University of Southern Queensland
Faculty of Engineering & Surveying

MATLAB based Energy Market Simulator

A dissertation submitted by

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in fulfilment of the requirements of

Courses 4111 and 4112 Research Project

Towards the degree of

Bachelor of Engineering, (electrical and electronic)

Submitted: October, 2012

Abstract

The size and complexity of deregulated energy markets requires the use of simulators to assess how changes can affect the whole market. This dissertation presents the development of a MATLAB based energy market simulator based on the Australian National Electricity Market (NEM). Background research was conducted on the NEM to gain an understanding of the organisation, management and the technology deployed within the network. Raw data on the NEM was analysed to understand demand and pricing and how different generation technologies are operated. This data was then used to create a generic simulator capable of analysing electrical supply systems. The simulator was then used to demonstrate the benefits and problems with market managed systems and the impacts intermittent renewables can have on electrical supply systems.

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CERTIFICATION

I certify that the ideas, designs and experimental work, results, analyses and conclusions set out in this dissertation are entirely my own effort, except where otherwise indicated and acknowledged.

I further certify that the work is original and has not been previously submitted for assessment in any other course or institution, except where specifically stated.

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25/10/2012_____
Date

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Definitions

Availability factor	The percentage of time a unit is capable of producing power. Reflects the need to shut down for maintenance
Capacity factor	the percentage of power produced from an electrical generator compared to the maximum possible
CCGT	Combined Cycle Gas Turbine
FOM	fixed operation and maintenance
MO	market operator, responsible for the operation of an electricity market
MP	market participant
NEM	Refers to the Australian National Electricity Market the electrical supply system used in NSW, Queensland, Victoria, Tasmania and South Australia.
OCGT	Open Cycle Gas Turbine
POE	probability of exceedance
PV	photovoltaic
Ramp Rate	the rate of change in the power output from an electrical generator
VOM	variable operational and maintenance

1 Introduction

Electrical supply systems are used to generate and transmit electrical power to a wide range of consumers. Electrical supply systems are complex systems that are constantly adapting to changes in technology, user demands and government policy. Electrical supply systems are managed in two main ways vertically integrated and market based systems. A vertical integrated system is a more traditional approach where a single entity operates the entire electrical supply system. In a market based approach the electrical supply system is deregulated and opened up to allow several companies to compete to provide services to drive efficiency as companies focus on maximising profits.

According to (J. Contreras 2002) there is a demand for Power Engineering Graduates to have a better understanding of theoretical and practical foundations of electrical markets. This is becoming increasingly important with the progressive sophistication of electricity grids due to the increase in 'must run' intermittent renewable power, incorporation of technology to create smart grids and the need for better efficiency due to rapidly escalating costs.

Due to the size, complexity, cost and practicality of access to resources the best method to analysis aspects of electrical supply systems is to perform mathematical simulations. The aim of this project is to develop a flexible adaptable simulator for market based electrical supply systems. The simulator will incorporate concepts from the largest electrical supply system in Australia the Australian National Electricity Market (NEM).

The development of the simulator required background research on the NEM including its organisation, management and the technology deployed within the network. Collection and analysis of NEM data to gain an understating of the key aspects including demand profiles and how different generation technologies are used.

The simulator was developed using a rapid prototype methodology with the high level programing language and environment MATLAB. The inbuilt functions and the graphical layout editor in MATLAB were used to speed up development and to incorporate higher levels of functionality.

2   Literature Review

There are extensive publications on software tools for research and analysis of electrical supply systems. The software tools range in functionality and design purposes. They also range in levels of complexity and realism from very basic to replicating real world systems. These tools can use game theory, price forecasting and market simulation to better understand the complexity of electricity supply systems. (M Widjaja 2001) concluded market simulation was the most effective due to its ability to capture the dynamic movements of markets. Game theory is limited to finding the market equilibrium and not suitable for dynamic analysis and price forecasting approaches employing time series methods. Using load demand trends will not reflect strategic bidding by generators.

The design purpose sets the theme of the simulator and range in their application from educational demonstration tools to in depth simulators for real world applications. The design purpose also sets the complexity which ranges from multiple generators competing in a single pricing pool with a single load to more sophisticated models incorporating multiple load centres and the required transmission infrastructure. Different models also vary in their use of technical constraints and the audience they cater for.

(J. Contreras 2002) and (Dejan Pavavan 2003) present simulators that allow a group of people to come together across a network to create an energy market with someone acting as the market operator (MO) and everyone else acting as market participants (MP) to simulate the multiple competitors. The simulator acts like a game with the winner being the person who earns the most profit and relies on the revenue of each MP being made public.

(J. Contreras 2002) educational market simulator for engineering students is based on the Spanish electrical supply system. Students are assigned five generators and their respective operational and cost characteristics and have no knowledge of the characteristics of their competitor's generators. The simulator works in three steps. The class instructor operates as the market operator and broadcasts hourly loads to the students. The students derive a strategy and send production bids back to the market operator. The market operator clears the market and determines the market price and the revenue of each group. The students have access to a price forecasting tool and an optimisation tool to help maximise the profit of each generator. Constraints used include maximum and minimum output power, up and down ramp rates, minimum up time and revenue. The tool has shown to be a good learning tool as it encourages active participation.

(Dejan Pavavan 2003) presents an educational day ahead energy market simulator which is used at the University of Ljubljana for teaching undergraduates and post graduates power trading systems and mechanisms. Again students compete with each other to maximise profits however the process uses a double sided auction mechanism allowing both production and consumption bids. The system was set up to allow students to explore market pricing concepts including withholding strategies where power is deliberately withheld from the market to increase prices Again, the experiment was received well by students as it requires active involvement to increase motivation and understanding in the area of electricity markets.

(M Widjaja 2001) presents a simulator based on the Australian National Electricity Market (NEM) it was designed to allow stakeholders in the industry to analyse market behaviours, formulate optimum bids, and to investigate different market structures. It includes a structure similar to the NEM of two inter-connected regions and includes calculations to model energy transmission between regions and the losses involved. It uses a load engine to generate demand forecasts in a similar manner to the NEM with 10%, 50% and 90% probability of exceedence based on a normal distribution. The simulator demonstrates the fundamentals of the market in a very simplistic model using fictional data. It provides a basic NEM simulator but there is a lot of potential to expand on the model and incorporate more accurate real world data.

(George Grozev 2007) present an agent based simulator for the NEM called NEMSIM to explore evolutionary pathways. The simulator is highly complex and attempts to use historical data, technical infrastructure, agents and markets and environmental impacts. The agents are intelligent, adaptive and behave differently to pursue unique goal, make decisions on the basis of their own knowledge and adapt to in response to there and others experiences. The agents are used as equations are too static, aggregate or stylized to handle the complexity of long term energy market simulations. The simulator includes all key players in the NEM and includes a weather model covering the next 100 years.

The education energy market simulators examined provide a good demonstration of the operation of energy markets and supply demand fundamentals. However the simulators would benefit from the incorporation of real world data on demand and technology constraints to enhance the learning experience. Most simulators reviewed had a limited application to their design purpose and there would be benefits in creating a simulator that was broken down into component functions so it could be easily adapted to suit multiple purposes.

3 NEM Background Information

Electricity is supplied through complex electrical supply systems that are broken down into generation, transmission, distribution and retail sectors. Generation covers the production of the electricity, transmission is the high voltage transportation of electricity from the generation centres to the load centres. Distribution connects individual customers to the transmission system and the retail sector collects the revenue from customers.

There are four main electrical supply systems in Australia. Two vertically integrated systems, NT Power (Northern Territory) and Water and Horizon Power (north Western Australia). There are two market based systems, Wholesale Electricity Market (WEM) covering south west Western Australia and the Australian National Electricity Market (NEM) covering Queensland, NSW, ACT, Victoria, Tasmania and South Australia. (Davidson 2010)

The NEM is the largest electricity supply system in Australia generating 204 TWh and collected $7.4 billion in revenue from 9 million customers in the 2010/2011 financial year. The NEM is made up of 305 large generators with an installed capacity of 49,110 MW.   There are six transmission companies with 41,865 km of line, thirteen distribution companies with 754,462 km of line and 26 retail companies. The NEM has a record maximum summer demand of 35,551 MW and maximum winter demand of 34,442 MW. The NEM supplies energy to several different types of customers from residential and commercial to heavy industry Figure 3.1 Electrical usage in the NEM *Source:* Energy Supply Association of Australia. (Australian Energy Regulator 2011)

There are three main organisations in control of the NEM. The Australian Energy Market Commission (AEMC) write the rules. The Australian Energy Regulator (AER) enforces the rules and the Australian Energy Management Operator (AEMO) manages the market.

The NEM is operated as a whole but is broken down into 5 regions based on the states that are priced separately. The regions are connected with high capacity transmission lines called inter-connectors that allow energy to be traded between the regions. Transmission and distribution are supplied by monopolies due to the nature of the service, but there is competition in the retail and generation of power.

Energy is traded in the market by retailers and generators using financial mechanisms to hedge and trade around the spot market in order to manage their financial risks. This allows the market to offer firm contract prices to end user customers. Electricity is traded three ways (Davidson 2010).

Bilateral contracts are used in the short term energy market and the balancing market. Bilateral contracts account for 95% of the energy traded in the NEM. They are contracts between retailers and generators.

The STEM 4 market volume is a day ahead, half hourly open market that allows participants to buy and sell volumes of electricity to manage their bilateral portfolio.

The Balancing Market accounts for 6% of market volume and is used to manage adjustments in traded volume (Davidson 2010)
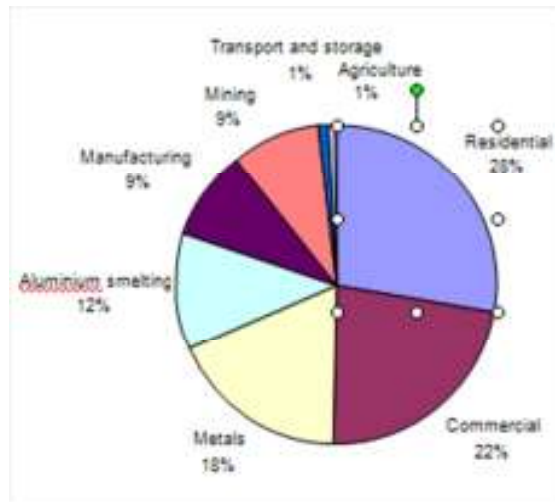
Figure 3.1 Electrical usage in the NEM *Source:* Energy Supply Association of Australia

3.2   Generators

Electricity is traditionally generated at large centralised installations using fossil fuels or hydro power. As well, energy generators generate revenue by providing ancillary services including reactive power and network frequency control. Different types of generators are used for maintaining grid stability and operational flexibility. Recently there has been a rapid increase in intermittent wind and solar power driven by large government incentives.

Generators are classified into three groups:

- Scheduled. (S)

- Semi scheduled. (SS)

- Non-scheduled. (NS)

Non-scheduled generators are typically less than 30 MW and greater than 5MW producing less than 20 GWh per year and do not participate in the dispatch system. Semi scheduled generators have a name plate rating of 30 MW or more powered from an intermittent energy source such as wind or run of river hydro. This classification gives the market operator scope to limit power output. Scheduled generators are 30 MW or more and participate in a dispatching system where they submit bids and receive operating instructions at five minute intervals.   (Australian Energy Market Commission 2012)

3.2.1 Power Generation Technology

Energy is typically generated at large centralised facilities. Most of the energy in the NEM is generated using two types of heat engine, the Rankin cycle and Brayton Cycle. Contributions also come from hydroelectricity, solar photovoltaic (PV) and wind power. Generators are rated in terms of their capacity for start-up time, maximum and minimum power levels and the rate at which their output levels can be changed (ramp rate). The majority of power in the NEM is generated in large centralised power stations that house several units. (Sharma 2012) (G Ramakrishnan 2010)

3.2.1.1 Hydroelectricity

Hydro power is generated from the energy from falling/flowing water. Hydro is highly valuable to the market due to its ability to start up and shut down in seconds. However output from hydro facilities is severely affected by drought and can be seasonal. Development of Hydro capacity is almost completely halted due to environmental concerns preventing any substantial new dam development. (MORAN 2006)

Hydro power is also used as grid scale energy storage to stabilise demand. Water is pumped up hill during periods of low demand to be stored as potential energy. During periods of high market prices the energy is extracted from the water. This occurs at facilities such as Wivenhoe Dam in Queensland where enough energy can be stored to produce 500MW for 10 hours (CS Energy 2011).

3.2.1.2 Wind

Energy is extracted from the wind using turbines of capacities up to 2.1 MW. They are generally grouped into wind farms comprising several turbines. Wind power can be highly intermittent but good weather models exist for predicting wind power output for several days ahead.

The output from a wind turbine is in proportion to wind speed as illustrated in Figure 3.2. The cut in speed is the minimum wind speed needed for the turbine to generate power. The cut out speed is the wind speed at which the turbine shuts down to prevent damage. (PelaFlow Consulting 2012)
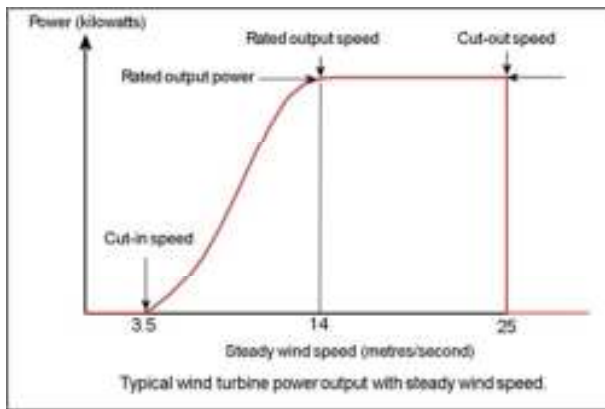
Figure 3.2 Wind turbine power output

3.2.1.3 PV Solar Power.

Solar photovoltaic (PV) systems use the photovoltaic effect to convert sunlight into electricity. Thousands of individual solar cells are connected together to generate high voltages and power is feed back into the grid by inverters. Solar PV systems are installed in the NEM as small distributed systems. The output from a solar PV system is shown in Figure 3.3 where the output is related to the solar irradiance and the temperature of the cells.
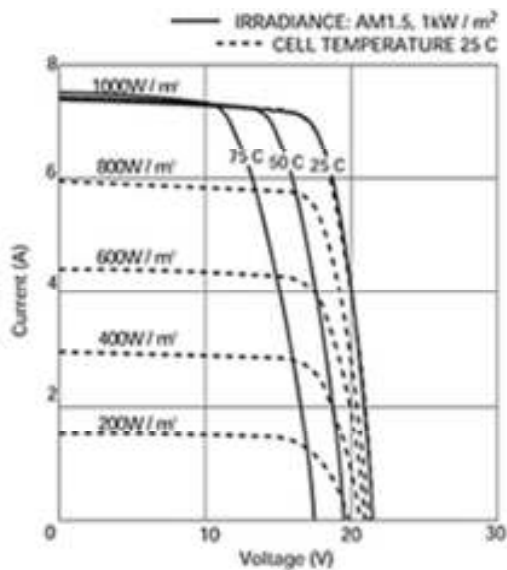
Figure 3.3 Output from solar PV (Wholesale Solar 2012)

3.2.1.4 Rankine Cycle (Steam)

The Rankine Cycle is a closed loop heat engine used to supply the majority of power around the world. It is capable of utilising any heat source including geothermal, coal and nuclear. The Rankine Cycle utilises an internal working fluid, typically water, but other chemicals can be used in an organic Rankine Cycle. The Rankine Cycle uses the difference in entropy between the gas and liquid states of its working fluid. Due to their size they can take hours to days to start up. They typically run for hundreds of days at time to reduce the need for expensive liquid fuel to start the boiler and to reduce stress and fatigue on the components. Evaporative cooled units can use as much as four litres of water per KWh produced to reject the waste heat (National Water Commission 2012). They require large volumes of water due to build ups of salt and silicon as the water evaporates. Units are rated based on steam operating temperature as either sub critical or super critical. The higher the temperature, the higher the efficiency. An example is the Toshiba units in NSW at Bayswater, Earring, Mount Piper and Munmorah. The units located at these power stations have a minimum capacity of 270MW up to 660 MW and ramp rates of 140 MW/ minute.
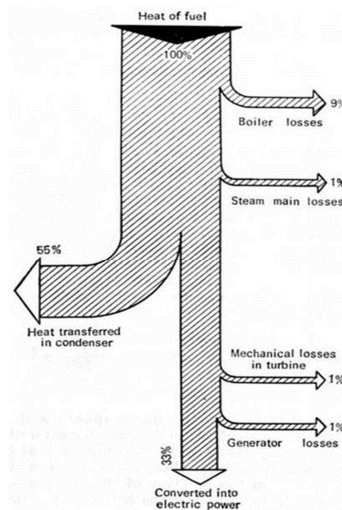
Figure 3.4 Schematic of the Rankine Cycle (MPEI 2012)

3.2.1.5 Brayton Cycle (Gas Turbine)

The Brayton Cycle describes the operation of open cycle gas turbines (OCGT). OCGT use air as the working fluid. Air is compressed to a high pressure. Heat is then added by burning natural gas or light petroleum products to increase the volume of the air. The energy is then extracted from the air by expanding it though a turbine. OCGT are simpler than the Rankin Cycle due to a smaller number of parts and the smaller size. They require precision manufacturing and expensive alloys to resist the high temperatures. OCGT are typically used as peaking plants due to their low installation cost ability to start and ramp up very quickly. As much as 70% of the energy from the fuel used is lost as waste heat in the exhaust with another 10% lost through lubrication radiation (Sharma 2012).

3.2.1.6 Combined Cycle Gas Turbine (CCGT)

A CCGT uses the waste heat in the exhaust gasses of an OCGT to power a boiler combining the Brayton Cycle with the Rankine Cycle. This approach results in very high thermal efficiency. Examples include the Tallawarra power station in NSW it has a 240MW gas turbine and a 160 MW steam turbine coupled together to drive a single generator (Alstom 2008).

3.2.2 Generator Properties

Depending on the type different generators have different technical properties that impact on the rest of the electricity network. This is important as they affect the electricity network to response to changing market conditions to change their output or start up or shut down. Other important properties include axillary loads, efficiency and the cost.

3.2.4 Technical Properties

Technical Properties cover the limitations of the different generation technologies including their technical limitations, life time and efficiency.

The axillary load (aux load) represents the electrical power consumed at the power station to run the generator. Auxiliary loads in a coal fired plant can be as high as 20% as large motors are used to run the pulverising mills, the induced and forced draft fans on the boiler and the condenser pump as well as the station plant used to process water, handle the fuel and manage the ash and dust produced.

A generator's efficiency varies directly with its output as components are designed to operate most effectively at high output power levels. This is referred to as the part load performance/efficiency.
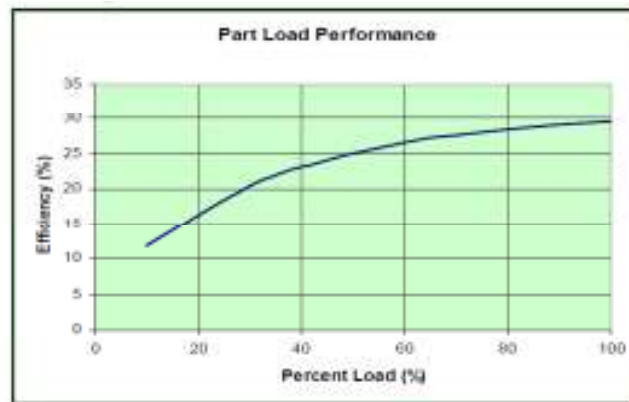
Source: EEA/ICF

Figure 3.5 Part load performance of OCGT (Energy and Environmental Analysis 2008)
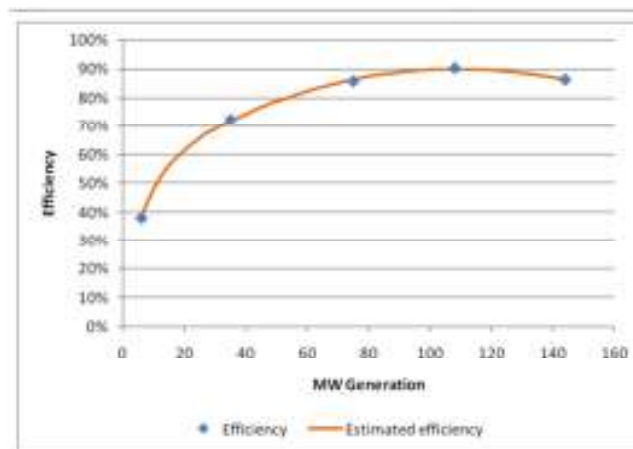
Figure 3.6 Hydro power part load efficiency (Intelligent Energy Systems 2008)

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Table 3-1 Comparison of Generator Properties

Generator Type	Start-up time	Ramp Rate	Efficiency at 100% load	Efficiency at 75% load	Efficiency at 50% load	Efficiency at 25% load	Aux load	Availability factors	Life time
Diesel Engines	1 – 5 min	40% min	38%	37%	35%	25%	-	-	-
Open Cycle Gas Turbine	5 – 20 min	20% min	33%	28%	25%	17%	1.00%	97%	30 years
Combined Cycle gas turbine	30 – 60 min	5-10% min	55%	52%	46%	-	2.90%	92%	27 years
Steam Turbine sub Critical	60-600 min	3-5% min	38%	34%	28%	-	9.80%	90%	40 years
Super Critical	60-600 min	3-5% min	45%	43%	41%	-	9.80%	90%	40 years
Hydro	seconds	41% AEMO	89%	84%	75%	60%	0%	30%	50 – 100 years
Wind	-	25% min	-	-	-	-	-	30%	20 years

(Vuorinen 2007) (Ihle 2003) (M.W. Coneya 2004) (H.I. Onovwiona 2004) (Chalmers 2010)

3.2.5 Generator Costs

The costs of electricity produced by a generator can be broken down into several components including capital costs, fuel costs and environmental costs. Costs that don't change with unit energy output are referred to as fixed costs. Variable costs vary based on the amount of energy produced. The life cycle costs vary significantly between different generation technologies Figure 3.7.
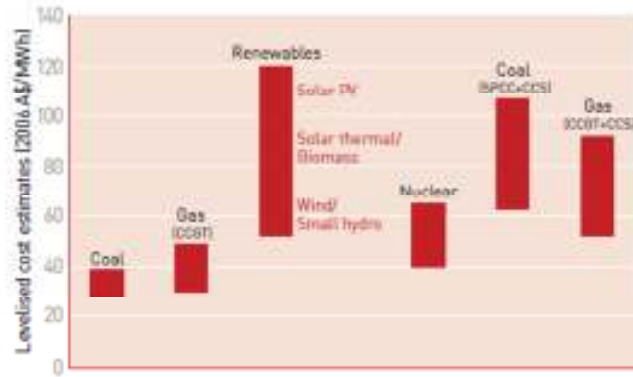
Figure 3.7 Life cycle cost estimate (Australian Energy Regulator 2009)

3.2.5.1 Capital Costs

The capital cost relates to the costs of building or buying a generator and the associated financing costs. This cost is spread out over all the output energy so unit capacity plays a big part in calculating finance costs per MW.

Table 3-2 Capital cost for different generation technologies

Technology	Black coal	Brown coal	OCGT	CCGT	Wind
Capital Cost ($/kw)	2348	2583	1010	1402	2588

(ACIL Tasman Pty Ltd 2010)

3.2.5.2 Fuel Costs

The fuel cost is a large component of total costs for generators and can vary based on the current world prices and on location as shown in Table 3-3. Fuel quality varies considerably between sources and can have considerable flow on effects. For example coal moisture and sulphur content have an impact on the cost of operating a plant. High moisture reduces plant efficiency and high sulphur levels increase compliance costs. Fuel prices vary significantly between geographical locations. Across Queensland coal fuel costs vary from 0.80 $/GJ at Kogan Creek to 2.45 $/GJ at Collinsville (Appendix E).

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Table 3-3 Generator fuel costs

Technology	Black coal	Brown coal	OCGT (natural gas)	CCGT (natural gas)	Wind
Fuel Costs ($/GJ)	1.68 NSW - 1.26 QLD	0.08 0.61 VIC	7.9 NSW – 5.24 VIC	5.32 SA – 4.19 VIC	0

(ACIL Tasman Pty Ltd 2010)

3.2.5.3 Operation and Maintenance

Operation and maintenance costs are calculated based on fixed and variable components. Factors influencing maintenance costs include hours running, ramp rates and the number of unit restarts.

Variable operations and maintenance (VOM) includes consumables such as chemicals, oils and energy used in auxiliaries and incremental running costs.

Fixed operation and maintenance (OM) cost includes servicing costs that do not vary with unit output this includes major periodic maintenance (bearings and valves), wages, insurance and overheads.

The maintenance costs of OCGT are typically high due to their operation as peaking plant where they only operate for short periods of time and are under extra stress due to continual starts and stops and high speed ramping.

Table 3-4 Generation operation and maintenance costs

Technology	Black coal	Brown coal	OCGT	CCGT	Wind
Fixed Maintenance costs ($/installed Mw/year)	51691	59229	14000	33384	22076
Variable Maintenance costs ($/Mwh)	$1.29	$1.29	$8.08	$1.13	$1.89

(ACIL Tasman Pty Ltd 2010)

3.2.5.4 Environmental Costs

Government policies are in place to charge power generators based on the impact on the environment. This includes the Federal Government's Carbon Pollution Reduction Scheme, initially charging $23 per ton of equivalent carbon dioxide emissions. However there is a $6.1 billion Electricity Sector Adjustment Scheme for the electricity industry from the Federal Government to compensate for the effects of the carbon tax. The bulk of the funding will go to the brown coal generators as the equation used to determine compensation heavily favours generators with the most emissions (Department of climate change and energy efficency 2012) .

Table 3-5 Power generation lifecycle greenhouse gas emission

Technology t co2e/MWH	Mean	Min	Max
Brown Coal	1.05	0.79	1.37
Black Coal	0.89	0.76	1.31
Oil	0.73	0.55	0.94
Natural Gas	0.5	0.36	0.89
Solar PV	0.09	0.01	0.73
Nuclear	0.03	0.02	0.13
Hydroelectricity	0.03	0.02	0.24
Wind	0.03	0.01	0.12

(World Nuclear Association 2012)

There are also state based emissions taxes such as the NSW Load Based Licence (LBL) implemented in 2000. It uses a formula to calculate emissions pricing that combines the total weigh of pollutants emitted, a weighting factor based on the hazard level of the pollutant and a weighting based on the location of the emissions.   Pollutant weighting include 9x for nitrous oxide, 2.2x for sulphur oxides and 125x for fine particles. This tax is to encourage the use of technology to reduce these emissions including bag houses for dust and better boiler controls for NOx. The fuel quantity and technology deployed has the greatest impact on this cost as shown in Table 3-5. (NSW EPA 2003)

Table 3-6 Variation in environmental loads between coal power stations

	Plant 1	Plant 2	Plant 3	Plant 4
Efficiency (HHV)	35	32	39	30
Nitrous oxides (kg/MWH)	4.22	2.89	3.02	3.48
Sulphur oxides (kg/MWH)	2.69	4.05	2.53	4.64
Particulate matter 10 micrometres or less (kg/MWH)	0.68	0.13	0.15	0.03

(J. C. DINIZ DA COSTA 2006)

Table 3-7 2011 LBL Emissions tax for Eraring Power Station

Pollutant	Total Emission's (kg)	Cost
Selenium - Estuarine	67	$2,718.19
Total suspended solids - Estuarine	43,895.000	$3,286.63
Benzo(a)pyrene	0.328	$38.59
Fine Particulates	1,232,189.000	$867,155.35
Fluorides	643,630.000	$372,026.67
Salt - Estuarine	0.000	$0.00
Arsenic	67.000	$17,363.88
Coarse Particulates	12,446.000	$908.88
Lead	87.000	$3,882.55
Sulphur oxides	34,326,112.000	$306,374.28
Nitrogen Oxides	28,077,930.000	$2,050,418.92
Mercury	84.000	$48,787.04
Administrative fee:		$45,360.00
Load based fee:		$3,627,600.98

In 2011 Eraring generated 13,971 GWH for a total LBL cost of $0.26 per Mwh with greenhouse gas emission of 0.843 tonnes of co2e/mwh (Eraring Energy 2011) (Environment NSW 2011)

3.3 Transmission

Transmission is the distribution of electricity at very high voltages, typically from 220 kV up to 500 kV. In the NEM this service is performed by Transmission Network Service Providers (TNSPs) who operate as large monopolies within each region e.g. Transgrid NSW and Powerlink Queensland. TNSPs are responsible for the high capacity transmission from the generator centres to the load centres. As TNSPs operate as monopolies their revenues are regulated by the AER under rules determined by the AEMC.

TNSPs also operate high capacity transmission lines between the NEM regions called interconnectors described below in

Table 3-8. This allows for better utilisation of generation equipment, enhanced competition in the NEM, an increased ability for the gird to handle contingencies and a smaller regional generation capacity. Typically there is little transmission congestion within regions and some congestion between regions.

