Short-Term Off-River Pumped Hydro Energy Storage (STORES)

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Statement of originality

I declare that the material presented in this thesis is my own original work, except where indicated or referenced otherwise in the text. Any contributions from colleagues in the collaboration are explicitly stated in the Acknowledgments.

Parts of this work (Chapter 2.3, 2.4, 2.5 and 3.2) have been published in:

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A. Blakers, M. Stocks, and B. Lu, "Meeting Australia's Paris greenhouse commitment at zero net cost," The Australian National University, Nov 2017.

A. Blakers, B. Lu, and M. Stocks, "100% renewable electricity in Australia," *Energy,* vol. 133, pp. 471-482, Aug 15 2017.

B. Lu, A. Blakers, and M. Stocks, "90-100% renewable electricity for the South West Interconnected System of Western Australia," *Energy,* vol. 122, pp. 663-674, Mar 1 2017.

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This thesis is dedicated to my family, Joan, Siya, Evelyn and Rachel, for their endless support and love.

Abstract

Short-Term Off-River Energy Storage (STORES) is a breed of pumped hydro energy storage which incorporates closed-loop pumped hydro systems located away from rivers. Compared with conventional river-based hydroelectric projects, the STORES facilities consume modest volume of water and have little impacts on the environment and natural landscape. A significant feature of STORES is the large altitude difference between upper and lower reservoirs (typically > 300 metres), which enables large amounts of electrical energy to be stored in pairs of medium-sized reservoirs. STORES is capable of large-scale energy time shifting and a variety of ancillary services such as frequency regulation and voltage control, which can facilitate high penetration of photovoltaics and wind in electricity systems.

This study investigates the potential for STORES to be deployed in Australia supporting large-scale photovoltaics and wind developments in the Australian electricity markets. The study is comprised of two aspects:

1. Grid integration modelling of photovoltaics, wind and pumped hydro with a focus on the analysis of energy supply and demand balance in 100% renewable electricity systems. Hypothetical scenarios for 100% renewable electricity in the Australian National Electricity Market (NEM) and 90-100% renewable electricity in the South West Interconnected System (SWIS) of Western Australia are modelled. An energy balance model is used to determine the least-cost configuration of generation, storage and transmission facilities based on the hour-by-hour analysis of historical solar and wind data and electricity demand in 2006-2010 (NEM) and 2007-2014 (SWIS). The levelised costs of electricity normalised to 2016 Australian dollars are \$75-93/MWh for the NEM and \$103-129/MWh for the SWIS, which can be competitive with new-build coal or natural gas-fired power stations in Australia. Importantly, the levelised costs of balancing are only \$25-\$28/MWh in the NEM and \$37-\$41/MWh in the SWIS, which are significantly lower than the results from studies using alternative balancing methods such as geothermal or concentrating solar power coupled with high-temperature thermal energy storage.

2. A comprehensive Geographic Information System (GIS)-based site survey for STORES across each state/territory of Australia. Two typical types of sites, dry-gully and turkey's nest, are modelled and a sequence of GIS-based procedures are developed which highlight the most

promising regions for STORES deployments and identify the prospective sites. A national atlas of pumped hydro energy storage is developed which demonstrates Australia has a large storage potential in the form of STORES - equivalent to 67,000 gigawatt-hours (GWh) or 670 gigawatts (GW) with 100 hours of storage; far beyond the storage requirements (about 20 GW, 500 GWh) to support 100% renewable electricity in the Australian energy market. In comparison, Tumut 3, the largest hydroelectric power station in Australia, has a generation capacity of 1.5 GW while the Hornsdale Power Reserve in South Australia, the world's largest lithium-ion battery, is only capable of 0.1 GW, 0.129 GWh of storage.

This study provides a generic, cost-effective approach to decarbonise electricity sectors through a synergy of flexible renewable energy resources, geographic dispersion of photovoltaics and wind, demand response and most importantly, large-scale energy storage, STORES. Significantly, the affordable and reliable low-carbon electricity systems can be built based on existing mature generation, storage and transmission technologies which have already been deployed on a large scale, namely photovoltaics, wind, existing hydro and biomass, pumped hydro and high-voltage direct-current and alternating-current transmission.

Table of Contents

Acronyms and abbreviations

A-CAES	Adiabatic-compressed air energy storage
AEMO	Australian Energy Market Operator
ARENA	Australian Renewable Energy Agency
BAU	Business as usual
CAES	Compressed air energy storage
CAPAD	Collaborative Australian Protected Areas Database
CAPEX	Capital expenditure
CIGRE	International Council on Large Electric Systems
CLUM	Catchment Scale Land Use
CMA-ES	Covariance Matrix Adaptation Evolution Strategy
CPU	Central processing unit
CSIRO	Commonwealth Scientific and Industrial Research Organisation, Australia
CSP	Concentrating solar power
DC/AC	Direct current to alternating current
DM	Demand management
DNI	Direct normal irradiance
EGS	Engineered geothermal system
ERGIS	Eastern Renewable Generation Integration Study
EU	European Union
EV	Electric vehicle
GDAL	Geospatial Data Abstraction Library
GHG	Greenhouse gas
GHI	Global horizontal irradiance
GIS	Geographic information system
GL	Gigalitre(s)
HPC	High-performance computing
HAS	Hot sedimentary aquifer
HVDC & AC	High-voltage direct current and alternating current
IEEE	Institute of Electrical and Electronics Engineers
IGBT	Insulated-gate bipolar transistor
kSU	1,000 service units
LCC-HVDC	Line-commutated converters high-voltage direct current
LCOB	Levelised cost of balancing
LCOE	Levelised cost of electricity
LCOG	Levelised cost of generation
LCOS	Levelised cost of storage
LCSC	Levelised cost of storage capacity
LUT	Lappeenranta University of Technology, Finland
NARIS	North American Renewable Integration Study
NASA	U.S. National Aeronautics and Space Administration
NEM	Australian National Electricity Market

NEMO	National Electricity Market Optimiser
NREL	U.S. National Renewable Energy Laboratory
NSP	Non-synchronous penetration
NSW	New South Wales, Australia
NT	Northern Territory, Australia
NWIS	North West Interconnected System, Western Australia
OPEX	Operating expense
PCM	Phase-change material
PHES	Pumped hydro energy storage
PtG	Power-to-gas
PtH	Power-to-heat
PV	Photovoltaics
QLD, Qld	Queensland, Australia
RAM	Random access memory
SA	South Australia, Australia
SAM	System Advisor Model
SGCC	State Grid Corporation of China
SNG	Synthetic natural gas
STES	Sensible thermal energy storage
STORES	Short-term off-river pumped hydro energy storage
SWIS	South West Interconnected System, Western Australia
TAS, Tas	Tasmania, Australia
TES	Thermal energy storage
UCED	Unit commitment and economic dispatch
UHVDC & AC	Ultra-high-voltage direct current & alternating current
UK	United Kingdoms
UNEP	United Nations Environment Programme
UNSW	University of New South Wales
UPS	Uninterruptible power supply
US, U.S, USA	United States of America
UTES	Underground thermal energy storage
VIC, Vic	Victoria, Australia
VSC-HVDC	Voltage-source converters high-voltage direct current
W, kW, MW, GW	Watt(s), kilowatt(s), megawatt(s), gigawatt(s)
WA	Western Australia, Australia
WACC	Weighted average cost of capital
Wh, kWh, MWh, GWh, TWh	Watt-hour(s), kilowatt-hour(s), megawatt-hour(s), gigawatt-hour(s)
WWS	Wind, water and solar
WWSIS	Western Wind and Solar Integration Study

1 Introduction

1.1 Giga-trends of solar and wind developments

Primary energy sources for electricity generation can be categorised into: (a) fossil fuels i.e. coal, oil and natural gas, (b) nuclear energy and (c) renewables including solar, wind[1], hydropower, biomass[2], geothermal and ocean. Figure 1-1 illustrates the global cumulative generation capacities (gigawatts, GW) by energy source, 2008-2017.

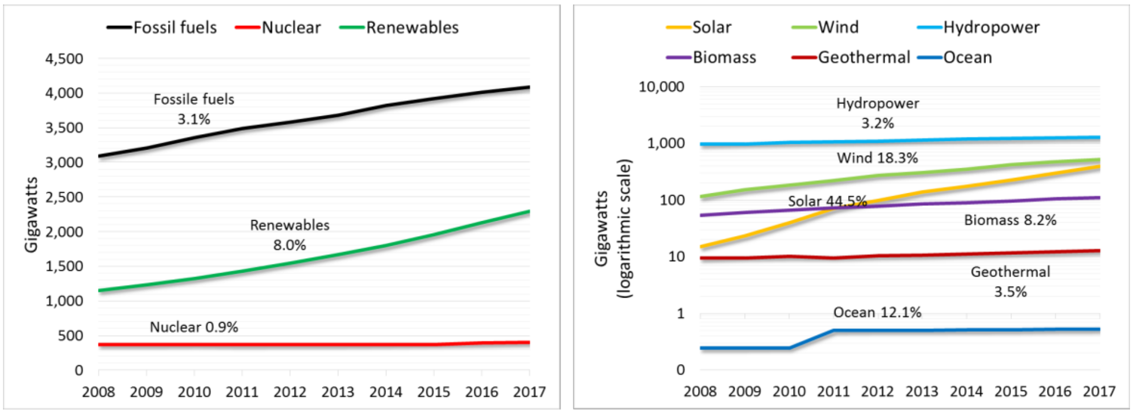


Figure 1-1 Global cumulative electricity generation capacities by energy source, 2008-2017. Percentages on/below the curves denote the average annual growth rates of installed generating capacities over the last decade. Data source: U.S. Energy Information Administration [1]; Frankfurt School-UNEP Centre & Bloomberg New Energy Finance [2]; International Renewable Energy Agency [3].

In 2008-2017, the global average annual build-rates of solar (photovoltaic 98%, concentrating solar power 2%) and wind reach 45% and 18% respectively, while the increases of other power generation technologies are considerably lower: 1-12%. At the end of 2017 the global installations of solar photovoltaics (PV) and wind were beyond 400 GW and 500 GW respectively, altogether contributing 2,000 TWh electricity generation (7.5% of the total) to the world's electricity markets [4].

Figure 1-2 shows the top 10 countries with highest penetration of solar and wind (> 1 TWh) in 2017. By contrast, Australia's PV and wind integration exceeded 9.5% of the total electricity generation at the end of 2017. A leading state, South Australia, has the highest penetration of PV and wind - approximately 45% of the state's annual electricity production coming from rooftop PV (8%) and wind (37%) [5].

[1] In this thesis, the term "wind" means wind resource, wind energy or wind turbine where appropriate.
[2] Burning of biomass/biofuels causes air pollution and increased ozone effects, which is discussed in Chapter 1.3.1.2.

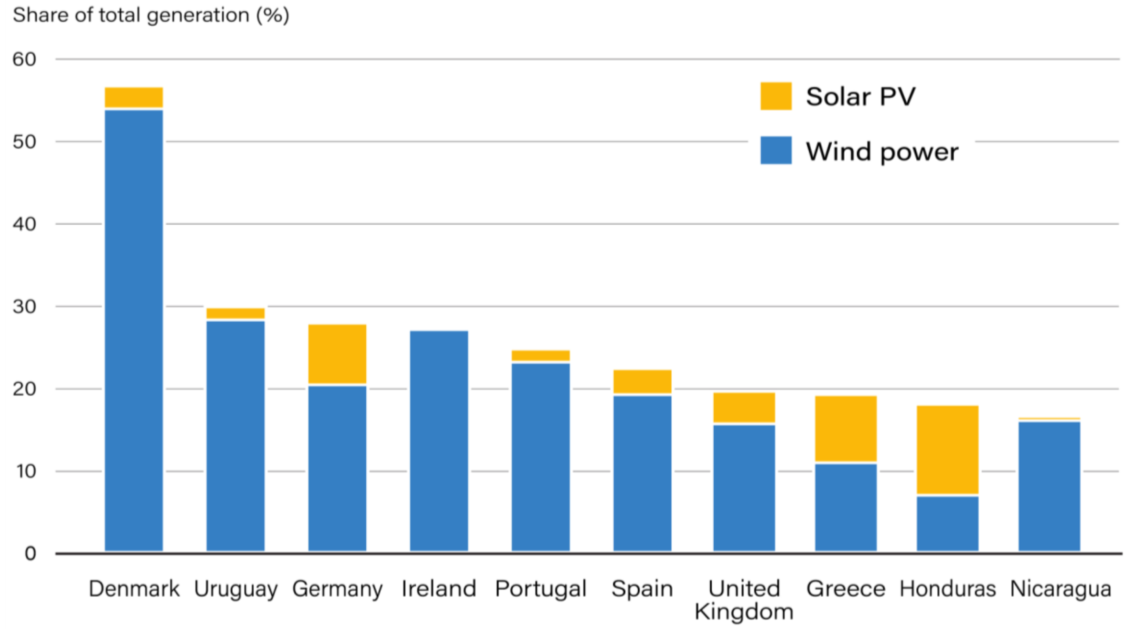


Figure 1-2 Top 10 countries with highest penetration of solar and wind energy (> 1 TWh) in 2017. Image source: Renewable Energy Policy Network for the 21st Century [4].

Rapid growth of PV and wind energy in global electricity sectors are expected to continue, driven by a broad range of issues associated with climate change, energy security and economics including:

- The overwhelming scientific consensus on the global warming mainly caused by anthropogenic greenhouse gas (GHG) emissions,
- Depletion of some fossil fuel resources in some countries,
- Safety, proliferation and waste concerns about the deployments of nuclear power and,
- Most recently, dramatically declining cost of PV and wind.

1.1.1 Global warming

Figure 1-3 illustrates the global land-ocean temperature index (red) and the annual global fossil-fuel carbon emissions (dark) from 1880 to present, which shows a clear correlation between the global warming and the anthropogenic GHG emissions. Figure 1-4 shows the breakdown of global carbon emissions by economic sector. Renewable energy, notably solar PV and wind, can make a significant contribution in decarbonisation of electricity generation and also the other energy sectors through the electrification of heating (heat pumps) and transportation (electric vehicles).

A possible solution to decarbonisation of aviation, shipping and heavy-duty road vehicles is using renewable electrofuels (indirect electrification) where hydrogen is produced from renewables through electrolysis and carbon is sourced from atmosphere and/or biomass [6, 7]. In addition, renewable electrofuels can also be used in metal refining as a substitute feedstock for carbon-based coking fuels [8]. However, indirect electrification will be more challenging than direct electrification through electric vehicles and electric heating in terms of technology maturity, cost and efficiency.

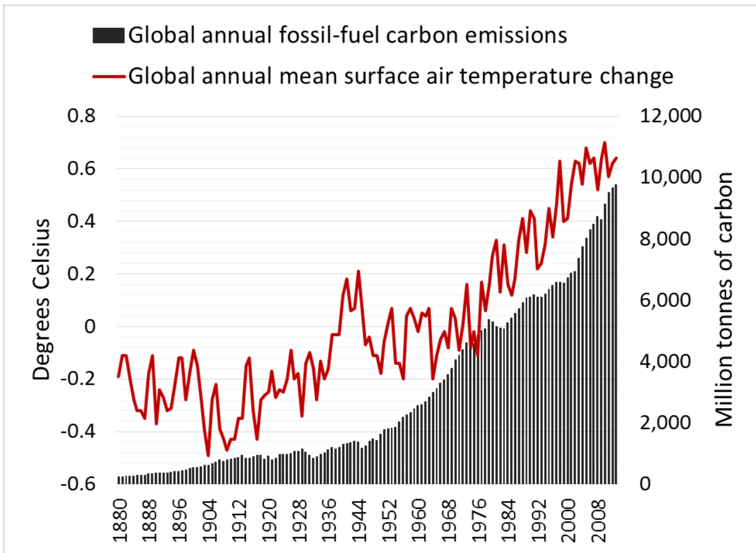


Figure 1-3 Growth of the global land-ocean temperature index (red) against the annual global fossil-fuel carbon emissions (dark). Data source: U.S. National Aeronautics and Space Administration [9]; Lawrence Berkeley National Laboratory [10].

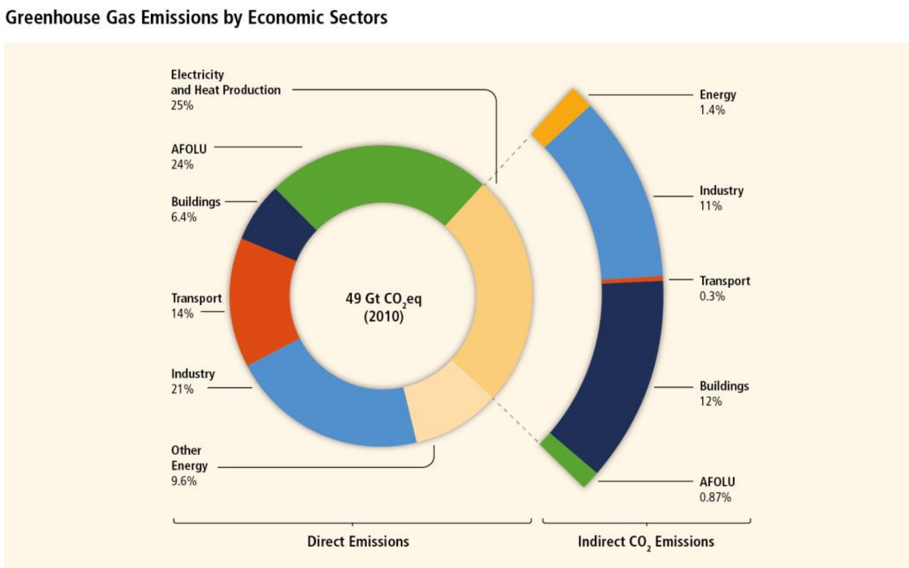


Figure 1-4 A breakdown of the global carbon emissions by economic sector in 2010. Image source: Intergovernmental Panel on Climate Change [11]

In December 2015, the historic Paris Agreement was adopted at the twenty-first session of the Conference of the Parties (COP21) to the United Nations Framework Convention on Climate Change [12]. This set up a long-term goal against climate change to limit the global temperature rise to 1.5-2 degrees Celsius above pre-industrial levels. To date (July 2018), 179 of 197 Parties to the Convention have ratified the Agreement, though the largest economy and the second biggest emitter of carbon dioxide, the United States, has announced its intention in 2017 to withdraw from the Climate Accord [12]. At the end of 2017, 179 countries have set renewable energy targets at national and state/provincial levels in electricity (150), heating/cooling (48) or transport (42) sectors. Renewable energy targets are also developed at regional levels, such as: (a) 48 members (developing countries) of the Climate Vulnerable Forum: joint commitments on 100% renewable energy, (b) European Union 2030 framework: 40% reduction of GHG emissions in 2030 from the 1990 levels and, (c) Canada, Mexico and the United States: 50% of electricity from no-carbon sources by 2025 [4].

Apart from global warming, the pollutants such as particulate matter and ozone from the burning of fossil fuels result in serious health problems including cardiovascular and respiratory diseases [13]. This is not only in developing countries with large population such as China and India but also in such as the United States, which cause millions of premature deaths globally each year.

1.1.2 Depletion of fossil fuel resources

According to BP statistics [14], the proved reserves of fossil fuels at the end of 2016 are: coal 1,139.3 billion tonnes, oil 1,706.7 billion barrels and natural gas 186.6 trillion cubic metres. Based on the 2016 global fossil fuels consumption figures, coal, oil and natural gas will be depleted within 153, 50.6 and 52.5 years respectively, or even sooner due to the expected economic growth, population expansion as well as increasingly urbanisation. For example, the projected Global primary energy demand in the New Policies Scenario of World Energy Outlook [15] will increase by 30% in 2040 (where the Asia-Pacific region accounts for 2/3 of the growth), and the projected electricity consumption will increase by 60%. Moreover, the concentrations of energy resources in a few countries raise concerns about energy security. Figure 1-5 shows the top resource-rich countries with the largest shares of coal, oil or natural gas reserves (proven) of 5% or more of the worldwide total.

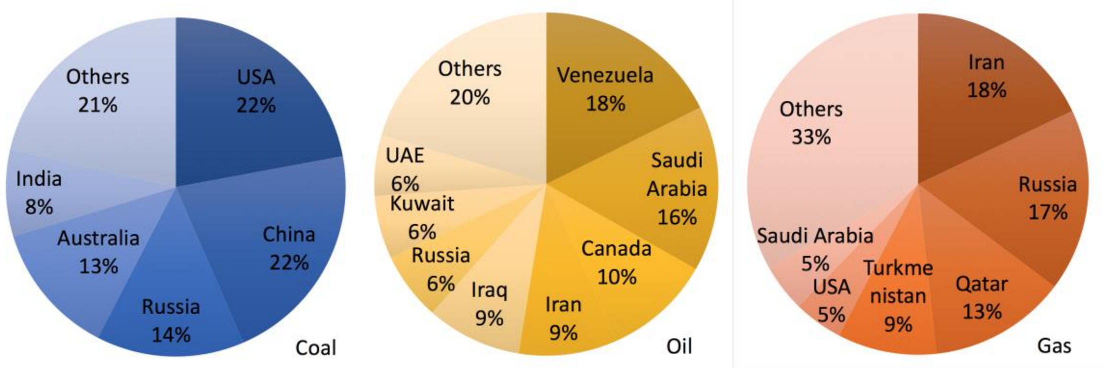


Figure 1-5 Resource-rich countries with the shares of coal, oil or natural gas reserves (proven) > 5%. Data source: BP [14].

By contrast, renewable energy resources, 99.97% from the Sun and 0.03% from the mantle (geothermal) and the gravitational attraction to other celestial bodies (tidal) [16], which co-exist with this planet, are naturally replenished without the risk of exhaustion and are widely distributed around the world . The energy history of human beings is turning over a new leaf transitioning from the current highly polluted age of burning fossil fuels to a promising renewable energy future.

1.1.3 Safety, proliferation and waste concerns about nuclear power

Nuclear power is a low-carbon electricity generation technology and has very high capacity factors (> 90%) - ideal for baseload generation to replace polluting coal. Globally, nuclear energy contributes 2,500 TWh, approximately 11% of the total electricity generation in 2017. In some countries, nuclear energy plays a major role of electricity production such as in France (72%) and Ukraine (55%) [17].

However, there is considerable public opposition to expansions of nuclear power due to the widespread concerns over the following issues [18]: (a) the safety of both reactor operation and fuel cycle, (b) proliferation risk i.e. acquisition of materials that can be used for nuclear weapons (materials protection, control and accountability) and, (c) long-term management of radioactive wastes (waste transportation, storage and disposal, geologic repositories).

In fact, these concerns were raised and strengthened following the Three Mile Island (1979), Chernobyl (1986) and most recently, Fukushima (2011) nuclear accidents. In Australia, nuclear actions including the development of nuclear power are prohibited under the Environment Protection and Biodiversity Conservation Act 1999, though this is often criticised by nuclear advocates. Another example is from Germany, where 8 of existing 17 nuclear reactors were decommissioned immediately following the catastrophic Fukushima nuclear disaster and the remaining reactors will be phased out by 2022 [19]. For the time being, prospects for nuclear power to be a significant part of global future energy mix are dim.

1.1.4 Declining cost of solar and wind

Figure 1-6 shows the learning curve of PV modules (crystalline silicon) as a function of cumulative installations in logarithmic scales. Figure 1-7 shows the installed cost of wind turbines (onshore) over time. During the period of 1979-2017, PV experienced an impressive learning rate of 22.8% while this figure increases to 39.1% in the more recent 2006-2017 period. For wind, the installed cost of onshore wind turbines has experienced a significant reduction over the last decades and most recently, it declined from US$2,000/kW in 2009 to less than US$1,500/kW in 2017.

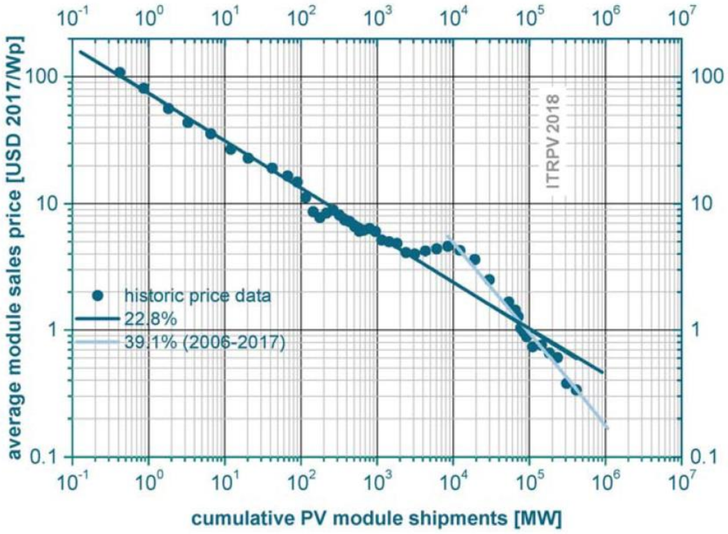


Figure 1-6 Learning curve of PV modules (crystalline silicon) as a function of cumulative installations in logarithmic scale. Image source: International Technology Roadmap for Photovoltaic [20].

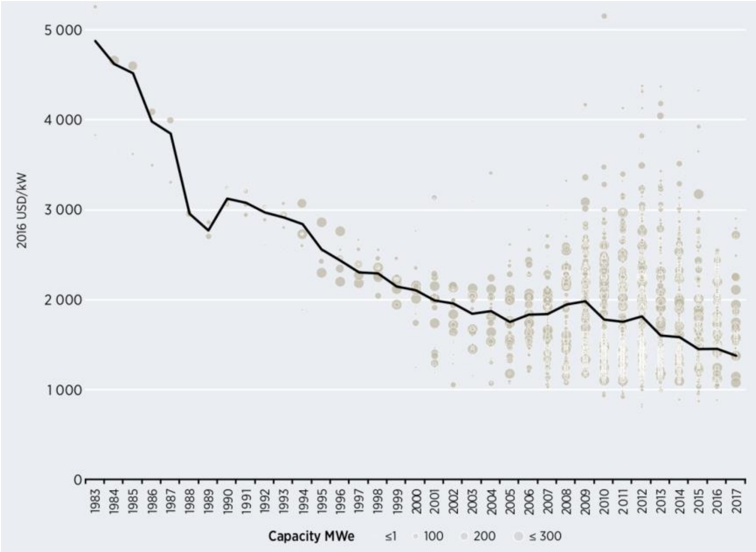


Figure 1-7 Installed cost of onshore wind turbines over time (1983-2017). Image source: International Renewable Energy Agency [21].

Depending on the regional energy resources, fuel prices and renewable energy policies, utility-scale PV and onshore wind are now competitive with conventional fossil fuels and/or nuclear power generation. In major economies, for example, the LCOE ($/MWh) for utility-scale PV and onshore wind have already been lower than new coal-fired power stations in the United States, and new combined cycle gas turbine in China and India. According to [22], PV and wind will overwhelmingly undercut the economics of new coal, natural gas and nuclear power in the near future and even become competitive with the marginal costs of legacy generating assets by 2030 in the U.S., China and Germany.

The driving force behind the significant cost reductions of PV and wind includes improvements in both technology and economies of scale which is in turn stimulated by the declining costs. In addition, PV and wind have no fuel costs and low O&M costs, typically 1-3% of the capital costs. This provides fuel saving benefits compared with fossil fuel power systems, decreasing the marginal costs of electricity generation as a whole, especially in the context of rising prices for fossil fuels.

1.2 Challenges to integrate high levels of photovoltaics and wind into power systems

Photovoltaics and wind turbines are weather-dependent electricity generation technologies, which have a variety of characteristics that are different from conventional thermal power generation including intermittency, imperfect weather forecasts, distributed energy resources and power electronics interface. Figure 1-8 illustrates the characteristics of PV and wind energy systems and the associated technical challenges to integrate high levels of solar and wind electricity into power systems, which may have adverse effects on energy reliability and affordability.

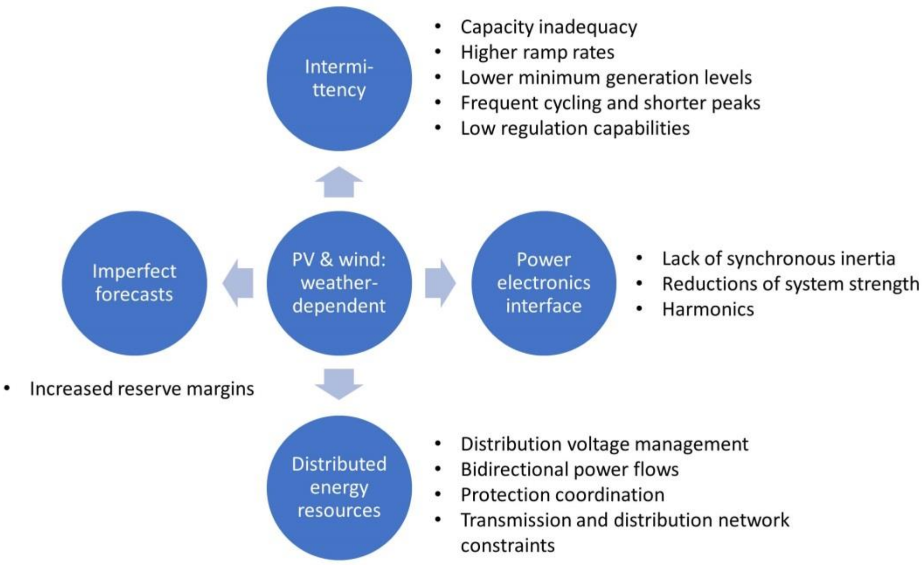
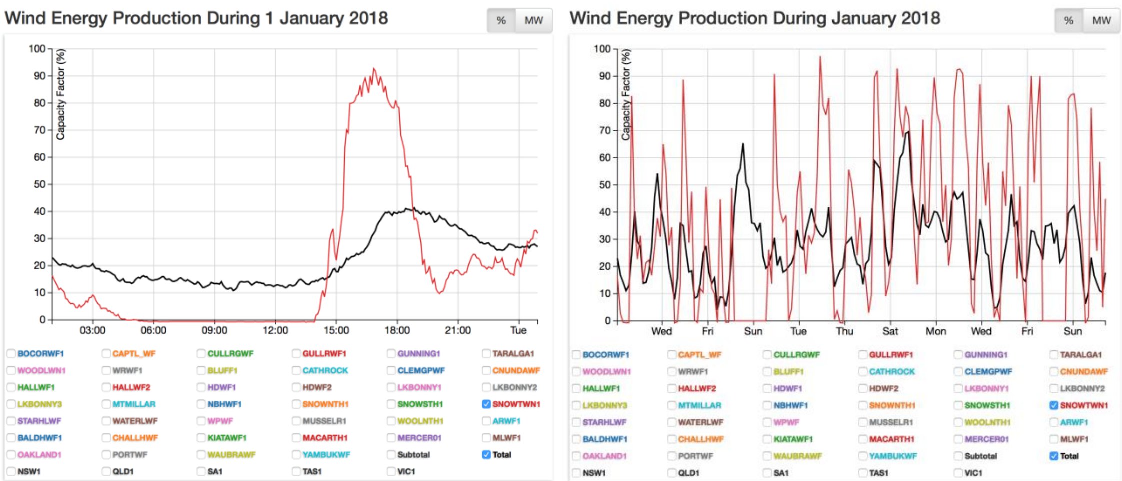


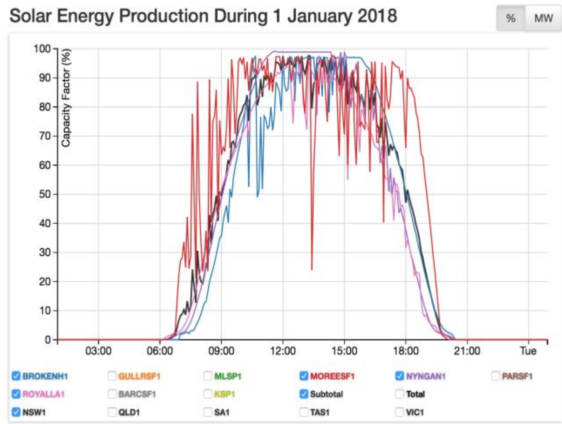
Figure 1-8 Characteristics of PV and wind energy systems and the associated technical challenges to integrate high levels of solar and wind electricity into power systems [23-27].

1.2.1 Intermittency

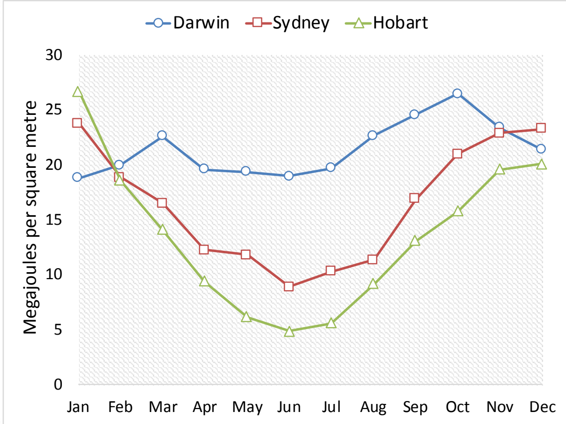
Solar and wind are intermittent energy sources which incorporate the fluctuations in energy production on multiple timescales of minutes, hours, days and seasons. In some literature, the intermittency is also termed variety, variability or volatility such as in [24].



(a) *(b)*



(c)



(d)

Figure 1-9 Intermittency of solar and wind energy production on multiple timescales: 5-minute (a, c), 3-hour (b) and monthly (d). Image source: Aneroid [28]. Data source: Australian Bureau of Meteorology [29].

Figure 1-9 (a, b, c) shows the normalised 3-hour (during January 2018) and 5-minute (during 1 January 2018) energy outputs from the Snowtown Wind Farm Stage 1 (SNOWTWN1, red) located in South Australia and the existing Broken Hill (BROKENH1, blue), Moree (MOREESF1, red), Nyngan (NYNGAN1, purple) and Royalla (ROYALLA1, pink) solar farms within New South Wales, which reflect the intermittency of PV and wind electricity generation on timescales of minutes, hours and days. Figure 1-9 (d) also shows the monthly average daily solar exposure (GHI) in Darwin (12.4500° S, 130.8333° E), Sydney (33.8650° S, 151.2094° E) and Hobart (42.8806° S, 147.3250° E) in 2014, which illustrates longer terms of fluctuations in solar energy i.e. seasonality. The coefficients of variation i.e. the standard deviations of solar exposure divided by the average values are: Darwin 20%, Sydney 45%, Hobart 59%, which reflect the different levels of seasonality in the three cities.

The nature of intermittency in solar and wind energy means that PV and wind contribute energy rather than firm and predictable power capacity to the electricity systems, which causes a range of technical challenges such as capacity inadequacy, higher ramp rates, lower minimum generation levels, frequent cycling and shorter peaks. Additionally, due to the characteristics of intermittent energy supply, PV and wind have low capability to provide regulation and load following services in response to the varying demand for electricity unless allowing a certain amount of energy (10% headroom or so) to be curtailed such as undertaken in tests did by the California Independent System Operator [30].

In this study, Short-Term Off-River Energy Storage (STORES) systems are primarily designed for amelioration of short-term energy fluctuations on timescales of minutes, hours and days, which are mainly caused by cloud and the diurnal cycles (i.e. day-night shifting). By contrast, for longer-term fluctuations such as seasonality, the low solar and wind availability is supplemented by available flexible energy sources in electricity systems including coal and natural gas in existing power systems or legacy hydropower and biomass (with limited contributions) in hypothetical 100% renewable electricity scenarios.

1.2.2 Imperfect forecasts

Predictions of weather conditions cannot be perfect and the forecast error varies on multiple forecasting timeframes which may be significant for long-range forecasts. For example, an AEMO report [31] showed that the average Normalised Mean Absolute Error for wind energy forecasts from the Australian wind energy forecasting system (in the NEM region, between April 2012 and April 2013) ranges from 1% (5 minutes), 3% (1 hour) to 5% (1 day) while for 6 days ahead forecasting, the error rose above 13%. However, as will be noted in Chapter 1.3.2, wide geographic dispersion of solar and wind across large areas hugely smooths forecast uncertainty, as well as intermittent renewable energy outputs.

Operating reserves, which are traditionally decided based on the statistical values of contingency and load forecasting errors, will need to increase in the context of high shares of PV and wind in order to cope with the uncertainty of PV and wind energy supply and very short-term energy fluctuations within dispatch intervals [27]. As a result, the costs of delivering solar and wind electricity is higher than merely the raw cost of the energy [32]. Nevertheless, the nature of a distributed renewable energy system comprised of thousands of individual wind and PV systems avoids a significant impact on system reliability and security resulting from a sudden loss of a single large power generator. The use of thousands of PV and wind energy systems greatly reduces the effect of unexpected individual generator failure compared with an electricity system comprising a small number of large fossil or nuclear power stations,

1.2.3 Distributed energy resources

Conventional fossil fuel power stations such as coal-fired and natural gas-fired power plants are usually centralised and located close to load centres or coal deposits. By contrast, PV and wind energy systems are widely dispersed within the electricity network including the behind-the-meter kW-scale PV devices distributed on building rooftops and the utility-scale PV and onshore/offshore wind farms located in local and remote regions, where there are high-quality solar and wind resources.

The existing transmission and distribution network, which is designed for the delivery of coal-fired or natural gas-fired electricity generation, may need modification to cope with high shares of distributed PV and wind resources, requiring network augmentation or even replanning. Moreover, the modest capacity factors of PV (typically 15-25%) and wind (typically 35-50%) could lead to relatively low utilisation of long-distance high-voltage direct current and alternating current (HVDC & AC) transmission lines, which affects the economic viability of new connections to remote solar and wind resources. However, it should be noted that the combined capacity factor of a wind/PV system can be higher than either separately if the solar and wind resources are counter-correlated.

Integration of numerous behind-the-meter PV systems will involve a range of technical challenges to the existing infrastructure including the management of distribution voltage, bidirectional power flows and protection relay coordination [26].

1.2.4 Power electronics interface

PV and wind are inverter (DC/AC)-based non-synchronous power generation technologies, which are interfaced with transmission and distribution network by power electronics, not electromagnetically. Consequently, the synchronous inertial energy, which is stored in the rotating mass of synchronous machines and is currently used for maintaining a low level of RoCoF (Rate of Change of Frequency) during network disturbances, cannot be contributed by PV and wind though synthetic inertial response may be available by other means [33]. Figure 1-10 shows the incremental decrease of synchronous inertia in South Australia during the years of 2013/14-2016/17 due to the increasing penetration of renewables and the retirement of Northern Power Station.

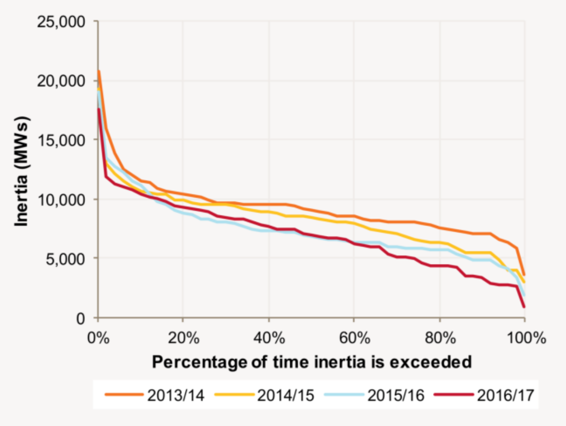


Figure 1-10 Decrease of synchronous inertia in South Australia during the years of 2013/14-2016/17. Image source: Australian Energy Market Operator [34].

Large-scale deployment of PV and wind in electricity systems will affect the fault currents, which leads to declines of system strength i.e. lower short circuit ratios in electricity network. Together, lack of synchronous inertia and reduction of system strength in the context of high penetration of PV and wind bring significant challenges to system stability and energy security, especially to those energy systems that are isolated or weakly interconnected with neighbouring network as is the case in South Australia. In 2016-17, South Australia experienced a range of system events such as load shedding and islanding [35-37], including a state-wide blackout on 28 September 2016, when three 275 kilovolts (kV) backbone transmission lines were damaged by a major storm event.In addition, power electronic components of PV and wind farms also contribute harmonics to electricity systems as investigated in the “NetzHarmonie” project in Germany [38].

It is noted that the term “high penetration of PV and wind” or “high levels of PV and wind integration” referred in this study means the integration levels of PV and wind that have significant impacts on the system operation and economics. The capability of electricity systems to accommodate intermittent renewable energy sources or the flexibility as defined by the U.S. National Renewable Energy Laboratory (NREL), “the ability of a power system to respond to change in demand and supply” [39], is decided by a wide range of factors, including both technical issues and regulatory framework and thus it varies from case to case.

For example, Soder et al. [40] examined a series of variable renewable energy integration studies from Sweden, Germany, Iberia, Ireland, European Network of Transmission System Operators for Electricity & EDF for Europe and Minnesota, the United States, and summarised that, with 30-40% solar and wind integration, no additional storage will be needed and the requirements for transmission expansions are moderate. Pfenninger & Keirstead [41] demonstrated that there will be no significant cost increase in the Great Britain power systems with up to 60% of variable renewable energy integration (fraction of installed capacity). NREL investigated 33% solar and wind integration in the Western Interconnection (Western Wind and Solar Integration Study, WWSIS) [42] and 30% PV and wind scenarios in the Eastern Interconnection (Eastern Renewable Generation Integration Study, ERGIS) [43] and the modelling outcomes showed the increases of cycling/start costs of thermal units due to intermittent solar and wind energy supply only account for slight proportions (WWSIS $35-157 million, ERGIS $122-400 million), compared with the large fuel cost savings in the systems (WWSIS $7 billion, ERGIS $30-31 billion).

South Australia has the highest variable renewable energy integration in Australia, and one of the highest around the world (only behind Denmark) – about 45% of the state's electricity was generated from rooftop PV and windfarms in 2017. High penetration of PV and wind, along with the shutdown of existing coal-fired power stations (Northern and Playford B), brings significant challenges to the system operation and energy security, including surges of wholesale electricity prices (caused by both technical factors and market manipulation) and a range of system events such as load shedding and islanding occasionally occurred in 2016–17 [35-37, 44]. Consequently, it can be concluded that, roughly speaking, high penetration of solar and wind entails a variable renewable energy integration level usually beyond the order of 50% of total electricity production or so, like South Australia.

In this study, apart from modelling 100% renewables scenarios, a hypothetical 67% renewables scenario (PV 19%, wind 41%, hydro 6%) for the Australian NEM is modelled (Appendix C), which demonstrates meeting Australia's Paris greenhouse commitment at zero net cost if moderate storage and transmission facilities can be built correspondingly.

While high penetration of solar and wind in electricity systems incorporates a wide variety of technical challenges as described in Figure 1-8, the first and foremost is the nature of intermittency in renewable energy production, since capacity/energy adequacy is a prerequisite for energy security and reliability. In Chapter 1.3, a range of possible solutions to the key issue, intermittency, are discussed which forms the basis for a synergy of electricity generation, storage, transmission and demand technologies in this study to solve intermittency problems. For other technical challenges listed in Figure 1-8, a range of constraints are included in the modelling such as the stability constraint and the mechanisms of reserve margins, which as discussed in Chapter 2.2.4.

For high-voltage transmission network, a national HVDC backbone (Figure 1-11) connecting the various states can be constructed on top of the existing 132-500 kV transmission lines in the NEM and its costs are included in the study. Upgrades of distribution network and the applications of Smart Grid devices in the systems are beyond the scope of this study.

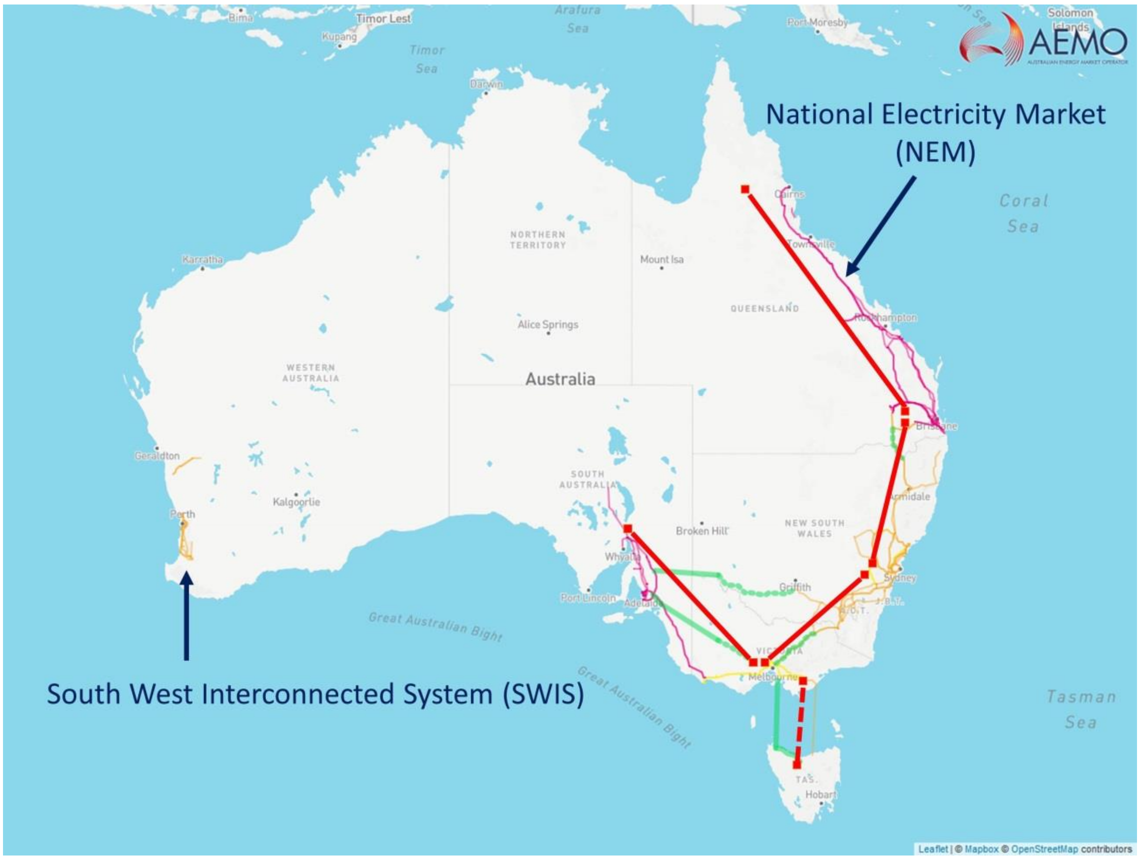


Figure 1-11 A hypothetical HVDC backbone (red lines) connecting Queensland, New South Wales, Victoria, South Australia and Tasmania lies on top of existing high-voltage transmission lines: 500 kV (yellow), 330 kV (brown) and 275 kV (pink). Image source: Australian Energy Market Operator [*http://www.aemo.com.au/aemo/apps/visualisations/map.html*](http://www.aemo.com.au/aemo/apps/visualisations/map.html)

Limitations of this study are further discussed in Chapter 2.7.

1.3 Possible solutions to the key issue: Intermittency

Possible solutions to the intermittency effects of solar and wind energy in renewable electricity systems include:

- Flexible renewable energy sources including hydropower, bioenergy and geothermal energy;
- Wide geographical dispersion of PV and wind i.e. electricity grids interconnection over large areas (tens to hundreds of millions of hectares – energy geo-shifting);

- Large-scale energy storage (energy time-shifting) e.g. pumped hydro energy storage, high-temperature thermal energy storage, lithium-ion battery, compressed air energy storage, hydrogen and synthetic natural gas;
- Demand response such as load shifting and shedding i.e. flexibility from demand-side participation;
- Other mitigation/amelioration measures such as regulation of solar and wind energy production during times of stress.

Apart from energy geo-shifting (grid interconnection) and time-shifting (energy storage and demand response), the “sector-shifting” of renewable energy also provides a promising approach to solving the intermittency problem, which adds significant demand flexibility to energy system. Excess energy from solar and wind can be utilised to charge electric vehicles, to heat up hot water tanks and to produce synthetic fuels via power-to-hydrogen/gas/liquid for aviation, shipping, heavy-duty road vehicles as well as industrial feedstocks. Energy and power deficiency due to low availability of renewable energy during critical periods can be effectively mitigated through demand response enabled by distributed energy storage in electric vehicles, residential and commercial batteries, hot water tanks with Smart Grid. Modelling of integration of electric vehicles and electric heating is introduced in Chapter 2.6 and Chapter 4.1.

1.3.1 Flexible renewable energy sources

In existing power systems, the flexibility, or “the ability of a power system to respond to change in demand and supply” [39], is obtained through the strategic dispatch of base load (e.g. coal, nuclear), load following and peaking (e.g. natural gas, hydropower and diesel) generating units. By contrast, in future renewable energy systems where fossil fuels will be incrementally phased out [45], the flexible energy sources can only be from hydropower, bioenergy and geothermal energy all of which are subject to resource availability and accessibility. Other renewables, including concentrating solar power, wave and tidal energy [16] are also intermittent energy sources (non-dispatchable or semi-dispatchable) like PV and wind, unless coupled with energy storage (large-scale energy storage is introduced in Chapter 1.3.4).

1.3.1.1 Hydropower

Hydroelectric power, including storage, run-of-river and a special type, pumped hydro, had a global installation of 1,096 GW by the end of 2016, serving 4,102 TWh, approximately 16.6% of the world's electricity demand in 2016 [4].

Figure 1-12 shows the top 10 countries with largest hydroelectricity production in 2015 [1], which altogether constituted more than 70% of the global hydroelectricity generation. In comparison, hydroelectricity in Australia represented 18 TWh, 7% of the total electricity generation in 2016 [5], mainly from the Snowy Mountains scheme and Tasmania, an island state with the majority of electricity generation from hydro resources, which are also included in Figure 1-12.

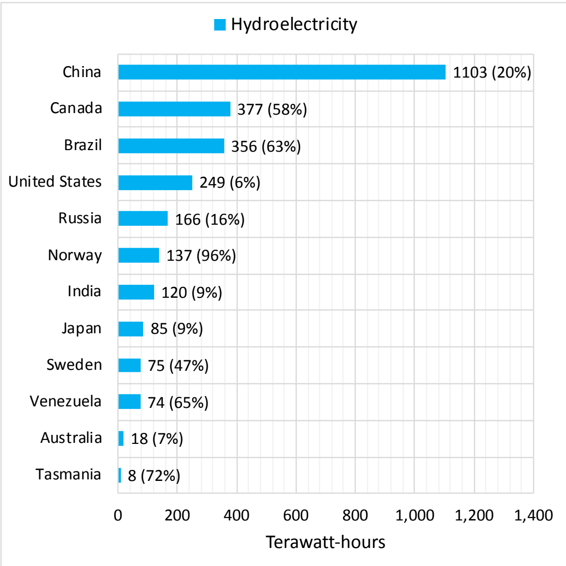


Figure 1-12 Top 10 countries with largest hydroelectricity productions in 2015. Data source: U.S. Energy Information Administration [1].

As a synchronous, fast-response power generation technology, hydropower can play a critical role in energy balancing and security in electricity systems with high shares of inflexible energy sources such as solar, wind and nuclear. Mason et al. [46] modelled a hypothetical 100% renewable electricity system in New Zealand, where the current coal and natural gas (accounting for 32% of the total electricity production) were replaced with wind (19%, energy) and geothermal (24%, energy). By the help of existing hydropower (5 GW), the capacity credits of wind, which are the fossil fuels capacity replaced minus the renewable backup capacity required and then divided by the added wind capacity, can be as high as 85% (without load shifting) and 105% (with load shifting). Krajacic et al. [47] demonstrated that, Portugal, another hydro resource-abundant nation, can achieve 100% renewable electricity with 36% of energy from variable renewable energy sources (wind 24%, solar 12%) even without any interconnections with Spain, which is supported by expansions of hydropower (storage: 2287 MW to 6289 MW, run-of-river: 2660 MW to 3454 MW).

However, in many parts of the world, hydro energy resources are extremely limited such as in mainland Australia [48], and opportunities for further developments of large-scale river-based hydroelectric projects in these regions are restricted. In fact, Gernaat et al. [49] undertook a comprehensive assessment of hydropower potential on a global scale using 15 x 15 arcsecs discharge maps and 3 x 3 arcsecs digital elevation models with a search interval of 25 km along the rivers. It concluded that, with economic considerations and ecological restrictions, the global remaining potential of hydropower (river, diversion canal) is 3.3 PWh which is similar to the current installations (3.4 PWh) and is further subject to the constraints of social acceptance, inland shipping etc. Indeed, during the last decades, developments of large-scale hydroelectric schemes are usually associated with a wide variety of environmental concerns, including environmental impacts on biodiversity, nutrient flows and landscape destruction and social impacts such as re-location of local residents [49, 50]. Besides the resource limits, hydroelectricity is also constrained by the availability of river flows, which competes with agricultural water consumption and ecological considerations, and consequently also has a nature of intermittency especially in run-of-river hydropower.

In this study, only the legacy hydropower assets (7.4 GW) in Australia are included and the hydroelectricity, together with bioenergy, are limited to contribute a maximum of 10% of the total electricity generation based on the historical energy productions from hydropower ranging from 12-18 TWh p.a. since 2000 [48]. This is in line with the Australian Energy Resource Assessment for hydropower which noted “hydroelectricity generation is projected to remain broadly unchanged in Australia due to the limited availability of suitable locations for the expansion of capacity and water supply constraints” [48].

Nevertheless, while developments of conventional river-based hydropower including pumped hydro energy storage (PHES) are constrained as described above, short-term off river energy storage (STORES), which refers to closed-loop PHES systems located away from rivers and thus has little environmental impacts, offers vast opportunities to access cost-effective mass energy storage, which is the focus of this study. Differences between conventional hydroelectric power and STORES in this study are explained in Section 2.2 of Appendix D Geographic information system (GIS) algorithms.

1.3.1.2 Bioenergy

Bioenergy comprises the utilisation of organic matters derived from plants and animals for:

- Heating by direct burning;
- Electricity generation including biomass-fired power or combined heat and power, co-firing in coal-fired power, and biogas by anaerobic digestion;
- Transport fuels (biofuels) such as bio-ethanol, biodiesel produced in chemical conversion processes (bio-chemically).

In addition, biomass can be used as a carbon source in productions of renewable electrofuels such as methanol, dimethyl ether and methane through gasification (thermal-chemically) and hydrogenation, which allows more efficient use of bioenergy [7].

Bioenergy can be a CO_2-neutral energy source that absorbs the carbon emissions during its energy conversion through the photosynthesis process. However, biomass harvesting is often neither sustainable nor carbon neutral, and the burning/combustion of biomass and biofuels contributes to significant local air pollution [51] and increased ozone-related health risk [52]. Photosynthesis has an energy conversion efficiency of only 1% (solar irradiance to energy content of biomass) while by contract, photovoltaic is typically 18% in conversion of solar irradiance to electricity [53]. This means that only one-eightieth of land area would be needed to capture the same energy from the Sun in a photovoltaic system compared with biomass. In addition, electric motor is far more efficient than combustion of biofuels for motion (electric vehicles) or for heating (heat pump).

In 2016, bioenergy accounted for approximately 13% of the world's final energy consumption. The vast majority was used for direct heating and only 0.4% for electricity generation and 0.9% for transport biofuels [4]. In some European countries, electricity generation from bioenergy represents a large share of the generation mix, such as in Finland (14%), Sweden (9%) and Germany (6%) while in Brazil, biofuels constituted 20% of transport fuels in 2010 [48].

