100 PER CENT RENEWABLES STUDY – DRAFT MODELLING OUTCOMES

VERSION: DRAFT FOR STAKEHOLDER BRIEFING

DATE: 24 April 2013

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Acknowledgement
AEMO acknowledges the support, co-operation and contribution of CSIRO, ROAM Consulting, the Bureau of Resources and Energy Economics, Melbourne University and numerous stakeholders in preparing this report.

[1] http://www.aemo.com.au/About-AEMO/Legal-Notices/Copyright-Permissions

1 Introduction

On 10 July 2011, the Australian Government announced its Clean Energy Future Plan.

As one initiative under that plan, the former Department of Climate Change and Energy Efficiency (DCCEE) commissioned AEMO to undertake a study which explores two future scenarios featuring a National Electricity Market (NEM) fuelled entirely by renewable resources.[2] DCCEE specified a number of core assumptions on which AEMO was asked to base its study.

Any study of future energy supply—particularly one based on solely renewable energy— must consider how existing technologies will develop, and how new technologies will mature and become commercially available. Some commercially available renewables have limited scope for future development; others are still emerging, but may have commercial potential.

This study considers two scenarios with differing views about how quickly renewable technologies will develop over time. Accordingly, power systems with differing configurations are expected to emerge in each scenario.

The modelling undertaken presents results for four selected cases, two scenarios at two years, 2030 and 2050. The first scenario is based on rapid technology transformation and moderate economic growth while the second scenario is based on moderate technology transformation and high economic growth. The modelling includes the generation mix, transmission requirements, and hypothetical costs for each.

Given its exploratory nature, this study should be regarded as a further contribution to the broader understanding of renewable energy. The findings are tightly linked to the underlying assumptions and the constraints within which the study was carried out. Any changes to the inputs, assumptions and underlying sensitivities would result in considerably different outcomes.

1. The results indicate that a 100 per cent renewable system is likely to require much higher capacity reserves than a conventional power system. It is anticipated that generation with a nameplate capacity of over twice the maximum customer demand could be required. This results from the prevalence of intermittent technologies such as photovoltaic (PV), wind and wave, which operate at lower capacity factors than other technologies less dominant in the forecast generation mix.
2. The modelling suggests that considerable bioenergy could be required in all four cases modelled, however this may present some challenges. Much of the included biomass has competing uses, and this study assumes that this resource can be managed to provide the energy required. In addition, while CSIRO believe that biomass is a feasible renewable fuel3, expert opinion on this issue is divided.[4,5]
3. The costs presented are hypothetical; they are based on technology costs projected well into the future, and do not consider transitional factors to arrive at the anticipated cost reductions. Under the assumptions modelled, and recognising the limitations of the modelling, the cost to build a 100 per cent renewable power system is estimated to be at least $219 to $332 billion, depending on scenario. In practice, the final figure would be higher, as transition to a renewable power system would occur gradually, with the system being constructed progressively. It would not be entirely built using costs which assume the full learning technology curves, but at the costs applicable at the time.

It is important to note that the cost estimates provided in this study do not include any analysis of costs associated with the following:

1. Land acquisition requirements. The processes for the acquisition of up to 5,000 square kilometres of land could prove challenging and expensive.

[2] As defined by DCCEE.
[3] AEMO. Available at http://www.climatechange.gov.au/en/government/initiatives/aemo-100-per-cent-renewables/~/media/government/initiatives/aemo/APPENDIX5-CSIRO-biomass-energy.pdf. Viewed 18 March 2013.
[4] WICI. Available at: http://wici.ca/new/resources/occasional-papers/#no.4. Viewed 18 March 2013.
[5] "Biofuels and biosequestration in perspective" Australian Academy of Technological Sciences and Engineering, *Focus*, April 2012 (171) pp. 35–37

2. Distribution network augmentation. The growth in rooftop PV and demand side participation (DSP) would require upgrades to the existing distribution networks.
3. Stranded assets. While this study has not considered the transition path, there are likely to be stranded assets both in generation and transmission as a result of the move to a 100 per cent renewable future.

Costs for each of these elements are likely to be significant.

This report is not to be considered as AEMO's view of a likely future, nor does it express AEMO's opinion of the viability of achieving 100 per cent renewable electricity supply.

1.1 Assumptions and limitations

The assumptions below are fundamental to the study outcomes. Some are drawn from the scope of works published by the DCCEE in July 2012; others result from AEMO's Modelling Assumptions and Input Report released and discussed with stakeholders in September 2012.[6]

Assumptions given in the scope of works are as follows.

- The scope of works acknowledges the inherently uncertain nature of this study. Uncertainty exists around technologies that could emerge in the intervening 40 years, the cost of those technologies, and the potential for regulatory change in that timeframe.
- The modelling data was taken from the 2012 Australian Energy Technology Assessment (AETA 2012) produced by the Australian Government Bureau of Resources and Energy Economics (BREE). CSIRO and ROAM Consulting were commissioned to provide other key data, including projected resource availability and technology development rates.
- The study limits consideration to the electricity sector, and does not include the associated social, political and economic changes likely to arise from the scenarios modelled.
- The transition path from the current power system to the modelled 100 per cent renewable power systems is not considered. The estimated capital costs assume building all the new generation and transmission infrastructure at the estimated 2030 or 2050 costs. This means that the full advantages of anticipated technology cost reductions and performance improvements are included.
- Distribution system costs are not included in this study. This does not imply that distribution systems would be unaffected.
- No allowance has been made for land acquisition costs, financing costs, the costs of stranded assets or possible Research and Development expenditure needed to drive the forecast cost reductions.
- The scope explicitly excludes any consideration being given to nuclear, gas, coal, and carbon capture and storage generation.
- The study does not consider electricity supply outside of the NEM regions. This means Western Australia and the Northern Territory are excluded.

The following assumptions and limitations are also relevant when considering the modelling results. Some are drawn from AEMO's Modelling Assumptions and Input Report released in September 2012.[7]

[6] AEMO. Available at: http://www.climatechange.gov.au/en/government/initiatives/aemo-100-per-cent-renewables/aemo-input-assumptions-html.aspx. Viewed on 18 March 2013.
[7] See footnote 5

- While AEMO sourced the best cost estimates currently available for renewable generation technologies under Australian conditions[8], these estimates are likely to change over time as the technologies evolve.
- No consideration is given to costs of government policies that that may be needed to drive the transition to the modelled 100 per cent renewable power systems.
- Other than an anticipated uptake of electric vehicles (EVs), no other fuel shifting from gas or petrol is considered.
- The demand assumptions used in this report are based on AEMO's 2012 National Electricity Forecasting Report (NEFR) with revisions to fit with the 100 per cent renewables scenarios and extended to 2030 and 2050 using a regression model.
- The costs of developing the demand side participation (DSP), energy efficiency measures, and EV infrastructure assumed in the modelling have not been taken into account.

1.2 Key observations

While appreciating the exploratory nature of this study and noting the assumptions and sensitivities that heavily influence the results, AEMO notes the following observations drawn from the modelling results:

- **A wide range of technologies and locations are likely to be needed.** There is unlikely to be a single technology that dominates; rather, reliance on a broad mix of generation technologies is likely to be required to meet the existing reliability standards. The study shows that generation plant is likely to be spread across all NEM regions. This diversity of generation and location is critical to maintaining the supply/demand equilibrium necessary for system security and reliability.
- **Total capital cost estimates (hypothetical) are greater than $219 and $332 billion dollars**, depending on scenario. These costs are driven primarily by the study assumptions—in particular that all the plant would be built at the future estimated costs rather than progressively over the period. No allowance has been made for the costs of any modifications required to the distribution networks, the cost of acquiring the required land for generation or the costs of stranded assets. The modelling results are highly sensitive to the assumed technology cost reductions, and any changes to these would see corresponding modelling outputs.
- **Overall required to support a 100 per cent renewable power system may be between 2,400 and 5,000 square kilometres.**
- **The high level operational review found that operational issues appear manageable,** but it is noted that several key considerations would require more detailed investigation. Overall, the transmission network would require significant expansion to transport renewable generation to customers and significant management of the transition to 100 per cent renewables.
- **Considerable PV generation in all four cases drives demand and load pattern changes**. Based on the modelled PV generation levels the NEM is likely to become winter-peaking (in contrast to most regions' current summer peak), which means managing heating loads would be more critical than the current air-conditioning loads. The PV contribution levels also (typically) cause generation availability to peak around midday, so DSP would move demand into this period rather than the traditional late night off-peak periods.

[8] Sourced from the AETA 2012, CSIRO and ROAM Consulting. http://www.climatechange.gov.au/en/government/initiatives/aemo-100-per-cent-renewables/aemo-input-assumptions-html.aspx. Viewed on 18 March 2013.

- **More capacity relative to maximum demand is likely to be required.** The results indicate that a 100 per cent renewable system is likely to require much higher energy reserves than a conventional power system. It is anticipated that generation with a nameplate capacity of over twice the maximum customer demand could be required. This results from the prevalence of intermittent technologies such as PV, wind and wave, which operate at lower capacity factors than other technologies less dominant in the forecast generation mix.

2 Scope and approach

2.1 Scope summary

AEMO was engaged to study a 100 per cent renewables-based electricity supply system for the following four cases (two scenarios applied to two target years).

The scope of works published by DCCEE in July 2012 requested AEMO to explore optimised combinations of renewable electricity generation sources, associated transmission infrastructure and energy storage systems, and the resulting impacts on electricity prices under two scenarios:

- **Scenario 1:** Rapid transformation and moderate growth—this scenario assumes strong progress on lowering technology costs, improving demand side participation (DSP), and a conservative average demand growth outlook in the lead up to the year being modelled.
- **Scenario 2**: Moderate transformation and high growth—this scenario assumes current trends in lowering technology costs, moderate DSP, and robust economic growth in the lead up to the year being modelled.

Each scenario was modelled under two timeframes: 2030 and 2050.[9] This resulted in a total of four cases being modelled: Scenario 1 (2030), Scenario 1 (2050), Scenario 2 (2030), and Scenario 2 (2050). Under the scope of works, AEMO was required to prepare a report containing the following:

- Scenarios for a 100 per cent renewable electricity supply at 2030 and 2050.
- Generation plant and major transmission networks required to support each scenario.
- The estimated capital cost requirements for each scenario based in 2012 dollars.

Table 1: Scenario attributes

Scenario attributes	Scenario 1	Scenario 2
Transformation of the electricity sector	rapid	moderate
Economic and electricity demand growth	moderate	robust
Demand side participation	strong	weak

In line with the published scope of works, AEMO undertook the following key steps:

1. Resource investigation

   AEMO engaged expert consultants to estimate the potential quantity and quality of a range of renewable energy resources that would be accessible by 2030 and 2050 for use in electricity generation or energy storage technologies in selected NEM locations.

2. Scenario input development

[9] The target years for this report are financial years ending 2030 and 2050. Unless otherwise stated, any reference to 2030 means financial year 2029–30 and any reference to 2050 means financial year 2049–50.

Based on the resource investigation, AEMO developed modelling inputs consisting of the availability of various generation and storage technologies and their projected capital and operating costs in 2030 and 2050.

The Bureau of Resources and Energy Economics' (BREE) Australian Energy Technology Assessment 2012 (AETA 2012), which estimates the generation costs for a range of technologies to 2050, was taken as a starting point for the costs. The AETA 2012 estimates were augmented with further inputs on the future costs of some technologies provided by CSIRO and ROAM Consulting.

Using the 2012 National Energy Forecasting Report (NEFR) as a starting point, AEMO also developed specific annual electricity consumption projections for each of the four cases to suit the scope of works.

Steps 1 and 2 were documented in the Modelling Assumptions and Input Report released in September 2012.[10]

3. Modelling

Using information from the steps above, AEMO undertook modelling to determine the following:

- The generation and energy storage combination most suited to each case that met the reliability standard at least cost.
- The likely scale of transmission network augmentation required under each case.
- The hypothetical capital costs for each case, including indicative estimates of energy price outcomes for consumers.

The study scope published by DCCEE in July 2012 defined the deliverables to DCCEE and the Department of Energy, Resources and Tourism (RET) as:

- September 2012: Modelling Assumptions and Input Report
- March 2013: Draft Modelling Outcomes Report
- Mid-2013: Final Report

The scope also included a Literature Review, comprising a review of relevant national and international studies into 100 per cent renewables. A summary of the review is contained in Appendix 7.

The full scope document is available in Appendix 1.

2.2 Report structure

The remainder of this report consists of:

- Section 3 summarising the modelling methodology employed.
- Section 4 discussing the key inputs into the modelling.
- Section 5 presenting an overview of the modelling results across the four cases.
- Section 6 providing detailed results for each case modelled.
- Section 7 discussing the key operational considerations.

This is followed by several appendices providing background information and additional detail:

- Appendix 1 – Study scope.

[10] AEMO. Available at: http://www.climatechange.gov.au/en/government/initiatives/aemo-100-per-cent-renewables/aemo-input-assumptions-html.aspx. Viewed 18 March 2013.

- Appendix 2 – Additional generation details.
- Appendix 3 – Modelling methodology.
- Appendix 4 – Modelling sensitivities.
- Appendix 5 – Transmission design and costing.
- Appendix 6 – Operational considerations.
- Appendix 7 – Literature review summary.

3 Methodology

3.1 Modelling overview

In line with the scope of works, AEMO used least-cost modelling to determine an optimal combination of generation, storage and transmission investments to match the forecast customer demand for each case. The modelling also factored in a requirement to meet the current reliability standard in the NEM.

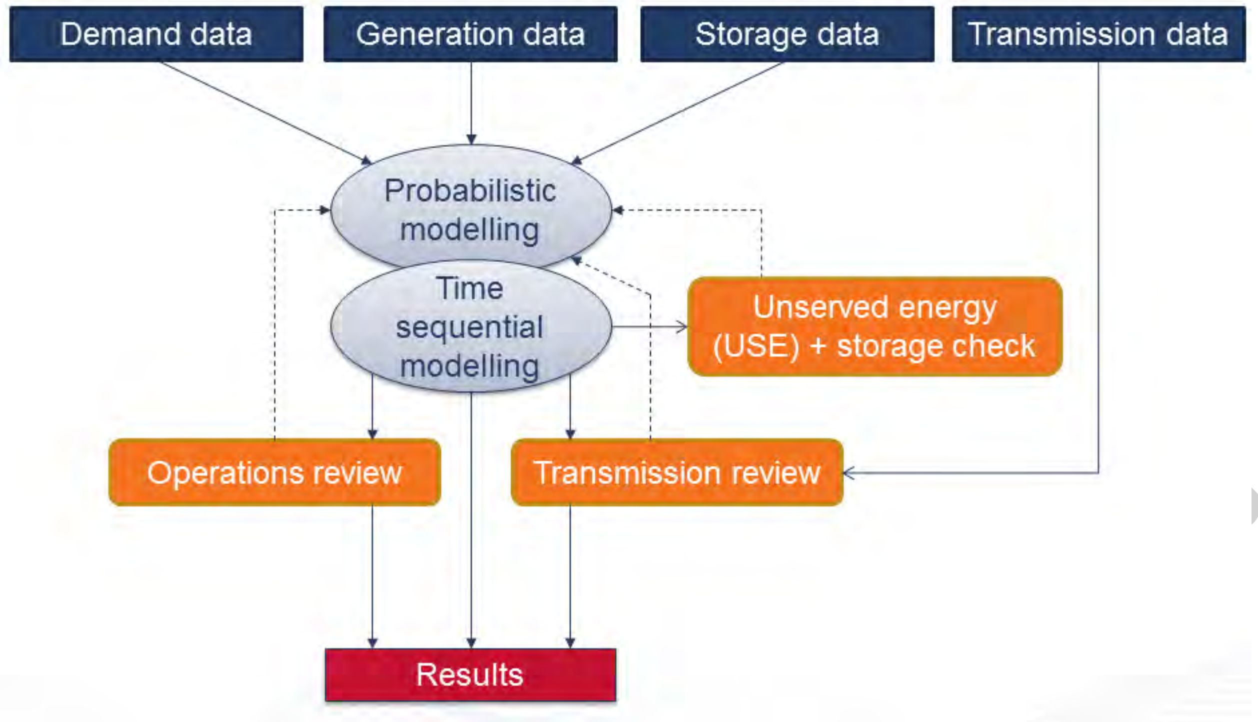
For each case, two different modelling tools were used:

- A probabilistic generation expansion model.
- An hourly time-sequential model for the year being studied.

The mathematical modelling results were reviewed from an operational perspective (to check that the resulting power system could be securely managed) and from a transmission network perspective (to estimate the transmission capability required to transport generation to load centres).

This process was repeated several times for both modelling tools, to take into account operational and transmission review feedback. After several iterations, the modelling for each case produced an optimised generation mix and transmission network which satisfied the operational and transmission assessments. The process is shown pictorially in Figure 1.

Figure 1: Methodology process overview



3.2 Probabilistic modelling

The probabilistic modelling used Monte Carlo simulation to generate 5000 random days for all four cases. Each random day contained hourly profiles of each renewable energy resource by location as well as customer demand and observed the historical correlations between each renewable resource, and between renewable resources and demand. The model simulated the dispatch of generation, demand side participation and daily storages (such as at Concentrating Solar Thermal (CST) plants and pumped hydro) to meet the customer demand at least cost across each of the random days.

For each of the four cases, the model was used to find the lowest cost mix of generation and storage that met the current reliability standard. Based on those hypothetical costs, the expected annual costs of supplying power could be calculated covering both capital and operating costs.

3.3 Time-sequential modelling

Time-sequential modelling was used to compare the hourly demand calculated for 2030 and 2050 with the hourly resource data for each renewable technology based on a historical year's climate data. This method addressed the following:

- Capacity sufficiency (the ability to meet maximum demand with the available renewable resources).
- Energy sufficiency (the ability to manage demand during sustained periods of time when generation from intermittent sources is low).

The time-sequential modelling was also used to calculate the power flows across the transmission system, which was then assessed in the transmission assessment. Finally, the time-sequential modelling was used to evaluate technological issues such as generator ramp rates, share of non-synchronous generation and other metrics identified in the operational assessment.

3.4 Operational and transmission assessments

The modelling assumed that the existing transmission system was available in all four cases. The transmission assessment investigated what additional transmission assets would be required to transport the modelled generation from where it is produced to the load centres at the lowest overall cost. This investigation explored both new transmission lines as well as upgrades to the existing transmission system.

The operational assessment considered a range of technical issues including frequency control and system inertia. Operational assessments also aimed to identify any generation mix adjustments likely to be required for system security purposes.

Operational considerations are detailed in Section 7.

Transmission outcomes are detailed in Section 5.4 and further detailed in Appendix 5.

4 Key inputs

In September 2012, a Modelling Assumptions and Input Report[11] detailing the key assumptions and inputs it would use during the modelling phase was published.

This section lists the key assumptions in that report, and includes any revisions or additions since its publication.

4.1 Electricity demand projections

AEMO developed a set of electricity demand projections for each scenario (detailed in Appendix 1 of the Modelling Assumptions and Input Report[12]), which were based on the 2012 National Electricity Forecasting Report.[13] Revisions were made to accommodate the 100 per cent renewables scenarios, including extending the forecast period out to 2050 using an electricity demand regression model.

The resulting demand projections for annual energy and diversified[14] maximum demand (50% Probability of Exceedence) used in the modelling are shown in the table below.

Table 2 shows two annual energy and maximum demand totals: one includes electricity generated by rooftop photovoltaic (PV)[15] installations and includes electricity consumption from electric vehicles (EVs); the other excludes these figures. Apart from the projected uptake of EVs, no other switching away from fossil fuels towards renewables-based electricity is assumed.

In the forecasts, 'accounting for rooftop PV' means subtracting the power generated by rooftop PV from maximum demand. Rooftop PV is not included in the NEM and does not require transmission infrastructure.

'Maximum demand accounting for rooftop PV' is the total energy to be supplied by utility-scale generators and transmission infrastructure. Similarly, 'annual energy accounting for rooftop PV' is the annual energy used by NEM customers minus that generated by rooftop PV.

Key points regarding the demand forecasts are:

- EV electricity demand was assumed to be optimised around availability of generation. This means EVs were assumed to be charged at times of high PV availability.

[11] AEMO. Available at:http://www.climatechange.gov.au/en/government/initiatives/aemo-100-per-cent-renewables/aemo-input-assumptions-html.aspx. Viewed 18 March 2013.
[12] See footnote 12
[13] AEMO. Available at http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2012. Viewed 10 March 2013.
[14] The diversified maximum demand takes into account that maximum demand in each state generally occurs at different times.
[15] Throughout this report, the term 'rooftop PV' refers to behind-the-meter generation. This generation is not included in the NEM and does not require transmission infrastructure.

- Accounting for rooftop PV results in the NEM becoming winter peaking in all four cases; summer demand is reduced significantly while winter peak demand remains essentially unchanged. Current maximum demand generally occurs during summer in most NEM regions.
- Demand side participation (DSP) was modelled as a supply-side option that acts to reduce peak maximum demand.

Table 2: Electricity demand projections

	2011 (for comparison)	Scenario 1 2030	Scenario 1 2050	Scenario 2 2030	Scenario 2 2050
Annual energy (TWh) not accounting for PV and EV	196	222	244	261	318
Annual energy (TWh) Rooftop PV generation	1[16]	23	35	15	27
Annual energy (TWh), EV	n/a	16	50	9	33
Annual energy (TWh) accounting for rooftop PV and EV	195	215	260	256	323
Maximum demand (GW) not accounting for rooftop PV, EV, and DSP*	34	38	42	43	52
Maximum demand (GW) accounting for rooftop PV, EV, and DSP*	34	35	40	41	52

* Most probable, or 50% POE

The PV figures are based on AEMO's 2012 Rooftop PV Information Paper.[17] The EV figures were modelled for this report based on the EV modelling used in AEMO's 2011 Electricity Statement of Opportunities.[18]

These projections include the impacts of increasing energy efficiency and decreasing energy intensity anticipated in a 100 per cent renewable electricity setting.

4.1.1 Trends affecting demand: energy efficiency, rooftop PV and demand side participation

These projections demonstrate relatively low growth in demand, reflecting a less energy-intensive future which is primarily driven by energy efficiency, rooftop PV and DSP.

This is particularly evident in Scenario 1, which assumes rapid transformation of renewable technologies, and where PV, energy efficiency and DSP more than counter any demand increases caused by expected EV uptake.

In all four cases, anticipated rooftop PV generation growth is likely to be high enough to contribute to the NEM becoming winter peaking—a major change from the situation today.

Expected DSP increases result from appropriate incentives being implemented to enable consumers to alter the quantity and timing of their energy consumption to reduce costs. This is expected to drive a shift in consumption patterns that responds to market needs and takes advantage of high renewable generation availability (usually when PV is peaking) to reduce energy spills.

Scenario 1 assumes up to 10% of demand in any hour is available for DSP and Scenario 2 assumes up to 5%. For each case modelled, half of the DSP is assumed to be curtailable load (that is, demand which can be reduced at a given cost[19]) and half is modelled as 'movable

[16] AEMO Rooftop PV Information Paper, 2012. Available from: http://www.aemo.com.au/Electricity/Planning/Forecasting/~/media/Files/Other/forecasting/Rooftop_PV_Information_Paper_20_June_2012.ashx.Viewed 10 March 2013.
[17] AEMO. Available at: http://www.aemo.com.au/Electricity/Planning/Forecasting/Information-Papers-2012. Viewed 18 March 2013.
[18] AEMO. Available at http://www.aemo.com.au/Electricity/Planning/Archive-of-previous-Planning-reports/Electricity-Statement-of-Opportunities-2011. Viewed 18 March 2013.
[19] This represents a potential loss in manufacturing output or loss of customer utility.

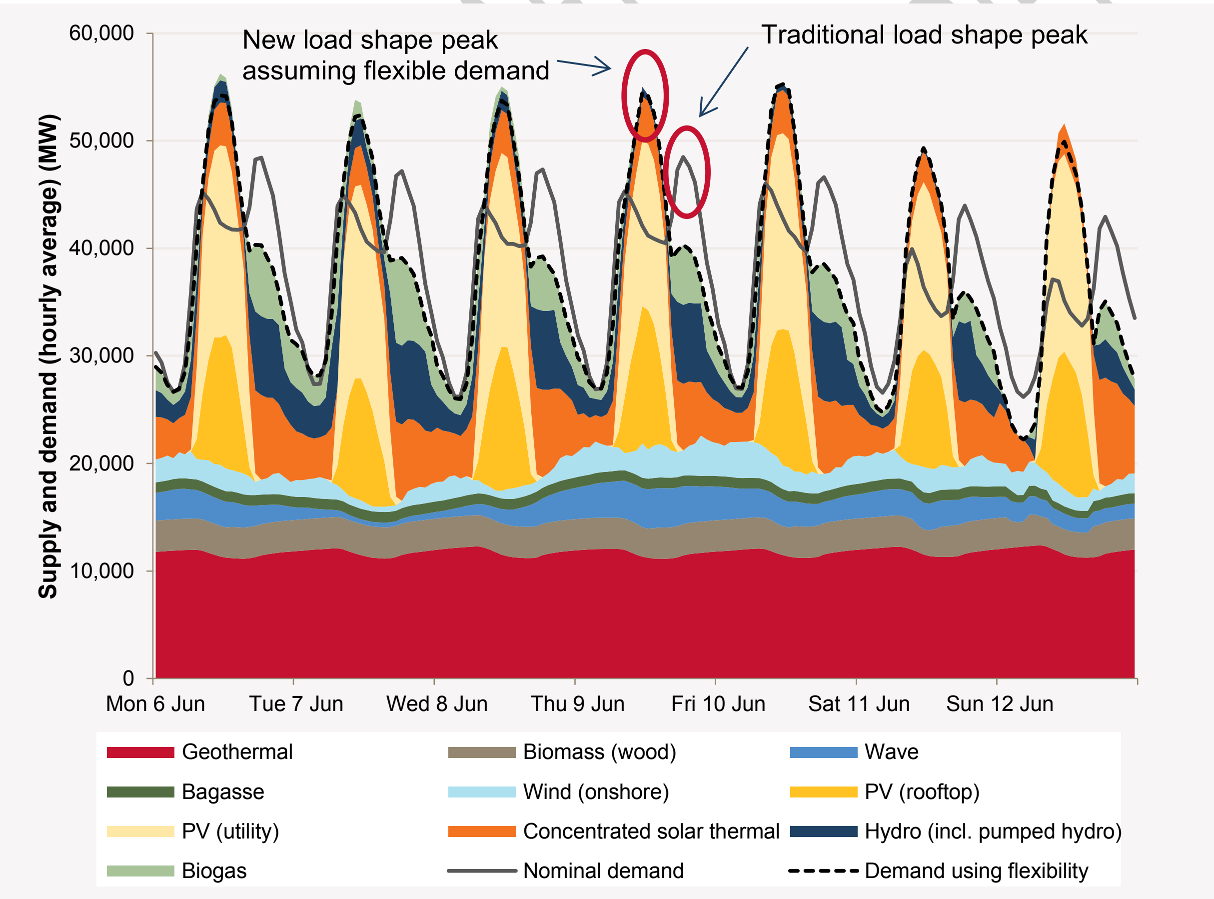
demand' (also known as flexible demand) where any reduction in demand must be consumed at an alternative time that day, though at no cost.

Figure 2 shows a sample forecast demand profile from the study, and demonstrates how DSP results in demand shifting from evening to midday, when solar generation is high. Both the flexible demand and voluntary curtailment components of DSP represent voluntary customer behaviour. These are separate to unserved energy, which is involuntary curtailment of customer demand. The reliability standard discussed in section 4.2 refers to unserved energy only, not DSP.

In this report's supply and demand graphs, such as Figure 2 below, the following terms are used to describe hourly demand assumptions:

- 'Nominal demand' means the demand forecast produced by AEMO for that hour, not accounting for rooftop PV or DSP, but including the average hourly EV energy recharging rate.
- 'Demand using flexibility' means the demand forecast produced by AEMO for that hour, not accounting for rooftop PV. It includes the flexible demand component of DSP but excludes the voluntary curtailment component. It includes the optimised EV charging rate for that hour.

Figure 2: A sample forecast demand profile demonstrating load shape changes



4.2 Reliability standard

The modelling assumed that a renewable electricity supply system would be configured to deliver electricity in line with current reliability standards.

Specifically, this means installing sufficient generation and transmission capacity to maintain the current long-term NEM reliability standard set by the Australian Energy Market Commission's Reliability Panel.[20]

The current standard is that the long-term average unserved energy (USE) over a year is less than 0.002% of annual energy consumption (or in other words, at least 99.998% of energy requirements are met).

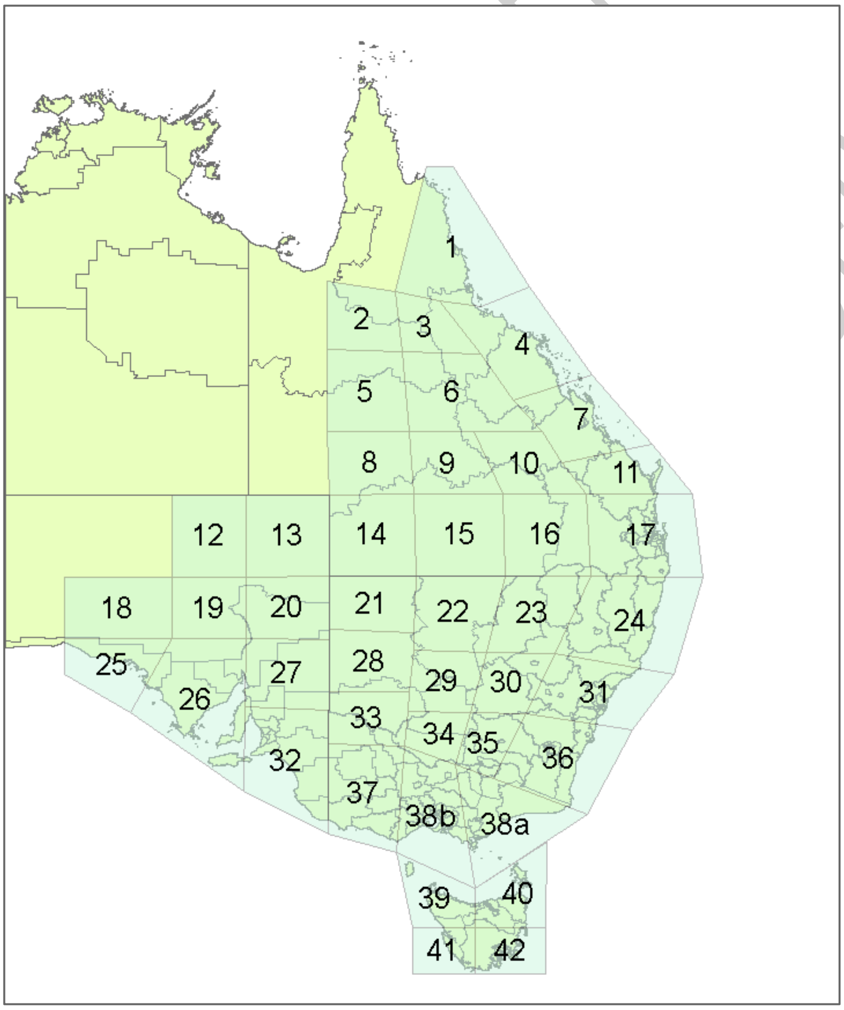
4.3 Energy resources and location

To account for geographical differences in resource quality and quantity, AEMO divided the five NEM regions into 43 locational polygons, shown in Figure 3 below.

This level of resolution also allowed conceptual costing of electricity transmission lines connecting renewable sources to load centres.

Renewable energy and energy storage data for the 43 polygons, including generation profiles and resource potential, is documented in the Modelling Assumptions and Input Report.[21]

Figure 3: NEM locational polygons



[20] AEMC. Available at: http://aemc.gov.au/panels-and-committees/reliability-panel.html. Viewed 18 March 2013.
[21] AEMO. Available at: http://www.climatechange.gov.au/en/government/initiatives/aemo-100-per-cent-renewables/aemo-input-assumptions-html.aspx, Appendix 1. Viewed 18 March 2013.

4.4 Energy resources assessed

AEMO's consultants investigated a range of historical weather and spatial data to develop estimates of the energy resource available from each technology at each of the 43 NEM polygons selected for this study. Consideration was given to issues that might limit access to these resources, such as competing land uses, topography and population density.

These energy resource estimates were used to calculate the maximum installable generation capacity for the renewable energy resources listed in Table 3 below.

Technologies included in the study are those which:

- Fit the project scope (so fossil fuel, carbon capture and storage, and nuclear are excluded).
- Are commercially available or projected to be commercially available.
- Were costed in the AETA 2012, CSIRO and ROAM Consulting reports.[22]

For simplicity, the modelling used one representative technology to infer several possible variants in the following cases:

- Concentrating Solar Technology (CST): This could stand for solar thermal with central receiver, linear Fresnel or parabolic trough. The modelling used central receiver costs and details.
- Utility PV: This could stand for PV with single axis tracking, double axis tracking or concentrated PV. The modelling used single axis costs and details.

The table below provides a summary of total resource by technology. A breakdown of technology per polygon is available in the Modelling Assumptions and Input Report appendices.[23]

This table demonstrates that the overall potential for renewable generation is about 500 times greater than forecast NEM demand in terms of both capacity and energy.

Table 3: Total resource by technology

Resource	Maximum installable generation capacity (GW)	Maximum recoverable electricity (TWh/yr)
Wind – onshore (greater than 35% capacity factor)	880	3100
Wind – offshore (greater than 50% capacity factor)	660	3100
Solar – CST/PV	18,500 / 24,100	41,600 / 71,700
Geothermal (EGS)	5,140	36,040
Geothermal (HSA)	360	2,530
Biomass	16	108
Wave	133	275
Hydro	8	12
Total	25,700 / 31,300	86,800 / 116,900
Current NEM (actual installed capacity and annual generation, all technologies)	50	200

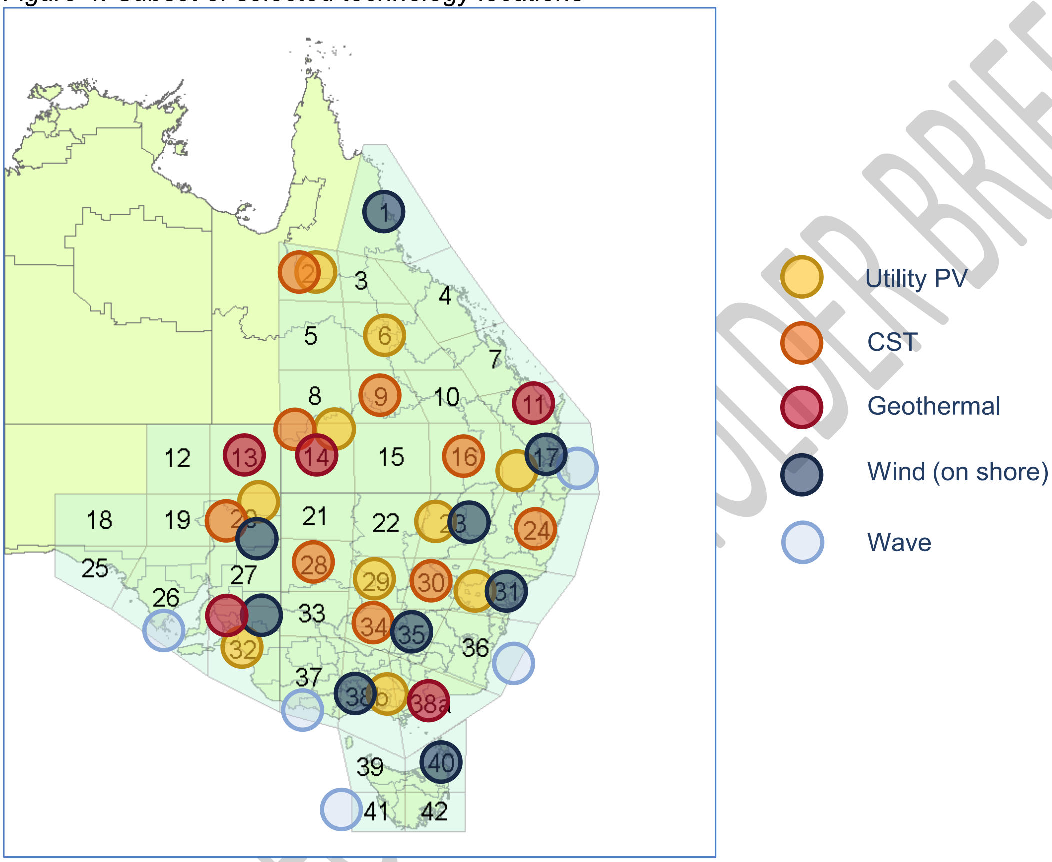
[22] AEMO. Available at: http://www.climatechange.gov.au/en/government/initiatives/aemo-100-per-cent-renewables/aemo-input-assumptions-html.asp. Viewed 18 March 2013.
[23] AEMO. Available at: http://www.climatechange.gov.au/government/initiatives/aemo-100-per-cent-renewables/aemo-input-assumptions-html.aspx#Section5. Viewed 18 March 2013

AEMO chose a subset of NEM locations to include in the modelling. The selection of this subset sought to provide for:

- The best resource for each technology in terms of energy production capacity factor and minimal seasonal variation.
- Reasonable spread across the entire NEM, to minimise fluctuations due to local weather conditions.
- Other geographical advantages, such as siting generation reasonably close to the transmission system and major load centres where practical.

As a result, the modelling used renewable technologies distributed over a wide area. The general location used for each technology is indicated by shaded circles on the image below. For simplicity, the size of each shaded circle has been kept small, but each represents deployment of technologies distributed over a much larger area, including neighbouring locations with equally good energy resources.

Figure 4: Subset of selected technology locations



4.5 Transmission network

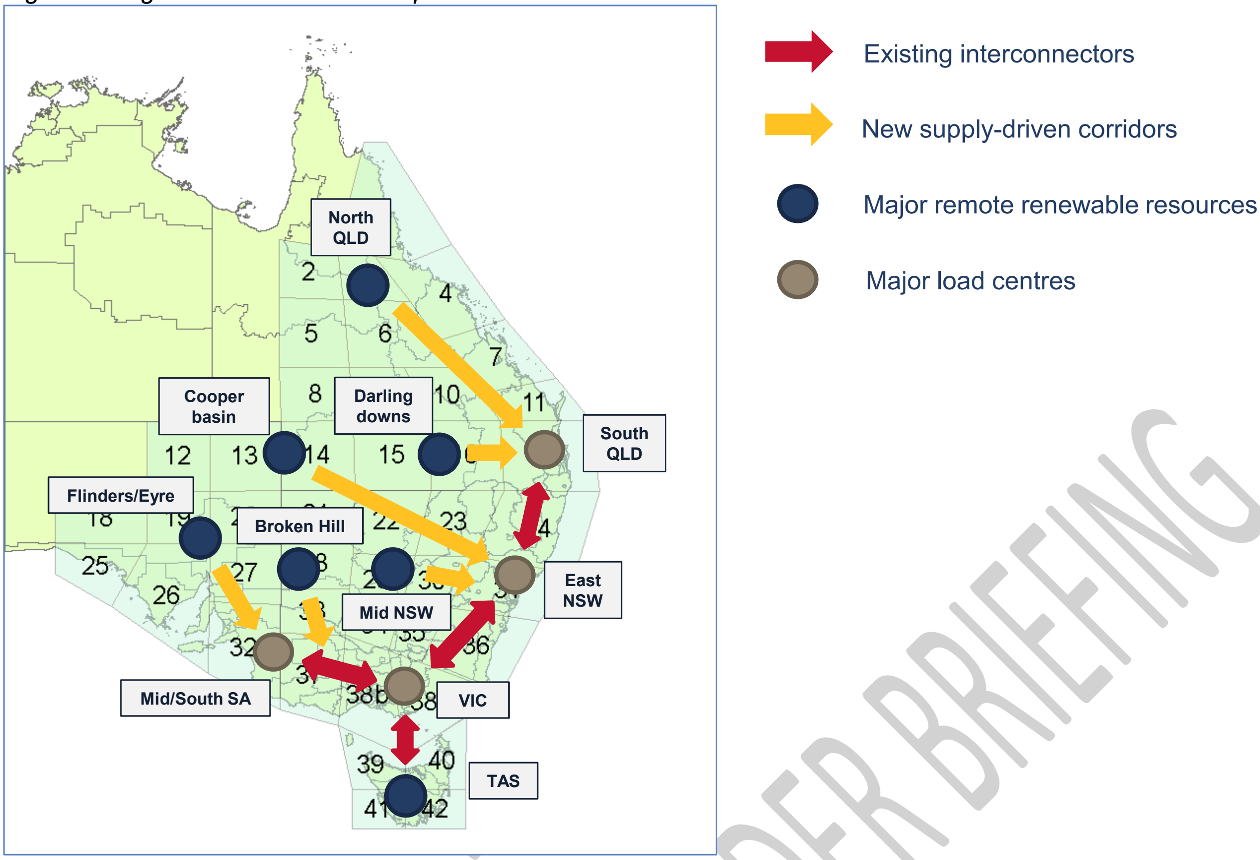
Many of the renewable resources within the subset identified are in locations that are remote from the current transmission system. Based on these locations, high-level transmission options were developed for use in this study.

These are shown in Figure 5 below.

The red arrows show existing cross-border interconnectors that connect the major load centres (grey dots) in the NEM. These interconnectors (with the requisite reinforcements defined by each scenario) will distribute renewable supply between load centres.

Significant amounts of generation will be connected to the grid (yellow arrows) from more remote renewable generation clusters (blue dots).

Figure 5: High-level transmission options



4.5.1 Local demand

To calculate the required transmission capacities from the likely remote renewable resource locations, it was necessary to estimate the demand (if any) in those locations.

Net generation (generation minus local demand) was used to calculate the transmission requirements to connect each of these zones to the NEM.

Based on the available data, only the following three of the renewables zones (blue dots) were estimated to have significant local demand:

- Tasmania, which uses the existing forecast for Tasmania.
- North Queensland (area north of Rockhampton), which is assumed to have 22% of total Queensland demand based on Powerlink's 2012 Annual Planning Report (APR).
- Flinders/Eyre, which is assumed to have 10% of total South Australian demand (based on ElectraNet's 2012 APR with some allowance for additional mining load).

4.5.2 Network losses

For this study, transmission losses across the NEM are assumed to be 5%. The modelling accounted for transmission losses by adding this 5% to the demand forecasts shown in Table 2. Five per cent was applied to both traditional and EV demand.

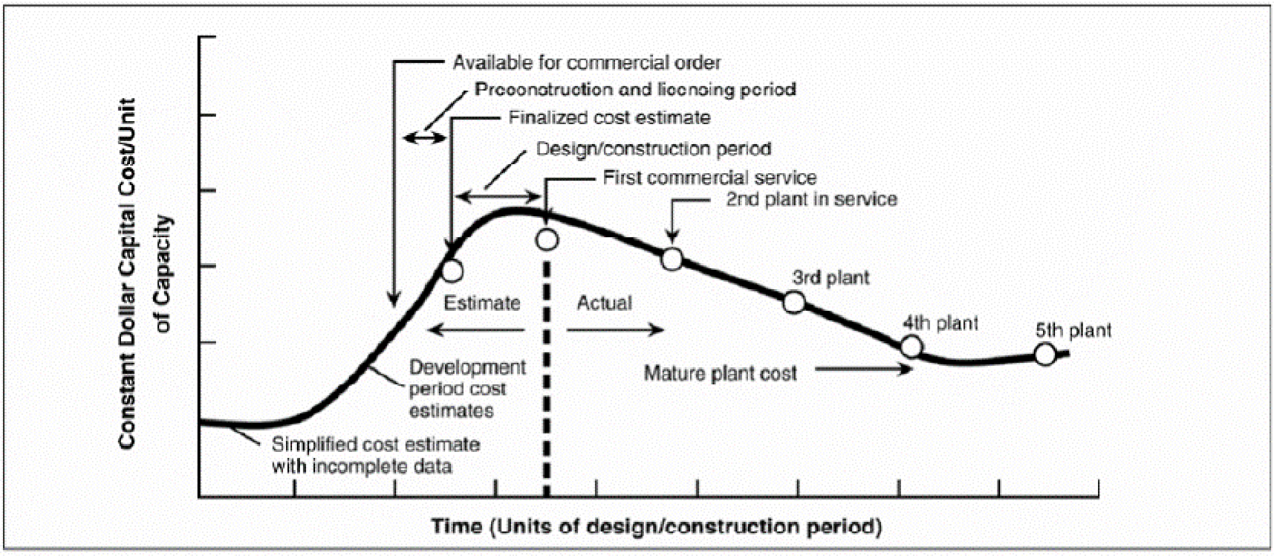
4.6 Cost assumptions

4.6.1 Generation technology cost basis

4.6.1.1 Capital costs

As new technologies emerge and mature, their costs generally follow a curve such as the generic learning curve, or Grubb curve, shown in Figure 6.[24] The renewable energy resources considered in this study are currently at varying stages of maturity and are likely to differ in terms of performance improvements and cost reductions in the coming decades.

