MEGS

Decarbonised Electricity

The Lowest Cost Path To Net Zero Emissions

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The Lowest Cost Path to Net Zero Emissions

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Preface

The nature of our electricity generation assets within the Australian East Cost Electricity system continues to change as Federal and particularly State Governments seek to both promote and deploy variable renewable energy (particularly wind and solar PV) as part of their plans to broadly decarbonise their economies. Within this context, Total System Cost is slowly being understood to be an important metric to be focused on and optimised, as the electricity system is transformed. The initial MEGS study of the National Electricity Market was the first to show the trajectory of total system costs in response to various technology additions.

While the Australian Energy Market Operator and others are beginning to incorporate aspects of total systems costs, we hope this book will greatly assist the energy discussion. By sharing the MEGS work to date, in a language that is more accessible, this book can be a tool that assists both policy makers and key stakeholder.

We trust this book will add positively to the work that is required to secure a lowest cost, safe, secure and reliable electricity system for many years to come.

Acknowledgements

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Contents

List of Figures

List of Tables

List of Equations

Executive Summary

The environmental mantra of thinking globally and acting locally applies in spades to power supply systems.

Most electricity grids around the world are now at some stage of a transformation designed to deliver lower-carbon (even no-carbon) power to residential, commercial and industrial users, while coping with rising demand along with political, social, economic and environment influences.

The key underlying factor in the transition is the shift from largely centralized generation systems to accommodate variable renewable energy (mostly wind and solar photovoltaic technologies). This is currently underway in Australia, with the growth of consumer self-generation and the development of utility-scale power storage.

A major, albeit not publicly well-appreciated, risk of this transformation is that far-reaching and expensive decisions may be made – and may already have been made – on incorrect or misleading information flowing from conventional modelling approaches. Metrics widely in use at present, it is argued here, are simplistic and no longer appropriate for supporting key decision-making.

In Australia, a decade of change in the National Electricity Market (the east coast power system) has been accompanied by controversy over the approach to climate change in which the costs and reliability of supply are prominent. Competing claims have wreathed debate on the transition to lower carbon emissions in the market in a fog of misunderstanding and misconception.

The purpose of this book is to clear the air on key aspects of grid technology assessment and give some insight into what a future grid may look like. This is not an easy task, as comparisons of the cost and value of electricity generation resources for the NEM have become increasingly complex.

Changes in the market's mix of generation, plus the public and political focus on the need to maintain a fit-for-purpose system, mean that cost comparison metrics used in the past have become less useful today.

What has not changed is the need for a holistic metric for a diverse grid to enable useful assessment of competing power generation technologies.

For a complex system of numerous moving parts like a grid, no simple metric can be the answer. However, in the absence of advice based on unbiased energy systems analysis, decisions by Governments and other stakeholders about the future energy mix may lead to expensive sub-optimal outcomes.

Valuing the System

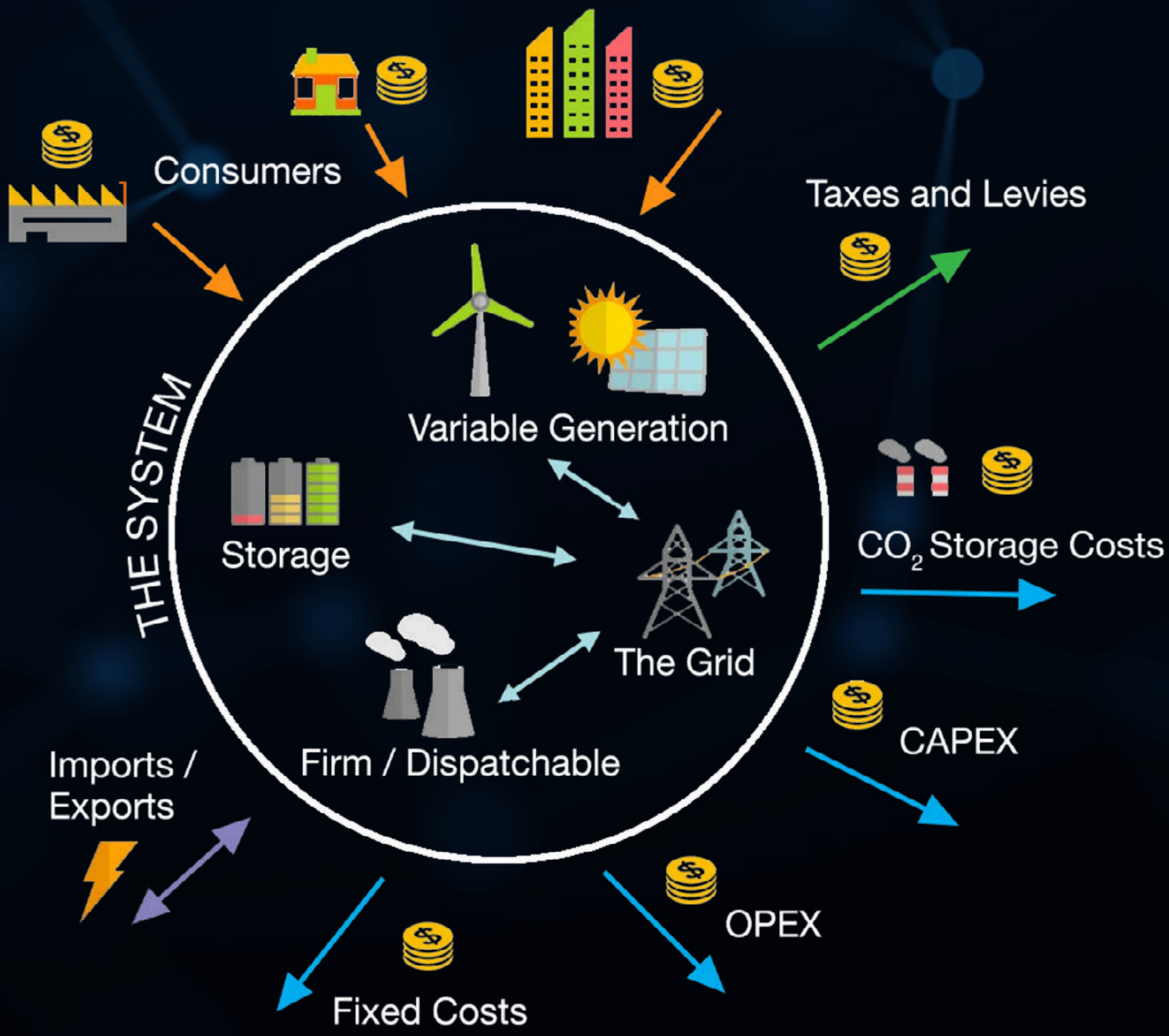
To a consumer and the wider economy, the cost of electricity is paramount. The "total system cost" (TSC) is the closest metric that reflects the price paid for consumption. This metric essentially equates to a planner's perspective to determine least-cost pathways for generation operations and investment – with carbon abatement costs incorporated to accurately assess the value a technology can bring to an existing grid while ensuring adequate supply and system security.

Any grid assessment starting point needs to be the recognition that energy is only one of many services that technologies provide to, or receive from, the grid. It must be appreciated that the value of technologies is changed by the nature of the system into which they are integrated.

For example, it is important to take into account in using the total system cost metric that simulations for output from variable energy technologies will be compromised unless actual weather data for a market region is included in modelling.

A fundamental flaw in much of the existing modelling is the mindset that assesses the cost (to consumers) of deploying a particular generation technology independently of the grid in which it must be integrated, and that assesses the only useful output from the technology as electricity. This is of importance as the currently dominant approach to grid transition involves adding technologies that cannot be measured via levelised cost of energy (LCOE), such as synchronous condensers and battery storage.

This book demonstrates that LCOE, as a guide for policy, planning and development in the NEM, has significant shortcomings and in a diversifying system, its applicability has become increasingly limited. Critically, the use of LCOE in a market pursuing large-scale decarbonization can deliver very inaccurate and misleading signals for investors.



In an environment where the need to maintain a ‘competent’ grid has become increasingly important by the complex impacts of change, a holistic approach to system modelling, akin to cost benefit analysis, is already overdue. The NEM developments now being proposed, and increasingly driven by government intervention, make it critically important if the system transition in eastern Australia is to be delivered at the lowest cost.

Measuring the Value of Generation Technologies Added to a Grid

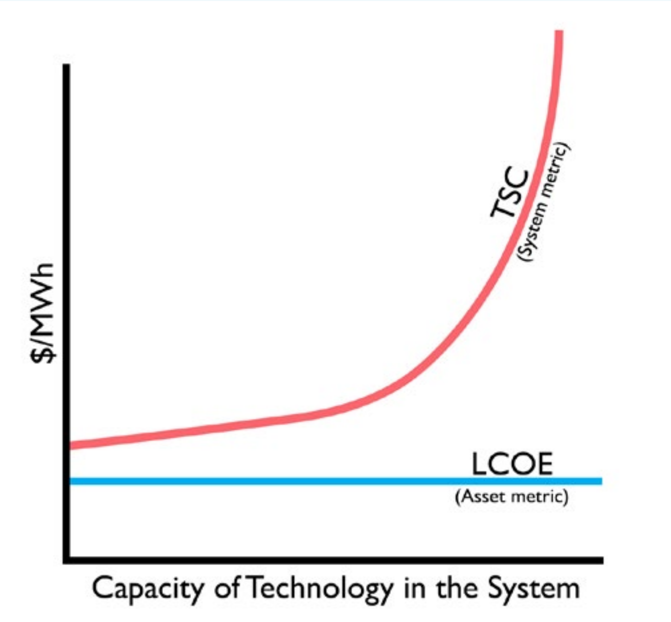
Summary

As the National Electricity Market, (the east coast power system) generation mix changes, as well as the public and political refocusing on the need to reduce carbon emission, the cost comparison metrics historically used are beginning to be called into dispute. As the National Electricity Market (NEM) moves towards low carbon emission levels, while still being a secure and stable grid, it becomes a more complex system with multiple moving parts, for which no simple metric can resolve.

There is a shift from largely fossil-fuelled power generation systems to ones that accommodate variable renewable energy (mostly wind and solar photovoltaic technologies), along with a growth of consumer self-generation and the development of utility-scale power storage. This shift is a key factor that compels the use of more complex cost comparison metrics.

The industry standard metric broadly used today is the levelised cost of energy (LCOE). However, as a metric for policy, planning and development across the NEM, LCOE has become less applicable. When using LCOE to analyse a market pursing decarbonization, the results can be vastly inaccurate and deceptive for investors, politicians and the general public.

This study utilizes a more appropriate metric to assess the financial implications of technology on the grid, called total system cost (TSC). TSC essentially equates to the required central planner's perspective, helping to determine the least-cost pathways for generation operations and future investment. A TSC optimisation approach incorporates carbon abatement costs to accurately assess the value a technology can bring to an existing grid while ensuring adequate supply and system security.



Introduction

Electricity grids globally are undergoing a transformation to enable the delivery of low-carbon electricity to domestic and commercial customers alike [3, 4]. The increasing penetration of variable renewable energy (VRE), such as wind and solar photovoltaic (PV) technologies, are leading this transformation. This increase in VRE has also resulted in an increase in the level of utility-scale storage, and the growing impact of consumer self-generation combined with behind the meter storage [5]. The grid is changing from a largely centralised energy generation system to a more de-centralised one, and from unidirectional electricity flows to bidirectional flows (refer to Figure 1) [6]. This combined with the natural grid expansion due to increasing demand impacted by political, economic, social and environmental influences, makes modelling the nature of future energy systems complex [7].

Importantly as part of this transformation, the inappropriate use of metrics may lead to setting poor policy direction, and decisions being made on incorrect or misleading information. Historically, the levelised cost of energy (LCOE) has been the go-to metric for investors comparing the economics of different generation technologies, but now as the grid is diversifying and its applicability is becoming increasingly limited, other metrics are being sought [8]. Furthermore, power plants do not only generate electricity, but provide a range of additional services which are essential for maintaining a permanent and stable supply of electricity across the system, including reserve capacity, voltage and frequency control [9].

This chapter seeks to inform energy stakeholders to be aware of the strengths and limitations of simplistic metrics, and the role of a total systems cost approach in aiding system planners, politicians and scenario modellers consider future electricity grid optimisations.

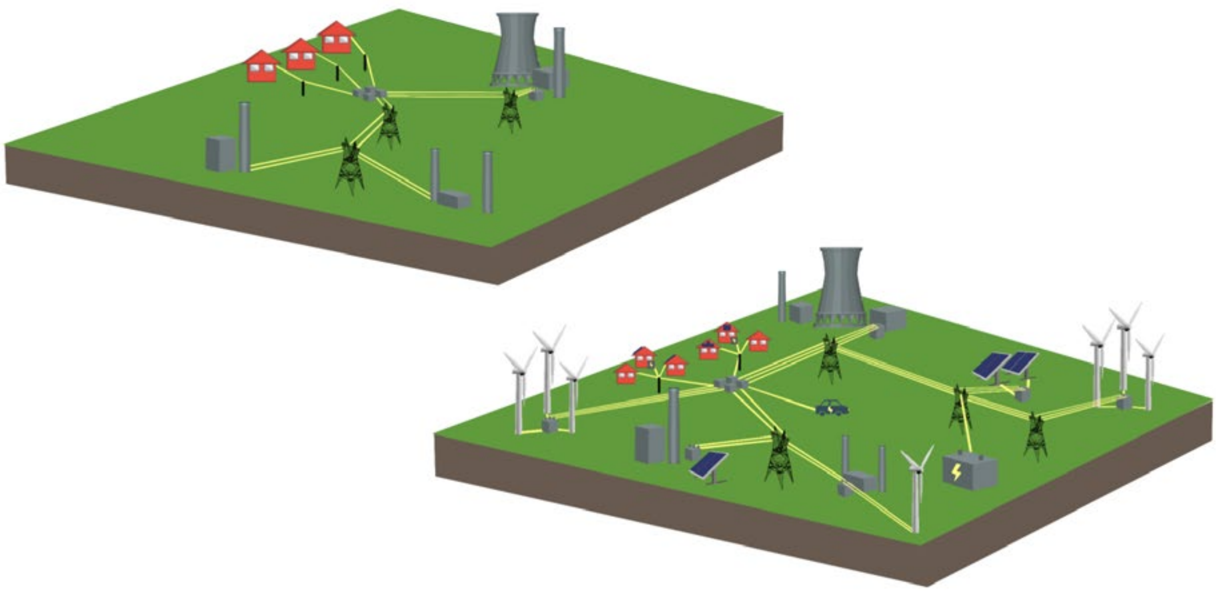


Figure 1: Centralised to de-centralised grid transformation

Background: The Issues of Cost Metrics in Measuring Technology Value

The key issue with the current technology cost metrics is that they are no longer useful in a diversifying grid. As grids change from predominately thermal power generation, to a more diverse mix of power generation technologies with emissions reduction targets, the way we measure the value of technologies must also change.

Technology cost metrics in popular use (such as LCOE) generally make two simplifying assumptions. Firstly, that the cost (to the consumer) of deploying a particular power generation technology is independent of the grid, and secondly, that the only useful output from a power generation technology is energy. However, as a technology is added to the grid, the impact on TOTAL SYSTEM COST may well be non-linear. The system can become "saturated" with a particular technology and further additions then result in diminishing returns or incur increasing costs within the grid. For example, if solar PV is added to a grid with little current solar generation, then it is likely that most of the output will be of high value and all of its generation consumed. However, if the grid already has a large share of solar PV, then the addition of extra capacity will tend to generate in times of surplus when all the other solar PV plants are generating. To maintain the grid's stability, either its output will be curtailed, or extra costs will be incurred, such as the deployment of new storage to capture lost production or synchronous condensers to provide grid services.

Just as a carpenter doesn't fill their toolbox with builders' pencils just because they are the cheapest tool, nor should a grid system be composed of just the cheapest generation. A competent carpenter will need a range of tools, some of which are relatively expensive, and some are used infrequently, but the full toolkit is essential to enable the delivery of the most cost-effective, quality product to the client. Similarly, a competent grid needs a range of technologies to deliver energy when it's available as well as when the customer needs it, and a whole range of technical grid services necessary for stability and security. Comparing power generation technologies based on one component, such as delivery of energy on an annual basis, does not take into account all its valuable characteristics. In fact, the changing grid means we are adding technologies, such as synchronous condensers and battery storage, that cannot be measured with a simple metric like LCOE. One could argue that the LCOE of a power generation technology is redundant in a changing grid, as each technology brings with it a different suite of services.

Metrics and models that incorporate total system cost (TSC) will inherently be able to show the non-linear nature of the cost of decarbonisation pathways. This is shown schematically in Figure 2, which displays the linear nature of LCOE with respect to capacity, and the more accurate TSC of a technology addition which takes into account the whole range of factors that influence the cost.

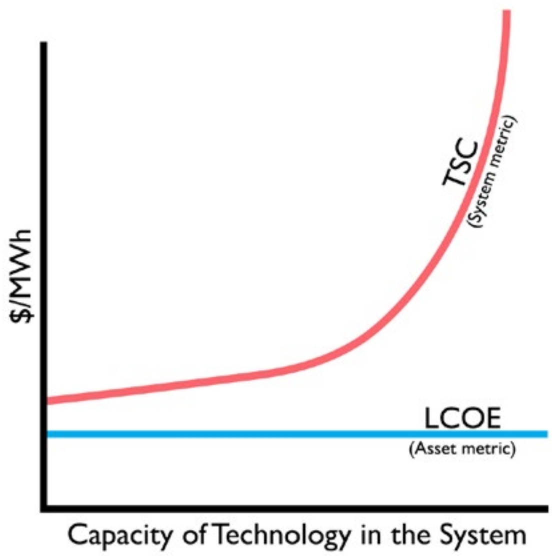


Figure 2: Representation of LCOE vs TSC as a grid decarbonises

Current Generation Cost Comparison Metrics

The majority of current power generation cost comparison metrics have been devised to address individual plants or clusters, and very few assess the characteristics of a complete grid system that the technology is joining. For the purposes of setting tariffs [10], making whole of system decisions, and keeping costs as affordable as possible, it is these characteristics which are the most important. However, most current metrics are not ideal from a total systems perspective as they are based on individual asset investment models and inherently fail to account for the impacts on the system as a whole [8]. Figure 3 shows a comparison of each cost metric with reference to the services incorporated within each metric.

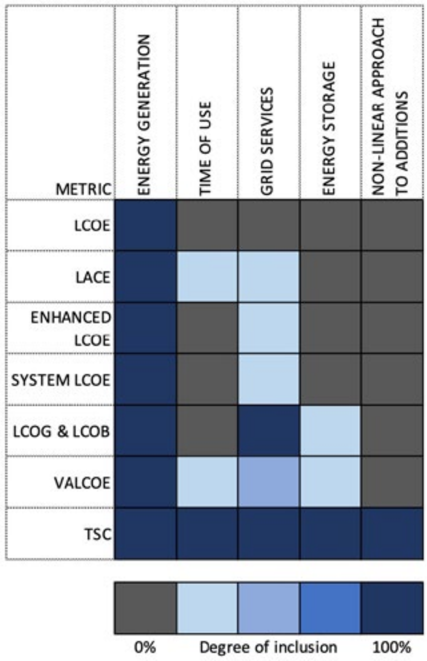


Figure 3: Comparison of cost metrics

The diversity of available power generation technologies is growing, resulting in a rapidly changing generation mix, leading to the task of comparing the cost and value of power generation technologies becoming more complex. In this environment, along with the need to maintain a competent grid, previously 'sound' metrics are becoming less useful.

Levelised Cost of Energy

LCOE is currently the most commonly used technology comparison metric, initially implemented as a first-order comparison of the competitiveness of similar thermal projects [8; 11]. LCOE considers generated electricity as a standardised product, not accounting for when the electricity was produced, where the power plant is in relation to demand, and how the electricity was produced [12]. It assumes that all the value of the asset is vested in the energy produced.

The key parameters that feed into LCOE include capital cost, fuel cost, fixed and variable operating and maintenance costs, financing costs, capacity factor, and life span for each plant [13]. It is expressed as dollars per megawatt hour. LCOE ignores any value that can be attributed to the technology's ability to dispatch energy (dispatchability), ancillary services or access to transmission.

LCOE also fails to consider system and regional impacts of various generation technologies [14] and is therefore inadequate for valuing technologies that are integrated into a diverse grid [8]. Additionally, LCOE does not capture all the contributing factors of actual investment decisions, making the direct comparison of LCOE across technologies misleading and problematic as a method to assess the economic competitiveness of various generation options [13]. LCOE fails to account for technologies that provide important services and yet deliver little or no energy to the grid, and for energy consumption technologies, such as storage, Demand Side Management (DSM) and synchronous condensers.

The simplified LCOE equation can be seen in Equation 1 [15]:

Equation 1: Levelised cost of energy

$$\frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

I_t	=	Investment expenditures, or capital cost, in year *t* (including financing)
M_t	=	Operations and maintenance expenditures in year *t*
F_t	=	Fuel expenditures in year *t*
E_t	=	Electricity generation in year *t*
r	=	Discount rate
n	=	Life of the plant

Other Metrics That Do Not Consider the Whole System

While the LCOE is an attractively simple metric for comparing power generation technologies, as discussed in the previous section, it suffers from well-documented weaknesses and is widely regarded as being poorly suited [12; 16; 17]. Despite the short comings of LCOE, no single alternative metric has been adopted as a suitable replacement. The following metrics are examples of the more prominent attempts to address the shortcomings of LCOE, however as discussed, none take into account the total system.

Levelised Avoided Cost of Electricity (LACE) is the United States of America's Energy Information Administration (EIA) metric that calculates the potential revenue available for a power generation technology reflective of its ability to provide both energy and capacity into selected representative periods of each season [16; 17].

Enhanced LCOE attempts to encompass the additional costs that non-synchronous power generation imposes on the grid and add this to the LCOE [12]. This metric uses power system modelling tools to compare synchronous and non-synchronous technologies with the same system conditions [12]. However, as there is no universally accepted definition for integration costs, this metric often proves challenging. Considering that no technology added to a system is independent, this metric is fraught with methodological errors, assumptions and risk of double counting costs [18].

Like the Enhanced LCOE, System LCOE incorporates integration costs of VRE to the grid. It does this through a profile cost for each generation technology which accounts for the impacts of VRE on the system [19]. Integration costs will increase as VRE penetration increases, potentially becoming an economic barrier to deployment. System LCOE aims to produce a market value perspective, deriving cost data from observed market prices to reflect marginal costs [19].

Levelised Cost of Generation (LCOG) is the weighted average cost of generation using the LCOE formula, while Levelised Cost of Balancing (LCOB) includes capital and operating costs of VRE, additional transmission and curtailment losses [16]. The two metrics are combined to provide a new LCOE to the model. This approach has been formed to model 100% renewable grids [20].

The Value Adjusted LCOE (VALCOE) makes three adjustments to LCOE, value, energy and flexibility, which are calculated from outputs of an hourly electricity market model [16; 21]. However, these adjustments do not lead to a cost measure, but simply creates relative rankings.

Total System Cost

Unlike other metrics, TSC takes a holistic approach to compare the changes in a whole system to derive the economic value of adding a power generation technology. The TSC approach is similar to cost benefit analysis, whereby the positive and negative effects of a new addition are all accounted for to determine the overall net cost or benefit to the power system [12]. All integration costs, values and benefits are captured in a whole system model, as opposed to simple integration cost analyses which deconstruct and allocate individual cost components to various technologies. This is becoming increasingly important, as most metrics will not allocate costs to all valuable characteristics of a technology which do not necessarily have a market value, such as inertia.

Additionally, models that use the TSC metric are often able to demonstrate that costs are exponential as technologies are added to a grid, not linear (refer to Figure 2). A power generation technology has a different value and cost for a first installation to the existing system then the nth capacity unit [22]. This is an important distinction as the amount of generation capacity on a system can greatly affect the TSC, CO_2 emissions and system strength.

TSC can be viewed as the most important metric for policy makers as it is the amount that needs to be funded by the consumer/taxpayer. The split between the private and public purse to cover the TSC is directly determined by the policy makers [23]. By examining changes to TSC when a technology is added, it can be used to directly give the value a technology brings to the existing grid.

The TSC for year y is shown in Equation 2:

Equation 2: Total system cost

$$TSC_y = \sum_{a=0}^{A} (ACC_{ay} + FC_{ay} + VOC_{ay} + IC_{ay})$$

ACC_{ay}	=	Annualised capex for asset a in year *y* calculated using an asset specific discount rate and commercial life
FC_{ay}	=	Fixed Costs for asset a in year *y*
VOC_{ay}	=	Variable Operating Cost for asset a in year *y*
IC_{ay}	=	Net Import costs attributed to external interconnection asset a in year *y*

TSC is expressed in units of dollars or another currency unit, however, it can usefully be divided by the annual demand for electricity on the system to be reported in terms of average customer cost of $/MWh. It is important to note that this unit is not a surrogate for wholesale electricity price and should not be interpreted as such.

Figure 4 helps to clarify the definition of TSC, illustrating the many components which make up an electricity grid that must be taken into account. The generating assets are those within the system circle in the diagram and refer to physical parts of the system, such as generators and network facilities. Costs refer to any payments that leave the electricity system, such as fuel costs shown by blue arrows, or taxes shown by green arrows. However, these costs exclude exchanges between participants of the system, such as a generator's network connection fees or the network operator's payments for grid services shown by light blue arrows. The price paid by consumers (orange arrows) must cover all of these outgoings and hence is also equal to TSC.

Although TSC captures all the costs that customers and taxpayers pay via bills and subsidies, it does not immediately help distinguish between different technologies on the grid. An additional metric, the carbon abatement cost, derived from TSC, helps planners and policy makers to do this, but has a more limited application.

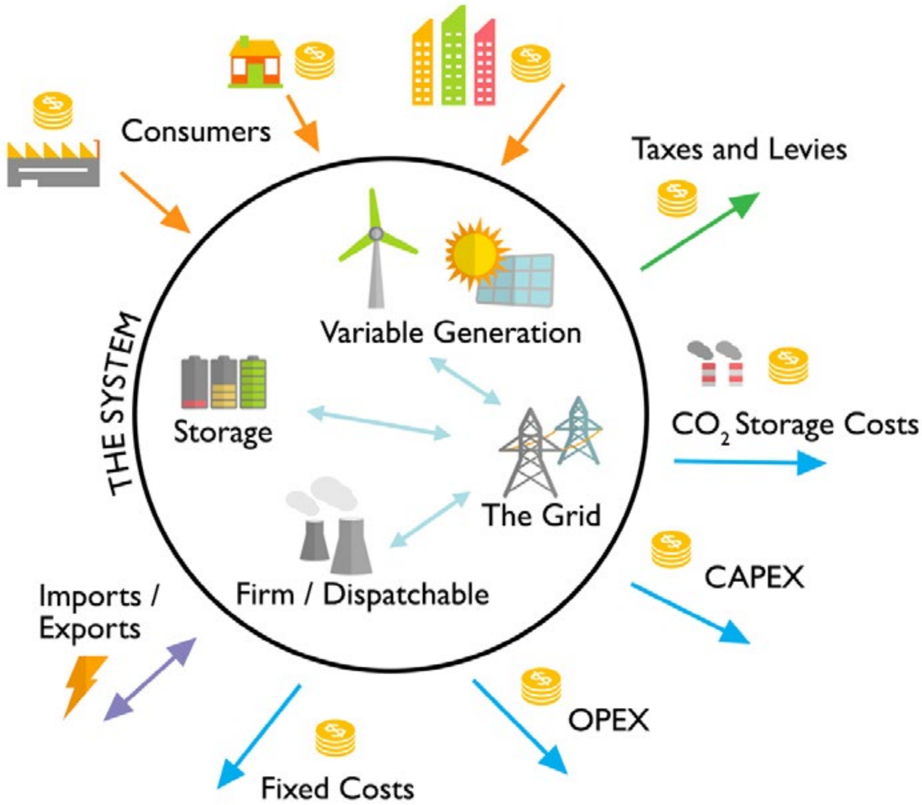


Figure 4: Derivation of total system cost

Carbon Abatement Cost

Carbon Abatement Cost is a measure of the cost effectiveness of reducing carbon emissions via a particular action or set of actions. It is highly relevant to a system embedded in an economy that needs to decarbonise and can be readily compared to abatement costs elsewhere in the economy. The abatement cost is the change in TSC upon completion of the action, divided by the CO_2 emissions reduction, and is simplistically shown in Equation 3.

Equation 3: Carbon abatement cost

$$CAB_T = \frac{-\Delta TSC}{\Delta CO_2}$$

ΔTSC	=	Change in TSC when adding technology *T*
ΔCO_2	=	Change in CO_2 emissions

Modelling Total System Cost

Many models have the inherent capability to report TSC, however the rationale for all of these models is the same: to address the energy trilemma of reducing CO_2 emissions, minimising costs, and maintaining security of supply [24]. MEGS has been used to model the Australian NEM, while FlexEVAL, highRES, and WeSIM have been used to model the United Kingdom National Grid.

MEGS Model Methodology

Model of Energy and Grid Services, or MEGS, was developed in 2017 by Red Vector in partnership with Gamma Energy Technology. It operates on two timescales: hour by hour throughout the year in a chronological sequence and year by year according to pre-set scenarios or using a capacity mix chosen by its own capacity expansion algorithm. The latter can be set to choose new technologies (generation, storage, synchronous condensers or interconnectors) with the lowest CO_2 abatement cost.

MEGS is able to model independent regions with interconnector constraints able to be built into the model. The goal of MEGS is to show the least system-cost mix of generation that satisfies both a demand constraint and grid service constraints [25]. MEGS models inertia, which can also be used as a proxy for grid strength. Inertia acts as the 'first responder' portion of frequency response [26].

FlexEVAL Model Methodology

FlexEVAL was developed in 2016 by Imperial College of London to value flexibility in carbon capture and storage (CCS) power plants. The model used the metric system value (SV) to quantify the benefit, or the reduction in TSC, of adding a unit of a particular technology to the grid [22]. The model is not time sequential within the year, using a limited number of scheduling points spread over 11 standard days and does not account for operational limits of energy storage technologies. When modelling the British system, the National Grid was represented as a single-node network, with interconnectors modelled as one-way imports. There is no inclusion of weather data input to assist in simulating the future output from VRE.

HighRES Model Methodology

The high spatial and temporal Resolution Electricity System model (highRES) is used to design cost-effective, flexible and weather resilient electricity systems for Great Britain and Europe. The model is specifically designed to analyse the effects of high shares of VRE and explore integration/flexibility options. HighRES integrates hourly wind speed and solar radiation data from historical weather data, provided by the European Centre for Medium Range Weather Forecasts and the Climate Monitoring Satellite Application Facility respectively [27].

The model's aim is to minimise power system investment and operational costs to meet hourly demand. It can model a variety of technical characteristics of thermal generators (e.g. ramping restrictions, minimum stable generation, start-up costs, minimum up and down times) depending on the requirements of the scenario, carbon dioxide emissions, and the technical characteristics of a variety of energy storage options [27].

WeSIM Model Methodology

The Whole Electricity System Investment Model (WeSIM) is a holistic electricity system analysis model which balances long-term investment-related decisions against short-term operation-related decisions, across generation, transmission and distribution systems [28]. WeSIM balances supply and demand, while maintaining security of supply, with the goal of minimising TSC. One key difference is that WeSIM incorporates demand side response, new network technologies and distributed energy storage. The model also allows the potential conflicts and synergies between demand side response as a way to support VREs at a national level, and the need to reduce reinforcement at a local distribution level [28].

