

Techno-economic assessment of the integration of high renewables into the Australian National Electricity Market

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I, Yunyang Wu, confirm that the work presented in this thesis is my own. Where information has been derived from other sources, I confirm that this has been indicated in the work.

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Abstract

This thesis explores the least cost combination of renewable generation technologies, transmission interconnectors and storage capacity in different supply and demand scenarios in the Australian National Electricity Market (NEM) regions. Australia faced high retail electricity prices due to investment in the electricity distribution system, significant increase in greenhouse gas emissions (144% compared to 1990 levels) from electricity sector. In the same time peak demand decreased in most states because of energy conservation, on-site generation and industry evolution. Future plans like reduce greenhouse gas emissions by 26% by 2030, use of energy storage (e.g. batteries, concentrated solar thermal power system), increase use of renewables will require a reshape and rethinking of the current energy system.

Although the high renewable penetration system in the NEM regions has been widely discussed, there is lack of co-optimization of the renewable technologies, transmission expansion and storage capacity together. Besides, most studies use historical demand data when optimizing the system, without a detailed assumption of the demand changed by various factors.

This study contributes to the current research by building in a depth demand model based on social behaviour, buildings and ambient temperature to analyse the possible changes on demand. A Genetic Algorithm (GA) together with an electricity dispatch simulation model at hourly temporal resolution was used in this study. The benefit of this approach consists in co-optimization the renewable generation technologies, transmission interconnectors and storage capacity in the NEM system in different renewable mix and demand scenarios.

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Glossaries and Terms

ABM	Agent Based Model
ACCU	Australian Carbon Credit Unit
AEMO	Australia Electricity Market Operator
BEV	Battery Electric Vehicle
CAES	Compressed Air Energy Storage
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CST	Concentrated Solar Tower
DEAM	Dynamic Energy Agent Model
DETRESO	The model built and used in this thesis
DKIS	Darwin Katherine Interconnected System
DNI	Direct Normal Irradiance
DynEMo	Dynamic Energy Model
EGS	Enhanced Geothermal Systems
ERF	Emissions Reduction Fund
EV	Electric Vehicle
GA	Genetic Algorithm
GHG	Greenhouse Gas
GHI	Global Horizontal Irradiance
HOMER	Hybrid Optimization Model For Electric Renewables
HPC	high-performance computer
HSA	Hot Sedimentary Aquifers
HVAC	Heating, Ventilation And Air Conditioning
IPSS	integrated PV and Storage Systems
LCOE	Levelized Cost of Electricity
LCVH	Large Light Commercial Vehicle
LCVL	Small Light Commercial Vehicle

LCVM	Medium Light Commercial Vehicle
LGCs	Large-scale Generation Certificates
LNG	Liquefied Natural Gas
LRET	Large-Scale Renewable Energy Target
NEFR	National Electricity Forecast Report
NEM	National Electricity Market
NERL	National Renewable Energy Laboratory
NSW	New South Wales
NTNDP	National Transmission Network Development Plan
NWIS	North West Interconnected System
OCGT	Open Cycle Gas Turbines
OLS	Ordinary Least Squares
PASH	Large Passenger Vehicle
PASL	Small passenger vehicle
PASM	Medium passenger vehicle
PHEV	Plug-in Hybrid Electric Vehicle
POLES	Prospective Outlook On Long-Term Energy System
PSO	Particle Swarm Optimization
PV	Photovoltaic
QLD	Queensland
ReEDS	Regional Energy Development System Models
RET	Renewable Energy Target
RGT	Rigid Truck
SA	South Australia
SAA	Simulated Annealing Algorithm
SRES	Small-Scale Renewable Energy Scheme
STC	Small-scale Technology Certificates
SWIS	South West Interconnected System
TAS	Tasmania
TUS	Time Use Survey

VIC Victoria

Chapter 1

Introductory Material

1.1 Context

In October 2016, the Paris Climate Change Agreement was ratified. The main aim of the Paris Agreement is to limit global average temperature rise this century to well below 2 degrees Celsius and to pursue efforts to limit the temperature increase even further to 1.5 degrees Celsius above pre-industrial levels [1]. This has significant implications for Australia given its emissions intensive economy [2].

Australia's high ranking in emissions per capita is mainly due to coal-fired electricity generation which accounted for 72.8 per cent of electricity generation in 2015 [3]. Electricity generation accounted for 187 Mt carbon dioxide equivalent in 2015, 35 per cent of the total greenhouse gas (GHG) emissions of Australia. The dominance of coal masks Australia's rich diversity of renewable energy resources: wind, solar, geothermal, hydro, wave, tidal, and bioenergy. Except for hydro and wind energy which currently account for most renewable electricity generation connected to the transmission system, these resources are largely undeveloped and could contribute significantly to Australia's future energy supply [4].

The GHG emissions from the electricity industry peaked in 2008 at 208 Mt carbon dioxide equivalent [5]. In order to reduce the carbon emissions from the electricity sector, the Federal Government has implemented a number of policies including the Renewable Energy Target (RET) [6], a carbon pricing scheme (July 2012-July 2014) [7] and Direct Action (July 2014-present) [8]. The RET scheme

was first introduced in 2001 and then expanded in 2007. The scheme has had two parts since 2010 the Small-scale Renewable Energy Scheme (SRES) and the Large-scale Renewable Energy Target (LRET). All these policies have facilitated the deployment of renewable energy in Australia.

While hydro, biomass, wind and solar photovoltaic (PV) are considered mature renewable electricity generation technologies, other less deployed technologies such as Concentrating Solar Thermal (CST), enhanced geothermal systems, wave and tidal may become more attractive in the future due to less variability in their output, evaluation and comparison of the levelized cost of tidal, wave, and offshore wind energy. This characteristic could prove more desirable in a high penetration renewable power system with significant deployment of wind and solar PV.

The Australian electricity system is at a major crossroads. With the cost of renewable electricity generation and storage technologies decreasing rapidly together with different system load profiles in the future, the generator mix and transmission system may be very different to the current power system that is dominated by mainly synchronous non-renewable electricity generation [9]. It is possible that a diversified portfolio of renewable electricity generation technologies and more interconnected transmission system could achieve a lower system cost and transition the electricity system to a low carbon future.

The hypothesis of this thesis is that the structure of the future high renewable penetration power system can be explored through spatiotemporal modelling which simulates the system dispatch process and optimizes the system cost, with the future electricity demand projected with a physical based model. This aim of this research is to explore the least cost combination of renewable technologies, storage devices, and transmission expansion in the NEM system under different demand projections. By answering the following questions, this research contributes to the understanding of the future structure of the power system in the NEM with high renewable penetration and demand changing:

- What role will the transmission system and energy storage devices play in the high penetration renewable system in the NEM?

- What is the least cost combination of renewable electricity generation technologies, energy storage devices and transmission system capacity in the NEM?
- What is the system impact of different CST and storage configurations? Which portfolio of CST configurations achieve a lower system cost in the NEM?
- What is the potential impact of changes in electricity demand caused by energy efficiency improvements, climate change and transport electrification in a future high penetration renewable system?

1.2 Thesis structure

Chapter 2 contains the literature review of existing studies of high renewable penetration electricity systems, for Australia and other jurisdictions. This review summarizes the methodologies employed and the main findings of the peer reviewed and other literature. This chapter also contains the discussion of the demand model used by AEMO. The review pivots to the research questions central to this thesis and provides reasons for the choice of modelling methodology used in the thesis.

Chapter 3 provides background on the current characteristics of the National Electricity Market (NEM), the empirical focus of this thesis, including the current demand structure, existing power generation capacity and transmission system.

Chapter 4 presents the overview of the model used in this thesis. The details of the demand side model are given in this chapter. A demand model based on the social activity use pattern and ambient temperature is described. With this demand model, we can model future demands with assumptions about changes to these factors driving demand, such as heating and cooling, and account for the correlation of demand with renewables which critically determines optimal system configuration.

Chapter 5 presents the supply side model and the optimization algorithm used in this thesis. The supply side model is made up of three modules: the dispatch module, transmission module and the optimization module. The flowchart of the

dispatch process is detailed in this chapter. Modelling of the renewable technologies are described and the source of their generation data are also discussed here.

Chapter 6 presents results from scenario modelling that is focussed on energy storage (especially battery) and transmission system expansion requirements in the future 100% renewable system. Historical demand and generation data was used. This chapter shows the importance of the transmission expansion and storage devices in the future 100% renewable system in the NEM.

Chapter 7 presents the results from additional scenario analysis that explores the potential role of different Concentrating Solar Thermal (CST) technologies impact in a 100% renewable electricity system. In these scenarios, we include offshore wind, biomass and biogas technology. Updated CST technology cost and performance parameters and projected 2029-2030 demand are used. Compared with Chapter 6, this chapter shows more details in the supply activities with detailed CST technology consideration.

Chapter 8 presents the results from scenario analysis that unpacks the potential impact of changes in demand on the system. Four scenarios developed from demand model are investigated to show the difference in the system cost and implications for the deployment of alternative renewable electricity generation technologies. Exploring the different demand scenarios shows that the system cost is more associated with the hourly demand profile, especially the winter morning demand, rather than the annual demand. This chapter shows what the demand change would impact on the renewable mix and system cost.

Chapter 9 concludes the thesis by summarizing the main research findings and avenues for further research.

Chapter 2

Literature review

2.1 Review of renewable generation technology

Renewable electricity generation has become a significant source of power generation in many systems around the world. Among these renewable technologies, solar PV, onshore wind and pumped storage or run-of-river hydro are considered mature electricity generation and constitute the bulk of global installed capacity. The capacity of installed solar PV and wind farms around the world was 227 GW and 433 GW respectively, at the end of 2015 [10]. The new installed solar PV capacity in 2015 contributed up to 25% of the total new power capacity added in that year [10]. The market expansion of solar PV in most countries is due mostly to its increasing cost competitiveness and some government incentive programs. The cost of solar PV has been decreasing rapidly in the last few years with further cost reductions expected in future years [11].

Apart from solar PV, concentrated solar thermal power is another type of renewable electricity generation technology which produces electricity by collecting energy from sunlight. CST plants use mirrors or lenses to concentrate a large field of sunlight to heat a small area, then the heat is used to drive steam turbine for generating electricity. Its operating capacity was about 4.8 GW by the end of 2015 [12]. More recently installed plants have been coupled with thermal storage systems, increasing the flexibility of plant operation.

Onshore and offshore wind accounted for 22% of the new installed power gen-

eration capacity in 2015. Onshore wind was the most cost-effective renewable electricity generation technology during 2015 in most jurisdictions [13]. The total capacity of offshore wind was around 12 GW in 2015. Offshore wind turbines cost more than onshore wind turbines due to the higher maintenance cost and additional auxiliary systems, such as the cable to connect the offshore wind turbines to the onshore power grid, but higher, less variable wind speeds at sea may counterbalance the extra capital costs.

The capacity of hydropower was 1064 GW at the end of 2015, with 28 GW new capacity installed in that year [14]. The pumped hydro storage capacity was around 145 GW, with 2.5 GW new capacity installed [14]. Compared with solar and wind power, hydropower has a stricter requirement on the site location and water resource, and this limits its total capacity. This technology can also present environmental challenges mainly from the damming of natural waterways.

The total capacity of geothermal power plants is about 13.2 GW, with 315 MW capacity added in 2015 [15]. It is estimated that there could be up to 17 GW of geothermal power generation capacity by 2020 [15]. Geothermal power plants obtain heat from the earth by circulating a fluid through the reservoir to bring the heat back to the ground. The heat is then used to create steam for power generation. The high capital cost caused by drilling, and limited quality resource sites and are the main challenges in increased investment in geothermal power plants. Most of the existing geothermal power plants are located in regions associated with tectonic plate boundaries and volcanic areas, such as the west coast of the USA, New Zealand, Indonesia, Iceland and Italy [16]. Due to the regional intraplate tectonic setting, the convective hydrothermal system cannot be deployed in Australia. The possible concepts of geothermal reservoirs that may be viable in Australia are Hot Sedimentary Aquifers (HSA) or Enhanced Geothermal Systems (EGS, also known as Hot Dry Rock). HSA and EGS technologies are still in the early stage of development and have not been demonstrated at scale due to significant technical challenges [16].

The capacity of bioenergy, both biomass and biogas, was about 106 GW in

2015 and its electricity generation was around 464 TWh that year [10]. There are some mature and commercially available biomass power generation options, such as using steam turbines or biogas-fired open cycle gas turbines (OCGT) while other technologies, such as integrated gasification combined cycle, are still in the R&D phase. A secure, stable and cheap supply of biomass feedstock is important for the operation of biomass power plants. Some feedstock costs are zero as they are wastes, but there may be some cost in the transportation of these materials [17].

Ocean power is still an emerging technology and has much smaller installed capacity compared with solar PV, wind or hydropower. The capacity of ocean energy (tidal stream and wave energy) is about 530 MW and most in the form of tidal power [18]. These plants were predominantly demonstration projects of ocean energy, with no commercial scale power plants currently planned [10]. Similar to offshore wind power plants, the connection cost for ocean power is significant which makes wave technology less competitive with other renewable electricity generation technologies.

The conventional or run-of-river hydro(without large dams), pumped storage hydro, CST and biogas electricity generation technologies are categorized as peak dispatchable generators. This type of generators has a quick response to changes in demand and are typically load following. However, the generation from run-of-river hydro and pumped storage hydro is limited by its water reservoir. CST plants require daily recharge of the thermal energy storage. Biogas generation is limited by its potential fuel.

Geothermal and biomass could provide a stable generation output during most time periods. These technologies are typically operated as baseload generators and are slow to respond to changes in demand.

The run-of-river hydro, pumped storage hydro, CST and biogas electricity generation technologies are categorized as peak dispatchable generators. This type of generators has a quick response to changes in demand and are typically load following. However, the generation from run-of-river hydro and pumped storage hydro is limited by its water reservoir. CST plants require daily recharge of the thermal

energy storage. Biogas generation is limited by its potential fuel.

Figure 2.1 shows the capacity share of the different renewable technologies in 2015 [19]. The hydropower takes more than half of the total renewable capacity around the world, followed by onshore wind, solid biomass and solar PV. Solar PV and wind turbines are considered in almost all the research focussed on the increasing penetration of renewable electricity generation in power systems globally. Concentrated solar thermal with storage seems to be gaining traction in more recent studies [20, 21, 22, 23, 24, 25]. The study [25] provides a comprehensive summary of CSP plants both in operation and under construction. The studies explore the potential CST role in the NEM [20, 21], Spain [22], US [23], Africa and Europe [24]. In [22] the study presents optimum power plant configurations in a region of Spain with different price-based grid integration strategies. The reservoir hydro, pumped storage hydro and geothermal electricity generation technologies are more geographically constrained. Some studies consider the expansion of existing hydro power stations in certain systems [26, 27, 28], while other studies discount hydro expansion due to environmental concerns or lack of suitable sites [29, 30, 31, 32] in some regions. In the studies where the expansion of hydro-electricity is not likely, they assume the existing hydro capacity will remain and play a significant role to balance intra-day fluctuations in system supply and demand. Geothermal was less commonly considered compared with hydro power due to the immature technology and the strict location requirement. Not many future renewable system planning studies consider ocean power.

2.2 Review of energy storage technologies

Energy storage technologies will likely have a critically important role in future power systems dominated by renewable electricity generation. It is likely that the more mature renewable electricity generation technologies, such as solar PV and wind turbines, due to their low cost and modularity, will constitute significant shares of electricity system output. Energy storage devices will likely be needed in a high penetration renewable power system to balance the demand when insufficient power

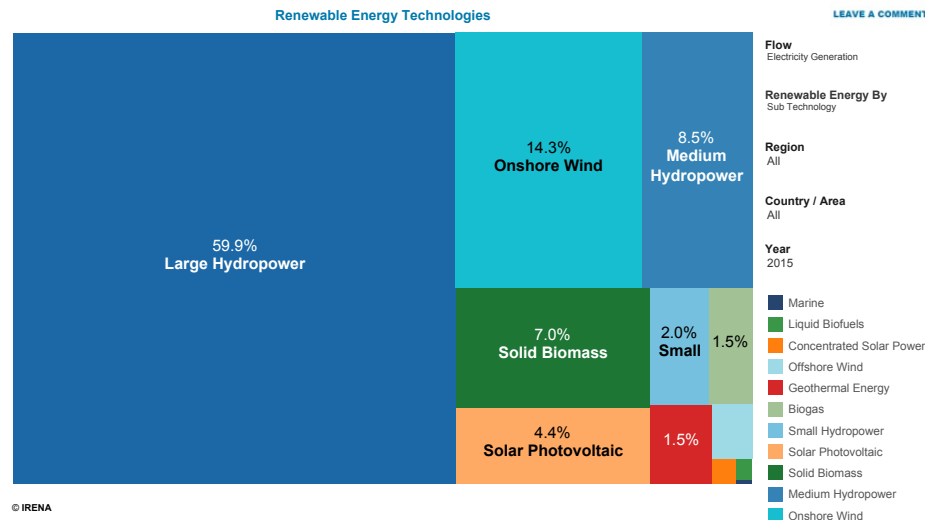


Figure 2.1: Capacity share by technologies worldwide, source [19]

can be obtained from variable renewable generators, such as solar PV and wind turbines. Energy storage devices can store excess renewable generation when system demand is lower than intermediated generators' output in thermal, chemical or kinetic energy forms. This stored energy can then be used to generate power when system demand is higher than the intermediated renewable generation.

Pumped hydro and concentrated solar thermal power with storage feature two types of energy storage system. Most renewable studies consider the existing pumped hydro plants. However, the future expansion of the pumped hydro may be constrained by environmental concerns. As discussed perviously, the concentrated solar power with storage system, mostly in the form of molten salt, has been considered in many renewable studies [21, 23, 24, 26]. These studies have different assumptions on the hours of storage system of the concentrated solar power, ranging from 8 to 16 hours of storage. Amongst this literature, no previous studies have explored the impact of CST with the different sizing of thermal storage.

Other possible power storage technologies include Compressed Air Energy Storage (CAES) and electric battery systems. CAES stores excess electricity by compressing air into vacant underground formations and then generates power us-

ing gas turbines with the compressed air. CAES can provide quick response to demand and serves as a peak generator. There are some CAES plants currently deployed around the world. There is a 290 MW plant with 2 hours of storage in Germany operational since 1978, and a 110 MW plant with 26 hours of storage in McIntosh, U.S. that has been operational since 1991. Previous studies have considered CAES as an energy storage option are mainly from the countries which already have operational CAES plants, such as the U.S. [26, 33] and Europe [34, 35, 36].

Regarding battery technologies, there are three technologies that have been demonstrated at large scale and prove the possibility to be considered as system storage options [37]. These are: 1) advanced lead-acid batteries, 2) flow batteries such as vanadium-redox or zinc-bromine batteries, 3) lithium-ion batteries. The current cost and performance of these batteries are shown in Table 2.1.

Table 2.1: Cost, performance, and availability assumptions for three selected battery technologies in 2012 AUD

Parameter	Advanced Lead-acid	Zinc-bromine	Lithium-ion (cost in 2020)
Energy-related cost	682 \$/kWh	400 \$/kWh	291 \$/kWh
Power-related cost	400 \$/kw	400 \$/kw	309 \$/kw
O&M cost	43 \$/kW/year	28 \$/kW/year	28 \$/kW/year
Cycle life	4500	10000	1800
Round-trip efficiency	90%	70%	90%
Useable charge range	65%	80%	70%

Some researchers acknowledge that bioenergy is a storage option as they can store the feedstock and use when needed [28, 38, 39]. Hydrogen is also considered in some studies as an energy carrier which can be produced during time periods of power surplus and then used in gas plants or fuel cells for power generation [33]. Compared to using batteries as storage devices, energy storage in hydrogen has a much lower round-trip efficiency (30% - 40%), as well as requiring additional cost for the electrolyser and hydrogen storage [40].

2.3 Previous studies of high penetration renewable electricity systems

There is a burgeoning literature on the transition to a high penetration renewable power system. The existing literature has identified some potential challenges with this type of power system. First, such systems usually have high capital costs (as most renewable electricity generation technologies have zero fuel costs and comparatively low maintenance costs) and levels of installed capacity, particularly if characterized by large amounts of variable renewable electricity generation [41]. Second, these types of systems may also present operational challenges such as system inertia and frequency control in periods of low demand or alternatively reactive power and voltage stability concerns in periods of high demand [42]. Third, co-optimization of electricity generation and transmission infrastructure may be more important to achieve system balance due to geographic variation in renewable resource availability impacting on generation output. Fourth, demand response and energy storage may also be required.

Most studies about high penetration renewable power systems acknowledge the importance of a well-designed structure of the future renewable system in order to provide enough generation across all timescales at the lowest possible overall system cost [43]. The capacity factors of solar PV or wind power plants varies with the sites' location and their generation vary across time periods. Also, a significant amount of area is needed for large scale solar PV or wind power plants. These constraints may mean that significant renewable power generation could be located at considerable distance from the major demand centres. These factors could lead to a temporal and spatial mismatch between generation and demand. The availability of low cost energy storage could alleviate the temporal problem, while expansion of the electricity transmission system could overcome the spatial problem. In the planning of such systems, the co-optimization of power generation, energy storage and transmission infrastructure becomes increasingly important.

2.3.1 Importance of storage and CST

Adequate levels of energy storage is critically important in high penetration renewable electricity systems. Numerous studies acknowledge that energy storage has a key role to balance the system demand, particularly in power systems which feature significant solar PV and wind generation. A study in [44] that examined high penetration renewable system in California, found that of the order of 186 GWh /22 GW (approximately 22% of the average daily demands of California) energy storage is required in a system with 85% penetration of renewable electricity. The study in [45] claims that a storage system equal to the 6 average hourly electricity load is able to smooth the intraday cycle for a fully European renewable system. Other studies also assessed how the optimal level of storage varies as the structure of renewables in the generation mix changes [45, 46].

CST and its thermal storage is attracting more attention in high penetration renewable studies. CST coupled with thermal storage can generate electricity after sunset with its stored thermal energy. [47] discussed the economic implications of thermal storage configuration, pointed out that a 12 hours' thermal storage system could increase the annual capacity factor of CST from around 30% with no backup to up to 55%. The solar multiple and storage capacity of CST needs to carefully considered. A plant with one solar multiple is sized to collect enough energy for the plant operating at its rating power capacity under reference conditions (normally $1000 \text{ W}/\text{m}^2$). A larger solar multiple reflects that the size of the solar field is scaled. [48] optimized the solar multiple and storage capacity for a concentrating solar power system located in Portugal. They found that for each solar multiple there is an optimal storage size.

2.3.2 Importance of transmission expansion

The importance of transmission system expansion in high penetration renewable electricity systems has been widely discussed. The transmission system could reduce the curtailment needs for renewable energy sources and improve the power system's reliability [49]. [50] stated that grid extensions are necessary for the high renewable penetration system in Europe and have important consequences for all

power system participants. In regard to economics, they showed that transmission grid extensions reduce the future revenue reduction from renewable technologies and distribute the economic surpluses evenly across interconnected regions. [51] discussed the transmission needs in the fully renewable European power system with solar and wind generators only. They noted that with zero capacity interconnectors, the annual balancing energy (negative mismatches between renewable generation and load) is around 24% of the total annual consumption. With unlimited interconnection, the balancing energy is around 15% of the total annual consumption. Their modelling approach revealed that an infinitely strong European transmission network should be 11.5 times the current total transmission capacities. [52] discussed the transmission grid extension during the build-up of a 100% renewable pan-European electricity supply. Their study focussed on maximum usage and optimal sharing of renewable resources at a minimal transmission capacity layout. One of the main arguments is to what extent the transmission system could reduce the backup capacity and when could it be built. The study found that keeping the transmission capacity at the current level, the required backup energy is about 13% less than the required backup energy in the system with no transmission system. An overall doubling or quadrupling of the transmission capacity will lead to a 26% or 33% reduction respectively of the required backup capacity.

2.3.3 Impact of demand change

Demand is another essential component of high penetration renewable studies. Study in [26] points out that not only the level of the demand, but also its shape (profile), will impact the structure of the renewable system. Many studies discussed the changes in the level of demand. Factors that cause the level of demand to increase include population and economic growth, transportation electrification (i.e., electric vehicles), and fuel switching (gas to electricity). There are also some factors that may lead to a decrease in the level of demand, such as the improved energy efficiency in appliances and thermal performance of buildings. The shape of demand may change due to demand-side interruptible load, flexible electric vehicle charging and behavioural response of consumers to changes in electricity prices. More

details about the demand change discussion will be provided in the Demand Modelling chapter. There are some studies in the literature that do not consider changes in the level or shape of demand [28, 53, 31, 54]. These studies assess whether a renewable mix could provide sufficient generation to meet demand at the current level and temporal profile. Similarly, the potential impacts of climate change on the level and shape of electricity demand are ignored in most studies. More details about the demand change will be given in the Chapter 4.

2.3.4 Impact of the transportation electrification

The electrification of road transport through the deployment of electric vehicles (EV) or plug-in hybrid electric vehicles (PHEV) may present a number of challenges to a 100 per cent renewable electricity system. Additional demand is created for the charging of batteries in the vehicles, they are a mobile source of electricity demand, and battery charging could add to peak demand. They may also present opportunities to the electricity system through vehicle to grid (V2G) capability to support distribution networks at times of peak demand and if charging time can be linked to times of high renewable generation (that would otherwise be curtailed) or during periods of otherwise low demand.

In the Australian context, previous studies have considered vehicle electrification, particularly for the passenger vehicle segment of the market. [55] considered a “stretch” scenario that explores a transition to 100% EVs by the year 2025 based on high oil price assumptions EV cost parity with conventional vehicles by 2025. Over a longer time period (to the year 2050), [2] found that vehicle electrification was key for Australia to achieve zero net GHG emissions by 2050, particularly if there were insufficient biofuels available to decarbonize the transport sector. Other studies showed less ambitious uptake of EVs accounting for between 5 and 20 per cent of vehicle kilometres travelled by around 2030 (e.g., [56]; [57]; [58]). Although these previous studies indicated varied impact on electricity consumption, the implications on the power system were not explored.

2.4 Review of demand modelling approaching

Electricity demand in a region can be split into the consumption from residential, commercial and large industry sectors. The residential and commercial demands are affected by the population, customers' behaviour, and weather conditions. It is not very complex to predict the hourly profile of the large industry sector since its consumption is more stable and linked with economic performance and population. However, it is difficult to find an accurate function or expression to predict the hourly profiles of the residential and commercial sectors.

The modelling of the demand profile is largely depending on the availability of the data. There are mainly two types of approach to predict the electricity consumption in the residential and commercial sector in the literatures, either the top down approach or the bottom up approach.

- Top Down

The top-down approach focuses on the interaction between electricity consumption and economic metrics at a high-level scale using aggregated socio-economic data and statistical analysis. These models are mostly used in high-level studies to predict the aggregated annual electricity demand by sectors (residential, commercial and industrial sector) in a regional or national scale. The typical target year in most top-down demand forecast models is the longer-term future when the economic variables change significantly.

For example, [59] discussed the residential electricity in Turkey with the top down approach. In the study, they modelled the relationship between the per capita residential electricity demand and the income per capita, price and level of urbanization. The economic growth improves the level of urbanization and then results the increasing in the electricity consumption. A study in Italy explores various regression models using data about the historical electricity consumption, GDP, GDP per capita and population [60]. Results in their study show that the demand is strongly related with these variables. Other similar studies that discuss the relationship between the electricity demand, residential income and electricity price can be found in [61, 62, 63]. The study

in [61] explored the relationship between the demand and tariff, real GDP, gas price and population in Malaysia. In [62] they estimated the long- and short-run elasticities of residential demand for electricity in Australia and found that the demand is more correlation to the income, own price, the temperature than the gas prices. [63] found that income is the main determinate of the electricity demand in South Africa.

Another example using the top-down approach is in [64]. This study forecasts the NEM demand using semi-parametric additive models to explore the relationship between the demand and driver variables, such as temperatures, calendar effects and some demographic and economic variables.

- Bottom up

The bottom-up approach utilizes disaggregated data to estimate the impact of various factors of the end-users on electricity consumption. This method uses statistical analyses of survey data and electricity consumption readings.

For the bottom-up approaches, a number of studies use the Monte Carlo method to simulate occupants' activity in the house and appliance usage during the day, some of them do not consider the temperature effect on the load profile. The typical limitation for detailed bottom-up methods is an extensive need for data about the consumers or their appliances and the households in general. Most of these studies use national statistical data on how people use time, and the average or typical energy consumption of the appliances [65]. In [65] they explain how to offset the seasonal load. In [66] they use Monte Carlo process to simulate the household load profile. Markov Chain process is used in [67] to generate the synthetic data such that it has the same overall statistics as the original survey data.

In [68], the authors use the bottom-up model with the data from USA time survey. This approach includes a method to simulate the resident behaviour during a day in high resolution. The demand in a dwelling is summed by energy used by cold appliances, HVAC devices, lights and human activities and

other fixed standby energy. The research simulates the cold appliance activities (simulated use profile for one day since it is independent of weather or season), The HVAC energy consumption is also simulated based on dwelling thermal characteristic, comfort temperature. The occupant behaviour is modelled by Markov chain model.

In [69] the authors provide demand modelling based upon a combination of patterns of active occupancy and daily activity profiles that characterise how people spend their time performing certain activities. A previous developed approach is used to create active occupancy data for large numbers of dwellings. It is based upon data derived from the UK 2000 Time Use Survey (TUS). The daily activity profiles are constructed from the TUS data by first finding the related codes that are used within the survey diaries to describe how people spend their time. The model simulates the use of appliances in the dwelling and then calculate the demand caused from these appliances.

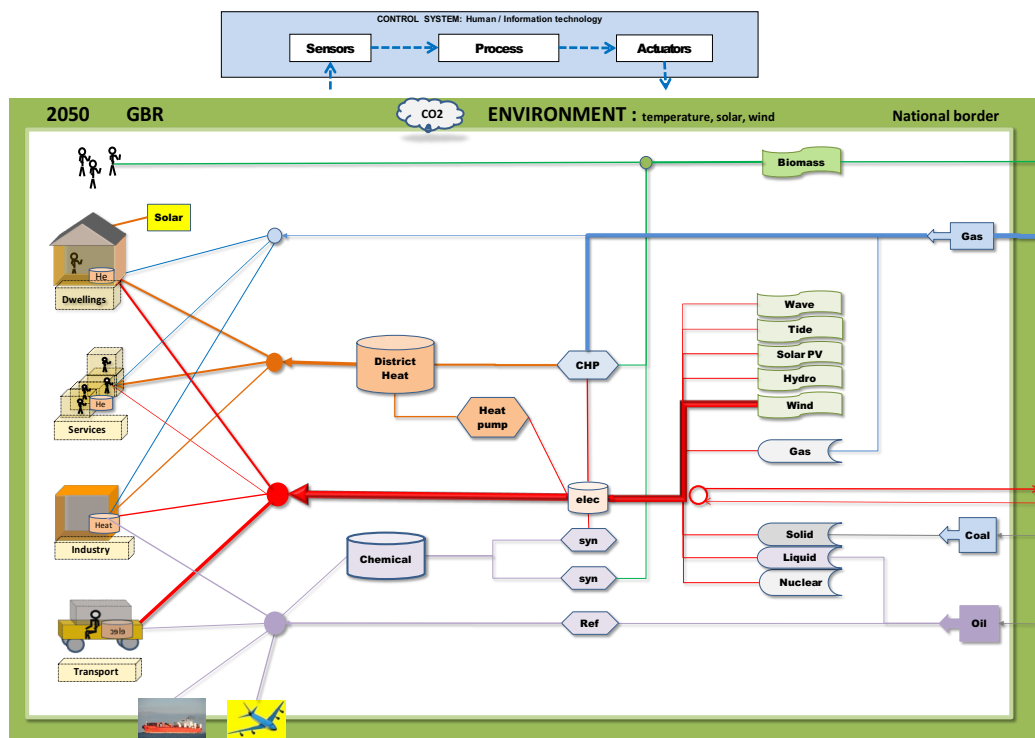


Figure 2.2: Whole Energy System Modelling - DynEMo, source: [70]

Another energy demand model approach based on human activity index is

suggested in [70] and [71], called DynEMo (Dynamic Energy Model). The same demand modelling approach is also used in another energy system model, called DEAM (Dynamic Energy Agent Model) [71]. The energy demands are disaggregated into four sectors: domestic, services, industry and transport (Figure 2.2). The time varying service demand are calculated for each sector or subsector. This model splits the demand into weather dependent demand and weather independent demand. For the weather independent demand (such as office computing, industry manufacturing demand), if the annual average demand (S_a), then this part of demand at hour t (S_t) is:

$$S_t = S_a \times U_t \quad (2.1)$$

where U_t is the human activity index which is a multiplicand of hourly (h), weekday (w) and monthly (m) profiles and U_{norm} which normalizes U_t to 1.0 across the year:

$$U_t = U_h \times U_w \times U_m \times U_{norm} \quad (2.2)$$

The weather dependent demand, such as space and water heating, space cooling and lighting, is determined by both the human activity index and weather:

$$S_t = f(U_t, W_t) \quad (2.3)$$

some service demand are also functions of building characteristics B_t :

$$S_t = f(U_t, W_t, B_t) \quad (2.4)$$

The advantage of DEAM is its capability to explore how certain energy policies might affect electricity systems in the future. It is able to simulate the energy demand uncertainty caused by the change of the building and appliance efficiency or extreme weather days.

2.4.1 Existing work on demand prediction in Australia

As this research is focussed on the Australian NEM, following of this subsection contains more literature review of the existing demand studies of the NEM regions, particular the demand study by AEMO.

Numerous studies have modelled the electricity demand in the NEM. [72, 73] use the physical bottom-up approach to estimate annual end-use electricity consumption (including the hourly load profiles) and peak demand of the Australian housing stock. Total energy consumption, including space heating and cooling, water heating, lighting and other household appliances was simulated by considering building construction and materials, equipment and appliances, local climates and occupancy patterns in [72]. The simulation result agrees well with the published model and statistical data at the state level. Their research does not discuss the demand profile in the commercial sector and industrial sector nor analyses the shape of future NEM electricity demand. Another major demand study for the NEM region is NEFR. This study uses the top down approach together with the PLEXOS software to predict the future demand trace. As the NEFR demand trace is used in Chapter CST uptake, the following part will give a detailed review of the NEFR demand modelling.

2.4.2 NEFR modelling methodology

AEMO produces the National Electricity Forecast Report (NEFR) every year to provide independent electricity consumption forecasts for each NEM region over a 20-year outlook period. Figure 2.3 shows the comparison of the NEM historical and forecast operation consumption. Australian electricity demand is dominated by the residential and commercial sectors. Space heating and cooling takes around 40% of household energy use in Australia. The historical high consumption in residential and commercial sectors occurred in the 2008-09 financial year. It is predicted that the electricity consumption from residential and commercial sectors will reach a historical high point in the next 20 years. This increase is mainly due to the population increase, while the per capita consumption continues to decline. The expansion of the LNG projects (mainly in Queensland) will increase the electricity consumption

in the next few years. Electricity is used for gas production, transmission, storage and liquefaction process for LNG projects.

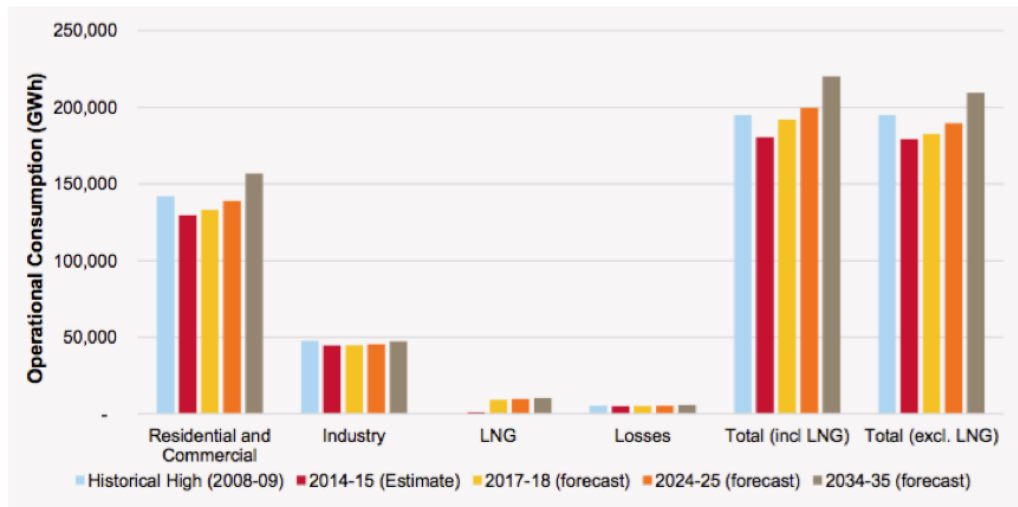


Figure 2.3: Comparison of NEM historical and forecast operational consumption, source: [74]

The objectives of the NEFR modelling is to forecast the annual operation consumption and operational maximum (or minimum) demand in the NEM regions.

- Annual operational consumption

This contains the electricity used by residential, commercial, and large industrial consumers drawn from the electricity grid, including transmission losses (supplied by scheduled, semi-scheduled and significant non-scheduled generating units). This is shown in 2.4 It is measured in gigawatt hours (GWh) and the forecasts are presented on a “sent-out (measured at the connection point between the generating system and the network)” basis.

- Operational maximum (minimum) demand

This is the highest (lowest) level of electricity drawn from the transmission grid at any one time in a year measured daily, averaged over a 30-minute period. It is measured in megawatts (MW) and the forecasts are presented ‘as generate’ (measured at the terminals of a generating system).

Apart from these, the demand from residential and commercial consumption,

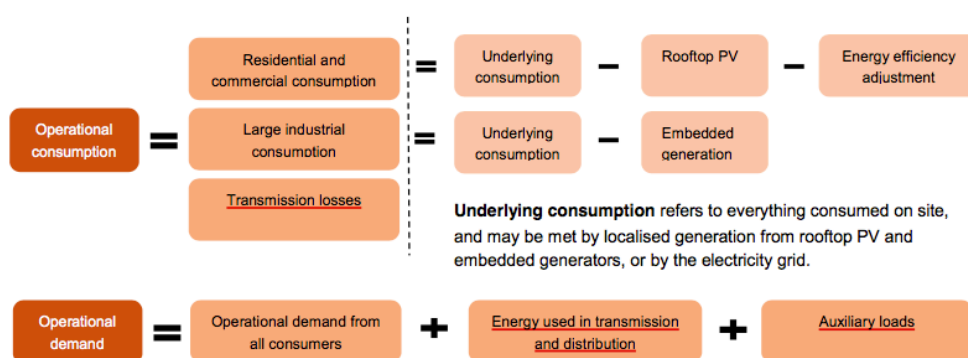


Figure 2.4: Forecast demand model in NEFR, source: [74]

large industrial consumption and transmission losses are separately modelled in NEFR.

- Model for Residential and Commercial Consumption

The residential and commercial demand model in NEFR uses historical data to estimate a relationship between electricity consumption and four key drivers of consumption (income, price, weather, and population). It then uses these estimates and forecasted values as the key drivers to calculate future consumption.

The historical consumption data for the residential and commercial segments is estimated using the data collected for market settlements. It aggregates data collected every half-hour for each NEM region since January 2000 to produce quarterly data. NEFR uses a top-down approach to derive residential and commercial load, by subtracting industrial consumption, auxiliary load, and transmission losses from total operational consumption.

Each region has its own demand model because the data is region-specific. NEFR uses quarterly data for modelling, commencing September, December, March, and June. Results are then aggregated to financial year (July-June). The estimated rooftop solar PV consumption are added to the calculated operational residential and commercial consumption.

2.4.3 NEFR hourly demand trace

The 2009 - 10 financial year's demand trace was chosen as a reference to develop the future demand traces in the NEFR report. The hourly historical demand is scaled up or down by Plexos¹, according to the projected maximum hourly demand and total annual demand. The residential and commercial rooftop solar PV generation is then subtracted from the demand trace. Figure 2.5 is the flow chart that produced of the future demand used in NEFR.

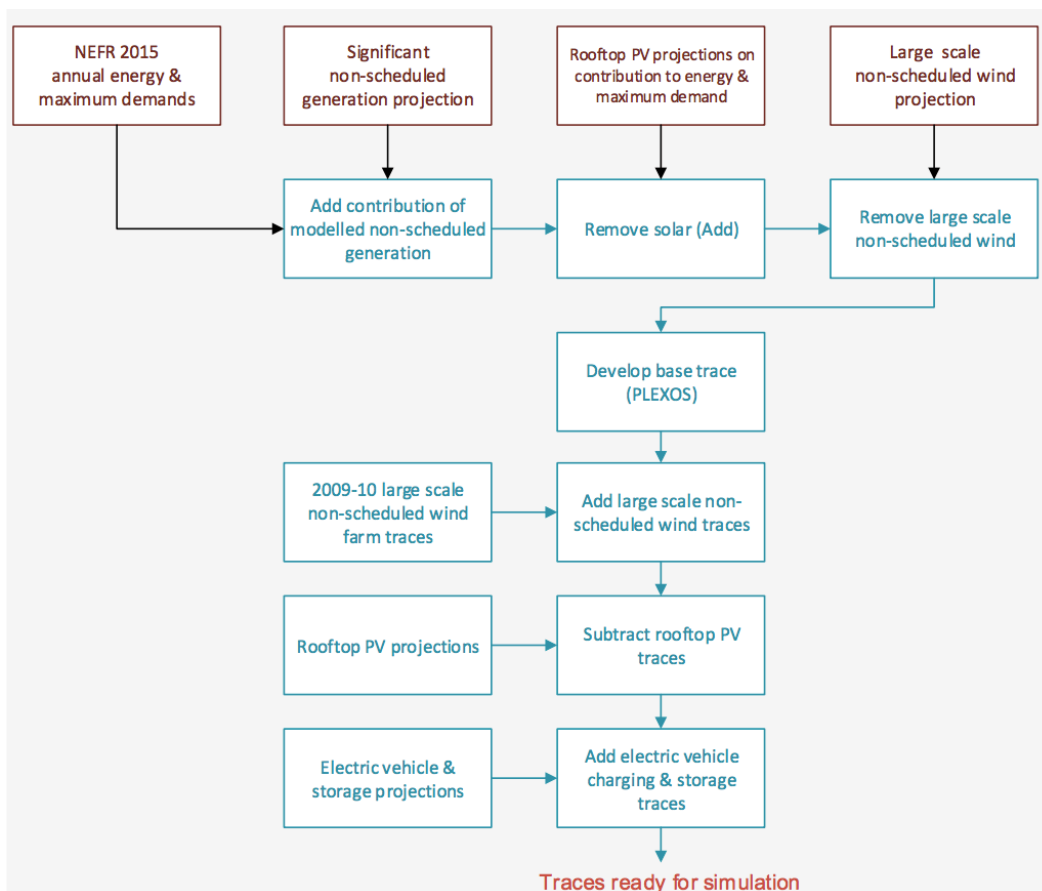


Figure 2.5: Demand trace development in NEFR, source: [74]

Electric vehicle charging profile is considered in NEFR, based on the forecast of the number of electric vehicles entering the Australian vehicle market. NEFR creates a daily charging profile of the electric vehicles. For example, Figure 2.6 shows

¹PLEXOS is a simulation software that uses mathematical optimisation combined with the data handling and visualisation and distributed computing methods, to provide a robust simulation system for electric power, water and gas

the electric vehicle charging profile in New South Wales. The hourly regional electric vehicle charging demand was added to the demand traces in the NEFR model. The battery storage profile is forecast using an economic model which optimizes the Integrated PV and Storage Systems (IPSS). Similar to the demand of electric vehicles, the IPSS demand is added to the demand trace produced by Plexos.

