**Curtin Graduate School of Business**
**Department of Mineral and Energy Economics**

# A Policy and Economic Comparative Study of Carbon Capture & Storage (CCS) and Renewable Energy Technologies in Australia within a Carbon-Constrained World

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**This thesis is presented for the Degree of**
**Doctor of Philosophy**
**of**
**Curtin University**

**December 2015**

# DECLARATION

To the best of my knowledge and belief this thesis contains no material previously published by any other person except where due acknowledgement has been made.

This thesis contains no material which has been accepted for the award of any other degree or diploma in any university.

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# ABSTRACT

This thesis has assessed and compared potential contributions of the renewable energy technologies (RETs) and the carbon capture and storage (CCS) technologies in reducing carbon emissions and meeting energy demand growth in the Australian power system consistent with Australian Governmental current and potential climate policies, at the least cost to society by 2049-50.

This investigation has been conducted in two largest Australian electricity markets: the National Electricity Market (NEM) and the Wholesale Electricity Market (WEM). The scenario analysis and power system optimisation modelling have been applied to explore the penetration paths of the RETs and CCS technologies in the NEM's power system and the WEM's power system under different carbon emissions reduction constraints and technological assumptions.

Three sets of carbon emissions reduction targets derived from current and potential Australian Government climate policies have been implemented as the constraints for the power system expansion simulation in the NEM and the WEM respectively. Under the 5% Carbon Emissions Reduction Target, the NEM will need to cut its carbon emissions by 5% by 2019-20 and by 80% by 2049-50 based on its 2000 levels; the WEM will be required to reduce its carbon emissions by 5% by 2019-20 and by 80% by 2049-50 based on its 2007-08 levels.

With the 25% Carbon Emissions Reduction Target, the NEM will need to cut carbon emissions by 25% by 2019-20 and by 80% by 2049-50 based on 2000 levels; the WEM will need to cut carbon emissions by 25% by 2019-20 and by 80% by 2049-50 based on 2007-08 levels. With the 5%-26%-80% Carbon Emissions Reduction Target, the NEM will reduce its carbon emissions by 5% based on 2000 levels by 2019-20, by 26% based on 2005 levels by 2029-30 and by 80% based on 2000 levels by 2049-50; the WEM will reduce its carbon emissions by 5% by 2019-20, by 26% by 2029-30 and by 80% by 2049-50 based on 2007-08 levels.

Based on established carbon emissions reduction targets, ten scenarios categorised in four groups have been designed to examine the potential roles of the RETs and CCS technologies in the long-term power system expansion of the NEM and the WEM

respectively. The first group is represented by the BAU scenario. The second group is comprised of 5% Reduction Scenario, 25% Reduction Scenario and 5%-26%_2030 Reduction Scenario. The 5%-26%_2030 Reduction Scenario is also referred as the Current Government Policy (CGP) Scenario. The third group contains three scenarios, including 5%-RETs Only Scenario, 25%-RETs Only Scenario and 5%-26%_2030-RETs Only Scenario. The fourth group of scenarios include 5%-CCS Only Scenario, 25%-CCS Only Scenario and 5%-26%_2030-CCS Only Scenario.

The power system optimisation program: the PLEXOS has been used as the modelling tool to simulate power system expansion in the NEM and the WEM. It was applied to find the optimal combination of new generation builds and retirements in the planning period. This optimal combination aimed at minimising the net present value of the total costs of the electric power system expansion over the period of 2012-13 to 2049-50 for the NEM and over the period of 2013-14 to 2049-50 for the WEM under the scenarios designed.

The modelling results revealed that if the Australian Government does not enforce any major carbon emissions mitigation policies in the NEM and the WEM beyond 2019-20, their electricity generation will increase its reliance on conventional fossil fuel technologies and carbon emissions from electricity generation will rise continuously and significantly from 2020-21 to 2049-50.

At the same time, the results suggested that currently the RETs and CCS technologies are not as competitive as the conventional fossil fuel technologies to enter the NEM and the WEM. Therefore, certain carbon reduction targets or climate change policies will be required in order to advance the deployment of the low-carbon emissions energy technologies in the NEM and the WEM in a carbon-constrained future.

In general, the 5%-26%_2030 Reduction (CGP) Scenario resulted in the capacity expansion pathway with the lowest generator total cost and the carbon avoiding cost in the NEM for achieving the 80% reduction of carbon emissions below 2000 emissions levels by 2049-50. It was also the least cost pathway to expand the WEM power system to attain the 80% reduction of carbon emissions below 2007-08 emissions levels by 2049-50.

Furthermore, the modelling results showed that if the NEM and the WEM would implement more ambitious carbon emissions reduction target than the targets investigated in this research, more investments will be required to increase the share of the LCETs generation in two markets.

When the market was subject to certain carbon emissions reduction targets, the optimal strategy for the NEM and the WEM to expand their electric power systems will be to deploy both the RETs and CCS technologies after 2020-21. It indicates that the government should promote the development of the RETs and CCS technologies at the same time with similar weights, instead of facilitating the development of either the RETs or the CCS technologies alone. The faster the costs of the RETs and CCS technologies are reduced, the earlier they can enter the NEM and the WEM, and more carbon emissions could be abated in a more cost effective way.

# DEDICATION

To my dearest husband Martijn Leonard Woltering and my parents, who love me, company me, support me and inspire me endlessly.

To our dearest son Leonard Liu Woltering, who makes our lives bright, meaningful and full of hope.

May peace, generosity and equality prevail on the Earth.

# ACKNOWLEDGEMENTS

I would like to express my sincere and immense gratitude to my supervisor Professor Daniel J. Packey for his continuous support of my Ph.D. study and related research, for his patience, motivation, and immense knowledge. His great guidance helped me in all the time of research and writing of this thesis.

I would also like to thank my co-supervisor Professor Ronald D. Ripple, who provided me with this great opportunity of Ph.D. study, for his insightful comments and encouragement supporting me through my research journey

Without precious support from Professor Daniel J. Packey and Professor Ronald D. Ripple, it would not be possible for me to conduct this Ph.D. research.

Here, I take this opportunity to sincerely thank the Energy Exemplar Company for providing me with the Academic Licence of the PLEXOS Model for my Ph.D. research free of the charge and offered great resources and support to my learning and application of the model.

# LIST OF ACRONYMS

| | |
|---|---|
| 2DS | 2°C Scenario |
| ABARE | Australian Bureau of Agricultural and Resource |
| ACT | Australian Capital Territory |
| AEMC | Australian Energy Market Commission |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| ARENA | Australian Renewable Energy Agency |
| BAU | Business as Usual |
| BNEF | Bloomberg New Energy Finance |
| BREE | Bureau of Resources and Energy Economics |
| CCA | Climate Change Authority |
| CCGT | Combined Cycle Gas Turbine |
| CCS | Carbon Capture and Storage Technologies |
| CEC | Clean Energy Council |
| CEFC | Clean Energy Finance Corporation |
| CFI | Carbon Farming Initiative |
| CGE | Computational General Equilibrium |
| CGP | Current Government Policy |
| CLASP | Collaborative Labelling and Appliance Standards Program |
| CPM | Carbon Pricing Mechanism |
| CSIRO | Commonwealth Scientific and Industrial Research Organisation |
| DKIS | Darwin-Katherine Interconnected System |
| DNI | Direct Normal Irradiance |
| DRET | Department Of Resources, Energy and Tourism |

| | |
|---|---|
| EDO | Electricity Demand Outlook |
| EDO | Electricity Demand Outlook |
| ERA | Economic Regulation Authority |
| ERF | Emission Reduction Fund |
| ESO | Electricity Statement of Opportunity |
| FO&M | Fixed Operation and Maintenance |
| GCCSI | Global CCS Institute |
| GHG | Greenhouse Gas |
| GHI | Global Horizontal Irradiance |
| GSO | Gas Statement of Opportunities |
| GSP | Gross State Product |
| GTEM | Global Trade and Environment Model |
| GW | Gigawatts |
| I/O | Input-Output |
| IAEA | International Atomic Energy Agency |
| IEA | International Energy Agency |
| IES | Intelligent Energy Systems |
| IGCC | Integrated Gasification Combined Cycle |
| IIASA | International Institute for Applied Systems Analysis |
| IMO | Independent Market Operator |
| INDCs | Intended Nationally Determined Contributions |
| IPCC | Intergovernmental Panel on Climate Change |
| KKT | Karush-Kuhn-Tucker |
| LCETs | Low-Carbon Emissions Energy Technologies |
| LCOE | Levelised Cost of Electricity |

| | |
|---|---|
| LDC | Load Duration Curve |
| LNG | Liquefied National Gas |
| LOLP | Loss of Load Probability |
| LRET | Large-Scale Renewable Energy Target |
| LRMC | Long-Run Marginal Cost |
| LT | Long-Term |
| MARKAL | MARkal ALlocation Model |
| MCD | Maximum Capacity Demand |
| MCD | Maximum Capacity Demand |
| MCRM | Minimum Capacity Reserve Margin |
| MESSAGE | Model for Energy Supply Strategy Alternatives and Their General Environmental Impact |
| MILP | Mixed-Integer Linear Program |
| MLFs | Marginal Loss Factors |
| MMA | Mclennan Magasanik Associates |
| MMRF | Multi-Regional Forecasting |
| MPC | Market Price Cap |
| MRET | Mandatory Renewable Energy Target |
| MRL | Minimum Reserve Level |
| MT | Mid-Term |
| MWEP | Mid West Energy Project |
| MWh | Megawatts Hour |
| MVA | Mega Volt Amp |
| NEM | National Electricity Market |
| NETL | National Energy Technology Laboratory |

| | |
|---|---|
| NPV | Net Present Value |
| NSW | New South Wales |
| NT | Northern Territory |
| NTNDP | National Transmission Network Development Plan |
| OCGT | Open Cycle Gas Turbine |
| PAMS | Policy Analysis Modelling System |
| PASA | Projected Assessment of System Adequacy |
| PC | Pulverized Coal |
| POE | Probability of Exceedance |
| PV | Solar Photovoltaic |
| QLD | Queensland |
| R&D | Research and Development |
| RCR | Reserve Capacity Requirements |
| RETs | Renewable Energy Technologies |
| RRNs | Regional Reference Nodes |
| SA | South Australia |
| SKM | Sinclair Knight Merz |
| SRES | Small-Scale Renewable Energy Scheme |
| SRMC | Short-Run Marginal Cost |
| ST | Short-Term |
| SWIS | South-West Interconnected System |
| TAS | Tasmania |
| TNPFS | Transmission Network Power Flow Studies |
| TSMSS | Time-Sequential Market Simulation Studies |
| TWh | Terawatt Hours |

| | |
|---|---|
| UNFCCC | United Nations Framework Convention on Climate Change |
| UNSW | University Of New South Wales |
| USE | Unserved Energy |
| VIC | Victoria |
| VO&M | Variable Operation and Maintenance |
| VOLL | Value of Lost Load |
| WACC | Weighted Average Cost Of Capital |
| WEC | World Energy Council |
| WEM | Wholesale Electricity Market |

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# Chapter 1 Introduction and Background

## 1.1 Introduction

Electricity generation in Australia is dominated by carbon intensive fossil fuel production technologies. In 2012-13, Australian electricity generation reached 249 terawatt hours (TWh), approximately 87% of which was generated from fossil fuel sources. Overall electricity production was comprised of 64% generation from coal, 20.5% from natural gas, and about 2.5% from oil and multi-fuel sources. Renewable energy sources accounted only for about 13% of total generation, including 7.3% hydro energy generation, 2.9% wind energy generation, 1.5% solar energy generation and 1.3% bioenergy generation (Bureau of Resources and Energy Economics [BREE] 2014a). The carbon emissions produced by the electricity generation sector accounted for approximately 33% of total national emissions (Climate Change Authority [CCA] 2014a). The electricity sector is one of the largest carbon emitters in the Australian economy. In 2012, Australia's greenhouse gas (GHG) emissions increased to 600 Mt $CO_2$-e. This was 2.5% above year 2000 levels.

Currently, Australia is a country under impending threat from climate change. The IPCC Fifth Assessment Report concluded with high confidence that increasing GHG concentrations have contributed to rising average temperatures, more extreme weather events and changed rainfall patterns in Australia (Intergovernmental Panel on Climate Change [IPCC] 2014). In recognition of these factors, the Australian Government has sought to mitigate climate change by committing to reducing its GHG emissions by 5% below year 2000 levels by 2020. This is irrespective of actions by other countries (CCA 2014a; Global CCS Institute [GCCSI] 2014). In August 2015, the Australian Government announced its 2030 carbon emissions reduction target. The Government has agreed to reduce GHG emissions by 26% to 28% below 2005 levels by 2030 (Australia Government 2015).

Furthermore, as a party that signed the Copenhagen Accord of United Nations Framework Convention on Climate Change (UNFCCC) in December 2009, Australia is committed to the collective goal of keeping global average warming below 2 $^{0}$C (United Nations Framework Convention on Climate Change [UNFCCC]

2009). Under the UNFCCC, in addition to unconditionally reducing emissions by 5%, the Australian Government will seek to further reduce emissions by up to 15% or 25% based on year 2000 levels under the conditions of international community's climate change mitigation efforts (CCA 2014a).

In order to achieve GHG emissions reduction targets in Australia, reducing carbon emissions from its electricity generation sector is essential. The electricity generation sector was projected to stay as the largest sectoral emitter until at least 2030. Moreover, it was also projected to be the largest sectoral contributor to emissions reduction under effective climate change policies and its transition to the low-carbon emissions energy technologies (LCETs) (Biberacher 2004; CCA 2014a).

In Australia, the development of nuclear power is legally prohibited under the 1998 Australian Radiation Protection and Nuclear Safety Act (Australian Radiation Protection and Nuclear Safety Act 1998 (Cth)). Current Australian Government has appointed a nuclear advocator as the country's next chief scientist in October 2015. This may signal a new openness by the Australian Government to consider nuclear power generation (Hurst 2015). However, the fact that Australia does not yet have the infrastructure and the training to enable a viable nuclear industry in a short term signifies a highly uncertain future of nuclear power generation in Australia (Henderson 2015). The reduction in carbon emissions of the Australian power system will be largely depend on the deployment of the LCETs including renewable energy technologies (RETs) and carbon capture and storage (CCS) technologies.

In sustainability terms, the RETs and CCS technologies are generally categorised into two separate groups. The RETs generate electricity from clean, naturally replenished energy sources and are thus regarded as sustainable, environmentally-friendly technologies. The opponents to the RETs say that the RETs are costly and produce power intermittently which requires more backup spinning reserves. The proponents of the CCS technologies advocate that these provide a viable way to reduce carbon emissions from existing fossil fuel power sources, while providing time needed to develop efficient, large-scale implementation of renewable energy production methods. On the other hand, the opponents of the CCS technologies suggest that their use prolongs the consumption of fossil fuel and retards the development of the RETs by competing away its limited financial resources (van Egmond and Hekkert 2012).

Several key questions naturally arise. To begin with, how can the RETs and CCS technologies contribute to carbon emissions reduction in the Australian power system? How could Australian electricity markets incorporate the RETs and CCS technologies into existing power generation systems to achieve carbon emission reduction target in a least cost way? How could the Australian Government support the RETs and CCS technologies in an optimal way?

## 1.2 Research Objectives

The objective of this research is to assess and compare potential contributions of the RETs and CCS technologies in reducing carbon emissions and meeting energy demand growth in the Australian power system consistent with Australian Governmental current and potential climate policies, at the least cost to society by 2049-50.

To accomplish this research objective, the quantification of carbon emissions targets the Australian Government will be facing in a long-term timeframe (2012-13 to 2049-50) is essential. Presently the Australian Government is unconditionally committed to reducing its GHG emissions by 5% below year 2000 levels by 2020, and by up to 15% or 25% based on year 2000 levels under strict conditions in line with international actions (CCA 2014a). Therefore, this research takes reducing GHG emissions by 5% to 25% base on year 2000 levels by 2020 as Australian economy-wide short-term carbon emissions target.

Recently, the Australian Government is committed to reducing GHG emissions by 26% to 28% below 2005 levels by 2030. This research considers reducing GHG emissions by 26% below 2005 levels by 2030 as the Australian Government's medium-term carbon emissions target.

Because there lacks a specific government's commitment to post-2030 emissions reduction target, this research adopts long-term emission reduction target used by the

Australian Treasury 2011's study (Australian Treasury 2011). In the Treasury 2011's study, two policy scenarios were constructed:

1) *"Core policy scenario — Assumes a world with a 550 ppm stabilisation target and an Australian emission target of a 5% cut on 2000 levels by 2020 and an 80% cut by 2050"* (Australian Treasury 2011, p.87);

2) *"High price scenario — Assumes a world with a more ambitious 450 ppm stabilisation target and an Australian emission target of a 25% cut on 2000 levels by 2020 and an 80% cut by 2050"* (Australian Treasury 2011, p.87).

The Treasury's study focused on a long-term target of reducing GHG emissions in Australia by 80% on 2000 levels by 2050. This long-term target is not identical but consistent with targets established by other developed countries. For example, the United Kingdom (UK) commits to reducing emissions by at least 80% in 2050 from 1990 levels in its Climate Change Act 2008 (Climate Change Act 2008). Expressed in its national 'energy transition' plan (Energiewende), Germany aims to achieve 80% to 95% emissions reduction by 2050 based on 1990 levels (Morris and Pehnt 2015). The European Union has also proposed to cut its emissions by 80 to 95% below 1990 levels by 2050 (European Commission 2011, 2015).

Accordingly, this research applies three assumptions of carbon emissions reduction targets for the Australian economy. The first assumption assumes an Australian emissions reduction target of a 5% cut by 2020 and an 80% cut by 2050 based on 2000 levels for the comparison purposes. The second one assumes an Australian emission target of a 25% reduction by 2020 and an 80% cut by 2050 based on 2000 levels, which is consistent with the target set by Australian Treasury 2011 study (Australian Treasury 2011). The third assumption takes short-term target of a 5% reduction on 2000 levels by 2020, a medium-term target of a 26% cut on 2005 levels by 2030, and a long-term target of an 80% cut on 2000 levels by 2050 which is consistent with recent announcement of the Australian Government's 2030 carbon emissions reduction target (Australia Government 2015).

These carbon emissions targets are established to capture and compare current established carbon emissions reduction targets and future potential emissions reduction targets committed by the Australian Government. In this research, the Australian economy wide carbon reduction targets will be converted proportionally to set targets and trajectories for the Australian electricity markets.

More specifically, under the assumptions of carbon reduction targets and trajectories, this research investigates the optimal way of expanding power systems to comply with these targets by deploying the RETs and CCS technologies in the two largest electricity markets in Australia: the National Electricity Market (NEM) and the Wholesale Electricity Market (WEM). Also sought here are ways to assess the economic implication of applying the RETs and CCS technologies in the carbon-constrained energy systems, and the carbon avoiding costs for a mix of generation technologies given the present climate policies and possible policy changes in the future.

This research also examines the competing relationship between the RETs and CCS technologies in terms of economic feasibility and emissions reduction capability. Explored here are the economic and policy implications of the increasing penetration of the RETs and CCS technologies in Australia's long-term energy markets.

This research is shaped by four key research questions listed below:

i. How to assess the optimal power systems expansion with the RETs and CCS technologies in the NEM and the WEM given that the overall target is to reduce carbon emissions and meet energy demand growth at the least cost to society?
ii. How may this optimal expansion change and differ under the proposed various targets for carbon emissions reduction given the existing electricity supply systems in the NEM and the WEM respectively?
iii. Are there significant different economic impacts of the large scale deployment of the RETs or CCS technologies in the NEM and the WEM over a long term period?
iv. What policy and economic implications the modelled optimal expansions with the RETs and CCS technologies may have on Australia's long-term national energy plans?

## 1.3 Thesis Structure

This thesis is comprised of two research tasks. They include a comparison of power system optimal expansion practices using the RETs and CCS technologies in the NEM, and a comparison of power system optimal expansion practices deploying the RETs and CCS technologies in the WEM.

The power system optimal expansion study in the NEM applies a power system model PLEXOS to simulate the potentials of the RETs and CCS technologies in the NEM under designed carbon emissions reduction scenarios. The definitions of scenarios are determined by carbon emissions reduction targets, the Renewable Energy Target, future fuel prices assumptions, the projections of energy technologies capital costs, as well as the availability of the RETs and CCS technologies. Compared with the Business As Usual (BAU) Scenario, the modelling results can reveal the impacts of scenario assumptions on the penetrations of the RETs and CCS technologies in the NEM, and their associated capability and economics of carbon emissions reduction.

The second task of this research involves the comparison of power system optimal expansion practices using the RETs and CCS technologies in Australia's second largest electricity market: the WEM. Similar to the method applied in the NEM, the RETs and CCS technologies are examined by utilising the PLEXOS model to simulate the WEM system expansion under designed scenarios.

The results of the NEM PLEXOS Model and the WEM PLEXOS Model are analysed and compared with the purpose of deriving the economic and policy implications of incorporating the RETs and CCS technologies into the Australian electric power sector.

This thesis is organised in seven chapters. Following this introduction section, next section of research background in Chapter 1 presents an overview of Australian electricity sector. In this section, the utilisation of the LCETs in the Australian power system is discussed. The existing physical structure of Australian electricity markets, the related energy and climate change policies, as well as the current status of LCETs development in Australia are reviewed. The second chapter is the literature review which summarises and reviews the categorisation of energy models and the long-term energy modelling practices in Australia. This chapter also provides the rationale of selecting the PLEXOS model as the modelling tool for conducting this research.

Chapter 3 presents the methodologies for this research, including the mathematical formulation of the PLEXOS model and the scenario design method. It introduces the optimisation theory and the structure of the PLEXOS model in details, and the logic and storylines of the scenarios designed. Chapter 4 describes important assumptions and data sources for the modelling work. Chapter 5 and Chapter 6 report the numerical results of the NEM and WEM modelling work respectively. Final research conclusion is made in Chapter 7.

## 1.4 Significance

This research investigates the potential roles of the RETs and CCS technologies in Australia's future energy supply system given current and potential Australian Government's climate policies. It also models energy demand changes and carbon emissions mitigation goals to determine the most cost effective ways of expanding electric power systems. It tries to obtain the optimal portfolios of energy technologies for future expansion and transformation of Australia power generation systems.

Faced with significant political, economic and technological uncertainties, policy makers will have to devise a strategy for limiting future carbon emissions from power generation systems in Australia. They are required to make challenging decisions involving the allocation of limited economic resources and the choice of what kind of technologies to support across a wide range of the LCETs.

This research has sought to capture up-to-date national energy and carbon policies and energy technology developments for simulating long-term low-carbon energy supply systems in Australia. It projects carbon emissions reduction possibility in future Australian electricity systems with the deployment of the RETs and CCS technologies. The results of this research can offer an academic and unbiased economic rationale upon which the Australian Government can make long-term decisions on supporting the research and development of the RETs and CCS technologies. This will benefit the transformation of the current carbon-intensive Australian power sector to a low-carbon one. At the same time, the scenario analyses that are performed in this research can be useful for the policy-makers designing and adjusting future national climate change mitigation targets and policies in Australia.

## 1.5 Research Background

The LCETs produce power with significant lower carbon emissions compared to conventional fossil fuel energy technologies. Technologies generating power from renewable sources such as wind, solar, geothermal, hydro, bioenergy and ocean are commonly considered as the RETs or LCETs. The CCS denotes a set of technologies deployed to capture $CO_2$ from large industrial sources, compress it for transportation and then safely and permanently store it underground (Department of Energy & Climate Change 2010; Socolow 2005). Equipping CCS to fossil fuel power plants prevents substantial amount of $CO_2$ emissions from being released into the atmosphere. It is accepted as one category of the LCETs. Hereafter, conventional fossil fuel energy technologies equipped with the CCS technologies is abbreviated and mentioned as the CCS technologies in the texts for the convenience.

Australian power system and current governmental climate change policies are briefly reviewed in the following sections. An up-to-date status of the LCETs development in Australia is also tracked in this section.

### 1.5.1 Australian Power System

In 2012, GHG emissions in Australia reached 600 million tons (Mt) $CO_2$-e, which was 2.5% above 2000 levels. The power generation sector accounted for about one third of total emissions, primarily resulting from its carbon intensive generation mix (CCA 2014a). The sector was forecasted to remain as the largest sectoral emitter, at least in the short-term in the Australian economy. At the same time, it was also projected to have the largest potential of emissions reduction with the deployment of the LCETs (Biberacher 2004; CCA 2014a).

Australia does not have a fully integrated national electricity market due to no transmission interconnections between eastern, western and northern Australia. This is a result of long distances between populous regions. The NEM is the largest electricity market covering eastern and southern Australia. It links six jurisdictions: Queensland (QLD), New South Wales (NSW), Australian Capital Territory (ACT), Victoria (VIC), South Australia (SA) and Tasmania (TAS) by an interconnected transmission network.

The WEM is the major electricity market in Western Australia (WA) operating in the South-West Interconnected System (SWIS). Along with SWIS, there are the North West Interconnected System and other non-interconnected distribution systems supplying electricity for industrial towns, resources centres and remote areas in WA (Australian Energy Regulator [AER] 2009). There are three relatively small regulated systems in Northern Territory (NT). The largest one is the Darwin-Katherine interconnected system (DKIS). For more information about these electricity markets, please refer to Appendix I.

In 2012-13, total electricity generation capacity in the NEM was around 50.0 Gigawatts (GW) (Australian Energy Market Operator [AEMO] 2013a). Approximately 6.0 GW capacity was installed in the WEM (Independent Market Operator [IMO] 2014a), and near 0.7 GW was installed in NT (Northern Territory Government 2014). Total electricity generated in Australia reached 249 TWh in 2012-13, which was comprised of approximately 85.3% of the NEM generation, 13.4% of the WEM generation and 1.3 % of generation in NT (BREE 2014a).

Eighty seven per cent (87.0%) of electricity was generated from fossil fuel sources in 2012-2013, approximately 44.8% from black coal, 19.1% from brown coal, 20.5% from natural gas and 2.6% from oil and other fuels. Only approximately 13.0% of electricity generated was from renewable sources including hydro, wind, solar photovoltaic (PV) and bioenergy. This resulted in high carbon intensity of power generation in Australia, which was approximately 6.0% and 60.0% higher than the carbon intensity of power generation in China and the United States (US) respectively (Vivid Economics 2013). As the LCETs emit near zero amount of carbon emissions, a greater deployment of the LCETs in Australian power system has the potential to bring down system emissions intensity and consequently reduce carbon emissions emitted by this sector.

### 1.5.2 Policy Environment

Since the late 1980s, Australia has drawn on a wide range of measures and policies at all levels of governments to reduce its GHG emissions. Examples include energy labelling from 1986 and the national Greenhouse Challenge Program for industry from 1995. In 2003, the NSW government introduced Greenhouse Gas Reduction Scheme, one of the first mandatory emissions trading schemes in the world (CCA 2014a).

At the Commonwealth level, the main legislated climate change policies before July 2014 were the Renewable Energy Target, the carbon pricing mechanism (CPM) and the Carbon Farming Initiative (CFI), complemented by funding bodies such as the Clean Energy Finance Corporation (CEFC) and the Australian Renewable Energy Agency (ARENA).

On 17 July 2014, the carbon pricing mechanism was repealed (Department of Employment 2014). The Emission Reduction Fund (ERF) as the replacement policy subsequently passed the Australian Parliament on 31 October 2014 (Hunt 2014). In June 2015, the Large-Scale Renewable Energy Target as one scheme of the Renewable Energy Target was reviewed by the Australian Government and reduced from the previously legislated 41,000 GWh to 33,000 GWh (Minister for the Environment 2015).

For more information about the Renewable Energy Target, the CPM, the ERF and government's funding mechanism for advancing renewable energy technologies, please refer to Appendix II.

*Clean Energy Act 2011* was introduced by the Australian Government in February 2011. The objects of *Clean Energy Act 2011* were (Clean Energy Act 2011 (Cth), p5),

*(a) to give effect to Australia's obligations under:*

*(i) the Climate Change Convention; and*

*(ii) the Kyoto Protocol;*

*(b) to support the development of an effective global response to climate change, consistent with Australia's national interest in ensuring that average global temperatures increase by not more than 2 degrees Celsius above pre-industrial levels;*

*(c) to:*

*(i) take action directed towards meeting Australia's long-term target of reducing Australia's net greenhouse gas emissions to 80% below 2000 levels by 2050; and*

*(ii) take that action in a flexible and cost-effective way.*

*Clean Energy Act 2011* has been repealed by *Clean Energy Legislation Act 2014* (Clean Energy Legislation Act 2014 (Cth)). Nevertheless, as introduced in the Introduction Section, Australia still commits to the collective goal of keeping global average warming below 2$^{o}$C set by the Copenhagen Accord of the UNFCCC in December 2009 (UNFCCC 2009).

Australia will reduce emissions by 5% on year 2000 levels by 2020 (CCA 2014a). It will reduce its GHG emissions by 25% on 2000 levels by 2020 if the world agrees to an ambitious global deal to stabilise GHGs concentration in the atmosphere at 450 ppm $CO_2$-e or lower by 2100. Australia will reduce emissions by up to 15% by 2020 if there is a global agreement which is inadequate to secure atmospheric stabilisation at 450 ppm $CO_2$-e. Under this global agreement, major developing economies commit to substantially restrain emissions and advanced economies take on commitments comparable to Australia's (UNFCCC 2014).

The Australian Government did not set post-2020 reduction target until its 2030 carbon emission reduction target announced in August 2015 (Australia Government 2015; CCA 2014b). The Government will bring its 2030 target of reducing GHG emissions by 26% to 28% below 2005 levels by 2030 to the UNFCCC Paris Climate

Conference in December 2015, where a new global climate agreement will conclude on negotiations (Australian government 2015).

### 1.5.3 Development Status of Low Carbon Energy Technologies

#### 1.5.3.1 Global Overview

The International Energy Agency (IEA) assessed global progress of the LCETs against the interim 2025 benchmarks in its 2°C Scenario (2DS) of limiting the concentration of GHGs in the atmosphere to be equivalent to 450 ppm of $CO_2$ (International Energy Agency [IEA] 2015). Renewable electricity generation grew 5.5% annually from 2006 to 2013, up from 3.0% annually from 2000 to 2006 (IEA 2015). It was expected to rise by 45.0% between 2013 and 2020, reaching 7310 TWh (IEA 2015). Nevertheless, the IEA concluded that the global development of the RETs were not completely on track to meet interim targets (IEA 2015).

Non-OECD countries dominated global renewable power generation with approximately 54.0% of the total in 2013. The IEA projected that the largest share of renewable generation in 2025 would come from China (26.0%) followed by OECD Europe (17.3%), the US (11.0%), Brazil (6.3%) and India (6.1%) (IEA 2015).

In 2013, hydropower remained the largest generation of renewable electricity and continued its stable growth globally. Onshore wind and solar PV showed strong growth. In 2014, over 45.0 GW of new onshore wind power was installed and solar PV power increased by about 40.0 GW (IEA 2015). Offshore wind, bioenergy, concentrated solar power, ocean and geothermal technologies were lagging behind. Some require further policy action to tackle technical and financing challenges. For example, early-stage exploration and drilling are major challenges for geothermal deployment. Ocean power technologies are still at the research and development (R&D) stage, and remain relatively expensive (IEA 2014).

The development of CCS technologies has progressed slower than anticipated. In 2013, there were fewer developments of large-scale demonstration projects, due to high costs and the lack of political and financial commitment (IEA 2015). At the end of 2014, there were 35 projects in operation, under construction or in advanced planning. They in total have the potential to capture 63.0 Mt $CO_2$ per year by 2025.

Thirteen large-scale CCS projects in operation capture 26.0 Mt $CO_2$ per year in total (IEA 2015). The IEA projected that CCS technologies will be still needed to provide around 14.0% of the cumulative emissions reductions to 2050 globally to reach the 2DS (IEA 2015). The global investment in CCS would need to increase significantly to meet this 2DS target (IEA 2015).

#### 1.5.3.2 Low Carbon Energy Technologies in Australia

In 2012-13, approximately 32.4 TWh of electricity was generated from renewable sources in Australia, accounting for approximately 13.0% of total electricity generation. Hydro power dominated renewable energy generation, representing around 56.1% of total renewable energy generation in 2012-13. The rest was contributed by wind (22.5%), solar (11.7%) and bioenergy (9.7%) (BREE 2014a).

In this section, the capital cost and the levelised cost of electricity (LCOE) are in 2012 US dollars (US$) and in 2012 Australian dollars (AU$). The annual average exchange rate for one US$ to one AU$ was 0.9622 in 2012 (Reserve Bank of Australia 2016).

***Wind Energy***

Wind energy was the fastest growing renewable source for electricity generation in Australia, increased at an average annual rate of 35.9% between 1999-2000 and 2011-12 (Geoscience Australia and BREE 2014). As shown in Table 1.1, Australia had 1866 wind turbines spreading across 71 wind farms at the end of 2014. Total installed capacity was approximately 3806.2 MW (Clean Energy Council [CEC] 2014). At the end of 2013, another 1790 MW of wind capacity was under construction (CEC 2013).

The World Energy Council (WEC) and Bloomberg New Energy Finance (BNEF) published a comprehensive cost study of energy technologies in 2013 (World Energy Council [WEC] and Bloomberg New Energy Finance [BNEF] 2013). It provided the LCOE data for the RETs in 2012 US$. The LCOE represents the full life-cycle costs (fixed and variable) of a technology per unit of electricity (MWh) generation (Ueckerdt et al. 2013).

**Table 1.1** Installed wind energy in Australia by state.

| State | Installed capacity (MW) | Number of turbines | Number of projects |
|---|---|---|---|
| South Australia | 1475 | 651 | 17 |
| Victoria | 1070.2 | 518 | 14 |
| Western Australia | 491 | 308 | 21 |
| New South Wales | 447.5 | 243 | 10 |
| Tasmania | 310 | 124 | 7 |
| Queensland | 12.5 | 22 | 2 |
| Northern Territory | 0 | 0 | 0 |
| Australian Capital Territory | 0 | 0 | 0 |
| Total | **3806.2** | **1866** | **71** |

Source: CEC (2014).

The estimated capital cost for onshore wind in the Australia was between US$2270-2450/KW (AU$2184-2357/KW). This estimate was higher than the estimated cost of standard onshore wind farm of US$1770/KW (AU$1703/KW) in developed markets. However, the LCOE for onshore wind in Australia was between US$71-99/MWh (AU$68-95/MWh), approximately in the range of the standard LCOE of US$78/MWh (AU$75/MWh) due to its relatively high capacity factor (WEC and BNEF 2013).

To date, there have been no off-shore wind developments in Australia. Almost 95.0% of roughly 4.0GW of global installed offshore wind capacity was situated in the waters off Europe's western coast in 2013. It estimated that the LCOE of offshore wind in the Western Europe was between US$147-367/MWh (AU$141-353/MWh) (WEC and BNEF 2013).

***Solar Energy***

There are a wide range of solar energy technologies at different stages of development in Australia. Small-scale rooftop solar PV systems had grown rapidly with capacity increased from 100.0 MW in 2008 to approximately 2.3 GW in 2012. This primarily resulted from falling costs of PV panels and government incentives

(Geoscience Australia and BREE 2014). The outlook for large-scale solar PV and solar thermal electricity generation depends on demonstration outcomes at commercial scale (Geoscience Australia and BREE 2014).

Australia had eight larger than 1.0 MW solar power plants on operating. Two largest plants were: a 20.0 MW Royalla solar PV Farm in ACT and a 10.0 MW Greenough River Solar PV facility in WA (CEC 2013, 2014). There were about 258.0 MW large-scale solar projects under construction at the end of 2014 (CEC 2014).

It estimated that the capital cost of solar PV without tracking was US$2410/KW (AU$2319/KW) in Australia. Its LCOE was between US$127-191/MWh (AU$122-184/MWh) (WEC and BNEF 2013). Regarding the solar thermal technologies, currently parabolic trough plant was the most widely deployed technology, followed by tower and heliostat plant (Thirugnanasambandam, Iniyan and Goic 2010). The LCOE of parabolic trough was with estimates of AU$347/MWh for generation without storage, and AU$339/MWh for generation with six-hour storage in 2012 (BREE 2012).

***Geothermal Energy***

There are two types of geothermal resource available in Australia: hot sedimentary aquifer (HSA) and engineered geothermal system (EGS). A HSA system is featured by hydrothermal groundwater resources in a sedimentary basin. An EGS uses resources deeper in the crust in crystalline rocks (Huddlestone-Holmes and Russell 2012).

Current data of Australia's geothermal potential was based on temperatures recorded at the bottom of more than 5700 deep drill holes, most of which were drilled for petroleum exploration. As of July 2009, eight companies had declared identified geothermal resources totalling 2.6 million PJ of heat in place (Bahadori et al. 2013).

Geothermal projects in Australia are still mostly at the exploration stage. Presently there was no commercial scale production of geothermal electricity in Australia (CEC 2013). There was only one small-scale HAS geothermal power plant with an installed capacity of 120 kW at Birdsville in Queensland (CEC 2014). It was estimated that the HAS geothermal technology would be commercial deployable in 2020 in Australia with the LCOE of AU$154/MWh (BREE 2012). The EGS would be commercial deployable in 2025 with the LCOE of AU$215/MWh (BREE 2012).

***Bioenergy***

They are plenty and diverse potential bioenergy resources in Australia, including wood, wood waste, bagasse, gas from landfill and sewage, crops and animal fats (BREE 2014b).

Five largest bioenergy projects in Australia had total installed capacity of 241 MW (CEC 2014). It was estimated that the LCOE of the bagasse was AU$112/MWh and the LCOE of the landfill gas was AU$91/MWh in 2012 (BREE 2012).

***Hydro and Ocean Energy***

Hydroelectricity generation growth was expected to be limited and outpaced by other renewables, especially by wind and solar energy in Australia. Most of best large scale hydro-energy sites have already been developed or are not available for future development due to environmental constraints. Future growth in hydro capacity is likely to mainly come from small-scale plants (Geoscience Australia and BREE 2014). A novel approach of extracting hydro energy has been proposed by Liu and Packey (2014). It describes a combined use of conventional hydropower station and hydrokinetic turbines to extract residual hydro energy from the tailwater of hydropower station. In future, it may provide a new way of harvesting hydro energy.

Australia has world-class wave energy resources along western and southern coastline and rich tidal resources located along the northern margin (Geoscience Australia and BREE 2014). Adoption of ocean energy technologies depends on further maturing of the industry and environmental impact assessments (Geoscience Australia and BREE 2014). A report completed by the Commonwealth Scientific and Industrial Research Organisation (CSIRO) concluded that tidal and ocean current technologies will not contribute to Australian electricity generation out to 2050 (Commonwealth Scientific and Industrial Research Organisation [CSIRO] 2012).

***Battery energy storage technology***

Battery technology has been through significant development in recent years. It is expected to experience accelerated growth and will promote increased uptake of renewable energy and electric cars (Climate Council 2015). Various types of battery technologies are suitable for power system applications, including lead acid batteries, flooded type batteries, valve regulated type batteries, sodium sulphur batteries, lithium ion batteries, metal air batteries and flow batteries (Divya and Østergaard 2009; Gallo et al. 2016).

Internationally, China, Germany, Japan and the US are leading the way on battery storage development (International Renewable Energy Agency, 2015). Australia has potential to become one of the largest markets for battery storage because of its high electricity cost, high penetration of residential solar panels and its abundant solar resources (Climate Council 2015). The most valuable opportunities for battery storage application in Australia are identified as 'behind-the-meter' applications such as for households with rooftop solar and off-grid areas, and on the fringes of electricity grids application where high costs are involved in getting back-up power from connecting to the grid or by importing diesel and LPG (AECOM 2015). Nevertheless, future deployment of battery storage in Australia will heavily rely on tariff and regulatory decisions, the actions of governments, electricity networks and retailers and other competitors (Climate Council 2015).

In 2014, approximately 400 MW of battery storage capacity was installed globally, representing more than doubling the installed base in 2013 (IEA 2016). The accelerated deployment of battery storage was largely driven by continued and rapid cost reductions in battery technology, particularly in lithium-ion (Li-ion) chemistries. High upfront costs, however, remain an obstacle to the wider deployment of battery technology (IEA 2016). In 2015, the reported LCOE of large-scale battery investment cost was just below US$400/kWh. IEA's Energy Technology Perspective 2016 projected that this LCOE will drop to at around US$200/kWh in 2020 and be further reduced to below US$200 /kWh in 2025 (IEA 2016).

### *CCS and Storage Potential*

The CCS technologies involve three major steps: capture, transport and storage. The approaches to capture $CO_2$ in power plants include post-combustion, pre-combustion and oxy-fuel technologies. Post-combustion systems separate $CO_2$ from flue gases produced by the combustion like in supercritical pulverized coal (PC) plants. It is a proven and commercially available technology today. Pre-combustion systems process primary fuel in a reactor before the combustion to produce separate streams of $CO_2$ for storage and $H_2$ for fuel. Oxy-fuel combustion uses oxygen instead of air for combustion, producing a flue gas that is mainly $H_2O$ and $CO_2$, which is readily for capture (IPCC 2005; National Energy Technology Laboratory [NETL] 2010).

Captured $CO_2$ is compressed and transported via pipelines to suitable geological storage sites. Depleted oil and natural gas reservoirs, un-mineable deep coal beds or deep saline aquifers are options for storage sites (Socolow 2005). Evidences from oil and gas fields indicate that hydrocarbons and other gases and fluids, including $CO_2$, can remain safely trapped underground for millions of years (Bradshaw and Dance 2004; Magoon and Dow 1994).

The Australian Government has commenced a range of initiatives and policies to speed up the development of CCS technologies. The Government passed the world's first legal framework *the Offshore Petroleum and Greenhouse Gas Storage Act 2006* for regulating geological storage of GHG emissions in Australian offshore territory (Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Cth)).

In 2008, National Low Emission Coal Initiative was established to provide financial and institutional support for Australia National Low Emissions Coal R&D agency, National Carbon Mapping and Infrastructure Plan, Callide oxy-fuel combustion project, Australia-China Joint Coordination Group on Clean Coal Technology and Advanced Lignite Demonstration Program (Department of Industry n.d.-b). In 2009, the CCS Flagships Program was established to support demonstrations of large-scale integrated CCS projects (Department of Industry n.d.-a). In the same year, the Australian Government established the Global CCS Institute (GCCSI) addressing barriers to the commercial deployment of CCS through fact-based advocacy and knowledge-sharing activities (GCCSI n.d.).

Despite the Australian Government's efforts, CCS development has been slower than expected. This was due to technical, costs and logistical challenges (CCA 2014a). Prompt commercial deployment of CCS technologies in Australia was further challenged by the repeal of the CPS and the AU$500 million funding reduction over three years for the CCS Flagships Program in the 2013-14 budget year (Department of Industry n.d.-a).

There were three large scale CCS projects under development by September 2014 in Australia. The Gorgon Project is a natural gas facility in WA that will capture and inject 3.4 to 4.0 Mt of $CO_2$ annually with the commencement expected in 2016. The CarbonNet Project in VIC and South West $CO_2$ Geo-sequestration Hub in WA are in early development stage. They will capture $CO_2$ from industrial sources (GCCSI 2014). Another 15 different sizes of scales CCS capture and/or storage projects were at under planning or construction (NETL 2012).

Sufficient geological $CO_2$ storage capacity is a critical requirement for large scale deployment of the CCS technologies. National geological assessments of $CO_2$ storage capacity discovered (with high confidence) that Australia has sufficient storage potential, especially in deep saline reservoirs. The east of Australia has aquifer storage capacity of 70 to 450 years at an injection rate of 200 million tonnes per annum (Mtpa). The west has capacity of 260 to 1120 years at an injection rate of 100 Mtpa (Carbon Storage Taskforce 2009).

The Australian Bureau of Resources and Energy Economics (BREE) projected that CCS technologies would reach commercial feasibility in 2025. The LCOEs of new built coal-fired power plants equipped with CCS were estimated at range of AU$192-242/MWh, and the LCOE of combined-cycle natural gas plant with post-combustion CCS was approximately AU$162/MWh in 2025 without a carbon price in place (BREE 2012).

# Chapter 2 Literature Review

This chapter first provides a review on the studies conducted in recent years on comparing renewable and CCS technologies in different regional contexts. This section is followed by a review of the methodologies of energy economic modelling. Major energy modelling studies on the Australian energy system conducted between 2009 and mid-2014 are also reviewed here. Also, the rationale for selecting the power system modelling tool PLEXOS for this research is explained.

## 2.1 Comparison Studies of the Renewable and CCS Technologies

Both on-shore wind and small scale solar PV technologies are mature LCETs in the Australian electricity market. Despite their technological readiness, their large scale deployment is still heavily depended on policy incentives. As emerging LCETs, widespread deployments of large scale solar PV, solar thermal, geothermal and CCS technologies are facing similar uncertainties: the timing of market entry and the cost competitiveness.

In the meantime, although the RETs and CCS technologies are both categorised as the LCETs, they differ and compete to some extent. As emerging technologies, the development of CCS requires significant financial support. The opponents of CCS argue that it delays the development of the RETs by competing away limited financial resources (van Egmond and Hekkert 2012). A more neutral view has arisen considering the CCS as a feasible way to reduce carbon emissions from existing fossil fuels-fired power plants and industrial sources. This does not impede the deployment of the RETs (Vergragt 2009).

Concerns also exist about the wider deployment of the RETs. The intermittent and distributed wind and solar energy would impose significant constraints on the reliability of existing electricity infrastructures. Higher penetration rate of intermittent renewable energy would require fundamental alterations to electricity transmission and distribution system. On the other hand, the deployment of CCS technologies on stationary and point power plants would allow continuing utilisation and expansion of existing power system with fewer challenges to existing infrastructures.

Therefore, research interests arose internationally in comparing the RETs and CCS in the power system. The comparison studies aimed at investigating how government should make decisions on supporting the development of the RETs and CCS technologies. Behind this question is the fact that governments' resources are limited and scarce, which should be allocated in the most effective and efficient way. Therefore, the comparison studies are needed to investigate potential roles of the RETs and CCS in an energy system under different policy considerations.

For example, the German Government has commissioned a series of studies of comparing the RETs with CCS using a combined lifecycle analysis and costs assessment in 2007 (Viebahn et al. 2010; Viebahn et al. 2007; Wuppertal Institute for Climate 2008). The economic assessments of the RETs versus CCS technologies focused on comparing their economical competiveness in a long-term timeframe (to 2050) for the German situation. Viehahn et al. (2007) compared the RETs with CCS regarding structural, economic and ecological aspects in Germany. The study's calculation showed that CCS technologies emitted more $CO_2$ than generally assumed in the clean-coal concepts and considerable more if compared with renewable electricity. This study concluded that depending on growth rates and the market development, the renewables could develop faster and be cheaper in the long term than the CCS based power plants in Germany.

Wuppertal Institute for Climate (2008) is an updated version of Viehanhn et al. (2007) which considered three years' new developments of the RETs and CCS at technical, political and scientific levels. It integrated the factors of fuel prices and carbon permits into the economic comparison. The study concluded that further expansion of the RETs would be more economic than developing CCS technologies for power generation in Germany. It was mainly due to the concern of fuel prices increase in future. This effect was particularly strong in the case of gas-fired CCS power stations.

The studies of Viehahn et al. (2007) and Wuppertal Institute for Climate (2008) referred to specific situation in Germany. The necessity of deploying CCS as a strategic option for carbon emissions mitigation could be more applicable for countries such as Australia, which have an increasing electricity peak demand and abundance of fossil fuel resources. The lifecycle assessment method applied by these studies is powerful for comparing the RETs with CCS given a set of sustainability metrics. However, this method has limitations in representing interactive relationships of a complex energy system, such as a capacity expansion path driven by policy and technical factors (Ogden and Anderson 2011).

Koljonen et al. (2009) investigated the roles of the RETs and CCS in tackling climate change in a global context. It simulated climate change policy scenarios and explored investments needed for clean energy technologies by 2050 by using of an energy system model (ESAP-TIAM). It focused on CCS, bioenergy and wind technologies. The energy system model applied in this research is a technological detailed bottom-up modelling tool. This type of energy model can capture and simulate dynamic interactions between policy drivers and energy technology penetrations. The results revealed that more stringent climate change policy would increase the deployment of clean energy technologies. This study was undertaken in a global setting, which had limited implications to a specific country context.

Torvanger and Meadowcroft (2011) reviewed the political economics of government's choices on supporting the RETs and CCS. The study used an illustrative economic modelling technique to explore the lowest cost technological alternatives to meet an emissions abatement objective. The main result showed that supporting only one technology would result in the least cost to governments. However, this economic model was illustrative and simplistic. It did not explore the technologies in an energy system setting. The authors later contextualised modelling results by discussing additional economic and political issues for making decisions about the support for technology development. It concluded that a 'lumpy' investment towards a relatively modest set of priorities, spread-out evenly across all alternatives, without concentrating on one technological option, may be the best strategy. This research revealed that governments' decision making on supporting the RETs and CCS should be based on integrated considerations of economic, social and political concerns.

A study done by Elliston, MacGill and Diesendorf (2014) compared the least cost scenarios of 100% renewable electricity against CCS scenarios in the Australian NEM in 2030. It applied a self-developed bottom-up energy model programmed by the Python language (Elliston, Diesendorf and MacGill 2012). The results indicated that the CCS scenarios cannot compete economically with a 100% renewable scenario in a carbon constrained world in the NEM. The findings suggested that pursuing very high penetrations of renewable electricity based on commercially available technologies offered a cost effective and low risk way to cut emissions in the NEM.

However, this study optimistically assumed that electricity demand in the NEM in 2030 will remain the same as in 2010. Additionally, a 100% of renewable generation is unlikely to be representative of future reality in the NEM. Furthermore, this study only compared the RETs to CCS in the years of 2010 and 2030. This provided insufficient information to examine market penetrations of the RETs and CCS over a long-term time period subject to their economic feasibilities and cumulative carbon reduction potentials.

Effective comparison of the RETs and CCS should incorporate multiple aspects of considerations. Firstly, the comparison should be in the context of a specific country or region. Future cost reduction of the RETs and CCS is subject to global learning-by-doing. However, they may still vary significantly across different countries due to local economic, technical and labour conditions, as well as governmental subsidies.

Moreover, the investigation of the RETs and CCS should be integrated into a specific power system. The power systems in different countries possess their own physical structures and constraints. In particular, the portfolio and ages of existing electricity generation fleet would have significant impacts on the entrance time and capacity volume of newly installed renewable and CCS capacity and energy generation. In addition, penetration outlooks of the RETs and CCS are sensitive to drivers like policies and incentives, which may be different among countries. A mandatory energy technology target is a typical example of a governmental policy, which could be set with different quota in different countries.

Secondly, the timeframe for investigating LCETs should be identified. Energy demand, policy settings, carbon reduction targets and economic parameters of the LCETs could differ greater over a short-, medium-, or long-term timeframe than a single year. Moreover, the longer timeframe a study has, the more challenging to collect sufficient and reliable data inputs for describing technological details.

The comparison of the RETs and CCS should address uncertainties of technological change, policy alternations, economic signals and their interactive relationships in an existing power system. The economic risks and policy uncertainties would become more apparent when comparing the RETs and CCS in a specific country within a long-term time frame. This often requires assumptions on the outlook of economic, policy and technological development.

This research compares the RETs and CCS in the Australian NEM and WEM between 2012-13 and 2049-50. Accordingly, a power system modelling will be chosen as a preferred approach for conducting this comparison. It is capable of dynamically incorporating economic, technological and policy factors; and consistently simulating the power systems into future.

## 2.2 Overview of Energy Economic Modelling

Energy modelling has been used as a tool for national energy planning since 1970s for coping with the energy crisis (Nakata 2004). A wide range of energy-economic models have been rapidly developed in recent years in order to better understand complex interactions between energy policies, environmental concerns and economic growth. Current energy models can be used to assess environmental impacts and economic feasibility of different energy technologies. They can appraise the effectiveness of energy policies for curbing carbon emissions.

An energy economic model performs as a numerical tool to predict future energy demand and supply. It also acts as a management tool for decision making on energy policies and development strategies to optimise energy system with economic and environmental constraints (Nakata 2004). The main components of an energy economic model include: economic system, technology system, resources constraints and environmental constraints, as shown in Table 2.1 (Nakata 2004). The interactions of these main components and elements are illustrated in Figure 2.1.

**Table 2.1** Main components of energy-economic models.

| **Economic system** | **Technology system** | **Resource constraints** | **Environmental constraints** |
|---|---|---|---|
| Price sensitivity and elasticity,<br>Energy preferences,<br>Carbon and energy tax,<br>Subsidy for specific industries,<br>Discount rate. | Technology innovation,<br>Efficiency improvement,<br>Operating cost reduction,<br>Capacity limit. | Exhaustion of natural resources,<br>Physical limits of renewable resources. | $CO_2$ emissions,<br>$NO_X$, $SO_X$ and THC emissions, etc. |

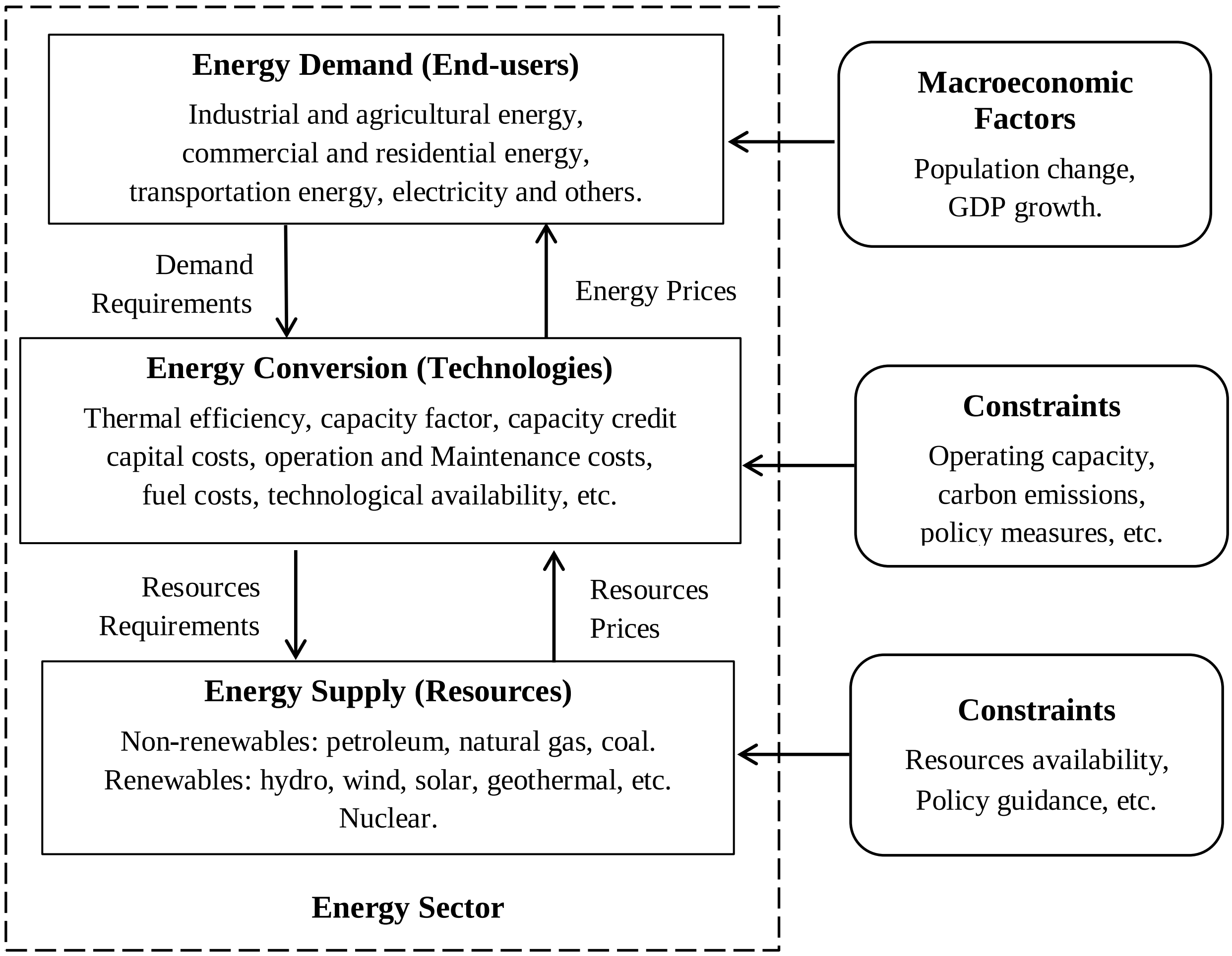



**Figure 2.1** Conceptual flow chart of an energy economic model.

## 2.3 Classification of Energy Economic Models

A large number of energy models (varying by different levels of sophistication) are available for users around the world. The question arises: which model is the best suited for a certain investigation, purpose or situation? A classification scheme can provide useful insight in differences and similarities among energy models. It can facilitate the selection of a proper energy model for a specific application and the interpretation of modelling results.

Van Beeck (1999) gave an overview of five primary aspects for classifying energy models as listed in Table 2.2 including:

i. General and specific purposes;
ii. Model structure;
iii. Analytical approach;
iv. Underlying methodology;
v. Mathematical approach.

Understanding design purposes of energy models is critical for users to choose a right model to achieve research objectives and avoid misinterpretation of results. Recent trend in energy model development is to integrate several purposes into one model. This is common in models studying energy, economy and environmental interactions. One example of this is MESSAGE (Model for Energy Supply Strategy Alternatives and their General Environmental Impact) model. The MESSAGE model, developed by the International Institute for Applied Systems Analysis (IIASA), is a system engineering optimisation tool. It examines long-term energy demand and supply analysis through scenario development and analysis (Connolly et al. 2010; International Institute for Applied Systems Analysis [IIASA] 2012).

In addition, energy models can be also distinguished by assumptions. The implicit or internal assumptions are ones embedded in models, the external or input assumptions are ones left to be determined by users. The type of assumption influences the structure of an energy model.

**Table 2.2** Overview of nine categories for classifying energy models.

| Classification | Description |
|---|---|
| **I. Purposes** | |
| ***General*** | |
| Forecast future | An endogenous description of economic behaviour and growth patterns. It is often seen in econometrically driven short-term economic models. |
| Scenario analysis | The designed scenarios are compared with a baseline scenario to explore future. Sensitivity analyses are crucial to analyse assumptions. |
| Back-casting | Construct visions of desired futures by interviewing experts, later look at what needs to be changed to achieve such futures. |
| ***Specific*** | |
| Energy demand | It is a function of population, income and energy prices etc. |
| Energy supply | Focus on technical aspects of energy supply, e.g. energy transformation technologies. |
| Impact analysis | Assess consequences of selecting certain options or changes as policies. |
| Appraisal | The consequences or impacts of each option are compared and appraised according to one or more pre-set criteria. |
| **II. Structure** | |
| ***Internal assumptions*** | |
| Endogenisation degree of parameters | Indicate the degree of incorporating parameters within the model equations so as to minimise the number of exogenous parameters. |
| Description degree of non-energy sectors | The more detailed described the non-energy sectors, the more suitable the model is for analysing impacts of energy policies on economy. |
| Description degree of energy end-uses | The more detailed described energy end-uses, the more suitable the model is for analysing the technological potential for energy efficiency. |
| Description degree of energy supply technologies | A detailed description of technologies is best for analysing technological potential for fuel substitution and new supply technologies. |
| ***External assumptions*** | |
| Population growth | Other things being equal, population growth increases energy demand. |
| Economic growth | It generally causes an increase in energy demand. |
| Energy demand | It is influenced by economy structural changes, as well as by technology choices and energy efficiency. |
| Energy supply | It is determined by the short-term availability of alternative resource supplies as well as by backstop technologies. |
| Price and income elasticities of energy demand | Elasticities measure the relative change in energy demand, given relative changes in energy prices and incomes. |
| Tax system | Taxes can have large impacts on the total costs of energy systems. |
| **III. Analytical approach** | |

| | |
|---|---|
| Top-down | Evaluate system from aggregate economic variables |
| Bottom-up | Simulate technological options or specific climate change mitigation policies. |
| **IV. Underlying methodology** | |
| Econometric | Apply statistical methods to extrapolate past market behaviour into future. |
| Macro-economic | Focus on entire economy and interactions between the sectors. Input-output tables are used to describe transactions among economic sectors. |
| Economic equilibrium | Simulate long-term growth paths, relying on perfect market equilibrium assumptions. |
| Optimisation | Energy investment decisions are optimised endogenously. The outcome represents optimal solution for given variables to meet given constraints. |
| Simulation | Based on a logical representation of a system, which are aimed at reproducing a simplified operation of this system. |
| Spread-sheet (tool boxes) | Include a reference model that can easily be modified according to individual needs. |
| Back-casting | Construct desired futures by interviewing experts, later identifies trends are required or need to be broken to realize such futures. |
| Multi-criteria | Include other criteria than just economic efficiency alone. It can include quantitative as well as qualitative data in the analysis. |
| **V. Mathematical approach** | |
| Linear programming (LP) | Maximize or minimises a defined criterion, subject to the operative constraints. All relationships are expressed in fully linearized terms. |
| Mixed integer programming (MIP) | Allow for greater detail in formulating technical properties and relations in modelling energy systems. |
| Dynamic programming | Find an optimal growth path. The solution of the original problem is obtained by optimally solving simple sub-problems. |

An analytical approach used for examining linkages between the economy and the energy system also influences the modelling technique. It defines major distinctions between energy models. Top-down and bottom-up are two basic analytical approaches. Top-down models evaluate energy system from aggregate economic variables; whereas bottom-up models consider detailed technological options. The differences between their results root in a complex interplay among purpose, structure and input assumptions. Recently, hybrid models have been developed with the objective of combining the strengths of traditional top-down and bottom-up approaches (Gurba and Lowe 2009; Loulou et al. 2005; Nakata 2004).

Common methodologies used in energy models include: econometric, macro-economic, economic equilibrium, optimisation, simulation, spread-sheet, back-casting and multi-criteria. These are depicted in Table 2.2 above. The analytical approach and underlying methodology are the two most important features for classifying energy models.

The distinction can also be made regarding mathematical approaches used for constructing and solving energy models (see Table 2.2). The most commonly applied techniques include linear programming, mixed integer programming and dynamic programming.

Additionally, the application of energy models are affected by factors such as defined geographical description, sectoral coverage and modelling time horizon. These factors determine the type and the explicitness of data required as inputs for the operation of energy models.

Geographical description reflects the level at which a modelling analysis happens. Global models describe the world economy or situation; regional levels frequently refer to international regions such as Europe, the Latin American countries. National models treat world market conditions as exogenous, but encompass all major sectors within a country, addressing feedbacks and interrelationships between different sectors. Local level is sub-national, referring to regions within a country.

A model can focus on one or more sectors. Single-sectoral model only provides information on a particular sector. It does not consider macro-economic linkages of that sector with the rest of economy. Multi-sectoral model focuses on interactions between different sectors. They can be used at international, national, as well as sub-national level.

Time horizon is an important parameter in energy modelling, because economic, social and environmental processes vary greatly at different time scales. There is no standard definition for short, medium and long term timeframe. Grubb et al. (1993) mentioned a commonly noticed period of 5 years or less for the short term, between 3 and 15 years for the medium term and 10 years or more for the long term. Time scale helps to determine structures and objectives of energy models.

Energy models require inputs of certain types of data. Most models will require a quantitative type of data; some may require data to be expressed in monetary units.

Furthermore, data may be aggregated or disaggregated. Long-term global and national models often require highly aggregated data with little technological details. Models specific for modelling the energy sector would require high temporal and disaggregated data to represent energy supply and consumption comprehensively (Van Beeck 1999).

## 2.4 Review of Top-Down and Bottom-up Energy Models

Top-down and bottom-up are two distinctive analytical methods for classifying energy models. Top-down energy models explore an aggregate macroeconomic and energy equilibrium framework. Bottom-up energy models specifically focus on the energy system by using highly disaggregated technological data to assess future energy demand and supply (Herbst et al. 2012).

### 2.4.1 Top-Down Energy Models

Top-down energy models apply macroeconomic theory and econometric techniques to historical data of consumption, prices, incomes and factor costs. The models project final demand for goods and services, and the supply from energy sector (IPCC 2001). Driven by population growth, economic development, inter-industrial structural variation and price trends; top-down models equilibrate market by maximising consumer welfare. Feedback iterations between welfare, employment and economic growth are applied in the models to seek equilibrium. Top-down models are often used to evaluate economic costs and environmental impacts of energy and climate policies (Bataille 2005).

Three typical types of top-down energy models are (Herbst et al. 2012; Welsch 2013):

i. Macro econometric models
ii. Input-output models
iii. Computational general equilibrium (CGE) models

Macro econometric models use national time series data, econometrically estimated sets of parameters and equations to project and analyse interactions of energy, economy and environmental policies (Kemfert 2003). Because of data constraints, macro econometric models are more widely used for national short-term energy and economic forecasting rather than long-term global prediction (Herbst et al. 2012; Kemfert 2003).

The E3ME model developed by the Cambridge Econometrics is a typical example of the macro econometric model. This model is able to simulate GDP, energy demand and carbon emissions for up to 69 sectors for 53 major world economies. It is an empirical model with a historical database covering the period of 1970 to 2012. The model projects forward annually to 2050 with an aim to produce a broad range of economic, energy and environment indicators (Cambridge Econometrics 2014).

Input-output (I/O) models structurally describe total of goods and services transacted among economic sectors in a country by use of value added and specific I/O coefficients (Kemfert 2003; Leontief 1986; Van Beeck 1999). I/O models are generally applied to evaluate direct and indirect economic and sectoral effects of energy policies in a short-term rather than in a long-term. They can only represent current economic structure based on historical data (Catenazzi 2009).

Lindner and Guan (2014) developed a hybrid-unit energy I/O model with a disaggregated electricity sector for China. It was used to estimate energy requirements and life-cycle carbon emissions from all industry sectors in Chinese economy in 2007. Lenzen, Pade and Munksgaard (2004) established a multi-region I/O model including Denmark, Germany, Sweden and Norway to calculate $CO_2$ embodied in commodities traded internationally by Denmark with the other three countries.

CGE models simulate behaviour of economic agents according to microeconomic principles and the assumption of perfect market equilibrium. An example of a CGE model is the Multi-Regional Forecasting (MMRF) model developed by the Centre of Policy Studies at Victoria University. This is a multi-regional, dynamic CGE model used to make policy analysis for Australian economy. The model covers eight Australian regions and up to 144 industries/commodities. It is able to make projections about energy usage and GHG emissions by fuels uses in the economy (Adams et al. 2010).