Modelling Energy and Grid Services (MEGS)

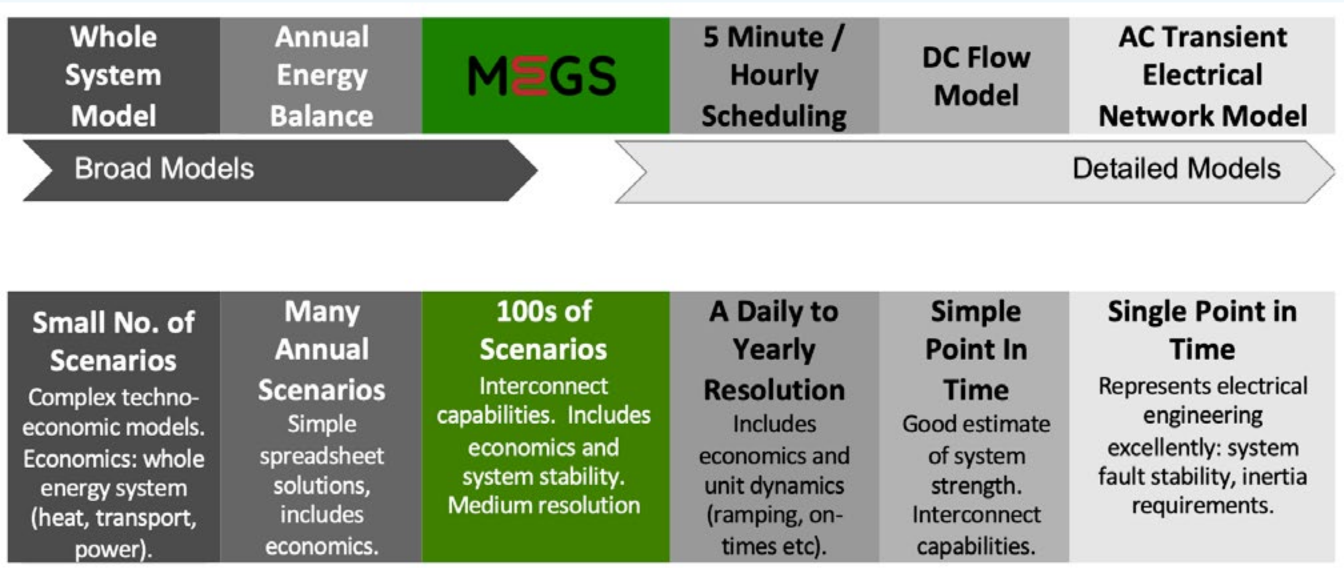
Summary

Electricity systems around the world are changing as a result of policy interventions, government responses to international commitments and evolving capital costs of power generation technologies among other factors. As the Australian National Electricity Market (NEM) moves to a more diverse grid with emissions reduction targets, the way technologies are valued must also change.

The electricity grid model (MEGS, the Modelling of Energy Grid Services) developed for this work takes into account the total energy system. This requires focussing on more than just electricity, with its outcomes challenging the current paradigm for understanding the cost for supplying electricity.

MEGS is a system assessment approach to the cost of electricity generation. It is fundamentally different to individual asset management metrics that asset owners might use. It recognises that the interests of the system may not always be aligned with the interests of the asset investors. Where the system is seeking to minimise cost to the consumer, the assets are seeking to maximise profit to the owner. MEGS seeks to maintain a healthy grid, keeping the lights on day and night, whether the wind blows or not, and factors in the impact of unexpected developments.

Using a holistic metric that can measure the value of a technology to the grid, not just the cost, is the most effective way to decarbonise. The goal of MEGS is to show the lowest total system cost mix of generation that satisfies demand and grid services requirements.



Introduction

MEGS – **M**odelling **E**nergy and **G**rid **S**ervices, is a regional electricity system model that ensures there is sufficient firm capacity to meet demand, and that the grid operator has sufficient services to maintain grid supply and stability.

It follows a similar solution methodology to Balancing Energy, Reserve, Inertia and Capacity (BERIC), a model used by Energy Research Partnership (ERP) in the United Kingdom (UK) to model flexibility in the system on the UK mainland [29]. Both were written by the same author, but MEGS has advanced capabilities that includes the ability to model the following:

- Regions with interconnects that can carry energy and reserve services;
- Resource limited hydro;
- Short and long term storage; and
- Weather-dependent renewable energy technologies (wind and solar photovoltaic (PV)) by soft-linking to the Renewables Ninja model [30].

MEGS departs from more traditional modelling as it captures the requirement and supply of grid services beyond the need to match generation with demand (net of imports). This need has come about because in a grid that is transitioning towards low emission renewables (especially wind and solar PV), there is increasing requirement on system operators to have access to frequency response, reserve and inertia services, and other grid services [31]. The conventional sources of these services are being lost as fossil-fuelled power generation is being displaced from the system. Figure 5 shows how MEGS compares to other modelling techniques.

Due to high levels of synchronous generation on the grid, historically the cost of these has been small and mostly neglected, and some services, like inertia, have been supplied for free [32; 33]. However, the perceived lack of importance of such services is no longer the case, as weather-dependent renewables have the potential to both increase demand for and reduce supply of these services.

The outcomes of the MEGS model seek to challenge current paradigms for understanding the total system cost (TSC) for electricity supply. Conventional modelling approaches make simple comparisons, which are made using traditional metrics like LCOE, do not take into account the grid system requirements. This modelling defines the resilience of a grid by its level of inertia and seeks to ensure that the operator has sufficient frequency response and reserve services to maintain a stable grid.

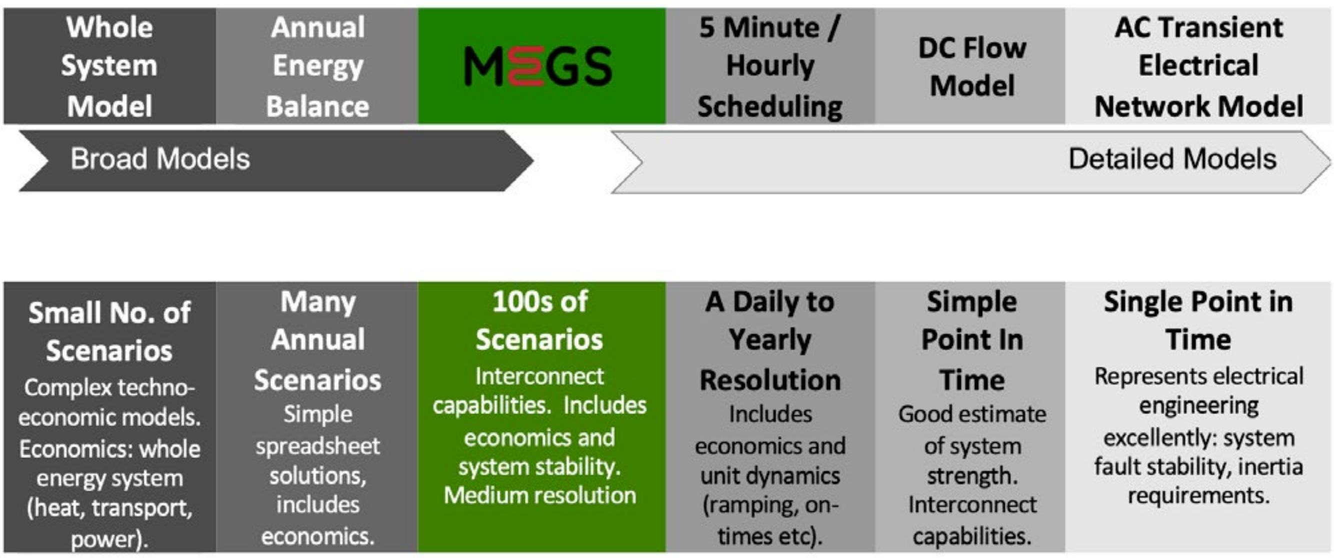


Figure 5: MEGS model comparison to other methodologies

MEGS Solution Procedure

The goal of MEGS is to determine the lowest cost asset portfolios for the National Electricity Market (NEM) that satisfy both the demand constraint and grid service constraints, whilst achieving a given level of emissions reduction. MEGS was configured to model the five regions of the Australian National Electricity Market (NEM), with interconnector constraints between regions built into the model.

A key functionality within MEGS is its ability to model future scenarios based on more than a decade of historical weather data. This is used to determine the impact that weather can have on various mixes of power generation technologies, in particular, more accurately reflecting the demand and utility of energy storage technologies and giving a more detailed estimated output of variable renewable energy (VRE). This is an important test to ensure a scenario outcome actually satisfies demand and grid service constraints in favourable and unfavourable weather conditions across all timescales.

MEGS solves in a time sequential manner, which enables storage to be modelled realistically [23]. Within MEGS, for short-term decisions the weather is known, but over the longer term its optimisation is based on seasonal averages. This avoids the lack of realism associated with perfect foresight, whilst simulating the ability to forecast weather over a time horizon of up to a week.

To ensure adequate grid service constraints are met, MEGS accounts for inertia both as a proxy for grid strength and for its damping effect on Rate of Change of Frequency (RoCoF) (refer to purple shading in Figure 6) [34]. MEGS also ensures that there is sufficient upwards frequency response and fast reserve for all timescales of less than 5 minutes.

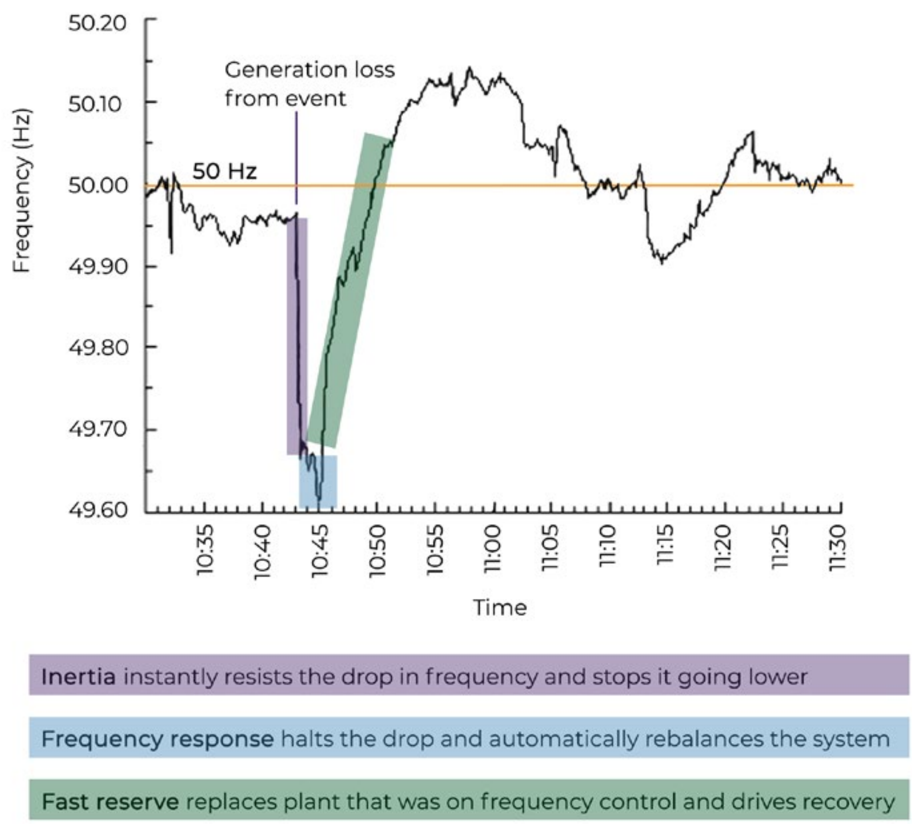


Figure 6: Types of frequency control services

The constraints at the core of MEGS are illustrated in Figure 7 to the left of the red brace, with the objective function displayed on the right. MEGS linearises all model variables, which allows it to use a highly efficient linear programming algorithm to find the optimum.

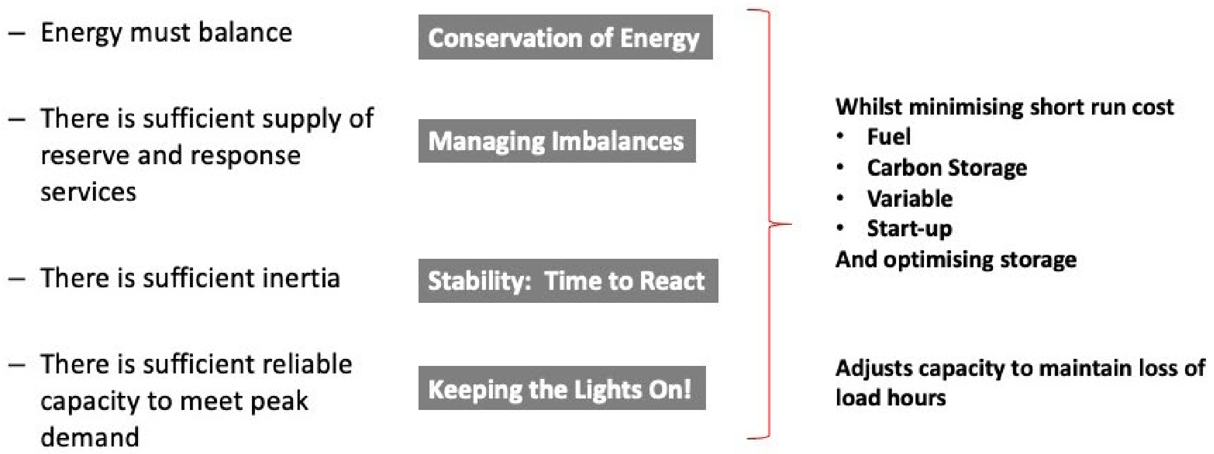


Figure 7: Definition of the constraints in MEGS

MEGS models regions with interconnectors that can carry both energy and reserve services. When MEGS is configured for the NEM as a whole, it treats it as an 'islanded' grid that consists of five state grids with relatively weak interconnections. The constraints on the left of Figure 7 are applied in each of the five regions, with interconnectors allowing transfer of energy or reserve services to fulfil those needs. The relative weakness of the interconnectors means that inertia (which is also a proxy for local system strength) cannot be transferred state to state. Likewise, it is assumed that each state will need to be able to cover its own demand with sufficient firm generation and storage capacity. Therefore, the minimum requirements for these must be met from within each state.

S-MEGS

To explore a large scenario space, MEGS needs to be run many times with different levels of capacity or input prices or weather patterns, depending on what is being tested. To facilitate this, a variation of MEGS was developed called Stochastic MEGS, or S-MEGS. This is in effect an algorithm to set off hundreds of annual MEGS runs with different variations of input parameters. To enable many runs to be completed, MEGS was set to run in a low-resolution mode with just 900 points to characterise the year. In the version used for this study, S-MEGS chooses a different combination of technologies, with capacities scaled randomly, that should achieve a high level of decarbonisation.

As S-MEGS randomly builds extra plant within the limits, it is a given then, that this capacity margin grows. To retain the same level of security in each scenario, high emitting plant was scaled back to give the same overall firm capacity margin over peak demand of +15% in each state.

Storage Algorithm

MEGS intentionally models storage with 'great care', including technology such as Concentrating Solar Power (CSP) that has inherent storage. Within a day, a perfect foresight algorithm is used to allocate generation and filling in a way that minimises total short-run costs for the day. In essence, MEGS is assumed to have a perfect weather forecast for the next 24 hours.

However, storage with a capacity of more than a few hours is optimised over a time horizon commensurate with its time scale for a full empty-refill cycle. The algorithm allocates an energy drawdown, or storage target, for each day according to limited foresight of the likely weather dependent generation and demand over that time horizon. The current day is optimised to satisfy that daily target with perfect foresight of the weather. For example, the current day scheduled takes the current simulated weather to determine renewable output and demand. Those days beyond the weather forecasting horizon are assumed to be a typical day for that season. The days in between the current day and beyond the weather forecast horizon are forecast as a mixture of the known weather and the seasonal average. Figure 8 shows how this knowledge of the wind (red) varies from the actual weather being used (blue) and the long-term average (green) over 10 days.

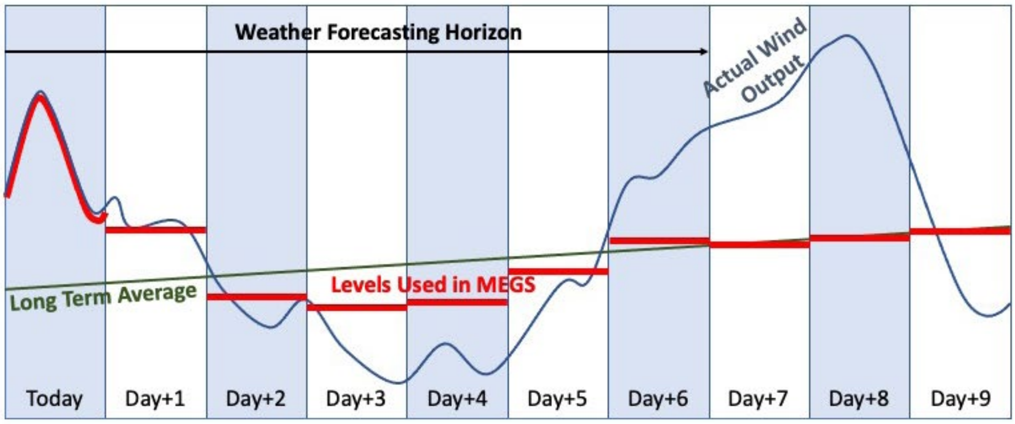


Figure 8: How MEGS uses actual weather data for forecasting storage operation

Capacity Credit

With the assumption of no increasing demand, the market is assumed to be fully supplied by an existing asset portfolio. Therefore, in order to maintain comparable market conditions, having the model "decommission" an equivalent quantum of existing capacity compensates for adding new capacity to this grid. To maintain and not compromise system security, decommissioning is constrained to ensure there is always sufficient supply capacity.

For thermal plant the assumption is that each MW of new plant allows 1 MW of old plant to be closed. For renewables, the calculation is more complex. MEGS calculated the capacity credit by first calculating the level of absolutely firm supply, which gave an unserved energy equal to the standard set by the Australian Energy Market Operator (0.002%) [35]. This was based on 10 years of data. A certain level of renewables were then added to the system (e.g. 1 GW of wind), and a new net demand calculated by subtracting output for those 10 years (as calculated by Renewables Ninja). The process of finding the level for 0.002% unserved energy was repeated. The reduction in this level was the capacity credit of the first GW of wind. Then a second GW of wind was added and the whole process repeated to build up capacity credit as a function of wind penetration. This function was then fed to MEGS as a best-fit logarithmic function, one for each state and one for each technology.

Impacts of Weather: Renewables Ninja

Historic data on Australia's renewable output is limited to the past 6 years for wind and 2 years for solar photovoltaic (PV), which is insufficient to represent the year-to-year variations in the underlying weather. To provide the consistent, long-term data required by MEGS, the half-hourly output from weather-dependent renewables was modelled using the Renewables Ninja platform [36]. This combines global weather data from NASA [37] with physics-based models of solar PV panels [30] and wind farms [38]. The simulation method is temporally and spatially explicit and is derived from consistent meteorological data meaning the correlations between wind and solar PV, between farms at different locations / in different states, and between renewable output and demand are modelled explicitly. Half-hourly capacity factors for each state were calculated based on weather data from the years 1999 to 2016, to align with historic demand data.

This technique is similar to that applied by Prasad [39] and Laslett [40], except that it also includes validation and correction to ensure that the resulting capacity factors match with reality. The underlying NASA weather data used in these studies under-estimates wind speeds in Victoria and NSW by 6–10%, and over-estimates speeds in Tasmania and Western Australia by 8–9%. Similarly, the irradiance data over-estimate solar PV capacity factors by 3–11%. Validation and correction was performed using output data from Australian Energy Market Operator (AEMO), the Australian PV Institute database [41] and solar PV Output database [42], using the methods described elsewhere [30; 38].

The wind simulation included each farm that was operating as of December 2016, consisting of 69 wind farms totalling 4,006 MW [43]. For the solar PV simulation, it was not possible to simulate the output of each individual panel in Australia as there are approximately 1.7 million systems (mostly small-scale rooftop installations) and their locations are not precisely known. The national solar PV fleet was simulated as a sample of 500 – 1,500 panels per state, which were randomly assigned based on the population density [44] multiplied by the solar PV installation density per Local Government Area (LGA) [41], so as to best match the actual distribution of installed panels. The orientation and tilt of each panel were randomly assigned based on the distributions observed from around 500 systems installed in Australia [42].

Australian National Electricity Market

Summary

Since its inception in 1998, the eastern Australian electricity system (the National Electricity Market) has been dominated by generation from black and brown coal generation plants, gas plants and hydro-electric operations. The policy-driven attempts to drive the National Electricity Market (NEM) to a much lower carbon-emitting system, in arbitrarily chosen time frames, need to be fully informed by rigorous analysis of the total system costs of the transition, a crucial element not currently considered.

A key factor for the NEM, as it has been since its inception, is the weak interconnection of its regions. Through the low carbon transition, the additional cost (both in terms of capex and eventual prices for consumers) of reducing or eliminating this problem of weak interconnection will be high. This will compound as a problem as both coal-burning generation is decommissioned, and a range of new technologies are introduced across the regions. The cost of technology integration will also differ from regions to region.

In summary the NEM:

- Incorporates around 40,000 km of transmission lines and cables.
- Comprises 5 weakly interconnected regions corresponding with each constituent state.
- Supplies about 200 terawatt hours of electricity to businesses and households each year [1].
- Supplies around 9 million customers.
- Has a total electricity generating capacity of about 55 GW in April 2020 [1], up from 54 GW in December 2017 [2].
- Saw $13.2 billion traded within the NEM in the 2019 – 2020 financial year [1].

Introduction

The technical aspects of the Australian National Electricity Market (NEM) are similar to other international power grids, consisting of power stations, transformers and switching stations, transmission and distribution networks and end users. The nature, size and scale, however, are unique to each jurisdiction, for example the United Kingdom, Germany, New Zealand, the United States of America and the Australian NEM all are vastly different in size and scale, as well as the natural resources each grid has access to.

In 2006 when Tasmania was physically connected in the Australian NEM, the NEM was dominated by black and brown coal, gas and hydroelectricity [45; 46]. While in the past decade wind and solar photovoltaic (PV) power have grown from very low levels to form an increasingly significant element of the energy generation mix (refer to Table 1 [47; 48]), their contribution needs to increase significantly to aid decarbonisation at a lowest total systems cost.

Table 1: The Transformation of the NEM, a comparison of 2006 and 2019, GWh

Technology	**2006**	**2019**
	GWh	GWh
Brown Coal	56,100	33,300
Black Coal	121,800	106,800
Hydro Power	14,900	13,700
Natural Gas	12,700	18,000
Solar PV	0	5,100
Solar PV (rooftop)	6	10,600
Wind	1,100	16,900
Other	300	1,000
Battery	0	100
Pumped Hydro*	--	100
Grand Total	**206,890**	**205,600**

*Estimated from average capacity factor

The Australian National Electricity Market and Interconnections

The Australian NEM commenced operation in December 1998. It interconnects five regional market jurisdictions – Queensland, New South Wales (including the Australian Capital Territory), Victoria, South Australia, and Tasmania (refer to Figure 9). The regions are connected together electrically via interconnectors and operate as "one market with multiple regions" [1].

The NEM involves the wholesale generation of electricity that is transported via high voltage transmission lines from generators to large industrial energy users, and to local electricity distributors in each region, who then deliver the electricity to homes and businesses. The transport of electricity from generators to consumers is facilitated through a 'pool', or spot market, where the output from all generators is aggregated and scheduled at five-minute intervals to meet demand. The market uses sophisticated systems to send signals to generators instructing them how much energy to produce each five minutes, so production is matched to consumer requirements, and sufficient spare capacity (known as reserve), is kept ready for emergencies. The current energy price can be calculated from the resultant generation stack [2].

The NEM includes generator plants, high voltage transmission lines, transformers and distribution lines on the supply side of its infrastructure. The demand side is made up of consumers in manufacturing plants, factories, offices and homes. While each region contains both major generation and demand centres, consumers may be supplied with electricity produced by any generator or combination of generators in the NEM. Interconnectors are used to import electricity into a particular region when the price of electricity in an adjoining region is low enough to displace local supply, or when local supply cannot meet demand.

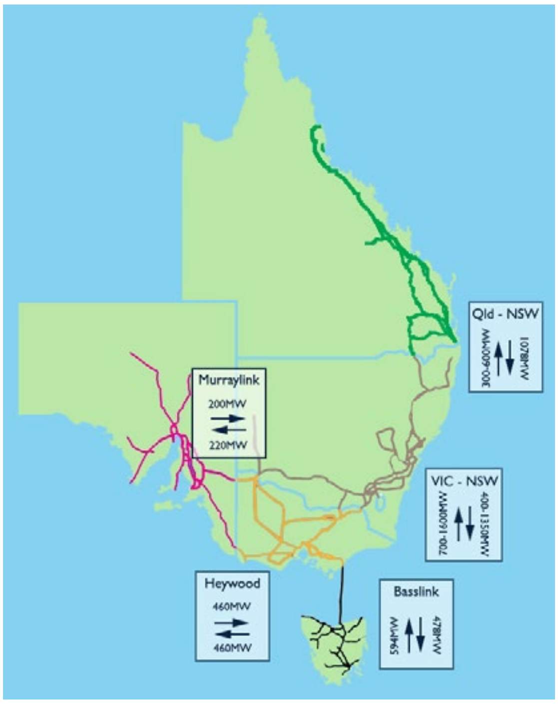


Figure 9: Interconnectors in the NEM 2020

Since supply and demand is kept in balance in 'real-time' and the connections between suppliers and consumers have limitations, congestion occurs from time to time. Congestion occurs because there are physical limits to the transmission infrastructure of the grid. Hence, congestion is specific to electricity flow, transmission capabilities and a specific point in time. Within the NEM, congestion may emerge within one five-minute dispatch interval and be gone before the next, or last for much longer periods of time. In theory, congestion may be eliminated if significant additions to interconnectors are constructed, however, this comes at additional cost.

International Experience – Great Britain

The electricity challenges currently faced by all levels of Australian governments is not unique. Great Britain has some similarities to the Australian system, with a diverse generation portfolio and a growing level of renewable penetration.

In 2008, the United Kingdom (UK) became the first country to set a legally binding target to decarbonise the energy system and set up an independent body to advise on the pathway and monitor progress. This organisation, the Committee on Climate Change (CCC), advised early on that the electricity system should be decarbonised first, preferably down to 50g/kWh by 2030. The UK government had accepted the carbon budgets set by the CCC and aims to decarbonise the electricity system by 2030, although with a central target of 100g/kWh [49]. More recently, however, the UK went beyond the prior commitment to an 80% reduction on 1990 emissions levels by legislating for a net zero greenhouse gas emissions target by 2050 [50].

According to the CCC, low carbon electricity generation will need to quadruple (to 645 TWh in 2050) to replace existing fossil fuel generation and to meet the expected increased demand from transport and heating [51]. The CCC suggest renewables are likely to provide over half of all electricity generation in 2050, with nuclear and decarbonised gas (either hydrogen or natural gas with carbon capture and storage (CCS)) providing the remainder [50; 52].

Since the early 1990s, the carbon intensity of the grid has been steadily reducing through a combination of low carbon support programs and good fortune. Renewables and nuclear have been encouraged through a number of support schemes over this period, and the availability of cheap gas in the 1990s combined with a market restructuring led to the "dash for gas", which replaced a large proportion of coal generation. In the last decade, European Union (EU) restrictions around SOx, NOx and other pollutants has restricted generation from remaining coal and in 2019 the UK announced that there would be no unabated coal generation post 2025 [53]. More recently, they have announced plans to consult on an even earlier closure of its unabated coal fleet [54].

There are a number of similarities between the Australian NEM and the UK National Grid:

- They both have a peak demand of around 50 GW.
- The NEM is completely isolated. The UK has only weak interconnections with continental Europe and Ireland.
- They have both seen a growth of wind and solar PV, the UK having 24% of its generation from these sources [55], compared to 8% penetration for the NEM.

There are some notable differences between the NEM and the UK electricity market:

- There are very few binding constraints within the UK grid. There is a constraint on flows between England and Scotland, but these are being overcome by "bootstrap" undersea cables.
- There is little hydro in the UK.

On the whole, the UK is a relevant case study for the NEM, with a number of similarities but being further down the decarbonisation path. Therefore, the conclusions from a prior Energy Research Partnership (ERP) study are worth noting [56]. These were developed by analysing the results of the forerunner of MEGS, which was written specifically to examine these issues:

- Firm low carbon capacity (such as nuclear, biomass or CCS) is needed to decarbonise fully.
- The value of technologies can only be assessed though whole system modelling.
- Grid services are becoming increasingly scarce and need markets to develop new suppliers.

Validation of MEGS Within the Context of the NEM

Introduction

Little confidence can be placed in a model that has not been validated against actual data. Although the architecture of MEGS is well designed to capture the main effects on key outputs, such as total system cost (TSC), an even greater confidence can be placed in a model that can faithfully reproduce the detailed generation on an hourly basis. If a good level of accuracy is achieved at this granularity, then more granular outputs, such as expected running regimes, interconnector usage and storage requirements, will have a commensurate level of accuracy. Furthermore, even greater confidence can be placed in the high-level aggregate outputs. This section presents the validation of MEGS at a high level and with hour-by-hour granularity.

State by State Validation

Validation was completed at a state-based level main, both for a standard 'complex weather week' and the annual generation for the state (illustrated as a pie chart). MEGS was run on 2.5-hour steps, which was found to be sufficient to characterise the main features of the day while maintaining granularity. The effect of the 2.5-hour steps can be seen in the sharper lines compared with the NEM data at 30-minute intervals for the entire period.

Queensland

The generation forecast by MEGS proved a reasonable match to the output recorded for Queensland (Qld) although the gas generation forecast by MEGS was initially too low. There are potentially two primary reasons for this. Firstly, a number of Qld's gas plant have legacy gas supply contracts at a significantly lower price than the price used in the modelling. Secondly, some of the gas plant maybe in a prime position to support Qld's long grid lines and sparse network and are therefore required to run for grid stability issues. MEGS does not model grid constraints like this that fall within a state.

To mimic the higher gas generation, some of the gas plant in MEGS is set to "must-run" status. This forces a minimum level of generation even when it would apparently be uneconomic at the current gas price to run.

MEGS shows some biomass generation not shown in the actual data. This is because this category of plant is not reported separately in the data source, NEM Review, and so does not show up in the left-hand chart (refer Figure 10).

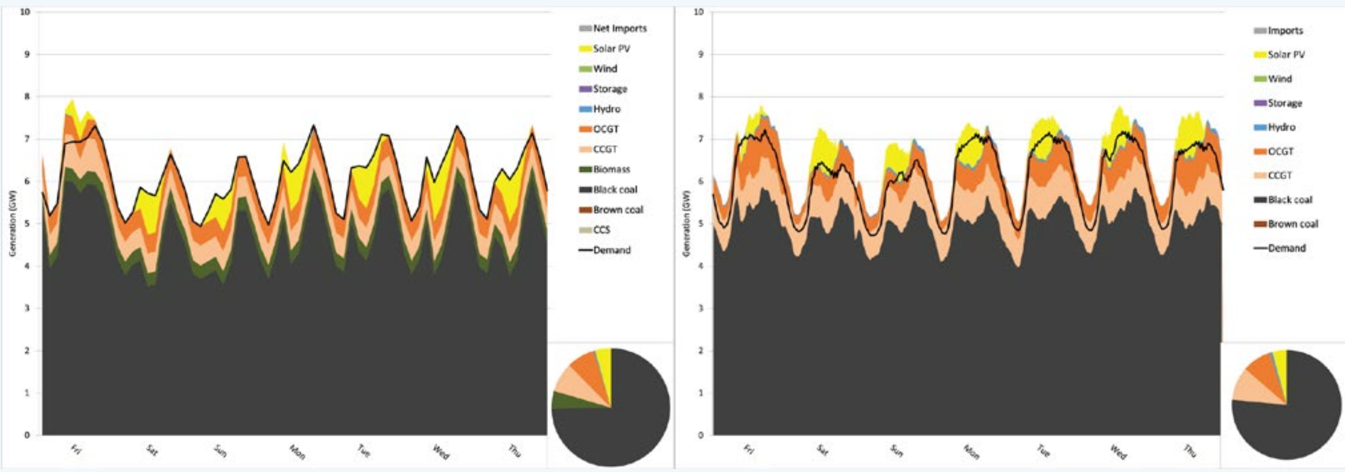


Figure 10: Comparing actual and modelled generation for Queensland

New South Wales

New South Wales (NSW) is dominated by black coal generation, as shown in both the charts above. MEGS slightly over predicts the level of coal generation and has import dependency of 6%, whereas in reality NSW generates slightly less and is reliant on imports for 12% of its energy. There is very good agreement with coal showing the same pattern of load following with a small amount of support from gas, hydro and wind.

