioned, some participants were partly economically motivated by the prospect of reducing their electricity bills. Ivor and Anthea had recently installed ducted air conditioning, having found the extremes of their local climate increasingly difficult to withstand. However, their first subsequent electricity bill was $300 more than previous bills, a shock which acted as an incentive to install photovoltaic panels. Financial considerations were influential among three other participants who perceived that electricity bills are likely to increase significantly in the future, as carbon pricing takes effect and non-renewable resources become scarcer. For these participants, therefore, DE is an insurance against future electricity price increases.

In three cases, rebates appear to have been irrelevant. When John and Judy bought their first panels over 20 years ago, and when Greg bought his first panels over ten years ago, there was no rebate available. They both had the option of grid connection, but their rural location made the cost of infrastructure prohibitively expensive and so in part, their decisions were driven by financial considerations. Meanwhile, the cost of Matthew's wind turbine will be similar to that of his panels, but the energy generated will be considerably less, suggesting that economic considerations are irrelevant for him.

Interestingly, further probing elicited the finding that, for this study's participants, future expectations of rebates can act as a *negative* influence. Rebates rarely seem to have been a significant incentive for implementing DE, but capital cost constraints, combined with a perception that rebates are insufficient and/or might be increased in the future, seems to have *dissuaded* participants from implementing a DE initiative, or delayed their implementation. For example, John and Judy postponed upgrading their old system until a NSW rebate scheme had been extended to Queensland, providing a 75% rebate. Ian and Sascha described the 2007 increase in the Commonwealth rebate for photovoltaic panels, from $4,000 to $8,000, as "fortuitous", but added that it was motivating them to delay a purchase, in case of improved rebates in the future. Similarly, David and Sara currently have four panels, but need another four, and are waiting for the rebate to be increased. Meanwhile, Richard and Cindy said that they would like to install grid-connected photovoltaic panels, but that the rebate is insufficient currently, and that cost is the only factor preventing them from going ahead. The one exception was Ken, who described the rebate of approximately one third of the cost of his solar hot water system as a significant incentive:

> *"Once the rebate was there, it persuaded me."*

However, Ken also noted that current rebates still left photovoltaic panels unaffordable for his family. Even for Ken, though, financial considerations seemed more to *mediate* his internally-held motivations, rather than to determine his actions.

Social and societal factors

Participants largely considered that their decisions are internally driven, and that neither social factors (i.e., people around them), nor societal factors (i.e., wider norms and expectations), have had much, if any, influence. As John and Judy commented bluntly:

> *"We don't care what other people think."*

Ian and Sascha said that their family, friends and colleagues are all "mainstream" and "conventional", and had thought that they were mad to move to the eco-village:

> *"My family thought we were doing this crazy, nutty thing… They tried to persuade us to be normal… But we are normal for us; we're not greenies."*

However some participants did credit family members with having some influence. For example Ken cited his parents as having instilled an ethic of understanding the consequences of actions, which has guided him to "do the right thing". When Richard was growing up, his family lived in a house with stand-alone solar power. He says this made him highly aware of the energy he was using, and he learned by that example. Ultimately this influence has been mutually constitutive: Ivor and Anthea are Richard's parents, and they cited their son as a significant influence in their own decision. David and Sara also saw themselves as being influenced by their family, but in a different way. They were motivated not by pressure placed upon them by family members, but by the significance they themselves attach to caring for their own family.

Thus, no participants acknowledged any influencing role of wider norms and expectations, at either a community or societal level. Both Matthew and Richard, for example, explained that they were motivated to take action not by those around them, but by reading Tim Flannery's The Weather Makers. However, acting after reading this book is itself an example of being influenced by external motivations, even though such influences may not exemplify mainstream norms and expectations. It is arguable, moreover, that social norms and expectations operate at an unconscious level; we may not always be aware of external influences. The increasing public discussion around climate change, the environment and energy can be seen as part of an emerging discourse of sustainability. Since discourses not only reflect social practice, but also constitute it (Fairclough, 1992), our worldviews are all partly influenced, to a greater or lesser extent, by the discourse of sustainability. Thus, people may be unconsciously influenced by others' values, attitudes, beliefs, worldviews and opinions, and their consequent statements, at both a local and societal level. This may be particularly true in the case of those living among communities with relatively high environmental awareness, as Gardner & Ashworth's second theoretical proposition - they perceive support for the technology from within their community - suggests.

Physical and technological factors

Participants were asked to consider physical and technological factors associated with DE and showed different preferences. The majority (five of the eight), had limited concern with aesthetics. Rather than trying to hide the system, these participants' overriding objective is for the system to make a public statement through its presence. In effect, their views and actions constitute efforts to be agents of social change:

> *"I didn't care if it looked like an elephant on the roof! In fact, that might be a good thing." (Richard)*

Matthew has had to challenge builders who wanted to hide his systems, which he wants to be highly visible:

> *"I want it to be 'in your face'… It'll get people talking, stir up some controversy, generate some complaints, and get some interest from the media."*

At the same time, these participants also emphasised efficiency, durability and practicality. These are all more important than design aesthetics. For John and Judy, it is just a question of what systems are available technologically, and what equipment is the most durable. They would buy the best in the knowledge that they are fortunate enough to be able to afford it.

The other three participants were more conscious of design aesthetics. Ian and Sascha were pleased that the photovoltaic panels could be fairly well hidden. They also said that, while they were not much concerned with aesthetics initially, they were pleasantly surprised by the aesthetically-pleasing nature of their passive solar design features:

> *"Our intention was to have a practical, comfortable house, but we were really pleased with the designs. As it went up, we said 'Wow!', which we never had intended."*

Anthea was somewhat disappointed in the visual impact of their photovoltaic panels:

> *"I was quite sorry that [the panels] didn't look nicer. I've planted a tree near the pergola so, when we sit there, I don't have to look at the bloody things."*

Ivor and Anthea were also disappointed to learn that, if there were a blackout, being grid-connected means that they would also lose power. Nevertheless, their environmental values seemed to override these design concerns, and they repeatedly stressed that they did not regret their decision.

Thinking of mainstream technological adoption, Ken proposed that Australians have come to expect to receive whatever they want, and that for widespread acceptance, energy systems need to be both space-efficient and functional. Further, being concerned about design features and aspiring to be a change agent appear not to be mutually exclusive. For example, Ian and Sascha were the first residents in a new 'eco-village', while Ivor and Anthea's decision to install solar panels differentiates them in a fairly conservative country town.

8.3.4 Problems and solutions

In the course of the interviews, participants discussed some problems and obstacles they had experienced in implementing, or trying to implement, their DE initiatives. The final four interview questions were particularly designed to encourage discussion of problems and obstacles, and of possible solutions:

- Is there anything else that influenced, or might influence, your decision?
- What would be your ideal energy scenario personally?
- What kind of system would be appropriate more generally in other households?
- Is there anything else you would like to say?

The two participants with stand-alone solar systems identified obstacles to their DE aspirations. John and Judy would like to increase their battery storage, but are dissuaded because government rebates apply only to panels, not batteries. Greg, meanwhile, would prefer a grid-interactive system to stand-alone, for two reasons. Firstly, he has found the batteries to be both difficult and expensive to maintain. Secondly, his environmental values convey the view that he could achieve a greater aggregate contribution to sustainability by returning his excess generated energy to the grid. However, the prohibitive cost of grid connection, as noted above, makes this option unfeasible economically.

Those with grid-connected systems have also identified physical and economic obstacles. Physically, Anthea considers that the existing panels are something of a visual blight on their home, even though they are relatively hidden. Ideally, she would prefer smaller panels to do the same job. Economically, while acknowledging that their decision to install air conditioning imposed a heavy energy demand, she and Ivor are disappointed that the cost of the system appears to be substantially disproportionate to the resulting savings on the electricity bills. As a solution, they suggested that utility companies credit customers at a *higher* rate, per kWh, than that at which they charge, as happens in some European countries. Matthew, similarly, suggested that there would be a greater incentive for people to install grid-connected systems if energy companies undertook to buy back customers' power at a rate greater than 1:1. He noted that the rate in Germany is 4:1, motivating many in Germany to consider solar energy as their superannuation provision.

As another part of the solution, many participants advocated passive solar design as a standard, mandatory practice for all future homes and buildings, to reduce energy demand. The majority also support solar and wind as energy sources suitable for widespread installation. This is consistent with the household survey, which found that 85% of respondents would be willing to use solar panels as an energy source, and 61% would be willing to use wind power. Additionally, some noted that focusing on domestic installation overlooks other opportunities to mitigate climate change. As a solution, they proposed that it would be relatively simple to retrofit photovoltaic panels onto large buildings, such as schools and hospitals.

Greg and Ken both highlighted the potentially constructive role of regulation in supporting DE initiatives and encouraging passive solar design. Finally, both Matthew and Greg also advocated greater education on climate change, to embed understanding of the magnitude of the problem, and to encourage the development of solutions at an early age.

8.3.5 Conclusions and implications

In the Intelligent Grid literature review, Gardner and Ashworth (2007) distinguished between 'antecedent interventions', designed to increase knowledge and promote positive attitudes and intentions towards DE generation, and 'consequence interventions', based around incentives to increase the likely uptake of specific DE technologies. This study has found that both types of intervention may have a role, and that the effectiveness of an intervention may be contextual, depending on the relative influence of internal and external motivators for each individual.

In terms of internal motivators, the participants in this study suggested that three types of motivation may exist. Some participants are mostly motivated by an aspiration of self-sufficiency and energy-independence; others are mostly motivated by the opportunity to demonstrate their environmental values in their consumption choices; and others are mostly motivated by the prospect of catalysing social change through political statements which challenge dominant assumptions.

Most participants assert that economic factors are, at most, a secondary consideration, although economic considerations, such as the perception that rebates might increase later, do appear to have a potential negative influence. Similarly, participants largely consider neither social factors (i.e., people around them), nor societal factors (i.e., wider norms and expectations) to be influential. However, such norms and expectations may operate at an unconscious, discursive level. In terms of physical and technological factors, most are little concerned with aesthetics, but do value efficiency, durability and practicality.

Additionally, we can propose a tentative correlation between the relative significance of internal and external motivators. It appears that those who tend towards the 'self-sufficiency and energy-independence' end of the internal motivation continuum are more influenced by external motivators, whereas those who tend towards the 'catalysing social change' end of the internal motivation continuum are less influenced by these external motivators (see Figure 8.8). Thus, John and Judy, motivated internally by the prospect of energy-independence, are eager to buy the 'best' equipment, and delayed upgrading their system until the rebate was sufficiently generous. Conversely, Matthew is motivated internally by trying to catalyse social change, and appears least concerned by design aesthetics, technological specifications and cost.

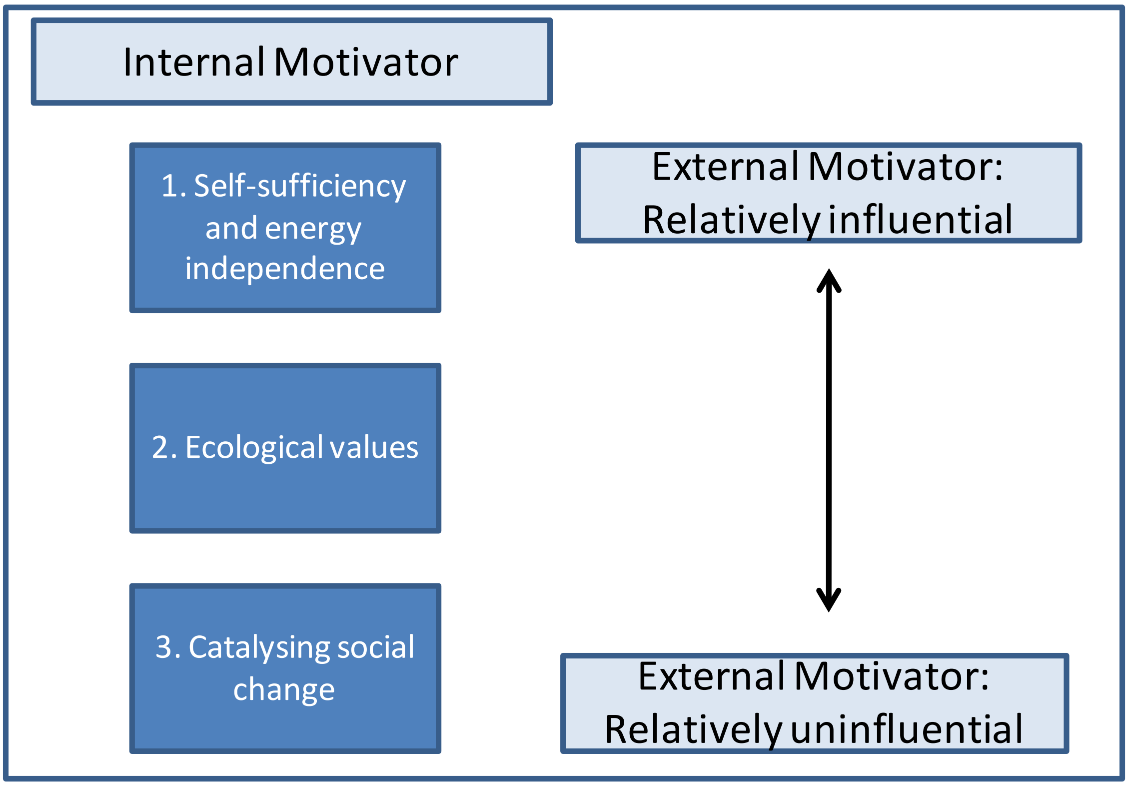


Figure 8.8: Linking internal and external motivators

However, lumping together all external motivators in this way perhaps oversimplifies the relationship with internal motivators. In practice, as described above, some external motivators are more influential than others. For example, while John and Judy appear to be somewhat influenced by economic and practical/technological factors, they appear to be less influenced by social/societal factors, as evidenced in the comment, "We don't care what other people think." Thus, the model in Figure 8.8 may be developed further in the light of subsequent research, in particular by incorporating urban residents.

Consistent with the household survey findings, most participants in this study claimed largely to be internally-motivated by environmental values, or by a sense that their actions exemplify a pro-environmental position, which might catalyse social change. However, this does not necessarily imply that DE will only be attractive to those with pre-existing pro-environmental values, especially when we consider motivations as something relatively open to discursive influence. People's motivations—both internal and external—are not necessarily fixed or given, but are subject to change. So while efficacious financial incentives help reduce barriers caused by a lack of capital, they don't necessarily motivate action. Action may be better motivated by education, normalising pro-environmental values, and by working collaboratively with innovators, early adopters and social change agents to transform DE into a mainstream energy supply option.

8.4 Australian organisations' propensity to accept DE.

Individual households and consumers constitute a relatively small percentage of total energy consumption across Australia. For this reason, for DE to significantly reduce Australia's emissions cost effectively, the attitude to DE of small and large businesses must be understood. For this reason, a survey of Australian organisations[9] was conducted to identify the types of organisations prepared to adopt demand management and distributed generation technologies.

The questionnaire was designed to be comparable in content and structure to the survey used for individual households described in Section 8.2 above. Respondents from organisations with more than one site were asked (and reminded throughout the survey) to reply for one specific site only.

The questionnaire contained five sections:

Section One: assessed reactions to an "automatic energy manager", an example of demand management technology

Section Two: assessed reactions to a "local electricity generator", an example of distributed generation technology

Section Three: measured details of electricity and water use for the particular site

Section Four: measured characteristics of the responding organisation (type, staff numbers, location, etc)

Section Five: assessed demographic details of the individual responding to the survey (age, gender, education, etc).

Questionnaire recipients were identified in three ways:

- A commercially-available mailing list of approximately 7,100 business decision makers was purchased; invitations to these people were sent via e-mail
- A list of email contacts (for the mayor or council manager) for 443 local councils in Queensland, NSW, Victoria and South Australia was created from government websites; invitations were sent via email
- A list of approximately 3,000 large electricity consumers (those with annual electricity bills greater than $10,000) was accessed from Origin Energy (Queensland), in return for providing feedback to Origin on the survey outcomes; these invitations were sent via post.

[9] Note that the term "organisation", as used throughout this report, is a general term that includes Local government and not-for-profit groups as well as commercial businesses.

The questionnaire was provided online and invitations were sent to recipients in July and August, 2007. Email invitations included a hyperlink within the message text to take recipients directly to the survey website. To comply with anti-spam legislation, email invitations also included a link to automatically remove the recipient's email from the mailing list. Posted invitations directed recipients to a simple web address which linked to the survey.

Web surveying of this sort involves several potential biases and problems. A major issue is attrition, as respondents drop out of the survey before completing it. Methods to minimise attrition include keeping the survey short and tightly focussed on important issues, convincing participants of the value of the research, and removing or reducing irrelevant questions. The survey used funnelling to ensure that only relevant questions were seen – e.g. if respondent said that a technology had no potential in their organisation, the next question asked why not, and questions asking them to rate importance of features of that technology were not displayed.

Several other steps were taken to improve the quality of responses to the survey. Potential participants were sent a personalised email or letter highlighting the importance of the survey and asking for their participation. Participants were assured of the anonymity of their responses, and were offered the chance to win one of five $100 shopping vouchers if they completed the survey. Potential bias due to order of presentation was addressed by randomising the order of response options between surveys.

The nature of this survey assumes that the individual responding is capable of responding on behalf of the organisation, and has a sufficient understanding of their organisation's needs. However, it is recognised that it is difficult for individuals to be completely objective in their answers, and some response bias is possible. The survey instructions outlined the sort of information required to answer the questions, and suggested that the survey link be passed on to the appropriate person if the recipient did not have the required information/expertise.

A total of 462 usable surveys were completed. As is typical for web-completed surveys, later questions in the survey had more missing data: as people progressed through the survey they were increasingly likely to stop, leaving the rest of the survey unanswered. Incomplete responses were included where there were sufficient answers to allow some analysis, as the sample was judged too small to allow for the valid replacement of missing data.

The sample, although not large enough to be judged truly representative of Australian organisations as a whole, does reflect a broad cross-section of organisational characteristics, including staff numbers, type of organisation, and electricity consumption.

8.4.1 Organisational characteristics

The State where each organisation operated was identified via postcode, and is summarised in Table 8.15. The majority of completed surveys were received from NSW/ACT (39%) and Victoria (36%). Seventeen percent of the survey sample came from Queensland and 7% from South Australia. The single respondent from Western Australia was excluded from the sample for statistical analysis.

Table 8.15: State where the organisation's site is located

State	Frequency	Percent
NSW/ACT	144	38.9
Victoria	135	36.5
Queensland	63	17.0
South Australia	27	7.3
Western Australia	1	0.3
Total	370	100.0

Note: 92 people did not provide a postcode.

Organisational classification was assessed via a menu of options; results are displayed in Table 8.16. Government and manufacturing organisations represent the largest groups in the sample, although a wide range of other organisational types are represented. The nine organisations listed as "other" included trade unions, conservation organisations and research institutions.

Table 8.16: Organisational classification (ANZSIC Code)

How would you classify your organisation?	Frequency	Percent
Accommodation, cafes and restaurants	16	4.3
Agriculture, forestry and fishing	9	2.4
Communication services	8	2.2
Construction	2	0.5
Cultural and recreational services	10	2.7
Education	19	5.1
Electricity, gas and water supply	7	1.9
Finance and insurance	30	8.1
Government administration and defence	83	22.5
Health and community services	19	5.1
Manufacturing	76	20.6
Mining	6	1.6
Personal and other services	13	3.5
Property and organisation services	17	4.6
Retail trade	13	3.5
Transport and storage	15	4.1
Wholesale trade	17	4.6
Other	9	2.4
Total	369	100.0

Note: 93 people did not answer.

Number of employees was used to classify organisations into small, medium and large as per the cut-offs used by the Australian Bureau of Statistics (2007), and these categories are displayed in the table below. The median staff size was 140, and responses ranged from 2 (an accounting firm) to 5,000 (a university). Two responses listed staff numbers higher than this figure, but it was apparent that the respondent had listed staff from multiple sites, rather than just a single site, so these responses were excluded from the variable before analysis. Because the variable was substantially positively skewed, it was log transformed for statistical analysis.

Table 8.17: Organisation size

How many people does your organisation employ at this location?	Frequency	Percent
Small (up to 19 staff)	30	8.2
Medium (20 to 199 staff)	194	52.7
Large (200+ staff)	144	39.1
Total	368	100.0

Note: 94 people did not answer.

Annual turnover ranged from \$100,000 (a hospitality business) to \$3 billion (an oil refinery). Some respondents listed company-wide turnover rather than specific site turnover, and where this was obviously the case, these values were excluded before analysis. The median turnover value was \$30 million. Because of the highly skewed distribution of this variable, it was log transformed for statistical analysis.

Annual cost of grid-supplied electricity ranged from \$123 (local council chambers) to \$37 million (a mining company). The median annual cost was \$109,000. Because of the highly skewed distribution of this variable, it was log transformed for statistical analysis.

Electricity intensity was calculated as grid-based electricity costs as a proportion of the organisation's total turnover. This measure was created to reflect the relative importance of grid-supplied electricity to each organisation. The median value of this measure was 3.5%, and values ranged from 0.01% (a State government treasury) to 11.45% (a glass and metal manufacturing plant). One value of 27.5% for this variable was assumed to reflect an error in reporting of either turnover or electricity cost, and was excluded from analysis. Because of the highly skewed distribution of this variable, it was log transformed for statistical analysis.

Other power sources were assessed. In particular, respondents identified if their site had a backup power generator (true for 111 respondents) and if they usually provided some of their own electricity (true for 19 respondents).

8.4.2 Results

Analyses were designed to provide a descriptive evaluation of organisations that were more likely to adopt the demand management and distributed generation technologies, and so statistical tests were conducted on pairwise relationships, rather than more complex multivariate relationships. Pairwise analyses used bivariate correlations, chi-squared tests and one-way analyses of variance as appropriate. A conservative significance level of $p < .01$ was adopted, to counteract the increased error rate caused by conducting multiple tests across the same group of variables.

Results of these analyses are presented in separate sections for demand management and distributed generation technologies. In both sections, predictors of acceptance are described, followed by ratings of the importance of specific features, and written comments regarding issues relevant to adoption.

Acceptance of demand management technology

In total 91.6% of respondents said that an 'automatic energy manager'[10] had the potential to be used in their organisation. These respondents also provided a rating of the likelihood that their organisation would be prepared to use this technology. The combined results of these two questions are summarised in the table below. A total of 51.0% of respondents thought that uptake by their organisation was likely or very likely. To simplify the descriptive analyses, organisations were classified into one of three groups:

- No potential (those that identified no potential for the use of an automatic energy manager)
- Low potential (those that gave ratings of "very unlikely", "unlikely" or "possible"), and
- High potential (those that considered their organisation "likely" or "very likely" to adopt an automatic energy manager).

Table 8.18: Acceptance of demand management technology

Overall, how likely is it that your organisation would be prepared to use this sort of automatic energy manager?	**Frequency**	**Percent**
No potential	38	8.4
Very unlikely	20	4.4
Unlikely	14	3.1
Possible	150	33.1
Likely	136	30.0
Very likely	95	21.0
Total	453	100.0

Note: 9 people did not answer.

[10] The concept of an automatic energy manager was described in the survey. The concept described a device that would measure and monitor energy consumption, be easy to use and install, and would optimise the timing of energy consumption within the business realising financial and emission savings.

Both respondent characteristics and organisational characteristics were tested as potential predictors of acceptance of demand management technology. Respondent characteristics included age, gender and education. There were no differences in acceptance of demand management technology related to respondent age, education level, or gender. This result is encouraging, suggesting that individual respondents were not providing biased reactions to the survey based on their own characteristics.

Continuous-scaled organisational characteristics included: number of employees, annual turnover, annual electricity costs, and the electricity intensity measure described above. Summaries of these variables for the three levels of acceptance of demand management technology are provided in the table below.

Statistical testing of the relationship between these characteristics was based on the original acceptance measure and the log transformed version of the characteristics above. Test showed significant positive associations between acceptance and number of employees, annual turnover and annual electricity cost. Since these measures all reflect organisational size, a general conclusion to be drawn here is that larger organisations are more likely to report acceptance of demand management technology. However, it must be noted that some smaller organisations also appear in the high potential group – organisational size is not the only predictor of acceptance.

Table 8.19: Characteristics of organisations described according to acceptance of demand management.

Acceptance of DM technology	Statistic	Number of Employees	Annual Turnover ($M)	Annual Electricity Cost ($k)	Electricity intensity (%)
No potential	Mean	170.6	251.29	698.00	1.25
	Median	55.0	16.00	50.00	0.30
	Range	2 to 1,500	0.35 to 3,000	1 to 9,000	0.01 to 5.86
Low potential	Mean	257.6	76.64	276.88	0.93
	Median	95.5	20.00	58.50	0.33
	Range	2 to 3,000	0.1 to 1,000	0.6 to 2,600	0.01 to 8.64
High potential	Mean	358.5	151.70	953.22	0.94
	Median	180.0	60.00	132.00	0.40
	Range	5 to 5,000	0.6 to 1,734	0.12 to 37,000	0.01 to 11.45

Note: Because these variables were all positively skewed, the median is a more informative measure than the mean.

Categorical organisational characteristics included State, classification, and access to other power sources. There were no differences apparent in the acceptance of demand management technology for organisations across States, or for those with and without access to other power sources. Acceptance of demand management appeared to differ markedly across organisational classification, but many specific classifications had small sample sizes which precluded a statistical analysis of these differences. Acceptance of demand management appeared to be highest for mining, construction, and health and community service organisations, and lowest for accommodation, cafes and restaurants, personal and other services, and agriculture, forestry and fishing organisations (see Figure 8.9).

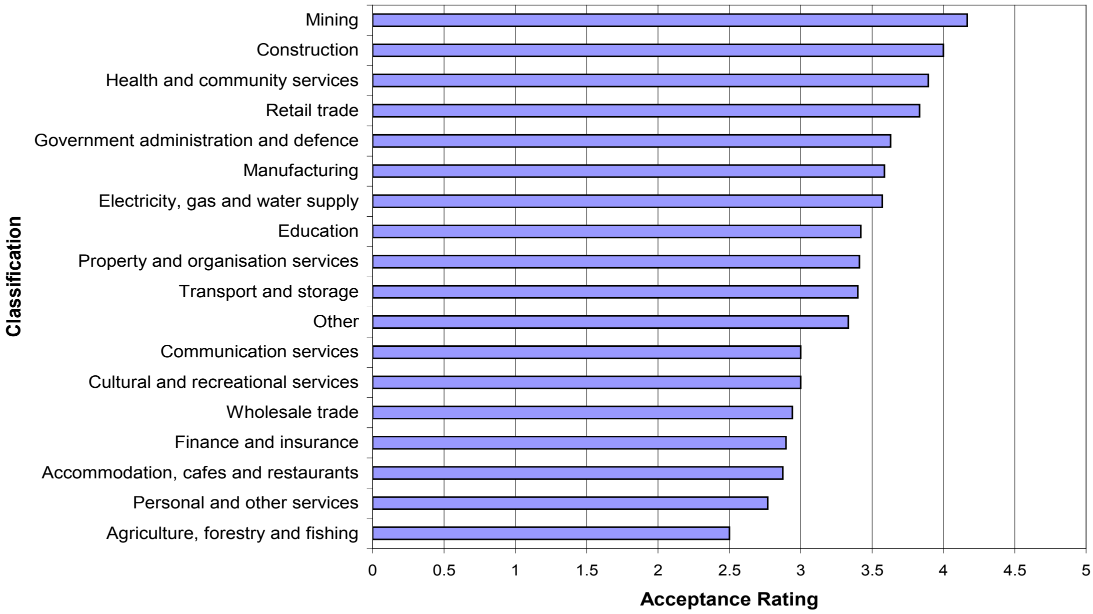


Figure 8.9: Acceptance of demand management for different organisational classifications (rated from 0 = no potential to 5 = very likely to adopt).

Perceived importance of demand management features

To understand the relative importance that people placed on various features of demand management technology, 12 features were assessed using Likert scales. The features were developed via a review of technical features and focus group work and were:

- Cost to install
- Ease of installation
- Ease of use
- Improved energy efficiency
- Interruptions to electricity supply
- Level of control over the device
- Potential government incentives
- Reduction in overall emissions
- Reliability and durability
- Safety levels
- Savings over time, and
- Time until return on investment.

Ratings of the relative importance of these features are displayed in Figure 8.10. Across the sample, improved efficiency, safety, interruptions to supply and reliability/durability were all rated as important, while ease of installation, cost to install, time until return on investment and potential government incentives were rated as least important. Although they prioritised features similarly, respondents with high acceptance attached relatively more importance to energy efficiency and reduction in emissions, whereas respondents with low acceptance attached relatively more importance to cost to install, return on investment and potential government incentives.

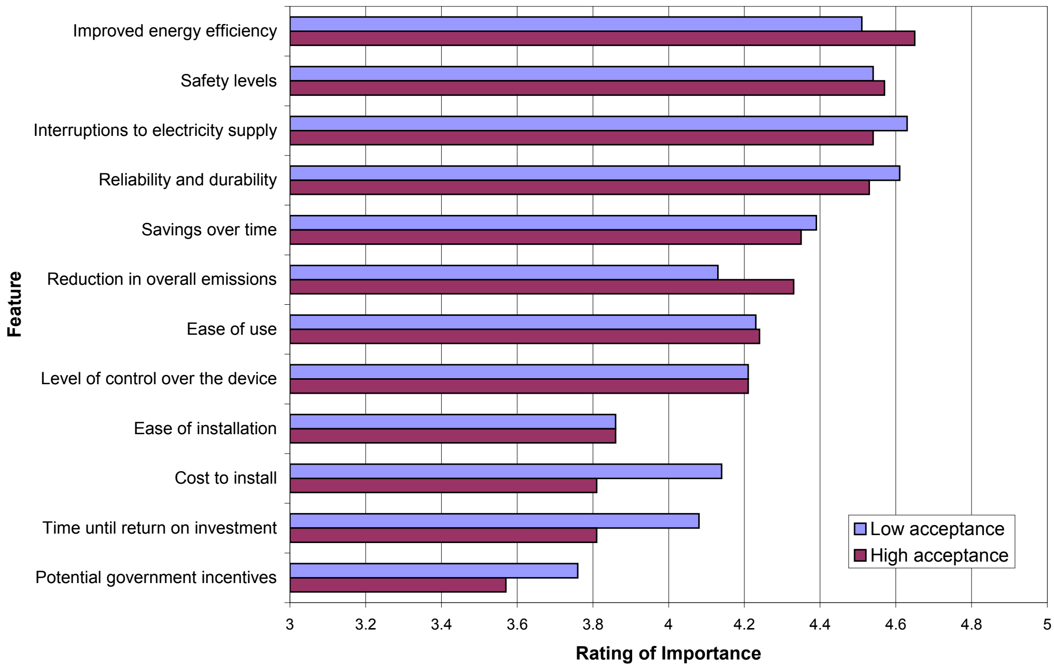


Figure 8.10: Rated importance of various features of demand management technology (original scale rated from 1 = not at all important to 5 = very important).

Barriers and other issues

Respondents who reported that there was <u>no potential</u> for demand management in their organisation were asked to explain why. Respondents who reported <u>some potential</u> for acceptance were asked to list other issues that would influence their organisation's decision (beyond the 12 features listed in the survey). A total of 131 respondents listed one or more issues, which were categorised into themes, and are summarised in Table 8.20.

Table 8.20: Themes from written comments about demand management technology

Issue Type	Theme	Description
Contextual issues	Approval	The use of the system would require approval from outside agencies, either government bodies and/or building/site owners in cases where the organisation was leasing
	Support	Would benefit from government incentives, would need to understand how it linked to the NSW State government Energy Savings Action Plan, would like to get recognition from electricity retailer in the form of reduced rates.
	Proof	Would like some guarantee of return on investment, would like to see a demonstration system already running, would like a recommendation from relevant professional associations, would need to see a cost comparison with alternative options.
Organisational issues	Interruptions to supply	Interruptions to supply are unacceptable given the nature of the organisation
	Relevance	Organisation already has a similar system in place
	Advantages	Would replace a number of separate devices currently used, would promote the organisation as environmentally responsible, would promote community recognition, would link with the organisation's existing sustainability policy.
	Scale	The organisation's electricity load is too small to make such a system worthwhile
	Site suitability	The system isn't suitable for a leased space.
Product-specific issues	Costs	Upfront installation cost, savings over time, time until return on investment, cost/benefit analysis, ongoing costs of maintenance and upgrading, staff time and training to control/monitor the device.
	Performance	Ease of use, reliability, accuracy, reaction time to changes in environment, need ongoing data on performance, need offsite access and to be able to program operational priorities.
	Compatibility	Capacity to be integrated with old plant equipment and existing building management systems, needs to be transparent to normal operation of the organisation

Acceptance of distributed generation technology

In total 64.9% of respondents said that a local electricity generator had the potential to be used in their organisation. These respondents provided a further rating of the likelihood that their organisation would be prepared to use this technology. The combined results of these two questions are summarised in the table below. Only 18.9% of respondents thought that uptake by their organisation was likely or very likely. To simplify the descriptive analyses, organisations were classified into one of three groups:

- No potential (those that identified no potential for the use of a local electricity generator)
- Low potential (those that gave ratings of "very unlikely", "unlikely" or "possible"), and
- High potential (those that considered their organisation "likely" or "very likely" to adopt a local electricity generator).

Table 8.21: Acceptance of distributed generation technology

Overall, how likely is it that your organisation would be prepared to use this sort of local generator?	Frequency	Percent
No potential	156	35.1
Very unlikely	18	4.1
Unlikely	28	6.3
Possible	158	35.6
Likely	51	11.5
Very likely	33	7.4
Total	444	100.0

Note: 18 people did not answer.

Statistical analyses were carried out to explore whether acceptance of distributed generation technology was related to either respondent or organisational characteristics. There were no differences in acceptance of distributed generation technology related to respondent age or education level. However, male respondents reported higher average acceptance of distributed generation technology than did females. It is possible this finding reflects a bias in individuals' responses (i.e. males are more accepting of generators than females), or a bias in the gender distribution of employees in certain organisations (i.e. organisations more likely to accept generators also hire more males).

Continuous-scaled organisational characteristics included: number of employees, annual turnover, annual electricity costs, and the electricity intensity measure described above. Summaries of these variables for the three levels of acceptance of distributed generation technology are provided in Table 8.22.

Table 8.22: Characteristics of organisations described according to acceptance of distributed generation

Acceptance of DG technology	Statistic	Number of Employees	Annual Turnover ($M)	Annual Electricity Cost ($k)	Electricity intensity (%)
No potential	Mean	169.5	108.63	257.98	0.67
	Median	60.0	20.00	35.00	0.20
	Range	2 to 2,400	0.1 to 3,000	1 to 9,000	0.01 to 6.67
Low potential	Mean	324.5	152.76	880.17	1.21
	Median	160.0	47.50	165.00	0.53
	Range	4 to 3,000	0.3 to 1,734	0.12 to 37,000	0.01 to 11.45
High potential	Mean	541.6	157.98	868.72	1.10
	Median	235.0	60.00	225.50	0.58
	Range	2 to 5,000	0.6 to 1,200	1 to 12,000	0.01 to 6.42

Note: Because these variables were all positively skewed, the median is a more informative measure than the mean.

Statistical testing of the relationship between these characteristics was based on the original acceptance measure and the log transformed version of the characteristics above. Tests showed significant positive associations between acceptance and number of employees, annual turnover, annual electricity cost and electricity intensity. As for demand management, acceptance of distributed generation appears to be higher for larger organisations. But in addition, organisations with higher electricity intensity (in which electricity is a larger cost relative to overall turnover) also reported higher levels of acceptance of distributed generation.

Categorical organisational characteristics included State, classification and access to other power sources. There were no differences apparent in the acceptance of distributed generation technology for organisations in different states, or for those with and without access to an emergency generator. However, organisations who already routinely supplied their own power tended to report higher acceptance of distributed generation technology (average acceptance rating 3.9) than those who used grid-supplied power only (average acceptance rating 3.2).

Further, acceptance of distributed generation appeared to differ markedly across organisational classification, but many specific classifications had small sample sizes which precluded a statistical analysis of these differences. Acceptance of distributed generation appeared highest for mining, health and community services, and manufacturing, and lowest for construction, finance and insurance, and personal and other service organisations (see Figure 8.11).

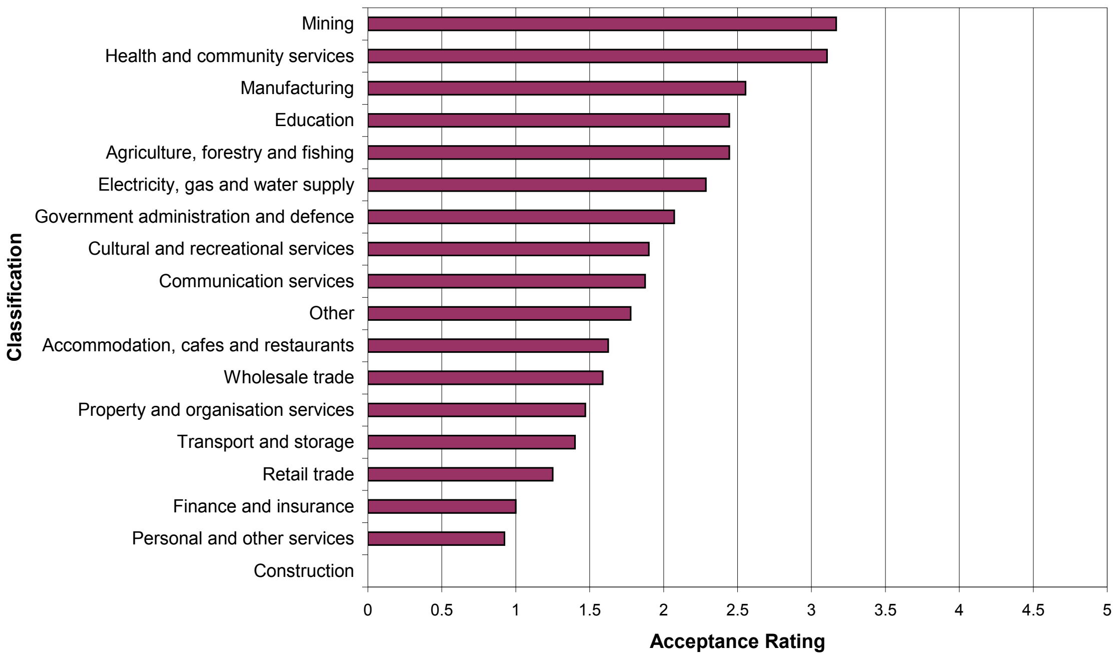


Figure 8.11: Acceptance of distributed generation for different organisational classifications (rated from 0 = no potential to 5 = very likely to adopt)

Perceived importance of distributed generation features

To understand the relative importance that people placed on various features of distributed generation technology, 13 features were assessed using Likert scales. The features, which were developed via a review of technical features and focus group work, were:

- Cost to install
- Ease of installation
- Ease of use
- Improved energy efficiency
- Noise levels
- Potential exhaust fumes
- Potential government incentives
- Reduction in overall emissions
- Reliability and durability
- Safety levels
- Savings over time
- The generator's energy source
- Time until return on investment.

Ratings of the relative importance of these features are displayed in the figure below. Across the sample, safety levels, improved efficiency, and reliability/durability were all rated as important, while the generator’s energy source, ease of installation, and potential government incentives were rated as least important. Comparing ratings from respondents with high acceptance and those with low acceptance shows some differences: those with high acceptance rated energy efficiency as more important, and cost to install, noise levels, the generator’s energy source and potential government incentives as less important than did those with lower acceptance of the technology.

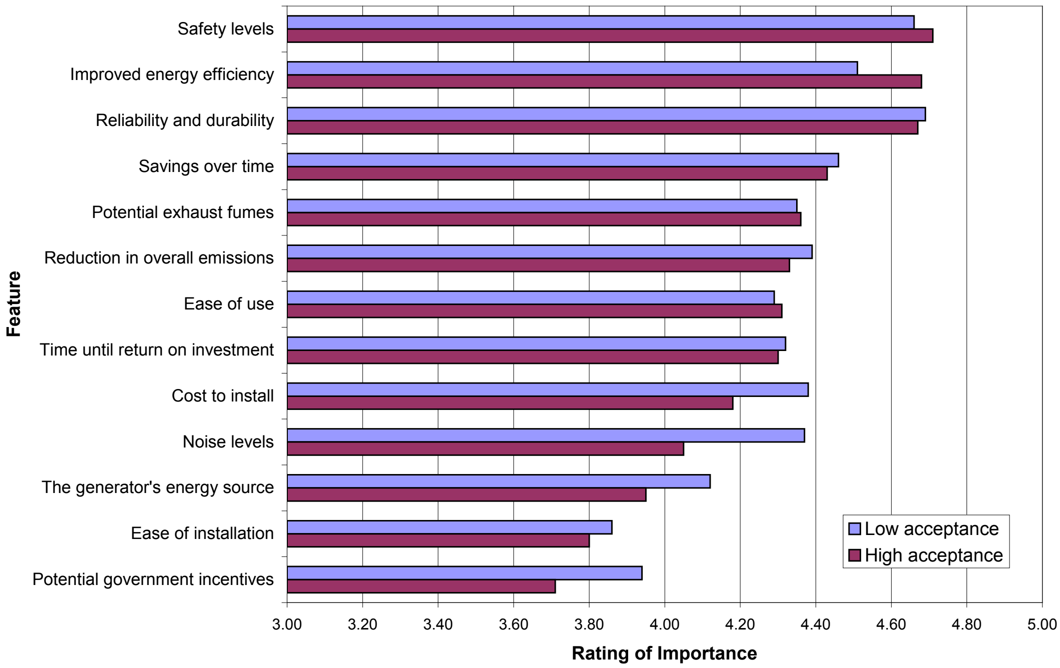


Figure 8.12: Rated importance of various features of distributed generation technology (original scale rated from 1 = not at all important to 5 = very important)

Barriers and other issues

Respondents who reported that there was no potential for distributed generation in their organisation were asked to explain why. Respondents who reported some potential for acceptance were asked to list other issues that would influence their organisation's decision (beyond the 13 features listed in the survey). A total of 84 respondents listed one or more issues, which were categorised into themes and are summarised in Table 8.23 below.

Table 8.23: Themes from written comments about distributed generation technology

Issue Type	Theme	Description
Contextual issues	Approval	Installation would require approval from building/site owners in cases where the organisation was leasing
	Support	Would benefit from government incentives.
	Distrust	Not trialled in other areas, uncertainty regarding costs/maintenance, not convinced it would deliver claimed benefits
Organisational issues	Scale	Don't use enough electricity, base load is too large for this technology, company has minimal budget for energy efficiency initiatives
	Relevance	Organisation already has a similar system in place
	Nature of site	Unsuitable for tenants in shared space, building structure not suitable, CBD location unsuitable, leased site not suitable, residential site not suitable, insufficient space.
Product-specific issues	Energy source	Would only be interested if used solar/other renewable power.
	Cost	Cost to install, cost too high relative to benefits, up front capital cost, time to return on investment, savings over time, ongoing maintenance/ staffing costs
	Environmental concerns	Potential exhaust fumes, environmental health issues, noise levels, emissions

8.4.3 Paths to adoption

Figure 8.13 summarises a range of drivers and barriers to organisational adoption of distributed generation and demand management that have been identified in the current research. From these, we can identify a range of actions that could be undertaken to promote adoption, either removing barriers or strengthening drivers.

Generic actions include: implement incentives and advertise them; provide more detailed explanation of technology and potential savings (along with working demonstrations); explore potential permission from building owners; or market these products to building owners directly.

More specific actions include targeting: electricity intensive organisations; organisations moving to new sites, and organisations that own commercial and industrial sites; organisations that are large enough (but not too large) to benefit from distributed generation and demand management.

To address issues associated with distributed generation and demand management products, actions include: provide more detailed information on performance; explain emissions benefits in more depth; explore compatibility with older systems; promote perceived advantages (environmental responsibility, potential to replace multiple separate control devices); reduce upfront costs (including via incentives); address environmental impacts of DG (noise, exhaust); explain non-intrusive supply interruptions for DM.

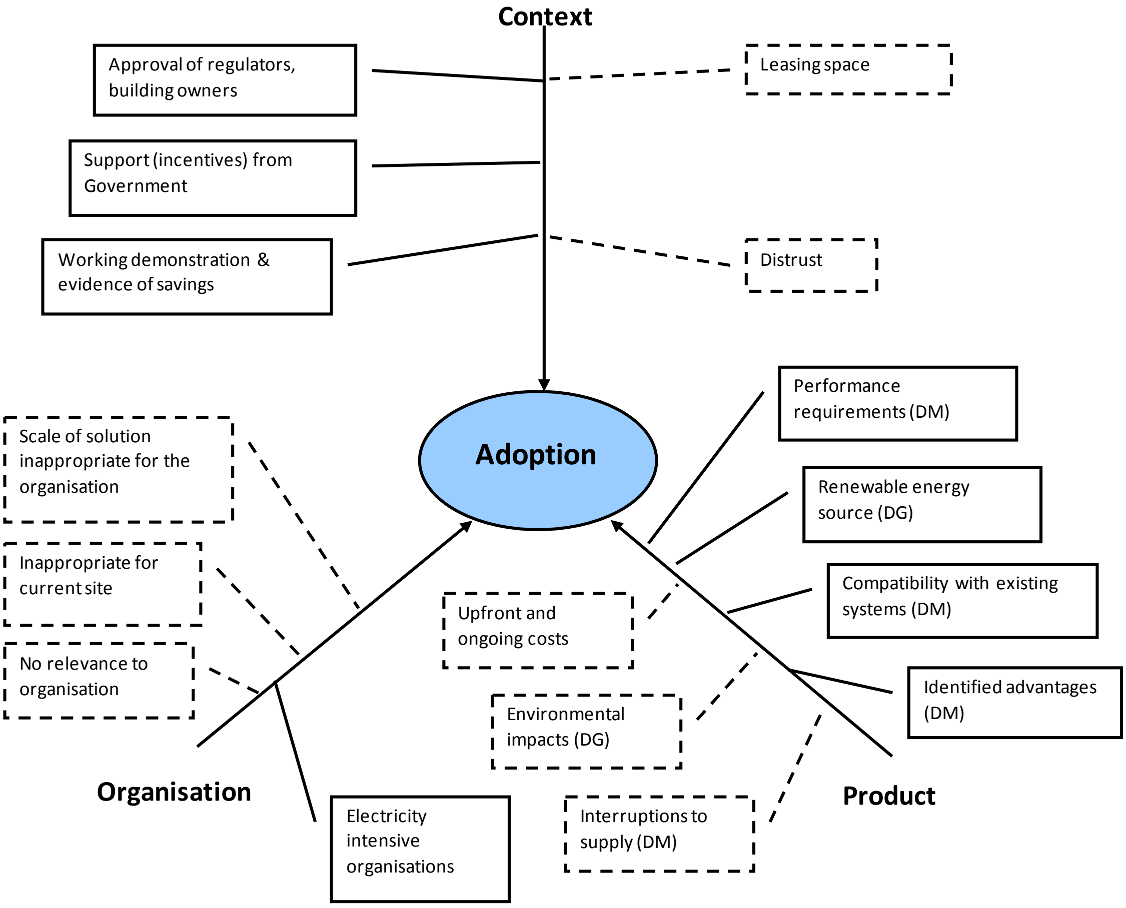


Figure 8.13: Map of the drivers (solid lines) and barriers (dashed lines) to adoption of distributed generation (DG) and demand management (DM)

8.4.4 Conclusion

The results of the study have identified a number of issues associated with the adoption of distributed generation and demand management technologies by Australian organisations. Organisations most likely to adopt the technology are relatively large, and so have large energy consumption. However many small businesses also appear likely to adopt DE. Therefore targeting large energy users may help maximise the impact of DE, but the DE market is not likely to be limited to large energy users.

A range of barriers and drivers were identified and many reinforce the importance of enablers discussed in Chapter 7. While financial payback periods are important, safety, efficiency and reliability were typically the most important features of demand management and distributed generation technology. To ensure these features are met, support for technology development, industry capacity and skills are key enablers, as well as education to overcome any unsubstantiated fears customers may have.

8.5 DE projects and case studies

The following case studies describe DE projects and provide insights into how efficient levels of DE can be encouraged and implemented. They help describe the real world implications of barriers and enablers discussed to date.

8.5.1 Solar bulk buying

Research presented here is part of a longitudinal study, aiming to document and assess the issues associated with large-scale uptake of solar PV systems. An interim CSIRO report published in June 2008, discusses the findings from interviews prior to installation (Parsons and Ashworth, 2008). Research presented here revisits these issues to track progress in the project and changes in participants' experiences, opinions, and behaviour.

In 2007, a bulk-buying solar photovoltaic (PV) programme started in regional New South Wales. The programme offered householders a fully-installed, grid-connected, 1kW solar PV system for $499, as long as 50 households in the neighbourhood signed up. Subsequently, the price was increased to $895, although it has recently returned to $499 following a reduction in the global price of silicon. There is an option to install larger systems, though these are not promoted heavily, and they cost substantially more. The programme is managed by a private company whose website claimed that $895 represented less than one eighth of the normal retail price, and that it could achieve this by dealing directly with manufacturers, and by buying and installing in bulk. A Neighbourhood Coordinator was appointed to recruit the 50 householders in each neighbourhood, and to liaise between householders and the company throughout the process.

Originally, the company managed the rebate applications on behalf of householders, submitting applications in bulk to the Australian Greenhouse Office (a section of DEWHA, now the Department of Climate Change; DCC) for processing. This represented a significant value proposition, as it meant that applicants did not have to pay the full cost upfront and wait for the rebate to be processed, as was the case ordinarily. However, following an overwhelming response and the introduction of means testing[11] in the 2008 federal rebate, the company found that it was unable to bear the cost of waiting for the rebates to arrive. To manage this, it introduced alternative neighbourhood funding models and currently potential neighbourhoods must either find a sponsor, or comprise 50 self-funding households. This means householders must now pay $8,499 up front, and will receive the $8,000 rebate after installation if eligible.

At the time of interviews for this report (February 2009), approximately 250 households had their systems installed, but several hundred more had been awaiting installation for many months. The latter have been asked retrospectively to pay $8,000 to accelerate their installations, and 20% have agreed to do so. The company has negotiated a low-interest loan with a local Credit Union for householders unable to find the money independently. Eligible householders receive this $8,000 back when the rebate has been approved and processed.

[11] The means-tested rebate will be replaced by the new Solar Credits scheme from 1st July 2009.

Method

For the interim report, eleven householders were interviewed: eight who were taking up the bulk-buying solar offer, and three who had initially expressed interest but decided not to proceed, citing various concerns and suspicions. For the follow-up process, ten months after the initial interviews, CSIRO re-contacted the eight households. It soon transpired that only five of these had had their systems installed. These participants, therefore, were sent follow-up interview questions, which were used in a semi-structured manner. This represents 'complete collection' sampling, a qualitative research technique in which the sample is delimited by certain criteria defined in advance. While this sampling restricts the space for developing a generalised theory, it enables us to learn more about a specific group of cases (Flick, 2002; Gerhardt, 1986). One of the five declined to participate, because of an acute, debilitating illness, leaving four household participants. While this small number restricts the capacity to make claims with broad validity, tracking a small number of cases over time enables us to obtain insights into specific situations.

In addition, six follow-up interviews were held with other stakeholders including:

- The company's CEO
- Two installers who had worked for the company
- Two energy companies operating locally (comprising two company managers and one regional inspector).

All ten interviews were conducted by telephone.

Issues for the company

In interviews for the interim report, company staff identified five key issues, or challenges, that they had encountered. These issues were:

- *Public scepticism* – the sentiment that the offer was 'too good to be true'
- *Organisational challenges* – dealing with the overwhelming response from potential customers, and managing staff in a growing organisation
- *Government bureaucracy* – an unwieldy application process for rebates, and confusion regarding responsibilities between government departments and agencies
- *Conservatism of finance institutions* – reticence regarding risk-taking within Australian financial institutions
- *Relationships with energy companies* – securing cooperation from organisations unaccustomed to the company's business model
- *Changes to the rebate regime* – upheaval resulting from the introduction of the means test, an unanticipated development that fundamentally threatened the company's business model.

For the final report, CSIRO again interviewed the company's CEO. The discussion this time can be divided into three areas:

- *An overview of the current status*. This form the basis of much of the background discussion above
- *A list of organisational and business challenges*. These are essentially operational matters that merely update some of the above issues, and are not considered relevant to this report
- *Policy and regulatory issues*. These are detailed below.

Policy issues

Uncertainty regarding rebate policy direction
The company has found that the changes to the rebate regime have led to a permanently high degree of uncertainty about policy direction. This has made it difficult to organise the business, and that it is always necessary to prepare for contingencies. This is not a complaint about DEWHA, which has been "helpful when we've needed help", but now "it's difficult to understand their direction".

Delays in processing rebates
The company has become very frustrated at the perceived tardiness in both approving and disbursing rebates. It claims that this has added 4½ - 5 months to the installation process, leading to the withdrawal of the original business model in place of having to ask householders to pay another $8,000 up front. This disadvantages low-income households, who cannot afford to pay the deposit and/or cannot obtain a loan. In the absence of these delays, the CEO claims that the volume of business could easily be multiplied tenfold.

General lack of government support
In the light of the above issues, the company senses a general lack of support from government. The CEO states that delays in processing rebates and successive changes to the rebate regime convey a suspicion that the government is, perhaps unwittingly, hampered by the strength of the coal lobby, and in turn thwarting the solar industry. The CEO proposes that a more supportive regime would comprise a gross feed-in tariff at around at 63c/kWh. (Note that this figure is somewhat lower than the 80c/kWh minimum cited by renewable energy company, Energy Matters, in its National gross feed-in tariff campaign: see http://www.feedintariff.com.au/).

Regulatory issues

Inverters
The CEO stated that, at present, only one type of inverter is listed as approved in Australia, and that this inverter includes a transformer. He argued that more flexibility is needed, as the company could have installed a better and cheaper inverter that does not include a transformer.

Certification standards
The company welcomes the higher standards for panels (IEC 61730) expected in June 2009. In general, having stringent requirements for certification of panels is desirable.

Occupational health and safety standards
The company has found OHS standards to be somewhat unclear and therefore open to interpretation. When new OHS regulations were introduced in 2008, it appeared initially that all installations might require edge restraints and safety harnesses, a requirement that would impose extra costs on customers. However, it turned out that this would apply only to certain households (*viz.*, two-storey buildings, and those where the roof pitch is greater than 30°). Nevertheless, these new regulations have applied in over 50 cases so far, meaning that the company has had retrospectively to increase the contract price for these customers.

Issues for householders

As explained above, of the eight households who subscribed to the programme and were interviewed for the interim report, three had not had their systems installed at the time of writing this report. Of the other five, one declined to participate, leaving four participants in follow-up interviews. Three of these four had purchased the basic 1 kW system for $499, but one participant had opted for a 5 kW system, at the substantially higher cost of $32,500. The following questions were used as a guide in semi-structured interviews:

- When did your installation take place? Did this mean a longer wait than you had anticipated?
- During installation, did any new problems or obstacles arise?
- Are you happy with the system (e.g., quality of panels, ease of operation, aesthetic appearance)?
- Are there any problems with the system?
- Has the system reduced your electricity bills? If so, how does the reduction compare with your prior expectations?
- Did the change in the federal rebate (means testing) affect your situation?
- Has ownership of the system altered your energy use more generally?
- Now that you have installed a small PV system, how would you describe you ideal energy scenario?

These responses can be grouped into five categories: overall impressions of the system; installation practicalities; the amount of energy generated; changes in energy-use behaviour; and future intentions and aspirations. With regard to question 6, none of the participants were affected by the change in the federal rebate, so this is not discussed further.

Overall impressions
As noted in the interim report, some householders had anticipated that the potential drawback of a relatively cheap product would be that the quality of the system may be suboptimal. The company has had to spend a considerable amount of time countering the scepticism that the offer was “too good to be true”. In the event, all four householders reported that they were

happy with the standard of the systems, and with their functionality. The quality seemed to be satisfactory, and the systems had required no maintenance hitherto. Two householders noted that their systems had survived hailstorms intact. Given that much of the earlier scepticism was based on there being no visible verification that the company could actually deliver what it was promising, this physical evidence is potentially significant in accelerating further bulk-buying programmes.

Installation practicalities

All four householders had bought into the programme around November 2007, and understood that the 'worst case scenario' was that installation would be six months away. Two of the systems (including the 5 kW system) were installed in July 2008, one in August, and one in November. Of these four householders, two expressed disappointment that the wait had been considerably longer than expected. The householder whose system was installed in November, a year after registering, was particularly frustrated by the company's failure to communicate adequately the reason for successive delays. The other two seemed more relaxed about the delay, apparently having anticipated that a new business model would encounter unforeseen obstacles. Thus, it appears that prior expectations played a crucial role in mediating householders' impressions of the programme, and that the company has some, though not exclusive, influence over these expectations. However, it is not clear why some householders anticipate unforeseen obstacles, while others are more influenced by company statements.

The company's business model was based originally on the assumption that an installer could install three systems per day on average. However, as noted in the interim report, many doubted the attainability of this target, and the four installations reported here support this doubt. Two of the systems were installed in half a day each. A third took one and a half days, and the fourth required "four or five" visits over several weeks, because of logistical complications. Clearly, longer installation times imply higher costs, particularly for contractors paying employees, and a sustainable bulk-buying solar programme therefore depends on realistically estimating installation times.

Energy generated

In research for the interim report, it was found that householders' power use averaged 14 kWh per day. There had been some confusion regarding the likely generating capacity of the systems, with many householders confusing kW with kWh. Most anticipated that the system would generate 25-40% of their energy use, but these figures were based on company estimates, not householders' calculations.

For the present report, participants were asked to consult readings on their new meters, and/or recent electricity bills. The total amount generated was then divided by the relevant number of days of operation to calculate the average amount generated per day. They were then asked to compare these actual outcomes with their prior expectations.

The responses here cannot be treated equally, because one householder had installed a much larger system than the other three. The former calculated that his 5 kW system had generated an average of 20.11 kWh/day, and that his recent electricity bill had been half the usual amount (his power supplies three separate buildings). Of the remaining three, there was considerable variation. One had not yet received a bill post-installation, but estimated that the system was able to generate 5 kWh on a sunny day, or a third of her average daily household use. The other two systems had generated 1.7 and 3.82 kWh/day.

All four householders downplayed prior expectations, proposing that their involvement had never been about saving money. The householder whose system had generated 3.82 kWh/day, however, was happy that his expectations had been exceeded.

Behavioural change

Previous research has found that a principal motivation for householders to adopt renewable energy technologies is the belief that it will produce a net environmental benefit (e.g. Brandao, 2007; Gardner and Ashworth, 2007; Parsons and Ashworth, 2007). The interim report confirmed this: household respondents reported that they perceived the bulk-buying solar programme as an opportunity to put their environmental principles into practice. That is, their principal motivation was environmental, not financial. The suggestion, then, is that installing a PV system constitutes part of a change in energy-use behaviour. However, based on the present small sample, the link between owning a PV system and behavioural change is not clear. Householders were asked whether ownership of the system had altered their energy use generally. For example, did partial dependence on an unreliable energy source make them tend to switch off appliances more, or conversely did they feel that harnessing renewable energy allowed them to be more extravagant in their overall energy use?

Of the four householders, two reported that their energy-use behaviour was the same as before installation. One acknowledged that their use had probably increased overall – they had increased the use of both the air conditioner and the dishwasher. This householder argued that she no longer felt guilty about using these appliances, because she was "doing her bit" by installing a PV system. In this case, it could be argued that installing the system has had the counterproductive effect of enabling householders to maintain levels of grid-energy usage, by diminishing their perceived need to make reductions. Ownership of a PV system perhaps endows some householders with a "feel-good" factor that partly desensitises them to the actual net impact on greenhouse gas emissions.

Caution on this finding must be exercised. In a survey of a much larger sample taken in the UK, Keirstead (2007 found a net decrease in electrical consumption after installing PV, probably because of heightened awareness of electrical consumption.

Only one householder reported a conscious effort to reduce grid electricity use post-installation. This householder favoured using power when the sun was shining, and minimising use at other times. For example, he programmed the swimming pool filter to operate for six hours during the day, and two at night, contrary to the manufacturer's recommendations of four and four. Similarly, he tended to use the dishwasher during the day, when previously he might have used it at night. However, while such behaviour may reduce this household's use of grid electricity, it does not constitute a net reduction in either the household's total energy use; it merely shifts the time at which energy is consumed. Nor does it meaningfully reduce overall grid energy use; it simply means that the household is consuming the PV energy on-site rather than exporting it to the grid, saving whatever would be lost in transmission. This behaviour does not optimise the potential for PV systems to reduce peak demand.

Energy intentions and aspirations
Given that, for most households, the system would only generate a fraction of their total use, it was pertinent to ask respondents whether installing a small system had motivated them to upgrade to a larger system. In all four cases, perhaps not surprisingly, respondents expressed a desire to upgrade but cited cost as a major disincentive. One was prepared to spend another $10,000 for an additional 2 kW, but felt unable to afford to do so.

Issues for installers

For the interim report, CSIRO interviewed two installers contracted by the company, and one who had declined an offer to work for the company. For this report, CSIRO again interviewed the former two installers, asking the following questions:

- Is there anything that has gone better than you were expecting?
- Is there anything that has not gone as well as you were expecting?
- How many installations have you done per day?
- Have any regulations made things harder for you?
- Is there any area where you would like to see stronger regulation?
- Have energy companies been cooperative with the installations and inspections?

For the purposes of this report, the resulting responses can be grouped into two principal issues: changes in the installers' experiences of the company and its PV systems; and emerging regulatory issues.

General experience of the company and PV systems
As noted in the interim report, both installers had satisfied themselves of the integrity of the company and its systems, in the face of considerable public scepticism. However subsequently, impressions changed. According to the installers, the first batch of panels and inverters was satisfactory, and was used in approximately 50 installations. However, the company then introduced different components, which the installers considered to be of a lower standard, and one considered to pose safety risks. Further, the installers became increasingly uncomfortable with the company's inability to meet its promised timeframes. Both installers felt unwilling to be associated with these developments, and resigned from the company.

Regulatory issues
In light of the above concerns, it is not surprising that the two installers called for tighter regulation of PV system suppliers. In this instance, the installers could not be certain that the new panels and inverters actually met Australian standards. This was a significant concern for one, who had contacted both the Department of Environment Water Heritage and the Arts (DEWHA) and the Clean Energy Council, and been advised that the installer, not the supplier, is liable if panels do not meet Australian standards. This situation is exacerbated, he added, by the fact that only inverters, and not panels, are checked after installation (by energy companies). These installers, were concerned that a loophole exists whereby unscrupulous companies can supply sub-standard components, since no one is monitoring or auditing them.

Issues for energy companies

Before the advent of bulk-buying programmes, energy companies only had to consider PV installations in terms of individual households. As discussed in the interim report, bulk-buying programmes have potentially significant implications, such as installing large numbers of new meters, additional workload to meet demand, and impact on energy demand. These issues were revisited with representatives from the two relevant energy companies. As well as interviewing the two company managers interviewed previously, CSIRO interviewed one regional inspector, to discuss emerging issues at an operational level. All three were asked the following questions:

- What impacts has the programme had on your operations?
- To what extent are you inspecting installations?
- Is the quality of the components proving to be satisfactory?
- Has the programme, as a bulk-buying exercise, thrown up any complications that do not exist with individual installations?
- Do you think that the business model is proving to be sustainable?
- Is this type of programme likely to have any material impact on energy use?

- The resulting responses can be grouped into discussions regarding impacts to date, and potential impacts in the future.

Impact on operations to date

The companies are inspecting every installation, as this is a requirement. However, as noted above, they do not inspect the panels. They check the model of inverter and the signage, and that the inverter is functioning correctly. Within these limitations, and as far as the three interviewees were aware, the installations had proven to be satisfactory, and no significant problems had arisen.

The two managers considered the bulk-buying programme to have had negligible impact on either energy demand or operations, however the regional inspector's work had been transformed. One manager noted that his company already had about 2,000 PV installations, so this programme had not yet made a significant difference. In contrast, the regional inspector noted that, whereas he used to make one or two inspections per month, he had done 359 in 2008, including 130 in just three weeks in December 2008. He spends approximately one hour on each inspection. Nevertheless, he pointed out that he was fitting this work into his existing schedules, rather than the company taking on more staff.

A further issue noted by the regional inspector was that some householders had complained about the delay between installation and grid connection, even though this delay was usually only around one week. Some had even asked to be compensated for 'lost income' during this time when they could have been generating energy. However, this may be less of a judgement that one week is an excessive delay, and more a symptom of frustration induced by the previous delay of several months.

Potential future impacts and their implications

All three interviewees were somewhat sceptical of the potential of this type of scheme, for various reasons. Firstly, they noted that it depends overwhelmingly on generous government subsidies, which are intrinsically subject to high levels of uncertainty. They argued that the rebate regime makes a meaningful difference only at the level of individuals, not at the social level. One manager commented that the government is focused on “look-good, feel-good” responses that are highly visible, at the expense of responses that are effective. The regional inspector noted further that the current practice of supplying all new meters free of charge may become unsustainable, and that in future a $200 charge might have to be introduced.

The other manager discussed the potential implications of a substantial penetration of domestic PV for energy generation. The current distribution system, he noted, depends on the voltage at the distribution point being higher than that at the consumption point. PV generation, however, causes a voltage rise at the consumption point while the sun is shining. If this becomes higher than the voltage at the distribution point, it can cause problems for domestic electronic equipment (e.g., DVDs, computers, LCD TVs.). However he believed this issue would not become significant until there is 40-50% penetration.

Finally, one manager identified the inherent variability of solar energy as becoming an issue if there is substantial penetration of domestic PV. Specifically, energy suppliers must somehow provide continuity of supply regardless of fluctuations in the weather. For example, if PV systems are generating fully one minute, and then a storm passes over, there is a sudden need for grid supply to take over. This means either finding ways to store surplus energy more efficiently, or increasing the capacity to ramp up base-load power at short notice.

Conclusions

This research project tracked a bulk-buying programme in NSW, and sought to document and assess policy and regulatory issues associated with large-scale uptake of solar PV systems. Ten stakeholders were interviewed, and asked to identify the relevant issues as they saw them.

For the company, the key policy issues were:

- Perceived uncertainty regarding policy direction on rebates
- A sense that the time taken in processing rebates was excessive
- A general feeling that the government has failed to support the solar industry adequately.

and the key regulatory issues were:

- The need for a more inflexible approach to approving inverters
- Support for stringent requirements for certification of panels
- The need for clear and unambiguous occupational health and safety standards.

The interviews with householders produced the following findings:

- An ability to demonstrate physical evidence of a working PV system, as opposed to the promise of a concept, may be a significant factor in assuaging potential customers' doubt
- Prior expectations may play a crucial role in mediating householders' impressions of the programme. A successful programme may depend on the supplier being realistic when estimating both waiting and installation times
- In contrast, expectations of how much energy a system will generate appear to have relatively little impact on householders' subsequent impressions of that system
- The link between owning a PV system and behavioural change is not clear. Installing PV systems may have unintended or counterproductive impacts on the way people use their energy. There appear to be some confusion regarding the link between the way householders use energy and the impact on greenhouse gas emissions
- Householders were generally keen to upgrade to larger systems, but felt impeded by lack of access to capital.

The interviews with installers, meanwhile, suggested that there is a case for tighter regulation of PV system suppliers, to minimise the risk of unscrupulous practice. Finally, interviews with energy companies found that the programme had had little impact in terms of regional load, but some impact in terms of local operations. Company interviewees were sceptical regarding the prospects for this type of programme, but noted that current mechanisms for grid energy provision would need to be substantially redesigned if domestic PV systems were to penetrate the market significantly.

8.5.2 Maine's Power project

The Maine's Power project was initiated by a local community and environment group (Mount Alexander Sustainability Group; MASG) who discussed the project concept with the four businesses (referred to within as Sites 1-4). With the help of representatives from the CSIRO Sustainable Communities Initiative (SCI), MASG gathered together external expertise and facilitated external funding through government funding agencies. The businesses and other project participants discussed an ambitious goal of 30% greenhouse gas reductions by 2010. This was selected based on what the businesses believed they could achieve, and to match the same target set by the local council.

The project was developed as a non legal partnership model to enable four businesses to work together with government agencies, peak industry bodies, energy retailers, distribution network owner operators and environmental organisations to achieve an ambitious 30 per cent reduction in greenhouse gas emissions by 2010.

This partnership model was advantageous in two ways. First, it helped facilitate and guide business decisions, particularly for those businesses not directly employing an energy and operation specialist. While energy costs may be significant to most businesses, in general the cost is considerably smaller than other processes such as labour and material costs. Second, the partnership model allows government agencies to continue their skill development, to retain information learnt, and to collate and pass on relevant knowledge to businesses and the community in the future.

In consultation with CSIRO, MASG developed a general project plan based on a three stage approach. The first stage was to analyse the energy landscape of the local region and more specifically for the four businesses. The second stage was the identification of options to meet the project reduction goals knowing the energy use patterns.

During the first stage, a project partner was identified to undertake energy efficiency audits as an in-kind contribution. Unfortunately, the partner moved from their business and their in-kind contribution was not able to be filled by remaining participants. In response, the businesses were asked to pay for an external audit of their sites (with financial assistance from SV) by an accredited company. It was thought appropriate that each business contributed financially to this task in the belief it was something they should undertake as part of their normal operations.

Given the timelines of the audit process it is recommended that this action is taken at the very beginning of the project and is preferably carried out by an external party unless contingencies are available for those contributing on an in-kind basis. This allows both a thorough understanding of the business operations and energy landscape as well as a more considered project goal to be established.

While the energy audits are vital, it should be noted that the process only informs action but does not ensure action is carried out. For example it was found one of the businesses had undertaken an audit in 1998 as part of the federal government greenhouse gas challenge with little action taken as a result. The partnership model undertaken in this study can help facilitate information exchange and dialogue which can increase the chance of implementing audit recommendations.

Surveys were also conducted at the beginning of the work program to establish the perceptions, understandings and goals of the diverse group of participants in the study. A number of interviewees expressed a wish that the solutions proposed included new and innovative ideas. In general, these innovations were considered primarily in a technological sense.

The surveys revealed that when attributing their funds to projects Government agencies aim to encourage the uptake of technologies or policies they believe have merit for their core agency values. In this case, the agencies involved were primarily driven by the environment and rural community development. Second, the agencies provide funds in the hope of developing new and novel ways of dealing with often common problems.

The businesses surveyed had interest in the project for similar reasons, those being an interest in improving their environmental performance and in fostering ties with the community. While the public sector may contribute funds to the development of innovative solutions, it is the businesses that bear the greatest financial impost and risk when adopting change in their operation. This is not an unreasonable position as it is the businesses who gain from efficiency improvements.

In a sense, the public sector is a vital source of information, skills and sometimes funds to ensure that changes to the business as usual approach can be tackled with minimal risk. The partnership model used in this project provides an excellent structure to improve project outcomes for all parties.

While technologies may play a significant role in innovation, there are potentially more gains to be had in developing new business and engagement models that allow risk and gains to be spread across all participants. Ultimately this is needed to overcome reluctance to deploy technology.

The project highlighted that the local network businesses are vital stakeholders when trying to reduce consumption in the stationary energy sector. It is their asset base which allows the flow of energy and it is their asset in which local generation or demand reduction activities may be located. Network businesses are highly regulated and subject to severe penalties when their service falls below specified standards. As such, these businesses have a propensity to adopt well understood practices, as opposed to continually innovate, to ensure their business operates within regulated guidelines. However new regulatory incentives are helping to change this.

For example, an energy recovery method for reducing high transient loads in the local network was identified as a potential project for Site 2. Figure 8.14 displays an example of the large intermittent peaks from this business. Realisation of this method would involve Powercor (the local DNSP) taking a risk based on the engineering knowledge, skills and information provided by Site 2 staff. If Powercor were to take this risk, they would need to retrain their staff or buy in the services of Site 2 personnel to ensure the system was well maintained and operated within regulatory requirements. However the recently proposed demand management Incentive Scheme (DMIS) by the Australian Energy Regulator (AER) provides a means for Powercor to consider trialling this option as a new and innovative technique to reducing the largest single source of transient peaks in the local network. While the adaptation of the technology used in this scenario is somewhat innovative (similar systems are used elsewhere such as in desalinisation plants for instance), the real innovation comes from changing business processes.

An alternative method for potentially alleviating peak load issues from Site 2 caused by equipment testing was also considered in discussion with the other project partners. At Site 1, large cold stores that have a high thermal inertia are used. The business could install simple switch gear that could coordinate a demand response that minimises network demand during the start-up of Site 2 tests by switching off compressors to the refrigeration system. This application could be used for small periods of time (say 10s of minutes) at minimal cost and with minimal disruption to Site 1 activities. Again, the innovation could only be realised through the partnership model.

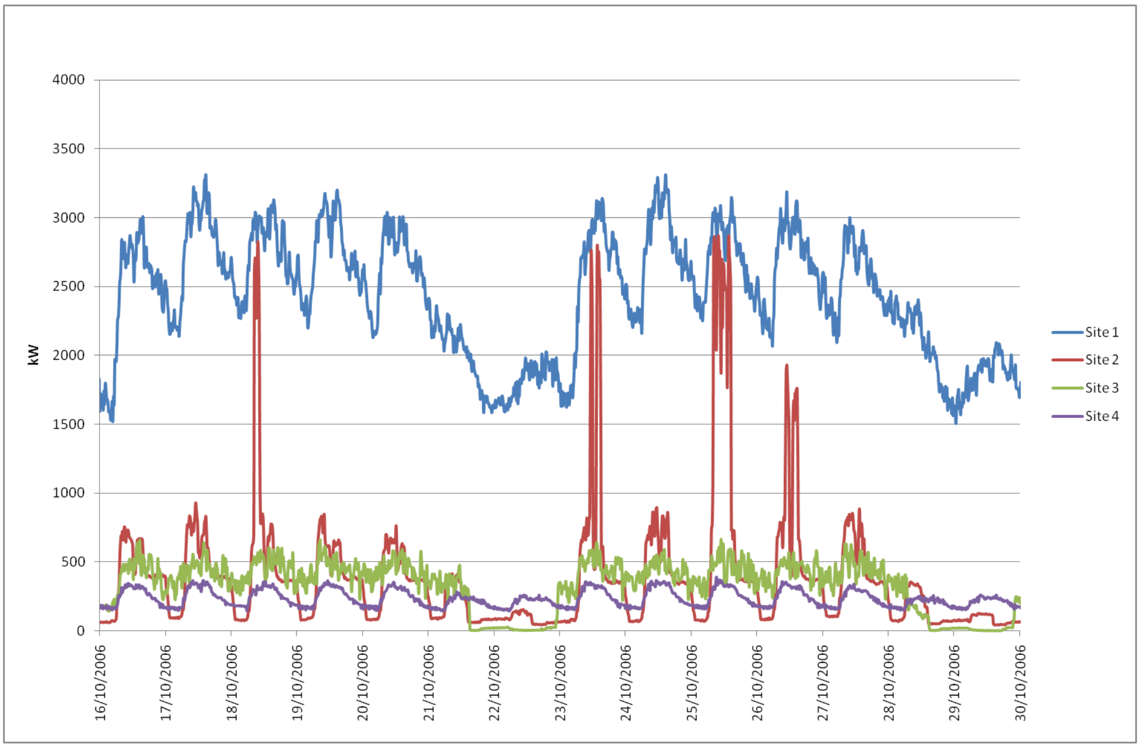


Figure 8.14: 15 minute average power (kW) consumption for a two week period in the base line year from the four businesses in the Maine's power study

The option of using CHP to deliver the hot air and steam requirements of the Site 3 business was also explored. Because the heat load of the site is significantly higher than the electrical demand, the business would need to export a significant amount of electricity. Due to the reduced greenhouse gas emissions from using natural gas, the excess electricity can be considered a form of cleaner energy. To export electricity to the grid, the operator of the generator needs to negotiate a price for export with a retailer. Generally the rate is less than retail and is to a large extent governed by the negotiating abilities of the proponent. However no established methodologies or regulation exists to ensure electricity exported from CHP units are rewarded based on their emissions factors. This reinforces the importance of effective policy frameworks that allow the value of DE to be captured.

Local CHP was particularly attractive as Castlemaine was found to have high transmission and distribution losses from the source (in general considered to be the Latrobe Valley) to the point of end use in the local community. By considering CHP, Site 1 found they could potentially reduce their GHG emissions by 60% for each unit of product manufactured. Due to the environmental savings and cost effectiveness of the CHP option, the business choose to supply their energy needs with this method rather than pay for upgrades to the local network to ensure grid supply.

During this study the local distribution network was found to be approaching its current peak capacity. Minimising network losses through local generation is advantageous from a greenhouse gas emissions perspective. However introducing local generation impacts the network business both financially through reduced energy supply and through operation and safety concerns given the network business is wholly responsible for the system performance.

Because of these issues, the network businesses can be seen as a barrier to the implementation of more efficient local measures, a point raised in many barrier studies reviewed in Chapter 6.

The investment cycle and revenue of a network business is subject to a five year regulatory approval, detailed in Chapter 3. While reform such as the introduction of a DMIS encourages innovation, the five year investment approval cycle dictates that any such claim needs to be considered well in advance of its implementation. This creates challenges for timing the introduction of innovative supply options. By the time a supply option can be supported by the local network business, momentum and support for the project may be lost. If another community group were to undertake a similar process then they need to strongly consider these impediments when setting the timelines for their goals. While local initiatives could be established mid investment cycle, it is likely that extra costs may occur that could have otherwise been avoided.

For policy makers and regulators, this highlights the importance of ensuring efficient distributed energy solutions are not impeded by regulation and that network businesses have an incentive and framework for engaging distributed energy solutions as they arise. We note the Australian Energy Market Commission (AEMC) is undertaking important work on this as part of its review of network planning and investment arrangements.

Lastly, when considering network issues and estimating greenhouse gas savings, distributed energy solutions need to be evaluated against other solutions that facilitate the use of clean large scale generation. In this study, only the local CHP and perhaps solar thermal hot water applications were as cost effective as purchasing green power.

To see the case study in full go to http://masg.org.au/

8.5.3 Transpower

This case study details the experience of participants in a Transpower led trial of ‘demand side participation’ (DSP) in the upper South Island of New Zealand. In 2008, Transpower contracted two aggregators – Energy Response Ltd and TrustPower Ltd, testing aggregation of sources.

Eleven organisations were interviewed in order to understand their experience of the 2008 trial and ultimately what influences the degree to which businesses can engage in demand management in response to market signals.

In November 2008, New Zealand’s electricity grid owner and system operator Transpower New Zealand Ltd, released a Report entitled “Demand-Side Participation (DSP) Trial 2008” detailing outcomes of a DSP trial conducted from June to August in 2008 in the network of the upper South Island in New Zealand.

The trial was the second stage of a two stage project which consisted of a Pilot conducted in the winter of 2007 and the 2008 DSP Trial also conducted in winter. The Trial was driven by Transpower’s desire to gain a better understanding of DSP and to assist in the development of a Grid Support Contract (GSC) product. The GSC is intended to ensure reliable supply is maintained in the event a transmission investment is delayed and/or existing transmission network is inadequate. Specifically, Transpower cites the following reason for conducting the trial:

> *“Transpower’s purpose for the Pilot and Trial was to test the ability of DSP to respond to requests to manage load of given quantities and for fixed periods of time, and to use the responsiveness and reliability of the DSP as an input for the development of a full GSC production.”*

The Transpower DSP Trial 2008 report indicates that pricing and incentive mechanisms applied during the DSP Trial 2008 were structured in a three tier process in which “aggregators were required to quote prices for: delivery in dollars per MW per hour; availability in dollars per month; and cancellation in dollars per block per event.” Incentive schemes during the 2008 trial included a contracted rate per hour per MW supplied as a delivery payment with delivery being “assessed at the minimum after aggregation,” and based on availability to deliver 100% of the contracted DSP block,” with no guaranteed number of calls, and a cancellation payment.

Organisations interviewed generally show a high degree of satisfaction with the Trial, being able to achieve financial savings that outweighed business disruptions. They support the concept of demand side participation as a short to medium term measure for managing supply side issues. However in the long term, they indicate a preference for managing supply issues directly through building transmission network and/or generation capacity.

While some organisations were new to the concept of demand side participation, they were able to overcome initial issues by developing strategies for optimising their demand response. They highlighted a need for developing automated processes, and receiving immediate feedback on the success of their response to improve their ability to manage their demand in the future.

Financial incentives were deemed an important motivator for participation. However along with financial considerations, participants noted the importance of assurances of minimal disruption to day to day business activities and therefore the low risk participation in the Trial. Some participants indicated they were assured by the opt out clause. This meant they could ‘give the Trial a go’, but pull out if it wasn’t working for them. Related to this assurance, several organisations noted the communication structure implemented during the Trial as a contributing factor in the decision to be involved.

All but one participant indicated they were happy with the communications process which typically involved an SMS and/or email being sent to the participant to signal an upcoming demand response event. Participants then confirmed receipt of the communication. If confirmation was not received, a call would be initiated. Participants often used multiple points of contact to ensure communication was not missed.

Some businesses had no prior experience with demand response and so faced a relatively steep learning curve, having to find ways of engaging in demand response in a way which balanced the trade off between altering their business operations and meeting the demand reductions that had been called for. The majority of businesses were able to do this through a process of iteration and learning. Businesses that had previous experience with demand response were very comfortable with the process and had established methodologies for minimising interruption to their business, and so maximising the value of engaging in demand response.

Difficulties were sometimes apparent in the operation of DSP. Most participants encountered some sort of operational difficulty initially, however they were able to either partially or fully overcome that difficulty often with flow on benefits. Difficulties were driven by a combination of lack of automation, notice periods and the decision making process required to determine whether to respond to the call or not respond. Automation and delegated decision making were particularly important due to the timing of some events which occurred between 2am and 4am.

Importantly, participating organisations indicated they were able to reduce and even cease production for limited periods of time without adversely impacting their customer service agreement or their bottom line. In addition, through reducing consumption down to the minimum possible levels during load shedding periods, organisations were able to gain valuable information to assist them with their ongoing energy consumption reduction and cost savings goals.

One organisation commented that it completed many modifications in order to comply with the requested load shedding throughout the Trial but that this was a positive as the Trial assisted the organisation in tidying up certain internal processes such as the improvement of the organisation's communication processes including data backup and recording.

One organisation indicated that "where it [DSP] is a bit more regular there may be incentive for us to generate during peak loading and modify our plants or do something." This same organisation's representative indicated that in the end it all came back to a cost benefit analysis.

Another benefit cited by one participating organisation was that the Trial demonstrated real application for DSP and proved the ability for DSP to be duplicated in other regions of New Zealand in the future.

These findings tend to corroborate research on energy efficiency and demand management, which typically finds they can help deliver organisational benefits beyond direct, or predicted financial savings.

On the whole, representatives indicated that their organisations would be likely to continue involvement in DSP in New Zealand should they be called upon to do so in the future citing the success of the 2008 Trial and the financial incentive involved. One organisation indicated that would definitely be involved in the future stating it was the "only intelligent response to peak demand constraints." However, one organisation did note that it would have to look more closely at the DSP option offered before committing to further involvement.

Feedback was mixed as to whether or not DSP should be used across the whole of the New Zealand network. The majority of interviewees indicated that in the short term, DSP was a viable and effective tool for mitigating supply issues during peak periods, however that its use should be short term. Long term, DSP was not considered to provide the answer to New Zealand's ongoing energy supply issues and it was felt it should not be used to deliberately avoid upgrading the network where this was necessary. Concern was raised in relation to placing the onus on industry for ensuring uninterrupted supply through DSP, commenting that industry should not have to "bear the brunt of poor investment decisions."

These preferences are broadly compatible with the intended use of DSP. That is, it is not intended to replace capital expenditure on grid infrastructure, rather complement it or delay it if necessary, to ensure reliable supply at peak times until new infrastructure can be built. However the concerns raised highlight the importance of ensuring network companies, or others, do not have an incentive to use DSP as a long term, ongoing measure to avoid network building, unless the benefits of doing so outweigh the costs in the long run.

The response of participants in the "Demand-Side Participation (DSP) Trial 2008" suggests the trial was very much a success from a participant perspective.

8.5.4 ENERGEX

This case study details findings from research into the ENERGEX *Cool Change – Energy Smart Suburbs* trial (CC2, http://www.energex.com.au/trial/index.html). The trial was undertaken by ENERGEX to enable better management of peak demand, specifically through remote cycling of residential air conditioning. It followed on from an initial trial, *Time for a Cool Change* (CC1). This research was conducted to address how customers interacted with the demand management program, understand the profile of CC2 participants and non-participants, illustrate how customers made sense of the technology and trial, why people referred others or decided to withdraw from the program, and to gather feedback for improving future trials.

A mix of qualitative and quantitative methodologies was used in this research. This included interviews and focus groups, which in turn helped to inform an internet-based survey through which the major data were collected. In total, 557 respondents completed the survey. The respondents were classified into four main categories for the purpose of this research and where relevant, the differences between these groups were explored. The largest group of respondents were CC2 participants (n=394) either continuing from CC1 (Continuers; n=233) or new to CC2 (Newcomers; n=161). Of the CC2 non-participants (n=163), most were eligible non-participants (n=95) and the remainder were ineligible non-participants (n=68).

There appear to be consistent differences in the demographics between participants and non-participants. Overall, participants were more supportive of the trial, tend to earn more money and are more likely to work in professional jobs. This effect of greater support for energy alternatives amongst people with higher incomes has been identified in previous research (Gardner and Ashworth, 2007). It may be that this is due to a perception amongst people on higher incomes that they can "afford" to make changes that reduce their energy usage, even if the change ultimately produces a net cost saving. Conversely, it could be said that people on lower incomes tend to perceive saving energy and reducing their environmental impact as more costly, which can prevent them from making cost-effective efficiency improvements.

Data analyses supported an overall conclusion that participation was primarily driven by two factors: the confidence customers had in the trial, and by the sense of community contribution and connection they associated with the trial. Overall, continuers, with the greatest exposure to the trial, reported the most confidence in the trial, and had the strongest sense of contribution and connection. Levels of confidence and sense of contribution/connection were moderate for trial newcomers, and were lowest for eligible non-participants. Positive outcomes, including positive evaluation of the trial, positive word of mouth, and intentions to participate in future trials, all tended to be higher for people with higher levels of confidence and connection/contribution. These conclusions are best represented in the illustration below (Figure 8.15).

Based on the initial qualitative data and previous research into consumer choice and decision-making, a preliminary model of potential drivers and barriers to trial participation was identified (see Figure 8.15). Each major element in the model was tested in the survey. As noted above, participants and non-participants reported very similar demographic characteristics. There were three key differences between participants and non-participants: people that participated tended to have higher incomes, higher electricity bills, and were more commonly professionals than those who did not participate.

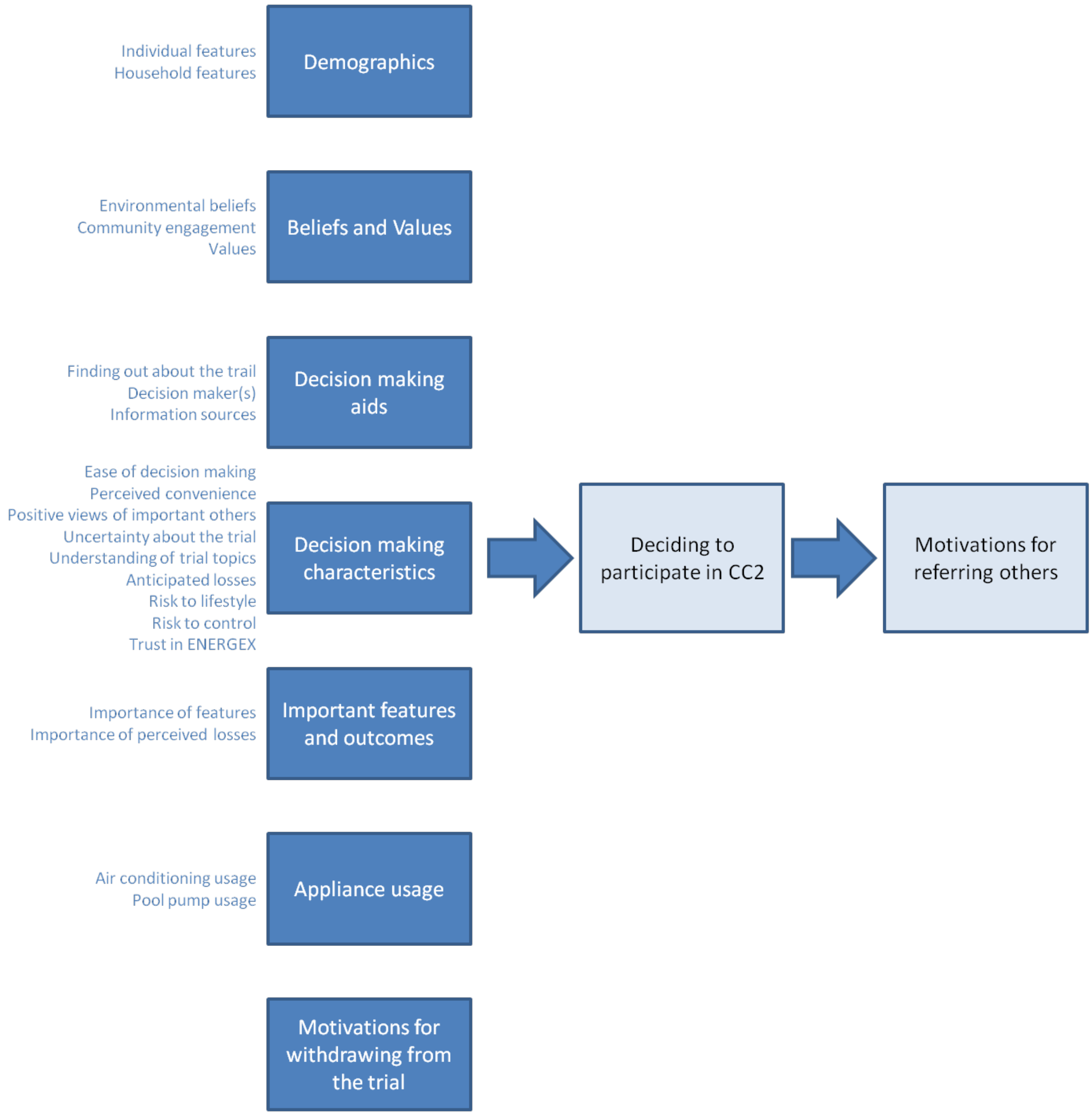


Figure 8.15: Potential barriers and drivers to participating in CC2

Customers that had been through CC1 and CC2 (continuers) had higher scores on positive measures such as trust, and lower scores on negative measures such as uncertainty, than customers who had been through CC2 only (newcomers). This result reinforces the importance of ensuring that a customer's initial experience with the program is positive. It appears that if the business (ENERGEX) can successfully manage a customer through an initial trial, they are highly likely to participate in subsequent trials.

Positive word of mouth and supportive opinions of others in the household appear to have been very important in encouraging people to participate in the trial. This effect is consistent with previous research which shows that people are more likely to trust and accept something if it has been tried or supported by people that they know, or by people who are similar to them in some way (including living nearby). When the trial is expanded, it may be most effective to expand to neighbouring suburbs first, rather than suburbs in a completely different area, because the former will benefit more from existing awareness and from the reassurance that people similar to them are already involved.

There is extensive misperception about the reasons for and outcomes of the trial. Although ENERGEX repeatedly and clearly explained issues of network infrastructure as the reason for the trial, the trial has been confused by many people with energy efficiency, reduction of household electricity consumption, reduction of household carbon footprint, and reduction in household electricity bills. This means that individuals are treating the trial as a way to contribute to the environment, in a way that involves no sacrifice and actually some rewards. This is a type of "pro-environmental" action that many people are most comfortable with – they get to feel good about contributing without experiencing a negative impact on their lifestyle.

Reasons for participating or not participating

From the qualitative research, a series of twenty potential reasons for participating or not participating in the trial were developed. Within the survey, these questions were answered by continuers, newcomers and eligible non-participants. In order to provide a more usable summary of the responses, the data from these 20 questions were factor analysed to identify the underlying themes among the reasons. From the factor analysis four themes were identified and these are detailed below.

Theme 1. Make a positive difference – this theme incorporated reasons relating to helping to conserve energy, reducing consumption, reducing environmental impact and emissions, "doing the right thing", and saving on household electricity bills. It is noted that some of these reasons represent a degree of misperception on the part of the respondents

Theme 2. Lifestyle/comfort – this theme involved reasons relating to reliability of electricity supply, comfort and maintenance of lifestyle

Theme 3. Be part of something – this theme involved notions of contributing to research that will assist in the development of the electricity network as well as the notion of being part of a locally-based trial

Theme 4. Control – this theme involved reasons relating to maintaining control of appliances and household rights.

The perceived risk of negative outcomes (costs, damage to the house or the air conditioner) seems to be a major barrier to involvement in the trial. These barriers are very difficult to overcome because they are underpinned by inherent distrust of information provided, or distrust of the business itself. Suggestions for overcoming this issue include partnering with other organisations that are trusted. Direct exposure to customers who have had a positive experience is another way overcome this fear, so as the number of people involved in demand-side management increases, we might expect the level of distrust in the community to decrease.

Confidence, contribution and connection appear to be driving positive outcomes

Overall, ENERGEX received positive feedback about the trial, including a strong interest from participants in future trials, and a clear indication of how customers can best be engaged in the future. Responses of continuers, newcomers and eligible non-participants were compared to identify what decision-making dimensions were driving participation in CC2 and subsequent positive outcomes such as intentions to participate in future trials and positive word of mouth. These comparisons led to the conclusion that participation and the related positive outcomes were primarily driven by the confidence customers had in the trial and by the sense of contribution and connection they associated with it. Overall, continuers, with their positive experiences in CC1, reported the most confidence in the trial, and the strongest sense of contribution and connection. This confidence and sense of contribution/connection, was moderate for newcomers, and lowest for eligible non-participants.

The confidence customers had in the trial was demonstrated by how they answered questions about their ease of decision-making, perceptions of support from important others, perceived convenience, anticipated losses, impacts on lifestyle, attitudes towards external influence, uncertainty and trust in ENERGEX. The sense of contribution and connection customers associated with the trial is based on responses to themes about being part of something and making a positive difference, and ratings of engagement with their local community.

Satisfaction with trial and technology

Most participants reported some satisfaction with the trial technology, although many of the responses in this section received slightly lower ratings by participants than in other sections. This perhaps reflects the participants' ease of decision making to be a part of the trial and therefore lack of need to engage with the trial technology at all. Responses from the majority of participants indicate that the trial technology did not limit their ability for perceived control and on the whole did not adversely affect the comfort levels of those living in their houses. Some participants did report sensing a difference in the temperature at certain times, namely not blowing enough cool air. It is worth noting, however, that the previous CC1 study identified that such comments did not necessarily correlate with the occurrence of actual load control events.

Participants were also asked a suite of questions about their experience with customer service. All mean responses indicated positive satisfaction with the service. Given the nature of the responses ENERGEX can be happy with the service provided and in particular, could recognise how well the call centre and installers were rated as part of this service. How participants reported their actual experience is contrast to the perceptions of risk and loss of control reported by non-participants, as found in this research. Accordingly future participation may be encouraged by messaging about the positive experiences of participants and how households just like theirs are already participating.

8.5.5 Alternative energy solutions for data centres

Data centres as green investments

Data centres make the internet work and all government, business, and leisure applications depend on their reliable and continuous function. They are significant consumers of energy, forming an estimated 1.5% of U.S. electricity demand in 2006 which is expected to increase to 3% by 2011 (Corum, 2008).

Cooling is the dominant non-IT (information technology) electrical load in data centres. Servers and other IT equipment have not generally been designed with high energy efficiency as a priority. However, apart from environmental concerns, design practices and priorities will be changed by economic drivers, because the cost of power and cooling is approaching equity with the capital cost of IT equipment (Lawton, 2007). As a result, the power-usage effectiveness (PUE) for data centres, defined as the ratio between the total power consumed and the IT power consumed, typically falls in the range 1.3 to 3.0 with 1.2 considered an achievable ideal.

Recent studies suggest that today's data centres are highly inefficient and that disciplined management practices provide substantial opportunities for reductions in both costs and carbon emissions. Current trends have seen an increase in the number of large data centres being built in New South Wales. Such projects present excellent opportunities for the application of distributed energy solutions, which would result in additional reductions in cost and carbon emissions.

CSIRO was commissioned by the NSW Government Chief Information Office, Department of Services, Technology and Administration, to evaluate the viability of alternative energy technologies that could reduce the carbon footprint of large data centres in NSW. Such data centres may arise, for example, through the consolidation of several smaller data centres presently operated independently by different organisations. There is also international demand for locations that will support large data centres with low greenhouse gas emissions (McNeil, 2009).

This case study outlined the feasibility of various energy solutions against a wide range of criteria and identified the critical requirements needed to make these initiatives feasible. A number of environmentally preferable sources of energy were reviewed for viability, with consideration also given to their suitability to produce chilled water for cooling, which is a major use of energy in a data centre.

