Clean Electricity Western Australia 2030
Modelling Renewable Energy Scenarios for the South West Integrated System

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ABOUT SEN

Sustainable Energy Now (SEN) is a not-for-profit member based organisation advocating for practical and affordable use of renewable energy (RE) in Western Australia. SEN’s technical and economics team includes scientific, technical and business professionals, with many collective years of energy industry and engineering experience.


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The Authors thank the SIREN Toolkit development team for their tireless and voluntary contributions to the development and testing of the SIREN Toolkit, which underpins the modelling in this Study.

The SIREN development team is a multidisciplinary group with direct experience in the RE industry. The core members are university qualified engineers, scientists, educators and business professionals, with over 140 combined years of industry experience in fields such as software development, engineering, technical writing, business management and education. Members of the Review and Promotion Teams add even more to the core team experience, with qualifications and experience in geology, finance, agriculture, environmental science and policy development in both government and private sectors.

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NOTES ON DATA SOURCES

System Advisor Model (SAM)

SIREN uses System Advisor Model (SAM) modules to perform energy calculations. The modelling carried out for this report used SAM SDK API (SSC Version: 45; Jun 30 2015). The System Advisor Model was provided by the National Renewable Energy Laboratory (NREL), operated by the Alliance for Sustainable Energy, LLC and supported by the U.S. Department of Energy.

http://www.nrel.gov/
https://sam.nrel.gov/

MERRA data

Weather data was obtained from the Modern Era Retrospective-analysis for Research and Applications (MERRA - a NASA atmospheric data reanalysis using the Goddard Earth Observing System Data Assimilation System v. 5 (GEOS-5)). MERRA focuses on historical analyses of the hydrological cycle on a broad range of weather and climate time scales, and places the NASA EOS suite of observations in a climate context. This data was made available through the Global Modeling and Assimilation Office (GMAO) and the GES DISC.

http://gmao.gsfc.nasa.gov/merra/

SWIS Load Data

SIREN models system performance against actual load data. Load data was obtained from the Australian Energy Market Operator (AEMO; formerly the Independent Market Operator, IMO). The AEMO collects and collates a range of data relating to the Wholesale Electricity Market within the South West Interconnected System (SWIS) in WA.


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1  **EXECUTIVE SUMMARY**

Western Australia’s South-West Interconnected System (SWIS) can move to 85% renewable energy (RE) for the same cost as new coal and gas. In reality, it is expected to be even cheaper as the modelling in this report has used conservative cost data for RE that is higher than current forecast costs. The SWIS can move to 100% RE for only an extra 3 to 4c/kWh, a premium of only 15% on current domestic electricity prices.

This study provides comparative assessments of a number of RE scenarios which could be realistically implemented in the SWIS by 2030 using existing proven, utility scale, commercial technologies. Using SEN’s new Integrated Renewable Energy Networks (SIREN) Toolkit software, the assessments provide technical, economic and environmental (CO₂e emissions) analyses to assist policy makers, regulators and community leaders to demonstrate how an orderly transformation of the SWIS to a RE dominant system can be achieved economically by 2030.

For each modelled scenario, SEN has analysed the requirements to build a new reliable RE power generation system and the corresponding carbon emission intensity in order to identify the most practical, efficient and cost-effective low carbon energy generation options for implementation by 2030.

Western Australia is in an excellent position to move to RE over the next 15 years, but the opportunity could be wasted unless commitment, planning and the transition begin immediately.
1.1 Key Findings

1.1.1 85% RE electricity prices equal to new coal/gas grid scenarios

The wholesale cost of electricity from a modernised electricity grid, whether coal or 85% renewable, would be about 1c/kWh more than the current (2016) wholesale cost. The retail cost of electricity\(^1\) to SWIS residential customers would increase by about 2c/kWh, regardless of whether Scenario 1 (85% RE) is implemented or the existing or renewed fossil fuelled grid is replaced.

1.1.2 RE costs trending lower

RE costs are falling as advances in technology improve efficiency and reduce installation costs (BREE 2013). It is confidently anticipated that even lower prices for electricity can be realised than those predicted with the current modelling assumptions (which have purposely been set at conservative levels). SEN considers that LCOEs of some RE technologies, for example wind and CST with MS storage, are already lower than those used in the modelling.

1.1.3 Phasing out of current coal fired electricity generation

Coal fired generation can be phased out over 14 years in an orderly and structured program. Section 6 of this study illustrates a possible transition plan to reach the lower-cost Scenario 1 (85% RE), starting with the immediate retirement of the aged Muja plants.

1.1.4 Transition to Renewable Energy (RE)

To transition to Scenario 1 (85% RE) by 2030, approximately 8,000 MW of new RE generation would need to be installed at an estimated cost of $20.1 billion, based on 2015 costs. This equates to an installation rate of approximately 570 MW per year.

1.1.5 Demand side management (DSM) would reduce LCoE

Universal installation of smart meters could be implemented at low cost to enable some customers to voluntarily opt to have some of their appliances turned down or off by the grid operator for short periods during times of peak energy cost. Use of 500 MW of this type of DSM with the RE scenarios could reduce the electricity cost by up to $2/MWh (0.2c/kWh) without DSM reserve capacity payments, while reducing carbon emissions by several thousand tonnes per year.

1.1.6 Carbon emissions reduction

RE electricity generation scenarios for the SWIS presented in this study reduce annual CO₂e emissions by 11.1 million tCO₂e for Scenario 1 (85% RE), or to 12.3 million tCO₂e for the best 100% scenario, which represent 85% and 92% reductions respectively. As Western Australia’s population is about 2.7 million (AustraliaPopulation2016 2016), this equates to emissions reductions of 4.1 – 4.6 tCO₂e per person.

\(^2\) The modelling assumes a $30/tCO₂e carbon price.
1.1.7 Protection from future gas and carbon price increases

RE scenarios have stabilising effects on the electricity price, because they are much less susceptible to fuel price fluctuations (only 5 – 15% of generation relies on fuelled generation).

The RE scenarios are also less sensitive to the price of carbon emissions, unlike the Business as Usual (BAU) Scenario 6, as the RE Scenarios incur only 8 – 17% of the carbon costs of BAU.

1.1.8 Benefits of BM battery storage

Behind-the-meter (BM) battery storage is likely to be a cost effective option for both consumers with rooftop PV and those without. This will tend to flatten the demand profile, reducing the amount of expensive gas turbine generation required (as shown in Figure 3, Section 3.4).

1.1.9 RE grids reduce network costs and capacity payments

A modernised dispersed wind and solar based electricity grid with battery storage would provide the following cost savings:

- Reduced network charges.
- Reduced tariff adjustment payments (TAP).
- Reduced reserve capacity payments (CP).

1.1.10 Reduced externalised costs of pollution

As Scenario 1 (85% RE) has less than 17% of the carbon emissions of Scenario 6 (BAU), the externalised impacts/costs of pollution (CO₂ contribution to global warming; heavy metal and particulate pollution) and negative effects on human and environmental health will be greatly reduced.

1.1.11 Fuelled scenarios have higher risks

The risk analysis in Section 7 shows that the two fuelled generation dominant scenarios modelled (coal/gas and nuclear/gas) carry much higher risks than any of the RE Scenarios. Nuclear had the highest risk profile, particularly in terms of safety and environment (radioactive waste) and also in terms of costs and project implementation. Coal and gas carry high environmental (carbon pollution) risks and are susceptible to fuel availability and price fluctuations. Moving to 100% gas fuelled generation would achieve less than a 30% reduction in CO₂ emissions.

1.1.12 Base load generation not required on RE systems

The large, inflexible base load generators that operate constantly in traditional fossil fuelled grids are not needed, and indeed are a hindrance, in RE powered grids. However, open cycle gas turbines (OCGTs) are essential components of the RE powered SWIS scenarios as they provide:

- Rapid response balancing power when storage runs out during extended periods of low wind and sun.
- Power quality control requirements (when spinning in synchronous compensation mode).
OCGTs and/or batteries and/or flywheels can be used instead of base load generators for frequency stability.

### 1.2 Recommendations

This study demonstrates that a RE dominant stationary electricity system for the SWIS can be economically implemented by 2030 and the following recommendations are made to enable the transition:

1. State Government of Western Australia to formally commit (legislate for) to 85% renewables by 2030 and develop a detailed transition plan in line with the plan proposed in this study.

2. State Government of Western Australia to establish an Office of Renewable Energy, linked with Synergy and Western Power, and charged with planning the transition to RE.

3. State Government to phase out all existing coal and base load gas generation. At the same time build RE capacity, according to a master plan along the lines of one of the high penetration scenarios presented in this study. Complement the RE generation with state of the art fast response OCGT capacity, with dual-fuel capability.

4. Conduct further research into the economics and locations of utility scale storage options to support a long term RE strategy, such as: pumped hydro (PHS); utility scale battery and MS molten salt (MS) or any combination of these or other storage technologies.

5. Universal installation of smart meters, with both user and utility interface capability, to enable consumers to track their energy use and opt to participate in DSM by the utility turning down some appliances during peak demand periods when electricity prices are highest.

6. State Government of Western Australia to commission a study to determine the savings in Synergy’s peak power costs that would be provided by installation of BM batteries and appropriate tariff structures and or subsidies. Direct Synergy to provide incentives according to the outcomes of the study, for example:
   a. introduce tariff structures with price signals that incentivise the uptake of energy storage and/or;
   b. legislate for an up-front subsidy as an incentive households and businesses to purchase BM storage systems.

7. Support the establishment of large commercial-scale sustainable woody biomass (oil mallee) production in the south-west of WA, through involvement of State Government industry departments and Federal Government financial incentives.

8. State Government of Western Australia, through the Department of State Development, to investigate the establishment of commercial-scale production of sustainable liquid bio-fuels with the view to establish a local liquid bio-fuels industry.
9. Conduct research and studies to investigate industries which can take advantage of the cheap surplus RE to produce renewable fuels such as hydrogen by electrolysis of water.

10. State Government of Western Australia to adopt policies to incentivise and implement innovative energy use optimisation strategies (e.g. turning off / down large industrial loads during winter months of greatest RE shortfalls and maximizing their use during summer months of RE surplus).

11. State Government of Western Australia to explore innovative collaboration opportunities between utilities for RE and energy efficiency (e.g. covering water supply dams with floating utility-scale PV to reduce evaporation and maximise productive use of the water area).

12. Federal Government through the AEMO to review the functioning of the electricity market mechanism with a view to facilitating wider adoption of power purchase agreements (PPAs) by reverse auctions, to provide security for investment in renewable generation as has been achieved in the Australian Capital Territory.

13. State Government of Western Australia to retain ownership and control of Western Power to facilitate transition to a renewable electricity system, and effect legislative and regulatory reforms to the operation of Western Power to facilitate the transition to RE, for example enabling Western Power to operate on-grid battery systems for ancillary reserve requirements and implement universal roll-out of smart meters.

1.3 Summary of Modelled Scenarios

Five optimized RE generation and transmission scenarios to meet the 2030 projected demand on the SWIS have been modelled and described in this study. The modelling was conducted using the SEN Integrated Renewable Energy Network (SIREN) Toolbox (see Section 3.2 and Appendices A4 and A5), with a carbon price of $30/tCO₂e and no Renewable Energy Certificate (REC) payments.

All of the scenarios use RE generated from wind and solar photovoltaic (PV) systems combined with storage and fuelled turbines for dispatchable balancing power. Concentrating Solar Thermal (CST) power is used in two scenarios and various types of storage; BM batteries, pumped hydro (PH) and molten salt (MS) are included in others. A sixth scenario was modelled for comparative purposes: the current coal-based system ‘Business as Usual’ (BAU). A detailed description of Scenario 6 (BAU) is included in the main body of the study.

Summaries of the five RE scenarios and the sixth BAU scenario, showing their mix of generation technologies and levelised cost of electricity (LCoE), are shown in Figure 1 (below).
The modelling shows that Scenario 1 (85% RE) is calculated to cost less than Scenario 6 (BAU), reducing emissions to only 16.9% of Scenario 6 (BAU) at no additional cost. Furthermore, this wind and solar based system with battery storage would reduce network charges, capacity payments and rural tariff adjustment payments while providing improved reliability and availability compared to large centralised generators.

It is possible to achieve 100% RE scenarios by substituting sustainably-grown bio-fuels for gas in the generation of up to 15% of the electrical energy. The 100% RE LCoE figures are $33-$39/MWh (3.3-3.9c/kWh) more than BAU coal/gas. However, since the generation cost is only about half the total retail price of electricity, the overall increase in electricity bills would only be 10-13% more than Scenario 6 (BAU) by 2030.

Scenario costs and carbon emissions relative to the BAU case are shown in Figure 2 (below).
Figure 2. Summary of scenario costs and carbon emissions.

Further information on each scenario and detailed modelling results are shown in Section 5 of this report. Table 10 demonstrates the power and storage capacities of the optimised scenarios.

In addition to the five RE and the 6th BAU scenarios, a further 3 non-renewable based scenarios were reviewed for comparative purposes: one gas-dominant and 2 nuclear-dominant, with gas turbines or nuclear reactors in place of the coal generators (see Appendix A12). Nuclear-Gas is more expensive than Scenarios 1 and 2 (Wind-PV-Gas). Nuclear with bio-oil to achieve low emissions is over $15/MWh more expensive than the 100% RE scenarios.

SEN does not condone or advocate for the use of nuclear energy in the SWIS. The inclusion of nuclear energy scenarios are for comparative purposes only.

Wave and geothermal energy were not included in the scenarios modelled at this stage. It is expected that SEN may include these technologies in future modelling when they mature further and their suitability and price competitiveness for utility scale deployment for the SWIS is further confirmed.

Coal with Carbon Capture and Storage (CCS) was not modelled in this study because it is not a proven mature technology and would cost as much as, or more than, the 100% RE Scenarios (see Appendix A10).
2 INTRODUCTION

2.1 Background

SEN shares the concern of most in the community that, in spite of the reality and dire consequences of global warming caused by carbon emissions from human activities, little is being done in Australia to decarbonize our economy. In December 2015, Australia was among the 195 countries which attended the United Nations Conference on Climate Change in Paris (COP21 2015) and, in April 2016, signed the Paris climate agreement to reduce its carbon emissions, however, Australia’s commitments are seen as insufficient and lagging behind the rest of the signatories (Climate Council 2016).

Stationary energy, mainly electricity generation, accounts for more than 30% of Australia’s emissions (Jerejian 2015) but there has been insufficient progress to date in developing a strategic plan to transition the stationary energy sector towards low carbon technologies. Instead, the Federal Australian Government repealed the carbon pricing scheme in 2014 (Clean Energy Regulator 2015) and reduced the Renewable Energy Target (RET) (Jerejian 2015), resulting in an increase in the emissions intensity of the sector (Commonwealth of Australia 2015). This study intends to assist policy makers, regulators and community leaders in Western Australia to understand how a transition to RE in the South West Interconnected System (SWIS) electricity grid can be achieved.

This study adopts a definition of RE as – ‘renewable within a human lifetime and can be produced safely and equitably for all time with minimal impact on the environment and future inhabitants’. SEN does not believe that nuclear power is a renewable or sustainable option as it uses non-renewable fuels and has costs and risks which are far greater than the renewable power options.

It is possible to model various generation and transmission scenarios for an electricity system with low emissions as there are many combinations of RE, storage and fuelled balancing generation which can provide reliable, low emissions electricity for the SWIS. Five RE dominant scenarios are presented in this study, each optimised to minimise costs and CO₂e emissions.

Whilst gas and nuclear scenarios are not considered sustainable, an all gas option and a nuclear option were also modelled for the purpose of cost comparison. The results for modelled nuclear and all gas scenarios are shown in Appendix A12.
2.2 Objectives

Using SEN’s new Integrated Renewable Energy Networks (SIREN) Toolkit software, this study demonstrates how a transformation of the SWIS to RE systems can be achieved economically by 2030 using existing commercial technologies.

This study provides comparative assessments, based on technical (performance), economic (LCoE) and social impact (CO₂e emissions) data, of a number of energy scenarios which could be realistically implemented in the SWIS by 2030. The assessments are designed to assist policy makers, regulators and community leaders in Western Australia to understand how a transformation of the SWIS towards a RE dominant system can be achieved.

More specifically, this study has:

1. Modelled electricity grid scenarios powered by RE technologies to achieve a reliable electricity supply for the SWIS.
2. Identified scenarios which minimise the cost of wholesale electricity (LCoE), can be practically implemented by 2030 and which will maximally reduce CO₂e emissions.
3. Modelled and compared costs and carbon emissions of the following scenarios for modernising the SWIS grid:
   a) A high penetration RE scenario with storage, that is cost competitive with renewing the existing fossil fuelled system.
   b) Three 100% RE scenarios with storage.
   c) A ‘Business as Usual’ (BAU) scenario – renewing the existing coal and gas infrastructure.
   d) Nuclear and gas scenarios, as for BAU but replacing coal with nuclear or gas power, for the purpose of cost comparison.
4. Outlined an achievable retirement strategy for existing coal generation assets.
5. Produced a risk assessment for each scenario.
6. Used a conservative basis for performance and costs of RE scenarios.
7. Not included externalised costs, such as those associated with community health and resource degradation, apart from a general price on carbon emissions.
3 METHODOLOGY

Modelling of the scenarios was done through the use of SEN’s Integrated Renewable Energy Network (SIREN) Toolkit and Powerbalance (PB). The use of SIREN and PB is outlined in Appendices A4 and A5.

SIREN is a tool to assist in modelling the potential for RE in an electricity network or geographic area. It uses technology models developed as part of System Advisor Model (SAM), a tool developed by the US National Renewable Energy Laboratory (NREL).

SIREN uses published weather and load data sets to model the potential for RE generation for a geographic region. The approach was to model the data hourly for a desired year, ignoring leap days, which represents 8,760 hours of data.

The generation data was then compared against actual load data and the hourly shortfalls were exported to PB (a set of programmed Excel spreadsheets that quantify, cost and optimise the various amounts of storage and fuelled balancing power technologies). Users can choose from several different spreadsheets, for modelling different combinations of storage and fuelled generation technologies.

The SIREN modelling and RE strategies outlined are flexible enough to enable options that may not currently be economic to be added in future, if and when they are proven to be commercially and technologically appropriate in the light of emission reduction requirements. For example, the SIREN model can be expanded to include wave and geothermal power, which could be integrated into the RE grid if they become economic at utility scale.

Distribution network costs comprise a larger portion of residential electricity bills than the generation and transmission costs that are modelled in this study. Network service utilities have recently been widely criticised for over-investing in and over-valuing their assets, increasing the network cost component of electricity bills. While this study identifies the potential for distributed PV and battery generation to reduce distribution network costs, it does not model or analyse them.
3.1 General Modelling Assumptions

The following assumptions are made in the scenario modelling:

1. The 2014 grid demand curve is scaled up 126% for 2030.

2. All scenarios are modelled to have sufficient power available to balance load with generation all year.

3. The SWIS remains a stand-alone electricity grid, with no inter-connection with the National Energy Market (NEM) grid in the Eastern States or with the northern Pilbara grids.

4. The transmission grid has been modelled and costed for only the additional transmission required to enable generation to be supplied to the Perth metro load centre for all scenarios, including BAU.

5. Time-of-use tariffs with peak/off-peak rates similar to the current structure are assumed. However, the highest peak rate period would change to winter nights and mornings with a predominantly RE grid.

6. The BM battery storage subsidy incentive of $40/MWh is a conservative assumption; it may not be necessary with mandatory variable tariffs, which would reduce the LCoE of the BM scenario.

7. Carbon price $30/tonne of CO$_2$e; zero REC payment for RE.

8. All scenarios include: New-build cost of the entire electricity generation and storage components. New-build costs for transmission lines & substations additional to existing. No difference in costs of distribution system (poles & wires).

9. Cost of capital 10% for all generation; Government low risk rate of 6% for transmission and pump hydro storage projects; 5% savings rate for BM PV and battery.

10. There is a single load source - the Perth metropolitan area.
3.2 Modelling Renewable Generation, Transmission and Demand

The SIREN Toolkit software enables hourly location-specific modelling of RE generation. The Toolkit contains two computer models – SIREN and PB.

SIREN uses hourly NASA MERRA global meteorological data and the US Department of Energy’s System Advisor Model (SAM) (Blair et al. 2014) to calculate hourly electricity generation for RE scenarios over any year between 1979-2014. It also uses Independent Market Operator (IMO) load data (IMO 2015) for the SWIS electricity grid on an hourly basis for each year from 2007-2015. SIREN uses this information to calculate for any network of wind and solar power stations the user chooses to model.

PB enables modelling of the dispatchable storage and generation required to produce balanced scenarios for reliable, stable electricity grids, with generation matching load for each hour of the year.

Capacity of a power station is the maximum power it can produce, (MW). This figure means very little without knowing the Capacity Factor (CF).

\[
CF = \frac{E_a}{E_t}
\]

Where:
\(E_a\) = Actual energy generated (MWh)
\(E_t\) = Rated capacity (MW) × 24h × 365days

Solar and wind power stations have low CF, (0.2 - 0.4) as sun and wind energy is not continuous. On the other hand, fuelled power stations can generate nearly full-time if required and have CFs around 0.8.

1,000 MW of PV with a CF of 0.2 will generate the same MWh of electricity as 250 MW of CCGT gas with a CF of 0.8.

