Snowy 2.0 and Beyond

The Value of Large-Scale Energy Storage

January, 2020

Andy BOSTON
Geoff BONGERS
Steph BYROM

Gamma Energy Technology
EXPERIENCE THINKING INNOVATION

RED Vector

Executive Summary

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 also seen a rapid and significant increase in installed capacity. As more renewables are added to the National Energy 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:

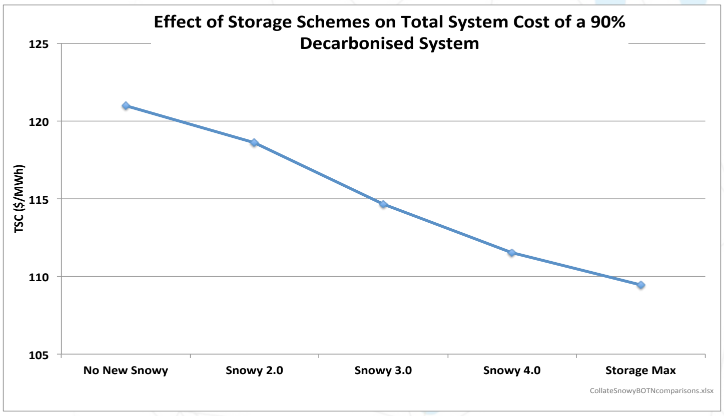
1. Storage can smooth out the often rapid increases and decreases of renewable generation output, to provide a steady output or provide a more dispatchable option in order to match demand,
2. Storage can provide some of the grid services that both wind and solar PV are unable to provide (such as inertia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

It is within this context that both Snowy 2.0 and Tasmania's "Battery of The Nation" (BoTN) are being considered. This study has examined the impact of Snowy 2.0 and the BoTN, 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.

A systems assessment approach is the ideal framework by which to explore alternative storage scenarios. Modelling Electricity Grid Systems (MEGS) is specifically designed to explore alternative storage scenarios, as it is specifically set up to explore deep decarbonisation scenarios with long term storage, whilst ensuring sufficient grid services and firm capacity is maintained. 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.

No Regrets – Snowy 2.0 and Battery of the Nation

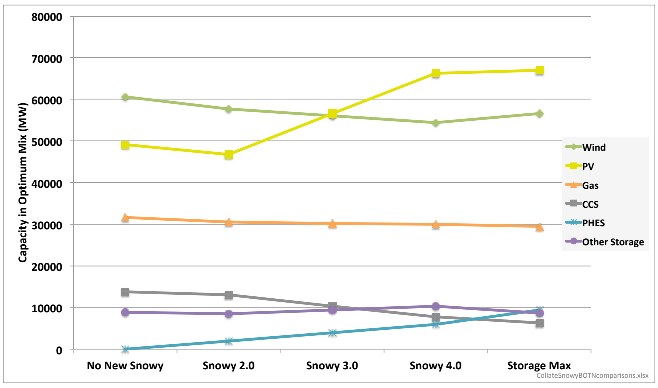
Both ***Snowy 2.0 and BoTN help reduce the cost of meeting moderate (60%) and deep (90%) decarbonisation targets.*** All of the scenarios examined within this study showed a positive impact for these large-scale storage projects. The benefit was significantly smaller for the moderate decarbonisation scenario examined, however within the deep decarbonisation case Snowy 2.0 demonstrated a reduction in TSC of around $3/MWh.



Large Scale Energy Storage Supports Renewables

The addition of Snowy 2.0 improves the efficiency of the installed wind and solar PV within the NEM. ***This may result in less capacity being built to achieve the same decarbonisation level.*** Larger volumes of pumped hydro energy storage (PHES) are particularly supportive of increased solar PV capacity, however, with such a large renewable capacity – significant amounts of curtailment will be the 'new normal'. Under current market conditions this will likely present a material business risk.

Pumped Hydro Changes the Mix



The firm capacity of large scale PHES when the pumping energy is supplied by VREs is a direct competitor to coal and gas-based carbon capture and storage (CCS). Future energy mixes that have an optimal TSC and achieve deep decarbonisation scenarios, which also include schemes like Snowy 2.0 and the BoTN, will have a reduced requirement for coal or gas CCS. The impact on installed capacity of wind and solar PV and their generation contribution is more complex. Initially adding a small amount of storage, such as Snowy 2.0 only, improves the utilisation of wind and solar PV (by avoiding curtailment) which in turn means less are required to be installed to achieve the same decarbonisation level. Adding more storage boosts solar PV firstly and then wind in the optimum mix, all at the expense of less CCS.

Snowy 2.0 and BoTN are Small Scale

Although these are large engineering projects and are clearly beneficial, Snowy 2.0 and especially the BoTN are actually small scale compared to the amount of energy storage that will be needed in a high VRE scenario. Many more schemes of this nature, or other comparably cost-competitive storage technologies, will be needed in a high VRE scenario in order to mitigate the impact of VREs on TSC.

Dispatchable Fossil Fuel Core Remains at the Heart of the Grid

Even with a significant storage build of 10 GW of both PHES and battery storage, there remains a core dispatchable suite of technologies which supports the electricity grid. Fossil fuel-based CCS operates at high capacity for more than 50% of the year, even with more than 20 GW of storage on the grid. In addition, both open and combined cycle natural gas remain crucial technologies on a lowest TSC grid.

Pumped Hydro is Not the Answer to Wind and Solar Droughts

In Australia, periods of low renewable input may last for many weeks, especially over the winter period (as indicated by the dips in storage level). ***In the 100% renewable scenario, with a 20% over-build of renewable capacity and theoretically perfect interconnection within the NEM, most winters require at least 15 Snowy 2.0's to 'keep the lights' on.*** In the 10 years analysed under this scenario, one winter, in 2010, had a prolonged wind and solar drought which would require 33 Snowy 2.0's to maintain adequate supply. This would more than double if realistic interconnections between the various states where in place and each state acted independently to secure their grids. Given that this volume of storage is unlikely to be achievable, and be too expensive even if locations were found, other solutions are needed to achieve deep decarbonisation.

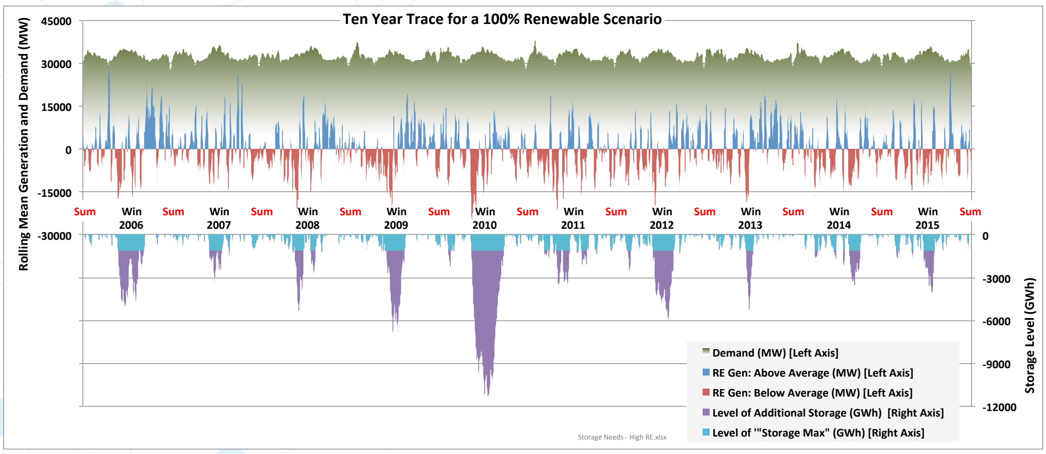


Table of Contents

Table of Figures

Table of Tables

1 Introduction

For the Australian electricity system to play its role in the decarbonising energy transition, this sector will need to undergo a major transformation.

As an electricity sector, a whole-of-system approach will be essential to guide the efficient transformation of the National Energy Market (NEM) to 2030 and beyond. Such an approach will need to:

- maximise value to both investors and the economy more broadly,
- minimise cost to the consumer to remain energy competitive,
- maintain a secure and reliable system,
- all within the context of meeting emissions reduction targets.

However, predicting the usefulness and future role of a long-lived power generation asset is fraught with difficulties, which is why this work seeks to give direction and guidance, rather than concrete solutions. This work is designed to provide information for grid system planning – to point to where there may be "lower cost green pastures" to be embraced or indeed 'high cost dragons" to avoid.

The physical infrastructure that supports the NEM is complex. The NEM incorporates approximately 40,000 km of transmission lines and cables and supplies some 200 terawatt hours (TWh) of electricity to businesses and households each year. It has a total electricity generating capacity of just over 50 gigawatts (GW) (as at August 2019).[1]

As a contribution to exploring these challenges for Australia, this report will examine the role of large-scale pumped hydro energy storage (PHES) as a key component of the energy decarbonisation transition within the context of minimising the total system cost (TSC).

It should be noted that this work has been given gracious guidance and feedback from a valued steering committee.

1.1 Importance of a Total Systems Cost Approach

A systems modelling assessment methodology recognises the pre-existence of a functioning monolith grid and its output reports on the economic value of adding a new power generation asset to it. This TSC approach is similar to a cost benefit analysis, whereby the positive and negative effects of a new technology are all accounted for to determine the overall net cost or benefit to the power system.[2]

Importantly, by using a TSC methodology, it is possible to determine if there is a difference in value for a first unit of a certain technology compared with the n^{th} unit.[3] This is an important distinction, as the amount of generation capacity on a system can greatly affect the cost of a system, its CO_2 emissions, and system strength of the electricity grid.

TSC modelling results should be viewed as a significant metric for policy makers as it is the amount that needs to be funded by the consumer/taxpayer.

[1] Australian Energy Market Operator (AEMO). (2019). *2019 Input and Assumptions workbook Sept 19*. www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/2019-Input-and-Assumptions-workbook-Sept-19.xlsx [Accessed Nov. 2019].
[2] Energy Information Administration (EIA). (2019). Levelised Cost and Levelised Avoided Cost of New Generation Resources in the Annual Energy Outlook 2019, US DOE.
[3] International Energy Agency Greenhouse Gas R&D Programme (IEAGHG). (2017). *Valuing Flexibility in CCS Power Plants*, 2017/09 December, 2017.

Figure 1[4] shows schematically the various elements of the TSC. Power generation, storage and transmission assets are those shown within the 'system' circle: these are the physical elements of the system. Costs refer to any payments that leave the electricity system, such as fuel costs (blue arrows), or taxes (green arrows). The price paid by consumers (orange arrows) must cover all of these outgoings, and hence, is also equal TSC.

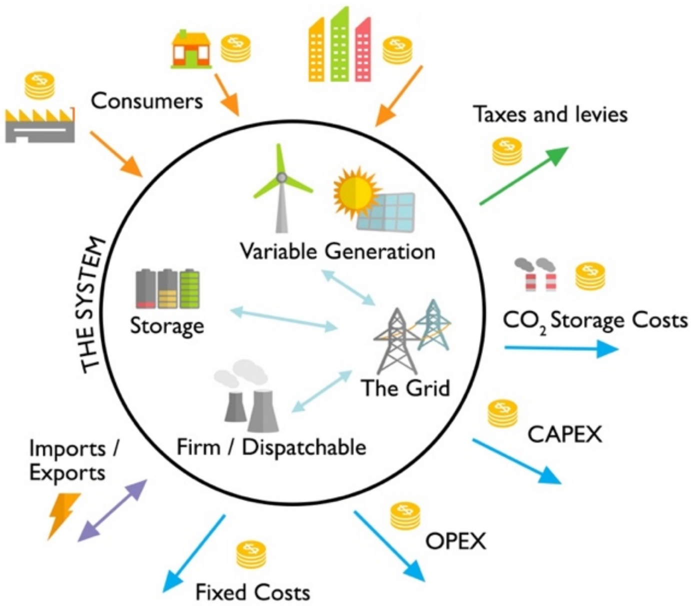


Figure 1: Derivation of Total System Cost

1.2 Prior MEGS Study of the NEM

The Australian electricity grid has, for the most part, delivered reliable and secure energy for decades, with the majority of electricity generation provided by brown and black coal-fired powered plants. These plants have also delivered the 'grid services' required for grid stability, such as inertia, frequency control, fault current, etc, which are inherent to these technologies. However, the electricity grid is changing. With increasing penetration of variable renewable electricity (VRE) generation and energy storage, ***it is becoming increasingly important to plan for and manage generation asset investment*** in order to track the least cost and highest reliability path to a low emissions future.

The pathway to a low emissions future for the NEM raises a number of questions and concerns. The previous MEGS study, "Managing Flexibility Whilst Decarbonising Electricity – the Australian NEM is changing"[5] drew the four following key messages about this transformation pathway.

1. A secure electricity grid requires a range of essential services, as the provision of electricity is not the only function of a grid. These services include inertia, frequency control, fault current provision, etc. Grid services have been provided in abundance where there have been large amounts of synchronous thermal power generation in the past. However, these power generation plants are slowly being retired due to age, and not being replaced with equivalent technologies which can provide these services.

[4] Byrom, S., Boston, A. and Bongers, G. (2019), *The Role of Total System Cost in Electricity Grid Modelling,* Gamma Energy Technology P/L, Brisbane Australia , Working Paper.
[5] Boston, A., Bongers, G., Byrom, S. and Staffell, I. (2017). *Managing Flexibility Whilst Decarbonising Electricity – the Australian NEM is changing.* Gamma Energy Technology P/L, Brisbane, Australia.

2. It is important to consider the whole electricity system, across all timescales to 2050 (and beyond), to successfully transition to a decarbonised grid. ***The value of a power generation technology depends on the existing grid, as it is not possible to correctly value plant independently of the grid to which they are being connected.*** The existing mix of generation and storage technologies on a grid makes a big difference to the optimum choice for a new power plant addition. It should also be noted that when looking at the whole system, the impacts of a new addition on a secure and reliable grid must be taken into account, as well as the electricity generation characteristics of the plant.