Process

The study involved three phases as follows:

Data gathering. During this phase, discussions were held with NSW Department of Commerce, energy retailers, alternative energy providers, and subject matter experts from a variety of disciplines, internally and externally from the CSIRO. The objective of this phase was to confirm the scope of energy solutions to be investigated and to understand the overall requirements of data centre operators

Development of alternative energy solutions. Based on the information obtained in the data gathering phase, a list of potential energy solutions was established for further investigation. Background information on these solutions was obtained from a wide range of sources

Assessment of alternative energy solutions. For each alternative energy solution, the state of technology and its applicability to data centres was estimated and summarised. Approximate physical and cash-flow modelling was performed for each solution for which sufficient data could be obtained, permitting a quantitative comparison of economic performance and greenhouse gas emission reductions against a base case of full reliance on grid electricity supply.

Methodology

The study provided an indicative cash flow analysis and greenhouse gas mitigation figure for each technology considered. Spreadsheet-based modelling of resource capacities, energy flows, and conversion efficiencies is sufficiently accurate for a first calculation of the financial viability and environmental benefit of each technology. Further analysis would require more accurate characterisation of the resource and the technology, more comprehensive costing, detailed modelling of the variation of load with time and season, and appropriately tailored engineering designs by specialists in each technology. These will be required during the planning of new data centre projects.

The net present value (NPV), the modified internal rate of return (MIIR), and the levelised costs of energy (LCOE) for electricity and cooling are presented for a representative case study for each technology. It is hoped that the combination of these parameters will provide a sufficient basis for comparison. The usual calculation of IRR implicitly assumes reinvestment of positive cash flows at the IRR rate, which is often unrealistic, so the modified IRR is used instead.

“MIRR is calculated by assuming that all cash inflows received before the end of the analysis period are reinvested at the discount rate until the end of the analysis period. The terminal (future value) amount at the end of the analysis is then discounted back to the base year.” (Short et al., 1995).

Investors in distributed energy technologies typically require higher rates of return than the electricity industry, reflecting in part the opportunity cost and availability of capital. Whereas investors in large grid energy assets seek to recover value over a 30-40 year timeframe, commercial entities whose principal business is not power generation, demand shorter payback periods. To account for this asymmetry, in tabulations the NPV, MIRR, and LCOE are shown at the 20th year. A salvage value of zero is assumed at the end of the investment period.

Outcomes

The study found that the following solutions appear to be the most feasible depending on site specific conditions and should be further investigated in order to decide how best to commit resources towards large data centre construction projects within NSW:

- Gas-fired trigeneration (potentially using locally sourced coal-seam methane)
- Solar thermal electricity generation (including storage)
- Solar thermal cooling (in association with gas-fired trigeneration)

- Large wind turbines
- Waste heat recovery (from a neighbouring business with industrial processes)
- Air-side cooling (where the climate is suitable), and
- Thermal energy storage (in a water reservoir).
- A geothermal exploratory bore is also potentially attractive but its use is highly dependent on the availability and reliability of a suitable bore.

The results of the study are summarised in Table 8.24. The table highlights the costs of generation and potential CO_2 reductions that could be obtained from the energy solutions identified. They are presented with a variety of capacities for power generation, ranging from one to several megawatts, so results are presented on a per-kWh or per-MW basis to allow easy estimation of portfolio opportunities by scaling these results. In addition to this, Table 8.24 identifies the minimum levels of space and other requirements that would need to be considered to pursue these options. Note that CO_2 reductions are not estimated for storage options because they are indirect, and the value of battery storage may be underestimated because it accounts for only direct economic benefits and not its ability to support increased use of variable-output renewable energy.

It is likely that a combination of the options presented here will provide the best overall solution, depending on the location of the data centre, the investment timeframe, the level of technical expertise required, and the desired level of CO_2 reductions. For example, gas-fired trigeneration may be supplemented by renewable energy options and additional sources of heat and cooling, and energy storage may provide value by assisting security of supply and integration of renewable sources.

Like the Maine's power study (Section 8.5.2) this case study highlights the ability of DE to meet the demand of large energy users in the commercial and industrial sectors. Similarly, the greatest cost and emission savings can be achieved when waste heat is utilised, in this case for cooling. While this waste heat is normally derived from combustion engines or turbines, this study highlights alternative sources such as geothermal and co-location with industrial neighbours may be viable alternatives.

Table 8.24: Summary of alternative energy solutions for data centres (assuming a 20-year investment lifetime)

Energy solution	**Electricity and/or cooling**	**Levelised cost of energy**	**Annual CO_2 reduction ($tCO_2e/MWr/y$)**	**Location requirements**	**Modified internal rate of return**
Electricity at present contract rates	Both	16.0 c/kWh (electricity) 9.4 c/kWh (cooling)	Emissions are 8,520 $tCO_2e/MWe/yr$		N/A
(Natural) Gas-Fired Trigeneration	Both	16.4 c/kWh (electricity) 8.3 c/kWh (cooling)	4,700 $tCO_2e/MWe/yr$	Emissions and noise should be considered in urban areas	8.6%
Coal Seam Methane	Both			Non-urban area above a coal seam	
Solar Photovoltaic Array	Electricity	50.0 c/kWh	1,930 $tCO_2e/MWe/yr$	Good solar irradiance	1.9%
Wind Turbines	Electricity	8.4 c/kWh	2,550 $tCO_2e/MWe/yr$	Good wind area (open hilltop or ridge)	11.4%
Solar (Only) Thermal Cooling	Cooling	3.3 c/kWh	380 $tCO_2e/MWr/yr$	Good solar irradiance	4.3%
Solar Thermal Cooling (Gas Co-Firing)	Cooling	4.6 c/kWh	170 $tCO_2e/MWr/yr$	Good solar irradiance	2.6%
Solar Thermal Electricity	Electricity	16.6 c/kWh	2,680 $tCO_2e/MWe/yr$	Good solar irradiance	7.6%
Waste Heat Recovery	Cooling	0.93 c/kWh	1,220 $tCO_2e/MWr/y$	Proximity to large industrial process	11.2%
Geothermal Exploratory Bore	Cooling	1.24 c/kWh	1,220 $tCO_2e/MWr/y$	An existing and successful exploratory 2-km bore	9.5%
Ground-Source Heat Pump	Cooling	1.86 c/kWh	1,220 $tCO_2e/MWr/y$	Adjacent space for 1000 bores	N/A
Air-Side Cooling	Cooling	0.26 c/kWh	300 $tCO_2e/MWr/yr$	Integrates with air conditioning	17.0%
Lead-Acid Battery	Electricity	N/A	N/A	Adjacent room meeting safety requirements	–0.6%
Flow Battery	Electricity	N/A	N/A	Adjacent room meeting safety requirements	–4.6%
Thermal Energy Reservoir	Cooling	N/A	N/A	Adjacent space for reservoir	12.2%
Graphite Block Thermal Storage	(Electricity)	N/A	N/A	Part of solar thermal concentrator	5.2%

9. THE VALUE PROPOSITION FOR DISTRIBUTED ENERGY: QUANTIFYING THE AUSTRALIAN POTENTIAL

9.1 DE as an early action response to climate change

This section of the report provides details of economic modelling that showcases the ability of DE to act as an early action response to climate change. The modelling is based on CSIRO's Energy Sector Model (ESM) which determines the least cost solution for change in the stationary energy and transport sectors of the economy.

9.1.1 Key findings

Modelling of four carbon price scenarios (CPRS-5, CPRS-15, Garnaut 550ppm, Garnaut 450ppm) found that DG has a significant role to play in a carbon constrained future. On the basis of technology characteristics and cost competitiveness, the modelling indicates that DG can significantly increase its share of supply in the near-term. The estimated technology uptake suggests that DG has a bridging role in transitioning from the current coal dominated system while large-scale renewable and near zero emission CCS technologies are either too expensive or unproven.

Results from the ESM modelling show that distributed energy has a significant role to play in a carbon constrained future. On the basis of technology characteristics and cost competitiveness, the economic modelling indicates that DG can significantly increase its share of energy supply in the near-term, decreasing the need for additional centralised generation and reducing the emission intensity of energy supply. The estimated technology uptake suggests that DG has a bridging role in transitioning from the current coal dominated system while large-scale renewable and near-zero emission carbon capture and storage technologies are either too expensive or unproven. In this way, DE is found to be an attractive early action response to climate change.

To develop a sense of the welfare gain provided by distributed energy, we compared two scenarios. The base case is Garnaut 450ppm with growth in electricity adjusted to account for energy efficiency and structural economic change, distributed generation included as an option, and demand endogenous in the model, so affected by price elasticity of demand for different end users. The alternative case is Garnaut 450ppm, with baseline growth in electricity demand set at business as usual (BAU) levels, DG not included as an option, and demand fixed (perfectly inelastic). The difference between the two gives a measure of the value (welfare gain) of energy efficiency, demand management, distributed generation and structural change in the economy. The model cannot distinguish between demand reduction due to energy efficiency and structural change in the economy.

Over the period 2006-2050, the undiscounted value of energy efficiency, demand management, distributed generation and structural change is around \$800b (currently GDP in real terms is around \$1,100b). This saving is calculated by measuring the difference in weighted average prices multiplied by energy consumed between scenarios modelled. The present value of the welfare gain is around \$130b discounted at 7% pa. Ultimately, these benefits are shared by all consumers of electricity.

Figure 9.1 below illustrates how this value accrues over time. The blue line represents total energy costs where distributed energy is excluded as an option in the model, the red line represents total energy costs where distributed energy.

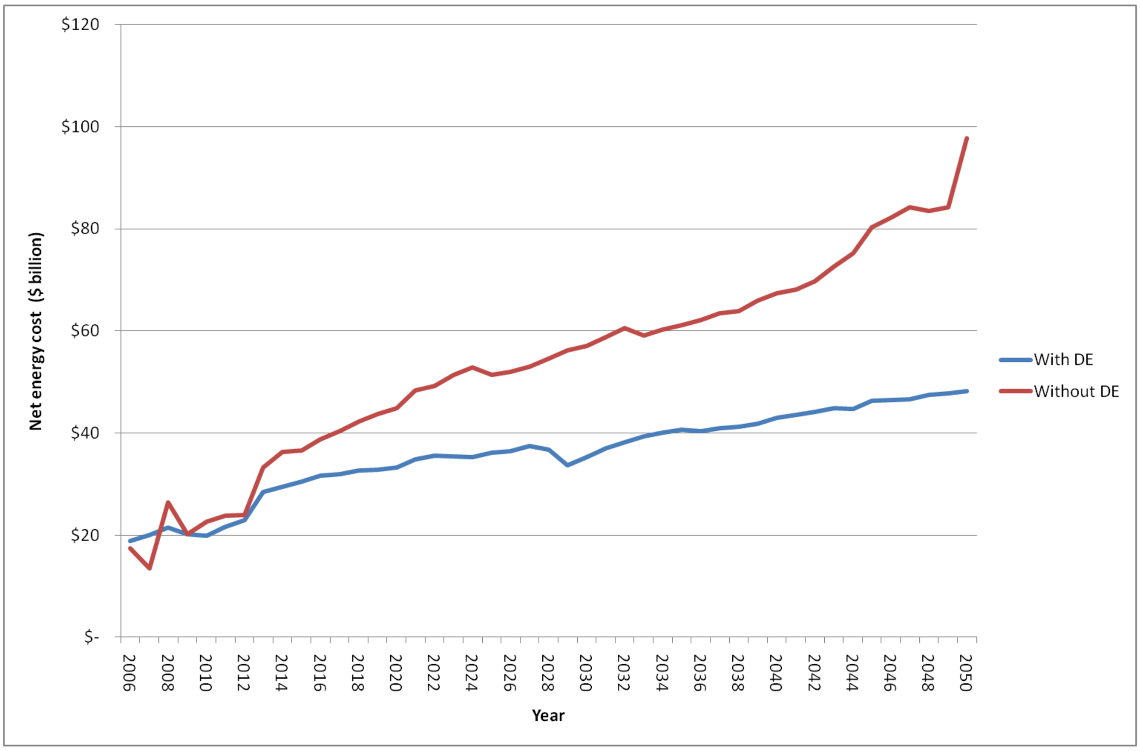


Figure 9.1: Comparison of energy costs with and without DE

It is important to note that the only major cost the ESM doesn't account for is the cost of structural change in the economy over time, such as the cost of unemployment or retraining that may occur. Costs associated with transforming the energy supply chain are built into the model and so can effectively be considered zero. The model optimised welfare by requiring a 7% rate of return on energy assets over their lifetime.

Fully valuing distributed energy based on avoided or delayed spending on network and generation infrastructure is a complex exercise that is not fully captured by the ESM. The ESM captures avoided spending on peak generation infrastructure, and transmission networks to a degree, but imperfectly due to modelling limitations. Previous attempts have been made to quantify the market value of demand management specifically excluding network benefits, with estimates ranging from $363M - $954M over the period 2007 – 2025 (Hoch et al. 2006).

Water savings are also made in the Garnaut 450ppm scenario through a mix of distributed energy and renewables, with approximately 200 gigalitres saved per annum in 2030 and 375 gigalitres saved in 2050. While this appears relatively small compared to Australia-wide water consumption (around 1%), it significantly reduces the exposure of energy wholesale markets to potential water shortages, with an approximate 66% reduction in water intensity of electricity supply by 2030 and 83% by 2050. This is likely to have significant risk management value, potentially resulting in lower prices for consumers, but also competitive advantage for suppliers and consumers of distributed energy where they compete with mains grid supply. We note water shortages in 2007 helped drive a near doubling of wholesale prices.

In general, DG appears to be an effective early action GHG mitigation option for Australia when it is considered within a portfolio of other mitigation options due to a number of factors:

- There are numerous low-emission DG technology options that are commercially available
- There are DG technologies which utilise waste heat that is lost in centralised electricity generation, increasing overall fuel energy efficiency
- DG options have less lead time in comparison to brown- or green-field expansions of centralised plant
- DG options are modular and can be tailored to individual end-user requirements
- Some DG options utilise fuel that is uneconomic for large centralised plant (e.g., landfill gas, waste streams, some forms of biomass)
- DG options are more able to match growing demand by installing smaller more appropriately sized units while centralised technologies result in large stepwise additions of supply, and
- DG options provide a mechanism to reduce electrical losses in transmission and distribution by locating the units close to the point of end use.

More specifically, the results indicate that:

- In the near-term, co- or trigeneration technologies using natural gas or biomass/biogas appear to be the most cost effective options, especially in the industrial (natural gas, waste gas, coal seam methane), commercial (natural gas and biogas) and rural (biomass) sectors. They provide a vital bridge towards a low carbon future
- Landfill gas and waste gas reciprocating engines are competitive but are limited by fuel availability
- Small scale wind turbines are more competitive in non-urban areas where alternatives are more expensive or better wind resources are available
- In the medium-term, there is potential for significant deployment of photovoltaic (PV) of solar PV in the residential, rural and commercial sectors. The estimated uptake has implications for employment
- In conjunction with energy efficiency and demand reduction, DG is the most cost effective greenhouse gas mitigation option in the near- to medium-term contributing between 4 to 18 Mt of abatement in 2020 and 23 to 40 Mt of abatement in 2030
- Sensitivity analyses indicated that the more rapidly DG technologies can get down the cost curve (i.e., technological breakthrough, imported learning) the more competitive these options are to other alternatives

- Should large scale low emission technologies prove unworkable or too expensive there appears to be some scope for DG to lessen negative impacts such as higher electricity prices, and
- Significant co-benefits resulting from the deployment of distributed energy solutions can be found in reduced water consumption and pollutant emissions such as NO_X, SO_2 and PM_{10}.

9.1.2 The necessity for early action

Contemporary debate on emissions trading in Australia has shifted substantially in recent times. The Federal Government currently has legislation before parliament for an emissions trading scheme referred to as a Carbon Pollution Reduction Scheme (CPRS).

Under CPRS, the Government has set an unconditional commitment for emissions reductions of 5 per cent below 2000 levels by 2020 and a long-term goal of reducing emissions by 60 per cent below 2000 levels by 2050. This long term goal is consistent with the CSIRO Energy Transformed Flagship (ETF) abatement target used in preliminary ESM modelling of DE (Reedman, 2006; Reedman, 2007).The Government has also committed to reduce Australia's carbon pollution to 25 per cent below 2000 levels by 2020 if there is global agreement to stabilise levels of greenhouse gases in the atmosphere at 450 parts per million (ppm) CO2-equivalent or lower by mid century.

To put these targets in perspective, the recent fourth assessment report of the Intergovernmental Panel on Climate Change (IPCC) posits that more stringent emission reduction targets are required to limit the chance of exceeding a 2°C increase in global mean temperatures. It noted that: "Using the 'best estimate' assumption of climate sensitivity, the most stringent scenarios (stabilizing at 445–490 ppmv CO_2-equivalent) could limit global mean temperature increases to 2–2.4°C above the pre-industrial level, at equilibrium, requiring emissions to peak before 2015 and to be around 50 per cent of current levels by 2050" (Fisher et al., 2007). This implies that: "developed countries as a group would need to reduce their emissions to below 1990 levels in 2020 (on the order of –10% to 40% below 1990 levels …) and to still lower levels by 2050 (40 per cent to 95 per cent below 1990 levels), even if developing countries make substantial reductions" (Gupta et al., 2007).

The position that developed countries may need to reduce emissions at a greater rate in the medium-term is a departure from the straight-line reduction path that has been typically modelled in emission reduction scenarios. Examples of the straight-line approach in the Australian context include the Business Roundtable on Climate Change examining 60 per cent below 2000 levels by 2050 (Allen Consulting, 2006) preceded by studies that adopted 60 per cent below "current" levels by 2050 (e.g. Australian Climate Group, 2004; Turton et al., 2002).

Debate on the proposed timing of global emissions trading is still on-going. However, it is increasingly recognised that 'early action' is preferential to 'delayed action' to limit the chance of exceeding 2°C increase in global mean temperatures. This is consistent with economic analysis that a delay in taking action on climate change would make it necessary to accept greater climate change (greater probability of exceeding 2°C), and, eventually lead to higher mitigation costs (for example: Stern et al., 2006; Allen Consulting, 2006; Energy Futures Forum, 2006).

9.1.3 Distributed energy as an early action option

In meeting the need for early action, distributed energy (DE) may have an important role to play. DE refers to a collection of small local generation technologies or distributed generation (DG) that can be combined with active load management and energy storage systems (demand management) and passive measures (energy efficiency) to improve the quality and/or reliability of the electricity system.

Technology options

With respect to DG, there are a number of technologies that are currently available to make significant reductions in GHG emissions. The technologies noted below include both renewable and non-renewable options. A more detailed examination of DG technologies is provided in Chapter 3.

Reciprocating engines
Reciprocating engines have a comparatively low installed cost, have high efficiency (up to 45% for larger units) and are suitable for intermittent operation. They have high part-load efficiency and have high-temperature exhaust streams suitable for combined heat and power (CHP) or combined cooling heat and power (CCHP) applications. Because they are common they are readily serviceable. These units have been popular for peaking, emergency, and base-load power generation. The units can run on a variety of fuels including diesel, natural gas, biogas, landfill gas, waste gas, compressed natural gas and petrol. The size of the units can vary from a few kilowatts to megawatts. A small emergency generator may be around 2 kW (electrical) for instance while a marine diesel engine may be 30 MW (electrical) or more.

In Australia, there are currently 600 MW of reciprocating engines installed. The main fuels being used are natural gas, diesel, coal waste methane and coal seam methane. The bulk of non-diesel non-renewable reciprocating engines operate in CHP mode in the industrial and mining sectors. In contrast, the bulk of renewable reciprocating engines operate in electricity only mode at waste and sewerage treatment works (ESAA, 2008).

Combustion turbines
Combustion turbines range in size from 10's of kilowatts to hundreds of megawatts. Smaller (25 kW to 500 kW) units are commonly referred to as microturbines (a trademark of Capstone) while the larger units (250 kW to 500 MW) are generally referred to as gas turbines although they can use a variety of fuel types such as diesel, biogas and kerosene. Similar to reciprocating engines, combustion turbines can be configured to CHP (cogeneration) or CCHP (trigeneration) operation to improve overall efficiency.

There is currently around 1300 MW of embedded combustion turbines installed. Over 90 per cent of these turbines use natural gas as the primary fuel. The bulk of these turbines operate in CHP mode in the industrial and mining sectors with over 50 per cent of installed capacity located in Western Australia (ESAA, 2008).

Steam turbines

A steam turbine is a mechanical device that extracts thermal energy from pressurised steam, and converts it into rotary motion. Because the turbine generates rotary motion, it is particularly suited to driving an electrical generator; about 80 per cent of all electricity generation in the world is by use of steam turbines. Although the majority of these units are large coal, nuclear or natural gas-fired, there are smaller units around the 30 MW nameplate rating.

In Australia, there are currently around 700 MW of steam turbines installed that are 30MW or less. The main fuels being used are coal, natural gas, oil products, coal waste methane, coal seam methane, black liquor, biomass and bagasse. The bulk of non-diesel non-renewable steam turbines operate in CHP mode in the industrial and agricultural sectors (ESAA, 2008).

Wind turbines

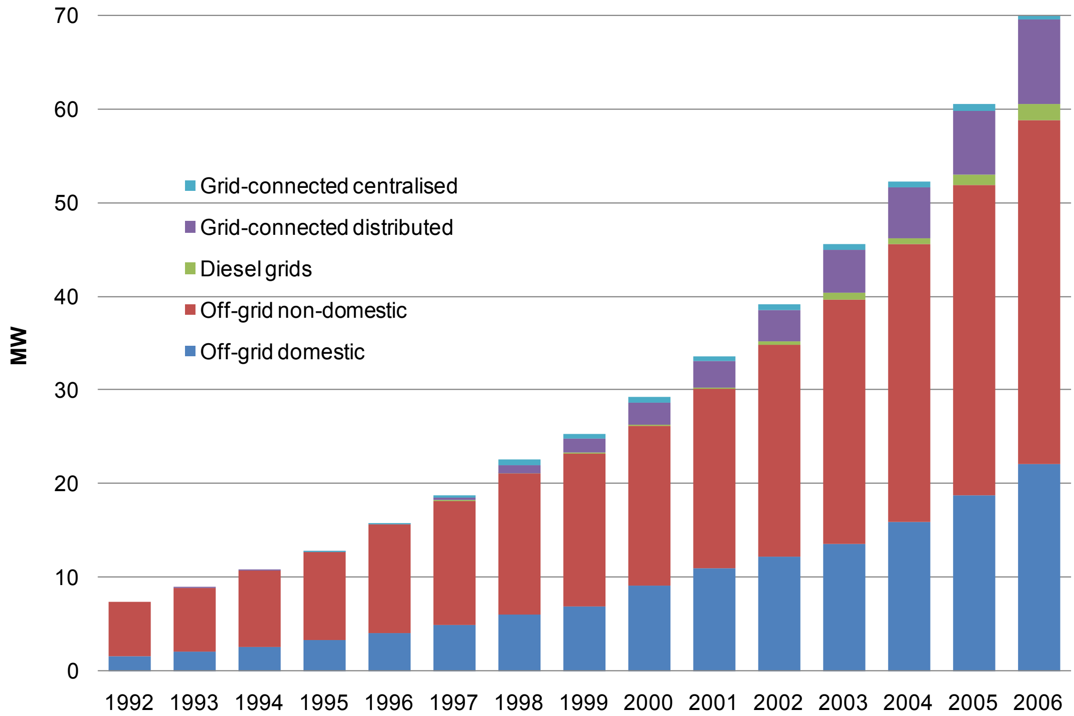
There are two main types of wind turbine commercially available for converting the kinetic energy in wind into useful electrical energy: the traditional horizontal axis wind turbines (HAWTs; Figure 3.17a) and newer vertical axis wind turbines (VAWTs; Figure 3.17b shows a Darrieus type turbine). Vertical axis turbines are not as efficient but have some benefits including greater tolerance to turbulence and high wind speeds. A single wind turbine can range in size from 1 kW for residential applications to more than 2 MW for use in rural communities. The largest turbines currently on the market now exceed 7 MW.

Excluding wind turbines or large wind farms connected to high-voltage transmission networks, there are currently around 150 MW of wind turbines installed (ESAA, 2008). In remote locations, some of these wind turbines operate as hybrid systems in conjunction with diesel generators.

Solar photovoltaics

Solar photovoltaics (PV) generate power through the absorption of solar radiation into a semi-conductor material that produces an electrical current. There are four main types of commercially available solar PV cells: monocrystalline; polycrystalline; amorphous and thin-film.

Installation of solar PV has been steadily rising (see Figure 9.2), and reached 70.3 MW in December 2006, 84% of which was off-grid (Watt, 2007). The off-grid market will remain important for PV in Australia, since little additional grid extension is likely and we have many extremely remote locations in need of reliable power. With an increased reliance on imported diesel, likely continued diesel price increases over the long term, as well as the constant problems of fuel delivery to remote locations, PV remains a cost-effective option (IEA, 2008a).



Source: Watt (2007)

Figure 9.2: Cumulative installed PV by sub-market, Australia, 1992-2006

Solar thermal

These systems capture solar energy to generate heat which is then utilised for some other purpose. The most common solar thermal systems are: concentrated systems, evacuated tubes and simple flat plate collectors. Concentrated systems create the highest grade heat which can be used for direct power production or high grade steam. Evacuated tubes and flat plate collectors are useful for creating hot water. Evacuated tubes can also be used to create low grade steam.

The most abundant DE technology currently deployed are solar water heaters (SWH) and heat pumps that are now installed in 7 per cent of households with annual sales approaching around 100,000 units (Perger, 2009). Table 9.1 shows the installed capacity of SWH by State and territory. Following the effective banning of electric water heaters in new homes and prohibiting them as replacements from 2012, combined with government rebates, sales of these systems are expected to grow substantially in the near-term.

There is some deployment of solar thermal systems in the commercial and industrial sectors. The main application is the provision of low temperature process heat to substitute for heat generated with natural gas or electric boilers. The need for higher temperatures or non-intermittent output means these systems require supplementary natural gas or electric boilers.

Table 9.1: Installed solar water heaters, Australia

	NSW & ACT	VIC	QLD	SA	WA	TAS	NT	AUST
Number of units ('000)	134.6	53.1	137.5	N/A	177.6	5.1	33.1	587.8
Proportion of total dwellings (%)	5.0	2.6	8.5	N/A	21.5	2.5	54.3	7.1

Source: ABS (2008)

Fuel cells

A fuel cell is an electrochemical device that converts chemical energy into electricity and thermal energy. It produces electricity from the reaction of a fuel (on the anode side) with an oxidant (on the cathode side) in the presence of an electrolyte. Fuel cells differ from batteries as they require a fuel source that must be replenished. The fuel substitutes electricity used for recharging in a battery device. Because individual fuel cells produce low voltages, fuel cells are stacked together to generate the desired output for DG applications. The fuel cell stack is integrated into a fuel cell system with other components, including a fuel reformer, power electronics, and controls. Depending on the application, fuel cells range in size from a few kilowatts to megawatts.

There are four primary fuel cell technologies. These include phosphoric acid fuel cells (PAFC), molten carbonate fuel cells (MCFC), solid oxide fuel cells (SOFC), and proton exchange membrane fuel cells (PEMFC). The technologies are at varying states of development or commercialisation. Fuel cell stacks utilise hydrogen and oxygen as the primary reactants. However, depending on the type of fuel processor and reformer used, fuel cells can use a number of fuel sources including petrol, diesel, LNG, methane, methanol, natural gas, waste gas and solid carbon (California Energy Commission, 2009).

Natural gas (methane) is considered to be the most readily available and cleanest fuel (next to hydrogen) for DG applications, so most research for stationary power systems is focused on converting natural gas into pure hydrogen fuel. This is particularly true for low-temperature fuel cells (PEMFC and PAFC). Here, fuel reformers use a catalytic reaction process to break the methane molecule and then separate hydrogen from carbon based gases.

High temperature fuel cells such as the MCFC or the SOFC do not require a reformer since the high operating temperature of the fuel cell allows for the direct conversion of natural gas to hydrogen. Current deployment of fuel cells in Australia is minimal at less than 1 MW installed capacity (ESAA, 2008).

The preceding discussion indicates that there are a number of DG technology options that are currently commercially available or are on the verge of commercial deployment. The next section contains a discussion of the economic modelling approach that is used to evaluate the potential DG uptake under alternative carbon reduction scenarios.

9.1.4 Overview of modelling framework

The aim of this report is to examine the uptake of DG and centralised electricity generation technologies in meeting future electricity demand, under four carbon price scenarios. We employ an economic model that seeks to optimise the portfolio of centralised and DG technologies over time that would minimise the total cost of the electricity system.

The framework employed in order to examine greenhouse gas abatement in the electricity sector is partial equilibrium modelling. This framework was chosen because it is relatively less resource intensive than general equilibrium modelling and because it offers the best opportunity to study the detailed technological implications of alternative scenarios.

Partial equilibrium models cannot directly model the economy wide impacts of the introduction of carbon prices. This limitation can be overcome via suitable integration with general equilibrium models and this type of framework has been applied in other studies (CSIRO and ABARE, 2006; BITRE and CSIRO, 2008). In this report, the economy wide impacts have been exogenously (an external variable) imposed based on observing the economic impact of a given carbon price in these past studies. This introduces some inconsistency in the modelling results since the economy wide impacts are not recalibrated for each scenario.

The partial equilibrium model employed is called the Energy Sector Model (ESM).

Energy Sector Model (ESM)

ESM is an Australian energy sector model co-developed by the CSIRO and the Australian Bureau of Agricultural and Resource Economics (ABARE) in 2006. Since that time CSIRO has significantly modified and expanded ESM. ESM is a partial equilibrium (bottom-up) model of the electricity and transport sectors. It has a detailed representation of the electricity generation sector with substantial coverage of DG technologies. The transport module considers the cost of alternative fuels and vehicles as well as detailed fuel and vehicle technical performance characterisation such as fuel efficiencies and emission factors by transport mode, vehicle type, engine type and age. Competition for resources between the two sectors and relative costs of abatement are resolved simultaneously within the model.

Model equations and structure

ESM is solved as a linear program where the objective function is to maximise welfare which is defined as the discounted sum of consumer and producer surplus over time. The sum of consumer and producer surplus are calculated as the integral of the demand functions minus the integral of the supply functions which are both disaggregated into many components across the electricity and transport markets. The objective function is maximised subject to constraints which control the physical limitations of fuel resources, the stock of electricity plant and vehicles, greenhouse gas emissions as prescribed by legislation or imposed carbon price paths, and various market and technology specific constraints such as the need to maintain a minimum number of peaking plants to meet rapid changes in the electricity load. See Graham and Williams (2003) for an example of the equations required to construct a similar partial equilibrium model.

The main components of ESM include:

- Coverage of all States and the Northern Territory (Australian Capital Territory is modelled as part of NSW)
- Trade in electricity between National Electricity Market (NEM) States
- Seventeen distributed generation (DG) electricity plant types: internal combustion diesel; internal combustion gas; gas turbine; gas micro turbine; gas combined heat and power (CHP); gas micro turbine CHP; gas micro turbine with combined cooling, heat and power (CCHP); gas reciprocating engine CCHP; gas reciprocating engine CHP; solar photovoltaic; biomass CHP; biomass steam; biogas reciprocating engine; wind; natural gas fuel cell and hydrogen fuel cell
- Seventeen centralised generation (CG) electricity plant types: black coal pulverised fuel; black coal integrated gasification combined cycle (IGCC); black coal with partial CO_2 capture and sequestration (CCS) (50 per cent capture rate); black coal with full CCS (90 per cent capture rate); brown coal pulverised fuel; brown coal IGCC; brown coal with partial CCS (50 per cent capture rate); brown coal with full CCS (90 per cent capture rate); natural gas combined cycle; natural gas peaking plant; natural gas with full CCS (90 per cent capture rate); biomass; hydro; wind; solar thermal; hot fractured rocks (geothermal) and nuclear
- Four electricity end use sectors: industrial; commercial and services; rural and residential
- Nine road transport modes: light, medium and heavy passenger cars; light, medium and heavy commercial vehicles; rigid trucks; articulated trucks and buses
- Twelve road transport fuels: petrol; diesel; liquefied petroleum gas (LPG); natural gas (compressed (CNG) or liquefied (LNG)); petrol with 10 per cent ethanol blend; diesel with 20 per cent biodiesel blend; ethanol and biodiesel at high concentrations; gas to liquids diesel; coal to liquids diesel with upstream CO_2 capture; hydrogen (from renewables) and electricity
- Four engine types: internal combustion; hybrid electric/internal combustion; hybrid plug-in electric/internal combustion and fully electric
- All vehicles and centralised electricity generation plants are assigned a vintage based on when they were first purchased or installed in annual increments
- Rail, air and shipping sectors are governed by much less detailed fuel substitution possibilities
- Time is represented in annual frequency (2006, 2007, …, 2050).

All technologies are assessed on the basis of their relative costs subject to constraints such as the turnover of capital stock, existing or new policies such as subsidies and taxes. The model aims to mirror real world investment decisions by simultaneously taking into account:

- The requirement that the plant is profitable over the term of its investment
- That the actions of one investor or user affects the financial viability of all other investors or users simultaneously and dynamically

- That consumers react to price signals
- That the consumption of energy resources by one user affects the price and availability of that resource for other users, and the overall cost of energy and transport services, and
- Energy and transport market policies and regulations.

The model evaluates uptake on the basis of cost competitiveness but at the same time takes into account the key constraints with regard to the operation of energy and transport markets, current excise and mandated fuel mix legislation, future carbon permit prices, existing plant and vehicle stock in each State, and lead times in the availability of new vehicles or plant. It does not take into account issues such as community acceptance of technologies but these can be controlled by imposing various scenario assumptions which constrain the solution to user provided limits. Greater detail and some further discussion on the model assumptions are contained in Appendix D.

Model outputs

For given time paths of the exogenous (or input) variables that define the economic environment, ESM determines the time paths of the endogenous (output) variables. Key output variables include:

- Fuel, engine and electricity generation technology uptake
- Fuel consumption
- Cost of transport services (for example, cents per kilometre)
- Price of fuels
- GHG and criteria air pollutant emissions
- Wholesale and retail electricity prices, and
- Demand for transport and electricity services.

Some of these outputs can also be defined as fixed inputs depending upon the design of the scenario.

The endogenous variables are determined using demand and production relationships, commodity balance definitions and assumptions of competitive markets at each time step for fuels, electricity and transport services, and over time for assets such as vehicles and plant capacities. With respect to asset markets, the assumption is used that market participants know future outcomes of their joint actions over the entire time horizon of the model.

Limitations of ESM

The limitations of partial equilibrium models in their representation of transport infrastructure and economy wide impacts (and possible remedies for these) has already been discussed above and so are not repeated here. The modelling conducted for this report suffers from two additional major limitations which are discussed.

The first is that it includes many assumptions for parameters that are in reality uncertain and in some cases evolving rapidly. Parameters of most concern are the future cost, performance and availability of different technology options. These limitations are only partially addressed by sensitivity cases.

A second major limitation is that ESM only takes account of cost as the major determining factor in technology and fuel uptake. Therefore, it cannot capture the behaviour of so-called “fast adopters” who take up new technology before it has reached a competitive price point. For example, most consumers of hybrid electric vehicles and solar PV systems today could be considered “fast adopters”. Their purchase cannot be justified on economic grounds since the additional cost of these options is not offset by savings in any reasonable period of time (relative to the cost of borrowing). Nevertheless, these options are purchased and such purchasers may be motivated by a variety of factors including a strong interest in new technology, the desire to reduce emissions or status. As a result of this limitation, ESM’s projections of the initial technology uptake for new technologies could be considered conservative.

However, another factor which ESM overlooks is community acceptance and this limitation might lead ESM to overestimate the rate of uptake of some fuels and technologies. For example, greater use of gaseous fuels such as LPG and the introduction of electricity as a transport fuel might be resisted by the Australian community which has predominantly used liquid fuels for transport over the past century. By design, ESM only considers whether the choice is economically viable.

As a result of these limitations, the technology and fuel uptake projections need to be interpreted with caution. In reality, consumers will consider a variety of factors in fuel and vehicle purchasing decisions. However, the projections presented in this report, are nonetheless instructive in that they indicate the point at which the various abatement options should become widely attractive to all consumers. The projections indicate that an increasing diversity of options are likely to become attractive compared to the present fuel and technology mix.

9.1.5 Scenario description

In considering the prospects for DE, a key policy uncertainty is the future value of the carbon permit price. The carbon permit price will be determined by the emission target and the cost of abatement throughout the economy and internationally if trading between countries comes into place. Given the state of the current debate summarised above we will examine four emission reduction scenarios for the Australian economy:

CPRS -5: A carbon pollution reduction scheme is adopted, commencing in 2010, with an emissions allocation that leads to a reduction in emissions of 5 per cent on 2000 levels by 2020 and 60 per cent below 2000 levels by 2050.

CPRS -15: A carbon pollution reduction scheme is adopted, commencing in 2010, with an emissions allocation that leads to a reduction in emissions of 15 per cent on 2000 levels by 2020 and 60 per cent below 2000 levels by 2050.

Garnaut 550ppm: An Australian emission trading scheme is adopted, commencing in 2013, with an emissions allocation that leads to a reduction in emissions of 10 per cent on 2000 levels by 2020 and 80 per cent below 2000 levels by 2050 for stabilisation at 550 ppm.

Garnaut 450ppm: An Australian emission trading scheme is adopted, commencing in 2013, with an emissions allocation that leads to a reduction in emissions of 25 per cent on 2000 levels by 2020 and 90 per cent below 2000 levels by 2050 for stabilisation at 450 ppm.

Within the modelling framework, the four scenarios are implemented by imposing the carbon price paths as estimated in Garnaut Climate Change Review (2008) and Treasury (2008). Figure 9.3 shows the carbon price paths for the four scenarios.

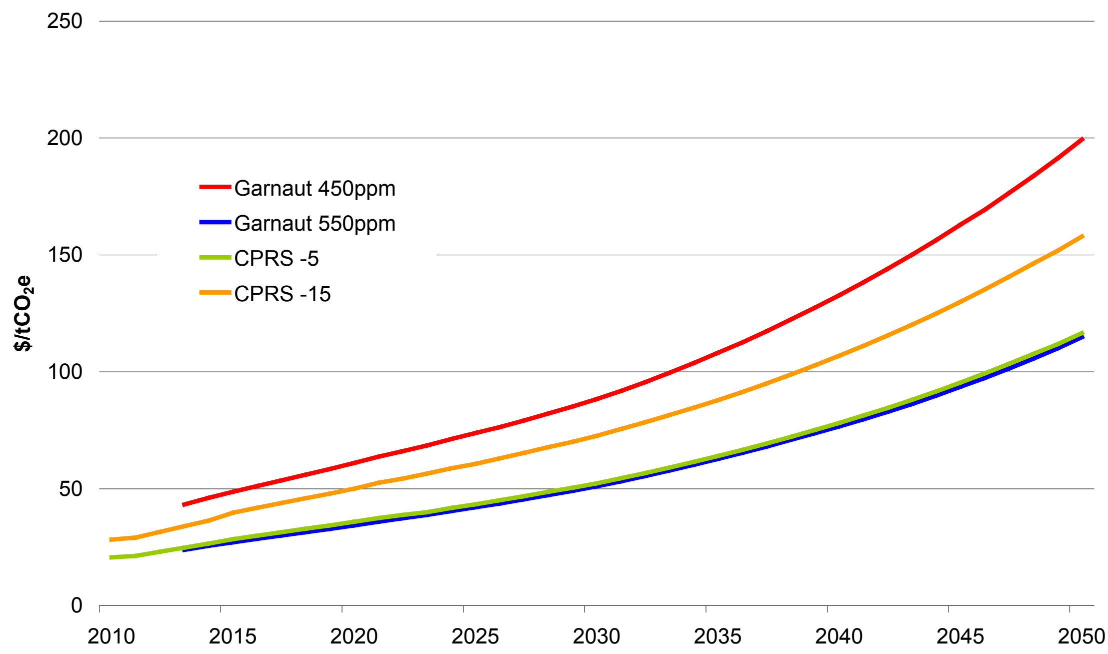


Figure 9.3: CO_2e permit prices

The expanded Renewable Energy Target (RET) is also an important policy change which supports the deployment of solar energy technology and other renewable electricity generation technologies. It requires that electricity retailers purchase enough renewable energy certificates (RECs) so that an additional 45,000 GWh of renewable electricity is generated by 2020. If all of this power were generated by renewables with a capacity factor of 0.27, then this implies that 19 GW of renewable electricity generation capacity must be deployed by 2020. If some of the electricity comes from higher capacity factor plant such as hot fractured rocks and biomass (with capacity factors of around 0.8), the capacity required is significantly reduced. However, hot fractured rocks remain unproven at this stage and limited biomass resources constrain the amount of electricity available from this technology.

9.1.6 Scenario results

This section presents the main modelling results for each of the scenarios modelled, starting with electricity generation profiles.

Electricity generation profiles

CPRS-5

To recap, CPRS-5 is assumed to commence in 2010, with an emissions allocation that leads to a reduction in emissions of 5 per cent on 2000 levels by 2020 and 60 per cent below 2000 levels by 2050. Figure 9.4 shows the optimal National technology mix under CPRS-5.

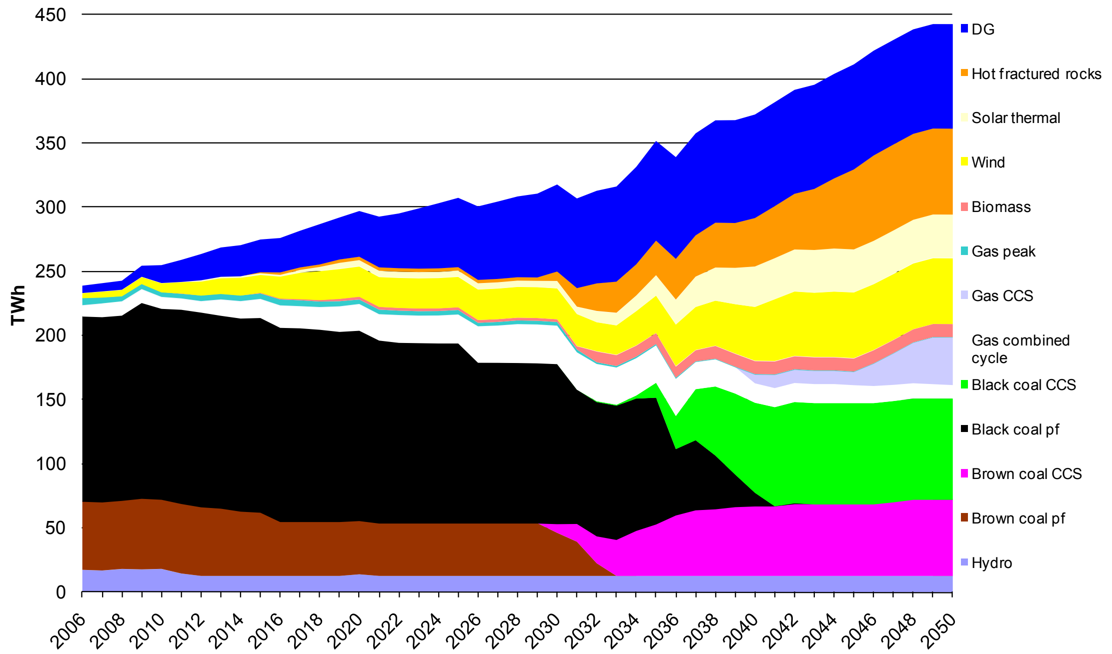


Figure 9.4: National electricity generation under CPRS-5, 2006-2050

It is clear from Figure 9.4 that the current deployment of DG technologies is relatively small in the National generation mix, with electricity generation dominated by coal-fired plant. Over time as the carbon price increases the competitive position of low emission technologies improves and as such the share of large-scale renewables increases (initially wind farms, followed by solar thermal and geothermal). Although CCS technologies are assumed to be commercial by 2020, they do not appear in the least-cost mix until around 2030. Also apparent from Figure 9.4 is that although centralised plant maintains a large share of supply, between 2010 and 2030, DG increases its share significantly. This time period represents a window of opportunity for DG to meet rising electricity demand before CCS technologies are viable. Figure 9.5 provides more detail on the optimal DG technology mix under CPRS-5.

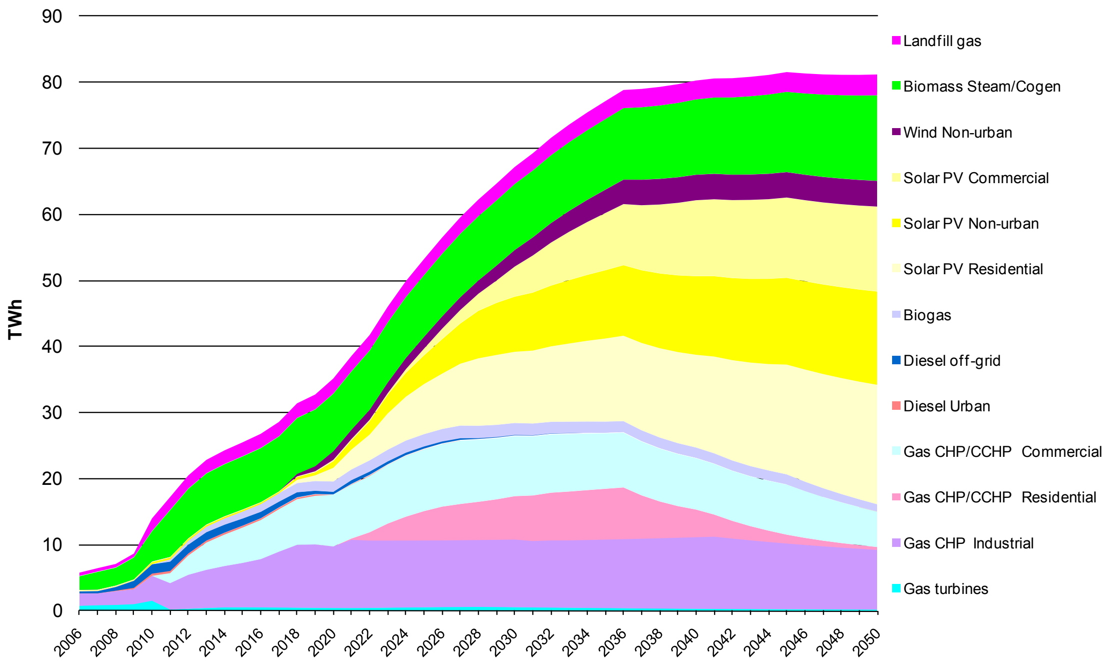


Figure 9.5: Distributed generation by technology under CPRS-5, 2006-2050

Figure 9.5 shows that initially it is the uptake of gas cogeneration technologies in the industrial sector that increases the share of DG in the National generation portfolio. Deployment of gas trigeneration technologies in the commercial sector also steadily increases reflecting opportunities in office buildings. Initially, cost-effective renewables include landfill gas engines and biomass CHP. A striking feature of Figure 9.5 is the significant uptake of solar photovoltaic from around 2020. Under the assumptions used, the installed cost of PV in the residential and rural sectors reaches grid-parity around this time. Wind turbines in rural areas are also competitive except where biomass is an option.

CPRS -15

CPRS-15 is assumed to commence in 2010. In contrast to CPRS-5, CPRS-15 represents an emissions allocation that leads to a reduction in emissions of 15 per cent on 2000 levels by 2020 and 60 per cent below 2000 levels by 2050. Figure 9.6 shows the optimal National technology mix under CPRS-15.

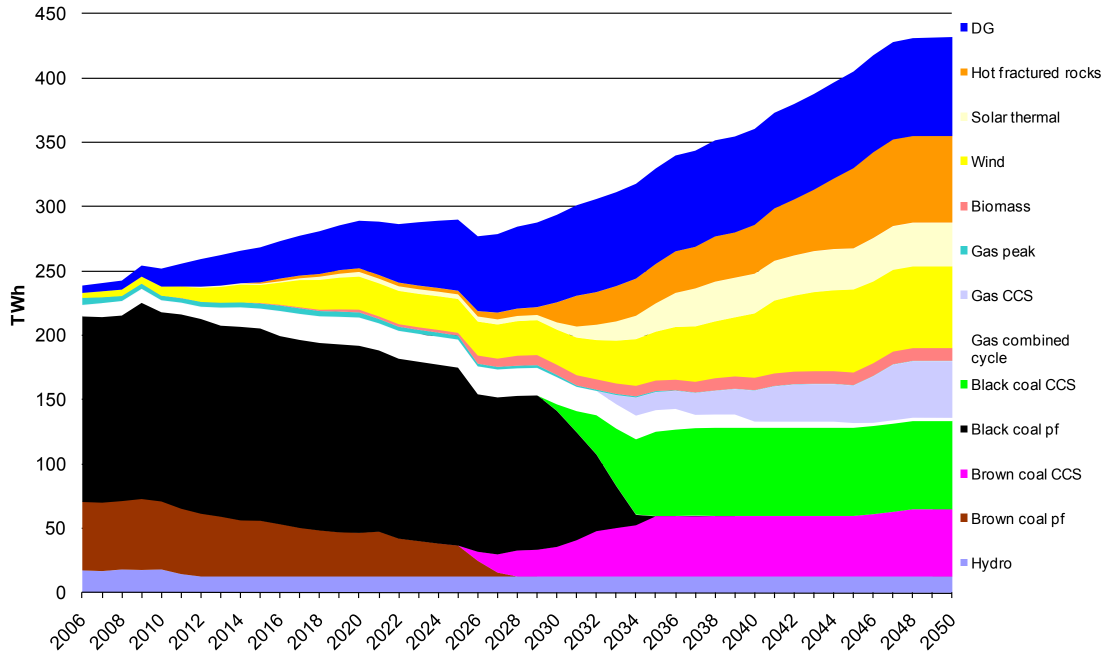


Figure 9.6: National electricity generation under CPRS-15, 2006-2050

Figure 9.6 shows that the more stringent emissions target results in a reduced electricity demand over the near term and has brought forward the retirement of coal-fired plant and the deployment of renewable and CCS technologies. Similarly, in Figure 9.7, although the uptake of gas co- and trigeneration technologies shows minimal difference (to CPRS-5), gas engines without the capture of waste heat fill a niche in the near term. The accelerated uptake of solar PV also commences sooner than in CPRS-5.

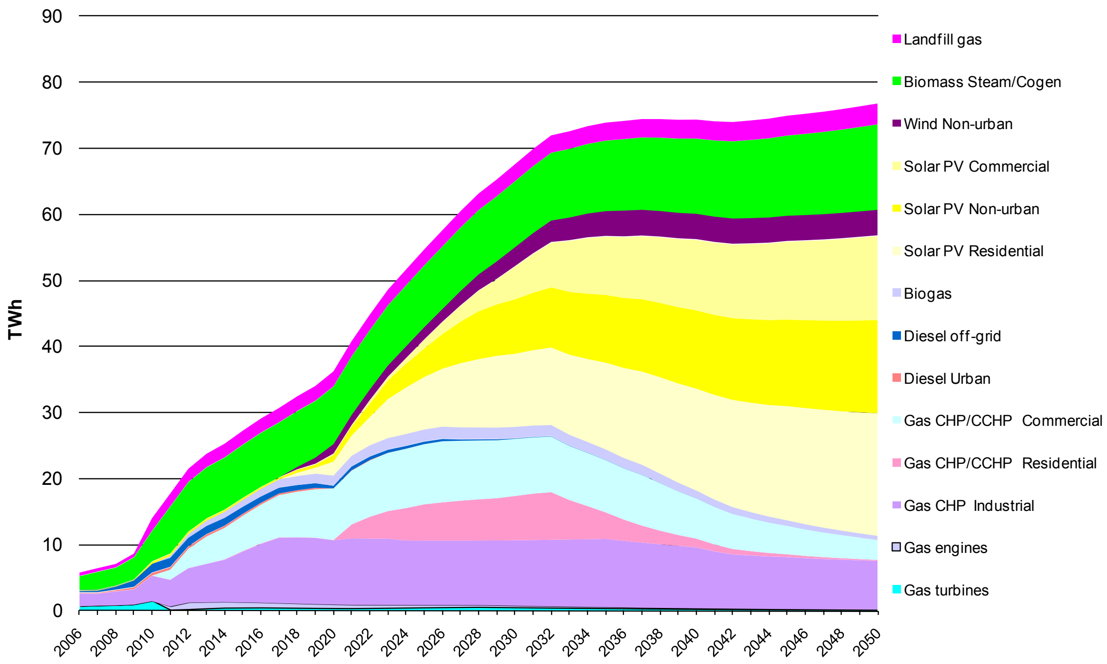


Figure 9.7: Distributed generation under CPRS-15, 2006-2050

Garnaut 550ppm

Garnaut 550ppm is assumed to commence in 2013. It represents an emissions allocation that leads to a reduction in emissions of 10 per cent on 2000 levels by 2020 and 80 per cent below 2000 levels by 2050 for stabilisation at 550 ppm.

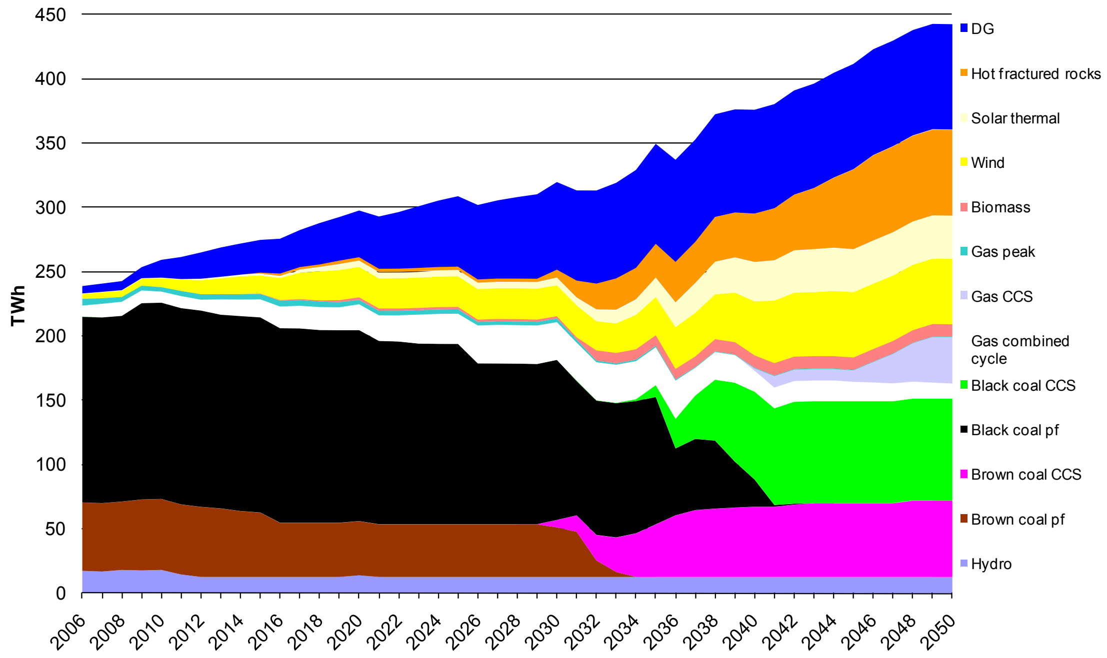


Figure 9.8: National electricity generation under Garnaut 550ppm, 2006-2050

Figure 9.8and Figure 9.9 show that there is little variation between Garnaut 550ppm and CPRS-5 scenarios. The only notable difference is that because of the 2013 start date, the initial uptake of DG and non-hydro renewables is slightly less than under CPRS-5.

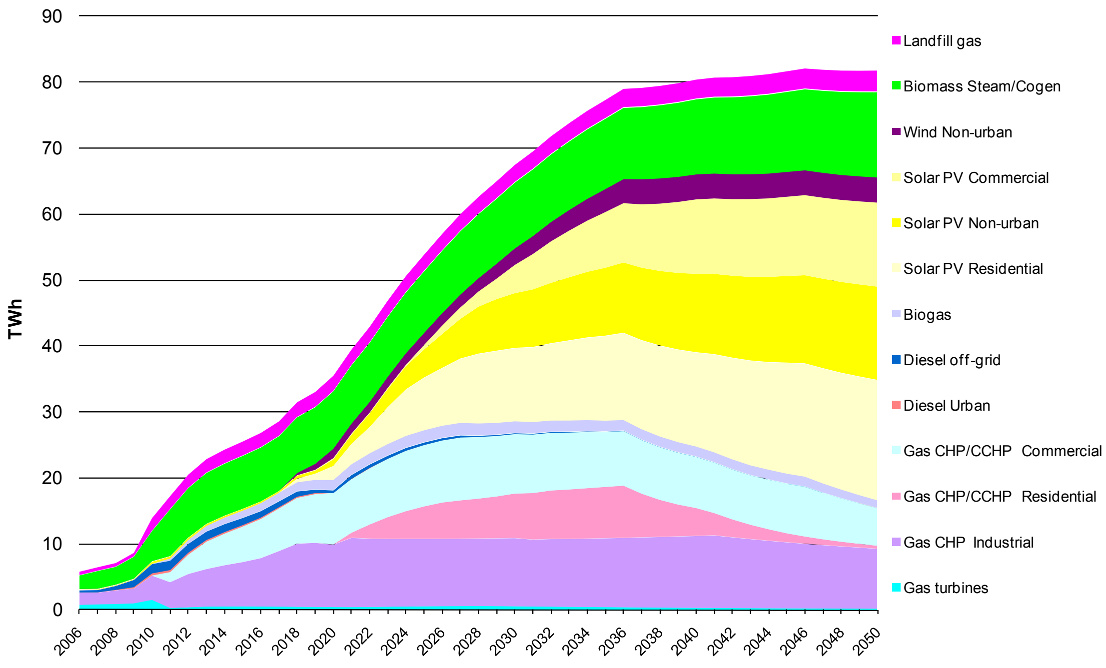


Figure 9.9: Distributed generation under Garnaut 550ppm, 2006-2050

Garnaut 450ppm

Garnaut 450ppm is assumed to commence in 2013. It represents an emissions allocation that leads to a reduction in emissions of 25 per cent on 2000 levels by 2020 and 90 per cent below 2000 levels by 2050 for stabilisation at 450 ppm. Garnaut 450ppm represents the most stringent emission abatement scenario that is modelled in this report.

Figure 9.10 shows the optimal National technology mix under Garnaut 450ppm. In contrast to all the other scenarios, there is greater structural adjustment in the electricity sector with brown coal pf plant off-line around 2020 and black coal pf shut down by 2030. Uptake of CCS occurs earlier because it is viable given the higher carbon price. Natural gas plays a greater role and there is more deployment of non-hydro renewables in the medium-term. The growth in the demand for electricity is also more subdued with a notable decline in demand just prior to 2030.

Figure 9.11 shows that the uptake of DG follows a similar profile as that under CPRS-15 although the absolute level of generation is slightly lower. However, because of lower electricity demand, the share of DG is greater than in the other scenarios.

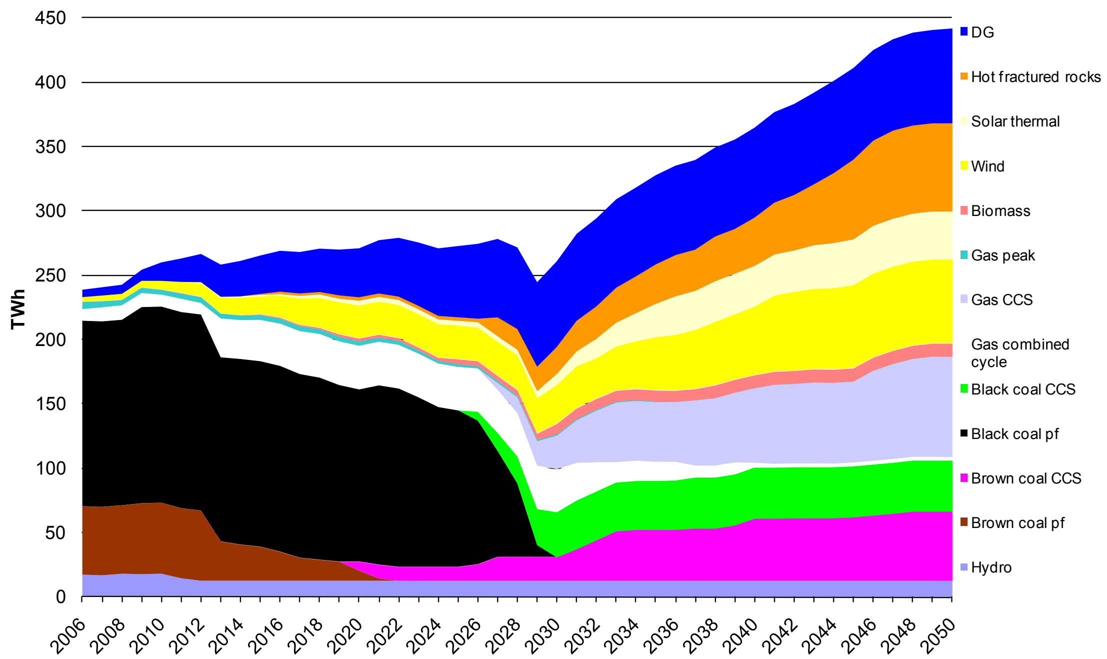


Figure 9.10: National electricity generation under Garnaut 450ppm, 2006-2050

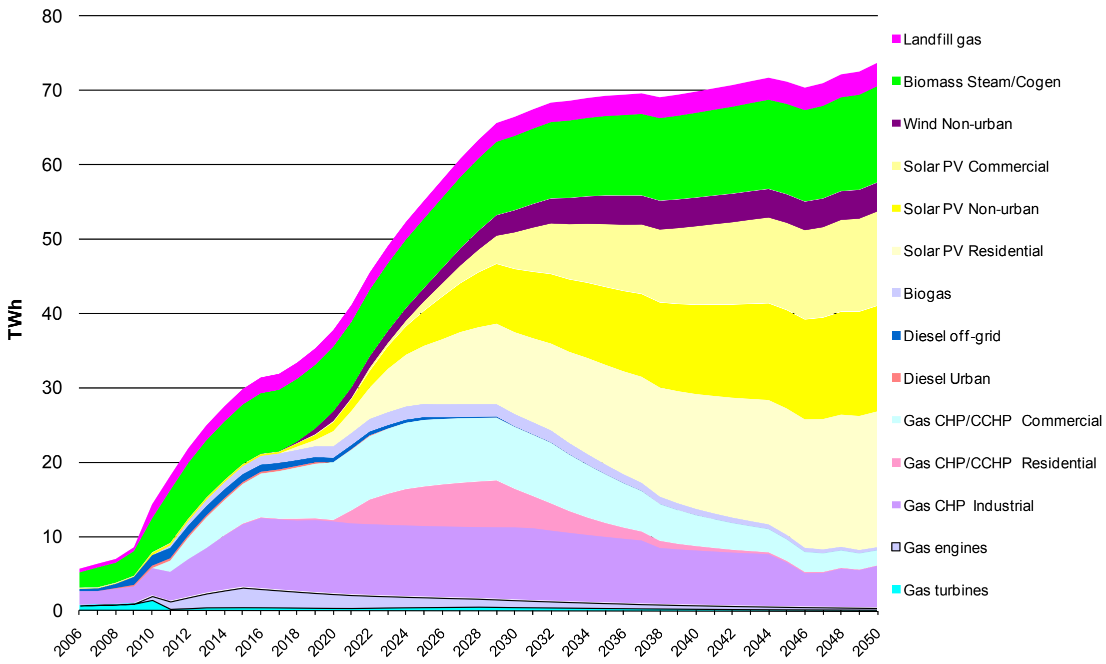


Figure 9.11: Distributed generation under Garnaut 450ppm, 2006-2050

Installed capacity

Another perspective on the structural changes in the electricity sector under the four modelled scenarios is the evolution of installed capacity over time. Under all scenarios, installed capacity increases from its 2006 level of around 47 gigawatts (GW) to around 105 GW by 2050. Figure 9.13 through to Figure 9.16 mirror the electricity generation profiles of the preceding section. DG capacity increases significantly over time matching the capacity of large-scale non-hydro renewables by 2050.

The similarity in the estimated installed capacity in each scenario by 2050 to some extent reflects the deployment of plug-in hybrid electric and electric vehicles (PHEVs and EVs) in the transport sector. Dependent on the scenario, this increases electricity demand in 2050 by between 10 to 13 per cent. The emergence of the partial electrification of the road transport sector is shown in Figure 9.12. The figure shows that by 2050 PHEVs and EVs will account for over half of kilometres travelled. Mild hybrids which generate their electricity on board rather than drawing on the electricity grid are projected to account for another 20 per cent of the fleet leaving internal combustion vehicles accounting for around 17 per cent of kilometres travelled.

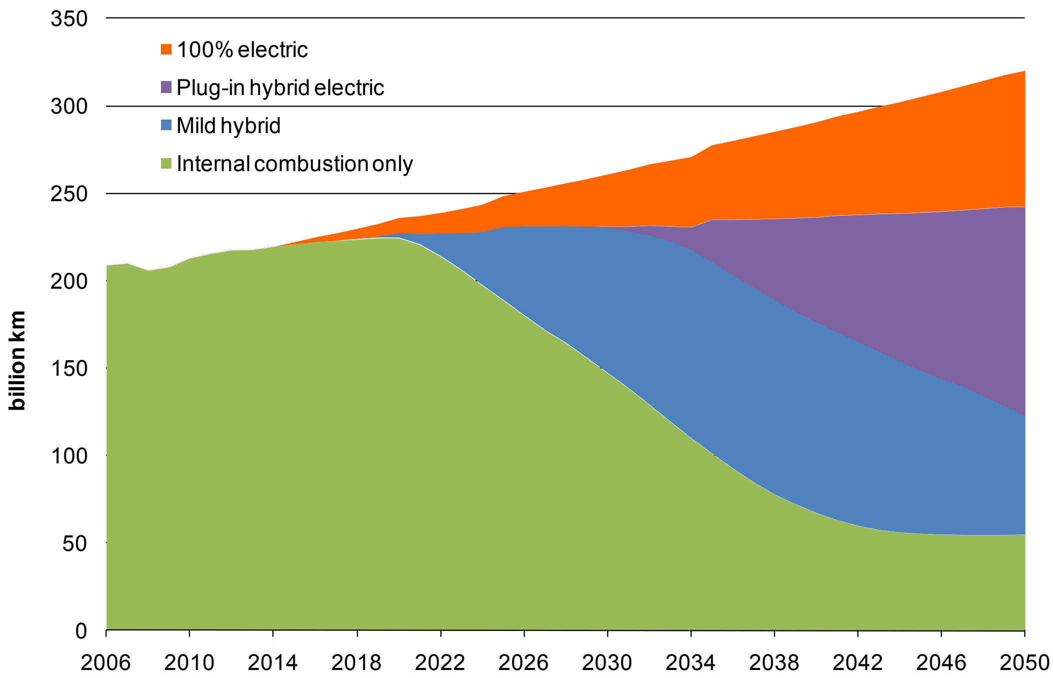


Figure 9.12: Projected increasing electrification of road transport vehicles, Garnaut 450ppm

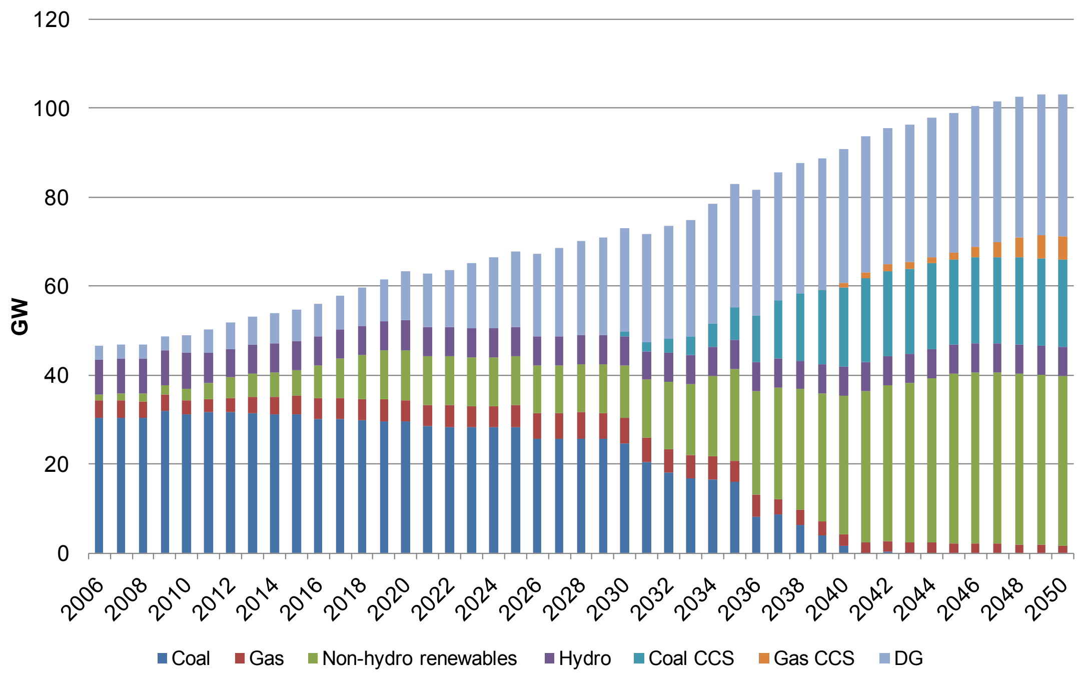


Figure 9.13: Installed capacity, CPRS-5

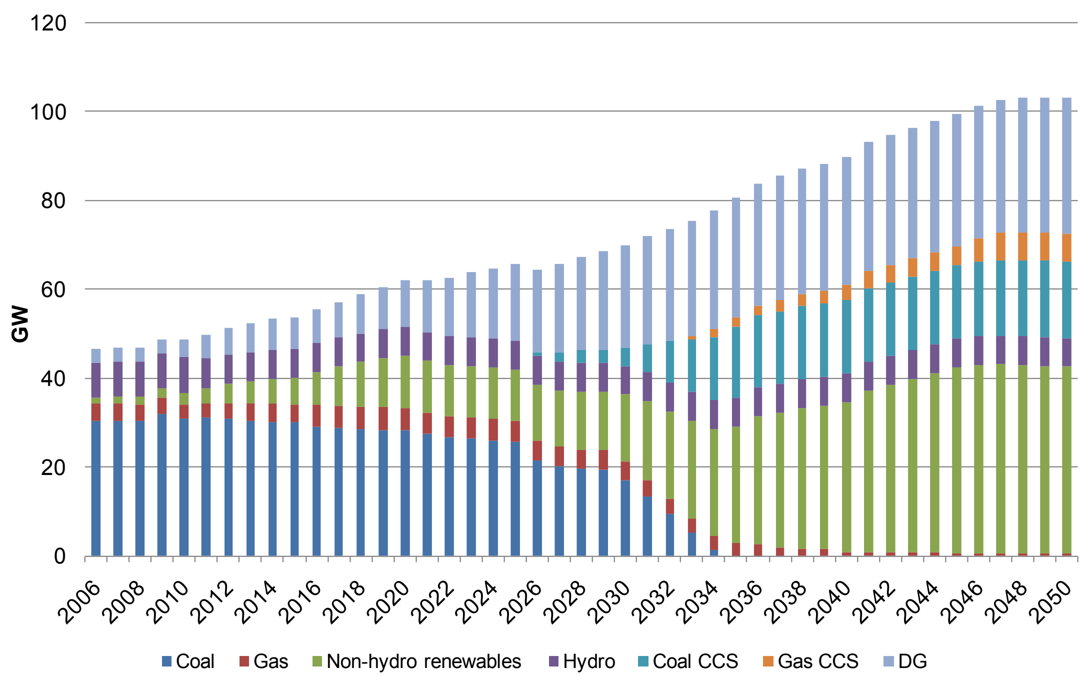


Figure 9.14: Installed capacity, CPRS-15

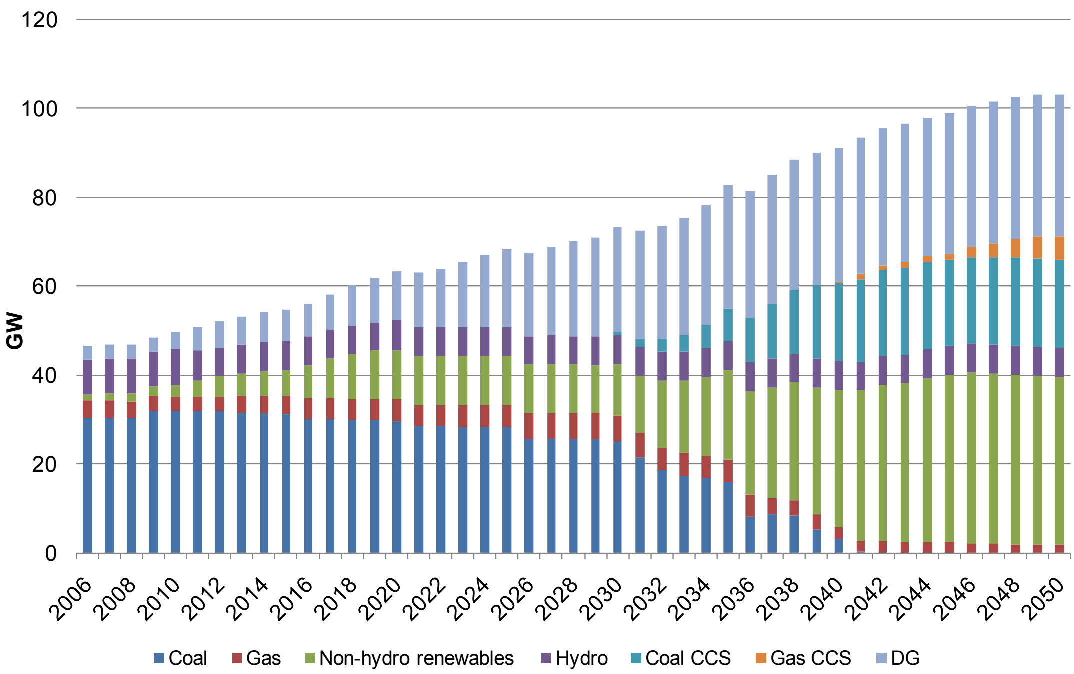


Figure 9.15: Installed capacity, Garnaut 550ppm

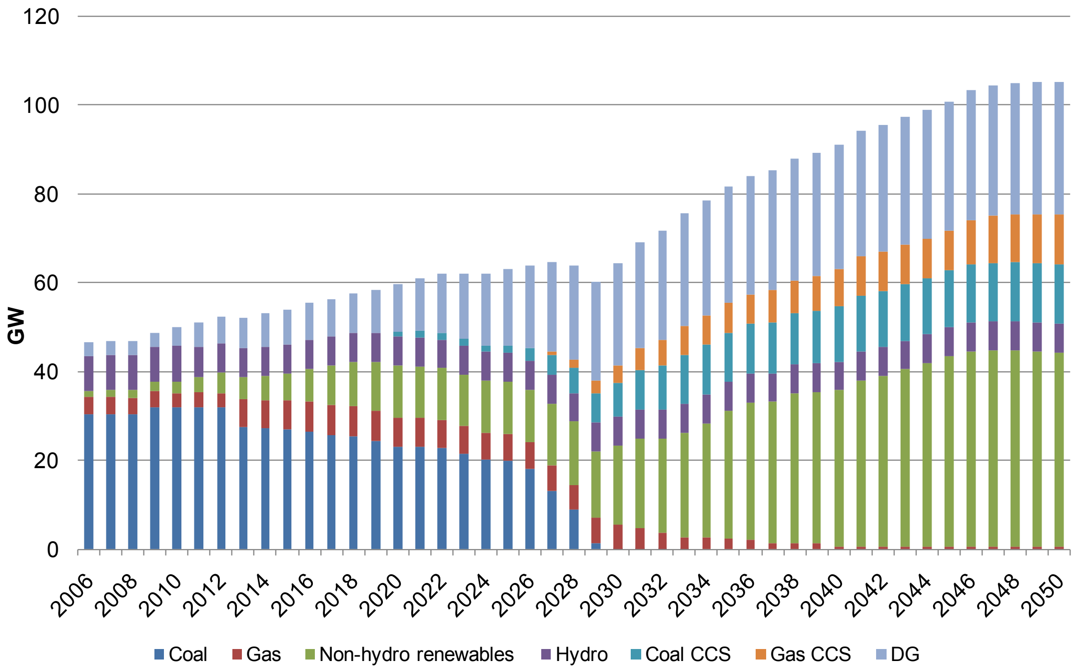


Figure 9.16: Installed capacity, Garnaut 450ppm

Retail electricity prices

Figure 9.17 through Figure 9.20 show the estimated National electricity price that is faced by different end-users over the projection period[12]. Note that all prices are in real 2006 dollars and measured in c/kWh. As shown, the retail price of electricity depends on the type of customer. Higher prices for rural end-users reflect premiums to cover higher costs of transmission and distribution of electricity via the grid. Lower prices for residential compared to commercial customers reflect differences in regulated tariffs. Industrial customers incur the lowest retail price due to discounts for high volume consumption, more intensive retail market contestability and participation in demand management (through load shedding for example).

In regard to the carbon price scenarios, the earlier start date for the CPRS scenarios is clearly visible in the charts with the price trace for CPRS-15 above that of CPRS-5. With commencement in 2013, the increase in prices is greatest under Garnaut 450ppm with the price trace for Garnaut 550ppm following a similar trajectory to that of CPRS-5.

Industrial customers face the largest percentage increases when compared to other end-users. In contrast to other end-users, network and retail costs make up a smaller proportion of their delivered cost meaning that higher wholesale electricity prices account for a greater share of their retail price.

A striking feature of Figure 9.20 is that from around 2030 onward, rural customers face declining costs under the carbon price scenarios. This reflects the significant deployment of DG in this sector reducing the unit cost of electricity used by rural customers.

[12] Estimated retail electricity prices are available for all States and Territories. Presented here is the volume weighted National average for illustrative purposes.

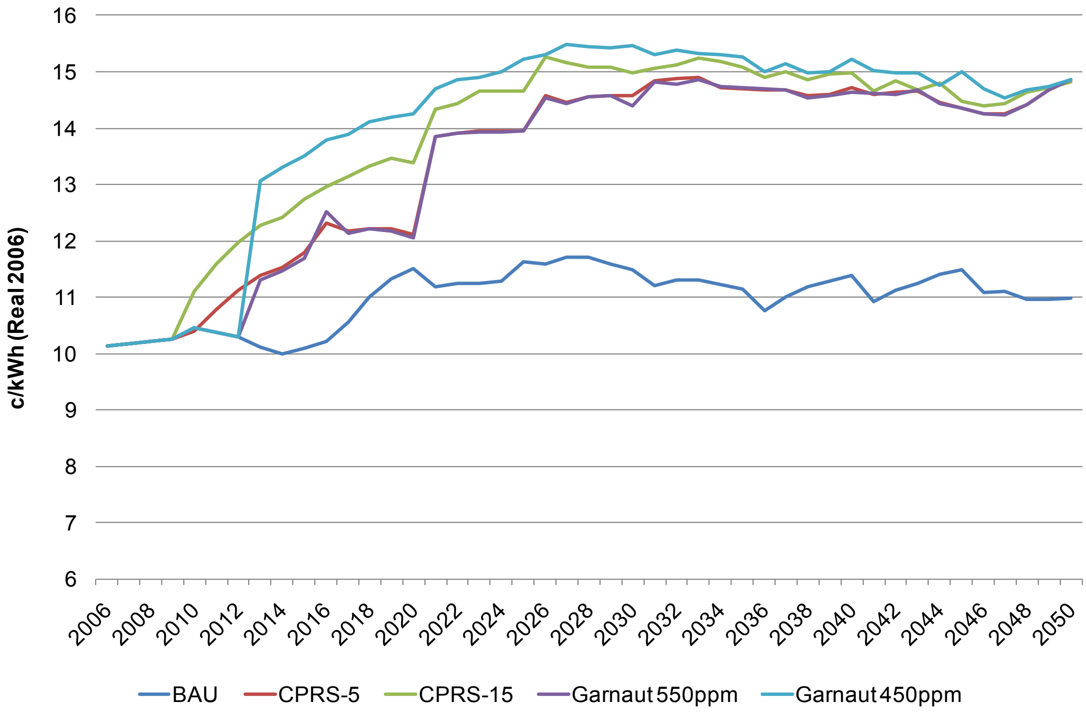


Figure 9.17: National average retail prices, Residential customers, 2006-2050

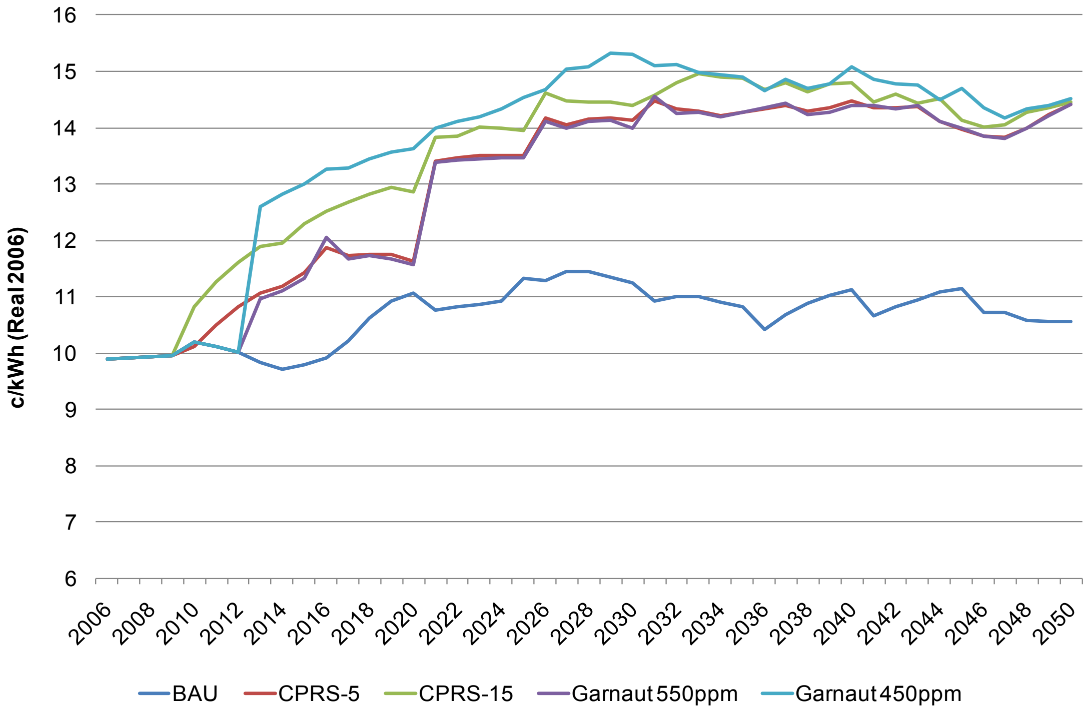


Figure 9.18: National average retail prices, Commercial customers, 2006-2050

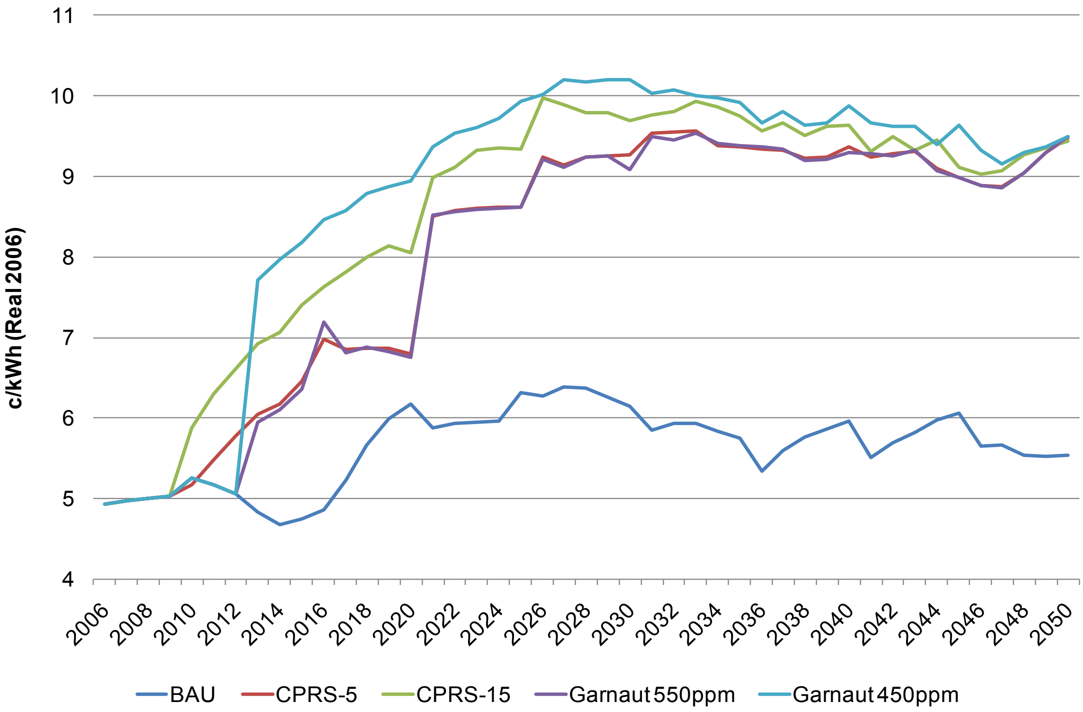


Figure 9.19: National average retail prices, Industrial customers, 2006-2050

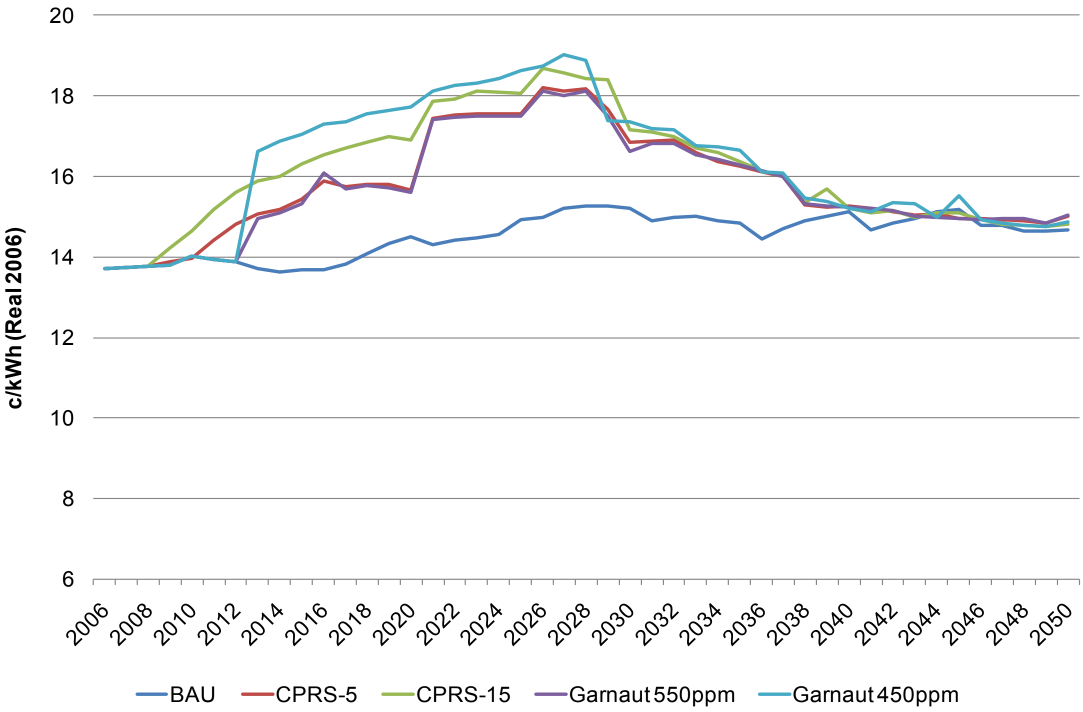


Figure 9.20: National average retail prices, rural customers, 2006-2050

Greenhouse gas emissions and abatement

Figure 9.21 shows the estimated greenhouse gas (GHG) emissions under business as usual and the four carbon price scenarios. Estimated emissions are an output of the model based on the technologies used to supply electricity which is influenced by the assumed carbon prices. The GHG emission factors employed in the modelling were obtained from DCC (2008).

Under business as usual (BAU), GHG emissions track an upward trend reaching around 430 million tonnes (Mt) by 2050. Figure 9.21 also shows that under all carbon price scenarios, the electricity sector almost fully decarbonises by 2050. The main difference is the rate of decrease in total emissions. GHG emissions are reduced more quickly under Garnaut 450ppm reaching around 20 Mt in 2030; a level that is not reached until 2050 under CPRS-5 and Garnaut 550ppm.

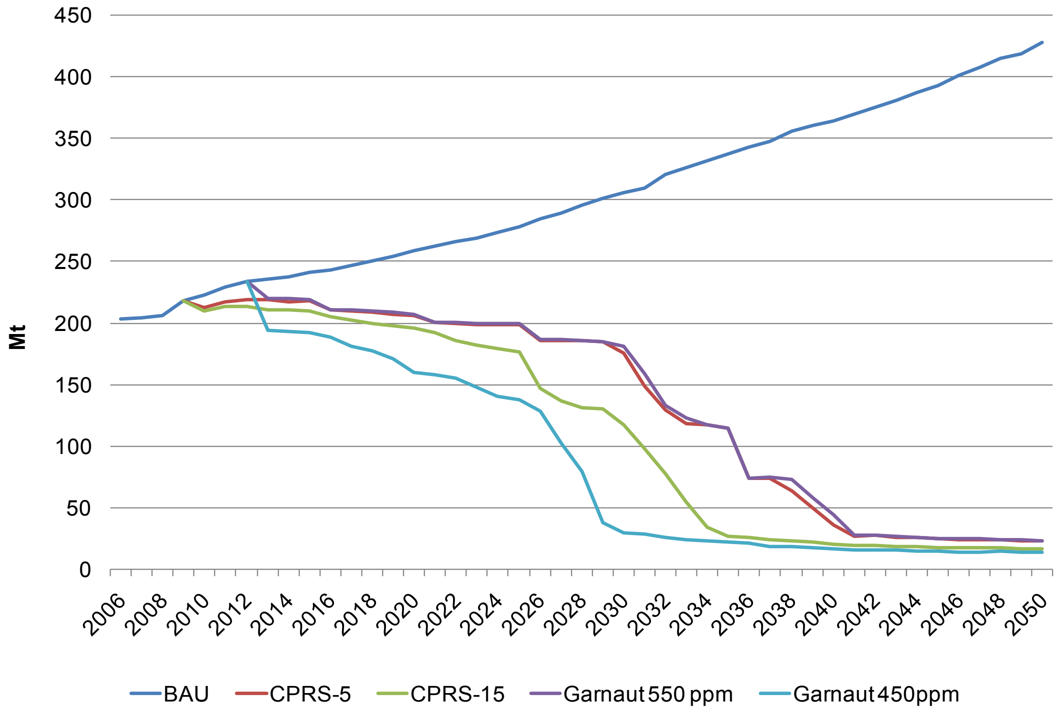


Figure 9.21: Electricity sector greenhouse gas emissions by scenario

An alternative way to examine the decline in emissions intensity of the electricity sector is to estimate the amount of abatement attributable to different technologies. Figure 9.22 through Figure 9.25 show the abatement by the following broad categories: electricity efficiency/demand reduction; distributed generation; large-scale renewables; natural gas plant without CCS; and coal and gas plant with CCS.

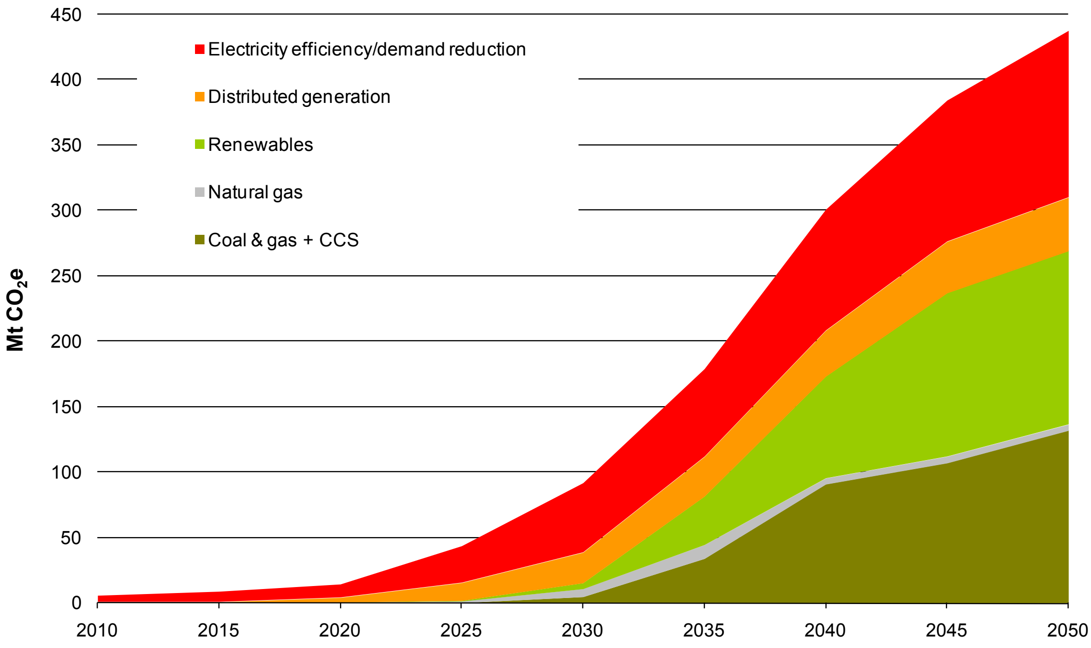


Figure 9.22: Electricity sector greenhouse gas abatement, CPRS-5

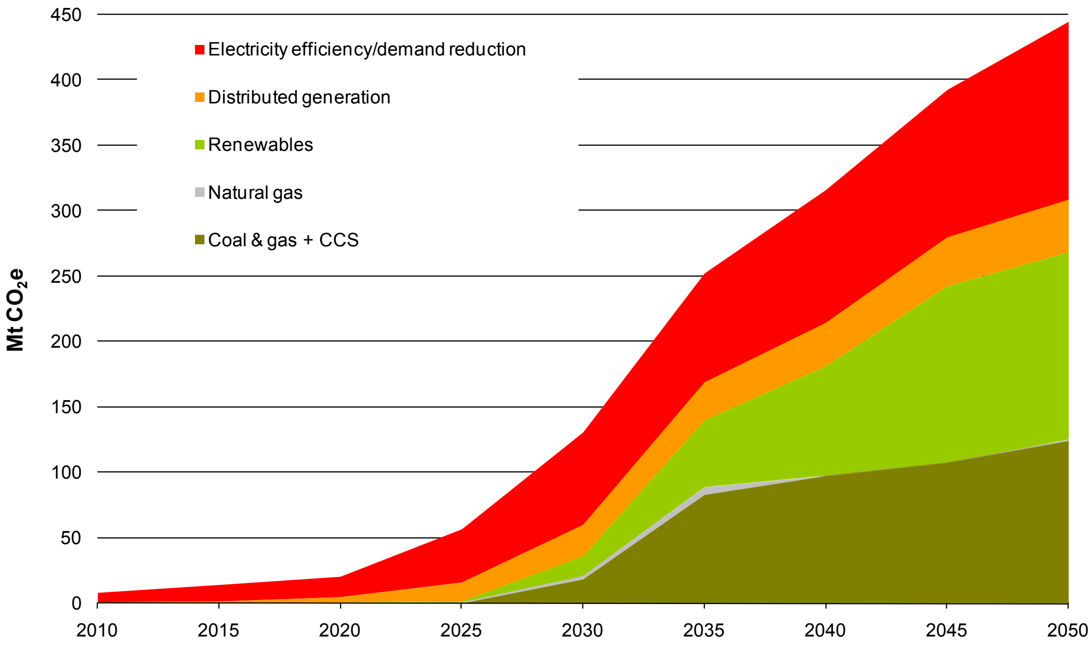


Figure 9.23: Electricity sector greenhouse gas abatement, CPRS-15

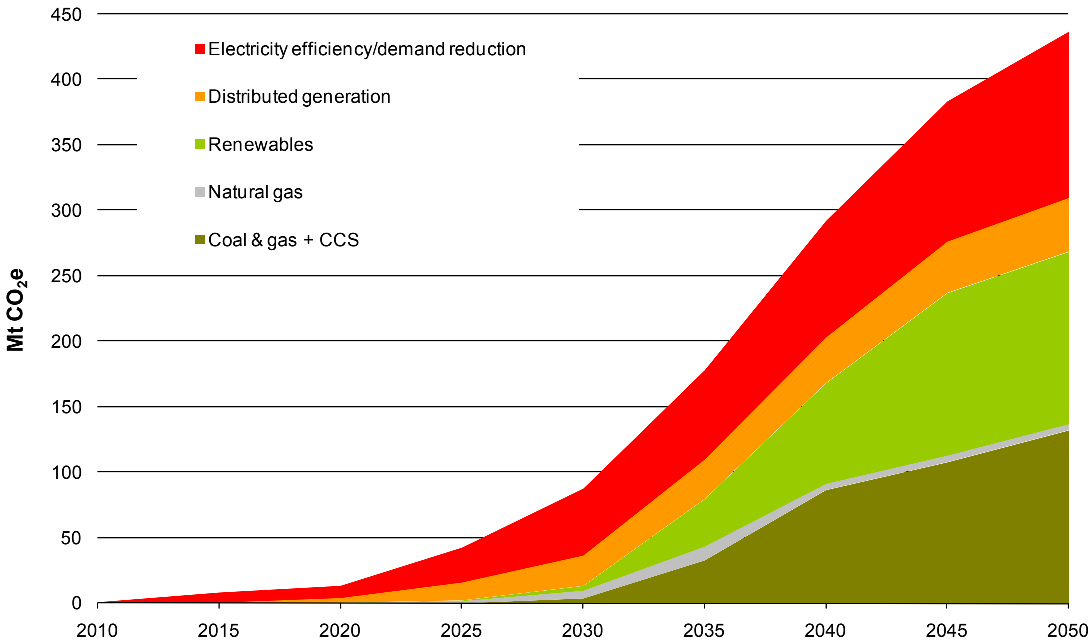


Figure 9.24: Electricity sector greenhouse gas abatement, Garnaut 550ppm

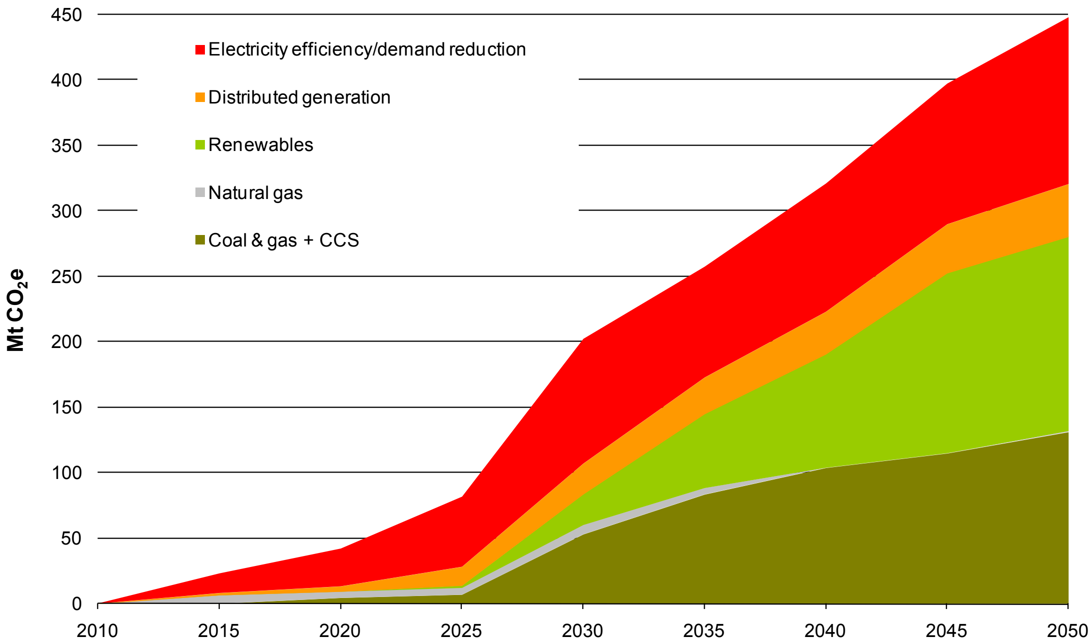


Figure 9.25: Electricity sector greenhouse gas abatement, Garnaut 450ppm

Figure 9.22 through Figure 9.25 shows that out to 2025, most greenhouse gas abatement in the electricity sector is achieved through energy efficiency/demand reduction followed by DG. The energy efficiency/demand reduction wedge is consistent with the view that such reductions represent the least cost abatement opportunities in the energy sector. Greenhouse gas abatement via DG is initially achieved through low cost CHP opportunities in the industrial and rural sectors. The abatement share of large scale renewables to 2030 appears minimal. This is because the model incorporates the expanded RET as a baseline, or business as usual condition. Accordingly, the difference between renewable electricity generation under BAU and most of the carbon price scenarios up to 2030 is only marginally different.