3.3 SWIS Electricity Demand Assumptions for 2030

Analysis of the shape and magnitude of future electricity demand curves is impossible to predict with any certainty and is beyond the scope of this study. Level of demand does not affect LCoE, as RE generation can simply be scaled up or down accordingly and the cost per unit remains constant. But the shape of the demand curve may affect LCoE (e.g. higher consumption during peak periods will increase the amount of expensive fuel generation required).
It is likely that adoption of energy efficiencies such as rooftop PV generation and BM batteries, roll-out of smart meters, and time of use tariffs will all exert downward pressure on per capita demand and reduce peaks in demand. On the other hand, new energy intensive mining and industrial projects will increase demand as will adoption of electric vehicles, which may provide some energy storage for the grid as well. Future government policy that may influence consumer behaviour in relation to these factors is also not predictable.

In this study, the SWIS 2014 electricity demand curve\(^2\) has been simply scaled up. The 2014 hourly electricity demand data is increased by 1.6% compounded per year for 15 years, equating to an increase of 126% by 2030. Thus, growth in both energy use and peak power demand are increased accordingly. This estimate is based on the Independent Market Operator of WA Statement of Opportunities 2014 mid-growth scenario of 1.3%/yr (IMO 2015) plus a small amount (0.3%/yr) to account for uptake of electric vehicles and electrification of other transport (not taken into account in the IMO (2015) study).

### 3.4 Effect of Behind-the-meter Batteries on Demand Curve

SIREN Toolkit modelling shows that battery storage combined with PV located behind-the-meter (BM) on customers’ premises reduces the peak grid demand on most days, as the batteries are normally replenished during the day and the energy is available for the following evening and early morning peaks. The effect does not occur during extended periods of cloudy weather when there is insufficient solar energy to replenish the batteries, but the overall amount of energy that has to be provided by expensive fuelled generation is reduced and this exerts downward pressure on grid prices.

The least cost Scenarios 1 and 2 have 2,000 MW of BM rooftop solar and 8,000 MWh of BM batteries installed within the SWIS grid. The effect BM batteries would have on the typical daily demand is conceptualised in Figure 3 (below). Each rectangle on in the graph gridlines represents 500 MWh. The PV and batteries installed by residential and commercial customers reduces and shifts 8,000 MWh of energy from the middle of the day, when the solar PV is generating and grid tariffs are low, to the evening and early morning. Daily average residential and commercial BAU demand curves (solid blue and green curves) will be flattened by use of BM batteries (dashed lines). However maximum shortfalls will not be reduced, as these require much more than 8,000 MWh.

The diagram shows no change to the industrial load curve, because industrial tariffs will continue to be about half the cost of commercial and residential tariffs due, as they incur minimal if any distribution network charges. Consequently, it will probably be uneconomic for SWIS customers on industrial tariffs to install batteries and there would be less incentive for them to install PV.

However, as the cost of batteries continues to fall, they will increasingly become an economic energy storage technology for on-site wind and solar generation at isolated mines, processing plants

and farms. These enterprises currently use expensive diesel or gas turbine power, which is 2 – 4 times more expensive than SWIS industrial tariffs.

![Conceptual effect of behind-the-meter battery on daily demand](image)

*Figure 3. Conceptual typical daily demand curves illustrating the load-leveling effect of batteries.*

### 3.5 SWIS Renewable energy generation modelling

By using projected demand data and correlating it to the same year’s wind and solar electricity generation from SIREN, this study is able to compare performance of RE and fossil fuel-based scenarios supplying a real load demand on an hourly basis.

Note that while SIREN’s renewable electricity generation calculations are based on MERRA meteorological data, they cannot agree completely with actual generation on an hourly basis. However, validating with existing solar and wind farms in WA indicate generally good cumulative correlation over longer timeframes, and these deviations can be accommodated with storage and dispatchable generation. A summary of the validation is provided in Appendix A4.

To investigate the effect of climate variability, an optimal RE simulation was re-run using actual load, wind and solar data for the years 2008 – 2013.
3.6 Modelling of Storage and Dispatchable Fuelled Generation

All generation and storage power stations incur annualised capital payments, regardless of whether they are used little (low capacity factor (CF)) or a lot (high CF). Capital intensive technologies (such as wind, solar PV, CST with MS biomass thermal, batteries and PHS) cost a lot to construct and to be economic they must operate at high CFs (at least 70% of their maximum). In short, they must be operating at least 70% of the time they are available and earning income from energy generated in order to pay off the high capital cost and make a profit for the owners. On the other hand, gas turbines have high fuel costs and therefore a high LCoE but the capital cost is low. Therefore, it is economic to let them idle for much of the year, saving fuel and only using them when the RE technologies are not available.

In summary, PB assumes a logical dispatch order for power technologies. Capital intensive technologies with no or low fuel/variable costs are dispatched first and cheap technologies with high fuel use are dispatched last:

1. Wind and solar PV are dispatched first. These have low LCoE, comprising more than 90% capital cost and no fuel cost.

2. BM battery storage is dispatched next, as it is also capital intensive and will be used first by consumers regardless of grid dispatch orders.

3. Any thermal generation fired by waste biomass is dispatched next. It has moderate fuel/variable cost ($30/MWh) but very high capital cost ($750,000/MW/yr) and must therefore be run at a high capacity factor.

4. Solar CST with 10 hours MS storage (Scenarios 4 and 5) is dispatched next. It has moderate LCoE with no fuel cost and more than 90% capital cost. It is dispatchable and can rapidly mitigate shortfalls left after wind and PV generation (capital cost over $500,000/MW/yr).

5. Additional MS storage ($7,000/MWh/yr) is an alternative to PHS. It can store surplus heat energy from CST generation but it would be inefficient to store surplus electrical energy from other sources as the round trip efficiency is about 30%. It can use the same CST steam turbines for the main plant to supply energy.

6. Co-firing of MS storage is more expensive as it has significant capital cost ($110,000 – $120,000 per MW/yr) and also incurs high fuel/variable costs of up to $66/MWh.

7. PHS (Scenarios 2 and 3) is relatively low cost storage (capital cost $241,000/MW/yr) which can be used instead of MS. Hydro generators have the advantages of rapid load following response capability and the ability to store cheap surplus wind and PV energy.
8. Additional PHS storage is cheap at $5,000/MWh/yr storage capacity fixed costs and near zero variable costs. It can store cheap surplus wind and PV generation at about 70% efficiency, using existing pumped hydro turbines.

9. OCGT generation is always dispatched last, to fill shortfalls when the storage capacities of technologies 2 – 5 have run out or the grid load exceeds their power capacity. It has by far the lowest capital cost (approximately $90,000 per MW capacity) and by far the highest fuel/variable costs ($128/MWh for gas and $371/MWh for bio-oil). It is cheaper to use OCGT than have excessive amounts of MS or PHS storage lying idle for much of the year.

10. Load reduction by demand side management (DSM) is a final (optional) means of balancing demand with generation. Low cost DSM could be achieved by voluntary controlled reduction of appliance loads such as pool pumps and heaters, through smart meters that can be controlled by the network provider.

Figure 4 and Figure 5 (below) show shortfalls produced directly from PB simulations for two weeks during January and July of 2014. The dashed red line is shortfall from wind and solar generation. It shows nightly shortfalls with daily surpluses, some large. The blue dashed line shows shortfall after battery storage using some of the surpluses dispatched and being first in order, filling the first part of some shortfalls. The much larger PHS storage is next in order of dispatch and results in the solid green shortfall line. It is sufficient to fill or greatly reduce the nightly shortfalls. The areas between the negative parts of the green curve and the zero axis are the remaining energy dispatched by OCGTs. Similarly, the positive areas between the green line and zero axis are surplus energy wasted.

The summer graph (Figure 4) shows that storage is sufficient to supply nearly all shortfalls. There are only six small shortfalls to be supplied by OCGT during this 14 day period.

![Figure 4. Hourly shortfall in summer for Scenario 2. (6,000 MW Wind, 2,000 MW PV, 8,000 MWh of BM batteries and 42,000 MWh of PHS storage).](image)

---

3 Existing demand side management on the SWIS grid is about 500 MW, but it is expensive as industrial participants are paid to curtail load if the needs arises.
The winter graph (Figure 5) is in marked contrast to the summer graph. The shortfalls are larger and more frequent; sometimes there are several consecutive days of net shortfalls. Some are supplied by storage but by this time storage is greatly depleted and the surpluses are too small to replenish it. By the last 5 days of the 14 day period, the storage is essentially empty and replenishment from the small, sporadic surpluses can reduce little, if any, of the consecutive large shortfalls. Figure 5 illustrates that up to 3300 MW of shortfall needs to be balanced for brief periods and the system is reliant on fuelled generation at those times. PB optimised modelling of RE Scenarios 1 – 3 achieves this with 3500 MW of OCGT capacity. Scenarios 4 and 5 utilise a combination of biomass fired generation and OCGT.

![Figure 5](image.png)

**Figure 5.** Hourly shortfall in winter for Scenario 2. (6,000 MW Wind, 2,000 MW PV, 8,000 MWh of BM batteries and 42,000 MWh of PHS storage).
3.6.1 Economic limits of storage

PB modelling indicates that the economic amount of MS storage for Scenario 4 is about 23,000 MWh. Similarly, the economic amount of the cheaper PHS storage in Scenarios 2 and 3 is 40 – 50,000 MWh.

A question that is often asked is why not store enough RE to fill all load shortfalls. This has been modelled in Appendix A5. About 100 times the economic amount of storage is required, incurring a high capital cost for infrastructure that is only used several times per year. This increases the LCoE to $545/MWh, which is more than three times as much as Scenario 3 using OCGTs.
4 **POWER GENERATION TECHNOLOGIES**

This Section discusses the different power generation technologies used in the modelling of the various scenarios. The focus of the RE technologies used in this study is on commercially mature technologies such as wind; rooftop solar PV; utility scale PV; CST with MS storage; PHS and biomass/biofuels.

In addition to the RE technologies, existing fossil fuelled technologies are also discussed to provide context.

4.1 **Wind**

The coastal and some higher inland areas of WA’s south-west have some of the best wind resources in Australia for land based wind farms (AREMI 2016). Therefore, there is no need for the more expensive off-shore wind generation option.

*Figure 6. The 210 MW Collgar wind farm at Merredin, WA, has a capacity factor over 45%. Source: Collgar Wind Farm (2016)*

All scenarios in the study assume land-based 2MW Vestas V90 class 3 turbines. Over 100 similar machines were installed near Merredin in 2011 (Collgar Wind Farm 2016). SIREN simulations using 3 models of turbines indicated that these machines had the best performance in low wind conditions. The same turbines were used in the modelling of all locations in all of the scenarios to standardise performance and make valid comparisons.

**Advantages:**

1. Zero fuel cost.
2. WA has excellent onshore wind availability.
3. Tie-ins to existing grid in some areas are available (e.g. Collie).

4. Low maintenance and potential for local content. Ship building facilities in Henderson, WA could be modified to manufacture rotor blades.

Disadvantages:
1. Dependent on the variable wind resource and have relatively low capacity factor (0.3 – 0.4).
2. Some locations require transmission line extensions.

4.2 Rooftop solar PV

Rooftop solar PV in Western Australia has been immensely popular, due to a combination of factors including initially generous feed-in tariffs, the small scale RECs being paid up-front and rapidly falling prices such that it is now economic even without subsidies.

![Rooftop solar PV panels](image)

*Figure 7. Typical rooftop solar PV panels.*

Rooftop solar PV installed in WA is such that, collectively, it already comprises the State’s de facto largest capacity power station in excess of 500MWe. The State has more than 192,000 rooftop solar power systems installed in the SWIS as of late 2015 (Clean Energy Regulator 2016), some 1,750 new residential solar installations were added to the SWIS each month in 2015 and rooftop solar is now installed on 20% of all homes in WA.

Given that (only) 20% of all homes have systems installed at present and prices are still falling, there is great potential for increased uptake of rooftop PV. There is potential for further increases in uptake if planning regulations are changed to include mandatory PV in new buildings and renovations.

Advantages:
- Zero fuel cost.
- Continually falling capex, federally subsidised through small-scale technology certificates (STCs).
- Ability to ‘shave’ summer peak (mainly air-conditioning) load.
- No real-estate or transformer substation costs are incurred.
- Funded by the consumer, reducing the power utility’s cost of raising capital for new generation.

Disadvantages:
- Generation is dependent on insolation (does not generate at night). It is not dispatchable and generation can be unpredictable on cloudy days. Rapid reduction in generation occurs in the late evening or when clouds cover the sun (manageable by dispatching storage and OCGT generation).
- Voltage control in distributed environments can be problematic, manageable by BM and grid batteries.

4.3 Utility scale solar PV

Utility scale solar PV power stations are a mature technology widely adopted throughout the world. The largest installed in Australia to date is the 53 MW Broken Hill Solar Plant. It occupies approximately 140 hectares of land, with 650,000 solar PV modules installed at a fixed (non-tracking) tilt, at a 25 degree angle facing north (EcoGeneration 2015).

![Broken Hill solar PV power station](image)

*Figure 8. Broken Hill solar PV power station. Source: Renew Economy (2016).*

As utility scale PV is significantly more expensive to install in WA than the popular option of rooftop PV, the RE scenarios assume 2,000 MW of rooftop and 1,000 MW of utility scale PV. Fixed axis PV is the cheaper of the two utility scale options at $110/MWh and 1,000 MW of this has been modelled in Scenarios 1 – 3.
Although tracking PV generates more electricity per MW capacity installed, it is significantly more expensive ($129/MWh) and it is unlikely that the additional cost would be justified. Scenarios 4 and 5 utilise 800 MW of tracking PV.

Advantages:
- Zero fuel cost.

Capex has been falling, as indicated by
- Figure 9 (below).
- Ability to ‘shave’ summer peak (mainly air-conditioning) load.
- Co-location with wind and CST power stations can better utilize the transmission and end station infrastructure, reducing the cost of both installations.
- Dispersed location of power stations reduces the effect of variable cloud cover.

Disadvantages:
- Generation is dependent on insolation (as for rooftop PV).
- Higher cost than rooftop PV.
- Cost curve appears to have ‘bottomed’; future of RET uncertain.

![Figure 9. Average monthly solar PV module prices by technology and manufacturing country sold in Europe, 2009 - 2014. Source: IRENA (2015).](image-url)
4.4 Concentrating Solar Thermal (CST) with Molten Salt Storage

Concentrating Solar Thermal (CST) with MS Storage is a relatively young technology that has just reached sufficient maturity to be suitable for deployment at utility scale in the last few years. While more expensive than wind or PV, it has the significant advantage of including storage so can provide dispatchable power.

![Concentrating solar-thermal plant in Spain. Source: Torresol Energy (2010).](image)

![Tower of a concentrating solar-thermal plant in Spain. Torresol Energy (2010).](image)

Scenarios 4 & 5 in the study include 1,200MW of CST and assume the use of MS solar tower with MS storage. Other technologies (such as solar trough) are also available and could be used, but it was considered that the tower technology provided a better fit for the scenarios modelled due to its storage capabilities.
Advantages:
- Zero fuel cost.
- Continually falling capex at a faster rate than wind or PV as a newer technology at utility scale.
- Provides dispatchable power, over a 24 hour cycle.
- Can be used for longer term storage.
- Dispersed location of power stations reduces the effect of variable cloud cover.

Disadvantages:
- Generation is dependent on insolation (but to a lesser extent than PV due to the storage component that allows a smoothing of power output).
- Only uses direct insolation so cloud cover has a greater impact than for PV.
- More expensive than PV and wind (but provides dispatchable power).

4.5 Pumped Hydro (Ocean) Storage

Pumped hydro storage (PHS) between cliff-top ponds and the ocean is a feasible energy storage option for wind and solar electricity generation in Western Australia. The large PHS facility on Lake Michigan (shown in Figure 12, below) has been operating since the mid-1970s. The reservoir is 34m deep, covers 350 ha and has 110m of head. The 6 large turbines can generate 1,872 MW for over 13 hours.
There are potentially suitable sites in WA for large cliff top ponds at 100 – 120 m elevation within 2 km of the ocean north of Perth, north of Geraldton and east of Albany. PHS plants located at the northern and/or southern ends of the SWIS grid could store some of the energy surpluses generated by wind and PV power stations envisaged near these locations for Scenarios 1 - 5.

PHS energy is generated by two-way turbines which can act as pumps and generators, and is calculated by the formula:

\[ E = m \times g \times h \times e \]

Where:
- \( m \) = mass of water;
- \( g \) = gravity;
- \( h \) = height of water level;
- \( e \) = efficiency factor.

Efficiency factors for the proposed cliff top systems with 100 m head are applied twice – when water is pumped up and when it flows back. Round-trip efficiency is approximately 70 - 75%, typically comprised of pipe friction loss (about 6%) and turbine efficiency loss (about 18%). Friction losses increase as diameter is reduced (due to higher fluid velocities) and distance. To keep friction losses low, pumping distances are kept short and large diameter pipes are required.

The optimal PHS installations modelled in Scenarios 1 – 3 would total 800 MW power capacity and provide 40 – 50,000 MWh of storage, which is the optimal economic amount arrived at by iterative modelling in PB. This equates to 800 MW of power for 52 hours, which would be used frequently enough to be economic. Larger storages would only be used occasionally and would thus be uneconomic.

The installations would comprise 6 – 8 headrace tunnels 5 – 8 m diameter less than 2 km in length feeding several 100 – 130 MW hydro generators, with intake/discharge into the ocean. Cliff-top clay/membrane sealed ponds 10 – 15 m in depth would provide the storage.

The engineering works are capital intensive, each pipe being larger in diameter than the Perth Rail tunnel.

Advantages:
- Probably the least expensive of all energy storage options, provided that any maintenance issues associated with salt water can be managed economically.

---

4 Small PHS plant(s) using the Wellington and or Serpentine Dams, while possible, are unlikely to be economic because the long distance (more than 10 km) to the pump back reservoir sites would incur high tunnelling costs and high friction losses.
An installation about twice the size of the one proposed has been operating successfully in the US at Ludington on Lake Michigan, but this uses fresh water. There is an ocean PHS plant operating commercially in Japan.

Disadvantages:

- Few ocean PHS plants have been installed commercially world-wide.

- Community acceptance and government approval for large saltwater ponds near the ocean may be difficult to obtain due to possible issues with risk of leakage and nature conservation.
4.6 Biomass and Bio-fuel Generation

Figure 13. Blue Gum plantation waste in the south-west forest region of WA.

Figure 14. Oil mallee alleys in agricultural region of WA.

Biomass fuel has up to three functions in the proposed scenarios:

1. Bio-oil fuel is used to replace natural gas as fuel for the balancing OCGTs in the 100% renewable scenarios. However, bio-oil fuelled OCGT would be double the cost of natural gas fuelled OCGT as production of bio-oil using current technologies would cost about 2.6 times as much as gas. This significantly increases the LCoE of the RE scenarios (see Table 10 in Section 5.1), but would only add about 2c/kWh (10%) to the residential electricity tariffs.

2. Oil mallee biomass woodchips are used in Scenario 4 to co-fire MS tanks at CST power stations.
3. Low cost plantation and municipal solid biomass waste is used in Scenario 5 to fuel a small amount (300 MW) of conventional steam thermal generation running at about 80% capacity.

Table 1. Cost of bio-fuels compared with natural gas.

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Fuel Cost ($/MWh)</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural gas (SWIS)</td>
<td>$138</td>
<td>BREE (2013) (2025 estimate)</td>
</tr>
<tr>
<td>Bio-oil from oil mallee biomass</td>
<td>$358</td>
<td>Steele et al. (2012)</td>
</tr>
<tr>
<td>Oil mallee woodchips (dry)</td>
<td>$56</td>
<td>Steele et al. (2012) and Taylor and McLaughlin (2010)</td>
</tr>
<tr>
<td>Wood waste</td>
<td>$20</td>
<td>BREE (2013)</td>
</tr>
</tbody>
</table>

The south-west of WA has the potential to produce at least 5.6 million tonnes of biomass from sustainable wood waste, agricultural waste and dedicated oil mallee plantation sources. Municipal waste is an additional but limited source of solid bio-fuel.

Table 2. Potential biomass resource from agriculture and forestry in Western Australia. Source: Taylor and McLaughlin (2010)

<table>
<thead>
<tr>
<th>Potential Biomass Resource in Western Australia</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dry biomass (oil mallee) from 10% of WA grain belt (0.1 x 14m/ha x 2.6t / ha /yr)</td>
</tr>
<tr>
<td>Straw and wood (plantation) waste</td>
</tr>
<tr>
<td>Total</td>
</tr>
</tbody>
</table>

Scenario 4 (100% RE: W/ PV/ CST MS with biomass co-fire/ bio-oil OCGT) uses biomass co-heating of MS storage for 3GWh of steam thermal generation and bio-oil fuelled OCGT for an additional 0.9 GWh of dispatchable generation.

Scenario 5 (100% RE: W/ PV/ biomass/ CST MS/ bio-oil OCGT) uses low-cost municipal and plantation waste, with some oil mallee woodchips to fire about 300 MW of steam thermal generation plant, which could also be equipped with MS storage.

Large amounts of biomass are required for each scenario, as shown in Table 3 (below). For Scenario 4 (moderate biomass case), about 900 train loads or 35,000 road train loads per year would be required. This represents 51% of the total biomass resource estimated in Table 2 (above). For Scenarios 1-3, which have only bio-oil fired OCGTs for dispatchable generation, 69% of the oil mallee resource biomass would be used.