However, while some report that there is a large potential for bioenergy utilisation in future energy systems including conversions into liquid fuels and synthetic natural gas, the projections for bioenergy-based electricity generation in the next decades are moderate due to the following issues [54]:

- Competition of land use with food, animal feed and materials markets;

- Land degradation i.e. impact of removal of nutrients in soil, which can damage soil structure and moisture retention;
- Environmental considerations e.g. deforestation;
- Availability of bioenergy feedstocks including agricultural residues, wood, organic wastes (e.g. manure) and energy crops, which are subject to changes in production;
- High capital cost, feedstock and logistical costs.

For example, the International Energy Agency [55] estimated an average annual growth rate of 6% in electricity production by bioenergy from 2010-2035, which is in accordance with the historical figure, averaged 7.5% during the last decade, as shown in Figure 1-1. In Australia, although the Australian Energy Resource Assessment [48] had an optimistic estimate for electricity generation from bioenergy: beyond 10 TWh p.a. by 2020, in fact, by the end of 2016, bioenergy only contributed about 2% of electricity (4 TWh) including biomass-fired (sugar cane waste, wood etc.) and biogas-fuelled (landfill gas and other products) power generation.

In this study, like hydropower, only the legacy bioenergy assets in the NEM are included without consideration of any further expansion. It is noted that, if expansion of existing bioenergy electricity generation were considered in the NEM modelling, the LCOE are more likely to decrease because of the advantage that it provides more flexibility to the electricity system and hence decrease the requirements for large-scale energy storage and interstate HVDC transmission.

By contrast, for the SWIS study, biogas-fuelled OCGTs are assumed to provide the residual 10% of energy in the 100% renewables scenario (90% from PV, wind and PHES). The logic of this assumption is by using biogas, which have a high fuel price ($12/gigajoules [56], to estimate the cost for the remaining 10% of energy establishes an upper bound on the LCOE avoiding underestimate of the costs of 90-100% renewable electricity systems. Modelling input and assumptions in the NEM and SWIS studies are further detailed in Chapter 2.2.

1.3.1.3 Geothermal

Geothermal energy refers to the heat from the earth's crust that can be utilised for: (a) direct heating e.g. in industrial process, (b) ground-source heat pumps as a heat source or sink, and (c) electricity generation (medium- and high-temperature > 100 °C) [57, 58].

Conventional geothermal resources are convective hydrothermal systems which are usually located in the regions with active volcanoes such as the West Coast of the United States, New Zealand and Indonesia i.e. the “Ring of Fire”. By contrast, unconventional geothermal systems entail: (a) hot sedimentary aquifer (HSA) and (b) engineered geothermal system (EGS), which involves permeability enhancement by engineering fracture system to exploit the heat within basement rocks.

Geothermal energy technologies for electricity generation include direct dry steam (> 235 °C), flash steam (150-300 °C), binary cycle (100-180 °C) and combined-cycle or hybrid, with flash steam being the most popular form of technology [48, 57]. Geothermal energy features a very high capacity factor (> 80%) [57], which means it can be operated as an alternative base load energy source substituting for existing coal and nuclear power with low GHG emissions. At the end of 2016, the global installed capacity of geothermal power was 13 GW (USA 2.5 GW, New Zealand 1 GW) which contributed 81 TWh, approximately 0.3% of the total electricity generation to the world’s energy markets. To date, the largest geothermal power field in the world is The Geysers located in California, the United States, which has a rated power of 750 MW (direct dry steam) [48].

According to the Geothermal Energy Association [59], the “Potential Capacity Additions of Plants with Announced Completion Dates” is 18 GW by 2021 while the “Announced Country Geothermal Development Goals 2030” are only slightly beyond 20 GW in total - far less than those of solar and wind, which have already been deployed on a large scale and had a rapid growth rate as described in Figure 1-1. Conservative outlook for electricity generation from geothermal energy, are mainly due to the issues related with resource availability and accessibility, technology maturity and cost/financing [60].

In this study, geothermal energy for electricity generation is not included because,

- No active volcanoes and rifting exist on the Australian continent.
- High-temperature geothermal resources, though believed to be considerable, are located in Great Artesian Basin (northeast of South Australia, southwest of Queensland), which are remote from existing transmission and distribution network. Figure 1-13 shows the predicted temperature at 5 km depth in Australia.
- Unconventional geothermal systems, including HSA and EGS, are still at early research and development stages which entails high capital costs (for power plant and drilling). For example, in [56, 61], the capital costs of geothermal power are: HSA $5,230-

7,232/kW, EGS $7,920-10,815/kW while the levelised costs of electricity for the system are: HSA $100-200/MWh, EGS$150-300/MWh.

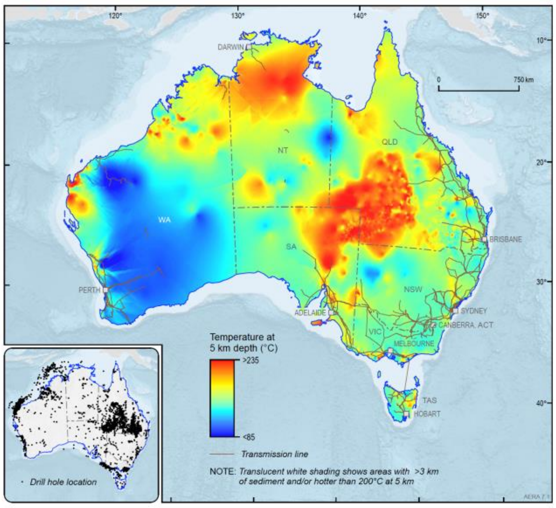


Figure 1-13 Predicted temperature at 5 km depth in Australia. Image source: Australian Energy Resource Assessment [48].

A recent cost estimate from Graham et al. [62] indicated that the capital cost of enhanced geothermal in Australia is as high as $14,000/kW in 2018-19, compared with low cost PV and wind energy: $1,000-1,500/kW. Also noted by Graham et al.: *"For technologies such as wave, tidal, enhanced geothermal and biomass with CCS the prospects for significant adoption in the next ten years is poor."*

It appears difficult for geothermal energy to make a major contribution since geothermal energy only constitutes 0.025% of the annual energy flows (averaged 30 TW) in the earth-atmosphere system while by contrast, more than 99% (average 172,500 TW with reflection 50,000 TW) come from the sun and stored in the forms of solar, wind, hydropower and bioenergy [16].

1.3.2 Geographic dispersion of solar and wind (grid interconnection)

1.3.2.1 Correlations of solar and wind resources

Unlike energy storage facilities which conduct energy time-shifting, geographic dispersion of solar and wind allows utilisation of less-correlated or even anti-correlated weather systems within different regions and hence deceases the fluctuations of solar and wind energy supply [63] i.e. geo-shifting of renewable energy.

Figure 1-9 (a, b) demonstrates a “smoothing” effect (the black curve) on wind energy output by aggregation of all the existing operated windfarms in Australia. Similarly, Figure 1-9 (c) shows the mitigation of intermittency in solar energy by the sum of the existing utility-scale solar farms located within New South Wales, compared with the outputs from individual solar farms. Further, Figure 1-14, which is produced by applying the “correlation” function of Microsoft Excel to the hourly solar and wind traces from the AEMO, shows the correlations between solar and wind resources in each state/territory of Australia (except the Northern Territory). A correlation coefficient of 1 indicates a perfect positive correlation and -1 indicates a perfect negative correlation. By contrast, low correlation coefficients (around zero) mean weak correlations between solar and wind resources while the negative numbers denote negative correlations i.e. anti-correlation. It demonstrates that, in most months of the year, solar and wind resources are negatively correlated in Queensland, New South Wales, Victoria and South Australia especially in summer (October-March) while in Tasmania and Western Australia, the correlation coefficients are less than 0.1 from April to December, which indicate a weak correlation between wind and solar resources in Australia.

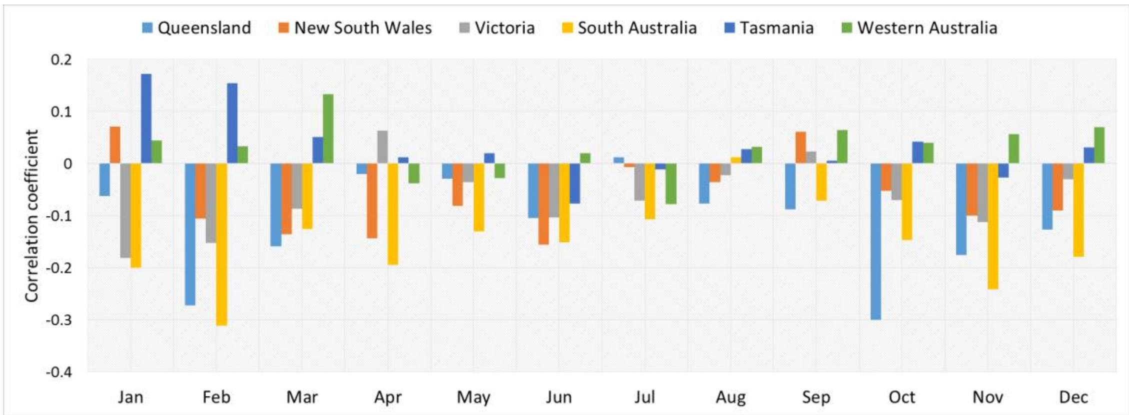


Figure 1-14 Correlations between solar and wind resources in each state/territory of Australia (except Northern Territory). Low correlation coefficients indicate a weak correlation between solar and wind resources. Data source: Australian Energy Market Operator [56].

It is noted that the “smoothing” effect is also shown in the aggregated electricity consumption throughout the NEM as Figure 1-15 demonstrates: the average 5-minute ramp rates of electricity demand in the NEM range from 0.63% (Queensland)-1.38% (South Australia) while that of the total NEM is only 0.48%, less than any individual states/electricity markets.

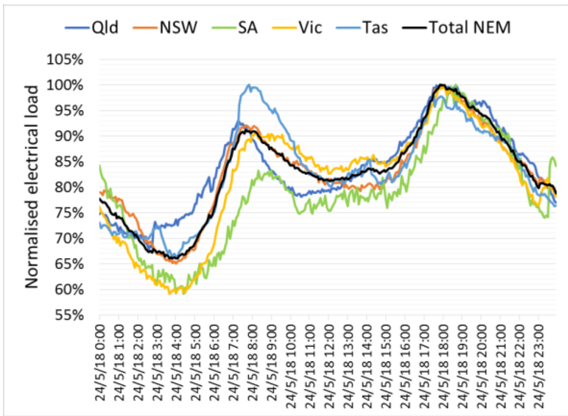


Figure 1-15 Electrical loads. 5-minute electrical loads in the National Electricity Market on 24 May 2018. A "smoothing" effect is shown in the aggregated electricity consumption (black). Data source: Australian Energy Market Operator [64].

1.3.2.2 Supergrids

A "Global Energy Interconnection" concept is developed by the State Grid Corporation of China, which entails balancing energy supply and demand on a global scale i.e. by utilisation of different time zones from east to west and seasonal climate differences between the Northern and Southern Hemispheres (Global Energy Interconnection = Ultra-HVDC & AC + Smart Grid + renewables) [65]. As a first step, the International Council on Large Electric Systems (CIGRE) is conducting an analysis of inter-regional/continental power flows amongst the defined 13 clusters: North America, South America, Australasia, East Asia, South East Asia, Central Asia, South Asia, West Asia, Europe, Russia, North Africa and Sub-Saharan Africa [66].

Following the 100% wind, water and sunlight (WWS) study for the world, Jacobson et al. [67] modelled large-scale interconnected energy systems by grouping 139 countries into 20 regions based on their geographic locations as well as geopolitics. Multiple scenarios were simulated including: (a) Business-as-usual (BAU) 2050; (b) 100% WWS Case A: using CSP, battery and low-temperature thermal energy storage; (c) 100% WWS Case B: CSP and expanded hydropower; (d) 100% WWS Case C: using CSP and battery as storage medium with integration of electric heat pump. It concluded that by transition of energy systems to 100% WWS, the overall energy consumption will be halved and the social cost of 100% WWS (incorporating health effects and climate change) is only a quarter of BAU 2050's. Australia was modelled as an individual region without intercontinental connections with neighbours e.g. Southeast Asia. The social cost of energy in Australia is US$87.3-164/MWh (All-energy in 100% WWS Case A) compared with the global average US$80.1-142.9/MWh and BAU 2050 US$209-817/MWh.

Likewise, the “e-Highway 2050” project undertakes a cost-benefit analysis of future high-voltage electricity grid expansions in Europe (cost €10-20 billion p.a. versus benefit €14-55 billion p.a.) to achieve the European GHG emissions reduction target: 80-95% in 2050. Several important transmission corridors were commonly highlighted in different scenarios (large-scale RES, 100% RES, big & market, fossil (carbon capture and storage) & nuclear, small & local) such as North Sweden - Germany, UK -Southwest France and the Italy Peninsula [68].

By contrast, Fraunhofer [69] conducted a comprehensive AC power flows analysis (steady and dynamic N-1 redundancy) of the Europe and North Africa Supergrid, which introduced a meshed overlay of ±800 kV VSC-HVDC network connecting Europe with abundant solar and wind resources in North Africa. The study showed that, by deployment of PV, wind and concentrating solar power (CSP) coupled with thermal energy storage (TES) in Morocco, Algeria, Tunisia, Libya and Egypt, 90% CO_2 reductions can be achieved in Europe and North Africa and the Super Grid may lead to cost reductions of €3-8/MWh compared with no electricity export to Europe from North Africa.

In other regions of the world, Bogdanov & Breyer [6] investigated the “North-East Asian Super Grid” which includes a series of 100% renewable energy scenarios in 2030 for the 13 sub-regions in China, North & South Korea, Japan and Mongolia. Region-wide, country-wide and area-wide interconnections were modelled respectively, which demonstrated that large extent of grid interconnections (i.e. the area-wide interconnection) decreases LCOE (region-wide: €80.9/MWh, country-wide: €71.5/MWh while area-wide: €69.4/MWh), renewable energy capacity, energy curtailment and storage requirements. A similar conclusion was obtained from other LUT studies for: (a) Americas: region-wide €59/MWh, country-wide €53.8/MWh, area-wide €50.7/MWh, Integrated €48.8/MWh; (b) Europe, Euroasia and MENA: region-wide €56/MWh, area-wide €51/MWh, Integrated €50/MWh and; (c) Asia-Pacific: region-wide €66.3/MWh, area-wide €61.1/MWh, Integrated €52.9/MWh. In addition, the LCOE can be further reduced by €3-8/MWh with integration of desalination and non-energetic industrial gas into the energy systems, as the numbers listed above for “Integrated”. It was found by the authors that there is only a negligible effect on the LCOE by interconnection of North and South Americas as a whole - reduced from €51.4/MWh to €50.7/MWh [70].

The “Asia-Pacific Super Grid” is studied by Blakers et al. [71], where a conceptual HVDC backbone was envisaged to connect the populous Southeast Asia (600 million population) with the desert regions of Australia (northwest, solar) and China (north, wind). Indonesia, Singapore, Malaysia and Timor-Leste, the southern half of the Asia-Pacific Super Grid, are supposed to be powered supported by indigenous solar (1/3), conventional energy sources (1/3) and importantly, the world-class solar resources in the North West Australia (1/3) in 2050, which involves a 500 km submarine cable across the Timor Trench (2,000 km depth).

In America, NREL is examining the benefits of integrating the Western and Eastern Interconnections of North America by expansions of existing back-to-back HVDC infrastructure to high levels of grid interconnection i.e. the Interconnection Seam study. Additionally, a series of high renewables scenarios for in the United States, Canada, and Mexico are investigated by considering the Eastern, Western, Quebec, Texas and Mexico interconnections as a whole i.e. the North American Renewable Integration Study (NARIS) [72].

In fact, as will be shown in Chapter 2.3, according to the NEM modelling, with extensions of HVDC links to Far North Queensland (1,500 km to Brisbane, across 10 degrees of latitude) and South Australia (1,000 km to eastern coasts, across 12 degrees of longitude), the system LCOE reduce by $2/MWh as detailed in Table 3 of Appendix A.

1.3.2.3 High-voltage direct current transmission

Developments of HVDC and Ultra-HVDC (e.g. ±800 kV, ±1100 kV) transmission technology enable delivery of GW-scale electric power over thousands of kilometres of distance with relatively low unit cost and much less transmission loss (3% per 1,000 km or so [73]). Figure 1-16 shows, the typical cost ($m)-distance (km) curves of HVDC transmission (±800 kV LCC-HVDC) compared with conventional HVAC technology (500 kV), which demonstrates that for long-distance (in the range of 500-1,000 km or more), bulk electricity transmission (multiple GW), HVDC is a more economical alternative to HVAC that involves high reactive power consumption. A dashed curve on Figure 1-16 illustrates the variation of HVDC costs by increasing the cost assumption for HVDC converter stations by 50%, which demonstrates a crossover distance of 500 to 1,000 km.

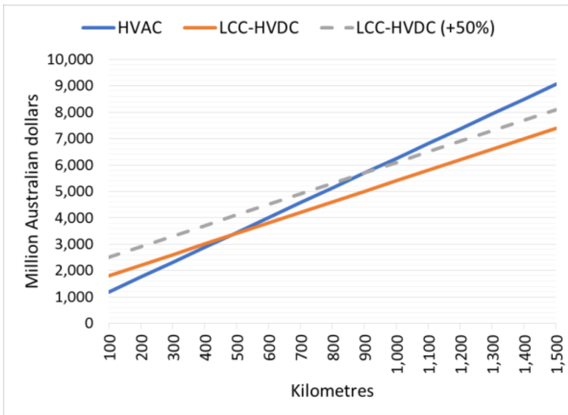


Figure 1-16 Costs of LCC-HVDC (±800 kV) and HVAC (500 kV) to transfer 10 GW of power as a function of transmission distance. For long-distance bulk electricity transmission, HVDC is a more economical alternative to HVAC. Data source: Australian Energy Market Operator [56]; Australian National University [71].

Basically, there are two types of HVDC technology:

- Voltage-source converters (VSC)-HVDC: Insulated-gate bipolar transistor (IGBT)-based, turning on/off by gate voltage V_G;
- Line-commutated converters (LCC)-HVDC: thyristor-based, which is turned on by gate current I_G and turned off by reversing voltage/current.

Attractively, VSC-HVDC (flexible HVDC technology) is capable of providing active and reactive power independently and also black start service and hence is widely applicable to electricity grid interconnections. For example, the North Sea Link between Norway and the UK, the world's longest submarine HVDC cable which will be commissioned in 2021, connects the Norwegian and British electricity grids using VSC technology (Power rating: 1.4 GW, DC voltage: ±525 kV, length of DC cables: 730 km). Nevertheless, due to the current limits of IGBT components, the maximum transmission capacity of VSC-HVDC is limited: only 1.8 GW at DC ± 500 kV (Skagerrak4) to date [74].

By contrast, the thyrister-based LCC-HVDC technology is capable of up to 12 GW (e.g. Changji-Guquan UHVDC link) power transfer (no reactive power provided though) and is usually used for bulk power transmission over long distances from remote renewable energy resources to load centres that are located thousands of kilometres away. For example, the Xiangjiaba – Shanghai ±800 kV UHVDC in China transfers hydroelectricity over a distance of 2,000 km with a rated power capacity of 6.4 GW and the North-East Agra ±800 kV UHVDC in India even connects 3 terminals located 1,700 km away, with a rated power capacity of 6 GW [74]. A brief comparison between the VSC-HVDC and LCC-HVDC technologies is included in Table 1-1.

Table 1-1 A brief comparison of HVDC technologies: VSC-HVDC and LCC-HVDC. Data source: ABB Group [74].

	VSC-HVDC	LCC-HVDC
Features	▪ IGBT (transistors) 6-pulse connection ▪ DC voltage polarity not changing	▪ Thyristors 12-pulse (harmonic filtering) ▪ DC current direction not changing
Characteristics /advantages	More flexible: ▪ Multi-terminals (maximum 5 to date) ▪ Independent active and reactive powers control ▪ Black start	More powerful: ▪ Ultra-HVDV ±800 kV (6.4 GW), ±1100 kV (10 GW) ▪ Less converter loss 0.5-1.0 %
Applications	Electricity grids interconnection ▪ Borwin, Germany (400 MW, 200 km) ▪ Troll A, Norway (88 MW, 65 km) ▪ Murraylink, Australia (220 MW, 360 km) ▪ Ireland-Wales Interconnection (± 200 kV, 500 MW, 260 km)	Bulk power transmission over long distances ▪ Xiangjiaba – Shanghai ± 800 kV UHVDC, China (6.4 GW, 2000 km) ▪ North-East Agra ± 800 kV UHVDC, India (6 GW, 1700 km, 3 terminals)

At the end of 2017, Australia had 3 small HVDC links in operation:

- Basslink (Vic-Tas): monopole 400 kV LCC-HVDC, 480 MW (short-term dynamic 600 MW), 295 km submarine cables
- Murraylink (SA-Vic): ± 150 kV VSC-HVDC, 220 MW, 2 x 180 km underground cables
- Directlink (Qld-NSW): ± 80 kV VSC-HVDC, 3 x 60 MW, 6 x 60 km underground cables

1.3.2.4 Limitations

Like PV and wind energy systems, HVDC technology is based on power electronics (inverters DC/AC, rectifiers AC/DC) and hence decouples the AC electricity systems it connects e.g. without sharing of synchronous inertia. While HVDC enables transferring of GW-scale electric power between the interconnected electricity systems, they also share the risk that HVDC transmission failures will lead to sudden and severe capacity/energy inadequacy and even system collapse. According to SGCC [75], the average forced outage rates of HVDC systems (overhead LCC-HVDC) are: (a) less than 2 times per pole p.a. for mono-polar faults and, (b) 0.2 times p.a. for bi-polar faults (losing both of the positive/negative poles at the same time).

In addition, multi-terminal HVDC systems still remain technically challenging, especially for the LCC-HVDC technology where the reversal of power flow is achieved by reversing the polarity of DC voltage, which is more difficult to control than reversing the direction of current like VSC-HVDC or HVAC.

It is noted that PHES system is a natural partner of HVDC transmission. Co-located with HVDC terminals and remote solar and wind resources, PHES can provide AC voltage/current source that is required by the LCC-HVDC converters in the same way as hydropower in the Xiangjiaba (China) and North-East Agra (India) projects and reduce transmission congestion by large-scale day/night shifting of renewable energy.

1.3.3 Demand response

Demand response is the change of electricity consumption pattern in response to: (a) electricity price through time of use, critical peaking pricing etc. and, (b) system events on the basis of economic incentives such as direct load control, interruptible/curtailable service and emergency demand response programs in capacity, energy and ancillary service markets [76]. It differs from involuntary load shedding following unexpected system events such as forced outages of generators or transmission failures.

Demand response involves load reductions during the critical periods when capacity/energy adequacy is strained in electricity systems through load shedding (actually a flexible energy source) or load shifting to other periods (like energy storage facilities). Apart from load shifting and shedding approaches, demand flexibility can also be sourced from: (a) behind-the-meter generation facilities such as diesel generators and, (b) dispatching of behind-the-meter energy storage like battery [77].

In the context of high penetration of intermittent PV and wind energy, demand response can be an effective approach to “correct” the mismatches between renewable energy supply (peaking around noon) and electricity demand (peaking in early morning and late afternoon), which are both volatile. Indeed, similar to flexible energy resources and storage facilities, demand response contributes capacity/energy values to electricity systems, minimising the requirements for expansions of electricity generation and transmission network as well as operating reserves and hence is able to reduce the cost for system operations [78].

In fact, the NEM modelling in this study (detailed in Table 3 of Appendix A) suggests that $2 billion of investment can be avoided in generation, storage and transmission facilities through the shedding of 5% of the maximum peak demand (2 GW) during the most difficult week over the simulated five years.

In the PJM Interconnection (Pennsylvania, New Jersey, Maryland), equivalent to 5% (11 GW) of the max peak demand with a value of $500 million were committed to the electricity markets in 2015/16 through Reliability Pricing Model (capacity market) auctions, bilateral transactions or fixed resource requirement plans, where 2/3 of the capacities were contributed by manufacturing (50%) and residential (14%). According to [79], the average load management performance across the 20 PJM zones were 91-104% during the load management events and 107-153% in the tests (as there were no events in some of the years) between the delivery years of 2009/10 - 2016/17.

Gils [80] conducted an assessment of demand response potentials in Europe, which indicated that average 93 GW (ranging from 61-172 GW) from industry, tertiary and residential sectors, equivalent to 1/3-1/7 (280-620 GW) of minimum and maximum capacities in the European electricity markets can be utilised as demand response sources.

In the Australian electricity markets, an AEMO and ARENA demand response trial [81] provides 200 megawatts of emergency reserves in Victoria, South Australia and New South Wales with a value of $36 million by 2020.

Demand response requires change in the behaviour of electricity customers and must be accompanied by additional investments in Smart Grid technology, which may be significant, to ensure the systems work effectively. In this study, demand response is considered as an auxiliary method to integrate large-scale PV and wind electricity and is only included in the demand management scenarios.

It is noted that in future electricity systems, large-scale integration of electric vehicles, heat pumps and hydrogen electrolysers will provide significant flexibility from demand-side participation, which may further decrease the system costs to a large extent. This will be included in a future study (Chapter 4). Preliminary work in the South Australian study shows that by moving the charging of electric vehicles (which increases demand by 40%) from late afternoon to midday, the levelised cost of electricity will reduce by $1/MWh and South Australia energy spillage would be halved.

1.3.4 Large-scale energy storage

Electricity cannot be useful stored by itself. Instead, it needs to be converted into other forms of energy rather than electricity for storage including:

- Power-to-Gravitational potential energy of water in pumped hydro energy storage (PHES)
- Power-to-Heat (PtH) including high-temperature thermal energy storage for power generation and low-temperature thermal energy storage for space and water heating/cooling
- Power-to-Chemical energy stored in battery (electrochemically) such as lead-acid, nickel-cadmium, lithium-ion, redox flow and NaS as shown in Table 1-2.
- Power-to-Elastic potential energy of air in compressed air energy storage
- Power-to-Gas (PtG) i.e. Chemical energy in electrolytic hydrogen and renewable electrofuels such as methanol, dimethyl ether and methane
- Power-to-Kinetic energy stored in flywheels
- Power-to-Electromagnetic fields including supercapacitors (electric field) and superconducting magnetic energy storage (magnetic field)

Table 1-2 Characteristics of battery storage technologies [82-84].

Battery technology	Components	Characteristics	Applications	Efficiency, lifetime and capital cost
Lead-acid	▪ Anode: sponge lead ▪ Cathode: lead dioxide ▪ Electrolyte: sulfuric acid	▪ Low self-discharge < 0.1% daily ▪ Performance affected by temperatures ▪ Low energy density 30 Wh/kg	Motor vehicles, UPS	▪ 72% ▪ 5-10 years ▪ US$556-606/kWh
Nickle-Cadmium	▪ Anode: metallic Cadmium ▪ Cathode: Nickel oxide hydroxide ▪ Electrolyte: alkaline KOH	▪ Low maintenance requirements ▪ Costly ▪ Toxicity and memory effect	Sealed cells, industries	▪ 72% ▪ 13-20 years ▪ US$400-2400/kWh
Lithium-ion	▪ Anode: graphite ▪ Cathode: Li-intercalation compound ▪ Electrolyte: Non-aqueous organic liquid	▪ High energy density 80-200 Wh/kg	Portable electronic devices, electric vehicles and stationary	▪ 86% ▪ 10 years ▪ US$385-489/kWh
Redox flow	▪ Anolyte/Catholyte: soluable redox couples ▪ Ion-selective membrane	▪ Uncoupled power and energy capacities ▪ Low energy density 20-35 Wh/kg	Stationary energy storage	▪ 67-70% ▪ 20 years ▪ US$360-819/kWh
NaS	▪ Anode: molten sodium ▪ Cathode: Sulfur ▪ Electrolyte: Beta-alumina (solid)	▪ High-temperature operation 350 °C ▪ High energy density 100-175 Wh/kg	Stationary energy storage, electric vehicles	▪ 75-87% ▪ 10-20 years ▪ 210-450 euros/kWh

In this study, the term "large-scale energy storage" refers to energy storage facilities that are capable of: (a) grid-scale (MW/GWh-scale) energy time-shifting and (b) duration of hours (for day-night shifting) to days (for critical weeks) instead of seconds or minutes, which can be utilised for facilitating large-scale PV and wind integration in electricity systems i.e. peak shaving, load levelling and ancillary services.

In this case, the energy storage technologies that remain at kW-scale or only available for minutes of storage such as flywheels, supercapacitors and superconducting magnetic energy storage are excluded, though they may have other important applications in electricity grids such as helping to meet short-term (seconds) fluctuation in voltage and frequency.

In addition, as the focus of this study is modelling of 100% renewable electricity systems rather than 100% renewable energy (i.e. decarbonisation of all the energy-related sectors such as [7, 85]), only "Power-X-Power" energy storage technologies are considered, where X refers to a storage medium that can convert its stored energy back into electricity. "Power-X-Power" energy storage technologies include PHES, PtH (high-temperature thermal energy storage), batteries, CAES and PtG (hydrogen and synthetic natural gas).

1.3.4.1 A comparison of large-scale energy storage technologies

The main characteristics of energy storage technologies include energy density (gravimetric Wh/kg, volumetric Wh/L), power density (W/kg), lifetime, efficiency and cost etc. as summarised in [83, 84]. However, for grid-scale storage application i.e. large-scale energy time-shifting and balancing, the following aspects of energy storage technologies are investigated:

- Cost, the levelised cost of storage capacity (LCSC), which is detailed in Chapter 1.3.4.2
- Efficiency i.e. the roundtrip efficiency of "Power to storage to Power"
- Technical maturity: research, development, demonstration, deployment and mature technology [48].
- Compatibility with existing electricity systems i.e. whether requiring significant system transformation/reconfiguration
- Resource constraints including geographical (PHES), geological (CAES) and material (e.g. high-temperature thermal energy storage) limits, or no/few constraints like hydrogen, batteries and low-temperature thermal energy storage.

A scoring system (1, 2, 3, 4, 5) is developed as indicators of competitiveness in each category (Table 1-3).

Table 1-3 A scoring system to indicate the competitiveness of large-scale energy storage technologies in each category.

	1	2	3	4	5
Cost (LCSC, $/kW-yr)	> 800	600-800	400-600	200-400	< 200
Efficiency	< 30%	30-50%	50-70%	70-85%	> 85%
Maturity	Research	Development	Demonstration	Deployment	Mature technology
Compatibility (transformation)	Very large	Large	Moderate	Few	No
Resource constraints	Very large	Large	Moderate	Few	No

Based on the scoring system, a comparison of 6 large-scale energy storage technologies is shown in Figure 1-17, where PHES is highlighted as it features lowest cost (Table 1-4), highest technical maturity (Figure 1-17) with second highest round-trip efficiency (80%) amongst 6 large-scale energy storage technologies. In addition, PHES, in particular STORES, has moderate resource limits (as demonstrated in Chapter 3) and does not require significant change of energy system configurations (as studied in Chapter 1).

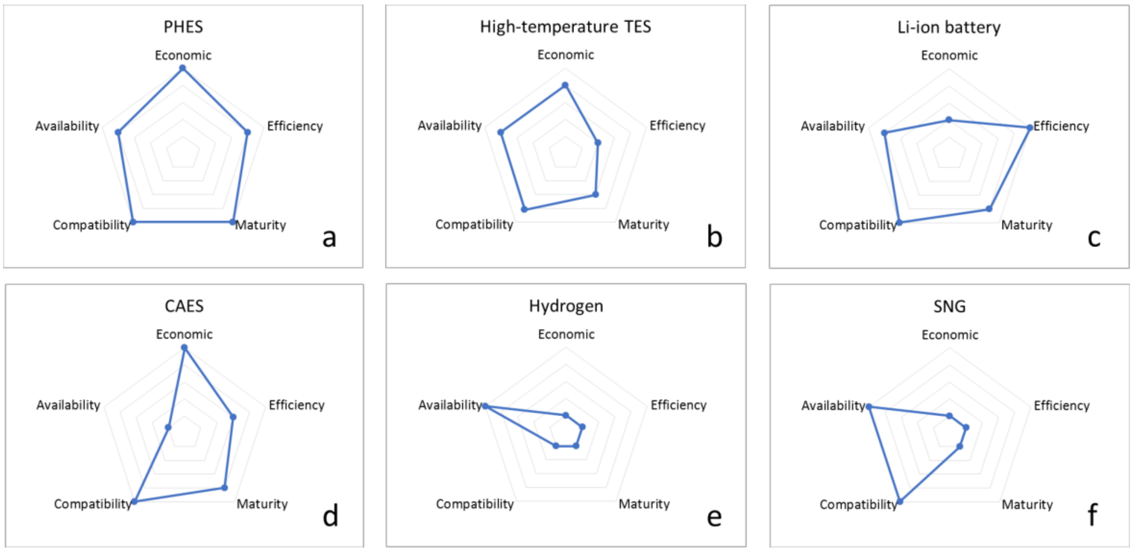


Figure 1-17 Comparisons of cost, efficiency, technical maturity, compatibility and resource availability amongst six large-scale energy storage technologies. Data source: high-temperature TES: National Renewable Energy Laboratory [86], International Renewable Energy Agency [87]; Li-ion battery: Lazard [88], Dunn et al. [82]; CAES: Luo et al. [89], Technical University of Denmark [90]; hydrogen/synthetic natural gas (SNG): International Energy Agency [91, 92], Fraunhofer [93].

Indeed, due to the advantages stated above, PHES constitutes the vast majority of global installations - over 160 GW at the end of 2017 (Figure 1-18). It is noted that the vertical axis of Figure 1-18 is the rated power in terms of GW while if changed to GWh, the storage capacity, pumped hydro accounts for more than 99% of the total.

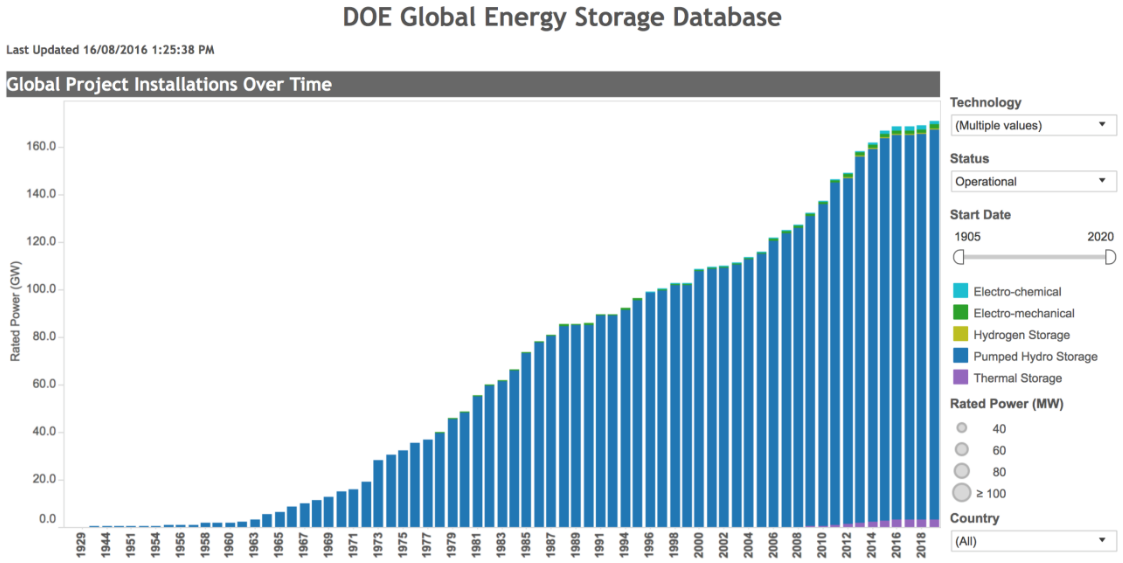


Figure 1-18 Global cumulative installations of large-scale energy storage facilities from 1905-2020. Pumped hydro energy storage (blue) dominates the deployments of energy storage technologies at all time. Image source: U.S. Department of Energy [94].

In this study, PHES is used as a large-scale energy storage to facilitate high penetration of solar and wind energy in the Australian electricity systems, which allows a reliable and stable cost estimate (i.e. a “benchmark”) by utilisation of generation, storage and transmission technologies that have already been deployed on a large scale (> 100 GW worldwide), namely PV, wind, PHES and HVDC & AC transmission.

1.3.4.2 Levelised cost of storage capacity

Economics of energy storage facilities are often measured by:

- Capital cost expressed in terms of $/kW and $/kWh. However, this metric doesn’t include operation and maintenance cost, fuel cost, return on investment and cost of external financing. In addition, efficiency and technical lifetime, which may significantly affect the economical viability of storage facilities, are also not factored into capital cost.
- Levelised cost of electricity for energy storage or levelised cost of storage, which requires assumptions of electricity price (purchase and sale) and operating cycles to calculate the expenditures and revenues from energy arbitrage. These assumptions vary significantly across different electricity markets and are beyond the storage technology itself.

For example, Lazard LCOS 3.0 [88] estimated the levelised cost of storage ($/MWh, translated to $/kW-year) for flow battery, lead-acid and lithium–ion batteries, which included the capital cost, O&M cost, charging cost and taxes. For large-scale storage application ("peaker replacement": 100 MW, 400 MWh), the LCOS were in the range of: US$282-$347/MWh (lithium–ion), US$209-$413 (flow battery) in 2017.

By contrast, in this study, a concept of levelised cost of storage capacity (LCSC) is introduced, which is defined as: the annual cost of building and operating a unit of storage capacity ($/kW-year or $/kWh-year) during the lifetime of a storage facility. LCSC is a measure of cost effectiveness amongst different energy storage technologies, which factors in the life-cycle cost (capital cost, O&M cost), roundtrip efficiency, lifetime and the weighted average cost of capital (WACC) of a storage facility. Assumptions for electricity price and operating cycles can be avoided in the LCSC calculation.

Table 1-4 lists the LCSC of six large-scale energy storage technologies: PHES (head 400 m), high-temperature thermal energy storage, lithium-ion battery, compressed air energy storage (CAES, diabatic), hydrogen and synthetic natural gas (alkaline electrolysis).

Table 1-4 Calculations of the levelised cost of storage capacity (LCSC) for six large-scale energy storage technologies, expressed in terms of $/kW-yr and $/kWh-yr. For comparison, the levelised costs of electricity of the storage facilities (LCOS) are also included, expressed in terms of $/MWh.

	PHES	High-temperature TES	Lithium-ion battery	CAES	Hydrogen	SNG
Capital cost-Power ($/kW)	900	2167	146	552	2470	4550
Capital cost-Energy ($/kWh)	100	0	532	24	10	0
Fixed O&M ($/kW-year)	20	0	14	9	0	0
Variable O&M ($/MWh)	0	0	0	0	0	0
Roundtrip efficiency	0.8	0.39	0.86	0.54	0.29	0.21
Lifetime (years)	50	30	10	35	15	15
Annual CAPEX-Power ($m/yr)	12	35	5	8	59	110
Annual CAPEX-Energy ($m/yr)	11	0	138	3	2	0
Annual OPEX-Fixed ($m/yr)	5	0	4	2	0	0
Annual OPEX-Variable ($m/yr)	0	0	0	0	0	0
Annual electricity cost ($m/yr)	53	107	49	78	145	200
LCOS ($/MWh)	115	203	278	131	295	442
LCSC ($/kWh-yr)	14	18	73	7	31	55
LCSC ($/kW-yr)	113	141	584	55	246	438
Efficiency-weighted LCSC ($/kWh-yr)	18	45	85	13	106	261
Efficiency-weighted LCSC ($/kW-yr)	141	360	679	102	848	2087
Data source	[95]	[96, 97]	[88]	[98, 99]	[100]	[100]

Note. General assumptions: power rating 250 MW, storage capacity 2,000 MWh, discount rate (real) 5%, electricity price (average) $60/MWh, charging/discharging cycles 350 cycles/yr, US dollars to Australian dollars 1.3, Euros to Australian dollars 1.5. Electricity price and charging/discharging cycles are only used in the calculations of LCOS.

In future, apart from time-shifting (energy storage) and geo-shifting (grid interconnection) of renewable energy, energy sector-shifting i.e. PtH, PtG provides a promising way to integrate high levels of solar and wind into other energy sectors such as transportation and heating/cooling, which occupy 14% and 6 % of GHG emissions as shown in Figure 1-4.

Sector-shifting of solar and wind energy forms the basis of 100% renewable energy. For example, Jacobson et al. [51, 85] integrated low-temperature thermal storage including sensible thermal energy storage (STES), Phase-change material (PCM)-ice and underground thermal energy storage (UTES) to establish 100% wind, water and solar systems for the United States and 139 countries of the world. Bogdanov & Breyer [6] modelled 100% renewable energy in North East Asia, South East Asia and Australasia by converting PV and wind electricity into synthetic natural gas. Connolly et al. [7] investigated a possible 100% renewable energy scenario for the European Union using renewable electrofuels such as methanol, dimethyl ether and methane: 50% from biomass hydrogenation and 50% from CO_2 hydrogenation (carbon capture and recycling). A brief summary of the above 100% renewable energy/electricity studies is provided in Chapter 2.2 (Table 2-2).

In addition, batteries in electric vehicles will contribute significant storage capacity and demand flexibility to electricity systems, though it is argued that vehicle-to-grid (V2G) causes degradation of Li-ion battery [101] and thus is not recommended. However, it is also believed that the degradation of lithium-ion battery capacity and power due to extensive charging/discharging operations (e.g. used for frequency regulation) of V2G can be effectively minimised through careful management of vehicle charging i.e. smart charging [102, 103]. Discussions on this topic are included in Chapter 2.6.

1.4 Structure of the thesis

During the last decade, renewable energy, notably solar photovoltaics and wind, has a 50-100 gigawatt-scale annual growth rate in the global energy markets (Chapter 1.1) because of global warming (Chapter 1.1.1), depletion of fossil fuel resources (Chapter 1.1.2), safety, proliferation and waste concerns about nuclear power (Chapter 1.1.3) and declining cost of solar and wind (Chapter 1.1.4). However, high penetration of solar and wind energy into electricity systems bring significant challenges to system security and reliability (Chapter 1.2) due to the characteristics of weather-based photovoltaics and wind electricity generation technologies including intermittency (Chapter 1.2.1), imperfect forecasts (Chapter 1.2.2), distributed energy resources (Chapter 1.2.3) and power electronics interface (Chapter 1.2.4). Possible solutions to the key issue, intermittency, include: flexible renewable energy sources (Chapter 1.3.1), geographic dispersion of solar and wind (Chapter 1.3.2), demand response (Chapter 1.3.3) and large-scale energy storage, where PHES has overwhelming advantages in cost, efficiency, technical maturity, and compatibility with existing electricity systems compared with alternative energy storage technologies (Chapter 1.3.4). Based on the isolated nature of the Australian electricity systems and the fact that flexible energy sources such as hydropower and bioenergy are limited on the Australia continent, in this study, a pumped hydro energy storage-oriented strategy is adopted to model high penetration of solar and wind, which incorporates short-term off-river pumped hydro energy storage, legacy hydropower and bioenergy assets, enhanced interstate high-voltage direct/alternating-current connections and lastly, moderate load management during the most critical periods.

In parallel with the GIS study, costs (levelised costs of electricity/generation/balancing) and benefits (reliability and low-carbon energy) of integration of pumped hydro energy storage in the Australian electricity markets are examined by using energy balance models (Chapter 2). Modelling methodology is introduced in Chapter 2.2, which includes modelling tools (Chapter 2.2.1), calculations of levelised costs of electricity & balancing (Chapter 2.2.2), input datasets (Chapter 2.2.3) and constraints (Chapter 2.2.4). A series of high penetration of solar and wind energy scenarios are modelled including 100% renewable electricity in the Australian National Electricity Market (Chapter 2.3, Appendix A), 90-100% renewable electricity for the South West Interconnected System of Western Australia (Chapter 2.4, Appendix B) and a 67% renewable energy scenario in the National Electricity Market, Meeting Australia's Paris greenhouse commitment at zero net cost (Chapter 2.5, Appendix C). The grid integration studies show that reliable and affordable electricity systems can be built using existing mature renewable energy technologies that have been deployed on a large scale, namely, photovoltaics, wind, pumped hydro energy storage, high-voltage direct/alternating-current transmission, existing hydropower and bioenergy.

A prerequisite for utilising pumped hydro energy storage to support high levels of solar and wind integration is that there are sufficient suitable sites located adjacent to electricity transmission infrastructure or co-located with solar and wind resources. In Chapter 3, Geographic Information System algorithms to locate prospective sites for pumped hydro energy storage (Chapter 3.2, Appendix D) are introduced, which features a sequence of Geographic Information System-based procedures for automatic site searching. A case study for South Australia is conducted to validate the GIS algorithms and finally, a national atlas of pumped hydro energy storage in Australia is developed, which demonstrates that Australia has a large storage potential in the form of 22,000 prospective pumped hydro energy storage sites (Chapter 3.3).

In a future study, integrations of electric vehicles and heat pumps in electricity markets will be modelled, which can be a cost-effective way (electrification) to significantly reduce greenhouse gas emissions in transportation and buildings (Chapter 4.1). Preliminary work on modelling of electric vehicles integration in the Australian National Electricity Market (Chapter 2.6.1), South Australia (Chapter 2.6.2) and Snowy 2.0 + residential batteries (Chapter 2.6.3) shows that the system levelised cost of electricity may further decrease due to the large demand flexibility contributed by electric vehicles and heat pumps (coupled with low-temperature thermal energy storage) with active load management (Chapter 4.1). Moreover, large-scale exports of Australia’s renewable electricity to Southeast Asia will be investigated to facilitate low-carbon or even zero-carbon energy in the Asia-Pacific region, which accounts for nearly half of the global greenhouse gas emissions (Chapter 4.2).

Following the national-scale site surveys for pumped hydro energy storage in Australia, the scope of the Geographic Information System-based study will be broadened to the rest of the world i.e. developing a global atlas of potential sites for pumped hydro energy storage (Chapter 4.3). Mapping of promising regions for pumped hydro energy storage deployments in Europe, North America and the Asia-Pacific region demonstrates a large storage potential, which can play a critical role in transitioning to a 100% renewable energy future.

An illustration of the structure of this thesis is included in Figure 1-19.

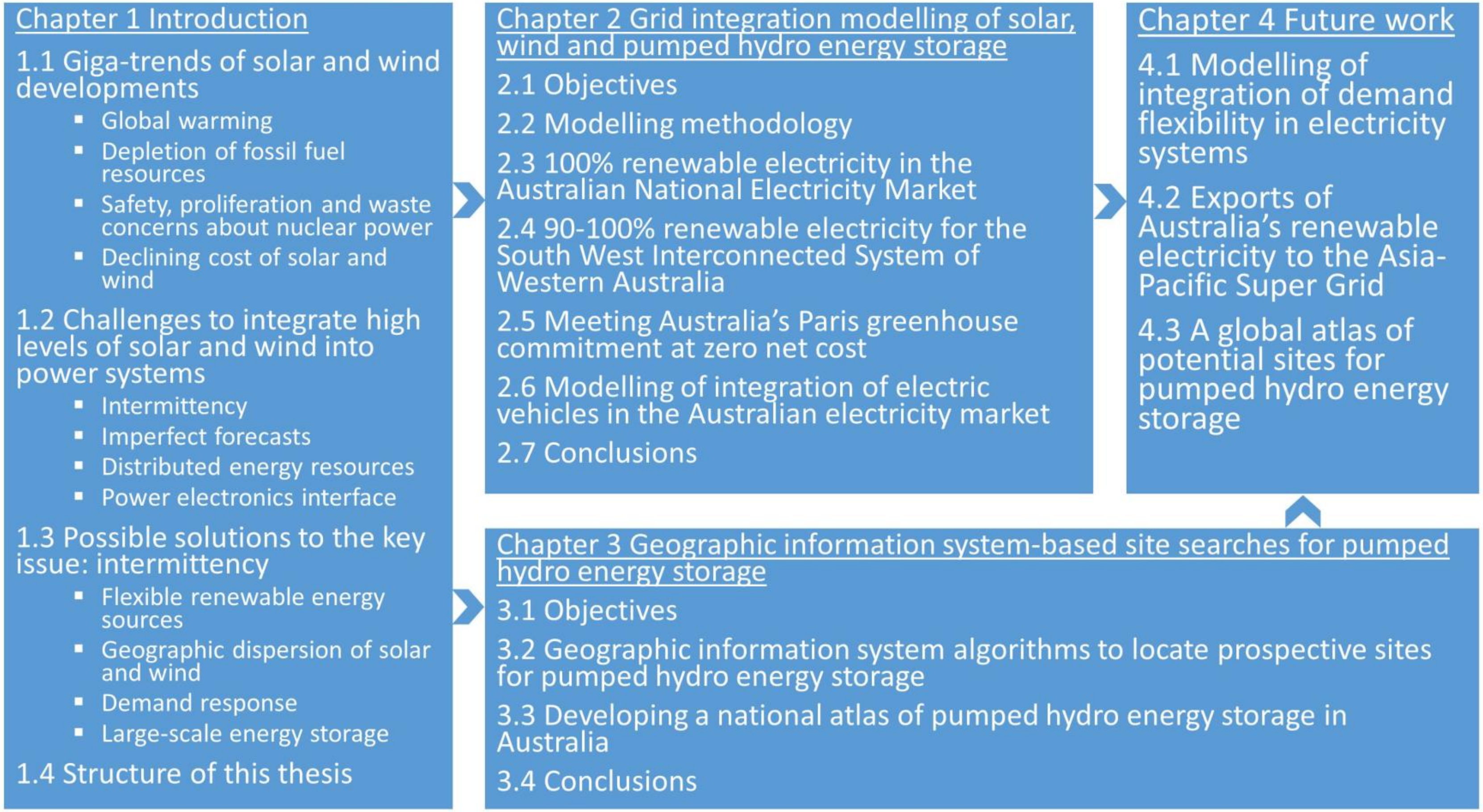


Figure 1-19 Structure of this thesis. Chapter 2 Grid integration modelling and Chapter 3 Geographic information system-based site searches are arranged in parallel.

2 Grid integration modelling of photovoltaics, wind and pumped hydro energy storage

2.1 Objectives

In Chapter 2, a series of 50-100% renewable electricity scenarios are modelled to examine the roles of pumped hydro energy storage in supporting high penetration of intermittent PV and wind energy in the Australian National Electricity Market (NEM) and the South West Interconnected System (SWIS) of Western Australia. Research questions in the grid integration modelling include:

- Can 100% renewable electricity systems be built based on existing mature energy technologies that have been deployed on a large scale (> 100 GW globally) i.e. (a) PV, wind, existing hydropower and bioenergy for power generation, (b) PHES for energy storage and, (c) HVDC & AC for electricity transmission.
- How can a 100% renewable electricity system satisfy current reliability standard by a synergy of flexible renewable energy resources, geographic dispersion of photovoltaics and wind, demand response and importantly, large-scale energy storage. How much energy storage will be needed in a balanced 100% renewable electricity system?
- What are the levelised costs of electricity/generation/balancing (LCOE/LCOG/LCOB) for 50–100% renewable electricity systems in the NEM and the SWIS? Are they competitive with new-build coal/natural gas-fired power plants in Australia or the average electricity price in current wholesale electricity markets?
- What are the least-cost configurations of electricity generation, storage and transmission technologies in Australia’s electricity markets with high levels of PV and wind integration, which highlight the most promising renewable energy zones?

Comparisons of modelling input, assumptions and outcomes in the selected 100% renewable energy/electricity studies for Australia and the world are included in Table 2-2 of Chapter 2.2.

2.2 Modelling methodology

The purpose of this study is to simulate large-scale PV and wind deployment in the Australian National Electricity Market (NEM) and the South West Interconnected System (SWIS) of

Western Australia. Figure 2-1 illustrates the framework and essential components of modelling 100% renewable electricity (RE100 modelling) in the NEM.

The philosophy of the study is to establish an upper bound on the cost of operating a 100% renewable electricity system. To this end only technologies that are in true mass production (> 100 GW worldwide deployment) and have very large potential resources are included. These comprise: (a) PV, wind, existing hydropower and bioenergy for power generation; (b) PHES for energy storage; (c) HVDC & AC for electricity transmission; and (d) moderate load management in energy systems. It is possible to accurately cost these options. As will be shown, the upper-bound cost of balancing a 100% renewable electricity system in Australia is quite low: $25-$28/MWh in the NEM and $37-41/MWh in the SWIS.

Excluded from the study are technologies that currently only have small-scale deployment as shown in Table 2-1. It is difficult to obtain reliable cost estimates for these technologies. If any of these technologies falls sufficiently in price to be competitive then the already-modest cost estimates of this study will be an over-estimate.

Table 2-1 Generation and storage technologies that currently only have small-scale deployment. Data source: International Renewable Energy Agency [3]; U.S. Department of Energy [94] .

Technology	Global deployment at the end of 2017	Constraint in respect of large-scale deployment
Concentrating solar thermal	5 GW	High cost, low technology maturity
Geothermal	13 GW	Resource availability and accessibility are constrained within Australia.
Ocean	< 1 GW	High cost, low technology maturity
Batteries	< 2 GW	High cost for large-scale energy storage
Compressed air energy storage	< 1 GW	Resource availability and accessibility are constrained within Australia.
Hydrogen	< 0.1 GW	High cost, low technology maturity High round-trip losses

The cost of battery is rapidly declining especially the case for lithium-ion battery in electric vehicles due to economies of scale (> 100 GWh worldwide, < US$200/kWh) [104]. Distributed energy storage in electric vehicles and households enables cost-effective demand-side management schemes through smart energy systems, which will be critical to the reliability and security of future energy system. However, for large-scale energy storage, the cost of stationery battery needs to reduce fivefold in order to be competitive with PHES as calculated in Table 1-4 (efficiency-weighted LCSC, $/kWh-yr and $/kW-yr).

This study is to set a benchmark for the cost of 100% renewable electricity and the cost of balancing 100% renewables in the Australian electricity market. Hence, only the energy technology that has a lowest cost of electricity generation, storage and transmission are included in the modelling, namely, PV and wind for power generation, pumped hydro and battery (distributed) for energy storage and high-voltage DC for electricity transmission. In addition, PV, wind, PHES, battery (distributed) and HVDC: (a) are renewable, clean and sustainable; (b) have already been deployed on a large scale (> 100 GW/GWh worldwide) and (c) will not be limited by resource availability and accessibility. Large-scale stationery battery system, which have a high cost and small-scale of global deployment (< 2 GW) is not included in the modelling.

However, stationary battery will be useful in the future energy mix as a transitional solution for large-scale energy storage as demonstrated in South Australia (Tesla lithium-ion battery 100 MW/129 MWh). Stationery battery can be an alternative to PHES in short- to medium-term timeframe in consideration that it can be quickly deployed (within 100 days) for immediate use, but only has a short lifetime (10 years or so). In comparison, deployment of PHES usually requires years of efforts: licensing, engineering design and construction, procurement and installation, while the facility lasts for typically 50-100 years. In addition, location of stationery battery system can be very flexible, which can be located anywhere within transmission and distribution network providing the perfect complement to PHES for large-scale energy storage.

Concentrating solar power is an emerging energy generation technology, which entails utilising solar thermal to generate high-temperature heat and electricity. Coupled with high-temperature thermal energy storage such as molten salt, CSP is capable of supplying 24/7 continuous power to electricity system as a low-carbon substitute for coal and gas.