3. Using the TSC optimisation approach, it was determined that to achieve deep levels of decarbonisation, the optimum solution is likely to involve a range of generation technologies. The modelling showed that technologies have natural limits in terms of how much they can contribute to a lowest cost system. Interestingly, the profile and solutions were geographically dependent, as natural resource availability differs significantly for each state within the NEM.

4. Finally, the study concluded that ***decarbonising the grid comes at an increased cost compared with the current system***. While the TSC optimisation methodology will lead to the lowest cost, highest reliability outcome, it must be noted that all new build plant are more expensive than the existing portfolio of generation assets.

The optimum, mixed generation solution for 2050, based on the previous study, is shown in Figure 2.[5] Its decarbonisation target was only 80% emissions reduction, so while instructive to this current study, not directly comparable. The carbon capture and storage (CCS) plant occupies the baseload market, with new gas taking a higher load factor than currently seen. The curtailment of VRE has been kept to a minimum to ensure effective utilisation of the resource. The simple construction of the least cost pathway to decarbonisation required the use of a diverse range of new technologies being added to the grid (solar PV, wind, battery storage, natural gas combined cycle, and coal with CCS plant) alongside a significant proportion of existing plant.

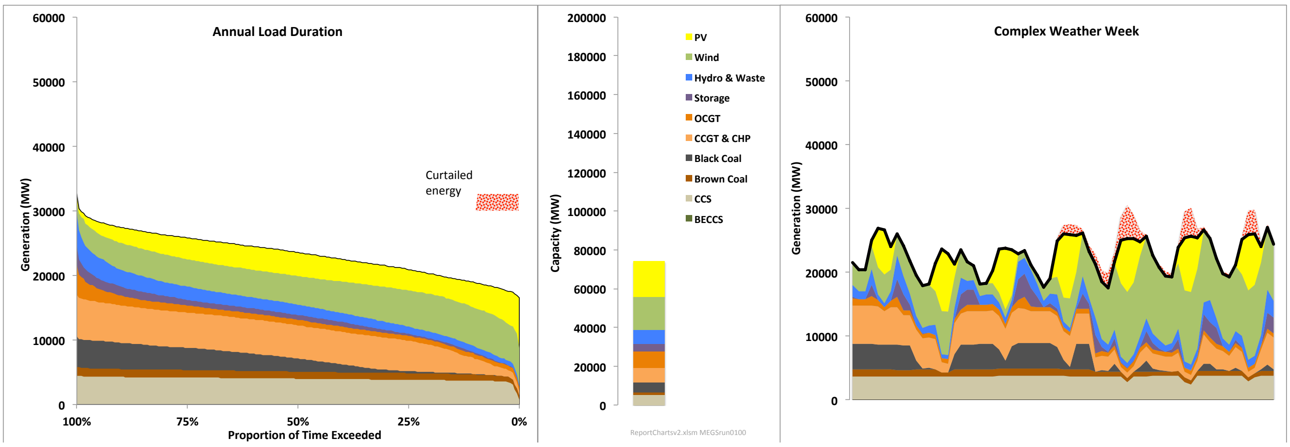


Figure 2: Previous MEGS study – 2050 Lowest TSC Solution.

1.3 Scope and Purpose of this Study

This study forms part of a broader project which seeks to examine the role of electricity systems modelling in optimising planning decisions. This report seeks to examine the role of large-scale energy storage, in particular focusing on the Snowy scheme and the Battery of the Nation (BoTN) projects.

The particular scenarios modelled are described in detail in the following sections of this report, but the large-scale hydro storage scenarios can be summarised as:

- 2030: 60% decarbonisation including Snowy 2.0
  - High VRE and gas scenario – interim target only
- 2030: 60% decarbonisation excluding Snowy 2.0
  - Examining the impact of minimal PHES at moderate decarbonisation levels
- 2050: 90% decarbonisation including Snowy 2.0
  - Study base case
- 2050: 90% decarbonisation excluding Snowy 2.0
  - Examining the impact of minimal PHES at deep decarbonisation levels
- 2050: 90% decarbonisation with Snowy 3.0 & 4.0
  - Examining the impact of incremental increases in PHES
- 2050: 90% decarbonisation with BoTN (1.0a) Marinus Link 1 and additional hydro
  - Role of additional Tasmanian interconnection
- 2050: 90% decarbonisation with BoTN (1.0b) Marinus Link 1 & 2 with Lake Cethena, Tribute and Rowallan
  - Role of the full BoTN proposal
- 2050: 90% decarbonisation with BoTN 2.0
  - Examining the role of expanded PHES and interconnection to Tasmania on the NEM
- 2050: 90% decarbonisation with Snowy 4.0 and BoTN 2.0
  - Examining impact of very large quantities of PHES

2 MEGS

2.1 Background on MEGS

The goal of MEGS is to determine the lowest TSC generation mix that satisfies a demand constraint and grid service constraints whilst targeting an emissions reduction. MEGS models the five regions of the Australian NEM, with interconnector constraints built into the model. It was developed by Red Vector in partnership with Gamma Energy Technology in 2017, and was used to model the Finkel scenarios for 2030 and 2050[6] in contrast to the Paris Agreement targets.[5]

A key functionality within MEGS is its ability to model future scenarios based on historic weather patterns. This is used to determine weather impacts on different mixes of power generation technologies. This is an important test to ensure a scenario outcome actually satisfies demand and grid service constraints in favourable and unfavourable weather conditions. Renewables Ninja,[7] a resource that simulates wind and solar PV for a given region in a historic weather year was used as the weather input for the NEM. This was combined with market data[8] for hydro generation and demand.

MEGS solves in a time sequential manner which enables storage to be modelled realistically[9] (for more detail, refer to Section 2.2). 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 (refer to Figure 3).[10] MEGS also ensures there's sufficient upwards frequency response for all timescales less than 5 minutes.

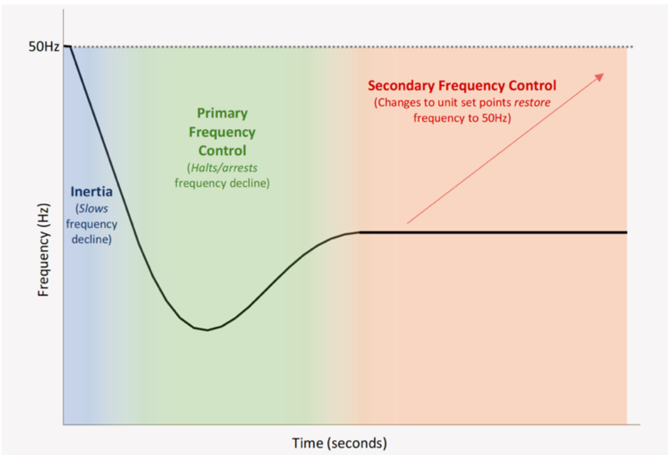


Figure 3: Types of Frequency Control Services.

[6] Finkel, A., Moses, K., Munro, C., Effeney, T. and O'Kane, M. (2017). Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future, Commonwealth of Australia 2017. Department of the Environment and Energy, Australia.
[7] Pfenninger, S., & Staffell, I. (2016) Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data, Energy 114.
[8] Global Roam. (2019). *Trending and Analysis of historical NEM data (Australian National Electricity Market Software).* [online] http://v6.nem-review.info/index.aspx [Accessed Nov. 2019].
[9] Boston, A., Bongers, G., and Byrom, S. (2018). *The Effect of Renewable Energy Targets on the National Energy Market*, Gamma Energy Technology P/L, Brisbane Australia.
[10] Australian Energy Market Operator (AEMO). (2019). *Fast Frequency Response in the NEM - Working Paper*. [ebook] AEMO. www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2017/FFR-Working-Paper---Final.pdf [Accessed Nov. 2019].

The constraints at the core of MEGS are illustrated in Figure 4 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.[11]

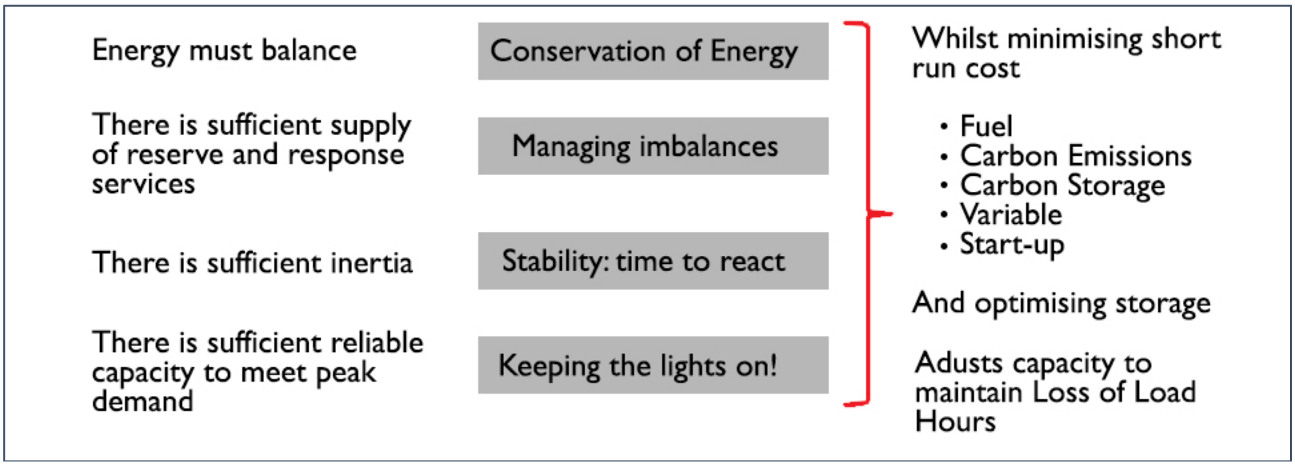


Figure 4: Definition of the Constraints in MEGS.

Key features of the MEGS application to Australian markets are as follows:

- MEGS models regions with interconnects that can carry energy and reserve services. The NEM is an 'islanded' grid that consists of five state grids that have relatively weak interconnections. Furthermore, each state is unique with a different set of resources for generation and different demand shapes.
- Resource limited hydro is included in the model. There are two main hydro schemes in Australia, with a third in planning. Initial MEGS modelling models the Snowy Hydro and Tasmanian Hydro systems.

2.2 Storage Algorithm

MEGS intentionally models storage with 'great care', including technology such as 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.

[11] The MEGS methodology will be the subject of a publication in a journal as part of broader deliverables of this study.

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 5 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.

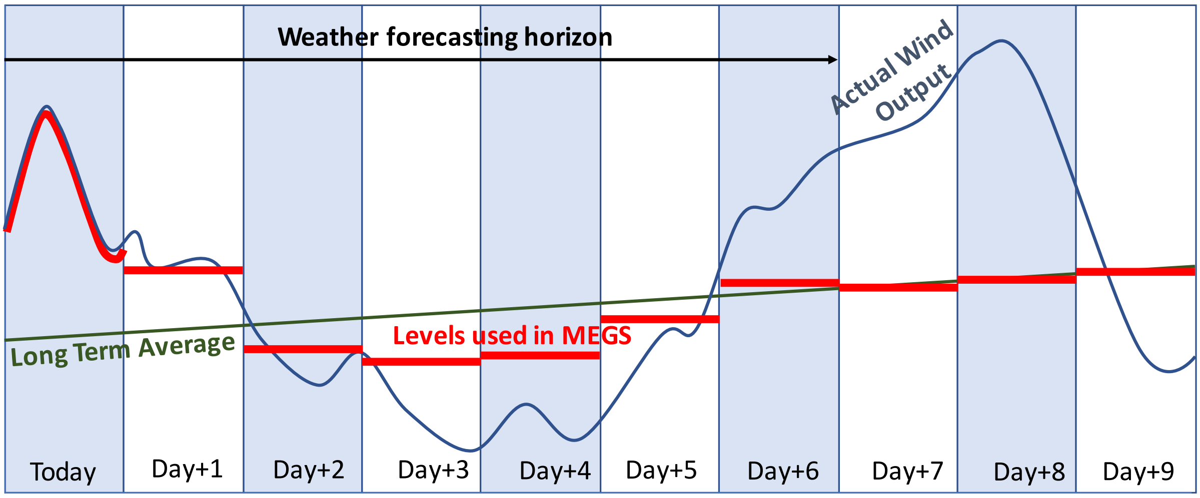


Figure 5: How MEGS uses Actual Weather Data for Forecasting Storage Operation.

2.3 Key Study Assumptions

The key study assumptions are detailed within this Section, with the full set of assumptions published separately.[12]

2.3.1 Data Sources

Data has been be sourced from the following, in order of priority, unless otherwise stated:

1. Australian Energy Market Operator (AEMO) Integrated System Plan 2019 (ISP) Fast Change scenario (ISP-FC).[13]
2. AEMO Costs and Technical Parameter Review: Report Final Rev4, by GHD.[14] While this data is used within ISP with an AEMO stakeholder review, the ISP does not use all the data within this report. Where data is missing from ISP, this GHD report will be used.
3. Commonwealth Scientific and Industrial Research Organisation (CSIRO) GenCost 2018 cost forecast.[15]
4. Other AEMO reports.

2.3.2 Regional Inertia

Minimum inertia levels proposed are based on the latest publicly available data from AEMO and summarised in Table 1.[16] For the most part MEGS uses the secure operating levels as its minimum and this is also sufficient to cover system strength requirements. However in the case of NSW the need for synchronous machines to provide system strength is greater, so this has been used as the minimum requirement here.

Table 1: Regional Data.

Inertia sub-networks (Regions)	Inertia available through System Strength (MWs)	Minimum threshold level of inertia (MWs)	Secure operating level of inertia (MWs)
Queensland	11,950	12,800	**16,000**
New South Wales	**18,100**	10,000	12,500
Victoria	10,900	12,600	**15,400**
South Australia	4,900	4,400	**6,000**
Tasmania	2,000	3,200	**3,800**

Bold – minimum values set in MEGS.