The CGE models equalise supply and demand in all markets using market clearance prices to guarantee zero economic profits and optimal distribution of resources (Kemfert 2003). They are commonly used for simulating long-term sectoral impacts of economy-wide price policies (Pezzey and Lambie 2001). CGE models examine the economy in different states of equilibrium. However, they are not able to provide detailed information into adjustment paths towards a new equilibrium (Wing 2011). Moreover, these models do not cover technological details. They represent the energy sector in an aggregated form by production functions. The production functions realise substitution possibilities through the elasticities of substitutions. Thus, CGE models have limitations in assessing the combined effects of price-based policies with technology-specific policies (Hourcade et al. 2006).

### 2.4.2 Bottom-Up Energy Models

Bottom-up energy models usually follow a partial equilibrium representation of an energy system sector. They apply an engineering approach to represent current and prospective energy end-uses and technological options in details. These models can simulate a practical technology mix in the energy system under impacts of market constraints, policy uncertainties and technology characteristics. They also can explore technological potentials to meet energy demand subject to technological, environmental or energy sources constraints (Böhringer and Rutherford 2008).

A typical characterisation of bottom-up models includes (Herbst et al. 2012):

i. Simulation models
ii. Optimisation models

Simulation models emulate an energy system by descriptively and quantitatively representing energy demand and technologies, as well as their interrelationships. These models aim to simulate the technological choices of an energy system. They do not follow a cost minimising requirement. Instead, the models are driven by exogenously determined technological data and factors such as income, population, government policies and energy prices, etc. These impact drivers interact with general economic, demographic development and policies (Herbst et al. 2012). Modelling approaches of game theory and accounting framework are regarded as two types of simulation models when applied to energy conversion sector (Sensfuß 2008).

Game theory models focus on interactions of energy market players and analyse energy market equilibria. Models such as Cournot, Bertrand and Supply Function Equilibria are typical game theory approaches for analysing an oligopolistic electricity market (Herbst et al. 2012). Lise et al. (2006) developed a static computational game theory model for eight North-Western European countries. The model investigated the impacts of competition on wholesale price of electricity, electricity demand, firms' profits and different kinds of polluting emissions. Su and Huang (2014) applied a game theoretic framework to propose and validate a next-generation retail electricity market. This market was characterised as an energy internet with a high penetration of distributed residential electricity suppliers.

Energy models with an accounting framework balance energy and thermodynamic flow, and calculate economic outcome of an energy system. These models are driven by presumed development such as a penetration rate of a specific energy technology within certain timeframe (Mundaca and Neij 2009). The Policy Analysis Modelling System (PAMS) model developed by the Collaborative Labelling and Appliance Standards Program (CLASP) and the Lawrence Berkeley National Laboratory is an example. It is based on the stock accounting framework. The model is capable of estimating costs and benefits of appliance efficiency standard and labelling programs. It is designed to help policymakers to identify the most attractive targets for appliances and efficiency levels (Collaborative Labelling and Appliance Standards Program 2014).

Optimisation models aim to find optimal energy investment decisions endogenously (Van Beeck 1999). The model's objective function minimises the total energy system costs across all time periods and assumes equilibrium on energy markets. The outcome represents the best solution given economic, physical, environmental and technological variable and constraints (Fleiter, Worrell and Eichhammer 2011). The objective function is commonly optimised using linear or mixed integer mathematical programs (Welsch 2013).

The MARKal ALlocation model (MARKAL) is a well-known energy system optimisation model developed by the Energy Technology Systems Analysis Program of the IEA. It combines a detailed bottom-up model (with a simplified macroeconomic approach) used for identifying a least-cost energy system with restraints on emissions (Loulou et al. 2005; Zonooz et al. 2009). The Wien Automatic System Planning Package (WASP) model is a power system optimisation model developed by the International Atomic Energy Agency (IAEA). It is used to project an optimal expansion plan for a power generating system over a long period within constraints defined by modellers (International Atomic Energy Agency [IAEA] 2001).

### 2.4.3 Remarks

Top-down and bottom-up models are different in analytical approaches, underlying methodologies and modelling structures. They have comparative advantages and disadvantages in investigating questions in associated with energy, economic and policy issues (Sue Wing 2008).

One main advantage of top-down models is the incorporation of feedback effects between welfare, employment and economic growth (Böhringer and Rutherford 2006). Economic and societal effects triggered by policies are endogenously assessed in the models. This helps to generate more consistent results and facilitate better understanding of energy policy impacts on the economy as a whole (Herbst et al. 2012).

Top-down models often represent an energy sector in an aggregate production function to capture substitution effects. They do not feature energy technologies in details, hence cannot readily incorporate economic and technological assumptions about technological progress. Thus, they are limited in projecting energy technology futures and the impacts of policy changes (Böhringer and Rutherford 2006).

Contrary to top-down models, bottom-up models describe current and prospective energy technologies in great details. This enables bottom-up models to conduct comprehensive analysis on impacts of technology-specific policies and project plausible future for energy technologies (Herbst et al. 2012). However, it lacks the feedback of energy policies and macro-effects of the technological changes on the overall economy. It also presents a significant challenge for modellers to collect sufficient and reliable data to meet modelling requirements.

In order to combine the economic richness of top-down models and technological explicitness of bottom-up models, the hybrid energy system modelling approach was developed. Hybrid models feature technological explicitness, microeconomic realism and macroeconomic completeness (Bataille 2005; Hourcade et al. 2006). Merging these properties into one hybrid system can be achieved by soft linking existing top-down with bottom-up models through transferring data, parameters and coefficients manually. The merging can be also realised by a 'hard link' approach, which integrates two models into one single framework to achieve overall economic consistency (Böhringer and Rutherford 2006).

This research focuses on exploring energy technologies future in the NEM and the WEM. This will require explicit and detailed descriptions of power systems in two electricity markets. In particular, the research will need to project long-term evolution of electricity generation mix subject to changes of technologies costs and energy policies. Considering these factors, a model with bottom-up analytical approach is the favoured type to achieve the research purposes.

## 2.5 The Selection of Modelling Tool

This section reviews studies on Australian power system published between 2009 and mid-2014.[1] These studies applied energy modelling tools in Australian context. The energy models applied in these studies constitute a pool of eligible candidates for identifying the modelling tool for this research, effectively narrowed the number of modelling tools needed to be reviewed. The most suitable modelling tool to conduct this research is selected from this pool.[2]

[1] The studies about carbon pollution reduction scheme and Australia national and regional electricity market before 2010 can refer to review studies of Betz and Owen (2010) and Nelson Kelley and Orton (2012).

[2] Broader review on energy models can refer to the study of Connolly et al. (2010). This study reviewed 37 energy computer tools developed in different countries that can be used to model electricity system. These wide ranges of energy tools are diverse in terms of regions they analyse, technologies they examine, and objectives they accomplish.

### 2.5.1 Overview of Energy Modelling Studies in Australia

Since 2009, the Australian Government has taken a series of efforts to investigate future development of energy sector in order to address challenges of energy security and carbon emissions. The AMEO and the Department of Resources, Energy and Tourism (DRET) commissioned consulting companies ACIL Tasman[3], Intelligent Energy Systems (IES) and ROAM in 2009 to conduct energy modelling for developing Australia Energy white Paper 2012 (Department of Resources, Energy and Tourism [DRET] 2012). ACIL Tasman has been engaged to prepare energy market data (ACIL Tasman 2010). The IES and ROAM were retained to apply different modelling approaches using data provided by ACIL Tasman (Intelligent Energy System [IES] 2010b; ROAM 2010).

Table 2.3 lists fourteen Australian energy modelling studies, which were conducted between 2009 and mid-2014. This period matches the commencement date of the enhanced Renewable Energy Target and the abolition date of the CPM. These studies employed energy modelling tools to evaluate Australia national and/or regional energy system with medium-term (2030) and long-term (2050) timeframes.

It is worth to highlight the differences between energy system models and power system models. Both types of models can be categorised as the energy economic models, however their focuses of application are fundamentally different. This leads to their different strengths of modelling electrical power system. The energy system models such as the MARKAL/TIMES, analyse the whole energy system from resources and primary fuels supply to energy conversion and transformation, and to end energy service demand (Loulou et al. 2005; Zonooz et al. 2009). The electrical power system as the energy conversion chain of an energy system is simulated endogenously. Its simulation is driven by the combined performance of resources supply sectors that provide primary fuels and demand sectors that is determined by exogenous end-use energy service demand (Deane et al. 2012).

The power system models such as the PLEXOS and HOMER focus exclusively on the electric power system and sometimes the gas network without incorporating the

[3] In April 2013, Allen Group and ACIL Tasman were merged to create ACIL Allen Consulting (Boxsell 2013).

rest sectors of the energy system (Energy Exemplar 2015; Sen and Bhattacharyya 2014). Therefore the power system models are often driven by the exogenous inputs including electricity demands, electricity load, fuel prices, carbon prices and power plant technical and economic parameters (Deane et al. 2012).

As shown in Table 2.3, the studies of CSIRO-2009, IES-2010, NTNDP-2010, NTNDP-2011, BREE-2010, BREE-2011 and BREE-2012 applied the energy system models. The power system models were adopted by the studies of ROAM-2010, ROAM-2011, SKMMMA-2011, NTNDP-2012, NTNDP-2013, ACILALLEN-2013 and NUSW-2014. The analytical approach of bottom-up represents the explicit and specific energy technology and process descriptions in the models, which is often applied by the simulation models and optimisation models. The reviewed fourteen studies all adopted the bottom-up optimisation modelling tools.

With the support of the DRET, the BREE has been committed to publishing long range projections of Australian energy production regularly. In 2010, the Australian Bureau of Agricultural and Resource (ABARE) has published Australian energy projections to 2029-30 [4] (Syed et al. 2010). The BREE updated the projection period to 2034-35 in 2011 (BREE 2011). In December 2012, the report was further updated to provide projections of Australian energy consumption, production and trade for the period 2012-13 to 2049-50. This report provided more detailed energy projections than was presented in the Energy White Paper 2012 (Deane et al. 2012).

In 2011, the Australian Treasury undertook one of the largest and most complex carbon price modelling projects in Australia. This was done to provide a comprehensive analysis of implications of carbon pricing on the economy. The Treasury's modelling was comprised of two top-down CGE models developed in Australia: the Global Trade and Environment Model (GTEM) and the MMRF model. They are economy-wide models that capture interactions between economic sectors, producers and consumers. The GTEM model simulates the global economy. The MMRF models the Australian economy in the state and territory level.

[4] It was published by the ABARE in 2010. The ABARE later merged with the Bureau of Rural Sciences to form Australian Bureau of Agricultural and Resource Economics and Sciences (ABARES). From 1 July 2011, responsibility for resources and energy data and research was transferred from the ABARES to the BREE.

**Table 2.3** Overview of Australian energy modelling studies.

| Project Acronym | Main modelling tool | Sector of modelling | Focus of modelling | Geographic boundary | Modelling timeframe | Research institution | References |
|---|---|---|---|---|---|---|---|
| CSIRO-2009 | Energy Sector Model (ESM) | Electricity and transportation system | GHGs and electricity prices | Country | 2006-2050 | CSIRO | (Lilley, Szatow and Jones 2009; Lilley et al. 2012) |
| IES-2010 | MARKAL | Stationary energy sector | Electricity sector development | Country | 2010-2030 | IES Consulting | (IES 2010b) |
| ROAM-2010 | Integrated Resource Planning Suite (IRP) | Electricity system | Generation and transmission expansion costs | Country | 2010-2030 | ROAM Consulting | (ROAM 2010) |
| BREE-2010 | $E_4$cast | Energy system | Energy consumption, production and trade | Country | 2007/08 -2029/30 | ABARE (BREE) | (Dickson et al. 2001; Syed et al. 2010) |
| BREE-2011 | $E_4$cast | Energy system | Energy consumption, production and trade | Country | 2008/09 -2034/35 | BREE | (BREE 2011) |
| BREE-2012 | $E_4$cast | Energy system | Energy consumption, production and trade | Country | 2010/11-2049/50 | BREE | (Deane et al. 2012) |
| NTNDP-2010 | MARKAL | Electricity system | Generation and transmission development | Region (NEM) | 2010/11-2029/30 | AEMO | (AEMO 2010b; IES 2010a) |
| NTNDP-2011 | MARKAL | Electricity system | Generation and transmission development | Region (NEM) | 2011/12-2029/30 | AEMO | (Johnson and Pride 2010) |
| NTNDP-2012 | PLEXOS | Electricity system | Generation and transmission development | Region (NEM) | 2012/13-2036/37 | AEMO | (AEMO 2012a, c, e; MWR and NBS 2013) |
| NTNDP-2013 | PLEXOS | Electricity system | Generation and transmission development | Region (NEM) | 2013/14-2037/38 | AEMO | (ACIL Tasman 2012b; AEMO 2013d, e; BREE 2013) |
| ROAM-2011 | Long Term Integrated Resource Planning (LTIRP) Model | Electricity generation sector | Electricity generation sector development | Country | 2010/11-2049/50 | ROAM Consulting | (IEA 2013a) |
| SKMMMA-2011 | Strategist | Electricity generation sector | Carbon emission abatement costs | Country | 2011-2050 | SKM MMA Consulting | (SKM MMA 2011) |
| ACILAllen-2013 | PowerMark LT | Electricity generation sector | GHGs emissions projection | Country | 2009/10-2049/50 | ACIL Allen Consulting | (ACIL Allen 2013) |
| UNSW-2014 | NEMO | Electricity system | Electricity sector development and energy technology costs | Region (NEM) | 2010 and 2030 | University of New South Wales (UNSW) | (Elliston, Diesendorf and MacGill 2012; Elliston, MacGill and Diesendorf 2014; Geoscience Australia and BREE 2014) |

The Australian Treasury has supplemented the CGE models with a series of sector-specific bottom-up models for hedging against inherent uncertainties of economic modelling (Australian Treasury 2011; Biberacher 2004). ROAM Consulting and SKM MMA Consulting were engaged to conduct electricity generation sector modelling with the applications of different modelling tools (ROAM 2011; SKM MMA 2011).

At the regional level, the AEMO annually publishes the National Transmission Network Development Plan (NTNDP). The annual NTNDP provides an independent and strategic view on the efficient development of generation capacity and transmission network over a 25-year medium-term planning horizon in the NEM (Scudder 2005). The first NTNDP was commenced with scenarios development for the Australian stationary energy sector to 2030 by the MMA[5] and Strategies Partners Consulting in 2009 (Sautter 2009). The AEMO has published NTNDP 2010, NTNDP 2011, NTNDP 2012 and NTNDP 2013, NTNDP 2014 up to date (AEMO 2010b, 2011, 2012b, 2013a, 2014a).

Two studies in Table 2.3 explored potential roles of the RETs in future Australian electricity sector. These were conducted by Australian research institutes. The CSIRO-2009 investigated key economic, technical, environmental, policy and regulatory barriers and enablers for the adoptions of the RETs from 2006 to 2050 (Lilley, Szatow and Jones 2009; Lilley et al. 2012). The UNSW-2014 made costs comparison of 100% renewable electricity scenario with low emission fossil fuel scenarios in the NEM in 2030 (Elliston, Diesendorf and MacGill 2012; Elliston, MacGill and Diesendorf 2014).

### 2.5.2 Overview of Modelling Scenarios

Scenario analysis projects different development paths to reflect future uncertainties and possible policy responses (Steenhof and Fulton 2007). Different scenarios involve different drivers such as economic and population growth rates. Scenario analysis provides an effective way to examine and develop robust technology

[5] The McLennan Magasanik Associates (MMA) has been acquired by the advisory, project delivery and engineering firm Sinclair Knight Merz (SKM) to form SKM MMA in August, 2010.

strategies and related investment portfolios to meet a range of user-specified carbon constraints and policy objectives.

Australian modelling studies listed in Table 2.3 focused on projecting the impacts of carbon prices on power system transformation. Scenarios constructed by these studies therefore centred on defining long-term carbon emissions reduction targets.

The representative scenarios of the reviewed studies were listed in Table 2.4. Three typical groups of scenarios were classified by carbon prices and GHG emissions reduction targets in these studies. The scenarios in the first group enforced the world carbon targets without the company of any Australian domestic carbon prices. The second group of scenarios set the domestic carbon target of 5% reduction on 2000 level by 2020. The third group placed 25% carbon emissions cut on 2000 level by 2020 for Australia. The scenarios in the second and third groups implemented long-term domestic carbon prices as the major instruments to materialise carbon reduction targets.

The Australian economy emitted 586 Mt GHG emissions in 2000 (CCA 2014a). In order to accomplish a 5 %, 15 % and 25 % emissions reduction targets, the economy wide emissions will need to be cut to 557 Mt, 498 Mt and 440 Mt respectively in 2020. For achieving 80 % long-term carbon reduction target, the emissions will need to be reduced to 117 Mt by 2050.

Specific carbon budgets for entire Australian economy were clearly and legitimately established (Australian government 2015). However, no explicit emissions reduction target has been set for Australian electricity generation sector. GHG emissions from the electricity sector were 198 Mt $CO_2$-e in 2012, accounting for around 33% of Australia's total domestic emissions (Commonwealth of Australia 2013). If the author assumes that carbon emissions from electricity generation sector remain about one third of national emissions to 2049-50. Then carbon emissions in power sector should be proportionally reduced from 198 Mt in 2012 to approximately 39 Mt in 2049-50 to comply national emissions reduction targets.

**Table 2.4** Overview of modelling scenarios and data sources.

| Project Acronym | Data sources of carbon prices assumptions | Selected scenarios | Scenario description | Scenario names |
|---|---|---|---|---|
| CSIRO-2009 | 2008 Garnaut Climate Change Review (Garnaut 2008) and Treasury 2008 study (Australian Treasury 2008). | CPRS-5 | An emission reduction mechanism leads to a reduction in Australian emissions of 5 % on 2000 levels by 2020 and 60 % below 2000 levels by 2050 for stabilization at 550 ppm. | CSIRO-2009(5%) |
| | | Garnaut-450 ppm | An emission reduction mechanism leads to a reduction in Australian emissions of 25 % on 2000 levels by 2020 and 90 % below 2000 levels by 2050 for stabilization at 450 ppm. | CSIRO-2009(25%) |
| ROAM-2010 | ROAM's estimates (ROAM 2010). | Fast rate of change with high carbon price | The scenario assumes targets have been set to achieve a global $CO_2$ concentration not exceeding 450 ppm by 2050 with domestic medium and high carbon prices. | IES-2010(25%)<br>ROAM-2010(25%) |
| IES-2010 | ACIL Tasman analysis on Treasury 2008 study (ACIL Tasman 2010; Australian Treasury 2008). | | | |
| NTNDP-2010<br>NTNDP -2011 | Treasury 2008 study (Australian Treasury 2008). | An uncertain world with low carbon price | A target of $CO_2$-e concentration not exceeding 550 ppm by 2050 has been agreed internationally with domestic no and low carbon prices. | IES-2010(5%)<br>ROAM-2010(25%) |
| BREE-2010 | Adjusted based on Treasury 2008 study (Australian Treasury 2008). | Most likely path | To reduce emissions to 5 % below 2000 levels by 2020, a long-term reduction in emissions to 80 % below 2000 levels by 2050. | BREE-2010(5%) |
| BREE-2011 | Calculations based on Treasury 2011 study (Australian Treasury 2011). | | | BREE-2011(5%) |
| BREE-2012 | Calculations based on Treasury 2011 study and updates (Australian Treasury 2011*)*. | | | BREE-2012(5%) |
| ROAM-2011 | Estimates in Treasury 211 study (Australian Treasury 2011). | Medium Global Action | World action to achieve a 550 ppm emissions target, without any domestic carbon price. | ROAM-2011(MGA)<br>SKMMMA-2011(MGA) |
| | | Ambitious Global Action | World action to achieve a 450 ppm emissions target, without any domestic carbon price. | ROAM-2011(AGA)<br>SKMMMA-2011(AGA) |
| SKMMMA-2011 | | Core Policy | Assumes that the world sets out to achieve a $CO_2$ 550 ppm emissions target, with a domestic \$20 starting carbon price in 2012, expressed in mid-2010 dollars. In FY 2016 the price jumps from \$20/t $CO_{2\text{-}e}$ to \$25/t $CO_2$ and grows at an average rate of 5% per annum thereafter. | ROAM-2011(5%)<br>SKMMMA-2011(5%) |

| | | | | |
|---|---|---|---|---|
| | | High Price | World action to achieve a 450 ppm emissions target, with a domestic carbon pricing commences in July 2012 and the initial carbon price is just under \$30/t $CO_2$-e. In FY 2016 the price jumps from \$30.5/t $CO_2$-e to \$52/t $CO_2$-e. | ROAM-2011(25%) SKMMMA-2011(25%) |
| NTNDP -2012 | Calculations based on Treasury 2011 study and updates (Australian Treasury 2011). | Planning scenario | The most likely direction that the market will move. To reduce emissions to 5 % below 2000 levels by 2020, a long-term reduction in emissions to 80 % below 2000 levels by 2050. | NNDP-2012(5%) |
| | | Fast rate of change | The targets aim to achieve a global $CO_2$ concentration not exceeding 450 ppm by 2050.To reduce emissions to 25 % below 2000 levels by 2020, a long-term reduction in emissions to 80 % below 2000 levels by 2050. | NNDP-2012(25%) |
| NTNDP-2013 | NIEIR revisions on Treasury 211 study (AEMO 2013d). | zero carbon price scenario | Where the explicit price on carbon emissions is removed from 2014 onwards. This scenario models generation dispatch without an explicit carbon emissions price, recognising the Federal Government's intention to repeal current legislation. | NNDP-2013(Zero) |
| | | A carbon price scenario | Reflecting current legislation, a lower expectation of carbon prices linking to international emissions trading schemes. To reduce emissions to 5 % below 2000 levels by 2020, a long-term reduction to 80 % below 2000 levels by 2050. | NNDP-2013(5%) |
| ACILAllen-2013 | Estimates in Treasury 211 study (Australian Treasury 2011). | No Carbon Price scenario | International agreement to reduce or limit emissions by 2020, with coordinated global action after 2019-20 to reduce GHG emissions with target of 550 ppm $CO_2$, no carbon price for Australia. | ACILAllen-2013(Zero) |
| | | Central Policy scenario | A fixed carbon price is set for the period 2012-13 to 2013-14, and a floating price from 1 July 2014. The carbon price provided by Treasury is consistent with global efforts to reduce greenhouse gas emissions to 550 ppm $CO_2$. | ACILAllen-2013(5%) |
| UNSW-2014 | Estimates in Treasury 211 study (Australian Treasury 2011). | 100% Renewable scenario | The generation fleet consists of commercially available renewable energy technologies. | n/a |
| | | Fossil fuel scenarios | Three fossil fuel scenarios with the generation fleet consists of coal and gas plants | n/a |

The scenarios listed in Table 2.4 served for exploratory purposes. They were used to project future portfolios of energy technologies in power system expansion. The projections were mainly driven by carbon prices and emissions reduction targets defined in the scenarios. The RETs and CCS were not specifically compared in the reviewed studies.

The modelling results of the scenarios listed in Table 2.4 reflected the penetration rates of the RETs and CCS in Australian electricity market in a long term. However, the RETs and CCS were not specifically compared in reviewed studies. They lacked the information of the comparative advantages of the RETs and CCS in reducing carbon emissions and their impacts on system costs. Thus, the reviewed studies provided limited insights on comparative carbon reduction potential of the RETs and CCS in Australian electricity markets from a long-term perspective.

### 2.5.3 Selection of the Modelling Tool

This section identifies the most suitable energy modelling tool for this research. Considering research purposes and objectives, the modelling tool applicable to this research should meet criteria listed below:

i. Bottom-up analytical approach with explicit, detailed and high temporal representation of an electric power system;
ii. The framework capable of finding the optimal combination of generation and transmission new construction and retirements that minimises the net present value (NPV) of the system's total costs over a long-term planning horizon;
iii. High reputation with up-to-date applications in live situations;
iv. The availability for academic users;
v. Economic affordability for academic users;
vi. The availability of acquiring data inputs.

All models listed in Table 2.5 satisfy criteria (i) and (ii). They are bottom-up energy and/or power system simulation platforms based on optimisation theory. In addition, these models were developed by well-known international and governmental agencies, major energy consultancy companies and university. They all have been applied in recent studies of Australian power system simulation. Hence, these models also meet the criteria (iii), which have credibility in modelling Australian electricity markets.

ESM was used to examine a long-term change (2006-2050) in the technology mix of Australian electricity and transport sectors driven by carbon prices in CSIRO-2009 study (Lilley et al. 2012). It is a partial equilibrium model solved as a mixed integer linear program. The model was co-developed by the ABARE and the CSIRO. It represents time in annual frequency (Lilley, Szatow and Jones 2009). For more precisely examining economic impacts and benefits of distributed energy in the NEM, a high temporal power system model PLEXOS was applied to simulate power system in 2020, 2030 and 2050 (Lilley et al. 2012).

**Table 2.5** Overview of modelling tools.

| Project Acronym | Primary modelling tool | Dispatch simulation | Investment Optimisation | Developer | Analytical Approach | Underlying Methodology | Time resolution |
|---|---|---|---|---|---|---|---|
| CSIRO-2009 | Energy Sector Model (ESM) | No | Yes | CSIRO and ABARE | Bottom up | Partial equilibrium and optimisation with linear programming | A year |
| IES-2010<br>NTNDP-2010<br>NTNDP - 2011 | MARKAL | No | Yes | IEA-Energy Technology Systems Analysis Programme | Bottom up | Partial equilibrium and optimisation with mixed integer linear Programming | 36 time-slice a year |
| ROAM-2010 | Integrated Resource Planning Suite (IRP) | Yes | Yes | ROAM Consulting | Bottom up | Optimisation with dynamic programming | Two hourly |
| BREE-2010<br>BREE-2011<br>BREE-2012 | $E_4$cast | No | Yes | ABARE | Bottom up | Partial equilibrium and optimisation | A year |
| ROAM-2011 | Long Term Integrated Resource Planning (LTIRP) Model | No | Yes | ROAM Consulting | Bottom up | Optimisation with linear programming | A discrete number of load blocks per year |
| SKMMMA-2011 | Strategist Suite | Yes | Yes | Ventyx | Bottom up | Optimisation with dynamic programming | Hourly electricity loads representing a typical week in each month of the year. |
| NTNDP - 2012<br>NTNDP-2013 | PLEXOS | Yes | Yes | Energy Exemplar | Bottom up | Optimisation with mixed integer linear programming | 120 time-slice a year |
| ACILAllen-2013 | PowerMark LT | No | Yes | ACIL Allen | Bottom up | Optimisation with linear programming | 100 time-slice a year |
| UNSW-2014 | NEMO | Yes | No | UNSW | Bottom up | Simulation and optimisation with Python programming | Hourly |

$E_4$cast model used for the BREE's Australian energy projection studies is a partial equilibrium model for the Australian energy sector. It projects energy consumption by fuel types, industry and state or territory, on a financial year basis. The first version of $E_4$cast was developed by the ABARE in 2000 and has been regularly updated since (BREE 2011). $E_4$cast analyses future energy requirements and supply using an annual time-step for up to a maximum of 30 years. This model was rejected because it was not for sale. Analysts need pay to have their analysis completed by the BREE (Connolly et al. 2010).

ESM and $E_4$cast models are properties of the Australian Government, which are challenging to be obtained individually by the researcher. Therefore, these two models do not meet the criteria (iv) as available modelling tools for this research.

The ROAM-2010 study used IRP modelling suite for the least cost optimisation of a power system expansion. It contained a time sequential dispatch engine ROAM 2-4-C to determine system costs with network and intermittent generation constraints. The IRP employed a dynamic programming algorithm to find a least cost path over entire study period. The calculation took into account of production costs, fixed and variable operating costs and capital repayments for new generation and transmission options (ROAM 2010).

Later, ROAM Consulting split IRP suite into a LTIRP model and a ROAM 2-4-C model in order to provide clients with an option of non-time sequential model to reduce study costs (ROAM 2013). In ROAM-2011 study, LTIRP was used to determine the least cost capacity expansion plan. The simulation minimised total cost of servicing energy demand for each year. ROAM has then used results from LTIRP modelling as inputs into ROAM 2-4-C model. This allowed an enhanced level of detail and accuracy for pricing, generation dispatch and interconnector flow forecasts for the NEM (ROAM 2013).

PowerMark LT model applied by ACIL Allen is a dynamic least cost model. It optimises system investments over a chosen model horizon. A range of input assumptions are implemented including demand growth, incumbent plant costs, interconnectors, new development costs and government policy settings. This model uses fewer dispatch periods than a full power system dispatch model in order to solve the problem more quickly. Typically 100 time slices for a year is defined in PowerMark LT compared to one time-slice per hour in a system dispatch model (ACIL Allen 2013).

IRP, the LTIRP, and the PowerMark LT models are intelligent properties of consultancy companies. These models cannot be obtained separately from consulting services provided by ROAM and ACIL Allen. Therefore, these models do not satisfy the criteria (iv) and are not practical for the researcher's use.

The SKMMMA-2011 employed Strategist modelling package for integrated resource planning. Strategist is comprised of multiple modules including forecasted load modelling, energy efficiency programs and production cost calculations. It can be used for simulating the dispatch of energy resources, optimising future decisions and calculating nonproduction-related cost recovery (Ventyx n.d.). The module of Strategist: Proview has been employed and run iteratively to choose the most economic expansion plan among a range of expansion possibilities (SKM MMA 2011).

The studies of NTNDP-2010 and NTNDP-2011 applied MARKAL for modelling the least-cost capacity expansion way to 2029-30 in the NEM. The key outputs were new and retired generation capacity and interconnector expansions. The studies were completed by adding Transmission Network Power Flow Studies (TNPFS) and Time-Sequential Market Simulation Studies (TSMSS). TNPFS was used to test real-world viability of MARKAL's outputs and assess the adequacy of main transmission network. TSMSS had the objective of producing detailed market dispatch results. It operated based on generation and transmission expansion projects and retirements produced by MARKAL and the power system simulation studies (AEMO 2010b).

As an economic optimisation model for energy system, MARKAL computes an inter-temporal partial equilibrium at all levels of an energy system: primary resources, secondary fuels, final energy and energy services. However, its limited temporal disaggregation cannot be utilised to investigate problems such as daily supply-demand balancing of electricity (Ekins, Skea and Winskels 2012).

NTNDP-2012 and NTNDP-2013 studies utilised similar modelling framework as NTNDP-2010 and NTNDP-2011 studies. However, the newer studies replaced MARKAL model with PLEXOS model as the tool for the least cost expansion modelling. PLEXOS model is able to simulate long-, medium- and short-term power system generation, transmission and capacity expansion in an optimal way (Energy Exemplar 2015). This replacement increased the time resolution from 36 to 120 time segments for a modelling year. Increased time resolution allowed the model to better capture implications of demand diversity between regions and the correlation of wind and demand (AEMO 2012a).

NEMO model used by the Elliston, MacGill and Diesendorf (2014) is a bottom-up, operation and investment optimisation tool written in the Python programming language. It has three components: a framework that supervises the simulation, a large integrated database of historical meteorology and electricity industry data, and a library of simulated power generators (Elliston, MacGill and Diesendorf 2014).

MARKAL, PLEXOS, the Strategist Suite and the NEMO are all available commercially or academically. MARKAL is a model generator freely distributed by its developer. However, its application requires purchasing third party software: the modelling language GAMS, an interface and a solver. Estimated total costs for acquiring third party software is thousands of dollars for academic licenses and tens of thousands of dollars for commercial licenses. Additionally, all third party programs are subject to an annual maintenance fee after the first year's use (Energy Technology Systems Analysis Programme 2013). Ventyx as the owner of Strategist Suite did not provide open information for its license price (Ventyx n.d.). NEMO is the intellectual properties of the University of New South Wales. It has free and open access, and requires no proprietary software for it to operate. However, it is not as sophisticated and widely used as the MARKAL and the PLEXOS.

PLEXOS is a successful, well-respected and widely used commercial power system modelling software (Deane et al. 2012; Deane, Drayton and Ó Gallachóir 2014; Wagner, Molyneaux and Foster 2014). As a least cost expansion algorithm and planning tool, PLEXOS model has been used to develop the AEMO's NTNDP 2012, 2013 and 2014 reports (AEMO 2012a, 2013b). AEMO has publically released a completed dataset of its NTNDP 2013 study modelled by PLEXOS. This database provides a great source for this research to obtain sufficient and reliable data inputs for its PLEXOS modelling.

PLEXOS can model electricity system in a long-term timeframe with coarse time resolution. At the same time, it is also capable of accurately simulating a short-term electricity dispatch process with fine time resolution (Energy Exemplar 2014). The developer of PLEXOS: the Energy Exemplar provides free license and mathematical programming packages for academic use. Its academic license allows six months of free use of PLEXOS. This can be renewed upon the research progress (Energy Exemplar 2015). In addition, the Energy Exemplar provides extensive online learning resources, workshops and support for its users. PLEXOS model fully meets selection criteria (iv), (v) and (vi). According to the criteria (v), PLEXOS model is the most economical to obtain compared to MARKAL and the Strategist Suite for academic researchers. Therefore, PLEXOS model was chosen over MAKAL and Strategist Suite and identified as the most suitable energy modelling tool for conducting this research.

This research aims to design scenarios specifically for the comparison of economic and environmental potentials of the RETs and CCS. The research will apply the PLEXOS model: a bottom-up optimisation energy model to conduct the modelling. This model will be used to simulate future evolvement of the Australian electricity markets including the NEM and the WEM, and explore least cost ways of generation capacity expansion with the RETs and CCS technologies under the current and potential Australian Government's climate policies.

# Chapter 3 Methodology

This chapter describes system and data structures of the selected energy modelling tool: the PLEXOS. Its core formulation for long-term planning is introduced here along with the constrained optimisation theory. Scenario analysis is a critical method used together with the PLEXOS modelling to explore future uncertainties in the Australian power systems. This chapter also presents scenario construction theory. It is followed by a detailed overview of the scenarios designed for this research.

## 3.1 The PLEXOS Model

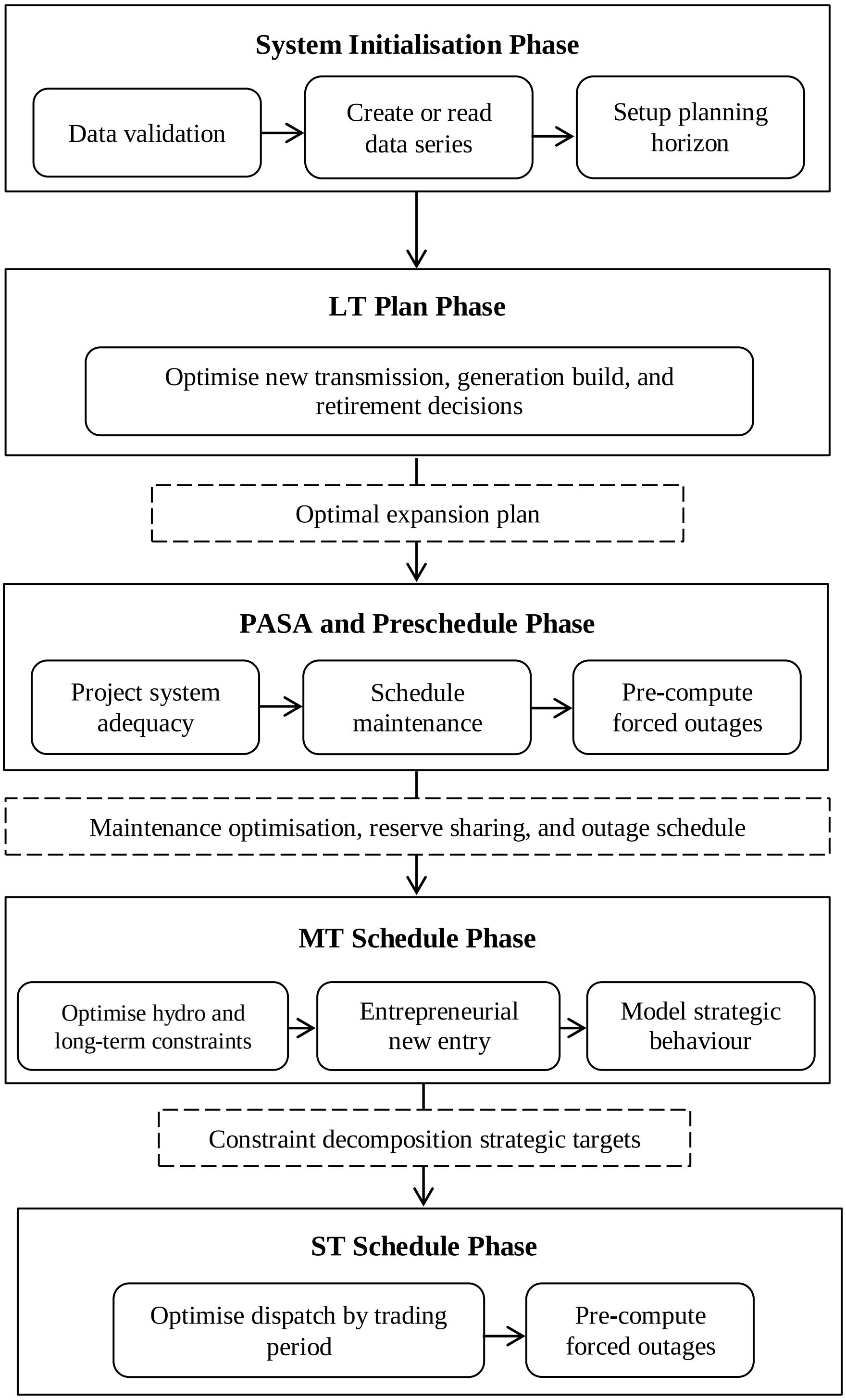
### 3.1.1 Overview

The PLEXOS is a successful fundamental power market simulation tool developed by the Energy Exemplar. It features with cutting-edge mathematical programming and stochastic optimisation techniques that are widely used for power market modelling, simulation and analysis (Energy Exemplar 2015).

Four unique simulation phases are incorporated in the PLEXOS, including long-term (LT) planning, projected assessment of system adequacy (PASA), mid-term (MT) and short-term (ST) schedule. The purpose of the LT Plan is to solve the capacity expansion problem over a long-term planning horizon, typically expected to be in the range of 10 to 40 years.

The LT Plan runs before the PASA, the MT Schedule and the ST Schedule phases. Based on the results of the LT Plan, the PASA phase creates maintenance events for the subsequent simulation phases: the MT Schedule and ST Schedule. It then computes reliability statistics such as loss of load probability (LOLP) for the system (Energy Exemplar 2014).

The MT Schedule handles power system operation simulation and scheduling problem. It can be executed stand-alone or run in concert with the other models as shown in Figure 3.1. In the stand-alone mode, the MT Schedule can be used to give fast results for medium to long-term studies. When runs as a component, the MT Schedule's results are automatically linked to the ST Schedule.




Source: Energy Exemplar (2014).

**Figure 3.1** PLEXOS simulation flowchart.

The MT Schedule provides the capabilities of handling medium term strategic objectives and financial optimisation. It does this by translating medium term equilibrium outcomes to shorter-term goals that can be handled by the ST Schedule, and decomposing medium term constraints. Otherwise these constraints would have to be approximated or ignored by the ST Schedule into constraints short enough that the ST Schedule can handle (Energy Exemplar 2014).

The ST Schedule is distinct from the LT Plan and the MT Schedule in that it models days of the horizon at full resolution. At the default setting, this means every hour, but the resolution can be customised to any feasible length e.g. 5-minute intervals. It is designed to emulate the dispatch and pricing of real market-clearing engines and provide additional functionality to deal with unit commitment, constraint modelling, financial/portfolio optimisation, Monte Carlo simulation and stochastic optimisation (Energy Exemplar 2014).

For the purpose of this research, the LT Plan phase was the major function of the PLEXOS to be applied. It was used to find the optimal combination of new generation builds and retirements. This optimal combination aimed at minimising the NPV of the total costs of the electricity markets in Australia over the period of 2012-13 to 2049-50 under the scenarios defined by various assumptions and constraints.

### 3.1.2 The Long-Term Planning

#### 3.1.2.1 Constrained Optimisation

The capacity expansion problem in the LT Plan phase is formulated in the simulator as a Mixed-Integer Linear Program (MILP). It aims to minimise the total costs of the system's capacity and transmission expansion in a long-term timeframe. The mathematical foundation for the costs minimisation calculation in the PLEXOS' LT Plan is the constrained optimisation theory (Energy Exemplar 2014).

A classic constrained optimisation problem is expressed in the following form (Baldick 2006; Biggar and Hesamzadeh 2014):

$$\mathbf{min}\{\boldsymbol{f}(\boldsymbol{x})|\boldsymbol{g}_{\boldsymbol{i}}(\boldsymbol{x}) = \boldsymbol{c}_{\boldsymbol{i}}, \boldsymbol{h}_{\boldsymbol{j}}(\boldsymbol{x}) \leq \boldsymbol{d}_{\boldsymbol{j}}\} \tag{3.1}$$

The equation (3.1) indicates that the minimisation of $f(x)$ is subject to the equality constraints $g_i(x) = c_i$ and the inequality constraints $h_j(x) \leq d_j$. Here $x$ is a vector of $k$ variables, and the functions $f(\cdot)$, $g_i(\cdot)$, and $h_j(\cdot)$ are all functions from $R^k \to R$.

To minimise equation (3.1), the Lagrange multipliers $\lambda_i$ and $\mu_i$ are introduced. Each constraint equation has its own Lagrange multiplier as shown below:

a. **For *i*= *1, 2,……, n*, $\boldsymbol{g_i(x) = c_i \leftrightarrow \lambda_i}$;**
b. **For *j*= *1, 2,……, m*, $\boldsymbol{h_j(x) \leq d_j \leftrightarrow \mu_i}$.**

If a set of values $x, \lambda\ and\ \mu$ satisfy the *Karush-Kuhn-Tucker* (KKT) conditions, then *x* is a solution to the constrained optimisation equation (3.1). The KKT conditions are listed below:

1) The First Order Condition: for *l= 1, 2,……, k,*

$$\frac{\partial f}{\partial x_l} - \sum_i \lambda_i \frac{\partial g_i}{\partial x_l} - \sum_j \mu_j \frac{\partial h_j}{\partial x_l} = 0 \tag{3.2}$$

2) Equality constraints: for i= 1, 2,……, n,

$$g_i(x) = c_i \tag{3.3}$$

3) Inequality constraints: for j= 1, 2,……, m,

$$h_j(x) \leq d_j \tag{3.4}$$

4) The complementary slackness conditions: for j= 1, 2,……, m,

$$\mu_j(h_j(x) - d_j) = 0 \tag{3.5}$$

5) For *j= 1, 2,……, m,*

$$\mu_j \geq 0 \tag{3.6}$$

Hence, the problem of finding a solution to the constrained optimisation equation (3.1) is converted to the problem of finding a solution to the KKT conditions 1) to 5). The Lagrange multipliers $\lambda_i$ and $\mu_i$ yield the sensitivity of the objective function to the right-hand side of the equality and inequality constraints.

The problem formulation and solving in the PLEXOS' LT Plan are consistent to the simplified constrained optimisation theory introduced above.

#### 3.1.2.2 The Formulation of LT Plan

In the PLEXOS, the objective function of the LT Plan seeks to minimise the NPV of build costs plus fixed operations and maintenance (FO&M) costs plus production costs. The core for the LT Plan MILP formulation is listed below (Energy Exemplar 2014):

**Objective function**:

Minimise

$$\sum_{(y)}\sum_{(g)} \boldsymbol{DF_y \times (BuildCost_g \times GenBuild_{(g,y)})} + \sum_{(y)} \boldsymbol{DF_y} \times \left[\boldsymbol{FOMCharge_g \times 1000 \times PAMX_g (Units_g} + \sum_{i \le y} \boldsymbol{GenBuild\ Units_{(g,i)}})\right] + \sum_{(t)} \boldsymbol{DF_{t \in y} \times L_t} \times \left[\boldsymbol{VoLL \times USE_t} + \sum_{g} \left(\boldsymbol{SRMC_g \times Gen\ Load_{(g,t)}}\right)\right] \tag{3.7}$$

Subject to:

Energy Balance Condition

$$\sum_{(g)} \boldsymbol{GenLoad_{(g,y)} + USE_t = Demand_t} \quad \forall_t \tag{3.8}$$

Feasible Energy Dispatch Accounting for Outage Rates Condition

$$\boldsymbol{GenLoad_{(g,t)} \le \left(1 - MOR_g \times MF_t - FOR_g\right) \times PMAX_g \times (Units_g} + \sum_{i \le y} \boldsymbol{GenBuild_i}) \quad \forall_{g,t} \tag{3.9}$$

Feasible Builds Condition

$$\sum_{\mathbf{i \le y}} \mathbf{GenBuild_{(g,i)}} \le \mathbf{MaxUnitsBuilt_{(g,y)}} \tag{3.10}$$

Integrity Condition

$$\boldsymbol{GenBuild_{(g,y)}\ to\ be\ integer}$$

Capacity Adequacy Condition

$$\sum_{(g)} \boldsymbol{PMAX_g (Units_g} + \sum_{i \le y} \boldsymbol{GenBuild_i) + CapShort_y} \ge \boldsymbol{PeakLoad_y + ReserveMargin_y} \ \forall_y \tag{3.11}$$

Where,

The variables defined are:

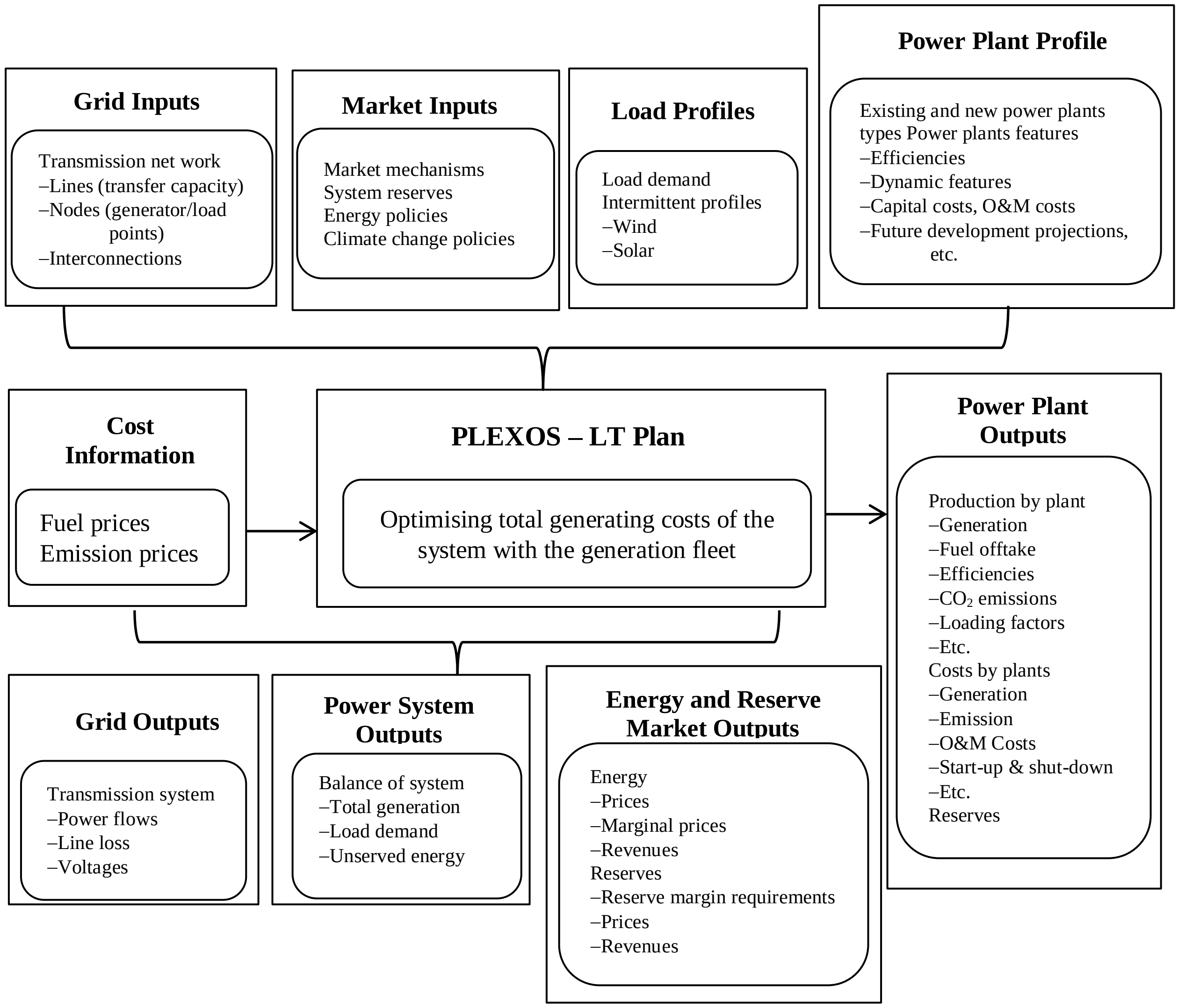
- $GenBuild_{(g,y)}$, number of generating units build in year $y$ for Generator $g$, integer;
- $GenLoad_{(g,t)}$, dispatch level of generating unit $g$ in period $t$, continuous;
- $USE_t$, unserved energy in dispatch period $t$, continuous;
- $CapShort_y$, capacity shortage in year $y$, continuous;

The parameters defined are:

- $\boldsymbol{D}$, discount rate. $\boldsymbol{DF_y} = 1/(1 + \boldsymbol{D})^y$ which is the discount factor applied to year $y$, and $\boldsymbol{DF_t}$ which is the discount factor applied to dispatch period $\boldsymbol{t}$**;**
- $\boldsymbol{L_t}$, duration of dispatch period $\boldsymbol{t}$, Hours;
- $BuildCost_{\boldsymbol{g}}$, overnight build cost of generator $\boldsymbol{g}$, AU$;
- $MaxUnitsBuilt_{(\boldsymbol{g},y)}$, maximum number of units of generator $\boldsymbol{g}$ allowed to be built by the end of year $\boldsymbol{y}$**,** integer;
- $PMAX_{\boldsymbol{g}}$, maximum generating capacity of each unit of generator $\boldsymbol{g}$**,** MW;
- $Units_{\boldsymbol{g}}$, number of installed generating units of generator $\boldsymbol{g}$**,** integer;
- *VoLL*, value of lost load (energy shortage price), AU$/MWh;
- $SRMC_{\boldsymbol{g}}$, short-run marginal cost of generator $\boldsymbol{g}$ which is composed of Heat Rate × Fuel Price + VO&M Charge, AU$/MWh;
- $FOMCharge_{\boldsymbol{g}}$, fixed operations and maintenance charge of generator $\boldsymbol{g}$**,** AUD$;
- $\mathbf{Load_t}$, average power demand in dispatch period $\boldsymbol{t}$**,** MW;
- $PeakLoad_y$, system peak power demand in year $\boldsymbol{y}$, MW;
- $ReserveMargin_y$, margin required over maximum power demand in year $\boldsymbol{y}$**,** MW;
- *CapShortPrice*, capacity shortage price, AUD$/MW;
- $MF_t$, the Region Maintenance Factor in period $t$.

### 3.1.2.3 Data Framework of the PLEXOS

A conceptual framework of data inputs and outputs is helpful to understand the way of applying the LT planning function of the PLEXOS to project generation capacity expansion in the NEM and the WEM.




Source: Energy Exemplar (2014).

**Figure 3.2** PLEXOS data framework

As shown in Figure 3.2, data required to construct a power system in the PLEXOS are comprised of power plant inputs, market information and grid profiles. Driven by environmental and technological constraints and energy demand, the LT plan runs optimisation algorithm to compute long-term pathway of system capacity development with minimised expansion costs. The LT Plan reports the outputs on grid expansion and constraints, energy market index and power system operation outcomes.

## 3.2 Scenarios Design

### 3.2.1 Scenarios Construction Theory

Scenario planning is a tool used to investigate future prospects affected by uncertainties. It has been proven to be a disciplined strategy for constructing plausible outlooks which may differ because of decision making (Schoemaker 1995). The analytical focus of the scenario development is on exploring what are the consequences and most appropriate responses under different drivers and their associated uncertainties. Hence, the scenario planning can effectively serve purposes of enhancing understanding and informing good decisions (Duinker and Greig 2007).

Schwartz (1996) presented three essential interacting components of scenario construction namely driving forces, predetermined elements and critical uncertainties. Driving forces are the dominant factors shaping the research object or field. Predetermined elements are the factors will remain the same or slow-changing in the scenario planning horizon. Critical uncertainties are the uncertain factors that are related to the driving forces and predetermined elements.

A deductive approach of constructing scenarios emerged based on the Schwartz's work and provided a useful guideline of scenarios design for this research (Duinker and Greig 2007; Schwartz 1996). The steps of this deductive approach were modified to fit into this research as listed below:

i. Define problems and focuses of the scenario analysis in the Australian electricity markets;
ii. Identify key factors influence on the problems;
iii. Identify critical uncertainties;
iv. Define scenario logics (using scenario matrices);
v. Create and simulate designed scenarios by use of the PLEXOS;
vi. Assess implications for the Australian electricity markets including the NEM and the WEM;

vii. Propose actions and policy directions.

### 3.2.2 Scenario Design Considerations

There are two primary aspects of decision making in the electricity market: the investment decision and the scheduling decision. The investment decision focuses on the time, the types and the locations of building new power stations. The scheduling decision is concerned with the economic dispatch of power stations considering their technical constraints and system load features (Green 2000).

Two critical factors drive the entry of new generation capacity in a competitive electricity market: the investment profitability and the system reliability criteria (Cramton, Ockenfels and Stoft 2013). The investment in new capacity will be attracted if electricity market sending a right price signal that new investment is profitable. In addition to the market clearing price, the economic incentives provided by the government policies play key roles in promoting new investments in certain types of capacity. The carbon price is an example which accelerates the penetration of the RETs in the market (O'Gorman and Jotzo 2014). Essentially the short-run marginal cost (SRMC) of production and long-run marginal cost (LRMC) of production of a generator combined with other electricity market operations decide the profitability of that generator (Cramton, Ockenfels and Stoft 2013).

The reliability of electricity supply has been one of the dominant concerns for the system operators. The system security and resource adequacy are two major aspects of power system reliability (Deane et al. 2012). The system security is associated with the ability of a power system withstanding sudden losses of generators or transmission links due to unforeseeable events such as extreme weather condition. It suggests that the system will remain uninterrupted even after outages or other equipment failures occur. The resource adequacy represents a power system has sufficient installed capacity to meet demand at all times. It implies that there are adequate generation and transmission resources available to meet projected energy needs plus reserves for contingencies (Hirst 2003).

In the context of the NEM, the reliability is measured in terms of the accumulated unserved energy over time, expressed as a percentage of the total energy requirement over the same timeframe. The Australian Energy Market Commission's (AEMC) has established the Reliability Standard which defines a minimum acceptable level of reliability to be met in each region. It currently specifies that no more than 0.002% of the annual energy consumption of a region should be at risk of not being met over the long term (AEMO 2010a).

Similarly, the WEM requires that sufficient capacity be provided to "limit expected energy shortfalls to 0.002% of annual energy consumption (including transmission losses)" (IMO 2013, p67). Additionally, the reliability planning criteria of the WEM also require that the capacity should meet the forecast peak demand plus a reserve margin equal to 7.6 % of peak demand or the capacity of the largest generating unit while being able to maintain normal frequency control whichever is greater (IMO 2013).

Although the NEM and the WEM have similar reliability requirement of unserved energy level, the approaches adopted to implement this requirement in these two markets are fundamentally different.

The NEM is an energy-only market. The Reliability Standard is implemented through the Market Price Cap (MPC) mechanism. The higher the MPC, the more revenue a new entrant can expect to make during periods of market scarcity. Thus, the attractiveness of investment for new capacity and the resource adequacy in the NEM is directly affected by the MPC, in combination with market expectations of how often extreme prices are likely to occur (Riesz and MacGill 2013).

Furthermore, as an energy-only market, the NEM relies on the short-run costs of power generation technologies for dispatch. The increased penetration of the RETs will bring major challenges to the capacity investment in the market. Except biomass, almost all the RETs have a very low or near to zero SRMC because of no fuel costs and very low variable operating costs. Therefore, very low SRMC of the RETs is likely to lead to the depressed wholesale electricity prices in the energy-only market. It means that generators will have less opportunity to recover fixed costs during periods when more expensive units are setting market prices (Riesz and MacGill 2013). This will reduce the attractiveness of investment in new capacity and eventually threaten resource adequacy in the market.

An increase in the MPC is a plausible approach to maintain resource adequacy in the energy-only market. This will increase revenue earned during extreme pricing events. However, this approach needs to be implemented carefully by considering a range of associated market risks (Riesz and MacGill 2013). Many strategies including legally binding frame, funding schemes and feed in tariffs to try to attract the investment in the RETs have been established by different nations (Solangi et al. 2011, Climate Change Authority 2012). In the UK, the government offers the low-carbon policy: contracts for difference for the investment in low-carbon technologies. It works "by paying the generator the difference between a measure of the cost of investing in a particular low-carbon technology (the 'strike price') and a measure of the average market price for electricity (the 'reference price')" (UK Department of Energy & Climate Change 2013, p5).

The WEM is a capacity market. The IMO determines the quantity of annual reserve capacity requirements (RCR) for next 10 years and allocates a share of the RCR to each market customer. A Market customer is required to procure capacity credits from generators or Demand Side Management facilities to meet individual RCR (IMO 2012).

Some opponents of capacity market expressed concerns that the capacity market is costly to implement and involves heavy regulatory intervention which can favour specific technologies (Orme 2016, Volk 2013). Further reform and design improvement is required to make capacity mechanism more cost effective and suitable for different markets (European Commission 2016).

For the market regulator, the energy-only market and the capacity market differ in the approaches of resource adequacy management. The regulator determines the value of lost load (VOLL) in the energy-only market. In the capacity market, the regulator controls the level of capacity that results in the optimal duration of blackouts. Since these parameters control the capacity level and the duration of blackout, these two approaches are equally regulatory in nature (Cramton, Ockenfels and Stoft 2013).

In the long-term capacity expansion modelling, the system reliability metrics such as the expected energy not served is not easily modelled directly in the optimisation algorithm (Energy Exemplar 2014). Thus it is often constrained by the parameter of the minimum capacity reserve margin (MCRM) (%) which sets a lower bound on the capacity reserve margin in the region. The expansion solution will attempt to meet the required MCRM by new entrants and/or restricting plant retirements.

The long-term system optimisation planning seeks to minimise the NPV of generator build costs, FO&M plus production costs while meeting the system reliability criteria. The key factors considered in this research are new energy technology availability and carbon emissions reduction targets. Different assumptions on the availability of energy technologies affect their dates of market entry. It will also have impacts on system energy production costs and energy prices. The constraints of carbon emissions reduction targets will compulsorily manipulate the generation of electricity market to comply with the emissions target. This will alter energy dispatch prices and result in a changed system capacity portfolio in a long-term timeframe.

As stated previously, the objective of this research was to investigate and compare the potential roles of the RETs and the CCS technologies in Australia's future power system expansion, given the Australian Government's policies. Australia's future power system expansion includes the expansion in both the NEM and the WEM. It centred on exploring optimal pathways for deploying the RETs and the CCS which would result in the minimisation of the system costs and/or maximisation of the carbon emissions reduction over a long-term planning horizon (2012-13 to 2049-50). This research also examined the economic and environmental implications of the trade-off between the RETs and the CCS deployment in the NEM and the WEM, given the Australian Government's policies.

Consequently, this research assumes that except the RET and carbon emissions reduction targets, the capacity expansion modelling of the NEM and the WEM is not subjected to any other possible low carbon policies over the planning period. The scenarios design for this research focused on exploring the impacts of the assumptions of technology availability and carbon emissions reduction targets on future penetrations of the RETs and CCS in the NEM and the WEM.

### 3.2.3 Overview of Scenarios Groups

In order to compare the capacity system expansion under different climate policies and compare the RETs and CCS technologies systematically in the expansion studies of the NEM and the WEM, ten scenarios were constructed and categorised into four groups. Scenario design was centred on the different carbon emissions reduction targets, the implementation of pervious or current Renewable Energy Target and the availability of the RETs and CCS technologies after year 2019-20.[6]

Additionally, parameters such as fuel prices and capital costs of energy technologies also have impacts on system capacity expansion. For excluding the impacts of fuel prices and capital costs on the modelling results, they were set to be the same across all scenarios. The assumptions of medium capital costs and fuel prices were adopted for all the scenarios as depicted in chapter 4 (please refer to Section 4.4 and Section 4.7 in Chapter 4).

The conventional coal and gas generation technologies, the RETs and the coal and gas generation equipped with CCS technologies were considered as candidates of energy technologies to enter the NEM and the WEM in the capacity expansion projections (see Table 4.2 in Chapter 4 for new entrant candidates in the NEM and the WEM).

It assumed that conventional coal and gas technologies were available for deployment in all scenarios over entire planning period. The availability of the RETs and CCS for entering the NEM and the WEM was assumed to be different among scenarios. The RETs and CCS technologies were set to be all available for deployment, or either the RETs or the CCS technologies were allowed to enter markets in a certain period of planning horizon in different scenario groups.

Currently the Australian Government does not implement any specific carbon emissions reduction targets in the commonwealth level in the Australian electricity sector. For the purpose of this research, three series of carbon emissions reduction

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[6]Annual data reported in the NEM and the WEM normally take the form of the financial year ending 30 June. Hence, the year assumptions of scenario design, and modelling data inputs and outputs of the NEM PLEXOS Model and the WEM PLEXOS Model are all reported for the financial year ending 30 June. For example, the year 2019-20 denotes the period of 1 July 2019 to 30 June 2020.

targets have been established for the Australian economy (please refer to Section 1.2 in Chapter 1). These Australian economy-wide carbon reduction targets were converted proportionally to set carbon emissions reduction targets explicitly for the NEM and the WEM based on their baseline emissions data.

Ten scenarios were categorised into four groups according to the assumptions of carbon emissions reduction targets and the availability of the RETs and CCS technologies in the NEM and the WEM (see Table 3.1 and Table 3.2). The first group is represented by the BAU scenario. The second group is comprised of 5% Reduction Scenario, 25% Reduction Scenario and 5%-26%_2030 Reduction Scenario (Australia Government 2015; Australian Treasury 2011; CCA 2014a). The 5%-26%_2030 Reduction Scenario is also referred as the Current Government Policy (CGP) Scenario.

The third group contains three scenarios, including 5%-RETs Only Scenario, 25%-RETs Only Scenario and 5%-26%_2030-RETs Only Scenario. The fourth group of scenarios include 5%-CCS Only Scenario, 25%-CCS Only Scenario and 5%-26%_2030-CCS Only Scenario.

The BAU Scenario described current policies and technological situation in the NEM and the WEM. In the BAU Scenario, the electricity markets will have to achieve current Renewable Energy Target (33,000 GW) by 2019-20. After 2019-20, the RETs and CCS technologies were all available for entering the markets.

At present, there is no formal implementation of carbon emissions reduction target in the Australian electricity sector in the Commonwealth level. Therefore the BAU Scenario did not implement any carbon reduction target in the NEM and the WEM during the planning period. It assumed that this situation will remain stable over entire simulation horizon. The BAU Scenario represented the status quo pathway of system capacity expansion in the NEM and the WEM. The BAU Scenario was not under the interventions of additional energy or climate policies except the current Renewable Energy Target. It provided a baseline reference case for the other scenarios to compare with.

The second group included the 5%, 25% and 5%-26%_2030 Reduction Scenarios. Similar as the BAU Scenario, the 5%-26%_2030 Reduction (CGP) Scenario implemented the current Renewable Energy Target, while the 5% and 25% Reduction Scenarios enforced the pervious Renewable Energy Target (41,000 GW). In all three scenarios, the RETs and CCS technologies were available for market entry after 2019-20.[7]

Different from the BAU Scenario was that the scenarios in the second group were subject to the specific carbon emissions reduction constraints. With the 5% Reduction Scenario, the NEM will need to cut its carbon emissions by 5% by 2019-20 and by 80% by 2049-50 based on its 2000 levels. The WEM will be required to reduce its carbon emissions by 5% by 2019-20 and by 80% by 2049-50 based on its 2007-08 levels (see Section 4.9.2 in Chapter 4 for further explanation). Hereafter, the carbon emissions reduction target described in 5% Reduction Scenario is denoted as the 5%-80% Reduction Target.

The 25% Reduction Scenario requires the NEM and the WEM to cut their carbon emissions by 25% based on 2000 levels (for the NEM) and based on 2007-08 levels (for the WEM) by 2019-20 and by 80% based on 2000 levels (for the NEM) and based on 2007-08 levels (for the WEM) by 2049-50. Hereafter, this carbon emissions reduction target is referred as the 25%-80% Reduction Target.

The 5%-26%_2030 (CGP) Scenario assumes that the NEM will reduce its carbon emissions by 5% based on 2000 levels by 2019-20, by 26% based on 2005 levels by 2029-30 and by 80% based on 2000 levels by 2049-50. The WEM will reduce its carbon emissions by 5% by 2019-20, by 26% by 2029-30 and by 80% by 2049-50 based on 2007-08 levels. Hereafter, this carbon emissions reduction target is referred as the 5%-26%-80% Reduction Target. This trajectory of carbon emission target aims to reflect Australian Government's current commitment to carbon reduction to 2030 and its long-term obligation under the UNFCCC (UNFCCC 2009). Meanwhile, this scenario also executes Australian Government's current Renewable Energy

[7] According to the IEA's *Technology Roadmap: Carbon Capture and Storage 2013*, by 2020, the CCS could be deployed at relatively low cost on processes such as coal-to-liquids and chemicals in non-OECD countries and on gas processing in OECD countries. Higher-cost applications of CCS in power generation in Canada, the United States, and OECD Europe, and in iron and steel production in non-OECD countries also need to be undertaken as early as 2020 (IEA 2013b).

Target. Hence, the 5%-26%-80% Reduction Target is also referred as the CGP Reduction Target in this study.