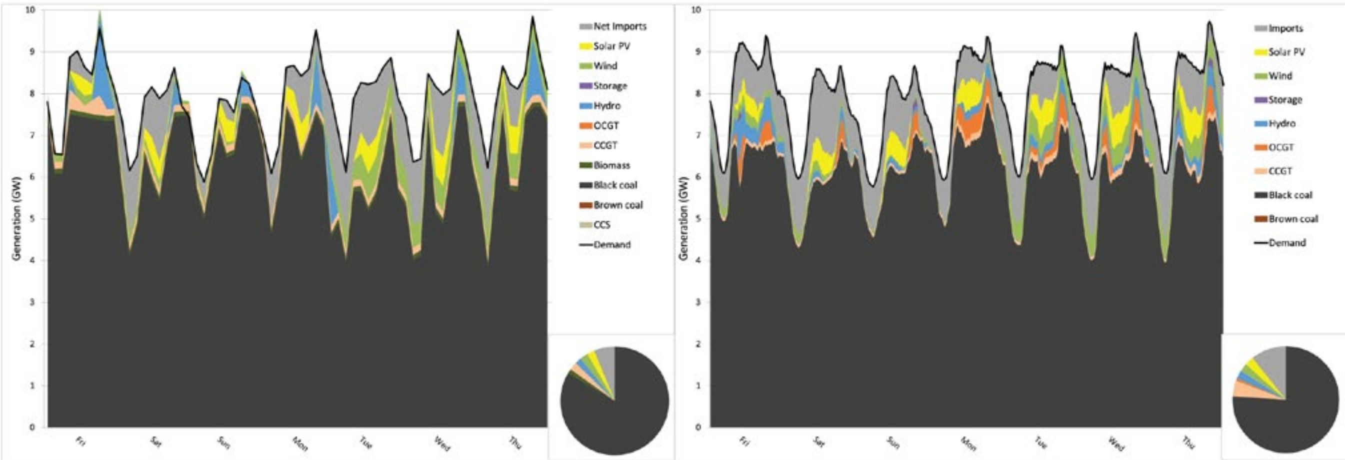


Figure 11: Comparing actual and modelled generation for New South Wales

Tasmania

The large portion of hydro generation and nominal thermal generation makes Tasmania quite different from the other states. Hydro is scheduled to over-produce at peaks to export via the Bass Link to Victoria. Tasmania draws in imports during low demand periods to enable the inflexible Victorian brown coal to run baseload. Although small in terms of generation and demand, Tasmania acts as a key provider of flexibility to the rest of the NEM. MEGS models this behaviour well.

AEMO recommends that at least 7.5 GW.s of inertia be available [57], MEG models this as the minimum in each state, however, the model suggests this was not achievable in Tasmania. It should be noted, however, a lower inertia is acceptable, within a region, so long as the system has smaller generation units and/or faster acting Frequency Control Ancillary Services (FCAS). In Tasmania, the system is secure against the loss of the Bass Link through the use of fast loss disconnection services contracted with an aluminium smelter.

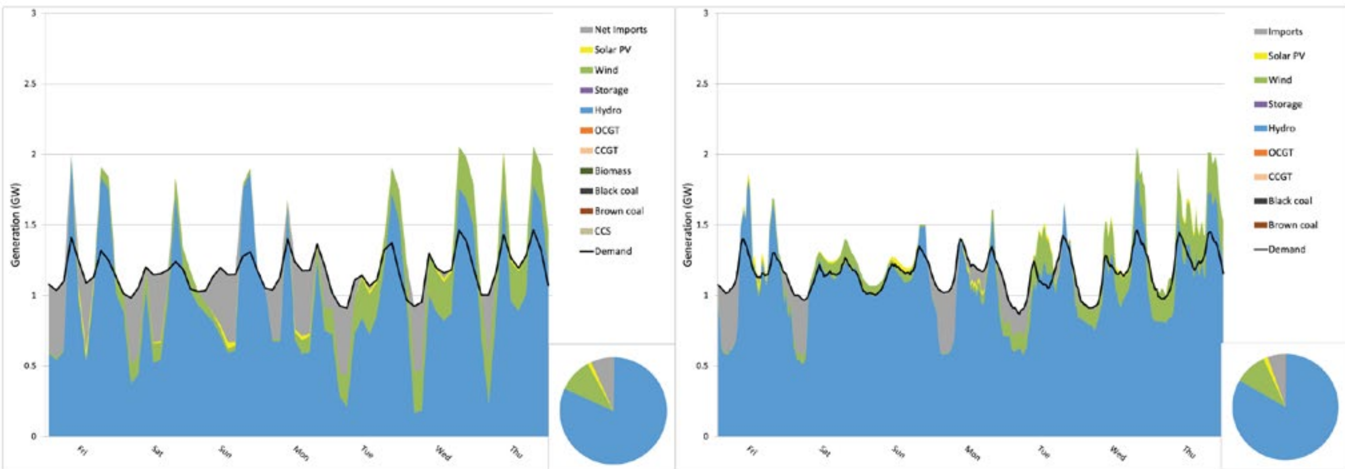


Figure 12: Comparing actual and modelled generation for Tasmania

Victoria

In 2015, Hazelwood was still open and providing up to 1,600 MW of brown coal-fired power generation for Victoria. Hazelwood and a further 4 GW of similar brown coal plant, allowed Victoria to be a net exporter to neighbouring states. The brown coal runs mostly baseload (a running pattern that is full power 24/7), very occasionally dipping load when demand is low and wind is plentiful, as both actual and modelled charts show in the centre. Modelled and actual output is very similar, with occasional extra generation from gas plant that MEGS does not pick up.

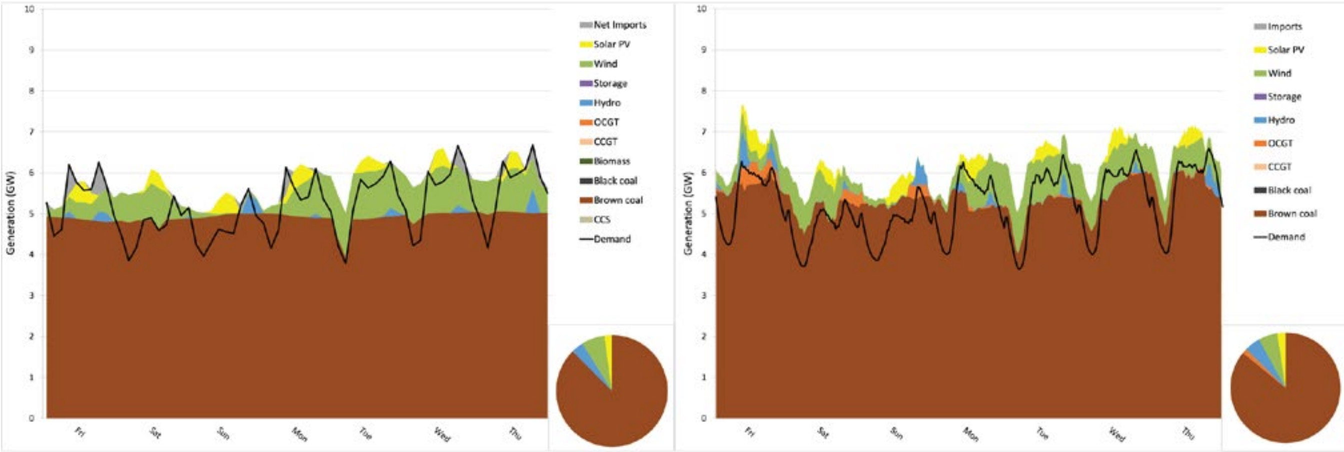


Figure 13: Comparing actual and modelled generation for Victoria

South Australia

South Australia has a very different profile to other NEM regions. Wind farm development has given it a generation profile strongly dependent on weather. The effect can be seen in the charts above where an average windy day is followed by a period with no wind, ending with four very windy days. South Australia is both absolutely dependent on and makes good use of the interconnectors to Victoria.

The interconnectors are a source of coal and gas fired power generation supply during shortfalls of renewables, and export during periods of excess. Victoria then is acting as a “purveyor of flexibility”, transferring it from Tasmanian hydro and moving it into South Australia.

MEGS predicts the pattern well, although the pie chart seems to suggest it slightly under-predicts the brown coal generation. However, this coal plant (Northern Power Station) has now been decommissioned and does not feature in the modelling work.

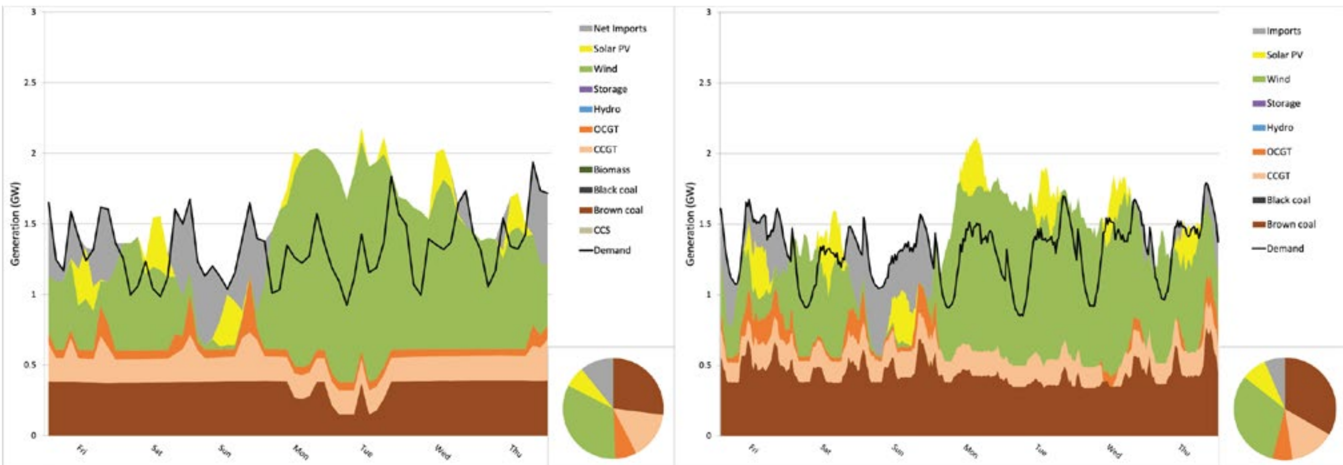


Figure 14: Comparing actual and modelled generation (MW) for South Australia

Using Total System Cost to Model the NEM

The power of using TSC and its derived metrics is best illustrated through the examples shown in Figure 15 and Figure 16 which have been calculated using MEGS. The purpose here is to demonstrate the methodology and to draw out broad lessons, as opposed to illustrating the optimal portfolio. However, the data is based on AEMO's Integrated System Plan [58] and in the mixed portfolios the capacity ratios have been optimised (TSC has been minimised) at the mid-point of the curves. Each curve started with the current portfolio and added a single technology option (reasonably distributed across the regions) until each technology reached a point in their curve where their abatement cost increased exponentially. Existing coal, currently the largest provider of firm electricity in the NEM [59], was decommissioned to the extent that grid adequacy was maintained at current levels.

Figure 15 shows the effect on TSC as each technology is added progressively to the system with the aim of decarbonisation. As expected, adding Ultra Supercritical (USC) coal cannot achieve more than 20% decarbonisation, confirmed as the curve recedes at 17% as further additions start to displace lower carbon plant, such as gas. Additions of wind made the most progress initially, but the increase in TSC accelerates as more is added. Coal with CCS is able to achieve a greater decarbonisation but is initially more expensive. Coal with CCS can be substituted with gas with CCS, however, when gas exceeds $9/GJ, coal with CCS begins to become the cheaper option for the most suitable plant.

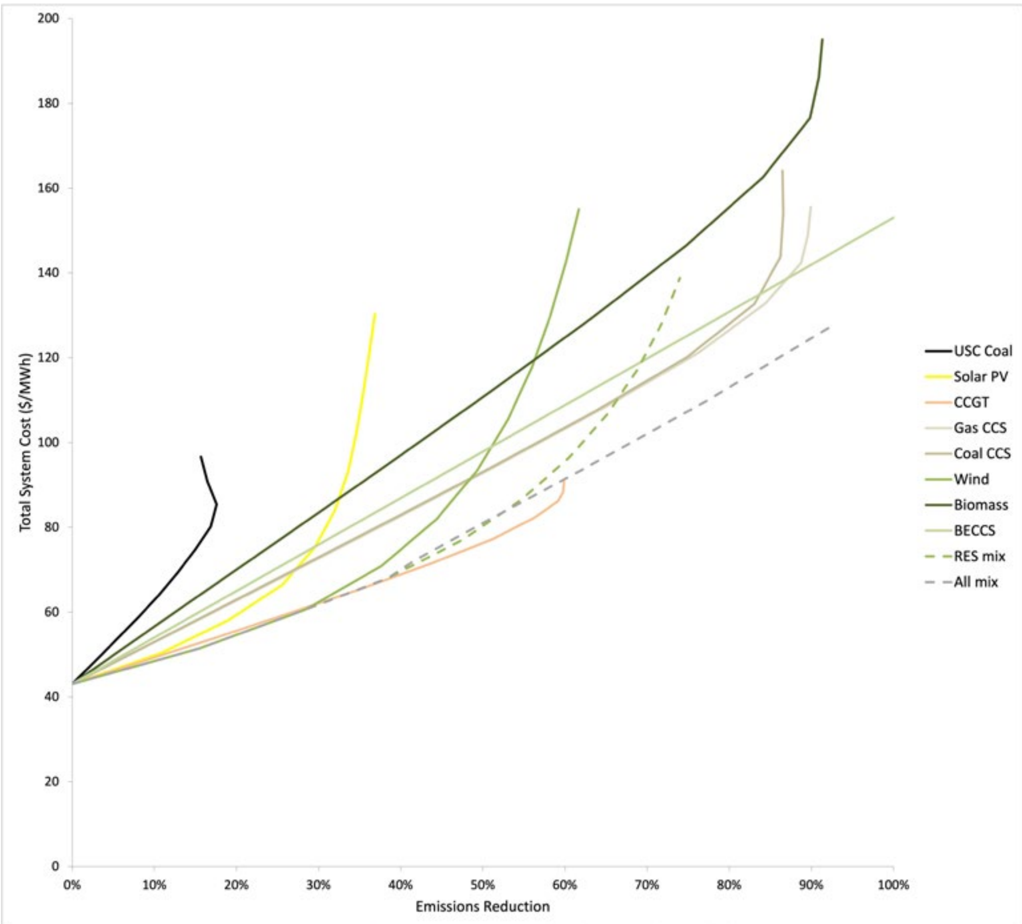


Figure 15: Calculation of TSC for key technologies for the NEM using MEGS

This becomes apparent through Figure 16, which shows the cost of abatement. For simplicity, gas technologies are omitted as is bioenergy carbon capture and storage (BECCS). Replacing old coal with new coal is predictably expensive and limited in effectiveness, as the efficiency gain only achieves incremental reductions in carbon emissions. The rapid saturation of the grid by unsupported VREs is apparent, as the solar PV and wind curves surpass $300/t at 30% and 50% decarbonisation respectively. With little storage on the system, their output is severely curtailed during high wind or sunny conditions, and further additions increasingly deliver the majority of their energy at times of grid surplus. CCS is clearly an expensive option compared to VREs for the initial stages of decarbonisation, but in contrast to VRE, its costs are relatively steady through to high levels of decarbonisation.

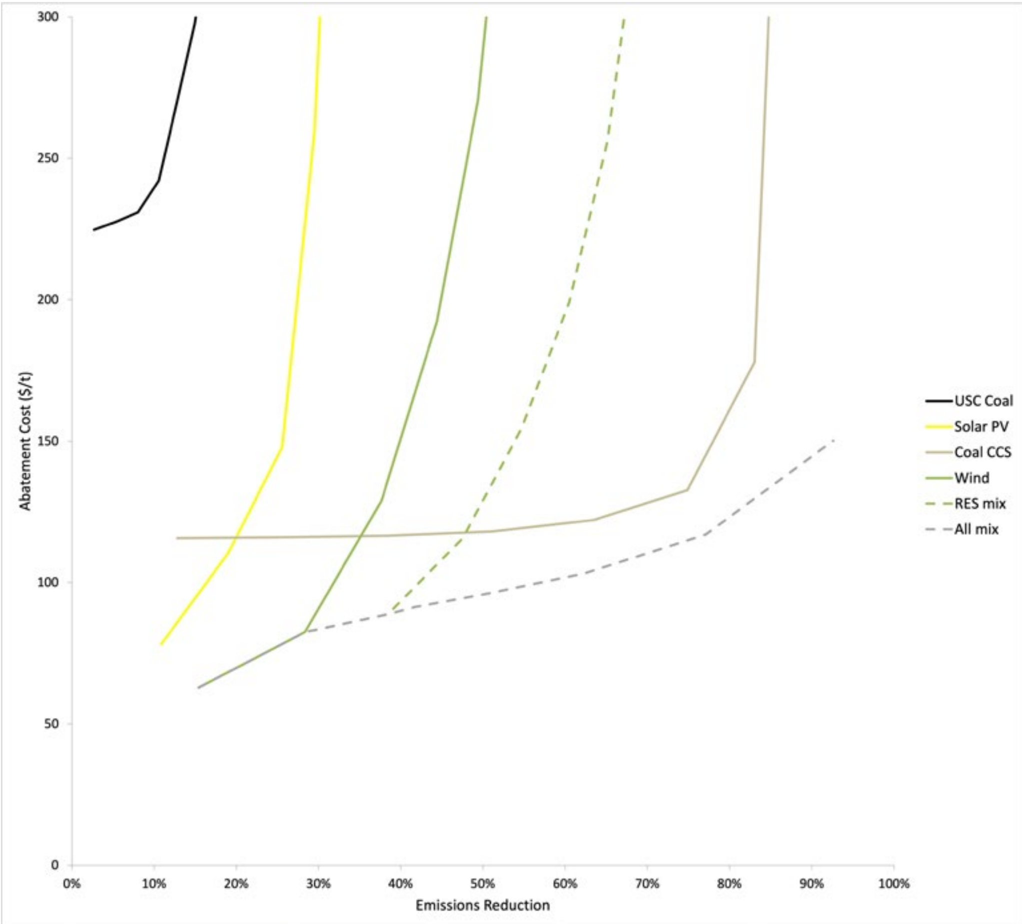


Figure 16: Calculation of abatement cost for key technologies for the NEM using MEGS

Even from this limited study the cost-effective nature of diversifying the grid, compared to investing in a single technology, is validated by the curves for broad technology mixes.

Single Technology Scenarios – the Three Horse Race

Summary

Technology advocates will often view decarbonisation as a race, with the levelised cost of energy (LCOE) declared as the key measure of who is winning.

The three technology focused scenarios examined here show that if decarbonisation is a race, the “winner” depends on where the finish line is. Are we talking a 100-metre sprint, a middle-distance run or a marathon?

Of the three scenarios presented here, the mix dependent solely on renewables is the cheapest for initial steps towards decarbonisation, at less than \$80/t CO_2 abated. It wins the sprint to initial decarbonisation.

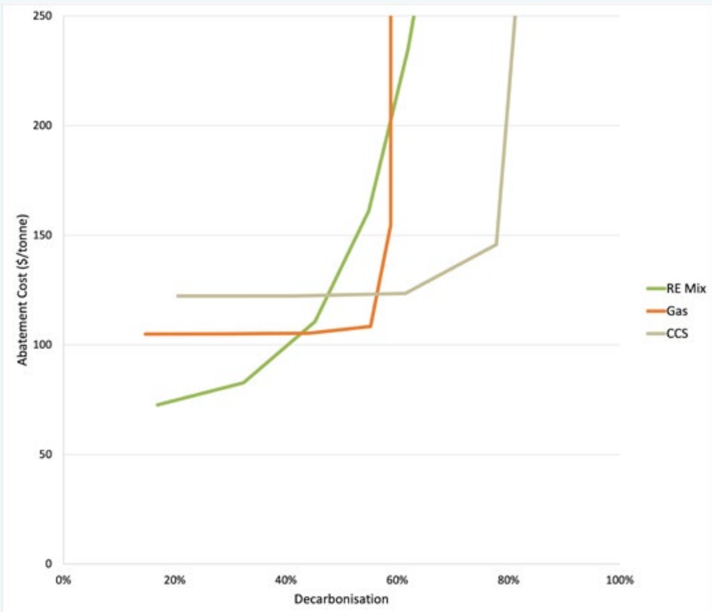
However, as the distance of the “race” increases, costs rapidly increase because renewable generation suffers diminishing returns due to large increasing costs of integration.

The gas mix is a bit slower off the blocks. However, beyond a 45 per cent reduction from today’s emissions levels at a cost of around \$100/t CO_2 abated, it wins the middle-distance “race” comfortably. However, this option’s costs rapidly increase as the gas mix hits its decarbonisation limits.

The third scenario featuring carbon capture and storage is a slow starter. With an initial \$120/t CO_2 abatement cost, it is not competitive until at least 60 per cent decarbonisation is reached. However, as the modelling demonstrates, it is a clear winner if the goal is achieving deep decarbonisation.

Non-partisan reflection on this situation should clarify that rather than low carbon technologies competing to win the decarbonisation “race”, they more resemble players in a sports team. Restrictions on the availability to the team of any of them will prevent the side as a whole reaching its goal, which in this case is decarbonisation at the lowest total system cost.

As highlighted previously in this book, decarbonisation of the NEM will require access to all available technologies to build the optimum team.

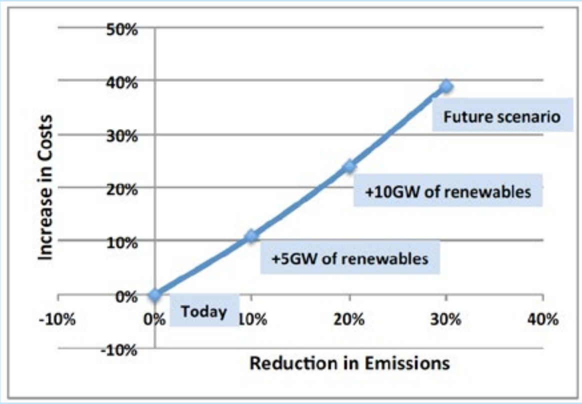


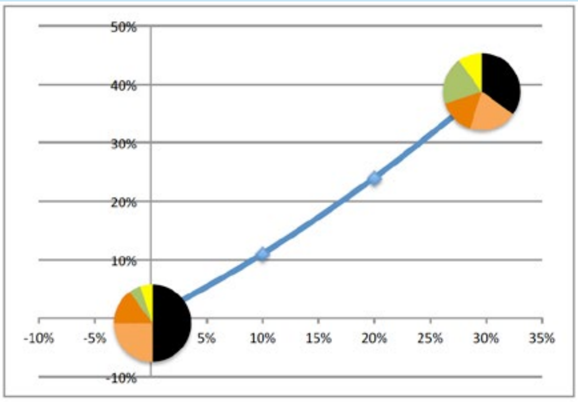
Introduction

Timely and appropriately targeted investments in power generation are key to decarbonising the power sector. When taking a total system cost approach, technology neutrality is important to enable the system to optimise to the lowest cost for a particular decarbonisation target. However, it is instructive to understand the impacts of targeted sector pathways, for example, what is the impact on cost and decarbonisation potential of a renewables focused approach.

Decarbonisation Pathway Curve

The contribution of a particular electricity generation technology to decarbonising the grid is examined in the results section using decarbonisation pathway curves. To generate these curves, multiple runs of MEGS are undertaken to examine the effect of progressively adding one type of generation plant. The curves plot the grid carbon intensity (x-axis) and TSC (y-axis).





The costs modelled here are the annualised costs of capital for new plant with all fixed and operating costs going forward. No attempt has been made to calculate the depreciation and debt repayment costs of prior investments, which will be the same for all scenarios. Generally, the base case will be shown at the origin, and successive plots in steps of new build will be illustrated as points on a line moving away from the origin.

For example, the TSC starts in the bottom left for the base case and as 5 GW of mixed renewables are successively added to the system, it makes progress on decarbonisation but also increases cost. The points represent scenarios with different plant mixes, as illustrated with the inset pie charts on the right-hand plot. The aim of decarbonisation is to move to the right, at the lowest cost (flattest line). Ideally costs would go down, but there is no pathway that has been discovered through this modelling that achieves such a reduction in the absence of a subsidy or other intervention in the economics (markets, etc.).

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Technology Options to Decarbonise the Grid

A number of different generation technologies have been proposed as being able to decarbonise the grid. MEGS was used to examine three options: renewables, combined cycle gas turbines (CCGT), and supercritical coal with carbon capture and storage. For each technology group, new capacity was added in steps to explore the pathway to a lower carbon system.

A starting point, or base case, was chosen that best reflected the NEM grid portfolio and conditions in 2017, however, the analysis was conducted using the 2015 weather data as this proved to be a "typical" or "ordinary" year [25].

Renewable, gas and carbon capture and storage pathways are explored in the following sections.

Renewables

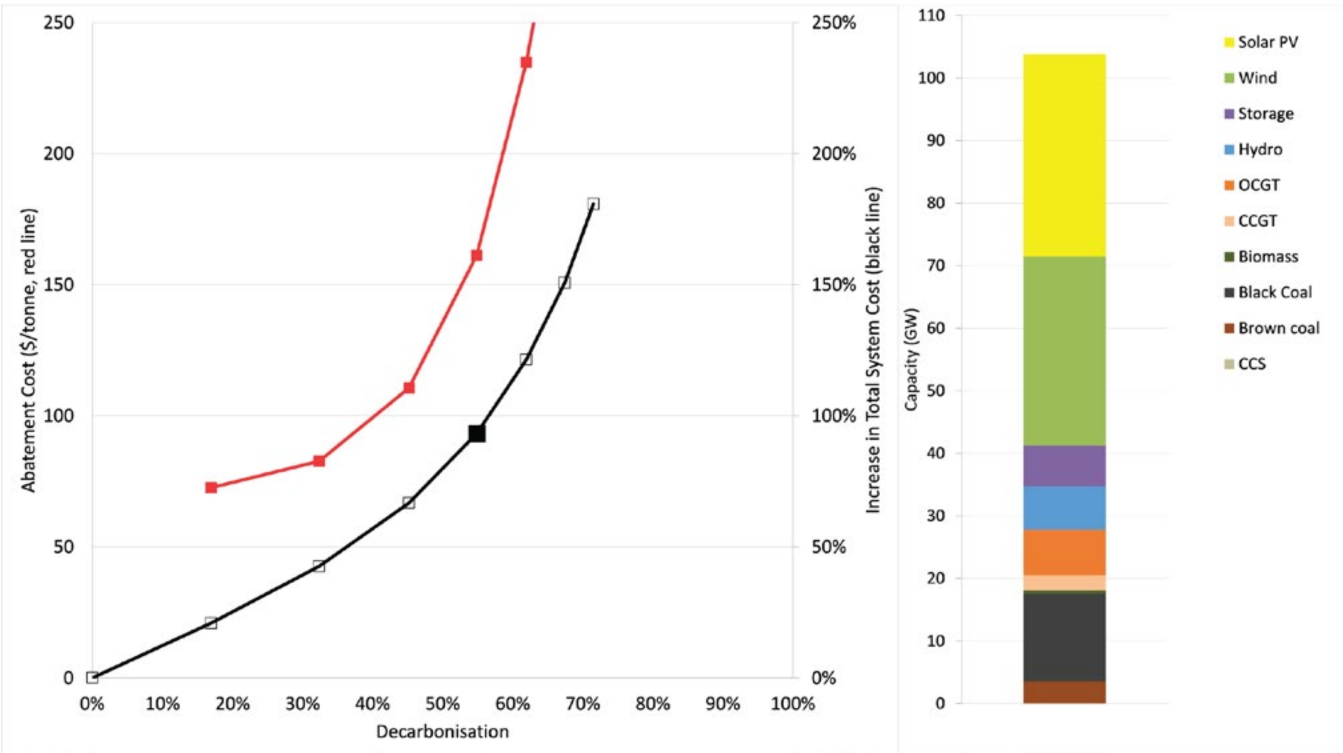


Figure 17: Pathway to decarbonisation using renewables (2017 base case)
(black curve – left axis, red curve – right axis, black square – capacity stack, right hand bar chart)

In this scenario, a mixture of renewables is added to the grid, supported by some battery storage. Each point on the black line, moving away from the origin, represents an additional 15 GW of capacity added, distributed amongst the states according to their demand and suitability for solar PV or wind (i.e., most solar PV is added up north, and most wind down south). The capacity additions include a small amount of 4-hour battery storage, for which 10% by capacity was found to be the optimum amount in terms of TSC. Alongside the capacity additions, as much coal plant is decommissioned as possible without compromising grid security. The slope of the line is the cost of abatement, which is shown as the red curve.

The first step results in a reduction in carbon emissions of around 17% at a cost of $75/tCO_2$. However, successive steps see a diminishing return for emissions reductions and an accelerating cost, which makes for a rapidly increasing abatement cost, reaching approximately $230/tCO_2$ at 60% decarbonisation.

The bar chart shows the capacity on the system by step four (marked on the chart with the black square), which achieves an emissions reduction of 55%. This required an additional 27 GW each of wind and solar PV. This is equivalent to building Australia's largest wind farm 60 times over and the largest solar park 80 times over.

Gas

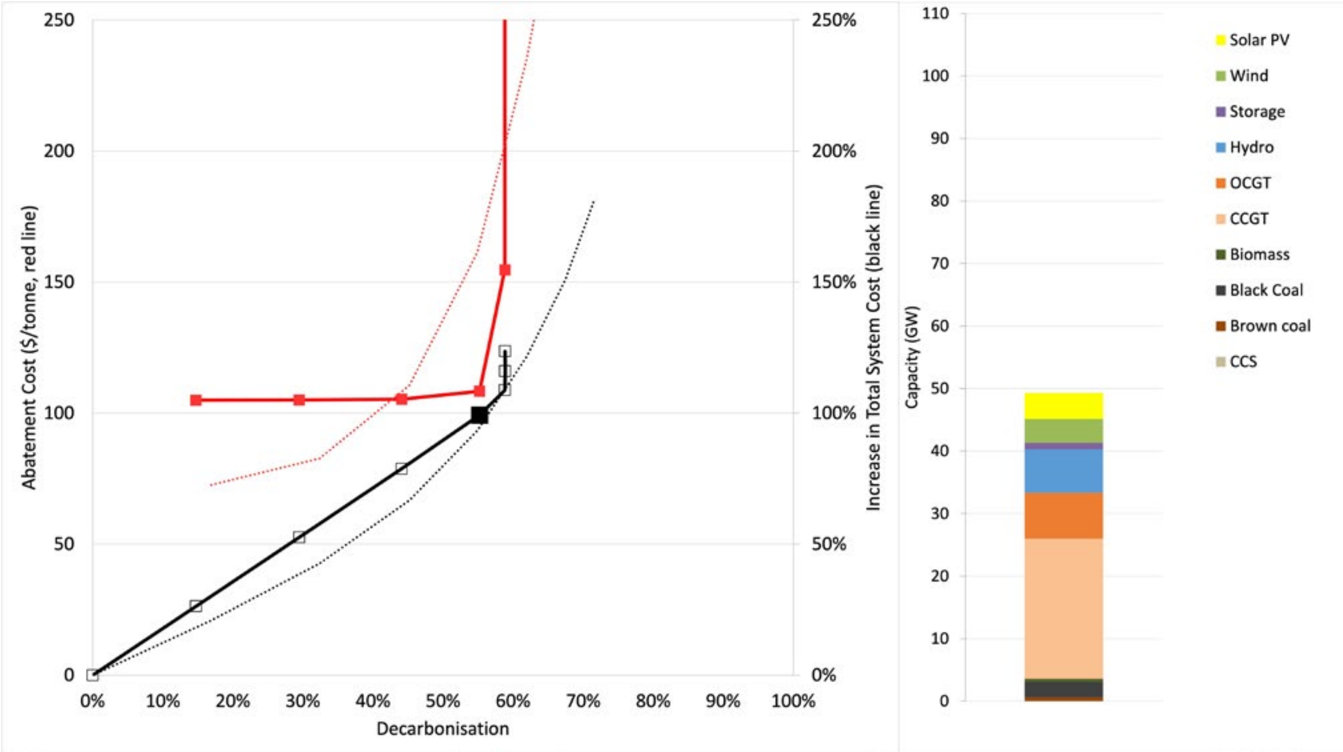


Figure 18: Pathway to decarbonisation using gas (2017 base case)
(thin red and black lines using renewables from Figure 17)

The second option modelled was to build CCGTs, which is a high efficiency way of generating electricity from gas. They are as reliable as coal so can replace it on a like-for-like basis in terms of power and grid services delivery. Each step represents the **addition of 5 GW** of CCGT distributed between Qld, NSW and Vic. The other two states already have a low emissions intensity due to their high renewables grid mix, so adding gas here would achieve little in terms of decarbonisation.

