Energy Policy 98 (2016) 298–308

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Research and deployment priorities for renewable technologies: Quantifying the importance of various renewable technologies for low cost, high renewable electricity systems in an Australian case study

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HIGHLIGHTS

- Photovoltaics saturate early, suggesting they need complementary measures.
- Biofuelled gas turbines or another peaking technology are important for low costs.
- Limits on the non-synchronous penetration are relatively expensive.

ARTICLE INFO

Article history:
Received 23 May 2016
Received in revised form
25 August 2016
Accepted 27 August 2016
Available online 10 September 2016

Keywords:
Renewable energy
Evolutionary program
Research priorities
Australian National Electricity Market
Portfolio optimisation

ABSTRACT

This study aims to identify research priorities to enable low cost, high renewable power systems. An evolutionary program optimises the mix of technologies in 100% renewable energy portfolios (RE) in the Australian National Electricity Market. Various technologies are reduced in availability to determine their relative importance for achieving low costs. The single most important factor is found to be the integration of large quantities of wind; therefore wind integration is identified as a research priority. In contrast, photovoltaics are found to “saturate” the system at less than 10% of total energy (in the absence of storage or demand management, installation of further photovoltaics does not contribute significant further value). This indicates that policies to promote utility-scale photovoltaics should be considered in partnership with complementary measures (such as demand side participation and storage). Biofuelled gas turbines are found to be important; a complete absence of bioenergy increases costs by AU$20–30/MWh, and even having only 0.1 TWh per year of bioenergy available reduces average costs by AU$3–4/MWh. Limits on the non-synchronous penetration (NSP) are found to be relatively expensive, suggesting a significant research priority around finding alternative approaches to providing synchronous services, such as inertia. Geothermal and concentrating solar thermal technologies do not appear essential as long as sufficient wind and peaking bioenergy is available.

1. Introduction

With the majority of new investment in power generation now being in renewable technologies, future electricity industries with a high proportion of renewable generation appear likely. For example, in 2014, renewables represented more than half (approximately 59%) of net additions to global power capacity (REN21, 2015). By the end of 2014, renewables comprised enough to supply an estimated 22.8% of global electricity (REN21, 2015). Research institutions and funding bodies around the world are now investing in research to enable larger quantities of renewable generation in power systems, suggesting that guidance as to the most effective relative priorities for investment in different technologies and enabling solutions would be valuable.

Some jurisdictions, such as New Zealand (Mason et al., 2010), Norway (Christiansen, 2002) and Brazil (Geller et al., 2004), are already close to 100% RE due to their development of conventional renewable resources such as hydro and conventional geothermal. Other jurisdictions where these technologies are not available at sufficient scale may find it more challenging to approach 100% RE. For example, modelling (Elliston et al., 2013, 2014) suggests that the lowest cost 100% RE portfolios in Australia might source 50–60% of energy from wind, and an additional 15–20% of energy from photovoltaics (PV). Wind and PV have a number of characteristics

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http://dx.doi.org/10.1016/j.enpol.2016.08.034
0301-4215/

that make them different from conventional generation technologies, including being highly variable and somewhat uncertain in availability, non-synchronous (meaning that they do not contribute system inertia, which is important for maintaining frequency stability), capital intensive (with high capital costs and low operating costs), and utilising renewable energy resources that are often located far from the existing transmission grid (Riesz and Milligan, 2014). Existing electricity system operational practices and electricity markets were not designed with these characteristics in mind, meaning that changes are likely to be required in a range of ways to efficiently integrate these new technologies as their penetration grows (Riesz and Milligan, 2014; Smith et al., 2007).

Despite these challenges, a growing number of modelling studies suggest that very high renewable systems (including 100% renewable systems) are technically viable in Australia (Elliston et al., 2013, 2014, 2012; Riesz et al., 2015a; AEMO, 2013; Vithayashrichareon et al., 2015; Wright and Hearps, 2010, 2016; Lenzen et al., 2016), and in other jurisdictions such as the USA (Hand et al., 2012), Ireland (Connolly et al., 2011), New Zealand (Mason et al., 2010), Portugal (Kraja et al., 2011), The Republic of Macedonia (Ćosić et al., 2012), Denmark (Lund and Mathiesen, 2009), Europe (Rassmussen et al., 2012), Northern Europe (Sørensen, 2008) and globally (Sørensen and Meibom, 2000; Mathiesen et al., 2011; Jacobson and Delucchi, 2011; Delucchi and Jacobson, 2011). Whilst all these studies involve significant assumptions and limitations, they do suggest that scenarios of 100% RE are likely to be feasible and reasonably cost effective based upon future cost estimates for key RE technologies.

The Australian NEM provides a useful case study for analysis of high renewable energy (RE) scenarios. The NEM serves approximately 80% of the electrical load in Australia (AEMO, 2014) over a wide range of distinct climate zones. As a relatively large but isolated system (without transmission connections to other grids), the NEM must manage the variability, uncertainty and other challenges associated with integrating highly variable and only somewhat predictable renewable technologies by itself. Australia has significant renewable resources in wind, solar, wave and potentially geothermal technologies, and therefore is well placed to achieve high renewable penetrations without utilisation of more conventional renewable technologies such as hydro. This makes it an interesting case study for analysis of novel high renewable systems.

There remains significant uncertainty around the availability, performance and future costs of some renewable technologies that are frequently used in studies on high renewable systems. For example, many modelled high renewable systems rely upon the firm, dispatchable and synchronous properties of geothermal technology, but the potential availability of geothermal technologies is uncertain in many jurisdictions. In Australia, it is questionable whether geothermal technologies will achieve commercial viability in the coming decades (ARENA, 2014). Australia does not have access to high temperature conventional (ie. hydrothermal) geothermal resources, but there are two possible geothermal resources that may eventually become available: Hot Sedimentary Aquifer (HSA), and Engineered Geothermal Systems (EGS) (Bureau of Resources and Energy Economics, 2012). HSA systems are characterised by hydrothermal groundwater resources in a sedimentary basin, while EGS involves extracting the earth's heat from rocks with no pre-existing high permeability. HSA systems are relatively less expensive, but the number of sufficiently shallow systems with the right characteristics remains relatively unknown. Neither type of geothermal technology has yet been deployed commercially, and there is significant uncertainty around the potential for eventual deployment. The impact of geothermal availability upon the costs of high renewable systems has not yet been explored, which makes it challenging to estimate how much funding should be targeted towards bringing these technologies to commerciality.

There is also uncertainty around the degree to which the utilisation of bioenergy technologies may be limited due to competition with food production, and other uses of land and water resources. In 2011–12, Australia sourced 2.3 TWh of electricity from bioenergy sources, representing 0.9% of total electricity generation, with 50% of the installed bioenergy generating capacity being fuelled by bagasse (Geoscience Australia and the Bureau of Resources and Energy Economics, 2014). Landfill and sewage biogas plants also contribute a significant proportion of bioenergy in Australia at present. It has been projected that this could be expanded significantly by accessing a wider range of bioenergy sources, including agricultural-related wastes, energy crops, woody weeds, forest residues, pulp and paper mills wastes and a wider range of urban wastes (Clean) Energy Council, 2008). However, it remains unclear to what degree these waste streams can be economically accessed, and to what degree energy crops may compete with other uses (Geoscience Australia and the Bureau of Resources and Energy Economics, 2014). Many high renewable scenarios in Australia rely upon the availability of bioenergy resources for peaking generation, and if these resources are constrained more severely than anticipated, the system cost impacts could be considerable. This has not yet been quantified.

Similarly, significant cost reductions are typically assumed for concentrating solar thermal (CST) technologies, which may not eventuate. CST is a demonstrated technology, with utility-scale plants operating, and nearly 4.8 GW installed internationally (Wright and Hearps, 2010; REN21, 2016). However, the technology remains at an early stage of deployment, meaning there is likely to be significant potential for cost reductions, as deployment grows. The widely used Australian Energy Technology Assessment projects solar thermal plant using central receiver technology with storage falling in cost from an average of AU$8308/kW in 2012 to around AU$4500/kW in 2030 (Bureau of Resources and Energy Economics, 2013). If these cost reductions do not occur as projected, this technology may remain prohibitively expensive, and may not be a viable component of future high renewable systems. The impacts of this cost uncertainty upon future high renewable systems has not yet been investigated.