**Table 3.1** Scenarios matrix in the NEM.

| Group | Scenario | Carbon Emissions Reduction Targets | Renewable Energy Target | RETs Availability | CCS Availability |
|---|---|---|---|---|---|
| **1** | BAU | No constraint | Current 20% by 2019-20 (35,000 GWh) | Available | Available |
| **2** | 5% Reduction | 5% by 2019-20, 80% by 2049-50, based on 2000 levels | Previous 20% by 2020 (41,000 GWh) | Available | Available |
| | 25% Reduction | 25% by 2019-20, 80% by 2049-50, based on 2000 level | Previous 20% by 2019-20 (41,000 GWh) | Available | Available |
| | 5%-26%_2030 Reduction | 5% by 2019-20 based on 2000 levels, 26% by 2029-30 based on 2005 levels, 80% by 2049-50 based on 2000 levels | Current 20% by 2019-20 (35,000 GWh) | Available | Available |
| **3** | 5%-RETs Only | 5% by 2019-20, 80% by 2049-50, based on 2000 level | Previous 20% by 2019-20 (41,000 GWh) | Available | Not available after 2019-20 |
| | 25%-RETs Only | 25% by 2019-20, 80% by 2049-50, based on 2000 level | Previous 20% by 2020 (41,000 GWh) | Available | Not available after 2019-20 |
| | 5%-26%_2030 -RETs Only | 5% by 2019-20 based on 2000 levels, 26% by 2029-30 based on 2005 levels, 80% by 204950 based on 2000 levels | Current 20% by 2019-20 (35,000 GWh) | Available | Not available after 2019-20 |
| **4** | 5%-CCS Only | 5% by 2019-20, 80% by 2049-50, based on 2000 level | Previous 20% by 2020 (41,000 GWh) | Not available after 2019-20 | Available |
| | 25%-CCS Only | 25% by 2019-20, 80% by 2049-50, based on 2000 level | Previous 20% by 2019-20 (41,000 GWh) | Not available after 2019-20 | Available |
| | 5%-26%_2030 -CCS Only | 5% by 2019-20 based on 2000 levels, 26% by 2029-30 based on 2005 levels, 80% by 2049-50 based on 2000 levels | Current 20% by 2019-20 (35,000 GWh) | Not available after 2019-20 | Available |

There are three scenarios in each of the third RETs Only scenario group and the fourth CCS Only scenario group. Scenarios in each group implement the 5%-80%, 25%-80% and 5%-26%-80% Reduction Targets respectively. The scenarios with the 5%-80% and 25%-80% Reduction Targets enforce the previous Renewable Energy Target. The scenarios with the 5%-26%-80% Reduction Target implement the current Renewable Energy Target.

The main difference between the third and fourth groups is the availability of the RETs and CCS technologies for the deployment after the year 2019-20. Scenarios in Group 3 only allow using the RETs as the LCETs to expand system capacity in the NEM and the WEM after the year 2019-20. The CCS technologies are assumed to be not available for the deployment over entire planning period for the scenarios in the RETs Only scenario group. While in the fourth CCS Only scenario group, the CCS technologies are assumed to be feasible to enter the NEM and the WEM after the year 2019-20 to meet capacity expansion requirement. In the meantime, the RETs are assumed to be not available for market entry after the year 2019-20.

**Table 3.2** Scenarios Matrix in the WEM.

| Group | Scenario | Carbon Emissions Reduction Targets | Renewable Energy Target | RETs Availability | CCS Availability |
|---|---|---|---|---|---|
| **1** | BAU | No constraint | Current 20% by 2019-20 (35,000 GWh) | Available | Available |
| **2** | 5% Reduction | 5% by 2019-20, 80% by 2049-50, based on 2007-08 levels | Previous 20% by 2020 (41,000 GWh) | Available | Available |
| | 25% Reduction | 25% by 2019-20, 80% by 2049-50, based on 2007-08 level | Previous 20% by 2019-20 (41,000 GWh) | Available | Available |
| | 5%-26%_2030 Reduction | 5% by 2019-20, 26% by 2029-30, 80% by 2049-50 based on 2007-08 levels | Current 20% by 2019-20 (35,000 GWh) | Available | Available |
| **3** | 5%-RETs Only | 5% by 2019-20, 80% by 2049-50, based on 2007-08 level | Previous 20% by 2019-20 (41,000 GWh) | Available | Not available after 2019-20 |
| | 25%-RETs Only | 25% by 2019-20, 80% by 2049-50, based on 2007-08 level | Previous 20% by 2020 (41,000 GWh) | Available | Not available after 2019-20 |
| | 5%-26%_2030-RETs Only | 5% by 2019-20, 26% by 2029-30, 80% by 2049-50 based on 2007-08 levels | Current 20% by 2019-20 (35,000 GWh) | Available | Not available after 2019-20 |
| **4** | 5%-CCS Only | 5% by 2019-20, 80% by 2049-50, based on 2007-08 level | Previous 20% by 2020 (41,000 GWh) | Not available after 2019-20 | Available |
| | 25%-CCS Only | 25% by 2019-20, 80% by 2049-50, based on 2007-08 level | Previous 20% by 2019-20 (41,000 GWh) | Not available after 2019-20 | Available |
| | 5%-26%_2030-CCS Only | 5% by 2019-20, 26% by 2029-30, 80% by 2049-50 based on 2007-08 levels | Current 20% by 2019-20 (35,000 GWh) | Not available after 2019-20 | Available |

By the year 2019-20, the entries of the RETs and the CCS technologies in all scenarios are only subject to their assumptions of market entry dates (please refer to Section 4.4.2 in Chapter 4).

There are three purposes for establishing four scenario groups as described above. Firstly, it aimed at exploring and comparing the least cost system expansion paths in the NEM and the WEM in the situations of with and without carbon emission reduction constraints. Secondly, it intended to examine the market shares of the RETs and CCS in the NEM and the WEM when the system expansion under the influences of carbon emissions constraints and technology availability assumptions. Thirdly, it was designed to compare the potential of the RETs and CCS in reducing carbon emissions in the NEM and the WEM, and their associated carbon emissions avoiding costs.

In summary, the BAU Scenario represented a future development of the NEM and the WEM where there will have no energy or climate policies in addition to the current Renewable Energy Target in enforcement in the Australian electricity sector.

Assuming the world takes action to stabilise GHGs concentration levels at around either 550 ppm or 450 ppm by 2100, the scenarios constrained with the 5%-80% Reduction Target for the Australian electricity sector in this research are consistent with a 550 ppm stabilisation target of $CO_2$-e concentration level in the atmosphere by 2100. The scenarios designed with the 25%-80% Reduction Target for the Australian electricity sector are consistent with a 450 ppm stabilisation target of $CO_2$-e concentration level in the atmosphere by 2100.

Therefore, the 5% Reduction Scenario designed is consistent with a world with a 550 ppm stabilisation target of $CO_2$-e concentration level in the atmosphere by 2100. In this scenario, a moderate global technology R&D support will be on the development of the RETs and CCS technologies. This will lead to moderate changes to their capital costs to 2049-50. Meanwhile, coal prices are assumed to decrease moderately and gas prices are assumed to increase moderately. The RETs and CCS technologies will be all available for the deployment in the NEM and the WEM after 2019-20 to achieve the 5%-80% Reduction Target.

The 25% Reduction Scenario assumed the world will stabilise at a 450 ppm $CO_2$-e concentration level in the atmosphere by 2100. The RETs and the CCS technologies will experience a moderate change rates to their capital costs to 2049-50 due to moderate global technology R&D support. Coal prices are with a moderate downward trend and gas prices rise moderately to 2049-50. The RETs and the CCS technologies will be all available for the deployment in the NEM and the WEM in the planning period to achieve the 25%-80% Reduction Target.

The 5%-RETs Only Scenario and 5%-CCS Only Scenario describe a world similar as the one in 5% Reduction Scenario, but with some exceptions. In the 5%-RETs Only Scenario, it assumes that global R&D support on the CCS technologies will be diminishing. CCS will be not made economic viable for the deployment before 2049-50. Hence, only the RETs as the LCETs will be available for deploying in NEM and the WEM. In the 5%-CCS Only Scenario, it will see a strong political obstacle of implementing the RETs after 2019-20. This will leave the CCS technologies as the only LCETs for the deployment in Australian electricity markets after 2019-20.

The 25%-RETs Only Scenario and 25%-CCS Only Scenario represented a world similar as the one in the 25% Reduction Scenario; except for the 25%-RETs Only Scenario, the CCS technologies will not be the options for expanding power systems in Australia. For the 25%-CCS Only Scenario, the RETs will cease their entries to the market after 2019-20.

Whether the intensity of carbon emissions reduction in the 5%-26%_2030 (CGP) Reduction Scenario, 5%-26%_2030-RETs Only Scenario and 5%-26%_2030-CCS Only Scenario would be consistent with the $CO_2$-e concentration level in the atmosphere at around 450 ppm or 550 ppm or other levels, the conclusion will be upon the comparison of the modelling results. The fuel prices and technological changing trends in these scenarios were similar as described in the 5% Reduction Scenario, 5%-RETs Only Scenario and 5%-CCS Only Scenario respectively.

# Chapter 4 Assumptions and Data Sources

The operation of the PLEXOS model is driven by data inputs, which impose physical, environmental and economic constraints on power system capacity expansion process. Required major inputs for the model can be categorised as: i) power system data including electricity demand and reliability criteria, ii) fuel prices including prices projections for coal and natural gas, iii) power plants data including technical and economic parameters for existing and new generators, iv) transmission data including interconnectors and transmission lines' technical and economic data, and v) carbon emission intensities, carbon prices and carbon emissions reduction targets. This section describes key assumptions and sources of input data for operating the NEM PLEXOS Model and the WEM PLEXOS Model.

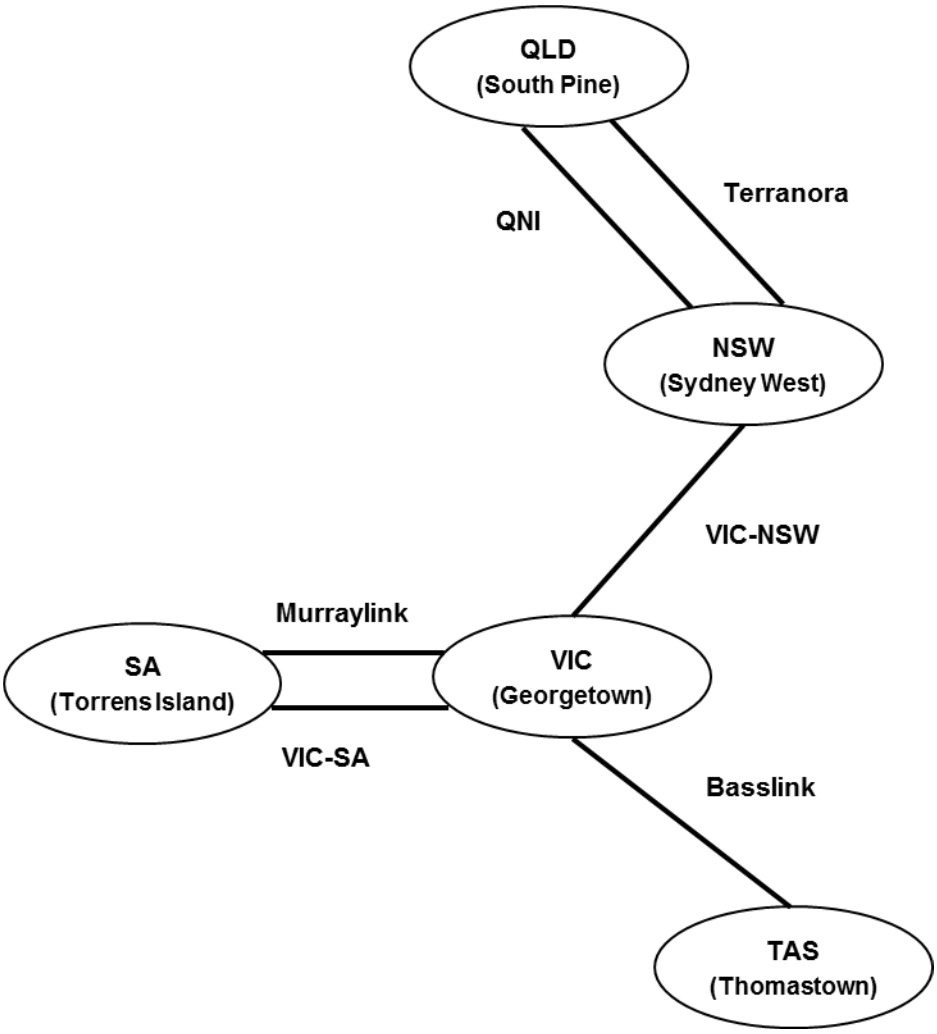
## 4.1 Overview

### 4.1.1 The NEM PLEXOS Model

The NEM PLEXOS Model takes financial year of 2012-13 as the baseline year and projects system capacity expansion over the period of 2012-13 to 2049-50. The model adopts a regional topology for simulating power system in the NEM. There are five regions in the NEM including NSW, QLD, SA, TAS and VIC. They are represented by the nodes of Sydney West, South Pine, Torrens Island, Thomastown, and Georgetown respectively in the model. An interconnected NEM system is established by linking the regional nodes with the inter-regional interconnectors as shown in Figure 4.1.

The interconnectors QNI and Terranora connect QLD and NSW, the interconnector VIC-NSW connects VIC and NSW, the interconnector VIC-SA connects VIC and SA and the interconnector Murraylink connects VIC and SA. These are regulated interconnectors in the NEM. The interconnector Basslink connecting VIC and TAS is the only unregulated interconnector in the NEM (AEMO 2014c). This system topology (see Figure 4.1) is consistent with the topology operationally used in the NEM Dispatch Engine (AEMO 2013g).

There are 254 existing generation units and more than 200 options of new generation units simulated in the NEM PLEXOS Model. New units are assigned with specific technology types and key technological parameters including thermal efficiency, emission intensity, minimum stable generation level, maximum capacity, firm capacity, build cost, FO&M cost, variable operation and maintenance (VO&M) cost and earliest entry date etc. In addition to the existing interconnectors, there are 9 options of new transmission lines modelled for future network development to accommodate generation capacity expansion.

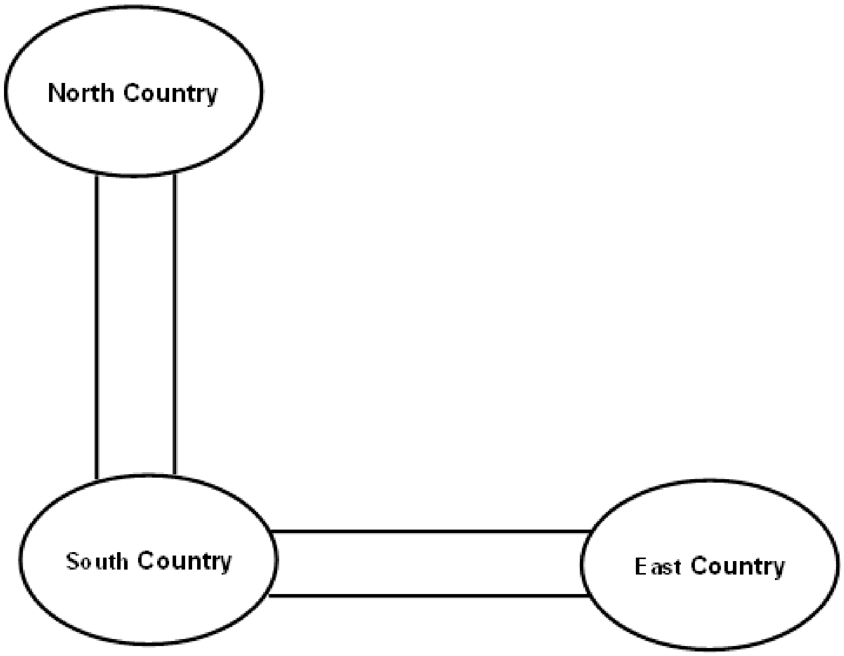



Source: AEMO (2013e).

**Figure 4.1** Regional representation of the NEM.

### 4.1.2 The WEM PLEXOS Model

The WEM PLEXOS Model simulates the SWIS in WA for the period of 2013-14 to 2049-50. This model simulates 15 traulnsmission load areas in the SWIS as a 3-node system as illustrated in Figure 4.2 to represent major congestion points in the system (SKM 2013a).




Source: SKM (2013a).

**Figure 4.2** 3-node model of the WEM.

The North Country node represents the load area from Pinjar and Muchea at the northern edge of the Neerabup Terminal Load Area to Kalbarri at the north extremity of Western Power Network (Western Power 2013). The South Country node covers the range of most part of Perth Metropolitan region to Manjimup and Albany at the south extremity of the SWIS. This node includes 12 transmission load areas namely Neerabup, Northern Terminal, Guildford Terminal, Western Terminal, East Perth, Cannington Terminal, South Fremantle, Southern Terminal, Kwinana, Mandurah, Bunbury and Muja. The South Country node represents the region with the largest electricity demand in the SWIS (Western Power 2013). The East Country node covers the Wheatbelt district of the south west and the area around City of Kalgoorlie-Boulder, including load areas of East Country and West Kalgoorlie

Terminal. The mining load is the major consumption of electricity generation in this area. The South Country is connected with North Country in the north and the East Country in the East.

There are 72 existing generation units and 45 options of new generation units modelled in the WEM PLEXOS Model. Similarly as in the NEM PLEXOS Model, new units are defined with specific technological types and the technical and economic parameters. Importantly, the options of new entries are assigned into each node to simulate geographical expansion of generation capacity in the SWIS.

## 4.2 Energy and Peak Capacity Demand Data

Economic growth and population growth are two primary drivers for electricity demand growth. The change of electricity demand is also driven by energy price, energy consumption pattern, technology advancement and government energy policies etc. (AEMO 2013b; IMO 2014e). The electricity demand projection in the NEM and the WEM often combine these drivers to establish various scenarios to forecast future demand.

For instance, in the AEMO 2012 National Electricity Forecasting Report (NEFR) and 2014 NEFR, the low demand growth projection was paired with Slow Growth Scenario, which had lower economic growth and slow development of new technologies. While the high demand growth was consistent with Fast World Recovery Scenario with higher economic growth and a moderate rate of new technology development, which is consistent with the income elasticity of demand for electricity (AEMO 2012b, 2014a).

For investigating the impacts of carbon policies, fuel prices and technology costs on the penetrations of the RETs and CCS technologies in the NEM and the WEM, this research adopts the estimates projected by the AEMO and the IMO for the future electricity demands of the NEM and the WEM respectively.

### 4.2.1 The NEM Data

The AEMO released the PLEXOS database for modelling 2012 NTNDP. This database contained the electricity demand forecast for the NEM from 2012-13 to 2037-38 (AEMO 2012d). The forecast was developed based on 2012 NEFR (AEMO 2012b, i). 2012 NEFR provided the projections of annual energy (sent-out) and the maximum capacity demand (MCD) of summer and winter from 2012-13 to 2031-32 in three scenarios: Fast World Recovery Scenario, Planning Scenario and Slow Growth Scenario. The Planning Scenario was based on the AEMO's best estimate of major drivers including predicted economic growth, a $CO_2$-e emissions reduction target of 5% by 2020 and 80% by 2050 based on 2000 levels, and a moderate rate of new technology development (AEMO 2012a). The energy forecast of 2012 NEFR's Planning Scenario was extrapolated in 2012 NTNDP to produce the energy demand for an additional five years (2032-33 to 2037-38) using each region's growth rate over final decades (AEMO 2012d).

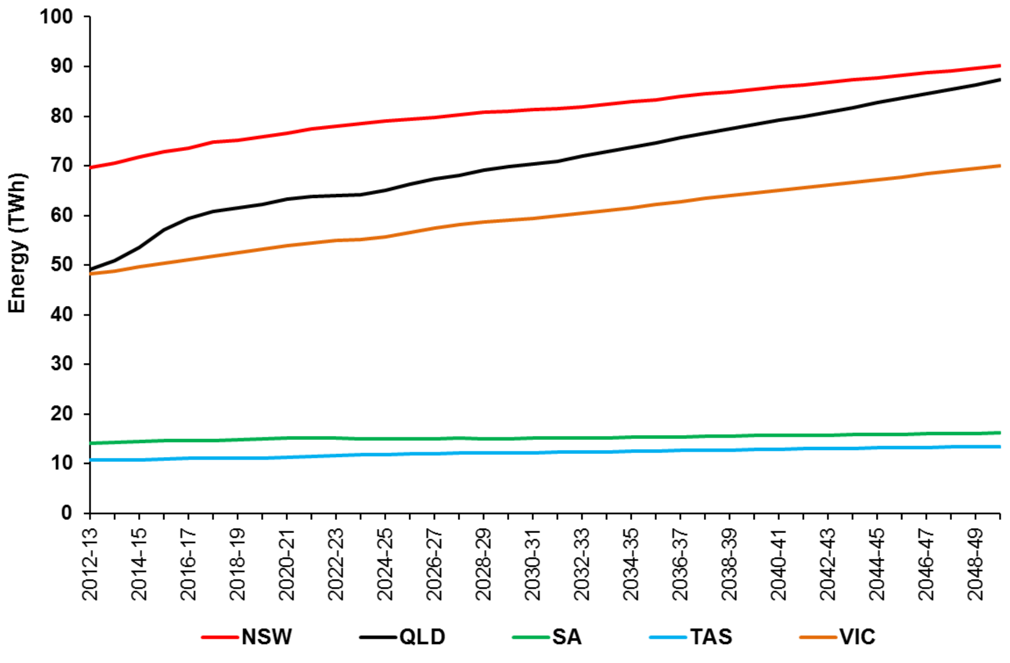



**Figure 4.3** Energy forecast for the NEM, 2012-13 to 2049-50.

The 2012 NEFR counted rooftop PV generation and energy savings from energy efficiency policies, and removed their contribution from energy forecasts. The average growth rate of annual energy demand from 2030-31 to 2037-38 in each region is used to project electricity demand from 2038-39 to 2049-50 in this research. Figure 4.3 above shows projected annual energy demand in the NEM from 2012-13 to 2049-50.

The MCD Projections from 2012-13 to 2031-32 are sourced from the Planning Scenario of 2012 NEFR (AEMO 2012b). The MCD projections adopted for NSW, QLD, SA and VIC are their summer MCD projections in this research. The winter MCD projection is used for TAS.

A probability of exceedance (POE) refers to the likelihood that a maximum capacity demand projection will be met or exceeded. Various probabilities (generally 90%, 50% and 10%) provide a range of likelihoods that the analysts can use to determine a realistic range of power system demand and market outcomes (AEMO 2012b). To ensure the supply capacity adequacy, this research applies 10% POE MCD projections. The 2012 NEFR's forecasts of the MCD projections for the period of 2012-13 to 2031-32 are extrapolated to 2049-50 by use of the average growth rate of annual MCD from 2022-23 to 2031-32 in this research. Figure 4.4 shows the projected annual MCD for the NEM from 2012-13 to 2049-50.

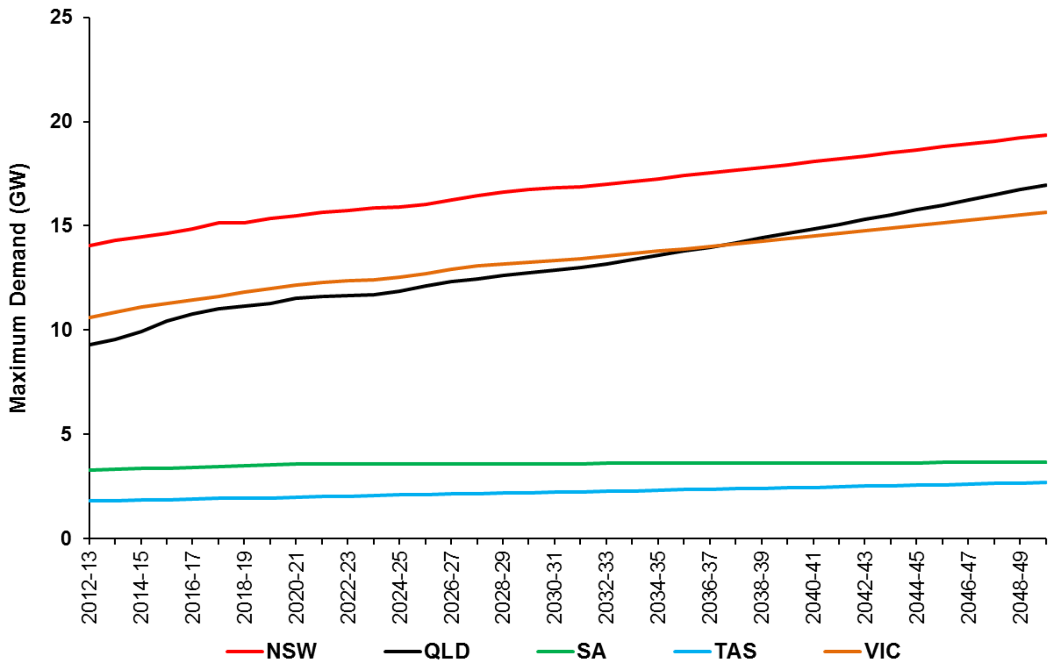
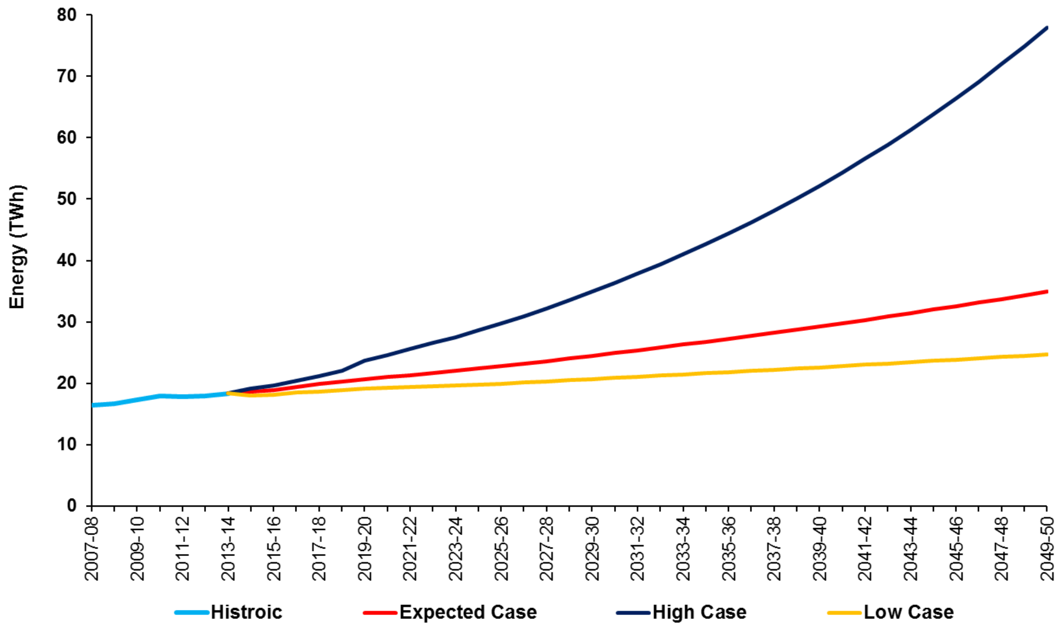



**Figure 4.4** Projected annual maximum capacity demand, 2012-13 to 2049-50.

### 4.2.2 The WEM Data

The IMO's 2014 SWIS Electricity Demand Outlook (EDO) projected energy demand for the SWIS from 2014-15 to 2023-24 under three different economic growth scenarios: High Case, Expected Case and Low Case (IMO 2014d). In the High Case Scenario, the gross state product (GSP) was assumed to grow at an average annual rate of 4.5%, and population growth was at 2.4% a year on average. In the Expected Case, the GSP and population were forecasted to grow at 3% and 2.1% on average respectively. In the Low Case, the GSP and population growth rates were at 1.9% and 1.8% a year on average (IMO 2014d). This research adopts the energy demand forecast of the Expected Case Scenario. The average growth rate of annual energy demand from 2014-15 to 2023-24 was 1.8% in this forecast. This avreage annual growth rate is also applied in this research to project energy demand over the period of 2024-25 to 2049-50 in the SWIS (see Figure 4.5).

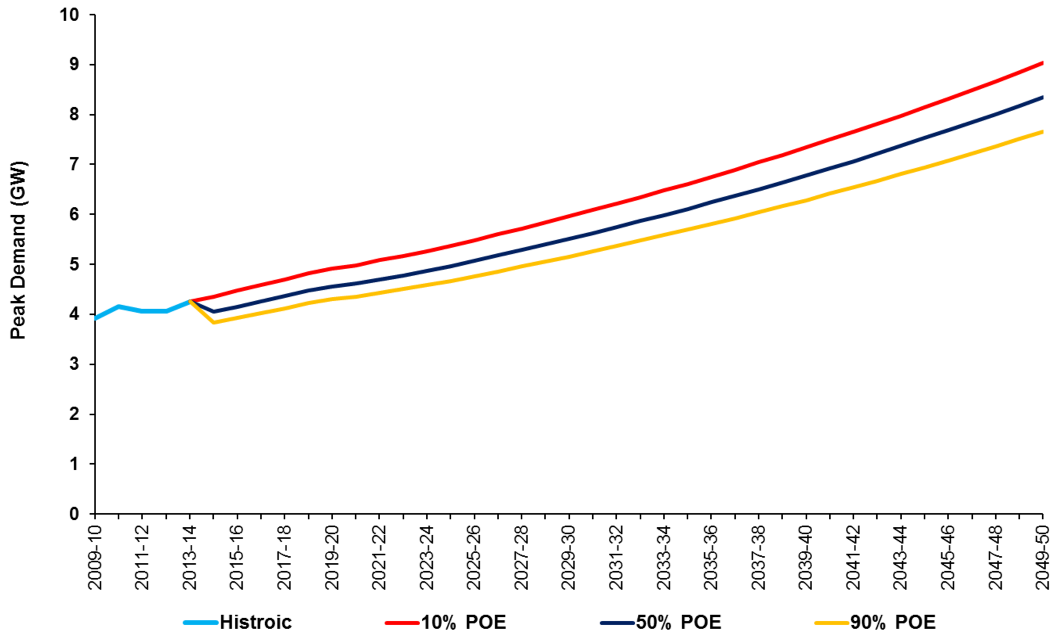



Source: IMO (2014c) and the author's extrapolation.

**Figure 4.5** Energy forecast for the SWIS, 2007-08 to 2049-50.

The SWIS is a summer peaking system. 2014 SWIS EDO showed peak capacity demand forecasts for 10%, 50% and 90% POE levels under the Expected Case of economic growth assumptions for the period of 2014-15 to 2023-24. Peak capacity demand was predicted to grow at an average annual rate of 2.1% between 2014-15 and 2023-24 at 10% POE. At 50% and 90% POE levels, peak demand was projected to grow at an average rate of 2.1% and 2.0% respectively (IMO 2014e). For projecting peak demand beyond 2023-24 in the SWIS, this study uses the same annual growth rates of peak demand for 2014-15 to 2023-24 stated above to extrapolate peak demand data of each POE level to 2049-50.

The projection of peak capacity demand with 10% POE level as shown in Figure 4.6 is selected as the peak demand forecast for the period of 2014-15 to 2049-50 in this study to ensure capacity adequacy in the WEM (IMO 2014e).




Source: IMO (2014d) and the author’s extrapolation.

**Figure 4.6** Peak demand forecast for the SWIS, 2007-08 to 2049-50.

The installation of roof-top solar PV system has increased significantly over past a few years in the SWIS. Installed solar PV capacity grew from approximately 63 MW in January 2011 to 336 MW in January 2014, representing an average annual growth rate of 75%. The rapid growth of solar PV system installation was mainly driven by government incentives and rising electricity prices. It was assumed that rising energy prices and falling costs for solar PV systems are expected to continue to drive residential installation of solar PV systems in the SWIS. The increased distributed solar PV capacity reduces energy demand on the network, particularly during its peak generation times (IMO 2014e).

2014 SWIS EDO projected the contribution of roof-top solar PV system's annual energy and peak demand to the SWIS over the period of 2014-15 to 2023-24 under three scenarios: Expected Case, High Case, and Low Case. The WEM PLEXOS Model adopts solar PV energy and peak demand forecasts of the Expected Case in the 2014 SWIS EDO study and extrapolates the values to 2049-50.

The Expected Case assumed a solar PV installation rate of 67.2 MW per year and total installed solar PV capacity was forecast to grow from 336 MW in 2013-14 to 1005 MW in 2023-24 (IMO 2014e). This growth rate is applied for the year 2024-25 to 2049-50 in this study and the projected solar PV capacity reaches around 2751 MW in 2049-50.

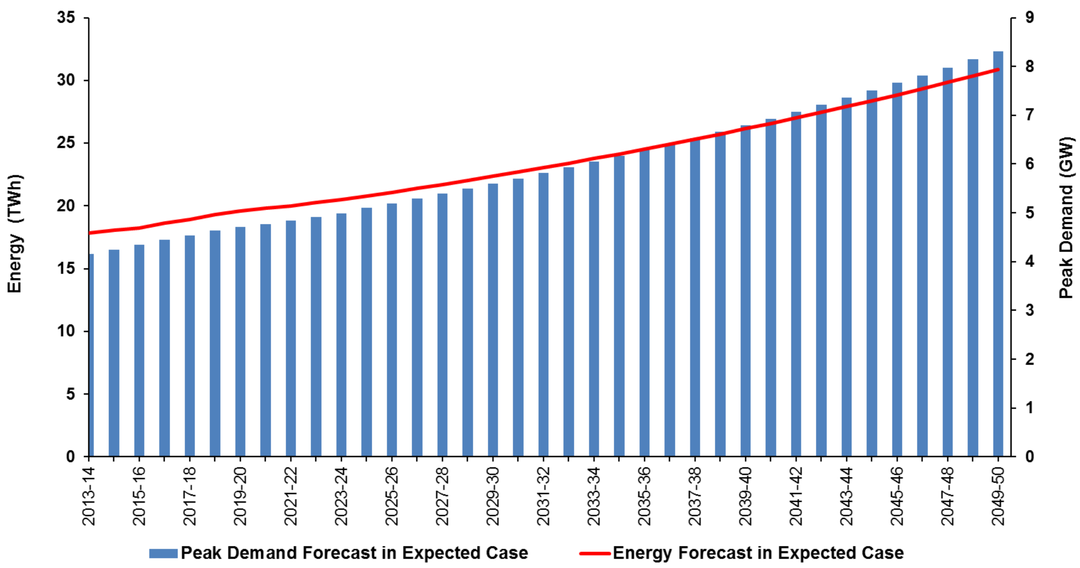



**Figure 4.7** Energy and Peak demand forecast for the WEM PLEXOS Model, 2013-14 to 2049-50.

2014 SWIS EDO also projected energy output of solar PV System for the period of 2014-15 to 2023-24 using the capacity factor of 17.1%. Based on the projected solar PV capacity in the Excpected Case between 2013-14 and 2049-50, energy output of solar PV system can be calculated with the same capacity factor for this period. For calculating the peak demand contribution of the solar PV system, an assumed output of 27% of nameplate capacity at the time of system peak is applied (IMO 2014e).

In summary, electricity demand and peak capacity demand projection used in the WEM PLEXOS Model are the outcomes of substracting solar PV energy output and peak capacity from total energy output and peak demand of the Expect Case projections respectively as shown in Figure 4.7 above.

### 4.2.3 Hourly Demand Traces Development

The forecasts of annual electricity demand and peak capacity demand for the NEM and the WEM needed to be converted to hourly trace data to develop the load duration curve (LDC). The LDC arranges all load levels in a descending order of magnitude rather than chronologically and presents a probability distribution for load and time (Willis and Schrieber 2013). In PLEXOS, the LDC Slicing Method controls the approach used to slice the LDC into required number of blocks. The more blocks a LDC has, the higher the accuracy of a LDC in representing the load. At the same time, because each block is a simulation period, slicing the LDC into more blocks also leads to a larger optimisation problem (Energy Exemplar 2014).

In this research, the Peak/Off-peak Bias LDC Slicing Method in the PLEXOS is chosen to preserve the peak and off-peak load values for both the NEM and WEM energy demand projections (Energy Exemplar 2014). For simulating the NEM and the WEM within a long-term planning horizon in a more manageable optimisation problem size and preserving a relatively good accuracy at the same time, a monthly LDC with 12 blocks is applied.

The Load Forecasting Function of the PLEXOS is used to develop demand trace. This function is able to develop a demand trace that matches a historical reference trace while meeting predetermined energy and maximum capacity demand targets (Energy Exemplar 2014). The 2012-13 historical hourly load data of the NEM are used as the reference profile for developing demand trace for the NEM from 2013-14 to 2049-50 (AEMO 2012d). The 2013-14 historical hourly load data of the WEM are used as the base year to develop demand trace for the WEM from 2014-15 to 2049-50 (IMO 2014d).

The load forecasting in PLEXOS has two mathematical models: Linear and Quadratic. Both methods calculate a continuous growth rate function applied to each point of the reference demand shape. The Quadratic model is applied in this research to grow hourly demand traces for the NEM and the WEM. The growth rate function is quadratic in Quadratic Growth Model. The points at the top of the demand duration curve are scaled by a factor that is quadratically higher than points at the bottom of the demand duration curve. This allows a more realistic fit when maximum capacity demand grows much faster than annual energy demand (Energy Exemplar 2014).

## 4.3 Minimum Capacity Reserve Margin

### 4.3.1 The NEM Reserve Margin

Power system reliability management is one of priorities of the AEMO as the market operation and system operator for the NEM. In the context of the NEM market, reliability refers to the likelihood of having sufficient supply to meet demand. It is measured in terms of accumulated unserved energy (USE) over time and expressed as a percentage of total energy requirements over the same timeframe. The AEMC has established the Reliability Standard which defines a minimum acceptable level of reliability to be met in each region. It currently specifies that no more than 0.002% of the annual energy consumption of a region should be at risk of not being met over the long term (AEMO 2010a).

Since 2005, the USE related to the reliability risk has only occurred during the extreme high temperatures over a prolonged period in 2009. The reliability related USE that occurred in 2009 was limited to VIC and SA regions. Assessed on a regional basis, in this single year, the USE levels reached 0.004% and 0.0032% in VIC and SA respectively (Australian Energy Market Commission Reliability Panel 2014). These levels exceeded the 0.002% requirement, but given that the Reliability Standard is assessed over multiple years, these regions remained compliant with the Standard.

Over the period 2005 to 2010, the NEM has achieved 0.0002% USE per year on average, ten times lower than the Standard allows. Even in 2009, the aggregate USE was around half the allowable standard (Riesz and MacGill 2013). This suggests that currently, the amount of installed capacity in the NEM generating sufficient energy to meet the Reliability Standard.

To apply this long-term Reliability Standard in an operational environment, the AEMO translates the Reliability Standard into a safety margin of local installed capacity for each region. By convention, this margin is expressed relative to a region's 10% POE MCD and is referred to as a minimum reserve level (MRL) (AEMO 2010a). The most recent MRL calculation was conducted by the AEMO in July 2010. The MRL is required to be reviewed regularly to ensure that the level remain appropriate as the power system evolves (AEMO 2012f). Therefore, there are no long-term MRLs established for the NEM.

In order to ensure the power system reliability in the NEM is met over the long-term planning horizon in the modelling work, the reliability measure of the MCRM of 15% is applied. This is consistent with international reserve margin benchmarks (Nelson et al. 2010; Sim 2011). The MCRM represents the minimum amount of generation capacity that a utility has on its system that is in excess of the highest projected load that the utility is expected to serve in both summer and winter seasons for a given year (Sim 2011). In the NEM PLEXOS Model, the 15% MCRM together with the mechanism of regional capacity reserve sharing will ensure the Reliability Standard of the NEM to be met over the long-term planning period.

### 4.3.2 The WEM Reserve Margin

Being different from the NEM's energy-only market, the WEM is designed as the capacity market. In the capacity market, the system reserve margin is pre-determined by regulators; while in the energy-only market, the reserve margin is driven by market forces (Spees and Newell 2014). In the WEM, Annual Reserve Capacity Requirement is determined by the IMO. Each market customer is allocated a share of the Reserve Capacity Requirement and is obligated to secure Capacity Credits to fulfil that requirement (IMO 2012).

The WEM Market Rule regulates that the WEM should have sufficient available capacity in each Capacity Year to (The Minister for Energy 2014, p191):

*(a) meet the forecast peak demand (including transmission losses and allowing for Intermittent Loads) supplied through the SWIS plus a reserve margin equal to the greater of:*

*i. 7.6 per cent of the forecast peak demand (including transmission losses and allowing for Intermittent Loads); and*

*ii. the maximum capacity, measured at 41°C, of the largest generating unit; while maintaining the Minimum Frequency Keeping Capacity for normal frequency control. The forecast peak demand should be calculated to a probability level that the forecast would not be expected to be exceeded in more than one year out of ten; and*

*(b) limit expected energy shortfalls to 0.002 per cent of annual energy consumption (including transmission losses).*

The most stringent element of the Planning Criterion is used to determine the Reserve Capacity Target. As 7.6% of the forecast peak demand is greater than the capacity of the largest generating unit (measured at $41^0$C) in each year of the Long Term Projected Assessment of Supply Adequacy Study Horizon, it sets the level of reserve margin in the SWIS (IMO 2013).

The IMO's 2013 Electricity Statement of Opportunity (ESO) projected 2016-17 Reserve Capacity Target of 5263 MW, which is comprised of 4797 MW peak demand and 466 MW capacity margin (IMO 2013). This capacity margin accounted about 8.9% of Reserve Capacity Target, which includes intermittent loads, reserve margin and loading following service.

Current load following rules in the SWIS require that sufficient plants be online to meet fluctuations in wind energy output and load in 99.9% of all periods (The Minister for Energy 2014). In 2013-14, a minimum of 72 MW of load following capacity was required to be online in all periods (IMO 2013). If significant intermittent renewable generation like wind and solar PV enters market, the requirement of load following capacity will continue to rise. ROAM (2010) estimated the amount of load following needed in the SWIS for a given amount of new wind under the current rules: approximately 10 MW of load following capacity is required for every 40-50 MW of wind.

Considering the SWIS's Reserve Capacity Target, future penetration of intermittent generation and the consistency with the MCRM applied in the NEM PLEXOS Model, the WEM PLEXOS Model also adopts the 15% MCRM in the simulation. This will guarantee sufficient amounts of capacity entering the SWIS to meet resource adequacy requirement of the WEM.

## 4.4 Energy Technologies Data

### 4.4.1 Data for Existing Power Plants

The representation of the existing power generation fleet is specified in a highly disaggregate way in the NEM PLEXOS Model and the WEM PLEXOS Model. The existing power plants in each region are represented by generation units and categorised by generation fuels. For example, the existing power plants in NSW are categorised into generation units fuelled by black coal, hydro, natural gas, liquid fuel and wind. The primary properties of existing power generation units in the database are listed in Table 4.1.

**Table 4.1** Major parameters for existing power generation units.

| **Parameters** | **Units** |
| --- | --- |
| Approximate year commissioned | n/a |
| Emission intensity | kg $CO_2$-e/GJ |
| Firm capacity | MW |
| Fixed operation and maintenance cost | AU$/MW/year |
| Fuel cost | AU$/GJ |
| Heat rate | GJ/MWh |
| Installed capacity | MW |
| Marginal loss factor | n/a |
| Variable O&M cost | AU$/MWh |

Capital costs of existing power units are considered as sunk investments which do not contribute to the costs of capacity expansion. Considering the standard technical lifespans of energy technologies and the operation periods of power plants in practical situation (Jungbluth et al. 2005; Kumar et al. 2011; Mann and Spath 1997; Spath and Mann 2000; Spath, Mann and Kerr 1999), this research assumes that the technical lifespans for coal-fired power plants, gas-fired power plants, biomass, hydropower and wind are 50 years, 40 years, 30 years, 80 years and 30 years respectively.

Only existing coal units in the models are subject to retirement test. The retirement test means that the model retires existing coal-fired generators if total costs could be minimised by replacing existing coal capacity with new capacity with a combination of lower fuel, emission and operating costs etc.

Input data for existing power plants in the NEM are sourced from AEMO 2013 NTNDP, which contains the information of the existing units in the NEM regions up to 2013 (AEMO 2013c, d). This data set includes 58, 60, 61, 51 and 24 existing generators in NSW, QLD, VIC, SA and TAS, respectively.

Existing generation units in the WEM are sourced from the IMO's 2014 Market Dataset of Facilities (IMO 2014c). Input data for the properties of the WEM existing units are collected from reports published by ACIL Tasman (ACIL Tasman 2013) and SKM Consulting (SKM 2013a). There are 72 existing generation units in total considered in the WEM PLEXOS Model.

### 4.4.2 Data for New Entrants

In the NEM PLEXOS Model and the WEM PLEXOS Model, thirteen types of energy technologies are considered as candidates for new entrants, as listed in Table 4.2. These candidates can be categorised into three technology groups: conventional fossil fuel technologies, fossil fuel equipped with CCS technologies and the RETs. Solar PV, solar thermal with storage, geothermal and biomass are candidates for new entrants in the RETs category. Because of lacking of resourceful hydro-energy sites, hydropower is not considered as feasible choice for entering Australian energy market in future. Ocean energy technologies and large-scale battery energy storage technologies are assumed to be not commercially available within the timeframe of this study due to their technology, cost and policy uncertainties. In addition to data inputs required in Table 4.1, the important parameters for new entrants include:

- Capital cost in AU$/kW
- Economic life in years
- Weighted average cost of capital (WACC)
- Project Start Date

**Table 4.2** Energy technology candidates for new entrants.

| Group | Technology Type | New entrant size |
|---|---|---|
| Fossil fuel | Supercritical Pulverized Coal (Super PC) | |
| | Black coal | 750 MW |
| | Black coal, with CCS | 750 MW |
| | Brown coal | 750 MW |
| | Brown coal, with CCS | 750 MW |
| | Integrated Gasification Combined Cycle (IGCC) | |
| | Black coal | 854 MW |
| | Black coal, with CCS | 821 MW |
| | Brown coal | 960 MW |
| | Brown coal, with CCS | 936 MW |
| | Combined Cycle Gas Turbine (CCGT) | |
| | Without CCS | 386 MW |
| | With CCS | 361 MW |
| | Open Cycle Gas Turbine (OCGT) | |
| | Without CCS | 564MW |
| | With CCS | 564MW |
| Renewables | Solar PV | N/A |
| | Solar Thermal with Storage | N/A |
| | Wind | N/A |
| | Geothermal | 50MW |
| | Biomass | 50MW |

Source: BREE (2012)

Various factors can affect the cost of an energy technology and its learning rate. These factors include technology structural changes, market forces, government policy and R&D spending, component learning and the country or region in which the learning has occurred (Hayward, Graham and Campbell 2011). As the NEM and the WEM are both in the same country and do not have significant different economic and policy environments for developing new energy technologies, the input data for new entrants in the NEM PLEXOS Model and the WEM PLEXOS Model are collected from the same sources.

The capital cost is per kW 'overnight cost' of building a unit of a generator, which is a critical parameter influencing the entry of new generator unit in the market. Apart from the cost data of the supercritical pulverized coal generation unit, data inputs for other new entrants' capital costs categorised in the Low Capital Costs Scenario, Medium Capital Costs Scenario and High Capital Costs Scenario are sourced from new generation technical dataset of AMEO's 2013 NTNDP (AEMO 2013d, i).

2013 NTNDP study projected technology capital costs for 2013-14 to 2037-38 with five scenarios including Fast Rate of Change Scenario, Fast World Recovery Scenario, Planning Scenario, Decentralised World Scenario and Slow Rate of Change Scenario (AEMO 2013i). For this research, the capital costs of the Planning Scenario in 2013 NTNDP study are taken as the Medium Capital Costs Scenario. The costs projections of the other four scenarios are compared to extract the lowest and highest capital costs of each technology to form the Low Capital Costs Scenario and High Capital Costs Scenario for this research.

Based on the assumption of the cost reduction of a technology slowing down from its intermediate development stage to mature stage, the selected capital cost projections are extrapolated to yield additional data for the period of 2038-39 to 2049-50 (Hayward and Graham 2012). This extrapolation uses half of the average annual growth rate of capital cost from 2013-14 to 2037-38 projected in 2013 NTNDP Study (AEMO 2013g).

ACIL Allen's 2014 report of Fuel and Technology Cost Review provided capital costs projections for supercritical pulverized black and brown coal generation units for the period of 2014-15 to 2044-45 (ACIL Allen 2014; AEMO 2014b). These data are extrapolated to generate an additional four years data for 2045-46 to 2049-50 using the same trends of cost change for 2040-41 to 2044-45. All capital costs projections are in real 2012-13 Australian dollars.

The capital cost is defined in combination with economic life and the WACC to compute an annualised cost in the model's long-term planning. The economic lifespans for coal with or without CCS, CCGT with or without CCS and OCGT are assumed to be 50 years, 40 years and 30 years respectively. The economic lifespans for the RETs including biomass, wind, solar and geothermal are assumed to be 30 years, 20 years, 35 years and 37 years respectively. These assumptions of technology economic lifespans are consistent with the 2103 NTNDP data (AEMO 2013d).

The WACC is the weighted sum of the cost of debt and the cost of equity. The cost of debt is determined by interest rates and the cost of equity is determined by reference against the returns received by other projects with similar risk. The 8.78% WACC adopted for this research is consistent with the 2103 NTNDP assumption (AEMO 2013d).

Project start date denotes the first date after which the generator expansion project can be constructed in the long-term capacity expansion planning. Currently, CCS technologies, solar (including solar PV and solar thermal) and geothermal have not yet reached commercial deployment stage. It assumed that market entry dates for these technologies are from 2020, 2016 and 2021 respectively (AEMO 2013d; BREE 2012; IEA 2014).

## 4.5 Wind and Solar Power Output Traces

Wind and solar are intermittent energy sources that their power output varies with geograhical locations, time and weather conditions. For better simulating the uncertainty of wind and solar generation in the NEM and the WEM, this research applies typical hourly wind and solar power output profiles to project energy output over simulation horizon. Hourly wind and solar power output traces are the normalised power output which represents hourly capacity factor of 1 MW nameplate capacity in a base year. It assumes that for most RETs, a representative hourly power output profile primarily relies on climate conditions and will not change significantly because of technological advancement by 2049-50 compared to present day's condition (ROAM 2012).

### 4.5.1 The NEM Traces

For existing wind generation in the NEM, the hourly power output traces in 2012-13 are sourced from 2013 NTNDP dataset (AEMO 2013f). These data are also applied as hourly power output traces for existing wind generation from 2013-14 to 2049-50.

The concept of a wind bubble was developed in the NEM to model available wind resource. A wind bubble describes a geographical area where wind speeds are considered sufficient to be attractive for new wind development in the NEM (AEMO 2013d). For these wind bubbles, 2010-11 geographical hourly wind power output traces were developed by the AEMO based on wind data (AEMO 2013f). These data are applied as hourly traces for new wind generation from 2013-14 to 2049-50.

Solar energy availability is highly correlated to the behaviour of weather system in an area. Geographical 1 MW hourly power output traces of solar energy of 2010-11 for the NEM was developed by the ROAM Consulting for the 100% Renewable Energy Study in 2013 (ROAM 2012). These data are obtained from 2013 NTNDP dataset and used as hourly traces for new solar generation from 2013-14 to 2049-50 in the NEM PLEXOS Model (AEMO 2013d).

To simulate the uncertainty of wind and solar generation supply during times of high demand, this research applies firm capacity coefficients extracted from 2013 NTNDP to represent long-term average availability of wind and solar generation during peak demand time (AEMO 2013d). These coefficients are used to calculate the reliable capacity of wind and solar generation contributable to the regional cpacity reserve margin.

### 4.5.2 The WEM Traces

The 2013-14 hourly energy output data of existing wind generation in the SWIS are obtained from the IMO market database (IMO 2015). Existing wind capacity 1 MW hourly power output traces are calculated based on its nameplate capacity and historical energy outputs (IMO 2014c). The 2013-14 hourly power output traces are assumed to be representative for existing wind power output to 2049-50 in the WEM PLEXOS Model.

For new wind generation in the WEM, the best available hourly power output information is hourly traces data developed for existing wind farms. In the WEM PLEXOS Model, it assumes that new wind generation could happen in all three load areas: East Country, North Country and South Country. Hourly power output traces of Collagr Wind Farm located in East Country, Mumbida Wind Farm located in

North Country and Albany Wind Farm located in South Country are selected to represent the best estimates for the power output of new wind generation units in East Country, North Country and South Country, respectively.

Australia’s first-utility scale solar farm - the Greenough River Solar Farm (10 MW) is located in North Country load area in the SWIS. Currently, it is the only grid connected solar generator in the SWIS (Greenough River Solar Farm 2015). Its 2013-14 hourly energy output data are obtained from the IMO market database (IMO 2015). The 1 MW hourly power output traces of this solar farm are developmed accordingly. These traces data are assumed to be valid for representing the solar farm’s power output through 2049-50. This set of traces data are also applied as energy output traces for new solar PV generation units in North Country load area (AEMO 2013f).

The SWIS region has similar monthly average values of global horizontal irradiance (GHI) and direct normal irradiance (DNI) as those of SA region in the NEM judging based on the information of the solar map provided by the Australian Solar Energy Information System. As the best available solar PV and thermal hourly power output traces data, SA solar data are selected for representing power output of new solar PV and thermal generation units in South Country and East Country load areas in the SWIS (AEMO 2013f).

## 4.6 Transmission Network Data

### 4.6.1 The NEM Transmission Network

The electricity transmission network simulated in the NEM PLEXOS Model is on a regional basis. The representation of the NEM’s transmission network includes regional reference nodes (RRNs) and interconnectors. It does not incorporate a representation of intra-regional transmission limitations.

The capacity expansion model’s regional representation of the NEM explicitly includes each RRN and each interconnector. Generators and regional demand are categorised into each region through connecting to the RRNs. In reality, generators are not located at the RRN. To account for the transmission losses from the generator station gate to the RRNs and consider the calculation of generator payment based on the regional reference price, a representation of marginal loss factors (MLFs) to each generator is applied in the model (AEMO 2013d). The input data of MLFs are sourced from AEMO's MLFs report for 2012-13 and assumed to remain unchanged through the planning period (AEMO 2012h).

The RRNs in the NEM model are Sydney West in NSW, South Pine in QLD, Thomstown in VIC, Torrens Island in SA and Georgetown in TAS (AEMO 2012e). AEMO surveys transmission projects according to the suggestion by jurisdictional planning bodies in annual planning reports. The interconnector upgrade projects in this model are selected from 2012 Annual Planning Reports Project Summary workbook (AEMO 2012g, 2013d). The NEM PLEXOS Model selects projects for inclusion in future network development based on their ability to reduce total system cost.

### 4.6.2 The WEM Transmission Network

In the SWIS, from North Country to South Country, thermal limits constrained flow is 84 Mega Volt Amp (MVA) in summer and 133 MVA in winter. While the power equivalent rating changes throughout the day, the Western Power System Management has suggested a power factor of 0.95 to be used for both seasons. The resulting constraint limits the flow from north to south to 79.8 MW in summer and 126.4 MW in winter (SKM 2013a).

Additionally, synchronous stability constraints limit generation levels in the Goldfields region. The Goldfield's load cannot exceed 130 MW, and the combined export (generated less self load of approximately 110 MW) of Parkeston and Southern Cross is limited to 85 MW (SKM 2013a).

Western Power has received considerable interest for new entrant generation connections in the North Country Load Area (Wheatbelt Development Commission 2014). This load area is highly sensitive to connection of generation and/or loads. No further generation is possible in this region without transmission reinforcements (Engineers Australia 2010).

The Mid West Energy Project (MWEP) was proposed to address the transmission capacity constraint in the Mid-West region of WA, primarily in the North Country Load Area. It has two stages. The Southern Section of the Mid West Energy Project provides a 330 kV transmission connection between Neerabup and Three Springs, which was completed on 31 March, 2015. The Northern Section will establish an important transmission line link between Geraldton and the Southern Section of the MWEP, construction of which is currently underway (Western Power 2013).

## 4.7 Fuel Prices

### 4.7.1 Coal and Gas Prices in the NEM

The price projections for black coal and gas in the NEM are sourced from the AEMO's 2013 NTNDP dataset. It provides fuel price projections for 2012-13 to 2037-2038 (AEMO 2013d, g). The AEMO's data of fuel prices were estimated by ACIL Tasman, who developed two forms of gas prices including spot price and levelised cost of energy. Meanwhile, the ACIL Tasman also developed a range of price sensitivities dependent on the expansion rates of gas powered generation (ACIL Tasman 2012a; AEMO 2013d). The AEMO used ACIL Tasman's spot price trajectories and appropriate price sensitivity to develop fuel price projections for its 2013 NTNDP (AEMO 2013d).

This research selects fuel prices from the Fast Rate of Change Scenario, Planning Scenario and Slow Rate of Change Scenario from the AEMO's fuel price scenarios in 2013 NTNDP to represent Low Gas and High Coal Prices Scenarios, High Gas and Medium Coal Prices Scenarios, and Medium Gas and High Coal Prices Scenarios, respectively (AEMO 2013d). Fuel price projections of the AMEO are extrapolated to produce fuel prices from 2038-39 to 2049-50 using the average growth rates of the AMEO's projections for 2012-13 to 2037-2038. All prices are in real 2012-13 Australian dollars.

Two important drivers for projecting black coal prices are export prices and production costs (ACIL Tasman 2011). It was projected that the supply of thermal coals will increase at a much faster rate than the demand in the mid-term outlook to 2029-30 with slightly decline trend of thermal coal export prices in Australia (Bullen, Kouparitsas and Krolikowski 2014). In the meantime, the production costs were projected with mild increase to 2029-30 (ACIL Tasman 2012b). Considering these factors with assumed similar trends of export prices and production costs to 2049-50, black coal prices for new entrant coal fired power stations are projected to remain relatively stable to 2049-50. Brown coal prices are projected to be held constant over the planning horizon. This projection is based on the fact that brown coal is abundant and economically extractable resources generally close to power stations in Australia and it is not for exporting trade.

With the commencement of liquefied national gas (LNG) export linking Australian eastern domestic gas market with global gas market, Australian gas prices were forecast to rise in a significant way (Wood and Carter 2013). The gas prices are projected to grow with a high trend to low, a low trend to high, and a medium trend to high for the Low Gas Prices Scenario, Medium Gas Prices Scenario and High Gas Prices Scenario, respectively (AEMO 2013d).

### 4.7.2 Coal and Gas Prices in the WEM

For the WEM PLEXOS Model, two trajectories of coal prices are developed: Base Coal Price Scenario and High Coal Price Scenario. The inputs for these two coal scenarios are sourced from regional average projections of coal prices for the Medium Coal Price Scenario and High Coal Price Scenario of the NEM in 2013 NTNDP respectively (AEMO 2013d, f).

IMO 2014 Gas Statement of Opportunities (GSO) made forecasts of medium to long-term average new contract gas prices for WA domestic market (IMO 2014b). It contained Base Scenario and High Scenario projection of WA domestic gas price from 2014-15 to 2023-2024. The average growth rates of regional gas prices of medium and high gas prices scenarios in the NEM (AEMO 2013f) are adopted to extrapolate GSO WA gas prices from 2024-25 to 2049-50.

## 4.8 Carbon Prices

There are five scenarios of carbon prices designed for the modelling, including Zero, Low, Medium, High and Treasury High carbon Price Scenarios, as shown in Figure

4.8. The NEM PLEXOS Model and the WEM PLEXOS Models apply the same sets of carbon prices for simulation.

The carbon price in the Zero Carbon Price Scenario is set to be AU$23/t in 2012-13 and AU$24.15/t in 2013-14. After the removal of the CPS in July 2014, there is no further carbon prices implemented in the planning horizon in the Zero Carbon Price Scenario (Australian Treasury 2011).

The carbon prices data of Low, Medium and High Scenarios are sourced from the AEMO's 2014 NTNDP carbon price projections (AEMO 2014b). These trajectories of carbon price for 2013-14 to 2039-2040 were forecasted by the Frontier Economics (AEMO 2014d). It assumed that the carbon prices from 2040-41 to 2049-50 in the Low, Medium and High Scenarios continued their trends respectively.

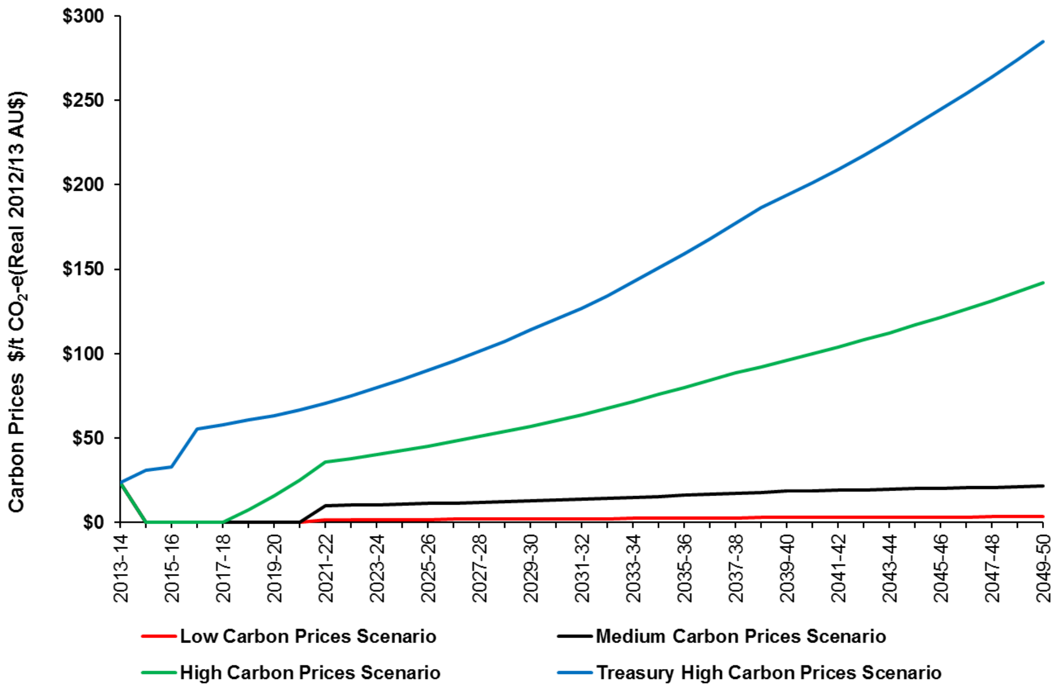



**Figure 4.8** Projected carbon prices by scenario, 2012-13 to 2049-50.

The Low Carbon Prices Scenario projects carbon prices remains at zero from July 2014 to 2017-18 in short-term. From 2018-19, the carbon prices adopts 2011 Treasury Core Carbon Prices Scenario to achieve 550pm $CO_2$-e concentration level (Australian Treasury 2011). The Medium Carbon Scenario assumes zero carbon prices from 2014-15 to 2020-21. Form 2021-22, carbon prices are projected to be aligned with the European carbon prices. For the High Carbon Prices Scenario, zero carbon prices are from 2014-15 to 2020-21. In the long run, form 2021-22, carbon prices are projected to adopt Clean Development Mechanism prices (Frontier Economics 2014a).

The carbon prices in Treasury High Carbon Prices Scenario are sourced from the High Price Scenario of 2011 Treasury Strong Growth, Low Pollution study (Australian Treasury 2011). The projections of carbon prices in this scenario are significantly higher than the other three carbon prices scenarios (Low, Medium and High). The inclusion of this scenario aims at investigating the impact of high carbon prices on the energy technologies selection in the capacity expansion planning. All carbon prices projections are in real 2012-13 Australian dollars.

## 4.9 Carbon Emissions Reduction Targets

As stated in Chapter 1, three carbon emissions reduction targets are established for the Australian economy. The first target assumes an Australian emission target of a 5% cut on 2000 levels by 2019-20 and an 80% cut on 2000 levels by 2049-50. The second assumption assumes an Australian emission target of a 25% reduction on 2000 levels by 2019-20 and an 80% cut on 2000 levels by 2049-50. The third assumption assumes a 5% reduction on 2000 levels by 2020, a 26% cut on 2005 levels by 2029-30, and an 80% cut on 2000 levels by 2049-50. For translating these targets into the emission reduction goals in Australian electricity generation sector, this research established reduction targets separately for the NEM and the WEM based on the national targets.

### 4.9.1 The NEM Carbon Reduction Targets

In the NEM model, three carbon emissions reduction targets are established to limit carbon production from electricity generation over the simulation horizon. The 5%-80% Reduction Target defined the NEM should reduce its GHG emissions by 5% in 2019-20 and by 80% in 2049-50 from its 2000 emission levels. The 25%-80% Reduction Target assumed the NEM should reduce its GHG emissions by 25% in 2019-20 and by 80% in 2049-50 from its 2000 emission levels. The 5%-26%-80% Reduction Target assumed the NEM should cut its GHG emissions by 5% by 2019-

20 based on 2000 levels, by 26% based on 2005 levels by 2029-30, and by 80% by 2049-50 based on 2000 levels.

Historical GHG emissions of the NEM are sourced from the AMEO Carbon Dioxide Equivalent Intensity Index database (AEMO 2013h). In 2000, the NEM emitted approximately 165 Mt GHGs. Correspondingly 5%, 25% and 80% reduction of this 165 Mt are 157 Mt, 124 Mt and 33 Mt respectively. In 2005, the emissions of the NEM reached 177 Mt. Therefore, 26% cut on 2005 levels of the NEM's emissions is around 131 Mt. The continuous emissions trends linking 2020, 2030 and 2050 targets are established by the linear extrapolation, as shown in Figure 4.9.

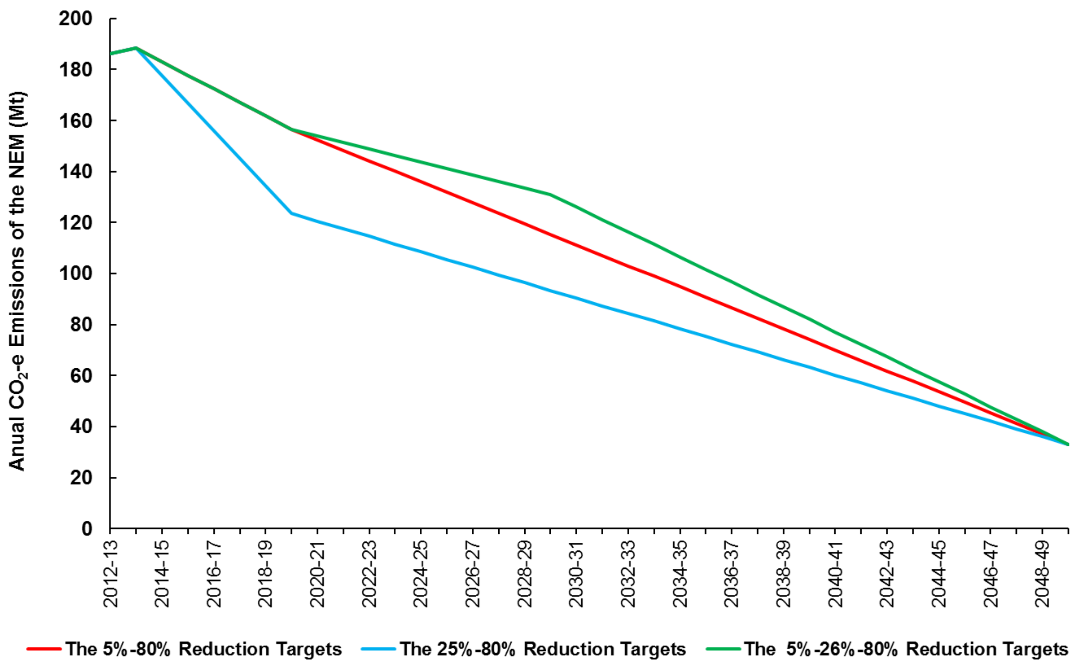



**Figure 4.9** The GHG emissions Trajectories for the NEM, 2012-13 to 2049-50.

### 4.9.2 The WEM Carbon Reduction Targets

The WEM was established in 2006 and its data of historical generation sent-out was available from September 2006. Hence, there was no available dataset to reflect carbon emissions of the SWIS in 2000. For establishing carbon emission reduction target for the WEM, the emissions in the year 2007-08 is selected as the base year for its historical carbon emissions estimation. The SWIS' carbon emissions in 2007-08 are calculated as the product of the SWIS' electricity generation in 2007-08 and the SWIS' Scope 2 carbon emission factor. The Scope 2 emissions are the emissions produced by burning of fuels (coal, natural gas, etc.) at power stations (Australia Government 2013).