To aid comparison, the chart shows the results for the renewable scenario as thin faint lines. The addition of unabated gas to the system initially makes good progress, displacing coal and, as a result reducing emissions. However, after 23 GW have been added and all the existing coal has been closed, no further progress can be made as gas is now the technology with the highest emissions profile on the grid. After this, further progress can only be made by switching tactics and adding a lower emission technology to displace the newly built gas plant, or by adding CCS to reduce its emissions. The cost of abatement is initially more expensive than adding renewables, but unlike renewables, costs are constant until nearly all the coal has been replaced.

The bar chart shows the scale of change for step four. It achieves the same effect as the 60 GW renewables scenario at the same cost with just 20 GW of CCGT, however this scenario requires almost the complete closure of the existing coal fleet.

New Build CCS

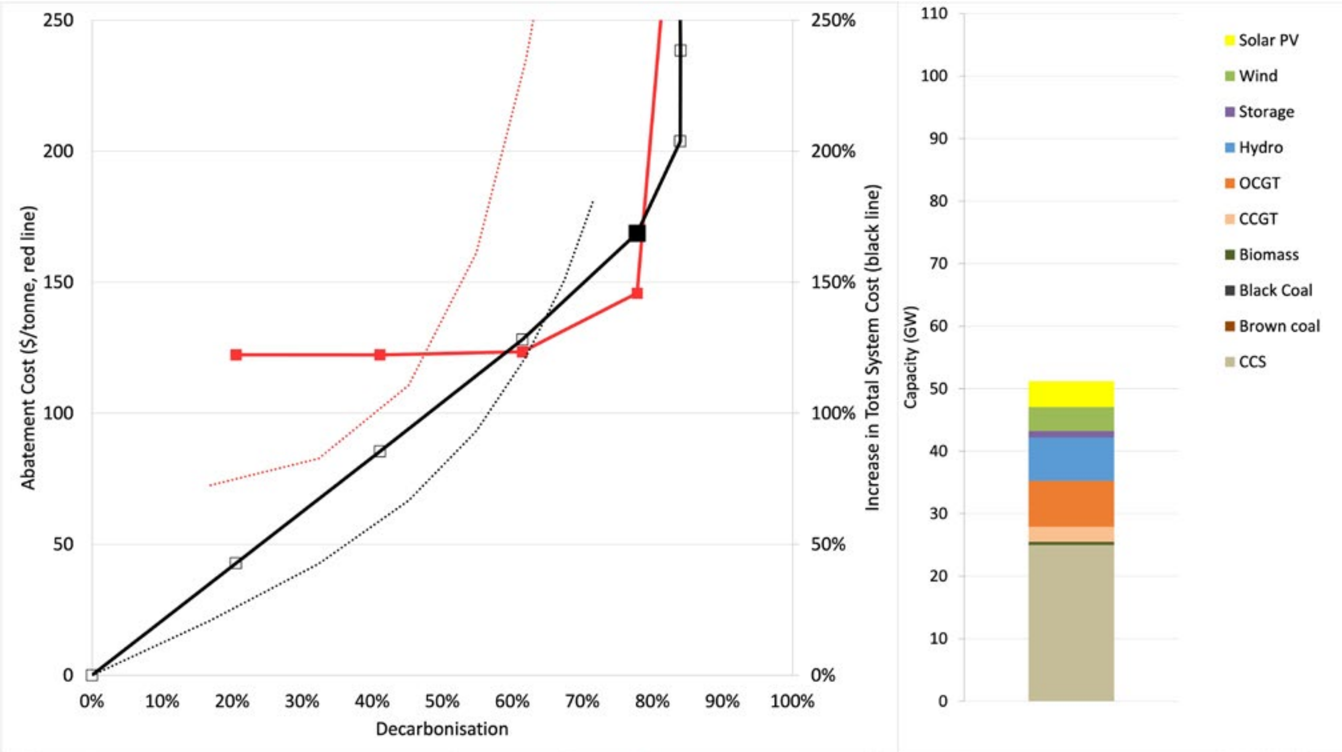


Figure 19: Pathway to decarbonisation using new build coal with CCS (2017 base case) (thin red and black lines using renewables from Figure 17)

The final chart in this series shows the effect of building coal with Carbon Capture and Storage (CCS). The initial steps are more expensive than renewables, but the abatement cost curve crosses over around 45%, after which renewables becomes a more expensive way of decarbonising the system. Of all the options explored, CCS offers the potential to go the furthest, achieving 80% emissions reduction. The scenario modelled was for brown and black coal to be built complete with CCS, but gas CCS is also an option and would be about the same cost as coal at a gas price of $12/GJ.

Role of Snowy 2.0 in Decarbonising the Grid

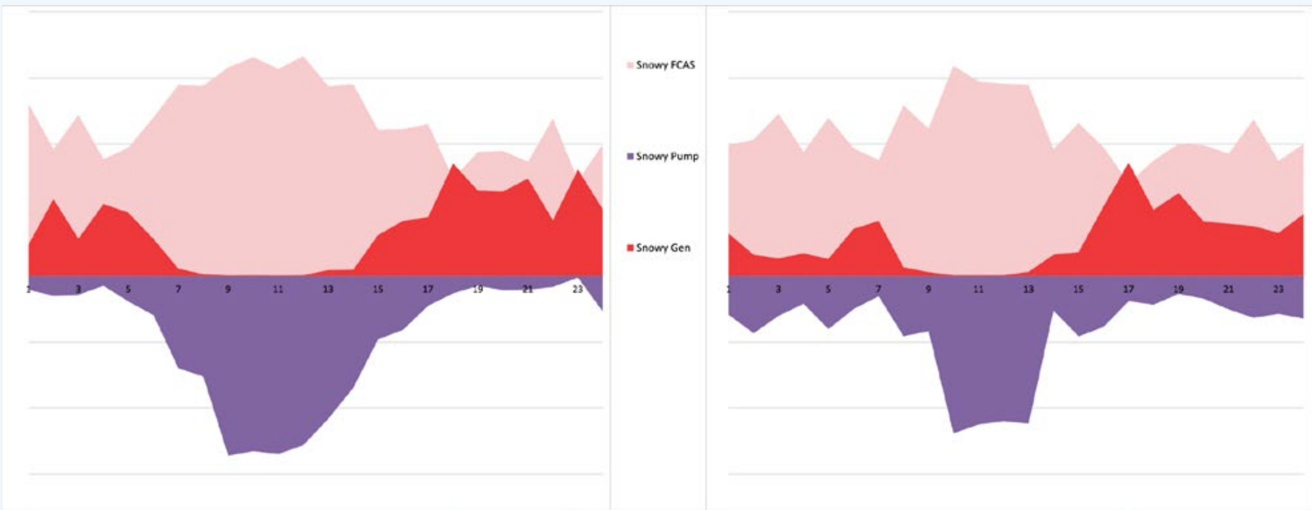
Summary

Along with Tasmania's Battery of the Nation (BoTN), Snowy 2.0 is conceived as the next major stage of large-scale energy storage projects for the National Electricity Market (NEM).

Snowy 2.0 is projected by Snowy Hydro to come online progressively from 2025, and to eventually provide the east coast market with 2,000 MW of dispatchable power and 350,000 MWh of pumped hydro energy storage.

While this large new level of storage will help support firm electricity supply in the NEM, especially during renewable energy droughts caused by long periods of calm weather or sustained wet weather on the east coast, it is actually a relatively small resource for a future market with very large variable renewable energy (VRE) capacity and decreased coal-burning capacity.

In a high renewables world, Snowy 2.0 is likely to operate as a peaking plant for much of the year, able to meet grid needs for a few hours in late afternoons and early evenings when solar PV availability, in particular, falls away as sunset approaches. As clarified by the project feasibility study, there needs to be significant upgrading of transmission from the Snowy system into Victoria and New South Wales to enable this addition to grid support.



Snowy 2.0 MEGS modelled average service in January & May in a deep decarbonisation scenario

Introduction

As Australia seeks to decarbonise its electricity sector, the move away from conventional gas and coal generation technologies to low emissions technologies, such as variable renewable energy (VRE) supported by energy storage, is underway. The core objective of transformation needs to be based on reducing emissions and utilising the competitive and energy advantages that come with Australia's natural resources. Of course, this objective needs to be achieved alongside energy security constraints and at the lowest total system cost (TSC).

Within this transformation process, many uncertainties of a changing energy sector must be considered. Factors such as the existing generation assets, particularly black and brown coal generators, that are ageing and approaching the end of their technical lives. It remains uncertain how these will be replaced and how the grid will operate without them. The current VRE penetration in the NEM (refer to Figure 20), along with future forecasts of VRE capacity means that the future electricity system will look very different than it does currently. Importantly, the magnitude and type of grid services available and required will depend on the characteristics of each region. Various types of energy storage are expected to play a major role in the provision of these services.

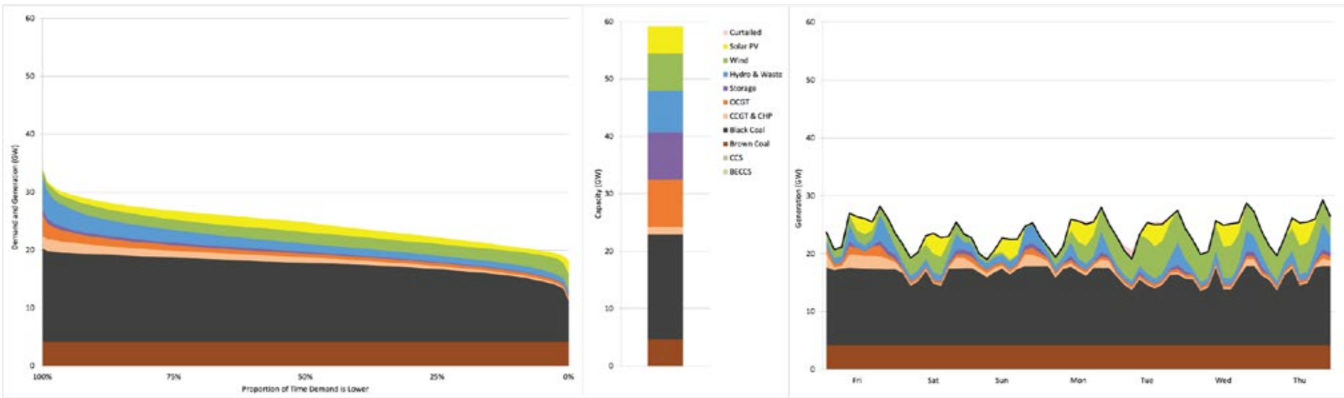


Figure 20: The NEM profile, 2018

Snowy 2.0 Configuration

Snowy 2.0 will connect Tantangara in the east (upper reservoir) to Talbingo in the west via tunnels which will be 27 km in length and 10 m in diameter (refer to Figure 21). This will deliver 350 GWh of storage working within the existing range of lake levels. The energy storage will be accessed via a new 2 GW pumping/generating power station built on the tunnel between the lakes. There will be six 333 MW pump/generators, three of which will be synchronous and three will be variable speed drives [60]. The feasibility study made it clear that to be of value, there needed to be an a significant upgrading of the transmission from the Snowy scheme, both south into Victoria and north towards Sydney [61]. The contract to build Snowy 2.0 was awarded to Salini Impregilo for $5.1B [62], and as Snowy Hydro have estimated that the necessary transmission upgrades will cost up to $2B [63], the entire capex used in MEGS is $7.1B.

Snowy 2.0 is assumed to be committed, a Snowy 3.0 (or beyond) is much more speculative. There is potential to expand the capacity of the Snowy scheme and add further pumped hydro, however, nothing has been announced. For the modelling, it will be assumed that Snowy 2.0 can be repeated twice more (at the same cost) for the sake of scenario exploration.

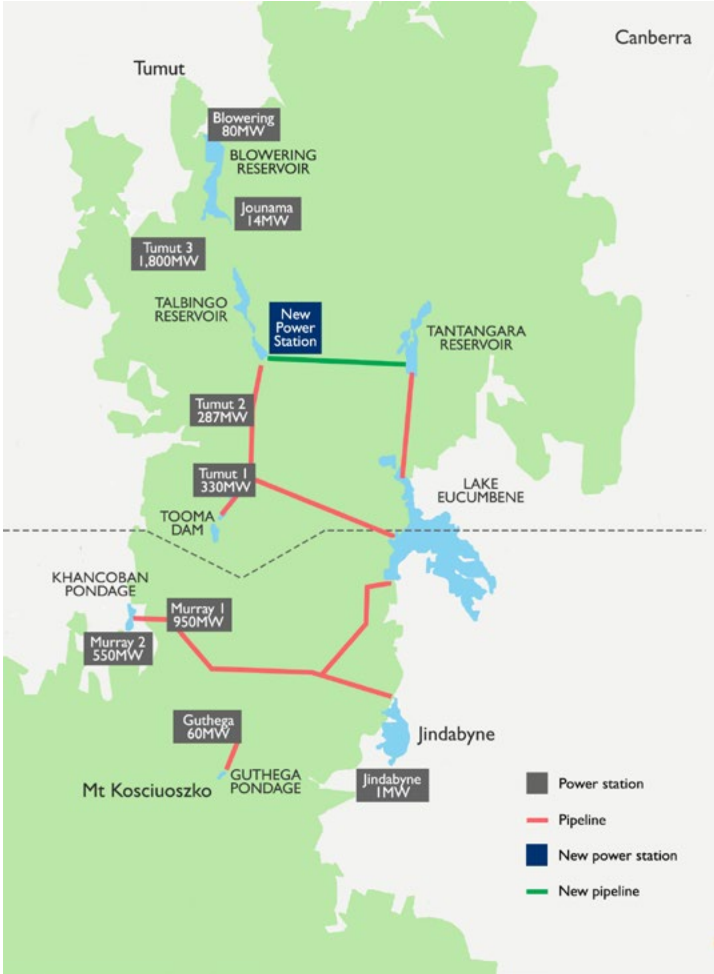


Figure 21: Snowy 2.0 configuration

Impact of Snowy 2.0 on Deep Decarbonisation by 2050

The lowest TSC solution to achieve deep decarbonisation will be diverse, as all technologies have natural limits in terms of what and how much that they can contribute to the decarbonisation target. Each technology brings a unique collection of services and commodities, along with its own set of challenges that require mitigation. The resources each region in the NEM has available are also diverse. Within this complex context, this study explores both deep decarbonisation solutions and the role of Snowy 2.0, whilst seeking to minimise TSC.

The optimum suite of technologies to deliver a lowest TSC outcome for the deep decarbonisation scenario by 2050 (90% decarbonisation) was determined. Neither Snowy 2.0 nor the Battery of the Nation (BoTN) were included as part solution at this stage. Figure 22 details the optimum lowest TSC solution. Without Snowy 2.0 there is a significant need for fossil fuel based CCS (over 12 GW) and a small amount of bio energy carbon capture and storage (BECCS) with its associated negative emissions, to achieve 90% decarbonisation. In such a deep decarbonisation scenario, unabated fossil fuel generation must be minimised to both achieve the 90% decarbonisation target and limit the use of expensive BECCS. The model indicates for this scenario that no unabated black or brown coal generation remains. While there is a significant amount of gas-based capacity, it has very low capacity factors, with its role to ensure sufficient supply during periods of low VRE generation.

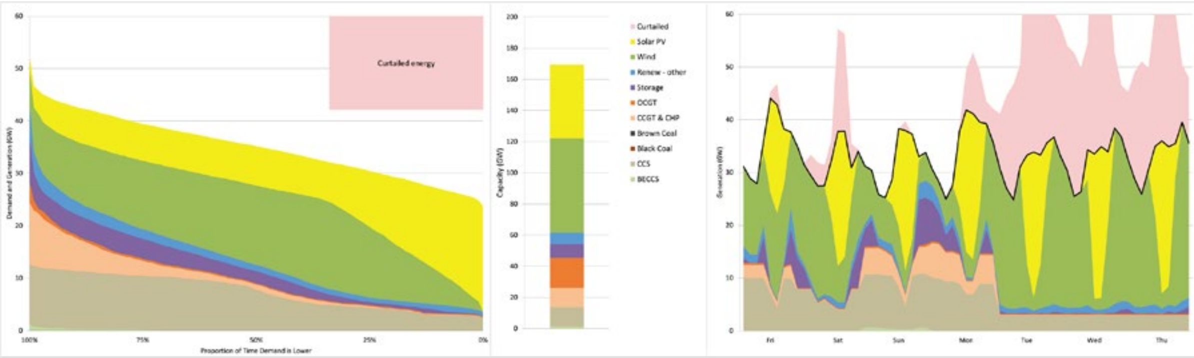


Figure 22: Deep decarbonisation, optimum generation mix – excluding Snowy 2.0 & BoTN

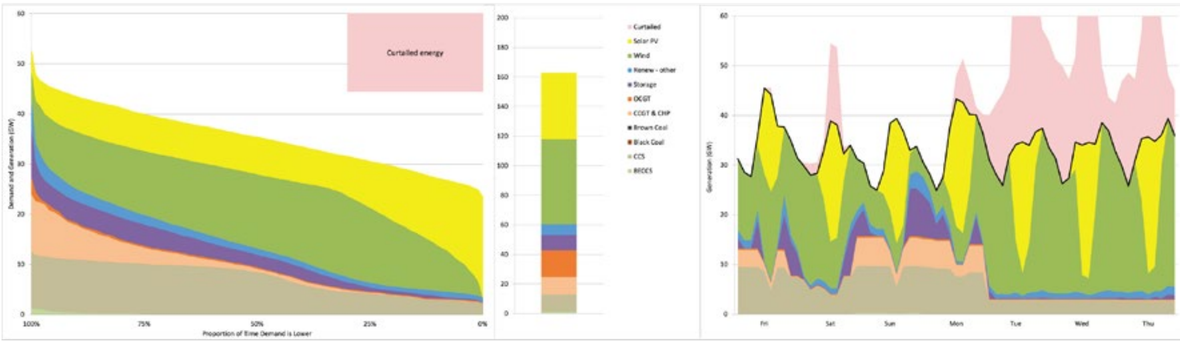


Figure 23: Deep decarbonisation, optimum generation mix – including Snowy 2.0, Excluding BoTN

There is change in the capacity required and generation profile produced from the addition of Snowy 2.0 in the deep decarbonisation scenario. The addition of long-lasting storage causes wind output to increase significantly. This is despite the model building less wind generation capacity. The increased output is a direct result of Snowy's ability to store generation that would otherwise have been curtailed in periods of excess.

Snowy 2.0 also reduces the need for Open Cycle Gas Turbine (OCGT) capacity, as it acts as a short duration generator to meet some of the occasional peak demand requirements that are traditionally secured by the use of OCGTs. The level of pumped hydro energy storage (PHES) within the total system is increased by 2,000 MW due to Snowy 2.0, however Snowy 2.0 also decreased the need for 400 MW of battery storage.

Both the capacity and generation required from CCS decreased. This is due to a combination of grid services that Snowy 2.0 is able to supply, its firm capacity, the availability of long duration generation from stored energy, and the increased generation from combined cycle gas turbine (CCGT) plant. BECCS capacity decreased slightly, and coal-based CCS decreased more significantly (refer to Figure 24).

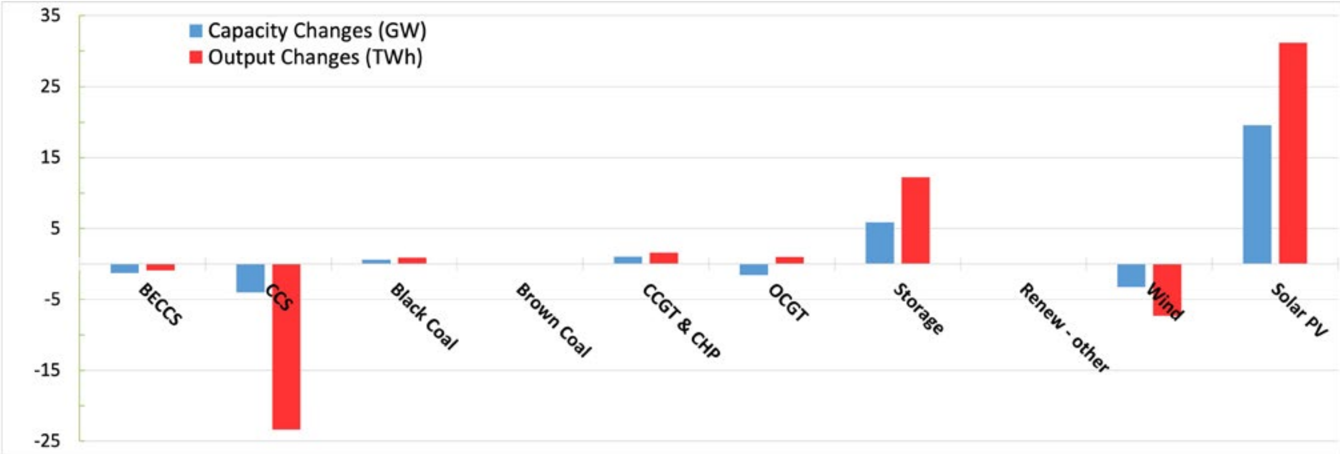


Figure 24: Comparison of generation capacity and output (including Snowy 2.0) – deep decarbonisation

Snowy 2.0 Utilisation in a Deep Decarbonisation Scenario

When its utilisation is optimised to minimise system cost, Snowy 2.0 is in almost continuous use across the much of the year. Its role and utilisation, however, vary depending on the season and the amount of VRE generation. Figure 25 and Figure 26 show its utilisation within the deep decarbonisation scenario (assuming only Snowy 2.0 is built). In the summer (Figure 25 highlights its operation in January), Snowy 2.0 often operates as a peaking plant, similar to an OCGT, as its output is generally peaking when solar PV no longer generates. It operates in a storage mode on a daily cycle, with pumping closely correlated to solar PV's output. Much of the time it is also used to provide frequency response services (shown as Snowy Frequency Control Ancillary Services (FCAS) in Figure 25). From a TSC perspective, this provision of frequency response is at very little extra cost. This operating behaviour allows Snowy 2.0 to support 25 GW of solar PV in NSW and Vic.

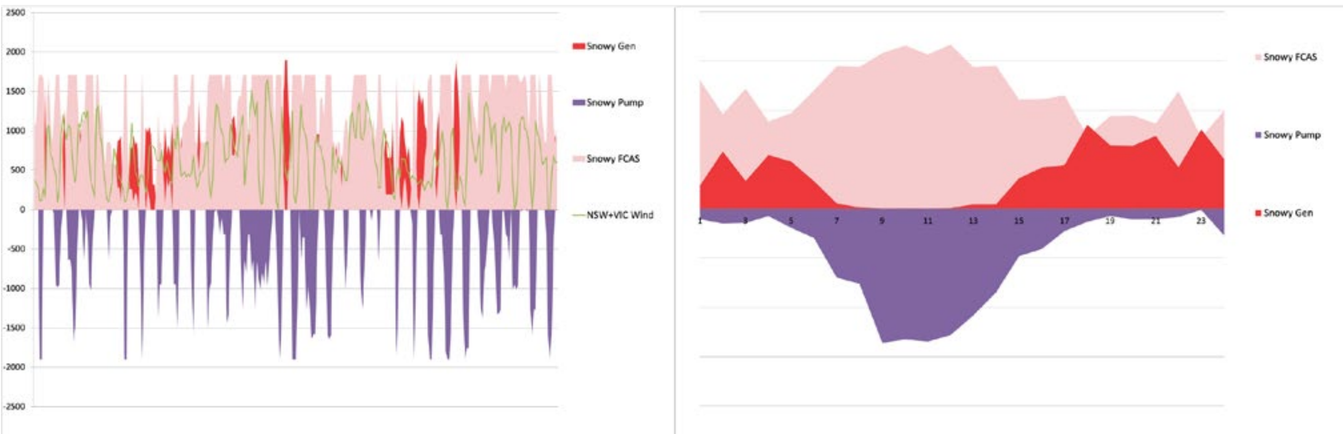


Figure 25: Snowy 2.0 utilisation in January – deep decarbonisation scenario

In the winter, the modelling shows that Snowy 2.0 would need to operate differently. While there is still a pumping peak around midday and generation is still provided overnight, the 'drumbeat' of daily solar PV driving the storage is less evident. The excess wind that is absorbed by Snowy 2.0 in storage mode can be seen as sustained periods in the first half of May. Wind output is high during this period. In fact, each midday, the wind is curtailed as solar PV floods the market (as illustrated by the regular dips in wind almost to zero in Figure 26). When the wind output drops in the middle of the month, Snowy 2.0 is mostly in generation mode, with only short pulses of pumping when PV output peaks.

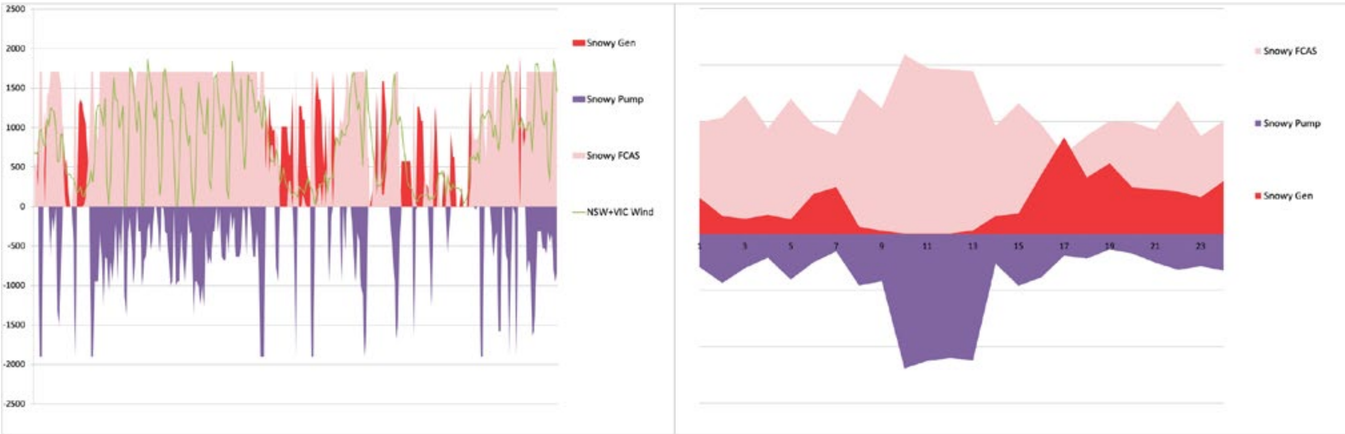


Figure 26: Snowy 2.0 utilisation in May – deep decarbonisation scenario

These utilisation profiles clearly show that Snowy 2.0 is being used at all timescales. Snowy 2.0 provides short term support via FCAS and peaking generation, along with daily cycling to complement solar PV. This reduces curtailment and increases overall utilisation, as well as long-term storage to absorb peaks in wind output.

Role of Battery of the Nation in Decarbonisation

Summary

Along with Snowy 2.0, Battery of the Nation (BoTN) is conceived as the other half of the next major stage of large-scale energy storage projects for the National Electricity Market.

Battery of the Nation is projected by Hydro Tasmania to eventually provide the east coast market with an installed capacity of 3,400 MW of dispatchable power and 73,000 MWh of pumped hydro storage. This project also includes the construction of the Marinus interconnector between Tasmania and Victoria.

While this project is at the smaller end of 'large storage' spectrum, it will provide significant firming support within the National Energy Market. Though the Battery of the Nation is much smaller than Snowy 2.0, it will enable wind and solar PV to have a larger capacity build out, by significantly reducing curtailment losses.

These larger, new storage plants will help support firm electricity supply in the NEM, the Battery of the Nation is likely to operate similar to a peaking plant for much of the year, able to meet grid needs for a few hours in the early morning and early evenings when solar PV availability, in particular, is low.

Introduction

Variable renewable energy (VRE) is currently at the centre of the global transition to a more sustainable and low carbon electricity system. Globally, installed renewable capacity has grown rapidly in recent years, and within the Australian context, wind and solar PV have seen an increase in installed capacity that is both rapid and significant. As more renewables are added to the National Electricity Market (NEM), it is expected that the variable nature of their output will have a significant impact.

Energy storage is often considered as the solution to VREs intermittency for three reasons:

- Storage can smooth out the often-rapid increases and decreases of renewable generation output, to provide a steady output or provide a more dispatchable option in order to match demand;
- Storage can provide some of the grid services that both wind and solar PV are unable to provide (such as inertia and frequency response); and
- Storage can provide firm capacity that can be called upon in extended periods of low output from wind and solar PV.

Battery of The Nation Configuration

The Battery of the Nation (BoTN) is the collective term for a number of projects that will increase pumped storage capability in Tasmania and add a new link to the mainland to bring more of the benefits of Tasmania's hydro to the NEM. The modelled configuration of the BoTN is illustrated in Figure 27 and detailed in Table 2, along with the additional interconnection to Victoria. BoTN is modelled as the Marinus 1 and 2 configurations, including the associated hydro and pumped storage investments in Table 2. Marinus 3 is considered to be the BoTN 2.0.

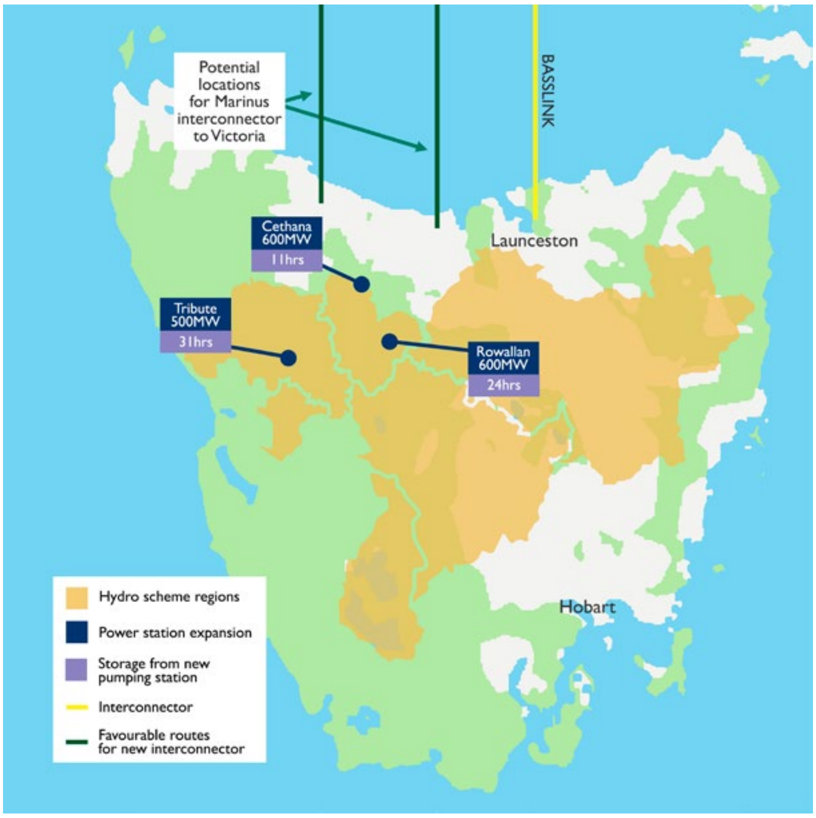


Figure 27: Battery of the Nation configuration

Table 2: The Transformation of the NEM, a comparison of 2006 and 2019 (GW and GWh)

Options	Capacity	Cost ($B)	Completed	Notes
Marinus Link 1 [64]	600 MW	$1.3 - 1.7	2025	
Conventional hydro upgrades	400 MW	$0.5 - 0.7	2021	Upgrades 3 existing schemes, + 50 MW small hydro
Marinus Link 2 [64]	800 MW	$0.6 - 1.4	2028	
Lake Cethena [65]	600 MW 11 hours	$0.9	~2027	Estimated completion is approximately two years behind Snowy 2.0
Lake Rowallan [65]	600 MW 4 hours	$0.99	~2027	Estimated completion
Tribute [65]	500 MW 31 hours	$0.915	~2027	Estimated completion
Marinus Link 3 [64]	900 MW	$0.6 - 1.4	~2035	
Unspecified PHES locations	1700 MW	$3	~2035	The PHES capabilities are modelled the same as for Marinus 2.