Table 3. Tonnes of dry oil mallee biomass feedstock required for Scenarios

<table>
<thead>
<tr>
<th>Scenario 3 (OCGT only)</th>
<th>Scenario 4 (biomass co-</th>
<th>Scenario 5 (biomass)</th>
</tr>
</thead>
<tbody>
<tr>
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</table>

CLEAN ELECTRICITY WESTERN AUSTRALIA 2030
SUSTAINABLE ENERGY NOW
<table>
<thead>
<tr>
<th>Conversion factor (dry t/MWh) – woodchips</th>
<th>fire/OCGT</th>
<th>thermal/OCGT</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>0.6</td>
<td>0.6</td>
</tr>
<tr>
<td>Conversion factor (dry t/MWh) – bio-oils</td>
<td>1.2</td>
<td>1.2</td>
</tr>
<tr>
<td></td>
<td>1.2</td>
<td></td>
</tr>
<tr>
<td>Electricity generated from woodchips (GWh)</td>
<td>0</td>
<td>3,000</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1,900</td>
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<tr>
<td>Electricity generated from bio-oil (GWh)</td>
<td>2,100</td>
<td>900</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1,800</td>
</tr>
<tr>
<td>Oil mallee required for woodchips (dry Mt)</td>
<td>0</td>
<td>1.80</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1.14</td>
</tr>
<tr>
<td>Oil mallee required for bio-oil (dry Mt)</td>
<td>2.52</td>
<td>1.08</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2.16</td>
</tr>
<tr>
<td>TOTAL mass of woody biomass (Mt)</td>
<td>2.52</td>
<td>2.88</td>
</tr>
<tr>
<td></td>
<td></td>
<td>3.3</td>
</tr>
</tbody>
</table>

**Advantages:**
- Renewable fuelled generation suitable for providing dispatchable balancing power for RE.
- Solid biomass (in particular, municipal and plantation waste) is low cost and power generation is a means of disposal of these wastes.

**Disadvantages:**
- Bio-oils would cost 2.6 times as much as natural gas because production requires high quality woody biomass feedstock and requires expensive pyrolysis plants.
- Biomass from dedicated plantations may displace a minor amount of cropping.
- Depending on location of power stations, new rail infrastructure may be required for transport of biomass to power stations.

### 4.7 Open Cycle Gas Turbine (OCGT)

OCGT is a mature technology that has been an essential component of traditional base load electricity generation systems since the 1950s to cope with rapid load variations, as thermal coal plants do not have this rapid response capability. OCGTs are also essential for all RE electricity generation systems to provide fast response dispatchable power during periods of low wind and solar generation and load increases.

It is economic to have large capacities of OCGT available because their capital cost is less than 20% of the cost of thermal (coal or biomass) power stations (see Section 4.8.4), but only if they are run at a low CF of around 0.10 (compared to 0.83 for thermal). OCGTs provide 5–15% of the energy generated in the RE scenarios modelled in this study. That is only 20–40% of the gas generation in Scenario 6 (BAU).

OCGT power capacity requirement is from 2,300 MW for Scenario 4 (with biomass co-firing of MS storage at CST power stations) to 3,500 MW capacity for Scenarios 1-3 & 5 (with no other form of
dispatchable generation). These amounts could be reduced by 500 MW if that amount of DSM was included in the scenarios.

New OCGTs installed in the RE scenarios would likely be state of the art ‘aero-derivative’ turbines with high (40%) efficiency and dual fuel capability (able to run on either gas or bio-oil) and be equipped to run in synchronous compensation mode (Section 5.4.2).

Units of 60 – 100 MW power capacity are envisaged. These are capable of cycling from ‘grid call’ to synch in 2 – 5 minutes and then to full load in 4 – 8 minutes (Parsons Brinckerhoff 2014); i.e. from cold start to full load in 6 – 13 minutes.

Advantages:
- Low cost fast responsive dispatchable power.
- Lower cost than storage for infrequent use.

Disadvantages:
- Biofuels suitable for OCGTs are at least 2.5 times more expensive than gas and will probably remain so.
- Gas is not renewable and produces CO₂ emissions.

4.7.1 Potential for Co-generation

Co-generation is hybridising of technologies to leverage higher efficiencies and use of waste heat. Although co-firing with biomass is the only co-generation technology included in modelling for this study, there are other co-generation technologies that may be integrated into RE generation systems; all are described below.
4.7.1.1 Combined Cycle Gas Turbine
This is a hybrid of the gas turbine which operates on the ‘Brayton Cycle’, resulting in a high degree of waste heat being emitted to the exhaust stream of the unit. This waste heat is captured in a heat recovery steam generator (HRSG) which provides steam to a steam turbine operating on the ‘Rankine Cycle’, the combination of the two technologies delivers very high efficiency of up to 62%. Larger plants have higher efficiencies than smaller. Bio-fuels (either gas or liquid) can be used to fuel Combined Cycle Gas Turbines (CCGT). Where a gas turbine is installed without waste heat recovery, this is referred to as Open Cycle Gas Turbine (OCGT) and the efficiency is in the order of 35%. CCGTs have not been included in modelling for this study due to their having higher capital cost and slower response time than OCGTs, making them unsuitable for the short duration balancing power requirements. However, some existing CCGT generation may continue to be used in winter months during extended periods of wind/solar generation shortfalls.

4.7.1.2 Biomass co-generation using MS storage tanks of CST plants
As the MS storage tanks are potentially large and the CST thermal input is affected by time of day and seasonal variables, additional heat input to the MS can be provided by combustion of solid biomass fuel (wood chips) in heat exchangers\(^5\). The combined benefit of solar and biomass is then realized as the heat reservoir in the tanks can be maintained at the high temperatures required for steam generation, even when there is insufficient solar heat input. As thermal generation from MS reservoirs can be rapidly ramped up and down, this may be used to replace some of the OCGT generation, which requires more expensive liquid or gas fuels. This technology is modelled in Scenarios 4 and 5.

4.7.1.3 Supplementary fired cogeneration
Heat energy can be added to a cogeneration boiler. This heat energy can be from biomass sources and can be used to maintain temperature and power production on a more continuous basis. While supplementary firing does not in itself generally improve efficiency, it allows the boiler asset to provide full output while the primary heat source is shut down for maintenance. This also has the benefit of ensuring thermal continuity which is desirable to minimize wear and tear on boiler technologies. It has potential for balancing power for variable power output from wind and solar generation, as it would enable biomass-fired steam thermal power to be rapidly ramped up and down, thus replacing some expensive OCGT generation.

4.8 Costing of Technologies
In this study, RE generation costs are based on LCoE, which amortises all costs including capital and operation and maintenance over the life of the generator. Storage and fuelled dispatchable technologies are costed with fixed and variable costs derived from recent Australian and US publications (as described in Section 3).

A default discount rate of 10% has been used in all financial calculations where investment is expected to be predominantly in the private domain. This aligns with BREE (2012) which assumes a

\(^5\) Molten salts can also be heated by high temperature electrical elements.
default discount rate of 10% for projects for all technologies assessed. Where it is expected that the investment will be by government-owned utilities, a discount rate of 6% (essentially the weighted average cost of capital with minimal risk premium) has been used. For example, transmission lines and large scale storage such as pumped hydro and grid batteries, which have network-wide application.

This approach is conservative, as other studies indicate lower discount rates for established technologies (coal, gas, solar and wind) and higher discount rates for new and riskier technologies such as wave, tidal, CCS and nuclear (Oxera 2011). Application of lower discount rates would reduce the costs of renewables and the overall LCoE. A sensitivity analysis has not been conducted to quantify the impact on the various technology LCoEs.

4.8.1 Utility-scale RE generation – wind, utility PV, solar thermal

The modelling costs every MWh of wind and solar generation regardless of how much of it was surplus to grid demand and curtailed (wasted) (that is, the LCoEs listed in the tables below are applied to every MWh of wind and solar energy generated in a scenario). This simplifies the costing of RE technologies and, most importantly, it enables a weighted average LCoE to be calculated so that the real energy costs of each scenario can be compared for the year modelled.

\[
LCoE_{wa} \text{ for scenario} = \left( \frac{C_{Gr} + C_{Gb}}{\text{total annual energy consumed on grid}} \right)
\]

Where:
- \(LCoE_{wa}\) = Weighted average LCoE
- \(C_{Gr}\) = Cost of renewable generation
- \(C_{Gb}\) = Cost of balancing generation

In reality, the wholesale price received for utilized generation would be variable and the price of the surplus generation would be zero. But the modelling is not concerned with variations in energy prices but rather the average cost of producing the energy (weighted average LCoE) for a given scenario in a given year.

Wind and solar energy costed in the modelling is the energy required to be generated and transmitted to the major load source allowing for transmission losses.

LCoE figures for utility scale RE generation are from Bureau of Resources and Energy Economics August 2013 update of the Australian Energy Technology Assessments (AETA) Model version 2 (BREE 2013). The AETA estimates for the year 2025, in AU$ per MWh, are used. Although costs will vary significantly at individual sites, the BREE (2013) average figures have been applied to all power stations. Note that these are conservative as the LCoEs of some wind and solar power stations built recently are already in the region assumed for 2025.
Table 4. LCoE of utility scale RE technologies. Source: BREE (2013).

<table>
<thead>
<tr>
<th>Technology</th>
<th>Projected LCoE (2025) ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CST</td>
<td>$169</td>
</tr>
<tr>
<td>Fixed PV (Utility)</td>
<td>$110</td>
</tr>
<tr>
<td>Tracking PV</td>
<td>$129</td>
</tr>
<tr>
<td>Wind</td>
<td>$85</td>
</tr>
</tbody>
</table>

4.8.2 Rooftop Solar PV

BREE (2013) does not provide LCoEs for rooftop solar PV. It presents a different case in that its return is paid from 3 sources: PV system owners, the fixed small scale REC price of $40/MWh paid up front and energy fed into the grid, which is paid for by the utility (Synergy).

In this study, a LCoE was calculated by using the current average actual installed cost of a 3kW system in WA (i.e. cost without the $40 STC subsidy under the RET scheme) calculated from system costs provided by Solar Choice (2015). Details of the calculation can be found in Appendix A6. The cost of installing a smart meter was added and cost of capital was assumed to be 5% (savings investment rate) over a 5 year payback time for the system.

Rooftop PV costs substantially less than fixed utility PV because the costs of grid connection (end station, step-up transformers), transmission and land are not incurred.

Table 5. LCoE of rooftop PV derived from average cost of typical 3kW systems in WA.

<table>
<thead>
<tr>
<th>Technology</th>
<th>LCoE ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rooftop PV</td>
<td>$65</td>
</tr>
</tbody>
</table>

4.8.3 Behind-the-meter (BM) battery storage

Batteries installed behind-the-meter by residential and commercial consumers are primarily used to store rooftop PV and or low cost off-peak grid electricity for their own use during the high cost peak tariff periods. Recent legislation by the WA Government enables some of this energy to be ‘spilled’ back to the grid.

AECOM (2015) estimates that the lower range LCoE of storage for Li-ion batteries in 2015 is $US250/MWh. With the battery component of systems forecast to be less than half its current cost by 2020, it is reasonable to assume that typical LCoEs will reach $AU180/MWh (18c/kWh) within a decade. This would still be uneconomic for batteries installed on the grid, as adding the LCoE of recharge energy (average $128/MWh for Scenario 1) to the stored energy would cost more than $300/MWh, compared to $227/MWh for OCGT generation (BREE 2013). However, it would be economic for consumers to install BM batteries. If the owner is generating their own rooftop PV energy, which would otherwise be spilled into the grid at the current feed-in tariff (FiT) of 7c/kWh,
their stored energy would cost them 18c plus 7c, or about 25c/kWh, which is less than the current standard tariff of 25.7c/kWh.

The modelling presented in this study assumes a nominal subsidy of $40 per MWh (4c/kWh) for BM stored electricity. This figure was used because:

- It is equivalent to the current fixed STC price paid to owners of PV systems and, based on the figures presented above, would be an effective incentive for BM adoption.
- It is a cost effective outlay for Synergy as it would save them paying >$200/MWh for the OCGT generation it would displace.
- It is less than 25% of the LCoE Synergy would incur for installation of large scale Li-ion battery systems in the grid.

Table 6. Behind-the-meter battery cost per MWh.

<table>
<thead>
<tr>
<th>Technology</th>
<th>Nominal subsidy ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Behind the meter battery</td>
<td>$40</td>
</tr>
</tbody>
</table>

4.8.4 Dispatchable power

The LCoE of dispatchable power technologies - OCGT, coal, nuclear and storage (MS, pumped hydro and on-grid battery) - varies depending on its capacity factor, i.e. the number of hours per year it is used. To enable the model to take this into account, the fixed and variable costs are separated out as shown in Table 8 and Table 7 (below).

Annual fixed costs, which are mainly annualised capital costs, are applied in proportion to the installed power capacity. Every MW of capacity installed will incur the same annual fixed cost regardless of whether it is operated for 100% of the year or is not used at all.

Variable costs, which are mainly fuel costs, are applied in proportion to the energy actually generated. This varies according to the power capacities set in PB by the user when modelling the scenario.

\[ C_{Ed} = (P \times C_{fa}) + (E_g \times C_v) \]

Where:
- \( C_{Ed} \) = Cost of electricity generated
- \( P \) = Rated power capacity
- \( C_{fa} \) = Fixed annual cost per unit of capacity
- \( E_g \) = Electricity generated
- \( C_v \) = Variable costs
Table 7. Dispatchable power costings for generation technologies.

<table>
<thead>
<tr>
<th>Technology</th>
<th>Type</th>
<th>Annual fixed costs ($/MW)</th>
<th>Variable costs (fuel + VOM) ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Concentrated Solar Thermal (CST)- no storage</td>
<td>Generation</td>
<td>529,138</td>
<td>6</td>
</tr>
<tr>
<td>Pumped Hydro (PHS) - no storage</td>
<td>Generation</td>
<td>240,995</td>
<td>5</td>
</tr>
<tr>
<td>Open Cycle Gas Turbine (OCGT) using Gas</td>
<td>Disp. Generation</td>
<td>87,121</td>
<td>128</td>
</tr>
<tr>
<td>OCGT using bio-oil fuel</td>
<td>Disp. Generation</td>
<td>87,121</td>
<td>371</td>
</tr>
<tr>
<td>Gas co-firing added to MS Storage</td>
<td>Disp. Generation</td>
<td>112,795</td>
<td>128</td>
</tr>
<tr>
<td>Biomass Waste co-firing added to MS Storage</td>
<td>Disp. Generation</td>
<td>374,928</td>
<td>30</td>
</tr>
<tr>
<td>Biomass Oil Mallee co-firing added to MS (CS)</td>
<td>Disp. Generation</td>
<td>374,928</td>
<td>66</td>
</tr>
<tr>
<td>Biomass Waste fired Thermal</td>
<td>Disp. Generation</td>
<td>749,856</td>
<td>30</td>
</tr>
<tr>
<td>Biomass Oil Mallee fired Thermal</td>
<td>Disp. Generation</td>
<td>749,856</td>
<td>66</td>
</tr>
<tr>
<td>Coal fired Thermal (SWIS)</td>
<td>Disp. Generation</td>
<td>487,144</td>
<td>32</td>
</tr>
<tr>
<td>Coal fired Thermal (SWIS) with CCS</td>
<td>Disp. Generation</td>
<td>711,960</td>
<td>56</td>
</tr>
<tr>
<td>Nuclear Thermal (Small Modular Reactor)</td>
<td>Disp. Generation</td>
<td>967,016</td>
<td>26</td>
</tr>
<tr>
<td>Combined Cycle Gas Turbine (CCGT) using Gas</td>
<td>Disp. Generation</td>
<td>140,994</td>
<td>88</td>
</tr>
</tbody>
</table>
Costing of battery and pumped hydro (ocean) storage were not covered in the BREE (2012) study, so capital and operating and maintenance costs were derived from recent publications. Capital costs were annualised using a low risk government rate of 6%, as it is assumed they would be built by Western Power or Synergy, which are government entities. Details of costing can be found in Attachment 3 - Dispatchable Power Costings.

Table 8. Dispatchable energy costings for storage technologies.

<table>
<thead>
<tr>
<th>Technology</th>
<th>Type</th>
<th>Annual fixed costs Storage ($/MWh)</th>
<th>Variable costs (fuel + VOM) ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>BM Battery Storage</td>
<td>Storage</td>
<td>149,455</td>
<td>0</td>
</tr>
<tr>
<td>BM Battery Storage (nominal subsidy)</td>
<td>Storage</td>
<td></td>
<td>40</td>
</tr>
<tr>
<td>Battery Storage On Grid (Li-ion; 1 MW scale)</td>
<td>Storage</td>
<td>247,389</td>
<td>6</td>
</tr>
<tr>
<td>CST MS (Storage component)</td>
<td>Storage</td>
<td>6,741</td>
<td>0</td>
</tr>
<tr>
<td>PHS (Storage component)</td>
<td>Storage</td>
<td>5,111</td>
<td>0</td>
</tr>
</tbody>
</table>
5  ELECTRICITY GENERATION SCENARIOS

5.1  Summary of Modelled Scenarios

Numerous scenarios with combinations of various amounts of the different RE technologies were modelled. Five scenarios, including one with the lowest weighted average LCoE and three with 100% RE, were selected by iteration and are presented in this study. Table 9 (below) shows the technology mix and power capacities for each of the 5 optimized RE scenarios. The BAU scenario – in which the existing fossil-fuelled generators are replaced with new fossil-fuelled installations – is included for comparison in terms of costs, CO₂e emissions, risks and benefits.

Scenario 1 (85% RE) provides lower cost electricity (LCoE $128 per MWh) than Scenario 6, BAU Coal and gas (129$/MWh). Scenario 2 (91% RE) includes additional large scale (PHS) storage and the LCoE is $138/ MWh. The three 100% scenarios are significantly higher cost – LCoE $159 - $165/ MWh – than Scenarios 1 and 2 because the biofuel-fired dispatchable generation is a lot more expensive than gas.

‘Nuclear-with-gas’ and ‘All gas’ scenarios were also modelled for comparison and are included in Appendix A12. The risks of the nuclear scenario, shown in Section 7, were found to be unacceptable and the LCoE ($175-$185/MWh) too high. ‘All gas’, although it produces low cost electricity, was also not considered an acceptable option because its carbon emissions were too high (73% of existing coal/gas) and the risks of total reliance on gas are high.

Coal with Carbon Capture and Storage (CCS) has not been modelled in this study because it is not a proven mature technology and in any case would cost as much or more than the 100% RE scenarios (as detailed in Appendix A10).
Table 9. Summary of power and storage capacities of the optimised scenarios modelled.

<table>
<thead>
<tr>
<th>Power Generation Capacity</th>
<th>Scenario 1: 85% RE</th>
<th>Scenario 2: 91% RE</th>
<th>Scenario 3: 100% RE</th>
<th>Scenario 4: 100% RE</th>
<th>Scenario 5: 100% RE</th>
<th>Scenario 6: BAU</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind (MW)</td>
<td>6,000</td>
<td>6,000</td>
<td>6,000</td>
<td>5,000</td>
<td>5,000</td>
<td>480</td>
</tr>
<tr>
<td>Solar PV (MW)</td>
<td>3,000</td>
<td>3,000</td>
<td>3,000</td>
<td>2,000</td>
<td>2,000</td>
<td>1,000</td>
</tr>
<tr>
<td>CST (MW)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1,200</td>
<td>1,200</td>
<td>0</td>
</tr>
<tr>
<td>OCGT (Gas) (MW)</td>
<td>3,500</td>
<td>3,500</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1,800</td>
</tr>
<tr>
<td>OCGT (Bio-oil) (MW)</td>
<td>0</td>
<td>0</td>
<td>3,300</td>
<td>2,300</td>
<td>3,300</td>
<td>0</td>
</tr>
<tr>
<td>Biomass (co-fired MS or thermal) (MW)</td>
<td>0</td>
<td>0</td>
<td>1,200</td>
<td>300</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Coal (MW)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1,750</td>
</tr>
<tr>
<td>CCGT (Gas) (MW)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1,250</td>
</tr>
<tr>
<td>Total (MW)</td>
<td>12,500</td>
<td>12,500</td>
<td>12,300</td>
<td>11,700</td>
<td>11,800</td>
<td>6,280</td>
</tr>
</tbody>
</table>

| Storage Power (MW)        | Batt.-1,600        | Batt.-1,600        | Batt.-1,600         | CST 1200            | CST 1200            | 0              |
|                          | PHS-1,000          | PHS-1,000          | PHS-1,000           |                     |                     |                |
| Storage Energy (MWh)      | 8,000              | Batt.-8,000        | Batt.-8,000         | 13,000              | 22,000              | 0              |
|                          | PHS-42,000         | PHS-42,000         | PHS-42,000          |                     |                     |                |

Table 10 (below) is a summary of the modelling results for the RE scenarios, generated from PB. It shows the following for each scenario:

- The optimised weighted average LCoE, calculated by summarising the cost of energy generated by all technologies in the system and dividing by annual energy consumption for the year modelled (2014).

- CO₂e emissions as a percent of the BAU Coal system, total tonnes CO₂e emissions for the year modelled and cost per tonne of CO₂e reduction from BAU emissions.

- Percent of surplus generation, total annual energy cost and cost of transmission.