Nevertheless, the cost of CSP is still very high, in the range of $120-150/MWh [62], while solar PV and wind have already fallen below $60/MWh in Australia at the end of 2018. Large-scale integration of CSP in the National Electricity Market as modelled in [105] (Table 2-2) may result in doubling or tripling ($197/MWh) of the cost of 100% renewables constituted by PV, wind, PHES and high-voltage DC transmission ($75-93/MWh). In addition, CSP has a relatively low technology maturity with only < 10 GW of worldwide deployment at the end of 2018, compared with PV > 400 GW, wind > 500 GW and hydropower > 1,000 GW (Figure 1-1).

PV and wind constituted more than half of net capacity additions globally in 2016-2018 and are very likely to have a significant share of the future Australian energy mix by 2030 [106] like South Australia (50%) today. As a storage medium, high-temperature thermal energy storage has a typical round-trip efficiency (i.e. power-storage-power) of less than 40% - well below the figures for PHES (80%) and lithium-ion battery (90%).

For the above reasons, CSP is not included in the modelling. As noted in [107], *"In future, more sustainable energy options can be integrated in the modelling once their economics and technology status can compete with PV and wind, although this seems to be unlikely in the foreseeable future."*

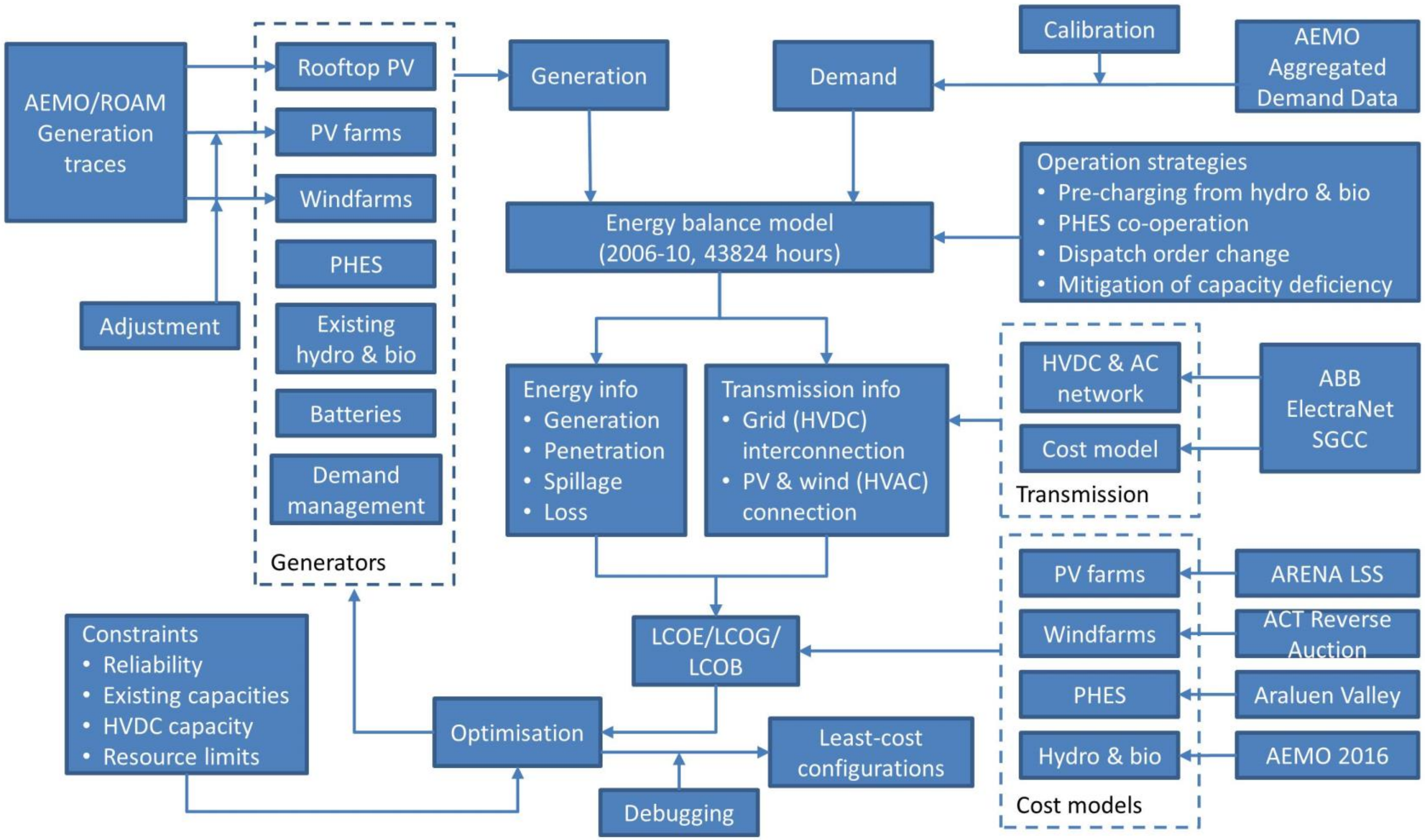


Figure 2-1 A diagram of the integration modelling framework.

The main features of this study are:

- Modelling 100% renewable electricity in Australia, where about 90% of electricity is contributed by PV and wind. This implies a fundamental change in electrical systems as existing coal- and natural gas-fired power plants, which play important roles of balancing and grid stabilisation, are retired. Although the modelling solely focuses on electricity sectors, it is noted that rapid decarbonisation of some other energy-related sectors can be achieved through electrification of land transport (i.e. electric vehicles) and low-temperature heating/cooling of buildings and water heating by electrical resistance and electric heat pumps.
- High-resolution energy balance modelling, which has an hourly temporal resolution (data source described in Chapter 2.2.3) and a spatial resolution of 100-300 km, or at state/territory level for demand profiles.
- Multiple years from 2006 to 2010 are modelled, which is computationally intensive.
- Based on mature generation, storage and transmission technologies to establish a benchmark of the costs for 100% renewable electricity systems, which allows the cost estimates for the generation, storage and transmission facilities to be readily accessible from publicly available and reliable sources with high accuracy.
- A synergy of flexible energy sources, geographic dispersion of PV and wind, demand response and most importantly, large-scale energy storage, STORES. Due to the fact that the NEM and SWIS are large-scale self-contained electricity systems isolated from neighbouring electricity grids, and the flexible energy sources e.g. hydro, bio and geothermal are limited by resource availability and accessibility, STORES is utilised as the primary enabler of 100% renewable electricity. Moderate demand response as mentioned in Chapter 1.3.3 is also included in the demand management scenarios.
- Incorporating system-wide, lifecycle costs (including HVDC & AC, O&M, financing costs) with a focus on the Levelised Cost of Balancing (LCOB). LCOB components include STORES, HVDC & AC, occasional spillage of excess PV and wind energy on sunny and windy days, and energy savings from load management (calculation see Chapter 2.2.2).

Table 2-2 lists the key characteristics and modelling assumptions of this study, compared with selected international and Australian studies on 100% renewable electricity/energy from Stanford University (Stanford), Lappeenranta University of Technology (LUT), Aalborg University (Aalborg), the Australian Energy Market Operator (AEMO), the University of New South Wales (UNSW) and the University of Sydney (Sydney). Chapter 2.2.1 to 2.2.4 provide the details of modelling tools, LCOE/LCOG/LCOB calculations, input datasets and constraints.

Table 2-2 Comparisons of modelling input, assumptions and outcomes in the selected 100% renewable energy/electricity studies for Australia and the world

	Stanford	LUT	Aalborg	AEMO	UNSW	Sydney	ANU
Study region	World (139 countries/20 regions)	World	Europe (EU 28 members)	Australia (NEM)	Australia (NEM)	Australia	Australia (NEM, SWIS)
Energy sectors	Electrifying all energy sectors [a]	Electricity	Electricity, heating/cooling, and transport	Electricity	Electricity	Electricity	Electricity
Resolution (temporal)	30 s (5 years)	Hourly (1 year)	Hourly (1 year)	Hourly (2030, 2050)	Hourly (1 year)	Hourly (1 year)	Hourly (5 years)
Resolution (spatial)	2.5 (W-E) by 2.0 (S-N) degrees	0.45 by 0.45 degrees	Unclear	100 – 300 km	100 – 300 km	38.6 km	100 – 300 km
PV and wind contributions	85%	87%	83%	< 50%	65%-75%	42%	90%
Primary approaches for energy balancing	Demand flexibility and TES	Battery and PtG	PtG	Geothermal, biomass/biogas, CSP + TES	Biogas	CSP + TES	PHES
Flexible renewable energy sources	Hydro (legacy), geothermal	Hydro (legacy), biomass, geothermal	Hydro (legacy), geothermal	Geothermal, biomass/biogas, hydro (legacy)	Biogas, hydro (legacy)	Hydro (legacy), biofuels	Hydro (legacy), biomass (legacy)
Grid interconnection	Additions of LCC-HVDC (onshore) and VSC-HVDC (offshore) costs in LCOE	Regions or countries interconnected by HVDC; HVAC for intra-region/country transmission	No transmission constraints included in the model	HVDC & AC transmission for energy markets interconnection and renewable energy integration	Enhanced energy markets interconnection	Expanded transmission network for renewable energy integration	An overlay of HVDC backbone, HVAC for solar and wind integration
Storage	STES, PCM-ice,	Battery, PtG [b],	Renewable	CSP + TES, PHES	CSP + TES, PHES	CSP + TES	PHES

Table 2-2 Comparisons of modelling input, assumptions and outcomes in the selected 100% renewable energy/electricity studies for Australia and the world

	Stanford	LUT	Aalborg	AEMO	UNSW	Sydney	ANU
	UTES, PHES (legacy), PCM-CSP, hydrogen, battery	PHES (legacy), A-CAES, CSP with TES	electrofuels [c], TES for heating/cooling, EV	(legacy)	(legacy)		
Demand response	Transportation, industry	Not included	Flexible electricity demand and EV	Peak demand reductions and intelligent charging of EV	Not included	Not included	Load shedding (5%, 7 days) in Demand Management scenarios
Grid stabilisation	Not included	Not included	30% from grid-stabilising units	NSP limit 85%	NSP limit 85%	Synchronous CSP	Synchronous PHES
Solar and wind data source	GATOR-GCMOM	NASA	Unclear	Australian Bureau of Meteorology	Australian Bureau of Meteorology	CCAM (CSIRO)	Australian Bureau of Meteorology
Demand data source	Demand 2050 (ENTSO-E, Neocarbon Energy and IEA)	Synthetic load data	Demand 2050 (by hourly distribution)	Probabilistic modelling & Demand 2030, 2050	Historical demand 2010	Historical demand 2014	Historical demand 2006-2010
Modelling tools	LOADMATCH, GATOR-GCMOM	LUT Energy System, REMix	EnergyPLAN (Smart Energy System)	PLEXOS	NEMO	A private “bidding” model	Modified NEMO , SAM
Deterministic or stochastic	Deterministic	Deterministic	Deterministic	Probabilistic	Deterministic	Deterministic	Deterministic
Mathematical optimisation	Not included	Linear programming	Not included	Mixed Integer Programming	CMA Evolution Strategy	Unclear	CMA Evolution Strategy
Cost assumptions (target years)	2050	2015-2050	2050	2030, 2050	2030	2030	2016, 2030

Table 2-2 Comparisons of modelling input, assumptions and outcomes in the selected 100% renewable energy/electricity studies for Australia and the world

	Stanford	LUT	Aalborg	AEMO	UNSW	Sydney	ANU
Discount rate (real, inflation-free)	1-3% (social)	WACC 7%	3%	10%	5%, 10%	4%	5%
LCOE/LCOG/LCOB	LCOE (2050) US$87.3-164 [e]	LCOE (2030) €55 = LCOG €40 + LCOB €15 [e]	€3,200 billion for 16,000 TWh (primary energy)	LCOE: AU$121-134 (2030), AU$122-139 (2050)	LCOE (2030): AU$104-119 (5%), AU$153-173 (10%)	LCOE (2030): AU$197/MWh	LCOE (2030) AU$75 = LCOG AU$50 + LCOB AU$25
Transition paths	WWS: 80% by 2030, 100% by 2050	2015-2050 with an interval of 5 years	9 steps starting from a BAU EU28 reference scenario	Not included	Renewable energy integration 0-100%	Not included	67%, 90% and 100% renewables
References	[51, 67, 85, 101]	[6, 108, 109]	[7, 110, 111]	[56]	[112-115]	[105]	[107, 116]

Note: A summary of features and limitations of the selected studies is included in Table 2-3.

Acronyms and abbreviations: adiabatic-compressed air energy storage (A-CAES), business as usual (BAU), concentrating solar power with thermal energy storage (CSP + TES), demand management (DM), electric vehicles (EV), high-voltage direct current & alternating current (HVDC & AC), levelised cost of electricity/generation/balancing (LCOE/LCOG/LCOB), non-synchronous penetration (NSP), phase-change material (PCM), power-to-gas (PtG), pumped hydro energy storage (PHES), sensible thermal energy storage (STES), underground thermal energy storage (UTES), wind, water and solar (WWS).

[a] Except for long-distance transportation where hydrogen (electrolytic) fuel cells were used.

[b] Synthetic natural gas: hydrogen (electrolytic) + carbon dioxide from air

[c] Including methanol, dimethyl ether and methane: carbon from bioenergy 50%, carbon capture and recycling 50%

[d] Discount rate 8% with a 50% debt

[e] Dollars or Euros per megawatt-hour, figures are for Australia

Table 2-3 A brief summary of the features and limitations of this study and the selected 100% renewables studies.

	Features	Limitations
Stanford	▪ Electrifying all energy sectors including transportation, heating/cooling and industry etc. (except long-distance transportation based on electrolytic hydrogen) ▪ Heating and cooling loads coupled with low-temperature thermal energy storage: STES, PCM-ice, UTES ▪ Significant demand flexibility from transportation sector and high-temperature, chemical and electrical processes	▪ Configurations of electricity generation, storage and transmission facilities are not optimised.
LUT	▪ Power-to-gas: synthetic natural gas produced from hydrogen (electrolysis) and carbon scrubbing ▪ Modelling of region-wide, country-wide and area-wide interconnected energy systems ▪ Battery as a dominant storage technology in the decarbonisation of the global power sector	▪ Power-to-gas has very low round-trip efficiencies typically < 30%.
Aalborg	▪ Renewable electrofuels: methanol, dimethyl ether and mathane ▪ Carbon source: 50% from bioenergy (biomass hydrogenation), 50% from carbon capture and recycling (CO_2 hydrogenation) ▪ 9-step transition from a reference business-as-usual scenario towards 100% renewable energy ("Smart Energy System") in Europe	▪ Mathematical optimisation of energy system configurations is not included. ▪ Constraints of power flow amongst countries/regions are not included.
AEMO	▪ Geothermal and biomass substituting for coal (baseload units) while concentrating solar power and biogas replacing natural gas (peaking) ▪ Load profiles significantly altered by demand-side participation and electric vehicles integration	▪ Penetration of PV and wind < 50% ▪ Geothermal resource located in remote regions of Australia
UNSW	▪ Biogas-fuelled gas turbines for energy balancing - no baseload power is needed ▪ Development of the NEMO model with Genetic Algorithms for mathematical optimisation	▪ Bioenergy availability/sustainability is not investigated.
Sydney	▪ An economic dispatch model based on emulating the bidding process ▪ Large-scale deployment of concentrating solar thermal coupled with high-temperature thermal energy storage ▪ Modelling a "greenfield" electricity network in the Australian continent	▪ Very high LCOE: $197/MWh
ANU	▪ Integration of short-term off-river energy storage (STORES) to support high penetration of PV and wind in electricity systems ▪ Modelling 100% renewable electricity based on existing mature energy technologies that have already been deployed on a large scale (> 100 GW) ▪ Low levelised cost of balancing for 100% renewables: AU$25-28/MWh in the Australian National Electricity Market	▪ Future uptake of electric vehicles and heat pumps in electricity systems is not included. ▪ A simplified demand response model

2.2.1 Modelling tools

A key objective of 100% renewable electricity (RE100) modelling is to derive optimal configurations of generation, storage and transmission technologies; i.e. the least-cost portfolios of PV, wind, PHES and HVDC & AC; while subject to a variety of constraints defined (Chapter 2.2.4). Traditional capacity expansion models such as ReDES (developed by NREL) and CGT-Plan (developed by Iowa State University) produce representative load blocks and a number of typical operational time slices to minimise the costs of dispatch, generation expansion, transmission augmentation and generation retirement. Due to large computational intensity, linear programming or reduced mixed integer programming is usually adopted in mathematical optimisations [117].

By contrast, the production cost models such as PLEXOS (developed by Energy Exemplar) solve the problem of unit commitment and economic dispatch (UCED) in day-ahead and real-time markets, minimising the dispatch cost plus start-up costs [118]. High-resolution (e.g. 5 minutes, 30 minutes, 1 hour), time-sequential data for energy supply and demand are used in the production cost modelling. Mixed integer programming is frequently utilised to solve mathematical optimisation problems in the modelling due to the characteristics of electricity system assets, which are typically binary or discrete integers variables.

For instance, NREL [119] explored 30-90% renewables scenarios for the contiguous United States with 2-year increment from 2010-2050. ReDES was used based on 17 representative time slices: mornings, afternoon, evening, night of 4 seasons plus a load peak in summer. GridView (developed by ABB) was then used to simulate electricity systems on an hourly basis, obtaining insights from the time-sequential modelling. Subsequent studies at NREL use 5-minute in PLEXOS to further investigate the benefits and impacts of renewable energy integration in the West and East of US, as well as the Interconnection Seam and NARIS studies [72]. NREL developed a “Geographic Decomposition” algorithm in the Interconnection Seam and NARIS studies [72], which simulates unit commitments in multiple energy markets of the United States simultaneously and importantly, it is split into 3 stages of modelling ensuring that the computational tractability is maintained.

AEMO uses PLEXOS for Power Systems for its electricity and gas markets outlook modelling such as the National Transmission Network Development Plan [120], on the basis of 12 and 20 load blocks for each month determined from load duration curves, which minimises the net present value sum of production cost, generation and transmission expansion cost, and decommission/retirement cost of legacy assets (remediation, site rehabilitation etc.) In addition, AEMO developed a probabilistic generation expansion model in its 100% Renewable Energy modelling, which simulated hourly time series across random 5,000 days and determined the least-cost mix of generation and transmission assets, which was then validated in a time-sequential model [56].

In general, both the NREL and AEMO modelling includes,

- A capacity expansion model, which optimises the configurations of generation and transmission facilities based on representative load blocks and typical operational time slides.
- A time-sequential production cost model (UCED) to verify/validate the investment portfolios that result from the capacity expansion model.

Nevertheless, this modelling approach cannot be applicable to the RE100 modelling where energy storage constitutes a significant proportion of generation mix, because the time intervals are no longer isolated and the marginal costs of PV, wind, PHES and HVDC & AC are very low (only the O&M, no fuel cost). Due to the nature of intermittency in energy supply, PV and wind contribute energy rather than dispatchable capacity to electricity systems [119]. Energy storage converts energy values of PV and wind into capacity values and hence the storage requirements in electricity systems are determined by: (a) the critical periods with low solar and wind availability (and high demand) in consecutive days or weeks i.e. energy deficiency and, (b) the largest instantaneous gap between energy supply and demand i.e. capacity deficiency. Consequently, the optimal generation, storage and transmission configurations cannot be decided by using representative load blocks or typical operational time slices in the optimisations. Instead, long-term (spanning 5 years or more) time-sequential modelling/data on an hourly or half-hourly basis will be more suitable as recommended by [121].

In this study, a modified version of NEMO (National Electricity Market Optimiser, developed by Dr Ben Elliston) is selected as the simulation tool because:

- NEMO is designed solely for electricity sectors, which is the current focus of this study. By contrast, EnergyPLAN (developed by Aalborg University) involves modelling electricity, heating, cooling, industry and transport sectors as a whole. Deep electrification of land transport, heating & cooling and other energy sectors over the next few decades is considered more likely in Australia than a "mixed mode" energy system due to rapid and sustained reductions in the cost of PV and wind.

- NEMO is a well-structured open source software under the GNU General Public License, which provides flexibility of modification and further extension compared with commercial products such as PLEXOS.
- Historical hourly time series of solar, wind and demand are incorporated in the model, which can better reflect the nature of Intermittency in energy production from of PV and wind. In addition, as noted above, it is more appropriate to model storage facilities on a continuous basis rather than stochastic modelling.
- An Evolution Strategy, the Covariance Matrix Adaptation Evolution Strategy (CMA-ES), is adopted for mathematical optimisation instead of mixed integer programming, which enables fast convergence within 100 runs [114].

Documentation of NEMO is available at https://nemo.ozlabs.org. NEMO has a series of successful applications in RE100 studies such as [112-115].

In this study several adjustments to the NEMO model have been made to better utilise the capability of synchronous, fast- ramping PHES to integrate fluctuating solar and wind energy. This includes a range of operation strategies: (a) pre-charging PHES facilities from existing bio and hydro plants to help ride through critical periods based on advanced weather forecasting; (b) changing the merit order of existing hydro ahead of PHES in critical periods to ensure PHES is not exhausted before the most difficult moments arrive.

This study modelled a generic, cost-effective approach to deep decarbonisation of electricity industry in Australia, i.e. through a synergy of grid interconnection (geo-shifting), energy storage (time-shifting) and demand-side management. The NEMO is utilised to simulate energy balance between renewable energy and electricity demand on an hourly basis, and to figure out the optimal/least-cost configurations of energy generation, storage and transmission technologies using Genetic Algorithms. As noted above, a series of operating strategies are incorporated in the model to fully utilise the advantages of PHES: (a) PHES is capable of large-scale energy time-shifting i.e. translation of variable renewable energy to credible capacity and, (b) PHES can provide a wide range of ancillary services such as frequency regulation and voltage control, which helps to build a reliable and secure 100% renewable electricity in Australia.

Figure 2-2 shows the load profiles and generation mix during the most difficult week in the hypothetical 100% renewables scenario for the NEM, where the energy outputs from PV and wind were only 80% and 62% of the 2006-10 average. During this critical period, the legacy hydropower and bioenergy assets were assumed to be dispatched ahead of PHES to maintain a sufficient amount of energy stored in PHES facilities until the end of the energy deficiency period. In addition to excess PV and wind energy, hydropower and bioenergy were also utilised to charge PHES when they are available. By contrast, the PHES generators are normally dispatched ahead of hydropower and bioenergy and only charged by energy spillage from PV and wind, due to the energy constraints of legacy hydro and bio assets.

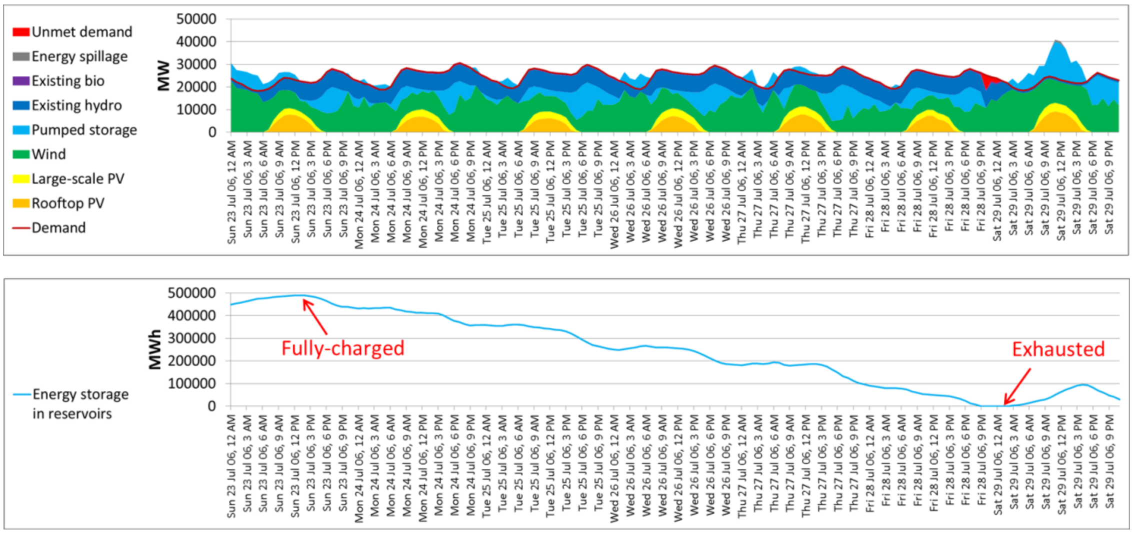


Figure 2-2 Load profiles and generation mix during the most difficult week in the hypothetical 100% renewables scenario for the National Electricity Market. Data source: Australian National University [116].

It is noted that NEMO has several limitations with regard to the modelling capability, including:

- NEMO is a deterministic model, which assumes the forecasting of weather and load is perfect and probabilistic modelling such as Monte-Carlo simulations for forced outages of generating facilities and transmission failure is not incorporated. Reserve margins for unexpected generator outages, contingency or the intermittency of PV and wind energy are discussed in Chapter 2.2.4. By contrast, stochastic processes for PV and wind production, and Monte Carlo simulations for maintenance and forced outages of generators can be modelled in PLEXOS [122].
- NEMO simulates the NEM as a whole i.e. assuming a single, centralised dispatch at a national scale while in reality, the NEM consists of 6 individual electricity markets that are operated separately in Queensland, New South Wales, South Australia, Victoria and Tasmania. However, a central feature of the modelling is a substantial HVDC grid that is built in parallel with the existing interstate transmission system. Essentially the HVDC system is a “copper plate” built in parallel to the existing transmission network,

allowing large-scale flow of energy from one state to another, which reduces the separate state-based markets to a single market.

- Capability of Demand flexibility modelling is limited. NEMO conducts load shedding/shifting in a manner that users define a proportion of load to be shed/shifted during specified intervals. In light of rapid uptakes of electric vehicles and heat pumps in electricity systems, this approach needs to be improved in order to utilise significant amounts of demand flexibility that can be provided by electric vehicles and heat pumps. In Jacobson et al. [101], for example, the LOADMATCH model moves flexible demand in transportation and industry sectors forward to next dispatching intervals in case the instantaneous energy supply is not sufficient. Flexible loads become inflexible once the maximum delaying timeframe (8 h) is reached.

It is also noted that while this study conducts a comprehensive investigation of resource adequacy and least-cost configurations of generation, storage and transmission technologies in 100% renewable electricity systems, it has not covered all the aspects of solar and wind integration such as,

- UCED modelling i.e. simulations of day-ahead and real-time electricity markets to obtain insights on the impacts of intermittency and imperfect forecasting of solar and wind, as well as the significant roles of STORES in energy balancing and grid stabilisation [120].
- A complete AC power flows analysis, which investigates the congestion and contingency modelling of transmission network based on AC flows instead of DC. However, as described above a strong HVDC system is included in the model which could substantially reduce congestion in the existing AC network. In the DC analyses, reactive power (P-Q-S power triangle) is ignored for the sake of simplicity and hence voltage issues have not yet been studied. In [72], NREL undertook a steady-state AC power flow analysis of the US Eastern and Western Interconnections and N-1 contingency modelling by using PSSE (developed by Siemens).
- Grid stability modelling exploring the stability of rotor angle, voltage and frequency following different scales of system disturbances. In particular, the control system stability is critical to system security in the context of large-scale integration of PV, wind and HVDC technologies, which have complex power electronics interface with transmission and distribution network.

2.2.2 Levelised costs of electricity, generation and balancing

Levelised cost of electricity (LCOE) is widely adopted as an economic indicator that can be used for comparisons between generation, storage and transmission technologies with different characteristics such as capacity factors and lifetime. When the LCOE definition extends to an electricity system, it is made up of 2 components: levelised cost of generation (LCOG) and levelised cost of balancing (LCOB). Levelised cost of electricity is a measurement of energy economics typically for a single generating facility. In this study, it was extended to be applicable to a large interconnected electricity system including PV, wind, PHES and high-voltage DC transmission, which is comparable to the average spot price in the National Electricity Market. Similar to the concept of spot price in the wholesale electricity market, electricity generation from behind-the-meter rooftop PV is excluded, as well as the cost of existing T&D network. However, it is noted that T&D network is a significant component of a typical retail electricity bill, say 30-50% in 2017-18 [123]. Energy storage, large-scale PHES, stationary battery and distributed energy storage in electric vehicles and households, will contribute to peak shaving, load shifting and deferral of T&D investment, which helps to further reduce the electricity cost for customers.

Basically, LCOG is the energy-weighted average LCOE for generating facilities in the electricity system, decided by the investments, financial costs (e.g. return on investment) and resource quality. By contrast, LCOB is the LCOE for storage, transmission and excess generation capacities i.e. the expenditure of maintaining energy supply and demand balance in the systems with high penetration of intermittent PV and wind, which is determined by the characteristics of the system including the availability and accessibility of flexible energy sources, demand response and large-scale energy storage, as well as the extent of geographic dispersion of solar and wind resources.

A "standard" form of LCOE calculation is introduced in [124, 125]. In this study, the LCOE equation is further interpreted as Equation 2-1 to 2-12:

$$LCOE = \frac{Cost_{Gen} + Cost_{Stg} + Cost_{Trans}}{Energy_{Gen} - Energy_{Curtail} - Energy_{Loss} - Energy_{Unmet}} \quad (2\text{-}1)$$

Equivalent to,

$$LCOE = \frac{Cost_{Gen} + Cost_{Stg} + Cost_{Trans}}{Energy_{Dmd}} \quad (2\text{-}2)$$

$$Cost_{Gen} = \sum_{i=1}^{l} \left[\left(\frac{Cost_{Geni.Capital}}{AF_i} + Cost_{Geni.FOM} \right) \times y + Cost_{Geni.VOM} + Cost_{Geni.Fuel} + Cost_{Geni.Carbon} \right] \quad (2\text{-}3)$$

$$Cost_{Stg} = \sum_{j=1}^{m}\left[\left(\frac{Cost_{Stgj.Capital}}{AF_j} + Cost_{Stgj.FOM}\right) \times y + Cost_{Stgj.VOM} + Cost_{Stgj.Fuel} + Cost_{Stgj.Carbon}\right] \quad (2\text{-}4)$$

$$Cost_{Trans} = \sum_{k=1}^{n}\frac{Cost_{Transk.Capital}}{AF_k} \times y \quad (2\text{-}5)$$

$$AF_i = \frac{\left(1-(1+r)^{-t_i}\right)}{r} \quad (2\text{-}6)$$

$$LCOG = \frac{Cost_{Gen}}{Energy_{Gen}} \quad (2\text{-}7)$$

$$Energy_{Gen} = \sum_{i=1}^{l} Energy_{Geni} \quad (2\text{-}8)$$

$$LCOB = LCOB_{Stg} + LCOB_{Trans} + LCOB_{Curtail} \quad (2\text{-}9)$$

$$LCOB_{Stg} = \frac{Cost_{Stg}}{Energy_{Dmd}} \quad (2\text{-}10)$$

$$LCOB_{Trans} = \frac{Cost_{Trans}}{Energy_{Dmd}} \quad (2\text{-}11)$$

$$LCOB_{Curtail} = \frac{Cost_{Gen}}{Energy_{Dmd}} - LCOG \quad (2\text{-}12)$$

Where,

- $Cost_{Gen}, Cost_{Stg}, Cost_{Trans}$ - Net present values of the investments on generation, storage and transmission technologies, $
- $Energy_{Gen}, Energy_{Curtail}, Energy_{Loss}, Energy_{Unmet}$ - Energy generation, curtailment and loss, MWh
- $Energy_{Dmd}, Energy_{Unmet}$ - Electricity demand and unmet energy/demand, MWh. It is noted that the unmet energy, which is not shown in the denominator of LCOE/LCOB equations (a tiny fraction), is also included in the LCOE/LCOB calculation by subtraction of unmet energy from electricity demand.
- AF_i, AF_j, AF_k - Present value annuity factors for the generator i, storage j and transmission k
- $Cost_{Geni.Capital}, Cost_{Geni.FOM}, Cost_{Geni.VOM}, Cost_{Geni.Fuel}, Cost_{Geni.Carbon}$ - Capital costs, fixed O&M costs, variable O&M costs, fuel costs and carbon taxes for the generator i, storage j and transmission k respectively
- $LCOB_{Stg} + LCOB_{Trans} + LCOB_{Curtail}$ - Storage, transmission and curtailment components of LCOB, $/MWh
- l, m, n - Numbers of generators, storage and transmission facilities
- r - Discount rate (real), %
- t_i, t_j, t_k - Technical lifetime for the generator i, storage j and transmission k, years
- y - Length of simulated period, years

Significantly, the estimates for LCOE, LCOG and LCOB in this study are based on mature generation, storage and transmission technologies that have already been worldwide deployed at a large scale (> 100 GW), which means the cost estimates are more robust than that of emerging technologies such as CSP and hydrogen-based generating and storage facilities. LCOB also reflects the competitiveness of the balancing solutions applied in the 100% renewable systems.

Additionally, different from some studies such as [56, 105, 114], costs of behind-the-meter rooftop PV systems are not included in the LCOE because they are privately funded. Accordingly, energy contributions from rooftop PV are also excluded in the calculation, which means both the cost (dividend) and the energy (denominator) of behind-the-meter rooftop PV are not included in the LCOE/LCOG calculations. However, the balancing cost for integration of rooftop PV is included in LCOB.

2.2.3 Input datasets

Hourly solar and wind data for the National Electricity Market region is used in the modelling, which comes from the AEMO 100% renewables study in 2012-13 [56]. The NEM region was divided into 43 locational polygons (Figure 2-3) and the representative traces of solar and wind power generation time-series for each polygon were derived on an hourly basis. In our study, large-scale solar farms are deployed in the polygons 3, 6, 10, 16, 23, 30, 33, 34, 35, 27 and windfarms are deployed in the polygons 3, 6, 10, 16, 23, 24, 30, 31, 35, 36, 26, 32, 37, 38, 39, 40, 41, 43. This is to exploit the best solar and wind resources in the eastern and southern states while in proximity to existing transmission network. Sensitive areas such as national parks have been excluded, as well as the coastal regions of Queensland and New South Wales due to the risk of cyclone.

Average capacity factor for 1-axis tracking PV system is expected to be 23% based on the Australian Renewable Energy Agency large scale solar grant round [126]. DC 23% is equivalent to AC 27-31% assuming a 75-85% DC/AC conversion factor [3]. In addition, to reflect the trends of using larger wind turbines such as 3 MW wind turbine, the original wind data from [52] was scaled up from 40% to 42%.

[3] So the original solar data from [52] was scaled from an average capacity factor of AC 34% to DC 23%.

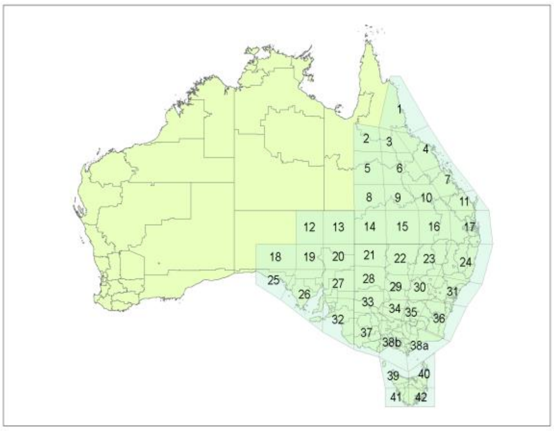


Figure 2-3 Locational polygon map for renewable energy resources in the Australian National Electricity Market. Image source: Australian Energy Market Operator [56].

For the SWIS modelling, as the regions outside the NEM were not covered by [56], the software System Advisor Model (SAM, developed by NREL) was used to simulate representative PV and wind time series on an hourly basis. Detailed information about the SAM input is included in Section 4 of Appendix B.

In this study, the historical demand in the NEM from 2006-10 was used on the basis of a conservative assumption of both demand growth and the change in load patterns. NEM demand was not significantly changing throughout the years 2006-10, while for the SWIS, there were significant impacts of rooftop PV integration during the simulated period 2007-14 because of the rapid uptake of rooftop PV. In 2014, rooftop PV contributed more than 500 MW at times, which is comparable with the largest thermal generators in the SWIS. Consequently, for the SWIS, a different method was used: the original demand (net load) from 2007-14 was adjusted with a time series produced also from SAM and then scaled to 2014, which has the maximum consumption during the last decade. Detailed information about the load adjustments is included in Section 4 of Appendix B.

Legacy assets of hydro and bio are assumed to be dispatchable across the simulated years but subject to 10% energy constraint as stated in Chapter 1.3.1.1.

2.2.4 Constraints

As described in Chapter 2.2.1, the objective of capacity expansion models is to optimise the configurations of electricity generation, storage and transmission technologies in energy systems while subject to a variety of modelling constraints, including [117, 119, 120, 122]:

- Reliability standard - maintaining energy supply and demand balance on an hourly basis or other temporal resolutions;
- Generator technical limits such as ramp rates, start-up time and minimum stable loading;
- Resource limits including build limits and energy limits such as fuel availability;
- Planning and operating reserves for contingency (generator outages, transmission failure), forecast errors and frequency regulation;
- Stability constraints;
- GHG emissions targets and/or energy policies;
- Power flow/transmission constraints (static).

Table 2-4 lists the modelling constraints defined in this study.

Table 2-4 Constraints in the grid integration modelling of photovoltaics, wind and pumped hydro energy storage.

Category	Constraints
I	NEM reliability standard 0.002% (approx 4 GWh p.a.)
	Demand-side management (not included in baseline scenarios)
II	Existing wind farms: NSW 1 GW, SA 1.7 GW, Vic 1 GW, Tas 0.3 GW
	Existing/announced solar farms [127]: Qld 165 MW, NSW 320 MW
	Existing PHES: Qld 500 MW, NSW 240 MW (Tumut-3 1,500 MW included in existing hydro)
III	Far North Qld-Brisbane (1,500 km): LCC-HVDC ± 800 kV, 6.4 GW (up to 7.2 GW) x 2
	SA-Vic (900 km): LCC-HVDC ± 800 kV, 6.4 GW (up to 7.2 GW)
	Vic-Tas (400 km, 300 km submarine cables): LCC-HVDC 400 kV, 500 MW (up to 630 MW) x 2
IV	Minimum capacities for each polygon/zone (equiv. to Category II)
	Maximum capacities for each polygon/zone (using the limits from [56])

Planning and operating reserves allow the systems to cope with: (a) contingency events such as forced generator outages or transmission failure, (b) forecast errors and, (c) frequency regulations [27]. For example, in AEMO [120], the minimum capacity reserve level is equivalent to the largest generating unit operated in the electricity market, while the California Independent System Operator sets a 15% reserve margin for operational reserves [128]. Similarly, the operation reserves for forecast errors 1-6%, contingency 6% and frequency regulation 1.5% of demand are used in [119].

In this study, the system is integrated with 16-20 GW pumped hydro facilities, equivalent to half of the maximum peak demand in the NEM. Storage facilities convert energy values that PV and wind contribute to the electricity systems into capacity values, so the considerations for reserve capacity are significantly different:

- PV and wind: a distributed renewable energy system is comprised of large amounts of PV and wind energy systems, which greatly reduces the effect of unexpected individual generator failure compared with an electricity system comprising a small number of large fossil or nuclear power stations, due to statistical reasons.
- PHES: the sensitivity analysis in Appendix A indicates PHES costs have moderate impacts on LCOE. For example, increasing PHES capacity by 2 GW, the system LCOE only increases by $2/MWh.
- Hydro and bio: costs for energy balancing services from legacy hydro and bio are assumed at a purchase price of $70/MWh rather than merely factoring in the O&M cost: $46-49/kW-year (fixed), $1-10/MWh (variable). The figure $70/MWh was the 2015-16 average electricity price for hydroelectricity in the NEM, which allows the costs for reserves/augmentations in existing hydro and bio power plants to be taken into account.
- Transmission: the cost of HVDC network $400/MW-km has incorporated the N-1 redundancy in DC, steady-state analyses.
- Forecast errors: perfect weather and load forecasting is assumed in the modelling. However, as noted in Chapter 2.2.4, for example, increasing PHES capacity by 2 GW (5% of the maximum peak demand in the NEM) to cope with the forecast errors, the system LCOE only increases by $2/MWh.
- Frequency regulations: the intermittency of power supply due to weather events (which take days to move across the NEM) is vastly mitigated by wide dispersion of renewable generating facilities as demonstrated in Chapter 1.3.2. Reserve capacity also includes the reserve sharing between neighbouring electricity markets and demand response. Pumped hydro is suitable for demand-side participation programs as it is able to quickly suspend the consumption of electricity (pumping) if the system requires help in maintaining frequency stability.

According to the IEEE/CIGRE Joint Task Force on Stability Terms and Definitions [129], power system stability refers to “the ability of the electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical or electrical disturbance, with system variables bounded so that practically the entire power system remains intact”.

PV, wind and high-voltage DC transmission are interfaced with electricity grid via power electronics (converters), which lack the synchronous inertia traditionally provided by synchronous generators leading to a reduction of system strength. Consequently, a non-synchronous penetration (NSP) limit of 70% was applied within each hour's generation mix in [130] while this limit was relaxed to 75-80% in the studies of [47] and [114]. In practice, AEMO established a requirement for a minimum level of thermal synchronous generation to stay online following the state-wide blackout in SA on 28 September 2016 [35]. Some studies such as [56, 105] assumed large amounts of geothermal, biomass and CSP to be integrated in 100% renewable electricity systems and operated as baseload power. However, as noted in Chapter 1.3.1, these generation technologies are either constrained by resource availability or are immature and have not been deployed at a large scale worldwide (> 100 GW).

By contrast, this study does not incorporate a NSP limit nor integrate geothermal or CSP technologies while utilising the synchronous and fast-ramping characteristics of PHES generators/pumps to maintain the grid stability.

- Firstly, 16-20 GW PHES will be established in the 100% renewable electricity systems, together with 8 GW legacy hydro and biomass. PHES has a heavy rotating generator, which can contribute a large amount of synchronous inertia and ensure adequate system strength.
- Secondly, the typical ramp rate for pumped hydro generators is 50%/min, which means it has excellent load-following/frequency regulations capabilities (ramping up and down) [131]. Dozens of pumped hydro facilities distributed within multiple nodes of the transmission network can help to stabilise the electricity systems with high penetration of PV and wind energy.
- Thirdly, PV, wind and flexible HVDC transmission technologies can also make contributions to the system stability, especially during the days when the surplus energy from PV and wind farms will be otherwise spilled. Significantly, PV can regulate to 4-second automatic generation control signal 24-30 points more accurately than even fast gas turbines as demonstrated in a test conducted by [30].

“Apart from peaking shaving and load shifting, battery can respond to system change e.g. frequency variations within milliseconds, which contributes synthetic inertia to the system with high penetration of solar and wind, as the case in the Hornsdale Power Reserve (Tesla lithium-ion battery 100 MW, 129 MWh) in South Australia.

2.3 100% renewable electricity in the Australian National Electricity Market

This work has been published in Energy: A. Blakers, B. Lu, and M. Stocks, "100% renewable electricity in Australia," *Energy,* vol. 133, pp. 471-482, Aug 15 2017. The full article is included in Appendix A and its Abstract is reproduced as follows.

An hourly energy balance analysis is presented of the Australian National Electricity Market in a 100% renewable energy scenario, in which wind and photovoltaics (PV) provides about 90% of the annual electricity demand and existing hydroelectricity and biomass provides the balance. Heroic assumptions about future technology development are avoided by only including technology that is being deployed in large quantities (>10 Gigawatts per year), namely PV and wind. Additional energy storage and stronger interconnection between regions was found to be necessary for stability. Pumped hydro energy storage (PHES) constitutes 97% of worldwide electricity storage, and is adopted in this work. Many sites for closed loop PHES storage have been found in Australia. Distribution of PV and wind over 10–100 million hectares, utilising high voltage transmission, accesses different weather systems and reduces storage requirements (and overall cost). The additional cost of balancing renewable energy supply with demand on an hourly rather than annual basis is found to be modest: AU$25–30/MWh (US$19–23/MWh). Using 2016 prices prevailing in Australia, the levelised cost of renewable electricity (LCOE) with hourly balancing is estimated to be AU$93/MWh (US$70/MWh). LCOE is almost certain to decrease due to rapidly falling cost of wind and PV.

2.4 90-100% renewable electricity in the South West Interconnected System of Western Australia

This work has been published in Energy: B. Lu, A. Blakers, and M. Stocks, "90-100% renewable electricity for the South West Interconnected System of Western Australia," *Energy,* vol. 122, pp. 663-674, Mar 1 2017. The full article is included in Appendix B and its Abstract is reproduced as follows.

Rapidly increasing penetration of renewables, primarily wind and photovoltaics (PV), is causing a move away from fossil fuel in the Australian electric power industry. This study focuses on the South West Interconnected System in Western Australia. Several high (90% and 100%) renewables penetration scenarios have been modelled, comprising wind and PV supplemented with a small amount of biogas, and compared with a “like-for-like” fossil-fuel

replacement scenario. Short-term off-river (closed cycle) pumped hydro energy storage (PHES) is utilised in some simulations as a large-scale conventional storage technology. The scenarios are examined by using a chronological dispatch model. An important feature of the modelling is that only technologies that have been already deployed on a large scale (>150 gigawatts) are utilised. This includes wind, PV and PHES. The modelling results demonstrate that 90–100% penetration by wind and PV electricity is compatible with a balanced grid. With the integration of off-river PHES, 90% renewables penetration is able to provide low-carbon electricity at competitive prices. Pumped hydro also facilitates a 100% renewables scenario which produces zero greenhouse gas emissions with attractive electricity prices. A sensitivity analysis shows the most important factors in the system cost are discount rate and wind turbine cost.

2.5 Meeting Australia's Paris greenhouse commitment at zero net cost

This work was initially submitted to the Prime Minister of Australia in February 2017 and has been published as a research report in November 2017: A. Blakers, M. Stocks, and B. Lu, "Meeting Australia's Paris greenhouse commitment at zero net cost," Australian National University, Nov 2017. The full article is included in Appendix C and the Summary is reproduced as follows.

Currently, Australia is installing about 3 Gigawatts (GW) per year of wind and solar photovoltaics (PV). This rate is sufficient (if continued until 2030) for renewable energy to meet more than half of Australia's electricity consumption and all of Australia's Paris greenhouse emissions reduction target. The net cost of meeting the Paris target is zero because the cost of electricity from new-build wind and PV is below (i) the cost of electricity from new-build coal generators and (ii) the cost of electricity from existing gas generators and (iii) the wholesale price in the National Electricity Market (NEM). The cost of renewables includes the cost of hourly balancing of the grid to retain the same reliability as at present. Hourly balancing comprises pumped hydro energy storage, stronger interstate high voltage power lines and the cost of PV and wind spillage on windy, sunny days when the energy stores are full. Snowy 2.0 provides half the new storage required to support 67% renewables in the NEM. Figure 1 in Appendix C shows the all-in cost of electricity under three scenarios:

- Renewables: replace enough old coal generators by renewables to meet the Paris target
- Gas: premature retirement of most existing coal plant and replacement by new gas generators to meet the Paris target. Gas is uncompetitive at today's gas prices

($8/gigajoules). The gas scenario requires a large increase in gas consumption, placing upwards pressure on prices.

- Status Quo: like-for-like replacement of retiring coal generators with supercritical coal. This fails to meet the Paris target by a wide margin and has similar cost to the renewables scenario.

2.6 Modelling of integration of electric vehicles in the Australian electricity market

Decarbonisation of electricity generation i.e. 100% renewable electricity as demonstrated in Chapter 2.3, 2.4 will lead to 25% of reductions in the global GHG emissions (Figure 1-4) or even more, due to the accordingly decreased energy consumption in fossil fuel-related exploitation, transportation and distribution activities. Moreover, further decarbonisation of energy industry can be achieved by electrifying other energy sectors such as transportation (via electric vehicles) and heating/cooling (via heat pumps) which produced 14% and 6% of the global GHG emissions respectively as shown in Figure 1-4.

Significantly, electrifications of land transportation with built-in batteries and heating/cooling coupled with low-temperature thermal energy storage contribute large demand flexibility to electricity systems, which facilitates large-scale integrations of intermittent solar and wind resources and delivery of more affordable renewable electricity in energy markets as discussed in Chapter 1.3.3. Although Vehicle-to-Grid (VtG) i.e. utilising electric vehicles as a storage medium causes degradation of batteries and hence is not recommended by car manufacturers, large electric vehicle fleets will be an important energy source for operating reserves and ancillary services such as frequency regulations, which helps to stabilise electricity systems with high penetration of intermittent solar and wind electricity [132].

Several initial studies have been conducted to explore the impacts/benefits of integration of electric vehicles in the Australian electricity markets, including electrifying light-duty vehicles including passenger cars and light commercial vehicles in (a) the National Electricity Market, (b) South Australia and, (c) a hypothetical scenario where Snowy 2.0 and residential batteries supports 100% renewable electricity during the most difficult week.

2.6.1 Integration of electric vehicles in the Australian National Electricity Market

Subsequent to the 100% renewable electricity study for the NEM (Appendix A), a further investigation was conducted to explore the impacts of integration of electric vehicles in the NEM. While the majority of modelling input, assumptions and methodology stay unchanged with the 100% renewable electricity study, the demand files are altered to incorporate electric vehicles demand, which adds approximately 40% to the original demand.

In light of the advancement of battery technology and economies of scale [104], electric vehicles are very likely to be overwhelmingly competitive than oil/gas/hybrid alternatives in the near future. According to the data from the U.S. Department of Energy [133], the fuel cost of passenger vehicles can be more than halved on average in the United States by transitioning from conventional internal combustion engines to electric motors. By comparisons of representative petrol/diesel, hybrid electric vehicle, plug-in hybrid electric vehicle and battery electric vehicle in the UK, USA and Japan, Palmer et al. [134] concluded that battery electric vehicle already has a lowest Total Cost of Ownership for 3 years in California and UK (including purchase price, fuel and maintenance costs, insurance and tax) - largely because of the high petrol cost in the UK and the considerable tax credits and other incentives in California.

A number of "EV" scenarios are modelled, which represent different charging strategies of electric vehicles including:

- Unregulated: unregulated charging of electric vehicles based on current travel patterns;
- Flat: a simplified charging model that assumes integration of electric vehicles adds 40% to the original demand at each hour;
- PV: moving 90% of the charging of passenger cars to the hours between 9 am and 4 pm (PV94) or 8 am and 5 pm (PV85) to accommodate solar energy;
- PM: moving 100% of the charging of passenger cars to the hours between 9 pm and 9 am (PM9), 10 pm and 10 am (PM10), 11 pm and 11 am (PM11) and 12 am and 12 pm (PM12);
- Worst: assuming all of passenger cars are charged over the evening peak (4-7 pm).

Modelling outcomes are listed in Table 2-5.

Table 2-5 Modelling outcomes of integration of electric vehicles in the NEM. In comparison, the LCOE figures for 100% renewable electricity without EV integration is $75/MWh (2030) in Table 3 of Appendix A.

Scenarios	PV (GW)	Wind (GW)	PHES (GW)	PHES (h)	LCOE ($/MWh)
Unregulated	39	54	29	28	81
Flat	38	57	26	26	80
PV94	53	49	24	27	80
PV85	44	55	23	25	78
PM9	25	66	22	29	80
PM10	29	66	21	27	80
PM11	25	62	22	37	79
PM12	39	58	22	30	80
Worst	25	66	47	16	88

Clearly, integration of electric vehicles, though adding 40% of the original demand to the NEM, will not significantly increase the system LCOE: $78-81/MWh (2030) compared with the scenarios without integration of electric vehicles: $75/MWh (2030).

In fact, these figures are expected to be lower than the original numbers in Table 3 of Appendix A, by applying active load management to the charging of electric vehicles as stated in Chapter 4.1. In other words, the levelised costs of balancing, which are in the range of $25-28/MWh with a synergy of flexible energy sources, geographic dispersion of solar and wind and large-scale energy storage in the 100% renewable electricity study, are expected to decrease below $20/MWh once active load management of electric vehicles is incorporated.

2.6.2 Integration of electric vehicles in South Australia

Similar to the EV integration modelling in the NEM as introduced in Chapter 2.6.1, preliminary work was conducted on modelling of integration of electric vehicles in South Australia, a particular state of the Australian NEM which had a variable renewable energy penetration level of 50% in 2016, comparable to Denmark (> 50%) and Portugal (> 30%), which rank the top two countries of renewable energy penetration around the world excluding hydroelectricity.

A series of 100% renewable electricity scenarios in SA are modelled, including:

- Baseline: 100% renewables in SA without integration of electric vehicles
- EV scenarios: Unregulated, PV and PM. Unregulated, PV and PM scenarios all add to 21.6% to the original SA demand, which is from electrification of light-duty vehicles: passenger cars and light commercial vehicles.

Table 2-6 lists the results from the modelling.

Table 2-6 Modeling outcomes of integration of electric vehicles in South Australia.

	100% renewables in SA [a]	Unregulated	PV	PM
Reliability	Unmet energy = 0	Unmet energy = 0	Unmet energy = 0	Unmet energy = 0
LCOE (base $60/MWh + difference 0%) [b]	$70 ($68 + $0.7 + $2) [c]	$67 ($66 + $0.7 + $0.4) [c]	$66 ($65 + $0.8 - $0.2) [c]	$69 ($66 + $0.6 + $2) [c]
Energy spillage	3%	4%	2%	6%
Electricity import	31%	26%	24%	32%
Electricity export	30%	26%	24%	29%
Gas capacity	2000 MW	2000 MW	2000 MW	2000 MW
Gas generation	0.1%	0.5%	0.2%	0.6%

Note. Assuming a new South Australia-New South Wales interconnector is built with a rated capacity of 1000 MW in all scenarios, as planned by ElectraNet [135].

[a] Without integration of electric vehicles

[b] For the import and export electricity price to calculate LCOE, the base price plus percentage difference is used, where base price $60/MWh is the average electricity price in Victoria and NSW in 2016 and 2017. By contrast, 0% difference means $60/MWh for import and $60/MWh for export while 100% difference means $90/MWh for import and $30/MWh for export.

[c] LCOE consists of three components in the brackets: electricity generation and storage (including interconnection), intrastate transmission augmentation and energy arbitrage.

It is shown that, by integration of electric vehicles in SA, the LCOE is lower than that of the baseline scenario where no electric vehicles are integrated, even in the absence of active load management of electric vehicles charging. This is because new solar and wind farms (proposed in SA), which are built to accommodate extra demand added by electric vehicles, generally have higher capacity factors than the legacy assets (commissioned in the last decade) due to the deployment of advanced PV technologies and larger wind turbines. Particularly, by moving the charging of electric vehicles from late afternoons to middays (i.e. PV), the LCOE further reduces by $1/MWh and South Australia becomes a net electricity exporter where energy spillage is halved.

Given SA has no significant hydro energy resources and the off-river pumped hydro sites are not as good as eastern states due to its flat terrain and lack of water resource, integration of electric vehicles provides an effective way to facilitate large-scale solar and wind integration transitioning to a 100% renewable electricity/energy future in SA. Electric vehicles and electric heating (coupled with low-temperature thermal energy storage such as hot water tanks) create large flexibility in electricity demand, which helps to mitigate the effect of intermittency in renewable energy production as demonstrated in [67, 101].

2.6.3 Snowy 2.0 + residential batteries

A giga-scale PHES scheme, the Snowy 2.0, was announced by the Australian Prime Minister in March 2017 and is proposed to connect the existing Tantangara (254 GL) and Talbingo (920 GL, active 160 GL) of the Snowy Mountains Scheme, which are separated by 600 m vertically and 30 km horizontally. Snowy 2.0 will have a rated capacity of 2 GW for power and 350 GWh [136] for storage which can be a critical flexible energy source during the most difficult weeks.