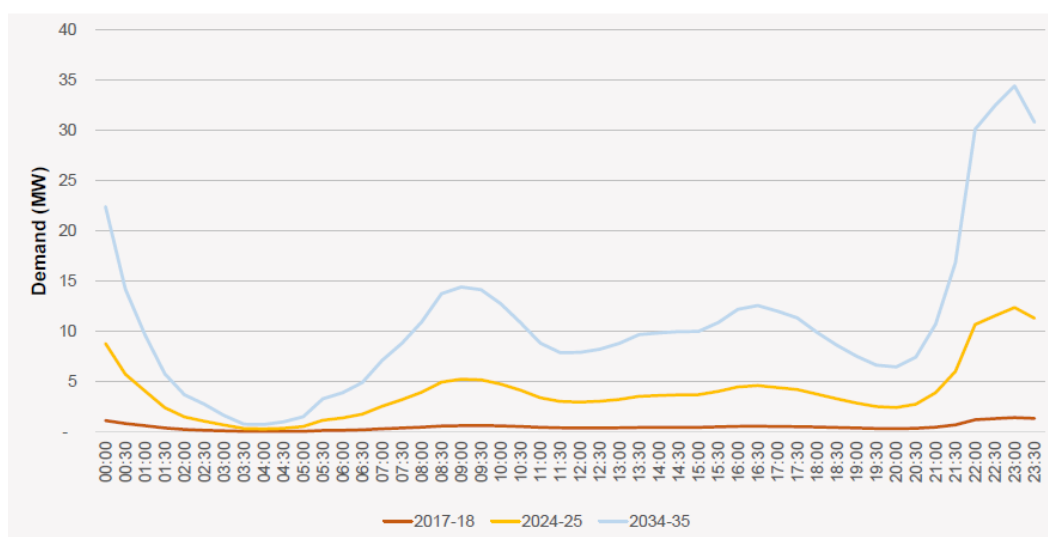


Figure 2.6: Electric vehicle charging profile used for New South Wales, source: [74]

The demand model of NEFR has the following limitations and exclusions, which has stated in the NEFR report [74]:

- The drivers for the residential and commercial market segments cannot be considered separately, because the segments have been modelled together.
- A top-down economic approach is used to model the regional consumption.
- The impact of appliance penetration or specific retail price offers has not been assessed.
- Behavioural effects have not been explicitly considered in the 2015 NEFR.
- Although EV demand is included, the total demand raised by transport electrification, such as demand from the hybrid EV, heavy transport and light commercial vehicles, is not fully considered.

2.4.4 NEFR demand analysis

When exploring the hourly demand traced in NEFR, we notice that the demand trace in different years is shifted by different days, while the rooftop solar PV generation is not shifted. This leads to an incorrect relation between net demand and weather data.

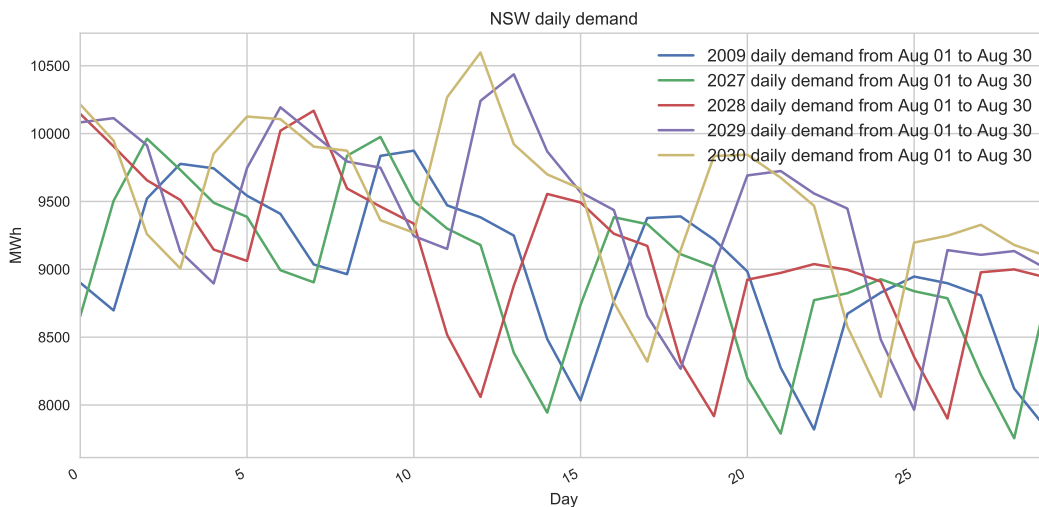


Figure 2.7: NSW average hourly demand on each day by Plexos produced in NEFR

In NEFR, the 2009 - 10 financial year is chosen as the reference trace. When comparing the daily electricity demand during a certain month but in different years, it is found that the demand curves do not have the similar shape, as shown in Figure 2.7. If we shifted the future demand with different days, we derive the plot in Figure 2.8. This shows there is a limitation in the NEFR modelled demand, and therefore we correct by shifting the trace by some days.

The hourly rooftop solar PV trace in NEFR is calculated on the same weather conditions in the different simulation years, which is not shifted with different days, as shown in Figure 2.9. This will give an inaccurate rooftop solar PV generation for the specific day.

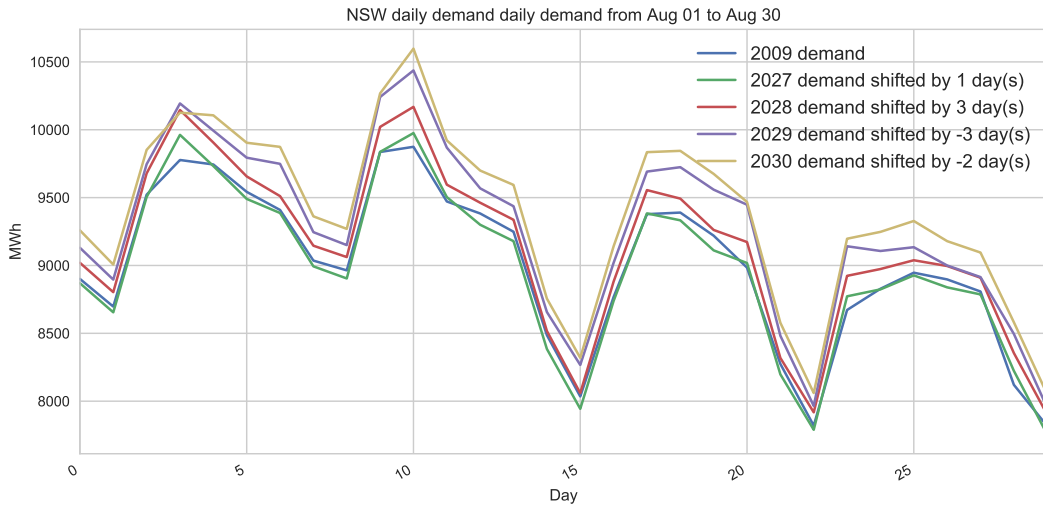


Figure 2.8: NSW average hourly demand on each day by Plexos produced in NEFR, with shifted days

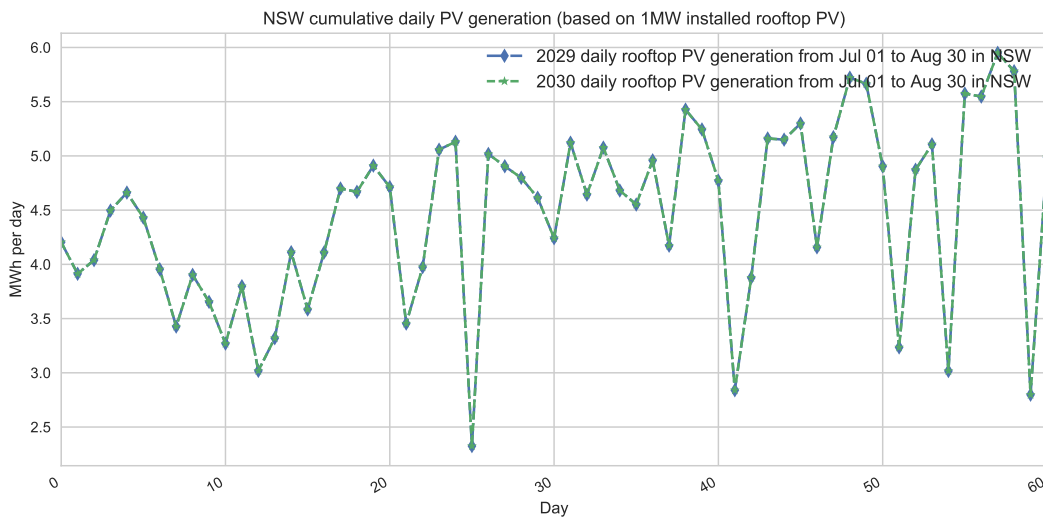


Figure 2.9: PV trace provide by NEFR, days are not shifted

Figure 2.10 is the scatter plot of the demand and ambient air temperature at 10 am in NSW region. The left figure is the 2010 historical demand and the right one is the 2030 Plexos modelled demand. It clearly shows that the Plexos demand has lost the correlation with historical ambient air temperature, because Plexos demand is not accounting for the shift in days relative to meteorological data. Therefore, this trace may give incorrect correlations between meteorology driven demands and renewables.

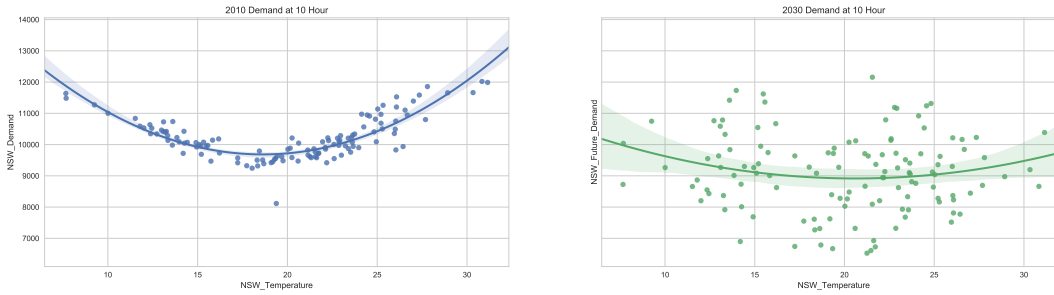


Figure 2.10: Scatter plot of the demand and temperature at 10am in NSW region

In the supply-side model (more of this will be discussed in Chapter 5), the generation of the renewable technologies (onshore and offshore wind farms, solar PV, CST) are based on historical meteorological data. We need to associate demand with meteorological data as renewables are correlated with this. Since the Plexos future demand is dissociated from the meteorological data, a demand model based on meteorological data needs to be built in this research.

2.5 Review of supply modelling approach

There is some literature that lists and discusses the simulation and optimisation models used in renewable system planning, such as [39, 75, 76]. There are many simulation or optimization tools that have been used to explore different facets of high penetration renewable systems. They differ in how the models calculate renewable generation, the spatial and temporal resolution of the analysis, and the complexity of energy exchange within or between regions. The following gives a brief discussion on these alternative approaches.

2.5.1 Renewable generation

System feasibility is usually tested by determining whether there is adequate supply provided by the calculated renewable generation to meet demand. Most studies use historical time series weather data to calculate the electricity generation from solar PV and wind farms. Some of these studies use high resolution mesoscale weather models to produce the weather data [77]. Other studies use observed or satellite-derived measurements for a discrete number of locations over longer time periods to calculate the daily average and minimum resource availability [33].

Climate change could impact the potential generation from renewable electricity generation technologies in different regions, such as in Croatia[78], Norway[79], Europe[80], Portugal[81], New South Wales in Australia[82], Brazil[83] and Nigeria[84]. Research in [78] used a global climate model to show that the wind generation potential in the Croatia region will be higher than the current level, caused by an increased average wind speed due to climate change. The study in[78] found that the solar generation remains the same level in Croatia(neutral by increase in mean temperature, decrease of mean cloud cover and more frequent extreme weather conditions). Most studies acknowledge that the hydro generation potential may be significantly impacted by climate change. The hydro potential may increase or decrease depending on its site location.

2.5.2 Spatial and temporal resolution

There is considerable variation in the spatial resolution for calculating renewable generation in different areas. While most studies are regional or national scale, a 1.5 km spatial resolution is used in [77]. The finer spatial resolution can simulate more precise solar PV or wind generation in different areas, with the optimization determining the best location for the plants. However, much finer spatial resolution requires better quality data and also increases the computation time of the model.

Different temporal resolutions are another differentiating feature in the literature. When the data are available, some studies calculate the electricity generation by a given renewable mix to test if there is adequate supply for the system demand at hourly resolution, such as [31, 41, 42]. Most studies model the system for one year, but there are some studies which consider many years. Most of these studies test the system reliability for a given target year, using the projected technology cost, system demand and renewable target for that simulated year. Typical target years are 2030, 2050 or 2100. For the studies using high spatial and temporal resolution, the power system transition pathway from a traditional system to a high renewable penetration system is not usually considered in these models due to the computation time involved.

Other studies use a load block or time slice approach, such as [85, 26, 86].

The load blocks are typically 4 to 6 hours. For example, load blocks used in [86] include four time slices for each season representing morning, afternoon, evening, and night time, with an additional summer-peak time slice. The time for simulating or optimizing the renewable system can be greatly reduced with this approach. Models using load block approach normally explore the system transition from the current fossil-fuel based system to a fully renewable system.

Wind speed, solar radiation and electricity demand can vary from seconds to minutes. Precise frequency control is an important operational component of power systems. The frequency is either 50 Hz or 60 Hz, dependent on national power system configuration. This implies that very high temporal resolution is needed to understand power system reliability considerations [42]. In [87] the impact of sub-hourly modelling of a power system with large generation from the wind farms is discussed. The system in this study contains some traditional thermal generators, which have slow ramping rates and cannot provide quick response when demand changes rapidly. The study modelled the system dispatch for one year at 5 minute, 15 minute, 30 minute and 60 minute temporal resolution and found that the estimated system cost would increase at finer temporal resolution. However, most studies agree that hourly temporal resolution is sufficient for long-term renewable system planning given that demand and weather data is usually available at this temporal level, and computation time is reasonable.

2.5.3 Modelling approaches

All energy models must have a physical basis - for example that there is energy balance at every conversion and flow point. This basis may be called a physical simulation and may be carried out at different time periods e.g. annual or hourly. Applying the capital and running costs of the system, the simulation may then be subjected to optimization whereby different sets of decision variables are input to the simulation to find the least total cost system. These models can be classified into either simulation based or optimisation based approaches. There are also some studies that combine simulation and optimisation models together, such as studies in [34, 86]. The optimisation based model here refers ones' majority part is to use

mathematic optimisation algorithm to find the best renewable mix or investment plan, instead of based on detailed dispatch process of the electricity system. The simulation based model refers the models' majority part is to simulate the physical energy flow to identify whether the system requirements can be met, some of the simulation based model are coupled with the optimisation algorithms to guide the system design.

- Optimisation based models

The optimisation based models refer to models which use optimisation tools to find the optimal mix of renewable electricity generation technologies. These models are usually built with an objective function that seeks to minimize overall electric system cost subject to a large number of constraints. The major constraints are balancing the demand within specific regions, the limitations of the regional available resource, the regional renewable policies and transmission capacity limits. The output of these models is the quantity of alternative renewable electricity generation technologies or required augmentation of the transmission system.

Linear programming and mixed integer linear programming techniques are widely used in the optimisation models (e.g., ReEDS, TNEP² and TIMES³). These models are normally computationally expensive (e.g., ReEDS and TNEP) and therefore do not optimize at hourly resolution, a resolution which is required for wind and solar generation. Instead, load blocks are used to represent the average case over a subset of hours or to stress cases for particular hours. For TNEP, the load block approach cannot track the electricity inventories in storage [88]. The use of solar thermal storage is modelled explicitly in the data pre-processing stage, with a daily charge-discharge profile set to blend a baseload (constant output) and peak (evening peak output) plant operation. The model may overestimate the utility of a certain amount of storage

²Transmission Network Expansion Planning

³The Integrated MARKAL-EFOM System, TIMES is a technology rich, bottom-up model generator, which uses linear-programming to produce a least-cost energy system, optimized according to a number of user constraints, over medium to long-term time horizons

capacity, especially on timeframes of three to six hours. It cannot consider the dynamics of charge-and-discharge, and this leads to optimistic estimates, or lower bounds, on the storage capacity required for the fulfilment of demand.

- Simulation based models

Simulation based models refer to models which simulate the electricity dispatch process with a finer temporal resolution, typically hourly. Unlike optimisation models, the capacity of the renewable electricity generation technologies, energy storage devices and transmission system are given exogenously and unchanged during the dispatch process. These models are usually built with some optimization algorithms, such as genetic algorithm (GA), agent based model (ABM), particle swarm optimization (PSO), or simulated annealing (SA). For example, [31] create a dispatch model which simulates the dispatch process for the NEM regions. Together with the dispatch model, a genetic algorithm is used to find the best mix of the generating capacity of each generator for the dispatch model.

Another simulation based model is the HOMER (Hybrid Optimization Model for Electric Renewables) energy modelling software, developed by National Renewable Energy Laboratory (NERL) [89]. The model contains a mix of conventional generators, combined heat and power plants, wind turbines, solar PV, batteries, fuel cells, hydropower, biomass and other inputs. HOMER is a time-step simulator that utilizes hourly load and environmental data inputs to assess the technical potential of renewable energy technologies via a renewable fraction setting, and economic viability via net present cost (NPC). The model predicts the optimized renewable energy configuration for a given set of constraints and sensitivity variables, based on NPC. HOMER has also been used in many studies [89].

Another example is [41]. This study explored the cost minimal combination of renewable electricity generation technologies for a large regional grid (PJM system in America). The study created a dispatch based model (Regional

Renewable Electricity Economic Optimization Model) which does not contain any optimization algorithm. The model was run using the enumerative method with 70 equally spaced-divisions per input variable (all inputs were linearly sampled 70 times and all combinations of these samples). Around 28 billion combinations of wind, solar and storage were evaluated to seek the least-cost result. The evaluation takes about 15.5 hours with 3000 processors. Most dispatch models focus on the system performance for a target year (mostly 2030 and 2050) and their simulation length ranged from 1 to 5 years. These models include a database of historical demand data and renewable generation data. They usually suggest one optimal generation mix result for the target year. These frameworks typically do not model investment decision making process or transition path from one year to another.

- Combined models

Combined models refer to models that include both dispatch and modelling of inter-temporal investment decision making. These models use an investment model first to find an optimal system configuration in several years' time-step and then use the dispatch model to test operational integrity of the designed system with a finer temporal resolution.

For example, [26] use this approach to examine separate issues or different temporal resolutions. In this study, the ReEDS⁴ model (an investment optimization model) is used to estimate the expansion of the generation and transmission capacity every two years. The estimated generation and transmission capacities from ReEDS were then imported into GridView (a dispatch simulation model) to examine the power system at a finer temporal resolution.

Another example is POLES (Prospective Outlook on Long-term Energy System) developed in [34]. It is a bottom-up simulation model with 57 regions of the world. The model is a large energy model, including oil, gas, coal and power aspects. For each simulation, 24 load block are chosen and each block

⁴Regional Energy Development System Models

is 2 hours. The model has 9 main sectors (industry, agriculture, etc.) and all the sectors have their typical load profile. The demand is then aggregated. Besides its capacity planning long term investment model, POLES also has a one-day hourly time-step simulation model (EUCAD) using GAMS programming language.

2.5.4 Summary of supply modelling approach

By mimicking investment decision making in long-lived assets, the investment based models are more suitable for long-term electricity system planning. They can inform alternative energy transition pathways towards high penetration renewable electricity systems in the long term. The main disadvantage is its temporal resolution, where the dynamic charge-and-discharge of storage devices and output characteristics of variable renewable electricity generation cannot be modelled as effectively. These models are data intensive and ‘technology rich’, and significant time and effort is required to develop an investment model which optimizes the combination of renewable electricity generation technologies, energy storage devices and transmission.

Most simulation based models usually have a finer temporal resolution, typically one hour. However, few models consider the least cost combination of renewable electricity generation technologies, energy storage devices and transmission system capacities at the same time. Simulation based models do not examine the transition pathway from the current system to the future system.

It is noticeable that many studies do not model the transmission system expansion when investigating the least-cost future renewable system, assuming an unconstrained transmission network, effectively minimizing the generation system cost. For example, [90] do not consider capacity constraints of the interconnectors between NEM regions, where the NEM is treated as a ‘copper-plate’. [41] also simplifies the grid model by assuming unconstrained transmission within PJM and no transmission to the adjacent grid.

2.6 The need for this research

Previous studies in the Australian context, the main focus of this thesis, have explored different facets of 100 per cent renewable electricity systems. [32] considered such a system by 2020 and focused on whether there are sufficient renewable resources available and if sufficient capacity can be deployed rather than the specific policy or regulatory measures that would drive the transition. In a comprehensive study, [42] found a 100 per cent renewable power system was technically and economically feasible using a potentially wide range of renewable electricity generation technologies in the National Electricity Market (NEM). [21, 90, 91] examined whether it is technically feasible to meet electricity demand with estimated renewable generation output based on historical data of demand and primary renewable resource availability in the NEM. [77] used mesoscale numerical weather models to examine cross-correlations between solar and wind generation with demand for the state of Victoria. [92] find that incremental costs of high renewable electricity systems increase approximately linearly as the share grows from zero to 80%, and then demonstrate a small degree of non-linear escalation, related to the inclusion of more costly renewable electricity generation technologies such as solar thermal electricity. Analysis by [93] suggests that the market price cap may have to rise to ensure supply adequacy in the energy-only market of the NEM. In [94] was more focused on employment gains as renewable energy production tends to be more labour intensive than non-renewable energy production.

Many studies discuss the optimal high penetration renewable system in future years. However, most of these studies do not co-optimize the renewable electricity generation mix, transmission system expansion at the same time in hourly resolution modelling. The co-optimization is informative for system expansion planning, such as the trade-off that exists between transmission network investment and quality of renewable resources in different locations. This is important given that the upgrade or augmentation of the transmission system can promote power trades and renewable integration across regions. In [41] they discuss a large regional grid (PJM regional system in Eastern U.S.) supplied by wind power, solar power, electrochem-

ical storage and fossil fuel backup generators. They found the above technology combination is able to meet the demand during most time periods at a cost similar to today. However, as the model used in their study is computationally-intensive, they did not consider the expansion of the transmission system.

Most studies about high penetration renewable power systems in Australia focus on whether there is enough renewable energy to meet the demand over a certain simulation period. Some studies determine the least cost renewable system under different scenarios. However, most of these studies do not include a detailed model of the NEM transmission network when they analysed the optimal renewable electricity generation mix. Accordingly, the importance and the cost of the transmission system in the high penetration renewable system may be underestimated. For example, in [21] an optimized power system features wind farms, solar PV, CST with 15 hours, existing hydro and peak bio-fuelled gas turbines. It used historical demand data from 2010 and projected generators' cost data by AETA [95]. The model used a simplified transmission algorithm, without the capacity constraints imposed on the interconnectors. Batteries were not considered in that study.

To address this gap in the literature, the first stage of this PhD thesis explores the least cost combination of renewable generators, energy storage devices (especially battery storage) and transmission infrastructure in the National Electricity Market (NEM) with a detailed transmission model. A model called DETRESO is built to explore this question.

The second stage of this work is to explore the impact of CST with different sizes of thermal storage. Studies which choose CST as a renewable technology option normally consider one particular CST type (solar multiple and hours of storage). No previous studies have explored the different CST types in a modelled 100 per cent renewable power system. This study will fill this gap by simulating the role of CST (with different hours of storage) in a 100 per cent renewable system in the NEM. It explores CST configurations of six, nine and twelve hours of storage versus battery storage and other renewable technologies to meet a given demand at hourly temporal resolution.

The last stage of this work is about the impact of changing demand on the renewable system. The shape and level of the electricity demand will change in the future and this will also change the optimal renewable mix configuration. Most research acknowledges the level of the demand change caused by population growth and improvements in energy efficiency. Few studies do include increased demand from the electrification of transportation (i.e., mainly electric vehicles), but do not simulate and optimize the renewable mix while recognizing EV charging as a flexible demand. The flexible EV demand charged by the surplus renewable generation will reduce the LCOE of renewables and the overall system cost. Potential changes in demand caused by climate change is also not normally included in renewable planning studies. To understand the impact of this, a demand model is developed to explore possible scenarios of future demand. These demand projections are then used in the renewable system simulation and optimisation model to see how the system behaviour may change.

Chapter 3

Australia electricity power system overview

3.1 Australian electricity system overview

In contrast to other OECD countries, Australia is not supplied by one interconnected electricity system serving all the population. This is largely a function of a comparatively large land area of 7.692 million square kilometres and small population of 24.637 million people. There are four main electricity systems:

- The National Electricity Market (NEM) interconnects five regional market jurisdictions - Queensland, New South Wales (including the Australian Capital Territory), Victoria, South Australia, and Tasmania, serves most of the population;
- The South West Interconnected System (SWIS) serves the south-west of Western Australia and is the second largest power system in Australia;
- The Darwin Katherine Interconnected System (DKIS) is the third largest power system in Australia and supplies Darwin, Palmerston, Darwin suburbs, Katherine and surrounding regions and rural areas of the Northern Territory; and
- The North West Interconnected System (NWIS) is the fourth largest power system in Australia and serves seven of the world's largest iron ore mines and

nearby townships in north Western Australia.

There are also other smaller power systems including:

- the North West Queensland Province /Mount Isa grid system (serving the Mount Isa communities and the surrounding base metal mines and processing plant, and a fertiliser plant);
- Minor grid systems serving reasonably sized rural communities. This includes the Alice Springs grid, Tennant Creek, and East Kimberley systems. These systems are dominated by diesel based generation but there are increasing proportions of renewable energy (such as solar PV in Alice Springs and hydro-electricity in East Kimberley);
- Isolated generation systems supplying remote mining operations (sometimes also adjoining communities) and isolated communities usually with diesel based generation or gas where there is a proximity to a major gas pipeline. In some cases there has been a shift to mix of generation technologies, including solar PV or compressed natural gas or LNG; and
- Micro systems supplying remote indigenous communities and tourist facilities.

Because of the relatively small demand and generation in the SWIS, DKIS, NWIS and other smaller power systems, this thesis focuses on the electricity system of the NEM.

3.2 The National Electricity Market (NEM)

The National Electricity Market (NEM) is a wholesale electricity market that interconnects five regional market jurisdictions Queensland, New South Wales (including the Australian Capital Territory), Victoria, South Australia, and Tasmania. The electricity market works as a spot market. Generators offer to supply the market with specified amounts of electricity at specified price for a set time period. From all the bids offered, the NEM choose the cheapest generators put into operation

first. The design of the NEM operation is to meet the electricity demand in the most cost-efficient way. A 'spot price' is set every 30 minutes for each NEM region. AEMO then takes the spot price as its basis for settling the financial transactions for all power traded in the system [96]. The National Electricity Rules set a maximum spot price, or called as Market Price Cap.

The Australian NEM is a gross pool, energy-only wholesale electricity market, with a very high Market Price Cap of \$14,200/MWh [96]. This contrasts with wholesale electricity markets in other jurisdictions (e.g. U.K.) that are more characterised as bilateral net settlement systems with respect to both energy and capacity, with an independent market operator facilitating settlement of energy and capacity that are not covered by bilateral contracts.

Those five states act as price regions and are connected via a large transmission network, as shown in Figure 3.1.

3.3 Generation mix

The NEM generated 198 TWh of electricity in 2015-16. The total installed capacity is 47,148 MW, with 336 registered generators in 2016 across the NEM regions. Figure 3.2 shows the mix of generation in the NEM.

As a reliable base-load technology, black and brown coal takes up 52 per cent of the registered generation capacity but 76 per cent of the total generation output in 2015-16. Victoria, New South Wales and Queensland heavily rely on coal-fired electricity than other regions. There is significant coal-fired capacity retired during 2016-17 as a result of these ageing plants or high operating costs of older plants. Numerous coal-fired plants have retired over the last few years (2015-17) due to a number of factors. These include lower wholesale market revenue due to increased periods of negative prices (mainly due to wind generation) and a number of plants reaching the end of their operating life. In regard to the latter, it has mainly been lignite plants that have high emissions intensity including Anglesea (commissioned 1969), Playford (commissioned 1960) and Hazelwood (commissioned 1968) [99].

Gas stations are distributed in all NEM regions. It takes 19 per cent of the NEM

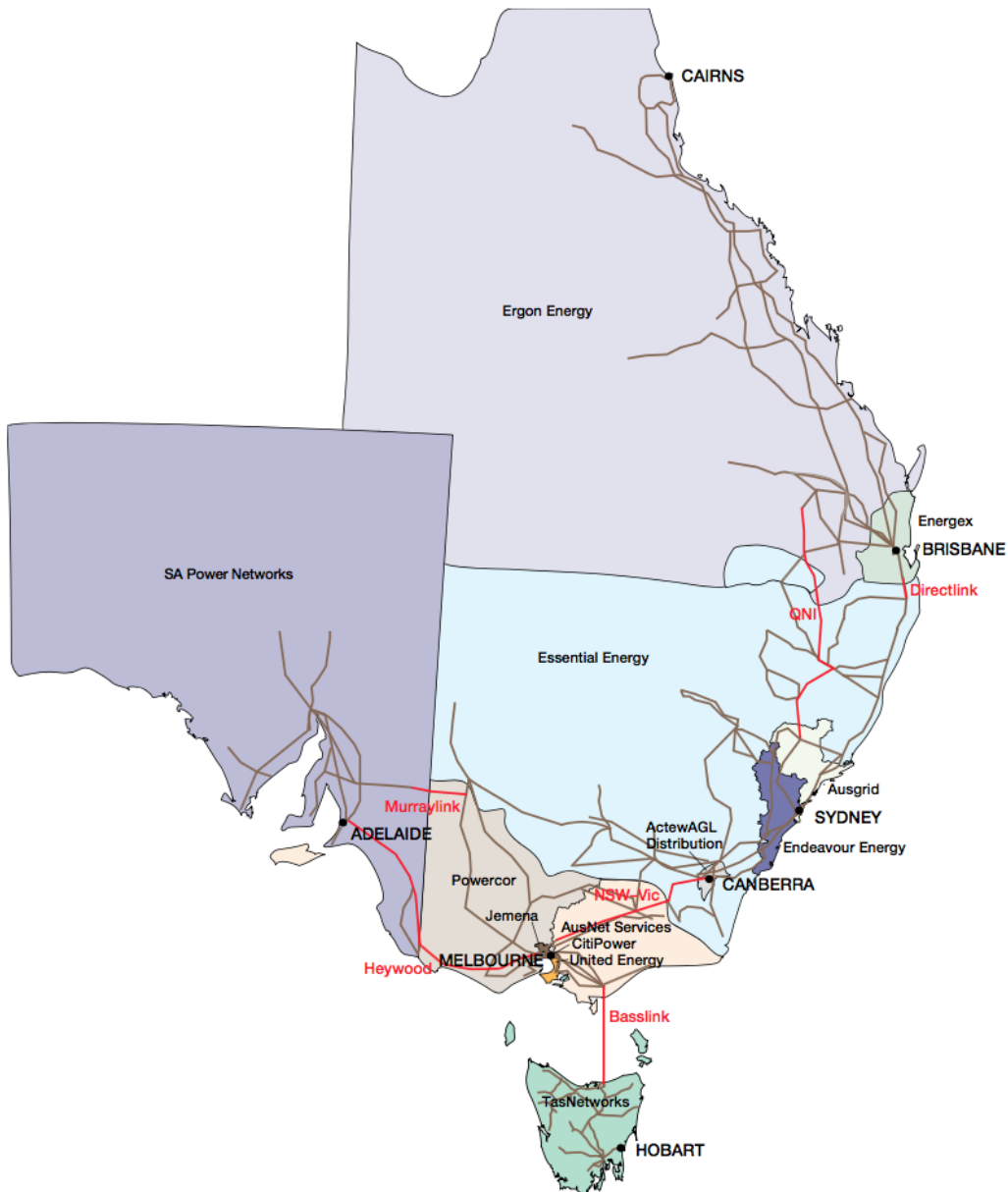


Figure 3.1: NEM transmission network, source: [97]

generator capacity but only contributes 7 per cent of NEM generation. The recent increasing gas price leads to a decreasing generation amount from gas generators. South Australia has the highest share of gas-fired power capacity among the NEM regions.

Hydroelectric generation is about 17% of registered capacity but only 10% of the output in 2015-16. Most hydro stations are in the Snowy Mountains and Tasmania areas. Tasmania changed from a net electricity exporter to a net electricity

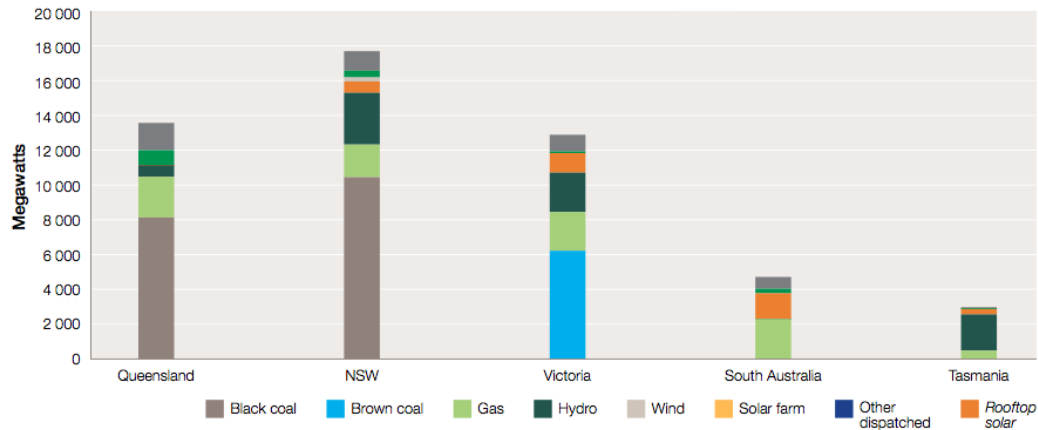


Figure 3.2: Generation mix in the NEM, by region and fuel source, 1 Jan 2017, source:[98]

importer during 2015, due to its low available hydroelectricity caused by dry conditions. Many studies point out it will be hard to build additional hydroelectric facilities due to the limited hydro resource in the NEM regions [30].

Renewable generation, such as from wind turbines or rooftop solar photovoltaic (PV), has little capacity and output compared with traditional technologies in the NEM. The wind power takes 7.5 per cent of capacity and 6.1 per cent of output in 2015-16. South Australia has the largest share of wind generator, accounts for 36 per cent of the regional generators' capacity and contribute 38 per cent of the regional demand.

The development of commercial solar farms is still in the early stage in Australia due to its high cost. The capacity of the commercial solar farms is 232 MW as of 2017. The installed capacity of rooftop solar PV has increased rapidly because of renewable policies in Australia over the last few years. Rooftop solar PV generation is not trading through the NEM but is consumed locally to supply the household demand locally (locally consumed). According to AER, there is about 5286 MW rooftop solar PV installed by 2016 and this capacity is equivalent to 9 per cent of the total installed generation capacity in the NEM.

Figure 3.3 shows the investment in new generation and plant retirements. The most investment on power generation in past few years is in the wind power. There has not been any new gas or coal-fired power plants since 2012. The total capacity has declined in the past few years, due to the oversupply of generation and flattening

demand in NEM regions.

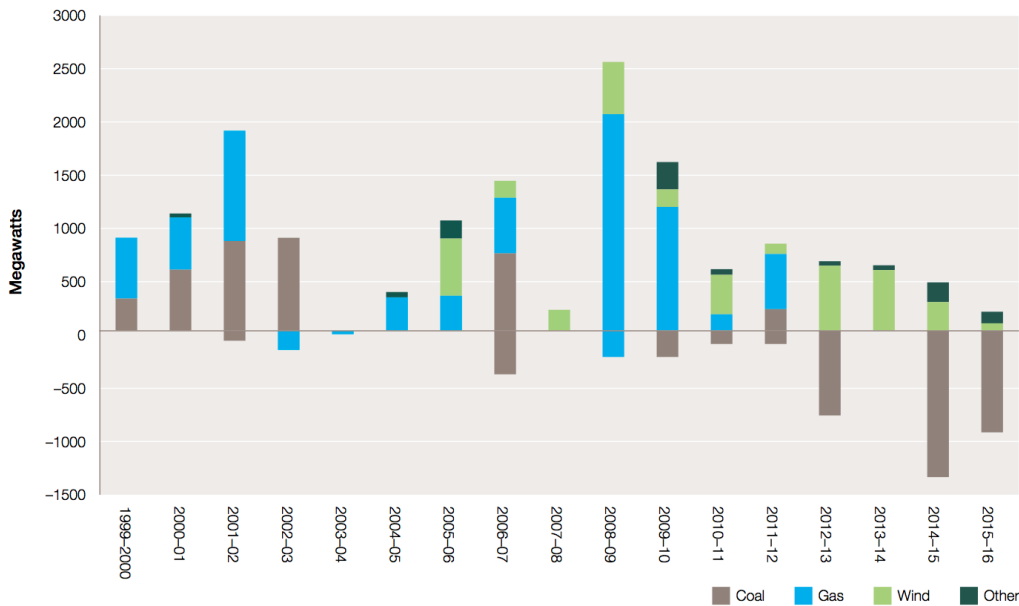


Figure 3.3: Investment in new generation, and plant retirements, source:[98]

3.4 Interconnector and energy exchange between regions in the NEM

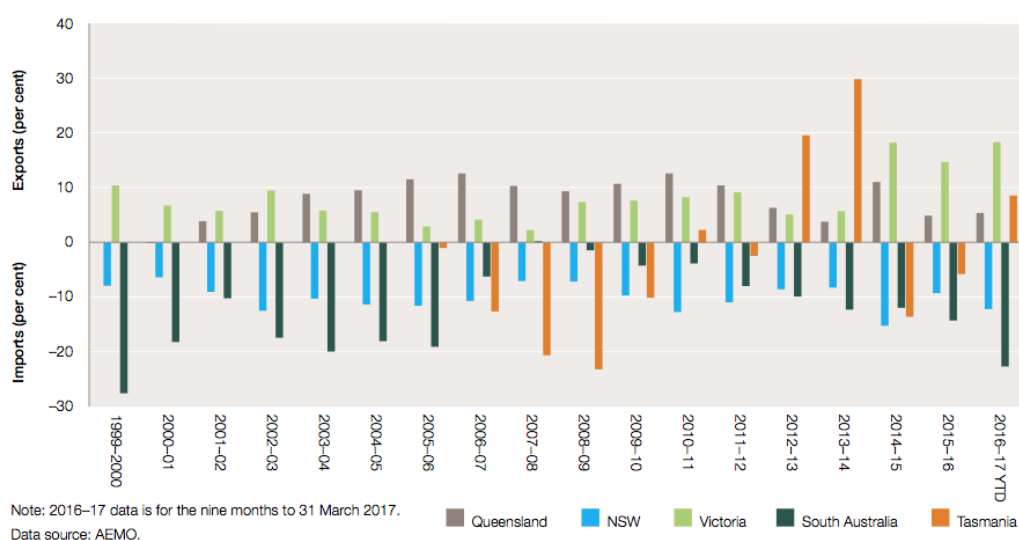
The transmission network (voltage larger than 100 kV) in the NEM is about 5,000 kilometres long and most of it is located in the eastern and south-eastern coasts. It is owned and operated by state governments, or private businesses in different states. The power system in different states is connected by several interconnectors. These interconnectors are to enable the electricity trading between regions and help the NEM reach a high reliability standard. The name and nominal capacity of the interconnectors are shown in Table 3.1.

Figure 3.4 shows the regional electricity exchange between the NEM regions since 2010. Queensland and Victoria are the major energy exporters, while New South Wales and South Australia are the principal energy importers. The abundant supplies of low cost coal generation in Victoria make it a net exporter. The surplus capacity and low cost gas make Queensland a net exporter. High fuel cost in New South Wales and South Australia make them as the net importers. Tasmania is a

Table 3.1: Interconnectors in NEM region, source: [97]

Name	From Region	To Region	Nominal Capacity (MW)
QNI	Queensland	New South Wales	1078
QNI	New South Wales	Queensland	300-600
Terranora	Queensland	New South Wales	210
Terranora	New South Wales	Queensland	107
VIC1-NSW1	New South Wales	Victoria	400-1350
VIC1-NSW1	Victoria	New South Wales	700-1600
Heywood	Victoria	South Australia	460
Heywood	South Australia	Victoria	460
Murraylink	Victoria	South Australia	200
Murraylink	South Australia	Victoria	220
Basslink	Victoria	Tasmania	478
Basslink	Tasmania	Victoria	594

net exporter during 2012-14 due to the carbon price policy at that time. Hydro generation is much more competitive when the carbon pricing is in action. However, when carbon pricing was replaced by Direct Action in 2014 along with declining dam levels, Tasmania became a net electricity importer during 2014-15.