2.3.3 Weather Impacts

MEGS uses a database of hourly historic load factors for wind, solar PV, CSP and hydro, alongside demand, which can stretch back ten or more years. For this study, demand and hydro production will be sourced from NEM-Review,[8] solar PV and wind data from Renewables Ninja.[17]

[12] Boston, A., Bongers, G., and Byrom, S. (2019), *MEGS Assumptions Book: Working Paper 01 – Oct '19,* Gamma Energy Technology P/L, Brisbane Australia.
[13] Australian Energy Market Operator (AEMO). (2019). *Integrated System Plan*. www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan [Accessed Mar. 2019].
[14] GHD. (2018). Report for AEMO - AEMO Costs and Technical Parameter Review: Report Final Rev4. GHD, Australia.
[15] Graham, P.W., Hayward, J, Foster, J., Story, O.1 and Havas, L. (2018) *GenCost 2018*. CSIRO, Australia.
[16] Australian Energy Market Operator (AEMO). (2018). *Inertia Requirements Methodology. Inertia Requirements & Shortfalls.* [ebook] AEMO. www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf [Accessed Nov. 2019].
[17] Pfenninger, S. and Staffell, I. (2016). Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data. Energy 114, pp. 1251-1265.

2.3.3.1 *Base Weather Year*

Figure 6 plots the TSC against the carbon intensity for a scenario with high renewables growth (14GW extra for both solar PV and wind). There is a clear correlation, as a year with high renewables output would reduce both carbon and cost through saved fuel burn. The year with highest renewable output is 2013, which resulted in emissions 5% less than average, and costs 3% lower. 2011 was a poor year for renewable generation, whereas 2015 was a very typical year. This validates the use of weather data from 2015 as a typical year for renewable generation, as data from this year is unlikely to skew the MEGS modelling results towards either low or high TSC and emissions intensity.

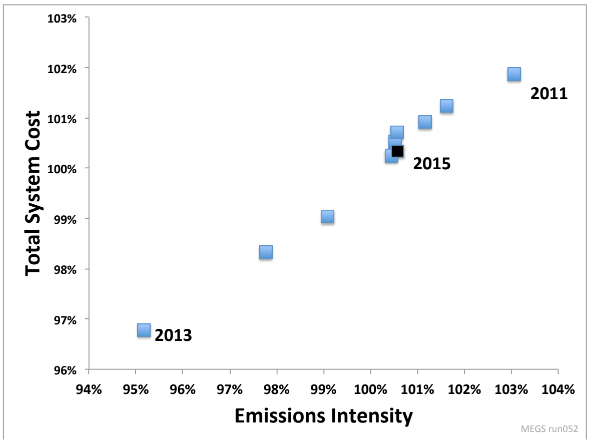


Figure 6: Effect of Weather on Cost and Emissions.

As well as reporting high level results such as TSC and CO_2 emissions, it is important to examine the effect of the various scenarios on the daily and intra-day running patterns. To facilitate a detailed examination of how a generation suite may operate, a high-resolution schedule for a particular week is depicted in many of the charts. The week analysed is based in early May and was chosen as its variation in weather allows several effects to be illustrated. This allows the scenario to be interpreted in low, medium and high wind conditions combined with low to medium solar PV output. It has been referred to as the “Complex Weather Week” in the charts.

2.3.4 Decarbonisation Targets

It is proposed that the whole NEM decarbonises together, with each state reducing emissions at a similar pace, albeit with a different mix of technologies according to the resources in that state. It will be assumed that no more than 10% of current emissions can be met by international carbon trading or the use of biomass, which means 90% decarbonisation of the electricity system must be achieved through fuel and technology choices for generation. Although short of the target, achieving a zero emissions target will need to involve additional bioenergy with CCS (BECCS), nuclear power, or the purchase of credits, none of which is modelled directly.

2.3.5 Snowy 2.0

Snowy 2.0 will connect Tantangara in the east (upper reservoir) to Talbingo in the west via tunnels which will be 27km in length and 10m in diameter (refer to Figure 7). This will deliver 350GWh of storage working within existing range of lake levels. The energy storage will be accessed via a new 2GW pumping/generating power station built on the tunnel between the lakes. There will be six 333MW pump/generators, three of which will be synchronous and three will be variable speed drives.[18] The feasibility study made it clear that to be of value, there needed to be an a significant upgrading of the transmission from Snowy south into Victoria and North towards Sydney.[19] The contract to build Snowy 2.0 was awarded to Salini Impregilo for $5.1B[20], and as Snowy Hydro have estimated that the necessary transmission upgrades will cost up to $2B,[21] 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 there are no concrete plans. 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.

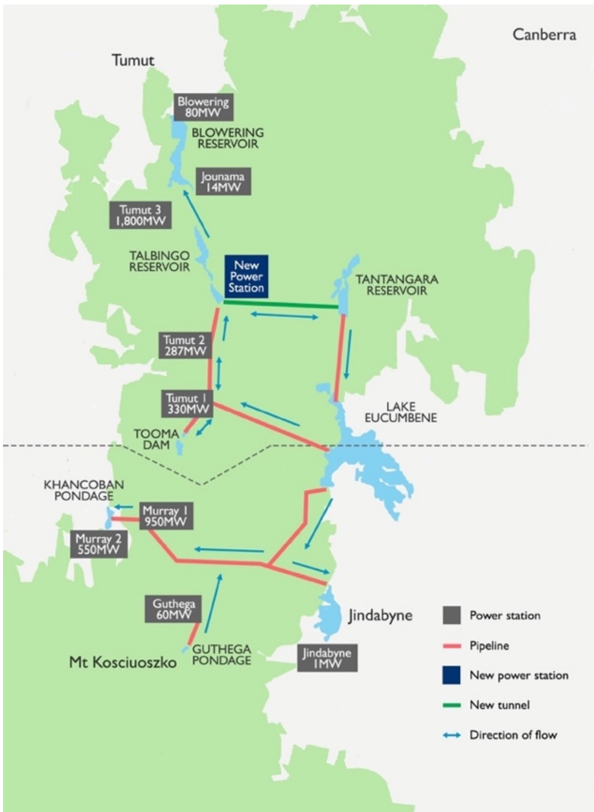


Figure 7: Snowy 2.0 Configuration.

[18] Snowy Hydro. (2019). *Project Update Snowy 2.0 – Pumped-Hydro Project*. [ebook] Snowy Hydro. https://www.snowyhydro.com.au/wp-content/uploads/2019/05/SH1387_SQUARE-BOOKLET_Snowy-2-Project-Update_MAY-2019_v6_lowres_spread.pdf [Accessed Nov. 2019].
[19] Snowy Hydro. (2019). *2017 Snowy 2.0 Feasibility Study*. [online] www.snowyhydro.com.au/our-scheme/snowy20/snowy-2-0-feasibility-study [Accessed Nov. 2019].
[20] Salini Impregilo (2019). *Press Release 5/4/2019. Salini Impregilo Wins Snowy 2.0 Hydropower Megacontract Worth AU$5.1B in Australia*. [online] https://www.salini-impregilo.com/en/media/press-releases/salini-impregilo-wins-snowy-2-0-hydropower-megacontract-worth-au-5-1b-3-228b-in-australia [Accessed Nov. 2019].
[21] Aston, H. (2019). Snowy Hydro Expansion Could Cost Double Initial $2 Billion Estimate. *The Sydney Morning Herald*. [online] www.smh.com.au/politics/federal/snowy-hydro-expansion-could-cost-double-initial-2-billion-estimate-20170523-gwb0vy.html [Accessed Nov. 2019].

2.3.6 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 8 and detailed in Table 2, along with the additional interconnection to Victoria.

Figure 8: Battery of the Nation Configuration.

Table 2: Battery of the Nation Configurations.

Options	Capacity	Cost	Completed	Notes
Marinus Link 1[22]	600MW	$1.3 - 1.7B	2025	
Conventional hydro upgrades	400MW	$0.5 - 0.7B	2021	Upgrades 3 existing schemes, + 50MW small hydro
Marinus Link 2[22]	800MW	$0.6 - 1.4B	2028	
Lake Cethena[23]	600MW, 11 hours	$0.9B	~2027	Estimated completion given it is about 2 years behind Snowy 2.0
Lake Rowallan[23]	600MW, 24 hours	$0.99B	~2027	Estimated completion given it is about 2 years behind Snowy 2.0
Tribute[23]	500MW, 31 hours	$0.915B	~2027	Estimated completion given it is about 2 years behind Snowy 2.0
Marinus Link 3[22]	900MW	$0.6 - 1.4B	~2035	
Unspecified pumped storage locations	1700MW	$3B	~2035	The pumped hydro capabilities are modelled the same as for Marinus 2.

BoTN is modelled as the Marinus 1 & 2 configuration including the associated hydro and pumped storage investments in Table 2. Marinus 3 is considered to be the BoTN 2.0.

[22] Potter, C., Williams, P., Allie, S., Piekutowksi, M., Butler, J. and Maxwell, C. (2018). *Battery of the Nation Analysis of the future National Electricity Market*. [ebook] Hobart, Tasmania: Hydro Tasmania. www.hydro.com.au/docs/default-source/clean-energy/battery-of-the-nation/future-state-nem-analysis-full-report.pdf [Accessed Nov. 2019].

[23] Hydro Tasmania. (2019). *Battery of the Nation – Pumped Hydro Energy Storage Projects Prefeasibility Studies. Summary Report*. [ebook] Hydro Tasmania. hydro.com.au/docs/default-source/clean-energy/battery-of-the-nation/botn-phes---prefeasibility-studies-summary-report-aug19.pdf?sfvrsn=2b089a28_2. [Accessed Nov. 2019].

2.4 Validation

A detailed validation of MEGS and its ability to reproduce real world schedules has been undertaken in a previous study: "Managing Flexibility Whilst Decarbonising Electricity – the Australian NEM is changing".[5]

2.5 Synchronous Condensers

A synchronous condenser[24] is a synchronous motor running without mechanical load with the ability to draw a large out of phase current. They work in a similar way to large electric motors and generators as they rotate freely and deliver system strength, inertia and voltage control. Such services are becoming increasingly important with the rising penetration of VREs and the gradual retirement of existing thermal plants, which leads to a potential shortfall of both inertia and short-circuit power. As an example of a typical synchronous condenser, the core components of a General Electric machine are shown in Figure 9.[25]

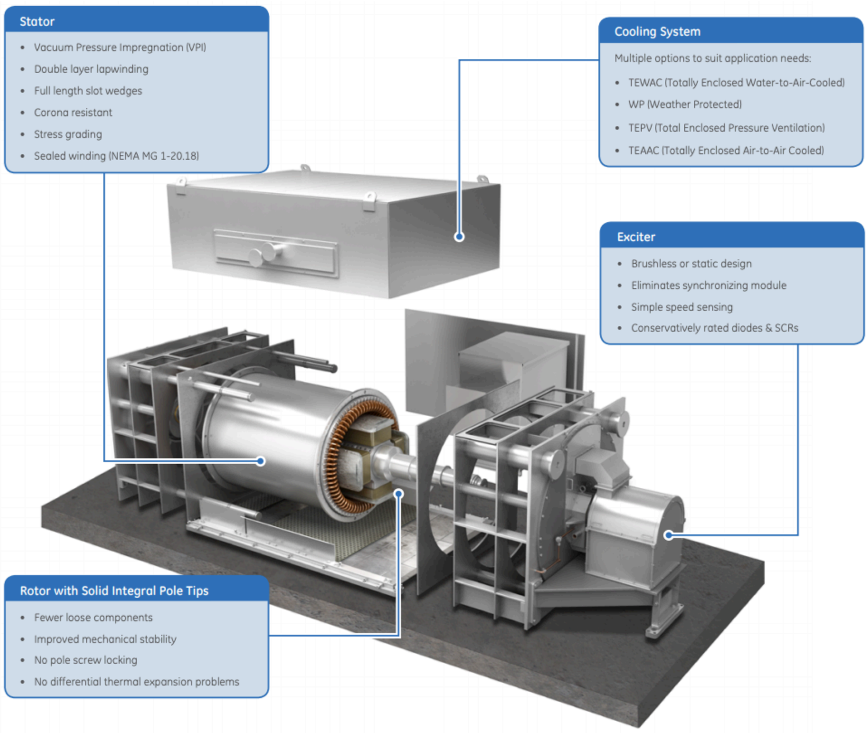


Figure 9: Core Components of a Synchronous Condenser.

The option of this technology has been added to the MEGS technology suite for this study. While they have been in use within the NEM for decades, they have not been widely utilised due to the abundance of existing synchronous thermal generation, which have provided the services that a synchronous condenser can offer. ElectraNet are installing four synchronous condensers in South Australia with the aim of improving system strength by adding 4,400MWs of system inertia, which is around three quarters of the required inertia in that state.[26,27] These will largely replace the need for gas plant to provide these grid services.

---

[24] These are also known as Synchronous Capacitors, Synchronous Compensators or Synchronous Phase Modifiers.
[25] General Electric Company. (2014). Synchronous Condenser Systems. www.gegridsolutions.com/products/brochures/powerd_vtf/Synch_Cond_web.pdf [Accessed Nov 2019].
[26] Australian Energy Regulator. (2019). *ElectraNet - Main grid system strength contingent project*. [online] Australian Energy Regulator. Available at: www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/electranet-main-grid-system-strength-contingent-project [Accessed Oct 2019].
[27] Australian Energy Regulator. (2019). *Power System Strength project – ElectraNet*. [online] ElectraNet. Available at: www.electranet.com.au/what-we-do/projects/power-system-strength [Accessed Oct. 2019].

MEGS was used to examine the impact of these synchronous condensers within the South Australian grid to validate their use for the provision of grid services. When operating within MEGS, the synchronous condensers will provide inertia at a low variable cost commensurate with the actual running cost. To understand its potential operation, and to provide some insights on the expected impact of these plants when they are in operation, the MEGS 2018 base case and a 2030 scenario with high renewables penetration was compared with the four synchronous condensers added to the South Australian network. The main effects of adding synchronous condensers to the system are described in Table 3.