It is interesting to examine a scenario where the centralised Snowy 2.0, widely distributed residential batteries and fully flexible charging of electric vehicles work in collaboration to help the system ride through the most difficult week i.e Saturday 22 July to Friday 28 July 2006 in the $93 baseline scenario. Basically, during the most difficult week, the original demand is 4.1 TWh and the flexible electric vehicles demand is 1.2 TWh while the available energy source is 5.0 TWh: PV 0.7 TWh, wind 2.6 TWh, Snowy 2.0 0.3 TWh, hydro and bio 1.3 TWh, as well as demand response 2-4 GW x 168 hours (though not activated in this case).

Modelling input and assumptions include:

- Snowy 2.0 is fully discharged during the most difficult week i.e. 2 GW lasting for 168 hours;
- Centralised dispatch of residential batteries: 15 GW, 50 GWh and the initial storage is zero;
- Integration of electric vehicles adds 30% to the original demand with a “flat” charging pattern i.e. magnifying the original demand by 1.3 on an hourly basis, as well as solar and wind energy supply;
- Charging of electric vehicles is fully flexible, which means it can be readily shedded or shifted to other weeks as needed.

Results are shown in Figure 2-4.

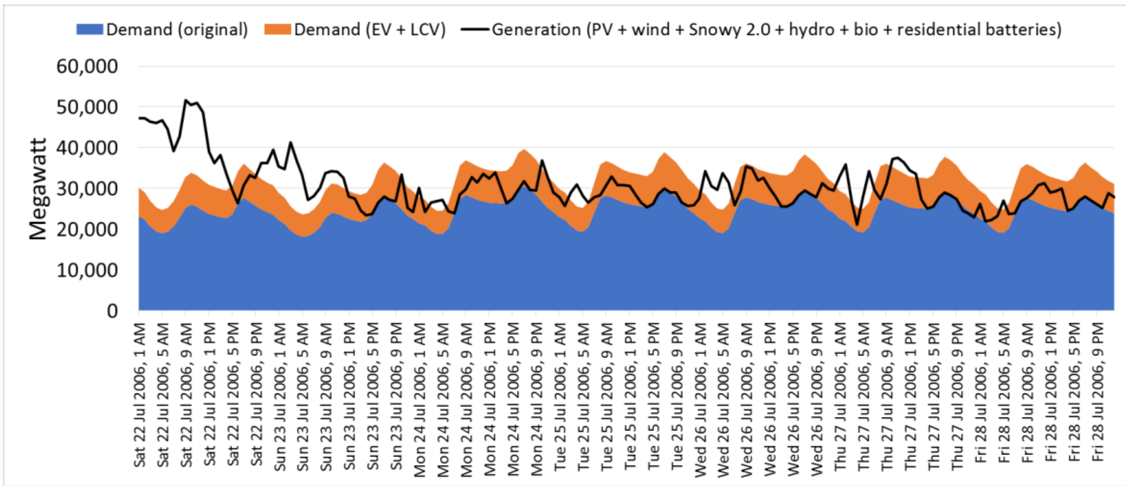


Figure 2-4 Load profiles and generation mix during the most difficult week (modified with electric vehicles demand and magnified PV and wind energy supply).

In summary, by integration of Snowy 2.0 (2 GW, 350 GWh) and residential batteries (15 GW, 50 GWh), together with large demand flexibility coming from electric vehicles charging, 99.97% of the original demand are met and 40% of the electric vehicles demand can be met, which enables the NEM reliability standard to be satisfied. Because of the avoided costs of building 10-20 GW additional PHES in the NEM (as optimised in Appendix A), the LCOE in this scenario are more likely to be lower than the figures in Table 3 of Appendix A. Actually, part of the LCOB is now embedded in behind-the-meter residential batteries and demand flexibility of EV charging instead of dispatches of centralised PHES facilities.

2.7 Conclusions

High shares of intermittent PV and wind energy in electricity grids bring significant challenges to the economics and security of the system. Pumped hydro energy storage is capable of large-scale energy time shifting and a range of ancillary services such as rapid response (20-200 seconds), rotational inertia and frequency regulation, which can facilitate high levels of photovoltaics and wind integration in electricity systems. This study demonstrates that by integration of STORES, reliable and low-carbon electricity grids can be built in the NEM in eastern Australia and the SWIS of Western Australia. Storage requirements in the electricity markets are driven by 2 factors: (a) the maximum difference between renewable energy supply and demand, which decides the power capacity, GW and (b) the most critical weeks with extremely low solar and wind availability, which determines the storage capacity, GWh.

Significantly, the LCOE for 100% renewable electricity in the NEM is only $75-93/MWh, which is competitive with new-build coal or natural gas-fired power stations in Australia. Due to the correlation of solar and wind resources (caused by the small geographical size of the SWIS system) and the lack of significant hydro energy resources in the southwest of Western Australia, the LCOE for 90-100% renewable electricity in the SWIS is much higher: $103-116/MWh (90%), $109-129/MWh (100%). Nevertheless, when factoring in the environmental burdens such as a moderate carbon tax, the cost of fossil fuel derived electricity is in the same range with 90% renewable electricity.

The LCOB, which is the cost to balance the intermittent PV and wind energy supply, is $25-$28/MWh in the NEM and $37-41/MWh in the SWIS. These figures are significantly lower than alternative balancing methods such as using geothermal or concentrating solar power coupled with high-temperature thermal energy storage. The LCOB is made up of 3 components: (a) PHES for large-scale energy time shifting, (b) HVDC & AC transmission for renewable energy geo-shifting and (c) energy spillage from excess PV and wind capacities. Proportions for the 3 components are 2:1:1 in the NEM study.

A map showing the deployments of PV and wind facilities in the NEM (baseline scenario) and a notional HVDC transformation network is demonstrated in Figure 2-5.

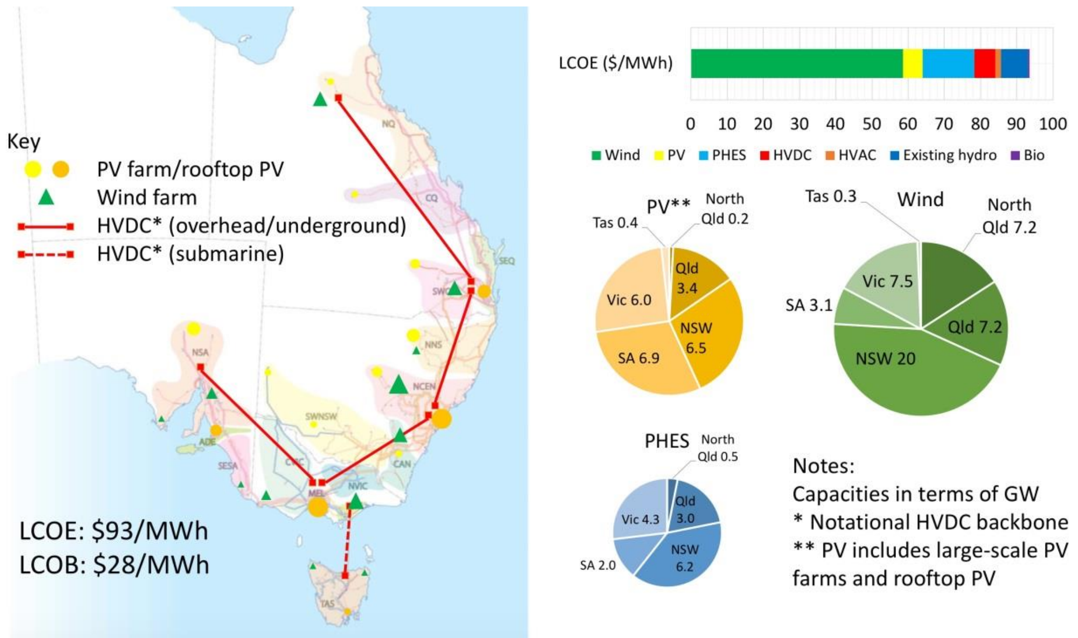


Figure 2-5 A map showing the deployments of PV and wind energy systems in the baseline scenario and a notional HVDC transmission network. Installed capacities of PV and wind are roughly denoted by the sizes of circles/triangles.

It is noted that the generation, storage and transmission technologies in this study only include PV, wind, PHES, HVDC & AC and existing hydro and bio, which have been deployed at a large scale (> 100 GW worldwide), which means that even without technical breakthroughs in generation, storage and transmission technologies and no significant transformation of energy sectors, the existing fossil fuels-dominated power systems can transition to a reliable, affordable and low-carbon electricity future.

Furthermore, solar and wind have effectively no resource limits and build limits compared with alternative electricity generation technologies such as hydro, bio and geothermal. The opportunities for STORES exist in most regions of the world (a global atlas of pumped hydro energy storage is under development http://re100.eng.anu.edu.au/research/re/for/). Consequently, a synergy of PV, wind, pumped hydro and HVDC & AC provides a generic, cost-effective approach to decarbonise the global energy sectors, transitioning to zero-carbon energy future.

The limitations of this work include:

- Perfect weather and load forecasting is assumed, which means forecasting errors are not incorporated in the modelling. However, the planning and operating reserves will be the solution to cope with the uncertainty of PV and wind energy supply as discussed in Chapter 2.2.4.
- Dynamical grid stability on a time scale of sub-seconds to minutes is not included. Pumped hydro can provide a wide variety of ancillary services such as frequency regulations, network supports and system restart. A further investigation of its significant roles in maintaining power system stability in the context of high penetration of PV and wind will be needed in a future study.

Future work will also include the integration of electric vehicles and heat pumps in electricity systems which will assist in further decarbonization of the energy sectors. Large numbers of batteries in electric vehicles and low-temperature thermal energy storage coupled with heat pumps can provide significant demand flexibility, which can further facilitate large-scale PV and wind deployments.

3 Geographic information system-based site searches for pumped hydro energy storage

3.1 Objectives

Prior to this study, substantial preliminary work has been undertaken at the Australian National University to explore the opportunities for PHES deployments in Australia, including:

- A pilot GIS model that is capable of identifying pairs of relatively flat lands suitable for construction of “Turkey’s nest”-type dams using the Geospatial Data Abstraction Library (GDAL/OGR) and 3 arc-second digital elevation models. Mapping of potential sites in the greater Canberra region and central Tasmania demonstrated a large storage potential in the form of off-river PHES [137].
- An “Alpha” version of cost models for PHES, which includes a budget estimate of a typical PHES site (upper/lower reservoirs 1 GL, head 580 m, capacity 180 MW with 6 hours of storage) located in Araluen Valley, New South Wales [138].
- Initial site surveys using Google Earth/ArcGIS for a list of promising PHES sites located in Tallangatta Valley (Victoria), Brown Mountain (NSW), Araluen Valley (NSW), Talbingo Reservoir (NSW), Naas Valley (ACT), Cotter Dam (ACT), Snowtown Wind Farm (SA) [139] and the Darling Range (Western Australia) [140].

While the preliminary work suggested a large potential for off-river PHES to be deployed in the extensive hills and mountains from North Queensland down the east coast to South Australia and Tasmania, it *“has been limited by the need to refine the software to better locate more reservoir sites on undulating sites (eg. in gullies of the required volume), and by the need to upgrade the software to run finer resolution (<100 m) digital elevation model data on parallel computer architectures (i.e. a super computer) to assess broader areas.“* [137].

Consequently, following the initial site surveys, this study focuses on the development of a series of advanced GIS algorithms which enable a comprehensive (multiple types of PHES site) high-resolution (1 arc-second digital elevation models) site searching to be conducted across each state/territory of Australia. The objectives of this study include,

- Devising of mathematical models to represent two typical types of PHES site: (a) “Dry-gully” which entails a gentle dry gully located near the top of a hill capable of impounding a certain amount of water by utilising existing terrain as a major part of the dam (Figure 3-1 (a)) and, (b) “Turkey’s nest” which refers to a large flatland which can be enclosed by a surrounding earth-filled embankment dam to store a certain amount of water (Figure 3-1 (b)).

Figure 3-1 Upper (a) and lower (b) reservoirs of Presenzano Hydroelectric Plant, Italy (elevation exaggeration: 3)

- Development of improved GIS algorithms that are capable of: (a) highlighting promising regions for PHES developments from a large region such as a state or a country, which can facilitate the planning of renewable energy development zones incorporating PV, wind, PHES and high-voltage direct current (HVDC) transmission, (b) rapid identification of prospective PHES sites with different characteristics of topography. For example, pairs of medium-sized reservoirs (dozens or hundreds of hectares) can be built on large flat lands as turkey’s nest dams or located in enclosed dry gullies and, (c) selection of optimal locations by ranking the sites identified from site searching on the basis of topography suitability and land use classes. Additionally, detailed site information such as the volumes of reservoirs, dam wall heights and lining areas will be helpful to integrate a costing tool in the next level of study.
- Developing a national atlas of PHES in Australia using the site models and the GIS algorithms developed in this study to explore the opportunities for PHES to: (a) support high penetration of intermittent PV and wind energy in Australia’s electricity grids and, (b) facilitate long-term reliable low-carbon electricity supply (by PV, wind and PHES hybrid systems) to large electricity customers e.g. mining and metal-refining industry.

Cost models for pumped hydro energy storage are under development in collaboration with hydropower engineering consultants from B&V, GHD and BetterAIM: (a) the “Alpha” model includes a budget estimate of a typical PHES site located in Araluen Valley, New South Wales, which has already been made publicly available; (b) by contrast, the “Beta” model is a generic costing tool, comprising cost functions of major components of a pumped hydro project at a pre-feasibility study level; (c) in future, a “Gamma” model is also expected, which will allow optimisation of site selection and pairing on an economic basis i.e. by dollars per kilowatt and dollars per kilowatt-hour.

3.2 Geographic information system algorithms to locate prospective sites for pumped hydro energy storage

The GIS algorithms developed in this study have been published in Applied Energy: B. Lu, M. Stocks, A. Blakers, and K. Anderson, "Geographic information system algorithms to locate prospective sites for pumped hydro energy storage," Applied Energy, vol. 222, pp. 300-312, Jul 15 2018. The full article is included in Appendix D and its Abstract is reproduced as follows.

Pumped hydro energy storage is capable of large-scale energy time shifting and a range of ancillary services, which can facilitate high levels of photovoltaics and wind integration in electricity grids. This study aims to develop a series of advanced Geographic Information System algorithms to locate prospective sites for off-river pumped hydro across a large land area such as a state or a country. Two typical types of sites, dry-gully and turkey’s nest, are modelled and a sequence of Geographic Information System-based procedures are developed for an automated site search. A case study is conducted for South Australia, where 168 dry-gully sites and 22 turkey’s nest sites have been identified with a total water storage capacity of 441 gigalitres, equivalent to 276 gigawatt-hours of energy storage. This demonstrates the site searching algorithms can work efficiently in the identification of off-river pumped hydro sites, allowing high-resolution assessments of pumped hydro energy storage to be quickly conducted on a broad scale. The sensitivity analysis shows the significant influences of maximum dam wall heights on the number of sites and the total storage capacity. It is noted that the novel models developed in this study are also applicable to the deployments of other types of pumped hydro such as the locations of dry-gully and turkey’s nest sites adjacent to existing water bodies, old mining pits and oceans.

3.3 Developing a national atlas of pumped hydro energy storage in Australia

A thorough screening for prospective pumped hydro sites is conducted across each state/territory of Australia by using the dry-gully model detailed in Section 3.1 of Appendix D GIS algorithms.

The dry-gully model is applied because it allows the delineation of outlines of reservoirs and dams in the modelling, which can then be visualised in 3D. By contrast, the locations identified by the turkey's nest model can only be denoted by pieces of square raster cells. In addition, the dry-gully model can also identify the turkey's nest dams located on the virtual streams derived from digital elevation models. Only a few turkeynest sites, which are located outside the stream network due to insufficient flow accumulation (details in Section 4.2 of Appendix D) are overlooked as demonstrated in the South Australian case study (5% of the total storage capacity).

Table 3-1 lists the search criteria defined in the development of a national atlas of PHES in Australia. Compared with Table 2 in Section 4.3 of Appendix D GIS algorithms, only the subclasses 541, 550, 552 of Catchment Scale Land Use (CLUM) Class 5 are excluded instead of excluding the entire CLUM Class 5 - the other subclasses of Class 5 are assumed to be negotiable instead of "no-go". Additionally, a minimum head of 200 m is used for WA, NT because of the characteristics of topography.

Table 3-1 Search criteria for a comprehensive site survey for pumped hydro energy storage in Australia.

No.	Criterion	Value
1	Minimum head to distance ratio	1:15
2	Minimum head	300 m
3	Minimum surface area of reservoir	10 ha
4	Minimum storage capacity	1 GL
5	Maximum dam wall height	40 m
6	Dam batter	1:1, 1:3
7	Maximum slope for dam construction	1:5
8	Protected areas	Not in CAPAD *
9	Intensive land use	Not in CLUM Class 541, 550, 552 **
10	Resolution (Searching interval)	10 m height

Note. Minimum head in Western Australia and the Northern Territory is 200 m. Illustration of dam batter, freeboard and crest width is included in: https://www.dropbox.com/s/vagey2kijogofet/Appendix%20A.docx?dl=0.

* Collaborative Australian Protected Areas Database (CAPAD)

** Catchment Scale Land Use (CLUM) datasets

Figure 3-2 is A national atlas of pumped hydro energy storage in Australia. As shown on the atlas, the prospective pumped hydro sites are concentrated in:

- Great Dividing Range, Qld, NSW and Vic (the eastern states)
- Flinders Ranges, SA
- Darling Scarp, WA (the southwest of WA)
- Macdonnell Ranges, NT (in central Australia)
- Kimberley & Lake Argyle, WA and NT (the north of WA and NT)

- Hamersley Range, WA (near Pilbara, the northwest of WA)
- Tasmania (outside national parks), “Battery of the Nation” [141]

The total storage potential of the 22,000 sites is equivalent to 67,000 GWh assuming an average hydraulic head of 400 m, which is far beyond the storage requirements (500 GWh roughly) to support 100% renewable electricity in the Australian energy markets.

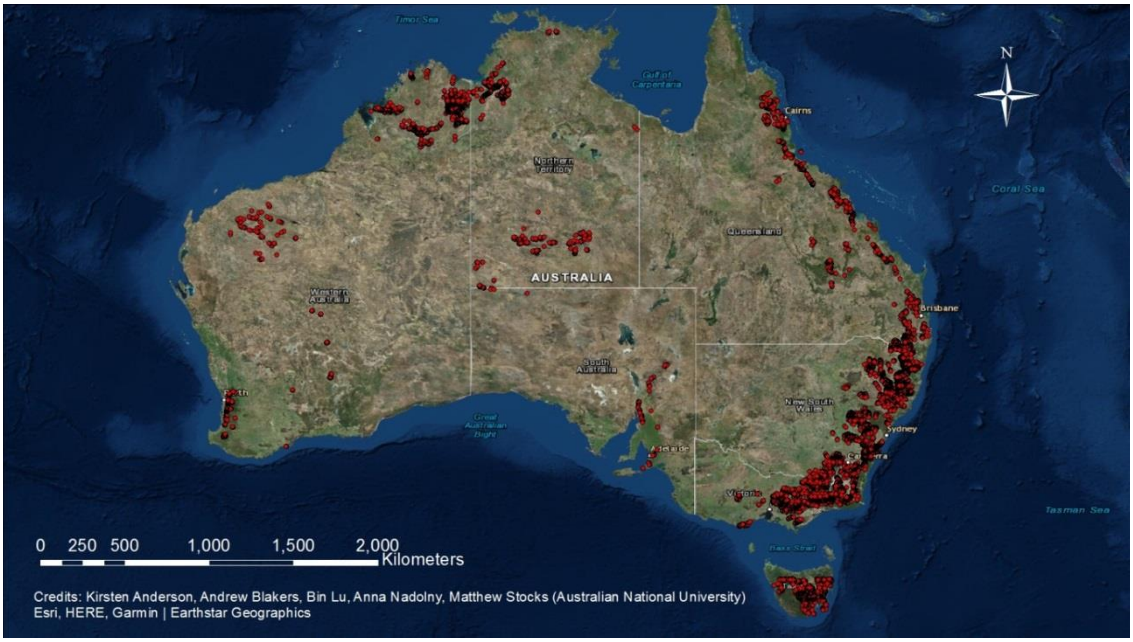


Figure 3-2 A national atlas of pumped hydro energy storage in Australia. Each red dot on this map represents a possible pumped hydro site identified from the modelling. Number of sites = 22,000.

Example sites with largest storage volume or water-to-rock ratio (the volume of stored water compared with the volume of rock required for the dam) in each state/territory include,

- Figure 3-3 (a). Site No. S38E145_RES_8068 (-37.10999999, 145.4161111): 464 ha, 67 GL, 56 GWh (400 m head). This is the largest site identified in Victoria.
- Figure 3-3 (b). Site No. S37E147_RES_11045 (-36.25944444, 147.4773889): 201 ha, 35 GL, 36 GWh (500 m head). This site is located within close proximity to the Victoria-NSW 330 kV interconnection and has a potential storage capacity of 36 GWh, comparable to the Tumut 3 Hydroelectric Power Station (1,500 MW with 24 hours of storage) located in NSW.
- Figure 3-3 (c). Site No. RES_136 (-35.63601855, 149.0352778): 64 ha, 11 GL, 7 GWh (300 m head). This is the largest site identified in the Australian Capital Territory. A short tunnel will be needed to cross the top ridge avoiding climbing up 100 m high.
- Figure 3-3 (d). Site No. S16E130_RES_1005 (-15.26655554, 130.4451667): 318 ha, 91 GL, 57 GWh (300 m head). This is the largest site (in terms of storage capacity, GL) in the Northern Territory.

- Figure 3-3 (e). Site No. S17E128_RES_3308 (-16.13076388, 128.7775695): 36 ha, 6 GL, 2 GWh (200 m head). Dozens of possible sites are located adjacent to Lake Argyle, which can potentially support large-scale exports of Australia’s renewable electricity to the Asia-Pacific Super Grid (Chapter 4.2).
- Figure 3-3 (f). Site No. RES_727 (-19.41905108, 146.495598): 746 ha, 155 GL, 161 GWh (500 m head). This is the largest site (in terms of storage capacity, GL) identified in Queensland, which has a potential storage capacity of 161 GWh - 30 times larger than the existing Wivenhoe Power Station (500 MW for 10 hours).
- Figure 3-3 (g). Site No. RES_37874 (-41.62194447, 146.2): 266 ha, 44 GL, 46 GWh (500 m head). This is the largest site (in terms of storage capacity, GL) in Tasmania.
- Figure 3-3 (h). Site No. RES_35638 (-41.6551769, 146.1689898): 331 ha, 29 GL, 27 GWh (450 m head). This site has the highest water-to-rock ratio (175) in Tasmania.

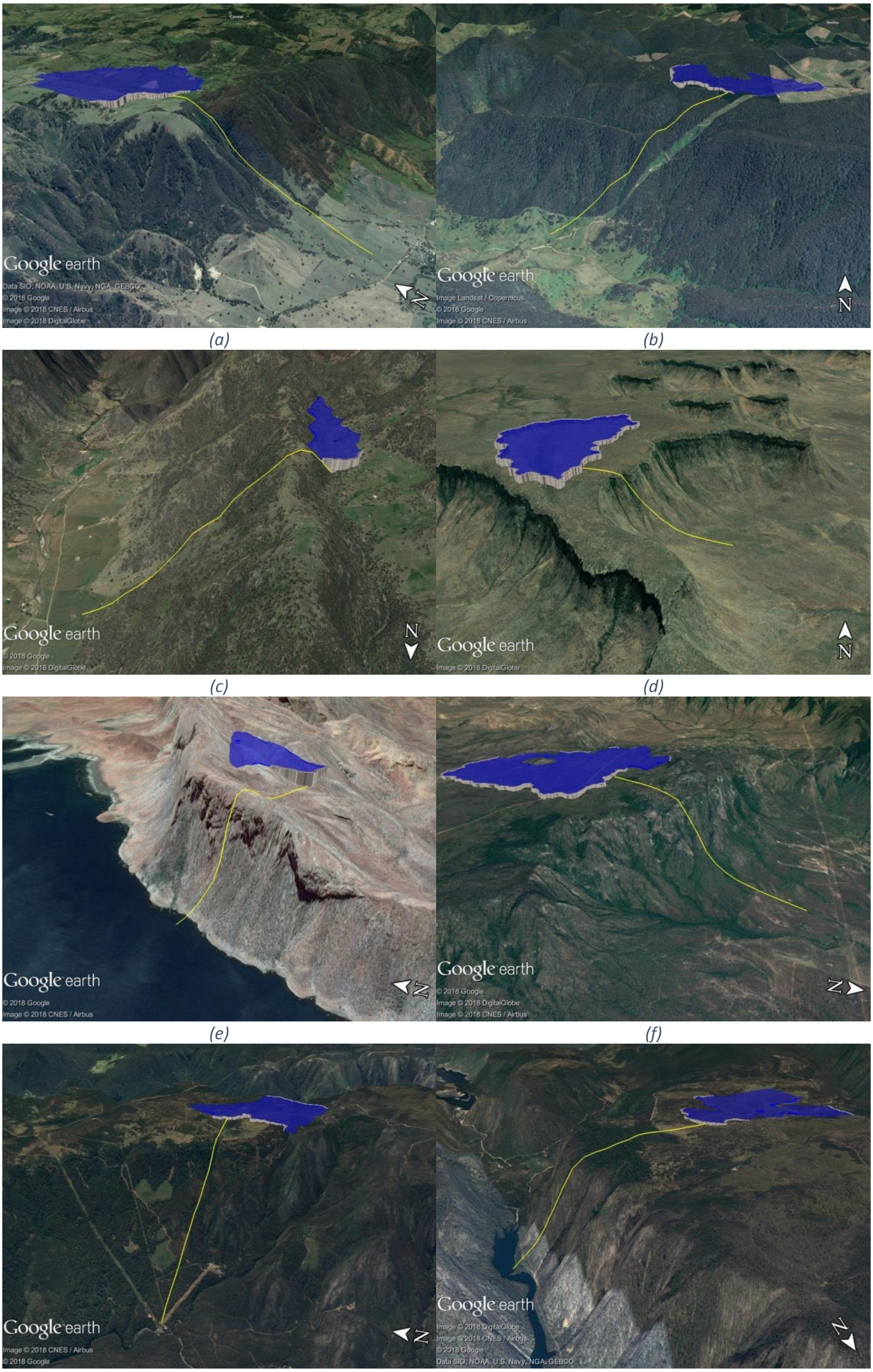


Figure 3-3 Example PHES sites with largest storage potentials or highest water-to-rock ratios in each state/territory of Australia.

Figure 3-4 shows the existing HVAC transmission lines (> 132 kV) from Far North Queensland down the east coast to South Australia and Tasmania. Clearly, a significant number of sites are located within close proximity (< 100 km) to the high-voltage transmission network. An example site is shown in Figure 3-3 (b). Pumped hydro is capable of large-scale energy time shifting and a range of ancillary services, which can facilitate high levels of photovoltaics and wind integration in electricity grids.

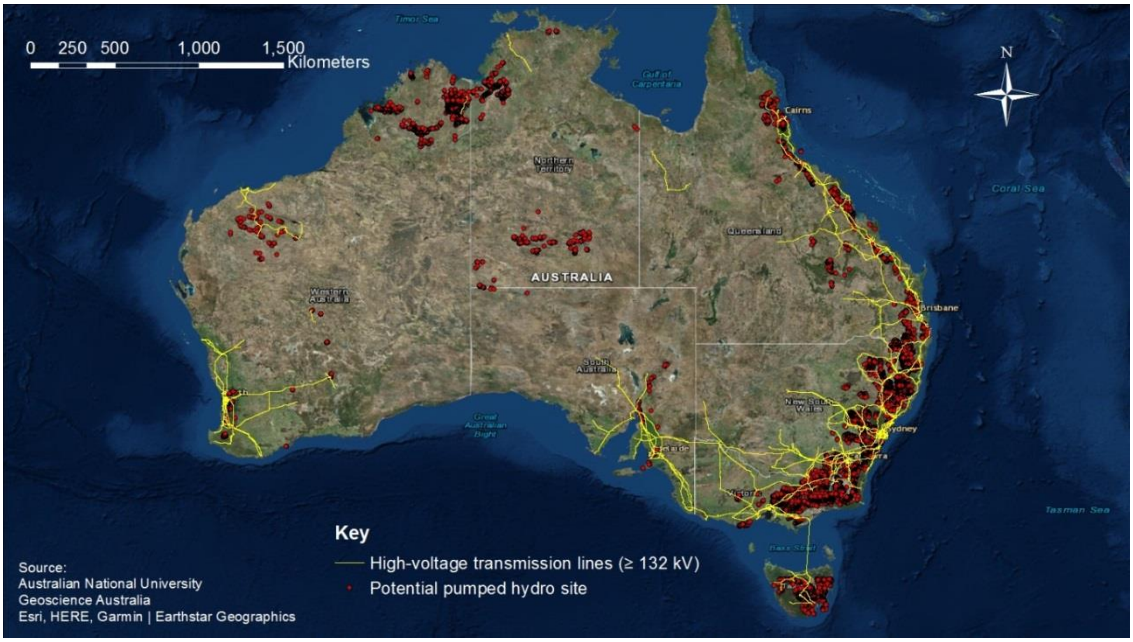


Figure 3-4 Existing high-voltage transmission network (≥ 132 kV) overlaying the Atlas of pumped hydro energy storage. A significant number of possible sites are located within close proximity to existing high-voltage transmission lines. Data source: Geoscience Australia [142].

Figure 3-5 and Figure 3-6 overlay a national solar and wind resources map with the atlas of pumped hydro energy storage. Northwest Australia has the world's best solar resource. Electricity generated from this source could potentially be exported to the populous Southeast Asia by submarine HVDC cables. Cooperated with PHES, the capacity factor of expensive submarine cables can be increase by a factor of 4 [71]. Dozens of pumped hydro sites have been identified adjacent to the Lake Argyle (98,000 hectares, 10,700 GL) [143] located in the Kimberley region, Western Australia, with the hydraulic heads ranging upwards from 200 m. An example site "Site no. S17E128_RES_3308" (36 ha, 6 GL, 200 m head, 2 GWh) is shown in Figure 3-3 (e).

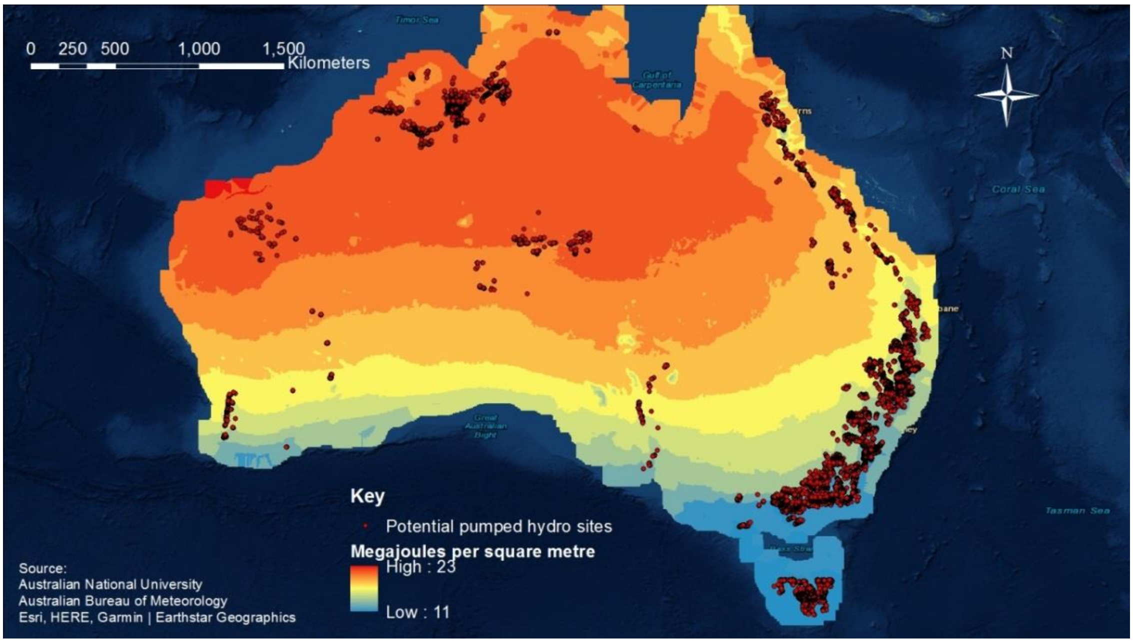


Figure 3-5 Average daily solar exposure in Australia (1990-2011). Australia's North West has world-class solar resources, which can be potentially exported to the populous Southeast Asia by the support of pumped hydro energy storage. Data source: Australian Bureau of Meteorology [144].

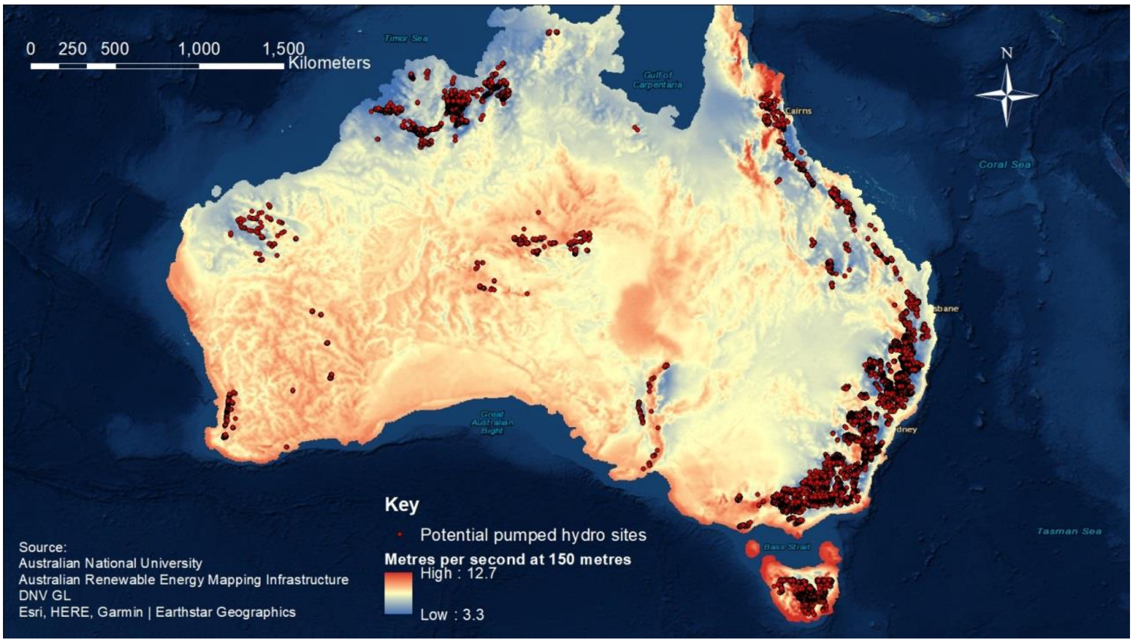


Figure 3-6 Average wind speed at 150 metres in Australia (2005-2014).

Similarly, the pumped hydro sites located in Far North Queensland and the north of South Australia can support large-scale exports of solar and wind electricity to the National Electricity Market by maximising the utilisation of long-distance (1,500 km) HVDC or AC transmission lines. Far North Queensland has different weather systems from the southern states (New South Wales, Victoria) and the sunsets in northern South Australia are one hour behind the east coast, which help to decrease the correlations of PV and demand in the NEM [116].

Furthermore, PV, wind and PHES hybrid systems can facilitate long-term (25 years) reliable energy supply to mining activities (Figure 3-7) such as the Olympic Dam mine (copper, uranium, silver and gold) located in northern South Australia, which has a continuous electricity demand of 125 MW (load factor 80%) [145]. The LCOE of PV, wind and PHES hybrid systems may be competitive with long distance high voltage transmission or diesel-/natural gas-fired power plants because of rapidly increasing fuel costs. Co-location of PV, wind and PHES hybrid systems and ore deposits enables electricity supply for exporting renewable energy refined metals such as iron (in place of iron oxide) in the Pilbara as well as hydrogen-based fuels including hydrogen, ammonia and synthetic natural gas.

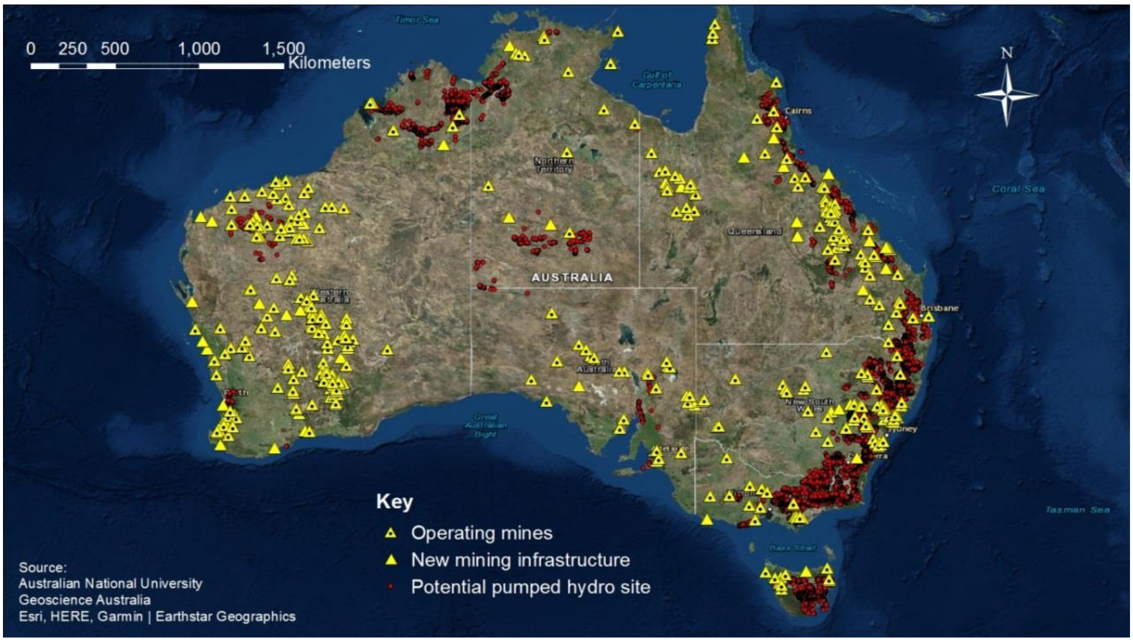


Figure 3-7 Operating mines and new mining infrastructure in Australia. Photovoltaics, wind and pumped hydro energy storage hybrid systems can provide long-term reliable electricity supply to mining activities and a future electrolytic hydrogen-based industry. Data source: Geoscience Australia [146].

Floating PV (floatovoltaics) is interesting. Deployment of solar panels on water surface can help to reduce evaporation and algae growth, and also potentially increases energy production due to the cooling effect, as well as minimising land use. According to a NREL study [147], the floating PV systems can contribute to 9.6% of electricity generation (786 TWh every year) by deployment of solar panels on 24,419 man-made water bodies in the contiguous USA, where either high land acquisition cost e.g. California and Florida or high electricity price e.g. California and New York was observed. A 40 MW floating solar farm has already in operation and a number of 100 MW-scale floating solar farms are under construction in China [148].

However, it is noted that, in a STORES system, water is frequently cycling between upper and lower reservoirs and storage level varies from full to nearly empty within a few hours, which may affect the stability of floating PV structure especially for those “irregular” dry-gully sites. Instead, in Australia, locating solar panels adjacent to the reservoirs will be much straightforward like the Kidston Renewable Energy Hub (solar 270 MW + PHES 250 MW, 2000 MWh) in Queensland, Australia [149].”

3.4 Discussion

3.4.1 Applications of the Geographic Information System model

This study investigates a series of advanced Geographic Information System algorithms to locate prospective sites for pumped hydro, with a focus on short-term off-river pumped hydro energy storage. The Geographic Information System algorithms highlight the promising regions for pumped hydro developments with a variety of search criteria (Table 2 of Appendix D), which significantly reduce the searching scope ensuring computational manageability (Fig. 8 of Appendix D). Mapping of promising regions for pumped hydro developments as demonstrated in Fig. 6 and Fig. 7 of Appendix D, can be used for the planning of renewable energy development zones such as [150]. The automatic Geographic Information System-based procedures work efficiently in the identifications of dry-gully and turkey’s nest sites, and also yield a range of site information such as coordinates, elevation, water surface area, storage capacity, dam length and volume (Fig. 9 of Appendix D).

As described in Appendix D, STORES refers to closed-loop PHES systems located away from rivers, which are to be built on large flat lands or within enclosed dry gullies (the “Greenfield” sites) separated by large altitude difference, typically > 300 m. Figure 3-8 (a) shows a typical greenfield PHES site, the proposed Coffin Butte Pumped Storage (20 ha, 3 GL, head/distance: 320 m/1.5 km) located in Montana, the United States, which is capable of 250 MW with 9 hours of energy storage.

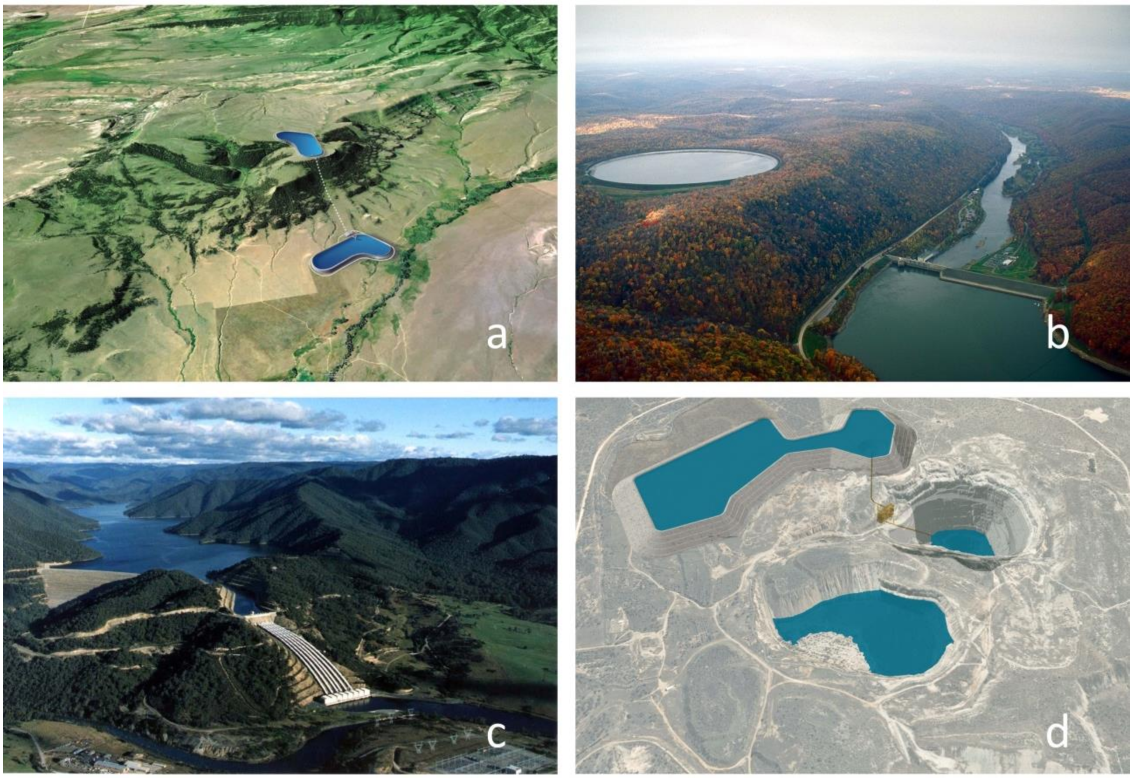


Figure 3-8 (a) Coffin Butte Pumped Storage Hydro, Montana, the United States: the initial fill is obtained by a temporary diversion on Miller Creek while the losses of evaporation and leakage are supposed to be supplemented by groundwater. (b) Seneca Pumped Storage Generating Station, Pennsylvania, the United States. (c) Tumut 3 Hydroelectric Power Station, Snowy Mountains, Australia. (d) Kidston Pumped Storage Hydro Project, Queensland, Australia. Image source: Absaroka Energy https://absarokaenergy.com/coffin-butte/; Wikipedia https://en.wikipedia.org/wiki/Seneca_Pumped_Storage_Generating_Station; South East Region of Renewable Energy Excellence http://www.serree.org.au/opportunities/article/?id=snowy-hydro-current-tenders; Entura http://www.entura.com.au/projects/7179/.

In a broader sense, STORES facilities can also include existing reservoirs that are affiliated to legacy hydroelectric or water schemes, which can be utilised as upper/lower reservoirs of a PHES system (the “Brownfield” sites). In a brownfield PHES site, however, a natural flow is usually involved and hence they are not strictly closed-loop PHES systems. They have the advantages of no shortage of water availability and less impact on environment and natural landscape compared with conventional river-based hydroelectric/PHES projects. An example of brownfield sites is shown in Figure 3-8 (b), the Seneca Pumped Storage Generating Station located in Pennsylvania, the United States, which utilises the Kinzua Dam, primarily for flood controls and hydropower, as a lower reservoir of PHES system. The Shoalhaven scheme located in New South Wales, Australia is also a brownfield PHES site which includes: (a) Kangaroo Valley Pumping & Power Station (Fitzroy Falls Reservoir - Bendeela Pondage, 480 m, 160 MW) and (b) Bendeela Pumping & Power Station (Bendeela Pondage - Lake Yarrunga, 120 m, 80 MW), originally for the Sydney water supply.

To assist the New South Wales Government Department of Planning and Environment in mapping of renewable energy resources, a comprehensive assessment of PHES resources, including both greenfield and brownfield sites, was conducted across the state of New South Wales which identified: (a) thousands of prospective greenfield sites (head > 300 m) widely distributed in the Great Diving Range region and, (b) hundreds of brownfield sites (head > 100 m) that are located adjacent to existing WaterNSW assets (40 dams/reservoirs). Given the water resources are relatively scarce in most of the states/territories of Australia, the greenfield/brownfield proportions may vary significantly when it comes to other regions outside NSW/Australia depending on local topography and hydrological conditions.

It is noted that for the STORES facilities, either greenfield or brownfield sites, no rivers (main stems of river) are to be dammed, no natural lakes located within nature reserve are to be utilised, and water requirement is much less than conventional river-based PHES due to the large hydraulic head as explained in Appendix D. Hence, the “pump-back” hydroelectric/PHES hybrid systems like Tumut 3 Hydroelectric Power Station located in Snowy Mountains, Australia (Figure 3-8 (c)) will not be included in the modelling. Instead, this kind of information may be included in a conventional resource assessment of hydropower potentials e.g. Gernaat et al. [49].

Additionally, old mining pits that can be transformed into PHES systems like the proposed Kidston Pumped Storage Hydro Project (Figure 3-8 (d)) located in Queensland, Australia may not be identified due to either low hydraulic head (< 300 m for example) or “out-of-date” terrain data in digital elevation models. In addition, the existing GIS algorithms (based on topography and land use) as described in Appendix D are not applicable to underground mines.

Particularly, the site for ocean-based PHES systems will be identified from the modelling as demonstrated in Figure 6 of Appendix D provided the search criteria e.g. minimum head-to-distance ratios, outside national parks can be satisfied. However, there are a range of technical challenges associated with the deployment of seawater PHES systems, including [140]:

- Lack of adequate cliff-top elevation difference, which means large volume of reservoirs and substantial land use are required to store sufficient electrical energy.
- Prospective coastal locations with large altitude difference are usually located in nature conservation or other protected areas.

- High construction costs related to corrosion resistance against saltwater and environment protection measures.

3.4.2 Conclusions

A comprehensive Geographic Information System-based site search for pumped hydro energy storage is conducted across each state/territory of Australia. Australia has a large storage potential in the form of pumped hydro energy storage, which is equivalent to 67,000 gigawatt-hours - far beyond (> 100 folds) the storage requirements to support 100% renewable electricity in the Australian energy markets.

Significantly, a large number of possible sites are located close to existing 275-500 kilovolts transmission infrastructure (Figure 3-4), which allows low connection costs to integrate pumped hydro systems facilitating high penetration of photovoltaics and wind energy within electricity systems. Prospective pumped hydro sites in Far North Queensland, the north of South Australia and North West Australia such as the Kimberley and Lake Argyle regions are co-located with the world-class solar and wind energy resources (Figure 3-5, Figure 3-6), which can potentially enable large-scale electricity exports to the National Electricity Market and Southeast Asia by maximising the usage of long-distance high-voltage direct/alternating current transmission lines or submarine cables.

In addition, by stabilising weather-dependent solar and wind resources with pumped hydro facilities, photovoltaics, wind and pumped hydro hybrid systems can ensure long-term reliable energy supply to the mining activities located in remote areas far from electricity main grids (Figure 3-7). Photovoltaics, wind and pumped hydro hybrid systems also create opportunities for low-carbon energy transition in the refining industry, exporting high value-added commodities to the world.

The limitations of this work include,

- Firstly, geology information such as rock types and structures is not incorporated. Geology has a significant influence on the site selection and construction cost of dams.
- Secondly, apart from the exclusion of protected areas and intensive land use classes, there has been no investigation of land tenure and no discussions with land owners and managers regarding the land acquisition.

- Thirdly, this is not an exhaustive site searching. A number of turkey's nest sites located outside the stream network cannot be identified, which may add 5% or more to the total storage capacity as demonstrated in the South Australian study (Section 5 of Appendix D).
- Opportunities for pumped hydro systems with head < 300 m (< 200 m in Western Australia and the Northern Territory) beyond the search criteria are not investigated, which may overlook the potential sites located adjacent to old mining pits, existing water bodies (fresh water) and oceans. However, the dry-gully and turkey's nest models developed in this study are also applicable to the deployments of these types of pumped hydro by altering the search criteria.

Given the input of modelling only includes information that is usually publicly available such as digital elevation models and protected areas datasets, this model can also be applied to other regions outside Australia. By using the models developed in this study, high-resolution assessments of pumped hydro energy storage potentials can be efficiently conducted in elsewhere around the world.

4 Future work

Several projects stemming directly from the work of this PhD are currently in progress, and will published in due course.

4.1 Modelling of integration of demand flexibility in electricity systems

In this study, a combination of flexible energy sources (e.g. hydro and bio), geographic dispersion of solar and wind (HVDC & AC network) and large-scale energy storage (PHES) is modelled to figure out the optimal configurations of generation, storage and transmission facilities in the NEM (Appendix A) and the SWIS of Western Australia (Appendix B). In addition, the benefits of demand response in high renewable energy scenarios are also explored by allowing the NEM reliability standard to be released from 0.002% to 0.03%, i.e. assuming 2 GW (5% of the maximum peak demand) can be shed during the most difficult week of a year. This permitted level of unreliability leads to a reduction of $1-2/MWh in LCOE compared with zero unmet demand, equivalent to a value of $6,000/MWh for unmet energy.

In the context of large-scale integration of electric vehicles and heat pumps in electricity systems, demand response, especially active load management, will be a cost-efficient approach to balancing intermittent renewable energy supply and varying demand for electricity in real time, adding significant flexibility to renewable electricity systems.

As noted in Chapter 2.2.1, the existing model, NEMO, has a limited capability of modelling demand response and consequently a novel load management model will be needed to simulate active load shifting and shedding in response to energy deficiency or surplus in the systems. As an initial thought, load shedding can be modelled as a flexible energy source like hydro and bio while load shifting is similar to energy storage facilities, though it is actually a “discharge-charge” cycle instead of “charge-discharge” and subject to the constraints of availability and maximum duration. Hence, a comprehensive analysis of demand flexibility, not only for electric vehicles and heat pumps, but also for the original demand in residential and industry sectors, is necessary in the future study, which will form the basis of modelling active load management.

A "net load" model will be applied as demonstrated in Figure 4-1 and the optimal configurations of generation, storage and transmission facilities and demand response will be decided by an innovative simulation approach, which differs from conventional capacity expansion models and production cost models.

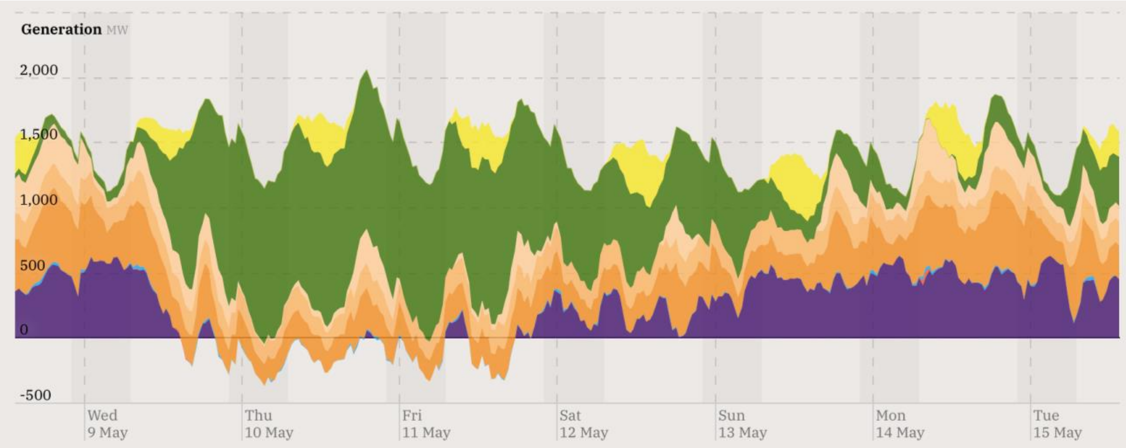


Figure 4-1 Load profiles and generation mix in South Australia between Wednesday 9 May and Tuesday 15 May 2018: solar (yellow), wind (green), natural gas (orange) and electricity import via interconnectors (purple). Image source: OpenNEM http://opennem.org.au

Nevertheless, there are a number of questions that need to be answered in the future study:

- Are the costs of residential batteries to be factored in the LCOE?
- How is the augmentation of distribution network and introduction of Smart Grid to be incorporated?
- Will there be a shift in the preference of solar PV over wind energy due to the reduction of additional PHES?
- How flexible is the electric vehicles demand i.e. to what degree the load can be shed or shifted?
- How can the renewable electrofuels e.g. methanol, dimethyl ether and methane help to mitigate GHG emissions in heavy-duty vehicles and industrial heating?

4.2 Exports of Australia's renewable electricity to the Asia-Pacific Super Grid

The Asia-Pacific region, including 38 countries/regions in East Asia and Pacific (or 46 countries/regions if including South Asia), constitutes 31% (or 55% including South Asia) of the world's population and 30% (or 33% including South Asia) of the global Gross Domestic Product [151]. In 2014, the primary energy consumption (215.361 quadrillion Btu equivalent to 63,116 TWh or 227,218 PJ) in Asia-Pacific contributed 15,290 million tonnes of GHG emissions, which accounted for 91% of the total GHG emissions in this region and 46% of the global GHG emissions from fossil fuel energy consumptions [1]. Notably, these figures are expected to increase due to the expected economic growth, population expansion as well as increasing urbanisation as noted in Chapter 1.1.2.

Several studies have envisaged a Super Grid across the Asia-Pacific region to facilitate large-scale integration of renewable energy resources that are diverse and widely-dispersed within different countries such as: (a) the world-class solar resource located in the northwest of Australia, (b) the excellent wind energy resources in North China and Mongolia, (c) the large hydropower potentials distributed in Southwest China and Indonesia, and (d) the high-temperature geothermal energy resources stored in the "Ring of Fire" e.g. Japan, Philippines and Indonesia (Figure 4-2).