There are two types of interconnectors in the NEM, regulated and unregulated. Unregulated interconnectors generate income by buying energy in a cheaper priced region and selling it in the higher priced region. Regulated interconnectors receive a fixed income based on the asset value of the inter-connector. This is collected from consumers as part of network charges. Basslink the interconnector connecting Victoria and Tasmania is currently the only unregulated inter-connector in the NEM (AEMO 2012).

While most transmission in the NEM is done using HVAC there are also some HVDC interconnectors. HVDC is used due to lower cost, higher efficiency and the greater control over power flow and eliminating frequency issues.

Figure 3.8 NEM transmission requirements

Table 3-8 NEM interconnectors

Inter connector name	Description	Export capacity (MW)	Import capacity (MW)	Inter region transfers week ending 4 August 2012 (Mwh)
VIC1-NSW1	330kV, 220kV AC Victoria to NSW	1620	1260	30,365 to NSW 11,008 to Vic 1,118 loss
Heywood	275kV AC Victoria to South Australia	420	460	52,023 to SA 1,244 to VIC 3,348 loss
Murrylink	180km Bipolar 150KV DC Victoria to South Australia	220	190	4,098 to SA 1,142 to VIC 710 loss
Directlink	Three circuits of 59km 160 kV bipolar DC NSW to QLD	100	250	0 to QLD 13,911 to NSW 736 loss
QNI	557km double circuit 330 kV and 275 kV AC transmission lines from NSW to Queensland.	520	1080	183 to QLD 72,564 to NSW 404 loss
Basslink	370 km 400 KV submarine cable DC VIC to TAS	600	480	59,466 to VIC 3,460 to TAS 2,451 loss

(ESAA 2012) (AEMC 2010)

3.4 Distribution

Distribution Network Service Providers (DNSPs) are monopolies that are responsible for the deployment and maintenance of the infrastructure that takes power from the transmission system and delivers it to the consumers. This area has been a significant driver in increased electricity prices due to substantial investment in this part of the network.

Table 3-9 DNSPs in the NEM

(Australian Energy Regulator 2011)

3.5 Retail

There are several retail companies that compete for consumers in the NEM. Each retail service provider consolidates all of the costs associated with generating and transmitting energy and collects the money from consumers. Several tariff structures are available to consumers including fixed pricing and Time of Use (ToU) pricing. Fixed pricing costs are passed on as a fixed tariff on energy consumed. Recently ToU is being used to better reflect the costs of supplying electricity where the price of electricity varies based on the time of day and if it is a business day. There are also different tariffs for scheduled loads such as off peak hot water systems.

Retailers use financial mechanisms to hedge variable market prices in order to manage financial risk and allowing them to offer firm contract prices for end users. Prices for regulated electricity is set through independent pricing tribunals like Independent Pricing and Regulatory Tribunal of NSW.

Figure 3.9 shows a breakdown of the cost components for the Aurora distribution network. The largest cost component for consumers in the Aurora network is the cost of the transmission and distribution with around 40% of a consumers bill paying for generation.
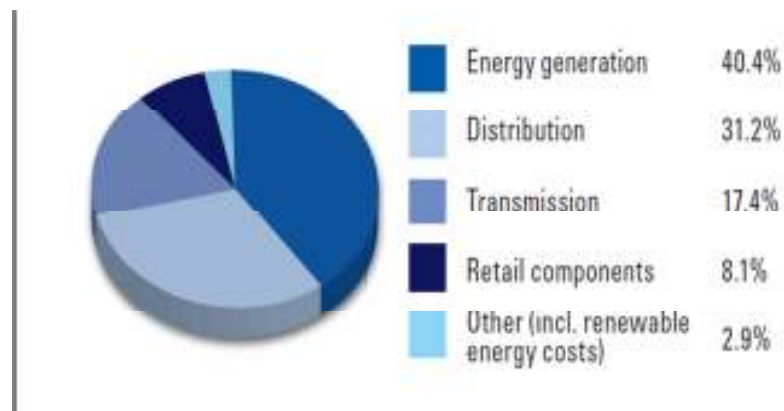
Figure 3.9 Residential bill cost breakdown for Aurora network. (Aurora Energy 2011)

3.6 Network losses

Losses account for approximately 10% of the sent out electricity generated in the NEM. Around 2.5 - 4.5% of the losses occur in the HV transmission network the rest in the LV distribution network. These losses are of significant monetary value and are accounted for in the NEM using a Distribution loss factor (DLF), a Marginal loss factor (MLF) and inter region loss factor. DLF and MLF values are static values calculated and fixed annually to simplify the scheduling and settlement process. While due to the dynamic nature of the interconnectors a dynamic loss factor is calculated during unit dispatch for the inter regional losses. (AEMO 2012)

To deal with losses in the NEM the transmission network is broken down into transmission connection points (TCP) and distribution connection points (DCP). With the DCPs allocated to a single TCP, the NEM rules also allow for virtual connection points if multiple TCPs are available. All loads and generators are allocated to a single TCP or DCP. A single TCP is chosen in each region and is known as the regional reference node (RRN). Regional demand and the spot price are then calculated at the RRN. The loss factors are then used as multipliers to get the spot price at each TCP and DCP in the network.

The DLF is used to account for the losses in the distribution system. The DLF is a static value calculated from the volume weighted losses in the network based on the previous year's data. Results are updated and published by AEMO each year.

Losses in the transmission network are calculated using a marginal loss calculation. The marginal loss factor reflects the increase in demand at the RRN based on an increase in demand at each TCP. The MLF is calculated from historic network flows from the previous financial year. This marginal calculation means the MLFs can be less than one if local generation is less than local demand i.e. energy flows away from the RRN.

Losses on interconnectors are calculated dynamically using a pre-determined loss flow relationship based on the demand in each region and the flow on the interconnector. It is done this way because flows and losses on the interconnector can be highly variable and can change significantly from year to year.

To take losses into account the spot price at each node is calculated as the price at the RRN multiplied by the MLF and DLF if applicable. Each generator submits bids offering electricity referenced to their TCP so their bids are multiplied by their MLF to get their bids at the RRN. During periods were the inter-connector system is unconstrained the entire NEM is calculated as a single pricing pool with the price difference between two regions based on the interregional loss factor. During periods where the interconnector system is constrained each region is considered a separate pricing pool and electricity prices between regions can vary dramatically.

3.7   Market Management

AEMO was established in 2009 as an independent organisation to operate the Australian NEM and the natural gas market. AEMO also publishes information to assist market participants to make appropriate business decisions. AEMO publishes information including pre dispatch data, short term and medium term forecasts, expected demand and required reserve levels. Under the rules AEMO is required to manage the NEM to a reliability standard of 0.002% unserved energy over a 10 year average (AEMO 2011).

AEMO operates several services to ensure adequate operation of the NEM

- Active Energy – Main product of the NEM supplied through a bidding system, generators receive dispatch instructions every five minutes, worth billions each year.

- Network Control Ancillary Service – Manages the voltage of the grid primarily through the control of reactive power levels. AEMO enters into contracts with generators to control reactive power levels, total value of the contracts is around $34 million per annum.

- Frequency Control Ancillary Service (FCAS) – Supplied by a bidding system used in between the energy dispatches and used to maintain the grid at 50 Hz and deal with forced outages. Worth around $34.8 million per annum.

- System Restart Ancillary Service – AEMO has contracts with several generators that have the capability of performing a black start of their generators. This function is essential for restoring power in case of a catastrophic blackout in the NEM. Worth around $37.7 million per annum.
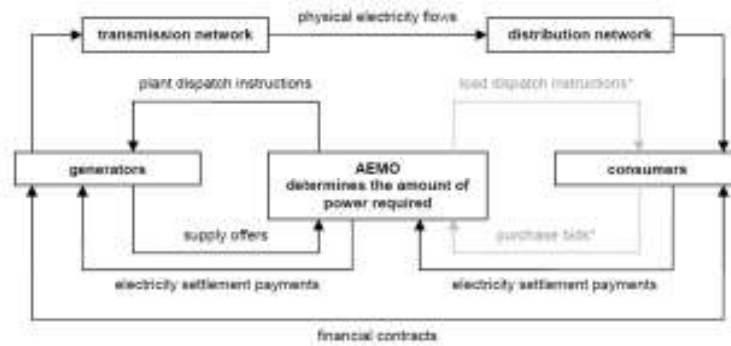
Figure 3.10 Operation of the NEM (Engineers Australia 2010)

Figure 3.10 shows the operation of the NEM for the bidding based services. Generators submit supply offers to AEMO detaining price and production levels. AEMO uses the supply offers to dispatches generators to meet the demands of the NEM. Even though generators and retailers make off market contracts all energy is still traded through AEMO with compensation being paid between generators and retailers when the market spot price varies from the contract price.

3.7.1 Forecasting

Forecasting is an important tool used in the NEM. It is used to forecast electricity demand and the adequacy of generation and transmission infrastructure over the short to long term. This is becoming increasingly difficult with the growing penetration of intermittent wind power and small scale distributed solar photovoltaic power. Long term forecasts are used to predict areas in the NEM that will require an increase in generation/ transmission capacity. AEMO publishes the forecasts and supplies tool to allow operators in the NEM to make appropriate business decisions.

Load forecasting is provided by Itrons MetrixIDR system. It uses an automated system that continual updates important data on large industrial loads, power station auxiliary loads and uses the latest weather forecasts to calculate demand in across each region. The system is integrated with AEMO wind generation forecasting system to accurately predict the impact of wind generation. The algorithm uses a 'neural network and regression model specifications, designed to capture linear and nonlinear interactions between load, weather and calendar information'. A Proprietary Dynamic learning algorithm ensures the forecasts are continuously tuned to most recent loads. (Itron 2011)

3.7.1.1 Short term projected assessment of system adequacy ST PASA.

The ST PASA provides half hourly demand forecasts for the next seven days. The algorithm is run and results updated every two hours. It provides a benchmark for AEMO to intervene in the market to commit extra capacity and provide information on expected demand to the market participants. The algorithm uses data on plant availability and network outages and calculates expected power demand giving a 10, 50 and 90 per cent Probability of Exceedence (POE). The 50% POE is the most likely load curve with 10% POE used to assess impacts of low generation capacity. 90% POE is used to assess the impacts of low demand. Scaling factors are varied to represent changes in the market that vary over season, week, day and peak/ off-peak time. (AEMO 2012)
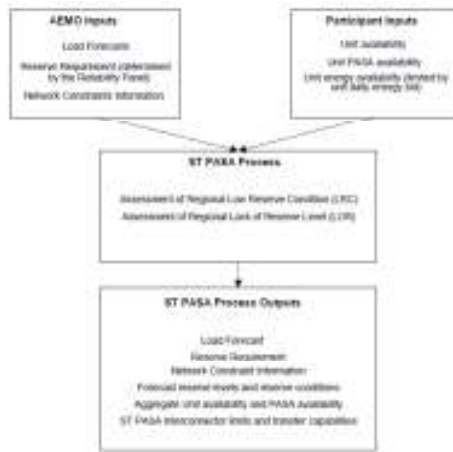
Figure 3.11 ST PASA process.

3.7.1.2 Medium Term Projected assessment of system adequacy (MT PASA)

MT Pasa is used to ensure sufficient generation capacity is available to satisfy demand over the next 24 month period. It is used by market participants to schedule maintenance. In cases were inadequate supply is available it is expected market participant will reschedule planned outages to take advantage of high market prices due to reduced supply. The results are based on a 10% POE and only includes units that can be made available within 2 hours.

To ensure the market will be able to satisfy the reliability standard AEMO calculates a minimum reserve level (MRL) on top of the MT PASA. The MRL is calculated using a Monte Carlo simulation of weather and subsequent demand levels and probable forced outage patterns to ensure enough generation capacity is available so the reliability standard can be met (Equation 3.2).

$$\text{Generation} + \text{import} > \text{demand} + \text{MRL} \quad \text{Equation 3.1 Reliability standard criteria}$$

$$\text{MRL} = \\ \text{minimum local generation} + \\ \text{interconnector support} - 10\% \text{ POE demand adjusted for demand side participation}$$

Equation 3.2 Minimum Reserve Level

The reliability standard is at risk during periods of a reserve deficit when supply is less than the MT PASA forecast plus the minimum reserve level (Equasion 3.1). If AEMO detects a reserve deficit, market forces will encourage generators to bring make more capacity available, if this does not occur AEMO can intervene in the market.
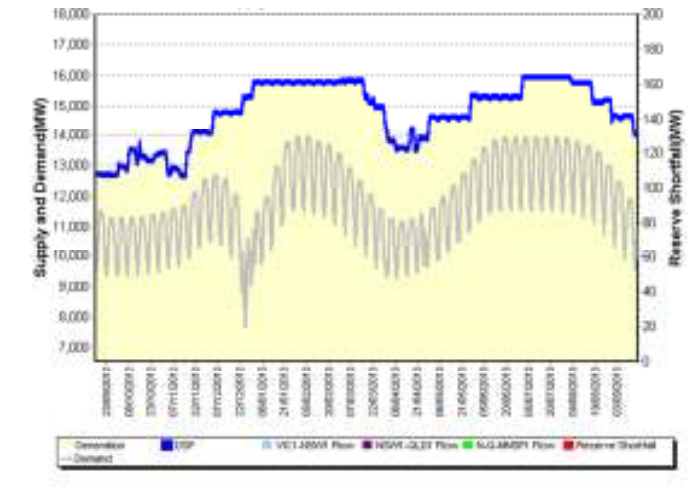
Figure 3.12 NSW supply outlook MT PASA 11/9/2012 (AEMO 2012)

3.7.3 Frequency Control Ancillary Service

The FCAS system is used in the NEM to maintain the frequency of the grid and manage the spinning reserve in the system. The FCAS system operates in between the five minute energy dispatches and allows both generators and large loads to bid into the system to rapidly increase or decrease energy availability. The FCAS system operates under a causer pays model where consumers pay around 60% of the costs and generators paying the remainder. Generators occur FCAS costs due to forced outages, not complying with market instructions and if they deviate from a linear ramp between two dispatches.

FCAS is used to maintain the system frequency using a regulation product for fine frequency adjustments and contingency products during a large frequency deviation caused by forced outages. During a contingency FCAS relies on the inertia of large generators to maintain system frequency for the first several seconds. AEMO then uses fast ramp rate generators to change their output levels to respond to the interruption. If system frequency drops below 49 Hz AEMO will begin under frequency load shedding (ufls) and begin dropping load. Load shedding is done using a pain sharing policy where demand is dropped from each region in proportion to total regional demand until the frequency can be stabilised. If the frequency continues to drop, AEMO will begin isolating sections of the NEM in an attempt to contain the frequency issue. The NEM is required to operate to the frequency standard of 49.85 – 50.15 Hz for 99% of the time, contain a multiple contingency to 47 – 52Hz and stabilise the frequency to 49.5 – 50.5 Hz within 2 minutes and recover to 49.85 – 50.15 Hz within 10 minutes (Australian Energy Market Commission 2009, p. 15).

Regulation raise and lower are used for continuous correction of small frequency deviations. Required reserve levels are set on a trial and error basis where each month the performance is assessed and levels modified.

FCAS regulation categories

- Regulation raise

- Regulation lower

Contingency raise and lower are used in the event of unplanned outages in the NEM. Required levels are set based on the largest generator and largest load block that could fail plus an allowance for load relief.

FACS Contingency products

- Raise 6s – arrest a large frequency deviations and load shedding
- Lower 6s –
- Raise 60s – stabilise and begin correction of frequency
- Lower 60s
- Raise 5 min – return system to normal frequency band
- Lower 5 min

Due to financial constraints the FCAS system is designed around the largest single contingency as this is the most practical method. Although as events on the 2nd of July 2009 showed there have been large multiple contingency events that the system adequately handled. On 2nd July 2009 a fault in the switch yard at Bayswater Power Station caused all four BW units to trip instantly. This then resulted in several transmission line trips and four other generator units from Victoria to Queensland to trip. The NEM lost a total of 3,205 MW of generation within a few minutes. With the aid of load sheading of some large industrial, commercial and residential consumers the FCAS system was able to maintain grid stability and recover from the fault. (ESOPP 2011)
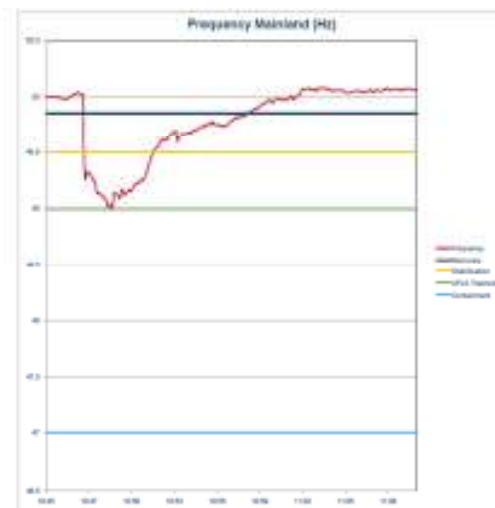
Figure 3.13 Under frequency load sheading containment. As frequency deviates from 50Hz FCAS response escalates.

3.7.4 Generator Dispatch

The core operation of AEMO is to run the energy market. By Midday one day ahead generators submit energy and FCAS bids to AEMO for every hour of the next day. The bid for each product can have up to ten blocks where each block details a price and production volume. Generators are able to change their bids up to 5 minutes before dispatch but they can only change the production volume, not the price.

At five minute intervals AEMO runs there Scheduling, Pricing and Dispatch algorithm (SPD) to calculate the instructions to send to generators. The SPD combines the bids into a merit order list and dispatches the lowest cost generation capacity until all demand is satisfied. The price of the highest accepted bid is then used to set the market price. The SPD algorithm uses a linear problem solver to find a solution to the problem ensuring all market supply security constraints are met. The SPD algorithm is set to minimise the total value of electricity purchased across the entire NEM not on a region by region basis. This includes generation capacity and ramp rate limits as well as transmission limits across the network. If an adequate solution cannot be found the SPD algorithm begins relaxing constraints until a solution is found (AEMO 2010, p. 52).

3.8 Future of the NEM

The NEM is under constant change as demand fluctuates, government policy intervention, new generation and transmission capacity is installed and aging generators are retired. AEMO has considered plausible futures for the NEM that cover several scenarios including a slow rate of change, a fast rate of change, oil shock and adaption and a decentralised world where it becomes cheaper to generate power at the load centres.

3.8.1 Aging Infrastructure

As power stations are designed with a limited life there is a need to replace existing power stations. Several power stations are expected to be retired in the next few years and will need to be replaced. There are long lead times for replace large power plants. Listed below are the candidates for retirement over the coming years.

Table 3-10 NEM retirements

Fixed retirement candidates Candidate	Region	By year
Callide A	QLD	2015/16
Mackay	QLD	2016/17
Swanbank B (2 & 4)	QLD	2010/11
Swanbank B (1)	QLD	2011/12
Swanbank B (3)	QLD	2012/13
Munmorah	NSW	2014/15
Playford[1]	SA	2016/17

As the power stations are retired and demand continues to grow there is considerable uncertainty in what they will be replaced with.
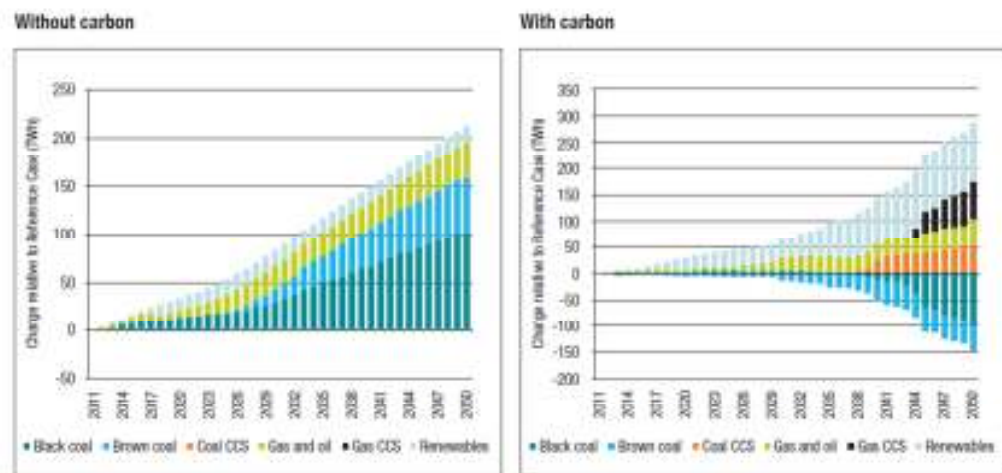
Figure 3.14 Potential growth in NEM generation infrastructure (National Water Commission 2012)

3.8.3 Renewable Energy Targets

Along with several other countries around the world the Australian Federal Government has set a target that at least 20% of Australia's electrical energy should come from renewable sources by 2020. This is designed to drive innovation and investment in green energy and propel Australia to a clean energy future. It is expected by 2020 green technologies to be providing 45,000 gigawatt- hours of energy. The scheme has been broken down into a Large scale Renewable Energy Target (LRET) and a Small scale Renewable energy scheme (SRES). LRET is to drive large scale projects including wind farms and large solar thermal facilities. SRES is to incentivise solar PV panels and solar water heaters. (Department of Climate Change and Energy Efficiency 2012)

This will have a significant impact on the NEM. One problem with high levels of renewable generation is the inertia in the system used to maintain system frequency during the first 6 seconds of the FCAS response. In order to ensure system stability minimum levels of inertia are needed. This means a minimum number of thermal generation plants need to be in operation at all times. In the case of South Australia which has the greatest instalment of wind energy, 500 MW of synchronous generation has been recommended.   (ACIL Tasman Pty Ltd 2010)

4 NEM Operation

To aid in the design of the simulator, data from several sources was collected and analysed to gain a greater understating of the operation of the NEM. Data from several sources including AEMO dispatch data, CSIRO solar irradiance data and temperature data was analysed in MATLAB. This helped to quantify relationships and better understand demand, pricing and how different generation technologies are deployed in the NEM.

4.1 NEM Demand

The demand in the NEM sets the requirements for the installed generation capacity and transmission infrastructure as electrical energy can't be easily stored. The power generated must equal the demand at all times for the grid to remain within frequency limits. The NEM must also have enough spare capacity to deal with any forced outages that can credibly occur.
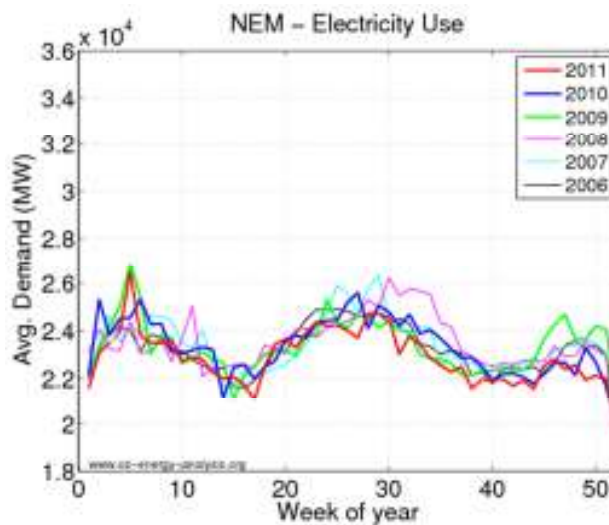
Figure 4.1 Weekly average demand in the NEM (oz-energy-analysis 2012)

Demand in the NEM has a summer and winter peak and a low during the Christmas New Year period. Summer/winter and spring/autumn demands averages are similar across the NEM. The MP PASA shows there is a reduction in generation capacity during autumn and spring as plants are shut down due to the surplus of generation capacity and plants that are taken off line for maintenance during these low demand periods. Figure 4.1 also indicates demand has been falling in the NEM recently and peaked in 2008/2009.
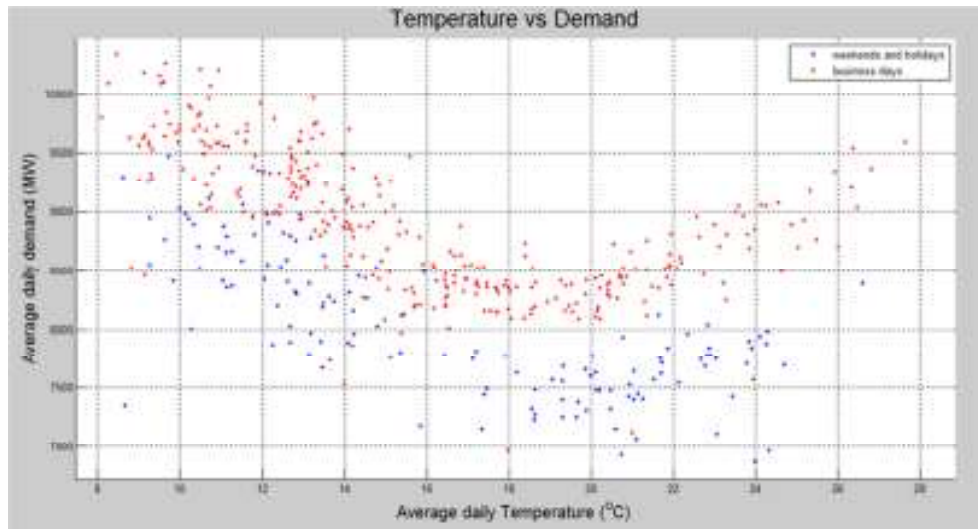
Figure 4.2 Average daily temperature vs. demand

Figure 4.2 shows the clear link between demand and average daily temperature in the NEM. Demand will be at a minimum when the daily average temperature is between 18 ^{o}C – 20°C and demand will increases the further the temperature is from this point. Although there is a strong link between temperature and demand there is still a large variation in demand at each of the daily average temperatures making forecasting expected demand challenging. There is a significant difference in demand between business days and weekends and public holidays with demand on weekend and public holiday typically varying more than on weekdays.
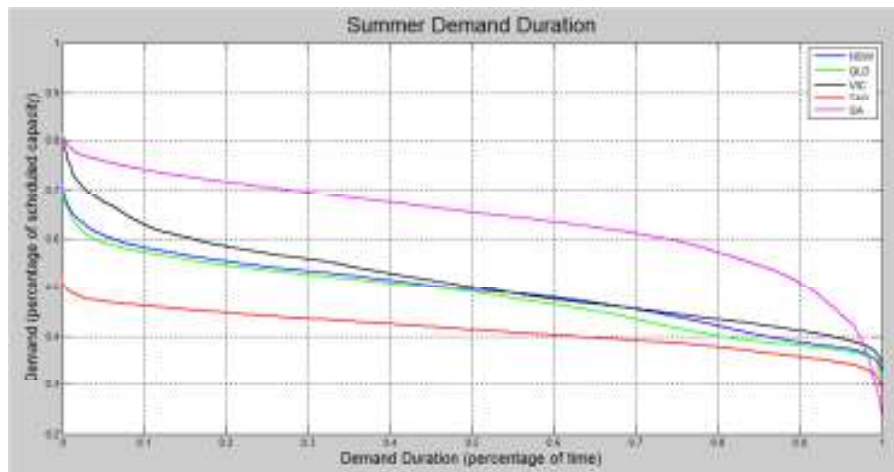
Figure 4.3 2012/2011 summer demand duration
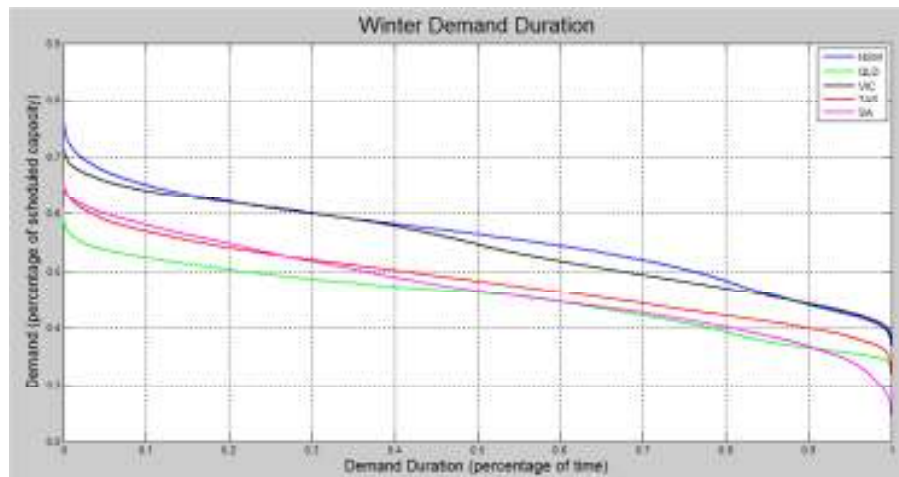
Figure 4.4 2012/2011 winter demand duration

The demand duration curve provides information on the length of time different levels of generation capacity are required. Electricity supply systems need to be sized for peak demand and the demand duration curves show there is significant excess capacity on top of peak demand. The peak is the most expensive power to supply as facilities that supply peaking power only run for a small part of the year. As most steam and CCGT plants run continuously there is a minimum demand needed to prevent shutting down of the units. In recent years peak demand has been growing faster than total consumption (Deliotte 2012, p. 4). The marginal cost of supplying peak power is estimated at $200,000 MW as it is only needed for a very small amount of time (Deliotte 2012, p. 20). Demand is greatest in summer for the Queensland, South Australia and Victoria and in winter for New South Wales and Tasmania.   The summer demand profile is similar in the three large states NSW, Queensland and Victoria but Queensland's winter demand is relatively lower than the other states.