Additional high voltage alternating current (HVAC) transmission lines for the RE scenarios add $7 - $9/MWh to the LCoE. Single and double 330 kV lines would be constructed from Geraldton and Merredin to the Perth metropolitan area; and east of Albany connecting to the existing 330 kV network at Collie.

The RE scenarios produce about 5 million MWh of surplus energy that is costed but assumed to be wasted. If this energy were sold cheaply (for example, at $30/MWh) for opportunistic industrial uses such as heat, ore grinding, pumping and desalination, this would raise nearly $150m, reducing the average LCoE by about $6/MWh and thus substantially offsetting the cost of new transmission infrastructure.
Table 10. Summary of scenario costs and carbon emissions.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Average LCoE ($/MWh)</th>
<th>Emissions (% of BAU Scenario 6)</th>
<th>Total Emissions (ktCO₂e)</th>
<th>Cost of emissions reduction from BAU ($/tCO₂e)</th>
<th>% surplus generation</th>
<th>Annual energy cost ($m)</th>
<th>LC of new transmission lines ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scenario 1: 85% RE</td>
<td>$128</td>
<td>16.9%</td>
<td>2,266</td>
<td>-$6</td>
<td>21.8%</td>
<td>$2,977</td>
<td>$7 – 9</td>
</tr>
<tr>
<td>Scenario 2: 91% RE</td>
<td>$138</td>
<td>11.9%</td>
<td>1,595</td>
<td>$17</td>
<td>14.0%</td>
<td>$3,248</td>
<td>$7 – 9</td>
</tr>
<tr>
<td>Scenario 3: 100% RE</td>
<td>$159</td>
<td>8.2%</td>
<td>1,095</td>
<td>$57</td>
<td>14.0%</td>
<td>$3,749</td>
<td>$7 – 9</td>
</tr>
<tr>
<td>Scenario 4: 100% RE</td>
<td>$160</td>
<td>8.6%</td>
<td>1,158</td>
<td>$59</td>
<td>20.7%</td>
<td>$3,763</td>
<td>$7 – 9</td>
</tr>
<tr>
<td>Scenario 5: 100% RE</td>
<td>$165</td>
<td>9.4%</td>
<td>1,256</td>
<td>$70</td>
<td>23.6%</td>
<td>$3,902</td>
<td>$7 – 9</td>
</tr>
<tr>
<td>Scenario 6: BAU</td>
<td>$129</td>
<td>100.0%</td>
<td>13,391</td>
<td>$30⁶</td>
<td>0.0%</td>
<td>$3,056</td>
<td>$0</td>
</tr>
</tbody>
</table>

‘100% renewable’ does not mean zero carbon as even the RE technologies outlined here have embodied emissions, albeit low. For example, comparing the following full cycle emission factors (EFs):

The EF of rooftop solar PV is about 0.04 kgCO₂e/kWh, comprised entirely of the embodied emissions from the manufacture, installation and recycling of the PV system components.

The EF of onshore wind is about 0.01 kgCO₂e/kWh (entirely embodied emissions).

The EF for coal fired electricity is 0.8 - 1.0 kgCO₂e/kW, more than 95% of which is from the combustion of coal in the plant.

i.e. Coal is about 20 times more emissions intensive than PV.

Source: (Schlömer et al. 2014)

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⁶ There is no carbon emissions reduction, although $30/tCO₂e is still paid for emissions.
5.2 Scenario Descriptions

The five RE scenarios modelled in the study are examples illustrating that high penetration RE powered electricity grids are feasible and economic. They are not claimed to be the most optimal; future modelling by power engineers using this and more sophisticated software will no doubt produce a better scenario for WA. It will certainly include wind, OCGT and PV (in that order of capacity) and may include CST. It may include any combination of the storage technologies described, depending on cost trajectories and results of in-depth system modelling.

Details of the modelling of all scenarios can be found in Attachment 1: Powerbalance Optimized Scenarios for Renewable Energy

5.2.1 Scenarios 1-3: Wind dominant lower cost

Scenarios 1 - 3 all use the W6000PV 3000 RE grid scenario described below. A large amount of wind generation (6,000 MW) is mainly located on the south coast east of Albany, Cape Leeuwin and around Geraldton, where the wind resource is best and generation is most cost-effective. Generation cost savings exceed the cost of extending transmission lines to these areas. About 20% of wind generation is located on rural land west of Harvey and east of Collie where the advantages are good wind resources and proximity to existing 330 kV transmission lines. These sites are envisaged to be the first to be developed. The 2 MW turbines are located mainly in rural hinterlands, remote from population centres, which will minimize any community objections to landscape impacts. The power stations and 330 kV AC transmission grid is shown in Figure 16 (below).

Solar PV is mainly rooftop due to its lower cost and is located in the north and south Perth metropolitan areas and in Bunbury. Half of the panels are modelled as facing east and half west, and the DC-AC conversion factor has been scaled down from that of utility scale PV to give a CF of 19%, which is considered average for current Perth installations. Utility scale fixed PV (1,000 MW) is mainly located in sunny locations near Geraldton, Southern Cross and Kalgoorlie. Benefits of utility scale are higher CF, and the dispersed locations minimize the effect of cloudiness while maximizing utilization of transmission infrastructure by co-location with wind generation.

The map in Figure 16 (below) shows the wind and solar power stations required for Scenarios 1-3. The small squares represent the area required for each solar or wind farm. For wind farms, less than 5% of this area would actually be occupied by turbine infrastructure and agriculture would continue as usual within the rest of the area. The larger circles represent the relative power (MW) of each power station.
Figure 16. Power stations and transmission for RE grid: Wind 6,000 MW, PV 3,000 MW.

Wind and solar with BM battery storage are the sole sources of generation for Scenario 1 for more than 68% of the year and this generation cannot be turned up if there is a lack of wind or sun (it is not dispatchable). Frequency stability needs to be provided by a fast response power source available at all times. For Scenarios 2 and 3, the pumped hydro turbines could provide dispatchable power.

5.2.1.1 Scenario 1 (85% RE) – Wind dominant with BM storage; gas OCGT

Scenario 1 provides 85% RE and reduces carbon emissions to 16.9% of BAU. It is also the most economical scenario, at $128/MWh. The dispatchable power for this scenario is provided by OCGTs and 8,000 MWh of batteries. The batteries would be embedded in the distribution grid, installed BM by consumers on their premises and by Synergy to support new urban mini-grids. The 8,000 MW figure was considered a plausible maximum by 2030 if the existing time of use tariff differentials are maintained and the nominal $40 subsidy that was modelled is paid by Synergy. This amount of
battery storage equates to 700,000 residences and shops with 10 kW batteries and 1,000 factories / residential mini-grids with 1 MW systems.

Scenario 1 could be implemented without any BM batteries, but the LCOE rises to $133/MWh and emissions are higher at 21.2% of BAU (see Appendix A2, Attachment 1 for details).

As Scenario 1 does not have turbines operating in spinning reserve at all times, ancillary reserves are provided by dedicated on-grid bi-directional inverter connected battery systems located in or near the load centres (Section 5.4.2 and Appendix A3).

Scenario 1, or a version of it scaled according to demand, would provide a logical strategy for phases 1 and 2 of the Transition Strategy outlined in Section 6. It is achievable by 2030 if appropriate government policies are implemented as recommended in Section 1.2.

5.2.1.2 Scenario 2: 91% RE – Wind 6 GW, PV 3 GW with Pumped Hydro (Ocean) Storage, gas OCGT

Essentially the same as Scenario 1 with 42,000 MWh of PHS (ocean) added to the 8,000 MWh of batteries, Scenario 2 significantly reduces carbon emissions to 11.9% of BAU. With a moderate LCoE $138/MWh (an increase $12/MWh over Scenario 1), it has a moderate carbon reduction cost of $17/tCO₂e. Scenario 2 is not 100% RE because 9% of energy is still supplied by gas fuelled OCGTs.

Up to 200 MW of the total 800 MW of PHS power capacity would be best located within 100 km of the major load centre of Perth to provide frequency stability for the grid. Possible locations are the existing Wellington Dam or high land close to the ocean near Lancelin. There are potential locations for larger sea water PHS installations about 120 km east of Albany and less than 100 km north of Geraldton.

5.2.1.3 Scenario 3: 100% RE – Wind 6 GW, PV 3 GW with Pumped Hydro (Ocean) Storage; bio-oil OCGT

Scenario 3 is the same as 2 but with bio-oil used to fuel the OCGTs. Bio-oil fuel would be about 2.6 times as expensive as gas as described in Section 4.6 increasing LCoE by $23 to $159/MWh. Carbon reduction cost is significantly higher at $57/tCO₂e.

Scenarios 3, 4 and 5 would require woody biomass production on farms and a bio-oil production industry to be established at Collie or Bunbury with a new rail line to transport biomass from existing rail at Narrogin or Wagin. The assumed biomass cost includes the cost of rail transport. Costing of the rail is beyond the scope of this study but would be minor in comparison to plant costs and could also be used for transporting agricultural and biomass exports to the port of Bunbury.

5.2.2 Scenarios 4 and 5: 100% RE – CST MS with biomass

Scenarios 4 and 5 both use the W5000 PV2000 CST1200 RE grid scenario described below. Rooftop PV (1200 MW) is located in the metropolitan area and tracking PV (800) co-located with CST plants near Mullewa and Kalgoorlie and at Merredin.
The modelled CST (1200 MW) comprises twelve 100 MW arrays with central receiver towers and 6 hours of MS storage at peak output, similar to the plant commissioned by Solar Reserve at Tonopah Nevada in June 2015. The locations are dispersed in sunny areas where cloud cover is infrequent, at or outside the northern and eastern periphery of the grid. There is plenty of unutilized land in these regions for the 700 ha sites. The actual location of the CST plants would depend on whether they are to be co-fired by biomass, in which case they would be best located near existing rail lines to transport the large quantities of woodchips.

Figure 17. Power stations and transmission for RE grid: Wind 5,000 MW; PV 2,000 MW; CST-MS 1,200 MW.

5.2.2.1 Scenario 4: Wind 5 GW; PV 2 GW, CST 1.2 GW with MS storage biomass co-fired; bio-oil OCGT

Scenario 4 includes 1200 MW of CST with 6 hours storage at full power (7,200 MWh of storage). There is biomass co-firing of an additional 13,000 MWh of additional MS storage capacity, making generation fully dispatchable all year.
An average of two large trainloads per day of dry biomass would be required for co-firing the 12 plants and most of this would have to be transported from southern agricultural areas. It would therefore be most economic to locate the plants close to the existing eastern and northern railway lines. As Scenario 4 does not have any biomass thermal generation, it may be feasible to locate one of the biomass co-fired CST MS plants within 100 km north or east of the Perth load centre so that it can provide frequency stability and utilise combustible municipal wastes.

The OCGT balancing power would be fired by bio-oil, as for Scenarios 3 and 5.

**5.2.2.2 Scenario 5: 100% RE; Wind 5 GW, PV 2 GW, Biomass thermal 0.2 GW, CST 1.2 GW with MS storage, bio-oil OCGT**

Scenario 5 has the same wind, PV and CST capacities as Scenario 4. There is 22,000 MWh of additional MS storage to enable more energy to be stored after days of surplus CST generation and dispatched during subsequent overnight shortfall periods. However, it does not have co-firing of the CST MS storage. Instead, there is 300 MW of biomass fuelled thermal generation from several 50 MW scale plants located near to fuel sources. Cheap plantation and municipal waste biomass (probably enough for up to 200 MW of generation) and some of the more expensive oil mallee woodchips is used.

PB modelling showed that, to be economic, this type of generation must be dispatched second in order after wind/solar and that 300 MW would be the upper limit, as CF decreases and fuel price increases as more capacity is added. At $165/MWh, Scenario 5 is more expensive than Scenario 4 but the biomass thermal generation has the advantages of providing frequency stability and utilisation of cheap fuels that would otherwise be wasted. The CO₂e emission reduction and abatement cost are slightly more than for Scenario 4.

**5.2.3 Business-as-Usual (BAU) Coal and Gas**

New supercritical coal fired plants, without carbon capture and storage, are used to replace the existing coal capacity. These plants are more rampable (flexible) than the current old Muja and Collie plants and may be capable of ramping up and down from 30% power at rates of about 26 MW per minute. CCGTs are rampable at faster rates than this. However, in the simplified modelling, all of the large coal and CCGT generators come on and off in steps of 250 MW (50% maximum power).

PB modelling is only an approximation of real operating conditions. For example, during a period where a ramp up to 500 MW and back down is required within several hours, this model assumes that 250 MW of coal generation would come on in one step then another 250 MW, ramping down in the same way with OCGT used to fill in the remaining shortfalls. In reality, a coal generator may not be ramped up when such short duration load increases are forecast. The model is, however, a fair approximation for the purposes of estimating capacity and generation requirements.

The following assumptions were made in the modelling of Scenario 6:

- The large coal and CCGT Generators are assumed to be 500 MW capacity; 4 coal and 2 gas CCGT generators are installed totalling 3,000 MW capacity.
The proportion of generation from coal and gas are the same as for 2015.

New coal generation capacity is 2,000 MW with a CF of 0.71.

New CCGT/ co-gen capacity is 1,000 MW, with a CF of 0.7. Existing gas co-gen is assumed to be either replaced by CCGTs or renewed at the same cost as new CCGT.

OCGT installed totals 1,800 MW, enough to cover all shortfalls with an additional 500 MW in reserve in case of failure of a major generator. OCGTs are used for load following/peaking response because they incur much less wear and tear/maintenance than coal fired power generation under rapid ramping.

Wind generation capacity remains at 2014 level and rooftop solar PV is increased to 1,000 MW (from about 510 MW in 2015).

No battery or other storage.

Capacity increase has not been proportional to demand increase as there is significant over-capacity of old coal generators on the existing grid.

Table 11. Generating capacity for Scenario 6 ‘BAU Coal/Gas’ compared to existing.

<table>
<thead>
<tr>
<th>Technology</th>
<th>Installed capacity @ 2015 (MW)</th>
<th>Modelled new capacity to meet 2030 demand with 500 MW in reserve</th>
<th>Capacity factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>1,778</td>
<td>1,750</td>
<td>0.71</td>
</tr>
<tr>
<td>Gas OCGT</td>
<td>n/a</td>
<td>1,800</td>
<td>0.08</td>
</tr>
<tr>
<td>Gas CCGT</td>
<td>n/a</td>
<td>1,250</td>
<td>0.70</td>
</tr>
<tr>
<td>Gas OCGT,CCGT, Diesel or Biofuel (non-Cogen)</td>
<td>2,459</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>Gas Cogen</td>
<td>675</td>
<td>0</td>
<td>n/a</td>
</tr>
<tr>
<td>Wind</td>
<td>481</td>
<td>481</td>
<td>n/a</td>
</tr>
<tr>
<td>Solar PV</td>
<td>510</td>
<td>1,000</td>
<td>n/a</td>
</tr>
<tr>
<td>TOTAL installed capacity (MW)</td>
<td>5,228</td>
<td>6,281</td>
<td>n/a</td>
</tr>
</tbody>
</table>

7 New installed capacity has not been increased 126% proportionally with demand because there is significant over-capacity in the existing grid.
5.2.4 Other fuelled (base-load) scenarios not presented in main study

Gas and nuclear are fuelled base-load scenarios not included in the main body of this study due to their high cost and high associated risks. They are included in Appendix A12 for comparative purposes.

5.2.5 Nuclear power using Small Modular Reactors (SMR)

Uranium is not a renewable fuel and reactors using an alternative fuel – thorium (also not renewable) have not yet been commercialised. For these and many other reasons, outlined in Appendix A11, SEN does not endorse the use of nuclear power.
5.2.6 Gas fuelled scenario

A gas fuelled scenario is also modelled in Appendix A12. This is essentially the same as Scenario 6 ‘BAU Coal/gas’, with gas CCGT replacing the coal fired power stations.

5.2.7 Carbon Capture and Storage technologies (CCS)

CCS has not been modelled in this study because it is not currently commercialized anywhere in the world for stand-alone coal power station application, is much more expensive than RE generation and it is very unlikely that the community would accept new coal generation with CCS. Details of CCS can be found in Appendix A10.

5.3 Transmission

The main assumptions made for transmission are:

1. As the existing transmission network will continue to be used at near full capacity in all scenarios, the cost of maintaining and upgrading it is not included.

2. Only additional lines required to supply energy from the renewable scenarios are costed as additional to the existing grid.

3. A stand-alone grid is modelled. Connection to the NEM grid in the Eastern States would reduce the power shortfalls during low wind/sun periods as weather systems in the East do not coincide with those in the south-west of WA. However the cost of constructing a 3000 km HVDC line to connect the SWIS to the NEM grid would be more than $4 billion. Annualized payments for this would likely exceed the cost savings from the reduction in the dispatchable balancing power capacity requirements or the addition of more storage.

The new transmission lines have been modelled to minimise cost by:

- Utilizing cost-effective high voltage 330 kV AC lines for all new generation, thus limiting transmission energy losses to below 3% in the maximum 500 km line distances.

- Locating RE generation in precincts of 800 MW or 1600 MW of capacity according to the capacity of the single or double 330 kV AC transmission connections.

- Where a line carries dispatchable generation, it is 330 kV double.

- SIREN assumes that a maximum 5/8 of an 800 MW capacity will be transmitted along a single 330 kV AC, which can carry up to 500 MW. Power exceeding 500 MW will be curtailed. The PB modelling shows that this equates to wastage of only about 4% of energy generated. Thus the 500 MW maximum transmission capacity of a single 330 kV line is most effectively utilised with minor wastage of peak generation.

- Co-locating wind and utility scale solar PV generators so that wind, which often blows at night, complements the daytime solar generation. This maximizes utilization of the spur lines.
and end stations while providing complementarity of generation (i.e. PV during the day and wind during most nights).

- Locating new RE generation precincts near existing transmission corridors (where existing transmission lines to retired coal power stations are available) and new transmission corridors.

- Locating the new additional 330 kV transmission lines in existing transmission corridors where these exist.

- Rooftop PV does not require any 330 kV transmission lines as it is located within the existing urban distribution grid.

Costing of the transmission network assumes capital costs of $1m and $1.5m per km for 330 kV single and double lines respectively and adding $8m and $10m respectively for a transformer end-station at the start of each new line. A 6% low risk, government bond rate of capital is applied to give annualised capital cost and operating and maintenance costs are added.

*Table 12. Costs of transmission lines used in SIREN.*

<table>
<thead>
<tr>
<th>Power range (MW)</th>
<th>Line Type(s)</th>
<th>Cost per Km</th>
<th>Substation Cost</th>
<th>Line Type(s)</th>
<th>Cost per Km</th>
<th>Substation Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>0 - 250</td>
<td>220_s</td>
<td>$0.6M</td>
<td>$7.0M</td>
<td>220_d</td>
<td>$0.9M</td>
<td>$8.0M</td>
</tr>
<tr>
<td>250 - 500</td>
<td>330_s</td>
<td>$1.0M</td>
<td>$6.0M</td>
<td>330_d</td>
<td>$1.5M</td>
<td>$10.0M</td>
</tr>
<tr>
<td>500 - 1,000</td>
<td>330_d</td>
<td>$1.5M</td>
<td>$10.0M</td>
<td>330_d + 330_s</td>
<td>$2.5M</td>
<td>$18.0M</td>
</tr>
<tr>
<td>1,000 - 1,500</td>
<td>330_d + 330_s</td>
<td>$2.5M</td>
<td>$18.0M</td>
<td>330_d x 2</td>
<td>$3.0M</td>
<td>$20.0M</td>
</tr>
</tbody>
</table>

Table 13 (below) estimates the cost for additional transmission infrastructure required for typical Wind - PV and CST RE scenarios (9,000 MW dispersed wind and PV; 1,200 MW CST). Only new transmission lines feeding into the existing 300 kV network at Collie and Perth are costed. Single 330 kV lines are generally utilised for wind and PV generation. Where a line carries dispatchable generation, it is 330 kV double.
Table 13. Estimated length and cost of transmission lines required for the RE scenarios modelled.