There are also significant questions around the potential for integrating large quantities of wind and photovoltaics. Although these technologies are widely available for commercial deployment, their non-synchronous nature and highly variable and somewhat uncertain generation creates challenges for system integration. There are questions around what proportion of energy can be realistically and cost effectively sourced from these variable, non-synchronous sources. The cost impacts of potential constraints on non-synchronous penetrations has not yet been explored, which means there is a lack of robust evidence on which to assess how much funding should be dedicated to enabling more efficient system integration of these technologies.

This study aims to explore the potential impact that various limitations on technology availability may have upon 100% RE NEM scenario costs. In particular, are there particular RE technologies which really need to succeed in achieving major deployment to achieve low-cost high renewable penetrations? Also, are there particular technologies which have key roles to play, even at small penetration levels? We seek to answer these questions using an evolutionary algorithm to optimise generating portfolios with time sequential, hourly representation of wind and solar generation. Various technologies are progressively removed from the portfolio mix to examine the impact upon portfolio costs. The intent is that such modelling work can assist key electricity industry stakeholders (particularly policy makers, but also industry and the community) in establishing research, commercialisation and deployment priorities for RE and the electricity industry more generally.

Section 2 outlines the methodology and data implemented in the modelling, with the results and discussion outlined in Section 3. Section 4 summarises the conclusions and policy implications of the work.

2. Methodology and data

2.1. The NEMO model

The scenarios described in this paper are simulated using NEMO (National Electricity Market Optimiser), an open source software package developed by one of the authors and previously described in detail (Elliston et al., 2012). This software package applies evolutionary computation to optimise the mix of generating technologies to meet hourly demand profiles over a year or more, to the required reliability standard, at lowest overall industry cost. The model uses an evolutionary algorithm known as the Covariance Matrix Adaptation Evolution Strategy (CMA-ES) to vary the generating capacity of each generator in the system, and ensure that various constraints are met. This strategy emulates the evolutionary process of breeding and mutation over a number of generations to find the fittest individuals according to objective criteria. CMA-ES is a powerful way of searching very large problem spaces by evaluating only a small number of the total possibilities (Goldberg, 1989). In this model, the installed capacities of each generator type are the key variables varied between each generation, and the objective function calculates a projected annualised cost of meeting the demand in the NEM, over the full year. Further details are provided in references (Elliston et al., 2013, 2014, 2012).

2.2. Modelling assumptions

The technologies listed in Table 1 were included. The capital and operating costs of each technology were based upon those projected for 2030 by the Australian Government's Bureau of Resources and Energy Economics in the 2013 Australian Energy Technology Assessment (Bureau of Resources and Energy Economics, 2013). A discount rate of 5% has been applied throughout.

Hourly wind and solar generation traces across 43 locations (“polygons”, as illustrated in Fig. 1) were applied, sourced from modelling by the Australian Electricity Market Operator (AEMO) (AEMO, 2013) for its own 100% RE study in 2013. These were based upon solar and wind’s historical temporal and geographical variability observed in the year 2010. Hourly demand traces from the same year were applied to ensure consistency between weather and electrical demand. Geographical smoothing was modelled by including multiple wind and solar generation traces from different geographic locations with high wind and solar resources, which the model could select from to optimise the share of electricity from each technology. For wind, polygons 1, 20, 24, 38b and 42 were selected from the AEMO dataset (AEMO, 2013), as illustrated in Fig. 1, on the basis of their high quality wind resources. For central receiver CST, polygons 14, 20 and 21 were applied, on the basis of their high quality solar resources. For single-axis tracking photovoltaics, polygons 13, 14, 21 and 37 were applied.

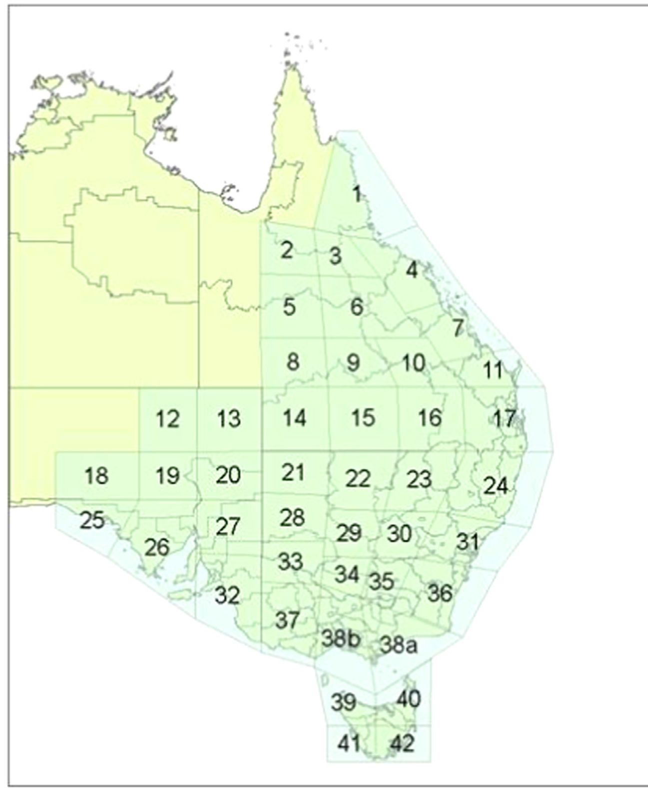

Fig. 1. Polygons used for geographical characterisation of wind and solar resources in the AEMO dataset. (AEMO, 2013).

The following constraints were applied in the model in all scenarios:

1. Total annual hydroelectric generation was limited to historical levels at 12 TWh per year (AEMO, 2013).
2. Total annual bioenergy generation was limited to 20 TWh per year (except where otherwise specified to be a lower limit).
3. A maximum instantaneous non-synchronous penetration limit of 85% was applied (except where specified) (AEMO, 2013)
4. The present NEM reliability standard (0.002% annual unserved energy) was met in all cases.

Table 1
Technologies included in the model, with costs and parameters assumed, based upon mid-point estimates listed in (Bureau of Resources and Energy Economics, 2013) for 2030 (2012 dollars).

	Capital cost (AU$/kW)	Fixed O&M (AU$/kW/year)	Variable O&M (AU$/MWh)
Hot Sedimentary Aquifer (HSA) geothermal	7233	234	0
Enhanced Geothermal Systems (EGS)	11,071	199	0
Concentrating Solar Thermal (CST), central receiver with 6hrs of thermal storage	4728	83	7
Utility scale photovoltaics (PV), 1 axis tracking	2277	29	0
Wind generation (on-shore)	1836	38	12
Hydro (existing only)	0	0	0
Pumped storage hydro (PSH) (existing only)	0	0	0
Gas turbines (GT) fuelled with biomass derived fuel	751	5	151

Technologies were dispatched in merit order in each hour period, based upon variable costs sourced from the AETA (Bureau of Resources and Energy Economics, 2013). The merit order is: geothermal, PV, wind, pumped hydro storage, hydro, CST, and finally, biogas turbines. Hour by hour dispatch patterns resulting from the model, including representation of the "most challenging week" have been extensively included in previous publications (Elliston et al., 2012).

2.2.1. Concentrating solar thermal with storage

CST plant was assumed to be a central receiver system (100 MW power block, solar multiple of 2.5, with 6 h of thermal storage), with parameters and costs sourced from the AETA (Bureau of Resources and Energy Economics, 2013). Hourly electrical power generation traces based upon historical weather patterns were sourced from the AEMO 100% renewables study (AEMO, 2013).

CST storage is managed opportunistically. CST is dispatched in the merit order as outlined above (after all other technologies except the biogas turbines), if there is sufficient solar resource, or stored energy in the thermal reservoir. Electrical energy is diverted from the power block into the thermal storage when generation exceeds dispatch. After sunset, the plant may operate for a number of hours until the storage is depleted.