The National Greenhouse Accounts Factors 2014 showed that the Scope 2 emission factor of the SWIS in 2007-08 was 0.86 kg $CO_2$-e-kWh (Australian Government 2014b). The electricity generation of the SWIS in 2007-08 was 16,387 GWh (IMO 2014e). Therefore, carbon emission of the SWIS in 2007-08 is approximately 14.09 Mt, which is the product of 0.86 kg $CO_2$-e-kWh and 16,387 GWh.

In the WEM PLEXOS Model, the carbon emission reduction target is set with three trends: 1) the 5%-80% Reduction Target denotes emissions cut in the WEM by 5% by 2019-20 and 80% reduction by 2049-50 based on 2007-08 emission levels; 2) the 25%-80% Reduction Target represents the emissions reduction by 25% by 2019-20 and 80% reduction by 2049-50 based on 2007-08 emission levels; and 3) the 5%-26%-80% assumes the emissions reduction by 5% by 2019-20, by 26% by 2029-30 and by 80% by 2049-50 based on 2007-08 levels. These assumptions may lead to less stringent emission reduction requirement compared to calculations based on the SWIS' 2000 emission levels. Nevertheless, these three trends can be used to represent the SWIS' possible carbon emissions reduction trajectories to 2049-50.

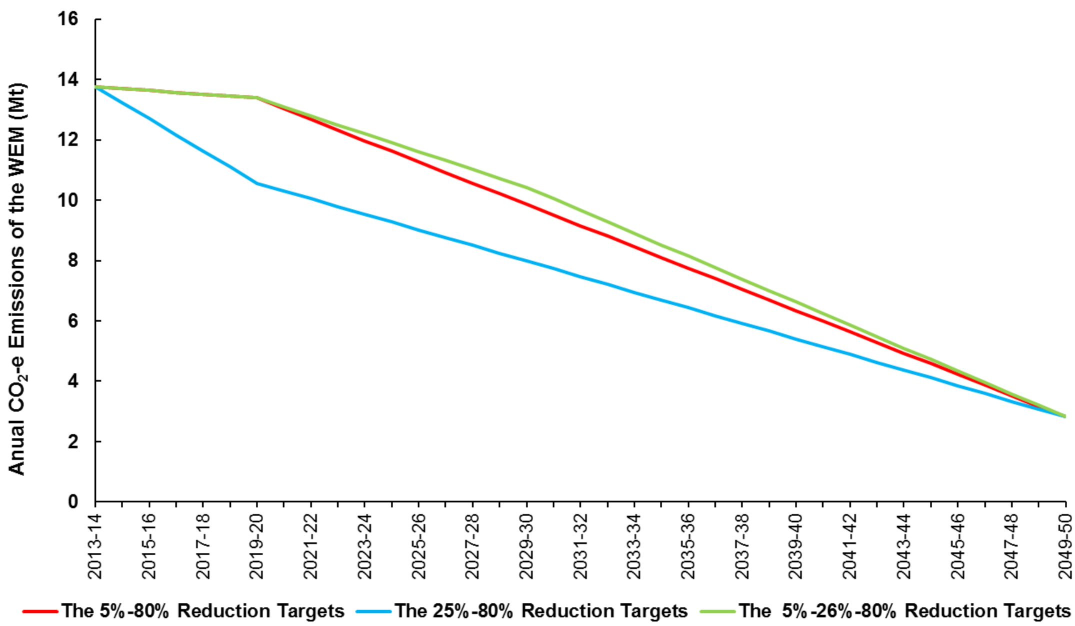



**Figure 4.10** The GHG emissions Trajectories for the WEM, 2013-14 to 2049-50.

As shown in Figure 4.10, the 5% and 25% of carbon emissions reduction by 2019-20 based on 2007-08 levels are approximately 13.39 Mt and 10.57 Mt respectively. The 26% of carbon reduction by 2029-30 based on 2007-08 levels is 10.4 Mt, and the 80% reduction by 2049-50 is about 2.82 Mt.

## 4.10 Renewable Energy Target

The Renewable Energy Target was comprised of the 41,000 GWh Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (4,000 GWh) (Clean Energy Regulator [CER] 2014a). On 23 June 2015, the LRET was reviewed and reduced to 33,000 GWh (Minister for the Environment 2015).

The current LRET was applied to the BAU Scenarios, the 5%-26%_2030 Reduction Scenario, the 5%-26%_2030-RETs Only Scenario and the 5%-26%_2030-CCS Only Scenario. The previous LRET is adopted by the 5% and 25% Reduction Scenarios, the 5% and 25%-RETs Only Scenarios and the 5% and 25%-CCS Only Scenarios.

In the NEM PLEXOS Model and the WEM PLEXOS Model, the current LRET and the previous LRET are scaled proportionally to reflect the requirement of renewable energy generation in the NEM and the WEM. They are implemented by setting a constraint of annual energy target that must be generated from renewable sources.

The current LRET for the NEM used in the model is sourced from 2012 NTNDP except the data for 2012-13 and 2013-14 (AEMO 2012d). The data for 2012-13 and 2013-14 (see Table 4.3) are sourced from 2014 Australian Energy Statistics Data which reflect the real renewable generations (Australian Government 2014a). This research assumes that although the LRET was reduced after June 2015, the NEM will keep its pace in deploying the RETs until 2016-17. After that, the renewable development will be slowing down. The annual data of current LRET (see Table 4.4) is extrapolated propotionally from the corresponding year of previous LRET data (see Table 4.3).

In 2012-13, the electricity generation of WA was accounted for around 13.4% of total electricity generation of Australia (Australian government 2014a). This research assumes that approximately 13.4% of 41,000 GWh LRET would be produced from the renewable sources by 2019-20 in WA. Considering the portions of energy generation in the SWIS and the rest of WA, the WEM PLEXOS Model assumes that 10% of 41, 000 GWh LRET would be from renewable generators in the WEM by 2019-20 (ROAM 2010).

**Table 4.3** Modelled Previous LRET in the NEM.

| Year | NEM Previous LRET (GWh) |
|---|---|
| 2012-13 | 15572 |
| 2013-14 | 18732 |
| 2014-15 | 18256 |
| 2015-16 | 20237 |
| 2016-17 | 23467 |
| 2017-18 | 27543 |
| 2018-19 | 31622 |
| 2019-20 | 36575 |

**Table 4.4** Modelled Previous LRET in the NEM.

| Year | NEM Previous LRET (GWh) |
|---|---|
| 2012-13 | 15572 |
| 2013-14 | 18733 |
| 2014-15 | 18256 |
| 2015-16 | 20237 |
| 2016-17 | 23467 |
| 2017-18 | 25451 |
| 2018-19 | 27545 |
| 2019-20 | 29434 |

In 2012-13, approximately 1,580 GWh in the SWIS was from renewable sources. To meet the quota of the WEM's previous LRET, the renewable energy output will need to increase to 4,100 GWh by 2019-20. The annual quota of the WEM's previous LRET is derived by the linear extrapolation from 1,580 GWh in 2012-13 to 4,100 GWh in 2019-20 (see Table 4.5). The annual data of current LRET in the WEM (see Table 4.6) is extrapolated propotionally from the corresponding year of the WEM's previous LRET data (see Table 4.5).

**Table 4.5** Modelled Previous LRET in the WEM.

| Year | WEM Previous LRET (GWh) |
|---|---|
| 2013-14 | 1580 |
| 2014-15 | 1940 |
| 2015-16 | 2300 |
| 2016-17 | 2660 |
| 2017-18 | 3020 |
| 2018-19 | 3380 |
| 2019-20 | 3740 |
| 2013-14 | 4100 |

**Table 4.6** Modelled Current LRET in the WEM.

| Year | WEM Current LRET (GWh) |
|---|---|
| 2013-14 | 1561 |
| 2014-15 | 1851 |
| 2015-16 | 2141 |
| 2016-17 | 2431 |
| 2017-18 | 2720 |
| 2018-19 | 3010 |
| 2019-20 | 3300 |

# Chapter 5 The NEM PLEXOS Modelling Results and Discussion

This chapter reports the results of the NEM PLEXOS Model. The RETs and CCS comparison scenarios were specifically designed to compare the potentials of the RETs and CCS technologies in reducing carbon emissions over a long term period in the NEM. This section reports and discusses the results of scenario simulation. Please refer to Section 3.2.3 in Chapter 3 for the details of scenarios construction.

## 5.1 Carbon Emissions Results

The carbon emissions trajectories adopted in the NEM were defined by the 5%-80% Reduction Target, the 25%-80% Reduction Target and the 5%-26%-80% Reduction Target. They were calculated by linear extrapolation and used as inputs for the modelling (please refer to Section 4.9.1 in Chapter 4). These reduction targets acted like constraints to control the adoption of energy technologies for capacity expansion in the NEM over the planning horizon. New entrants of energy technologies should contribute to system capacity expansion in a way that they not only help to meet energy demand growth in the NEM, but also satisfy pre-defined carbon emissions reduction targets at a least cost.

The BAU Scenario optimised power system expansion path in the NEM with the requirements of meeting energy demand growth and the current Renewable Energy Target. In this case, carbon emissions in the NEM were not capped. Consequently, it resulted in the largest amount of emissions compared to other scenarios. It also showed the likely carbon emissions in the NEM, if the Australian electricity sector was not subjected to any carbon emission reduction commitments.

The outcome of carbon emissions in the BUA Scenario was generated by the NEM PLEXOS Model (see Figure 5.1). It showed that the carbon emissions started at 186.1 Mt in 2012-13, first peaked at approximately 201.6 Mt in 2014-15 and then reduced gradually to the year 2019-20. Afterwards, the emissions increased almost linearly from 199.8 Mt in 2020-21 to 256 Mt in 2049-50. This represented an approximate 37.6% increase when compared to the emissions in 2012-13. A short period of decreasing $CO_2$-e emissions between 2014-15 and 2019-20 in this scenario may be a result of implementing current Renewable Energy Target.

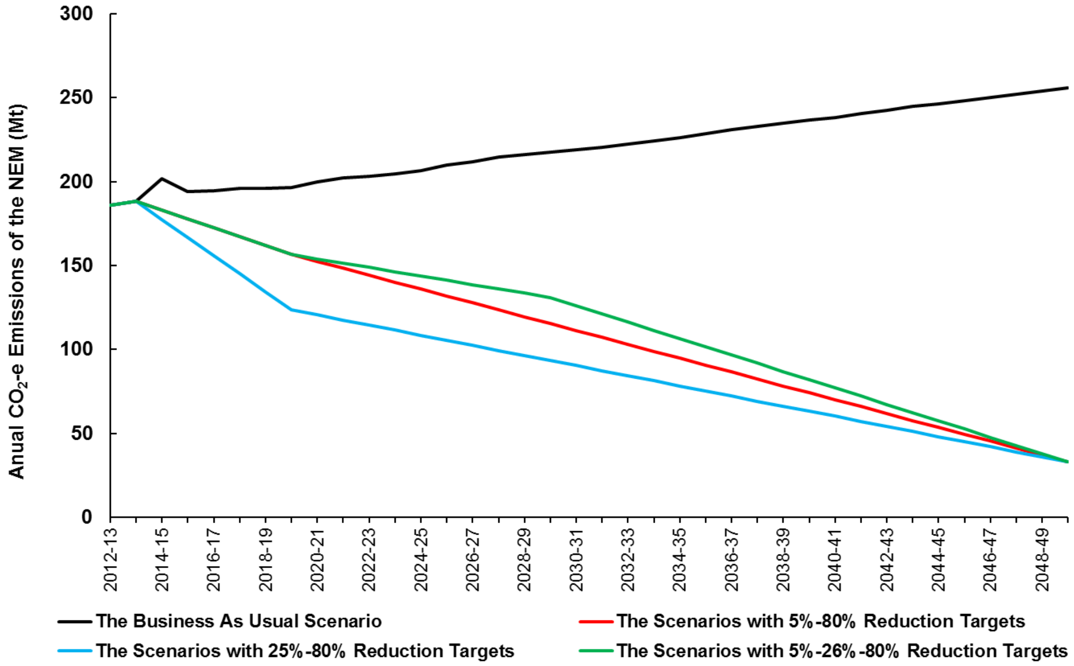



**Figure 5.1** The trends of annual $CO_2$-e emissions in the NEM by scenario group, 2012-13 to 2049-50.

The scenarios with the 5%-80% Reduction Target, the 25%-80% Reduction Target and the 5%-26%-80% Reduction Target adopted three trends of annual $CO_2$-e emissions from 2012-13 to 2049-50 respectively. These three trends of emissions all experienced the reduction from 186.1 Mt in 2012-13 to 33 Mt in 2049-50, representing an 82.3% reduction on 2012-13 levels and an 80% reduction on 2000 level. As displayed in Figure 5.1, a distinctive difference between these trends is that the 25%-80% Reduction Target cuts emissions much faster than the 5%-80% Reduction Target and the 5%-26%-80% Reduction Target before the year 2019-20.

There were significant variations among the cumulative carbon emissions of the BAU Scenario, the scenarios with the 5%-80% Reduction Target, the 25%-80% Reduction Target and the 5%-26%-80% Reduction Target over the planning horizon. From 2012-13 to 2049-50, the cumulative emissions for these four reduction trends reached 8387.4 Mt, 4147.6 Mt, 3581.3 Mt and 4409 Mt respectively. They are indicated by the areas below emissions trend lines in Figure 5.1. Compared to the cumulative emissions of the BAU Scenario; over the planning period the 5%-80% Reduction Target, the 25%-80% Reduction Target and the 5%-26%-80% Reduction Target emitted almost 50.2%, 57.3% and 47.3% less carbon emissions respectively.

## 5.2 Electricity Generation Results

This section first reports generation results of the BAU Scenario in 2012-13 and 2014-15. Then the generation results in the years of 2019-20, 2029-30 and 2049-50 are reported and compared for the BAU Scenario, the Scenarios with the 5%-80%, 25%-80% and 5%-26%-80% Reduction Targets.

### 5.2.1 Generation Results of the BAU Scenario in 2012-13 and 2014-15

The BAU Scenario served as the reference case for the comparison of other scenarios' results. The year 2012-13 was the baseline year set for the NEM PLEXOS Model. The carbon price of AU$23/t was applied in the BAU Scenario in 2012-13. From 2014-15, no carbon price or a zero carbon price existed in the BAU Scenario.

For the year 2012-13, the generation mixes of all scenarios simulated in the model were identical, which can be represented by the generation mix of the BAU Scenario in 2012-13 (see Figure (5.2-a)). Total energy generation in the NEM was approximately 204 TWh in 2012-13, primarily from black and brown coal, natural gas, hydro and wind sources. Black and brown coals generated approximately 77.4% of total output (158 TWh). CCGT and OCGT accounted for 6.8% (13.9 TWh) and 4.2% (8.5 TWh) respectively. Hydro and wind contributed 7.6% (15.5 TWh) and 4.0% (8.1 TWh) respectively. In total, fossil fuel sources and renewable sources accounted for approximately 88.4% (180.4 TWh) and 11.6% (23.6 TWh) of total energy output respectively in the BAU Scenario in 2012-13.

In 2014-15, total electricity generation in the NEM reached 213 TWh, as shown in Figure (5.2-b). The energy output from black and brown coal increased and from natural gas decreased compared to their generation in 2012-13. Energy generation from the black and brown coal in total accounted for approximately 83.9% (178.7

TWh) in 2014-15. Energy generation from CCGT and OCGT reduced to 2.5% (5.3 TWh) and 1.2% (2.6 TWh) respectively of total generation in 2014-15.

Energy generation from hydro in 2014-15 remained at similar level as in 2012-13. Wind energy generation experienced a growth from 2012-13, reaching approximately 5.0% (10.6 TWh) of total energy generation in 2014-15. In 2014-15, fossil fuels and renewables contributed to approximately 87.6% (186.6 TWh) and 12.4% (26.4 TWh) of total energy output respectively in the BAU Scenario.

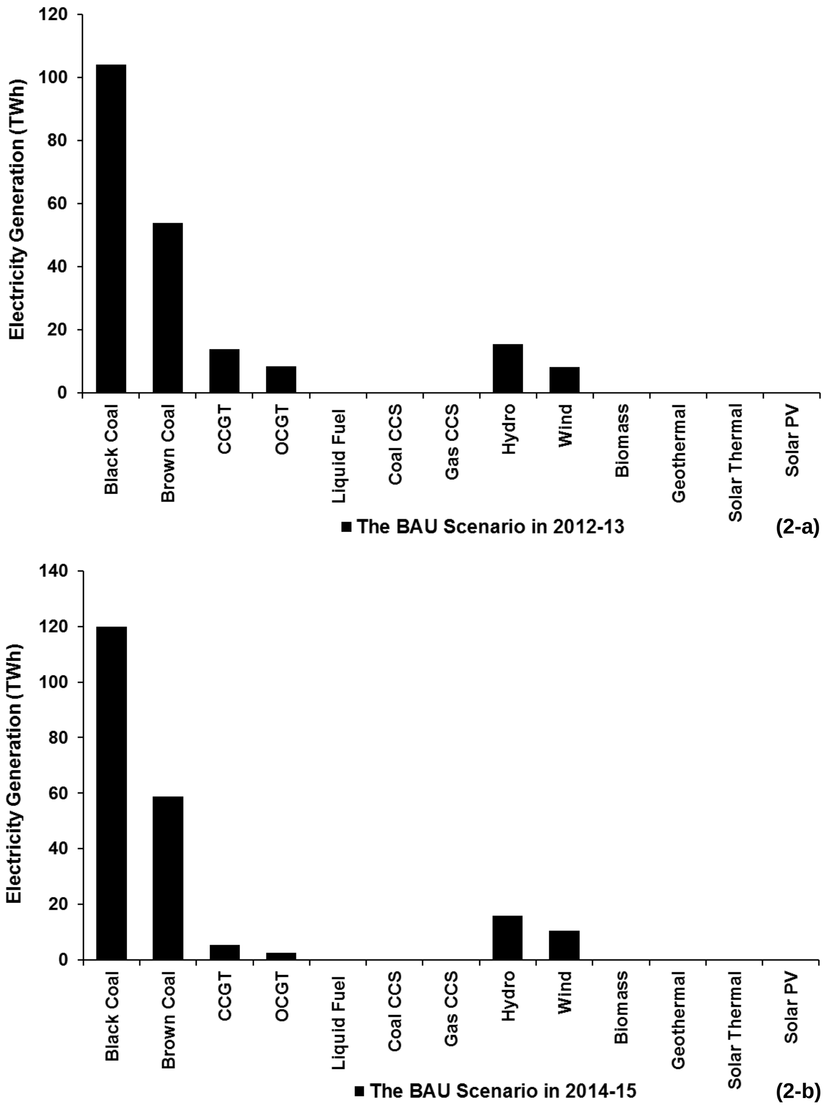



**Figure 5.2** Energy generation in the BAU Scenario in 2012-13 (2-a) and 2014-15 (2-b).

It was expected that the removal of the carbon price would cause an increase in fossil fuel energy generation in the BAU Scenario in 2014-15. At the same time, the implementation of the current Renewable Energy Target was expected to take effect on increasing the penetration of renewable energy. The generation results of the BAU Scenario in 2014-15 were consistent with these expectations.

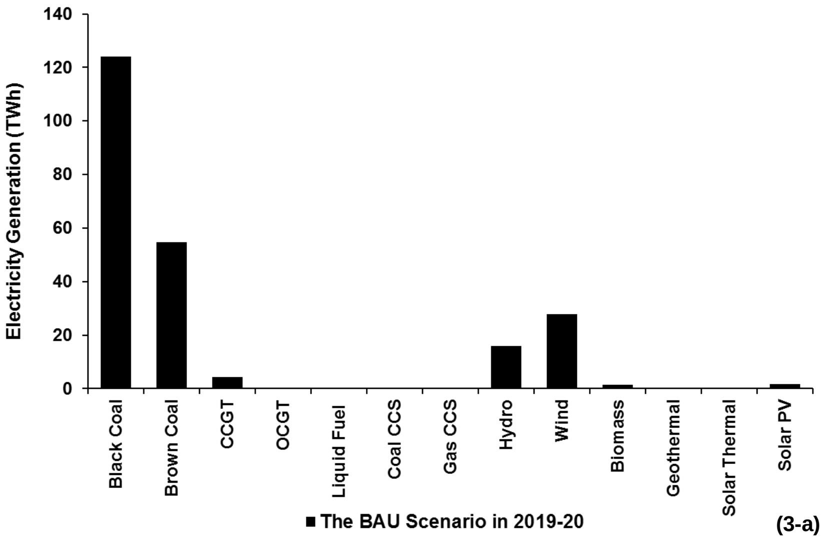
### 5.2.2 7Generation Results in 2019-20 and 2029-30

Figure 5.3 below shows the generation results of the BAU Scenario in 2019-20 and 2029-30. In 2019-20, the black coal and brown coal generated approximately 124.1 TWh (53.9%) and 54.6 TWh (23.8%) of electricity respectively in the BAU Scenario, as shown in Figure (5.3-a). Electricity generated by the CCGT and OCGT dropped to 4.4 TWh (1.9%) and 0.2 TWh (0.1%) respectively. Hydro generation in 2019-20 stayed at the similar level of 15.9 TWh (6.9%) as the generation in 2012-13. Wind energy generation increased significantly and reached 27.8 TWh (12.1%) in 2019-20. Biomass and solar PV generation started in 2018-19 and produced 1.3 TWh (0.6%) and 1.7 TWh (0.7%) respectively in 2019-20.

In 2019-20, the fossil fuels and renewables accounted for around 79.7% (183.3 TWh) and 20.3% (46.8 TWh) of total generation respectively in the BAU Scenario. The renewables almost doubled the generation in 2019-20 (46.7 TWh) compared to the generation in 2012-13 (23.7 TWh). As no carbon price existed in the BAU Scenario from 2014-15, the increased renewable generation suggested a positive impact of current Renewable Energy Target on the renewable energy generation in the NEM.

The generation mix displayed in the Figure (5.3-b) reveals that in 2029-30, the energy demand growth of the NEM was primarily met by the increased fossil fuel energy generation in the BAU Scenario. The renewable energy generation in 2029-30 remained at almost the same level as in 2019-20.

In 2029-30, fossil fuel generation accounted for approximately 81.3% (204.5 TWh) of total energy output in the BAU Scenario. It was comprised of 55.9%, 23.4%, 1.9% and 0.1% of black coal, brown coal, CCGT and OCGT generation respectively. Hydro, wind, biomass and solar PV generation in 2029-30 was at the similar level as their generation in 2019-20. In total, renewable energy contributed to approximately 18.7% (46.9 TWh) of total energy output in the BAU Scenario in 2029-30.



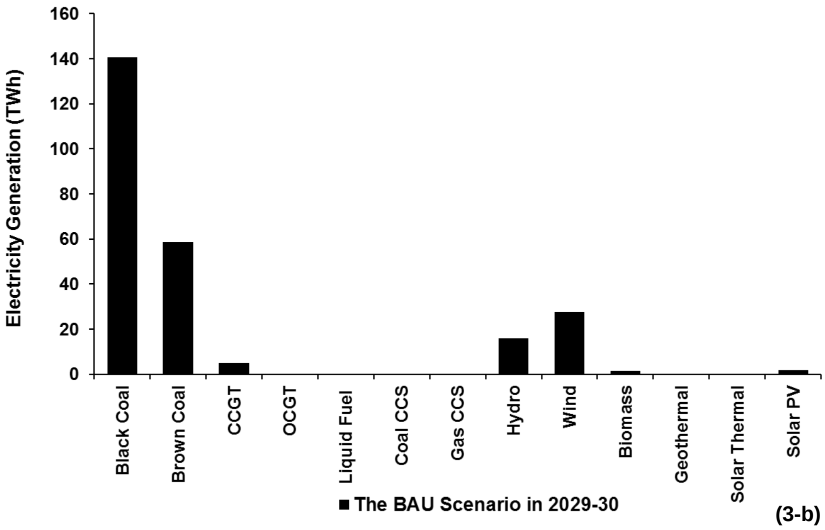




**Figure 5.3** Energy generation in the BAU Scenario in 2019-20 (3-a) and in 2029-30 (3-b).

The generation results of the BAU Scenario in 2029-30 indicated that without carbon prices or a carbon reduction target, there was no impetus for more renewable energy penetration in the NEM after 2019-20. The energy demand growth in the NEM between 2019-20 and 2029-30 was predominately met by fossil fuel energy.

Figure 5.4 shows energy generation in the 5% Reduction Scenario, the 5%-RET Only Scenario, the 5%-26%_2030 Reduction (CPG) Scenario and the 5%-26%_2030-RET Only Scenario in 2019-20. Displaying these results together was because they presented a similar generation pattern in year 2019-20.

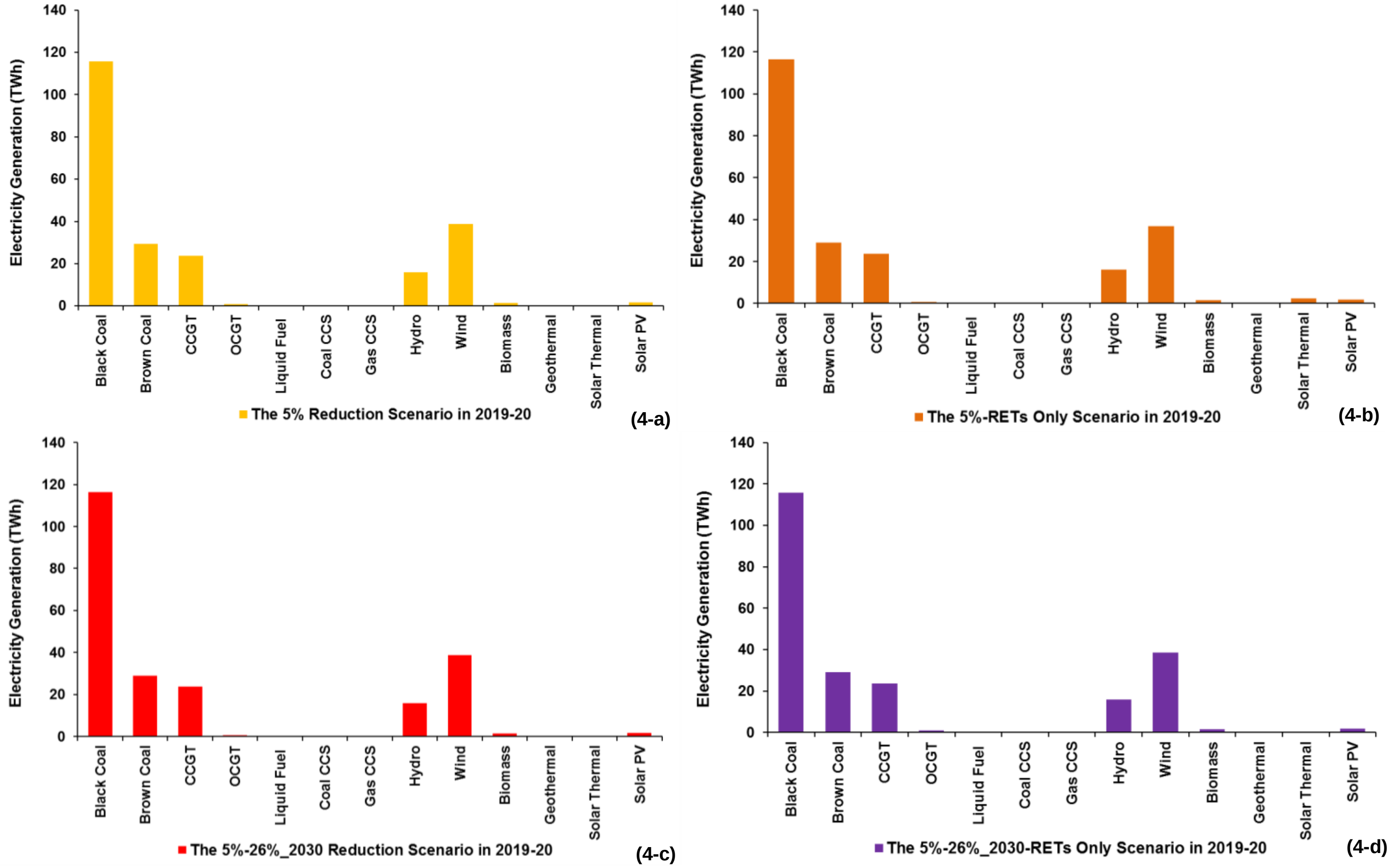



**Figure 5.4** Energy generation in the 5% Reduction Scenario (4-a), the 5%-RET Only Scenario (4-b), the 5%-26%_2030 Reduction Scenario (4-c) and the 5%-26%_2030-RET Only Scenario (4-d) in 2019-20.

Compared to the BAU Scenario in 2019-20, these scenarios had significantly reduced amount of energy output from black coal and brown coal. Meanwhile, they had increased generation from CCGT and OCGT. Black coal and brown coal represented approximately 51% (116 TWh) and 12.8% (29 TWh) of total generation respectively in each of these scenarios. CCGT and OCGT generation reached approximately 10.4% (23.7 TWh) and 0.33% (0.75 TWh) respectively in each of these scenarios.

Hydro, biomass and solar PV generation in these scenarios were at the same levels as their generation in the BAU Scenario in 2019-20. Wind generation increased considerably and reached approximately 38.6 TWh in the 5% Reduction Scenario, the 5%-26%_2030 Reduction Scenario and the 5%-26%_2030-RET Only Scenario respectively; and 36.9 TWh in the 5%-RET Only Scenario.

Additionally, solar thermal generation entered the 5% Reduction Scenario, the 5%-26%_2030 Reduction Scenario and the 5%-26%_2030-RET Only Scenario in 2019-20 and generated approximately 0.46 TWh in the same year. It entered the 5%-RET Only Scenario one year earlier in 2018-19 and reached 2.4 TWh in 2019-20.

In general, conventional fossil fuel and renewable energy made up approximately 74.5% (170 TWh) and 25.5% (58 TWh) of total generation in the 5% Reduction Scenario, the 5%-RET Only Scenario, the 5%-26%_2030 Reduction Scenario and the 5%-26%_2030-RET Only Scenario in 2019-20 respectively.

These scenarios were all constrained by the 5% Reduction Target by 2019-20, but the 5% Reduction Scenario and the 5%-RET Only Scenario were subjected to the previous Renewable Energy Target, and the 5%-26%_2030 Reduction Scenario and the 5%-26%_2030-RET Only Scenario were subject to the current Renewable Energy Target. The results in 2019-20 revealed that the 5% Reduction Target outweighed the Renewable Energy Target in promoting the penetration of renewable energy from 2014-15 to 2019-20 in these scenarios.

In 2029-30, the generation results of the 5% Reduction Scenario (see Figure (5.5-a)) presented a similar pattern as the results of the 5%-RETs Only Scenario (see Figure (5.5-b)), except the occurrence of coal CCS generation in the 5% Reduction Scenario.

The 5%-80% Reduction Target drove the generation of coal CCS in the 5% Reduction Scenario to happen as early as in 2028-29 and reaching 7.9 TWh (3.2%) in 2029-30. Due to the assumption of the CCS technologies not available in the 5%-RETs Only Scenario after 2019-20, coal CCS generation did not occur in this scenario.

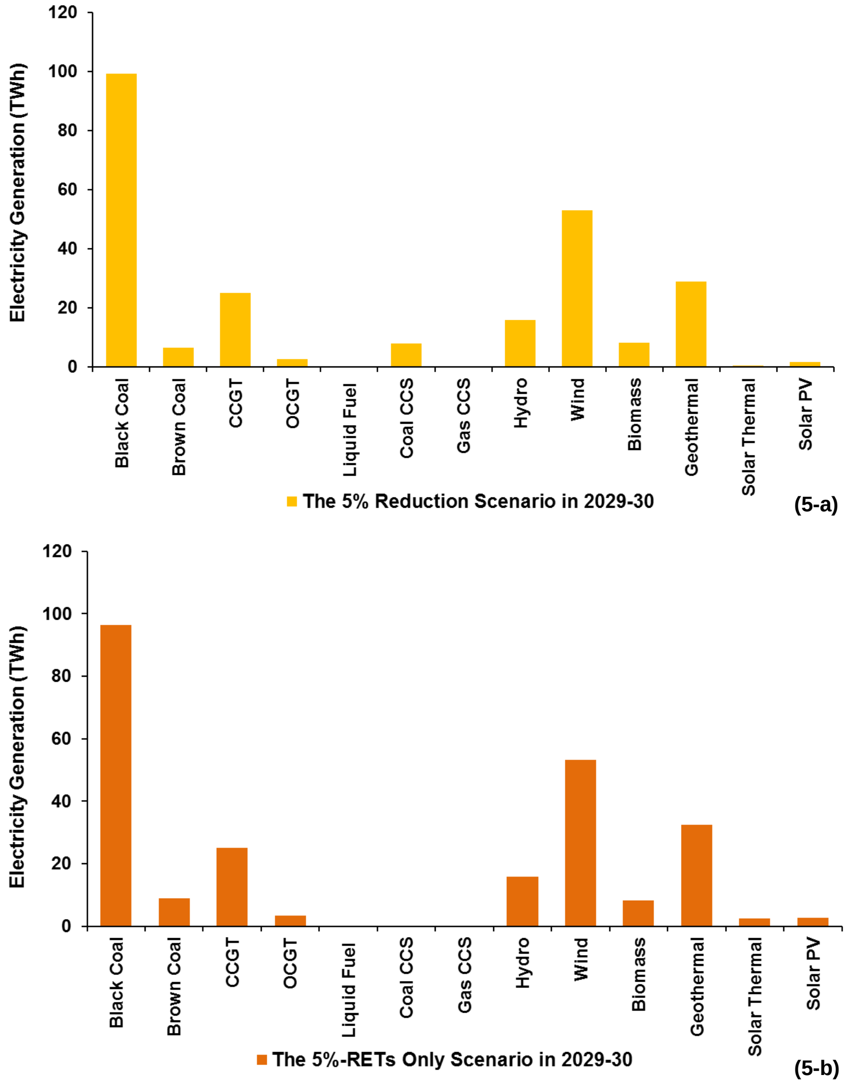



**Figure 5.5** Energy generation in the 5% Reduction Scenario (5-a) and the 5%-RET Only Scenario (5-b) in 2029-30.

Apart from coal CCS generation, in 2029-30 the 5% Reduction Scenario and the 5%-RETs Only Scenario both experienced the reduction of black and brown coal generation and the growth of CCGT and OCGT generation compared to 2019-20. In 2029-30, black coal and CCGT generated around 96 TWh and 25 TWh of electricity in the 5% Reduction Scenario and the 5%-RETs Only Scenario respectively. Brown coal and OCGT generated approximately 6.4 TWh and 2.5 TWh in the 5% Reduction Scenario respectively. They generated 8.8 TWh and 3.3 TWh in the 5%-RETs Only Scenario respectively. Altogether conventional fossil fuel generation accounted for approximately 53.4% (133.3 TWh) and 53.8 % (133.6 TWh) of total energy outputs respectively in the 5% Reduction Scenario and the 5%-RETs Only Scenario in 2029-30.

In 2029-30, the 5% Reduction Scenario and the 5%-RETs Only Scenario had similar levels of hydro, wind and biomass generation; producing 15.9 TWh, 53.1 TWh and 8.2 TWh of electricity respectively. Geothermal generation first occurred in both scenarios in 2021-2022, which reached 29 TWh in the 5% Reduction Scenario and 32.4 TWh in the 5%-RETs Only Scenario. In 2029-30, solar thermal generation in the 5% Reduction Scenario and in the 5%-RETs Only Scenario remained at the same levels as their generation in 2019-20. Solar PV generation reached approximately 1.7 TWh and 2.7 TWh in two scenarios respectively. Altogether, the renewable generation accounted for 43.4% (108.4 TWh) and 46.2% (114.7 TWh) of total generation in the 5% Reduction Scenario and the 5%-RETs Only Scenario respectively in 2029-30.

These results suggested that the decarbonisation of energy generation continued to progress in the NEM in the 5% Reduction Scenario and the 5%-RETs Only Scenario for the period of 2019-20 to 2029-30, which was mainly driven by the 5%-80% Reduction Target.

The generation results of the 5%-26%_2030 Reduction Scenario resembled the results of 5%-26%_2030-RET Only Scenario in 2029-30 (see Figure 5.6 below). Geothermal generation entered both scenarios in 2021-22, and reached 22.2 TWh and 23 TWh in 2029-30 respectively. In 2029-30, solar PV generation in two scenarios was at approximately 1.7 TWh and 2.0 TWh respectively. In 2029-30, conventional fossil fuels and renewables contributed to approximately 59.1% (146.4 TWh) and 40.9% (101.5 TWh) of total energy generation in the 5%-26%_2030 Reduction Scenario respectively. They contributed around 58.6% (145.5 TWh) and 41.4% (102.7 TWh) of total energy generation in the 5%-26%_2030-RET Only Scenario respectively.

The generation results displayed in Figure 5.5 and Figure 5.6 suggested that the 5%-80% Reduction Target was more effectively in driving the entrance of the coal CCS generation in the NEM and encouraging more energy production from renewable sources in the 5% Reduction Scenario and the 5%-RETs Only Scenario than the 5%-26%-80% Reduction Target did in the 5%-26%_2030 Reduction Scenario and the 5%-26%_2030-RET Only Scenario in 2029-30.

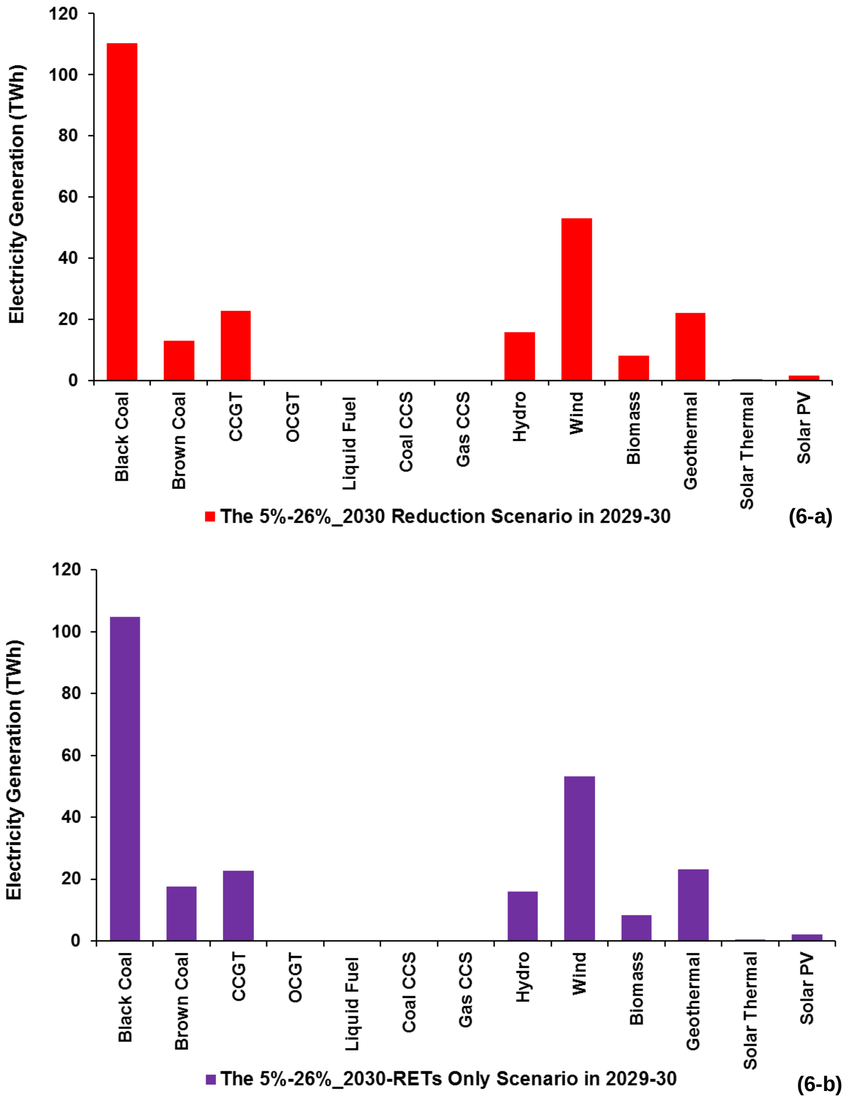



**Figure 5.6** Energy generation in the 5%-26%_2030 Reduction Scenario (6-a) and the 5%-26%_2030-RET Only Scenario (6-b) in 2029-30.

In 2019-20, the generation results of the 5%-CCS Only Scenario were similar as the results of the 5%-26%_2030-CCS Only Scenario (see Figures (5.7-a) and (5.7-b)). They had less energy generation from black coal and brown coal than the generation in the BAU Scenario in 2019-20. Black coal and brown coal generated 112.3 TWh and 35.8 TWh respectively in the 5%-CCS Only Scenario; and 116.4 TWh and 34.7 TWh respectively in the 5%-26%_2030-CCS Only Scenario in 2019-20.

CCGT generation in the 5%-CCS Only Scenario and the 5%-26%_2030-CCS Only Scenario was at similar level (4.4 TWh) as the generation in the BAU Scenario in 2019-20. The electricity generation from OCGT reached approximately 1.1 TWh in the 5%-CCS Only Scenario and 0.17 TWh in the 5%-26%_2030-CCS Only Scenario in 2019-20. In total, there were 153.7 TWh (67.5%) and 155.7 TWh (68.4%) of electricity generated from conventional fossil fuel sources in the 5%-CCS Only Scenario and the 5%-26%_2030-CCS Only Scenario respectively in 2019-20.

In 2019-20, hydro generation was 15.9 TWh in both the 5%-CCS Only Scenario and the 5%-26%_2030-CCS Only Scenario. It was at the same level as the generation in the BAU Scenario in 2019-20. These two scenarios had the same biomass generation at 1.4 TWh and the same solar PV generation at 1.7 TWh in 2019-20. Solar thermal generation first occurred in both the 5%-CCS Only Scenario and the 5%-26%_2030-CCS Only Scenario in 2019-20. It reached approximately 1.7 TWh in the 5%-CCS Only Scenario and 0.85 TWh in the 5%-26%_2030-CCS Only Scenario.

In 2019-20, wind generation increased significantly in these two scenarios compared to the generation in the BAU Scenario. It reached 53.3 TWh in the 5%-CCS Only Scenario and 52.1 TWh in the 5%-26%_2030-CCS Only Scenario. Altogether, renewable sources contributed to approximately 55 TWh (32.5%) and 53.8 TWh (31.6%) in the 5%-CCS Only Scenario and the 5%-26%_2030-CCS Only Scenario respectively in 2019-20.

Figures (5.7-c) and (5.7-d) below illustrate the energy generation results of the 5%-CCS Only Scenario and the 5%-26%_2030-CCS Only Scenario in 2029-30. As both scenarios only deployed CCS technologies as the LCETs in the NEM to cut carbon emissions after 2019-20, a significant amount of coal CCS generation occurred in both scenarios in 2029-30. Coal CCS generation first happened in the 5%-CCS Only Scenario in 2023-24 and reached 53.9 TWh in 2029-30. Coal CCS generation first occurred in the 5%-26%_2030-CCS Only Scenario in 2024-25 and generated 35.5 TWh in 2029-30.

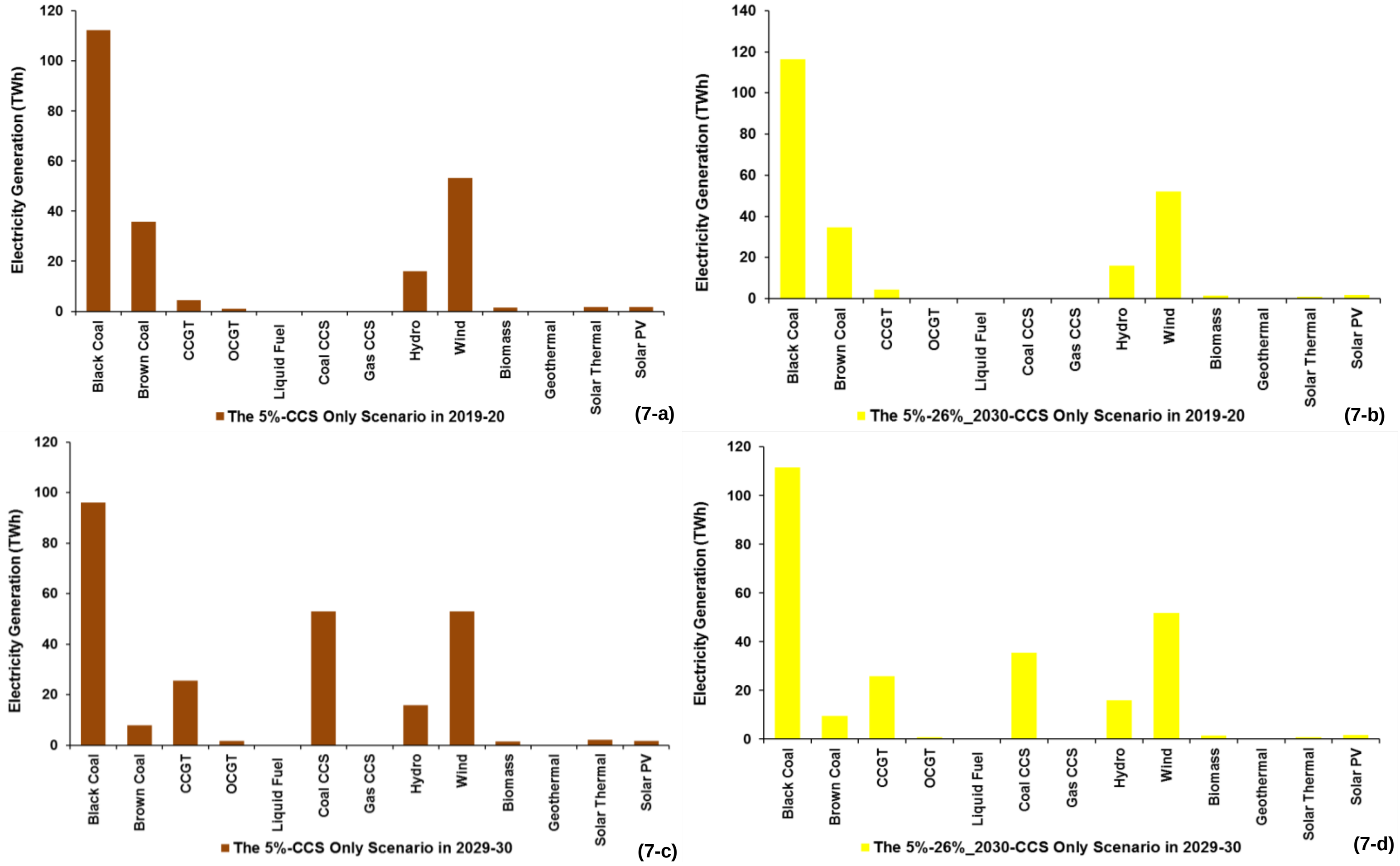



**Figure 5.7** Energy generation in the 5%-CCS Only Scenario in 2019-20 (7-a) and in 2029-30 (7-c) and in the 5%-26%_2030-CCS Only Scenario in 2019-20 (7-b) and in 2029-30 (7-d).

In 2029-30, there were a moderate reduction in black coal generation, a significant drop in brown coal generation and a considerable growth of CCGT production in the 5%-CCS Only Scenario and the 5%-26%_2030-CCS Only Scenario than the generation in 2019-20. Black coal, brown coal and CCGT generated approximately 96 TWh, 7.9 TWh and 25.6 TWh respectively in the 5%-CCS Only Scenario in 2029-30. In the 5%-26%_2030-CCS Only Scenario, the energy generation of black coal, brown coal and CCGT reached 111.5 TWh, 9.5 TWh and 25.7 TWh respectively in 2029-30. OCGT generated approximately 1.7 TWh and 0.91 TWh in two scenarios respectively in 2029-30.

In the 5%-CCS Only Scenario and the 5%-26%_2030-CCS Only Scenario, their renewable energy generation in 2029-30 remained at the similar levels as their generation in 2019-20. This could be attributed to the assumption that no new renewable capacity allowed to enter the CCS Only Scenario after 2019-20.

In total, fossil fuels generated approximately 50.8% (131.4 TWh) and 58% (147.7 TWh) of total energy in the 5%-CCS Only Scenario and the 5%-26%_2030-CCS Only Scenario respectively in 2029-30. Coal CCS generation and renewable generation made up 20.5% (52.9 TWh) and 28.7% (74.1 TWh) in the 5%-CCS Only Scenario respectively; and 13.9% (35.5 TWh) and 28.1% (71.6 TWh) in the 5%-26%_2030-CCS Only Scenario respectively in 2029-30.

These results suggested that the 5%-80% Reduction Target was more effective than the 5%-26%-80% Reduction Target in introducing more coal CCS generation in the NEM and reducing carbon emissions from conventional fossil fuel generation during the period of 2019-20 to 2029-30.

Figures (5.8-a), (5.8-b) and (5.8-c) display the generation outputs in the 25% Reduction Scenario, the 25%-RETs Only Scenario and the 25%-CCS Only Scenario in 2019-20. The generation of these three scenarios in 2019-20 presented a similar pattern. This was due to these scenarios facing the same 25% Reduction Target between 2012-13 and 2019-20. These scenarios had less energy generation from fossil fuels and more generation from renewables than the generation in the BAU Scenarios in 2019-20 (see Figure (5.3-a)).

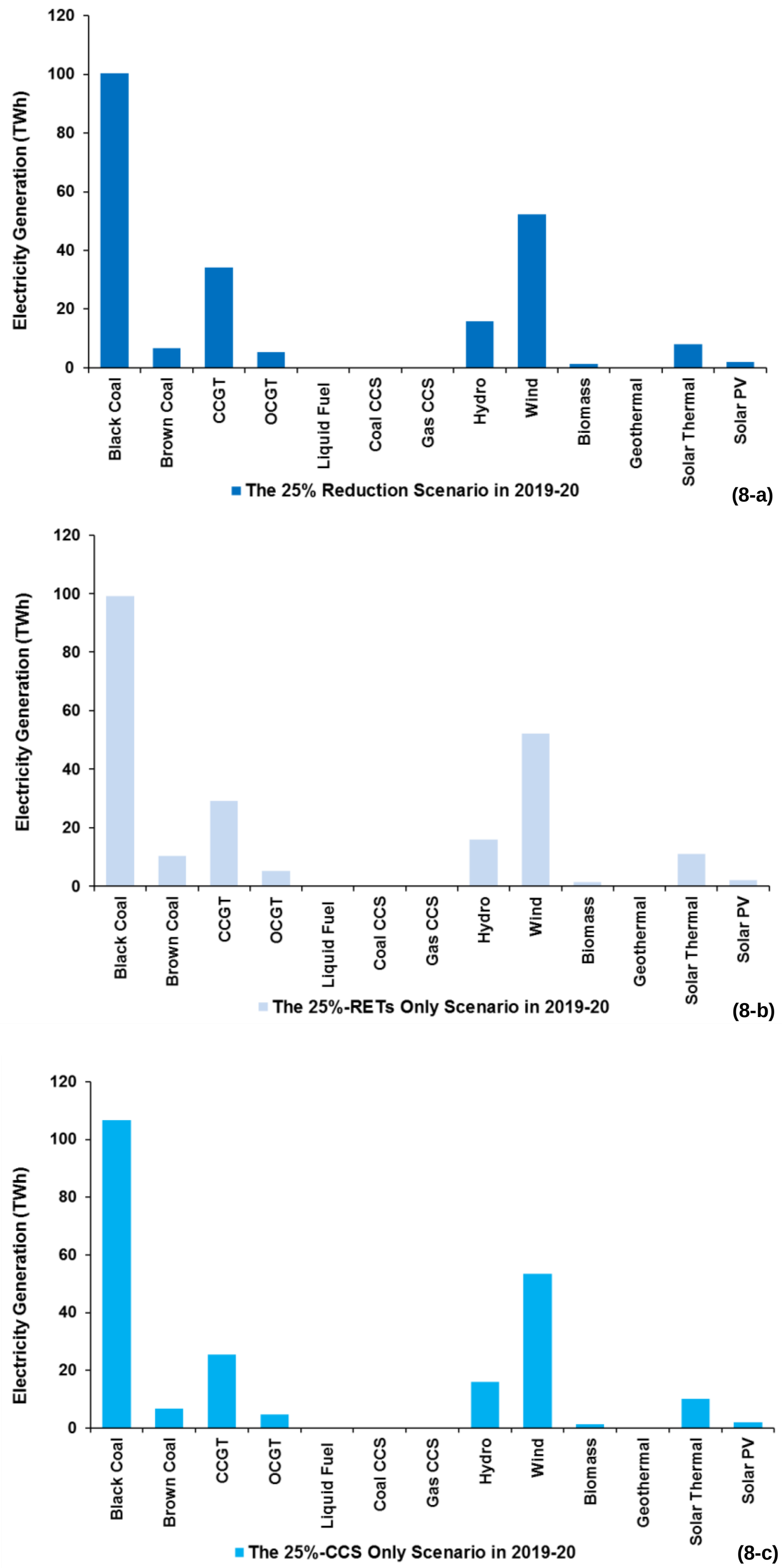



**Figure 5.8** Energy generation in the 25% Reduction Scenario in 2019-20 (8-a), in the 25%-RETs Only Scenario in 2019-20 (8-b) and in the 25%-CCS Only Scenario in 2019-20 (8-c).

In 2019-20, black coal still dominated the generation in the 25% Reduction Scenario, the 25%-RETs Only Scenario and the 25%-CCS Only Scenario and reached 100 TWh, 99.2 TWh and 106.7 TWh respectively. As a result of the implementation of previous Renewable Energy Target, wind became the second largest energy source in these scenarios and generated 52.3 TWh, 52.1 TWh and 53.5 TWh in three scenarios respectively in 2019-20. CCGT generation also increased significantly in these scenarios, contributing approximately 34.2 TWh, 29.2 TWh and 25.5 TWh respectively in 2019-20. OCGT generation experienced a moderate increase, reaching 5.3 TWh, 5.2 TWh and 4.8 TWh in three scenarios respectively in 2019-20.

In 2019-20, hydro, biomass and solar PV generation in the 25% Reduction Scenario, the 25%-RETs Only Scenario and the 25%-CCS Only Scenario remained at similar levels as the generation in the BAU Scenario. Solar thermal generation first occurred in these three scenarios in 2017-18, earlier than in any other scenarios. In 2019-20, solar thermal generation reached 8.1 TWh, 11.1 TWh and 10.1 TWh in three scenarios respectively.

Altogether in 2019-20, conventional fossil fuels generated approximately 64.7% (146.4 TWh), 63.6% (144.0 TWh) and 63.4% (143.6 TWh) of total energy generation in the 25% Reduction Scenario, the 25%-RETs Only Scenario and the 25%-CCS Only Scenario respectively. The renewables generated approximately 35.3% (79.8 TWh), 36.4% (82.6 TWh) and 36.6% (82.8 TWh) of total energy output in three scenarios respectively.

The results indicated that in 2019-20, less conventional fossil fuel generation and more renewable energy generation occurred in the 25% Reduction Scenario, the 25%-RETs Only Scenario and the 25%-CCS Only Scenario when compared to the generation results of the scenarios with 5% Reduction Target (see Figure (5.4-a), Figure (5.4-b) and Figure (5.7-a)). This suggested that the 25% Reduction Target promoted more energy generation from renewable source and reduced carbon emissions faster in the NEM than the 5% Reduction Target did during the period 2012-13 to 2019-20.

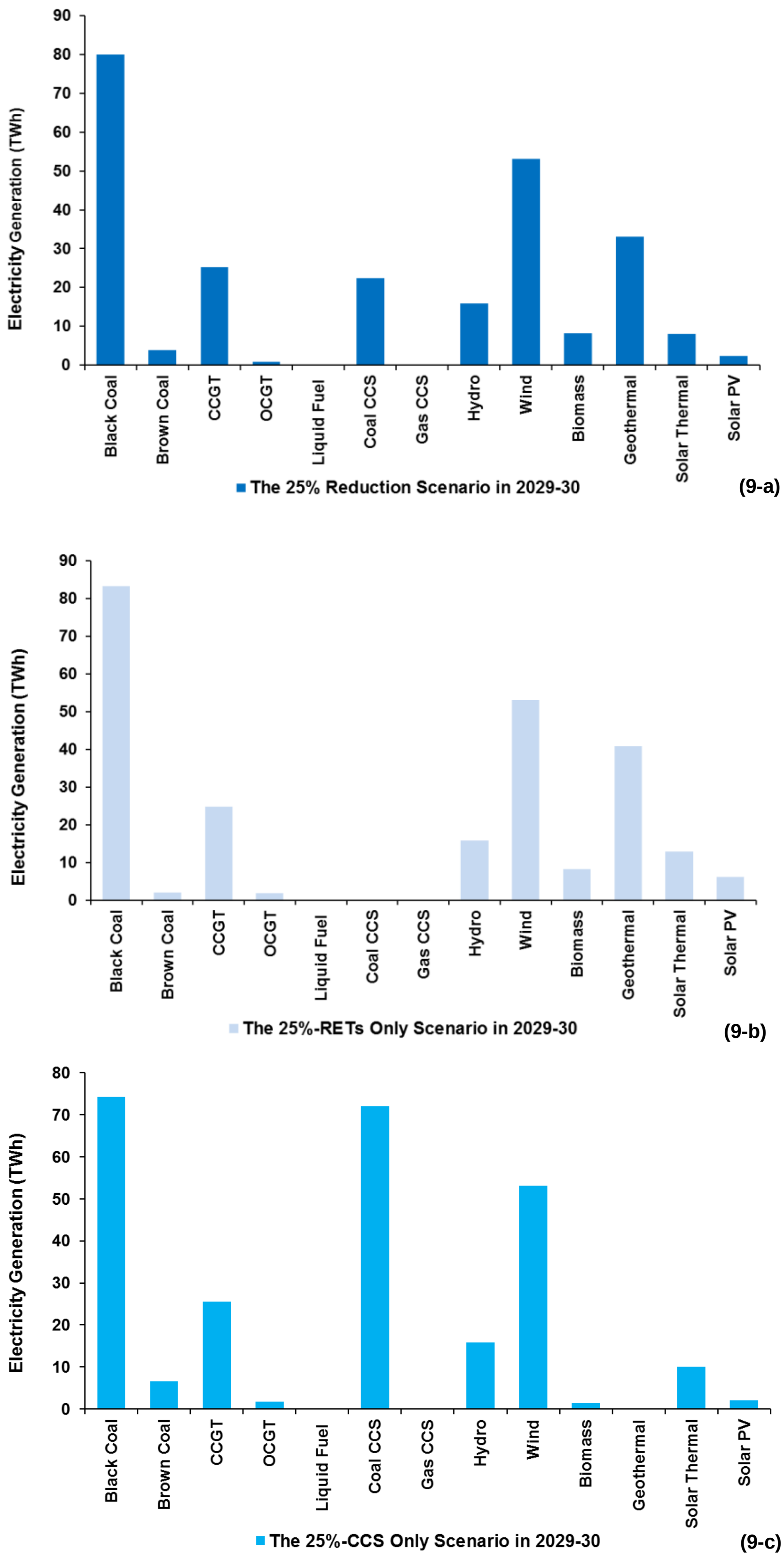



**Figure 5.9** Energy generation outputs in the 25% Reduction Scenario in 2029-30 (9-a), in the 25%-RETs Only Scenario in 2029-30 (9-b), and in the 25%-CCS Only Scenario in 2029-30 (9-c).

Figures (5.9-a), (5.9-b) and (5.9-c) above display the energy generation in the 25% Reduction Scenario, the 25%-RETs Only Scenario and the 25%-CCS Only Scenario in 2029-30. In 2029-30, coal CCS generation and renewable generation both increased in the 25% Reduction Scenario, while there was no coal CCS generation occurred in the 25%-RETs Only Scenario and no growth of renewable generation in the 25%-CCS Only Scenario.

From 2020-21 to 2029-30, black coal, brown coal and OCGT generation experienced the reduction in the 25% Reduction Scenario, the 25%-RETs Only Scenario and the 25%-CCS Only Scenario. CCGT in 2029-30 kept its generation level as the same as in 2019-20 in these three scenarios. In 2029-30, conventional fossil fuel generation contributed approximately 43.4% (109.9 TWh), 44.9% (111.7 TWh) and 41.1% (108.1 TWh) of total generation in three scenarios respectively.

Coal CCS generation first occurred in the 25% Reduction Scenario and the 25%-CCS Only Scenario in 2020-21. It made up 8.8% (22.3 TWh) and 27.5% (72.1 TWh) of total generation in two scenarios respectively in 2029-30.

The renewable generation in the 25%-CCS Only Scenario in 2029-30 remained at the similar level as the generation in the 2019-20. In the 25% Reduction Scenario and the 25%-RETs Only Scenario, the energy outputs of wind, hydro, and solar thermal in 2029-30 were at similar levels as their outputs in 2019-20.

In 2029-30, the energy generation from biomass, geothermal and solar PV experienced the growth in the 25% Reduction Scenario and the 25%-RETs Only Scenario. Biomass, geothermal and solar PV generated 8.2 TWh, 33.1 TWh and 2.4 TWh of energy respectively in the 25% Reduction Scenario; and 8.2 TWh, 40.8 TWh and 6.1 TWh respectively in the 25%-RETs Only Scenario. In total, renewable generation was comprised of 47.8% (120.9 TWh), 55.1% (136.9 TWh) and 31.4% (82.4 TWh) of total generation in the 25% Reduction Scenario, the 25%-RETs Only Scenario and the 25%-CCS Only Scenario respectively in 2029-30.

These results suggested that the 25%-80% Reduction Target led to more reduced carbon emissions in the NEM than the 5%-80% Reduction Target and 5%-26%-80% Reduction Target did for the period of 2020-21 to 2029-30. Without entry constrain for the RETs and the CCS after 2019-20, both coal CCS and geothermal generation will happen in the NEM in the period of 2020-21 to 2029-30. With the assumption of only the RETs available after 2019-20, coal CCS generation will be largely replaced by the geothermal and solar PV production for the period 2020-21 to 2029-30. Similarly, with the assumption of only the CCS available after 2019-20, geothermal and some of biomass production will be replaced by the coal CCS generation.

### 5.2.3 Generation Results in 2049-50

Figure 5.10 shows generation results of the BAU Scenario in 2049-50. It illustrates that the generation mix of the BAU Scenario in 2049-50 remained almost the same as that in 2019-20 and 2029-30 (see Figure 5.3). Coal-fired generation kept its dominance over the planning period. It was followed by the wind and hydro generation. Gas, biomass and solar PV took up small portions of total energy output in 2049-50. There was no generation from CCS, geothermal and solar thermal.

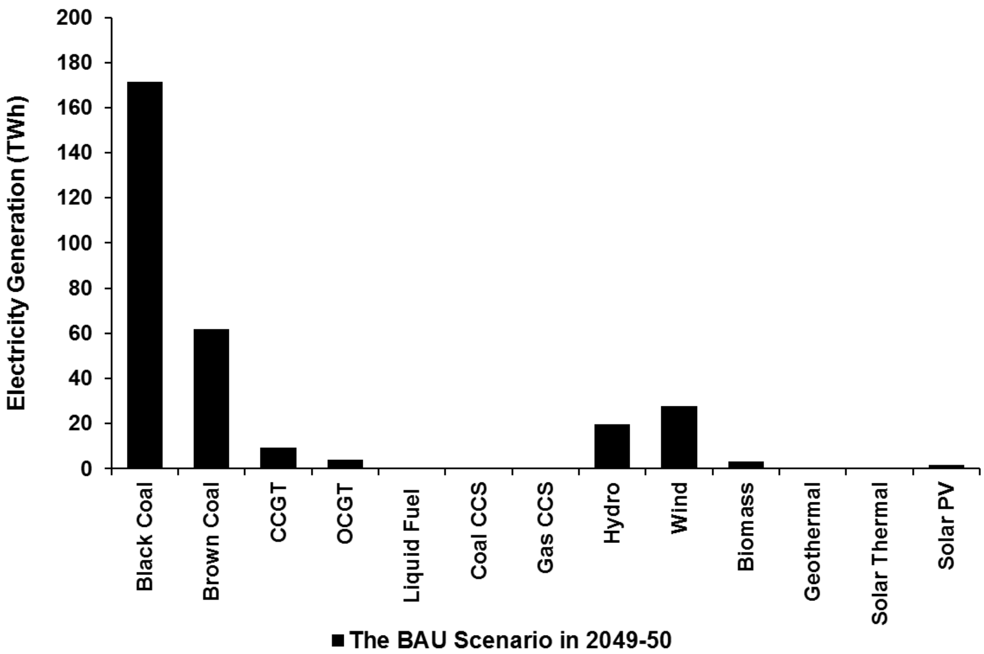



**Figure 5.10** Energy generation in the BAU Scenario in 2049-50.

In 2049-50, Black coal generation increased from 140.6 TWh to 171.5 TWh, brown coal generation rose from 58.8 TWh to 61.9 TWh, CCGT generation climbed from 4.8 TWh to 9.5 TWh and OCGT generation grew from 0.35 TWh to 4.0 TWh in the BAU Scenario when compared to the generation in 2029-30. Wind and solar PV generation in 2049-50 remained at similar levels as their generation in 2029-30. Hydro generation experienced a small increase from 15.9 TWh in 2029-30 to 19.8 TWh in 2049-50. Biomass generation also increased from approximately 1.6 TWh in 2029-30 to 3.1 TWh in 2049-50.