**Figure 3.4:** Interregional trade as a percentage of regional electricity demand, source: [98]

In order to facilitate the development of an efficient national electricity network that considers forecasts of constraints on the national transmission flow path, the Australian Energy Market Operator (AEMO) publishes the National Transmission Network Development Plan (NTNDP) frequently. In the recent 2014 NTNDP

report, it was observed that the transmission network augmentation needs are reducing and transmission network asset replacement is becoming the most common form of network development [100].

3.5 Demand in the NEM regions

The operational demand in NEM in 2014-15 is 180,390 GWh. Queensland, New South Wales and Victoria are the main demand regions. The demand in South Australia and Tasmania is much smaller than other regions due to their relatively smaller population and economy.

The demand in NEM peaked at 194,971 GWh in the year 2008-09. The operational consumption has been decreasing since then, shown in Figure 3.5. The consumption is increasing after 2014-15 and this is mainly due to the ramp-up of Liquefied Natural Gas (LNG) projects in Queensland and the recovery in residential and commercial consumption in New South Wales, which offsets the closure of the Point Henry aluminium smelter in Victoria. The main reasons for the declining trend of demand in the past few years are:

- Demand response activities by commercial and residential customers.
- Customers now make more use of energy efficiency products.
- Low economic growth and energy demand from the manufacturers, together with the closure of several aluminium smelters.
- Increased installed capacity of rooftop solar PV. The generation from rooftop PV reduces the demand from the grid.

Figure 3.6 shows the monthly aggregated demand in the five NEM regions, in 2010. The monthly demand of New South Wales and Victoria peaked in July, while the monthly demand peak in January for Queensland region. This reflects the different heating or cooling need in these regions. In the NEM, the peak hourly demand usually occurs in the extreme hot summer days or cold winter when air conditioning or heaters are working. The peak demand in NEM reached its maximum value

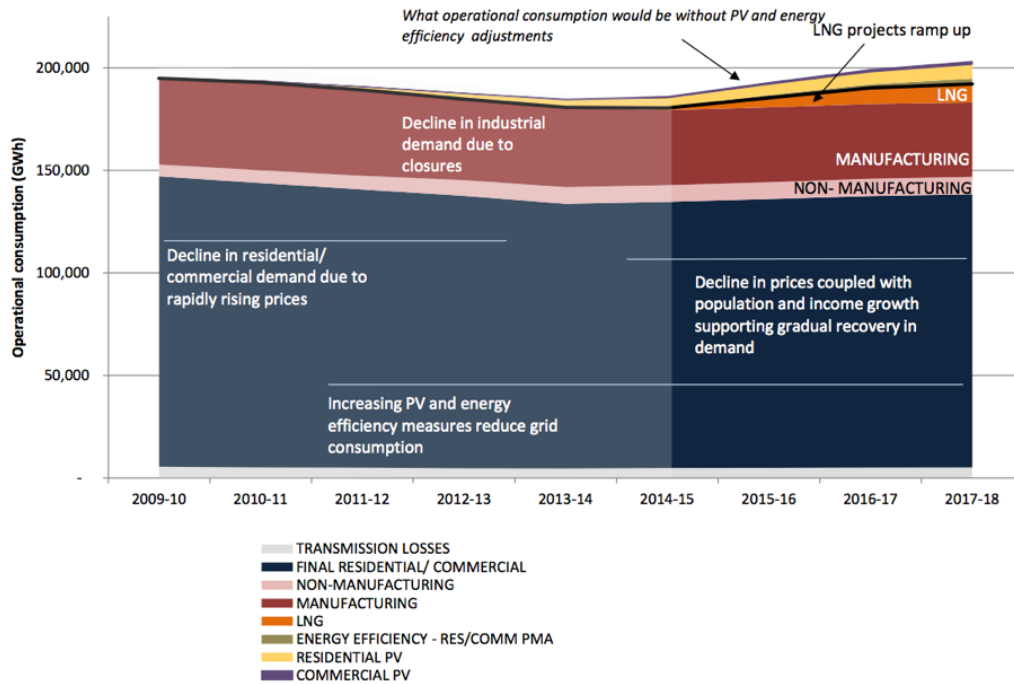


Figure 3.5: NEM annual operational consumption to 2017-18, source:[101]

in 2008-09. Although the average 2012-13 summer temperature was the highest recorded, the NEM’s peak demand in that year was still below the 2008-09 level.

According to AEMO, NEM total electricity consumption is predicted to increase in next few years. The forecast residential and commercial consumption per capita continues to decline, with population growth as a key driver for any increase in consumption. Since the carbon pricing scheme was repealed in 2014, the electricity price has decreased. The falling electricity bills, together with the increasing average income per capita, changed consumer behaviour in terms of energy saving activities [74].

Industrial consumption in the NEM is also forecast to increase in the coming years. This is because of the Queensland LNG projects¹, whose annual consumption will jump from 1063 GWh to 9075 GWh. Other industrial consumption is forecast as flat. The forecast consumption in Queensland and New South Wales also remains relatively flat, with the closure of several large consumers causing a

¹Queensland Australia Pacific LNG project began in 2015, Gladstone LNG began production in September 2015 and will be expended in 2016. Queensland Curtis LNG projects began in December 2014.

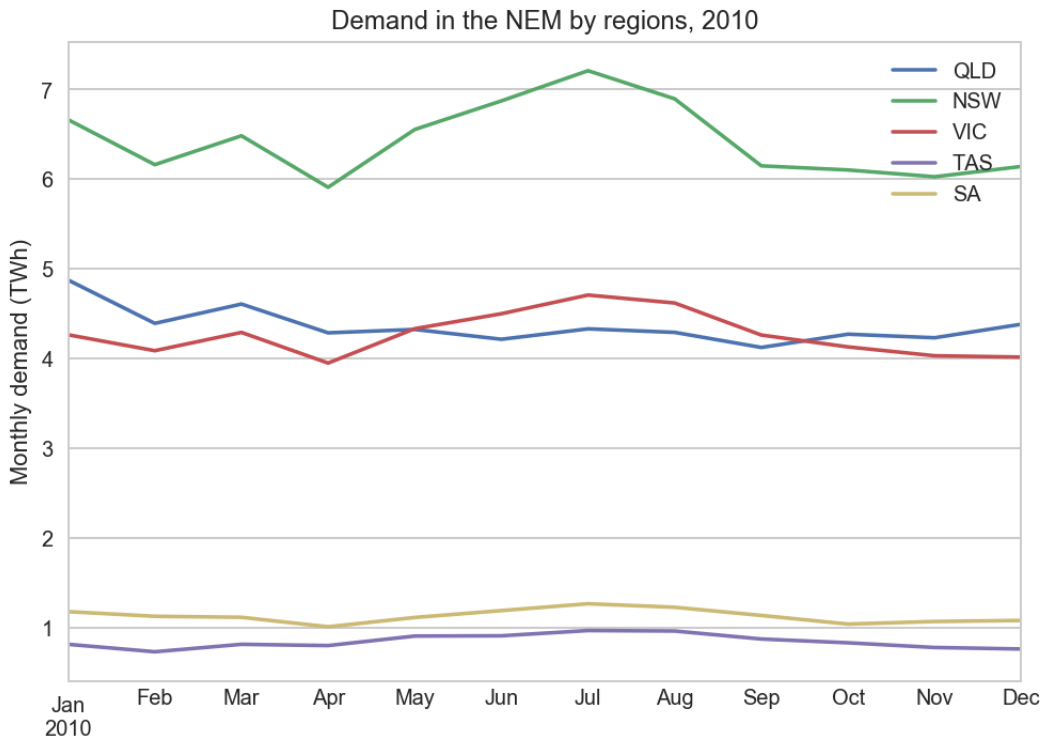


Figure 3.6: Demand in the NEM regions, 2010, data source:[102]

decline in consumption in Victoria being offset by increases in Tasmania and South Australia.

Fuel switching activities will increase the electricity demand but this will not significantly change the demand level. The retail gas price in Australia is expected to increase in future, because of the high overseas demand for LNG exports and the international gas price. Customers may want to avoid the higher gas expense of residential gas appliances for space heating, water heating and cooking by using the electric appliances. Table 3.2 shows the prediction of the operational consumption of residential fuel switching. It expects the impact will be low due to the small proportion of households able to switch and the high upfront cost of efficient electrical appliances relative to annual energy cost savings [101].

Table 3.2: Forecast impact on operational consumption (GWh),[101]

Year	NEM	QLD	NSW	SA	VIC	TAS
2017-18	31.5	1	23	7	-	0.5
2024-25	815	32	502	153	120	8
2034-35	2,552	38	608	182	1,715	9

The take-up of residential rooftop PV and storage devices will reduce the amount of electricity drawn from the grid. Battery storage has recently received extensive media attention, particularly with the high-profile launch of the Tesla Motors' PowerWall [103], followed by energy storage packages offered by major retailers. Battery technologies have been quickly developed and the cost of them has become more attractive recent years. Together with the residential rooftop solar PV development, the consumer demand from the grid will be reduced as part of their demand could be supplied by themselves.

The number of electric vehicles (EVs) has rapidly increased in recent years globally. According to the AEMO, 1197 Plug-in Hybrid Electric Vehicle (PHEVs) and Battery Electric Vehicle (BEVs) were sold in the NEM by April 2015. However, there are no significant policy incentives for electric vehicles in NEM regions. Key consumer barriers such as range anxiety, and lack of public infrastructure and awareness exist in the NEM regions. The cost of EVs remains high compared to conventional vehicles but EVs may become cost-competitive over the next 20 years.

3.6 Blackout in South Australia on 28 September 2016

On 28 September 2016, tornadoes with wind speeds in the range of 190-260 km/h occurred in areas of South Australia. A single circuit 275 kV and a double circuit 275 kV transmission line were damaged by the tornadoes almost at the same time. These three transmission lines were tripped at around 4.16 pm. This caused a system-wide voltage dip. Because of this, nine wind farms in South Australia region which provided 456 MW supply left the grid as their feature activated. The quick drop of the regional supply caused increasing import electricity via Heywood Interconnector, which was then tripped due to the maximum rating capacity being reached. The SA power system then become separated or islanded from the rest of the NEM. The remaining generation could not maintain the system frequency and finally SA region lost all supply at 4.18 pm. Around 40% of the load was resupplied by 8.30 pm while all customers had supply restored by 11 October 2016 [104].

The AEMO investigated this event and addressed the importance of the sufficient frequency control services for the management of extreme conditions in the NEM system. As most of the current solar PV and wind turbines design are not synchronous generation, maintaining the system frequency would be a challenge in a 100% renewable system where most solar PV and wind turbine dominates. Hydro, biogas using OCGT and CST could provide synchronous generation, but these technologies are either resource limited or more expensive than solar PV and wind turbines. Apart from the generation mix, a higher capacity interconnector would also improve the system reliability by allowing more electricity to be imported from other regions when needed. This implies that a well-designed renewable mix is critical for a high penetration renewable system.

3.7 Renewable policies in Australia

The major national level climate change policies in Australia are the Renewable Energy Target (RET), carbon pricing and Direct Action. There are also some region level policies, such as feed-in tariff schemes by the different state government.

The RET was introduced in 2001 and has been amended several times. The RET scheme has operated in two parts: the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). The LRET provides a financial incentive for large centralized renewable power stations. Retailers receive Large-scale Generation Certificates (LGCs) created for each MWh of eligible renewable electricity that an accredited power station generates, and then LGCs can be traded with other companies to meet their RET scheme's annual targets. The recent reforms (23 June 2015) to the RET scheme propose to achieve a 23.5% renewable energy in electricity mix of Australia by 2020. More specifically, it aims to achieve 33,000 GWh electricity from large-scale renewable energy facilities, which is lower than the previous 41,000 GWh target set in 2001 [6].

The SRES encourage households, small businesses and community groups to install eligible small-scale renewable energy systems such as solar water heaters, heat pumps, rooftop solar PV, small-scale wind turbines or small-scale hydro sys-

tems. In return, they are rewarded with Small-scale Technology Certificates (STCs) and the STCs can be traded with other entities [105].

The carbon pricing scheme was launched in July 2012 by the Labor Government[7]. The scheme enforced a fixed price on carbon for three years, starting at \$23 per tonne of carbon dioxide equivalent emitted. The government was going to introduce a carbon emission trading scheme from July 2014, whereby the carbon price will be determined in the market instead as fixed price at \$23 per tonne. During 2012 to 2014, the coal generation share of the NEM total generation dropped to 73.6%, while the gas, wind and hydro generation share ramped up. This trend is shown in Figure 3.7.

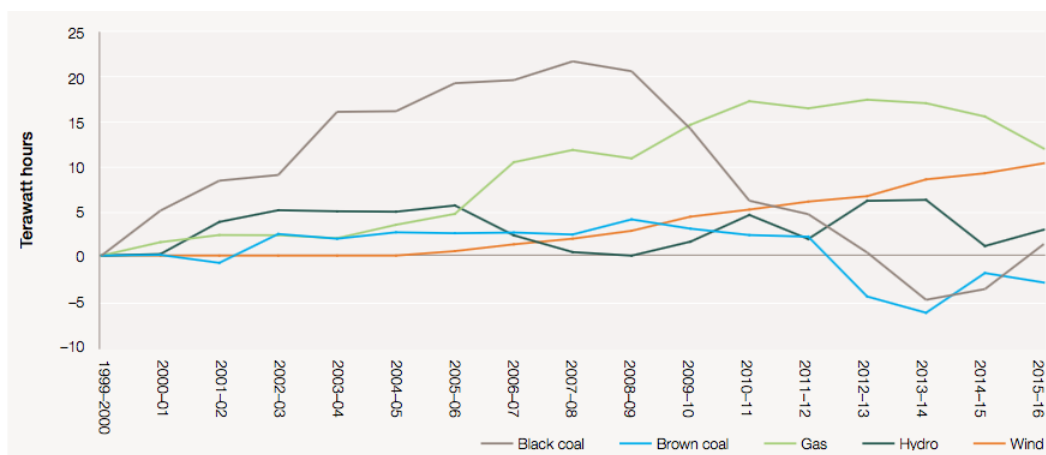


Figure 3.7: Annual change of generation by energy source, source:[98, 106]

After the Coalition Government was elected in 2014, the carbon pricing scheme was abandoned and the Direct Action plan was introduced to replace the carbon pricing. The plan comes with a \$ 2.55 billion Emissions Reduction Fund (ERF). The ERF aims to provide financial incentives for polluters to reduce carbon emissions. The eligible participants can earn Australian carbon credit units (ACCUs) for emission reductions. ACCUs can be sold to the government through a carbon abatement contract or in the secondary market [107]. Five auctions were held to April 2017, spending AU\$2.2 billion to abate 189 million tonnes of carbon dioxide. Only one electricity project has successfully enrolled in the scheme until now. The project uses waste gas from a coal mine to generate electricity [108].

During the past years, all the five regions in the NEM have announced zero

emissions targets by 2050. Climate Action 21 by Tasmania Government established a long-term target to achieve zero net emissions for Tasmania by 2050 [109]. Queensland Climate Transition Strategy sets the target that powering Queensland with 50% renewable energy by 2030 and achieving zero net emissions by 2050 [110]. Target Zero by South Australia aims to achieve net zero emission by 2050, including establishing Adelaide as the world's first carbon neutral city [111]. Victoria's Climate Change Act 2017 by the Victorian Government sets the zero greenhouse gas emissions target by 2050 [112]. New South Wales Government has also committed to achieving net zero emissions by 2050 [113]. These State government commitments give strong policy and financial support in transforming the current coal based power system to a renewable dominated power system. This thesis explores the possible scenarios of the high renewable penetration power system in the NEM regions.

3.8 Summary of this chapter

This chapter gives an overview of the Australia electricity power system, with more details in the NEM system. There is increasing amount of renewable capacity installed in the NEM regions. Renewable mix and the electricity demand is changing. The five states in the NEM regions set zero emissions targets by 2050. All these show that the Australian electricity system is at a major crossroads and indicate the need to think about the structure of the future power system, which this research focus on.

Chapter 4

Demand Side Model

4.1 Introduction and overview of the model (DETRESO)

A model including electricity DEMand change, Transmission network expansion, REnewable generators, Storage system and system Optimisation (DETRESO) is built in this research. DETRESO can simulate and optimize a 100% renewable power system and in this research is applied to the Australian NEM (National Electricity Market) regions with future demand projections. Figure 4.1 shows the structure of DETRESO. The model has two main parts, one is demand modelling and the other is demand-supply balancing and optimization. This chapter gives an overview of the DETRESO model and the details of its demand module.

DETRESO is a region level model. The five NEM regions are treated as demand and generation hubs, and there are interconnectors linking the adjacent regions (Figure 4.2). The capacities of renewable technologies and demand are aggregated to the region level. It is possible to scale down DETRESO to a higher spatial resolution model. However, the available demand and generation data at the smaller spatial resolution, as well as the computation time are difficulties to consider.

The demand module in DETRESO is based on social activity use patterns, heat load factors and ambient temperature. This module is also a regional level model and each region has its own demand modelling parameters. With this module,

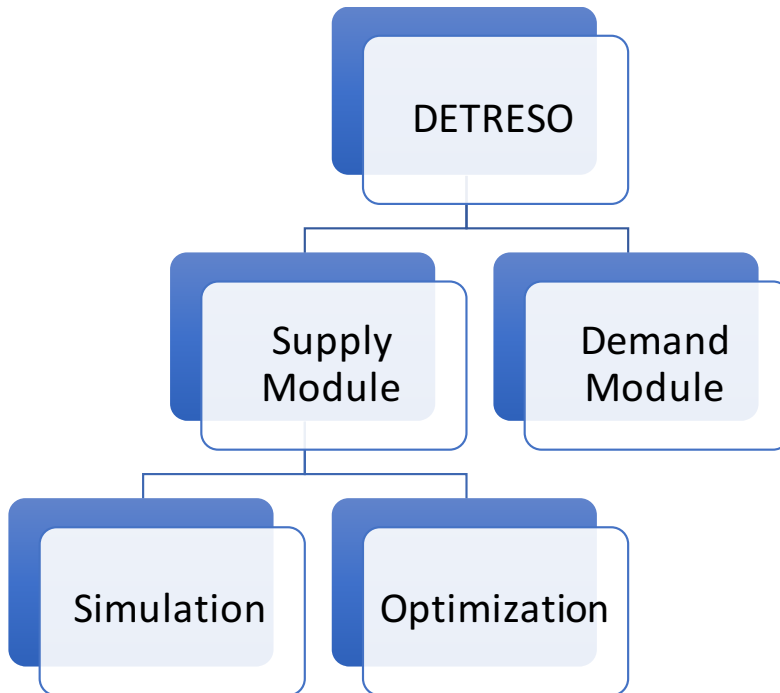


Figure 4.1: Structure of DETRESO model

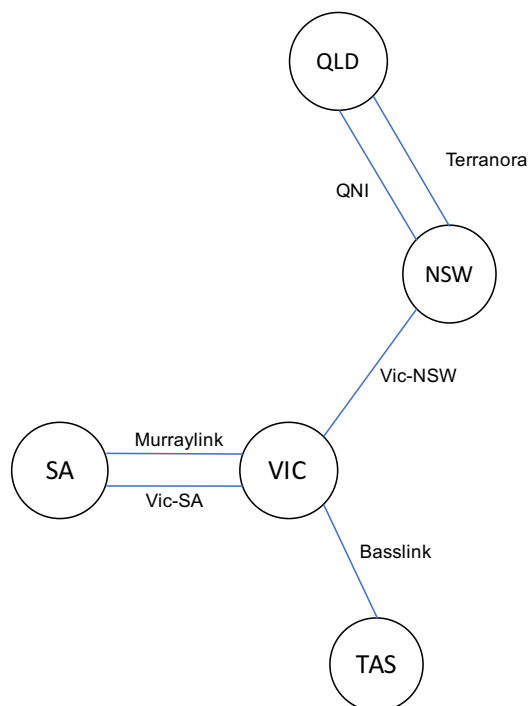


Figure 4.2: Demand and generation hub, interconnectors

we can simulate the demand change caused by the temperature change or energy efficiency improvement of the household appliances or buildings.

In the supply module of DETRESO, there are two sub modules: 1) simula-

tion module and 2) optimisation module. Parts of the simulation module and optimization module use the framework developed in [21]. The simulation module balances generation and system demand at an hourly resolution. It considers solar PV, onshore and offshore wind farms, CST with different hours of storage, existing pumped hydro and hydro stations, electric batteries and biomass and biogas generators. The model does not consider geothermal or marine generators but it has the capability to include these technologies. Inside the simulation module, there is a transmission module which simulates the electricity exchange between the five NEM regions with the interconnector capacity constraints. However, the transmission module does not model the transmission and distribution network within each region in order to reduce the complexity of the model. It assumes that there are no constraints on the capacity of the transmission and distribution system within each region. The optimisation module uses an optimization algorithm to seek the least cost combination of renewable power capacity, interconnector and storage capacity in the NEM system.

The remainder of this chapter will give the details of the demand model of DETRESO.

4.2 Demand side model

Electricity demand is fundamental when optimising the possible future renewable mix. The emerging technologies, such as electric vehicles, energy saving appliances and fuel switching, together with the customers' behaviour change will lead to the demand curve shape changing. While the demand shape will impact the efficiency and curtailment rate of renewable electricity in some time periods, it is critical to know how those emerging technologies and trends will change the future hourly demand profile in AEMO regions.

During the first two years of the PhD, the electricity demand data used in the optimization model was 1): simply scaling of the historic hourly load curve according to the annual demand projection, 2): using the demand traces developed by NEFR. As discussed in Chapter 2, these demand data were inadequate for long-

term energy system modelling where new technologies are deployed and existing ones leave the market, implying a significant change to the future load shape. In particular, the correlations between demand and renewables are critical to system management. Therefore, to investigate the future power system structure, it is fundamental to understand future electricity demand. The following part of this section explains a new demand model developed with a new approach.

A demand simulation model based on the social activity use pattern and ambient temperature is built in this study, as the demand part in the DETRESO model. Given the limited time and data for the demand model, a similar methodology in [70, 71] is used. With this demand model, we may assume the changes to the building specific heat loss for cooling or heating and know its impact on the demand. We may also consider other thermal storage (cooling or heating) technologies to modify electricity demand to better match renewables, and find the optimization between the thermal storage and renewable generators with other parts of the DETRESO model.

The demand model is a regional level model. Each NEM region has its own demand modelling parameters, which accounts for regional differences in economic, population, climate and social behaviour. EV demand is not considered in this demand model, instead, the EV demand is embedded in the dispatch process in the DETRESO supply side model. Details about the supply side model will be given in Chapter 8. In the DETRESO demand model, the calendar days are categorized into working days and non-working days (holidays). The non-working days contain the weekends and some public holidays when most people are not working. We account for the situations that each region in the NEM may have different public holidays.

The demand D_h of a given hour (h) is separated into two part: a weather independent part Dwi_h and a weather dependent part Dwh

$$D_h = Dwi_h + Dwh \quad (4.1)$$

The weather independent part contains the baseload demand (*BaseLoad*, not related to human activity with demands such as domestic refrigeration) and demand related

to human activity C_h :

$$Dwi_h = C_h + BaseLoad \quad (4.2)$$

The hourly social activity use pattern U_h is given by:

$$U_h = C_h / mean(C_h) \quad (4.3)$$

The simulated hours can be categorized into heating hours, cooling hours and normal hours. The heating hour is when ambient temperature is lower than the heating on thermostat temperature (Equation 4.4a). The total demand at the heating hour is the sum of the weather independent demand and the space heating demand. The space heating demand of the hour is associated with the building space heating loss or specific loss factor ($MW/^\circ K$), the difference between the ambient temperature and comfortable temperature, as well as the social activity use pattern at the hour. Vice versa, the cooling hour is when ambient temperature is higher than the cooling on thermostat temperature (Equation 4.4c). We did not model or simulate the demand when the temperature of the hour is between the assumed heating and cooling thermostat temperatures, we simply use Dwi_h as the modelled demand value in the final model (Equation 4.4b).

$$D_h = \begin{cases} Dwi_h + E_h + U_h \times SHL_h(T_{min,h} - T_h) & T_h \leq T_{min} & (4.4a) \\ Dwi_h & T_{min} < T_h < T_{max} & (4.4b) \\ Dwi_h + E_c + U_h \times SHL_c(T_h - T_{max,h}) & T_h \geq T_{max} & (4.4c) \end{cases}$$

where D_h is the electricity demand at hour h (MWh),

Dwi is the weather independent demand (MWh),

C_h is the weather independent demand caused by social activity (MWh),

$BaseLoad$ is the weather independent demand not related to social activity (MWh),

U_h is the use pattern at hour h , normalized to 1,

SHL_h is the specific heat loss for heating ($MWh/^\circ C$),

SHL_c is the specific heat loss for cooling ($MWh/^\circ C$),

T_h is the ambient air temperature in the region at hour h ($^\circ C$),

$T_{min,h}$ is the heating on thermostat temperature at hour h ($^\circ C$),

$T_{max,h}$ is the cooling on thermostat,temperature at hour h ($^\circ C$),

E_h is the regression intercept for heating (MWh),

E_c is the regression intercept for cooling (MWh).

The following section uses the New South Wales region as an example region to explain how the demand model was constructed in detail. The other four regions use the same methodology. However, there may be some difference in the thermostat temperature setting in different regions. The plots of the social activity use pattern and modelling results for these regions are given in this section.

4.3 Demand model for New South Wales region

4.3.1 Weather independent demand

The level and shape of demand on working days is different to the ones on holidays, as well as the social activity use pattern, thermal performance of the buildings. Thus, we categorized the demand into the working day demand and holiday demand. The following gives the details on how the working day demand model was constructed. The holiday demand uses the same steps, so only some key points of it will be discussed.

The red points in Figure 4.3 show the 30 lowest demand days among all the working days. This clearly shows how the demand increases with lower temperatures because of heating, and for higher temperatures because of air conditioning and other cooling activities. There is a central temperature range where demand is insensitive, this is assumed to be because the temperature is above the thermostat setting for heating to be on, and below the setting for air conditioning to be on. This can be also proven in Table 4.1, which shows the statistical summaries of the demand and temperature in the lowest 30 demand days when most people are working. The standard deviation of the demand is 1297 MW, less than 0.7% of the mean demand over the days.

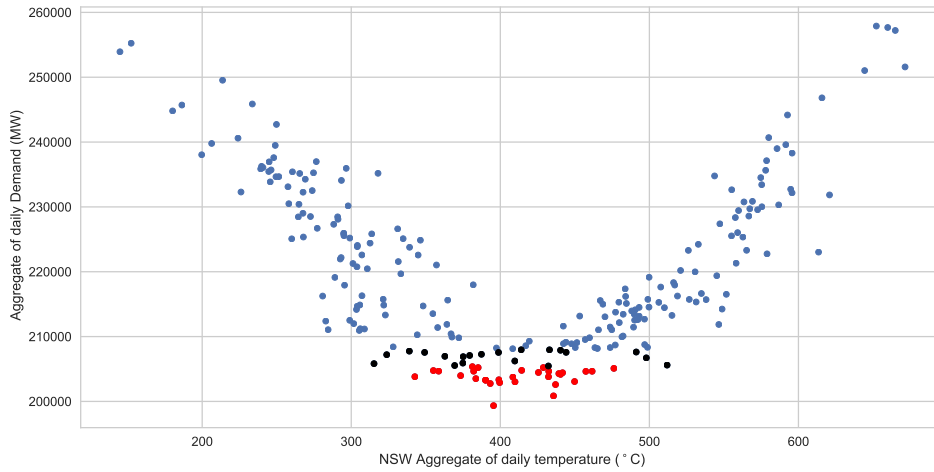


Figure 4.3: Scatter plot of daily temperature and daily demand, NSW working days

Table 4.1: The 30 lowest demand days’ statistic summaries, NSW working days

	NSW Demand (MWh)	NSW Temperature (°C)
count	30.0	30.0
mean	203811.5	410.68
std	1297.0	33.54
min	199345.1	342.67
25%	203276.9	386.35
50%	204075.0	409.14
75%	204657.7	436.70
max	205361.7	476.20

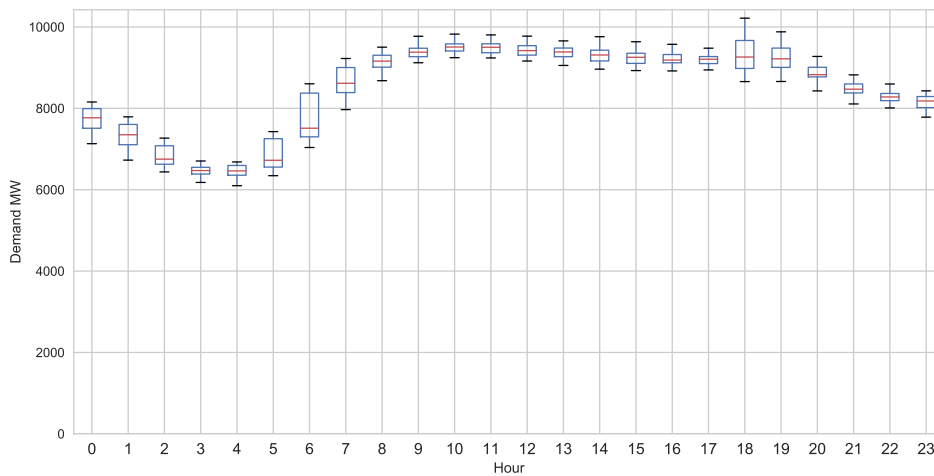


Figure 4.4: Boxplot of demand of each hour in the 30 lowest demand days, NSW working days

Figure 4.4 is the boxplot of the demand of each hour in these lowest demand

days, which also shows that the variance of demand in each hour is not large. The median value of the demand among the 30 lowest demand days is used as the typical day demand in a comfortable day when no heating or cooling demand is required (Equation 4.4b).

4.3.2 Heating and cooling thermostat temperature

Figure 4.5 is the boxplot of the temperature of each hour in the lowest demand days. The difference between the highest and lowest temperature at each hour during these days is around 8°C in the night time. The temperature range is slightly smaller during day time. The heating thermostat and cooling thermostat setting temperature at NSW given by NATHERS is around 18°C and 25.5°C , respectively (<http://www.nathers.gov.au>, but note the temperature range varies in regions). This fits the temperature range of the hours around 3pm.

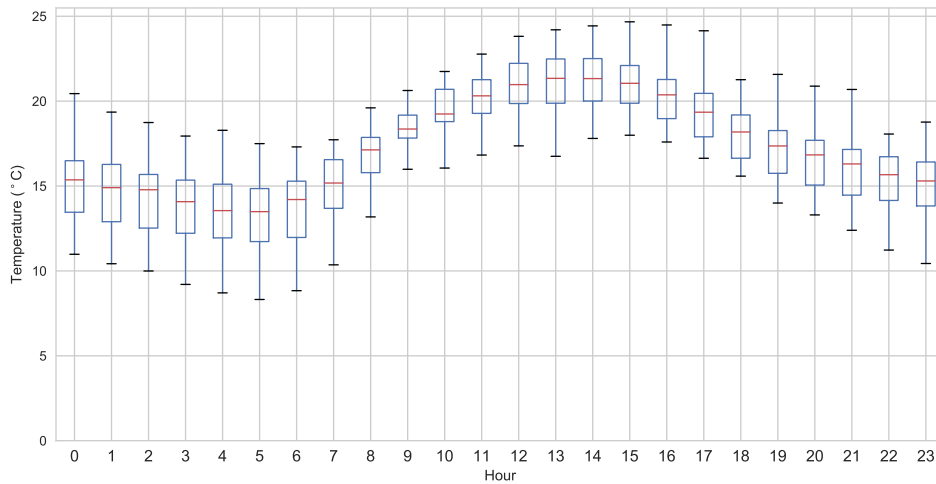


Figure 4.5: Boxplot of temperature of each hour in the 30 lowest demand days

Table 4.2: Thermostat temperature in NATHERS, NSW region

Hour	Heating thermostatTemperature $^{\circ}\text{C}$	Cooling thermostatTemperature $^{\circ}\text{C}$
00-07	15	25.5
07-09	18	25.5
09-16	20	25.5
16-24	18	25.5

We firstly use the maximum temperature among these 30 lowest demand days as the cooling thermostat temperature, while the minimum temperature among the

30 lowest demand days as the heating thermostat temperature for each hour, shown in Figure 4.6. However, when using this temperature setting to classify the demand into heating demand or cooling demand and then build the demand model for hot and cold hours, the modelled result is not fit well to historical demand and the coefficients of determination in the models are less than 0.3.

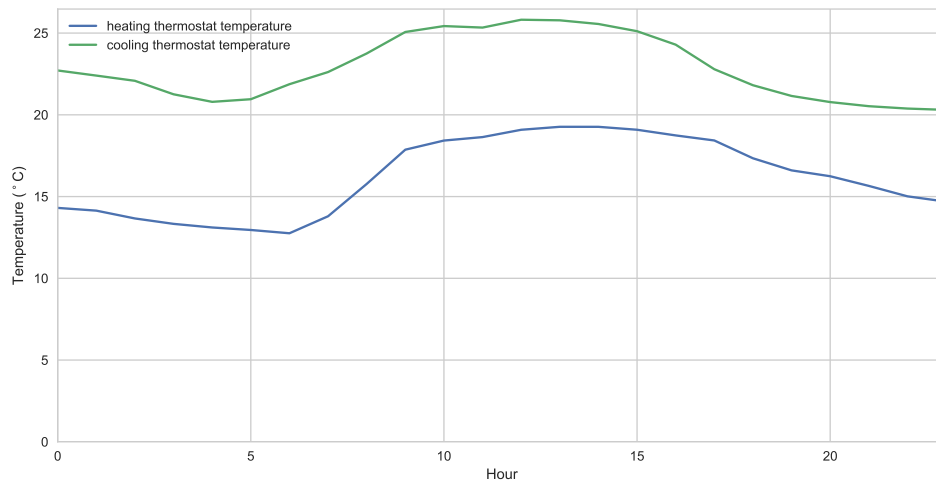


Figure 4.6: Cooling and heating thermostat temperature

Changing the thermostat temperature setting will result in different heating or cooling demand hours in the simulation year. The modelled result fits much better and the coefficients of determination in the models are larger than 0.3 if we use the thermostat temperature settings in Figure 4.7. This modified thermostat temperature setting is then chosen as our temperature setting for both working days and holidays in NSW region.

4.3.3 Social activity use pattern

The social activity use pattern is partly calculated from the baseload demand. The minimum weather independent hourly demand is around 6500 MW. Hence, the baseload is smaller than 6500 MW. A high baseload will result in a higher variation of the social activity use pattern. Examples of the social activity use pattern calculated with different baseload demand are shown in Figure 4.8.

We use OLS linear regression to find the correlation between the $U_h \times \Delta T_h$ and demand required for cooling or heating. Figure 4.9 is the OLS plotting when

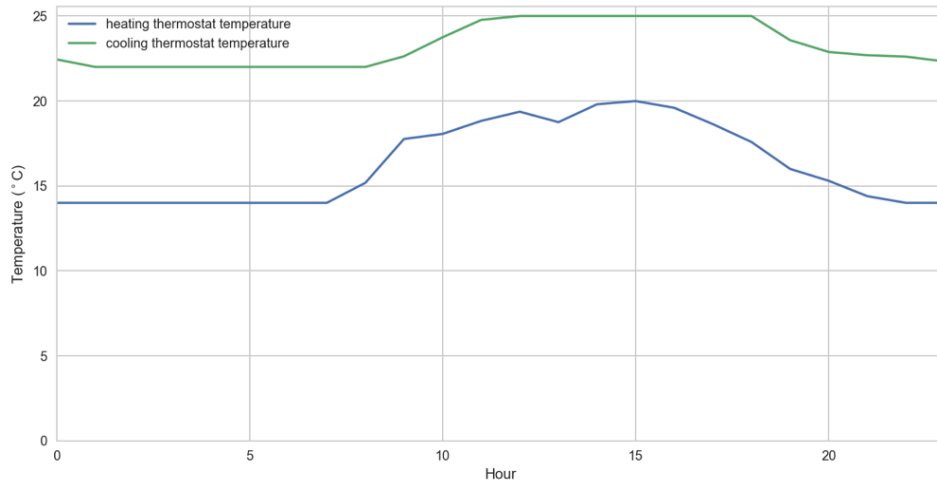


Figure 4.7: Final thermostat temperature used in NSW demand model

baseload is 3200 MW. This clearly shows that the heating or cooling demand is correlated with $U_h \times \Delta T_h$.

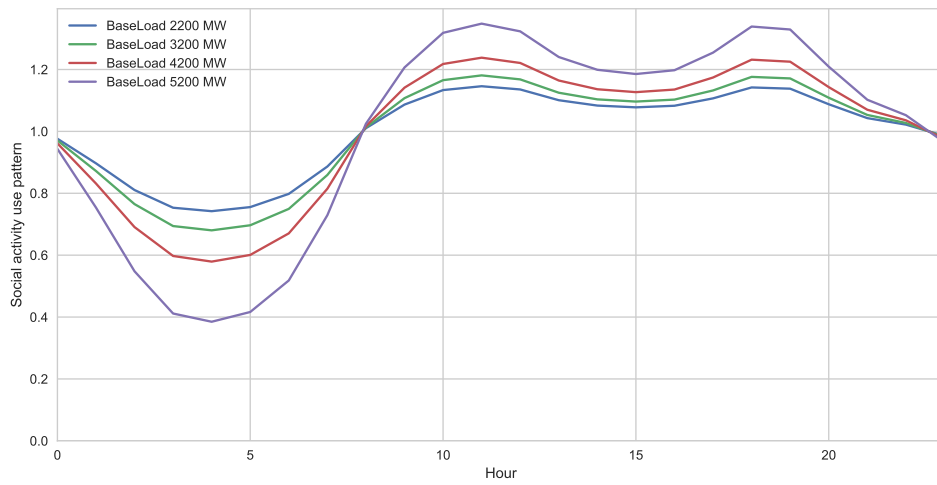


Figure 4.8: Use pattern and baseload

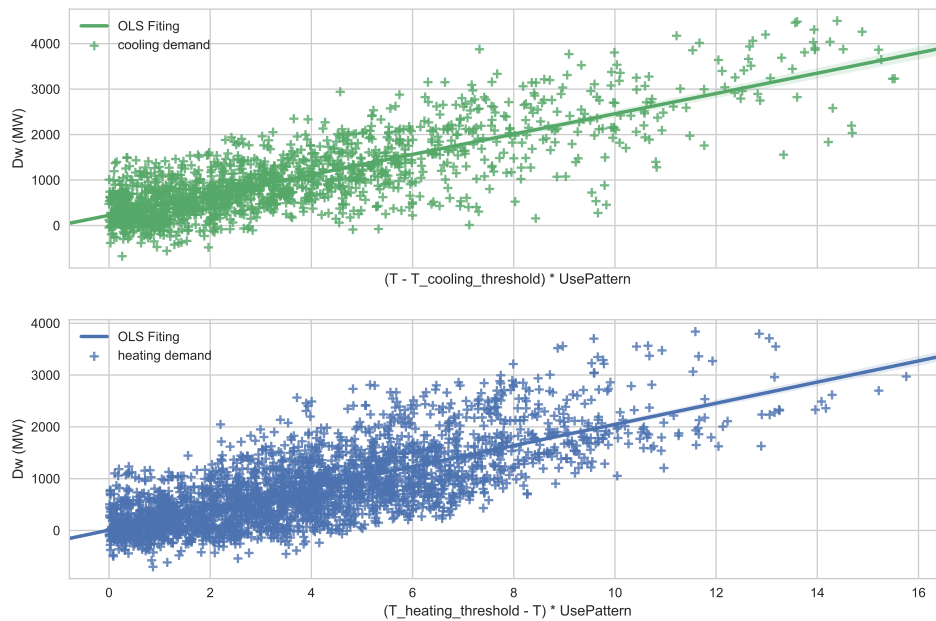


Figure 4.9: OLS modelling results (working days)

We test the different baseload from 400MW to 6400MW. For each baseload we test, the coefficient of determination of the model is calculated. The coefficient of determination of the model has maximum value when the baseload is 3200 MW. Thus, the baseload chosen for NSW demand model is 3200MW.

4.3.4 Holiday demand model

For the holiday demand model, we repeat the above steps used in the working day demand model. The holiday model uses the same thermostat temperature and baseload as the one used in the working day model. However, the temperature independent demand and social activity use pattern in the holiday model are different to the ones in the working day model.

Figure 4.10 shows the social activity use patterns of the working day and holiday model. Comparing these two curves, we noticed the following social behaviours, and these activity differences between working day and holiday are as expected:

- People get up and start their activities later in holidays.
- People have more activities in holiday nights.

- Fewer actives in holidays afternoon.

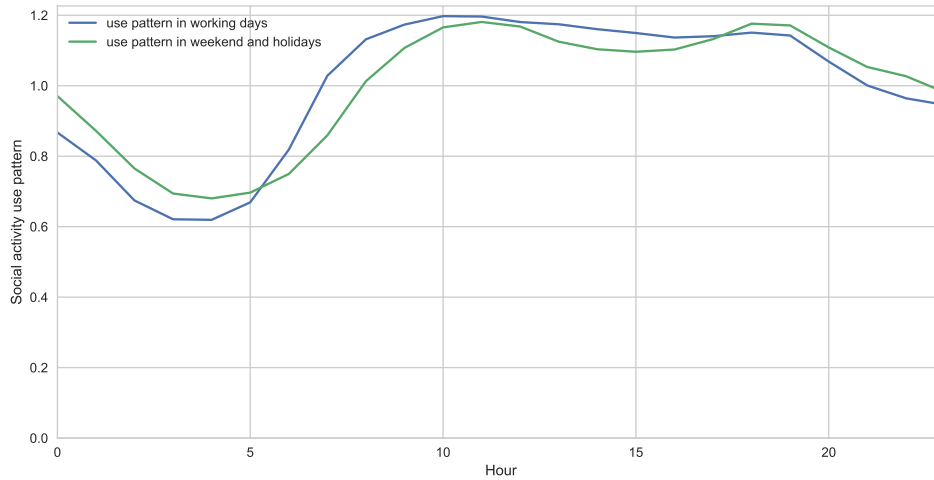


Figure 4.10: Social activity use pattern for working days and non-working days, NSW

4.3.5 Model result

Based on the thermostat temperature and use pattern discussed above, we use the linear regression to calculate the specific heat loss for heating and cooling (SHL_h and SHL_c). Table 4.3 shows the parameters given by the OLS calculation. The difference between specific heat loss for heating and cooling in working day model or holiday model is not large. This gives us confidence in our physical modelling.