Table 3: Effect of New Synchronous Condensers Installed in South Australia.

Factor	Annual Impact		Commentary
	Current (2018) System	High Renewables, 60% Decarbonisation	
Annualised Capex	+$15M	+$15M	This capex ($182M) of synchronous condensers was discounted over 30 years at 8.3%.
System Opex	-$98M	-$177M	These savings are from ceasing operations at South Australian gas plants for inertial reasons and utilising cheaper plant elsewhere on the system. As expected, savings (from avoided curtailment of VRE in South Australia) increase in the High Renewables case.
Total System Cost	-$83M	-$161M	Sum of Capex + Opex.
South Australian CO_2 Emissions	-0.98Mt	-1.20Mt	27% reduction due to South Australian gas plant capacity factor decrease.
Remain NEM CO_2	+0.94Mt	+1.16Mt	As the synchronous condensers did not relieve any constraints on wind, the shortfall was taken up by fossil plant in rest of NEM.
Total effect on CO_2	Negligible	Negligible	In current base case system, emissions are simply 'shifted' from South Australia (which had been obliged to run expensive gas plant) to cheaper coal generation in New South Wales in particular. The overall reduction from synchronous condensers in the High Renewables case is relatively small.

In summary, the effect of synchronous condensers on the current system is to reduce TSC, as they minimise the operation of natural gas generation which was used solely for the provision of grid services. They have no significant effect on NEM emissions overall, although South Australia will achieve some reductions and the rest of NEM will see a similar increase. In a High Renewable case (50% decarbonisation through VRE) the synchronous condensers are more valuable, but still make little difference to overall emissions.

Importantly, these results show that MEGS models synchronous condensers as expected, so it will be taken that they are being realistically represented within the model.

3 The Value of Large-Scale Pumped Storage

As Australia seeks to decarbonise its electricity sector, the move away from conventional gas and coal generation technologies to low-emissions technologies, such as VREs 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 TSC.

Within this transformation process, many uncertainties within a changing energy sector must be considered. Factors such as the existing supply sources, particularly black and brown coal generators, 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 with the NEM (refer to Figure 10), along with future forecasts of VRE capacity means that the future electricity system will look very different than does currently. The details of how the system operator will manage the supply variability and ensure energy security constraints are met, at lowest TSC, is not well understood. Importantly, the magnitude and type of grid services available and required will depend on the characteristics of each region. Energy storage of various forms is expected to play a major role in the provision of these services.

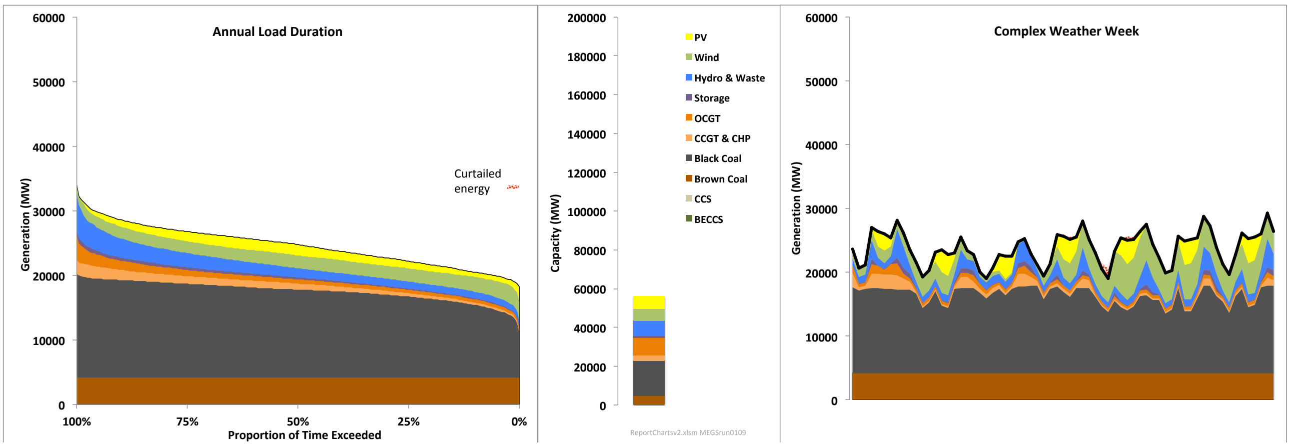


Figure 10: The Current NEM Profile – 2018.

3.1 The Impact of Snowy 2.0 on Moderate Decarbonisation

The journey to deep decarbonisation is a complex series of steps from where we are today, and where we seek to be in the future. It is very important to consider the whole electricity system across all times to 2050, and beyond when making technology choices.[5] Choosing a suite of technologies to meet a moderate decarbonisation target, a waypoint on the journey, gives an insight into which steps are beneficial in achieving both an intermediate target and the long term goals.

The optimum suite of technologies to deliver a lowest TSC outcome for the 'moderate' decarbonisation scenario (60% decarbonisation) was determined. Neither Snowy 2.0 nor the BoTN were included as part solution at this stage.

Figure 11 details the three aspects of the optimum lowest TSC solution. In the annual load duration curve (left chart), the area represents energy delivered and the shape represents the load pattern for the year.

It can be seen from this load duration curve that unabated black coal, for example, varies from a maximum of 13GW of output down to zero output. In this scenario, its dominant role is 'load following', playing no role as a baseload generator. An example of this flexible, load following role is shown in the right-hand chart, a weekly output chart. For the first portion of the week, unabated black coal accounts for 20 – 30% of demand at times and playing almost no role in the second half of the week. In this 60% decarbonisation scenario, unabated black coal must be very flexible. Importantly, to minimise the TSC, VRE technologies must be used efficiently. Shown on the load duration curve is the annual energy lost through curtailment. As can be seen, very little VRE undergoes curtailment. The central generation stack is shown in the centre of the figure. ***The generation stack is just above 100GW, nearly double the existing 50GW system, dominated by a very large increase in VRE deployment.***

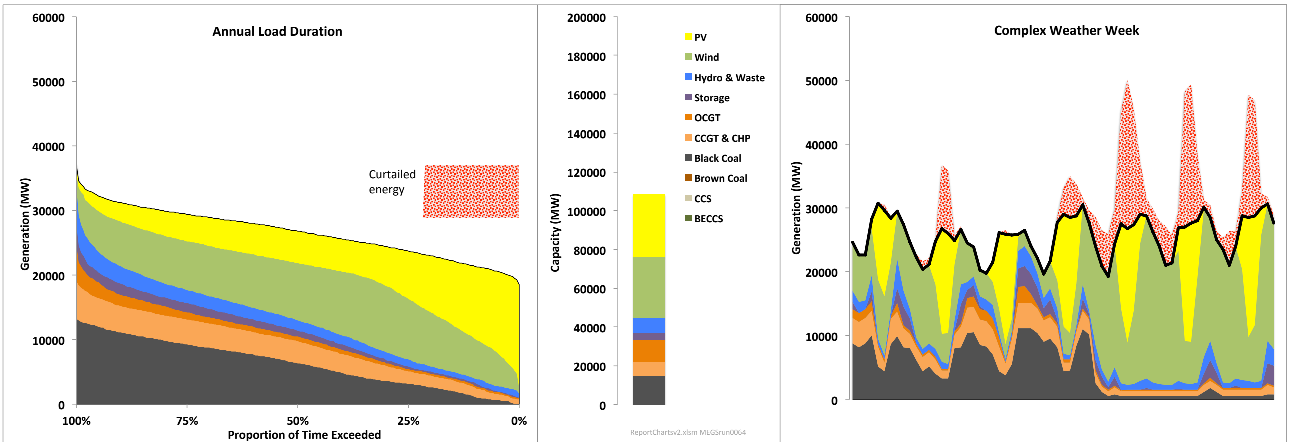


Figure 11: Moderate Decarbonisation, Optimum Generation Mix – Excluding Snowy 2.0 & BoTN.

Snowy 2.0 was added to the generation mix for moderate decarbonisation scenario. This added 350GWh of storage at a range of efficiencies and 1GW of additional generation capacity for both New South Wales and Victoria. An additional 800MW interconnector was also added between New South Wales and Victoria. Refer to Section 2.2 for more details on Snowy 2.0 and how MEGS considers both storage generally and Snowy 2.0 in particular.

A new optimum solution was determined to achieve the moderate decarbonisation goal at lowest TSC including Snowy 2.0, shown in Figure 12. At first glance, there seems to be little impact of adding Snowy 2.0 to the system. However, the differences between are best highlighted in Figure 13.

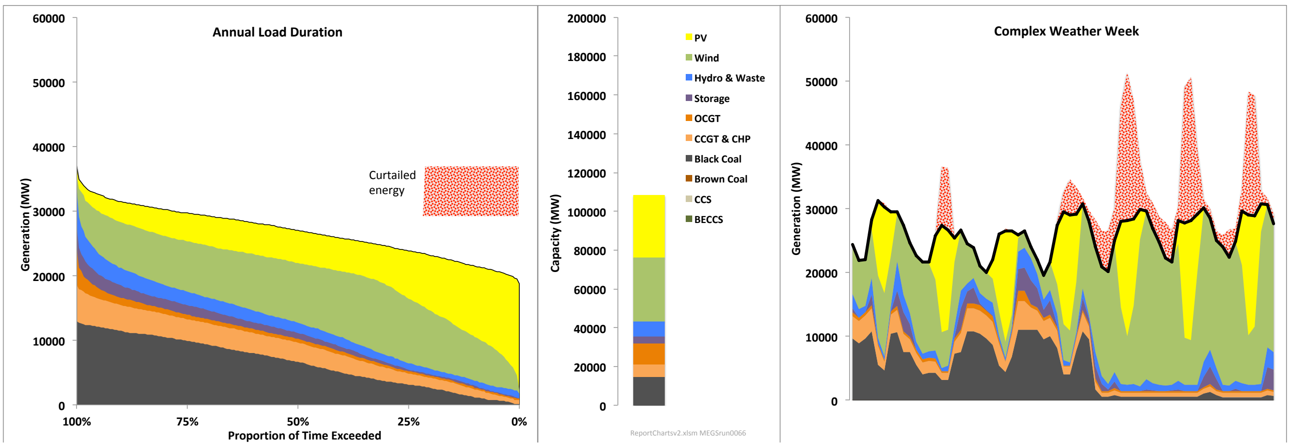


Figure 12: Moderate Decarbonisation, Optimum Generation Mix – Including Snowy 2.0, Excluding BoTN.

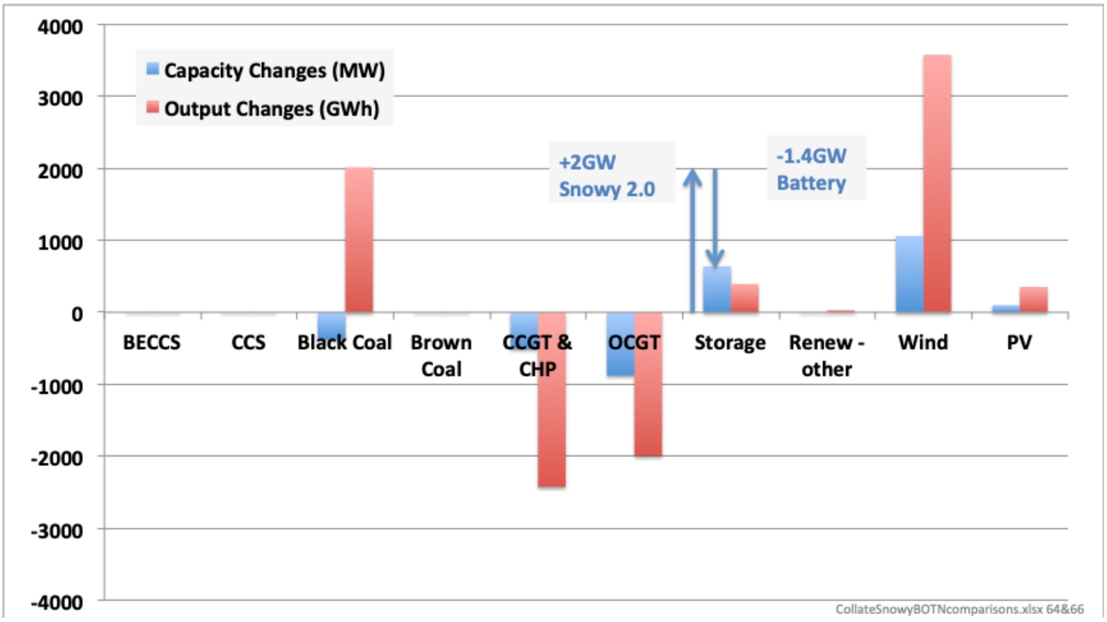


Figure 13. Comparison of Generation Capacity and Output (Including Snowy 2.0) – Moderate Decarbonisation.

The blue columns in Figure 13 show the differences in the generation capacity mix across the NEM. The addition of Snowy 2.0, representing 2,000MW of storage, the overall capacity of storage only rises by 600MW. This is due to Snowy 2.0 facilitating less batteries capacity both in New South Wales and Victoria. However, unlike batteries which are used for short duration storage, the large reservoirs associated with Snowy 2.0 allow it to provide firm back-up for VRE.

The addition of Snowy 2.0 also resulted in MEGS having 2GW less of fossil fuel plant in the optimum generation mix, mostly avoiding the construction of new build gas. Significantly more VRE (mostly wind) was also part of the optimised mix, which produced substantially more output than when Snowy 2.0 was not part of the generation mix. The inertia provided by Snowy 2.0 also resulted in only 30 synchronous condensers within the mix, four less than without Snowy 2.0.

Table 4: Effect of Snowy 2.0 on Annual Costs ($M).