Overall, fossil fuels and renewables were comprised of 82.5% (246.9 TWh) and 17.5% (52.4 TWh) of total generation in the BAU Scenario respectively in 2049-50. The results suggested that when there is no constraint on carbon emissions in the NEM, coal and gas will remain as the favoured energy sources to meet electricity demand growth from 2029-30 to 2049-50. Additionally, the results indicated that although Renewable Energy Target would effectively drive the penetration of renewable generation by 2019-20, without further policy support or carbon emissions constraint, there will have no momentum for the scale-up of renewable generation in the NEM after 2019-20. This could be attributed to the assumptions of relatively higher costs of the RETs compared to fossil fuels technologies in the planning period.

Figures (5.11-a), (5.11-b) and (5.11-c) below illustrate energy generation of the 5% Reduction Scenario, the 25% Reduction Scenario and the 5%-26%_2030 Reduction Scenario in 2049-50. Their generation results showed a similar pattern in 2049-50 which largely attributed to their adoption of the same emissions reduction target (80% Reduction Target) in the year 2049-50.

In the 5% carbon reduction scenario, total generation from coal and gas reduced considerably from 74.5% (169.7 TWh) in 2019-20 to 10.2% (33.5 TWh) in 2049-50. The coal CCS technologies accounted for approximately 53.1% (175.2 TWh) of total electricity output in 2049-50. Electricity generation by the RETs increased from 25.5% (58.1 TWh) in 2019-20 to approximately 36.7% (121.0 TWh) in 2050.

Energy from wind and geothermal generation presented the strongest growth among renewable sources in the 5% Reduction Scenario since 2019-20. Their outputs increased from 38.6 TWh and zero in 2019-20 to approximately 53.5 TWh and 30.8 TWh in 2049-50 respectively. Biomass, solar thermal and solar PV generation experienced a moderate growth during this period. They grew from 1.4 TWh, 0.45 TWh and 1.7 TWh in 2019-20 to 8.9 TWh, 4.2 TWh, and 6.5 TWh in 2049-50 respectively.

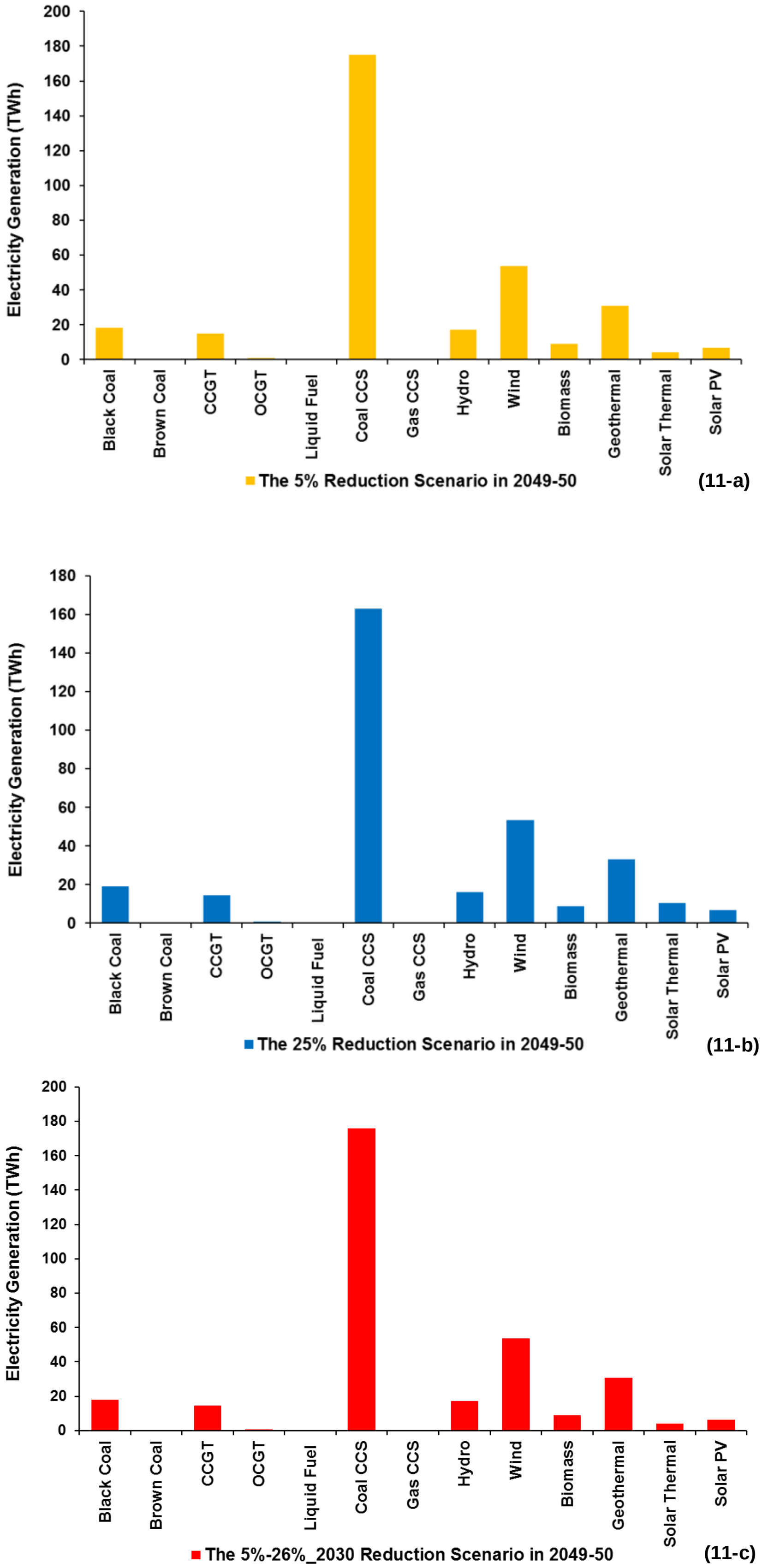



**Figure 5.11** Energy generation in the 5% Reduction Scenario (11-a), 25% Reduction Scenario (11-b) and the 5%-26%_2030 Reduction Scenario (11-c) in 2049-50.

In general, for the period of 2019-20 to 2049-50, the 5%-26%_2030 Reduction Scenario had similar changes to its energy generation as the 5% Reduction did.

Generation mix in the 25% Reduction Scenario exhibited similar pattern of change from 2019-20 to 2049-50 as in the 5% Reduction Scenario. Total energy generation from coal and gas decreased considerably from 64.7% (146.4 TWh) in 2019-20 to approximately 10.5% (34.2 TWh) in 2049-50. In this scenario, coal CCS generation did not enter system until 2020-21. Electricity output from coal CCS reached 163.1 TWh in 2049-50. This accounted for approximately 50% of total generation in 2049-50. The RETs generation took up 39.5% (128.9 TWh) of total generation in 2049-50, growing from 35.3% (79.8 TWh) in 2019-20.

In 2049-50, the electricity generation in the BAU Scenario was comprised of 82.5% of conventional fossil fuels and 17.5% of renewable generation (see Figure 5.10). This generation mix contrasted substantially to the generation mixes of the 5% Reduction Scenario, the 25% Reduction Scenario and the 5%-26%_2030 Reduction Scenario in 2049-50. These scenarios had approximately 10% of electricity produced from conventional fossil fuel sources and 90% of electricity generated from low carbon energy sources including CCS and renewables in 2049-50. This contrast highlighted the strong effect of the 80% Reduction Target on reducing carbon emissions in the NEM over the planning period.

Figure 5.12 below displays generation outputs in the 5%-RETs Only Scenario, the 25%-RETs Only Scenario and the 5%-26%_2030-RETs Only Scenario in 2049-50. These scenarios also presented a similar pattern of generation mix in 2049-50, which was attributed to their application of the same carbon emissions reduction target in the year 2049-50 and the same RETs only technological assumption after 2019-20.

Conventional fossil fuel generation in the 5%-RETs Only Scenario reduced from 74.4% (169.7 TWh) in 2019-20 to approximately 15.9% (46.5 TWh) in 2049-50. In the 25%-RETs Only Scenario, total conventional coal and gas generation dropped from 63.6% (144.0 TWh) in 2019-20 to approximately 16.0% (46.6 TWh) in 2049-50. Total conventional coal and gas generation in the 5%-26%_2030-RETs Only Scenario reduced from 74.5% (169.7 TWh) in 2019-20 to approximately 16.0% (46.8 TWh) in 2049-50.

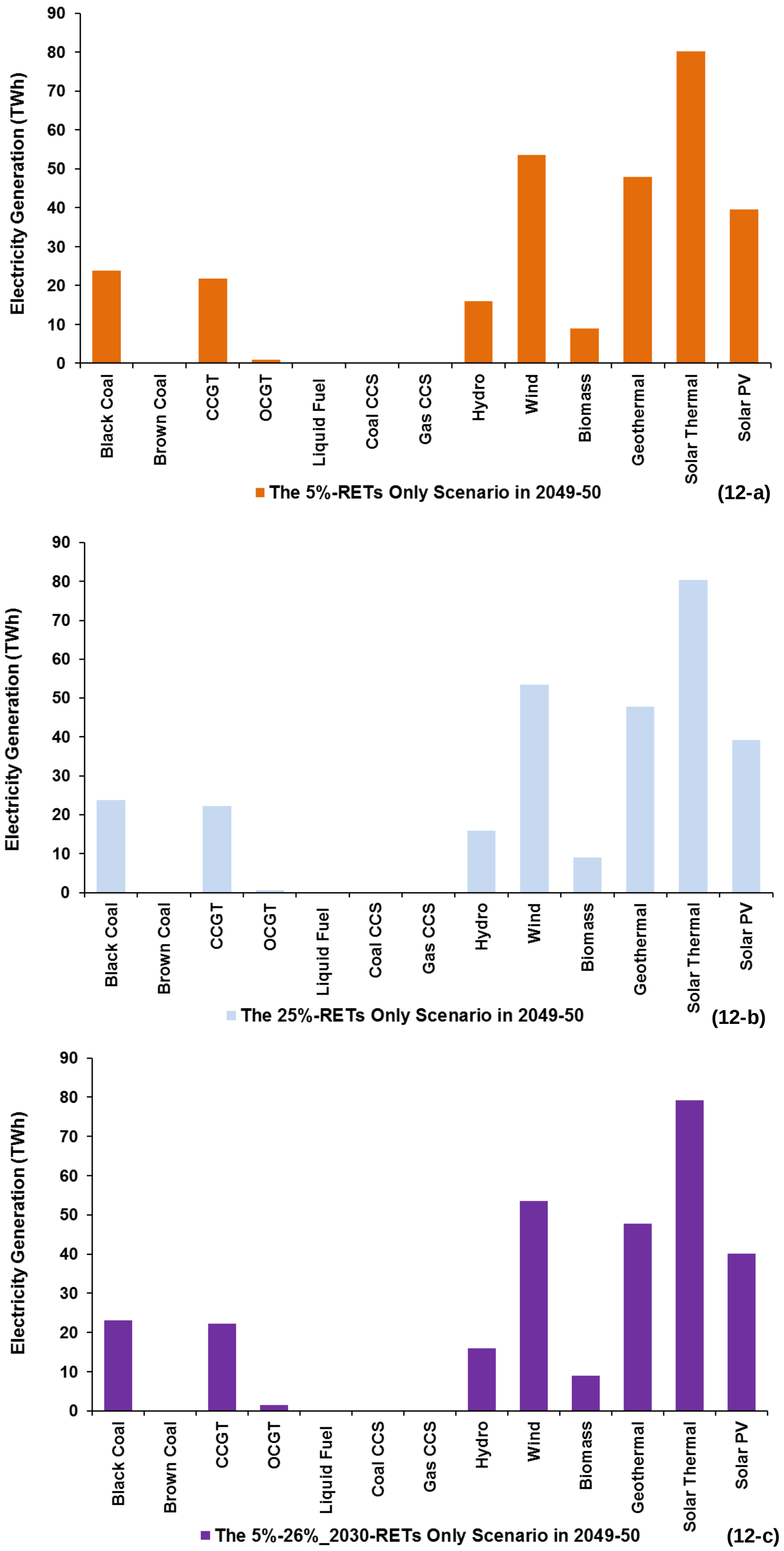



**Figure 5.12** Generation outputs in the 5%-RETs Only Scenario (12-a), the 25%-RETs Only Scenario (12-b) and the 5%-26%_2030-RETs Only Scenario (12-c) in 2049-50.

The renewable generation increased significantly since 2019-20 in the 5%-RETs Only Scenario, the 25%-RETs Only Scenario and the 5%-26%_2030-RETs Only Scenario and reached 84.1% (245.8 TWh), 84.0% (245.6 TWh) and 84.0% (245.4 TWh) respectively in 2049-50.

The generation results of the RETs only scenarios revealed that under the combined effects of the carbon emissions reduction targets and the RETs only technological assumptions, the renewable energy will be able to contribute to as high as 84% of total generation in the NEM in 2049-50. The electricity produced from intermittent renewable sources including wind and solar PV took up about 31.8% (93.0 TWh), 31.7% (92.7 TWh) and 32.0% (93.5 TWh) of total generation in the 5%-RETs Only Scenario, the 25%-RETs Only Scenario and the 5%-26%_2030-RETs Only Scenario respectively in 2049-50. The baseload renewable energy contributed to the rest of renewable energy generation in these scenarios in 2049-50.

Figure 5.13 below illustrates energy generation in the 5%-CCS Only Scenario, the 25%-CCS Only Scenario and the 5%-26%_2030-CCS Only Scenario in 2049-50. These scenarios again presented a similar generation pattern of energy output in 2049-50. This can be attributed to the adoption of the same carbon emissions reduction (80% Reduction Target) in 2049-50 and the application of the same CCS only technological assumption after 2019-20.

These scenarios did not allow new renewable energy capacity to be built after 2019-20. The renewable energy produced in these scenarios came from existing RETs constructed before 2019-20. This assumption meant that conventional fossil fuel technologies and CCS technologies were the only available energy technologies to meet energy demand growth after 2019-20 in the NEM.

Total energy generation from coal and gas reduced from 67.5% (153.7 TWh), 63.4% (143.6 TWh) and 68.4% (155.8 TWh) in the 5%-CCS Only Scenario, the 25%-CCS Only Scenario and the 5%-26%_2030-CCS Only Scenario respectively in 2019-20 to approximately 9.2% (31.7 TWh), 9.5% (32.5 TWh) and 9.1% (31.5 TWh) respectively in 2049-50.

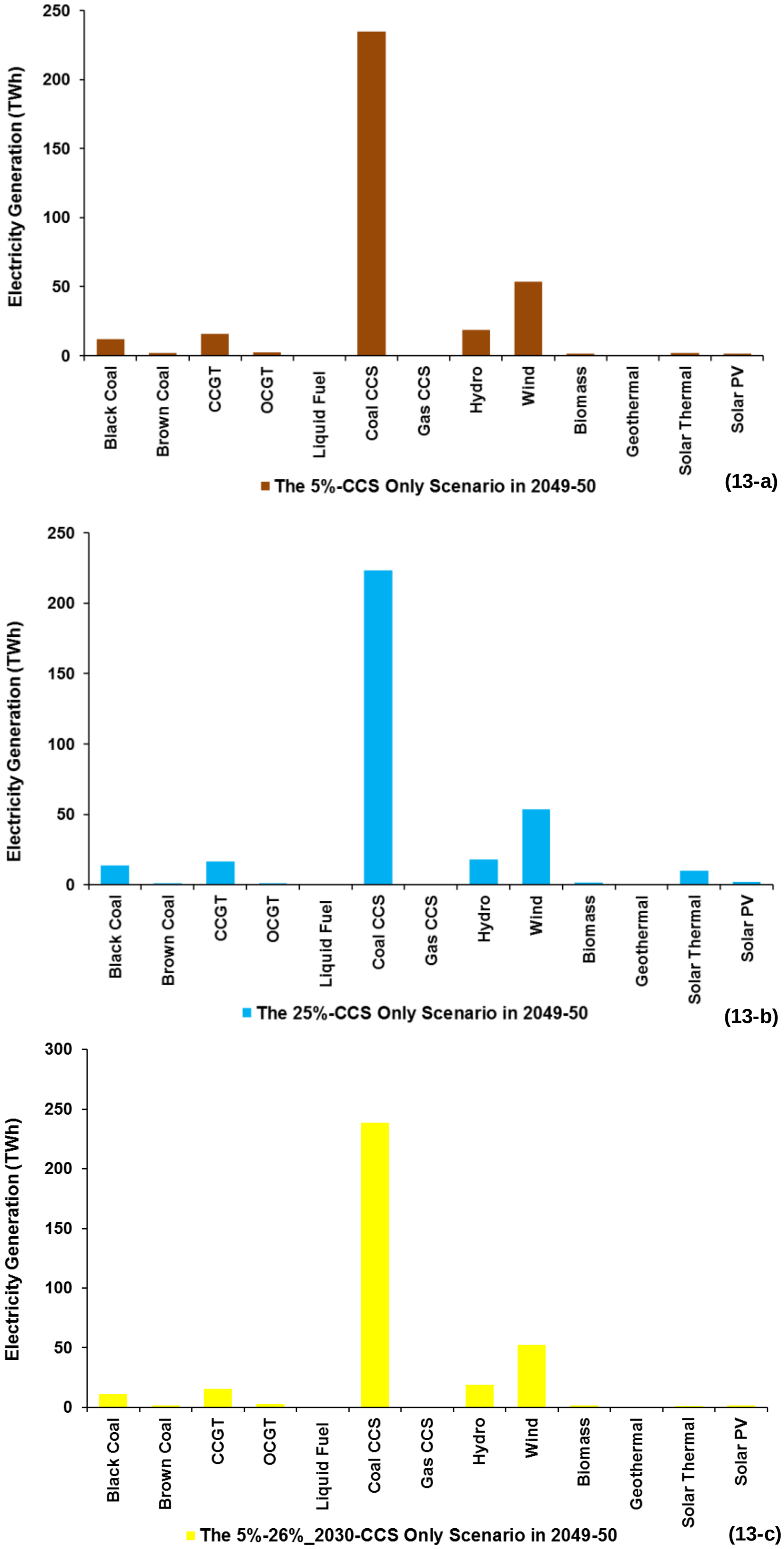



**Figure 5.13** Energy generation in the 5%-CCS Only Scenario (13-a), the 25%-CCS Only Scenario (13-b) and the 5%-26%_2030-CCS Only Scenario (13-c) in 2049-50.

Coal CCS generation first entered the 5%-CCS Only Scenario, the 25%-CCS Only Scenario and the 5%-26%_2030-CCS Only Scenario in 2023-24, 2020-21 and 2024-25 respectively. Its generation reached approximately 68.3% (234.9 TWh), 65.5% (223.4 TWh) and 69.2% (238.4 TWh) in three scenarios respectively in 2049-50.

These scenarios' renewable energy generation in 2049-50 remained at the similar levels as their generation in 2019-20, accounting for 16.0% (55.0 TWh), 16.3% (55.5 TWh) and 15.6% (53.8 TWh) in three scenarios respectively in 2049-50.

The generation results of the CCS only scenarios suggested that the coal CCS technologies will be able to contribute to more than 65% of total energy generation in the NEM in 2049-50 with the constraints of the carbon emissions reduction targets and the CCS only technological assumptions. Due to high cost assumptions of gas CCS technologies, there was no gas CCS generation occurred in the NEM in these scenarios by 2049-50.

In 2049-50, total electricity generation of the 5%-CCS Only Scenario, the 25%-CCS Only Scenario and the 5%-26%_2030-CCS Only Scenario reached approximately 344 TWh, 341 TWh and 345 TWh respectively. They were significantly higher than the total electricity generation of the 5%-RETs Only Scenario (292 TWh), the 25%-RETs Only Scenario (292 TWh), the 5%-26%_2030-RETs Only Scenario (292 TWh) and the BAU Scenario (299 TWh); moderately higher than the generation in the 5% Reduction Scenario (330TWh), 25% Reduction Scenario (326TWh) and 5%-26%_2030 Reduction Scenario (330 TWh).

The CCS system is associated with substantial extra energy requirements, which is called the energy penalty. While current CCS system can significantly reduce power plant carbon emissions by 85-90%, it would increase approximately 15-30% of energy requirements (Rubin et al. 2007). This means that electricity system in the 5%-CCS Only Scenario, the 25%-CCS Only Scenarios and the 5%-26%_2030-CCS Only Scenario required more electricity output to support CCS operation compared to no CCS generation or less CCS generation in other scenarios in 2049-50.

## 5.3 Generation Capacity Results

Along with the growth of energy demand, the capacity installed in the NEM also increased over time. The amount of installed capacity in each scenario was the same in 2012-13, did not differ much in 2014-15, started to diverge in 2019-20 and 2029-30, and became fairly different in 2049-50 (see Figure 5.14).

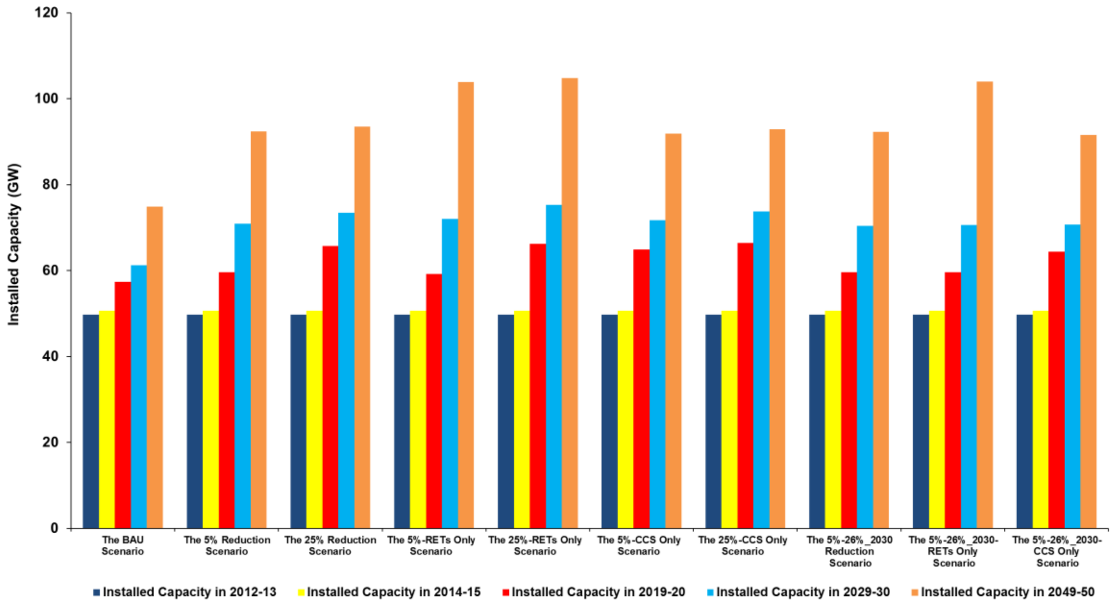



**Figure 5.14** Total installed capacity by scenario, in 2012-13, 2014-15, 2019-20, 2029-30 and 2049-50.

The capacity installed in the BAU Scenario increased from approximately 49.7 GW in 2012-13 to 74.9 GW in 2049-50. It had the smallest amount of capacity installed in 2049-50 among all scenarios. The capacity installed in the 5%, 25% and 5%-26%_2030 Reduction Scenarios were in similar range and reached approximately 92.7 GW on average in 2049-50. This represented approximately 23.8% more than the capacity installed in the BAU Scenario n 2049-50.

There were also similar amounts of capacity installed in the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios in 2049-50, reaching approximately 92.1 GW on average. This indicated an approximate 23.0% increase of capacity in these scenarios compared to the capacity in the BAU Scenario in 2049-50.

The 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios had the most capacity installed in 2049-50, reaching 103.8 GW, 104.8 GW and 104.0 GW respectively in 2049-50. These levels of capacity installation represented approximately 39.2% more on average than the capacity built in the BAU Scenario in 2049-50.

The results suggest that the scenarios with the largest amounts of capacity installed were the scenarios with the highest penetration rates of the RETs. This was attributed to the intermittency nature of wind and solar generation. Wind and solar generation generally have smaller capacity credits. This means that higher amount of installation of the RETs requires more capacity reserve to maintain system reliability and meet minimum reserve margins. This was illustrated in Figure 5.15 below.

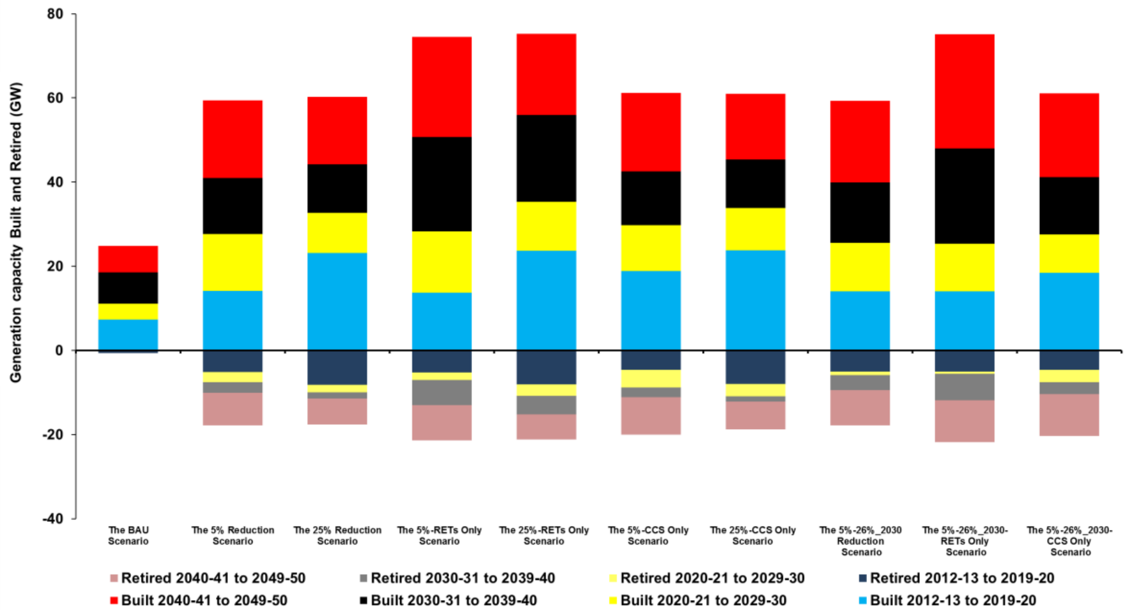



**Figure 5.15** Retired and new built generation capacity in the NEM by scenarios.

Figure 5.15 shows capacity built and retired by scenarios in four periods: 2012-13 to 2019-20, 2020-21 to 2029-30, 2030-31 to 2039-40 and 2040-41 to 2049-50 in the NEM. For the BAU Scenario, it shows that near 641 MW of black coal capacity was retired by 2019-20, and no retirement happened in any other periods.

For the period of 2012-13 to 2049-50, the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios had the largest amount of capacity retired. In total, approximately 14.2 GW of black coal and 7.3 GW of brown coal capacity retired in the 5%-RETs Only

Scenario, approximately 13.9 GW of black coal and 7.3 GW of brown coal capacity retired in the 25%-RETs Only Scenario, and approximately 14.6 GW of black coal and 7.3 GW of brown coal capacity retired in the 5%-26%_2030-RETs Only Scenario.

The 5%, 25% and 5%-26%_2030 Reduction Scenarios had 10.6 GW, 10.4 GW and 10.6 GW of black coal capacity retired respectively between 2012-13 and 2049-50. There were approximately 7.2 GW of brown coal capacity retired in each of these scenarios between 2012-13 and 2049-50.

The 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios had approximately 13.3 GW, 12.0 GW and 13.6 GW of black coal capacity retired, and 6.7 GW, 6.8 GW and 6.7 GW of brown coal capacity retired respectively in the period of 2012-13 to 2049-50.

Except in the BAU Scenarios, there was at least 50% black coal capacity and 88% brown coal capacity retired across all other scenarios. There were more capacity retired in the periods of 2012-13 to 2019-20 and 2040-41 to 2049-50 than in the periods of 2020-21 to 2029-30 and 2030-31 to 2039-40.

The BAU had the least amount of capacity built in the planning period compared to the capacity built in other scenarios. There were 24.8 GW of capacity in total built between 2012-13 and 2049-50 in the BAU Scenario. The 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios had the highest amounts of capacity built during the planning horizon, reaching 74.5 GW, 75.2 GW and 75.1GW respectively. Similar amounts of capacity built in the 5%, 25% and 5%-26%_2030 Reduction Scenarios in the planning horizon, totalling at 59.5 GW, 60.3 GW and 59.3GW respectively. There were 61.2 GW, 60.9 GW and 61.1 GW of capacity in total installed in the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios respectively in the period of 2013-13 to 2049-50.

For scenarios with the 5%-80% Reduction Target and 5%-26%-80% Reduction Target, more capacity was built from year 2030-31 to 2049-50 than in the period of 2012-13 to 2029-30. For scenarios with the 25%-80% Reduction Target, more capacity was built in the period of 2012-13 to 2029-30 than in the period of 2030-31 to 2049-50 (except in the 25%-RETs Only Scenario). The BAU Scenario had similar amount of capacity built in these two time frames. This result may indicate that for achieving 80% carbon reduction target in 2049-50, scenarios with the 5%-80% Reduction Target and 5%-26%-80% Reduction needed to deploy more LCETs to abate higher amount of carbon emissions after 2019-20 than that in the scenarios with the 25%-80% Reduction Target .

Figure 5.16 and Figure 5.17 below show capacity installed in each scenario in 2012-13 and 2019-20. While the capacity portfolio was the same across each scenario in 2012-13 and totalled at around 49.7 GW, it started to differ in 2019-20 across scenarios.

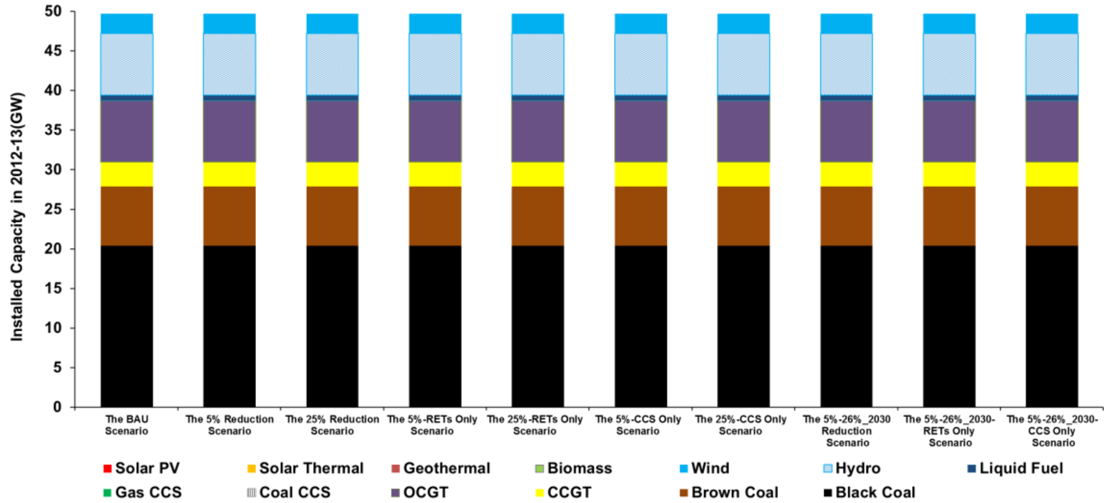



**Figure 5.16** Installed capacity in each scenario by technology, in 2012-13.

In 2012-13, it was evident that black coal (20.4 GW) was the dominant type of capacity installed in all scenarios. There were also significant amounts of OCGT (7.8 GW), hydro (7.8 GW) and wind (2.5 GW) capacity installed in each scenario. The installed capacity also included brown coal (7.5 GW), CCGT (3.1 GW) and liquid fuel (0.68 GW).

Although installed black coal capacity reduced in 2019-20 compared to in 2012-13, it was still the dominant type of capacity in 2019-20. Biomass and solar PV capacity were newly installed in the NEM in period of 2012-13 to 2019-20 in all scenarios. Solar thermal capacity firstly entered the NEM in all scenarios by 2019-20, except in the BAU Scenario.

In the BAU scenario, more OCGT capacity and significantly more wind capacity were installed in 2019-20 compared to the capacity installed in 2012-13. Biomass and solar PV capacity entered the NEM in 2018-19. Brown coal, CCGT, liquid fuel and hydro capacity kept the same levels as their levels in 2012-13.

In 2019-20, comparing the BAU scenario with the other scenarios, the major differences laid in OCGT, brown coal, wind and solar thermal capacity as displayed in Figure 5.17. In 2019-20, installed OCGT capacity in the BAU Scenario (8.7 GW) was less than the installed OCGT capacity in the other scenarios (around 11 GW).

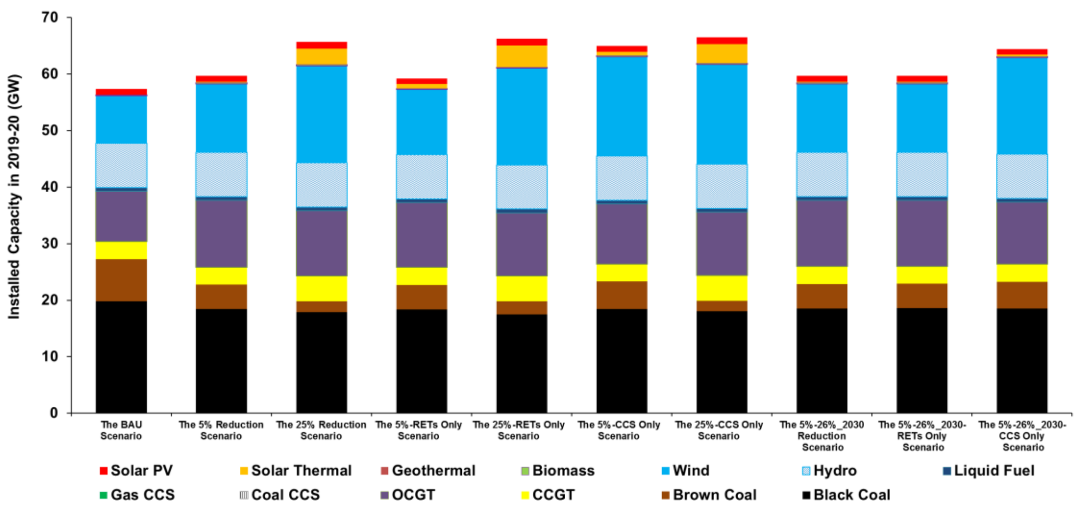



**Figure 5.17** Installed capacity in each scenario by technology, in 2019-20.

The BAU Scenario had the largest amount of installed brown coal capacity (7.5 GW) in 2019-20. The brown coal capacity reduced in the scenarios with the 5% Reduction Target and the scenarios with the 5%-26%-80% Reduction Target. The brown coal capacity reduced further in the scenarios with the 25% Reduction Target. This suggested that the Renewable Energy Target and the carbon emission reduction targets acted together as the major drivers to retire brown coal capacity in the NEM between 2012-13 and 2019-20.

While the Renewable Energy Target promoted the installation of wind, biomass and solar PV capacity; the carbon emissions reduction targets also encouraged more wind and solar thermal capacity to enter the market. This was especially apparent in the scenarios with the 25% Reduction Target.

Between 2012-13 and 2019-20, the 25% Reduction Scenario (17.2 GW), the 25%-RETs Only Scenario (17.1 GW) and the 5%_26%-2030 CCS Only Scenario (17.1 GW) had larger amounts of installed wind than in the 5% Reduction Scenario (12.1 GW), the 5%-RETs Only Scenario (11.5 GW), the 5%_26%-2030 Reduction Scenario(12.1 GW) and the 5%_26%-2030-RETs Only Scenario (17.1 GW). The highest amounts of installed wind capacity were in the 5%-CCS Only Scenario (17.6 GW) and 25%-CCS Only Scenario (17.6 GW). CCS only scenarios generally have higher amount of installed wind capacity may be a result of the technological assumption that the RETs was not available to enter the NEM in these scenarios after 2019-20.

Solar thermal capacity entered in the scenarios with the 25% Reduction Target earlier than in other scenarios. In 2017-18, 200 MW of solar thermal capacity was built in the scenarios with the 25% Reduction Target. In 2019-20, solar thermal capacity reached 2.8 GW, 3.8 GW and 3.4 GW in the 25% Reduction Scenario, the 25%-RETs Only Scenario and the 25%-CCS Only Scenario respectively. By 2019-20, there was a small amount of solar thermal capacity added to the scenarios with the 5% Reduction Target and the scenarios with the 5%-26%-80% Reduction Target, while no solar thermal capacity was installed in the BAU Scenario.

In addition to wind and solar thermal, solar PV capacity first entered each scenario almost evenly in 2017-18 except in the BAU Scenario. The solar PV capacity entered the BAU Scenario in 2018-19. In 2019-20, there was approximately 1.0 GW solar PV capacity installed in each of the BAU Scenario, the scenarios with the 5% Reduction Target and the scenarios with the 5%-26%-80% Reduction Target; and around 1.2 GW installed in each of the scenarios with the 25% Reduction Target .

More OCGT capacity has been added to all scenarios. The BAU scenario installed with approximately 8.9 GW of OCGT capacities in 2019-20. Each of the other scenarios installed at around or more than 11 GW of OCGT capacities in 2019-20.

Figure 5.18 below shows installed capacity in each scenario by technology in 2029-30. Black coal and brown coal capacity continued to be retired during the period of 2020-21 to 2029-30 in all scenarios except in the BAU Scenario. The BAU Scenario had the largest amount of installed black coal and brown coal capacity in 2029-30, totalling at 19.8 GW and 7.5 GW respectively. The 25%-CCS Only Scenario had the largest amount of black coal capacity retired, which resulted in the smallest amount of installed black coal capacity at 15.1 GW in 2029-30. The 25%-RETs Only Scenario had the smallest amount of installed brown coal capacity in 2029-30 at 0.96 GW.

During the period of 2020-21 to 2029-30, OCGT capacity as the major type of capacity to meet peak demand and backup system increased in all scenarios (See Figure 5.18). During this period, the smallest amount of installed OCGT capacity was in the 25% Reduction Scenario at 1.5 GW, and the highest amount installed was in the 5%-26%_2030-CCS Only Scenario at 5.1 GW.

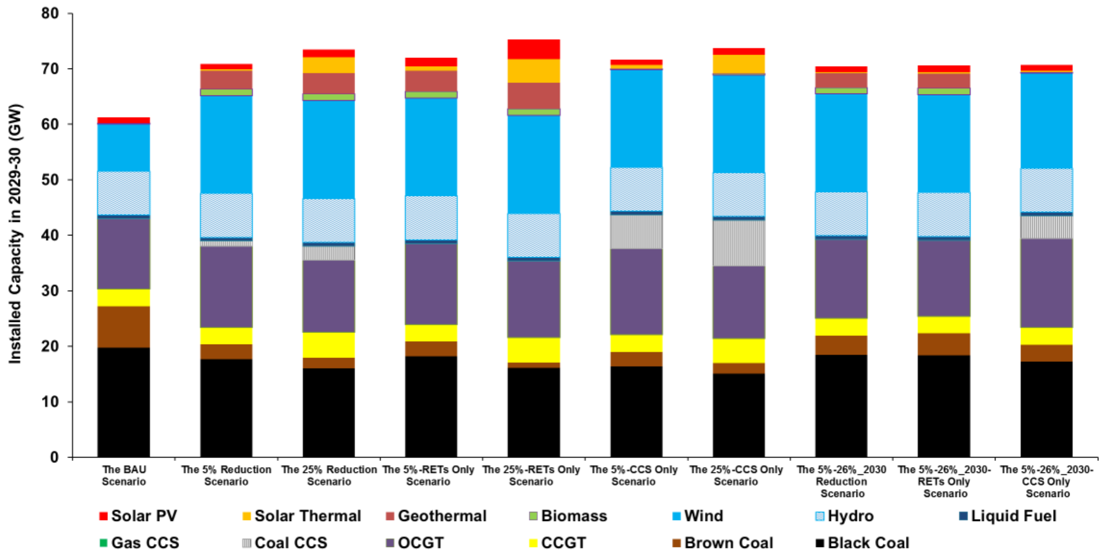



**Figure 5.18** Installed capacity in each scenario by technology, in 2029-30.

Overall, the BAU Scenario installed approximately around 12.7 GW of OCGT in 2029-30. The installed OCGT capacity in the 5% Reduction Scenario, the 5%-RETs Only Scenario and the 5%-CCS Only Scenario were approximately 14.6 GW, 14.6 GW and 14.2 GW respectively. The installed OCGT capacity in the 25% Reduction Scenario, the 25%-RETs Only Scenario and the 25%-CCS Only Scenario were approximately 13.0 GW, 13.8 GW and 13.0 GW respectively. The 5%-26%-2030 Reduction Scenario, the 5%-26%-2030-RETs Only Scenario and the 5%-26%-2030-CCS Only Scenario installed approximately 14.2 GW, 13.7 GW and 16.1 GW of OCGT respectively.

Coal CCS capacity first entered the 25% Reduction Scenario and the 25%-CCS Only Scenario the earliest in 2020-21, reaching approximately 2.5 GW and 8.2 GW respectively in 2029-30. It entered the 5%-CCS Only Scenario in 2023-24, the 5%-26%_2030-CCS Only Scenario in 2024-25 and in the 5% Reduction Scenario in 2028-29. In 2029-30, the installed coal CCS capacity in the 5%-CCS Only Scenario, the 5%-26%_2030-CCS Only Scenario and the 5% Reduction Scenario reached approximately 6.0 GW, 4.1 GW and 0.91 GW respectively.

Wind, biomass and geothermal capacity continued to be added to all scenarios expect the BAU Scenario and the CCS only scenarios between 2020-21 and 2029-30. The BAU Scenario had lowest amount of wind capacity installed in 2029-30 at approximately 8.4 GW. The 5%-26%_2030-CCS Only Scenario had installed wind capacity at 17.1 GW, the other scenarios had similar amount of installed wind capacity at approximately 17.6 GW in 2029-30.

Geothermal capacity first entered the market in the same year of 2021-22 in the 5%, 25% and %-26%_2030 Reduction Scenarios and the 5%-, 25%- and %-26%_2030-RETs Only Scenarios. In the 5%, 25% and %-26%_2030 Reduction Scenarios, the installed geothermal equalled 3.3 GW, 3.8 GW and 2.5 GW respectively in 2029-30. The installed geothermal capacity reached 3.7 GW, 4.7 GW and 2.6 GW in the 5%-, 25%- and %-26%_2030-RETs Only Scenario respectively in 2029-30. The other scenarios did not have geothermal capacity installed.

Solar thermal capacity was not installed in any scenarios in the period of 2020-21 to 2029-30, except a small amount (0.4 GW) was added to the 25%-RETs Only Scenario. Therefore, the installed solar thermal capacity in each scenario in 2029-30 remained more or less the same amount as installed in 2019-20.

Solar PV capacity was added to the 25% Reduction Scenario (0.2 GW), the 5%-RETs Only Scenario (0.6 GW), the 25%-RETs Only Scenario (2.4 GW) and the 5%-26%_2030-RETs Only Scenario (0.2 GW) during the period of 2020-21 to 2029-30. In 2029-30, the 25%-RETs scenario had the largest amount of solar PV capacity installed at 3.6 GW, the other scenarios installed from 1.0 GW to 1.4 GW of solar PV capacity.

Figure 5.19 below displays installed capacity in each scenario by technology in 2049-50. It shows that the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios had the largest amounts of installed capacity in 2049-50 among all scenarios.

The intermittent capacity (includes wind and solar PV) was considered as candidate to expand power system in the NEM in this research. Utilities consider such intermittent generation resources as ‘‘non-dispatchable,’’ because they cannot be reliably called upon to generate electricity on demand (Sovacool 2009).

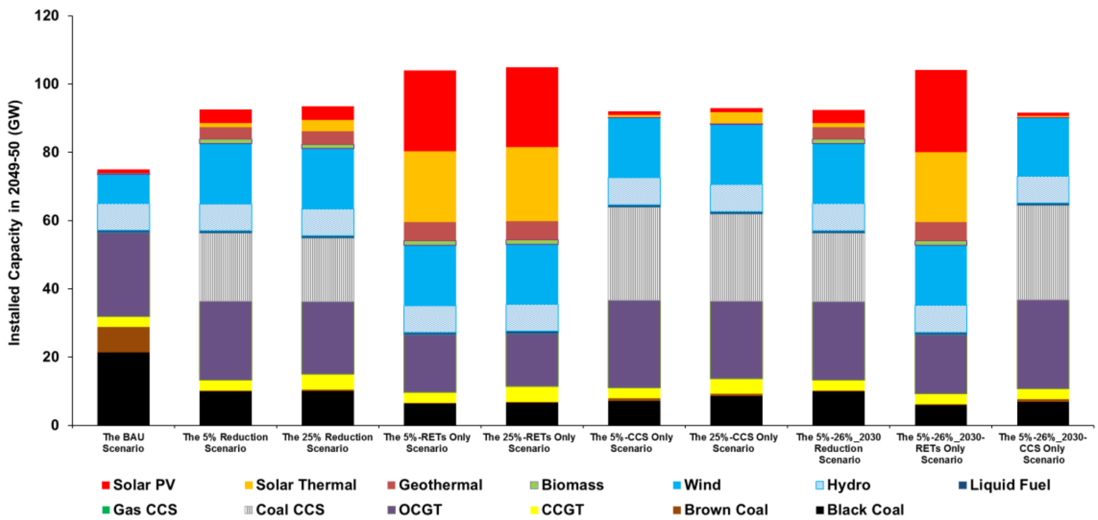



**Figure 5.19** Installed capacity in each scenario by technology, in 2049-50.

Capacity credit of a generating unit represents its reliable contribution to the generation adequacy of a power system (Amelin 2009; Keane et al. 2011). Intermittent generation capacity will generally have a lower capacity credit. The capacity credit is subject to the correlation between generation availability and the periods of high demand. The capacity credit of wind power, for example, ranges from 5% to 40% of the nameplate capacity (Holttinen et al. 2011; Mason, Page and Williamson 2010). On the other hand, in a normal condition, the dispatchable generation technologies such as nuclear, thermal plants with CCS, geothermal and large hydro are expected to have capacity credits higher than 90% (IPCC 2014).

In the NEM PLEXOS Model, the capacity credits of generation units were used to calculated system’s firm capacity. This was used to meet energy peak demand and system reliability requirement. Adding significant amount of generation plants with lower capacity credits can result in the need for higher planning reserve margin to ensure the same degree of system reliability (IPCC 2014).

In 2049-50, the intermittent generation capacity (wind and solar) reached approximately 9.4 GW, representing 12.6% of total installed capacity in the BAU Scenario. On average, wind and solar PV together accounted for approximately 23% (21.5 GW) of total installed capacity in the 5%, 25% and 5%-26%_2030 Reduction Scenarios. In the 5%, 25%- and 5%-26%_2030-CCS Only Scenarios, wind and solar PV together covered near 20% (18.5 GW) of total capacity. Wind and solar PV together accounted for, on average, almost 39.6% (41.3 GW) of total capacity in each of the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios. Higher percentage of installed intermittent capacity in the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios may be the reason to explain the highest amount of total installed capacity in these scenarios compared to other scenarios at the end of planning period.

At the end of planning period, the installed capacity in the BAU Scenario remained to be dominated by fossil fuels technologies (see Figure 5.19). Black coal and OCGT accounted for 28.4% (21.3 GW) and 32.8% (24.6 GW) of installed capacity respectively in 2049-50. Brown coal and CCGT took up 10.0% (7.5 GW) and 4.1% (3.1 GW) of total capacity respectively. Liquid fuel accounted for approximately 0.9% (0.7 GW) of total capacity. Renewable capacity represented 23.8% (17.8 GW) of total capacity installed, including 11.3% of wind, 10.5% of hydro, 1.3% of solar PV and approximately 0.6 % of biomass.

In 2049-50, the 5%, 25% and 5%-26%_2030 Reduction Scenarios were equipped with similar portfolio of capacity. The conventional fossil fuel capacity installed in these scenarios in 2049-50 reduced largely when compared to the capacity installed in 2012-13.

In 2049-50, the fossil fuel capacity accounted for approximately 40%, 39.4% and 40% of total installed capacity in the 5%, 25% and 5%-26%_2030 Reduction Scenarios respectively. Brown coal generation capacity was significantly decreased to approximately 0.3 GW (0.3%) in each of these three scenarios in 2049-50. Black coal, CCGT and OCGT capacity was approximately 9.8 GW (10.6%), 3.1 GW (3.3%) and 23 GW (25%) in the 5% and 5%-26%_2030 Reduction Scenario. They were

10.0 GW (10.7%), 4.6 GW (4.1%) and 21.3 GW (22.8%) respectively in the 25% Reduction Scenario. Liquid fuel capacity accounted for approximately 0.7% of total capacity in each of these three scenarios in 2049-50.

At the same time, the 5%, 25% and 5%-26%_2030 Reduction Scenarios had 20 GW (21.6%), 18.6 GW (19.9%) and 20.1 GW (21.7%) of coal CCS capacity installed respectively in 2049-50.

In total, renewable capacity reached 35.5 GW (38.4%), 38.0 GW (40.7%) and 35.3 GW (38.2%) in the 5%, 25% and 5%-26%_2030 Reduction Scenarios respectively in 2049-50. Wind was the most prominent renewable capacity in these scenarios, which accounted for 19.1%, 18.9% and 19.1% of total installed renewable capacity in three scenarios respectively. Hydro maintained its capacity installed over time, and represented 8.5%, 8.4% and 8.6% of total installed renewable capacity in these three scenarios respectively in 2049-50. There was more solar thermal capacity installed in the 25% Reduction Scenario (3.6%) than installed in the 5% and 5%-26%_2030 Reduction Scenarios (1.3%). These three scenarios also had similar levels of installed biomass, geothermal and solar PV capacity in 2049-50.

The 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios had a similar mix of installed capacity in 2049-50. They had larger component of renewable capacity compared to other scenarios. Conventional fossil fuels sourced capacity accounted for approximately 26.2% (27.3 GW) of total capacity on average in each of three scenarios.

In 2049-50, renewable capacity took up approximately 73.8% (77 GW) of total capacity on average in each of 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios. Wind and solar capacity was the largest among installed renewable capacity. In the 5%-RETs Only Scenario, wind, solar thermal and solar PV accounted for approximately 17%, 20.1%, and 22.7% of total capacity respectively in 2049-50. In the 25%-RETs Only Scenario, similar amount of wind (16.8%), solar thermal (20.7%) and solar PV (22.3%) capacity was installed as in the 5%-RETs Only Scenario. In the 5%-26%_2030-RETs Only Scenario, wind, solar thermal and solar PV made up approximately 17.0%, 19.7%, and 23.1% of total capacity respectively.

There was approximately 7.6% of hydro, 1.2% of biomass and 5.2% of geothermal installed in each of three scenarios in 2049-50.

The 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios had considerable amount of coal CCS capacity installed in 2049-50. There was approximately 27.3 GW (29.7%), 25.6 GW (27.6%) and 27.7 GW (30.3%) of coal CCS capacity installed in the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios respectively in 2049-50. Because no new renewable capacity was added to the NEM after 2019-20, fossil fuels capacity, primarily black coal and OCGT still accounted for relatively high percentages (40.6%, 39.8% and 40.8%) of total capacity installed in these scenarios in 2049-50.

In 2049-50, renewable energy capacity was accounted for approximately 29.8% (27.3 GW), 32.6% (30.3 GW) and 29.0% (26.5 GW) in the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios respectively. Wind was the primary type of renewable capacity installed, representing about 19.1% (17.6 GW), 19.0% (17.6 GW) and 18.7% (17.1 GW) of total installed capacity in three scenarios respectively. The installed renewable capacity in the 5%-CCS Only Scenario was comprised of 8.6% of hydro, 0.2% of biomass, 0.7% of solar thermal and 1.1 % of solar PV. The 25%-CCS Only Scenario installed with 8.5% of hydro, 0.2% of biomass, 3.7% of solar thermal and 1.3% of solar PV capacity. In the 5%-26%_2030-CCS Only Scenario, there was 8.6% of hydro, 0.2% of biomass, 0.3% of solar thermal and 1.1% of solar PV installed.

## 5.4 Generator Total Cost

The NEM PLEXOS Model's LT plan computes a system's generator total cost as the sum of a system's total generation cost, total FO&M cost, and generator annualized build cost (Energy Exemplar 2014).

### 5.4.1 Total Generation Cost

In this study, system's total generation cost is the cost incurred by a generator's operation including fuel cost, VO&M cost and emissions cost. As the emission cost only occurred in 2012-13 and 2013-14 in the NEM PLEXOS Model, fuel cost and VO&M cost should contribute the most to the differences of total generation cost in ten scenarios. The emissions costs occurred in the year 2012-13 and the year 2013-14 were the same for every scenario, totalling at approximately AU$4.3 billion and AU$4.4 billion for each year respectively.

Over the planning period, total fuel cost of the BAU Scenario resulted in AU$98.4 billion. Total fuel costs of the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios amounted at AU$89.3 billion, AU$89.0 billion and AU$91.9 billion respectively. The 5%, 25% and 5%-26%_2030 Reduction Scenarios had total fuel costs of AU$110.5 billion, AU$113.1 billion and AU$109.5 billion respectively. The 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios had the highest fuel costs at AU$128.7 billion, AU$133.0 billion and AU$129.0 billion respectively.

These results suggested that the scenarios with higher portions of renewable energy generation consumed fewer fuels than the scenarios with more generation from fossil fuels. Therefore, the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios had the least fuel costs among all scenarios.

The input data for VO&M charges showed that generally conventional coal and gas generation have lower VO&M charges compared to renewable and CCS generation. In addition, CCS generation has higher VO&M charges than that of renewable generation. The modelling results of system VO&M costs were consistent with the inputs of VO&M charges.

The BAU Scenario had the lowest VO&M cost of AU$23.8 billion. The 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios had the highest VO&M costs, reaching approximately AU$74.2 billion, AU$81.9 billion and AU$70.3 billion respectively. The 5%, 25% and 5%-26%_2030 Reduction Scenarios had VO&M costs of AU$ 57.8 billion, AU$ 62.7 billion and AU$ 40.1 billion respectively. The VO&M costs of the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios were AU$ 41.4 billion, AU$ 45.7 billion and AU$ 40.1 billion each.

The fuel costs weighed more than the VO&M costs in calculating total generation costs, as indicated by Figure 5.20. The BAU Scenario had the lowest total generation cost at approximately AU$131 billion. Total generation costs of the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios were among the highest compared to other scenarios. Their total generation costs were approximately AU$212 billion, AU$224 billion and AU$208 billion respectively.

The 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios had total generation costs at approximately AU$139 billion, AU$143 billion and AU$141 billion respectively. Total generation costs of the 5%, 25% and 5%-26%_2030-Reduction Scenarios reached approximately AU$177 billion, AU$185 billion and AU$173 billion respectively.

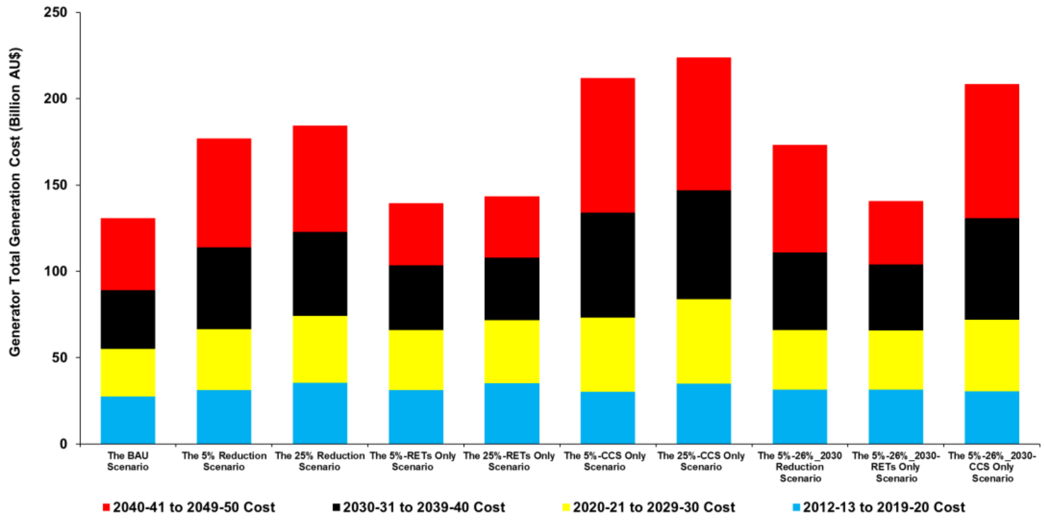



**Figure 5.20** Total generation cost by scenario, 2012-13 to 2049-50.

Due to relatively similar generation profiles of all scenarios in the period of 2012-13 to 2019-20, generator total generation costs had small variation in this period across all scenarios. Generation profile started to differ to a larger extent after 2019-20, so did the total generation cost of each scenario.

### 5.4.2 FO&M cost and Annualized Build Cost

The generator FO&M cost is the total fixed operations and maintenance cost incurred by the generator, as defined by the FO&M Charge (Energy Exemplar 2014). In the NEM PLEXOS Model, the inputs of the FO&M Charges showed that renewable and CCS capacity had higher FO&M Charges than those of conventional coal and gas capacity.

The BAU Scenario resulted in approximately AU$103.4 billion of total FO&M cost, which was the lowest FO&M cost among all scenarios (see Table 5.1). The FO&M costs of the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios were similar, at approximately AU$169.0 billion, AU$169.9 billion and AU$169.2 billion respectively. The FO&M costs of the 5%, 25% and 5%-26%_2030 Reduction Scenarios did not differ much and were approximately AU$188 billion, AU$192.5 billion and AU$187.8 billion respectively. The FO&M costs of the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios were the highest among all scenarios, reaching near AU$220.0 billion, AU$224.5 billion and AU$220.9 billion separately.

**Table 5.1** The FO&M cost and annualized build cost of each scenario (in billion AU$).

| **Model** | **FO&M Cost** | **Annualized Build Cost** |
|---|---|---|
| The BAU Scenario | 103.4 | 49.9 |
| The 5% Reduction Scenario | 188.0 | 296.8 |
| The 25% Reduction Scenario | 192.5 | 339.1 |
| The 5%-26%_2030 Reduction Scenario | 187.8 | 278.9 |
| The 5%-RETs Only Scenario | 220.0 | 365.7 |
| The 25%-RETs Only Scenario | 224.5 | 412.0 |
| The 5%-26%_2030-RETs Only Scenario | 220.9 | 340.4 |
| The 5%-CCS Only Scenario | 169.0 | 296.6 |
| The 25%-CCS Only Scenario | 169.9 | 341.6 |
| The 5%-26%_2030-CCS Only Scenario | 169.2 | 276.6 |

Generator annualised build cost is the capacity build cost annualised and is calculated according to the formula in the LT Plan (Energy Exemplar 2014). It aims to convert built cost to an equivalent annual charge. This is applied in the year of build and every subsequent year across the economic life of the generator. The results in Table 5.1 show that the BAU Scenario has the lowest annualised build cost compared to the other scenarios, while the 5%-, 25%- and 5%-26%_2030-RETs Only Scenario have the highest annualised build costs among all.

### 5.4.3 Generator Total Cost

System generator total cost is the sum of total generation cost, FO&M cost and annualised build cost, as shown in Table 5.2. It shows that the generator total cost of the BAU Scenario accumulated at AU$284.1 billion, representing the lowest amount of generator total cost among all scenarios.

As listed in Table 5.2, the 5%, 25% and 5%-26%_2030 Reduction Scenarios had total costs of approximately AU$661.8 billion, AU$716.0 billion and AU$639.9 billion respectively. The total costs of 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios resulted in AU$725.2 billion, AU$779.9 billion and AU$702.1 billion. The total costs of 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios were AU$677.6 billion, AU$735.5 billion and AU$654.2 billion respectively.

**Table 5.2** The generator total cost of each scenario (in billion AU$).

| **Model** | **Total Generation Cost** | **FO&M Cost** | **Annualized Build Cost** | **Total** |
|---|---|---|---|---|
| The BAU Scenario | 130.8 | 103.4 | 49.9 | 284.1 |
| The 5% Reduction Scenario | 177.0 | 188.0 | 296.8 | 661.8 |
| The 25% Reduction Scenario | 184.5 | 192.5 | 339.1 | 716.0 |
| The 5%-26%_2030 Reduction Scenario | 173.3 | 187.8 | 278.9 | 639.9 |
| The 5%-RETs Only Scenario | 139.4 | 220.0 | 365.7 | 725.2 |
| The 25%-RETs Only Scenario | 143.4 | 224.5 | 412.0 | 779.9 |
| The 5%-26%_2030-RETs Only Scenario | 140.8 | 220.9 | 340.4 | 702.1 |
| The 5%-CCS Only Scenario | 212.0 | 169.0 | 296.6 | 677.6 |
| The 25%-CCS Only Scenario | 223.9 | 169.9 | 341.6 | 735.5 |
| The 5%-26%_2030-CCS Only Scenario | 208.4 | 169.2 | 276.6 | 654.2 |

Simply dividing these total costs by the total cost of the BAU Scenarios revealed that the total costs of the 5%, 25% and 5%-26%_2030 Reduction Scenarios accounted for near 133%, 152% and 125% more than the total cost of the BAU Scenario. The total costs of 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios represented approximately 155%, 175% and 147% more of the total cost of the BAU Scenario. The total costs of 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios were approximately 139%, 159% and 130% more of the total cost of the BAU Scenario.

Comparing the results of total costs in each group of scenarios, it revealed that in the same scenario group, the scenario with the 25%-80% Reduction Target had the highest generator total cost and the scenarios with the 5%-26%-80% Reduction Target had the lowest generator total cost.

## 5.5 Cost of Avoiding $CO_2$-e Emissions

An important aspect of scenarios comparison in this study is to compare each scenario's cost of avoiding $CO_2$-e emissions relative to the BAU Scenario. The carbon avoided cost can be also understood as the system $CO_2$-e emissions abatement cost. It reflects the economics of a scenario's least cost pathway for system capacity expansion while curbing carbon emissions. It calculates the ratio of a scenario's relative generator total cost to a scenario's $CO_2$-e emissions savings, as illustrated by the formula below:

$$\mathbf{C_{Avoiding}} = \frac{\boldsymbol{TC_r}}{\boldsymbol{ES}} \qquad \textbf{(5.1)}$$

Where,

$C_{Avoiding}$ is a scenario's cost of avoiding $CO_2$-e emissions;

$TC_r$ is the scenario's relative generator total cost, calculated as a scenario's generator total cost minus the BAU Scenario's generator total cost;

$ES$ is the scenario's $CO_2$-e emissions savings, calculated as the cumulative emissions of the BAU Scenario minus the cumulative emissions of the scenario.

Two components for calculating a scenario's cost of avoiding $CO_2$-e emissions are a scenario's generator total cost as described in above section and its cumulative emissions in the planning horizon. The results of scenarios' cumulative emissions can refer to Section 5.1 in this chapter.

**Table 5.3** Cost of avoiding $CO_2$-e emissions by scenario.

| | BAU | 5% Reduction | 25% Reduction | 5%-RETs Only | 25%-RETs Only | 5%-CCS Only | 25%-CCS Only | 5%-26%_2030 Reduction | 5%-26%_2030-RETs Only | 5%-26%_2030-CCS Only |
|---|---|---|---|---|---|---|---|---|---|---|
| **Generator Total Cost (Billon AU$)** | 284.1 | 661.8 | 716.0 | 725 .2 | 779.9 | 677.6 | 735.5 | 639.9 | 702.1 | 654.2 |
| **Generator Total Cost Relative to BAU Scenario's (Billon AU$)** | 0.0 | 377.7 | 432.0 | 441.1 | 495.8 | 393.5 | 451.4 | 355.9 | 418.1 | 370.1 |
| **Accumulative $CO_2$-e Emissions (Mt)** | 8387.4 | 4174.6 | 3581.3 | 4174.6 | 3581.3 | 4174.6 | 3581.3 | 4409.0 | 4409.0 | 4409.0 |
| **$CO_2$-e Savings (Mt)** | 0.0 | 4212.8 | 4806.1 | 4212.8 | 4806.1 | 4212.8 | 4806.1 | 3978.4 | 3978.4 | 3978.4 |
| **Cost of Avoiding $CO_2$-e emissions (AU$/t)** | n/a | 89.7 | 89.9 | 104.7 | 103.2 | 93.4 | 93.9 | 89.4 | 105.1 | 93.0 |

The calculation results showed that the 5%-26%_2030 Reduction Scenario had the lowest carbon avoiding cost at AU$ 89.4/t, while the 5%-26%_2030-RETs Only Scenario had the highest carbon abatement costs at AU$ 105.1/t (see Table 5.3).

Overall, the 5%, 25% and 5%-26%_2030 Reduction Scenarios had the lowest costs of avoiding $CO_2$-e emissions. The 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios had the highest costs of avoiding $CO_2$-e emissions. The costs of avoiding $CO_2$-e emissions of the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios were in between.

The 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios had the highest costs of avoiding $CO_2$-e emissions. Dividing the cost difference between the carbon avoiding cost of the RETs Only Scenario and the carbon avoiding cost of the CCS Only Scenario by the carbon avoiding cost of the CCS Only Scenario revealed that the carbon avoiding costs of the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios represented near 12.1%, 9.8% and 13.0% respectively more than the carbon avoiding costs of the 5%-, 25-% and 5%-26%_2030-CCS Only Scenarios respectively. Similarly, the carbon avoiding costs of the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios were approximately 16.8%, 14.8% and 17.5% respectively more than the carbon avoiding costs of the 5%, 25% and 5%-26%_2030 Reduction Scenarios.

## 5.6 System Levelised Cost

The NEM PLEXOS Model simulated the NEM with regional reference prices. Because the implementation of carbon reduction targets, the energy dispatch prices of all scenarios except the BAU Scenario were affected by emission shadow prices from 2014-15.

The emission show price is the dual variable value associated with the emission production constraint internally calculated by the LT Plan. It represents the system marginal cost of last unit of emission production and is used to adjust generator offer prices to account for emissions. Therefore, the energy price reported by the LT Plan counted in the carbon shadow price. Nevertheless, this research assumed that there was no carbon price imposed on emissions in the planning period apart from the modelling years of 2012-13 and 2013-14.

This section reports modelling results of system levelised cost of electricity (LCOE). It is a unit price of electricity resulted from dividing generator total cost by total generation in each scenario.

Usually, the LCOE denotes the average cost of a unit of electricity generated by a technology, as described in section 2.1.3 of Chapter 2. It is a common metric for calculating the costs of generation technologies in the power sector and a tool for comparing the unit costs of different technologies over their economic life (IEA and NEA 2010).