<table>
<thead>
<tr>
<th>Name</th>
<th>Line type</th>
<th>Cost rate ($/km)</th>
<th>End station Cost ($)</th>
<th>Main line distance (km)</th>
<th>Connector distance (km)</th>
<th>Total Line Costs ($ million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>C Leeuwin station</td>
<td>220d</td>
<td>900,000</td>
<td>8,000,000</td>
<td>144</td>
<td>0</td>
<td>137.6</td>
</tr>
<tr>
<td>Collie E</td>
<td>330s</td>
<td>1,000,000</td>
<td>8,000,000</td>
<td>0</td>
<td>10</td>
<td>18</td>
</tr>
<tr>
<td>Collie E 2</td>
<td>330s</td>
<td>1,000,000</td>
<td>8,000,000</td>
<td>22</td>
<td>20</td>
<td>50</td>
</tr>
<tr>
<td>Dongara station</td>
<td>330s</td>
<td>1,000,000</td>
<td>8,000,000</td>
<td>0</td>
<td>10</td>
<td>18</td>
</tr>
<tr>
<td>Walkaway station 2</td>
<td>330s</td>
<td>1,000,000</td>
<td>8,000,000</td>
<td>0</td>
<td>10</td>
<td>18</td>
</tr>
<tr>
<td>Walkaway station</td>
<td>330s</td>
<td>1,000,000</td>
<td>8,000,000</td>
<td>0</td>
<td>10</td>
<td>18</td>
</tr>
<tr>
<td>Oaka station</td>
<td>330d</td>
<td>1,500,000</td>
<td>10,000,000</td>
<td>385</td>
<td></td>
<td>587.5</td>
</tr>
<tr>
<td>Horrocks Station 2</td>
<td>330s</td>
<td>1,000,000</td>
<td>8,000,000</td>
<td>0</td>
<td>10</td>
<td>18</td>
</tr>
<tr>
<td>Northampton Station</td>
<td>330s</td>
<td>1,000,000</td>
<td>8,000,000</td>
<td>45</td>
<td></td>
<td>53</td>
</tr>
<tr>
<td>Harvey</td>
<td>330s</td>
<td>1,000,000</td>
<td>8,000,000</td>
<td>0</td>
<td>10</td>
<td>18</td>
</tr>
<tr>
<td>Waroona</td>
<td>330s</td>
<td>1,000,000</td>
<td>8,000,000</td>
<td>0</td>
<td>10</td>
<td>18</td>
</tr>
<tr>
<td>Lancelin station</td>
<td>330s</td>
<td>1,000,000</td>
<td>8,000,000</td>
<td>0</td>
<td>20</td>
<td>28</td>
</tr>
<tr>
<td>Jurien station 2</td>
<td>220d</td>
<td>900,000</td>
<td>8,000,000</td>
<td>250</td>
<td>50</td>
<td>278</td>
</tr>
<tr>
<td>Kronkup station</td>
<td>330s</td>
<td>1,000,000</td>
<td>8,000,000</td>
<td>0</td>
<td>47</td>
<td>55</td>
</tr>
<tr>
<td>Mt Barker station</td>
<td>330s</td>
<td>1,000,000</td>
<td>10,000,000</td>
<td>10</td>
<td></td>
<td>20</td>
</tr>
<tr>
<td>Kojonup 1&amp;2, Kronkup, Mt Barker)</td>
<td>330d</td>
<td>1,500,000</td>
<td>10,000,000</td>
<td>83</td>
<td>20</td>
<td>164.5</td>
</tr>
<tr>
<td>Marvel Loch</td>
<td>330s</td>
<td>1,000,000</td>
<td>8,000,000</td>
<td>100</td>
<td></td>
<td>108</td>
</tr>
<tr>
<td>Merredin stations 1 &amp; 2</td>
<td>330d</td>
<td>1,500,000</td>
<td>8,000,000</td>
<td>243</td>
<td>20</td>
<td>402.5</td>
</tr>
<tr>
<td>Wellstead station</td>
<td>330s</td>
<td>1,000,000</td>
<td>8,000,000</td>
<td>0</td>
<td>10</td>
<td>18</td>
</tr>
<tr>
<td>Wellstead station 2</td>
<td>330d</td>
<td>1,500,000</td>
<td>10,000,000</td>
<td>269</td>
<td></td>
<td>413.5</td>
</tr>
<tr>
<td>Total (RE Scenarios 1 – 3)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$2,441.6</td>
</tr>
<tr>
<td>CST Scenarios</td>
<td>330d</td>
<td>1,500,000</td>
<td>10,000,000</td>
<td>220</td>
<td></td>
<td>340</td>
</tr>
<tr>
<td>Total (RE Scenarios 4 &amp; 5)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$2,781.6</td>
</tr>
<tr>
<td>Value of existing lines</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$1,791</td>
</tr>
</tbody>
</table>
5.4 Operational Considerations

5.4.1 Load following and ramp rates

Wind and solar generation are highly variable depending on season and time of day; solar varies daily from zero at night up to near full capacity on summer days and wind can drop rapidly depending on weather conditions. While RE can directly supply 100% of grid energy requirements for 70% of the time, low wind conditions exist throughout most of the grid on some still nights in winter and autumn. At these times, even with the most dispersed, wind-intensive scenario modelled (wind 6,000 MW, PV 2,000 MW), RE generation sometimes falls to less than 100 MW within a few hours and remains at that level for several hours. Doubling the wind capacity would have little effect, increasing generation from 100 to 200 MW (for example), when the grid demand could be up to 3,500 MW.

The economic means of supplying these deep shortfalls is by OCGTs and storage as described in Section 4.8. With the technology costings used in this study (outlined in Attachment 3 in Appendix A2), the economic maximum size for even the lowest cost storage (PHS) is 40,000 – 50,000 MWh or about one winter night’s energy supply. To supply all shortfalls with the most economic storage technologies alone (PHS or CST with MS) would cost in excess of $2,000/MWh and increase the weighted average LCoE by 300% to over $500/MWh (Appendix A7). The only way to economically fill the infrequent consecutive large shortfalls which occur during autumn and winter is by rapid response fuelled generation (OCGTs). About 2,300 – 3,500 MW of OCGT capacity is required, depending on the RE scenario.

As steam thermal plants cannot be ramped quickly and must be operated at CF of over 60% to be economic, their application for supplying RE shortfalls is limited. However, supplementation of the OCGTs by co-firing MS storage with biomass, or adding small amounts of cheap waste wood-fired steam thermal plant, reduces the OCGT capacity requirement (Scenarios 4 and 5). Minor amounts of cheap fuelled energy from cogeneration plants may also be used to charge storage, which can then provide some rapid response balancing generation.

The existing SWIS grid already requires 1,400 MW of OCGT generation to follow changes in load. For the RE scenarios, the OCGT capacity increases to 2,300 – 3,500 MW. The greater frequency and magnitude of ramping will not cause undue wear and tear on generators as there would be a large fleet of relatively small (<100 MW) OCGTs, which are designed to accommodate many rapid cold starts. OCGTs can ramp up to full power within several minutes of starting. More than thirty 60-100 MW units are envisaged in and around the load centres (mainly around Perth). They do not have to be kept running and can be fired up serially as shortfalls increase. Modelled magnitude, rate and occurrence of ramping for the existing system compared with a typical RE scenario are shown in Table 14 (below).

The impact of unforeseen generator outages has very different impacts on RE-based and fuel-based generation systems. Failure of one large coal, gas CCGT or nuclear generating unit requires an additional instantaneous ramping of 400 – 500 MW, compared to 100 MW for one OCGT or 2 MW for one wind turbine in the RE scenarios.
Large reductions in wind generation due to weather conditions is predictable and happens over hours, thus the ramping can be planned in advance (see Section 5.4.4).

Table 14. Required OCGT/storage ramp rates for RE scenarios compared with existing coal and nuclear.

<table>
<thead>
<tr>
<th>SCENARIO</th>
<th>Maximum required ramp rate MW/hr</th>
<th>Maximum ramp rate if one generating unit fails MW/hr</th>
<th>No. of hours ramp rate exceeds 1,000 MW per hour</th>
<th>No. of hours OCGT ramp rate exceeds 500 MW per hour</th>
<th>Max ‘sum consecutive 5 hours’ ramp rate</th>
<th>Number of positive OCGT ramp rates</th>
</tr>
</thead>
<tbody>
<tr>
<td>W7PV2 9000</td>
<td>1,362</td>
<td>1,464</td>
<td>72</td>
<td>317</td>
<td>2,924</td>
<td>2,155</td>
</tr>
<tr>
<td>W5PV2 7000</td>
<td>1,384</td>
<td>1,484</td>
<td>82</td>
<td>380</td>
<td>3,383</td>
<td>2,875</td>
</tr>
<tr>
<td>Existing Coal</td>
<td>653</td>
<td>1,053</td>
<td>0</td>
<td>69</td>
<td>1,679</td>
<td>4,232</td>
</tr>
<tr>
<td>Nuclear</td>
<td>653</td>
<td>1,128</td>
<td>0</td>
<td>53</td>
<td>1,531</td>
<td>4,302</td>
</tr>
</tbody>
</table>

The ramp rates shown for the existing coal and nuclear scenarios are the difference between the averages of power in an hour to the next, as recorded in the IMO SCADA data; higher actual ramps rates may occur for brief periods.

5.4.2 Frequency control and power quality

Sudden changes in load, such as starting and stopping of large industrial machinery, constantly occur within large grids. These tend to cause fluctuations in the frequency of the AC voltage, which is nominally 50 Hz. Frequency stability means keeping the frequency of the AC voltage within specified limits. To reduce rapid changes in frequency, all dispatchable synchronous generators increase their power output if the frequency falls below 50Hz and decrease their power output if the frequency rises above 50Hz. To restore frequency back to 50Hz, some dispatchable synchronous generators and/or inverter connected energy storage systems are operated well below rated power to provide ancillary reserve power capacity. These generators are operated in isochronous mode: they continuously adjust their power output to restore the frequency back to 50Hz. If the frequency falls below specified lower limits, for example when there is insufficient spinning reserve to cover for the loss of a large generator, a system of under-frequency load shedding reduces the system load in steps until the frequency stops declining, when there may be sufficient spinning reserve to increase the frequency back to 50Hz. The types of generation that can be used to provide ancillary reserve power are:

- Dispatchable synchronous generators (OCGT, CCGT, steam or diesel) running in isochronous mode. This is the source deployed in traditional fuelled grids such as Scenario 6 and is included in Scenarios 4 and 5.

- Dedicated on-grid bi-directional inverter connected batteries (the BM batteries used as storage in Scenarios 1 – 3 would not be sufficient on their own to provide frequency stability).
• Bi-directional inverter connected flywheel systems.

• Synchronous generator connected hydro and pumped hydro systems (available in Scenarios 2 and 3).

It is envisaged that an on-grid bi-directional inverter connected battery system would be used to provide ancillary reserve power for Scenario 1, which does not have fuelled or hydro generation for most of the time. This is estimated to add less than $2 / MWh to the LCoE of the scenarios (Appendix A3).

Power quality is the smoothness of the AC voltage, which should ideally be a perfect sine wave of fixed frequency and magnitude. However, fluctuating loads and non-linear loads cause fluctuations in the frequency and magnitude of the AC voltage and distortion of the voltage sine wave. To maintain power quality, synchronous generators have traditionally been commonly used, which typically spin at 3000 RPM to generate 50Hz AC electricity. OCGT generators are good at performing this function, even when not generating real power. A portion of them can be equipped to run as synchronous compensators. This entails installation of a clutch to decouple the gas turbine from the synchronous generator so that the synchronous generator can be run in synchronous compensator mode to provide a voltage source and some inertia to help stabilise the frequency and magnitude of the voltage (Peltier 2011; Wikipedia Contributors 2016).

In addition to synchronous compensation, new wind turbines and battery systems are equipped with inverters and power controllers that produce high quality AC power very similar to that produced by synchronous generators.

5.4.3 Supply reliability

The current SWIS generating system has a large amount of generating capacity lying idle in reserve in case of failure of one of the few large (more than 300 MW) generating units. Coal and nuclear generating units are also inflexible (generally cannot be ramped down below 50% power).

The fleet of gas generators would eventually comprise mainly new highly efficient aero-derivative 60 - 100 MW OCGTs. Some cogeneration from existing plant may also be during longer shortfall periods. This fleet of many smaller generators requires less reserve capacity in the event of one of them failing. The capital cost per MWh of OCGT capacity installed is less than 20% of coal thermal and 12% of nuclear thermal plants. They can ramp up from a cold start within minutes, which is impossible for coal and nuclear plants. These two attributes make it economic for OCGTs to operate only when required. Each OCGT, being about 30% of the power and operating at about 12% of the CF of large thermal units, generates less than 4% of the energy produced annually from a typical large coal or nuclear generator. Therefore, the consequences of one OCGT plant failing is much less than the failure of one coal thermal plant.

The grid is supplied directly by RE for 70% of the time and requires only partial use of the OCGTs most other times; 3%-100% of the OCGTs are not generating (i.e in reserve) for all but a few hours of the year. One additional OCGT unit should provide adequate reserve capacity even for those few remaining hours. Using the relative cost and power figures stated above, having one OCGT in
reserve would incur only about 6% of the reserve capacity costs of having a large coal generator in reserve, as is required for the existing system.

As the modelled wind turbines are 2 MW, even if several failed at once there would be little or no impact on the electricity grid. Therefore, the biggest consideration for these is weather variability.

5.4.4 Forecast uncertainty and seasonal variability

Forecasting wind and solar is increasingly accurate. The Australian Wind Energy Forecasting System (AWEFS) provides accurate forecasts of wind generation down to 5 minutes in advance.

The AWEFS forecasts wind generation on the NEM grid at 5 minute intervals, 5 minutes in advance for individual wind farms and NEM regions. It is provided by integrating the current real-time windfarm generation data and meteorological SCADA data (AEMO 2016). This accuracy of short term forecasting has proven in practice world-wide to allow adequate time for dispatch of stored or fuelled energy to compensate for falling RE generation.

Variability in weather conditions in 2014 - the year used in the scenario comparisons - has been shown in this study to pose no problems, with the OCGTs providing adequate power during the worst wind/solar low.

The effect of variability in wind and solar resources between years is another consideration. To test this, a typical RE scenario – 6,000 MW of wind and 3,000 MW of solar PV with set amounts of storage and gas fuelled OCGTs for balancing power – was modelled for 6 years. SIREN uses real time wind and solar data. Data for 2007, 2008, 2009, 2010, 2011 and 2013 was modelled against actual load for those years (IMO 2015) scaled up to so that total energy demand for the year equals total demand in 2014.

The results are presented in the tables and graphs below. Percentage renewable generation varied from 85.5% to 90.3%. Weighted average LCoE varied from $120/MWh in 2007, which had the highest percentage of RE, to $128 in 2014 (the year modelled for this study) and $127/MWh in 2013, when the OCGT generation was highest due to low RE generation.
Table 15. Variation due to weather variability over 7 years for Scenario 1 (W6PV3).

<table>
<thead>
<tr>
<th>Year</th>
<th>% Direct Wind and PV</th>
<th>% BM Battery Storage</th>
<th>% Gas OCGT Fuelled</th>
<th>% Renewable Energy</th>
<th>LCoE</th>
</tr>
</thead>
<tbody>
<tr>
<td>2007</td>
<td>86.5%</td>
<td>3.8%</td>
<td>9.7%</td>
<td>90.3%</td>
<td>$122</td>
</tr>
<tr>
<td>2008</td>
<td>84.5%</td>
<td>3.9%</td>
<td>11.7%</td>
<td>88.3%</td>
<td>$125</td>
</tr>
<tr>
<td>2011</td>
<td>83.6%</td>
<td>3.7%</td>
<td>12.7%</td>
<td>87.3%</td>
<td>$124</td>
</tr>
<tr>
<td>2010</td>
<td>83.1%</td>
<td>3.7%</td>
<td>13.1%</td>
<td>86.9%</td>
<td>$127</td>
</tr>
<tr>
<td>2009</td>
<td>85.5%</td>
<td>3.7%</td>
<td>10.8%</td>
<td>89.2%</td>
<td>$127</td>
</tr>
<tr>
<td>2013</td>
<td>81.4%</td>
<td>4.1%</td>
<td>14.5%</td>
<td>85.5%</td>
<td>$129</td>
</tr>
<tr>
<td>2014</td>
<td>81.9%</td>
<td>4.4%</td>
<td>13.7%</td>
<td>86.3%</td>
<td>$128</td>
</tr>
</tbody>
</table>

Percentage of RE generation per year varies up to 4.1% over the 6 years modelled but accounts for less than $7/MWh variation in LCoE. Note that 2014 is the year that was modelled to produce the scenario results presented in this study.

Figure 19. Graphical representation of LCoE variance due to weather variability 2007 – 2014 for Scenario 1.
Figure 20. Annual variation in percentage of OCGT and battery storage used.
6 Transition Strategy

The transition from our existing primarily fossil-fuelled electricity generation system to a high-penetration RE electricity grid must ensure a reliable, economically affordable supply at all stages as all the existing coal plants are retired. Muja A, B, C and D are presently 31-51 years and all of the other plants will be over 30 years old by 2030 (except Blue Waters, which reaches that age in 2039).

The existing grid comprises coal, gas OCGT, gas CCGT, co-generation such as combined heat and power and minor amounts of wind and solar PV. As coal plants are phased out, there will be a few years where a higher portion of natural gas fuelled energy is needed to make up the initial energy shortfall until the installed capacity of RE increases to a point where it takes up the difference.

While the final makeup of the grid will not include coal, it does require that the gas-turbine generation capacity be retained and increased slightly to meet the shortfall periods of low solar and wind supply, which are relatively short in duration. However, the amount of energy supplied by gas is reduced from the existing 43% (Appendix 10) to about 15% in Scenario 1, and none in Scenarios 3, 4 and 5 where that energy is supplied by sustainable liquid and/or solid bio-fuels.

Three notional phases are presented here to illustrate how a transition to Scenario 1 (85% RE) can occur, with the option to continue on to the 100% RE in Scenarios 3, 4 or 5.

6.1 Assumptions

6.1.1 SWIS characteristics - Demand & Supply growth

Table 16 (below) summarises the demand and average annual growth (installation rate) of wind and solar electricity generation and battery energy storage required to implement Scenario 1 (85% RE) by 2030.
### Table 16. General demand and generation growth assumptions for the implementation of Scenario 1. Source: IMO (2015).

<table>
<thead>
<tr>
<th>Demand or growth parameter</th>
<th>Assumption</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sent out Energy growth 2015-25</td>
<td>1.6%/yr</td>
</tr>
<tr>
<td>Peak Demand 2014-15</td>
<td>3,744 MW</td>
</tr>
<tr>
<td>Grid Demand in 2015</td>
<td>18,731 GWh</td>
</tr>
<tr>
<td>Grid demand in 2030</td>
<td>23,767 GWh</td>
</tr>
<tr>
<td>Capacity Credit payment 2014/15</td>
<td>$122,427/MW</td>
</tr>
<tr>
<td>Energy growth due to increase in electric vehicles, light rail &amp; other electrified transport demand</td>
<td>Estimated 0.3%/year is included in the 1.6% energy growth projection</td>
</tr>
<tr>
<td>Solar PV growth average (residential embedded)</td>
<td>91 MW/yr</td>
</tr>
<tr>
<td>Solar PV growth average (utility scale)</td>
<td>76 MW/yr</td>
</tr>
<tr>
<td>Wind growth average</td>
<td>365 MW/yr</td>
</tr>
<tr>
<td>BM battery storage growth average</td>
<td>533 MWh/yr</td>
</tr>
<tr>
<td>Large-scale energy storage growth (PHS or CST MS)</td>
<td>Not required for Scenario 1, but for Scenarios 2-5 implementation would commence in Stage 3</td>
</tr>
<tr>
<td>Solar PV degradation rate</td>
<td>0.8%/yr</td>
</tr>
<tr>
<td>Wind farm replacement life</td>
<td>25-30 years</td>
</tr>
</tbody>
</table>

### 6.2 Phase 1 (to 2020): Remove excess coal capacity and install lowest-cost renewables to meet the RET in WA

The first stage of the transition - retiring excess coal generation and installing more wind and solar at locations where the existing network can best accommodate it - can be relatively easily achieved.

Small-scale embedded rooftop solar PV systems installed on residential, commercial and industrial premises are growing rapidly, simply due to the economic attractiveness of PV. This market has a very large potential and the installation rate is expected to accelerate. The Western Australian Government has acknowledged that it will have a significant impact on the electricity grid (Parkinson 2015).

Simultaneously, small BM batteries and larger battery systems servicing urban and rural mini-grids are already being installed as costs decrease and the economics improve. As dispersed PV systems are installed in conjunction with batteries, this will assist in reducing typical daily peak energy requirements, thus reducing the cost of grid electricity (see Section 3.4).
The SWIS is forecast to have 1,000 MW excess capacity for at least the next 2 years (IMO 2015), as shown in Figure 21 (below). The cost for this excess is approximately $122 million/year in capacity payments in the Reserve Capacity Market. It has also been an impediment to new utility scale wind and solar farms being built, despite the Federal RET of 33,000 GWh/year by 2020.

WA’s proportional contribution to the Federal RET would be about 3,000 GWh/year, and presently SWIS renewable power plants generate 1500 GWh/year, so a further 1,500 GWh/year is needed to meet this by 2020. Note (for example) that while just over 500 MW of wind capacity alone could provide this capacity, it will also require a capacity payment on approximately 175 MW (depending on where they are located), still resulting in a net saving of just under $100 million/year (IMO 2015).

The cost of the 1,500 GWh/year of Large Scale Generation Certificates (LGCs) at the current rate of $65/MWh is around $98 million/year by 2020. If LGCs are not bought, non-compliance penalties in excess of this figure will be incurred.

Retiring coal will mean that in the first few years slightly more gas will need to be burned until the wind and solar plants are operating, assuming the current demand forecast.

The benefits of new RE electricity generation include:

- Addressing the RET and improved economic development in WA.
- Gas fuel cost savings.
- Deferral of network upgrades through the targeted use of embedded PV and batteries.
- Reduction in capacity payments.
- Reduction in tariff adjustment payments (TAP) to subsidize rural customers.
- Installation of wind, solar and biomass plant near Collie will help the community to transition their economy with employment in building renewable generators and long-term operation and maintenance. A Taskforce has been set up to review Collie transition from coal to other industries (ABC News 2015).
6.3 Phase 2 (to 2025): Add more solar and wind; consider new Biomass industry

Phase 2 continues the installation of both wind and solar, along with battery storage. Adoption rates of electric vehicles and other electrification of transport are envisaged to grow significantly. Some new 330 kV AC transmission lines will need to be constructed and others upgraded as new solar and wind capacity is installed in high wind / solar areas further from the Perth metropolitan load centre (e.g. Geraldton and Kalgoorlie).