	Running Cost	**Fixed Cost**	**Capex**	**TSC**
Excluding Snowy 2.0	5,419	3,238	7,839	16,496
Including Snowy 2.0	4,960	3,277	8,128	16,365
Difference	(459)	39	289	(131)

Table 4 shows the impact of Snowy 2.0 on costs. The decrease in overall running costs was attained by shifting generation from gas to coal. The fixed and capital cost increased due to the increase in VRE capacity. Overall, an annualised improvement of $0.13B is relatively modest compared to overall system cost of $16B p.a. ***Importantly too, the technology suite proposed for this moderate decarbonisation waypoint, both achieves a competent lowest TSC solution and does not overbuild nor adversely impact the transformation still required to achieve deep decarbonisation.*** Achieving a lowest TSC, 90% decarbonised electricity sector is difficult enough. Had the solution for the 60% decarbonisation turned out to be based on a very different mix of technologies than the end point, it would not have given good guidance for setting intermediate targets. As it is, this waypoint can be used to set intermediate targets (say for 2030) without it adding to the expense, or restricting outcomes, for the deep decarbonisation solution sought for 2050.

3.2 The 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 decarbonisation. Each technology brings a unique collection of services and commodities, along with its own set of challenges and issues which require mitigation. Within the NEM, the resources each region has available is also diverse.[5] 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 BoTN were included as part solution at this stage. Figure 14 details optimum lowest TSC solution. Without Snowy 2.0 there is a significant need for fossil fuel-based CCS (over 12 GW) with a small amount of 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 BECSS. 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.

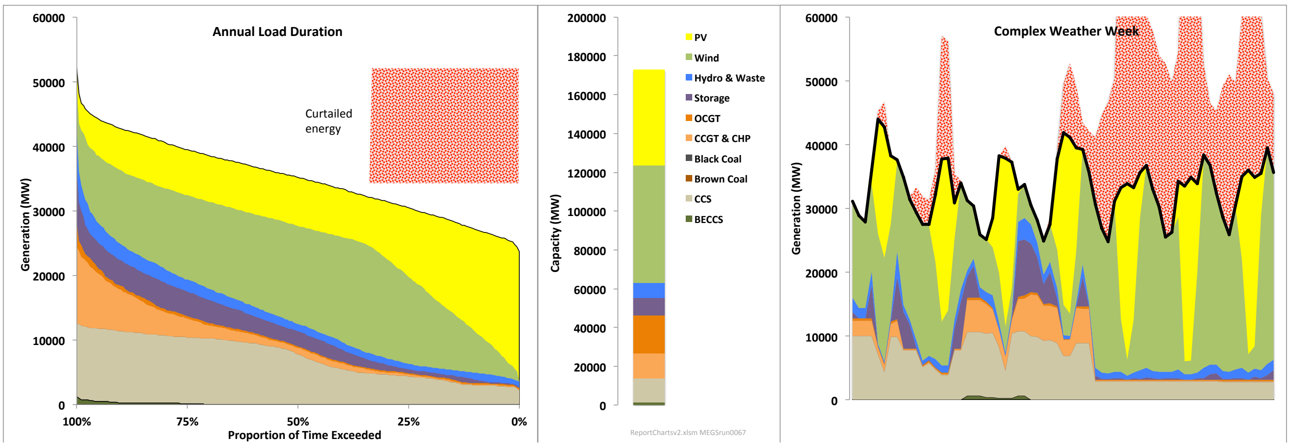


Figure 14: Deep Decarbonisation, Optimum Generation Mix – Excluding Snowy 2.0 & BoTN.

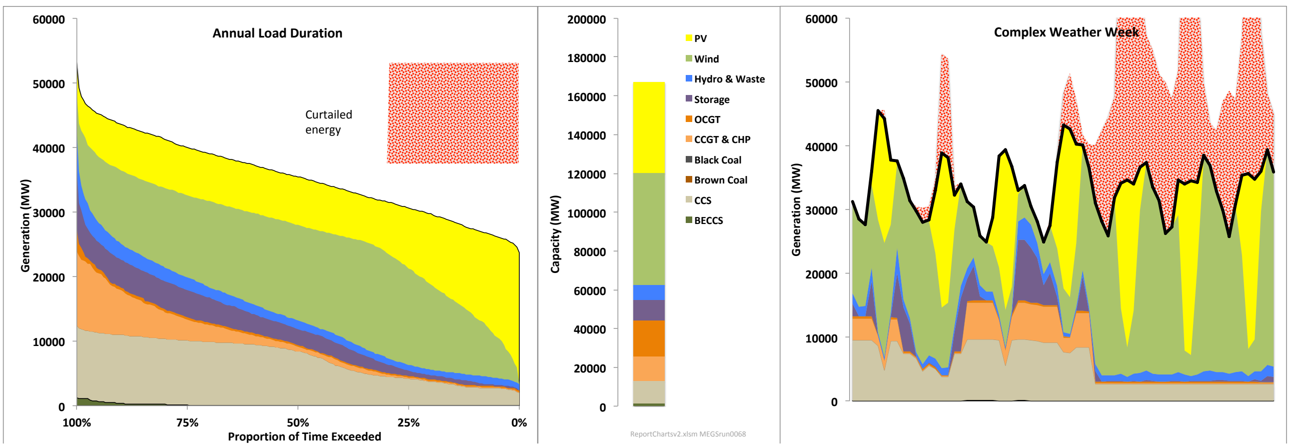


Figure 15: Deep Decarbonisation, Optimum Generation Mix – Including Snowy 2.0, Excluding BoTN.

Figure 16 illustrates the changes in capacity and generation from the addition of Snowy 2.0 in the deep decarbonisation scenario. Similar to the moderate decarbonisation scenario (refer to Section 3.1), 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, acting 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 PHES within the total system is increased by 2,000MW due to Snowy 2.0, however Snowy 2.0 also decreased the need for 400MW 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 CCGT plant. BECCS capacity decreased slightly, and coal-based CCS decreased more significantly.

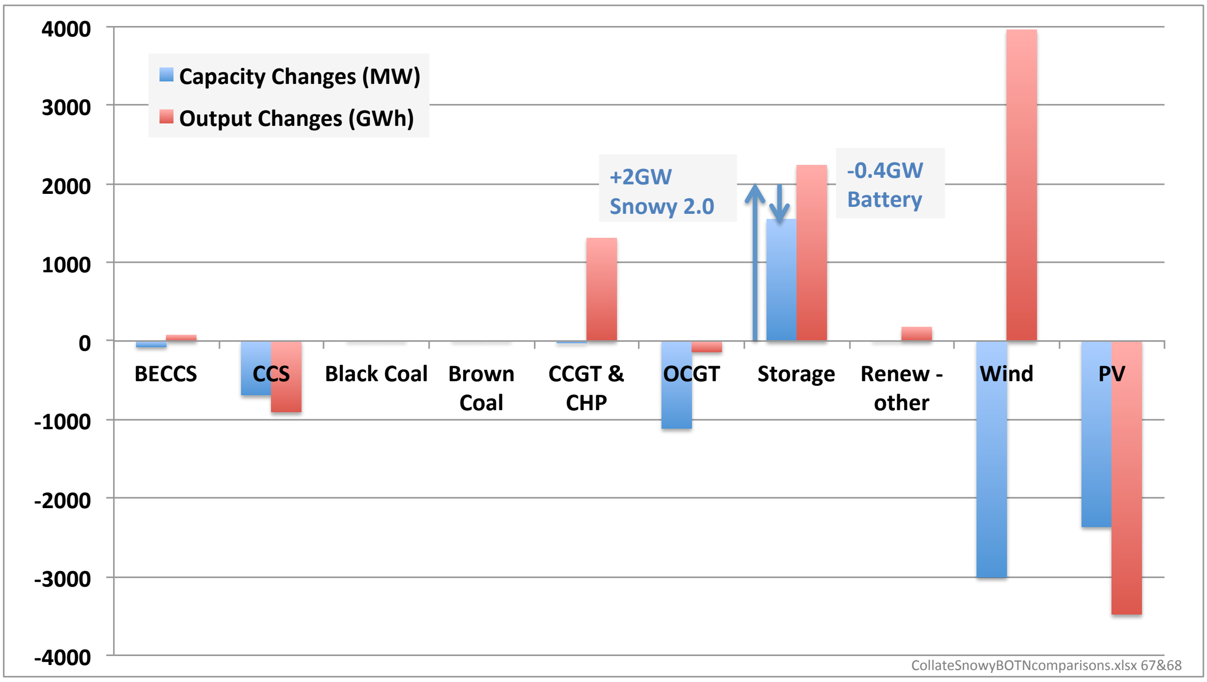


Figure 16: Comparison of Generation Capacity and Output (Including Snowy 2.0) – Deep Decarbonisation.

Within the deep decarbonisation scenario, the addition of Snowy 2.0 improves both the efficiency of the installed wind and solar PV and results in less capacity being built to achieve the same decarbonisation level. These large volume, PHES systems are particularly supportive of increased solar PV capacity. Importantly however, ***future grids, with a large proportion of installed renewable capacity will have significant amounts of curtailment, which will be the 'new normal'***. It should be noted that under current market conditions this will likely present a material business risk.

3.2.1 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 17 and Figure 18 show its utilisation within the deep decarbonisation scenario (assuming only Snowy 2.0 built). In the summer (Figure 17 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 17). ***From a TSC perspective, this provision of frequency response is at very little extra cost***. This operating behaviour allows Snowy 2.0 to support 25GW of solar PV in New South Wales and Victoria.

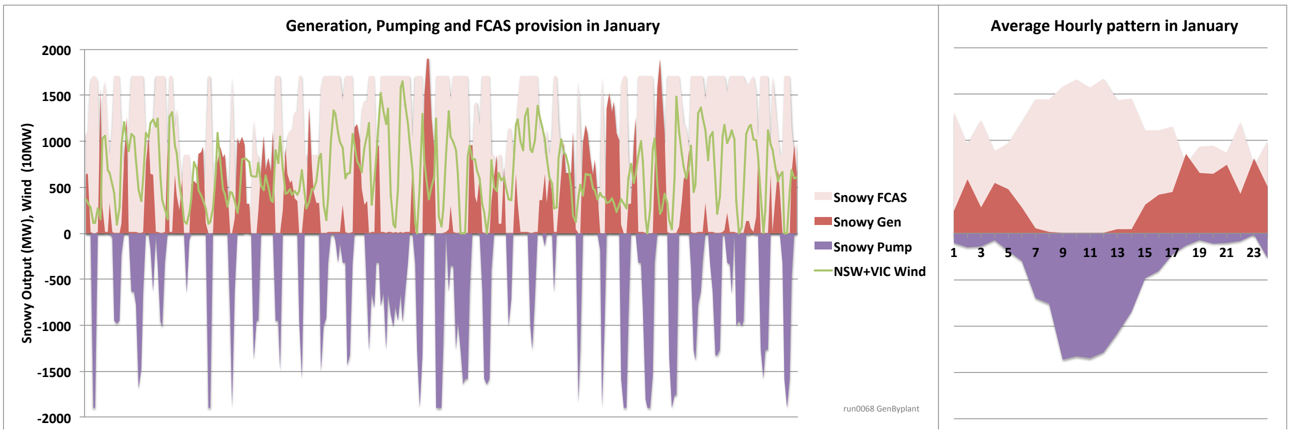


Figure 17: Snowy 2.0 Utilisation in January – Deep Decarbonisation Scenario.

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 18). 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.

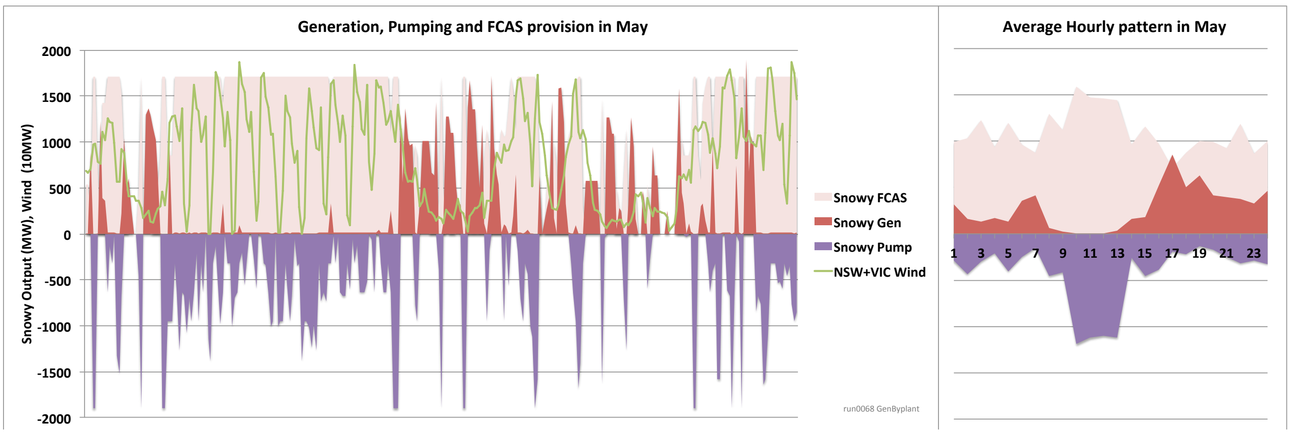


Figure 18: Snowy 2.0 Utilisation in May – Deep Decarbonisation Scenario.

These utilisation profiles clearly show that Snowy 2.0 is being used at all timescales. Snowy 2.0 provides short term support via FCAS services 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.

3.3 Battery of the Nation

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, optimising the use of its existing hydro portfolio and by developing new pumped storage projects.[23] 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 pumped hydro upgrades. The Marinus 1 interconnector and associated improvements to 400MW of traditional hydro has only a very small impact on the 90% decarbonisation scenario (refer to Figure 19). This is perhaps unsurprising given the scale of the 2050 system with its 160GW of generation capacity.