Table 4.3: Space heating/cooling loss in NSW model

Variable	Unit	Value	
		Working day	Weekends and holidays
SHL_h	$MWh/^\circ C$	204.0	194.9
SHL_c	$MWh/^\circ C$	223.6	204.4
E_h	MWh	6.1	262.0
E_c	MWh	224.9	434.0

Figure 4.11 and Figure 4.12 are the plots of the historical and modelled demand in some summer days and winter days. For each figure:

- The top plot contains the modelled demand only (demand of the hours outside the threshold temperature, Equation 4.4a and 4.4c). The discontinue points indicated the temperature at that hour is between the heating and cooling threshold temperature.

- The middle plot contains the points in the top plot, and the demand in the hours when its temperature is within the threshold temperature range, which is filled with the D_{wi} (Equation 4.4b).
- The bottom plot is about the temperature data.

The modelled demand fits the historical demand well in both summer and winter night time. The modelled demand is slightly lower than the historical demand in some peak hours.

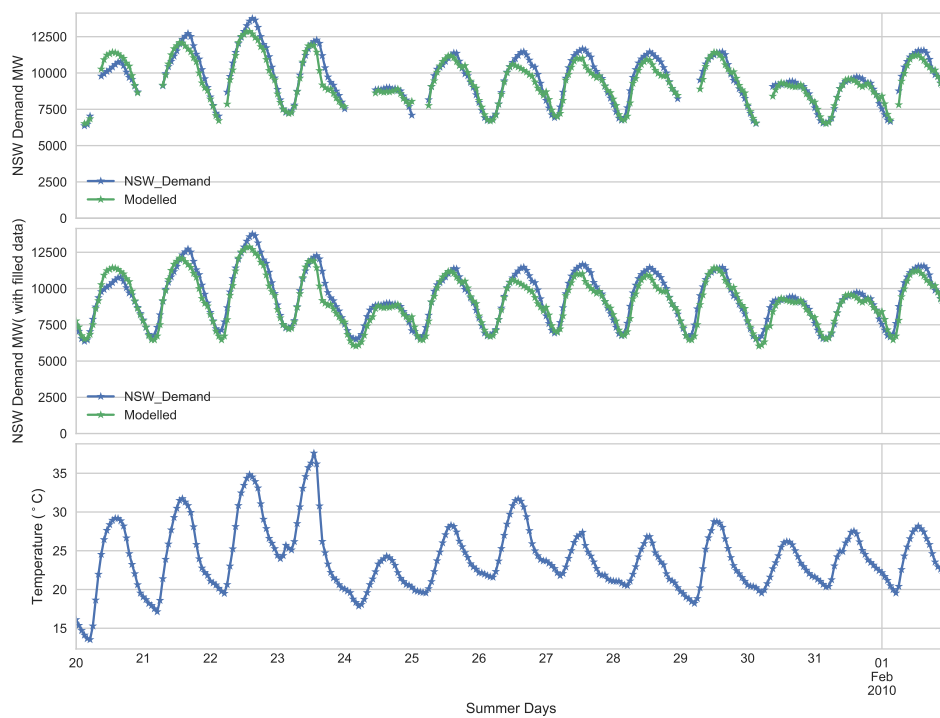


Figure 4.11: Modelled demand and historical demand of some summer days, NSW

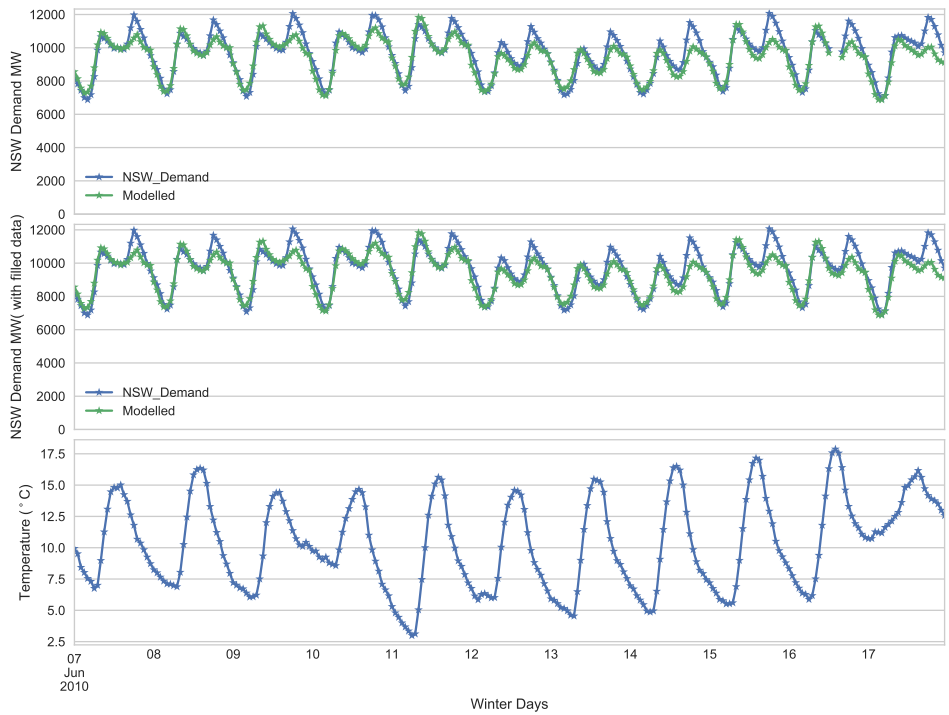


Figure 4.12: Modelled demand and historical demand of some winter days

Figure 4.13 is the histogram plot of the modelled error. The largest difference between the modelled result and historical demand is around 20% of the hourly demand, but there are only a few hours with a 20% error.

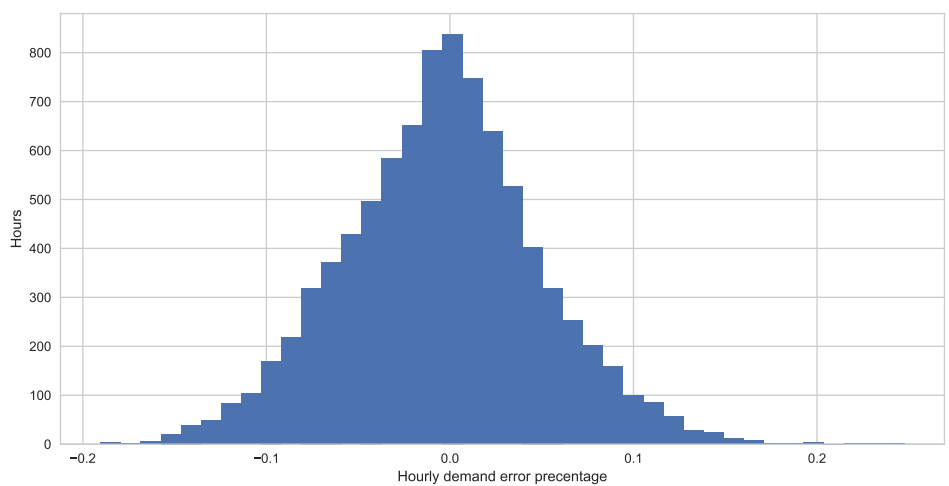


Figure 4.13: Histogram plot of error, NSW region

4.4 Demand model for other NEM regions

The following figures show the demand model results in other regions. The value of the specific heat loss for heating and cooling is given in a table at the end of this part.

4.4.1 Queensland demand model

In Queensland, the demand for space cooling is larger than the space heating. Figure 4.14 and Figure 4.15 shows the Queensland historical and modelled demand in some summer and winter days. The modelled summer demand is smaller than the historical ones in some peak hours. The modelled demand fits the historical demand better in the winter days.

Figure 4.16 is the histogram plots of the modelled error for Queensland model. In the most hours, the difference is between the historical and modelled demand is smaller than 10%.

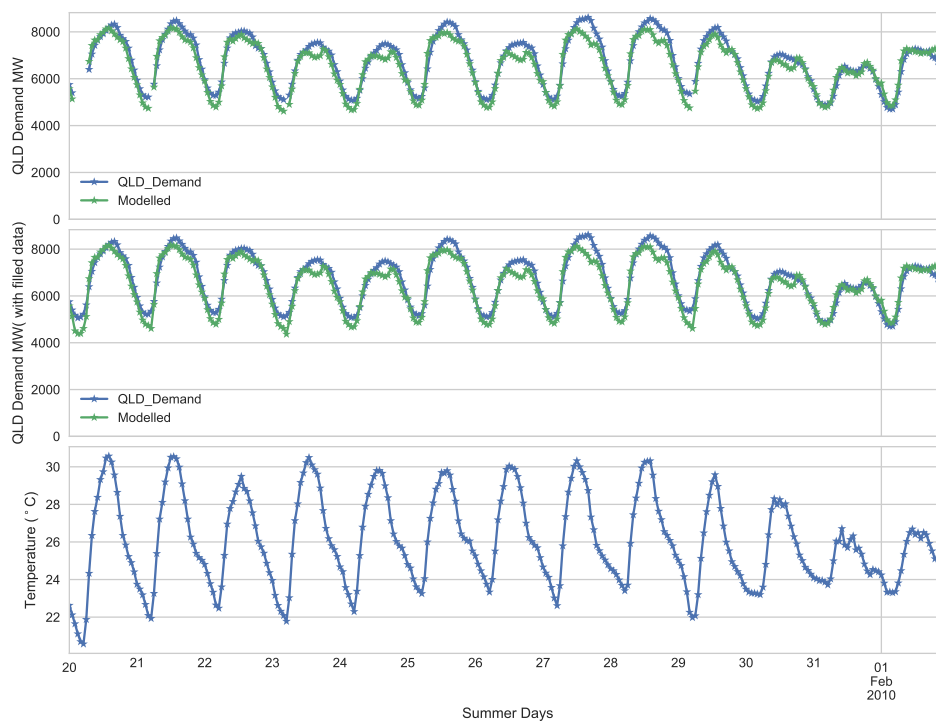


Figure 4.14: Modelled demand and historical demand of some summer days, QLD

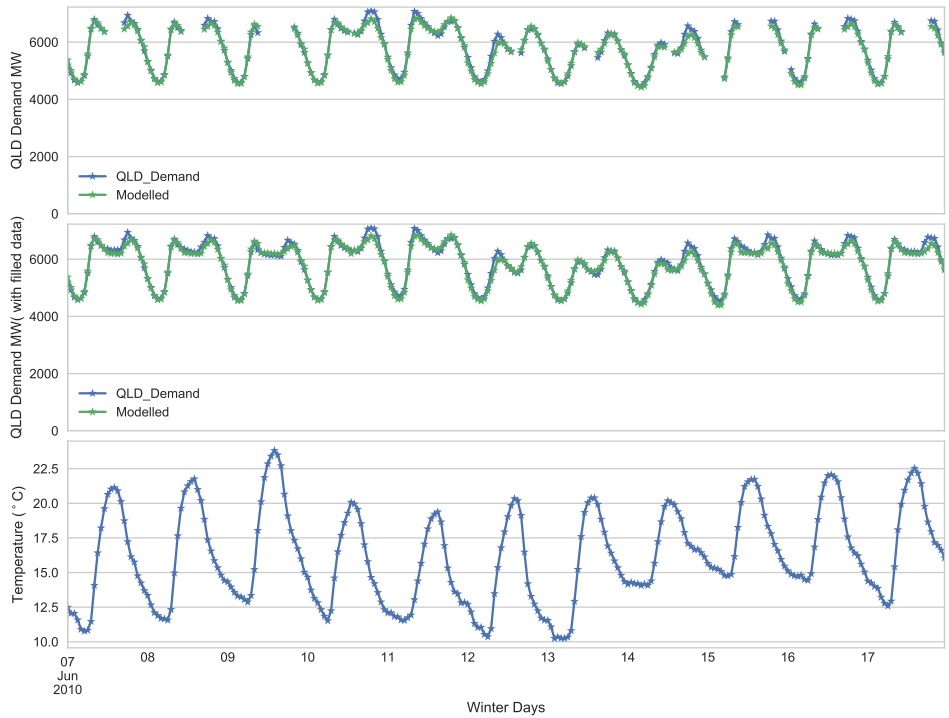


Figure 4.15: Modelled demand and historical demand of some winter QLD

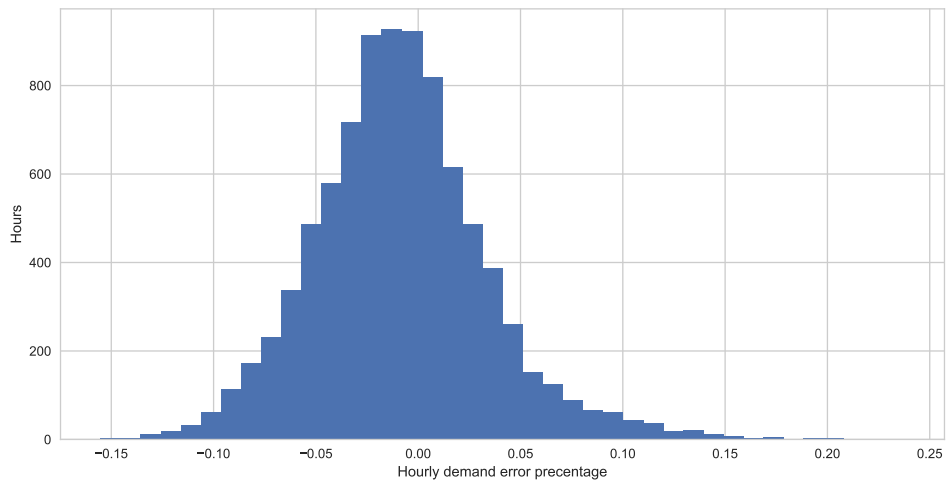


Figure 4.16: Histogram plot of error, QLD region

4.4.2 Victoria demand model

Figure 4.17 is the scatter plot of the daily temperature and demand in Victoria. There are some outliers on the hot weather days and they are excluded in the modelling data. Figure 4.18 and Figure 4.19 shows Victorian historical and modelled demand in some summer and winter days. Similar to the Queensland demand model result,

the modelled demand at some peak hours is less than the historical demand. Figure 4.20 is the histogram plot of the modelled error for the Victoria demand model. In most hours, the difference is between the historical and modelled demand is smaller than 15%.

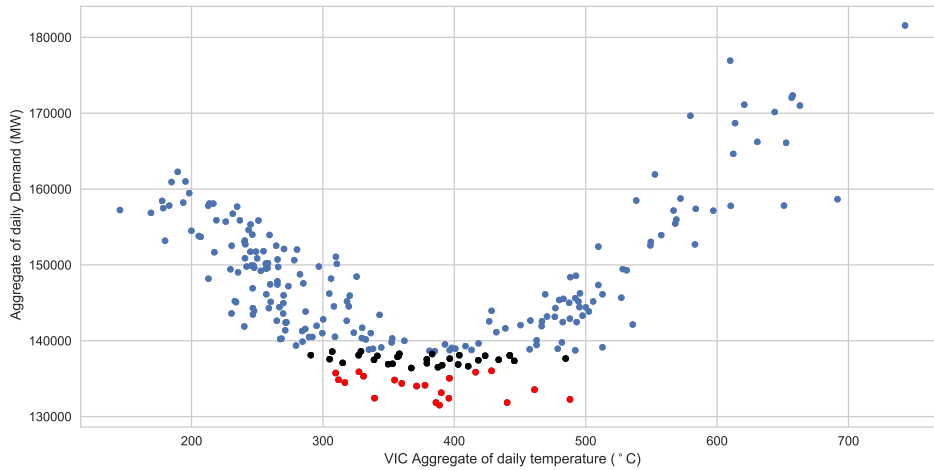


Figure 4.17: Scatter plot of daily temperature and daily demand, VIC working days

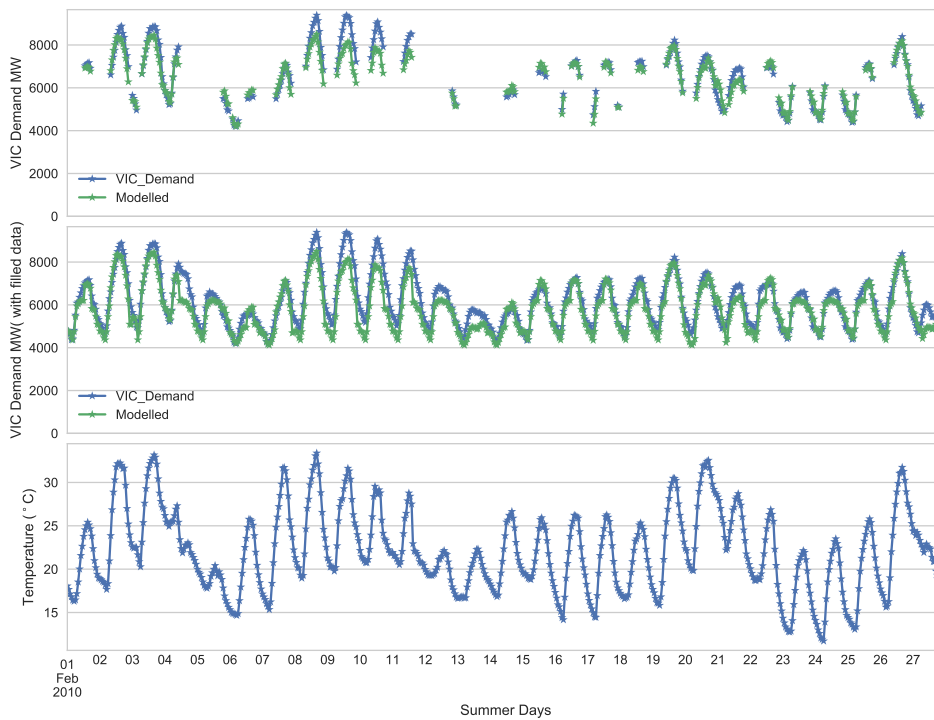


Figure 4.18: Modelled demand and historical demand of some summer days, VIC

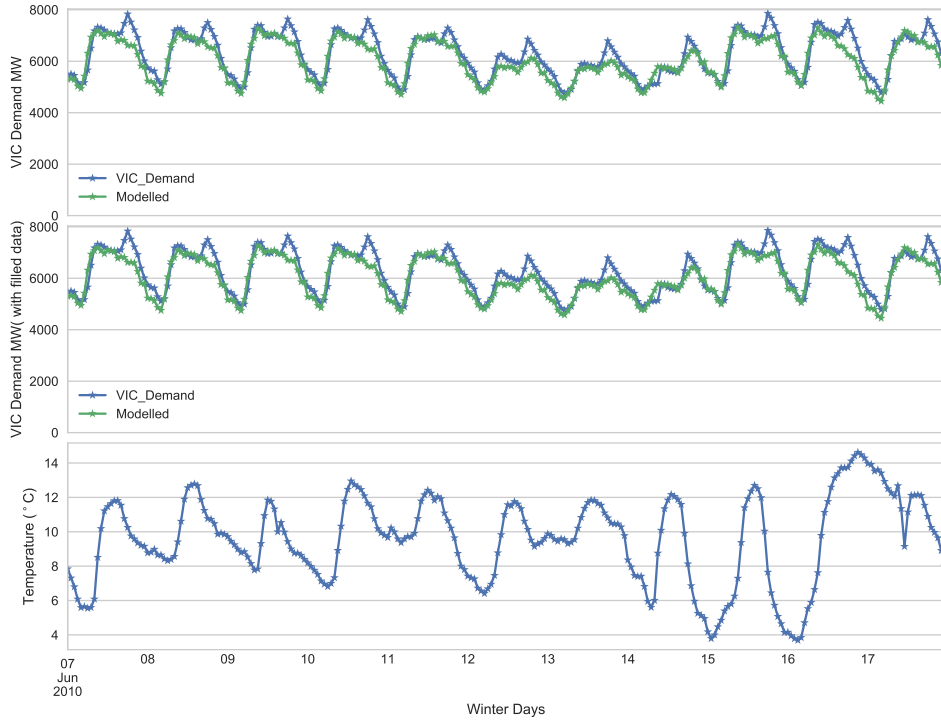


Figure 4.19: Modelled demand and historical demand of some winter VIC

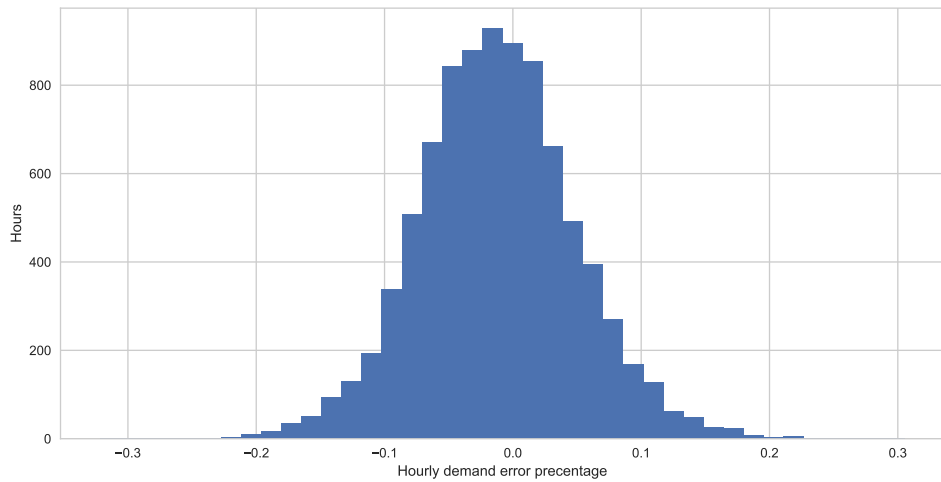


Figure 4.20: Histogram plot of error, QLD region

4.4.3 South Australia demand model

Figure 4.21 is the scatter plot of the daily temperature and demand in South Australia. Figure 4.22 and Figure 4.23 shows the South Australia historical and modelled demand on some summer and winter days. Similar as the demand model result in other regions, the modelled demand at some peak hour is less than then historical

demand. The model does not perform well in some holiday mornings during the winter. However, it generally gives a reasonable demand value at most modelled hours. Figure 4.24 is the histogram plot of the modelled error for the regional demand model. We noticed this modelled error is much larger compared with other regions. Given the SA demand share in the NEM regions is relatively small (6%), this error is not large and is deemed acceptable.

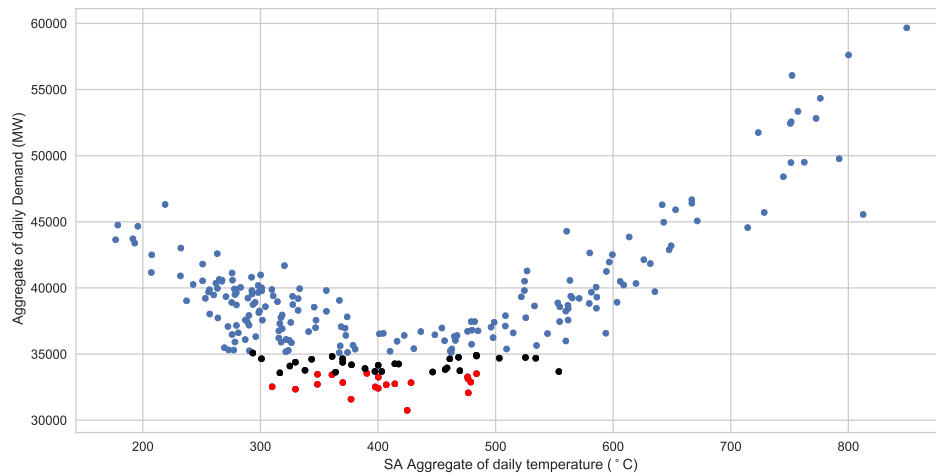


Figure 4.21: Scatter plot of daily temperature and daily demand, SA working days

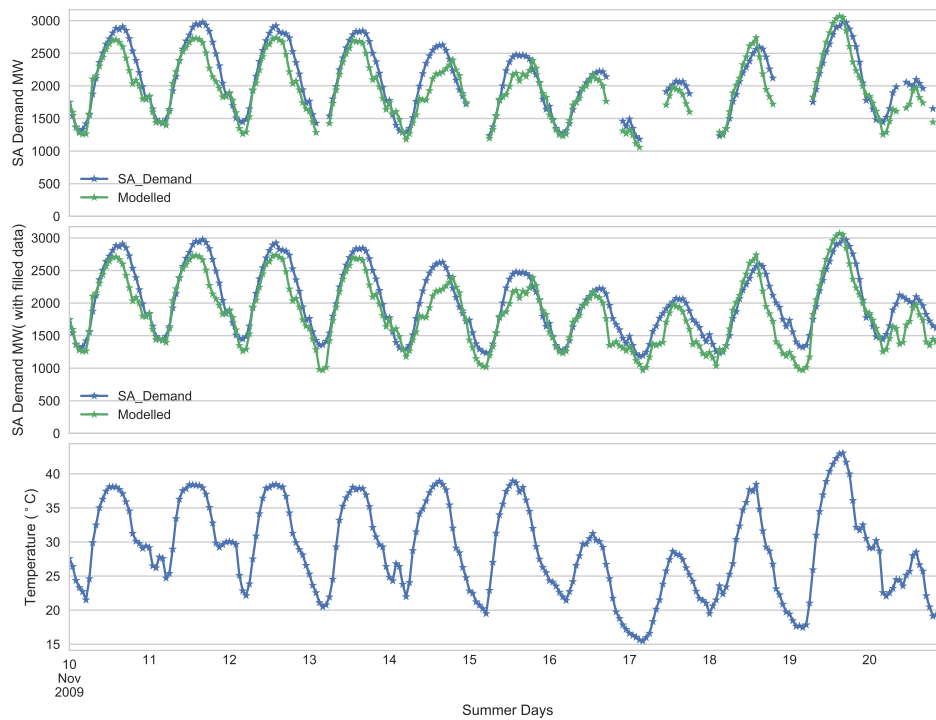


Figure 4.22: Modelled demand and historical demand of some summer days, SA

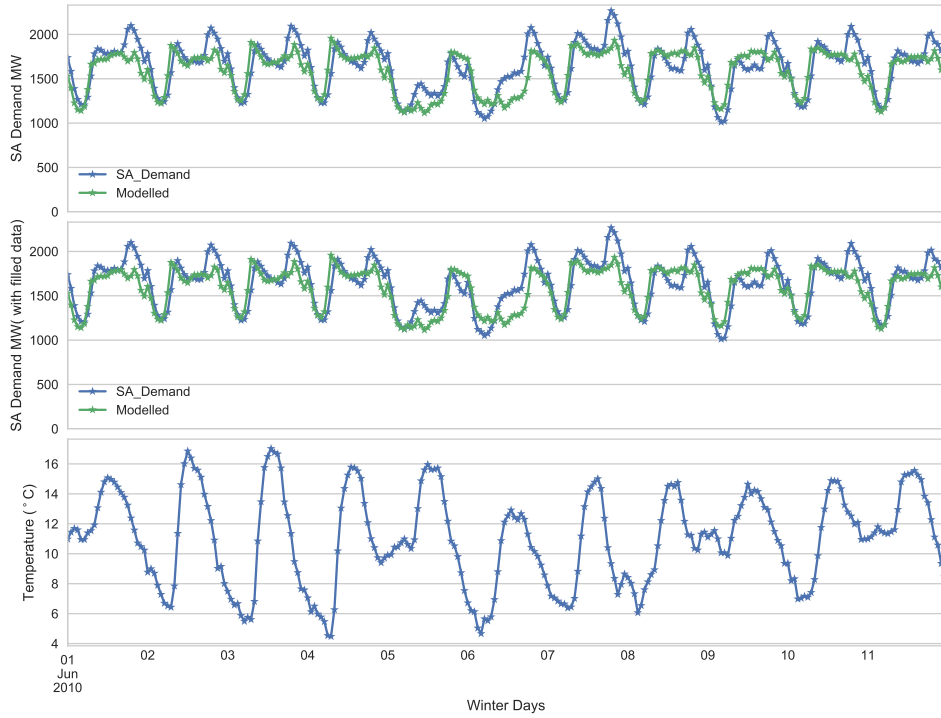


Figure 4.23: Modelled demand and historical demand of some winter SA

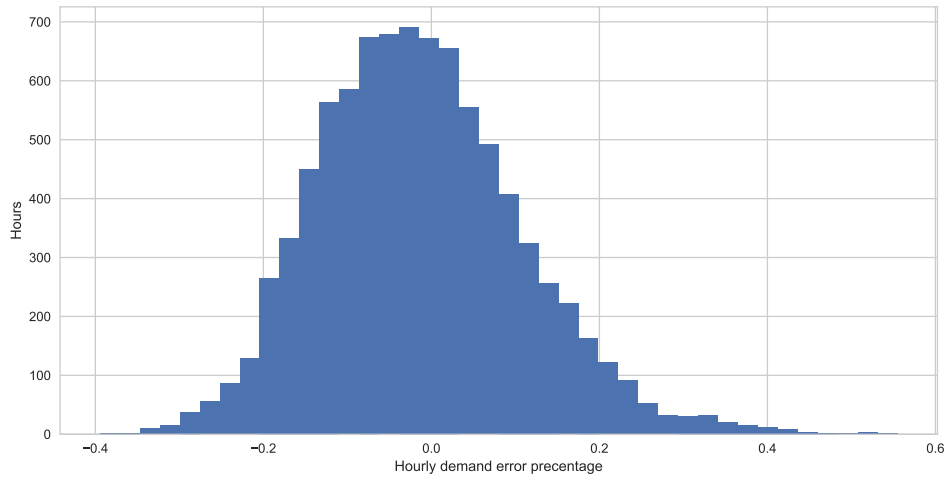


Figure 4.24: Histogram plot of error, SA region

4.4.4 Tasmania demand model

As shown in Figure 4.25, Tasmania has many cold days than hot days. There are only 24 hours when the air temperature is above than 25 °C. We ignore the cooling demand model for TAS and only consider the heating demand model.

Figure 4.26 and Figure 4.27 shows the Tasmania historical and modelled demand on some January and winter days. Similar to the demand model result in other regions, the modelled demand at some peak hour is less than then historical demand. Figure 4.28 is the histogram plots of the modelled error for the regional demand model. In the most hours, the difference is between the historical and modelled demand is smaller than 10%.

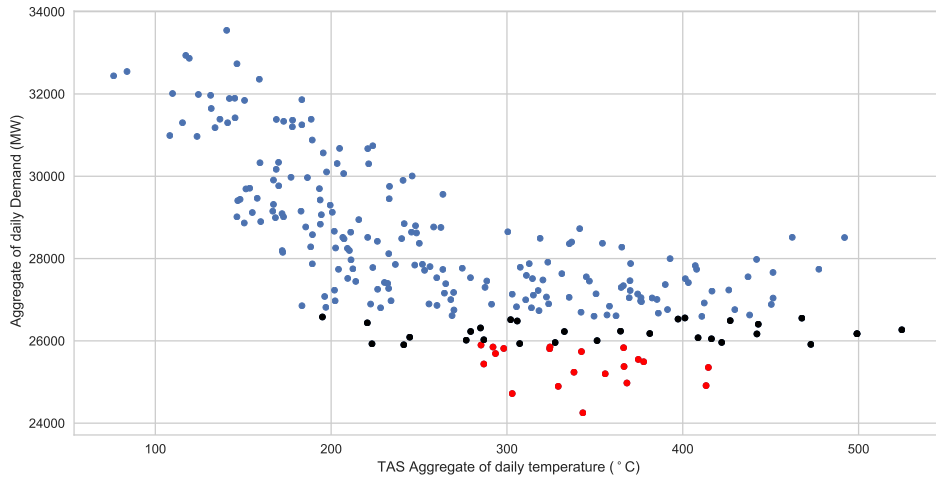


Figure 4.25: Scatter plot of daily temperature and daily demand, TAS working days

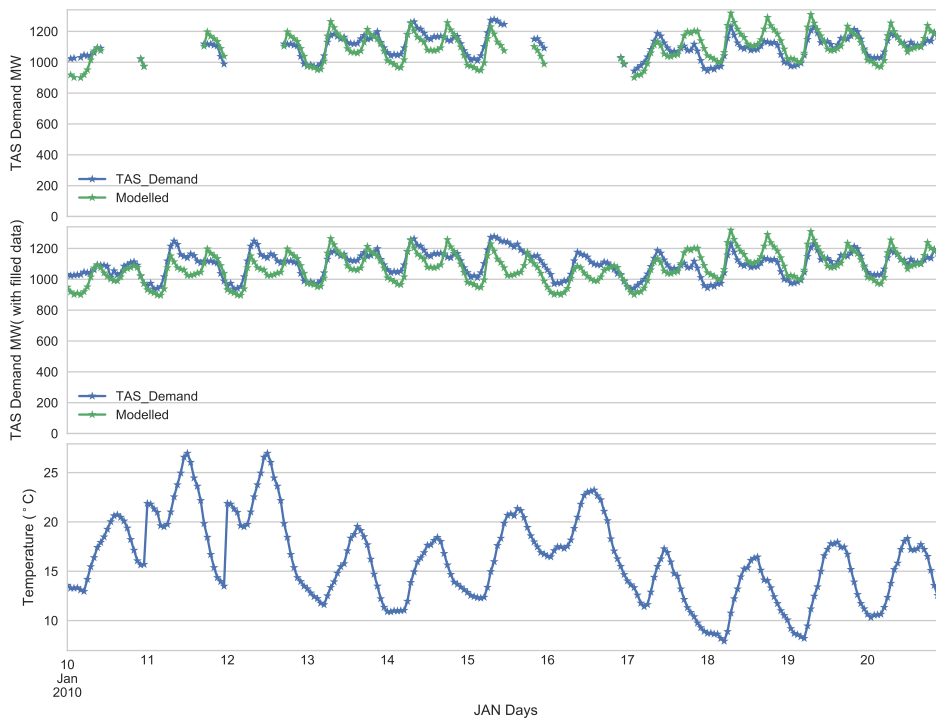


Figure 4.26: Modelled demand and historical demand of some summer days, TAS

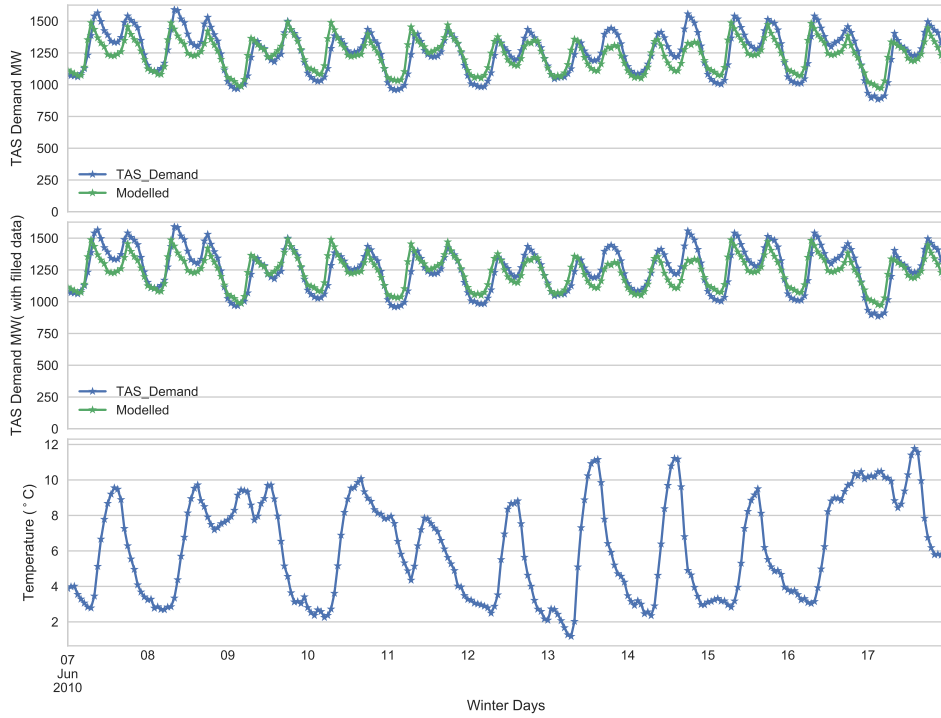


Figure 4.27: Modelled demand and historical demand of some winter TAS

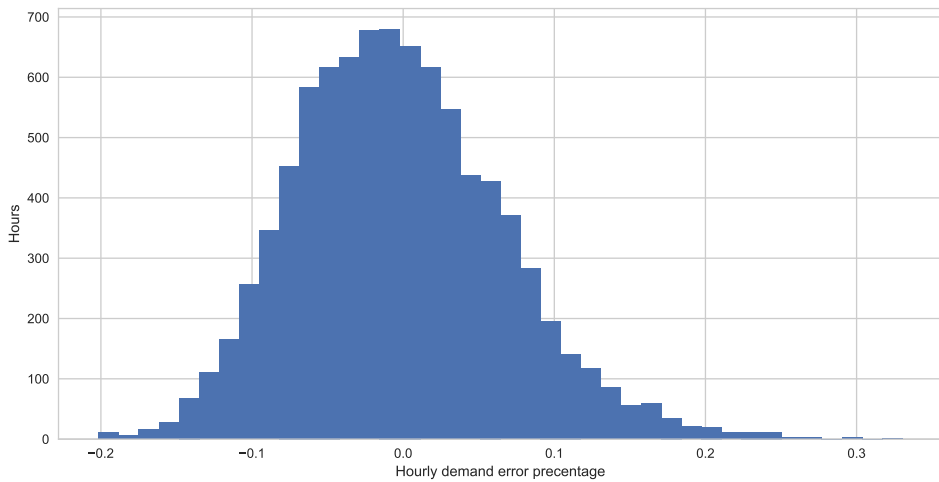


Figure 4.28: Histogram plot of error, TAS region

Table 4.4 shows the coefficient of the determination in our model, in most regions the R^2 for the cooling hours is larger than 0.6. The R^2 of the heating hours are lower. This may be due to the thermal mass of buildings is not included here, which will result a peak heat load might occur when heating the building in the winter night.

Table 4.4: Coefficient of Determination

	Cooling		Heating	
	Working day	Weekend	Working day	Weekend
NSW	0.64	0.60	0.55	0.51
QLD	0.62	0.43	0.42	0.42
VIC	0.62	0.64	0.41	0.50
SA	0.67	0.62	0.36	0.32
TAS	-	-	0.45	0.47

4.5 Summary of this chapter

When comparing the historical demand with the Plexos demand, we noticed that the Plexos based future demand became separated from meteorological data. This highlights the need to build a demand model for this study. A physical demand model which accounts for social activity, heating and cooling, as part of our DETRESO model. With this demand model, we can model future demands with assumptions about changes to these factors driving demand, such as heating and cooling, and account for the correlation of demand with renewables which critically determines optimal system configuration. The model might also be used to explore stress conditions such as very high or very low temperatures with low renewable output.

The demand model does not perfectly simulate historical data. Reasons for this might include:

- Use patterns may change across the days of the year, and be different for different sectors
- Morning internal dwelling temperatures may be lower than evening temperatures
- Solar gain as a driver of air conditioning is not included.
- The thermal mass of buildings is not included which will change the temporal profile of heating and cooling. For example: air conditioning peak may occur sometime after peak ambient temperature; a peak heat load might occur when heating the building fabric from cold.

- The heating and cooling systems controls may not depend so simply on instant ambient temperatures.

We note that the model tends to give low estimates for the early evening winter heating peaks; this may result from a combination of the above and other factors.

We note that the NEFR model does not explicitly include the factors listed above.

Although the modelled demand does not perfectly match the historical demand, we found that the modelled demand gives the similar optimized cost result when running with our supply side model, with less than 1% difference in system cost. This demand model is reasonably accurate for us to explore the system possibility of the future high renewable penetration system. To further improve the fit of the demand model is beyond the scope of this thesis.

Chapter 5

Supply Side Model

5.1 Introduction

This chapter describes the supply side model in DETRESO. The supply side model is made up of three modules: the dispatch module, transmission module and the optimization module. Renewable generation data and cost data are explained in this chapter. Model performance is also presented in this chapter.

5.2 Dispatch module

5.2.1 Generator technology and generation data

Power frequency control in power system operation is an important part in order to provide a safe, secure and reliable transmission of power. The system set frequency in the NEM is 50 Hz. In normal operation, the frequency must be in the range between 49.85 Hz and 50.15 Hz. The traditional power generators, such as coal-fired generators, gas-fired generators or hydro generators, can provide the automatic damping of any frequency deviations by automatically releasing or absorbing some stored rotational energy. However, solar PV and most wind turbines are the non-synchronous generators because of the process of their generation¹. The study in [42] suggests that synchronous generation should be at least 15 per cent of the total generation during any hour. Although this synchronous generation share is small,

¹There is some increasing discussion on the synchronous wind turbine design. However, most wind turbine used currently are non-synchronous. In this study, we assumed that the wind turbines considered in the generation mix are non- synchronous.

recent developments in frequency control technology are fast and it is possible to maintain the reliability of such a low synchronous frequency system. Similar to [42], the dispatch module considers implements this non-synchronous generation limit in the system. Since we assume that future interconnectors between Victoria and Tasmania will remain HVDC, there are two separate synchronous areas in the NEM: the mainland region (Queensland, New South Wales, Victoria, South Australia) and the Tasmania region.