6.3.1 Energy storage

It is expected that BM storage (batteries installed in premises and possibly EV batteries) will be increasingly economic. Rules and regulations need to be changed to allow the network operator to optimise use of batteries within the distribution network. Adjustment of time of use tariff differentials and possibly a battery subsidy may need to be introduced to ensure installation of the optimal amount of BM batteries. These batteries, coupled with embedded PV generation, will reduce the amount of energy required during summer peaks and may enable the deferral (possibly indefinitely) of distribution network upgrades.

6.3.2 Maintaining power quality and frequency control

Some OCGTs will need to be equipped to run in synchronous compensation mode to maintain power quality. In the first two phases, little network or utility scale energy storage is needed. However, relatively small capacities of very rapidly dispatchable power - dedicated on-grid batteries and/or bi-directional inverter connected flywheel systems – will need to be installed for frequency control.

6.3.3 Planning to achieve 91% or 100% RE

Scenario 1 (85% RE) could be achieved by the building of wind, solar and transmission as described above. However, if the decision is made to proceed with higher penetration of RE to 91% - 100% by implementing one of Scenarios 2 – 5 or a combination of these, the type of large scale storage would need to be decided on and projects planned and approved by the end of phase 2 in 2025. If either of CST MS scenarios (4 or 5) is chosen, then in phase three 1,200 MW of CST with MS storage would be installed in place of the last 2,000 MW of wind and 1,000 MW of PV shown in Appendix A9.

For three 100% Scenarios (3-5), biomass growing and bio-fuel production industries would need to be planned and large scale woody biomass crop plantings in the ground by the end of phase two in 2025 ready to supply biofuels to power stations by 2030.

6.3.4 Utilizing surplus RE energy

All RE scenarios include 15-20% surplus wind and solar generation, which is costed in the weighted average LCoE but is assumed to be wasted. There is potential for this energy to be sold cheaply for opportunistic industrial activities such as ore grinding, pumping, heat and desalination. This would
mean retailers would pay slightly lower average wholesale prices, which may be passed on to the consumer.

6.4 Phase 3 (to 2030): Retire last coal plant, install utility-scale PHS or MS storage and biomass co-fired / cogeneration plant

At this stage it is anticipated that additional storage will have been planned and approved and biomass production on farms will have commenced. The final projects to complete a 100% renewable SWIS would be implemented:

- Large-scale PHS or MS storage in addition to embedded battery storage (as applicable to the particular scenario decided collaboratively by the community, State Government and the Network Utility).

- Completion of the of the 300kV AC transmission lines to large wind farms east of Albany and / or CST plants in the Goldfields / Murchison areas.

- Existing coal-powered generation assets would all be retired. The newer OCGTs and a small amount of industrial gas co-generation would be retained and new state of the art dual fuelled OCGTs would be added.

- Completion of a bio-liquid fuel production plant (probably at Collie or Bunbury) and woodchip transport systems.

- Woody biomass production on farms feeding the solid and liquid biofuels industries, which could be scaled up to export these products. More biomass would be required if the CST/biomass route (100% scenarios 4 or 5) is chosen.

- Significant additional amounts of electrified transport (trains, buses and private electric vehicles). This will only represent a small portion of the SWIS grid energy demand, but may possibly benefit the grid by the provision of ancillary services in the form of Vehicle-to-Grid interaction.

6.5 Transition Trajectory

The transition of power capacity and electricity generation to 85 -100% wind and solar using the RE generation outlined for Scenarios 1 -3 by 2030 is illustrated in Table 17 and Table 18 (below).
Table 17. Power capacity transition (MW), Scenarios 1 – 3.

<table>
<thead>
<tr>
<th></th>
<th>2015</th>
<th>2017</th>
<th>2019</th>
<th>2021</th>
<th>2023</th>
<th>2025</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>TOTAL RE POWER CAPACITY (BM PV) (MW)</td>
<td>991</td>
<td>2,073</td>
<td>3,149</td>
<td>4,220</td>
<td>5,285</td>
<td>6,345</td>
<td>8,981</td>
</tr>
<tr>
<td>TOTAL POWER CAPACITY (including existing and new gas turbines) (MW)</td>
<td>5,903</td>
<td>6,023</td>
<td>7,166</td>
<td>7,932</td>
<td>9,063</td>
<td>10,189</td>
<td>12,557</td>
</tr>
<tr>
<td>New Gas/biofuel OCGT power capacity added</td>
<td>0</td>
<td>66</td>
<td>132</td>
<td>198</td>
<td>264</td>
<td>330</td>
<td>495</td>
</tr>
</tbody>
</table>

Table 18. Electricity generation transition (MWh), Scenarios 1 – 3.

<table>
<thead>
<tr>
<th></th>
<th>2015</th>
<th>2017</th>
<th>2019</th>
<th>2021</th>
<th>2023</th>
<th>2025</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>TOTAL RE GENERATION (including rooftop PV) (MWh)</td>
<td>2,353</td>
<td>4,696</td>
<td>7,029</td>
<td>9,353</td>
<td>11,666</td>
<td>13,971</td>
<td>19,709</td>
</tr>
<tr>
<td>ALL ELECTRICITY GENERATION (including existing and new gas turbines) (MWh)</td>
<td>18,782</td>
<td>19,380</td>
<td>20,007</td>
<td>20,616</td>
<td>21,265</td>
<td>22,035</td>
<td>23,818</td>
</tr>
</tbody>
</table>

The retirement of the Muja coal plants by 2017 will result in an increase of gas generation (including minor amounts of industrial co-generation) until the RE capacity increases sufficiently after 2017 to reduce gas energy generation. This means that capacity factors of plants will be increased as needed to meet demand for about 2 years, before declining permanently.

Although the power capacity of gas generation increases, the increase in capacity is additions to a fleet of OCGTs, which are only turned on briefly when needed to provide rapidly ramping dispatchable power to cover periods of low solar and wind energy, mostly during winter months. The amount of energy generated using gas fuel decreases from 43% in 2016 to less than 17% by 2030.

The graphs in Figure 23 and Figure 24 (below) illustrate how power and generation would change over the period 2015 – 2030 for Scenarios 1 – 3.
Figure 23. Trajectories for coal, gas and RE generation for Scenarios 1-3.

Figure 24. Trajectories for coal, gas and renewable power capacities for Scenarios 1-3.
7 Risk Analysis of Scenarios

Reliable and cost effective electricity supply is essential to Western Australia at all levels, from domestic life to business, education, health and transport. As such it is, along with housing, transport and fuel supply, the State’s most crucial infrastructure.

It is most important that policy-makers make careful consideration of the risks associated with future electricity supply scenarios. Risks to supply adequacy, continuity and reliability of electricity are not the only considerations. Electricity infrastructure can impact on the economy (cost blowouts) and environment (pollution).

The risk analysis summarised in Table 19 (below) and detailed in Attachment 4 in Appendix A2 has been conducted using a standard industry methodology used for large projects, which systematically identifies and objectively quantifies risks identified in four categories: safety, cost, environment and production (reliability). It also captures mitigation strategies and the resultant risk reduction. Colour coding enables quick comparison of the overall risk profile associated with each scenario.

While not exhaustive, the analysis covers major identified risks for each scenario (grouped on technology) and some lower risks that have attracted a higher profile in the media. Each risk assessed is considered and quantified in terms of its consequence and likelihood in terms of its use at utility scale for the SWIS.

While RE scenarios also have risks, they are less severe, as indicated by lower inherent risk ratings. They are also much more easily mitigated, as evident by the lower residual risk ratings.

7.1 Key Findings of the Risk Analysis

1. All scenarios have some risk.

2. Nuclear, followed by BAU fossil fuels (in particular coal), have significantly higher risk profiles across all categories of both inherent risks and mitigated risks.

3. The largest risks with the RE scenarios are due to the reliance on gas in the short to medium term, followed by project risk in some cases due to the relative newness of some technologies at utility scale (such as CST with MS storage, PHS and bio-liquid fuels).

4. Reliance on mitigations for risk reduction is still problematic as those mitigations may be compromised. This is a particular issue with complex technologies such as nuclear with its associated fuel production and nuclear waste disposal industries. Historically, mitigations (especially complex ones) tend to degrade over time and provide reduced risk reduction.
Table 19. Risk analysis of three RE and three fuelled electricity generation scenarios for the SWIS grid.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Safety</th>
<th>Cost</th>
<th>Environment</th>
<th>Production</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. PV-Wind with BM Storage and Gas OCGT</td>
<td>Inherent Risk</td>
<td>Inherent Risk</td>
<td>Inherent Risk</td>
<td>Inherent Risk</td>
</tr>
<tr>
<td></td>
<td>Residual Risk</td>
<td>Residual Risk</td>
<td>Residual Risk</td>
<td>Residual Risk</td>
</tr>
<tr>
<td></td>
<td>$$CO_2$$ and other GHGs released from gas combustion</td>
<td>Sudden gas supply interruption</td>
<td>$$CO_2$$ and other GHGs released from gas combustion</td>
<td>Sudden gas supply interruption</td>
</tr>
<tr>
<td>2. PV-Wind with PHS and Gas OCGT</td>
<td>Inherent Risk</td>
<td>Inherent Risk</td>
<td>Inherent Risk</td>
<td>Inherent Risk</td>
</tr>
<tr>
<td></td>
<td>Residual Risk</td>
<td>Residual Risk</td>
<td>Residual Risk</td>
<td>Residual Risk</td>
</tr>
<tr>
<td></td>
<td>$$CO_2$$ and other GHGs released from gas combustion</td>
<td>Cost blowout of PHS projects</td>
<td>Death of species due to flooding from PHS reservoirs</td>
<td>Sudden gas supply interruption</td>
</tr>
<tr>
<td>3. PV-Wind with PSH and Bio-fuel OCGT</td>
<td>Inherent Risk</td>
<td>Inherent Risk</td>
<td>Inherent Risk</td>
<td>Inherent Risk</td>
</tr>
<tr>
<td></td>
<td>Residual Risk</td>
<td>Residual Risk</td>
<td>Residual Risk</td>
<td>Residual Risk</td>
</tr>
<tr>
<td></td>
<td>$$CO_2$$ and other GHGs released from combustion</td>
<td>Cost blowout of PHS projects</td>
<td>Death of species due to flooding from PHS reservoirs</td>
<td>Commercial scale bio-fuels not a mature industry</td>
</tr>
<tr>
<td>4. PV-Wind with CST Storage and Bio-fuel OCGT</td>
<td>Inherent Risk</td>
<td>Inherent Risk</td>
<td>Inherent Risk</td>
<td>Inherent Risk</td>
</tr>
<tr>
<td></td>
<td>Residual Risk</td>
<td>Residual Risk</td>
<td>Residual Risk</td>
<td>Residual Risk</td>
</tr>
<tr>
<td></td>
<td>$$CO_2$$ and other GHGs released from combustion</td>
<td>CST Cost Blowout</td>
<td>Loss of containment of bio-fuels</td>
<td>Commercial scale bio-fuels not a mature industry</td>
</tr>
<tr>
<td>5. PV-Wind with CST Storage and Bio-fuel co-firing and OCGT</td>
<td>Inherent Risk</td>
<td>Inherent Risk</td>
<td>Inherent Risk</td>
<td>Inherent Risk</td>
</tr>
<tr>
<td></td>
<td>Residual Risk</td>
<td>Residual Risk</td>
<td>Residual Risk</td>
<td>Residual Risk</td>
</tr>
<tr>
<td></td>
<td>$$CO_2$$ and other GHGs released from combustion</td>
<td>CST Cost Blowout</td>
<td>Loss of containment of bio-fuels</td>
<td>Commercial scale bio-fuels not a mature industry</td>
</tr>
<tr>
<td>6. BAU Coal with Gas OCGT</td>
<td>Inherent Risk</td>
<td>Inherent Risk</td>
<td>Inherent Risk</td>
<td>Inherent Risk</td>
</tr>
<tr>
<td></td>
<td>Residual Risk</td>
<td>Residual Risk</td>
<td>Residual Risk</td>
<td>Residual Risk</td>
</tr>
<tr>
<td></td>
<td>$$CO_2$$ and other GHGs released from combustion</td>
<td>Sudden gas supply interruption</td>
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<td></td>
<td>Residual Risk</td>
<td>Residual Risk</td>
<td>Residual Risk</td>
<td>Residual Risk</td>
</tr>
<tr>
<td></td>
<td>Management of radioactive waste</td>
<td>Generation 4 design technology unproven</td>
<td>Management of radioactive waste</td>
<td>Generation 3 design technology limitations</td>
</tr>
</tbody>
</table>

**Inherent Risk** is the risk that an activity would pose if no controls or other mitigating factors were in place (the gross risk or risk before controls).

**Residual Risk** is the risk that remains after controls are taken into account (the net risk or risk after controls). Mitigations may reduce the consequences or likelihood or both together. Credit can only be taken for a lower residual risk while the mitigations remain in place and fully effective.
8 COSTS AND BENEFITS OF RE SCENARIOS

1. Cost of RE Electricity Cheaper than BAU - The modelling shows that electricity generated in Scenario 1 - the most economical RE scenario - would cost no more than that from new coal and gas generation (Scenario 6 - BAU).

The LCoE of Scenario 1 (85% RE) is $128/MWh (12.8c/kWh). This is marginally less than that of Scenario 6 (BAU new coal and gas generation), which is $129/MWh (12.9c/kWh).

2. Wholesale Electricity Cost increases by about 1c/kWh for both New 85% RE and New Fossil Fuelled Grid Scenarios – According to a recent study by the AEMC (2015), wholesale electricity costs comprised 40% of the total SWIS residential tariff. This translates to current wholesale electricity costs of 11.7c/kWh. Assuming wholesale costs approximate LCoE, both the 85% RE and new fossil fuelled grid (at 12.8 and 12.9 c/kWh respectively), would incur wholesale costs about 1.1 c/kWh higher than in 2015.

3. Retail Cost of Electricity increase of less than 2c/kWh for 85% RE and New Coal Scenarios – With a carbon price of $30/tCO$_2$e, the retail cost of electricity to SWIS customers will increase by about 2c/kWh regardless of whether Scenario 1 (85% RE) is implemented or the existing or renewed fossil fuelled grid is retained. The reasons for this increase in modelled costs are:

   a. Since the repealing of the carbon price in 2014, which was about $25/tCO$_2$e (equating to 1.9c/kWh), there is no price being paid for pollution. This study assumes that with modernised electricity systems, some of the externalised pollution costs of coal and gas generation will be paid through a carbon price of $30/tCO$_2$e. This raises the cost of Scenario 6 (BAU) to more than that of Scenario 1 (85% RE).

   b. There will be a small increase of 0.7 - 0.9c/kWh to pay off the cost of new transmission lines. This is likely to be partly offset by sale of the cheap surplus electricity that the modelling assumes to be wasted. The net cost of new HVAC transmission is likely to be less than 0.5c/kWh.

4. Demand Side Management (DSM) Reduces LCoE of All Scenarios – Although all scenarios presented in this study assume no DSM, it has the potential to reduce electricity cost and carbon emissions of RE scenarios by reducing the amount of OCGT generation required during wind and solar lows. If 500 MW of DSM (similar to the existing grid) could be provided at low or no cost, LCoE could be reduced by up to $2/MWh and emissions reduced by about 4,000t (Scenario 1) to 9,000t (Scenario 4) of CO$_2$/year.

5. DSM Could Be Achieved at Low Cost Using Smart Meters – Smart meters with user interface should be provided for all consumers so they can keep track of their electricity use. These would also enable some customers to voluntarily opt to have some of their appliances turned down or off by the grid operator for short periods during times of peak energy cost.
With the RE generation systems, up to 500 kW of DSM would be called on about 20 times during a year, mainly winter nights during prolonged periods of still, cloudy weather.

6. **Cost of Carbon Abatement** – RE generation scenarios for the SWIS presented in this study reduce CO$_2$ emissions by 13.4 million (Scenario 1 - 85% RE) to 14.6 million tonnes (best 100% Scenario) of CO$_2$e/year. As WA’s population is about 2.7 million (Australia 2016 Population), this equates to emissions reductions of 5.4-5.4t CO$_2$e per person.

In percentage terms, the CO$_2$ emissions for Scenario 1 (85% RE) are about 14.5% and for the 100% scenarios, 7 - 8% of the emissions for Scenario 6 (BAU).

In dollar terms, for Scenario 1 (85% RE) there is actually a cost saving of $6 per tCO2e abated. The 91% - 100% scenarios incur carbon abatement costs of $17 - $70 per tCO2e abated. The cost of the additional carbon abatement would need to be weighed against the cost of other carbon abatement methods.

7. **Protection from Future Gas and CO$_2$ Price Increases** – Scenario 6 (BAU) has generation assets affected by variable gas prices and an increasing carbon price. The RE scenarios, will provide more stable electricity prices because they use little or no gas and incur only 8 – 17% of the carbon emissions. The PB modelling shows that if the gas price were to increase by 50%, the LCoE of Scenario 6 (BAU) would rise by $21/MWh, which translates to 2c/kWh in electricity costs. Similarly, if the carbon price were to double to $60 (which is near the real cost of carbon and other pollution) the electricity price would rise by $19/MWh, which translates to an additional 2c/kWh in electricity prices. Such events are quite possible before 2030 and if both were to occur, the result would be a 4c/kWh increase in electricity prices.

Under the 85% RE scenario the same events would increase electricity prices by less than 1 c/kWh and under the 100% RE scenarios the price increase would be negligible.

8. **Economic Benefits of BM Battery Storage** - Behind-the-meter (BM) battery storage will soon be a cost effective option for both consumers with rooftop PV and those without. This will flatten the average daily demand profile, reducing the amount of expensive gas turbine generation required (as shown in Figure 3 in Section 3.4).

The modelling shows that tariff structures and a subsidy incentivising the uptake of BM batteries are effective in lowering the cost of electricity and should be given high priority by Government agencies.

9. **Reduced Network Costs and Capacity Payments** – A modernised dispersed wind and solar based electricity grid with battery storage will potentially provide the following cost savings:

   a. **Reduced network charges** - The major component of residential and commercial tariffs is Western Power’s charges for the poles and wires and transformers that comprise the network. Network costs for SWIS customers in 2015-16 totalled $14.5c/kWh, comprising transmission (1.7c) and distribution (12.8c) (AEMC 2015).
Increasing the uptake of rooftop PV by 400%, adding batteries to these systems will reduce the size and number transformers needed in urban areas. The battery systems have their own power factor and voltage controllers which collectively improve the quality of power across the network, reducing the need for dynamic tapping transformers locally. For example, a battery system in the new Perth suburb of Alkimos will provide these cost saving services to the network plus electricity cost savings to local residents by enabling them to purchase and store cheap off-peak energy.

b. **Reduced tariff adjustment payments (TAP)** – These subsidise the long connection lines for rural customers and are another significant component (about 1.6c/kWh) of electricity tariffs (Parliament of Western Australia 2016). By installing rooftop PV/battery systems and going off-grid, many rural and remote properties will have more reliable and better quality electricity supply, while eliminating thousands of expensive poles, wires and transformers which are vulnerable to fires, storms and voltage fluctuations. This will decrease the cost burden to other network users.

c. **Reduced reserve capacity payments (CP)** – The wholesale energy cost in 2015-16 was 11.7c/kWh (AEMC 2015). This includes CP of about 0.6c/kW (which pays for ancillary reserve capacity - generation kept in reserve in case of failure of one of the large coal fired generators). With hundreds of wind generators, thousands of PV installations and batteries and over thirty OCGT generators, the risk of failure of one large generator will be removed. The large coal generators currently kept running in ‘spinning reserve’ will be closed down. Ancillary reserve capacity will be provided by battery, PSH or MS storage at greatly reduced cost. For example the cost of a dedicated on-grid bi-directional inverter connected battery system to provide ancillary reserve is estimated at less than 0.2c/ kWh (Appendix 3).

10. **Externalised Costs of Fossil Fuelled Generation are partially accounted for by a Carbon Price of $30/tCO\(_2\)e** – The warming climate caused by human emissions of greenhouse gases (CO\(_2\)e) is increasingly damaging human health, food production and infrastructure. About 1/3 of CO\(_2\)e emissions are from the burning of coal, mainly for electricity generation. The cost of the damage is currently being externalized by passing it on to future generations and the public purse. The additional health costs of heavy metal and particulate pollution from coal mining and power generation are being similarly externalised.