Figure 6: Generic 'Grubb' curve showing typical technology cost cycle



Source: Cost of Construction New Generation Technology, November 2011, Worley Parsons[25]

The generation technology costs used in this study account for expected cost improvements by 2030 and 2050 using outputs from CSIRO's Global and Local Learning Model (GALLM).

While technology costs are expected to fall over time, resource costs will generally increase as higher quality resources and more favourable sites close to the transmission system diminish, leaving lesser resources available. This leads to longer-term stabilisation of generation costs for some technologies.

While capital costs are only one part of the picture, they do illustrate the effects of expected learning curves for each case.

In Scenario 2, AEMO used the mid-point capital costs for 2030 and 2050 published in the 2012 Australian Energy Technology Assessment[26] (AETA 2012) produced by the Australian Government Bureau of Resources and Energy Economics (BREE). The AETA 2012 provides the best available and most recent estimates for the costs of electricity generation technologies under Australian conditions. The mid-point costs represent the most likely future projections of these costs.

The AETA 2012 only provides a single scenario which, while adequate for Scenario 2, is not consistent with the rapid technology development assumptions featured in Scenario 1.

The Scenario 1 capital costs were produced by taking the current (2012) cost estimates for the chosen technologies from the AETA 2012 and having CSIRO project the future costs using their

[24] WorleyParsons. Cost of Construction New Generation Technology, November 2011. Available at: http://www.aemo.com.au/Consultations/National-Electricity-Market/Open/Planning-Studies-2012-Consultation. Viewed 18 March 2013.
[25] See Footnote 25
[26] Australian Energy Technology Assessment 2012, Australian Government Bureau of Resources and Energy Economics (BREE). 31 July 2012. Available at: http://www.bree.gov.au/publications/micro/index.html. Viewed 18 March 2013.

Global and Local Learning Model (GALLM).[27] This was to ensure consistency as the GALLM was also used in the AETA 2012 costing. The assumptions used for these simulations correspond to rapid development of low emissions technologies both in Australia and the rest of the world leading to reduced technology costs.

Table 4 lists the capital costs for each electricity generation technology (using real 2012 dollars per kilowatt of electricity generation capacity) for 2030 and 2050, and includes the AETA 2012 capital costs for comparison.[28]

Table 4: Hypothetical generation capital costs

Electricity generation technology	AETA 2012 (NSW) ($/kW)	Scenario 1 2030 ($/kW)	Scenario 1 2050 ($/kW)	Scenario 2 2030 ($/kW)	Scenario 2 2050 ($/kW)
Wind – onshore	2,579	2,678	2,600	1,764	1,813
Wind – offshore	4,538	4,712	4,574	3,866	4,040
CST – central receiver with storage[a]	10,215	4,642	4,700	5,514	5,444
PV – rooftop, non-tracking	3,347	1,075	1,387	1,590	1,074
PV – utility scale, single axis tracking	3,822	1,228	1,584	2,160	1,544
Geothermal (EGS)	Technology not available	7,920	7,946	10,634	10,815
Geothermal (HSA)	Technology not available	5,230	5,248	7,064	7,232
Biomass	5,123	4,700	5,527	5,220	5,325
Biogas-fuelled OCGTs[b]	734	751	751	782	782
Wave	Technology not available	2,511	2,465	3,671	3,521
Pumped hydro[c]	4,887	4,887	4,887	4,887	4,887

[a] The CST plant used in the modelling had a higher solar multiplier and larger storage than assumed in AETA 2012. The costs shown here are therefore about 23% higher than those reported in the 2012 AETA. See Appendix 2 for further details.
[b] Similar costs apply to biogas-fuelled open cycle gas turbines (OCGTs) in all scenarios as this is considered a mature technology.
[c] Pumped hydro costs were not covered in the AETA 2102, so these were based on costs provided by ROAM Consulting.[29]

Open Cycle Gas Turbines (OCGTs) fuelled by biogas have also used the AETA 2012 costs. The same costs apply to both scenarios as this is considered to be a mature technology. These costs include the anticipated improvements in efficiency between now and 2030 or 2050.

4.6.1.2 Operating and maintenance costs

With the exception of bioenergy, the capital cost of the technology is often the dominant factor in the cost of renewable generation as, once constructed, fuel cost for most technologies tends to be low or zero. Only bioenergy requires fuel that is costly to collect and, in the case of biogas, costly to convert.

[27] *AEMO 100 per cent renewable energy study – Projection of capital costs for Scenario 1*, CSIRO, Hayward and Graham, 19 September 2012.
[28] The capital costs in the AETA 2012 differ by region. This table shows the New South Wales region costs for comparison purposes.
[29] AEMO. Available at: http://www.climatechange.gov.au/en/government/initiatives/aemo-100-per-cent-renewables/~/media/government/initiatives/aemo/APPENDIX4-ROAM-report-on-pumped-storage.pdf. Viewed 18 March 2013.

All generation plant requires maintenance, however, and for renewable technologies such as geothermal and wave, fixed operating and maintenance (O&M) costs can be considerable.

The assumed O&M costs, both fixed and variable, are based on the mid-point estimates from the AETA 2012.[30] Pumped hydro is not one of the technologies considered in the AETA 2012, so these costs were calculated using the estimated costs for existing NEM pumped hydro schemes as published in AEMO's 2012 National Transmission Network Development Plan (NTNDP) dataset.[31]

Scenario 2 uses the AETA 2012 assumption that O&M costs escalate at around 150% of Consumer Price Index (CPI), which leads to cost increases of 27% by 2030 and 46% by 2050. Scenario 1 assumes that rapid technology transformation will drive real reductions in O&M costs outweighing any increases projected in the AETA 2012, so O&M costs reduce by 12.5% by 2030 and 25% by 2050.

The resulting O&M costs for each scenario are detailed in the table below.

Table 5: Fixed costs

	Scenario 1 2030 ($/MW/year)	Scenario 1 2050 ($/MW/year)	Scenario 2 2030 ($/MW/year)	Scenario 2 2050 ($/MW/year)
PV, rooftop	21,875	18,750	31,630	36,380
PV, utility	33,250	28,500	48,077	55,297
CST	52,500	45,000	75,911	87,311
Wind, onshore	35,000	30,000	50,607	58,207
Wind, offshore	70,000	60,000	101,214	116,414
Wave	166,250	142,500	240,384	276,484
Geothermal (HSA)	175,000	150,000	253,036	291,036
Pumped hydro	48,999	41,999	70,848	81,488
Biomass (bagasse)	109,375	93,750	158,148	181,898
Biomass (biogas)	3,500	3,000	5,061	5,821
Biomass (wood)	109,375	93,750	158,148	181,898

Table 6: Variable costs

	Scenario 1 2030 ($/MWh/year)	Scenario 1 2050 ($/MWh/year)	Scenario 2 2030 ($/MWh/year)	Scenario 2 2050 ($/MWh/year)
PV, rooftop	-	-	-	-
PV, utility	-	-	-	-
CST	13.1	11.3	19.0	21.8
Wind, onshore	10.5	9.0	15.2	17.5

[30] BREE. Available at: http://www.bree.gov.au/publications/micro/index.html. Viewed 18 March 2013.
[31] AEMO. Available at: http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Assumptions-and-Inputs. Viewed 18 March 2013.

	Scenario 1 2030 ($/MWh/year)	Scenario 1 2050 ($/MWh/year)	Scenario 2 2030 ($/MWh/year)	Scenario 2 2050 ($/MWh/year)
Wind, offshore	10.5	9.0	15.2	17.5
Wave	-	-	-	-
Geothermal (HSA)	-	-	-	-
Pumped hydro	6.7	5.8	9.7	11.2
Biomass (bagasse)	7.0	6.0	10.1	11.6
Biomass (biogas)	8.8	7.5	12.7	14.6
Biomass (wood)	7.0	6.0	10.1	11.6

Bagasse and biomass (wood) costs are also taken from the AETA 2012. Scenario 1 uses the 'low' case and Scenario 2 the 'medium case'. Biogas costs are taken from CSIRO's storage report.[32]

Table 7: Fuel costs and thermal efficiency of fuel burning technologies

	Scenario 1 2030		Scenario 1 2050		Scenario 2 2030		Scenario 2 2050	
	Cost ($/GJ)	Efficiency (%)	Cost ($/GJ)	Efficiency (%)	Cost ($/GJ)	Efficiency (%)	Cost ($/GJ)	Efficiency (%)
Biomass (bagasse)	0.6	22	0.6	22	0.8	22	0.8	22
Biomass (biogas)	12.0	39	12.0	44	12.0	39	12.0	44
Biomass (wood)	0.4	27	0.4	27	1.5	27	1.5	27

4.6.2 Energy Storage technologies and costs

Maintaining system security requires supply and demand to be balanced at all times, and preserving this balance is more challenging in a 100 per cent renewable power system.

Several key renewable energy sources are variable given they depend on weather conditions that vary on several time scales (minutes, daily, seasonally, annually). This means flexible supply and demand options would be required to achieve the balance traditionally provided by fossil fuel generators. Energy storage would be central to providing this flexibility.

AEMO's consultants provided estimates on the availability and costs of five categories of large utility-scale energy storage technologies: batteries; biomass, as solid matter and as biogas; compressed air; pumped hydroelectricity; and molten salt thermal energy storage associated with CST energy collection (see Figure 7 below).

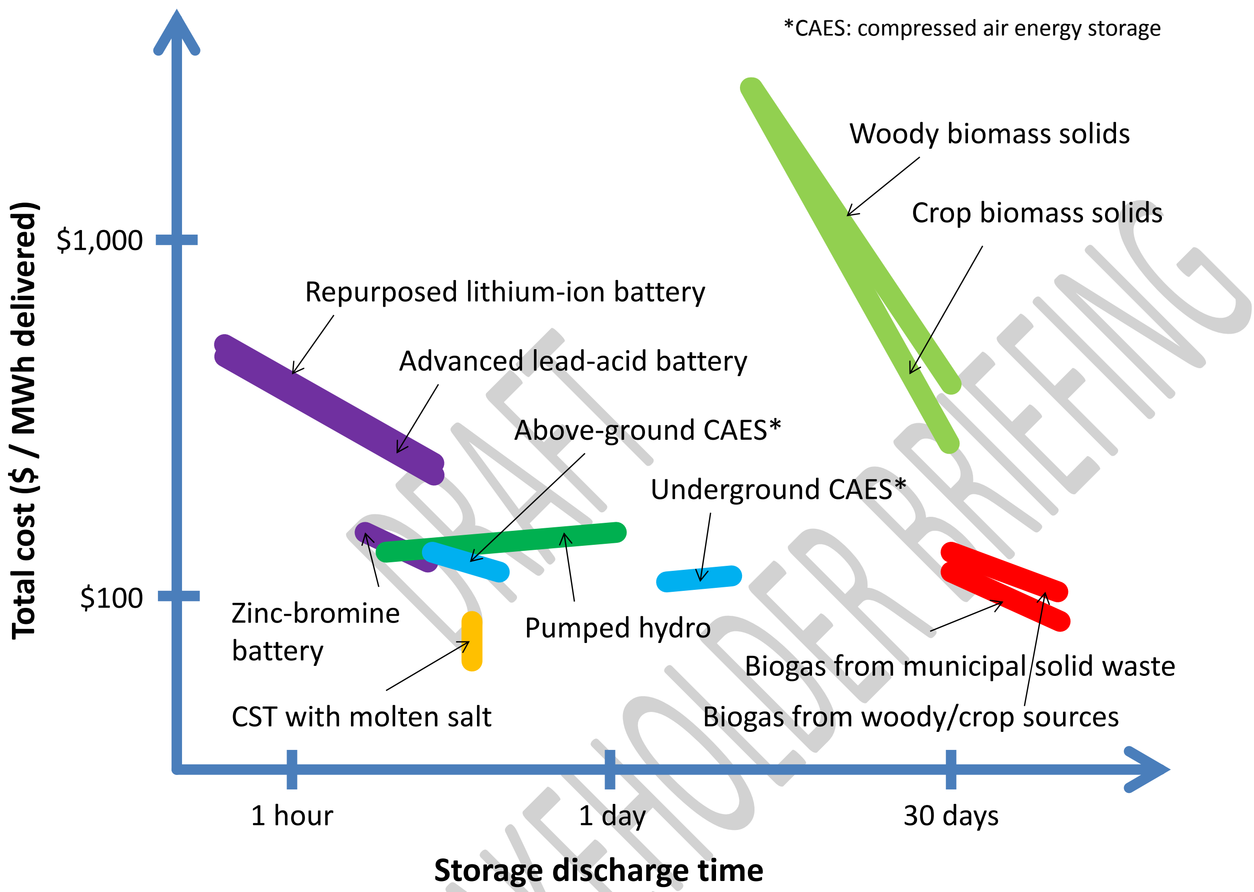
Based on this information, AEMO modelled a subset of storage technologies, selecting those that provide the required storage flexibility at least cost, and to cover periods of high demand or low generation from other sources.

Existing pumped hydro in the NEM was assumed to remain, and the subset selected adds to this a mix of CST with molten salt, biogas (stored in the existing gas systems), biomass, and additional pumped hydro.

[32] AEMO. Available from: http://www.climatechange.gov.au/en/government/initiatives/aemo-100-per-cent-renewables/aemo-input-assumptions-html.aspx. Appendix 8. Viewed 18 March 2013.

Given the chosen mix of generation from diverse sources across the NEM, investment in specific storage solutions such as batteries and compressed air did not emerge as being economic for large-scale deployment and were not included in the modelling.

Figure 7: Storage technologies and costs adapted from CSIRO storage report[33]



4.6.3 Transmission cost basis

Transmission network expansion costs were based on the building block costs provided in the 100 per cent Renewables Study – Electricity Transmission Cost Assumptions and Network extensions to remote areas Part 2 – Innamincka case study.[34,35]

AEMO only costed additional electricity transmission facilities required; other network costs were not assessed.

For each case modelled, the requisite new transmission lines and/or upgrades to existing transmission facilities were identified and costed. In most cases, transmission costs to connect generators to the closest transmission node are based on the 2012 NTNDP[36] connection cost estimates. AEMO developed specific cost estimates of the transmission lines, substations and easements required for the three technologies not covered by the NTNDP.

[33] AEMO. Available at: http://www.climatechange.gov.au/en/government/initiatives/aemo-100-per-cent-renewables/~/media/government/initiatives/aemo/APPENDIX8-CSIRO-energy-storage.pdf. Viewed 18 March 2013.
[34] AEMO. Available at: http://www.aemo.com.au/~/media/Files/Other/planning/0400-0005%20pdf.ashx. Viewed 4 February 2013.
[35] AEMO. Available at: http://www.climatechange.gov.au/government/initiatives/aemo-100-per-cent-renewables/aemo-input-assumptions-html.aspx#Section5. Viewed 18 March 2013.

[36] AEMO. Available at: http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan. Viewed 18 March 2013.

- Pumped hydro: The same connection cost as solar technologies ($120/kW) was assumed. This is in the lower range of connection costs and assumes that pumped hydro is generally built close to the existing network and existing hydro plants are converted into pumped hydro plants.
- Offshore wind and wave power: The connection cost (about $580/kW) for these two technologies assumes 400 MW of generic offshore plant connected via a HDVC link.[37]

Costs of transmission connection assets required for individual generators are included in the generation costs.

4.6.4 Other costs (not included)

The study does not include costs for any changes that might be required to local electricity sub-transmission or distribution networks.

In practice however, the amount of PV generation forecast and the assumed DSP increases suggest that network investment may be required to manage changed fault levels, to maintain power quality during more significant variations in flow, and to accommodate changes in flow direction.

The study does not include the costs associated with the acquisition of the land required for the renewable generation. This is likely to be significant and the actual acquisition may present some challenges.

The study also does not include the costs associated with any generation or transmission assets left stranded by the shift to the 100 per cent renewables.

5 Modelling results

This section provides an overview of the overall results across the four cases for comparison purposes. Detailed results for each case are available in Section 6.

The 100 per cent renewable generation mix consists of three categories of generation technologies. All three categories must be optimally combined to reliably meet supply for the lowest cost.

The categories are:

- **Non-dispatchable (PV, wind, and wave):** variable, weather-dependent, low operating cost technologies where output to some extent can be forecast ahead of time but not increased on demand. However, output can be decreased (curtailed) for operational reasons if required.
- **Baseload (geothermal, biomass (wood), bagasse):** technologies where output can be controlled, but which are relatively slow to respond and/or have high capital and fixed costs but low variable costs. These are best suited to operating almost continuously at close to their maximum output, with some variability to match demand.[38]
- **Peak dispatchable (hydro, pumped hydro, CST, biogas):** flexible, fast-to-respond technologies which are typically more expensive, and either have limited annual energy potential or require daily recharge of energy storage.

5.1 Generation mix

Overall, the generation mix identified included a diverse range of resources and technologies.

[37] AEMO. Available at: http://www.climatechange.gov.au/government/initiatives/aemo-100-per-cent-renewables/aemo-input-assumptions-html.aspx#Section5. Viewed 18 March 2013.

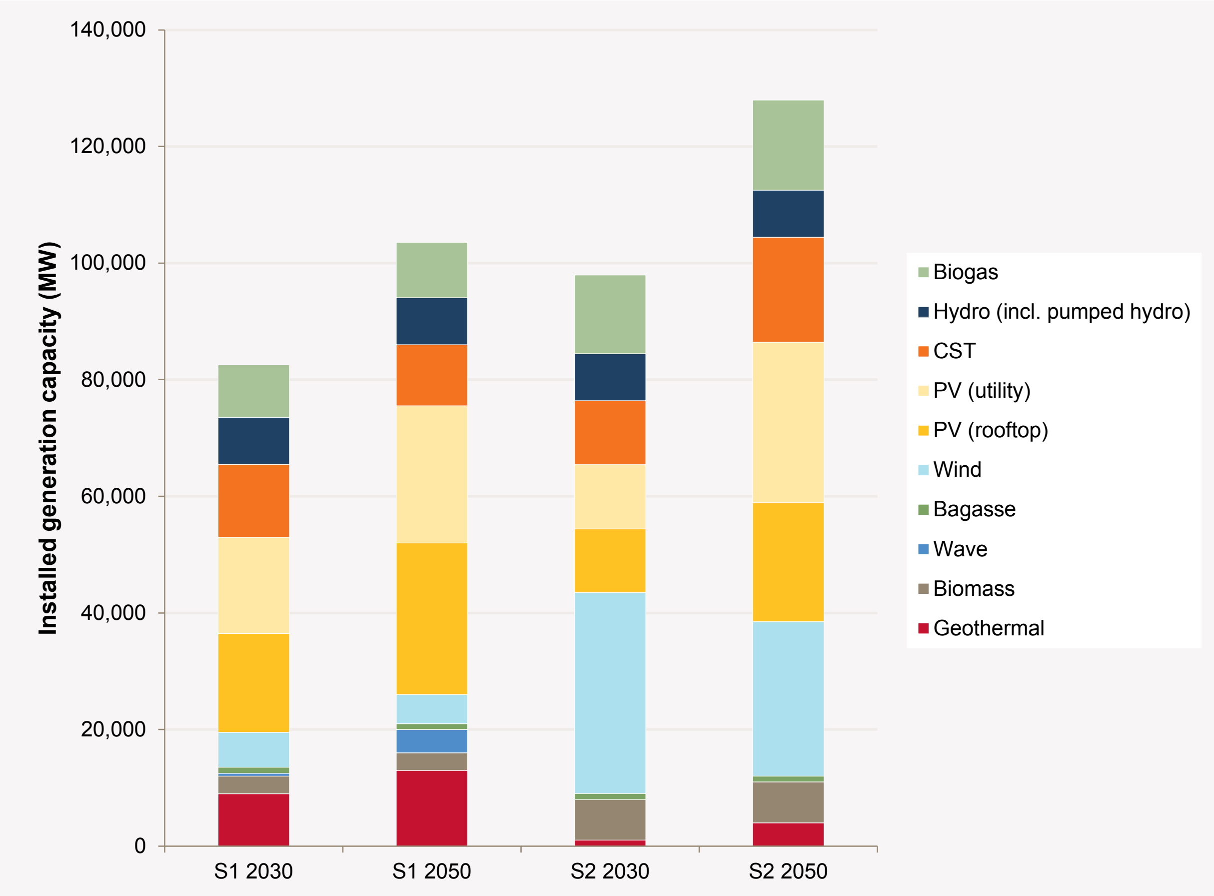
[38] In the modelling, biomass (wood) and bagasse plants are assumed to operate continuously at 70–80% capacity, rising up to 100% if demand is high.

The results show that the optimised 100 per cent renewable system for each case has a broad mix of technologies. This mix is necessary to manage intermittent generation output and the technical issues related to maintaining reliability and system security.

The projected mix of generation technologies differs greatly across the four cases. This is primarily driven by generation costs, which vary by both scenario and the year being modelled given the learning curve variations for the technologies applicable in each case.

The optimised generation mix determined for each case is shown below. As the assumed demand and required reserve varies in each case, the total generation capacity also varies.

Figure 8: Projected generation mix per scenario



5.1.1 Technology-specific results

Based on the modelled assumption that PV costs continue to fall rapidly in both scenarios, PV generation is likely to be considerable in all four cases. The rapid technology transformation assumed in Scenario 1 means that geothermal and wave technologies are likely to develop more quickly than in Scenario 2. As a result, there is expected to be more geothermal generation in Scenario 1 for both 2030 and 2050, with wave power uptake increasing towards 2050.

Wind generation is a relatively mature technology with wide deployment and would need large investments to drive further cost reductions. In Scenario 1 a greater deployment of other technologies is assumed, so the cost of wind generation would not decrease as quickly as other technologies. Consequently, wind is expected to be less prominent than PV in both Scenario 1 cases.

In Scenario 2, however, deployment of PV and CST is assumed to be slower, leading to an increased global deployment of wind. As a result, wind generation costs reduce relative to other technologies. In both Scenario 2 cases, wind therefore generates a greater proportion of supply.

Bioenergy generation is modelled to operate as a flexible resource that can respond to system requirements. Bioenergy is included in the modelling both as baseload steam turbines and as biogas-fired open cycle gas turbines (OCGT). This combination emerged as being the most flexible and efficient for this resource. The model assumes storage of biogas in existing gas infrastructure for use when demand peaks or intermittent generation production is low.

5.1.2 Installed capacity by technology

To provide reliable supply that allows for contingencies (from generation or transmission trips), the total generation capacity available to the system must exceed maximum demand. In a conventional system, the excess capacity is typically 15 to 25% above maximum demand, whereas this study indicates that a 100 per cent renewable system requires 100 to 130% of excess capacity to meet the same reliability standards. This is due to the variable, weather-dependent nature of many renewable resources.

In the systems modelled, wind and PV account for a large proportion of the capacity installed, but a smaller proportion of the energy produced, as both technologies are intermittent and have relatively low capacity factors. Onshore wind has a capacity factor of around 30–40% at the best sites and rooftop PV around 15%.

Other renewable technologies such as geothermal and biomass are similar to traditional baseload generation in that they can operate most of the year at very high capacity factors (80–90%). For this reason, they account for a lower proportion of installed capacity compared to the energy produced.

The total required generation capacity differs between the cases modelled, primarily due to the different projected maximum demand forecasts in each. The technology mix also affects the total amount of generation capacity required due to variations in how each technology contributes to system reliability. This appears to be particularly the case in 2050 for both scenarios, where the higher percentage of intermittent generation (PV, wind and wave) means more reserve is expected to be required.

In all four cases, generation with a nominal capacity of more than twice maximum demand must be built. Table 8 summarises the total installed capacity required for each case.

Table 8: Hypothetical generation capacity required

Type	Scenario 1 2030	Scenario 1 2050	Scenario 2 2030	Scenario 2 2050
Total capacity (MW)	82,550	103,572	97,985	127,982
Maximum demand (10% POE)	40,791	45,046	45,822	55,576
Capacity relative to maximum demand	202%	230%	214%	230%

5.1.3 Installed capacity by location

The modelling results show a wide dispersion of generation across most regions of the NEM. Table 9 shows the geographic spread of modelled generation.

Table 9: Installed capacity by region

Region/zone	Scenario 1 2030		Scenario 1 2050		Scenario 2 2030		Scenario 2 2050	
	MW	%	MW	%	MW	%	MW	%
North QLD	3,450	4	4,700	5	5,450	6	7,450	6
South QLD	15,950	19	19,915	19	19,450	20	26,110	20
Darling Downs	2,500	3	3,000	3	3,000	3	5,000	4
Cooper Basin	6,500	8	9,750	9	0	0	0	0
Broken Hill	1,000	1	0	0	0	0	0	0
East NSW	25,300	31	28,030	27	35,000	36	46,950	37
Mid NSW	500	1	1,000	1	500	1	2,000	2

Region/zone	Scenario 1 2030		Scenario 1 2050		Scenario 2 2030		Scenario 2 2050	
VIC	15,660	19	22,240	21	18,790	19	23,410	18
SA	5,330	6	8,935	9	8,780	9	10,245	8
Eyre/Flinders	3,000	4	2,000	2	2,500	3	2,000	2
TAS	3,360	4	3,999	4	4,520	5	4,815	4
Total	**82,550**	**100**	**103,570**	**100**	**97,990**	**100**	**127,980**	**100**

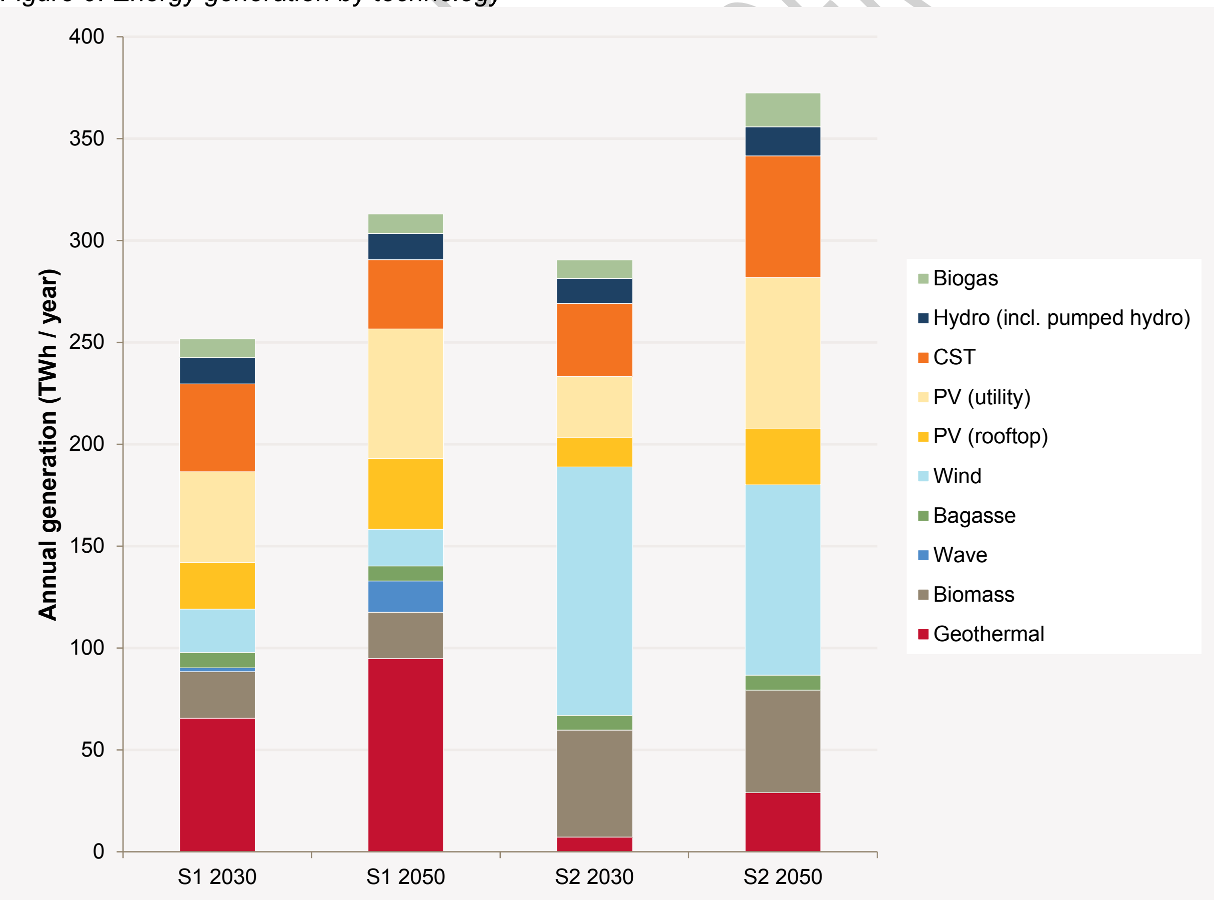
5.1.4 Generation by technology

Some renewable technologies (geothermal and biomass) can operate for most of the year at capacity factors similar to traditional baseload generation (80–90%), but most are highly dependent on local weather conditions and operate at lower capacity.

CST can also be designed to operate at baseload generator levels (for example the Gemasolar in Spain includes 15 hours of CST storage), but only with much larger solar collection fields (mirrors, in the case of the proposed central receiver technology), which would see a corresponding increase in capital costs.

The modelling concluded that it was more efficient to limit the extent of the solar collection fields and assumes nine-hour storage for CST primarily to cover morning and evening periods when PV generation falls, even though this results in a lower capacity factor than designing it to run as baseload.

Figure 9: Energy generation by technology



5.2 Storage

Energy storage is likely to be required predominantly to meet demand after sunset and in particular to manage the evening peak. It is also used to cover periods of low wind speed or solar radiation and to provide backup in case of contingency events such as the loss of a transmission line or a large generator.

The model selected CST with storage as the primary storage technology, extending the use of daytime solar energy by applying it to meet demand at a different time. This technology is supplemented by hydro and biogas on most days to manage the evening peak.

The modelling included existing pumped hydro, but no additional pumped hydro was added to the mix as the modelling found it to be an uneconomic option.

Hydro generators and biogas-fuelled OCGTs are readily able to ramp up to maximum generation within an hour, and biogas-fuelled OCGTs alone add enough low cost flexibility to cover any anticipated periods of low generation.

The modelling shows that the combined dispatch of all three technologies is sufficient to match demand in all four cases, even with the rapid decline of PV generation in the late afternoon.

CST is still in the early stages of commercialisation and its ramping capabilities are uncertain. The current modelling assumes that CST can ramp to full output in one hour from a 'hot start'. However, a modelling sensitivity was done where CST was restricted to a maximum ramp of 33% of installed capacity per hour; reliability standards were maintained and there was only a slight increase in biogas use. (See details in Appendix 4.)

5.3 Land use

AEMO estimated the additional land use requirements for deployment of the technologies identified in each case. These are based on the land use estimates produced by ROAM Consulting and CSIRO[39] and AEMO's experience in carrying out its own transmission planning obligations.

Depending on the case, the estimated total land required varies between 2,400 and 5,000 square kilometres. This total area is a gross figure and with some technologies, such as wind, the net area occupied for actual generation is considerably lower, leaving much of the land available for other uses.

The land requirements do not include any allowance for any additional land requirements for biomass, which is assumed to be sourced by redirecting existing sources of bioenergy to energy production.

It should be noted that bioenergy requirements could be considerable in all cases in the study. Those requirements might be met with a mix of waste, stubble, plantation and native forest resources identified in the CSIRO input report on biomass.[40]

While the requirements under the modelling do not necessarily require exclusive use of any land currently used for food production, the diversion of biomass sources from competing uses is likely to affect the energy production costs, depending on the value of the alternate uses.

The process to acquire this land could be challenging and the costs could be significant.

The figures quoted in the table below for wind include the total wind farm areas, however the actual turbines and substations only require a small proportion of this with the majority of this land still available for farming. Similarly, transmission line easements are also available for farming.

[39] AEMO. Available at: http://www.climatechange.gov.au/government/initiatives/aemo-100-per-cent-renewables/aemo-input-assumptions-html.aspx#Section5. Viewed 18 March 2013.
[40] AEMO. Available at http://www.climatechange.gov.au/en/government/initiatives/aemo-100-per-cent-renewables/~/media/government/initiatives/aemo/APPENDIX8-CSIRO-energy-storage.pdf. Viewed 18 March 2013.

Table 10: Additional land requirements

Renewable technology	Scenario 1 2030 (km^2)	Scenario 1 2050 (km^2)	Scenario 2 2030 (km^2)	Scenario 2 2050 (km^2)
PV (rooftop)	n/a	n/a	n/a	n/a
PV (utility)	633	1,351	316	1,054
Wind (onshore)	400	333	3,450	2,650
Wave	n/a	n/a	n/a	n/a
Geothermal	900	1,300	100	400
CST	500	420	550	900
Pumped hydro	n/a	n/a	n/a	n/a
Hydro	n/a	n/a	n/a	n/a
Bagasse	n/a	n/a	n/a	n/a
Biogas	n/a	n/a	n/a	n/a
Biomass (wood)*	n/a	n/a	n/a	n/a
New transmission line easement area	688	809	429	583
New terminal station land area	4	4	3	3
Total	**3,124**	**4,217**	**4,848**	**5,590**

n/a: assumes land requirements are minor, already existing, entirely co-located with other land use (such as rooftop PV), or that energy generation is not the primary product of the land used (for example, waste residues from crop land).
* Excludes land currently (in 2012) used for plantation timber or native forests managed for timber.

5.4 Transmission

The mix and location of renewable generation affects the transmission system requirements. For modelling purposes AEMO selected two alternative combinations for generation and transmission development:

- Selecting resources remote from load centres and building the transmission needed to transport generation to load centres. While rooftop PV requires minimal transmission given its proximity to load, most other renewable resources tend to be remotely located.
- Selecting resources located close to the existing system. This can result in a lower cost transmission system, but usually involves using lower quality resources which increase generation costs.

The modelling assessed both options for all four cases. In seeking to optimise the total combined generation and transmission costs, the modelling assessed whether building new transmission infrastructure to access more remote, better quality resources, outweighed the generation costs incurred when selecting inferior quality resources.

The outcome for each case modelled typically included a mix of the two options, depending on the technology costs and resource quality by location and the associated transmission costs.

The modelling also considered the most appropriate technology required to handle the transmission requirements of the system. Both traditional alternating current (AC) connections and new, high voltage direct current (HVDC) lines were assessed. AC transmission design may not be capable of transferring large amounts of power over very long distances (such as 9,350 MW from the Cooper Basin to NSW over 1,500 km in Scenario 1, 2050). HVDC technology was included as the more suitable option in those situations.

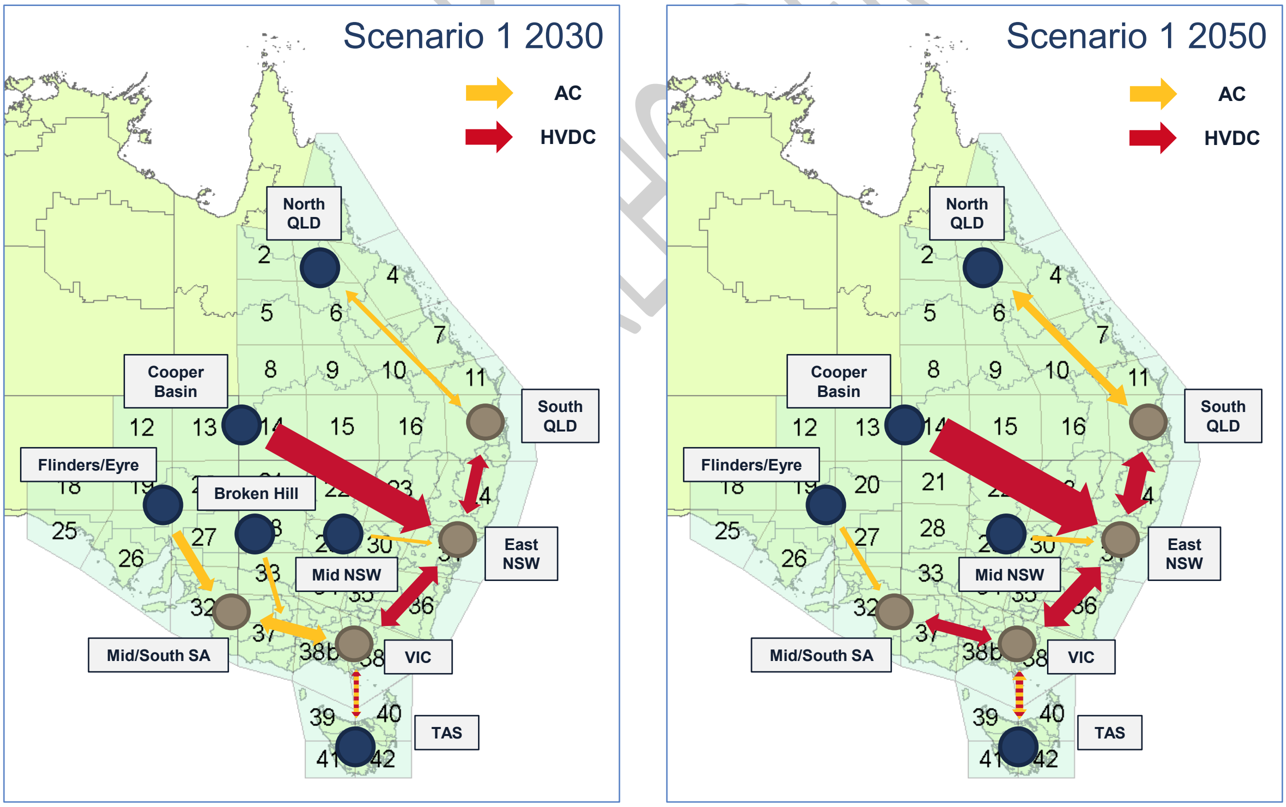
To maximise the new transmission system design, additional connection points were included where feasible along new, long-distance transmission routes to tap renewable generation sources along those routes.

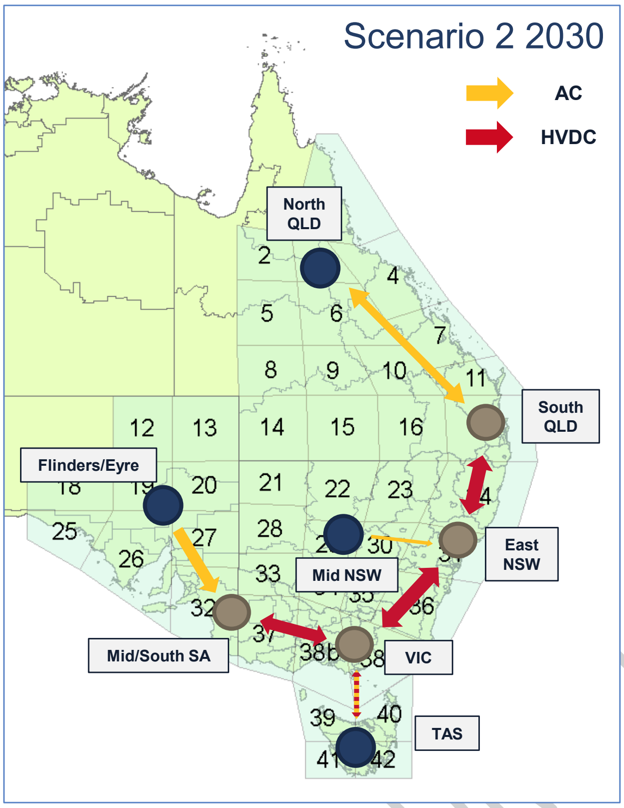
In all cases, the existing transmission system was assumed to remain. Additional transmission requirements and the choice of technology are listed in Table 11 below and graphically shown in Figure 10.

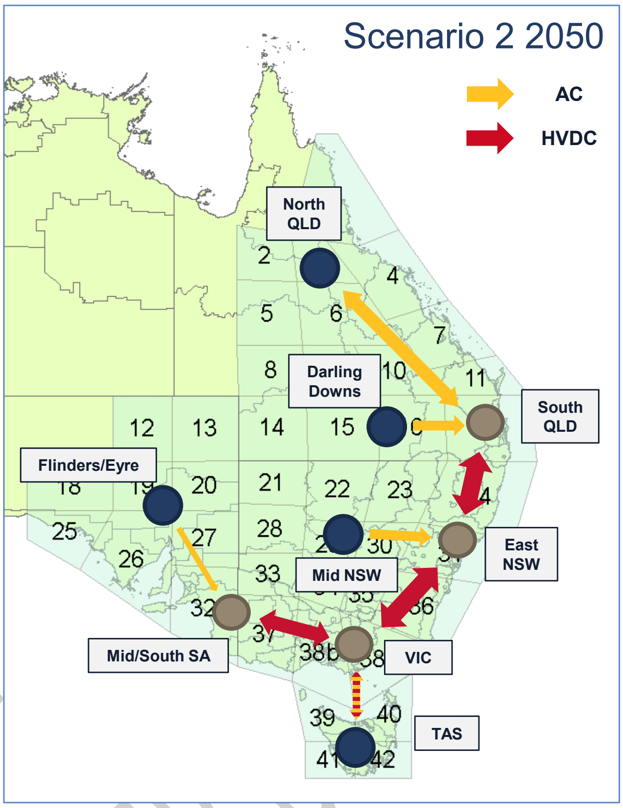
Table 11: Hypothetical additional transmission requirements

	Scenario 1 2030		Scenario 1 2050		Scenario 2 2030		Scenario 2 2050	
	New capacity (MW)	Tech.	New capacity (MW)	Tech.	New capacity (MW)	Tech.	New capacity (MW)	Tech.
East NSW to South QLD	3,190	HVDC	5,300	HVDC	4,050	HVDC	5,250	HVDC
VIC to East NSW	3,490	HVDC	4,590	HVDC	4,600	HVDC	5,020	HVDC
TAS to VIC	1,100	AC-HVDC	2,070	AC-HVDC	1,380	AC-HVDC	1,500	AC-HVDC
VIC to Mid/South SA	2,700	AC	2,600	HVDC	2,720	HVDC	3,400	HVDC
East NSW to Cooper Basin	6,240	HVDC	9,350	HVDC				
Mid/South SA to Flinders/Eyre	2,350	AC	1,340	AC	2,000	AC	1,280	AC
South QLD to North QLD	1,060	AC	2,110	AC	1,740	AC	3,550	AC
South QLD to Darling Downs							2,000	AC
East NSW to Mid NSW	500	AC	1,000	AC	500	AC	2,000	AC
Broken Hill to VIC–SA Interconnector	1,000	AC						

Figure 10: Maps of additional transmission requirements







Appendix 5 provides detailed descriptions of the transmission network designs resulting from the high-level study carried out to identify the additional new transmission network required.

It also summarises the capacity and costs of the projected transmission system for each of the four cases modelled. The transmission flows used to determine the required transmission capacities were based on meeting the maximum 10% POE demand (that is, the maximum demand expected to be exceeded, on average, only one year in 10).

5.5 A new operating pattern and ‘critical period’

The most challenging power system design issue, or ‘critical period’, that emerged from the modelling was meeting the evening demand when PV generation decreases to zero on a daily basis.

To manage demand at this time, the modelling shifts the available flexible demand from evening to midday, to take advantage of the surplus of PV generation that typically occurs. Even so, the majority of dispatchable generation and the largest ramps in dispatchable generation occur in the evening in all four cases.

With EV recharging possibly being more efficient during the day rather than overnight (when a fossil fuelled system would have surplus generation), installing EV recharging infrastructure at workplaces and shopping centres may need to be considered.