The synchronous technologies in this study are biomass, CST, pumped hydro and run-of-river hydro, and biogas using OCGT. The non-synchronous technologies are solar PV, onshore and offshore wind and electricity battery. The following gives the details of modelling data and assumptions used in these technologies.

- PV and wind

The hourly generation of wind farms and solar PV is dependent on the wind speed or Global Horizontal Irradiance (GHI) and Direct Normal Irradiance (DNI) resource at the location and the capacity and efficiency of the generators. The AEMO 100 per cent renewable study provides hourly generation traces of 1 MW wind and single-axis tracking solar PV from 2004 to 2010 at sub-region spatial resolution using historical weather data from the Australian Bureau of Meteorology (BOM). The 43 locational polygons are sub-regions of the five NEM regions and provide geographical diversity in resource quality and quantity. Details about the data can be found in [114]. A scale factor of 0.95 is applied to hourly wind generation for consideration of the turbine unavailability and wake effects [114].

Since the spatial resolution of the model used here is at state level, we use the average hourly renewable generation across the polygons for each state. The existing wind farm capacity and solar farm capacity in each region is set as the lower bound in the optimization model. A derating of 6.5% is included for solar PV outage and panel efficiency over its lifetime [42].

Table 5.1 lists the mean capacity factors of solar PV, onshore and offshore wind in the NEM regions during the 2009-10 financial year. The capacity factor of PV ranges from 0.30 to 0.35. South Australia and Queensland are the regions with

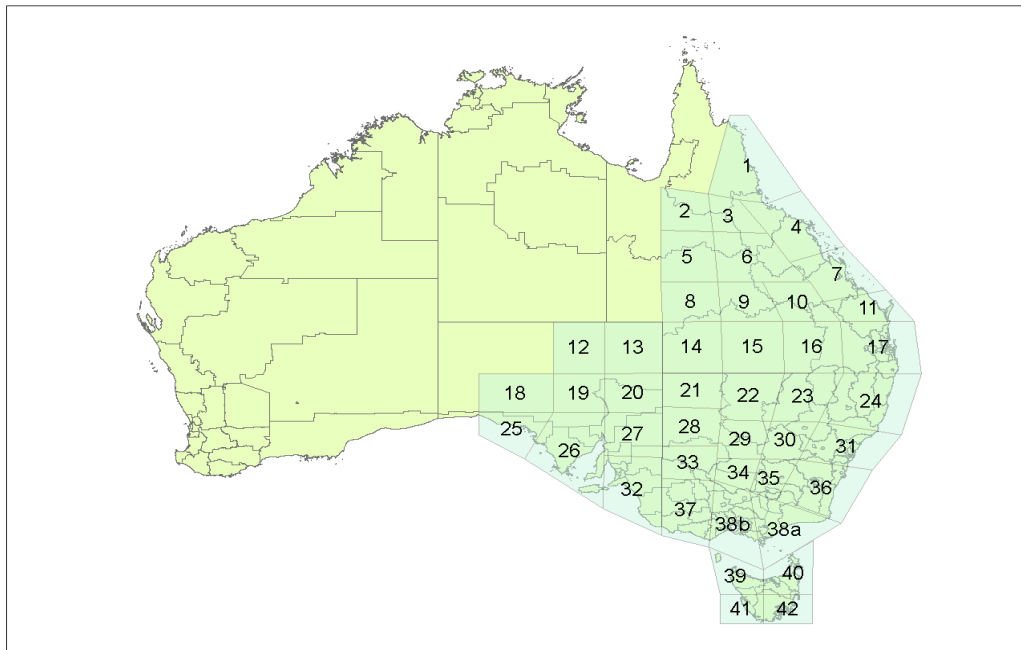


Figure 5.1: Polygons used in AMEO 100 per cent renewable study, source: [114]

the highest capacity factor, while Tasmania has the lowest solar resources. There is not much difference in the onshore wind capacity across the five regions. All the onshore wind capacities are around 0.37. The offshore wind has the highest capacity factor compared with solar PV and offshore wind.

Table 5.1: Mean capacity factor of PV and Wind in different regions in 2009-10 financial year

	QLD	NSW	VIC	TAS	SA
PV	0.34	0.33	0.31	0.30	0.35
Onshore Wind	0.37	0.37	0.38	0.38	0.38
Offshore Wind	0.51	0.52	0.52	0.56	0.52

Figure 5.2 and 5.3 show the monthly mean capacity factor of solar PV and onshore wind in the five NEM regions during the 2009-10 financial year. As Australia is in the southern hemisphere, the summer season in Australia is December, January and February. The solar resource quality is superior in these months. The poorest months of solar resource quality are June, July and August, which are the winter months in Australia. The best wind resource quality month in Australia is August, while the summer months have poorer quality. We noticed that these ca-

capacity factors are higher than other studies, the accuracy of these capacity factors are discussed in the AEMO report and they are in line with the historical observed values [114].

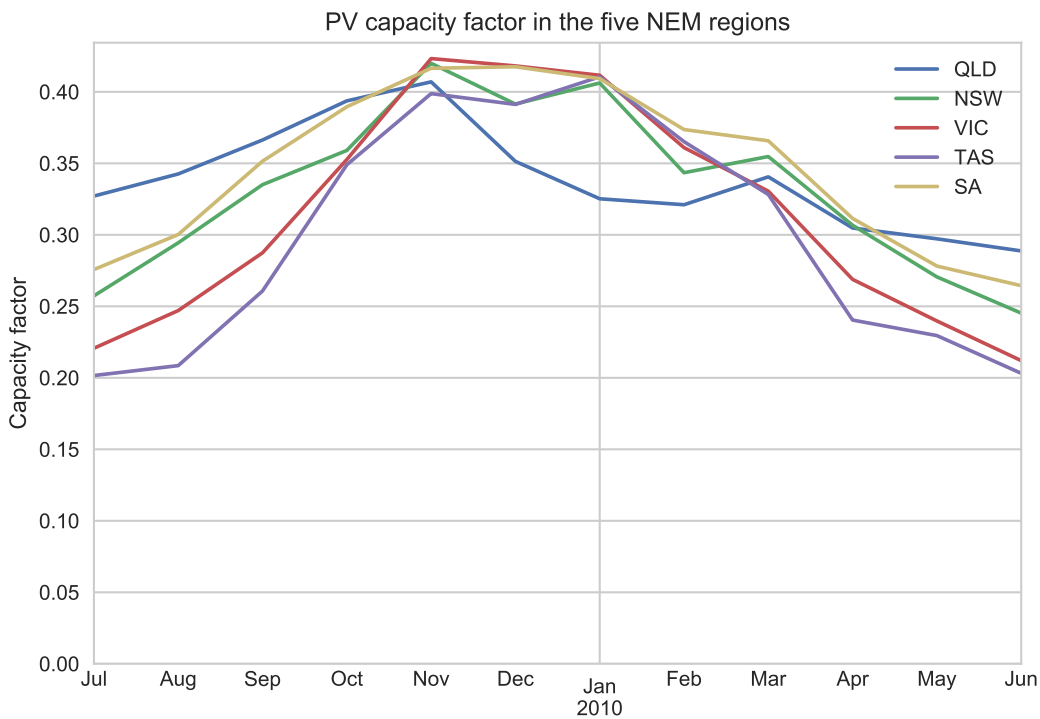


Figure 5.2: Monthly mean capacity factor of PV in the five NEM region, 2009-10 financial year, data source:[114]

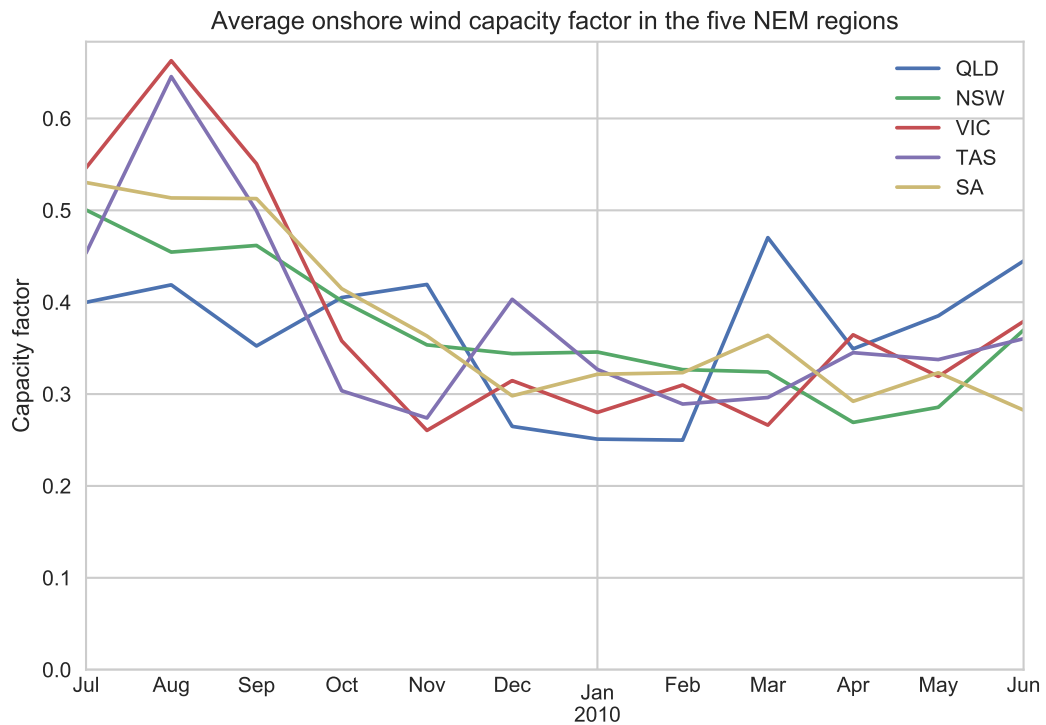


Figure 5.3: Monthly mean capacity factor of onshore wind in the five NEM region, 2009-10 financial year, data source:[114]

The available generation from the PV, onshore or offshore wind are calculated from the following equations:

$$E_{Tech,h,region} = ReferenceE_{Tech,h,region} \times Capacity_{Tech}/100 \quad (5.1)$$

where $ReferenceE_{Tech,h,region}$ is the average generation of the 100 MW plant of the technology hour h in the region, given by the AEMO 100 per cent study report;

$Tech$ is for PV, onshore or offshore wind;

$Capacity_{Tech}$ is the capacity of the simulated plant.

- CST

CST can provide synchronous generation to the system and it can generate electricity after sunset using thermal energy collected during the daytime. There are three principal parameters when designing a CST plant: capacity, solar multiple and the storage size.

The capacity refers the maximum power it can deliver. The output power of a CST plant also depends on the thermal energy it collects using mirrors or stores in the tanks at that time.

The solar multiple refers to the areas of mirrors equipped with the CST plant as a function of the plant capacity [115]. A CST plant with solar multiple 1.0 means that the areas of mirrors could collect enough thermal energy to support the plant generation at rated capacity under perfect solar insolation. A reference value for the perfect solar insolation is 1000 W/m^2 , but this value varies between 850 to 1150 W/m^2 , in different designs. While perfect solar insolation is not a normal condition in most days, most CST plants have a solar multiple larger than 1.0 in order to increase the amount of collected energy for power generation when the solar insolation is lower. Figure 5.4 shows the relationship between the solar multiple and annual capacity factor of a CST plant in a good solar resource region. A higher solar multiple could improve the plant annual capacity factor but will lead to surplus solar energy collection during the days with good direct normal insolation condition. A higher solar multiple increases the system capital cost but may reduce overall net capital and operational costs. The optimal solar multiple for a CST plant is a trade-off between the plant cost and the system capacity factor.

The storage size for a CST plant is normally measured in hours of full load operation. For example, a 1 GW CST plant with 9 hours' storage means the system has a 9 GWh energy storage. A CST plant with longer hours storage typically comes with a larger solar multiple in order to collect enough energy in the thermal tanks during daylight hours.

The AEMO 100 per cent renewable study also provides generation data of the 100 MW CST plant with 1.0 solar multiple in the 43 locational polygons. Similar with the solar PV and wind generation data, the CST generation hourly traces are calculated based on historical weather station data obtained from the Bureau of Meteorology. In the CST generation data, a constant derating of 3% (2%-5% is the typical range) was assumed due to outages, in addition to a derating due to degradation over time. The latter is lower for CST than for solar PV and 2% has

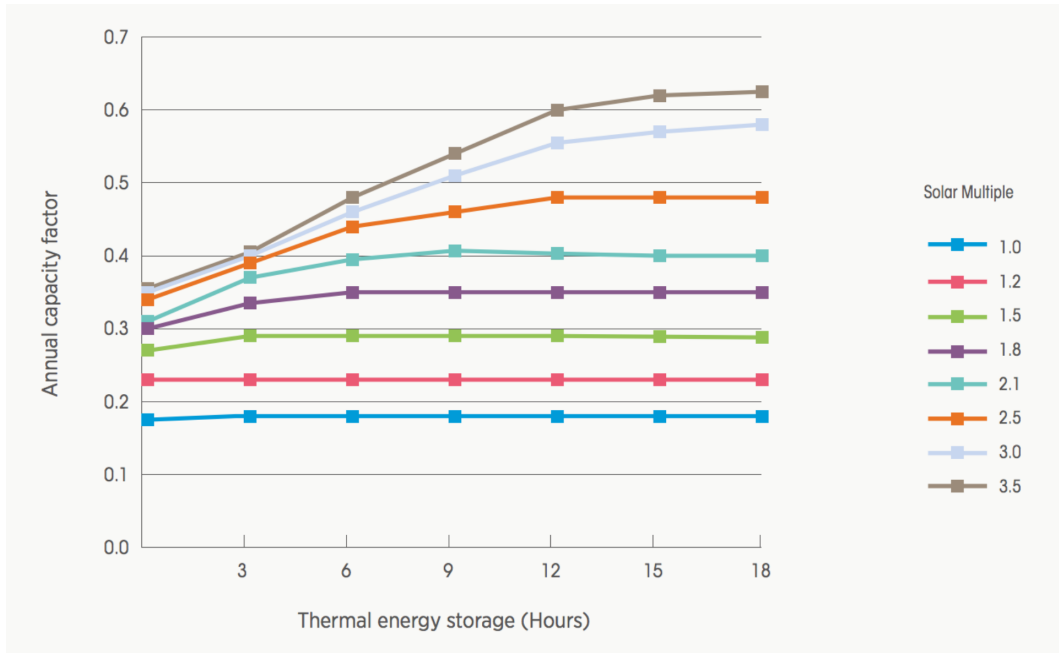


Figure 5.4: CST capacity and solar multiple, source:[115]

been assumed across the installed CST capacity. The ‘as-generated’ output was converted to ‘sent-out’ by applying a 7% derating to account for auxiliary load. The total derating of collected energy is 12% while the derating of available generation capacity is 3% [42].

There are three types of CST with storage configurations considered in this study: six, nine and twelve hours of storage. The solar multiple for the six, nine and twelve hours of storage CST is 2.36, 2.53 and 2.95 respectively. The solar multiples for the CST plants are suggested from [116]. The available electricity generated by CST plant with a specific solar multiple in a simulation hour can be calculated by the following equations:

$$E_{Tech,h,region} = ReferenceE_{Tech,h,region} \times SM_{tech} \times Capacity_{tech}/100 \quad (5.2)$$

where $ReferenceE_{Tech,h,region}$ is the generation of the 100 MW CST plant with 1.0 solar multiple at hour h , given by the AEMO 100 per cent study report;

SM_{tech} is the solar multiple of the simulated CST plant.

When simulating the CST, we assume the initial thermal storage at the start of simulation time is half of its maximum storage. Also, if the energy collected from solar fields exceeds the storage size, the excess amount of energy will be spilled.

$$S_{tech,h} = \min(S_{tech,h-1} + E_{tech,h}, Storage_{tech}) \quad (5.3)$$

where the $S_{tech,h}$ is the amount of energy stored in the CST plant at hour h ;

$S_{tech,h-1}$ is the stored energy in the previous hour;

$Storage_{tech}$ is the storages size (MWh) of the CST.

The available sent-out power is the minimum value of the CST power and its stored energy:

$$P_{tech,h} = \min(S_{tech}, Storage_{tech}) \quad (5.4)$$

where the $P_{tech,h}$ is the available sent-out power of the CST at hour h .

- Batteries

Batteries are also considered in our study. The cost of alternative types of battery technologies based on different chemistries is shown in Table 5.2. Based on the cost we choose lithium-ion (Li-Ion) battery with 0.9 round trip efficiency since it has the cheapest base case cost in 2030.

Table 5.2: Batteries cost in 2030 value, source:[117]

Battery type	Minimum (\$/MWh)	Base case (\$/MWh)	Maximum (\$/MWh)	Round trip efficiency
Li-ion	152.7	196.8	279.2	0.9
Zinc bromide	113.9	209.2	353.4	0.75
Advanced lead acid	258.5	317.1	496.8	0.9
Molten salt	155.2	264.2	415.4	0.85

A simplified battery model is used in this study. We consider its rated output/input, rated power (MW , $Capacity_{tech}$), rated energy could be stored size (MWh , $Storage_{tech}$) and we track the stored energy (MWh , $S_{tech,h}$) in the battery at each hour. The electricity stored in the battery at a given hour is given by the following

equation:

$$\begin{aligned} \text{Charging Hour : } S_{tech,h} &= \min(S_{tech,h-1} + Charge_h * RET_{tech}, Storage_{tech}) \\ \text{Discharging Hour : } S_{tech,h} &= S_{tech,h-1} - Discharge_h \end{aligned} \quad (5.5)$$

where the RET_{tech} is the round-trip efficiency of the battery;

the $Discharge_h$ is the energy sent out from the battery;

the $Charge_h$ is the amount of input energy to charge the battery.

The available sent-out power of a battery at a certain hour is the minimum value of its rating power and stored energy at that hour given in the following equation, as for the CST technology:

$$Discharge_h = \min(S_{tech,h}, Capacity_{tech}) \quad (5.6)$$

- Pumped Hydro and run-of-river hydro

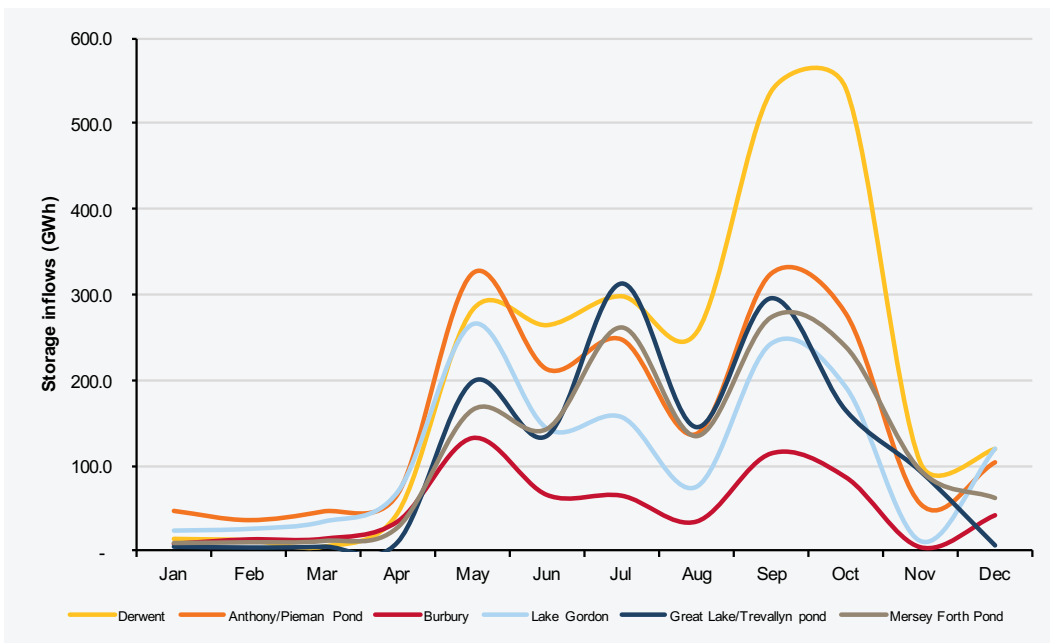
Both pumped storage and run-of-river hydro can provide synchronous electricity to the system, which is critically important for frequency control of the power system [118]. Tasmania and the Snowy Mountain region in NSW and Victoria have rich hydro resources, most of these resources have already exploited. There are some potential sites that could be used to build new hydro stations in these regions but greenfield sites have long construction times and face environmental challenges. Other regions in Australia lack quality sites. For this reason, only the existing hydro stations are considered and we do not propose any expansion of hydro capacity in the NEM. The run-of-river and pumped storage hydro capacity data are obtained from the Australian Energy Market Operator (AEMO) data published in 2016 [106] and [114]. Table 5.3 shows the capacity of the hydro stations used in this model, which might be different in other studies. This may due to part of the Snowy Mountain hydro stations is located in New South Wales region and the other part is in Victoria.

The hydro inflows vary in locations, month and year. This study applied the monthly water inflow data in 2010 and initial storage levels at the beginning of

Table 5.3: Capacity of hydro stations

	QLD	NSW	VIC	SA	TAS
Run-of-river hydro capacity MW	152	2285	2192	-	2238
Run-of-river hydro annual inflow GWh	707.7	5002.3	504.6	-	9098.8
Pumped Hydro capacity MW	500	840	-	-	-
Pumped Hydro storage MWh	5000	11490	-	-	-

2010 to the run-of-river hydro generators. The hydro data in 2010 are chosen here because of its data availability. Besides, this year can be considered as a typical year with the average water inflow conditions [119]. Figure 5.5 shows the hydro inflow of Tasmania hydro station as an example.

**Figure 5.5:** Hydro inflows of Tasmania run-of-river hydro, source:[119]

For pumped hydro, we assume the initial storage at the beginning of the simulation time is half of its maximum storage. The pumped hydro can be charged when surplus energy is available with a roundtrip efficiency of 80%. This efficiency is slightly higher than the study in [42] but it could be modified easily. The charging and discharging equations of the pumped hydro are the same as the ones used in the battery modelling.

- Biomass and biogas

Consistent with [42], two biomass electricity generation technologies are considered in the model: biomass from wood waste, and biogas-fired OCGTs. Similar to conventional thermal generators, biomass wood is modelled as a base-load generator (able to generate 80% of its capacity at any hour, and the hourly generation could be up to the installed capacity if needed). Biogas-fired OCGT is modelled as a peak-load generator that can ramp to full capacity within the time interval; this utilizes the integral storage of biomass for system management. The maximum allowed capacity of biogas for each region is 2 GW [42]. The total generation of biogas generators is limited to 5 TWh/yr.

5.2.2 Dispatch process

The real-time dispatch algorithm used in the NEM is based on the power demand and the bid price stack of all generating units. The model here does not simulate the bid stack for each generator since this is not publicly available data and would increase the computational requirement. Thus, we use a simplified dispatch module based on priority dispatch of the nearest available renewable generation. There are three stages in the dispatch module. The first is to meet the synchronous demand in the two synchronous areas. The second is meet the remaining demand in the NEM regions. The third is the charging of storage devices if possible.

In the first stage, the process will dispatch the generation from synchronous generators with a priority sequence to meet the minimum mainland and Tasmania synchronous demand. The sequence is biomass base-load component (80% of its rating capacity), CST generation, hydro generation and biogas generation. Since we assume that future interconnectors between Victoria and Tasmania will remain HVDC, there are two separate synchronous areas in the NEM: The mainland region (Queensland, New South Wales, Victoria, South Australia) and the Tasmania region. At this stage, electricity can be only exchanged within the mainland area, but not with Tasmania. The synchronous demand in each area is 15% of the total demand within the area. Figure 5.6 is the flowchart of the first stage.

In the second stage, five dispatch generation groups are set: 1) baseload biomass, solar PV, on-shore and off-shore wind; 2) CST; 3) pumped hydro and

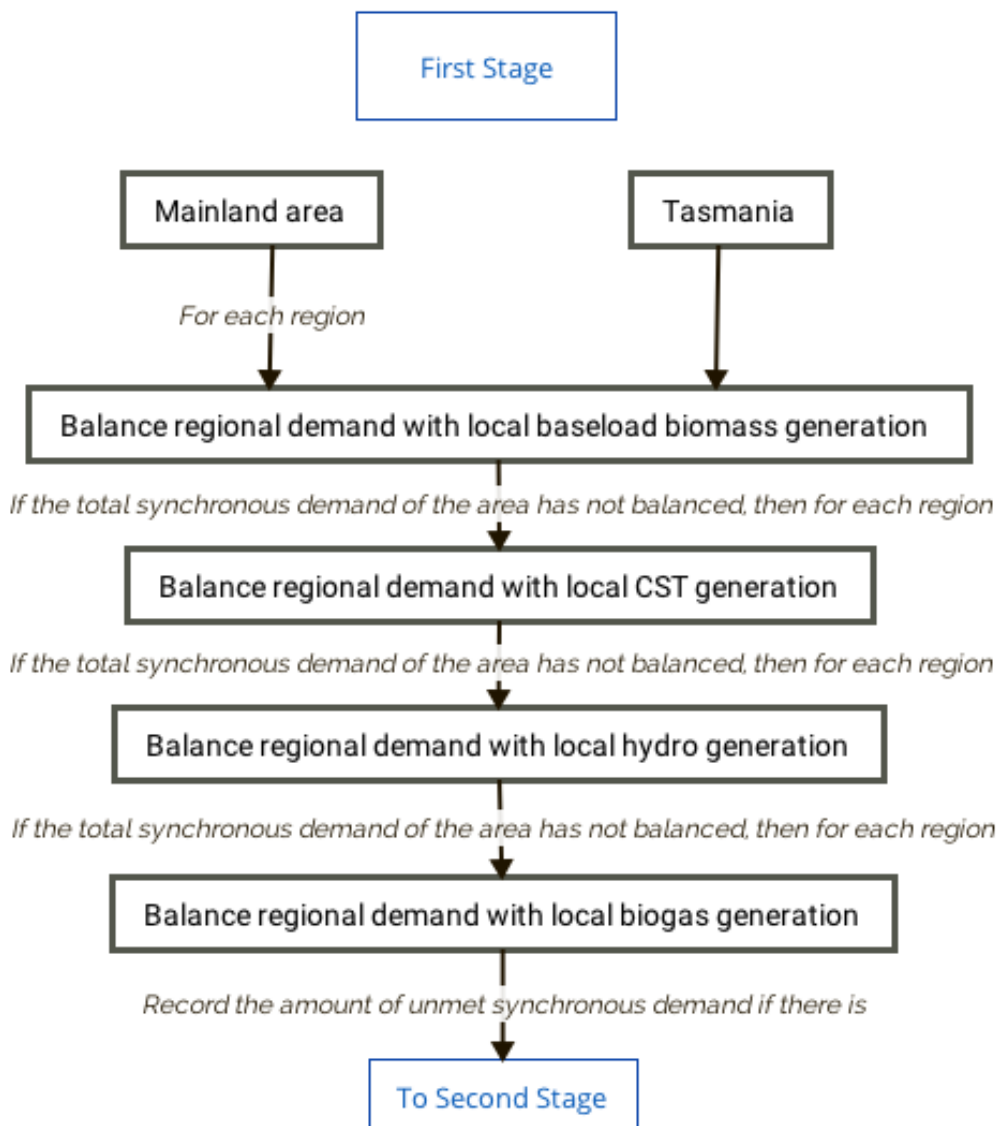


Figure 5.6: Dispatch process flowchart, first stage

battery devices; 4) run-of-river hydro; 5) peak-load biogas using OCGT and peak biomass component (20% of its rating capacity). The remaining demand will be met by its local or regional generation based on the sequence of each generation group. That is, local (within the region) generation from each generation group is dispatched first to meet demand. If demand cannot be met by local generation, then the regional generation from each generation group will be imported subject to interconnector capacity. At the end of each dispatch generation group, the model checks for surplus or deficit. The deficit regions are balanced via power transfer

from surplus regions in the following dispatch generation group. The process of this stage is shown in Figure 5.7.

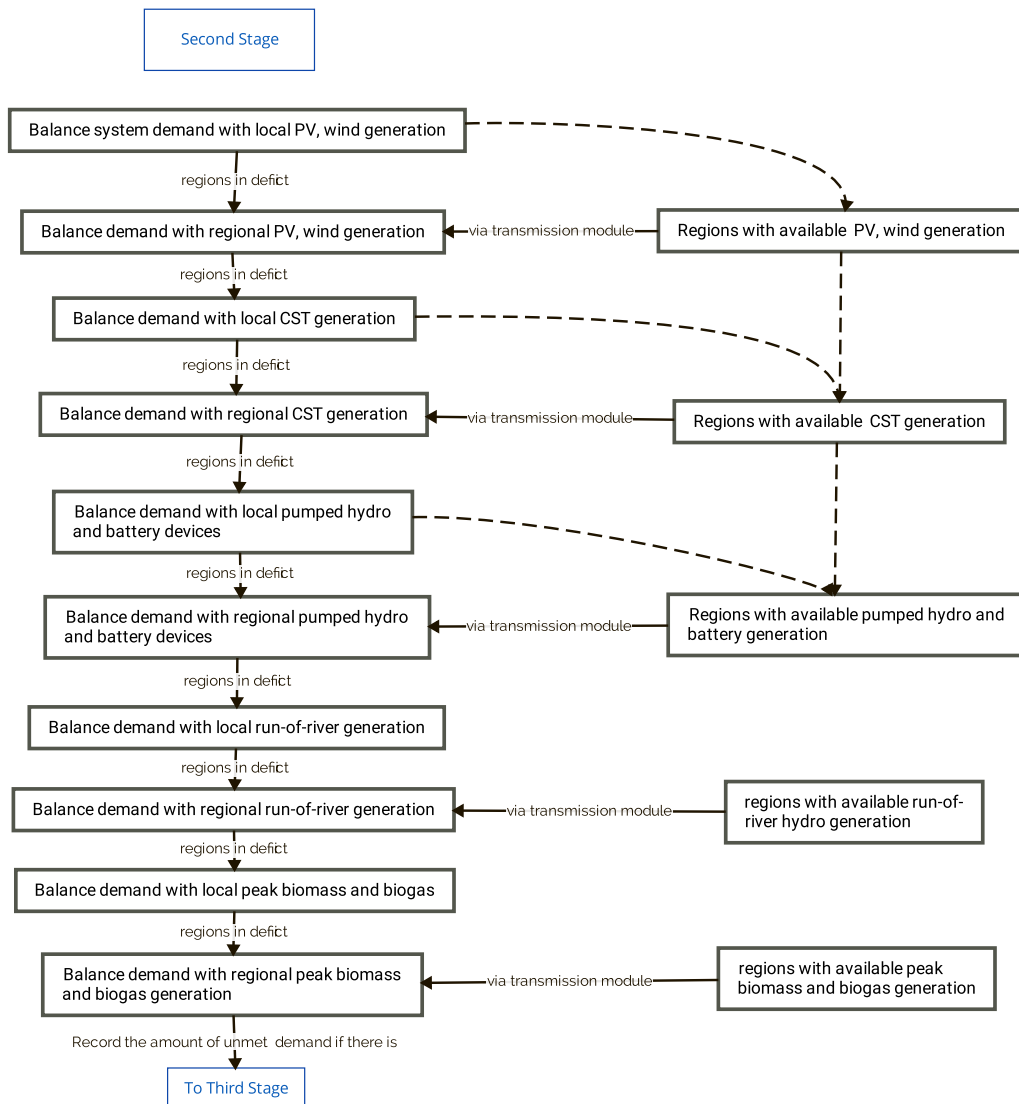


Figure 5.7: Dispatch process flowchart, second stage

The last stage is that after the demand has been balanced and if there is still any remaining generation from solar PV or wind generators, this module will use the surplus power to charge storage devices subject to constraints on interconnector and storage capacity. After this, any remaining generation from solar PV or wind is spilled. Figure 5.8 shows this stage.

The following box shows how the entire simulation processed in text:

```
# First stage:
```

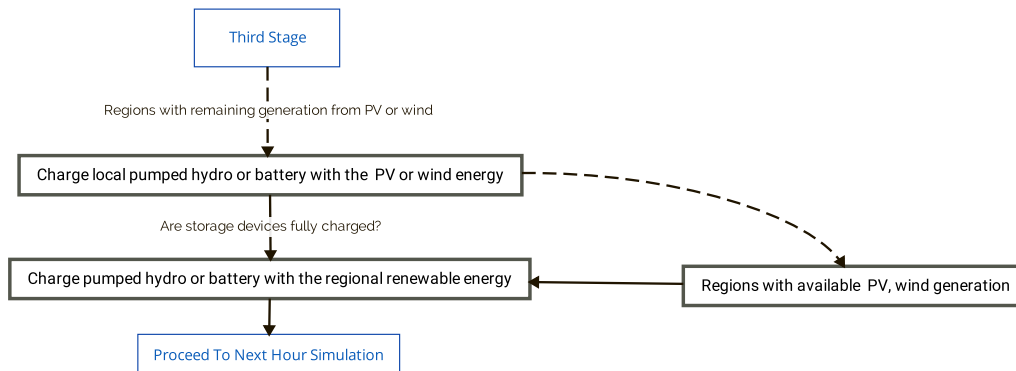


Figure 5.8: Dispatch process flowchart, third stage

For each area **in** [mainland area, Tasmanian area]:

Balance the area synchronous demand by generation

from synchronous generators with the priority sequence

Second stage:

For each generation group **in** the sequence of five
dispatch generation groups:

For each region **in** deficit:

balance demand **with** local generation **from**
the generation group

For each region **in** deficit:

balance demand **with** imported regional generation
from the generation group subject to
interconnector capacity

Third stage:

For each region **with** remaining generation **from PV or wind**:

charge local storage devices

For each region **with** remaining generation **from PV or wind**:

charge regional storage devices subject
to interconnector capacity

The dispatch process here meet the demand at the pre-defined merit order, which is corresponding to increasing marginal cost of the power plants (exclude ind the first stage where we want to meet the synchronous demand). In the pre-defined merit order, we control the generation from the lower marginal cost dispatched first, such as the generation from the PV and wind plants. The plants with the highest

marginal cost, biogas, was placed at the end of the order. In DETRESO we do not take a classical approach to economic dispatch because in our dispatch module, only biogas plants are dispatchable and have a fuel cost. The generation from biogas takes less than 1.5% of the total annual cost of the system. The detailed economic dispatch accounting for spinning reserve, ramping rate, part load efficiency and other features such as emission control requires complex and slow unit commitment models, and this is not needed to explore the best combination of the renewables, storage and transmission: using this approach, the program can simulate one year in 3 seconds with a laptop.

The simulation length used in this study is one year, however, this length can be extended easily. Once finishing the simulation, this module will calculate the annual generation from each generator and the annual unserved energy of the system. These will be used for system cost calculation.

5.2.3 System cost

The Australian National Electricity Market is a gross pool, energy-only wholesale electricity market, with a very high Market Price Cap (MPC) of AU\$14,200/MWh [96]. This contrasts with wholesale electricity markets in other jurisdictions (e.g. U.K.) that are more characterised as bilateral net settlement systems with respect to both energy and capacity, with an independent market operator facilitating settlement of energy and capacity that are not covered by bilateral contracts. The modelling completed in this thesis assumed no change to the market structure of the NEM.

The cost of renewable generation technologies have decreased significantly in recent years [120, 121, 122] . Figure 5.9 shows the price decreasing of solar PV and wind turbines from 2010 -2017. Two different cost sets are used in this study at different research stage. The first cost set is from Australian Energy Technology Assessment report in 2013 [95], which is used in the scenario analysis of battery uptake and transmission uptake. The second cost set is from CO2CRC power generation technology report in 2015 [123]. The second cost set is used in the scenario analysis of CST uptake and demand change. Details of these costs will be given in

the scenario analysis chapter where it was used.

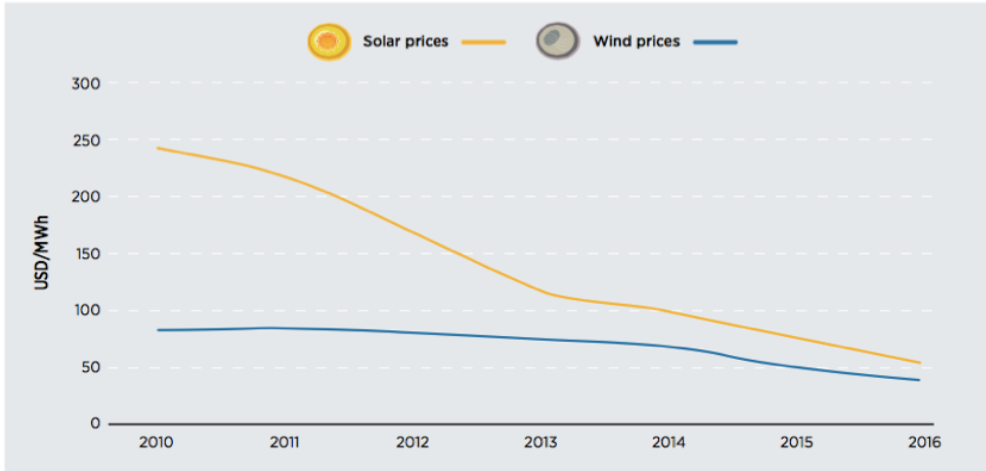


Figure 5.9: Cost of solar PV and winter turbine from 2010-2016, source: [122]

Generally, for each generator, its capital cost, fixed O&M cost, variable O&M cost are calculated. The capital cost is the one-time cost to purchase and build the generator. The fixed O&M cost is associated with the capacity of the generators and it includes costs from labour and associated support, fixed service provider, fixed inspection, diagnostic and repair maintenance services etc. The variable O&M cost is associated with the amount of electricity generated from generators and it includes scheduled and unplanned maintenance.

The total annualized cost of generators, batteries and interconnectors is calculated at the end of the dispatch process in the simulation algorithm:

$$SystemCost = \sum ACC_{t,r} + \sum FOM_{t,r} + \sum VOM_{t,r} * E_{t,r} + \sum ACC_{i,r} \quad (5.7)$$

where ACC , FOM and VOM represent annualized capital cost, fixed operating and maintenance (O&M) cost and variable O&M cost, respectively;

E stands for the electricity output by technology by region;

t , r stand for technology type (except hydro and pumped hydro as expansion opportunities are limited) and NEM region;

5.3 Transmission module

The capacity rating of interconnectors is determined by the thermal, voltage stability, transient stability and dynamic stability limits of the power system. AEMO develops constraint equations which contain several hundred mathematical expressions to calculate the capacity of the interconnectors. We simulate a 100% renewable power system, which is a significant contrast to the current system dominated by coal-fired generation. The current transmission capacity constraints for voltage stability, transient stability and dynamic stability limits will not be valid in the new system. However, the constraints from thermal limits will still be valid. Hence, the thermal limit of the existing interconnectors is maintained as the input value of the capacity of the interconnectors. It is beyond the scope of this thesis to model stability.

Table 5.4 lists the capacities of the existing interconnectors in the NEM. The length of the interconnectors listed here is not the real physical length. The actual length of the transmission line will be longer because they do not follow straight lines. Instead, it is approximated using geodetic distances between the centres of each state and territory obtained from Geoscience Australia.

Table 5.4: Original Interconnectors' Rating

Variable Name	Regions	Original Capacity (MW)	Approximate Length (km)
SA-VIC interconnector	SA - VIC	880	1100
VIC-TAS interconnector	VIC - TAS	600	600
VIC-NSW interconnector	VIC -NSW	3200	600
NSW-QLD interconnector	NSW - QLD	1300	1100

In the transmission module, electricity can be transmitted between two distant, non-adjacent regions. For example, to transmit electricity from South Australian to New South Wales, both SA-VIC and VIC-NSW interconnectors would be used. In this case, the maximum transfer capacity will be determined by the smallest capacity rating of the two interconnectors. Following [124], we assume that the energy loss of the transmission line is 1% of the electricity transmitted per 100 km. For example, if 100 MW of power is generated in the SA region and transmitted via

the Heywood interconnector to VIC, only 89 MW of power will be received in VIC.

The main principle of the transmission module is transmitting the available energy to the most nearby region to avoid the energy loss as much as possible. The module creates a list for each region to store the other regions in ascending order of their distance from it.

```
NSW.SHORTRGN = [VIC, QLD, TAS, SA]
```

```
QLD.SHORTRGN = [NSW, VIC, TAS, SA]
```

```
SA.SHORTRGN = [VIC, NSW, TAS, QLD]
```

```
TAS.SHORTRGN = [VIC, NSW, SA, QLD]
```

```
VIC.SHORTRGN = [NSW, TAS, SA, QLD]
```

The above lists are then converted the transmission paths.

```
SHORTRGN[NSW] = [(VIC, NSW), (QLD, NSW),
                 (TAS, VIC, NSW), (SA, VIC, NSW)]
SHORTRGN[QLD] = [(NSW, QLD), (VIC, NSW, QLD),
                 (TAS, VIC, NSW, QLD), (SA, VIC, NSW, QLD)]
SHORTRGN[SA] = [(VIC, SA), (NSW, VIC, SA), (TAS, VIC, SA),
                 (QLD, NSW, VIC, SA)]
SHORTRGN[TAS] = [(VIC, TAS), (NSW, VIC, TAS),
                 (SA, VIC, TAS), (QLD, NSW, VIC, TAS)]
SHORTRGN[VIC] = [(NSW, VIC), (TAS, VIC), (SA, VIC),
                 (QLD, NSW, VIC)]
```

The following example shows how the transmission model works:

In the simulation, if South Australia cannot meet its demand by local renewable generation, the model will try to import renewable generation from other regions with the minimal transmission loss where possible. The module finds that surplus renewable energy is available in New South Wales and Queensland. In this circumstance, the module will first transmit the energy in New South Wales to South Australia via the path (*NSW, VIC, SA*), as *NSW* is in front of *QLD* in *SA.SHORTRGN*. The maximum transmitted electricity is smaller or equal to the remaining capacity of *NSW-VIC*, *VIC-SA* or the available electricity in *NSW*. Once the electricity is transmitted, the module will update the remaining forward and backward capacity of each interconnector.

If South Australia is still in deficit, the module will send the *QLD* surplus electricity to *SA* via the path (*QLD, NSW, VIC, SA*). The maximum transmitted electricity should be smaller or equal to the remaining capacity of *QLD-NSW*, *NSW-VIC*, *VIC-SA* or the amount of available electricity in *QLD*. Once the electricity is transmitted, the module will update the remaining forward and backward capacity of each interconnector.