2.3. Modelling system non-synchronous penetration limits

Non-synchronous technologies such as wind and photovoltaics do not contribute significant rotational inertia to the power system. When the system has insufficient inertia, frequency control and handling of fault conditions becomes more difficult. The rate of change of frequency during a transient condition may be unacceptably fast and the frequency nadir may trigger load shedding before primary response from synchronised generators can inject energy into the system. For this reason, many previous modelling exercises of very high RE systems have included a limit on the amount of non-synchronous generation, applied in each period (Riesz et al., 2015a; AEMO, 2013; Vithayashrichareon et al., 2015).

The appropriate choice of non-synchronous penetration (NSP) limit is still uncertain and system specific, depending on the generator portfolio, power quality requirements, the choice of AC versus DC interconnection, and interconnection with other networks. In Ireland, the national system operator, Eirgrid, maintains a 50% NSP limit due to its reasonably isolated interconnected grid, but believes that a 75% NSP limit is achievable in the future (Eirgrid, 2011). In this work, an NSP limit of 85% is applied in most cases, following previous modelling by AEMO (AEMO, 2013). NSP limits as low as 50% are also modelled, to allow comparison of the situation where these ambitious NSP limits are not achieved in future. The simulation begins dispatching generators out of merit order once the total non-synchronous generation reaches 85% of instantaneous demand, spilling wind and PV generation.

2.4. Modelling limitations

2.4.1. Technology costs

The outcomes presented in this paper depend heavily upon the technology costs assumed for this analysis (as outlined in Table 1). If these costs change significantly, the results of this analysis could also change. Technology costs have changed rapidly and unexpectedly in the past; for example, photovoltaics costs have fallen rapidly in the past decade (REN21, 2016). Further such reductions in the cost of photovoltaics could mean that a larger proportion of photovoltaics is included in the least cost scenarios (for example).

2.4.2. Transmission

The modelling does not incorporate the additional transmission costs that may be involved in connecting remote renewable resources. However, transmission costs for the NEM in scenarios with 100% renewable energy have been broadly estimated in previous studies, and were found to typically constitute no more than 10% of total system costs (Elliston et al., 2013; AEMO, 2013). For example, previous modelling in NEMO costed transmission augmentation based upon an estimate of average \$/MW/km for transmission, and the distances and maximum flows calculated between the five NEM regions. This provided a high level estimate of the cost of the additional transmission required in the NEM of \$8–11/MWh (with a 5% discount rate), to support 100% renewable scenarios (Elliston et al., 2013). For comparison, AEMO's 2013 study included a more bespoke analysis of transmission requirements to support a 100% renewable portfolio. This study included transmission upgrades within regions (as well as between regions), although it remains high level. This analysis estimated total transmission costs in the range \$6–10/MWh (AEMO, 2013). These independent studies are broadly aligned, and indicate transmission costs in the range of 10% of the total scenario costs. While these studies use a very simplistic and high level representation of the necessary network augmentations, and significant further research in this area is required, these indicative estimates fall within the uncertainty of the capital costs for the generating portfolio.

2.4.3. Operational considerations beyond NSP constraints

The modelling does not include detailed operational considerations beyond the maximum NSP constraint such as ramp rate limitations, minimum load constraints and start-up costs. However, previous work has suggested that these constraints do not contribute significantly to system costs, by comparison with the influence of the maximum NSP constraint (Vithayasrichareon et al., 2014).

2.4.4. Electricity markets

The modelling also does not explicitly consider the operation of the electricity market. Generator revenues and profitability have not been analysed. Previous work has indicated that the NEM's energy-only market may continue to operate successfully with very high renewable systems, but this requires further research (Riesz and Milligan, 2014; Riesz et al., 2016, 2014). The detailed operation of market ancillary services, such as frequency control, has not been explicitly modelled, although other work suggests that present arrangements may also still be suitable at high RE penetrations (Riesz et al., 2015b).

2.4.5. Demand profile

This modelling applies the hourly demand profile observed in the NEM in 2010. This demand profile has not been modified to represent possible future demand profiles that may apply. Although demand growth in the NEM has plateaued in recent years (AEMO, 2015), patterns of demand are likely to change in ways that remain unclear at present. These effects have not been captured in this modelling. If demand grows to much higher levels, this may deplete the availability of the highest quality renewable resource sites. Changing patterns of demand growth may affect the role of peaking plant, such as biogas turbines and hydro, discussed in this paper.

2.4.6. Storage and demand side participation

Electricity storage technologies and demand side participation were not included in this modelling, aside from a small amount of existing pumped storage hydro generation. The inclusion of cost effective storage and demand side participation should favour greater inclusion of variable renewables such as wind and photovoltaics.

2.4.7. Hydro dispatch

Calculating the optimal dispatch of energy-limited plant (such as hydro) requires complex decision making and a range of assumptions about operator behaviour, risk preferences and forecasting abilities. In this model, hydro generation (including pumped storage hydro) is included with no capital cost (since it is existing plant), and is dispatched in the merit order after all technologies except bioenergy (dispatched last). This means that the model underestimates the degree to which hydro generation operators may be able to apply more sophisticated strategies to optimise hydro dispatch, and potentially reduce system costs below those reported here. However, given the relatively small amount of hydro generation in the NEM (5 GW total capacity, supplying a maximum of 12 TWh per year), this is likely to be a relatively unimportant limitation of the model.

3. Results and discussion

Fig. 2 illustrates the lowest cost optimised generating mix for various combinations of technology availability modelled in NEMO. All combinations tested meet the required demand in each hour in the historical 2010 demand year used, at the NEM's reliability standard of no more than 0.002% unserved energy. This suggests significant robustness in being able to achieve 100%

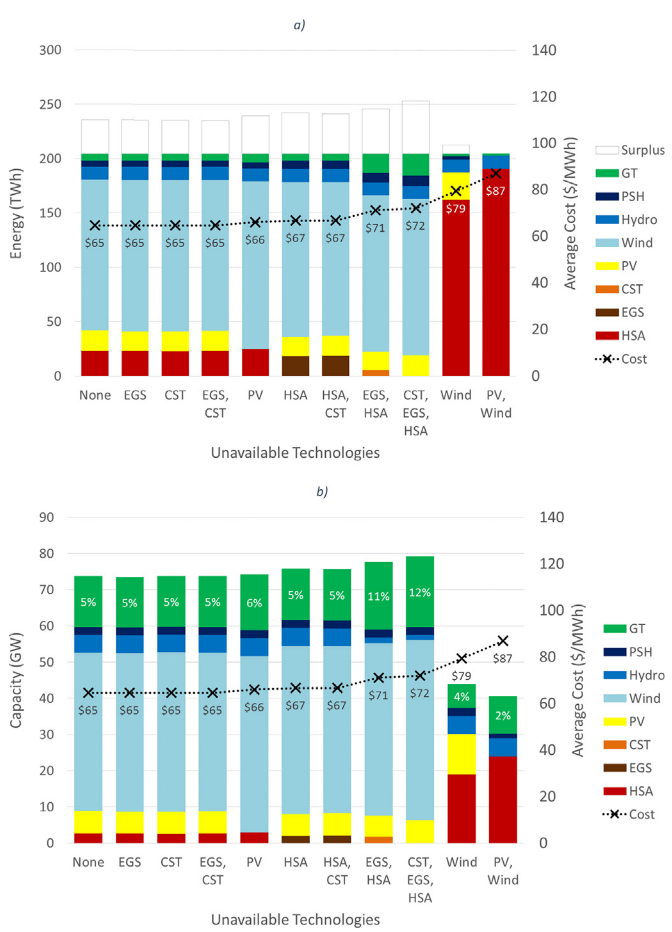

Fig. 2. Optimised portfolios and average system costs with various technology availability combinations, illustrating (a) energy provided and (b) capacity installed of each technology included in the lowest cost portfolio. Percentages show capacity factors for bioenergy turbines.

renewable generation, even if various combinations of technology prove to be not viable for significant deployment. Average wholesale generation system costs in the scenarios considered are found to range from AU$65/MWh (with all modelled technologies available) to AU$87/MWh (with wind and photovoltaics excluded).[1]