The system LCOE reported here differs from common concept of the LCOE described above. It represents the cost of a power system per unit of electricity (MWh) generation during the planning period. This cost includes generator generation cost, fixed cost and capacity capital cost. The system LCOE reflects an average energy price level of a power system with its specific portfolio of generators in the planning period. It can be used to compare different scenarios' energy price levels for expanding a power system with different combinations of technologies.

Figure 5.21 shows the annual regional averaged system LCOE of the NEM. The system LCOE of the BAU Scenario in the planning horizon was the lowest among all scenarios. With a moderate rising trend, the system LCOE of the BAU Scenario started at AU$ 42.5/MWh in 2012-13 and ended at AU$ 54.4/MWh in 2049-50. Dividing AU$ 54.4/MWh by AU$ 42.5/MWh suggested that the system LCOE in the BAU Scenario experienced a 27.9% increase over the simulation horizon.

Because the cancellation of the carbon price from 2014-15, the system LCOE of the BAU Scenario dropped significantly from AU$ 42.5/MWh in 2012-13 to AU$ 15.3/MWh. Since 2014-15, the system LCOE of the BAU Scenario grew steadily to reflect increased energy demand in the NEM over time.

Overall, the system LCOEs of all other scenarios present upward trends as shown in Figure 5.21 below. By 2020-21, the system LCOEs of the 5% and 5%-26%_2030 Reduction Scenarios, 5%- and 5%-26%_2030-RETs Only Scenarios and 5%- and

5%-26%_2030-CCS Only Scenarios followed a similar trend of cost change. The system LCOEs of the 25% Reduction Scenario, 25%-RETs Only Scenario and 25%-CCS Only Scenario displayed another similar trend of cost change.

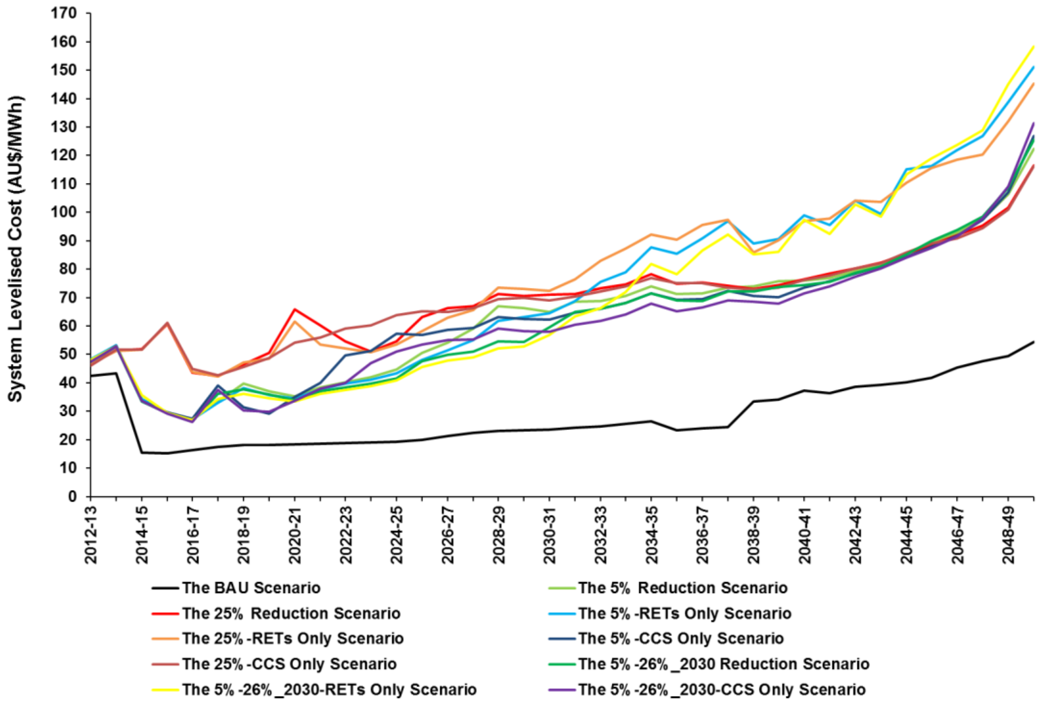



**Figure 5.21** System levelised cost by scenarios, between 2012-13 and 2049-50.

The system LCOEs of the scenarios with the 5% Reduction Target first dropped from approximately AU$47.7/MWh on average in 2012-13 to AU$34.2/MWh on average in 2014-15 as a result of the scrapping of the carbon price. Since 2014-15, their system LCOEs fluctuated between on average AU$29.4/MWh and AU$35.6/MWh until 2019-20. From 2020-21, their system LCOEs climbed up steadily from on average AU$34.3/MWh to AU$59.6/MWh in 2029-30.

The system LCOEs of the scenarios with the 25% Reduction Target did not dropped to reflect the scrapping of the carbon price from 2014-15. Instead, their system LCOEs increased from on average AU$46.5/MWh in 2012-13 to AU$51.7/MWh in 2014-15, perhaps due to higher amount of capacity installed to satisfy the higher carbon emissions reduction requirements. From 2014-15 to 2019-20, their system LCOEs varied between on average AU$42.4/MWh to AU$60.9/MWh. From 2020-21, the system LCOEs increased gradually from on average of AU$60.5/MWh in 2020-21 to AU$71.2/MWh in 2029-30.

From 2029-30, the system LCOEs of the 5%, 25% and 5%-26%_2030 Reduction Scenarios, and the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios followed an upward trend of cost change and gradually converged at a price level of approximately AU$135.9/MWh in 2049-50. It represented approximately 1.9 times more than the system LCOE of the BAU Scenario in 2012-13. The system LCOEs of the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios increased with a higher speed than the change in other scenarios after 2029-30. At the end, they resulted with a similar price level of approximately AU$151.6/MWh in 2049-50, standing for almost 2.6 times higher than the system LCOE of the BAU Scenario in 2012-13.

## 5.7 Discussion

This chapter reported the results of ten scenarios modelled for the NEM, including the BAU Scenario, the 5%, 25% and 5%-26%_2030 Reduction Scenarios, the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios and the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios.

The BAU Scenario executed the current Renewable Energy Target (33,000 GW). It represented the status quo pathway of system capacity expansion in the NEM without the intervention of the carbon emissions reduction targets. The 5%-26%_2030 Reduction Scenario was also labelled as the CGP Scenario, which implemented the current Renewable Energy Target and the carbon reduction targets of 5% cut based on 2000 levels by 2019-20, 26% reduction based on 2005 levels by 2029-30 in the NEM.

The 5% Reduction Scenario represented a progressive carbon emissions reduction scenario compared to the CGP Scenario. It enforced the pervious Renewable Energy Target (41,000 GW) and the carbon reduction targets of 5% cut based on 2000 levels by 2019-20 and approximately 34.9% reduction based on 2005 levels by 2029-30 in the NEM. The 25% Reduction Scenario denoted an ambitious carbon emission reduction scenario in the NEM. In addition to applying the pervious Renewable Energy Target, the 25% Reduction Scenario required to cut carbon emissions in the NEM by 25% based on 2000 levels by 2019-20 and by approximately 47.3% reduction based on 2005 levels by 2029-30.

The 5% and 25% Reduction Scenarios simulated the capacity expansion pathways when the NEM was subject to the Australian Government's future possible more stringent carbon emissions reduction polices. The CGP Scenario, the 5% Reduction Scenario and the 25% Reduction Scenario all executed the carbon emissions reduction target of a 80% cut based on 2000 level by 2049-50.

The BAU Scenario resulted in the lowest generator total cost of AU$284.1 billion for the power system expansion in the NEM among all scenarios. The system LCOE of the BAU Scenario in the planning horizon was also the lowest among all scenarios. It experienced a 27.9% growth, increased from AU$ 42.5/MWh in 2012-13 to AU$ 54.4/MWh in 2049-50.

Meanwhile, the NEM's annual carbon emission in the BAU Scenario grew from 186.1 Mt in 2012-13 and reached 196.4 Mt, 217.7 Mt and 256 Mt in 2019-20, 2029-30 and 2049-50 respectively. It represented the highest levels of annual carbon emissions among all scenarios. This led to the largest amount of cumulative carbon emissions happening in the BAU Scenario when compared to other scenarios, totalling at 8387.4 Mt over the entire planning period.

In 2012-13, conventional fossil fuel sources including coal and gas made up approximately 88.4% of total generation in the NEM, renewable sources contributed to approximately 11.6%. Primarily due to the lack of any emissions reduction targets, the NEM's energy mix in 2049-50 in the BAU Scenario did not differ significantly from that in 2012-13. In 2049-50, conventional fossil fuel technologies still generated approximately 82.5% of total energy output in the BAU Scenario; renewable sources accounted for approximately 17.5% of total energy generation.

At the same time, in 2012-13, the conventional fossil fuel capacity and the renewable capacity accounted for approximately 79.3% (39.4 GW) and 20.7% (10.3 GW) of total installed capacity respectively in the BAU Scenario. In 2049-50, they accounted for approximately 76.2% (57.1 GW) and 23.8% (17.8 GW) of total installed capacity respectively.

The 5%-26%_2030 Reduction Scenario which is also the CGP Scenario had the lowest generator total cost for the system expansion after the BAU Scenario. Its generator total cost was AU$639.9 billion, standing for approximately 2.25 times more than the generator total cost of the BAU Scenario.

Significantly increased generator total cost of the CGP Scenario was attributed to its considerable higher penetration rate of the LCETs compared to that in the BAU Scenario. In 2019-20, the conventional fossil fuel technologies and the RETs generated approximately 74.5% (169.7 TWh) and 25.5% (58.1 TWh) of total energy output respectively in the CGP Scenario. In 2029-30, they produced approximately 59.1% (146.4 TWh) and 40.9% (101.5 TWh) of total energy output respectively. In 2049-50, the LCETs including the RETs and the CCS technologies generated approximately 89.9% (296.5 TWh) of total electricity generation. The rest of 10.1% (33.5 TWh) was produced by the conventional fossil fuel technologies.

In 2019-20, the conventional fossil fuel capacity, the CCS capacity and the renewable capacity were comprised of approximately 64.2% (38.3 GW), 0% and 35.8% (21.3 GW) of total installed capacity respectively in the CGP Scenario. These proportions changed to be approximately 56.7% (39.9 GW), 0% and 43.3% (30.5 GW) respectively in 2029-30. In 2049-50, the conventional fossil fuel capacity, the CCS capacity and the renewable capacity accounted for approximately 40% (36.9 GW), 21.7% (20.1 GW) and 38.3% (35.3 GW) of total installed capacity respectively in the CGP Scenario.

Higher investment in adding more LCETs to the NEM power system led to significant lower carbon emissions in the CGP Scenario than the emissions in the BAU Scenario. The annual level of carbon emissions in the CGP Scenario was cut from 186.1 Mt in 2012-13 to 157 Mt in 2019-20. It was reduced further to 131 Mt in 2029-30 and 33 Mt in 2049-50. The cumulative carbon emissions in the CGP Scenario were approximately 4409 Mt. It stood for approximately 3978.4 Mt of carbon emissions avoidance when compared to the cumulative emissions of the BAU Scenario over the simulation horizon.

The 5% Reduction Scenario which had a more progressive carbon emissions reduction target than that of the CGP Scenario resulted in higher generator total cost than the costs of the BAU Scenario and the CGP Scenario. The generator total cost of the 5% Reduction Scenario reached AU$ 661.8 billion, representing AU$ 21.9 billion more or approximately 3.4% higher than the cost of the CGP Scenario.

Higher generator total cost promoted higher level of generation from the LCETs and financed larger amount of the installation the LCETs capacity in the 5% Reduction Scenario by 2029-30 than in the CGP Scenario. In the meantime, it also helped to achieve larger amount of carbon emissions reduction in the NEM than that in the CGP Scenario.

The 5% Reduction Scenario had similar amount of generation from the conventional fossil fuel technologies and the LCETs as the generation of the CGP Scenario in the year 2019-20 and the year 2049-50. In 2029-30, the 5% Reduction Scenario simulated with higher amount of energy generation from the LCETs including the RETs and the CCS technologies than the generation in the CGP Scenario. The conventional fossil fuel technologies and the LCETs generated approximately 53.4% (133.4 TWh) and 46.6% (116.3 TWh) of total energy output respectively in the 5% Reduction Scenario in 2029-30.

Similarly, the installed capacity profile of the 5% Reduction Scenario resembled the profile of the CGP Scenario in 2019-20 and 2049-50. In 2029-30, the installed capacity of the 5% Reduction Scenario had a higher portion of the LCETs than that of the CGP Scenario. The conventional fossil fuel capacity, the CCS capacity and the renewable capacity contributed approximately 54.6% (38.8 GW), 1.3% (0.9 GW) and 44.1% (31.3 GW) respectively in the 5% Reduction Scenario in 2029-30.

The annual level of carbon emissions of the 5% Reduction Scenario was at 186.1 Mt in 2012-13 and was cut to be 156.6 Mt in 2019-20, 115.4 Mt in 2029-30 and reached 33 Mt in 2049-50. Its cumulative carbon emission totalled at 4174.6 Mt, representing 234.4 Mt less or approximately 5.3% cut based on the cumulative emissions of the CGP Scenario.

The 25% Reduction Scenario had the most ambitious carbon reduction target and resulted in the highest generator total cost compared to the BAU Scenario, the CGP Scenario and the 5% Reduction Scenario. Its generator total cost reached AU$ 716 billion, accounting for AU$ 76.1 billion more or approximately 11.9% higher than the generator total cost of the CGP Scenario.

Compared to the CGP Scenario, the 25% Reduction Scenario had higher energy generation and installed capacity from the LCETs in 2019-20 and 2029-30. The conventional fossil fuel technologies and the RETs generated approximately 64.7% (146.4 TWh) and 35.5% (54.3 TWh) of total energy output respectively in the 25% Reduction Scenario in 2019-20. A considerable amount of CCS energy generation occurred in the 25% Reduction Scenario in 2029-30, contributing to approximately 8.8% (22.3 TWh) of total energy output. In 2029-30, approximately 43.4% (109.9 TWh) and 47.8% (120.9 TWh) of total electricity generation were from conventional fossil fuel technologies and the RETs respectively in the 25% Reduction Scenario. The generation profile of the 25% Reduction Scenario converged to be similar as the profile of the CGP Scenario in 2049-50.

The installed capacity in the 25% Reduction Scenario had higher percentage of the LCETs installation in 2019-20 and 2029-30 than the installation in the CGP Scenario. In 2019-20, the conventional fossil fuel capacity and the renewable capacity took up 55.5% (36.5 GW) and 44.5% (29.2 GW) respectively in 25% Reduction Scenario. In 2029-30, the conventional fossil fuel capacity, the CCS capacity and the renewable capacity accounted for approximately 49.2% (36.2 GW), 3.5% (2.5 GW) and 47.3% (34.7 GW) respectively. The capacity profile of the 25% Reduction Scenario became relatively similar as the profile of the CGP Scenario in 2049-50.

The 25% Reduction Scenario had significantly reduced carbon emissions when compared to the emissions of the CGP Scenario due to higher portion of its electricity generation from the LCETs over the planning period. In the 25% Reduction Scenario, the annual level of carbon emissions in the NEM started at 186.1 Mt in 2012-13 and was reduced to be 123.6 Mt in 2019-20, 93.4 Mt in 2029-30 and 33 Mt in 2049-50. This resulted in considerably lower level of cumulative carbon emissions, totalling at 3581.3 Mt. It cut approximately 827.7 Mt of emissions or represented 18.8% less emissions based on the cumulative emissions level of the CGP Scenario.

Three RETs Only Scenarios and three CCS Only Scenarios are the exploratory scenarios used to investigate the potential of the RETs and the CCS technologies in meeting the 5%-80%, 25%-80% and 5%-26%-80% carbon reduction targets in the NEM.

In 2049-50, the renewable energy was modelled to contribute as high as 84% of total energy generation in the NEM on average in each of the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios. Conventional coal and gas technologies together accounted for approximately 16% of total energy output on average in each of these scenarios.

The CCS technologies generated near 68.3%, 65.5% and 69.2% of total energy output in the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios respectively in 2049-50. The RETs made up approximately 22.5%, 25% and 21.7% in the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios respectively. The conventional fossil fuel technologies contributed to the rest of 9.2%, 9.5% and 9.1% in the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios respectively in 2049-50.

In the CCS Only Scenarios, more coal CCS capacity was installed and more energy generated by the coal CCS technologies to replace energy output otherwise generated by the RETs in the RETs Only Scenarios. Gas CCS technologies were still too expensive to enter the NEM in the CCS Only Scenarios by the end of planning period.

Because of higher capital costs associated with deploying the RETs and CCS technologies, it was expected that the scenarios with emissions reduction targets would yield higher system capacity expansion costs. The modelling results verified this expectation. For achieving the same carbon emissions reduction target in 2049-50, the RET Only Scenarios resulted in the highest generator total costs, the Carbon Reduction Scenarios had the lowest generator total costs and the generator total costs of the CCS Only Scenarios were in between (see Table 5.2).

In the meantime, simply comparing the generator total costs of the scenarios was not sufficient to distinguish the advantages of different generation mixes. The results of carbon avoiding costs indicated that the 5% Reduction Scenario, the 25% Reduction

Scenario and the CGP Scenario had the lowest carbon avoiding costs at AU$ 89.7/t, AU$ 89.9/t and AU$ 89.4/t respectively. The 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios had the highest carbon avoiding costs at AU$ 104.7/t, AU$ 103.2/t and AU$ 105.1/t respectively. The carbon avoiding costs of the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios were in the middle at approximately AU$ 93.4/t, AU$ 93.9/t and AU$ 93.0/t respectively.

## 5.8 Conclusions

In this study, ten scenarios were constructed for simulating and assessing the impacts of the Renewable Energy Target, different assumptions of carbon emissions reduction targets and energy technology availabilities on the NEM's power system expansion to 2049-50.

Significant amounts of carbon savings were achieved through deploying the LCETs (including the RETs and CCS technologies) in the scenarios constrained with emissions reduction targets. The modelling results demonstrated that the power system of the NEM was transformed substantially from a system highly depending on conventional fossil fuel technologies to a system dominated by the LCETs.

In the short-term (2012-13 to 2019-20), the Renewable Energy Target contributed largely by adding wind capacity and generation to increase the penetration of renewable energy generation in the NEM. In the long-term (2020-21 to 2049-50), more substantial carbon emissions reduction was attained by the implementation of the carbon emissions reduction targets in the NEM.

In the BAU Scenario, coal CCS technologies, solar thermal and geothermal were not competitive enough to enter the least cost pathway of expanding capacity system in the NEM from 2012-13 to 2049-50. While in the 5% Reduction Scenario, the 25% Reduction Scenario and the CGP Scenario, these technologies became available and contributed to energy production. Therefore, carbon emissions reduction targets were proved to be the important drivers for the entries of the CCS technologies, solar thermal and geothermal in the NEM by 2049-50.

The CGP Scenario was modelled with the least generator total cost after the BAU Scenario. It also had the highest amount of cumulative carbon emissions apart from the BAU Scenario. In the CGP Scenario, the NEM can achieve an emission target of an 80% cut on 2000 level by 2049-50 with the least generator total cost and the lowest carbon avoiding cost (AU$ 89.4/t) when compared to other scenarios.

However, if the Australian Government would establish a more progressive national emissions budget and set a budget for the electricity sector emissions accordingly for the period 2012-13 to 2049-50 in near future, the NEM would need to comply with a more stringent carbon emissions reduction target than the target applied for the CGP Scenario.

If the Australian Government aims to achieve a lower level of cumulative emissions in the NEM than the cumulative emissions (4409 Mt) attained by the CGP Scenario, current Renewable Energy Target and post-2020 emissions target would not be sufficient to abate enough emissions in the NEM.

By lifting the Renewable Energy Target from 33,000 GW to 41,000 GW and implementing stricter 5%-80% Reduction Target as simulated in the 5% Reduction Scenario, the NEM can reduce additional 234.4 Mt of emissions, representing approximately 5.3% less than the cumulative emissions under current Australian Government's policies. The investment in the generator total cost would be required to increase moderately to achieve this emissions reduction target in the 5% Reduction Scenario. The generator total cost would increase by AU$21.9 billion, standing for approximately 3.4% more than the generator total cost required under the CGP Scenario. This emissions reduction was mainly achieved by the higher penetration of the LCETs generation between 2020-21 and 2029-30.

Establishing more ambitious 25%-80% Reduction Target with 41, 000 GWh Renewable Energy Target as modelled in the 25% Reduction Scenario will result in less cumulative emissions in the NEM over the planning horizon than in the CGP Scenario and the 5% Reduction Scenario. It resulted in 827.7 Mt of cumulative emissions reduction in the NEM, representing approximately 18.8% less cumulative emissions than the level under the CGP Scenario.

More ambitious carbon emissions reduction was achieved by higher penetration of the LCETs from 2012-13 to 2029-30 in the 25% Reduction Scenario. It resulted in elevated generator total cost in the 25% Reduction Scenario, costing AU$76.1 billion more than the cost of the CGP Scenario. This was approximately 11.9% more than the generator total cost required in the CGP Scenario. Consequently, its carbon avoiding cost would rise approximately 0.56% than the carbon avoiding cost under current Australian Government's policies.

The modelling results of the RETs Only Scenarios and the CCS Only Scenarios suggested that the RETs and the CCS technologies can replace each other to achieve emission reduction targets in the NEM. By replacing CCS generation, there was considerably more energy generated from geothermal, solar thermal and solar PV in the RETs Only Scenarios.

At the same time, the results of carbon avoiding costs revealed that deploying both the RETs and CCS technologies in the long-run was the most economical way to achieve carbon emissions reduction target in the NEM. Exclusively depending on the RETs or the CCS technologies after 2019-20 to abate carbon emissions will result in higher carbon avoiding costs than deploying both the RETs and CCS technologies.

# Chapter 6 The WEM PLEXOS Modelling Results and Discussion

The results of the WEM PLEXOS Model are explained in this chapter. The WEM PLEXOS Model contained four scenario groups, similar as the scenarios constructed in the NEM PLEXOS Model (please refer to Section 3.2.3 in Chapter 3).

The scenario in the first group was the BAU Scenario which represented the baseline projection for the energy generation system expansion in the WEM. A carbon reduction target was not expected to exist in this scenario in the planning period (2013-14 to 2049-50). In the BAU Scenario, conventional fossil fuel technologies, the CCS technologies and the RETs were served as technology candidates for system capacity expansion in the WEM. Their time for the earliest entry into the WEM depended on the assumptions of technological available dates in the model.

The second scenario group included the 5% Reduction Scenario, the 25% Reduction Scenario and the 5%-26%_2030 Reduction Scenario. These scenarios implemented the 5%-80% Reduction Target, the 25%-80% Reduction Target and the 5%-26%-80% Reduction Target respectively over the planning horizon. The 5%-26%-80% Reduction Target was to cut carbon emissions of the WEM by 5% by 2019-20, by 26% by 2029-30 and by 80% by 2049-50 based on 2007-08 levels (see Section 4.9.2 in Chapter 4).

Similar as described in Section 5.7 in Chapter 5, the 5%-26%_2030 Reduction Scenario applied the current Renewable Energy Target and the 5%-26%-80% Reduction Target. This scenario reflected the current government's policies in reducing carbon emissions in the Australian electricity sector. Therefore it is considered as the CGP Scenario for the WEM.

The scenarios in the third and fourth groups inherited the same assumptions from the scenarios in the second group, except for the assumptions of the availability of the RETs and CCS technologies after 2019-20. In the 5%-, 25%- and 5%-26%_2030-RETS Only Scenarios, only conventional fossil fuel technologies and the RETs were allowed to enter the WEM after 2019-20, the CCS technologies were assumed to be not available in the planning period.

The fourth scenario group contained the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios. In this group, the RETs were prohibited to enter the WEM after year 2019-20. The available technologies for capacity expansion were conventional fossil fuel technologies and the CCS technologies after 2019-20 in the WEM.

## 6.1 Carbon Emissions Results

The carbon emissions results of the WEM PLEXOS Model were reported in four categories: the BAU Scenario, the scenarios with the 5%-80% Reduction Target, the scenarios with the 25%-80% Reduction Target and the scenarios with the 5%-26%-80% Reduction Target (see Figure 6.1).

The carbon emissions of the BAU Scenario were computed by the WEM PLEXOS Model. The emissions of the other three categories were calculated by the researcher based on the 5%-80%, 25%-80% and 5%-26%-80% Reduction Targets of the WEM (see Section 4.9.2 in Chapter 4). Four categories of carbon emissions all started at 13.8 Mt in 2013-14, and then changed along different trajectories to 2049-50 as shown in Figure 6.1.

In the BAU Scenario, the emission first rose to 16.1 Mt in 2014-15 possibly due to the abolition of the carbon price in July 2014. After that, the annual emissions remained relatively stable at approximately 16 Mt till 2019-20. The stable annual carbon emissions in this period despite the growth of energy demand may be attributed to the pickup of the renewable energy generation promoted by the current Renewable Energy Targets (33,000 GWh) in the WEM.

From 2020-21, the emissions in the BAU Scenario climbed upwardly until it arrived at its peak at the end of planning period. It reached 18.0 Mt and 24.3 Mt in 2029-30 and 2049-50 respectively, representing approximately 30.7% and 76.4% increase compared to its emissions in 2013-14 respectively. These two emissions levels were also approximately 27.7% and 72.4% respectively more than the emissions of 14.09 Mt in the baseline year 2007-08 (please see Section 4.9.2 in Chapter 4).

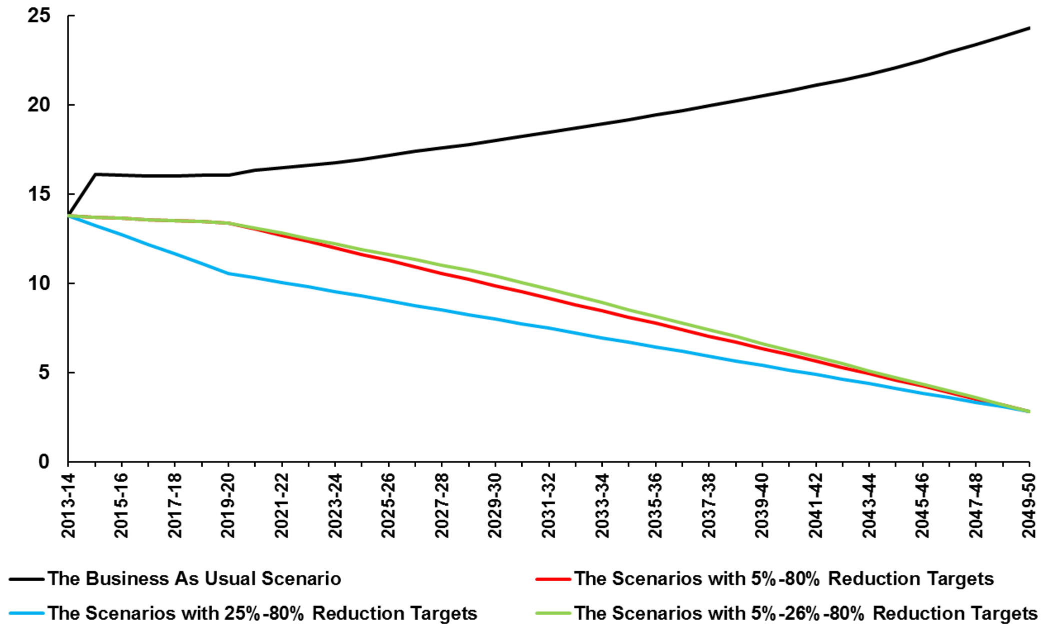



**Figure 6.1 The** trends of annual $CO_2$-e emissions in the WEM by scenario group, 2013-14 to 2049-50.

The emission trends of the 5%-80% and the 5%-26%-80% Reduction Targets were both constrained by the 5% emissions reduction requirement in 2019-20 based on the 2007-08 levels. Their emissions in 2019-20 reached approximately 13.4 Mt. The WEM was required to cut 25% emissions based on 2007-08 levels by 2019-20 with the constraint of the 25%-80% Reduction Target. Its emissions reached approximately 10.6 Mt in 2019-20.

The 5%-26%-80% Reduction Target required the emissions in the WEM to meet 26% reduction based on the 2007-08 levels by 2029-30. This requirement was not imposed on the 5%-80% and the 25%-80% Reduction Targets. In 2029-30, the emissions reached approximately 8.0 Mt, 9.9 Mt and 10.4 Mt in the 25%-80%, the 5%-80% and the 5%-26%-80% Reduction Targets respectively (see Figure 6.1).

In 2049-50, the emissions trends of the 5%-80%, the 25%-80% and the 5%-26%-80% Reduction Targets converged at approximately 2.8 Mt, accounting for approximately 80% of emissions reduction based on the 2007-08 emissions levels in the WEM. It also represented approximately 79.5% less emissions than the emissions level in 2013-14.

The annual level of carbon emissions revealed annual variation of emissions emitted by the projected generation mix in the WEM. The levels of cumulative carbon emissions over the planning period were helpful to reflect long-term effectiveness of the projected generation mix in cutting total carbon emissions. They are illustrated by the areas below emissions trend lines as displayed in Figure 6.1.

The cumulative carbon emissions of the BAU Scenario were 698 Mt from 2013-14 to 2049-50. Comparing this value with the cumulative carbon emissions of the scenarios with the 5%-80% (333 Mt), the 25%-80% (282 Mt) and the 5%-26%-80% Reduction Targets (341 Mt) respectively suggested that the cumulative carbon emission of the BAU Scenario was the largest among all. It was approximately 104.5% more than that of the scenarios with the 5%-26%-80% Reduction Target, 109.7% more than the cumulative emissions of the scenarios with the 5%-80% Reduction Target and 147.4% higher than that of the scenarios with the 25%-80% Reduction Target.

The scenarios with lower cumulative carbon emissions were expected to be equipped with higher portion of LCETs than the scenarios with higher cumulative carbon emissions. The validity of this assertion was verified by the modelling results of the WEM reported in following sections.

The emission results also indicated that the cumulative emissions of the 5%-26%-80% Reduction Target was slightly more (8 Mt) than the cumulative emissions of the 5%-80% Reduction Target. This insignificant difference may result in relatively similar generation and capacity profiles modelled for the scenarios with the 5%-80% Reduction Target and the scenarios with the 5%-26%-80% Reduction Target.

## 6.2 Electricity Generation Results

This section reports generation results of the WEM PLEXOS Model. The results are reported in three sub-sections. The first sub-section reports the generation results of the BAU Scenario in 2013-14 and 2014-15. The second sub-section reports generation results in 2019-20 and 2029-30 for all scenarios. The third sub-section contains all scenarios' generation results in 2049-50.

The generation results in 2013-14, 2019-20, 2029-30 and 2049-50 were compared to show the changes of generation mix in the WEM over the planning horizon. It revealed the impacts of the scenario assumptions on the penetrations of the RETs and CCS technologies in the WEM and their carbon emissions reduction potentials over time.

The WEM differs from the NEM in its much smaller generation scale. In 2013-14, total electricity output in the WEM was near 19.2 TWh, approximately 9.1% of generation in the NEM (208 TWh). Additionally, the existing generation portfolio of the WEM did not contain brown coal and hydro power technologies.

### 6.2.1 Generation Results of the BAU Scenario in 2013-14 and 2014-15

In 2013-14, total electricity generation in the BAU Scenario was approximately 19.2 TWh. As shown in Figure (6.2-a), energy generated from fossil fuels dominated the electricity output in the WEM in the BAU Scenario. The energy output from black coal, CCGT and OCGT accounted for approximately 8.9 TWh (46.3%), 4.9 TWh (25.6%) and 3.3 TWh (17.2%), respectively. In total, coal and gas generation was comprised of near 89.1% of total electricity generation in the WEM.

Wind energy was the most prominent renewable energy output in 2013-14 in the BAU Scenario. It contributed over 1.5 TWh (8.1%) of total generation. Other renewable output was from biomass (0.35 TWh), landfill gas (0.18 TWh) and solar PV (0.002 TWh). In total, renewable sources took up near 10.9% of total generation in the BAU Scenario in 2013-14.

Although the BAU Scenario was not subjected to an emissions reduction target, it was applied with a carbon price of AU$24.15/t in 2013-14. The carbon price was scrapped from 2014-2015. This led to the surge of the electricity generation from black coal in 2014-15 and the increase of carbon emissions from 13.8 Mt in 2013-14 to 16.1 Mt in 2014-15 in the WEM (see Figure (6.2-b)).

In 2014-15, total energy output in the BAU Scenario remained at the similar level as total output in the 2013-14 (19.2 TWh). The energy output from black coal increased significantly, while energy output from gas sources reduced greatly in 2014-15 compared to those in 2013-14. In 2014-15, black coal, CCGT and OCGT generated approximately 13.6 TWh (71%), 2.9 TWh (15%) and 0.78 TWh (4.1%) of total energy output respectively. In total, conventional fossil fuel generation accounted for approximately 90.1% of total energy output in the BAU Scenario in 2014-15.

Energy generation from wind in 2014-15 kept the same as the generation in 2013-14 (1.5 TWh). At the same time, electricity generation from biomass (0.35 TWh) and solar PV (0.002 TWh) also remained unchanged. Energy produced from landfill gas reduced from 0.18 TWh in 2013-14 to 0.02 TWh in 2014-15. In total, renewable sources produced approximately 9.9% of total generation in 2014-15.

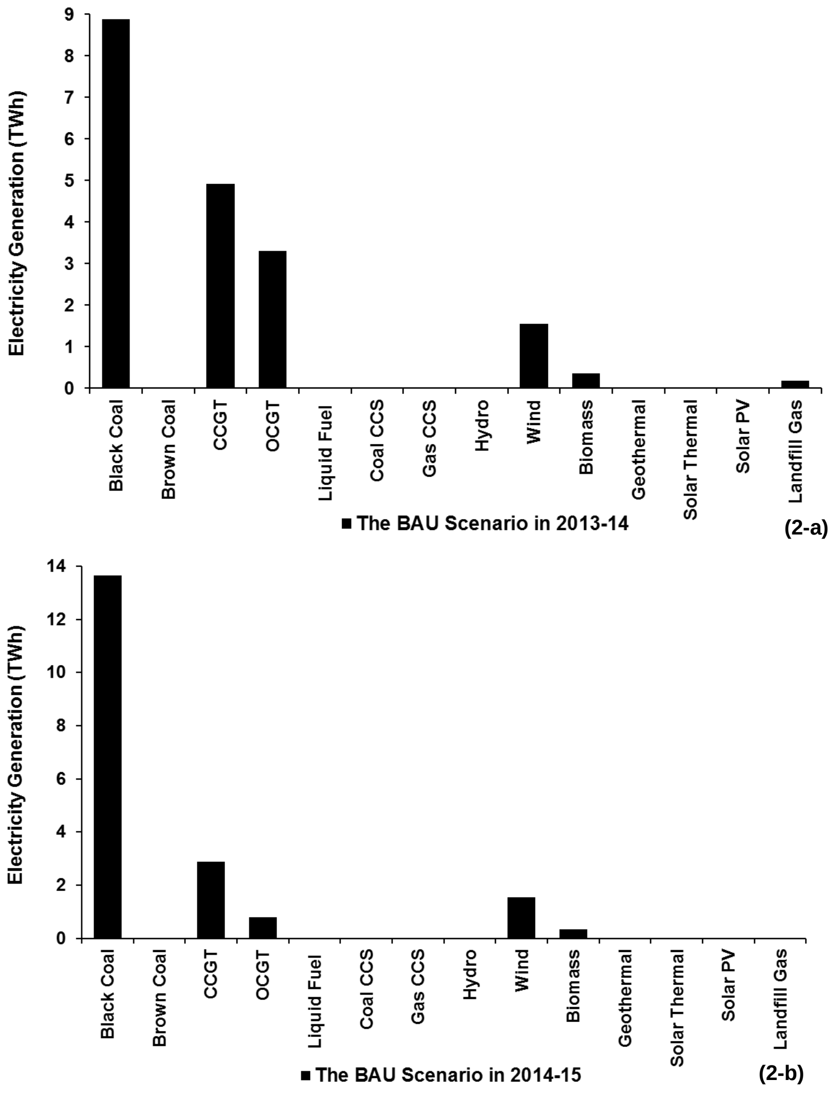



**Figure 6.2** Energy generation in the BAU Scenario in 2013-14 (2-a) and 2014-15 (2-b).

The projected generation mix in 2014-15 reflected the operation status of the WEM which was not constrained by a carbon price or carbon reduction target. It was only under the influence of the current Renewable Energy Target (33,000 GWh). Hence, it was taken as the reference year for the comparison.

### 6.2.2 Generation Results in 2019-20 and 2029-30

In the BAU Scenario, the lack of carbon emissions target led to significant amount of electricity generation still from the black coal generation in 2019-20 and 2029-30 (see Figure (6.3-a) and Figure (6.3-b)). Energy produced by the fossil fuels contributed to approximately 83.9% and 86.4% of total energy generation in 2019-20 and 2029-30 respectively. Renewable sources produced the rest of 16.1% and 13.6% of total energy in 2019-20 and 2029-30 respectively.

The black coal generation in 2019-20 and 2029-30 remained almost the same as the generation in 2014-15. It generated approximately 13.4 TWh in 2019-20 and 13.7 TWh in 2029-30, taking up near 64.8% and 57.9% of total generation in 2019-20 and 2029-30 respectively in the BAU Scenario.

The enforcement of the current Renewable Energy Target greatly promoted wind generation in the BAU Scenario from 2014-15 to 2019-20. In 2019-20, wind generation reached more than 2.8 TWh, which accounted for approximately 13.5% of total energy generation in the BAU Scenario. Compared to the generation in 2014-15, there was not obvious change in CCGT generation (2.9 TWh) in 2019-20, representing approximately 13.9% (2.5 TWh) of total generation. Energy produced from OCGT increased to 1.1 TWh (5.2%). Biomass, solar PV and landfill gas maintained their output at 0.35 TWh, 0.002 TWh and 0.18 TWh respectively.

In 2029-30, energy generation from black coal remained at the similar level as the generation in 2014-15 (13.6 TWh) in the BAU Scenario. There was a large increase of energy generation from CCGT (3.9 TWh) and OCGT (2.8 TWh) in 2029-30 compared to their generation in 2014-15. The energy generation from wind, biomass and solar PV kept at the same levels as their generation in 2019-20. The energy produced from landfill gas reduced from 0.18 TWh in 2019-20 to approximately 0.07 TWh in 2029-30.

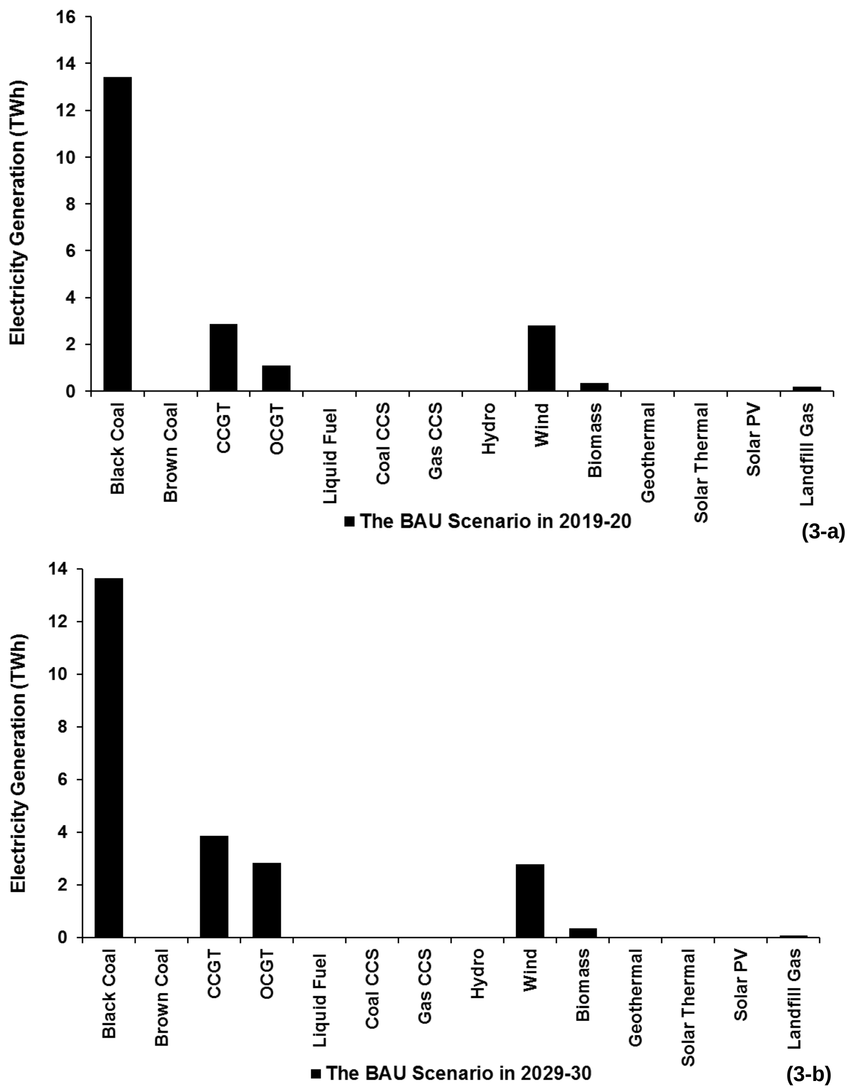



**Figure 6.3** Energy generation outputs in the BAU Scenario in 2019-20 (3-a) and 2029-30 (3-b).

The 5% Reduction Scenario, the 5%-RET Only Scenario, the 5%-26%_2030 Reduction Scenario and the 5%-26%_2030-RET Only Scenario were constrained by the same 5% carbon reduction target by 2019-20. Therefore, these scenarios had generation profiles in 2019-20 as displayed in Figure 6.4 below.

In these scenarios, fossil fuels including coal and gas remained as the dominant energy sources in 2019-20. In total, they represented approximately 79.7% of total energy generation in each of the 5% Reduction Scenario and the 5%-RET Only Scenario. They accounted for approximately 83.7% of total energy production in each of the 5%-26%_2030 Reduction Scenario and the 5%-26%_2030-RET Only Scenario in 2019-20.

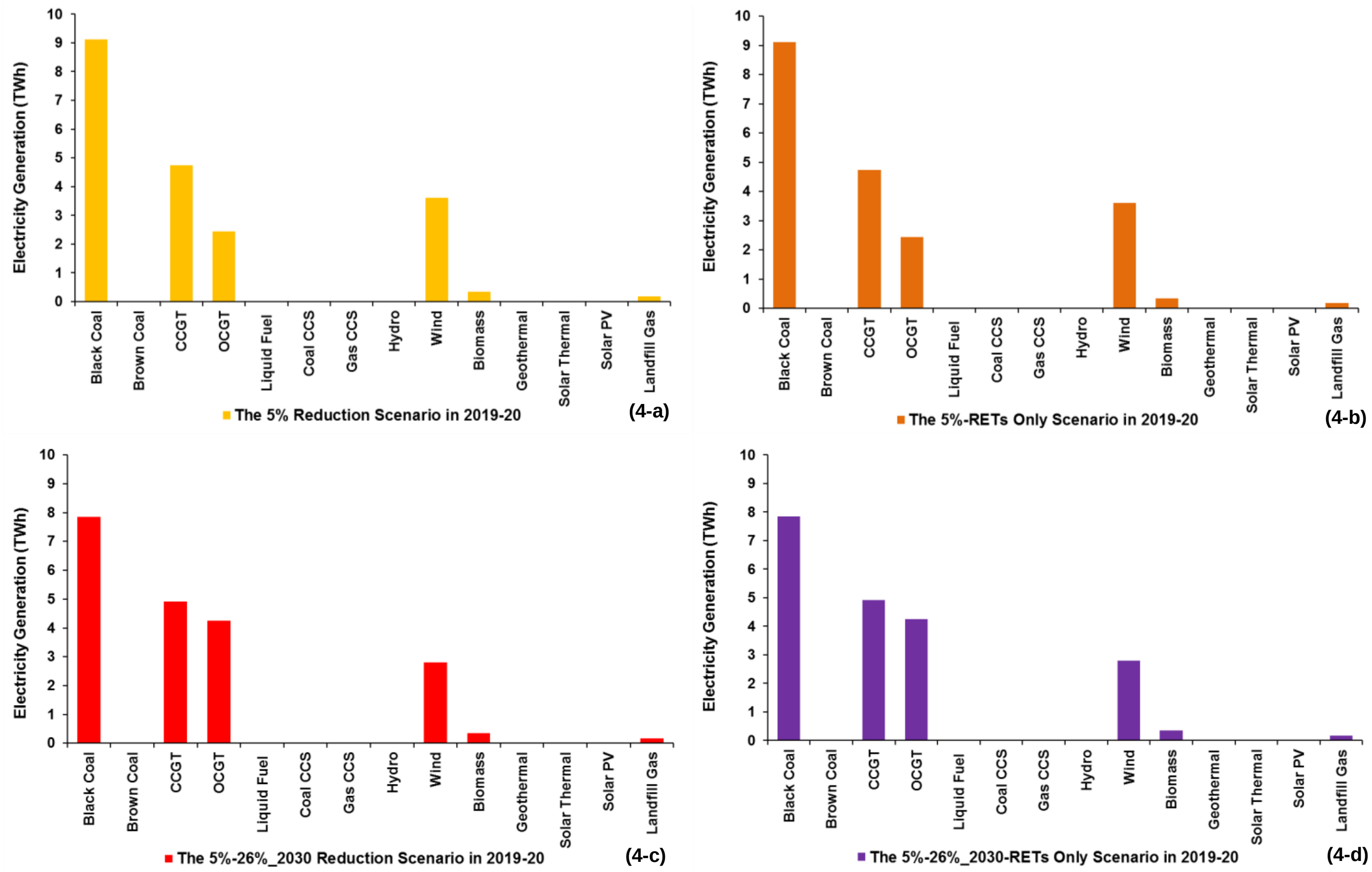



**Figure 6.4** Energy **g**eneration in the 5% Reduction Scenario (4-a), the 5%-RET Only Scenario (4-b), the 5%-26%_2030 Reduction (CGP) Scenario (4-c) and the 5%-26%_2030-RET Only Scenario (4-d) in 2019-20.

Specifically, black coal, CCGT and OCGT accounted for approximately 44.6% (9.1 TWh), 23.2% (4.7 TWh) and 11.9% (2.4 TWh) of total electricity generation respectively in each of the 5% Reduction Scenario and the 5%-RET Only Scenario in 2019-20. Black coal, CCGT and OCGT generated approximately 38.6% (7.9 TWh), 24.2% (4.9 TWh) and 20.9% (4.3 TWh) of total energy outputs respectively in each of the 5%-26%_2030 Reduction (CGP) Scenario and the 5%-26%_2030-RET Only Scenario in 2019-20.

In 2019-20, wind energy generation increased to approximately 17.7% (3.6 TWh) of total generation in each of the 5% Reduction Scenario and the 5%-RET Only Scenario. It increased to 13.8% (2.8 TWh) of total generation in each of the 5%-26%_2030 Reduction Scenario and the 5%-26%_2030-RET Only Scenario. Biomass, solar PV and landfill gas maintained their generation of approximately 0.35 TWh, 0.18 TWh and 0.002 TWh respectively in each of these scenarios as their generation in 2013-14.

In total, renewable energy accounted for approximately 20.3% in each of the 5% Reduction Scenario and the 5%-RET Only Scenario; and approximately 16.3% in each of the 5%-26%_2030 Reduction Scenario and the 5%-26%_2030-RET Only Scenario in 2019-20. The renewable energy generation was higher in these scenarios than the generation in the BAU Scenario (9.9%) in 2014-15.

Figure 6.5 below illustrates generation profiles of the 5% Reduction Scenario, the 5%-RET Only Scenario, the 5%-26%_2030 Reduction Scenario and the 5%-26%_2030-RET Only Scenario in 2029-30. In general, the generation patterns of these four scenarios are similar to each other in 2029-30.

Compared to the generation in 2019-20, these scenarios experienced significant reduction of energy generation by the black coal and growth of energy generation by the OCGT in 2029-30. Energy generation from the black coal reached approximately 1.8 TWh (8%) and 1.5 TWh (6.6%) in each of the 5% Reduction Scenario and the 5%-RET Only Scenario respectively in 2029-30. In the 5%-26%_2030 Reduction Scenario and the 5%-26%_2030-RET Only Scenario, the black coal produced approximately 2.6 TWh (11.5%) and 2.1 TWh (9.3%) of electricity respectively in 2029-30.

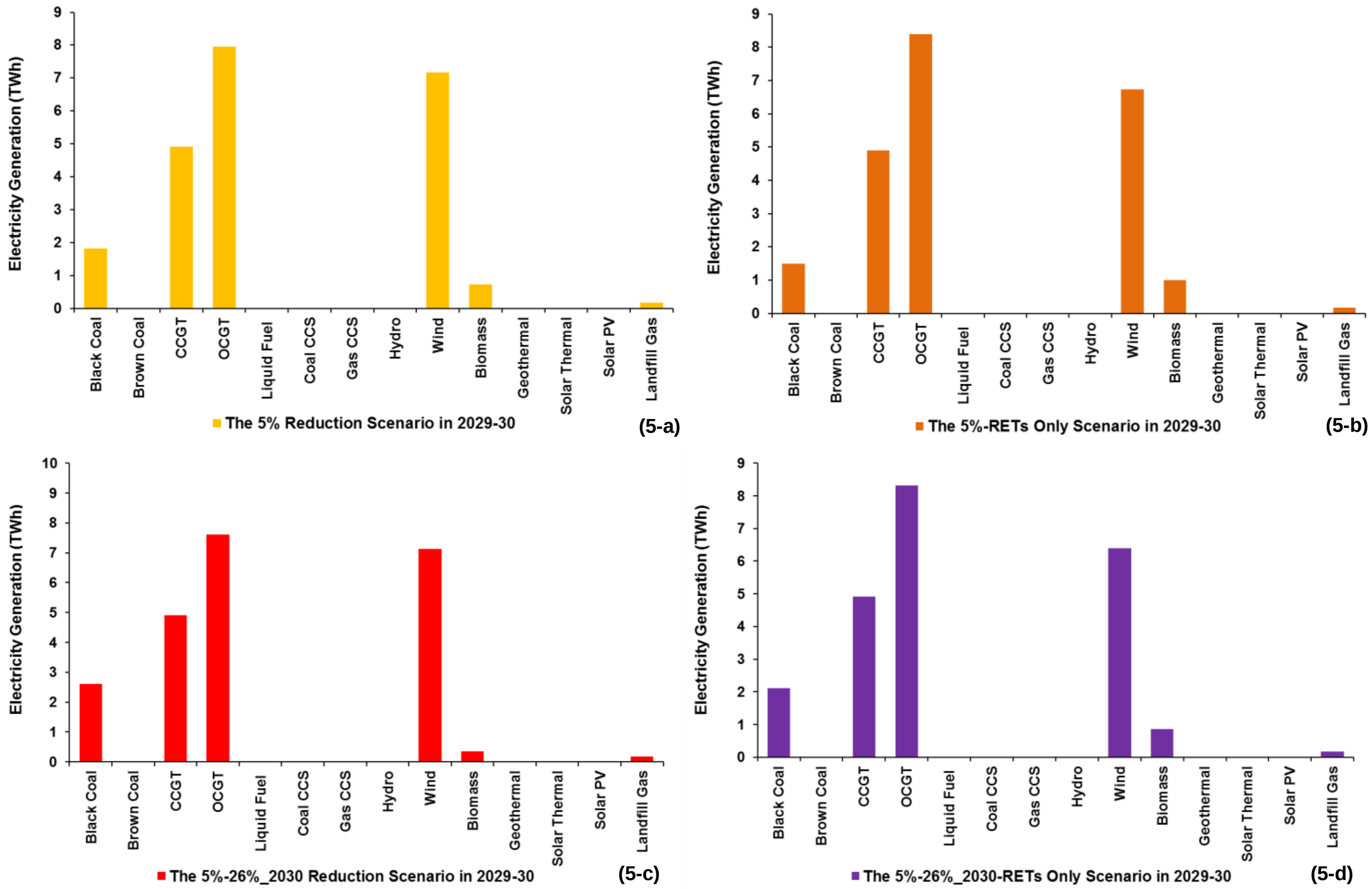



**Figure 6.5** Energy generation outputs in the 5% Reduction Scenario (5-a), the 5%-RET Only Scenario (5-b), the 5%-26%_2030 Reduction Scenario (5-c) and the 5%-26%_2030-RET Only Scenario (5-d) in 2029-30.

In 2029-30, energy generation from the OCGT reached 7.9 TWh (34.5%), 8.3 TWh (36.5%), 7.6 TWh (33.4%) and 8.4 TWh (11.5%) in the 5% Reduction Scenario, the 5%-RET Only Scenario, the 5%-26%_2030 Reduction Scenario and the 5%-26%_2030-RET Only Scenario respectively. Four scenarios resulted in the similar level of CCGT generation at approximately 4.9 TWh (21.6%) in 2029-30.

In 2029-30 wind energy generation increased largely in the 5% Reduction Scenario, the 5%-RET Only Scenario, the 5%-26%_2030 Reduction Scenario and the 5%-26%_2030-RET Only Scenario compared to the generation in 2019-20. Its generation reached 7.2 TWh (31.5%), 6.7 TWh (29.6%), 7.1 TWh (31.3%) and 6.4 TWh (28.1%) in these four scenarios respectively. Biomass energy output was 0.73 TWh (3.2%), 1.0 TWh (4.4%), 0.35 TWh (1.5%) and 0.86 TWh (3.8%) in four scenarios respectively. Energy generation from solar PV (0.002 TWh) and landfill gas (0.18 TWh) remained unchanged in these four scenarios as their generation in 2013-14.

Fossil fuels energy generation in the 5% Reduction Scenario and the 5%-RETs Only Scenario was less than the generation in the 5%-26%_2030 Reduction Scenario and the 5%-26%_2030-RETs Only Scenario in 2029-30. Fossil fuels took up approximately 64.5% (14.7 TWh) and 65.1% (14.8 TWh) in the 5% Reduction Scenario and the 5%-RETs Only Scenario respectively in 2029-2030. In the 5%-26%_2030 Reduction Scenario and the 5%-26%_2030-RETs Only Scenario, fossil fuels contributed approximately 66.4% (15.1 TWh) and 67.4% (15.3 TWh) in 2029-30.

In 2029-30, renewable energy generation accounted for approximately 35.5% (8.1 TWh), 34.9% (7.9 TWh), 33.6% (7.7 TWh) and 32.6% (7.4 TWh) in the 5% Reduction Scenario, the 5%-RET Only Scenario, the 5%-26%_2030 Reduction Scenario and the 5%-26%_2030-RET Only Scenario respectively.

Figure (6.6-a) and Figure (6.6-b) illustrate generation profiles of the 5%-CCS Only Scenario and 5%-26%_2030-CCS Only Scenario in 2019-20 respectively. Due to the application of similar constraints in these two scenarios, they had similar electricity generation patterns in 2019-20.

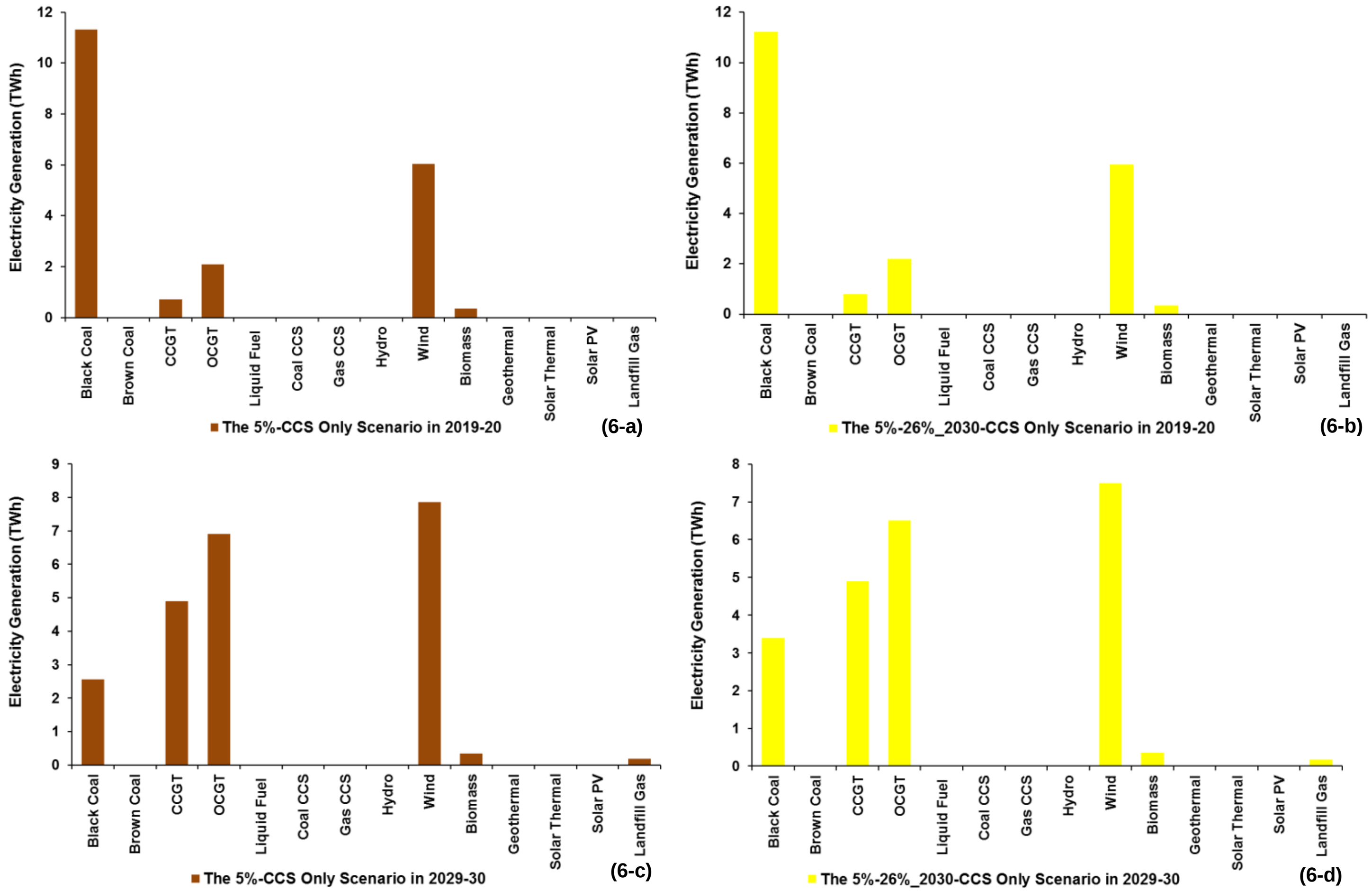



**Figure 6.6** Energy generation in the 5%-CCS Only Scenario in 2019-20 (6-a) and in 2029-30 (6-c) and in the 5%-26%_2030-CCS Only Scenario in 2019-20 (6-b) and in 2029-30 (6-d).

In 2019-20, the assumption of not allowing new renewable capacity to enter the WEM beyond 2019-20 drove considerable more wind energy generation in the 5%-CCS Only Scenario and 5%-26%_2030-CCS Only Scenario when compared to wind generation in the other scenarios with the 5%-80% Reduction Target.

At the same time, compared to the output in the BAU Scenario in 2014-15, the 5%-CCS Only Scenario and 5%-26%_2030-CCS Only Scenario had less energy generation from black coal and CCGT, and more generation from OCGT in 2019-20.

In the 5%-CCS Only Scenario, black coal, CCGT, OCGT and wind accounted for 55.2% (11.3 TWh), 3.5% (0.7 TWh), 10.2% (2.1 TWh) and 29.4% (6.0 TWh) of total generation respectively in 2019-20. In the 5%-26%_2030-CCS Only Scenario, there were 54.7% (11.2 TWh), 3.9% (0.8 TWh), 10.7% (2.2 TWh) and 29% (6.0 TWh) of total energy outputs from black coal, CCGT, OCGT and wind generation respectively in 2019-20. While the electricity generation from biomass and solar PV kept the same as their generation in 2014-15, energy generation from landfill gas reduced to zero in both scenarios in 2019-20.

Figure (6.6-c) and Figure (6.6-d) above illustrate energy generation in the 5%-CCS Only Scenario and the 5%-26%_2030-CCS Only Scenario in 2029-30. Comparing to their generation in 2019-20, both scenarios had much less energy generation from black coal and more generation from CCGT, OCGT and wind in 2029-30.

In 2029-30, black coal, OCGT and wind accounted for approximately 11.2% (2.6 TWh), 30.3% (6.9 TWh) and 34.6% (7.9 TWh) of total generation in the 5%-CCS Only Scenario respectively. In the 5%-26%_2030-CCS Only Scenario, black coal, OCGT and wind contributed to approximately 14.8% (3.4 TWh), 28.5% (6.5 TWh) and 32.8% (7.5 TWh) of total energy output respectively in 2029-30. CCGT took up approximately 21.5% (4.9 TWh) of total generation in the 5%-CCS Only Scenario and the 5%-26%_2030-CCS Only Scenario respectively in 2029-30. In both scenarios, energy generation from biomass (0.35TWh), solar PV (0.002 TWh) and landfill gas (0.2 TWh) kept the same as their generation in the 2013-14.

The results suggested that in 2029-30, the 5%-CCS Only Scenario had slightly less energy generation from fossil fuels than the generation in the 5%-26%_2030-CCS

Only Scenario. In the 5%-26%_2030-CCS Only Scenario, fossil fuels and renewables generated around 14.4 TWh (63.1%) and 8.4 TWh (36.9%) respectively in 2029-30. Fossil fuels and renewables generations reached 14.8 TWh (64.8%) and 8.0 TWh (35.2%) in the 5%-26%_2030-CCS Only Scenario respectively in 2029-30. There were no generation from the CCS in both scenarios by 2029-30.

Figure (7.7-a), Figure (7.7-c) and Figure (7.7-e) below display generation results of the 25% Reduction Scenario, the 25%-RETs Only Scenario and the 25%-CCS Only Scenario in 2019-20. In 2019-20, the black coal generation was largely replaced by the gas generation in the 25% Reduction Scenario and the 25%-RETs Only Scenario. This resulted in more carbon emissions reduction in these two scenarios than the emissions reduced in the scenarios with the 5% Reduction Target in 2019-20.

In 2019-20, black coal, CCGT and OCGT contributed to approximately 13.1% (2.6 TWh), 24.6% (4.9 TWh) and 39% (7.8 TWh) of total generation in each of the 25% Reduction Scenario and the 25%-RETs Only Scenario**.** Wind generation increased to 20.7% (4.1 TWh) of total generation. In 2019-20, both the 25% Reduction Scenario and the 25%-RETs Only Scenario had similar amount of electricity generation from biomass, solar PV and landfill gas respectively as the generation in the BAU Scenario in the 2013-14.

In the 25%-CCS Only Scenario, considerable less energy generated from gas technologies in 2019-20 than the BAU Scenario did in 2013-14 (see Figure (7.7-e)). Black coal, CCGT and OCGT took up approximately 40.4% (8.2 TWh), 6.2% (1.3 TWh) and 11.6% (2.3 TWh) of total generation respectively in the 25%-CCS Only Scenario in 2019-20. Wind energy generation increased significantly and reached 7.5 TWh (37.0%) in the 25%-CCS Only Scenario in 2019-20. Biomass generation grew to 0.99 TWh (4.9%), solar PV generation remained the same at 0.002 TWh (0.01%), and landfill gas generation decreased to zero in this scenario in 2019-20.

Figure (7.7-b), Figure (7.7-d) and Figure (7.7-f) display generation results of the 25% Reduction Scenario, the 25%-RETs Only Scenario and the 25%-CCS Only Scenario in 2029-30. Compared to their generation in 2019-20, much less energy was produced from black coal, and more energy was generated from CCGT, OCGT, wind and biomass.

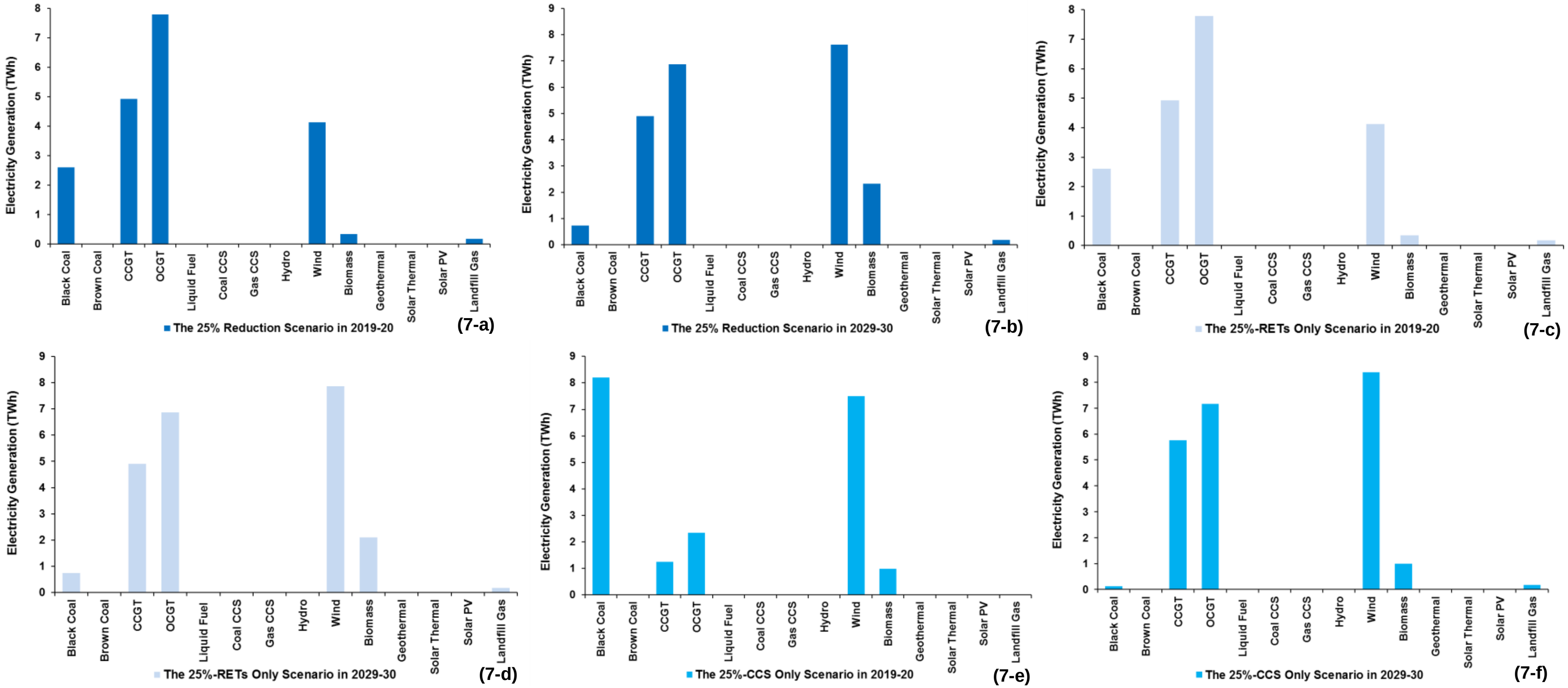



**Figure 6.7** Energy generation in the 25% Reduction Scenario in 2019-20 (7-a) and in 2029-30 (7-b), in the 25%-RETs Only Scenario in 2019-20 (7-c) and in 2029-30 (7-d), and in the 25%-CCS Only Scenario in 2019-20 (7-e) and in 2029-30 (7-f).