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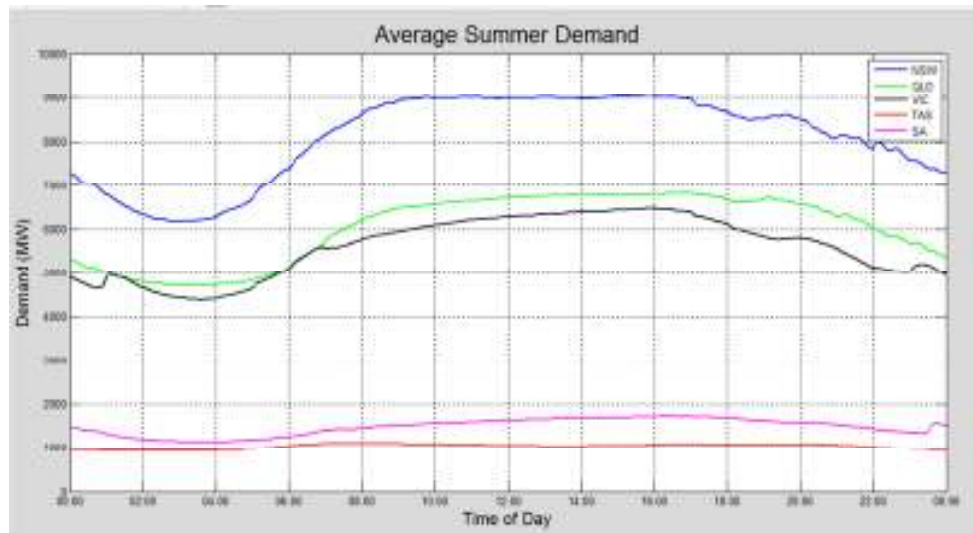
Figure 4.5 Average summer day demand profile.
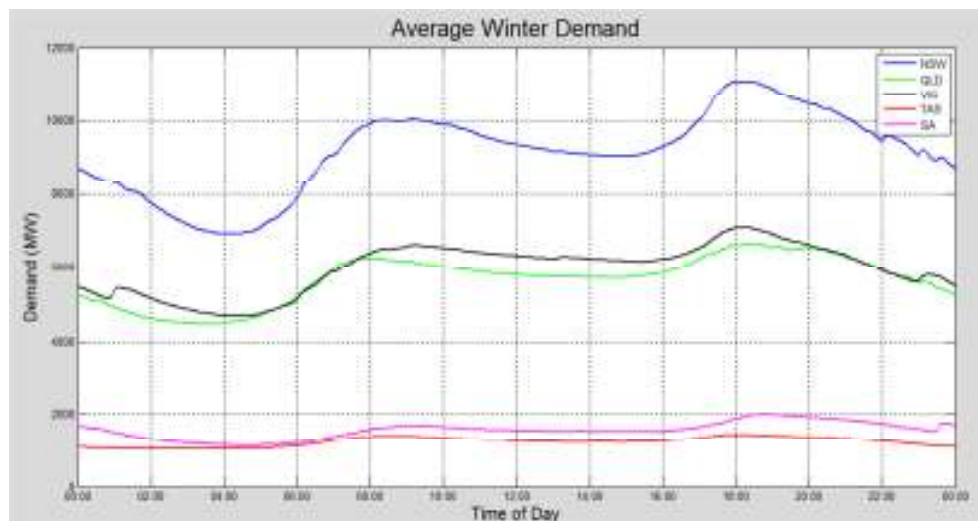
Figure 4.6 Mean winter daily load profile

The NEM has a minimum demand around 3:00 to 4:00 am (AEST) in the morning. In summer there is a flat demand throughout the day and peaks around 4pm in the afternoon. In winter there are two significant demand peaks each day one in the morning around 9am and one in the evening at 6 pm. The disadvantage of the north south grid in Australia is clearly shown with all regions peak at the same time of the day with the exception of SA. The effect of controlled loads e.g. hot water heating is clearly visible as large jumps in demand between 10pm and 1 am.

4.1.1 New South Wales

This section looks at the variation in the demand profiles.
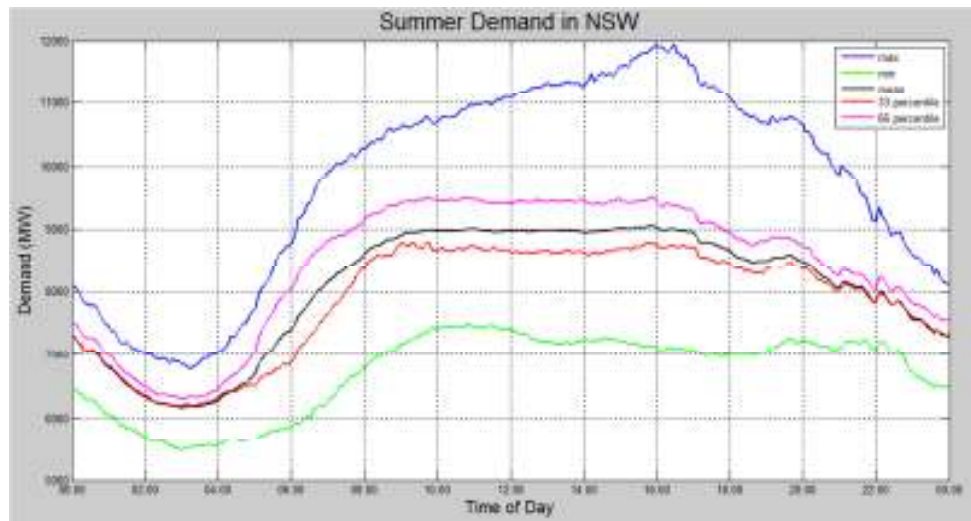
Figure 4.7 Summer demand in NSW

Figure 4.8 Winter demand in NSW

NSW is the region with the highest demand in the NEM and has a summer peak at 4pm and winter peak at 6pm. The variance in demand is typically small but can vary significantly, on extreme weather days there is an extra 3000 MW of generation capacity needed on top of the mean demand.

4.1.2 South Australia
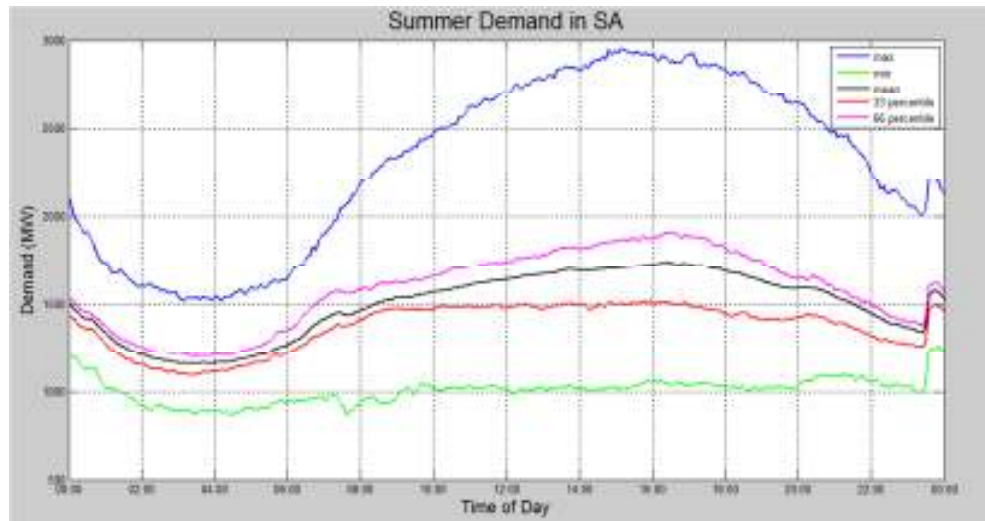
Figure 4.9 Summer demand in South Australia
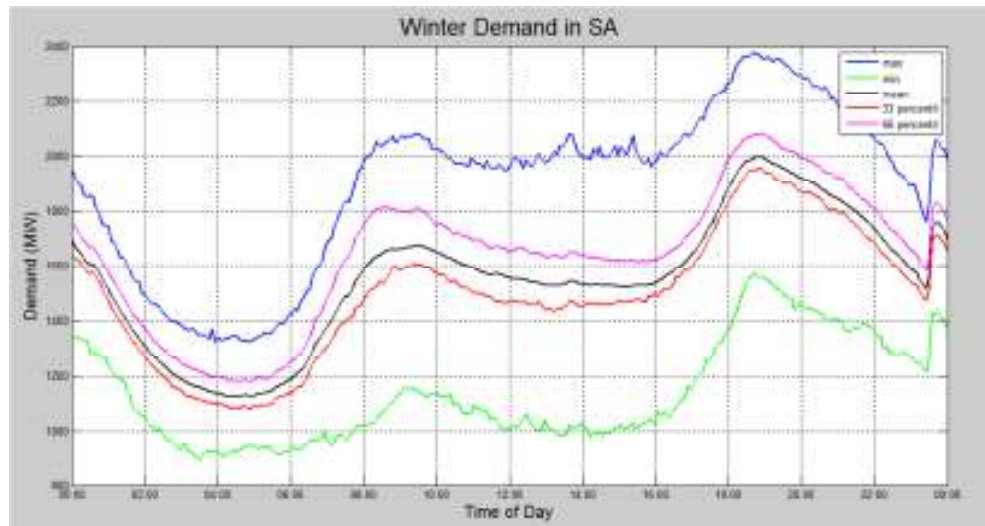
Figure 4.10 Winter demand in South Australia

South Australia has the second smallest demand in the NEM. There is a steep increase in demand at 11pm as there is only a single distribution network and all controlled loads being turned on at the same time results in a large increase in demand. The summer peak demand is almost twice the mean demand.
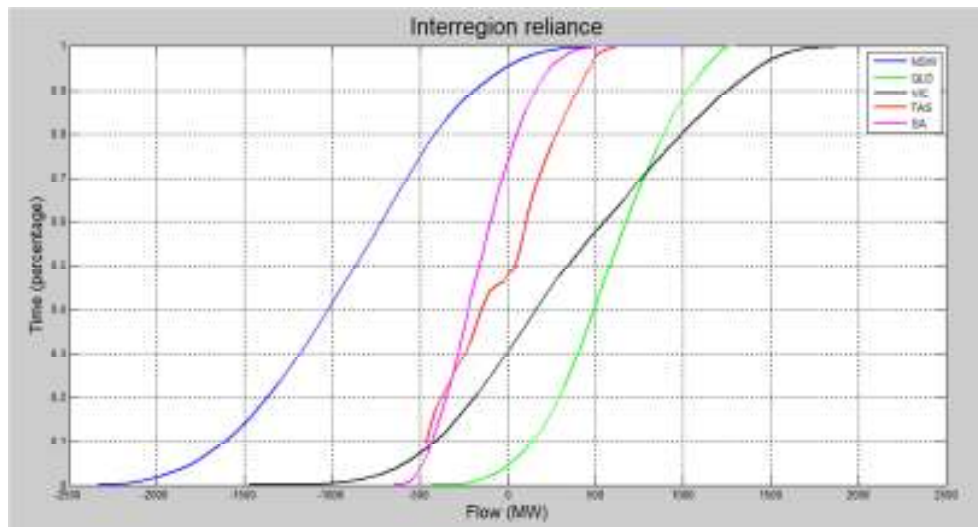
Figure 4.11 Inter region electricity flows

Figure 4.11 displays the interregional flows of electricity in the NEM as a function of time. New South Wales has the highest demand for imported power with Queensland exporting the most. Victoria has the most variance due to its central location in the NEM. There is only a small amount of time that the transmission lines between regions are pushed to their maximum limits.

4.1.3 Installed Generation

Table 4-1 Installed generation capacity in the NEM (winter)

	Steam	OCGT	CCGT	Wind	Solar	Hydro	Reciprocating Engine	Non scheduled	Total (MW)
QLD	64.78	13.86	12.15	0.09	3.19	4.97	0.98	2.4	13,399
NSW	66.83	8.58	3.35	1.57	2.58	15.8	1.18	4	17,841
VIC	56.23	15.41	0	7.08	2.33	18.5	0.41	4.45	12,358
TAS	0	6.3	7.37	4.96	0.43	80.78	0.17	9	2,823
SA	39.1	17.45	12.55	22.95	5.09	0.05	2.8	15.3	5242
Total (MW)	29,603	6,390	3,090	2,510	1,455	8,071	544.6	2,381	51,665

(AEMO 2012)

Generation and transmission limits in the NEM have a lower value in summer than in winter as the higher atmospheric temperature reduces the ability to reject waste heat and effect thermal efficiencies. Electricity generation in the NEM is dominated by steam power plants fuelled by coal. The market is experiencing a rapid increase in the installation of wind and solar power. The non-scheduled capacity in the NEM several smaller generators made up of 1,113 MW of wind, 544 MW of reciprocating engines and 417 MW of hydro. SA is the leader in intermittent renewable energy and is highly reliant on the inter connecter system with Victoria. Generators can exceed their registered capacity for short periods if high market prices justify the added cost. For example Eraring Power Station is registered with a capacity of 720 MW and a maximum capacity of 750 MW.

4.2   Market Prices

The spot market prices in the NEM are set every half hour as the average of the 6 previous 5 minute dispatches. The NEM is limited to a current floor price of negative $1000 MWh during periods of excess generation capacity and a market cap of $12,500 MWh where the demand is greater than supply. A cumulative price limit also applies so the average price over a seven days period in a single region can't exceed $558 MWh. Most electricity is sold through off market contracts with compensation being paid between retailers and generators when the spot price varies from the contract price. (AEMO 2012)
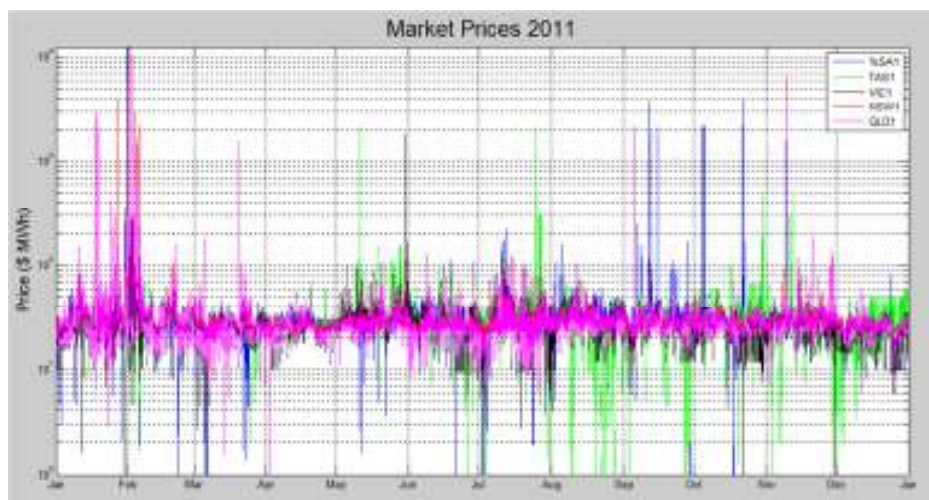
Figure 4.12 Market prices 2011 (negative prices ignored).

Table 4-2 Average energy price in the NEM

Year	NSW	QLD	SA	TAS	VIC
2008-2009	38.85	34.00	50.98	58.48	41.82
2009-2010	44.19	33.30	55.31	29.37	36.28
2010-2011	36.74	30.97	32.58	29.45	27.09
2011-2012	29.67	29.07	30.28	32.58	27.28
2012-2013	60.31	58.25	69.25	51.03	63.68

(AEMO 2012)

Queensland had a high number of price spikes in 2011 but across the NEM the price typically trades in tight bands. Drought in 2009 resulted in very high prices in Tasmanian due to their heavy reliance on hydroelectricity (Bureau of Meteorology 2009). The energy price in the NEM has generally been falling due to reduced demand with the exception of 2012 – 2013 following the introduction of carbon pricing.

Prices vary each day with demand in tight bands as shown in Figure 4.13. The extreme ends of the price scale only occur for small periods of time but as the market pricing cap allows a 500x increase in price they can still have an effect on the average market prices. High priced periods are caused during supply short falls as the price moves from the cost of generating the electricity to the cost of not having the electricity.

Figure 4.13 Cumulative histogram of market prices 2011

Table 4-3 Average and volume weighted energy prices in the NEM

	NSW	QLD	VIC	SA	TAS
2011-2012 Average Price	29.67	29.07	27.28	30.28	32.58
2012-2013 Average Price	63.10	60.48	66.84	74.00	55.25
2011-2012 Volume Weighted Price	30.56	30.07	28.30	32.11	32.94
2012-2013 Volume Weighted Price	66.13	63.27	71.39	80.26	58.22

(2012-2013 July and August only)

Table 4-3 shows that as more electricity is needed the price of electricity goes up. Post carbon pricing, Tasmania has the cheapest power due to its large hydro generating capacity where Victoria and South Australia had the largest price increases due to their reliance on the emissions intensive brown coal. Indicating the carbon tax compensation may not be being passed on to consumers.

4.3   Forecast Accuracy
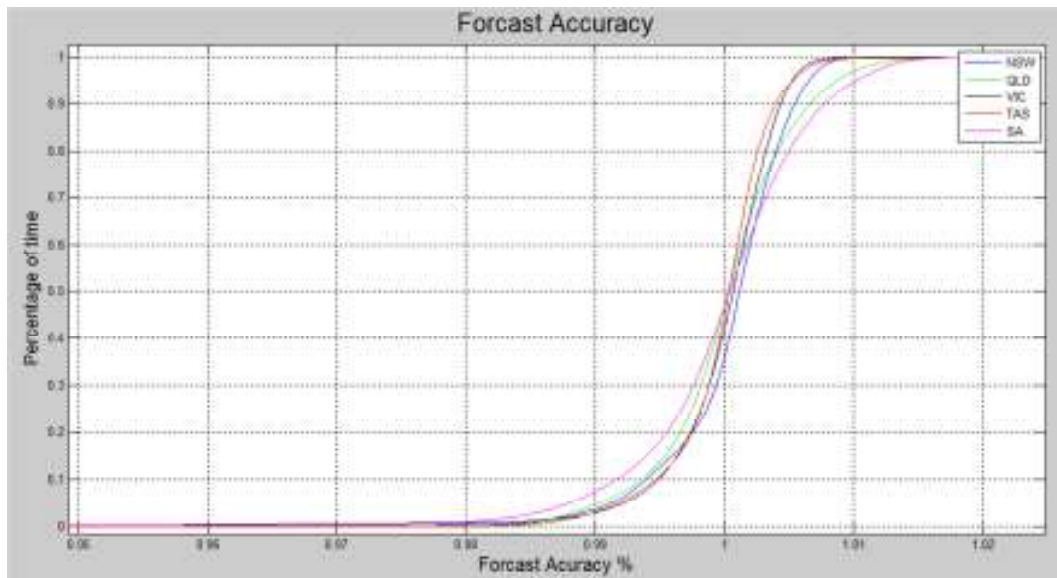
Figure 4.14 Forecast accuracy

Short term forecasts in the NEM are typically accurate to within 1% of actual demand for 95% of the time, however there can be a large errors due to failures in the network. The small size of demand in South Australia means any failures in the network causes a big variation in the forecast.

4.4   NEM Illustration

Data from different regions in the NEM was compiled to examine the relationship between generator production from different technologies, interconnector support, price and demand during a week of high demand. Queensland was chosen as it has a small installation of intermittent renewables and is a large power exporter. Whereas South Australia is the opposite, importing large volumes of electricity and has a large deployment of intermittent renewables.

4.4.1 Queensland

During periods of high demand it can be seen that when demand tests the available capacity there is a price spike as shown in Figure 4.15.
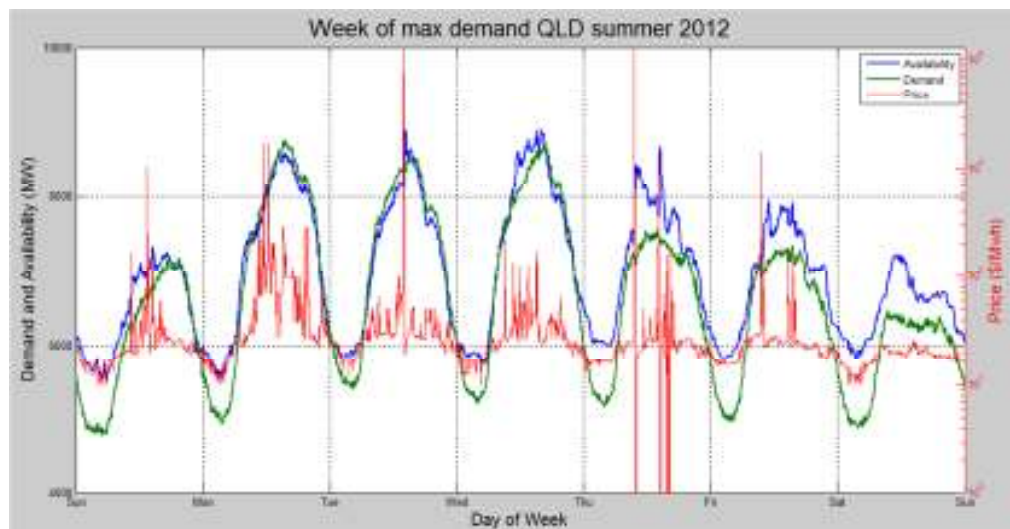
Figure 4.15 Week of maximum demand Queensland summer 2012

Figure 4.16 shows the relationship between demand and generation technology. As demand increases the more expensive technologies are brought online to satisfy the increased demand.
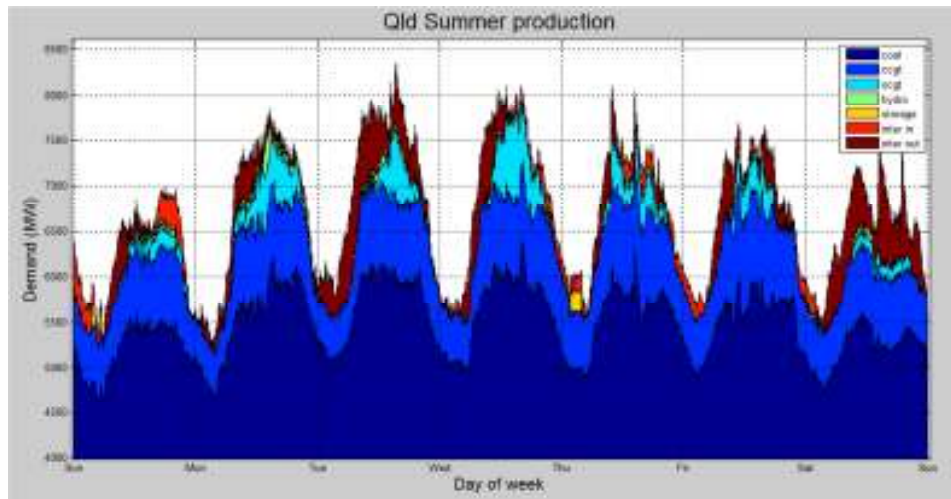
Figure 4.16 Relationship between demand and generation technology Queensland

A drop in availability and simultaneous price spike on Friday has likely occurred due to a forced outage. On Monday demand tests availability and there is a resulting price spike. On Thursday a drop in availability triggers a price spike which in turn brings significant capacity online, the excess capacity then crashes the price. Wivenhoe pumped storage recharges during low demand Thursday morning. OCGT and hydro are only used to cover the demand peaks.
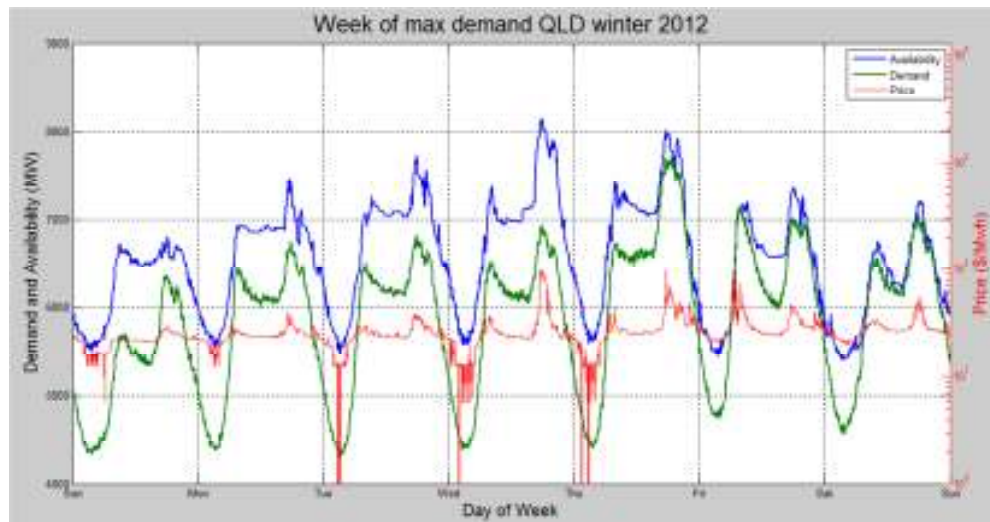
Figure 4.17 Price, demand and available generation capacity week of maximum demand Queensland winter 2012

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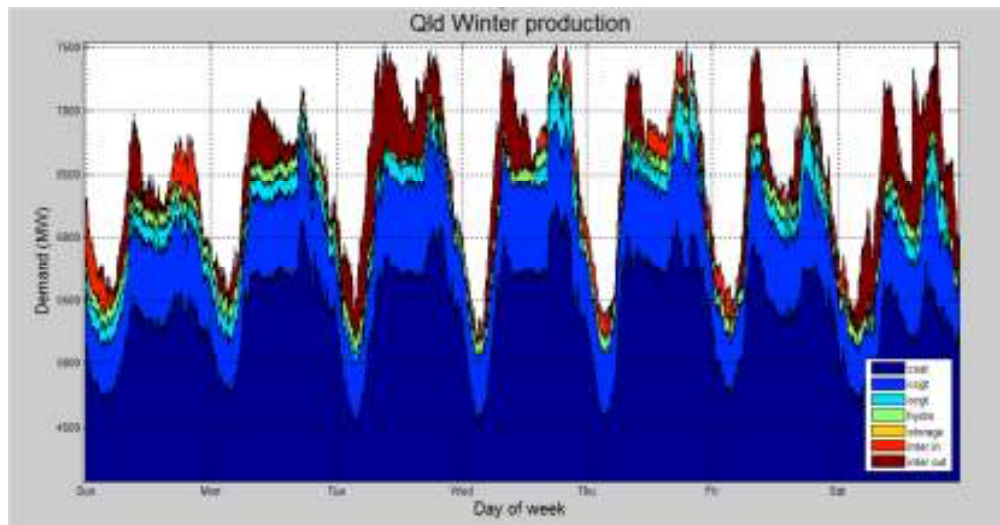
Figure 4.18 Relationship between demand and generation technology Queensland

Figure 4.17 shows a large difference between availability and demand on Tuesday, Wednesday and Thursday resulting in unstable prices. With winter demand in Queensland being lower than summer demand there are no price spikes due to excess generating capacity.