Role of the Battery of the Nation in Decarbonsiation

As the NEM continues to transform, the role of dispatchable capacity in the form of energy storage is important, as determined by the positive impact of Snowy 2.0. Hydro Tasmania is proposing a BoTN scheme that optimises the use of its existing hydro portfolio and develops new PHES projects [65]. It also includes more interconnection between Tasmania and Victoria with a view to unlock the full potential of the Tasmanian hydropower system.

The BoTN is modelled here in two phases: Marinus 1 and associated minor hydro upgrades, and Marinus 2 and associated PHES upgrades.

The Marinus 1 interconnector and associated improvements to 400 MW of traditional hydro has only a very small impact on the 90% decarbonisation scenario (Figure 28). This is predictable given the scale of the 2050 system with its 160 GW of generation capacity.

The Marinus 2 interconnector, the third interconnector to Tasmania overall, along with a significant PHES upgrade, would take the overall interconnection capacity to 1900 MW, with 1700 MW of PHES. Although much smaller in energy storage capacity than Snowy 2.0, its shorter duration is more suited to supporting further solar PV capacity (refer to Figure 28).

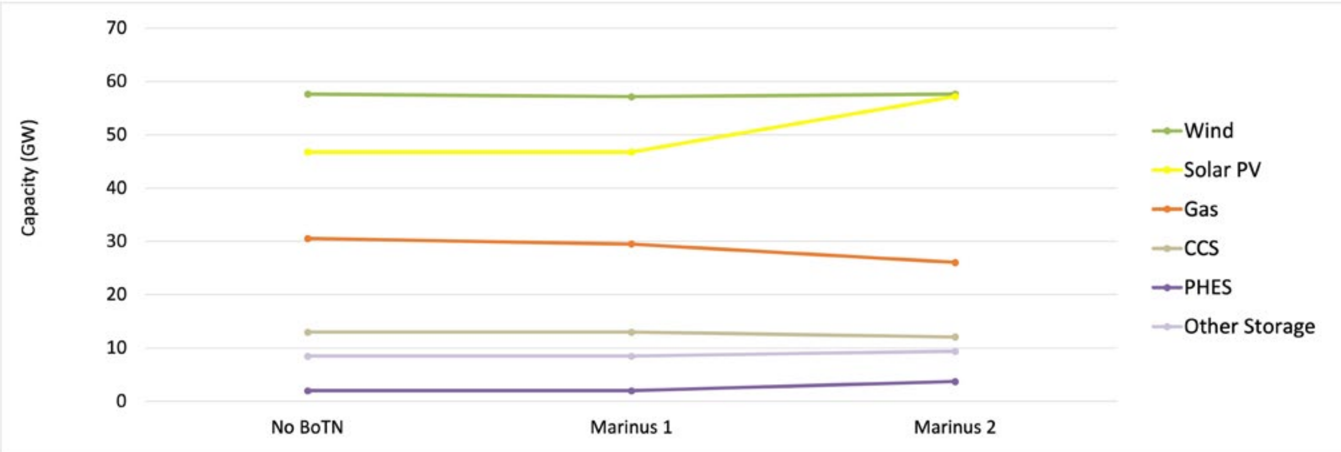


Figure 28: Progression of optimum plant mix as BoTN is expanded

Some important details about the addition of the BoTN can be observed in Figure 29. This lowest total system cost (TSC) optimum mix includes both the Snowy 2.0 and BoTN Marinus 1 and 2 interconnections and associated upgrades. The inclusion of the BoTN into the generation suite allowed the solar PV capacity to increase to 51 GW, and the total system capacity 176 GW. However even in this 90% decarbonisation scenario, the optimum mix has 3.5 GW of unabated coal, which was not present in the Snowy 2.0 base case. While this may seem counter intuitive, the addition of extra storage and solar PV into the mix leaves head room for the unabated coal to serve a very specific role. It was the cheapest form of dispatchable load for peaking duties, essentially assuming the role of an OCGT.

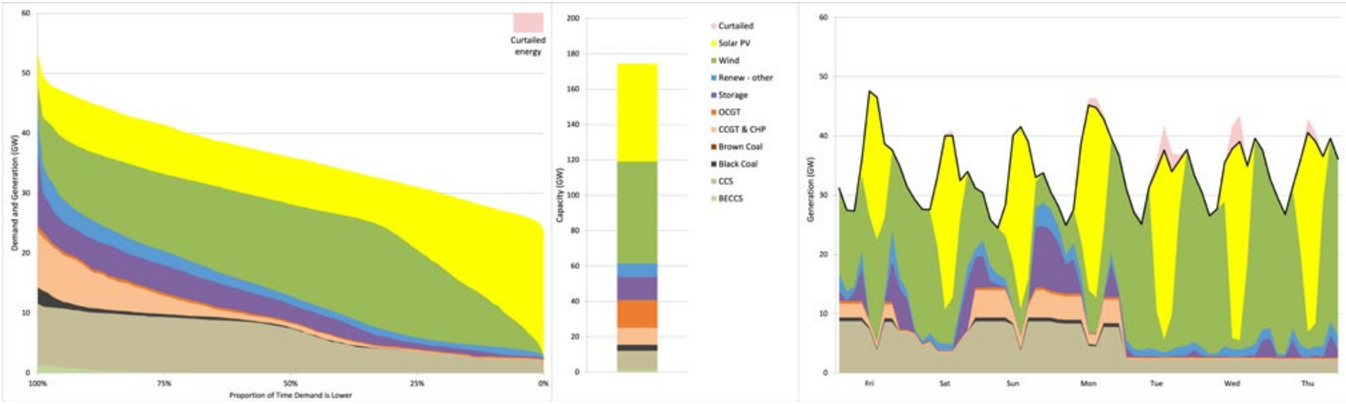


Figure 29: Deep decarbonisation, optimum generation mix including BoTN (Marinus 2)

This role of 'peaking' and 'back up' coal is observed in other jurisdictions, as a much diminished but still active role, even within low emissions electricity grids. This is fully consistent with the United Kingdom's (UK) actual experience. The UK's decarbonisation is well underway, with emissions declining from >750 g/kWh to approximately 200 g/kWh [66; 67]. As illustrated in Figure 30, the UK generation profile is similar to the optimum generation profile for the NEM, with nuclear replacing coal with carbon capture and storage (CCS) [68; 69]. Unabated coal is relegated to a peaking role for high demand winter days with little wind. It 'two-shifts', coming on for the 'working day' and into the evening peak, but mostly shutting down overnight. When the wind picks up on the Friday and throughout the weekend there is no need for coal. MEGS utilised unabated coal in the NEM in a similar manner at such low load factors, as there is still room for it even in a 90% decarbonisation world.

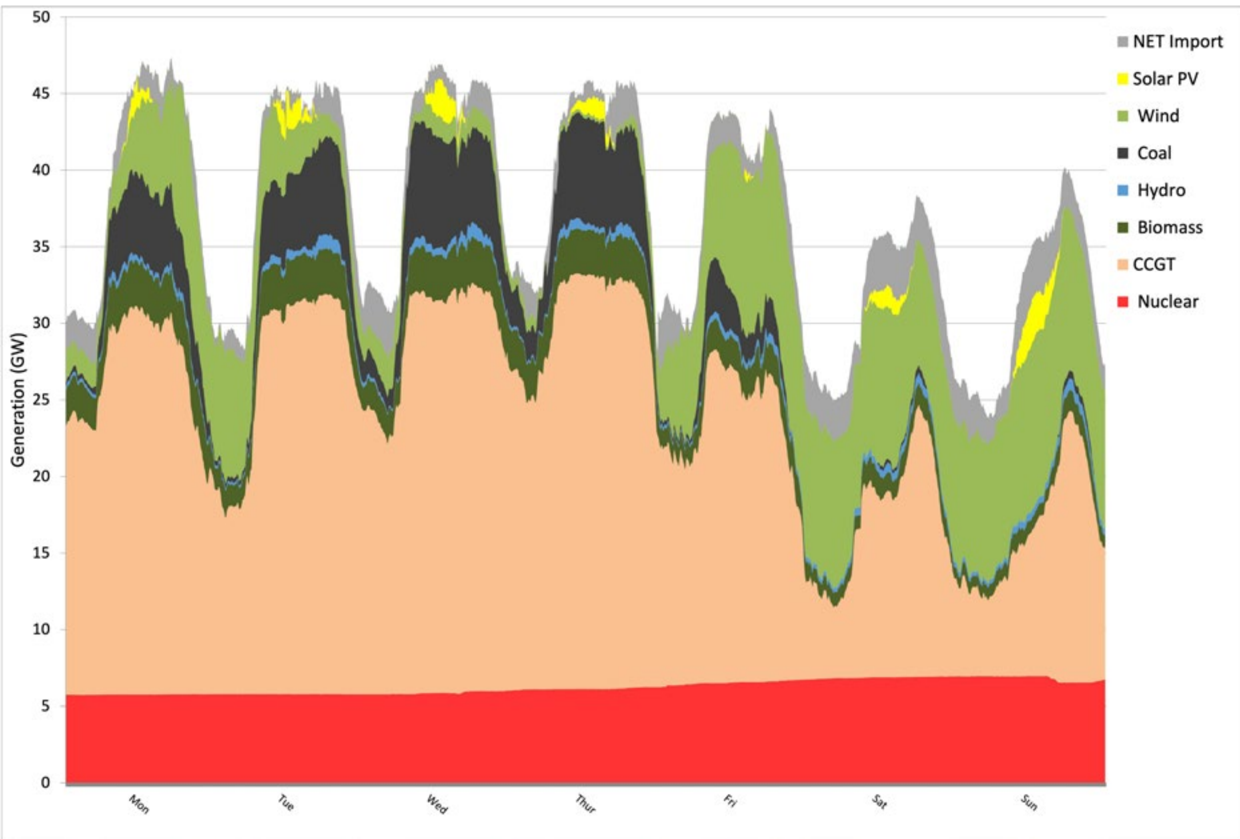


Figure 30: UK generation for the winter week of peak demand

The utilisation of the BoTN scheme (refer to Figure 31) is similar to the utilisation of Snowy 2.0 (refer to Figure 26), although it is more ‘blocky’ with less time spent pumping. This lower pumping time is partly due to the BoTN having a better cycle efficiency than Snowy 2.0. Despite its small scale relative to Snowy 2.0, the BoTN results in a marked reduction in TSC if both Marinus 1 and 2 along with the associated hydro and PHES assets are developed.

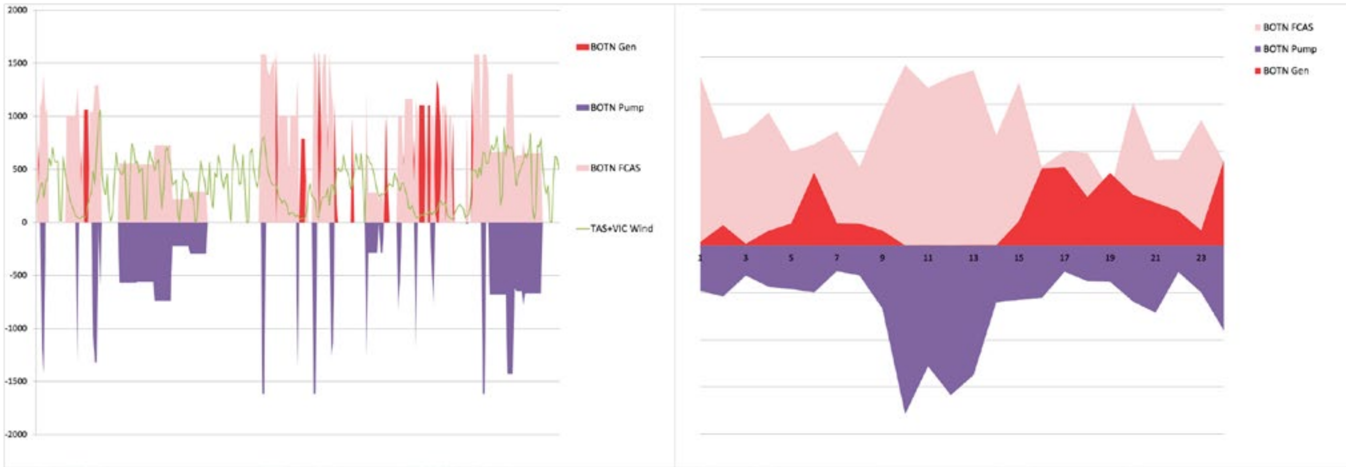


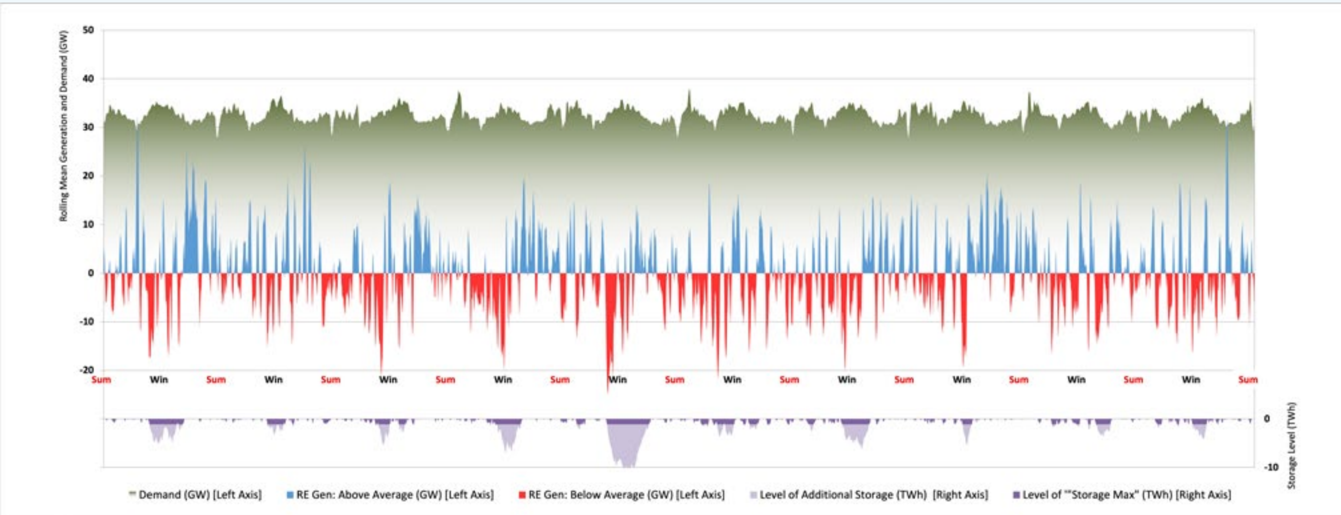
Figure 31: Phase 3 BoTN (Marinus 2) utilisation in May – deep decarbonisation scenario

Role of Large Long-Term Storage in a 100% Renewables Environment

Summary

In some quarters, decarbonisation and the building of renewables backed by storage are considered the only viable pathway to achieving our climate goals. A 100% renewable electricity grid will rely very heavily on many different types of storage. For wind and solar PV to generate a large portion of the required electricity, storage will be required to compensate for the long periods of low generation. In the past, the national electricity market (NEM) has been subject to low periods of renewable generation, also known as renewable droughts, and in the past, non-renewable power has been responsible for fulfilling the deficit.

To support a 100% renewable grid, without non-renewable power options, multiple large energy storage systems will be required. **In terms of storage scale, more than 30 Snowy 2's will be required to meet the storage demand to get through a renewables drought.** However, some of these storage systems would only be used once during a 1 in 10-year drought. For seasonal and year to year storage, these large storage systems will likely be pumped energy storage systems.



Overview of 2006-2015, modelled as a 100% renewable system

Introduction

As the power generation mix diversifies to reduce carbon emissions from the grid, the impact of the natural environment will have impacts that we have not previously had to consider. The reliability of electricity supply is imperative. An interruption to supply has both direct and indirect impacts that are nearly always much greater than the value of the electricity not supplied, especially for large blackout events [70-73]. Extreme weather events are the leading causes of electric power outages [73]. However, as the power generation mix changes, more 'ordinary' weather events need to be considered to ensure the grid does not become vulnerable to more outages.

Wind droughts have been previously described in the UK, where the output of wind is near zero from the wind fleet [74]. Australia, too, has a weather pattern which provides the conditions for a wind drought within the National Electricity Market (NEM). Most recently this has been seen in 2017 where a much lower production level from wind farms NEM-wide was observed [75].

The Role of Storage to Enable a 100% Renewables Powered NEM

To determine the requirements for long-term storage in a very high variable renewable energy (VRE) electricity grid, a simple scenario, looking at a 100% renewables grid was examined. Using the optimum base case for deep decarbonisation as the basis of the generation profile, the generation suite for wind and solar PV was scaled appropriately in each state to meet demand across 10 years of weather and associated demand data.

For this scenario, the need for inertia and grid services was neglected and a simple energy balance used. All intraday variations, such as the daily peaks of PV, were also assumed to be 'smoothed out' with short term battery storage. The focus of this scenario is to identify long term requirements for pumped hydro energy storage (PHES). The NEM was also considered a 'copper plate' for the purpose of transmission interconnection.

The role of long-term storage is to ensure enough energy is stored to cover periods of time where insufficient renewable generation (wind, solar PV and hydro) is available, i.e., a 'renewables drought.' An examination of 10 years of weather data and the long-term operation of the VRE scenario is illustrated in Figure 32. The top portion of the figure shows the overall demand, shown as a green shaded portion. It is smoothed over a week with a rolling average to illustrate its long-term trends and seasonality. This averaging shows that at these time scales demand fluctuates seasonally between 30 – 35 GW.

Imposed on the demand is the renewable output compared to its long-term generation average. Shown in blue are weeks of surplus renewable generation, which can be used to charge the PHES facility. The distribution of weeks which show renewable deficits compared with the long-term average are of greater importance and shown in red. These periods can be quite long, and the deficit can exceed half of average demand.

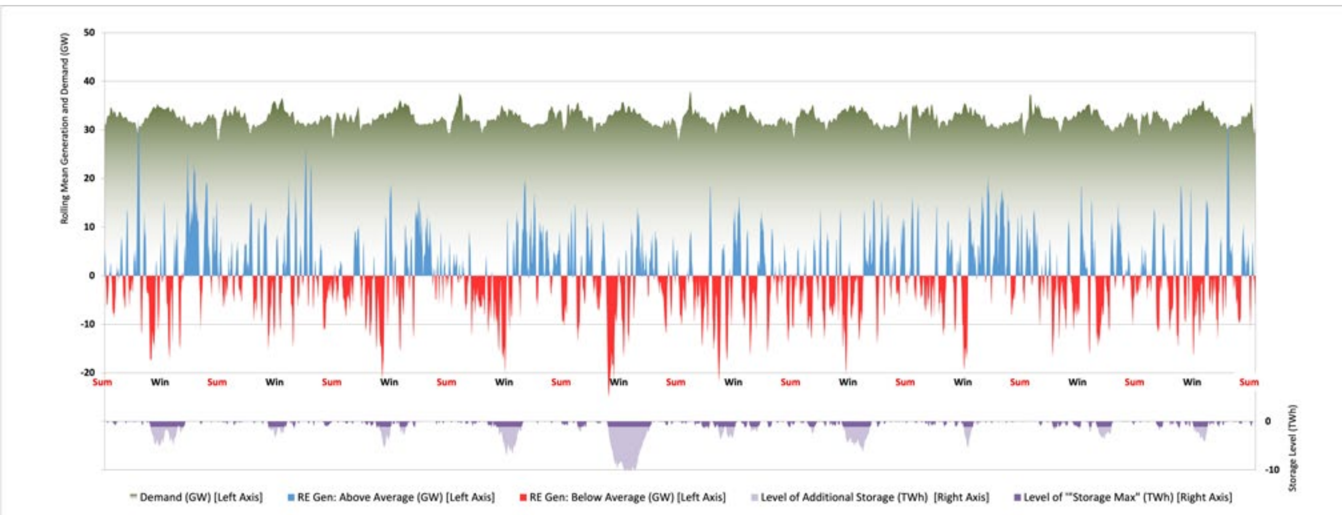


Figure 32: Overview of 10 years of operation of a 100% renewable system

The lower trace illustrated in Figure 32 highlights how PHES responds to demand, and the excess and deficit of renewable generation. The modelling aims to keep it full until it is needed to make up a growing shortfall, meaning the amount the storage level drops to before recovery is indicative of depth (or quantity) of storage required. It is noteworthy that all the episodes of significant storage drawdown occur in the winter, when lulls in wind coincide with low solar PV output.

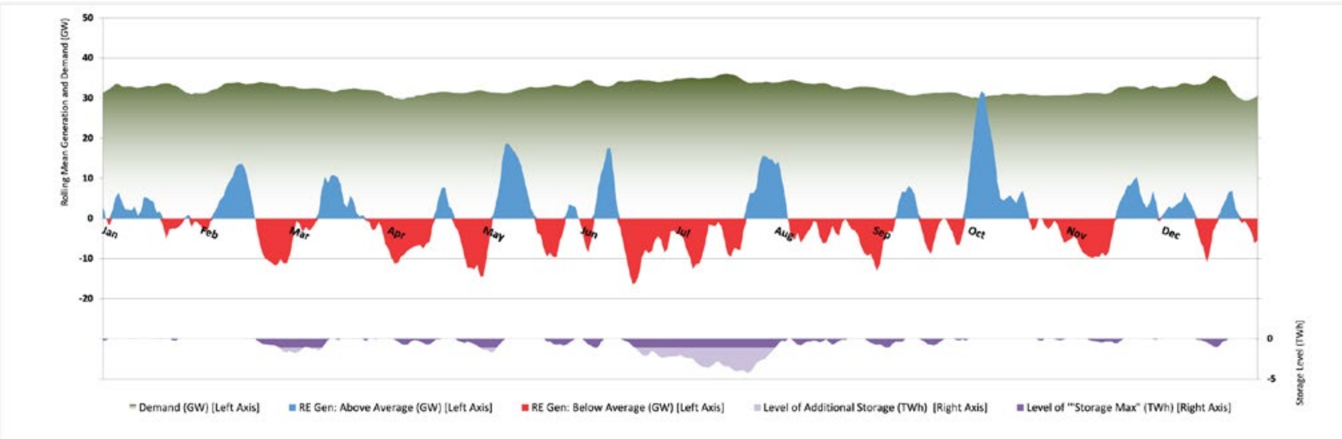


Figure 33: Overview of 2015 – operation of a 100% renewable system (subset of Figure 32)

The depth of storage required to cover most years is approximately 5 TWh, which is shown as the lower portion of Figure 33 in GWh scaled on the right axis. All but one year would be adequately supported by approximately 7 TWh of storage, but for 2010, the year of the most significant renewables drought (refer to Figure 32), there is the need for 11 TWh of storage. However, 4 TWh (about 10 Snowy 2.0's) of the 11 TWh of storage built would only be used once every 10 years.

A detailed examination of the largest renewable drought between 2006 and 2015 is illustrated in Figure 34. The renewable drought occurred in the May of 2010, starting with a prolonged wind drought that spanned all five regions of the NEM. Combined with the wind, the solar PV was naturally lower than summer, the 'full' reservoir levels did not begin to recover until August, when a long windy period and recovering solar PV output was sufficient to exceed demand for more than several of days at a time. This clearly illustrates how difficult a very high VRE suite of technologies is to manage, and how vast a storage network is required to support such a regime.

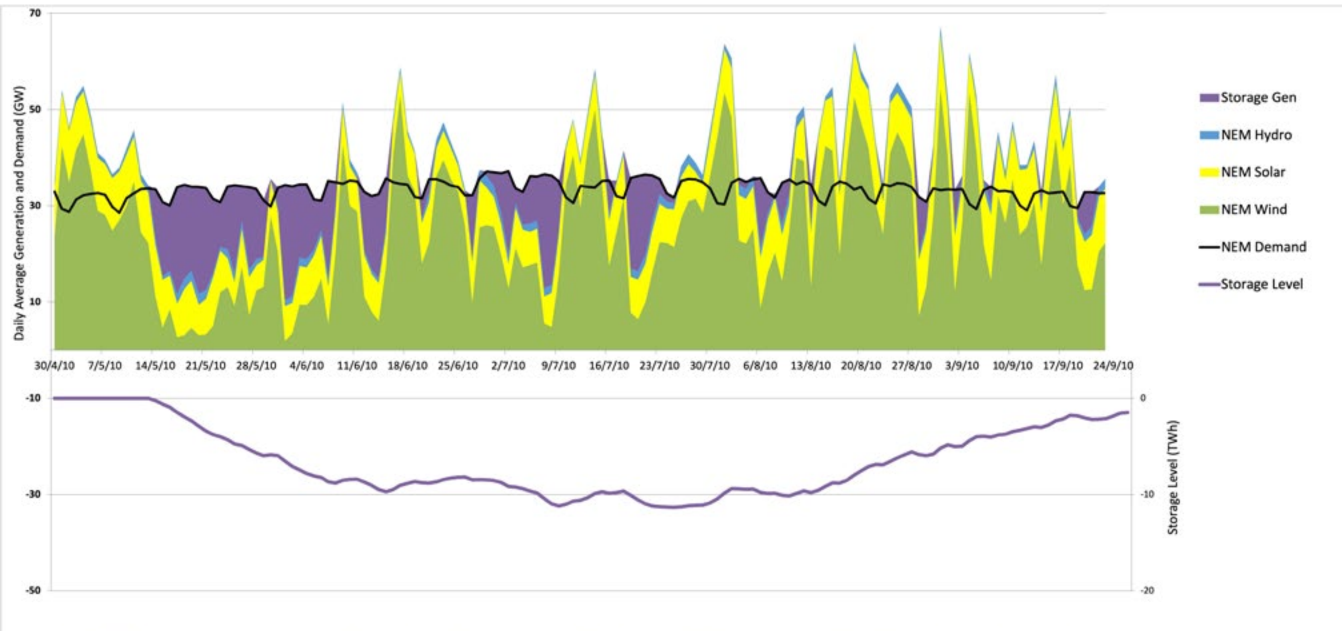


Figure 34: Renewables drought of winter 2010 showing drawdown of storage

The results from this simple 100% scenario are summarised in Table 3. It can be seen that the scale of the storage volume required is extremely large. For scale and reference, Snowy 2.0 is a 0.35 TWh, 2 GW system expected to cost around $8B. If strong interconnection were built between each state then 33 Snowy 2.0 schemes would be needed, but if states continued to act independently with weak interconnections, that could rise to the equivalent of 75 Snowy 2.0s distributed throughout the system.

Table 3: Requirements in 100% renewable scenario compared to the current NEM

	2019 NEM	**100% Renewable**	
		Independent States	**Copper plate NEM**
Storage Volume (TWh)	<0.01	24	11
Storage Capacity (GW)	1.3	30	24
Wind Capacity (GW)	6	80	80
Solar Capacity (GW)	6	65	65
Hydro Capacity (GW)	7	7	7
Total Capacity (GW)	**56**	**182**	**176**

Value of Large Interconnectors

Summary

The national electricity market (NEM) covers a vast land area of almost 5,000km, with electricity generation and demand scattered. This is where interconnectors can bring great value as they allow electricity and grid services to be shared across the NEM by connecting the different states to each other.

As different locations across the NEM have varying levels of variable renewable capacity, being able to build an asset in a higher capacity area and move the electricity to the demand centres in another area will improve the value of technologies.

Interconnectors facilitate power generation at a low cost in one area to be available in another area where the demand is required. The interconnectors linking Tasmania to the rest of the NEM is a textbook example, as this linkage allows low-cost hydropower and wind to be utilised in other parts of the NEM where demand is higher.

Introduction

The NEM consists of five interconnected electrical regions: Queensland, New South Wales, Victoria, South Australia and Tasmania. The regions are connected together electrically via interconnectors and operate as 'one market with multiple regions.'

The interconnector limits are broadly characterised by thermal and stability limits:

- Thermal limits refer to the physical properties of the transmission lines, for example, as electricity is transmitted through a line, heat is generated which causes the lines to sag. The limits of a line's sag relate to minimum distances that a line must maintain from the ground. Other infrastructure, such as transformers, also has thermal limits driven by the degradation of insulation at high temperature [76].
- Stability limits refer to the ability of the system to withstand loss of generation or transmission infrastructure. For example, a system is usually operated to at least an n-1 standard, meaning any one piece of infrastructure can be unexpectedly lost and the remaining system will remain within its limits. These limits are usually lower than thermal limits and are dependent on the state of the system, so can change minute by minute [76].

Therefore, congestion is very dependent on local electricity flow, transmission capabilities and a specific point in time. Congestion may emerge within the NEM within one five-minute dispatch interval and no longer be present during the next interval, or it may last for a much longer period of time. In theory, congestion may be eliminated if significant additions to the interconnectors are constructed. In summary, there are both direct and indirect as well as short- and long-term consequences of congestion [76].

An interconnector upgrade, or series of upgrades is potentially part of the transformation required to decarbonise the grid at the lowest total system cost (TSC). Unless part of specific scenarios, interconnector upgrades have not been an option for MEGS to include in a future grid. The value of individual or collective interconnectors have been explored here to examine whether they result in a lower cost solution, or if these upgrades increase the TSC and be considered as expensive 'white elephants.'

Impact of Interconnector Upgrades

As Australia seeks to decarbonise its electricity sector, the core objective and focus of this transformation must be based on reducing emissions and using the competitive and energy advantages of the candidate technologies that may be added to the NEM. The NEM operates on one of the world's longest interconnected power systems. Spanning from Port Douglas in Queensland to Port Lincoln in South Australia, it covers a distance of approximately 5,000 kilometres [77]. Shown in Figure 35 [77], its geographical diversity lends itself to be able to take advantages of the different energy resources available, for example, the sun in Queensland, the wind in South Australia and Tasmania, along with the hydro in New South Wales and Victoria. Overlaid on the variety of renewable resources is the diversity in fossil fuels and CO2 storage options.

The six interconnectors that allow electricity to be transported between the states are critical to the NEM. The interconnections were designed to encourage more competition and to help match supply and demand for electricity. The last interconnector to be commissioned was Basslink in 2006 which linked Victoria and Tasmania. Over the years, interconnectors have served their purpose, importing and exporting electricity where required, to help meet the demand.

Regions can be subject to various constraints which can affect the amount of locally available generation and associated wholesale electricity costs. The challenge is having enough electricity to supply demand at any given time, in any given region. At times of constraints, imported energy from an interconnector can be an important supply of power when local generation is insufficient to meet demand [78]. While greater interconnection in the NEM is considered of benefit, the nature, quantum and location of the benefit needs to be better understood.

Within the transformation process toward a decarbonised electricity system, many uncertainties within a changing energy sector must be considered. The current wind and utility scale solar PV penetration within the NEM generated approximately 7% of the electricity [45] (refer to Figure 36). This generation compared with future forecasts of variable renewable energy (VRE) capacity means that the future electricity system will look very different than it does currently (refer to Figure 37, a 2050 scenario at 90% decarbonisation) [79].

Australian Energy Market Operator's (AEMO) 2018 Integrated Systems Plan (ISP) assigns particular renewable energy zones (REZs) to shape future deployment [58]. As interconnection is expensive, it is important to assess the effectiveness of such investment for a future electricity system.