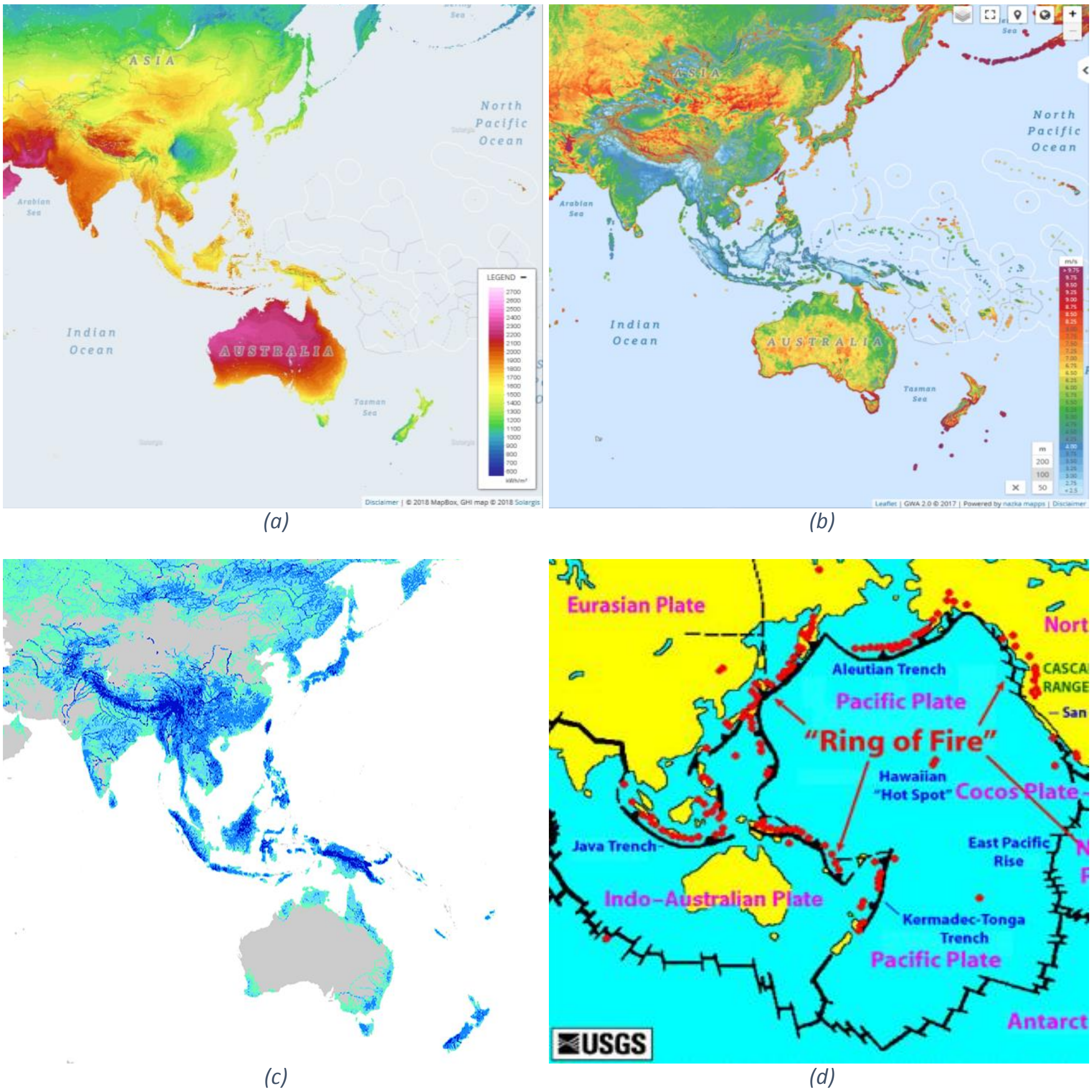


Figure 4-2 Renewable energy resources in the Asia-Pacific region: (a) Average annual sum of solar GHI, image source: Global Solar Atlas [152]; (b) Average wind speed at 100 m hub height, image source: Global Wind Atlas [153]; (c) Gross hydropower potentials, image source: Delft University of Technology [154]; (d) "Ring of fire": high-temperature hydrothermal energy resources, image source: National Oceanic and Atmospheric Administration [155].

For example, Blakers et al. [71] developed a concept of “Asia-Pacific Super Grid” which spreads over millions of squared kilometres extending from North China (wind resource), to Southeast Asia (large population density) and further to the north of Australia (solar resource). The southern countries of the Super Grid, including Indonesia, Singapore, Malaysia and Timor-Leste, are supposed to be powered by: indigenous solar (1/3), conventional energy sources (1/3) and the solar electricity from North West Australia (1/3) through a submarine HVDC cable across the Timor Sea.

The Global Energy Interconnection advocated by the State Grid Corporation of China (SGCC) includes a vision of “Asia Grid Interconnection”, which features a "5+1" interconnection comprising 6 regional electricity grids in North East Asia, Southeast Asia, South Asia, Middle Asia, West Asia and China. A direct Australia-Timor HVDC link is also suggested for the Asia-Oceania intercontinental interconnection.

Similarly, a “South-East Asia and the Pacific Rim Super Grid” is modelled in [109] from the Lappeenranta University of Technology (LUT), which includes 15 subregions in Australia, Indonesia, Malaysia and the Mekong countries with a projected population of 646 million and an annual electricity consumption of 1,629 TWh in 2030. By simulations of multiple 100% renewable energy scenarios including (sub)regional-wide, country-wide, area-wide and area-wide open trade with water desalination and industrial gas production, the study demonstrated that the LCOE for 100% renewable electricity in the Super Grid are in the range of €51-67/MWh while the LCOS vary between €10-21/MWh. Electricity grid interconnections between Australia and Papua New Guinea, Australia and New Zealand, the Australian NEM and the SWIS of Western Australia are also explored, though not recommended in its “Internet of Energy” model.

Recently, the Asian Renewable Energy Hub, which occupies 7,000 square kilometres located 250 km east of Port Hedland, aims to export 6 GW, equivalent to 20 TWh p.a. of solar and wind electricity to South East Asia from Pilbara. The Hub will also be a reliable and sustainable energy source for future developments of large-scale mining activities, metal refining industry and productions of electrolytic hydrogen, ammonia and synthetic renewable electrofuels (e.g. methane) in the Pilbara region.

Indeed, Australia has world-class solar resources in the northwest region of the country and excellent wind resources in Far North Queensland as shown in Figure 4-2, which can be potentially exported to the Asia-Pacific Super Grid. For example, the average annual sum of solar GHI in North West Australia is in the range of 2,200-2,600 kWh/m^2, comparable to the sunniest regions around the world such as the Middle East and North Africa region. In many locations of Far North Queensland, the average wind speeds at 100 m hub height are beyond 8 m/s, which means a 3 MW wind turbine e.g. Vestas V112-3.0 can be operated at its full capacity more than 40% times of the year translating to an average LCOE of $50-65/MWh. By contrast, solar resources across Indonesia, Singapore, Malaysia and East Timor are in the range of only 1,600-2,000 kWh/m^2 because of the cloudiness and heavy rainfall within the regions. Apart from the relatively low resource quality (solar, wind) and accessibility (e.g. geothermal), large-scale deployments of solar and wind farms in the Southeast Asia region are significantly constrained by land availability due to large population density.

Consequently, an intercontinental HVDC link between Australia and Southeast Asia (Indonesia) will enable large-scale solar and wind electricity exports to the Asia-Pacific Super Grid, facilitating low-carbon energy consumptions in the Asia-Pacific region. In addition, as stated in Chapter 1.3.2, balancing of renewable energy supply and demand on a much broader scale, i.e. continentally or intercontinentally, allows utilisation of different time zones from east to west and seasonal climate differences between the Northern and Southern Hemispheres, which helps to reduce the scales of electricity generation, storage and transmission facilitates delivering more affordable energy.

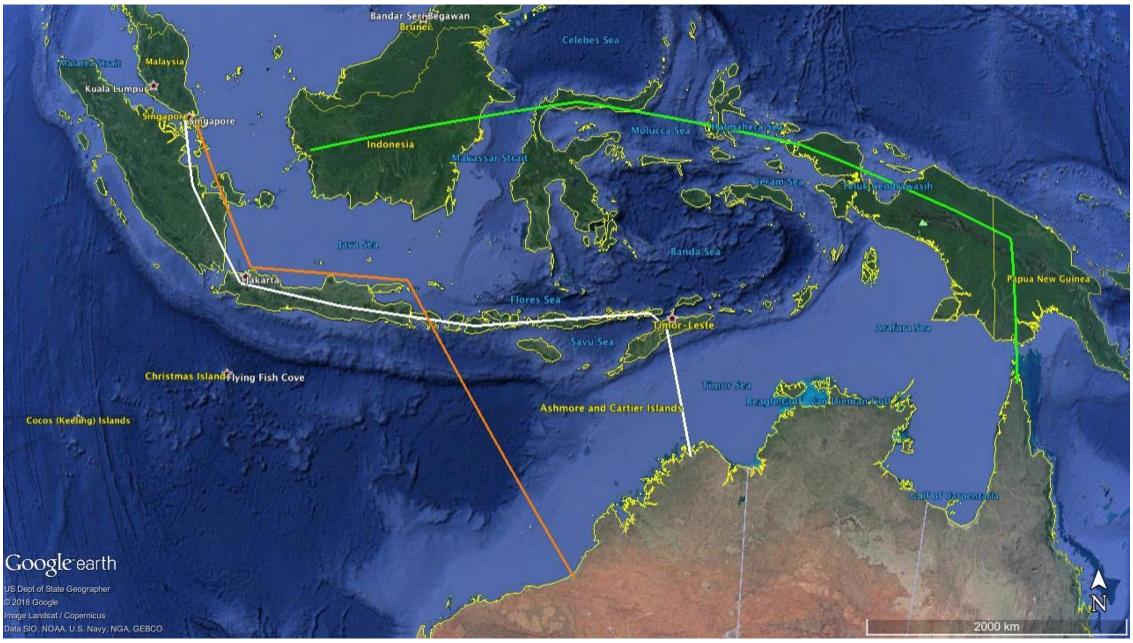


Figure 4-3 Possible routes for an Australia-South East Asia HVDC link: (a) Western route (orange): Pilbara-Java-Malaysia/Singapore, (b) Central route (white): Kimberley-East Timor-Indonesia/Malaysia/Singapore and (c) Eastern route (green): Far North Queensland-Papua New Guinea-South East Asia.

Basically, as noted in the previous studies, there are 3 possible routes for an Australia-South East Asia HVDC link (Figure 4-3):

- Central route: Kimberley-East Timor-Indonesia/Malaysia/Singapore, as recommended by [71, 109, 156]. This option features a shortest distance to the South East Asian load centres such as Java (1,500 km) and a large number of prospective sites around the Lake Argyle for future PHES developments. Co-located with solar and wind energy systems, PHES facilities are capable of large-scale energy time-shifting with a high round-trip efficiency of 80%, which allows 24/7 continuous electricity supply to the Asia-Pacific Super Grid. However, the Timor Trench has a maximum depth of 2000-3000 m in the Timor Sea as shown in Figure 5 of [71], which is a main technical challenge to install submarine HVDC cables.
- Western route: Pilbara-Java-Malaysia/Singapore. This is the route suggested by the Asian Renewable Energy Hub. Currently, $62 billion of ion ore and $27 billion of petroleum are produced in Pilbara each year and future developments of the Pilbara region include new mining activities (e.g. Eliwana iron ore mines) and production of renewable energy-rich export products (e.g. iron refining) and fuels (including hydrogen, ammonia and synthetic fuels). Although this option is significantly longer (2,000 km) than the alternatives such as the Central route, it allows to utilise solar and wind resources both for direct exports to South East Asia and also for the productions of high value-added products in Pilbara.
- Eastern route: Far North Queensland-Papua New Guinea-South East Asia, as examined by [109] . Compared with the Central and Western routes, this corridor takes advantages of a short submarine HVDC cable (200 km) in shallow seawater (10 m) and will connect the Far North Queensland region (with excellent wind resource and diverse weather systems) with the Australian National Electricity Market as a whole. Nevertheless, the Eastern route is located far away from major electricity networks and load centres such as Jakarta (> 4,000 km) and Brisbane (> 1,500 km) and hence is expected to have a relatively low economic value.

While the ANU, SGCC and LUT studies envisaged a conceptual HVDC link between Australia and South East Asia, a detailed analysis of the intercontinental interconnectors has not been conducted, including the following aspects:

- High-resolution assessments of solar and wind resources in the northern regions of Australia, both temporally (e.g. on an hourly basis) and spatially (e.g. at a resolution of 1 degree by 1 degree latitude/longitude grid cell).

- Comparisons between the 3 alternative routes i.e. Kimberley, Pilbara and Far North Queensland, which incorporate different meteorological and geographical characteristics.
- Future developments of hydrogen-based renewable energy industry such as in Pilbara, which adds significant demand flexibility to energy systems.
- A cost-benefit analysis including the estimates of: (a) LCOE of electricity generation, storage and transmission facilities and (b) revenues from energy arbitrage in the South East Asian energy markets, which indicates the economics of the proposed Australia-Indonesia HVDC link.

In this future study, exports of Australia's renewable electricity to the Asia-Pacific Super Grid will be further investigated, including the following topics:

- A comprehensive, high-resolution assessment of solar and wind resources in the northwest region of Australia. Meteorological data (solar GHI & DNI, wind speed) from the Australian Bureau of Meteorology and/or NASA will be utilised to simulate electricity generation from utility-scale solar and wind farms by using the System Advisor Model developed by NREL [157]. As initial estimates based on the average solar radiation and wind speed obtained from the Australian Renewable Energy Mapping Infrastructure, the capacity factors for 1-axis tracking PV (e.g. Trina Solar TSM-315PD14) are expected to reach 22-25%, while for wind turbines (e.g. Vestas V112-3.0 MW), it may be in the range of 30-45%. Resolutions of the proposed solar and wind resource assessments, both temporal and spatial, will be decided on the basis of resource quality, accessibility and its geographic distributions.
- Modelling of an intra-state HVDC & AC network in North West Australia, which transfers GW/TWh-scale solar and wind electricity from renewable energy resource to the export energy hub and local load centres such as Pilbara. Applications of HVDC technologies i.e. LCC-HVDC or VSC-HVDC, overhead power lines or underground cables will be further discussed in the study. The scales of HVDC & AC infrastructure may be in the range of 1-15 GW depending on the locations of HVDC links and more importantly, the roles of the Australia-Indonesia intercontinental connections in the South East Asian electricity markets.
- A cost-benefit analysis of exports of Australia's solar and wind electricity to the Asia-Pacific Super Grid including: (a) Calculations of LCOE (in terms of $/MWh) for the PV, wind, PHES and HVDC & AC hybrid systems established in the northwest of Australia. Mathematical optimisations e.g. using Linear Programming or Mixed Integer

Programming will be included to figure out the optimal configurations of electricity generation, storage and transmission facilities, i.e. the least-cost solutions of exporting Australia's renewable electricity to South East Asia; (b) Revenues from energy arbitrage in the Southeast Asian energy markets based on the volitalities of electricity price in Indonesia, Malaysia and Singapore.

- LCOE of the hybrid PV, wind and PHES systems to support local load centres such as Pilbara. PV, wind and PHES hybrid systems can facilitate long-term reliable energy supply to the mining activities and electrolytic hydrogen-based industry, as noted in Chapter 3.3. In light of rapidly declining costs of PV and wind as well as increasing fuel costs, this solution may become competitive with long-distance high-voltage transmission or diesel-/natural gas-fired power plants.

Grid interconnections of the South West Interconnected System (SWIS) and the North West Interconnected System (NWIS) of Western Australia will be discussed though may not be considered in the modelling, as the investments of this HVDC link may not be justified by the savings of production costs in the SWIS due to the following reasons: (a) No significant difference between the solar resources (resource quality and timing) in the SWIS and NWIS. In fact, the wind resources distributed along the southwest coasts of Australia are evidently better than those of the North West; (b) Moderate size of the SWIS (approximately 5 GW, 20 TWh), which means the economies of scale of HVDC links for long-distance, bulk energy transfers (e.g. 7-11 GW over 1,000-2,000 km) may fail to be well represented; (c) Energy security, which requires large reserves to cope with the transmission failures. According to SGCC, the forced outages of LCC-HVDC infrastructure are expected to be 2 times per pole p.a. and 0.05 times p.a. for a bipolar failure.

A national-scale site survey for PHES across each state/territory of Australia has been conducted as described in Chapter 3.3, which demonstrated a large amount of potential sites located in the North West (Figure 3-2). Cost information derived from the costing models, developed by ANU in collaboration with B&V and GHD, will be integrated in the LCOE calculations of PV, wind and PHES hybrid systems in terms of \$/kW and \$/kWh. However, further investigations of PHES sites such as dam wall heights ranging from 10-80 m, locations of adjacent lower reservoirs, pairings of upper and lower reservoirs are outside the scope of this study but will be included in other studies of the ANU 100% Renewable Energy Group. In addition, alternative energy storage technologies such as batteries and concentrating solar power coupled with high-temperature thermal energy storage will be discussed, while may not being included in the modelling because of the overwhelming advantages of PHES in cost, efficiency and technology maturity as stated in Chapter 1.3.4.

4.3 A global atlas of potential sites for pumped hydro energy storage

Subsequent to the work of developing a national atlas of PHES in Australia as demonstrated in Chapter 3, a global-scale site survey for short-term off-river PHES is now being proposed. Given the world's land area is approximately 130 million squared kilometres excluding Antarctica [151], 10-20 times larger than Australia, the proposed work will significantly expand the computation requirements (CPU, memory and storage) for high-resolution site searching, for example, from 1 kSU to, roughly speaking, the magnitude of tens or even hundreds of kSU.

A statistic of the computation time for PHES site searches in South Australia, Queensland, Tasmania, ACT and the surrounding areas is shown in Table 4-1, where the average CPU usage is > 80%. Depending on the suitability of topography and land use, the computation time for PHES site searches ranges from 0.02 to 7 seconds per square kilometre, with an average of 3. Hence, a global-scale PHES site searching on millions of square kilometres is expected to consume up to one million CPU-hours.

Table 4-1 Processing time for site searches in South Australia, Queensland, Tasmania, ACT and the surrounding areas.

Case studies	Land area (km^2)	Promising regions (% of the total)	Number of calculations (Type 1)	Number of calculations (Type 2)	Processing time[1] (hours)
South Australia	983,482	0.17	2,565	423	5
Queensland	1,730,648	1.85	36,416	7,978	106
ACT & surroundings	20,000	10.1	9,322	5,761	37
Tasmania	68,401	9.0	32,109	10,858	105

Note. Type 1 ≤ 111 cells (5 s), Type 2 > 111 cells (15-25 s).
Based on a Windows desktop (8 cores): Intel® Core™ i7-3770 CPU @ 3.40GHz, RAM 16.0 GB.

Therefore, for a high-resolution site survey on a global scale, high-performance computing (HPC) resources will be required to cope with enlarged computational and storage requirements ensuing computational tractability. Porting the existing Python/ArcPy-based software to HPC resources such as the National Computational Infrastructure, Raijin, or the Amazon Web Services, will incorporate two major adaptions: (a) ArcPy/GDAL translation and (b) Parallel computing.

Similar to the Australian site survey, the following information will be integrated in the GIS algorithms described in Appendix D,

- Digital elevation models
- Land use datasets or data for protected areas/urban regions such as the World Database on Protected Areas and more [Data source: https://www.protectedplanet.net]
- Existing waterbodies
- High-voltage transmission network
- Political/administrative boundaries of states/territories
- Load centres, solar and wind resources, operating mines

A significant contribution of the proposed global PHES atlas will be the integration of cost information in high-resolution site surveys. As noted in Chapter 3.1, the "Beta" cost model is a generic costing tool, containing a PHES scheme (Figure 4-4). Cost functions of major components of a pumped hydro project at a pre-feasibility study level.

Worksheet	Outline
Spatial Model Input	User to input Upper Reservoir ID (cell C5) and Lower Reservoir ID (cell C7) and then press the "Reload" button (cell H2). Output of spatial model is imported to this worksheet and is used for the calculation of scheme costs in worksheets UC6B to UC12B.
Cost Model Input	User to input Upper and Lower Reservoir information output from the Find Reservoir Pair Model and then select the dam wall type, design power output, equipment efficiency from the provided drop-down menu. The user input is used for the calculation of scheme costs in worksheets UC6B to UC12B.
Scheme Summary	The total scheme cost for a single reservoir pair is presented which includes Power House, Convenyance System, Upper and Lower Reservoirs, Transmissions, Access Road, and Water Supply (UC6B to UC12B). Total construction cost, cost of energy storage, and Key Scheme data are also presented in this summary.
UC6B Power House	The Power House costs associated with cavern and tunnel excavation, stabilisation using shotcrete and rock bolts, concrete works, pump-turbine and motor generator, ancillary mechanical, ancillary electrical, instrumentation and control are calculated in this worksheet.
UC7B Intake & Penstock	The conveyance system construction costs associated with the intake tower and outlet conduit, above ground penstock and supports/anchor blocks, surge tank, tailrace tunnel, trash racks and stoplogs are calculated in this worksheet.
UC7B Intake & Tunnel	The conveyance system construction costs associated with the intake tower, vertical shaft, horizontal tunnel, tailrace tunnel, trash racks and stoplogs are calculated in this worksheet.
UC8B Upper Reservoir	The upper reservoir construction costs including foundation preparation and treatment by grouting, dam wall construction, and spillway construction are calculated in this worksheet. Both clay core rockfill dam and concrete-faced rockfill dam options are provided.
UC9B Lower Reservoir	The lower reservoir construction costs including foundation preparation and treatment by grouting, dam wall construction, and spillway construction are calculated in this worksheet. Both clay core rockfill dam and concrete-faced rockfill dam options are provided.
UC10B Transmission	The transmission costs including transformers, terminal/switch yard, transmission line, and grid connection are calculated in this worksheet.
UC11B Access Road	The access road and bridge costs including roads to upper reservoir, lower reservoir, and power house are calculated in this worksheet.
UC12B Water Supply	Costs associated with first filling are calculated in this worksheet. It's assumed the first filling is via nature (rain, snow water etc.), pumping bore water and transfer via pipeline, and water carting bore water.
Unit Rates	The default unit rates used in the scheme cost estimation (UC6B to UC12B) are stored on this worksheet.
Design Parameters	The worksheet summaries the design parameters of the PHES scheme including design freeboard, crest width and slope gradient of the dam wall, design operating water levels of the reservoirs, gross head and net head, design flow rates in turbine mode and pumping mode, numbers of pump-turbine sets, penstocks, tailrace tunnels, access road type and width, and pipe diameter and water cart size for initial reservoir filling. The fields on this worksheet are not editable by the users.
Reservoir Curves	This worksheet generates reservoir curves using the reservoir information entered by the user on worksheet "Cost Model Input" and determine the relationship between water levels of the upper and lower reservoirs and the head available under different wate levels.
Lookups	Throughouot the sheet there are a number of drop down lists to aid user input. This tab contains those lookups

Figure 4-4 An outline of the costing tool (Beta), PHESCEM. Costs of the major components of PHES schemes are calculated in the models.

It is noted that, while the costs of storage components of a PHES scheme e.g. dam construction, reservoir excavation and lining are decided by local topography, geology and hydrology conditions, the economics of power components e.g. machinery parts (turbines/pumps, motors/generators, transformers and switchyards) and pipes can be heavily affected by the configurations of PHES facilities. For example, a prospective PHES scheme that has a storage potential of 1 GWh can be designed as 200 MW with 5 hours of storage or 100 MW with 10 hours of storage, which may have significantly different figures for $/kW and $/kWh and also the revenues from energy arbitrage. In this case, different assumptions will be needed for the following 2 types of PHES cycling: (a) daily cycling: 6-12 hours of storage in accordance with diurnal cycles of renewable energy, and (b) weekly cycling: 12-36 hours of storage, to cope with low solar/wind availability in several days within a week.

In addition, costs of flood controls, evaporation reduction and ice melting in high-latitude regions will be incorporated on the basis of local/regional meteorology and hydrology conditions.

It is noted that Australia is such a “fortunate” state where there are no active volcanoes [48] and the seismic hazard risk is relatively low due to its geographic location (the Australian Plate) away from the boundaries of tectonic plates. The largest historical earthquake recorded in Australia occurred in Tennant Creek, Northern Territory in 1988 with a magnitude of up to 6.6. However, when it comes to the “ring of fire” as demonstrated in Figure 4-2, additional costs for engineering reinforcement resistant to geologic hazards such as earthquake may be significant in the regions with high seismic hazard risk. In the future study, instead of defining “no-go” zones for PHES development, the geologic hazard information will be integrated in the mapping which indicates “preferable” or “less-preferable” site locations and helps decision making. A Global Seismic Hazard Map is available at: http://gmo.gfz-potsdam.de; https://mitnse.files.wordpress.com/2011/09/globalseismichazardmap.pdf

As a preliminary work, Figure 4-5 illustrates the promising regions for future PHES deployments in Europe, which are classified as 200 m, 400 m, 600 m and 800 m according to the potential head (the altitude difference between upper and lower reservoirs). A minimum head-to-distance ratio of 1:10 is assumed in the modelling, which is stricter than that of the Australian study due to the fact that Europe has extensive mountainous regions in the South while Australia is the flattest continent of the globe. Protected areas, based on the World Database on Protected Areas, have been excluded from the promising regions.

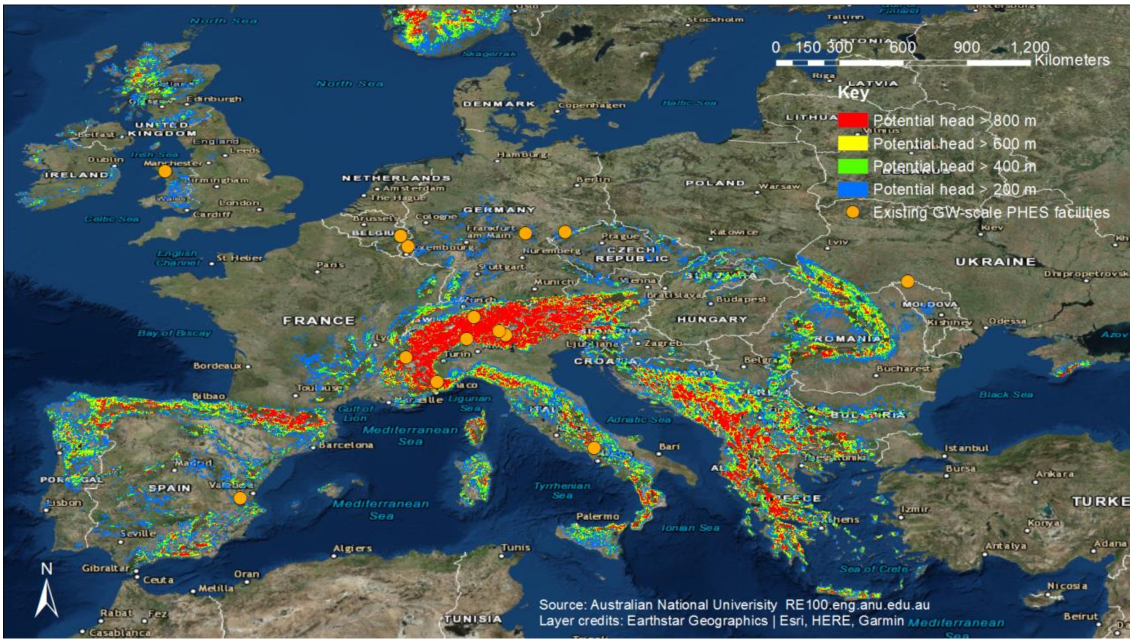


Figure 4-5 Promising regions for PHES deployments in Europe: latitudes 35 N - 60 N, longitudes: 11 W - 40 E.

Figure 4-5 demonstrates that large storage potentials may exist in the regions of Alps, Apennines, Pyrenees, Dinaric Alps, Carpathian Mountains on Continental Europe and the Cambrian Mountains and Scottish Highlands in Britain. Large altitude difference (> 400 m) commonly exists in the Iberian Peninsula, the Alpine states, the Balkans as well as Scotland and Norway. By contrast, the opportunities for PHES development are much less the northeast countries of Europe such as Poland, Ukraine and European Russia due to the characteristics of flat terrain.

Existing GW-scale PHES facilities in Europe are marked on the map, which are in accordance with the ranges of potential head, including (ranked by head):

- Lago Bianco Pumped Hydro Storage Power Station, Switzerland: capacity 1,000 MW, head 1,300 m
- Edolo Pumped Storage Plant, Italy: capacity 1,000 MW, head 1,265 m
- Chiotas Hydro Power Plant (Entracque Pumped Storage), Italy: capacity 1,184 MW, head 1,050 m
- Grand'Maison Dam Pumped Storage Power Plant, France: capacity 1,820 MW, head 920 m
- Roncovalgrande (Lago Delio) Hydroelectric Plant, Italy: capacity 1,000 MW, head 740 m
- Dinorwig Power Station, UK: capacity 1,728 MW, head 520 m
- La Muela Pumped-Storage Plant, Spain: capacity 2,000 MW, head 500 m

- Domenico Cimarosa (Presenzano) Hydroelectric Plant, Italy: capacity 1,000 MW, head 500 m
- Goldisthal Pumped Storage Power Station, Germany: capacity 1,060 MW, head 300 m
- Markersbach Pumped Storage Power Plant, Germany: capacity 1,050 MW, head 300 m
- Vianden Pumped Storage Plant, Luxembourg: capacity 1096 MW, head 300 m
- Coo-Trois-Ponts Hydroelectric Power Station, Belgium: capacity 1,164 MW, head < 300 m
- Dniester Pumped Storage Power Station, Ukraine: capacity 2,268 MW, head 130 m
- Zagorsk Pumped Storage Station, Russia: capacity 1,200 MW, head 100 m (outside the scope of this map)

In summary, the promising regions for future PHES deployments in Europe occupy 2% (> 200 m), 1% (> 400 m), 0.6% (> 600 m), 0.3% (> 800 m) of the European land mass (approximately 10 million square kilometres). It is noted that, other than exclusion of protected areas as noted above, there is no investigation of land tenure/acquisition within these regions. Detailed information on land availability or land use management may be collected and integrated in future country-by-country site searches. Geology, hydrology and meteorology information will be incorporated in a comprehensive, high-resolution site survey in Europe by applying the GIS algorithms [158] to the promising regions highlighted in Figure 4-5.

Similarly, maps of promising regions for PHES development in Africa, Asia (Central and West Asia, East Asia, South Asia, Southeast Asia), North America (USA & Canada, Mexico, Central America & the Caribbean), South America and Oceania are available from: http://re100.eng.anu.edu.au/research/re/for/.

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Appendices

Appendix A

A. Blakers, B. Lu, and M. Stocks, "100% renewable electricity in Australia," *Energy,* vol. 133, pp. 471-482, Aug 15 2017.

Appendix B

B. Lu, A. Blakers, and M. Stocks, "90-100% renewable electricity for the South West Interconnected System of Western Australia," *Energy,* vol. 122, pp. 663-674, Mar 1 2017.

Appendix C

A. Blakers, M. Stocks, and B. Lu, "Meeting Australia's Paris greenhouse commitment at zero net cost," The Australian National University, Nov 2017.

Appendix D

B. Lu, M. Stocks, A. Blakers, and K. Anderson, "Geographic information system algorithms to locate prospective sites for pumped hydro energy storage," *Applied Energy,* vol. 222, pp. 300-312, Jul 15 2018.

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100% renewable electricity in Australia

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ABSTRACT

An hourly energy balance analysis is presented of the Australian National Electricity Market in a 100% renewable energy scenario, in which wind and photovoltaics (PV) provides about 90% of the annual electricity demand and existing hydroelectricity and biomass provides the balance. Heroic assumptions about future technology development are avoided by only including technology that is being deployed in large quantities (>10 Gigawatts per year), namely PV and wind.

Additional energy storage and stronger interconnection between regions was found to be necessary for stability. Pumped hydro energy storage (PHES) constitutes 97% of worldwide electricity storage, and is adopted in this work. Many sites for closed loop PHES storage have been found in Australia. Distribution of PV and wind over 10–100 million hectares, utilising high voltage transmission, accesses different weather systems and reduces storage requirements (and overall cost).

The additional cost of balancing renewable energy supply with demand on an hourly rather than annual basis is found to be modest: AU$25–30/MWh (US$19–23/MWh). Using 2016 prices prevailing in Australia, the levelised cost of renewable electricity (LCOE) with hourly balancing is estimated to be AU$93/MWh (US$70/MWh). LCOE is almost certain to decrease due to rapidly falling cost of wind and PV.

1. Introduction

In this paper, Australian dollars are used and an exchange rate of AU$1.00 = US$0.75 is assumed.

It is interesting to consider the practicalities of supplying all of Australia's electricity from renewable energy. In this study a scenario is developed in which the National Electricity Market (NEM) is exclusively supplied by renewable energy. The focus is on hourly energy balance (meeting demand for every hour of the year).

Deployment of wind and solar photovoltaic (PV) electricity is overwhelmingly dominant in terms of new low emissions generation technology because they cost less than alternatives. PV and wind constitute half of the world's new generation capacity installed in 2014–16 (Fig. 1). In recent years, these sources provided nearly all new generation capacity installed in Australia.

In Australia, wind and PV are unconstrained by land or resource availability or water requirements or material supply or security issues. Hydro power is unable to keep pace due to the constraint that there are a limited number of rivers to dam, and bioenergy is severely limited by sustainable biomass availability [4,5]. Heroic growth rates are required for other renewable or low emission technologies (nuclear, carbon capture & storage, concentrating solar thermal, ocean, geothermal) to span the 10–1000-fold difference in annual deployment (GW per year) to approach the scale of wind and PV – which are moving targets since both industries are themselves growing rapidly and both access large economies of scale.

Currently, two thirds of Australian electricity comes from coal fired power stations. However, by 2030, three quarters of these power stations will be more than 40 years old, and replacement of these generators by coal, gas or renewable energy will be a looming necessity. For instance, Wallerawang C 960 MW (NSW), Anglesea 150 MW (Victoria) and Northern 530 MW (South Australia) and Hazelwood 1640 MW (Victoria) were closed during 2013–17 [6,7]. It seems unlikely that more coal fired generators will be constructed in Australia due to public opposition and risk aversion of financiers. In contrast, there is strong financial support for wind and PV in Australia, as evidenced by the fact that about 9 GW of wind and PV will be constructed over the next 3 years [8] in an economy whose GDP is about one thirteenth that of the United States of America.

Australia has excellent wind and solar resources. If current deployment rates of PV and wind (approximately 1–2 GW per year of each) continue then about half of the electricity generated in

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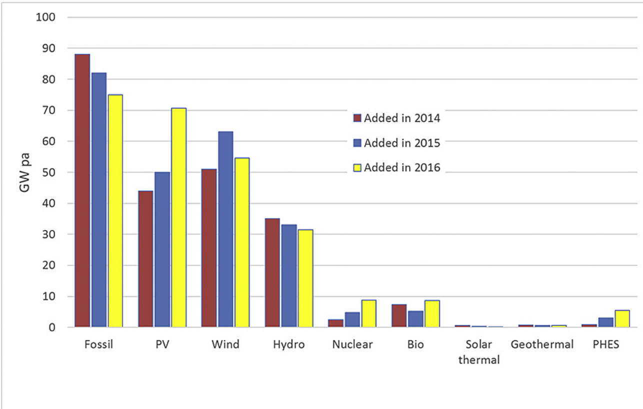

Fig. 1. Net new generation capacity added in 2014–16 by technology type. In 2016, about 125 Gigawatts (GW) of net new wind and PV was deployed, which is similar to everything else combined [1–3].

Australia in 2030 will come from renewable energy sources. In the state of South Australia wind and PV already provide about half of the annual electricity generation. The nearly zero marginal cost of PV and wind generation means that PV and wind electricity (when available) are used in preference to electricity from coal and gas. This causes declining system capacity factors for coal and gas power stations, which causes economic pressure on their continued operation. However, closure of coal and gas power stations removes the ancillary benefits that they provide, including coping with periods of poor solar and wind availability and managing short term supply fluctuations over differing time periods via inertia, spinning reserve and dispatchability.

This work differs from previous international work that examines high renewable energy futures in a range of countries. Bogdanov and Breyer [9] provide a good summary of previous work. Key differences from previous work are summarised in section 3.2.

This paper is divided into a modelling section and a results section. Within the modelling section we discuss generation, transmission, storage, grid stability, environmental considerations, economic parameters and the modelling methodology. Within the results section we include modelling outcomes, a sensitivity analysis and comparison with previous work. Finally, we include a discussion to place the modelling in context.

2. Modelling

2.1. Assumptions

We model the Australian National Electricity Market (NEM) which services 19 million people [10], but exclude the much smaller systems that exist in Western Australia, the Northern Territory and remote regions in other states (which are not connected to the NEM).

In our modelling, we make the following conservative assumptions:

- NEM demand remains stable at 205 TWh per year (including roof-mounted PV). NEM demand has changed little since 2008 [11], with energy efficiency offsetting growth in demand (driven mostly by population growth). Electrification of land transport (which could add 30–35% to electricity demand in the future [12]) is excluded in order to focus on the current electricity system.
- Batteries are excluded. Batteries located in homes and electric cars may contribute very substantially to future energy storage, either directly through bi-directional energy flow or indirectly through control of the timing of battery charging.
- Heroic assumptions about future technology development are avoided: the only low emission technologies considered are those that are being deployed in large quantities (>10 GW per year), namely PV and wind. On this basis, nuclear, bio, solar thermal, geothermal and ocean energy are excluded. We also exclude nuclear energy because of the unlikelihood of its deployment in Australia.
- High voltage DC (HVDC) and AC (HVAC) transmission and pumped hydro energy storage (PHES) is included to help provide balancing between supply and demand.
- Existing hydroelectricity generation and pumped hydro stations are included but additional river-based hydroelectric deployment are excluded due to lack of significant further rivers to dam in Australia. Existing biomass generation (based on agricultural waste) is included, but additional deployment of biomass is excluded because utilization competes with food, timber and ecosystem values for the provision of land, water, fertilisers and pesticides. Wind and PV contributed about 18 TWh in Australia in 2015, compared with hydroelectricity (14 TWh) and biomass electricity (3 TWh) [13].
- Our scenario is that wind and PV contribute about 90% of annual electricity consumption, while existing hydro and biomass contribute the balance.
- Energy balance modelling is undertaken using historical data for wind, sun and demand for every hour of the years 2006–10 and ensuring that there is sufficient electricity to meet demand in every hour through utilization of sufficient PV, wind, PHES and HVDC/HVAC. The Levelised Cost of Energy (LCOE) for each solution is then calculated.
- A modified and extended version of the National Electricity Market Optimiser (NEMO) model [14,15] is used to identify solutions which meet the energy balance requirement. NEMO is a chronological dispatch model. Several adjustments to the NEMO model have been made to better utilise the capability of synchronous, fast-ramping PHES to integrate fluctuating solar and wind energy. This includes pre-charging PHES facilities from existing bio and hydro plants to help ride through critical periods based on advanced weather forecasting; and changing the merit order of existing hydro ahead of PHES in critical periods to ensure PHES is not exhausted before the most difficult moments arrive.
- The NEM standard for unmet energy demand (0.002%) is required except where stated otherwise.
- Dynamical simulation for robustness under fault conditions is not included, such as unexpected transmission line breakdown, bushfires or widespread severe weather. However, we note that PHES provides significant inertia, spinning reserve and rapid response capability to help maintain a high level of dynamical grid stability. Although outside the scope of this study, dynamical stability will be included in future work.

2.2. Off-river (closed loop) pumped hydro energy storage

Pumped hydro energy storage (PHES) entails using surplus energy to pump water uphill to a storage reservoir, which is later released through a turbine to recover around 80% of the stored energy. PHES constitutes 97% of electricity storage worldwide (159 GW [3]) because it is much cheaper and has much greater technological maturity than alternative sources, including batteries.

Australia already has river-based PHES facilities comprising Wivenhoe, Kangaroo Valley and Tumut 3. However, the on-river opportunities are limited. There are opportunities to pair existing reservoirs, although it would be difficult to procure approvals for penstocks and additional power lines in national parks.

Unlike conventional "on-river" hydro power, off-river (closed loop) PHES requires pairs of hectare-scale reservoirs, rather like oversized farm dams, located away from rivers in steep hilly country outside national parks, separated by an altitude difference (head) of 300–900 m, and joined by a pipe containing a pump and turbine. In these systems, water cycles in a closed loop between the upper and lower reservoir. They consume little water (evaporation minus rainfall) and have a much smaller environmental impact than river-based systems. Energy storage volume (i.e. reservoir size) is typically 5–20 h at maximum power. Shorter hours (5–12 h) of PHES work well in summer and for energy arbitrage while longer hours (>12 h) are primarily to cope with rare sequences of consecutive days of low wind and solar availability in winter.

The energy storage capability of a PHES system is the product of the mass of water stored in the upper reservoir, the gravitational constant, the head and system efficiency. For example, a PHES system comprising twin 10 ha reservoirs, each 20 m deep, separated by an altitude difference of 700 m, and operating with a round-trip efficiency of 80%, can operate at 500 MW of power generation for 6 h (3000 MWh).

Australia has hundreds of excellent potential sites for off-river PHES, outside national parks and other sensitive areas, in the extensive hills and mountains that exist close to population centres from North Queensland down the east coast to South Australia and Tasmania (Fig. 2). Heads of more than 500 m are commonly available (Figs. 3 and 4). Some old mining sites are also available, such as the proposed 250 MW Kidston PHES project in an old gold mine in north Queensland [16].

Off-river PHES differs significantly from conventional river based hydro:

- the reservoirs are small (1–100 ha rather than thousands of hectares)
- minimal flood control measures are needed (off-river)
- the heads are 2–5 times larger because the upper reservoir can be on top of a hill rather than in a river valley. An increased head is advantageous because a doubled head allows doubling of energy stored and power developed, while the cost is generally much less than doubled.
- Minimal environmental impacts as there is no dam to be built on river systems

Alternative storage methods to PHES include batteries, compressed air and molten salt (in conjunction with solar thermal systems). Batteries are likely to be important in the near future competing with retail prices "behind the meter", and in electric vehicles. Compressed air and molten salt were excluded from this study because of the very small scale of deployment hitherto, and the consequent difficulty of obtaining reliable cost estimates.

2.3. High voltage DC transmission

Rapid improvements in high voltage DC transmission allows large amounts of power (GW) to be transmitted cheaply and efficiently over thousands of kilometres, meaning that adverse local weather can be accommodated using PV and wind power from elsewhere. An HVDC transmission line comprises two relatively expensive terminals, between which power is transferred at high voltage. There is more than 200 GW of HVDC installed worldwide, including powerlines carrying 6 GW at ±800 kV DC over 2000 km with energy loss of about 3% per thousand km [17,18].

In our modelling, we include an HVDC and HVAC "backbone" down the east coast of Australia and along the southern coast to South Australia. Terminals are located close to the major population centres (Brisbane, Sydney and Melbourne) or near the most important renewable energy sources. This HVDC/HVAC backbone passes within 200 km of three quarters of the Australian population (most of whom live within 50 km of the coast). The existing transmission and distribution system is connected to this HVDC/HVAC system to distribute power to consumers, and to transmit power from PV and wind generators to the HVDC/HVAC interconnector.

2.4. Local generation and demand management

Local generation refers to small scale systems, usually on urban rooftops. Australia presently has 1.5 million domestic roof-mounted PV systems (6 GW) from a housing stock of about 9 million dwellings (7.3 million in the NEM) [13]. Our modelling

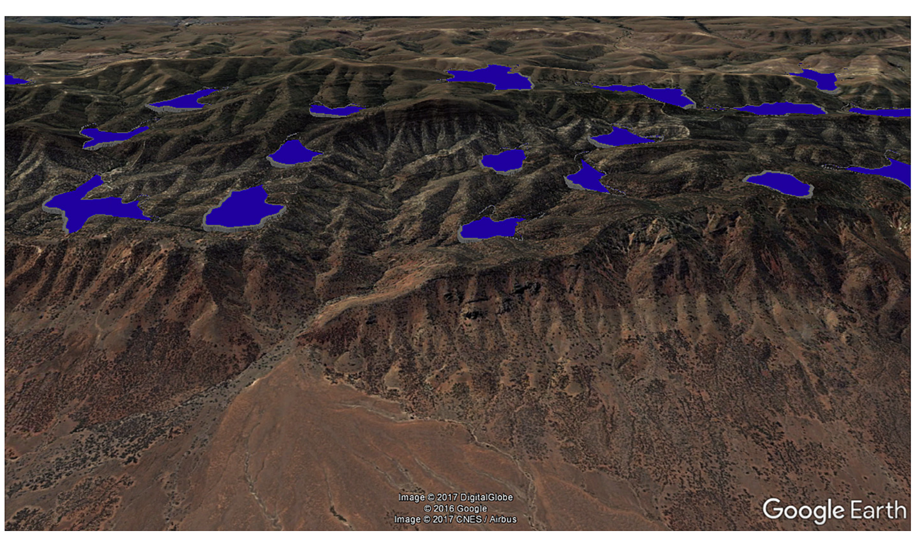

Fig. 2. Synthetic Google Earth image of hills east of Spencer Gulf (South Australia) with up to 600 m head showing hypothetical off-river upper reservoirs. The lower reservoirs would be at the western foot of the hills (bottom of the image).

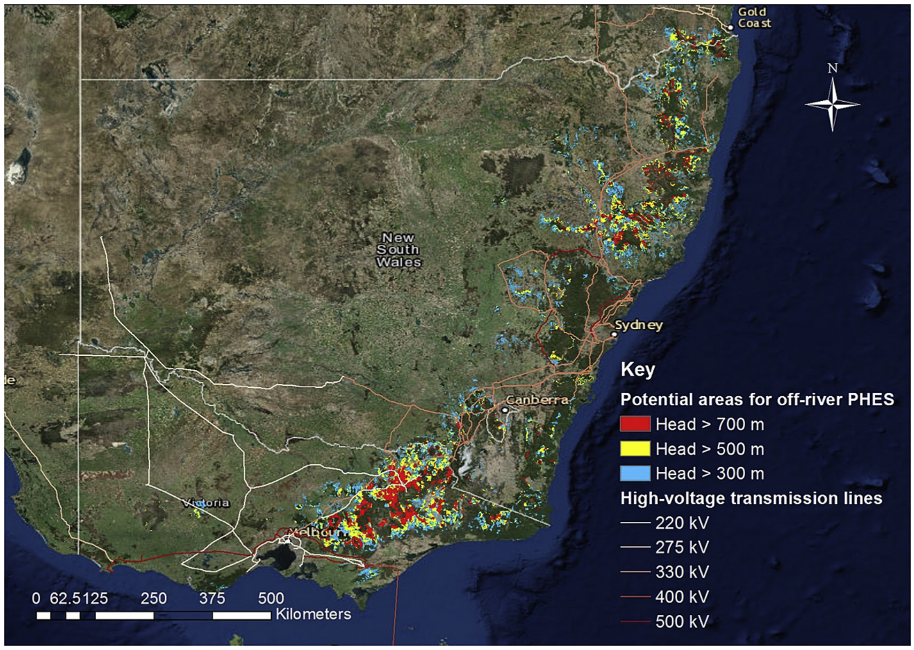

Fig. 3. Potential areas for off-river PHES between Brisbane and Melbourne (excluding national parks and other protected areas).

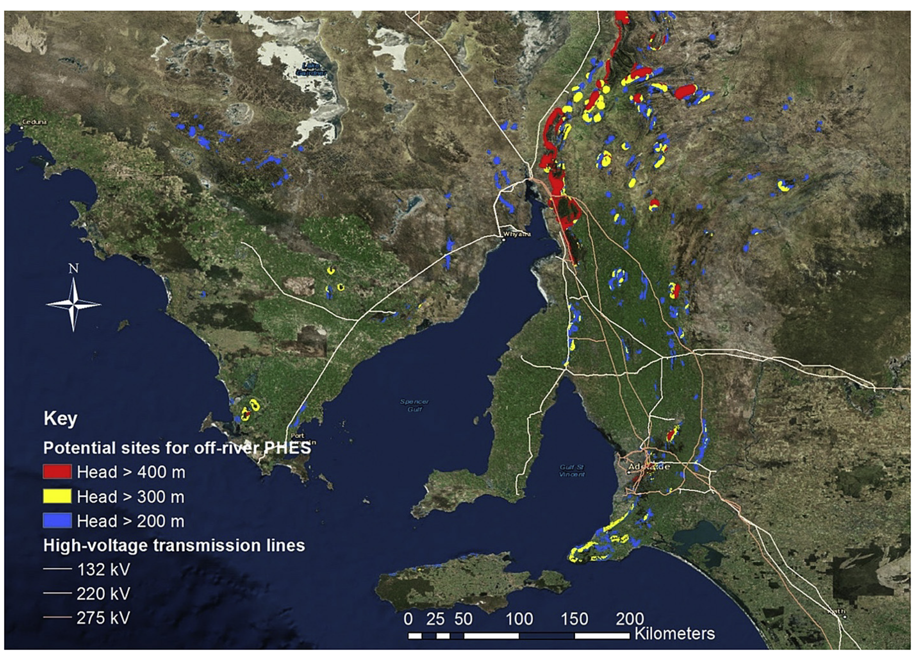

Fig. 4. Map showing South Australia's extensive array of potential PHES sites (excluding national parks and other protected areas). In general, larger heads (red areas) lead to lower cost.

recognizes the likelihood of continued substantial growth in privately funded rooftop PV systems. We assume that, in the future, one quarter of dwellings in the NEM are mounted with a fixed 5 kW PV system. Additionally, a similar capacity of solar panels is assumed on commercial building roofs. The total capacity of roof mounted systems is therefore assumed to be 17.3 GW, and based on simulation this yields 23 TWh of annual generation. This is about 11% of annual electricity consumption in the NEM (205 TWh per year).

These PV systems are distributed in the capital cities of each state, where the majority of the population lives. The output of these PV systems is assumed to be preferentially consumed before contributions from any other generator. Hourly demand is reduced by the modelled rooftop generation. The cost of these systems is absorbed by the building owners, and does not directly affect calculated electricity costs under this model. The modelling does include the cost of providing sufficient ground mounted PV, wind, PHES and HVDC/HVAC to provide hourly energy balance for the remaining demand for the entire electricity grid.

Demand management is an important tool for reducing the cost of a power system. Typically, the cost of meeting the last several percent of electricity demand (for example, the air conditioning load on a hot summer afternoon) is a large fraction of the total cost of electricity supply. Power demand management tools include interruptible industrial loads, adjusting air conditioning temperature settings, moving domestic and commercial water heating to times of abundant wind and sun, and in the future, managing the timing of household and electric car battery charging and discharging.

Most of the scenarios meet the NEM reliability standard of no more than 0.002% of unmet load (4 GWh per year) without demand management. However, in some scenarios demand management is employed during critical periods, which are typically cold wet windless weeks in winter that occur once every few years. During these periods the PHES reservoirs run down to zero over a few days because there is insufficient wind and PV generation to recharge them, leading to a shortfall in supply. The amount of PV, wind and PHES storage could be increased to cover this shortfall. However, this substantial extra investment would be utilised only for a few days every few years.

In some scenarios, demand management during critical periods is modelled by relaxing the NEM reliability standard. For example, the allowable unmet load might be increased to 336 GWh per 5 year period through contractually agreed load shedding arrangements. In most years demand would be fully met, but every few years this additional shortfall allowance would be utilised. Modern techniques allow cloudy and windless periods to be forecast (thus providing ample warning), and the PHES storages represent a substantial buffer. A portion of the savings in investment in PV, wind and PHES would be available to compensate certain consumers for partial loss of supply for a few days every few years. For example, reducing the overall cost of electricity supply by $2/MWh by allowing an unmet load of 336 GWh per 5 years would save $2 billion per 5 years, which is equivalent to $6000 per unmet MWh.

2.5. Stability of the NEM

In our study, we model scenarios in which the National Electricity Market is exclusively supplied by renewable energy, with most of this generation having limited controllability. PV and wind can be rapidly curtailed, but cannot be increased at will unless operating in a curtailed mode. Variable wind and solar power supply must be balanced with the uncontrolled (but reasonably predictable) instantaneous demand for electricity in real time.

The dynamical behaviour (on time scales of sub-seconds to minutes) of a 100% renewable energy grid is outside the scope of the present study. PV and wind are variable generators and lack the inertial energy storage possessed by conventional fossil, nuclear and hydro generators. However, this does not mean that a renewable electricity grid will be inherently less reliable than an equivalent fossil fuelled system. As previously noted, PHES can provide excellent inertial energy storage, very fast response time (typically 1% per second) and black start capability (to restore a collapsed grid).

Hundreds of wind and PV farms are statistically more reliable than several large fossil fuel power stations because breakdowns of individual generators have only a small effect on overall output. Wide distribution of wind, PV and PHES means that collapse of major transmission lines need not bring down local supply.

Solar and wind forecasting skill is already very good, and continues to improve. The combined output of thousands of wind and PV systems distributed over tens or hundreds of millions of hectares can be predicted on every time scale from seconds to years. Even a fast-moving weather event takes hours or days to move over a significant fraction of the PV and wind generators (and thus affect generation). This allows ample time for supporting measures to be taken in the event of widespread adverse weather conditions [19], such as moderating demand or drawing energy from storage. Furthermore, the output of wind and PV systems is often counter-correlated - for example, cloudy weather may be windy.

2.6. Environmental considerations

The area of land required for large scale off-river PHES is small. For example, 20 GW of PHES capacity with 20 h of storage (400 GWh), a head of 600 m and depth of 20 m requires a total reservoir area (upper and lower) of 36 km^2. This represents 5 parts per million of the Australian land mass, and is far smaller than the existing area of artificial reservoirs. Environmental impact is likely to be small because of the relatively small area of land required. No intrusion into protected land, river systems, urban areas or intensive agriculture is required, Very many potential sites have been identified and it will not be necessary to intrude upon national parks and other protected land. Similarly, sites that intrude upon visual, environmental, cultural, economic and other values can be discarded in favour of less intrusive sites.

Average annual evaporation in southern states is 1200–1800 mm and the annual rainfall ranges from 500 to 1000 mm in the Great Diving Range area [20,21]. Initial fill water will be transported from nearby water sources by pipelines or channels. Micro-catchments around the reservoirs can be built to collect rainwater maintaining the balance between rainfall and evaporation plus leakage. In addition, various evaporation and leakage reduction measures such as floating covers can be used to mitigate water loss by up to 95% [22].

Taking total reservoir area of 36 km^2, and an excess of evaporation over rainfall of 300 mm per year, the annual water requirement is 11 GL. This represents 0.3% of current water extraction from rivers under Murray Darling Basin Authority (MDBA) control. The cost of this water at commercial prices is small relative to other costs. Our modelling suggests that the cost of water delivery is a small fraction (~1%) of the cost of building and operating a PHES system.

2.7. Economic parameters

The levelised cost of energy (LCOE) is calculated using a real (i.e. inflation-free) discount rate of 5% per year. This includes bank finance for 70% of capital expenditure at a nominal rate of 5% per year, a return on investment of 10% (nominal) on equity (30% of capital expenditure) and an inflation rate of 1.5% per year. The Reserve Bank of Australia cash rate is currently 1.5% per year. Australian dollars are used, and an exchange rate of AU$1.00 = US$0.75 is assumed.