4.4.2 South Australia
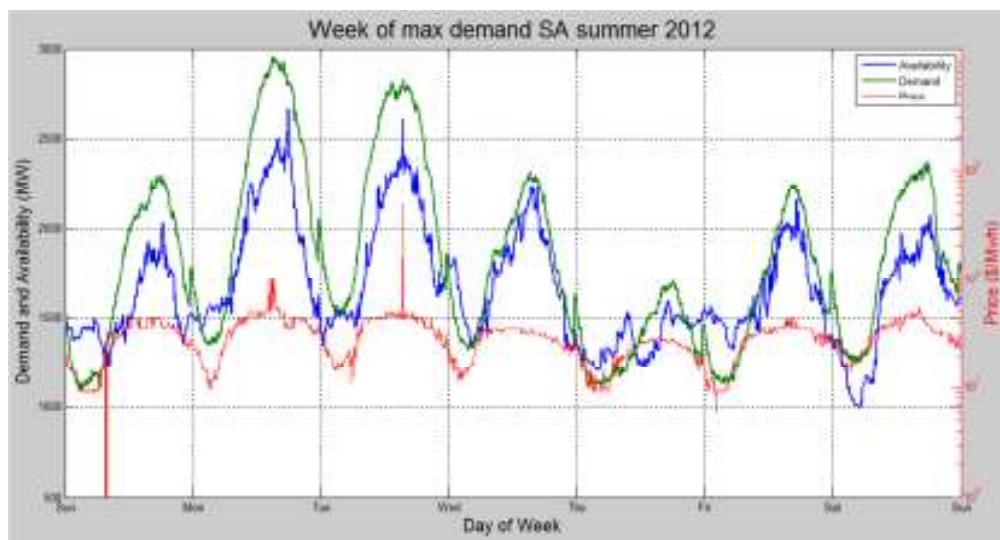
Figure 4.19 Week of maximum demand South Australia 2012
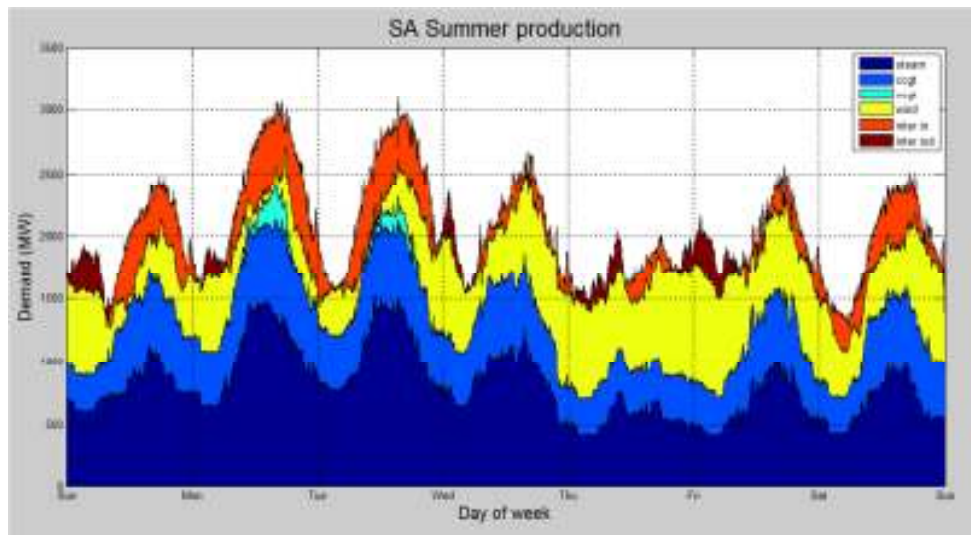
Figure 4.20 Relationship between demand and generation technology South Australia

In South Australia available generation capacity is typically less than demand, interconnector flow from Victoria is used extensively to cover peaks. On windy days a large amount of power is generated from the wind turbines with the interconnector used to export excess power to Victoria. On days with high demand there is typically little power generated from wind farms. When there is a high output from the wind farms the market prices is usually lower than on days with low wind power generation.
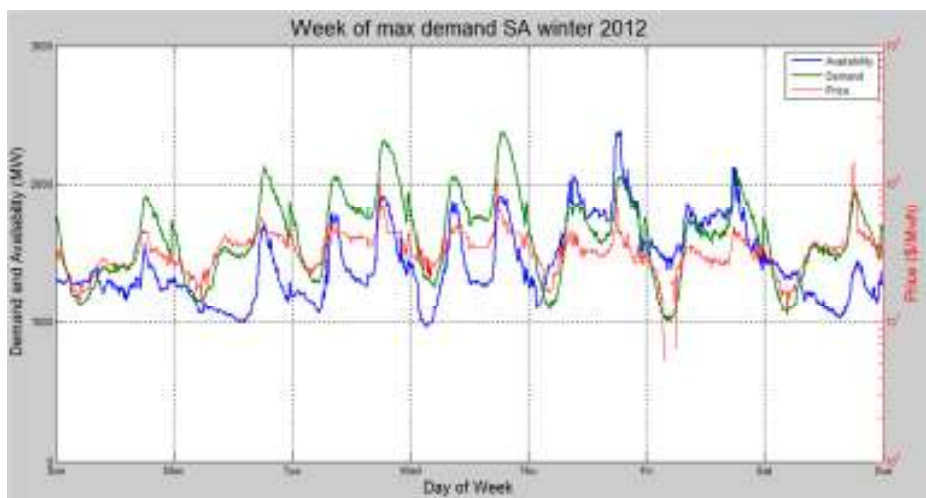
Figure 4.21 Week of maximum demand South Australia winter 2012
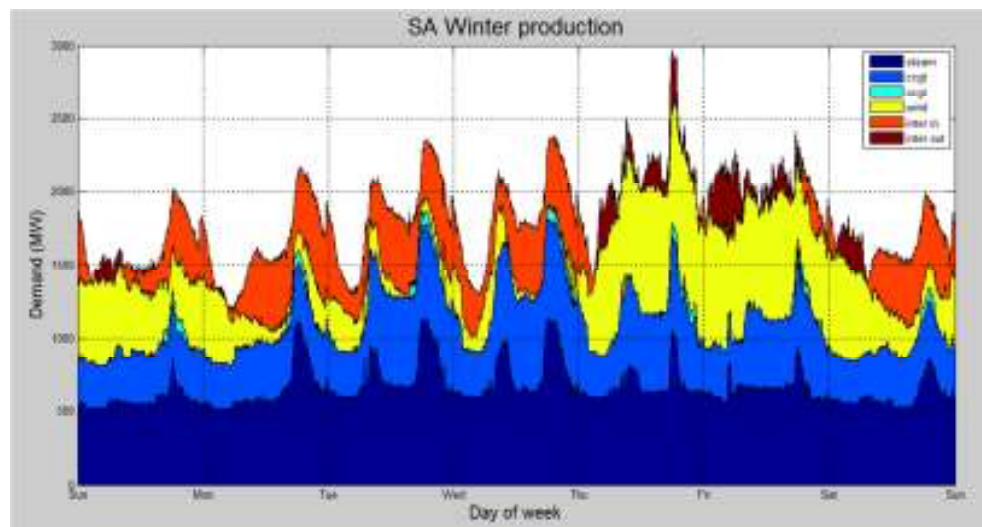
Figure 4.22 Relationship between demand and generation technology South Australia.

Figure 4.22 shows the interconnector usage was preferred over OCGT until the power limits of the interconnectors are reached and the OCGT are used to cover the extra demand. On Friday morning low demand, interconnector congestion and high wind generation sent the price negative for a significant period of time. Again there is minimal wind generation during times of peak demand.

4.5   Unit Bidding Strategies

NSW is the only state with significant generation capacity across the range of large scale generation types. This section describes how different generation technologies are operated in the market.

Table 4-4 shows coal fired steam and CCGT generators are running most of the time and are run with high capacity factors. OOGT are only run for small amounts of time and for high market prices. The difference between SHPUMP and SHGEN the Shoalhaven pumped storage system show it is only around 75% efficient and operates on a large difference in energy pricing. The other hydro system UPPTUMUT is only for around half the time but for high market prices. The wind farms have a capacity factors from 23 – 39% but are producing power for 50% of the time. Wind power also receives the lowest earnings out of all the technologies. The Solar PV system has a very low

capacity factor but receives a higher level of earnings than wind indicating the energy it produces is of higher value to the market.

Table 4-4 NEM generator operation

Power Station	Capacity Factor (%)	Tine Units generating power (%)	2011/2012 Volume weighted earnings ($/MWh)	2012 July August Volume weighted earnings ($/MWh)
Bayswater (Black Coal Steam 4×660MW)	73.19	93.29	30.45	65.99
Tallawarra (1×460MW CCGT)	61.01	87.19	31.24	67.86
Colongra (4×181MW OCGT)	0.53	1.07	63.87	133.58
SHPUMP (40MW×6) pumped storage	3.4	8.68	25.98	55.24
SHGEN (2×40MW + 2×80) Hydro	2.56	4.98	47.51	90.58
UPPTUMUT (82MW×4 + 4×72MW) Hydro	17.78	38.95	35.45	65.84
Solar 29.7 KW system near Canberra ACT	16.01	45.65	31.58	91.69
Capital wind farm (wind)	23.09	58.24	29.76	60.39
WOODLWN1 (wind)	30.7	47.4	29.5	60.8
NBHWF1 (wind SA)	39.44	74.45	25.58	63.36

The next section compares the frequency of unit output and market prices for the financial year before carbon pricing and the first two months with carbon pricing. The colour bar displays the log of the probability. The x axis displays the spot market price the left hand value is $0 MWh and below, the right hand value is $100 MWh and above.

4.5.1 Base Load
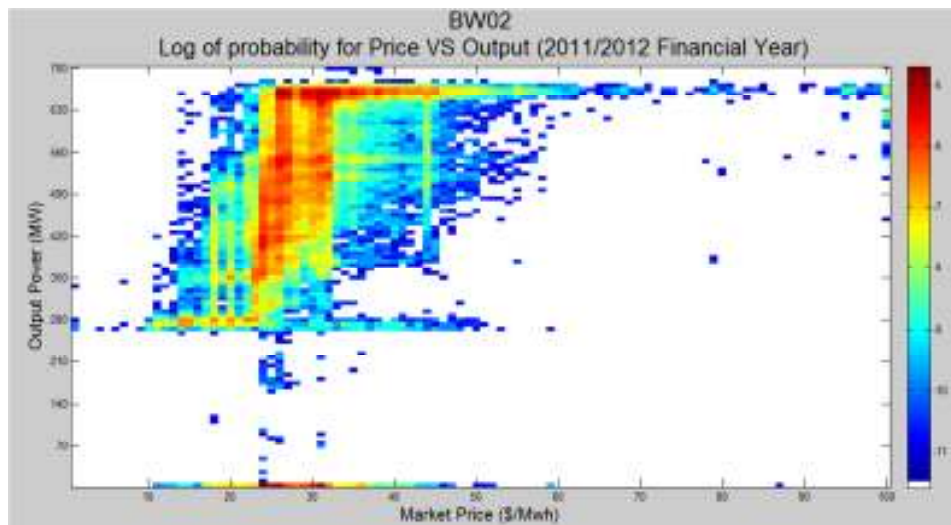
Figure 4.23 Unit BW02 2011/2012 operation
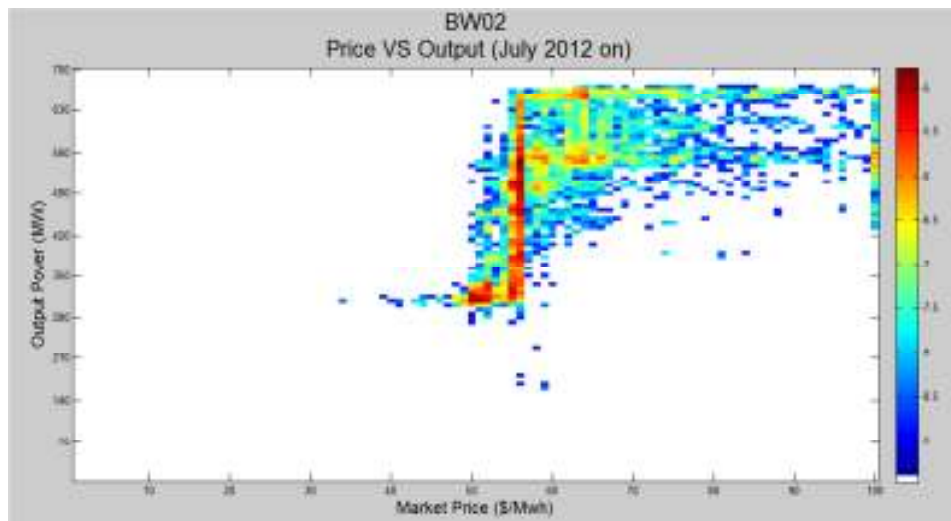
Figure 4.24 Unit BW02 2012/2013 operation

Unit 2 Bayswater is a subcritical coal fired steam plant operating in base load. The base load unit is running most of the time to minimise unit restarts and increase its capacity factor. The unit is typically generating near maximum power during high priced market periods and reduces power at low priced periods. During times the unit is offline there are very few high priced periods. It appears that the unit has a marginal cost around $66/67 MWh. BW2 also appears to do some load following spending time in between its maximum and minimum outputs. There is also a hard minimum output limit that is only crossed during start up and shutdown of the unit.
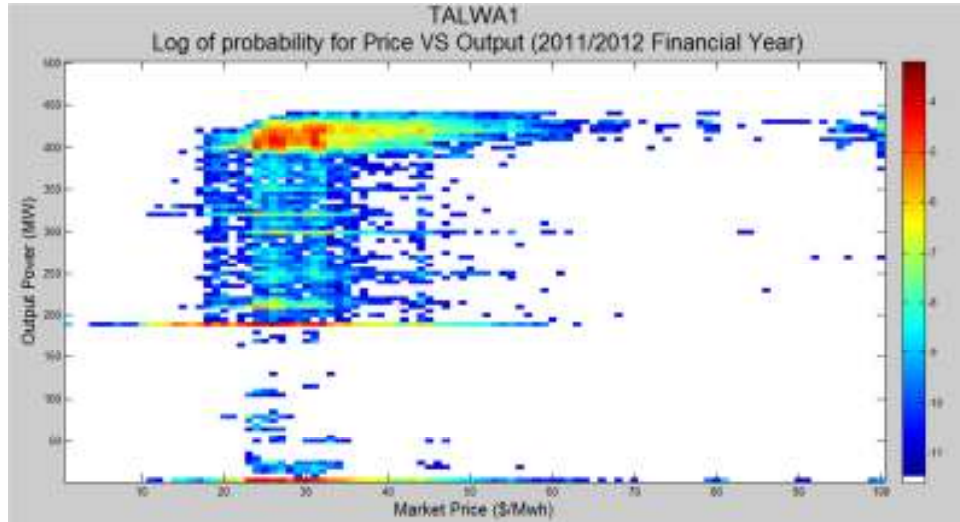
Figure 4.25 Unit Talwa1 2011/2012 operation
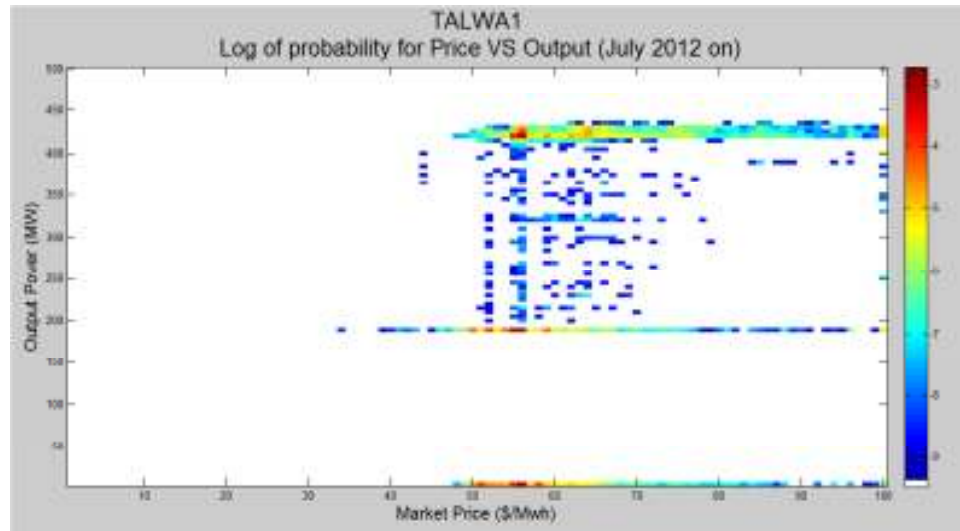
Figure 4.26 Unit Talwa1 2012/2013 operation

Tallawarra is a base load 400MW CCGT it is run at low output during low prices and high output during high prices. Tallawarra spends very little time offline during periods of high prices and spends most of its time at full power or minimum power indicating it is run to minimise start-ups and at maximum efficiency.

4.5.2 Peaking Plants
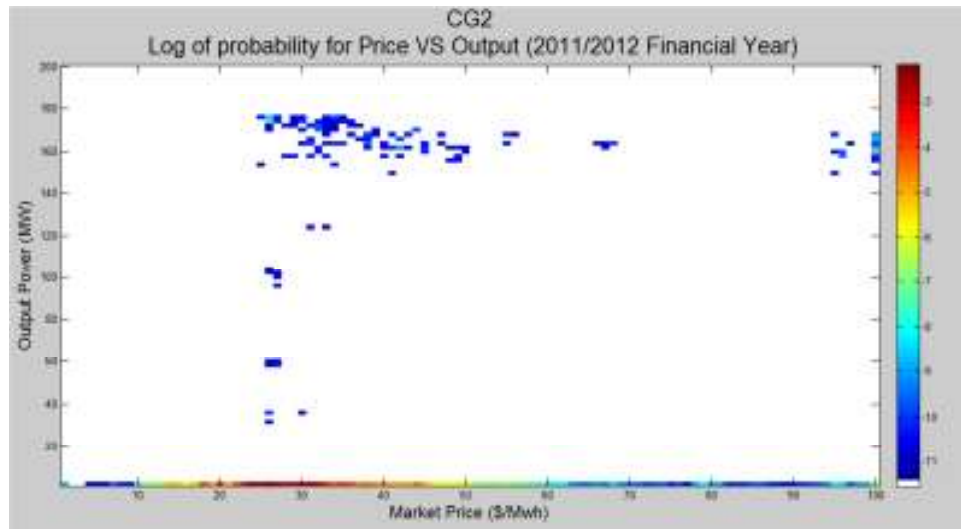
Figure 4.27 Unit CG2 2011/2012 Operation
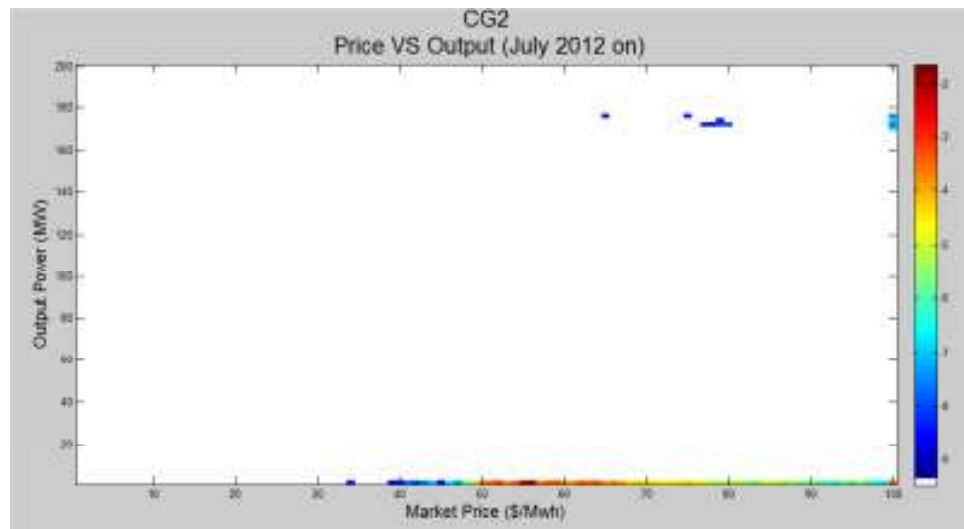
Figure 4.28 Unit CG2 2012/2013 Operation

Colongra unit 2 is an OCGT that runs for a very small amount of time. OCGTs appear to only be run at high outputs for high efficiencies spending most of the time offline. If the unit is started it runs close to full power to maximise part load efficiency. With minimal points between zero and full power showing the unit is able to ramp quickly. OCGT typically run for very high price $100 MWh and above.

4.5.3 Hydro
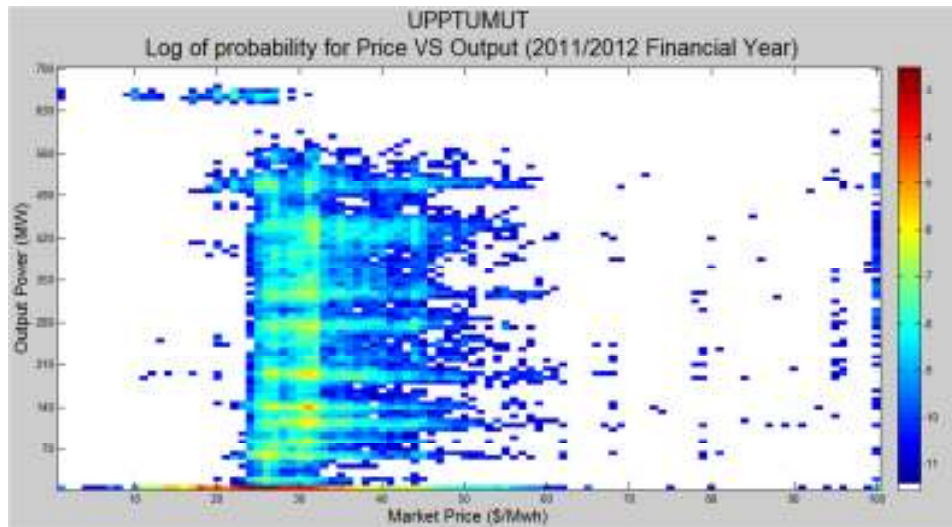
Figure 4.29 Upper Tumut 2011/2012 operation
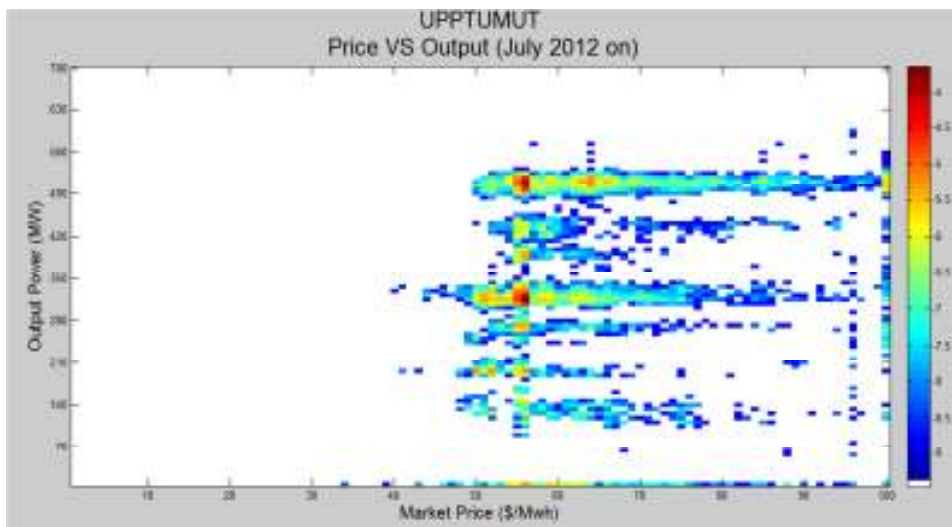
Figure 4.30 Upper Tumut 2012/2013 operation

Upper Tumut is a 616 MW hydroelectricity facility and is operated at levels around the turbine sizes showing that hydro facilities are run at maximum efficiency. Most of the generation is done around market price averages and they don't appear to increase output to take advantage of high market prices.
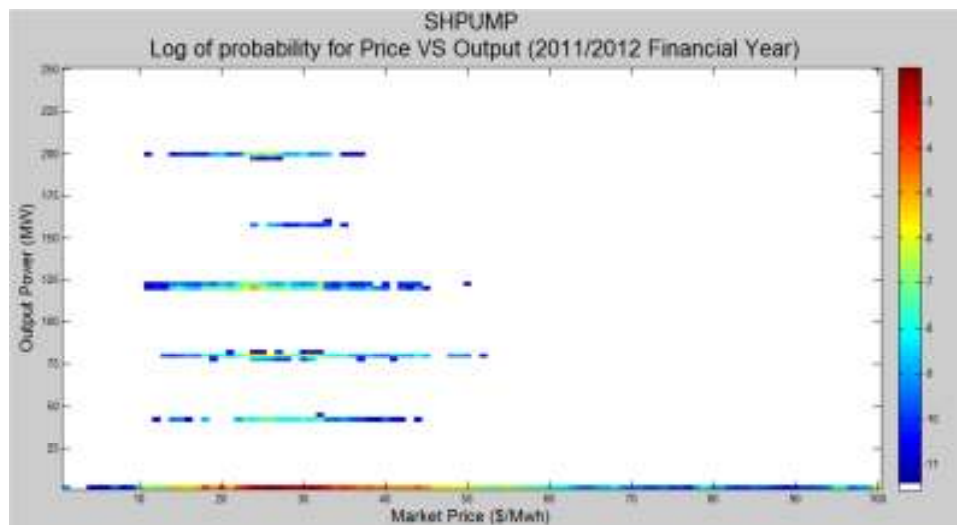
Figure 4.31 NEM pumped storage store
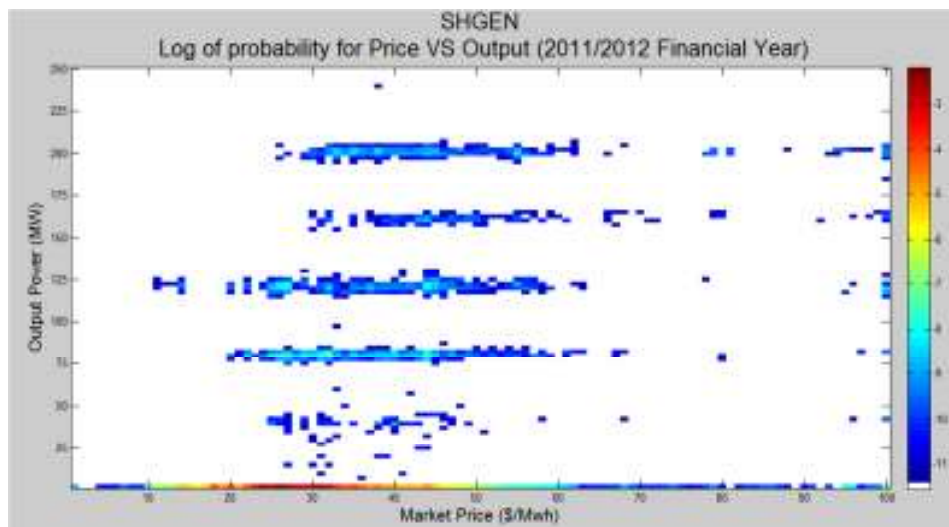
Figure 4.32 NEM pumped storage generate

SHGEN and SHPUMP is a pumped storage facility in NSW. The pumps move water uphill to store energy during low price periods. The generators run during high price periods. The storage facility is run strictly around unit sizes to maximise efficiency. The pumps can also be used as dispatchable load to consume energy during periods when there is an oversupply in the market.