The Marinus 2 interconnector, the third interconnector to Tasmania overall, along with a significant pumped storage upgrade would take the overall interconnection capacity to 1900MW, with 1700MW of pumped storage (refer to Section 2.3.6 for more detail***). 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 19).

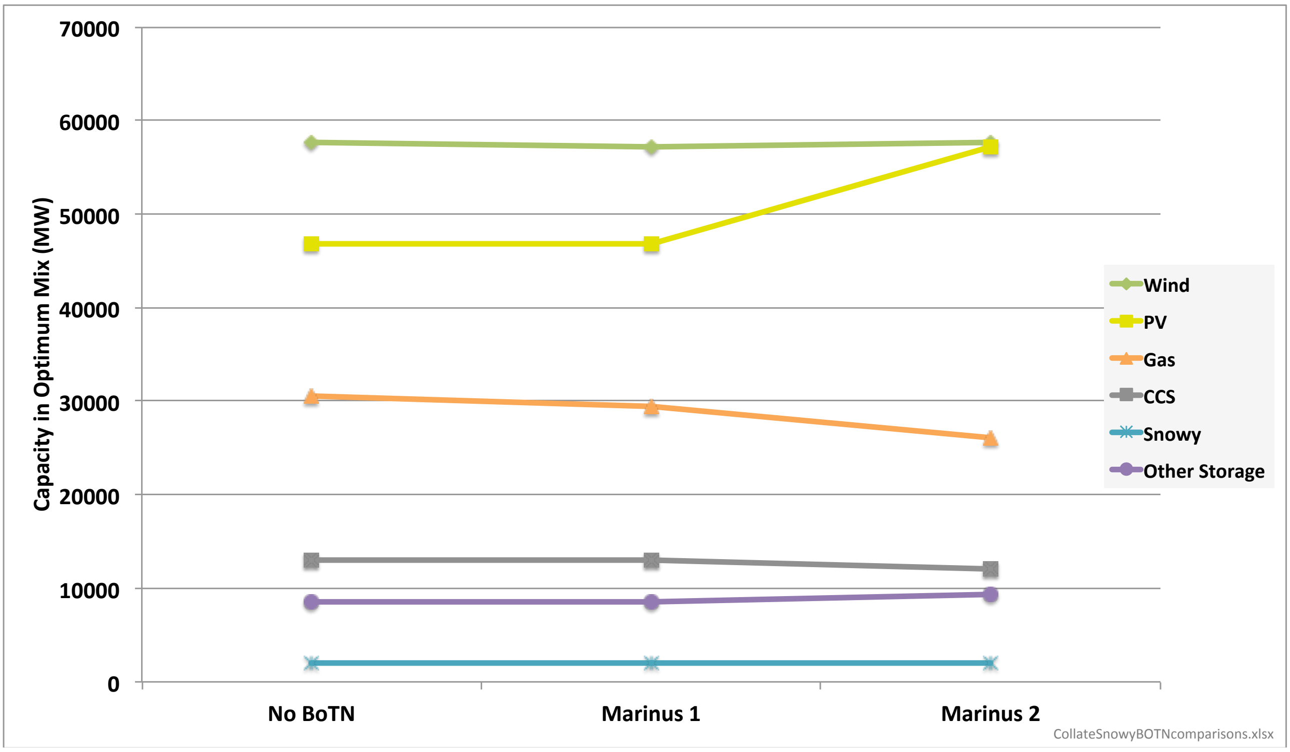


Figure 19: Progression of Optimum Plant Mix as BoTN is Expanded.

Some important details about the addition of the BoTN can be observed in Figure 20. This lowest 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 as noted allowed the solar PV capacity to increase to 51GW and the total system capacity 176GW. ***Importantly, however, the optimum mix has 3½GW of unabated coal, even in this 90% decarbonisation scenario, 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.

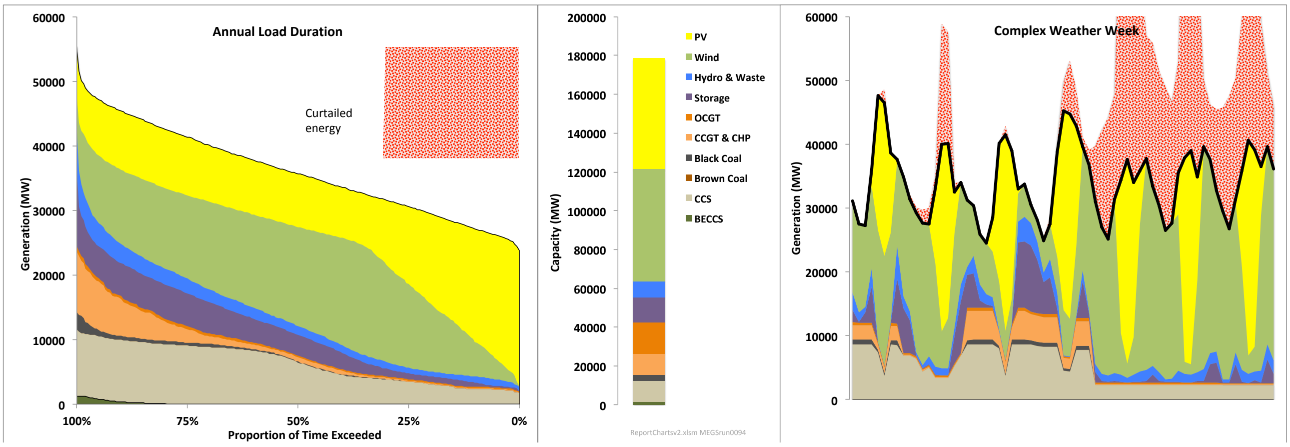


Figure 20: Deep Decarbonisation, Optimum Generation Mix Including BoTN (Marinus 2).

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 250 g/kWh.[28] As illustrated in Figure 21, the UK generation profile is similar to the optimum generation profile for the NEM, with nuclear replacing coal with CCS.[29] 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 through 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.

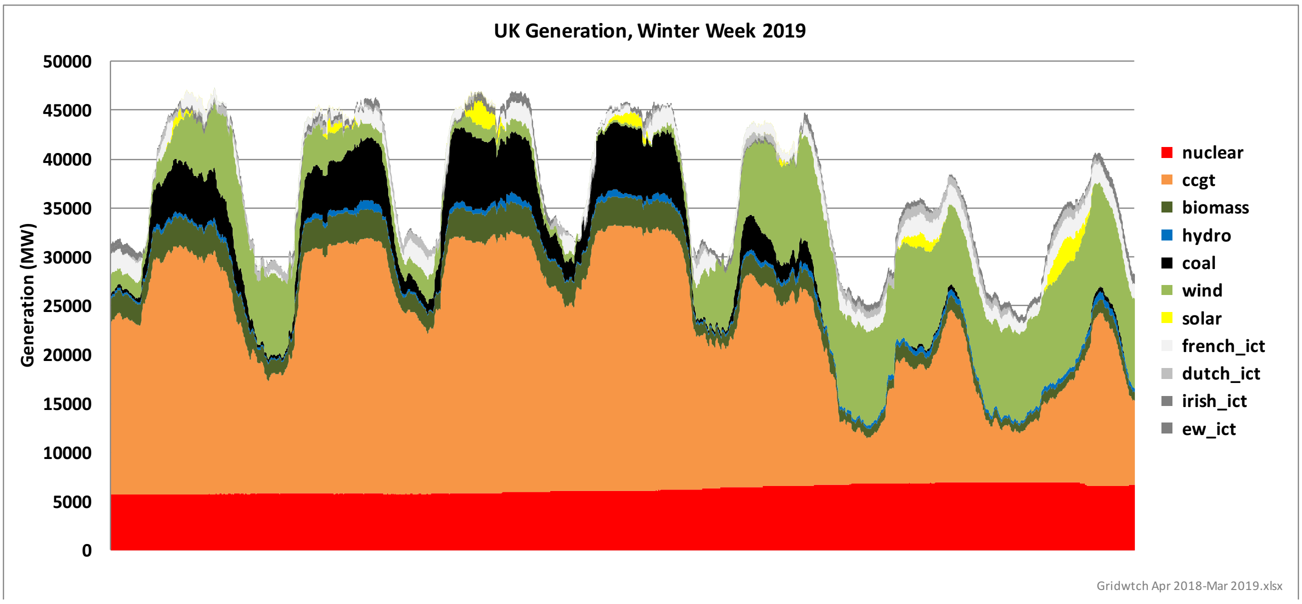


Figure 21: UK Generation for the Winter Week of Peak Demand.

[28] Hausfather, Z. (2019). *Analysis: Why the UK's CO_2 Emissions have Fallen 38% Since 1990.* | Carbon Brief. [online] www.carbonbrief.org/analysis-why-the-uks-co2-emissions-have-fallen-38-since-1990 [Accessed Nov. 2019].
[29] Red Vector analysis of data downloaded from Gridwatch (based on Elexon Portal and Sheffield University). Generation data for April 2018-March 2019 retrieved in April 2019 from http://www.gridwatch.templar.co.uk.

The utilisation of the BoTN scheme (refer to Figure 22) is similar to the utilisation of Snowy 2.0 (refer to Figure 18), 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.

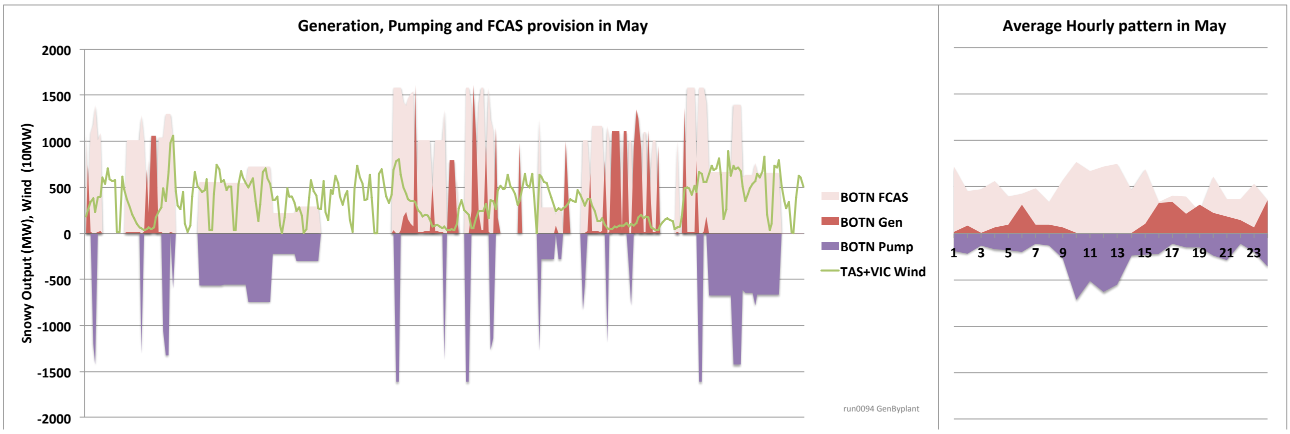


Figure 22: Phase 3 BoTN (Marinus 2) Utilisation in May – Deep Decarbonisation Scenario.

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 pumped hydro assets, are developed. BoTN is able to collectively reduce the TSC by nearly $3.30/MWh.

3.4 Ultimate Large Scale Pumped Hydro Storage Scenarios

While there are no definitive plans for expansion of the Snowy system beyond Snowy 2.0, nor the BoTN beyond Marinus 1 and 2, it is insightful to speculate the impact of more large scale PHES if it were to be added to the NEM. To examine the impact of very large amounts of additional PHES, several additive scenarios where examined.

3.4.1 The Impact of Very Large Scale Pumped Hydro Storage: Snowy 3.0 and 4.0

The NEM was re-optimised for Snowy 4.0. where for the sake of modelling, it was assumed to be the addition of the third and fourth phase of expansion the Snowy hydro scheme. These were identical to Snowy 2.0 in cost and storage and generation capacities.[30]

The impact of Snowy 4.0 on the Snowy 2.0 base case is significant. The change in capacity and generation is illustrated by the generation and capacity difference chart, Figure 23. In a NEM with access to very large amounts of long-term storage, there is no the need for the expensive BECCS to achieve 90% decarbonisation. The most significant change, however, is the very large increase in solar PV capacity and generation, an addition of nearly 20GW producing more than 30TWh. The availability of such large storage infrastructure also results in a small decrease in wind capacity and generation, and a decrease in coal with CCS capacity and generation.

[30] Refer to Section 2.3.5 for more details.

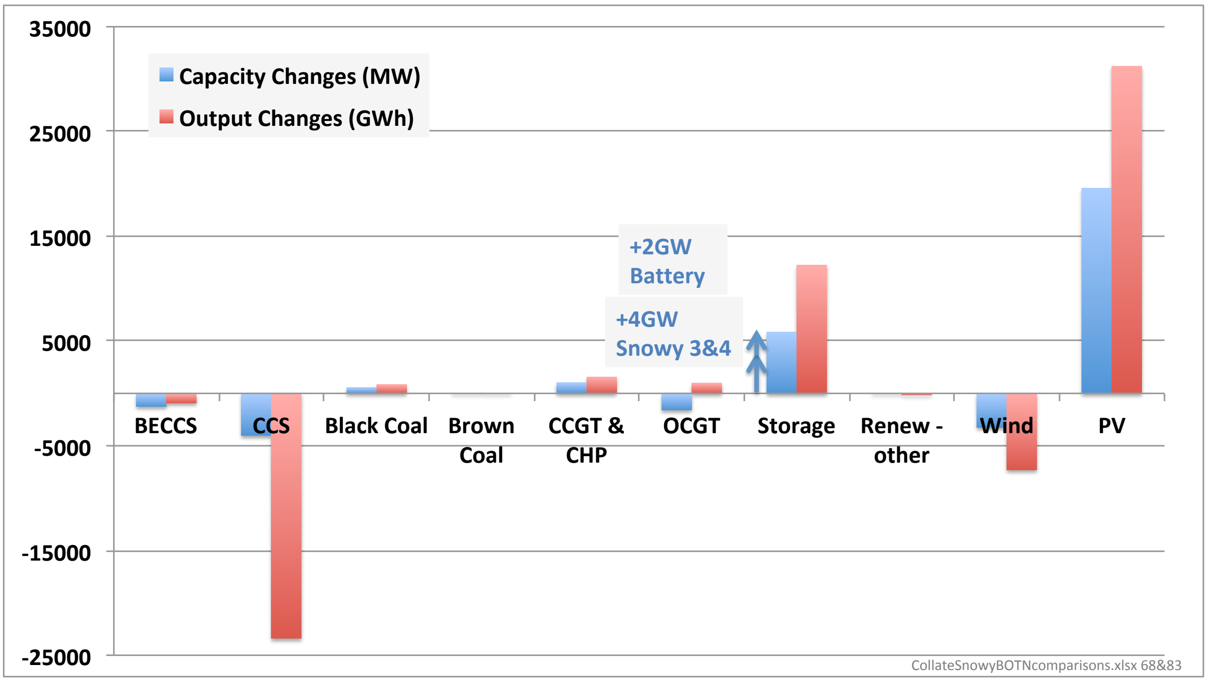


Figure 23: Changes to Capacity from Snowy 2.0 Optimal Mix with the Inclusion of Snowy 3.0 and 4.0.