Our cost estimates pertain to 2016 costs in Australia. Our cost estimates of PV, wind and PHES in Table 1 are derived from the following sources:

2.7.1. PV

Data for the current cost of PV in Australia comes from the Australian Renewable Energy Agency (ARENA) large scale solar grant round. Approximately 600 MW_{DC} will be supported by ARENA, to be constructed during 2017. Most of the PV comprises single axis tracking systems located in Queensland and New South Wales, in the 15–50 MW range, at a cost of $1800 per kW. In view of the recent rapid fall in PV module prices, a figure of $1700/kW is used in our modelling. The DC capacity factor is around 23%, the lifetime is 25 years and the cost of operations and maintenance is $20/MWh [23]. This yields an LCOE of $78/MWh.

Table 1
Cost assumptions for power generation technologies.

Technology	Capital cost ($/kW)	Fixed O&M ($/kW/year)	Variable O&M ($/MWh)	Fuel cost ($/GJ)	Technical lifetime (years)
1-axis tracking PV	1700 DC[a]	0	20	0	25
Wind turbines	2300[b]	35	10	0	25
Pumped hydro	800/70[c]	10	0	0	50
Hydro (existing)[d]	–	49	10	0	50
Bio (existing)[d]	–	46	1	1–12	30

Note. Cost estimates for 2016.
[a] Source: ARENA Large Scale Solar program taking account of large recent falls in PV module price.
[b] Source: ACT reverse auctions (including indexing by CPI of the contract price).
[c] $800/kW for power components including turbines, generators, pipes and transformers; $70/kWh for storage components such as dams, reservoirs and water. Sources: private model.
[d] Purchase prices for existing hydro and bio are assumed to be $70/MWh.

2.7.2. Wind

The Government of the Australian Capital Territory (ACT) recently conducted three public reverse auctions which resulted in the contracting of the output of 600 MW of new windfarms. The energy price for each contract is a fixed number (no allowance for inflation). The price (after adjusting for inflation) is equivalent to $64/MWh. The figures presented in Table 1 are consistent with this figure using an assumed average capacity factor of 41%.

Our cost estimates do not include a carbon price or subsidies. PV and wind costs are very likely to continue to fall.

2.7.3. PHES

A private cost model is used, developed by an experienced hydro engineer based upon existing models. The model has been tested for consistency with publicly available PHES systems costs. The unit off-river PHES system is assumed to have a power of 200 MW, a head of 600 m, twin 20 m deep 5 ha "turkey nest" ponds with earth walls built on flat land, penstock slope of 13°, easy access, minimal flood control measures and a round trip efficiency of 80%. The estimated cost is $800 per kW (for penstocks, machinery and power conversion) and $70 per kWh (for pond excavation and construction), with scaling factors applied for different head and pond size. Head is a strong inverse driver of cost of storage. Transmission to a high voltage node is an additional cost and calculated separately.

2.7.4. Transmission

An HVDC connector has two major components: the two terminals and the cable in between. In addition, AC power lines deliver energy to the HVDC terminals. Our cost estimates in Table 2 are derived as follows:

The proposed $300 million, 100 km long, 2000 MW, 500 kV double-circuit AC, Krongart – Heywood interconnector in South Australia has an estimated cable cost of about $1500/MW-km [24].

We envisage sequential construction in the 2020–2030 timeframe of several independent overhead HVDC interconnectors, each 700–1500 km long, through flat country with good access (inland Australia). The interconnectors operate at a voltage of ±800 kV and have nominal power capacity of about 6–7 GW. On the basis of similar systems constructed around the world we estimate a cost of $400/MW-km [25].

Undersea HVDC cables between Victoria and Tasmania are estimated to cost $1 billion for up to 600 MW, 400 km. This estimate comes from the Tasmanian Government [26].

Our estimate for the cost of HVDC terminals is $1b for 2 paired converter stations up to 7.2 GW, and is derived from ±800 kV HVDC projects in China and India (for which the inverters and rectifiers were produced by ABB and Siemens) [17,18]. The high cost of HVDC terminals means that HVDC interconnectors operate from node to node without intermediate interconnections. Our cost estimates include HVAC connection to HVDC nodes.

2.8. Methodology

The NEM geographical region is divided into 43 cells and utilise historical hourly data for wind and PV in each cell throughout the years 2006–10, which comes from the AEMO 100% renewables study in 2012–13 [27,28]. Historical NEM demand data for every hour of the years 2006–10 is assumed as per the AEMO study [28].

Existing bio and hydroelectricity (about 10% of annual electricity demand) is assumed to be dispatchable. The existing river-based PHES is utilised.

We have modelled several scenarios and for each find many solutions with similar LCOE that cover demand for every hour of the years 2006–10. In general, there is a wide variety of combinations of PV, wind, PHES and HVDC/HVAC capacity and location that yields similar LCOE. Fig. 5 illustrates typical 3 day periods of supply and demand.

For each solution, we calculate quantities that we call the Levelised Cost of Generation (LCOG) and the Levelised Cost of Balancing (LCOB). LCOE is the sum of LCOG and LCOB.

LCOG is the weighted average cost of generation from each PV farm, windfarm, existing river-based hydro and existing bio power station as measured at its nearest high voltage transmission node (assuming no spillage).

LCOB comprises the capital and operations costs of PHES and

Table 2
Cost assumptions for high voltage transmission.

Component	Cost ($/MW-pair)	Cost ($/MW-km)	Technical lifetime (years)
HVDC terminals	140,000		25–50
HVDC transmission lines		400	50
Submarine HVDC cables		4000	50
HVAC substations & lines		1500[a]	50

Note. Cost estimates for 2016.
Cable lifetime: 50 years; terminal lifetime: 25 years.
[a] Assuming 50 km for wind farms and PHES, 10 km for solar farms located in existing transmission zones and 150 km for the inland regions.

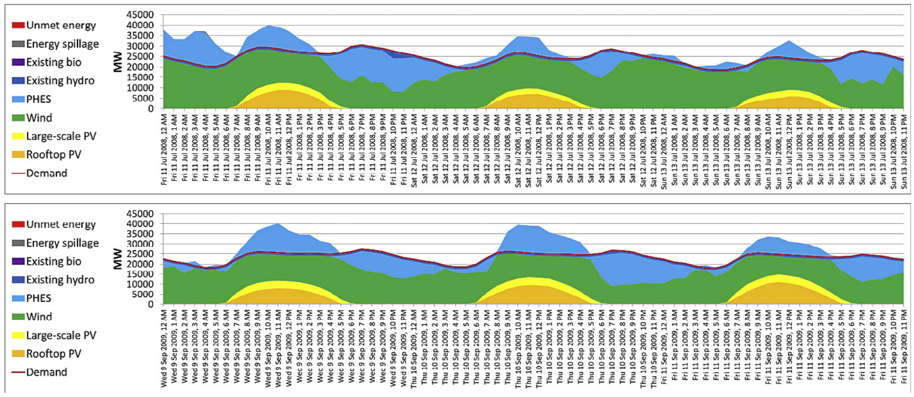

Fig. 5. Example demand and supply curves over the course of 3 days from the 100% renewables modelling. PV energy (yellow and gold) is supplied during the day. Wind energy (green) is available at most times. PHES is utilised in generation mode when demand (red line) exceeds the supply of PV and wind energy, and in pumping mode at other times.

HVDC/HVAC, round trip energy losses in PHES systems, resistive losses in HVDC/HVAC systems, and spillage of excess PV and wind energy during sunny and windy periods when storages are full (i.e. the cost of building excess wind and PV). For small penetrations of PV and wind LCOB is approximately zero and LCOE and LCOG are approximately equal. For large penetrations LCOB becomes significant to cover the cost of coping with the variability of PV and wind.

In general, LCOB is minimized by utilising PHES to store excess energy for later use (and thus minimize spillage), and by distributing PV and wind very widely using HVDC/HVAC (to take advantage of different weather systems in different regions). In some regions the output of PV and wind are counter-correlated and so utilization of both can reduce LCOB.

Fig. 6 illustrates Australia's wind energy resources [29]. Also shown are the major cities and a notional HVDC "backbone" interconnector that traverses the NEM and passes within 200 km of three quarters of the Australian population. In general, Australia has excellent solar resources west and north of this backbone (i.e. away from the sea and the Great Dividing Range). The four southern HVDC interconnectors service Tasmania, Victoria, South Australia, New South Wales and southern Queensland as shown.

Some of our modelling includes an HVDC interconnector to north Queensland to access an extensive area of excellent wind and solar resources. Importantly, this area generally experiences different weather from the south. In future work we will explore alternative options including a link to Perth in the west to access excellent wind and solar resources along the southern and western coastline. Additionally, a link to the west coast allows access to 3 h of time difference, and it typically takes several days for west coast weather to move to the east coast.

3. Results

3.1. Modelling outcomes

Representative results of our modelling are presented in Table 3 which cover the scenarios listed below.

- Current price for PV/wind: 2016 prices for wind and PV as listed in Tables 1 and 2 are used to establish a baseline. The current

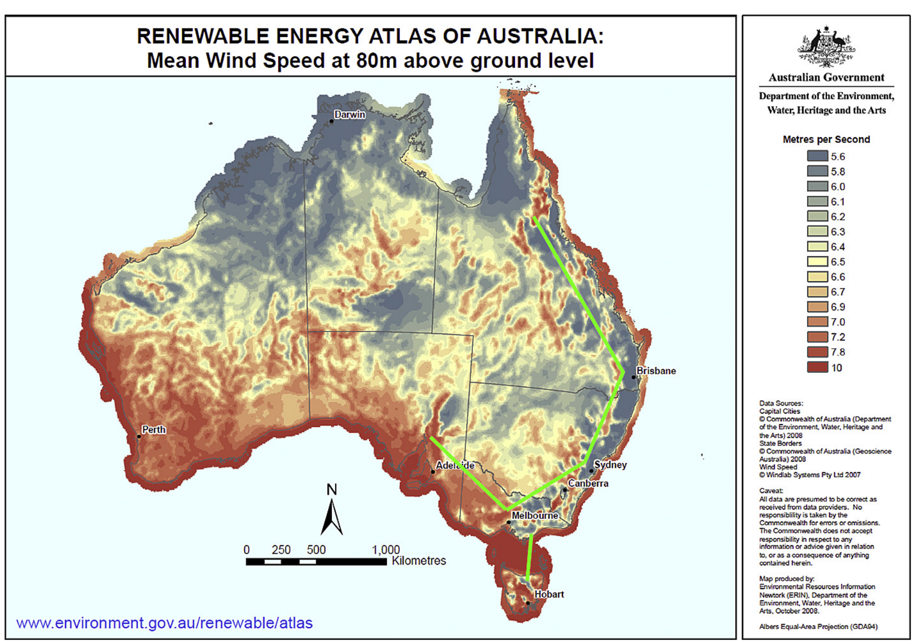

Fig. 6. Australia's wind energy resources and a notional HVDC "backbone" (green line).

Australian levelised cost of generation for wind and PV is estimated as $64/MWh and $78/MWh respectively. Current Australian prices pertain to small-scale (<1 GW per year for the whole country) wind and ground-mounted PV deployment and are very likely to fall in the future.

- Future prices for PV/wind: In some of the modelling future prices for PV and wind are used, for which both wind and PV are assumed to be $50/MWh. We do not predict when these prices might be achieved in Australia. However, there are numerous reports of such prices being achieved already in regions which do not have markedly superior wind and solar resources compared with those available within Australia [30–32].
- No FNQ HVDC: In baseline scenarios a 1500 km long HVDC interconnector to access excellent wind and solar resources in Far North Queensland (FNQ) is allowed for. FNQ generally has different weather from southern regions of Australia, and has less seasonal variation of solar availability. In some of the scenarios an FNQ interconnector is disallowed.
- Similar PV and wind generation: In the baseline scenarios, the relative proportions of annual wind and PV generation is unconstrained. In some of the scenarios the annual amount of wind and PV generation is constrained to be similar

We also present several sub-scenarios in addition to the baseline case.

- Demand management (DM): In baseline scenarios the unmet demand standard for the NEM (4 GWh per year, 0.002% of annual energy) is adhered to. In some scenarios this standard is relaxed through voluntary curtailment of demand by 2 GW (about 5% of peak demand) for 7 days over 5 years. This corresponds to an unmet demand of 336 GWh over 5 years (0.033% of annual energy).
- Add 50% to PHES or HVDC costs: Some sub-scenarios are modelling with 50% higher HVDC or PHES costs to test the sensitivity of the model to these cost inputs.

In each scenario rooftop PV power and energy generation amounts to 17 GW and 23 TWh/year respectively. Generation from existing bio and hydro amounts to 17–20 TWh per year and is purchased at a price of $70/MWh for current (2016) scenarios and $50/MWh for future scenarios. Annual electricity consumption is assumed to be constant at 205 TWh per year (corresponding to an average demand of 23 GW). Peak demand is assumed to remain at 35 GW.

For each scenario Table 3 shows optimised amounts of PV and wind in terms of power capacity (GW) and annual generation (TWh). The optimised PHES power capacity (GW) and hours of storage (h) at that capacity is also shown. The levelised cost of Balancing (LCOB), Generation (LCOG) and Energy (LCOE) is shown, together with the LCOB components. The total optimised storage (GWh) is shown, which is the product of capacity and hours of storage.

3.2. Sensitivity analysis

A sensitivity analysis has been performed on the baseline scenario by varying the following cost-components by ± 25%: PV, wind, PHES, HVDC/HVAC and discount rate. The effect on LCOE of varying parameters is except for wind capital cost and discount rate, for both of which the effect is ±$10/MWh (about 10%) (see Fig. 7).

3.3. Comparison with previous work

The key outcome of our modelling is that the cost of balancing energy supply and demand on an hourly basis for 100% renewable electricity supply is relatively small. This work differs from previous work that examines high renewable energy futures in a range of countries:

- PHES as a primary energy storage mechanism is generally overlooked; PHES constitutes 97% of worldwide storage for the electricity industry and is cheaper than alternatives;
- Much of the work is based on national analysis of relatively small countries where the weather and demand is similar everywhere, whereas large-scale interconnection (as in this paper) accesses a wide range of different weather and demand profiles, thus reducing the amount of required storage;
- Focus is generally on northern countries (Europe, north Asia, north America) for which heating loads are high and there is strong variation of solar energy supply by season. However, most of the world's population (including most Australians) live in latitudes lower than 35° for which there is low winter heating load and far less seasonality;
- Speculative technologies that are being deployed on only a small scale (<1 GW per year) are often included, whereas this is avoided in this work by only including those with global deployment rates above 10 GW per year. Because of mass production, wind and PV are considerably cheaper than alternative low emission technologies (except in special circumstances).
- Our estimated cost of supply of 100% renewable electricity is considerably lower than previous estimates, mostly because of the above-mentioned differences.

Bogdanov and Breyer [9] provide a good summary of previous work. They examined energy supply for high renewable energy penetration in north east Asia utilising mainly PV and wind for generation and batteries and power-to-gas as storage. Assumed PV and wind prices are well below those assumed in our paper. However, calculated LCOE is higher than $100/MWh, which is well above the comparable figure from our work. In common with our work there is a sharp fall in LCOE for continental-scale interconnection compared with regional interconnection because a wider range of weather and demand profiles are accessed. It would be interesting to repeat this study with the inclusion of off-river PHES as the major storage mechanism since it has a much higher round-trip efficiency and longer lifetime than power-to-gas.

Plessman [33] examined electrical supply and demand at an hourly level in 160 countries utilising PV, wind energy and concentrated solar power. Storage comprised “batteries, high-temperature thermal energy storage coupled with steam turbine, and renewable power methane (generated via the Power to Gas process) which is reconverted to electricity in gas turbines.” They found that LCOE (for 2020 technology prices) is in the range 80–200 EUR/MWh, ($120–300/MWh) which is well above the LCOE that we have found for Australia, even though the projected cost of PV and wind in the Plessman paper is well below the cost that we have assumed in our work. Compared with our work, this paper has passed over PHES in favour of other technologies that are in small scale deployment and hence their cost at large scale is speculative. The storage techniques suggested are considerably more expensive than PHES (taking account of round trip efficiencies and system lifetime).

The authors of this paper have recently modelled the South West Interconnected System (SWIS) in Western Australia using

Table 3
Modelling results. See text for details.

Scenarios	Sub-scenarios	Capacities, energy generation and spillage				Costs ($/MWh)			LCOB component costs ($/MWh)			Storage (GWh)
		PV (GW/TWh)	Wind (GW/TWh)	PHES (GW/h)	Spillage (%)	LCOB	LCOG	LCOE	PHES	HVDC&AC	Spillage & loss	
Current price for PV/wind	C1.1 Baseline	23/36	45/168	16/31	7%	28	65	93	14	7	7	490
	C1.2 Add DM	23/34	46/170	14/28	8%	26	65	91	12	7	7	407
	C1.3 Add 50% to PHES cost	23/36	45/168	16/31	7%	36	65	101	21	7	7	490
	C1.4 Add 50% to HVDC cost	23/36	45/168	16/31	7%	31	65	96	14	10	7	490
Future price for PV/wind	F1.1 Baseline	30/49	43/159	17/26	9%	25	50	75	13	6	6	430
	F1.2 Add DM	23/34	46/170	14/28	8%	24	50	74	12	7	5	407
	F1.3 Add 50% to PHES cost	30/49	43/159	17/26	9%	32	50	82	20	6	6	430
	F1.4 Add 50% to HVDC cost	30/49	43/159	17/26	9%	27	50	77	13	8	6	430
Similar PV & wind generation	C2.1 Current PV/wind price	57/103	34/127	24/21	18%	40	70	109	17	7	16	498
	C2.2 Current price + DM	59/107	35/129	25/12	20%	39	70	109	13	8	18	289
	F2.1 Future PV/wind price	60/109	36/134	26/15	23%	36	50	86	15	6	15	396
No FNQ HVDC	C3.1 Current PV/wind price	25/39	45/170	17/33	10%	30	65	95	16	5	9	565
	C3.2 Current price + DM	21/31	48/181	15/31	11%	28	64	92	14	5	9	469
	F3.1 Future PV/wind price	28/44	46/173	16/29	13%	27	50	77	13	5	8	452
Similar PV & wind + no FNQ HVDC	C4.1 Current PV/wind price	61/112	34/129	27/21	21%	48	69	117	19	9	19	574
	C4.2 Current price + DM	61/111	34/129	27/16	22%	42	70	111	16	6	20	425
	F4.1 Future PV/wind price	61/111	36/134	28/15	24%	37	50	87	16	6	15	417

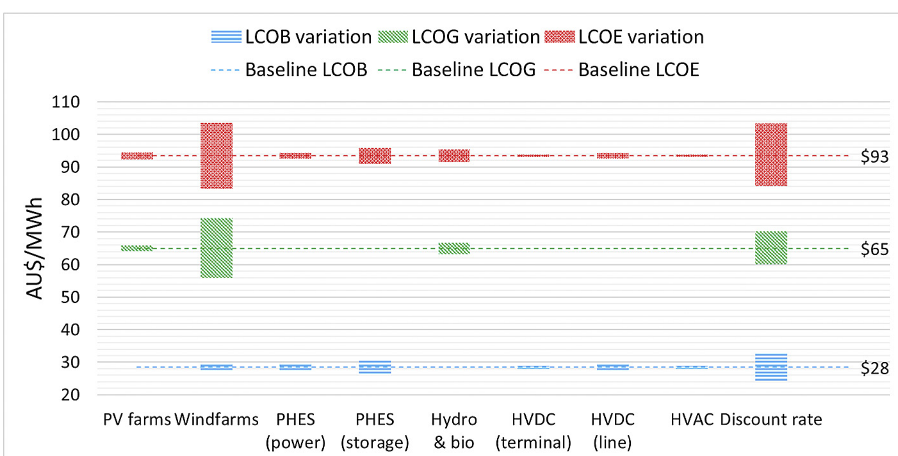

Fig. 7. Sensitivity of LCOE to variation of 25% in selected input parameters.

similar assumptions to those used here [34,35]. The major differences between the SWIS and the NEM are that the SWIS has much smaller geographical area (the weather patterns are generally the same everywhere) and that only small heads are available for PHES (200 m rather than 600 m). As a result, the cost of balancing supply and demand is about $40/MWh higher in the SWIS than in the NEM.

This work differs significantly from earlier simulations of 100% renewable electricity in the Australian Energy Market [14,28,36]. Table 4 lists the generation technology assumptions for these earlier works along with this study. All of these studies rely on significant capacity of technologies that have not been demonstrated at scale, in particular geothermal, concentrating solar thermal (CST) and biogas (where the supply of sufficient biomass is the constraining factor). In contrast, this work demonstrates that the system can manage variable generation provided it is well distributed and that sufficient low cost storage can be provided to balance supply and demand.

4. Discussion

In our modelling, we have optimised for a range of constraints, combinations and locations of PV, wind and PHES. Using 2016 prices we estimate that LCOB is $26–48/MWh. In a future scenario

Table 4
Comparison of 100% renewable energy studies for the National Electricity Market.

Generation technology	Capacity (GW)/Electricity generation mix (TWh pa)			
	AEMO 2013 [28] [a]	Elliston et al., 2013 [14] [b]	Lenzen et al., 2016 [36]	This study baseline
Rooftop PV	17/23	Included in Utility PV	4.1/8.5	17/23
Utility-scale PV	16.5/45	29.6/41	23.1/29.9	6/13
Wind	6/20	34.1/94.8	52.2/82.5	45/136
Pumped storage	Included in Hydro	2.2/0.5	–	16/16
Hydro	8/13	4.9/11.5	2.6/7.5	7.4/17
Biomass[c]	4/30	–	–	0.6/1
Biogas	9/5	22.7/12.7	19.6/16.5	–
CST	12.5/45	13.3/43.9	61.2/140	–
Geothermal	9/65	–	–	–
Wave	0.5/2	–	–	–

Note: Off-river pumped hydro with 31 h of storage.
[a] From Scenario 1 (rapid technology transformation and moderate economic growth) at 2030.
[b] From the low cost scenario with 5% of discount rate.
[c] Including bagasse and wood.

in which the generation cost of wind and PV are both AU$50/MWh we estimate that LCOB is $24–37/MWh. If no modelling constraints are applied then we estimate that average LCOB is $28 and $25 per MWh respectively using current and future wind and PV prices.

The two key requirements for low cost of hourly balancing are dispersion of PV and wind over large areas (100 million hectares in this case), assisted by HVDC and HVAC interconnectors, and the use of off-river PHES storage. The difference in LCOE of $40/MWh between this study and the earlier SWIS study [32] using identical modelling assumptions and methodology illustrates this point.

If no modelling constraints are applied, then we estimate that average LCOE for a balanced 100% renewable electricity system is $93 and $75 per MWh respectively using current and future wind and PV prices. This can be compared with the 2017 average wholesale market price in Australia of about $80/MWh [37]. Another comparator is that the estimated LCOE from a new supercritical black coal power station in Australia is $80/MWh. This estimate is derived from a major "whole-of-Government" report [38]. The current NEM contains mostly coal generators that are several decades old and have sunk capital costs. Much of Australia's coal power stations will reach the end of their economic life over the next 15 years. It will be cheaper to replace these with renewable energy.

LCOB comprises three components: PHES, HVDC and spillage of excess wind and PV generation (including pumping and transmission losses). In most scenarios all three components are significant. One can be traded for another with moderate effect upon total LCOB. Thus a variation in the cost of any one of the LCOB components, or a modelling constraint imposed upon one of the components, has only a moderate effect on LCOB after re-optimisation. This can be seen in scenarios C1.3, C1.4, F1.3 and F1.4, where a 50% increase in the capital cost of PHES or HVDC adds $7–8 (30%) and $2–3 (10%) per MWh to LCOB respectively.

Using current (2016) prices, the lowest LCOE is for scenarios in which wind produces most of the energy because wind energy is significantly cheaper than PV at present. The lowest LCOB is also for scenarios in which wind produces most of the energy for both current and future wind and PV price scenarios. If wind and PV annual energy generation is constrained to be similar then LCOB rises by about $11/MWh. The advantage of wind is that it can deliver energy at any time, rather than only during the day. Wind is better able to service successive days of high demand during cloudy periods in winter.

The optimum PHES contribution is 15–25 GW of power capacity with 15–30 h of energy storage. Higher power capacity is optimally correlated with shorter storage periods. If wind and PV annual energy generation is constrained to be similar then higher power (25 GW) and lower energy storage (12–21 h) is optimum. Total storage of 450 GWh ± 30% is optimum for all the scenarios. This is equivalent to the average electricity consumed in the NEM in 19 h.

The addition of demand management reduces the optimal amount of storage, and reduces LCOB by $1–2/MWh. Stronger demand management than modelled is required to produce large reductions in LCOB.

The addition of a 1500 km long HVDC interconnector to access excellent wind and solar resources in far north Queensland (FNQ) (which generally has different weather from southern regions) reduces LCOB by the small amount of $2/MWh except in the case that a double constraint is applied (that wind and PV annual generation are constrained to be similar and there is no demand management). In that case an interconnector to FNQ reduces LCOB by $12–20/MWh. We conclude that strengthening existing interconnectors in the south-east corner of Australia will be generally sufficient to achieve low cost energy balancing.

The capital cost of the baseline scenarios (PV, wind, PHES and HVDC) for current and future PV/wind prices are $184 billion and $152 billion respectively. Approximately 60% is for construction of the PV and wind collectors, and 40% is for construction of PHES and HVDC. This capital cost is amortised over the system lifetime, which is 25 years for most components. Unlike a fossil fuel system, PV and wind have no fuel costs, although operations and maintenance costs apply.

In this work we focus on the current electricity system. Future work will examine electrification (with renewable energy) of other parts of the economy. Energy-related greenhouse gas emissions constitute about 84% of Australia's total. Electricity generation, land transport and low temperature heat in urban areas comprise 55% of total emissions. Conversion of these three energy functions to renewable energy is easier than for other components of the energy system. Transport and urban heat can be electrified through large scale deployment of electric vehicles and heat pumps respectively. Electric heat pumps are already providing strong competition for natural gas in the space and water heating markets. Large scale deployment of electric vehicles and heat pumps would increase electricity demand by up to 40%. Importantly these devices have large scale storage in the form of batteries in vehicles and heat/cool in water stores and the building fabric. This storage may substantially reduce LCOB in the future.

In the near future it is likely that electric cars will enter the market in large numbers. There are about 18 million registered cars in Australia. If the future fleet of cars is of a similar size but entirely electric, with an average of 50 kWh of useable storage per car, then the usable storage is 900 GWh. This is twice the storage envisaged in our modelling. Unlike PHES, each storage cycle of a battery causes significant degradation, and batteries may therefore be significantly more expensive than PHES even in the longer term. However, timing the charging cycles is also effective in mitigating peaks in demand. This load is flexible and interruptible.

The LCOB calculated in this work is an upper bound. A large fraction of LCOB relates to periods of several days of overcast and windless weather that occur once every few years. Substantial reductions in LCOB are possible through reduced capital and maintenance costs, contractual load shedding, the occasional use of legacy coal and gas generators to charge the PHES reservoirs, household battery storage and management of the charging times of batteries in electric cars.

It will take some time for wind and PV penetration to reach into the range 50–100% of annual energy in the NEM, and so the future price scenarios are more relevant than current price scenarios. With PV and wind in the price range of $50/MWh, the LCOE of a balanced 100% renewable electricity system is around $75/MWh. This is below the LCOE of any alternative supply option, and is close to the current NEM pool price. A future carbon price will tip the balance further in favour of an all-renewable energy system. Further modelling is likely to refine costs and uncover improved solutions that lead to lower LCOB.

In our work we used demand, wind and solar data for the 5-year period 2006–10. In future work we will extend this period to 15 years using historical records, and for considerably longer using synthetic data sets where necessary.

In our modelling we avoid heroic assumptions about future technology development by only including technology that has already been deployed in large quantities around the world (>100 GW), namely PV, wind, HVDC/HVAC and PHES. This means that our cost estimates are more robust than for models that utilise technology projections that are far beyond current practice.

The relatively low LCOE that we calculate for balanced supply of 100% renewable electricity based upon wind and PV, coupled with the large scale of these manufacturing industries, suggests that wind and PV will dominate the Australian grid in the future. PHES and HVDC/HVAC offers an effective and low cost solution to the variability of wind and PV. Unlike the case of molten salt energy storage or biomass energy balancing, excess wind energy can be stored in a PHES system to reduce spillage with only small loss (80% round trip efficiency).

In the view of the authors, it will be difficult for any other low emission technology (such as nuclear, solar thermal, geothermal, ocean and biomass) to become competitive, neither on the basis of competitive supply of energy alone nor on the basis of supply of both energy and ancillary balancing services.

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Abbreviations list

ACT	Australian Capital Territory
CST	Concentrating Solar Thermal
DM	Demand Management
FNQ	Far North Queensland
GDP	Gross Domestic Product
GW	Gigawatt
GWh	Gigawatt hour
HVAC	High Voltage AC
HVDC	High Voltage DC
LCOB	Levelised Cost of Balancing
LCOE	Levelised Cost of Energy
LCOG	Levelised Cost of Generation
MWh	Megawatt hour
NEM	National Electricity Market
NEMO	National Electricity Market Optimiser
NSW	New South Wales
PHES	Pumped Hydro Energy Storage
PV	photovoltaics
SWIS	South West Interconnected System
TWh	Terawatt hour

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90–100% renewable electricity for the South West Interconnected System of Western Australia

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ABSTRACT

Rapidly increasing penetration of renewables, primarily wind and photovoltaics (PV), is causing a move away from fossil fuel in the Australian electric power industry. This study focuses on the South West Interconnected System in Western Australia. Several high (90% and 100%) renewables penetration scenarios have been modelled, comprising wind and PV supplemented with a small amount of biogas, and compared with a "like-for-like" fossil-fuel replacement scenario. Short-term off-river (closed cycle) pumped hydro energy storage (PHES) is utilised in some simulations as a large-scale conventional storage technology. The scenarios are examined by using a chronological dispatch model. An important feature of the modelling is that only technologies that have been already deployed on a large scale (>150 gigawatts) are utilised. This includes wind, PV and PHES. The modelling results demonstrate that 90–100% penetration by wind and PV electricity is compatible with a balanced grid. With the integration of off-river PHES, 90% renewables penetration is able to provide low-carbon electricity at competitive prices. Pumped hydro also facilitates a 100% renewables scenario which produces zero greenhouse gas emissions with attractive electricity prices. A sensitivity analysis shows the most important factors in the system cost are discount rate and wind turbine cost.

1. Introduction

1.1. Decarbonisation of Australian energy sector

Australia announced its 2030 Emission Reduction Target at the historic Paris Agreement on climate change, namely to reduce greenhouse gas (GHG) emissions by 26–28% below 2005 levels by 2030 [1]. This translates to emission reductions of 50–52% per capita, although these figures are considerably smaller if a different baseline year is selected. Australia's annual GHG emissions have averaged 570 Mt CO2-e over the last decade with around two thirds produced by energy-related sectors including stationary energy, transport and fugitive emissions [2]. Electricity generation, currently dominated by fossil-fuel power stations, is the largest source of emissions accounting for around one third of the total.

Low carbon electricity has the greatest potential for rapid decarbonisation of the energy sector [3]. This is the approach adopted by the Australian Capital Territory (ACT) Government to achieve its early GHG target of 100% renewable electricity by 2020 [4]. Wind and photovoltaics (PV) systems constitute virtually all new generation systems in Australia now and for the foreseeable future. Over the last decade, wind power has grown at an annual average rate of 22% with a total installed capacity of about 4 GW at the end of 2015. Solar PV has seen even stronger growth, dominated by residential solar installations, rising from around 4 MW to 5 GW. Wind and PV contributed about 18 TWh in Australia in 2015, compared with hydroelectricity (14 TWh) and biomass electricity (3 TWh) [5].

New capacity installations in the worldwide renewable electricity industry is heavily dominated by wind and PV, which are unconstrained by resource availability or water requirements or material supply or security issues. Together, wind and PV constituted about half of new generation capacity installed in 2015 (Fig. 1). Hydro power is unable to expand considerably due to lack of rivers to dam, and bioenergy is severely limited by biomass availability [6]. Heroic growth rates are required for other renewable or low emission technologies (nuclear, carbon capture & storage, concentrating solar thermal, ocean, geothermal) to span the 20 to 1000-fold difference in scale to catch up with wind and PV

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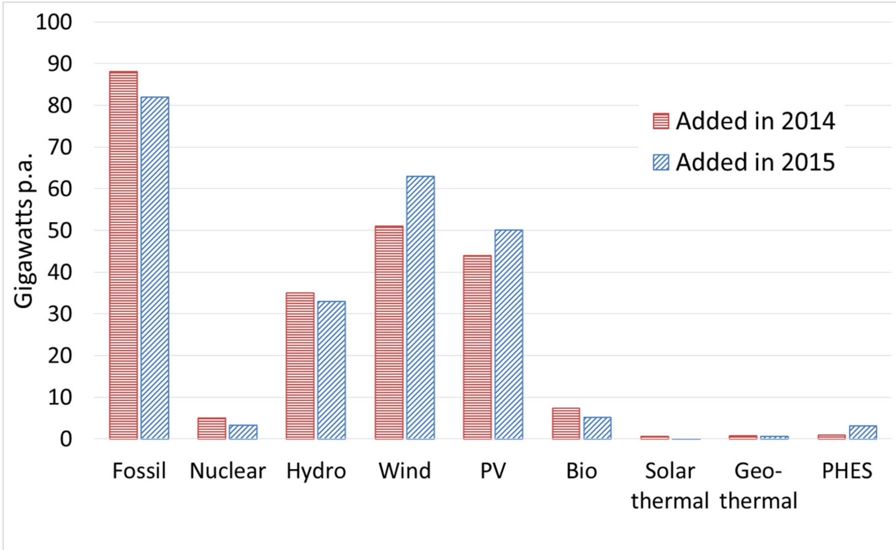

Fig. 1. New generation capacity installed worldwide in 2014 and 2015. Virtually all new Australian capacity is PV and wind [49–51].

– which are moving targets since both industries are themselves growing rapidly and both access large economies of scale.

In this paper wind and PV are assumed to continue their absolute dominance of new energy generation systems in Australia. As Australia's existing coal power stations reach the end of their working lives they are being replaced by wind and PV generators. For example, the last coal generator in the state of South Australia was recently closed, and from 2017 that state will procure about half of its annual electricity from windfarms and rooftop PV [7].

1.2. High wind and PV penetration

High penetration (50–100%) of variable wind and PV electricity in power systems requires technical adaptation, particularly relating to balancing variable wind and solar power supply and varying demand for electricity in real time [8]. Mitigation of this problem is as follows:

- Prediction: Solar and wind forecasting skill is already very good, and continues to improve. The combined output of thousands of wind and PV systems can be predicted on every time scale from seconds to years, which allows supporting measures to be taken [9–11];
- The use of PV and wind energy systems distributed over thousands or millions of square kilometres greatly reduces the effect of local weather [11,12]; a future study of the Australian National Electricity Market will quantify this reduction;
- In some interconnected regions the output of wind and PV systems is counter-correlated – for example, cloudy weather is often windy;
- Active load management allows interruptible loads to accommodate fluctuating wind, PV and demand, and also allows loads such as water heating or battery charging to be moved from night time to daytime [13].
- Controllable and quick-response peaking power plants such as hydro and natural gas or biogas-fuelled gas turbines, operated for only a small fraction of the year, can fill shortfalls in supply; and
- High power energy storage can shift excess energy produced by wind and PV to match the loads during periods of electricity shortage [14].

The purpose of this study is to simulate supply and demand for high renewables penetration scenarios for the South West Interconnected System (SWIS) of Western Australia (WA) centred on Perth. A “no heroic assumptions” policy is applied throughout the study, which means that only those commercially available technologies currently deployed on a large scale (more than 150 GW of worldwide deployment) and that have a sufficient resource base in WA are included in the simulation. This restricts the simulation to PV and wind for renewable energy generation, and pumped hydro energy storage (PHES) for storage, with a small amount of gas or biomass supplementation.

1.3. Off-river pumped hydro energy storage

Pumped hydro energy storage is simulated through the use of closed loop, off-river systems. Closed loop PHES comprises pairs of small reservoirs (1–100 ha), placed close together in steep hilly country outside national parks and other sensitive areas, separated by an altitude difference of 200–900 m, and connected by a pipe or tunnel containing a pump and a turbine. The small size of the reservoirs relative to conventional on-river PHES reflects the fact that off-river PHES provides storage for hours or a day rather than for weeks or a season. The reservoirs are essentially “oversized farm dams”. The reservoirs are 10–20 m deep, and the walls are created from earth and rock scooped from the centre. Lining of the base and evaporation control suppresses the annual water consumption (evaporation minus rainfall). Construction costs are low because of the absence of flood control and the small size of the reservoirs. A previous Geographic Information System (GIS)-based screening study [15] demonstrated the substantial potential for off-river PHES to be deployed in the southwest of WA especially along the Darling Range escarpment.

1.4. Innovation

Large-scale energy storage is recognised as an effective approach to integrate intermittent solar and wind electricity into power systems through the mitigation of electricity supply fluctuations and load levelling. It is able to shift energy from times of excess generation to periods of low solar and wind availability and hence helps to maintain energy supply and consumption balance.

However, in many analyses of energy systems deployment of bulk energy storage is considered to be restricted by the availability of river-based hydro resources (pumped hydro energy storage); the requirement of special geologic structures (compressed air energy storage, CAES); limited deployment of the primary technology (molten salt storage); or low technology maturity associated with high capital expenditures such as batteries in electric vehicles.

For example in Australia, the Australian Energy Market Operator (AEMO) modelled four 100% renewables scenarios through the generation mix of thermal generation technologies such as geothermal, biomass and concentrating solar thermal (CST) [16]. The penetration of fluctuating wind energy was under 10% of the total generation although it was one of the lowest-cost generation technologies in Australia. Elliston et al. [17] utilised fast-ramping biogas-fuelled gas turbines to solve energy balancing problems and thus increased the wind integration to 46%. Lenzen et al. [18] mainly used CST with molten salt storage to conduct day-night shifting of solar energy which constitutes half of the energy generation and nearly 40% of the total installed capacity in the system. However, geothermal, wave, biomass and CST have not been technically and/or economically feasible to be deployed at gigawatts to dozens of gigawatts scale as PV and wind can do in Australia. Additionally, only existing PHES was included in these studies.

Globally, wind-PHES hybrid systems have been included in numerous studies but restricted to small-scale applications in existing power systems or in isolated islands. There are a few studies that have focused on using large-scale energy storage as a primary solution to achieve 50–100% wind integration in large-scale power systems such as in Denmark, Ireland and Portugal. Lund and Salgi [19] identified that an optimal 59% wind integration can be achieved via the deployment of CAES in the Danish energy sector and undertook a system-economic and a business-economic analyses for a 360 MW CAES plants to be operated in the system. Alternatives such as combined heat and power (CHP), industrial electric heat pumps and electric boilers were also analysed in the study. Connolly et al. [20] examined the role of PHES in wind energy penetration from 0 to 100% in the Irish power system and explored the economic viability of a 2.5 GW/25 GWh PHES plant in the 2020 scenario which was also compared with CHP and domestic electric heat pumps. Krajacic et al. [21] modelled the Portuguese power system to achieve 100% renewables penetration through the addition of 2 GW PHES.

Although the grid scale of SWIS can be comparable to those of the European countries, it has no interconnection with other electricity systems which brings a significant issue of energy balancing as well as grid stabilisation. Also, there are no river-based hydro resources that can be exploited at a large scale to support peak loads or contribute frequency control services in the south-west of WA. In addition, significant heating loads, which makes CHP even more attractive than PHES as discussed in the Danish and Irish grids, are not applicable in the SWIS region.

This study utilises closed loop (off-river) PHES as a primary approach to achieve 90–100% renewables penetration in a large-scale, self-contained power system. It features a “no heroic assumptions” policy which only includes those commercially available technologies currently deployed on a large scale and that have a sufficient resource base in WA. This study establishes a benchmark for the cost of an isolated GW-scale power system with 90–100% renewables penetration using existing mature generation and storage technologies and cost estimates for 2016. In future, more sustainable energy options can be integrated in the modelling once their economics and technology status can compete with PV and wind, although this seems to be unlikely in the foreseeable future.

2. The South West Interconnected System (SWIS)

2.1. Transmission and distribution network

The Transmission and distribution (T&D) network in the SWIS covers an area of 261,000 km^2 in the southwest of WA. It is not connected to Australia's eastern states, and has more than 7000 km of high-voltage transmission lines extending to Kalbarri in the north (132 kV), Kalgoorlie in the east (220 kV) and Albany in the south (66 kV) as showed in Fig. 2. Major mining fields in the region such as the Kalgoorlie gold mines and the Karara Iron Ore mines are connected to the coal-fired power stations located around the Collie Coalfield by 220 kV and 330 kV transmission infrastructure. This T&D network currently operated by the Western Power supports over 1 million electricity customers [22].

2.2. Electricity generation

SWIS generating facilities comprise: a) black coal power stations (Muja, Collie and Bluewater) with a total installed capacity of 1.9 GW; b) natural gas and distillate-fuelled combined cycle gas turbines (CCGT) and open cycle gas turbines (OCGT) operated as load following and peaking plants contributing 4 GW of installed capacity to the system and c) renewable generators such as wind turbines, solar panels and biomass which produced over 2.3 TWh of electricity in 2015 constituting around 12% of the state's total annual energy generation [5,23].

Currently about 20% of the households in the state have rooftop PV panels, which contributes more than 0.5 GW of generating capacity connected to the SWIS. This is expected to increase [24].

2.3. The Wholesale electricity market

The operation of the Wholesale Electricity Market (WEM) for the SWIS commenced in 2006. The vast majority of energy is traded through bilateral contracts between generators and retailers due to the dominance of a state-owned generation and retail business. A small fraction of energy is traded in a day-ahead Short Term Energy Market for 30-min trading intervals on the following trading days.

Unlike the National Electricity Market (NEM) in the eastern states, which operates a market for frequency control ancillary

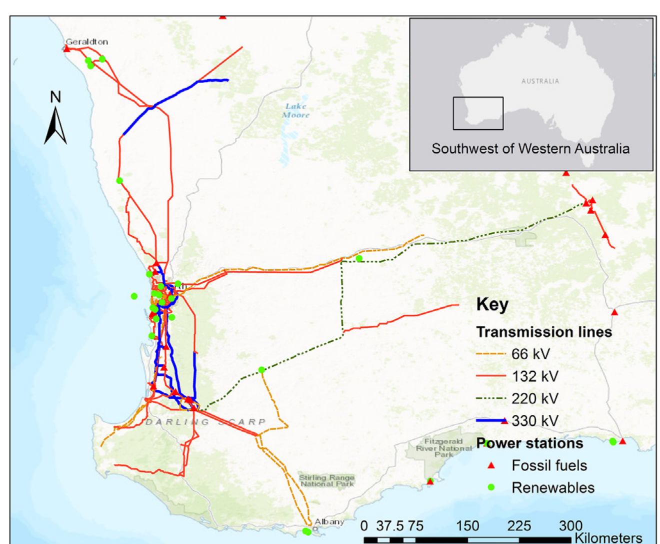

Fig. 2. Transmission lines and power stations in the SWIS [52].

Table 1
Thermal efficiencies and emission intensities.

Technology	Thermal efficiency (%)	Emission intensity (t/MWh)
Subcritical black coal	36	0.88
Natural gas-fuelled CCGT	50	0.37
Natural gas-fuelled OCGT	34	0.55
Biogas-fuelled OCGT	31	0

Note. Biogas-fuelled OCGT only used in the renewables scenarios.

services, WEM operates a Reserve Capacity Mechanism for the allocation of adequate capacity credits to the reserve capacity suppliers (which includes generators and demand-side management) [25].

At present, electricity valued at around $1 billion is annually traded in the WEM, and there is a subsidy of over $500 million per year provided by the WA Government to maintain lower market retail electricity prices for the end-users [26].

3. Hypothetical scenarios

As mentioned above, a “no heroic assumptions” policy is applied in the modelling. Mature power generation technologies are included: subcritical black coal units, CCGT, OCGT, wind turbines, PV panels (fixed and 1-axis tracking) and PHES. Emerging technologies for power generation from renewable sources that remain at early stage of development are not integrated into the modelling, such as CST, geothermal and wave technology. Carbon capture and storage for the mitigation of GHG emissions from fossil-fuel power stations is also excluded because of lack of commercial deployment.

3.1. “Like-for-like” fossil-fuel replacement scenario

A “like-for-like” baseline fossil-fuel replacement scenario is modelled whereby all the current generating fleet of fossil-fuel power stations is replaced with new power generation technology utilising coal and natural gas. This is on the basis that most existing coal and natural gas power plants in the SWIS will reach the end of their technical life by 2030 [23]. New-for-old replacement allows access to the higher thermal efficiencies and lower GHG emissions of modern units. However, because of the modest size of the SWIS, where the maximum demand is approximately 3.9 GW and the residual demand through nights is as low as 1.5 GW, smaller subcritical coal units are modelled rather than larger supercritical coal units, even though they have lower thermal efficiency [27].

Table 1 shows the assumed thermal efficiencies and emission intensities for new-built subcritical black coal plants, CCGT and OCGT in the scenario [17,28].

2015-16 average international prices for Australian thermal coal and the Japan liquefied natural gas (LNG) import price [29] are used in the scenario. There has been substantial volatility in fossil fuel prices, and it is beyond the scope of the study to project future prices of coal and gas.

3.2. 90–100% renewables penetration scenarios

For comparison, two high renewable energy penetration scenarios are developed whereby the vast majority (90%) or all (100%) of annual electricity comes from wind turbines, PV panels and biogas. Biogas use is limited to 10% of annual electricity production, primarily for cold, wet, windless weeks in winter. For the 90% renewable energy scenario, natural gas-fuelled OCGTs are utilised as a supplement to biogas.

In both the 90% and 100% scenarios, off-river PHES is available to improve the balance between demand and wind/PV generation by shifting excess energy generated by wind and PV to periods of electricity shortfall which could not be met with a 10% biogas limit. One 90% renewable energy scenario is also considered with no PHES for comparison.

Natural gas-fuelled OCGTs rather than CCGT technologies or coal power generation are used in the 90% renewables scenarios due to the likely need for peaking response rather than constant generation. OCGT has relatively fast ramp rates, typically 8%/min and 22%/min for spin and quick start (which is much faster than coal plant), and has low capital cost (1/3 of the coal units and 2/3 of the CCGTs) [30].

While fossil-fuel power stations are mature technology with no significant variations expected in their capital costs, wind and PV are likely to experience reductions from current construction and operation costs. Consequently, two cost assumptions are considered: current cost estimates for 2016, and future projected costs for 2030. There is a range of price reduction factors as shown in Table 2 displaying the cost projections derived from the reports published by the Australian Energy Technology Assessment (AETA) in 2012, CO2CRC in 2015 and the International Technology Roadmap for Photovoltaic (ITRPV) in 2016 also included for comparison [28,31,32]. In this study we assume reductions by 2030 of 22% and 35% in the cost of wind and PV systems respectively.

Current costs for the construction and operation of the plants are estimated from recently commissioned or proposed wind and solar projects. Hornsdale Wind Farm signed a 20-year contract with ACT at a price of $77/MWh in December 2015 [33]. This price had no allowance for inflation, and is equivalent to $65/MWh after allowing for an inflation rate of 2.5%/year. By using its announced capacity factor 49% [34] with an assumption of the operation and maintenance (O&M) cost (3%) and a discount rate of 6.5%, the capital cost of $2300/kW for the wind farm can be derived from this price.

Information about large-scale solar farms to be funded by the Australian Renewable Energy Agency (ARENA, data released in September 2016) [35] shows an average capital cost of $1.8/W-DC and $20/MWh for the average operating expenditure of single axis tracking systems. In view of the recent rapid fall in PV module prices, a figure of $1.7/W-DC is used in our modelling.

Table 2
Percentage reductions of capital costs for power generation technologies.

Technology	Capital cost reduction (%)				
	Modelling input	AETA 2012	CO2CRC 2015	CSIRO GALLM[a]	ITRPV 2016
Wind turbines	22	24–33	20	22–24	
PV systems	35	34–48	50	51–52	30–32

Note. Projections for capital cost reductions in the years 2030 (AETA, CO2CRC, CSIRO) and 2026 (ITRPV) compared with the costs in the years 2015 (CO2CRC, CSIRO, ITRPV) and 2012 (AETA).
[a] Also from the report released by CO2CRC in 2015.

4. Modelling input and assumptions

The SWIS was divided into 14 square "activity cells", each with a side length of one degree of latitude/longitude (Fig. 3). Representative wind and solar data was obtained for each cell. The amount of wind, PV and PHES systems assigned to each cell was optimised, depending mainly upon the solar and wind resources available within the activity cell.

4.1. Solar PV

Solar resources are available using the Australian hourly Direct Normal Irradiance (DNI) and Global Horizontal Irradiance (GHI) gridded data produced by the Bureau of Meteorology (BoM) for the last decade. NREL's (National Renewable Energy Laboratory) modelling software, System Advisor Model (SAM) [36], was used to determine energy production for rooftop and 1-axis tracking of PV. Assumptions were 97–98% for the inverter efficiency, 15% for the 1-axis tracked system loss (including soiling, mismatch, DC and AC wiring, diodes and connections, nameplate degradation and availability losses and additional 3% of shading loss for rooftop PV) and 0.3 for the ground coverage ratio (1.0 for rooftop PV). The assessment points to a preferred location of large-scale solar farms in four activity cells north of Perth, where the capacity factors can exceed 23% (Fig. 3, above the lines), and also east of Perth in order to create a wide geographical distribution of PV panels to mitigate the impact of local weather events. Solar farms can be located in close proximity to the existing transmission network.

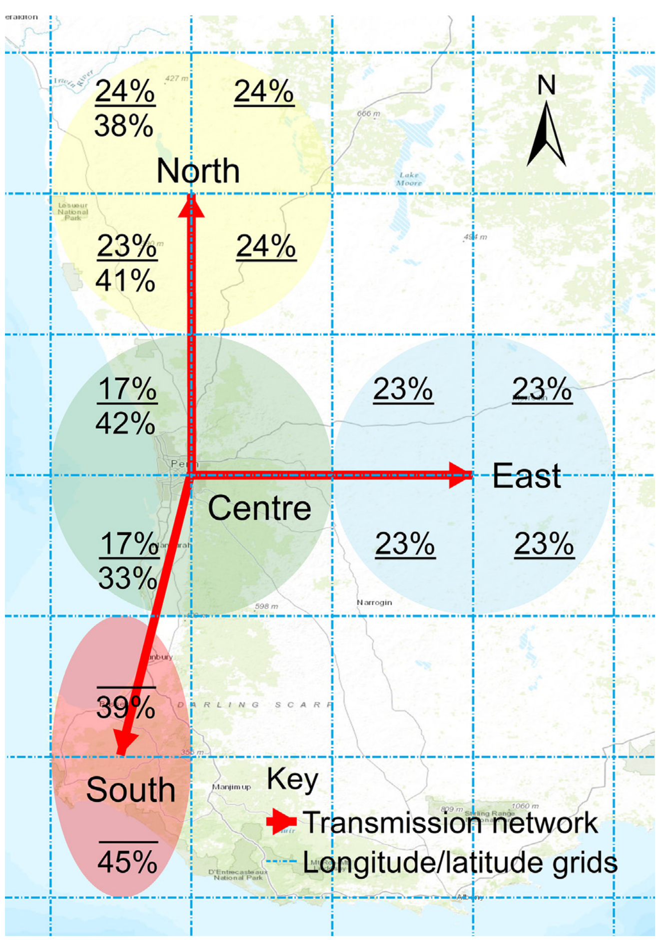

Fig. 3. Capacity factors for PV (upper figure) and wind (lower figure) in each activity cell.

All of the scenarios, including the high fossil fuel scenario, recognise the continuing substantial growth in rooftop PV systems. The scenarios incorporate 2.8 GW of rooftop PV capacity. This level of penetration assumes half of the residential houses and townhouses in the SWIS are mounted with a non-tracking 5 kW PV system (1.4 GW) [37]. The same capacity of solar panels (1.4 GW) is assumed on commercial building roofs. These PV systems are distributed across the two cells that contain the Perth/Fremantle population centres. The cost of these systems is absorbed by the building owners, and does not directly affect calculated electricity costs under this model. The output of these PV systems is assumed to be preferentially consumed before contributions from any other generator.

4.2. Wind farms

Historical half-hourly wind speed data is available from BoM for the last decade. The wind speed was originally derived from the weather stations and scaled up to the average figures at hub heights. It's then converted to power output by using the 3 MW turbine model in SAM. This data was used to determine the energy produced by the wind farms in each time period. The coastal regions from the north of Perth to the south-west corner of WA are particularly prospective, with potential capacity factors (CFs) ranging from 33% to 45% (Fig. 3, below the lines) [36]. Six activity cells distributed along the west coast hosted the simulated wind farms, which comprise 3 MW turbines. A preliminary assessment of land availability for the construction of wind farms was undertaken, demonstrating sufficient potential for each cell to deploy wind turbines at the hundreds of MW scale.

4.3. Pumped hydro

Opportunities for conventional on-river PHES such as the Tumut-3 and Shoalhaven projects in New South Wales and the Wivenhoe project in Queensland don't exist in WA. A GIS-based screening study [15] over the southwest of WA demonstrated numerous potential sites for off-river pumped hydro with a potential hydraulic head of 200–220 m, especially in the Darling Range area. The capacity of these sites far exceeds that required in this study. Moreover, some mining fields such as the Kalgoorlie Super Pit are expected to be closed in the near future which creates an opportunity to be converted into off-river pumped hydro facilities similar to that proposed for the Kidston PHES project (250 MW with 6 h of storage) in Queensland located on the site of the historical Kidston Gold Mine [38].

4.4. Biomass

Currently bioenergy constitutes 1% of the total electricity production in Australia's energy markets, and mainly comprises bagasse and landfill gas [39]. It is expected that stationary bioenergy generation in Australia is able to provide terawatt-hours of electricity to the power grids [39,40]. In this modelling, electricity production from biomass is limited to less than 10% (approximately 1.8 TWh per year) of the total consumption for the 90% and 100% renewables scenarios, and is assumed to be reserved for quick-response biogas-fuelled OCGTs.

4.5. Electricity loads

The historical demand of the SWIS is recorded by the system operator AEMO Western Australia (previously the Independent

Market Operator) showing a slow growth of the annual energy consumptions since the last decade as well as an undulating trend of the peak demand (Fig. 4). In order to model the interaction of wind and PV with demand in each hour interval over many years, demand in previous years is inflated to bring the annual total for each year up to that of 2014 (18.4 TWh).

4.6. Cost assumptions

Cost assumptions for baseline cases are listed in Table 3 [23,28,29,31].

4.7. Discount rates

A nominal discount rate of 6.5% is assumed for the baseline assumption to reflect the integrated rates for the returns on investment (30% of the capital with a 10% internal rate of return) and the interest rates from banks (70% of the capital with a loan interest rate of 5%). The baseline assumption reflects a decreasing interest rate environment in Australia and low risk and equity margins for renewable energy business once entering the era of high renewables penetration. This translates to a real discount rate of 5% by factoring in an inflation rate of 1.5%. The Australian Reserve Bank rate is currently 1.5% per year [41]. This is further discussed in the sensitivity analysis.