5.4 Optimization module

Previous literature discusses the optimization methods used in energy system planning [125, 126, 127]. Meta-heuristic algorithms are widely used to find the optimum solution to a problem while subject to the constraints set by the researchers. Meta-heuristic algorithms can be classified into two types: one using the trajectory and the another one using population-based method [128]. The typical trajectory method algorithms are hill climbing, simulated annealing, etc. These algorithms use a single set of decision variable values during the optimum searching and the optimum result will also be a single gene. The typical population-based meta-heuristics are genetic algorithms and particle swarm optimization algorithms. These algorithms use a population of genes which will be evolved during the searching process, the optimum result will also be a set of genes.

The time of searching the optimum is one of our considerations when choosing the algorithm. The use of the high-performance computing platform (HPC) could reduce the computing time significantly. Genetic algorithm (GA), simulated annealing and PSO are possible algorithms considered here. Discussion about these algorithms can be found in [39, 75, 128].

A genetic algorithm (GA) is chosen as the optimization algorithm to seek the least cost combination of renewable generation, interconnector and storage capacity in the system. GA is a part of evolutionary computing and has been widely used as a function optimizer in many research fields. One of the reasons for using GA in this study is there is available package for GA written in Python. This package is used because it is free and effective, and it works well on the high-performance

computing platform employed to achieve fast optimization to within a small tolerance of the fitness score. For these energy systems, exact global optimisation is not guaranteed whatever practicable algorithm is used, so optima are tested using different random starting values for the decision variables. Little variation in optima was found indicating that the problem is not badly behaved, i.e, it did not have several local optima close in objective function value yet with very different decision variable values.

Since the GA can find reproducible near optimal results with reasonable speed, there is little immediate need to try other algorithms. Further research into improving the speed by changing the simulation and optimisation algorithms could be done, particularly if the model were to be more widely used or run on a less powerful desktop machine.

The sum of the annualized cost of the system and penalty cost is used here as the objective function in GA, and GA trends to find the lowest value during its evolution. This objective function is given by:

$$\text{Total Cost} = \text{System Cost} + \text{Penalty} \quad (5.8)$$

The penalty in the above function will guide the optimization to find a generation mix which could follow our assumptions and requirement. The maximum generation from biomass and biogas is 20 TWh and 5 TWh, respectively [42]. If their generation exceed this value, a heavy penalty will be added in the objective function. Also, any unserved energy exceeding 0.002% of the total NEM demand (i.e., the reliability standard in the NEM is that the maximum amount of unserved energy in each region cannot exceed 0.002% of the energy consumed in each region) is heavily penalized. This is given by the following equation:

$$\begin{aligned} \text{Penalty} = & \max(0, \text{Total Generation}_t - \text{Max Allowed Generation}_t) \times 10^{20} \\ & + \max(0, \text{Total Unserved Energy} - \text{Max Allowed Unserved}) \times 10^{20} \quad (5.9) \end{aligned}$$

where t here includes the biomass, biogas and hydro plants.

The evaluation function in the GA calculates a projected annual cost of meeting the assumed demand in 2030 by summing up the annualised capital costs of generating and transmission capacity and the fixed and variable O&M costs. We are therefore comparing across scenarios the average cost (\$/MWh) of meeting the demand, not the marginal cost of generation. The average cost provides a more comprehensive measure of all the costs in a 100% renewable system particularly with significant deployment of variable renewables that have zero (or close to zero) short run marginal cost.

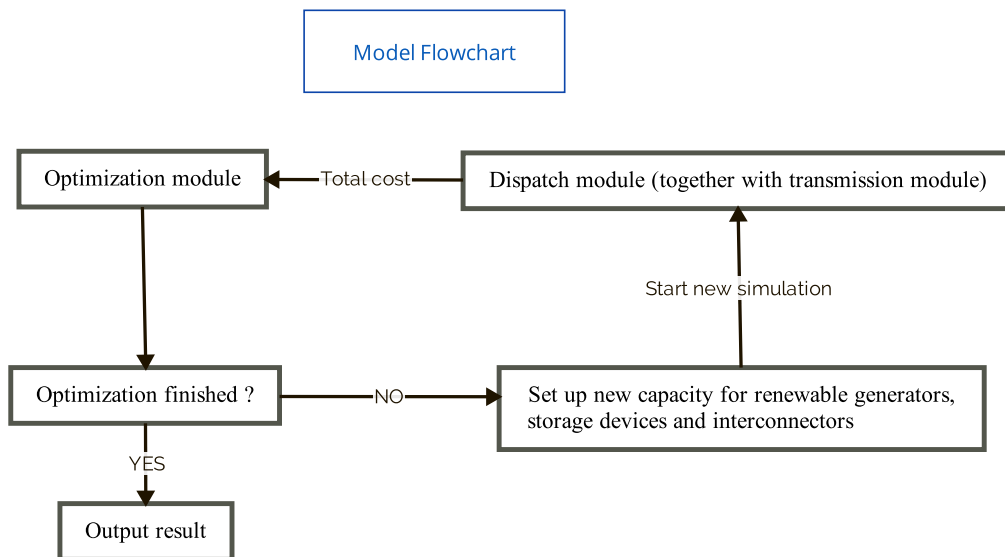


Figure 5.10: Model flowchart

Figure 5.10 shows the relationship between the dispatch module and the optimization module in DETRESO. In the optimization module, the GA initializes the capacity mix of the 100% renewable power system. This mix is then passed to the dispatch module. The total annualized cost of generators, batteries and interconnectors is calculated at the end of the dispatch process in the simulation algorithm. The GA stores the annualized costs with the additional penalty cost and then ‘breeds’ a new mix which is simulated and if lower cost this replaces the least cost mix and so the GA iteratively approaches a least cost solution.

In order to assist the optimization module in finding the least cost combination

faster, we give a specific capacity constraint for the renewable generation technologies. The assumed constraints are, for each state:

- The wind or solar capacity cannot exceed 50 GW.
- The power capacity and energy capacity of the battery devices cannot exceed 8 GW and 30 GWh, respectively.

We found the capacities of these technologies did not reach this maximum value in any optimization result, which shows these upper bounds are reasonable.

The mutation rate is 0.2, cross-over rate is 0.9 and selection algorithm is Rank selection. Population size is 200. These parameters are based on experimentation to ensure the model could get optimal renewable mix within a reasonable running time.

For the generations, no limits are set on the quantum of generation that will evolve in the optimization model. The optimization will stop when the difference in the fitness score between two continuous generations is less than 0.2%. We found the optimization stops after around 200 generations in most cases.

5.5 Data

Table 5.5 lists the renewable generation and demand data used in this research. Same renewable generation data are used through this thesis. In the following chapters of this thesis, Chapter 6 uses the historical demand form 2009-2010. Chapter 7 uses the projected demand by NEFR in 2029-2030. Chapter 8 uses the demand from the our demand model.

5.6 Model performance

The model is written in Python (2.7) and can run on Windows or Unix systems. It takes about 3 seconds to finish a one-year simulation with a standard laptop. The Pandas and Matplotlib packages are used for data analysis and visualization of the dispatch activates.

It is assumed that possible capacities are a continuum i.e. any value can apply evolve in the optimization model. The optimization will stop when the difference

Table 5.5: Data used in this thesis

Renewable generation	Year	Resolution	Source
PV	2004-2010	hourly	[118]
Onshore Wind	2004-2010	hourly	[118]
Offshore wind	2004-2010	hourly	[118]
CST	2004-2010	hourly	[118]
Hydro	2009-2010	monthly	[119]
Temperature for five regions	2009-2010	hourly	[129]
Historical demand	2009-2010	hourly	[102]
Projected future demand	2029-2030	hourly	[130]

in the objective function (fitness score) between two consecutive generations is less than 0.2%. In most cases, it requires less than 200 generations (each generation has a population of 200) in the GA algorithm setting to finish the searching of the optimal result.

A high-performance computer (HPC) platform is used to run the model, provided by CSIRO. This system is called Ruby and it has 64 Intel Haswell 10-core processors. Details about the HPC can be found in [131]. It takes about one hour to finish the optimization using 200 cores of Ruby.

5.7 Summary of this chapter

This chapter described the supply side model in DETRESO. The supply side model is made up of three modules: the dispatch module, transmission module and the optimization module. The dispatch module is for the demand supply balancing of the system. The transmission module enables the energy exchange between different regions under the constraints of the interconnectors capacities. The optimization module uses the sum of the generators cost and penalty cost as the objective function. The following sections use the model described here to make different scenario analyses.

Chapter 6

Scenario analysis - battery uptake and transmission expansion

6.1 Background of this scenario

In the literature review we found that most studies about high penetration renewable power systems for Australia focus on whether there is enough renewable energy to meet the demand over a certain simulation period. Some studies discussed the least cost renewable system with different scenarios. However, most of these studies do not include a detailed model of the NEM transmission network when they analyse the renewable system. Accordingly, the importance and the cost of the transmission system in the high penetration renewable system may be underestimated. This section explores the least cost combination of renewable generators, storage devices and transmission infrastructure in the NEM using the DETRESO model. The aim of this section is to explore the importance of storage devices and transmission system in a 100% renewable electrical system. This section is also used to estimate the required storage size and interconnectors capacity for the high penetration renewable power systems in NEM. Section 6.2 outlines the modelling data and assumptions used in this scenario analysis, Section 6.3 discusses optimization results with a focus on the system dispatch in a typical winter week and presents sensitivity analysis. Section 6.4 concludes this part.

6.2 Modelling data and assumptions

6.2.1 Renewable technology set and cost parameters

Solar photovoltaic (PV) and on-shore wind turbines are chosen as the main renewable generation technologies in this study. These technologies are currently the most cost competitive and mature of renewable technologies. The details about their generation data has been given in section of Supply Side Model. In general, the hourly generation traces of wind and single-axis tracking PV in 2010 in the 43 NEM polygons was used here. The 43 locational polygons are sub-regions of the five NEM regions in order to account for geographical differences in resource quality and quantity. In this section, we do not model other forms of renewable generation such as geothermal, solar thermal or ocean renewables resource. However, the solar thermal is considered in the next section of this thesis.

In addition to existing pumped hydro storage capacity, this section considers the potential role of battery storage in balancing a power system with high penetration of intermittent renewable generation. The sizes of the storage devices are optimised here. The sizes of the storage devices are optimised here. Details about how the storage devices are treated has explained in Chapter 5.

Table 6.1: Technology cost assumptions, 2030

Technology	Capital Cost \$/kW	Fixed O&M \$/kW/year	Variable O&M \$/kWh
Wind onshore	1701 - 1917	32.5	10
PV single Axis tracking	2013 - 2542	30	-
Zinc-bromine	Energy-related cost @ \$260/kWh and Power-related cost @ \$260/kW O&M cost @ \$36/kW/year		
Interconnector	\$800/MW/km (Assume that the lifetime for interconnectors is 50 years)		

The cost of renewable generation technology has decreased significantly in recent years[73]. The model uses renewable technology cost data from Australian Energy Technology Assessment 2013 report [95]. The assumed cost of technologies in 2030 is shown in Table 6.1.

Similarly, the cost of batteries is expected to decrease in the future as global deployment accelerates [85]. We consider zinc-bromine flow batteries here for grid-scale application because of its relatively cheaper price. The assumed cost of zinc-

bromine battery storage systems is listed in Table 6.1.

6.2.2 Regional demand

Electricity demand in NEM regions has been declining and is forecast to be lower until 2020. The exception is Queensland where demand is projected to increase mainly due to new liquefied natural gas facilities [132]. The total annual NEM demand is expected to flatten after 2020. In this scenario analysis, we did not use the demand projections from NEFR report or our demand model. Instead, historical electricity demand data at hourly interval for each NEM region in 2010 was used. (Queensland's demand is scaled with a factor to reflect the increase its electricity consumption based on the AEMO's forecast)

6.2.3 Dispatch process

In Chapter 5, the details of the dispatch process were discussed. As most types of synchronous technology, such as CST, biomass and biogas, are not considered in this scenario, we do not place any constraints on the synchronous limits during the demand supply balancing. This means the first stage of the dispatch process is not used in this scenario. The second stage of the dispatch process is used with the removal of the CST, biomass and biogas generators.

6.3 Results and discussion

6.3.1 Electricity generation mix

The optimization results give several different combinations at a similar cost and we choose one possible least cost combination which has the fewest shortage hours to discuss the result, shown in Table 6.2.

The result shows that wind generators contribute around 56% of total energy supplied while solar PV contributes around 37%. The total energy supplied by run-of-river hydro is 13.1 TWh, which is less than the actual amount (15.39 TWh) of energy supplied by run-of-river hydro in the NEM in 2010. The total power and energy capacity of the batteries in this system is 17.4 GW and 109.3 GWh, respectively. The reason for such large capacity requirement can be easily explained that

Table 6.2: Possible least cost combination for the NEM, assuming low technology costs with 5% discount rate

		QLD	NSW	VIC	TAS	SA	Total
Wind	Capacity (GW)	29.6	18.4	16.9	1.6	4.3	70.9
	Energy Supplied (TWh)	36.1	39.4	33.6	3.8	6.2	119.1
PV	Capacity (GW)	11.3	10.1	4.5	1.7	4.9	32.6
	Energy Supplied (TWh)	27	28	11.6	4	7.6	78.2
Run-by-river Hydro	Capacity (GW)	0.1	3.1	0.6	2.2	-	6
	Energy Supplied (TWh)	0.2	7	1.7	4.3	-	13.1
Pumped Hydro	Capacity (GW)	0.5	0.8	-	-	-	1.3
	Energy Supplied (TWh)	0.1	0.4	-	-	-	0.5
Battery	Power Capacity (GW)	3.4	3.8	2.2	4.4	3.8	17.4
	Energy Capacity (GWh)	13	23.9	26.1	23.9	22.4	109.3
	Energy Supplied (GWh)	319.9	855.2	874.5	277	385.7	2712.3
Total Region Supplied Energy (TWh)		63.7	75.6	47.7	12.4	14.2	213.6

since we do not consider gas turbines or concentrated solar thermal systems in the model (dispatchable plant), a significant amount of power and energy requirement needs to be met by batteries when insufficient generation is provided by PV or wind generators in certain regions, such as night-time in winter. This is observed in Figure 6.2 that most battery storage energy are discharged during the fourth night.

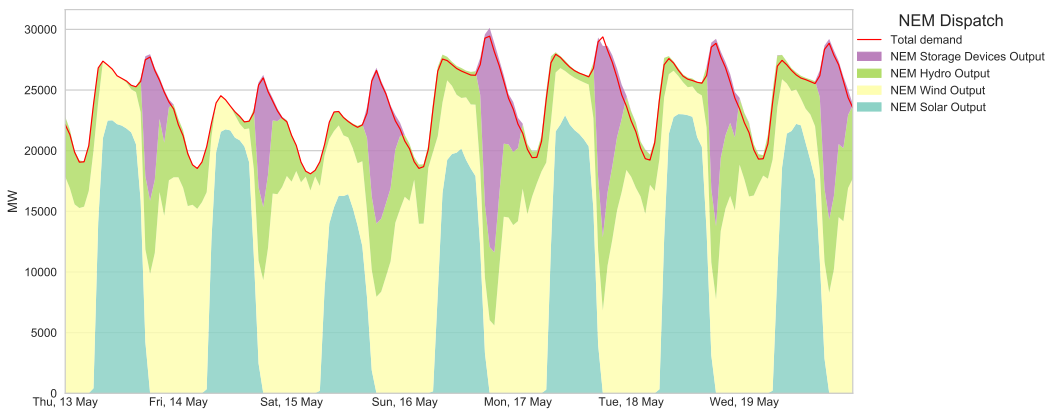


Figure 6.1: NEM demand and supply in a winter week

Figure 6.1 shows the supply and demand power during a winter week when most storage energy is used during the year. Spilled energy is not shown in the figure. PV and wind generation are able to meet the demand in most day time periods. Hydro and battery devices are activated during time periods of insufficient renewable generation to meet local demand or demand in other regions. The capacity requirement for batteries in the NEM is 109.3 GWh/17 GW, which is approximately

19% of the average daily demands of the NEM regions. The hours of discharge for batteries for the five batteries listed in Table 6.2 are all less than 11 hours. This result is similar to [44] which modelled an 85% renewable system in California.

The storage level of batteries during the winter week is shown in Figure 6.2. The batteries usually supply energy during night-time. They are quickly charged up by wind energy following the discharge period. It can be observed that because the wind has limited generation during the Sunday night of the selected winter week, significant amount of the stored energy in batteries are provided during this night. The batteries located in NSW, QLD, VIC and TAS were empty at this night. This indicates that the difficult time of demand supply balancing for a high renewable penetration system in the NEM is the night time when solar generation is not available and the wind resource is poor.

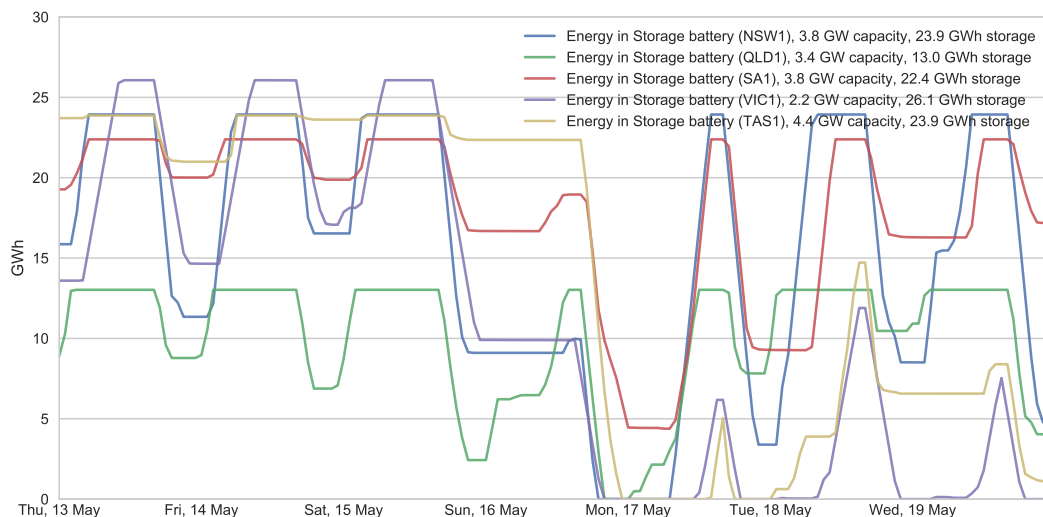


Figure 6.2: Energy storage level in batteries in the winter week

6.3.2 Interconnectors and energy exchange activities

The need for a large transmission system in high renewable penetration systems is noted in the previous literature [50, 133]. The transmission expansion plan for this least cost combination is shown in Table 6.3. It shows that the capacity of the interconnectors in NEM regions increase dramatically to support the high renewable energy system, although the overall utilization factors of the interconnectors are less than that of today (shown in Figure 6.3). For example, the capacity of the VIC-

TAS interconnector increases from the current level of 600 MW to 5193 MW. This interconnector allows significant export of hydro energy from TAS-VIC.

Table 6.3: Transmission expansion plan for least cost combination

	Proposed capacity by model (MW)	Total forward transmitted electricity in the year (GWh)	Total backward transmitted electricity in the year (GWh)	Hours when flow large than 99%	Hours when flow large than 80%	Hours when flow large than 50%
SA -VIC	2875	1114	1148	50	124	459
VIC - TAS	5193	154	2057	10	36	127
VIC - NSW	4835	1422	4605	145	348	947
NSW -QLD	8448	240	6924	120	242	644

Table 6.4 shows the total energy exported from and imported to the five regions during the simulation year. QLD and TAS are major energy export regions reflecting significant renewable capacity in excess of demand, whereas VIC and NSW are major energy import regions reflecting relatively low levels of capacity relative to demand. These outcomes mainly reflect capacity being installed at prime locations (in terms of renewable resource quality) as regional interconnector capacity is unconstrained.

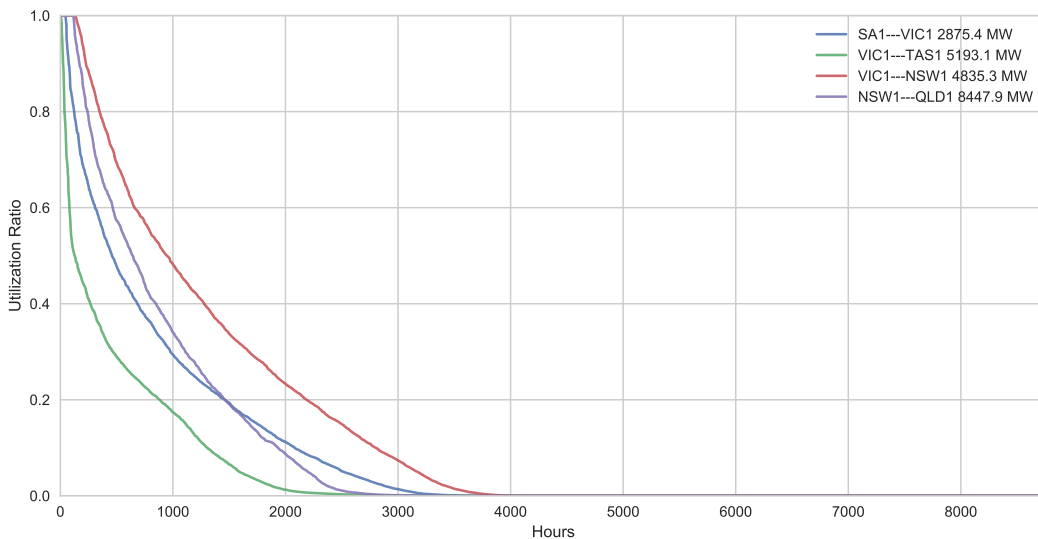


Figure 6.3: Utilization level of the interconnectors

6.3.3 Cost analysis

The total annualized cost of the system is around \$100 per MWh, assuming low technology costs with 5% discount rate. The cost would be up to \$163 per MWh

Table 6.4: Energy exchange between regions

	QLD	NSW	VIC	TAS	SA
Import Electricity in GWh	197.24	4175.29	5401.67	119.1	877.19
Export Electricity in GWh	6925.85	1216.75	1040.68	2058.3	1121.4
Net Import(Negative value shows export)	-6728.62	2958.54	4360.99	-1939.21	-244.21

if the high technology costs and 10% discount rate were used in the model. The following discussion is based on the optimization result assuming low technology costs with 5% discount rate.

As shown in Table 6.5, more than half of the total cost comes from wind generation. Solar PV represents 27% of total cost and storage constitutes 13%. The interconnectors are the smallest contributor, at 3% of the total cost.

Table 6.5: System Cost

Components	Wind farms	PV	Storage device	Interconnectors
Percentage	57%	27%	13%	3%

The system cost here is much smaller than the cost found in [85] which used a similar technology set and cost data but projected a wholesale unit cost around AU\$176/MWh. The cost given in AEMO 100 per cent study is around AU\$110/MWh. Reasons for the higher cost in CSIRO comparing with other NEM 100% study have been listed in their study. When optimizing the 100% renewable system in the CSIRO study, batteries were not dynamically simulated in hourly dispatch and this may underestimate the role and capacity of storage devices [85]. The CSIRO study used their projected demand, which is 225 TWh at the target year. This chapter uses the historical demand which is 213.6 TWh. Another reason for the difference is that the model in this chapter assumes that all renewable generation is constructed overnight in 2030 at the prevailing assumed cost. The CSIRO study used an investment model that constructed capacity over the decade prior to 2030 at higher prevailing technology costs. Besides, the CSIRO study considered the cost of transforming from the present system to the 100% renewable system, which involve a high price signal for any fossil units built before 2050 to shut down. AEMO study used biomass converted to biogas in peaking plant to back-up to variable renewable. However, CSIRO study also consider the bio-energy resources for the transport sec-

tor, which results in a higher cost of bioenergy for generation. Table 6.6 shows the difference among the three studies.

Table 6.6: Different assumptions in the [85], AEMO 100 study and this chapter

	System Cost \$/MWh	Demand TWh	Storage Options	Biogas Usage	Other Cost
AEMO study	111-113	222	CST and pumped hydro	Only for electricity sector	-
[85]	176	225	CST and pumped hydro	For electricity sector and transportation sector	Retirement cost of the fossil plants
This chapter	100	213	Batteries	-	-

The similar study in [21] estimated the cost for a high renewable system at \$104/MWh. The generation mix in this study is compared to that of [21] in Table 6.7. The main contrast is the use of biogas turbines to meet demand in periods of insufficient wind or solar generation. In this study, more wind generation is deployed than solar generation to charge battery storage devices during night-time periods of low demand.

Table 6.7: Least cost system in [21] and this study

	Technology	Wind	PV	CST	Pumped	Hydro	GTs	Battery
Cost in [21]	Capacity GW	34.1	29.6	12.5	2.2	4.9	22.7	-
	Energy TWh	94.8	41	43.9	0.5	11.5	12.7	-
This scenario	Capacity GW	70.9	32.6	-	1.3	6	-	17.4GW with 109GWh storage
	Energy TWh	119.1	78.2	-	0.5	13.1	-	2.7

6.4 Section conclusion

This section modelled a possible least cost combination of wind and solar generation, battery storage devices and augmentation of regional interconnectors in the NEM for the year 2030. Historical demand and generation data were used in this section. The results showed that battery storage devices have a key role in meeting power demands in a system dominated by intermittent renewable generation. Discharge of battery storage devices is estimated to provide around the 20% of the average daily demand in NEM regions. The amortized cost of this high penetration renewable power system is around \$100 per MWh. This cost is similar to other high renewable penetration studies that do not consider batteries as the dispatchable

plant.

The results show that significant amounts of energy are exchanged between the five NEM regions in such a high renewable energy penetration system. Tasmania and Queensland act as net energy exporters given their relative superior renewable energy resources while New South Wales and Victoria are net energy importers. Significant augmentation of regional interconnectors is required to support this energy exchange, but the overall utilization of this infrastructure is less than that observed in the current system.

The optimization result shown in this chapter is dependent on the renewable generation dataset sourced from the AEMO 100% Renewable project. The high average wind capacity of Queensland in the simulation winter (May and June) causes the optimization to favour placement of more wind farms in Queensland. This may overestimate the wind capacity needed in Queensland (and underestimate wind capacity in other regions) in the simulated high renewable penetration system.

In this section we explore the required size of the storage devices and transmission for the high renewable penetration system, considering the PV, onshore wind and existing hydro plants. The next section will focus on what will happen if the CST can be deployed in the NEM system.

Chapter 7

Scenario Analysis - CST uptake

7.1 Background of this scenario

Previous studies in the Australian context, the main focus of this thesis, have explored different facets of 100 per cent renewable electricity systems. [32] considered such a system by 2020 and focused on whether there is sufficient renewable resources available and if sufficient capacity can be deployed rather than the specific policy or regulatory measures that would drive the transition. In a comprehensive study, [42] found a 100 per cent renewable power system was technically and economically feasible using a potentially wide range of renewable technologies in the National Electricity Market (NEM). [21, 90, 91] examined whether it is technically feasible to meet electricity demand with estimated renewable generation output based on historical data of demand and primary renewable resource availability in the NEM. [77] used mesoscale numerical weather models to examine cross-correlations between solar and wind generation with demand for the state of Victoria. [92] find that incremental costs of high renewable electricity systems increase approximately linearly as the share grows from zero to 80%, and then demonstrate a small degree of non-linear escalation, related to the inclusion of more costly renewable technologies such as solar thermal electricity. Analysis by [93] suggests that the market price cap may have to rise to ensure supply adequacy in the energy-only market of the NEM. In contrast, [94] was more focused on employment gains as renewable energy production tends to be more labour intensive than non-renewable

energy production.

Many studies examining high renewable penetration systems do not co-optimize the renewable mix and transmission system expansion in hourly temporal resolution modelling. The co-optimization is useful for system expansion planning, such as the tradeoff that exists between transmission investment, the quality of primary renewable resources, and the capacity of the storage devices. This is important given the large transmission investments that are anticipated to promote power trades and renewable integration. In [41] they discuss a large regional grid (PJM regional system in Eastern U.S.) supplied by wind power, solar power, electrochemical storage and fossil backup generators. They found the above technology combination is able to meet the demand during most of time at today's cost of electricity. However, as the model used in their study is computing-intensive, they did not consider the transmission expansion.

In [21] an optimized power system is built up by wind farms, PV, CST with 15 hours storage tank, existing hydro and peak bio-fueled gas turbines. It used 2010's historical demand data and projected generators' cost data by AETA [95]. The model used a simplified transmission algorithm, without the capacity constraints imposed on the interconnections. Batteries are not considered in that study.

Despite a burgeoning literature on 100 per cent renewable electricity systems, no previous studies have explored the impact of CST with different sizing of thermal storage. This study seeks to address this gap. The purpose of the study is to simulate the role of CST (with different hours of storage) in a 100 per cent renewable system in the National Electricity Market (NEM), the main power system in Australia. It explores CST configurations of six, nine and twelve hours of storage versus battery storage and other renewable technologies to meet a given demand at hourly temporal resolution.

In order to answer the above questions, we use the DETRESO to find the optimal system configuration of the high renewable penetration NEM system. We use projected demand data for 2030 from AMEO [134], which is based on 2010's demand with additional consideration on demand change in the future. The new

demand includes projections about roof-top PV installed in NEM and demand from new LNG facilities in future. Compared to previous section, the updated renewable technology cost from [123] is used in this section.

7.2 Demand and technology cost data

7.2.1 Renewable mix set

This scenario considers numerous renewable electricity generation technologies: utility-scale solar photovoltaic (PV), onshore and offshore wind, run-of-river hydro and pumped storage hydro, CST (with different hours of thermal storage capacity), biomass (wood or bagasse) and biogas using open cycle gas turbine (OCGT). There are other renewable electricity generation technologies identified in previous studies that are not modelled, including enhanced geothermal systems, hot sedimentary aquifer geothermal systems, or ocean renewables (e.g., wave and tidal).

The generation data for PV, wind, pumped hydro and run-of-river hydro has been discussed in previous section. For the CST technology, there are three types of CST with storage configurations considered in this study: six, nine and twelve hours of storage. For each CST configuration, a constant derating of 3% (2%-5% is the typical range) was assumed due to outages, in addition to a derating due to degradation over time. The latter is lower for CST than for PV and 2% has been assumed across the installed CST capacity. The ‘as-generated’ output was converted to ‘sent-out’ by applying a 7% derating to account for auxiliary load. The total derating of collected energy is 12% while the derating of available generation capacity is 3%[42].

In addition to pumped hydro and CST, we also consider battery storage in our study. The cost of alternative types of battery technologies based on different chemistries is shown in Table 7.1. Based on the cost we choose Li-Ion battery with 0.9 round trip efficiency since it has the cheapest base case cost in 2030.

Consistent with [42], two biomass electricity generation technologies are considered in the model: biomass from wood waste, and biogas-fired OCGTs. Similar to conventional thermal generators, biomass wood is modelled as a base-load gen-

Table 7.1: Batteries cost in 2030 value, source:[117]

Battery type	Minimum (\$/MWh)	Base case (\$/MWh)	Maximum (\$/MWh)	Round trip efficiency
Li-ion	152.7	196.8	279.2	0.9
Zinc bromide	113.9	209.2	353.4	0.75
Advanced lead acid	258.5	317.1	496.8	0.9
Molten salt	155.2	264.2	415.4	0.85

erator (could generate 80% of its capacity at any hour, and the hourly generation could be up to the installed capacity if needed). Biogas-fired OCGTs is modelled as a peak-load generator that can ramp to full capacity within the time interval; this utilizes the integral storage of biomass for system management. The maximum allowed capacity of biomass for each region and maximum 2GW capacity of biogas generators in each state [42]. The total generation of biogas generators is limited at below 5 TWh/yr.

7.2.2 Demand data and technology cost data

The AEMO releases annual updates on electricity demand projections as part of its National Electricity Forecasting Report (NEFR) [134]. 2030 50 POE medium data / low data used in this chapter. The NEFR provides electricity consumption forecasts for each NEM region over a 20-year forecast period (2017 to 2036).

Table 7.2 lists the cost data used in the model. All costs are in 2015 Australian dollars.

Table 7.2: Technologies costs in 2030, BaseCost

Technology	Capital Cost (\$/kW)	Variable Cost (\$/MWh)	Fixed Cost (\$/kW/year)	Lifetime (year)	Source and Notes
Large Scale PV	1108	0	25	30	[123]
Onshore Wind	1917	0	58	30	[123]
Offshore Wind	Capacity: \$5022 Connection: \$618	12	75	30	[123]
Battery Li-Ion	PCS: 336 \$/kW PSS: 197 \$/kWh	3.1	10	10	[117]
CST 6hr	2328	4	30	30	[135]
CST 9hr	2844	4	30	30	[135]
CST 12hr	3225	4	30	30	[135]
Biomass Wood	4036	9	134	30	fuel cost at 111 \$/MWh, [42],[123]
Biogas	800	9	4	30	fuel cost at 111 \$/MWh, [42]

7.3 Results

7.3.1 Scenario definition

To find the optimal mix of CST configurations for the NEM, the model deploys the available electricity generation types to minimize total system cost. This section investigates four scenarios:

- **CST all:** all renewable electricity generation and storage technologies can be deployed in the optimization. As this chapter is primarily interested in the role of potential role of different CST configurations, the scenario is called ‘CST all’ meaning that the three CST configurations (six, nine, and twelve hours of thermal storage) can be deployed.
- **CST6:** all non-CST renewable electricity generation and storage technologies can be deployed. The only CST configuration available is CST with six hours of thermal storage.
- **CST9:** all non-CST renewable electricity generation and storage technologies can be deployed. The only CST configuration available is CST with nine hours of thermal storage.
- **CST12:** all non-CST renewable electricity generation and storage technologies can be deployed. The only CST configuration available is CST with twelve hours of thermal storage.

7.3.2 CST all scenario

A priori, it is expected that CST all will achieve a lower system cost among the four scenarios. This reflects the general observation in energy system modelling that exclusion of technologies or limiting their availability tends to increase cost. We focus on CST all assuming a 5% real discount rate to discuss the system behavior of the high penetration renewable system as all generation types in the technology set are available in this scenario. Table 7.3 lists the estimated capacity of each technology in each NEM region. while Table 7.4 lists the cost performance matrix by each technology in the whole NEM regions.

The total installed capacity in this scenario is 91.2 GW and the thermal storage in the system is around 166 GWh. Onshore wind has the largest capacity (28%) and generation (34%) share among all the technologies. This is consistent with other studies in the Australian context that find due to its cost and wind resource geographical diversity, onshore wind has a key role in a 100% renewable electricity system. There is also 5% capacity from offshore wind, which contributes around 8% of the annual consumption. Solar PV has the second largest capacity installed at around 26%. The generation from solar PV and CST supplies around 43% of the total demand of the year. There is more capacity installed in CST with 9 or 12 hours of storage than CST with 6 hours of storage. The capacity of the biogas-fired OCGT units reached the maximum allowed limit in all regions. Serving as peak load generators, the biogas generators have the highest levelised cost among all electricity generation technologies because of their low capacity factors.

Table 7.3: Regional generator capacity in GW, CST all with 5% discount rate

Region	PV	Wind	Offshore Wind	CST6	CST9	CST12	Hydro	Pumped Hydro	Battery	Biomass Wood	Biomass Gas
New South Wales	6.8	9.5	0.0	0.8	0.0	0.8	2.3	0.8	0.0	0.1	2.0
Queensland	7.3	12.9	2.9	0.1	7.3	2.6	0.2	0.5	0.0	1.0	2.0
South Australia	2.6	1.6	0.0	0.0	0.2	0.7	-	-	0.0	0.0	2.0
Tasmania	5.9	0.3	0.0	0.0	0.0	0.0	2.2	-	0.0	0.0	2.0
Victoria	1.0	1.5	2.1	0.7	0.0	3.2	2.2	-	0.0	1.1	2.0

Table 7.4: Cost and performance matrix by technology in the whole NEM regions, CST all with 5% discount rate

	PV	Wind	Offshore Wind	CST6	CST9	CST12	Hydro	Pumped Hydro	Battery	Biomass Wood	Biomass Gas
Capacity Share	25.9%	28.3%	5.4%	1.8%	8.2%	8.1%	7.5%	1.5%	0.0%	2.3%	11.0%
Generation Share	24.0%	33.7%	8.2%	2.4%	7.9%	9.0%	6.0%	0.5%	0.0%	7.1%	1.3%
Average Capacity Factors	24.9%	32.1%	40.9%	34.7%	26.0%	29.8%	21.6%	8.5%	-	81.3%	3.2%
Energy Spilled (GWh)	8207.7	11738.6	4112.1	1160.5	13266.5	14828.9	3833.2	0.0	0.0	0.0	0.0
Total Cost (Million \$)	2293.3	4713.5	2386.2	323.2	1681.0	1850.5	0.0	0.0	0.0	1106.6	892.4
Levelized Cost (\$/MWh)	44.5	65.0	135.4	63.8	98.4	96.0	-	-	-	72.7	320.6

7.3.2.1 Typical summer and winter week dispatch

Figure 7.1 and Figure 7.2 show the dispatch of generation in the CST all scenario for a summer and winter week, respectively. The demand for each region and generation from each technology is accumulated across the NEM, while energy exchange between regions is not shown in these figures. The storage level shows

the total amount of energy stored in pumped-hydro, CST and battery devices. The dispatched energy above the demand curve is the energy loss in the transmission.

The selected summer week has the largest weekly demand during the year. Solar PV and wind generators provided most of the electricity during daytime hours. Wind and CST contribute most of the generation during night time periods. In this week, hydro and biogas generators were running on Monday and Tuesday nights when there is not enough energy stored in CST.

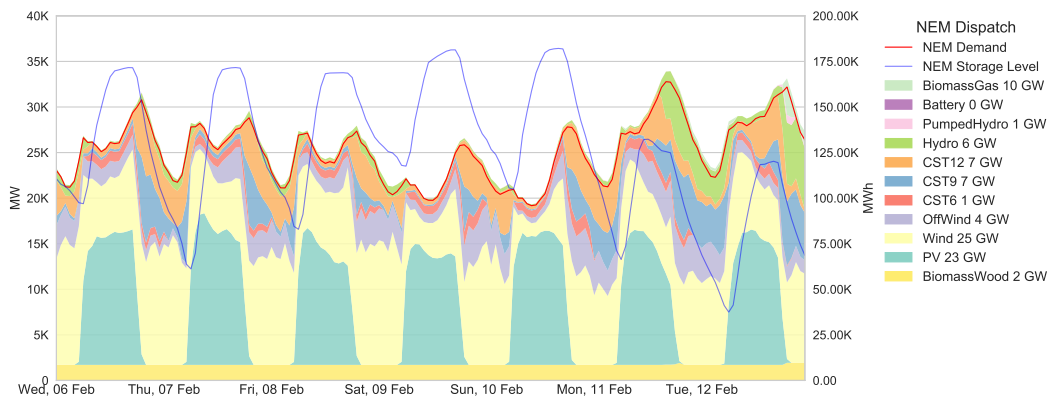


Figure 7.1: Summer week dispatch in NEM, CST all scenario

For a 100% renewable electricity system, meeting demand in winter is more challenging than in summer for the NEM. The NEM-wide storage was empty for several nights during the selected challenging winter week. Output from CST is limited by the limited energy collected during daytime hours. Run-of-river hydro and biogas almost ran on every day during this week.

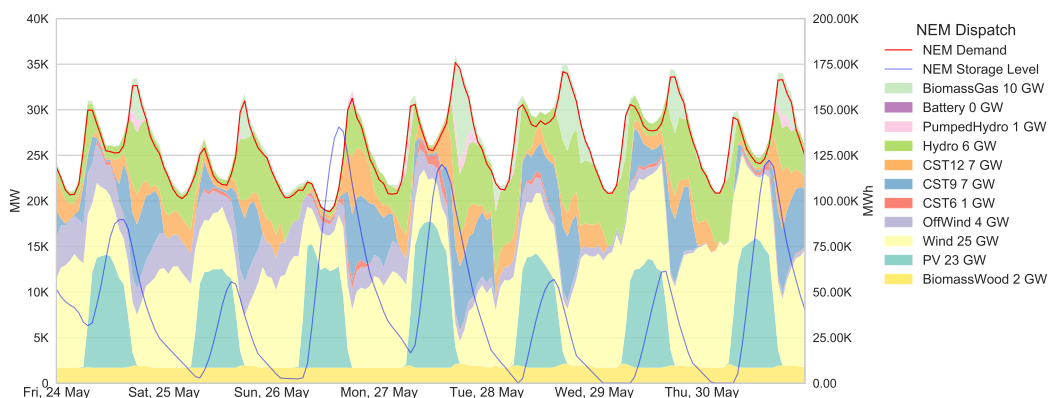


Figure 7.2: Winter week dispatch in NEM, CST all scenario

7.3.2.2 Interconnectors capacities and energy exchange

With the majority of the electricity generated from intermittent renewable resources, the transmission system is critically important to balance regional supply and demand. Figure 7.3 shows the capacities and activities of the interconnectors during the year. The capacity of the interconnectors in NEM regions increase dramatically to support the high renewable energy system. The capacity of the NSW-QLD and VIC-NSW interconnectors increase to around 6000 MW as New South Wales and Victoria are positioned in the ‘middle’ of the NEM and act as transit states. The capacity of the VIC-TAS interconnector increases from 600 MW to 3388 MW, indicating a key role for hydro generation exports from Tasmania to the mainland.