From 2030 onwards, the shares attributed to energy efficiency/demand reduction and DG continue to grow. However, there is an increasing share of greenhouse gas abatement attributed to large-scale renewables and coal and gas CCS out to 2050. The abatement achieved by centralised natural gas-fired electricity generation is negligible in all scenarios.

As pointed out in Graham (2009), the greenhouse gas abatement attributable to alternative technologies is not only dependent on the assumptions contained in the emission reduction scenarios but also on the reference case or business as usual scenario. For example, the inclusion of the expanded RET in the BAU scenario limited the abatement attributed to large scale renewables up to 2030. Similarly, our inclusion of DG technologies as generation options in the BAU reduces their share of abatement. This may underestimate DG as a mitigation option when compared to a BAU that does not include DG.

To illustrate this difference, Table 9.2 shows the greenhouse gas abatement in Mt/y resulting from DG under a BAU that includes DG and a BAU that does not.

Table 9.2: Greenhouse gas abatement attributed to DG under alternative BAU scenarios

	2020	**2030**	**2040**	**2050**
BAU incl. DG				
CPRS-5	3.6	23.4	35.1	41.0
CPRS-15	3.9	24.0	33.4	40.6
Garnaut 550ppm	3.9	23.4	35.1	41.2
Garnaut 450ppm	4.1	23.6	32.7	40.4
BAU excl. DG				
CPRS-5	17.0	38.8	53.3	61.3
CPRS-15	17.4	39.3	51.1	59.6
Garnaut 550ppm	17.2	38.9	53.3	61.6
Garnaut 450ppm	17.6	38.8	49.3	58.1

In proportional terms, Table 9.2 shows that the differential is greatest in 2020 with DG abatement increasing four to five fold. In absolute terms, the differential is greatest in 2050 where DG contributes around 60 Mt of abatement compared to around 40 Mt when DG is included in the BAU scenario. This reflects the deployment of natural gas-fired co- and trigeneration technologies over the projection period.

Pollutant emissions and water consumption

The existing literature indicates that increased DG deployment can lead to significant reductions in non-greenhouse gas pollutants including: nitrogen oxides (NOx); sulfur dioxide (SO_2) and particulate matter (PM_{10}); by reducing the amount of coal-fired generation (see Azzi et al., 2005; Reedman and Mtwa, 2006).

Direct pollutant emission factors for centralised generation technologies were obtained from the NPI (2005). Pollutant emission factors for DG technologies were obtained from EPRI (2004) and are provided in Appendix D.

Figure 9.26 shows the estimated NOx emissions for the BAU and the four carbon price scenarios over the projection period. NOx emissions in the electricity sector are estimated to be around 525,000 tonnes in 2006 (ESAA, 2008). Under BAU, emissions follow an upward trend to 2050 reflecting the dominance of coal-fired plant. The difference in the carbon price scenarios reflects the role of coal-fired generation. The difference between CPRS-15 and Garnaut 450ppm from 2030 onwards reflects a greater role for natural gas CCS under Garnaut 450ppm and a greater role for coal CCS under CPRS-15.

SO_2 and PM_{10} emissions shown in Figure 9.27 and Figure 9.28 respectively depict similar declining patterns to NOx. It is important to note that while the total emissions reduce significantly the geographical location of the emission sources will change. In particular small scale DG technologies will be located close to populations centres compared with large central generation options. The effect of locating emission sources into urban areas is being considered in a separate CSIRO study sponsored by the NSW Department of Environment, Climate Change and Water (DECCW).

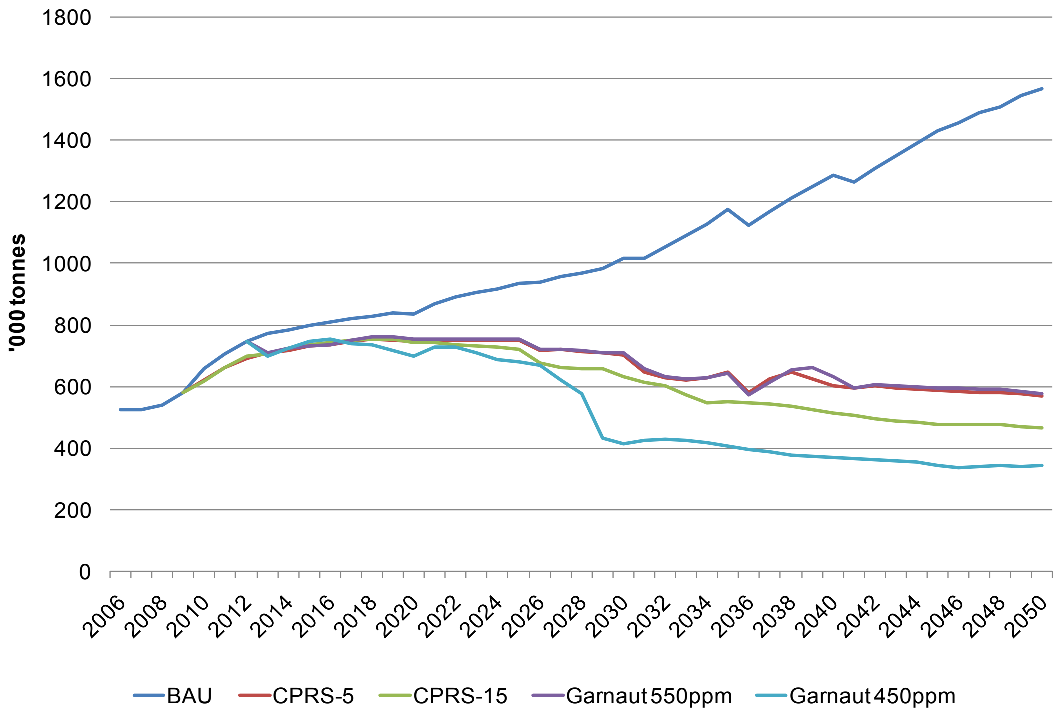


Figure 9.26: NOx emissions by scenario, 2006-2050

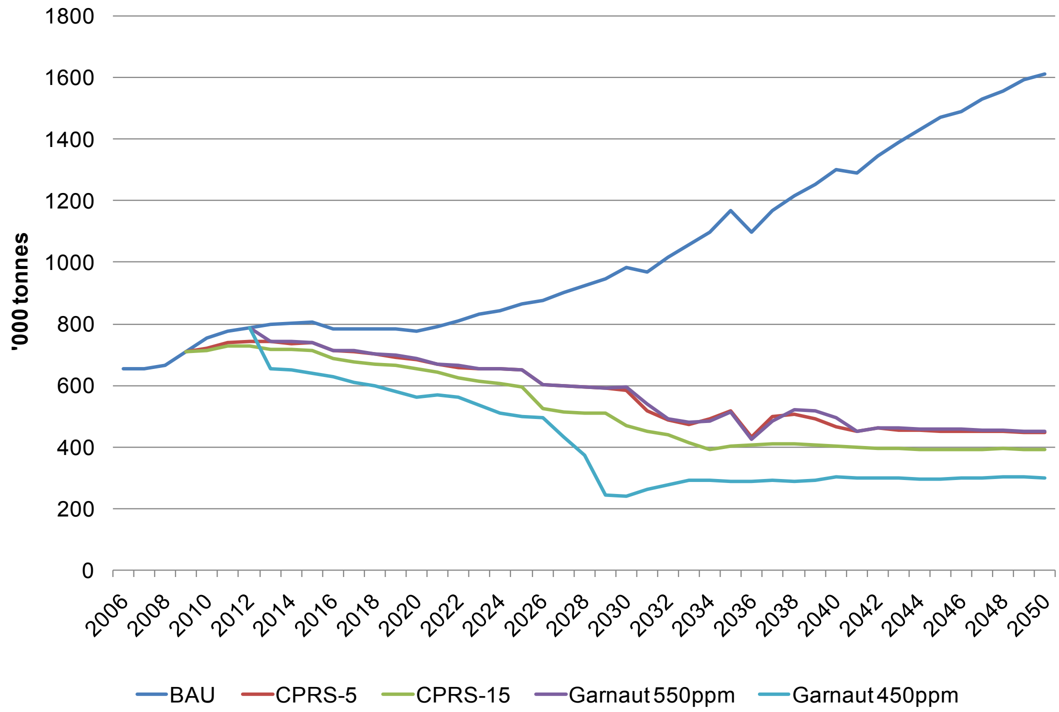


Figure 9.27: SO_2 emissions by scenario, 2006-2050

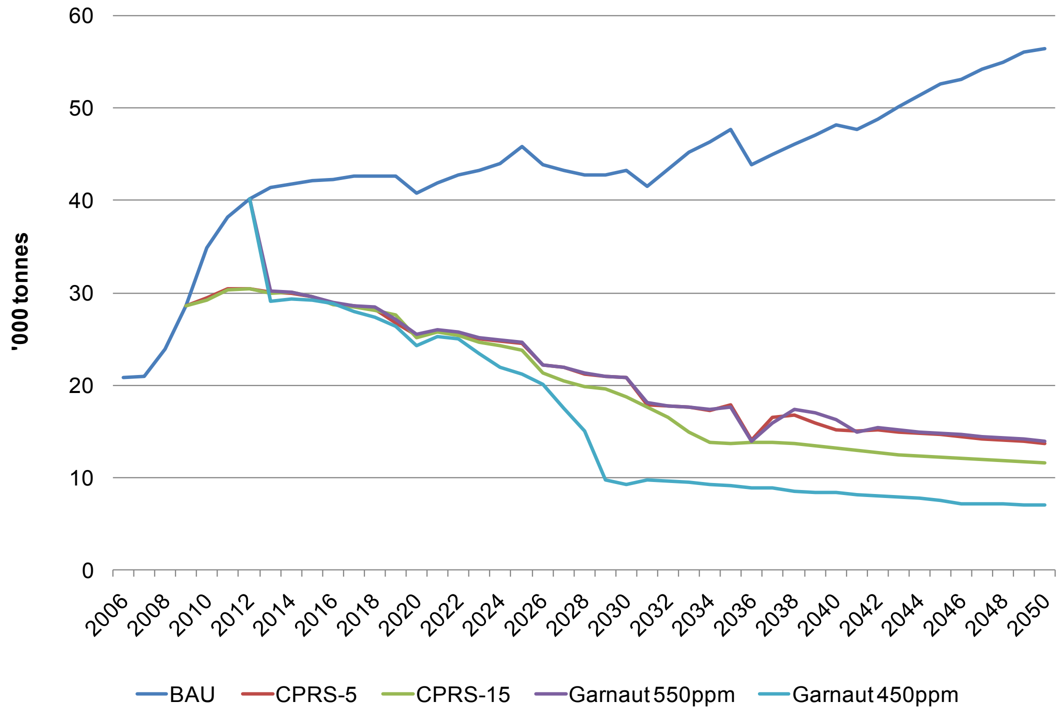


Figure 9.28: PM_{10} emissions by scenario, 2006-2050

Electricity generators are a significant user of water. Most of the water is used for hydro-electricity power generation, but coal-fired power stations also use considerable amounts of water in their boilers and cooling towers. Water used for hydro-electricity power generation is not a consumptive use as the water extracted passes through turbines to generate electricity and is discharged and made available to downstream users. Therefore, water use for hydro-electricity power generation is treated differently from other water uses and is called in-stream use. Water consumption by electricity generation is largely due to evaporation from cooling towers. According to the Australian Bureau of Statistics (ABS, 2006), the electricity generation sector consumed 271 gigalitres (Gl) of water in 2004/05; a 6% increase from 2000/01. Figure 9.29 shows the estimated water consumption for the BAU and four carbon price scenarios over the projection period.

The modelling in this report assumes that new base load fossil fuel power stations installed after 2007 will be (air) dry-cooled. It is not assumed that existing water-cooled base load fossil fuel power stations will be converted to air-cooled plant. Air-cooling is somewhat a misnomer as water consumption is curtailed but not eliminated. Water use is typically around 75 to 90 per cent less for technologies where this option is available (Ikeda et al., 2007; Smart and Aspinall, 2009).

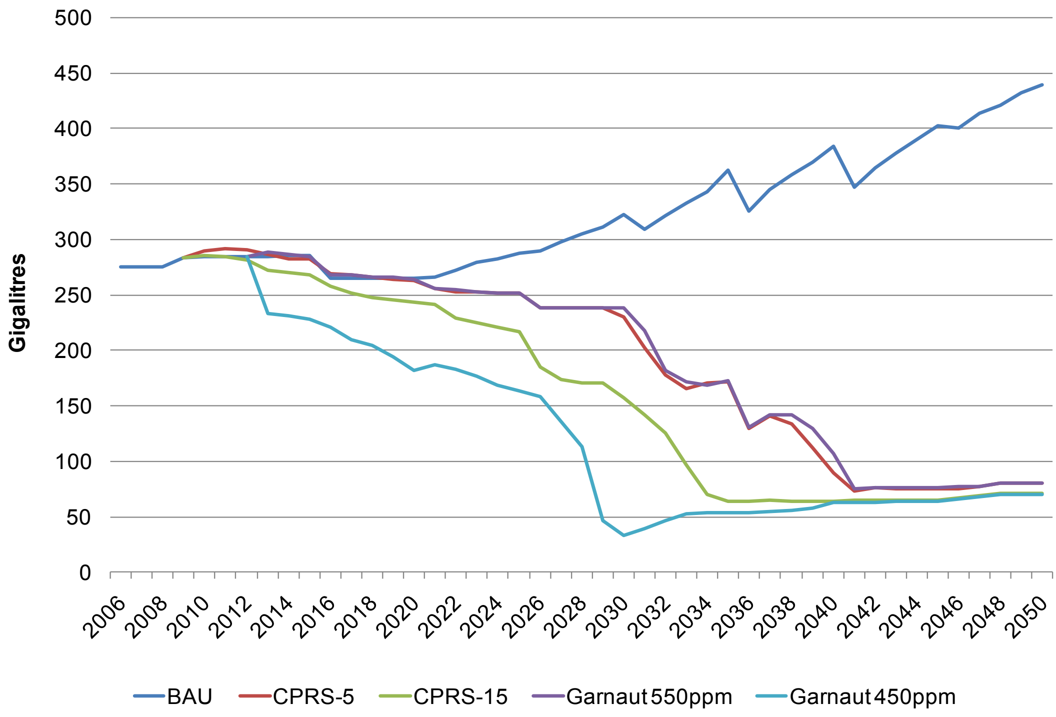


Figure 9.29: Water consumption by scenario, 2006-2050

Figure 9.29 shows that after an initial small increase, water consumption levels off or declines dependent on the scenario being examined. For BAU and the relatively mild carbon price scenarios (CPRS-5 and Garnaut 550ppm), the stabilisation is due to increased natural gas-fired generation and renewable deployment under MRET. For the relatively stringent carbon price scenarios (CPRS-15 and Garnaut 450ppm), the steady decline to 2030 reflects the shutdown of water cooled coal-fired plant and the deployment of DG and large scale renewables. Similar to greenhouse gas emissions, there is a convergence in water consumption in all carbon price scenarios towards 70 to 80 Gl in 2040. This reflects the attrition of water cooled coal-fired plant from the installed capacity and significant deployment of DG and large-scale renewables. Overall these water savings represent a substantial co-benefit when optimising the energy sector for a greenhouse emission reduction with total use in 2050 around ¼ current values.

9.1.7 Sensitivity analysis

The results reported above for the four carbon price scenarios may be sensitive to changes in some of the data inputs. Results from the base case scenarios show that DG technologies have a significant role to play, especially in the medium term, and the estimated uptake of CCS technologies is significant in the long term. Four sensitivity cases were explored:

Capital cost minus 20% (Capex-20): Given the technology coverage within our modelling framework, a number of the DG technologies considered are relatively immature in the Australian market or are currently undergoing research and development (e.g., fuel cells). Similarly, for centralised generation technologies, CCS and some geothermal technologies (e.g., hot fractured rocks) are currently unproven. Given the projection period being considered, the future capital costs of these technologies are subject to considerable uncertainty. The methodology for estimating point estimates of future capital costs for the base case is outlined in Appendix D. In this case, the future capital cost of all technologies is reduced by 20 per cent in all time periods. This case attempts to capture the lower bound of the uncertainty range

Capital cost plus 20% (Capex+20): In this sensitivity case, the future capital cost of all technologies is increased by 20 per cent in all time periods. This sensitivity case attempts to capture the upper bound of the uncertainty range

CO_2 capture and sequestration infeasible (CCS infeasible): In this sensitivity case it was assumed that CCS was infeasible for technical, political or environmental reasons and was therefore not an option. In the base case scenarios, uptake of CCS technologies is constrained with a cap on the amount of CO_2 that can be sequestered in a given year (see Appendix D for a discussion). In this sensitivity case, CCS is excluded as an option. This may lead to increased uptake of DG technologies depending on their relative economics to centralised zero emission renewable technologies

No investment constraint on DG technology (no DG CAP): in the base case, there is a cap on the amount of investment for all electricity generation technologies in the model. For DG technologies, investment is limited to 200 MW per technology for each State. For centralised technologies, investment is limited to 1,000 MW per technology for each State. The investment cap on some DG technologies may be overly restrictive. For example, it is not uncommon for some CHP installations to be 30 MW or greater. In contrast, 200 MW could equate to 100,000 - 2 kW solar PV installations per State. In this sensitivity case, the investment constraint on DG technology is removed.

Figure 9.30 through Figure 9.33 show the sensitivity of DG uptake as a percentage of total electricity generation for selected years under the four carbon price scenarios. Figure 9.34 summarises the range of DG uptake estimated in the base and sensitivity cases. Overall, the most sensitive assumption tested is the investment constraint on DG technology (no DG CAP). The removal of this constraint significantly increases the share of DG from around 2030 onwards, mainly from greater deployment of solar PV.

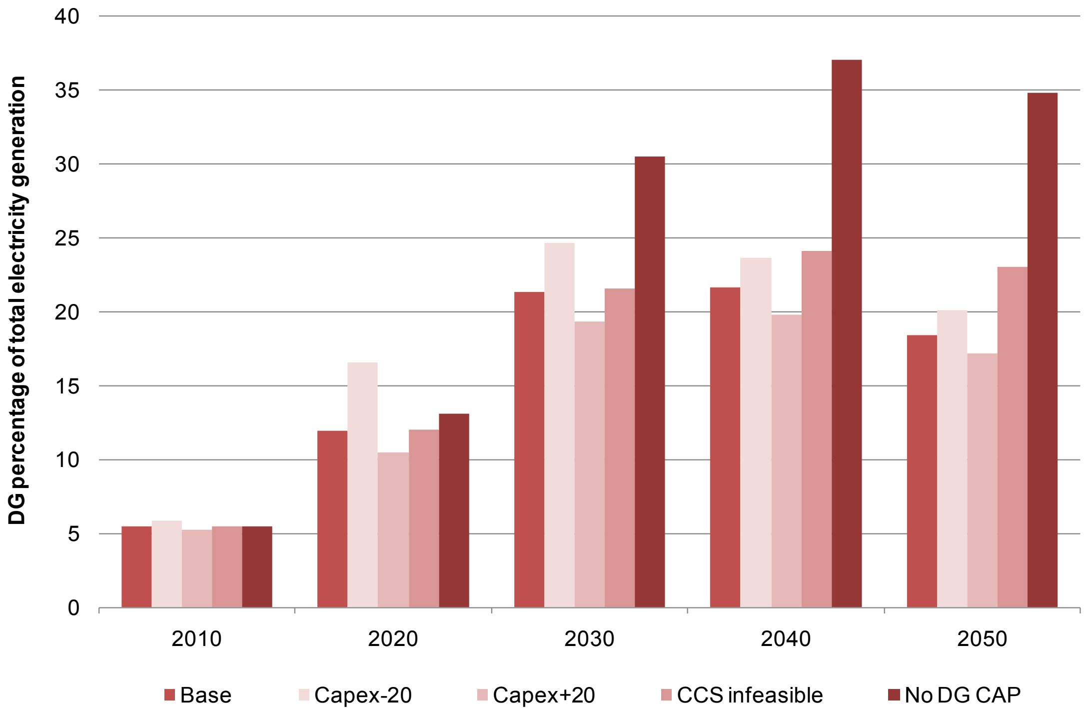


Figure 9.30: Sensitivity of DG uptake, selected years, CPRS-5

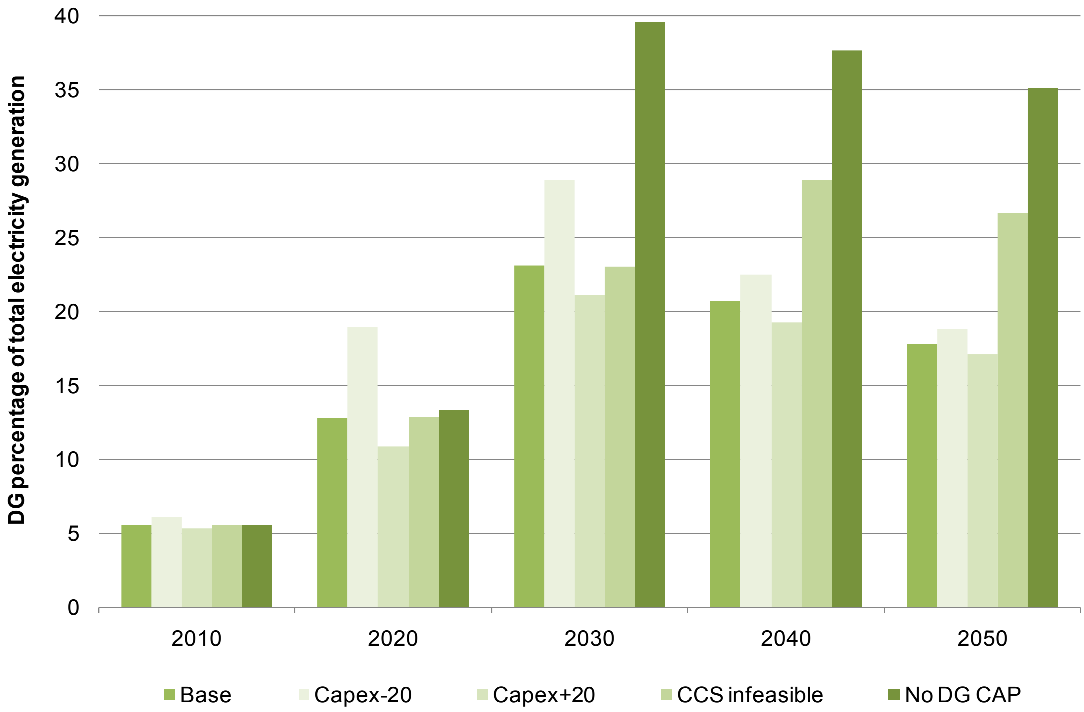


Figure 9.31: Sensitivity of DG uptake, selected years, CPRS-15

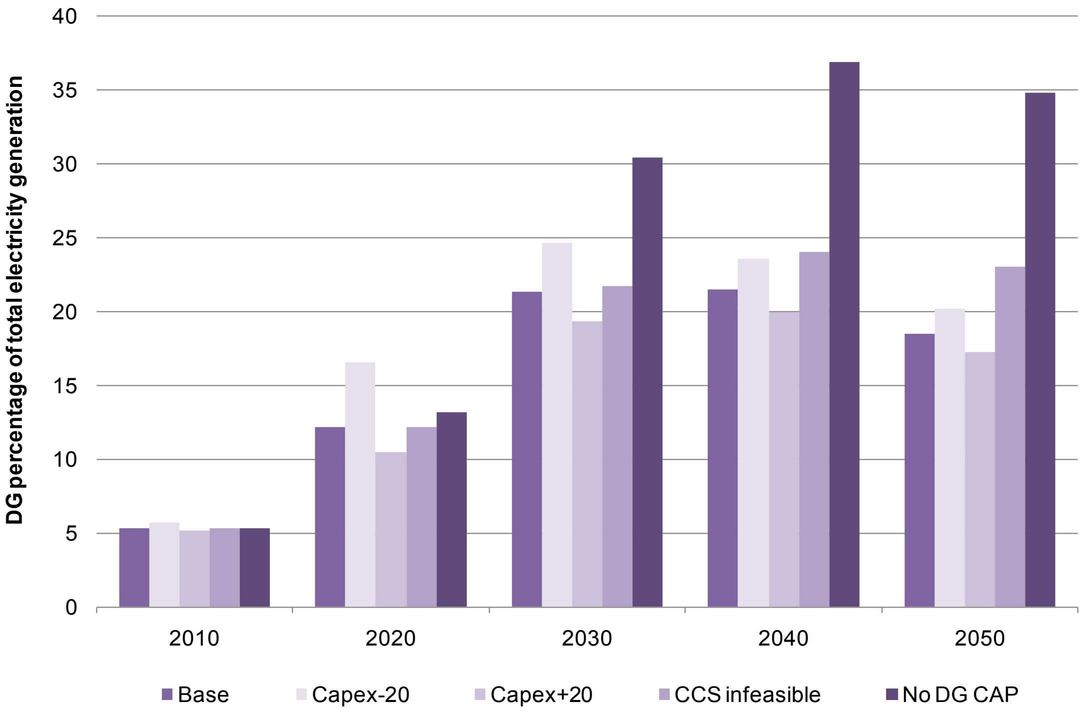


Figure 9.32: Sensitivity of DG uptake, selected years, Garnaut 550ppm

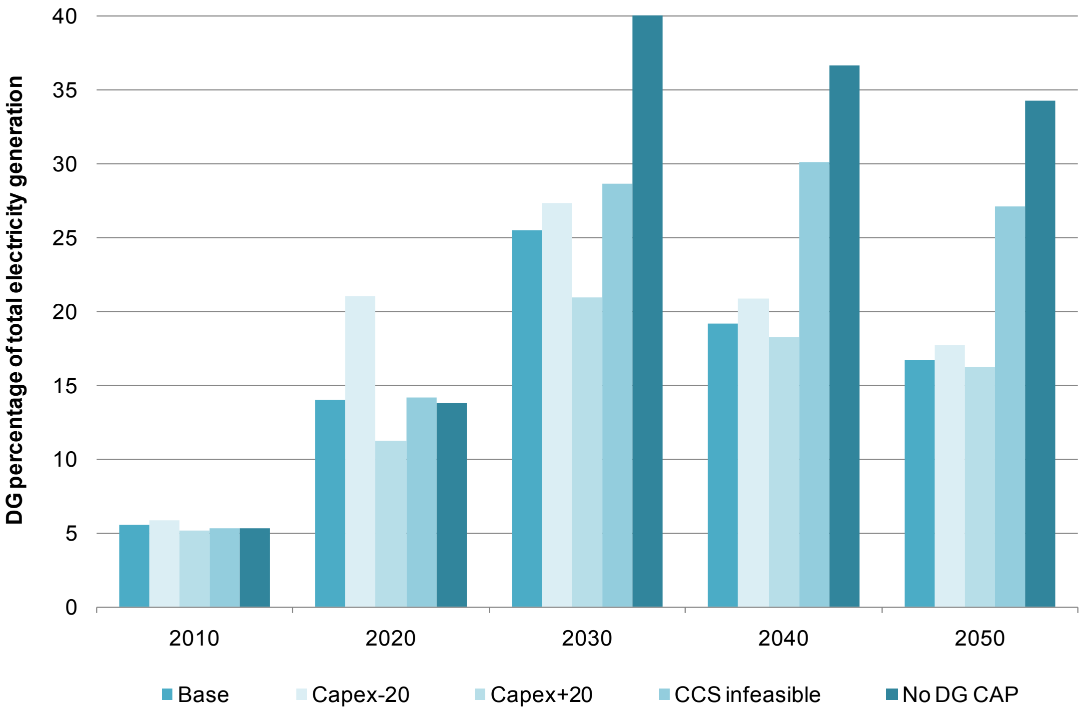


Figure 9.33: Sensitivity of DG uptake, selected years, Garnaut 450ppm

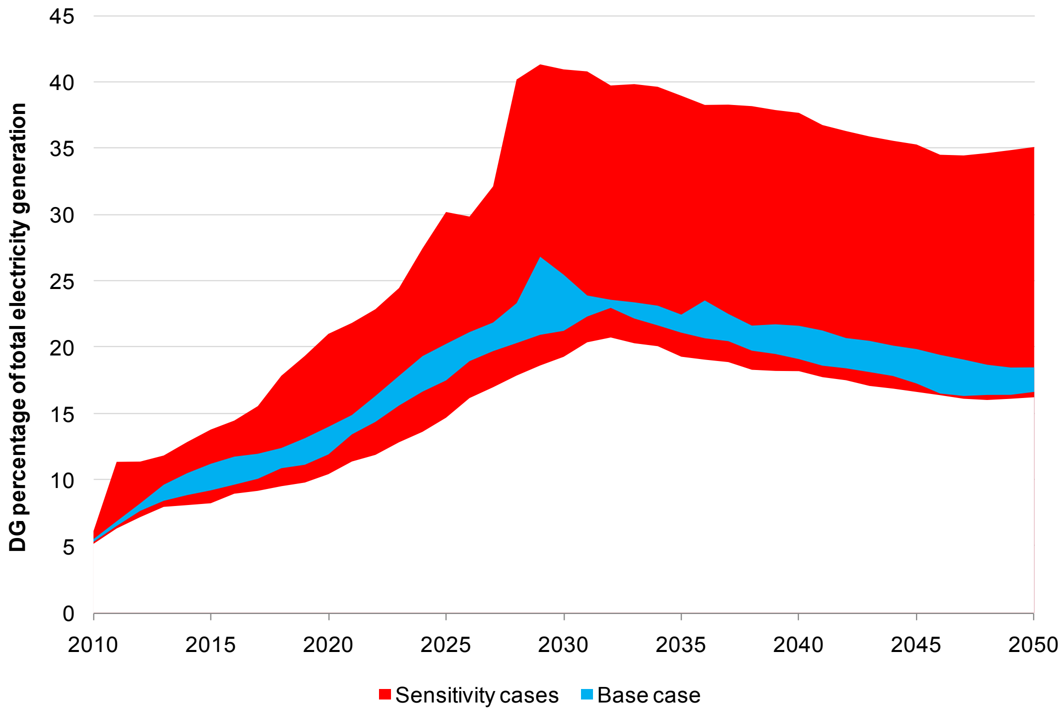


Figure 9.34: Sensitivity of DG uptake

The uptake of DG is also sensitive in the case that CCS proves to be infeasible. This is also more apparent from 2030 onwards when the uptake of CCS technologies occurs in the base case. In contrast to the no DG CAPS case, some of the increased share is due to lower demand in the CCS infeasible case.

Results are also sensitive to assumptions of the future capital costs of different technologies. In the Capex-20 case where the capital cost of all DG and centralised technologies is reduced by 20 per cent in all time periods, the share of DG increases the most around 2020. This would seem to indicate that the more rapidly DG technologies can get down the cost curve, the more competitive these options are to the alternatives. Similarly, in the case that future capital costs have been underestimated (Capex+20), the share of DG is more affected in the near-term compared to the long-term.

9.1.8 Conclusion

The results of the four carbon price scenarios illustrate that DG has a significant role to play in a carbon constrained future. On the basis of technology characteristics and cost competitiveness, the scenario analysis indicates that DG can significantly increase its share of supply in the near-term. The estimated technology uptake suggests that DG has a bridging role in transitioning from the current coal dominated centralised system while large-scale renewable and near zero emission CCS technologies are either too expensive or unproven.

In general, DG appears to be an effective early action GHG mitigation option for Australia when it is considered within a portfolio of other mitigation options due to a number of factors:

- There are numerous low-emission DG technology options that are commercially available
- CHP and CCHP technologies utilise waste heat that is lost in centralised electricity generation, increasing total energy efficiency
- DG options have less lead time in comparison to brown- or green-field expansions of centralised plant
- DG options are modular and can be tailored to individual end-user requirements
- Some DG options utilise fuel that is not economic for large centralised plant (e.g., landfill gas, waste streams, some forms of biomass)
- DG options are more able to match growing demand by installing smaller more appropriately sized units while centralised technologies result in large stepwise additions of supply
- DG options provide a mechanism to reduce electrical losses in transmission and distribution by locating the units close to the point of use.

More specifically, the results indicate that:

- In the near-term, co- or trigeneration technologies using natural gas or biomass/biogas appear to be the most cost effective DG options, especially in the industrial (natural gas, waste gas, coal seam methane), commercial (natural gas and biogas) and rural (biomass) sectors. They provide a vital bridge towards a low carbon future
- Landfill gas and waste gas reciprocating engines are competitive but are limited by fuel availability
- Small scale wind turbines are more competitive in non-urban areas where alternatives are more expensive or better wind resources are available
- In the medium-term there is potential for significant deployment of photovoltaic (PV) technology in the residential, rural and commercial sectors. The estimated uptake has implications for employment
- In conjunction with energy efficiency/demand reduction, DG is the most cost effective greenhouse gas mitigation option in the near- to medium-term contributing between 4 to 18 Mt of abatement in 2020 and 23 to 40 Mt of abatement in 2030

- Sensitivity analysis indicated that the more rapidly DG technologies can get down the cost curve (i.e., technological breakthrough, imported learning) the more competitive these options are to other alternatives
- Should large scale low emission technologies prove unworkable or too expensive there appears to be some scope for DG to lessen the impacts.
- Significant co-benefits can be found in reduced water consumption and primary emissions such as NO_X, SO_2 and PM_{10}.
- The modelling results need to be interpreted with some caution. Some key limitations of the modelling include:

- The modelling framework considers cost effectiveness and a limited set of constraints in projecting technology uptake. In reality community concerns and many other non-price factors not included in the modelling will influence the future technology choices individuals and businesses make
- DG technologies that are not included in the modelling (e.g., mini-hydro and Stirling CHP)
- Assumed capacity factors for each technology are fixed and do not account for spatial variation.

9.2 DE in the urban environment

Section 9.1 detailed economic modelling to showcase the ability of DE to act as an early action response to climate change. The modelling is based on CSIRO's Energy Sector Model (ESM) which determines the least cost solution for change in the stationary energy and transport sectors of the economy over time. A number of limitations exist when using this modelling approach two of which are a limited ability to model people's behaviour and acceptance and an incomplete understanding of the physical limitations of the locations in which the technologies are to be deployed. In this section we develop a modelling framework that begins to address these concerns.

In this section we use geographic information system (GIS) methods to estimate the potential uptake of renewable and non-renewable electricity generation technologies in an urban setting. Estimates of the physical potential for deployment of small wind turbines and solar photovoltaic (PV) systems in the Greater Sydney region are formulated from a combination of building type, technology performance and climate variables. These estimates based on physical constraints are compared to penetration levels estimated by economic forecasts of ESM (Section 9.1) as constrained only by demand and supply at the State scale, and to customer acceptance estimates determined from a survey of public attitudes to different stationary energy technologies (Section 8.2). The work forms the basis for future modelling which will investigate, for example, the air quality implications in the Sydney region from large scale deployment of DE

9.2.1 Key findings

Outputs from modelling which combine economic, social and physical constraints for urban renewable technologies showed that there is considerable potential for solar PV installations in the greater Sydney region. Wind resource estimates from The Air Pollution Model (TAPM) suggest that the capacity factors for wind turbines are too small for the technology to be economically attractive in this location. The modelling also indicates that solar PV is economically rather than physical constrained in this region. Social analysis found a high acceptance for solar PV technologies which did not limit the potential uptake of the technology. While wind turbines were socially less favourable than solar PV the limitation in this regard was found to be much smaller than the effects of poor wind resources in the urban area. Looking at a wider set of DE technologies, including efficient non-renewable generation, a preliminary analysis using the geographical location of commercial, industrial and residential sectors in the Greater Sydney region shows that industrial and residential DE are well placed to provide non network solutions in areas of constraint.

9.2.2 Modelling techniques

The Air Pollution Model (TAPM)

The Air Pollution Model (TAPM) is a combined weather prediction and chemical transport modelling system (Hurley, 2008). TAPM solves the equations governing the transport of mass, momentum, energy, and moisture on a series of user defined, nested grids. Initial and boundary conditions for the meteorological fields are provided by a large scale analysis, generated by the (Australian) Bureau of Meteorology. The model is able to simulate the transport of tracers, primary particles, and a simple photochemical system including sulfates and nitrates, for a variety of source characteristics. For this analysis, TAPM provides an appropriate level of accuracy for urban-scale wind modelling as it has been extensively tested in Australia.

For this analysis, TAPM was run using a series of three nested grids. The outer grid spacing was 10 km, the middle grid 6 km and the inner grid 2 km. Each of the three grids was centred on Granville (33°49' S, 151°1' E) in Sydney. Each grid consisted of 70 cells in an east-west direction, 70 cells in a north-south direction and 25 cells (layers) in a vertical direction. The vertical layer spacing was variable from 10 m for the lowest layer to 1000 m for the highest layer for all three grids. The model is solved in a sequential order which passes larger scale information as boundary conditions to the next grid. This ensures that the model adequately treats processes outside the area of interest (the inner grid). The inner grid is 140 km x 140 km in size and captures the entire Sydney basin. The model was used to calculate meteorological parameters such as wind speed, temperature and pressure in each of the 122,500 cells of each of the three grids for each hour between 1 January 1997 and 31 December 2008.

Estimates of shortwave radiation at the surface were extracted from the inner grid. The values calculated by the model include attenuation from the effects of cloud cover and absorption by atmospheric gases. In this analysis, the effects of cloud cover are only partially dealt with, because with a horizontal spacing of 2 km the resolution of the model does not adequately treat the effects of shallow convection on cloud generation. As such, some degree of over prediction of the flux of shortwave radiation may be expected. Hourly average wind speed estimates were extracted from the inner grid at a height of 25 m above the ground while temperature was determined from the lowest layer (10 m). The effects of turbulence and terrain are explicitly calculated in the model through roughness coefficients. We used TAPM v.4.01 for our calculations.

Energy Sector Model (ESM)

The Energy Sector Model (ESM) is an Australian energy sector model used by the CSIRO as a scenario analysis tool. The sectoral scope of ESM is the electricity and transport sectors. We employed the electricity module only in this study.

The model optimises, finding the portfolio of centralised (i.e. large power stations) and distributed generation (DG) technologies that would minimise the total estimated cost of the electricity system over the period 2006 to 2050. It utilises linear programming techniques to mirror real world plant investment decisions by simultaneously taking into account:

- The requirement to earn a reasonable return on investment over the life of electrical generation plant

- That the actions of one plant affects the profitability of all other plants simultaneously and dynamically
- That the consumption of energy resources by one plant affects the price and availability of that resource for other plants and the overall cost of electricity generated, and
- Electricity market policies and regulations.

The model projects uptake on the basis of cost effectiveness, but at the same time takes into account the key physical and policy constraints on the operation of electricity markets such as requirements for peaking plant, current renewable energy and natural gas legislation, existing plant in each State and lead times in construction of new plant. Further details of ESM and its modelling outcomes are presented in Section 9.1.

Social survey overview

In 2007, the CSIRO conducted a postal survey of around 2,000 households on attitudes and opinions about household energy issues (Gardner and Ashworth, 2007). Details are provided in Section 8.2. Models based on analysis of the responses allow three outcome measures: intention to reduce household electricity consumption; acceptance of demand management technology, and; acceptance of DG technology to be predicted from a range of demographic and psychological variables.

The demographic variables were state of residence, age group, electricity consumption, gender, education, employment type, household income, household size and household type. The psychological variables were knowledge of energy/environment, pro-environmental beliefs, pro-environmental behaviours, pro-economic values, attitude to reduced consumption, and subjective norms about reduced consumption.

To understand preferences related to the type of energy source used for DG, a survey question asked people to identify what energy sources they would be willing to use for an example household generator.

9.2.3 Multi-domain modelling methodology

This section details the methods used to estimate the physical, social and economic potential for renewable DG in the Greater Sydney region by combining outputs from the modelling platforms, responses from the household energy survey and various simplifying assumptions.

The hourly data from TAPM were used to estimate the output from a 1 kilowatt (kW) solar PV panel and a 10 kW wind turbine. The PV panel was assumed to produce 1 kW for a shortwave radiative solar flux of 1,000 W/m^2 at an ambient temperature of 25°C. A temperature correction factor (Equation 9.1) was applied assuming the panel was operating at 30°C above ambient (Mills, 2001) and had a loss of 0.4% per degree increase in ambient temperature:

$$P = R_{in}\left[1 - \left({0.4\left(PT + (AT - 25)\right)}/{100}\right)\right] \tag{9.1}$$

Where,
P is the output of the solar cell (W),
R_{in} is the short wave radiation flux (W/m^2),
PT is the panel operating temperature above ambient (°C) and,
AT is the ambient temperature (°C).

The power output from the wind turbine was estimated for each hour of the twelve-year period using the average hourly wind speed estimate and the performance characteristics of a WestWind 10 kW turbine (http://westwindturbines.co.uk/products/10kwwindturbine.asp). The turbine was assumed to be installed at a height of 25 m.

Outputs from the wind turbine and solar panels where used to estimate the capacity factors for these technologies at a 2 km spacing over the Greater Sydney region. These data were imported into ArcInfo v.9.3, a GIS software application, to form an estimate for each collection district (CD) in the Australian Bureau of Statistics (ABS) data set (ABS, 2007a,b). Upper bounds of potential electrical output from these two devices where determined for each CD (approximately 200 households).

Solar resource estimates were obtained by calculating the total roof area for semi-detached and detached dwellings assuming that one quarter of the useable area was available for optimal installation. Useable roof space was estimated by assuming an area of 154 m^2 for a one-storey detached, 77 m^2 for a two-storey detached, 110 m^2 for one storey semi-detached and 55 m^2 for two storey and higher semi-detached dwelling (Mills, 2001).

The potential wind resource was calculated for each CD by assuming simply that 5% of land was available for the installation of wind turbines in agricultural areas, 1% was available for residential areas and 2.5% was available for all other areas including commercial and industrial. In each CD, ABS data for land use type was used to determine the number of turbines that could fit within each sub region. Each turbine was assumed to be a 10 kW unit installed at a height of 25 m. The turbines were assumed to be spaced 100 m apart (greater than 10 times the blade diameter to reduce turbulence effects) resulting in a potential density of 100 turbines per km^2. Hourly outputs derived from TAPM data were used to calculate the annual electrical output from the turbines.

In order to consider economic feasibility, ESM was used to derive a least-cost portfolio of electricity generation technologies required to meet electricity demand at the State scale over the period 2006 to 2050 assuming carbon pricing consistent with assumptions in the CPRS-15 scenario (Treasury, 2008). The plant capacity factors used in the economic model were the spatial average capacity factors derived from the physical analysis. To approximate the level of deployment in the Greater Sydney region, estimates of economic decentralised plant deployment for NSW were re-scaled assuming that uptake is proportional to dwelling stock for solar PV and proportional to population for small scale wind. Note that, excluding the capacity factor calculations, the economic analysis is essentially independent of the analysis of physical potential, so that total physical capacity limitations did not constrain the economic uptake estimates.

A social acceptance rating for each technology in each CD was determined from the social survey (Section 8.2). The rating was calculated by correlating the survey data with 2006 Census data on age, education, employment and occupation. The rating was used to scale the physical outputs to derive a simple estimate of the potential capacity that is both physically feasible and socially acceptable.

9.2.4 Results

Distribution of renewable resources and physical potential

Outputs from TAPM for the capacity factors are displayed in Figure 9.35 and Figure 9.36. Capacity factors represent the ratio of actual electricity output of a plant over a year to its technical maximum net electricity output based on its rated capacity. Figure 9.35 clearly shows that wind turbine output is greater along the coastal fringe and in the far west where the turbulence created by the built environment is less marked. When referring to the figure, it is obvious that the even the best wind areas in this region are much smaller than a prime urban location where capacity factors might be typically 15% or more.

Figure 9.36 shows that the solar resource capacity factor is significantly higher than that for wind. It is also less variable with ±6% variation across the Greater Sydney region. The solar capacity factor is lowest in the western suburbs of Sydney due to the performance de-rating from higher ambient temperatures. Conversely, the capacity factors are higher in the Blue Mountains (west of Penrith) and on the coast where ambient temperatures are lower.

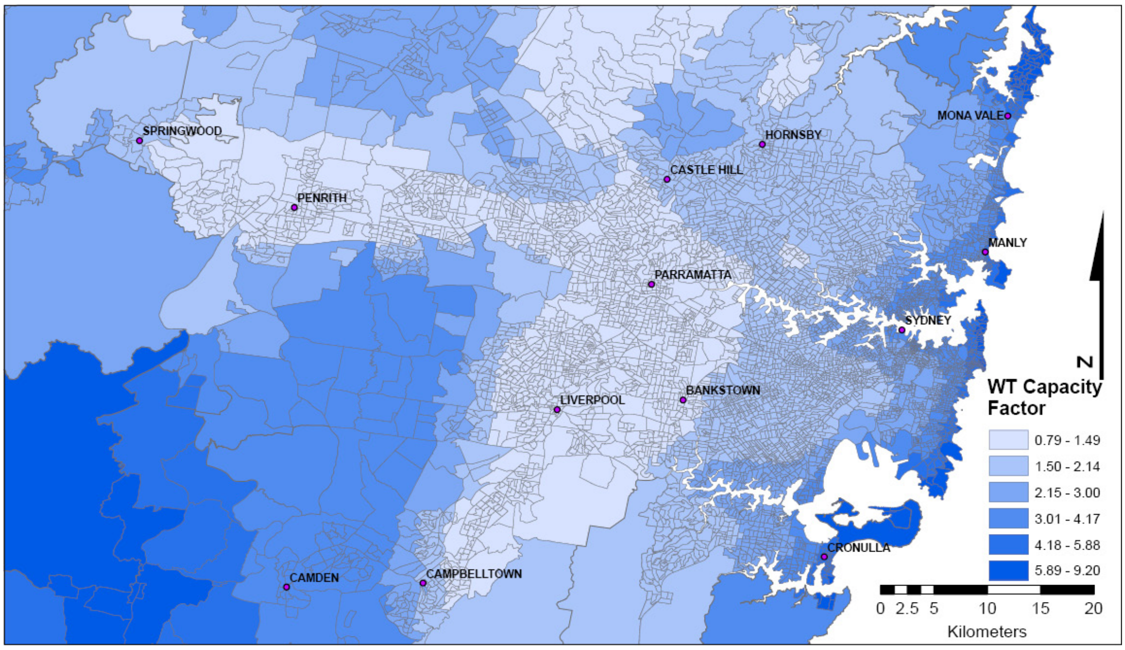


Figure 9.35: Estimated capacity factor for wind turbines by collection district in the Greater Sydney region

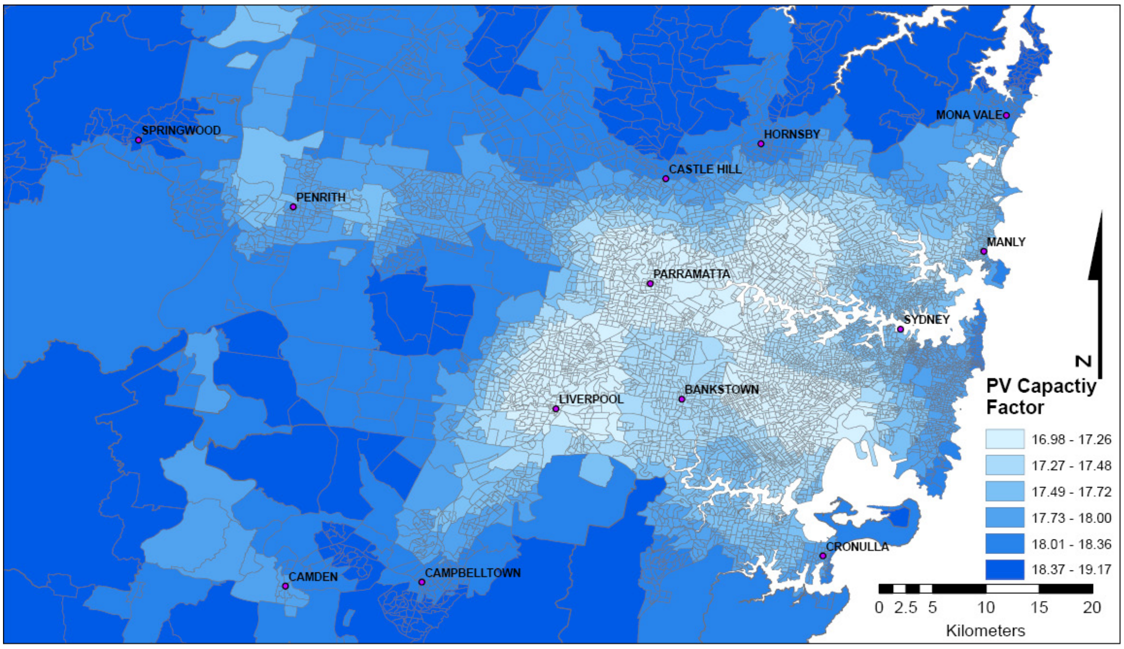


Figure 9.36: Estimated capacity factor for solar PV by collection district in the Greater Sydney region

Based on the physical resource availability and land use constraints outlined in Section 9.2.3, Figure 9.37 and Figure 9.38 show the maximum electricity production of small wind turbines and solar PV by CD in the Greater Sydney region. Figure 9.37 shows the influence of land use and resource availability on wind turbine output with outer areas featuring greater installed capacity than CDs dominated by residential housing. In practice the installed capacity in peri-urban regions will be moderated by access to distribution network infrastructure. In contrast, Figure 9.38 shows that CDs with a greater proportion of detached dwellings (i.e. more roof space) are potentially able to have more installed PV.

In aggregate, the analysis indicates a maximum physical potential, per annum, of around 29 gigawatt hours (GWh) of wind generation and 6,900 GWh of solar PV generation in the Greater Sydney region assuming current housing stock and land use patterns. This corresponds to around 120 megawatts (MW) of installed wind turbines and around 4,500 MW of installed solar PV and average capacity factors of around 3% and 17.5% respectively.

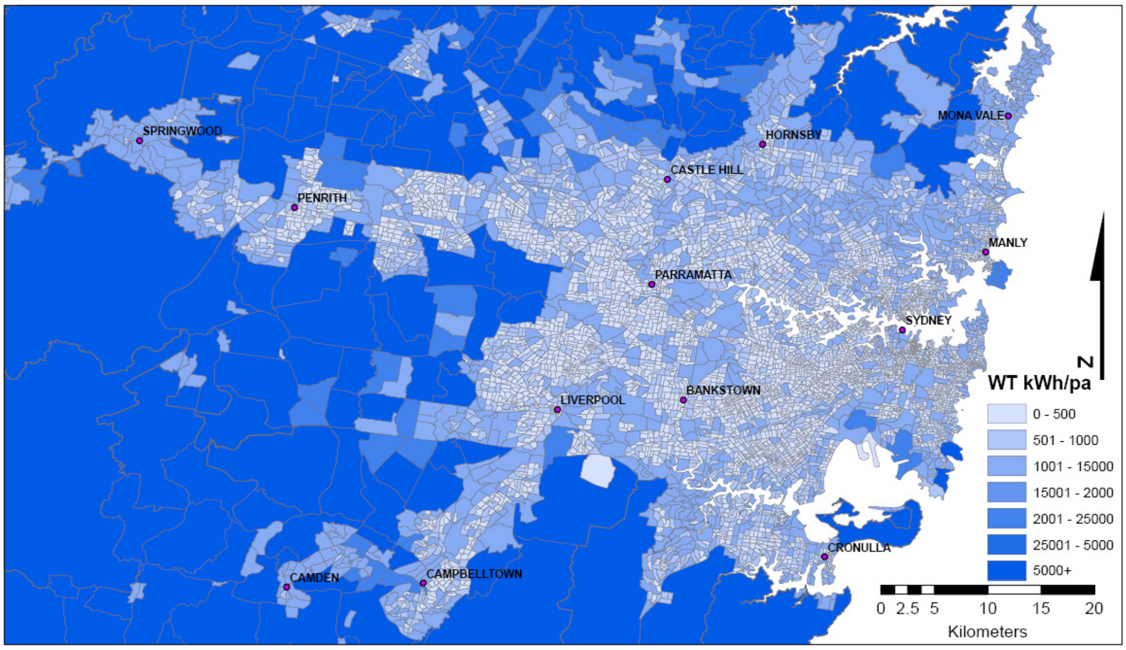


Figure 9.37: Electricity production of wind turbines by collection district, Greater Sydney region

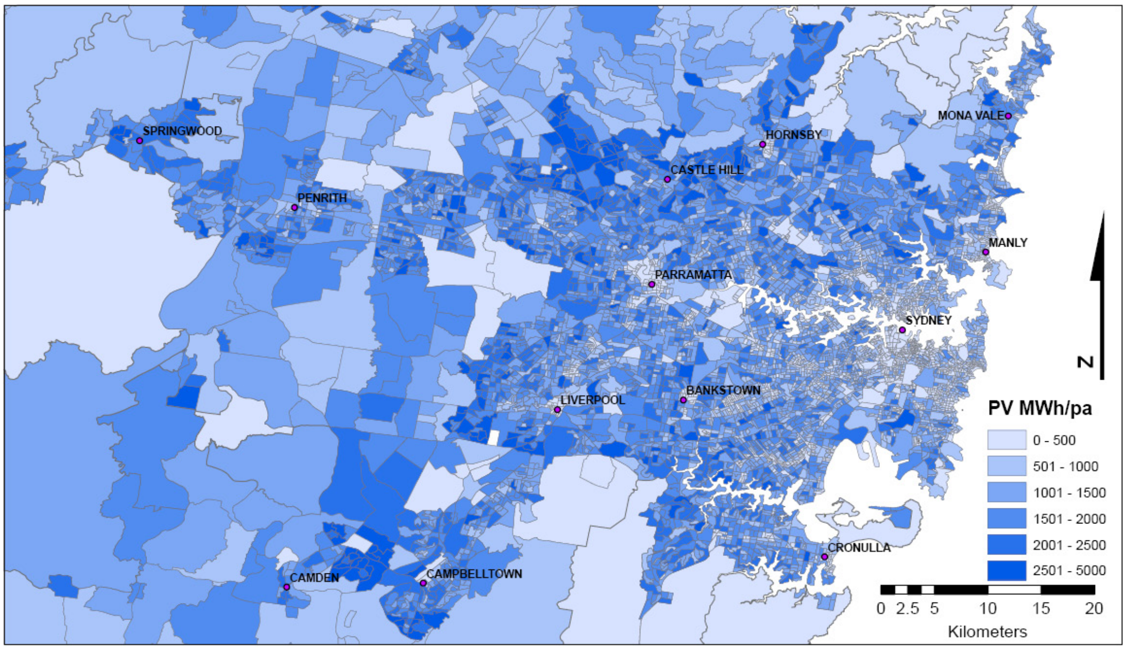


Figure 9.38: Electricity production of solar photovoltaic by collection district, Greater Sydney region

Comparison of socially acceptable and economically feasible capacities for renewable resources

As noted in the previous subsection, the physical potential of wind and solar PV is constrained by land use and building stock. However, the deployment of these technologies will arguably also be further constrained by social acceptance and economic feasibility. Table 9.3 summarises the physical, social and economic potential for wind and residential solar PV electricity generation in the Sydney Region. Recall that the estimate of socially acceptable potential was derived by scaling down the estimates of physical potential by 'propensity to adopt', whereas the calculation of the economic potential estimate was not constrained by that of physical potential.

Table 9.3: The physical, social and economic potential for wind and solar PV electricity generation in the Greater Sydney region in 2050 (assuming current housing stock and land use patterns)

	Physical Potential (GWh)	Socially Acceptable Potential (GWh)	Economically Feasible Potential (GWh)
Wind	29	18	0
Solar PV	6,900	5,900	3,300

Table 9.3 suggests that based on the methodology used and under the assumptions noted in Section 9.2.3, it is economic factors that provide the tightest constraints on the deployment of solar PV while wind appears limited by a combination of physical and economic constraints. The most notable feature of Table 9.3 is that small scale wind is not economic relative to other electricity generation technologies. This is mainly due to the low average capacity factor of around 3% for the Greater Sydney region that is predicted by TAPM. Furthermore, the table shows that there is considerable physical potential for solar PV as the modelling is based on current housing stock while the economic modelling forecasts capacities to 2050. Over this timeframe more housing stock will be available for PV installation while it could be expected that less land use will be available for the installation of wind. It should be recalled however, that the assumptions behind the turbine installations in this assessment are rather crude although it should be noted it is the capacity factor, not the number of installations that is the critical factor which leads to a determination of no wind turbines in the urban area when applying the economic model.

Optimising the allocation of DE resources

An important consideration for DE in an urban environment is the effect of changes in local emissions that might arise from the installation non-renewable resources in the urban area. CSIRO is conducting a complementary study to assess the potential impacts from urban based non-renewable DE in Sydney. The investigation is examining the optimal location and installed capacity of DE sources taking into account their social, economic and environmental impacts.

Optimising the location of DE sources needs to incorporate a number of factors including population density, land use patterns, electricity and heat loads, social acceptance and pre-existing emissions including motor vehicle, commercial and industrial sources. Appropriate accounting of these factors will allow decision makers to make balanced considerations when investigating the merit of installing DE in the urban area.

In Section 9.1 results were provided for ESM uptake of various DE technologies. The ESM estimates these uptakes based on aggregate demand profiles for each technology and for specific end user types such as the residential, commercial and industrial sectors. While ESM accounts for some savings in the transmission sector through avoided infrastructure, the model does not provide an analysis of network savings at the distribution level which may be critical to the financial viability of DE technologies and critical in the potential optimisation of their placement.

Figure 9.39 displays a map of potential deficits and surpluses in substation capacities during summer in the Greater Sydney region. The data represent the firm capacity of the station minus the predicted peak load. The firm capacity in this case represents the N-1 rating, so if a substation is comprised of four 50 MVA transformers for instance then the N-1 rating represents the capacity if one units fails, in this case 150 MVA. The map (Dunstan and White, 2009) while slightly out of date, shows that there is a large degree of variation in the network capacity across the region. For example, in this plot, the area around Penrith in the west of the region is observed to be in deficit while regions in the CBD and southern beaches appear to have excess capacity. This variation to a large extent shows how the city has evolved over time with more network capacity generally available toward the coast and less available in the west which has experienced considerable growth in the previous decades.

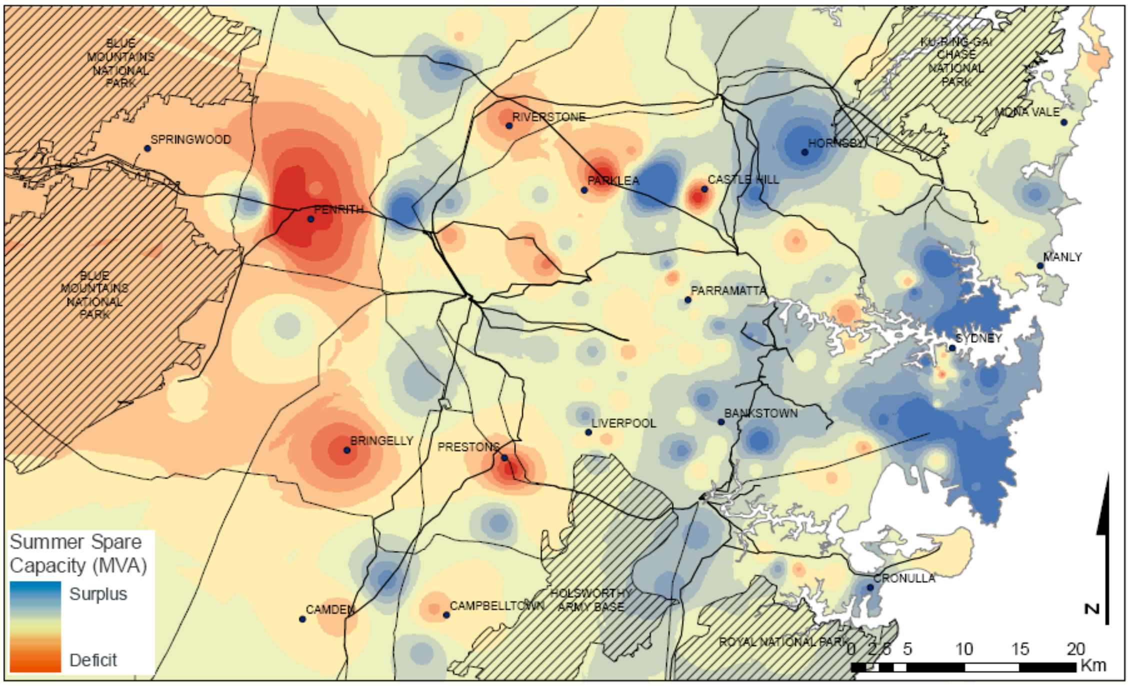


Figure 9.39: Illustrative deficits and surpluses in substation capacity in the Greater Sydney region

While Figure 9.39 indicates there is considerable potential for non network solutions particularly in the western areas of Sydney, it is interesting to compare it with the spread of commercial, industrial and residential areas in the region, illustrating the demographic implications on DE's ability to alleviate these network constraints.

Figure 9.40 provides an estimate of commercial DE in the Greater Sydney region taken from the uptake of DE for NSW predicted by the ESM (Section 9.1) using preliminary NEXIS data from Geoscience Australia to describe the amount of commercial and industrial space in the region. The apportionment to specific regions was performed with an assumed liner relationship. This means that if 100 MW of natural gas fired turbines are predicted in NSW for the commercial sector, and 5% of the State's commercial sector floor space is in one data cell (a collection district; CD), then it is assumed that 5 MW of natural gas fired turbines are in the cell. The data in the figure are a combination of all DE technologies in each CD expressed as a percentage of the NSW total from ESM. The figure shows that DE in this sector is spread primarily throughout the eastern half of the city with some increased aggregation present around major centres such as Parramatta and the CBD.

Figure 9.41 provides an overlay of the estimated commercial uptake with the network constraints. This figure shows that in general the network constrained areas are not particularly well correlated to the commercial zones. As such installations in this sector (in their present location) may not attract economic benefits beyond that predicted by ESM.

Figure 9.42 shows the placement of DE technologies across the Greater Sydney region in the industrial sector. Figure 9.43 provides an overlay with network capacity. These figures show a better correlation with network constraints. To an extent this is not unexpected as industry tends to be located on the periphery of major urban centres which in this case are the most under serviced portion of the network. In this case, it might be expected that DE located within the industrial sector may be more economically viable than ESM predicts, particularly if it receives payment reflecting its value to the network. In many cases industries have large process heat requirements and installation of cogeneration may provide a mechanism to deliver the process heat while alleviating network constraints through the production of electricity for onsite use and for export to the grid.

While these potential network benefits appear clear, the change that might result to local and regional air quality are not. Sydney's west and south west occasionally experience elevated air pollution and increasing emissions within this area may exacerbate the problem. Understanding this complex mix of economic, technical and environmental concerns highlights a major issue with DE technologies which by their nature are located close to load and thereby close to population centres. A thorough analysis of these issues is required to assist regulatory authorities to make a value judgement on whether DE projects can proceed. For example, it is possible that the optimal placement of non renewable DE technologies in this region might involve the requirement for additional pollution control equipment. While this provides an increased financial burden for the DE installation, it is possible this could be offset by financial gain if the unit is able to capture its economic value to the network.

The majority of DE technologies predicted by ESM in the residential sector are solar PV. Figure 9.38 shows that these units can be spread across the entire region with some efficiency lost from temperature effects in the western suburbs. If the units could be aggregated and coordinated they may attract increased financial value (than predicted by ESM) from their contribution to the network if it is able to be captured.

While the value of DE resources is obvious in constrained areas, their value may also be substantial in areas with excess supply through increased security and increased potential to cater for load growth. As noted in Chapter 6 measuring and receiving payment for this and other values such as reduced greenhouse gas emissions remains a major challenge for DE technologies.

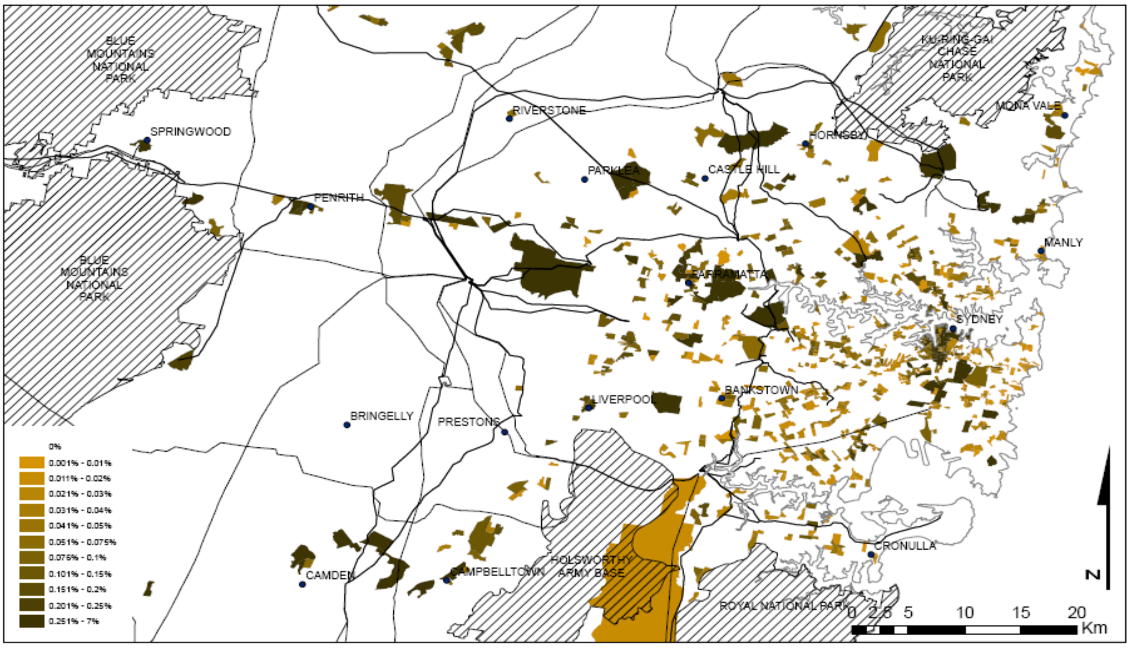


Figure 9.40: Percentage of commercial DE installations from ESM for NSW in the greater Sydney region

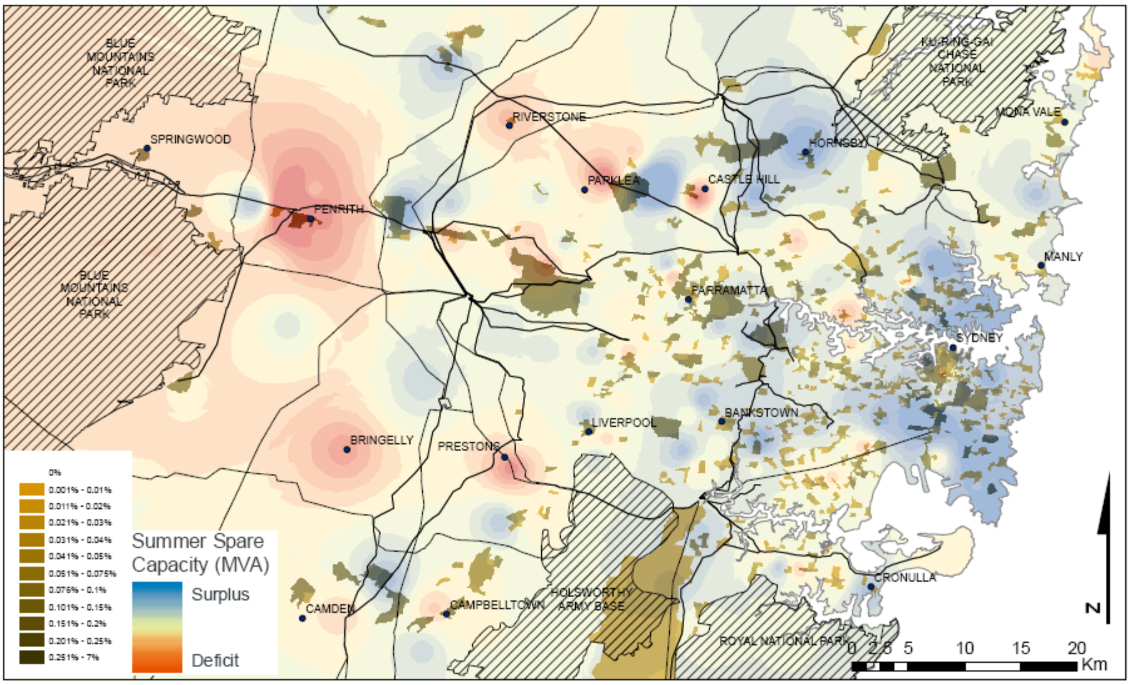


Figure 9.41: Percentage of commercial DE installations from ESM for NSW in the greater Sydney region overlaid with distribution network capacity

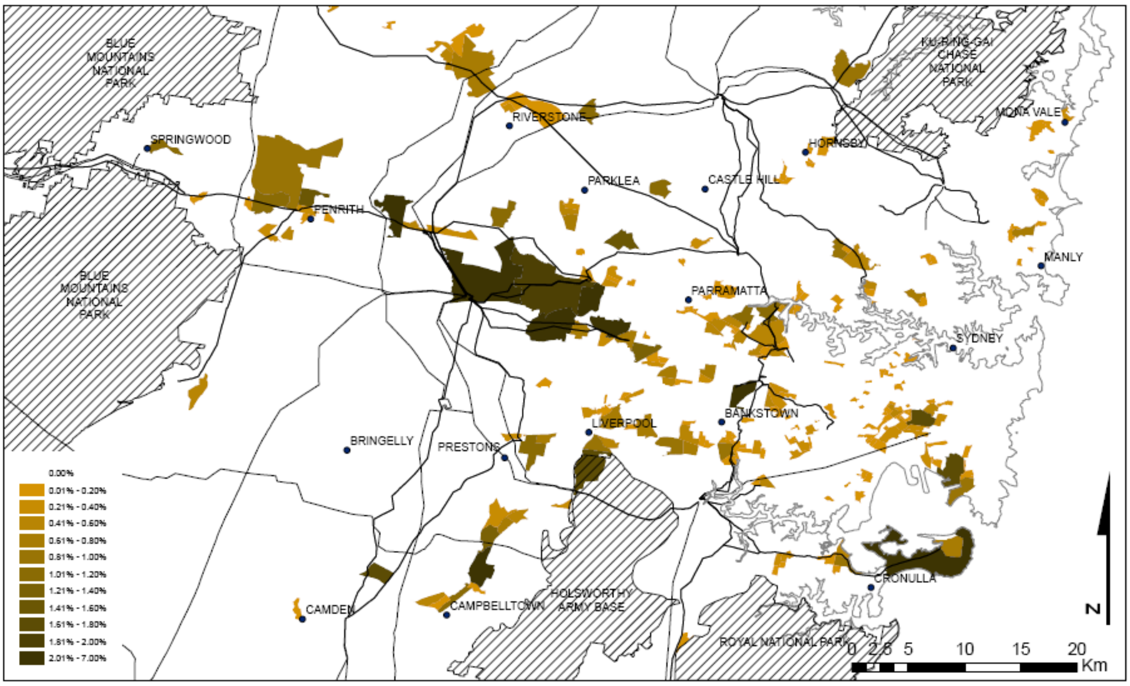


Figure 9.42: Percentage of industrial DE installations for NSW from ESM in the greater Sydney region

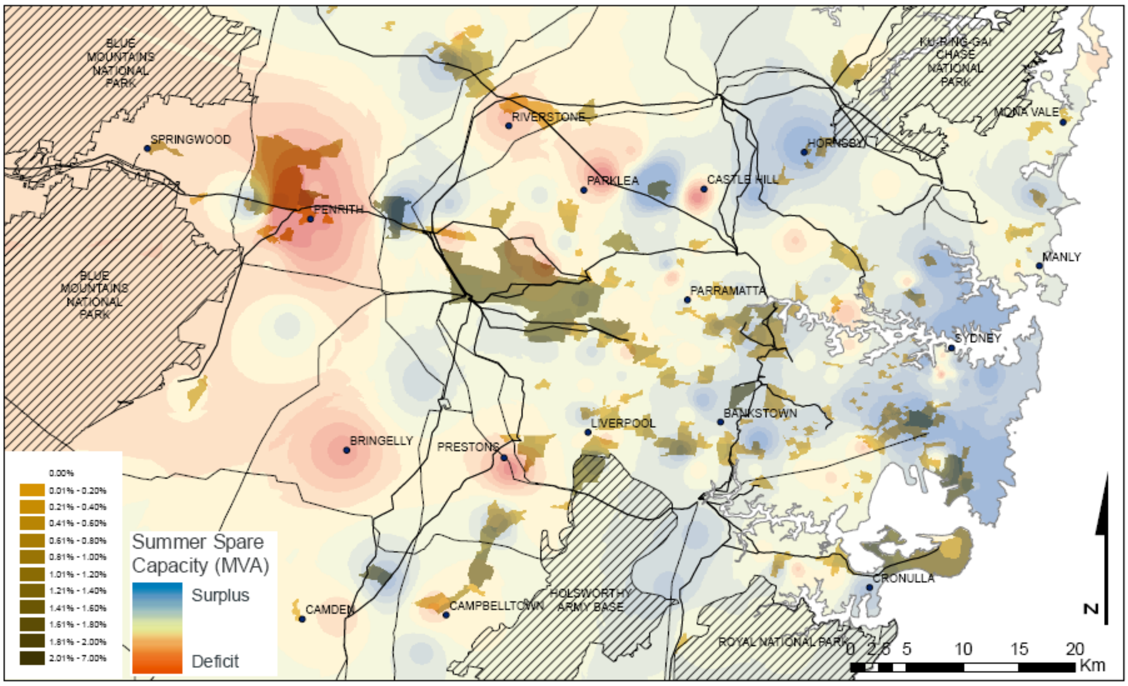


Figure 9.43: Percentage of industrial DE installations for NSW from ESM in the greater Sydney region overlaid with distribution network capacity

9.2.5 Discussion and conclusion

In this analysis, we used GIS methods to estimate the potential of a subset of renewable electricity generation technologies in the Greater Sydney region. The work indicates that there exists significant physical potential for residential solar PV due to consistency of the solar resource and the dominance of one-storey detached dwellings in the residential building stock across the region. In contrast, the potential for wind is hampered by land-use constraints. Solar PV is also more socially acceptable compared to wind. However, it appears to be economic feasibility that limits the deployment prospects for these technologies. Despite these findings, the results should be interpreted with caution.

For example, our results for the physical potential of wind may also be skewed due to the performance characteristics of the wind turbine we selected. Given the estimated average wind speed over the Greater Sydney region of around 3 m/s, selection of a different wind turbine may marginally increase output depending on the choice of model. Furthermore, it is possible that smaller-scale vertical axis wind turbines under development for mounting directly onto built structures compared to traditional tower-mounted horizontal axis wind turbines may be more efficient in low wind speeds, more socially acceptable, more cost effective and less subject to competing land-use constraints.

It is also possible that solar PV output may have been overestimated. For example, TAPM does not factor in shading from vegetation or adjacent buildings. In addition, small scale convective cloud may not be well represented by TAPM even when operating at 2 km resolution leading to a marginal over prediction in shortwave radiation.

In some respects however, the physical potential for solar PV has been underestimated as we have not examined commercial and industrial roof space. This is potentially a significant resource and these end-users may be more able to deploy PV more economically than residential end-users.

Looking at a wider set of DE technologies, including efficient non-renewable generation, a preliminary analysis using the geographical location of commercial, industrial and residential sectors in the Greater Sydney region shows that industrial and residential DE are well placed to provide non network solutions in areas of network constraint.

Further development and refinement of this type of tool will provide better information on the costs and benefits of DE, accounting for time and location specific factors as well as social preferences. Ultimately, this will enable more targeted policy making and could motivate innovation within the energy supply chain to provide more efficient energy services.

9.3 Impacts and benefits of DG on the NEM

In Section 9.1 results from modelling DE using CSIRO's long term investment model were provided. In this Section the impacts and benefits of DG (energy efficiency and demand management are not explicitly considered in this analysis) to the NEM are assessed by performing economic modelling with a higher temporal resolution economic model PLEXOS (http://www.plexossolutions.com/). This modelling was undertaken by the University of Queensland (Wagner, 2009) and considers the effects of DE on spot prices in the NEM.

9.3.1 Key findings

The effects of DE in the NEM were considered by running five case studies representing policy frameworks. The modelling used assumptions which were provided by the CSIRO based on their Energy Sector Model (ESM; Section 9.1), forecasts performed by the Treasury (2008), McLennan Magasanik and Associates (MMA, 2008), and ACIL Tasman (2009). These assumptions include energy demand forecasts, installed centralised generation assets, fuel prices, carbon costs and new entrant cost data. The period of interest for this work revolves around the three landmark years, namely 2020, 2030 and 2050.

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

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 reaches 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

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 reaches 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

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 will allow for additional cuts in emissions than the corresponding CPRS -15% case study

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

Effects on emissions

Modelling performed with PLEXOS indicates that the Emissions Intensity Factor (EIF; t-CO_2/MWh) of delivered energy throughout the NEM is significantly reduced across all three years, and under both emissions reduction scenarios, when DG has been considered. The EIF was chosen as the benchmark for analysis to better reflect emissions behaviour given the different rates of load growth across all scenarios. Table 9.4 features the EIF's of delivered energy across the NEM and shows significant structural change with respect to the emissions profile, demonstrating that DG could have a significant impact on curtailing CO_2 emissions.

Table 9.4: Emissions Intensity Factor (EIF; t-CO2/MWh)

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
2020	0.878	0.944	0.791	0.776	0.795
2030	0.932	0.429	0.500	0.390	0.433
2050	0.970	0.140	0.310	0.110	0.210

Effects on average electricity prices

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

For example the installed capacity of low-cost coal-fired generation in the reference case will ensure that energy prices remain relatively low especially with brown coal generators having a LRMC of less than $30/MWh. Conversely the increased cost of the generation types such as Combined Cycle Gas Turbines (CCGT) contributes greatly to the observed average price. Furthermore, the difference in prices between Scenario 2 and 3 (see Table 9.5), are due to the lower demand and generation mix changes due to the higher carbon price observed for a 25% carbon abatement pathway.

Table 9.5: NEM average spot prices ($/MWh)

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

The modelling indicates that the role out of DG will have a significant impact on the average spot price of electricity throughout the NEM. The drop in average spot prices for each of the DG scenarios indicates that investment in new technology stimulated by the CPRS will lower the delivered energy cost across the NEM.

Effects on spot price volatility

The modelling indicates that another benefit of the roll out of DG is lower volatility of observed prices on the wholesale market. Lower volatility of spot price behaviour also provides significant benefits from a risk management perspective and reduces the cost of serving the retail consumer base. Valuing the premium on a $100/MWh base cap product (outlined in Section 9.3.4), is a simple method of measuring market participant's exposure to high and volatile prices (see Table 9.6).

Table 9.6: Premium price of a $100/MWh Base Cap

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

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

9.3.2 PLEXOS

The 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 Federal Energy Regulatory Commission (FERC).

Simulation engine

The PLEXOS modelling platform divides 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 9.44. The following discussion details the procedures used to model the NEM with PLEXOS.

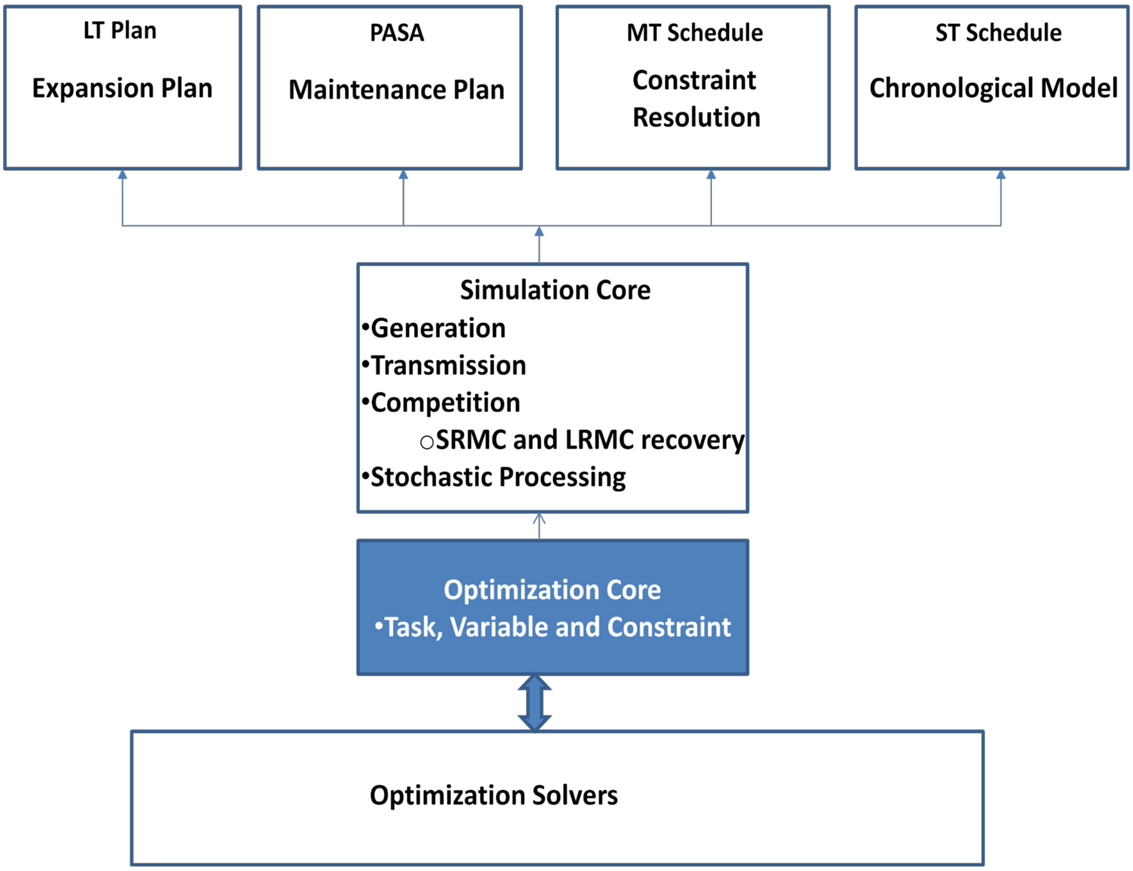


Figure 9.44: PLEXOS design engine

Optimal power flow solution

The solution of Optimal Power Flow (OPF) is one of the core functions of the PLEXOS simulation engine. The OPF utilises 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 restrictions on how dynamic the network data can be, thus it can model transmission augmentations and transmission outages dynamically.

Long term (LT) planning
The Long term (LT) planning module establishes the optimal combination of new entrant generation plant, economic retirements and 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.

Projected assessment of system adequacy (PASA)
The Projected Assessment of System Adequacy (PASA) schedules maintenance events such that the optimal share of generation capacity is 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.

Medium term (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. It 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 (see below) 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.

Short term (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 integer programming. Some examples of how the ST Schedule can be used 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.

PLEXOS dispatch engine

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 (see Section 9.3.3). 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:

- The dispatch algorithm calculates separate dispatch and markets prices for each RRN in the NEM
- 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
- The market clearing price is the marginal price, not the average price of all dispatched generation
- 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:

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

Short run marginal cost recovery

The core capability of an electricity market model is the economic dispatch or short run marginal cost (SRMC) recovery based simulation 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.

User defined market bids

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.

Long Run Marginal Cost Recovery

PLEXOS implements 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:

- Run MT Schedule with ‘default’ pricing (i.e. SRMC offers for each generating unit)
- For each firm (company), calculate total annual net profit and record the pool revenue in each simulation block of the LDC
- 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)
- 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’
- 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)
- Re-run the MT Schedule dispatch and pricing with these new premium values

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 this modelling PLEXOS has been operated by setting the LRMC recovery algorithm to run three times for each time step. This is used to produce price trace forecasts with sufficient volatility and shape as recommended by the software’s vendor, Energy Exemplar (http://www.energyexemplar.com). This method ensures that under normal demand conditions, generating units will bid effectively to replicate market conditions as seen in the NEM.

Modelling distributed generation

A variety of technology types can be easily represented by PLEXOS including:

- 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 estimates for each year. These estimates are treated as passive generation (i.e. negative demand) and such are subtracted from forecasted demand.

9.3.3 Assumptions and methodology

Three key years from CSIRO's modelling (see Section 9.1) were chosen to investigate the effects of DG on the NEM. The periods were chosen to provide a range across the future and to ensure that large changes predicted by ESM were accounted for. The three years selected were 2020, 2030 and 2050. Five case studies were designed to investigate the effects of DG as shown below. These cases provide a base case with current market conditions, two future policy settings which assume a carbon policy reduction framework and no additional installation of DG and two cases with the carbon reduction pathways which include additional DG technology.

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

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 reaches 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

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 reaches 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

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 will allow for additional cuts in emissions than the corresponding CPRS -15% case study

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

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 include:

- Electricity demand forecasts (see Section 9.3.3)
- Thermal plant fuel prices
- Distributed Generator technology specifications
- 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 ESM (see Section 9.1) is attributed to new generic companies for each region.

Demand

Base demand

Yearly energy demand forecasts for the three years modelled were derived from ESM outputs (see Section 9.1). Table 9.7 displays the NEM wide demand for each of the three years for each of the five scenarios considered. From the data presented in Table 9.7 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 run elasticities of demand (NIEIR, 2004).

Table 9.7: 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%

Peak demand

NEMMCO's (2008) statement of opportunities (SOO) was used as a forecast of the load profile which represents consumer demand behaviour on the NEM for the business as usual case. Peak demand for the other four scenarios was derived by scaling the yearly load forecasts from ESM (Section 9.1) and incremental load growth from historical data (see Table 9.8 and Table 9.9).

Table 9.8: 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 9.9: 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

Fuel prices

Natural gas

Natural gas prices for this modelling were based on analysis by Treasury (2008) and MMA (2008) for the examination of the impacts of the CPRS on generator revenues (see Figure 9.45). These price data represents a city node price for gas in each State rather than each individual generation site. The value of gas for peaking or CCGT were not changed to ensure no distortion to the assumptions of the ESM modelling (Section 9.1) 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.

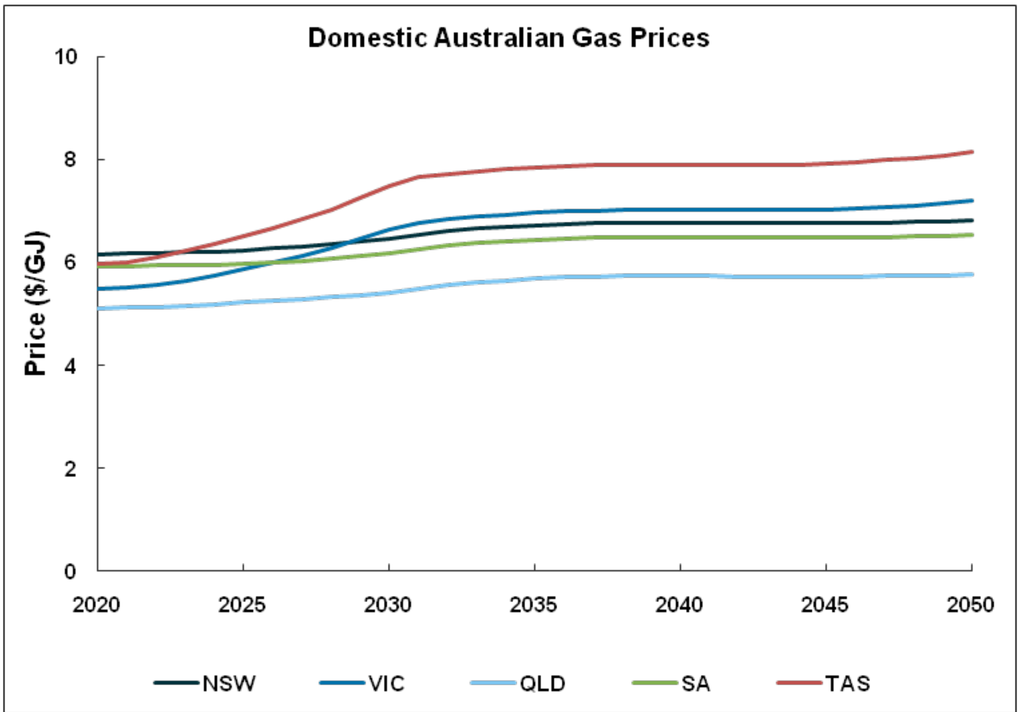


Figure 9.45: Trends in natural gas prices in NEM States

Biomass

The price of Biomass fuel prices (excluding transport costs) are those output by ESM (Section 9.1) as a shadow price. Table 9.10 provides the prices in each State for each of the years modelled.

Table 9.10: 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

Coal

The price of black and brown coal was derived from ACIL Tasman's modelling (ACIL Tasman, 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 ACIL Tasman estimates range out to 2025 and as such data to 2050 were obtained by extrapolating the average growth rate of fuel prices. Figure 51 provides a visual representation of the Coal prices.

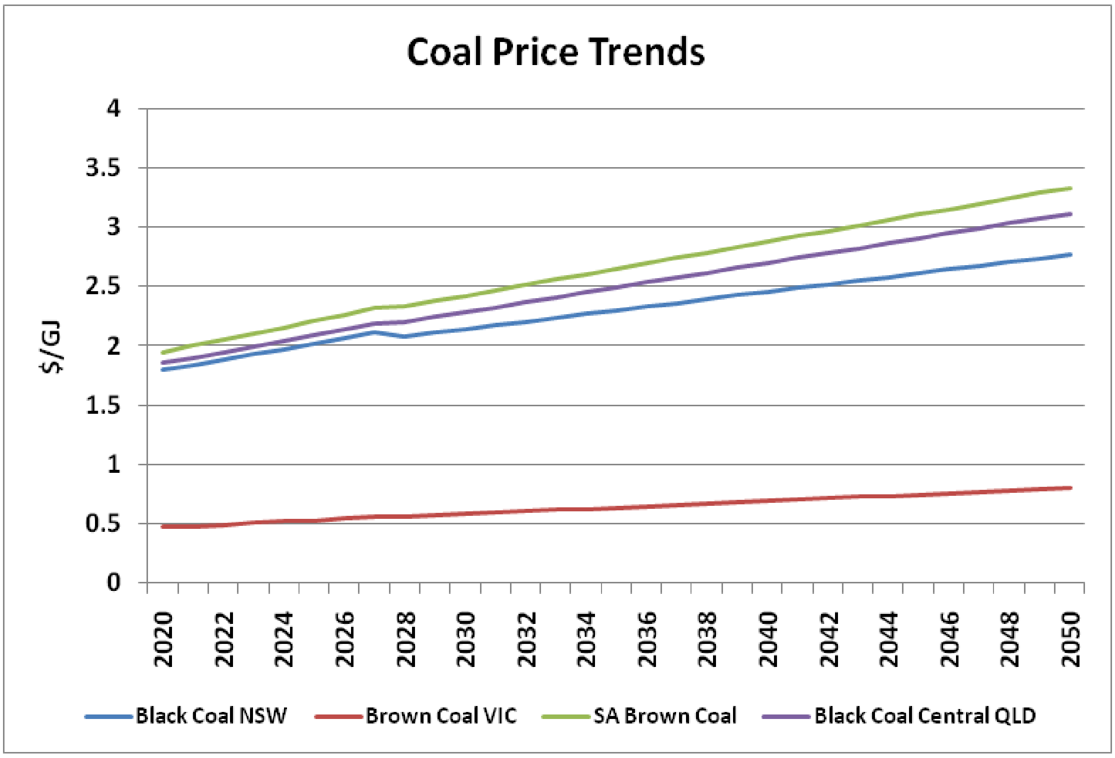


Figure 9.46: Trends in coal prices in NEM States

Technology specifications and costs

Centralised plant

The installation of new generation assets into the NEM provides many advantages for Australia's proposed carbon abatement pathway and renewable energy target. Table 9.11 provides a technology listing of large centralised technologies considered in this modelling.

Table 9.11: New centralised generation plant data (ACIL Tasman, 2009)

Technology	Typical new entrant size (MW)	Minimum stable generation level (%)	Aux load (%)	Thermal efficiency HHV (GJ/MWh) sent-out	FOM ($/MW/ year) for 2009-10	VOM ($/MWh) sent-out for 2009-10	Emission intensity (tCO_{2eq}/ 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

CCGT = combined cycle gas turbine
OCGT = open cycle gas turbine
SC BLACK = black coal steam plant
IGCC = Integrated gas combined cycle
USC = Ultra super critical steam plant
CCS = Carbon capture and sequestration

Distributed generation plant

The following DG technology types are considered in this modelling to estimate the impacts of large scale deployment (Table 9.12).

Table 9.12: Distributed generation plant data

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

Renewable generation output

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. In this modelling solar and wind power production was treated as negative load. These resources are uninterruptible and would naturally be bid in at full capacity with a $0 dollar price.