3.1. Lowest cost 100% RE system

The lowest cost 100% RE system provides wholesale generation at an average cost of AU$65/MWh. This portfolio sources the majority of energy (68%) from wind, with 44 GW installed. In addition, 11% of energy is sourced from Hot Sedimentary Aquifer (HSA) geothermal, 9% from photovoltaics (with 6 GW installed), 6% from existing hydro generation, 3% from existing pumped storage hydro (powered only by surplus generation from variable renewables) and 3% from gas turbines fuelled with bioenergy. 15% of energy generated over the year is surplus to demand, providing a potential opportunity for additional energy storage and demand-side participation. Concentrating solar thermal and EGS geothermal are not included in this lowest cost system, since HSA geothermal provides a lower cost alternative with a similar operating profile. The 2.7 GW of HSA geothermal plant installed operate at a very high capacity factor of 98% (reflecting the projected high capital cost yet low operating cost of this technology), while the 14 GW of biogas turbines installed operate at a very low capacity factor of 5% (reflecting the low capital cost and high operating cost of this technology). These findings are broadly consistent with the findings of previous studies, taking into account the varying input assumptions applied for each study (Elliston et al., 2013, 2014, 2012; AEMO, 2013; Wright and Hearps, 2010).

3.2. Wind generation

This study finds that large quantities of wind generation are the most effective way to lower system wholesale generation costs. Wind generation provides around 70% of the energy in the lowest cost scenarios in every scenario where it is available, operating at aggregate delivered capacity factors ranging from 22% to 37%. The lowest wind capacity factors achieved are associated with scenarios with severe bioenergy constraints, combined with no geothermal technology availability, meaning that the model finds it lowest cost to meet the required reliability standard by installing a large capacity of wind generation (70–80 GW), and allowing significant spilling of excess wind energy.

Wind generation is important because it can cost effectively provide a large proportion of the annual energy required in the NEM. This is partly because it is the least expensive form of renewable generation, and is projected to remain so for the coming decades. Importantly, the model also finds that wind generation in Australia varies sufficiently between the different "polygons" modelled (as illustrated in Fig. 1). This means that the geographical and chronological diversity between the wind generation in the various polygons allows solutions to be found which cost effectively meet the majority of demand (with the remainder being met by peaking generation, and other firm sources, in the rare periods when little wind is available across the system). This is clearly illustrated in the modelled scenarios, for example, by the provision of 70% of annual energy from wind generation, with a surplus of spilled generation of only 15%.

These combined factors mean that a portfolio of wind distributed around the NEM is found to provide an efficient way of

[1] All dollar values within this paper are quoted in Australian dollars. At the time of writing (March 2016), 1 AUD = 0.7 USD.

supplying large quantities of bulk low cost energy in the majority of time periods.

System costs are found to vary by only up to 10% in cases where wind generation is available, indicating that the availability of other technologies (such as the two types of geothermal power, concentrating solar thermal and photovoltaics) are of relatively lower importance than the availability of large amounts of wind. However, if it were not possible to install such large quantities of wind generation (for example, because of local community opposition, or grid integration challenges), system costs were found to escalate by20–30%. Systems that do not have wind generation are found to be AU$3 billion per year more expensive (a 23% increase in total system cost), while systems that do not have either wind or photovoltaics are found to be AU$4.5 billion per year more expensive than the lowest cost system (with all technologies available), a 34% increase in total system cost.

These results suggest that research and policy mechanisms that promote significant wind deployment and research that addresses barriers to wind integration could be of high value for transition to a 100% renewable NEM. For example, this may include investment in integration studies that explore the most efficient approaches for managing displacement of synchronous generation, reducing system inertia, frequency management, skilful forecasting and other ancillary services in high wind systems. Some power systems (such as Ireland) have implemented maximum non-synchronous penetration limits to maintain system security under high wind conditions (Eirgrid, 2011); modelling indicates that this may be a relatively high cost approach (Vithayasrichareon et al., 2014), with lower cost alternatives available. Other barriers to wind integration may include the system rules around grid connection of wind (including the detailed grid code that dictates connection requirements), and the manner in which investment in new transmission network is negotiated and funded.

Another important priority might be to better understand and hence effectively address public concerns regarding wind development. Some jurisdictions have encountered objection in rural areas on the basis of visual amenity disruption and almost certainly spurious health concerns (Chrichton et al., 2014; Chapman et al., 2014). Investment in developing community support to address these issues may be warranted, in jurisdictions where this poses a tangible barrier to wind deployment.

As illustrated in Fig. 2b), a significantly lower total system capacity is installed in the no-wind scenarios (40–44 GW, compared with 74 GW in the lowest cost system). This is because the geothermal technologies (providing the majority of the energy in these scenarios without wind) operate at high capacity factors, and are fully dispatchable, and therefore provide the energy required with a smaller installed capacity (compared with wind). However, total system costs are significantly higher due to the absence of the low-cost wind technology, and the need for a large capacity of HSA geothermal to be installed to compensate. This indicates that systems with significant surplus generation and a large installed capacity of wind generation can still be a highly cost effective and efficient solution. Market rules in many jurisdictions will need to change to accommodate the different operational pattern that this necessitates, ensuring that wind and photovoltaics generators can be effectively curtailed when required, and are not paid during periods of spilling (unless they are providing market value through ancillary services or other means during those periods).

3.3. Photovoltaics

Unlike wind, utility-scale photovoltaics are found to “saturate” the system at less than 10% of energy supplied in all the lowest cost portfolios under our assumptions of an unchanged NEM demand profile and no additional electrical energy storage deployment (from existing pumped hydro generation or other sources). This means that further installation of photovoltaics, beyond the 10% level, provides minimal value to the system, in the absence of storage or demand management (Gilmore et al., 2015).

Costs only escalate slightly (by around AU$270 million per year, or 2% of total system costs) if photovoltaics are not included in the portfolio, since wind can be used as a cost effective substitute (except in the case where wind is also not available). Photovoltaics are found to saturate at relatively low levels due to the high degree of self-correlation across the NEM (in large part due to the strong north-south orientation of the NEM which exists almost entirely in a single time zone). Photovoltaics only operate during daylight hours, meaning that even if the full load (taking into account the NSP limit) is met by photovoltaics in the middle of the day, the total energy contribution of the technology remains relatively low.

This modelling suggests that research investment in improving integration and reducing costs of utility-scale photovoltaics should be entered into with caution, with a regard for possible market saturation effects. Further work on the integration of distributed (rooftop) photovoltaics could be an exception; distributed generation was not explicitly included in this modelling, and may provide additional opportunities in terms of reducing network costs and losses, and facilitating demand-side participation that moves loads into daylight hours.

The inclusion of storage or demand side participation may mitigate the rapid saturation effect for utility-scale photovoltaics. Including storage systems in NEMO and most of the current models used for studies of this nature is non-trivial, since it requires time-sequential modelling of reservoir levels and sophisticated algorithms to optimise storage dispatch for charging and discharging. Developing these algorithms to allow inclusion of storage and demand-side participation in the model is identified as important future work, to allow comparison of systems involving high photovoltaics and these complementary technologies, as a possible alternative to high wind systems.

3.4. Synchronous generation technologies

In part to meet the maximum NSP constraint, around 10% of energy in all cases is supplied by some combination of geothermal, concentrating solar thermal or bioenergy technologies. System costs were found to remain relatively similar regardless of which technology is utilised. The lowest cost scenarios involve moderate quantities of HSA geothermal (2.7–2.9 GW, operating at a 98% capacity factor and supplying 11–12% of energy).

If the HSA technology is not available, but EGS geothermal technology is available, costs increase slightly (around a 3% increase in total system costs). The absence of any kind of geothermal technology increases costs somewhat further, by around 10%. This suggests there may be justification for policy measures and some amount of government-funded research to promote the development and, if successful, commercialisation of geothermal power in Australia. Systems including geothermal technologies at the costs projected in the AETA for 2030 (Bureau of Resources and Energy Economics, 2013) are found to be around AU$1.5 billion per year less expensive in 2030 than those that do not have cost effective geothermal technologies available, giving a sense of the value that might be derived from success in such policy efforts.