5.6 Meeting the reliability standard

A critical scope requirement was to keep USE below 0.002% over a year, in line with the current reliability standards.

With careful selection of the mix and capacity for each technology, the modelling achieved this as part of the modelling optimisation.

5.7 Hypothetical costs

AEMO estimated the hypothetical capital costs for generation, storage, and transmission infrastructure in each of the four cases. As previously noted, these costs are hypothetical and must be interpreted with due consideration given to the assumptions and constraints outlined in Section 1.1. While these estimates are consistent with the study scope, in practice the costs of building a 100% per cent renewables electricity system would be significantly higher.

These estimates assume building all the new generation and transmission infrastructure using the applicable costs for the target year, 2030 or 2050. This takes full advantages of the cost reductions and performance improvements expected between now and 2030 or 2050.

Due to the nature and scope of this study, the transition path from the current power system to the modelled 100 per cent renewable power systems is not considered, and no transition costs are included.

Furthermore, no allowance has been made for distribution augmentation costs, financing costs, land acquisition costs, the cost of stranded assets or the R&D expenditure that may be needed to drive the forecast cost reductions.

The hypothetical capital costs below are expressed in 2012 dollars.

Table 12: Hypothetical capital costs ($2012)

	Scenario 1 2030*	Scenario 1 2050*	Scenario 2 2030*	Scenario 2 2050*
Rooftop PV	$18 billion	$36 billion	$17 billion	$23 billion
Generation (excluding rooftop PV)	$171 billion	$209 billion	$208 billion	$276 billion
New generation connection	$8 billion	$11 billion	$10 billion	$13 billion
New transmission corridors	$22 billion	$28 billion	$17 billion	$21 billion
Total	**$219 billion**	**$285 billion**	**$252 billion**	**$332 billion**

*Capital costs are based on DCCEE scope assumptions which include: assumed system build in 2030 or 2050 without consideration of the transition path; and no allowance for distribution network costs, financing costs, stranded assets, land acquisition costs or R&D expenditure. Cost inputs are based on data provided by the AETA 2012, CSIRO and ROAM Consulting.

5.8 Impact on wholesale prices

Using the hypothetical capital costs presented above and making allowances for O&M, fuel and financing costs, AEMO estimated the hypothetical annualised costs for generation and storage required for each case, including network connection costs. Again, while these estimates are consistent with the study scope, they do not represent what costs might be in practice.

To cover the hypothetical capital and operating cost of generation and storage plant and connections only, wholesale electricity prices in the range of $111/MWh (in Scenario 1 2030) to $133/MWh (in Scenario 2 2050) would be required. These costs are in 2012 dollars. For comparison, this component is over double the average 2012 wholesale electricity spot price of around $55/MWh.

Additional investment required in new shared network transmission infrastructure would add another $6 to $10/MWh to the above estimates.

The wholesale electricity price increase and the additional transmission prices would be passed on to consumers via retail prices. The relative impact of these price rises would depend on other retail price components, such as distribution prices, and would be greater for industrial and commercial customers for whom wholesale prices represent a greater proportion of the total retail cost.

The projected wholesale prices include the impact of wholesale energy prices and transmission costs but do not include other possible factors such as distribution costs, land acquisition, stranded assets or any other government policy schemes. If these costs were included, retail prices would be likely to be higher than the figures shown. Table 14 shows the combined impact of these hypothetical costs on the average retail price for end users in cents per kilowatt hour (c/kWh).

Table 13: Hypothetical unit costs

	Scenario 1 2030 ($/MWh)	Scenario 1 2050 ($/MWh)	Scenario 2 2030 ($/MWh)	Scenario 2 2050 ($/MWh)
Total wholesale	111	112	128	133
Current wholesale (2012 estimate)	55	55	55	55
Additional wholesale	56	57	73	78
Additional transmission	10	10	6	6

Table 14: Projected impact on retail prices

	Scenario 1 2030	Scenario 1 2050	Scenario 2 2030	Scenario 2 2050
Cents/kWh	6.6	6.7	8.0	8.5

6 Detailed results by scenario

6.1 Introduction

The following section describes the chosen generation mix and detailed results for each scenario. As with the entire report, it is important to note that these results are closely tied to the study assumptions and the scenario definitions.

Results concerning the suitability or cost-effectiveness of particular technologies may be a consequence of the assumptions for that scenario. They do not necessarily reflect AEMO's view, nor do they constitute a complete assessment of that technology.

6.2 Generation mix

6.2.1 Scenario 1: Rapid transformation and moderate growth

Scenario 1 assumes rapid progress on lowering technology costs, widespread demand side participation (DSP), and moderate demand growth in the lead up to the year being modelled.

The rapid technology progress assumed sees PV costs reduce substantially. Under this scenario, many other emerging technologies also become commercial and are widely deployed.

Based on the technology costs provided to AEMO, PV is the cheapest technology in Scenario 1, and as a result is heavily used in both 2030 and 2050 cases. In these two cases the modelling shows that PV makes up 25–30% of annual energy and 40–50% of the installed capacity.

CST is also assumed to attract significant cost reductions in Scenario 1 and therefore could provide cost-effective daily storage. The modelling shows that it provides 17% of annual energy in 2030, and 11% in 2050, but its real benefit is providing storage to manage the evening reduction in PV generation between 6:00 and 11:00 PM. During those hours, the modelled CST increases to 33% of energy in 2030 (the single largest energy source) and 24% in 2050 (the second largest source after geothermal).

The costs provided to AEMO also show that emerging technologies such as wave and geothermal (HSA) could also become competitive in Scenario 1. In particular, geothermal (HSA) in the

Cooper Basin could become competitive despite being located remotely from demand centres and requiring considerable transmission expenditure. Geothermal (HSA) is the second largest modelled energy source in Scenario 1 (after PV), providing 26% of annual energy in 2030 and 30% in 2050.

The data shows that wave energy in South Australia and Victoria has a slightly higher unit cost than wind (especially in the 2050 case), however the resource data shows that it generates at times when wind generation is low, so small amounts of capacity are included to reduce fluctuations which would otherwise need to be compensated by more expensive technologies. In total, the modelling shows that wave provides 1% of annual energy in 2030 and 5% in 2050.

Biomass (wood) and biogas are used extensively in Scenario 1, although less than in Scenario 2. In both 2030 and 2050, biomass generates about 22–23 TWh/yr, or 13–18% of annual energy (about half that used in Scenario 2). Bagasse is expected to be cost effective and is used up to limit of the resource (7 TWh/y, or 2–3% of annual energy).

The 2050 case uses proportionally less peak dispatchable generation (27% of generation capacity) than 2030 (37% of capacity). This is primarily because:

- 2050 assumes greater EV usage (consuming 16% of annual energy in 2050 and 6% in 2030). High EV usage reduces the need for dispatchable capacity because EV charging is assumed to be fully flexible (in Scenario 1) and can be scheduled to match intermittent generation.[41]
- 2050 has a more diverse generation mix given its higher use of wave power (1% capacity in 2030, 4% in 2050). Generation mix diversity provides less intermittency and a reduced requirement for rapid dispatchable generation.

Even under the rapid progress assumed, off-shore wind and geothermal (EGS) the costs provided show that these technologies remain uncompetitive in Scenario 1 and are not included in the generation mix for either case.

Table 15: Technology capacities Scenario 1

Type	Scenario 1 2030 (MW)	Scenario 1 2030 (%)	Scenario 1 2050 (MW)	Scenario 1 2050 (%)
PV (rooftop)	16,970	21	25,992	25
PV (utility)	16,500	20	23,500	23
Wind (onshore)	6,000	7	5,000	5
Wave	500	1	4,000	4
Geothermal (HSA)	9,000	11	13,000	13
CST	12,500	15	10,500	10
Hydro	7,330	9	7,330	7
Pumped hydro	740	1	740	1
Bagasse	1,010	1	1,010	1
Biomass (wood)	3,000	4	3,000	3
Biogas	9,000	11	9,500	9
Total	**82,550**	**100**	**103,572**	**100**

[41] In Scenario 1, EV charging is assumed to be fully flexible for scheduling at any time. In Scenario 2, 80% of EV charging is flexible and 20% must occur between 8:00 AM and 7:00 PM and be evenly spread across those hours.

Figure 11: Installed capacity by technology, Scenario 1

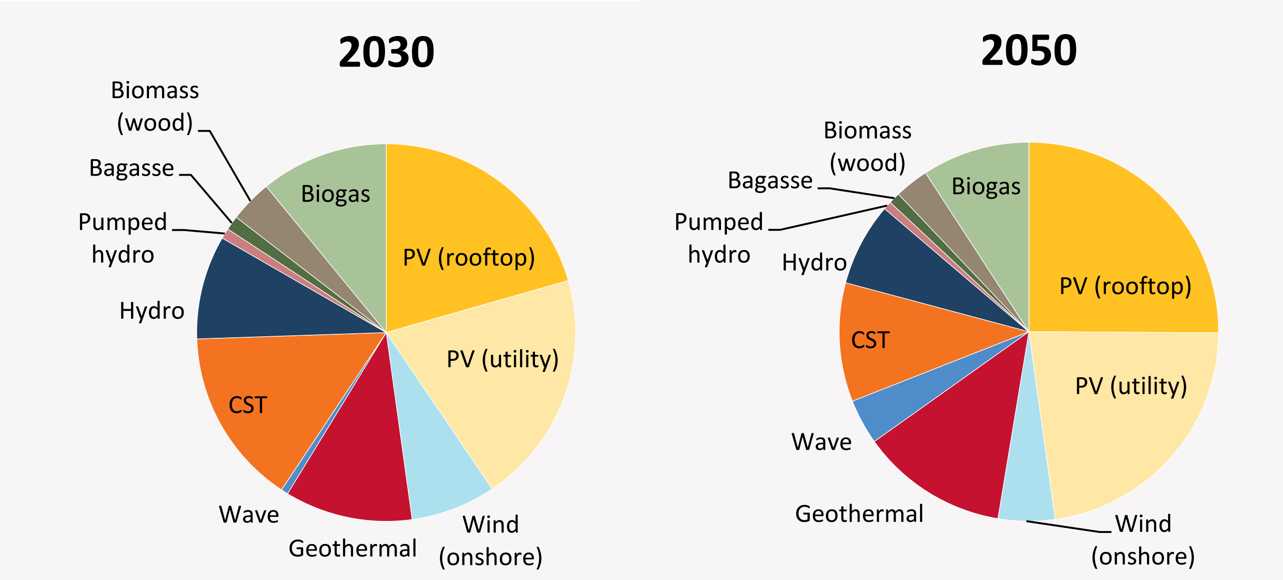
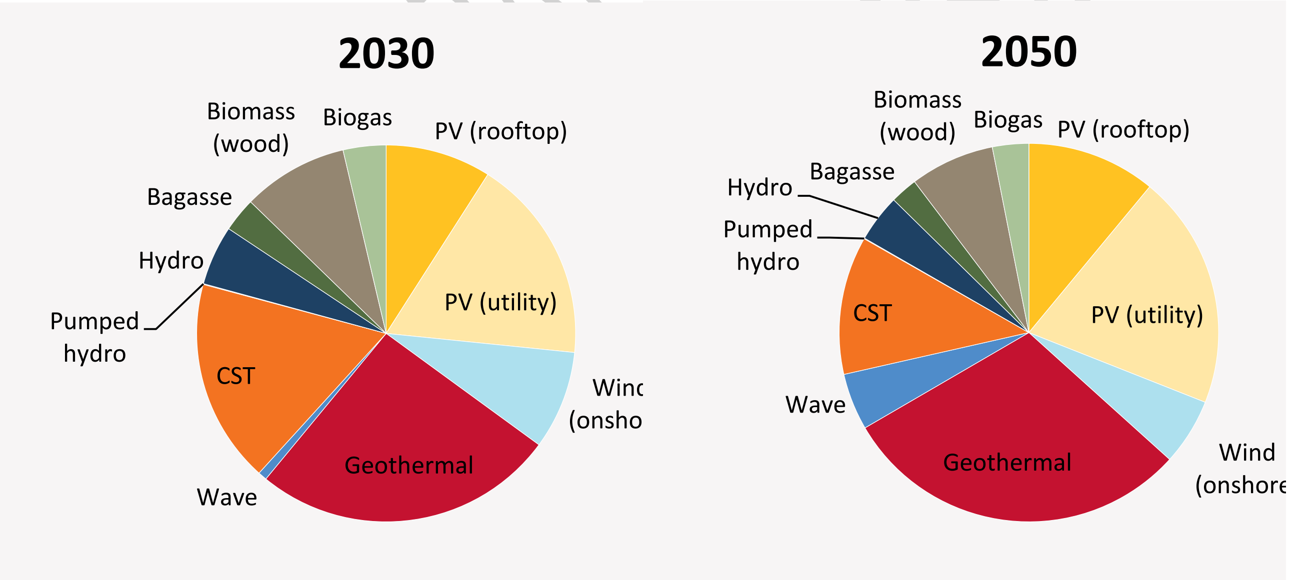


Figure 12: Annual energy generation by technology, Scenario 1



6.2.2 Scenario 2: Moderate transformation and high growth

Scenario 2 assumes moderate trends in lowering technology costs, moderate DSP, and high demand growth in the lead up to the year being modelled.

These assumptions result in less development and learning of emerging technologies, but increased development of mature technologies such as wind. In the 2030 case, wind is likely to be the cheapest technology and has the greatest capacity (34,500 MW or 35% of installed capacity).

Even assuming the slower rate of learning in Scenario 2, by 2050 utility-scale PV is likely to be the lowest cost technology. Consequently, it is modelled to have an installed capacity of 27,500 MW (or 22%).The next low-cost option is onshore wind, with 26.5 GW (or 20%).

CST costs are not expected to reduce as much as they did in Scenario 1, although by 2050 CST costs are similar costs to biomass (wood), and it is used more heavily in that case.

As in Scenario 1, the principle benefit of CST is as storage to balance the evening PV reduction. While higher CST costs mean it produces only 12% of annual energy in 2030 and 16% in 2050, this makes up 20% of energy between 6:00 and 11:00 PM in 2030 and 31% in 2050.

Biomass (wood) is assumed to provide effective baseload power (18% of annual energy in 2030 and 13% in 2050).

Geothermal (HSA) is less developed than in Scenario 1, but the most cost-effective sites (in Victoria, South Australia and near Bundaberg in Queensland) are modelled as being used according to the capacity limit.

Remote geothermal generation in the Cooper Basin is not used, as technology cost reductions in this scenario are not sufficient to overcome the high transmission costs.

Wave, off shore wind and geothermal (EGS) are not expected to be cost competitive in this scenario and are not used in either case.

Both 2030 and 2050 cases use a similar proportion of dispatchable generation (about 35% of total capacity).

Table 16: Technology capacities Scenario 2

Type	Scenario 2 2030 (MW)	Scenario 2 2030 (%)	Scenario 2 2050 (MW)	Scenario 2 2050 (%)
PV, rooftop	10,905	11	20,402	16
PV, utility	11,000	11	27,500	21
Wind, onshore	34,500	35	26,500	21
Geothermal (HSA)	1,000	1	4,000	3
CST	11,000	11	18,000	14
Hydro	7,330	7	7,330	6
Pumped hydro	740	1	740	1
Bagasse	1,010	1	1,010	1
Biomass (wood)	7,000	7	7,000	5
Biogas	13,500	14	15,500	12
Total	**97,985**	**100**	**126,982**	**100**

Figure 13: Generation capacity by technology, Scenario 2

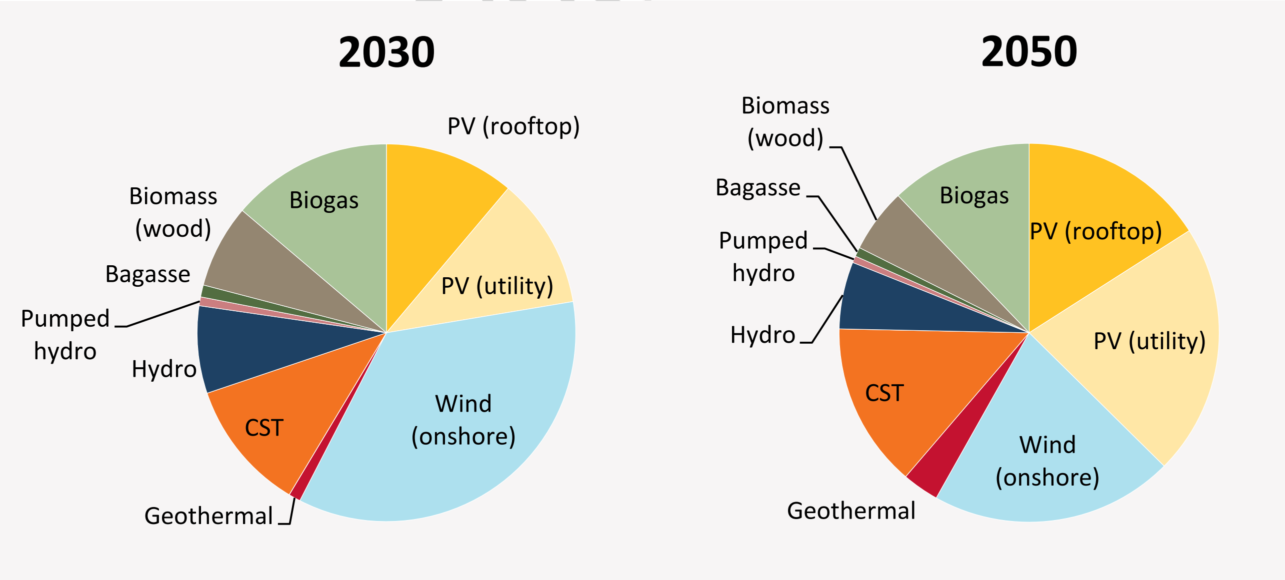
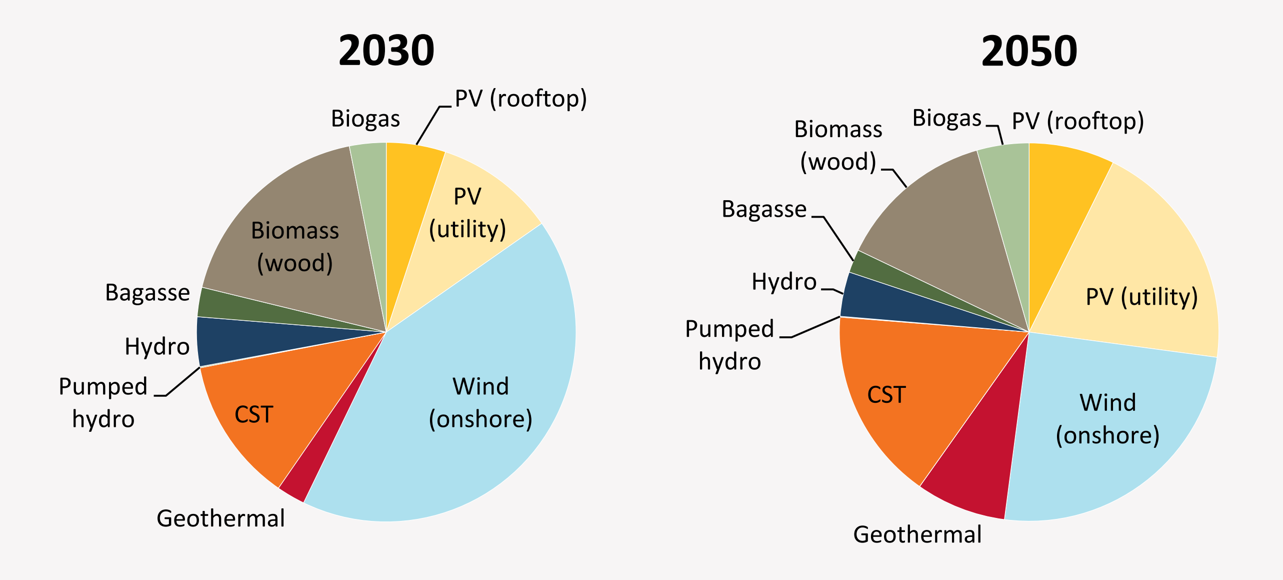


Figure 14: Energy generation by technology, Scenario 2



6.3 Typical operating profiles

Figures 15 to 22 below show example summer and winter supply–demand profiles for both Scenarios. These demonstrate how the different technologies combine at an hourly level to create the daily demand and generation patterns. The summer and winter profiles show how seasonal variation affects this pattern, for example, how lower PV generation in winter is accommodated.

While the graphs appear to show some hours where generation exceeds demand, in reality this would not occur. During these times PV and wind generation would be curtailed to match demand.

In addition to this, there are several hundred hours per year where peak dispatchable generation (CST, hydro and biogas) is used even though non-dispatchable generation (PV, wind) across the NEM would have been sufficient to meet demand. There are two reasons for this altering of the NEM-wide merit order:

1. **To manage transmission constraints**: When non-dispatchable generation, such as PV and wind, from one part of the NEM cannot be transported to the required location due to optimised transmission capacities, it is likely to be more cost efficient to use local CST, hydro or biogas than to increase transmission capacities that would rarely be used. For example, using this approach reduced the transmission requirements in Scenario 1 (2050) of the South Australia to Victoria transmission line from 5000 MW to 3200 MW.
2. **To help manage frequency control and maintain system reliability**: At times when the percentage of synchronous generation was low, additional peak dispatchable generation (mainly CST, rarely biogas) was used to increase it. (Full discussion regarding frequency control management in system with low synchronous generation is available in Appendix 6.)

The figures below also demonstrate that in summer, generation from PV and CST is expected to be particularly high, so less hydro and biogas are generally required to meet daily peak demand.

There is generally less PV and CST available in winter, but wind generation is typically higher. Still, overall, about twice as much hydro and biogas is used compared to summer.

Figure 15: Example summer supply and demand Scenario 1, 2030

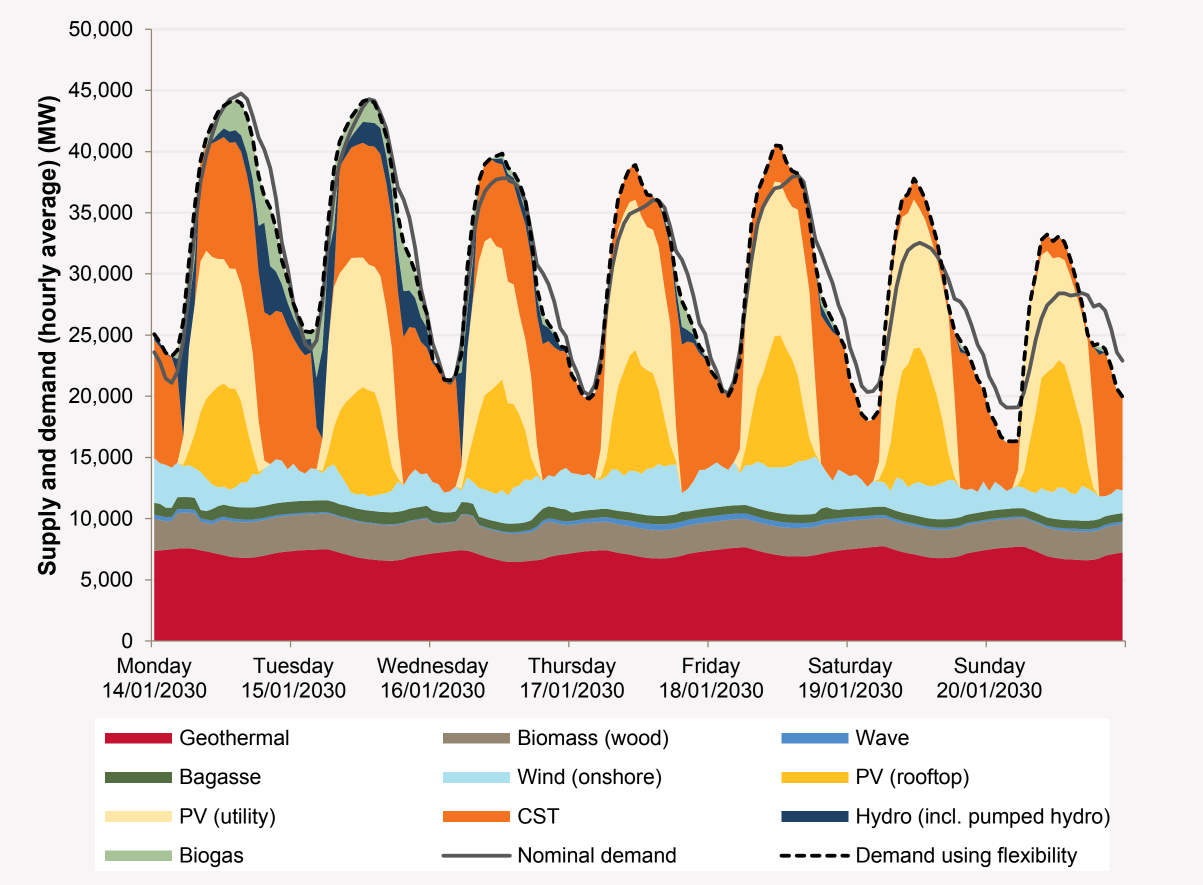


Figure 16: Example winter supply and demand Scenario 1, 2030

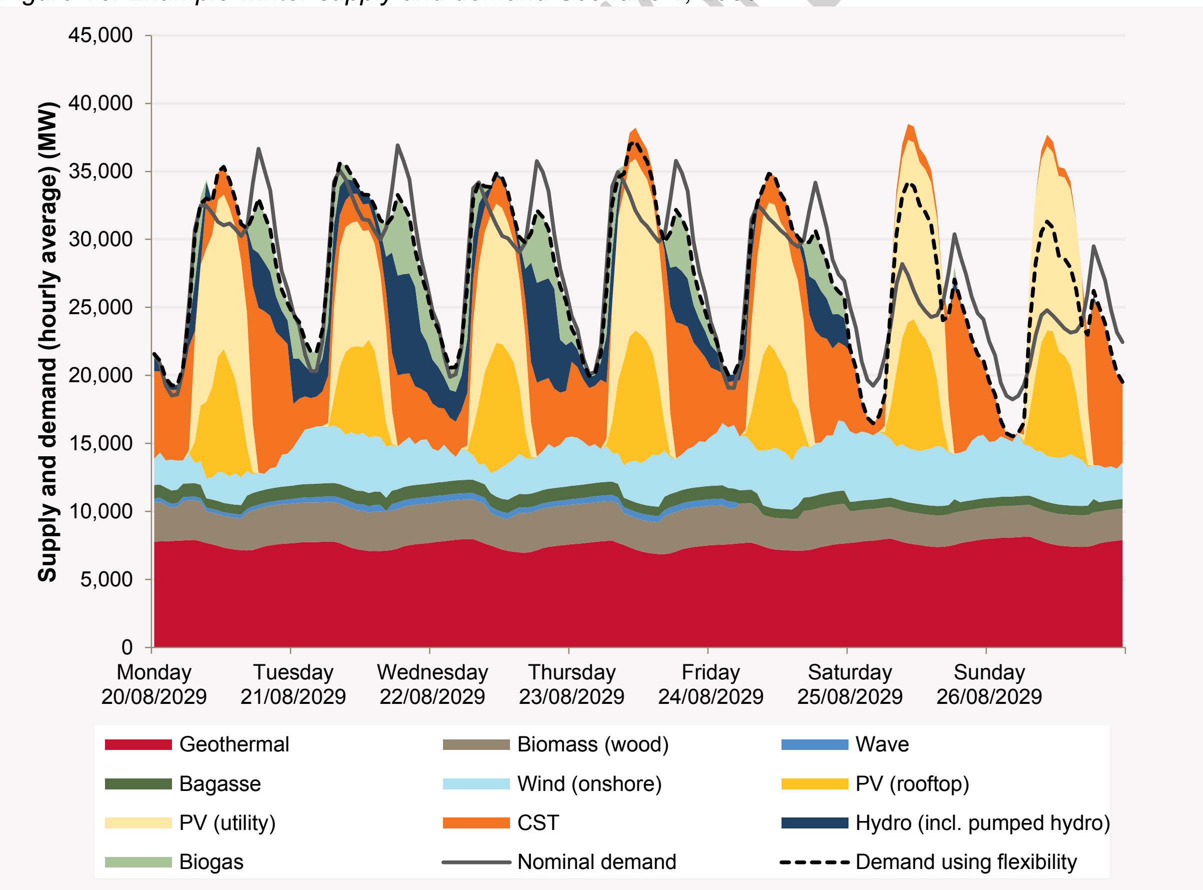


Figure 17: Example summer supply and demand Scenario 1, 2050

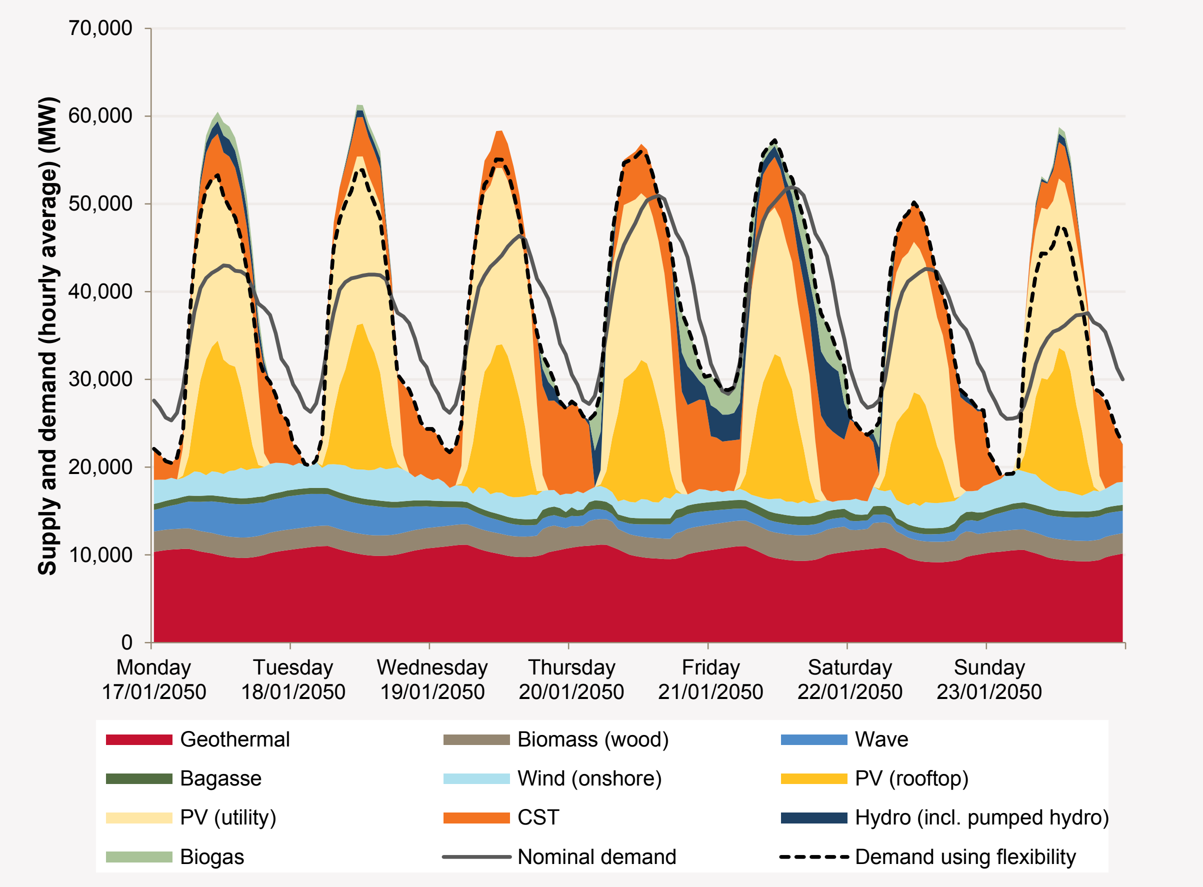


Figure 18: Example winter supply and demand Scenario 1, 2050

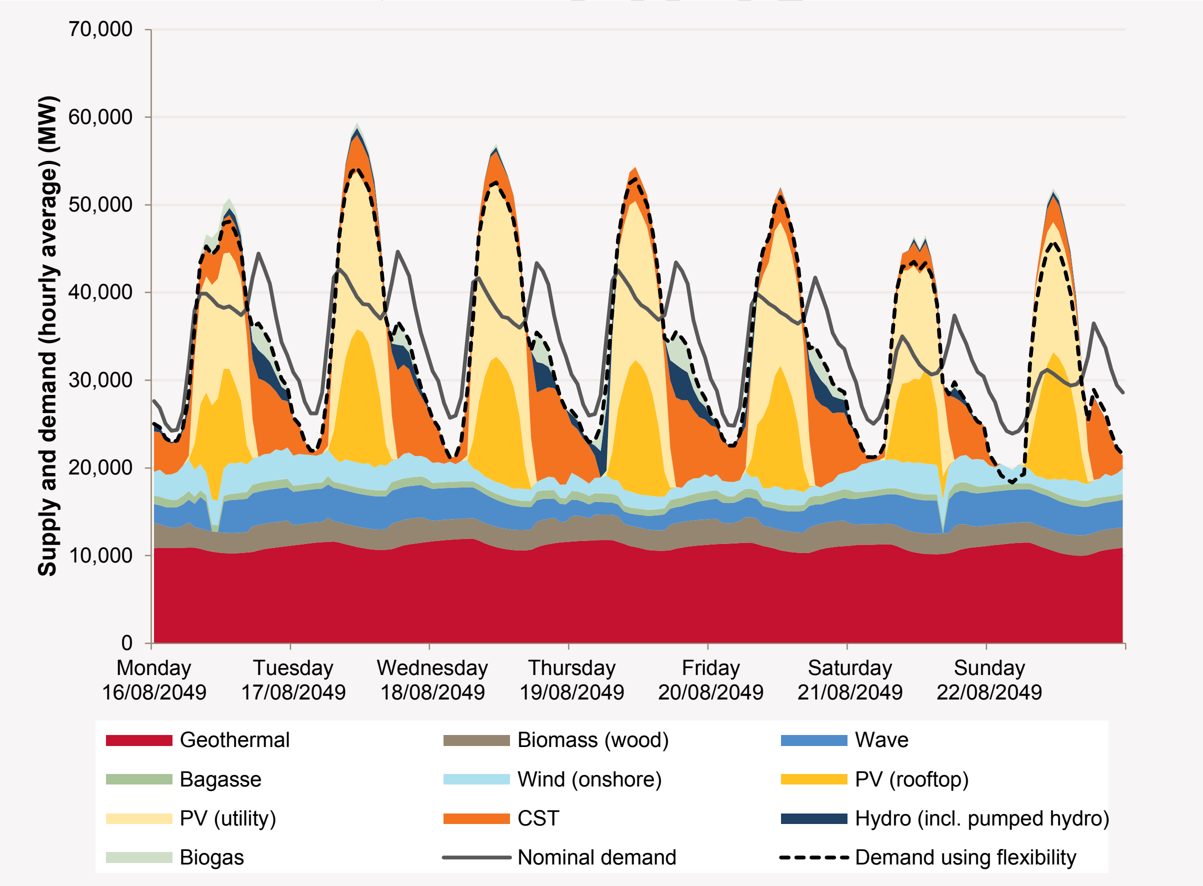


Figure 19: Example summer supply and demand Scenario 2, 2030

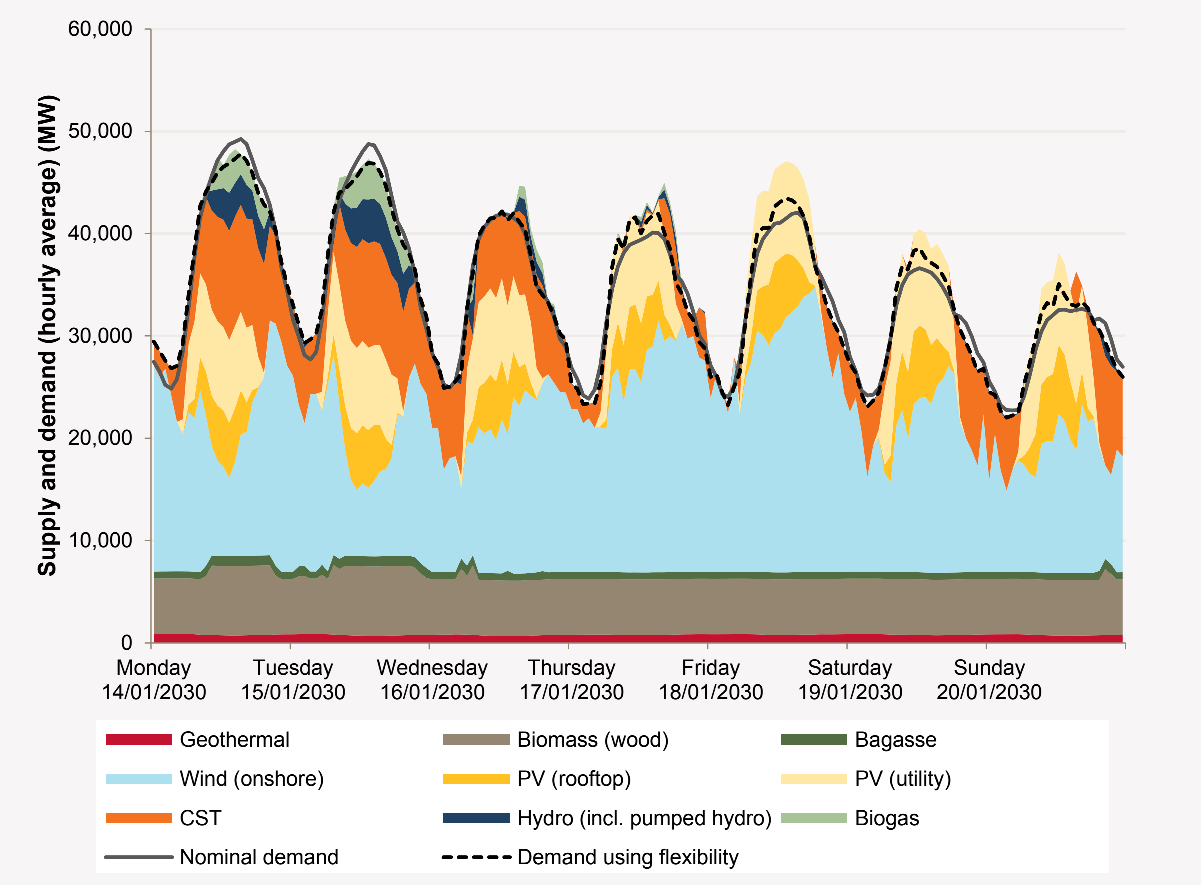


Figure 20: Example winter supply and demand Scenario 2, 2030

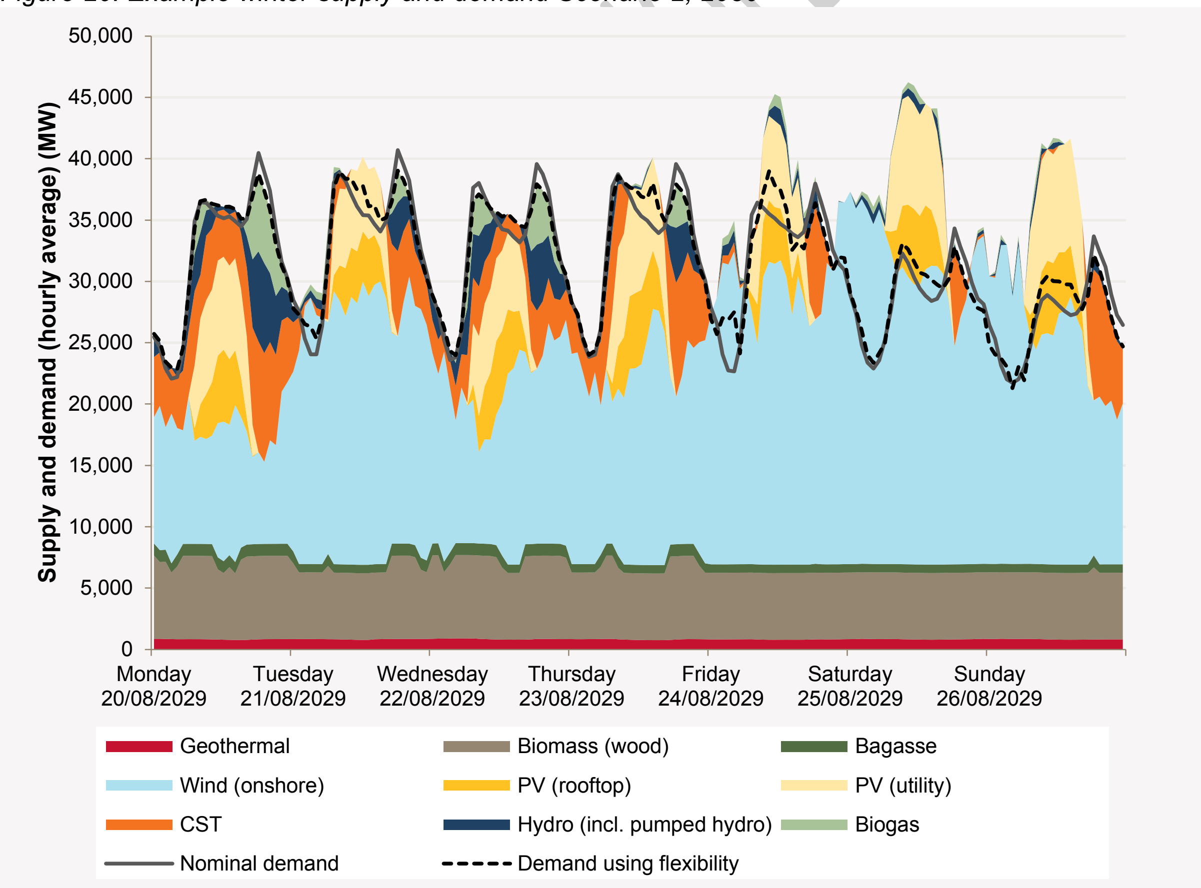


Figure 21: Example summer supply and demand Scenario 2, 2050

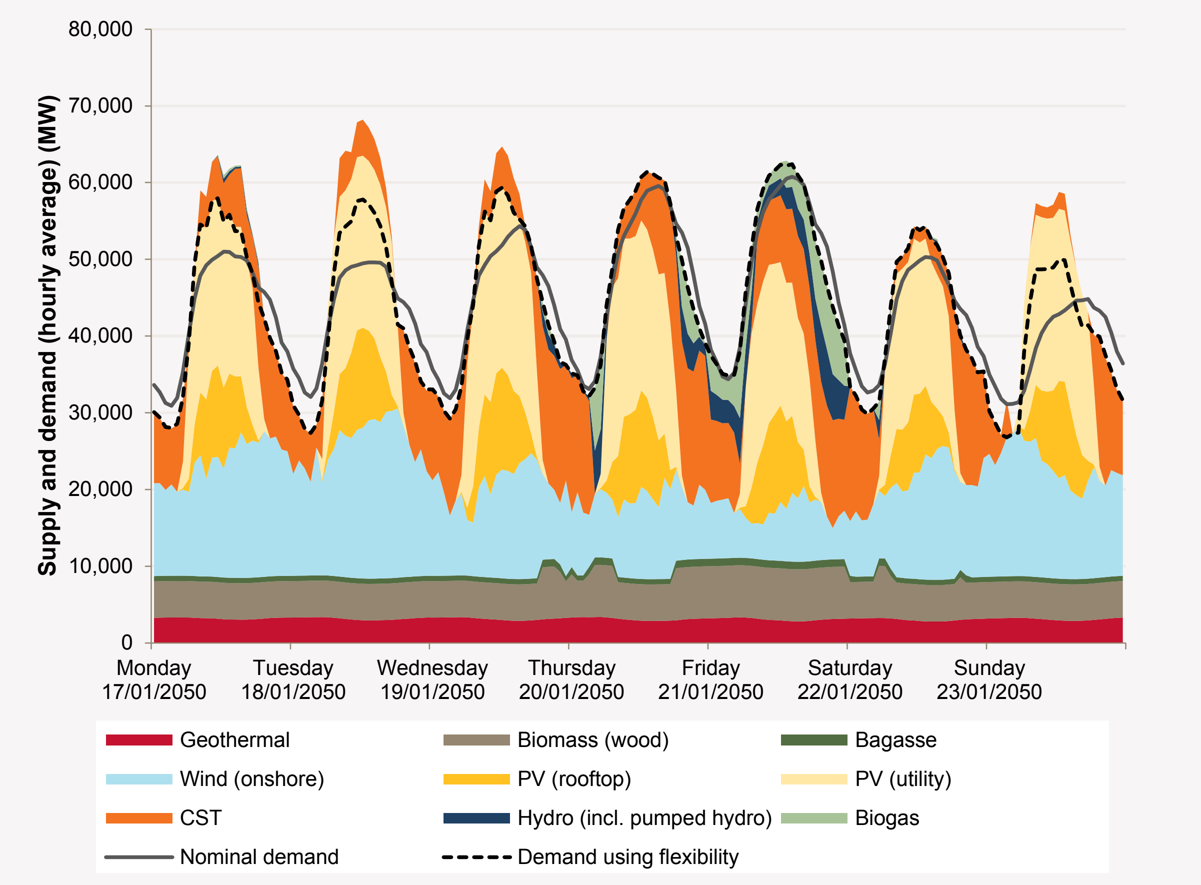
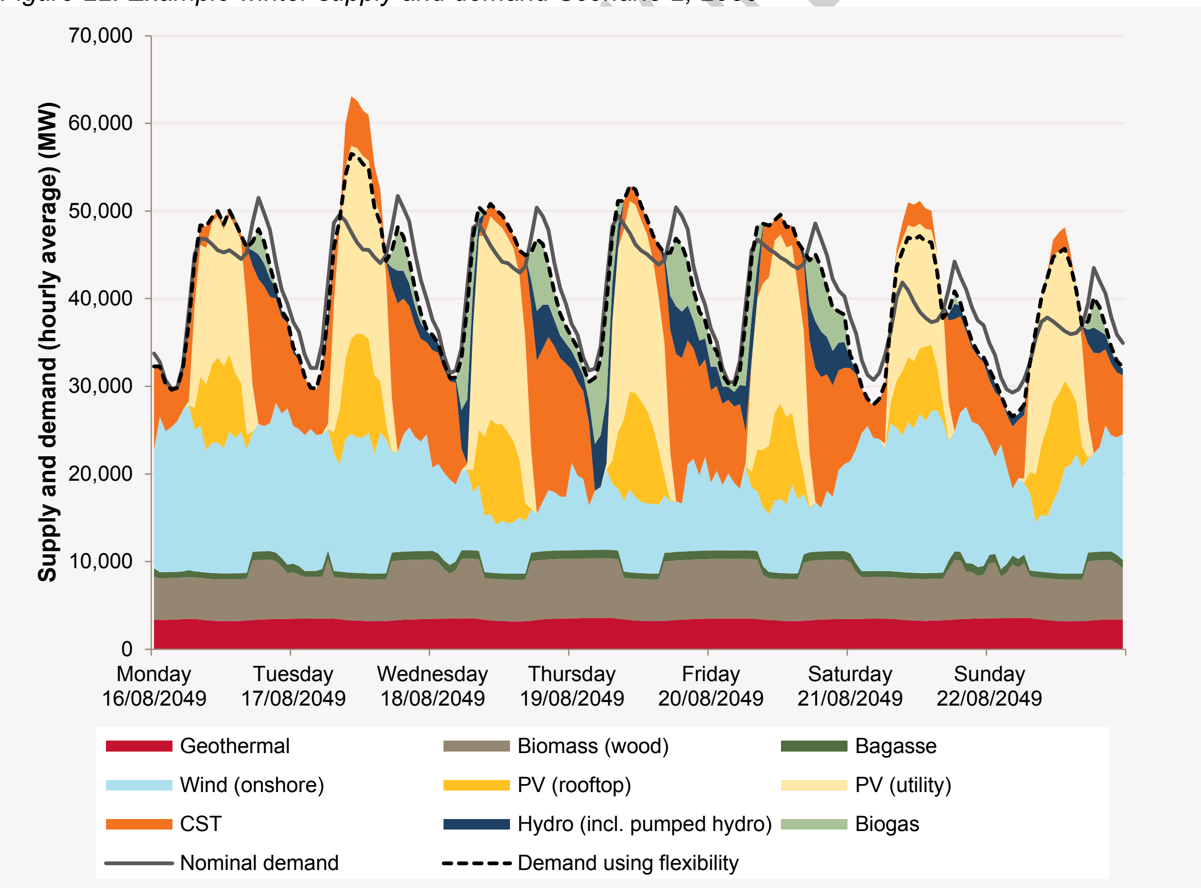


Figure 22: Example winter supply and demand Scenario 2, 2050



6.4 Operational considerations

6.4.1 Most challenging week

A key consideration in evaluating a power system is its capacity to ensure reliable supply year round.