4.8. Modelling

This study undertakes an hourly energy balance analysis on the basis of historical solar, wind and demand data throughout the years 2007-14 in the SWIS. The supply of electricity was balanced against historical demand (uprated as discussed in section 4.5) for each hour period of each year by utilising PV, wind, coal, gas, biogas and PHES generators [17]. If supply was less than demand in any period, then additional capacity was included in the next modelling iteration. Thousands of iterations were performed, and for each iteration the cost of energy was calculated. In this way, optimised configurations of the various generating units could be determined. The modelling assumed 0.002% unserved energy.

The energy balancing model used in this study is modified and extended from the National Electricity Market Optimiser (NEMO) which was developed by Elliston et al. [42]. NEMO is a chronological dispatch model aiming to explore lowest-cost solutions for the Australian energy markets and has been used in a series of high renewables studies [17,43,44].

In this study, several adjustments to the NEMO model have been made in order to better utilise the capability of synchronous, fast-ramping PHES to integrate fluctuating solar and wind energy.

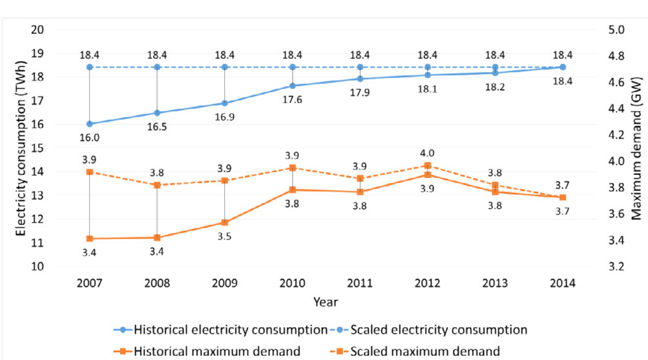

Fig. 4. Electricity consumptions and maximum demands in the SWIS.

This includes a range of operation strategies: a) pre-charging PHES facilities from existing bio and hydro plants to help ride through critical periods based on advanced weather forecasting; b) changing the merit order of existing hydro ahead of PHES in critical periods to ensure PHES not to be exhausted before the most difficult moments arrive; c) PHES co-operation to maintain maximum power and storage capacities for pumping and generation.

As with AEMO [16], Elliston et al. [17] and Lenzen et al. [18], the optimisation objective of this modelling is to find the lowest-cost generation mix while ensuring the current NEM reliability standard (<0.002% of the total demand) can be met. This is different from the studies of Connolly et al. [20] and Lund and Salgi [19] where a maximum energy spillage figure was set as a constraint when increasing wind penetration levels in the systems.

Moreover, Connolly et al. [20] and Lund and Salgi [19] modelled the entire energy sectors in Ireland and Denmark, including electricity, heating, industry processes and transportation while this study only focuses on the electricity industry. However, we note that transport and urban heat can be electrified through large-scale deployment of electric vehicles and heat pumps respectively in high renewables penetration systems. These devices have large-scale storage in the form of batteries in vehicles and heat/cool in water stores and the building fabric. This storage may substantially reduce system costs in the future.

In addition, the grid stabilisation measures applied in this study are much different from these previous studies. This is described in section 5.6. Stochastic modelling for power generation, fuel costs and electricity demand is not included while the historical meteorological data and loads are used in this study.

5. Modelling results

5.1. GHG emissions

By replacing the existing fleet of coal and natural gas generators burning low grade coal with modern generators burning higher grade coal and gas, the associated annual GHG emissions (23 Mt CO2-e in 2013 [45]) can be halved to 11 Mt CO2-e per year (Fig. 5). In the 90% renewables scenarios, about 95% of the current GHG emissions are eliminated.

5.2. Levelised cost of electricity (LCOE)

The system LCOE calculated for the "like-for-like" fossil-fuel replacement scenario is $94/MWh while the 90% renewables scenario without pumped hydro costs $126/MWh under the cost estimates for 2016, and $110/MWh under the cost projects for 2030. Under this scenario a significant gap of LCOE between fossil-fuel power generation and renewables exists.

Pumped hydro makes a significant improvement to the LCOE of the high renewable scenarios. For example, with the integration of pumped hydro, the system LCOE for the 90% renewables scenario reduces from $126/MWh to $116/MWh under 2016 cost estimates and from $110/MWh to $103/MWh under the projected costs for 2030, which mitigates the difference with the fossil-fuel scenario from $32/MWh to $22/MWh under current capital and O&M costs and $9/MWh in 2030 costs.

By integrating pumped hydro into high renewables penetration scenarios, reductions in installed capacities of wind turbines (from 4.5 GW to 3.5 GW) and OCGTs (from 3 GW to 2 GW) are achieved. Wind energy that would otherwise be spilled can be stored to produce electricity during critical periods of electricity shortfall when solar and/or wind availability is low. Fig. 7 illustrates load profiles and generation mix for a typical week under the 90% renewables scenarios without (a) and with (b) pumped hydro.

Table 3
Baseline cost assumptions for power generation technologies (2016 AU$).

Technology	Capital cost ($/kW)	Fixed O&M ($/kW/year)	Variable O&M ($/MWh)	Fuel cost ($/GJ)	Technical lifetime (years)
Subcritical black coal	2900	45	2.5	3.1	40
CCGT	1450	20	1.5	11	30
OCGT	1000	8	12	11	30
Wind turbines	2300	35	10	0	25
1-axis tracking PV	1700	0	20	0	25
Pumped hydro	1180/200[a]	10	0	0	50
Biogas-fuelled OCGT	1000	8	12	12	30

Note. Cost estimates for 2016.
[a] $1180/kW for power components including turbines, generators, pipes and transformers, $200/kWh for storage components such as dams, reservoirs and water. A 200 m head for PHES systems is assumed.

Pumped hydro only accounts for a small fraction of the system LCOE (Fig. 6). This is because: a) rather than long-term energy storage with a duration of weeks, short-term pumped hydro (hours) is preferred by the model; b) unlike conventional on-river pumped hydro, off-river PHES needs no construction of dams on existing river systems and hence avoids high construction and operation costs related to environment protection and flood control issues.

Although biomass contributes only 10% of annual energy, it contributes more than 20% of the LCOE because of its relatively high fuel cost.

5.3. A pure renewable system

Pumped hydro storage is necessary to enable the 100% renewables scenario due to the constraint imposed on biomass of 10% of annual energy. This constraint is imposed to avoid a “heroic” increase in the quantity of biogas produced each year. The quantity of energy unable to be serviced by wind and PV is more than 10% due to the amount of time with both low wind and insolation. Short term storage is beneficial to this system, shifting energy from times when it would otherwise have been shed to periods of low solar and/or wind resource. This reduces the need for biomass support in the 100% renewables scenario to less than 10% for the simulated years.

It is noted that this pure renewable system costs $129/MWh under current costs which is close to the 90% renewables scenario without pumped hydro integrated ($126/MWh), and costs $109/MWh under 2030 cost estimates. The 100% scenario is able to compete with the fossil-fuel replacement scenario ($112/MWh) if a carbon price of $25/tonne of CO_{2e} is factored into the system LCOE. Significantly, no GHG-emissions are produced from this 100% renewables scenario.

5.4. Wind and solar penetration

Rooftop PV, which peaks each sunny day, contributes about a quarter of the total annual electricity generation (Fig. 5) in both the fossil-fuel and the renewables scenarios.

Large-scale solar PV is not included in the least-cost portfolio of generation mix under the cost estimates for 2016 (90% renewables) but contributes to the generation portfolio under the cost projections for 2030 where its capital cost decreases by 35% from current levels. This indicates a significant cost reduction of large-scale solar PV is needed for it to become more attractive in the WA system. This is due to the much higher capacity factors for wind in southwest WA, and insufficiently strong anti-correlation between wind and PV generation profiles in the SWIS. In other locations PV and wind may have more complementary generation profiles, and their combined use would reduce spillage of wind and PV electricity (equivalently they would have a higher combined capacity factor).

In the high renewable energy penetration scenarios, wind farms produce the largest proportions of electricity to the system accounting for 51% (with pumped hydro) and 57% (without pumped hydro) for the 90% renewables scenarios and 44% for the 100% renewables scenario (Table 4). Additionally, a further 5% of the total electricity that is contributed by pumped hydro in the 90% renewables scenario is mainly derived from the excess generation of wind turbines, and this figure increases to 10% in the 100% renewables scenario. Wind energy plays a key role in the high SWIS renewable power scenarios due to the very high capacity factors along the coastal regions of the southwest WA (33%–45%). This

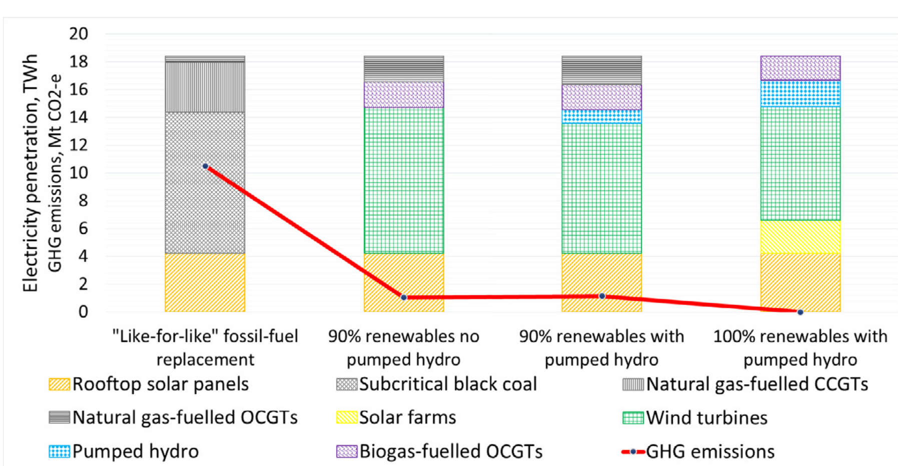

Fig. 5. Electricity penetration and GHG emissions of each scenario.

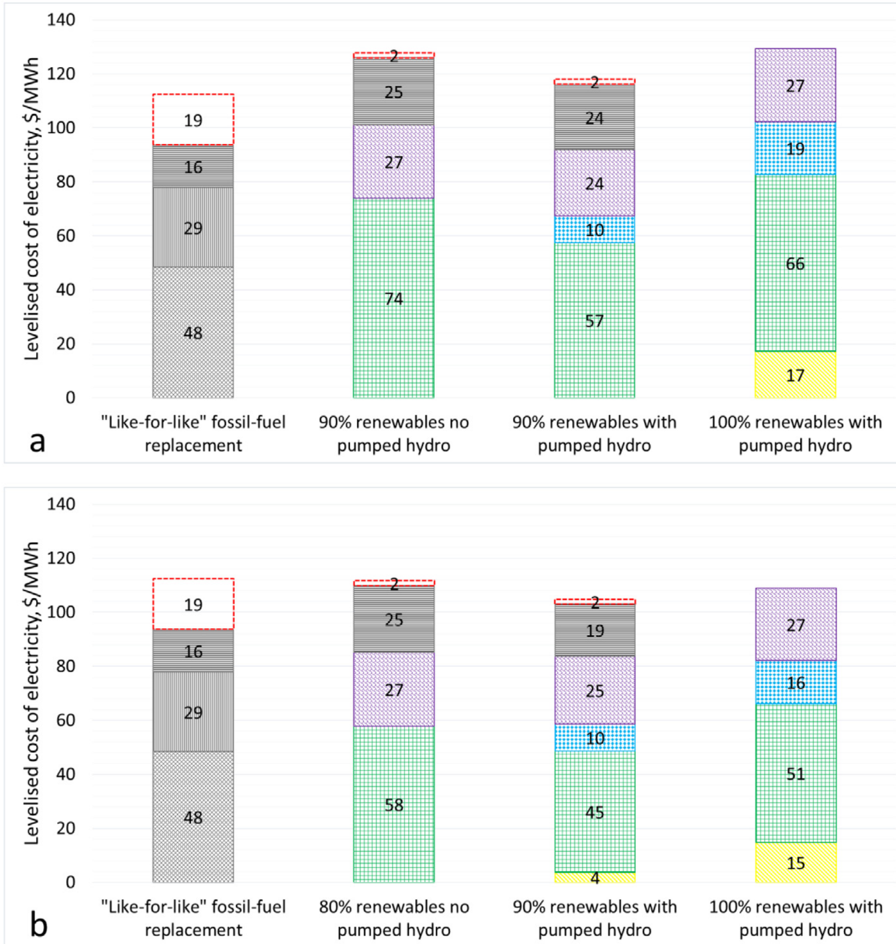

Fig. 6. LCOE breakdown for each scenario in (a) 2016 and (b) 2030. Colour scheme is the same as Fig. 5 with the top red dashed lines denoting carbon prices.

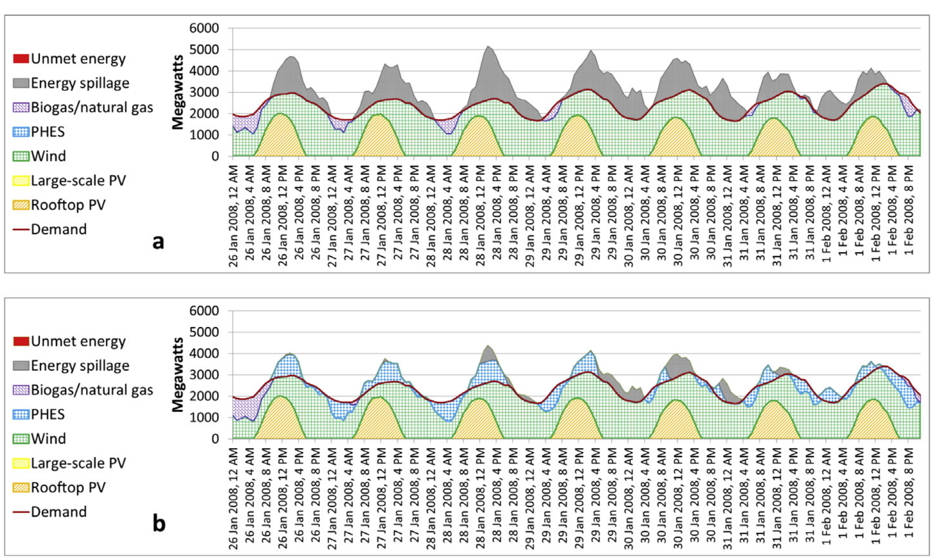

Fig. 7. Load profiles and generation mix for a typical week under the 90% renewables scenarios without (a) and with (b) pumped hydro.

compares favourably to the capacity factors for large-scale solar farms made up of 1-axis tracking PV panels of 23%–24%.

In addition, thanks to rapid ramp rates of PHES, which is typically 50%/min for spin and quick start, PHES is able to rapidly respond to short-term fluctuations in the system which comes from the imbalance between power supply and demand. This facilitates high penetration of intermittent and also less controllable wind and solar electricity in the electricity market.

Table 4
Generating capacity and electricity penetration for each scenario (2016 costs).

Technology	Capacity (GW)/Annual electricity penetration (TWh)			
	Fossil-fuel replacement	90% renewables without PHES	90% renewables with PHES	100% renewables
Subcritical black coal	1.6/10.1	–	–	–
Natural gas-fuelled CCGTs	1.1/3.6	–	–	–
Natural gas-fuelled OCGTs	2.2/0.5	1.5/1.9	1.1/2.0	–
Rooftop PV	2.8/4.2	2.8/4.2	2.8/4.2	2.8/4.2
Wind turbines	–	4.5/10.5	3.5/9.4	4.0/8.2
Large-scale solar farms	–	0.0/0.0	0.0/0.0	1.5/2.3
Pumped hydro	–	–	1.0[a]/1.0	1.5[b]/1.9
Biogas-fuelled OCGTs	–	1.5/1.8	0.9/1.8	1.5/1.7

Note. Electricity penetration (TWh) for a simulated year.
[a] 1.0 GW pumped hydro with 6 h of storage for the 90% renewables scenario.
[b] 1.5 GW pumped hydro with 10 h of storage for the 100% renewables scenario.

5.5. Reserve capacity

In the existing fossil fuels-dominated power industry of the SWIS, a large quantity of generating facilities (over 1 GW) needs to be operated as reserve capacity to ensure an adequate generation capacity available in case of emergency and during the peaking periods.

The nature of a distributed renewable energy system comprised of thousands of individual wind and PV systems avoids a significant impact on system reliability and security resulting from a sudden loss of a single large power generator. The use of thousands of PV and wind energy systems greatly reduces the effect of unexpected individual generator failure compared with an electricity system comprising a small number of large fossil or nuclear power stations, due to statistical reasons. In addition, pumped hydro is also suitable for demand-side participation programs as it is able to quickly suspend the consumption of electricity (pumping) if the system requires help in maintaining frequency stability.

The intermittency of power supply due to weather events is mitigated by wide dispersion of renewable generating facilities and by using advanced weather forecasting techniques. However, the relatively small geographical size of the SWIS compared with the eastern states grid substantially limits the ability to widely disperse the wind and PV generators. System robustness under high penetration of wind and solar energy scenarios and the behaviours of pumped hydro in power systems in case of emergency will be further investigated in future work.

5.6. Grid stability

Although the dynamical behaviour (on time scales of sub-seconds to minutes) of a 90–100% renewable energy grid is outside the scope of the present study, we note that PHES provides significant inertia, spinning reserve and rapid response capability to help maintain a high level of dynamical grid stability.

Connolly et al. [20] applied a non-synchronous penetration (NSP) limit of 70% in each hour's generation mix as a grid stabilisation measure while this limit was released to 75–80% in the studies of Krajacic et al. [21] and Elliston et al. [17]. AEMO [16] integrated a significant proportion of thermal generation technologies such as geothermal, biomass and CST to ensure the modelled 100% renewables system ensembles current structures of fossil fuels-dominated system (baseload – intermediate – peaking units).

By contrast, this study does not incorporate a NSP limit nor integrate geothermal or CST technologies while utilising the synchronous and fast-ramping characteristics of PHES generators/pumps to maintain the grid stability. As an initial estimate, 1.5 GW PHES when operated as generators or spinning reserve in the 100% renewables scenario is capable of providing 3000–6000 MW.s of inertial energy. While pumping or operated in electric motor mode, it is also able to contribute significant inertial energy required by the system stability. Also, the 1.5 GW biogas-fuelled OCGTs in that scenario can play an important role in the grid stabilisation. Detailed analyses of dynamical stability will be undertaken in future study.

In addition, we also note that interconnections with neighbouring electricity systems can be another approach to strengthen the grid stability. Future work will examine the possibility of connecting the SWIS network with the National Electricity Market (Perth to Port Augusta 2500 km or Kalgoorlie to Eyre Peninsula 2000 km) by utilising high voltage DC which can transmit gigawatts of power over thousands of kilometres [46].

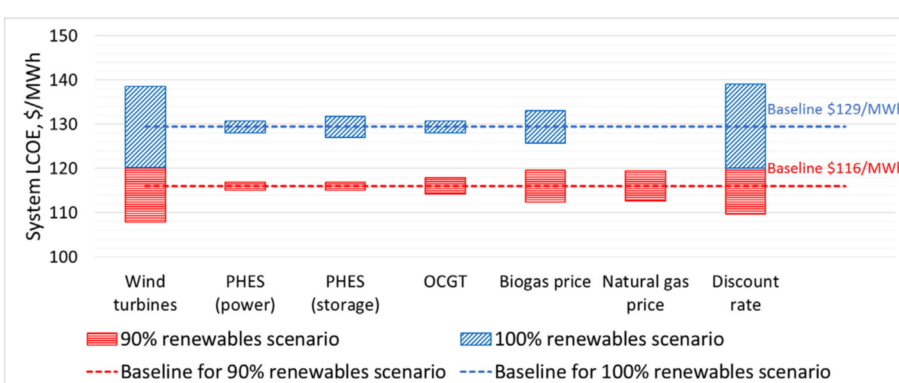

Fig. 8. Sensitivity analysis of the system cost components (Baseline 2016 costs).

6. Sensitivity analysis

Each critical cost component of the renewable system LCOE is analysed by varying the values between −20% and 20% to examine its significance in the overall cost of the system.

6.1. Discount rate

As illustrated in Fig. 8, a 20% change of real discount rates causes $6–7/MWh of cost variations for the 90% renewables scenario (with pumped hydro and without carbon price) and $9–10/MWh for the 100% renewables scenario under the cost estimates for 2016.

This demonstrates renewable energy systems, which are mainly driven by capital costs rather than fuel prices, are sensitive to the change of discount rates. Under an environment of low discount rates, the 90% renewables scenario is fully competitive with the fossil-fuel scenario especially when a carbon price included.

This indicates financial incentives such as low interest loans or a committed renewable energy target from government (in order to attract low risk/cost finance) are critical to the capital-intensive renewable industry, especially in the context of existing fossil-fuel power industry in WA receiving a subsidy of approximately $500 million per year.

6.2. Capital cost

A 20% decrease of the capital cost for wind turbines from the baseline $2300/kW to $1840/kW also cause a significant reduction of the system LCOE from $116/MWh to $108/MWh for the 90% renewables scenario (with pumped hydro and without carbon price) and from $129/MWh to $120/MWh for the 100% renewables scenario. The capital cost of OCGT and the prices for biogas and natural gas can affect the system LCOE to some degree, although the small amount of fossil fuel used mitigates the effect. In other words, a high renewables scenario insulates the SWIS from future fossil fuel price variability.

It is noted that off-river pumped hydro cost has a minor effect on system LCOE. Variation in the cost of PHES has only a small influence on the system LCOE because the cost of pumped hydro only accounts for a small proportion of the system LCOE.

7. Conclusion

This work has demonstrated that very high penetrations of renewable energy can be delivered in the SWIS electricity network through the use of proven renewable technologies that are already in large scale (>150 GW) deployment. This is particularly significant given the relatively small, closed nature of the SWIS with no interconnection to neighbouring regions. Levels of 90% penetration or more can be managed at reasonable cost with the use of natural gas or biogas peaking to manage medium term (a few days) shortages. The cost of the system can be significantly reduced through the use of off-river pumped hydro to manage short term (hours-day) energy shifts.

A second important conclusion is that there is a $22/MWh of difference in cost between a fossil fuel scenario in 2016 ($94/MWh) and a 90% renewable energy scenario ($116/MWh). This difference is highly likely to decline over time, and is immediately reduced to $6/MWh if the moderate carbon price that prevailed until 2014 [47] ($23–25/tonne of emitted CO_2) were to be reinstated. Construction of fossil fuel generators is inhibited by the current small economic advantage, when account is taken of the risk of a future carbon price.

Through the transition of the existing fossil fuels-dominated power industry to a high renewables penetration system such as the 90% renewables scenarios hypothesised for the SWIS, the vast majority of GHG emissions from electricity production can be eliminated. This would result in a removal of nearly one third of the state's GHG emissions which helps achieve the 2030 Emission Reduction Target of Australia.

Australia's current Renewable Energy Target is effectively 33 TWh of electricity generated from large-scale non-hydro renewable power stations by 2020, which is equivalent to PV, wind, hydro and biomass contributing about 24% of total electrical energy. This plays an important role in achieving Australia's 2020 emissions reduction target [47]. Similarly, a renewable energy target (or equivalent) for the post-2020 period is critical for further reducing GHG emissions to ensure the 2030 emissions reduction target is met. Legislated targets facilitate long-term supply contracts between electricity retailers and renewable project developers and provide future renewable investments with greater certainty and lower cost of capital.

With the integration of off-river pumped hydro, the costs for a renewable system substantially reduces while the system operation can still satisfy the reliability standard and security requirements, which helps high renewables penetration systems become more competitive with the existing fossil fuels-dominated power industry. Significantly, a pure renewables system where all the demands are powered by mature technologies of power generation from renewable sources become realistic in a cost-effective way by the deployment of off-river pumped hydro in the system.

Discount rates and the capital cost of wind turbines are the most significant factors that influence the system LCOE while construction costs for off-river pumped hydro has a moderate influence on the system LCOE though it plays significant roles in reducing the system LCOE as a whole and facilitating high penetration of intermittent wind and PV electricity in power system.

Acknowledgements

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Appendix

A1. Water requirement for off-river pumped hydro

An off-river pumped hydro plant is one in which water is cycled in a closed loop between upper and lower reservoirs. A moderate volume of water is needed to initialise the facilities. Ongoing top-up is required to offset the losses from evaporation and leakage during the operation, minus water delivered by rainfall. In the least-cost 90% renewables scenario, the required energy storage from pumped hydro is 1 GW of power capacity and 6 h of storage capacity. This translates to 2 GL of water consumed every year on average (evaporation minus rainfall). By contrast, existing fossil-fuel power stations in the SWIS consume around 18 GL of water per year accounting for 1.4% of the state's annual water consumption (Fig. 9) [48].

In other words, compared with conventional fossil-fuel power industry which consumes respectively 1.5 L and 0.56 L of water for a kWh of electricity production in coal and natural gas power stations, the 90% renewables scenario with short-term off-river energy storage from pumped hydro merely requires 0.11 L/kWh for the power generation.

This moderate amount of water can be transported from nearby water sources by pipelines, channels or water trucks depending on which is the most economical approach. Alternatively, it can be harvested by creating natural or artificial catchments to collect

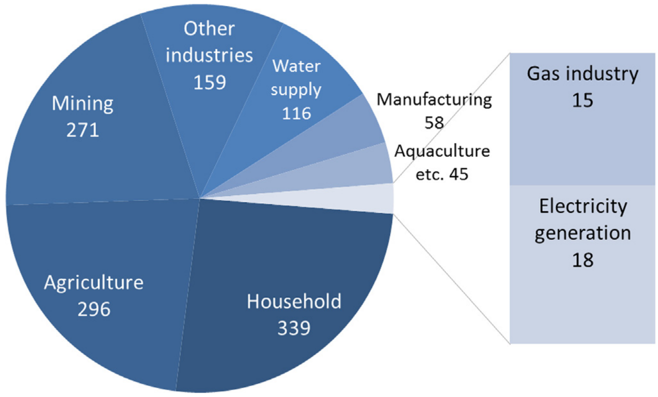

Fig. 9. Water consumptions (GL) in Western Australia 2013–14.

rainwater as a supplement or by utilising evaporation and leakage reduction measures to balance the water losses with gains during the operation. Further, although the cost of water is site-specific and decided by the approaches for water transportation, the total capital expenditure of storage components for a medium-sized pumped hydro which includes water cost is calculated to have only a small impact on the system LCOE in the sensitivity analysis.

A2. Residential battery storage system

Residential batteries mounted behind-the-meter such as the Tesla Powerwall and Panasonic LJ-SK84A are able to change the load profiles allowing more electricity from rooftop PV consumed by end-users and mitigating demands in the periods of evening peaks. A residential battery system with 8 kWh of storage capacity (2 kW × 4 h) is integrated into the 90% and 100% renewables scenarios in the WA households where there is a rooftop PV installed, which can contribute 2 GWh of energy storage capacity to the system for day-night load shifting. These batteries are assumed to be charging from 10 a.m. to 3 p.m. (peaking at 12 p.m. and 1 p.m.) to store surplus renewable energy and powering the evening demands between 5 p.m. and 10 p.m. (peaking at 6 p.m. and 7 p.m.). A slight reduction in the system LCOE ($2/MWh, compared with $10/MWh reduction from the integration of PHES for the 90% renewables scenario) is demonstrated in the modelling.

However, future development of residential battery storage systems in Australia's households remains uncertain and is driven by a range of factors such as price decreases and financial incentive programs offered by the utilities. The operation of residential batteries in the system as well as the role in the amelioration of system reliability needs further investigation.

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Meeting Australia's Paris greenhouse commitment at zero net cost

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Summary: ***continued construction of wind and PV at current rates yields a reliable predominantly renewable electricity system by 2030 that meets the Paris greenhouse targets at zero net cost.***

Currently, Australia is installing about 3 Gigawatts (GW) per year of wind and solar photovoltaics (PV). This rate is sufficient (if continued until 2030) for renewable energy to meet more than **half** of Australia's electricity consumption and **all** of Australia's Paris greenhouse emissions reduction target.

The net cost of meeting the Paris target is **zero** because the cost of electricity from new-build wind and PV is **below** (i) the cost of electricity from new-build coal generators and (ii) the cost of electricity from existing gas generators and (iii) the wholesale price in the National Electricity Market (NEM).

The cost of renewables includes the cost of hourly balancing of the grid to retain the **same reliability** as at present. Hourly balancing comprises pumped hydro energy storage, stronger interstate high voltage power lines and the cost of PV and wind spillage on windy, sunny days when the energy stores are full.

Snowy 2.0 provides half the new storage required to support 67% renewables in the NEM.

Figure 1 shows the all-in cost of electricity under three scenarios:

- Renewables: replace enough old coal generators by renewables to meet the Paris target
- Gas: premature retirement of most existing coal plant and replacement by new gas generators to meet the Paris target. Gas is uncompetitive at today's gas prices ($8/GJ). The gas scenario requires a large increase in gas consumption, placing upwards pressure on prices.
- Status Quo: like-for-like replacement of retiring coal generators with supercritical coal. This **FAILS** to meet the Paris target by a wide margin and has similar cost to the renewables scenario.

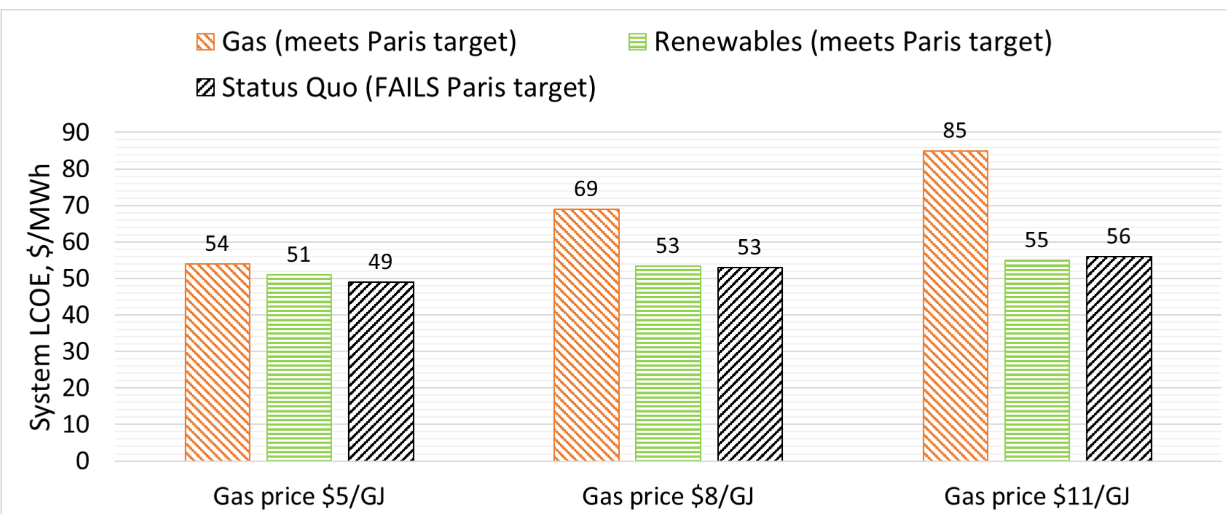

Figure 1: Cost of electricity ($/MWh) for three scenarios and a range of gas prices. See text for details.

Meeting the Paris greenhouse emissions target

The cheapest way to meet the Paris emissions reduction target is by large scale substitution of zero emission wind and solar PV into the electricity system in place of retiring coal and gas.

Australian Greenhouse gas emissions in 2016 were 543 Megatonnes (MT) [1]. Under the Paris agreement Australia will reduce greenhouse gas emissions to 441 MT/year by 2030 [2], a reduction of 102 MT/year from current emissions. Electricity sector emissions in 2016 were 192 MT. We assume that all emission reductions are obtained within the National Electricity Market (NEM). Emissions from electricity production outside the NEM (in WA, NT and remote areas) are about 24 MT/yr.

Thus the 2030 NEM emissions target is 66 MT/yr (= 192 – 24 – 102).

Snowy 2.0 provides half the new storage required to balance the NEM

Snowy 2.0 [3] provides half the new storage required to balance the NEM up to a renewable penetration of 67% (two thirds). Snowy 2.0 has 2 GW power capacity and 350 Gigawatt-hours (GWh) of energy storage [1]. The additional storage needed to reliably balance the NEM when it reaches 67% renewables is Snowy 2.0 plus an additional 2 GW of new storage capacity elsewhere with 6 hours of storage (12 GWh). This may come from pumped hydro, batteries (houses, electric cars) and demand management.

Indeed, Snowy 3.0 [4] with 4 GW capacity could reliably balance a 67% renewables NEM.

Cost of hourly balancing remains low for <75% renewables in the NEM

Hourly balancing ensures that there is enough power available to meet demand for every hour of the year. The hourly balancing cost comprises energy storage, stronger interstate high voltage power lines and the cost of PV/wind spillage on sunny/windy days when the storages are full.

The cost of hourly balancing of the NEM is only about $5/MWh for 67% renewable energy fraction, and rises to about $25/MWh for 100% renewable electricity as shown in Figure 2 [5]. The total cost of renewables is the cost of generation ($50/MWh) plus the cost of balancing (i.e. $55/MWh for 67% renewables). The current wholesale price of electricity in Australia is $70-100/MWh.

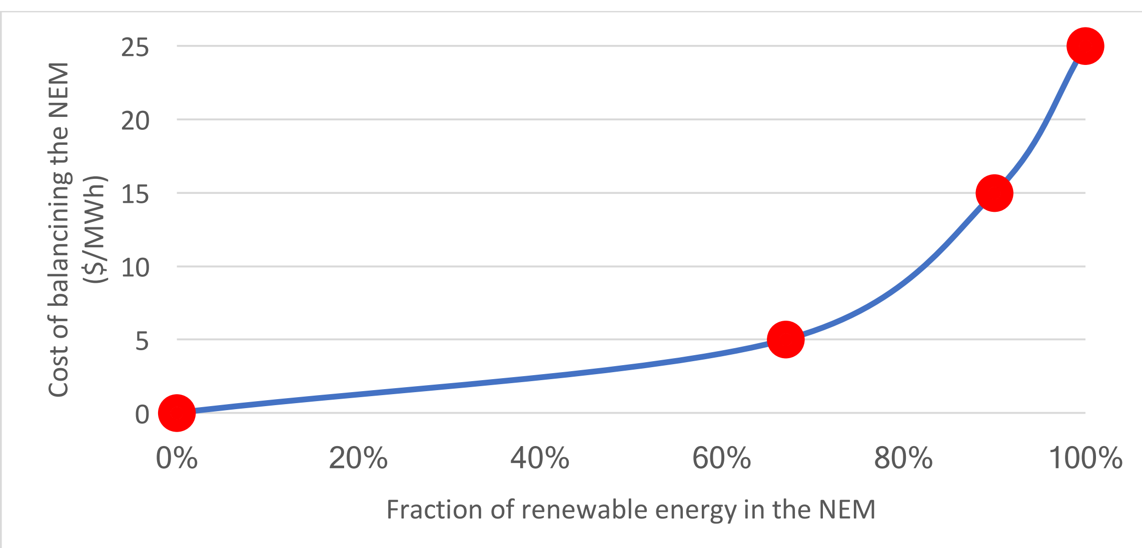

Figure 2: Cost of hourly balancing of the NEM ($/MWh) as a function of renewable energy fraction

Cost of renewable energy is low and falling

The current cost of new-build wind and PV in Australia is around $60/MWh and $70/MWh respectively. We assume that in the 2020s both wind and PV fall to an average of $50/MWh. There are numerous reports of such prices (and lower) already being achieved in overseas locations that have similar wind and solar resources [6-9]. It would be surprising if such prices were not achieved in Australia by 2025.

Renewable energy dominates new generation capacity

PV and wind have 1st and 2nd place in the world's net new generation capacity installed in 2016 (Figure 2), pushing coal into 3rd spot. Wind and PV provide nearly all new capacity installed in Australia.

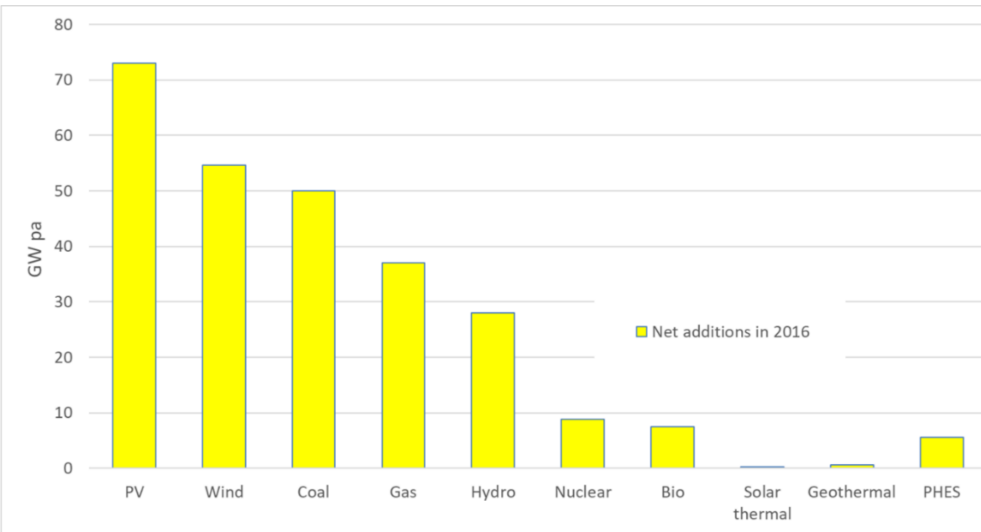

Figure 2: Net new generation capacity installed worldwide in 2016 [10-12]

Stability and reliability remain high under all scenarios

The Renewables scenario is likely to be highly stable because of the wide geographical distribution and highly diverse mix of generators: PV (26 GW), wind (24 GW), coal (9 GW), gas (5 GW), pumped hydro storage (5 GW) and existing hydro/bio (8 GW). Within this mix, a large amount (27 GW) of traditional capacity (coal, gas, hydro and bio) is retained. Inertial energy, spinning reserve, rapid start, black start capability, voltage regulation and frequency control can be provided by a combination of pumped hydro, batteries, demand management and synthetic inertia (from PV and wind farms operated in a conservative fashion at times of grid stress).

All scenarios meet the National Electricity Market standard for unmet energy demand (0.002%) and are likely to achieve stability that matches the current system. A substantial amount of residual coal remains in the Renewables scenarios (9 GW), but only 3 GW remains in the Gas scenario.

Because a renewable electricity system comprises thousands of small generators spread over a million square kilometres, sudden shocks to the electricity system from generator failure, such as occur with aging large coal generators, are unlikely. Neither does cloudy and calm weather cause shocks, because it is predictable and weather patterns take days to move over the Australian continent. Increased interstate interconnection (part of the cost of balancing) reduces the probability of transmission failure, which was the prime cause of the 2016 South Australian blackout.

Retirement of existing coal power stations is gathering speed

Two thirds of Australia's fossil fuel generators will reach the end of their technical lifetimes by 2036, and will need to be replaced either by fossil or renewable energy generators. Data for technical lifetime of each power station is taken from a 2013 report to Government by ACIL Allen [13].

Five coal fired power stations are closed early in the Renewables scenario (Table 2). Coal capacity in 2030 falls from 19 GW (Status Quo) to 9 GW. Brown coal power stations have the highest emission intensity but the lowest operational cost. The Renewables scenario envisages retention of Loy Yang because of its low cost and also its role in supporting Victoria, South Australia and Tasmania.

For the Gas scenario to meet the Paris target requires premature closure of all brown coal power stations and most black coal power stations by 2030 (Table 2), and their replacement with new Combined Cycle Gas Turbines (CCGT) which have lower emissions but higher cost. Coal capacity in 2030 falls from 19 GW (Status Quo) to 4 GW in the Gas scenario.

The coal power stations that would close prematurely in our modelling relative to the ACIL Allen Report [13] are tabulated below.

Power station	Capacity (GW)	Fuel (coal type)	Renewables scenario	Gas scenario
Liddell	2.1	Black	2022	2022
Eraring	2.9	Black	2030 (3 years early)	2030 (3 years early)
Yallourn	1.5	Brown	2030 (5 years early)	2030 (5 years early)
Tarong	1.4	Black	2030 (5 years early)	2030 (5 years early)
Bayswater	2.7	Black	2030 (6 years early)	2030 (6 years early)
Callide B	0.7	Black	2030 (9 years early)	2030 (9 years early)
Loy Yang A	2.2	Brown		2030 (6 years early)
Loy Yang B	1.1	Brown		2030 (15 years early)
Stanwell	1.4	Black		2030 (15 years early)
Callide C	0.8	Black		2030 (21 years early)
Tarong North	0.4	Black		2030 (22 years early)

Table 1: premature closure of coal power stations under the Renewables and Gas scenarios

DETAILS

- Renewable energy technology: We avoid heroic assumptions about future technology development: we only consider technology that has already been deployed in large quantities (> 200 GW) with annual deployment rates above 50 GW/year, namely PV and wind. On this basis, we exclude solar thermal, geothermal and ocean energy. We also exclude nuclear energy because of the unlikelihood of its deployment in Australia.
- Wind and PV is being installed at around 3 GW per year [14] to meet the Renewable Energy Target (RET) in 2020. We assume a similar deployment rate until 2030, with 1.5 GW/year each for wind and PV. In all scenarios, we assume that the 2020 RET is met, and that new rooftop PV continues to be deployed after 2020 at a rate of 1 GW per year. The cost and benefit of rooftop PV systems accrues

to the building owner and appears as an apparent drop in electricity demand. However, the cost of hourly balancing of rooftop PV is included in our modelling.

- High voltage transmission: Optimisation of renewable energy deployment requires additional high voltage transmission to allow movement of wind and PV energy between states depending upon weather and demand. We utilise high voltage AC transmission for this purpose, at a cost of $1000 per MW-km (and lifetime of 50 years). Distances amongst the major cities, Brisbane, Sydney, Melbourne, Adelaide and Hobart, are used to estimate the length of new high voltage AC transmission lines. The new transmission lines comprise Qld-NSW (5.2 GW), NSW-Vic (5.4 GW), SA-Vic (1.4 GW) and Vic-Tas (1.5 GW). A second (undersea) Basslink costs $4000/MW-km.
- Gas prices have increased in recent years due to exposure of Australian gas consumers to world pricing via the construction of large LNG export facilities. A recent report to Government noted *"The opaque nature of Australia's wholesale natural gas markets and the deregulation of natural gas retail markets in most states and territories mean there is limited information in the public domain about the gas prices paid by industrial and residential customers"* [15]. This report estimates the wholesale price of gas to be $7-11/GJ. The Renewables scenario does not require an increase in gas consumption for electricity generation, thus reducing pressure on gas prices.
- Electricity demand in Australia has been static or falling since 2008, caused by improving energy efficiency, reduced demand from heavy industry, and increased price of electricity. We assume that this trend continues until 2030. Demand in the NEM remains at 205 TWh per year (including rooftop PV). Thus, improved energy efficiency is offset by rising population.
- Existing hydro and bio energy: We include existing hydroelectricity generation and pumped hydro stations but exclude additional river-based hydroelectric deployment due to lack of significant further rivers to dam in Australia. We also include existing biomass generation (based on agricultural waste), but exclude additional deployment of biomass because utilization competes with food, timber and ecosystem values for the provision of land, water, fertilisers and pesticides. Wind and PV (including rooftop PV) contributed about 21 TWh in Australia in 2016 compared with hydroelectricity (18 TWh) and biomass electricity (4 TWh).
- Modelling: For ease of modelling we make all of the required emission reductions in the NEM. Electricity emissions in Western Australia, the Northern Territory and remote areas is about 13% of total emissions. We divide the NEM geographical region into 43 cells and utilise historical hourly data for wind and PV in each cell throughout the years 2006-10, which comes from the AEMO 100% renewables study in 2012-13 [16,17]. We use historical NEM demand data for every hour of the years 2006-10. Existing bio and hydroelectricity (less than 10% of annual electricity demand) is assumed to be dispatchable. The existing river-based PHES is utilized.
- PHES: A private cost model is used, developed by an experienced hydro engineer based upon existing models. The model has been tested for consistency with publicly available PHES systems costs. The unit off-river PHES system is assumed to have a power of 200 MW, a head of 580 m, twin 20 m deep 5-hectare "turkey nest" ponds with earth walls built on flat land, penstock slope of 13 degrees, easy access, minimal flood control measures and a round trip efficiency of 80%. The estimated cost is $800 per kW (for penstocks, machinery and power conversion) and $70 per kWh (for pond excavation and construction), with scaling factors applied for different head and pond size.

Head is a strong inverse driver of cost of storage. Transmission to a high voltage node is an additional cost and calculated separately.

- Discount rate: We calculate the levelised cost of electricity (LCOE) using a real (i.e. inflation-free) discount rate of 5% per year. This includes bank finance for 70% of capital expenditure at a nominal rate of 5% per year, a return on investment of 10% (nominal) on equity (30% of capital expenditure) and an inflation rate of 1.5% per year. The Reserve Bank of Australia cash rate is currently 1.5% per year. We use Australian dollars and an exchange rate of AU$1.00 = US$0.75.
- The price of wind and PV continues to fall rapidly. Our estimate for current (2017) prices in Australia is <$60/MWh and <$70/MWh for wind and PV respectively [5-9,18]. This takes account of a 20% reduction of the international market price for PV modules over the past 18 months, and the rapidly growing scale of the PV industry in Australia. Whereas the ARENA LSS program funded systems of typically a few tens of Megawatts, today there are frequent announcements of PV systems in the hundred-megawatt range. Wind energy technology also continues to improve in every aspect, including the size of turbines and the ability to achieve capacity factors above 40%.

Three scenarios summary

Table 1 shows details of the modelling of the Renewables, Gas and Status Quo scenarios.

Scenario	**Renewables**	**Gas**	**Status Quo**
Emissions (MT); NEM target = 66 MT	66	66	113
Emission reduction **shortfall** (MT)	0	0	**47**
Coal capacity (GW)	9	3	19
Coal generation (TWh)	58	20	107
Gas capacity (GW)	5	16	9
Gas generation (TWh)	10	106	20
Wind capacity (GW)	24	8	8
Wind generation (TWh)	88	28	28
PV capacity (incl. rooftop PV) (GW)	26	23	23
PV generation (TWh)	40	33	33
Existing hydro and bio capacity (GW)	8	8	8
Existing hydro and bio generation (TWh)	13	18	18
Pumped hydro capacity (GW)	5.3	1.3	1.3

Table 2: optimised capacity and electricity production for each scenario

- Storage: Snowy 2.0 (2 GW power, 350 GWh energy) plus additional pumped hydro (2 GW, 12 GWh) + existing pumped hydro of 1.3 GW and 26 GWh.
- Average capacity factors in the Renewables scenario: rooftop PV (15%), 1-axis tracking PV (23%), wind (41%), coal average (74%), CCGT (34%), OCGT (23%).
- LCOE: wind ($50/MWh), PV ($50/MWh), existing coal (brown $20/MWh, black $40/MWh)

Costs

Operational and financial parameters are tabulated in Table 3 and 4, taken from the CO2CRC report [19].

Technology	Capital cost ($/kW)	Fixed O&M ($/kW/year)	Variable O&M ($/MWh)	Fuel cost ($/GJ)	Thermal efficiency (%)	Emission intensity (t/MWh)	Technical lifetime (years)
Brown coal	0	111	1.1	0.4	27	1.22	50
Subcritical black coal	0	47	2.0	3.1[a]	35.6	0.918	50
Supercritical black coal	0	45	1.9	3.1[a]	37.6	0.895	50
CCGT	0	30	1.1	8, 11	47.5	0.389	30
OCGT	0	12	8.3	8, 11	30	0.620	30
Hydro	0	49	6.6				150
Bio[b]	0	109	7	0.6	22		30

Note. Cost estimates for 2016. Data for legacy assets is derived from the ACIL Allan report 2013 & 2014.
[a] 2015-16 average prices for Australian thermal coal
[b] Source: AEMO 100% renewables study 2013

Table 3. Cost assumptions for power generation technologies (legacy assets)

Technology	Capital cost ($/kW)	Fixed O&M ($/kW/year)	Variable O&M ($/MWh)	Fuel cost ($/GJ)	Thermal efficiency (%)	Emission intensity (t/MWh)	Technical lifetime (years)
Supercritical black coal	3000	45	2.5	3.1	40	0.792	40
CCGT	1450	20	1.5	8, 11	50	0.373	30
OCGT	1000	8	12	8, 11	34	0.548	30
1-axis tracking PV	1100 DC	0	15	0			25
Wind turbines	1800	30	10	0			25
Pumped hydro	800 / 70[a]	20	0	0			50

Note. Cost estimates for 2020s. Data for new-build coal and gas power plants is derived from the CO2CRC report 2015 [19]
[a] $800/kW for power components including turbines, generators, pipes and transformers; $70/kWh for storage components such as dams, reservoirs and water. Sources: private model

Table 4. Cost assumptions for power generation technologies (new-build plants)

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Geographic information system algorithms to locate prospective sites for pumped hydro energy storage

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HIGHLIGHTS

- Developments of the "dry-gully" and "turkey's nest" site models.
- A software "STORES" to locate prospective sites for pumped hydro energy storage.
- 190 sites identified in South Australia, with a storage capacity of 441 GL, 276 GWh.
- A comprehensive literature survey of Geographic Information System-based site searches.

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ABSTRACT

Pumped hydro energy storage is capable of large-scale energy time shifting and a range of ancillary services, which can facilitate high levels of photovoltaics and wind integration in electricity grids. This study aims to develop a series of advanced Geographic Information System algorithms to locate prospective sites for off-river pumped hydro across a large land area such as a state or a country. Two typical types of sites, dry-gully and turkey's nest, are modelled and a sequence of Geographic Information System-based procedures are developed for an automated site search. A case study is conducted for South Australia, where 168 dry-gully sites and 22 turkey's nest sites have been identified with a total water storage capacity of 441 gigalitres, equivalent to 276 gigawatt-hours of energy storage. This demonstrates the site searching algorithms can work efficiently in the identification of off-river pumped hydro sites, allowing high-resolution assessments of pumped hydro energy storage to be quickly conducted on a broad scale. The sensitivity analysis shows the significant influences of maximum dam wall heights on the number of sites and the total storage capacity. It is noted that the novel models developed in this study are also applicable to the deployments of other types of pumped hydro such as the locations of dry-gully and turkey's nest sites adjacent to existing water bodies, old mining pits and oceans.

1. Introduction

Photovoltaics (PV) and wind constitute approximately half of the world's new generation capacity installed in 2014–16. At the end of 2016, the global installations of PV and wind were beyond 300 gigawatts (GW) and 480 GW respectively [1,2]. Rapid growth of PV and wind energy in the electricity sector is expected to continue, driven by a broad range of issues associated with climate change, energy security and economics.

High shares of intermittent PV and wind energy in electricity grids bring significant challenges to the economics and security of the system as is the case in South Australia (SA), where nearly half of the state's electricity production come from rooftop PV and wind farms [3]. SA has a low level of interconnection with the rest of the Australian National Electricity Market (NEM) and there is no existing hydroelectric or pumped hydro facility established within the region. This brings significant challenges to power system operation and the state's energy security due to supply intermittency and lack of sufficient inertial energy to support PV and wind electricity, especially in light of continuing rapid growth of PV and wind energy investment. In July 2016, when upgrades to the Heywood interconnector coincided with low wind generation at peak times, the average wholesale electricity prices in SA surged to $229/MWh (Australian dollars per megawatt-hour) with 3 extreme price events on 7, 13 and 14 July beyond $5000/MWh [4]. By contrast, the long-term average price in SA when the interconnector is available to import brown coal electricity from Victoria is $50/MWh. Additionally, a range of system events such as load shedding and islanding occasionally occurred in 2016–17 [5,6]. This included a

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state-wide blackout on 28 September 2016, when three 275 kilovolts (kV) backbone transmission lines were damaged by a major storm event [7].

Pumped hydro energy storage (PHES) is capable of large-scale energy time shifting and a range of ancillary services such as frequency regulation, which can facilitate high levels of photovoltaics and wind integration in electricity systems. Developments of PHES began in the 1890s and surged through the 1960s, 70s and 80s in Europe, the United States and Japan where the rapid growth of nuclear energy and coal-fired units continued. These large thermal steam plants lack sufficient operational flexibility to accommodate changing demand and required the capability of load levelling. PHES was also regarded as a more economical alternative to oil and natural gas-fired plants for peak shaving, especially during the post-periods of energy crisis in the 1970s [8,9]. In recent years, the prosperity of PV and wind developments has led to a resurgence of interest in PHES. Open-loop PHES, which is continuously connected to a naturally flowing water feature [10], dominates the deployment of existing PHES. However, developments of conventional river-based hydroelectric including PHES are usually constrained by the availability of water resources and a variety of environmental concerns such as the interactions with ecology and natural systems [11]. Consequently, expansions of pumped hydro were generally not included in many high renewables future studies such as [12–14]. By contrast, short-term off-river PHES, which incorporates closed-loop pumped hydro systems, consumes modest amounts of water and has little impacts on the environment and natural landscape.

Recent studies [15,16] from the Australian National University show Australia can build an affordable and reliable electricity network with 100% renewable energy, using PV, wind, existing hydroelectric and biomass with the support of short-term off-river PHES. Preliminary Geographic Information System (GIS)-based works [15,17] suggested a large potential for off-river PHES to be deployed in the extensive hills and mountains close to population centres from North Queensland down the east coast to South Australia and Tasmania. This study focuses on the development of a series of advanced GIS algorithms which are capable of:

- Highlighting promising regions for PHES developments from a large region such as a state or a country, which can facilitate the planning of renewable energy development zones incorporating PV, wind, PHES and high-voltage direct current (HVDC) transmission.
- Rapid identification of prospective PHES sites with different characteristics of topography. For example, pairs of medium-sized reservoirs (dozens or hundreds of hectares) can be built on large flat lands as turkey's nest dams or located in enclosed dry gullies.
- Selection of optimal locations by ranking the sites identified from site searching on the basis of topography suitability and land use classes. Additionally, detailed site information such as the volumes of reservoirs, dam wall heights and lining areas will be helpful to integrate a costing tool in the next level of study.

Section 2 is a brief summary of the reviewed GIS-based studies on locating sites for the development of hydroelectric/PHES projects. Section 3 describes the mathematical models developed in this study. Section 4 outlines the GIS algorithms used to identify two different types of PHES sites. Section 5 illustrates the results from site searching by applying the models and algorithms introduced in Sections 3 and 4 to South Australia.

2. Literature review

PHES is a mature technology of large-scale energy storage. At the end of 2016, there were over 160 GW (rated power) of PHES in operation around the world with more than 85% of the installations deployed in Europe (> 50 GW), China (32 GW), Japan (26 GW) and the United States (23 GW) [18]. Recent studies on PHES focus on:

- Its significant roles as large-scale energy storage to facilitate large fractions of variable renewable energy integration while maintaining system reliability and security [19–21]. Our NEM and Western Australian studies [15,16] also demonstrated that energy affordability can be maintained in a system dominated by PV, wind, PHES and HVDC transmission.
- Operation strategies to maximise profits from energy arbitrage in competitive electricity markets and providing inertial response and ancillary services such as frequency control [22–24].
- Analyses of mechanisms and policy reform in electricity markets to facilitate development of PHES which is typically capital intensive and has a long lead time [25–28].
- Seawater and underground PHES which have minimum environmental impacts to ecology systems [29–33].
- Modern adjustable-speed PHES with wide operating ranges and higher efficiency, as well as improved dynamic stability under grid disturbances [34].
- GIS-based siting to locate sites by utilising contemporary advanced GIS and remote sensing technology.