If geothermal technologies are not available, the model instead utilises some concentrating solar thermal (CST) technology, and an increased amount of bioenergy. In this case, 9% of energy, or 17.5 TWh is sourced from bioenergy, which remains below the conservative annual limit applied for bioenergy in all scenarios. Growth in demand (beyond the 2010 level of demand used in this modelling) may increase the ideal quantity of bioenergy utilised beyond this level. In that case, additional CST could be used to meet the increased requirement for firm, synchronous capacity with a growth in demand.

If neither CST nor geothermal technologies are available, the model still finds a feasible solution subject to all of the constraints. An increased amount of bioenergy is used, with 10% of energy, or 19.9 TWh, being sourced from bioenergy. This is close to the conservative bioenergy constraint of 20TWh per year applied. This scenario is only slightly higher in cost than the scenario where CST is included. This suggests that CST is not an essential technology, as long as a sufficient quantity of bioenergy is available. However, if bioenergy constraints are likely to be more significant than those modelled here, and geothermal options do not prove successful, CST could be an important technology for achieving 100% RE scenarios.

3.5. Bioenergy availability

There is some controversy around the use of bioenergy for electricity in Australia, particularly when it involves the use of native forest resources, or where bioenergy production may compete with other (potentially higher value) land uses, such as food production. This section examines how much costs may increase if bioenergy is constrained to levels much lower than the conservative limit applied in this study (which has been assessed to be economically and ecologically sustainable) (Geoscience Australia and ABARE, 2010).

Fig. 3 illustrates how the average wholesale generation system costs change as the amount of bioenergy available is progressively constrained, under three different conditions of technology availability and NSP limit.

If CST and both geothermal technologies are available, reducing the amount of bioenergy available incrementally increases system costs from AU$65/MWh (where the optimal quantity of bioenergy generation is calculated to be much less than the 20TWh per year imposed limit) to AU$83/MWh (with no bioenergy being available). This is an increase in cost of AU$3.6 billion per year, or 27% of total system costs. Although the biofuelled gas turbines operate infrequently as peaking plant (due to their high operating cost), their complete absence has a significant impact on scenario costs because they provide cost effective low capacity factor generation which allows the NEM's reliability requirements to be met at low cost. The influence on NEM costs is more extreme in the case where geothermal technologies are not available; if CST is the only other synchronous technology available (aside from existing hydro resources) costs escalate from AU$77/MWh (with essentially unlimited bioenergy) to more than AU$106/MWh (with no bioenergy); this is an increase in cost of almost AU$6 billion per year.

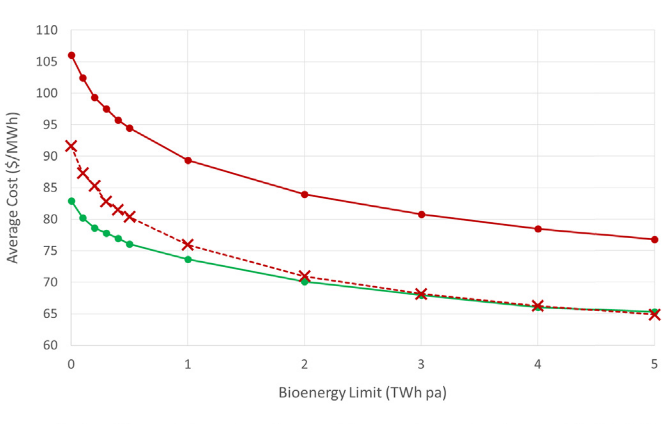

Fig. 3. Bioenergy availability impact upon system costs.

However, it may be possible to achieve a lower cost outcome if the amount of storage at CST plants was optimised to allow for lower cost peaking operation (this modelling assumes a fixed amount of six hours of thermal storage at each CST plant).

Bioenergy is found to be important since it is the only peaking renewable technology with characteristics of low capital costs yet high operating costs, such that it generally operates with a low capacity factor of less than 10%, but plays a vital role when it does run. These results show that a complete absence of bioenergy (the only peaking renewable technology included in this modelling) increases costs by AU$20–30/MWh.

Even a very small amount of bioenergy is found to have high value. Allowing just 0.1 TWh per year of bioenergy reduces average wholesale generation costs by AU$3–4/MWh, or AU$230 to AU $350 million per year.

These results suggest that enabling some amount of peaking technology should be a significant research priority if the goal is to achieve 100% RE. This could come from gas turbines fuelled using bioenergy, pumped hydro storage, battery storage, demand response or other technologies. However, including a small amount of natural gas peaking generation may be a suitable substitute in many cases, if it is not necessary to achieve 100% RE. Natural gas in a peaking role would provide a similar reduction in cost as the bioenergy technology, and would add only a small amount of greenhouse gas emissions (because peaking plant operate infrequently and therefore consume only a small amount of fuel). This may be a suitable alternative in many jurisdictions, and removes the priority around investment in bioenergy technology commercialisation.

Fig. 4 shows the manner in which the technologies included in the least cost portfolio evolves as the amount of bioenergy available is reduced with all other technologies available. In this case, the model responds to the reduced bioenergy availability by installing more HSA geothermal capacity, and reducing the amount of wind capacity installed. It is worth noting that even in the case where only 0.1 TWh of bioenergy is available for the year, a significant capacity of bioenergy turbines are installed (2.8 GW), indicating the high value of this technology in a peaking role.

Fig. 5 shows the portfolio evolution under conditions where EGS and HSA geothermal technologies are not available. In this case, since the geothermal technologies are absent, the model instead uses an increased amount of CST capacity combined with an increased capacity of wind to replace the lower bioenergy availability. The absence of any geothermal or bioenergy technology creates relatively expensive solutions with increasing amounts of surplus energy, since the relatively expensive CST technology must be utilised to meet all the peaking requirements and provide synchronous generation to meet NSP limits. This result may reflect a modelling limitation around the lack of flexibility in the amount of CST storage modelled; in this case it may be more cost effective to install a range of CST storage sizes, rather than the standard six hours of thermal storage assumed for this study.

Fig. 3 also illustrates the reduction in cost if the maximum NSP constraint is effectively removed (set to 100%). Although the total system cost does reduce for all levels of bioenergy availability (indicating that the NSP limit does elevate system costs considerably, by around AU$12–15/MWh), it does not eliminate the escalation effect as lower levels of bioenergy become available. This indicates that the escalation in marginal cost as the availability of bioenergy is reduced is not primarily driven by the maximum NSP constraint, but instead is related to the peaking role of the gas turbine technology.

3.6. Non-synchronous penetration (NSP) constraints

To further explore the effect of the NSP constraint, the maximum non-synchronous penetration limit was varied under two

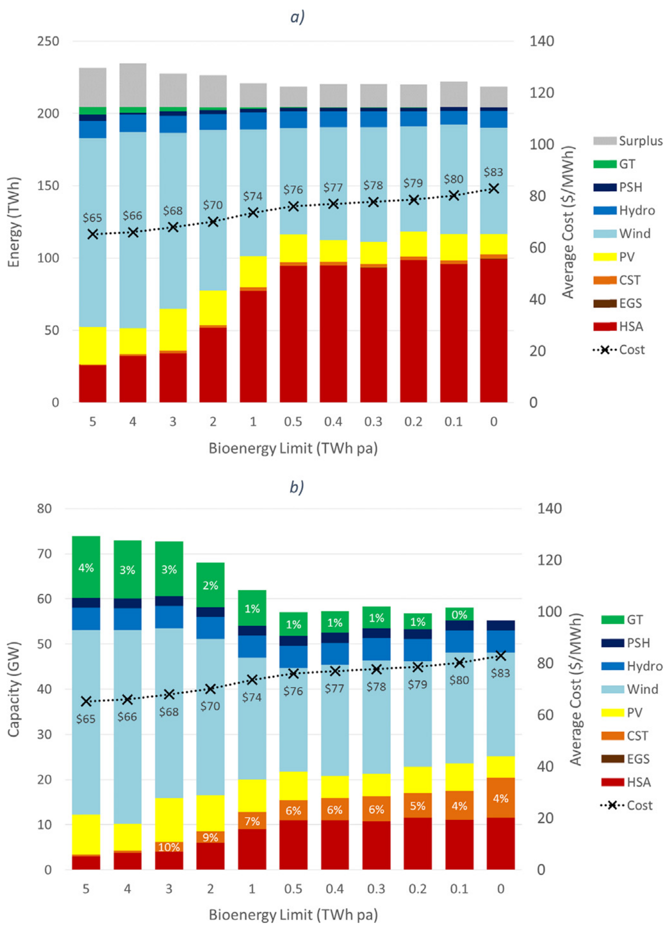

Fig. 4. Evolution in the least cost optimised portfolios and average system costs as the bioenergy limit is progressively reduced, with all technologies available. (a) Illustrates the energy provided and (b) illustrates the capacity installed of each technology. Percentages show capacity factors for bioenergy turbines. An 85% NSP limit is applied in all cases.