Given the potential requirement to manage several consecutive days of low wind and solar generation with limited amounts of storage (see Section 5.5), it was important to assess how a 100 per cent renewable energy power system could handle such conditions.

Further, given that the systems modelled rely on storage that is recharged each day, managing several consecutive days of low sun and wind is more challenging than managing isolated days of low sun and wind. Our modelling of the most challenging week demonstrates that this problem should be manageable.

Under the assumptions modelled, the results in all four cases show that there is no significant unserved energy during the whole modelled year. On that basis, it was considered reasonable to label the most challenging week as the one which uses the most biogas (due to low storage levels). Biogas is the last technology to be dispatched given its expensive fuel costs.

In Scenario 1 2030, this week requires 600,000 MWh of electricity produced by biogas, and in Scenario 1 2050 it requires 560,000 MWh of electricity produced by biogas. In both cases, this is more than three times the average weekly biogas use.

In Scenario 2, the largest weekly biogas use is 788,000 MWh in the 2030 case and 1,166,000 MWh in 2050. Both are approximately four times the average weekly use.

As demonstrated in figures 23 to 34 below, despite the challenges this week would bring, energy storage levels remain sufficient and the modelling shows a reasonable amount of dispatchable generation to manage the occurrence of a credible contingency (such as a major plant failure).

Key observations are:

- CST storage levels drop to almost zero during this week, as the CST dispatch algorithm used in the modelling tries to use all solar energy collected in the preceding 24-hour period. A possible extension to the modelling, not considered in this report, would be to conserve CST storage levels by using more expensive dispatchable generation, such as biogas, in the early part of each evening during a forecasted challenging period to save stored CST energy for more challenging days to come.
- Pumped hydro is not recharged at all during the most challenging week because there is never any excess non-dispatchable generation. It would be used as a last resort if required.

Figure 23: Supply and demand in most challenging week Scenario 1, 2030

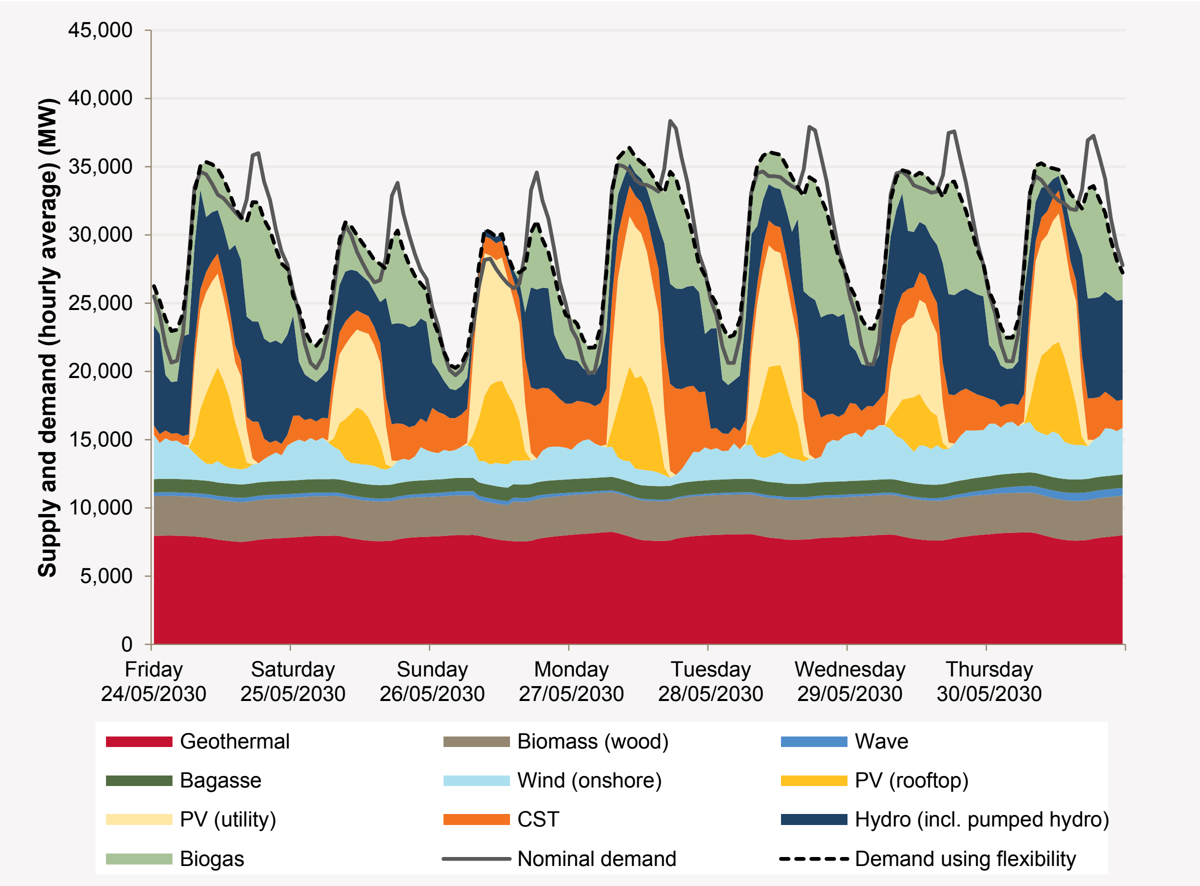


Figure 24: Spare dispatchable capacity in most challenging week Scenario 1, 2030

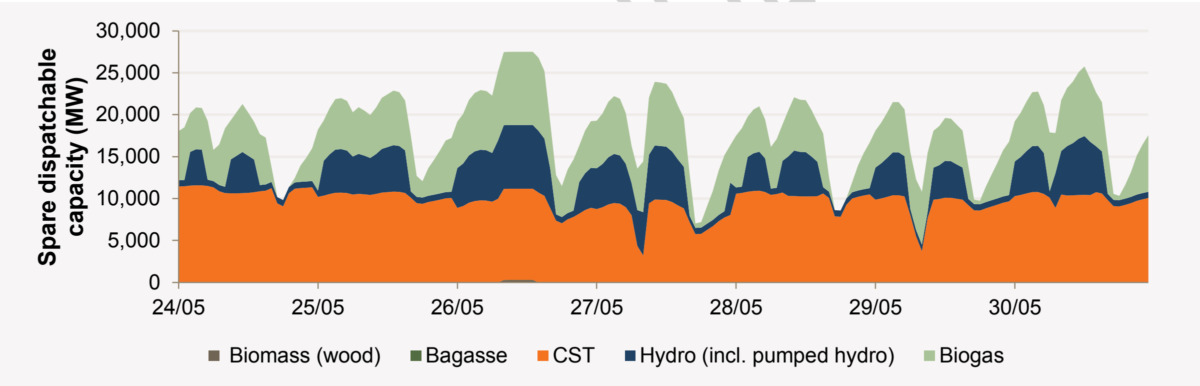


Figure 25: Energy storage levels in most challenging week Scenario 1, 2030

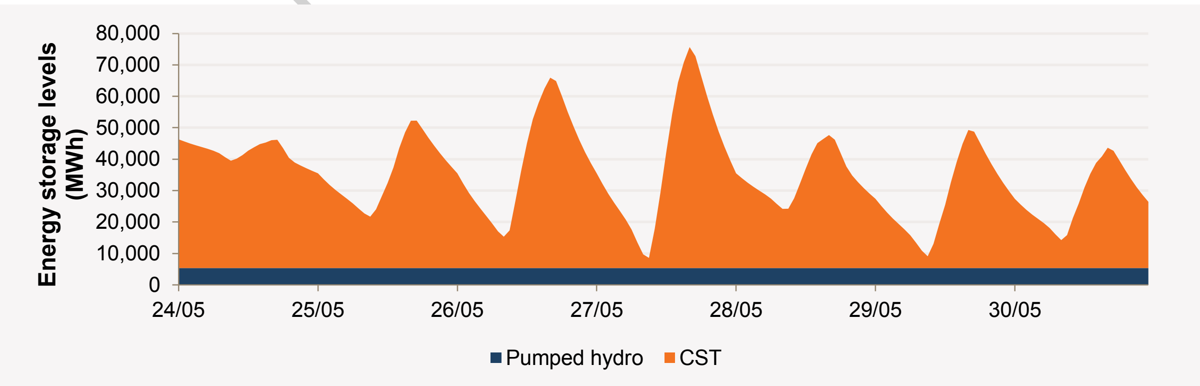


Figure 26: Supply and demand in most challenging week Scenario 1, 2050

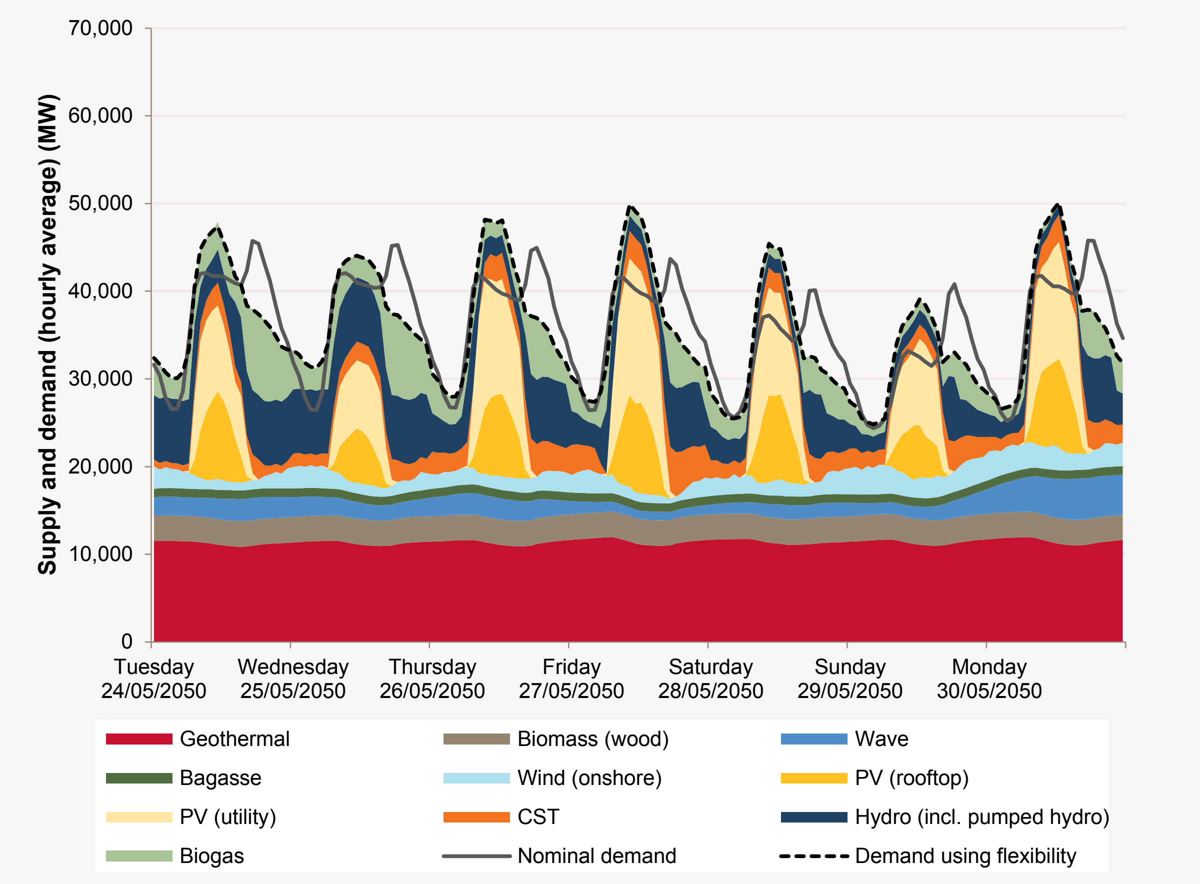


Figure 27: Spare dispatchable capacity in most challenging week Scenario 1, 2050

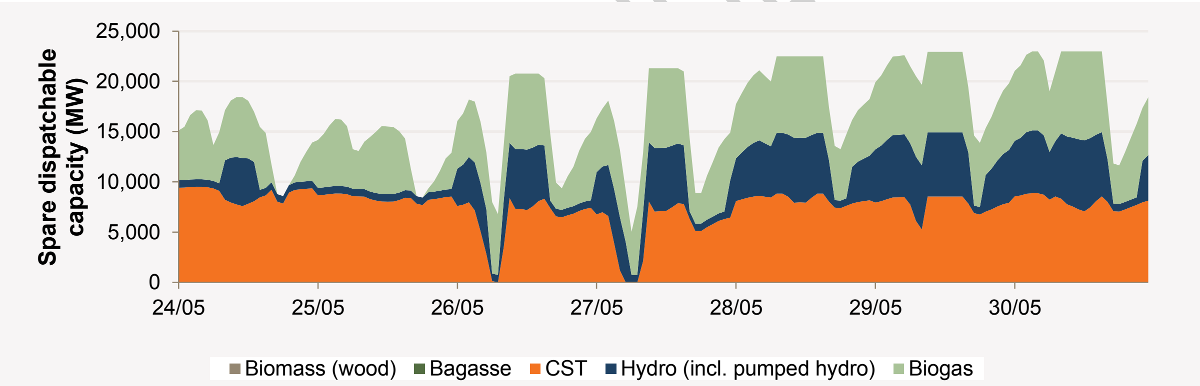


Figure 28: Energy storage levels in most challenging week Scenario 1, 2050

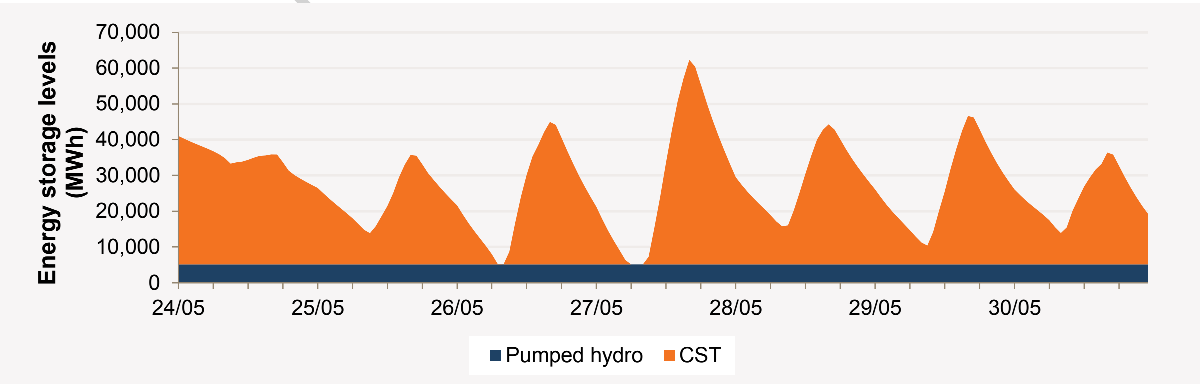


Figure 29: Supply and demand in most challenging week Scenario 2, 2030

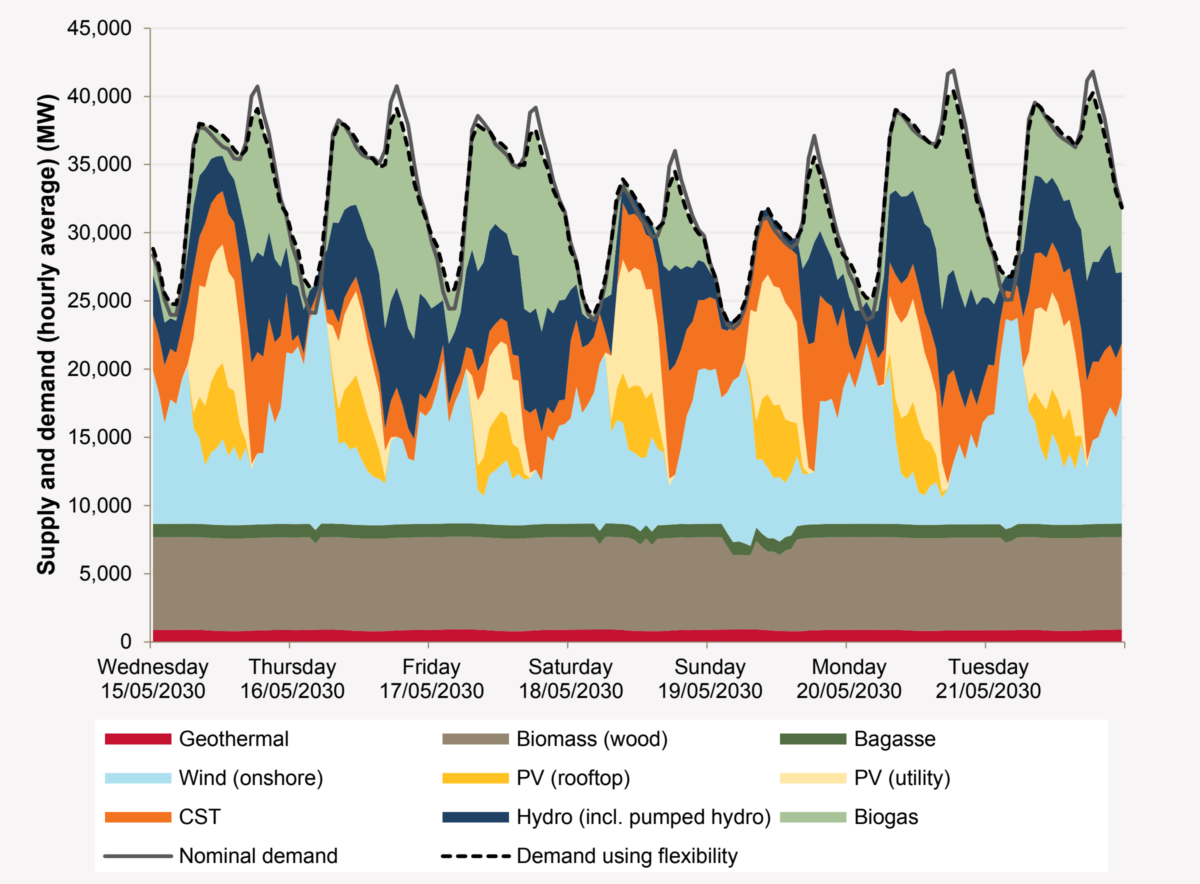


Figure 30: Spare dispatchable capacity in most challenging week Scenario 2, 2030

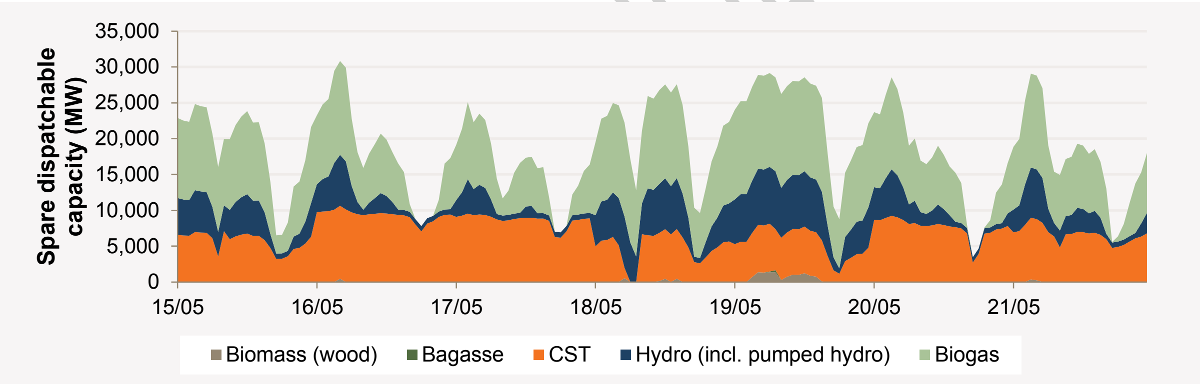


Figure 31: Energy storage levels in most challenging week Scenario 2, 2030

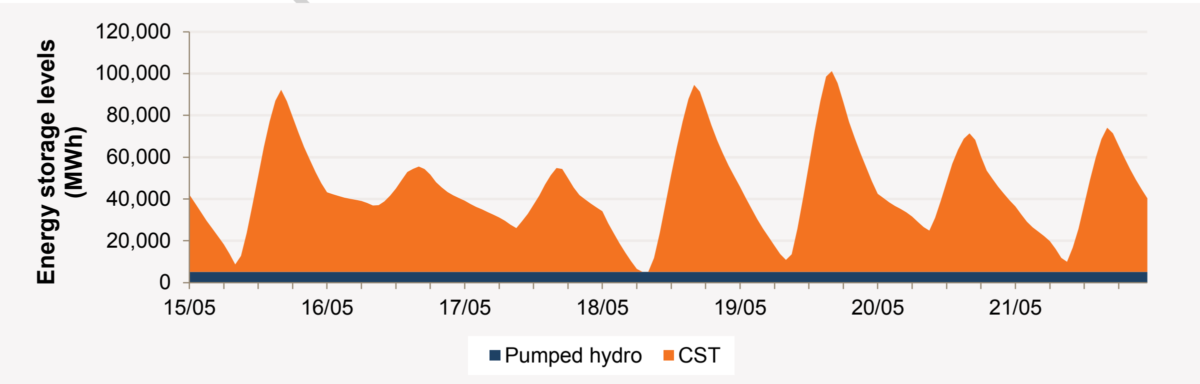


Figure 32: Supply and demand in most challenging week Scenario 2, 2050

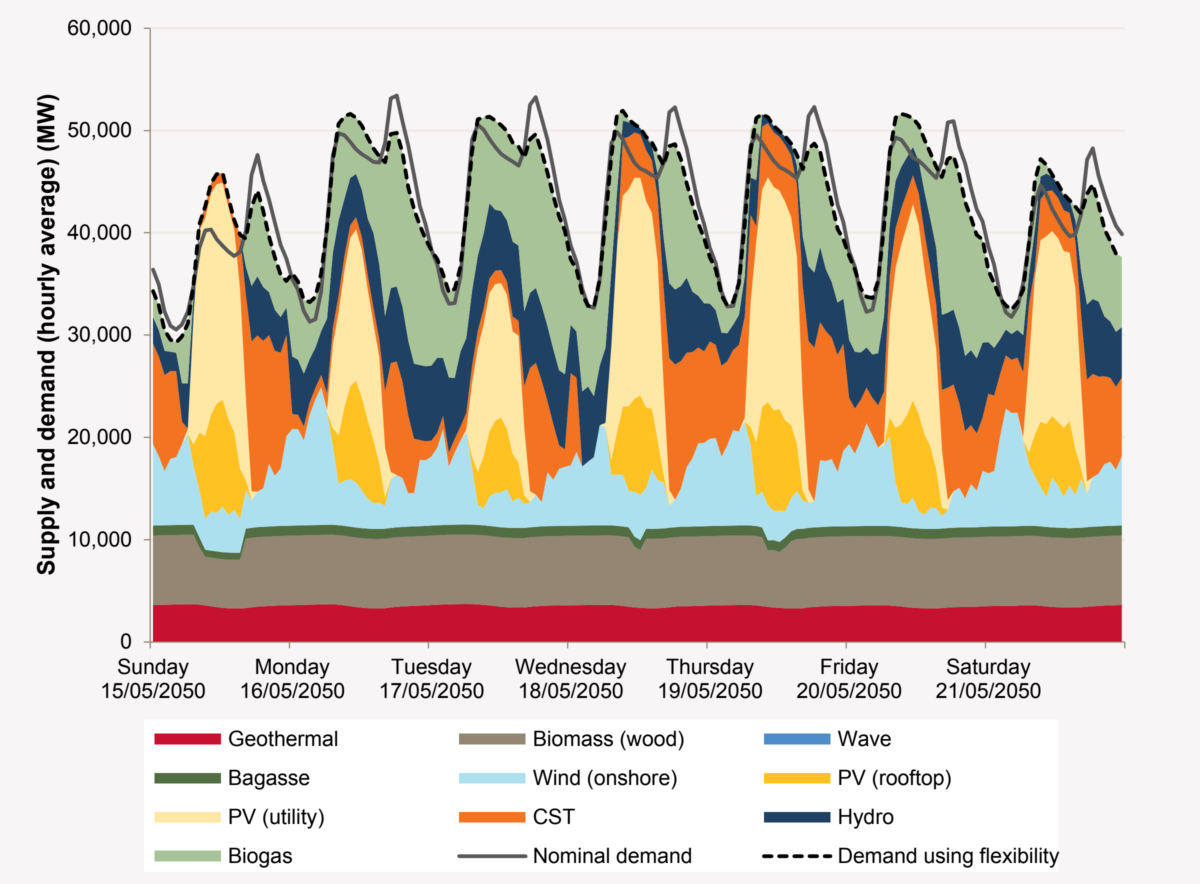


Figure 33: Spare dispatchable capacity in most challenging week Scenario 2, 2050

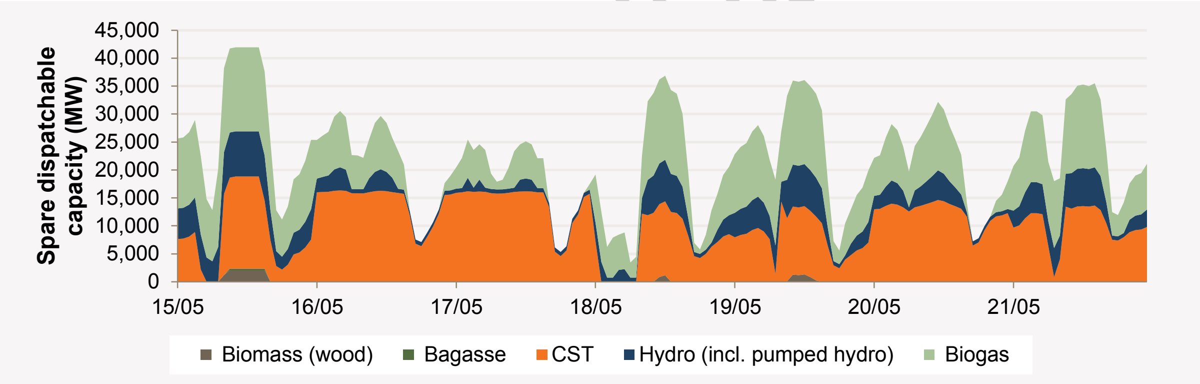
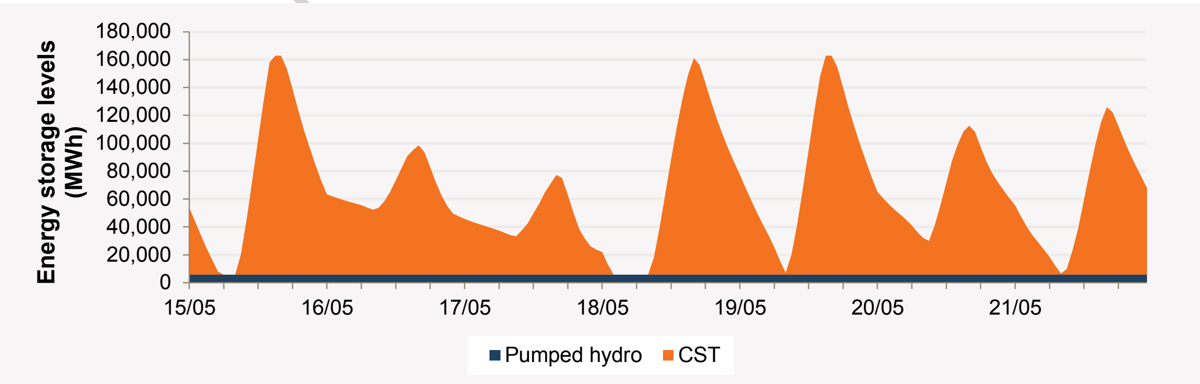


Figure 34: Energy storage levels in most challenging week Scenario 2, 2050



6.4.2 Synchronous generation

Synchronous generation is provided by plant with a generating rotor whose spin frequency corresponds to the power system frequency. Synchronous generators considered in this modelling are: geothermal, bagasse, biomass (wood), CST and hydro.

Synchronous generators provide some natural damping of any frequency deviation by releasing or absorbing stored rotational energy in response to changes in system frequency. As such, the percentage of synchronous generation is an important operational metric for a 100 per cent renewable power system. (For more details on the role of synchronous generation in power system operations, see Section 7.)

The modelling examined the percentage of synchronous generation in all four cases, and these results were then assessed in the operational review.

The lowest amount of synchronous generation by power (see definition below) during any one hour period in the modelling is 15%. While this level would be extremely challenging operationally, techniques to manage low synchronous systems do exist and are actively being developed around the world.

Figures 35 to 42 below show the modelling results for the percentage of synchronous generation in each case. This was calculated separately for the mainland and Tasmania, as these two areas are connected by a HVDC link, which makes them separate synchronous regions. (Smaller regional breakdowns were not considered as part of this study, but would be required for a more detailed technical review).

Synchronous generation was calculated using two methods:

- **By power**: The first method only considers actual power being generated by each synchronous unit, as a percentage of total power use in the synchronous region.
- **By power including hydro capacity**: The second method also includes the full capacity of all hydro plants (not just the power generated at that time), as well as the total capacity of all bagasse and biomass (wood) plant (since they are assumed to be all running at 80% capacity, rather than 80% of plant running at full capacity). This is equivalent to each hydro plant running in 'synchronous condenser mode', which provides the benefits of its synchronous generation without actually generating and consuming water. (Costs to convert all existing hydro plants to run in synchronous condenser mode have not been considered in this study.)

Power from HVDC transmission lines was included in the total power if the line was exporting from the synchronous region. They were treated as non-synchronous generators if importing into the region.

Therefore, geothermal power in the Cooper Basin (being connected by HVDC transmission) was treated as non-synchronous generation in the NEM mainland synchronous region.

Figure 35: % of synchronous generation (mainland) by power (left) and by power including hydro capacity (right) Scenario 1, 2030

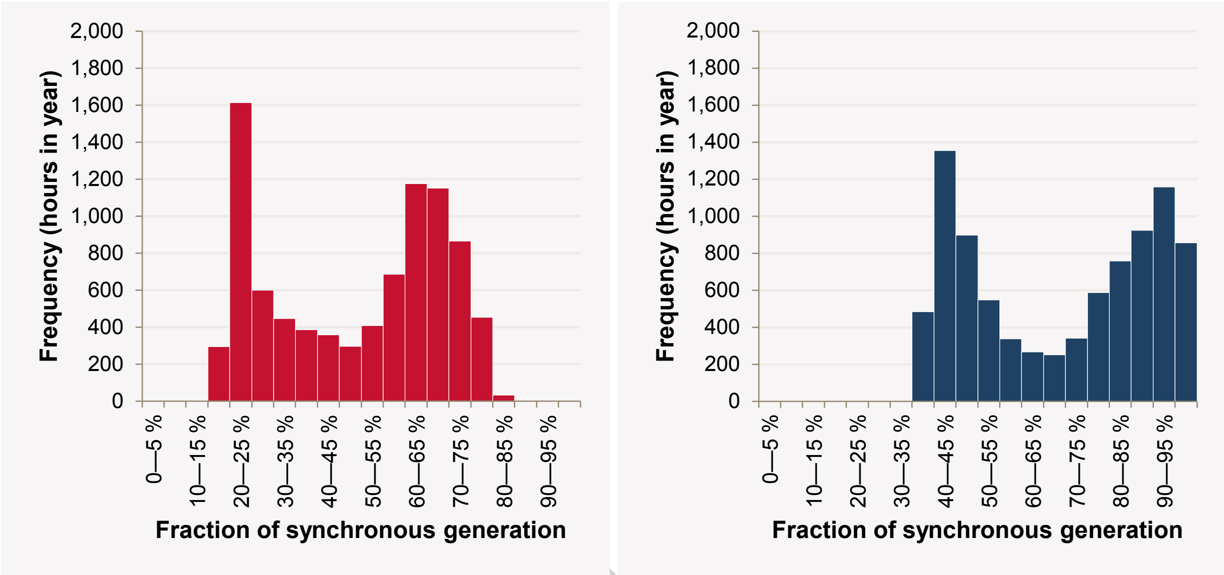


Figure 36: % of synchronous generation (Tasmania) by power (left) and by power including hydro capacity (right) Scenario 1, 2030

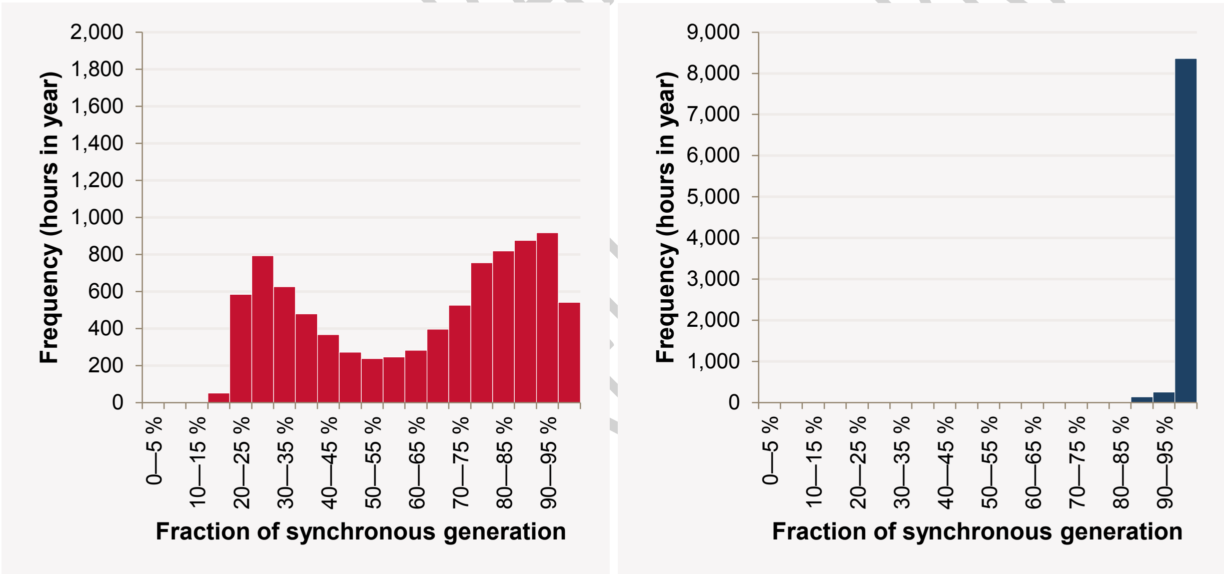


Figure 37: % of synchronous generation (mainland) by power (left) and by power including hydro capacity (right) Scenario 1, 2050

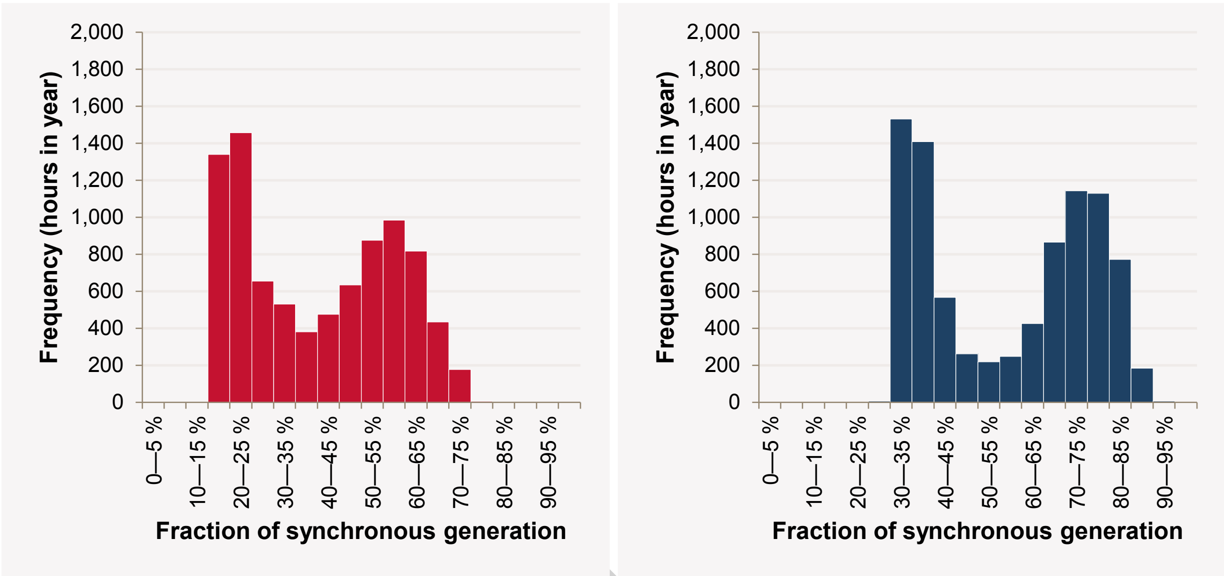


Figure 38: % of synchronous generation (Tasmania) by power (left) and by power including hydro capacity (right) Scenario 1, 2050

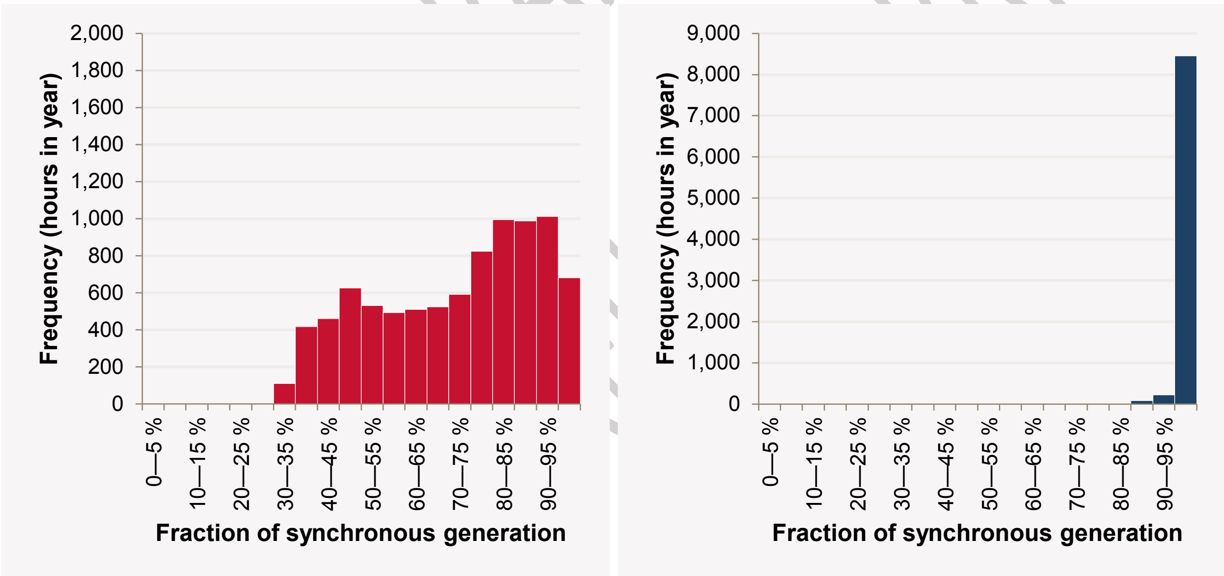


Figure 39: % of synchronous generation (mainland) by power (left) and by power including hydro capacity (right) Scenario 2 2030