2.1. GIS-based siting

Developments of advanced GIS and remote sensing techniques in recent years allow efficiency and accuracy improvements in the assessments of hydroelectric and water supply schemes such as computerised site identification utilising high-resolution digital elevation models (DEM). Table 1 is a brief summary of the reviewed GIS-based studies on hydroelectric/PHES site searching.

A number of studies focused on small hydro with power capacities ranging from hundreds of kilowatts (kW) to dozens of megawatts (MW), including both run-of-the-river and storage types of hydroelectric generation. Larentis et al. [35] developed a computerised "Survey & Selection" methodology for the evaluation of small run-of-the-river and storage hydroelectric systems within a river basin of Brazil. The study included a section-by-section analysis of dam and powerhouse locations and flow regulation and at-site optimisation for the assessment of total hydropower potentials of the basin. Kusre et al. [36] conducted a GIS-based site location with hydrological analyses for small run-of-the-river hydroelectric in northeast India by searching upstream from the outlet of a watershed to the fifth order of streams at an interval of 500 m. Yi et al. [37] undertook a cell-by-cell analysis to identify potential small hydro sites along rivers and a scoring system was established in the modelling, incorporating a variety of issues including topography, hydrology and environmental impacts. Petheram et al. [38] also examined the opportunities for developing water supply schemes with a minimum catchment area of 10 square kilometres (km^2) in northern Australia.

For PHES, most studies concentrated on examining opportunities for existing waterbodies to be utilised as upper and/or lower reservoirs of PHES systems. This includes the investigation of existing artificial reservoirs belonging to hydroelectric or water supply schemes as well as natural lakes as greenfield projects. Hall & Lee [39] investigated the potentials of utilising existing waterbodies in close proximity to hydroelectric or water supply schemes to serve as open-loop PHES reservoirs on the basis of 4 critical criteria (capacity, area, distance and elevation difference) derived from the characteristics of 43 existing PHES in the contiguous United States. Gimeno-Gutierrez & Lacal-Arantegui [40] investigated the potentials of matching pairs of existing reservoirs as PHES facilities within distances of 1–20 km (elevation difference > 150 m) across 31 countries of Europe, where thousands of sites were identified with a realisable storage capacity of 29 terawatt-hours (TWh), especially in Turkey, Spain and the Alps countries. Jimenez Capilla et al. [41] demonstrated a multi-criteria GIS-based analysis of site selection for an existing dam to be retrofitted into PHES systems, which incorporated the aspects of topography, land use, geology and meteorology by applying the analytic hierarchy process into a decision model. Fitzgerald et al. [42] investigated the adjacent

Table 1
A brief summary of the reviewed GIS-based studies on hydroelectric/PHES site searching.

Study	Region	Project type	Site type	Input datasets	GIS platform and processing time	Results	Ranking metrics	Cost model
Larentis et al. [35]	Taquari-Antas (26,500 km^2), Brazil	Small hydro	Run-of-the-river, storage	DEM 90 m, Hydro, PA	ArcGIS & Fortran	997 sites, 736 MW	Products of head and slope	Not included
Kusre et al. [36]	Umkhen watershed (1,204 km^2), India	Small hydro	Run-of-the-river	Topo 1:50,000, LU, Hydro, Meteo	ILWIS	107 sites on 9 streams, 133 MW	Not included	Not included
Yi et al. [37]	Bocheong stream basin (554 km^2), Korea	Small hydro	Run-of-the-river, storage with dam heights 5–20 m	DEM 30 m, LU, Hydro, PA	ArcView & Avenue (5 hours)	4 storage sites, 2 run-of-the-river sites	A scoring system	Not included
Petheram et al. [38]	Finniss and Adelaide catchments (16,950 km^2), Australia	Water supply	Earth embankment, roller compacted concrete	DEM 30 m, Hydro	GDAL modules & Python	Dozens of sites > 5 GL per $m	Storage-cost and yield-cost ratios	A cost function
Hall & Lee [39]	Contiguous United States	PHES	Existing waterbodies	DEM 10 m, LU, PA, Res, Lakes	Unknown	2,505 sites	Capacity of base plants and head	Not included
Gimeno-Gutierrez & Lacal-Arantegui [40]	31 European countries	PHES	Existing reservoirs of hydroelectric and water supply projects	DEM 90 & 250 m, LU, PA, Res, Infra	ArcGIS & DIVA-GIS	Thousands of sites, 29 TWh (realisable)	Not included	Not included
Jimenez Capilla et al. [41]	Rules dam, Spain	PHES	Flatlands near existing water supply schemes	Topo, LU, Geo, Meteo, PA	ArcGIS	3 alternatives for Rules Dam	A decision (suitability) model	Not included
Fitzgerald et al. [42]	612 reservoirs in Turkey	PHES	Flatlands adjacent to existing reservoirs	DEM 90 m, Res, PA, Infra, LC	ArcGIS & ModelBuilder	444 sites, 3.8 TWh (realisable)	Largest energy storage capacity	Not included
Kucukali [43]	7 existing hydroelectric in Turkey	PHES	Flatlands adjacent to existing hydroelectric	Topo 1:25,000, LU, Geo, PA	Unknown	5 upper reservoirs 200–650 m	A suitability model	Not included
Lu & Wang [44]	Tibet (1.22 million km^2), China	PHES	Existing lakes and narrow valleys	DEM 30 m, Lakes, Grid	ArcGIS & ModelBuilder (hours)	558 sites, 4.3 TWh	Smallest slopes or minimum distances	Not included
Rogeau et al. [45]	France (675,000 km^2)	PHES	Existing lakes and natural depressions	DEM 25 m, Topo, PA	RStudio & R (2–3 weeks)	1,145 pairs, 33 GWh	A virtual "cost of energy"	Not included
Connolly et al. [46]	Abbeyfeale (800 km^2), Ireland	PHES	Off-stream flatlands	DTM 10 m	Atlas SCC & C++ (6–10 days)	5 sites, 710–979 MW, 8,634 MWh	Not included	Not included

Note. GIS algorithms and search criteria of these studies outlined in Section 2 and 4.
Acronyms and abbreviations: topography (Topo), hydrology (Hydro), geology (Geo), meteorology (Meteo), digital elevation models (DEM), digital terrain models (DTM), transmission network (Grid), infrastructure (Infra), land use (LU), land cover (LC), protected areas (PA), dams & reservoirs (Res), natural waterbodies (Lakes).

flat areas (with slopes of 0–5 degrees) of 612 existing reservoirs in Turkey, identifying over 400 sites with heads > 150 m and storage capacity > 1 gigalitre (GL), where the sensitivity of the number of sites, energy storage capacity and head to buffer distance (radius) was also studied. Similarly, Kucukali [43] established a suitability model for the multi-criteria assessment (scoring 1–3) of surrounding areas of existing hydroelectric projects to be exploited as PHES upper reservoirs. Lu & Wang [44] investigated existing lakes and natural narrow valleys that can be utilised for the development of large-head (> 500 m) PHES, where the site searching was conducted at an interval of 500 m on stream lines created to represent valleys.

Only a few studies investigated site identification for closed-loop off-stream PHES on a large scale. Rogeau et al. [45] investigated the opportunities for small-scale PHES in France (with a minimum storage capacity of 500 kW × 10 h) utilising existing waterbodies (lakes) and natural depressions as upper and lower reservoirs. A virtual "cost of energy" was used to rank the identified sites, which incorporated energy storage capacity and a range of cost components such as lining, water conveyance and grid connection in a scoring system. Connolly et al. [46] developed a Triangulated Irregular Network model searching for flatlands to locate PHES reservoirs, where the flatness of terrain was defined by the thresholds of maximum earthwork from cut and fill balancing.

2.2. Novelty of this work

Previous GIS-based studies such as [35–44] concentrated on river-based hydroelectric/water supply schemes or PHES systems based on natural lakes and existing artificial reservoirs. However, constructions of such generation or storage facilities are usually associated with a wide variety of environmental concerns such as the interactions with ecology and natural systems and the negative impacts on soils and geology [11]. By contrast, this study focuses on short-term off river energy storage (STORES), which refers to closed-loop PHES systems located away from rivers and thus has little environmental impacts. Environmental impacts of STORES facilities are further discussed in Section 4.5.

A significant feature of STORES is the large altitude difference between upper and lower reservoirs, typically > 300 m. Large hydraulic heads enable significant amounts of electricity to be stored in pairs of medium-sized reservoirs where the consumption of water is modest. For example, a PHES system with twin 100 hectares (ha), 1 gigalitre (GL) reservoirs separated by a height difference of 500 m is able to contribute 1 gigawatt-hour (GWh) of storage capacity (assuming an usable fraction of 85% and an efficiency of 90%), or 200 MW of power with 5 hours of storage to the electricity system - equivalent to a large gas-fired power plant.

Section 4.6 Access to water provides a brief introduction of the source of initial fills, as well as a variety of measures to mitigate evaporation and leakage losses.

In addition, a novel turkey's nest site model is developed in this study. Conventional definitions of turkey's nest sites were usually based on average surface slopes [42] or amounts of the earthwork required to flatten the sites [46]. While these approaches can highlight large flat lands with slight slopes, they may fail to identify those sites with larger slopes but still being desirable because the construction work for the dams is modest. This is detailed in Section 4.3 and examples are shown in Fig. 5. In this study, the turkey's nest site model incorporates the calculations of dam volumes and dam wall heights, which have significant influences on the economics of PHES systems, and hence can effectively reflect the suitability of the sites.

Dry-gully sites impound a reservoir by utilising existing terrains as a major part of the dam. The lack of efficient GIS algorithms for dry-gullies has constrained the assessments of PHES potentials on a broad scale, as well as limiting the accuracy of the modelling results. Lu & Wang [44] used approximations (a triangle pyramid) to represent narrow valleys. Rogeau et al. [45] matched existing waterbodies (lakes) and terrain depressions, where the storage capacities only ranged from megawatt-hours (MWh) to hundreds of MWh (compared with GWh-scale in this study). In this study, an improved dry-gully model is presented, which incorporates a series of advanced GIS algorithms such as: (1) distributions of a large number of pour points on a virtual stream network which allows high-resolution (10 m) site searches to be conducted along the "streams" where the dry-gully sites are more likely to be located and, (2) delineation of reservoirs and dams in a watershed model, which enables PHES facilities to be visualised in three dimensions (Fig. 10).

Furthermore, the automatic GIS-based procedures provide a powerful mapping tool, the software "STORES". "STORES" can highlight the most promising regions for PHES deployments and efficiently identify the optimal PHES sites in terms of high water to rock (W/R) ratios i.e. large reservoir volumes with less earthwork. A range of detailed site information such as surface area and volume are also produced from the modelling. The development of the software "STORES" facilitates high-resolution site searches across a large land area which are typically computationally intractable. This allows a rapid estimate of PHES potentials to be conducted within a state or a country as demonstrated in Section 5.

It is noted that although fresh-water PHES is the focus of this study, the dry-gully and turkey's nest site models are also applicable to the deployments of other types of pumped hydro.

3. Models for potential PHES sites

The direct cost of constructing a PHES facility can be broken down into two major components:

- Power components including the machinery parts such as turbines, generators, transformers and switchyards, the costs of which are in proportion to or associated with the power rating (MW) of PHES and expressed in terms of dollars per kilowatt ($/kW). Water conveyance facilities between upper and lower reservoirs are also included in this category as its size decides the flow rate and hence determines the power capacity.
- Storage components, which are related to the storage capacity (MWh) of a plant consisting of such as dams, earth excavation and lining costs, expressed in terms of dollars per kilowatt-hour ($/kWh).

While a wide range of factors such as geology and hydrology are involved in site selection and dam construction, the topography of a site is always a critical issue which decides the type, height and shape of a dam, as well as the amount of earthwork required to build it. In this study, two types of terrain are considered to be of high priority in site selection in terms of topography fitness for the deployment of short-term off-river PHES: dry-gully (DG) sites and turkey's nest (TN) sites. The definition of DG and TN sites is in line with the T2, T3 types of PHES in European studies [47]. The TN and DG models outlined as follows were developed with experienced hydro and civil engineers from Australia and New Zealand.

3.1. Dry-gully sites

A dry-gully site features a gentle gully located near the top of a hill, which is capable of impounding a certain amount of water by utilising existing terrain as a major part of the dam. A typical example of this type of site is the upper reservoir of Presenzano Hydroelectric Plant in Italy (Fig. 1).

A notional model for the DG sites is established as shown in Fig. 2, where the terrain of a location at latitude −32.116638, longitude 137.987237 is used as a prototype. V_{res} and A_{res} represent the volume and the surface area of a reservoir while V_{dam}, B_{dam} and $H_{dam.max}$

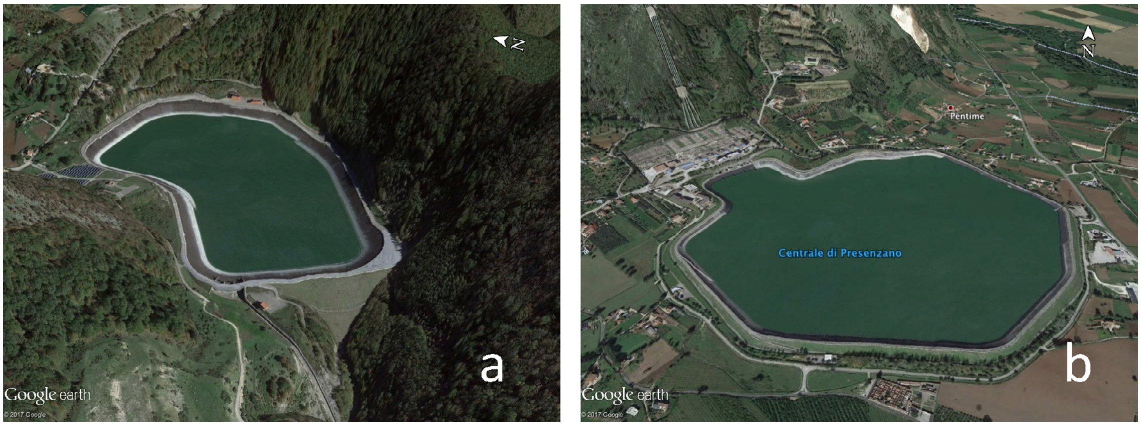

Fig. 1. Upper (a) and lower (b) reservoirs of Presenzano Hydroelectric Plant, Italy (elevation exaggeration: 3).

denote the volume of earthwork required to build a dam, the dam's batter ratio and maximum wall height.

Dam batters of typical earth dams in USACE [48] range from 1:2–1:4 (downstream) and 1:2.5–1:4.5 (upstream) while for rock-filled dams, it is in the range of 1:1.6–1:2. Similarly, Mai [49] suggested 1:2.5–1:3.5 (upstream), 1:2–1:3 (downstream) for earth dams and 1:1.4–1:1.7 for rock-fill dams. For concrete dams, it is in the range of 1:0.7–1:0.8 [50]. In this study, the dams of the DG sites are assumed to be rock-fill or concrete with a batter of 1:1 while for the TN sites (Section 3.2) where the dam heights are typically lower than the DG sites, an earth-filled embankment dam with a batter of 1:3 is assumed. This assumption allows a rapid screening for DG and TN sites across a large land area and will be subject to optimisation when a specific site is chosen for feasibility study and engineering design.

3.2. Turkey's nest sites

A TN site is located on relatively flat land, which can be enclosed by a surrounding earth-filled embankment dam to store a certain amount of water. The lower reservoir of Presenzano Hydroelectric Plant in Fig. 1 is an example of the TN sites. Fig. 2 illustrates the model of TN sites developed in the study, where the definition of parameters remains the same with Section 3.1.

3.3. Equations

$$V_{res} = V_{org} + \frac{V_{dam}}{2} \tag{1}$$

$$V_{org} = A_{res}\frac{\sum_{i=1}^{m}(E_{dam}-E_i)}{m} \tag{2}$$

$$V_{dam} = L_{dam}B_{dam}\frac{\sum_{j=1}^{n}(E_{dam}-E_j)^2}{n} \tag{3}$$

$$E_{dam}-E_i \geqslant 0, E_{dam}-E_j \geqslant 0 \tag{4}$$

$$H_{dam.max} = E_{dam}-E_{j.min} \tag{5}$$

Eqs. (1)–(5) demonstrate the calculations of the volume of the reservoir, V_{res}, and the maximum dam wall height, $H_{dam.max}$, where L_{dam} represents the dam's crest length; E_i and E_j represent the elevations for the i_{th} cell of the reservoir and the j_{th} cell of the dam while E_{dam} denotes the elevation of the dam crest; m and n are the total numbers of raster cells within the reservoir and dam respectively. Eq. (1) assumes the soils or rocks required to build the dam are obtained from excavation within the reservoir area and hence adds half of the dam volume $V_{dam}/2$ to the total volume of reservoir. V_{org} is the volume impounded by original terrain of the site (i.e. prior to excavation), where the thickness of dam is assumed to be zero. Eq. (3) is a simplified form of dam volume calculation, where freeboard and dam crest width (decided in detailed engineering design) are not factored in. A full equation of dam volume calculation, which incorporates freeboard height and dam crest width,

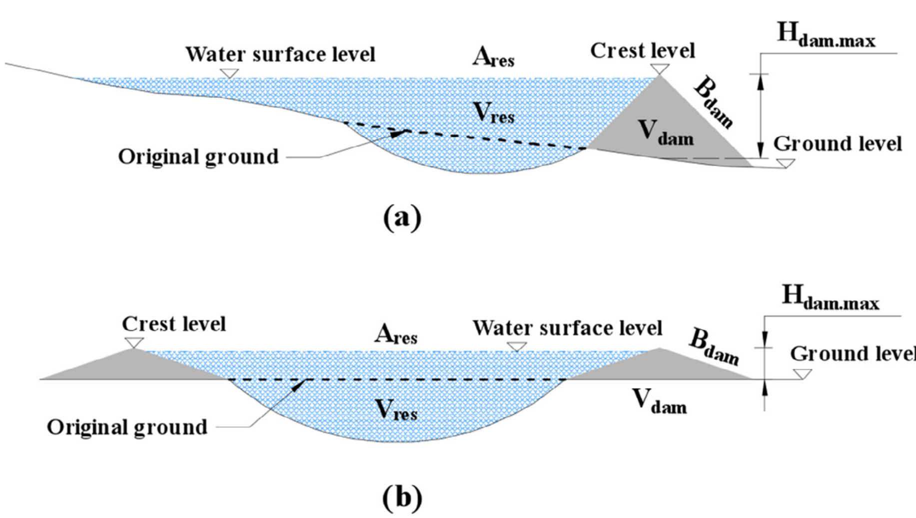

Fig. 2. Cross sections of typical dry-gully (a) and turkey's nest (b) sites.

is included in Appendix A.

3.4. Other types of PHES sites

Due to the long-term prosperity of mining activities in Australia, there are a large number of old mining pits likely to be converted into PHES systems such as the proposed Kidston Pumped Storage project in northern Queensland [51]. Opportunities for retrofit of existing hydroelectric schemes also exist (though it is limited) such as in the Snowy Hydro scheme and in Tasmania, an island state with over 90% of electricity from hydro resources [52,53]. Furthermore, a seawater PHES facility is being studied which is located at the top of Spencer Gulf of SA [54] though there are a number of challenges in the development of ocean-based PHES [17]. The models established in Section 3.1, 3.2 and the GIS algorithms outlined in Section 4 can be used for site searching within the regions for mining pits, existing reservoirs, as well as near ocean sites.

4. GIS algorithms

A software named STORES is developed in the modelling which includes the following functional modules (Fig. 3):

- “Highlight” to exclude the regions without sufficient altitude difference within an acceptable distance
- “DryGully” to identify DG sites within the highlighted areas
- “TurkeysNest” for the identification of TN sites within the highlighted areas
- “PrettySet” for the optimisation of site selection

All of the scripts are written in Python and using its libraries such as NumPy and SciPy, as well as the ArcPy package from Esri ArcGIS.

4.1. Highlighting promising regions

In order to reduce computation loads which are associated with the search scope, an exclusion criterion is applied to exclude the regions without the height differences required for efficient storage. A threshold of minimum head to horizontal distance (H/D) ratio is used to highlight the regions that meet the criterion. A minimum H/D ratio of 1:10 was used in [43–45,55]. In this study, a moderate relaxation of the ratio (1:15) is assumed to include those sites with a ratio slightly lower than 1:10. Additionally, protective areas and intensive land uses are excluded at this procedure to allow elimination of any conflict or competition with the regions which are sensitive to environmental impacts and social acceptance.

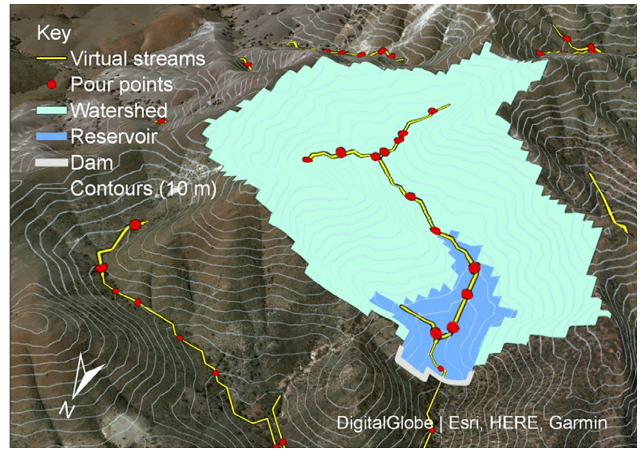

Fig. 4. Delineation of the watershed, reservoir and dam of a dry-gully site (elevation exaggeration: 2).

Detailed information of the results from applying this approach to the DEM of the case study region, South Australia, is demonstrated in Section 5.2.

4.2. Identifying dry-gully sites

To identify potential dry-gully sites as defined in Section 3.1, a virtual stream network is derived from the void-filled DEM. A threshold minimum of 111 accumulation cells is set in the delineation of virtual streams to allow the surface area of reservoir to be greater than 10 ha at the cell resolution of approximately 30 m. Lu & Wang [44] also extracted a virtual stream network from the DEM to identify natural valleys that can be utilised as a PHES reservoir. Different from Lu & Wang [44], this study calculates the storage capacity of dry gullies and the required earthwork to build a dam through a watershed model (Fig. 4).

Then, for raster cells at an interval of 10 m height on the virtual stream network, a sequence of virtual pour points are created by extracting intersections of the streams and the 10 m contours (Fig. 4). A watershed is calculated for each pour point from its location and a flow direction raster derived from the DEM.

Maximum dam wall heights are then used to define the flooded areas (reservoirs) within that watershed. A minimum surface area of 111 raster cells (around 10 ha) is applied again at this step to ensure the reservoirs selected for further analysis are capable of a sufficient storage capacity. In addition, the pour points located on a slope greater than 1:5

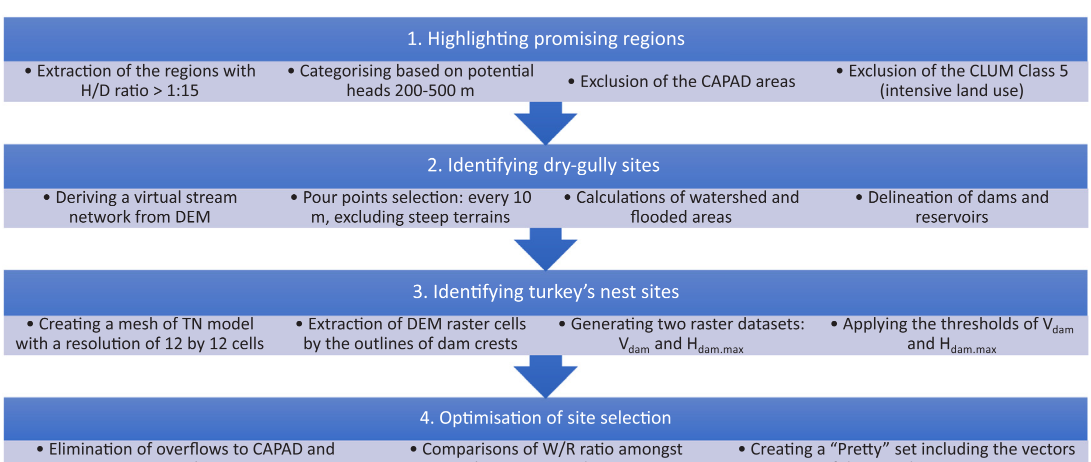

Fig. 3. GIS-based procedures for pumped hydro site searching.

are excluded due to the likelihood of insufficient storage capacity. Moreover, it avoids dam construction on steep terrain which is only technically feasible under limited conditions [48].

A cell-by-cell or section-by-section analysis along a stream network is a generic approach for decision making in the planning of hydro-electric or water supply schemes such as [35] and [38]. By specifying a maximum height of dam wall at the location of each pour point, the flooded areas, which includes all the raster cells of watershed with an altitude difference less than the maximum dam wall height from the pour point, can be decided. The outline of a dam is then delineated from the common edges (cells) of the watershed and its corresponding flooded areas (reservoir) as shown in Fig. 4.

4.3. Identifying turkey's nest sites

While the GIS algorithms outlined in Section 4.2 are capable of a quick identification of DG sites as shown in Section 5.3, a different approach is needed to identify the second type of PHES site, turkey's nest, as defined in Section 3.2. This is needed due to the different characteristics of TN sites.

- A TN site usually incorporates a broader surrounding flat areas than a single watershed in order to increase the storage capacity while reducing dam wall heights.
- For lower reservoirs, a TN site is usually preferred to facilitate the construction of the underground powerhouse closer to the upper reservoir to reduce the penstock or tunnel length

Generally, flat land or a natural depression is preferred for the dam construction at TN sites as local terrain characteristics determine the maximum dam wall height and the required earthwork to build a dam. On flat land (slope = 0) for example in Fig. 5, a dam height of 15 m with an impoundment area of 5 ha is capable of storing 1 GL of water while $H_{dam.max}$ reduces to 13 m on a "depression"-like terrain with an average slope of 15%. By contrast, a "slope"- or "rise"-like topography with an average slope of 15% requires greater $H_{dam.max}$ (17–25 m) and a greater V_{dam} (635–650 megalitres, ML) to store 1 GL of water.

As shown in Fig. 5, the maximum dam wall height and the earthwork required to build a dam to store 1 GL of water are heavily influenced by the topography and hence either $H_{dam.max}$ or V_{dam} can be a guide to reflect the appropriateness of the terrain to build TN dams. Connolly et al. [46] developed a similar approach calculating maximum allowable earthworks to reflect the flatness of terrains whereas in this study, V_{dam} and $H_{dam.max}$ are used to assess the suitability for a TN dam

Table 2
Search criteria.

Criterion	Dry-gully sites	Turkey's nest sites
Minimum head to distance ratio	1:15	1:15
Minimum head	300 m	300 m
Minimum surface area of reservoir	10 ha (111 raster cells)	5 ha
Minimum storage capacity	1 GL	1 GL
Maximum dam wall height	40 m	20 m
Maximum excavation	–	600 ML
Dam batter	1:1	1:3
Maximum slope for dam construction	1:5	–
Protected areas	Not in CAPAD	Not in CAPAD
Intensive land uses	Not in CLUM Class 5	Not in CLUM Class 5
Resolution (Searching interval)	10 m height	12 cells × 12 cells

construction. Consequently, two raster datasets of $H_{dam.max}$ and V_{dam} are created by using the TN model established in Section 3.2. The cell size of the $H_{dam.max}$ and V_{dam} rasters is approximately 360 m × 360 m to incorporate the TN model in the data. After the $H_{dam.max}$ and V_{dam} rasters are created, a threshold of $H_{dam.max}$ or V_{dam} can then be applied to select out most promising TN sites.

The search criteria used in the modelling are listed in Table 2.

4.4. Optimisation of site selection

In the previous procedure, overlaps of identified DG sites cannot be avoided since the sites searching is at a vertical interval of 10 m while the maximum dam wall height is 40 m. Consequently, a ranking metric is needed to highlight the most promising sites. As summarised in Table 1, a variety of ranking metrics such as head, storage capacity or cost of energy can be used to rank the sites highlighting the most promising locations. In this study, a W/R ratio is used to select optimal sites with larger water capacity relative to the amount of earthwork when overlaps occur. The W/R ratio is defined as the water storage capacity divided by the earthwork required to build such a reservoir/dam capable of this storage capacity.

It is noted that, in some cases, a DG site with a higher elevation and hence a larger potential head may not be competitive with a lower site which has a larger W/R ratio. So before the optimisation algorithm is applied, a "Master" set is established including all the identified sites in site searching, which allows an optimisation on the basis of cost per unit of storage capacity ($/kWh) can be considered when cost models

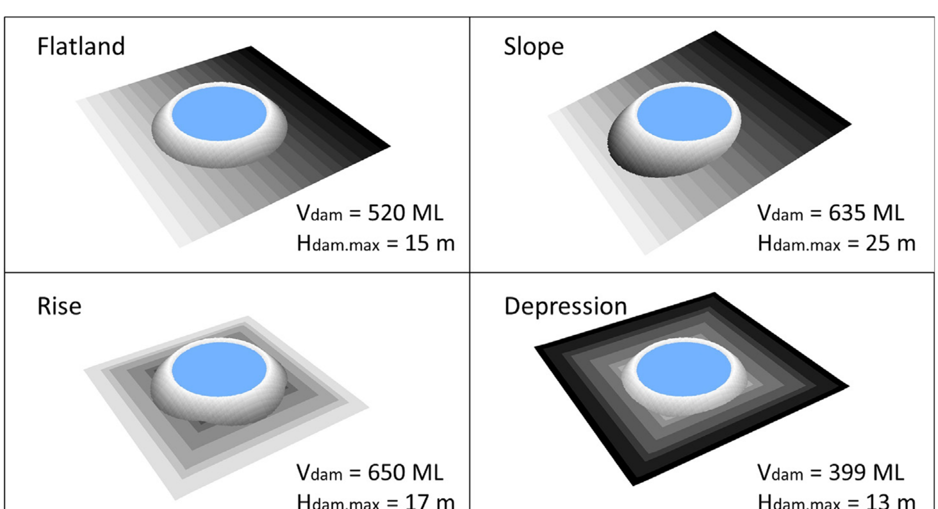

Fig. 5. Excavation for dam construction (V_{dam}) and maximum dam wall height ($H_{dam.max}$) under 4 typical terrains to store 1 GL of water (elevation exaggeration: 3).

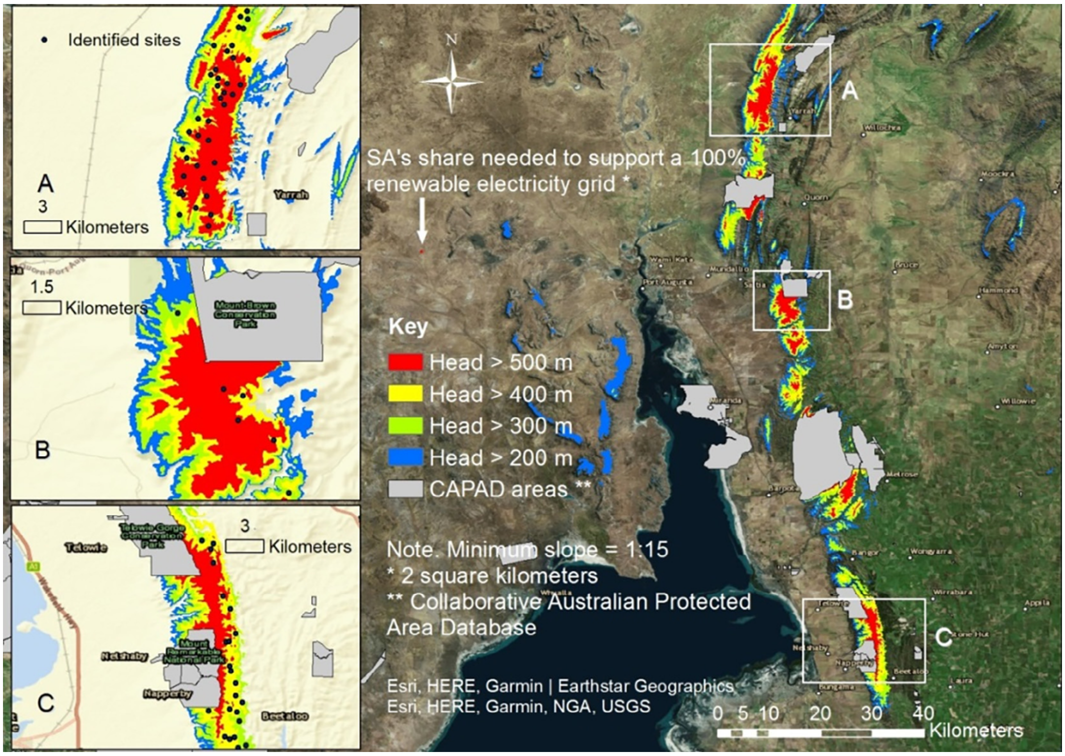

Fig. 6. Highlighted promising regions for off-river pumped hydro in the Flinders Ranges, east of the upper Spencer Gulf near Port Augusta.

are integrated in a future study.

4.5. Environmental impacts

Unlike conventional river-based hydroelectric projects, STORES is located away from rivers and has little impacts on the environment and natural landscape due to: (1) no interaction with the ecosystem of main stem rivers, (2) no conflicts or competition with nature reserves and intensive land uses and, (3) medium-sized reservoirs located within close proximity to electricity infrastructure and renewable energy resources.

Wänn et al. [11] demonstrated that closed-loop PHES systems have lower impacts on soils, geology & sediment transport and have moderate impacts on water resources & quality compared with conventional pump-back or semi-open PHES facilities. The environmental assessment report released by the Federal Energy Regulatory Commission for the proposed Gordon Butte Pumped Storage Hydro Project in Montana, the United States concluded that there will be no significant environmental impacts in constructing and operating the project. Temporary, short-term effects during the constructions can be further mitigated by a variety of environmental management measures.

Detailed environmental impact assessment, which includes the assessments of human interaction, ecology and natural systems and physical environment, will typically be conducted in the engineering feasibility study of any specific sites. This is beyond the scope of this study which is only focusing on the development of GIS algorithms.

4.6. Access to water

Pairs of medium-sized reservoirs mean STORES facilities consume much less water (as explained in Section 2.2) compared with conventional river-based hydroelectric projects. Typically, the initial fill to initiate the facilities is either conveyed from nearby water sources such as from existing reservoirs or lakes, or collected by creating on-site micro-catchments. During operation, the imbalance between rainfall and losses due to evaporation and leakage can be supplemented by the micro-catchments, groundwater, or by trucked water depending on local availability.

For example, the initial fill of the proposed Coffin Butte Pumped Storage (20 ha, 3 GL) in Montana, the United States is obtained by a temporary diversion on Miller Creek and the loss of evaporation and leakage is supplemented by groundwater. The Kidston Pumped Storage project, which will utilise the abandoned gold mines in Queensland, Australia as upper (52 ha) and lower (54 ha) reservoirs, has access to the existing Copperfield Dam previously built for mining activities.

Additionally, despite the evaporation issues are site-specific, they can generally be mitigated by various evaporation reduction measures such as floating covers which have a claimed reduction efficiency of 90%.

5. Case study

5.1. Input datasets

1 arc-second DEMs for South Australia are downloaded from the United States Geological Survey's Long Term Archive. Given the surface area of a typical short-term off-river PHES facility ranges from 10 to 100 ha, the resolution of DEM (approximately 30 m) is well suited, where a typical reservoir contains 100–1000 raster cells. The Collaborative Australian Protected Area Database (CAPAD) and the Catchment Scale Land Use (CLUM) datasets, available from the Australian Department of the Environment and Energy and Department of Agriculture and Water Resources respectively, include the information of protected areas and intensive land use classes, which are considered to be not suitable for the construction of PHES. High-voltage transmission lines (> 132 kV) data are derived from the National Electricity Transmission Lines dataset developed by Geoscience Australia.

The coordinate systems of all the datasets in this study use or are projected to the GCS WGS 1984 as well as the GDA 1994 Geoscience Australia Lambert which is used for the calculation of reservoir surface area and dam length.

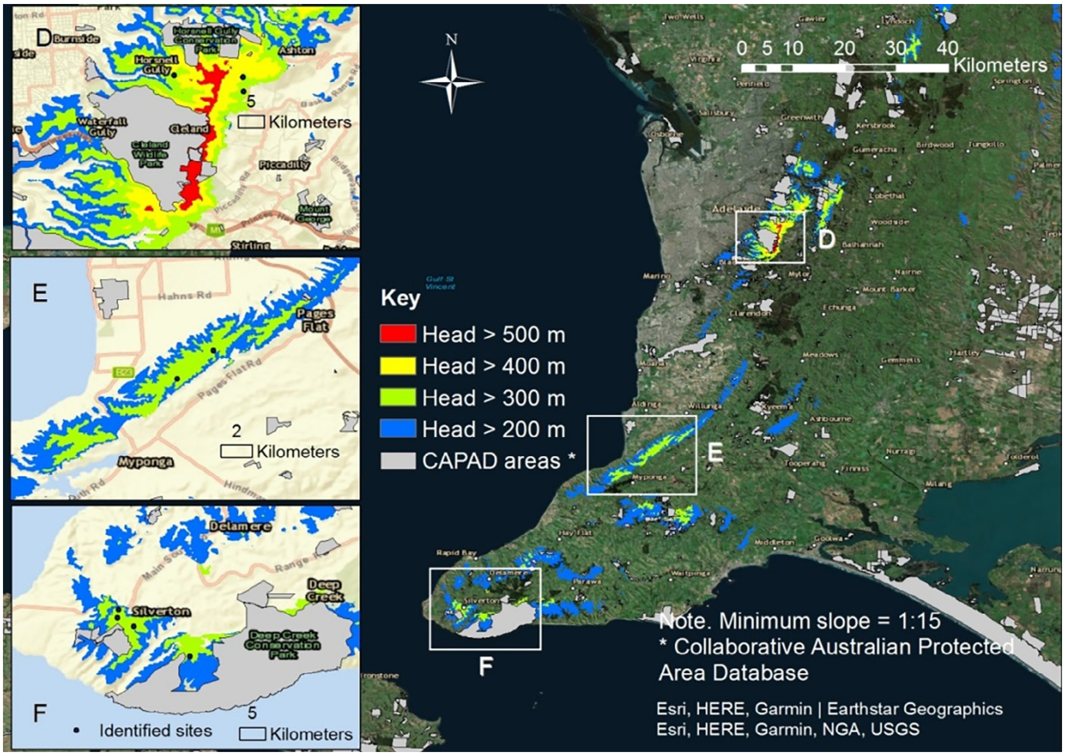

Fig. 7. Highlighted promising regions for off-river pumped hydro in Mount Lofty and the Fleurieu Peninsula near the capital city, Adelaide.

5.2. Promising regions

South Australia has a land area of 983,482 square kilometres [56]. By applying the models described in Section 3 and the algorithms outlined in Section 4, together with a range of search criteria listed in Table 2, a GIS-based screening was conducted across SA. Figs. 6 and 7 show two promising regions of SA highlighted from the modelling constituting 0.1% of the land area of the state:

- Flinders Ranges, east of the upper Spencer Gulf near Port Augusta and,
- Mount Lofty and the Fleurieu Peninsula near the capital city, Adelaide.

Each location of these regions has a H/D ratio greater than the threshold defined in Table 2. A minimum H/D ratio of 1:15 is used on the basis of the previous engineering experiences as discussed in Section 4.1, while any other values that users desire can be specified. Potential locations for upper reservoirs are denoted by multiple colours according to the different hydraulic heads. It shows a large potential of off-river PHES in SA, especially compared with the amount of storage required in SA to support a 100% renewable electricity grid in Australia [15].

As shown in the figures, the CAPAD areas have been excluded to ensure the sites are outside national parks. It is noted that while freshwater, large-head PHES is recommended in this study as discussed in Section 2.2, potential seawater PHES sites can also be identified from the modelling such as the project proposed for the upper Spencer Gulf [54].

5.3. Identified dry-gully sites

Promising regions with potential heads greater than 300 m are further analysed to identify DG sites as well as TN sites illustrated in Section 5.4.

As shown in Fig. 8, the searching scope within South Australia reduces from nearly 1 million to 31 km^2 after applying a sequence of GIS-based procedures including the exclusion of remote regions, CAPAD, CLUM Class 5 and slopes > 1:5. A total of 423 DG sites, which satisfy the criteria listed in Table 2, are identified from the searching algorithms and 168 are included in the final set by excluding overlapping reservoirs with lower W/R ratios. Dots shown in the insets of Figs. 6 and 7 represent the exact locations of DG sites included in the final set within those regions.

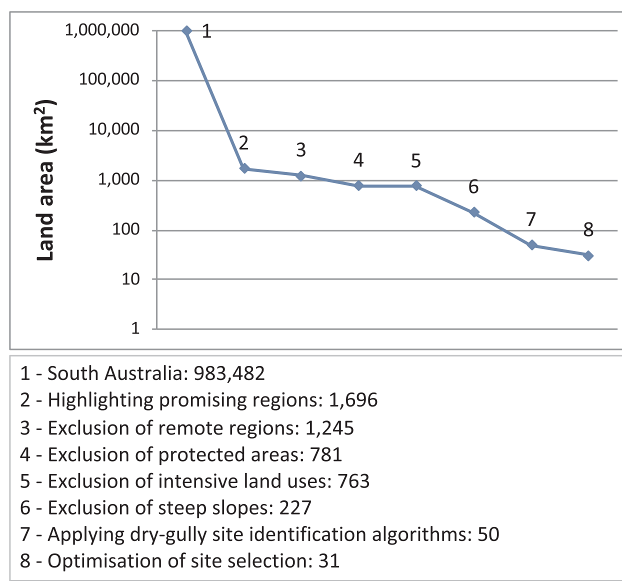

Fig. 8. Evolution of the searching scope within South Australia by applying the GIS-based site searching algorithms.

A snapshot of site information such as storage capacity and dam length is shown in Fig. 9, while a full collection of the identified DG sites is included in Appendix B. A promising DG site located at latitude −32.116638, longitude137.987237 is shown in Fig. 10 by 3-

	A	B	C	D	E	F	G	H	I	J	K
1	Index	Latitude	Longitude	Elevation (m)	Water area (ha)	Ground area (ha)	Reservoir volume (GL)	Dam length (m)	Dam area (ha)	Dam volume (GL)	Water-rock ratio
2	RES_1	-35.6322222	138.1994444	303	9	9	2	1812	5.1	0.7	3
3	RES_8	-35.6149537	138.167037	309	19	19	3	2617	5.3	0.5	6
4	RES_11	-35.61	138.1577778	310	40	40	7	3260	6.2	0.6	12
5	RES_12	-35.4615278	138.5509722	350	15	15	3	2238	5.7	0.7	5
6	RES_19	-35.4547222	138.5213889	369	10	11	1	1754	3.6	0.4	5
7	RES_20	-35.4539811	138.5427778	371	9	9	1	1645	3.2	0.3	4
8	RES_21	-35.4536111	138.5493522	362	8	9	2	1594	5.3	0.9	3
9	RES_29	-35.4391667	138.5597222	360	11	11	2	1807	3.8	0.4	6
10	RES_38	-35.3431944	138.4938889	322	90	91	12	3019	5.7	0.5	23
11	RES_46	-35.3268056	138.5148611	330	12	13	3	1964	4.8	0.6	5
12	RES_87	-34.9527778	138.7266667	530	23	23	3	1404	2.9	0.3	12
13	RES_102	-34.9477083	138.7263194	542	15	15	3	1342	3.9	0.6	5
14	RES_106	-34.9469444	138.7026389	449	9	10	1	347	1.2	0.2	9
15	RES_139	-34.9152778	138.7997222	543	11	11	2	1482	3.6	0.4	6

Fig. 9. A snapshot of detailed information on the identified sites.

dimensional visualisation of the dam and reservoir in ArcGIS Pro.

The sensitivity of the total storage capacity and the number of sites to the maximum dam wall height is examined by varying the height from 10 m to 80 m as illustrated in Fig. 11. Dams of the Snowy Mountains Scheme in Australia range from 18.3 to 116.5 m (earth-fill), 43.9–161.5 m (rock-fill) and 21.3–86.3 m (concrete gravity/arch) with gross capacities of 21.1–4798.4 GL [57].

5.4. *Identified turkey's nest sites*

As stated in Section 4.3, the maximum dam wall height of a TN site, $H_{dam.max}$, and the required earthwork to build it, V_{dam}, are heavily influenced by the topography of that site. Fig. 12 illustrates the distributions of V_{dam} and $H_{dam.max}$ within the promising regions (head > 300 m) and Fig. 13 shows their relationships with the standard deviation $E_{res.std}$ and range $E_{res.rng}$ of elevation as well as the average slope $S_{res.avg}$ in degrees. In this study, a maximum dam wall height of 20 m and a maximum excavation volume of 600 ML are used to highlight the optimal TN sites as illustrated in Fig. 12, which represents 0.2% and 7.8% percentiles respectively. In addition, the thresholds of $H_{dam.max}$ and V_{dam} can be specified by users as search criteria.

Finally, 22 TN sites were identified with a total area of 110 ha and a volume of 22 GL by applying the search criteria listed in Table 2. At some locations, the sites identified by the two different algorithms may have overlapping sections and in this case, the W/R ratio is once again applied to decide the most promising sites with larger storage capacity while less required earthwork. A final set of the TN sites is included in Appendix B.

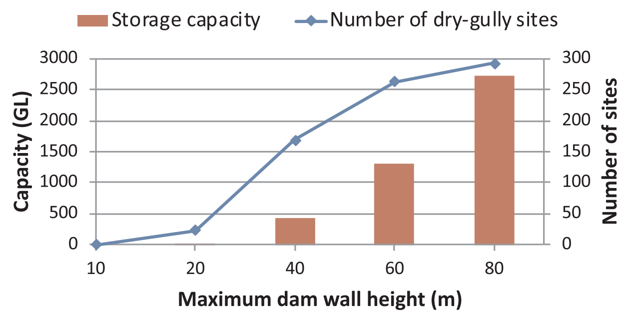

Fig. 11. Sensitivity of the total storage capacity (GL) and the number of sites to the threshold of maximum dam wall height (10–80 m).

6. Conclusion and future work

Grid-scale storage facilities can play an important role of providing energy balancing in electricity systems when the shares of intermittent photovoltaics and wind energy become significant. This study investigates a series of advanced Geographic Information System algorithms to locate prospective sites for pumped hydro, with a focus on short-term off-river pumped hydro energy storage which has little environmental impacts.

Mathematical models developed in this study represent two typical types of off-river pumped hydro reservoir sites: dry-gully and turkey's nest, which have different characteristics as described in Section 3. The Geographic Information System algorithms first highlight the promising regions for pumped hydro developments with a variety of search criteria (Table 2), which significantly reduce the searching scope ensuring computational manageability (Fig. 8). Protected areas and intensive land uses are excluded in site searches to avoid any possible conflicts or competition with nature reserves, urban regions or intensive farming

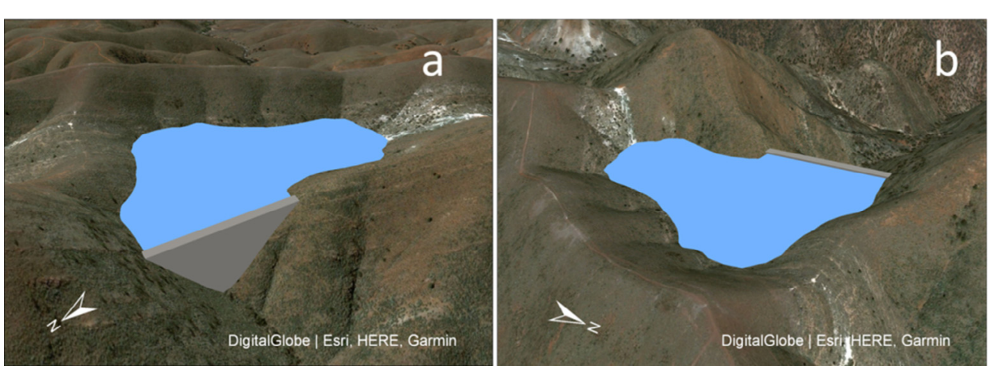

Fig. 10. 3-dimensional visualisation (a. frontview and b. backview) of a typical dry-gully site (elevation exaggeration: 2).

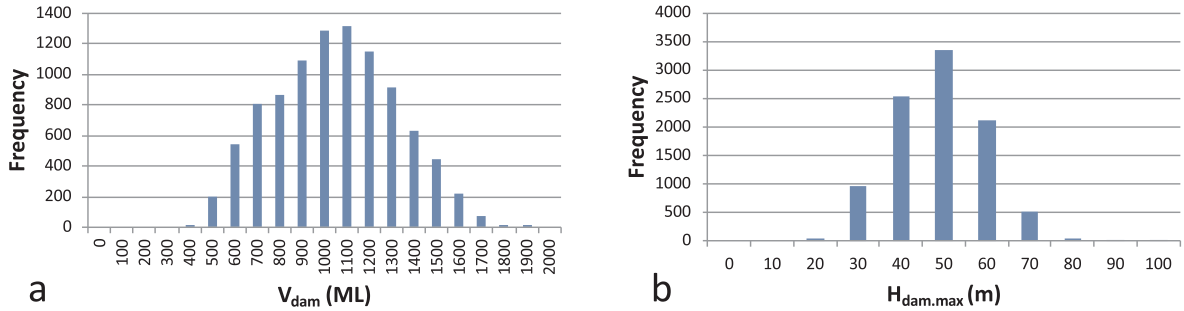

Fig. 12. Distributions of the excavation for dam construction (V_{dam}) and the maximum dam wall height ($H_{dam.max}$) within the promising regions (head > 300 m) of South Australia.

activities. Mapping of promising regions for pumped hydro developments as demonstrated in Figs. 6 and 7, can be used for the planning of renewable energy development zones such as [58].

The automatic Geographic Information System-based procedures work efficiently in the identifications of dry-gully and turkey's nest sites and also yield a range of site information such as coordinates, elevation, water surface area, storage capacity, dam length and volume (Fig. 9). Prospective sites with higher water to rock ratios are further selected from a large number of identified overlapping sites, which can be then visualised in 3 dimensions (Fig. 10). Presentation of such site information facilitates the decision makings of local administrative authorities and project developers.

A case study is conducted for South Australia, which has high levels of photovoltaics and wind integration and the intermittency of renewable energy has already brought significant challenges to the electricity system economics and security. Despite having no existing hydro developments, South Australia demonstrates a large energy storage potential: 190 sites, with 441 gigalitres of water storage equivalent to 276 gigawatt-hours of energy storage assuming a minimum head of 300 metres, an usable fraction of 85% and an efficiency of 90% - far beyond the South Australia's share to support 100% renewable electricity in Australia [15]. Promising regions for pumped hydro developments in South Australia are located in the Flinders Ranges and the Mount Lofty region near the capital city, Adelaide (Figs. 6 and 7).

Given the input of modelling only includes the information that is usually publicly available such as digital elevation models and protected areas datasets, this model can also be applied to other regions outside South Australia. By using the models developed in this study, high-resolution assessments of pumped hydro energy storage potentials can be efficiently conducted in other states or territories of Australia and elsewhere around the world.

Future work will include the development of a costing model. Cost-related information will be incorporated in the model which is now under development by experienced hydropower engineering consultants, including: (1) geology information such as rock types and structures which influence the stability and construction cost of dams; (2) geographical distances to existing high-voltage transmission network and transport infrastructure; (3) meteorology and hydrology conditions to determine the requirements for micro-catchments and evaporation reduction measures.

List of acronyms and abbreviations

CAPAD	Collaborative Australian Protected Area Database
CLUM	Catchment Scale Land Use
DEM	Digital elevation model(s)
DG	Dry-gully
GCS	Geographic Coordinate System

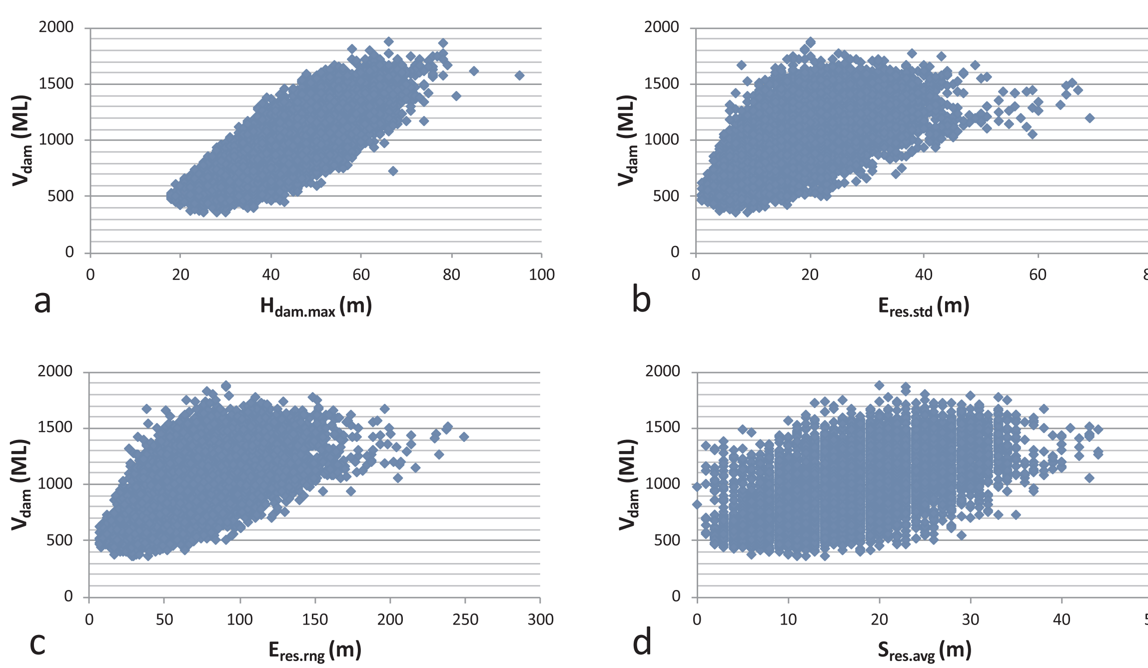

Fig. 13. Relationships between the excavation for dam construction (V_{dam}), the maximum dam wall height ($H_{dam.max}$), the standard deviation ($E_{res.std}$) and range ($E_{res.rng}$) of elevation and the average slope ($S_{res.avg}$).

GDA	Geocentric Datum of Australia
GIS	Geographic Information System
GL	Gigalitre(s)
GW	Gigawatt(s)
GWh	Gigawatt-hour(s)
H/D	Head to distance
HVDC	High-voltage direct current
kV	Kilovolt(s)
kW	Kilowatt(s)
kWh	Kilowatt-hour(s)
MW	Megawatt(s)
MWh	Megawatt-hour(s)
NEM	National Electricity Market
PHES	Pumped hydro energy storage
PV	Photovoltaics
SA	South Australia
STORES	Short-term off-river pumped hydro energy storage
TN	Turkey's nest
WGS	World Geodetic System
W/R	Water to rock

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Appendix A

Dam volume calculation incorporating freeboard and dam crest width is included in: https://www.dropbox.com/s/vagey2kijogofet/Appendix%20B.docx?dl=0.

Appendix B

A full collection of the identified dry-gully and turkey's nest sites is included in:

https://www.dropbox.com/s/d53us0k78t4kf8r/DGSites168.xlsx?dl=0

https://www.dropbox.com/s/2t1pc2fpk65xcpd/TNSites22.xlsx?dl=0

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