Wind

The 30 minute wind speed data were scaled for the presumed height of the wind turbine (70 metres) using Equation 9.2. Power produced by the wind turbines was determined by fitting the adjusted wind speed data to the turbine output profile displayed in Figure 9.47.

$$u_z = u_{10}\left(\frac{ln\left(\frac{z}{z_0}\right)}{ln\left(\frac{z_{10}}{z_0}\right)}\right) \qquad 0 < u < \infty \qquad 9.2$$

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

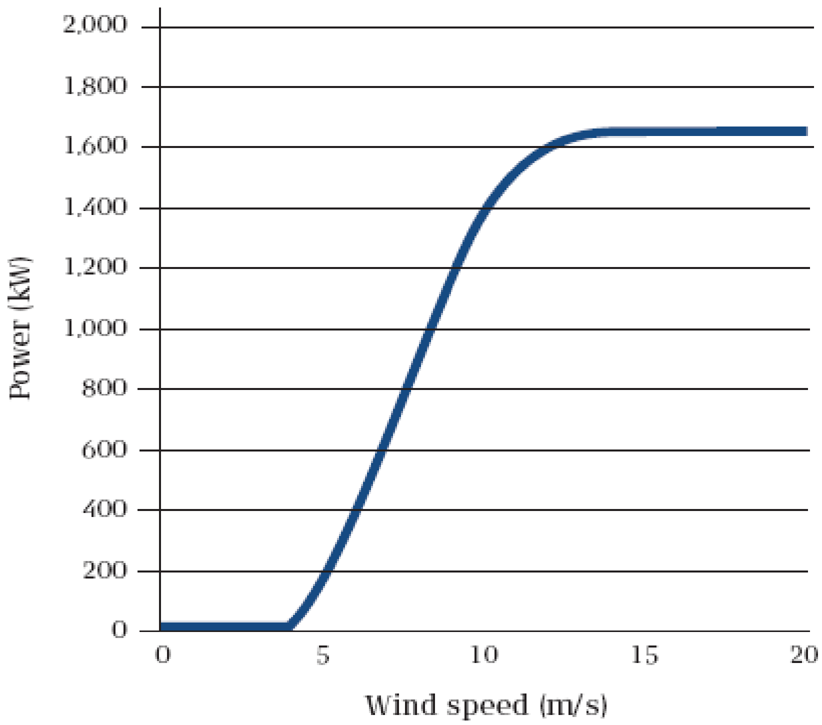


Figure 9.47: Power curve for a Vestas V82 wind turbine

Solar

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 9.3 (Mills, 2001). The PV panel was assumed to produce 1 kW for a shortwave radiation solar flux of 1,000 W/m^2 at an ambient temperature of 25°C. A temperature correction factor was applied assuming the panel was operating at 30°C above ambient and had a loss of 0.4% per degree increase in ambient temperature.

$$P = R_{in}\left[1 - \left({0.4\big(PT + (AT - 25)\big)}\Big/_{100}\right)\right] \qquad 9.3$$

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.

Hydro storage

The Snowy, Tasmanian and Southern Hydro reservoir storage levels were detailed within the 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, 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.

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 9.13shows the predicted carbon price in each of the three years modelled for the two carbon abatement paths.

Table 9.13: Carbon price forecasts ($/tCO$_2$)

	CPRS-15%	**Garnaut 450ppm**
2020	$ 50.02	$ 61.06
2030	$ 72.70	$ 88.41
2050	$ 157.90	$ 199.37

Mandatory Renewable Energy Target (MRET)

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 9,500 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 45,000 GWh 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 (see Section 9.1). 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 45,000 GWh target is predicted to be met.

Transmission network topology

The NEM region model used within PLEXOS contains five regional reference nodes and the main NSW to VIC interconnection (the Snowy) which includes inter-regional transfer limits (see Figure 9.48). 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).

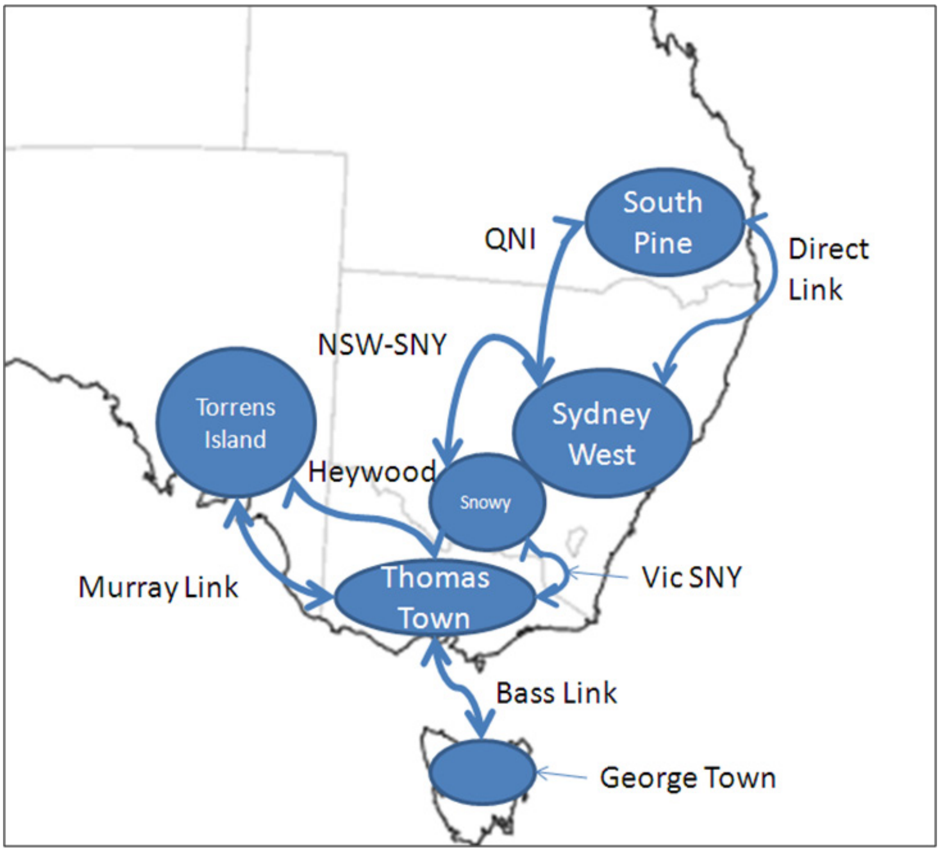


Figure 9.48: NEM network topology

Upgrades to inter-regional line limits were introduced incrementally during the testing phase for each milestone year within the planning horizon (see Table 9.14 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, the optimal power flow solution should not include USE of more than 0.002% of yearly demand. This is consistent with AEMO's own planning criteria. Therefore, the major constraint to solving the optimal power flow is inter-regional line flow limits.

After each simulation test the level of USE was examined. If it did then the line limit was upgraded by the peak amount of USE. This was done to improve the flow of energy and maintain the forecasted energy supply and demand balance. In taking this approach it was found that upgrades to the line limit between the 2020 milestone and 2030 were fairly modest, while upgrades between 2030 and 2050 would be considered substantial. Line losses, outage and repair pattern timings of the interconnectors were consistent with those currently observed in the NEM.

Table 9.14: NEM interconnector line limit upgrade schedule (MW)

Link Name	From	To	2020	2030	2050
QNI	NSW	Qld	600	1,200	10,000
QNI	Qld	NSW	1,200	3,600	10,000
Direct Link (DC)	NSW	QLD	100	360	5,000
Direct Link (DC)	Qld	NSW	180	360	5,000
Murray Link (DC)	Vic	SA	220	5,000	10,000
Murray Link (DC)	SA	Vic	120	2,500	5,000
Heywood	Vic	SA	460	3,200	10,000
Heywood	SA	Vic	300	3,000	10,000
Basslink (DC)	Tas	Vic	630	3,000	10,000
Basslink (DC)	Vic	Tas	480	3,000	10,000
Snowy NSW	NSW (Snowy)	NSW Sydney West 330KV	3,200	5,000	10,000
Snowy NSW	NSW Sydney West 330KV	NSW (Snowy)	1,150	5,000	10,000
Snowy Vic –NSW	Vic	NSW	1,200	5,000	10,000
Snowy Vic –NSW	NSW	Vic	1,900	5,000	10,000

9.3.4 Results

For each of the 3 years modelled results are presented for:

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

It should be noted that a number of challenges result from linking the outputs of ESM (Section 9.1) with this modelling. Firstly, 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. Secondly, 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 buyer (generally a retailer) of a call option (or cap) attempts to avoid risk by purchasing the right (but not obligation) to buy electricity at a specified price at a point in time. The end user purchases the cap by paying an upfront premium (in $/MWh) for this right. This option ensures that the price the paid for electricity does not exceed the specified amount. When the spot price is below the cap, the end user buys from the pool. When the spot price exceeds the cap, the end user buys electricity from the option holder. Alternatively the option can be sold on or before its expiry date.

A premium as used in this report is determined from the frequency of prices exceeding a cap price barrier (Equation 9.4). The sum of all of these cap premiums is equal to the time weighted average price of the price trace considered. The premium for each cap in this case, is for a perfect system in which no loss or gain is experienced relative to having purchased all electricity at the spot market. As such, the cap option simply minimises the peak expenditure rather than the total expenditure. Clearly in real world conditions this varies depending on the number and price of the options purchased.

$$Premium = \sum_{i=1}^{m}(SP_i - CAP)/_n - \sum_{j=1}^{k}\left(\sum_{i=1}^{m}(SP_i - CAP)/_n\right)_j \qquad 9.4$$

Where, n is the total number of timesteps,
m is the number of occasions the spot price exceeds the designated cap and,
k is the number of prices caps considered above the current cap.

The representation of relative GHG emissions to compare the five scenarios with each other is performed by using the EIF expressed as the number of emitted tonnes of CO_2/MWh.

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.

Solar PV, solar thermal and wind energy production are 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.

Results for 2020

The first year within the planning horizon begins with forecasting the effects of DG in the NEM in 2020, the last year of the current renewable energy target (MRET) and the first target proposed for the CPRS. The installed capacity used for this time step is represented in Figure 9.49. The greatest structural change observed is the decrease in the amount of brown coal generation and an increase in brown coal IGCC plant.

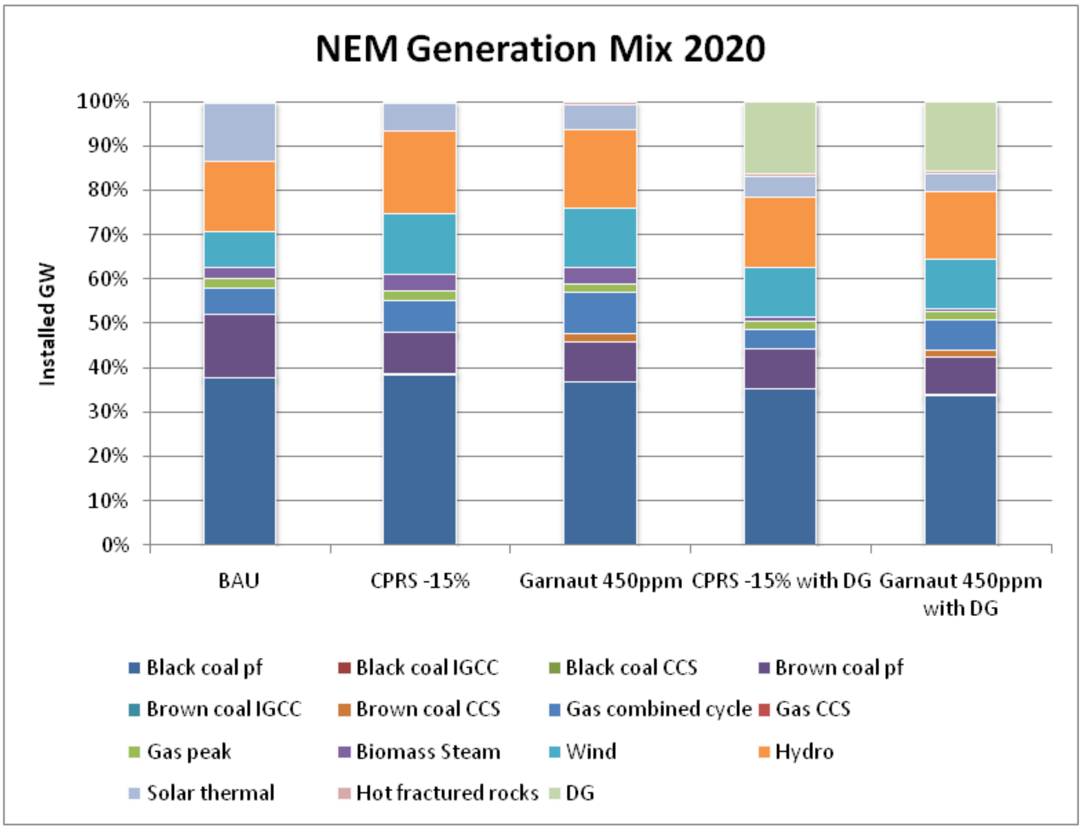


Figure 9.49: Installed NEM generation in 2020

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.

Table 9.15: 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 9.16. The Base value represents the sum of premiums up to and including the $100 cap which represents a benchmark hedge position generally observed on the NEM.

Figure 9.50 provides a graphical representation of the data in Table 9.16 which shos a cumulative price distribution for each scenario. The black line in this figure shows link the cumulative price representing the Base (i.e. the sum of all caps to $100), while the brown line links the totals. In this figure, it is clear that a smaller premium is required to ensure a cap price for the scenarios where DG is included when modelling the impacts of a carbon price. Scenario 1 (S1) which sees a continuation of current practice displays less price volatility (as measured by a cap) than any of the carbon abatement scenarios.

Table 9.16: Cap premiums in 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

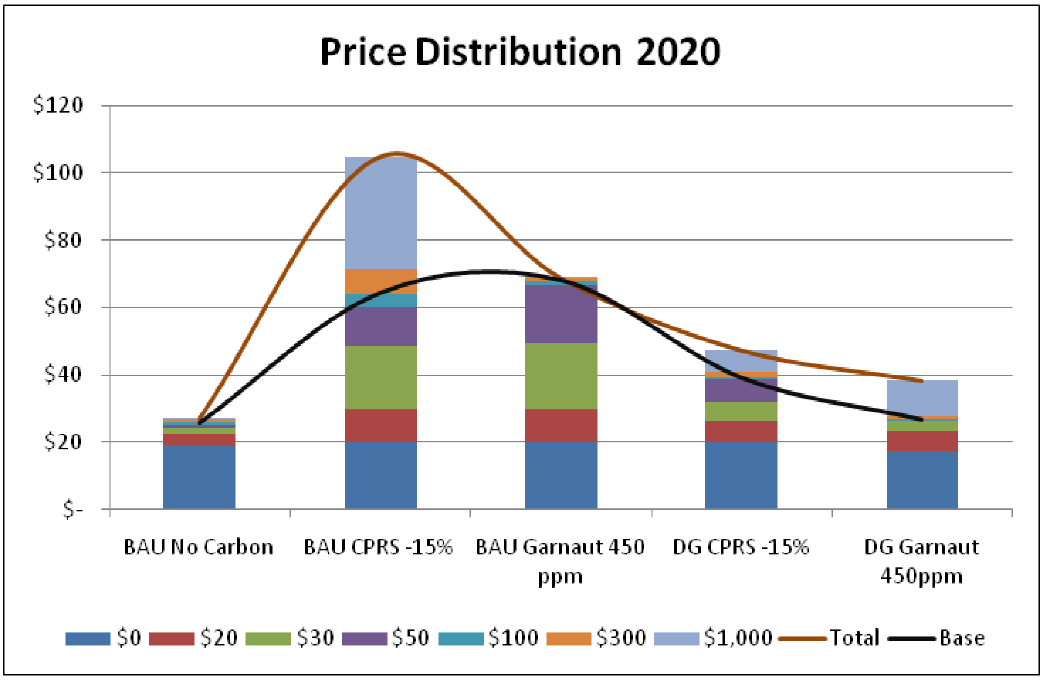


Figure 9.50: Cumulative price distribution for 2020 Simulations

Effects on transmission congestion

Evaluating transmission congestion in this modelling is performed by examining the inter-regional price spread. The observed spread between prices (Table 9.17) for each of the scenarios in this time step is consistent with the proximity of demand and maximum available supply (i.e. S2 NSW-QLD). In each scenario, the spreads which may indicate future inadequacy to cope with future demand are represented by higher prices in SA compared to Victoria. The transmission congestion observed in SA and VIC (using this proxy measure) may be a result of insufficient home State generation deployment as determined by ESM (see Section 9.1). 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 9.17: Inter-regional price spread in 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 (Table 9.18) is a significant outcome resulting from the deployment of DG.

Table 9.18: Greenhouse gas emissions in 2020

	GHG Emissions (MT/year)	**Emissions Intensity Factor (t CO_2/MWh)**
Scenario 1	229.5	0.88
Scenario 2	223.7	0.94
Scenario 3	201.2	0.79
Scenario 4	200.0	0.78
Scenario 5	199.2	0.80

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 9.18 is that the share of demand served by centralised generation is lower causing a loss in revenue relative to those experienced in S1.

Table 9.19: Percentage of 2020 demand met by technology type

	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%**

Results for 2030

Further shifts away from installed brown coal generation assets and the deployment of CCS and IGCC technologies all play a part in facilitating major structural change within the NEM (see Figure 9.51). The further deployment of DG across the NEM has major effects on average price, volatility and GHG emissions reduction in all four carbon price scenarios as noted below.

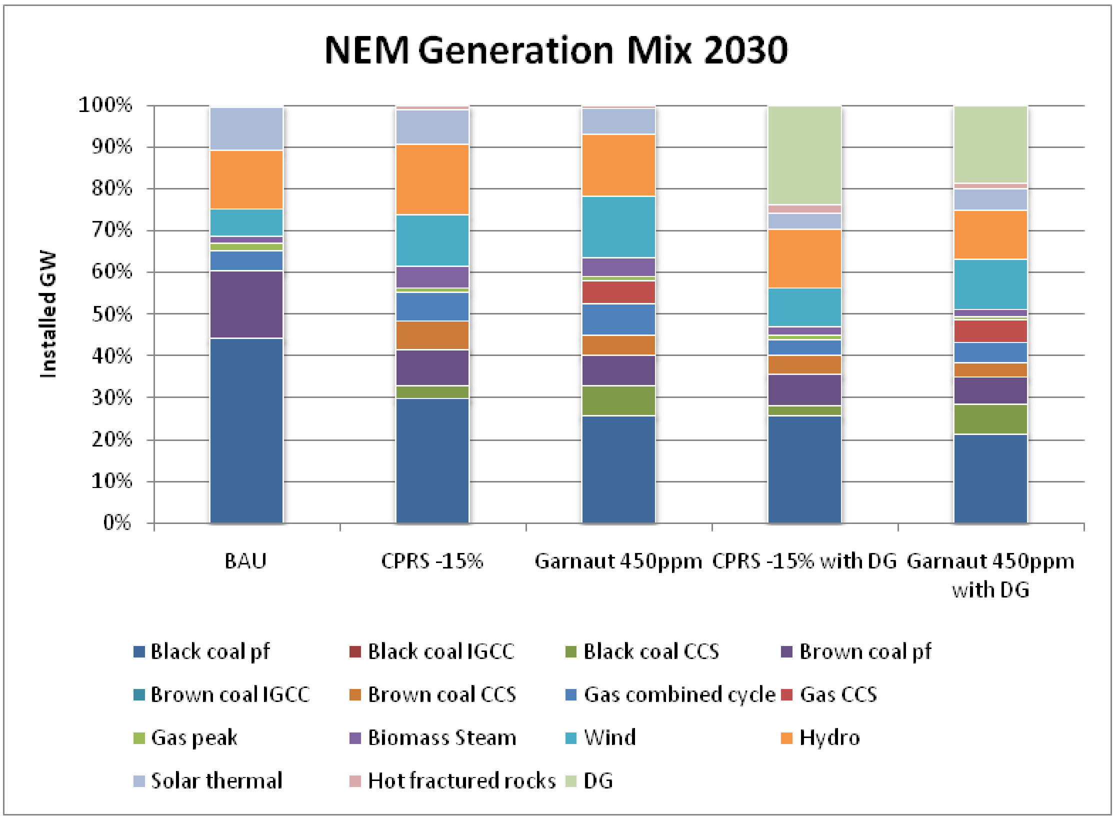


Figure 9.51: NEM 2030 installed generation mix

Effects on average prices

Results for 2030 indicate that the NEM experiences a significant shift in the average price of delivered energy across all States and all scenarios as a result of installed DG. As expected, S1 shows that there is little change in prices from 2020. While there is a decrease in the average price for S2 and S3 compared to 2020 which can be attributed to the uptake of large centralised renewable generation s bid into the merit order of dispatch at $0/MWh. The two DG scenarios however suggest a potential for significant shifts in market behaviour and reduction of uncertainty in market conditions for retailers.

Table 9.20: Average prices in 2030 ($/MWh)

	NSW	QLD	SA	TAS	VIC
Scenario 1	$27.82	$53.07	$38.83	$18.22	$24.61
Scenario 2	$57.75	$72.69	$47.17	$38.65	$38.67
Scenario 3	$48.39	$62.25	$63.02	$63.02	$50.95
Scenario 4	$39.70	$34.77	$34.51	$34.51	$31.44
Scenario 5	$26.65	$39.69	$33.09	$33.09	$30.53

Effects on price volatility

One of the striking results from this modelling is the overall reduction in the premium for a $100 price cap (see Table 9.21 and Figure 9.52). A notable reduction in volatility of prices on the NEM may enable retailers to reduce their risk management costs which will flow on to consumer tariff prices.

Table 9.21: Cap premiums in 2030

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Premium on Cap: $0	$17.38	$19.23	$19.76	$18.66	$19.66
Premium on Cap: $20	$2.86	$8.73	$9.22	$7.20	$7.28
Premium on Cap: $30	$1.97	$11.77	$15.01	$6.05	$3.96
Premium on Cap: $50	$0.93	$8.42	$10.21	$2.78	$0.88
Premium on Cap: $100	$1.54	$3.90	$0.75	$0.72	$0.61
Premium on Cap: $300	$2.94	$2.03	$0.01	$0.06	$0.02
Premium on Cap: $1,000	$9.03	$1.80	$0.00	$0.00	$0.00
Total	$36.66	$55.87	$54.97	$35.46	$32.40
Base	$24.69	$52.05	$54.96	$35.40	$32.38

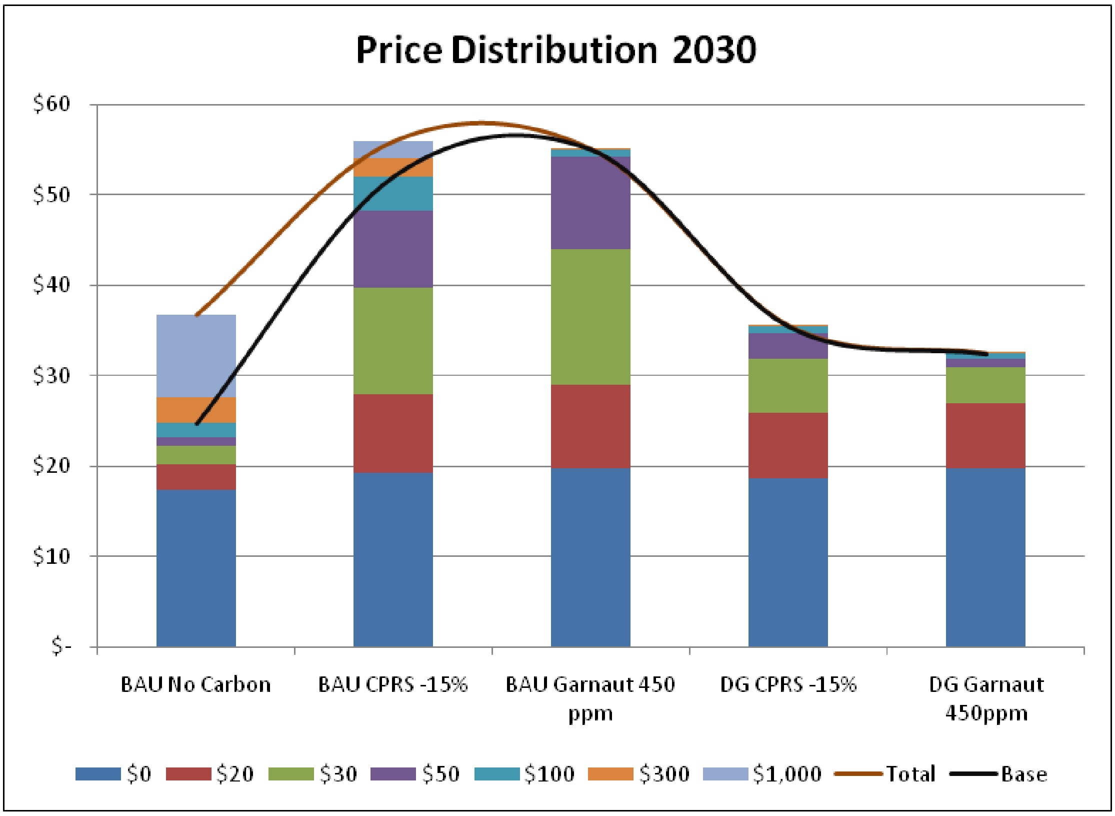


Figure 9.52: Cumulative price distribution for 2030 Simulations

Effects on transmission congestion

The growth of QLD demand compared to that of NSW may cause congestion reflected in the higher average prices experienced across four of the five modelled scenarios (Table 9.22). With interconnectors having been upgraded so as not to have any un-served energy across the market, prices are still unstable due to the close proximity of demand to maximum own State supply. Price spreads while negative in the three main interconnector points in S5 are still within what could be expected when each State supply maintains a very close margin to the required generation reserve margin.

Table 9.22: Inter-regional price spread 2030

	NSW - QLD	NSW - VIC	VIC - SA	Tas-Vic
Scenario 1	-$25.25	$3.21	-$14.23	-$6.39
Scenario 2	-$14.94	$19.09	-$8.51	-$0.01
Scenario 3	-$13.85	-$2.55	-$12.07	$12.07
Scenario 4	$4.93	$8.26	-$3.06	$3.06
Scenario 5	-$13.04	-$3.88	-$2.56	$2.56

Effects on greenhouse gas emissions

Table 9.23 shows a significant reduction in the EIF of electricity generation when compared to business as usual. It shows that the EIF for scenarios that include DG are lower when compared to scenarios where DG is not considered.

Table 9.23: Greenhouse gas emissions in 2030

	GHG Emissions (MT/year)	**Emissions Intensity Factor (t CO_2/MWh)**
Scenario 1	309.6	0.93
Scenario 2	96.7	0.43
Scenario 3	112.0	0.50
Scenario 4	97.4	0.39
Scenario 5	110.7	0.43

Effects on centralised generation

Table 9.24 shows that the model predicts that the electricity sector will increasingly move away from emission intensive fuel sources towards low emission technologies. Increased DG deployment in conjunction with centralised renewable generation assets reduces the competitiveness of combustive generators that are unable to implement emissions reduction measures.

Table 9.24: Percentage of 2030 demand met by technology type

	Scenario 1	**Scenario 2**	**Scenario 3**	**Scenario 4**	**Scenario 5**
Brown coal pf	25.39%	0.00%	0.00%	0.00%	0.00%
Brown coal IGCC	0.02%	0.02%	0.00%	0.02%	0.00%
Brown coal CCS	0.00%	12.19%	11.67%	8.45%	7.85%
Black coal pf	54.38%	41.80%	0.00%	37.08%	2.78%
Black coal IGCC	0.05%	0.06%	0.08%	0.06%	0.04%
Black coal CCS	0.00%	5.74%	17.85%	4.61%	16.81%
Gas combined cycle	4.67%	10.94%	17.77%	5.99%	10.77%
Gas CCS	0.00%	0.00%	14.31%	0.00%	12.60%
Gas peak	0.80%	0.15%	0.00%	0.00%	0.00%
Biomass Steam	0.73%	7.31%	9.03%	2.98%	3.14%
Wind	3.52%	8.58%	14.38%	7.06%	11.27%
Hydro	3.75%	5.17%	6.30%	4.76%	5.02%
Solar thermal	5.96%	6.16%	6.63%	3.07%	5.10%
Hot fractured rocks	0.74%	1.87%	1.99%	3.78%	3.38%
Centralised Generation	**100.00%**	**100.00%**	**100.00%**	**77.85%**	**78.75%**
DG	**0.00%**	**0.00%**	**0.00%**	**22.15%**	**21.25%**

Results for 2050

The business as usual case shows that electricity generation in 2050 is dominated by black coal-fired generation (see Figure 9.53). In contrast, the carbon price scenarios exhibit a more differentiated mix dominated by low emission electricity generation in the form of near-zero emission CCS and zero emission large scale renewables. The two scenarios that consider DG as an option show that these technologies could contribute to a significant share of electricity supply in 2050.

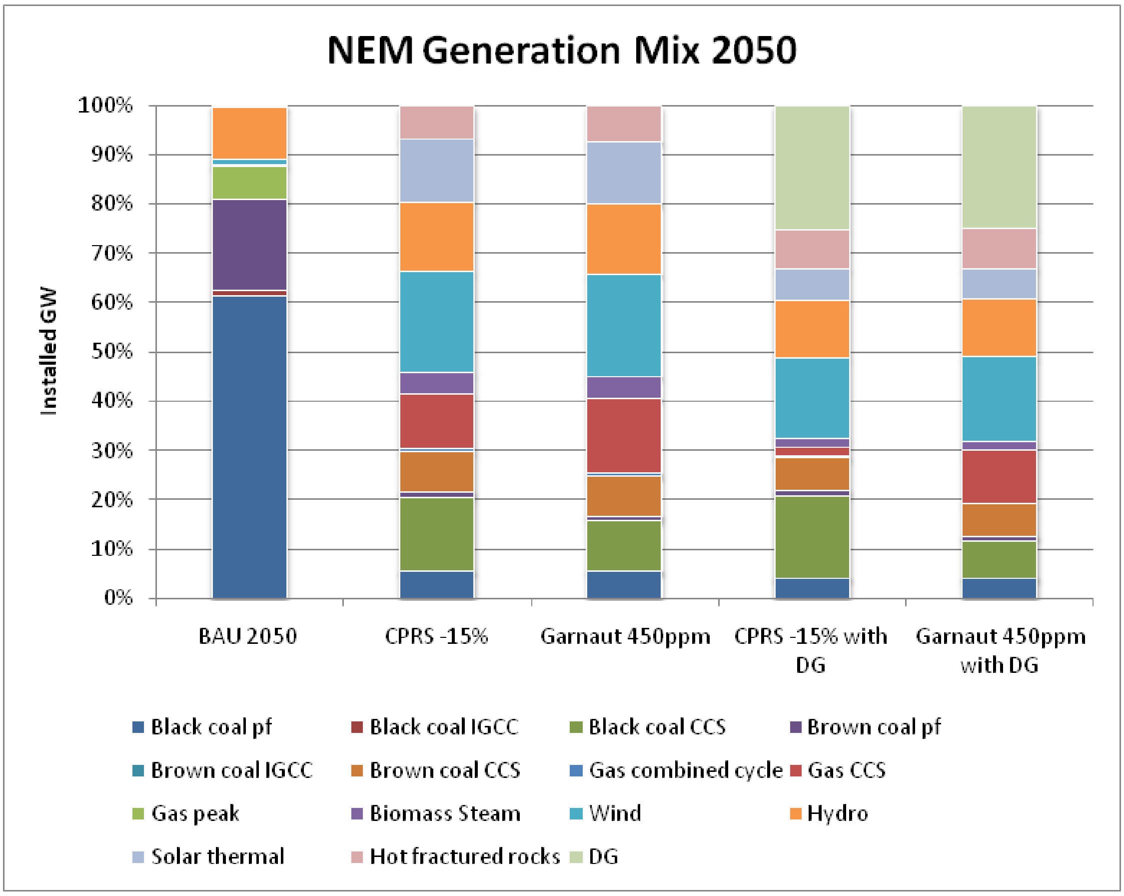


Figure 9.53: NEM 2050 installed generation mix

Effects on average prices

With carbon permit prices reaching in excess of \$180/t CO_2 for both carbon reduction scenarios, the average price in States that have a large amount of combustive coal based power generation will increase from sustained high energy prices. The reduction of average prices across S4 and S5 compared to their non-DG counterparts (Table 9.25), suggests that DG can reduce average spot prices in most regions of the NEM.

Table 9.25: Average prices in 2050 ($/MWh)

	NSW	QLD	SA	TAS	VIC
Scenario 1	$97.86	$151.15	$101.37	$75.65	$75.66
Scenario 2	$107.72	$117.39	$113.28	$105.29	$105.29
Scenario 3	$268.45	$283.26	$28.67	$28.67	$53.17
Scenario 4	$36.11	$47.93	$37.81	$37.81	$29.60
Scenario 5	$51.96	$49.63	$59.93	$59.93	$53.57

Effects on price volatility

Declines in price volatility are an important benefit to retailers (see Table 9.26 and Figure 9.54). Valuing the $100 price of cap premiums is a technique used by market participants to establish their risk profile for purchasing wholesale energy for retail consumers. Each of the non-DG scenarios suffer from much higher incidence of prices above $100 which could, and has in the past, placed significant stress on retail portfolio management.

Table 9.26: Cap premiums in 2050

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Premium on Cap: $0	$18.25	$18.80	$19.84	$17.54	$18.53
Premium on Cap: $20	$6.46	$4.69	$9.16	$3.71	$6.90
Premium on Cap: $30	$8.02	$3.33	$13.49	$2.85	$5.29
Premium on Cap: $50	$4.26	$1.61	$5.27	$2.88	$7.53
Premium on Cap: $100	$7.81	$2.27	$5.79	$2.38	$1.84
Premium on Cap: $300	$16.27	$6.01	$16.11	$1.48	$1.64
Premium on Cap: $1,000	$49.67	$73.39	$133.50	$7.82	$10.47
Total	$110.74	$110.10	$203.17	$38.67	$52.20
Base	$44.79	$30.70	$53.56	$29.36	$40.09

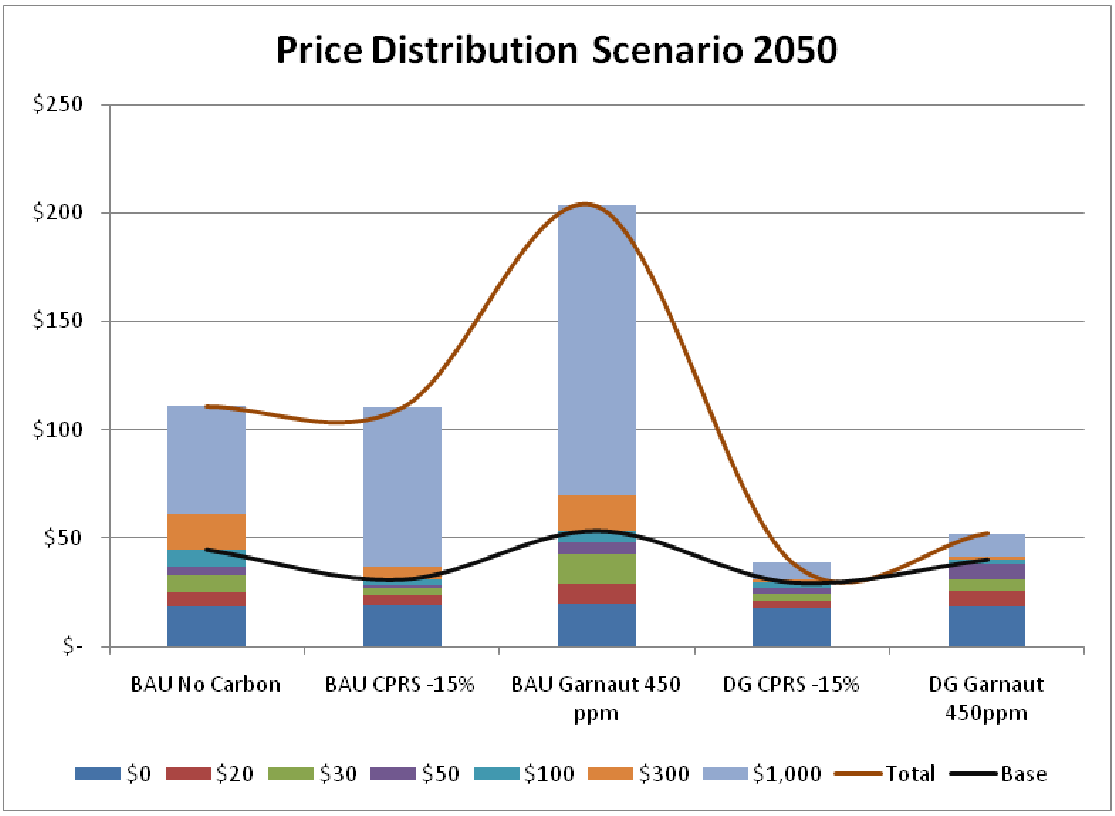


Figure 9.54: Cumulative price distribution for 2050 simulations

Effects on transmission congestion

Inter-regional transmission congestion is highly prevalent for scenarios without DG (Table 9.27). While S4 and S5 do have some transmission constraint concerns, the average price and its volatility indicate that own State generation is the main concern rather than interconnection constraints reaching their limit. It should be noted again that due to the upgrade of transmission interconnector line limits there are zero hours of binding transmission constraint.

Table 9.27: Inter-regional Price Spread 2050

	NSW - QLD	NSW - VIC	VIC - SA	Tas-Vic
Scenario 1	-$53.28	$22.20	-$25.71	-$0.01
Scenario 2	-$9.67	$2.43	-$7.99	$0.00
Scenario 3	-$14.82	$215.28	$24.50	-$24.50
Scenario 4	-$11.83	$6.51	-$8.21	$8.21
Scenario 5	$2.34	-$1.61	-$6.36	$6.36

Effect on greenhouse gas emissions

The observed GHG emissions in S1 are significantly higher in previous years and any other scenario modelled for this report (Table 9.28). While S2 and S3 represent significant drops in GHG emissions and the EIF, S4 and S5 produce greater savings than their non-DG counterparts.

Table 9.28: Greenhouse gas emissions in 2050

	GHG Emissions (MT/year)	Emissions Intensity Factor (t CO_2/MWh)
Scenario 1	545	0.97
Scenario 2	31	0.14
Scenario 3	70	0.31
Scenario 4	27	0.11
Scenario 5	54	0.21

Effects on centralised generation

Table 9.29shows that the electricity generation mix under the four carbon price scenarios is radically different from that modelled under business as usual. The introduction of DG in conjunction with CCS and centralised renewable generating assets has significant implications for the viability of emission intensive generating assets.

Table 9.29: Percentage of 2050 demand met by technology type

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Brown coal pf	24.71%	0.00%	0.00%	0.00%	0.00%
Brown coal IGCC	0.00%	0.00%	0.00%	0.00%	0.00%
Brown coal CCS	0.00%	12.92%	12.71%	11.64%	11.14%
Black coal pf	66.75%	0.00%	0.00%	0.00%	0.00%
Black coal IGCC	1.43%	0.00%	0.00%	0.00%	0.00%
Black coal CCS	0.00%	23.59%	16.08%	28.30%	12.76%
Gas combined cycle	0.18%	0.84%	0.82%	0.00%	0.00%
Gas CCS	0.00%	17.72%	24.16%	3.34%	18.58%
Gas peak	3.13%	0.00%	0.00%	0.00%	0.00%
Biomass Steam	0.42%	6.85%	6.92%	2.94%	2.93%
Wind	0.63%	14.37%	14.65%	12.17%	12.91%
Hydro	2.58%	3.78%	3.82%	3.71%	3.71%
Solar thermal	0.00%	9.30%	9.27%	5.04%	5.03%
Hot fractured rocks	0.17%	10.64%	11.58%	13.42%	13.67%
Centralised Generation	**100.00%**	**100.00%**	**100.00%**	**80.55%**	**80.72%**
DG	**0.00%**	**0.00%**	**0.00%**	**19.45%**	**19.28%**

9.3.5 Summary of main findings

This study examined the possible effects of the significant deployment of DG in the NEM. The modelling results suggest that average prices, price volatility and GHG emissions would be lower when DG is considered as an abatement option under alternative carbon price scenarios.

Effects on average prices

The modelled uptake of DG has significant impacts on average spot prices for electricity throughout the NEM. The estimated lower average prices for each DG scenario indicates that the inclusion of small scale electricity generators as GHG abatement options in the electricity sector can result in a lower delivered cost of energy to end-users (Figure 9.55).

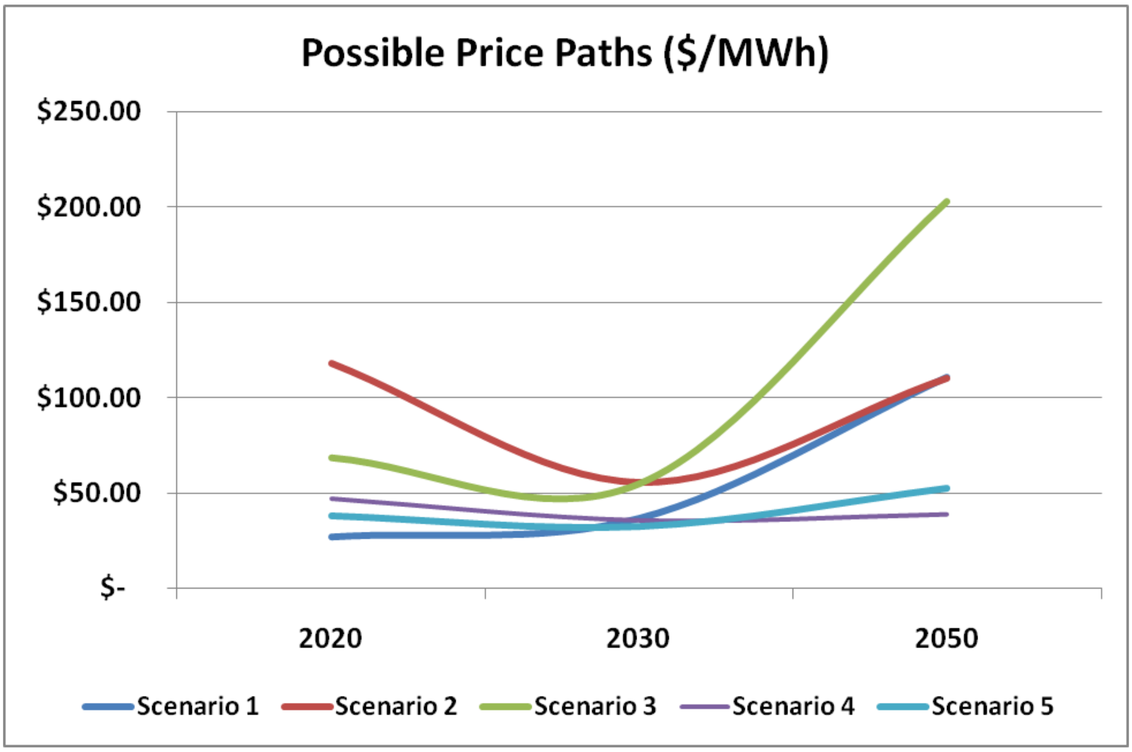


Figure 9.55: Forecasted energy prices

Effects on spot price volatility

The modelling indicates that the deployment of DG results in a decrease in the frequency of price events above $100 throughout each simulated year (Figure 9.56). In the NEM, the frequency and severity of high prices has been observed in previous years which have resulted in adverse consequences for the viability of retailers to recover the price of wholesale electricity from consumers. Lower spot market price volatility may result in lower tariff price increases over the planning horizon and the deferral of investment in expensive higher emitting peaking generator plant.

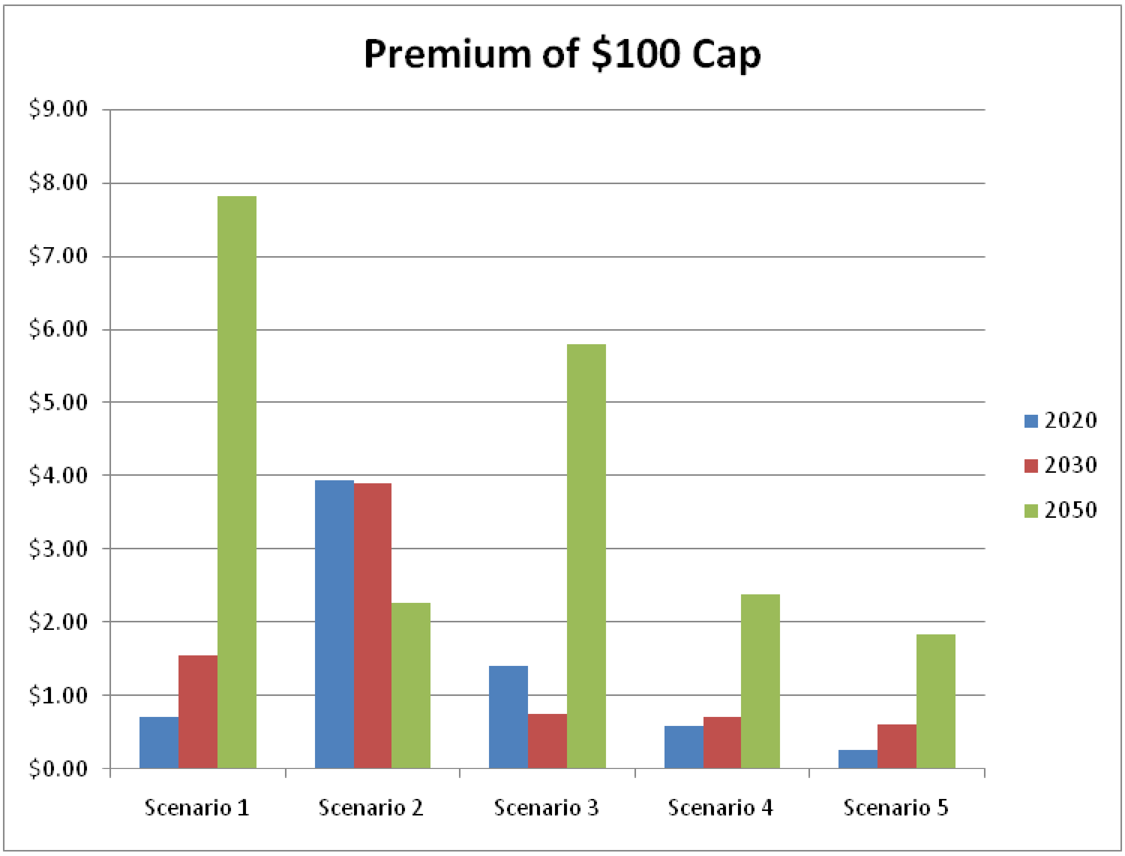


Figure 9.56: Market volatility determined by the premium on a $100 cap

Effects on greenhouse gas emissions

The modelling found that the EIF (t-CO_2/MWh) of delivered energy throughout the NEM is significantly reduced across all three years under both emissions reduction scenarios when DG is introduced. Figure 9.57 features the EIF's of delivered electricity across the NEM and shows significant change with respect to the emissions profile, demonstrating that DG can provide an important role in curtailing CO_2 emissions in the electricity sector.

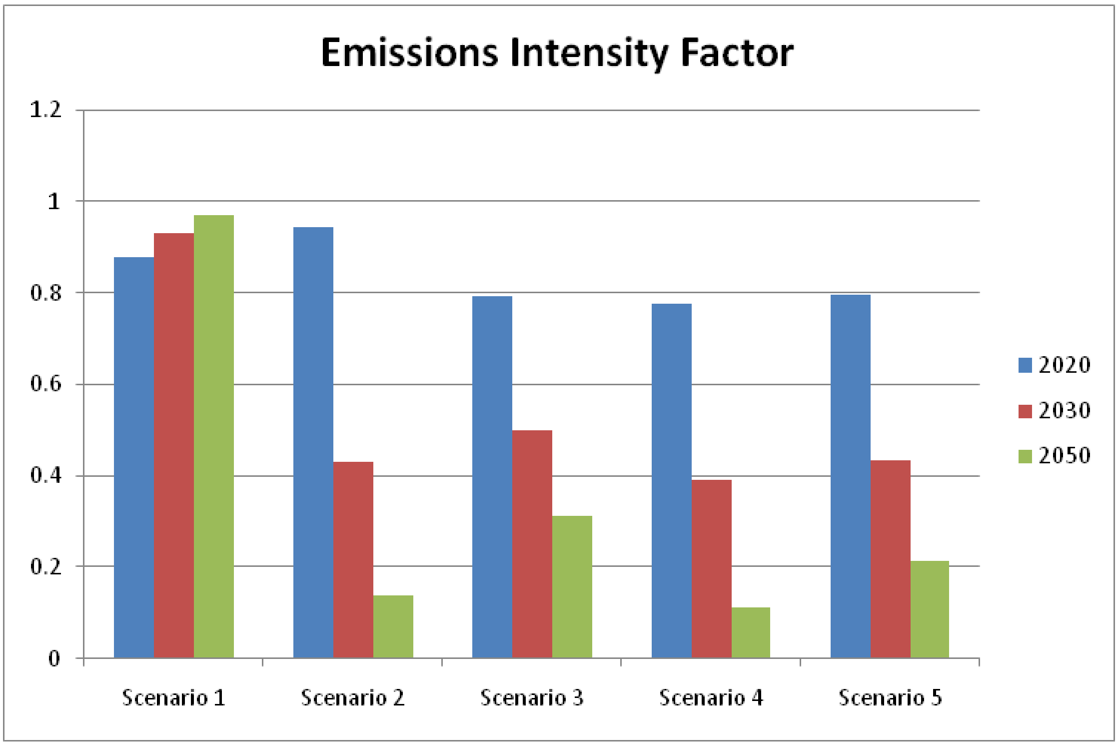


Figure 9.57: Emissions Intensity Factor (EIF) for delivered energy (t/MWh)

9.3.6 Modelling limitations

The analysis undertaken in this study is not a complete analysis of the potential impacts of the introduction of DG in the NEM. No consideration has been made for the following market characteristics:

- The effects on changes in fuel prices based on supply and demand changes
- Hedge contracts currently in place that extend into the modelling period
- Drought implications for hydro modelling
- The break-up of NSW generating portfolios as proposed by the Owen Inquiry
- Demand Side Participation (DSP)
- Availability of low emission technology types
- Unit retirements.

The reliance on this modelling should be taken in context of the assumptions used to produce the results. The modelling horizon consists of three landmark years in a 31 year timeframe and only provides a snapshot of what could be expected. Furthermore, the modelling consisted of input assumptions from ESM which were not operated in an iterative manner to enable feedback of results for benchmark testing.

9.3.7 Conclusion

The electricity market modelling of DG with PLEXOS 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.

9.4 Impacts and benefits of DG on distribution networks

Findings presented here are taken from a study commissioned by CSIRO and undertaken by Senergy Econnect to inform the impact of high penetration of distributed generation on distribution networks (Senergy Econnect, 2009). It incorporates findings from two different analyses conducted in parallel. Firstly, Distribution Network Impact Studies (DNIS), using recognised modelling techniques, provide a quantitative analysis of the technical impacts of projected generator installations from 2010 to 2050 on four real-world distribution feeders (data provided by SP Ausnet). Secondly, the study uses qualitative methods to assess the implications of policy and regulation on the DNIS and vice versa. The following summarises key findings of the study.

9.4.1 Key findings

The DNIS successfully developed base-case feeder models and projected generator installation trajectories onto them as required for this study, including one that achieves a 60% reduction in greenhouse-gas mitigations by 2050 compared to 1990 levels. Although there are many assumptions included in this process, they were validated with appropriate research. The key findings of the DNIS are as follows:

- DG is of benefit in reducing network losses and improving voltage profiles
- DG is of some value in postponing network upgrades where thermal limits are a critical factor, although attention must be given to the effective capacity contribution under peak loading conditions. Network upgrades may be necessary in any case due to reliability considerations (value of lost energy), but depending on DG characteristics it may be possible to upgrade feeders with lighter conductors than would otherwise be necessary
- Under the investigated scenarios to 2050, DG is unlikely to pose widespread issues with fault current capacity of existing equipment, or to raise issues with protection coordination through displacement of conventional generation leading to reduced fault levels
- The envisaged embedded generator technologies are not considered to be a significant source of voltage flicker, rapid voltage change or phase imbalance. Harmonic emissions from inverter-connected generators such as PV are expected, but are unlikely to result in harmonic distortion on feeders in excess of regulatory limits
- The opportunity for power from DG to result in a power flow reversal across zone substation MV busbars is limited due to the fact the embedded generators have a tendency to generate at times of human activity and so energy consumption. As such it is considered unlikely to be a problem
- High-level investigations indicate that DG is unlikely to pose issues due to steady-state voltage stability, frequency stability, rotor angle stability or small-disturbance (oscillatory) stability. However, these investigations are limited and more detailed investigations are warranted in future to confirm these results

- Fault ride-through capabilities have been found to be desirable for embedded generators but not necessary at the present or prior to 2050 given the high level assessment applied here.

The purpose of the qualitative analysis was to assess the implications of the Distribution Network Impact Studies in terms of regulation and operation of the NEM. Key findings of the analysis are as follows:

- Currently, due diligence assessment of each individual embedded generator connection is required by the DNSP, if the DNSP foresees the potential for adverse network impacts. This could become impractical as the rate of connection requests increases. It is suggested that in future, an aggregated due diligence assessment might be undertaken instead based on an anticipated penetration of embedded generators. This would establish a level of DG that could connect without further assessment before network limits are reached
- The safety standards which are currently in place to achieve safe operation of distribution feeders are considered to remain appropriate for DG into the future. However, the protection philosophies and settings of existing equipment may need reconsideration, and some equipment may need to be upgraded, as embedded generator installations increase in number
- DG at present largely falls outside the scope of the National Electricity Rules generator technical requirements. There is some technical justification for extending some of these requirements to embedded generators as penetration increases toward 2050
- Given the level of interaction suggested between DNSPs, local electricity retailers, and embedded generators of all types, it can be expected that a myriad of contractual arrangements may be required between parties. It is suggested that arrangements should prioritise system security.
- Islanded operation of distribution networks is in principle highly effective in realising the full value from embedded generation. However, the technical and commercial barriers to such operation remain formidable and will require substantial work to address. It is reasonable to expect that islanded operation of networks will become feasible prior to the 2050 time horizon used in this study.

9.4.2 Introduction

As described previously in this report, Distribution Network Service Providers (DNSPs) are crucial stakeholders in the Australian electricity industry who are already experiencing distributed energy at first hand. They are proponents of demand management with several trials completed and underway, and they are gatekeepers for DG in the sense that they must respond to customer connection requests and, in doing so, assess the impact on power quality and network planning and operations. Uncertainty about a range of potential impacts of wide-spread embedded generation, including the benefits that network operators might capture, created the need for this broad-ranging technical study.

Senergy Econnect Australia was appointed to conduct independent research to study the impacts and benefits of distributed generation (IBDG) in Australian electricity distribution networks. In particular, the focus of the IBDG study is on small-scale renewable generators such as photovoltaic and micro-wind systems along with other generation technologies which promote increased energy efficiency such as larger capacity combined heat and power generators.

The distribution network impact study (DNIS) assesses technical aspects of the broader scope through the application of proven modelling techniques. Further qualitative assessments are made on energy policy, regulation and network design.

Throughout Australian distribution networks medium voltage feeders are widely used. The focus of the IBDG study is the effect of small generators on real-world models of these feeders and their low voltage subsidiaries. The IBDG aims to incorporate the dynamic nature of both load and generation growth from the present day to 2050 with the incorporation of projected installation growth trajectories of small generators. By studying the effects of distributed generation in realistic distribution feeder scenarios, the aim is to uncover underappreciated direct benefits as well as innovative responses to the technical challenges posed by these newer technologies. In order to quantify the additional value to the distribution network, the study relies on both steady-state and high level dynamic modelling, and includes a number of sensitivity analyses.

9.4.3 Project methodology

The study considers four medium voltage distribution feeder case studies subjected to a combination of DG and load scenarios. The main channel for conducting qualitative studies is the application of DIgSILENT PowerFactory™ (http://www.digsilent.de/) power system modelling software which utilises a Newton-Raphson based iterative approximation technique. The overall DNIS includes modelling of both MV and LV distribution networks along with some consideration for Single Wire Earth Return (SWER) networks. Model data and ongoing assistance has been provided by SP AusNet (Victoria; http://www.sp-ausnet.com.au/) as a contributory party to this work (the DNSP). Feeder case studies are assumed to be typical of the class they represent and have these characteristics:

Feeder 1: Urban established commercial feeder, supplying predominantly commercial zones in an established urban area

Feeder 2: Urban established residential feeder, supplying predominantly residential load in a long-established urban area (to account for incremental network augmentation in response to evolving electrical applications over a period of decades)

Feeder 3: Urban 'green-field' residential feeder, supplying developing residential subdivisions. This feeder will contain some rural and semi-rural load including some SWER circuitry but be evolving toward predominantly urban use

Feeder 4: Rural feeder, containing a combination of three-phase and SWER circuits.

Any modelling of LV distribution network is considered explicitly as required. Accordingly, where information is not provided, reasonable engineering assumptions are made. The studies consider possible future distributed generation and customer load scenarios and compare network outcomes with a 'base-case' formulated from present-day data and policies. Scenarios are then developed and compared for the years 2010, 2015, 2020, 2030, 2040 and 2050.

DG technologies considered are on a 'small but broad' scale such as may be installed by electricity customers in distribution networks and typically fall into the individual size ranges of 1kW to 1MW. A limited number of industrial gas and diesel engines are also considered in some analyses. These range in size from 1MW to 30MW and are included in the context of industrial sites having a similar level of load demand.

The basis for each scenario is a forecast of various DG technology penetration, provided by CSIRO under both 'Business As Usual' and 'Emissions Mitigation' scenarios (CSIRO, 2008) and of customer load growth as extracted from published information.

Generation forecasts have been provided in figures of installed MW and number of units of each technology considered. Generation technologies considered are natural gas CHP (combined cycle and micro turbine), biomass CHP, biogas engines, photovoltaic (PV) systems, micro-wind turbines, and diesel engines. All figures are provided in five-year intervals from 2010 to 2050 and broken down according to the type of customer (residential, commercial and services, industrial or rural). Figures are compounding and inclusive of attrition as devices age and are taken out of service. Consideration of existing generation on each feeder was only given where detailed in the model data provided by the DNSP.

On the demand side, figures provided total load in MW along with an assumed lagging power factor of 0.9 for the base year (2008). For residential customers the proportion of each load type (e.g. heating, hot water, cooling, lighting, refrigeration, cooking, clothes drying, and electronic appliances) was derived from published information as required.

Specific tasks relating to the quantitative and qualitative studies undertaken are as follows.

Quantitative components (DNIS):

- Define characteristic study parameters for investigation and associated benchmarks for network outcomes
- Establish base-case scenarios for distribution feeders based on projected load and generation growth
- Conduct load flow studies in accordance with future scenarios

- Analysis of results in accordance with benchmarks for network outcomes
- Assess, define and conduct sensitivity analyses as required
- Summarise results.

Qualitative components (IBDG):

- Characterise distribution networks and feeder models
- Classify generators used in the study
- Provide commentary on state of the art distributed generation technologies
- Draw conclusions from DNIS case study findings
- Assess the level of due diligence required by DNSPs in respect to DG
- Assess the applicability of Schedule 5.2 of the Australian Electricity Rules (AEMC, 2009b) and other energy policy issues in respect of DG
- Assess the applicability of safety standards in respect of DG
- Provide commentary on reliability and islanding
- Detail overall conclusions, recommendations and further work resulting from the DNIS and IBDG study.

9.4.4 Distribution network characteristics

In the transmission of electrical energy, the role of the distribution network is to deliver electrical energy from a bulk supply point, or zone substation, directly to the end user. Distribution ‘feeders’ operate at medium voltages, as is replicated here with case study models operating at a nominal 22kV. From these feeders, MV loads are supplied or small distribution transformers step the voltage down to a more practical low nominal voltage from which a number of LV loads are supplied as shown by Figure 9.58.

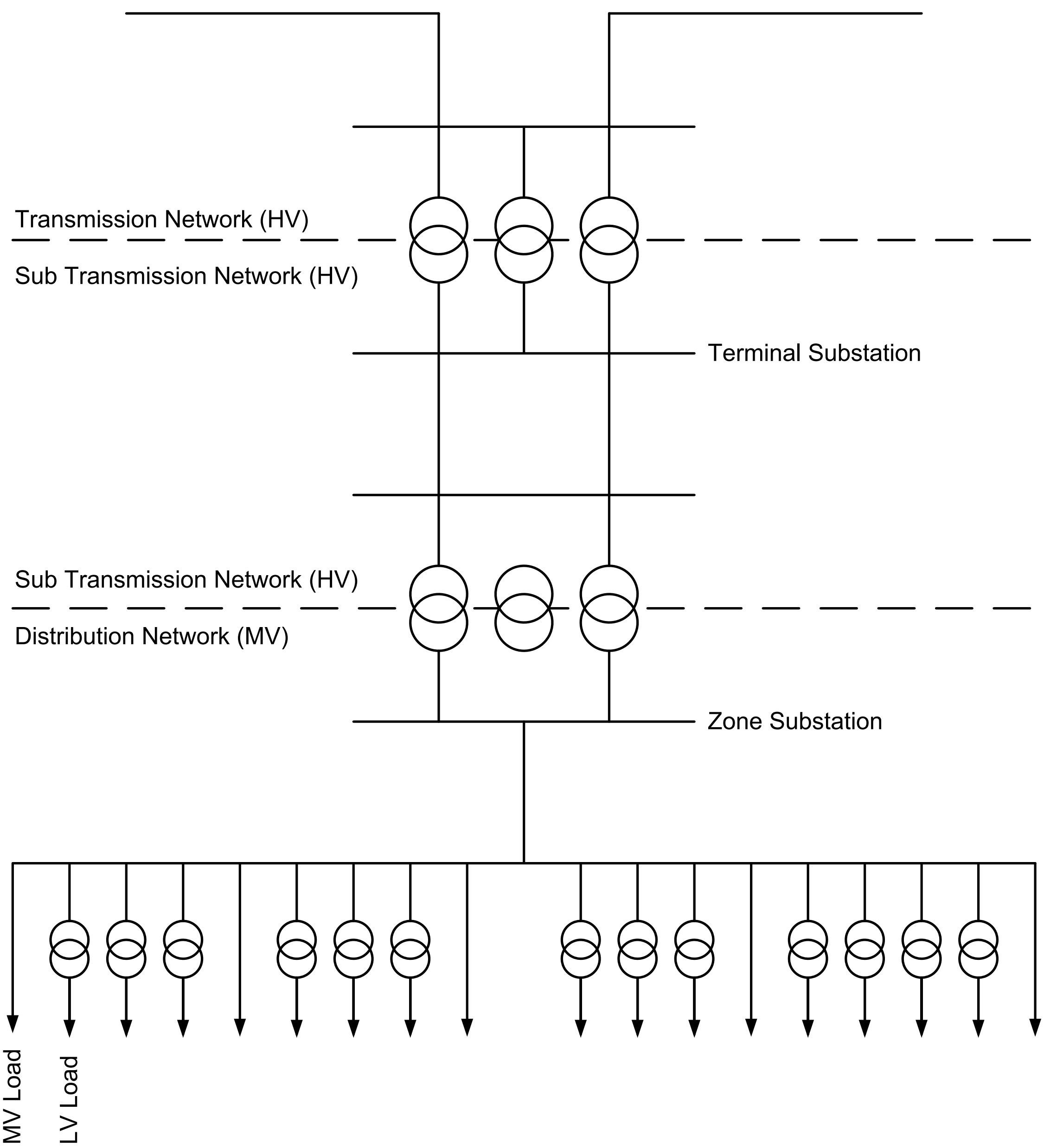


Figure 9.58: Indicative single-line diagram of the electrical network as a whole showing where MV and LV distribution networks are placed. Note that the distribution networks effectively begin at the secondary side of zone substation transformers and end at MV and LV loads.

There are thousands of kilometres of MV distribution network in Australia and the use of this voltage level optimises cost whilst maintaining acceptable efficiencies. As a result of the distances involved, a large majority of distribution feeders consist of overhead lines (OHL), however, the use of underground cabling is becoming increasingly prominent and is often the preferred option for new installations or where OHL may be susceptible to faults.

Distribution network components and structures

Distribution networks consist of a variety of components and their performance is influenced by a variety of factors depending on the function they carry out. This section introduces these other factors and describes how they are accounted for in the study.

Network voltages and voltage regulation

Nominal voltages are defined by a number of sources in Australia. As they apply to this study low voltage is a nominal 400V with a tolerance of +10%/-6% (ANZS, 2007a) while the nominal medium voltage (MV)[13] is 22kV with a tolerance of ±6% or ±10% for rural areas (Essential Services Commission of Victoria, 2008). Although not considered here, it is worth noting that any voltage above 22kV is recognised as being a high voltage.

Distribution networks typically incorporate active network components such as voltage regulating transformers and shunt capacitors when they cover large distances such as those covered by rural feeders. Feeder 4 incorporates three voltage regulating transformers along its length and the impact on voltages is evident in the apparent ‘saw-tooth’ behaviour of the voltage profile illustrated in Figure 9.59.

Each of these transformers is capable of ±15% voltage regulation on its secondary winding and they are capable of On Load Tap Changing (OLTC) in order to maintain a voltage set point of 104% on their secondary winding terminals. Shunt capacitors are not included in the network model data provided and so are not represented in this study.

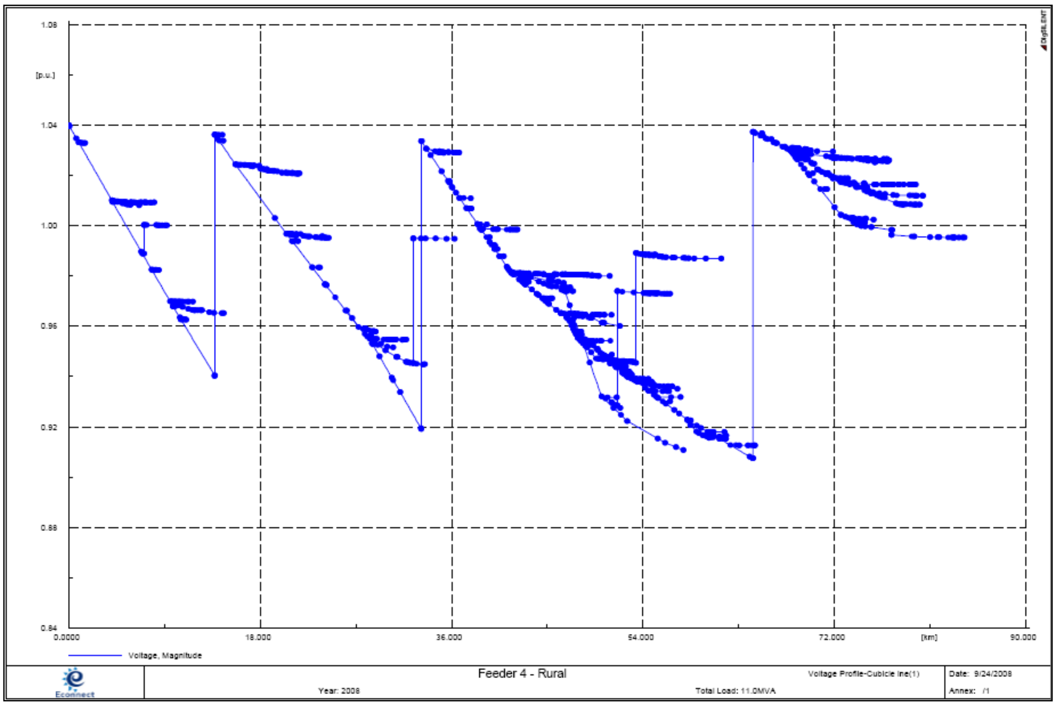


Figure 9.59: Feeder 4 voltage profile under maximum summer load

13 While the term ‘ MV’ is technically inapplicable in accordance with the Australian Standards, it is used here in order to maintain exclusion of the high voltage transmission and sub-transmission levels of the network from the networks included in this study.

SWER transformers are also usually fitted with some manually adjusted off-load tap changing capability as it is their nature to be installed in scenarios where this is beneficial. In this study it is assumed that SWER transformers have the capacity to tap to +2.5%/-5% and their 2008 tap positions are retained throughout the study period in order to ascertain the importance of monitoring them.

Distribution feeder supply transformers (represented here as 66kV/22kV transformers in keeping with the DNSP's jurisdiction) are also fitted with voltage regulation capabilities. In the case of the MV feeder case studies, these maintain a fixed tap setting and can be changed at the DNSP's discretion if required. As the feeders are radial in layout, this action gives them a high level of reliability of maintaining nominal voltages to customers along the whole length of the feeder. In the case of the DNIS, Feeders 1-3 have a tap setting of 102% at the zone substation while Feeder 4 is set to 104%.

Load assessment and characteristics
It is typically unnecessary for DNSPs to provide for measurement devices at each MV/LV distribution transformer in their network. Thus, the load information provided for the DNIS is based on the average metered energy supplied by the LV side of each distribution transformer. This method derives an average real power (kW) to which an assumed power factor of 0.9 (lagging) is applied.

While the DNSP does not measure the loading at each MV/LV distribution transformer they do include SCADA based current measurement in each feeder at the respective zone substation from which daily load profiles can be recorded. In order to properly model the loading on the feeder, the DNSP has provided load profiles of a typical peak load day. The information from the load profile is then used to derive a scaling factor for all of the loads that gives the model the correct peak current demand at the zone substation end of the feeder. Where loadings are noted in the DNIS, unless otherwise mentioned, it is the peak load that is considered as this represents the most strenuous operating conditions of the network.

Electricity consumption per capita in Australia is expected to steadily increase throughout the study period and, as a result of society's growing demand for services enabled by electricity, the nature of electrical appliances is rapidly changing. Many appliances transform low voltages delivered by the mains supply into extra-low voltages (ELV, rated at <50V) and then convert the ELV AC voltage waveform to DC for end use. Traditionally this has been carried out with iron core transformers and diode rectifiers which appeared as linear devices to the wider network. However, with the evolution of electronic components, the cost of power electronic devices has fallen and high investment has seen these technologies advance rapidly. Subsequently, traditional waveform conversion processes are expected to be superseded. While most appliances still operate on ELV DC, it is now much more common for them to use switch-mode power converters and this evolution is expected to bring new challenges. Furthermore, it is not just electronic appliances that incorporate power electronics, because new motorised equipment often incorporates variable speed drives rather than simpler speed control techniques.

Many electrical loads such as ovens and space and water heaters have resistive heating elements that present linear characteristics and have little negative impact on power quality. Almost all other appliances fall into the inductive category which includes existing and older motorised appliances that consume reactive power and impact on voltage profiles. The vast majority of these older appliances are expected to be phased out within the DNIS time scales.

The Department of the Environment, Water, Heritage and the Arts (DEWHA) recently released a report on the projected growth of energy consumption by individual domestic appliances to 2020 (DEWHA, 2008). Information contained in the report indicated the present mixture and projections to 2020 of the three load categories described above and illustrated the trend towards switch-mode power supplies.

There are clear benefits to the use of power converters due to their size and potential for efficiency improvements with advancements in component technologies. Their role is becoming increasingly important in this aspect. Switch mode converters draw non-sinusoidal currents which naturally induce frequencies other than that of the fundamental frequency which is 50 Hz in Australia. The result is a set of harmonic current components which have frequencies with integer multiples of the fundamental that are well recognised to affect power quality.

Power converters use fast switching devices which usually operate in the 20-100 kHz range and their individual harmonic contribution is limited by the requirements of the Australian Standard, AS61000.3.2. It is the accumulated harmonic currents of multiple appliances which are of concern, particularly when large concentrations of such appliances are found (Larsson and Bollen, 2005). The impact of harmonics can include reductions in the efficiency of electricity transmission as a result of non-sinusoidal currents (harmonic line losses); motor inefficiencies due to induced non-sinusoidal voltages; high zero sequence currents in neutral conductors; poor performance of electronic equipment; noise in audio and telecommunications equipment and; an increase in the overall losses in distribution networks.

There is a clear trend for the use of power converters regardless of the uptake of DG and, for the most part, this falls outside of the study scope. However, issues are expected to be found in the introduction of new power electronic devices in the form of inverters used in grid-connected PV and micro-wind systems, and these are discussed below under inverter-connected generators. It is interesting to note that the harmonic requirements for the inverters considered in this study are considerably more onerous than for individual load devices as dictated by AS61000.3.2.

Overhead line thermal limits

OHL conductors are given steady state thermal ratings in amperes or apparent power which depend on the manufacturer’s specifications and specific installation characteristics such as height and span between supports. Conductor manufacturers provide thermal capacities at an operating temperature of 40°C above ambient (Olex, 2008). However, where a DNSP modifies installation characteristics, modification of thermal limits is permitted.

As OHL is exposed to the elements, differences in ambient air temperature must be considered. In order to reflect temperature extremes, two ambient air temperatures are assumed: summer noon, 35°C, and winter night, 10°C. These operating conditions then derive maximum and minimum thermal capabilities for overhead lines on a summer day and winter night respectively.

These conditions create some difficulties in their representation with power system modelling software. In order to overcome them, a worst case scenario of operation under summer noon conditions with a conductor operating temperature of 65°C is assumed for all OHL modelled herein.

Single wire earth-return

In the Australian context, it is typical for rural distribution networks to incorporate SWER. The incentive behind using SWER is an optimisation of the cost of installation of a three phase supply over the requirement for it when the load is light on that particular section of the feeder. SWER systems operate on the principal of using the earth as a return path for the current drawn by the loads.

Medium voltage networks which include SWER are typically characterised by an emphasised unbalanced demand which in turn emphasises voltage unbalance (voltage unbalance is discussed in Section 9.4.8). The emphasised phase unbalance phenomenon and the corresponding impact on voltages can clearly be seen in the Feeder 3 voltage profile illustrated in Figure 9.60.

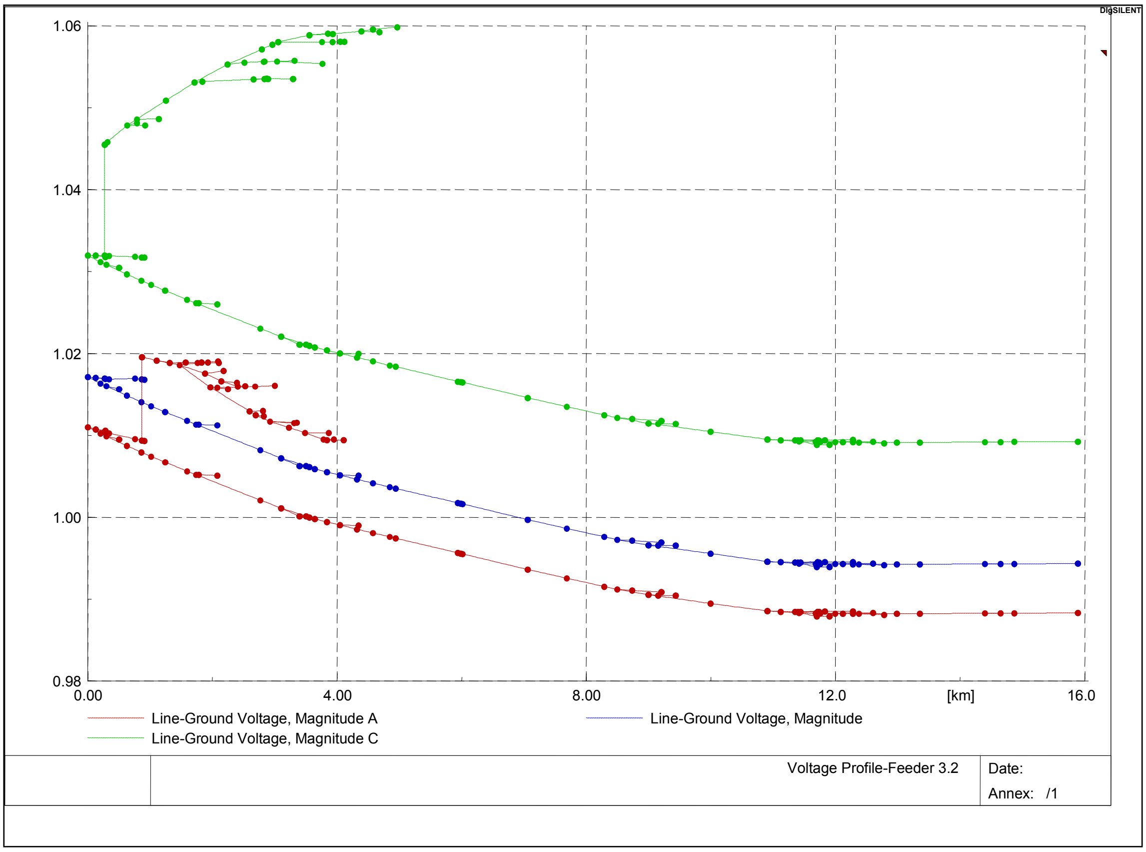


Figure 9.60: Voltage profiles for Feeder 3.2 (supplying newer developments after installation of a zone substation in Feeder 3) under 2050 EM scenario conditions. The unbalance is due to the SWER component.

DNSP responsibilities

DNSPs are responsible for the maintenance of distribution networks which supply the essential service of electricity to homes and businesses. In order to maintain their accountability, the reliability of their network is measured by a number of indices. In Victoria these indices are prescribed by the Essential Services Commission through the Electricity Distribution Code

(Essential Services Commission of Victoria, 2008), a role now assumed by the Australian Energy Regulator, and they consist of the following:

- The average minutes off supply per customer due to planned and unplanned outages (SAIDI)
- The average number of unplanned interruptions per customer, excluding momentary interruptions (SAIFI)
- The average number of momentary interruptions per customer (MAIFI)
- The average number of unplanned interruptions (CAIDI), and
- Estimates of the number of customers to which DNSP is expected to be liable for payments.

These indices are used to calculate penalty payments owing to customers where DNSPs fail to meet guaranteed service levels set by the regulator. For example, in 2006, a total of $4.04 million was paid to customers in guaranteed service level charges from Victoria's five operating DNSPs (Essential Services Commission of Victoria, 2007).

Traditionally, distribution networks maintain high levels of reliability through the installation of a large number of switches and sectionalisers. They are installed within the distribution network in order to isolate sections of the feeder under faulted or maintenance conditions and to return/maintain temporary supply to other sections of the feeder that may be inadvertently or unnecessarily de-energised. Sectionalising switches are normally left in the open position at all other times and must be manually closed according to specified procedures.

The introduction of high DG penetrations brings opportunities to implement more adaptive design techniques such as islanding to potentially further improve the reliability performance of distribution networks.

Existing distributed generation
It is often the case that there are already distributed generators connected to distribution feeders such as the MV feeder case studies used in this study. These generators could include micro-hydro generators, small scale induction generator based wind farms, older inverter-interfaced PV systems or any of the generators included in the CSIRO data for this study. As many of these generators are based on older designs, they may require reactive power, or create power quality issues on the existing network to which they are connected. As mentioned in the scope of works, these generators are not considered in this study as the DNSP has not provided any detail of such generation in the feeder model case-study data sets. However their impact must be considered by DNSPs where they are installed and while they remain in operation.

Distribution network automation schemes
It is well understood that the prevalence of network structures which include schemes such as Distribution Feeder Automation is expected to increase. This is expected to greatly increase the complexity of distribution networks while providing easier access to the network for DG. It is recognised that such schemes are of a level of complexity that they should be the subject of a different study and so are not explicitly considered here.

Protection in distribution networks

MV distribution network protection equipment is arranged for passive operation using settings based on minimum fault currents, while equipment sensitivities depend on maximum prospective fault currents. In a traditional radial network, power flow is unidirectional and fault currents are delivered from centrally located generating plant to the fault where the only limiting factor is the sequence impedance of the fault current path.

The introduction of DG into distribution networks equates to the introduction of additional sources of fault current and the potential for bi-directional fault currents. In order to assess the impacts of high DG penetrations, the protection issues that must be considered by DNSPs are maximum short circuit current, impedance relay reach, power flow reversal, auto re-closure, and safety.

There is ample evidence to indicate that the available fault current from grid-connected inverters is negligible and so they can be neglected when considering protection systems (Intelligent Energy Europe, 2007; Moore, 2008). As a result, it is only synchronous and induction machines connected to distribution networks that can contribute to fault conditions.

This study makes the assumption that DGs sized to 0.5MW and above are to be connected to the MV network via unit transformers. Connection of generators to the MV distribution network occurs under negotiated arrangements with DNSPs and with scrutiny of the network conditions and the operating points at the point of connection (POC). Such arrangements are in place to ensure that the network will continue to operate correctly and safely post connection and while they remain in place. While these mechanisms are in place, the impacts of high DG penetration on protection systems at the MV level should remain manageable.

Maximum short circuit currents
As mentioned above, the coordination of MV distribution system protection is heavily reliant on prospective fault currents. Concern lays in the possibility of additional DG changing existing fault levels and interfering with existing protection equipment.

There is a possibility for the DG fault current accounting for a significant amount of the total fault current. This may reduce flow through upstream protection equipment and interfere with equipment settings. However this scenario is not likely as the impedance between the distribution network and the fault will not vary under DG scenarios. While an increase in prospective fault levels is expected, the current from each source is not expected to vary greatly under fault conditions.

Attention must also be paid to the connection arrangements of generators at the LV level. The available fault current from a synchronous generator is often in the order of six times the generator’s nominal current. Where generators are connected to LV networks, thermally operated circuit breakers are typically used. Under the provision that the circuit breaker is selected appropriately, it is expected that it will operate on time scales of a few cycles rather than the tenths of a second as is often found in the melting time of low-voltage, high-performance (Niederspannungs Hochleistungs or NH) or high rupture current (HRC) fuse links that often protect LV distribution feeders at their supply point. Thus, the LV system should maintain safe operation while appropriate discrimination techniques are maintained.

The potential for encroachment of fault levels is also an issue to consider. As generator installations increase in number, it may become possible for prospective fault levels to exceed the rating of existing equipment. It needs to be noted that fault levels 'naturally' increase due to the constant need for network augmentation and reinforcement at all levels. The main issue of concern to this study is whether the installation of additional generators accelerates fault level encroachment faster than that of natural encroachment.

Impedance relay reach
Impedance relays used in distance protection arrangements are pre-set to operate on faults that occur within certain 'zones' along a feeder. These zones are derived from the nominal voltage and maximum permitted fault current seen by the relay. With the addition of DG, voltage profiles can be modified which has the effect of reducing the reach of the relay's zone (i.e. the fault must be closer to the relay in order for it to function normally).

As discussed previously, connection of DG to the MV distribution network is an issue that requires consultation with the relevant DNSP and so, if addressed at the time of connection, the correct reach of impedance relay zones can be maintained.

Power flow reversal
Traditionally, distribution networks and their protection systems have been designed and constructed in a radial fashion to facilitate unidirectional power flow. In cases with light feeder loading or high DG penetration, the distribution network may need to be able to accommodate reversed power flow which could interfere with traditional protection system designs, particularly in cases where MV protection systems have been designed with directional relays that may now see power flow in the opposite direction.

It is more likely that the installation of DG will result in the reversal of power flow within sections of a network rather than across the HV/MV zone substation transformer into the HV network. Where thermally operated circuit breakers are installed in order to provide protection to the LV system from DG, no significant issues are expected to arise from the reversal of power flow.

Automatic re-closure
It is very common for distribution network faults involving OHL to have durations of a few seconds or even cycles. In order to prevent long term outages resulting from temporary faults, reclosers are used extensively in MV distribution networks. While reclosers are not utilised in LV distribution schemes, they play an important role at the MV level and an issue can occur when a section that is isolated by a recloser opening manages to maintain an island after the fault is cleared. Danger lies in the potential for automatic re-closure between two asynchronous feeder sections.

The generator connection arrangements made with the DNSP give serious consideration to the operation of such reclosing equipment. Some potential future scenarios could include the installation of communication channels to facilitate the operation of the generator's circuit breaker upon the recloser opening. Reconnection of the generator can then occur via the generator's synchronising equipment once the recloser is closed.

Alternatively, the existing anti-islanding protection schemes may be considered to be appropriate and reconnection can be made manually once anti-islanding protection has operated.

As discussed later in this report, the level of DG penetration may become such that there is financial incentive to incorporate the potential for islanded operation into distribution network functionality. Here it is expected that reclosing action would need to incorporate the necessary synchronising equipment to permit flexible islanding operations.

Safety

The primary purpose of distribution network protection equipment is to disconnect faulty network components and to prevent damage to plant and ensure safety to the public and DNSP personnel. In order to maintain appropriate levels of safety, all generators that have the ability to significantly contribute to fault conditions will require case-by-case assessment until experience can determine a more turn-key approach.

9.4.5 Generator technology mix

The DNIS incorporates projected installation quantities of a number of different generators of varying sizes and technologies as provided by the CSIRO (2008). Generators considered are all within the small to micro size range and are all currently available to be easily operated in parallel with the grid. Their primary energy source varies from fossil fuel to renewable energy.

It should be noted that at the time this study was undertaken, future energy policy in Australia was uncertain. Subsequently two scenarios were modelled: 'Business As Usual' (BAU) which reflects government policy at the time and 'Emissions Mitigation' (EM) which accounts for incentives for DG such as emissions trading and stringent emission reduction targets. The installed capacity resulting from the two scenarios is provided in Figure 9.61. It is evident in this chart that a large amount of DG is predicted in both cases. These results are based on early modelling of the economic feasibility of DG in the Australian market (CSIRO, 2008) with the EM scenario corresponding to a straight-line trajectory to a 60% reduction in greenhouse-gas emissions in 2050 compared to 1990 levels. Section 9.1 provides the latest predictions which incorporate the most up to date policy settings in conjunction with improved performance estimates for given technologies.

It is important to note there are three types of DG considered here that impact on the wider electrical network: synchronous machine; induction machine; and inverter-connected generators. A further characteristic of the generators included in this study is the POC voltage. Under both the BAU and EM scenarios, CSIRO projections indicate that there will be a number of small (1.5-50kW) generators installed in residential and rural applications where practical connection can only be made at low voltages. This study assumes the connection of generators sized 0.5MW and above can only be made to the medium voltage distribution network.

Figure 9.62 and Figure 9.63 show the installed peak DG penetration[14] by class as calculated over the study period. Installed generation capacity (Australia wide) in 2008 is 47GW with a 1.9% p.a. growth rate (ABARE, 2006). Note that while the plots in Figure 9.63 only distinguish between generator technologies, the penetration of renewable and non-renewable primary

[14]As referred to in this report, penetration is defined as the DG generated as a percentage of the total demand under scrutiny such that total demand = loads plus losses. Unless otherwise stated, penetrations are derived under peak generation conditions.

energy sources varies significantly for each scenario. In 2050, only 41% of the total installed DG capacity under BAU (blue line) is projected to use renewable fuel while the corresponding 2050 EM scenario (red line) projections indicate 97% of DG capacity using renewable energy sources.

One of the benefits of considering these two scenarios is that the impact on the network caused by the projected technology mix is very different. The EM scenario entails high penetrations of PV generation and so inherent generator variability while BAU scenarios entail a generation mix which has more potential to be scheduled. The next three sections introduce the different characteristics of the three classes of generator.

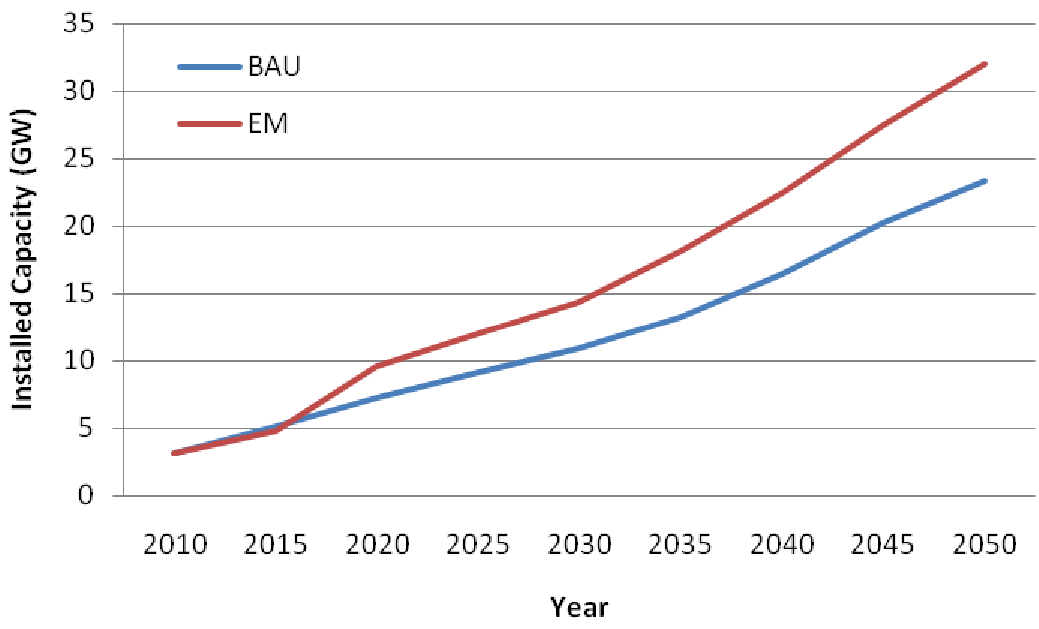


Figure 9.61: Comparison installed GW of DG under the BAU and EM scenarios Australia wide.

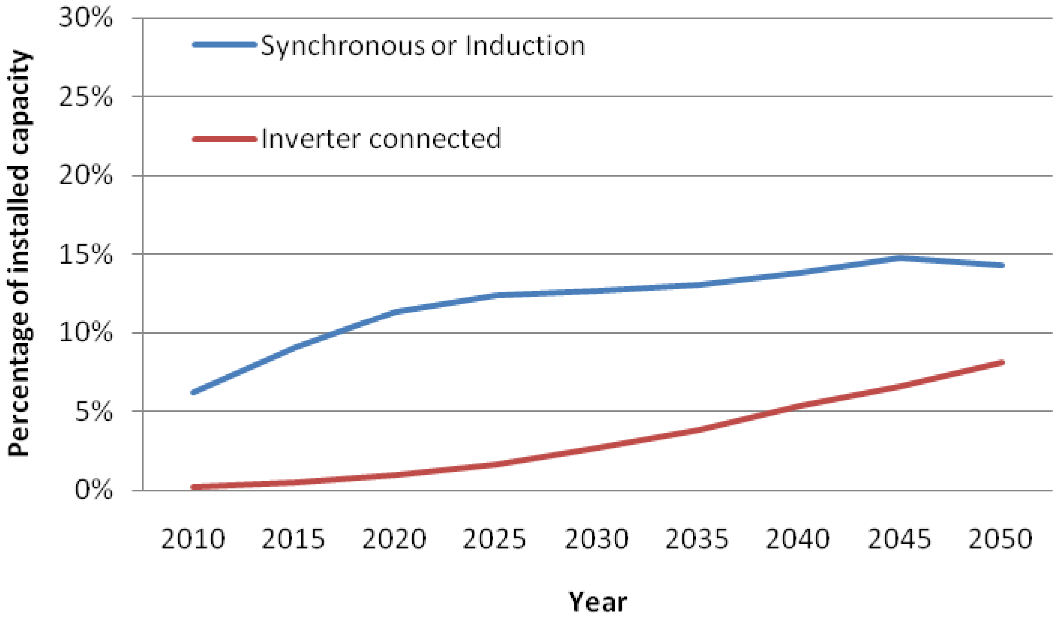


Figure 9.62: Comparison of the installed DG capacity as a percentage of peak demand under the BAU scenario.

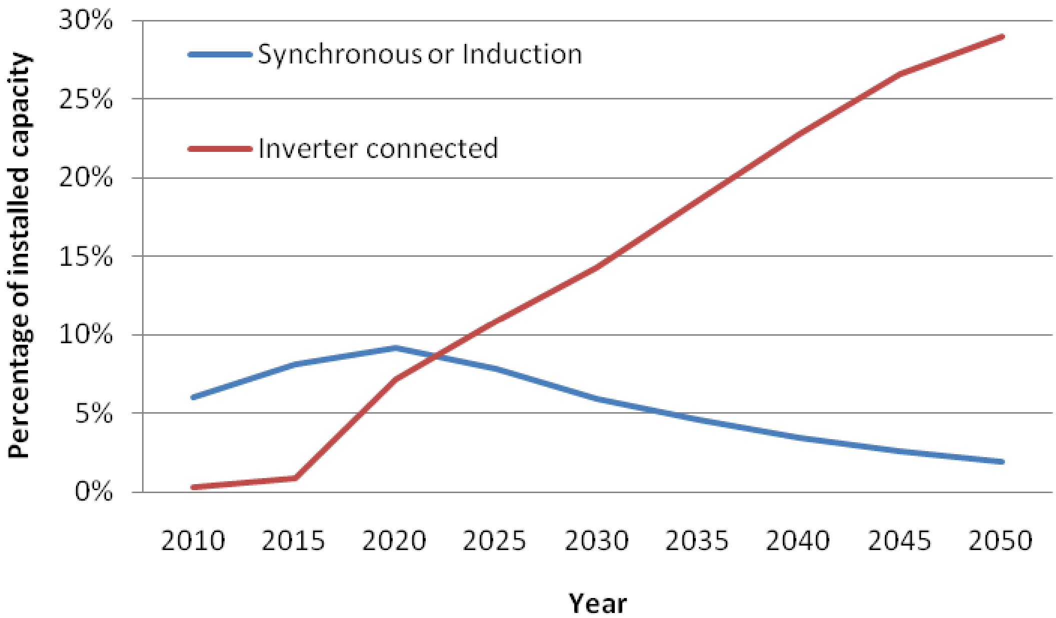


Figure 9.63: Comparison of the installed DG capacity as a percentage of peak demand under the EM scenario.

Synchronous machine generators (SMGs)

As discussed in Section 3.4.9, the synchronous machine is the backbone of electricity generation throughout the world and its fundamental principles have dictated the nature of AC electrical networks as we know them. Where fuels are in plentiful supply, generation can be held constant or adjusted to meet the desired load.

In the context of grid connection, the technology behind the common SMG is well understood. Through fuel regulation and voltage control they can be adjusted to operate within the requirements of almost any network in which they are integrated with few issues. The SMGs considered in the study are primarily CHP plant along with diesel and biogas generators.

In large modern power systems, the frequency cannot change instantaneously under normal operating conditions due to the inertia held in large, centrally located, synchronous generators. This inertia also maintains stability in the network by ‘locking’ the generators together to the same frequency through their individual rotating magnetic fields. A matter of concern under very high penetrations of renewable generation is the potential reduction in inertia which would in turn reduce the inherent stability of the network. The research community will advance our understanding of this issue in parallel with the worldwide growth of renewable generation.

Asynchronous machine generators (AMGs)

Similarly to SMGs, asynchronous or induction machines are based on mature technologies. Principally, the AMG is simpler than a SMG in design, can be operated at a range of speeds and still produce useful power. However, where a grid-connected AMG is operated at a speed lower than the grid frequency (related by the number of generator poles) it is in effect operated as a motor. Thus, the rotor must be driven at a rotational speed higher than the grid frequency in order to deliver power to the network. This capacity to generate at variable speeds often lends the AMG to renewable energy applications where the primary energy source is variable.

AMGs require an external supply in order to provide excitation to establish a rotating magnetic flux in the rotor, thus they are not classified as self-excited. This ‘excitation’ flux then induces a current in the rotor windings which, depending on the rotational speed of the rotor, will either consume power (as a motor) or deliver power at the synchronous frequency (as a generator). For a grid connected AMG the excitation flux current is supplied from the network which results in the generator requiring reactive power. Thus, AMGs will always operate at a leading power factor when generating and often require reactive support to be installed for power factor correction.

Since AMGs do not have a self-excitation system, they are not capable of delivering sustained fault currents due to the collapse of POC voltages. While a contribution is present, it is reliant on the discharge of the flux held in the rotor which cannot change instantaneously. This flux will maintain the generator’s terminal voltage while discharging and will typically only maintain a fault current for approximately four cycles (note that given the situation where there is a distant fault, the network impedance may support the terminal voltage for longer time periods). Thus, AMG fault contributions are more related to the making fault current and will only be present at the earliest stages of the breaking current cycles which implies that their contribution must be included in the calculation of the available breaking fault level.

Of significant importance to this study is the fact that there are very few AMGs included in the projected generator technology mix. Further, the connection of all generators occurs under the access standards of the Rules and, in terms of many of the network outcomes studied here, AMGs entail little difference to SMGs. Thus, as the impact of these generators is considered to be negligible, they are effectively omitted in regard to the results presented in this study.

Inverter-connected generators (ICGs)

In the case of micro and small-scale renewable generators, those that rely on mechanical principals in the energy conversion process are often constructed with a DC generator that incorporates permanent magnets. Alternatively, static technologies, such as photovoltaics or fuel cells, also produce a DC output. As a result, a power converter is required to interface the generator's variable DC output to the fixed AC grid signal. At somewhat larger scales, AC rotating machines are operated at variable speed and a power converter is used to interface the generated variable-frequency, variable-voltage AC signal (often termed 'wild AC') with the fixed AC grid.

Here, it is all of the micro-wind, micro-CHP and PV generators that are classified as ICGs and the impacts from them could potentially pose some significant issues. The CSIRO's ESM model predicts that there could be 30GW of installed, grid-connected, micro-wind and PV systems Australia wide in 2050 under an emission reduction scenario – all of which can be expected to be interfaced with the grid through inverters. To put this into perspective, the same data set indicates that SMGs will only hold a 2GW share of a 32GW total. The projected total DG penetration compared to Australian peak demand can be seen in Figure 9.63.

Modern grid-connected inverters are typically H-bridge in design and are passive in their interaction with the grid. The role of the grid-connected inverter is to convert a DC signal into a PWM approximation of the mains frequency in order to stably export power to the grid. In all cases, generated voltages are rectified accordingly prior to being inverted. Where there is a nearly constant voltage generated by the source, the inverter will be a Voltage Source type that incorporates a capacitive energy storage element on the DC bus. Where a constant current is generated relative to a fluctuating voltage, the inverter will be a Current Source type and will utilise an inductive energy storage element on the DC bus.

Voltage Source inverters are most commonly grid-connected in Australia in accordance with the 'constant' voltage, variable current behaviour of PV systems. They are able to control real power flow through the filtering inductor, in either direction, via adjustments of the phase angle between the generated and mains voltages. The extent of reactive power export is influenced by the filter inductor which is also designed to suppress switching frequency currents to the mains and control the sensitivity of power export to phase angle variations (Ledwich, 2008).