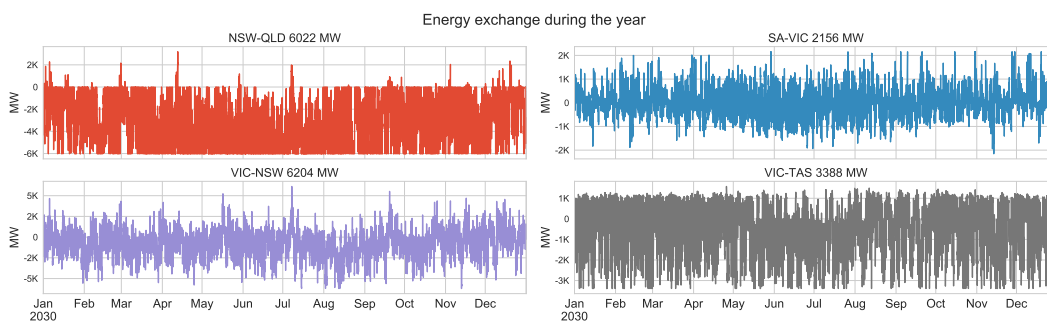


Figure 7.3: Interconnector flows

Table 7.5 shows the amount of electricity imported and exported from each region (the electricity transferred via the region is not included to avoid double counting). Queensland and Tasmania are major energy export regions reflecting significant renewable capacity in excess of demand, whereas Victoria and New South Wales are major energy import regions reflecting relatively low levels of capacity relative to demand. These outcomes mainly reflect capacity being installed at prime locations (in terms of renewable resource quality) as regional interconnector capacity is unconstrained.

Table 7.5: Energy export and import from/to each region

Region	New South Wales	Queensland	South Australia	Tasmania	Victoria
Import (GWh)	20172	67	1453	2319	11426
Export (GWh)	3118	26533	1661	7010	1794

The cost of transmission expansion increases the system cost by around \$2 per

MWh. This cost is lower than other studies [21, 136], as we calculated the cost based on the optimized capacity. This would likely underestimate the real system cost as additional transmission capacity within each region would be required to deliver power to load centres.

7.3.2.3 Spilled energy / Biomass gas usage / Challenge week

The biogas-fired OCGTs that serve as peaking plants are used when there is not enough available electricity generation from other technologies. Accordingly, time periods where biogas OCGTs are dispatched may indicate periods of system stress. Figure 7.4 shows the daily biogas generation for each region. Biogas is more frequently used during the cooler months, especially between May and August. Since solar PV and CST account for around 40% of system capacity, it is more difficult to meet the system demand with wind farms and hydro facilities after sunset in winter if the storage in CST is low.

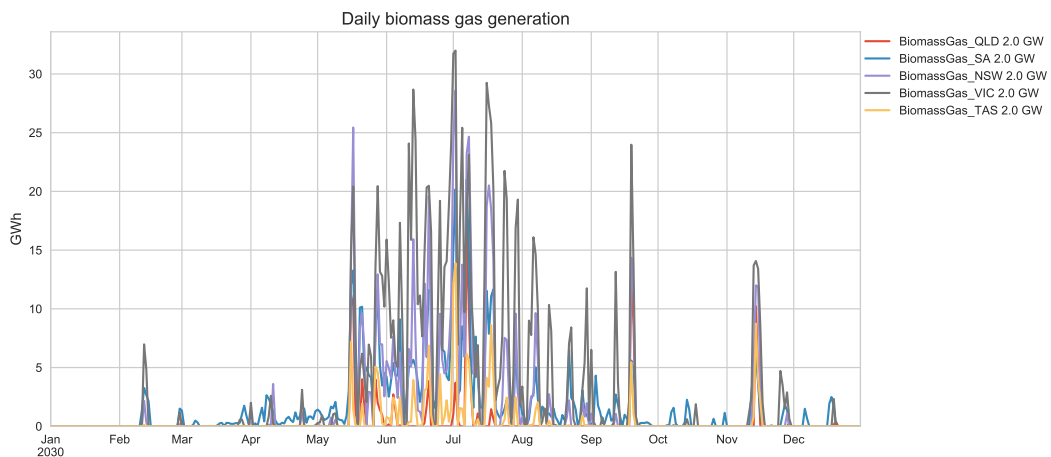


Figure 7.4: Daily biogas generation

The total spilled energy in the CST all scenario is 53 TWh, around 26% of the annual demand. More than half of the spilled energy is from CST generators, while wind also contributes more than 22% of total spilled energy. Due to our dispatch priority, less spilled energy comes from solar PV. Figure 7.5 shows the spilled energy by technology in each month. It shows that spilled energy from CST exhibits seasonal variation with significant spilled energy in the summer months (when solar irradiance is high) compared to winter months. This suggests that the

model is deploying CST capacity mainly as a means to meet winter demand. This aligns with the observation that larger amounts of storage are preferred (nine and twelve hours compared to six). In contrast, the seasonal variation in spilled energy for solar PV and wind is more muted.

Large amounts of spilled energy are common in previous studies of high penetration renewable systems. In [41], the average annual excess power is around double the demand for a 99.9% renewable system for the PJM system in the eastern United States. It is important to note, consistent with previous studies, no penalty is placed on spilled energy in this study. However, more responsive ‘flexible’ demand has potential to reduce the amount of spilled energy in a high penetration renewable system. In addition to conventional demand side management, this could include pre-cooling of buildings in summer months, charging of other storage mediums (e.g., hot water systems, ice storage for heating and cooling applications, production of hydrogen for transportation fuels or industrial processes), and the charging of electric vehicles. Another option to reduce spilled generation especially from CST, is to have maintenance outages or reduce output during the summer months. This is the reverse of the current situation in the NEM where thermal power stations (mainly coal-fired) are taken offline during low demand winter months.

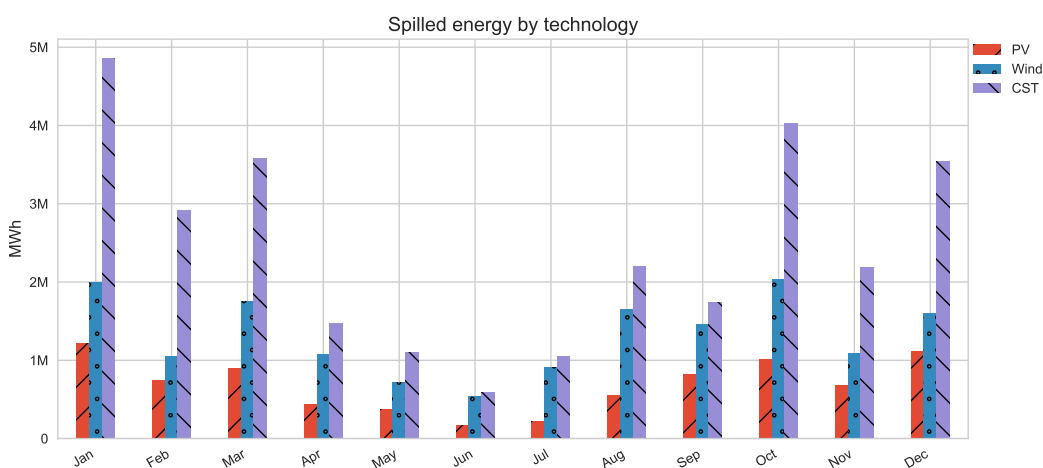


Figure 7.5: Spilled Energy, each month

7.3.3 Comparison of CST with different hours of storage

We then run the other three scenarios to observe the impacts of reducing the CST options on the technology mix and system cost with 5% and 10% real discount rates. Table 7.6 lists the least cost optimization results of the four scenarios. In general, the scenario with all three types of CST configuration has the least cost of all scenarios. This reflects three factors. First, the levelised cost of CST declines (but not indefinitely) as the number of storage hours increases (increased upfront capital cost is more than offset by improved capacity factor). Second, an increased number of CST configuration options increase the utilisation of each CST plant type. Third, the CST all scenario results in less deployment of solar PV and onshore wind in poorer quality resource regions. This increases the average capacity factor and marginally reduces the levelised cost of electricity generation. It also shows that in the scenarios when only one CST configuration is available, CST12 is the next lowest overall cost.

For both discount rate cases, the capacity of individual technology varies in different scenarios except biomass and biogas. The total capacity of biogas in all four scenarios are all 10 GW, which is the maximum allowed capacity in the model used in [42]. The biogas peaking plants are critically important to the system with large share of intermittent renewable generators. Similarly, the capacity of biomass generation has minor variations around the 2.2 GW upper bound in all scenarios. The reason for this is that they could provide least 80% continuous synchronous generation throughout the year, which is important to meet the synchronous demand together with generation from CST and run-of-river hydro. There is no deployment of battery storage in the CST all scenario in both discount rate cases. This reflects the multiple CST storage configurations meaning that large-scale batteries are not economic given the cost assumptions. Another factor is the temporal resolution in this study (i.e., hourly). This likely means that battery storage is undervalued in the modelling compared to a finer temporal resolution model, since batteries could provide frequency control ancillary services and faster ramping in shorter time scales.

In the 5% discount rate case, the capacity share of wind decreases while the share of solar PV increases if CST with longer hours of storage is available. This is because by the year 2030, the capital cost of large scale solar PV is projected to be lower than wind farms in Table 7.2, and the system could overcome the night period utilizing CST storage (i.e. the CST plant charges its thermal storage during the day and generates during the night) which reduces the need of generation from wind farms. The total capacity of CST in the CST all scenario is 16.6 GW and its average storage capacity is 10 hours. The total capacity of all CST in CST all scenario is similar to that in the CST9 scenario.

Table 7.6: Least cost combination for all scenarios, 5% and 10% discount rate

Technology	5% Discount Rate				10% Discount Rate			
	CST6	CST9	CST12	CST all	CST6	CST9	CST12	CST all
PV (GW)	18.8	22.9	23.4	23.6	25.8	20.8	21.5	20.8
Onshore Wind (GW)	36.3	28	22.3	25.8	30.4	33.9	33.1	31.6
Offshore Wind (GW)	2.8	4.5	1.7	4.9	4.4	4.4	3.8	3.1
Hydro (GW)	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9
Pumped Hydro (GW)	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
CST6 (GW)	21.7	-	-	1.7	17.2	-	-	7.6
CST9 (GW)	-	18.8	-	7.5	-	16.5	-	4.5
CST12 (GW)	-	-	26.1	7.4	-	-	14.9	7.8
Biomass (GW)	2.1	2.1	1.8	2.1	2.2	2.0	2.2	2.0
Biogas (GW)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Battery Capacity (GW)	0.1	0.3	0.0	0.0	0.6	0.0	0.0	0.0
Battery Storage (GWh)	0.3	1.5	0.0	0.0	3.5	0.0	0.0	0.0
Cost (\$/MWh)	77.1	76.8	75.6	74.6	112.5	113.1	110	109.7
Total Capacity (GW)	100.0	94.7	93.5	91.2	98.8	95.8	93.7	95.6
Spilled (TWh)	73.8	60.1	76.2	53.3	64.1	60.7	62.4	67.1

With the 10% discount rate, the total capacity of CST in the CST all scenario is 19.9 GW and its average storage is 9 hours. The discount rate is only used to calculate the annualized capital cost for each technology and it does not change the technology's O&M cost. The main effect of a different discount rate is to change the relationship between the annualized capacity cost and the O&M cost for the technology [21]. Interestingly we found that the capacity share of wind will be larger while share of PV be smaller if CST with longer hours of storage is used, which is opposite to the result in the 5% discount rate. The storage size of CST is not the only variable determined, but also its generating capacity.

When comparing the results on a subset of the scenarios (CST9, CST12 and

CST all) for the two discount rate cases, the capacity share of solar PV and CST decreases while the share of wind increases when discount rates are higher. The increased wind capacity could offset the inadequate generation caused by decreasing CST storage size during night. However, in the CST6 scenarios, the wind capacity slightly decreased while the share of solar PV largely increased when higher discount rate is used. This is caused by the increased battery storage which could provide sufficient electricity during night.

7.4 Additional sensitivity cases

7.4.1 Impact of CST cost

The previous results show that CST has a role to play in a 100 per cent renewable NEM system. In the following sensitivity analysis, we scale the cost of CST by 150% and 200%, while keeping other cost of other technologies unchanged, to test the robustness of these results.

Table 7.7 summarizes the results for the four CST scenarios with three cost sets. The battery storage size increases and the CST capacity decreases when higher CST costs prevail. The system cost difference between ScaleCST150 and BaseCost is much larger than the difference between ScaleCST200 and ScaleCST150.

It is also observed that in ScaleCST150 and ScaleCST200 the battery storage size increases and CST capacity decreases if the CST with longer hours of storage is used. CST6 scenario has the smallest cost except CST all in the ScaleCST150 and ScaleCST200 cost cases. While in the ScaleCST200 cost case, the CST12 scenario has the highest system cost compared with others. The system cost difference between ScaleCST150 and BaseCost of the four scenario ranges from 6.5% to 9.5%, while the cost difference between Scale200 and Scale150 only ranges from 2.1% to 4.1%. The assumed cost of CST has less impact on the system cost when it increases further. This can be explained as the price of CST increases, CST with more storage is less cost competitive compared to a system with some battery storage.

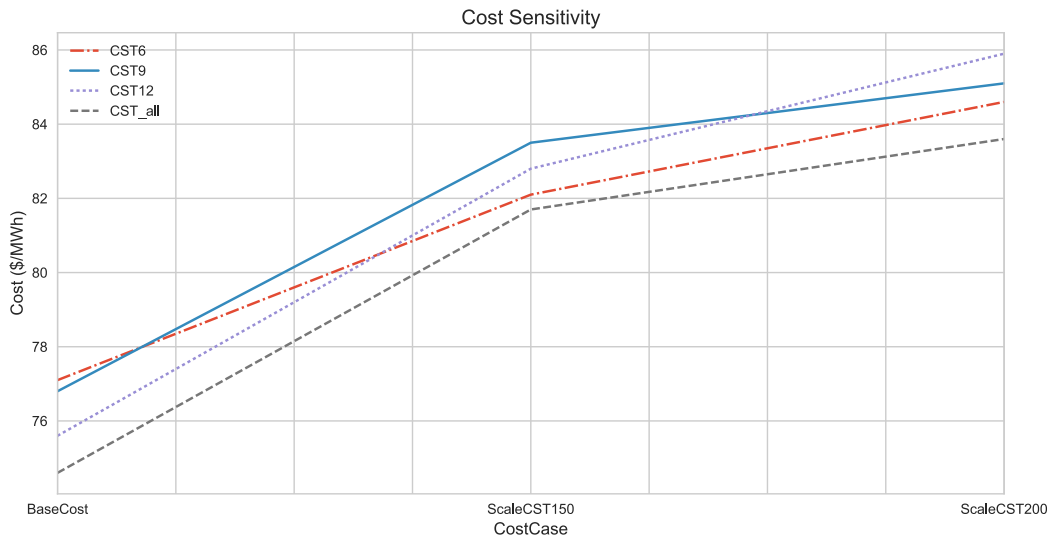


Figure 7.6: Cost Sensitivity

Table 7.7: CST cost analysis

CST Cost analysis	CST6			CST9			CST12			CST all		
	System Cost \$/MWh	Battery Storage GWh	CST Capacity GW	System Cost \$/MWh	Battery Storage GWh	CST Capacity GW	System Cost \$/MWh	Battery Storage GWh	CST Capacity GW	System Cost \$/MWh	Battery Storage GWh	CST Capacity GW
BaseCost	77.1	0.3	21.7	76.8	1.5	18.8	75.6	0	26	74.6	0	16.5
ScaleCST150	82.1	7	11.5	83.5	17.2	9	82.8	24.2	7	81.7	15.5	8.8
ScaleCST200	84.6	24	5.6	85.1	30.2	4.5	85.9	34.9	3.6	83.6	44.3	2.9

7.4.2 Impact of the renewable resources quality for different years

Results that were discussed in previous sections assumed renewable output over the simulated year using historical data for the year 2010. In order to test whether the optimized renewable mix could meet the minimum system reliability requirement (i.e., unserved energy less than 0.002% of energy consumed per year) in the NEM, the renewable mix from CST all was tested with 2004-2009 renewable profile data (solar PV, onshore and offshore wind, CST).

Two years passed the test without any penalty on excess unserved energy. The maximum unserved energy occurred when the 2007 renewable trace data was assumed, at 0.01% of the annual demand. The maximum unserved demand in an hour was around 6 GW across 6 years’ simulation and this occurred at 6pm on a Tuesday night in June (Tuesday is typically the highest demand day of the week in the NEM). The biogas-fired OCGTs were operating at full output in that hour. The wind gen-

eration or solar PV generation drops sharply while the CST generation is limited by its available storage at the time (typically low during winter). The unserved demand could be met if there is sufficient energy stored in CST at that hour.

This sensitivity result reiterates the finding that meeting demand during winter evenings is the most challenging time period for a 100 per cent renewable NEM power system. It underscores the importance of sufficient capacity of dispatchable renewable generation to be available during winter evenings. It also suggests that more flexible demand may have a critical role to limit the amount of additional capacity required. This is an important avenue for future research.

7.4.3 Impact of rooftop solar PV uptake

The hourly demand trace used in the analysis thus far has assumed a certain uptake of rooftop solar PV which reduces the demand to be served by renewable generators connected at high voltage, the main focus of this chapter. It is possible that the uptake of rooftop solar PV will be greater, and therefore less demand is presented to the wholesale market. Using an alternative scenario of rooftop solar PV uptake given by [134], the future annual demand in the NEM may sharply reduce to 156 TWh (compared to 210 TWh) due to increasing installation of residential and commercial rooftop solar PV. We test the renewable mix from the CST all scenario with the low demand data. The mix could meet the NEM's demand while the biogas-fired OCGTs in NSW and TAS are not used during the year. The annual cost of the NEM system is lower than the medium demand case as the operation cost is lower. However, the cost per MWh in the NEM is higher as the annual demand is smaller.

In addition, the CST all scenario was re-run with the low demand data, and the estimated system cost is around \$70/MWh. Figure 7.7 and Figure 7.8 shows the generation dispatch of the optimized renewable mix in the same winter and summer week.

The total capacity of the optimized renewable mix is 66.7 GW. The capacity size of biogas peaking plant and biomass does not change significantly. The following discussion are based on the comparison with the medium demand, 3CST, 5% discount rate case. All the biogas-fired power stations reach the allowed maximum

medium- and long-term emissions reduction targets. To address a gap in studies of 100 per cent renewable electricity systems, this chapter explored the impact of CST with different sizing of thermal storage. This chapter explored the potential role of CST in a 100 per cent renewable NEM system under different scenarios of CST configuration and subjected the results to sensitivity analysis.

A genetic algorithm (GA) was chosen as the optimization algorithm to seek the least cost combination of renewable generation technologies, transmission interconnectors and storage capacity in the NEM system. The main finding is that the scenario where all three CST configurations (six, nine, and twelve hours of thermal storage) can be deployed achieves a lower system cost than scenarios where the size of thermal storage coupled with CST is limited to one option. This result was robust to an increase in the real discount rate from 5% to 10% p.a.

The results also showed that there seemed to be a limited role for utility scale battery storage in the NEM when many CST configurations are available to be deployed. However, the sensitivity analysis showed that if the capital cost for CST is much higher than assumed in the main scenarios, then increased deployment of battery storage was economic. It is also possible that given the hourly temporal resolution of the modelling in this chapter, battery storage could be undervalued compared to a finer temporal resolution model, since batteries could provide frequency control ancillary services and faster ramping in shorter time scales.

The sensitivity analysis also showed that the scenario results are sensitive to assumptions of renewable resource availability. Similar to previous studies, this chapter found that meeting demand during winter evenings is the most challenging time period for a 100 per cent renewable NEM power system. This finding underscores the importance of sufficient capacity of non-intermittent renewable generation to be available for dispatch during winter evenings. It also suggests that more flexible demand may have a role to limit the amount of additional capacity required. This is an important avenue for future research.

Chapter 8

Scenario Analysis - Demand change

8.1 Background of this scenario

In the previous two sections, we have explored the possible generation mix and identify some key challenges in the future 100% renewable system using the historical demand or the projected demand by NEFR. For the future power system, not only the structure of the supply side will be changed, but also the level or shape of demand will be changed by many factors. The future annual amount of the energy and hourly profile will determine the optimum system configuration of renewables, storage and transmission. The total electrical energy demand (TWh) will change, as will the composition of demand by end use (heating cooling, etc.) and sector (domestic, services, industrial, transport), and changing composition will change profiles.

In this section, we explore the possible three demand change scenarios impact on the 100% renewable mix. By using the demand side model in DETRESO, we explore the demand change caused by building efficiency improvements and climate change. The demand changed caused by electric vehicles uptake is also considered in this section. We then explore the impact of the demand change in the renewable mix in future.

8.2 Demand model impact on optimization

In order to test the impact of the demand model on system optimization, we run the supply-side-model with the modelled demand and compare the optimized system

cost between using the modelled demand and using the historical demand. The *cst12h* scenario is used in the demand model validation. More information on this scenario will be given in Chapter 7. The following technology set is used in the *cst12h* scenario:

- Onshore and offshore wind
- Large scale PV
- CST with 12-hour storage
- Battery
- Existing run-of-river hydro and pumped hydro
- Biomass and Biogas
- CSIRO 2015 technology cost sets
- HistoryDemand: Historical demand from 2009-07-01 to 2010-06-31, 0910 financial year
- ModelledDemand: Modelled demand from 2009-07-01 to 2010-06-31, 0910 financial year

The optimization results are shown in Table 8.1. The least system cost from the optimization is 67.9 if ModelledDemand is used and 67.23 if HistoryDemand is used. The difference between the score is less than 1%. This difference is acceptable and shows that our demand model is accurate enough for high penetration renewable system optimization.

8.3 Scenario setup

There are five scenarios discussed in this section. They are NC (no change in profile), EE (Energy Efficiency), CC (Climate Change), TE (Transport electrification) and CS (Combination Scenario). In the NC scenario, we simply multiply historic

Table 8.1: Demand model validation result

Optimization ID	System Cost	Scenario	Info
0	67.23	cst_12h	HistoryDemand
4	67.56	cst_12h	HistoryDemand
6	67.9	cst_12h	ModelledDemand
11	68.26	cst_12h	ModelledDemand
1	68.52	cst_12h	HistoryDemand
7	68.74	cst_12h	ModelledDemand
2	68.84	cst_12h	HistoryDemand

profiles by the index percentage change in demand TWh for each region in scenarios assuming all end uses and sectors change by the same percentage. However, we noticed that in reality the profile would change because of different changes in sectors e.g. industry more base-load than domestic; the introduction of EVs. This scenario is to provide a benchmark generation mix result and for comparison of the other scenarios. The EE scenario discussed the demand change caused by buildings thermal efficiency improvement. The CC scenario discussed the demand change caused by increased ambient temperature due to climate change. The TE scenario discussed the demand change due to the transport electrification, especially the electrical vehicle uptake. The CS considered all the changes in the EE, CC and TE. The following of this section gives details about these scenarios.

8.3.1 NC: No change in profile

The NEFR suggests the total annual demand for each region at the target year (2030), based on the assumptions of economic growth, population growth, industry demand and other macro factors. When NEFR produced the future hourly demand trace, they assumed the shape of the hourly demand trace remains unchanged and remove the demand offset by residential rooftop PV and energy efficiency. The NEFR hourly trace also contains the EV demand. Using the NEFR hourly demand trace data cannot help us fully understand the impact of climate change, energy efficiency improvement and EV uptake in future to the NEM system. However, NEFR provides the useful implication for the relationship between the total annual electricity demand and the macro factors. To account the annual demand growth caused

by these macro factors, we scale the modelled annual demand to match the NEFR projected annual demand (without PV and energy efficiency adjustments) for each region. The following gives the details of the demand growth in each NEM region.

- Queensland: The Queensland actual demand in 2009-10 was around 50 TWh and the forecast demand in 2029-30 demand is around 60 TWh (excluding LNG demand, rooftop solar PV and energy efficiency adjustments). The LNG projects in Queensland are expected to consume around 10 TWh in 2029-30. We assume these plants are running all time across the year without any peak demand management, which means the baseload demand of Queensland will increase by around 1142 MW (10 TWh / 8760 hours) in our Queensland demand model.

We scale the modelled Queensland demand to 120% and then add 1142 MW baseload in order to account the electricity demand increased caused by population and economic growth.

- New South Wales: The New South Wales annual electricity demand in 2009-10 was around 75 TWh and the forecast demand in 2029-30 demand is around 85 TWh (excluding rooftop solar PV and energy efficiency adjustments). We scale the modelled New South Wales demand to 112%.
- South Australia: The South Australia annual electricity demand in 2009-10 was around 14 TWh and the forecast demand in 2029-30 demand is around 15 TWh (excluding rooftop solar PV and energy efficiency adjustments). We scale the modelled South Australia demand to 107%.
- Victoria: The Victoria annual electricity demand in 2009-10 was around 48 TWh and the forecast demand in 2029-30 demand is around 55 TWh (excluding rooftop solar PV and energy efficiency adjustments). We scale the modelled Victoria demand to 114%.
- Tasmania: The annual electricity demand in Tasmania changes slightly between 2009-10 and 2029-30. We keep the modelled Tasmania demand un-

changed in the NC scenario.

Table 8.2 summarises the changes in the modelled demand to match the NEFR 2029-30 annual demand assumption.

Table 8.2: Base scenario: no change in profile scenario

Region	Scale factor	Additional base load
QLD	120%	1142 MW
NSW	112%	-
SA	107%	-
VIC	114%	-
TAS	100%	-

8.3.2 EE: Energy efficiency improvement

With the improvement in the building thermal efficiency or introduction of new energy efficiency design buildings, the overall specific heat loss for buildings will decrease. This changes SHLh in the model and changes the hourly demand profile. Based on the NC demand scenario, we assume that the space heat loss will reduce 10% compared with the current level. The SHL_{new} is given by the following equation

$$SHL_{new} = SHL_{base} \times ScenarioTWhIndex \times BldgEffIndex \quad (8.1)$$

The $ScenarioTWhIndex$ is the base change in consumption because of population, economic growth or other macro factors. This is same as the scale factor shown in Table 8.2.

The $BldgEffIndex$ is the index of the building thermal efficiency. In this scenario, this will be 90%.

The retail gas price is expected to grow across in Australia as a result of global market energy price increase [137]. Consumers who currently use gas for space heating may replace the gas heaters with air conditioners, which will increase the winter electricity demand. Figure 8.1 shows the electricity and gas use in Australian dwellings in 2007. About 32% of Australian household use gas as their main source of energy for space heating, while 37% used gas for heating water. Between 2005

and 2008, the share of using reverse cycle as main heater increased from 28% to 37%, but the share of gas heaters dropped from 36% to 33% [138]. The main reason of selecting type of heating is comfort and convenience for Australian households, following by cost of the heating appliances, then the energy cost. The demand model does not simulate this trend as there are no available scenarios for this and lack of data. However, this may be considered in future work.

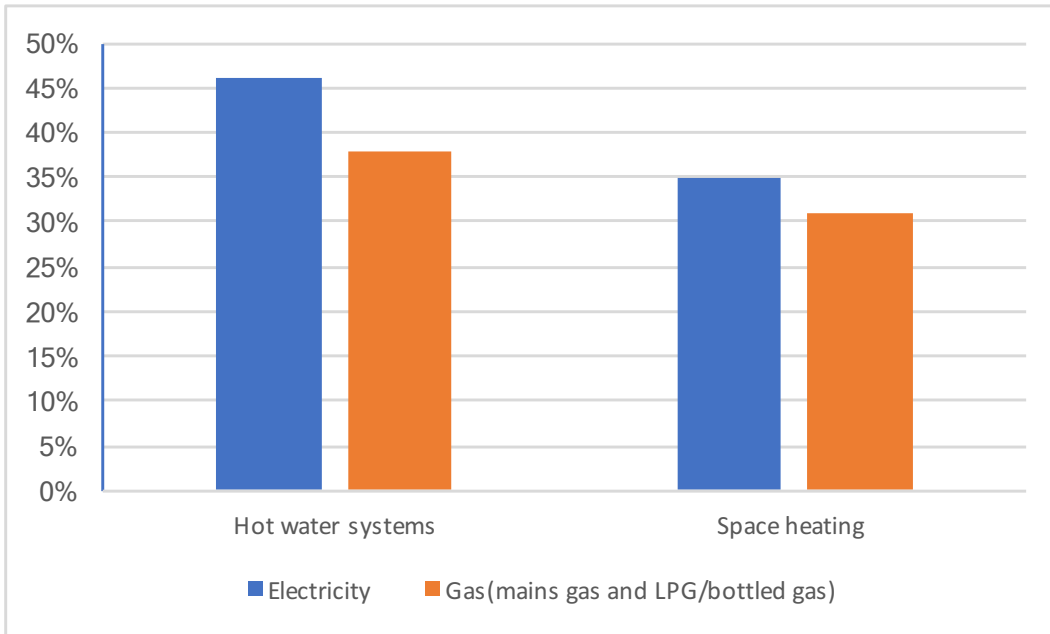


Figure 8.1: Electricity and gas use in Australian dwellings, source [139]

8.3.3 CC: Climate change

The energy required for space heating or cooling is partly determined by the difference between the ambient temperature and human comfort temperature. Climate change will increase the occurrences of the extreme weather as this will affect the T_h . By 2030, Australian annual average temperature is projected to increase by 0.6-1.3 °C above the climate of 1986 - 2005 under RCP4.5¹. The median temperature rise is around 0.9 to 1.0 °C².

¹Different Representative Concentration Pathways (RCPs) represent different scenarios of emissions of greenhouse gases, aerosols and land-use change in the IPCC assessment. RCP4.5 is the scenario with slower emission reductions that stabilise the CO₂ concentration at about 540 ppm by 2100.

²<http://www.environment.gov.au/climate-change/climate-science/climate-change-future/temperature>

Based on the historical weather data and NC demand data, we increase the ambient temperature by 1 degree Celsius across the whole year.

8.3.4 TE: Transport electrification

Transport electrification is increasing. The share of EVs will continue to increase in future with the reductions in battery cost, improved battery energy capacity, better charging infrastructure and tightening vehicle emission standards. These EVs increase the electricity demand and could change the demand profile. However, a possible strategy is using the surplus electricity from the renewables to charge these vehicles, which could improve the utilisation of the generation and reduce the overall cost of the electricity. It is estimated that in the optimisation model, the capacity share of the non-dispatchable renewable technology, especially the solar PV, will be increased as a result of its higher utilisation factor with EV charging.

- EV data

The EV numbers and fuel consumption per km at 2030 is from [140]. A medium projection of 20 per cent light duty road electric vehicle adoption by 2034 is used in [140], consistent with other studies which tend to focus on the next 15-20 years. The EV travel distance data is from a report by Australian Bureau of Statistics. Figure 8.2 to Figure 8.4 shows the detailed data and Table 8.3 shows the daily electricity consumption for each type vehicle.

1. PASL: Small passenger vehicle
2. PASM: Medium passenger vehicle
3. PASH: Large passenger vehicle
4. LCVL: Small light commercial vehicle
5. LCVM: Medium light commercial vehicle
6. LCVH: Large light commercial vehicle
7. RGT: Rigid truck

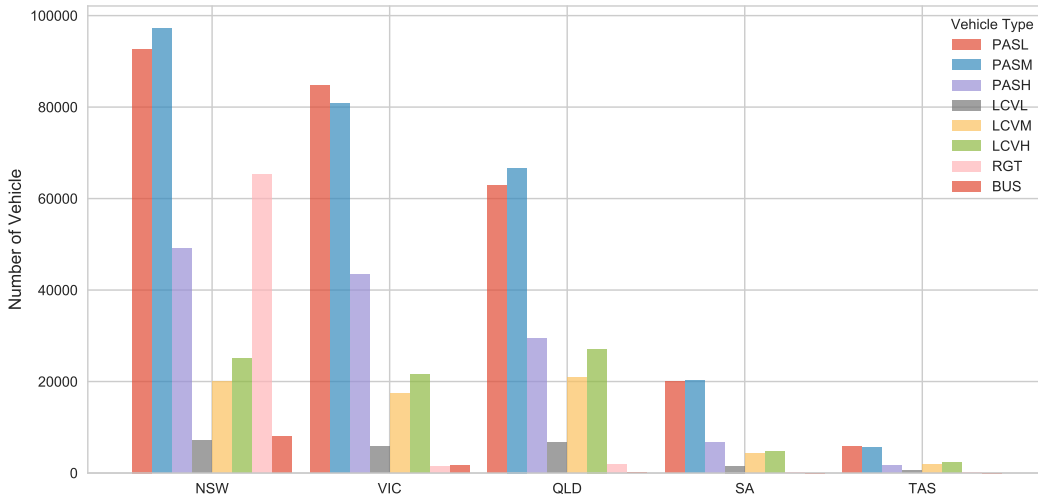


Figure 8.2: Number of EVs in 2030 [141]

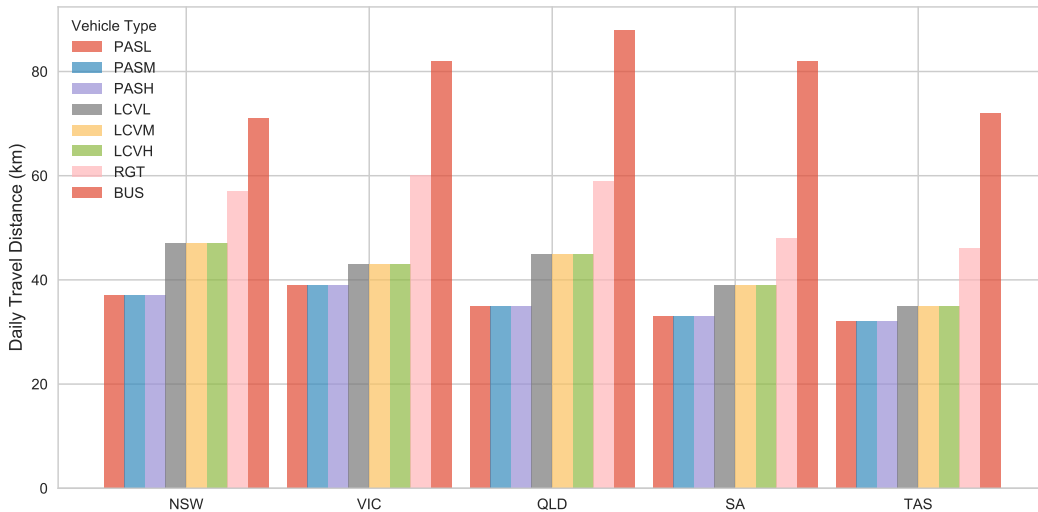


Figure 8.3: Travel distance of EV in 2030 [142]

Then the required charging electricity for each region is given by:

$$DailyElectricity_r = \sum VNumber_{r,y} \times Distance_{r,V} \times FuelPerKm_V \quad (8.2)$$

where r represent the NEM region and V is the type of vehicles.

The daily EV demand of the five NEM regions is 11.8 GWh, which equals to 2% of average daily NEM demand.

The EV charging activities are placed before the Second Stage of the supply

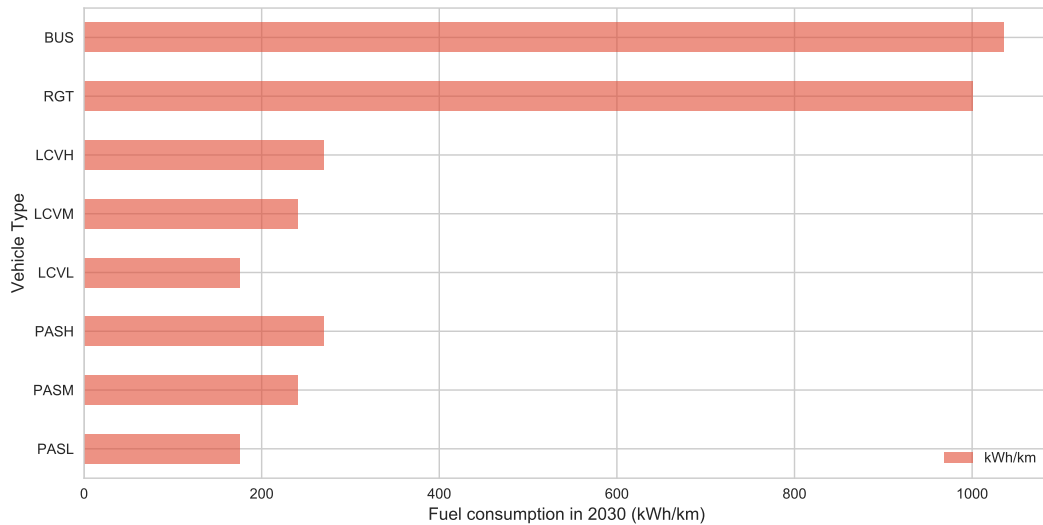


Figure 8.4: Fuel consumption in 2030, including a 15% charging loss

Table 8.3: Daily electricity consumption

Daily demand kWh/car	NSW	VIC	QLD	SA	TAS
PASL	6.5	6.8	6.1	5.8	5.6
PASM	8.9	9.4	8.4	7.9	7.7
PASH	10.0	10.5	9.5	8.9	8.6
LCVL	8.2	7.5	7.9	6.8	6.1
LCVM	11.3	10.3	10.8	9.4	8.4
LCVH	12.7	11.6	12.2	10.5	9.5
RGT	57.0	60.0	59.0	48.0	46.0
BUS	73.5	84.9	91.1	84.9	74.5

side model, which charges pumped hydro or other storage devices. A simplified dispatch flowchart is shown in Figure 8.5. We assumed a simplified daily charge behaviour of the EV in our model, which means in each simulation day, there should be enough electricity provided to EV to meet its daily energy consumption.

Generally, the surplus generation from solar PV, onshore or offshore wind and CST are used to charge EV batteries. When the daily EV demand is not satisfied at the end of a simulation day (2300), the storage devices (CST storage, electrical battery or hydro) and peak generators (the biomass peak part and biogas) will run to charge the EV battery at this hour. We call this hour the force charging hour. We trialled 4 am or 5 am as the force charging hour but the optimisation results show a higher system cost. This because that the challenging supply demand hour in the

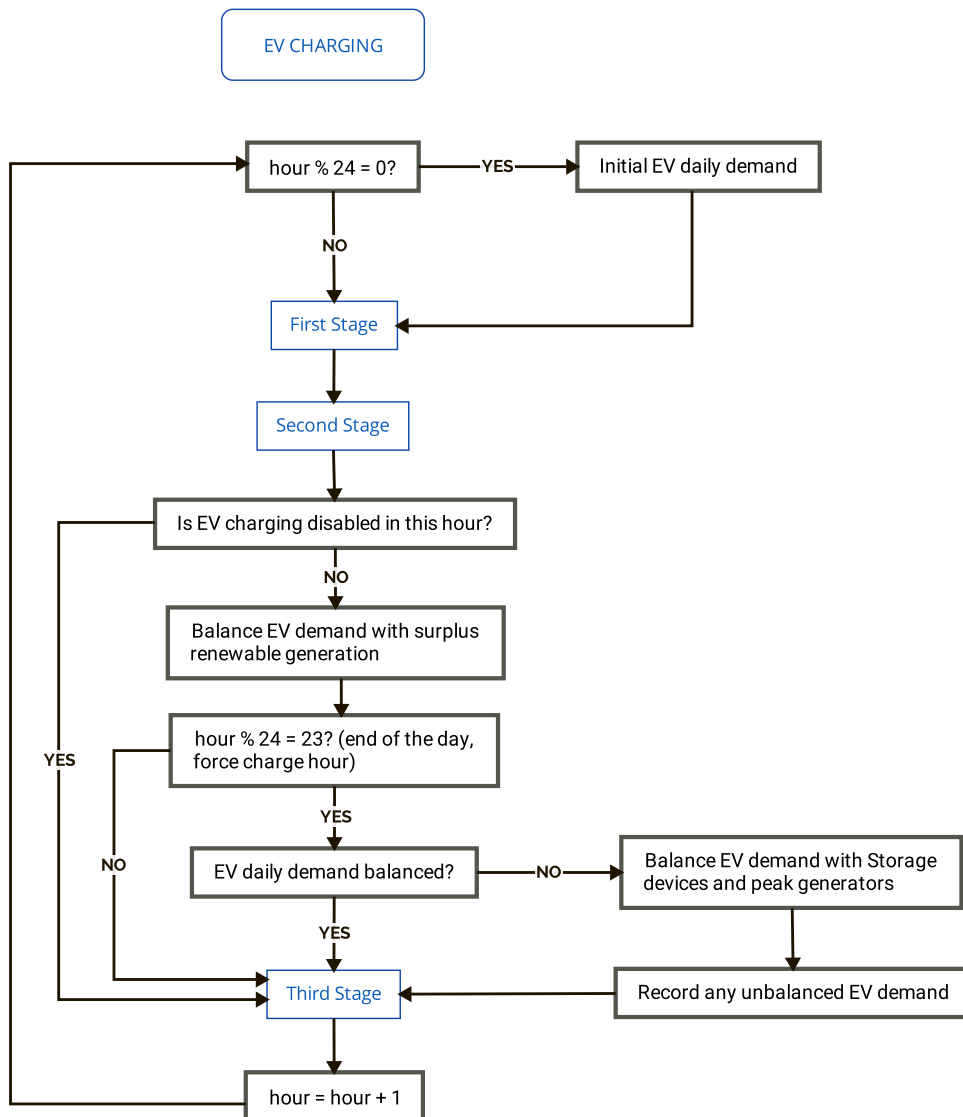


Figure 8.5: Dispatch process including EV charging

100% renewable electricity system is the cold winter early morning. In some winter mornings, the CST storage is empty and biogas generates at its installed capacity to balance the NEM demand. Charging EVs at these hours will increase this stress and the optimisation algorithm will allocate more capacity of the storage devices, and this will decrease the annual capacity factor of these storage devices as they are only used in full capacity for some hours. System cost will be increased as a result this. To avoid this, in the dispatch model we charge the EV at late night (such as 2300) by biogas generators when these generators are not needed for balancing the

system electricity demand and the daily EV demand exists.

Assumptions and control of charging:

- We firstly assume that EVs can be charged at any hour. It turns out most of the charging happens between 6am to 9am, during which most passenger cars may be used for commuting.
- Then we block the EV charging process during 07:00 to 08:59. The system cost and renewable mix does not change a lot compared with the 24 hour-free charging scenarios. In the following report, we will discuss the optimised system with block charging at 7am and 8am.
- The cost penalty will occur if daily EV demand is not balanced.
- Since our model is at state level and the daily travel distance of the EV is less than 90km, vehicles are assumed charged in their region (within each state).
- The capacity of the EV chargers installed at home could be 7.4 kW, however this capacity may increase in future. The current charger station capacity could be up to 120 kW (Tesla supercharge station). With these types of charger, the daily EV demand could be charged in less than one hour if there is sufficient electricity available for them.