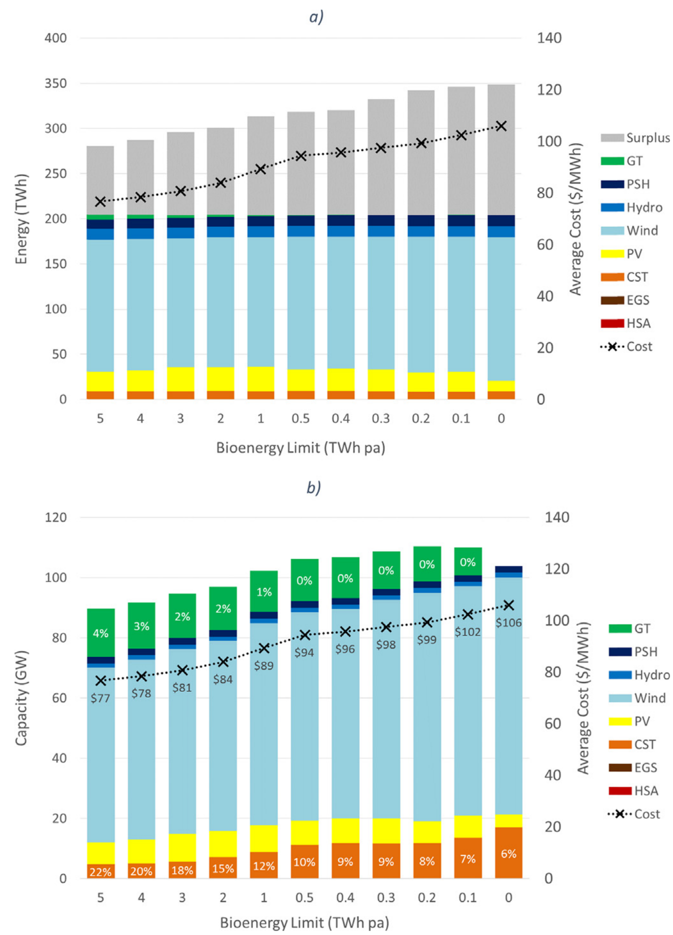

Fig. 5. Evolution in the least cost optimised portfolios and average system costs as the bioenergy limit is progressively reduced, with EGS and HSA geothermal technologies unavailable. (a) Illustrates the energy provided and (b) illustrates the capacity installed of each technology. Percentages show capacity factors for bioenergy turbines. An 85% NSP limit is applied in all cases.

different cases (with all technologies available, and with geothermal technologies unavailable). Fig. 6 compares the average system wholesale generation cost as the NSP limit is varied in the two cases. The impact of varying the NSP limit under various levels of bioenergy constraints is also illustrated. Fig. 7 shows the least cost portfolios selected by the evolutionary program where all technologies are available, and as the NSP limit is varied.

The NSP limit is found to have a significant influence on system wholesale costs. Constraining the NSP to 50% (the limit currently applied in Ireland, for example) increases costs by AU$1.42 billion per year (an 11% increase in total system costs) in the case where all technologies are available, compared to no NSP limit being applied. The cost increase is AU$5.8 billion per year (a 45% increase in total system costs) in the case where geothermal technologies are not available.

The impact of the 85% NSP limit (compared with no NSP limit) is to increase costs by AU$2.5 billion per year (18% increase in total system costs) if bioenergy is relatively freely available, or by AU$3 billion per year (16% increase in total system costs) if bioenergy use is very limited and geothermal technologies are not available.

This modelling finds that relaxing the NSP limit reduces costs approximately linearly, with the slope being determined by the mix of technologies available. If all technologies are available, there is relatively less benefit from relaxing the NSP limit. In this case, relaxing the NSP limit leads to less geothermal technology being installed, and exchanged for a greater quantity of wind generation, as illustrated in Fig. 7. When the NSP limit is removed

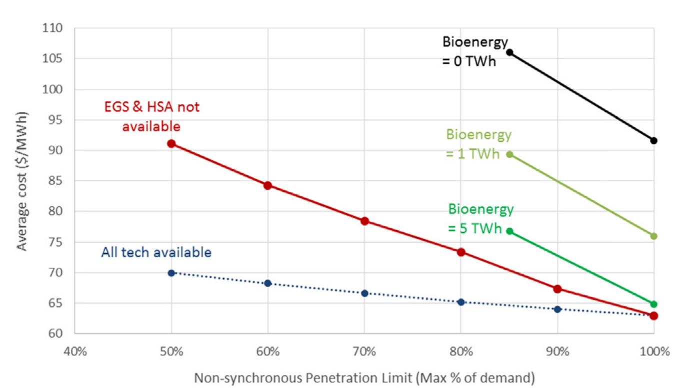

Fig. 6. The impact of varying the NSP limit on average system costs for the least cost portfolios. EGS and HSA are not available in the three bioenergy limited portfolios illustrated.

entirely (set to 100%), HSA technology is not included in the least cost portfolio at all. Similarly, if geothermal technologies are not available, the least cost system at a 50% NSP limit includes significant quantities of CST technology, but as the NSP limit is relaxed less CST is installed, to the point where none is included with the NSP limit removed. This reduces system wholesale costs substantially.

This study indicates that geothermal and CST technologies are important for low cost renewable systems in Australia (and

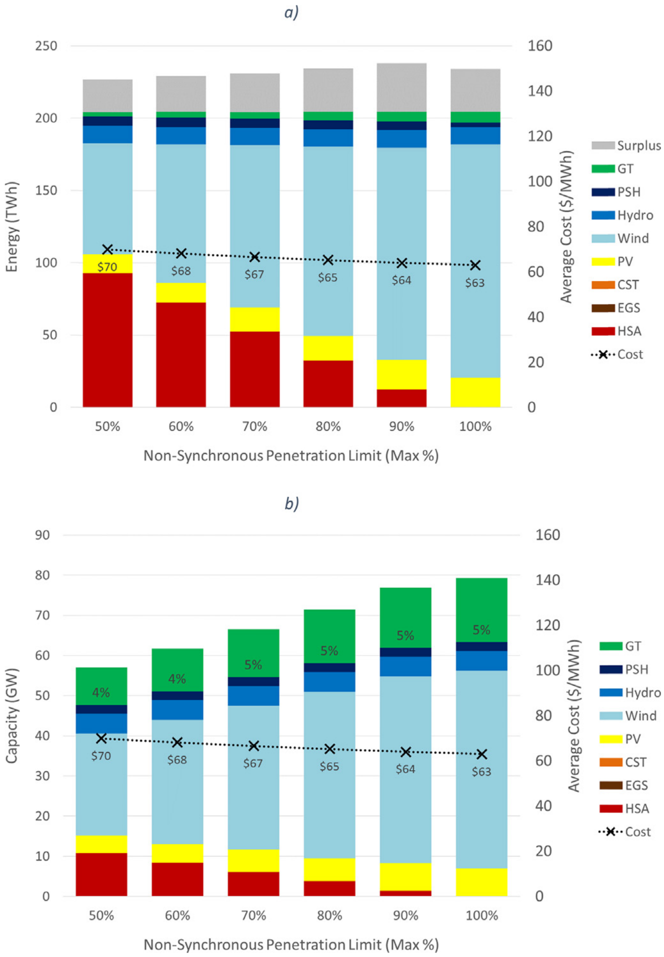

Fig. 7. Evolution in the least cost optimised portfolios and average system costs as the NSP limit is progressively relaxed, with all technologies available. (a) Illustrates the energy provided and (b) illustrates the capacity installed of each technology. Percentages show capacity factors for bioenergy turbines.

potentially other similar jurisdictions) mostly for their synchronous properties, and provide value mostly by contributing towards meeting the NSP limit.[2] This means that seeking alternative ways to manage system inertia and stability that avoid placing an NSP limit on the system may have significant value (up to AU$5.8 billion per year, or 45% of total system costs, if geothermal technologies are not available).