While coal with CCS is still required, its installed capacity is significantly reduced to 7GW. Its role, however, is very similar, with a similar load shape, albeit with a longer time at minimum stable generation (Figure 24). ***It should be noted that the total capacity of the NEM in this Snowy 3.0 and 4.0 scenario is three times greater than the current ~50GW system. Much of the new capacity is the 120GW of wind and solar PV, which is a ten-fold increase over the current capacity of each.***

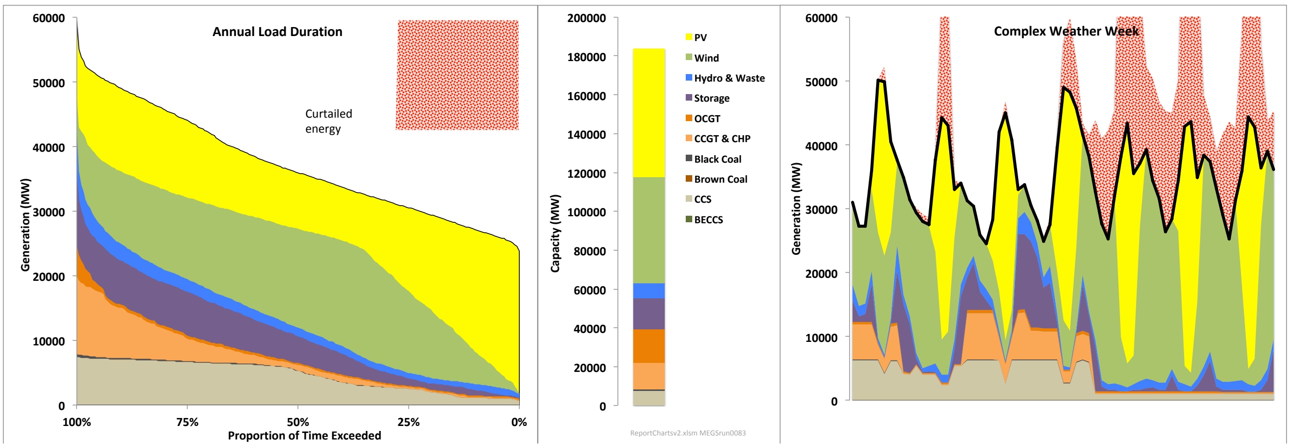


Figure 24: Deep Decarbonisation, Optimum Generation Mix Including Snowy 3.0 and 4.0.

3.4.2 The Impact of Very Large Scale Pumped Hydro Storage: Marinus 3 (BoTN 2.0)

The comparative sizes of Snowy and BoTN options are illustrated in Figure 25. A fully expanded BoTN (Marinus 3) offers a similar capacity addition as the first phase of Snowy expansions (Snowy 2.0), however its storage capability is more than a magnitude smaller.

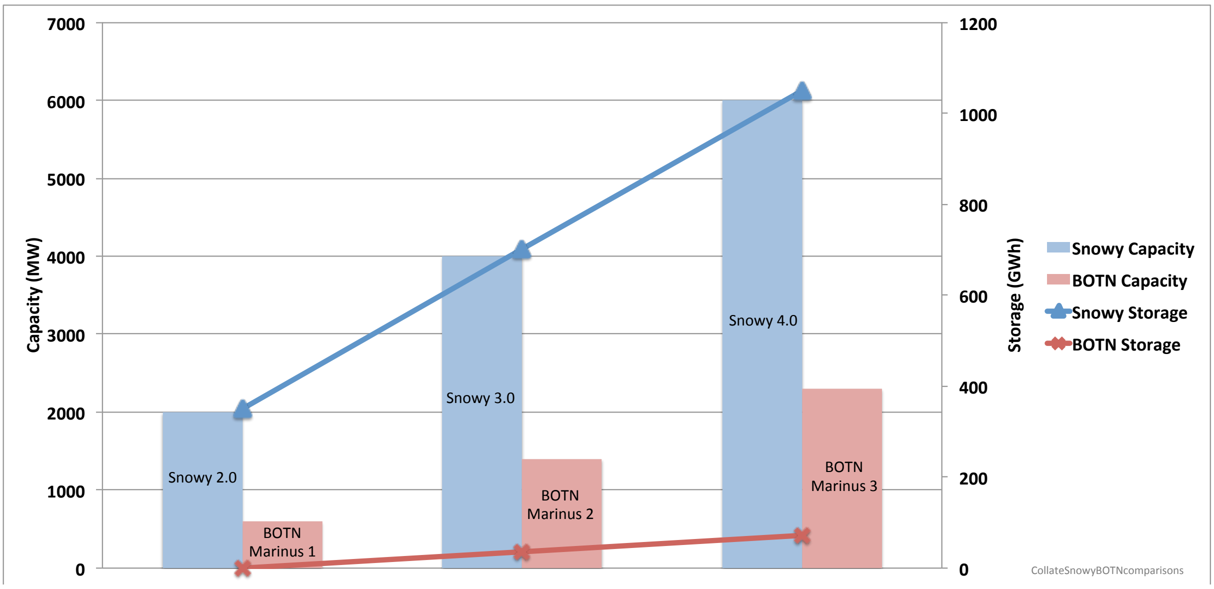


Figure 25: Comparative sizes of Snowy 2.0 – 4.0 and BoTN Marinus 1 – 3.

This 'maximum' PHES scenario, includes Snowy 2.0, 3.0 and 4.0 in addition to the BoTN Marinus 1, 2 and 3 with the associated hydro and pumped hydro upgrades. This hypothetical, very large, or better described as the maximum storage scenario, seeks to examine the impact of a dramatic increase in the availability of PHES.[31]

At a high-level overview as illustrated in Figure 26, the impact of Snowy 2.0 is moderate, reducing all other generation capacities slightly. While the addition of both Snowy 3.0 and 4.0 follows this with moderate reduction in the amount of gas fired power generation, both wind and coal with CCS show more significant reductions in the required installed capacity. Unlike Snowy 2.0, solar PV is a major beneficiary of the storage provided by Snowy 3.0 and 4.0. The final 'storage max' scenario includes the addition of a BoTN 2.0. Unlike the cumulative Snowy additions, this scenario does not significantly increase solar PV capacity, but results in a slight increase in wind capacity.

[31] PHES is chosen for this assessment because today, it represents the cheapest form of market-ready storage. This analysis is agnostic to the chosen storage technology and could apply to other forms of storage with similar characteristics and costs.

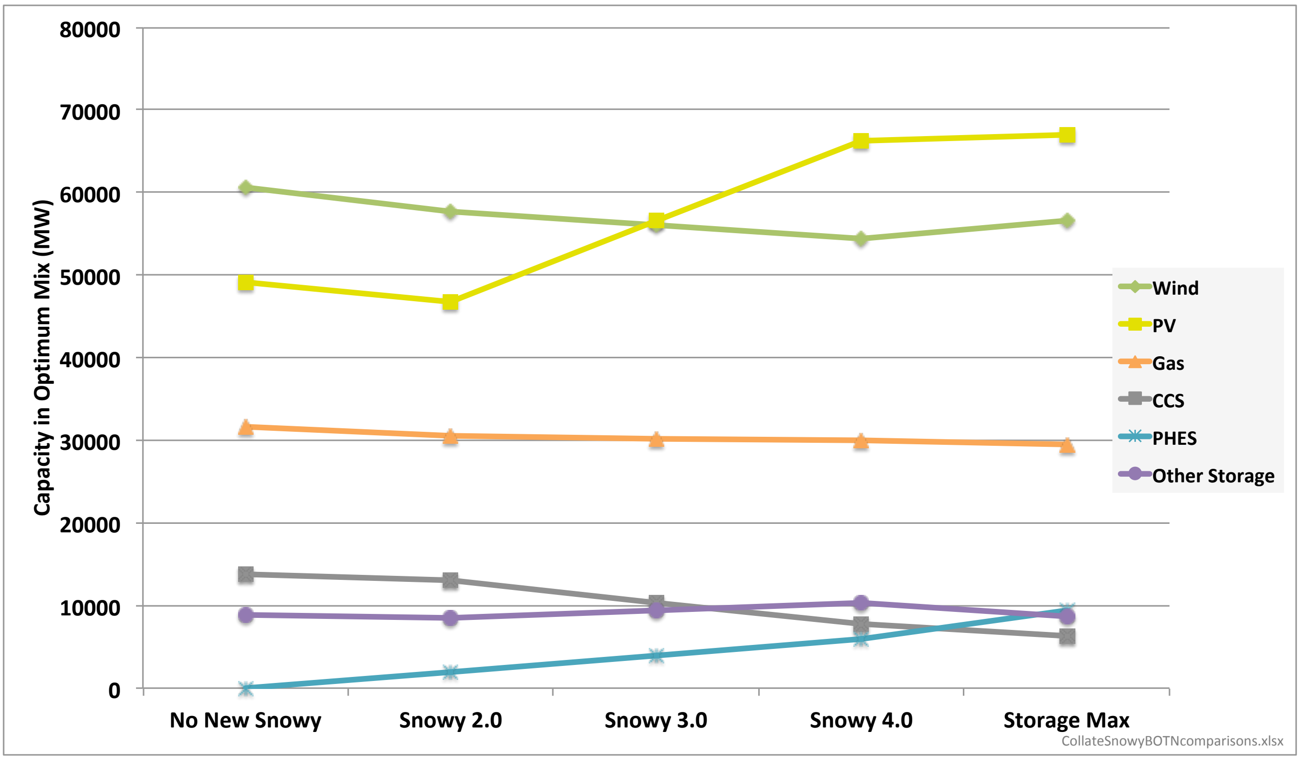


Figure 26: Change in Generation Capacity Make-up as Storage is Added.

For the maximum storage scenario, the optimised lowest TSC generation suite has more than 180GW of capacity compared to the current fleet of 50GW of installed capacity, as illustrated in Figure 27. Solar PV and wind dominate the generation suite, with just over 120GW of combined capacity, resulting in almost no fossil generation on high wind and solar PV generation days. As shown in the load duration curve, the wind and solar PV make up nearly all of the generation for 15 percent of the year, and dominate for nearly 50 percent of the year, with less than 10GW of generation from coal with CCS, CCGT, pumped storage and conventional hydro. For most of the remainder of the year, coal with CCS operates at very high capacity factors, with CCGT, storage and hydro contributing significant amounts of generation. An examination of the hour by hour MEGS output shows that for about 11 percent of the year, more than 75 percent of the load is supported by non-wind and solar PV technologies.

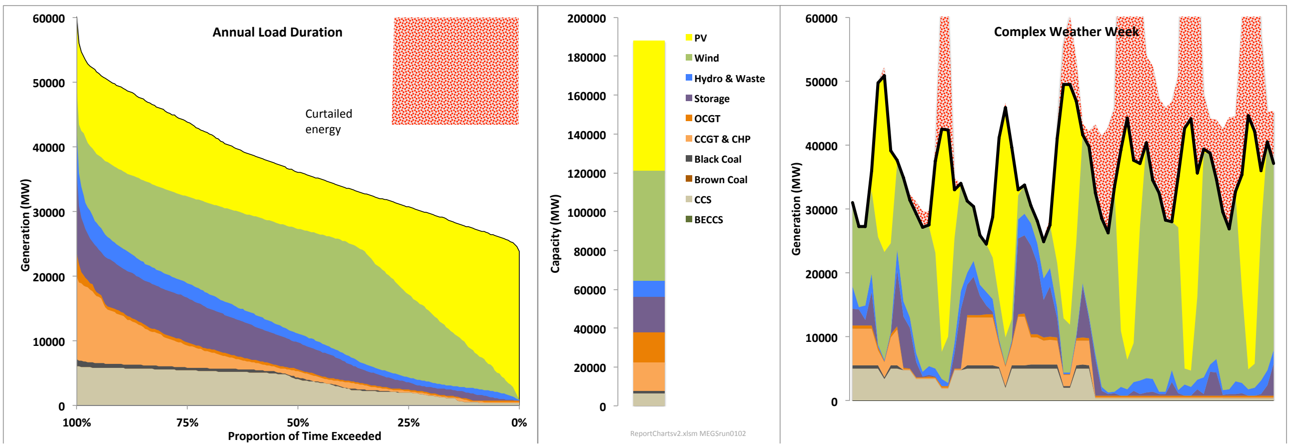


Figure 27: Deep Decarbonisation, Optimum Generation Mix – Maximum Storage Scenario.

The effect on TSC as a result of the addition of the Snowy and BoTN schemes is shown in Figure 28. The very large amounts of long-term storage provides additional value to the system over and above its costs, hence results in a decrease in TSC. Each addition scheme reduces the TSC by $2 – 3/MWh.