It is due to this filter design constraint that the modern voltage source inverter uses a closed loop, hysteretic phase-locked current control algorithm. This scheme adjusts current injection relative to connection point voltage in order to achieve an appropriate power output at unity power factor. Hence, this control strategy results in voltage source inverters operating passively and offering very little reactive power support to the wider network.

Many modern power converters can now convert almost any form of electrical energy into a more utilisable form and inverter technologies have assisted greatly to advancements in the field of power electronics. New technologies are constantly aiming to reduce cost and device size and to improve device operation. There are currently 34 different grid-connected inverters that are approved by the requirements of the Australian Standard AS4777 (Moore, 2008) for the Australian market. They differ in construction by the use of high and low frequency transformers and pure power converter (PWM) devices and operate in a single phase or in three phases. Each poses different grid interaction characteristics and a summary of the main areas of concern follows.

Grid interface safety mechanisms
AS4777 imposes a number of grid interface safety mechanisms to be built into grid-connected inverters. Islanding protection schemes must include both passive (under and over voltage and frequency detection) and active protection schemes (frequency shift, frequency instability or current injection amongst other means such as rate of change of frequency). As inverters are passive in nature, the goal of these protection schemes is to disconnect from the grid under a 'first sign of trouble' principal. Thus, passive protection schemes disconnect when the grid supply is disrupted or falls outside set voltage or frequency boundaries while active islanding protection mechanisms avoid the rare case of multiple sources achieving a balanced operating point within an island (ANZS, 2005).

Active protection mechanisms have been known to introduce disturbances into the grid that degrade power quality and there is a concern that they may interfere with the protection devices of other inverters connected in close proximity. This scenario has reportedly created widespread disconnection of PV generators before and it has been suggested that active impedance measurement or rate of change of frequency protection methods are the most susceptible (Intelligent Energy Europe, 2007). There has also been evidence of early active protection mechanisms being affected by the utilities' remote control signals on the distribution network. In their analysis, Intelligent Energy Europe (2007) finds no evidence of the opposite occurring.

While not examined any further here, it is widely understood that problems arising from active protection schemes built into inverters can be overcome through the use of stringent type testing parameters in the inverter certification process.

Current harmonics
Current harmonics originate from nonlinear devices such as full bridge converters that incorporate high frequency switching components such as MOSFETS. In Australia, harmonic interference is measured and limited by harmonic voltages which succeed injected harmonic currents and are dependant on the available fault levels at the devices POC. Thus, harmonic currents injected must be limited in order to maintain the prescribed limits on voltage total harmonic distortion (THD) and individual voltage harmonics as outlined by the relevant regulations. In the case of inverters, harmonic current limitations are prescribed by AS4777.2.

Intelligent Energy Europe (2007) has shown that in a network with a high short circuit capacity, the actual impact of the harmonics induced by many grid-connected inverters being introduced into one area of a distribution feeder (80% of households) is less than that of the power electronics loads that already exist on the network. However, this result may not be representative of the high impedance distribution networks typically found in Australia.

Other studies have shown that, in low impedance networks, the THD will tend to increase in approximately 1:1 proportion to the number of inverters, whereas in high impedance networks, the THD will increase in a higher proportion to the number of inverters (Halcrow Gilbert Associates, 1999). The overall impact has also been shown to have a dependence on the mixture of the type of inverters utilised in clusters of generators on the network, as identical inverters will incorporate identical control schemes. Thus, control scheme diversity should be expected to result in harmonics that are less correlated amongst inverters, thereby reducing THD.

Transformerless inverters and DC injection

Transformerless or ‘PWM’ inverters are pure power converter devices that incorporate full-bridge inverters without the use of an isolating transformer. As of 2008, in the Australian market, there are only two certified grid-connected PWM inverters. Notably the economic and size advantages have seen PWM inverters take an approximate 75% market share in Europe (Calais, 2008).

Both high and low frequency transformer-based inverters intrinsically suppress the dc component in their output current. PWM inverters, however, incidentally inject a DC offset current into the network. The potential impacts of this additional DC signal are the saturation of distribution transformers which can lead to increases in audible noise and energy losses, an increased tripping current flow in residual current protection devices along with the distortion of current transformer and mechanical energy meter readings.

A European experiment has shown that DC current from these devices is directly related to the modulation frequency (DISPOWER, 2006a) and that PWM inverters can, principally, eliminate DC components by filtering the network voltage or increasing the modulation frequency. Corresponding findings indicate that state of the art PWM inverters do not introduce a significant DC component.

Work is currently being conducted at the Research Institute for Sustainable Energy in Western Australia into the potential impacts of PWM inverters on typical Australian distribution network components (Calais, 2008).

Australia can benefit from lessons learnt during the rapid uptake of small scale distributed generation in other countries. For example, quantitative knowledge of network impacts of distributed PV has already been gained in the German and Japanese markets where the installed PV capacity in 2006 was 2.5GW and 1.7GW respectively (European Photovoltaic Industry Association, 2007). Similarly, recent experiments have shown that hysteretic current control can be applied to wind generators (i.e. micro-wind) interfaced with the grid through current source inverters whilst providing support to the network (Sharod and Aware, 2008).

Renewable generators

Power produced by generators using renewable fuel is typically variable. In high renewable penetration scenarios, this variability may be correlated to some extent. In the case of clustered PV installations, however, it has been shown that the correlating effect is similarly impacted upon by a smoothing effect of irradiance across the cluster’s geographical area and that the resulting variation in aggregate power generation is not remarkable (Kawasaki et al., 2005).

Using the much researched field of large-scale wind generation as an example, a similar smoothing effect can be seen in the power production from wind turbines spread across geographical areas. This effect depends on the number of turbines connected to the network and the geographical area covered by the sample. The smoothing effect for an aggregate of large-scale wind farms spread over 10s or 100s of km would be governed by the motion of large air masses due to weather patterns. In contrast, the smoothing effect for an aggregate of micro-wind installations connected to a single MV distribution feeder would be governed more by local features of the geographic and built environment.

A comment must be made at this point on the use of the term ‘intermittent’ when referring to renewable generators. As described in the Electricity Rules (AEMC, 2009b), an ‘intermittent’ generator is one whose output is not readily predictable. This includes PV, hydro, wave and wind generators with the exclusion of any material storage capability. Within the electricity industry, the term ‘variable’ is preferred over intermittent as the latter indicates that renewable generators are unavailable for significant periods of time or alternatively, that the aggregated generator output will vary from its rated capacity to zero instantaneously. This is not the case as widespread renewable generation is subject to the smoothing effect mentioned above.

One of the major characteristics of renewable generation is the generator’s capacity factor. The capacity factor can be in terms of an individual generator or a group of generators as in a wind farm. A renewable generator’s capacity factor, defined as the total energy generated divided by the total possible energy generated, is an indicator of how much energy it makes relative to the availability of the resource at its location. Thus, it can either give an indication of the quality of the generator or the resource.

Typical capacity factors for wind farms range between 20-40% while for PV they are often in the 10-15% range when exposed to good resources. Traditional thermal generators have capacity factors in the range of 70-90%, except when used only occasionally for backup supply or network support purposes, as can be seen in Table 3.8.

Along with the capacity factors applied to renewable DG, there is an element of resource availability at any given time. This is difficult to assess due to its reliance on stochastic modelling techniques which fall outside the scope of this study. In order to represent this factor in later analysis, simple availability factors that limit the available generation to a noted percentage are applied to the modelling scenarios.

It should be noted that in the development of the MV feeder models, the assumption that all generators are operating at maximum generation is made in the first instance as this will assess the extremes of operation. Further assessment is made explicitly under availability factors of 25% and 75%.

Distributed generation and state of the art technologies

In the current climate, new technologies that offer support to existing DG technologies and devices are subject to intensive research and investment. To date, much of this effort has been directed at technologies that assist in generator, grid and demand side control and management. There has also been significant progress made in the area of power quality improvements and control of the transient behaviour of embedded generators.

One such Demand Side Management (DSM) technology has shown an ability to operate at the appliance level by optimising the use of the available generation in small island networks through frequency based control techniques (Econnect, 2005a). In the NEM, the imminent 'smart' metering system and its communication infrastructure may hold some potential to provide an invaluable level of support to DSM mechanisms at the distribution level. Further, the ability to monitor both generation and load at multiple points around the distribution network promotes the introduction of new 'intelligent' grid technologies which can provide real-time power balancing and load control during normal operation and contingency events. Correspondingly, in the interests of increasing renewable energy penetration levels, the ability of these technologies to provide real-time control encourages access to the network under already high penetration levels.

There are also active network management technologies which interface existing Automatic Voltage Control (AVC) equipment with new DG in order to optimise DG generation without interfering with the operation of AVC strategies. GenAVC™ is one such technology. It incorporates real-time voltage measurements and state estimation techniques based on network modelling which maximises variable DG penetration and facilitates bi-directional power flow while maintaining statutory voltage margins throughout an assigned area of network (Econnect Ventures, 2009). This capability permits the easy connection of additional DG without the need for some network upgrades and brings the benefit of maximising renewable penetration while maintaining network stability.

The capacity of the inverter to provide some form of support to the network is rapidly becoming a reality. Modern and state of the art inverters have or can be produced with the capacity to provide additional support through a variety of means (DISPOWER, 2006b; IEA, 2002). It is only due to significant cost barriers that the traditionally passive inverter still holds the majority market share. Some other grid connected inverter functions currently available, or considered likely to be available in the near future, are as follows.

Active power quality improvement: It has been shown by (Menitti et al., 2008) and (Angeli et al., 2008) that inverter control strategies can be applied to a shunt active power filter fitted to the inverter connection that improves harmonic voltage components existing at the POC.

Power factor regulation, reactive power control and voltage control: If inverters can incorporate a small energy storage element (i.e. capacitor based) the reactive power issues described above can be overcome. This enables the device to play a more interactive supporting role to the grid through voltage control and will enable inverters to avoid the curtailment of generation during transient network conditions.

Phase symmetry: Three phase inverters can purposefully produce asymmetrical phase currents in order to maintain phase voltage symmetry across the three phases if they are equipped with an energy storage element (i.e. capacitor based).

Grid stabilisation and UPS operation: When the generator incorporates some buffering device (e.g. a battery such as those utilised in smoothing the connection of larger micro-wind generators) it can provide grid support through UPS operation. With the coordination of local energy management and an adequate control system, the inverter could contribute to: grid voltage; frequency and power quality; UPS supply to selected loads; or the diversion of excess energy to devices such as pumped storage. Furthermore, recent advancements have seen converters used in wind turbines being able to harness the rotating mass in the blade to 'appear' to hold inertia in the converter with respect to the wider network (Morren et al., 2005). Similar channels can be expected to be pursued for static generators in the near future.

Participation of distributed grid-forming or grid-supporting modes of operation: The active integration of DG into distribution networks provides the opportunity to allow these devices to provide assistance in the overall management, control and formation of the grid. The aforementioned ability to incorporate storage gives inverters the capacity to contribute to fault clearing requirements, while control mechanisms permit localised grid control and the ability to partake in 'intelligent' grid forming.

Distributed generation and scheduling

Currently, much of the existing and planned DG is installed either to run continuously, generate to suit the customer's heat and power requirements (in the case of CHP) or to maximise profits to generators. Little control capacity is offered to DNSPs. As high DG penetrations are realised, the ability for DG to participate in active grid support becomes more of a reality. Correspondingly, the issues surrounding these scenarios begin to have more extreme impacts, and benefits can be seen in a degree of control by DNSPs. The benefits of this operation may include increases in the generator's exported energy, reduced interruptions and additional revenue for the offering of network support.

The level of value that the DNSP could be offered by a generator is dependent on the size of the generator(s) in question, its system reliability, the aggregated installed capacity of each generator technology, and the location of such generation. The type of control desired by a DNSP is also dependent on several factors as follows (Wright and Formby, 2000).

Deferred augmentation and reinforcement: Requires generation to match peak load times very reliably. Hence it is best facilitated when many smaller SMGs are dispersed within the network, since diversity (in terms of both geography and generator technologies) increases reliability by decreasing the probability of coincident failure. In its simplest form, control through monitoring the generators combined output would be desirable for this function. In many cases, increasing numbers of DG installations may automatically begin to defer reinforcement works even without knowledge of how much generation is operating on the network.

Emergency support: May require generators to be called upon at any moment. A generator's energy source will need to be very reliable to participate. Mechanical durability may not be as important as operation will typically be for a few hours. Automatic starting facilities and monitoring may be required or a permanently manned site may be preferred. The capacity for operation in a voltage control mode in order to maintain an island may be required from the generator(s) along with the capability to 'black start'. Permanently operated generators such as land fill gas are not considered to be very useful in this role as their generation will not be displacing load normally supplied from the network.

Active voltage support: Requires significant costs in the implementation of two-way communications and additional equipment for generators. It may be a function that is only justifiable on large industrial SMG plant. Dispersed, smaller generators will raise voltages along feeders regardless of the installation of control mechanisms. Feedback on local voltages can be incorporated into existing active voltage control devices to maintain desired set points.

Conditions of low demand and high generation also need to be considered as voltage rise may occur and generation may need to be curtailed.

Reactive power: Can be supplied or absorbed by SMGs. Here, operation at all times would be preferred and two-way communication facilities would be required.

For DG to be scheduled, it requires a reliable energy source. SMGs are most suited to being scheduled, however feedback from the generator is very important and two-way communication may be required. In this study, scheduling of SMGs is accounted for with a simple availability factor as is applied to PV availability. Variations are considered explicitly as required.

Many of the generators assumed to be installed under scenarios tested are CHP plant. It is expected that scheduled implementation of such plant will only be possible under agreements made between the DNSP and the generator. These arrangements will also dictate the functionality that is available from a given generator. It is important to note that such arrangements may become complicated where many businesses rely on the plant being operated according to competing requirements. The primary purpose of the plant is often the generation of useful heat in the form of steam or hot water, or heat for input to an absorption chilling process, and electricity generation will accordingly occur when this heat is being utilised. Hence, industrially or commercially installed CHP plant may match loads very closely while domestic plant will tend to generate during colder periods and often overnight when loads are low.

Although the capacity for scheduled operation of generators is usually considered to be limited to traditional generation plant, some 'scheduled' capabilities are offered by PV generators aside from a simple 'off' function. Although generation is limited by the availability of the solar resource, adjustments can be made in generation profiles by shifting the plane-of-array orientation of PV modules in order to shift the timing of the generation peak.

9.4.6 Distribution network impact study characteristics

Distribution feeder model development

The four MV feeder types tested in the DNIS are described below while the technical aspects and components included in the base-case models for each feeder are described in Appendix A of the full report (Senergy Econnect, 2009).

Feeder 1: Urban established commercial feeder, supplying predominantly commercial zones in an established urban area

Feeder 2: Urban established residential feeder, supplying predominantly residential load in a long-established urban area (to account for incremental network augmentation in response to evolving electrical applications over a period of decades)

Feeder 3: Urban 'green-field' residential feeder, supplying developing residential subdivisions. This feeder will contain some rural and semi-rural load including some SWER circuitry but be evolving toward predominantly urban use

Feeder 4: Rural feeder, containing a combination of three-phase and SWER circuits.

In order to model each feeder for the years investigated over the study period, it is necessary to firstly develop base-case feeder models for each of the desired years (i.e., 2010, 15, 20, 30, 40 and 50). These are derived based on projected load growth only, noting that this load growth will also dictate the timeframes in which network augmentation occurs and the potential impact of DG on this augmentation.

The following sections outline the assumptions behind the development of the MV feeder models for the conditions outlined above along with the characteristics of the LV feeder models and the network outcomes on which the DNIS results are based.

MV feeder base-case model development and assumptions

Load growth

In distribution network planning, DNSPs consider load growth projections on historic load trends, expected load step changes, planned support, imminent upgrades, and planning and economic circumstance. Data extrapolation techniques are applied to provide short-term (3-4 year) projections of maximum demand on network assets to within a reasonable level of accuracy (Lakervi and Holmes, 2003). The capacity of zone substations is assessed accordingly.

While this method is accurate enough for planning purposes, it is not considered to provide a sufficient level of accuracy for the time scales considered in this study. Furthermore, information on load growth at a zone substation can only indicate the aggregated load growth in the area supplied by that zone substation. It may not reflect the nature of load growth seen by an MV feeder originating from the zone substation and an alternative method of long-term load projection must be assumed.

Assumptions must be made of the characteristics of the future developments of each of the 22kV feeders along with an individual set of assumptions about the nature of the loads on each feeder and each load type’s growth characteristics. Further, in the development of base-case models, it is assumed that there is no DG installed on the feeders as generator availabilities cannot be assumed as explained above. An assessment of the performance of each feeder under specific conditions is available in the full report (Senergy Econnect, 2009).

The Australian Bureau of Agricultural and Resource Economics (ABARE) provided information on the National and State projections of energy consumption by sector in their 2006 Energy Report (ABARE, 2006). ABARE detail projections of energy consumption in Australia to 2029-30 and the data provided is used as the basis for the following assumptions.

Trends in average annual electricity consumption growth from 2004-05 to 2029-30 are assumed to continue to the end of the study period (2050)

Electricity consumption growth rates for each feeder are derived by weighting the ABARE data by the load mixture on each feeder and these growth rates are applied to both the maximum and minimum load data for each feeder

The 2008 load mixture is assumed to remain constant throughout the study period with the exclusion of any known developments

In the case of Feeder 3 the ‘S’ shaped electricity demand growth curve described in (Lakervi and Holmes, 2003) is applied. According to this curve, demand reaches a maximum growth rate before growth moderates. All other feeder case studies are assumed to be operating within the saturation period of the 'S' curve

Residential electricity consumption growth is expected to be 1.5% pa to 2029-30; however, this growth is Australia wide and is thought to not reflect the nature of load growth in established residential areas. Established residential areas are assumed to be of a stable population and not subject to any further significant development. Thus, growth rates in this case are assumed to be closer to the Australian per-capita growth rate, and a rate of 0.64% pa is assumed

Commercial and industrial electricity consumption growth is assumed to be 2.5% p.a. This is thought to account for typical growth of commercial and industrial buildings in established and semi-established areas as these are often continually being developed

Electricity consumption in the agricultural sector is maintained at 1.1% p.a. It is assumed that there is little growth in terms of the development of new rural areas for agricultural land use in Australia. As such this rate is applied across the entire rural sector.

Network augmentation

Some of the deciding factors that DNSPs base network augmentation and reinforcements on are forecasted load growth, reliability targets, life-cycle cost and optimisation of the costs and benefits of the works along with an assessment of the assumptions that are made in the decision process.

In construction of the model scenarios required for the DNIS, two factors are assumed to be of the most importance for decision making on network augmentation.

Cost of energy not supplied: DNSPs base their investment in major network upgrades on an analysis of the potential value of energy not supplied should the work not be carried out. The value of the energy not supplied by each zone substation is directly related to the number of customers supplied. It is derived and applied to each sector of the electricity market and forecasted load growth permits a comparison against equipment capacities. Ultimately, the process indicates the most cost effective means of maintaining the network in terms of customer satisfaction and financial impact. This method is reportedly used to assess the need for large works such as new transformers or zone substation upgrades. Here, it is applied in determining when new feeders are to be installed in the PowerFactory™ models. In order to conduct this assessment, it is assumed that works should be undertaken when conductors approach 95% of their thermal capacity under peak load conditions. This corresponds to assuming that the occurrence of outages when operating near this level of load is considered acceptable to customers

Conductor thermal capacity: Given no other network upgrades, the thermal capacity of each feeder will be exceeded due to load growth and subsequent network augmentation will be required. As the four feeders are composed of a variety of different conductors with various thermal ratings, the thermal capacity method is assumed to apply to upgrades of smaller sections of the feeders as their capacity is met. This method is thought to reflect the nature of past gradual changes to the networks as they stand.

In this study, changes to the interconnection of feeders are not represented as the feeders are considered only as singular entities. Subsequently, network augmentation that involves reconfiguring the interconnection of feeders is not modelled in the DNIS.

MV feeder embedded generator distribution model assumptions

The generator technology mix provided by the CSIRO for this study models the projected Australia-wide purchase rates of distributed generators in five year intervals to 2050. A methodology has been derived which projects reasonable generator installation rates onto each PowerFactory^{TM} feeder model. The model is developed from the percentage share of total Australian electricity consumption consumed by each MV feeder and the following assumptions apply.

The sector set is defined as residential, commercial and services, industrial and rural and the division of the load on each feeder is also assumed under the same social sectors

Total annual electrical energy (GWh/year) supplied to each feeder is derived from the peak day load profile provided by the DNSP with an assumed power factor of 0.9 (lagging). Peak day energy consumption is assumed to be 35% higher than the annual daily average as reported by westernpower (Western Australian Office of Energy, 2004). Published information on total Australian energy consumption by sector (Commissioner for the Environment and Sustainability, Victoria, 2008) coupled with ABARE's electricity consumption growth by sector is used to determine the percentage share of total energy consumption of each sector supplied by each feeder for each year in the study period. These percentages are then applied to the Australia-wide generator installation rates in each sector in order to project DG installations on each feeder for the required years. The following information applies:

- Australian electricity generation in 2005-06 is provided by (ABARE, 2006) along with electricity generation growth of 1.9% p.a. to 2030 which is maintained to 2050 here
- Percentage shares of electricity consumption by sector and State are reported for Victoria by the Victorian Commissioner for Environmental Sustainability for 2005-06 (residential: 25.4%; commercial and services: 24.4%; industrial: 44.8%, and; rural: 5.4%). Unaccounted for sectors and parasitic electricity consumption (~17% of total consumption) are evenly distributed to the four sectors and these percentages are applied to all states in the NEM (Econnect Ventures, 2009).

Appendix B in the full report (Senergy Econnect, 2009) tabulates DG growth by sector for each feeder under each DNIS scenario as calculated by the generator distribution model detailed above.

LV feeder models and model assumptions

In electrical engineering practice it is understood that different power quality issues can have varying degrees of impact at different voltage levels. As a result, it is necessary to model distribution networks at these voltage levels in order to ascertain potential impacts on DNIS parameters.

Three different LV distribution feeders are modelled in PowerFactory^{TM} in order to represent the diversity found in the construction of such feeders. Each LV feeder is modelled as an unbalanced network supplying single phase residential loads in the range of 2-5kW. LV conductor lengths are small in comparison to MV networks. As modelled, they range in length from 10-100m with the longest point in each feeder being less than 500m from the MV/LV transformer. The LV feeder models are introduced below.

LV Feeder 1 supplies 27 single phase loads. It is located 8km from its zone. Its conductors are all OHL and are operating at an acceptable thermal loading under peak load conditions

LV Feeder 2 supplies 54 single phase loads requiring a total of 223kVA. It originates from a transformer located 2km from the zone substation. LV Feeder 2 is considered to represent a heavily populated area in which the feeder is approaching its thermal capacity

LV Feeder 3 represents a relatively new urban feeder. It consists of underground cable supplying 36 single phase loads totalling 145kVA.

9.4.7 Distribution network impact study – General findings

This section presents general findings of the DNIS relevant to each distribution feeder modelled. Sections 9.4.8 and 9.4.9 detail issues and findings relating to notable indices of steady-state and transient network performance.

Feeder 1: Established urban industrial/commercial feeder

Feeder 1 is the study's 'established urban industrial/commercial' feeder and it consists of 9.4km of OHL and underground cabling. The feeder incorporates a heavy industrial load from local municipal council yards and offices, along with a large commercial load from an adjoining shopping centre.

Modelling of the development over the DNIS time line indicates that major upgrades will be required for Feeder 1 in 2023 based on an analysis of the value of lost energy. This augmentation results in the feeder being split into a commercial/industrial and commercial/residential feeder. The generator distribution model then applies DG capacities to the feeder under both the BAU (25% peak penetration in 2050) and EM (27% peak penetration in 2050) scenarios. Under BAU, the commercial sector realises a significant CHP contribution and under EM, the same sector realises more significant PV.

The high CHP penetration in the BAU scenario indicates that there is significant opportunity for a DNSP to incorporate scheduled operation of DG and given this ability the 2023 network reinforcements may be postponed to approximately 2031. Where the CHP is replaced with PV, as in the EM scenario, the same conclusion cannot be drawn and only three potential years of postponement may be realised.

Due to the relatively short length of Feeder 1, peak losses are not large, being 260kW in the base case (no DG) in 2050 compared to a projected load of 26MVA by that year. Nevertheless, the inclusion of DG indicates that, given scheduled CHP in the BAU scenario, significant energy savings could be realised during peak load times. By 2050 there is a 45% (125kW) reduction of peak losses, corresponding to an extra 2% gain in power over the installed generation. In other words, for every 100kW of embedded generation installed, the power required from the zone substation is reduced by 102kW. This is similar for the BAU and EM scenarios. The coincidence of PV generation with peak load times in the EM scenario will also realise significant reductions in energy losses, and given variations in availability factors, a linear relationship is found between PV penetration and losses during peak load periods.

An investigation into the potential for power flow reversal during minimum load periods found that power flows did not reverse to the zone substation until DG penetration reached 95%. Thus, where significant CHP generator penetration exists in commercial areas and coincides with extremely low loads, it is more likely that power flows will reverse within the network rather than across a supply point transformer.

In summary, the performance of Feeder 1 would be similar in both IBDG scenarios. Reduced network augmentation spending and network losses are realised in both scenarios, particularly where generation can be scheduled.

Feeder 2: Established urban residential/commercial feeder

Feeder 2 is an urban feeder with established residential load. It consists of 25km of predominately OHL with the inclusion of some underground cabling. Loads along the first half of the feeder are residential and the second half of the feeder is a mixture of commercial, residential and large industrial load. The extremity of Feeder 2 also supports the largest single load on the feeder (2.9MVA in 2008).

Modelling of the development over the DNIS time line indicates that major upgrades will be required throughout the study period. In 2016, Feeder 2 is split into two feeders where the original section supplies a residential area and a new supply point supplies commercial/industrial loads.

The generator distribution model applies moderate DG capacities to the feeder over the study period, particularly in the EM scenarios as a result of residentially installed PV systems. However, all results show that Feeder 2 is the least affected MV distribution feeder in the DNIS.

The BAU scenario indicates that there will be a moderate CHP penetration by 2015 which, given scheduled operation, may contribute to a two year postponement of the original major reinforcement works. The EM scenario presents a low uptake of DG in the form of residential PV and no notable impact on the development of the feeder at all. These results are attributed to the fact that, from the onset, Feeder 2 is approaching thermal constraints. Added to this are the DG installation trends for Feeder 2 in which the uptake of DG is slow when compared to the load growth trend.

While the inclusion of DG on Feeder 2 reduces losses, the impact is minimal in all cases. Correspondingly, the impact on voltage profiles is also not significant despite there being a significant difference in DG penetration between the scenarios. Even when the largest single load was removed from the feeder in order to simulate a regular switching event corresponding to peak DG generation, the impact on voltage profiles was not found to be serious.

In summary, given the CSIRO projected generator installation figures, feeders such as Feeder 2 are the least affected by future DG installations.

Feeder 3: Green-field feeder

Feeder 3 represents the ‘green-field’ feeder in the study. It originates from a zone substation located in a newly developed area which is subject to rapid growth. The feeder itself extends to the outer extremities of the rapid growth area where, to date, there has only been a small amount of development adjacent to the zone substation.

In 2008 the feeder consists of cable and OHL from the zone substation past the newly developed residential area which is supplied by teed off cabling. Three phase OHL then continues beyond the residential area for some distance. Five SWER tee sections that supply light loads some distance away radiate from it. Feeder 3 consists of 51km of SWER OHL and 24km of three phase cable and OHL conductors. The larger loads on Feeder 3 are relatively small and are located along the three phase sections of the feeder. They fall into the range of 110-330kVA.

Modelling of the development over the study time line follows a traditional ‘S’ curve and major works are built into the model throughout the DNIS study period. Feeder 3 is split into two residential and commercial feeders in 2025 as a result of this continual load growth.

The generator distribution model applies a high DG capacity of 11% in 2050 under BAU while the EM scenario reaches 27% in the same year mainly due to PV installation rates in both scenarios. It was found that a mismatch between fast load growth and slow DG uptake results in no significant impact on pressures for network reinforcements until after 2020 in either scenario. Beyond that year the only real impact will come from the availability of PV in the EM scenario, noting that results may not be representative of green-field areas that move through an ‘S’ shaped development curve at a later date.

In 2050, the peak losses are substantially reduced in the EM scenario and further installations will result in modest improvements. Correspondingly, a linear relationship is found between the losses that occur at peak load and the DG availability at that time. Voltages along the feeder are maintained within reasonable levels as a result of DG penetration. Although the option for adjustment of SWER transformer tap settings was present, it was found that this option may only be required for peak generation and low load periods.

In summary, while the performance of the Feeder 3 shows an improvement under both scenarios, the assumptions that led to the development of the model leave a great deal of room for misrepresentation. It is clear that there will be benefits found in the uptake of residential PV; however, under a BAU scenario there will be little impact on residential distribution feeders from the DG installation trajectories projected by the CSIRO model.

Feeder 4: Rural feeder

Feeder 4 represents the ‘rural’ DNIS feeder. It is composed of both three phase and SWER OHL and after originating from the local zone substation it extends across 50km of rural area, passes through a small township and then continues on to rural areas beyond. Feeder 4 consists of approximately 415km of overhead line with no significant inclusion of any underground cabling. As is typical of rural feeders of this size, Feeder 4 includes voltage support which consists of three OLTC transformers along the length of its main artery and there are a substantial number of tee sections that radiate from the main feeder to supply the surrounding areas. The nine SWER sections included in the feeder all extend from different radial tees.

Initial investigations have discovered that during summer peak load periods the voltage range along the feeder has variability that utilises the full permissible steady-state range for rural MV distribution networks of ±10%. In doing so, the three voltage regulating transformers on the network are being utilised well with two of them approaching their full tapping range.

Modelling of the development over the study time line indicates that slow load growth will eventually require major network reinforcements in 2025 without DG. Outcomes of the DG distribution model indicate that rural feeders will receive a significant contribution from DG in the future as is evident in the EM scenario for 2050 where the peak DG penetration is 42% of peak load – mainly due to rurally installed PV. The model also indicates that under BAU scenario conditions there may be significant PV penetration in rural areas and that approximately 20% of the peak load can be accounted for by PV.

This high PV capacity in both scenarios indicates that there may be significant network augmentation benefits to be found in rural feeders in the future. Applying an availability factor of 25% to the installed BAU scenario capacity delays the initially projected 2025 works to 2035. In the EM scenario the same conditions postpone the works to 2039, while an assumed maximum availability of 40% will further postpone the same works to 2048.

While not examined in detail here, an apparent benefit can be seen in the ability to incorporate some form of scheduling or DSM in rural areas. The solar resource peak is poorly matched to the peak load in this case, however, should the peak load be shifted to an earlier time, with strategies such as those mentioned above, the assumed maximum availability factor for PV could increase beyond 40%. Furthermore, adjusting DG availability factors shows a nonlinear relationship between the DG penetration and the losses during peak load conditions. Benefits are clearly realised in reduced losses should peak loads be correlated to peak generation times. This factor is further evident in the potential for energy savings from DG penetration increases in the 2050 EM scenario.

Initial investigations revealed that during summer peak load periods the voltage range along the feeder has variability that utilises the full permissible steady-state range for rural MV distribution networks of ±10%. However, an assessment of the performance of these OLTC transformers indicates that under a variable DG availability factor they are not exposed to reverse power flows and are capable of maintaining correct voltage set points. The voltages found at some SWER transformers indicate that the tap positions may need to be reconsidered in order to manage the impact on MV/LV distribution transformer secondary voltages.

In summary, it can be expected that rural feeders will realise the greatest benefit from DG – particularly in the form of improvements in losses and delays in network augmentation. However, a caveat may lay in the additional financial burden that could result from the assessment of the performance of voltage support equipment under new operating conditions.

Network augmentation

Due to the assumptions made in the development of the base-case models, the exact impact on network augmentation is difficult to quantify accurately. In almost all cases DG provides some benefit; however, it is clear that this impact is very small for feeders located in green-field areas and those which supply mixed commercial, industrial and residential loads such as in the case

Feeder 2. The very heavy reliance on PV implies that there will be significant sensitivity to the availability of generation during peak load times.

In the case of Feeder 4, there appears to be significant opportunity for some form of DSM strategy to shift the peak load in time to better match peak PV generation. An alternative method of managing this mismatch is achieving a shift in peak PV generation by shifting the installed array azimuth angle.

Another opportunity can be found in the ability for scheduled operation of commercially installed CHP plant. This is clearly evident in the case of Feeder 1 where the BAU scenario could potentially delay major works on the feeder by eight years.

Some issues remain unaccounted for in these results. Firstly, the matter of the feeder needing to 'black-start' after an outage may require the feeder to supply the full peak load until generators are able to be put back on-line automatically or manually. Secondly, the assumptions made in the development of the models in this study can only give an indication of possible outcomes and it will be experience that dictates real-world outcomes.

9.4.8 Steady-state network outcomes

There are a number of indices that need to be measured in order to assess the DNIS outcomes. This section outlines the steady-state network outcome benchmarks for the study, including some of the relevant expectations in regard to DG scenarios, and summarises the findings of the DNIS based on analysis of Feeders 1-4.

Feeder (peak) thermal loading

The limiting factor to power transfer in MV and LV networks is the thermal capacity of conductors which are derived by methodologies similar to those outlined above. Distribution networks continuously see demand growth and their thermal capacity is always in question, particularly in older networks where feeders are often composed of a variety of conductor types of differing ages.

Under increased DG penetrations, the additional generation supplies loads in parallel with the rest of the network which reduces demand from the feeder's supply point. As a result, DG is expected to lighten thermal loading on conductors in most instances and could even prolong the time periods between network augmentation and reinforcement – particularly when these works are based on the thermal loading of network components.

In cases where there is a considerable amount of renewable generation such as PV, it is difficult to ascertain the actual impacts on feeder augmentation. Take a comparison of the load profile for Feeder 3 when compared to the ideal solar radiation falling on an optimally positioned PV module as in Figure 9.64. It is evident that, even if the solar resource is a reasonable match for the peak load around midday, the load will need to be satisfied from the local zone substation for other periods of the day. Alternatively, other forms of DG may be available.

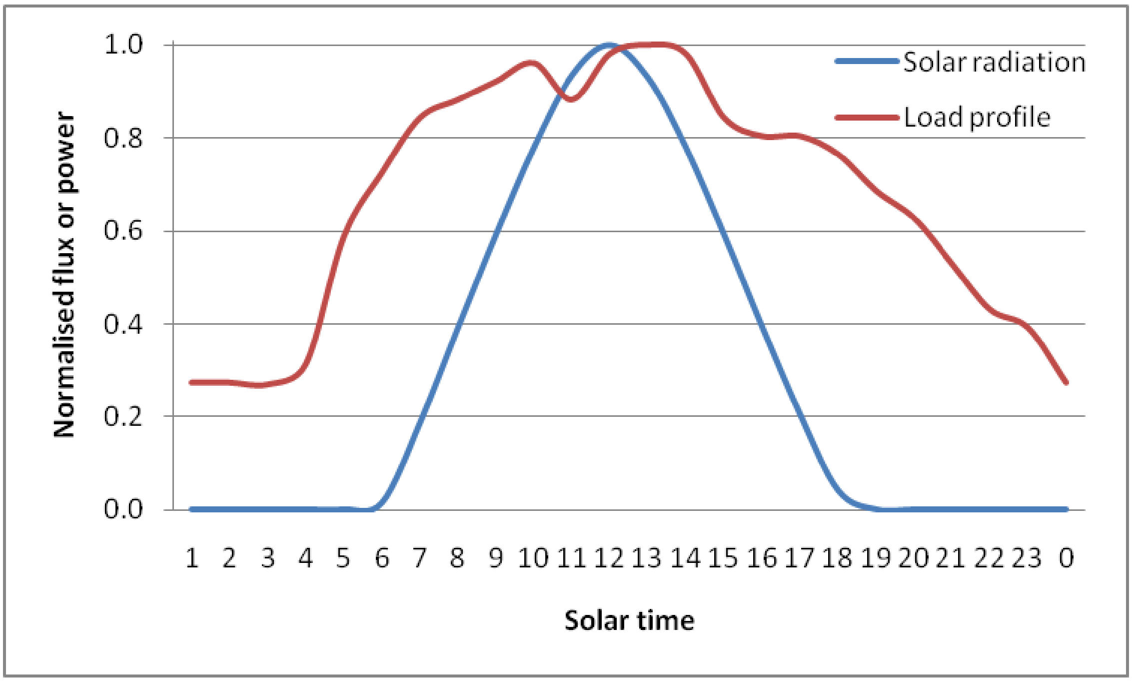


Figure 9.64: Example of a typical peak load profile compared to an example of the solar radiation incident on an optimally tilted (latitude angle) fixed plane in Sydney (solar time = EDST - 1hr).

Note that the example used above represents ideal solar radiation such that the availability of the resource and the implementation of DSM technologies are not considered. Similarly, the availability of other DG usually cannot be considered with 100% availability (as discussed above). Thus it is acceptable that, in many cases, the network will require augmentation based on load growth and the number of customers irrespective of the installed DG penetration.

It is also important to recognise that the impact of DG on thermal loading relies on the voltage at which generators are connected. Generators sized under 500kW are assumed to be connected at low voltages and are assumed to be installed with the intention to offset local loads. Thus, in these cases, any thermal loading issues are assessed by the proponent rather than the DNSP. Larger generators may need to be assessed on a case-by-case basis as thermal loading issues increase with generator capacities.

Distribution network losses

The vast distances covered by Australian transmission and distribution networks inherently result in accepted overall[15] losses in the order of 11%. The vast majority of these losses are thermal in nature (i.e., I^2R) and DG is widely recognised to reduce transmission currents and corresponding losses through reducing the load seen by the rest of the network. Past studies have indicated that even a modest DG penetration of 10-20% on the feeders load can result in significant improvements in system losses (Jaganathan and Saha, 2004). Also recognised is a ‘saturation’ effect which results in increases in losses once DG penetration has exceeded this saturation point. This can be shown by scaling the total load on Feeder 4, the longest feeder

[15] Overall losses implies the sum of both technical and commercial losses where technical losses are described above and commercial losses are the result of energy unaccounted for such as in metering errors.

considered, to below 50% of the projected 2050 load while maintaining DG levels. In general, nevertheless, DG is likely to reduce system losses.

All DNIS feeder models presented significant improvements in network losses and the potential for DG to contribute here is promising. It has been shown that in older established feeders that supply a mixture of commercial and residential load, the least benefit will be realised from DG. This is evident in Figure 9.65 which summarises the impact of the study scenarios on real power losses when peak DG availability corresponds to peak load on each feeder.

It is evident that the response of rural feeders to increased penetrations is of great promise. There are two factors which contribute to this result. Firstly, the large distances covered by rural feeders typically results in the use of cost effective conductors, such as galvanised steel, which are characterised by high losses. Secondly, the CSIRO model provides significant generator numbers in rural locations to the extent that peak penetration of Feeder 4 reaches 42% in 2050. The combination of these two factors results in the non-linear relationship between the availability of DG and losses under peak load conditions.

A comparative method has been developed in which the impacts of each scenario can be assessed in terms of a percentage improvement in energy supplied per kW of DG installed in 2015 (Figure 9.66), comparing the BAU and EM scenarios to the base-case as using Equation 9.5.

$$\%_{\text{improvement}} = \frac{\text{Losses}_{BAU} - Losses_{EM}}{Generation_{EM}} \times 100\% \qquad 9.5$$

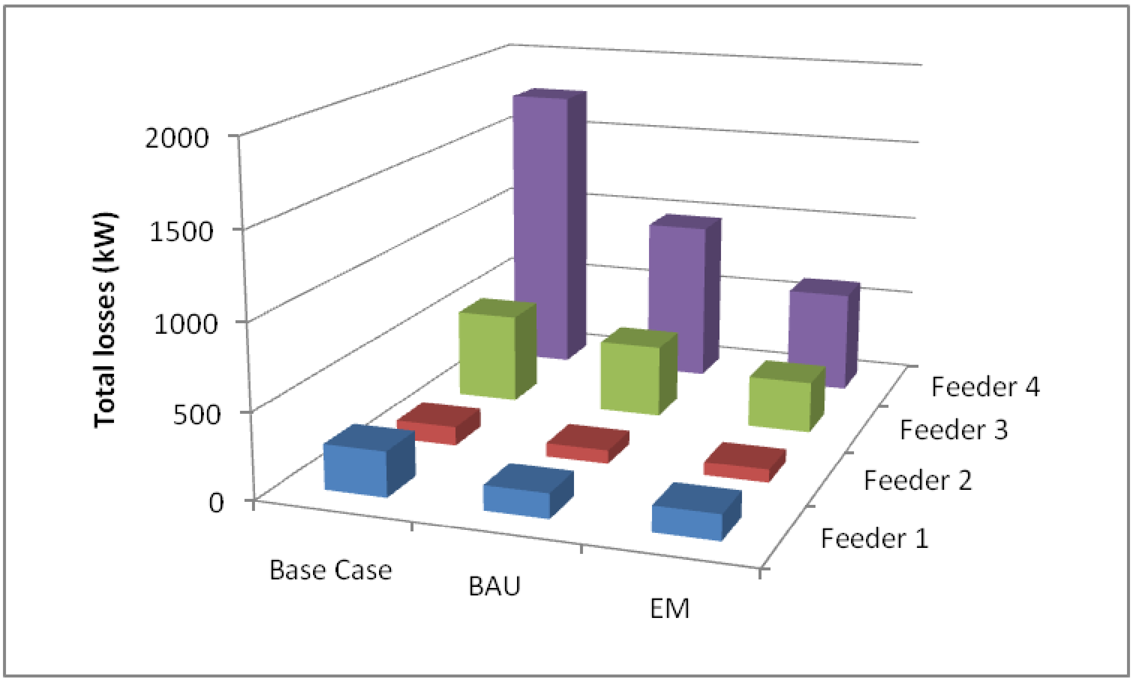


Figure 9.65: Summary of peak losses for the four DNIS MV feeders in 2050. Peak real power losses over the feeder are shown for the three IBDG scenarios for 2050.

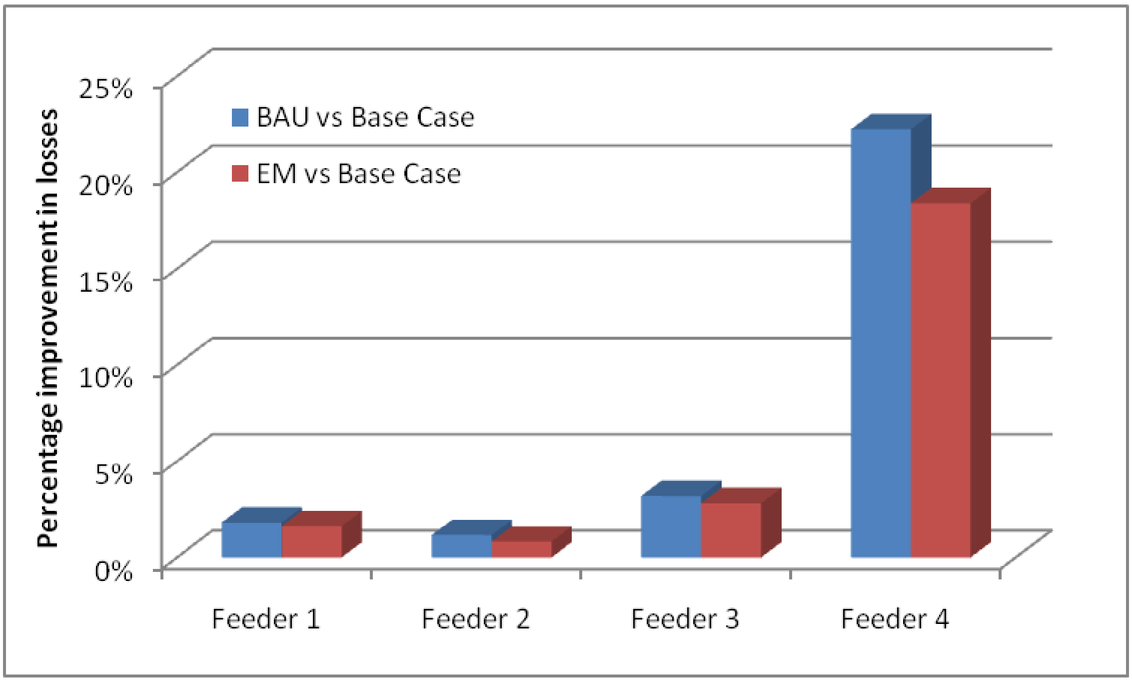


Figure 9.66 Percent improvement in losses for each feeder in 2015. Note that a percentage of 10% implies that for every kW of peak DG the supply point sees a 1.1kW reduction in energy required from the substation given 100% DG availability.

Figure 9.66 clearly shows that reductions in supplied energy occur with the introduction of DG and that the greatest benefit (of the four scenarios considered) will be found in rural areas. The figures are all positive which implies that no feeder has passed the saturation point at this time.

Voltage profiles

Distribution feeder voltage profiles often utilise a large range within the permissible tolerances outlined above. They also give an indication of the status of a feeder in regard to loading, as heavily loaded conductors are exposed to high currents and high voltage drops result. In some networks, these voltage drops are compensated with voltage regulation techniques such as OLTC transformers or reactive compensation which maintains end use voltages within nominal tolerances. Voltage profiles normally vary with time due to variations in load. The addition of a high DG penetration is considered to increase the occurrence of these variations. A key issue here is the interaction of DG with existing voltage support equipment.

In radial networks without compensation, the voltage naturally decreases from the source to the load. In most cases, it is expected that the introduction of DG will slightly improve the maximum voltage drop along a feeder due the natural correlation between peak generation and high load periods. As maximum voltages typically occur during low generation periods (i.e., overnight) the impact of DG is considered to be minimal. However, the nature of these impacts is highly dependant on the type of DG technology and the feeder’s load characteristic. There are many possible outcomes.

As discussed above, modern inverters typically do not provide any voltage support function. While the real power they deliver can help to improve POC voltages through reducing the apparent load, this does not equate to a voltage support function (see above for commentary on the functionality offered by some state of the art inverters).

The capacity of SMGs to offer voltage support through reactive power control has been utilised for many years. Unless otherwise noted, the SMGs considered here are installed to operate in a power factor mode such that they are not regulating POC voltages. However, the injection of real and reactive power will result in improved POC voltages.

In the DNIS, improvements in voltage profiles were realised in all cases studied despite voltage supportive functions for generators being neglected. Figure 9.67 summarises the minimum voltages in 2050 for all four feeders under 100% availability and peak load conditions.

In all cases, voltages increase such that the margin between the operating voltages and normal minimum voltages is increased as a result of the additional DG. Given a variable DG availability, linear relationships have been found between the minimum voltage under a DG scenario and the minimum voltage in the base-case scenario. Feeder 4 maintains the largest voltage range in the two scenarios while the very low impact on Feeder 2 is representative of the low DG capacity installed on that feeder.

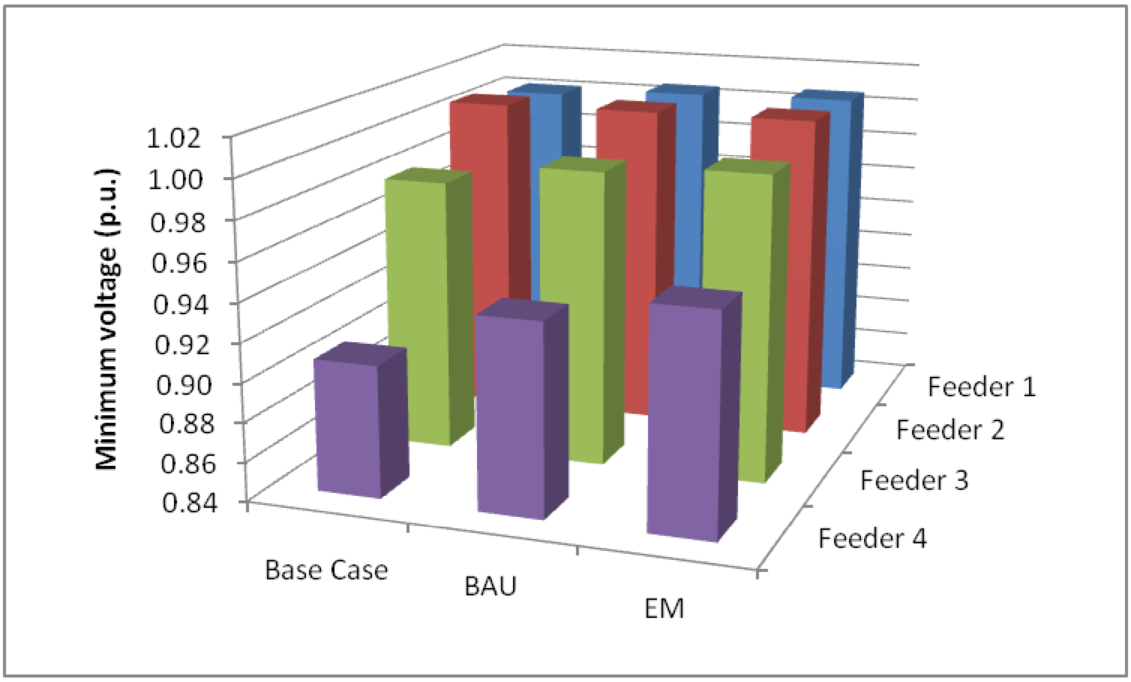


Figure 9.67: Summary of voltage drops for the MV distribution feeders in 2050 showing minimum per-unit voltages along each feeder as modelled for the three IBDG scenarios in 2050.

Analysis of the interaction between voltage support elements and DG found that there are no immediate threats to existing equipment. In the case of Feeder 4, it was found that the three

OLTC transformers are capable of maintaining their initial (base-case) operation strategies regardless of the installed DG capacity. A case study of rapid voltage fluctuations found that the worst case scenario of a generation availability swing of 100% to 0%, with a high penetration of photovoltaic generation, occurred in one branch of Feeder 4 following the installation of a new zone substation. This new branch is referred to as Feeder 4.1 and it is created following load growth to 2025 because the original Feeder 4 showed poor voltage control performance. Feeder 4.1 is representative of a typical rural feeder which incorporates voltage regulating equipment. Under the worst case scenario the two OLTC transformers in Feeder 4.1 were capable of maintaining correct operation given realistic time scales for such a generation swing. This result is considered realisable due to the fact that such devices are installed with maximum load conditions in mind.

It is apparent that with the addition of significant DG penetration, normal distribution feeder operating voltage bandwidths are increased depending on network conditions. Where generation patterns are correlated with peak loads, minimum voltages will be expected to increase. Alternatively, where this correlation does not exist, minimum network voltages will remain as they are in the base-case model. At the other end of the voltage bandwidth, correlated maximum generation and minimum load will increase upper limits. However, this is thought to be an unlikely scenario as generation will tend to occur during maximum load conditions rather that during minimum load conditions such as overnight. Again, the results of the Feeder 4.1 OLTC voltage fluctuation study found these conditions to be acceptable for voltage regulator operation and the situation only improves slightly as steady state operation moves between the improved state and the original design state (where DG is excluded).

In terms of voltage rise, where SWER transformers are included the fixed-tap setting on their secondary side may need review under high DG penetration. Similarly, whilst not expected to be an issue, the impact of high DG penetration on low voltages may need to be reviewed. Due to the variability of both generation and load, it is recommended that these issues be dealt with on a case-by-case basis as they arise until experience dictates a reliable methodology.

Power flow reversal

When significant levels of DG are introduced into distribution networks, power flows can be reversed. Thus, the traditionally passive, unidirectional, network design must now accommodate an active, bidirectional, energy flow and network voltages are now determined by both the loads and DG. As previously discussed, it is mainly in the area of protection that this issue has an impact, however, further consideration is required in regard to the operation of other active network elements such as OLTC transformers. Some network management technologies such as GenAVC™ may be able to offer assistance in this regard.

In order to assess the possibility for reversed power flow, an adaptation of Feeder 1 is constructed during low load periods and a high level analysis of the situation is offered in the full report (Senergy Econnect, 2009). While power flow reversal does occur under high DG penetrations it is typically a phenomenon that occurs within branches of the network and not in the sense of delivering power back to the network's supply point. The main reason for this is that, in the case of the IBDG generators, generation is well matched to load by the nature of the generators. Thus, at night time when the load is lightest, there is very little coinciding generation. While peak daytime zone substation loading is reduced it rarely reversed. The results of the Feeder 1 study indicate that even under light load, high generation conditions there is little risk of the zone substation experiencing any reversed power flow.

All present investigations indicate that power flows seen by zone substations will not reverse until the load reduces to approximately 25% of its peak or generation increases such that DG penetration approaches 95%. Power flows can be expected to reverse within sections of the network rather than across zone substation protection equipment.

Fault levels

The introduction of SMGs to a distribution network is expected to increase the overall fault levels at all points within that network, especially when a high impedance is seen between the network and the DG. Distribution network codes and regulations place limitations on the fault levels present in MV and LV networks which will need to be taken into serious consideration under high DG penetration scenarios.

The introduction of DG into distribution networks equates to the introduction of additional sources of fault current, hence, fault levels are expected to increase. MV distribution network protection equipment is arranged to operate passively from settings based on minimum fault currents and with sensitivities depending on the maximum prospective fault currents. LV protection equipment is designed with fixed breaker ratings and maximum breaking capacities ≥6kA (Clipsal Australia, 2007; Schneider Australia, 2007). Should they be exceeded the circuit breaker may not operate correctly or at all.

Thus, it is important to assess the behaviour of three phase fault currents and levels under high DG penetrations in both LV and MV networks. In respect to network fault capacities, it should be noted that continual network upgrades and additional interconnections and generation already promotes increases in fault levels. It is left to further work to determine whether this ‘natural’ encroachment may result in LV network fault capacities exceeding protection ratings regardless of DG installations.

Results of the analysis of the impacts of SMG DG on prospective three phase fault currents indicate that, as previously stated, the introduction of DG into distribution networks equates to the introduction of additional sources of fault current. Thus, increases are always going to occur with any additional embedded generation. The analysis included DG penetrations of ~100% at the LV level where the impacts appear to be manageable in all cases. Under the extremely high DG penetration levels used in the LV case studies, the additional fault capacity may exceed that of previously installed LV protection equipment – this was not found to be the case under low DG penetration scenarios.

The compounding impact of multiple LV feeders with very high SMG DG penetration (~100%) on MV feeders is not considered to be realistic. The more realistic scenario of a single 15kW generator connected to the LV side of an MV/LV distribution transformer was investigated. It was found that there was no impact on the fault currents in the MV network. Thus, it is assumed that the overall impact on the MV network in the more realistic scenario of multiple LV feeders with low SMG DG penetrations will be minimal.

The results of the analysis of Feeder 1 indicate that a 24% SMG DG penetration (6x500kW generators) does have the capacity to offset a small amount (1.6%) of the fault currents delivered by the zone substation under present day MV network fault conditions. Under increased fault capacities the same assessment found a reduction of 0.8%. These variations are considered to be small enough to have little or no impact on MV protection equipment settings.

It is important to note that this study did not include a CBD network as the DNSP supplying network feeder information does not operate in these areas. Discussions with staff from DNSPs operating in the major capital cities of Australia suggest that fault levels are at or approaching critical levels in these areas. Quantification of fault level effects in these areas is an area in which further research is required.

Harmonic distortion

Additional harmonic currents introduced to the network from DG are considered to be an issue of concern when they compound the existing harmonic levels to an extent that regulatory limitations are exceeded. The discussion above indicates that the area of the most concern is the use of PWM in grid-connected inverters.

In order to assess the harmonic levels under high DG penetration, the three LV feeder models are assessed with and without PV generation and comparisons are made to the statutory limits. Existing harmonic levels introduced by power converter loads are modelled with the square-wave method outlined in (Morton, 2007) where electronic loads draw square wave currents with a spectrum of odd order harmonics with magnitude $1/h$ for harmonic order h. The harmonic spectrum applied to the inverter models is derived from the limits of AS4777.2, in order to assess the worst-case scenario, and modelling is conducted under very high PV penetration, where each single phase load is considered to be a residence which is fitted with a 1.5kWP PV system that is operating with an availability factor of 100%. The impact of the introduction of the ICGs includes the occurrence of even harmonics that did not occur in the modelled loads, and the ICGs generally have an impact on the harmonics up to the 30^{th}. While the impact on the third harmonic appears to be manageable, the 5^{th}, 7^{th}, 9^{th}, 11^{th} and 13^{th} all show an increased magnitude. In LV feeder 2, which is approaching its thermal capacity, the THD exceeded the statutory limit of 5%. In LV feeder 3, significant attenuation of harmonics was evident due to the sections of underground cabling.

Thus, the introduction of high concentrations of grid-connected inverters operating with the largest permissible current harmonic injections is found to have an impact on the existing voltage harmonics, and the extent of this impact is reliant on the network impedance and the extent to which conductors are loaded.

It is apparent that the ICG harmonic impact on the MV side of distribution transformers is minimal and this is assumed to be due to the inability of triplen harmonics to propagate through delta windings. Although not considered in depth here, it is probable that the accumulated harmonic distortion appearing in MV networks will not be affected by the widespread uptake of grid-connected inverter based DG.

Voltage unbalance

In three phase systems voltage unbalance is considered to be a significant concern. Voltages are usually well balanced at the transmission level; however, voltages at the distribution level can be subject to significant unbalance due to unequal system impedances, non-transposed OHL, single-phase loads, phase to phase loads and unbalanced three-phase loads.

When a balanced three-phase load is connected to unbalanced voltages, the line currents drawn by the load also become unbalanced – a problem of particular concern for three phase induction motors and variable speed drives (Gosbell et al., 2002).

Methods to manage voltage unbalance include alternating between phases where many single phase loads are connected, and balancing of loads between phases internal to premises that are provided with three phase supplies. The overall impact is an averaging effect which minimises the impacts of loads on voltage unbalance.

With high DG penetration levels, a large number of single phase generators are expected to be installed at the LV level. These generators are connected to the same phases as the loads which supply the premises where they are installed. Thus it is expected that the averaging out effect will similarly apply to single phase generators and that they may even improve the voltage unbalance.

Three phase generators considered in this study are not installed with the aim of providing voltage support. Nevertheless, it can be expected that the inclusion of three phase generators will improve the voltage unbalance.

The load flow simulations of both the LV and MV distribution networks in the DNIS indicate that the penetration of DG is unlikely to exacerbate voltage unbalance issues. In the case of Feeder 3, the voltage unbalance is dependent on the amount of SWER, and the voltage unbalance generally decreases with increasing DG penetration. For the three LV feeders, the voltage unbalance is more dependent on the topology of the network. The penetration of DG in LV networks does increase the voltage unbalance; however, it is not expected that voltage unbalance will be an impediment to increased DG penetration.

In summary, while voltage unbalance on a distribution network can be a serious issue (particularly in regards to induction motors) and requires careful monitoring, it is not expected that voltage unbalance issues will be a significant impediment to the increased DG penetration as considered here.

9.4.9 Transient network outcomes

This section outlines the transient network outcome benchmarks for the study, including some of the relevant expectations in regard to DG scenarios, and summarises the findings of the DNIS based on analysis of Feeders 1-4.

Voltage flicker

Some loads draw fluctuating currents and as a result impose rapid voltage fluctuations on the network (e.g. large motor drives that perform start-stop functions). Alternatively, some generator types inherently impose similar variations in their output current. In severe cases, these variations cause incandescent lighting to fluctuate at frequencies that can have psychological and even pathological impacts on humans. Thus, voltage flicker is a significant issue in regard to power quality. Its impacts can be defined as either steady-state or transient.

The Australian Standard AS61000.3.7 defines two parameters which characterise the severity of and impose limits on flicker levels induced by fluctuating loads at HV and MV levels. These values are again stated in the Australian Standards 61000.3.5 and 61000.3.3 for loads with rated currents greater than 16A and up to 16A connected to LV networks respectively.

With the exclusion of non-converter based wind turbines, generators are not considered separately to loads by the relevant Australian Standard in terms of imposed flicker limitations. Accordingly, AS4777.3 refers the limits placed on grid-connected inverters to AS61000.3.5 and AS61000.3.6 for inverters rated up to 30kVA (41.7A/phase). Furthermore, generator connections made at MV voltages are also referred to AS61000.3.7.

In the simplest form, the flicker emissions limits for MV systems are described by the Stage 1 assessment method defined by AS61000.3.7. The method assesses the ratio of the fluctuating component of the apparent power load to the minimum short circuit capacity at the POC, or $\Delta S/S_{sc}$, and its relationship to the number of ΔS changes per minute (r/min).

IBDG synchronous generators which can potentially be connected at MV voltage levels are sized to capacities of 500kW and above. These generators are not expected to contribute to significant flicker emissions at their POC, while network fault levels remain in the order of 4.5kA in accordance with the Stage 1 assessment of AS61000.3.7. IBDG generators that are sized in the MW capacity ranges are not expected to operate with the capacity of fluctuating generation within the time scales of concern.

Rapid voltage fluctuations

Voltage fluctuations are complex in nature and occur as a direct result of current changes seen across complex reference impedances. All distribution networks are subject to rapid voltage fluctuations due to the presence of fluctuating demand, particularly when loads have high reactive power requirements on starting as is the case with direct on-line started induction motors. Rapid voltage changes have similarities to flicker, however, they differ in the frequency of their occurrence in the sense that a voltage fluctuation may occur once, and at any time, followed by a new steady-state operating point. Hence, they are considered to be dynamic in nature, occurring over time scales of minutes or seconds.

Considering that the majority of the IBDG generators are of nameplate capacities that are in the same class as many loads, it is not expected that the additional DG will place any additional pressures on distribution networks in terms of voltage fluctuations. The inclusion of synchronous DG plant is not expected to impose any real issues of rapid voltage change as there are very effective techniques that can be implemented in order to ‘ramp’ up or down their power output.

An issue may arise, however, in the apparently instantaneous generation changes that are presented by PV systems under scattered and dense cloud cover. A similar issue may also be expected for small scale wind turbines. Of particular relevance here are the impacts of the PV penetration levels as projected by the CSIRO’s emissions mitigation scenario model. In the EM scenario, Australia-wide ICG penetration levels are projected to be in the order of 37% by 2050 with the vast majority of this generation being from PV systems (totalling 29.9GW_P). The issue scrutinised here is that of the impact of such high PV penetrations on voltage fluctuations in the distribution network and the corresponding effect on active voltage regulating components.

Results of this assessment show that with the scenario of high PV penetration there would not be any adverse voltage changes should a sudden loss of generation occur for Feeder 4. As Feeder 4 is thought to be representative of a typical rural feeder which incorporates voltage regulating equipment, it has been concluded that there will be a slight impact on the operation of such equipment. While the voltage variations seen here are manageable by both of the OLTC transformers, they can be expected to be exposed to more frequent tap-changing operations which will result in higher maintenance requirements. It is expected, however, that these voltage variations will occur over gradual timescales, which will be sufficient to allow tap changing operations to take place.

Nominal operating voltage envelopes are maintained in this case. Hence, under high DG penetrations it is recommended that distribution planning processes should allow for OLTC transformers with sufficient rating and tap range to allow for any change in voltage due to the loss of a large portion of generation.

Steady-state voltage stability

Voltage stability is defined as a network's ability to maintain or return to acceptable steady-state voltages at all points within the network after any disturbance which induces a significant voltage drop. Alternatively, voltage instability on a network occurs when the voltage at any bus decreases with an injection of reactive power rather than increases. The voltage stability of a localised point in a system depends on the relationship between the real power transmitted through the point, the reactive power injected into that point and the voltage at the receiving end. It has theoretical limits that are defined by the P-V (power-voltage) and Q-V (reactive power-voltage) relationships at the point in the network under scrutiny. Assessments of the theoretical voltage stability limit of a network can be made through a series of load-flow model solutions under varying power transfer conditions which enables the derivation of the relationships mentioned above and the subsequent critical stability limits (Jaganathan and Saha, 2004).

The introduction of significant DG into distribution networks is expected to improve the networks overall voltage stability limit as less power is transferred through the distribution network. There is a dependence on the location and type of DG installed as it is only SMGs that have the capacity to provide reactive power support and the ability to ride-through low voltage periods (Jaganathan and Saha, 2004). Inverters typically do not have this capacity and will disconnect from the network, even under brief voltage excursions.

In order to confirm these expectations, Feeder 3 in the 2050 EM scenario is selected as a representative case study. While high penetrations of DG do slightly improve distribution network stability, conductor thermal capacities are the constraining factor in regard to power transfer – not voltage stability. Therefore, voltage stability is not expected to be an issue for distribution networks, even under high DG penetration scenarios.

Frequency stability

In respect of AC generation throughout the world, frequencies are maintained during transient events by the inertia held in the rotating masses of all of the generators connected to each system. The energy embedded within the total system inertia relative to system power flows dictates the performance of the system following step changes in load or generation where an increase in load (decrease in generation) will result in a frequency decrease and vice versa for frequency increases. In terms of frequency stability, the measures of performance are the system's capability to stabilise after a non-contingency event and the time taken to stabilise at a new steady-state (depending on the magnitude of such a step change).

The effective available inertia (i.e., the energy which can be lost before rotational phase angle stability is threatened) within the system varies with the type of generation connected to the system. It affects normal system frequency control and recovery of system frequency following transient events. As the inertia held in individual plant types varies, the on-line generation mixture governs the effective available inertia at any given instant in time. Due to the increasing penetration of DG, there is speculation that offsetting the power delivered by centralised synchronous plant with smaller generators will reduce the effective available inertia and hence, the frequency will become less stable.

It has been reported by (Moura et al., 2008) that "changes to system inertia due to substantial quantities of distributed generation are not likely to be large and that frequency control on the system is unlikely to be significantly affected". That study bases peak and minimum system inertias on load profiles and makes the comparison by replacing all transmission connected generation with medium voltage connected generators of varying nature. While this result is promising for the integration of larger embedded generators, it does not consider impact of large quantities of micro DG as are being considered here. It also neglects to consider the impact of large ICG penetrations such as are being considered here.

A further consideration provided by this analysis is that of the capacity of embedded synchronous generators to cope with transient events (Section 9.4.9). Results obtained when all generation is taken offline differ significantly from those where synchronous plant is kept on line during the switching event, in keeping with its likely technical capabilities. It must be noted however, that due to the limitations of the current study, much of the detail of plant control systems has not been considered in this investigation, and the results are of a conceptual nature only. It is recommended that more detailed investigations be undertaken in future to confirm the results of this high level analysis.

Large-disturbance (transient) rotor angle stability

'Rotor angle stability' (also known as 'transient stability') refers to the capability of the synchronous machines in an AC power system to recover a satisfactory operating point following a disturbance to the system. When a synchronous machine is connected to an AC grid, there is a close relationship between the rotational speed of the machine and the grid frequency, and any deviation between the two is quickly opposed by large synchronising torques, which the system sees as large power swings. As a result, all the synchronous machines in an interconnected AC system are coupled to one another through the grid frequency, and their rotors 'swing' against one another in the manner of coupled torsional pendulums.

Because a number of the distributed generation technologies considered in this study take the form of grid-connected synchronous machines, there are potential stability implications from the connection of large numbers of such generators in distribution networks connected through the wider transmission system. Inverter-connected generators, on the other hand, are not expected to have any significant implications for rotor angle stability since such devices are ‘frequency takers’ and do not automatically respond to frequency or power angle fluctuations with noticeable power swings (unless this behaviour is explicitly programmed into the control system as discussed in Section 9.4.5). This is true even when the device behind the inverter is itself a synchronous machine, since the inverter decouples the frequency of the grid from the local frequency seen by the machine. Any issues posed for rotor angle stability by ICGs are likely to be indirect, resulting from the displacement of conventional synchronous plant. As demonstrated elsewhere in this report, DG even at the scale envisaged in the highest-penetration scenario is unlikely by itself to result in significant quantities of conventional synchronous plant being taken offline[16].

For this study, a high-level investigation of rotor angle stability was undertaken, focussing on the combined effect of many small synchronous machines in conjunction with varying amounts of large conventional plant. The model used is similar in structure to that used for the frequency stability assessment of the previous section. Indicative results appear to confirm the common understanding that DG at the forecast penetration levels has no significant implications for rotor angle stability in the broader system. A slight degradation in stability performance may result if DG begins to displace the installed capacity of large conventional generators (at levels of 10% or so). However, at the forecast penetration levels such displacement is unlikely to occur.

As suggested above, much of the detail of plant control systems has not been considered in this investigation, and the results are of a conceptual nature only. It is recommended that more detailed investigations be undertaken in future to confirm the results of this high level study.

Small-disturbance (oscillatory) rotor angle stability

‘Small disturbance stability’ (also known as ‘oscillatory stability’ or ‘dynamic stability’) relates to the continuous operation of a power system, in the absence of large disturbances such as short circuit faults. A real power system is continually subjected to small changes in power flow and voltage levels due to normal generation and load variations. These small changes can excite natural modes of oscillation in the power system (in much the same way a bell rings when lightly tapped). In a complex nonlinear system such as an AC grid, not all these oscillatory modes are guaranteed to be stable. Stable oscillations will decay in magnitude and go virtually unnoticed, but if unstable modes exist, initial small oscillations can grow in magnitude and threaten the stability of the system. Slow-decaying ‘marginally stable’ modes, while not unstable, can also pose a risk since a change in system configuration (such as growth in nonlinear load) may render them unstable.

It is very difficult to identify the full range of unstable oscillatory modes that exist in a power system. In theory, potential oscillatory instability in a power system may be detected by linearising the full dynamic equations of the system and performing an eigenvalue analysis. Eigenvalues with a real part greater than or close to zero correspond to unstable and marginally

[16] Like ICGs, asynchronous machines are not directly relevant for rotor angle stability, as their rotor speeds are not closely coupled to the grid frequency.

stable modes respectively. Once again, the dynamic equations have traditionally been described in terms of the rotor-angle dynamics of synchronous plant, and for this reason it is typical to consider only the main transmission system in the analysis, as this is where traditional synchronous plant connects. Even so, the analysis is vulnerable to modelling errors and incomplete information. System operators such as AEMO insist on accurate models for generators to help combat this uncertainty, but a certain amount of error is inevitable when modelling loads and network elements, so that in practice extensive sensitivity analysis is required to detect potential instabilities, and some unstable modes will remain undetected.

As with mechanical vibrations, oscillatory instability in power systems is generally mitigated by the presence of 'damping'. Resistive loads have a natural damping effect, as do resistive elements in lines and transformers (at the expense of efficiency) and damper windings in synchronous machines. In conventional synchronous generating plant, 'power system stabilisers' (PSS) are frequently employed to inject artificial damping into the system and render potentially unstable modes stable. A PSS is an auxiliary control device that modulates the DC excitation voltage of the synchronous machine in response to speed, power or frequency variations, in such a way as to damp out an oscillatory mode in the nearby power system. Under the National Electricity Rules (AEMC, 2009b), a PSS is required for synchronous generating units in order to comply with the S5.2.5.13 Automatic Access Standard (but not required under the Minimum Access Standard). However, at present most embedded generators are not subject to NER technical requirements.

It is considered an open question whether the connection of large numbers of embedded generators in distribution feeders has any implications for small-disturbance stability. As a general working assumption, unstable oscillatory modes are regarded as sporadic occurrences and the creation of new unstable modes by a new connection is considered possible but unlikely. Hitherto, there has been no evidence to suggest that even the aggregate combination of many embedded generators is likely to give rise to unstable modes in a power system. Thus, while many transmission NSPs will carry out an eigenvalue analysis as part of their routine due diligence assessment of a generator connection to a transmission network, and will negotiate a performance standard requiring a PSS for a synchronous generator, this is not generally regarded as necessary for small generator connections in distribution networks.

In order to study the possibility of a significant (positive or negative) contribution to small-disturbance stability from embedded generation, a high level investigation was undertaken using a simplified model of varying quantities of SMGs and ICGs connected in a distribution feeder, together with varying amounts of conventional generation feeding the grid.

As with rotor angle stability, indicative results of this investigation suggest that in line with common understandings, DG at the forecast penetration levels is unlikely to raise any significant issue for small-disturbance stability in general.

As for frequency stability and large-disturbance rotor stability, much of the detail of plant control systems and of the design of PSS devices has not been considered in this investigation, and the results are of a conceptual nature only. It is recommended that more detailed investigations be undertaken in future to confirm the results of this high level study. In particular, area-specific studies may be warranted where there is locally high penetration of distributed generation at levels greater than forecast for this study. Such studies are unlikely to be required for each individual generator but may be undertaken for the envisaged portfolio of distributed generation as a whole.

Fault ride-through

The concept of embedded or distributed generation is relatively recent, and embedded generators have only been seen in significant quantities in large AC power grids since the 1980s. In this early phase of development, it was generally both an assumption and a requirement that all 'unconventional' power sources would disconnect themselves from the grid whenever a short circuit or other fault occurred. As the behaviour of these new technologies was not well understood, the understandable preference was that they not be present when the system was trying to recover from a major disturbance.

This habit of operation can no longer be sustained when DG makes up a large proportion of the total generation in a power system. If generators disconnect in response to a fault, the power system must subsequently recover with less generation available than prior to the fault, but usually with the same aggregate load. When the 'generation deficit' is small, spinning reserve capacity (required in any case to cover sudden failures of much larger generating units) will pick up the slack. This capability cannot however be relied on beyond a percentage of lost generation corresponding to the largest generator in the relevant NEM region, loss of which is regarded as a credible contingency. It is then necessary to shed load or take other corrective action, which raises the risk of adverse events such as blackouts or abnormal grid separations.

As penetration of DG increases, therefore, it becomes necessary to reverse the earlier operational practice, and require embedded generators to remain connected through a fault and to recover their pre-fault power after fault clearance (subject to energy source availability). This capability is known as fault ride-through (FRT) and became a regulatory requirement for large wind turbine generators in most jurisdictions between 2003 and 2006.

If the aim is to ensure 100% of embedded generators remain online after a fault, FRT standards must require generators to tolerate transient voltage dips all the way down to zero – since this is a realistic scenario for a transient fault affecting a radial distribution feeder with downstream generators. Synchronous machines can tolerate such transient voltage dips, and inverter-connected generators can be made to ride through these as well, provided they are designed with an alternative method to sink excess generated power during the fault (such as with a crowbar or dump resistors). If there is some retained voltage (say 20% or more), then it is potentially possible to generate into the fault for a short period, making even an energy sink unnecessary. Accordingly, many larger embedded generators now on the market already have some FRT capability, and many more can in principle be redesigned to have this capability using known methods.

Nevertheless, requiring FRT capability for all embedded generators will not come at zero cost. To assess the real value of FRT capability for embedded generators requires some assessment of the likely consequences of retaining the present approach, which does not explicitly mandate FRT capability for generators less than 1MW in size except when they form part of a larger generating system (such as a wind farm).

It is considered that the 'worst-case credible scenario' for loss of distributed generation is a three-phase line fault close to a main transmission terminal within a load centre. During such a fault, voltage can be expected to drop to nearly zero on all sub-transmission and distribution circuits supplied from this terminal. This would typically affect in the order of 10 zone substations, each of which typically supplies 10 or so MV distribution feeders. Therefore, a reasonable estimate of the quantity of distributed generation affected by such a fault is 100 times the expected magnitude of distributed generation on a single feeder.

While distribution faults can take a much longer time to clear than transmission faults, and therefore increase the likelihood of DG being disconnected, such faults generally only affect the feeders supplied from a single zone substation, and therefore the amount of generation affected is an order of magnitude less than from a worst-case transmission fault.

Results from the present study indicate that under the highest-penetration EM scenario, levels of distributed generation on urban feeders range from approximately 4MW to 8MW of installed capacity, the bulk of which are PV generators. Networks over a large urban area will contain a range of feeders of each type. Accordingly, in a worst-case scenario, a distribution fault close to a zone substation HV bus potentially affects approximately 60MW of embedded generators, while a transmission fault close to a terminal station potentially affects up to 600MW.

Of course, these figures are order-of-magnitude estimates only. However, the 600MW potentially affected by a transmission fault is comparable in size to the largest single generating units currently operating in the NEM. Current operational protocols require the maintenance of adequate spinning reserve to cover the instantaneous loss of the largest generating unit in the relevant NEM region (currently 500MW in Victoria and 700MW in NSW, with the possibility of 1000MW units in future). The same spinning reserve capacity can in principle cover the worst-case loss of 600MW of solar PV generators, keeping in mind the latter is expected to be a very rare event.

It may be concluded that FRT capability for embedded generators is desirable, but not absolutely essential for system security at the anticipated maximum levels of penetration to 2050. In any future uniform technical standard for DG it may be helpful to adopt a two-tier approach mirroring that of the National Electricity Rules, with an ‘automatic access standard’ matching the NER S5.2.5.5 automatic standard for FRT capability, and a ‘minimum access standard’ that reflects current practice.

9.4.10 Distributed generation and variability in network power flows

The introduction of large penetrations of variable generation into networks that have, traditionally, only been designed to accommodate variability in load presents significant problems. To some extent the existing strategies such as Frequency Control Ancillary Services (FCAS) are expected to be able to compensate, however, it is widely recognised that these strategies will need to be reconsidered as system-wide variable generator penetration levels increase. Whilst the control strategies of the wider network are beyond the scope of this study, it is important to note that projections made by the CSIRO on renewable DG indicate an installed capacity of 29.9GW_P of PV in 2050. This alone equates to a penetration of 37%[17] of the

[17] Based on a 2008 NEM maximum demand of 37GW [Australian National University, 2008] and a growth rate of 1.9% p.a. (ABARE, 2006).

projected maximum demand in the NEM for that year and is expected to require considerable control strategy redesign.

A fundamental requirement in electricity markets is that under normal operating conditions generation capacity is always sufficient to meet demand with a high degree of reliability. In systems where generators all have broadly similar and low forced outage rates, generation reliability is based on the N-1 criterion: that the system can tolerate the loss of any one generating unit and still provide sufficient capacity to meet demand. This implies that available generating capacity should equal the total demand plus a 'capacity margin' equal to the size of the largest generating unit.

The output of a variable generator depends on its primary energy source, which is outside the control of the operator. As it must be ensured that the system has adequate generation capacity to reliably supply the expected demand at all times, a reserve capacity margin must be factored in to the extent that generator availability is uncertain. A concern is often raised that systems with high penetrations of variable generation must maintain large reserves of conventional generation as spinning reserve or on standby, or sacrifice reliability. Provided it is ensured that a competitive market exists for load following services, the existing NEM design largely addresses the energy balancing issues associated with increased penetration of variable generation.

While renewable resources are variable in nature, they are not unreliable or even unpredictable. 'Reliability' refers to the likelihood that a piece of equipment will fail to operate. The majority of the renewable generators considered in this report are rated at fractions of the capacity of conventional generating plant. Correspondingly, the likelihood for any one of these generators to be out of service for any reason is similar to the likelihood of a conventional generator being out of service. The impact of such an outage, however, is clearly not similar due to the differences in rating.

It is normal practice for the system operator to carry sufficient 'spinning reserve' to cater for the instantaneous loss of the single largest (or largest two) generating plants or the largest industrial load. This reserve is not only oversized to cope with faults on renewable generators, but can also cope with variations in renewable energy output even with significant penetration levels of renewable generation.

Increased reserves under high embedded generator penetration

All power systems must maintain reserve capacity to cover unforeseen but probable losses of generation. The failure of a single generating unit is considered a probable event, while the simultaneous failure of two units is not considered a sufficiently probable event to justify reserve capacity. Hence, smaller systems typically schedule reserve capacity based on the output of the largest generating unit[18]. The requirement for reserve capacity should therefore remain unchanged in power systems with low renewable energy penetrations. It is only when penetrations reach a level corresponding to the largest generator in the relevant NEM region that an adjustment to reserve capacity may be required.

[18] Larger interconnected systems, such as the European Grid, cater for the simultaneous loss of two or more of the largest generator sets.

While variable generators do not have a firm generating capacity by nature, it has been recognised that they do reliably contribute to generation capacity due to geographic diversity. Moreover, as more generators are added and this diversity is increased, the reliability further improves to approach that of conventional generators. It is therefore now standard in best-practice jurisdictions to count a proportion of variable generators' installed capacity as 'firm' capacity for planning purposes. This proportion is typically taken as 20-30 per cent (AGO, 2003) and is based on an assessment of the probability of a high-demand period, the loss of a large generating unit, and unavailability of the variable generator occurring simultaneously.

At moderate renewable energy penetration levels, the impact of variable generation on reserve capacity requirements is expected to be negligible. At higher penetration levels, there is an increase in the requirement for reserve capacity that leads to higher ancillary service charges, the effect of which will be seen by all market participants. However, analysis of the impacts of penetration in the South-West Interconnected System (SWIS) electricity market found that when expressed as a cost per megawatt-hour of electricity, this amount is found to be a small proportion (2%) of the retail value of electricity (Morton, 2005). In relation to ancillary services this finding is also relevant to the NEM. Accordingly, the additional reserve requirement should not be seen as an impediment to increased energy penetration.

With regards to FCAS standing costs, it is necessary for the market operator to determine the optimal level of each frequency control service to procure. In practice FCAS services are procured based on a determination of the optimal 'frequency control margins' above and below the system's energy trading position (a positive margin for generator loss, and a negative margin for load rejection or variable generator pick-up). In best-practice jurisdictions the requirement for FCAS is determined by the maximum credible 'simultaneous' change in net generation in the positive and negative direction (counting load as negative generation). The response time for each kind of frequency service determines which types of output changes are relevant for its application along with the timescale on which changes are classed as 'simultaneous'. The maximum credible change for a 'spinning reserve' service is therefore based on the output of the largest generator on the system, counting as a single generator a collection of small variable generators having a common energy source and in geographic proximity (such as a cluster of PV units).

Currently, and while the penetration of variable generation remains low in the NEM, the treatment of the capacity available from variable generation is no different to the treatment of the capacity available from any other form of generation. In the NEM potential energy shortfalls are the market driver for additional generation such that the availability of generation at any given time determines the need for the installation of additional generation. In the longer term it will be necessary to review reserve requirements based on a full probabilistic assessment of generator availability as is presently exemplified by worlds best practice jurisdictions (Morton, 2005). Industry consensus currently considers this to become a requirement as variable generation penetration approaches 20 percent.

Load following ancillary services

From an 'energy balancing' point of view there is no difference between a variable generator and a conventional load of equivalent size. Therefore, in best-practice jurisdictions the same 'balancing' or 'load following' ancillary service that provides for real-time unpredictable variations in load, also manages real-time variations in generation.

The requirement for load following services does not increase proportionally to the amount of variable generation. If the random load variations and variable generator variations are assumed to be independent, the total variation is less than the sum of the variations. If the load and generator variations are positively correlated then the total variation will be further reduced.

The cost of load following service is generally small compared with FCAS, as it requires only that some generators provide small variations in output around their optimal operating point. Commonly, load following services are provided by the same generators that provide FCAS, and the cost of output variations is largely absorbed in the latter.

Non-schedulability

Even under very high DG penetration scenarios the need to maintain the real-time balance between generation and load remains. When DG penetration is low, its variability can be accommodated in a similar fashion to variable industrial loads, however, given that a large amount of the projected DG is only subject to the schedulability discussed in Section 9.4.5, very high DG penetrations may create new difficulties in network operation.

Worldwide experience points to a 'threshold effect' for variable generation. When the proportion of energy generated from variable sources is only a few per cent of the total these issues can be accommodated through existing reserve capacity measures, without major change to existing operational arrangements. As variable generator penetration passes the 5 per cent level, it becomes necessary for network operators to take explicit account of variability in high-level network planning, and to develop innovative operational practices, usually involving significant demand management initiatives.

Some of the major issues posed include system control strategies for embedded generator clusters, control communication, and high output swings as discussed below.

System control strategies for distributed generator clusters

New methods for cluster management include the aggregation of geographically dispersed DG according to various criteria, providing an overall degree of schedulability similar to that for conventional generators. This may also include the mixing of non-controllable DG units with controllable ones to enable the former to fulfil service obligations as part of a cluster. Cluster control will include strategies such as output curtailment to provide frequency control, and ramp rate limitations on cut-in and cut-out to avoid unwanted frequency variations on the system. To enable the development and implementation of DG cluster control, comprehensive SCADA systems will be required. The 'master' SCADA system used by the system operator will need to be able to communicate with DG units having different types of SCADA systems, which in turn communicate with different types of generators. Given the CSIRO generator installation figures such a system would need to be large and complex. Here, an 'open architecture' approach to system design may assist.

Use of aggregated distributed generation requires market acceptance as well as a suitable approach system control. There have been significant studies and trials of aggregated distributed generation in the USA (National Renewable Energy Laboratory, 2004) and in Europe (EU-DEEP, 2008) and significantly different opportunities are available in different jurisdictions depending on the regulatory requirements for distributed generation and on the electricity market design. In Australia it is not presently possible to bid aggregated DG into the wholesale or ancillary services markets but this is an issue currently under investigation:

"NEMMCO had raised in submission its intention to promote a rule change to provide more flexibility for the aggregators of small generators to register multiple generators within one 'Market Generator' registration. AEMO prefers to undertake further investigation into these issues before progressing with the rule change. A NEM Market Development project: 'Small (Embedded) Generation Integration Project' has been scoped and is expected to be approved shortly after the inception of AEMO. A rule change to facilitate the registration of small generators is a key part of the project's scope and it is hoped this could be proposed in late 2009 or early 2010." (Australian Energy Market Operators (Transitional), 2009)

Control communication

At high DG penetration levels the provision of an increasing amount of data for control purposes may be necessary. In some cases communication links may already be provided by the DNSP's existing infrastructure such as radio telemetry, power line carrier communication links, optical fibre ground wire, or all-dielectric self-supported cables. However, experience indicates that the majority of distribution networks do not currently have the capacity to manage the increased data transfer requirements. Further, sites with abundant renewable resources are located in rural areas populated with modest and dispersed loads where the grid is not well developed in terms of both network capacity and communication facilities. Here the DG developer may be required to provide the required communication upgrade for the grid integration of their project, at their own expense. Depending on the technology under consideration network communication upgrades can impact significantly on the economical viability of embedded generator developments. Given the capacity of the DG units considered here, radio telemetry is the most economically attractive as it requires very limited additional infrastructure and no network interconnections and radio telemetric links are usually acceptable by DNSPs and will have a limited impact on the project costs.

High output swings

The power output from variable generators can change on a timescale of seconds to minutes. Under traditional assessment methods for conventional generators, a variable generator will be prescribed a 'forced outage rate' several times greater than a conventional generator. Importantly, variable generation can potentially swing in both the positive and negative direction (where a positive swing function is subject to some reserve capacity margin), while conventional generation is subject only to sudden output loss.

It does not necessary follow that the output of an aggregated group of distributed generators will decrease on the same rapid time scale due to geographic diversity. Hence, under generation swings due to resource variations the aggregated generation will 'ramp down' over several minutes rather than being subject to a sudden drop to zero. This effect has been observed for both wind and photovoltaic generation (Electricity Supply Industry Planning Council, 2003; PV Upscale, 2007). As the penetration of DG increases, so too does the geographic diversity of generators, which provides a natural means of smoothing output swings.

Aggregated dispatch of renewable generation

In its simple form, aggregation of renewable generation would enable a well-defined set of dispersed renewable generators to be categorised as a single semi-dispatchable generator. This category has been available in the NEM since March 2009 subject to adequate forecasting tools to assist dispatch calculations. The lack of a single point of connection is not an inherent barrier, although the NEM has not yet developed in this direction as discussed above, and the dispatch engine may need to account for correspondingly dispersed transmission requirements in its computations of network loads and margins. A more advanced form of aggregated dispatch would incorporate renewable generation with fuel-based generation, storage, and demand management resources, allowing a certain amount of firm capacity to be delivered, and creating a resource that could compete with conventional generation in suitably adapted markets (Bel et al., 2007). Both the simple and advanced forms of aggregation are potentially attractive to DNSPs and retailers wishing to diversify and use dispersed resources in a strategic manner, or to new third-party businesses, which creates interesting future opportunities.

9.4.11 Embedded generation – DNSPs and due diligence

Given the projected generator installation rates applied in this study, there is a clear indication that DNSPs may need to consider some additional aspects when conducting due diligence studies in the future.

The results of the generator distribution model as applied to the DNIS indicate that large numbers of grid-connected inverters are projected to connect at low voltages. In such scenarios, DNSPs will need to consider the impacts of large amounts of real power being offset by these generators under high availability factors. This may result in a poor overall power factor seen by the wider network. It may become important in the future to provide dynamic reactive support in order to locally supply reactive power. Alternatively, it may be a matter of future policy that grid-connected inverters provide in-built reactive support in the manner described by Section 9.4.5.

Under the connection of larger embedded generators to the MV network, a heavy reliance exists on the location of the POC relative to the feeder supply point. Where larger generators are connected toward the extremities of a feeder, the issues of relevance may include network voltages while fault levels are not expected to be an issue. On the other hand the opposite is true for a similar generator connected toward the feeder supply point where fault levels may already be high. As stated earlier, the current due diligence requirements of generators connecting to MV distribution networks should be retained in order to monitor these issues and ensure appropriate equipment ratings. Furthermore, given very high penetration of DG connected to the LV network, there may be a desire to incorporate some form of voltage monitoring system in order to ensure voltages maintain nominal levels at all times.

In this study assessments of the impacts of embedded generators on augmentation of the network have considered the value of potential energy lost and the thermal capacities of network components. Black start capabilities are not considered. While existing islanding protection measures are retained, all embedded generators connected to a distribution feeder will disconnect under the loss of mains. Under the requirements of AS4777 grid-connected inverters cannot reconnect until the POC has been re-energised and remains stable for one minute (ANZS, 2005). Non-scheduled SMGs will either take a similar time to reconnect automatically or manually after a longer time period. As a result black start capabilities will be left to the operation of the feeder and any scheduled generation connected to it. It may become a necessity for DNSPs to isolate a portion of the load on the feeder which is equivalent to that of the non-scheduled generation. Alternatively, it may be possible to stagger the reconnection process such that generators can come back online or generator operation could be subject to contractual obligations to provide black start assistance. Another scenario may see small generators given the capability to operate in an aggregated scheduled manner through future communications channels.

As discussed in Section 9.4.5 the capability of PV to provide a limited amount of 'scheduled' operation should not be ignored. Under future conditions, the effectiveness of PV to meet peak loads can be tailored to some extent through selecting the correct array orientation. For planning purposes it may become a strategic advantage for DNSPs to monitor load profiles on feeders and specify preferred PV array orientations for a designated feeder or area based on the peak load time. Given that many PV installations are limited in orientation by the angle of residential rooftops, some incentive may need to be offered for additional supporting structures required to achieve the correct orientation. Alternatively, some form of compensation may need to be provided in order to cover a reduction in system yield.

Under future conditions, an aggregated capacity assessment process may be desirable. Given the generator installation rates, it appears that post 2020 this aggregated assessment may be able to accommodate 1MW 'allotments' of micro embedded generators per feeder. Under the more strenuous emissions mitigation scenario, it appears that this 1MW allotment will require reviewing every five subsequent years, while under business as usual the same review may not be required until ten years after the initial assessment.

Such a measure will be expected to provide DNSPs with a higher level of control over the operating conditions and safety of their networks. There may, however, be significant financial hurdles to overcome for this to occur. For example, under the current Electricity Distribution Code (EDC) regulations, the connection of any embedded generator which increases the fault level in any part of the distribution network above the prescribed level (13.1kA and 50kA in 22kV and 400V distribution networks respectively (Essential Services Commission of Victoria, 2008) will be responsible for mitigating the problem. Under current arrangements, it is not uncommon for the generator proponent to carry this responsibility, even if the pre-connection fault level is already exceeding the EDC limits. Under the aggregated connection arrangements described above, such costs will need to be carried by DNSPs while returns would need to be spread across the projected number of generator connections for each feeder over the aggregated block time period (i.e., five or ten years depending on the generator installation trajectory taken in the future).

Given the level of interaction suggested between DNSPs, local electricity retailers, and embedded generators of all types, it can be expected that a myriad of contractual arrangements could possibly be required between parties. Such a scenario could become complicated and would need to focus on the ultimate goals of each relationship. In the ideal situation, a DNSP would prefer to schedule generator operation in order to maintain system security, while retailers would prefer to operate generators freely in order to maximise financial benefits based on the electricity market spot price. Given these conditions a compromise may be required between DNSPs and retailers for such a system to operate effectively.

There are a number of different compromises which could be made. However, a correlation will occur between the peak electricity price (which occurs at peak load times) and a DNSP's desire to schedule operation of generators during similar times (depending on a feeder's load mixture and the feeder's location as these factors govern load profiles). Where a compromise must be made between DNSPs and retailers an ideal assumption might be that system security is given the priority and the retailer must then operate within the generation timeframes as required.

Furthermore, where renewable generators are involved, generation will occur when it is available regardless of system security or the current market prices as resource availability is not schedulable. As neither the DNSP nor retailer currently has control over generation, it can be expected that in the near term, the retailer could simply aggregate generators by geographic area and sell the energy generated at the current market price. The DNSP then has the option of making the best possible attempt to match generation profiles to load profiles by means such as that outlined in Section 9.4.5 for PV generators.

9.4.12 National Electricity Rules – Access standards

For generators connecting to the NEM, there are strict rules and access standards that must be adhered to. These are provided in Section 5.2 of the National Electricity Rules (AEMC, 2009b). While the application of the Rules has a varying degree of impact on the generators included in the IBDG study, the changing face of generation may impact on the Rules themselves as the network is forced to adapt to new distributed generation scenarios.

As the level of DG penetration increases over time, the sustained exemption of smaller generators from the requirements ascribed by the Rules could result in a reduction in the reliability of the correct operation of the network to which the generation is connected. In regard to distribution networks, reliability is the responsibility of the DNSP. As the level of DG penetration exempt from the Rules increases, the amount of control the DNSP has over the power quality on their network decreases. Therefore some consideration may be required in regard to the applicability of the Rules to small embedded generators.

The purpose of this section is to assess the current state of the applicability of the Rules to the embedded generators considered in the IBDG study. In this section, a number of possible suggestions in regard to the Rules are provided. These suggestions represent the views of Senergy Econnect staff and are considered in greater detail in the full report (Senergy Econnect, 2009).

The findings of this study suggest that access standards for embedded generators may need consideration as currently most of the generators considered in this study are exempt for registration.

Registration as a generator

Version 30 of the Rules (AEMC, 2009b) describes the registration of generators in Section 2.2. Clause 2.2.1 requires the registration of any person who supplies electricity to a transmission or distribution system. However, Clause 2.2.1(c) states that NEMMCO (now AEMO) may grant an exemption from the requirement to register as a Generator. In practice, DGs are often granted exemption as part of an exempt embedded network, and hence individual generators do not always require registration in the NEM. AEMO is actively investigating this area as the number of generators applying for exemption in the current climate is likely to increase. It may be desirable in the future for AEMO to develop a registration process more suited to DG in order to accommodate projected penetration increases.

Table 9.30 provides a summary of the classification of the generators considered in the IBDG study.

Table 9.30: IBDG generator classifications and registration requirements.

Gen. Type	Classification	Exemption Possible?	Market / Non-Market	Scheduling
Gas Combined Cycle CHP	SMG	Comm. & Services - Yes. Industrial - No.	Non-Market	Non-scheduled
Gas Micro-Turbine CHP	SMG	Yes	Non-Market	Non-scheduled
Biomass CHP (≥30MW)	SMG	No	Non-Market	Scheduled
PV	ICG	Yes	Non-Market	Non-scheduled
Diesel Engines	SMG	Yes	Non-Market	Non-scheduled
Micro-wind	ICG	Yes	Non-Market	Non-scheduled or Semi-scheduled
Biogas Rec. Engines	SMG	Yes	Non-Market	Non-scheduled

Access standards

In cases where the generators in the study are not exempt from registration, they need to fulfil the requirements of Schedule 5.2 of the Rules. All of the generators, with the exception of the two larger CHP generators listed above, would currently qualify for exemption. As the penetration level increases for small and micro DG, the cumulative impact on the network may increase to the point that exemption from the access standards may need consideration. Possible mechanisms may be to:

- Continue to grant exemptions from the registration and access standard requirements for small generators (current practice)
- Develop new access standards tailored for small generators
- Change the exemption process so that smaller generators are required to register and meet the current access standards
- Pool the small generators in a specified geographical area and require that the pooled generation satisfy the access standard requirements.

A high-level analysis of the access standards for smaller generators has been performed. Generally, all of the National Electricity Rules (AEMC, 2009b) access standards are applicable and suitable for those generators with nameplate ratings ≥10MW and, for those that remain, are subject to varying degrees of applicability.

Table 9.31 summarises the relevance of the access standards for all of the embedded generators considered in the IBDG.

One conclusion that can be drawn from this analysis is that the effects of large scale aggregation of small generators may need consideration. This measure would ease the uptake of DG in the future and assist DNSPs with the operation of their networks. In this regard, the application of technologies such as 'smart' metering and its communication infrastructure could prove helpful. It is worth noting the inapplicability of grid-connected inverters to Section 5.2 of the Rules. Here the application of state of the art technologies as discussed in Section 9.4.5 may also prove to be valuable.

Table 9.31: Applicability of Access Standards to Distributed generation Types.

Access Standard	**Applicable (Y/N)?**		
	ICGs	**Synchronous Generators (>10MW)**	**Synchronous Generators (<10MW)**
Reactive Power Capability	Y	Y	Y
Quality of Electricity Generated	Y	Y	Y
Response to Disturbances and Contingency Events	N	Y	N
Protection	N	Y	Y
Control Systems	N	Y	Y
Monitoring and Communication	Y	Y	Y
Fault Current	N	Y	N

9.4.13 Distributed generation and safety standards

This section considers the current status of safety standards in terms of generator protection schemes and potential options.