The total externalised socio-environmental costs of coal generation have been estimated at over $60/MWh (EUR 20198 2003). Under the previous Federal Government, these were partly paid for by the carbon price of about $25/tCO\(_2\)e, which added about 1.9c/kWh to electricity prices. However, this was repealed, meaning that coal and gas generation currently pays no price for these costs. This study assumes a carbon price of $30/tCO\(_2\)e.
# APPENDICES

## A1 Glossary of Terms and Acronyms

<table>
<thead>
<tr>
<th>Term</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>AC</td>
<td>Alternating current</td>
</tr>
<tr>
<td>AEMO</td>
<td>Australian Energy Market Operator</td>
</tr>
<tr>
<td>AETA</td>
<td>Australian energy technology assessments</td>
</tr>
<tr>
<td>AWEFS</td>
<td>Australian wind energy forecasting system</td>
</tr>
<tr>
<td>BAU</td>
<td>Business as Usual</td>
</tr>
<tr>
<td>BM</td>
<td>Behind the meter</td>
</tr>
<tr>
<td>BOM</td>
<td>Bureau of Meteorology</td>
</tr>
<tr>
<td>BREE</td>
<td>Bureau of Resources and Energy Economics</td>
</tr>
<tr>
<td>CCGT</td>
<td>Combined cycle gas turbine</td>
</tr>
<tr>
<td>CCS</td>
<td>Carbon capture and storage</td>
</tr>
<tr>
<td>CF</td>
<td>Capacity factor</td>
</tr>
<tr>
<td>CO₂e</td>
<td>Carbon dioxide equivalent</td>
</tr>
<tr>
<td>CP</td>
<td>Reserve capacity payments</td>
</tr>
<tr>
<td>CST</td>
<td>Concentrated solar thermal</td>
</tr>
<tr>
<td>DC</td>
<td>Direct current</td>
</tr>
<tr>
<td>dispatchable</td>
<td>Type of generator or storage that can be turned up or down by the operator</td>
</tr>
<tr>
<td>DSM</td>
<td>Demand side management</td>
</tr>
<tr>
<td>EF</td>
<td>Emission factor</td>
</tr>
<tr>
<td>FOM</td>
<td>Fixed operating and maintenance (expenses)</td>
</tr>
<tr>
<td>GEOS-5</td>
<td>Goddard earth observing system data assimilation system Version 5</td>
</tr>
<tr>
<td>GHG</td>
<td>Greenhouse gas</td>
</tr>
<tr>
<td>GMAO</td>
<td>Global Modeling and Assimilation Office</td>
</tr>
<tr>
<td>HVAC</td>
<td>High voltage AC</td>
</tr>
<tr>
<td>IMO</td>
<td>Independent market operator</td>
</tr>
<tr>
<td>kV</td>
<td>Kilovolt</td>
</tr>
<tr>
<td>kW</td>
<td>Kilowatt</td>
</tr>
<tr>
<td>kWh</td>
<td>Kilowatt hour(s)</td>
</tr>
<tr>
<td>LC</td>
<td>Levelised cost</td>
</tr>
<tr>
<td>LCoE</td>
<td>Levelised cost of electricity</td>
</tr>
<tr>
<td>LGC</td>
<td>Large scale generation certificates</td>
</tr>
<tr>
<td>MERRA</td>
<td>Modern era retrospective-analysis for research and applications</td>
</tr>
<tr>
<td>MS</td>
<td>Molten salt</td>
</tr>
<tr>
<td>MtcCO₂e</td>
<td>Megatonnes of carbon dioxide equivalent (millions of tonnes)</td>
</tr>
<tr>
<td>MW</td>
<td>megawatt</td>
</tr>
<tr>
<td>Acronym</td>
<td>Description</td>
</tr>
<tr>
<td>---------</td>
<td>-------------</td>
</tr>
<tr>
<td>MWh</td>
<td>megawatt hour(s)</td>
</tr>
<tr>
<td>NASA</td>
<td>National Aeronautics and Space Administration</td>
</tr>
<tr>
<td>NEM</td>
<td>National Electricity Market</td>
</tr>
<tr>
<td>NREL</td>
<td>National Renewable Energy Laboratory</td>
</tr>
<tr>
<td>OCGT</td>
<td>Open cycle gas turbine</td>
</tr>
<tr>
<td>PB</td>
<td>Powerbalance</td>
</tr>
<tr>
<td>PHS</td>
<td>Pumped hydro storage</td>
</tr>
<tr>
<td>PV</td>
<td>Photovoltaic</td>
</tr>
<tr>
<td>RE</td>
<td>Renewable energy</td>
</tr>
<tr>
<td>REC</td>
<td>Renewable energy certificate</td>
</tr>
<tr>
<td>RET</td>
<td>Renewable energy target</td>
</tr>
<tr>
<td>SAM</td>
<td>System advisory model</td>
</tr>
<tr>
<td>SCADA</td>
<td>Supervisory control and data acquisition (system)</td>
</tr>
<tr>
<td>SEN</td>
<td>Sustainable Energy Now</td>
</tr>
<tr>
<td>SIREN</td>
<td>SEN integrated renewable energy networks</td>
</tr>
<tr>
<td>STC</td>
<td>small-scale technology certificate</td>
</tr>
<tr>
<td>SWIS</td>
<td>South-west interconnected system</td>
</tr>
<tr>
<td>TAP</td>
<td>Tariff adjustment payment</td>
</tr>
<tr>
<td>tCO₂e</td>
<td>Tonnes of carbon dioxide equivalent</td>
</tr>
<tr>
<td>TWh</td>
<td>Terrawatt hour(s)</td>
</tr>
<tr>
<td>VOM</td>
<td>Variable operating and maintenance (expenses)</td>
</tr>
<tr>
<td>yr</td>
<td>year</td>
</tr>
</tbody>
</table>
A2  List of Attachments

1. Powerbalance Optimized Scenarios for Renewable Energy (final 12-5-2016)
2. Powerbalance Optimized Scenarios for Nuclear, Gas (final 29-4-2016)
3. Dispatchable Power Costings (final 9-5-2016)
4. 2030 Renewable SWIS Risk Matrix 2016-04-03
5. RE Roadmap 1.6% growth, 3500 MW gas (final 28-4-2016)
6. Ramp rates (final 28-4-2016)
7. Storage required to eliminate fuelled generation (final 28-4-2016)
A3 Costing Ancillary Reserve Using On-grid Batteries

For reasons stated in Section 5.4.2, spinning reserve would not be required for RE Scenarios 1, 2 and 3 in this study. Instead, ancillary reserve power is provided by a system of dedicated on-grid bi-directional inverter connected batteries, possibly augmented by distributed BM batteries, fitted with control systems to detect falling frequency.

The current ancillary reserve requirement for the SWIS is 240 MW, which satisfies the requirement of 70% of the largest generator, to cover generator failure events. It also covers the load following reserve (LFR) requirement of 72 MW to meet fluctuations in supply and demand in real time, thus ensuring frequency stability (Jacobs 2015). It is provided by gas and coal generators operating in spinning reserve mode i.e. at low load in readiness for fast ramp ups.

The existing transmission distance from Collie is 218 km, using 330 kV AC double lines. In the RE Scenarios, the transmission distance using single 330 kV AC lines is up to 385 km, meaning that the risk of line outage is much greater and is assumed to require reserve capacity to cover such an event.

Applying the current criteria, the maximum ancillary reserve power likely to be required for Scenarios 1, 2 and 3 are:

i. Reserve of 350 MW to cover the possible loss of a major power supply transmission line (70% of the 500 MW capacity of a single 330kV line).

ii. Load following reserve of 72 MW scaled up in proportion to 2030 demand (about 90 MW).

iii. Reserve of 70 MW to cover failure of the largest generator (70% of 100 MW).

The ancillary reserve requirement considers only one contingency at a time, hence all of the above requirements would be satisfied by (i) 350 MW.

Specification and costing of the system is beyond the scope of this study and would entail in-depth studies by electrical engineers. However, an indicative estimate is outlined in Table 20 (below). It is assumed that the battery system would need to deliver the required power within seconds and for up to 10 minute periods, after which OCGTs could be deployed if required. It would be recharged as required by RE (which would be available >70% of the time) or OCGTs. Both types of generation can be brought into synchronization with grid frequency from a cold start with 5 minutes.

Assuming that a Li-ion battery system is used, 350 MW could be provided by a system with 175 MWh nominal energy capacity. (This is well within the power performance capabilities of current batteries.)

Approximate costing of a 175 MWh battery system for ancillary reserve is outlined in Table 20 (below). This cost would add less than $2 / MWh (<0.2 c/kWh) to the LCoE of Scenarios 1 – 3.
Table 20. Indicative costing for on-grid bi-directional inverter connected battery system for ancillary reserve.

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ancillary reserve power requirement</td>
<td>350 MW</td>
</tr>
<tr>
<td>Duration of power requirement</td>
<td>&lt;10 minutes</td>
</tr>
<tr>
<td>Assumed battery system capacity</td>
<td>175 MWh</td>
</tr>
<tr>
<td>Assumed battery system installed cost (AECOM 2015)</td>
<td>$1,600,000/MWh</td>
</tr>
<tr>
<td>Discount rate</td>
<td>6%</td>
</tr>
<tr>
<td>Costing period</td>
<td>10 years</td>
</tr>
<tr>
<td>Fixed operating &amp; maintenance (FOM)</td>
<td>$30,000/MWh/yr</td>
</tr>
<tr>
<td>Annualized cost</td>
<td>$247,389/MWh/yr</td>
</tr>
<tr>
<td>Total system annualized cost</td>
<td>$43,293,028/yr</td>
</tr>
<tr>
<td>Cost of battery system for supplying ancillary reserve, assuming annual grid demand of 23,500,000 MWh</td>
<td>$1.84/MWh</td>
</tr>
</tbody>
</table>
A4 SEN Interactive Renewable Energy Network Toolbox (SIREN Toolbox)

The toolbox consists of two parts, the SIREN model and Powerbalance (PB).

SIREN MODEL

SIREN is a tool to assist in modelling the potential for RE in an electricity network or geographic area. It uses technology models developed as part of System Advisor Model (SAM), a tool developed by the US National Renewable Energy Laboratory (NREL).

The tool uses external data sets to model the potential for RE generation for a geographic region. The approach is to model the data hourly for a desired year (ignoring leap days, that is, 8,760 hours). The following data sets are contained in SIREN.

Essential:

- Hourly load details for the electricity grid with a single column of electrical load data for the 8,760 hours in the year of interest.

- Hourly solar and weather details for the area of interest. This data is in formats required for input to SAM and contains entries for the 8,760 hours in the year of interest.

- A map of the area of interest - a simple JPEG or PNG image. The map covers a geographically rectangular area of the earth.

Desirable:

- Names and locations of towns.

- Names, technologies and locations of existing power stations (for example, details of facilities registered with the local electricity regulator) augmented by geographic location of the station and details on turbines for wind farms.

- A layout of the existing electrical grid showing the layout of the major power lines in the grid and an outline of the network boundary.

The simulation enables the user to build scenarios for the energy mix for their area of interest. It is based around the map of the chosen study area that includes the layout of the existing electricity network. New stations are placed on the map by the user to build new scenarios. The map initially shows the main skeleton of the existing electricity grid infrastructure and current generation stations.

To add a new station, the user right-clicks on the map at the desired location and then enters the details for the new power station. As the scenario is built up, the simulation adds additional transmission lines to connect the new generation plants to the grid. Navigating the map is by normal mouse movements to scroll, zoom, etc. and interact with it to modify the scenario. Using the
various menu options a whole scenario can be modelled or individual stations can be modelled by right-clicking on them. Multiple scenarios can be added to, saved or removed.

The strength of the simulation is in running the SAM Power Models. This will run the appropriate SAM modules for each chosen station or for all renewable stations in the current simulation. SAM calculates a list of power outputs for each hour of the year (8,760 points). The user then selects options to display desired plots (graphs) showing generation, load, generation shortfall and so forth. There is also an option to run SAM Financial Models, which displays annual energy output, capacity factor and LCoE for each station.

SAM uses meteorological and solar data to model output of various RE technologies. The NASA MERRA data is the current source used by SIREN to generate data files for input to SAM. It allows weather files to be created on a grid of 2/3 degree of longitude by 1/2 degree of latitude. This is approximately an area of 55 km x 55 km for the SWIS latitudes.

Initial correlations between generation calculated by SAM modules using NASA MERRA data and actual observations from BOM data (obtained by SEN in 2014) are strong enough to support the use of NASA MERRA-derived data for the purposes of the simulation (as shown in Figure 25, below). The average correlation was 0.77, varying from 0.70 to 0.83 for wind and 0.95 for the one utility scale PV farm on the SWIS network.

![Figure 25. Correlation between SAM generation data and actual observations from BOM data.](image)

**Background on MERRA**

The Modern Era Retrospective-analysis for Research and Applications (MERRA) is a NASA atmospheric data reanalysis for the satellite era using a major new version of the Goddard Earth Observing System Data Assimilation System Version 5 (GEOS-5). MERRA focuses on historical...
analyses of the hydrological cycle on a broad range of weather and climate time scales, and places the NASA EOS suite of observations in a climate context. Each time-averaged collection consists of a continuous sequence of data averaged over the indicated interval and time stamped with the central time of the interval. For hourly data, for example, these times are 00:30 GMT, 01:30 GMT and 02:30 GMT.

**Powerbalance (PB)**

PB is a set of programmed Excel spreadsheets that quantify, cost and optimize the various amounts of storage and fuelled balancing power technologies. Users can choose from several different scenario templates for modelling different combinations of storage and fuelled generation technologies.

The energy shortfall column from the SIREN Hourly Shortfall table is copied and pasted into the leftmost column of a PB spreadsheet. Working left to right in the spreadsheet, the user adds storage and dispatchable generated power, progressively reducing shortfalls. The last column is an option for demand side management, which may be used to reduce OCGT generation requirements. Costings and where applicable CO₂ emissions are calculated by formulae in the spreadsheet cells, linking to a Power Balance Input Table (see Costing of Technologies below).

In all cases the aim is to balance power supply with load for all 8760 hours of the year. The user inputs power, energy and storage parameters to a dashboard at the top of the table. The Excel program instantly calculates outputs as the user changes parameters. The outputs below are also shown in the dashboard:

- Total energy generation for each dispatchable energy technology used.
- Total cost of energy for each technology.
- LCoE for each technology.
- CF for each technology.
- Annual totals and percentages of stored energy, fuelled energy, RE and demand.
- Weighted average LCoE for the whole scenario. LCoE = total generation cost/ total MWh consumed.

By changing their inputs to the PB parameter cells, users can rapidly optimize LCoE, storage, or fuelled input by iteration. Usually, the aim is to minimize annual weighted average LCoE, but any other chosen output can be optimized in this way.
A5  Storage and Dispatchable Power Modelling and Network Balancing

The RE scenarios modelled in SIREN produce hourly electricity surplus/shortfalls and other data, which for each scenario are imported into PB to enable optimizing for LCoE as outlined below.

Wind and solar energy costed is the energy transmitted to the major load source:

\[
\text{Energy calculated and costed} = (\text{generated energy}) - (\text{transmission losses}).
\]

Dispatchable (balancing) power and storage are costed differently: a fixed annual cost per MW capacity installed plus variable costs (including fuel) for each MWh of energy generated.

Wind and solar generation surplus to load is still fully costed in the LCoE, even though in reality it may be curtailed or sold more cheaply.

SIREN produces a PB data Excel file for each scenario, which contain:

1. A table of power stations and subtotal of energy generated and energy transmitted for each technology. The blue shaded transmitted cells are copied into the selected PB template work sheet for the type of scenario to be modelled, then transferred into the relevant red-bordered data entry cells in the summary table part of the PB template.

2. A shortfall/surplus table with power data for each hour of the year, totalling 8760 hours. This column is copied and pasted into the first (red bordered column of the PB template). The numbers in the table represent average power for each hour and also energy for that hour.

This data is imported into PB (as illustrated in Figure 26, below).

The PB is a set of Excel spreadsheets programmed for several types of scenarios. It allocates dispatchable power to balance generation with load on the grid and enables users to rapidly balance power supply with load for every hour of a year through several manual iterations. Users can use optimization criteria, such as LCoE or carbon emissions abatement, to find the mix of complementary RE generation, storage and energy balancing technologies best suited to their requirements.
The user copies the hourly user downloads into the PB, the shortfall/surplus figures for the scenario they have constructed in SIREN and saved in a PB data file. These are pasted into the first shortfall column of the PB template spreadsheet that applies to the type of system they are simulating (e.g. CST with MS storage, battery, PHS, biomass generation).

Next, a power capacity is entered into the PB dashboard, as shown in Figure 27 (below), for each dispatchable power technology in order of dispatch. Capital intensive/high capacity factor technologies (those, such as storage or biomass, which are only economic when used frequently) are dispatched first. OCGT, which has low capital cost and high fuel cost, is entered last in order. Possible constraints such as availability of fuel resources and suitable sites need to be taken into account when estimating power capacity of each technology.

PB calculates the power generated and the cost. The user continues to iterate changes to the capacity of dispatchable power technologies until there are zero shortfalls (or an acceptable number of shortfalls to be curtailed). Then power supplied equals load for every hour of the year and the

\[
\text{Energy} = \text{Power} \times \text{Time}
\]

\[
1 \text{ MW of Power applied for } 1 \text{ hour} = 1 \text{ MWh of Energy}
\]
scenario is balanced. Further iterative adjustments enable optimization for cost or percentage RE or minimizing CO$_2$e emissions.

Users can then make further changes to the various technology capacities until the scenario is optimized for cost (weighted average LCoE) or other criteria such as fuelled generation. The PB’s fast calculation time (a few seconds) enables this optimization by iteration to be done rapidly.

![Powerbalance scenario ‘dashboard’](image)

**Figure 27.** Powerbalance scenario ‘dashboard’.

**Dispatchable power and CO$_2$ emissions costing data**

The ‘Disp. Power cost’ and ‘RE LCoE, EFs tables’ tabs are copied into each PB workbook from the master ‘Dispatchable Power Costings’ work book. The yellow costing formula and CO$_2$e cost formula cells in PB are linked to cells in these two tables as illustrated in Figure 28 (below).
Figure 28. Costing of dispatchable power and storage.
A6  Calculation of LCoE for Rooftop PV

Assumptions:

- Average cost of a typical 3kW system us $1.35/Watt (Solar Choice 2015).
- generation is 1.8MWh/kW/year.
- STCs are $40 each.
- system has a 20 year life.
- variable costs = 0.
- Cost of capital = 5% per annum over 5 years.
- Fixed Operations and Maintenance = $30/kW/year.

Average cost is $1.35/Watt implies a system cost of $4050, with deemed STCs deducted (this includes a smart meter - $250).

Eligible STCs are 3kW x 1.8MWh/kW/year x 15 years = 81 STCs.

Add cost of STCs at $40 each = 4050 + 3240. Total capex = $7290.

Apply cost reduction to 2025 (BREE, 2014) = 0.75*7290 = $5467.

Apply cost of capital 5% over 4 years payback time = $6167.

Add Fixed Operations and Maintenance $40 /year for 20 years = $6967.

Lifetime generation is 20 years x 1.8MWh/year x 3kW = 108 MWh.

Cost per MWh = 6967/108 = $64.50 (round to $65/MWh).
A7 Economics of Storage to Fill Longer-duration Consecutive Shortfalls

A question that is often asked is why not install enough storage of RE to fill all load shortfalls. PB modelling of the wind dominant Scenario 2 shows that the economic limit of storage in batteries and PHS combined is about 50,000 MWh.

A RE scenario that already has some overnight storage – 5,000 MW of wind, 2,000 MW of PV and 1,200 MW of CST with 7,200 MWh of MS storage – was modelled using PB. The cheapest form of storage – PHS, with an assumed efficiency of 70% – was added to this scenario until generation from storage replaced all OCGT generation. The results of increasing storage to cover all shortfalls that would have occurred (assuming 2014 weather data and 2030 demand) are shown in Table 21 (below) and are summarised as follows:

- Nearly all of the surplus RE generation was used (i.e. passed through storage).
- However, about 4.3 million MWh of PHS storage was required to cover all shortfalls, most of which would only be used several times per year.
- The resulting LCoE was $545 per MWh.

Conclusion: The LCoE of this scenario using all storage and no OCGT is about 3.4 times that of Scenario 4 (the most economical 100% RE scenario in this study), which has the same amount of wind and PV but uses bio-oil fired OCGTs instead of this large amount of storage.

This simulation demonstrates that using large amounts of even the cheapest form of storage instead of OCGTs is uneconomic. Some form of fuelled generation will probably always be needed to balance longer-duration consecutive shortfalls on RE grids.

Table 21. Powerbalance (PB) modelling output: Scenario W5,000 PV2,000 CST1,200 MS, with additional PHS storage to fill all shortfalls.

<table>
<thead>
<tr>
<th>Storage costs to fill longer duration shortfalls</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Percentage of biomass fuelled</td>
<td>0%</td>
</tr>
<tr>
<td>Percentage of OCGT gas fuelled</td>
<td>0%</td>
</tr>
<tr>
<td>Percentage of RE storage</td>
<td>18%</td>
</tr>
<tr>
<td>Surplus generation</td>
<td>1%</td>
</tr>
<tr>
<td>Total energy consumption</td>
<td>23,583,515 MWh</td>
</tr>
<tr>
<td>Average LCOE</td>
<td>$553/MWh</td>
</tr>
<tr>
<td>Total energy cost</td>
<td>$13,030,588,692</td>
</tr>
</tbody>
</table>
A8  Ramp Rates of Coal, Nuclear and CCGT Generation

Figure 29 (below) shows ramp rates for coal, new nuclear and new combined cycle gas turbine (CCGT) generation.