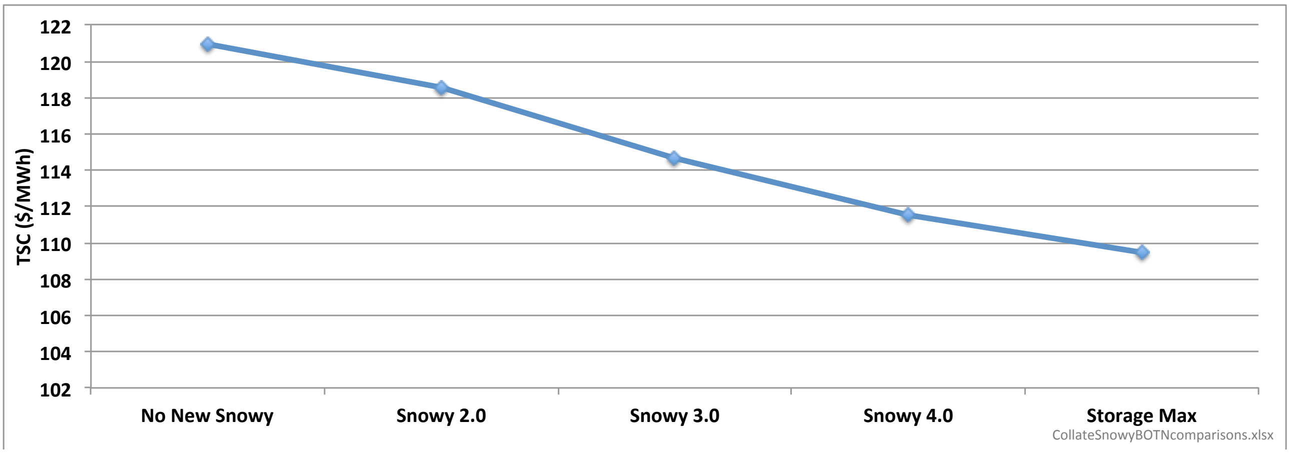


Figure 28 Reduction in TSC with Addition of Maximum Storage Options.

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

To determine the requirements for long-term storage in a very high 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 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 29. 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 – 35GW.

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 pumped storage facility. Of greater importance are the distribution of weeks which show renewable deficits compared with the long-term average, this is shown in red. These periods can be quite long and the deficit can exceed half of average demand.

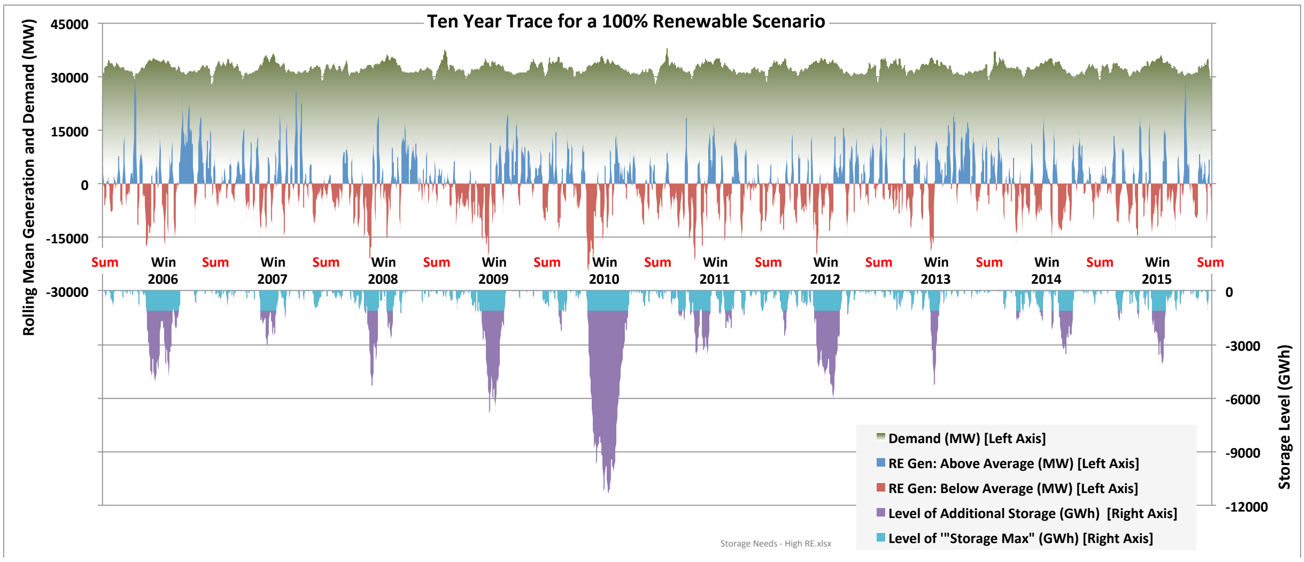


Figure 29: Overview of 10 Years of Operation of a 100% Renewable System

The lower trace illustrated in Figure 29 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.

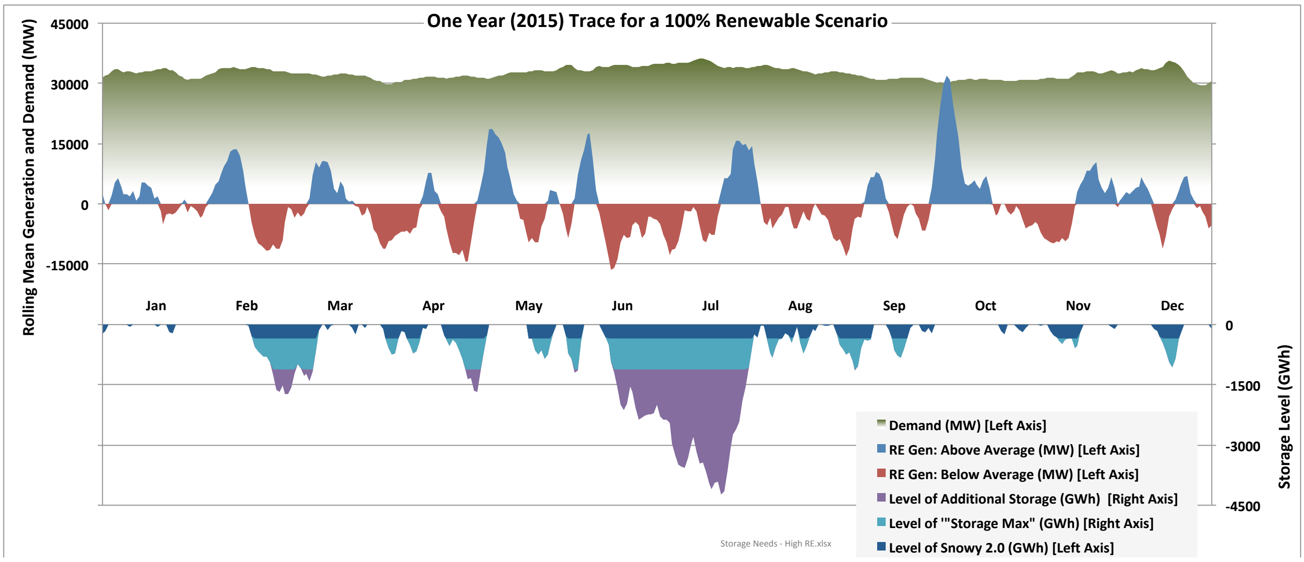


Figure 30: Overview of 2015 – Operation of a 100% Renewable System (subset of Figure 29).

The depth of storage required to cover most years is approximately 5TWh, which is shown as the lower portion of Figure 30 in GWh scaled on the right axis. ***All but one year would be adequately supported by approximately 7TWh of storage, but for 2010, the year of the most significant renewables drought (refer to Figure 29), there is the need for 11TWh of storage***. 4TWh of the 11TWh of storage would need to be built would be used just once every 10 years.

A detailed examination of the largest renewable drought between 2006 and 2015 (Figure 30) is illustrated in Figure 31. ***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.

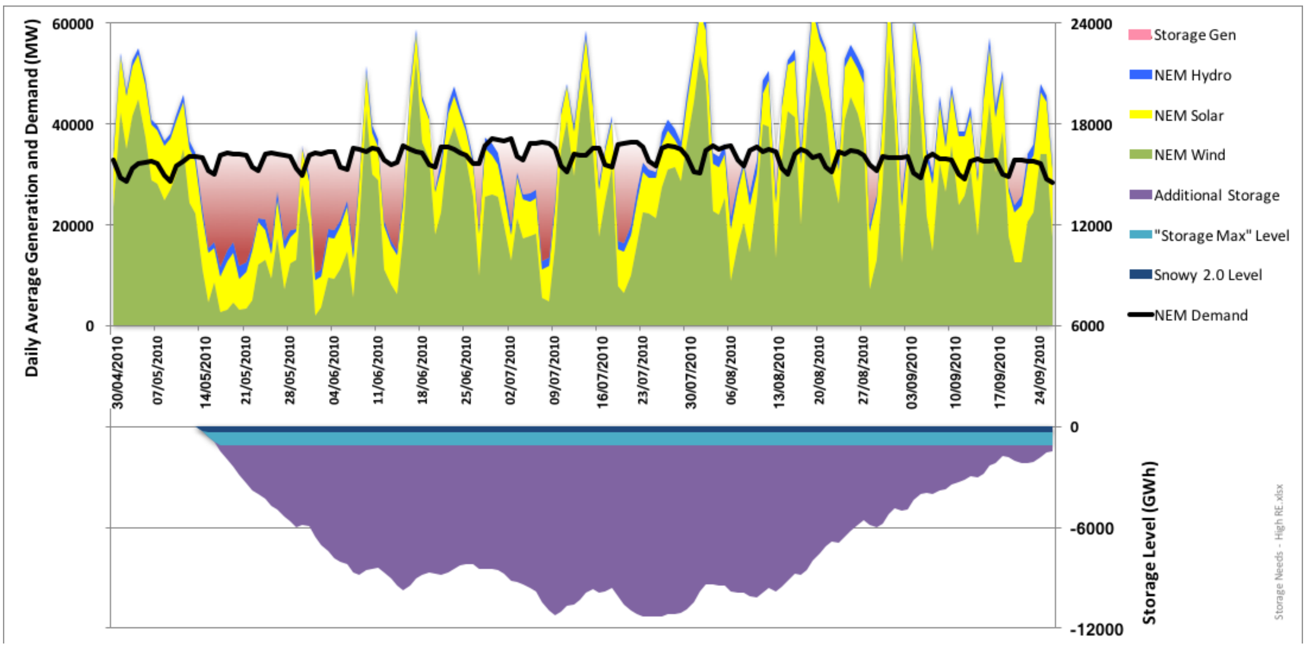


Figure 31: Renewables Drought of Winter 2010 Showing Drawdown of Storage.

The results from this simple 100% scenario are summarised in Table 5. It must be noted, that if the current interconnection constraints were to be applied, significantly more storage capacity and double the volume would be required. For scale and reference, Snowy 2.0 is a 0.35TWh, 2GW system and the storage max scenario (Snowy 2, 3 & 4 and BoTN 2) equals a 1.1TWh, 9.4GW system.

Table 5: Requirements in 100% Renewable Scenario Compared to Current NEM.

	2019 NEM	**Copper plate NEM**
Storage Volume (TWh)	<0.01	11
Storage Capacity (GW)	1.3	24
Wind Capacity (GW)	6	80
Solar Capacity (GW)	6	65
Hydro Capacity (GW)	7	7
Total Capacity (GW)	56	176

Disclaimer

This analysis for report was completed on 1st of November 2019 and therefore the report does not take into account events or circumstances arising after that time. The authors of the report take no responsibility to update the report. The reports modelling considers only a limited set of input assumptions which should not be considered entirely exhaustive. Modelling inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from actual events. There will usually be differences between estimated and actual results, because events and circumstances frequently do not occur as expected, and those differences may be material. The authors of the report take no responsibility for the modelling presented to be considered as a definitive account.

The authors highlight that it does not constitute investment advice or a recommendation to you on your future course of action. The authors provide no assurance that the scenarios modelled will be accepted by any relevant authority or third party.

Conclusions in the report are based, in part, on the assumptions stated and on information which is publicly available. No listed author, company or supporter of this report, nor any member or employee thereof undertakes responsibility in any way whatsoever to any person in respect of errors in this report arising from information that may be later be proven to be incorrect.

In the preparation of this report the authors have considered and relied upon information sourced from a range of sources believed after due enquiry to be reliable and accurate. The authors have no reason to believe that any information supplied, or obtained from public sources, was false or that any material information has been withheld.

The authors do not imply, and it should not be construed that they have verified any of the information provided, or that the author's enquiries could have identified any matter which a more extensive examination might disclose.

While every effort is made by the authors to ensure that the facts and opinions contained in this report are accurate, the authors do not make any representation about the content and suitability of this information for any particular purpose. The report is not intended to comprise advice and is provided "as is" without express or implied warranty. Readers should form their own conclusion as to its applicability and suitability. The authors reserve the right to alter or amend this report without prior notice.

Authors:
Andy Boston, Red Vector
Geoff Bongers, Gamma Energy Technology
Stephanie Byrom, Gamma Energy Technology

How to reference this report:
Boston, A., Bongers, G., and Byrom, S. (2020), *Snowy 2.0 and Beyond – The Value of Large-Scale Energy Storage,* Gamma Energy Technology P/L, Brisbane Australia.

Financial Support:
The authors wish to acknowledge financial assistance provided through Australian National Low Emissions Coal Research and Development (ANLEC R&D). ANLEC R&D is supported by COAL21 Ltd and the Australian Government through the Clean Energy Initiative.

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.
www.redvector.co.uk

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.
www.powerfactbook.com.au
www.gamma-energy-technology.com.au

Gamma Energy Technology
EXPERIENCE THINKING INNOVATION

WWW.POWERFACTBOOK.COM

RED Vector

WWW.REDVECTOR.CO.UK