Fault levels and protection

In general, transmission network protection systems have been designed to accommodate fault levels appropriate for their normal operation and some additional generation. However, it is atypical for distribution networks to be adapted for embedded generation. Further, traditional distribution network protection systems are designed for unidirectional power flow with protective devices such as over-current relays used to differentiate between upstream and downstream faults (EA Technology, 2001).

Radial distribution feeders are often protected with graded over-current relays and the addition of multiple sources of fault current adds a level of complexity to this traditional protection design (Electricity Market Services, 2000). With the connection of embedded generators there is now a possibility that the fault levels ‘seen’ by relays will be increased potentially affecting protection scheme grading and operation. A further consideration is the impact of DG fault contributions on up-network fault levels where voltages are higher than POC voltages.

Radial network designs represent the minimum cost to connect the maximum number of consumers. Correspondingly, fault levels are also minimised and hence cheaper switchgear can be used (Powerforce APP, 2000). The variables of cost, security of supply, switchgear ratings and protection schemes will need to be considered and weighted for priority when assessing embedded generator connections.

The protection philosophy and settings of existing protective devices on distribution networks may need to be re-considered prior to the connection of embedded generators. As such, the ratings and capacity of the distribution network with significant levels of DG may be exceeded. They suggest there are a number of possible solutions in the event of fault levels exceeding existing switchgear ratings which include:

- Splitting busbars and/or opening rings at the voltage levels where the problem exists
- Replacement of switchgear with that of a higher rating
- Series reactors such as a transformer with a 1:1 winding ratio
- The installation of short-circuit limiting couplings.
- Splitting busbars is considered the most cost effective short-term solution. However, as a consequence of the addition of DG it may be inevitable that switchgear will need to be upgraded (Powerforce APP, 2000).

Islanding and 'loss of mains' protection

Faults on a distribution network cleared by relays closest to the fault can result in islanded operation, with one or more embedded generators supplying the islanded network. Networks are not designed to operate in 'island' mode, as plant in the islanded section cannot rely on the main grid for voltage and frequency control, particularly embedded generators that need grid connection to operate correctly (EA Technology, 2001).

Islanding of a network may leave a section of the network without an earth. Some distribution network codes require large embedded generators to provide earth fault protection to isolate each embedded generator from the distribution network under earth fault conditions (Essential Services Commission of South Australia, 2005). ETSA Utilities require large embedded generators connecting to high voltage networks to have their neutral isolated or earthed via a high impedance to limit any contribution to a network earth fault (ETSA Utilities, 2005).

Another issue is that the fault contribution of an embedded generator in the islanded network may be insufficient to operate protection relays. Therefore for safety reasons it is important that the network to which the embedded generator is connected has protective devices that can detect loss of grid supply and automatically disconnect embedded generators within the island and keep them disconnected until supply from the grid is restored.

It is for this reason that the Australian Standard AS4777.3 stipulates the need for grid protection for grid-connected inverters that will operate in the event of:

- Disruption of grid supply
- The grid going outside preset parameters (e.g. under/over voltage, under/over frequency), or
- Islanding.

The standard also specifies the need for active anti-islanding protection to prevent the rare event where multiple inverters within a network provide frequency and voltage reference for each other in an island (ANZS, 2005).

Where the network is designed or required to operate in islanded mode, adequate protective devices and voltage and frequency control systems are required within the distribution network to allow correct operation for embedded generators.

Embedded generating technologies are becoming more intelligent and complex as they develop with future generating units likely to be more independent with less reliance on the distribution network to which it is connected. Likewise, as protective devices and control systems advance in capability a system may be developed to allow safe islanded operation of generating units to reliably supply load during periods of network de-energisation (EA Technologies, 2001).

Presently, SCADA and communications equipment is compulsory for loads and generation connected to the MV network. A similar sophisticated communication and control system for LV distribution networks will enable greater interaction between distribution networks and network elements allowing for smoother operation in dealing with safety issues.

The interaction of distributed generation and NSP safe working practices

While the majority of the on-site safety issues and procedures for generation plant is the responsibility of the generator, there is a significant cross-over and cooperation between generators and DNSPs. Various aspects which need to be considered include ensuring that the generator's personnel are competent, that sufficient operations and management plans and safety procedures are well established and in place. In terms of the relationships between DNSPs and generators, these aspects are intrinsic to safety and safety procedures (Australian Business Council for Sustainable Energy, 2004).

9.4.14 Islanding and network reliability

'Islanding' refers to the scenario in which a section of the electrical network which contains some distributed generation is separated from the main transmission or distribution system. When this occurs the DG in the 'islanded' section of the grid maintains the generation on that section of the network either through a shut down and restart process or seamless transfer capabilities which maintains supply from a customer perspective. In some scenarios, it has been shown that the utilisation of the islanding concept can be beneficial, however, its present position in terms of distribution networks suggests that there are some significant complexities in its implementation.

The present position

Currently the potential for islanded operation of parts of the distribution or transmission network is considered to be undesirable for safety and security reasons. As the level of penetration of DG increases on these networks it may become appropriate to review this current policy.

At present, publicised materials indicate that the majority of DNSPs have little experience with the operation of islanded networks. Some examples have been found, however, where the addition of this function has been found to be beneficial (Econnect, 2005b). Currently islanding is an expensive option and the cost needs to be justifiable against the savings made in the avoidance of guaranteed service level charges as described in Section 9.4.4. Technical criteria that also need consideration include:

- Meeting statutory limits of frequency, voltage, and power quality parameters throughout the disconnection, islanding and reconnection process
- Difficulties in achieving seamless transfer between interconnected and islanded modes of operation. Especially on the loss of the network and transferring into an islanded mode
- Maintaining adequate earthing arrangements when operating in the islanded state. The focus here is directed at the loss of the neutral at the distribution transformer
- Establishing synchronisation and generator and load control schemes to prevent any out-of-phase re-connection to the grid
- Management of large step increases in load such as off-peak hot water services

- Provision of ancillary equipment at the distribution level, especially where there is a large amount of variable generation involved
- Management of protection schemes under varying fault levels
- Difficulties in ensuring that DNSP staff can react efficiently and in a coordinated manner to new network design options.

Because safety is paramount, an element of risk aversion to islanded operations has been noted which has led to the use of anti-islanding protection devices on all embedded generators. Senergy Econnect (2009) notes that some degree of disparity is present, with inverter based generators covered by one set of rules (AS4777.3; ANZS, 2005), while the islanded operation of generators that are not inverter interfaced is governed by other measures such the National Electricity Rules or the Western Power Technical Rules (WPTR). In the NEM, the Rules indicate that the option for islanded operation rests on decisions made by, and/or negotiated with, DNSPs whereas the WPTR states that islanded operation of distribution networks is to be protected against by all connected embedded generators.

A general conclusion on the status of islanding in distribution networks is that despite the seemingly daunting technical hurdles that need to be overcome, there can be benefits to this mode of operation. It is typically accepted that these benefits increase with both the penetration of DG and the advancement of supportive technologies.

Benefits and case study

In present scenarios, the implementation of islanding functions within distribution networks is considered to be undesirable for safety and technical reasons. Under significant DG penetration scenarios the active involvement of DG in the supervision of the network becomes more realisable albeit with substantial complexity and increased capital cost.

Technically, the issues that arise can be overcome with the implementation of existing technology. Thus, the inhibiting factor is the justification of the cost of implementing such technology. Compounding this cost is the non-idealised location of DG plant in distribution networks and the requirement of substantial communications infrastructure.

Assessment of the IBDG generator technologies has concluded that the only SMG generators should be considered for islanding purposes as they have the capacity to implement both power factor and voltage/frequency control methods. While the focus has been on the use of such plant, a review of the capability of ICGs to assist in the provision of network support in the future is suggested along with consideration of low level DSM technologies.

A high-level theoretical modelling case study has shown that islanding can be made possible through the use of a synchronous generator. This example showed a necessity for the use of additional reactive plant in order to overcome the significant transients involved as described by Moura et al. (2008). Nominal voltage and frequency envelopes where maintained during the disconnection event with this mode of operation. However, this result highlights the necessity for complex generator and load control strategies requiring remote monitoring, switching, control, protection, and communications infrastructure.

9.4.15 Conclusions

DNSP dialogue and further work

The methodology and results of the study "Impacts and Benefits of Highly Distributed Embedded Generation in Australian Distribution Networks" (IBDG) by Senergy Econnect (2009) were presented to representatives of 10 Australian DNSPs and the AER at a workshop in June 2009. The workshop endorsed the approach used and indicated that the results will assist the network community to manage change over coming years. The workshop recommended expanding the report to encompass the circumstances of DNSPs throughout the country, including a wider range of example feeders selected from several states so that the findings are universally applicable. At the time of writing, the scope of work towards an expanded report is under discussion with DNSPs through the Energy Networks Association.

Feedback from workshop participants has provided initial guidance for this scope. The main areas identified as needing further work were as follows.

Broad representation and extreme cases
Further work is required for the results to be broadly representative by including examples of networks from a range of Australian states including at least one feeder in a central business district (CBD), and at least one very long rural feeder. A greater range of embedded generation scenarios, such as more clustered and varied deployments reflecting likely investment patterns, would help the impact assessment. Sensitivity analyses should be extended.

Comprehensive technical coverage
Several topics would benefit from a deeper treatment, for example, grounding of feeders, influence on sub-transmission networks, voltage regulation and transformer tap strategies, merits of different connection levels, characteristics of low-voltage feeders, and necessary interactions between transmission and distribution planning.

Monitoring the progress of embedded generation
Data should be accumulated on the penetration of different technologies, notably embedded generation, but also trends in appliances and demand-side management that will affect power quality and the application of embedded generation. Observations on the influence of embedded generation on power quality and distribution system operations should also be consolidated as a collective resource and to validate modelling.

Technology and standards development
Further review of technology trends overseas and the potential convergence of standards would assist the development of an Australian approach. The study can include draft recommendations on new standards and technical requirements for embedded generation, ideally leading to a "black box" approach in which classes of network and generation can be identified and treated in a consistent manner.

Regulatory development and financial mechanisms
The technical findings permit recommendations on how new regulatory and market developments may assist the orderly proliferation of embedded generation. The study might also cover mechanisms for funding and obtaining revenue from embedded generation, including tariff strategies, risk and cost sharing, economies of scale, and provision of aggregated services.

This will be a continuing process of analysis and reporting involving Australian network business and centres of expertise. Meanwhile, the present IBDG study has begun this process by considering in detail the impacts of large scale penetration on distribution networks. The study included two significant components. Firstly, Distribution Network Impact Studies (DNIS) used recognised modelling techniques to provide a quantitative analysis of the technical impacts of projected generator installations from 2010 to 2050 on four real-world distribution feeders. Secondly, the IBDG study assessed qualitative aspects while giving consideration to the results found in the quantitative analysis provided by the Distribution Network Impact Studies. The following concludes on the main findings of the IBDG study, provides recommendations under the proposed high embedded generator penetration scenarios, and highlights the requirements for future work forthcoming from the IBDG study.

DNIS: conclusions

Overall the DNIS has successfully developed base-case feeder models and projected appropriate generator installation trajectories onto them as required for this study. Although there are many assumptions included in this process, they were validated with appropriate research and are contained herein. Thus the study has accurately represented its expectations of providing analysis of the impacts of the widespread uptake of a variety of distributed generation technologies under two possible future scenarios.

The key conclusions of the study are as follows:

- Distributed generation is of benefit in reducing network losses and improving voltage profiles
- Distributed generation is of some value in postponing network upgrades where thermal limits are a critical factor, although attention must be given to the effective capacity contribution under peak loading conditions. Network upgrades may be necessary in any case due to reliability considerations (value of lost energy), but depending on DG characteristics it may be possible to upgrade feeders with lighter conductors than would otherwise be necessary
- Under the investigated scenarios to 2050, distributed generation is unlikely to pose widespread issues with fault current capacity of existing equipment, or to raise issues with protection coordination through displacement of conventional generation leading to reduced fault levels
- The envisaged embedded generator technologies are not considered to be a significant source of voltage flicker, rapid voltage change or phase imbalance. Harmonic emissions from inverter-connected generators such as PV are expected, but are unlikely to result in harmonic distortion on feeders in excess of regulatory limits
- The opportunity for power from distributed generation to result in a power flow reversal across zone substation MV busbars is limited due to the fact the embedded generators have a tendency to generate corresponding to human activity. As such it is considered unlikely to be a problem
- High-level investigations indicate that distributed generation is unlikely to pose issues due to steady-state voltage stability, frequency stability, rotor angle stability or small-

disturbance (oscillatory) stability. However, these investigations are limited and more detailed investigations are warranted in future to confirm these results

- Fault ride-through capabilities have been found to be desirable for embedded generators but not necessary at the present or prior to 2050 given the high level assessment applied here.

IBDG study: conclusions

The purpose of the Impacts and Benefits of Highly Distributed embedded generation in Australian Distribution Networks Study was to provide an appropriate context for the Distribution Network Impact Studies in the wider NEM in terms of regulatory and operational perspectives. In doing so the study appropriated the points raised with results and indicative data from the Distribution Network Impact Study.

The key conclusions of the study are as follows:

- Currently, due diligence assessment of each individual embedded generator connection is required by the DNSP, if the DNSP foresees the potential for adverse network impacts. This can have prohibitive impacts on the cost to a customer of connecting an embedded generator. It is suggested that, in future, an aggregated due diligence assessment might be undertaken instead based on an anticipated penetration of embedded generators. This would establish a level of distributed generation that could connect without further assessment before network limits are reached
- The safety standards which are currently in place to achieve safe operation of distribution feeders are considered to remain appropriate for DG into the future. However, the protection philosophies and settings of existing equipment may need reconsideration in the future as embedded generator installations increase in number
- Distributed generation at present largely falls outside the scope of the National Electricity Rules generator technical requirements. There is some technical justification for extending certain of these requirements to embedded generators as penetration increases toward 2050
- Given the level of interaction suggested between DNSPs, local electricity retailers, and embedded generators of all types, it can be expected that a myriad of contractual arrangements may be required between parties. It is suggested that arrangements should maintain system security as a primary requirement
- Islanded operation of distribution networks is in principle highly effective in realising the full value from embedded generation. However, the technical and commercial barriers to such operation remain formidable and will require substantial work to address. It is however reasonable to expect that islanded operation of networks will become feasible prior to the 2050 time horizon for this study.

IBDG study: recommendations

In light of the intentions of the IBDG study, the following recommendations are made for consideration under increasing embedded generator uptake.

- The current protocols for generators connecting to medium voltages should remain in place. However, given the projected increases in embedded generator installations it is suggested that the connection process maintain a consideration for additional embedded generators to connect either by allowing for predicted additional capacity when undertaking studies or by aggregating connection application processes for multiple generators where possible
- Modelling indicates that large PV penetrations could have an adverse effect on the power factor at a feeder supply point. Given current inverter technologies, there may be a need to offset this poor power factor with reactive support equipment. Consideration should be made for state of the art inverters which can provide reactive support
- It will become increasingly important under high DG penetrations for DNSPs to have access to information on the exact locations, capacities and technologies of all DG on their networks. Some reasons include the development of generalised understandings of the impacts of DG through experience, monitoring of the impacts of DG on network reinforcements and maintaining an understanding of the feeder's ability to meet black-start loads
- The development of some form of 'scheduling' communications channel is recommended. This may help the owner of schedulable plant understand the benefits of this mode of operation and to ensure that DNSPs are able to meet peak demand with peak generation. 'Smart' metering may be able to provide such functionality, as could an internet based communications system. In addition optimisation of PV module orientation may be advantageous for peak demand reduction
- It is suggested that studies to understand the degree of 'firmness' in capacity for renewable generators be established. Such studies may need to be undertaken on a regional basis
- Given that large PV penetrations are projected for rural areas variable generation patterns are expected to impose more frequent tap-changing operations onto OLTC transformers. While it is left to future work to estimate the actual number of operations involved, it is recommended that DNSPs operating in rural areas reconsider maintenance regimes in the future in order to account for this. Alternatively, investments into new transformers with the capability for more frequent operations may be required
- As fault ride-through capabilities may be desirable for embedded generators in the future, it is recommended that uniform standards may be required. One possible suggestion is a two-tier approach mirroring that of the National Electricity Rules, with an 'automatic access standard' matching the NER S5.2.5.5 automatic standard for FRT capability, and a 'minimum access standard'.

9.5 Impacts and benefits of DG on transmission networks

In Section 9.4, the impacts and benefits of DG on Distribution networks was considered through the use of power system modelling. In Section 9.3, the impact of DG on the NEM was considered through the application of an economic dispatch model PLEXOS. In this section, the effects of DG on transmission systems are considered by examining the impact of passive DG installations within an Institute of Electrical and Electronics Engineers (IEEE) transmission test grid. It is important to recognise this test grid is not based on real conditions of any Australian electricity grids, and so results cannot be directly extrapolated from these tests to the Australian context. The study examines the impact of DG on the economic dispatch of units within the system in a similar but more simplified manner to PLEXOS and determines effects in the power system through the use of a full AC power flow model rather than the more simplified linear DC approximations used by PLEXOS. The computational limitations of the full AC power flow model limited the study to the simulation of market operations over a one week period.

9.5.1 Key findings

Modelling performed in this study found that adding constant passive DG to the IEEE test grid results in reduced congestion and a moderation of the price of electricity. Surprisingly, the modelling found that transmission losses could increase contrary to convention wisdom. The increased losses resulted from a complex mix of power flows and economic dispatch.

In general, capacity utilisation and net energy benefit were affected by the addition of DG, there were however some notable exceptions:

- The utilisation of nuclear, hydroelectric, and the largest coal units remained largely unaffected by DG. However, as electricity prices decline markedly once DG capacity is installed, the net energy benefit realised by these units decreased
- In most scenarios, the utilisation of the #6 fuel-oil conventional steam units at Arne is higher with DG installed. And, this increase is more than sufficient to offset the lower electricity prices; units at Arne are often more profitable with DG installed in the system than without it.
- Further interesting findings from the modelling include that:

- Adding even small amounts of DG can have dramatic impacts on the power flows and economics of an electricity system. For example, the fact that 20 MW_e of DG, a small amount (~0.6% of total system capacity), installed at one location can reduce the average electricity price by 12%
- The effects of adding DG aren't limited to the bus at which the capacity is installed. They are felt by pre-existing generation units both near and far and, from generators' perspectives, can be positive or negative
- The effects of adding DG may depend more upon where the DG is added than on how much
- The effects of adding DG depend quite heavily upon specific characteristics of the target electricity system (e.g., disposition of sources and sinks relative to one another, types of generation units in the system, electricity demand).

9.5.2 Introduction

In Australia, electricity supply is predominantly provided by large, centralised, dispatchable generators. In this report we consider a value proposition which envisages that in the future an increasing share of electricity will be provided by DG. In this paradigm, generation capacity is situated in close proximity to where the electricity is consumed. In contrast to current sources of supply, DG units would be small, decentralised, and, frequently, be non-dispatchable and use different sources of energy.

Section 9.4 examined the impacts and benefits of DG on distribution networks. This section examines the impacts and benefits of DG on transmission networks. Of interest to stakeholders may be:

- What aspects of the system are affected?
- What are the magnitudes of the changes?
- Are the changes beneficial or problematic for the transmission system?

There has been some treatment of this subject in the literature. An assessment of the impact of DG on reliability; the ability of an electricity system to cope with the unexpected loss of system components, has received attention. Taken together, Chowdhury and Koval (2003) and Ghajar and Billinton (2006) demonstrate the ability of DG to offset losses from random system events. Zerriffi et al. (2007) show that DG can also mitigate the negative impacts resulting from the wilful targeting of system components.

This study conducted a preliminary assessment of the effect of adding DG to an existing electricity system using an IEEE test case. As the effect of DG on system reliability is fairly well understood, this study is focused on impacts of DG on power flows and the overall system economics. Key areas of interest are:

- Congestion
- Transmission losses
- Market price of electricity
- Capacity utilisation
- Energy benefit.

9.5.3 Approach

The objective of this study is to perform a preliminary assessment of the effect of adding DG to an existing electricity system. This section discusses the methodology used to make this assessment. It is organised into three parts. First, the economic dispatch model is described. Formulating and solving this model is at the core of the electricity system assessment. Second, the simulation of the electricity system operation is described. Third, we provide an overview of the IEEE Reliability Test System (RTS). Its features are briefly described and the results observed prior to the addition of DG are presented.

Nomenclature

The following list contains the variables used in this analysis.

Variables

CoE	cost of electricity, e.g., $/MWh
C	cost, e.g. $
D	length of time period, e.g., hours
FC	fuel cost, e.g., $/MMBtu
FOM	fixed operating and maintenance cost, e.g., $/year
HI	heat input required to start-up thermal unit, e.g., MMBtu
IHR	incremental heat rate, e.g., Btu/kWh$_e$
I	current, e.g., Hz
MCR	Maximum continuous rating of a transmission line, e.g., MVA
P	real power, e.g., MW$_e$
$\dot{q}$	heat input to boiler, e.g., MMBtu/h
Q	reactive power, e.g., MVAr
ρ	price of electricity, e.g., $/MWh
S	apparent power, e.g., MVA
θ	phase angle, e.g., rad
u	unit start-up ('1' if unit started-up, '0' otherwise)
VOM	unit variable operating and maintenance costs (excluding fuel), $/MWh
V	voltage, e.g., V
y	portion of offer to sell power that is accepted, e.g., MW$_e$

Superscripts

d	pertaining to day
DG	pertaining to distributed generation
D	pertaining to demand
h	pertaining to hour
min	indicates minimum value
max	indicates maximum value
S	pertaining to supply
w	pertaining to week

Subscripts

b	index of offers to sell power
k,m	index of bus
n	index of generating unit
t	index of time period

Sets

N_b	number of offers to sell power
NG	set of generating units
T	number of time periods

Economic dispatch model

In its most basic form, economic dispatch involves identifying the power output of each plant (unit) in a system such that the total benefit to producers and consumers is maximised. For the simple case of a single producer and a single consumer, the economic dispatch is the level at which their respective utilities are equal; graphically, it is the point at which their supply and demand curves intersect.

In time period *t*, unit *n* is willing to produce electricity $P_{n_t}^S$ so long as the price, ρ_t, is greater than or equal to its marginal cost of generation, $dC(P_{nt}^S)/dP_{nt}^S$. Consider the general expression for cost of generation shown below in which time is omitted for clarity:

$$C_n = \left[\frac{FCF_n CapitalCost_n + FOM_n}{HPY}\right] D_t + VOM_n P_{nt}^S + \dot{q}_{nt} FC_n D_t \qquad 9.6$$

Where, *FCF* is the fixed charge factor to convert annualised capital cost
HPY are the number of hours per year

To a first approximation, the non-fuel components costs can be ignored. The marginal cost of generation is obtained by taking the first derivative of Equation 9.6 with respect to $P_{n_t}^S$

$$\frac{dCn}{dP_n^S} \approx FC_n \frac{d\dot{q}_n}{dP_n^S} = FC_n IHR_n \qquad 9.7$$

Using Equation 9.7, the supply curve for a generation unit is readily obtained. To mimic the mechanics of a deregulated electricity system, the utility function for each unit is discretised in a step-wise, linear fashion; each 'step' then represents an offer to produce a block of power. The offers from all units are aggregated in order of increasing price and this forms the composite supply curve for the electricity system. Assuming the consumers are all price-takers, the economic dispatch problem can be expressed as:

$$\min_{y_{nt}^S, u_{nt}} \sum_{t=1}^{T} \sum_{n \in NG_D} \sum_{b=1}^{N_b} y_{bnt}\, IHR_{bnt} FC_n D_t + \sum_{t=1}^{T} \sum_{n \in NG} u_{nt} HI_n FC_n \qquad 9.8$$

The second term in Equation 9.8 incorporates the significant cost associated with starting up a unit into the dispatch decision.

There are considerations outside of economics that inform the selection of offers. The constraints considered in this study are related to security, reliability, and the physical realities of the equipment involved in generating and transmitting power. They are described below.

Net real and reactive power injected at each bus

The net real and reactive power injected at each bus is the difference between the aggregate output from generators and the local demand.

$$P_{kt} = \sum_{n \in NG_k} \left(P_{nkt}^{S}\right) - \left(P_{kt}^{D}\right) \tag{9.9}$$

$$Q_{kt} = \sum_{n \in NG_k} \left(Q_{nkt}^{S}\right) - \left(Q_{kt}^{D}\right) \tag{9.10}$$

Real and reactive power flow

Not withstanding the above, the apparent flow of electric power at any bus k can be shown to depend upon the current, voltage magnitude, and phase angle at that bus:

$$S_k = |V_m|(\cos\theta \pm \hat{\jmath}\sin\theta)I_k^* \tag{9.11}$$

Additionally, the current depends upon the properties of transmission lines connected to the bus (length, resistance, reactance, and line charging susceptance) through the bus admittance:

$$I_k = \sum_{m \in NG_k} Y_{km}|V_m|(\cos\theta \pm \hat{\jmath}\sin\theta) \tag{9.12}$$

The basic power flow model is obtained by writing out, for each bus k, Equations 9.11 and 9.12.

Unit ramp rates

These constraints enforce the fact that thermal generators are limited with respect to how quickly they can move from one set point to the next.

Unit minimum up- and down-times

Once a decision has been made to turn a thermal power plant on or off, it must remain in that state for a minimum amount of time.

Energy balance on generators with storage (e.g., hydroelectric facilities with reservoirs)

Hydroelectric power stations are unable to deliver their maximum rated capacity over sustained periods. It is therefore necessary to constrain the electric energy output of the generator by the total potential energy represented by the available water.

Reserve power

Electricity system operators maintain capacity reserves; this flexibility is essential should a contingency arise. Different classes of reserves are considered:

- 10-minute spinning and non-spinning reserves (the 10-minute reserve requirement is the size of the largest contingency. Half-of this reserve should be spinning i.e., synchronised with the grid)
- 30-minute non-spinning reserve (This is half the size of the second-largest contingency).

Electricity system simulation

Simulating a day's operation of the electricity system is accomplished in three phases:

Pre-dispatch
The economic dispatch of generation units is performed for the dispatch horizon. During this phase, the economic dispatch model is solved for a time interval that is at least as long as a dispatch day. Here, an approximate power flow model is used; sinusoidal terms in the Equations 9.11 and 9.12 are replaced with their first-order approximations. The solution of the economic dispatch provides the generation schedule for those units that are energy-constrained.

Real-time operation
For each period of the dispatch day, economic dispatch of generation units is re-done but, this time, using an exact power flow model. Conceptually, this represents the real-time operation of the electricity system.

Market settlement
For each period of the dispatch day, the market settlement is performed. During this phase, the market price for electricity is determined. The general procedure is to re-solve the economic dispatch problem with the following modifications:

Power flow is ignored. Effectively, the sources and sinks are modelled as being connected to the same bus

Offers from units that were *not* dispatched in the period are removed from set of available units.

This is shown graphically in Figure 9.68. Within the composite supply curve for the IEEE RTS '96, the shaded areas represent offers to produce power that have been accepted during the market settlement phase for the first time period. The price of electricity in this period is then the price of the most expensive offer accepted: \$21.66/MWh, in this case.

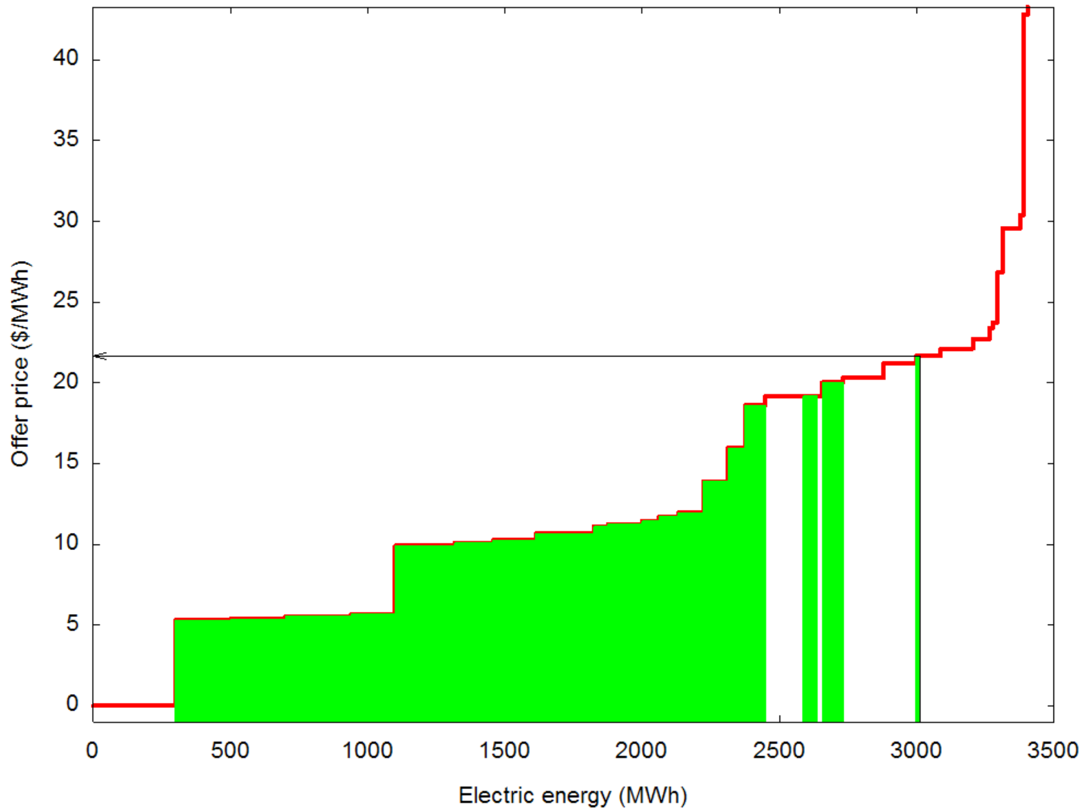


Figure 9.68: Offers selected in first hour of IEEE RTS ’96 simulation

It is often assumed that economic dispatch strictly follows the merit order. In this case, given an electricity demand, one can use the composite supply curve to determine the dispatch schedule and the market price of electricity. As Figure 9.68 should make clear, this approach would not be valid for the IEEE RTS ’96 test case.

Description of IEEE RTS ’96

The ‘1-area’ IEEE RTS ’96 (Grigg et al., 1999) was selected for use in this study. The IEEE RTS ’96 has been used in many other electricity system studies including many focused specifically on DG (Chowdhury and Koval, 2003; Ghajar and Billinton, 2006; Zerriffi et al., 2007). This allows the results from this study to be easily compared with the work of others. It has several desirable features:

- Sources and sinks are spatially disaggregated
- Parameters describing the technical and economic performance of the generation units are provided
- Physical properties of the transmission network are specified.
- A one-line diagram of the IEEE RTS ’96 is shown in Figure 9.69. Table 9.32 summarises the sources and sinks that are present in the system.

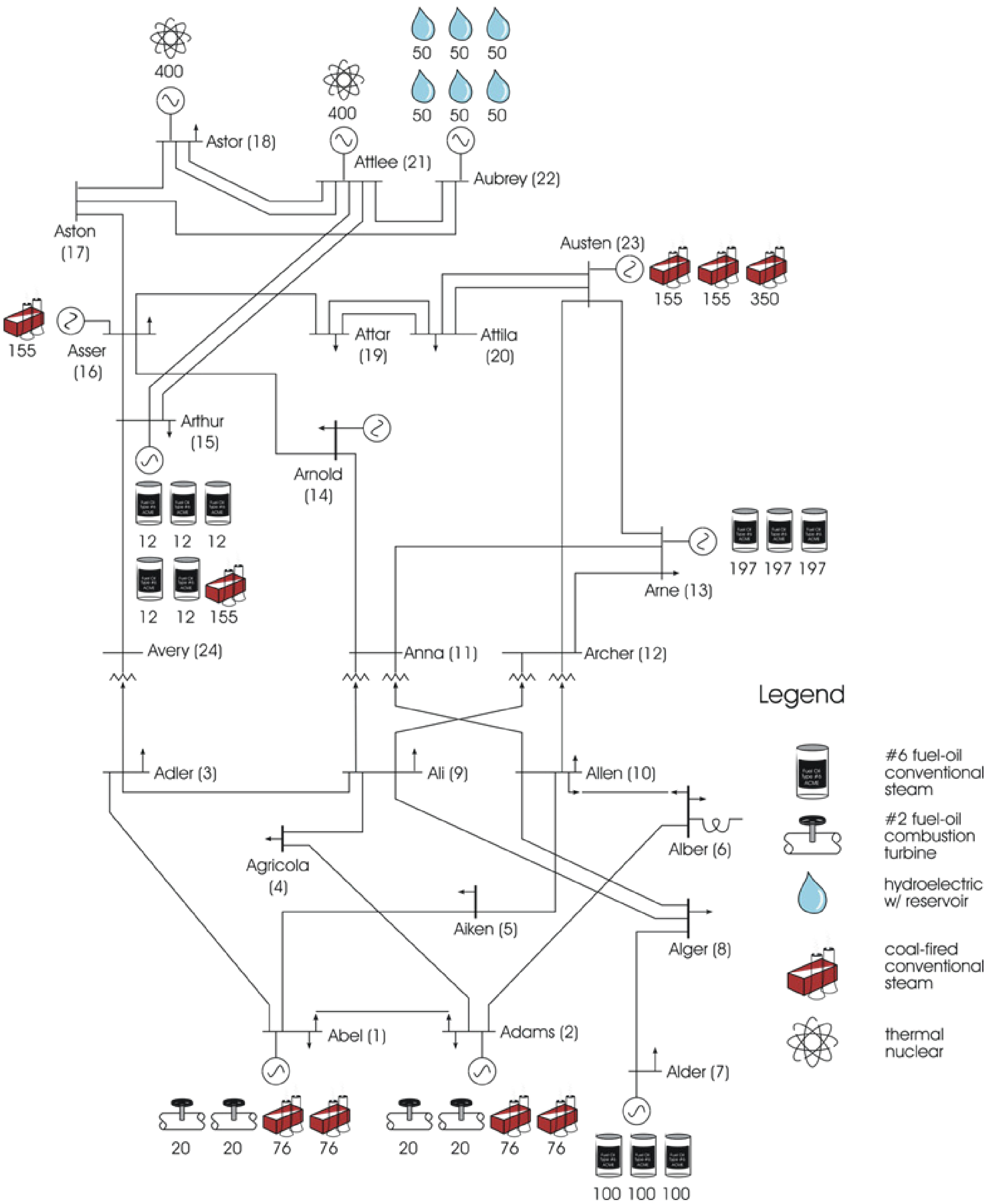


Figure 9.69: One-line diagram of IEEE RTS '96

Table 9.32: Role of buses in IEEE RTS '96

Bus	Peak demand MW_e	Installed capacity MW_e
Abel	118.8	192
Adams	106.7	192
Adler	198.0	300
Agricola	81.4	
Aiken	78.1	
Alber	149.6	
Alder	137.5	
Alger	188.1	
Ali	192.5	
Allen	214.5	
Anna		
Archer		
Arne	291.5	591
Arnold	213.4	
Arthur	348.7	215
Asser	110.0	155
Aston		
Astor	366.3	400
Attar	199.1	
Attila	140.8	
Attlee		400
Aubrey		300
Austen		660
Avery		
Total	3,135	3,405

Demand

The load duration curve for the system is shown in Figure 9.70. Peak demand is 3135 MW_e and off-peak demand is 1,062 MW_e. Figure 9.71 shows the aggregate electricity demand in the IEEE RTS '96 over the course of a week; it is this week that is the basis for the current investigation.

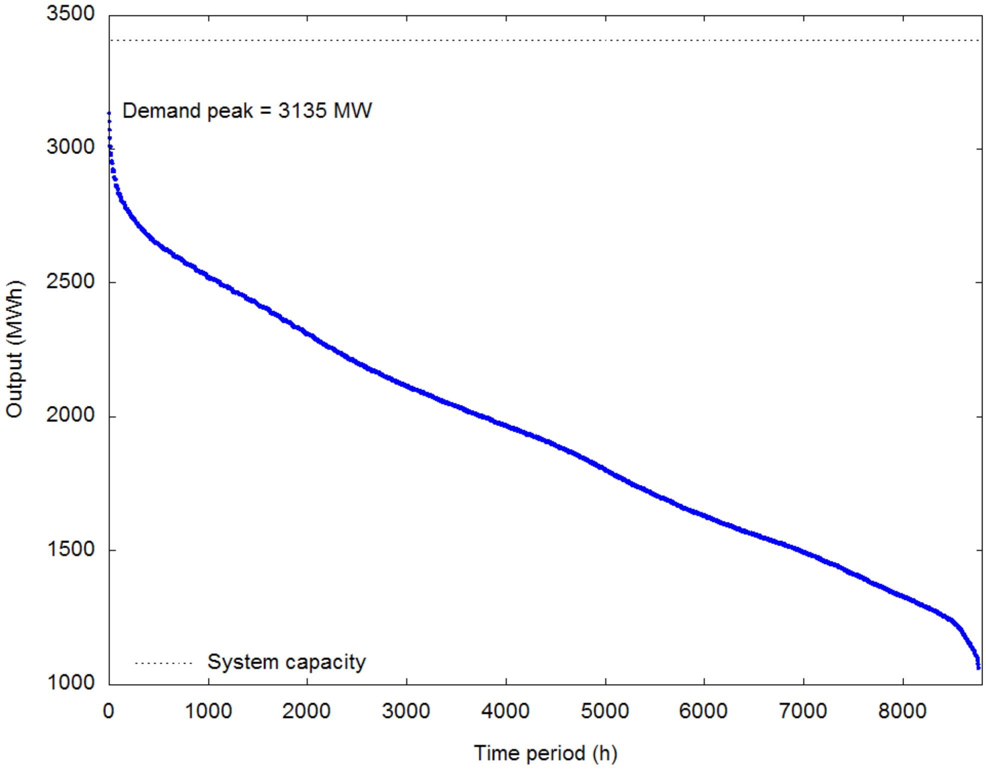


Figure 9.70: Load duration curve for IEEE RTS ’96

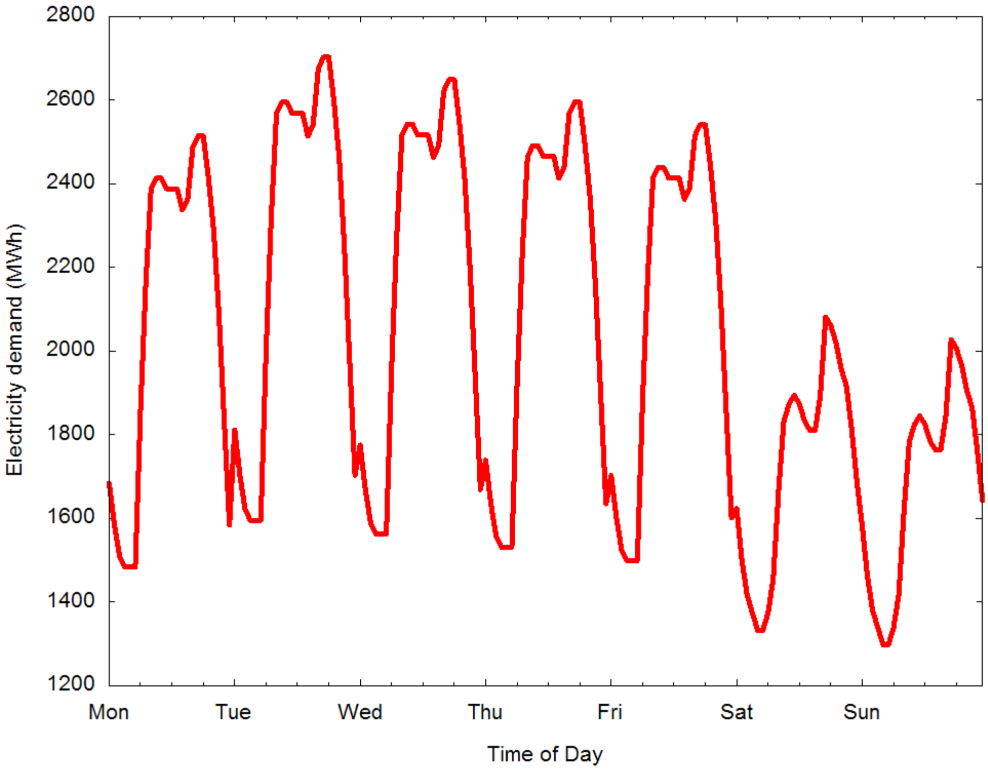


Figure 9.71: Aggregate electricity demand in IEEE RTS ’96 for week of interest

Composite supply curve

Figure 9.72 shows the composite supply curve for the IEEE RTS ’96. Additionally, the unit type from which each offer originates is indicated.

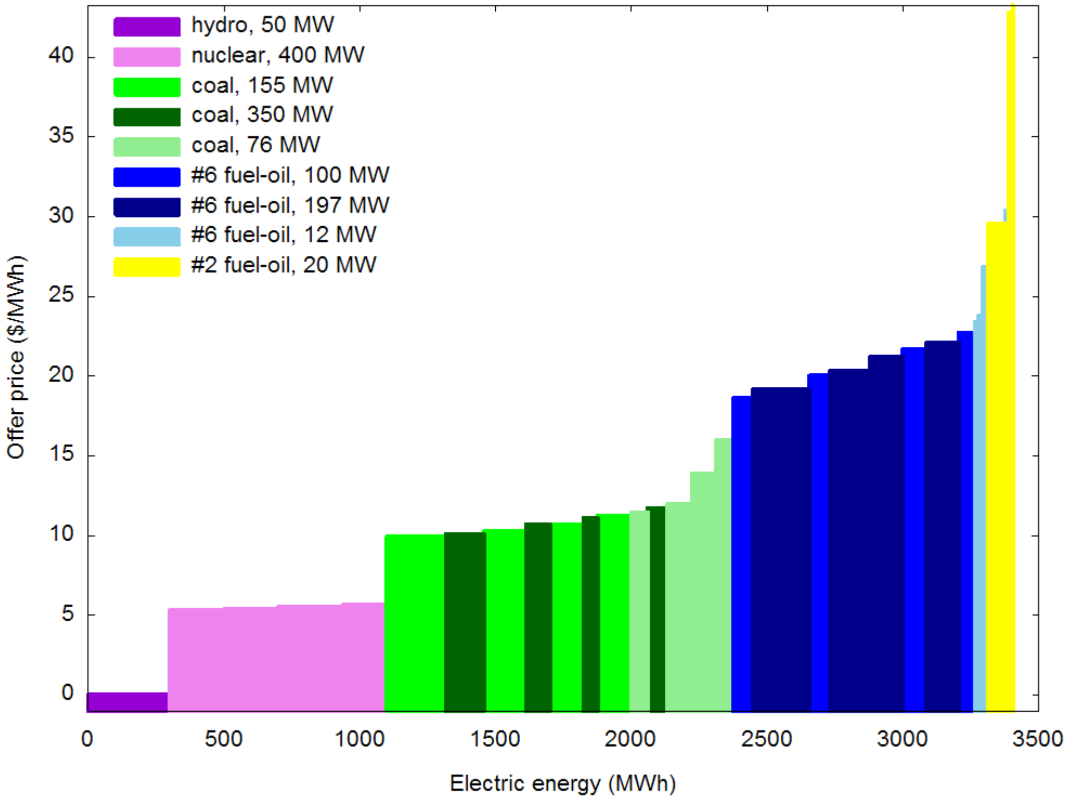


Figure 9.72: Composite supply curve for IEEE RTS ’96

Capacity utilisation

Figure 9.73 shows the electricity generation occurring at each bus over time. The following attributes are apparent for this figure:

- The nuclear units, at Astor and Attlee, operate continuously at their nominal load
- More power is produced at Austen than anywhere else although it still has headroom given the maximum output of its units are 660 MW
- Arne is basically a ‘peaking’ plant. It goes from maximum load to shutdown in a few hours. On days with low demand (e.g., weekends), it may not be dispatched
- Units at Alder behave similarly to those at Arne but on a smaller scale
- Aubrey, with its hydroelectric units, is dispatched during the day and is off at night.

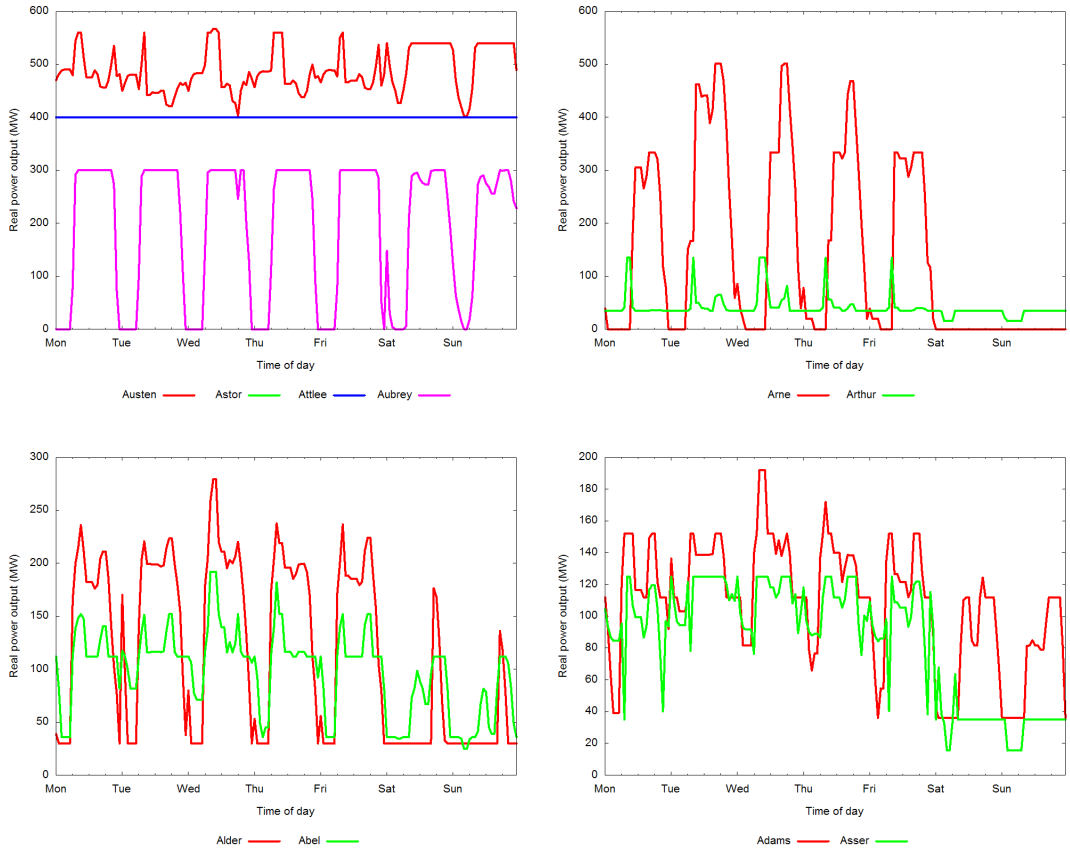


Figure 9.73: Real power output of units in IEEE RTS '96 (Top left = Large buses, Top Right = Medium buses, Bottom left = small buses, Bottom right = very small buses)

Congestion

There are physical limits to the quantity of electric power that a transmission line can support. This determines the rating which is quoted as the maximum quantity of power the line could carry is specified.

It may happen that a set of dispatch instructions would result in power flows that cause one or more transmission lines to exceed their specified continuous rating. To avoid this, the dispatch schedule may need to be reformulated. In such a situation, *congestion* is said to exist.

Identifying congestion in the IEEE RTS '96 is performed by examining the unused capacity of the transmission lines; *unused capacity* is the difference between a line's continuous rating and the apparent power flow along it. There are 38 transmission lines in the IEEE RTS '96 grid and Figure 9.74 summarises the unused line capacity of each line during the week of interest. The height of the bars gives the mean quantity of unused capacity for the week and the error bars indicate the minimum and maximum unused capacity observed. The blue lines indicate the maximum continuous rating (MCR) for each of the transmission lines.

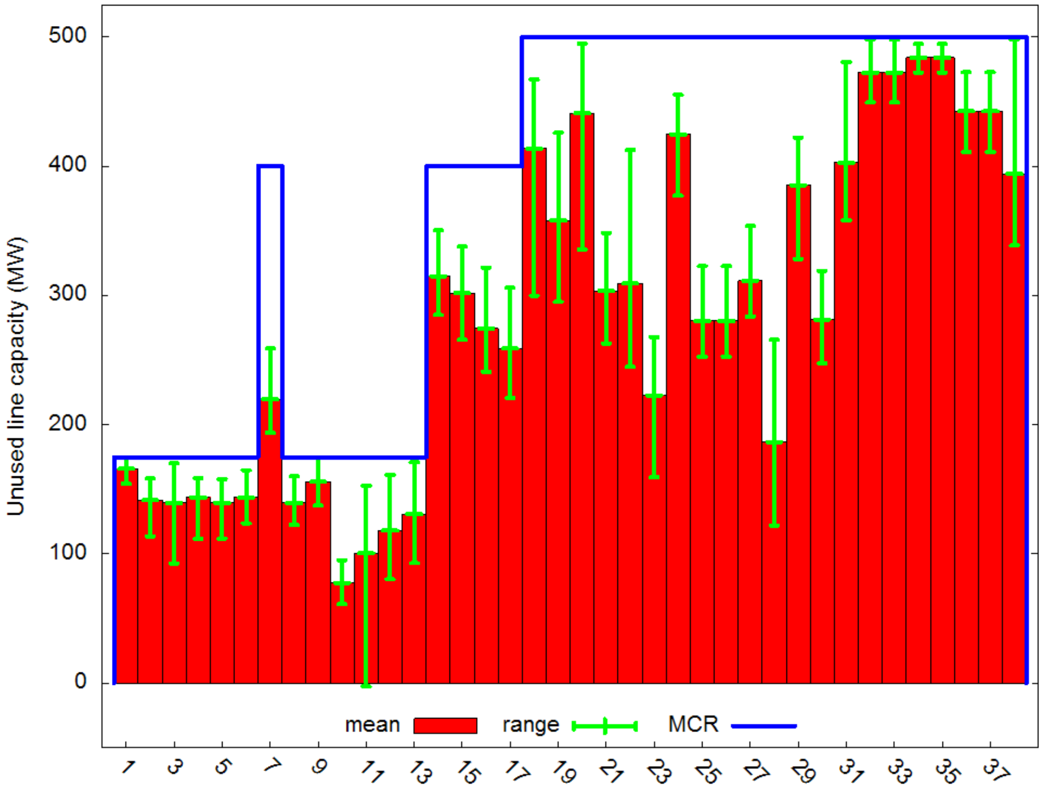


Figure 9.74: Unused line capacity in IEEE RTS '96

In all the transmission lines except one, the power flow is always less than the continuous rating. The lone exception is the Alder–Alger transmission line where the apparent power flow exceeds the continuous rating by a small amount (~2.5 MVA) for a 2hr period (09:00 and 11:00 Wednesday morning). The line is still within its long-time emergency (24 hour) rating so there is no danger. But, exceeding the continuous rating during normal operation is notable.

Transmission losses

Figure 9.75 indicates the losses of electricity that occur as a result of transmission within the IEEE RTS '96.

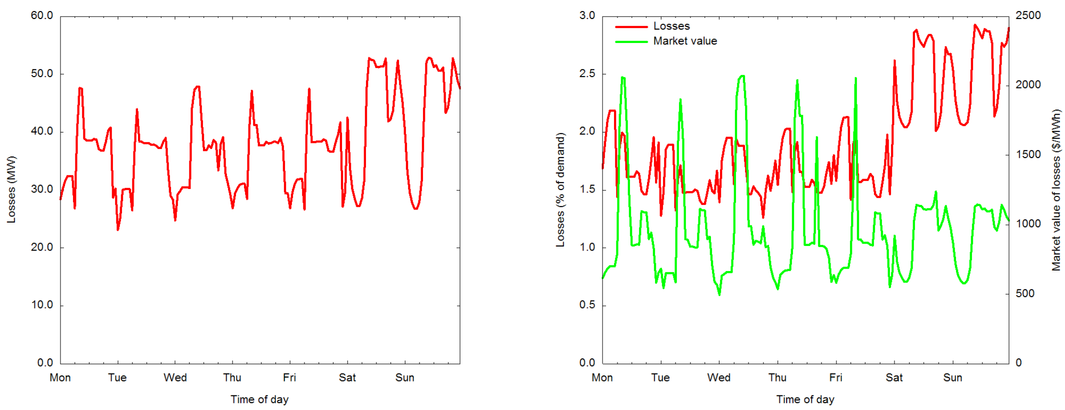


Figure 9.75: Transmission losses in IEEE RTS '96

The left portion of Figure 9.75 specifies the aggregate electricity losses that occur throughout the system in absolute terms. At any given time, between 25 MW_e and 55 MW_e of the electricity being generated is lost. In general, the magnitude of the losses changes monotonically with electricity demand. However, losses on the weekend are significantly greater than during weekdays even though demand on the weekend is about 25% lower.

The weekend increase in transmission losses is caused by the significant differences in the dispatch schedule during the weekend versus weekdays. On the weekend, electricity demand is 20% lower then during the rest of the week (see Figure 9.71). The much lower demand leads to a different outcome with respect to capacity utilisation.

These differences are visible in Figure 9.73. The generation profiles of the buses depicted in the top-left plot change little from day to day whereas the output from the other buses drop substantially on the weekend. As it happens, it is buses that are co-located with loads whose production is dropping off: Arne, Alder, Abel, Adams, in particular. Also, it is buses with no local demand that are increasing their share of production: Attlee, Aubrey, and Austen. Thus, while overall demand is lower, the electricity that is required is travelling greater distances. The increased distance in transmission of the electricity is, therefore, accompanied by increased transmission losses.

The plot on the right of Figure 9.75 attempts to place the magnitude of the transmission losses in context by presenting them as a percentage of the aggregate electricity demand and on a value basis. In the latter case, the market value of electricity is calculated as the product of the real power and the price of electricity.

Electricity losses are lower during the week (1.5-2.0% of demand) when compared to weekends (2.0-3.0% of demand). However, since electricity prices are lower on the weekend (see Figure 9.76), the market value of the losses is greater during the week.

Electricity prices

Figure 9.76 shows the electricity prices over the week of interest. Each time period is identified by the bus containing the unit(s) that are price-setting. The electricity price varies from \$20/MWh to \$45/MWh. The price-setting units are those that use #2 or #6 fuel oil as an energy source. Prices tend to be greatest when demand is greatest and vice versa.

It is worth reiterating here that we are using a test grid to estimate the impacts of DG on transmission lines. The IEEE test case incorporates a number of generator and fuel combinations not used within Australia. The purpose of this study however is to examine the impacts of DG on dispatch and transmission power flows and as such the type of modelling approach is considered more important than the types of generators and fuels being used.

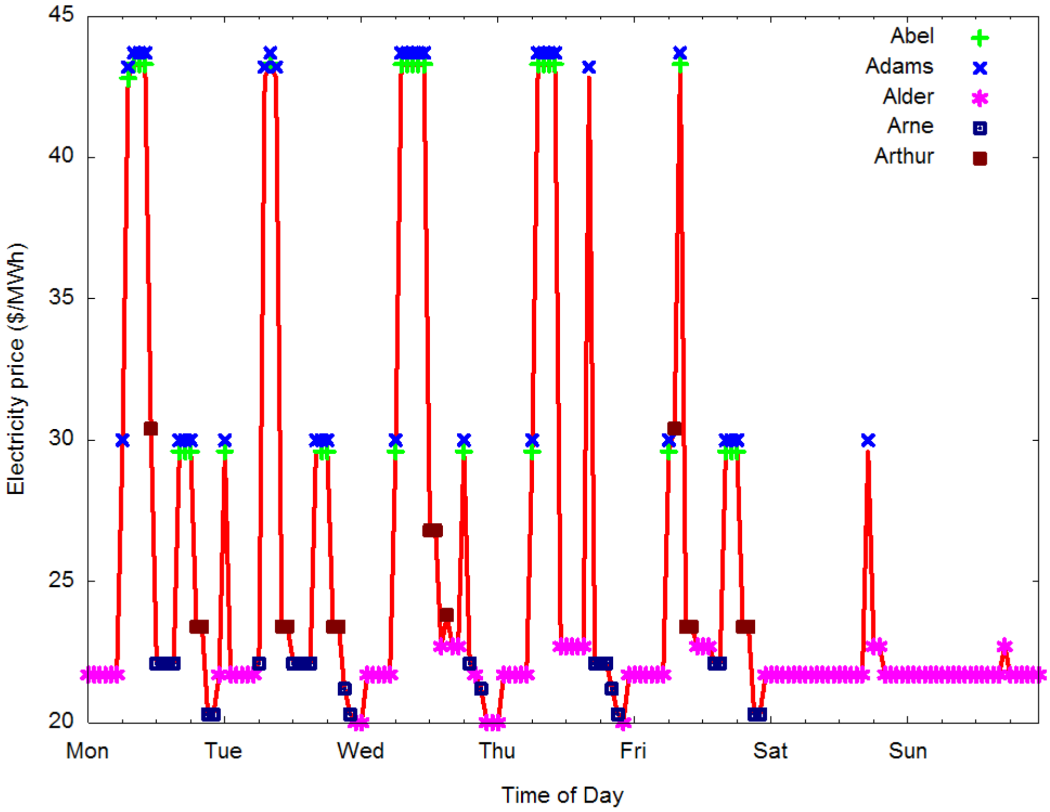


Figure 9.76: Electricity price and location of price-setting units in IEEE RTS ’96

Energy benefit

Energy benefit is the revenue a unit receives from selling its power into the market; *net energy benefit* is the difference between a unit’s energy benefit and its generation costs. The net energy benefit realised by each unit is shown in Figure 9.77.

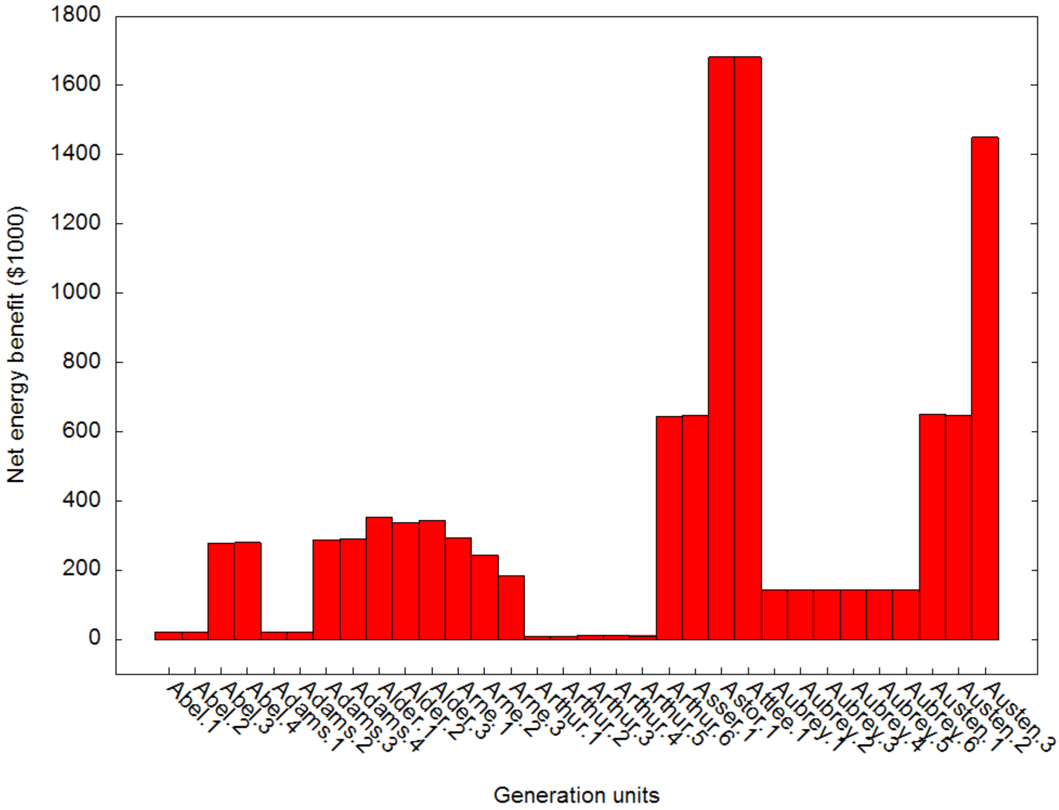


Figure 9.77: Net energy benefit of units in IEEE RTS ’96 for one week of operation

9.5.4 Case studies

The objective of this study is to perform a preliminary assessment of the effects of adding DG on the operation of an existing electricity system. There are a number of ways in which capacity can be added to an electricity system. In doing so, one needs to address three questions:

- Where to add capacity?
- How much capacity to add?
- What kind of capacity to add?
- Case studies used in this assessment were devised to address these questions.

With respect to ‘Where to add capacity?’ the two extreme cases are used. One, when DG is installed at a single bus in the system and, two, when DG is installed at all the demand buses

As far as ‘How much capacity to add?’ enough DG needs to be added to stimulate a response from the system but not so much that the effect is exaggerated. As this is a preliminary assessment, there is no feel for the ideal quantity. Therefore, a range of values is examined. In cases where DG is installed at a single bus, the range of capacities extends from zero up to something less than the minimum demand of the bus. For cases where DG is installed across all demand buses simultaneously, the capacity additions range from 0% to 20% of the peak demand at each location

Given the preliminary nature of this study the third question, 'What kind of capacity to add?' was not examined.

The three case studies examined in this report are summarised in Table 9.33.

Table 9.33: Summary of DG case studies

Case	Description
1	0-100 MW_e of DG capacity installed at Alder
2	0-100 MW_e of DG capacity installed at Arne
3	DG capacity, 0-20% of peak demand, available 24-hours a day, installed at all demand buses in the system

DG units are handled quite simply compared to other units in system. To be more specific:

- The reactive power contribution of DG units is ignored
- The marginal cost of generation of DG units is set at zero.

Given these simplifications, the power generated from DG units can be treated as *negative demand* which makes extending the economic dispatch model to accommodate DG relatively simple. Equation 9.9 defines P_{kt}, the net real power available at bus *k* in time period *t* in terms of the real power generated at that bus, P_{kt}^{S} and the real power consumed, P_{kt}^{D} . Extending the dispatch model is accomplished by adding the real power generated by DG units, P_{kt}^{DG}, to the demand-side of that constraint. The modified constraint is shown in Equation 9.13.

$$P_{kt} = \sum_{n \in NG_k} \left(P_{nkt}^{S}\right) - \left(P_{kt}^{D} - P_{kt}^{DG}\right) \qquad 9.13$$

For each scenario, the operation of the electricity system with DG is simulated for a week and the results are compared to those prior to DG being installed.

Case 1: 0–100 MW_e of DG capacity installed at Alder

Alder has three 100 MW_e #6 fuel-oil conventional steam units and a yearly peak demand of 137.5 MW_e. It is connected to the remainder of the grid via a 20 km, 138 kV transmission line with a continuous rating of 175 MVA.

In the period of interest, demand at Alder ranges from 57 MW_e to 119 MW_e. For this case study, six scenarios were considered differing from one to the next by the amount of DG capacity that is installed. The scenarios are enumerated in Table 9.34. In each scenario, all DG units are assumed to generate at full capacity when available.

Table 9.34: Scenarios involving DG installed at Alder

Scenario	Description
1a	10 MW_e DG capacity installed at Alder
1b	20 MW_e DG capacity installed at Alder
1c	40 MW_e DG capacity installed at Alder
1d	50 MW_e DG capacity installed at Alder
1e	80 MW_e DG capacity installed at Alder
1f	100 MW_e DG capacity installed at Alder

During off-peak periods, the units at Alder are off or turned-down and Alder imports power from the grid. Conversely, during peak periods, the units are on or turned-up and Alder exports power to the grid. It is of interest to observe the effect that adding DG has on the self-sufficiency of this bus in terms of power.

Figure 9.78 shows power flows between Alder and Alger for the time period of interest. This case was chosen to observe the effect that adding DG at the end of this line has on the direction of power flow between Alder and Alger.

Alder was selected as a site for DG for several reasons:

The link between Alder and Alger is the only place in the IEEE RTS ’96 where, for the time period considered, electricity transmission exceeds the line’s continuous rating. It is of interest to observe the effect of adding DG capacity at the end of this line has on congestion

For most buses, whereas the magnitude of the net real power injected changes over time, the sign is constant. However, Alder is one of five buses that is, at some times, a net exporter of power and, at other times, a net importer of power. Figure 9.79 shows how its role changes over time for the study period. Figure 9.80 shows a composite supply curve for the IEEE RTS ’96 system with the offers from the three units at Alder highlighted. These units are relatively high in the merit order and, thus, one would expect them to, at times, be price-setting. This is indeed the case, Figure 9.81 shows the market price over the week of interest with the time periods highlighted at which units at Alder set the price

Reducing the demand for power at Alder by adding DG may allow other, less-expensive units in the system to displace the more expensive local production. And, this may affect the overall price of electricity.

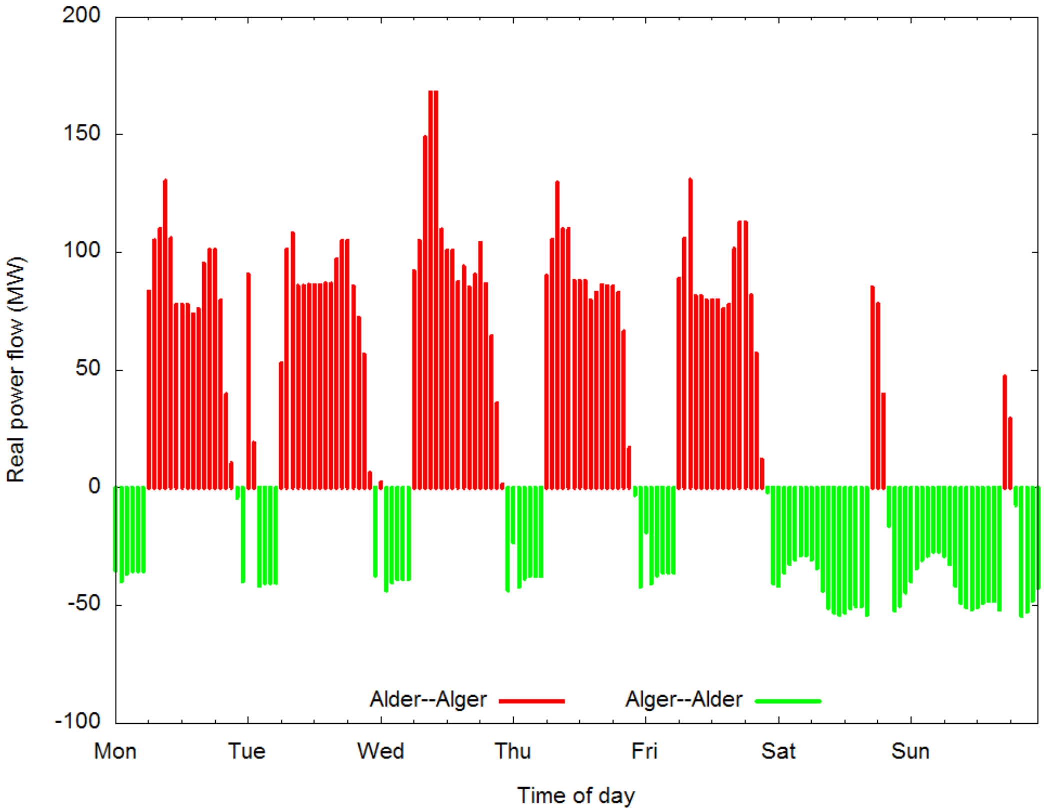


Figure 9.78: Power flow between Alder and Alger

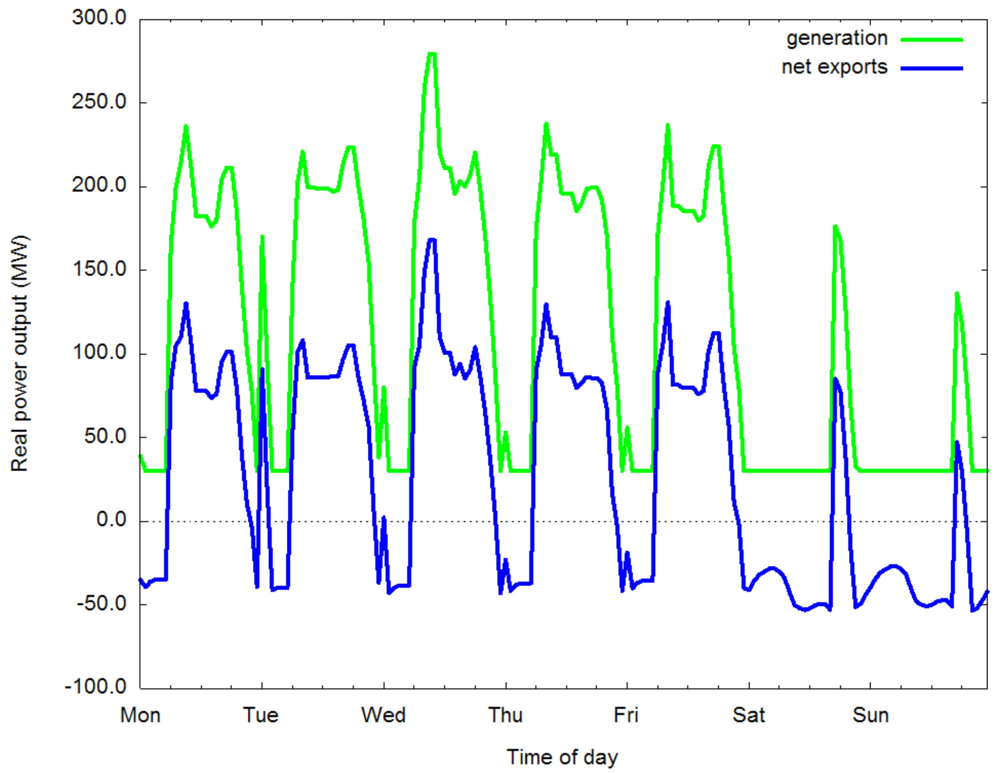


Figure 9.79: Real power generation and injection into the grid at Alder

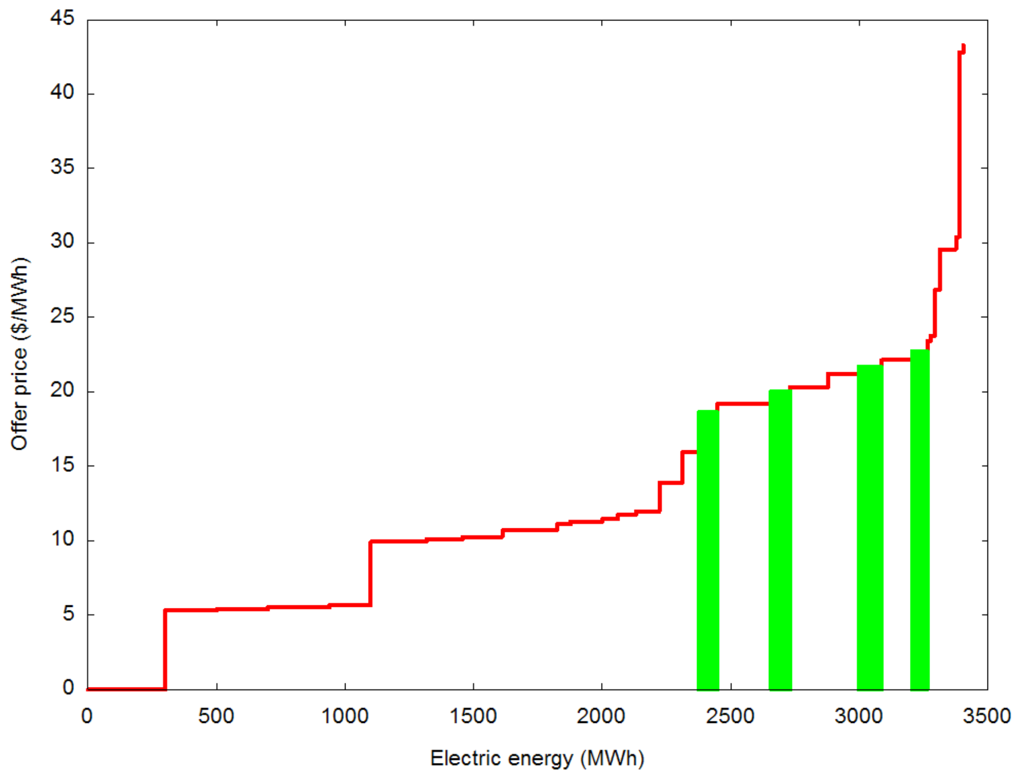


Figure 9.80: Positions of units at Alder (green bars) in merit order

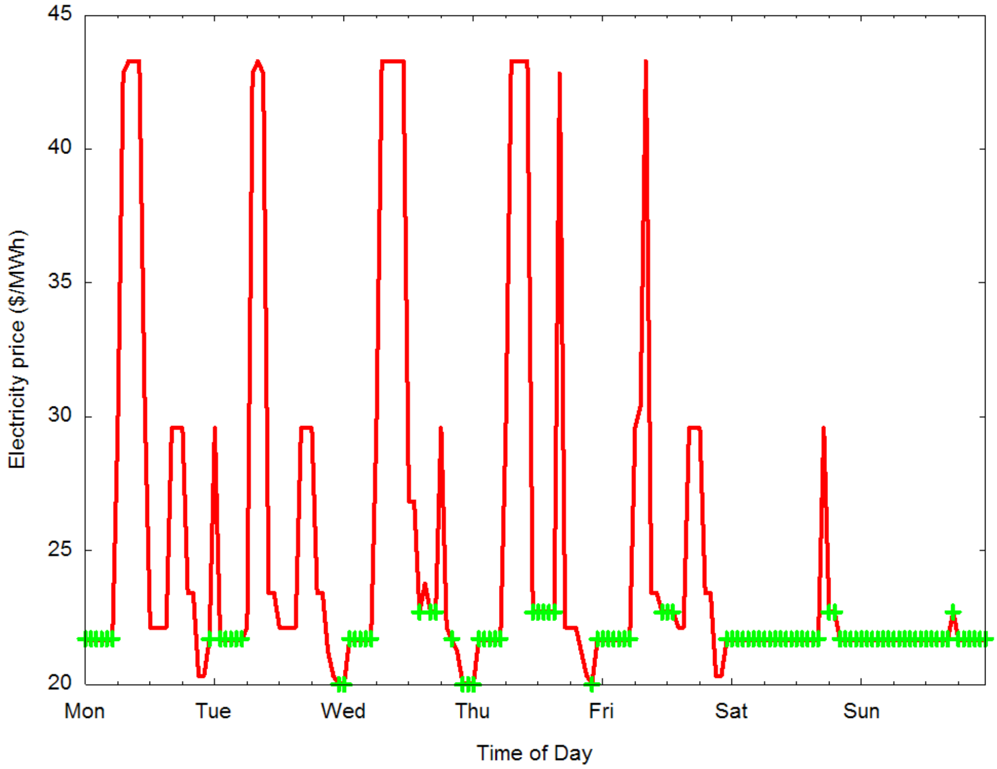


Figure 9.81: Time periods (green markers) where units at Alder are price setting

Case 2: 0–100 MW_e of DG capacity installed at Arne

Arne has three 197 MW_e #6 fuel-oil conventional steam units and a yearly peak demand of 291.5 MW_e. It is directly connected to three buses: Anna, Archer, and Austen. Figure 9.82 provides a cut-out of the IEEE RTS '96 showing the connectivity and power flow between Arne and its neighbours; a summary of the characteristics of the transmission lines shown in the figure is given in Table 9.35.

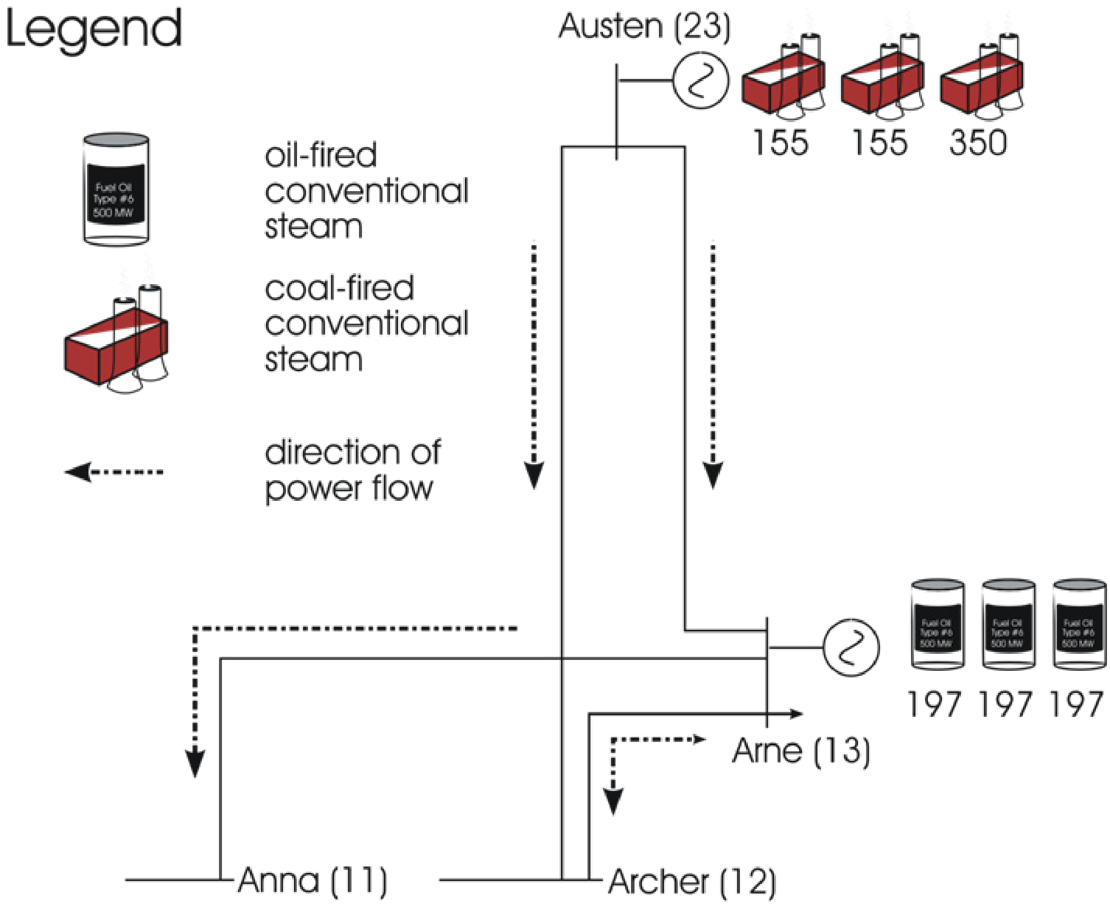


Figure 9.82: Anna-Archer-Arne-Austen sub-network within IEEE RTS '96

Table 9.35: Transmission lines connecting Arne to the grid

Line	Voltage (kV)	Length (km)	Continuous rating (MA)
Anna-Arne	230	53	500
Archer-Arne	230	53	500
Archer-Austen	230	67	500
Arne-Austen	230	96	500

For the week of interest, demand at Arne ranges from 121 MW_e to 251 MW_e. For this case study, five scenarios are considered differing from one another with respect to how much DG capacity is installed. The scenarios are enumerated in

Table 9.36. In each scenario, all DG units are assumed to generate at full capacity when available.

Arne was selected as a site to install DG for a number of reasons:

- For most buses, whereas the magnitude of the net real power injected changes over time, the sign is constant. However, Arne is one of five buses that is sometimes a net exporter of power and, at other times, a net importer of power. Figure 9.83 shows how its role changes with time. During off-peak periods, the units at Arne are off or turned-down and Arne imports power from the grid. Conversely, during peak periods, the units are turned-up and Arne exports power to the grid. It is of interest to observe the effect that adding DG has on the self-sufficiency of this bus in terms of power
- As observed for Alder and Alger, the direction of power between Arne and Archer reverses direction for a few hours each weekday morning. This corresponds to the times during the week when the units at Arne are shutdown. It is of interest to observe the effect that adding DG at the end of this line has on the frequency of the power flow reversals between Arne and Archer

Figure 9.84 shows a composite supply curve for IEEE RTS '96 system with the offers from the three units at Arne highlighted. These units are relatively high in the merit order and, thus, are expected at times to be price-setting. Figure 9.85 highlights that this occurs

Reducing the demand for power at Arne by adding DG may allow other, less-expensive units in the system to displace the more expensive local production. And, this may affect the overall price of electricity.

Table 9.36: Scenarios involving DG installed at Arne

Scenario	**Description**
2a	20 MWe of DG capacity installed at Arne
2b	30 MWe of DG capacity installed at Arne
2c	40 MWe of DG capacity installed at Arne
2d	50 MWe of DG capacity installed at Arne
2e	70 MWe of DG capacity installed at Arne

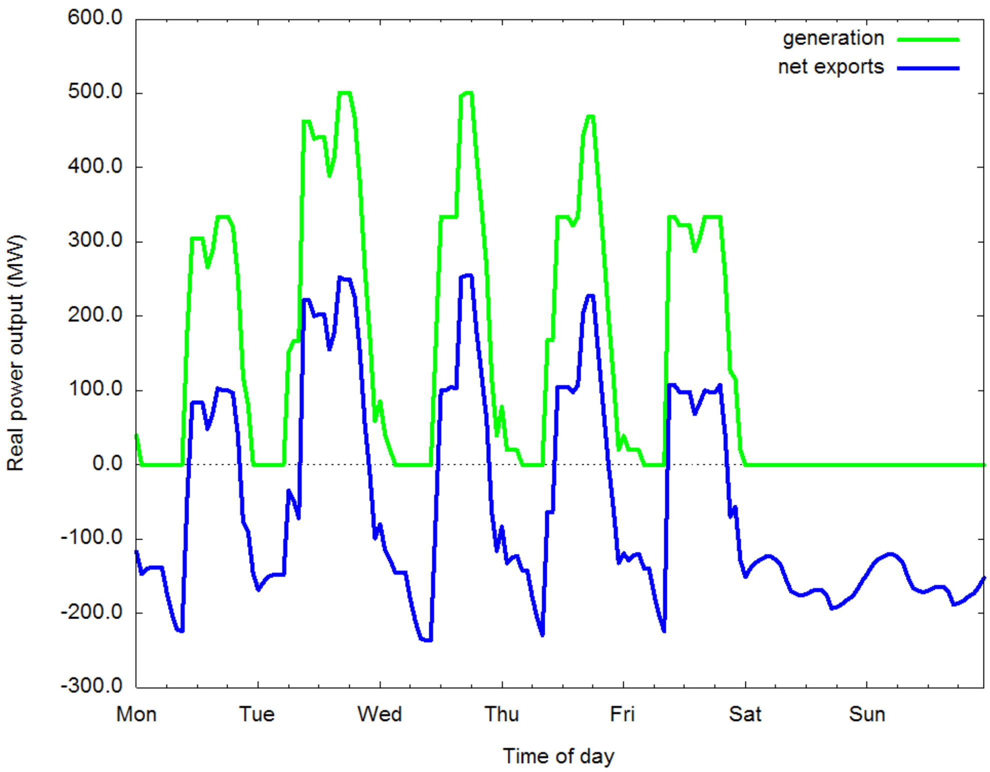


Figure 9.83: Real power generation and injection into the grid at Arne

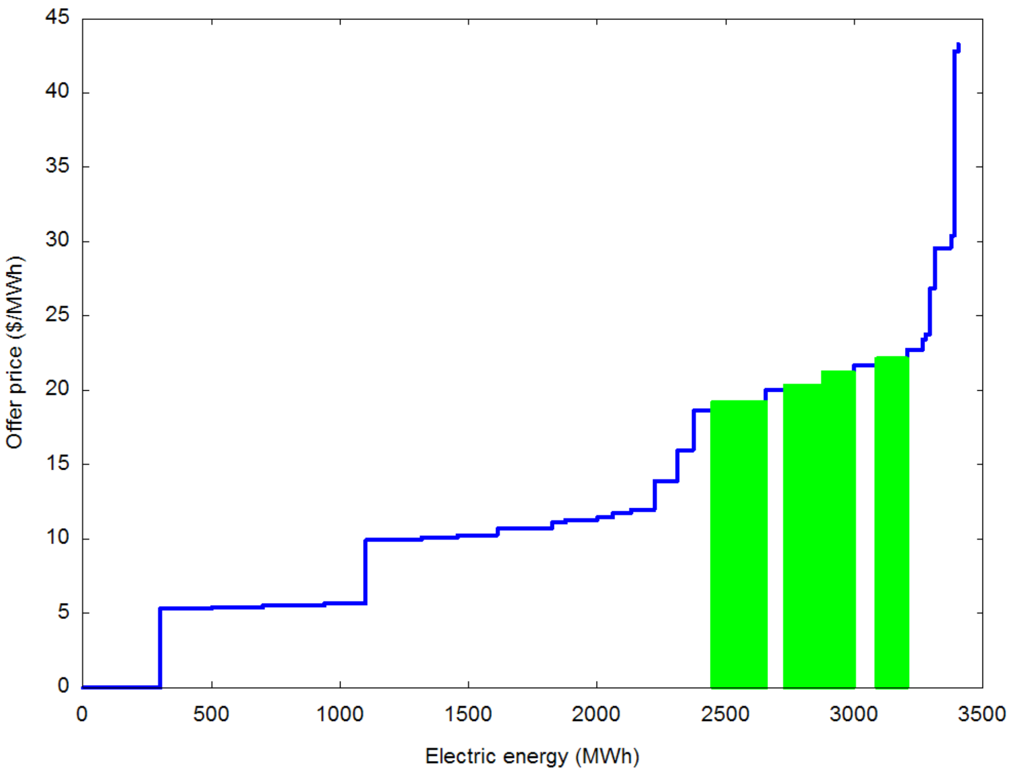


Figure 9.84: Position of units at Arne (green bars) in merit order

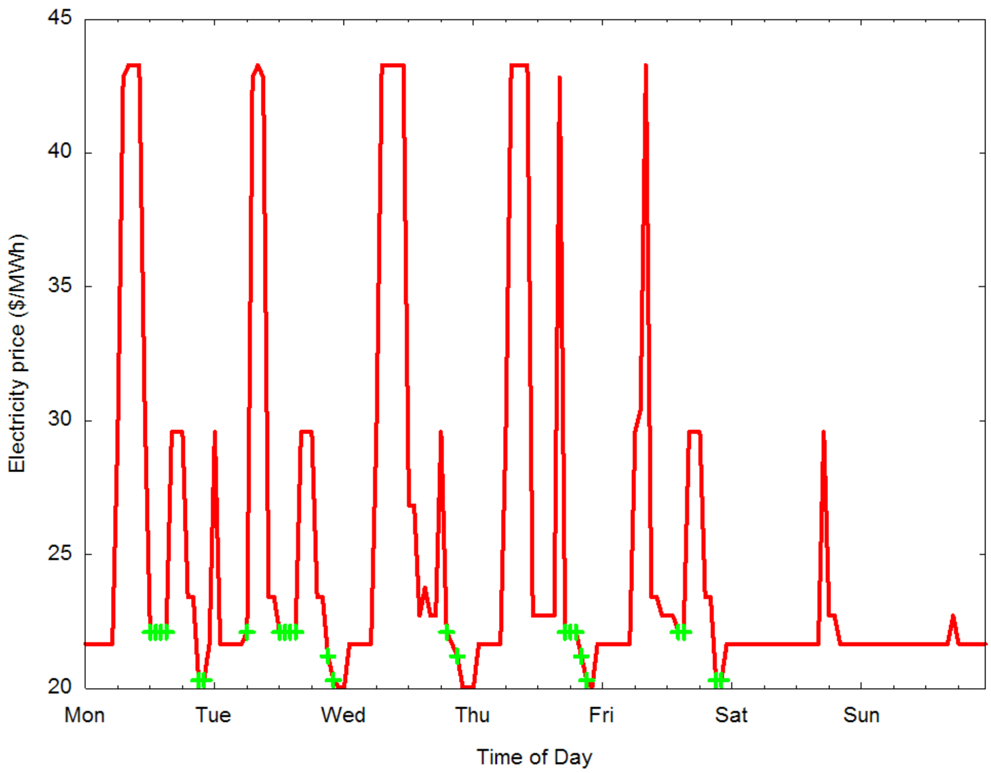


Figure 9.85: Time periods (green markers) where units at Arne are price-setting

Case 3: DG capacity, 0%–20% of peak demand, available 24-hours a day, installed at all demand buses in the system

In the period of interest, aggregate demand in the IEEE RTS '96 ranges from 1,298 MW_e to 2,702 MW_e. For this case study, four scenarios are considered differing from one another in terms of how much DG capacity is installed. The scenarios are listed in Table 9.37. In each scenario, all DG units are assumed to generate at full capacity when available.

Table 9.37: Scenarios involving DG installed across the IEEE RTS '96

Scenario	Description
3a	DG capacity, 5% of peak demand (158 MW_e), available 24-hours a day, installed across all demand buses in the system
3b	DG capacity, 10% of peak demand (314 MW_e), available 24-hours a day, installed across all demand buses in the system
3c	DG capacity, 15% of peak demand (470 MW_e), available 24-hours a day, installed across all demand buses in the system
3d	DG capacity, 20% of peak demand (627 MW_e), available 24-hours a day, installed across all demand buses in the system

9.5.5 Results and discussion

Each scenario presented in Section 9.5.4 is simulated for one week under the same set of conditions (e.g., demand, offers to sell power, etc.). In this section, for each case study, results are presented in the following areas:

- Capacity utilisation
- Power flows
- Congestion
- Transmission losses
- Electricity price
- Energy benefit.

Capacity utilisation

DG at Alder
Figure 9.86 shows the real power generation at Alder for varying amounts of DG installed at this site. Installing DG at Alder was found to reduce the generation of the pre-existing units at this bus. Further it was found that the incremental reduction in output was often greater than the incremental addition of DG. This is particularly so for short-term peaks in generation; on three occasions a peak of the order of 100 MW was substantially avoided by the introduction of only 10 MW of DG. Conversely, there are some time periods in which the generation from Alder is unaffected by the installation of DG. This occurs in periods of low demand primarily overnight and on weekends.

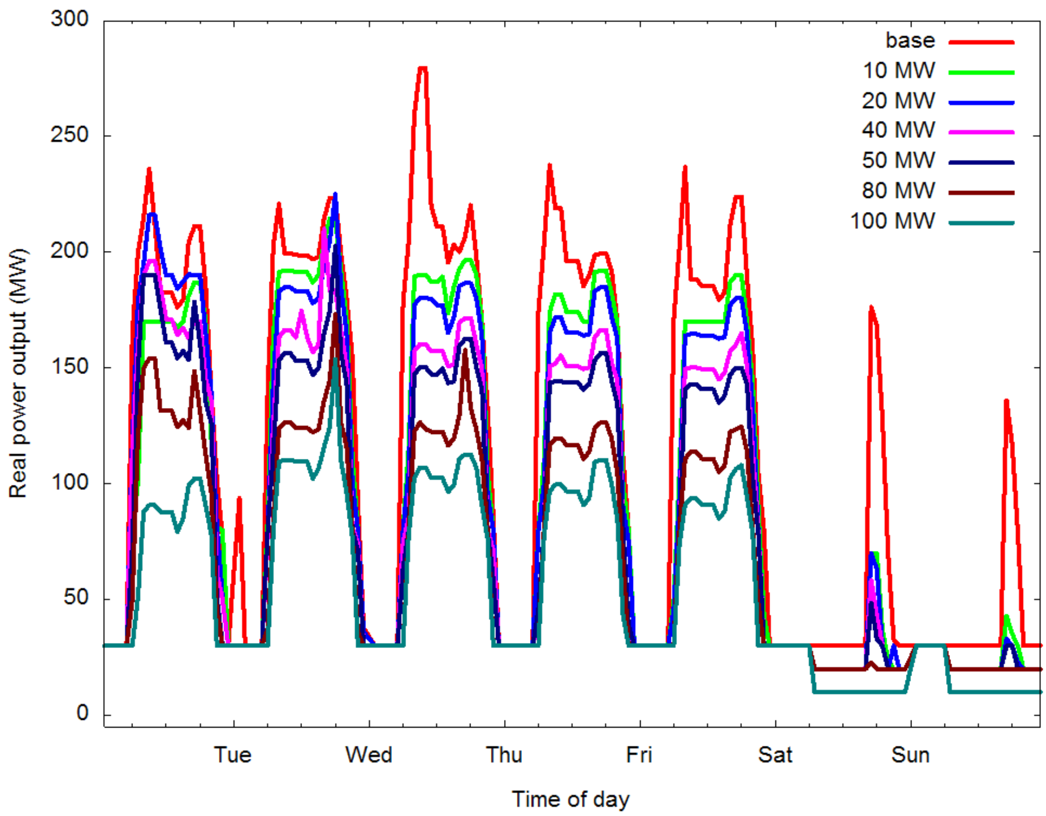


Figure 9.86: Real power generation at Alder for varying amounts of DG installed at Alder

Capacity factor is a measure of the capacity utilisation of one or more generation units; it is defined as the ratio between the actual amount of electrical energy generated and the amount that would have been generated if the unit(s) had operated at the maximum continuous rating over the entire period.

Figure 9.87 shows effects of adding DG at Alder on the capacity factor observed at buses throughout the system. Of all the units in the system, the impact of adding DG at Alder is felt most directly by units on the same bus. However, significant effects are also observed at other buses in the system as noted below:

- Units at Arthur and Asser see a small decrease in their utilisation as the amount of DG installed at Alder increases
- Utilisation of units at Arne is greater after DG is installed at Alder. The increase was greatest for 10 MW of installed DG and dropped with each incremental increase in DG installed at Alder
- The generation at the large supply buses — Astor, Attlee, Aubrey, and Austen — is unaffected.

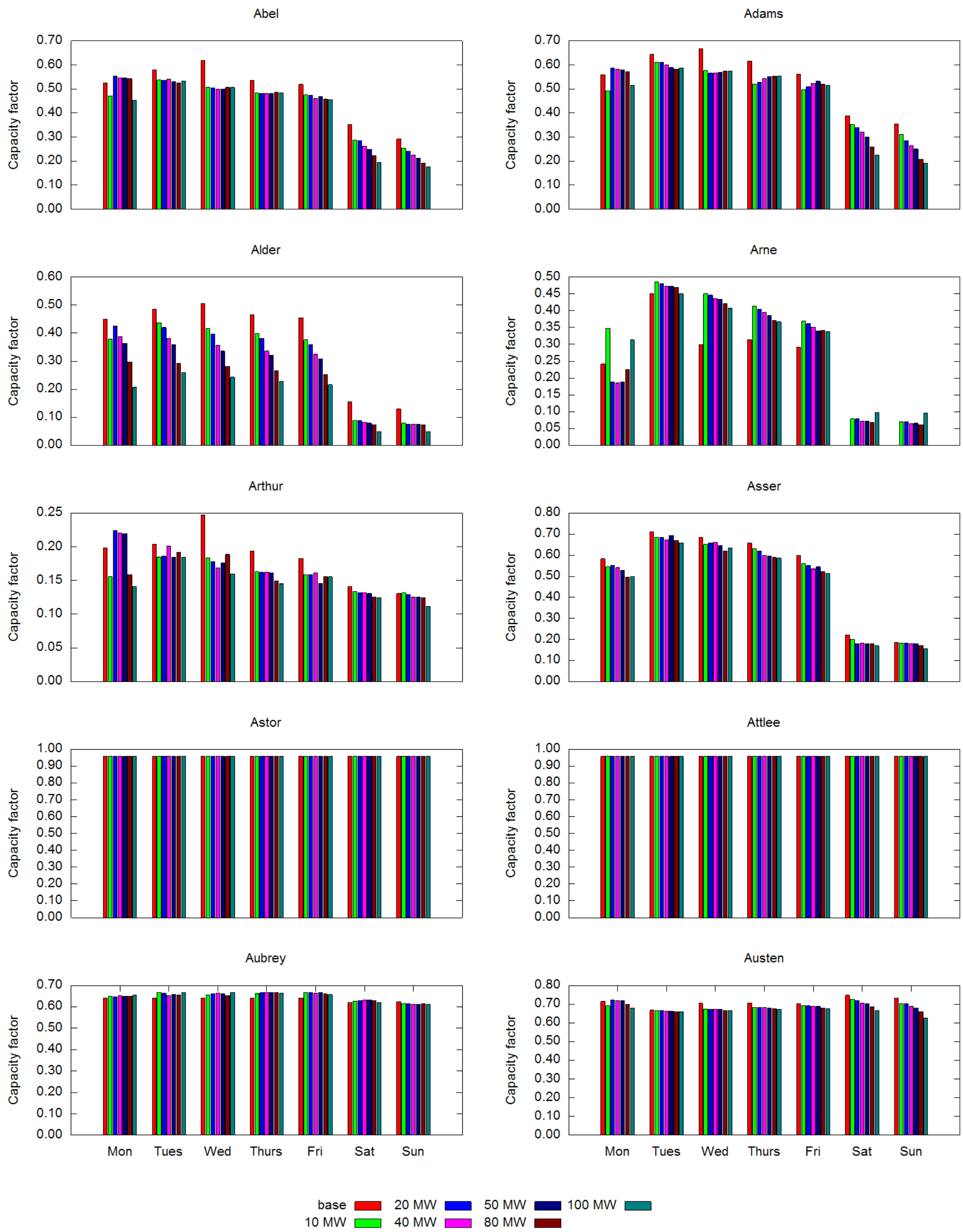


Figure 9.87: Capacity factor at buses for varying amounts of DG installed at Alder

Figure 9.88 shows the net power availability at Alder for varying amounts of DG installed at Alder. As expected as the amount of installed DG increases, the extent to which Alder imports power from the grid diminishes. At 40 MW_e of installed DG at Alder, power is not imported at all during the week; during these periods, the units at Alder are operating at or close to minimum load. With 80 and 100 MW_e of DG installed, Alder's demand is always met from local generation.