3.7. Summary

Fig. 8 compares the relative cost impacts of the various portfolio constraints explored in this analysis. Individual scenario results are also listed in Table 3, and for context can be compared with Table 2 (which provides the installed capacity of each technology in the NEM at present).

Bioenergy limitations are shown to have relatively significant cost impacts, especially when the level of bioenergy permitted is low. Non-synchronous generation constraints are also highlighted as having important cost impacts, particularly in the case where geothermal technologies are not available. The availability of wind and photovoltaics technologies is relatively important, while the availability of any particular synchronous renewable technology

[2] Nuclear generation is also synchronous, and could similarly contribute to a low emissions system. Australia does not have any nuclear generation at present, but consideration of the potential contribution of nuclear technologies could be considered for future work.

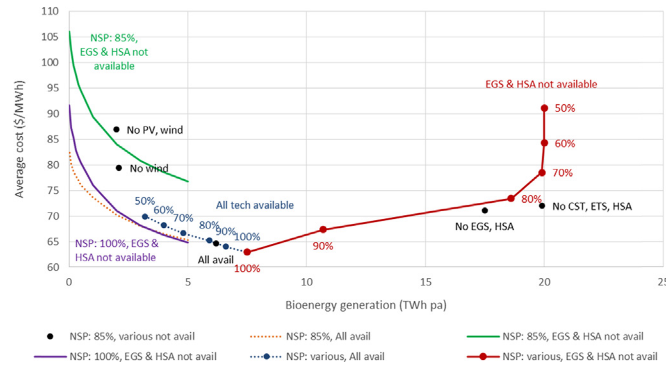

Fig. 8. Comparison of the relative cost impacts of various assumptions on a 100% renewable portfolio.

Table 2
Capacity installed in the NEM at present (2016). Source: AEMO, (2016b)

Technology Type	Installed capacity (GW)
Steam (coal, gas)	28
CCGT	3
Peaking gas/diesel	7
Hydro	8
Rooftop photovoltaics	5
Wind	4
Total capacity	54
Total “firm” capacity	45
Minimum demand	15
Peak demand	35

(geothermal and CST) is found to be relatively less important to system costs.

4. Conclusions and policy implications

This modelling suggests that enabling significant wind penetration levels (around 70% of energy from wind) is likely to provide the most significant opportunity to enable a low cost, efficient, high penetration renewable NEM. On this basis, Australian policy makers could consider prioritising mechanisms that identify and address barriers to widespread deployment of wind technologies. This could include, for example:

1. Measures targeted at facilitating more efficient grid integration of wind generation. This in includes, for example, improving forecasting of wind generation (on a range of timescales), adapting system dispatch process to have shorter dispatch intervals and shorter gate-closure times (to minimise the need for operational reserves) (Riesz and Milligan, 2014), and procuring reserves over larger balancing areas (to allow sharing of reserves, minimising costs).
2. Exploring measures to relax NSP limits, or finding alternative approaches to managing displacement of synchronous generation. This includes, for example, the work proceeding in AEMO's “Future Power System Security” program (AEMO, 2016a), which aims to address system integration challenges for systems with a large proportion of non-synchronous generation, such as system strength, and frequency control with low synchronous inertia.
3. Improving public acceptance of wind generation. This includes, for example, public outreach campaigns designed to combat public perceptions around spurious claims on the negative health impacts of wind turbines, and may include promoting

Table 3
Summary of modelling outcomes for various scenarios considered.