In 2029-30, the 25% Reduction Scenario and the 25%-RETs Only Scenario were simulated with the similar generation profiles (see Figure (6.7-b) and Figure (6.7-d)). They had similar amounts of energy generated from the CCGT (4.9 TWh) and OCGT (6.9 TWh). Black coal generated 0.72 TWh and 0.74 TWh in two scenarios respectively. Energy generation from wind reached 7.6 TWh and 2.3 TWh in the 25% Reduction Scenario and the 25%-RETs Only Scenario respectively in 2029-30. Biomass energy generation contributed to 7.9 TWh and 2.1 TWh in the 25% Reduction Scenario and the 25%-RETs Only Scenario respectively in 2029-30. The generation from solar PV and landfill gas remained unchanged since 2013-14 in both scenarios.

In 2029-30, there was less energy generation from black coal and biomass, and more generation from gas and wind in the 25%-CCS Only Scenario when compared to the generation in the 25% Reduction Scenario and the 25%-RETs Only Scenario. In the 25%-CCS Only Scenario, black coal, CCGT and OCGT generated 0.13 TWh, 5.8 TWh and 7.2 TWh of electricity respectively in 2029-30.Wind and biomass contributed to 8.4 TWh and 1.0 TWh respectively. Again, solar PV and landfill gas produced the same amounts of energy output in the 25%-CCS Only Scenario in 2029-30 as their output in 2013-14.

In 2029-30, fossil fuel energy generation accounted for much smaller portion of total generation in the 25% Reduction Scenario, the 25%-RETs Only Scenario and the 25%-CCS Only Scenario than the generation in other scenarios. In total, black coal and gas energy generation in total made up approximately 55.3% (12.5 TWh), 55.2% (12.5 TWh) and 57.8% (13.1 TWh) in three scenarios respectively in 2029-30. Particularly, most of fossil fuel energy generation was from natural gas generation. The results suggested that higher carbon emissions reduction target implemented in 2019-20 would have stronger effects on transfering energy generation from black coal to natural gas, wind and biomass sources in the WEM in the period of 2020-21 to 2029-30.

The generation results in 2019-20 indicated that the Renewable Energy Target effectively promoted the penetration of the wind energy in the WEM by 2019-20. However, without the carbon emission reduction target, there will not have enough incentive for the WEM to reduce the black coal generation between 2014-15 and 2019-20.

The 5% and 25% Reduction Targets greatly promoted the electricity generation transition from black coal to gas, and limited carbon emissions by 2019-20 in the WEM. The results showed that less generation from the black coal and more generation from gas in the scenarios with the 25% Reduction Target than those in the scenarios with the 5% Reduction Target from 2013-14 to 2019-20 in the WEM.

In addition to the Renewable Energy Target and the Carbon Emissions Reduction Targets, the assumption of the unavailability of the RETs after 2019-20 also had impact on the electricity generation results in 2019-20 in the WEM. It led to more wind generation particularly happened in the year 2019-20 in the WEM.

In 2029-30, the generation results suggested that except the BAU Scenario, the scenarios with the 5%-26%-80% Reduction Targets had the most energy generation from fossil fuel sources. The scenarios with the 25%-80% Reduction Target had the smallest portions of their generation from fossil fuels. This can be explained by the different levels of emissions reduction targets imposed on the year 2029-30 in these scenarios.

Higher emissions levels led to more energy generation from fossil fuel sources. The 5%-26%-80% Reduction Target required the WEM to emit less than 10.43 Mt in 2029-30. The 5%-80% Reduction Target and the 25%-80% Reduction Target restricted the emissions to be no more than 9.86 Mt and 7.98 Mt respectively in the WEM in 2029-30.

### 6.2.3 Generation Results in 2049-50

In 2049-50, for accommodating the growth of energy demand in the WEM, energy output from black coal largely increased in the BAU Scenario compared to the generation in 2014-15 and reached 17.5 TWh (54.3%) (see Figure 6.8). At the same time, electricity generated from CCGT and OCGT in 2049-50 also increased considerably compared to the generation in 2014-15. They accounted for near 14.4%

(4.7 TWh) and over 21.3% (6.9 TWh) of total generation in the BAU Scenario respectively in 2029-30.

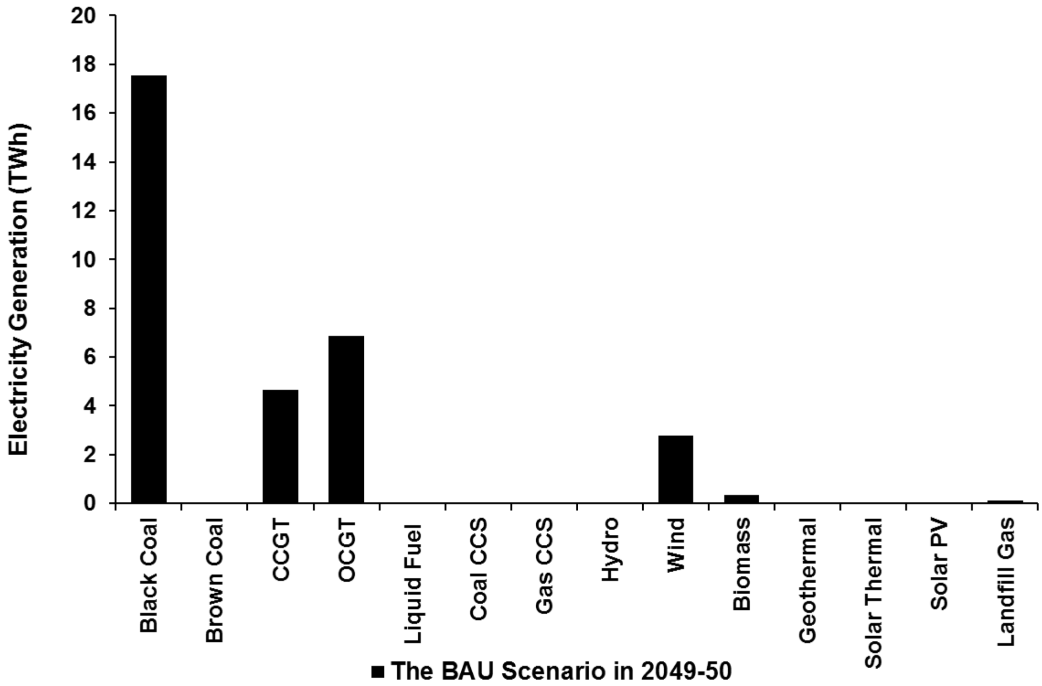



**Figure 6.8** Energy generation outputs in the BAU Scenario in 2049-50.

In the BAU Scenario, wind generation reached 2.8 TWh in 2049-50, which remained at the similar level as the generation in 2019-20. The outputs from biomass and solar PV in 2049-50 kept at similar levels as their generation in 2013-14 and 2019-20. The generation from landfill gas reduced to 0.12 TWh in 2049-50.

In the BAU Scenario, electricity generation in the WEM was projected to reach approximately 19.2 TWh, 20.7 TWh, 23.6 TWh and 32.3 TWh in 2014-15, 2019-20, 2029-30 and 2049-50 respectively. In the BAU Scenario, fossil fuels maintained their dominance in energy generation over the planning horizon. However, their generation decreased moderately from 90% in 2014-15 to 83.9% in 2019-20, and increased again to 86.4% in 2029-30 and to 87.4% in 2049-50.

In the BAU Scenario, renewable energy generation contributed to 16.1% of total electricity generation in 2019-20, reduced to 13.6% in 2029-30, and to 12.6% in 2049-50. In addition to wind, biomass, solar PV and landfill gas, there was no electricity generation from any other types of the RETs or CCS technologies in this scenario.

The generation results of the BAU Scenario indicated that without the constraint of carbon emissions reduction target, there will have no force to drive the WEM to decarbonise its electricity generation over the planning horizon.

Figure 6.9 below displays generation results of the 5% Reduction Scenario, 25% Reduction Scenario and the 5%-26%_2030 Reduction Scenario in 2049-50. In 2049-50, total electricity generation was projected to be approximately 34.1 TWh, 33.8 TWh and 34.2 TWh in the 5% Reduction Scenario, the 25% Reduction Scenario and the 5%-26%_2030 Reduction Scenario respectively. Similar generation profiles of these three scenarios in 2049-50 may be attributed to the similar constraint of 80% of carbon emissions reduction in 2049-50.

Figure 6.9 shows that energy output in the WEM was predominantly generated by the LCETs instead of conventional fossil fuel technologies in the 5% Reduction Scenario, 25% Reduction Scenario and the 5%-26%_2030 Reduction Scenario in 2049-50. Generation from black coal decreased significantly in these three scenarios, only contributing to approximately 0.17% (0.06 TWh), 0.15% (0.05 TWh) and 0.17% (0.06) of total energy generation respectively in 2049-50. There was also large reduction from CCGT and OCGT energy generation in 2049-50 compared to their generation in 2019-20. CCGT and OCGT energy generation represented approximately 6.1% (2.1 TWh) and 4.2% (1.4 TWh) of total generation respectively in the 5% Reduction Scenario, approximately 6.3% (2.1 TWh) and 4.5% (1.5 TWh) of total generation respectively in the 25% Reduction Scenario, and approximately 6.0% (2.1 TWh) and 4.1% (1.4 TWh) of total generation in the 5%-26%_2030 Reduction Scenario respectively.

In the 5% Reduction Scenario, 25% Reduction Scenario and the 5%-26%_2030 Reduction Scenario, there was prominent growth of energy generation from the coal CCS technologies in 2049-50 (see Figure 6.9).

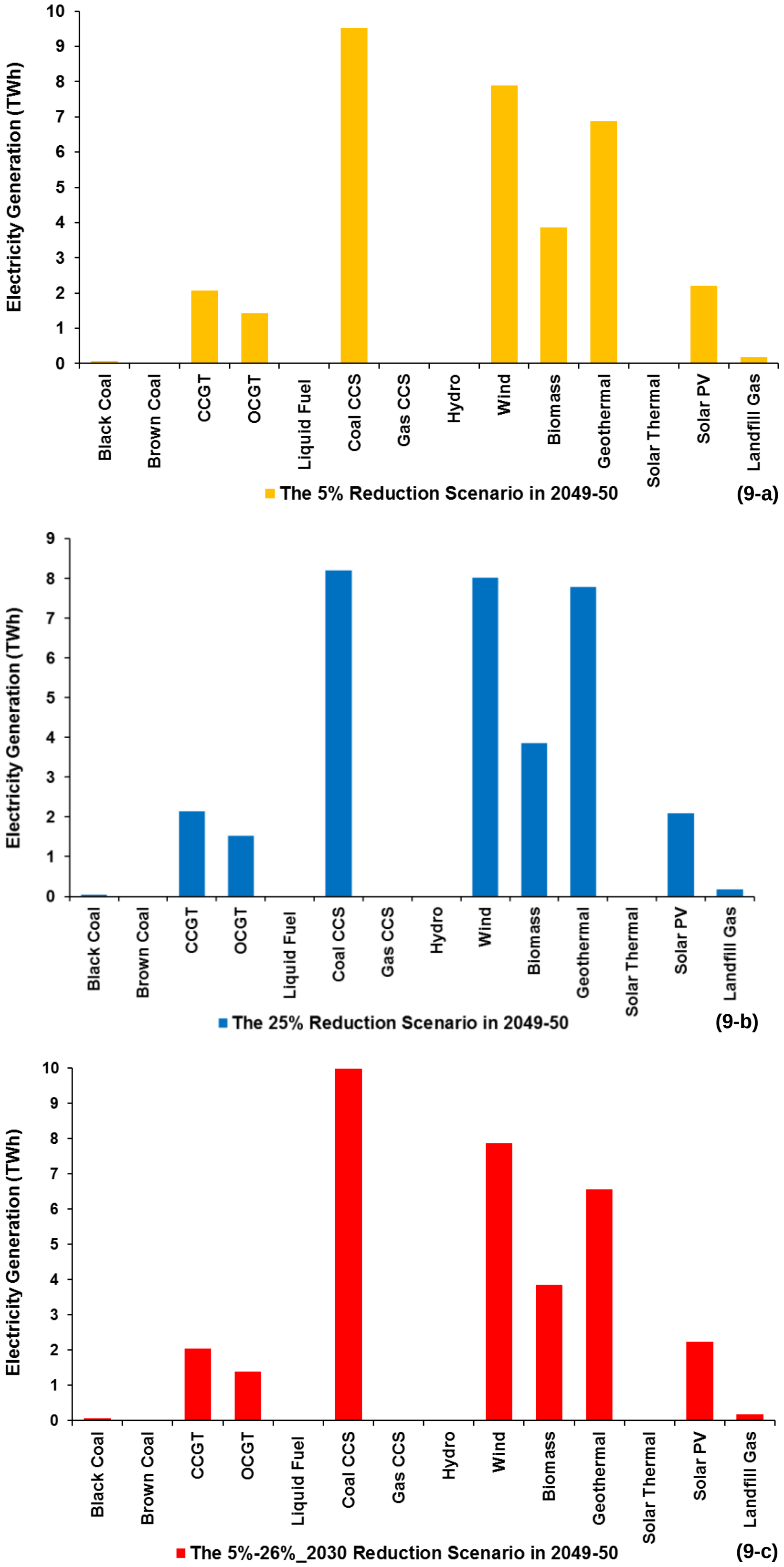



**Figure 6.9** Energy generation in the 5% Reduction Scenario (9-a), 25% Reduction Scenario (9-b) and the 5%-26%_2030 Reduction Scenario (9-c) in 2049-50.

The generation of coal CCS technologies in the 5% and 25% Reduction Scenarios both started in the year of 2040-41. Coal CCS generation commenced in the 5%-26%_2030 Reduction Scenario in the year of 2041-42, one year later than in the 5% and 25% Reduction Scenarios. The electricity generation from the coal CCS reached over 9.5 TWh (28.0%) in the 5% Reduction Scenario, approximately 8.2 TWh (24.2%) in the 25% Reduction Scenario and approximately 10 TWh (29.2%) in the 5%-26%_2030 Reduction Scenario.

Geothermal started its first generation in the 5% Reduction Scenario, 25% Reduction Scenario and the 5%-26%_2030 Reduction Scenario in 2034-35, 2032-33 and 2035-36 respectively. Its generation reached approximately 6.9 TWh (20.2%), 7.8 TWh (23%) and 6.6 TWh (19.2%) in three scenarios respectively in 2049-50.

The energy generation also considerably increased from wind, biomass, and solar PV generation in the 5% Reduction Scenario, 25% Reduction Scenario and the 5%-26%_2030 Reduction Scenario. In 2049-50, their energy generation was near 7.9 TWh (23.2%), 3.9 TWh (11.3%), and 2.2 TWh (6.5%) in the 5% Reduction Scenario respectively; approximately 8.0 TWh (23.7%), 3.9 TWh (11.4%), and 2.1 TWh (6.2%) in the 25% Reduction Scenario respectively; and approximately 7.9 TWh (23%), 3.9 TWh (11.3%), and 2.2 TWh (6.5%) in the 5%-26%_2030 Reduction Scenario respectively.

In the 5% Reduction Scenario, the WEM had approximately 10.4% of energy generation in total from conventional fossil fuel sources, 61.6% from renewable sources, and 28% from CCS generation in 2049-50. In the 25% Reduction Scenario, conventional fossil fuels, renewable sources, and CCS accounted for 11%, 64.8% and 24.2% of electricity generation respectively in 2049-50. In the 5%-26%_2030 Reduction Scenario, approximately 10.2% of generation from conventional fossil fuels, 60.6% from renewable sources and 29.2% from coal CCS generation in 2049-50. These generation profiles suggested that under the constraint of carbon emission reduction target, the electricity generation switched away from conventional fossil fuels and heavily relied on the LCETs at the end of planning horizon in the WEM.

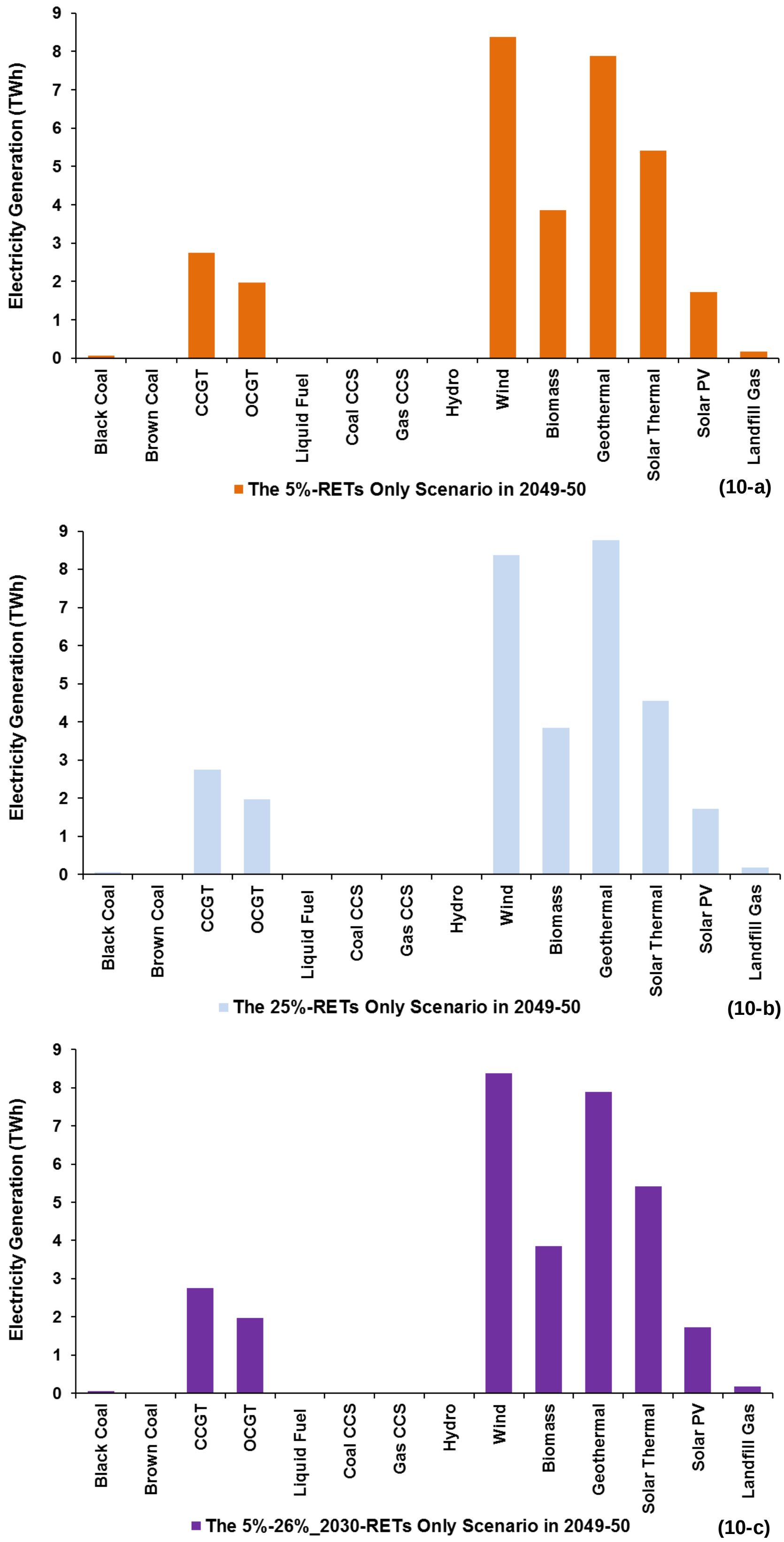



**Figure 6.10** Energy generations in the 5%-RETs Only Scenario (10-a), the 25%-RETs Only Scenario (10-b) and the 5%-26%_2030-RETs Only Scenario (10-c) in 2049-50.

In 2049-50, the renewables became the major sources for electricity generation in the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios. Three scenarios had similar patterns of energy generation in 2049-50 (see Figure 6.10). Approximately 14.8% of energy output in total was produced by black coal (0.06 TWh) and gas (CCGT: 2.75 TWh and OCGT: 2.0 TWh) in each of the three scenarios in 2049-50. Approximately 85.2% of energy output was from renewable sources in three scenarios respectively in 2049-50. They also had similar amount of energy generated from wind (8.4 TWh), biomass (3.85 TWh), solar PV (1.7 TWh) and landfill gas (0.18 TWh) in 2049-50.

Geothermal and solar thermal generation first occurred in the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios between 2030-31 and 2049-50. Geothermal commenced its generation in 2032-33 in the 5%- and 5%-26%_2030-RETs Only Scenarios and in 2030-31 in the 25%-RETs Only Scenario. Solar thermal started its generation in year 2042-43 in the 5%- and 25%-RETs Only Scenarios and in year 2043-44 in the 5%-26%_2030-RETs Only Scenario.

Geothermal and solar thermal outputs reached 7.9 TWh (24.5%) and 5.4 TWh (16.8%) respectively in each of the 5%- and 5%-26%_2030-RETs Only Scenarios, and 8.8 TWh (27.2%) and 4.6 TWh (14.1%) respectively in the 25%-RETs Only Scenario respectively in 2049-50.

In 2049-50, the dominance of renewable energy generation in the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios was largely due to the carbon emission targets and the assumption of only the RETs available as the LCETs to enter the WEM generation portfolio after 2019-20.

Figure 6.11 below displays the electricity generation in the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios in 2049-50. These scenarios had relatively similar generation patterns with a substantial reduction of energy generation from conventional fossil fuels in 2049-50. There was no energy generation from conventional black coal in these scenarios in 2049-50. CCGT and OGCT generation also reduced to small amounts, altogether only representing approximately 2.8% (1.0 TWh), 3.4% (1.2 TWh) and 2.6% (1.0 TWh) of total energy generation in the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios respectively in 2049-50.

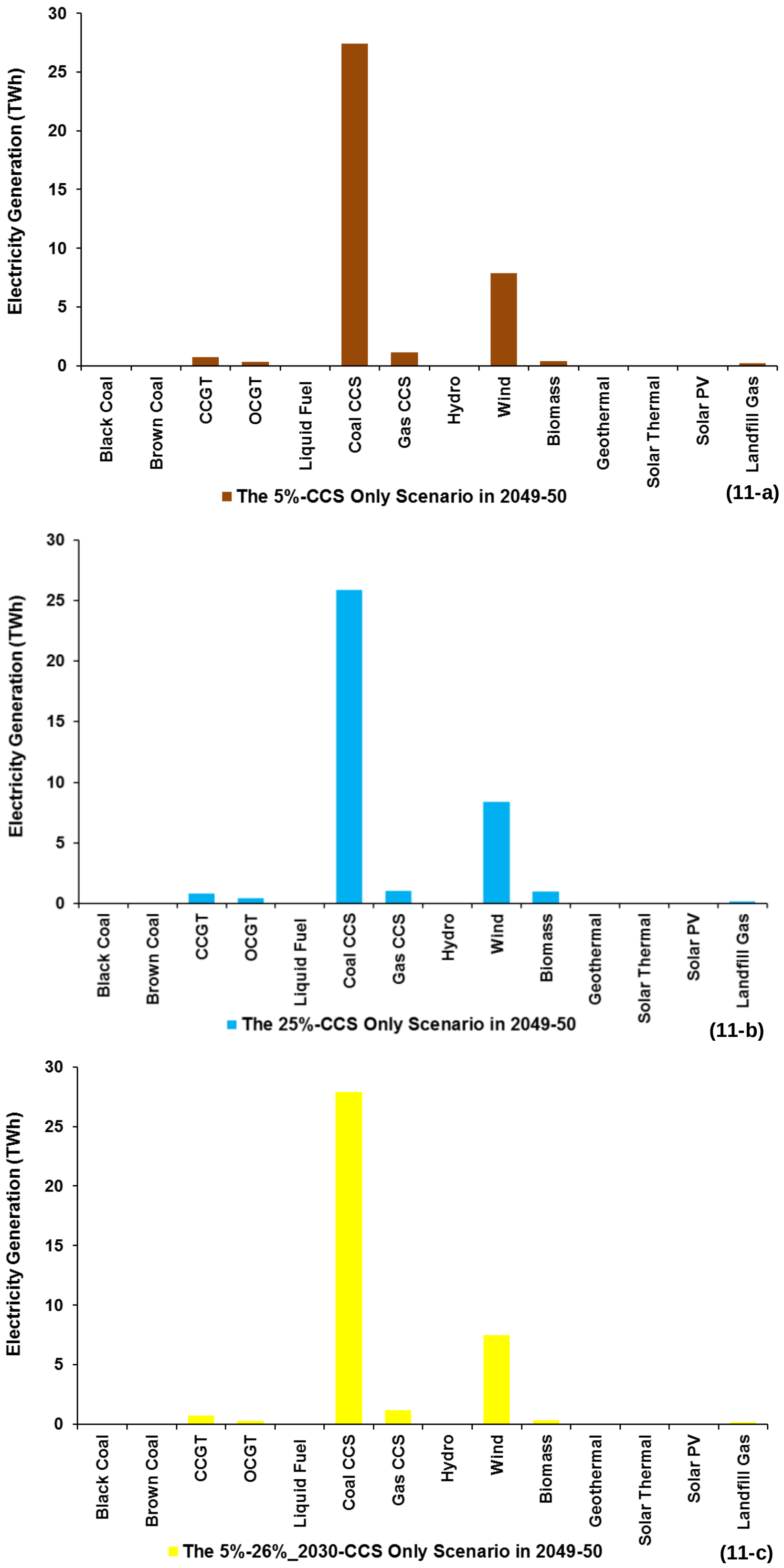



**Figure 6.11** Energy generation in the 5%-CCS Only Scenario (11-a), the 25%-CCS Only Scenario (11-b) and the 5%-26%_2030-CCS Only Scenario (11-c) in 2049-50.

In 2049-50, CCS generation took up a substantial proportion of total generation in the WEM in the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios. In the 5%-CCS Only Scenario, coal CCS and gas CCS generation accounted for approximately 72.2% (27.4 TWh) and 3% (1.1 TWh) of total generation respectively in 2049-50. In the 25%-CCS only Scenario, coal CCS and gas CCS generation contributed to approximately 68.6% (25.9 TWh) and 2.7% (1.0 TWh) of total generation respectively. In 5%-26%_2030-CCS Only Scenario, coal CCS and gas CCS generation made up approximately 73.3% (27.9 TWh) and 3.1% (1.2 TWh) of total generation respectively.

Coal CCS started its generation earlier in the WEM compared to gas CCS. Coal CCS technologies commenced the generation in the 5%-CCS Only Scenario in 2031-32, in the 25%-CCS Only Scenario in 2030-31 and in the 5%-26%_2030-CCS Only Scenario in 2032-33. Gas CCS technologies began generation in 2048-49 in three scenarios, almost at the end of planning period.

Due to the entry restriction of the RETs after 2019-20 in the CCS Only Scenarios, there was no new type of renewable generation entering the WEM in the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios after 2019-20. Energy generation from biomass, solar PV and landfill gas kept their generation levels as the ones in 2013-14 in the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios. They had more electricity generation from wind than in 2019-20, reaching approximately 7.9 TWh (20.7%), 8.4 TWh (22.2%) and 7.5 TWh (19.7%) respectively in 2049-50.

## 6.3 Generation Capacity Results

This section reports capacity installation results of each scenario in the WEM. The capacity in the WEM experienced an expansion to accommodate the growth of energy demand over the planning period of 2013-14 to 2049-50.

Figure 6.12 shows capacity installed in 2013-14, 2014-15, 2019-2020, 2029-30 and 2049-50 for each scenario in the WEM. In 2013-14, a uniform amount of approximately 6.0 GW of capacity was installed across all scenarios. In 2014-15, after the removal of the carbon price, the installed capacity in the 5% and 25% Reduction Scenarios, the 5%- and 25%-RETs Only Scenarios and the 5%- and 25%-

CCS Only Scenario increased to approximately 6.1 GW. The installed capacity in the BAU Scenario and the 5%-26%_2030 Scenarios remained at approximately 6.0 GW.

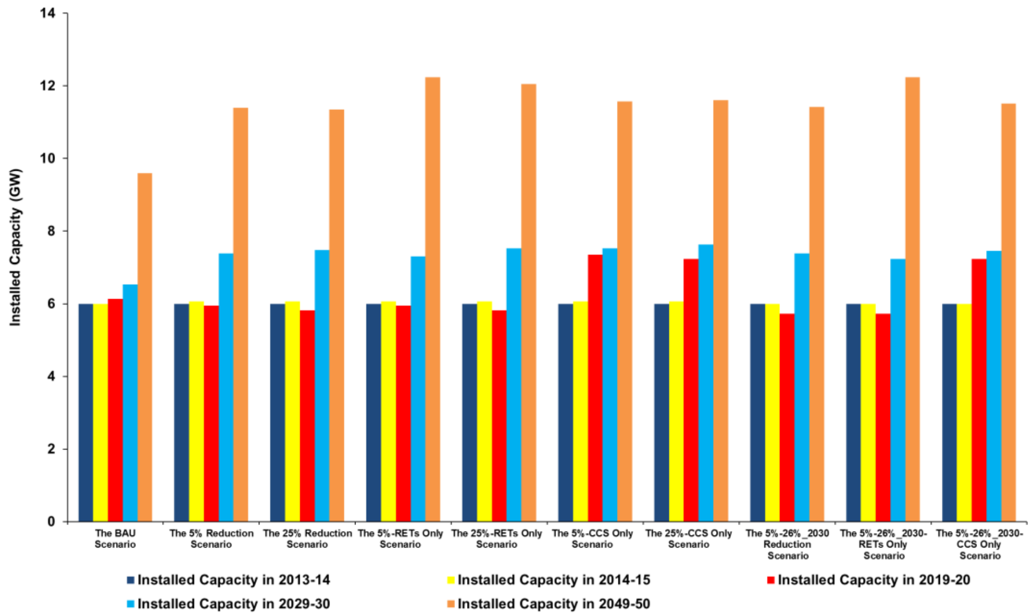



**Figure 6.12** Total installed capacity by scenario, in 2013-14, 2014-15, 2019-20, 2029-30 and 2049-50.

Except the CCS Only Scenarios, the installed capacity in 2019-20 in the other scenarios did not present a big difference from their installed capacity in 2014-15. The installed capacity in the 5%, 25% and 5%-26%_2030 Reduction Scenarios and the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios experienced a small amount of reduction compared to their installed capacity in 2014-15. This can be explained further by examining the capacity built and retired in the period of 2013-14 to 2019-20 in these scenarios (see Figure 6.13).

Between 2013-14 and 2019-20, there were approximately 360 MW of new capacity built in the BAU Scenario. The retirement of black coal capacity was 220 MW. This resulted in a slightly increase of installed capacity in the BAU Scenario from 6.0 GW in 2013-14 to be near 6.13 GW in 2019-20. In the period of 2013-14 to 2019-20, the capacity retired in the 5%, 25% and 5%-26%_2030 Reduction Scenarios, and the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios exceeded the capacity built in this period. This led to a small reduction of installed capacity in these scenarios in 2019-20 when compared to the installed capacity in 2013-14 (see Figure 6.13).

In the period of 2013-14 to 2019-20, new capacity added to the WEM in the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios reached approximately 1.85 GW, 2.1 GW and 1.74 GW respectively. This was due to the rapid pick up of wind capacity in the 2019-20. In the same period, capacity retired accumulated at near 0.49 GW, 0.85 GW and 0.5 GW respectively in these scenarios. This resulted in higher level of installed capacity in these scenarios in 2019-20 than installed in 2013-14, reaching near 7.3 GW, 7.2 GW and 7.2 GW respectively (see Figure 6.12).

All scenarios had increased installed capacity in 2029-30 compared to their installed capacity in 2019-20. Except the BAU scenario, the other scenarios had fairly similar level of installed capacity in 2029-30 (see Figure 6.12). In 2029-30, installed capacity in the BAU Scenario, the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios reached approximately 6.54 GW, 7.53 GW, 7.51 GW and 7.46 GW respectively.

The installed capacity in the 5%, 25% and 5%-26%_2030 Reduction Scenarios, and the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios largely increased in 2029-30 compared to their installed capacity in 2019-20. The 5%, 25% and 5%-26%_2030 Reduction Scenarios installed with 7.39 GW, 7.48 GW and 7.38 GW of capacity respectively in 2029-30. The installed capacity reached 7.31 GW, 7.53 GW and 7.24 GW in the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios respectively in 2029-30**.**

Figure 6.13 illustrates that the BAU Scenario was installed with the lowest amount of capacity (9.6 GW) in 2049-50, representing approximately 60.1% increase compared to its installed capacity in 2013-14.

The 5%, 25% and 5%-26%_2030 Reduction Scenarios had similar amount of installed capacity at approximately 11.4 GW in 2049-50. The installed capacity in the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios reached approximately 11.6 GW each in 2049-50. The installed capacity in these scenarios in 2049-50 represented approximately 90% growth of their installed capacity in 2013-14.

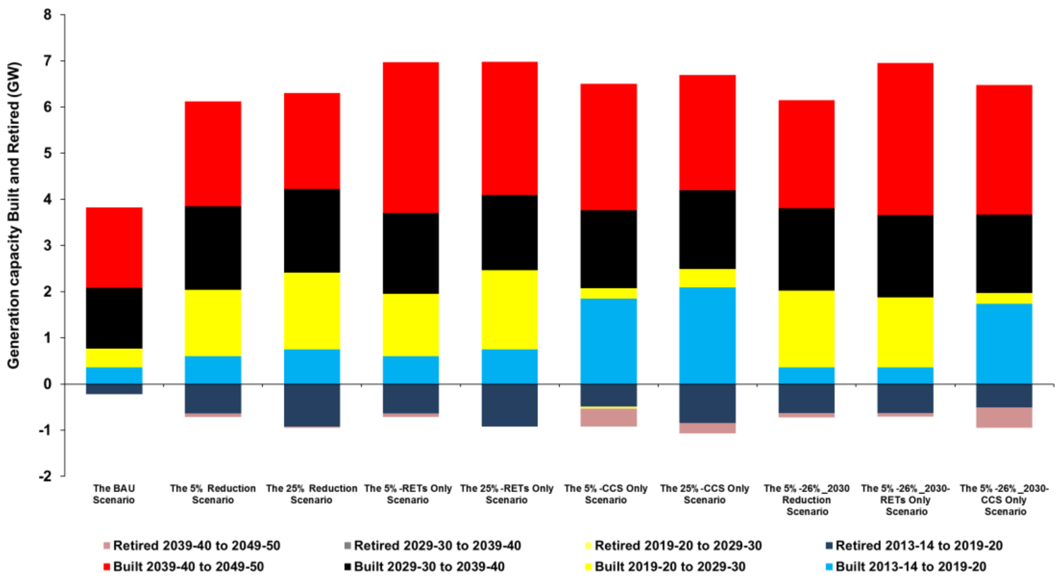



**Figure 6.13** Retired and new built generation capacity by scenario, in the WEM.

The 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios had the largest amount of installed capacity in 2049-50 among all scenarios. Their installed capacity reached approximately 12.2 GW, accounting for near 103% more than their installed capacity in 2013-14.

In the BAU scenario, capacity retirement only occurred to black coal (220 MW) in the period of 2013-14 to 2019-20 (see Figure 6.13). More capacity was built in the period of 2030-31 to 2049-50 (3.1 GW) than was built in the period of 2013-14 to 2029-30 (0.77 GW) in this scenario, resulting in 3.6 GW of capacity gain at the end of the planning period.

In addition to the BAU Scenario, the other scenarios also had more capacity installed in the period of 2030-31 to 2049-50 than installed in the period of 2013-14 to 2029-30 (see Figure 6.13). In total, on average near 6.2 GW of capacity was installed in each of the 5%, 25% and 5%-26%_2030 Reduction Scenarios**,** approximately 7.0 GW of capacity was installed in each of the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios**,** and 6.6 GW of capacity was built in each of the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios.

Apart from the BAU Scenario, mostly retired capacity in other scenarios happened in the period of 2013-14 to 2019-20 (see Figure 6.13). A small portion of capacity also retired in the period of 2040-41 to 2049-50. No capacity retirement happened between 2030-31 and 2039-40. Between 2020-21 and 2029-30, capacity retirement only happened to the 5%-CCS Only Scenario with a small amount of 41 MW (see Figure 6.13). Except the BAU Scenario, the 5%-26%_2030-RETs Only Scenario had the least amount of capacity retired (702 MW), while the 25%-CCS Only Scenario had the largest amount of capacity retired (1070 MW).

Figure 6.14 displays installed capacity in each scenario by technology in 2013-14. It shows that each scenario had the same portfolio of capacity installed in 2013-14. Total installed capacity was near 6.0 GW in each scenario, including approximately 29.7% of black coal, 9.4% of CCGT, 41.6% of OCGT, 10.1% of liquid fuel, 8.0% of wind, 0.7% of biomass, 0.2% of solar PV and 0.3% of landfill gas. In total, fossil fuel capacity was comprised of near 91% of total installed capacity, while renewable capacity only accounted for approximately 9% of total installed capacity at the beginning of planning period in the WEM.

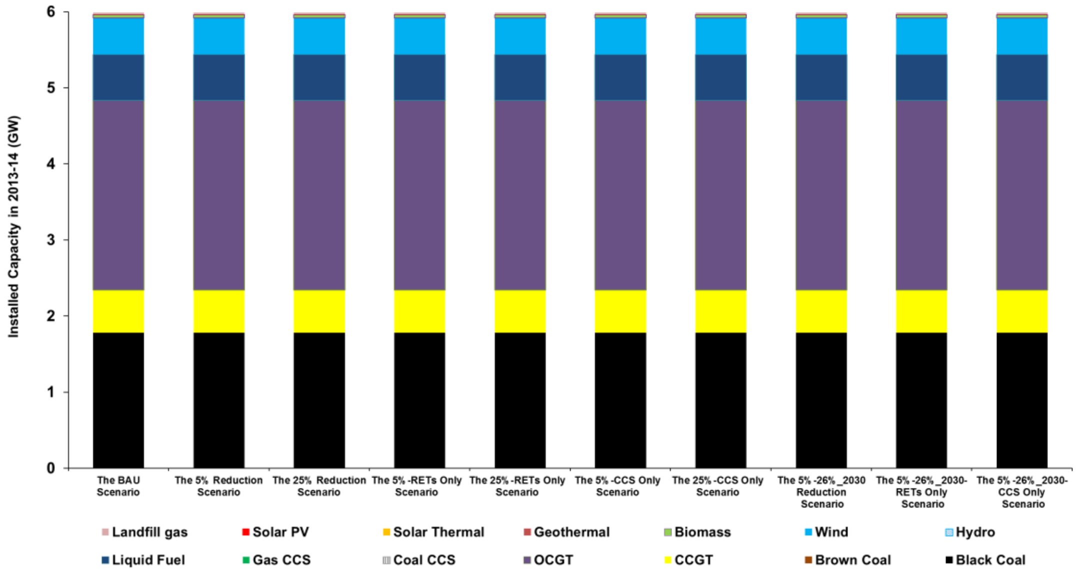



**Figure 6.14** Installed capacity in each scenario by technology, in 2013-14.

In 2019-20, the capacity portfolio in each scenario did not differ significantly from that in 2013-14, except the black coal and wind capacity (see Figure 6.15). The BAU Scenario had the least amount of reduction in black coal capacity in 2019-20, which decreased from approximately 1.78 GW to 1.56 GW. The black coal capacity in the

5% and 5%-26%_2030 Reduction Scenarios and the 5%- and 5%-26%_2030-RETs Only Scenarios reduced from 1.78 GW to approximately 1.15 GW in 2019-20. The black coal capacity dropped from 1.78 GW to 0.86 GW in the 25% Reduction Scenario and the 25%-RETs Only Scenario in 2019-20. The black coal capacity in the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios was approximately 1.29 GW, 0.93 GW and 1.28 GW respectively in 2019-20.

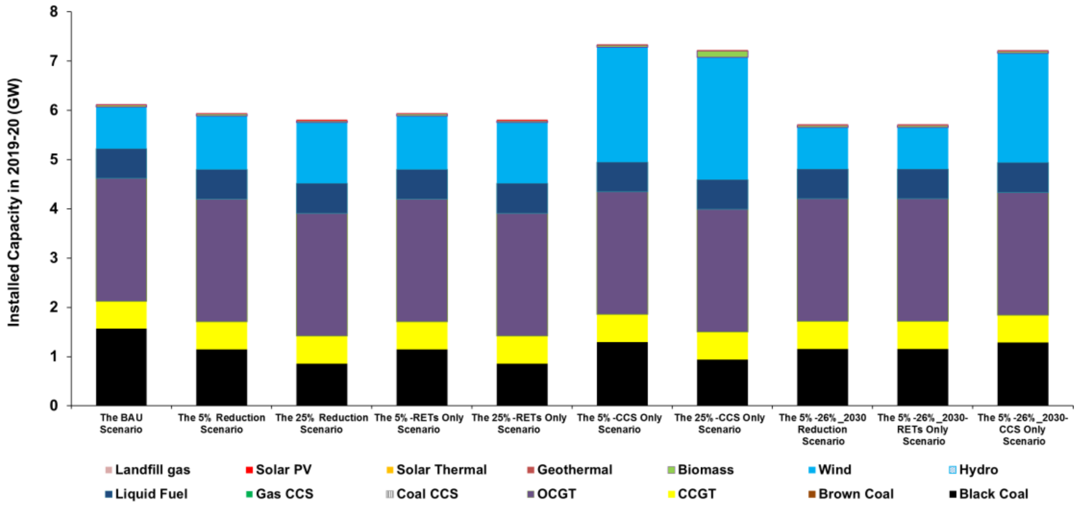



**Figure 6.15** Capacity installed in each scenario by technology, in 2019-20.

Wind capacity increased across all scenarios in 2019-20 compared to its installed capacity in 2013-14. It grew from near 0.48 GW in 2013-14 to approximately 0.85 GW in 2019-20 in the BAU Scenario, the 5%-26%_2030 Reduction Scenario and the 5%-26%_2030-RETs Only Scenario. Wind capacity in the 5% Reduction scenario and the 5%-RETs Only Scenario reached approximately 1.1 GW in 2019-20. In both the 25% Reduction Scenario and the 25%-RETs Only Scenario, wind capacity grew to be more than 1.2 GW in 2019-20. The wind capacity increased the most in the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios, reaching approximately 2.3 GW, 2.5 GW and 2.2 GW respectively in 2019-20.

In 2019-20, new biomass capacity was only added to the 25%-CCS Only Scenario, increasing from 0.04 GW in 2013-14 to be approximately 0.13 GW. The other types of capacity in 2019-20 including CCGT, OCGT, liquid fuel, solar PV and landfill gas remained unchanged as the ones in 2013-14 in all scenarios.

Between 2013-14 and 2019-20, no new type of energy technology entered the WEM across all scenarios. In 2019-20, fossil fuel capacity was still the majority (63.5% - 85.1%) in all scenarios, renewable capacity increased but remained relatively small portions of total installed capacity in each scenario, except in the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios (31.7% - 36.5%).

Figure 6.16 below displays installed capacity in each scenario by technology in 2029-30. The black coal, CCGT, liquid fuel, wind, solar PV and landfill gas maintained their levels of installed capacity in 2029-30 as their levels in 2019-20 in each scenario.

There was a small increase of the installed OCGT capacity in each scenario in 2029-30. The installed biomass capacity also increased in the 5% Reduction Scenario (0.094 GW), the 25% Reduction Scenario (0.32 GW), the 5%-RETs Only Scenario (0.13 GW), the 25%-RETs Only Scenario (0.29 GW), the 25%-CCS Only Scenario (0.13 GW) and the 26%_2030-RETs Only Scenario (0.13 GW) in 2029-30 compared to their installed capacity in 2019-20.

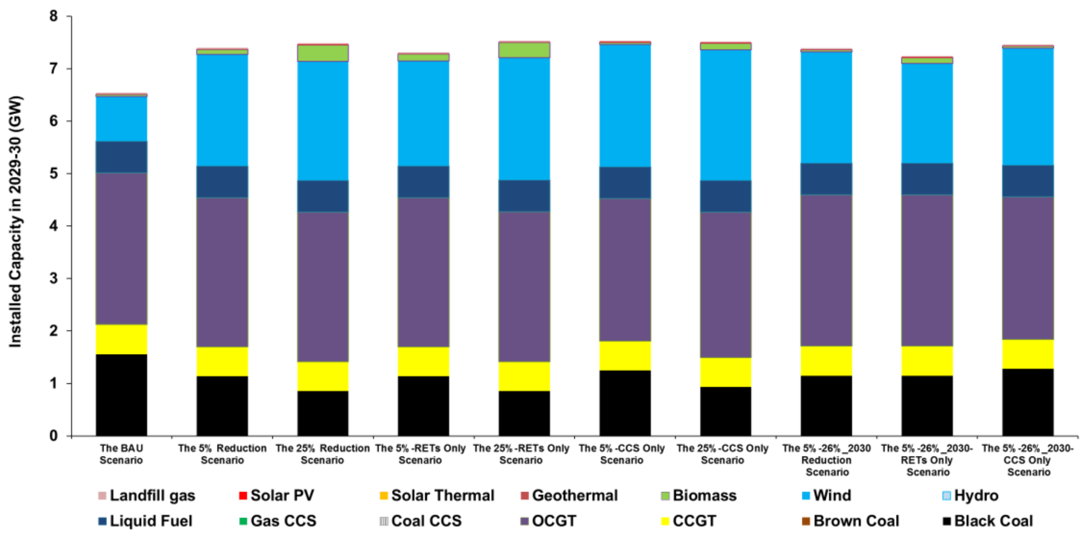



**Figure 6.16** Installed capacity in each scenario by technology, in 2029-30.

In 2049-50, the installed capacity of the LCETs including the RETs and CCS technologies increased substantially in all scenarios except in the BAU Scenario (See Figure 6.17). In the BAU Scenario, fossil fuel capacity still took up more than 90.5% of total installed capacity and only near 9.5% of capacity from renewable sources in

2049-50. Specifically, the installed OCGT capacity largely increased compared to that in 2019-20 and reached 5.5 GW in 2049-50, representing near 57.4% of total installed capacity in the BAU Scenario. There was no new type of energy technology entering the market in the BAU scenario over the planning period. It was the only scenario which new black coal capacity was added between 2020-21 and 2049-50. The black coal capacity grew from near 1.78 GW in 2013-14 to 2.0 GW in 2049-50. The other existing types of capacity remained unchanged as their installation in 2019-20.

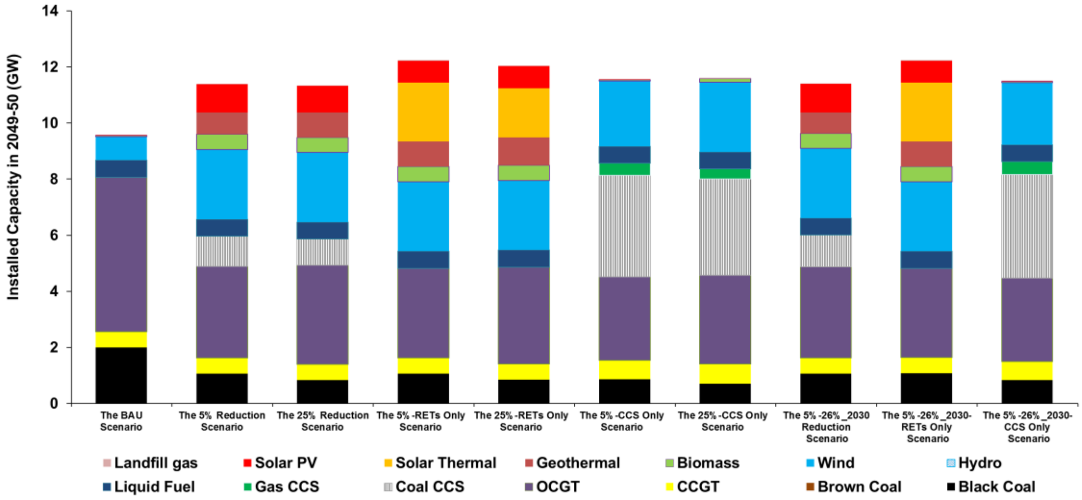



**Figure 6.17** Installed capacity in each scenario by technology, in 2049-50.

In the 5%, 25% and 5%-26%_2030 Reduction Scenarios, the coal CCS and geothermal technologies entered the WEM by the end of simulation period. In 2049-50, there were approximately 1.1 GW of installed coal CCS capacity in 5% and 5%-26%_2030 Reduction Scenarios respectively, and approximately 0.94 GW of installed coal CCS capacity in the 25% Reduction Scenario. Geothermal capacity in the 5%, 25% and 5%-26%_2030 Reduction Scenarios reached near 0.79 GW, 0.89 GW and 0.75 GW respectively in 2049-50.

There were moderate growths of OCGT, wind and solar PV capacity in 5%, 25% and 5%-26%_2030 Reduction Scenarios in 2049-50. In the 5% Reduction Scenario, the installed capacity in 2049-50 contained near 48.1% of conventional fossil fuel capacity and 51.9% of the LCETs capacity, including 9.6% of CCS capacity and 42.3% of renewable capacity. In 2049-50, the installed capacity in the 25%

Reduction Scenario was comprised of approximately 48.8% of conventional fossil fuels capacity and 51.2% of the LCETs capacity, including 8.2% of CCS capacity and 43% of renewable capacity. The conventional fossil fuel capacity and the LCET capacity accounted for approximately 47.9% and 52.1% of total installed capacity in the 5%-26%_2030 Reduction Scenario, including approximately 10% of CCS capacity and 42.1% of renewable capacity in 2049-50.

Solar thermal capacity was only installed the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios in the WEM (see Figure 6.17). It entered the market in year 2042-43 in the 5%- and 25%-RETs Only Scenarios, and reached near 2.1 GW and 1.75 GW in two scenarios respectively in 2049-50. In the 5%-26%_2030-RETs Only Scenario, solar thermal capacity was first added in 2043-44. It grew to approximately 2.1 GW in 2049-50.

Geothermal capacity entered the market in 2034-35 in the 5% Reduction Scenario and reached approximately 0.79 GW in 2049-50. It entered the 25% Reduction Scenario, the 5%-RETs Only Scenario, the 25%-RETs Only Scenario, the 26%_2030 Reduction Scenario and the 26%_2030-RETs Only Scenario in 2032-33, 2032-33, 2030-31, 2035-36 and 2032-33 respectively, and reached 0.89 GW, 0.9 GW, 1.0 GW, 0.75 GW and 0.9 GW of installed capacity respectively in 2049-50.

Wind capacity almost doubled and reached 2.48 GW and solar PV capacity increased to approximately 0.78 GW on average in each of the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios in 2049-50 compared to those in 2019-20. There was an increase of installed OCGT capacity in these scenarios, while CCGT, liquid fuel and landfill capacity kept at similar levels in 2049-50 as their installation in 2029-30. In total, conventional fossil fuel capacity accounted for approximately 44.3% and renewable capacity took up near 55.7% of total installed capacity in each of the 5%- and 5%-26%_2030-RETs Only Scenarios. In the 25%-RETs Only Scenario, conventional fossil fuels and renewables contributed to approximately 45.4% and 54.6% of total installed capacity respectively in 2049-50.

In the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios, no new renewable capacity installed after 2019-20. The existing renewable capacity including wind, biomass, solar PV and landfill gas capacity remained at the same levels as their installation in 2019-20. Meanwhile, there was no new geothermal or solar thermal capacity was added to the WEM in these scenarios in the planning period.

Substantial amount of coal CCS capacity as well as gas CCS capacity entered the WEM in the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios. In the 5%-CCS Only Scenario, there was near 3.6 GW of coal CCS and 0.43 GW of gas CCS capacity installed in 2049-50. In the 25%-CCS Only Scenario, approximately 3.4 GW of coal CCS and 0.35 GW of gas CCS capacity existed in 2049-50. In the 5%-26%_2030-CCS Only Scenario, coal CCS and gas CCS capacity reached 3.7 GW and 0.46 GW respectively in 2049-50. Overall, these scenarios were comprised of 44.2%, 44.6% and 44.1% of conventional fossil fuel capacity (majority was gas capacity), 35.1%, 32.7% and 36% of CCS capacity; and 20.7%, 22.7% and 19.9% of renewable capacity respectively in 2049-50.

## 6.4 Generator Total Cost

Similar as described in Section 5.4 in Chapter 5, the generator total cost in the WEM PLEXOS Model was calculated by the LT Plan. It represented the total value of the power system's total generation cost, total FO&M cost and generator annualised build cost (Energy Exemplar 2014).

### 6.4.1 Total Generation Cost

A power system's total generation cost includes fuel cost, VO&M cost and emissions cost in the WEM PLEXOS Model. Specifically, fuel cost and VO&M cost are the main components of total generation cost. Because it assumed that the carbon price only existed in 2013-14 and remained at zero for the period of 2014-15 to 2049-50 in the WEM PLEXOS Model. The emissions cost occurred in the year of 2013-14 was AU$ 0.32 billion, which was the same for every scenario in the WEM PLEXOS Model.

The BAU Scenario had the total fuel cost of AU$20.3 billion, representing the highest fuel cost among all scenario in the planning horizon. Except the total fuel cost of the BAU Scenario, the total fuel costs of the 5%-, 25%- and 5%-26%_2030-

CCS Only Scenarios were higher than the other scenarios, reaching AU$15.8 billion, AU$15.0 billion and AU$16.1 billion respectively.

The 5%, 25% and 5%-26%_2030 Reduction Scenarios had the total fuel costs of AU$13.5 billion, AU$12.5 billion and AU$13.9 billion respectively. The total fuel costs of the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios were at AU$13.0 billion, AU$12.0 billion and AU$13.4 billion respectively. The results indicated that the scenarios with higher penetration of renewable energy had less fuel consumption than the scenarios with more fossil fuels generation.

Regarding the system VO&M costs, the BAU Scenario had the lowest VO&M cost of AU$2.4 billion. The 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios had the highest VO&M costs, approximately at AU$7.3 billion, AU$7.6 billion and AU$7.2 billion respectively. The VO&M costs of the other scenarios were in a similar range.

The VO&M costs of the 5%, 25% and 5%-26%_2030 Reduction Scenario were AU$4.6 billion, AU$4.8 billion and AU$4.6 billion respectively. The VO&M costs of the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios were near AU$4.3 billion, AU$4.5 billion and AU$4.1 billion respectively. These results were consistent with the assumed levels of energy technologies' VO&M charges. Generally, the emerging LCETs have higher VO&M charges than the conventional fossil fuel technologies.

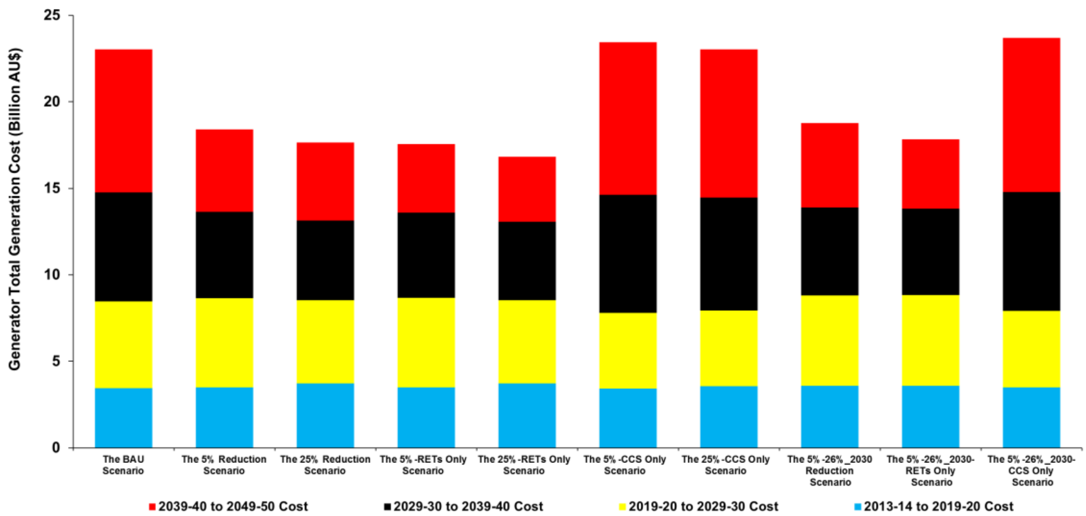



**Figure 6.18** Total generation cost by scenarios, between 2013-14 and 2049-50.

Overall, the total generation costs of the BAU Scenario and the CCS Only Scenarios were higher than the total generation costs of other scenarios (See Figure 6.18). The total generation cost of the BAU Scenario reached AU$23.0 billion. The 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios had the total generation costs of  AU$23.4 billion, AU$23.0 billion and AU$23.7 billion respectively.

The 25%-RETs Only Scenario resulted in the lowest total generation cost, reaching AU$16.8 billion. The total generation costs of the 5%- and 5%-26%_2030-RETs Only Scenarios were near AU$17.6 billion and AU$17.8 billion respectively. The 5%, 25% and 5%-26%_2030 Reduction Scenarios had total generation costs of near AU$18.4 billion, AU$17.6 billion and AU$18.8 billion respectively.

Total generation costs did not differ much among all scenarios between 2013-14 and 2019-20, mainly due to their similar generation mixes. As soon as the generation mixes became different, the scenario's total generation cost also started to differ from each other.

### 6.4.2 FO&M cost and Annualized Build Cost

The generator FO&M cost was calculated based on the inputs of the FO&M Charge (Energy Exemplar 2014). As displayed in Table 6.1, the FO&M cost of the BAU Scenario was the lowest among all scenarios at near AU$7.1 billion. The FO&M costs were similar in the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios at approximately AU$10.3 billion on average. The FO&M costs of the 5%, 25% and 5%-26%_2030 Scenarios were AU$11.0 billion, AU$11.3 billion and AU$10.8 billion respectively. The 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios had the FO&M costs of AU$11.4 billion, AU$11.7 billion and AU$11.3 billion respectively. These results were consistent with the inputs of F&OM Charge in the WEM PLEXOS Model, showing that the LCETs had higher FO&M Charges than those of conventional fossil fuel technologies.

The annualised build cost of the BAU Scenario was at approximately AU$ 5.0 billion. It was significantly lower than the annualised build costs of all other scenarios. The scenarios with the 5%-26%-80% Reduction Target had the lowest annualised build costs. The scenarios with the 25%-80% Reduction Target had the highest annualised build costs. The annualised costs of the scenarios with the 5%-80% Reduction Target were in between (see Table 6.1).

**Table 6.1** The FO&M cost and annualised build cost of each scenario (in billion AU$).

| Model | FO&M Cost | Annualized Build Cost |
|---|---|---|
| The BAU Scenario | 7.1 | 5.0 |
| The 5%-26%_2030 Reduction Scenario | 10.8 | 25.5 |
| The 5% Reduction Scenario | 11.0 | 26.6 |
| The 25% Reduction Scenario | 11.3 | 29.4 |
| The 5%-26%_2030-RETs Only Scenario | 11.3 | 26.9 |
| The 5%-RETs Only Scenario | 11.4 | 28.0 |
| The 25%-RETs Only Scenario | 11.7 | 30.7 |
| The 5%-26%_2030-CCS Only Scenario | 10.2 | 28.7 |
| The 5%-CCS Only Scenario | 10.3 | 29.6 |
| The 25%-CCS Only Scenario | 10.4 | 32.2 |

The 5%, 25% and 5%-26%_2030 Reduction Scenarios had the lowest annualised build costs, while the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios had the highest costs. Overall, the 25%-CCS Only Scenario had the highest annualised build cost of AU$ 32.2 billion among all scenarios.

### 6.4.3 Generator Total Cost

The sum of total generation cost, FO&M cost and annualised build cost represents the generator total cost of a system, as displayed in Table 6.2 (Energy Exemplar 2014). The results showed that the generator total cost of the BAU Scenario was near AU$35.1 billion, which was the lowest value among all scenarios.

The 5%, 25% and 5%-26%_2030 Reduction Scenarios had the generator total costs of approximately AU$56 billion, AU$58.4 billion and AU$55.0 billion respectively, standing for near 59.3%, 66.1% and 56.5% more than the total cost of the BAU Scenario. The 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios resulted in the generator total costs of AU$57.0 billion, AU$59.3 billion and AU$56 billion respectively, accounting for near 62.2%, 68.6% and 59.3% increase from that of the BAU Scenario. The highest generator total costs were the costs with the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios, reaching near AU$63.4billion, AU$65.6 billion and AU$62.6 billion respectively. They were approximately 80.4%, 86.5% and 78.0% more than the total cost of the BAU Scenario respectively.

**Table 6.2** The generator total cost of each scenario (in billion AU$).

| Model | Total Generation Cost | FO&M Cost | Annualized Build Cost | Total |
|---|---|---|---|---|
| The BAU Scenario | 23.0 | 7.1 | 5.0 | 35.1 |
| The 5%-26%_2030 Reduction Scenario | 18.8 | 10.8 | 25.5 | 55.0 |
| The 5% Reduction Scenario | 18.4 | 11.0 | 26.6 | 56.0 |
| The 25% Reduction Scenario | 17.6 | 11.3 | 29.4 | 58.4 |
| The 5%-26%_2030-RETs Only Scenario | 17.8 | 11.3 | 26.9 | 56.0 |
| The 5%-RETs Only Scenario | 17.6 | 11.4 | 28.0 | 57.0 |
| The 25%-RETs Only Scenario | 16.8 | 11.7 | 30.7 | 59.3 |
| The 5%-26%_2030-CCS Only Scenario | 23.7 | 10.2 | 28.7 | 62.6 |
| The 5%-CCS Only Scenario | 23.4 | 10.3 | 29.6 | 63.4 |
| The 25%-CCS Only Scenario | 23.0 | 10.4 | 32.2 | 65.6 |

## 6.5 Cost of Avoiding $CO_2$-e Emissions

The concept of the cost of avoiding $CO_2$-e emissions has been introduced in Section 5.5 in Chapter 5. Similarly, each scenario's cost of avoiding $CO_2$-e emissions was calculated relatively to the emissions and the generator total cost of the BAU Scenario. The generator total cost and the cumulative amount of emissions are two important components for calculating the cost of avoiding $CO_2$-e emissions for a scenario (please refer to Formula (5.1) in Chapter 5). The results of the cost of avoiding $CO_2$-e emissions for each scenario in the WEM were listed in Table 6.3 below.

**Table 6.3** Cost of avoiding $CO_2$-e emissions by scenario.

| | BAU | 5%-26% _2030 Reduction | 5% Reduction | 25% Reduction | 5%-26%_ 2030-RETs Only | 5%-RETs Only | 25%-RETs Only | 5%-26% _2030- CCS Only | 25%- CCS Only | 5%-CCS Only |
|---|---|---|---|---|---|---|---|---|---|---|
| **Generator Total Cost (Billon AU$)** | 35.2 | 55.0 | 56.0 | 58.4 | 56.0 | 57.0 | 59.3 | 62.6 | 65.6 | 63.4 |
| **Generator Total Cost Relative to BAU Scenario's (Billon AU$)** | 0.0 | 18.7 | 19.7 | 22.1 | 19.7 | 20.7 | 22.9 | 26.2 | 29.2 | 27.1 |
| **Accumulative $CO_2$-e Emissions (Mt)** | 698.0 | 341.3 | 332.8 | 282.1 | 341.3 | 332.8 | 282.1 | 341.3 | 282.1 | 332.8 |
| **$CO_2$-e Savings (Mt)** | 0.0 | 356.7 | 365.2 | 415.9 | 356.7 | 365.2 | 415.9 | 356.7 | 415.9 | 365.2 |
| **Cost of Avoiding $CO_2$-e emissions (AU$/t)** | n/a | 52.4 | 53.9 | 53.0 | 55.2 | 56.7 | 55.1 | 73.6 | 70.3 | 74.2 |

The lowest carbon avoiding cost of AU$ 52.4/t was modelled for the 5%-26%_2030 Reduction Scenario. The 5%-CCS only scenario had the highest carbon avoiding cost of near AU$ 74.2/t. In a scenario group with the same technology assumptions, the scenario with the 25%-80% Reduction Target had lower carbon avoiding cost than that of the scenario with the 5%-80% Reduction Target (see Table 6.3). The carbon avoiding costs of the Carbon Reduction Scenarios were lower than the RETs Only Scenarios; the CCS Only Scenarios had the highest carbon avoiding costs.

Overall, the 5%, 25% and 5%-26%_2030 Reduction Scenarios had the lowest costs of avoiding $CO_2$-e emissions among all scenario groups. The costs of avoiding $CO_2$-e emissions of the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios were slightly higher than those of the 5%, 25% and 5%-26%_2030 Reduction Scenarios. The 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios had the highest avoiding costs. Dividing the difference of carbon avoiding costs of the CCS Only Scenario and the Carbon Reduction Scenario by the carbon avoiding cost of the Carbon Reduction Scenario tells how much higher the carbon avoiding cost of the CCS Only Scenario than the carbon avoiding cost of the Carbon Reduction Scenario.

The results showed that the carbon avoiding costs of the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios were near 37.6%, 32.5% and 40.4% higher than the corresponding costs of the 5%, 25% and 5%-26%_2030 Reduction Scenarios. It suggested that when constrained with the same carbon emission reduction target, the scenario deploying both the RETs and CCS technologies for the long-term capacity expansion in the WEM would result in a lower unit cost of avoiding $CO_2$-e emissions than the expansion strategy using only the RETs or only CCS technologies after 2019-20.

## 6.6 System Levelised Cost

The WEM PLEXOS Model simulated the SWIS with a single uniform price. As explained in Section 5.6 in Chapter 5, the system LCOE of each scenario was presented here instead of reporting simulated single uniform energy price. Similarly, the system LCOE of the WEM was calculated based on generator generation cost, fixed cost and capacity capital cost. It denotes an average energy price level of a power system with a least cost capacity expansion pathway.