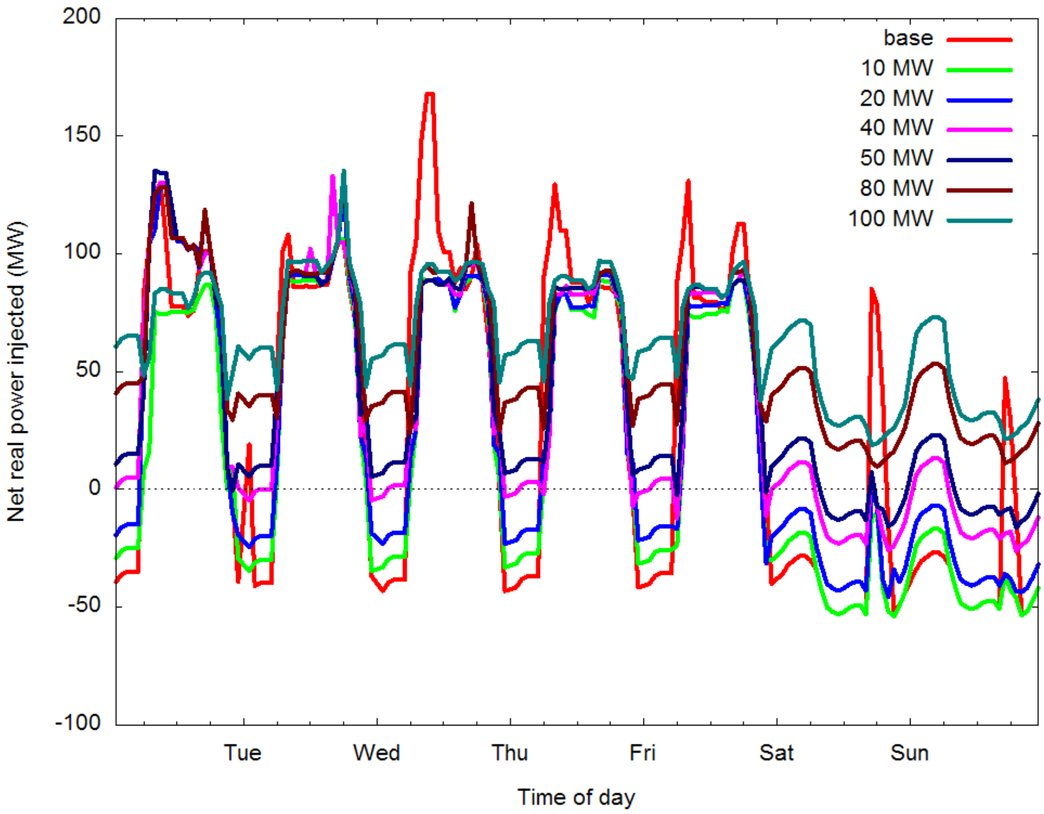


Figure 9.88: Net power generation at Alder for varying amounts of DG installed at Alder

DG at Arne

Pre-existing units at Arne also benefit when DG is installed locally. Figure 9.89 shows the real power generation at Arne for varying amounts of DG installed at this location. Adding DG narrows the gap between Arne's minimum and maximum power generation; output is down slightly during peak periods and up significantly in off-peak periods and on weekends. Overall, the capacity utilisation is increased.

Figure 9.90 shows the effects of adding DG at Arne on the capacity utilisation at supply buses in the system. Significant effects are felt throughout as noted below:

Adding DG at Arne increased the utilisation of existing units at this bus. Decreases in utilisation at the beginning of the week were more than offset by increases in the middle. And, whereas prior to the installation of DG, the units at Arne are shutdown on the weekends, with DG capacity available, units at Arne are now producing small quantities of electricity on Saturday and Sunday

Increases in generation at Arne must be accompanied by reductions elsewhere in the system. In this case, the level of generation is zero at the smaller generation centres: Abel, Adams, Alder, Arthur, and Asser. It is interesting to note an apparent lack of equity between this case and the previous. Adding DG capacity at Alder benefited the units at Arne but adding DG capacity at Arne does not provide an increase to the units at Alder

The generation at the large supply buses — Astor, Attlee, Aubrey, and Austen — is generally unaffected.

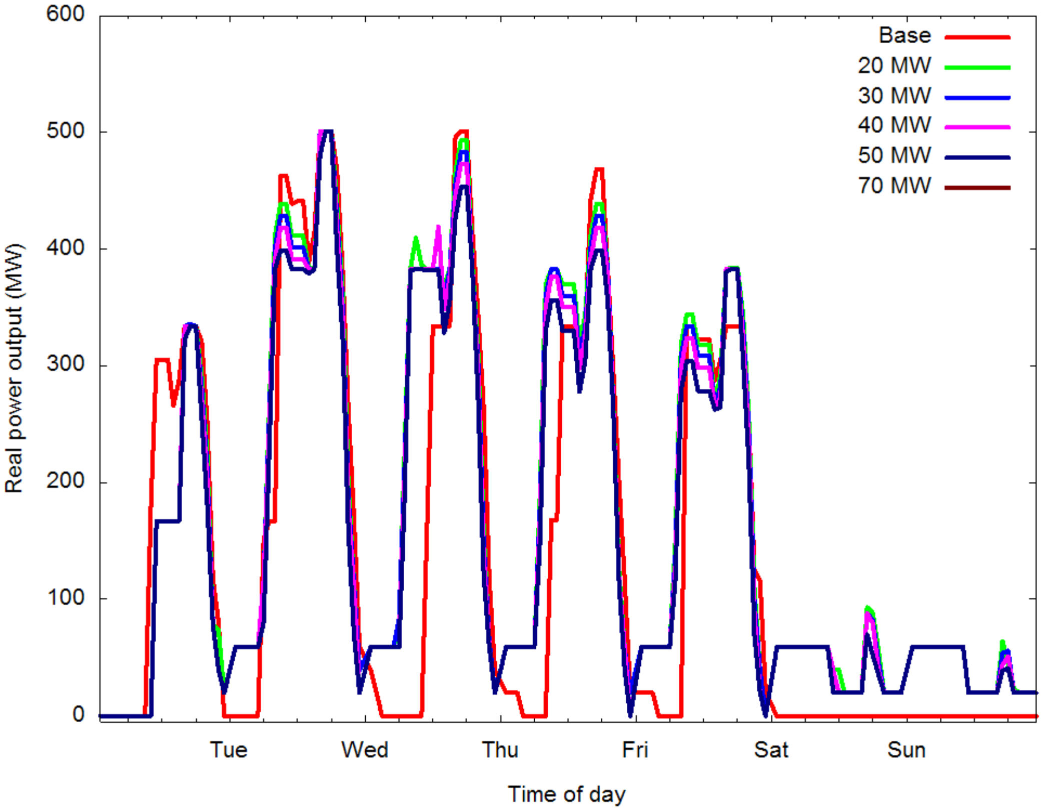


Figure 9.89: Real power generation at Arne for varying amounts of DG installed at Arne

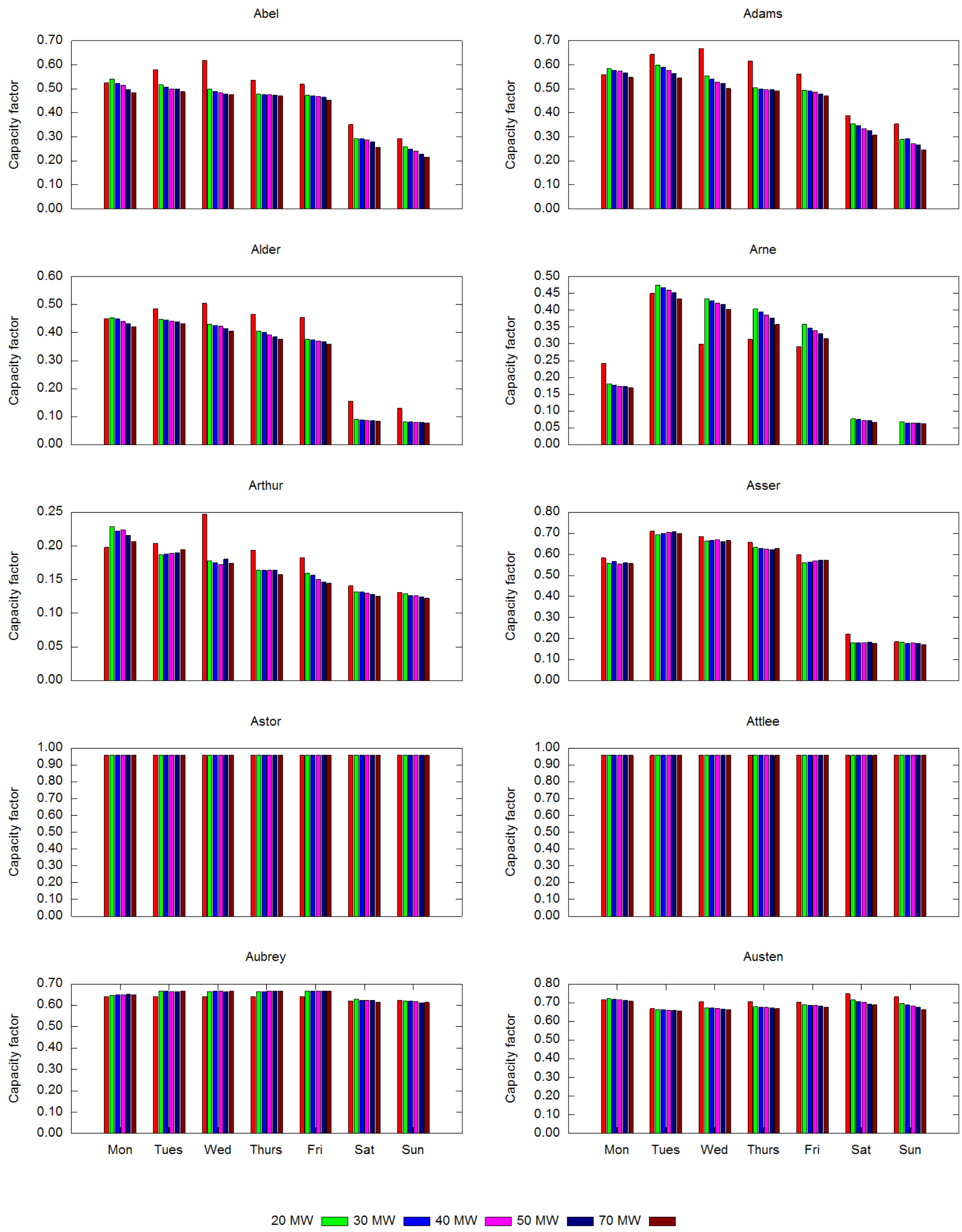


Figure 9.90: Capacity factor at buses for varying amounts of DG installed at Arne

DG across system

Figure 9.91 and Figure 9.92 show the real power generated at Alder and Arne for different amounts of DG installed across the system. Both of these buses see dramatic drops in their real power generation. At the 20% DG penetration level, both these buses only see activity for a handful of hours of the week.

Figure 9.93 summarises the effects of adding DG at all demand buses on the capacity utilisation throughout the system. The effects are more dramatic then what is observed when DG is added at single buses as noted below.

Existing units at Arne, which had seen their capacity utilisation increase in previous cases, produce dramatically less power when DG capacity is spread throughout the system. By the time DG installation reaches 20% of the system peak, units at Arne make a nominal contribution toward over electricity demand. The smaller generation centres — Abel, Adams, Alder, Arthur, and Asser — also see dramatic reductions in their utilisation.

Utilisation of units at Austen is also affected. During week days, it isn't until the DG installed capacity reaches 15% of the system peak demand that Austen generation scales back. The weekend capacity utilisation is more sensitive and declines significantly once any amount of DG appears in the system

The other large generation centres are mostly immune to the installation of DG. However, some effect is observed at the higher levels of DG penetration. Two points worth noting:

- The utilisation of the hydroelectric units at Aubrey is typically energy limited. Therefore, the decline in capacity utilisation on Saturday indicates that available energy is being dumped
- Astor and Attlee units are only marginally affected by the installation of DG, where their output dips below their rated capacity of 400 MW_e for a handful of hours during the course of the week. It is worth noting that both units in question are nuclear plants and, anecdotally, operators of nuclear plants are reticent of changing the output of units under their control, even when such adjustments are technically feasible. Therefore, the observation that high levels of DG penetration would indicate the nuclear units be turned down is notable.

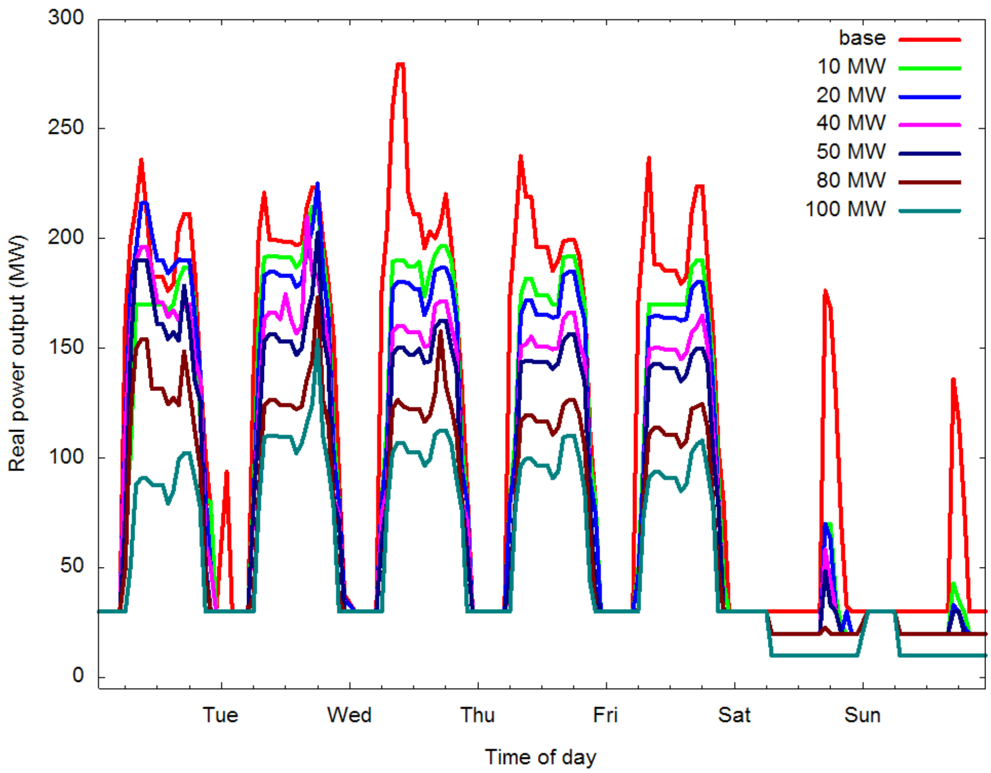


Figure 9.91: Real power generation at Alder for varying levels of DG installed throughout out the system

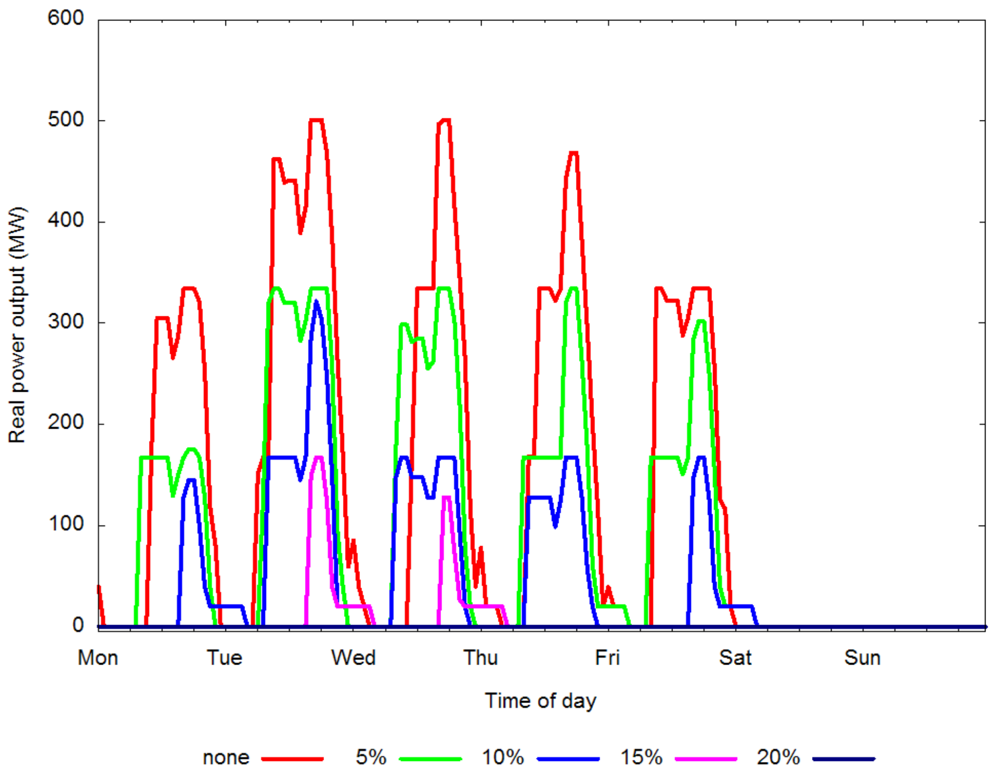


Figure 9.92: Real power generation at Arne for varying levels of DG installed throughout out the system

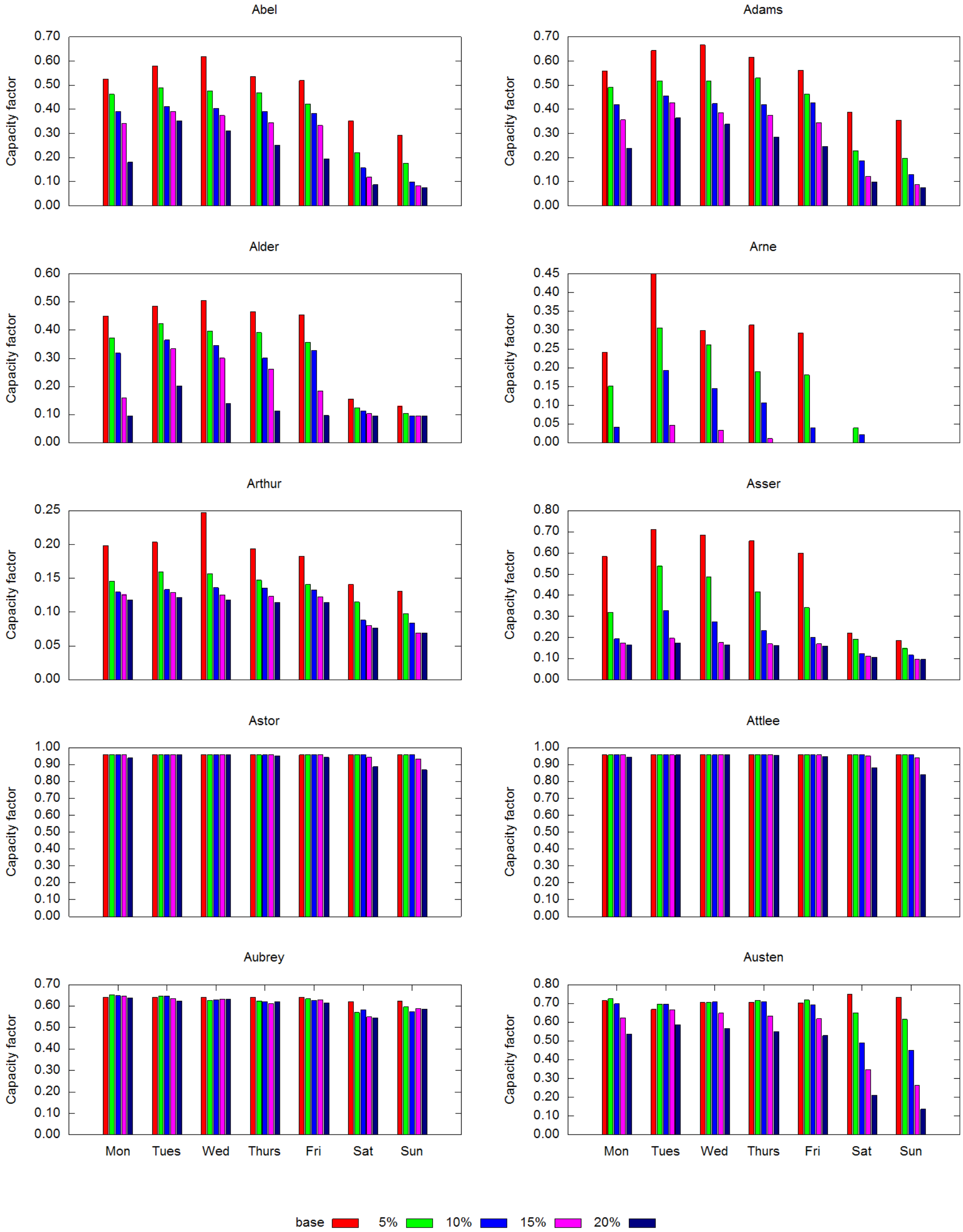


Figure 9.93: Capacity factor at buses for varying amounts of DG installed throughout the system

Power flow

Figure 9.94 shows the power flows from Arne to Archer for cases with DG capacity installed at Arne. Recall that, in the base case, the direction of power flow was from Archer to Arne in a small number of times periods. After having added DG capacity at Arne, though, the power flow is always in the one direction.

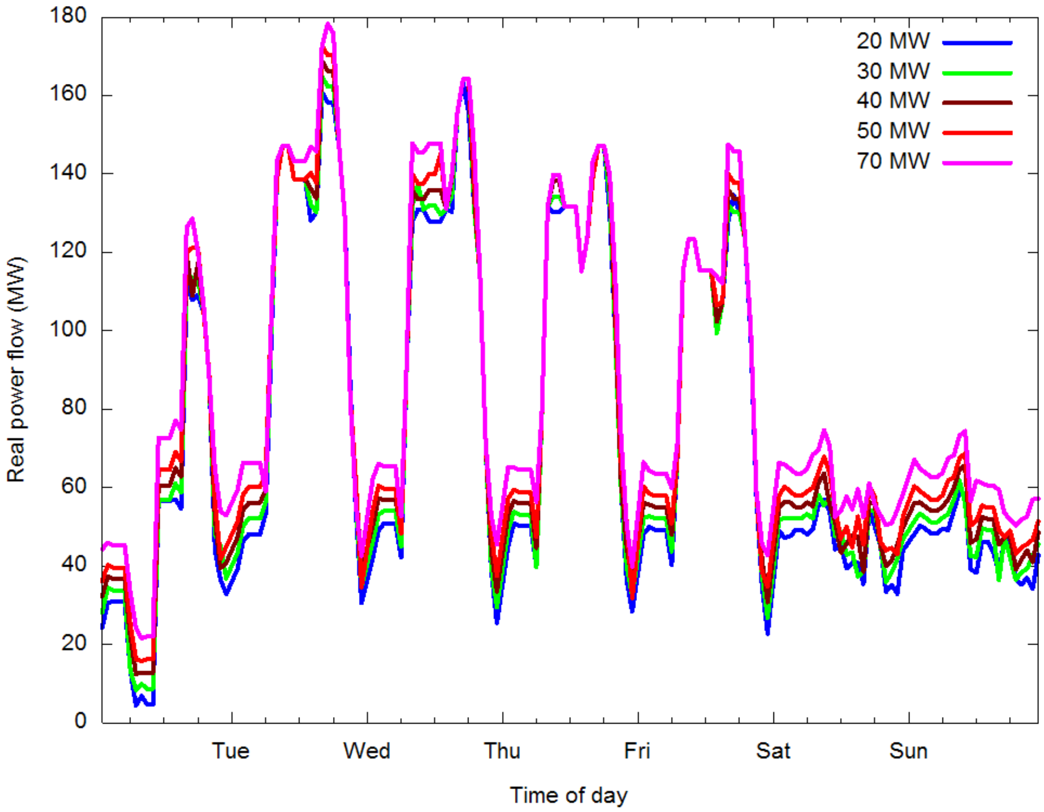


Figure 9.94: Power flow from Arne to Archer for varying amounts of DG at Arne

Congestion

Initially, congestion is observed in the IEEE RTS ’96 for a two-hour period Wednesday morning. At this time the Alder–Alger transmission line exceeds its maximum continuous rating by 2.5 MVA from 09:00 through 11:00. Figure 9.95 shows the unused capacity of the Alder–Alger transmission line for varying amounts of DG installed at Alder. In all cases with DG, this line always has some spare capacity.

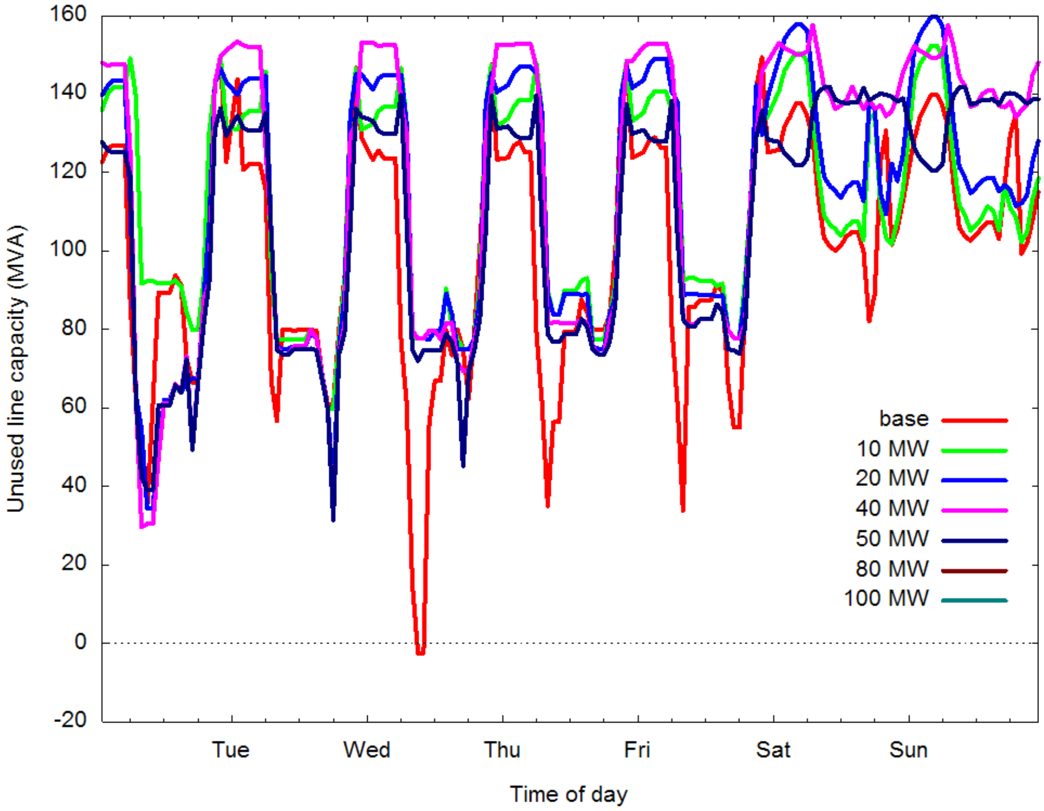


Figure 9.95: Unused capacity in Alder–Alger transmission line for varying amounts of DG installed at Alder

Figure 9.96 shows the unused line capacity of the Alder–Alger transmission line for DG installed at Arne and Figure 9.97 shows DG installed throughout the system. Note that, in these cases as well, congestion between Alder and Alger is also non-existent.

So, whether DG capacity is installed at the end of an affected line or elsewhere in the system, doing so is enough to relieve congestion. In relieving congestion between Alder and Alger, it is interesting to determine whether congestion was created elsewhere in the system. Figure 9.98 contains summaries of the unused line capacities in IEEE RTS ’96 for a representative number of scenarios. There are two subfigures for each case study: one at the low end of the DG installed capacity range and one at the high end. In each subfigure, the height of the bars gives the mean quantity of unused capacity for the week and the lines indicate the range of unused line capacity values observed. This summary figure reveals that adding DG to the IEEE RTS ’96 grid alleviated congestion along the Alder–Alger and accordingly, no new incidences of congestion were created.

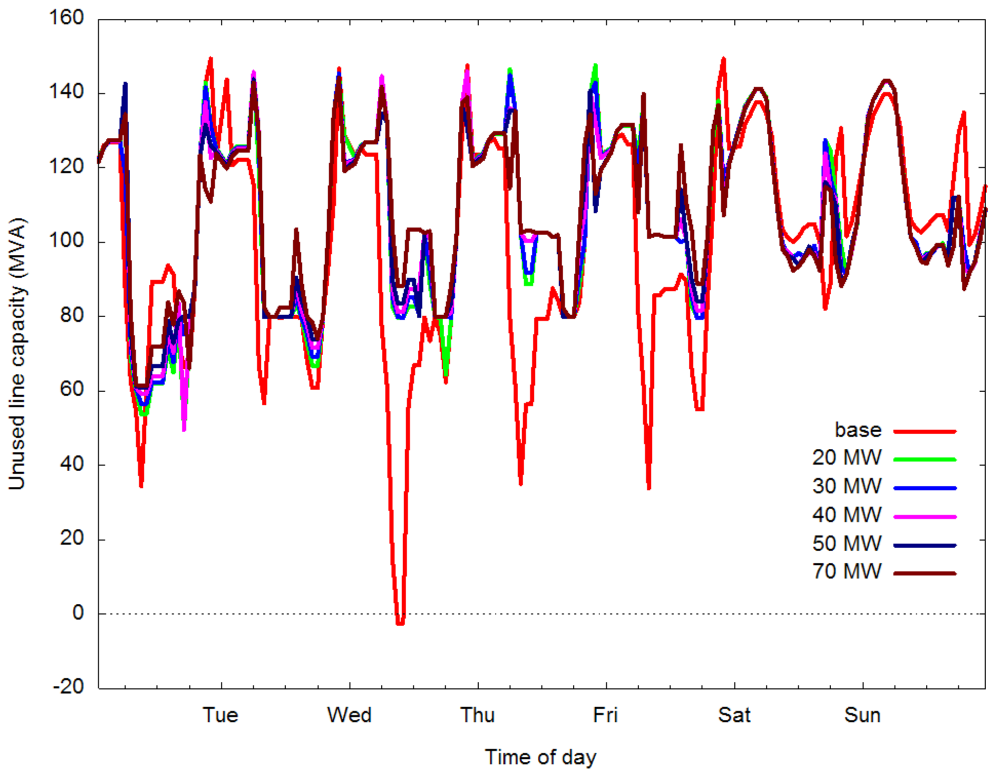


Figure 9.96: Unused capacity in Alder–Alger transmission line for varying amounts of DG installed at Arne

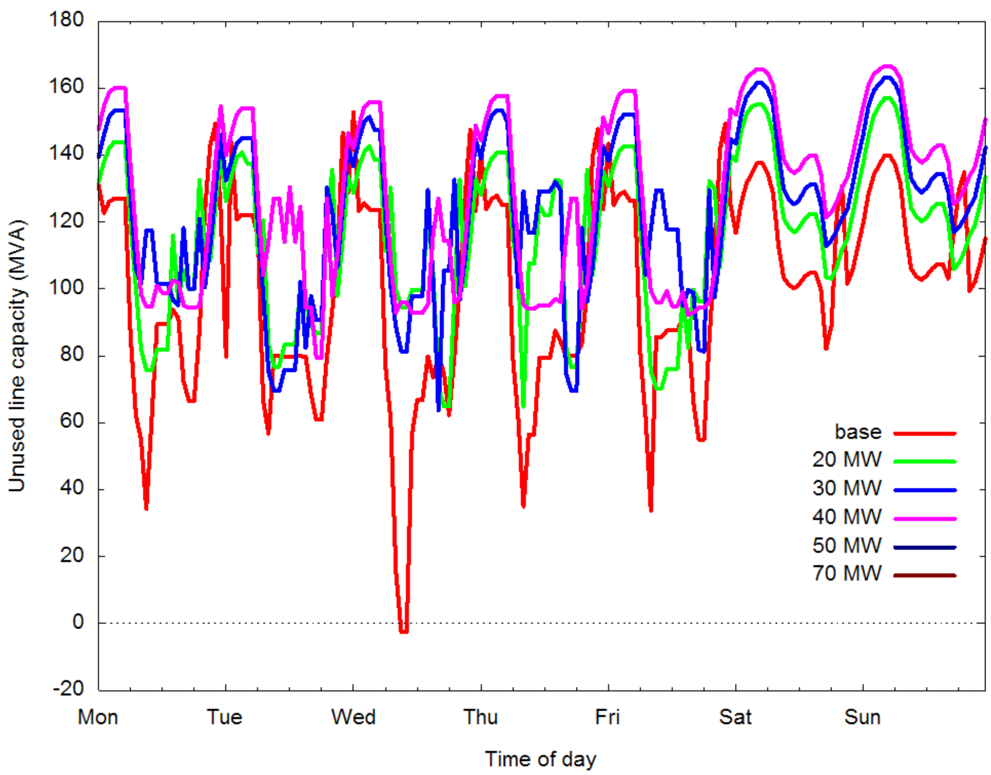
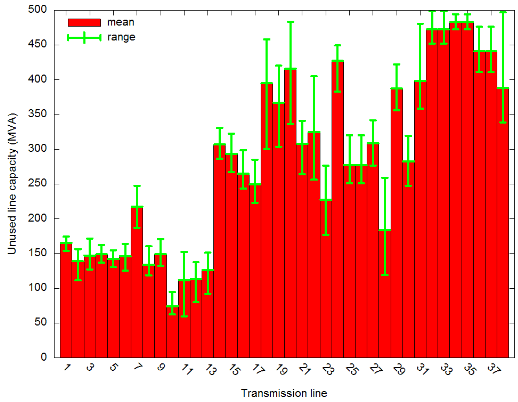
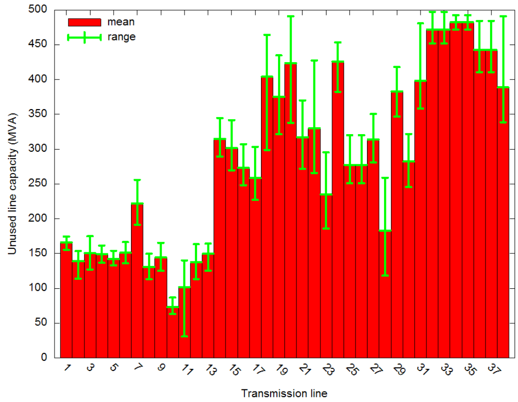


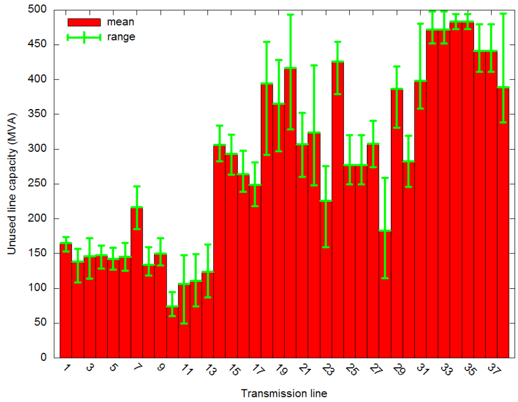
Figure 9.97: Unused capacity in Alder–Alger transmission line for varying DG installed across the system



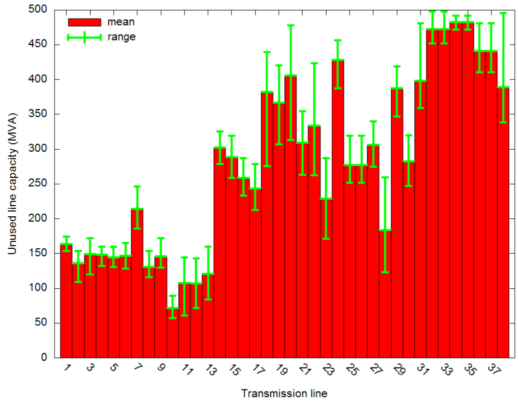
A: Alder 10 MW



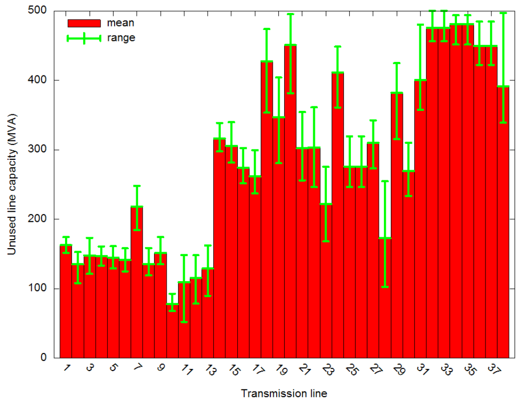
B: Alder 100 MW



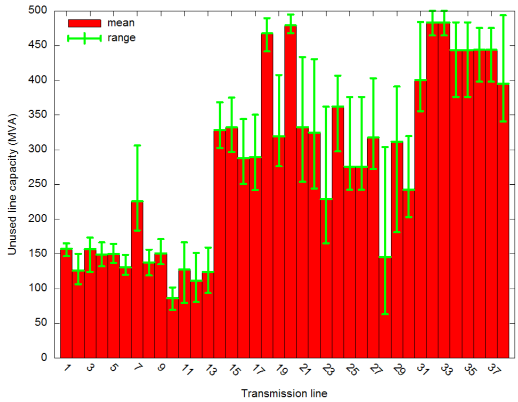
C: Arne 20 MW



D: Arne 70 MW



E: Full 5%



F: Full 20%

1	Abel.Adams	2	Abel.Adler	3	Abel.Aiken	4	Adams.Agricola	5	Adams.Alber
6	Adler.Ali	7	Adler.Avery	8	Agricola.Ali	9	Aiken.Allen	10	Alber.Allen
11	Alder.Alger	12	Alger.Ali	13	Alger.Allen	14	Ali.Anna	15	Ali.Archer
16	Allen.Anna	17	Allen.Archer	18	Anna.Arne	19	Anna.Arnold	20	Archer.Arne
21	Archer.Austen	22	Arne.Austen	23	Arnold.Asser	24	Arthur.Asser	25	Arthur.Attlee #1
26	Arthur.Attlee #2	27	Arthur.Avery	28	Asser.Aston	29	Asser.Attar	30	Aston.Astor
31	Aston.Aubrey	32	Astor.Attlee #1	33	Astor.Attlee #2	34	Attar.Attila #1	35	Attar.Attila #2
36	Attila.Austen #1	37	Attila.Austen #2	38	Attlee.Aubrey				

Figure 9.98: Summary of unused capacities for all transmission lines from selected DG scenarios

Transmission losses

Figure 9.99 shows the absolute change in transmission losses for different amounts of DG installed at Alder. Figure 9.100 provides the results on a relative basis. Adding DG capacity at Alder results in increased transmission losses.

This finding is not particular to DG installed at Alder. Figure 9.101 and Figure 9.102 show the results for varying amounts of DG capacity installed at Arne. Figure 9.103 and Figure 9.104 provide absolute and relative results for all demand buses throughout the system. In every scenario, adding DG increases the transmission losses observed for the week of interest.

This observation appears to be at odds with the common presupposition that co-locating electricity supply with electricity demand will reduce transmission losses from a reduction in power flows. It should be noted that this general assertion is based on the losses experienced by an individual site rather than the system as a whole. If we consider for instance a gas-fired cogeneration unit installed at an industrial site, then if the unit provides the electrical needs of the facility it is reasonable to state that this facility receives its energy with less losses than an equivalent supplied by the grid.

While this analysis shows that DG can affect the system losses through changes to the merit order of generator bids, it is worth noting that a similar effect is observed on the weekends through reduced load. This simply shows that the system is designed to minimise price not transmission loss. Transmission loss is dealt with to an extent through price but it is clearly not the defining objective function as these results attest. This method is in keeping with the manner in which the Australian NEM is operated, where electricity flows are established by taking into account the bids from every generator in conjunction with predetermined yearly average loss factors.

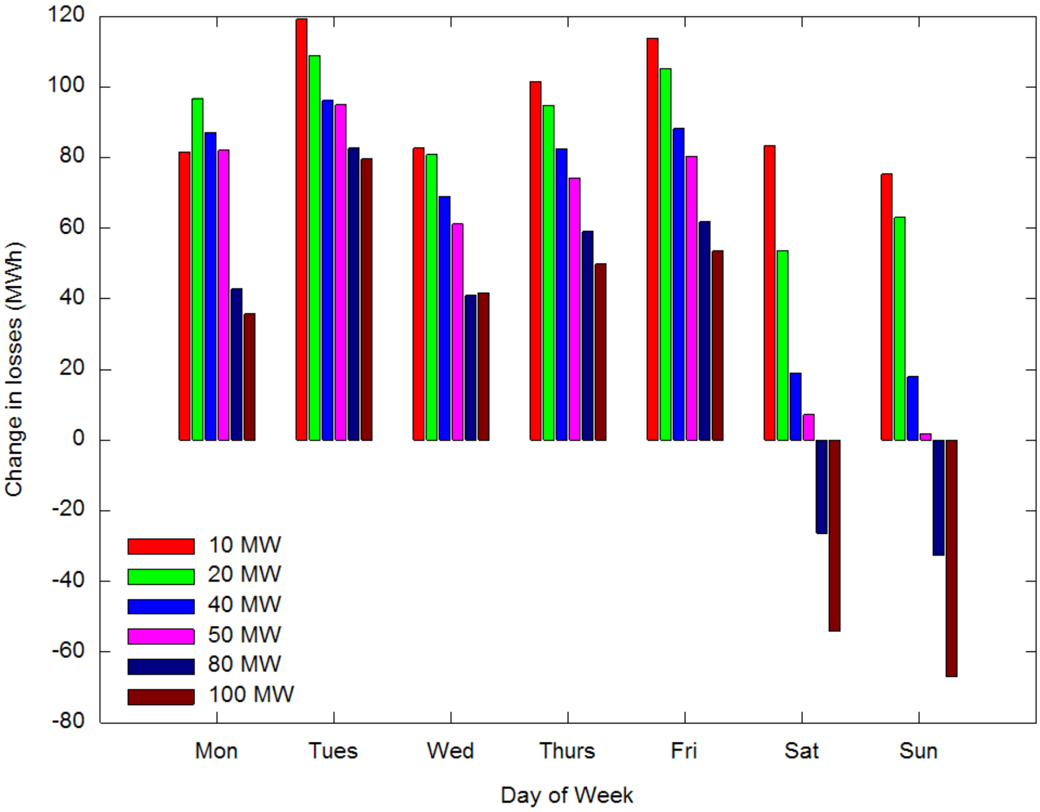


Figure 9.99: Absolute change in transmission losses for varying amounts of DG installed at Alder

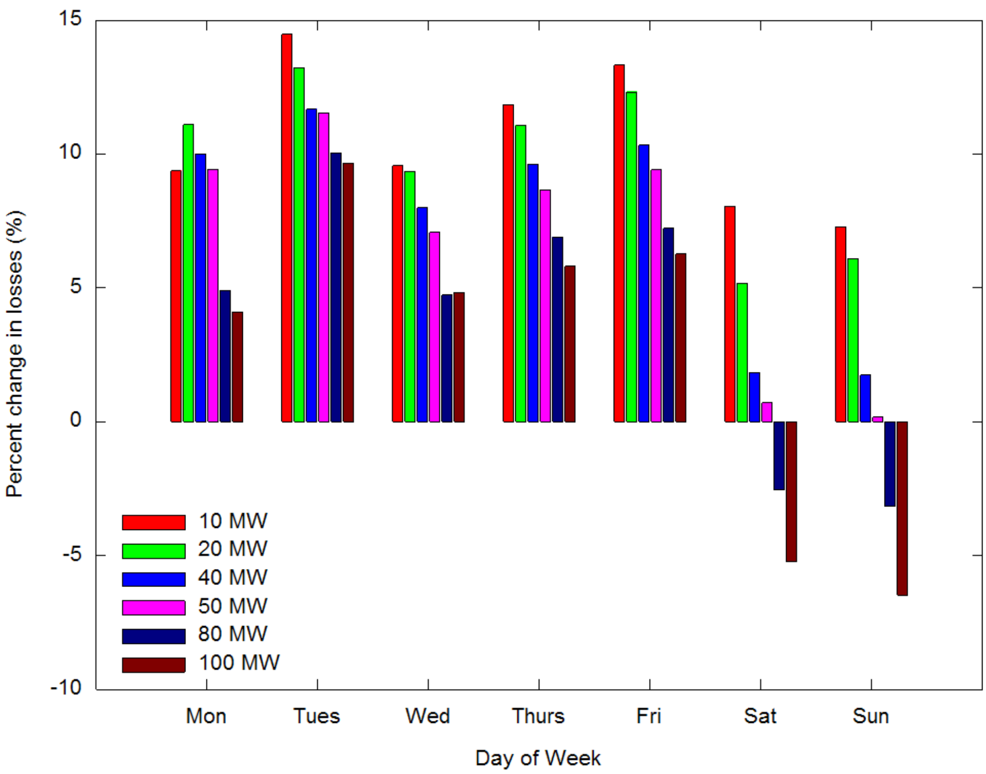


Figure 9.100: Relative change in transmission losses for varying amounts of DG installed at Alder

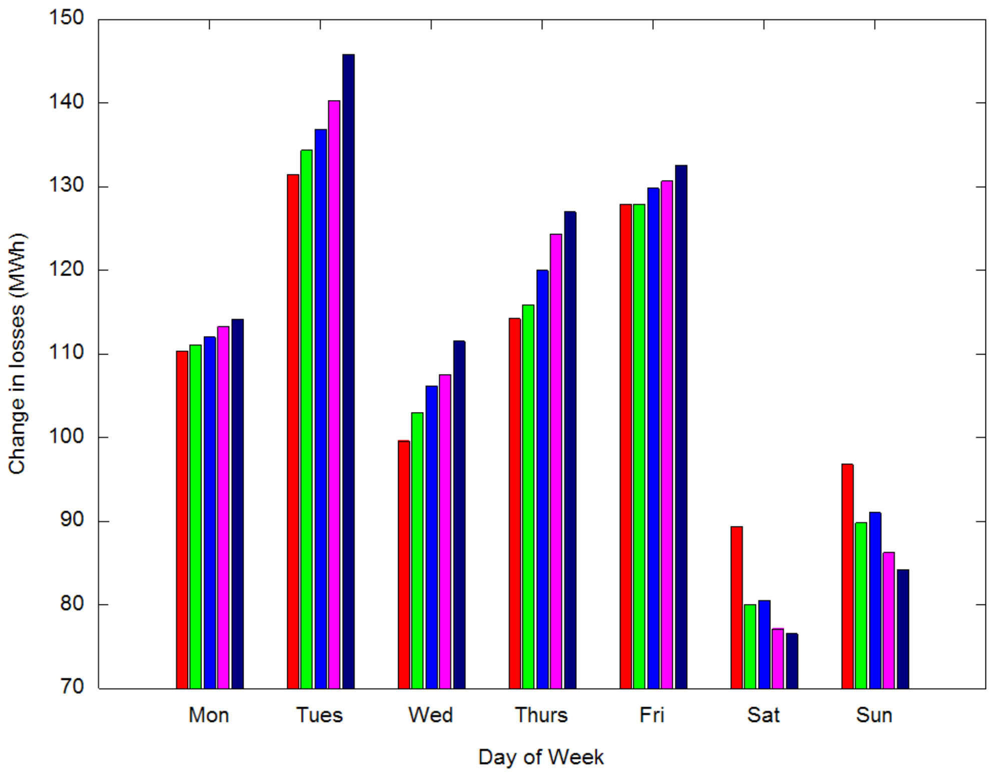


Figure 9.101: Absolute change in transmission losses for varying amounts of DG installed at Arne

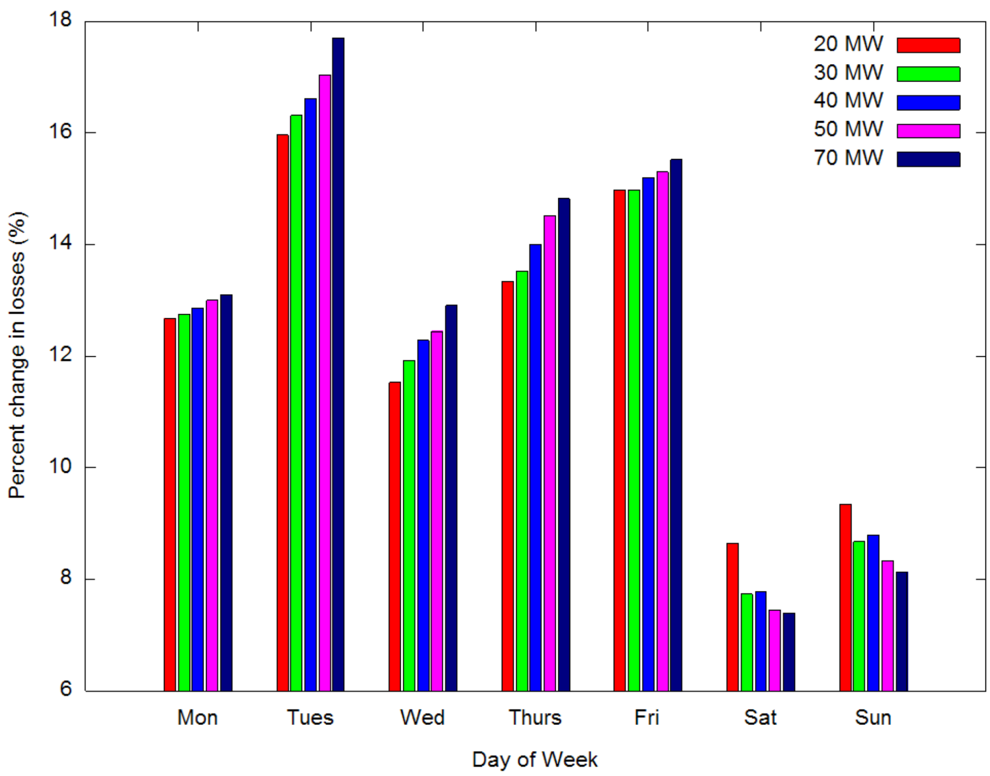


Figure 9.102: Relative change in transmission losses for varying amounts of DG installed at Arne

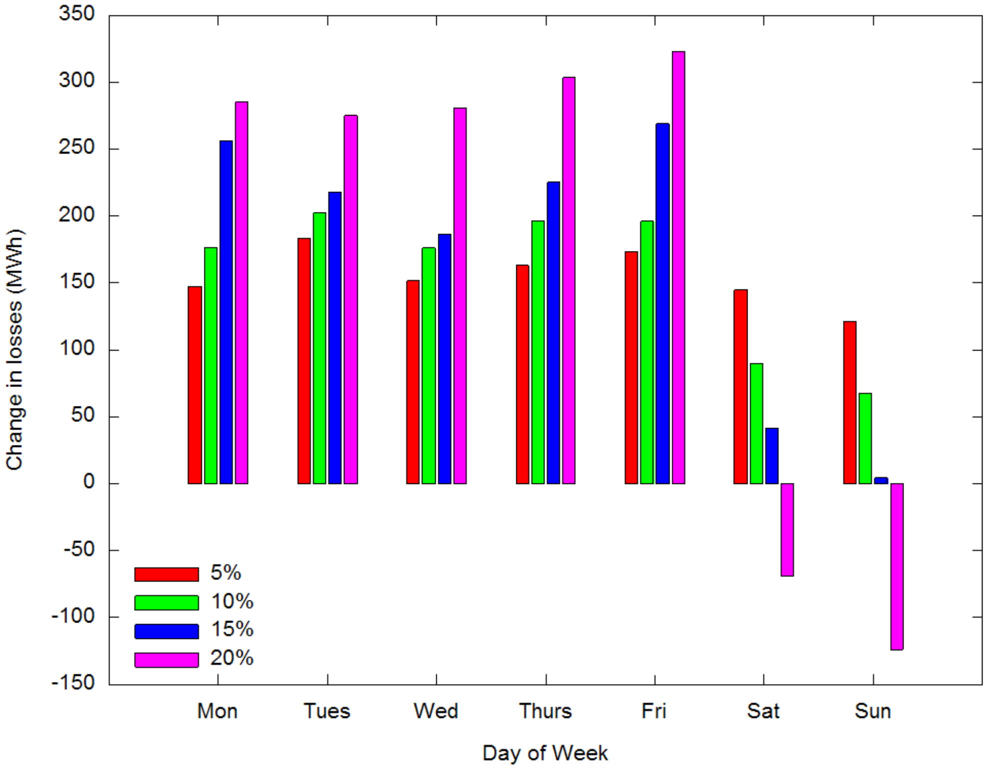


Figure 9.103: Absolute change in transmission losses for varying amounts of DG across the entire system

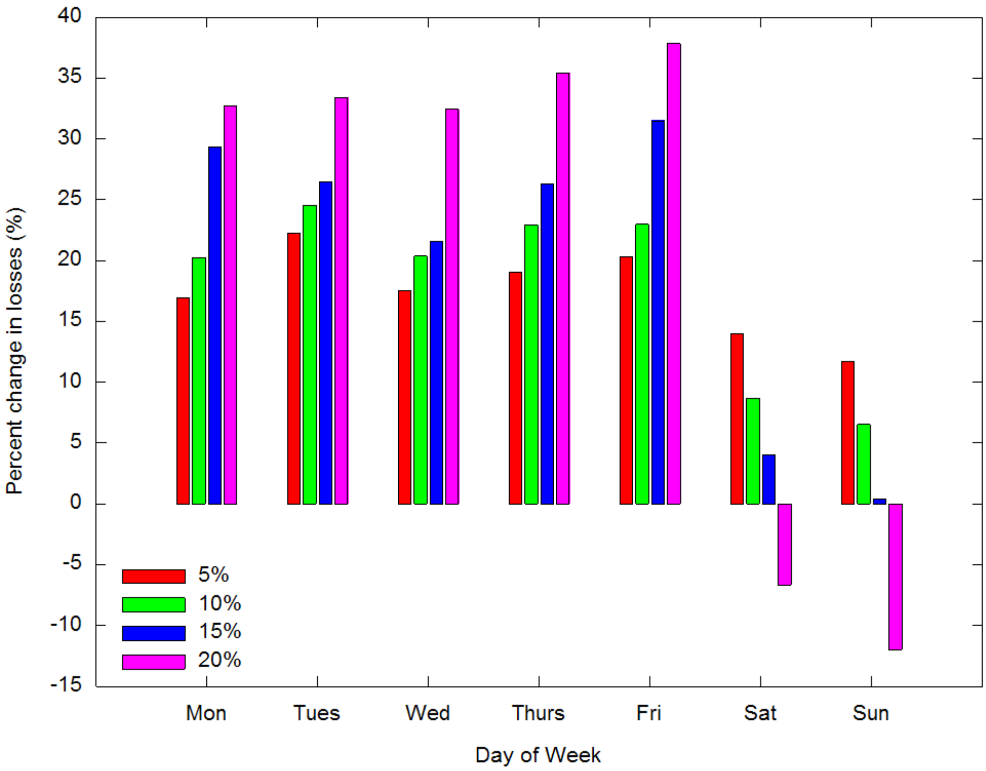


Figure 9.104: Relative change in transmission losses for varying amounts of DG across the entire system

Figure 9.105 shows the change in the real power generated at Alder as a result of the installation of 10 MW_e of DG at Alder. While output from Alder is lower as a result of adding DG, the magnitude in the reduction of real power generation was often greater than the 10 MW_e reduction in net demand at the bus. In the base-case the units at Alder are just economically viable at certain times. Adding a small amount of DG at this bus results in this plant not being dispatched at these times. This effect was not limited to only the Alder bus, net generation decreases were also apparent at Abel, Adams, Arthur, and Asser. The conclusion from these results is that adding DG at Alder has drastically changed the dispatch schedule. Generation is shifted from the units at Alder — and the other aforementioned buses — to other units in the system (see Figure 9.69). This results in the power being transmitted along a different path that is both longer and using lines of varying characteristics. This results in increased losses relative to the base case in which no DG is installed.

An examination found that Arne is the prime beneficiary of the new dispatch schedule; the other units in the IEEE RTS ’96 — those at Astor, Attlee, Aubrey, and Austen — remain much the same. Figure 9.106 shows the change in the real power generation at Arne in response to the addition of 10 MW_e of DG at Alder. The change in dispatch schedule affects transmission losses as follows. In the base case, power generated at Arne flows through Anna and Archer into the lower half of the IEEE RTS ’96. When DG is added, power generation increases at Arne. This is coupled with reductions in generation at Abel, Adams, and Alder which exacerbate the situation. Figure 9.107, contrasts the power flow between Arne and Archer observed in the base case to that observed when 10 MW_e of DG is installed at Alder. The increased power flows when DG is present explains the observed increase in transmission losses.

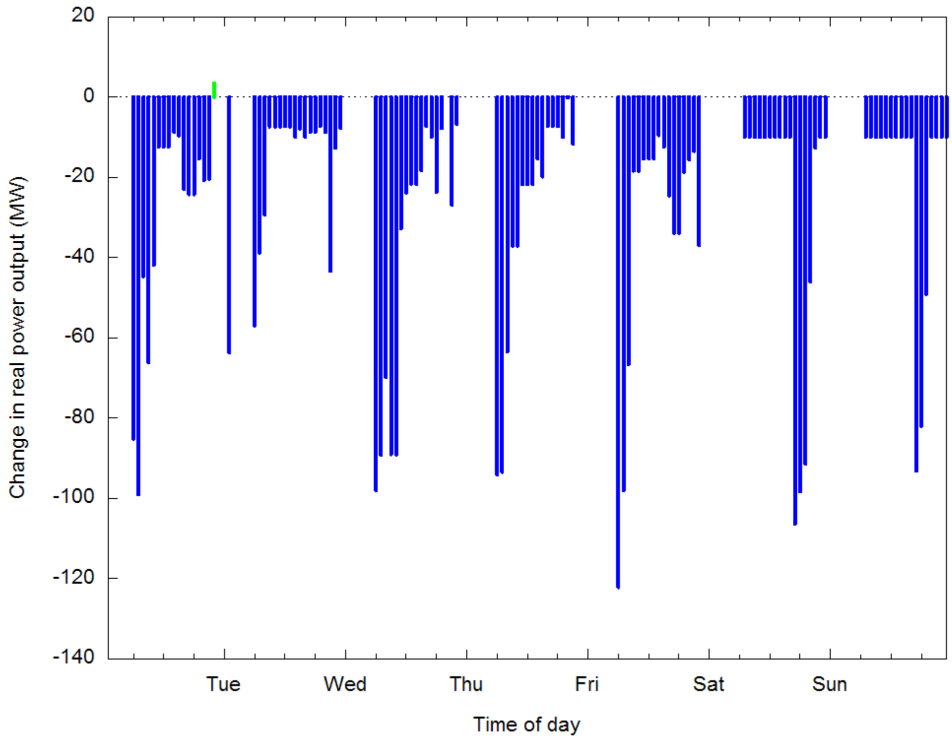


Figure 9.105: Change in real power generated at Alder after installing 10 MW_e DG at Alder

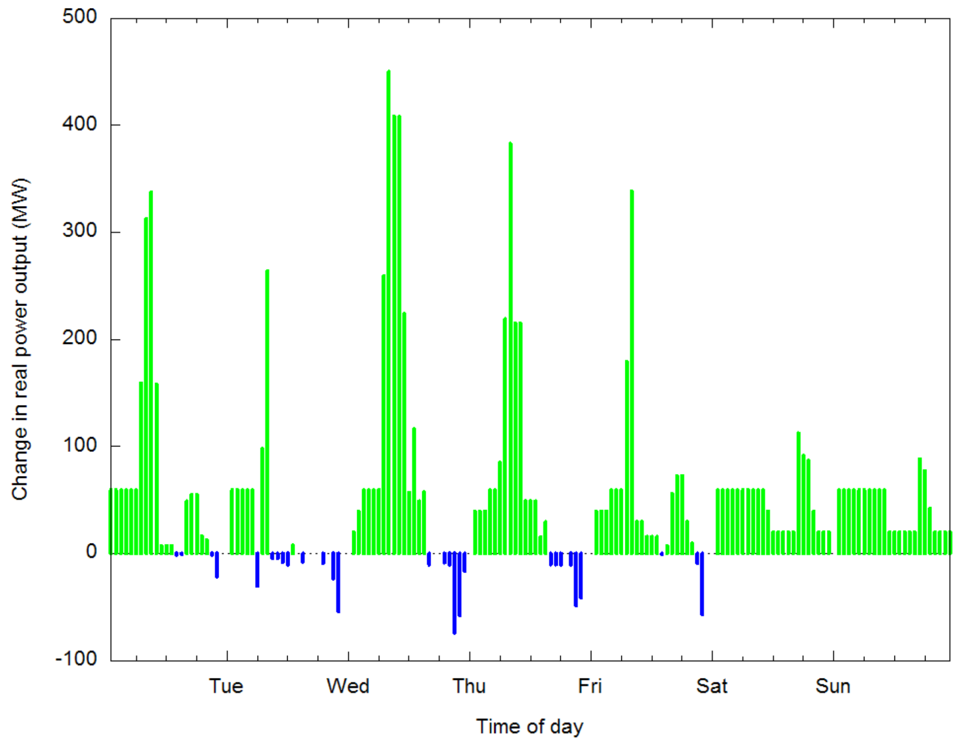


Figure 9.106: Change in real power generated at Arne after installing 10 MW_e DG at Alder

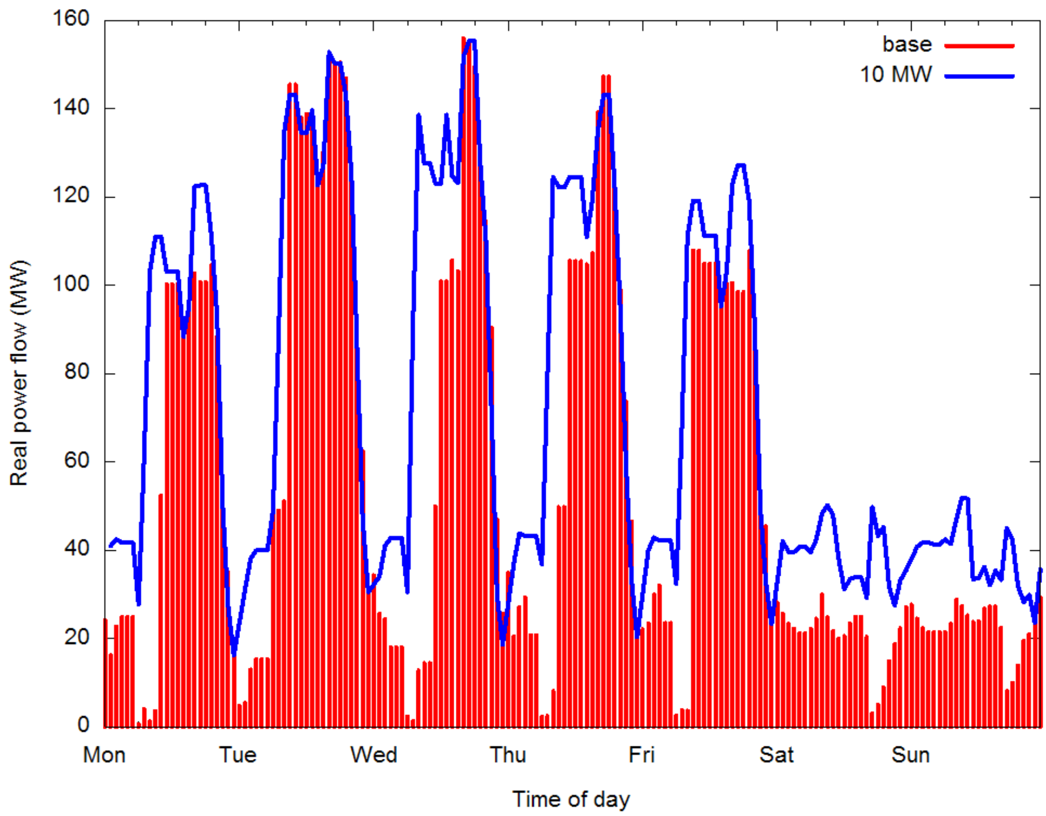


Figure 9.107: Change in power flow between Archer and Arne for 10 MW_e DG at Alder

Electricity price

Figure 9.108 shows the hourly electricity price in each time period for varying amounts of DG installed at Alder. Adding DG at Alder has a striking impact on electricity price; the spikes that appear in the base-case all but disappear once DG is present. Figure 9.109 shows the price for the same set of scenarios but averaged over each day.

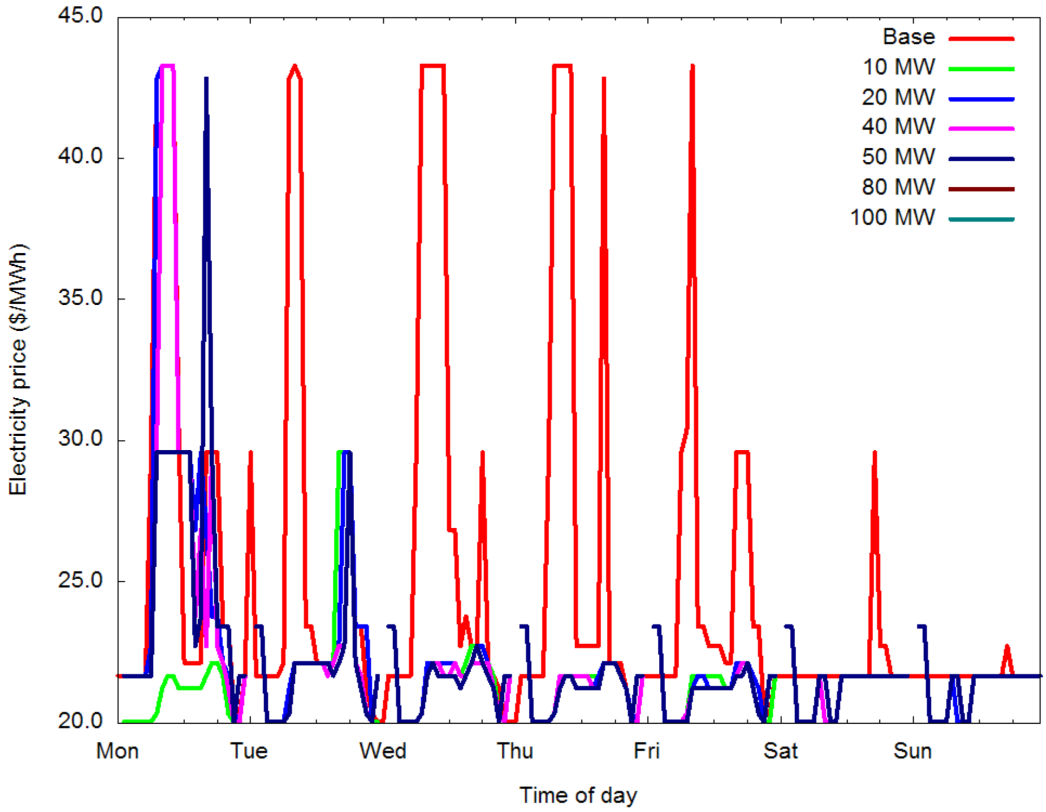


Figure 9.108: Hourly electricity price for varying amounts of DG at Alder

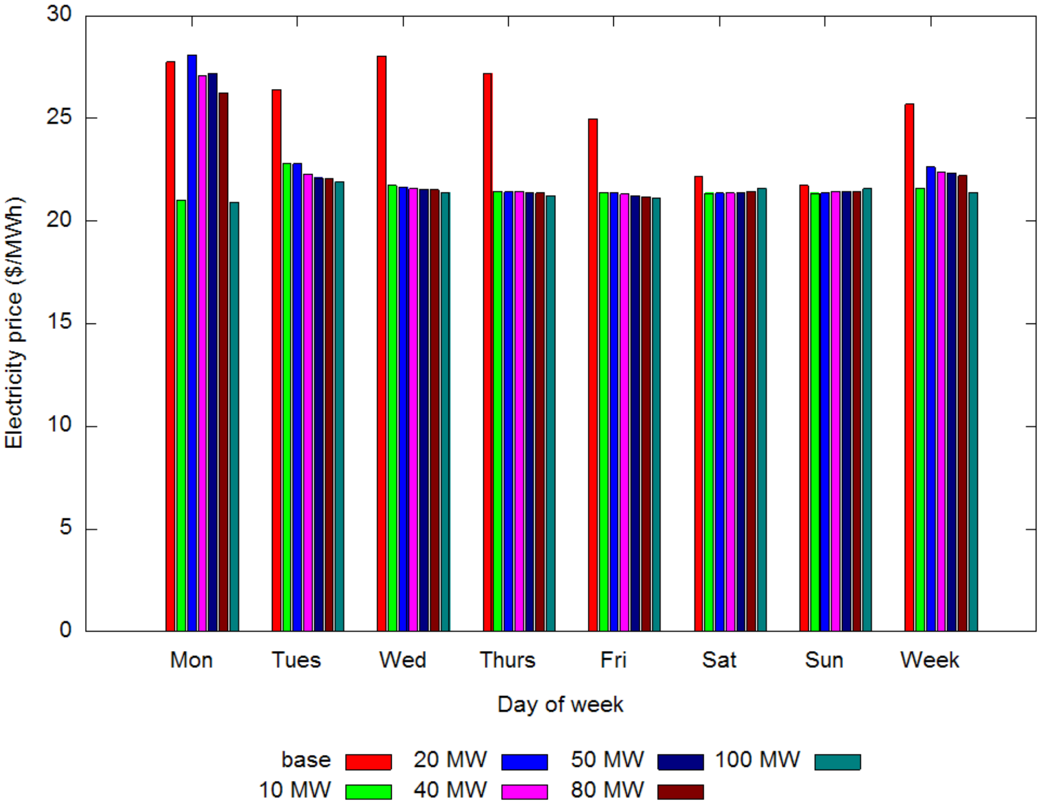


Figure 9.109: Average daily electricity price for varying amounts of DG at Alder

Reviewing Figure 9.110 provides some understanding of how a small addition of DG at Alder so dramatically affects prices. This figure shows the composite supply curve for the IEEE RTS '96 with the offers from Abel and Adams highlighted. Note that the highest-priced offers in the system are submitted by units at these buses. Also note that these offers are for small quantities of power (shown by the width of the green bars); thus, a small change in the dispatch schedule could have a dramatic effect on electricity price. This is what happens when DG is installed at Alder.

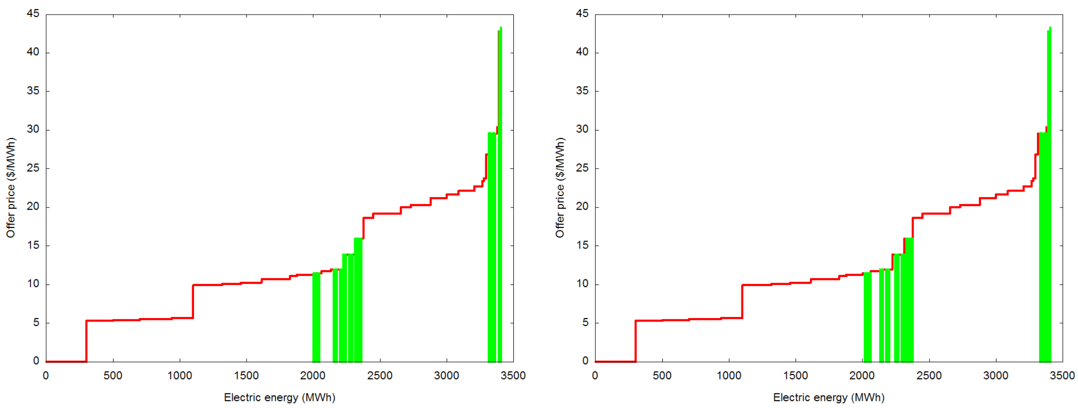


Figure 9.110: Position of units at Abel and Adams in merit order

Figure 9.111 shows the electricity price as a function of time for the base-case and Figure 9.112 for the case with 10 MW_e of DG installed at Alder; it also shows the buses at which units setting the electricity price reside. With DG installed in the system, the high-priced units at Abel and Adams are no longer dispatched and, hence, cannot set the market price. Thus, a significant reduction in price is observed.

The effect on electricity price is similar for the cases with DG capacity installed at Arne and throughout out the system. Each day's average electricity price is illustrated for these two cases in (Figure 9.113 and Figure 9.114). It is worth pointing out that:

In all cases, as the DG capacity ramps up, the average electricity price approaches about $21/$MWh_e$ asymptotically. It is the offers from the #6 fuel oil-fired plants located at Alder, Arne, and Arthur that become more marginal. Further reducing the price would require a dispatch schedule in which these plants are shutdown; the coal units in the system would then become price determinant

Adding DG at Alder and Arne is observed to have a greater impact on electricity price than when it is added across the system. Table 9.38 lists the average electricity price for the week for selected scenarios. Installing 158 MWh of DG capacity dispersed throughout the system had less impact on electricity price than 20 MWh at either of Alder or Arne.

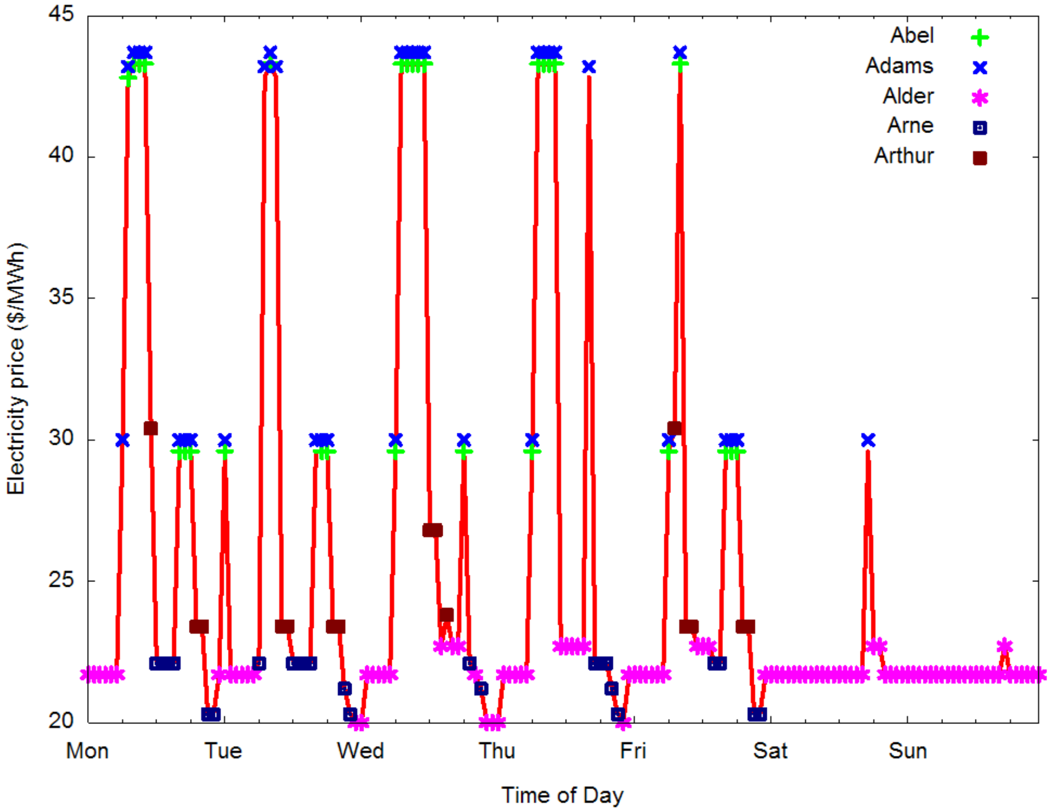


Figure 9.111: Buses containing units setting electricity price in base-case

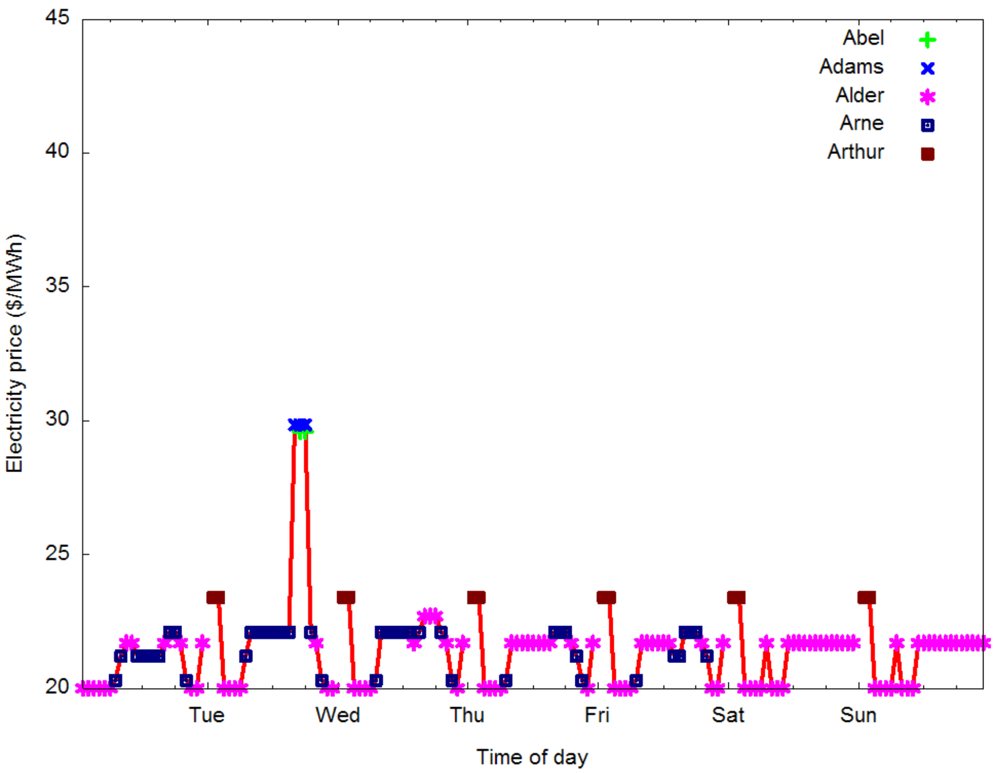


Figure 9.112: Buses containing units setting electricity price with 10 MW_e DG installed at Alder

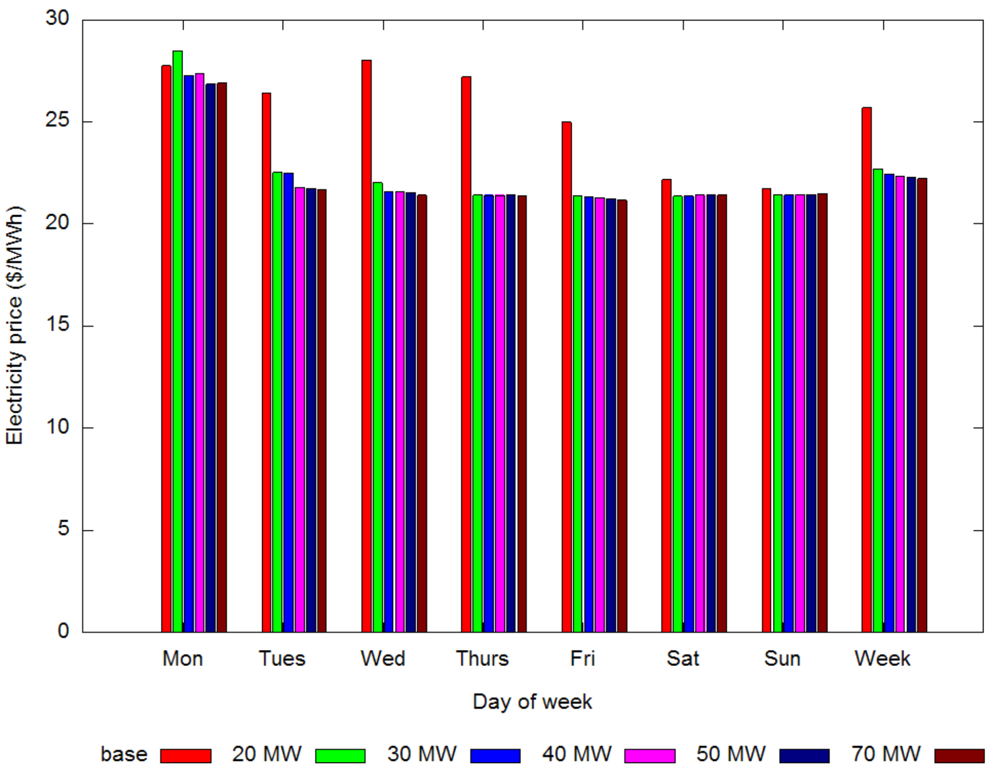


Figure 9.113: Average daily electricity price for varying amounts of DG at Arne

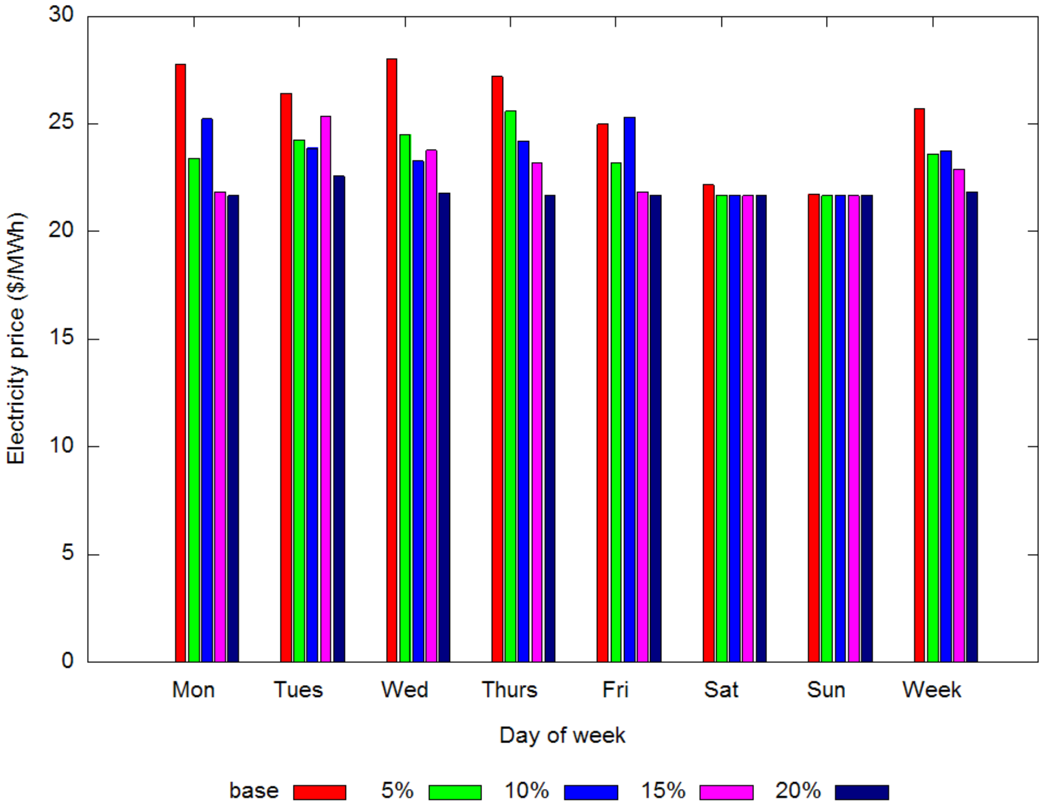


Figure 9.114: Average daily electricity price for varying amounts of DG across the system

Table 9.38: Average electricity prices observed in IEEE RTS ’96

Scenario	Location	DG capacity MWh	HEP $/MWh
Base	N/A	N/A	25.69
1b	Alder	20	22.63
2a	Arne	50	22.45
3a	Across system	158	23.60

Energy benefit

Figure 9.115 through Figure 9.117 show the change in net energy benefit for the three case studies: DG installed at Alder, DG installed at Arne, and DG installed across the system.

In the cases where DG is installed at Alder and Arne, existing units at Arne see an increase in their net energy benefit. That is, they earn more income with DG installed than before. The rest of the units in the system see a decline in their gross operating margin.

With DG capacity installed throughout the system, though, all units realise a decline in their net energy benefit.

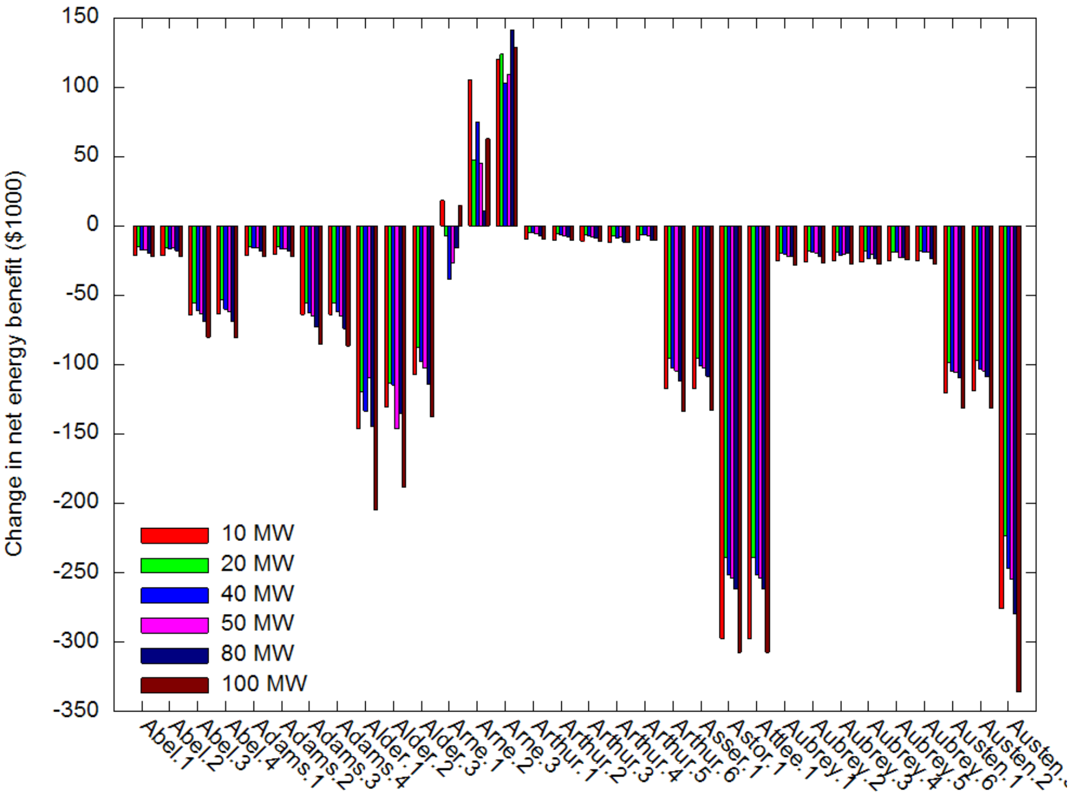


Figure 9.115: Change in net energy benefit of all units for varying amounts of DG installed at Alder

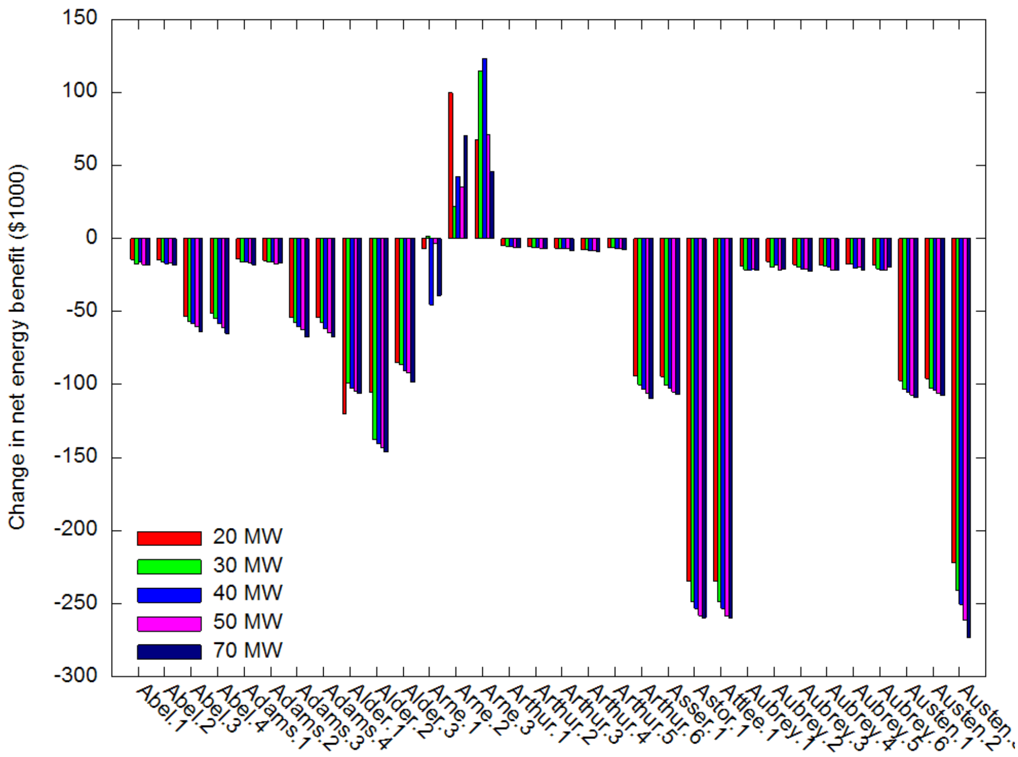


Figure 9.116: Change in net energy benefit of all units for varying amounts of DG installed at Arne

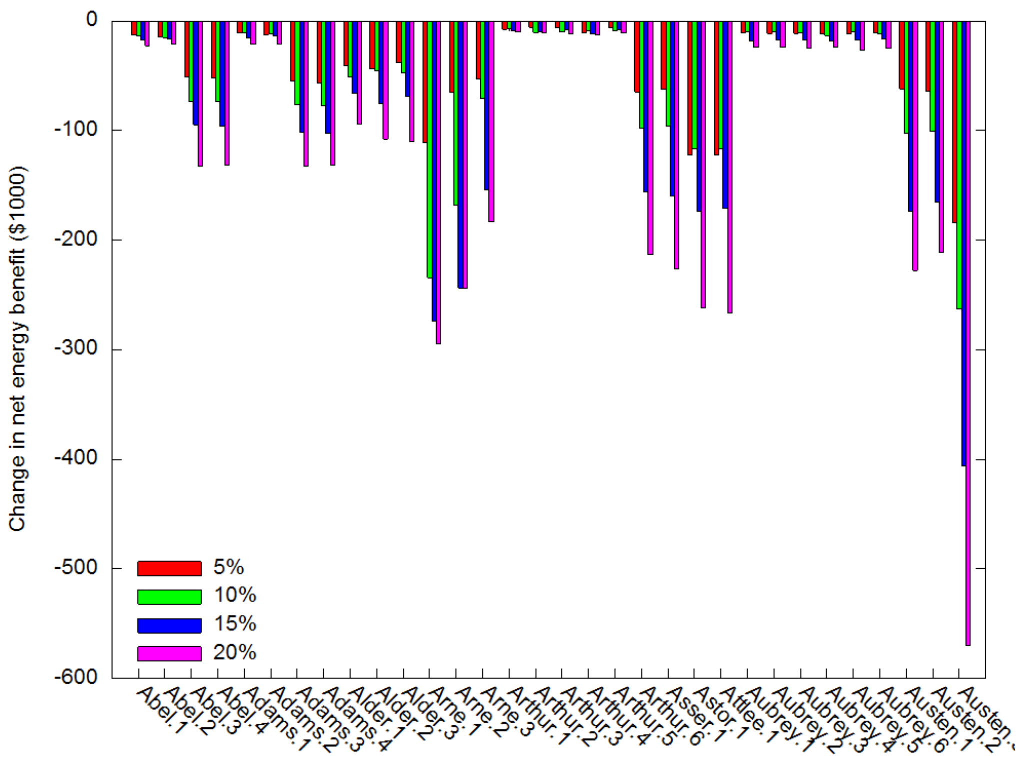


Figure 9.117: Change in net energy benefit of all units for varying amounts of DG installed throughout system

9.5.6 Conclusions

The objective of the study was to perform a preliminary assessment of the effect that adding DG has on an electricity system. The primary focus was on the impacts of adding DG capacity on power flows and electricity system economics. The IEEE RTS '96 (IEEE Reliability Test System — 1996) was selected as the target electricity system and three case studies were carried out; they differ with respect to where and how much DG capacity is installed.

It was anticipated that DG would help to relieve congestion, reduce transmission losses, and moderate the price of electricity. While the first and last effects were observed, adding DG capacity to the system was found to cause an increase in transmission losses. This resulted from power being transmitted along a different path that is both longer and using lines of varying characteristics.

In general capacity utilisation and net energy benefit were impacted by the addition of DG, there were however some notable exceptions:

- The utilisation of nuclear, hydroelectric, and the largest coal units remained largely unaffected by DG. However, as electricity prices decline markedly once DG capacity is installed, the net energy benefit realised by these units decreased
- In most scenarios, the utilisation of the #6 fuel-oil conventional steam units at Arne is higher with DG installed. And, this increase is more than sufficient to offset the lower electricity prices; units at Arne are often more profitable with DG installed in the system than without it.

It is concluded, then, that:

- Adding even small amounts of DG can have dramatic impacts on the power flows and economics of an electricity system
- The effects of adding DG are not limited to the bus at which the capacity is installed. They are felt by pre-existing generation units both near and far and, from generators' perspectives, can be positive or negative
- The effects of adding DG may depend more upon where the DG is added than on how much
- The effects of adding DG depend quite heavily upon specific characteristics of the target electricity system (e.g., disposition of sources and sinks relative to one another, types of generation units in the system, electricity demand).

10. MAKING DISTRIBUTED ENERGY WORK

Many of Australia's centralised supply infrastructure assets are either in need, or in the process of renewal. Combined with growing recognition of the importance of reducing greenhouse gas pollution, emission intensive centralised generation will become increasingly more expensive. With technological development that allows the use of heat for cooling, well suited to the Australian climate, Australia is well positioned to increase its penetration of distributed energy as an alternative to centralised generation.

Australia's energy supply system was developed at a time when large scale, centralised generation plant close to fossil fuel resources, was the optimal supply model. It allowed economies of scale, and took advantage of the relative efficiency of transporting electricity, as opposed to transporting coal or gas.

Today, the imperative to address climate change and technological change is challenging the dominance of this central supply model. Small scale generation close to load creates significant efficiencies, allowing for the useful recovery of heat, otherwise wasted in the generation of electricity. It can reduce electrical losses on transmission and distribution network infrastructure, particularly in rural areas and can improve power quality while imposing minimal additional costs and risks to network assets.

Advances in emerging technologies such as solar photovoltaics has the potential to make clean energy generation at the point of consumption viable with grid supplied electricity. Advances in communications and control devices has the potential to facilitate smart grids, where the supply and consumption of energy can be seamlessly optimised, maximising the potential to integrate clean renewable energy generation with grid infrastructure. Combined with building design optimisation and efficient heating and cooling systems, distributed energy systems are currently reducing, and offer significant potential to reduce greenhouse gas emissions cost effectively in the future.

This new energy supply model, with decentralised generation, decentralised decision making, and active consumer input has the potential to create highly resilient energy supply systems, reducing the cost of high impact, low probability events such as power outages caused by bushfires. Naturally this type of resilience comes at a cost, requiring network islanding and sophisticated control systems. However as climate change heightens the risk of extreme weather events such as bush fire and high wind speeds, decentralised energy supply models offer risk mitigation, by removing the reliance on vulnerable transmission and distribution infrastructure. While detailed modelling of costs and benefits of this type of supply model have not been undertaken here, it may be a field of future research.

This imperative of transitioning to a decentralised energy supply model is heightened by the need to mitigate the risk of clean central supply technologies failing to emerge from concept to reality, highlighted by economic modelling work which shows distributed energy playing an even greater role in emission reductions should carbon capture and storage technology not evolve.

A distributed energy system may naturally evolve over time without intervention from Governments as communities take unilateral action to reduce their emissions from stationary energy. There is a movement across Australia at the community level working towards distributed energy solutions which is important to acknowledge. However a full and efficient transition of the energy supply chain is likely to require the union of many complementary policies. This is because of significant social and environmental costs associated with energy use that remain unpriced, and the current centralised supply system showing characteristics of inefficient technology lock-in, with modelling consistently demonstrating the significant untapped potential of distributed energy, and in this report, energy efficiency and DG in particular.

Overcoming technology lock-in requires targeted policy support for new technologies that allows them to emerge from a market niche to maturity. Technology support starts with research and development funding, creates subsidies for emerging technologies, then as the technology matures, makes use of market based and competition policies to drive efficiency improvements.