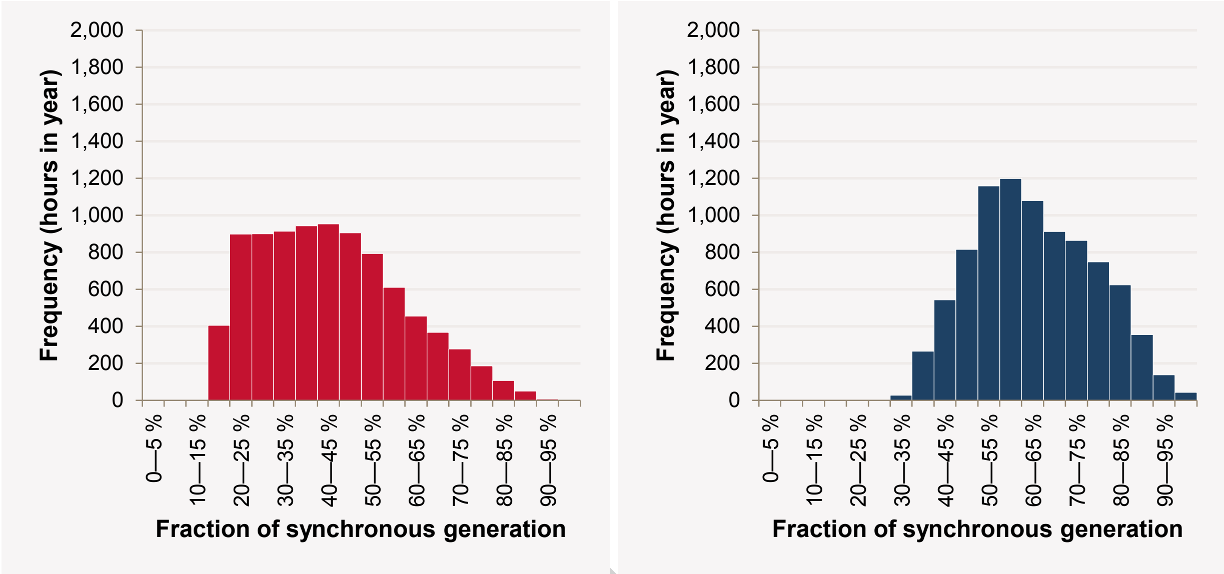


Figure 40: % of synchronous generation (Tasmania) by power (left) and by power including hydro capacity (right) Scenario 2, 2030

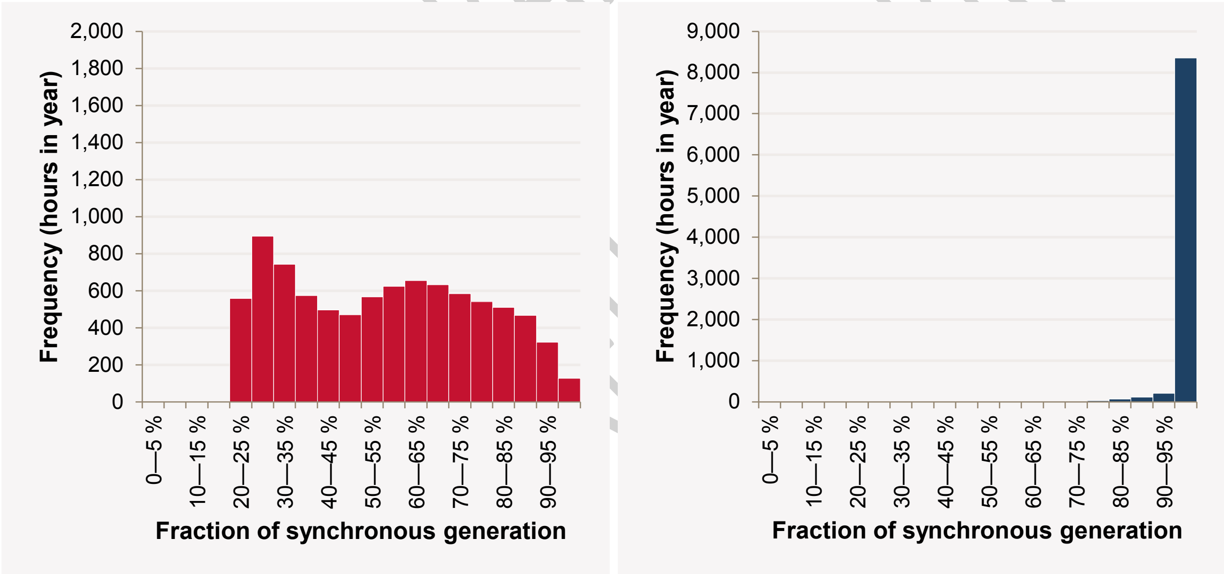


Figure 41: % of synchronous generation (mainland) by power (left) and by power including hydro capacity (right) Scenario 2, 2050

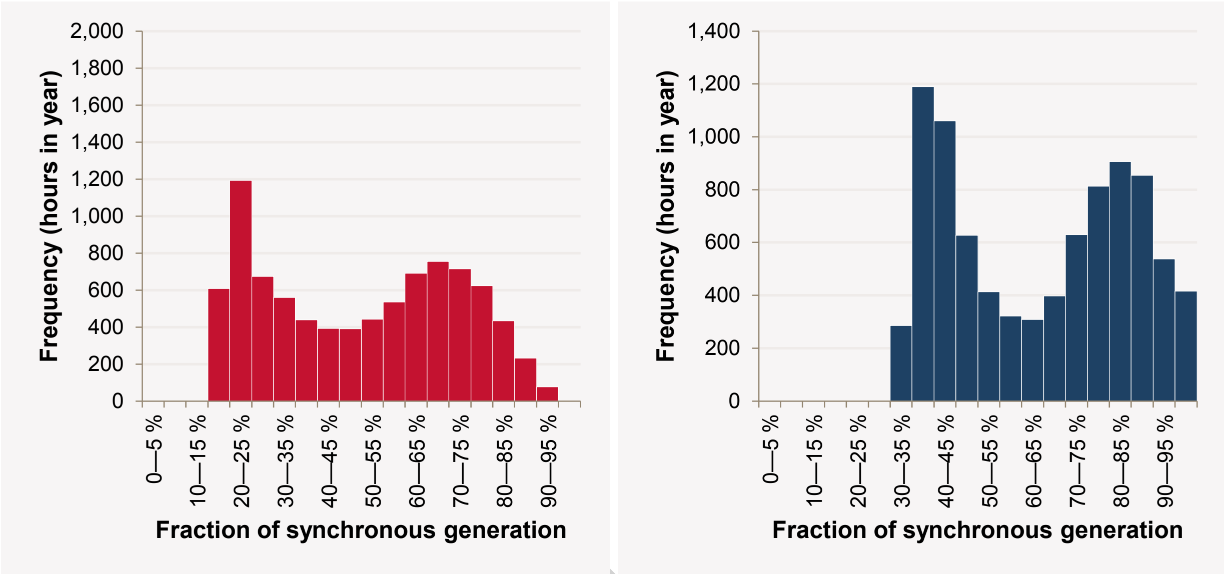
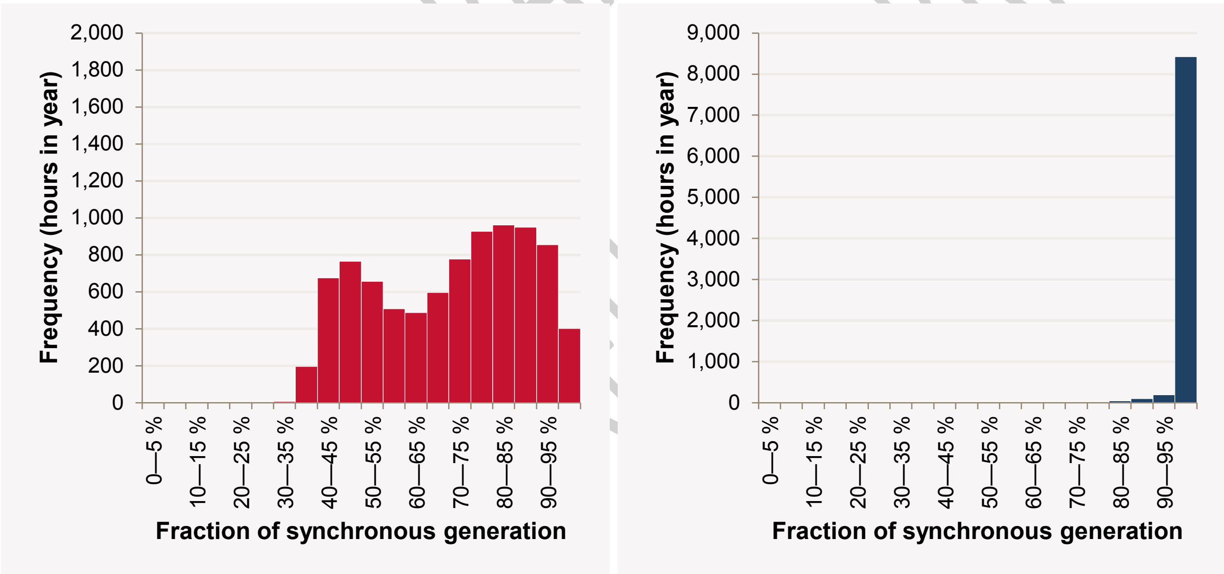


Figure 42: % of synchronous generation (Tasmania) by power (left) and by power including hydro capacity (right) Scenario 2, 2050



6.4.3 Ramp rates

In operating any power system, fluctuations between demand and non-dispatchable generation must be balanced by ramping dispatchable generation up or down as required.

A 100 per cent renewable system is likely to require greater ramp rates, so this section analyses the maximum ramp rates of dispatchable technologies which the system is likely to require.

In both Scenarios 1 and 2, the highest ramp of dispatchable technologies occurs around sunset, when PV generation decreases to zero. The largest required ramp rate in a one-hour period in all four cases modelled is 40–45% of peak dispatchable capacity.

This is challenging but is within the assumed technical capabilities of the generating plant. CST is still an emerging technology, and the current modelling assumes it can ramp to full output in one hour from a 'hot start'. While not used in the results, a modelling sensitivity where CST was restricted to a maximum ramp of 33% of installed capacity per hour was conducted; reliability standards were maintained and there was only a slight increase in biogas use. (See details in Appendix 4.)

In Scenario 1 (2030), the modelling shows the greatest ramp of dispatchable power in one hour is 12,400 MW/h, or 43% of dispatchable capacity.

Figure 43: Largest dispatchables ramp Scenario 1, 2030

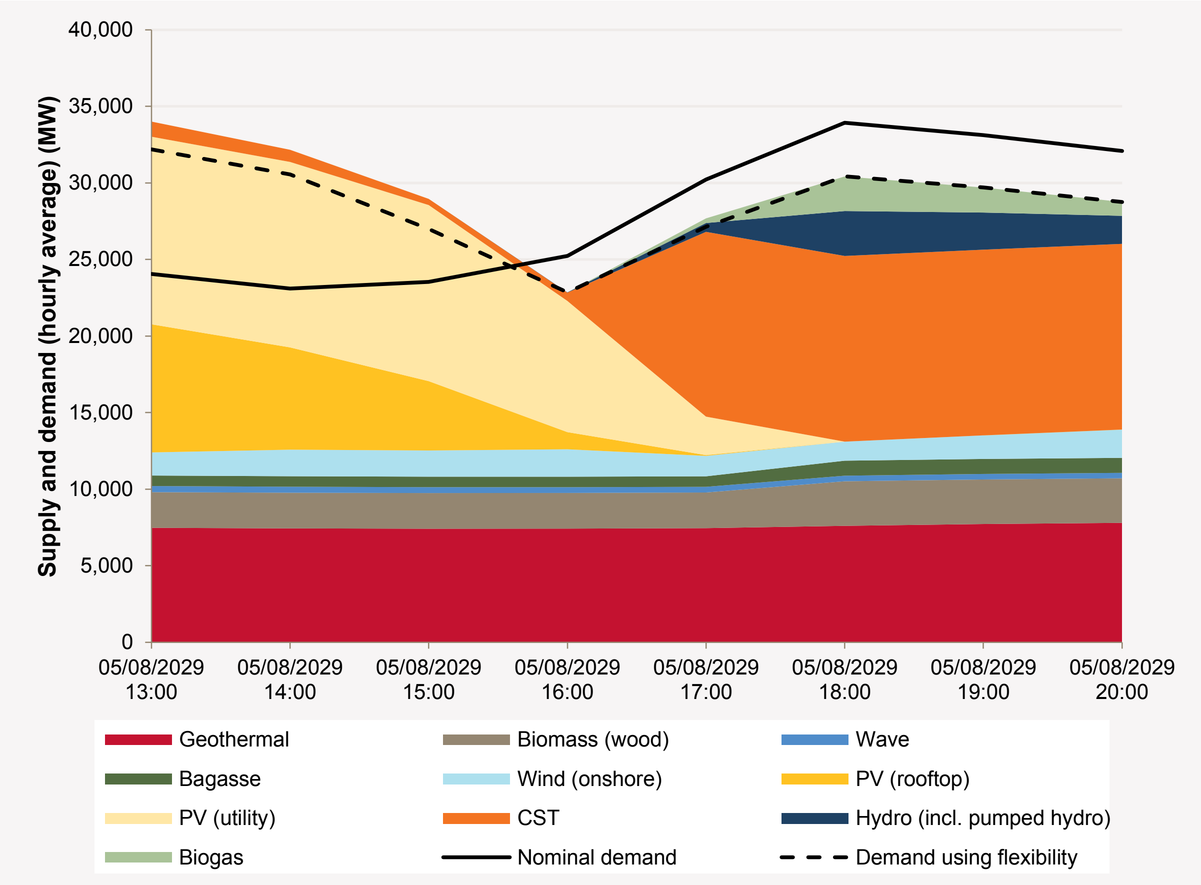
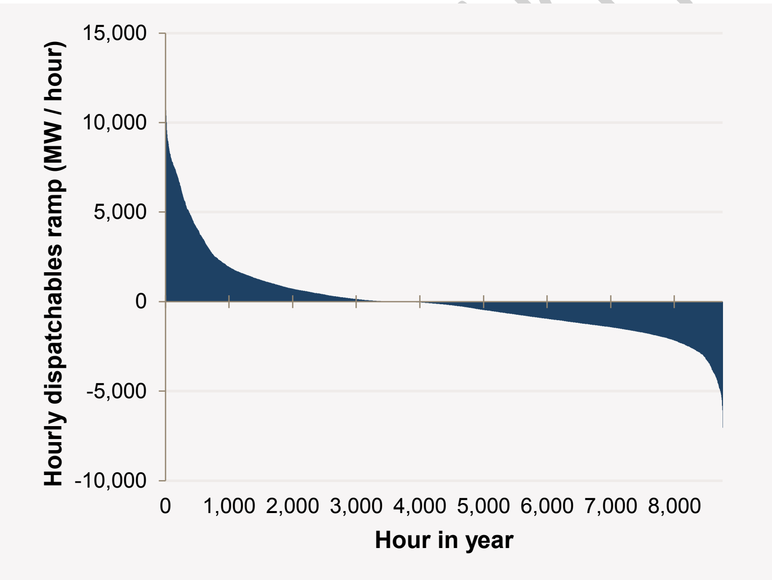


Figure 44: Hourly dispatchable ramps Scenario 1, 2030



In Scenario 1 (2050), the modelling shows the greatest ramp of dispatchable generation in one hour is 12,800 MW in one hour, or 45% of dispatchable capacity.

Figure 45: Largest dispatchables ramp Scenario 1, 2050

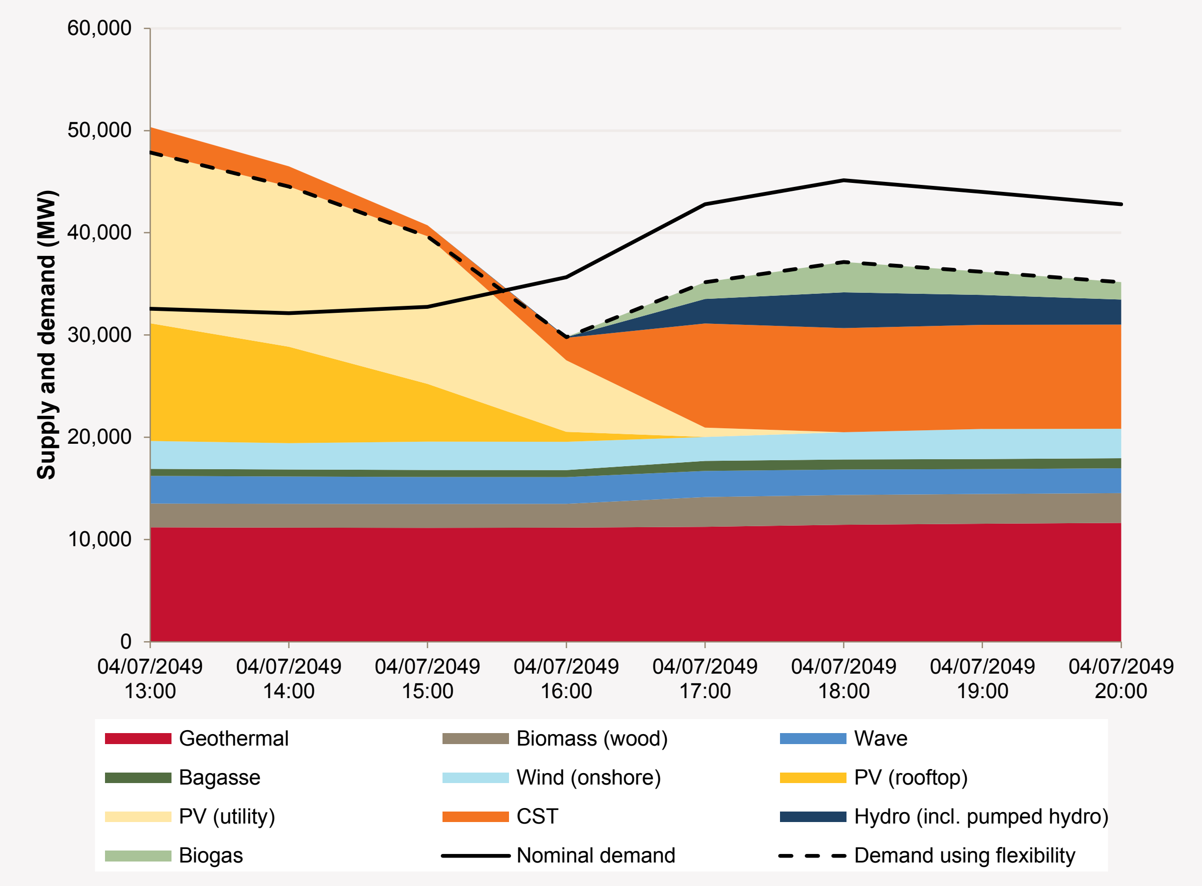
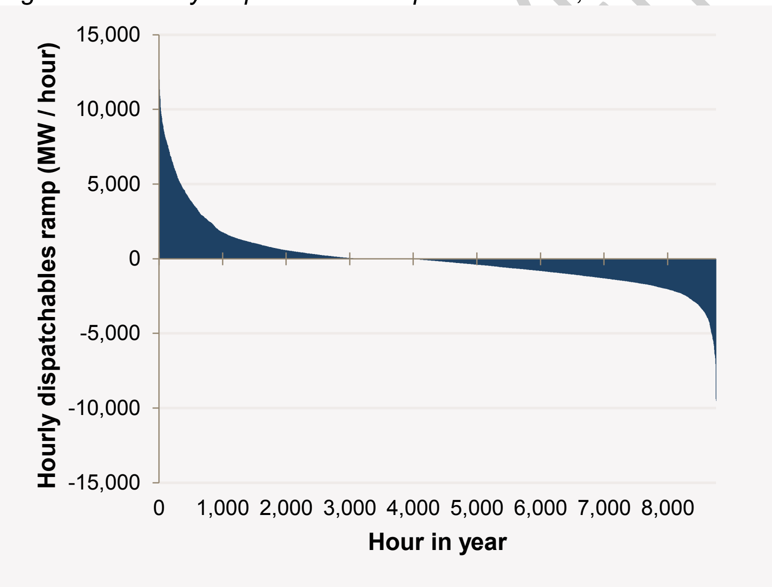


Figure 46: Hourly dispatchable ramps Scenario 1, 2050



In Scenario 2 (2030), the modelling shows the greatest ramp of dispatchable power in one hour is 13,200 MW/hour, or 40% of dispatchable capacity.

Figure 47: Detail of largest dispatchables ramp Scenario 2, 2030

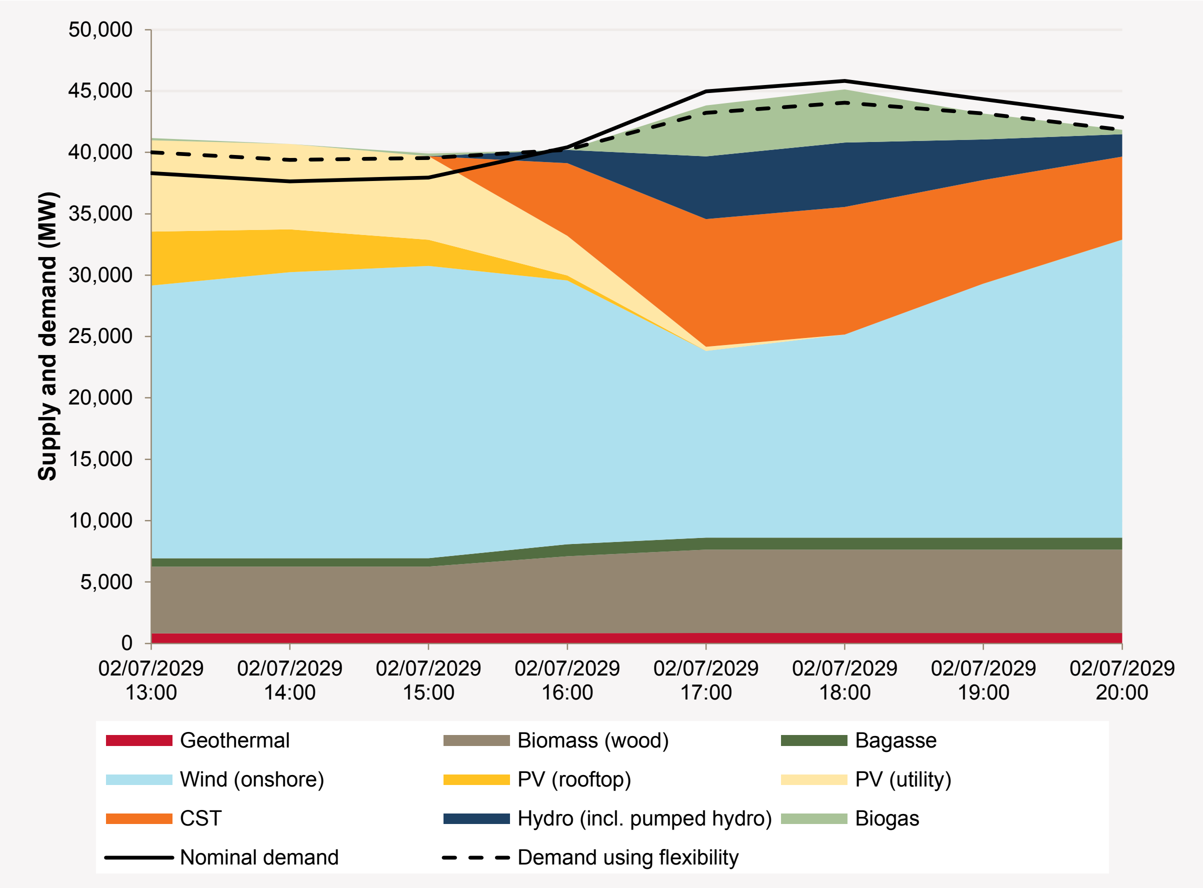
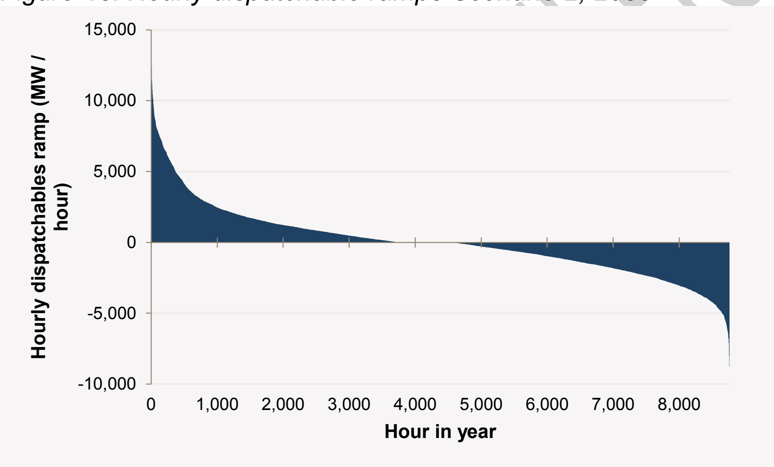


Figure 48: Hourly dispatchable ramps Scenario 2, 2030



In Scenario 2 (2050), the modelling shows the greatest ramp of dispatchable power in one hour is 18,000 MW/hour, or 43% of dispatchable capacity.

Figure 49: Largest dispatchables ramp Scenario 2, 2050

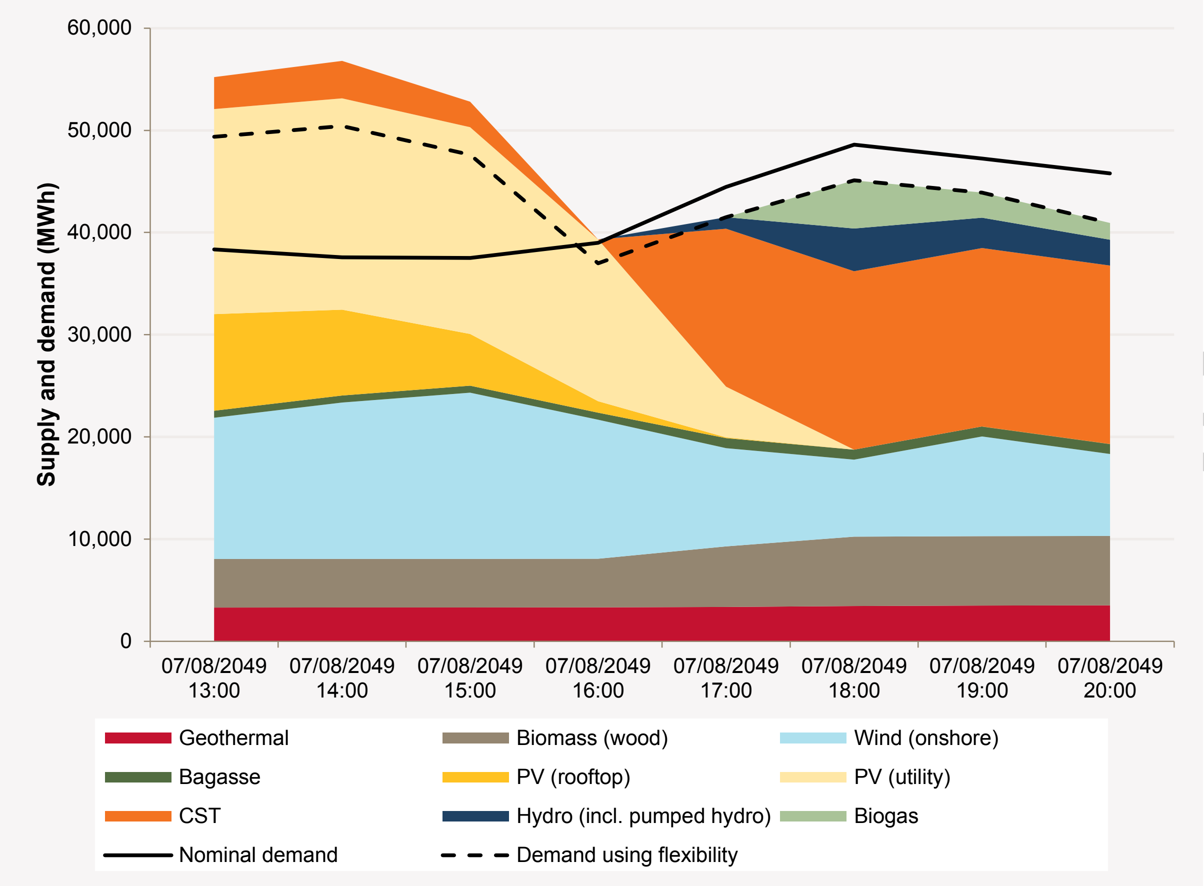
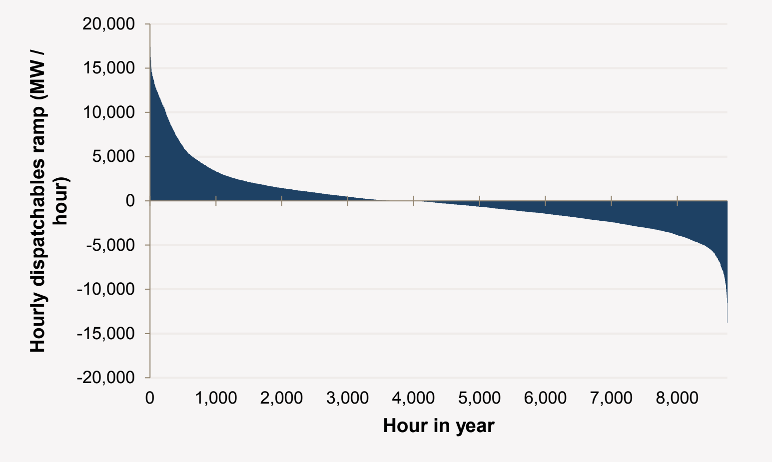


Figure 50: Hourly dispatchable ramps Scenario 2, 2050



7 Summary of operational considerations

7.1 Overview

A future 100 per cent renewable power system would operate based on a very different generation technology mix than today. While a precise understanding of the technical and operational issues involved is very complex, the high level operations review found that the operational issues identified in this study appear to be manageable and should not prevent secure and reliable operability of a 100 per cent renewable future NEM power system. However, to fully understand the operational issues that such a system might pose, it would be necessary to undertake a full set of dynamic power system studies, which is beyond the scope of this report.

In a 100 per cent renewable NEM, there are likely to be instances when non-synchronous technologies would contribute the majority of generation. Many of these non-synchronous generation sources are subject to the inherent weather variations and forecast-uncertainty of the wind, sunshine or waves.

The resulting power system is likely to be one that is at or beyond the limits of known capability and experience anywhere in the world to date, and would be subject to a number of important technical and operational challenges.

Many of the issues identified would require highly detailed technical investigations that are beyond the scope of this study. Transitioning to a very high renewable energy NEM over time would allow more scope for learning and evolution of these challenges. Further refinement of the generation mix or geographical locations could also be applied to overcome particularly onerous operational issues. International collaboration and learning will also be helpful.

The following anticipated challenges are summarised in this chapter and addressed in more technical detail in Appendix 6:

- Higher levels of non-synchronous generation causing more extreme frequency deviations.
- Keeping renewable generators connected to the transmission during system disturbances.
- Addressing transmission network fault level assessment and system protection design to handle higher levels of non-synchronous generation.
- Using peak dispatchable resources (pumped hydro, bio, CST) to manage the increase in extreme operational variability.
- Redefining ‘reliability contribution’ for non-dispatchable resources (PV, wind, wave).

7.2 Power system frequency control

While the largely non-synchronous nature of a 100 per cent renewable system means there could be more extreme frequency deviations, this is a known problem currently being successfully managed. Several mitigation strategies are available.

Precise frequency control is a critical aspect of system integrity in any synchronous AC power system. In the NEM, supply frequency must be maintained within a very tight tolerance band around 50 Hz in normal operation. Disturbances such as unexpected outages of large generators or sudden and large changes in load, cause system frequency deviations that must be managed quickly to prevent a wider system collapse.

Synchronous power system elements inherently provide some natural damping of any frequency deviations by automatically releasing or absorbing some stored rotational energy as appropriate.

However, in systems with few synchronous plants running, frequency control could be problematic, especially at times of low demand.

Given the amount of non-synchronous generation anticipated in the 100 per cent renewable scenarios, it is likely that more extreme frequency deviations could be routinely experienced. All generators in the 100 per cent renewable generation mix, both synchronous and non-synchronous, would require generation performance standards framed within this context.

Given that a large number of smaller capacity units are possible, the source of operational risks will also change. For example, it is likely that the largest contingency from a frequency stability point of view could be the loss of a heavily loaded HVDC link spanning the NEM mainland and Tasmania.

Several mitigating strategies using Frequency Control Ancillary Services (FCAS) mechanisms might be possible to minimise the impact of frequency disturbances in a 100 per cent renewable NEM. These are outlined in Appendix 6.

While a detailed frequency stability study was not part of this study, one area of the NEM (Tasmania) already has significantly higher frequency variations than the mainland NEM region, and still manages to maintain the current reliability standard. Similar systems also operate successfully in other parts of the world, such as the standalone synchronous power system of Ireland.

7.3 Grid code performance standards

As with conventional power systems, renewable generators need to remain connected during system disturbances to ensure system reliability. Developments in this area suggest this is not likely to be a major issue for 100 per cent renewable power system operability.

The ability of generators to remain connected to the power system during a network disturbance is critical to power system reliability, as it enables the system to return to normal once the disturbance is removed. Renewable energy sources based on conventional synchronous generators (such as CST and geothermal steam turbines, biomass gas turbines and hydro-generator turbines) would rely on quick isolation of a faulted network element in order to maintain stable operation.

While detailed simulations would have to be carried out for each individual generator, this issue is well understood by power engineers given this challenge already exists for conventional fossil fuel based generators. It should not present any additional challenges for synchronous technologies in a 100 per cent renewable scenario.

The NEM already has performance standards relating to the ability of generators to ride through fault conditions. These standards apply to all types of utility-scale generators. The standards are currently achieved either by the generators directly or by installing ancillary equipment such as Static Var Compensation (SVCs and STATCOMs). Detailed studies may be required to determine whether these standards continue to be appropriate or will need to be amended for a 100 per cent renewable system.

See Appendix 6 for more detail.

7.4 Fault level design

Non-synchronous renewable sources require specific consideration with regard to transmission network fault level assessment and system protection design. To address this, synchronous generators may have to be constrained online at specific NEM regions during times of high non-synchronous generation output.

High voltage power system networks rely on rapid, selective operation of system protection devices to quickly isolate faulted elements for public safety, system stability and infrastructure integrity.

Faults generally lead to a much higher current flow than usual, allowing circuit breakers to sense that a fault has occurred. System protection is designed with maximum and minimum fault level detection: the maximum level is the highest fault current that can be safely interrupted by the system protection, and the minimum level is the lowest fault current that still allows the system protection to detect a fault.

Synchronous generators in a 100 per cent renewable power system are likely to have fault current characteristics almost identical to existing conventional synchronous plant, and should not present any additional difficulties.

However, non-synchronous generation sources may complicate the design and operation of the 100 per cent renewable power system. Some non-synchronous generators behave differently depending on the location and nature of the fault. This will complicate the transmission network fault level assessment and system protection design.

Other non-synchronous generation, including PV, contribute little fault current above normal operation, which means that their minimum fault level in-feed may not be guaranteed to trigger system protection to operate correctly.

To enable the protection system to detect faults, synchronous generators may have to be constrained at specific regional areas during times of high non-synchronous generation output.

See Appendix 6 for more detail.

7.5 Operational timeframe variability and forecast uncertainty

The NEM would be subject to far more extreme operational variability than currently observed, however dispatchable resources (hydro, bio, CST) are expected to be flexible enough to accommodate these variations.

The modelling results show that in a 100 per cent renewable scenario the NEM could be subject to far more significant operational timeframe variability (due to the more intermittent fluctuation of wind and PV).

The generation mix must have sufficient flexibility to compensate for renewable energy variations to ensure demand is met. Baseload dispatchable technologies must be flexible enough to:

- start up or shut down within a given time horizon
- ramp up or down quickly once online
- maintain such capabilities repeatedly over a multi-annual timeframe
- do so at reasonable cost.

The most consistently challenging time of day when extreme downward ramps would likely occur is in the evening, when a drop in wind power and a larger-than-usual rise in demand may coincide with the reduced PV generation at sundown.

The flexible nature of all chosen baseload dispatchable elements of the 100 per cent renewable generation mix (hydro, pumped hydro, and biomass) is likely to assist in addressing this challenge. The key technology expected to provide significant up-ramping capability to meet the evening peaks is CST.

Flexibility can also be sourced from demand side functions if sufficient customer load is responsive enough to the power system's needs. The 100 per cent renewable supply-side modelling already assumes significant availability of peak demand reduction and shifting to meet demand effectively, as well as intelligent charging of EVs to largely suit the system requirements.

Renewable generation forecast uncertainty (given that wind, wave and PV are subject to fluctuations that are not fully predictable) may also be a concern within the power system operational timeframe as it compounds the challenges expected for the ramping events described above.

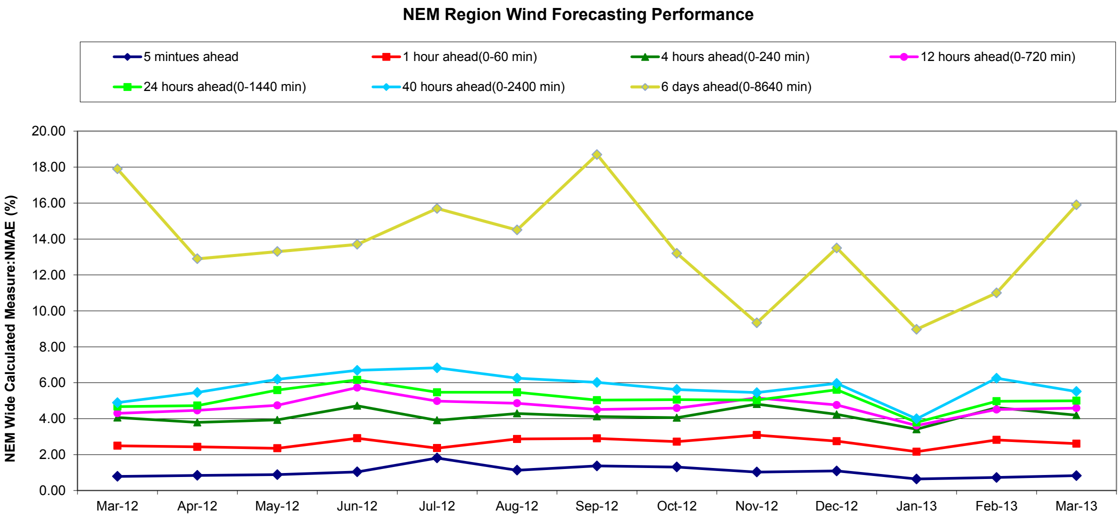
AEMO's available data indicates that this is unlikely to be a fundamental constraint as the anticipated geographic distribution of renewable generation plant should help smooth out any fluctuations in very short timeframes (seconds or minutes).

Weather forecasting methods have been applied to wind power prediction with appreciable success, both in terms of producing wind forecasts, and also in interpreting such forecasts to successfully modify the power system operation. AEMO continues to develop its wind and solar power forecasting capabilities.

While some level of operational uncertainty is likely to continue indefinitely due to inherent chaos in weather forecasting systems, state-of-the-art forecasting tools can be expected to minimise any major impacts on 100 per cent renewable system costs or reliability.

Figure 51 below demonstrates the accuracy of current wind forecasting.

Figure 51: Average accuracy of Recent Australian Wind Forecasting System AWEFS



	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13
5 mintues ahead	0.79	0.84	0.89	1.04	1.81	1.13	1.37	1.31	1.03	1.09	0.64	0.73	0.83
1 hour ahead(0-60 min)	2.49	2.43	2.35	2.91	2.36	2.87	2.90	2.72	3.09	2.75	2.16	2.82	2.61
4 hours ahead(0-240 min)	4.06	3.79	3.93	4.72	3.91	4.29	4.12	4.05	4.81	4.24	3.41	4.61	4.19
12 hours ahead(0-720 min)	4.30	4.46	4.74	5.73	4.98	4.86	4.51	4.59	5.15	4.76	3.62	4.51	4.59
24 hours ahead(0-1440 min)	4.67	4.73	5.59	6.16	5.47	5.47	5.03	5.06	5.03	5.61	3.79	4.97	5.00
40 hours ahead(0-2400 min)	4.89	5.46	6.19	6.69	6.83	6.25	6.02	5.62	5.45	5.96	3.99	6.25	5.51
6 days ahead(0-8640 min)	17.90	12.90	13.30	13.70	15.70	14.50	18.70	13.20	9.33	13.50	8.97	11.00	15.90

See Appendix 6 for more detail.

7.6 Supply reliability

Critical risks of a demand shortfall are likely to arise at different times to those traditionally experienced, so a better understanding of power system reliability may be required for non-scheduled resources (PV, wind, wave).

Traditionally, the reliability contribution of NEM generators was assessed by reference to the 10% POE regional demand conditions on very hot days, with the possibility of independent outages in each generator separately contributing to an overall loss of supply.

The behaviour of fully baseload dispatchable renewable sources, such as biomass and geothermal, should be mostly consistent with previously observed characteristics of conventional generators.

Assessing system reliability contributions of non-dispatchable resources (wind, PV, wave) is more complex. For example it is necessary to consider the statistical likelihood of high wind speed and wave incidence occurring together, or the correlation of possibly lower wind speed on very hot days when customer demand and PV generation peak.

The modelling results suggest that the typical periods of peak demand in a 100 per cent renewable system are likely to differ from existing patterns, both in terms of season and time of day. This is likely to result in reliance on hydro and CST storage, as well as demand side management, to meet residual peak demand.

See Appendix 6 for more detail.

Appendix 1 - Scope of works

In July 2012, DCCEE published the scope of the 100 per cent renewables study. This is reproduced in *italics* below.

“This contract implements the government's commitment to investigate the energy market and transmission planning implications of moving towards 100 per cent renewable energy.

The Australian Energy Market Operator (AEMO) must provide a report to the government addressing the following scope.

Purpose

The government announced its Clean Energy Future Plan in July 2011, which foreshadowed that the government would ask AEMO to expand its planning scenarios to include further consideration of energy market and transmission planning implications of moving towards 100 per cent renewable energy. AEMO has held discussions with the Department of Climate Change and Energy Efficiency (DCCEE) and the Department of Resources, Energy and Tourism (RET) to prepare a scope for such a study.

This document sets out the scope of an initial study of potential 100 per cent renewables electricity generation mix scenarios at 2030 and 2050.

Scope

The form of a 100 per cent renewable scenario for this period is inherently uncertain, due to uncertainty around the types of technology that could emerge in the intervening 40 years, the cost of those technologies and the potential for regulatory change in that timeframe. There are also uncertainties around the strength of growth in energy demand and the load profile of the network. The proposed study also extends well beyond the scope of AEMO's National Transmission Network Development Plan (NTNDP) which has a 20 year horizon.

With those limitations in mind, the objective of this study is to develop some scenarios which could shed light on generation and transmission network outcomes, for 100 per cent renewable electricity generation in the National Electricity Market (NEM) at 2030 and 2050.

The Deliverable will be a report to be provided to DCCEE and RET. The report will contain:

- *scenarios for a 100 per cent renewable electricity supply at 2030 and 2050*
- *generation plant and major transmission networks required to support each scenario*
- *the estimated capital cost requirements for each scenario based in today's dollars, and*
- *an indicative estimate of the impact on customer energy prices.*

This report will not model the year-to-year transition to 100 per cent renewable electricity supply for any of the scenarios.

Approach

The proposed approach involves a scenario planning approach to identify possible long term outcomes to achieve 100 per cent renewable electricity supply by 2030 and 2050. Given the transformational task being assessed is a significant departure from the incremental changes currently being modelled in the NTNDP, some uncertainty exists over the modelling approach and its sensitivities. These issues are expected to be more pronounced in the scenario involving a more rapid transformation to 2030.

The key steps involved are as follows:

1. Resource investigation

This is the key step in this process. Research is required on availability and potential cost of a range of generation technologies and demand side developments at 2050. In particular, we need to develop a reasonable view of resource availability, timing of availability, and profile (e.g. wind *and solar capacities) needs to be developed. In relation to demand, we will need a view on demand growth, energy efficiency and load shapes.*

The Bureau of Resources and Energy Economics (BREE), an economic research unit within RET, is preparing the Australian Energy Technology Assessment (AETA) to estimate generation costs for a range of technologies to 2050, with a final report published on 31 July 2012. These technology costs will be taken as a fixed input into the study.