Technologies not available	NSP limit (%)	Bioenergy limit (TWh pa)	Cost ($/MWh)	Installed Capacity (GW)								Energy (TWh pa)								
				HSA	EGS	PV	Wind	CST	Hydro	PSH	GT	HSA	EGS	PV	Wind	CST	Hydro	PSH	GT	Surplus
None	85%	20	64.65	2.7	0	6.2	43.7	0	4.9	2.2	14	23.2	0	18.8	138.5	0	11.9	5.8	6.2	31.1
EGS	85%	20	64.6	2.7	0	6	43.8	0	4.9	2.2	13.9	23.2	0	17.7	139.4	0	12	5.8	6.3	31
CST	85%	20	64.6	2.6	0	6.1	44	0	4.9	2.2	14	22.8	0	18.3	139.1	0	12	5.9	6.2	31.2
EGS, CST	85%	20	64.59	2.7	0	6.1	43.8	0	4.9	2.2	14	23.1	0	18.1	139.1	0	12	5.8	6.3	30.9
PV	85%	20	65.99	2.9	0	0	48.8	0	4.9	2.2	15.5	24.9	0	0	154.1	0	12	5.4	7.9	35.3
HSA	85%	20	66.73	0	2	6	46.5	0	4.9	2.2	14.2	0	18.2	18	142	0	12	8	6.2	38.2
HSA, CST	85%	20	66.71	0	2.1	6.2	46.1	0	4.9	2.2	14.2	0	18.6	18.5	141.2	0	12	7.8	6.2	37.4
EGS, HSA	85%	20	71.11	0	0	5.8	47.8	1.7	1.5	2.2	18.6	0	0	17.2	143.6	5.2	12	8.9	17.5	41.8
CST, EGS, HSA	85%	20	71.98	0	0	6.4	49.7	0	1.4	2.2	19.5	0	0	19.2	143.5	0	12	9.7	19.9	49.2
Wind	85%	20	79.4	19	0	11.2	0	0	4.9	2.2	6.7	161.9	0	25.2	0	0	12	3.2	2.1	8.2
PV, Wind	85%	20	86.88	24	0	0	0	0	4.9	1.4	10.3	190.4	0	0	0	0	12	0	2	0
None	85%	5	65.3	3	0	8.8	40.9	0.4	4.9	2.2	13.7	25.9	0	26.2	130.2	0.5	11.9	4.7	5	27.3
None	85%	4	66.44	3.5	0	8.5	39.7	1.2	4.9	2.2	12.7	30.3	0	25.2	128.2	1.2	11.9	3.5	4	24.1
None	85%	3	68.01	4	0	9.7	37.6	2.2	4.9	2.2	12.1	34.3	0	28.7	121.7	1.9	11.8	3.1	3	23
None	85%	2	70.15	6	0	8	34.6	2.5	4.9	2.1	10	51.8	0	23.9	111.1	1.9	10.9	2.7	2	22
None	85%	1	73.63	9	0	7.2	27	3.8	4.9	2.2	7.8	77.4	0	21.7	87.5	2.4	11.7	2.6	1	16.5
None	85%	0.5	76.08	11	0	6.4	22.9	4.4	4.9	2.2	5.3	94.8	0	19.2	73.4	2.4	11.6	2.5	0.5	14.2
None	85%	0.4	76.98	11	0	4.9	24.6	4.9	4.9	2.2	4.8	95.1	0	14.9	77.9	2.5	11	2.5	0.4	16
None	85%	0.3	77.79	10.8	0	5	25.1	5.5	4.9	2.2	4.8	93.3	0.1	15	79.4	2.7	10.9	2.6	0.3	16
None	85%	0.2	78.63	11.5	0	5.8	23.4	5.5	4.9	2.2	3.5	98.7	0	17.5	72.7	2.3	10.4	2.4	0.2	15.7
None	85%	0.1	80.21	11.1	0	6.1	24.5	6.4	4.9	2.2	2.8	96	0.1	18.2	75.6	2.3	9.7	2.5	0.1	17.5
None	85%	0	82.95	11.5	0	4.8	22.9	8.9	4.9	2.2	0	99.4	0.1	14.1	73.5	3.1	11.7	2.4	0	14.3
EGS, HSA	85%	5	76.78	0	0	7.4	58	4.7	1.4	2.2	16	0	0	21.9	146.1	9.1	12	10.3	5	76
EGS, HSA	85%	4	78.49	0	0	7.9	59.8	5.1	1.4	2.2	15.4	0	0	23.5	145.2	9	12	10.7	4	83.1
EGS, HSA	85%	3	80.76	0	0	9.2	61.4	5.7	1.4	2.2	14.7	0	0	27.1	142.5	8.9	12	10.8	3	91.9
EGS, HSA	85%	2	83.98	0	0	8.8	63.1	7.1	1.4	2.2	14.4	0	0	26.4	143.6	9.6	12	10.8	2	96.5
EGS, HSA	85%	1	89.37	0	0	9	67.1	8.8	1.5	2.2	13.6	0	0	26.9	143.8	9.2	12	11.4	1	109.2
EGS, HSA	85%	0.5	94.47	0	0	8	69.3	11.2	1.5	2.2	14	0	0	23.8	146.9	9.7	11.9	11.5	0.5	114.2
EGS, HSA	85%	0.4	95.74	0	0	8.3	69.5	11.7	1.5	2.2	13.6	0	0	24.7	146.1	9.7	12	11.5	0.4	116
EGS, HSA	85%	0.3	97.55	0	0	8.3	72.7	11.6	1.5	2.2	12.4	0	0	24.4	146.9	8.9	12	11.8	0.3	128
EGS, HSA	85%	0.2	99.33	0	0	7.2	76	11.8	1.5	2.2	11.7	0	0	21.3	150.3	8.5	12	12	0.2	138.1
EGS, HSA	85%	0.1	102.44	0	0	7.5	76.2	13.5	1.4	2.2	9.2	0	0	22.5	149.2	8.4	12	12.2	0.1	141.7
EGS, HSA	85%	0	106.04	0	0	4.2	78.9	17	1.5	2.2	0	0	0	11.5	159.3	9.1	12	12.4	0	144.1
EGS, HSA	100%	5	64.85	0	0	9.4	49.5	0.8	4.9	2.2	15.3	0	0	28.2	156.9	0.8	10.6	2.8	5	32.7
EGS, HSA	100%	4	66.26	0	0	9	50.1	2	4.9	2.2	14.4	0	0	27	158.3	1.7	10.6	2.8	4	33
EGS, HSA	100%	3	68.16	0	0	9.9	51.5	2.4	4.9	2.1	14	0	0	29.5	158.1	1.8	9.3	2.7	3	38.8
EGS, HSA	100%	2	70.99	0	0	9.1	53.5	3.9	4.9	2.2	12.6	0	0	27.4	161.3	2.4	8.5	2.7	2	42.1
EGS, HSA	100%	1	75.97	0	0	8.6	58.9	5.1	4.9	2.2	11.6	0	0	25.7	167	2.1	6.2	2.4	1	57
EGS, HSA	100%	0.5	80.4	0	0	9.8	61.3	6.4	4.9	2.2	9	0	0	29.3	165.1	2	5.2	2.3	0.5	66.2
EGS, HSA	100%	0.4	81.52	0	0	8.1	58.4	8.6	4.9	2.2	11.1	0	0	24.2	167.2	3.2	6.9	2.5	0.4	54.1
EGS, HSA	100%	0.3	82.81	0	0	8.1	59.8	8.9	4.9	2.2	9.8	0	0	24	168.4	2.9	6.2	2.4	0.3	58.6
EGS, HSA	100%	0.2	85.31	0	0	8.1	60.4	10.1	4.9	2.1	8.5	0	0	22.6	170.2	2.9	6	2.3	0.2	59.9
EGS, HSA	100%	0.1	87.29	0	0	6	61.5	11.6	4.9	2.2	8.8	0	0	17.4	174.4	3.6	6.5	2.5	0.1	60.3
EGS, HSA	100%	0	91.6	0	0	3	64.3	15.3	4.9	2.2	0	0	0	8.8	181.1	4.4	7.3	2.8	0	65
None	50%	20	69.94	10.8	0	4.4	25.4	0	4.9	2.2	9.3	93	0	13	76.7	0	12	6.3	3.2	22.5
None	60%	20	68.21	8.4	0	4.6	31	0	4.9	2.2	10.6	72.4	0	13.9	95.7	0	12	6.4	4	24.8
None	70%	20	66.65	6.1	0	5.6	35.8	0	4.9	2.2	11.9	52.4	0	16.9	112	0	12	6.2	4.8	26.7
None	80%	20	65.23	3.8	0	5.7	41.5	0	4.9	2.2	13.3	32.4	0	16.9	131.1	0	12	6.1	5.9	29.9
None	90%	20	64.03	1.4	0	6.9	46.5	0	4.9	2.2	15	12.3	0	20.6	146.7	0	12	6.2	6.6	33.5
None	100%	20	62.97	0	0	7	49.2	0	4.9	2.2	16	0	0	20.6	161.3	0	12	3	7.5	29.5
EGS, HSA	50%	20	91.12	0	0	0.1	33.1	19.8	1.4	2.2	20.5	0	0	0.3	94.5	69	12	8.6	20	33.8
EGS, HSA	60%	20	84.3	0	0	0.5	37.7	14.2	1.4	2.2	19.9	0	0	1.3	111.3	51.3	12	8.5	20	34.9
EGS, HSA	70%	20	78.5	0	0	3.1	41.3	8.6	1.3	2.2	19.3	0	0	9.1	123	31.5	12	8.8	19.9	37.4
EGS, HSA	80%	20	73.41	0	0	4.8	46	3.6	1.4	2.2	18.7	0	0	14.6	137	13.2	12	9	18.6	41.6
EGS, HSA	90%	20	67.36	0	0	7	52	0	3	2.2	17.5	0	0	20.9	151.2	0	12	9.6	10.7	50.5
EGS, HSA	100%	20	62.95	0	0	6.7	49.4	0	4.9	2.2	15.9	0	0	20	161.9	0	12	3	7.5	29.4

alternative ownership models that empower local communities, as applied in Denmark and elsewhere.

In contrast, this modelling indicates that enabling utility-scale photovoltaics may be a relatively lower priority, since they saturate at low levels due to their high degree of self-correlation within the NEM. Rooftop photovoltaics may be a possible exception, where their integration interacts with distribution network costs; this requires further research. Greater uptake of demand side participation could also enable larger capacities of photovoltaics to be utilised effectively; this has not been included in this modelling. There is growing interest in enabling demand side participation in Australia; this modelling indicates this could be particularly valuable for offsetting PV saturation effects, and thereby enabling higher PV penetrations.

This modelling suggests that low cost 100% RE systems are feasible even in the absence of new storage technology, although further work is required to reveal whether integrating some amount of low cost storage may reduce costs further. If the goal is to achieve 100% renewable systems, enabling a small amount of peaking generation (such as gas turbines fuelled with liquid or gaseous biofuels, pumped hydro, demand response or other technologies) with characteristics of high operating costs but low capital costs is of significant value. However, utilising a small amount of natural gas in a peaking role may be an appropriate substitute in the medium-term that allows high renewable penetrations to be achieved at low cost, even in the absence of renewable peaking alternatives.

Enabling the commercialisation of cost effective geothermal and CST technologies may be important to some degree, if stringent NSP limits persist, and if the deployment of these technologies remains the only satisfactory way to observe that limit in high renewable systems. However, these technologies do not appear to be essential for achieving efficient high renewable systems as long as sufficient wind and bioenergy generation is available (within the limits identified as economically and ecologically sustainable for this analysis).

Acknowledgements

This work was supported by funding from the Australian Renewable Energy Agency (ARENA), and the CSIRO Future Grid project. The authors acknowledge the generous discussions, input and advice from Associate Professor Iain MacGill and Dr Peerapat Vithayasrichareon at the University of New South Wales.

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