The majority of clean energy research and development priorities in Australia to date have focussed on addressing emissions caused by large scale generation. While this remains very important, modelling in this report shows that an efficient reduction of emissions requires a mix of technologies, with the role of distributed energy heightened by scenarios where promising future technologies such as carbon capture and storage fail to be deployed commercially. To mitigate the risk of stranded energy assets, more support for development of distributed energy technologies and systems may be required.

Policies are also needed to address systemic issues created by the dominance of the central supply model. Systemic issues include the lack of a pervasive skills base required to deliver distributed energy, the inability to capture the value of distributed energy solutions due to incomplete energy prices, and the decision making bias of customers.

A lack of skills is largely caused by the complex and disaggregated chain of businesses involved in designing and building the infrastructure that determines how we consume energy. From property developers, energy retailers, architects and network companies, no one business can capture all the value of distributed energy, therefore their incentive to pursue DG, energy efficiency or demand management is diluted. The flow on effect is a lack of commercial imperative to develop training and education that supports skills other than those required to perpetuate existing business models. To address this lack of skill development, policy is needed to signal the value of distributed energy, and create frameworks that allow its value to be captured. This will create innovation within the existing supply chain, but also ensure a competitive market for energy service delivery, with new energy supply models likely to emerge.

Policy and regulatory frameworks that start to address these issues have emerged in Australia including the use of energy white certificates to target energy efficiency at the household level through energy retailers, demand management incentive schemes for network companies to seek alternatives to network building, Smart Grid funding for a large scale demonstration of distributed energy technologies, building and appliance regulation, and the planned rollout of interval meters coupled with the potential for price deregulation to signal opportunities for more efficient energy services.

However there remains scope to refine those frameworks and in some cases expand their scope to allow the full value of distributed energy to be realised. To support this, better methodologies are required for valuing various distributed energy measures and incorporating them into policy and regulation including the value of time specific energy costs that distributed energy may avoid or substitute the value of environmental externalities and the value of enhanced energy system security and reliability that distributed energy can bring.

Systemic decision making bias in the energy supply chain appears to be caused by the interplay of inherent human decision making characteristics, the delivery model for centralised and decentralised energy and a lack of effective price signals for energy consumption. Consumers appear to systemically prefer to avoid loss as opposed to seek gain, and make imperfect trade offs between incurring costs today to securing benefits in the future. This decision making bias complements the central energy supply model which uses highly geared companies to finance capital intensive infrastructure, paid off over long time periods, resulting in low operating costs for energy. The low, flat tariff price signal encourages consumers to seek cheap, inefficient energy appliances, building design options and sub optimal energy supply options.

The decentralised model of high efficiency and local infrastructure ownership can entail high capital costs. This can affect the uptake of distributed energy as consumers typically lack access to cheap finance and inherently place high discount rates on their decisions. Consumer uptake may also be suppressed from uncertain payback periods that result from a combination of not knowing future energy prices, and not knowing how their energy demand may change over time.

Customers may also lack the ability to augment the infrastructure required to facilitate distributed energy, for instance they may not own the building they live or work in. They may also face significant information asymmetries and split incentives when integrating distributed energy with the grid, including navigating the grid connection process, and the inability to recover the time specific value of energy they avoid consuming, or substitute with a local alternative.

Addressing these systemic decision making biases can be achieved in a number of ways. Innovative models for delivering distributed energy can change the price signal seen by customers. Existing examples include bulk supply of technologies to reduce up front costs, or leasing models where distributed energy equipment is leased to customers for an annual fee or installed for no cost but paid for by energy cost savings.

They can also be addressed by using information and/or financial incentives, helping consumers make better decisions considering the true cost of operating energy consuming appliances. For example, decisions at the point of sale of energy appliances can be influenced, by providing efficient rebates for more efficient appliances. Rebates can be calculated to consider the time specific value of avoided energy costs not factored into energy prices, reflecting the significant cost difference between suppling base load power and temperature sensitive peak demand. Refining information disclosure requirements on buildings and appliances can also help consumers make better decisions about energy, for example by giving them clear guidance on likely avoided costs and paypack periods, not just avoided consumption.

In part, because of the differing characteristics of centralised and decentralised supply models, distributed energy can often compete with the central supply model in green-field developments and where customers are forced to contribute significant capital costs up-front for infrastructure building. This is particularly evident in developing countries where centralised energy supply infrastructure has yet to be established. This should be considered an important signal as to the future value of distributed energy, with significant economic growth, and energy demand, likely to be driven by emerging economies such as China and India.

Importantly, distributed energy has significant potential in developed urban areas although capturing its value is made difficult because of the lack of clear price signals. As opposed to rural or green-field sites where the price signal for trade offs between centralised and decentralised energy models is often clear, in dense urban areas, upgrade and renewal of infrastructure is an ongoing processes with costs allocated across diverse customer bases. Coordinating decisions required to capitalise on avoiding asset renewal and upgrading is a difficult process, particularly if an optimal distributed energy solution is being sought across a network zone, as opposed to a single distributed energy solution such as DG to meet a very specific network constraint. Processes are underway to develop such signals through the AEMC and it will be important for policy makers and regulators to observe how the distributed energy market responds to these signals, and to refine signals where necessary.

Insights from social science can also help overcome some of decision making biases. Distributed energy product retailers and service providers can use social science to target consumers who are more likely to adopt distributed energy technologies and systems. Using insights documented in this report, awareness raising, education and messaging campaigns can be tailored to overcome a reluctance to adopt distributed energy, and help promote the values and attitudes that make consumers more likely to adopt distributed energy.

Fundamentally, in order to bring about the market transformation required to realise the value of distributed energy, long term policy with firm targets and commitments are required to give the market confidence about developing and deploying distributed energy solutions. The use of formal policy networks, where policy research, ideas and intentions can be shared, can help create the collaborative environment needed to transform the energy supply chain. These policy networks must involve multiple parties and be inter disciplinary in nature to capture the diverse range of stakeholders that influence energy supply options. Most importantly, policy networks need to bring together the complementary disciplines of economics, engineering and science so that decisions can be optimised considering a full diversity of variables.

Undoubtedly, transforming how energy is generated and consumed is one of the great challenges facing societies around the world. It is a challenge we believe distributed energy will play a major role in meeting.

11. FUTURE RESEARCH

While this report provides a clear indication of the potential for distributed energy in Australia, a number of topics require further investigation to fully capture the value that distributed energy can provide. Throughout this report, topics for further research have been noted and here we provide a brief summary of future research we believe may help quantify and realise the value of distributed energy within Australia. These areas of research relate to understanding the impact of distributed energy and while we acknowledge ongoing product research and development remains important as a topic in itself, it is beyond the scope considered in this report.

11.1 Modelling distributed energy value and uptake

- Analysis undertaken from this report indicates significant financial and risk management benefits from a large scale take up of distributed energy. However fully quantifying the value including distribution network savings remains difficult. To the extent this can inform efficient decision making, more research may be required to understand this value, how it accrues and the impact it has on market incentives to undertake DE.

- While modelling for this project has considered various emission reduction trajectories and their impact on DE, we have not considered what an optimal DE uptake may be considering the value of avoided climate change costs. This is subtly different from optimising DE based on prices set through CRPS. Future research may consider the value of DE based on climate risk mitigation costs and benefits.

11.2 Understanding and managing the impacts of high levels of distributed energy

- Detailed study is required to ascertain the impacts and possible benefits of inherent variability of renewable resources, particularly solar radiation, and correlations with load profiles. This work may be required on a regional basis and should focus one of its goals on the derivation of a ‘firm’ generation capacity from renewable embedded generators.
- The introduction of significant quantities of inverter connected generation, such as PV may have a negative impact on networks. As this impact could be substantial, initial studies are required into the regulatory issues and financial impacts of the introduction of inverters with the capacity to operate with variable power factor.
- Where feeders utilise voltage regulation equipment such as OLTC transformers, work needs to be conducted into the increase in frequency of tap changing operations caused by DG. The results of such an investigation can then inform design and maintenance regimes, helping to plan and prepare for the impact of significant future DG penetration in these feeders.

11.3 Facilitating uptake of distributed energy

- The process of signalling where efficient locations for DE exist is currently fragmented and incomplete, putting it at a comparative disadvantage to centralised generation. Providers of DE products and services may benefit from an integrated tool that can provide fine grain assessments of where probable opportunities for DE exist. Such a tool could incorporate building stock data, distribution network data, climate data, implications of emissions to air, demographic data and be joined up with policy initiatives such as white certificate schemes, feed in tariffs and rebates.
- Current methods of processing connection applications may not be efficient in the future where significantly greater volumes of connections are required. In order to streamline DNSP commitments to DG connections, it may be appropriate to consider a process for aggregated capacity assessment depending on feeder load characteristics, which includes the time frames for generator connections and the financial impacts of implementing such a system.
- Decisions affecting the uptake of DE are wide and varied and include factors such as customer preferences, policy making, market design, innovation and regulation. Further research on individual and group decision making including how price and non price based information is traded-off may help provide insights that can overcome inherent decision making biases that may unintentionally impede the uptake of DE where it is efficient.
- The incentive of distribution businesses to undertake efficient demand management is a contentious issue in the literature reviewed and the interviews performed in this study. More research may be required to fully understand the implications of the current regulatory framework on distribution business incentives, and how they can be effectively aligned to provide demand management services where they are efficient.

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APPENDIX A: LIST OF ACRONYMS AND ABBREVIATIONS

A	Amperes
ABARE	Australian Bureau of Agriculture and Resource Economics
ABS	Australian Bureau of Statistics
AC	Alternating current
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGO	Australian Greenhouse Office
AMG	Asynchronous machine generator
ANZSIC	Australian and New Zealand Standard Industrial Classification
ATO	Australian Tax Office
AUD	Australian dollars
BAU	Business as usual
BITRE	Bureau of Infrastructure, Transport and Regional Economics
BOM	Bureau of Meteorology
CBD	Central business district
CBO	Congressional Budget Office
CCGT	Combined cycle gas turbine
CCHP	Combined cooling, heat and power
CCS	Carbon capture and sequestration
CD	Collection district
CDM	Clean development mechanism
CG	Centralised generation
CH_4	Methane
CHP	Combined heat and power
CNG	Compressed natural gas
CNY	Chinese dollar
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
COAG	Council of Australian Governments
cogen	Cogeneration
COP	Coefficient of performance
CPRS	Carbon pollution reduction scheme
CRA	Charles River Associates
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSM	Coal seam methane
CUAC	Consumer Utilities Advocacy Centre
CWM	Coal waste methane

DC	Direct current
DCC	Department of Climate Change
DE	Distributed energy
DECCW	Department of Climate Change and Water
DEWHA	Department of Environment, Water, Heritage and the Arts
DG	Distributed generation
DHC	District heating and cooling
DIISR	Department of Innovation, Industry, Science and Research
DKIS	Darwin and Katherine Interconnected System
DLF	Distribution loss factor
DM	Demand management
DMIA	Demand management incentive allowance
DMIS	Demand management incentive scheme
DNIS	Distribution network impact study
DNSP	Distribution network service provider
DOE	Department of Energy (U.S.)
DPI	Department of Primary Industry
DRET	Department of Resources, Energy and Tourism
DSM	Demand side management
DSP	Demand side participation
DSR	Demand side reduction
DTEI	Department of Transport, Energy and Infrastructure
DUoS	Distribution use of system charge
DWE	Department of Water and Energy
e.g.	For example
EA	Energy Australia
EE	Energy efficiency
EIA	Energy Information Administration
EIF	Emissions intensity factor
ELV	Extra low voltage
EMS	Emission management scenario
ENA	Electrical Networks Association
EPRI	Electric Power Research Institute
ESAA	Energy Supply Association of Australia
ESCO	Energy services company
ESCOSA	Essential Services Commission SA
ESCV	Essential Services Commission VIC
ESM	Energy sector model
ESSA	Energy Supply Association of Australia
ESSCI	Environmentally sustainable site for CO_2 injection
ETF	Energy Transformed Flagship
ETSA	SA network utility operator
EU	European Union

EVs	Electric vehicles
FC	Fuel consumption
FCAS	Frequency control ancillary service
FERC	Federal Energy Regulatory Commission
FiT	Feed-in tariff
g	grams
GDP	Gross domestic product
GGAS	NSW greenhouse gas abatement scheme
GHG	Greenhouse gas
GIS	Geographical information systems
GJ	Gigajoule
Gl	Gigalitre
GSC	Grid support contract
GSOO	Gas statement of opportunities
GST	Goods and services tax
GW	Gigawatt
GWe	Gigawatt electric
GWh	Gigawatt-hour
HC	Hydrocarbon
HHV	Higher heating value
HV	High voltage
IAA	Ideas and agendas
IBDG	Impacts and benefits of distributed generation study
ICE	Internal combustion engine
ICG	Inverter connected generator
IEA	International Energy Agency
IEEE	Institute of Electrical and Electronics Engineers
IG	Intelligent Grid
IGCC	Integrated gasification combined cycle
IMO	Independent Market Operator
IPART	Independent Pricing and Regulatory Tribunal
IPCC	Intergovernmental Panel on Climate Change
kA	Kiloampere
kHz	Kilohertz
kJ	Kilojoule
km	Kilometre
kV	Kilovolt
kVA	Kilovolt-ampere
kW	Kilowatt
kWe	Kilowatt electric
kWh	Kilowatt-hour
LDC	Load duration curve
LMP	Locational marginal prices

LNG	Liquefied natural gas
LP	Linear program
LPG	Liquefied petroleum gas
LRMC	Long run marginal cost
LV	Low voltage
M	Million
m	Metre
MA	Mega ampere
MASG	Mount Alexander Sustainability Group
MCDA	Multi criteria decision analysis
MCE	Ministerial Council on Energy
MCFC	Molten carbonate fuel cell
MEPS	Minimum energy performance standard
MIP	Mixed integer programming
MJ	Megajoule
MLF	Marginal loss factor
MMA	McLennan Magasanik Associates
MMBtu	Million BTU
MRET	Mandatory renewable energy target
MT	Million tonnes
MV	Medium voltage
MVA	Mega volt-ampere
MVAr	Mega volt-ampere reactive
MW	Megawatt
MWe	Megawatt electric
MWh	Megawatt-hour
MWp	Megawatt peak
n.a.	Not applicable
N/A	Not applicable
N_2O	Nitrous oxide
NEC	National electricity code
NECA	National Electricity Code Administrator
NEL	National electricity law
NEM	National Electricity Market
NEMDE	National electricity market dispatch engine
NEMMCO	National Electricity Market Management Company
NEPM	National environment protection measure
NER	National electricity rules
NETT	National Emissions Trading Taskforce
NG	Natural gas
NGA	National greenhouse accounts
NGACS	New South Wales greenhouse gas abatement scheme
NGOs	Non government organisations

NMOC	Non methane organic compounds
NO	Nitrogen oxide
NO_2	Nitrogen dioxide
NOx	Oxides of nitrogen
NPI	National pollution inventory
NPV	Net present value
NRET	New South Wales renewable energy target
NSP	Network service provider
NSW	New South Wales
NT	Northern Territory
NTNDP	National transmission network development plan
NTP	National Transmission Planner
NWIS	North Western Integrated System
O&M	Operating and maintenance
O_2	Oxygen
O_3	Ozone
OCE	Office of Clean Energy Queensland
OCGT	Open cycle gas turbine
OECD	Organisation for Economic Co-operation and Development
OPF	Optimal power flow
OHL	Overhead power line
OHS	Occupational health and safety
OLTC	On load tap changing
OPF	Optimal power flow
OTC	Over the counter contracts
p.a.	Per annum
PAFC	Phosphoric acid fuel cell
PASA	Projected assessment of system adequacy
PC	Productivity Commission
PCC	Point of common coupling
PEMFC	Proton exchange membrane fuel cell
pf	Pulverised fuel
PHEVs	Plug-in hybrid electric vehicles
PJ	Petajoule
PM_{10}	Particulate matter
POC	Point of connection
ppm	Parts per million
PSS	Power system stabilisers
PURPA	U.S Public Utilities Regulatory Policy Act
PV	Photovoltaic
PWM	Pulse width modulated inverter
QLD	Queensland
RAB	Regulated asset base

RCR	Reserve capacity requirements
REC	Renewable energy certificate
rec.	Reciprocating
RET	Renewable energy target
RRN	Regional reference nodes
RRPGP	Renewable remote power generation program
RTS	IEEE reliability test system
SA	South Australia
SCADA	Supervisory control and data acquisition
SCI	Sustainable communities initiative
SCO	Standing Committee of Officials
SCR	Selective catalytic reduction
SEDO	Sustainable Energy Development Office
SKM	Sinclair Knight and Merz
SMG	Synchronous machine generator
SMS	Short messaging service
SO_2	Sulfur dioxide
SOFC	Solid oxide fuel cell
SOM	Self organised map
SOO	Statement of opportunities
SOx	Oxides of sulfur
SRMC	Short run marginal cost
STEM	Short term energy market
SWER	Single wire earth return
SWH	Solar water heater
SWIS	South western interconnected system
T&D	Transmission and distribution
TAPM	The air pollution model
TAS	Tasmania
TDC	Top dead centre
THC	Total hydrocarbons
THD	Total harmonic distortion
TNSP	Transmission network service providers
TPI	Total plant investment
TUoS	Transmission use of system charge
TWh	Terawatt-hour
UK	United Kingdom
UNFCCC	United Nations Framework Convention on Climate Change
UNSW	University of New South Wales
UPS	Uninterruptible power supply
US	United States
USD	U.S dollars
USE	Un-serviced energy

UTS	University of Technology Sydney
V	Volts
VA	Volt-amperes
VCEC	Victorian Competition and Efficiency Commission
VEET	Victorian energy efficiency target
VENCorp	Victorian Energy Networks Corporation
VIC	Victoria
VOC	Volatile organic compounds
VRET	Victorian renewable energy target
W	Watt
WA	Western Australia
WACC	Weighted average cost of capital
WADE	World Alliance for Decentralised Energy
WELS	Water Efficiency Labelling and Standards
WEM	Western Australian Energy Market
WPTR	Western power technical rules

APPENDIX B: CURRENT POLICY FOR DE IN AUSTRALIA.

This appendix provides a schematic overview of National and State policies relevant to DE at the time of writing. Included is a map of the organisations responsible for the polices.

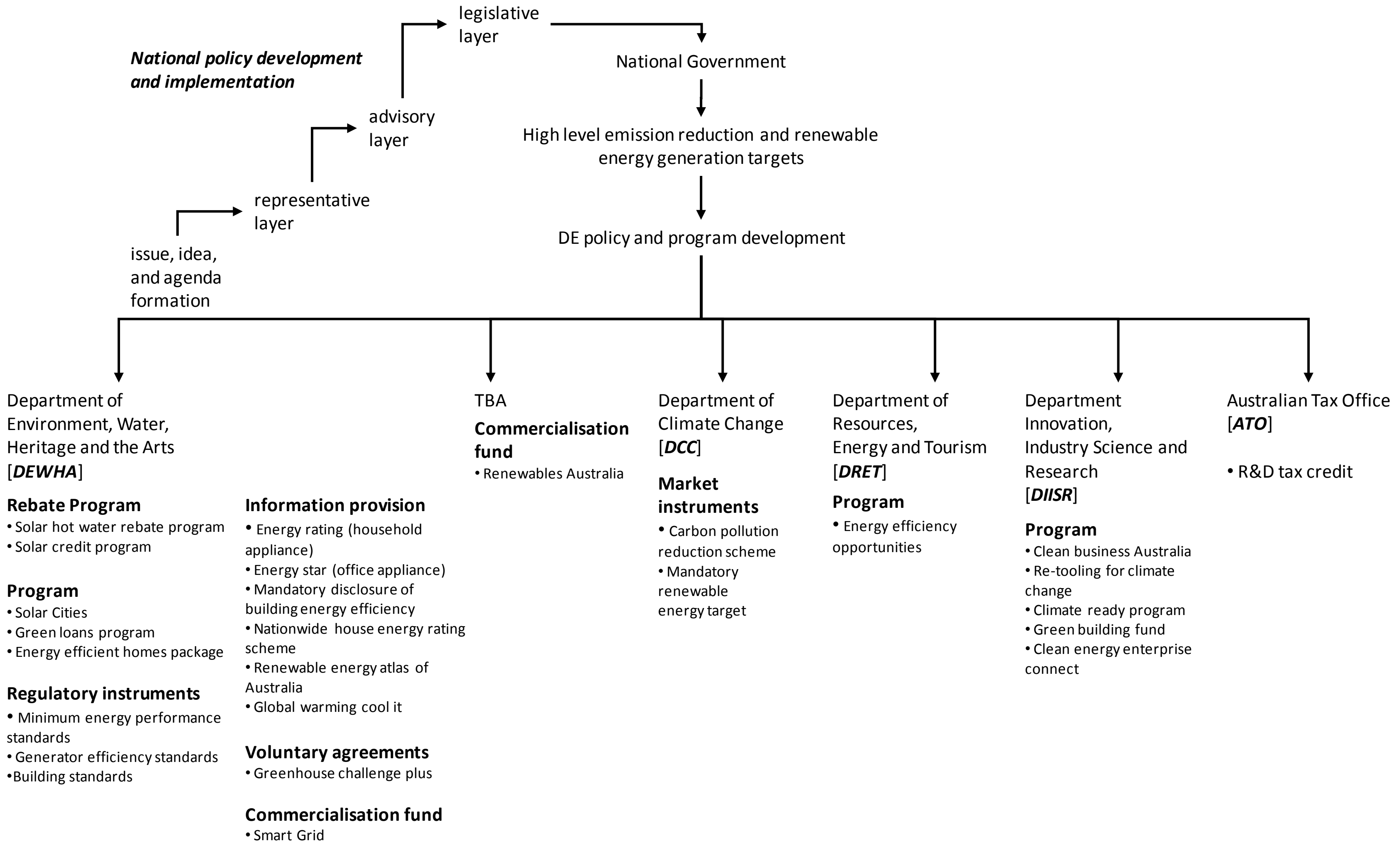


Figure B.1: National DE policy development

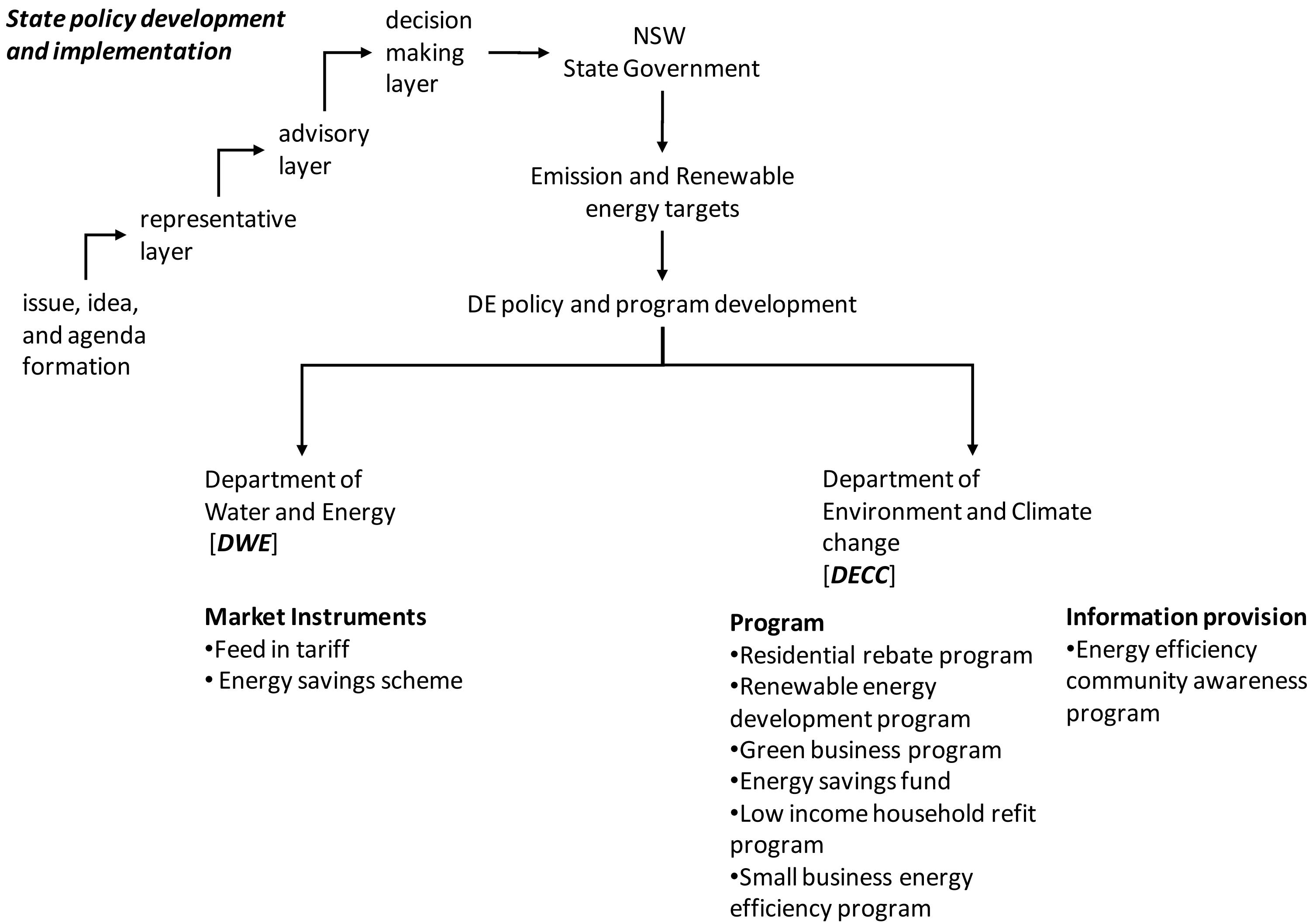


Figure B.2: New South Wales DE policy development

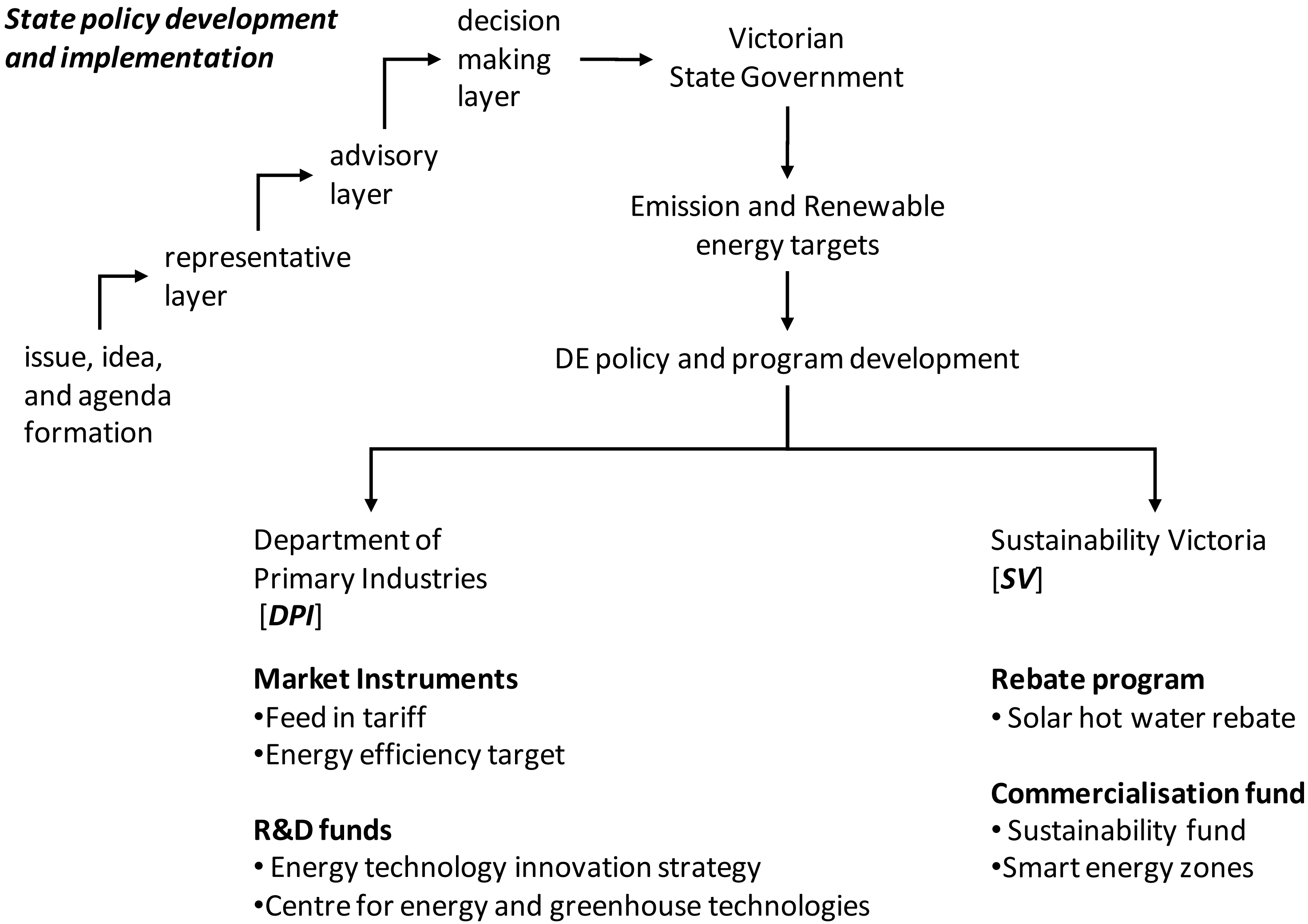


Figure B.3: Victorian DE policy development

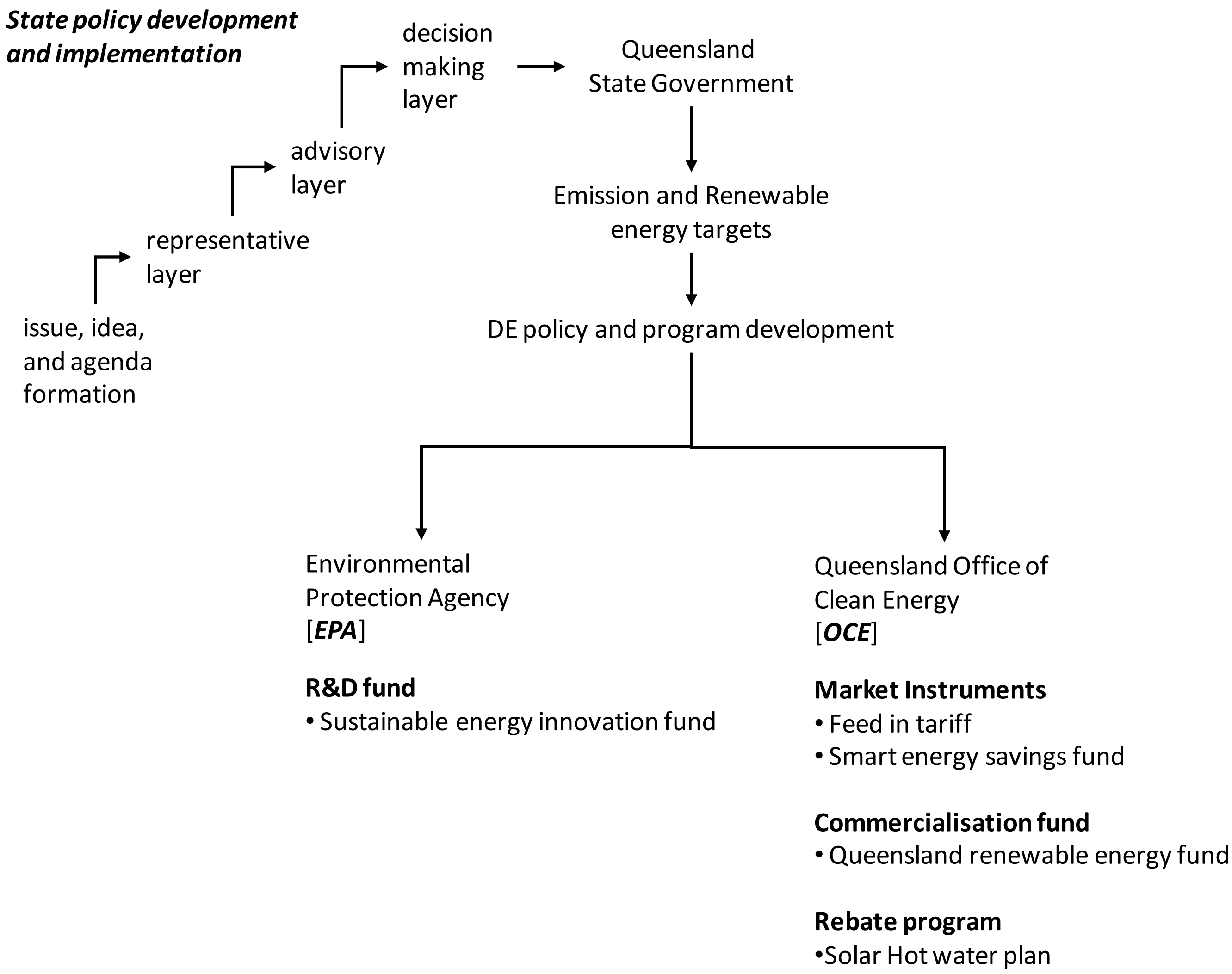


Figure B.4: Queensland DE policy development

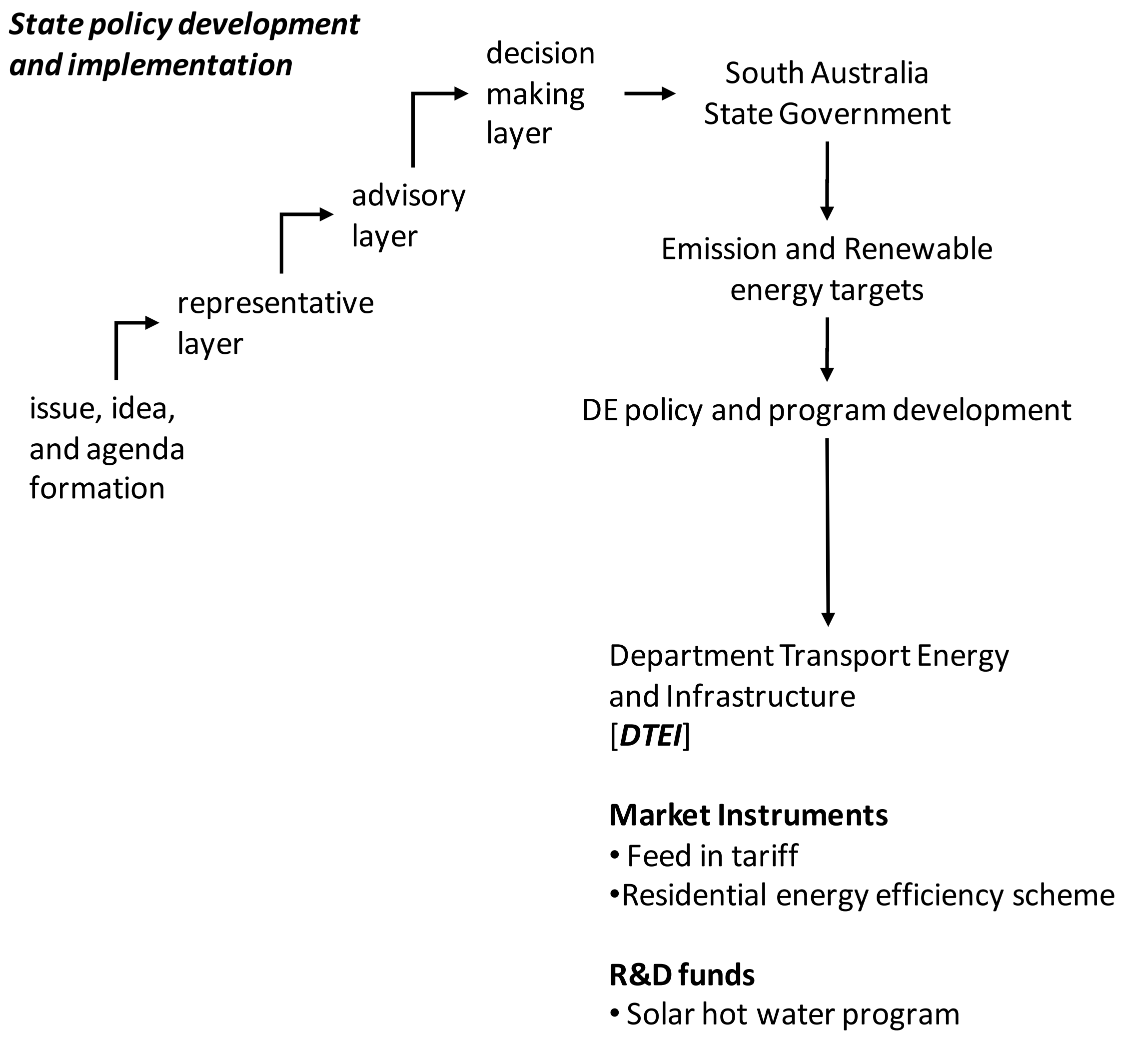


Figure B.5: South Australia DE policy development

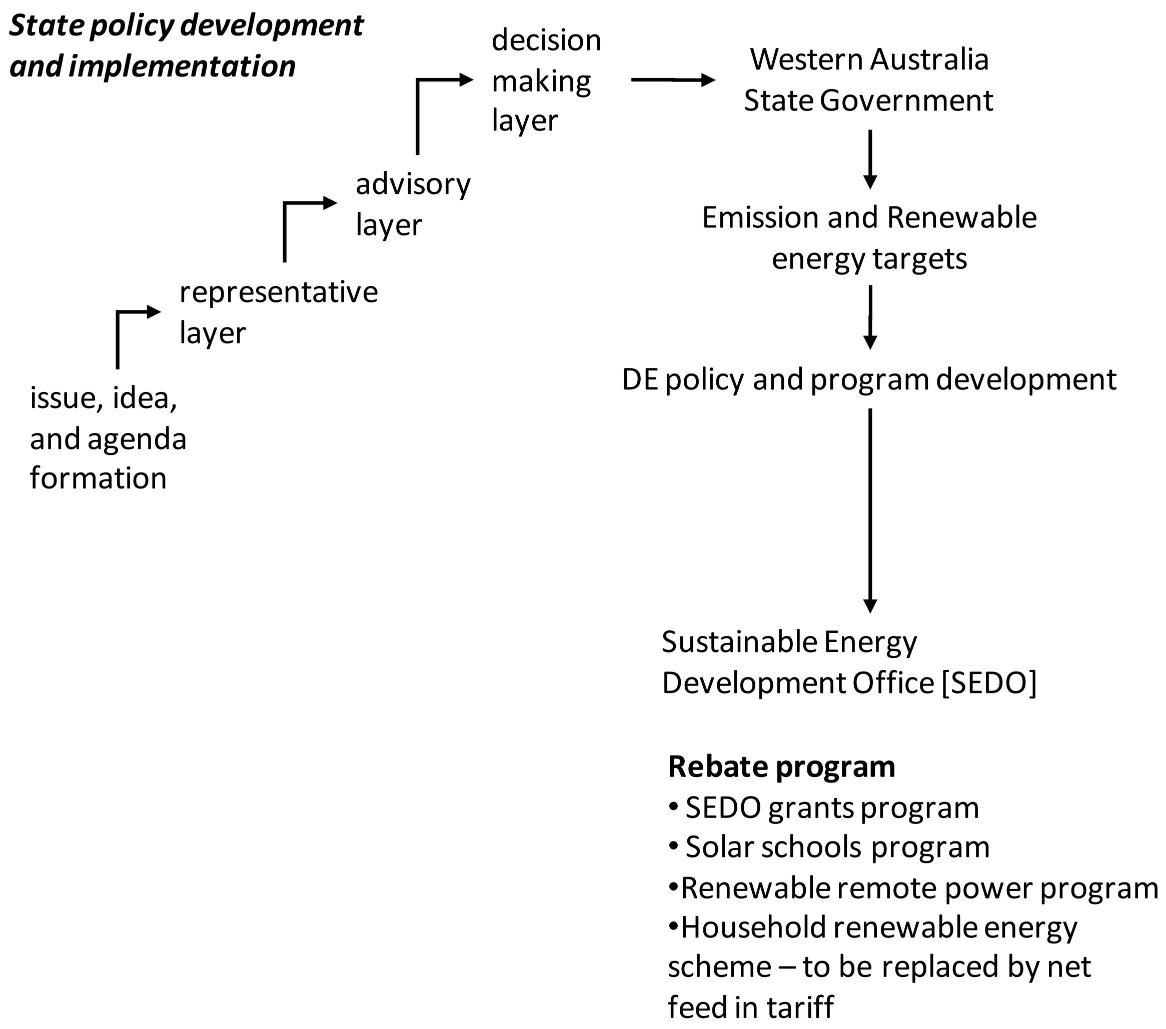


Figure B.6: Western Australia DE policy development

APPENDIX C: EMISSIONS FROM SELECTED DISTRIBUTED GENERATION TECHNOLOGIES

This appendix contains emission estimates for selected distributed generation technologies including projections in time. All values reported are derived from (EPRI, 2004) and the reader should consult this text for specific details regarding the measurements and assumptions of the data.

Table C.1: Gas turbine emission characteristics

Emissions Characteristics	**System1**	**System2**	**System3**	**System4**
Electricity Capacity (kW)	1,000	5,000	10,000	25,000
Electrical Efficiency (HHV)	22%	27%	29%	34%
NO_x, ppmv	42	25	25	25
NO_x, kg/MWh	1.08	0.54	0.49	0.40
CO, ppmv	20	20	20	20
CO, kg/MWh	0.32	0.27	0.22	0.18
SO_X, ppmv	0.23	0.24	0.24	0.24
SO_X, kg/MWh	0.004	0.004	0.003	0.003
THC, ppmv	25	25	25	25
THC, kg/MWh	0.24	0.17	0.16	0.14
NMOC, ppmv	2.5	2.5	2.5	2.5
NMOC, kg/MWh	0.024	0.017	0.016	0.014
PM_{10}, ppmv	N/A	N/A	N/A	N/A
PM_{10}, kg/MWh	0.299	0.239	0.223	0.188
CO_2, kg/MWh	828	669	624	528
Carbon, kg/MWh	234	187	175	148

Table C.2: Current and advanced gas turbine characteristics.

Emissions & Performance Projections 1,000 kW Gas Turbine System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
System Size, kW	1,000	1,000	1,000	1,000	1,000
Electrical Heat Rate (KJ/kWh), HHV	16,437	16,651	14,997	13,847	13,330
Electric Efficiency (%)	21.9%	23.0%	24.0%	26.0%	27.0%
Fuel Input (GJ/hr)	16.4	15.6	14.9	13.8	13.2
Emissions Characteristics					
NOx, ppmv	42	25	25	15	3
NOx, kg/MWh	1.10	0.62	0.59	0.33	0.06
CO, ppmv	20	20	15	9	9
CO, kg/MWh	0.32	0.29	0.21	0.12	0.11
SOx, ppmv	0.23	0.23	0.24	0.24	0.25
SOx, kg/MWh	0.004	0.004	0.004	0.003	0.003
NMOC, ppmv	2.5	2.5	2.5	2.5	2.5
NMOC, kg/MWh	0.022	0.020	0.020	0.018	0.017
PM10, ppmv	N/A	N/A	N/A	N/A	N/A
PM10, kg/MWh	0.30	0.28	0.26	0.24	0.23
CO2, kg/MWh	856	807	774	714	688
Carbon, kg/MWh	234	220	211	195	188
Emissions & Performance Projections 5,000 kW Gas Turbine System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
System Size, kW	5,000	5,000	5,000	5,000	5,000
Electrical Heat Rate (KJ/kWh), HHV	13,282	12,676	12,000	11,077	10,286
Electric Efficiency (%)	27%	28%	30%	33%	35%
Fuel Input (GJ/hr)	66.3	63.4	60.0	55.3	51.3
Emissions Characteristics					
NOx, ppmv	25	15	5	3	3
NOx, kg/MWh	0.53	0.30	0.29	0.05	0.05
CO, ppmv	20	20	15	9	9
CO, kg/MWh	0.25	0.24	0.18	0.09	0.09
SOx, ppmv	0.24	0.23	0.24	0.22	0.23
SOx, kg/MWh	0.003	0.003	0.003	0.002	0.002
NMOC, ppmv	2.5	2.5	2.5	2.5	2.5
NMOC, kg/MWh	0.017	0.016	0.016	0.014	0.014
PM10, ppmv	N/A	N/A	N/A	N/A	N/A
PM10, kg/MWh	0.24	0.22	0.20	0.17	0.16
CO2, kg/MWh	669	637	603	558	517
Carbon, kg/MWh	187	179	171	158	152

Emissions & Performance Projections 10,000 kW Gas Turbine System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
System Size, kW	10,000	10,000	10,000	10,000	10,000
Electrical Heat Rate (KJ/kWh), HHV	12,412	11,921	11,394	10,497	9,864
Electric Efficiency (%)	29%	30%	32%	34%	37%
Fuel Input (GJ/hr)	124.1	119.2	113.9	104.9	98.6
Emissions Characteristics					
NO_x, ppmv	25	15	5	3	3
NO_x, kg/MWh	0.48	0.28	0.16	0.05	0.04
CO, ppmv	20	20	15	9	9
CO, kg/MWh	0.24	0.22	0.17	0.09	0.08
SO_x, ppmv	0.24	0.25	0.22	0.24	0.25
SO_x, kg/MWh	0.003	0.003	0.002	0.002	0.002
NMOC, ppmv	2.5	2.5	2.5	2.5	2.5
NMOC, kg/MWh	0.016	0.015	0.014	0.014	0.013
PM_{10}, ppmv	N/A	N/A	N/A	N/A	N/A
PM_{10}, kg/MWh	0.22	0.20	0.18	0.15	0.13
CO_2, kg/MWh	624	599	574	528	497
Carbon, kg/MWh	175	168	161	149	128

Emissions & Performance Projections 25,000 kW Gas Turbine System					
Year	**Current**	**2005**	**2010**	**2020**	**2020**
System Size, kW	25,000	25,000	25,000	25,000	25,000
Electrical Heat Rate (KJ/kWh), HHV	10,491	10,196	9,732	9,352	8,999
Electric Efficiency (%)	34%	35%	37%	39%	40%
Fuel Input (GJ/hr)	262.3	254.8	243.1	233.7	225.0
Emissions Characteristics					
NO_x ppmv	25	9	5	3	3
NO_x, kg/MWh	0.42	0.24	0.14	0.05	0.05
CO, ppmv	20	20	15	9	9
CO, kg/MWh	0.20	0.20	0.14	0.08	0.08
SO_x, ppmv	0.24	0.25	0.25	0.22	0.22
SO_x, kg/MWh	0.003	0.003	0.003	0.002	0.002
NMOC, ppmv	2.5	2.5	2.5	2.5	2.5
NMOC, kg/MWh	0.014	0.014	0.013	0.013	0.013
PM_{10}, ppmv	N/A	N/A	N/A	N/A	N/A
PM_{10}, kg/MWh	0.186	0.177	0.159	0.141	0.136
CO_2, kg/MWh	528	512	490	469	453
Carbon, kg/MWh	148	143	139	136	135

Table C.3: Microturbine emission characteristics

	System1	**System2**	**System3**	**System 4**
Nominal Electrical Capacity (kW)	30 kW	70 kW	80 kW	100 kW
Net Electrical Efficiency, HHV	23%	25%	24%	26%
Emissions Characteristics				
NO_x, ppmv	9	9	25	15
NO_x, kg/MWh	0.23	0.23	0.59	0.32
CO, ppmv	40	9	50	15
CO, kg/MWh	0.59	0.14	0.73	0.18
SO_x, ppm	0.21	0.23	0.22	0.23
SO_x, kg/MWh	0.004	0.004	0.004	0.003
THC, ppmv	< 9	<9	<9	<9
THC, kg/MWh	<0.09	<0.09	<0.09	<0.09
NMOC, ppmv	0.9	0.9	0.9	1
NMOC, kg/MWh	0.009	0.008	0.009	0.009
PM_{10}, ppmv	N/A	N/A	N/A	N/A
PM_{10}, kg/MWh	0.28	0.26	0.27	0.25
CO_2, kg/MWh	800	719	748	696
Carbon, kg/MWh	225	197	197	190

Table C.4: Current and advanced microturbine characteristics.

Emissions and Performance Projections 30 kW Microturbine System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Nominal Capacity (kW)	30	30	30	50	50
Turbine	Metallic	Metallic	Metallic	Ceramic	Ceramic
Electrical Heat Rate (KJ/kWh), HHV	15,904	14,400	13,846	11,246	10,586
Electric Efficiency (%), HHV	23%	25%	26%	32%	34%
Fuel Input (GJ/hr)	0.44	0.43	0.41	0.55	0.52
Emissions Characteristics					
NO_x, ppmv	9	9	5	3	3
NO_x, kg/MWh	0.23	0.21	0.11	0.05	0.05
CO, ppmv	40	40	30	20	20
CO, kg/MWh	0.63	0.57	0.41	0.20	0.20
SO_x, ppmv	0.21	0.22	0.23	0.23	0.24
SO_x, kg/MWh	0.004	0.004	0.004	0.003	0.003
NMOC, ppmv	0.9	0.9	0.9	0.9	0.9
NMOC, kg/MWh	0.009	0.009	0.009	0.005	0.005
PM_{10}, ppmv	N/A	N/A	N/A	N/A	N/A
PM_{10}, kg/MWh	0.281	0.254	0.240	0.118	0.104
CO_2, kg/MWh	800	721	692	567	533
Carbon, kg/MWh	225	215	206	152	147

Emissions and Performance Projections 70 kW Microturbine System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Nominal Capacity (kW)	70	70	110	110	110
Turbine	Metallic	Metallic	Ceramic	Ceramic	Ceramic
Electrical Heat Rate (KJ/kWh), HHV	14,289	13,741	11,251	10,286	9,732
Electric Efficiency (%), HHV	25%	26%	32%	35%	37%
Fuel Input (GJ/hr)	0.96	0.94	1.23	1.12	1.06
Emissions Characteristics					
NO_x, ppmv	9	9	5	3	3
NO_x, kg/MWh	0.20	0.19	0.09	0.05	0.05
CO, ppmv	9	9	9	9	9
CO, kg/MWh	0.12	0.12	0.10	0.09	0.08
SO_x, ppmv	0.23	0.24	0.22	0.24	0.22
SO_x, kg/MWh	0.004	0.004	0.003	0.003	0.002
NMOC, ppmv	0.9	0.9	0.9	0.9	0.9
NMOC, kg/MWh	0.009	0.005	0.005	0.005	0.005
PM_{10}, ppmv	N/A	N/A	N/A	N/A	N/A
PM_{10}, kg/MWh	0.259	0.249	0.168	0.127	0.100
CO_2, kg/MWh	718	692	567	517	490
Carbon, kg/MWh	197	197	161	147	139
Emissions and Performance Projections 100 kW Microturbine System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Nominal Capacity (kW)	100	100	160	160	160
Turbine	Metallic	Metallic	Ceramic	Ceramic	Ceramic
Electrical Heat Rate (KJ/kWh), HHV	13,846	12,417	10,001	9,473	9,231
Electric Efficiency (%), HHV	25%	29%	36%	38%	39%
Fuel Input (GJ/hr)	1.38	1.24	1.60	1.51	1.47
Emissions Characteristics					
NO_x, ppmv	15	9	5	3	3
NO_x, kg/MWh	0.33	0.18	0.09	0.05	0.04
CO, ppmv	15	15	15	15	15
CO, kg/MWh	0.20	0.18	0.10	0.14	0.14
SO_x, ppmv	0.21	0.23	0.23	0.25	0.22
SO_x, kg/MWh	0.003	0.003	0.003	0.003	0.002
NMOC, ppmv	1	1	1	1	1
NMOC, kg/MWh	0.009	0.009	0.005	0.005	0.005
PM_{10}, ppmv	N/A	N/A	N/A	N/A	N/A
PM_{10}, kg/MWh	0.25	0.22	0.14	0.11	0.09
CO_2, kg/MWh	696	624	503	476	465
Carbon, kg/MWh	198	184	152	143	136

Emissions and Performance Projections 250 kW Microturbine System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Nominal Capacity (kW)		200	250	250	250
Turbine		Metallic	Ceramic	Ceramic	Ceramic
Electrical Heat Rate (KJ/kWh), HHV		12,000	10,001	9,473	9,231
Electric Efficiency (%), HHV		30%	36%	38%	39%
Fuel Input (GJ/hr)		2.39	2.99	2.36	2.31
Emissions Characteristics					
NO_x, ppmv		9	5	3	3
NO_x, kg/MWh		0.17	0.08	0.04	0.04
CO, ppmv		20	20	20	20
CO, kg/MWh		0.23	0.19	0.18	0.17
SO_x, ppmv		0.24	0.25	0.23	0.23
SO_x, kg/MWh		0.003	0.003	0.002	0.002
NMOC, ppmv		1	1	1	1
NMOC, kg/MWh		0.005	0.005	0.005	0.005
PM_{10}, ppmv		N/A	N/A	N/A	N/A
PM_{10}, kg/MWh		0.20	0.12	0.10	0.09
CO_2, kg/MWh		603	503	476	465
Carbon, kg/MWh		172	143	137	132
Emissions and Performance Projections 500 kW Microturbine System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Nominal Capacity (kW)			500	500	500
Turbine			Ceramic	Ceramic	Ceramic
Electrical Heat Rate (KJ/kWh), HHV			10,001	9,231	8,999
Electric Efficiency (%), HHV			36%	39%	40%
Fuel Input (GJ/hr)			5.00	4.61	4.50
Emissions Characteristics					
NO_x, ppmv			5	3	3
NO_x, kg/MWh			0.08	0.04	0.04
CO, ppmv			20	20	20
CO, kg/MWh			0.19	0.17	0.17
SO_x, ppmv			0.25	0.23	0.23
SO_x, kg/MWh			0.003	0.002	0.002
NMOC, ppmv			1	1	1
NMOC, kg/MWh			0.005	0.005	0.005
PM_{10}, ppmv			N/A	N/A	N/A
PM_{10}, kg/MWh			0.12	0.08	0.07
CO_2, kg/MWh			503	465	454
Carbon, kg/MWh			143	132	129

Table C.5: Gas engine emission characteristics

Emissions Characteristics	System1	System1a	System2	System3	System4	System5
Electricity Capacity (kW)	100	100	300	800	1000	5000
Electrical Efficiency (HHV)	30%	29%	31%	34%	35%	37%
Engine Combustion	Rich burn	Rich burn three way catalyst	Lean burn	Lean burn	Lean burn	Lean burn
NO_x, ppmv @ 15% O_2	1,100	11	150	80	44	46
NO_x, kg/MWh	20.87	0.21	2.81	1.41	1.00	0.73
CO, ppmv @ 15% O_2	1,366	67	391	300	290	300
CO, kg/MWh	16.8	0.8	2.8	2.8	3.5	3.4
SO_x, ppmv	0.24	0.24	0.24	0.23	0.23	0.23
SO_x, kg/MWh	0.003	0.003	0.003	0.003	0.002	0.002
UHC, ppmv @15% O_2	310	311	830	1400	1130	160
UHC, kg/MWh	2.08	2.08	5.58	9.07	7.03	0.91
NMOC, kg/MWh	1.00	0.21	1.41	1.41	1.81	0.73
CO_2, kg/MWh	610	603	582	533	515	489
Carbon, kg/MWh	171	171	159	149	141	127

Table C.6: Current and advanced gas engine characteristics

Emissions & Performance Projections 100 kW Gas Engine System – Rich Burn with Three-Way Catalyst					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Electrical Heat Rate (KJ/kWh), HHV	12,132	11,802	11,427	11,077	10,586
Electric Efficiency (%)	30%	31%	32%	33%	34%
Fuel Input (GJ/hr)	1.21	1.18	1.13	1.10	1.05
Emissions Characteristics					
NO_x, ppmv	11	11	8	8	8
NO_x, kg/MWh	0.21	0.21	0.14	0.14	0.14
CO, ppmv	69	69	62	40	14
CO, kg/MWh	0.81	0.81	0.68	0.40	0.13
SO_x, ppmv	0.24	0.24	0.25	0.23	0.24
SO_x, kg/MWh	0.003	0.003	0.003	0.003	0.003
NMOC, kg/MWh	0.21	0.21	0.14	0.14	0.14
CO_2, kg/MWh	610	593	575	557	533
Carbon, kg/MWh	171	171	159	150	143
Emissions & Performance Projections 300 kW Gas Engine CHP System, Lean Burn					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Electrical Heat Rate (KJ/kWh), HHV	11,570	11,427	11,075	10,745	10,285
Electric Efficiency (%)	31%	32%	33%	34%	35%
Fuel Input (GJ/hr)	3.48	3.42	3.32	3.22	3.08
Emissions Characteristics					
NO_x, ppmv	148	115	79	40	8
NO_x, kg/MWh	2.68	2.00	1.39	0.66	0.16
CO, ppmv	255	272	215	220	148
CO, kg/MWh	2.81	2.81	2.09	2.09	1.41
SO_x, ppmv	0.22	0.23	0.24	0.21	0.21
SO_x, kg/MWh	0.003	0.003	0.003	0.002	0.002
NMOC, kg/MWh	1.41	1.41	1.41	1.05	0.70
CO_2, kg/MWh	582	574	557	540	517
Carbon, kg/MWh	159	152	143	136	136

Emissions & Performance Projections 800 kW Gas Engine System, Lean Burn					
Year	**Current**	**2005**	**2010**	**020**	**2030**
Electrical Heat Rate (KJ/kWh), HHV	10,809	9,472	8,999	8,570	8,570
Electric Efficiency (%)	33%	38%	40%	42%	42%
Fuel Input (GJ/hr)	8.65	7.57	7.19	6.85	6.85
Emissions Characteristics					
NO_x, ppmv	83	66	50	26	11
NO_x, kg/MWh	1.41	0.98	0.70	0.35	0.14
CO, ppmv	350	390	412	260	173
CO, kg/MWh	3.66	3.52	3.52	2.11	1.41
SO_x, ppmv	0.23	0.26	0.23	0.24	0.24
SO_x, kg/MWh	0.003	0.003	0.002	0.002	0.002
NMOC, kg/MWh	1.34	0.98	0.98	0.84	0.14
CO_2, kg/MWh	544	476	445	431	431
Carbon, kg/MWh	149	130	122	117	117

Emissions & Performance Projections 1000 kW Gas Engine System, Lean Burn					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Electrical Heat Rate (KJ/kWh), HHV	10,602	10,139	9,599	9,113	8,674
Electric Efficiency (%)	34%	36%	38%	40%	42%
Fuel Input (GJ/hr)	10.65	10.13	9.60	9.11	8.67
Emissions Characteristics					
NO_x, ppmv	90	68	51	27	11
NO_x, kg/MWh	1.41	0.98	0.70	0.35	0.14
CO, ppmv	296	322	253	272	186
CO, kg/MWh	2.81	2.81	2.11	2.11	1.41
SO_x, ppmv	0.21	0.22	0.23	0.21	0.21
SO_x, kg/MWh	0.002	0.002	0.002	0.002	0.002
NMOC, kg/MWh	1.41	1.41	0.98	0.84	0.70
CO_2, kg/MWh	517	464	441	411	398
Carbon, kg/MWh	141	127	120	112	109

Emissions & Performance Projections 5000 kW Gas Engine System, Lean Burn					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Electrical Heat Rate (KJ/kWh), HHV	9,719	9,230	8,779	8,371	7,999
Electric Efficiency (%)	37%	39%	41%	43%	45%
Fuel Input (GJ/hr)	48.6	46.1	43.8	41.8	39.9
Emissions Characteristics					
NO_x, ppmv	46	49	41	27	11
NO_x, kg/MWh	0.70	0.70	0.57	0.35	0.14
CO, ppmv	384	413	371	309	206
CO, kg/MWh	3.36	3.36	2.81	2.11	1.41
SO_x, ppmv	0.23	0.24	0.26	0.23	0.23
SO_x, kg/MWh	0.002	0.002	0.002	0.002	0.002
NMOC, kg/MWh	0.70	0.70	0.70	0.35	0.35
CO_2, kg/MWh	465	433	398	362	362
Carbon, kg/MWh	127	118	109	99	99

Table C.7: Fuel cell emission characteristics

Emissions Analysis	**System1**	**System2**	**System3**	**System4**	**System5**	**System6**
Fuel Cell Type	PAFC	PEMFC	PEMFC	MCFC	MCFC	SOFC
Electricity Capacity (kW)	200	5-10	150-250	250	2000	100-250
Electrical Efficiency (HHV)	36%	30%	35%	43%	46%	45%
Emissions						
NO_x, ppmv @ 15% O_2	1	1.8	1.8	2	2	2
NO_x, kg/MWh	0.02	0.05	0.05	0.03	0.02	0.02
CO, ppmv @ 15% O_2	2	2.8	2.8	2	2	2
CO, kg/MWh	0.02	0.03	0.03	0.02	0.02	0.02
SO_x, ppmv	0.21	0.24	0.24	0.24	0.24	0.24
SO_x, lb/MWh	0.002	0.003	0.003	0.002	0.002	0.002
NMOC, ppmv @ 15% O_2	0.7	0.4	0.4	0.5	1	1
NMOC, kg/MWh	0.005	0.005	0.005	0.005	0.005	0.005
CO_2, kg/MWh	515	617	531	431	404	413
Carbon, kg/MWh	141	168	143	118	109	111

Table C.8: Current and advanced fuel cell characteristics

Emissions and Performance Projections 200 kW PAFC Fuel Cell System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Fuel Cell Technology	PAFC	PAFC	PAFC	PAFC	PAFC
System Size, kW	200	200			
Electrical Heat Rate (KJ/kWh), HHV	10,001	10,001			
Electrical Efficiency (%)	36%	36%			
Fuel Input (GJ/hr)	2.0	2.0			
Emissions Characteristics					
NO_x, ppmv	1.2	1.2			
NO_x, kg/MWh	0.02	0.02			
CO, ppmv	2.4	2.4			
CO, kg/MWh	0.02	0.02			
VOC, ppmv	0.8	0.8			
NMOC, kg/MWh	0.005	0.005			
CO_2, kg/MWh	517	517			
Emissions and Performance Projections 5-10 kW PEMFC System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Fuel Cell Technology		PEMFC	PEMFC	PEMFC	PEMFC
System Size, kW		10	10	10	10
Electrical Heat Rate (KJ/kWh), HHV		11,995	11,246	10,286	10,001
Electrical Efficiency (%)		30%	32%	35%	36%
Fuel Input (GJ/hr)		0.11	0.11	0.10	0.09
Emissions Characteristics					
NO_x, ppmv		1.5	1.5	1.4	1.4
NO_x, kg/MWh		0.03	0.03	0.02	0.02
CO, ppmv		2.8	2.5	2.8	2.8
CO, kg/MWh		0.03	0.03	0.03	0.03
VOC, ppmv		0.7	0.7	0.8	0.8
NMOC, kg/MWh		0.005	0.005	0.005	0.005
CO_2, kg/MWh		617	581	531	517

Emissions and Performance Projections 200-250 kW PEMFC System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Fuel Cell Technology		PEMFC	PEMFC	PEMFC	PEMFC
System Size, kW		200	200	200	200
Electrical Heat Rate (KJ/kWh), HHV		10,286	10,001	9,473	9,473
Electrical Efficiency (%)		35%	36%	38%	38%
Fuel Input (GJ/hr)		2.05	2.00	1.89	1.89
Emissions Characteristics					
NO_x, ppmv		2.8	2.0	1.5	1.5
NO_x, kg/MWh		0.05	0.03	0.02	0.02
CO, ppmv		3.3	1.9	2.0	2.0
CO, kg/MWh		0.03	0.02	0.02	0.02
VOC, ppmv		0.8	<0.8	<0.8	<0.8
NMOC, kg/MWh		0.005	<0.005	<0.005	<0.005
CO_2, kg/MWh		531	517	490	490

Emissions and Performance Projections 250 kW MCFC Fuel Cell System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Fuel Cell Technology	MCFC	MCFC	MCFC	MCFC	MCFC
System Size, kW	250	250	250	250	250
Electrical Heat Rate (KJ/kWh), HHV	8,366	8,336	7,999	7,300	7,300
Electrical Efficiency (%)	43%	43%	45%	49%	49%
Fuel Input (GJ/hr)	2.08	2.08	2.00	1.83	1.83
Emissions Characteristics					
NO_x, ppmv	2.0	2.0	1.8	1.6	1.6
NO_x, kg/MWh	0.03	0.03	0.02	0.02	0.02
CO, ppmv	2.3	2.3	2.4	1.9	1.9
CO, kg/MWh	0.02	0.02	0.02	0.01	0.01
VOC, ppmv	1.0	1.0	<1.0	<1.1	<1.1
NMOC, kg/MWh	0.005	0.005	<0.005	<0.005	<0.005
CO_2, kg/MWh	431	431	412	378	378

Emissions and Performance Projections 2,000 kW MCFC Fuel Cell System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Fuel Cell Technology		MCFC	MCFC	MCFC	MCFC
System Size, kW		2,000	2,000	2,000	2,000
Electrical Heat Rate (KJ/kWh), HHV		7,828	7,501	7,195	6,920
Electrical Efficiency (%)		46%	48%	50%	52%
Fuel Input (GJ/hr)		15.6	15.0	14.4	13.84
Emissions Characteristics					
NO_x, ppmv		1.9	1.9	1.6	1.6
NO_x, kg/MWh		0.02	0.02	0.02	0.02
CO, ppmv		2.4	1.9	1.9	2.0
CO, kg/MWh		0.02	0.01	0.01	0.01
VOC, ppmv		1.1	<1.1	<1.1	<1.2
NMOC, kg/MWh		0.005	<0.005	<0.005	<0.005
CO_2, kg/MWh		404	386	372	358
Emissions and Performance Projections 100-250 kW SOFC Fuel Cell System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Fuel Cell Technology		SOFC	SOFC	SOFC	SOFC
System Size, kW		100	100	100	100
Electrical Heat Rate (KJ/kWh), HHV		7,996	7,342	7,057	6,794
Electrical Efficiency (%)		45%	49%	51%	53%
Fuel Input (GJ/hr)		0.80	0.73	0.70	0.67
Emissions Characteristics					
NO_x, ppmv		1.8	1.9	1.6	1.7
NO_x, kg/MWh		0.02	0.02	0.02	0.02
CO, ppmv		2.4	1.9	2.0	2.1
CO, kg/MWh		0.02	0.01	0.01	0.01
VOC, ppmv		1.0	<1.1	<1.1	<1.2
NMOC, kg/MWh		0.005	<0.005	<0.005	<0.005
CO_2, kg/MWh		412	378	363	350

APPENDIX D: ESM MODEL ASSUMPTIONS

Technology performance and cost data

Table D.1 shows key technology cost and performance assumptions for centralised generation (CG) plant that have been applied in modelling the base case scenario. Capital costs refer to the installed cost including the capital charges during construction period, royalty allowances, cost of land and site improvement or mine development and other owner's costs.

The volatility of generation markets can have a positive or negative effect on generation plant costs. For example, in the years during and following the Asian Economic Crisis, the costs of power plant, particularly gas-fired units, fell significantly as many potential buyers in Asia were forced out of the generation plant market. Currently it appears the market has moved in the opposite direction. A surge in demand for new power plants has occurred together with a period of strong demand growth for metals and other plant input materials (DOE/EIA, 2006).

Table D.1: Technology cost and performance assumptions, 2010: centralised generation

	Installed Capital Plant cost A$/kW years	**Capacity factor**	**Thermal Efficiency**	**O&M cost A$/MWh**	**Fuel cost A$/MWh**	**life**
Brown coal pf	2050	0.87	0.31	6.0	5.8	50
Black coal pf	1850	0.80	0.40	6.6	9.0	50
Black coal IGCC	2450	0.80	0.41	8.0	8.8	50
Natural gas combined cycle	1200	0.80	0.49	7.8	22.0	25
Solar Thermal	3420	0.27	na	20.3	na	25
Wind	1925	0.29	na	7.9	na	25
Large Hydro	3010	0.20	na	28.5	na	100
Biomass	2975	0.55	0.26	6.0	20.8	30
Brown coal IGCC	2900	0.80	0.41	8.3	4.4	50
Brown coal CCS	3295	0.80	0.32	11.3	5.6	50
Black coal CCS	3215	0.80	0.33	11.0	10.8	50
Brown coal partial CCS	2555	0.80	0.37	11.3	4.9	50
Black coal partial CCS	2450	0.80	0.37	11.0	9.7	50
Gas peaking	700	0.20	0.20	23.5	54.0	25
Gas with CCS	1750	0.80	0.43	12.0	25.1	25
Nuclear	4175	0.80	0.34	12.8	7.9	50
Hot fractured rocks	5290	0.80	na	17.8	na	25

Notes:
Pf: pulverised fuel; IGCC: integrated gasification combined cycle.
Capture rate of 90% and 50% is assumed for CCS and partial CCS technologies, respectively.
The capital cost of nuclear power includes the cost of decommissioning the plant (it adds approximately $300/kW). This approach is mathematically equivalent to adding the decommissioning cost to the annual operating cost of the plant and so does not pre-empt any potential arrangements in Australia with regard to paying upfront versus making annual payment over the life of the plant.
Thermal efficiency refers to the ratio of useful energy output to non-renewable energy input based on gross calorific value (higher heating value). These ratios are only recorded if they use a fuel.
Capacity factors for renewables represent an average of the best available currently undeveloped sites across all States.
Fuel costs assume current cost of fuel. Fuel costs increase with time or volume consumed in the modelling

Operating and maintenance (O&M) costs include labour charges for regular operation and maintenance of plant equipment, cost of maintenance material, and labour charges associated with administration and support functions for plant operations.

The capital cost, O&M cost and thermal efficiency data for CG technologies are recent CSIRO estimates but are closely related to Wibberley et al. (2006). Fuel costs are derived from the primary cost of fuel that prevailed in the base-year, 2006. On average, across the States these are estimated to be: black coal ($1/GJ); brown coal ($0.5/GJ); natural gas ($3/GJ); biomass ($1.5/GJ); diesel ($15/GJ) and uranium ($0.75/GJ).

Table D.2: Main ESM assumptions for distributed generation technologies at 2010.

Technology name	End-user	Fuel	Indicative size	O&M cost ($/MWh)	Capital Cost ($/kW)	Electrical Efficiency (% HHV)	Maximum Total Efficiency (% HHV)	Fuel transport cost ($/GJ)	Economic life (years)	Capacity factor (%)
Combined cycle CHP	Industrial	Gas	30 MW	35	1935	45	81	1.35	20	65
Fuel cell CHP	Residential	Gas	2 kW	70	3476	58	79	11.20	15	80
Microturbine CCHP	Commercial	Gas	60 kW	15	4268	28	78	5.85	15	43
Microturbine CHP	Commercial	Gas	60 kW	10	3734	28	78	5.85	15	18
Rankine CHP	Rural	Biomass	30 MW	30	3169	28	56	24.60	25	65
Reciprocating engine	Industrial	Gas	5 MW	5	1265	40	N/A	1.35	20	1
Reciprocating engine	Commercial	Gas	500 kW	2.5	1265	38	N/A	5.85	20	3
Reciprocating engine	Residential	Gas	5 kW	2	919	36	N/A	11.20	20	1
Reciprocating engine	Commercial	Diesel	500 kW	5	460	45	N/A	1.55	15	3
Reciprocating engine	Commercial	Biogas	500 kW	0.5	2068	38	N/A	0.50	20	80
Reciprocating engine CCHP	Residential	Gas	5 MW	15	4439	40	84	1.35	20	80
Reciprocating engine CCHP	Commercial	Gas	500 kW	10	2497	38	80	5.85	20	43
Reciprocating engine CCHP	Residential	Biogas	5 MW	15	4439	40	84	0.50	20	80
Reciprocating engine CCHP	Commercial	Biogas	500 kW	10	2497	38	80	0.50	20	43
Reciprocating engine CHP	Industrial	Gas	1 MW	7.5	1776	40	84	1.35	20	65
Reciprocating engine CHP	Commercial	Gas	500 kW	5	1998	38	80	5.85	20	18
Solar PV	Commercial	Solar	40 kW	0.5	7027	N/A	N/A	N/A	25	variable
Solar PV	Residential	Solar	1 kW	0.5	8384	N/A	N/A	N/A	25	variable
Wind turbine	Commercial	Wind	10 kW	0.5	6090	N/A	N/A	N/A	15	variable
Wind turbine	Residential	Wind	1 kW	0.5	4964	N/A	N/A	N/A	10	variable

Treatment of technological change

There are several factors that impact upon projections of future costs of electricity generation technologies. The three factors which we have attempted to account for in our methodology are:

- Resource constraints or the quality of resources available
- The volatility of generation plant markets, and
- Technological improvement or "learning".

With regard to the third factor, it is broadly recognised that technological improvement has a close relationship with deployment. This observation was first made in the early part of last century during the study of industrial production of military aircraft (Wright, 1936). It was found that a reduction in costs of technologies can be observed as a fixed rate for each doubling of cumulative production. These relationships are often called experience or learning curves.

Experience or learning curves are applied at the world level so that costs decline as a function of each doubling of cumulative global capacity installed. The learning curve approach recognises that reductions in the cost of capital or plant are directly the result of learning that occurs through experience ("learning by doing") and economies of scale as a technology is adopted, rather than indirectly through the passing of time. A key implication of this approach is that cost changes can occur at any point in time so long as there has been a sufficient interval for capacity to be installed and the relevant economic or policy drivers are in place to kick-start adoption.

The historical learning rate for currently deployed electricity generation technologies has been comprehensively reported elsewhere (e.g., McDonald and Shrattenholzer, 2001). However, what we require for our purposes is the future learning rate. Future learning rates will change as technologies pass through various stages of their technological development. For example, a technology with a learning rate of 20 per cent for each doubling of cumulative capacity in the last ten years may have a learning rate of only 10 per cent in the next 20 years as it becomes more mature. As a result, setting a fixed learning rate now based on historical rates may overestimate future technological change.

To form estimates for future capital costs of our CG technologies, we used the following approach:

- Average learning rates for immature technologies of around 10-15 per cent
- Average learning rates for mature technologies of around 0-5 per cent
- A lower bound on technology costs equal to the cost of the current most dominant technology, and
- Maximum rate of change in five year period is 10 per cent unless specific advice available that a breakthrough is occurring.

Based on this approach, the estimated time path of capital costs for our CG technology set is shown in Figure D.1. With regard to DG technologies, we employed estimates from a report commissioned by the UK Department of Industry (Energy Savings Trust, 2005). It uses a similar methodology to that described for CG technologies, but does not place limits on the maximum rate of change over a time period or impose lower bounds. The estimated time path of capital costs for our DG technology set is shown in Figure D.2.

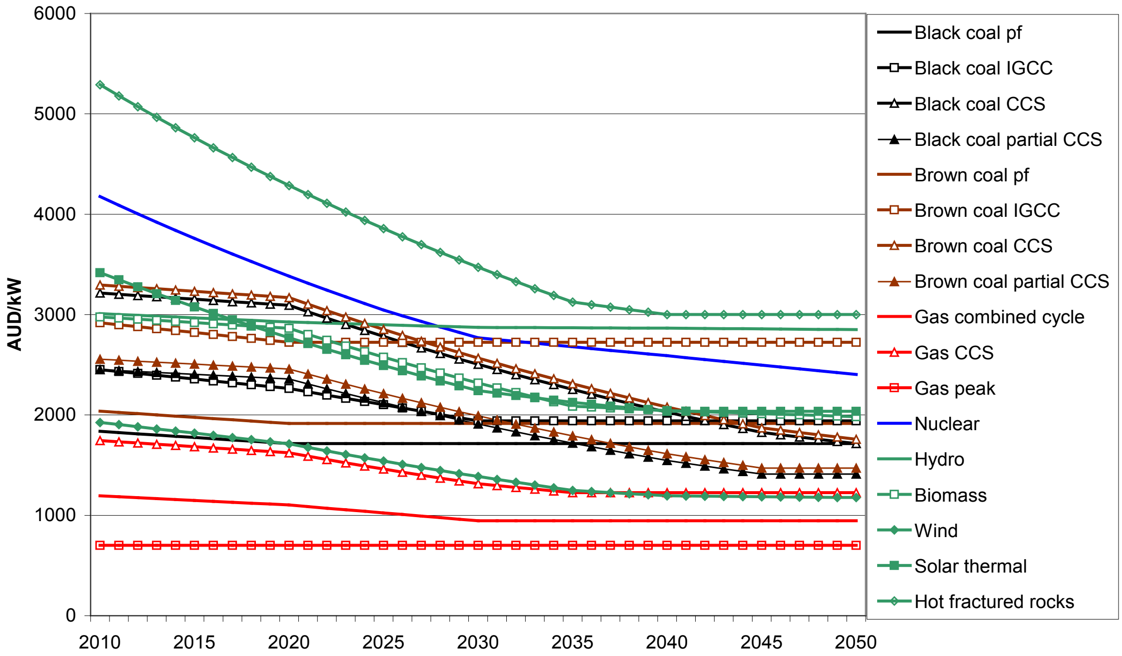


Figure D.1: Estimated time path of installed capital costs for CG technologies

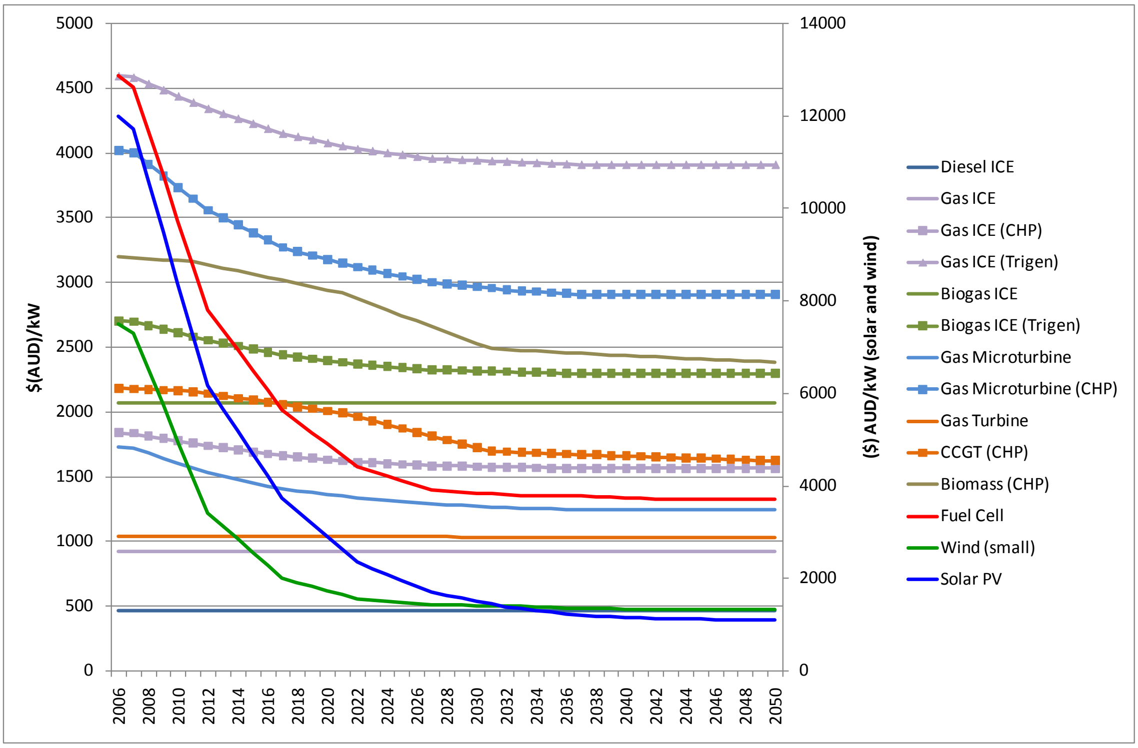


Figure D.2: Estimated time path of installed capital costs for DG technologies

It is important to note that these capital costs are not the sole determinant of technological choice. For technologies based on natural gas, for example, the cost of fuel may be of greater importance. Also some high cost technologies such as hydro, solar thermal and gas peaking plant derive a significant portion of their revenue from the higher value peak market. The quality of the resource available to the power plant is also very important. For example, there is significant variance in the quality of wind sites available across Australia.

Electricity demand, economic growth and price responsiveness

Projections of future electricity demand by State are available from ABARE (ABARE, 2006). ABARE's regular national projections relate only to business as usual scenarios. They are based on future projections of economic growth, improvements in energy efficiency and some efforts to identify near term energy intensive projects, such as those associated with alumina refineries. ABARE projects the average growth rate for Australia to 2030 to be around 1.9 per cent, per annum.

Base case demand projections are adjusted downward for emission reduction scenarios to take into account:

- Lower economic growth as a result of internalising costs of CO_2 emissions into final goods and services consumed, and
- Lower energy required per unit of GDP due to structural change in the economy (energy intensive industries decline at the expense of less energy intensive industries) and greater uptake of energy saving technologies and processes. Counter to this is the possible protection of carbon intensive export exposed industries which will reduce the amount of restructuring that might have taken place (Prime Ministerial Task Group on Emissions Trading, 2007).
- The degree of change in GDP and energy efficiency is not calculated by the model but is adapted from the literature such as Energy Futures Forum (2006). The imposition of CO_2 prices generally reduces electricity demand growth to around 1.5 per cent to 2030.
- Demand growth is not entirely fixed because ESM assumes that consumers will respond negatively to electricity price rises and positively to electricity price decreases. As reported in Graham et al. (2005), price elasticities of demand for electricity in the literature generally range from -0.2 to -0.5. This means a 10 per cent increase in prices would lead to a 2 to 5 per cent decrease in electricity demand.
- The price elasticity of demand for electricity can be expected to change over time. A useful way to consider this is to think of a household budget. For a person earning an after tax income of $25,000 and an annual electricity bill of $1,000, electricity represents 4 per cent of their annual budget. By 2050, assuming a 2 per cent per annum real increase in wages, their after tax real income will be approximately $60,000. On a constant price basis electricity now represents just 1.6 per cent of the annual budget. As a result, the household's response to a given percentage change in this budget item is likely to be smaller than at present. If we also consider that price elasticity of demand estimates are based on data from the previous two decades then it is possible that

present price elasticity estimates are already out of date in terms of reflecting household and other group's responses to price changes.

For this reason, in ESM it is assumed the price elasticity of demand is at the very bottom of the range in the literature at -0.2. Furthermore, this price elasticity only applies for large price changes (above 25 per cent). For small price changes, the price elasticity of demand is assumed to be -0.1. These are applied uniformly across all customers, except for industrial end-users.

Capacity factors

Capacity factors for DG technologies can vary depending on end-user requirements. Table D.3 lists the capacity factors that have been assumed in the modelling.

Table D.3: Capacity factors by DG technology and end-user

Technology/end-user	Industrial	Commercial	Residential	Rural
Diesel engines	3%	1%	1%	30%
Gas engines	30%	30%	N/A	N/A
Gas turbines	30%	N/A	N/A	N/A
Gas Cogeneration	65%	30%	30-80%	N/A
Gas Trigeneration	N/A	43%	80%	N/A
Biomass Cogen	N/A	N/A	N/A	45-80%
Biomass	N/A	N/A	N/A	80%
Biogas Trigeneration	N/A	43%	80%	N/A
Landfill gas engines	N/A	80%	N/A	N/A
Solar PV	17%	17%	17%	25%
Wind	17%	17%	17%	25%

The following are general comments on Table D.3:

- N/A means technology and end-user combinations are generally not applicable
- 30% capacity factor used where specific information not available
- A capacity factor of 80% usually reflects technology operating as base-load, and
- Capacity factors vary by State. Values in table are for NSW.

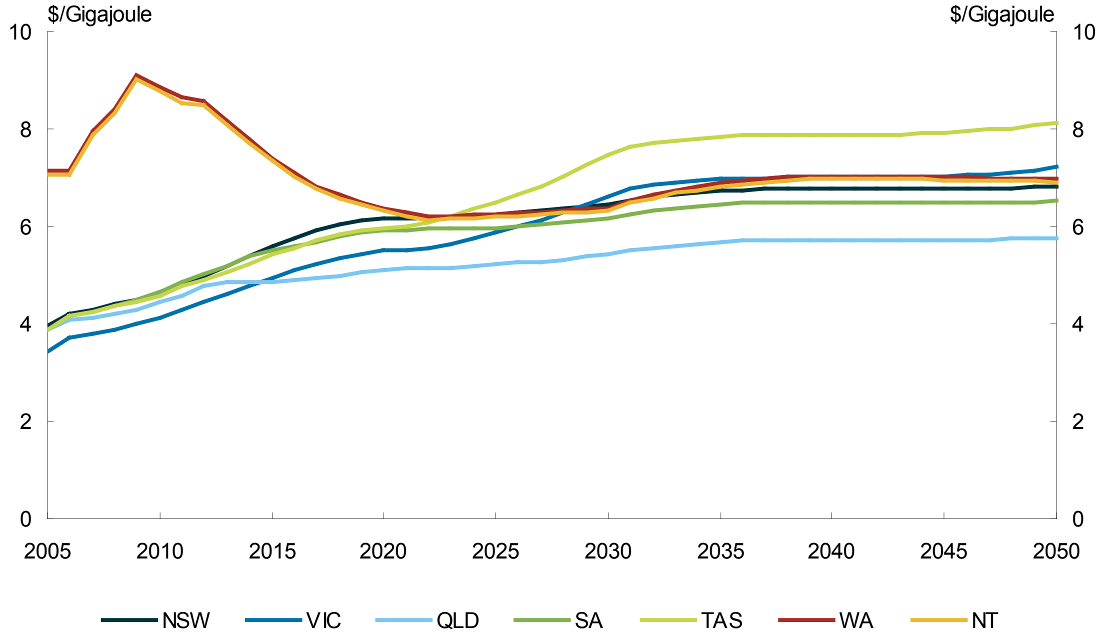
Some specific comments are also in order for Table D.3. These include:

- Diesel engines in industrial category mainly used for network support by distribution network service providers (DNSPs). Financial analysis typically conducted on 300 hours of operation per year (approximate 3% capacity factor). Employed in commercial and residential sectors as stand-by capacity in case of a power outage. Principally used in rural areas for off-grid power supply. Due to the lack of specific information a 30% capacity factor is assumed in rural areas
- Gas cogeneration installed in an industrial setting reflects a derived demand for process heat. It is assumed that the cogen unit meets the base-load heat demand (steam or hot water) with boilers used to meet peaks. Industrial processes are assumed to be operating during weekdays at a unit availability of 95%, gives a capacity factor of approximately 65%. This may understate usage in firms running processes on a twenty-four hour basis

- Gas cogeneration in a commercial setting is usually sited in buildings to provide hot water and space heating during cooler months. This gives an approximate capacity factor of 14-30% depending on State
- Gas cogeneration in a residential setting reflects two alternative models. One is a high-density model where the provision of space heating and hot water is provided to an apartment building during cooler months. The second model is the provision of space heating and hot water to a single household via a micro CHP unit. The high capacity factor applies to the latter because of the large heat to electricity output of micro CHP units (e.g. fuel cells)
- Gas trigeneration in a commercial setting is usually sited in buildings to provide hot water and space heating and cooling during week day office hours (7:00 – 22:00). This implies a 43% capacity factor. Note, this may understate usage in other commercial settings (e.g. shopping centres, airport terminals) where capacity factors could be higher
- Gas trigeneration in a residential setting reflects a high-density model similar to cogeneration. It can also reflect a low-density model such as a district heating and cooling system in a housing sub-division (e.g. GridX). The distribution of loads between a large number of households implies a base-load operation
- Biomass Cogen and biomass plants usually operate where the fuel is a by-product of another process (e.g. bagasse from sugar cane harvesting or wood waste from timber mills). The lower capacity factor reflects seasonal processes where fuel is only available during the harvesting season with the higher capacity factor applicable to non-seasonal processes
- Biogas trigeneration: see Gas cogeneration
- Landfill gas engines are generally assumed to be operating as base-load plant
- Solar PV capacity factors for metro areas are lower than that for rural areas reflecting the influence of cloud cover in coastal metropolitan areas. The 17% capacity factor is estimated data for Sydney for residential PV (Rae et al., 2009)
- Lower capacity factors for wind in non-rural areas reflect the influence of turbulence from the built environment on useful power production from small wind turbines. Higher capacity factors in rural areas reflect use of larger turbines and less impact of turbulence.

Natural gas prices

Natural gas is seen as a transition fuel to assist the electricity sector in transitioning from a high GHG emission intensity to more moderate GHG emission intensity in the medium term. The assumed natural gas prices employed in the modelling are shown in Figure D.3.



Source: MMA

Figure D.3: Domestic Australian natural gas prices (city node)

Prices for Western Australia and the Northern Territory are assumed to track the export price for liquid natural gas (LNG). The projected East coast gas prices assume moderate LNG penetration in Queensland. Prices at the Gladstone port are predicted to reach export parity in 2025 with the southern State prices converging with the Queensland price by around 2030.

The price of natural gas in other States is assumed to be largely driven by domestic demand and longer term supply contracts which do not completely track international market volatility.

Intermittency

Under the National Electricity Code (NEC), an intermittent generator is classified as: "a generating unit whose output is not readily predictable, including, without limitation, solar generators, wave turbine generators, wind turbine generators and hydro-generators without any material storage capability" (NECA, 2002: Chapter 10, p 27A).

An increased penetration of intermittent supply raises several issues in the Australian context. First, it may impair the accuracy of "demand" (scheduled generation) forecasts within the NEM. Second, it has implications for electrical system stability in maintaining power system frequency within defined limits through the dispatch of frequency control ancillary services (NEMMCO, 2003). Related to the above issues, is the increased need for spinning reserve to meet unexpected shortfalls in scheduled generation or increased fluctuations in frequency. To be reliable, such reserve would need to be provided by base-load fossil fuels (most likely gas), or non-intermittent renewable sources (e.g., biomass or hot fractured rocks).

A number of measures are being considered to overcome the problems posed by an increased proportion of intermittent generation in the NEM. The first measure is an improved spatial positioning of the intermittent technologies to reduce the volatility of their combined output. This measure relates to the observation that wind regimes experienced across a large power system are unlikely to be highly correlated (Archer and Jacobsen, 2003). Ideally, wind farms should be spread over different regions and not be permitted to bank up in single regions. Another measure is improvements in weather forecasting to reduce the uncertainty in the dispatch interval. Reliable wind power forecasting has the potential to considerably improve the cost-effectiveness of wind farms connected to the grid by reducing dispatch and commitment errors, reducing the need for spinning reserve (Outhred, 2003).

Recognising the potential difficulty in managing intermittency associated with wind and solar energy, the contribution of large intermittent technologies (>30 MW) was constrained to not exceed 20 per cent of total system generation capacity by 2020 and then linearly increased to a limit of 30 per cent by 2030 to recognise some improvement in cost effective storage availability. There is some uncertainty about whether this constraint is at the right level. Wind is already at a high penetration in overseas countries (e.g., Denmark and Germany) and South Australia, suggesting the constraint may be too low. The highly probable future development of cost-effective electricity or energy storage could push shares above 30 per cent if is progresses faster than expected.

Within ESM it is assumed that the intermittent constraint applies to centralised and not DG on the presumption that DG will be sufficiently geographically dispersed and at smaller scale than large (>30 MW) intermittent power stations.

Geological storage of CO_2

In determining the potential for the geological storage of CO_2, the GEODISC program assessed over 100 potential environmentally sustainable sites for CO_2 injection (ESSCIs) by applying a deterministic risk assessment based on five factors: storage capacity; injectivity potential; site details; containment; and natural resources. Utilising this approach, Australia has a CO_2 storage potential in excess of 1600 years of current annual total net emissions. However, this estimate does not account for various factors such as source to sink matching. According to Bradshaw et al. (2004), if preferences due to source to sink matching are incorporated, Australia may have the potential to store a maximum of 25 per cent of current annual total net emissions, or approximately 100 to 115 Mt CO_2 per year.

More recent analysis for Victoria assessed the cost and potential for the geological storage of CO_2 in the offshore Gippsland basin from the Latrobe Valley (Hooper et al., 2005). The study determined that up to 2000 Mt may be stored over a forty year period (50 Mt per year) and estimated the cost of CO_2 transport and storage via a 200 km pipeline at \$10.50/t. For Western Australia, analysis by Allinson et al. (2006) identified three potential storage sites in the Perth basin capable of storing 25 Mt per year for twenty five years with the cost of CO_2 transport and storage ranging from \$10 to \$15/t.

Given the lack of detailed information which would facilitate the construction of CO_2 transport and storage cost curves for all States, a disposal cost of \$10/t has been applied to any CO_2 stored. The amount of CO_2 that can be sequestered per year has been capped at 115 Mt as estimated by Bradshaw et al. (2004)

Air (dry) cooling

The occurrence of the worst drought conditions in eastern Australia since Federation has heightened debate about the efficient allocation of scarce water resources among competing end-users. This has been manifested in the widespread use of water restrictions, debate over desalination and stormwater harvesting in major cities, and discussions between the States and Commonwealth over administration of the Murray-Darling Basin.

The situation in south-east Queensland has forced the State Government to cut the water usage of Tarong North and Swanbank coal-fired power stations by 40 and 20 per cent, respectively. Given that electricity supply in Australia is currently dominated by coal-fired generation (approximately 81 per cent) this has raised the possibility of reduced water supply to power stations in other jurisdictions.

The default is to assume that new base load fossil fuel power stations installed after 2007 will be dry-cooled. We do not assume that existing water-cooled base load fossil fuel power stations will be converted to air-cooled plant.

The effect of air cooling is a subtraction of approximately 2 per cent in thermal efficiency relative to a water cooled plant and an additional \$100/kW in installed capital cost.

Discounting issues

Private rather than public discount rates are appropriate for this study because Australian electricity markets are, for the most part, deregulated, soon to be deregulated or operating on similar financial grounds. Private discount rates are typically in the order of 10-12 per cent in nominal or current price terms, equivalent to 7 to10 per cent in real terms (assuming inflation of around 2-3 per cent). Public discount rates which tend to be more sensitive to long-term benefits or costs might be closer to 5 per cent in nominal terms.

Currently, risk free assets such as treasury bonds deliver a real return on investment of 2-3 per cent per annum. The risk premium implied by applying the discount rate of 7 per cent to electricity industry investments is perhaps too high for some technologies and too low for others. What is sought for our purposes is an appropriate average real discount rate that can be applied to all technologies in the analysis.

Default electricity policy settings

Nuclear power

Nuclear power is not supported by the current federal government and is also legislatively prevented from being taken up in most States. The default assumption is to not allow nuclear power to be available as a technology.

Renewable Energy Target (RET)

RET seeks to increase the contribution of renewable energy sources in Australia's electricity mix by 9500 GWh per year by 2010. The recent change in government means that this will now increase to 45 000 GWh by 2020.

Within ESM, RET is modelled as a constraint on sent out electricity by ensuring that the amount of centralised and distributed renewable generation is not less than the minimum amounts set out in the legislation for each year to 2020 and a declining threshold to 2030.

Queensland 18 per cent gas target

On 24 May 2000, the Queensland Government announced the *Queensland Energy Policy – A Cleaner Energy Strategy*, with the key objectives of the policy being to diversify its energy mix, facilitate the supply and use of natural gas in Queensland, especially in electricity generation, and reduce growth in greenhouse gas emissions. A key component of the energy policy is the State’s 13 per cent gas scheme, which requires electricity retailers and other liable parties to source at least 13 per cent of their electricity from natural gas-fired generation. The scheme commenced on 1 January 2005 and will remain in place until 31 December 2019.

It should be noted that the Queensland Government recently expanded its gas target, requiring the share of natural gas-fired electricity consumed in Queensland to increase to 18 per cent by 2020. This policy change was included in the modelling in this report.

This scheme is implemented in the model in an approximate manner, requiring the share of natural gas-fired electricity consumed in Queensland to increase to 18 per cent by 2020. This modification reflects evidence that the amount of gas-fired generation was below target in 2005.

NSW Greenhouse Gas Abatement Scheme (GGAS)

In January 2002, the NSW Government released a Benchmarks Position Paper that set the aims and methodology for the Greenhouse Gas Abatement Scheme (GGAS). The scheme came into effect from 1 January 2003. From that time, NSW electricity retailers and some other parties (“benchmark participants”) must meet mandatory targets for abating the emission of greenhouse gases from electricity production and use, up until 2012.

The State-wide benchmark is to reduce greenhouse gas emissions to 7.27 tonnes of carbon dioxide equivalent per capita by 2007, which is 5 per cent below the baseline year of 1989-90.

The targets for abatement are higher each year from 2003 to 2007, and then the benchmark level must be maintained until 2012.

To reduce the average emissions of greenhouse gases, participants will purchase and surrender abatement certificates to the Independent Pricing and Regulatory Tribunal (IPART). Abatement certificates can be created from the following activities:

- Reduction in the greenhouse intensity of electricity generation
- Activities that result in reduced consumption of electricity ("demand side abatement")
- The capture of carbon from the atmosphere in forests, referred to as CO_2 sequestration, and
- Activities carried out by elective participants that reduce on-site emissions not directly related to electricity consumption.

Similar to RET, GGAS is modelled as a constraint that requires total emissions from NSW electricity generation to be less than or equal to the product of per person emissions and State population.

As mentioned above, currently the benchmark scheme ends in 2012. Rather than extending the scheme beyond 2012, the NSW Government has stated the preference for the introduction of a single national trading scheme. In the modelling of emission reduction scenarios, NGACS is not extended beyond 2012 due to the commencement of emissions trading.

State Renewable Energy Targets

It is assumed that the State renewable energy targets are replaced by the expanded RET

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