AEMO will provide DCCEE with a report setting out the inputs and assumptions to be used in the study, in a form that can be published and used for a stakeholder information forum by DCCEE.

Literature Review: This step would also include a review of relevant national and international studies into 100 per cent renewables.

2. Develop scenarios

The scenarios considered at 2030 and 2050 are:

1. *Rapid transformation and moderate growth—this scenario would describe strong progress on lowering technology costs, improving demand side participation, and a conservative average demand growth outlook.*
2. *Moderate transformation and high growth—this scenario would describe current trends in lowering technology costs, moderate demand side participation, and robust economic growth.*

The key factors which will define the scenarios are generation and storage costs and availability; demand forecasts and load profiles; and reliability standard assumptions.

3. Develop capacity requirements

Determine the generation portfolio required under each scenario and the level of storage necessary to reliably meet demand.

4. Develop transmission requirements

Determine the impacts on the shared transmission network and project the likely scale of investment requirements under each scenario.

5. Develop total capital cost requirements

Total capital cost requirements will be developed for each scenario and include indicative estimation of impact on energy price outcomes for consumers. Costs will be presented in net present value terms, where appropriate.

Assumptions

Stakeholder engagement

The project may be undertaken in consultation with industry, academia and other stakeholders.

An information forum will be hosted by DCCEE on the inputs to the modelling once a report detailing the inputs has been provided by AEMO and published by DCCEE. The purpose of this forum will be to provide information to stakeholders on the inputs and assumptions being used for the modelling.

A consultation forum to test the draft results will be hosted by DCCEE and RET following the release of the draft report. It is envisaged there will be a single consultation.

Publication

The scope will be published by DCCEE at the start of work.

A document detailing the inputs to the analysis will be published by DCCEE when finalised by AEMO.

It is envisaged that the draft report be publicly released and, following consultation, the final report will be made available on DCCEE's website.

Coverage

The interconnected NEM only will be covered in the analysis by AEMO (i.e. not WA and NT).

Commentary

The report will include no "finding" or recommendation based on the results of the study. In particular, the study will not be expressing a view as to the viability of achieving 100 per cent renewable electricity supply by 2030 or 2050.

Technology costs and availabilities

These costs, as seen in 2030 and 2050, are key assumptions for this study. The study will use the AETA estimates, supplementing this with information from international sources where necessary, with implications of lower future technology costs to be assessed as part of the defined scenarios.

Renewables

The study will explicitly exclude consideration of nuclear, gas, coal, and CCS generation and the range of detailed generation options to be considered will be confirmed with DCCEE and RET prior to the commencement of modelling.

Transition path

Scenarios would be required for 2030 or 2050 only, and there is no requirement to describe the path to these years.

Modelling approach

The modelling approach is to be determined by AEMO. Given the very long term nature of this study, and therefore the many uncertainties and assumptions required, it is unlikely that market modelling approaches used in the NTNDP would be useful, and may in fact imply a level of accuracy in the results that is not appropriate. Instead, it is understood AEMO may utilise a more simplified scenario planning based approach.

Stakeholder engagement

As above, DCCEE will hold two forums, one on the inputs to the analysis, and another on the outcomes of the modelling exercise as detailed in the draft report. For reference, this scope is to be published on the DCCEE website shortly after contracts between DCCEE and AEMO have been signed.

Timeframe

Input assumptions report to be finalised 21 September 2012. Draft report available 30 March 2013.

Final report by 31 May 2013.

Governance and project team

AEMO would establish this project as a consultancy, and establish an internal project team and report to the AEMO Chief Executive Officer and Board."

Appendix 2 - Additional generation details

While the main generation assumptions used in the modelling are covered in AEMO's Input Assumptions Report[42] from September 2012, some additional assumptions were needed to undertake the modelling. This appendix lists these additional generation assumptions.

Hydropower

The annual limit of hydro generation was based on Geoscience Australia's Australian Energy Resource Assessment.[43] This reports the long-term (2029–30) expected average hydro generation to be 13 TWh per year. While this number covers hydro-based electricity generation Australia-wide, this generation is almost entirely in the NEM. Western Australia uses 0.4% of installed hydro capacity (and about the same share of generation) and there is no significant hydro power at all in the Northern Territory.

Pumped hydro

Pumped hydro (sometimes referred to as pumped storage hydropower) is one of the storage technologies considered in the 100 per cent renewables study. ROAM Consulting provided an assessment of the potential capacity that could be installed in each polygon, along with estimate of capital costs involved.

The modelling also requires fixed and variable operating costs. No estimates were available from the AETA 2012, so AEMO used the cost estimates used for the pumped hydro schemes at Shoalhaven and Wivenhoe in the 2012 NTNDP.[44]

ROAM Consulting provided estimated capital costs for a large number of pumped hydro plants. To remain consistent with the level of detail for other technologies, typical plant costs for each state were calculated.

These capital costs are based on the average of those plants with 60-meter dam and with at least 12 hours of storage. This is assumed to be the minimum amount for providing capacity at times with little or no PV generation, and generally lowers the costs for a $/MWh storage capacity basis. For instance, the average cost per megawatt hour of storage capacity (60-meter dam height) is about $700,000 but the average when counting only those with larger storages (over 12 hours) is $228,000.

Table 17: Costs for pumped hydro plants used in the modelling

State	Installed capital cost ($/kW)
QLD	4,879
NSW	4,887
VIC	4,278
SA	4,020
TAS	4,116

As per ROAM Consulting's advice, costs do not differ by year or scenario.

[42] AEMO. Available from: http://www.climatechange.gov.au/government/initiatives/aemo-100-per-cent-renewables/aemo-input-assumptions-html.aspx.Viewed 18 March 2013.
[43] Geoscience Australia. Available from: http://www.ga.gov.au/energy/australian-energy-resource-assessment.html. See Figure 8-13. Viewed 18 March 2013.
[44] AEMO. Available from: http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Assumptions-and-Inputs. Viewed 18 March 2013.

In the modelling, a cycle efficiency of 75% was assumed. While ROAM Consulting's study gives an average of 73% for all new sites (at least 12-hour storage, 60-metre dam height), we have assumed that the most cost effective (and typically most efficient) ones would be built first.

Wind power

A total of nine polygons were selected to represent developments of onshore wind across the NEM. These ranged from Far North Queensland to the Eyre Peninsula, and from Flinders Ranges in South Australia. The selection of polygons generally reflected the better quality wind resources in coastal regions.

Four polygons were selected to represent offshore wind developments. Subsequent analyses of the levelised cost of electricity showed that offshore wind would be uneconomic compared with onshore wind, that onshore wind potential was sufficient, and that there should not be any problems with siting enough onshore wind to match the required capacity.

In the final modelling, offshore wind was not included as a generation option.

Solar technologies

The CST plant assumed in the modelling has a solar multiplier of 2.5[45] (the AETA 2012 costing is based on a solar multiplier of 1.8) and assumes nine hours of available storage (the AETA 2012 costing is based on six hours of storage). To reflect these different assumptions, new capital costs were calculated based on CSIRO's storage report[46]. This detailed costs by component allowing different configurations to be costed while remaining consistent with the AETA 2012 study. The resulting capital costs for the CST plant configuration used here are 23% higher than the AETA 2012 costs.

CST plants are assumed to be capable of ramping up from zero to full output within an hour. To lengthen the life of the steam turbine, it is assumed that the CST plants use some of the collected energy to keep the turbine warm so that ramp-ups for the evening peaks cause less steam turbine wear and tear than they otherwise would. Unlike the wind generation profiles per polygon supplied to AEMO, the solar generation profiles did not take outages into account nor derating to account for degradation over time. Based on advice from ROAM Consulting, this was accounted for as follows:

Utility PV: A derating of 1–2% for outages was included, plus a derating reflecting degradation of the panel efficiency over time (0.4% to 0.7% per year). With a lifetime of 20–25 years, if panels were installed at a steady rate, this assumes an accumulated 5% reduction across the installed utility PV capacity in any hour. This gives a total derating of 6.5%.

CST: 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 CST generation profiles are 'as-generated' and therefore exclude any adjustment of the generating plant auxiliary load. The 'as-generated' output was converted to 'sent-out' by applying a 7% derating to account for auxiliary load.

Because the CST plants modelled include storage, they may not generate at the same time as they collect the energy. For this reason, the derating is split across collection of energy and generation of power.

- Total derating of collected energy: 12%
- Derating of available generation capacity: 3%

[45] Solar fields have 2.5 times the capacity of the plant generation, with excess heat being required to increase the capacity factor of the plant.
[46] AEMO. Available from: http://www.climatechange.gov.au/en/government/initiatives/aemo-100-per-cent-renewables/~/media/government/initiatives/aemo/APPENDIX8-CSIRO-energy-storage.pdf. Viewed 18 March 2013.

The first assumes all derating (including outages, as some mirrors would regularly be out for maintenance) while the latter only assumes outages.

Rooftop PV: No further derating was required as profiles were scaled to match observed annual output by rooftop installations, which includes all outages, shading and degradation.

Biomass

All biomass technologies use a 3% forced outage rate to derate capacity at any given point in time. Planned maintenance is assumed to happen outside critical seasons.

Biomass (bagasse): It was assumed that bagasse is used in cogeneration plants. This limits the flexibility of power output, as cogeneration plants are mainly used for providing process steam/hot water for industrial processes.

Both models assumed 70% of the capacity would be generating at any hour. The modelling allowed cogeneration plants to generate above this—up to installed capacity[47] if needed—but not under this level.

Biomass (wood): This technology mainly uses mainly wood (including wood waste) as fuel, but may also use grass/stubble if needed.

Depending on the model's settings, biomass (wood) can be used to provide baseload energy or as an energy backup during sustained periods of tight supply.

Ultimately, it proved most economic as a baseload option. Here, it was set up to generate at the specified level (80% of installed capacity) in any hour and could, as the bagasse plant, produce above this level (but not under) if needed in any particular hour.

In the energy backup option, biomass (wood) was only triggered on days with tight supply. If the margin between demand and available non-dispatchable generation was too tight, the biomass plant would be committed at a specified capacity (e.g., 50%) for at least 13 hours (this included the hour that triggered it plus six hours before and after to account for ramping and forecasting uncertainty). As in the baseload option, generation could go above the specified level if needed in particular hours.

As baseload generation, the logistics of getting the biomass to the generation plants is simpler and the need for stockpiling biomass is decreased. In a peaking role, transport and stockpiling would have constrained biomass generation or increased costs. These issues are discussion in CSIRO's biomass report[48], but not considered in this study given biomass (wood) was used for baseload operation only.

Biogas: Various types of biomass and municipal solid waste (MSW) are assumed to be converted to biogas which is then distributed using the existing gas infrastructure, and burned in OCGTs when needed.

Costs: The cost of biomass fuels (wood, bagasse) is based on the AETA 2012 fuel cost estimates provided by ACIL Tasman. Their low-cost estimate was used for Scenario 1 and the medium-cost estimate for Scenario 2. As sensitivity, AEMO also considered higher prices, as reported in Appendix 4.

Biogas costs are based on CSIRO's storage report.[49] This shows minor locational cost differences for wood- and crop-based biogas on the mainland, and somewhat cheaper biogas from sources in Tasmania. However, there is limited scope for exporting more electricity from Tasmania to the mainland without incurring significant additional transmission costs, so use of any additional capacity planted there would be limited. Biogas from MSW is substantially cheaper near capital

[47] Adjusted for the 3% forced outage rate mentioned above.

[48] AEMO. Available from: http://www.climatechange.gov.au/en/government/initiatives/aemo-100-per-cent-renewables/~/media/government/initiatives/aemo/APPENDIX5-CSIRO-biomass-energy.pdf. Viewed 18 March 2013.

[49] AEMO. Available from: http://www.climatechange.gov.au/en/government/initiatives/aemo-100-per-cent-renewables/~/media/government/initiatives/aemo/APPENDIX8-CSIRO-energy-storage.pdf. Viewed 18 March 2013.

cities. That said, any locational price difference (assuming all biogas is fed into the same gas network) will be limited assuming a fairly unconstrained gas network.

The weighted average of biogas from woody/crops/MSW was used across all regions.

Costs of biomass plants, both bagasse and wood-based, and the OCGT costs for Scenario 2 are based on the AETA 2012 costs. OCGTs costs are assumed to be the same in Scenarios 1 and 2 as OCGT is a mature technology. The biomass plants use CSIRO costing for Scenario 1.

OCGT generation efficiency improvements for 2030 and 2050 are also taken from the AETA 2012, and are the same for both scenarios).

Capacity limits: The allowed installed capacity of bagasse and baseload wood/stubble biomass plants is based on the biomass resource available (CSIRO's biomass report) and the assumed capacity factor for those plants (AETA 2012). The resulting limits are shown in Table 18:

Table 18: Maximum allowed installed biomass capacity

	Bagasse potential (MW)	Wood, grass, stubble potential (MW)
QLD	912	2871
NSW	62	4590
VIC	0	2928
SA	0	2139
TAS	0	1564
Assumed capacity factor	0.75	0.8

The tables above exclude waste biomass and MSW, which is assumed to be used entirely for biogas production. Waste biomass has a potential of 20 TWh/yr of generation based on OCGT efficiency. Generation from biogas derived from MSW is limited to around 5 TWh/yr.[50]

Geothermal

While the Cooper Basin in north-east South Australia and south-west Queensland in particular holds considerable geothermal resources, those closer to load centres (such as polygons 11, 32 and 38) are more limited, and this was accounted for in the modelling.

Table 19: Limits for installed geothermal capacity by polygon

Polygon	Region/Zone	Maximum HSA capacity (MW)	Maximum EGS capacity (MW)
11	Bundaberg	1,338	*
13	Cooper SA	72,439	347,283
14	Cooper QLD	98,335	571,148
32	SE SA	1,867	*
38	Melbourne	828	*

* Not modelled

Generation from geothermal plants follow a daily profile accounting for the impact of ambient temperature on power plant efficiency. The generation is further scaled to match the capacity factor assumed in the AETA 2012.

Summary of costs assumed

[50] AEMO. Available from: http://www.climatechange.gov.au/government/initiatives/aemo-100-per-cent-renewables/~/media/government/initiatives/aemo/A82CSIROenergystoragedata.xlsx.Table 23. Viewed 18 March 2013.

The following tables summarise capital, fixed and variable costs of the different generation technologies considered by location.

Table 20: Capital costs

Technology	Polygon	Region/Zone	Scenario 1 2030 ($/kW)	Scenario 1 2050 ($/kW)	Scenario 2 2030 ($/kW)	Scenario 2 2050 ($/kW)
PV, rooftop	Regional	QLD	1032	1331	1527	1031
PV, rooftop	Regional	NSW	1064	1373	1574	1063
PV, rooftop	Regional	VIC	1154	1489	1707	1153
PV, rooftop	Regional	SA	1038	1340	1536	1037
PV, rooftop	Regional	TAS	1265	1632	1871	1264
PV, utility	2	NW QLD	1150	1484	2022	1446
PV, utility	6	Central QLD	1150	1484	2022	1446
PV, utility	14	Cooper QLD	1179	1521	2074	1483
PV, utility	17	Brisbane	1179	1521	2074	1483
PV, utility	20	Flinders	1186	1531	2087	1492
PV, utility	23	North NSW	1216	1569	2138	1529
PV, utility	29	Mid NSW	1216	1569	2138	1529
PV, utility	31	Sydney	1216	1569	2138	1529
PV, utility	32	SE SA	1186	1531	2087	1492
PV, utility	38b	Melbourne	1318	1701	2319	1658
CST	2	NW QLD	4388	4443	5213	5146
CST	9	Central QLD	4388	4443	5213	5146
CST	14	Cooper QLD	4507	4563	5353	5286
CST	16	Darling Downs	4507	4563	5353	5286
CST	20	Flinders	4523	4579	5372	5303
CST	24	Central Coast	4628	4686	5497	5427
CST	28	Broken Hill	4628	4686	5497	5427
CST	30	Blue Mountains	4628	4686	5497	5427
CST	34	SW NSW	4628	4686	5497	5427
Wind, onshore	1	Far North QLD	2910	2824	1917	1970
Wind, onshore	17	Brisbane	2910	2824	1917	1970
Wind, onshore	20	Flinders	2632	2555	1734	1781

Technology	Polygon	Region/Zone	Scenario 1 2030 ($/kW)	Scenario 1 2050 ($/kW)	Scenario 2 2030 ($/kW)	Scenario 2 2050 ($/kW)
Wind, onshore	23	North NSW	2730	2650	1799	1848
Wind, onshore	31	Sydney	2730	2650	1799	1848
Wind, onshore	32	SE SA	2632	2555	1734	1781
Wind, onshore	35	SW NSW	2730	2650	1799	1848
Wind, onshore	38b	Melbourne	2774	2692	1827	1877
Wind, onshore	40	TAS	2582	2506	1701	1747
Wind, offshore	11	Bundaberg	4804	4663	3942	4119
Wind, offshore	26	Eyre Peninsula	4631	4495	3800	3970
Wind, offshore	37	SE SA/VIC	4881	4737	4004	4184
Wind, offshore	40	TAS	4543	4409	3727	3894
Wave	17	SE Q/NNSW	2674	2625	3910	3750
Wave	26	Eyre Peninsula	2530	2483	3699	3547
Wave	36	SE NSW	2604	2556	3807	3651
Wave	37	SE SA/VIC	2406	2361	3517	3373
Wave	41	TAS	2320	2278	3392	3253
Geothermal (HSA)	11	Bundaberg	5817	5837	7856	8044
Geothermal (HSA)	13	Cooper SA	5199	5217	7022	7189
Geothermal (HSA)	14	Cooper QLD	5153	5171	6960	7126
Geothermal (HSA)	32	SE SA/VIC	5523	5543	7460	7638
Geothermal (HSA)	38A	Melbourne	4951	4968	6687	6846
Geothermal (EGS)	13	Cooper SA	8954	8984	12023	12228
Geothermal (EGS)	14	Cooper QLD	8418	8446	11302	11495
Pumped hydro	Regional	QLD	4879	4879	4879	4879
Pumped hydro	Regional	NSW	4887	4887	4887	4887
Pumped hydro	Regional	VIC	4278	4278	4278	4278
Pumped hydro	Regional	SA	4020	4020	4020	4020
Pumped hydro	Regional	TAS	4116	4116	4116	4116
Biomass (bagasse)	Regional	North QLD	3910	4598	4343	4430
Biomass (bagasse)	Regional	South QLD	3900	4586	4331	4418

Technology	Polygon	Region/Zone	Scenario 1 2030 ($/kW)	Scenario 1 2050 ($/kW)	Scenario 2 2030 ($/kW)	Scenario 2 2050 ($/kW)
Biomass (bagasse)	Regional	NSW	3853	4531	4280	4365
Biomass (biogas)	Regional	QLD	781	813	781	813
Biomass (biogas)	Regional	NSW	751	782	751	782
Biomass (biogas)	Regional	VIC	725	755	725	755
Biomass (biogas)	Regional	SA	755	786	755	786
Biomass (biogas)	Regional	TAS	694	723	694	723
Biomass (wood waste)	Regional	QLD	4875	5732	5414	5523
Biomass (wood waste)	Regional	NSW	4816	5664	5349	5457
Biomass (wood waste)	Regional	VIC	4715	5436	5237	5237
Biomass (wood waste)	Regional	SA	4824	5561	5357	5357
Biomass (wood waste)	Regional	TAS	4590	5291	5097	5097

Table 21: Fixed costs

Technology	Polygon	Region/Zone	Scenario 1 2030 *$/MW/yr*	Scenario 1 2050 *$/MW/yr*	Scenario 2 2030 *$/MW/yr*	Scenario 2 2050 *$/MW/yr*
PV, rooftop	Regional	QLD	21875	18750	31630	36380
PV, rooftop	Regional	NSW	21875	18750	31630	36380
PV, rooftop	Regional	VIC	21875	18750	31630	36380
PV, rooftop	Regional	SA	21875	18750	31630	36380
PV, rooftop	Regional	TAS	21875	18750	31630	36380
PV, utility	2	NW QLD	33250	28500	48077	55297
PV, utility	6	Central QLD	33250	28500	48077	55297
PV, utility	14	Cooper QLD	33250	28500	48077	55297
PV, utility	17	Brisbane	33250	28500	48077	55297
PV, utility	20	Flinders	33250	28500	48077	55297
PV, utility	23	North NSW	33250	28500	48077	55297
PV, utility	29	Mid NSW	33250	28500	48077	55297
PV, utility	31	Sydney	33250	28500	48077	55297
PV, utility	32	SE SA	33250	28500	48077	55297
PV, utility	38b	Melbourne	33250	28500	48077	55297

Technology	Polygon	Region/Zone	Scenario 1 2030 *$/MW/yr*	Scenario 1 2050 *$/MW/yr*	Scenario 2 2030 *$/MW/yr*	Scenario 2 2050 *$/MW/yr*
CST	2	NW QLD	52500	45000	75911	87311
CST	9	Central QLD	52500	45000	75911	87311
CST	14	Cooper QLD	52500	45000	75911	87311
CST	16	Darling Downs	52500	45000	75911	87311
CST	20	Flinders	52500	45000	75911	87311
CST	24	Central Coast	52500	45000	75911	87311
CST	28	Broken Hill	52500	45000	75911	87311
CST	30	Blue Mountains	52500	45000	75911	87311
CST	34	SW NSW	52500	45000	75911	87311
Wind, onshore	1	Far North QLD	35000	30000	50607	58207
Wind, onshore	17	Brisbane	35000	30000	50607	58207
Wind, onshore	20	Flinders	35000	30000	50607	58207
Wind, onshore	23	North NSW	35000	30000	50607	58207
Wind, onshore	31	Sydney	35000	30000	50607	58207
Wind, onshore	32	SE SA	35000	30000	50607	58207
Wind, onshore	35	SW NSW	35000	30000	50607	58207
Wind, onshore	38b	Melbourne	35000	30000	50607	58207
Wind, onshore	40	TAS	35000	30000	50607	58207
Wind, offshore	11	Bundaberg	70000	60000	101214	116414
Wind, offshore	26	Eyre Peninsula	70000	60000	101214	116414
Wind, offshore	37	SE SA/VIC	70000	60000	101214	116414
Wind, offshore	40	TAS	70000	60000	101214	116414
Wave	17	SE Q/NNSW	166250	142500	240384	276484
Wave	26	Eyre Peninsula	166250	142500	240384	276484
Wave	36	SE NSW	166250	142500	240384	276484
Wave	37	SE SA/VIC	166250	142500	240384	276484
Wave	41	TAS	166250	142500	240384	276484
Geothermal (HSA)	11	Bundaberg	175000	150000	253036	291036
Geothermal (HSA)	13	Cooper SA	175000	150000	253036	291036

Technology	Polygon	Region/Zone	Scenario 1 2030 $/MW/yr	Scenario 1 2050 $/MW/yr	Scenario 2 2030 $/MW/yr	Scenario 2 2050 $/MW/yr
Geothermal (HSA)	14	Cooper QLD	175000	150000	253036	291036
Geothermal (HSA)	32	SE SA/VIC	175000	150000	253036	291036
Geothermal (HSA)	38A	Melbourne	175000	150000	253036	291036
Geothermal (EGS)	13	Cooper SA	148750	127500	215081	247381
Geothermal (EGS)	14	Cooper QLD	148750	127500	215081	247381
Pumped hydro	Regional	QLD	48999	41999	70848	81488
Pumped hydro	Regional	NSW	48999	41999	70848	81488
Pumped hydro	Regional	VIC	48999	41999	70848	81488
Pumped hydro	Regional	SA	48999	41999	70848	81488
Pumped hydro	Regional	TAS	48999	41999	70848	81488
Biomass (bagasse)	Regional	North QLD	109375	93750	158148	181898
Biomass (bagasse)	Regional	South QLD	109375	93750	158148	181898
Biomass (bagasse)	Regional	NSW	109375	93750	158148	181898
Biomass (biogas)	Regional	QLD	3500	3000	5061	5821
Biomass (biogas)	Regional	NSW	3500	3000	5061	5821
Biomass (biogas)	Regional	VIC	3500	3000	5061	5821
Biomass (biogas)	Regional	SA	3500	3000	5061	5821
Biomass (biogas)	Regional	TAS	3500	3000	5061	5821
Biomass (wood waste)	Regional	QLD	109375	93750	158148	181898
Biomass (wood waste)	Regional	NSW	109375	93750	158148	181898
Biomass (wood waste)	Regional	VIC	109375	93750	158148	181898
Biomass (wood waste)	Regional	SA	109375	93750	158148	181898
Biomass (wood waste)	Regional	TAS	109375	93750	158148	181898

Table 22: Variable costs

Technology	Polygon	Region/Zone	Scenario 1 2030 $/MWh	Scenario 1 2050 $/MWh	Scenario 2 2030 $/MWh	Scenario 2 2050 $/MWh
PV, rooftop	Regional	QLD	0	0	0	0
PV, rooftop	Regional	NSW	0	0	0	0
PV, rooftop	Regional	VIC	0	0	0	0

Technology	Polygon	Region/Zone	Scenario 1 2030 *$/MWh*	Scenario 1 2050 *$/MWh*	Scenario 2 2030 *$/MWh*	Scenario 2 2050 *$/MWh*
PV, rooftop	Regional	SA	0	0	0	0
PV, rooftop	Regional	TAS	0	0	0	0
PV, utility	2	NW Q	0	0	0	0
PV, utility	6	Central QLD	0	0	0	0
PV, utility	14	Cooper QLD	0	0	0	0
PV, utility	17	Brisbane	0	0	0	0
PV, utility	20	Flinders	0	0	0	0
PV, utility	23	North NSW	0	0	0	0
PV, utility	29	Mid NSW	0	0	0	0
PV, utility	31	Sydney	0	0	0	0
PV, utility	32	SE SA	0	0	0	0
PV, utility	38b	Melbourne	0	0	0	0
CST	2	NW QLD	13	11	19	22
CST	9	Central QLD	13	11	19	22
CST	14	Cooper QLD	13	11	19	22
CST	16	Darling Downs	13	11	19	22
CST	20	Flinders	13	11	19	22
CST	24	Central Coast	13	11	19	22
CST	28	Broken Hill	13	11	19	22
CST	30	Blue Mountains	13	11	19	22
CST	34	SW NSW	13	11	19	22
Wind, onshore	1	Far North QLD	11	9	15	17
Wind, onshore	17	Brisbane	11	9	15	17
Wind, onshore	20	Flinders	11	9	15	17
Wind, onshore	23	North NSW	11	9	15	17
Wind, onshore	31	Sydney	11	9	15	17
Wind, onshore	32	SE SA	11	9	15	17
Wind, onshore	35	SW NSW	11	9	15	17
Wind, onshore	38b	Melbourne	11	9	15	17

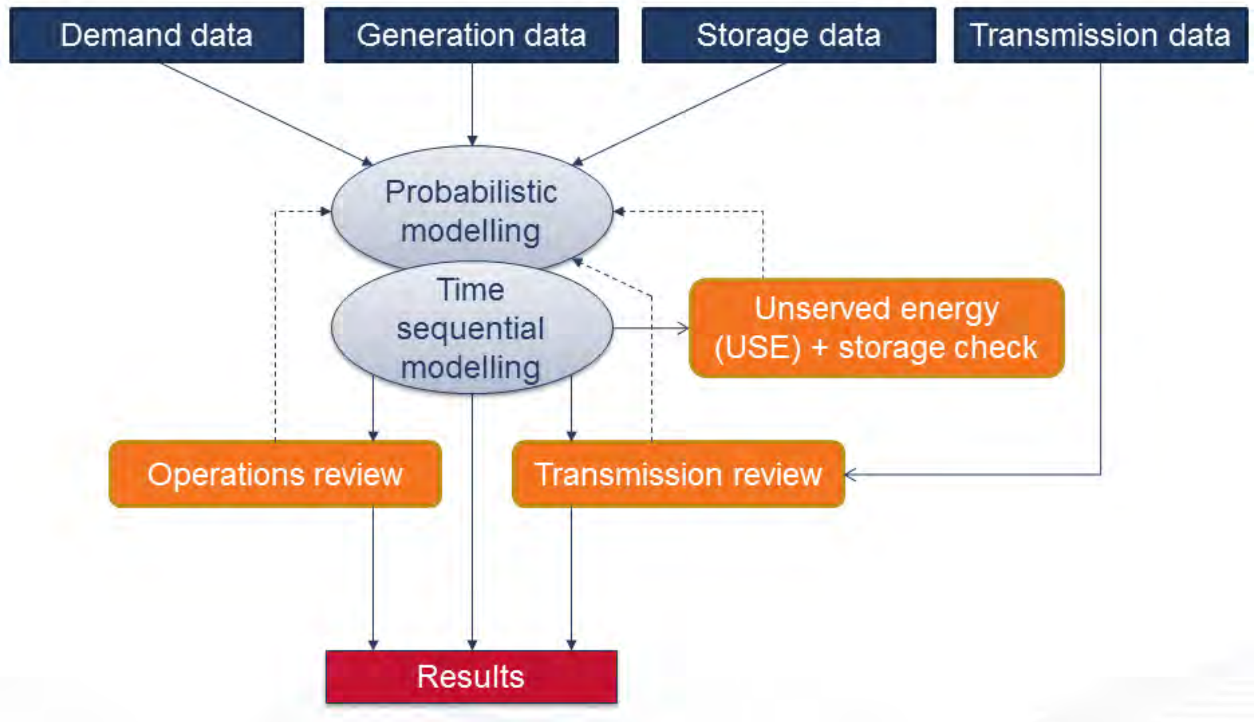
Technology	Polygon	Region/Zone	Scenario 1 2030 *$/MWh*	Scenario 1 2050 *$/MWh*	Scenario 2 2030 *$/MWh*	Scenario 2 2050 *$/MWh*
Wind, onshore	40	TAS	11	9	15	17
Wind, offshore	11	Bundaberg	11	9	15	17
Wind, offshore	26	Eyre Peninsula	11	9	15	17
Wind, offshore	37	SE SA/VIC	11	9	15	17
Wind, offshore	40	TAS	11	9	15	17
Wave	17	SE Q/NNSW	0	0	0	0
Wave	26	Eyre Peninsula	0	0	0	0
Wave	36	SE NSW	0	0	0	0
Wave	37	SE SA/VIC	0	0	0	0
Wave	41	TAS	0	0	0	0
Geothermal (HSA)	11	Bundaberg	0	0	0	0
Geothermal (HSA)	13	Cooper SA	0	0	0	0
Geothermal (HSA)	14	Cooper QLD	0	0	0	0
Geothermal (HSA)	32	SE SA/VIC	0	0	0	0
Geothermal (HSA)	38A	Melbourne	0	0	0	0
Geothermal (EGS)	13	Cooper SA	0	0	0	0
Geothermal (EGS)	14	Cooper QLD	0	0	0	0
Pumped hydro	Regional	QLD	7	6	10	11
Pumped hydro	Regional	NSW	7	6	10	11
Pumped hydro	Regional	VIC	7	6	10	11
Pumped hydro	Regional	SA	7	6	10	11
Pumped hydro	Regional	TAS	7	6	10	11
Biomass (bagasse)	Regional	North QLD	7	6	10	12
Biomass (bagasse)	Regional	South QLD	7	6	10	12
Biomass (bagasse)	Regional	NSW	7	6	10	12
Biomass (biogas)	Regional	QLD	9	8	13	15
Biomass (biogas)	Regional	NSW	9	8	13	15
Biomass (biogas)	Regional	VIC	9	8	13	15
Biomass (biogas)	Regional	SA	9	8	13	15

Technology	Polygon	Region/Zone	Scenario 1 2030 *$/MWh*	Scenario 1 2050 *$/MWh*	Scenario 2 2030 *$/MWh*	Scenario 2 2050 *$/MWh*
Biomass (biogas)	Regional	TAS	9	8	13	15
Biomass (wood waste)	Regional	QLD	7	6	10	12
Biomass (wood waste)	Regional	NSW	7	6	10	12
Biomass (wood waste)	Regional	VIC	7	6	10	12
Biomass (wood waste)	Regional	SA	7	6	10	12
Biomass (wood waste)	Regional	TAS	7	6	10	12

Appendix 3 - Modelling methodology

Two models were used for the study– a probabilistic and a time-sequential model.

Figure 52: Methodology process overview



The models differ mainly in terms of the time modelled. The probabilistic model worked on a large number of days generated based on probability distributions, whereas the time-sequential model used one year of historical data, hour by hour.

That said, they use the same logic when it comes to dispatch of generation, storage and demand side measures to optimally balance supply and demand.

The dispatch model is key to determining the cost effectiveness of the different generation and storage options and therefore to identifying the optimal mix of generation and storage to meet demand in each case. Demand side measures on the other hand, including rooftop PV, are fixed by the assumptions in each of the four cases.

Generation and storage

The generation technologies considered in the 100 per cent renewable study can be split into three categories. All three categories must be optimally combined to reliably meet supply for the lowest cost.

The categories are:

- **Non-dispatchable (PV, wind, and wave):** variable, weather-dependent, low operating cost technologies where output to some extent can be forecast ahead of time but not increased on demand. However, output can be decreased (curtailed) for operational reasons if required.[51]
- **Baseload (geothermal, biomass (wood), bagasse):** technologies where output can be controlled, but which are relatively slow to respond and/or have high capital and fixed costs but low variable costs. These are best suited to operating almost continuously at close to their maximum output, with some variability to match demand.

[51] In the NEM, these technologies are also referred to as semi-scheduled generation.

In the modelling, biomass (wood) and bagasse plants are assumed to operate continuously at 70–80% capacity (in the following denoted by their baseload component), but this can be increased to 97% (a 3% derating for outages at any point in time is assumed) if demand is high (this increase represents their flexible component).

- **Peak dispatchable (hydro, pumped hydro, CST, biogas):** flexible, fast-to-respond generation or storage technologies which either have limited annual energy potential or require daily recharge of energy storage. They can either be:
  - expensive but low operating cost plants (hydro, pumped hydro and CST with limited fuel supply) or
  - relatively cheap, high operating cost plants, (such as biogas fuelled OCGTs).

Demand

The modelled demand can also be categorised. In any hour, demand can be either:

- **Fixed demand:** demand that must be consumed at the given time.
- **Flexible demand:** demand that may not necessarily be consumed in that hour but must be used at another point that day. This can be either traditional residential, commercial or industrial demand, or it can be demand from recharging of EVs.
- **Curtailable demand:** demand that may be forfeited on a voluntary basis if the cost of supply is higher than the utility it provides to consumers.

Dispatch modelling

The dispatch model (or merit order) used is the same for both the probabilistic and time sequential models. It is explained below:

- Non-dispatchable generation is dispatched first. This includes:
  - Rooftop PV
  - Utility PV
  - Wind
  - Wave

  This is followed by baseload generation:
  - Geothermal
  - Bagasse (baseload component)
  - Biomass (wood) (baseload component)
- The above non-dispatchable generation is first balanced against the non-flexible demand for each hour in the day. This will leave each hour with either a surplus or shortfall. The daily flexible demand and EV demand is then allocated between each hour in the day, with varying amounts with most allocated to the hours with the highest surplus and least (if any) to hours with a shortfall, subject to various limits.[52]
- To satisfy the flexible demand and any remaining non-flexible demand, the following technologies are used (in the following order):
  - Storage technologies (CST with storage and pumped hydro)
  - Hydro generation
  - Bagasse (flexible component)

[52] To account for a minimum recharge time for EV (assumed six hours), all scenarios include a maximum EV recharging rate in any one hour of one sixth of daily EV demand. In Scenario 1 that is the only requirement, and EV demand is otherwise assumed to be fully flexible. Scenario 2 has an additional requirement for at least 20% of daily recharge to occur between 8.00 AM and 7.00 PM.

  - Biomass (wood) (flexible component)
  - Biogas

  Normally, the dispatch algorithm for storage (CST and pumped hydro) will try to only allocate energy collected on a particular day to be used on that day. However, if required to meet demand, additional energy from storage can also be dispatched (this is possible in the time-sequential model only).

- Should there be any unmet demand left at this point, the model will use curtailable demand up to its limit to balance supply and demand. If there is insufficient voluntary curtailable demand available to ensure balance, unserved energy will occur.

While the same structure was used for the two models, the time-sequential model added some additional functionality. Apart from the additional functionality around storage where energy could be carried over from one day to another (as mentioned above), this was in particular around transmission. The time-sequential model was used to calculate power flows across the transmission system, which were then used to calculate transmission requirements. The model could also try to minimise these power flows by allocating more flexible generation in regions with supply deficits at times of high power flows.

Generation expansion

Selecting the optimal generation mix was an iterative process to ensure the reliability standard was met at the lowest cost possible taking into account generation costs, transmission costs and operational security considerations.

In theory, selecting the generation mix could have been done using either model. It was decided that the probabilistic model (which runs through 5000 synthetic days[53]) be used to find the lowest cost generation mix, and the time sequential model be used to verify the feasibility of this solution based on historical generation profiles.

For generation costs, the levelised cost of electricity (LCOE) for each technology and location was use as a guide of the cost-effectiveness of that technology, though adjustments were made on the basis on its ability to meet demand when needed. Following several iterations adding the lowest-cost technologies, the modelling generally showed a supply shortfall in the evenings and at night. Adding more PV (generally the lowest cost option in terms of dollars per megawatt hour) would not help, wind would help a little, while baseload and flexible technologies would generally contribute close to its full capacity.

The generation choice also had to account for transmission costs. For each of the transmission options (see Appendix 5) a cost in $/MW/year was calculated. These costs were added to the generation investment costs in the relevant location, but with some scaling applied if, for example, a particular location would only need half the length of a transmission option. An example of this is in Central Queensland where only half the transmission line between North and South Queensland would be needed to enable this generation to flow to the load centres.

Finally, generation expansion took into account operational considerations. For instance, the operations review showed a need for extra synchronous generation in Tasmania in one case, leading to some biomass (wood) generation being moved from Victoria to Tasmania in the subsequent iteration.

[53] These synthetic days are created based on probability distributions of historical demand and renewable generation and account for the correlation between those, both across locations and over time.

Appendix 4 - Modelling sensitivities

During the modelling, a number of sensitivity studies were undertaken to verify findings and test how robust the results were. The main sensitivity studies are explained briefly below.

Alternate demand and generation reference year

The demand profiles created by AEMO for the main modelling in both models were based on historical demand from a particular year. Similarly (and for consistency), the renewable generation profiles produced by ROAM Consulting and CSIRO were taken from the same historical year.

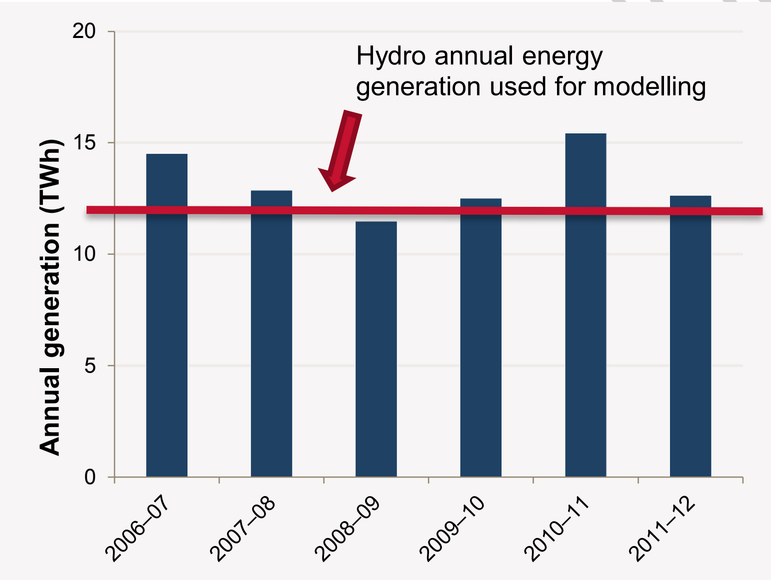
This input data was used to design and optimise the generation mix and additional transmission lines. The year was chosen because it was judged to be a representative year with solar generation, wind generation, and demand being neither particularly high nor low.

To check the results, AEMO re-ran the time-sequential model with renewable generation and demand profiles based on a different historical year, which had lower solar generation. For this input data, the model again met the reliability standard in all four cases using the same generation mix as presented in this report. It was, however, more challenging to meet the reliability standard, and required better conservation of energy stored on days with low solar insolation to ensure storage was available when needed most.

Hydro availability (wet/dry year) sensitivity

The modelled generation mix for each of the four cases is robust enough to withstand variation in hydro availability (i.e., wet or dry years). Sensitivity studies using hydro availability different to the long-term average of 13 TWh/year (see Appendix 2) showed that the reliability standard would still be met even with as little as 6 TWh/year of hydro generation. This is well below historical lows as the minimum annual value of hydro generation in the previous 30 years was 11 TWh.[54]

Figure 53: Historical NEM hydro production

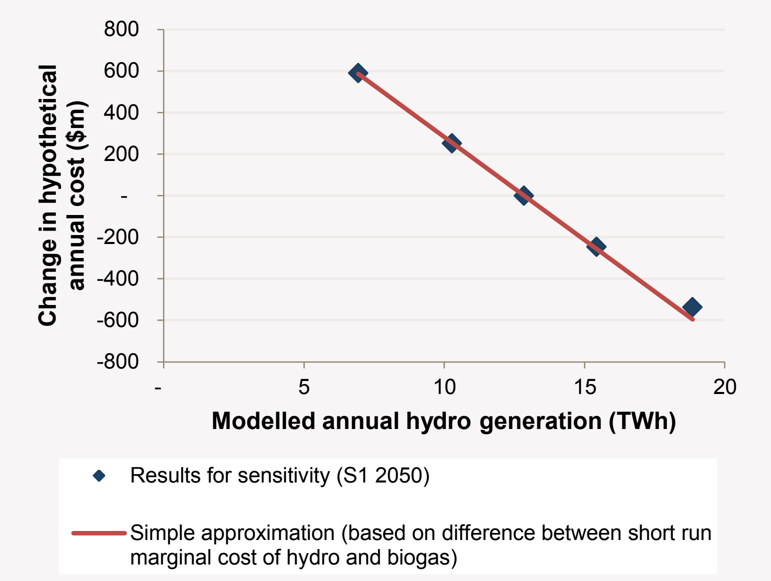


In the dispatch model used, a reduction in annual hydro generation is substituted primarily with biogas generation.[55] The effect of lower hydro availability is an increase in the total cost by the difference in the short run marginal cost between biogas and hydro (approximately $100/MWh)

[54] NEM states only. Source: ABARE Energy Statistics Update 2011. Available from: (http://adl.brs.gov.au/data/warehouse/pe_abares99010610/EnergyUpdate_2011TableH200910.xls). Viewed 18 March 2013.
[55] It is assumed that the drought conditions leading this will affect biomass production only to a minor extent.

multiplied by the reduction in hydro generation (see Figure 54 below, which is for Scenario 1, 2050).

Figure 54: Change in total costs for different levels of annual hydro generation



CST ramping sensitivity

To investigate whether different assumptions around CST ramping rates would change the results, a sensitivity limiting CST ramp rates to 33% of capacity per hour was undertaken. In the time-sequential model, the reliability standard was still met in any scenario.

This sensitivity was modelled two different ways:

- Using a two-hour look ahead to ramp up the CST, the modelling simply uses the CST storage more efficiently (wastes less storage).
- With no look ahead, the modelling increases annual biogas usage by about 10%.

This is illustrated in figures 55 to 57 below.