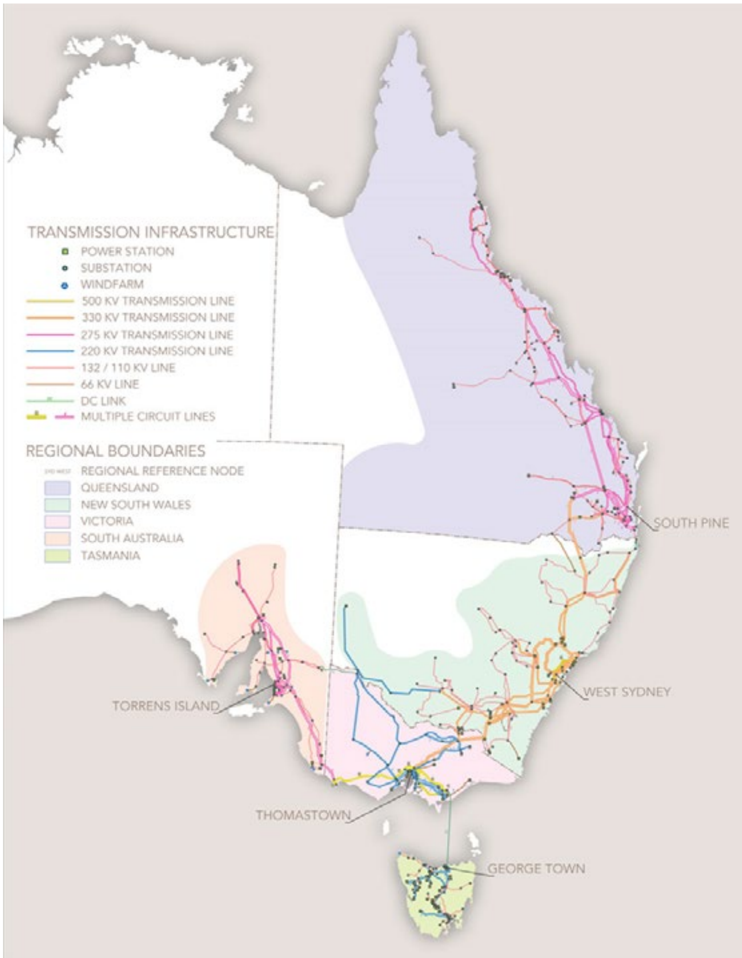


Figure 35: The national electricity market (NEM), 2020

Individual Interconnections Upgrades Within the NEM

Four interconnector scenarios were considered individually as separate additional capacity. For each scenario, it is assumed that this additional interconnector capacity is added to an optimised 2050 system (based on the optimum baseline 2050, 90% decarbonisation, refer to Figure 37) to which there are no changes to the generation fleet. Therefore, any benefits accrue solely from better utilisation of the existing generation assets to meet demand and reserve requirements in each region.

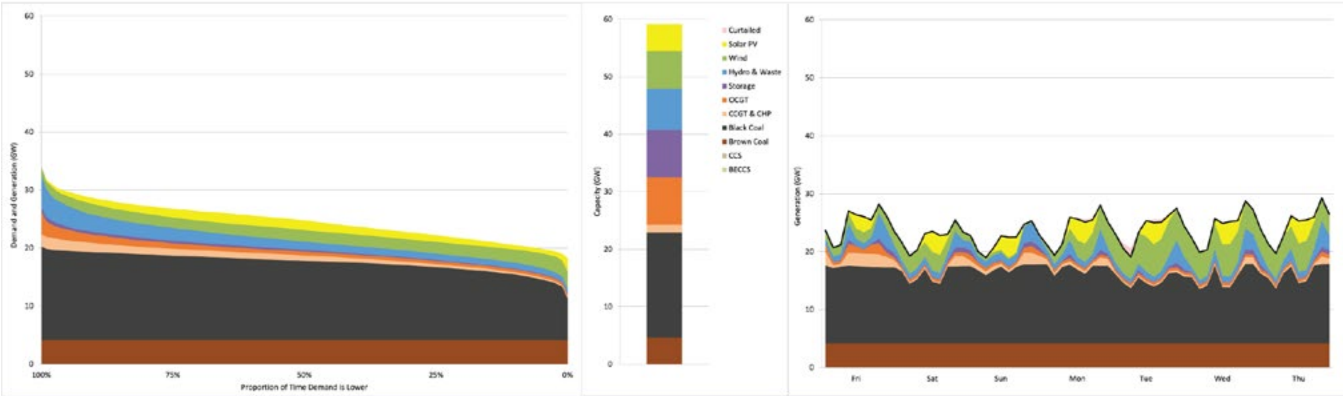


Figure 36: The current NEM profile – 2018

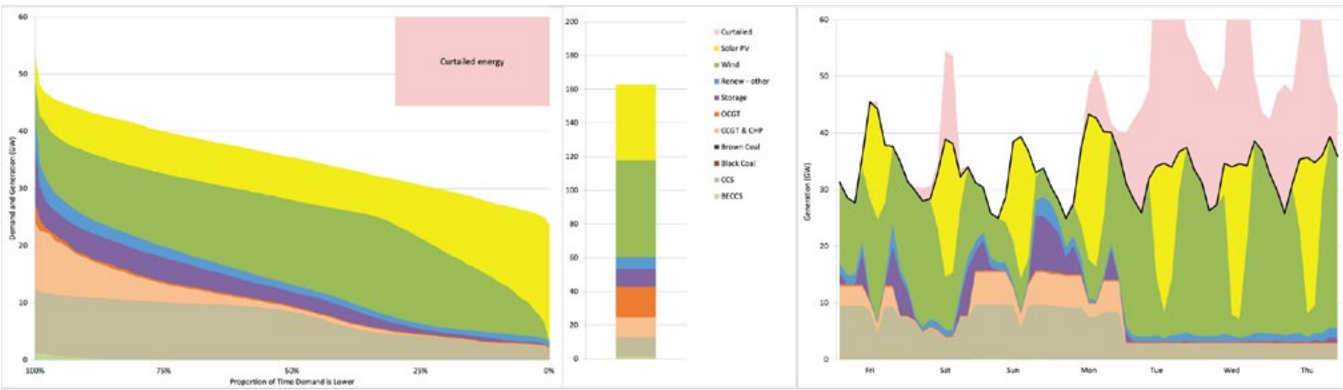


Figure 37: 2050 90% Decarbonisation scenario (Snowy 2.0 and Beyond)

The four interconnectors modelled were:

- Additional Qld / NSW by 1 GW each way
- Additional NSW / Vic by 1 GW each way
- Additional Vic / SA by 500 MW each way
- New SA / NSW 500 MW interconnector

The current interconnector capacity and the modelled upgrade capacities are also summarised in Table 4 [80]. Each region has an approximate doubling of capacity, with the new SA – NSW upgrade 500 MW, the same as the additional Vic – SA upgrade scenario.

Table 4: Interconnectors in the NEM, current and modelled upgrade

Interconnector Name	From	To	Existing Nominal Capacity	Upgraded Capacity
N – Q – MNSP1	NSW	Qld	107 MW	-
	Qld	NSW	210 MW	-
QNI	NSW	Qld	300 to 600 MW	-
	Qld	NSW	1078 MW	-
Qld – NSW (additional)	NSW	Qld	-	1000 MW
	Qld	NSW	-	1000 MW
VIC1 – NSW1	Vic	NSW	700 to 1600 MW	-
	NSW	Vic	400 to 1350 MW	-
Vic – NSW (additional)	Vic	NSW	-	1000 MW
	NSW	Vic	-	1000 MW
V – SA	Vic	SA	600 MW	
	SA	Vic	500 MW	
V – S – MNSP1	Vic	SA	220 MW	
	SA	Vic	200 MW	
Vic – SA (additional)	Vic	SA	-	500 MW
	SA	Vic	-	500 MW
SA – NSW (new)	NSW	SA	-	500 MW
	SA	NSW	-	500 MW

The effect on electricity flows and the Net Present Value (NPV) from each scenario is shown schematically in Figure 38, with the red arrows indicating the upgraded interconnector in that scenario. The numbers within the arrows indicate a change in mean electricity flow in that direction, so positive values indicate an increased utilisation of the interconnector in that direction.

Upgrading an interconnector's capacity will often bring about savings in running the system, as cheaper generation is less likely to be constrained by inter-state flow limits. Therefore, for each scenario, the reduction in operating cost of the system can be calculated by comparison with the base case and the annual savings converted into an NPV using a discount rate of 8.3% over a 60-year life. This effectively sets an upper limit on capex to build that additional interconnector, while spending over this would mean the upgrade cost is greater than the benefits it brings.

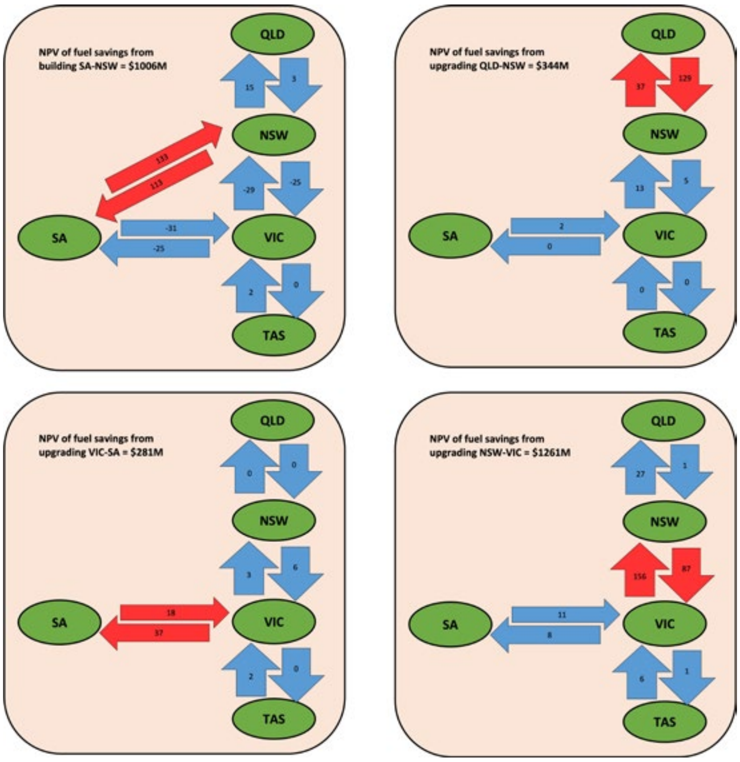


Figure 38: Effect of each interconnector upgrade showing changes in flows across all interconnectors

As expected, the new interconnectors result in a significant benefit due to the additional electricity flows now possible between the two states connected by the new interconnector. However, the impact in the other states within the NEM is much more modest. The new interconnector between SA and NSW is the exception because it results in a significant decrease in the existing VIC / SA and VIC / NSW interconnectors flow.

The interconnector upgrade with the greatest value as a project is the NSW / VIC, with an NPV of over $1.2B. The interconnector upgrade with the greatest value per MW is a new SA / NSW link (refer to Table 5). The high traffic across this new interconnector would allow a capital expenditure of up to $2B per GW before the project would no longer have positive NPV. As expected, this new interconnector also relieves some of the pressure on existing VIC / SA and NSW / VIC interconnectors.

Table 5: New interconnection value summary

New Interconnector	Size* (MW)	Value	
		NPV	$M/MW
Qld / NSW	1,000	$344 M	0.34
NSW / Vic	1,000	$1,261 M	1.26
Vic / SA	500	$281 M	0.56
SA / NSW	500	$1,006 M	2.01

* Bi-directional

Impact of Constraints on the Lowest TSC Outcomes

Summary

Modelling in this study demonstrates that 95 per cent decarbonization of the National Electricity Market (NEM) in 2050 with no restrictions on technology choices would see a total annual system cost of $33 billion (in 2020 AU dollars) while every constraint increases this expense to a significant extent. In a net zero world, this additional cost could be beyond $20 billion per year if neither carbon capture and storage nor nuclear are available.

Given the high social and economic impacts of expensive electricity in the NEM, as already demonstrated in the past decade, this is not an issue to be passed over lightly. Especially where contrived constraints can result in such large cost penalties.

The central theme of this study is to demonstrate the critical importance of total system costs in assessing Australia's approach to deep decarbonization of the east coast electricity market. This section canvasses the reasons that constraints applied to supply technologies, whether physical or policy-driven, are a key factor in the effectiveness of the NEM's transformation. It also discusses why continuing to rely on any form of levelized cost of energy (LCOE) as the defining metric for decarbonization beyond 20 per cent of market supply provides very misleading and inaccurate signals to investors.

The mindset influencing the transition is a significant issue in the energy debate today. This is driven by stakeholders with vested interests and recurrent rhetoric on which low carbon technology can 'win' the decarbonization 'race'. However, this chapter demonstrates it is advantageous to consider low emissions technologies as members of a team. Restrictions on the availability of any technology, like a player missing from a team, will limit the collective capacity to claim the real prize for stakeholders, the lowest possible cost transformation.

Behind this proposition lies another important point: all efforts to reduce carbon emissions in the NEM will come at increased cost. A major driver of managing the transition toward the best outcome needs to be keeping this additional cost at an optimum level. This work show's that getting it wrong, at a first approximation, can penalise the economy in the order of $20 Billion per year.

Total system cost is not a simple metric, but the electricity grid is not a simple system. It has many moving parts, including the impact of weather on the output of variable renewable energy developments. A simple metric is not adequate for cost judgements in planning the least-cost path for investment and operations in a decarbonizing environment.

Introduction

As the Australian Federal and State Governments begin making the necessary changes to the electricity generation mix in order to achieve their decarbonisation goals, resource and system diversity will be vital to maintaining a resilient and competitive energy environment. Stakeholders with vested interests seek to frame the transformation toward a low carbon grid as a race, in which their favoured technology will win over all other low carbon options. However, a managed transformation is more akin to a team sport, where a variety of technologies will need to work together, each bringing with them different strengths.

A managed transformation will likely have to deal with a range of constraints that will limit the technology options, or players, available to deliver the low carbon grid required. These constraints may be related to physical constraints, price or policy implications. Ideally, a managed transformation of the electricity grid towards net zero emissions will configure the grid to minimise the impact of these constraints while still delivering a low cost, stable system that meets the expectations of the consumer. This requires the best team, or asset portfolio, with the lowest total system cost (TSC), to deliver the best possible outcome.

Figure 39 highlights the change in the composition of the National Electricity Market (NEM) from 2014 to 2018 [46]. It is evident that we are seeing the beginnings of this transformation, as more than 4 GW of coal-fired power generation capacity has retired, and a similar amount of renewable capacity, predominantly wind and solar PV, has been built. However, it is important to note that this 'slowly changing' generation mix supplying energy to the NEM shows that coal, with some 23 GW of capacity remaining, has not changed its overall generation contribution since 2014 even after the large power station closure in 2015 [46]. We are still in the early days of the pursuit of a low carbon grid.

Transitioning from these currently unabated black and brown coal, and gas electricity generation sources will be a critical element in the transition to low emissions future. A low emissions system requires a significant contribution from renewable energy sources, as well as dispatchable, low emissions generation such as coal and / or gas with carbon capture and storage (CCS) and nuclear power [81]. This report examines what these asset portfolios might look like in 2035 and 2050, focusing on delivering the lowest cost configuration. Importantly, this report also examines possible futures in the light of some potential constraints which will impact the composition of a future low emissions grid.

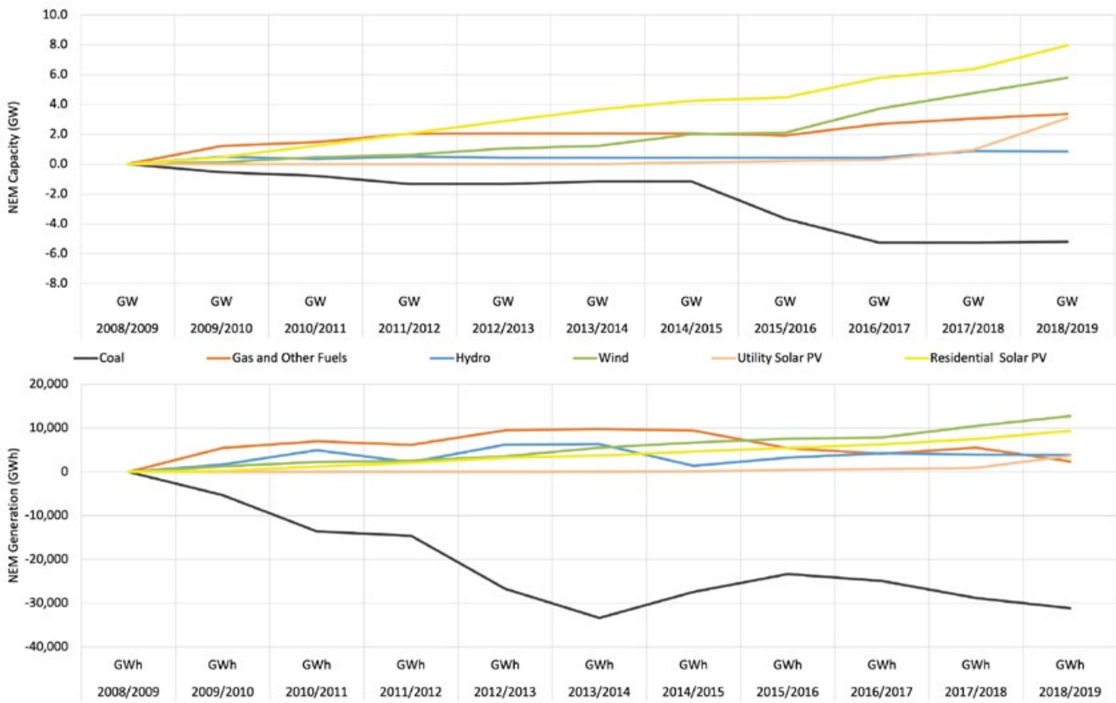


Figure 39: Change in capacity and annual production by fuel type (2014 – 2018)

Background: The Changes in the NEM Over the Past 10 Years

The current NEM is dominated by fossil fuels, with brown coal, black coal and natural gas making up more than 80% of the primary energy supply in 2018 [46]. The impact of wind and solar PV can be seen by the increasing contribution over time, however, as can be seen in Figure 40, the impact of solar PV is only now beginning to be significant [46]. Moving away from these currently unabated electricity generation sources will be a critical element of a transition to low emissions future and will take considerable effort. A significant contribution will need to come from renewable energy sources, as well as dispatchable low emissions sources such as coal and / or gas with CCS and nuclear energy [81].

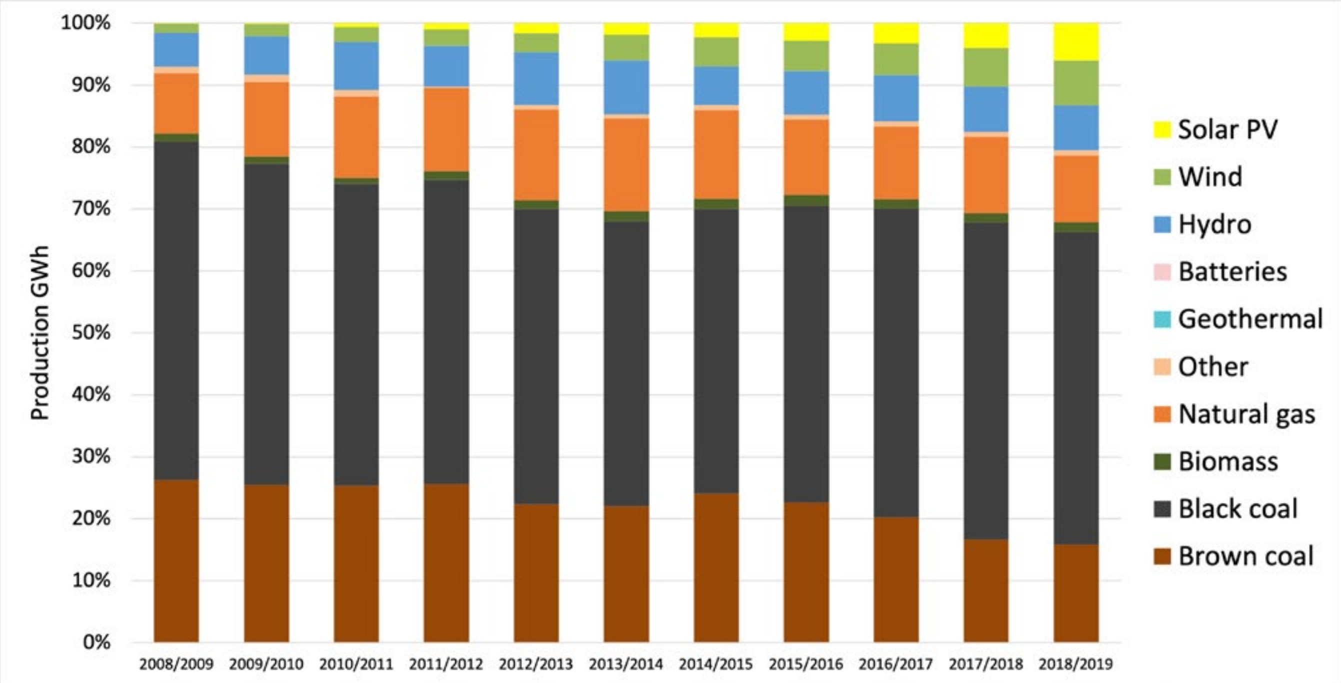


Figure 40: 2010 - 2018 NEM generators contribution to production (all regions)

Transforming the entire energy system, currently underpinned by unabated fossil fuel technologies with a small but increasing amount of renewable and other low emissions technologies, has wide ranging implications. For the grid, considerations such as grid stability, energy diversity, grid connections, available grid services, reserve sufficiency and other such factors must be taken into account. In order for the asset construction pipeline to be capable of meeting the build rate required, the disparate industries in the construction supply chain [81] must be ready and optimised.

To understand some of the issues facing the decarbonisation transformation, this work has examined a range of system constraints to better understand their impact on the lowest TSC of this energy transformation.

The Lowest Cost, Unconstrained Frontier in 2050

To understand the impact of constrained access to a technology option on the lowest TSC outcomes, it is important to consider what an unconstrained environment could deliver. This requires a starting base configuration for the NEM. In the modelling presented in this study, NEM-wide interconnector upgrades and Snowy 2.0 are included, along with existing renewables assumed to remain. Given these fixed points, each scenario modelled is a unique combination of a range of technologies.

As observed in previous studies, when a TSC methodology has been used to examine a range of scenarios [23; 25; 79; 82], decarbonising the grid comes at an increased cost to the system. While the TSC optimisation methodology will lead to the lowest cost, high reliability outcome at a particular level of decarbonisation, it must be noted that all new build plants will be more expensive than the existing portfolio of generation assets. This increase in TSC is clearly shown in Figure 41. Each point represents a viable NEM portfolio as a particular decarbonisation point at its respective system cost. Figure 41 is a scatter plot of 3000+ individual S-MEGS solutions. The lower bound of this scatter is modelled as the lowest cost Frontier Line, which traces the TSC points of the cost optimal scenarios as levels of decarbonisation increases. This line has a positive gradient, showing an increase in TSC as decarbonisation increases.

At 100% decarbonisation, providing wholesale energy will cost in excess of $110/MWh, which is more than $30Bn/year using AEMO's projected growth in demand to 2050. For comparison, the current system costs around $55/MWh, which equates to $12Bn/year. To achieve this level of decarbonisation, all abatement options costing $180/tonne CO_2 or less will have to be utilised.

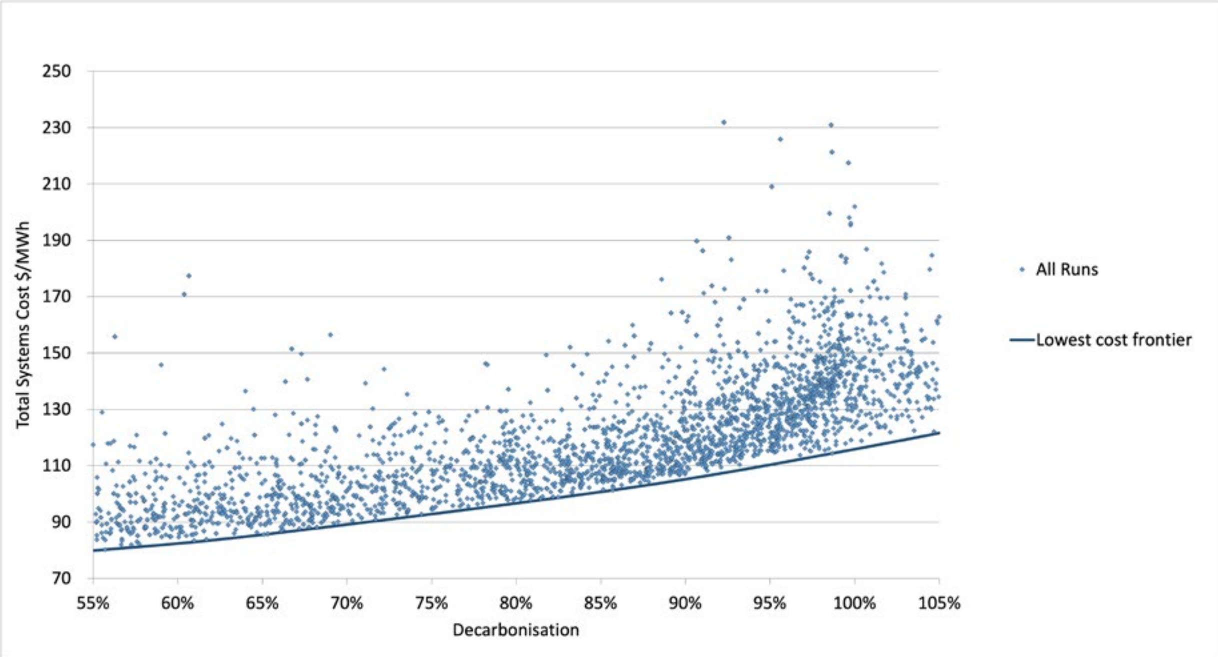


Figure 41: The lowest cost frontier of decarbonisation at lowest TSC in 2050 for the NEM

The portfolio characteristics at the lowest cost frontier of various decarbonisation levels for 2050 is shown in Figure 42. This chart does not describe a pathway from 60% to 100% decarbonisation, but rather the best individual S-MEGS model solutions that lays on the lowest cost frontier at each of the nine decarbonisation levels.

Despite the wide range of decarbonisation outcomes at the 2050 scenario, there are some key common elements to their portfolios. All deep decarbonisation scenarios beyond 65% each have at least 12 GW of firm low emissions capacity, made up of a combination of fossil fuel carbon capture and storage (BECCS), biomass energy CCS (BECCS) and nuclear. In addition to these low emission technologies providing firm capacity, at least 6 GW of unabated coal remained (most scenarios had around 10 GW), which is used for low merit and peaking duties, even in the 100% decarbonisation case. At 95% decarbonisation and beyond, all the scenarios rely on BECCS to offset remaining fossil emissions from either coal or gas.

The other important common characteristic of these decarbonisation outcomes for 2050 is the consistent need for a high level of renewable generation. Each lowest TSC solution at different levels of decarbonisation has approximately 40 to 75 GW of wind and between 30 to 80 GW of solar PV. A lowest TSC NEM in 2050 would require a renewable build for both wind and solar PV of at least 8 times the renewable capacity deployed in the current NEM. These renewable plants would generate nearly two thirds of the electricity.

The 2050 grids are also supported by a significant capacity of energy storage which varies from around 5 to 15 GW. All scenarios have approximately 15 GW of open cycle gas turbine (OCGT) as low-cost firm backup. Both these technologies are available to the grid, despite their very low generation capacity factors as they are occasionally relied on to meet high peak loads.

Again, it must be noted that each of these portfolios are the result of a random scenario generation process and do not represent a pathway to decarbonisation. They are chosen as the lowest cost asset portfolios that qualify as a solution at the specific decarbonisation level that satisfies the predicted 2050 NEM demand. There may be other proximate points that represent a different asset portfolio and might equally qualify as a lowest cost grid system. Within this methodology, any plant retirements are on merit based on their emissions profile.

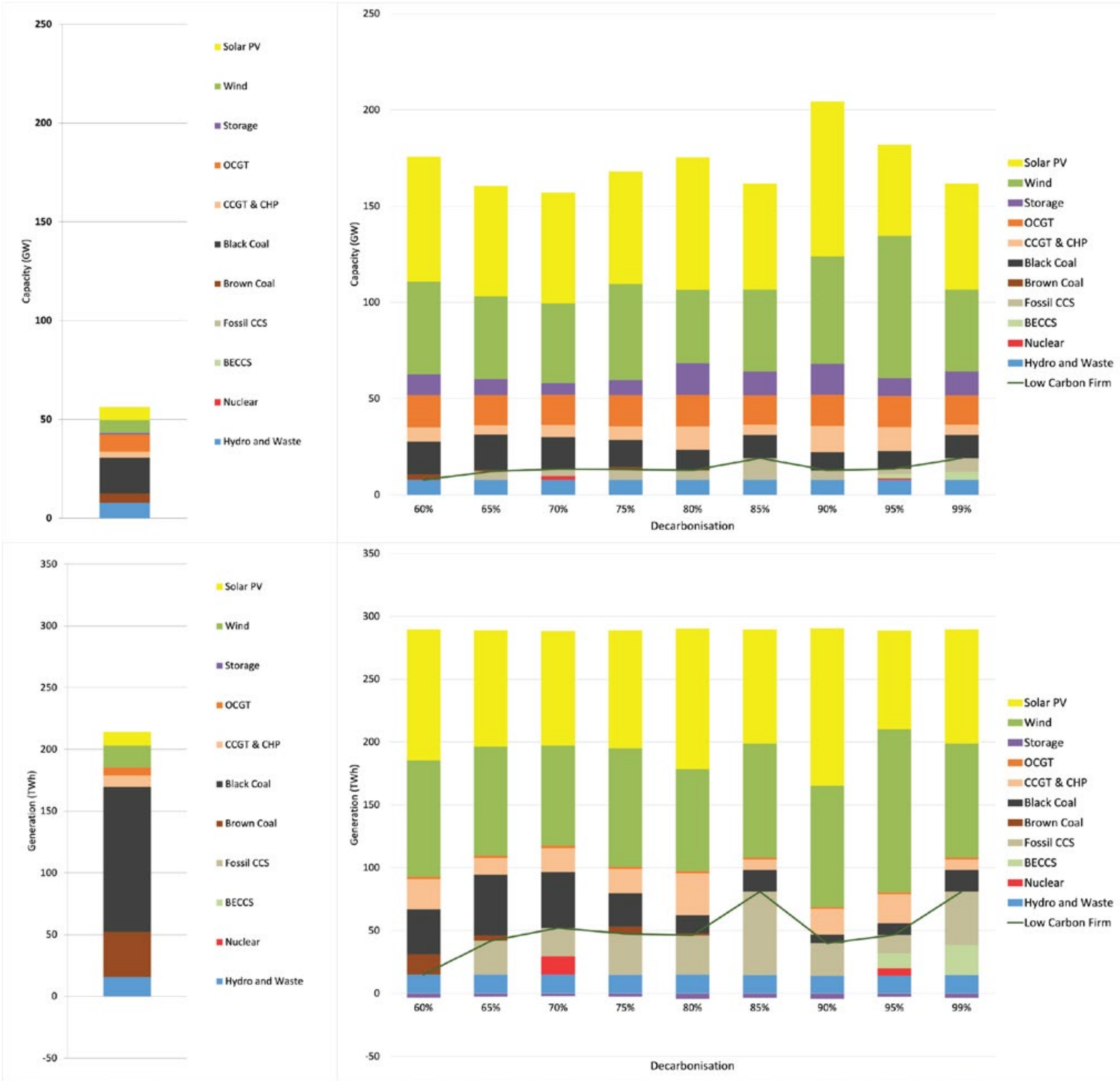


Figure 42: The ideal portfolios at different decarbonisation targets in 2050 for the NEM
For reference, far left stacks represent the current 2020 NEM

Understanding the Use of Unabated Coal in Deep Decarbonisation

In the current Australian NEM, unabated coal accounts for a significant share of both capacity and generation. However, as part of the decarbonisation transformation it is expected that unabated brown and black coal will have to be replaced by lower emissions technologies, including renewables, storage and CCS [83; 84].