4.5.4 Intermittent Renewables
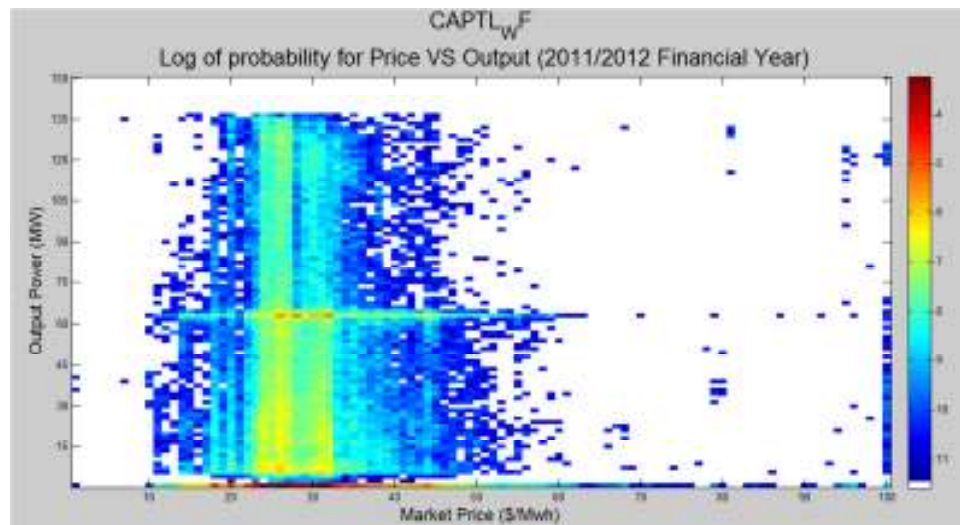
Figure 4.33 Capital wind farm generation

As the power output from wind farms is dependent on the wind speed it is only a price taker and can only depress market prices as it displaces fossil fuel generation. Figure 4.33 shows Capital Wind Farm does not produce much power at times of high demand so receives mainly low prices for the electricity it produces. Capital Wind Farm spends most of the time not producing any power and the rest of the time is only producing low levels of power. With the renewable energy target rapidly increasing installation of intermittent renewable generation capacity other generators will need to reduce output to accommodate the must run renewable power from the intermittent sources.
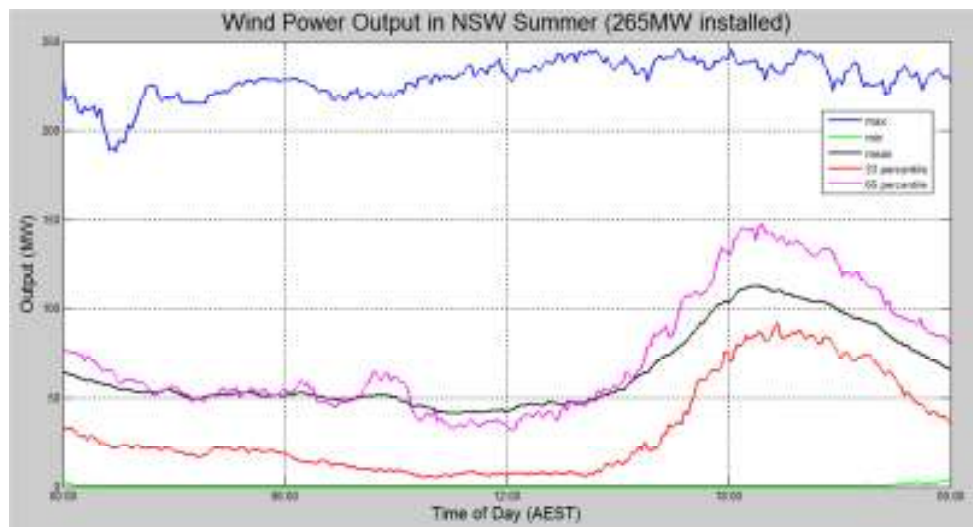
Figure 4.34 NSW wind power generation summer
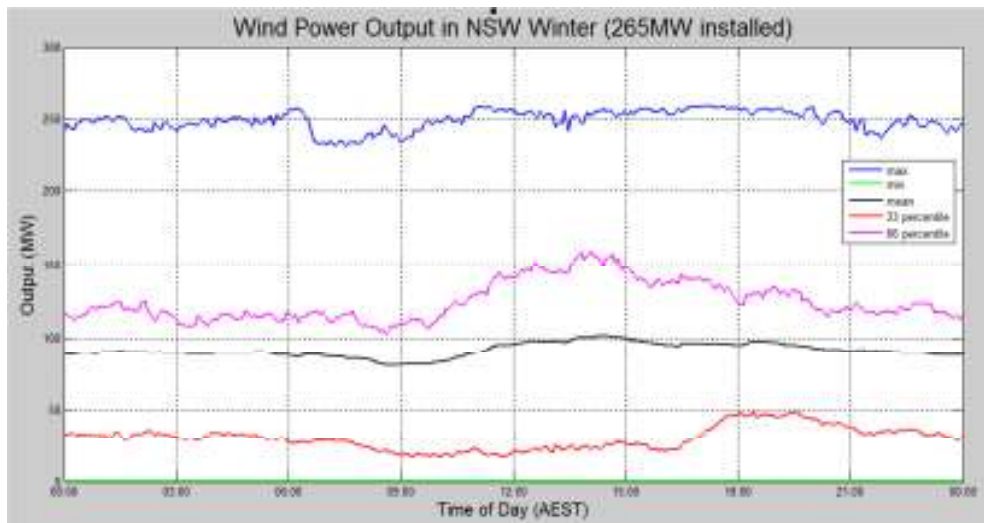
Figure 4.35 NSW wind power generation winter
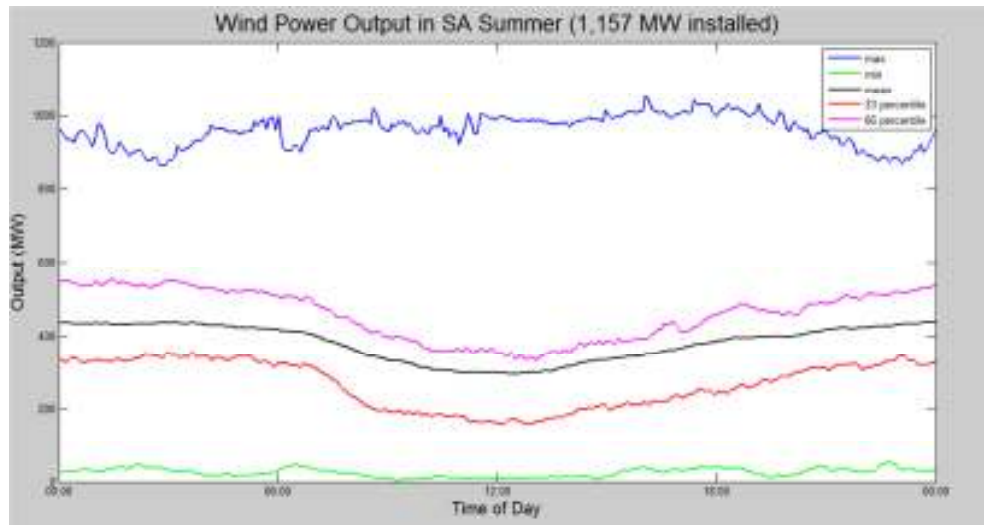
Figure 4.36 SA summer wind generation
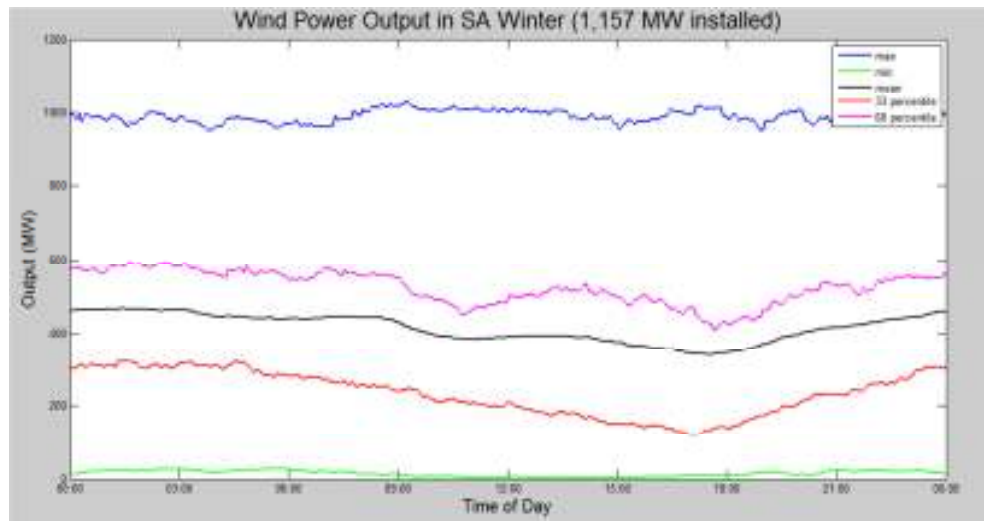
Figure 4.37 SA winter wind generation

Table 4-5 Covariance matrix of NEM wind generation

	NSW	VIC	TAS	SA
NSW	0.0745	0.0215	0.0202	0.0139
VIC	0.0215	0.0674	0.0317	0.0301
TAS	0.0202	0.0317	0.0891	0.0119
SA	0.0139	0.0301	0.0119	0.0474
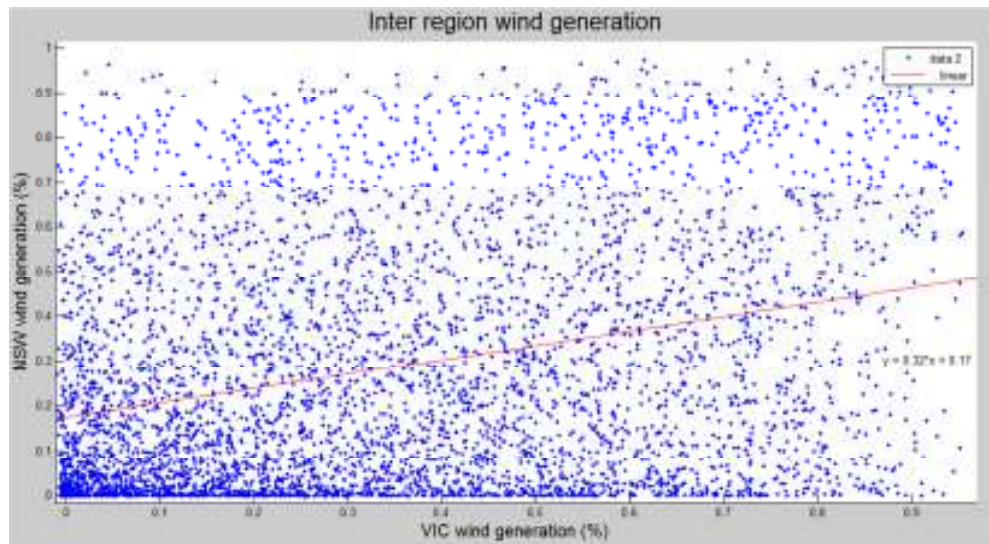
Figure 4.38 Inter region NEM wind generation

As expected SA the region with the highest installation of wind capacity has the lowest variation. Where TAS with only one SS wind farm has the highest variation. All covariances are small but positive, indicating as wind power increases in one region there is an increase in the other region.

Even with large distributed wind installations in South Australia and NSW, wind generation has the potential to be at a maximum output or minimum output at any period during the day. The dip in mean South Australian wind production during the day when power is needed the most and higher production at night during low prices periods leads wind power to being of lower value to the grid. As the wind power output drops to zero in each region it indicates wind power needs to be entirely backed up by storage or fossil fuel plants.
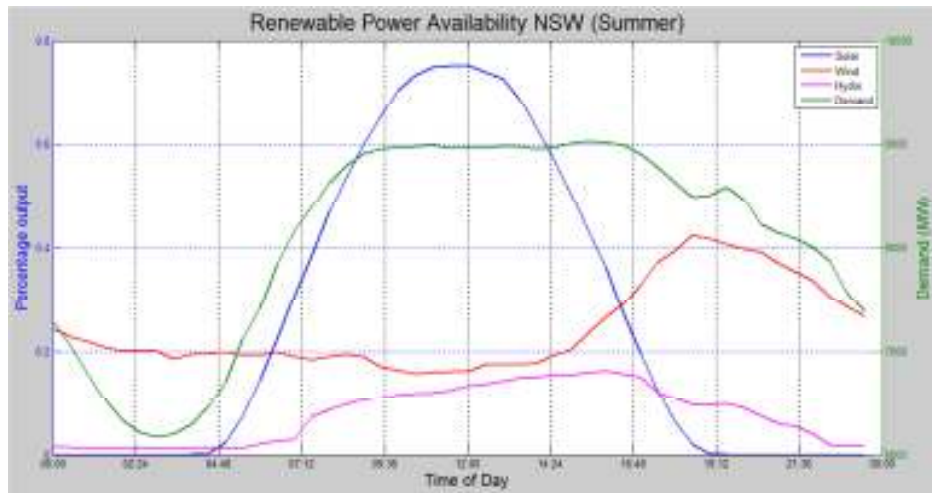
Figure 4.39 Mean summer output from renewable sources

Figure 4.40 Mean winter power from renewable generation

Hydro has the highest value as it is able to be dispatched to match demand.

Solar works well in summer but still has a low output during afternoon peak demand. It also has limited capacity during winter and has zero output for the winter evening peak.

High output of wind power during times of low demand will impact the ability for fossil fuel generators to stay online at night. The daily profile for wind power output doesn't match well with the demand daily profile.

5   Simulator Design

The market simulator was developed and programed in MATLAB using a rapid prototype methodology. It was designed to be flexible, scalable and easily modifiable tool able to simulate the generation and transmission side of electrical supply systems. An electrical supply system is created as a network of inter connected nodes. Each node is then allocated a generation capacity and a maximum power demand reference.

An energy market is established by setting up a single market operator (MO) and many market participants (MP). The MO designs the network of nodes, there interconnection and sets the MPs generation capacity and demand reference of each node. MPs then register with the MO. Upon successful registration the MO allocates several generation units to each MP and where there generation units are located.

After all MP have registered the simulation begins. The MO generates a forecast for the demand at each node and broadcasts it to all the MPs. MPs then assess the forecast and submit energy production bids for each of their generators.   Once all MPs have submitted their bids to the MO, the MO 'runs the round' to execute the dispatch algorithm to calculate the power outputs from each generator and the subsequent electricity price. The MO then broadcasts the results of the simulation to the MPs. The process is then repeated from the forecasting step until the simulation objectives have been accomplished with each MP trying to earn larger profits than their competitors.
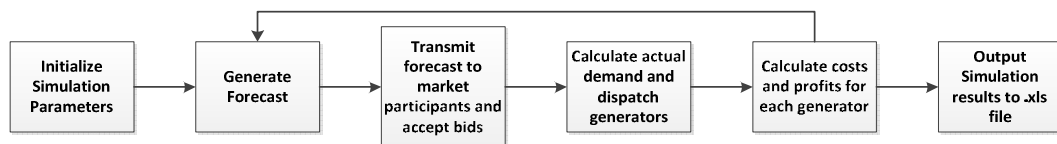
Figure 5.1 Flowchart of simulator operation

5.1   Simulation Parameters

The simulator creates an electrical supply system by establishing a network of interconnected nodes. Each node represents a demand or load centre with the interconnections the transmissions system. The simulator allows any network topology to be created and allows for several parameters to be varied.

At the beginning of each simulation the person acting as the MO sets the number of nodes and the transmission links between them. The simulation can be set up so that each node represents an entire region or each node represents a transmission connection point of an intra-regional network.

The Simulation Parameters that can be varied are

- The number of nodes in the network to be simulated
- The price on carbon emissions
- How the demand at each node is calculated
- If the market price is determined by the bid pool of each node or all bids across the entire network

The Parameters of each node

- Installed generation capacity – the total installed dispatchable generation capacity in MW of each MP
- Generation mix – how the generation capacity is split between different generation technologies
- Generation efficiency – the peak sent out efficiency of the different generation technologies. This redraws the predefined part load efficiency curve for each generator so it peaks at the supplied value.
- Generator minimums – The minimal production level of each generator
- Emissions – the emissions factor from each form of generation technology, specified in terms of tonnes of CO_2 per GJ of fuel consumed.
- Fuel Costs – the cost of fuel for each generation technology in dollars per Gigajoule of fuel
- Renewables – the extra installed capacity of hydroelectricity, wind and solar PV power.
- Demand diversity – the variation in time of peak demand between each node.

Node Interconnection

- The transmission links in the network
- The capacity of the link between two nodes (MW)
- The static efficiency of the transmission link between two nodes

5.2 Generation Forecast

Each day of operation is broken down into a number of simulation rounds the default is 24, one round per hour (in the NEM this is 288). A forecast for the demand at each node is generated for the day ahead and is based on a fixed demand value either entered manually or calculated based on the total installed dispatchable generation at the node. Demand is calculated as a percentage of this fixed value at each node using two separate methods either a manually entered vector input or from cumulative distribution functions (CDFs) calculated from NEM data.

5.2.1 Vector Input Mode

In the vector input mode, an N length vector representing a daily load profile is imputed into the simulation. Each value of the vector is typically a number between 0 and 1. A daily variation factor is then calculated for each day of the simulation. The daily variation factor is calculated as a random number between 0.7 and 1.1 with a uniform distribution. The forecast is then calculated as the fixed demand value multiplied by the daily load profile and the daily variation factor.

It is calculated in this manner as a review of NEM data showed the daily load profile is well defined based on the time of year. There is a smooth transition over the course of a day and the magnitude of the daily demand profile can change significantly from day to day with little change in shape.

5.2.3 File Input Mode

To make the demand profile more realistic real world demand data collected from AEMO for each of the NEM regions. This data for the last 18 months was grouped based on average daily temperature and if it was a business or week end/ public holiday. It was found that by grouping the business day data into four average daily temperature groups of $< 11^{o}$C, 11 to 15°C, 16 to 20°C $> 20^{o}$C there was a sample size of around 80 days in each group for the NSW and SA data. The data in each group was then used to calculate a cumulative distribution function for the demand in each region for every hour of the day. The demand in each region was then divided by the total installed dispatchable generation capacity in each region to get a percentage value. This created eight CDFs for each region, four for each temperature category over the business days and the weekend/ holidays. Figure 5.2 shows how the daily demand profile changes with average daily temperature. In colder times of their year there is a double peak in warmer parts there is a single peak.

To generate the forecast, a file with the CDFs is loaded and the temperature range selected. A daily variation factor is calculated for each day of the simulation as a random number between 0 – 1 with a uniform distribution. The daily variation factor and the time of day is then used to find the demand capacity percentage (y axis value of Figure 5.2). The demand capacity percentage is then multiplied by the fixed demand value to get the demand at each node.

Again the daily variation factor is only updated one per day as there is little high frequency variation in NEM demand.
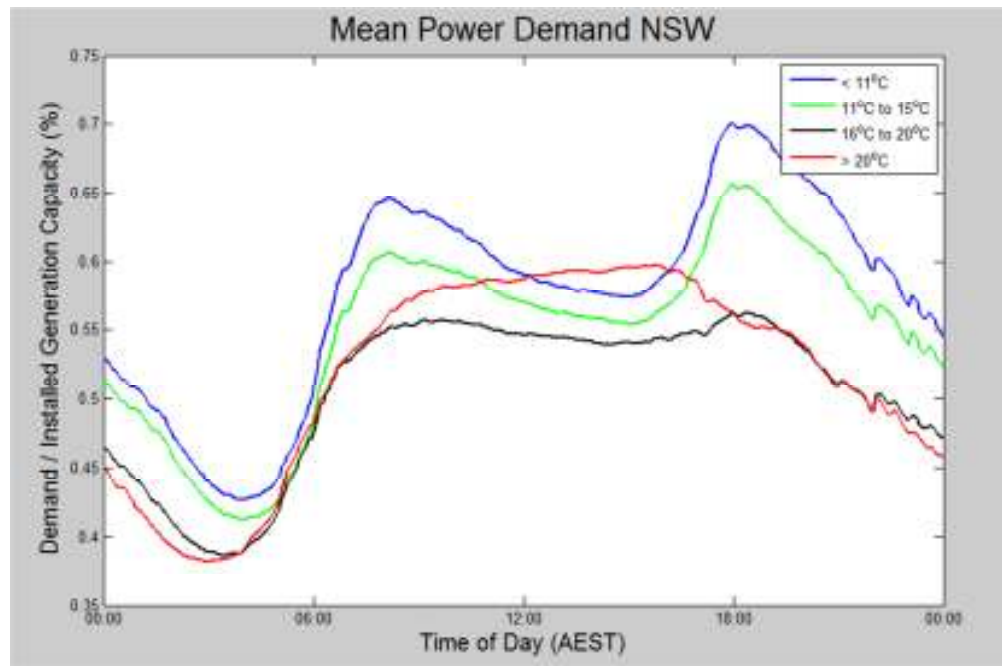
Figure 5.2 Temperature vs. daily demand profiles NSW 2011 – 2012
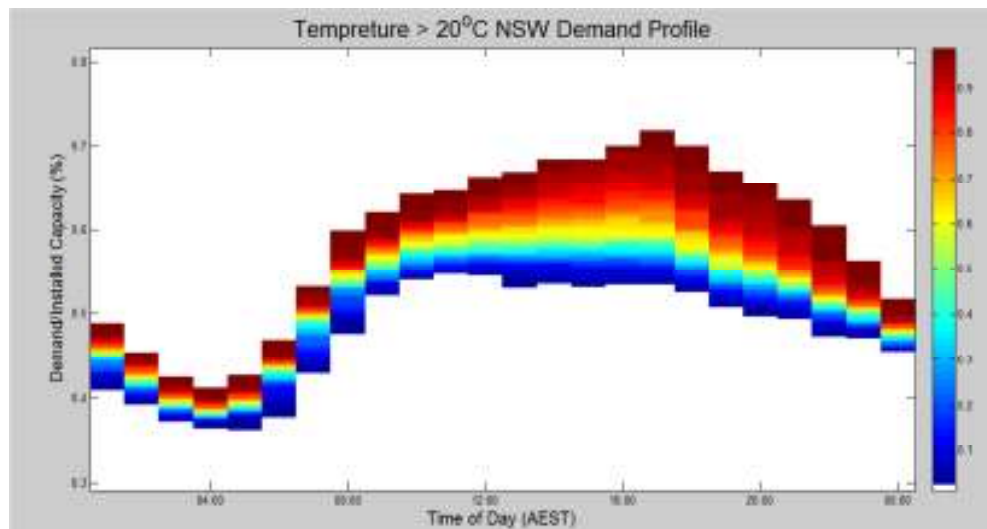
Figure 5.3 CDFs used to calculate NSW Daily load profile for average daily temperatures greater than 20°C.

Figure 5.3 shows the CDFs for NSW demand on days with average temperatures greater than 20°C. The daily variation factor is matched to a colour in the colour bar, the colour is then used to look up the y axis values to calculate the demand percentage for the entire day. Figure 5.3 shows there is little variation in demand in the early hours of the morning but a high variation in demand during the afternoon peak. Day time demand is mostly flat on the high temperature days.

5.3 Bidding

The forecast for each region is broadcast to the MPs. The MPs assess the forecast and submit bids for each generator back to the MO for each round of the next day. Each bid can have up to four blocks for each generator with the price offered referenced to the local node. The available generation capacity for each round is updated as bids are submitted and the updated availability data is transmitted back to MPs. The market participants need to continually assess the forecast and market conditions to ensure they are using an optimum bidding strategy.

5.4 Running a round

Once all MPs have submitted their bids, the MO will proceed to run a round. This executes the code to compute the power generated by the renewable technologies and is used to calculate the actual demand. After the actual demand has been calculated the dispatch algorithm will be run calculating the required production levels from each of the generators and the power flows across the network. As the simulation progresses the MO can choose to update several of the simulation parameters including changes in the transmission network and the type of demand profile.

5.4.1 Actual Demand

As demand forecasts are never perfect the actual demand is calculated from the forecast using Equation 5.1. This is done using the addition of a small forecast error and the addition of a contingency load to simulate the effect of a sudden loss of a generator or load block.

$$Actual\ Demand = Forecast\ Demand\ \times Forecast\ Error + Contingency - Renewable\ Generation \quad \text{Equation 5.1}$$

The contingency load is important as faults can be common in electrical supply systems and there needs to be procedures in place to ensure the network is capable of dealing with any likely faults while maintaining the integrity of the entire system. The contingency load can be negative to represent the loss of a load block or positive for the loss of generation capacity.

The forecast error is calculated randomly using a normal distribution with a variance specified during program run time. The magnitude of the error is calculated for each round independently. Over short time durations the forecast error in the NEM is typical only small.

5.4.1.1 Renewable Generation

The renewable generation at each node is generated in a similar manner to demand using cumulative probability functions calculated from real world data. The CDFs are also split based on average daily temperatures and business days/ holidays and weekends. Renewable generation is calculated at each node independent of renewable generation in other parts of the network. Only wind, solar PV and hydroelectricity technologies have been included as they are the only renewable technology's deployed at scale in the NEM. There are also large sources of data available for Wind, solar PV and hydro generation to analyse their real world operation. However AEMO does use a wind generation forecasting tool to forecast power production from these intermittent sources.

5.4.1.1.2 Solar Photovoltaic

With no large scale solar PV power stations in the NEM intraday solar PV production data was downloaded from pvoutput.org. Pvoutput.org is a website that allows individuals to upload production figures from there solar PV systems to the internet. Data from several systems from geographically diverse locations was combined to reduce the impact of any dubious data and reflect the distributed nature of solar PV systems. The systems were then grouped based on which states they were located. Each solar system was divided by its capacity to give each system equal weighting in the calculation of the CDF.

To generate solar PV production levels at each node an output factor is calculated as a random number between 0 and 1 with a uniform distribution. The output factor is then used to find the location in the CDF and the corresponding production level. The production level is then multiplied by the installed solar PV capacity to calculate the reduction in demand. The output factor is calculated for each round as the Pvoutput data shows that the output from individual system can change rapidly throughout the day.

Table 5-1 Sources used to generate solar PV probability function

Pvoutput System id	Size (watts)	System details	Location (Post code)
312	29,700	North orientation, low shade 25.0 Degrees tilt. Orientation is about 20 degrees West of North.	2603
25	9,400	22 panels at 5 deg elev & 9 deg Az, 9 panels at 15 deg elev & 9 deg Az, 9 panels at 28 deg elev and 279 Az.	2229
1562	20,000	North no shade 20 degree tilt	2358
793	9,690	orientation slightly west of north low shade tilt 30 degrees	2620
453	30,40	North orientation, 30.0 Degrees tilt	2018

Source pvoutput.org
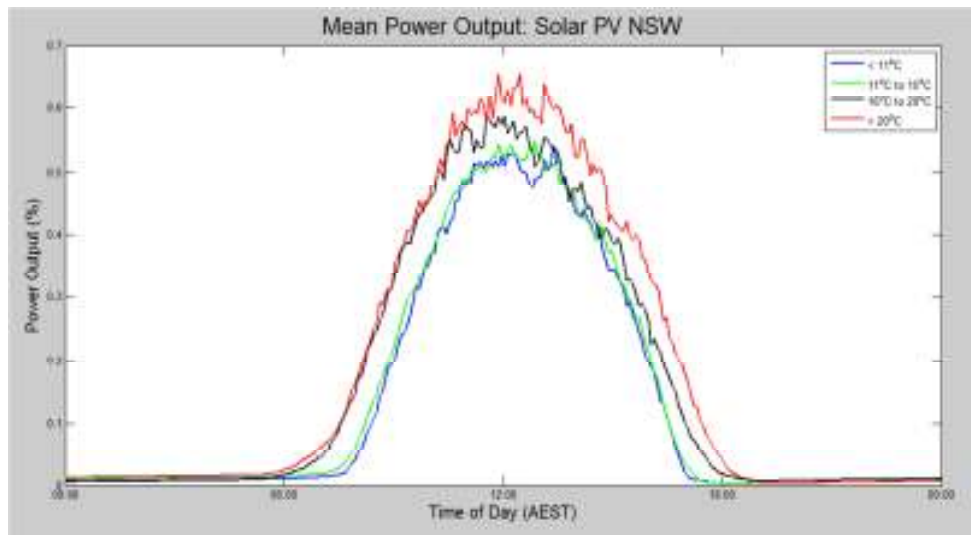
Figure 5.4 NSW average solar PV output with average temperature

Figure 5.4 shows solar PV output is linked to average daily temperature and is lower in the cooler parts of the year. The length of time solar PV generated power is also reduced with the shorter day lengths in the cooler parts of the year. Figure 5.4 also shows that while the output from individual systems can vary significantly throughout the day the combined output of several systems reduces the erratic behaviour.

5.4.1.1.3 Hydroelectricity

AEMO production data for each of the large hydroelectricity generators in the NEM was collected and combined to calculate the total power generated in each NEM region. This regional dataset was then used to calculate the CDFs for hydro power outputs at hourly intervals for different times of the day. The values in NSW appear low in terms of capacity factor for hydro due to extremely large installation Tumut 3 in the Snowy Hydro Scheme. Tumut 3 is capable of generating 1500 MW but due to limited water it is very rarely run near this limit.

The same process to calculate solar PV output is used for hydro with the exception that the same daily variation factor used to calculate demand is used for hydro. This is to reflect the ability for hydro to be dispatched according to market conditions. A potential fault with the hydro CDFs is that a large part of the data used was taken from 2011. With 2011 being one of the wettest years on record for NSW the hydro output data is most likely higher than average (Bureau of Meteorology 2011).
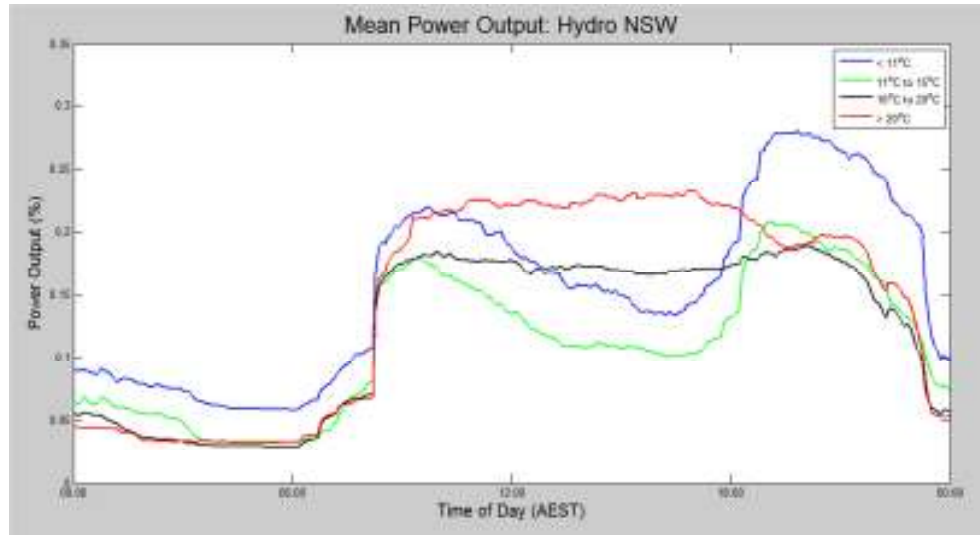
Figure 5.5 NSW Hydroelectricity generation day profile vs average daily temperature

Figure 5.5 shows hydroelectricity has a clear ability to follow the demand profile as power production is low at times of low demand but high at times of high demand. The figure also indicates that water is saved during days with low demand so it can be used for days when there is high demand.

5.4.1.1.4 Wind

As the power output from wind farms is not directly related to time of day a different approach was used for calculating wind generation. AEMO data was used to sum the power output from all the large wind farms in each NEM region and grouped based on average daily temperature, business day or weekend/holiday. The data was then used to calculate the hourly change in the output from wind farms in each region. This was then used to calculate the CDFs for each hour of the day for use in the simulation.

To generate the wind power output at each region a random number between 0 and 1 with a uniform distribution is calculated. The point is found in the cumulative histogram Figure 5.6 this is a number between -1 and 1. This value is then added to a tracking variable with limits of 0 and 1. The wind output is then calculated as the tracking variable multiplied by the installed capacity.