Figure 55: Generation dispatch with CST able to ramp 100% capacity per hour (used in main report)

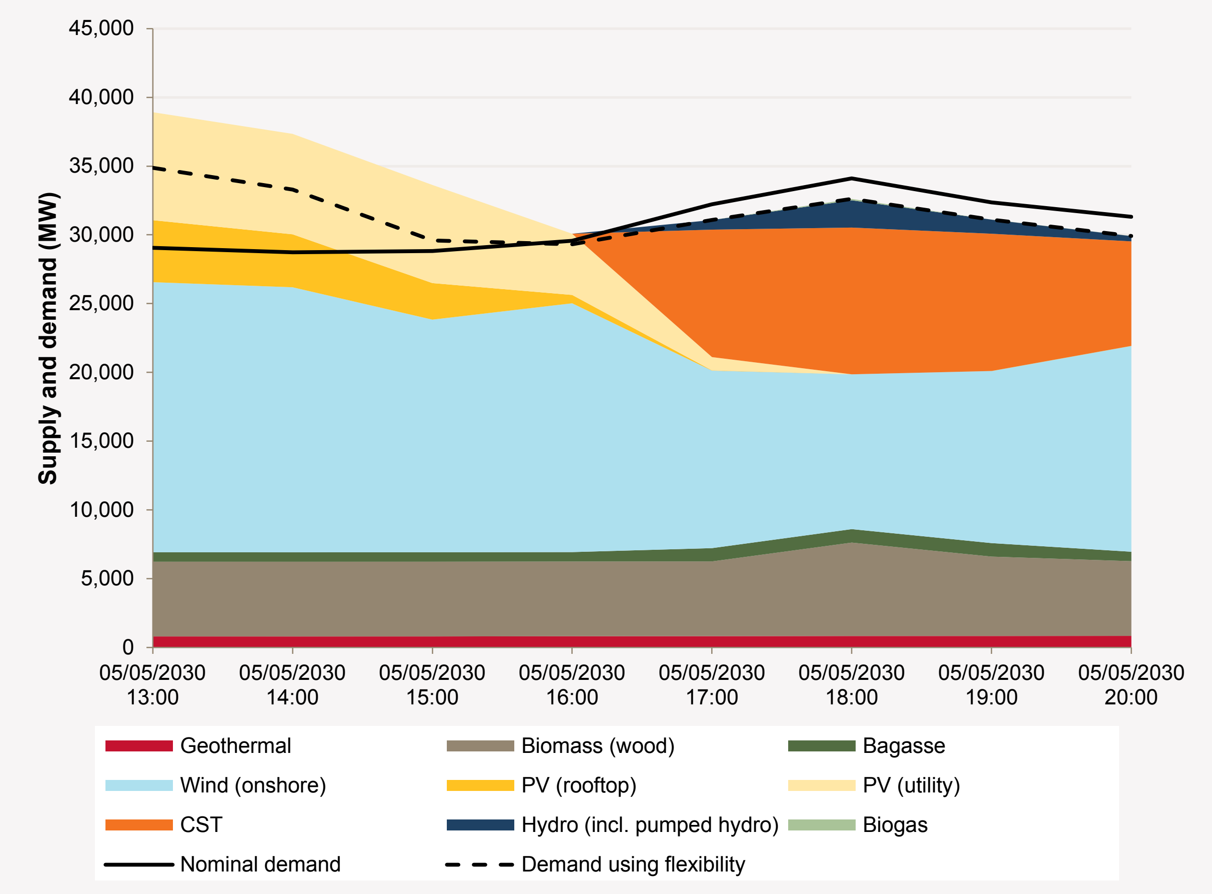


Figure 56: Generation dispatch with CST able to ramp 33% capacity per hour and 2-hour look ahead

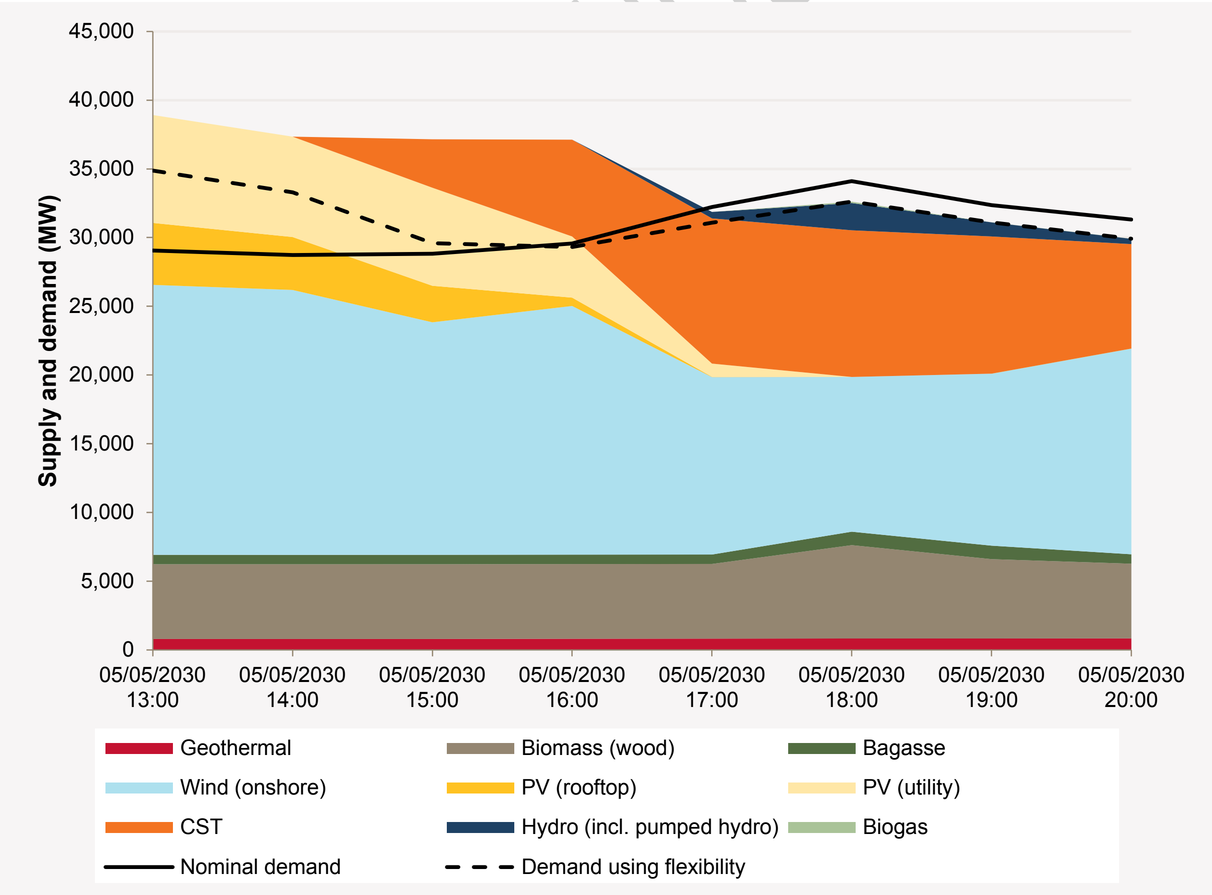
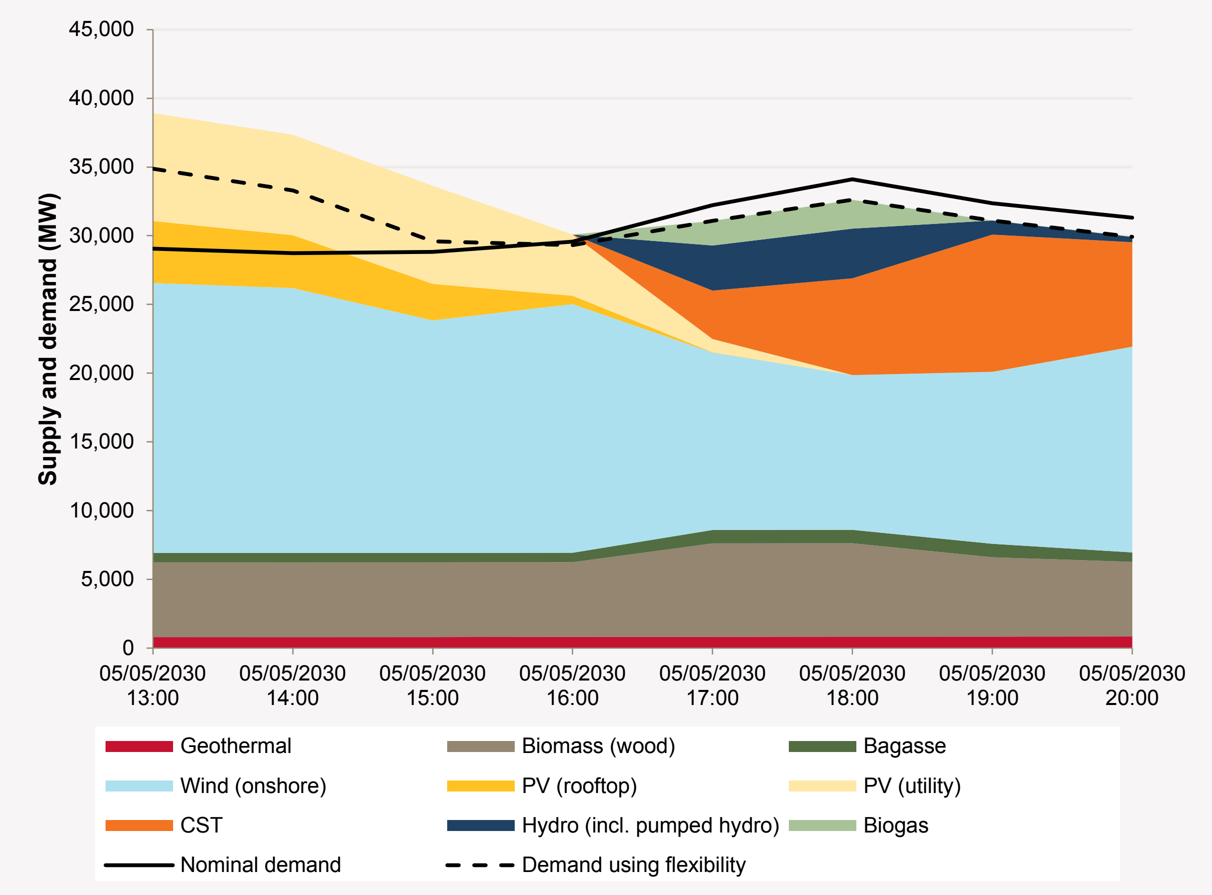


Figure 57: Generation dispatch with CST able to ramp 33% capacity per hour – uses more biogas



Biomass (wood) fuel price sensitivity

Biomass fuel costs for the modelling were taken from the AETA 2012 report (see Appendix 2). Those costs used were $0.4/GJ in Scenario 1 and $1.5/GJ in Scenario 2. The CSIRO storage report also contained estimates of biomass costs, using different assumptions and a methodology from Graham et al. 2011.[56]

AEMO undertook a sensitivity analysis with higher biomass fuel costs derived from the CSIRO storage input modelling and CSIRO's sustainable aviation fuel modelling.[57] The costs used for this sensitivity were $3.6/GJ for Scenario 1 and $4.6/GJ for Scenario 2. These costs were derived from the following fuel price estimates for different biomass sources (all in $/GJ):

Table 23: Fuel costs for high biomass (wood) cost sensitivity

Biomass type	Native forest	Pasture	Plantation	Short rotation trees	Stubble
Costs ($/GJ)	2.7	4.8	2.6	7.0	4.8

The least expensive biomass sources sufficient to satisfy the annual energy requirements were selected, and a transportation cost of $1/GJ was assumed for the sensitivity, which led to the adopted costs for each scenario.

Under this sensitivity, total costs were approximately 5–8% higher depending on scenario and year. Although the higher unit cost of biomass was approximately similar to CST (depending on polygon), increasing CST capacity also required some additional biogas peaking plant capacity (to

56 Graham, P. et al. (2011). Sustainable Aviation Fuels Road Map: Data assumptions and modelling. CSIRO, Canberra.

57 AEMO. Available at: http://www.climatechange.gov.au/en/government/initiatives/aemo-100-per-cent-renewables/~/media/government/initiatives/aemo/A82CSIROenergystoragedata.xlsx. Viewed 18 March 2013. And CSIRO (2011) Unpublished data from the Sustainable Aviation Fuels Road Map project, CSIRO.

compensate for the storage limit of CST). For this reason, the previously chosen generation mix for each case still satisfied AEMO's lowest cost objective.

Biogas for baseload sensitivity

An alternative to using biomass to generate electricity in steam turbine based plants exists. This involves using biogas from municipal solid waste (MSW) and the gasification of solid biomass to fuel combined cycle gas turbines (CCGT) for baseload generation and ancillary service provision in the NEM.

The option of using biogas for peaking type generation (in OCGTs) is already included in the modelling, but this alternative could be relevant particularly in Scenario 2, where there are no "cheap" baseload type technologies available. This is particularly relevant if higher biomass costs are considered as per the sensitivity above.

Substantial use of biogas for baseload generation raises some questions regarding whether biogas in those quantities is available at the prices quoted by CSIRO in the storage report. As result, this section considers sensitivities on higher costs of biogas than those provided by CSIRO to cover use of higher-cost biomass as inputs to the gasification process.

Also, as gasification technology is undergoing substantial research and development, there is significant uncertainty about the future cost of biogas produced.

Finally, it is unclear if biogas costs included cost for upgrading the gas to natural gas network standard.[58]

Overall, the cost of baseload CCGT generation from biogas assuming different prices was compared with the following baseload technologies:

- Geothermal (HSA) - Hot Sedimentary Aquifers based geothermal generation.
- Geothermal (EGS) - Enhanced Geothermal Systems (also known as hot rocks).
- Bagasse - Industrial cogeneration using bagasse as fuel.
- Biomass - Steam turbine based generation fuelled by solid biomass (generally wood).
- Concentrated solar thermal (CST) - Assumes a solar multiplier of 2.5 and nine hours of storage.

Calculations were undertaken for:

- Biogas costs from CSIRO.
- Biogas costs from CSIRO – 50% increase.
- Biogas costs from CSIRO – 100% increase.

The ranking of the technologies can be seen below.

Table 24: Ranking of baseload technologies for different biomass fuel costs

Technology	LCOE ($/MWh)	Notes
Biogas (CCGT), CSIRO price	**93.4**	
Biomass (bagasse)	124.0	Limited potential
Biogas (CCGT), CSIRO price + 50%	**127.8**	
Biomass (wood waste, ACIL price)	138.3	Only a limited potential at that low price
Geothermal (HSA)	147.5	Limited potential near load centres

[58] Biogas contains a high percentage of CO_2 compared to traditional "fossil" gas. Removing this increases the heating value of the gas. While it can be used in OCGT's without removing the CO_2, the efficiency of the OCGT plants would be substantially lower than those used in the AETA 2012 assumptions. Besides CO_2, biogas also contains small amounts of hydrogen sulphide (H_2S). When water is present, H_2S forms sulphuric acid (H_2SO_4), which is highly corrosive and renders the biogas unusable.

Technology	LCOE ($/MWh)	Notes
Concentrated Solar Thermal	151.2	Not 100% firm, some transmission costs
Biogas (CCGT), CSIRO price + 100%	**162.3**	
Biomass (wood waste, CSIRO price)	178.3	
Geothermal (EGS)	207.1	Significant transmission costs

This does not take into account connection and transmission costs. These would add significant costs to geothermal generation in the Cooper Basin and many of the CST plants.

As evident, the CCGT option becomes favourable even for the +100% cost case taking into account the transmission costs for the other options, and that CST will need some degree of backup from other plants on cloudy days.

For CCGT, the calculations are based on an assumed 83% capacity factor and an efficiency of 62.8% (49.5% is the current efficiency, which is expected to improve by 2050) as per the AETA 2012.

CST plants are not true baseload plants given the assumed storage (nine hours) and dependency on cloud cover, but would still be a suitable substitution for biomass baseload generation if biomass costs were high. The capacity factors used for CST in the calculations vary between 52% and 61% depending on location and are based on the Scenario 2, 2050 simulations rather than the AETA 2012.

Appendix 5 - Transmission design and costing

The modelling assumptions showed significant, high-quality renewable potential located in remote areas far from major load centres.

To be usable, this would require construction of new major transmission lines to transport generation to load centres. A high-level study was carried out to identify the required additional new transmission network needed to enable generation to be located in these remote locations.

This was required so that transmission costs could be taken into account when determining where to locate generation to supply the given demand at the lowest overall generation and transmission cost.

Planning considerations

Transmission line

It was assumed that remote generation would be collected in a central, remote location and that transmission lines would transport power from that central location to the load centres. The transmission distance between the remote location and the load centre was generally assumed to be 'as the crow flies' to minimise distance and cost.

The study did not consider the actual routes that the new transmission lines would take, but rather considered a generic design for the system. AEMO recognises that transmission line routes may need to avoid any sensitive areas, and this would increase the total length of the transmission lines.

AC transmission and HVDC transmission options

Both AC and HVDC transmission options were considered. Except for the connection between Victoria and Tasmania, all options were based on either AC transmission or HVDC transmission exclusively. In the case of Victoria and Tasmania, additional new interconnections, HVDC submarine cables and short connection of AC transmission lines were applied. The voltage level included for AC options was 500 kV and for HVDC, +/-500 kV.

The advantage of AC transmission is its ability to connect renewable generation and/or load along the transmission route with relatively low connection costs. The disadvantage is that long distance AC transmission lines pose system and voltage stability issues. These issues were overcome by introducing additional, intermediate switching stations, series compensation and shunt reactors.

For HVDC transmission, at least one intermediate terminal station was included to accommodate new renewable energy sources along the route. Most of the HVDC transmission around the world is either point-to-point or back-to-back HVDC systems. Presently, application of HVDC technology with one intermediate terminal station is available and development of multi-terminal HVDC technology is undergoing further advancement in this area.

Many countries around the world are building or considering building HVDC systems at voltage levels of ±800 kV and above.[59] Subject to the need for multi-terminal HVDC technology, multi-terminal HVDC systems are likely to be available in future. The cost estimates applied in this report are based on similar cost estimates of converter stations at the termination ends and intermediate stations.

In this study, the type of transmission line technology (AC or HVDC) was selected on a least-cost basis. AEMO recognises that more detailed studies could highlight circumstances where an alternative technology might be considered superior to the least-cost option in certain locations.

Security and reliability

It was assumed that there would be no loss of supply following single credible contingency events if loss of power to a region is limited to the rating of the largest existing generator in the region. In

[59] IEEE Power & Energy. Volume 10, Number 6, November/December 2012.

addition, loss of power due to a double circuit line loss was limited to reasonable levels. In most cases, the design resulted in no loss of supply following a single credible contingency event.

In all cases modelled, double circuit lines were considered over two single circuits to minimise costs.

Project costs

High level indicative project costs were prepared and are shown in Table 25. Individual plant and easement cost estimates were sourced from two AEMO reports: The *100 per cent renewables study–electricity transmission cost assumptions*[60] and *Network extensions to remote areas Part 2 – Innamincka case study.*[61]

Transmission line diagrams

While all transmission options were considered for each case, only the ones leading to the lowest cost solution were selected by the model. These are shown in the diagrams below.

Figures 58 and 59 show the additional, new transmission lines required to transfer power from generation to load centres for the two Scenario 1 cases.

Figures 60 and 61 show additional, new transmission lines required to transfer the power from generation to the load centres for the two Scenario 2 cases.

In all cases, the existing AC transmission system and HVDC lines are assumed to be available.

[60] AEMO. Available at: http://www.climatechange.gov.au/government/initiatives/aemo-100-per-cent-renewables/~/media/government/initiatives/aemo/APPENDIX2-AEMO-transmission-cost-assumptions.pdf

[61] AEMO. Available at: http://www.aemo.com.au/~/media/Files/Other/planning/0400-0005%20pdf.ashx Viewed 4 February 2013.

Figure 58: Additional new transmission lines – Scenario 1, 2030

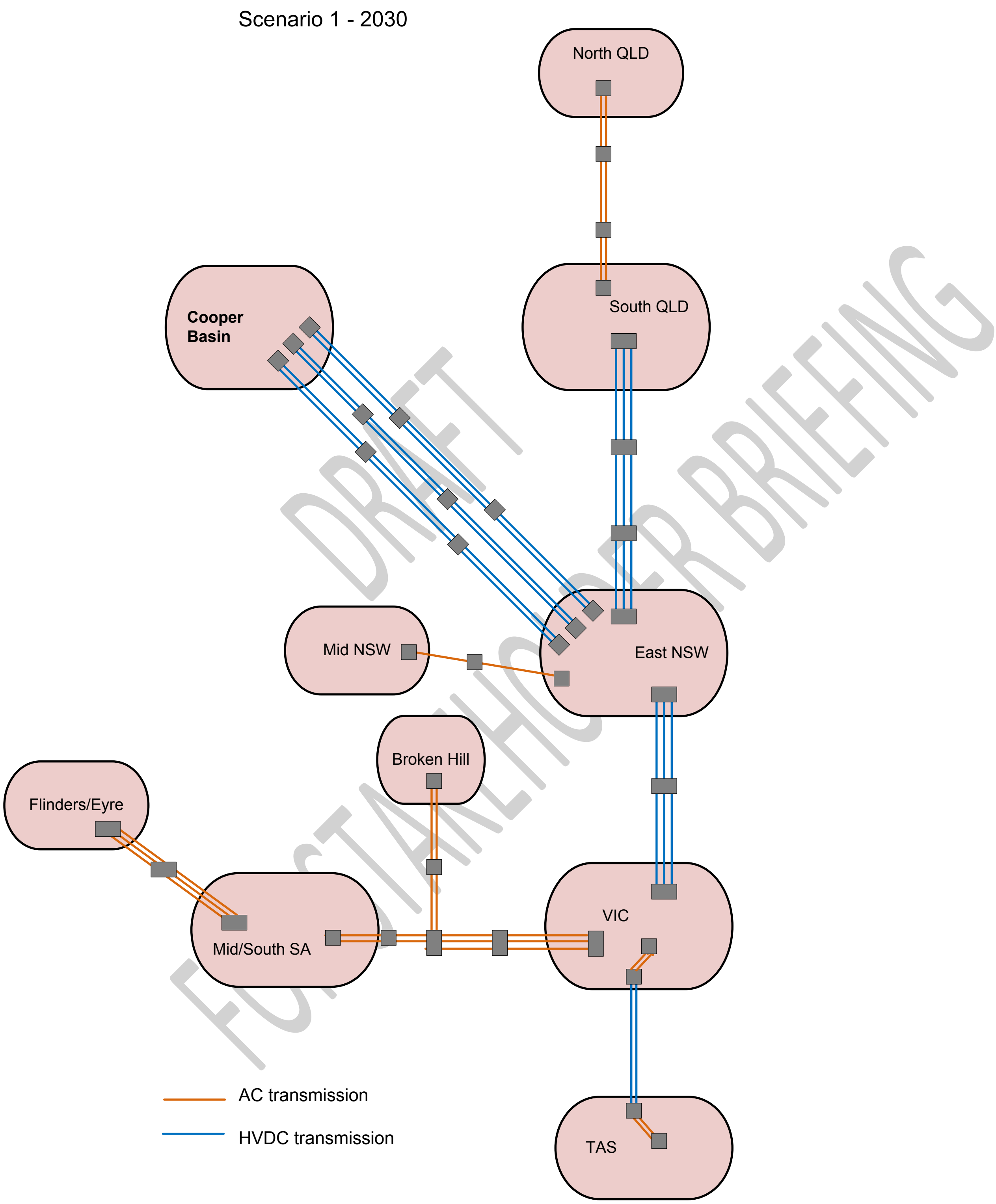


Figure 59: Additional new transmission lines – Scenario 1, 2050

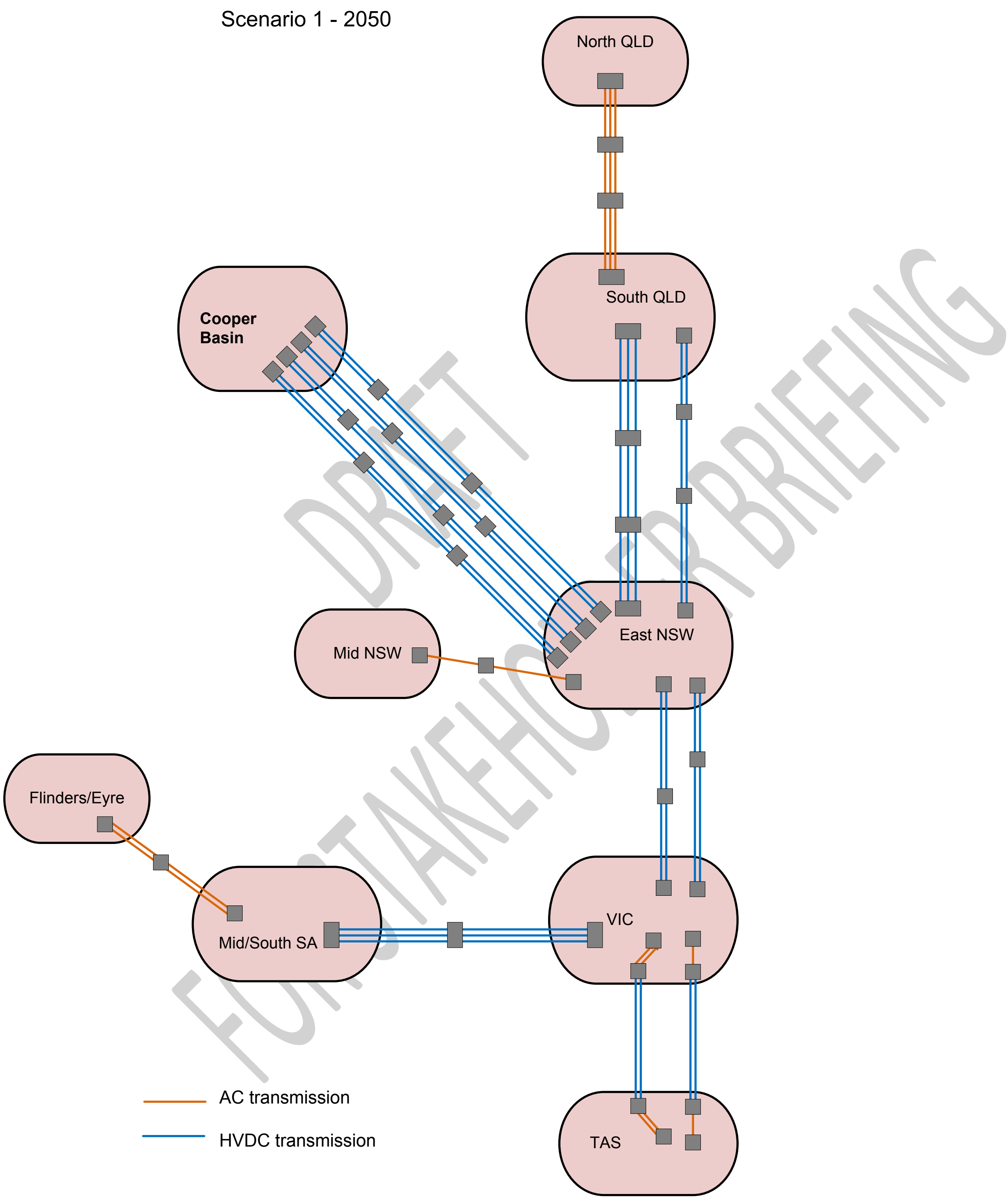


Figure 60: Additional new transmission lines – Scenario 2, 2030

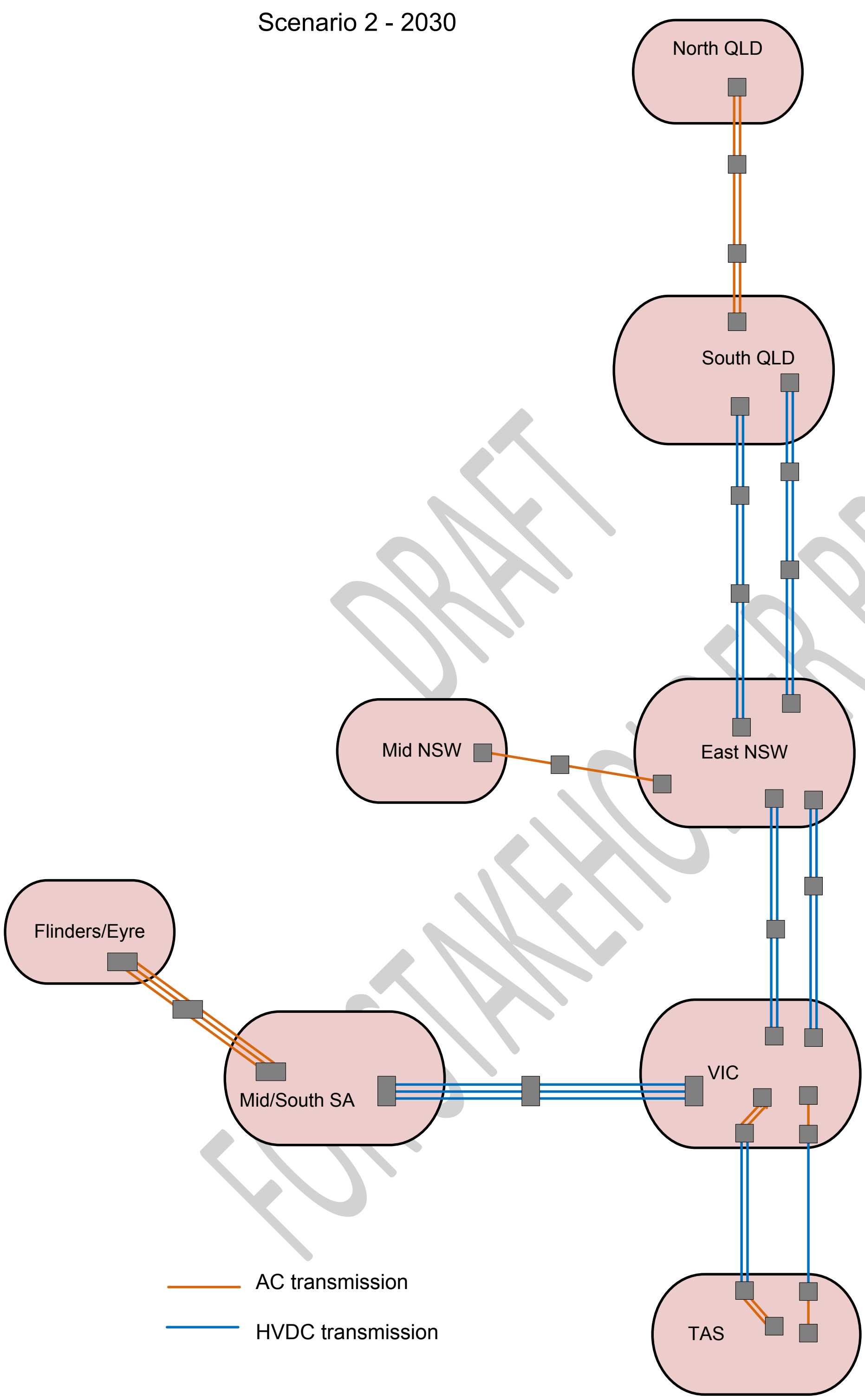


Figure 61: Additional new transmission lines – Scenario 2, 2050

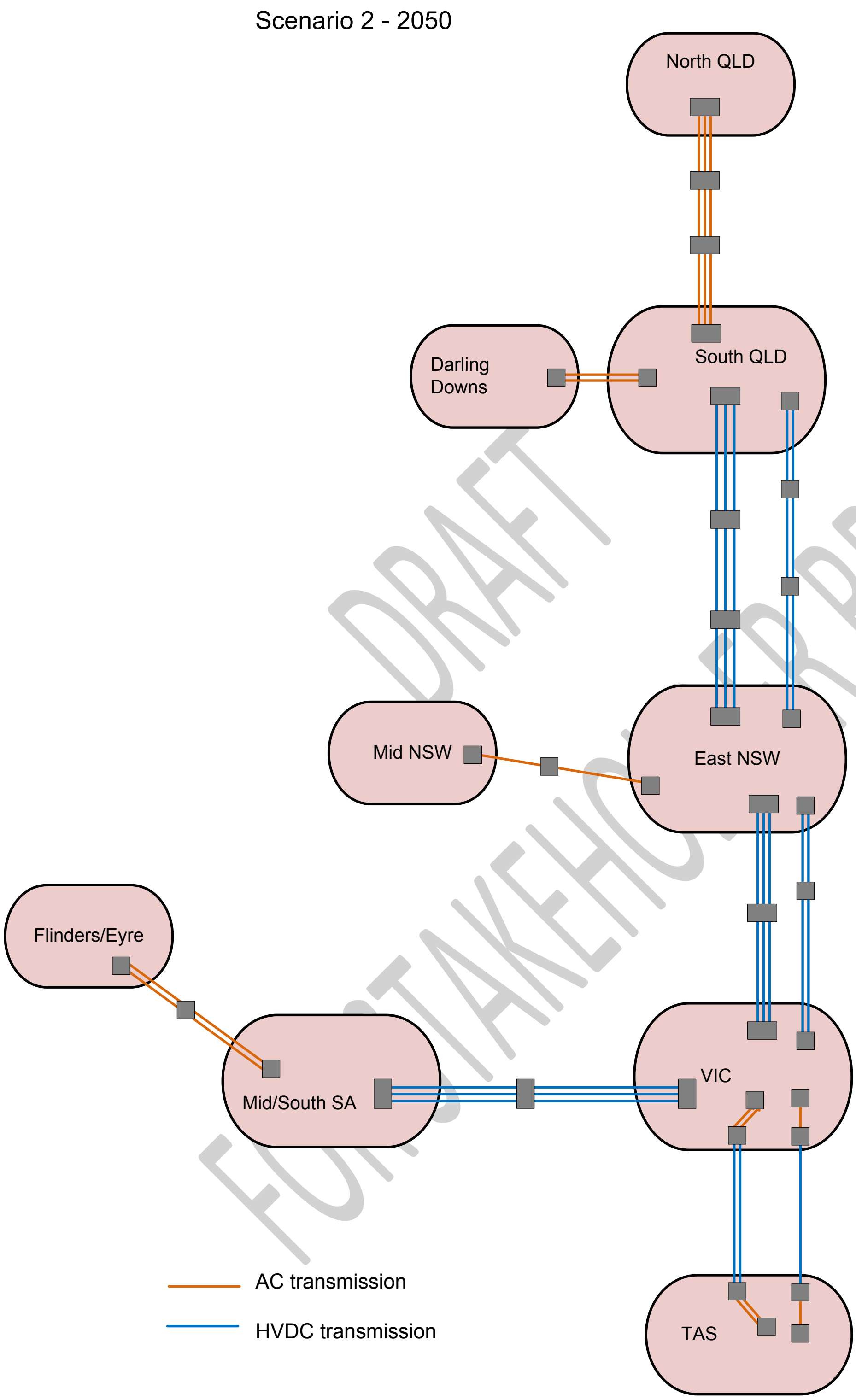


Table 25: New transmission capacity and cost requirements (10% POE)

	East NSW to South QLD	VIC to East NSW	TAS to VIC	VIC to Mid/South SA	East NSW to Cooper Basin	Mid/South SA to Flinders/ Eyre	South QLD to North QLD	South QLD to Darling Downs	East NSW to Mid NSW	Broken Hill to VIC–SA Interconnector	Total
Scenario 1, 2030				(See Note 1)						(See Note 2)	
Total required capacity (MW)	4,190	3,990	1,600	3,300	6,240	2,550	1,460	2,500	500	1,000	
Existing capability (MW)	1,000	500	500	600	-	200	400	3,000	-	-	
New capacity requirement (MW)	3,190	3,490	1,100	2,700	6,240	2,350	1,060	-	500	1,000	
Least-cost technology	HVDC	HVDC	AC-HVDC	AC	HVDC	AC	AC		AC	AC	
Transmission line easement area (ha)	12,000	7,500	1,260	8,400	22,500	7,000	4,200	-	2,450	3,500	68,810
Terminal station land area (ha)	40	30	32	64	79	34	30	-	23	23	345
Total estimated cost ($M)	**3,445**	**2,332**	**1,781**	**2,693**	**7,107**	**1,989**	**1,495**	**-**	**522**	**1,032**	**22,397**
Scenario 1, 2050											
Total required capacity (MW)	6,300	5,090	2,570	3,200	9,350	1,540	2,510	3,000	1,000		
Existing capability (MW)	1,000	500	500	600	-	200	400	3,000	-		
New capacity requirement (MW)	5,300	4,590	2,070	2,600	9,350	1,340	2,110	-	1,000		
Least-cost technology	HVDC	HVDC	AC-HVDC	HVDC	HVDC	AC	AC		AC		
Transmission line easement area (ha)	18,000	7,500	2,520	8,500	30,000	3,500	8,400	-	2,450		80,870
Terminal station land area (ha)	66	40	56	30	106	23	45	-	23		386
Total estimated cost ($M)	**5,659**	**3,043**	**2,929**	**2,540**	**9,513**	**1,168**	**2,368**	**-**	**786**		**28,005**
Scenario 2, 2030											
Total required capacity (MW)	5,050	5,100	1,880	3,320	-	2,200	2,140	3,000	500		
Existing capability (MW)	1,000	500	500	600	-	200	400	3,000	-		
New capacity requirement (MW)	4,050	4,600	1,380	2,720	-	2,000	1,740	-	500		
Least-cost technology	HVDC	HVDC	AC-HVDC	HVDC		AC	AC		AC		
Transmission line easement area (ha)	12,000	7,500	2,520	8,500	-	7,000	4,200	-	2,450		44,170
Terminal station land area (ha)	53	40	56	30	-	34	30	-	23		266
Total estimated cost ($M)	**4,427**	**3,043**	**2,737**	**2,540**	**-**	**1,896**	**1,715**	**-**	**522**		**16,878**
Scenario 2, 2050								(See Note 3)			
Total required capacity (MW)	6,250	5,520	2,000	-4,000	-	1,480	3,950	5,000	2,000		

	East NSW to South QLD	VIC to East NSW	TAS to VIC	VIC to Mid/South SA	East NSW to Cooper Basin	Mid/South SA to Flinders/ Eyre	South QLD to North QLD	South QLD to Darling Downs	East NSW to Mid NSW	Broken Hill to VIC–SA Interconnector	Total
Existing capability (MW)	1,000	500	500	600	-	200	400	3,000	-		
New capacity requirement (MW)	5,250	5,020	1,500	3,400	-	1,280	3,550	2,000	2,000		
Least-cost technology	HVDC	HVDC	AC-HVDC	HVDC		AC	AC	AC	AC		
Transmission line easement area (ha)	18,000	11,250	2,520	8,500	-	3,500	11,200	2,100	2,450		59,520
Terminal station land area (ha)	66	50	56	30	-	23	45	15	23		306
Total estimated cost ($M)	**5,631**	**3,854**	**2,737**	**2,568**	**-**	**1,168**	**3,484**	**900**	**922**		**21,262**

Note 1: VIC–SA transmission line cost estimates include additional transmission lines on VIC–SA interconnector for transfer of generation from Broken Hill to load centres. This does not include estimates of transmission lines between Broken Hill and the VIC–SA interconnector.
Note 2: Transmission line from Broken Hill connected to the transmission line from VIC to SA.
Note 3: A 1000 MW capacity is assumed to be needed to connect solar generation to Darling Downs. A 100 km distance is assumed.

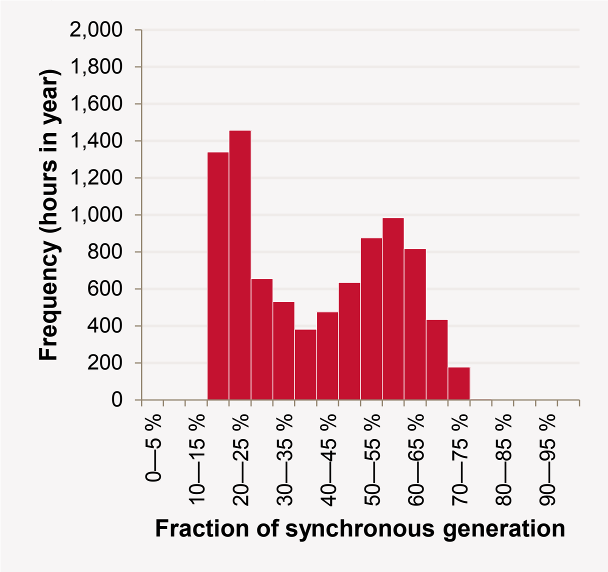
Appendix 6 - Operational considerations

General introduction:

It is clear that the NEM in a future 100 per cent renewable energy scenario would be operating from the basis of a very different generation technology mix than is traditionally the case. There are likely to be instances when generation from asynchronous or power electronic converter based sources (collectively referred to here as non-synchronous sources) would contribute to the majority of load demand service. Furthermore, many of these non-synchronous generation sources are primarily of a semi-scheduled or non-scheduled nature, subject to the inherent variations and forecast-uncertainty of the wind, sunshine or waves. A power system with such high penetrations of semi-scheduled and non-synchronous generation would constitute a system that may be at or beyond the limits of known capability and experience anywhere in the world to date, and as such would be subject to a number of important technical and operational challenges.

Several of these issues have been touched on briefly by the results and discussion sections of this report. Metrics such as the non-synchronous generation penetration level (as reproduced in Figure 62 below for scenario 1 in 2050) are useful in an overview or summary context, underlining the fact that the future 100 per cent renewable NEM power system would likely be of a radically different composition.

Figure 62: Synchronous energy penetration on mainland NEM area, Scenario 1 (2050)



It should be noted however that the metric of non-synchronous generation penetration is of a ‘proportional’ or relative nature. An instantaneous 50% non-synchronous generation penetration at times of low customer demand level would likely present system inertia and frequency control challenges, while the same 50% proportional penetration at times of peak customer demand would likely present different challenges more of a reactive power and voltage stability nature, even though these two situations are not distinguished by the non-synchronous generation histograms. Furthermore, given that the NEM consists of two separate synchronous areas in the Australian mainland and Tasmania, then overall NEM-wide conclusions may have some location-specific caveats.

A precise understanding of the technical and operational challenges facing a 100 per cent renewable energy NEM power system is a very nuanced and complex issue therefore, likely requiring highly detailed technical investigations and indeed ongoing research efforts that are beyond the scope of this assessment. The situation is also complicated by the degree of technology uncertainty that exists when looking forward 20 or 40 years into the future. This appendix however seeks to address in a high-level manner some challenges and related mitigation strategies that can be foreseen at this time, and any associated limitations on or cost-implications for the feasibility of operating the NEM with the given 100 per cent renewable energy generation portfolio mixes. In the discussion that follows, it is important though to note that there are no fundamental technical limitations to operating the given 100 per cent renewable NEM power system generation portfolios that have been identified.

To fully understand the operational issues from a 100 per cent renewable system, it would be necessary to undertake a full set of dynamic power system studies, which is beyond the scope of this report.

The NEM already has performance standards relating to the ability of generators to ride through fault conditions. These standards apply to all types of utility-scale generators. The standards are currently achieved either by the generators directly or by installing ancillary equipment such as Static Var Compensation (SVCs and STATCOMs). Detailed studies may be required to determine whether these standards continue to be appropriate or will need to be amended for a 100 per cent renewable system.

Power system frequency control

Precise frequency control is a critical aspect of system integrity in any synchronous AC power system. In the NEM, supply frequency must be maintained within a very tight tolerance band around 50 Hz in normal operation. Disturbances such as an instantaneous outage of a large generator, or a sudden and large step increase or decrease in load, cause system frequency to deviate from nominal and must be mitigated quickly with appropriate control actions to prevent a wider system collapse. Traditional generators that are synchronised to the common system frequency are generally comprised of large rotating masses of appreciable mechanical inertia. Load demand also has an inertial component comprised of large synchronous or (to a lesser extent) squirrel-cage induction motors. Synchronous power system elements will inherently provide some natural damping of any frequency deviations by automatically releasing or absorbing some of their stored energy as appropriate. This allows time for other compensating actions by spinning and replacement power reserves to further arrest the deviation in frequency and then revert it back to nominal again. Frequency control is known to be problematic in systems with few synchronous plants installed, especially at times of light customer load.

The synchronous nature of renewable sources such as concentrating solar thermal and geothermal steam turbines, biomass gas turbines and hydro-turbines means that they will contribute inertia to the system. In contrast, the power electronic characteristics of both PV and modern wind turbine generators (WTGs) are inherently asynchronous in nature and do not naturally provide any inertial support to the interconnected system during frequency disturbances. Older squirrel cage induction machine (Type 1) and variable rotor resistance (Type 2) based WTGs may have a limited natural inertial response, but it is expected that most future wind farms will be of the doubly-fed induction machine (Type 3) or full converter (Type 4) nature. Though all Type 3 and 4 WTGs are highly controllable and have a significant stored kinetic energy component in the rotating blades, this is (usually) not accessible to the wider synchronous system due to the power electronics interface and control schemes that they use. PV has no natural rotating-machine stored energy component at all, and thus cannot offer inertial support in the traditional sense.