The decrease in emissions associated with CO_2 emitting technologies at different decarbonisation targets is shown in Figure 43. It is very clear that the role of unabated brown and black coal decreases as decarbonisation targets increase. These emissions are replaced with natural gas, then with fossil CCS and finally with BECCS. Interestingly, BECCS provides an offset opportunity for unabated black coal within the lowest TSC solutions at 95% and 100% decarbonisation, allowing emissions from unabated coal to increase compared with the 90% decarbonisation solution.

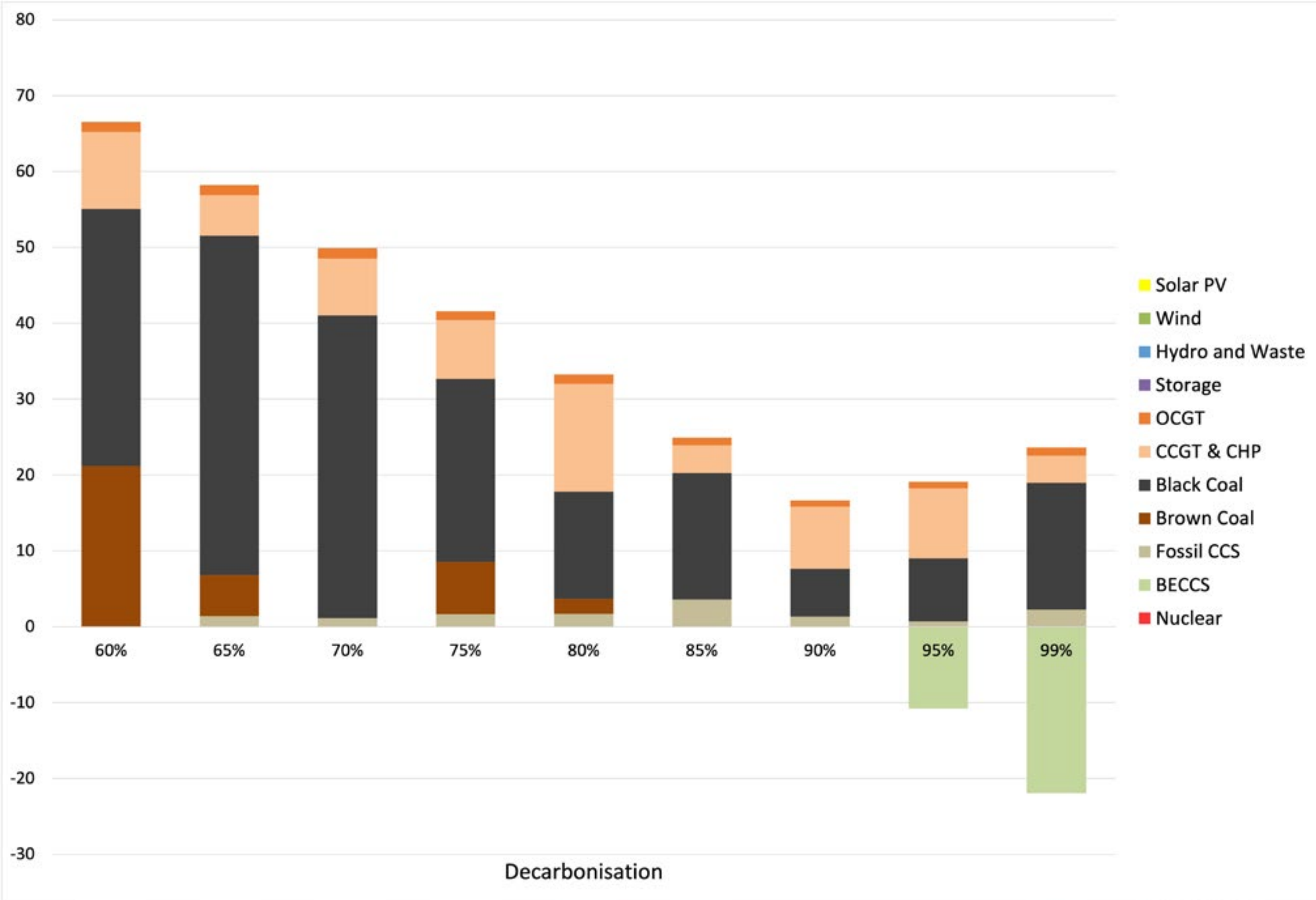


Figure 43: The source of CO_2 emissions at the lowest TSC frontier in 2050 for the NEM

It is important to understand how and why unabated coal remains on the system in a deep decarbonisation scenario. Specifically, why is unabated coal being used as a peaking plant and high merit and expensive BECCS is being used to cancel out their emissions?

Firstly, it is important to consider the residual load duration curves in the deep decarbonisation scenarios, net of both wind and solar PV. This remaining load needs to be met by firm capacity. This is shown schematically in Figure 44. In this figure, we can see the 'traditional' view of peaking plant on the left-hand side, where OCGT power plants provide peaking capacity and the BECCS power plants offset the OCGT emissions, as well as the emissions from the fossil CCS plants. Fossil CCS plants capture the majority of emissions, but have a 5% slippage, which needs to be offset at very high decarbonisation levels. When unabated coal is used as a peaking plant [85; 86], it has higher CO_2 emissions than OCGTs due to the higher carbon content of the fuel, however BECCS completes the offset for coal as for gas.

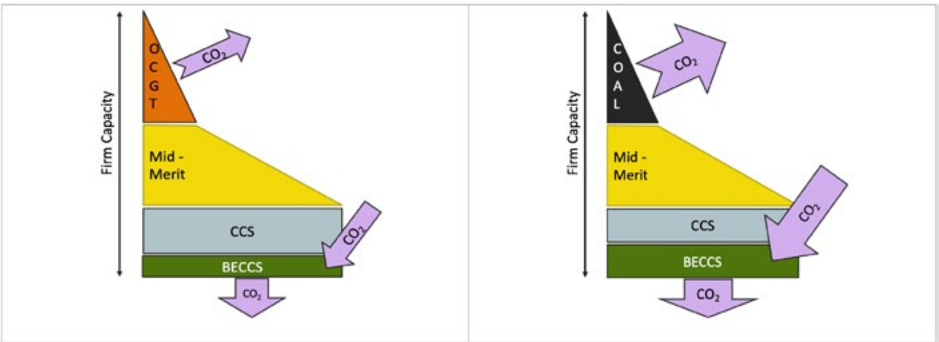


Figure 44: The role of peaking plant in deep decarbonisation – OCGT vs coal

In considering the alternatives to unabated coal, lower emission OCGT or very flexible combined cycle gas turbine (CCGT) and traditional biomass were examined in order to established if these could have a lower TSC. Batteries were not considered for this peaking role, as the nature of the residual load curve means the batteries would need to have three weeks discharge capability to cover calm periods in winter. The Hornsdale Power Reserve in South Australia (the largest battery in the world at time of writing) could only deliver 255kW if run for three weeks continuously so is unsuitable for this role [25; 79].

In examining the four peaking options (coal, OCGT, CCGT and biomass, all unabated), coal provided the cheapest option on a TSC basis. Figure 45 shows all of the cost elements that change when a different option is chosen for peaking plant. Despite the fact that coal needed the most BECCS to offset its emissions, this was more than offset by low cost of coal as a fuel and utilising its fully depreciated asset status, meaning no new builds. However, as we have seen in other jurisdictions, unabated coal may be retired for a number of reasons, including additional emissions restrictions (SOx and NOx limits within the EU [53; 87], CO_2 limits within California, USA), economics (within the NEM this would include Hazelwood, Vic and Northern Power Station, S.A.) [88], or politics [53].

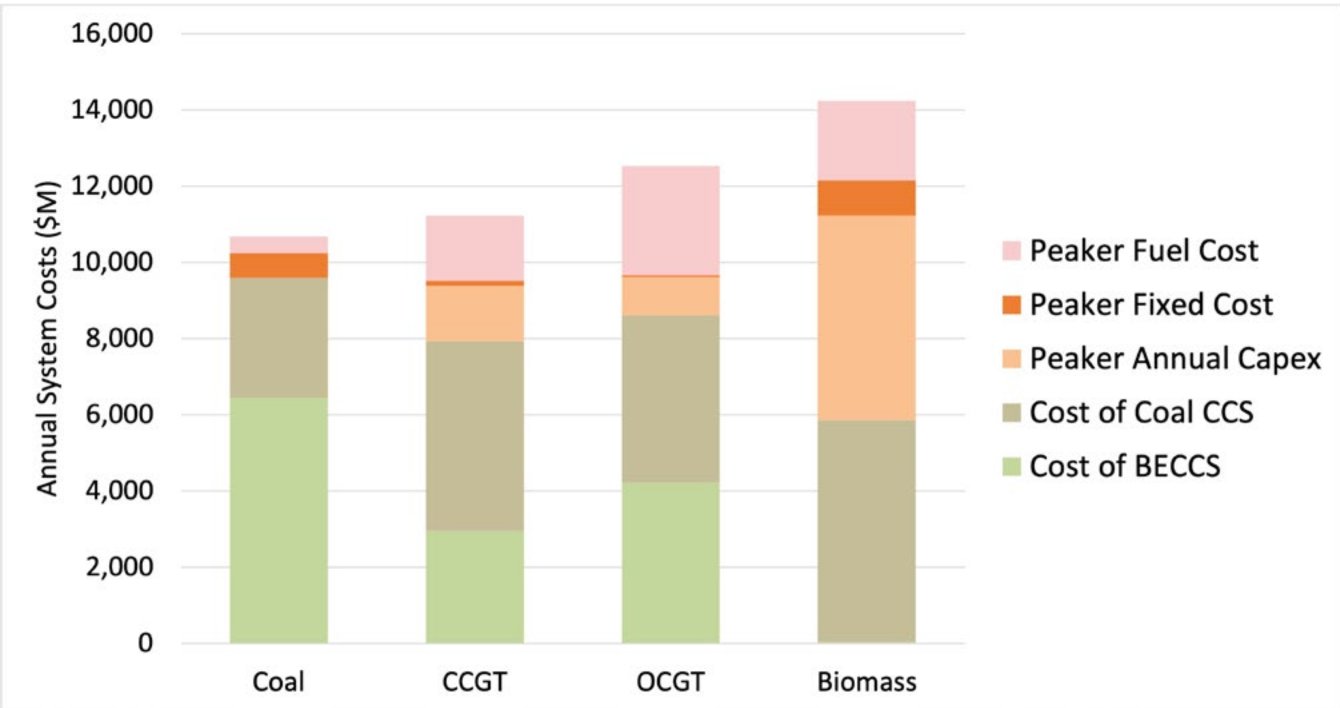


Figure 45: Peak plant options showing why coal contributes to the lowest TSC solution in 2050 for the NEM

The Role of Unabated Coal and Constraint Impacts

The previous section has demonstrated why there is a significant capacity (around 10 GW) of unabated coal in the lowest TSC scenarios, even at deep decarbonisation. However between 2015 and 2019, 14 European Union countries announced the phasing out of coal entirely by 2030, and Germany by 2038 [89]. Given the political momentum for phasing out coal, it is important to explore what would occur to the lowest TSC scenarios if no legacy coal plant were available.

Analysis of the 3,300 scenarios show that for the scenarios which exclude coal, no scenario gets within $7/MWh of the scenarios with the lowest TSC. Eliminating coal early would cost the Australian consumer at least and additional $2Bn per year. However, it is important to note that the remaining coal plant would run at very low load factors, with some plants running for just a few days over winter. This can be seen in Figure 46 where the plants above the green line only operate between May and August. In reality, high load factor plant below the red line would probably be replaced by CCGT for their lower emissions. Other unabated coal plants would run across the year, but only for a few hours at a time with many start-up/shutdown cycles.

Preparing a coal plant to run in this regime would require significant capital investment to ensure that the plant is capable, and ongoing maintenance costs would also likely increase. With a very low output it is unlikely that the current energy market would remunerate these ‘peaking’ coal plant sufficiently, or indeed any plant running at such low load factors. Speculating on how the market might change is outside the remit of this report, but this report assumed that ‘the lights will stay on,’ meaning that some means will be found to reward peaking plant.

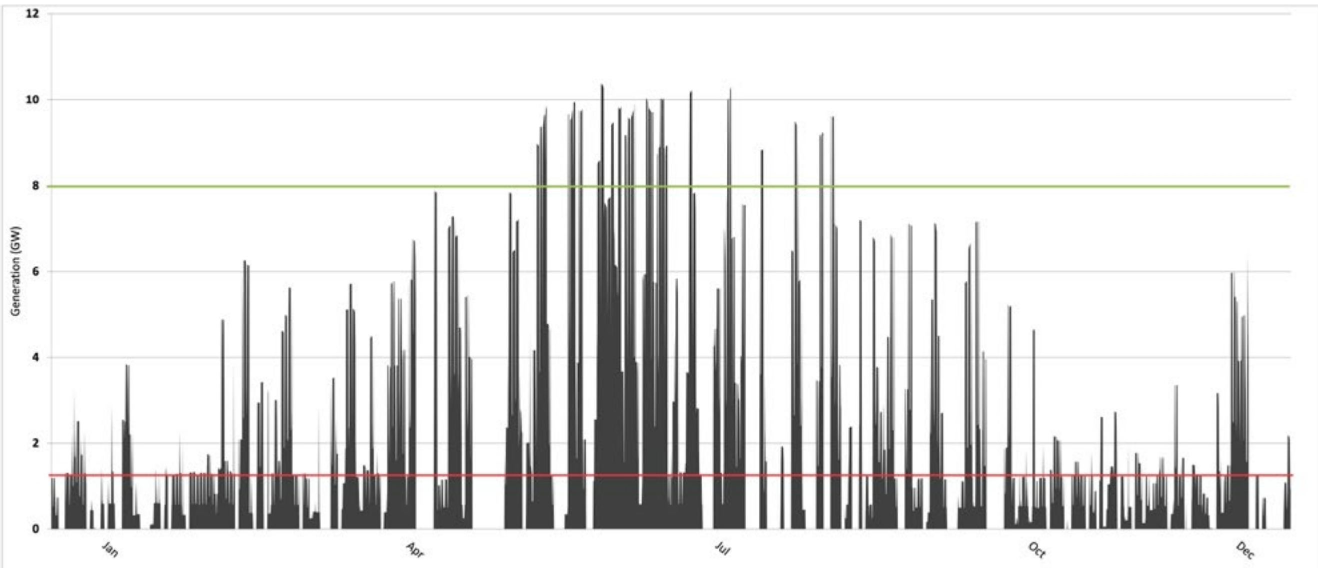


Figure 46: Daily generation of coal plants across the year for a lowest TSC scenario

Role of BECCS and Constraint Impacts

In many cases, modelling of all sources of global emissions has shown that holding the increase in average global temperature to below 2°C will need economies to aspire to net zero emissions, which implies atmospheric CO_2 removal [90; 91]. In order to meet Australia's national and international obligations, it is likely that BECCS will form a key part of enabling the electricity sector to completely decarbonise. To be effectively deployed, BECCS would greatly benefit from the wide-scale deployment of CCS [92; 93]. Historically, biomass for power generation, and BECCS deployment more broadly, has been challenging.

The deployment of BECCS would increase competition over limited biomass resources, and potentially result in competition with food production and biodiversity [94]. Land use is a key constraint for biomass production, where energy crops or plantations may face tough competition for agriculture land alongside use for food production and, to a lesser extent, residential use [95].

In order to examine the impact of BECCS in achieving the lowest TSC options, the S-MEGS scenarios are separated into those with or without BECCS. Figure 47 demonstrates the impact of no BECCS available on the constrained lowest cost frontier (red). This shows the marginal cost of abatement is higher and begins to deviate from the lowest TSC frontier at 90% decarbonisation, and it is extremely high beyond 95% without BECCS. Decarbonisation beyond 99% is not possible without BECCS. The purple frontier and runs in Figure 47 also shows the S-MEGS solutions with up to 4 GW of installed BECCS within the NEM. At this level of constrained BECCS installation, it is possible to achieve 100% decarbonisation at near minimum TSC.

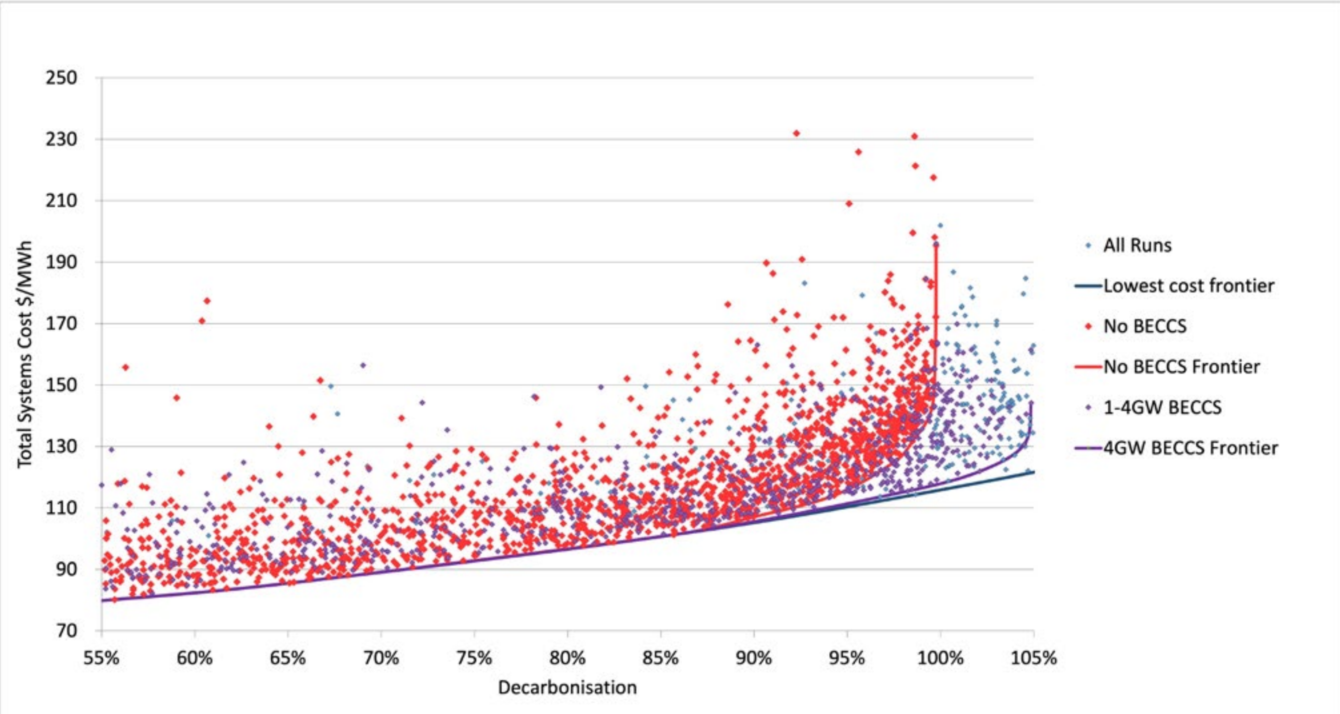


Figure 47: Impact of no available BECCS on lowest TSC frontier (role of 4 GW of BECCS in purple) in 2050 for the NEM

The generation mix at the various 2050 decarbonisation targets without BECCS is shown in Figure 48. These new portfolios are on the new constrained lowest cost frontier with no BECCS. The last two scenarios are the only decarbonisation scenarios that are substantially different to the unconstrained portfolios in Figure 42. In these very deep decarbonisation targets of 95% and 99%, BECCS is replaced by nuclear. There are still some small residual CO2 emissions from CCS, but within 1% of complete decarbonisation. It should be noted that unabated coal and natural gas exists in the capacity mix, however, are not called on to generate to any significant degree and are present for system reserve only.

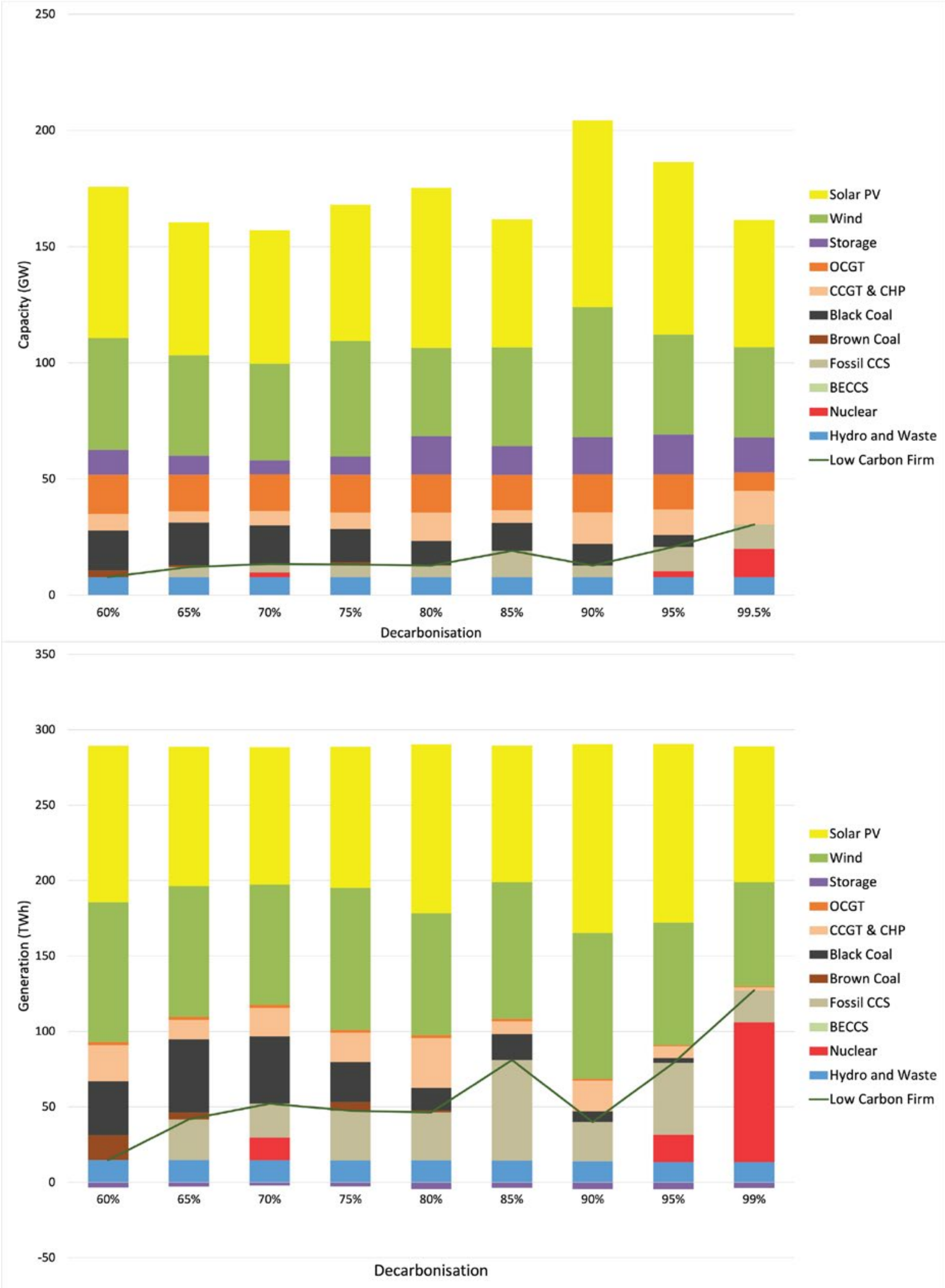


Figure 48: Impact of no available BECCS in the ideal portfolios in 2050 for the NEM

Without the option of BECCS, the NEM can only be decarbonised completely by replacing the unabated fossil fleet entirely. Even fossil fuel-based CCS plant, with a capture rate of 95%, would emit too much CO_2, as anything over zero is disallowed. The impact on the sources of CO_2 at various decarbonisation points for 2050 is shown in Figure 49. Technologies such as fossil-based oxy-fuel and Allam cycle power generation plants, which are capable of capture rates greater than 99%, may also be a viable contribute to near complete (>99%) decarbonisation.

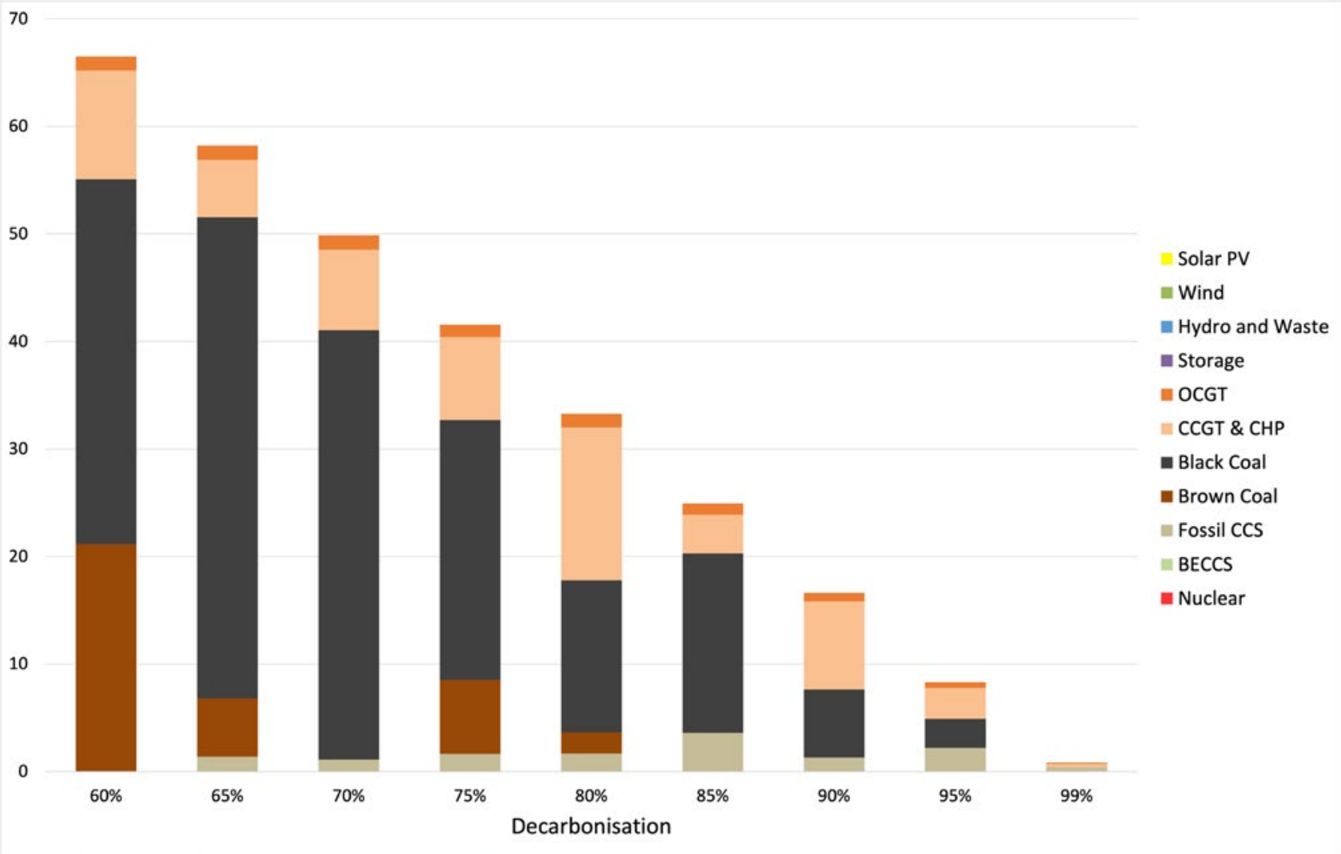


Figure 49: Impact of no available BECCS on the source of CO_2 in 2050 for the NEM

Role of CCS and Constraint Impacts

Like BECCS, fossil fuel-based CCS is also considered to be a critical technology within the electricity sector in order to facilitate achieving deep decarbonisation [93]. In their Sustainable Development Scenario, the International Energy Agency (IEA) envisage CCS capturing 310 Mt/year by 2030 and 1300 Mt/year by 2040 [21; 96]. In all previous MEGS TSC modelling of the NEM, CCS has contributed to a the lowest TSC outcome [23; 25; 79; 82].

The injection of CO_2 and storage in underground formations has been identified as a critical method to reduce CO_2 emission into the atmosphere. In this regard, CO_2 used for enhanced oil recovery (EOR) has gained some attention during the last few years, though suitable sites are not widespread. Deep saline formations have been recommended as an alternative option for CO_2 storage due to their more widespread availability and considerable capacity to hold and store CO_2. Injection rate must be managed as a key constraint to more realistically estimate CO_2 injection rate and storage capacity in any geological formation [97]. In addition, public opposition may constrain the extent of available CO_2 storage due to concerns about the injection of CO_2 for many reasons, although not all of them are technical [98].

The impact of CCS being unavailable for both fossil fuel and biomass-based CCS power generation technologies is shown in Figure 50. While having no CCS seems an extreme constraint, it remains instructive to examine possible system alternatives and the impact this has on TSC. Similar to BECCS, the constrained lowest cost frontier begins to be impacted, but more severely and at a lower point of approximately 85% decarbonisation. Beyond 85% decarbonisation, CCS is essential to establish the lowest TSC power generation portfolio.

Figure 50: Impact of no available CCS on lowest TSC frontier in 2050 in the NEM

The resulting portfolio options at various decarbonisation targets in 2050 are shown in Figure 51, where the solutions now have no CCS power generation options in the constrained lowest cost frontier. The impact of no available CCS technologies results in natural gas technologies replacing CCS at the lower decarbonisation targets for 2050. At decarbonisation targets above 85%, the technology constraint begins to have more significant impacts than just 'simple' fuel switching to unabated natural gas. Without 5 to 10 GW of CCS capacity, the system requires 20 to 50 GW of additional VRE assets. This comes with an additional cost above the lowest TSC frontier, that would not be necessary if CCS were available. This increase in capacity is underwritten at 95% and 99% decarbonisation by nuclear power as the firm, low emissions source of generation.

At decarbonisation targets above 85% with CCS constraints, the system relies on nuclear power, with the exception of the 90% portfolio which illustrates an alternative with high gas and high renewable capacity option. However, all of these scenarios above 85% decarbonisation are above the lowest TSC frontier when compared to portfolios with CCS. The 100% generation outcome, also known as the net zero goal, is made up of almost 40% nuclear and 50% solar PV generation, and costs 50% more than the optimum when all available technologies may be employed.