Figure 29. Ramp rates for coal, new nuclear and new combined cycle gas turbine (CCGT) generation. Source: Fuchs and Timpf (2011).
## A9  Phase-out of Existing Fossil Fuelled Plants

### Table 22. Proposed technology asset capacity retirement schedule.

<table>
<thead>
<tr>
<th>Power Capacity (MW, ref. IMO)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
</tr>
<tr>
<td>DEMAND</td>
</tr>
</tbody>
</table>

#### Technology/Asset Retirement Schedule:

**FOSSIL-FUELED GENERATORS**

<table>
<thead>
<tr>
<th>Owner</th>
<th>Yr built</th>
<th>Fuel</th>
<th>Est Eff of Gas Plant</th>
<th>Retire age, yrs</th>
<th>Retire</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alinta AB (G1, G2, G3, G4)</td>
<td>2016</td>
<td>Coal</td>
<td></td>
<td>22</td>
<td></td>
</tr>
<tr>
<td>Pinjar Small</td>
<td>2018</td>
<td>Gas</td>
<td>25%</td>
<td>211</td>
<td></td>
</tr>
<tr>
<td>Alinta (G5, G6)</td>
<td>2011</td>
<td>Coal</td>
<td></td>
<td>36</td>
<td></td>
</tr>
<tr>
<td>W. Kalgoorie (GT2, GT3)</td>
<td>2013</td>
<td>Diesel</td>
<td>24%</td>
<td>53</td>
<td></td>
</tr>
<tr>
<td>Mool D G7, G8</td>
<td>2019</td>
<td>Coal</td>
<td></td>
<td>422</td>
<td></td>
</tr>
<tr>
<td>RCF_PV Karrama Cogeneration Plant - Perth Power Partnership</td>
<td>2021</td>
<td>Gas, Cogen</td>
<td>33%</td>
<td>2025</td>
<td>80</td>
</tr>
<tr>
<td>Alinta Wagerup</td>
<td>1994</td>
<td>Gas</td>
<td>33%</td>
<td>2023</td>
<td>80</td>
</tr>
<tr>
<td>Kuringa</td>
<td>1990</td>
<td>Gas</td>
<td>25%</td>
<td>2024</td>
<td>80</td>
</tr>
<tr>
<td>Karrana GT</td>
<td>2010</td>
<td>Coal</td>
<td>30%</td>
<td>2014</td>
<td>105</td>
</tr>
<tr>
<td>Kimba Fields</td>
<td>1996</td>
<td>Gas</td>
<td>30%</td>
<td>2024</td>
<td>80</td>
</tr>
<tr>
<td>Pinjar Large</td>
<td>1993</td>
<td>Gas</td>
<td>30%</td>
<td>2024</td>
<td>105</td>
</tr>
<tr>
<td>Kemerton 11</td>
<td>2005</td>
<td>Gas</td>
<td>33%</td>
<td>2015</td>
<td>146</td>
</tr>
<tr>
<td>Kemerton 12</td>
<td>2005</td>
<td>Gas</td>
<td>33%</td>
<td>2015</td>
<td>146</td>
</tr>
<tr>
<td>Lalla</td>
<td>1990</td>
<td>Coal</td>
<td>30%</td>
<td>2025</td>
<td>80</td>
</tr>
<tr>
<td>Nearra</td>
<td>2008</td>
<td>Gas</td>
<td>35%</td>
<td>2027</td>
<td>191</td>
</tr>
<tr>
<td>Fox Bruce**</td>
<td>2003</td>
<td>Gas, Cogen</td>
<td>55%</td>
<td>2024</td>
<td>25</td>
</tr>
<tr>
<td>NewGen Karrama</td>
<td>2008</td>
<td>Gas, C cog</td>
<td>55%</td>
<td>2024</td>
<td>25</td>
</tr>
<tr>
<td>NewGen Karrama</td>
<td>2009</td>
<td>Coal</td>
<td>30%</td>
<td>2019</td>
<td>105</td>
</tr>
<tr>
<td>Merredin Energy*</td>
<td>2013</td>
<td>Diesel</td>
<td>30%</td>
<td>2030</td>
<td>18</td>
</tr>
<tr>
<td>Fefa diesel</td>
<td>2013</td>
<td>Diesel</td>
<td>38%</td>
<td>2030</td>
<td>17</td>
</tr>
<tr>
<td>Alinta Wagerup 1</td>
<td>2007</td>
<td>Gas</td>
<td>40%</td>
<td>2030</td>
<td>18</td>
</tr>
<tr>
<td>New Gas/Biofuel OCOT (%)</td>
<td>2003</td>
<td>Gas</td>
<td>40%</td>
<td>2030</td>
<td>18</td>
</tr>
<tr>
<td>Southern Cross Energy</td>
<td>1996</td>
<td>Gas, Cogen</td>
<td>35%</td>
<td>2030</td>
<td>34</td>
</tr>
<tr>
<td>Alerta Pinjarra 1</td>
<td>2006</td>
<td>Gas, Cogen</td>
<td>20%</td>
<td>2030</td>
<td>129</td>
</tr>
<tr>
<td>Alerta Pinjarra 2</td>
<td>2006</td>
<td>Gas, Cogen</td>
<td>20%</td>
<td>2030</td>
<td>129</td>
</tr>
<tr>
<td>Alerta Wagerup 1</td>
<td>2007</td>
<td>Gas, Cogen</td>
<td>20%</td>
<td>2030</td>
<td>129</td>
</tr>
<tr>
<td>Alerta Wagerup 2</td>
<td>2007</td>
<td>Gas, Cogen</td>
<td>20%</td>
<td>2030</td>
<td>129</td>
</tr>
</tbody>
</table>

#### Coal Subtotal

1778 751 751 434 434 434 0

#### Gas, Diesel or Biofuel OCOT, CCGT, IC Subtotal

2459 2525 2591 2604 2679 2736 2901

#### Gas Cogen (Future use may transition to OCOT)

675 675 675 675 675 675 675

#### FOSSIL TOTAL

4012 3951 4011 3711 3779 3849 3976

#### RENEWABLE GENERATORS

<table>
<thead>
<tr>
<th>Owner</th>
<th>Yr built</th>
<th>Fuel</th>
<th>Est Eff of Gas Plant</th>
<th>Retire age, yrs</th>
<th>Retire</th>
</tr>
</thead>
<tbody>
<tr>
<td>Walkaway</td>
<td>2006</td>
<td>wind</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Alinta</td>
<td>2005</td>
<td>wind</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Collie</td>
<td>2011</td>
<td>wind</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Eneva Dowas</td>
<td>2006</td>
<td>wind</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gumina</td>
<td>2012</td>
<td>wind</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mumbida</td>
<td>2013</td>
<td>wind</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Solar Subtotal</td>
<td>481</td>
<td>wind</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

#### Wind Subtotal

481 1211 1941 2671 3461 4131 5956

#### Solar PV (Roof-top - res & Comm)**

507 862 862 1067 1250 1430 1670

#### Solar PV (Utility)

1 170 327 482 634 784 1151

#### Solar Thermal (Storage)

0 0 0 0 0 0 0

#### TOTAL ALL GENERATION

5963 6052 7166 7932 9063 10189 12557

#### NETT (Tot Gen - Demand)

2129 2189 3269 3973 5041 6102 8304

---

**CLEAN ELECTRICITY WESTERN AUSTRALIA 2030**

**SUSTAINABLE ENERGY NOW**
### Table 23. Proposed technology asset retirement schedule by generation and capacity factor.

<table>
<thead>
<tr>
<th>Technology/Asset Retirement Sc</th>
<th>Energy (GWh)</th>
<th>Capacity Factor (ref. IMO &amp; SCADA data) modified to balance demand</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fossil-Fuelled Generators</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas, Diesel or Biofuel OCOT, CCOT, IC Subtot</td>
<td>5468</td>
<td>6782</td>
</tr>
<tr>
<td>Gas Cogen (Future use may transition to OCOT)</td>
<td>2581</td>
<td>2581</td>
</tr>
<tr>
<td>FOSSIL TOTAL</td>
<td>16429</td>
<td>14627</td>
</tr>
<tr>
<td>RENEWABLE GENERATORS</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mullaway</td>
<td>312</td>
<td>312</td>
</tr>
<tr>
<td>Albany</td>
<td>55</td>
<td>55</td>
</tr>
<tr>
<td>Collie</td>
<td>650</td>
<td>650</td>
</tr>
<tr>
<td>Alinta Pinjarra 1</td>
<td>1057</td>
<td>1057</td>
</tr>
<tr>
<td>Alinta Pinjarra 2</td>
<td>1009</td>
<td>1009</td>
</tr>
<tr>
<td>Alinta Wagerup 1</td>
<td>79</td>
<td>79</td>
</tr>
<tr>
<td>Alinta Wagerup 2</td>
<td>79</td>
<td>79</td>
</tr>
<tr>
<td>Coal Subtot</td>
<td>5180</td>
<td>5263</td>
</tr>
<tr>
<td>Wind - new (for Scenarios 1-3)</td>
<td>0</td>
<td>1173</td>
</tr>
</tbody>
</table>

**Notes:**
- Relatively new diesel generators can run on biofuel.
- High-efficiency gas turbines: Keep as central generation and run on biofuels (gas or liquid).
- Efficient Combined Cycle gas turbines worth keeping and run on biofuels.
A10  Carbon Capture and Storage (CCS)

CCS is a set of technologies designed to reduce carbon dioxide (CO$_2$) emissions from large-point sources into the atmosphere – in particular coal-fired power plants - to mitigate greenhouse gas emissions. CCS technology involves capturing CO$_2$ and then storing the carbon in an underground reservoir instead of allowing it to be released into the atmosphere.

An integrated CCS system would include four main steps:

- Capturing and separating CO$_2$ at the plant.
- Compressing and transporting the captured CO$_2$ to the sequestration site.
- Sequestering CO$_2$ in suitable reservoirs.
- Ongoing monitoring and maintenance of the reservoir to detect and address leaks.

Although electricity-generating plants are the most likely initial candidates for CCS, this technology has not yet been used in stand-alone applications for power plants on a commercial scale.

There are several different means of storing CO$_2$. The only one suitable for the amounts of CO$_2$ emitted from power stations is geologic carbon storage, which is the injection of captured CO$_2$ into underground, naturally occurring geologic reservoirs that will trap the gas to prevent it from re-entering the atmosphere.

CCS is not considered a viable solution in WA’s power generation context for several reasons.

- Although CCS has been applied in a number of gas and oil extraction sites, notably at the Gorgon Liquified Natural Gas development at Barrow Island in WA, it has never been integrated into a stand-alone coal power plant on a commercial scale.

- Suitable reservoir-specific qualities like porosity, permeability, and overlying sealing strata are conditions that must be considered before a development may be approved.

- The required storage sites, which could be depleted oil and gas reservoirs, un-mineable coal seams or deep saline aquifers, are not normally found in close proximity to power generation facilities. Exploration of possible sites south of Perth has met with resistance from landholders, due to risk of contamination of overlying potable water aquifers.

- The cost of pulverised coal supercritical plant with CCS based on bituminous coal (SWIS scale) is estimated at $154/ MWh (AETA, 2014) which, when OCGT gas balancing power is added, would be higher cost than the RE Scenarios 3 and 4.
A11 Nuclear Power using Small Modular Reactors (SMR)

Nuclear energy represents only 11% of the electricity produced worldwide. A quarter of Europe’s electricity production is nuclear and in France it is 75%, to be reduced to 50% by 2025 (World Nuclear Association, 2016). Nuclear power is generated using uranium, a mineral of which one of the isotopes, U-234, is unstable. The nucleus breaks down, resulting in the emission of heat and radiation followed by a chain reaction. This is called nuclear fission and this process liberates a large amount of energy, but the process also releases various types of radiation and radioactive materials, some of which necessitates substantial containment to prevent damage to human health.

Advantages

- Very low greenhouse gas emissions. Practically no carbon emissions from operation but embodied emissions from plant construction and mining and enrichment of uranium are significant.

- High energy density in terms of physical plant size compared to hydro or wind energy.

- Australia has large reserves of uranium fuel.

- Continuous generation of power.

- Latest generation of reactors can ramp well (from 50% to 100% power; ramp rate +/- 63 MW/min) (Fuchs and Timpf 2011), but not sufficiently to replace gas turbines for fast ramping.

- Relatively cheap to operate.

Disadvantages

- Nuclear weapons proliferation issues (plutonium in waste can be used for atomic bombs).

- Major initial capital investment.

- High decommissioning costs.

- Long approval and build times.

- Radioactive waste disposal issues have not been resolved.

- Risk of serious accidents. For example: reactor melt-downs at Chernobyl (1986) and Fukushima (2010) continue to cause illness and cancer deaths through radioactive particulate contamination. Site clean-up has cost over $100 billion and radioactivity has rendered them uninhabitable for many decades.
• Community resistance to siting of reactors in their locality and difficulty in obtaining public acceptance and government approvals are likely to be prohibitive barriers to new reactors.

• Uranium is not a renewable fuel and reactors using an alternative fuel – thorium (also not renewable) - have not yet been commercialised.

• Sovereign risk due to limited insurance options.

• As for all base load technologies, nuclear still requires gas or bio-fuel balancing power for fast ramping.

• Nuclear is not suitable for providing balancing power for RE dominant grids.

It is unlikely that the high cost of electricity from nuclear power and the high risks will be accepted by the community. As a consequence, nuclear plants are unlikely to be considered a serious contender for a clean energy scenario in WA.
A12 Nuclear and Gas Scenarios Modelled for Comparison

Both the nuclear and gas scenarios are essentially the same as Scenario 6 (BAU) in the main study, with the coal generation replaced by nuclear or gas. The small amounts of wind and solar are as for Scenario 6 (BAU). As for Scenario 6 (BAU), the large generators are assumed to be 500 MW and are modelled as coming on and off in steps of 50% of maximum power capacity.

Nuclear modelling assumptions: Total nuclear capacity is 3000 MW, supplied by 6* 500 MW SMRs, providing enough reserve to cover a major generator failure event. Plant capacity factor is 83% and thermal efficiency 34% (as assumed in BREE, 2014 AETA Model). There is 1800 MW of gas OCGT capacity, enough to cover the largest shortfalls.

Gas modelling assumptions: The large gas power generators are CCGTs with a plant capacity factor of 83% and thermal efficiency of over 60% (as in BREE, 2014 AETA Model Assumptions). Total CCGT capacity is 3000 MW, supplied by 6* 500 MW CCGT power stations, providing enough reserve to cover a major generator failure event. There is 1800 MW of gas OCGT capacity, enough to cover the largest shortfalls.

Results of modelling

The modelling results are presented in Table 24 (below). The low emissions nuclear scenario with bio-oil fuelled gas turbines has an LCoE of $185/MWh, which is $26/MWh higher cost than Scenario 3 (100% RE: Wind, PV, battery, PHS and bio-oil OCGT). Although CO₂ emissions are 2.8% lower when compared to Scenario 6 (BAU), the cost of emissions reduction is $48/t CO₂e more than the RE scenario.

The predominantly gas scenario was low cost – LCoE $125/MWh – which is $3/MWh less than Scenario 1 (85% RE). However, the CO₂ emissions are still 73% of Scenario 6 (BAU), with 9.8 million tCO₂e being emitted each year, which is 7.5 million tonnes more than for 85% RE.
Table 24. Generating capacity for Nuclear and Gas scenarios, compared to existing.

<table>
<thead>
<tr>
<th>Technology</th>
<th>Installed capacity in 2016 (MW)</th>
<th>Nuclear scenario</th>
<th>Gas scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Assumed capacity in 2030 demand with 500 MW in reserve</td>
<td>Capacity factor</td>
<td>Assumed capacity in 2030 demand with 500 MW in reserve</td>
</tr>
<tr>
<td>Coal</td>
<td>1,778</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Gas OCGT</td>
<td>2,400</td>
<td>0.1</td>
<td>1,800</td>
</tr>
<tr>
<td>Gas CCGT</td>
<td>n/a</td>
<td>0</td>
<td>3,000</td>
</tr>
<tr>
<td>Gas OCGT,CCGT, Diesel or Biofuel (non-Cogen)</td>
<td>2,459</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>Gas Cogen</td>
<td>675</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>Nuclear</td>
<td>n/a</td>
<td>2,425</td>
<td>0</td>
</tr>
<tr>
<td>Wind</td>
<td>481</td>
<td>481</td>
<td>481</td>
</tr>
<tr>
<td>Solar PV</td>
<td>510</td>
<td>1,000</td>
<td>1,000</td>
</tr>
<tr>
<td>TOTAL Installed Capacity</td>
<td>5,903</td>
<td>6,306</td>
<td>6,281</td>
</tr>
</tbody>
</table>

Table 25. Comparison of Gas, Nuclear and RE scenario costs and carbon emissions.

<table>
<thead>
<tr>
<th>Gas: W0.48PVrt1.0-Gas CCGT3.0 OCGT1.8</th>
<th>Nuclear: W0.48PVrt1.0-Nuclear3000-OCGTbio-oil1800</th>
<th>Nuclear: W0.48PVrt1.0-Nuclear3.0 Gas OCGT1.8</th>
<th>100% RE (Scenario 3): W6PV3-battery-PHS - bio-oil OCGT</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average LCOE ($/MWh)</td>
<td>$125</td>
<td>$185</td>
<td>$171</td>
</tr>
<tr>
<td>CO₂ Emissions: % of BAU coal/gas</td>
<td>73.3%</td>
<td>5.5%</td>
<td>8.1%</td>
</tr>
<tr>
<td>Total CO₂ emissions (Kt)</td>
<td>9,815</td>
<td>737</td>
<td>1,090</td>
</tr>
<tr>
<td>Cost of CO₂ reduction from BAU ($/tCO₂)</td>
<td>-$30</td>
<td>$105</td>
<td>$80</td>
</tr>
<tr>
<td>% surplus generation</td>
<td>0.0%</td>
<td>0.0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Total annual energy cost incl. carbon price ($M)</td>
<td>$2,941</td>
<td>$4,374</td>
<td>$4,026</td>
</tr>
<tr>
<td>Cost of new transmission ($/MWh)</td>
<td>$1</td>
<td>$1</td>
<td>$1</td>
</tr>
</tbody>
</table>
A13 Technology CAPEX Break-down by Scenario

Table 26 shows a summary of capital expenditures for the electricity generation Scenarios 1-6 presented in this study. Capex for wind, solar PV, solar CST, OCGT, CCGT and coal are derived from BREE (2013). Capex for biomass and storage technologies are from Attachment 3 in Appendix A2 of the study. Table 27 shows the Capex breakdown for the nuclear and gas only scenarios.

Table 26. CAPEX summary of Scenarios 1 - 6.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>TOTAL grid generation, storage and transmission CAPEX ($billion)</th>
<th>Power Generation Capacity Capex per MW installed ($AU)</th>
<th>Additional storage, capex per MWh installed ($AU)</th>
<th>Behind meter storage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capex $/MW</td>
<td></td>
<td>Wind</td>
<td>Solar PV (non tracking)</td>
<td>Solar CST (with 6 hours MS storage)</td>
</tr>
<tr>
<td>1 85% RE: W-PV-battery-PHS-gas OCGT</td>
<td>$1,727,156</td>
<td>$1,623,085</td>
<td>$4,462,837</td>
<td>$773,688</td>
</tr>
<tr>
<td>Cost ($billion)</td>
<td>$20.1</td>
<td>$10.4</td>
<td>$4.9</td>
<td>$2.7</td>
</tr>
<tr>
<td>2 91% RE: W-PV-battery-PHS-gas OCGT</td>
<td>$26.3</td>
<td>$50.4</td>
<td>$4.9</td>
<td>$2.7</td>
</tr>
<tr>
<td>Cost ($billion)</td>
<td>$26.3</td>
<td>$50.4</td>
<td>$4.9</td>
<td>$2.7</td>
</tr>
<tr>
<td>3 100% RE: W-PV-battery-PHS-bio-oil OCGT</td>
<td>$25.9</td>
<td>$8.6</td>
<td>$3.2</td>
<td>$5.4</td>
</tr>
<tr>
<td>Cost ($billion)</td>
<td>$25.9</td>
<td>$8.6</td>
<td>$3.2</td>
<td>$5.4</td>
</tr>
<tr>
<td>4 100% RE: W-PV-CSTMS-biom co-fine-bio-oil OCGT</td>
<td>$25.6</td>
<td>$8.6</td>
<td>$3.2</td>
<td>$5.4</td>
</tr>
<tr>
<td>Cost ($billion)</td>
<td>$25.6</td>
<td>$8.6</td>
<td>$3.2</td>
<td>$5.4</td>
</tr>
<tr>
<td>6 BAU: Coal - gas</td>
<td>$11.0</td>
<td>$0.8</td>
<td>$1.6</td>
<td>$0.0</td>
</tr>
<tr>
<td>Cost ($billion)</td>
<td>$11.0</td>
<td>$0.8</td>
<td>$1.6</td>
<td>$0.0</td>
</tr>
</tbody>
</table>
### Table 27. CAPEX summary of nuclear and gas only scenarios.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>$/MWh</th>
<th>TOTAL MW</th>
<th>Wind</th>
<th>Solar PV</th>
<th>Solar CST</th>
<th>OCGT</th>
<th>CCGT</th>
<th>Nuclear SMR steam thermal</th>
</tr>
</thead>
<tbody>
<tr>
<td>A1</td>
<td>$125</td>
<td>6,280</td>
<td>480</td>
<td>1,000</td>
<td>0</td>
<td>1,800</td>
<td>3,000</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>$7.4</td>
<td></td>
<td>$0.8</td>
<td>$1.6</td>
<td>$0.0</td>
<td>$1.4</td>
<td>$3.6</td>
<td>$0.0</td>
</tr>
<tr>
<td>A2</td>
<td>$185.5</td>
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A14 References


AEMO. 2016. Aemo Awefs. AEMO. Accessed 04/04/2016,  