It was decided this method was more realistic than the procedure used for solar PV and hydro as wind power output is not strictly related to the time of day. The solar PV method ether resulted in to either too many or not enough rapid changes of wind power output. This method allows realistic changes in wind power generation as it can move from one extreme to the other quickly but typically floats around expected values.
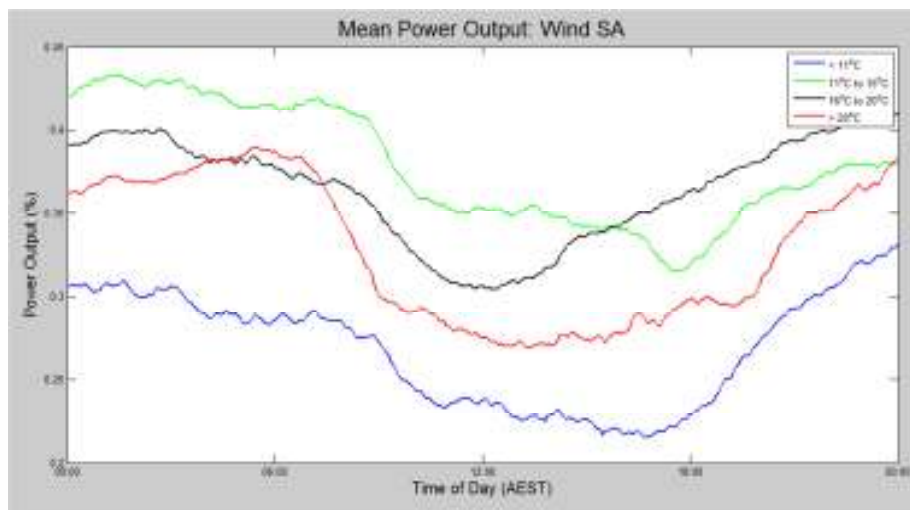
Figure 5.6 Mean wind generation vs. average daily temperature
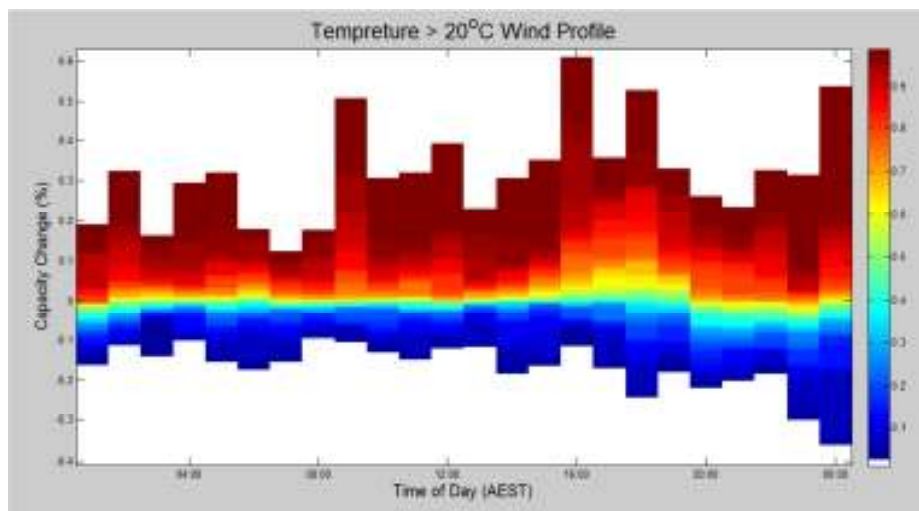
Figure 5.7 NSW Wind generation CDF

Figure 5.6 shows in South Australia where there is the largest instalment of wind power that wind power output is lowest during days of high temperatures and subsequent high demand. Wind power on average is also lower during times of high demand. Figure 5.7 shows how the wind CDF is calculated with the change in percentage of installed capacity. Although very rare, wind has the capability to have a change in power output of up to a 60% increase and 35% decrease in a single hour but typical varies less than 5-10%.

5.4.2 Generator Dispatch and Pricing

The aim of the dispatch algorithm is to minimise the value of the electricity purchased across the whole network while ensuring supply security constraints are met. The dispatch algorithm calculates generator production levels using linear optimisation with the objective function

$$min \sum_{k=1}^{nR} \sum_{i=1}^{nG} \sum_{j=1}^{nb} p_{i,j,k} . x_{i,j,k}$$ Equation 5.2 Objective function

nR number of nodes

nG number of generators

Nb number of energy blocks offered by each generator

x is the power level offered at price p of generator i block j in region k

Under the equality that the total demand at each node must be met

$$\sum_{i=1}^{nG} \sum_{j=1}^{nb} r_i \cdot x_{i,j,k} + \sum_{n=1}^{nL} r_n \cdot l_{i,k,in} + \sum_{n=1}^{nL} l_{n,k,out} = d_k$$ Equation 5.3 Regional supply capacity

nL number of transmission lines connected to the node

l interconnector n with power flowing in and out of node k

r_i is generator loss factor

r_n is transmission loss factor of the transmission line

d_k demand in region k

These calculations are also subject to the constraints

$$x_{min} < \sum x_{i,j,k} < x_{max} \quad \text{Equation 5.4 Generator loading constraint}$$

Generator I must be dispatched above its minimum stable load and less than its maximum registered load

$$\left| \left(\sum_{j=1}^{nb} x_{i,k} \right) - \sum x_{last} \right| \leq x_r \quad \text{Equation 5.5 Ramp rate constraint}$$

The change in output from any generator cannot exceed the maximum ramp rate x_r. The transmission line L must be used within its minimum and maximum power flow limits

$$0 < L_{in} < L_{max}, \; 0 > L_{out} > -L_{max} \quad \text{Equation 5.6 interconnector limitations}$$

The market price at each node is then calculated from either a pricing pool of all of the generator bids (intra-region mode) or from separate pricing pool from generator bids at each node (interregional mode). The market price is then set as the highest accepted bid in each pricing pool from a generator that is not constrained by a ramp rate or at it minimum stable load.

$$Node\ Price_k$$

$$= \begin{cases} \max(p_{i,j,k}) & subject\ to\ acepted\ x_{i,j,k} > 0 \quad \sum_{j=1}^{nb} x_{i,j,k} > x_{i,min} \quad \left| \left(\sum_{j=1}^{nb} x_{i,k} \right) - \sum x_{last} \right| \leq x_r \\ -1000 & otherwise \end{cases}$$

Equation 5.7 Node Price Calculation

Should the program be unable to satisfy all of the constraints the dispatch algorithm is re-run with the minimum stable load constraints removed in the hope that a solution can be found and the users notified that there was an error with the simulation.

5.4.4 Generator Profit

To calculate the profit of each MP the cost of each generator is calculated using the current simulation values for fuel and emissions costs and other generator costs preprogramed into the simulation. The preprogramed data for each generator includes the capital cost, FOM and VOM costs and the base part load efficiency curve, new generators can easily be added to the simulator by adding new data to generatos.m.

To calculate the costs from each generator the thermal efficiency of is calculated at their dispatched power level. This is done using linear interpolation of the base part load efficiency curve matched to the specified peak generator efficiency. The finance cost of each generator is then calculated using

$$Finance\ Cost = \frac{\left. Capital\ Cost \times {0.05}/{(1 + 0.05)^{plant\ lifetime}} \right.}{365.25 \times N}\ \text{Equation}$$

5.8 Generator Finance Cost

The finance cost is calculated at a 5% interest rate compounded annually with the capital paid back over the lifetime of the generator. A 5% interest rate was used as it the approximate interest rate for long term government bonds. The finance cost is split evenly over the entire year and N the number of simulation periods per day.

The Fuel load in GJ is then calculated using the estimated generators efficiency value and the dispatched load of the generator.

$$Fuel\ Load = Generator\ Load \times {24}/{N} \times {3.6}/{efficency}\ \text{Equation 5.9 Fuel quantity}$$
calculation

Emissions costs are calculated based on the fuel load and the emissions factor.

$$Emissions\ Cost = Fuel\ Load \times Emissions\ Factor \times Emissions\ cost\ \text{Equation}$$
5.10 Emissions cost calculation

The total cost of each generator

$$Generator\ Cost = Finance\ Cost + Fuel\ Load \times Fuel\ Cost + Emissions\ Cost +$$
$$VOM\ cost \times Generator\ Load \times {^{24}/_N} + {^{FOM\ cost}/_{365.25 \times N}}$$ Equation 5.11 Total
generator cost

The income for each generator is then calculated

$$Income = Generator\ Load \times Node\ market\ price\ \text{Equation 5.12}$$

The profit of each MP is then calculated as the sum of profits from all there generators

$$Round\ Profit = Income - Generator\ Cost\ \text{Equation 5.13}$$
$$Total\ Profit = \sum Round\ Profit\ \text{Equation 5.14}$$

5.4.5 Simulator Outputs

At the end of the simulation run the details and settings can be saved to an Excel file for review and analysis. The excel file contains the details on the demand, renewable generation and price at each node, the power flows on each of the transmission links, generator production levels, MP bid details and the emissions and costs for each of the generators.

5.5 Simulation Implementation

The simulator is implemented as an event drive GUI program developed using MATLAB GUIDE. Events are triggered by user inputs and the responses are listed in Table 5-2 for the MO interface and Table 5-3 for the MP interface. There is also a timer in each program executing code at fixed intervals.

Table 5-2 Events triggering code execution in MO software

Event	Response
Load Default button pressed	After choosing the number of nodes to be in the network for the simulation the load default button will correctly setup the simulations settings panel with default values.
Start button pressed	This triggers the timer to start generating forecasts. The MO also begins polling the chosen port listing for MPs attempting to transmitting data. If the start button is pressed again the timer and port polling will stop until it is pressed again.
Output button pressed	The program will request a file name from the user and will collate the simulation data and export it to an excel file.
Reset button pressed	This resets the simulation to round 1 and all data is deleted. The MO will begin telling MPs to reset until the start button is pressed down again. MO can now change all the simulation settings.
Run Round pressed	The triggers the code to calculate actual demand and run the dispatch and pricing algorithm. The forecast will be updated and results transmitted to the MPs.
MPs allocated node modified in the results table	The MO is able to change the node location of each of the MPs throughout the simulation in the results table..
Timer Function	At fixed intervals the timer will update the forecast and the results table update results table.

Table 5-3 Events triggering code execution in MP software

Event	Response
Register button pressed	After setting the IP address and port number of the MO this registers the MP with the MO. If this was successful the MP will be allocated several generators. This also starts the timer that begins downloading forecast and market information.
Bid (MP) button pressed	The bid details for the currently selected round in the bidding window will be sent to the MO.
Select a generator in the generator panel	After a MP has register with the MO the details of each of the allocated generators can be looked at one a time. This code updates the generators window as the MP goes through each generator.
Changes selected generator in the bid window	This retrieves the bidding data saved for each generator. The total offered energy value is also recalculated
Modify the values of a bid	If the edit boxes are modified in the bid panel the values will be sorted and stored. The total offered energy value is also recalculated
Copy previous bid button	The bids from the previous round for each generator will be copied to the currently selected round.
Submit bid button	The bids for each generator for the currently selected round will be submitted to the MO, if this was successful a tick will appear in the checkbox.
Timer Interrupt code	The timer runs a block of code at a fixed interval that requests the latest data from the MO for either the results panel, network panel or the forecast panel.
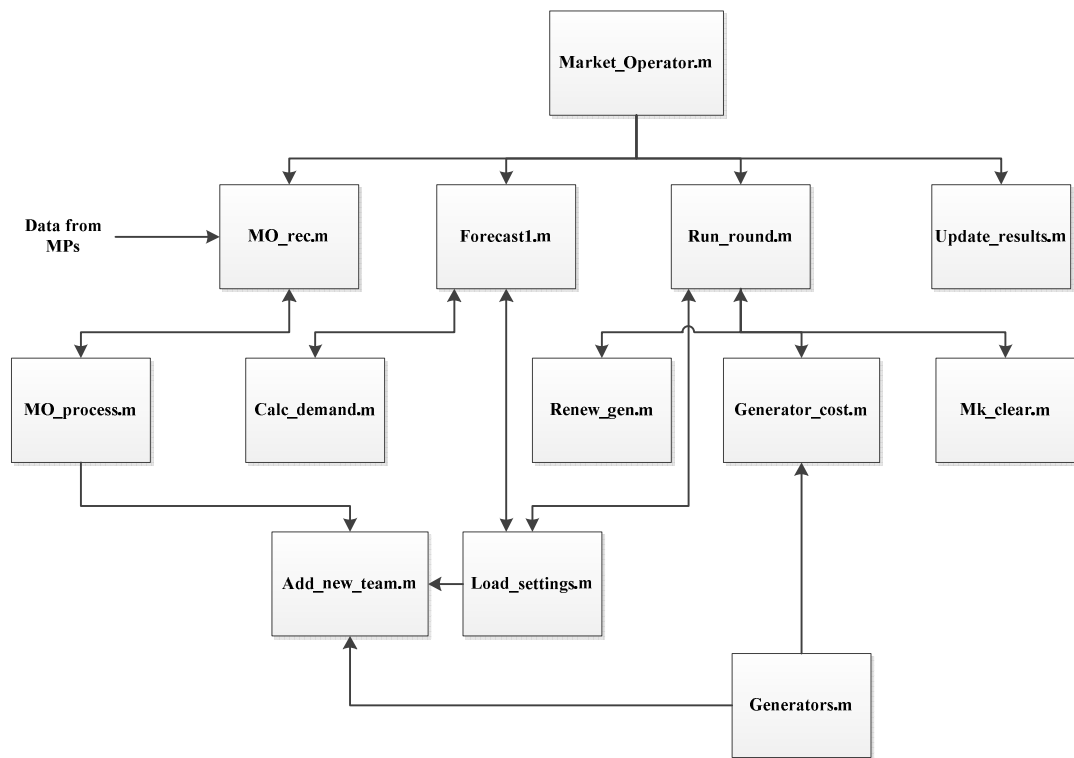
Figure 5.8 Market Operator MATLAB files

Table 5-4 Market Operator files and functions

File name	Description
Market_Operator.m	This is the main file that handles the MO GUI calls backs, it's from here that all other code is executed. Contains the port polling code for communications.
MO_rec.m	This implements the server socket that listen for MP communication attempts, it is continuously called from the market_operator.m code and awaits a fixed period listing to the chosen port for communication attempts from MPs.
MO_Process.m	Once a message has been received by a MP this code generates the appropriate return message
forecast1.m	Generates the forecast for the day ahead
Run_round.m	Calculates the actual demand, collects and prepares the bidding and constraints data for input into the market clearing algorithm. Stores the output from the market clearing algorithm and calculates the profits of each MP.
Update_results	Updates the results table in the MO interface
Calc_demand.m	Uses the specified CDFs to calculate the demand at each node.
Renew_gen.m	Uses the specified CDFs to calculate the output percentage for the wind, hydro and solar PV generation sources.
Generator_Cost.m	Calculates the cost of each generator
Mk_clear.m	The market clearing algorithm, it uses a linear optimiser to calculate generator loads, interconnector flows and market prices.
Add_new_MP.m	This code executes each time a new team registers with the MO. It allocates the location of each new MP and the appropriate generators.
Load_settings.m	This is called each time data needs to be retrieved on the simulation settings.
Generators.m	Stores the part load efficiency, finance and maintenance costs for each type of generator in the simulation.
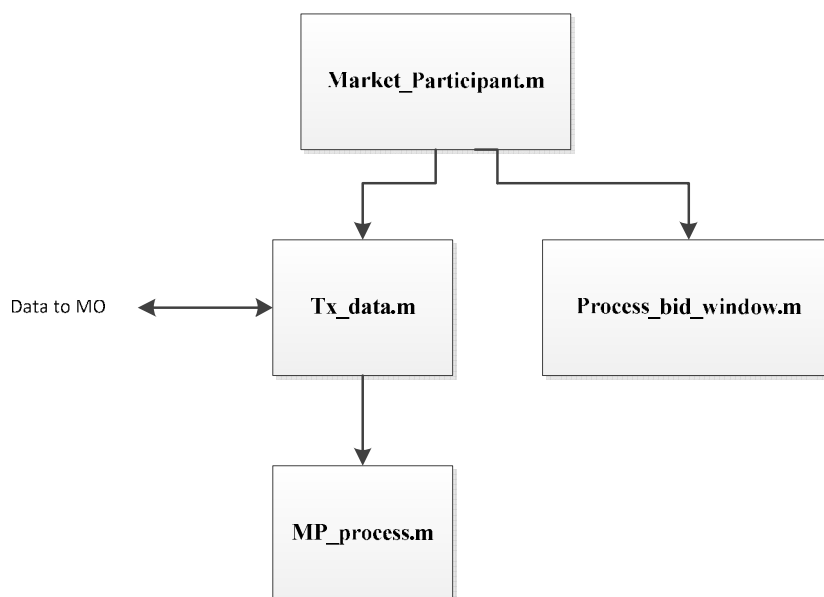
Figure 5.9 Market Participant matlab files

Table 5-5 Market Participant functions and scripts

File	Description
Market_Participant.m	Main MP code that handles the call-backs from the MP interface.
Tx_data.m	The message to be sent and the MOs IP address and port number are imputed. This code attempts to transmit the message to the MO.
MP_process.m	This code processes the response from the MO after a message has successfully been transmitted. The return message is used to update the MP interface.
Process_bid_window.m	Processes user inputs to the bid panel. This code is used to sort, check and store each of the bids and updates the bid panel when the selected generator or round is changed.

5.5.2 Communication

Several MPs are able to connect to the MO to transmit and retrieve data but only in a one to one configuration. This allows for the forecast, simulation settings and bidding data to be transmitted between the MO and MPs.

5.5.2.1 Network Communication

Data is transmitted between the MO and the MPs using text strings on top of a TCP/IP socket. All communication is initiated by the MPs and only one user can connect to the MO at a time. After a MP successfully registers with the MO a timer starts that periodically requests the latest data from the MO. The MO continuously polls a chosen port waiting for a MP to connect. When a MP connects to the MO a single text string is read in and processed. The MO then transmits a single return text string to the MP with the appropriate response. The connection is then closed and the MO returns to polling the port to allow the next MP to connect. This communication is done using the protocol set out in Appendix C.

The code uses java sockets and the implementation uses a DataReader function written in java by (Thomson 2009). The DataReader function reads the entire communicated message in one function call instead of the inbuilt function that requires multiple calls as it only reads in one byte at a time. This significantly increases execution speeds allowing for better functionality.

5.6   Simulator Operation

As described the simulator is broken down into a Market Operator with several Market Participants. Each user has their own interface allowing several MPs to compete with one another. A standalone file can be specified that adds dummy MPs who will compete with themselves and any people acting as MPs. The simulator can be run on an individual PC or on multiple PCs across a network.

5.6.1 Market Operator

The MO interface is broken down into several panels that control the simulator. Settings are specified in the settings panel (MO 6) with the simulation controlled from the communications panel (MO 1) and the simulation panel (MO 2).
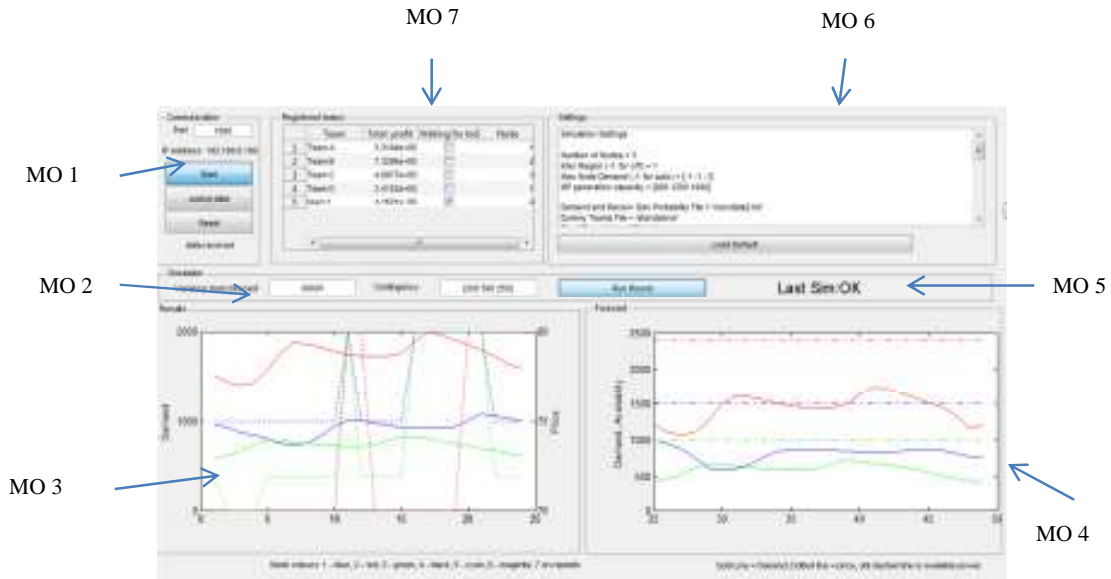
Figure 5.10 Market Operator Interface

MP 1 communication and master control panel – Displays the IP address of the computer the MO is running on, allows user to select the communications port and start or reset the simulation. The start button is a toggle button only when it is down are the forecasts being updated and the MO responding to MPs communication requests. The output button will save simulation results to an excel file.

MO 2 Simulation control – The main simulation parameters and is used to set the variation in demand from the forecast, add the contingency load and execute the dispatch algorithm to run a round.

MO 3 Market History Panel. Displays the results for the last 24 simulations including the actual regional demand (solid line left y axis) and the market price (dashed line right hand y axis) for each node. The x axis indicates which round the simulation results are from. Each node is allocated a separate colour that is consistent across the history and forecast panel.

MO 4 Forecast panel – Displays the forecast for the day ahead (solid line) and the available generation capacity (dot dashed line) for each node. Along with the history panel it is updated with new availability data each time the timer runs its interrupt function. The graphics step from left to right in one round increments, each time a simulation round is run the history and forecast panel move one round to the right.

MO 5 – Displays outcome of the previous simulation, OK means the dispatch algorithm successfully ran and a solution was found. Error indicated the dispatch algorithm was unable to find a solution and began dropping constraints so a solution could be found.

MO 6 settings panel. The settings for the simulation set here in accordance with Table 5-6

Table 5-6 Simulation Parameters

Simulation Parameter with example input	Description	Modifiable after the first round of simulation
Number of Nodes = 3	The number of nodes in the network to be simulated	No
Inter Region Mode (-1 for off) = 1	Specifies if there is to be a pricing pool at each node or one pricing pool for the whole network.	Yes
Max Node Demand (-1 for auto) = [-1 1000 -1]	The demand reference used for calculating the demand at each node. -1 the reference will be calculated from the installed generation capacity otherwise it will be from the specified value (entry for each node).	Yes
MP Capacity = [1000 1000 1000]	The total generation capacity allocated to each MO (entry for each node).	No

Demand and Renew Gen Probability File = 'nsw20112012.txt'	File with the probability distributions used to calculate the demand and renewable generation power output. Each row has a cumulative probability distribution.	Yes
Dummy Teams File = 'standalone'	An m file that contain artificial MPs and their bids, can manual set the node they are located at or let it be assigned randomly.	Yes
Fixed Demand Input File = ''	Use if pre calculated demand values are to be used. Once column for each node and a row for each simulation round use with max node demand.	Yes
Fixed Renew Gen Input File =	Predetermined renewable generation data in percentage of installed capacity. One column containing a string that describes a vector for each node for each renewable technology.	Yes
Node Generation Details	The format for specifying details at each node from here is done as columns for each parameter and a row for each node	
Gen Split (steam, CCGT, OCGT) = [0.8 0.05 0.15;0.8 0.05 0.15;0.8 0.05 0.15]	How a MPs generation capacity will be split over the different generation technologies (each row should add to 1).	No
Peak Sent Out efficiency (steam, CCGT, OCGT) = [0.338 0.5 0.22;0.338 0.5 0.22;0.338 0.5 0.22]	The peak sent output thermal efficiency for each of the generators.	Yes

gen minimum levels (steam, CCGT, OCGT) = [0.4 0.4 0;0.4 0.4 0;0.4 0.4 0]	Minimum stable outputs for each of the generators as a percentage of maximum generator output.	Yes
Emissions t CO2e per GJ of fuel (steam, CCGT, OCGT) = [0.08 0.03 0.04;0.08 0.03 0.04;0.08 0.03 0.04]	Emissions factor for each generator in tonnes of CO_2e per GJ of fuel used. Suggested values Natural gas 0.02 – 0.05, black coal 0.06 – 0.1, brown coal 0.9 – 0.15	No
ramp rate MW/ round (steam, CCGT, OCGT) = [400 1000 4000;400 1000 4000;400 1000 4000]	The ramp rate of each generator in MW change per turn	Yes
Installed Renewable Capacity (hydro, solar PV, wind) = [0 0 0; 0 0 0; 0 0 0]	Installed renewable generation at each node	Yes
Intra region losses = [1 1 1]	Efficiency of power distribution within each node.	Yes
Regions connected = [1 2;2 3]	The transmission system that connect each of the nodes. Each row describes a single link and has a single starting node and a single finishing node	Yes
Inter region losses = [0.9 0.9;0.9 0.9]	The efficiency of the transmission link in each direction	Yes
Inter node transmission capacity = [200 200]	The maximum power flow of each of the transmission links (MW)	Yes

Demand mode (0 - 4) = 0	Sets the mode used to calculate demand. 0 – Vector Input 1 – File input temperature < 11 2 – File Input temperature 11 – 15 3 – File input temperature 16-20 4 – File Input temperature > 20	Yes
Fuel cost $/GJ (steam,CCGT,OCGT) = [1.36 4.73 5;1.36 4.73 5;1.36 4.73 5]	The cost of fuel for each generation technology at each node	Yes
Carbon Price ($ tonne CO2e)= 23	The emissions tax applied across the entire network	Yes
Inter region diversity = [1 0 -1]	The difference in rounds between the peak demand at each node (whole numbers only)	Yes

MO7 Results Table – displays the register MPs and the success of their bidding strategy by showing their total profit, displays where each team is located (this can be changed at run time). If the waiting for bid checkbox is ticked it means that MP is yet to submit a bid for the next round.

5.6.3 Market Participant

The MP interface runs in a separate instance of MATLAB and controls the actions of each of the MPs.

MP 1

MP 2

MP 3

MP 6

MP 4

MP 5
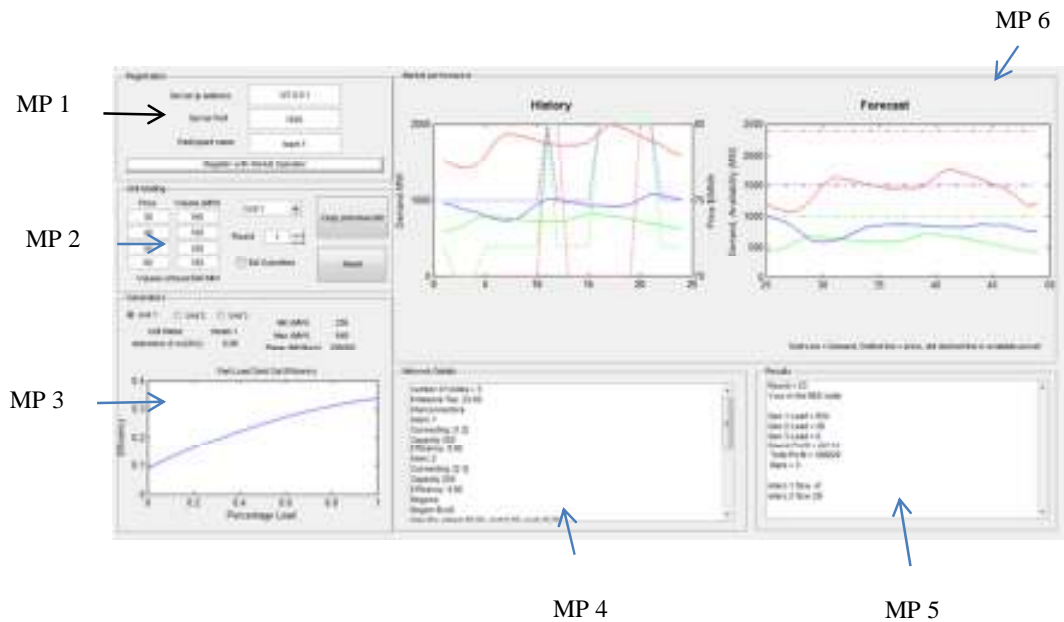
Figure 5.11 Market Participant interface

MP 1 The registration panel. This is where the MP enters a team name and adds the IP address and port of the MO. The MP then selects the 'Register with Market Operator' if this is successful the generator's panel, results and forecast graphs will fill with data from the MO. The team name is the key identifier used across the simulation to discriminate between MPs.

MP 2. The bidding panel. Used to enter the bids for each of the MPs generators, the bids can have up to four blocks each with a separate price and volume. Each MP needs to enter a bid for each of their generators for each round of the simulation. The four edit boxes in the left hand column are for the bid prices. The edit boxes in the right hand column are for the production volumes. The submit button is used to send the bid for the currently selected round to the MO. If the bid was successfully received by the MO

a tick will appear in the check box. The drop down box selects the generator that the bid is for.