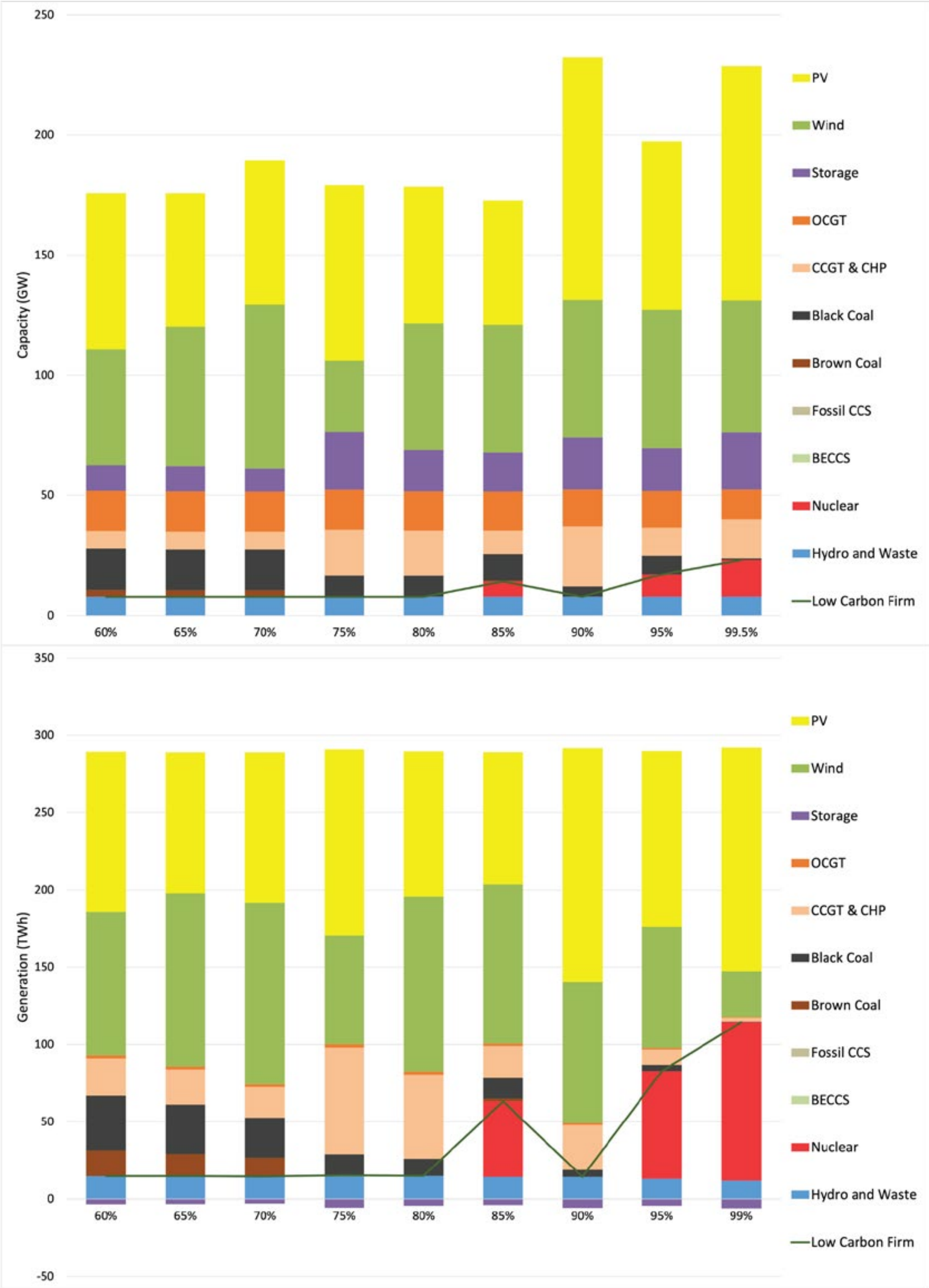


Figure 51: Impact of no available CCS in the ideal portfolios in 2050 for the NEM

It is unlikely that no CCS would be available within the NEM, with studies on the Surat Basin in Queensland [99] and the Bass Strait in Victoria [100] showing significant promise. In order to examine the impact of limited CCS, a more realistic 5 GW CCS constraint was examined, which is approximately half the ideal value needed to achieve lowest TSC.

Figure 52 shows the effect of just 5 GW of CCS (including 1.2 GW BECCS). Compared to the no CCS case costs are reduced significantly above 90%, although compared to there being no restriction on CCS, costs are still significantly higher above 95% decarbonisation.

Figure 52: Impact of limited availability of CCS on lowest TSC frontier in 2050 in the NEM, showing improvement from no CCS

The corresponding portfolios at the frontier are shown in Figure 53. With limited CCS, there is more reliance on nuclear to reach 100% decarbonisation, although if 95% were the target then there is little need for nuclear. This illustrates how important the destination is to the pathway. If full decarbonisation is the ambition, and CCS is limited, then it is important to prepare for nuclear builds.

However, backing off the decarbonisation goal by 10 to 15%, near-zero emissions technologies like CCS and nuclear are much less likely to have a role. However, as these are long-lead technologies to deploy, if they are required, planning for their deployment should commence immediately in order to ensure that there is sufficient capacity available in the remaining period to 2050.

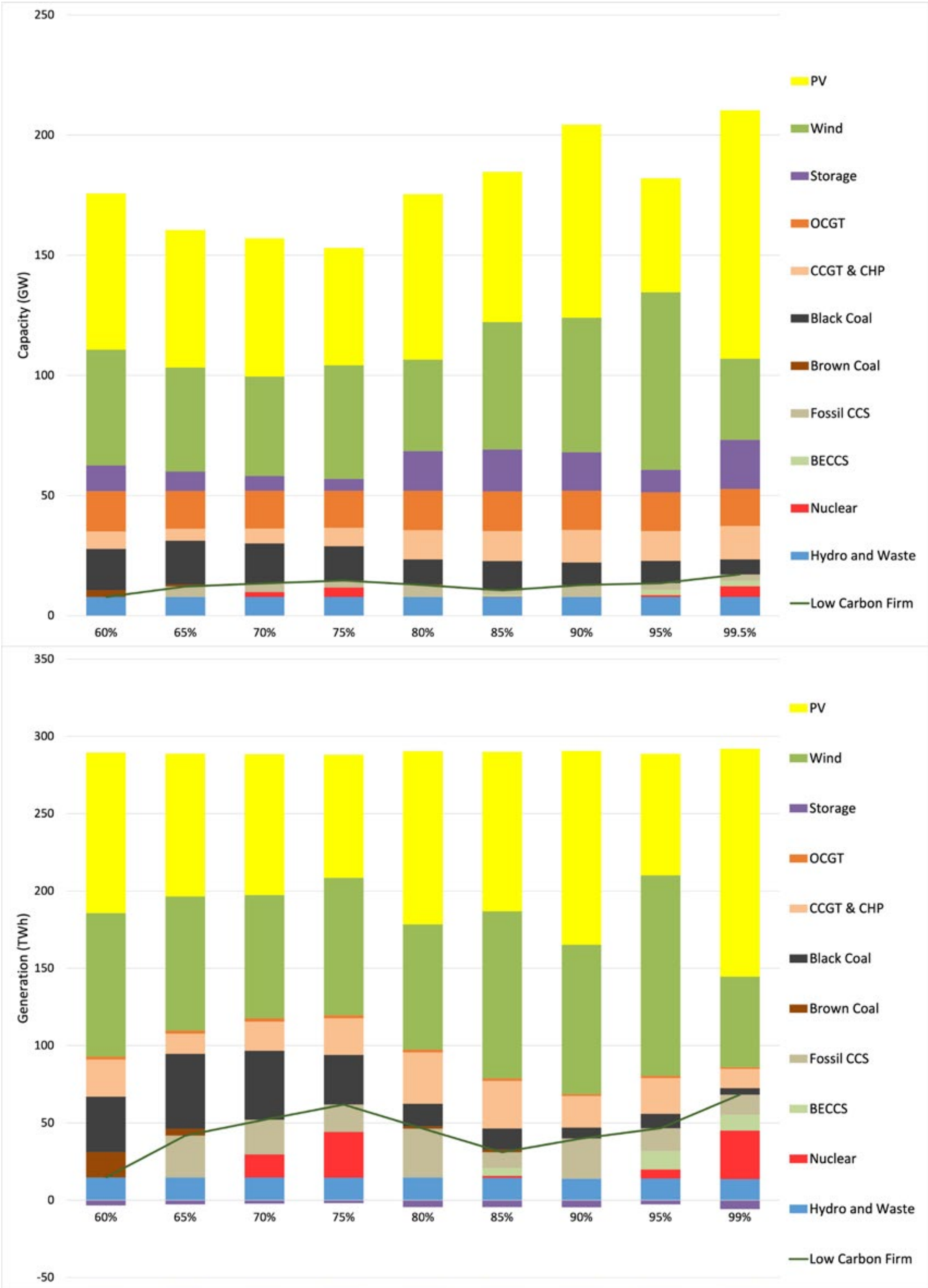


Figure 53: Impact of limited availability of up to 5 GW in the ideal portfolios in 2050 for the NEM

Role of Nuclear and Constraint Impacts

Any discussion of net zero emissions targets in the Australian context will be incomplete if it did not consider the availability of nuclear power. Nuclear power has extensive global application as a firm, dispatchable, low emissions source of electricity. While nuclear power is not a legal option within the current Australian context [101], nuclear power underpins many low carbon power grids. For example, Great Britain has 9% of nuclear power as installed capacity, contributing around 20% to the annual generation mix [102]. In France, nuclear is the main source of energy, with 50% of the capacity mix and more than 70% of the generation portfolio [24]. At the end of 2019 the capacity of the world's 442 operable reactors was 392 GW. Six reactors started up in 2019, one in South Korea, one in Russia and two in China. In addition, two small reactors on the first purpose-built floating nuclear power plant harboured at the town of Pevek in northeast Russia. In 2019, construction began on five reactors, two in China and one each in Iran, Russia and the UK [103].

While the development of other low emissions technologies will influence whether nuclear power would be required to meet Australia's future energy needs, it would not be able to play a role unless action is taken now to plan for its potential implementation [104]. While a Royal Commission recommended that all technologies, including nuclear, contribute to a reliable, low emissions electricity network at the lowest possible system cost, it gave no guidance on removing the legal obstacles to its use within Australia [101].

The impact of not having nuclear technology as part of the energy mix within the NEM in 2050 is shown in Figure 54. While nuclear often contributes to decarbonisation in low TSC solutions, nuclear is not an essential element of the lowest TSC solution if CCS and BECCS are available as shown in Figure 54 with the constrained and unconstrained lowest TSC frontier are superimposed. The two scenarios that had a small amount of nuclear in the unconstrained environment (refer to Figure 42) saw nuclear replaced with slightly larger capacity of CCS.

Figure 54: Impact of no available nuclear on lowest TSC frontier in 2050 in the NEM

Role of the Combined Impact of CCS and Nuclear Constraint Impacts

In considering the impact of a combined constraint on the two key technologies which are capable of providing firm, low emissions electricity, the results were filtered for the no CCS and no nuclear scenarios. As shown in Figure 55, the constrained lowest TSC frontiers begin to separate at just over the 80% decarbonisation goal. For decarbonisation targets above 83% either CCS or nuclear needs to be part of the solution to achieve the lowest TSC.

Figure 55: Impact of no available CCS and nuclear on lowest TSC frontier in 2050 in the NEM

In order to attempt to decarbonise the NEM beyond 85% decarbonisation, wind and solar PV capacity would need to be expanded significantly. A 280 GW system would be required to meet demand at 95% decarbonisation target (refer to Figure 56), which is more than five times the capacity of the current NEM. Realistically, the system cannot progress beyond 95% decarbonisation without extraordinary TSC impacts.

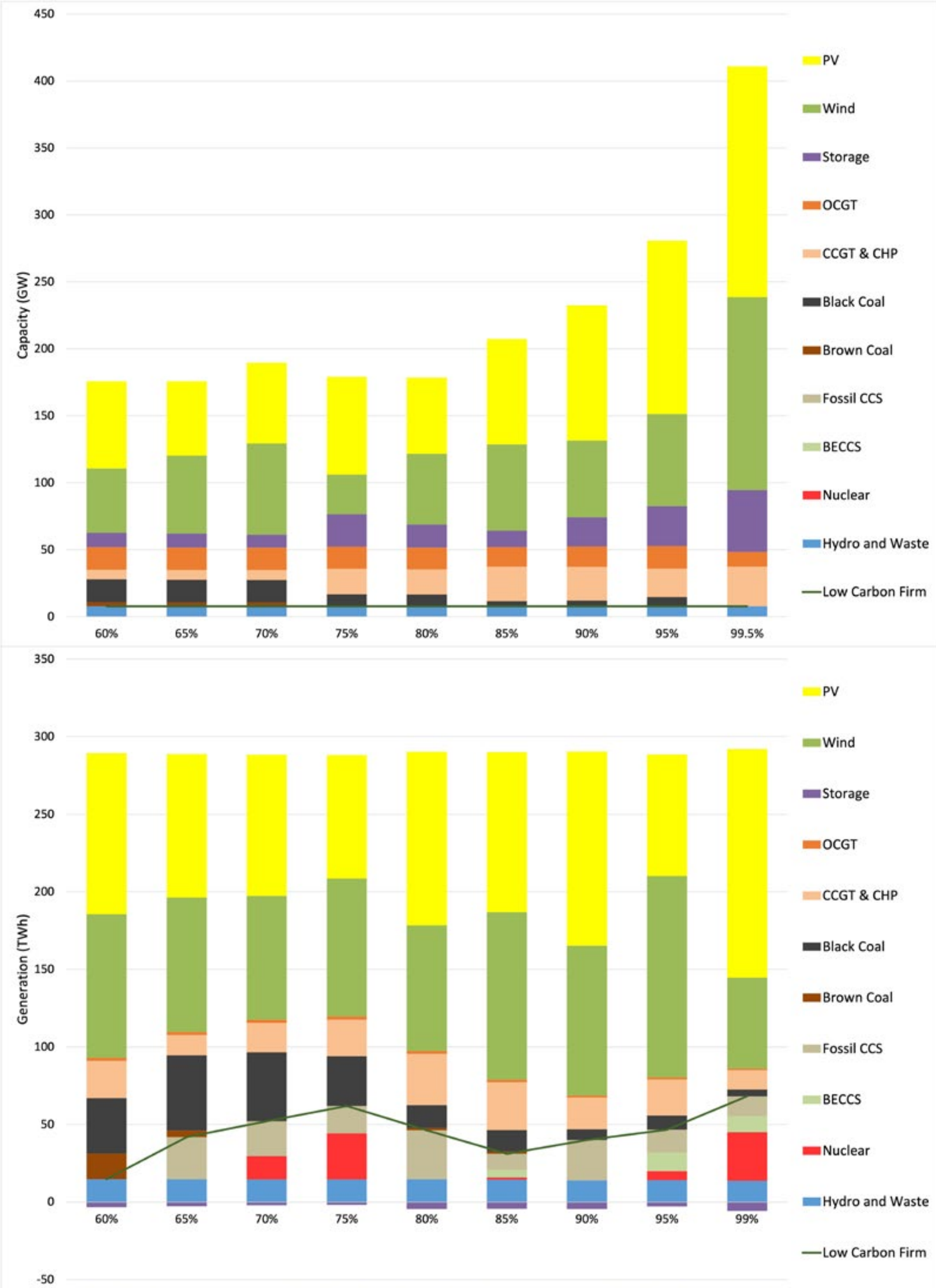


Figure 56: Impact of no available CCS and nuclear in the ideal portfolios in 2050 for the NEM
Note: the capacity scale on this figure is 100 GW larger than most of the graphs in this book

Role of Renewables and Constraint Impacts

As seen in Figure 42, the lowest cost frontier contains scenarios with at least 80 GW of renewables, and often more. To examine the value of renewables, the scenarios which have only half this amount, or less, are plotted on Figure 57. Without renewables, predominantly wind and solar PV, reaching their optimum levels, typically between 80 to 100 GW of installed capacity for nearly all scenarios close to the lowest TSC frontier, systems costs are likely to be $10/MWh higher, at whatever level of decarbonisation is chosen. This would equate to nearly $3Bn/year. To achieve a lowest TSC in 2050, at least 80 GW of renewables will need to be built across the NEM, for any decarbonisation target greater than 50%.

Figure 57: Impact of renewables restricted to 40 GW or less on lowest TSC frontier in 2050 in the NEM

In order to compensate for the constrained renewable capacity build within the NEM, nuclear and fossil CCS is built (refer to Figure 57). The total physical system is also considerably smaller in terms of overall capacity, at approximately 100 GW compared with approximately 150 GW to 180 GW in an unconstrained scenario (refer to Figure 41). Consequently, nearly 50% of the generation is now provided by the firm low carbon sources (refer to Figure 58), which in an unconstrained system would account for approximately 35% of generation (refer to Figure 42).

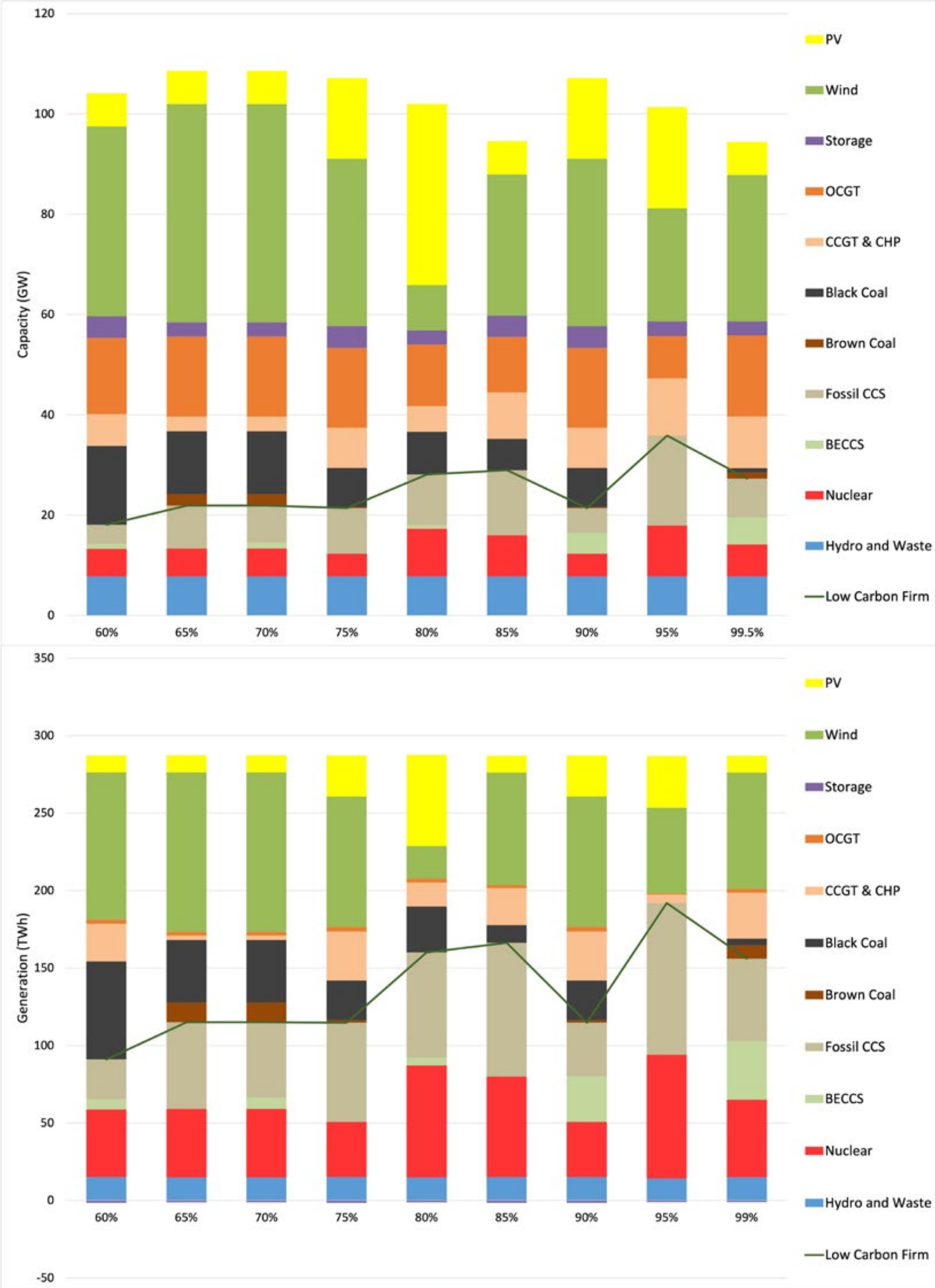


Figure 58: Impact of renewables restricted to 40 GW or less in the ideal portfolios in 2050 for the NEM. The capacity scale in this figure is much lower than all the others in the book.

Appendix: Grid Services Terminology

To ‘keep the lights on’, the power system needs to be secure. It should be able to operate within defined technical limits, despite an incident such as loss of a major transmission line or large generator. It also needs to be reliable by having enough capacity to supply demand.

A secure system: The power system is in a secure and safe operating state if it is capable of withstanding the failure of a single network element or generating unit. Security events are caused by sudden equipment failure (often associated with extreme weather or bushfires) that results in the system operating outside of defined technical limits, such as voltage and frequency [105].

A reliable system: A reliable power system has sufficient generation and network capacity to meet the consumer load in that region. Reliability events are caused by insufficient generation or network capacity to meet consumer load, which are usually predicted ahead of time by supply and demand forecasting [105].

Unserved Energy: A measure of the number of blackouts suffered by consumers. It is the total energy demand in MWh that was not met as a result of customers being involuntary cut off from supplies.

Inertia: The ability of the system to resist changes in frequency is determined by the inertia of the power system. Inertia is provided as a consequence of having spinning generators, motors and other devices that are synchronised to the frequency of the system. Historically, inertia has been provided in the NEM by large amounts of synchronous generators, such as coal and gas-fired power stations and hydro plant.

However, as many new generation technologies, such as wind turbines and PV panels, are not synchronised to the grid and have low or no physical inertia, they are currently limited in their ability to dampen rapid changes in frequency.

Rate of change of frequency (RoCoF): The rate at which the frequency changes determines the amount of time that is available to arrest the decline or increase in frequency before it moves outside of the permitted operating bounds. AEMO may constrain the power system to reduce the size of a potential contingency and minimise the resulting initial frequency change. Alternatively, an increase in the level of inertia in the power system would permit the occurrence of larger contingencies for a given level of initial RoCoF [105].

System strength: System strength is a measure of the current that would flow into a fault at a given point in the power system. Reduced system strength in certain areas of the network may mean that generators are no longer able to meet technical standards and may be unable to remain connected to the power system at certain times [105]. Non-synchronous generators provide little contribution to system strength.

Transmission Constraint: A limitation on the flow that can be carried on part of the transmission network. When that constraint is binding (i.e., more power would flow if the limitation were lifted) it can lead to different prices on either side of the constraint in markets such as the NEM.

Ride-through: The ability of generators and loads to withstand or ‘ride-through’ changes in frequency can influence the ability to maintain control of power system frequency following a contingency event. Generators and loads have a range of capabilities to withstand RoCoF. Generators and loads must also be capable of riding through network faults. Generators that trip as a consequence of high RoCoF may exacerbate the disturbance to the system and lead to an even higher RoCoF by both contributing to the overall size of the contingency as well as reducing the level of inertia in the system [105].

Firm capacity: Firm capacity power plants have the ability to generate or dispatch electricity on demand, and include gas, coal, hydro, geothermal, biomass and nuclear power plants. The thermal plants are typically operated as consistently as possible, with a minimal stable generation state.

Flexibility: A flexible power plant has the ability to adjust its power output as demand for electricity fluctuates throughout the day. Flexibility impacts overall efficiency and maintenance costs.

Reserve: The operating reserve is the generating capacity available to AEMO within a short amount of time to meet demand in case of a supply disruption. The operating reserve is made up of the spinning reserve as well as the non-spinning or supplemental reserve.

Response Timeframes: Key timeframes for ensuring grid stability and security range from the microsecond level out to the seasonal level and are described in Table 6. Beyond stability, the security of electricity supply can stretch to months and years.

Table 6: Timeframes for ensuring grid stability and security

Timeframe	**Stability/Security Issue**	**Stability/Security Response Measure**
Microseconds	RoCoF	Inertia Instantaneous “cycle-by-cycle” acting frequency response
Sub-second	Frequency rapid rate-of-change	Very fast acting frequency response (e.g., demand disconnection, inherent or synthetic inertia, battery response)
~ A few seconds	Frequency Control	Fast acting (e.g., governor valve or stored electricity)
~ Five minutes	Electricity Market Balancing	Load following (e.g., generator dispatch target)
A few minutes to a few hours	Contingency for generation loss or forecast error	Reserve (e.g., spinning reserve or gas turbine with fast start)
Day	Electricity Market Daily Supply Matching	Diurnal supply matching (e.g., sufficient fuel or energy storage)
Season	Electricity Market Seasonal Supply Matching	Seasonal supply matching (e.g., sufficient fuel storage alongside fossil generation)
Annual	Insufficient generation to meet peak demand	Capacity market. Legal notice to close plant.

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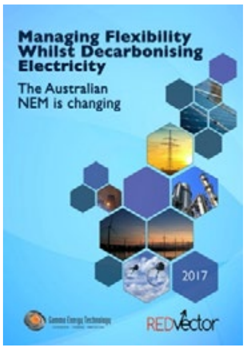
Additional Reports

The Following Reports have been undertaken as supporting studies for this book. To download these reports at no charge, please visit: **www.powerfactbook.com/downloads/energy-reports**

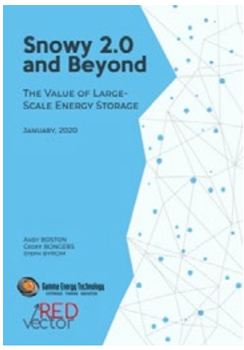


Managing Flexibility Whilst Decarbonising Electricity: Full Report

The National Electricity Market has embarked upon a pathway to a gradual decarbonisation, driven by State and Federal Governments along with the commitments made in Paris. This report, which is the first in the series of MEGs studies, gives insights into a new modelling approach and initial results to encourage a different energy conversation.

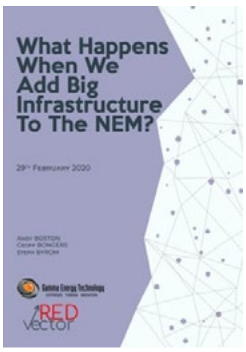
The Lowest Total System Cost NEM: The Impact of Constraints

This study highlights the need for firm zero-carbon dispatchable generation to support the NEM. It also clearly shows that a net-zero grid will be much more expensive, the total system of today's grid is ~S11Bn/y – this will TRIPLE by 2050 with very deep decarbonisation. Restricting VRE, CCS or nuclear has a mostly modest impacts, but no CCS means a ~$5Bn/y impact. Excluding both CCS and nuclear results in a very large increase in TSC at 99% decarbonisation.



Snowy 2.0 and Beyond: The Value of Large-Scale Energy Storage

This study has examined the impact of Snowy 2.0 and the Battery of The Nation, as well as scenarios beyond these two projects, to examine what benefit large scale pumped hydro storage could provide to the NEM as it decarbonises. In line with previous studies, the analysis undertaken focuses on total system cost (TSC) and CO_2 emission reductions as the key metrics. Decarbonisation is assumed to be the objective and TSC optimised, as this is what the consumer will ultimately have to fund.



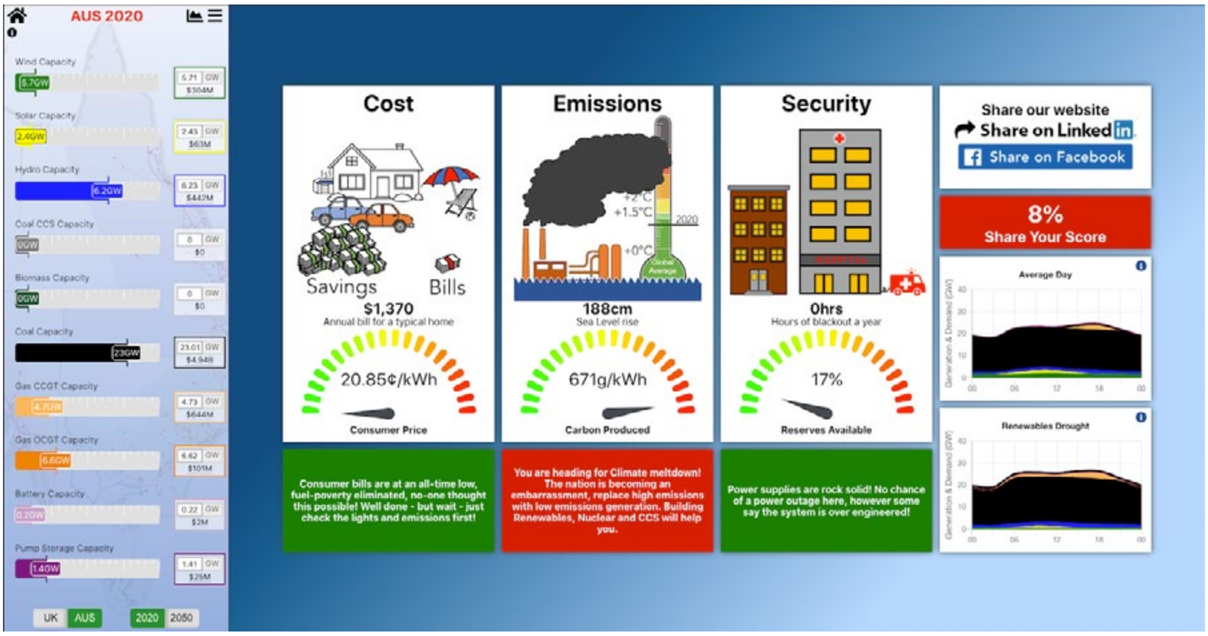
What Happens When We Add Big Infrastructure To The NEM?

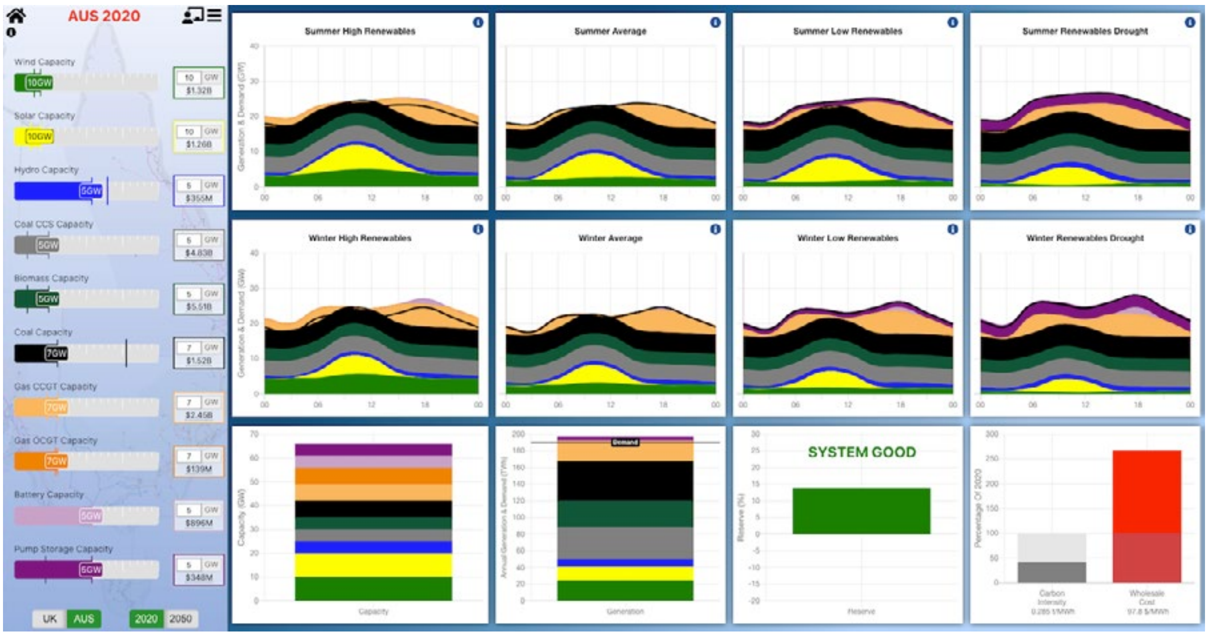
The purpose of this study was to examine the effect of four substantial upgrades and how they may impact the shape of the anticipated decarbonisation transformation. When comparing the four infrastructure upgrade options, it was clear that they offered very different options and services to the grid and result in different impacts / benefits to the system.

Modelling Energy Website

Along with this book, the authors have also developed a website to allow readers to explore TSC.By visiting **https://modelling.energy/** readers can model the NEM for both 2020 and 2050, with their own generation makeup. The website has been developed for both the general public as an educational tool, as well as a detailed breakdown for those who require additional information.

The website has been designed with the purpose of demonstrating some of the basic principles of good electricity system modelling, in a fun environment that should bring out broad brush principles. Though it is not intended as a tool for detailed analysis or system planning, if understood well, it is sufficiently robust to enable a user to ask the right questions about decarbonisation and to better interrogate results from other models advocated in the electricity system literature.





ABOUT RED VECTOR:

Red Vector is a UK Limited Company that provides an energy consulting service based on Andy Boston's 30 years' experience in the energy industry starting with the nationalised Central Electricity Generating Board (CEGB), through privatisation firstly with PowerGen and then E.ON, and finally with the Energy Research Partnership.

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ABOUT GAMMA ENERGY TECHNOLOGY P/L:

Gamma Energy Technology P/L is an independent energy consulting service, offering a range of technical and support services, including but not limited to power generation technology. We are proud to contribute to the on-going discussions on energy as we seek to solve the trilemma of energy supply.

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