High wind power and PV output will displace significant amounts of synchronous generator inertia in the dispatch, while not contributing any of their own to replace it. This will make frequency control more challenging. If comprised of significant amounts of such non-synchronous generation, the future NEM power system may be routinely subject to larger frequency deviations following disturbances than are observed at present. Both the initial rate of change of frequency (ROCOF), and indeed the maximum deviation of frequency from nominal, will be more extreme in such a low synchronous-inertia system. These two indices are linked of course (faster initial ROCOFs generally tend to lead to larger absolute deviations), but are separately important.

A mitigating factor of the 100 per cent renewable generation portfolios is that the size of the largest generator contingency online (even at full power output level) is typically smaller than at present. In fact the largest single frequency-control contingency in the 100 per cent renewable system could come from the loss of a heavily loaded HVDC network link spanning Tasmania and the mainland synchronous systems (such as Basslink). Otherwise, if a severe and sustained fault occurs in an area of the transmission network near to a large cluster of non-synchronous generators that go into low voltage ride through mode (LVRT) then there may be a temporary generation shortage even after the fault is cleared until such time as the non-synchronous units recover to normal operational level. Depending on the prevailing dispatch conditions therefore, the largest frequency-disturbance contingency in the future 100 per cent renewable scenarios might come from a different underlying cause than at present.

All generators in the 100 per cent renewable generation portfolios, both synchronous (hydro plants, biomass gas turbines, CST steam turbines, geothermal turbines etc) and non-synchronous (wind, PV and probably wave [Drew]) would likely require generation performance standards framed within a context of more severe frequency deviations, so that subsequent tripping of additional generation following an initial disturbance is minimised. This might be a challenge for gas turbines in particular [NERC_1]. More extreme ROCOFs will also be critical for smaller distribution system connected generator anti-islanding protection schemes. A key finding of a recent ultra-high wind integration study in the Irish All-Island power system found ROCOF based relay protection settings may have to be relaxed in order to prevent cascading frequency-deviation related outages [Eirgrid].

Several other mitigating strategies using FCAS type mechanisms might be possible to minimise the impact of frequency disturbances in the future 100 per cent renewable NEM. Dispatch intervention could be applied to reduce the size of the largest possible contingency. More spinning reserve, and of a faster nature, could be carried. Synchronous generators could also be constrained online at their minimum generation level at times of high non-synchronous generation output, and indeed hydro power generators could also be operated in synchronous condenser mode, in order to make the system ‘heavier’. Pumped hydro and battery electric vehicles (that are likely to be recharging at times of high wind and PV output) could also be specifically put on under-frequency load shedding alert to provide additional control capability. Under-frequency customer load shedding settings might also be appropriately adapted so that the collective system frequency response is optimised. HVDC links spanning Tasmania and the mainland NEM systems could be fitted with frequency-support schemes analogous to that which presently exists for Basslink.

Future technology advances are also likely in the area of inertial response from Type 3 and 4 WTGs. Given their otherwise excellent controllability (especially the Type 4 machines) it has long been proposed that a supplementary control loop be fitted to these WTGs that would ensure an artificial or emulated inertial response when a drop in system frequency occurs [Supergen]. Some demonstration projects have been recently installed around the world with this functionality [Ruttledge]. Even though the provision of artificial inertial response from wind turbine generators may lead to increased mechanical stress on the turbine shaft and gearboxes etc with design and economic implications, this could still be a very useful option. It is known to be a complicated issue to assess from the wider system impact however. For example, even at low to medium wind speeds across the system, it is likely that most of the WTGs will be online and spinning. They would therefore have stored rotational energy available if it could be accessed by a supplementary inertial-response control loop [Doherty_1]. At such wind speeds, the WTGs will displace little synchronous inertia in the economic dispatch, so the net total system inertia will be much higher and the frequency control performance of the system better. At higher wind speeds though, more synchronous generation will be displaced in the dispatch by the WTGs, while not contributing much more inertia of their own, and thus the total system frequency response may be poorer [Doherty_1]. The actual provision of stored inertial response from WTGs can also interrupt the optimal aerodynamics and mechanical input power capture of the turbine blades at low to medium wind speeds. When the blades slow down during provision of inertial response, then their blade tip-speed ratio (ratio of turbine rotational speed to incident wind speed) may become sub-optimal, possibly making the overall frequency deviation worse [Ruttledge]. The provision of inertial response also might not be possible from WTGs near to a fault location, if this fault is the causal factor behind the frequency dip. When assessing the overall potential for inertial emulation of WTGs, it is therefore a very nuanced statistical issue of how likely different values of wind power output occur across the system and coincide with the rest of the dispatch and system operational aspects.

A full investigation of how the NEM power system would operate with a very low level of inertia has not been carried out for this project. However, it should be noted that one area of the NEM, Tasmania, already has a significantly lower inertia level than the mainland NEM system. Other analogously low inertia systems exist around the world (e.g. the standalone synchronous power system area of Ireland), and manage to maintain acceptable reliability levels, even with quite high non-synchronous generation levels at present [Eirgrid]. In such power systems, then large frequency disturbances can regularly occur as a matter of course. It is likely therefore that while a NEM with the higher non-synchronous generation penetration levels indicated in earlier chapters will pose some frequency stability challenges, at this stage it might be considered as a problem of detailed investigation and design rather than a fundamental-limit upon the 100 per cent renewable generation portfolios.

Grid code performance standards

The ability of generators to remain connected to the power system during a disturbance is a critical element of interconnected power system reliability, so that the system can return to an intact customer demand servicing state once the disturbance is removed. Given the disparity between generator input mechanical power and the electrical output power that can occur during a transmission network fault incident, then a transient instability risk exists for many forms of generators. The renewable energy sources that are based on conventional synchronous generators (such as concentrating solar thermal and geothermal steam turbines, biomass gas turbines and hydro-generator turbines etc) would rely on fast separation of the faulted network element in order to maintain their rotor angle dynamic swings within stable bounds. While detailed transient simulation would have to be carried out for each individual plant of course, this category of problem is well understood by power engineers given that the same challenge already exists for conventional fossil fuel based generators. It should not represent any additional technical limits for synchronous generator technologies in the 100 per cent renewable generation scenarios.

The LVRT performance of non-synchronous wind and PV technologies is still as of yet a developing technical field though. In the early days of utility scale wind generation when most of the wind farms were small collections of Type 1 machines, then it was considered acceptable for WTGs to trip off the system following a network fault in order to protect both themselves and to maintain post-disturbance voltage stability on the system. As more and more wind farms of larger size began to be developed, then the total amount of generation at risk following a network disturbance became a concern from a system stability point of view, and thus 'grid-code' performance standards began to be developed that mandated improved grid interaction of WTGs [ECAR]. The discussion of whether or not the WTGs simply 'stay connected' during the disturbance has in the last decade further evolved to a discussion around what is the nature of the WTG grid interaction during ride-through i.e. what are the reactive power and voltage support capabilities required during the disturbance [Te Uku, Nelson, Itani], and how quickly can active power return to pre-disturbance levels etc.

This is important as if significant numbers of WTGs delay return to pre-disturbance active power output levels, then this could have detrimental effects on system frequency control in an already lower inertia NEM power system. For example, recent wind integration studies on the Irish All-Island power system would suggest that at times of high wind power output, the propagation of a network fault voltage dip throughout a large area of the system could cause Type 1, 2 and 3 WTG LVRT related system-frequency stability impacts that would exceed the traditional worst-case scenario of loss of the largest base-load generator unit [Eirgrid]. Furthermore, this type of event was seen to be worst when a lot of wind power is generating and thus displaces synchronous inertia from the economic dispatch. This is an issue that would transfer directly to non-synchronous generation penetration in the geographically-small Tasmanian area of the NEM, which already has some well-recognised challenges in this regard. On the mainland areas of the NEM, then the likely distributed geographical installation of any non-synchronous generation sources should prevent this being a major issue to the same degree as Tasmania – some generators local to the fault would go into LVRT mode but most others would be unaffected.

In any case, grid interaction of modern WTGs is much better than the older style induction generators that may have given WTGs a bad reputation to date. Most TYPE 1, 2 and 3 WTGs, and some Type 4 WTGs employ fast-responsive blade pitching strategies to reduce the active power captured during the fault incident that helps to prevent turbine over-speed. On weaker parts of the electricity network, this can be combined with installation of Static Var Compensation (SVCs and STATCOMs) to help boost the local voltage during faults and improve transient performance. Some TYPE 4 full converter machines employ power-electronically switched 'dump resistors' instead of blade pitching to manage the electrical and mechanical active power imbalances [Itani] – in this scenario there is complete separation of the turbine blades and generator from the grid disturbance and the fast controllability of the power electronic converters allows very quick recovery to pre-disturbance conditions for even the most severe faults. Type 4 machines and Type 3 machines (depending on the extremity of the disturbance) can also to some extent prioritise reactive over active current during disturbances if necessary to help with dynamic voltage support. Type 3 and 4 machine power electronics may still 'block' however for close in 3-phase bolted faults where the voltage reduces to zero, and loss of voltage phase angle information occurs [Mohseni]. Type 3 machines may also have to employ 'crowbar' bypass of their rotor-side power electronic converters during extreme voltage dips, momentarily transitioning them into traditional induction generators, with limited controllability as a result. A very detailed discussion and comparison of international WTG grid-codes to generation access standards that presently exist in the NEM is contained in [ECAR].

It should be noted that some WTGs of the highly-controllable Type 4 nature are already connected to the NEM. The versatility of these types of machine to ride through grid disturbances and even support the network during them, should not be under-estimated. In some respects, for certain disturbances their transient performance may even exceed that of conventional synchronous based generation in speed and damping of response. Uprating of power electronic converters in future machines could also potentially allow enhanced reactive power provision. Even power system stabiliser functionality provided from modern wind turbine topologies has been discussed in [Itani]. Some of these advanced functions might indeed have additional economic costs, though the cost of power electronics is expected to continue to reduce in the decades ahead.

The LVRT characteristics of PV are a novel field of investigation, though several utility-scale-PV and rooftop-solar-PV grid performance standardisation efforts are ongoing [EPRI, WECC]. It could be reasonably assumed that the LVRT capability of large-scale PV will be akin to that of Type 4 WTGs, given that they are both comprised of fully-rated power electronic converter technologies. High-voltage ride through problems may be more of a concern for rooftop PV, where the typically reduced X/R ratio and higher impedance low voltage networks are not presently designed for significant back-feed of generation to the main grid. While it is a detailed issue in itself, it is likely to be more of a distribution-system voltage-profile planning and adaptation issue for specific feeders, rather than an operational timeframe concern for the wider power system. The significant active power intermittency of large-scale PV during cloud transitions is also known to be a concern for voltage control device 'hunting' effects, but again it is likely to be an issue of design adaptation rather than a critical limitation [Walling].

There are of course some challenges to be overcome when modelling and studying the grid interaction capability and performance of WTG machines and PV, in terms of model validation and suitability of modelling environment (positive sequence equivalent versus full three-phase representation). Concerted effort between manufacturers, researchers and system operators is ongoing [Ellis] though. Considering the rapid pace of non-synchronous generation technology advances in the last decade or so, then given the future 20-40 year time horizon of the 100 per cent renewable study assumptions, then grid interaction capability and performance is unlikely to be a major limitation on the overall integration of large scale non-synchronous generation.

Fault level in-feed

High voltage electric power system networks rely on fast-acting and selective operation of system protection devices following the occurrence of faults to quickly isolate the faulted elements for public safety, system stability and infrastructure integrity reasons. The occurrence of a fault generally leads to a much higher current flow than usual, allowing the system circuit breakers to sense that a fault has indeed occurred. System protection is thus designed with respect to a maximum and minimum fault level – the maximum level being the highest fault current that can be safely interrupted by the protection, and the minimum level being the lowest fault current that will still allow the system protection to differentiate between the occurrence of a fault or not.

The 100 per cent renewable generators that are based on synchronous machines would likely have fault current characteristics almost identical to existing conventional synchronous plant, and thus should not present any undue difficulties for system design over and above those that presently exist. Once again however, the non-synchronous generation sources have some peculiarities in respect of fault level in-feed that may complicate the design and operation of the 100 per cent renewable power system. Type 1 and Type 2 WTG machines behave akin to a voltage source behind a sub-transient impedance when maximum symmetrical or 'withstand' fault level [Muljadi_1] is assessed. For a three phase bolted fault, as these induction generators do not have an internal excitation system then the fault current can quickly decay to zero and the circuit breaker 'interrupt' current can be far less than the initial withstand value. For asymmetrical faults, the induction generators may not become completely demagnetised and thus a more substantial interrupt current may persist [Muljadi_2]. Type 3 machines are more complex to assess depending on their LVRT strategy. For less extreme voltage dips caused by distant faults or faults with an appreciable impedance, the rotor side power electronic converter remains in control of the machine and thus from a fault level assessment point of view it acts like a rated current source. For close-in faults, the rotor side power electronic converter may be required to be bypassed by a crowbar mechanism in order to prevent damaging transient conditions. In this mode, the rotor side converter loses control and the Type 3 machine is more akin to a conventional induction generator with fixed external rotor resistance [Sulla]. A voltage source behind sub transient impedance would then be a better representation in this situation for Type 3 machine maximum fault level contribution. The situation is once again complicated for asymmetrical fault disturbances in Type 3 machines. Type 4 full-converter machines will act akin to a rated current source pretty much no matter where the fault occurs, and for power electronic current limitation reasons, cannot supply fault currents much more than rated current value. Given that PV is also of a full power electronic converter nature, its fault current in-feed behaviour is likely to be akin to a Type 4 WTG machine. Non-synchronous generator fault level in-feed may also be somewhat manufacturer specific depending on the LVRT control strategy employed – i.e. voltage dip threshold and time duration of DFIG crowbar control mechanism [Meegahapola], prioritisation of active or reactive current in Type 4 machines during disturbances etc. Additionally, some wind farms may have power electronic STATCOMs included for plant LVRT purposes, which would further complicate the process.

Clearly the representation of different WTGs in standard fault current assessment software packages for different fault locations and fault types is a rather complicated affair [IEEE_SC_WG], and assumption of fixed voltage source impedances may be a simplistic and necessarily conservative one. Significant research and industrial collaboration is ongoing to better understand and properly characterise the modern non-synchronous generator fault level in-feed for wider power system planning purposes though [IEEE SC_WG].

It might be argued that the non-synchronous generation sources complicate the fault level assessment no more than voltage source converter (VSC) HVDC links that already exist on the NEM (Murraylink for example), but perhaps the issue is that they are far more distributed at multiple locations on the power system, reducing the scope for simpler rules of thumb that may have been used in the past for the point-to-point HVDC links [AEMO AFLR].

The expansion of fully-rated power electronic converter based generation sources in the future 100 per cent renewable power system (PV and Type 4 WTGs) may have implications for the minimum fault level requirement in the NEM power system. Given that these converters can provide little more than rated current output, then the ability of present-day protection system technology to determine when a fault has occurred on a weak part of the network may be compromised at times of high non-synchronous generation output. This would have important safety and security implications for a power system that would in itself represent a fundamental limitation to the instantaneously high penetrations of non-synchronous generation on the NEM. It is possible that traditional synchronous generators would have to be constrained online (either at minimum active power generation level or as synchronous condensers) in order to guarantee minimum fault level in-feed in this scenario, with some associated economic costs. The minimum fault level in-feed issue would also likely have some locational specific constraints in each area of the NEM - e.g. Victorian hydro generators acting as synchronous condensers would be unlikely able to guarantee minimum fault level in-feed in northern Queensland for example. With some additional dispatch constraints of this regard, combined with some detailed fault level studies, then the issue could be surmountable in due course however.

Ramping, variability and uncertainty, regulation reserve and DSP

Significant expansion of semi-scheduled renewable resources such as PV, wave and wind in a power system's generation portfolio is likely to lead to more operational timeframe variability (increased ramps) and forecast uncertainty (potential difficulty to foresee such ramps) in the overall system's supply side function. It is important such operational complexity does not lead to undue increases in cost or decreases in system reliability. There is presently great discussion in academic and industrial forums about the need for and merits of power system scheduling flexibility with increased renewable energy variability and forecast uncertainty [Lannoye, Bouffard]. Flexibility definitions, metrics and assessment techniques have been considered for semi-scheduled plant portfolios as a result [IEA_1]. To summarise these efforts, it can be said that the generation portfolio must have sufficient flexibility in order to compensate for the renewable energy variations so that load demand can continue to be served. Flexibility assessment of a scheduled plant (or portfolio of plants) includes the ability to start up or shut down within a given time horizon, the ability to ramp up or down quickly once online, maintaining such capabilities when tasked to perform them repeatedly over a multi-annual timeframe, and crucially, the ability to do so at reasonable cost.

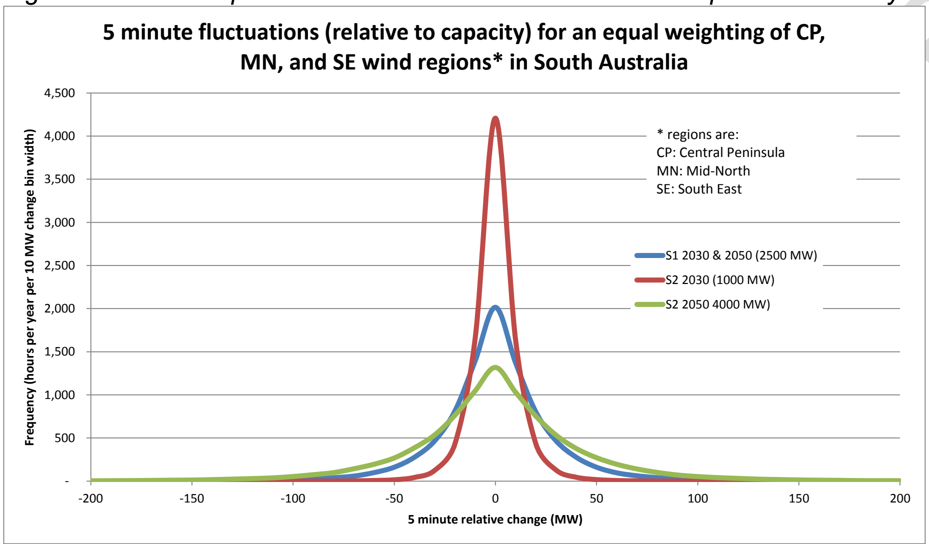
From the detailed results chapters earlier, it is indicated that in a 100 per cent renewable scenario the NEM could be subject to far more significant operational timeframe variability or ramping events than historically observed to date, both in the up-ramping and down-ramping directions. Severe ramps over short time periods are a major challenge, yet less extreme but sustained ramps over a number of hours could be problematic as well. The most consistently onerous time of the day that the extreme downward ramps could occur is understood to be in the evening time, when a drop in wind power availability and a larger than usual rise in the electricity demand may coincide with the natural reduction in PV generation at sundown.

The scheduled plant elements of the 100 per cent renewable generation portfolio are fortuitously of a very flexible nature however. Hydro power, pumped hydro, biomass gas turbines are all naturally very flexible sources of generation. The key technology in the 100 per cent renewable portfolios that is expected to provide the significant up-ramping capability to meet evening peaks in demand is the CST. It is understood that these generators have the thermal and mechanical structural capability to be able to flexibly perform as required, with some thermal energy used from the store during the day to keep the plant warm and ready to respond at evening time. Furthermore, given that there are a relatively large number of medium sized CST units in the proposed portfolios rather than a small number of large units, this should also help with overall system flexibility concerns. It should also be noted that curtailment of the semi-scheduled resources can always be applied as a last resort to help smooth out any severe ramps, both in the up and down directions. For example pre-curtailing the PV from early afternoon onwards in a controlled down-ramp fashion would allow a managed transition from PV to solar CST on the supply side, without sundown uncontrollably driving the process over a much shorter time period. Curtailment might reduce the overall system economics slightly, yet if it is required, the most extreme ramps are expected to be rare enough in occurrence to not be of too great concern in this regard.

Flexibility can also be sourced from the demand side function if sufficient customer load can be made responsive enough to the power system's needs. The 100 per cent renewable supply-side planning analysis already assumes significant availability of load demand peak reduction and shifting to meet demand effectively, as well as intelligent charging of electric vehicles to largely suit the grid requirements. The exact co-ordination of this demand side participation would in practice require detailed consideration to maintain system security in the operational timeframe. Some 'smart-grid' related research efforts are ongoing to better understand the co-ordination challenges of distributed demand side participation [Mathieu]. The overall assumption is that while some challenges remain, demand side participation is expected to be of significantly more help than hindrance to future 100 per cent renewable power system operation.

It is also important to study the impacts of stochastic or random variations in the semi-scheduled renewable energy resources that would be of relevance in the short-term frequency regulation timeframe. Detailed theoretical and practical treatments of increased FCAS required to cover short-term renewable energy variations have been reported previously [Doherty_2, CSIRO]. The 100 per cent renewable power system will at times be operating from quite a low synchronous-inertial basis as discussed above, meaning that any short-term supply and demand imbalances would more quickly lead to greater stochastic variations in system supply frequency if not carefully managed. It is known that for single large-scale PV plants that the impacts of temporary cloud transitions over the plant can lead to severe intermittency on a local scale [Walling]. Unfortunately, extensive data on the very short-term stochastic variability of Australian solar, wind and wave does not exist for very long historical timeframes or at very wide spatial spread at this time. Some data is presented in Figure 63 below though for the very-short-term wind variability that would be concentrated in the region of South Australia in the future 100 per cent renewable scenarios.

Figure 63: AEMO operational data of South Australian wind power variability



Note that significant levels of frequency-support reserve are already carried on the NEM for the potential loss of the single largest base-load fossil fuel plant. In that comparative context, it is likely that the spatial smoothing of the stochastic renewable energy sources when spread across a wide geographical area will allay any major concerns about this topic.

The basic availability of regulating reserve to match these stochastic variations should not be a major concern either. The synchronous renewable energy plants using conventional steam or gas turbines should be able to provide conventional governor capability which is well understood. In theory, both wind turbines and PV are also capable of providing fast-responsive reserve as well if required, either through blade pitching in the case of wind turbines or perhaps switching in and out individual panel subsets in the case of PV. The supply of reserve from the semi-scheduled renewable resources may be of questionable economic value if used on a regular basis though, as it requires these generators to spill available energy on a continuous basis in order to ramp up production in the somewhat unlikely case of a large frequency transient. Renewable generation forecast uncertainty is also a concern within the power system operational timeframe. Wind, wave and PV are subject to natural fluctuations that are not fully predictable well in advance. Such forecast uncertainty will therefore compound the challenges expected for likely ramping events described above. Weather forecasting methods have been applied to wind power prediction with some appreciable success however, both in terms of producing the wind forecast itself, and also the task of effective interpretation of such forecasts to modify the power system dispatch process accordingly [IEA_2,Argonne, Anemos_1, Anemos_2]. AEMO itself presently utilises the AWEFS tool for wind power forecasting, which is based on the European ANEMOS project methodology adapted for and applied to the NEM.

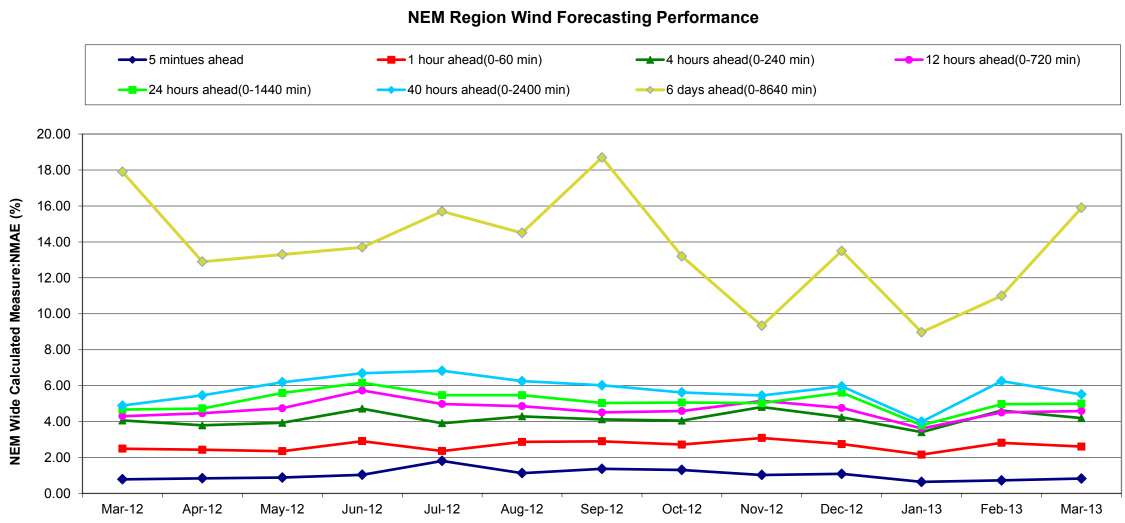
In the immediate 6-hour-ahead time horizon, statistical auto-regressive type models based on 'persistence' of present weather conditions and recent observations are considered the most accurate for wind power forecasting. In the subsequent time horizons, the solution of large scale dynamic mathematical models of meteorological states and variables or 'numerical weather prediction' (NWP) is demonstrated to be the superior approach. Such equations relate important time-dynamic interactions between weather variables such as temperature, pressure, humidity etc, and are solved for varying resolution geographical grids depending on the spatial breadth and granularity required. Data analytics, learning algorithms corrections for local surface topographies etc are all applied to improve accuracy at specific wind farm sites. Optimal combinations of separate models are sometimes used to reduce error also [Argonne, Anemos_1, Anemos_2]. Wind speed forecasts are then translated to wind power output using a wind farm's effective power curve. Extreme-event forecasting techniques are also under investigation to predict low probability ramp events, and/or storm-induced wind turbine cut-outs [SAFEWIND, Cutler].

Forecast error will still exist regardless however, given the underlying chaotic nature of the weather process, so a point-prediction or 'expected value' of wind power output at any given time horizon will usually be wrong, to some degree. The degree to which the forecast will be inaccurate is obviously of concern to market participants and system operators alike, so techniques are emerging to account for this forecast error using probabilistic forecast representations. Ensemble-based prediction methods are pushing the present state-of-the-art capability, aiming to specify a distribution of wind forecast uncertainty instead of a single expected value or given confidence interval. A set of time-related uncertainty distributions can then be converted into probability-weighted scenario trees for advanced decision making purposes [Pinson]. This is useful as the error band for the same point prediction value could be radically different on any given day due to variations in atmospheric stability [Anemos_2]. Note that the non-linearity of the turbine wind speed to power curve generally modifies the shape of the error distribution as well. Forecast uncertainty distributions for individual wind farms (useful when assessing local network congestion impacts) must be statistically consistent with the overall system total wind power uncertainty (useful when deciding the optimal amount of spinning or replacement reserve). Given that both will likely be specified in terms of complex non-parametric probability distributions, then advanced statistical techniques must be applied to consider their multivariate dependencies [Papaefthymiou_1]. As even though nearby wind farm forecast errors will be correlated due to so called 'phase error' of delayed weather transitions, increased spatial smoothing will surely reduce the effect of individual errors on the overall value.

Solar power forecasting is a scientific discipline still somewhat in its infancy. In the medium-term forecast horizon (six hours onwards), it relies to a great deal on the same type of NWP tools as wind forecasting, though such tools may have difficulty accounting for the formulation and propagation of cloud cover (that most influences solar generation) without massive computational implications [Windlogics]. It is proposed that direct satellite observations of cloud cover and transitions might be used to supplement any such deficiencies for PV predictions in the short-term horizon (less than six hours). Sky cameras located at individual PV installations can supply immediate-term predictions (seconds to minutes) [UWIG]. It seems there is not as widespread solar forecasting applied experience around the world to date as there exists with wind power forecasting. Impact of short-term demand prediction accounting for residential PV has been discussed in [CAISO] as one example. AEMO has, in tandem with some partners, undertaken to develop a state-of-the-art solar forecasting scheme for the NEM [ASEFS], which is expected to be delivered in 2013.

The solution of NWP equations is a very difficult task in both complexity and dimensionality respects, and can require a number of hours to solve on even the fastest available computer resources – the requirement to produce probabilistic forecasts based on ensembles of input boundary conditions will magnify this task therefore. The provision of forecast uncertainty estimations is very useful from the power system scheduling point of view though. Techniques such as stochastic scheduling using forecast scenario trees when combined with advanced decision making tools, have been shown to limit the negative effects operational timeframe uncertainty to a great deal [Meibom]. Applied wind and solar power forecasting is at an interesting interdisciplinary confluence of meteorology, informatics, power engineering and decision sciences. Research efforts will likely continue to progress and develop better industry standard tools in the coming decades. Some recent forecast accuracy information for AEMO's AWEFS tool is presented below in Figure 64 for example.

Figure 64: Recent AWEFS average accuracy with respect to forecast horizon – source [AEMO]



	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13
5 mintues ahead	0.79	0.84	0.89	1.04	1.81	1.13	1.37	1.31	1.03	1.09	0.64	0.73	0.83
1 hour ahead(0-60 min)	2.49	2.43	2.35	2.91	2.36	2.87	2.90	2.72	3.09	2.75	2.16	2.82	2.61
4 hours ahead(0-240 min)	4.06	3.79	3.93	4.72	3.91	4.29	4.12	4.05	4.81	4.24	3.41	4.61	4.19
12 hours ahead(0-720 min)	4.30	4.46	4.74	5.73	4.98	4.86	4.51	4.59	5.15	4.76	3.62	4.51	4.59
24 hours ahead(0-1440 min)	4.67	4.73	5.59	6.16	5.47	5.47	5.03	5.06	5.03	5.61	3.79	4.97	5.00
40 hours ahead(0-2400 min)	4.89	5.46	6.19	6.69	6.83	6.25	6.02	5.62	5.45	5.96	3.99	6.25	5.51
6 days ahead(0-8640 min)	17.90	12.90	13.30	13.70	15.70	14.50	18.70	13.20	9.33	13.50	8.97	11.00	15.90

Wind/solar variability and uncertainty may have some economic consequences to the scheduling and dispatch of the NEM in the 100 per cent renewable scenarios however. Several international studies have attempted to estimate such cost impacts for other power systems [Poyry, Ela, NVEnergy]. Other operational time frame assessments considered issues of a more practical nature, such as the effective scheduling of network and plant maintenance [Burke_1] in a situation where much greater network power flow diversity occurs due to forecast uncertainty. The resource time series of the wind, PV and wave etc used in the AEMO 100 per cent renewable dispatch process in previous chapters essentially assume a ‘perfect forecasting’ approach. That is to say they will account for the influence and cost of renewable resource variability, but not the operational timeframe forecast uncertainty. It is difficult to precisely estimate the true cost impacts of forecast uncertainty without a very detailed and technically-advanced study of the calibre as presented for the Irish All-Island power system in [Meibom], however there will likely be some costs. The same would apply to the precise impacts of forecast uncertainty on power system reliability. [Meibom] applied a state of the art wind power forecast error scenario tree development process, stochastically optimised unit commitment and economic dispatch combined with dynamically updated ‘rolling planning’ techniques. The type of model derived in [Meibom] is useful in another regard too – the cost differential between the assumption of perfect forecasting and that value given by the very best stochastic scheduling approach can be implicitly understood as the maximum economic benefit which additional weather forecasting research and development can bring to the system operation. In any case, [Meibom] calculated the cost-underestimation of a perfect forecast assumption to be in the order of one or two per cent of annual energy costs in a scenario where approximately one third of the annual energy was supplied from semi-scheduled generation sources. It is difficult to transfer such quantitative findings from one power system to another. Based on a qualitative understanding of how the 100 per cent renewable generation dispatch portfolio would operate, then the following operation costs have been estimated for the various 100 per cent renewable scenarios.

Table 26: Estimated annual energy cost increases due to operational timeframe forecast uncertainty

	Scenario 1 2030 (%)	Scenario 1 2050 (%)	Scenario 2 2030 (%)	Scenario 2 2050 (%)
Variable generation penetration*	35	37	57	51
Wind generation penetration	8	6	42	25
Extra operating costs assumed	0.5	0.5	1.5	1.0

* includes rooftop PV

On the basis of the above arguments, it is likely that the operational time frame variability and uncertainty characteristics of the combined 100 per cent renewable generation portfolio should not provide an insurmountable challenge to balancing customer load demand. There are of course some caveats to this preliminary conclusion. Significant operational experience of CST plants applied for ramping response en masse over an extended period of time does not yet exist. Furthermore, most of the analysis has been completed with hourly resolution of wind, PV and wave data – sub-hourly ramps may be more or less extreme than this for shorter periods of time. Also, some level of operational uncertainty will always exist due to inherent chaos in numerical weather forecasting systems. However, with the application of state of the art wind and solar power forecasting tools, as well as effective decision making processes could prevent any major impacts on 100 per cent renewable system economics or reliability.

Generation reliability contribution – (capacity value)

The contribution of generation to customer supply reliability is a very important power system operational concern, especially given the large penetration of semi-scheduled PV, wind and wave generators in some of the 100 per cent renewable portfolios. Assessment of this generation reliability contribution or 'capacity value' is very much a statistical issue, with 'tail-risk' events primarily driving the unreliability instances in modern power systems. Traditionally, the reliability contribution of NEM generators was considered with regard to the 10%POE regional demand conditions on very hot days, with the possibility of independent outages in each generator separately contributing to an overall loss of supply. Behaviour of the fully scheduled 100 per cent renewable sources such as biomass and geothermal should be mostly consistent with such previously observed characteristics of conventional generators, and reliability contribution of NEM hydro resources has been long understood. In contrast, generation contribution from multiple spatially distributed variable renewable energy sources, with energy inputs that are based on common underlying weather vectors is a more complex topic. High wind speed and wave incidence are likely to be interdependent for example, while wind speed could be somewhat lower on the very hot days which customer demand and PV peak etc. The results and discussion of previous sections would suggest that the typical instance at which peak NEM net demand (natural demand minus rooftop PV) occurs in the 100 per cent renewable scenarios may change compared to the present day situation, both in terms of the season of the year, and also the typical time of day. Furthermore the significant reliance on chronologically dependent or energy-limited storage (both hydro and solar CST), and demand side management, to meet residual peak demand would constitute an important change to the current reliability status-quo as well. Modifications to the present understanding of NEM reliability may be required in a 100 per cent renewable situation therefore.

The partial overlap of generation availability from variable renewable sources with peak/shoulder demand instances has received significant attention in recent times from both international sources [Amelin, IEEE_CV_WG, Kavanagh, Sinden, Mackay] and here in the NEM itself [AEMO_Wind_CV]. With very high renewable energy penetrations, the present state-of-the-art thinking would tend to suggest a movement away from defining reliability with respect to availability at times of absolute peak demand to consideration more of a long-run reliability contribution. Generator 'effective-load-carrying-capability' (ELCC) may thus be the most refined metric to capture the complexities of system-total renewable energy contribution to demand reliability [IEEE_CV_WG]. The frequency and duration of unreliability instances, or the number of instances which interruptible load is actually called upon, may have an effect on the economic value of lost load (VOLL) or interruptible load contract cost [Billinton]. Chronological ELCC analyses may be best suited to such assessments.

Assessing resource availability from many variable renewable sources at different geographical locations, and the interdependence of such patterns with overall electricity demand trends, is a complex non-parametric multivariate statistical dependency problem, requiring advanced techniques [Papaefthymiou_2]. Time synchronised historical recorded data has the benefit of inherently containing any such complicated statistical dependencies [Boehme], but assessing the reliability contribution of the 100 per cent renewable sources may be limited by any lack of significant historical NEM observations (high-frequency actual recorded power output data rather than meso-scale model estimated data) upon which to base a statistical analysis. For such a reason, a bootstrapping analysis was proposed by [Hasche] to estimate the convergence properties of wind power capacity value with respect to quality of data available. Other approaches propose use of time series synthesis techniques to artificially grow an arbitrary length of statistical samples by fitting a statistical model to observed data [Lojowska, Klockl] – the degree of model precision required to correctly estimate the relatively uncommon or 'tail-risk' occurrence of system unreliability events is always a concern however with such analytical approaches. All approaches will unavoidably suffer from any ambiguity around longer term climate trend uncertainties that are obscured from very recent data records [Pryor].

In any case, regardless of any statistical model robustness concerns, one well established trend observed from variable renewable energy capacity value analyses is the decrease in marginal capacity value with respect to increasing capacity installed [IEEE_CV_WG]. The degree of which spatial smoothing influences the system reliability is also important to consider – the more geographically separated the variable renewable energy sources are, the generally less correlated they will be [Ackermann], and thus the greater the overall system total capacity value contribution. The physical size of the NEM power system should be a very positive influence in this regard. Transmission constraints on renewable energy [Burke_2] sources may be important to consider also.

With increasing installation of renewable energy sources in the NEM, analysis of their actual operating pattern data will allow in due course a much better understanding of reliability contribution effects.

Summary and transitional comments

This section has considered some of the likely system operational challenges that could result from the NEM 100 per cent renewable generation scenarios presented earlier, and any practical or economic limitations they could place on 100 per cent renewable NEM operability. The issues have been addressed in a high level manner, with corroborating references and evidence given to support the views where possible. The exact nature of operational constraints affecting a NEM with ultra-high instantaneous penetrations of non-synchronous generation might only be fully determinable with detailed technical investigations that are beyond the scope of this project. There are of course likely to be significant technical challenges associated with transitioning to a 100 per cent renewable future scenario. There are also likely to be some modelling and design challenges, such as the requirement to consider much greater transmission power flow diversity from stochastic sources, three-phase versus positive-sequence modelling for power electronics devices, consideration of macro-economic impacts associated with large scale demand side participation etc. These are likely to be mainly process refinement issues rather than insurmountable unknowns though.

It must also be acknowledged that there are technical limits within which the present conventional plant based NEM system has been designed. For example, the NEM is not presently designed to be guaranteed transient-stable for a 3-phase fault disturbance on the EHV system in a scenario with large-scale inter-regional power transfers - only a double line to ground fault at this voltage level is supposed to be within 'credible-event' tolerances [NER]. In that context it might be said that while the system operational challenges in a 100 per cent renewable scenario might come from a different underlying technical source (i.e. frequency stability or flexibility constraints), a higher or more exacting level of robustness should not be sought than exists at present. The pragmatic understanding of risk versus investment-economics in power system design and operation should be maintained in continuation of that which is presently accepted for the conventional generation system.

Many issues remain to be determined without doubt, but it is valuable to note that this operational review has uncovered no fundamental limits to 100 per cent renewable that can definitely be foreseen at this time. In any case, operational constraints can usually be overcome with some economic cost implications, and further refinement of the 100 per cent renewable generation portfolio compositions or geographical locations could be applied to overcome any particularly onerous issues. It is equally important to note that any transition to a very high renewable energy NEM would most likely occur dynamically over time, allowing proper scope for learning and evolution with additional experience gained. At present levels of NEM renewable energy integration, the prevailing approach might be summarised as a "do no harm" philosophy for renewables. A point in any transition to 100 per cent renewable at some stage in the future would surely be reached following which the renewables plants would likely transition from 'passive' to 'active' grid interaction behaviour, taking on responsibility for more and more system-support ancillary services. International collaboration and learning through technical organisations such as IEEE, IET, UWIG and CIGRE will be helpful too.

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Appendix 7 - Summary of literature review

CSIRO reviewed 23 studies examining costs and feasibility of high penetration renewable electricity generation into electricity grids. The review focused on Australian studies or studies of other electricity systems of a similar size to the National Electricity Market (NEM).

The review found that analysis of 100 per cent (or near 100 per cent) renewable electricity systems is a recent development with most studies being published in the last two years. Target dates for developing such systems vary widely (from 2020 to 2100) and considerable variation exists in the approach, models used and the temporal and spatial resolution of the analysis.

The majority of studies considered changes in the level or shape of electricity demand over time, but generally did not conduct power flow analyses of the renewable electricity system. Many of the studies did not estimate the cost of a renewable electricity system. A minority of studies conducted extensive sensitivity analysis of a 100 per cent renewable electricity system.

MEETING DEMAND

The majority of studies found that there are sufficient renewable resources in terms of theoretical potential to achieve a 100 per cent renewable electricity system.

In considering whether renewable supply could service peak demand, most studies concluded that the challenges presented are generally regarded as not insurmountable, and energy storage is key to managing supply and demand.

Elliston et al. (2012), for example, find that as a 100 per cent renewable electricity system is approached, maintaining supply and demand equilibrium becomes more problematic, and when variable sources of renewable power are not available during high demand periods, a large capacity of peaking plant is required to meet demand, equating to a high system cost.

COSTS AND CHALLENGES

Most studies did not estimate the cost of a high penetration renewable electricity system, with many focussing more specifically on technical feasibility. The subset of studies that do investigate costs provide estimates of either the total cost of transformation, or the impact on electricity prices to end-users.

Seligman (2010) estimated a total cost of $317 billion for a 100 per cent electricity system for Australia by around 2035. The bulk of this cost was for renewable electricity generation (wind, solar and geothermal), followed by storage and high voltage direct current (HVDC) transmission lines. Seligman notes that the main cost increase from a 90 per cent renewable electricity system (costed at $254 billion) was the increased storage required.

Australian study, Beyond Zero Emissions (2010) notes that although the upfront investment costs of their proposed 100 per cent renewable electricity system by 2020 are significant ($370 billion), they posit that over a longer timeframe (out to 2040) their proposed transition would be similar to a business as usual scenario, mainly due to avoided spending on fossil fuel in later years.

Besides costs, the literature recognises a number of other challenges to achieving high penetration of renewables. The high investment rates and capacity additions required may pose challenges for supply chains, manufacturing facilities, skilled labour or materials availability. Also, the process of developing and siting renewable energy facilities and associated transmission infrastructure may face social, environmental, and institutional constraints that would need to be overcome.

ELECTRIC VEHICLES

Numerous studies considered the impact of electric vehicles on increasing electricity demand, including the additional demand created, the mobile nature of the demand, and how battery charging might add to peak demand.

Very few modelled the potential benefits of vehicle to grid (V2G) capability. They could potentially support distribution networks at times of peak demand, and charging time could be linked to times of high renewable generation during periods of otherwise low demand. In general, V2G could provide load-management services such as peak-power supply, spinning reserves, or power regulation.

One of the studies (NREL, 2012) that opted not to include V2G cited 'uncertainty in the ultimate acceptance among equipment manufacturers, network service providers, and consumers of V2G' as the rationale.

The full report is available at http://www.climatechange.gov.au/en/government/initiatives/aemo-100-per-cent-renewables/~/media/government/initiatives/aemo/CSIRO-literature-review.pdf.

List of measures and abbreviations

7.7 Units of measure

Abbreviation	Unit of measure
GWh	Gigawatt hours
Hz	Hertz
MW	Megawatts
MWh	Megawatt hours
TWh	Terawatt hours
Twh/yr	Terawatt hours per year
$	Australian dollars
$/kWh	Australian dollars per kilowatt hour
$/MWh	Australian dollars per megawatt hour
$/MW/year	Australian dollars per megawatt per year

7.8 Abbreviations

Abbreviation	Expanded name
AC	Alternating current
AEMO	Australian Energy Market Operator
AETA 2012	2012 Australian Energy Technology Assessment
APR	Annual Planning Report
BREE	Australian Government Bureau of Resources and Energy Economics
CPI	Consumer price index
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CST	Concentrating Solar Thermal
DSP	Demand-side participation
DCCEE	Department of Climate Change and Energy Efficiency
EGS	Enhanced Geothermal Systems (also known as hot rocks
EVs	Electric Vehicles
GALLM	Global and Local Learning Model
HSA	Hot Sedimentary Aquifers (based geothermal generation)
HVDC	High voltage direct current
MSW	Municipal solid waste (a form of bioenergy)
NEM	National Electricity Market
NEFR	National Electricity Forecasting Report
NTNDP	National Transmission Network Development Plan
OCGT	Open-cycle gas turbine
POE	Probability of exceedence
PV	Photovoltaic
RET	Department of Energy, Resources and Tourism
USE	Unserved energy
WTG	Wind turbine generator