MP 3 Generator panel. Shows the details of each of the generators allocated to the MP one at a time selected through the radio buttons. The panel displays the minimum and maximum production levels, the ramp rate, emissions factor and the part load efficiency of the selected generator.

MP 4 Details the simulation settings including a description of the network, installed renewable generation capacity at each node, and the current fuel and emissions costs.

MP 5 Results window, displays the results from last round run by the MO. Includes the profit made, the current power output level of each generator and how the MP ranks in terms of total profit compared to their competition.

MP6 shows the day ahead forecast and the results from the previous day of simulation rounds. This is identical to the graphics shown in the MO window.

5.8   Steps to use Simulator

Table 5-7 Typical Simulation steps

Step	Action
1	The person acting as the MO modifies the values in the settings panel to set up the simulator as required. The best approach is to set the number of nodes and use the load default button to load the default setting and ensure the panel is set up correctly before editing any other values.
2	The MO then selects the port to use and presses the start button. When this is done the forecasts will be calculated and the TCP communication server will start. The MO then gives out there IP address and the port number to use to all the MP.
3	The MO then waits for all MPs to register and to begin submitting bids.
4	Each MP starts their own instance of the MP program and enters a team name and the MOs IP address and the port number and pushes the register button. This sends a registration request to the MO.
5	MO receives MP registration request and randomly assigns the MP to a single node in the network. The MP is then allocated three generation units based on the settings of the node they are assigned to.
6	The MO software automatically updates the forecasts and broadcasts the data to the MPs.
7	The MPs assess the generation units they have been allocated and the market conditions from the forecast. They use this information to create bids which they submit to the MO.
8	Once all bids have been received the MO presses the 'run round' button to calculate generators loads and compute the profit and loss of each MP. The forecast and history panel automatically updates and move one round to the right. Results from the round are then broadcast to the MPs.
9	Steps 7 and 8 are repeated for as long as required
10	The MO can then choose to output the data from the simulation to an excel file or uses the reset button to begin a new simulation

6 Results

The simulator is a flexible test bed capable of simulating many scenarios faced in market managed electrical supply systems. Several scenarios have been constructed to demonstrate the capabilities of the simulator and key concepts of electricity supply systems. The scenarios show the marginal cost of generating electricity, advantages and disadvantages of market managed electricity supply systems and the impacts of intermittent renewable generation.

6.1 Marginal Cost of Energy Generation

This example reviews the cost of power generation in the NEM from different generation technologies. It compares cost structures between coal fired steam across QLD, NSW and VIC, natural gas fired OCGT & CCGT and wind generation. The capital cost data used was from Table 13 (ACIL Tasman 2008, p. 46) and a capacity weighted average for the other costs using AEMO data (Appendix E). An annual interest rate of 5% was applied to capital costs with the costs spread over the life of the plant. All power produced was calculated at a single 'sent out' efficiency value.

Table 6-1 NEM cost data (Appendix E)

	Fuel Cost ($/GJ)	Sent out efficiency %(HHV)	Carbon emissions CO_2e per GJ of Fuel	Fixed O&M ($/MW p.a.)	Variable O&M ($/MWh)	Capital Cost $ million / MW
QLD Coal	1.36	35.4	0.0923	50,186	1.21	1.6
NSW Coal	1.51	34.91	0.0897	50,073	1.26	1.6
VIC Coal	0.31	25.1	0.0931	59,229	1.45	1.6
CCGT (Natural Gas)	3.77	46.9	0.06	30,482	1.34	0.962
OCGT (Natural Gas)	4.73	27.6	0.07	13,000	8.89	0.714

Up to 36% of emissions from natural gas fired plants are fugitive emissions. South Australian coal fired power was ignored in the simulation due to its small size and high cost as fuel costs around $1.52 GJ and generators have Victorian coal efficiencies. Cost for liquid fuels used for unit start up and in some OCGT is estimated at $30 GJ. Coal costs range from $0.08/GJ at Hazelwood to $2.13 at Collinsville.

The marginal cost of coal fired steam generation in the three large states and natural gas fired CCGT and OCGT across all regions has been deduced from the raw data and is set out below.
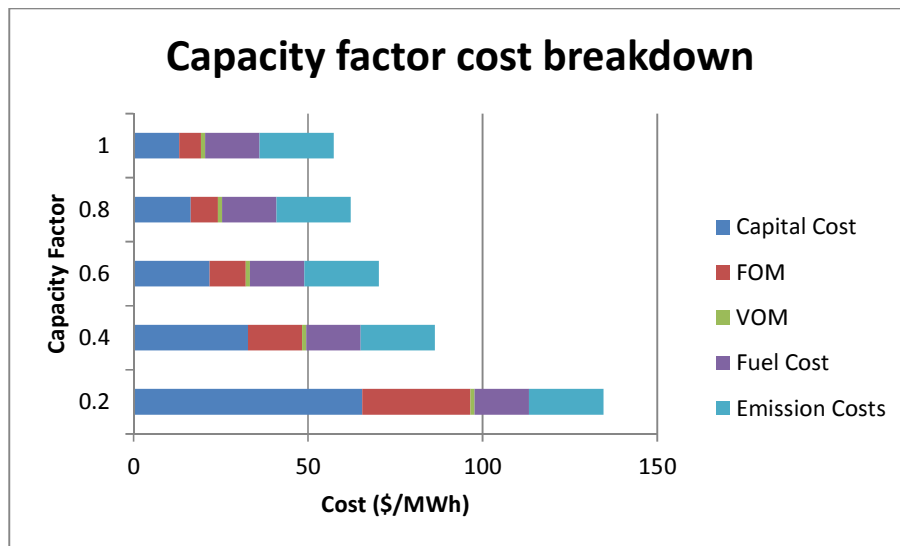
Figure 6.1 Cost breakdown of NSW coal

The capacity factor is a measure of productivity of power stations and is calculated as total energy generated / maximum possible generated energy, taking into account plant availability. It has a significant impact on the cost of power produced at a power station as the greater the amount of power produced the more the fixed costs for capital and FOM can be spread. With fixed 'sent out' efficiency the emissions cost, VOM and fuel costs remain constant while capital costs and FOM are significantly reduced as the cost is spread over more energy. With typical capacity factors of coal fired power stations at 0.75 the largest costs are emissions taxes and fuel costs. At low capacity factors the finance costs dominate, at high capacity factors fuel and emission costs dominate.
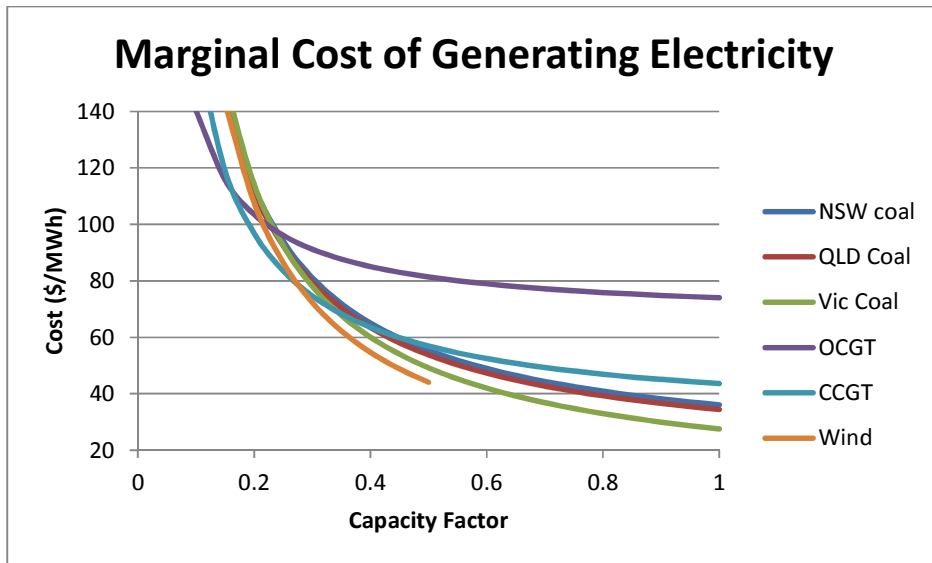
Figure 6.2 Marginal cost of generating electricity in the NEM
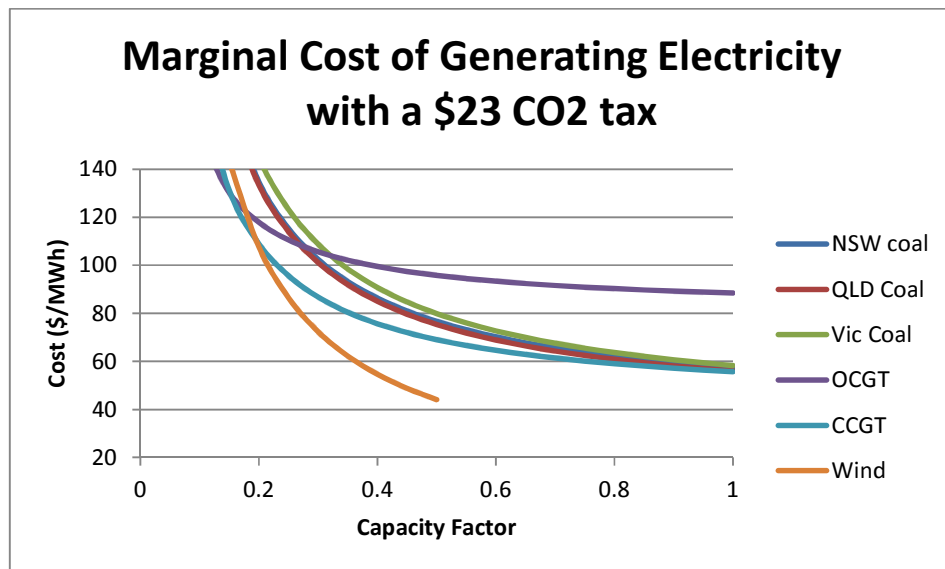
Figure 6.3 Marginal cost of generating electricity in the NEM with a $23 per tonne carbon price

Marginal cost of generating electricity in the NEMFigure 6.2 shows coal is used for base load as it is cheapest at high capacity factors while OCGT are used as peaking plants as they are cheapest for low capacity factors. Figure 6.2 confirms power from QLD and VIC is imported into NSW due to the lower generation costs. Due to the introduction of the carbon tax Victorian brown coal generation costs have risen steeply. While compensation currently addresses the issue, the compensation arrangements will eventually come to an end.

CCGT operating as base load have been given a significant financial advantage from the introduction of the carbon tax. It would take a doubling of the carbon tax for OCGT to become a cheaper alternative compared to coal for base load power.

Pre carbon tax wind was only marginally cost effective around a 0.35 to 0.4 capacity factor with a renewable energy certificate priced at $38.39 in 2011 and $35.24 in 2012 (Clean Energy Regulator 2012). Figure 6.2 also highlights the importance of site selection and the needed for a high capacity factor for wind power to be competitive.

6.2   Competition Effectiveness

Shown below is a demonstration of the operation of a market based electrical supply system. Two identical coal generators in a single region compete with one another on a winter base load profile. Each generator has a minimum load of 800MW and a maximum load of 2000MW. Generator 1 submits a bid offering power at 65$/MWh, Generator 2 offers power at 66 $/MWh.
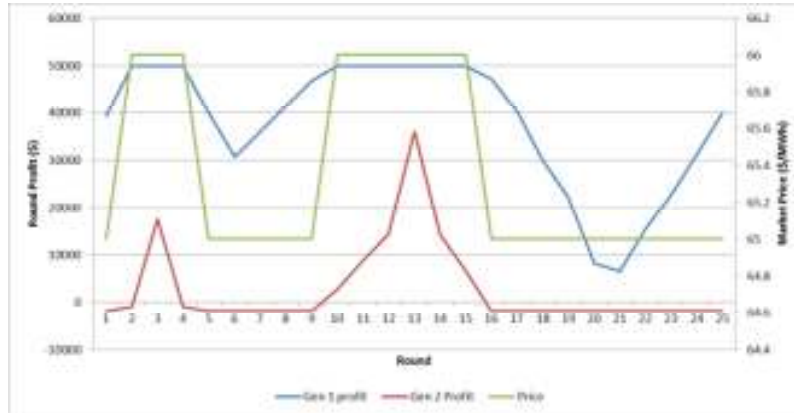
Figure 6.4 Generator Profit and market price
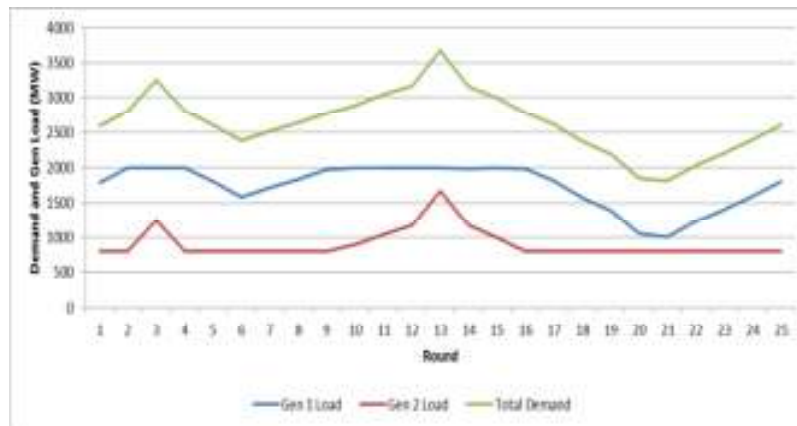
Figure 6.5 Generator outputs and demand

The result after a single day is Generator 1 has a capacity factor of 91% and a total profit of $945,331. Generator 2 has a capacity factor 47% and a total profit of $67,578.

During the time, Generator 2 is in a constrained dispatch situation at its minimum output of 800 MW, so its bids are dismissed. Due to the capacity factor and the impact of part load efficiency at $65 MWh Generator 2 is losing money were generator 1 is making money. When Generator 1 is at maximum load the price moves to $66 kwh. As generator 1 is at full load it receives the greatest benefit from the higher price.

Within this example with limited competition there is nothing stopping generator 2 from bidding up to the market price cap to make super profits. However, if this occurs generator 1 will still be the largest beneficiary from higher prices. This is the main benefit from market based electrical supply systems, generators are rewarded for bidding lower than their competitors. As generators underbid each other this drives the cost of electricity down. Market based systems will only work if there is enough competition so no lone company can control the prices.

6.3   Interconnector Savings

In this example there are two identical regions with a large diversity in demand. Each region has an installed capacity of 1000 MW. The two regions are connected by a 90% efficient 200 MW interconnector. Each region has a 900MW coal plant and a 100 MW OCGT. The coal generators are bid in blocks of 25% of their capacity priced at $40, $50, $60, $70 MWh. The OCGT bid in blocks of 25% capacity at $100, $110, $120 , $130 MWh.
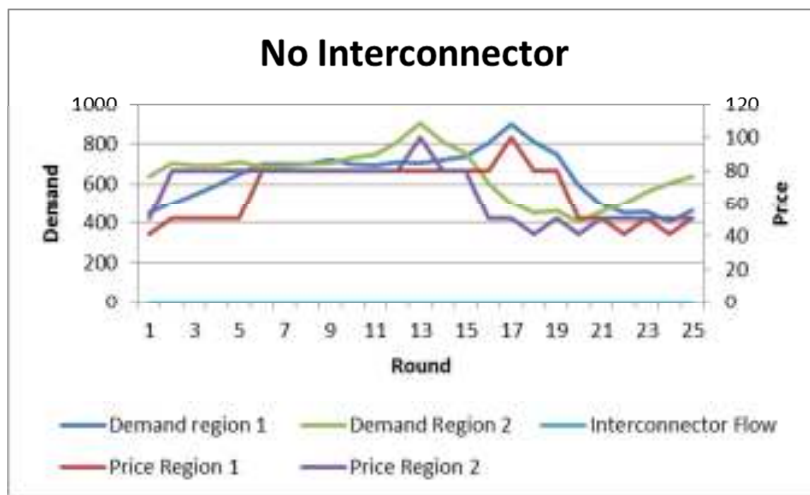
Figure 6.6 Results with no interconnector
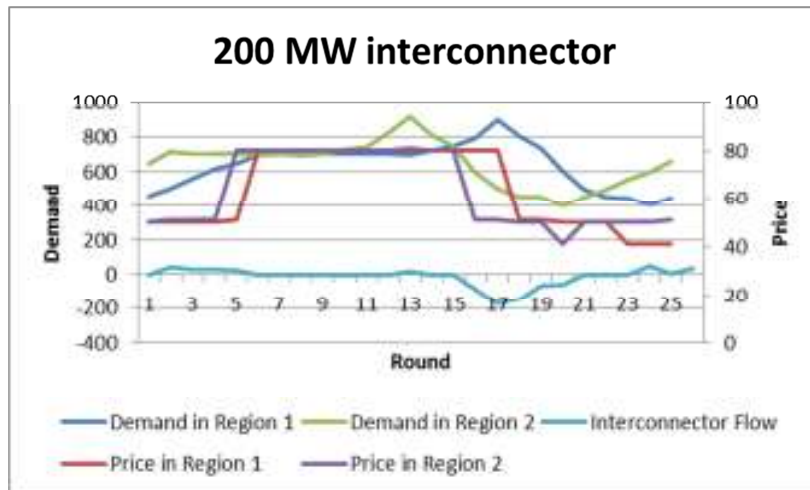
Figure 6.7 Results with 200 MW interconnector

The average price across the two regions without the interconnector is $66.63 but with the interconnector the average price is $63.28. Energy flows in both directions across the interconnector and despite losses, cheaper electricity is available in the adjacent region. Without the interconnector the OCGTs are needed to satisfy demand which raises the price to $100MW/hr. With the interconnector there is no need for the OCGT to start and the price in both regions is also depressed when there is low load in one region but high load in the other.

Therefore despite the losses in the interconnector it receives heavy use as the energy price is optimised over the whole network. The OCGT aren't needed with an interconnector allowing for a reduction in local installed generation capacity. The interconnector adds extra competition to both the regions.

In this example the interconnector saves $3.35 per MWh for the day across all energy sold in the system. These savings amount to a significant value over the life time of the interconnector providing a significant incentive to invest in the interconnector link if there is a favourable cost benefit analysis.

6.4   Market Efficiency

This simulation looks at the efficiency of a market based electrical supply system. An eight node network with three generation centres and five load centres was established as shown in Figure 6.8 and detailed in Table 6-2 Table 6-3.
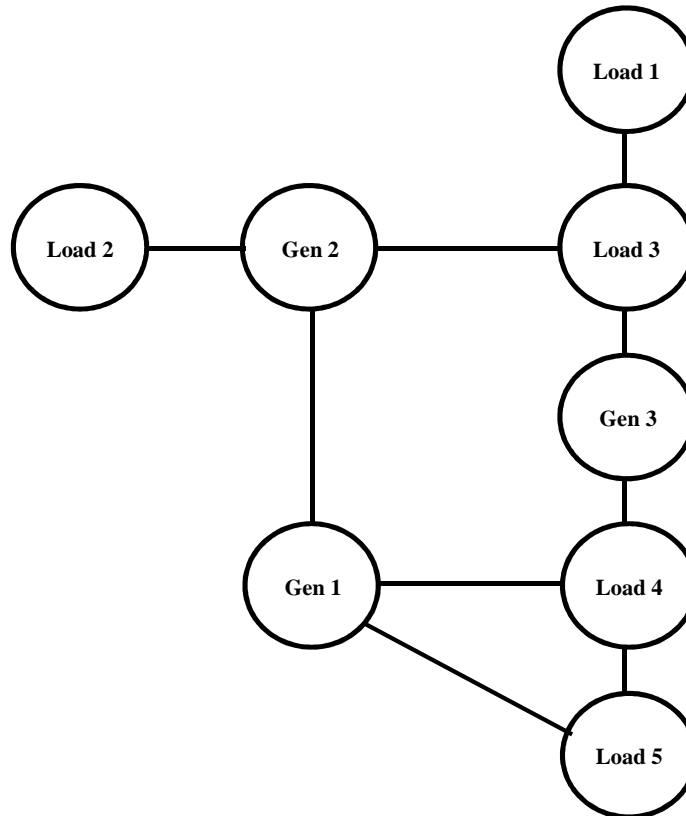
Figure 6.8 Eight node simulation network

Table 6-2 Node details

Node	Generation	Peak Demand
Gen1	2000 MW steam Generator	0 MW
Gen 2	2000 MW steam Generator	0 MW
Gen 3	2000 MW steam Generator	0 MW
Load 1	0 MW	500 MW
Load 2	0 MW	500 MW
Load 3	0 MW	1000 MW
Load 4	0 MW	2500 MW
Load 5	0 MW	1500 MW

Table 6-3 Inter node transmission links

Transmission link	Capacity (MW)	Static Efficiency (MW)
Gen1 – Gen 2	2000	0.95
Gen1 – Load 4	3000	0.94
Gen1 – Load 5	1500	0.93
Gen 2 – Load 2	500	0.95
Gen 2 – Load 3	2000	0.94
Gen 3 – Load 3	2000	0.97
Gen 3 – Load 4	2000	0.98
Load 3 – Load 1	500	0.9
Load 4 – Load 5	1000	0.96

The three generation centres were identical and the impact of different bidding strategies was tested.

- Same fixed price - all generators are bid in at $50 MWh, the generators will be dispatched to minimise losses in the network.
- Different fixed price – generator 1 bid in at $53 MWh, generator 2 bid in at $50 MWh, generator 3 at $56 MWh. This simulates the generators bidding in at different cost due to varying fuel prices.
- Staggered pricing - each generator places a staggered bid to ensure they will produce above minimum output to boost their capacity factor.

  Generator 1 has 50% capacity $54, 25% capacity $60, 25% capacity $65

  Generator 2 has 50% capacity $46, 25% capacity $50, 25% capacity $55

  Generator 3 has 50% capacity $60, 25% capacity $65, 25% capacity $70
- Half transmission losses – the losses in the transmission network were halved to assess the impact losses play in the cost of generation capacity. Generators bid in at the different fixed price bidding strategy.

Table 6-4 Simulation results

Simulation description	Total Energy Generated (MWh)	Total Cost of generated energy ($)	Total Emissions (tonnes CO_2)
Generators submit the same bids	25,978,591.1	1,262,736,334	25,440,994.6
Generators submit different fixed price	26,391,023.3	1,271,976,077	25,659,407.8
Generators Staggered bidding	26,309,881.9	1,271,532,487	25,650,791.8
Half transmission losses	25,186,931	1.24E+09	24,987,499

With generators submitting the same bids, the dispatch algorithm finds the solution that will minimise the total electricity produced, accounting for all transmission losses. This results in the lowest quantity of energy generated, cheapest cost for generating electricity and produces the least emissions.

With different fixed price, the generator with the cheapest offered electricity will be run up to full power before the others. This results in the greatest amount of power needing to be generated making it the most expensive practice and results in the most emissions.

Transmission losses are high in the network, under the different fixed price bidding strategies. Losses account for approximately $64 million in extra costs and 1,343,817 tonnes of CO_2.

Therefore in this example by dispatching generators, based on maximising efficiency instead of production cost, results in a cost saving of 1.56% and an emissions reduction of 0.85%. So bidding strategies have a direct impact on the cost of electricity and due to losses, the cheapest produced is not necessarily the lowest cost option for the network.

6.5   Renewable generation

Continued increase in the capacity of intermittent solar pv and wind generation installed in the NEM can potential have a big impact on the NEM. This example looks at the effect the different renewable technologies can have on an electrical supply system.

In this example there is a single region with an installed capacity of 14,000 MW made up of four coal generators at 2,975MW each, one 700MW CCGT and four 350 MW OCGT. The dispatchable generators are bid in at the different fixed prices.

Each renewable technology is simulated as a reduction in demand and it is assumed the renewable power must be accepted by the market. The different renewable technologies were tested using the same dataset over the period of one year to assess the impacts of different levels of penetration. This simulation required a total of 76,435,612.24 MWh to be generated to meet demand. The dataset was generated based on the NSW data file for demand and renewable generation capacity.

Table 6-5 Renewable generation simulation results

	Cost increase of remaining electricity ($.MWh)	Emissions reduction (%)	Renewable generation (%)	Market Earnings ($)	Market errors
No Renewables	49.8408 $/MWh	0.9512 tonnes / CO_2	0	0	0
1400MW hydro	100.8578%	1.0462%	1.6918%	79,471,420	0
1400 MW solar PV	101.9161%	2.2300%	3.6466%	156,571,030	0
1400 MW wind	103.6693%	3.6774%	6.4030%	244,379,562	10
8275 MW hydro	105.5450%	6.2049%	10.00%	397,545,730	14
3839 MW solar PV	105.6929%	6.0471%	10.00%	376,675,117	27
2186 MW wind	106.2066%	5.4677%	10.00%	363,831,675	149

A market error indicates there is excess generation capacity in the market. i.e. no solution can be found to satisfy all market constraints. If this occurs the minimum generation capacity constraint is dropped allowing power generation output to fall to zero at coal and CCGT power stations. The ability for hydro to be dispatched is reflected in the error count as even at very high levels of installed capacity there is a minimum number of errors. Winds ability to generate at full power during periods of low demand result in it producing the greatest number of errors approximately 1.7% of the total simulation steps at 10% generation capacity. Solar PV also causes a significant amount of market errors particularly on days with winter type load profiles with low demand in the middle of the day. The impact of a market error sending the price to -1000 $/MWh has a severe impact on the revenue in the simulation.

On a capacity installed basis, wind is the most beneficial as it has the highest capacity factor of 40% followed by solar PV 22.7% with hydroelectricity having the lowest 10.54%. This means you only need to install half as much wind as solar PV and a quarter if hydro to achieve renewable targets and emissions reductions. However due to winds ability to generate power at all times of the day and periods of low demand it has the most trouble integrating into the market.

On an energy generated basis hydroelectricity is the most beneficial renewable technology, it has the lowest impact on the increase in cost to generate the remaining electricity by minimise the reducing in part load efficiency of fossil fuel plants. The means Hydro also has the greatest emissions reduction and by generating during periods of high demand it generates the most revenue from the market. With Wind and Solar PV not following the demand curve they force thermal units into the very low region of the part load efficiency curves pushing up the cost to produce the remaining electricity and have a lower impact on emissions.

This simulation shows emission reduction are not linearly linked with the quantity of renewable power generation as fossil fuel generators are moved up and down their part load efficiency curves. It appears to be more beneficial in terms of carbon emissions for renewable generation to be at times of high demand. As well as the cost of installing renewable generation capacity there is also an increase in the cost fossil fuel fired generation due to a reduction in part load efficiency's and reducing the capacity factor of fossil fuel generators.

6.5.1 Business day demand reduction

As supply must equal demand, using data from the previous simulations this section looks at the quantity of fossil fuel generation that can be displaced by renewable generation sources on business days under the 10% renewable energy generation scenarios. By creating the demand duration curves for summer and winter it is clear to see how the renewables displace fossil fuel generation.
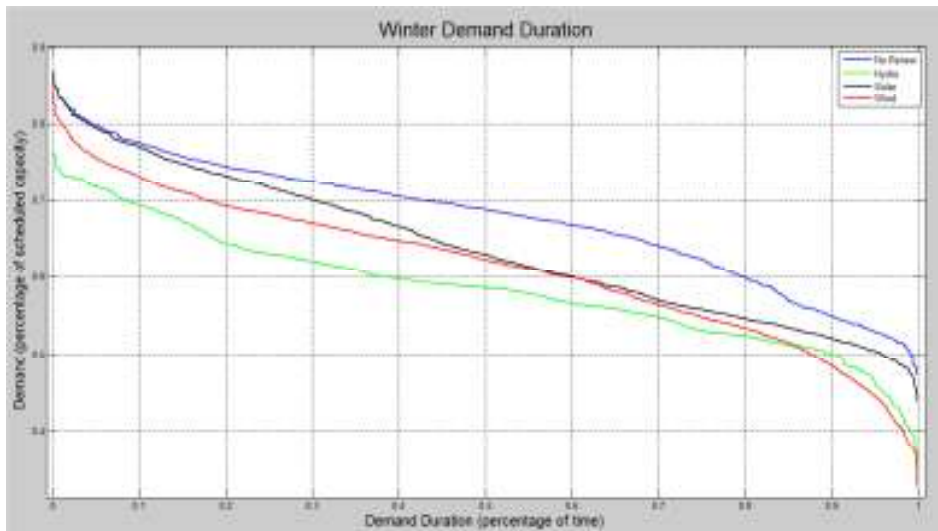
Figure 6.9 Winter business day demand duration

Figure 6.9 shows hydroelectricity is the only technology to significantly reduce the peak demand and the need for backup fossil fuel generation. Solar PV contributes nothing to the winter peak and displaces very little fossil fuel generation at high demand time in winter. Wind only reduces peak demand by 2.5% but does displace a reasonable amount of fossil generation capacity during high demand times indicating it could be used with grid scale energy storage. All technologies significantly reduce the minimum demand levels potential requiring a shutting down of base load fossil fuel generation and may cause issues with system inertia requirements.
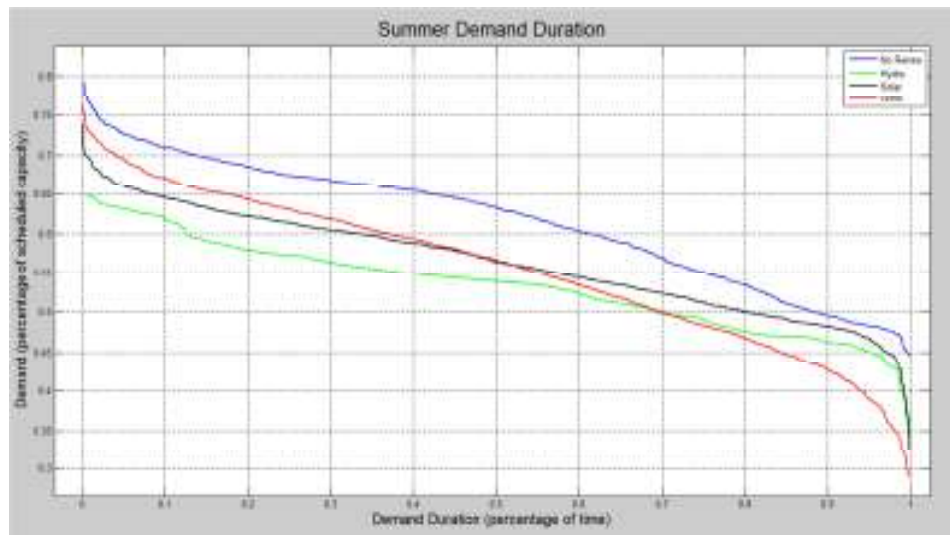
Figure 6.10 Summer Demand Duration

Again only hydro is able to impact peak demand significantly but typically generates most of its energy in cooler parts of the year. Due to the time of the day Solar PV contributes to the peak and displaces a large amount of generation capacity at high demand levels in summer. In this example Solar PV is outputting at approx. 32% of capacity during the demand peak. Again all renewables push minimum demand lower potentially destabilising the market. Wind only has a minimal impact on peak demand and is producing power across all demand levels.