8.3.5 CS: Combination Scenario

In this scenario we combine all the previous three scenario together(the EE, CC and TE) and call it as the combination scenario(CS). For most regions, the demand in CS is larger than the EE and CC scenario, but lower than the TE scenario, which is shown in Table 8.4.

8.3.6 Summary of scenarios setup

We modelled four demand scenarios: profile unchanged(NC), energy efficiency(EE), climate change(CC), transport electrification(TE) and combination scenario . The dispatch module is same in the NC, EE and CC. For the TE scenario, the dispatch module is slightly modified to simulate the EV charging process.

Each demand scenario has three technology scenarios. They are CST6, CST9 and CST12, similar to the ones used in CST uptake chapter. In total, there are 12 scenarios (four demand scenarios times three technology scenarios).

The following will give a discussion about the results in the EE, CC, TE and CS scenarios.

8.4 Modelled demand comparison

Table 8.4 shows the annual regional demand in different scenario. As expected, the EE scenario has the lowest annual demand among all the scenario, however the difference is small (1.5 TWh, 0.6%). The TE scenario has the highest demand.

Table 8.4: Regional annual demands in different scenarios

Demand(TWh)	NC_Scenario	CC_Scenario	EE_Scenario	TE_Scenario	CS_Scenario
NSW	86.4	86.5	85.8	88.9	88.4
QLD	73.2	74.3	72.9	73.9	74.7
SA	14.0	14.0	13.9	14.2	14.1
TAS	10.0	9.8	9.9	10.0	9.8
VIC	57.4	57.2	57.0	58.3	57.7
Total NEM	241.0	241.8	239.5	245.3	244.6

Figure 8.6 shows the modelled demand in NSW during a typical summer week. In the CC scenario, the higher ambient temperature increases the demand for air conditions in hot summer days and this is also when the peak demand occurs. QLD has the largest demand increased in CC scenario, around 1.1 TWh. For some regions where the energy used for space heating purposes is much larger than space cooling, the regional annual demand decreased in the CC scenario as the winter becomes warmer. This occurs in VIC and TAS.

In the EE scenario, the demand is lower due to the improved efficiency of the appliances and buildings. Similar to the CC scenario, the largest hourly demand difference between EE scenario and base scenario occurs in the hours when the ambient temperature is higher.

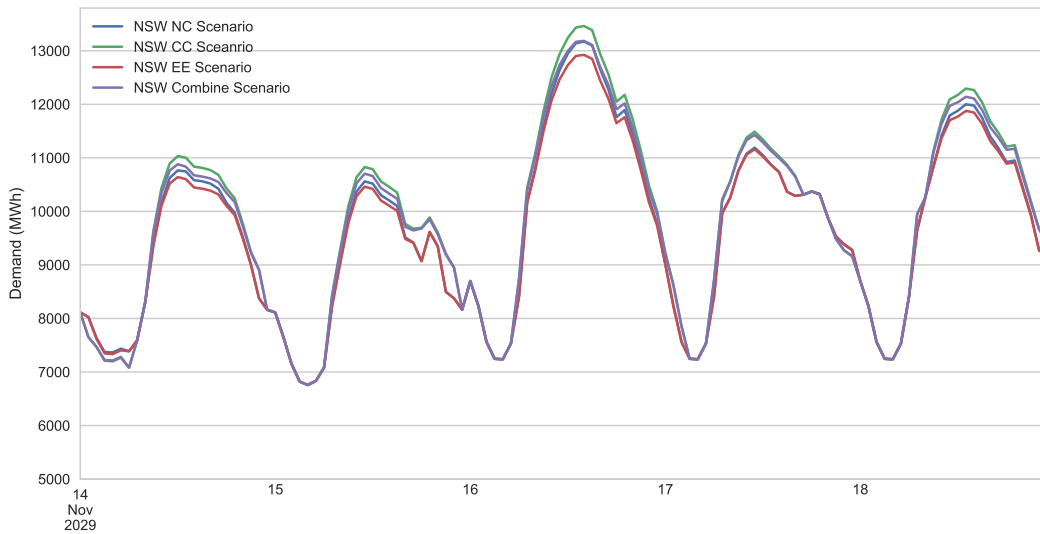


Figure 8.6: Summer demand in NSW in different scenario

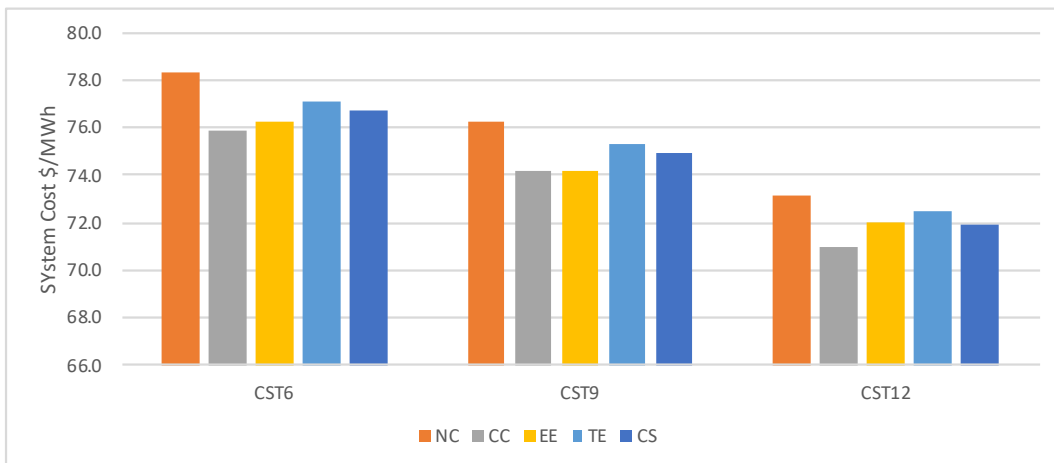


Figure 8.7: System cost in different scenario

8.5 Optimization result

8.5.1 System cost

Figure 8.7 shows the optimised system cost in each scenario. The NC scenario acts as a benchmark for comparison. The NC cost here is not comparable with the results we listed in the CST uptake chapter. The CST uptake chapter uses the NEFR demand trace developed by Plexos. Although the NEFR projected annual demand is lower than in the NC scenario, the demand at some winter morning in NC scenario is smaller than the ones in the NEFR.

Figure 8.8 shows the number of days in a month when the NC demand is

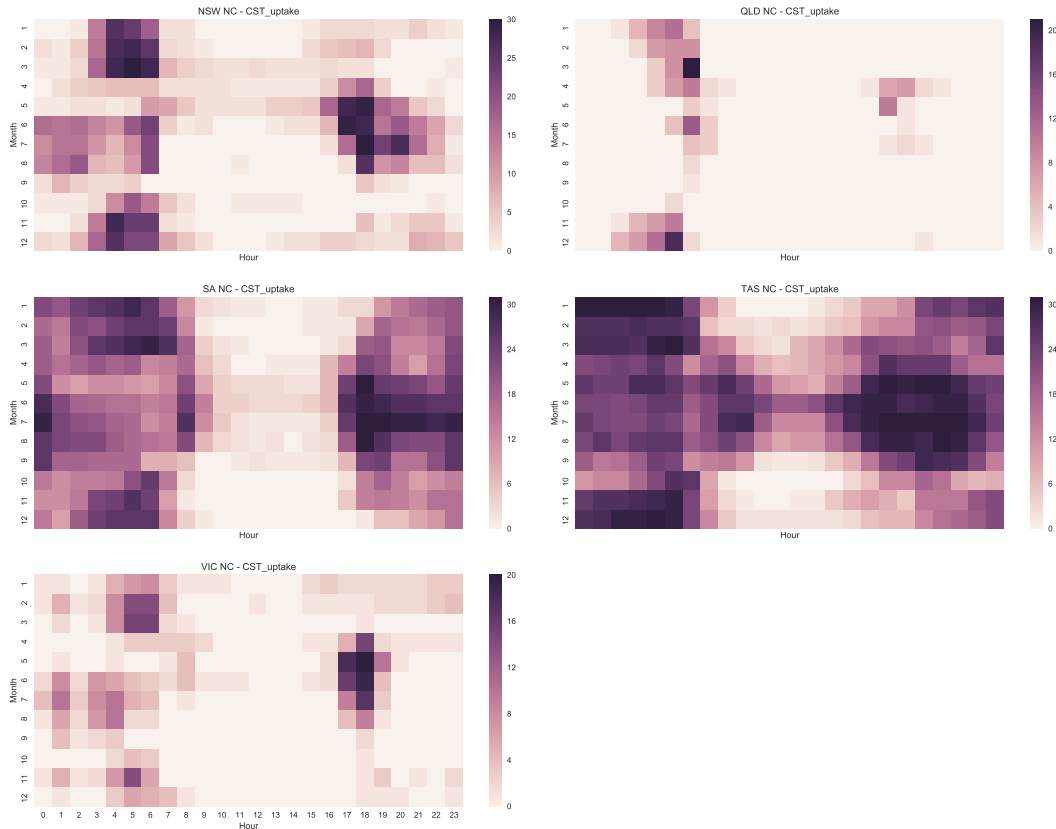


Figure 8.8: Number of days in a month when demand in NC is smaller than CST uptake scenario NEFR

smaller than NEFR demand in each hour, which indicates that the frequency of the NC demand being smaller than the NEFR demand is much higher at 4, 5 and 6 am in the winter months.

The most challenging time of demand-supply balancing for a 100% renewable electricity system in the NEM is the early winter morning. This is apparent in Figure 8.9, which shows the average hourly biogas utilization factor (we use the NC CST9 scenario result as an example). The highest biogas utilization occurs in the winter early morning. The winter morning demand in NC is smaller than the one in NEFR which reduces the need for the use of the biogas generators in these hours. As a result, the system cost is lower in the NC scenario.

In all the scenarios, the system cost will be lower if the longer CST storage technology used. Also, as expected, the system cost in EE scenario is lower than the NC scenario, because in the EE scenario the peak demand is lower. As a result

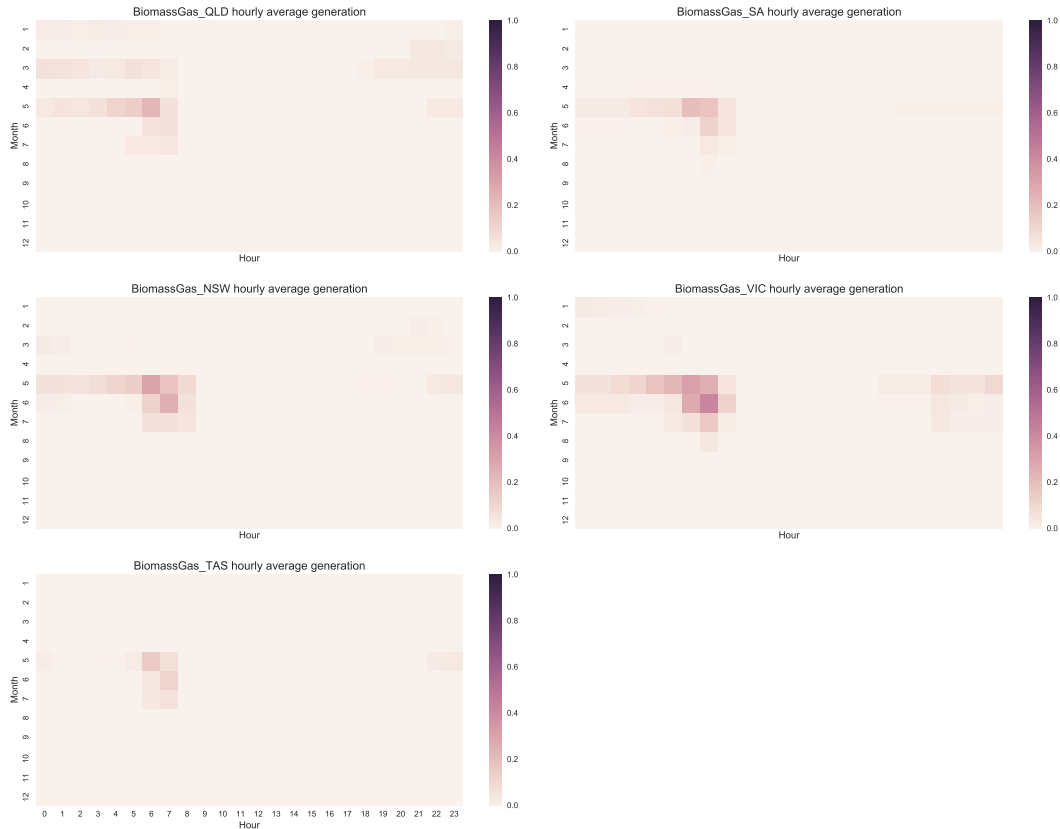


Figure 8.9: Average hourly biogas capacity factor in NC CST9 scenario

of the combination, the system cost of the CS scenarios is between the EE and TE scenario. This is mainly because it has a higher demand compared with the EE scenario, but lower demand compared with the TE scenario.

Table 8.5: CST and battery capacity in different scenario, unit MW

Scenario	CST6		CST9		CST12	
	CST capacity	Battery capacity	CST capacity	Battery capacity	CST capacity	Battery capacity
NC	37238	4482	37915	1607	41965	0
CC	39580	1353	34326	485	29071	0
EE	37434	1176	33309	430	31612	0

The system cost in CC scenario is lower than NC scenario, although CC demand is slightly higher than NC demand. As discussed before, the challenging time in the NEM is the early winter morning when PV generation is unavailable and limited output from wind and CST plants. In these time periods, the biogas plants will be used to supply the demand at a much higher cost. In the CC scenario, the winter night demand is lower due to increased ambient temperature. This reduced

the required amount of storage capacity in CST plants or batteries for the winter nights and mornings. Table 8.5 shows the storage capacity in different scenarios. The CST and battery capacity in CC and EE scenario is lower than the one in NC scenario.

The system cost in TE scenarios are smaller than NC scenario. The cost reduction is because the previously spilled energy was used to charge EV batteries. The increased utilisation of the renewables reduces the levelized cost.

8.5.2 Renewable mix

Table 8.6 shows the total generator capacity in each scenario. The CC and EE scenarios require less capacity than the NC scenario, although the difference is not very significant. The TE and CS scenarios require the highest capacity, but they have smaller system cost. The increased capacity in the TE and CS scenarios is mainly from solar PV generators. More details about this will be discussed below.

Table 8.6: Total generator capacity in each scenario

Total capacity (GW)	NC	CC	EE	TE	CS
CST6	111.9	113.2	110.2	115.0	116.4
CST9	107.5	104.2	102.0	112.7	113.5
CST12	103.3	98.1	96.7	108.9	104.0

The renewable mix of the three technology sets with NC demand is similar to the ones we have discussed in the CST uptake. The share of the PV capacity increased if the CST with longer storage system used. The EE, CC, TE and CS scenarios have the same trend. For the same technology scenario, the PV capacity share is higher in the TE or CS scenarios than the ones in the CC and EE scenario. Comparing with the NC, CC and EE scenarios, the TE scenarios have the largest PV share, particularly with the CST12 technology scenario.

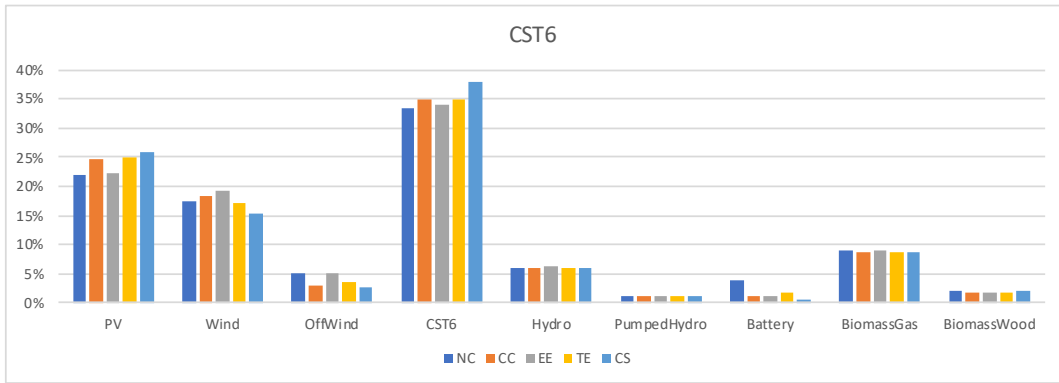


Figure 8.10: Capacity of each renewable technology, CST6 technology scenarios

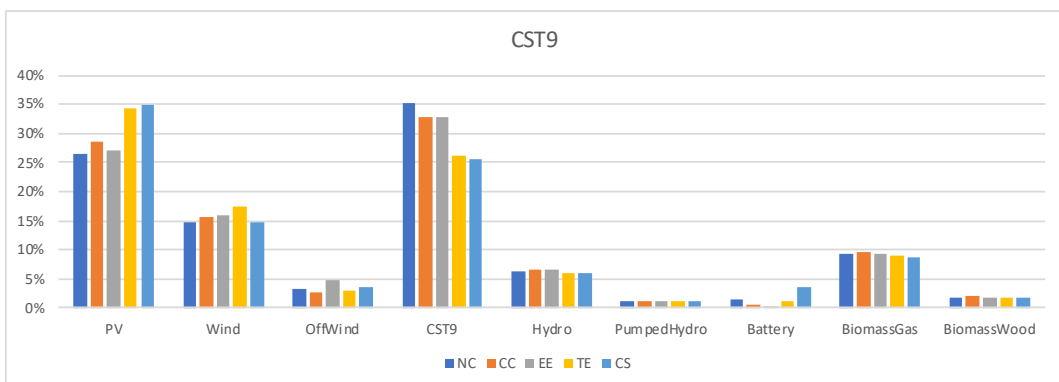


Figure 8.11: Capacity of each renewable technology, CST9 technology scenarios

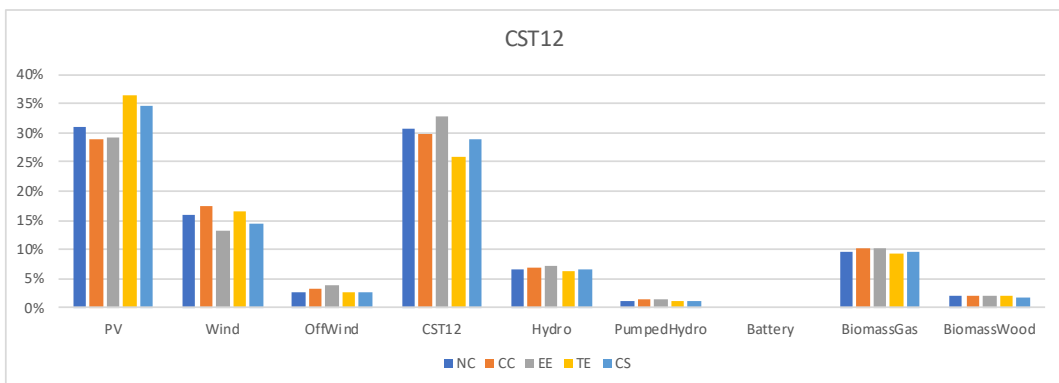


Figure 8.12: Capacity of each renewable technology, CST12 technology scenarios

8.5.3 TE model result

The TE CST9 scenario is used here as an example to present the EV charging activities using surplus renewable energy. Table 8.7 is the optimised renewable mix in the TE CST9 scenario. Onshore wind charges 24% of EV demand, while the solar

PV and offshore wind contribute 57% and 13%, respectively. CST contributes 5% of EV charging demand. Other technologies, used in the force charging hour, contribute around 1% of the total EV charging demand. The share of the EV demand charging is consistent with the dispatch algorithm since the EV charging sequence is solar PV, followed by onshore, offshore wind and CST.

The CST plants have the largest spilled energy followed by solar PV and wind. The CST9 annual spilled energy equals 27% of the annual modelled demand and 14.5 times the annual EV demand.

Table 8.7: Renewable technology mix in EV uptake scenario

Scenario: TE CST9	Capacity		To demand		Spilled GWh	Spilled Curtailed ratio	To EV	
	GW	Share	GWh	Share			GWh	Share
PV	38.6	34.3%	85,294	34.0%	17,358	16.5%	2,688	57%
Onshore Wind	19.5	17.3%	56,747	22.6%	7,050	10.9%	1,129	24%
Offshore Wind	3.5	3.1%	10,339	4.1%	5,158	32.0%	607	13%
CST9	29.5	26.1%	71,522	28.5%	67,184	48.4%	231	5%
Hydro	6.9	6.1%	10,525	4.2%	-	-	8	<1%
Pumped Hydro	1.3	1.2%	847	0.3%	-	-	2	<1%
Battery	1.4	1.2%	471.9	0.2%	-	-	4	<1%
Biomass Gas	10.0	8.9%	873	0.3%	-	-	43	<1%
Biomass Wood	2.0	1.8%	14,223	5.7%	-	-	-	-

If we run the NC demand scenario with the renewable mix from TE CST9 scenario (listed in Table 8.7), the system cost is \$78/MWh. The increased system cost is because, with the EV demand removed, the total electricity demand decreases while the total annualised capital cost and O&M cost of generators does not change.

8.5.4 EV Charging activities

Figure 8.13 shows the amount of EV charging by technology type in each hour. There is little charging between 00:00 and 06:00. During these hours, as shown in Figure 8.14, most generation to NEM demand is from wind turbines or CST storage while no surplus is available from other renewable generators. After 06:00, the solar PV starts generating and surplus energy is available from wind and solar PV. 06:00 to 08:00 is blocked for charging as we assume that most vehicles are in use and not connected to the grid during this time. The daily EVs charging demand could be met before midday.

Since most of the EVs charging between 8 am and 10 am, the average daily

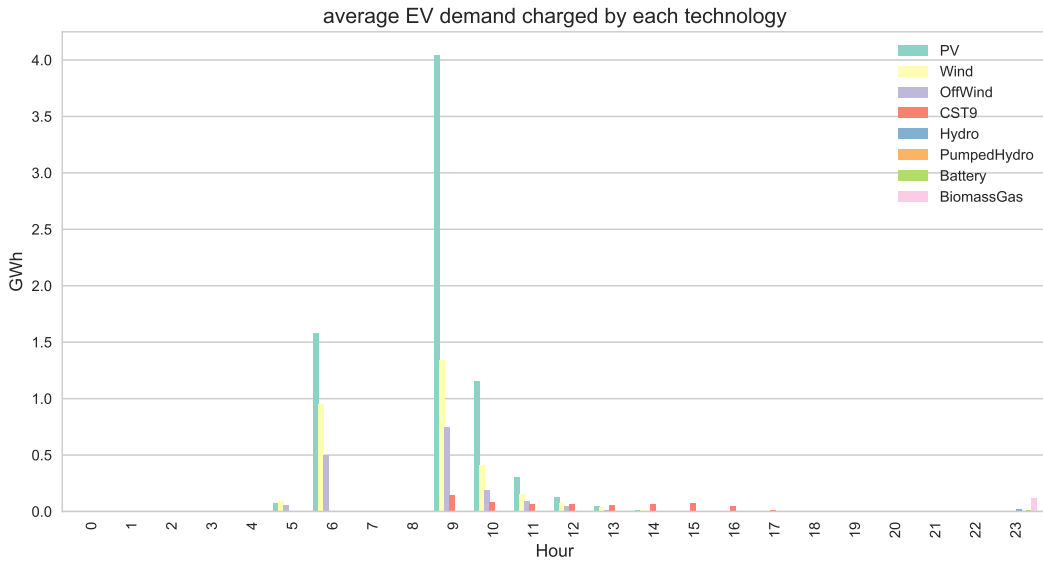


Figure 8.13: Hourly EV charged by technology type

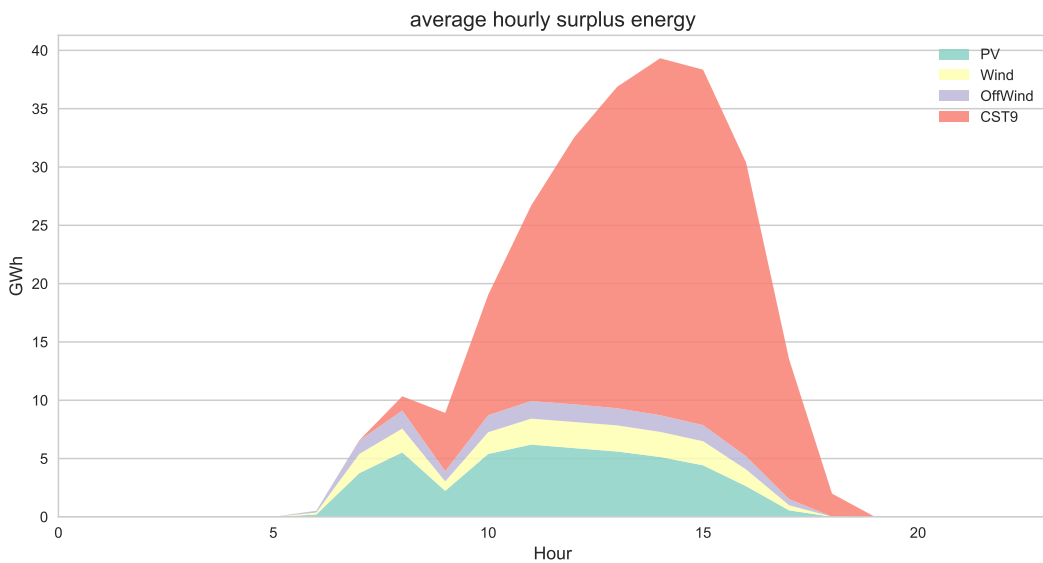


Figure 8.14: Hourly surplus energy by each technology

supply curve has a new peak in the morning if the EV demand is included, shown in Figure 8.15. The morning peak is higher than the evening peak. However, this peak does not increase the stress on the demand-supply system as it makes use of the surplus energy for the EV demand. The stressful demand-supply time of the 100% renewable electricity system is still the cold winter night.

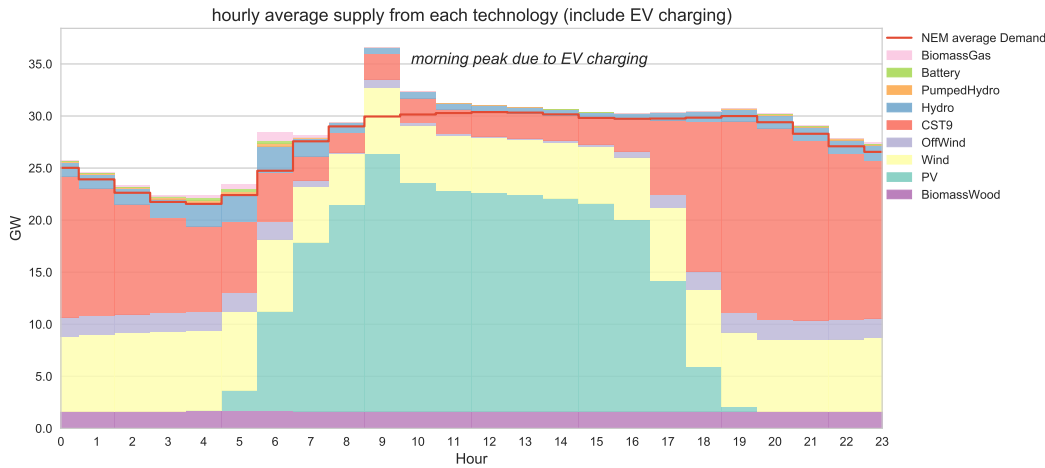


Figure 8.15: Average hourly dispatch generators technology

8.6 Concluding remarks from this section

In this chapter, we discussed the optimised renewable mix when demand profile changes due to energy efficiency, climate change and transportation electrification. Although the demand difference is not significant in these demand scenarios, the optimised renewable mix and system cost indicate some useful insights of the 100% renewable power system.

In the high renewable penetration system, the cost of supply is more associated with the hourly demand profile, especially the winter morning demand, rather than the annual demand. The stressful time in the traditional power system is normally when the peak demand occurs. For the NEM system, this is summer afternoon when a large amount of electricity is required for space cooling. In the high renewable penetration system, the capacity factor of the solar PV and CST are usually high in the hot summer afternoon. These solar generators can provide sufficient electricity.

The demand for space cooling increases as a result of climate change, while the demand for space heating decreases. For NEM regions, the annual demand of NSW and QLD increases while the annual demand of TAS and VIC decreases with climate change. The annual demand in CC scenario is about 0.3% higher than NC scenario, but the overall system cost in CC scenario is 2.5% lower than NC scenario. The reduced cost due to the lower demand in the winter nights.

Transport electrification could reduce the cost of the renewable electricity sys-

tem. A large amount of surplus generation is probably with a large fraction of renewable generation. Charging electrical vehicles with the surplus electricity could reduce the renewable curtailment ratio and levelized cost. A new morning demand peak is caused by the EV charging activities. The peak will not increase the system stress as the EV charging will only happen when the system has surplus renewable generation.

In the same technology scenario, NC demand scenario required more storage capacity from CST plants or batteries. The share of each technology type does not change significantly in different demand scenarios except the TE and CS scenarios. In NC, EE and CC demand scenarios, CST technology has the largest capacity share, varying from 30% to 35% in different technology scenarios. Solar PV constitutes around 25% to 30% of the total capacity. The share of the onshore and offshore wind capacity ranges from around 15% to 25%.

The solar PV capacity share is higher in TE and CS scenarios. The solar PV capacity share is around 35% in the CS CST9 scenario, compared with the 27% in the NC CST9 scenario. The higher solar PV capacity share results from surplus energy to charge EVs, marginally reducing the levelized cost of solar PV.

Chapter 9

General Conclusions

9.1 Summary of the work

This thesis concerns electricity only. It may be the case that energy services delivered by other vectors will have an impact on renewable electricity. For example, some of the constrained biomass resources might be used to make biofuels for aircraft or industrial products. However, a large fraction of renewable supply will be via electricity, and an extension to the whole Australian energy system is beyond the scope of this thesis.

The Australian electricity system is at a significant crossroads. Historically high retail electricity prices, the widespread deployment of solar panels, greenhouse gas emissions abatement, and declining aggregate peak demand and consumption in most states are some of the major issues that have put it at this crossroads, and there are several potential future directions. With environmental targets such as greenhouse gas emission limits, renewable technology costs decreasing, maturing storage systems and different electricity demand profiles in the future, the optimal generator mix and transmission system will be significantly different from the current system. A well designed renewable mix and transmission system can achieve net minimum system costs and transition the electricity system successfully.

The major work of the PhD is that some possible scenarios in the high renewable penetration in the five regions of the NEM, the main power system in Australia, are analysed. If the geographical range were extended to connection to other regions

such as Western Australia, or other countries, this might change the optimal mix, but this is beyond the scope of this thesis. Renewable generators, storage systems and transmission are the major parts of the system. The locations and capacities of the renewable technologies, such as solar PV, onshore and offshore wind, concentrated solar tower (CST), existing pumped and run-of-river hydro, batteries, biomass and biogas, together with the transmission expansion are considered in this study. The simulation model developed dispatches these renewable generators with preferred order and tracks the power exchange between the five regions of the NEM via interconnectors. A genetic algorithm (GA) is chosen as the optimization algorithm to seek the least cost combination of renewable generation, interconnector and storage capacity in the system.

For the demand side study, a model based on social behaviour and the ambient temperature was built to discover the possible change of demand shape or level due to improved energy efficiency or increased temperature due to climate change. The demand for EV battery charging is also considered in this study, but this demand is treated as a flexible demand and embedded in the system simulation model.

Three scenarios are discussed in this study: 1) battery uptake and transmission expansion; 2) CST uptake; 3) demand change.

We noticed that there is lack of the detailed co-optimisation of the renewable, storage and transmission for the high renewable penetration system in the NEM regions. To fill the gap, in the first scenario, we discussed the possible least cost combination of the wind and solar generation, battery storage devices and augmentation of regional interconnectors in the NEM for the year 2030. The results showed that battery storage devices have a key role in meeting power demands in a system dominated by intermittent renewable generation. We also found that significant amounts of energy are exchanged between the five NEM regions in such a high renewable energy penetration system. This scenario shows the importance of the storage in the future renewable power system, which leads us to the future research of the possible storage options in the NEM regions.

CST can collect and store the thermal energy of sunlight and then convert it

into electricity when needed. In the second scenario, we explored the potential role of CST in a 100 per cent renewable NEM system under different scenarios of CST configuration and subjected the results to sensitivity analysis. The main finding is that the scenario where all three CST configurations (six, nine, and twelve hours of thermal storage) can be deployed achieves a lower system cost than scenarios where the size of thermal storage coupled with CST is limited to one option. We also found that there seemed to be a limited role for utility scale battery storage in the NEM when many CST configurations are available to be deployed. The analysis also showed that the scenario results are sensitive to assumptions of renewable resource availability. Similar to previous studies, it was found that meeting demand during winter evenings is the most challenging time period for a 100 per cent renewable NEM power system.

The change of the shape and level of the demand impacts the renewable mix. In the third scenario, we discussed the optimised renewable mix and system cost when demand profile changes due to energy efficiency improvement (EE demand scenario), climate change (CC demand scenario), transportation electrification (TE demand scenario) and the combination scenario (CS). The optimised 100 per cent renewable system cost reduced in all the three demand scenarios. The main finding is that the cost of supply is more associated with the hourly demand profile, especially the winter early morning demand, rather than the annual system demand. The increased ambient temperature in the CC demand scenario leads to a lower space heating demand in the winter night and morning, which in turn reduce the overall system cost. The lower cost in the TE demand scenario caused by using the surplus renewable energy to charge the EVs. Charging electric vehicles with the surplus electricity could reduce the renewable curtailment ratio and levelized cost, and this also leads to an increased share of solar PV in the renewable mix. We found that a new morning demand peak is caused by the EV charging activities. However, this peak will not increase the system stress as the EV charging will only happen when the system has surplus renewable generation.

9.2 Limitation of the work and future work

There are some limitations and assumptions used in our model and scenario analysis to simplify this research. Improvements in results and robustness can be achieved with additional effort. The following lists the possible future work in the modelling and scenario analysis.

9.2.1 Modelling improvements - demand side

- Disaggregate into a residential and commercial & industrial demand

In this thesis, a physical demand model accounts for social activity, heating and cooling is built. This demand model is a regional level model. Each region has its hourly social activity use pattern to represent the customers behaviour to demand at different hours. However, the behaviour of residential customers and commercial & industrial customers are not the same in reality. Using the same hourly social activity use pattern for both residential and commercial & industrial customers may not accurately represent how these customers demand behaviour in different hours, and the mix of sectoral demands will change.

A possible improvement of this demand model is to disaggregate it into a residential demand and a commercial and industrial demand, and introduce separate hourly social activity use pattern for these demands. To do this, we need the hourly residential, commercial and industrial demand data, but this is not currently publicly available. One possible approach is to categorize the distribution level substations into serving residential area substations and serving commercial & industrial area substations. Figure 9.1 shows two weeks load in four substations in Victoria. The upper left figure (AC - MW) shows the load of a substation connected to a chemical factory. The bottom right figure (BAS - MW) shows the load of a substation serving a residential area. This shows that the demand profiles in these two substations are quite different. However, there are around 1000 substations in the NEM regions and it would take considerable time to analyse them and make best estimates

of sectoral profiles.

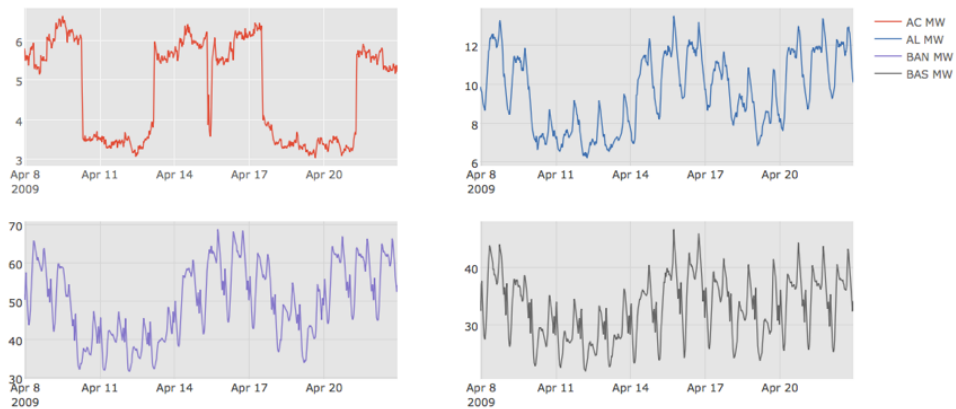


Figure 9.1: Demand load of 4 substations in Victoria, from 8 April to 22 April 2009

With separate models for residential and commercial and industrial demand, we could have a better estimation of the demand change driven by different factors, such as the closure of the energy-intensive factories, new LNG projects, or using efficient appliances in residential buildings.

- Additional variables in the demand model

As stated in Chapter 4.4, the demand model does not perfectly emulate historical data. One possible reason is that solar gain as a driver of air conditioning is not included. Future work may consider the solar gain as a variable in this model.

- Demand change caused by climate change

When exploring the demand change caused by climate change, we increase the ambient temperature by 1 degree Celsius across the whole year, which underestimates the demand in extreme climate conditions, such as on extremely hot days. Future work could introduce better assumptions on the ambient temperature change in the different NEM regions for the climate change scenario analysis.

9.2.2 Modelling improvement - supply side

- Finer spatial and temporal resolution

The DETRESO model has been applied at a state level and the electricity demand and renewable generation are aggregated to the demand hubs. Electricity is exchanged between these hubs. This is acceptable since the majority of the electricity demand is consumed at its local capital city in the NEM regions.

A model with a finer spatial resolution could better represent the actual electricity system. One possible future research avenue is to expand DETRESO model to the sub-state polygon level. The NEM regions are resolved into 43 polygons in the AEMO 100% renewable study. The generation data for each polygon is available while the demand data is not. A possible way to get the demand data is to mapping the distribution level substations into each polygon and then aggregate these demand data of all the substations in each polygon.

In addition, in the transmission module, we assumed the length of the interconnector is the distance between the regions geographical centres. The actual interconnector length will be longer than this because of geographical and other factors, and so this underestimates the cost of transmission expansion. If the model could be expanded into the polygon level, a detailed transmission network can be simulated. We could also identify the key part of the transmission network where requires capacity expansion. However, this would lead to a significant increase in computation time for simulating and optimizing a model with such a spatial resolution.

The DETRESO model uses an hourly temporal resolution. However, the hourly resolution model cannot fully simulate the events of the electricity system happening on shorter timescales. As discussed in Chapter 7, battery storage could be undervalued compared to a finer temporal resolution model, since batteries could provide frequency control ancillary services and faster

ramp rates that are evident in shorter timescales. The major difficulty in improving the temporal resolution of the model is the generation and demand data at the corresponding temporal resolution level.

- **Generation data**

The renewable generation data used in this research is from the AEMO 100 per cent renewable study. We noticed that the annual capacity factor of the solar PV, wind turbine and CST are slightly higher than in other studies. The primary aim of this thesis is to explore the optimal renewable mix in the future NEM system. The higher annual capacity factors of all the renewable technologies would not fundamentally change the share of the different technologies capacities, but indicate that the actual power system would cost more than we suggested in the optimization. In future work, alternative modelling of renewable generation might be applied.

Hydro plants play a critical role in the future high renewable penetration system, but the available hydro generation varies because of the rainfall, evaporation rates and temperatures in different years. This study uses the 2010 hydro generation data but the future work should analyse the system impact of the hydro resource variation.

9.2.3 Sensitivity of scenario analysis

- **Operating strategy to reduce the surplus electricity**

In Chapter 7 we noticed that there is a large amount of spilled electricity by CST in the summer months. Future work may explore using the electricity to pre-cooling of the buildings or charging of the other storage types such as hydrogen. More flexible demand may have an important role in the future system. As stated in Chapter 7, another option to reduce this surplus electricity is to have maintenance outages or reduce output during summer months of the CST plants.

- **Sensitivity of renewable technology costs**

In this thesis, two sets of the renewable cost data are used: one as given by AETA in 2012 [95], and the other given by CSIRO in 2015 [123]. The cost of the renewable technology ranges in different studies. Changes in the costs of technologies will impact the share of the renewable mix. This has been shown in Chapter 7, where the sensitivity of the CST technology's cost is analysed. Renewable costs have fallen in the five years to 2017, so future work could include further sensitivity analysis of technology costs, such as of solar PV, wind turbines and batteries.

- Smooth transition to the 100% renewable power system

This study explores the possibility and consideration of the fully renewable power system at target future year of 2030 because of the available projection and cost data, and we assume that the renewable generators can be built sufficiently rapidly to supply 100 percent in this future year. It would be more realistic to take a later year, say 2040 or 2050; this would require more input data but we conjecture that the optimal mix might not be substantially different as the relative technology costs may not change significantly. It would be worthwhile to exploring a smooth transition path from the current power system to a future fully renewable power system and this would mean including traditional power generators, such as coal-fired power stations. And further, non-electric renewable supplies such as solar heating could be included.

- 100% renewable power system in all the Australian states

This study simulated and optimized the fully renewable power system in the five NEM regions (Queensland, New South Wales, Victoria, Tasmania and South Australia). It might be interesting to explore the fully renewable power system in whole Australian regions, which needs accounting two more states - West Australia and Northern Territory. These two states could be connected to NEM transmission system, sensitivity analysis should consider whether to keep these two states power system isolated or connect them to the NEM system with building new transmission lines. Or further, to consider international

connectors.

- 100% renewable energy system

This study focuses on the 100% renewable electricity system in the NEM regions. It would be interesting to examine the fully renewable energy system in the NEM regions, which including other sector such as the agriculture, industrial process and transportation. In this thesis, the transportation electrification only includes road vehicles, which does not account for the aviation and shipping sectors. Biofuels might be an option for these sectors, but its limited feedstock will be a concern given that we assumed biomass and biogas have been used to generate electricity. Models for the agriculture, industrial process and transportation sectors need to be built. Future work might include examine the impact of such considerations on the whole energy system, and on the electricity system

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