As drought may significantly affect hydro generation it along with all forms of renewable generation seem to need to be backed up by fossil fuel generation capacity to ensure that both the summer and winter demand peak can be met.

Table 6-6 Renewable power demand reductions

Demand	0% of time	5% of time	50% of time	95% of time	100% of time
Winter Results					
Demand – hydro output	11.92%	10.11%	14.86%	12.86%	31.55%
Demand – Solar PV Output	0.07%	0.49%	8.49%	4.72%	7.21%
Demand – Wind output	2.53%	5.33%	9.42%	16.01%	29.94%
Summer Results					
Demand – hydro output	18.15%	13.14%	14.97%	6.63%	26.08%
Demand – Solar PV Output	6.99%	9.07%	10.54%	3.22%	27.12%
Demand – Wind output	3.78%	4.27%	10.91%	19.28%	35.01%

Hydro power has the lowest capacity factor but it is capable of producing the highest reduction in peak demand, particular in summer where Hydro flattens out peak demand completely. It also has most of its output in the higher demand times were market price will be the highest and it will generate the most revenue.

Solar power does not provide and support during winter demand peaks but does reduce peak summer demand by 7 – 9%. Solar PV also provides most of its output during higher demand times.

Despite Wind having the highest capacity factor it gives the least support to peak demand across the year indicating it needs to be fully backed up. It also has the greatest reduction of minimum demand potential destabilising the grid.

7 Conclusion

Background information was collected on the NEM to understand its construction and organisation. This quantified the cost and the operational limits of the generation technology used in the NEM. Raw NEM operational data was collected and processed in MATLAB to gain an understanding of demand, pricing and how the different generators are operated.

This data was then used to design and develop a MATLAB based energy market simulator. The simulator includes realistic data and makes the simulation as realistic as possible by using probability functions generated from the NEM data.

The simulator was then used to illustrate the operation of a market based electrical supply system. It shows how important accurate demand and availability forecasting is to ensure reliable operation of an electrical supply system. It also shows that energy markets provide an effective method to manage electrical supply systems provided there is an adequate transmission system and there is significant competition. A market managed electrical supply system may not necessarily provide the most efficient solution as the lowest cost energy producer is not necessarily the best option for reducing emissions and total system cost.

The simulator also showed the continued growth in the instalment of renewable power generation technologies will upset traditional base load generators. There are significant cost and emissions savings differences between the renewable technologies based on installed capacity and power generated. Without energy storage, renewable technologies also need to be heavily backed up by traditional fossil fuel generation.

8 Future Work

In the renewable simulation the capacity factor for solar PV was around 22%. A review of solar data on pvoutput.org showed real systems seem to have a capacity factor between 15-19% indicating a potential problem with the CDF functions used in the simulator.

In the simulator, attempts were made to make the demand and renewable generation outputs as realistic as possible. This was done using CDFs calculated using real world data. Due to limited time and the extent of the publicly available data the real world data was taken from a relatively short period of 18 months. To ensure these values weren't affected by any short term economic or weather influences it would prudent to obtain data over a longer time period.

Only a very basic procedure was used to generate the outputs from the intermittent renewable energy sources. It would be beneficial to develop a more advanced method that better reproduces any relationship between demand and the output from the intermittent renewable energy sources.

The demand and renewable energy output is calculated at each node independently of the demands at adjacent nodes. It would be beneficial to research the relationships that would exist between different sub regions in the NEM so this could be included in the simulator. This would allow an examination of how generation resources can be better shared across the NEM.

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10 Appendix A: Project Specifications

University of Southern Queensland
Faculty of Engineering and Surveying

ENG4111/4112 Research Project

<u>Project Specification</u>

Chris Flynn 0061009752

Topic: Electricity Market Simulation using MATLAB

Supervisior: Tony Ahfock

Enrolment: ENG 4111 – S1, External, 2012
              ENG 4112 – S2, External, 2012

Project Aim: The aim of this project is to develop a MATLAB based electricity market simulator that can be used as a teaching tool. The simulator will include the main features of the Australian National Electricity Market.

1. Research the technology and infrastructure used in the Australian National Electectricity Market.
2. Research the management and operation of the Australian National Electricity Market.
3. Design and develop a simulator for demonstration and analysis of market managed electrical supply systems.

Chris Flynn 21/3/2012

11 Appendix B: Files Included with Submission

Table 11-1 Data files submitted with assignment

Data file	Description
NEM_dispatches.zip	The raw 5 minute AEMO dispatches used in the study of the NEM. Contains data on the demand and price in each region, the interconnector flows and NEM constraints.
Generator dispatches.zip	Raw 5 minute AEMO data on the power production levels at the different AEMO generators.
Generator_outputs.zip	Processed data from NEM_gereator_outputs.zip. Collects the data from each of the 5 minute dispatches for each generation unit giving each generator its own file. The file is a tab delimited with a column for a MATLAB datenum time and a generator output level (MW).
NEM_hydro_data.txt	A tab delimited text file the combines the total hydro outputs in the NEM for each region. The column structure of the file is [datenum time, new south wales outputs, victoria outputs, Tasmanian outputs]
NEM_wind_data.txt	A tab delimited text file the combines the total wind outputs in the NEM for each region. The column structure of the file is [datenum time, new south wales outputs, victoria outputs, Tasmanian outputs, south Australian outputs]
Nswsolardata.txt	A tab delimited text file with the combined solar PV pvoutput data. The column structure [datenum time, solar output]
Nswtempdata.txt	A tab delimited text file with the temperature data used in nswtempdem2.m. The column structure [datenum time, tempreture]
NEM demand.txt	Tab delimited file with the output from Regional_dispatch_results.m for regional demand in the NEM at the 5 minute dispatch interval. Column structure [datenum time, nsw,qld, vic, tas, sa]

NEM price.txt	Tab delimited file with the output from Regional_dispatch_results.m for regional spot market price in the NEM at the 5 minute dispatch interval. Column structure [datenum time, nsw,qld, vic, tas, sa]
NEM available generation.txt	Tab delimited file with the output from Regional_dispatch_results.m for available generation in the NEM at the 5 minute dispatch interval. Column structure [datenum time, nsw,qld, vic, tas, sa]
NEM inter region reliance.txt	Tab delimited file with the output from Regional_dispatch_results.m for interregionly energy transfers in the NEM at the 5 minute dispatch interval. Column structure [datenum time, nsw,qld, vic, tas, sa]

Table 11-2 MATLAB files not used in simulator included with submission

MATLAB File	Description
Generator_stats.m	Calculates the capacity factor, available factor and volume weighted earnings of generators in the NEM for before and after the introduction of carbon pricing. Need to specify the unit, its capacity and which NEM region it is in.
Demanddayprofile.m	Uses the NEM data to calculate the average daily load profiles for each NEM region
Demandhistogram.m	Code to display the summer and winter cumulative demand profile of all NEM regions
Hydroall.m	calculates the hydroelectricity generated in each region of the NEM
Nswtempdem2.m	Calculates the probability function from NEM data to use in the simulator
Probs.m	Calculates the probability functions for demand, hydro and solar capacity at 1 hour intervals throughout the day

Probs2.m	Calculates the probability functions for wind power at 1 hour intervals throughout the day
Nempricehistogram.m	Plot spot NEM prices using oz energy analysis data and plot histograms of market prices
Pribfiletest.m	Tests the probability functions used to calculate demand, solar and wind generator in the simulator
Generator_loads.m	Script used to combine the data from thousands of 5 the minute AEMO dispatched files of generator loads into a single file for each generator
Regional_dispatch_results.m	Compiles the data from thousands of 5 minute individual AEMO dispatches for individual parameters into a single file. Used to get the Price, demand and available generation in each NEM region
QLD_price_demand_avail.m	This code fines the week of highest demand in QLD and plots the relationship between demand, price and availability plot region data from summer and winter week of max demand
SA_price_demand_avail.m	This code fines the week of highest demand in SA and plots the relationship between demand, price and availability plot region data from summer and winter week of max demand
Qld_genstack.m	Shows how demand is covered by the different generation types in weeks of high demand in Queensland
SA_genstack.m	Shows how demand is covered by the different generation types in weeks of high demand in south Australia
Pv_output.m	Downloads the intraday solar PV output data from pvoutput.org
Tempreture_data.m	Downloads intraday temperature data from weather underground.

| Solarjoin.m | Combines the data from several individual solar system downloaded with pv_output.m into a file with 5 minute time steps. |

12 Appendix C: Communication Strings Format

Table 12-1 Communication messages between MPs and the MO

Message type	Sent from MP	MO response
Register add new MP to simulation	'type=reg,id=%s,name=%s' The id is the ip address of the MP, name is used the string used to identify each MP.	'Type=gens gen1=%s,max=%.0f,min=%.0f,ramp=%i,aux=%.3f,co2=%.3f,eff=%s gen2=%s,max=%.0f,min=%.0f,ramp=%i,aux=%.3f,co2=%.3f,eff=%s gen3=%s,max=%.0f,min=%.0f,ramp=%i,aux=%.3f,co2=%.3f,eff=%s' If registration successful MO responds by allocating 3 generators to the MP
Update network data – retrieves data on the node details, fuel prices and transmission network	'type=networkdata,team=%s,round=%i'	'type=networkdata,%s' A single is returned which is copied directly into the appropriate edit box
Market data – retrieve the forecast and history data	'type=mkdata,id=%s,name=%s'	'type=mkdata,round=%i,forcast=%s,avl=%s,demand=%s,price=%s' A string is returned for demand, available, forecast and price. Eval is use to convert the string into a matrix which is then plotted in each axis.

Market instructions – Request the results from last market round and current team ranking	'type=mkinst,team=%s,round=%i'	type=mkinst,Round = %d \nYour in the %s node\n\nGen 1 Load = %.0f \nGen 2 Load = %.0f \nGen 3 Load = %.0f \nRound Profit = %.0f \n Total Profit = %.0f \n Rank = %d\n' and '\ninterc %i flow %.0f' Creates a string that can be copied straight into the edit box
Reset mode – used to reset the MP	Any message when MO in reset mode	'msg=reset' Tells the MP software to delete all data and have the MP re register
Bid – update MPs bid with MO	'type=bid,name=%s,rnd=%i,bid1=%s,bid2=%s,bid3=%s' The bid for each unit is a 2 column by 4 row matrix. Where each row is a block the MP can chose to use	type=bid,stat=received MO acknowledges the bid

13 Appendix D: Market Operator Data Structure

Table 13-1 Data structure used by MO software

Structure Breakdown	Purpose
simpram.round	Stores the current round of the simulation.
simpram.forcast_mul_update	Vector containing the multiplication factors used to calculate demand in. each region
simpram.resetmode	Flag used to respond to MPs with a reset message. Set by the reset button, cleared by the start button.
simpram.act_demand	Stores the matrix of actual demand values plotted in the history axis. Vector for each node.
simpram.old_prices	Stores the matrix of old market prices values plotted in the history axis. Vector for each node.
simpram.wind_gen	Vector used to store the output percentage of wind generation capacity from the last round.
simpram.last_round	Flag used to tell the forecast code if it needs to update values.
simpram.forcast_demand	Stores the matrix of the forecast values plotted in the forecast axis. Vector for each node.
simpram.available_capacity	Stores the matrix of available capacity values plotted in the forecast axis. Vector for each node.
simpram.node	Stores the actual demand and market price matrixes from each simulation round.
simpram.team	Stores the details on each team. Including the name, total profit and the node they are located at. Also simpram.team{}.gens which holds the cost efficiency and other details on each of the generators allocated to the team.
simpram.rnddetails	Stores the bids for each generator and the results from running the simulation for each round.
Simoram.rnds{}	Holds the cost and emissions results for each round of the simulation and if the simulation was successful without dropping constraints.

14 Appendix E: AEMO NEM Generator Data

Station Name	Plant type	Fuel type	Thermal efficiency HHV (%) sent-out	Auxiliaries (%)	FOM ($/MW/year) for 2009-10	VOM ($/MWh sent-out) for 2009-10	Combustion emission factor (kg CO2-e/GJ of fuel)	Fugitive emission factor (kg CO2-e/GJ of fuel)	Capacity (MW) 2012	Fuel Cost $/GJ2012
Bayswater	Subcritical pf	Black coal	35.9%	6.0%	49,000	1.19	90.2	8.7	2720	1.23
Blowering	Hydro	Hydro	100.0%	1.0%	52,000	6.15	0.0	0.0	80	0.00
Capital Wind Farm	Wind	Wind	100.0%	0.0%	20,500	1.75	0.0	0.0	140	0.00
Colongra GT	OCGT	Natural gas	32.0%	3.0%	13,000	9.98	51.3	14.2	664	8.16
Cullerin Range Wind Farm	Wind	Wind	100.0%	0.0%	20,500	1.75	0.0	0.0	30	0.00
Eraring	Subcritical pf	Black coal	35.4%	6.5%	49,000	1.19	89.5	8.7	2877	1.69
Guthega	Hydro	Hydro	100.0%	1.0%	52,000	6.15	0.0	0.0	60	0.00
Hume (NSW)	Hydro	Hydro	100.0%	1.0%	52,000	7.15	0.0	0.0	29	0.00
Hunter Valley	OCGT	Liquid fuel	28.0%	3.0%	13,000	9.61	69.7	5.3	50	30.00
Liddell	Subcritical pf	Black coal	33.8%	5.0%	52,000	1.19	92.8	8.7	2100	1.23
Mt Piper	Subcritical pf	Black coal	37.0%	5.0%	49,000	1.32	87.4	8.7	1320	1.75
Munmorah	Subcritical pf	Black coal	30.8%	7.3%	55,000	1.19	90.3	8.7	600	1.70
Redbank	Subcritical pf	Black coal	29.3%	8.0%	49,500	1.19	90.0	8.7	150	1.01
Shoalhaven	Hydro	Hydro	100.0%	1.0%	52,000	7.15	0.0	0.0	240	0.00
Smithfield	Cogen	Natural gas	41.0%	5.0%	25,000	2.40	51.3	14.2	176	4.18
Tallawarra	CCGT	Natural gas	50.0%	3.0%	31,000	1.05	51.3	14.2	410	3.79
Tumut 1	Hydro	Hydro	100.0%	1.0%	52,000	6.15	0.0	0.0	330	0.00
Tumut 2	Hydro	Hydro	100.0%	1.0%	52,000	6.15	0.0	0.0	286	0.00
Tumut 3	Hydro	Hydro	100.0%	1.0%	52,000	6.15	0.0	0.0	1500	0.00
Uranquinty	OCGT	Natural gas	32.0%	3.0%	13,000	9.98	51.3	14.2	664	6.37
Vales Point B	Subcritical pf	Black coal	35.4%	4.6%	49,000	1.19	89.8	8.7	1320	1.70

Wallerawang C	Subcritical pf	Black coal	33.1%	7.3%	52,000	1.32	87.4	8.7	1000	1.75
Barcaldine	CCGT	Natural gas	40.0%	3.0%	25,000	2.40	51.3	5.4	55	6.62
Barron Gorge	Hydro	Hydro	100.0%	1.0%	52,000	7.15	0.0	0.0	60	0.00
Braemar	OCGT	Natural gas	30.0%	2.5%	13,000	7.93	51.3	5.4	504	2.67
Braemar 2	OCGT	Natural gas	30.0%	2.5%	13,000	7.93	51.3	5.4	504	2.89
Callide B	Subcritical pf	Black coal	36.1%	7.0%	49,500	1.19	95.0	2.0	700	1.34
Callide Power Plant	Supercritical pf	Black coal	38.0%	4.8%	49,500	1.19	95.0	2.0	810	1.34
Collinsville	Subcritical pf	Black coal	27.7%	8.0%	65,000	1.32	89.4	2.0	190	2.13
Condamine	CCGT	Natural gas	48.0%	3.0%	31,000	1.05	51.3	2.0	140	0.95
Darling Downs	CCGT	Natural gas	46.0%	6.0%	31,000	1.05	51.3	2.0	630	3.41
Gladstone	Subcritical pf	Black coal	35.2%	5.0%	52,000	1.19	92.1	2.0	1680	1.58
Kareeya	Hydro	Hydro	100.0%	1.0%	52,000	7.15	0.0	0.0	81	0.00
Kogan Creek	Supercritical pf	Black coal	37.5%	8.0%	48,000	1.25	94.0	2.0	750	0.76
Mackay	OCGT	Liquid fuel	28.0%	3.0%	13,000	9.05	69.7	5.3	34	30.00
Millmerran	Supercritical pf	Black coal	37.5%	4.5%	48,000	1.19	92.0	2.0	850	0.86
Mt Stuart	OCGT	Liquid fuel	30.0%	3.0%	13,000	9.05	69.7	5.3	418	30.00
Oakey	OCGT	Natural gas	32.6%	3.0%	13,000	9.61	51.3	5.4	282	4.22
Roma	OCGT	Natural gas	30.0%	3.0%	13,000	9.61	51.3	5.4	80	4.30
Stanwell	Subcritical pf	Black coal	36.4%	7.0%	49,000	1.19	90.4	2.0	1440	1.41
Swanbank B	Subcritical pf	Black coal	30.5%	8.0%	55,000	1.19	90.4	2.0	480	1.90
Swanbank E	CCGT	Natural gas	47.0%	3.0%	31,000	1.05	51.3	5.4	385	3.47
Tarong	Subcritical pf	Black coal	36.2%	8.0%	49,500	1.43	92.1	2.0	1400	1.02
Tarong North	Supercritical pf	Black coal	39.2%	5.0%	48,000	1.43	92.1	2.0	443	1.02
Townsville	CCGT	Natural gas	46.0%	3.0%	31,000	1.05	51.3	5.4	240	4.03
Windy Hill Wind Farm	Wind	Wind	100.0%	0.0%	20,500	1.75	0.0	0.0	12	0.00
Wivenhoe	Hydro	Hydro	100.0%	1.0%	52,000	7.15	0.0	0.0	500	0.00
Yarwun Cogen	Cogen	Natural gas	34.0%	2.0%	25,000	0.00	51.3	5.4	168	3.55

Angaston	Reciprocating Engine	Liquid fuel	26.0%	2.5%	13,000	9.61	67.9	5.3	50	30.00
Cathedral Rocks Wind Farm	Wind	Wind	100.0%	0.0%	20,500	1.75	0.0	0.0	66	0.00
Clements Gap Wind Farm	Wind	Wind	100.0%	0.0%	20,500	1.75	0.0	0.0	57	0.00
Dry Creek	OCGT	Natural gas	26.0%	3.0%	13,000	9.61	51.3	18.6	156	4.69
Hallett	OCGT	Natural gas	24.0%	2.5%	13,000	9.61	51.3	18.6	180	6.64
Hallett 1 Wind Farm	Wind	Wind	100.0%	0.0%	20,500	1.75	0.0	0.0	95	0.00
Hallett 2 Wind Farm	Wind	Wind	100.0%	0.0%	20,500	1.75	0.0	0.0	71	0.00
Hallett 4 Wind Farm	Wind	Wind	100.0%	0.0%	20,500	1.75	0.0	0.0	132.3	0.00
Ladbroke Grove	OCGT	Natural gas	30.0%	3.0%	13,000	3.60	51.3	18.6	80	4.91
Lake Bonney 2 Wind Farm	Wind	Wind	100.0%	0.0%	20,500	1.75	0.0	0.0	159	0.00
Lake Bonney 3 Wind Farm	Wind	Wind	100.0%	0.0%	20,500	1.75	0.0	0.0	39	0.00
Lake Bonney Wind Farm	Wind	Wind	100.0%	0.0%	20,500	1.75	0.0	0.0	80.5	0.00
Mintaro	OCGT	Natural gas	28.0%	3.0%	13,000	9.61	51.3	18.6	90	6.64
Mt Millar Wind Farm	Wind	Wind	100.0%	0.0%	20,500	1.75	0.0	0.0	70	0.00
Northern	Subcritical pf	Brown coal	34.9%	5.0%	55,000	1.19	91.0	0.9	530	1.52
Osborne	CCGT	Natural gas	42.0%	5.0%	25,000	5.09	51.3	18.6	180	4.12
Pelican Point	CCGT	Natural gas	48.0%	2.0%	31,000	1.05	51.3	18.6	485	3.96
Playford	Subcritical pf	Brown coal	21.9%	8.0%	70,000	3.00	91.0	0.9	240	1.52
Port Lincoln	OCGT	Liquid fuel	26.0%	8.0%	13,000	9.61	67.9	5.3	50	30.00
Quarantine	OCGT	Natural gas	32.0%	5.0%	13,000	9.61	51.3	18.6	216	6.00
Snowtown Wind Farm	Wind	Wind	100.0%	0.0%	20,500	1.75	0.0	0.0	99	0.00
Snuggery	OCGT	Liquid fuel	26.0%	3.0%	13,000	9.61	67.9	5.3	63	30.00
Starfish Hill Wind Farm	Wind	Wind	100.0%	0.0%	20,500	1.75	0.0	0.0	34.5	0.00
Torrens Island A	Steam Turbine	Natural gas	27.6%	5.0%	40,000	2.25	51.3	18.6	480	4.02
Torrens Island B	Steam Turbine	Natural gas	30.0%	5.0%	40,000	2.25	51.3	18.6	800	4.02
Waterloo	Wind	Wind	100.0%	0.0%	20,500	1.75	0.0	0.0	111	0.00
Wattle Point Wind Farm	Wind	Wind	100.0%	0.0%	20,500	1.75	0.0	0.0	90.75	0.00

Bastyan	Hydro	Hydro	100.0%	1.0%	52,000	6.15	0.0	0.0	79.9	0.00
Bell Bay Three	OCGT	Natural gas	29.0%	2.5%	13,000	7.93	51.3	5.8	105	5.54
Cethana	Hydro	Hydro	100.0%	1.0%	52,000	6.15	0.0	0.0	85	0.00
Devils Gate	Hydro	Hydro	100.0%	1.0%	52,000	6.15	0.0	0.0	60	0.00
Fisher	Hydro	Hydro	100.0%	1.0%	52,000	6.15	0.0	0.0	43.2	0.00
Gordon	Hydro	Hydro	100.0%	1.0%	52,000	6.15	0.0	0.0	432	0.00
John Butters	Hydro	Hydro	100.0%	1.0%	52,000	6.15	0.0	0.0	144	0.00
Lake Echo	Hydro	Hydro	100.0%	1.0%	52,000	6.15	0.0	0.0	32.4	0.00
Lemonthyme_Wilmot	Hydro	Hydro	100.0%	1.0%	52,000	6.15	0.0	0.0	81.6	0.00
Liapootah_Wayatinah_Catagunya	Hydro	Hydro	100.0%	1.0%	52,000	6.15	0.0	0.0	170	0.00
Mackintosh	Hydro	Hydro	100.0%	1.0%	52,000	6.15	0.0	0.0	79.9	0.00
Meadowbank	Hydro	Hydro	100.0%	1.0%	52,000	6.15	0.0	0.0	40	0.00
Poatina	Hydro	Hydro	100.0%	1.0%	52,000	6.15	0.0	0.0	300	0.00
Reece	Hydro	Hydro	100.0%	1.0%	52,000	6.15	0.0	0.0	231.2	0.00
Tamar Valley CCGT	CCGT	Natural gas	48.0%	3.0%	31,000	1.05	51.3	5.8	200	5.54
Tamar Valley OCGT	OCGT	Natural gas	29.0%	2.5%	13,000	9.61	51.3	5.8	58	6.63
Tarraleah	Hydro	Hydro	100.0%	1.0%	52,000	6.15	0.0	0.0	90	0.00
Trevallyn	Hydro	Hydro	100.0%	1.0%	52,000	6.15	0.0	0.0	80	0.00
Tribute	Hydro	Hydro	100.0%	1.0%	52,000	6.15	0.0	0.0	82.8	0.00
Tungatinah	Hydro	Hydro	100.0%	1.0%	52,000	6.15	0.0	0.0	125	0.00
Woolnorth Bluff Point Wind Farm	Wind	Wind	100.0%	0.0%	20,500	1.75	0.0	0.0	140	0.00
Anglesea	Subcritical pf	Brown coal	27.2%	10.0%	81,000	1.19	91.0	0.3	160	0.39
Bairnsdale	OCGT	Natural gas	34.0%	3.0%	13,000	2.26	51.3	5.8	92	4.29
Bogong	Hydro	Hydro	100.0%	1.0%	52,000	7.15	0.0	0.0	140	0.00
Dartmouth	Hydro	Hydro	100.0%	1.0%	52,000	7.15	0.0	0.0	158	0.00
Eildon	Hydro	Hydro	100.0%	1.0%	52,000	7.15	0.0	0.0	120	0.00
Energy Brix Complex	Subcritical pf	Brown coal	24.0%	15.0%	60,000	1.19	99.0	0.3	195	0.59

Hazelwood	Subcritical pf	Brown coal	22.0%	10.0%	84,030	1.19	93.0	0.3	1640	0.08
Hume (Vic)	Hydro	Hydro	100.0%	1.0%	52,000	7.15	0.0	0.0	29	0.00
Jeeralang A	OCGT	Natural gas	22.9%	3.0%	13,000	9.05	51.3	5.8	228	3.88
Jeeralang B	OCGT	Natural gas	22.9%	3.0%	13,000	9.05	51.3	5.8	255	3.88
Laverton North	OCGT	Natural gas	30.4%	2.5%	13,000	7.93	51.3	5.8	312	4.10
Loy Yang A	Subcritical pf	Brown coal	27.2%	9.0%	79,000	1.19	91.5	0.3	2180	0.08
Loy Yang B	Subcritical pf	Brown coal	26.6%	7.5%	51,200	1.19	91.5	0.3	1050	0.37
McKay Creek	Hydro	Hydro	100.0%	1.0%	52,000	7.15	0.0	0.0	160	0.00
Mortlake	OCGT	Natural gas	32.0%	3.0%	13,000	8.50	51.3	5.8	550	5.62
Murray 1	Hydro	Hydro	100.0%	1.0%	52,000	6.15	0.0	0.0	950	0.00
Murray 2	Hydro	Hydro	100.0%	1.0%	52,000	6.15	0.0	0.0	550	0.00
Newport	Steam Turbine	Natural gas	33.3%	5.0%	40,000	2.25	51.3	5.8	500	4.08
Somerton	OCGT	Natural gas	24.0%	2.5%	13,000	9.61	51.3	5.8	160	4.11
Toora Wind Farm	Wind	Wind	100.0%	0.0%	20,500	1.75	0.0	0.0	21	0.00
Valley Power	OCGT	Natural gas	24.0%	3.0%	13,000	9.61	51.3	5.8	300	3.87
Waubra Wind Farm	Wind	Wind	100.0%	0.0%	20,500	1.75	0.0	0.0	192	0.00
West Kiewa	Hydro	Hydro	100.0%	1.0%	52,000	7.15	0.0	0.0	62	0.00
Wonthaggi Wind Farm	Wind	Wind	100.0%	0.0%	20,500	1.75	0.0	0.0	12	0.00
Yallourn	Subcritical pf	Brown coal	23.5%	8.9%	82,400	1.19	92.5	0.3	1480	0.09
Yambuk Wind Farm	Wind	Wind	100.0%	0.0%	20,500	1.75	0.0	0.0	30	0.00

Source file: http://www.aemo.com.au/planning/0410-0029.zip