In 2013-14, all scenarios had a similar system LCOE of AU$50.4. As the removal of the carbon price, the system LCOEs dropped considerably in 2014-15 as shown in Figure 6.19. The system LCOE of the BAU Scenario was the lowest among all scenarios across the planning horizon. It grew slowly between 2014-15 and 2049-50 from AU$ 32.0/MWh in 2014-15 to approximately AU$ 46.1/MWh in 2049-50, representing a 44.0% increase over the planning period.

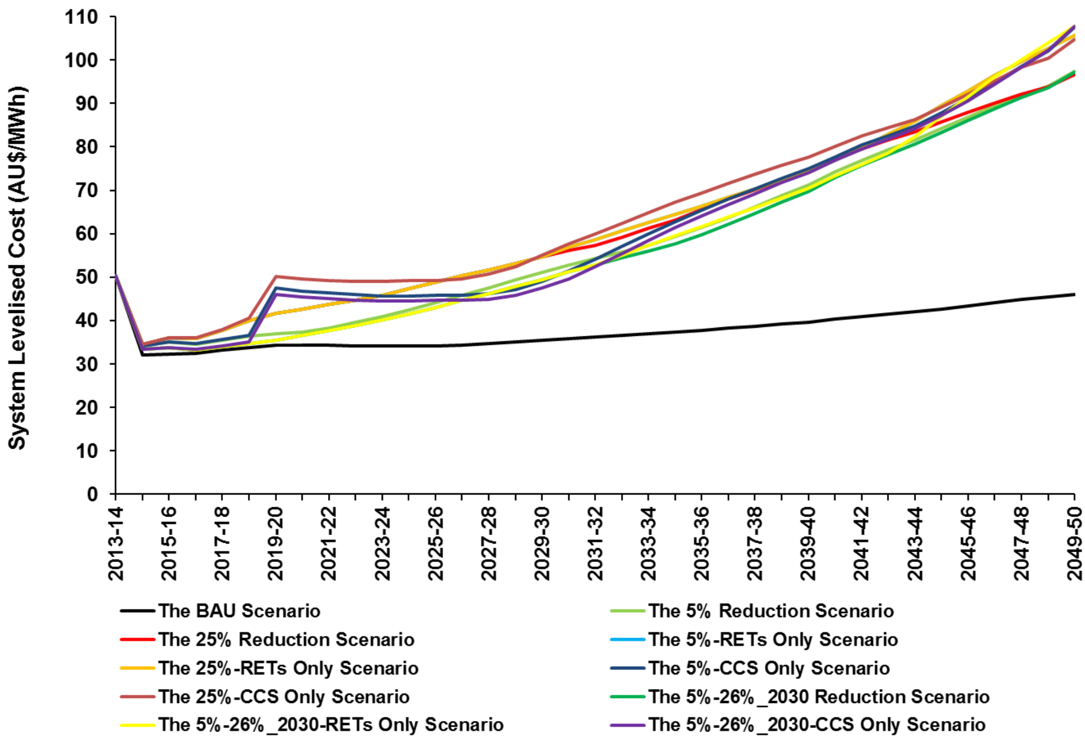



**Figure 6.19** System levelised cost by scenario, between 2014 and 2050.

The system LCOEs of the 5%, 25% and 5%-26%_2030 Reduction Scenarios, the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios increased moderately between

2014-15 and 2019-20. They grew steeply from 2020-21 to 2049-50. For the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios, their projected trajectories of the system LCOEs first climbed slowly in the period of 2014-15 to 2018-19. Then their system LCOEs experienced a sharp increase in 2019-20 and their values remained relatively stable till 2029-30. After 2029-30, their system LCOEs presented the similar steep upward trends like the other scenarios.

The noticeable spikes on the system LCOE trajectories of the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios in 2019-20 may be attributed to a significant higher amount of wind generation occurred in the year of 2019-20 in these scenarios compared to wind generation in other scenarios.

After 2029-30, the system LCOEs of all scenarios except the BAU Scenarios did not differ much from each other (see Figure 6.19). The system LCOEs in the 5%, 25% and 5%-26%_2030 Reduction Scenarios increased from AU$ 34.1/MWh, AU$ 34.5/MWh and AU$ 33.4/MWh in 2014-15 to AU$ 97.4/MWh, AU$ 96.7/MWh and AU$ 97.2/MWh respectively in 2049-50, representing more than 1.8 times higher than their prices in 2014-15.

The system LCOEs of the 5%-RETs Only Scenario and the 5%-CCS Only Scenario reached approximately AU$ 108.1/MWh and AU$ 107.5/MWh in 2049-50 respectively. They represented near 2.2 times higher than their LCOEs in 2014-15 (AU$ 34.1/MWh). The 25%-RETs Only Scenario and the 25%-CCS Only Scenario had system LCOEs of AU$ 105.7/MWh and AU$ 104.9/MWh in 2049-50 respectively, accounting for more than 2.05 times more than their LCOEs in 2014-15. The system LCOEs of the 5%-26%_2030-RETs Only Scenario and the 5%-26%_2030-CCS Only Scenario increased to approximately AU$ 107.8 in 2049-50, standing for approximately 2.2 times more than their LCOEs in 2014-15 (AU$33.4/MWh).

As shown in Figure 6.19, without counting the cost trajectory of the BAU Scenario, the system LCOEs trends of the 5% Reduction Scenario, the 5%-26%_2030 Reduction Scenario and the 5%-26%_2030-RETs Only Scenario located at the lower end of cost trends. The LCOEs trend of the 25%-CCS Only Scenario positioned relative higher than other trends.

## 6.7 Discussion

The annual carbon emissions in the BAU Scenario increased more than 76.4% in 2049-50 compared to the emissions in 2013-14 in the WEM. Over the planning period, the cumulative carbon emissions reached near 698 Mt in the BAU Scenario.

The emission trend of the BAU Scenario suggested that the implementation of the current Renewable Energy Target eased the growth of carbon emissions in the WEM for the first six years from 2013-14 to 2019-20. The carbon emissions in the BAU scenario reached approximately 16.0 Mt in 2019-20. This emission level is higher than the emission level of the 5% Reduction Target at 13.4 Mt in 2019-20. It indicated that the WEM will not be able to achieve 5% carbon emissions reduction target by 2019-20 by only enforcing the current Renewable Energy Target. From 2020-21, carbon emissions in the WEM increased annually and reached 24.29 Mt in 2049-50 in the BAU Scenario.

In the BAU Scenario, the absence of carbon emissions reduction targets led to no incentive for the WEM to divert from carbon insensitive generation to low carbon generation. This was verified by the results of generation capacity retirements and new builds in the BAU Scenario.

Over the planning period, there was 220 MW black coal capacity retired in contrast to near 441 MW of black coal capacity and 3.0 GW of gas capacity built in the BAU Scenario. Particularly, the total amount of wind capacity constructed in the BAU Scenario was approximately 364 MW, which was all constructed by year 2019-20. No other type of renewable capacity entered the WEM in this scenario over the planning period.

Furthermore, the electricity generation mix in the BAU Scenario did not differ much from 2014-15 to 2049-50. In 2014-15, the conventional fossil fuel technologies and the RETs accounted for approximately 90.0% and 10.0% of total energy generation in the BAU Scenario respectively. In 2049-50, the conventional fossil fuel technologies still contributed more than 89.9% of total generation, the renewable generation accounted for less than 10.1%.

The major distinction between the BAU Scenario and the other scenarios was the implementation of carbon emissions reduction targets in the other scenarios during the planning period.

Similar as described in Section 5.7 in Chapter 5, the 5%-26%_2030 Reduction Scenario in the WEM PLEXOS Model was also referred as the CGP Scenario. It applied the current Renewable Energy Target and the carbon reduction targets of 5% cut by 2019-20, 26% reduction by 2029-30, and 80% cut by 2049-50 based on the emissions levels of the WEM in 2007-08. The 5%-26%-80% Reduction Target in the CGP Scenario represented current government's climate policies and carbon emissions reduction target.

The 5% and 25% Reduction Scenarios simulated more ambitious carbon emissions reduction targets for the WEM between 2013-14 and 2049-50. Both of the scenarios executed the pervious Renewable Energy Target. The 5% Reduction Scenario aimed at reducing carbon emissions by 5% in 2019-20, by 30% in 2029-30 and by 80% in 2049-50 based on the emissions levels of the WEM in 2007-08. The 25% Reduction Scenario had the highest magnitude of carbon emissions reduction. It required the WEM to cut emissions by 25% in 2019-20, by 43% in 2029-30 and by 80% in 2049-50 based on the emissions levels of the WEM in 2007-08.

The BAU scenario resulted in the least generator total cost of AU$ 35.1 billion compared to all other scenarios. The generator total cost of the CGP Scenario was the second lowest among all, totalling at AU$ 55.0 billion. It is approximately AU$ 19.9 billion more or 56.7% higher than the generator total cost of the BAU Scenario.

The significantly increased generator total cost in the CGP Scenario was contributed by its larger amount of electricity generation from the LCETs. In 2019-20, the conventional fossil fuel technologies and the RETs accounted for approximately 83.6% (17.0 TWh) and 16.4% (3.3 TWh) of total electricity generation respectively in the CGP Scenario in the WEM. In 2029-30, the energy generation from conventional fossil fuel technologies reduced to approximately 66.4% (15.1 TWh) and the energy generation from the RETs increased to 33.6% (7.7 TWh). In 2049-50, the CCS technologies generated near 29.2% (10.0 TWh) of total energy output in the CGP

Scenario. The RETs produced approximately 60.6% (20.7 TWh) of total electricity generation in 2049-50. The conventional fossil fuel technologies generated the rest of 10.2% (3.5 TWh) of total energy output in the CGP Scenario in 2049-50, considerably lower than its generation in 2019-20.

The installed capacity in the CGP Scenario also reflected a higher share of the LCETs capacity. In 2019-20, the conventional fossil fuel capacity and the RETs capacity took up approximately 84.0% (4.8 GW) and 16.0% (0.9 GW) of total installed capacity respectively in the CGP Scenario. In 2029-30, the installed conventional fossil fuel capacity reduced to near 70.4% (5.2 GW). It reduced further to approximately 47.9% (5.5 GW) in 2049-50. On the contrary, the installed RETs capacity increased to 29.6% (2.2 GW) in 2029-30 and grew further to 42.1% (4.8 GW) in 2049-50. The CCS technologies were also installed to the CGP Scenario at the later period and reached approximately 10.0% (1.1 GW) of total installed capacity in 2049-50.

Higher penetration of energy generation from the LCETs directly led to lower carbon emissions in the CGP Scenario than the emissions in the BAU Scenario. The CGP Scenario's annual level of carbon emissions was at 13.77 Mt in 2013-14. It was reduced to 13.39 Mt in 2019-20, 10.43 Mt in 2029-30 and 2.82 Mt in 2049-50. The cumulative carbon emissions of the CGP Scenario totalled at approximately 341 Mt. It avoided approximately 357 Mt emissions or represented 51.1% less emissions based on the cumulative emissions of the BAU Scenario.

Compared to the CGP Scenario, the 5% Reduction Scenario resulted in slightly higher generator total cost for expanding the WEM's capacity system, adding up to AU$ 56.0 billion. It represented approximately AU$1.0 billion more or 1.8% higher than the generator total cost of the CGP Scenario.

The higher expense on expanding the WEM's capacity system in the 5% Reduction Scenario was mainly attributed to more LCETs generation and capacity in this scenario than in the CGP Scenario. In 2019-20, the conventional fossil fuel technologies and the RETs generated approximately 79.7% (16.3 TWh) and 20.3% (4.1 TWh) of total energy generation respectively in the 5% Reduction Scenario. In 2029-30, they contributed to approximately 64.5% (14.7 TWh) and 35.5% (8.1 TWh) of total energy output respectively. More electricity was generated by the RETs in the 5% Reduction Scenario than in the CGP Scenario in 2019-20 and 2029-30.

In 2049-50, the conventional fossil fuel technologies contributed to approximately 10.4% (3.55 TWh) of total energy generation in the 5% Reduction Scenario. The CCS technologies and the RETs generated 27.9% (9.5 TWh) and 61.6% (21.0 TWh) of total energy production respectively. The generation profile of the 5% Reduction Scenario in 2049-50 was similar as the generation profile of the CGP Scenario in 2049-50.

In 2019-20, the installed capacity of the 5% Reduction Scenario was comprised of 80.6% (4.8 GW) of conventional fossil fuel capacity and 19.4% (1.2 GW) of the renewable capacity. This capacity profile changed to be 69.6% (5.1 GW) of conventional fossil fuel capacity and 30.4% (2.2 TWh) of the renewable capacity in 2029-30. In 2049-50, the conventional fossil fuel capacity, the CCS capacity and the renewable capacity accounted for approximately 48.1% (5.5 GW), 9.6% (1.1 GW) and 42.3% (4.8 GW) of total installed capacity respectively in the 5% Reduction Scenario. Overall, the 5% Reduction Scenario had higher installation rate of renewable capacity in 2019-20 than in the CGP Scenario. Its capacity profile transformed to be similar as the profile of the CGP Scenario in 2029-30 and 2049-50.

More energy generation from the LCETs in the 5% Reduction Scenario than in the CGP Scenario led to lower level of carbon emissions in the 5% Reduction Scenario. Its annul level of carbon emissions was at 13.77 Mt in 2013-14. It was cut to 13.39 Mt in 2019-20 and 9.86 in 2029-30. In 2049-50, the carbon emissions were reduced to 2.82 Mt. The cumulative carbon emissions of the 5% Reduction Scenario was 333 Mt, standing for approximately 8.0 Mt less or 2.5% lower than the cumulative emissions of the CGP Scenario.

The 25% Reduction Scenario resulted in higher generator total cost than the CGP Scenario and the 5% Reduction Scenario. Its generator total cost reached AU$ 58.4 billion, which is approximately AU$3.4 billion more or 6.2% higher than the generator total cost of the CGP Scenario.

The 25% Reduction Scenario featured with considerable higher penetration of the LCETs compared to the CGP Scenario. The conventional fossil fuel technologies and the RETs produced approximately 76.7% (15.3 TWh) and 23.3% (4.7 TWh) of total energy output respectively in the 25% Reduction Scenario in 2019-20. In 2029-30, they contributed to 55.3% (12.5 TWh) and 44.7% (10.1 TWh) of total electricity generation respectively. In 2049-50, the conventional fossil fuel technologies, the CCS technologies and the RETs accounted for approximately 11.0% (3.7 TWh), 24.2% (8.2 TWh) and 64.8% (21.9 TWh) of total energy production respectively.

The 25% Reduction Scenario had higher installation rate of the renewable capacity compared to that of the CGP Scenario in 2019-20 and 2029-30. The conventional fossil fuel capacity took up 77.6% (4.5 GW) and 65.1% (4.9 GW) of total installed capacity in 2019-20 and 2029-30 respectively. The renewable capacity accounted for 22.4% (1.3 GW) and 34.9% (2.6 GW) of total installed capacity in 2019-20 and 2029-30 respectively. In 2049-50, the conventional fossil fuel capacity, the CCS capacity and the renewable capacity accounted for 48.8% (5.5 GW), 8.2% (0.9 GW) and 43.0% (4.9 GW) of total installed capacity respectively.

The highest penetration of the LCETs generation in the 25% Reduction Scenario resulted in the lowest carbon emissions emitted by the WEM over the planning period. Its annual level of carbon emissions started at 13.77 Mt in 2013-14, was reduced to 10.57 Mt in 2019-20 and 7.98 Mt in 2029-30. It was cut to 2.82 Mt in 2049-50. The lowest level of annual emissions also resulted in the lowest cumulative carbon emissions in the 25% Reduction Scenario when compared to the cumulative emissions of the CGP Scenario. The cumulative carbon emissions in the 25% Reduction Scenario were 282 Mt. It represents approximately 59 Mt lower or 17.3% less than the cumulative emissions of the CGP Scenario.

In the CGP Scenario, the 5% Reduction Scenario, and the 25% Reduction Scenario, the renewable capacity installed in the planning period included wind, solar PV, geothermal and biomass. Most of wind capacity was installed before 2029-30 in three scenarios, and the other types of renewable capacity were installed after 2024-25.

In the WEM, coal CCS capacity first entered the CGP Scenario in 2041-42, and entered the 5% and 25% Reduction Scenarios one year earlier in 2040-41. Late market entry time and relatively small amount of installed capacity suggested that the coal CCS technologies were less competitive compared to the RETs in these scenarios. Nonetheless, the emissions reduction targets enabled the entry of coal CCS technologies in the WEM in the planning period. Without emissions reduction targets, coal CCS technologies will not be competitive enough to enter the WEM under the assumptions of medium fuel prices and medium CCS capital costs in the scenarios by 2049-50.

With similar carbon emissions constraints, can the WEM only rely on the RETs or the CCS technologies to meet the growth of energy demand to 2049-50? What will be the economic outcomes? These were the questions that the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios, and the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios aimed at answering.

The 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios only allowed the RETs as the options of the LCETs entering the WEM after 2019-20. The WEM's least cost capacity expansion pathway in the 5%-RETs Only Scenario was comprised of 44.3% (5.4 GW) of conventional fossil fuel capacity and 55.7% (6.8 GW) of renewable capacity in 2049-50. Conventional fossil fuel and renewable capacity contributed approximately 45.4% (5.5 GW) and 54.6% (6.6 GW) of total installed capacity respectively in the 25%-RETs Only Scenario. In the 5%-26%_2030-RETs Only Scenario, there were 44.3% (5.4 GW) and 55.7% (6.8 GW) of total installed capacity from conventional fossil fuel technologies and the RETs respectively. Accordingly, in 2049-50, energy output was primarily from the renewable sources (85.2%) in these three scenarios, conventional fossil fuel energy generation only accounted for on average near 14.8% of total electricity generation.

Renewable capacity built in the 5%- and 25%-RETs Only Scenarios included wind, geothermal, solar PV, solar thermal and biomass. In particular, solar thermal capacity only installed in the 5%- and 25%-RETs Only Scenarios. It did not add to other scenarios. This suggested that the deployment of solar thermal technologies in the WEM will not be realised if it does not have other type of climate policy or financial support in addition to the assumed carbon emissions reduction targets.

Meanwhile, energy generation from intermittent sources (wind and solar PV) made up approximately 31.4% of total outputs in 2049-50 in the 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios. The results indicated that the WEM energy market can achieve 80% of carbon emissions reduction target in 2049-50 by generating more than 85% of its energy from the renewable sources.

The 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios only permitted coal CCS and gas CCS technologies as the LCETs to enter the WEM after 2019-20. A large amount of coal CCS capacity was built in these three scenarios. The gas CCS technologies also entered the WEM by the end of planning period. The CCS capacity made up 35.1% (4.1 GW), 32.7% (3.8 GW) and 36.0% (4.1 GW) of total capacity in three scenarios respectively in 2049-50. Conventional fossil fuel capacity accounted for approximately 44.2% (5.1 GW), 44.6% (5.2 GW) and 44.1% (5.1 GW); and renewable capacity made up for approximately 20.8% (2.4 GW), 22.8% (2.6 GW) and 19.9% (2.3 GW) of total installed capacity in the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios respectively.

In 2049-50, energy generated by the CCS technologies dominated the energy output in the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios. The coal CCS and the gas CCS capacity together produced more than 75.2% (28.6 TWh), 71.4% (26.9 TWh) and 76.4% (29.1 TWh) of total energy output in three scenarios respectively in 2049-50. Less than 24.8% (9.4 TWh), 28.6% (10.8 TWh) and 23.6% (9.0 TWh) of total energy output was generated by the conventional fossil fuel technologies and the RETs together in three scenarios respectively. Therefore, under the enforcement of emissions reduction targets and the setting of technological preference, the CCS technologies would be able to play a major role in meeting system capacity expansion requirement and carbon reduction targets in the WEM.

Additionally, the coal CCS technologies entered the CCS Only Scenarios in different year, so did the solar thermal technologies in the RETs Only Scenarios. The coal CCS technologies entered the 5%-26%_2030-CCS Only Scenario in the year 2032-33, and entered the 5%- and 25%-CCS Only Scenarios in 2031-32 and 2030-31 respectively. Similarly, the solar thermal generation started in the 5%-26%_2030-RETs Only Scenario in 2043-44, which was one year later than its generation commenced in the 5%- and 25%-RETs Only Scenarios (2042-43).

The generator total costs of the CCS Only Scenarios were the highest among all scenario groups. The 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios had the generator total costs of AU$63.4 billion, AU$65.6 billion and AU$62.6 billion respectively. They represented approximately 15.3%, 19.3% and 13.8% higher than the generator total cost of the CGP Scenario.

The 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios resulted in the generator total costs of AU$57.0 billion, AU$59.3 billion and AU$56.0 billion respectively, representing approximately 3.6%, 7.8% and 1.8% more than the generator total cost of the CGP Scenario.

It also discovered that for the scenarios with the same assumptions of technology availability, the scenario with the 25%-80% Reduction Target had slightly higher generator total cost than the scenario with the 5%-80% Reduction Target. The scenario with 5%-26%-80% Reduction Target had the lowest total cost compared to the scenarios with the 5%-80% and 25%-80% Reduction Target.

Although the generator total costs of the carbon reduction scenarios were all significantly higher than the total cost of the BAU Scenario, these scenarios also avoided substantial amounts of carbon emissions released in the BAU Scenario. The modelling results of carbon avoiding costs showed that the CGP Scenario had the lowest carbon avoiding cost at AU$ 52.4/t, while the 5%-CCS Only Scenario had the highest carbon avoiding cost at AU$ 74.2/t. In general, the 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios had the highest carbon avoiding costs among all scenarios groups. The carbon avoiding costs of the 5%-, 25%- and 5%-26%_2030-RETs Only scenarios slightly higher than those of the CGP Scenario, the 5% and 25% Reduction Scenarios.

## 6.8 Conclusions

The modelling results revealed that when there is lack of any restriction of carbon emissions in the WEM, the least cost way for the WEM to expand the capacity system to meet future energy demand growth will heavily rely on the conventional fossil fuel technologies. The current Renewable Energy Target will facilitate more wind capacity installation and wind energy generation in a short term. However, as soon as the Renewable Energy Target expires, renewable energy will become less competitive to enter the WEM and more conventional fossil fuel capacity will enter the market to meet energy demand growth. This will result in increasing annual carbon emissions and the cumulative carbon emissions over the planning period.

Apart from the BAU Scenario, the CGP Scenario was simulated with the lowest generator total cost and highest cumulative carbon emissions compared to those of the 5% and 25% Reduction Scenarios. This suggested that current Australian government's policies on curbing carbon emissions including current Renewable Energy Target and the post-2020 carbon emissions reduction target will facilitate the WEM to achieve 80% carbon emissions reduction in 2049-50 based on 2007-08 emission levels with the least generator total cost.

The results of the 5% and 25% Reduction Scenarios revealed that higher investment will be required to expand the WEM with higher share of the LCETs. This will result in higher amount of carbon emissions reduction in the WEM than the emissions reduction can be achieved in the CGP Scenario.

The results of the 5% and 25% Reduction Scenarios suggested that cutting the cumulative emissions in the WEM over the planning period by 2.5% more than the cumulative carbon emissions of the CGP Scenario will increase system generator total cost by 1.8% compared to that of the CGP Scenario. Reducing the cumulative emission by 17.3% based on the cumulative carbon emissions of the CGP Scenario will increase the generator total cost by 6.28% based on the generator total cost of the CGP Scenario. These results indicated that by lifting the carbon emissions reduction target in the WEM from the 5%-26%-80% to 5%-80%, and to 25%-80%, the WEM will be able to achieve higher amount of carbon emissions reduction with relatively smaller increase of the generator total costs.

Additionally, the modelling results demonstrated that the WEM's power system can be successfully expanded from 2020-21 to 2049-50 by relying on both the RETs and CCS, or only the RETs, or only the CCS technologies. However, different expansion strategy held different economic implications regarding their capability of reducing carbon emissions.

Over the planning period, the CGP Scenario resulted in the lowest carbon avoiding cost at AU$52.4/t in the WEM compared to the costs of other scenarios. The carbon avoiding cost of the 25% Reduction Scenario was the second to the lowest at AU$53.0/t. The 5% Reduction Scenario had higher avoiding cost than the costs of the CGP Scenario and the 25% Reduction Scenario at AU$53.9/t. The carbon avoiding costs of the RETs Only Scenarios and the CCS Only Scenarios were all higher than the carbon avoiding costs of the CGP Scenario, the 5% and 25% Reduction Scenario.

This result suggested that in the WEM, the most economical way to avoid carbon emissions over the long term was to make both the RETs and CCS technologies available for the deployment and their entry time was upon the market's choice. Secondly, it suggested that the combination of the RETs would be more economic competitive in cutting carbon emissions compared to the CCS technologies in the WEM in a long run.

# Chapter 7 Conclusions

This research applied the bottom up power system optimisation model PLEXOS to investigate the optimal (least cost) way of expanding the electric power systems in the NEM and the WEM in Australia, given Australian Government's current energy and climate policies. It examined the impacts of carbon emissions reduction targets on the expansion of the electric power systems in the NEM and the WEM to meet the growth of energy demand to 2049-50. This research focused on exploring the roles of the RETs and CCS technologies in reducing carbon emissions in the NEM and the WEM. The scenarios were explicitly designed to compare the potentials of the RETs and CCS technologies in mitigating carbon emissions in the NEM and the WEM.

## 7.1 The Conclusions of Modelling Results

The NEM represents the largest electricity market and the WEM is the second largest electricity market in Australia. In 2013-14, energy generation in the NEM (83.8%) and the WEM (7.4%) in sum contributed to approximately 91.2% of total electricity generation in Australia (Australian government 2014a; IMO 2014d). The rest of energy was generated by the generators in the NT (1.4%) and scattered generators in the WA regional and mining areas (7.4%) (Australian Government 2014a; IMO 2014d). Therefore, the combined modelling results of the NEM and the WEM PLEXOS Models can represent the development of the Australian electricity power sector to a large extent.

Ten scenarios categorised in four groups were constructed for the NEM and the WEM PLEXOS Models respectively. The baseline level of total carbon emissions listed in Table 7.1 is the sum of the NEM's emissions in year 2000 and the WEM's emissions in year 2007-08. In 2013-14, the total emissions of the NEM and the WEM reached 202.1 Mt. In 2049-50, the emissions were projected to increase to 280.3 Mt in the BAU Scenario, representing a 57% growth compared to its baseline total emissions (see Table 7.1 and 7.2).

The other three scenario groups were constrained by three sets of Carbon Reduction Targets. Their levels of total carbon emissions all decreased from 202.1 Mt in 2013-14 to around 35.8 Mt in 2049-50, standing for approximately 80% less than the baseline level of total emissions (see Table 7.1 and 7.2).

**Table 7.1** The sum of annual and cumulative carbon emissions of the NEM and the WEM (Unit: Mt $CO_2$-e).

| | **Baseline Total Emissions** | **Total Emissions in 2013-14** | **Total Emissions in 2019-20** | **Total Emissions in 2029-30** | **Total Emissions in 2049-50** | **Total Cumulative Emissions (2013-14 to 2049-50)** |
|---|---|---|---|---|---|---|
| The BAU Scenario | 179.1 | 202.1 | 212.5 | 235.7 | 280.3 | 8899.3 |
| The Scenarios with 5%-26%-80% Reduction Targets | 179.1 | 202.1 | 169.9 | 141.4 | 35.8 | 4564.2 |
| The Scenarios with 5%-80% Reduction Targets | 179.1 | 202.1 | 169.9 | 125.2 | 35.8 | 4321.4 |
| The Scenarios with 25%-80% Reduction Targets | 179.1 | 202.1 | 134.2 | 101.4 | 35.8 | 3677.4 |

In particular, the 5%-26%-80% Reduction Target represents Australian Government's current carbon reduction target the closest. It assumes a short-term target of a 5% reduction on 2000 levels by 2019-20, a medium-term target of a 26% cut on 2005 levels by 2029-30, and a long-term target of an 80% cut on 2000 levels by 2049-50 (Australia Government 2015). The 5%-80% Reduction Target assumes a 5% cut by 2019-20 and an 80% cut by 2049-50 based on 2000 levels. The 25%-80% Reduction Target assumes an Australian emission target of a 25% reduction by 2019-20 and an 80% cut by 2049-50 based on 2000 levels (Australian Treasury 2011).

In 2019-20, the sum of the BAU Scenario's carbon emissions in the NEM and the WEM was around 19% higher than the baseline level of total emissions. In the same year, the total emissions of the scenarios with the 5%-80% and the 5%-26%-80%

Reduction Targets were approximately 5% less than the baseline level of total emissions respectively. The total emissions of the scenarios with the 25%-80% Reduction Target represented a higher level of emissions reduction in 2019-20, resulting in approximately 25% less than the baseline level of total emissions (See Table 7.2).

In 2029-30, the total emissions in the BAU Scenario increased to be 32% higher than the baseline level of total emissions. The total emissions in the scenarios with the 5%-80%, 25%-80% and 5%-26%-80% Reduction Targets reduced to be approximately 30%, 43% and 21% less compared to the baseline level of total emissions respectively (See Table 7.2).

**Table 7.2** Percentage changes relative to the baseline level of total emissions in 2013-14, 2019-20, 2029-30 and 2049-50; and percentage change relative to the BAU scenario's cumulative total emissions level (in %).

| | **Baseline Total Emissions** | **Total Emissions in 2013-14** | **Total Emissions in 2019-20** | **Total Emissions in 2029-30** | **Total Emissions in 2049-50** | **Cumulative Total Emissions** |
|---|---|---|---|---|---|---|
| The BAU Scenario | 100% | +13% | +19% | +32% | +57% | +100% |
| The Scenarios with 5%-26%-80% Reduction Target | 100% | +13% | -5% | -21% | -80% | -49% |
| The Scenarios with 5%-80% Reduction Target | 100% | +13% | -5% | -30% | -80% | -51% |
| The Scenarios with 25%-80% Reduction Target | 100% | +13% | -25% | -43% | -80% | -59% |

In 2049-50, the total emissions in the BAU Scenario reached approximately 57% higher than the baseline level of total emissions. The total emissions of the scenarios with the 5%-80%, 25%-80% and 5%-26%-80% Reduction Targets all achieved an 80% reduction based on the baseline level of total emissions.

The total levels of cumulative carbon emissions in four scenario groups differed significantly. Ranked from the largest to the lowest, they were 8899.3 Mt in the BAU Scenarios, 4564.2 Mt in the scenarios with the 5%-26%-80% Reduction Target, 4321.4 Mt in the scenarios with the 5%-80% Reduction Target and 3677.4 Mt in the scenarios with the 25%-80% Reduction Target (see Table 7.1).

Compared to the total level of the BAU Scenario's cumulative carbon emissions, the total levels of cumulative carbon emissions in the scenarios with the 5%-26%-80%, 5%-80% and 25%-80% Reduction Targets represented a 49% reduction, a 51% reduction and a 59% reduction respectively (see Table 7.2).

Table 7.1 and Table 7.2 show that except the BAU Scenario, the scenarios with the 5%-26%-80% Reduction Target resulted in the smallest amount of annual and cumulative carbon emissions reduction compared to the results in the scenarios with the 5%-80% and 25%-80% Reduction Targets.

The scenarios with the 5%-80% Reduction Target and the scenarios with the 25%-80% Reduction Target emitted approximately 5.6% (242.8 Mt) and 19.4% (886.8 Mt) respectively less cumulative emissions than the total cumulative emissions of the scenarios with 5%-26%-80% Reduction Target.

Different annual emissions trajectories and cumulative emission levels led to specific least cost paths for expanding the electric power systems in the NEM and the WEM under four scenario groups. In 2013-14, the sum of the energy generation in the NEM and the WEM was approximately 227 TWh, which was contributed by approximately 88.3% of conventional fossil fuels generation and 11.7% of renewable generation. Total installed capacity of the NEM and the WEM in 2013-14 was approximately 56 GW, contributed by near 80.4% of the conventional fossil fuel capacity and 19.6% of renewable capacity.

In 2013-14, all ten scenarios started with the same generation and capacity profiles in the NEM and the WEM PLEXOS Models respectively. In 2019-20, the generation and capacity profiles became different among scenarios (see Table 7.3 and Table 7.4).

In 2019-20, renewable energy increased its penetration in the BAU Scenario and generated approximately 20% of total energy output of the NEM and the WEM. At the same time, the conventional fossil fuel generation reduced to 80% (see Table 7.3). Correspondingly, the installed renewable capacity increased to 28.9% and the installed conventional fossil fuel capacity reduced to 71.1% of total installed capacity of the NEM and the WEM in the BAU Scenario (see Table 7.4). This was largely attributed to the rapid take-up of the wind capacity and the retirement of existing coal capacity driven by the current Renewable Energy Target (33,000 GWh) between 2013-14 and 2019-20.

**Table 7.3** The percentages of conventional fossil fuels, CCS and renewable energy generation in each scenario in 2019-20.

| | **Total generation in 2019-20 (TWh)** | **Conventional Fossil Fuels Energy (%)** | **CCS Technologies Energy (%)** | **Renewable Technologies Energy (%)** |
|---|---|---|---|---|
| The BAU Scenario | 251 | 80.0% | 0.0% | 20.0% |
| The 5%-26%_2030 Reduction Scenario (The CGP Scenario) | 248 | 75.3% | 0.0% | 24.7% |
| The 5% Reduction Scenario | 248 | 74.9% | 0.0% | 25.1% |
| The 25% Reduction Scenario | 246 | 65.7% | 0.0% | 34.3% |
| The 5%-26%_2030-RETs Only Scenario | 248 | 75.3% | 0.0% | 24.7% |
| The 5%-RETs Only Scenario | 248 | 74.9% | 0.0% | 25.1% |
| The 25%-RETs Only Scenario | 247 | 64.6% | 0.0% | 35.4% |
| The 5%-26%_2030-CCS Only Scenario | 248 | 68.5% | 0.0% | 31.5% |
| The 5%-CCS Only Scenario | 248 | 67.6% | 0.0% | 32.4% |
| The 25%-CCS Only Scenario | 247 | 63.0% | 0.0% | 37.0% |

In 2019-20, predominately due to the implementation of the carbon reduction targets, there was higher amount of renewable energy generation and installed renewable capacity in the scenarios other than the BAU Scenarios. Particularly, among the scenarios with the same technology assumption, the scenario with the 25%-80%

Reduction Target had more renewable energy generation and installed capacity than the scenario with 5%-80% Reduction Target and the scenario with 5%-26%-80% Reduction Target.

**Table 7.4** The percentages of conventional fossil fuels, CCS and renewable installed capacity in each scenario, in 2019-20.

| | **Total capacity in 2019-20 (GW)** | **Conventional Fossil Fuel Capacity (%)** | **CCS Technologies Capacity (%)** | **Renewable Technologies Capacity (%)** |
|---|---|---|---|---|
| The BAU Scenario | 63 | 71.1% | 0.0% | 28.9% |
| The 5%-26%_2030 Reduction Scenario (The CGP Scenario) | 65 | 65.9% | 0.0% | 34.1% |
| The 5% Reduction Scenario | 66 | 65.7% | 0.0% | 34.3% |
| The 25% Reduction Scenario | 71 | 57.3% | 0.0% | 42.7% |
| The 5%-26%_2030-RETs Only Scenario | 65 | 65.9% | 0.0% | 34.1% |
| The 5%-RETs Only Scenario | 65 | 65.5% | 0.0% | 34.5% |
| The 25%-RETs Only Scenario | 72 | 56.4% | 0.0% | 43.6% |
| The 5%-26%_2030-CCS Only Scenario | 72 | 59.9% | 0.0% | 40.1% |
| The 5%-CCS Only Scenario | 72 | 59.0% | 0.0% | 41.0% |
| The 25%-CCS Only Scenario | 74 | 55.4% | 0.0% | 44.6% |

Excluding the BAU Scenario, the CGP Scenario and the 5%-26%_2030-RETs Only Scenario had the least share of the renewable energy generation and installed capacity compared to other scenarios in 2019-20. They each had approximately 75.3% of conventional fossil fuel energy generation and 24.7% of renewable energy generation in 2019-20. The conventional fossil fuel capacity and the renewable capacity accounted for 65.9% and 34.1% of total installed capacity in two scenarios respectively in 2019-20.

The 25%-80% Reduction Target required the scenario to achieve a higher amount of annual emissions reduction than the 5%-80% Reduction Target and the 5%-26%-80% Reduction Target did in 2019-20. This resulted in the reduced energy generation from black and brown coal and the increased energy generation from wind in the scenarios with the 25%-80% Reduction Target in 2019-20. At the same time, more retirement of existing coal capacity and more installation of wind capacity occurred in the scenarios with the 25%-80% Reduction Target than in the scenarios with the 5%-80% Reduction Target and the 5%-26%-80% Reduction Target in this period.

The current Renewable Energy Target and the previous Renewable Energy Target (41,000 GWh) were applied to the scenarios with the 5%-26%-80% Reduction Target and the scenarios with the 5%-80% Reduction Target respectively. When comparing the scenarios which have the same technology assumption, the scenario with the 5%-26%-80% Reduction Target (current government policy) had slightly more energy generated from conventional fossil fuel technologies and less energy generated from renewable sources than in the scenario with the 5%-80% Reduction Target (see Table 7.3). These results were consistent to their capacity results listed in Table 7.4.

As the scenarios with the 5%-80% Reduction Target and the scenarios with the 5%-26%-80% Reduction Target were constrained with a similar 5% Reduction Target by 2019-20, their different generation and capacity results in 2019-20 can be largely explained by their different levels of the Renewable Energy Targets. The results suggested that the current Renewable Energy Target with reduced renewable energy generation quota by 2019-20 will act less effective in promoting the penetration of renewable energy generation in the NEM and the WEM than the previous Renewable Energy Target does by 2019-20.

The results revealed that under the combined influences of the Renewable Energy Target and carbon reduction targets, the NEM and the WEM were forced to reduce conventional coal energy production and retire more existing coal capacity by 2019-20. In the meantime, more energy output and capacity installed resulted from gas and wind technologies in this period.

In the BAU Scenario, the conventional fossil fuel generation grew from 80% in 2019-20 to 81.8% in 2029-30, and the renewable energy generation reduced from 20% in 2019-20 to 18.2% in 2029-30 (see Table 7.5). In the same scenario, the capacity of conventional fossil fuels also increased from 71.1% in 2019-20 to 72.7% in 2029-30, and the renewable capacity decreased from 28.9% in 2019-20 to 27.3% in 2029-30 (see Table 7.6).

**Table 7.5** The percentages of conventional fossil fuels, CCS and renewable energy generation in each scenario in 2029-30.

| | **Total generation in 2029-30 (TWh)** | **Conventional Fossil Fuel Energy (%)** | **CCS Technologies Energy (%)** | **Renewable Technologies Energy (%)** |
|---|---|---|---|---|
| The BAU Scenario | 275 | 81.8% | 0.0% | 18.2% |
| The 5%-26%_2030 Reduction Scenario (The CGP Scenario) | 271 | 59.7% | 0.0% | 40.3% |
| The 5% Reduction Scenario | 272 | 54.3% | 2.9% | 42.7% |
| The 25% Reduction Scenario | 276 | 44.4% | 8.1% | 47.5% |
| The 5%-26%_2030-RETs Only Scenario | 271 | 59.3% | 0.0% | 40.7% |
| The 5%-RETs Only Scenario | 271 | 54.7% | 0.0% | 45.3% |
| The 25%-RETs Only Scenario | 271 | 45.8% | 0.0% | 54.2% |
| The 5%-26%_2030-CCS Only Scenario | 278 | 58.5% | 12.8% | 28.7% |
| The 5%-CCS Only Scenario | 281 | 51.8% | 18.8% | 29.3% |
| The 25%-CCS Only Scenario | 285 | 42.5% | 25.3% | 32.2% |

The results suggested that in the BAU Scenario, the NEM and the WEM will choose to install more gas capacity and generate more electricity from conventional fossil fuel technologies to accommodate the growth of energy demand for the period of 2020-21 to 2029-30. This result was attributed to the expiration of the current Renewable Energy Target in 2019-20. It was consistent with the assumption of no carbon emissions reduction target in place in the BAU Scenario.

In the other scenarios, the conventional fossil fuel energy generation and capacity continued to decrease and the LCETs energy generation and capacity (including the RETs and CCS) kept entering the market over the period of 2020-21 to 2029-30. This was mainly driven by various levels of carbon emissions reduction targets implemented in these scenarios (see Table 7.5 and Table 7.6).

**Table 7.6** The percentages of conventional fossil fuels, CCS and renewable installed capacity in each scenario in 2029-30.

| | **Total capacity in 2029-30 (GW)** | **Conventional Fossil Fuel Capacity (%)** | **CCS Technologies Capacity (%)** | **Renewable Technologies Capacity (%)** |
|---|---|---|---|---|
| The BAU Scenario | 68 | 72.7% | 0.0% | 27.3% |
| The 5%-26%_2030 Reduction Scenario (The CGP Scenario) | 78 | 58.0% | 0.0% | 42.0% |
| The 5% Reduction Scenario | 78 | 56.1% | 1.2% | 42.8% |
| The 25% Reduction Scenario | 81 | 50.7% | 3.1% | 46.1% |
| The 5%-26%_2030-RETs Only Scenario | 78 | 57.8% | 0.0% | 42.2% |
| The 5%-RETs Only Scenario | 79 | 55.9% | 0.0% | 44.1% |
| The 25%-RETs Only Scenario | 83 | 49.4% | 0.0% | 50.6% |
| The 5%-26%_2030-CCS Only Scenario | 78 | 57.9% | 5.2% | 36.9% |
| The 5%-CCS Only Scenario | 79 | 54.8% | 7.6% | 37.6% |
| The 25%-CCS Only Scenario | 81 | 49.3% | 10.1% | 40.6% |

Overall, the scenarios with the 25%-80% Reduction Target had the largest amount of energy generation and capacity from the LCETs in 2029-30. The scenarios with the 5%-26%-80% Reduction Target had the lowest amount of energy generation and capacity from the LCETs in 2029-30. This result was because the 5%-26%-80% Reduction Target executed lower carbon emissions reduction requirement than the 5%-80% and 25%-80% Reduction Targets did for the period of 2019-20 to 2029-30. Thus, the CGP scenario had the least amount of the LCETs energy generation and installed capacity among all scenarios apart from the BAU Scenario in 2029-30.

For the scenarios with the same technology assumption, the results revealed that more stringent carbon emissions reduction target led to higher penetration of both the RETs and/or the CCS technologies and lower energy output from conventional fossil fuel technologies (see Table 7.5 and 7.6).

Furthermore, for the scenarios with the same carbon reduction target, the scenario with the RETs Only assumption resulted in more energy generation and installed capacity from geothermal and solar thermal technologies. The scenario with the CCS Only assumption had larger penetration of coal CCS generation and capacity installation. These results demonstrated that the implementation of technology preference strategies will effectively promote the penetration of certain types of the LCETs in the Australian energy markets within a decade time.

Additionally, the results also suggested that current 5%-26%-80% Reduction Target committed by the Australian Government will delay the penetration of coal CCS generation and capacity installation in the Australian energy markets to beyond 2029-30. Moreover, it will also result in less penetration of renewable energy generation and capacity in 2029-30 compared to either the commitment of the 5%-80% Reduction Target or the 25%-80% Reduction Target.

The electricity generation and capacity profiles of the scenarios with the same technology assumption differed from each other in 2019-20 and 2029-30. Their energy generation and installed capacity profiles will eventually converge more or less the same to meet equal 80% Reduction Target in 2049-50 in the NEM and the WEM (see Table 7.7 and Table 7.8).

The BAU Scenario had mild growth of the conventional fossil fuel generation and capacity, and moderate reduction of the renewable generation and capacity in 2049-50 compared to those in 2019-20 and 2029-30. The results again demonstrated that when carbon emissions reduction targets are absent in the NEM and the WEM, at the same time, there are no other climate change policies in place, the NEM and the WEM will have no incentive to switch their power generation away from conventional fossil fuels. Conventional fossil fuels will still dominate the energy generation and installed capacity in the NEM and the WEM to 2049-50.

The CGP Scenario, the 5% and 25% Reduction Scenarios allowed the entries of both the RETs and the CCS technologies into the NEM and the WEM after 2019-20. In these scenarios, the conventional fossil fuel energy generation reduced to be around 10% of total generation, the CCS technologies (mainly coal CCS) produced approximately 50% of total generation and the RETs contributed to near 40% of total generation in 2049-50 (see Table 7.7). The installed conventional fossil fuel capacity in these scenarios decreased to be around 41% of total installed capacity n 2049-50. Meanwhile, the installed capacity of the CCS technologies and the RETs reached approximately 20% and 39% of total installed capacity in 2049-50 respectively (see Table 7.8).

**Table 7.7** The percentages of conventional fossil fuels, CCS and renewable energy generation in each scenario in 2049-50.

| | **Total generation in 2049-50 (TWh)** | **Conventional Fossil Fuel Energy (%)** | **CCS Technologies Energy (%)** | **Renewable Technologies Energy (%)** |
|---|---|---|---|---|
| The BAU Scenario | 332 | 83.2% | 0.0% | 16.8% |
| The 5%-26%_2030 Reduction Scenario (The CGP Scenario) | 364 | 10.2% | 51% | 38.8% |
| The 5% Reduction Scenario | 364 | 10.2% | 50.8% | 39.0% |
| The 25% Reduction Scenario | 360 | 10.6% | 47.6% | 41.9% |
| The 5%-26%_2030-RETs Only Scenario | 324 | 15.9% | 0.0% | 84.1% |
| The 5%-RETs Only Scenario | 324 | 15.8% | 0.0% | 84.2% |
| The 25%-RETs Only Scenario | 324 | 15.8% | 0.0% | 84.2% |
| The 5%-26%_2030-CCS Only Scenario | 383 | 8.5% | 69.9% | 21.7% |
| The 5%-CCS Only Scenario | 382 | 8.6% | 69% | 22.4% |
| The 25%-CCS Only Scenario | 379 | 8.9% | 66.1% | 25.0% |

The 5%-, 25%- and 5%-26%_2030-RETs Only Scenarios only allowed the entries of the RETs as the options of the LCETs in the NEM and the WEM after 2019-20. In these scenarios, the renewable energy generation took up more than 84% of total generation in 2049-50 (see Table 7.7). They had less than 16% of energy generated from conventional fossil fuels. In 2049-50, the renewable energy generation in these scenarios was largely from wind, geothermal, solar thermal and solar PV. In 2049-50, the installed conventional fossil fuel and renewable capacity reached approximately on average 28% and 72% of total installed capacity respectively in these scenarios (see Table 7.8).

**Table 7.8** The percentages of conventional fossil fuels, CCS and renewable capacity installed in each scenario in 2049-50.

| | **Total capacity in 2049-50 (GW)** | **Conventional Fossil Fuel Capacity (%)** | **CCS Technologies Capacity (%)** | **Renewable Technologies Capacity (%)** |
|---|---|---|---|---|
| The BAU Scenario | 84 | 77.8% | 0.0% | 22.2% |
| The 5%-26%_2030 Reduction Scenario (The CGP Scenario) | 104 | 40.9% | 20.4% | 38.7% |
| The 5% Reduction Scenario | 104 | 40.9% | 20.3% | 38.8% |
| The 25% Reduction Scenario | 105 | 40.4% | 18.7% | 40.9% |
| The 5%-26%_2030-RETs Only Scenario | 116 | 28.1% | 0.0% | 71.9% |
| The 5%-RETs Only Scenario | 116 | 28.0% | 0.0% | 72.0% |
| The 25%-RETs Only Scenario | 117 | 28.2% | 0.0% | 71.8% |
| The 5%-26%_2030-CCS Only Scenario | 103 | 41.1% | 30.9% | 27.9% |
| The 5%-CCS Only Scenario | 103 | 41.0% | 30.3% | 28.7% |
| The 25%-CCS Only Scenario | 105 | 40.3% | 28.1% | 31.5% |

The 5%-, 25%- and 5%-26%_2030-CCS Only Scenarios only allowed the entries of the CCS technologies as the options of the LCETs in the NEM and the WEM after 2019-20. In these scenarios, the conventional fossil fuel generation reduced to be only around 9% of total generation in 2049-50. They had approximately 66% to 70% of total energy generation from the CCS technologies and around 21% to 25% of total energy generation from the RETs in 2049-50 (see Table 7.7). These scenarios had on average approximately 41%, 30% and 29% of total installed capacity from conventional fossil fuel technologies, the CCS technologies and the RETs respectively in 2049-50 (see Table 7.8). In both the NEM and the WEM, coal CCS technologies were the major types of CCS technologies entered the market. The gas CCS technologies only entered the WEM at last two years of the planning period.

The execution of carbon emissions reduction targets including the 5%-26%-80%, 5%-80% and 25%-80% Reduction Targets (please refer to Section 3.2.3 in Chapter 3) led to the reduction of carbon emissions in the NEM and the WEM over the planning period. The modelling results demonstrated that it can apply both the RETs and the CCS technologies or solely rely on the RETs or the CCS technologies after 2019-20 to achieve proposed long-term emissions reduction targets in the NEM and the WEM. However, the costs for carrying out capacity expansion with different combinations of energy technologies will vary to a large extent.

The modelling results revealed that wind technology was the most competitive energy technology among all types of LCETs to enter the NEM and the WEM by 2019-20, influenced by the cost assumptions and the Renewable Energy Target. By implementing sufficient levels of carbon emissions reduction targets, coal CCS and geothermal technologies competed to enter the NEM and the WEM. The large scale solar PV, solar thermal and gas CCS technologies were the least competitive types of LCETs.

Different generator total costs required for expanding the NEM and the WEM power system resulted from a variety of shares of conventional fossil fuel and the LCETs energy generation and installed capacity in each scenario, as listed in Table 7.9.

The sum of the generator total cost of the NEM and the WEM in the BAU Scenario was the lowest among all scenarios, totalling at AU$319.2 billion. It was followed by the CGP Scenario of AU$694.9 billion, representing approximately 117.7% more than the total cost of the BAU Scenario.

The generator total costs of the other scenarios were all higher than the total cost of the CGP Scenario. The 5% and 25% Reduction Scenario had generator total costs of AU$717.8 billion and AU$774.4 billion respectively, standing for approximately 3.3% and 11.4% higher than the total cost of the CGP Scenario.

For the RETs Only Scenarios, the scenario with the 5%-26%-80% Reduction Target had the lowest generator total cost and the scenario with the 25%-80% Reduction Target resulted in the highest generator total cost. The generator total cost of the scenario with the 5%-80% Reduction Scenario was in the middle. The CCS Only

Scenarios had the similar results with the scenario's ranking of the generator total cost (see Table 7.9).

**Table 7.9** The sum of the generator total cost of the NEM and the WEM by scenario.

| Model | Total Generation Cost | FO&M Cost | Annualized Build Cost | Total |
|---|---|---|---|---|
| The BAU Scenario | 153.8 | 110.5 | 54.9 | 319.2 |
| The 5%-26%_2030 Reduction Scenario (The CGP Scenario) | 192.1 | 198.6 | 304.4 | 694.9 |
| The 5% Reduction Scenario | 195.4 | 199 | 323.4 | 717.8 |
| The 25% Reduction Scenario | 202.1 | 203.8 | 368.5 | 774.4 |
| The 5%-26%_2030-RETs Only Scenario | 158.6 | 232.2 | 367.3 | 758.1 |
| The 5%-RETs Only Scenario | 157 | 231.4 | 393.7 | 782.2 |
| The 25%-RETs Only Scenario | 160.2 | 236.2 | 442.7 | 839.2 |
| The 5%-26%_2030-CCS Only Scenario | 232.1 | 179.4 | 305.3 | 716.8 |
| The 5%-CCS Only Scenario | 235.4 | 179.3 | 326.2 | 741 |
| The 25%-CCS Only Scenario | 246.9 | 180.3 | 373.8 | 801.1 |

The generator total costs for the 5%-26%_2030-, 5%- and 25%-RETs Only Scenarios were at AU$758.1 billion, AU$782.2billion and AU$839.2 billion respectively. They were approximately 9.1%, 23.5% and 20.7% more than the generator total cost of the CGP Scenario. The 5%-26%_2030-, 5%- and 25%-CCS Only Scenarios resulted in the generator total costs of AU$716.8 billion, AU$741.0 billion and AU$801.1billion respectively, accounting for approximately 3.2%, 6.6% and 15.3% of the generator total cost of the CGP Scenario.

In terms of carbon avoiding costs, the results suggested that the expansion pathway deploying both the RETs and CCS technologies had lower carbon avoiding costs than the RETs only and CCS only pathways in both the NEM and the WEM.

In the NEM, the expansion pathways constrained by the RETs Only assumption had higher carbon avoiding costs than the pathways constrained by the CCS Only assumption (please note that conventional fossil fuel technologies were still allowed to enter the market for all scenarios). This result was opposite to the result in the WEM. One possible explanation for this difference is that a higher amount of spinning reserve capacity was needed to be built in the RETs only scenarios in the NEM to secure minimum reserve margin.

Table 7.10 lists the combined cost of avoiding $CO_2$-e emissions of the NEM and the WEM by scenario over the modelling period. The scenarios with the deployment of both the RETs and the CCS technologies after 2019-20 resulted in lower combined carbon avoiding cost than the avoiding costs of the RETs Only Scenarios and the CCS Only Scenarios. This result is similar as the costs of avoiding $CO_2$-e emissions in the NEM and the WEM individually.

**Table 7.10** Combined cost of avoiding $CO_2$-e emissions in the NEM and WEM by scenarios

| | **BAU** | **5%-26%_2030 Reduction (CGP)** | **5% Reduction** | **25% Reduction** | **5%-26%_2030-RETs Only** | **5%-RETs Only** | **25%-RETs Only** | **5%-26%_2030-CCS Only** | **5%-CCS Only** | **25%-CCS Only** |
|---|---|---|---|---|---|---|---|---|---|---|
| Generator Total Cost (Billon AU$) | 319.2 | 695.0 | 717.8 | 774.4 | 758.2 | 782.2 | 839.1 | 716.8 | 741.0 | 801.0 |
| Generator Total Cost Relative to BAU Scenario's (Billon AU$) | 0.0 | 375.7 | 398.5 | 455.2 | 438.9 | 463.0 | 519.9 | 397.5 | 421.8 | 481.8 |
| Accumulative $CO_2$-e Emissions (Mt) | 9085.4 | 4750.3 | 4507.4 | 3863.4 | 4750.3 | 4507.4 | 3863.4 | 4750.3 | 4507.4 | 3863.4 |
| $CO_2$-e Savings (Mt) | 0.0 | 4335.1 | 4578.0 | 5222.0 | 4335.1 | 4578.0 | 5222.0 | 4335.1 | 4578.0 | 5222.0 |
| Cost of Avoiding $CO_2$-e emissions (AU$/t) | n/a | 86.7 | 87.1 | 87.2 | 101.2 | 101.1 | 99.6 | 91.7 | 92.1 | 92.3 |

The combined carbon avoiding costs of the RETs Only Scenario were higher the combined carbon avoiding cost of the CCS Only Scenario (see Table 7.10). This result was consistent with the result in the NEM PLEXOS Model. This consistency was attributed to the significant higher carbon avoiding costs of the RETs Only Scenarios and the CCS Only Scenarios in the NEM PLEXOS Model than the costs in the WEM PLEXOS Model.

The combined carbon avoiding costs of the CGP Scenario was the lowest at AU$87.1/t, followed by the 5% and 25% Reduction Scenarios at AU$87.2/t and AU$86.7/t respectively. If judging from achieving the assumed carbon reduction target with the lowest generator total cost and the lowest carbon avoiding cost, the simulation results of the CGP Scenario may be the preferred electric power system expansion pathway for the NEM and the WEM.

If considering the combined factors of the generator total cost, the carbon avoiding cost and the amount of cumulative emissions avoided compared to the BAU Scenario, perhaps the simulation results of the 25% Reduction Scenarios will be the optimal solution for the NEM and the WEM to expand their electric power systems. The generator total cost of the 25% Reduction Scenario was AU$79.5 billion more or 11.4% higher than the generator total cost of the CGP Scenario. Meanwhile, the combined carbon avoiding cost of the 25% Reduction Scenario was AU$0.5/t more or around 0.58% higher than the combined carbon avoiding cost of the CGP Scenario. However, it can avoid approximately 886.9 Mt or 20.5% more carbon emissions than the CGP Scenario can over the planning period.

The generator total cost of the 5% Reduction was AU$22.9 billion more or 3.3% higher than that of the CGP Scenario. At the same time, the combined carbon avoiding cost of the 5% Reduction Scenario was AU$0.4/t more or around 0.46% higher than the combined carbon avoiding cost of the CGP Scenario. The 5% Reduction Scenario resulted in cutting approximately 242.8 Mt or 5.3% of cumulative carbon emissions more than the cumulative emissions of the CGP Scenario.

Therefore, the 25% Reduction Scenario resulted in more economically reducing carbon emissions for the NEM and the WEM based on the effectiveness of cutting cumulative emissions in the CGP Scenario, 5% Reduction and 25% Reduction Scenario described above.

The 5%-26%_2030-RETs Only Scenario and the 5%-26%_2030-CCS Only Scenario achieved similar amount of avoided cumulative emissions as the CGP Scenario did. Nevertheless, they both had higher generator total costs and the carbon avoiding costs than those of the CGP Scenario.

The 5%-RETs Only Scenario and the 5%-CCS Only Scenario realised similar amount of the cumulative carbon emissions as that of the 5% Reduction Scenario. However, these two scenarios also had higher generator total costs and the carbon avoiding costs than those of the 5% Reduction Scenario.

Similarly, the 25%-RETs Only Scenario and the 25%-CCS Only Scenario had similar amount of the cumulative carbon emissions as that of the 25% Reduction Scenario. Nonetheless, these two scenarios also had higher generator total costs and the carbon avoiding costs than those of the 25% Reduction Scenario.

## 7.2 Research Implications

The results of the NEM and WEM PLEXOS Models demonstrated that if the Australian electric power system does not implement any major carbon emissions mitigation policies beyond 2019-20, its electricity generation will deepen its reliance on conventional fossil fuel technologies from the period of 2020-21 to 2049-50. Its carbon emissions will continue to rise to 2049-50.

The climate talks held in Warsaw (2013) and Lima (2014) reached an agreement that all countries need to submit their proposed emissions reduction targets as “intended nationally determined contributions (INDCs)” for the Paris Climate Conference held in December 2015 (GCCSI 2015). The INDCs will essentially determine whether the world would achieve an ambitious 2015 agreement and construct a path toward a low-carbon and climate-resilient future.

The Australian Government has set its INDC in August 2015 and stated as implementing an economy-wide target to reduce GHGs by 26% to 28% below 2005 levels by 2030. The Australian Government will bring this INDC to the Paris Climate Conference and finalise this commitment under a new global agreement (Australian Government 2015).

For achieving the Australian Government’s proposed INDC, based on current existing carbon intensive electric power system, the modelling results revealed that different types of renewable technologies and coal CCS technologies will need to enter the Australian electric power sector to reduce carbon emissions.

As revealed by the simulation results, if there was no carbon emissions reduction target in place, the LCETs except wind technology, had little chance to penetrate the NEM and the WEM after 2020-21. This suggested that presently the RETs and CCS technologies are not as competitive as the conventional fossil fuel technologies to enter the NEM and the WEM. Therefore, certain carbon reduction targets or climate change policies will be required to put in place in order to advance the deployment of the LCETs in the NEM and the WEM in a carbon-constrained future.

The Renewable Energy Target was demonstrated to be an effective instrument to promote the penetration of wind energy in the NEM and WEM, and the penetration of solar PV technologies in the NEM by 2019-20. However, the Renewable Energy Target was not sufficient to drive the entry of the other type of renewable technologies in the NEM and WEM. In the BAU Scenario, without the application of any carbon emissions reduction target; there was no geothermal, solar thermal and solar PV energy generation developed over entire planning period.

The current Renewable Energy Target did result in lower share of renewable energy generation in the Australian electricity market by 2019-20, compared to the previous Renewable Energy Target. Therefore, enforcing higher Renewable Energy Target with longer operation period beyond 2019-20 will be an effective tool to increase market penetration of renewable energy technologies, and consequently, to reduce carbon emissions in the NEM and the WEM.

In the NEM's scenarios with the carbon reduction targets, the results revealed that the levels of carbon reduction targets will not have major effects on the entry time of the geothermal, solar thermal and solar PV technologies. The market entering time for these technologies will be more affected by their assumed available entry dates in the model.

Nevertheless, the magnitude of carbon reduction targets will influence the amount of geothermal capacity installed by 2029-30, and the amount of solar thermal and solar PV capacity installed after 2029-30. More stringent carbon emissions reduction targets will drive more penetration of the geothermal energy by 2029-30 and more penetration of solar thermal and solar PV energy after 2029-30 in the NEM.

This indicated that the readiness of the geothermal, solar thermal and solar PV technologies is a critical factor influencing their future prosperity of deployment. The earlier they are available to enter the market; the more penetration will be achieved under the same carbon emissions reduction targets. This suggests that geothermal and solar thermal could play important roles in cutting carbon emissions and meeting the growth of energy demand in the NEM if sufficient supporting mechanisms are committed by the government and industry. The supporting mechanisms should aim at accelerating their demonstration, development and deployment, and bringing forward their technological and commercial available date (Fischer and Newell 2008; Menanteau, Finon and  Lamy 2003).

In the WEM's scenarios with the carbon reduction targets, the results suggested that the carbon reduction targets will have relatively minor effects on the entry time of the geothermal and solar PV technologies. Even though higher carbon reduction levels will drive earlier entry of geothermal and solar PV technologies, their entry dates in the WEM were much later than the dates in the NEM. Solar thermal technologies will be too expensive to enter the WEM under the assumed carbon reduction targets in this study.

Coal CCS technologies especially the black coal oxy-combustion equipped with CCS technologies could enter the NEM after 2019-20 - driven by the carbon emissions reduction targets. Higher level of carbon reduction targets will lead to earlier market penetration of the coal CCS technologies. Natural gas CCS technologies will not be competitive enough to enter the NEM by 2049-50, even under the influences of carbon reduction target. Natural gas CCS technologies will only enter the WEM at the end of modelling period and will not reach a significant level of capacity installation.

This result suggested that the black coal oxy-combustion equipped with CCS was the most competitive type of CCS technologies in Australian electricity market in the model. The Australian Government and industry could target the advancement of this type of CCS technology instead of other CCS technologies. This would accelerate the earlier and higher penetration of the CCS technologies in the NEM and the WEM by 2049-50, especially when the retrofit of existing coal generation capacity with CCS technologies is not available or practical.

Comparing the RETs Only Scenarios and the CCS Only Scenarios revealed that when CCS technologies are not available for the deployment, there will be significantly higher solar thermal and solar PV energy generation in the NEM; and more geothermal and solar thermal energy generation in the WEM. Solar thermal technologies will only enter the WEM if the CCS technologies are not available for the deployment.

This indicated that the geothermal, solar thermal and solar PV, especially solar thermal will compete with the CCS technologies to enter the NEM and the WEM in the period of 2020-21 to 2049-50. The magnitude of cost reduction and the timing of technology readiness of these technologies will determine their penetration rates in the Australian electric power system to 2049-50.

Overall, the CGP Scenario represented the capacity expansion pathway with the lowest generator total cost and the carbon avoiding cost to achieve the 80% reduction of carbon emissions below 2000 emissions levels by 2049-50 in the NEM. It also represented the least cost pathway to expand the WEM and achieve the 80% reduction of carbon emissions below 2007-08 emissions levels by 2049-50 with the lowest carbon avoiding cost.

At the same time, the modelling results suggested that if the NEM and the WEM would implement more ambitious carbon emissions reduction targets, more investments will be required to increase the share of the LCETs generation in two markets.

For the NEM, implementing a stricter 5%-80% Reduction Target will cost at least extra AU$21.9 billion (3.4%) more generator total cost than the CGP Scenario to cut additional 234.4 Mt (5.3%) of emissions based on the cumulative carbon emissions of the CGP Scenario. Enforcing a more ambitious 25%-80% Reduction Scenario in the NEM will result in a further AU$76.1 billion (11.9%) spending on the system expansion compared to the CGP Scenario. Meanwhile, this ambitious reduction target will achieve extra 827.7 Mt (18.8%) of emissions saving from the cumulative carbon emissions of the CGP Scenario.

Similarly, for achieving 5%-80% Reduction Target, extra AU$1.0 billion (1.8%) investment would be required in the WEM compared to the generator total cost of the CGP Scenario. This will resulted in 8.0 Mt (2.5%) of emissions saving than the cumulative carbon emissions of the CGP Scenario. For realising the 25%-80% Reduction Target in the WEM, the 25% Reduction Scenario will cost AU$3.4 billion more or 6.2% higher than the generator total cost of the CGP Scenario. It will lead to 59 Mt lower or 17.3% less than the cumulative emissions of the CGP Scenario.

If we consider the NEM and the WEM as a whole, the combined results indicated that the generator total costs of the 5% and 25% Reduction Scenarios were AU$22.9 billion (3.3%) and AU$79.5 billion (11.4%) more than the generator total cost of the CGP Scenario respectively. At the same time, they can avoid 242.8 Mt (5.3%) and 886.9 Mt (20.5%) of cumulative carbon emissions more than CGP Scenario respectively.

When the market was subject to certain carbon emissions reduction targets, the optimal strategy for the NEM and the WEM to expand their electric power systems was to deploy both the RETs and CCS after 2020-21. It indicated that instead of facilitating the development of either the RETs or the CCS technologies, the government should promote the development of the RETs and CCS technologies at the same time with similar weights. The faster the costs of the RETs and CCS are reduced, the earlier they can enter the NEM and the WEM, and the carbon emissions could be reduced in a more cost effective way.

## 7.3 Further Research

This research investigated the expansion of the NEM and the WEM in a carbon-constrained future by setting specific carbon emissions reduction targets according to the Australian Government’s current and potential policies. This setting did not limit the instrument choices that can be applied to reduce the carbon emissions in the Australian electric power system. It allows the flexibility of choosing different types of strategies including technological and policy strategies to achieve carbon emissions reduction targets in the NEM and the WEM. This research provided a plausible approach to project the least-cost capacity expansion pathways for the NEM and the WEM to 2049-50 within a carbon-constrained world.

Further research can be conducted to investigate in details that whether command-and-control regulation and/or economic instruments like a carbon price or trading scheme would be more effective and efficient to achieve projected capacity expansion pathways in the NEM and the WEM.

For achieving similar level of carbon reduction targets, the WEM had overall lower carbon avoiding costs for the capacity expansion with the deployment of both the RETs and CCS technologies, the deployment of only the RETs and the deployment of only the CCS technologies compared to the NEM results. Further research can be carried out in examining whether setting the carbon reduction targets for the electric power system at a state level in the NEM would achieve more cost effective carbon reduction results than setting the reduction target as a whole in the NEM.

This research is not a renewable energy integration study which seeks to understand the impacts of variable and uncertain wind and solar generation on the planning operations of electric power systems and networks. The US National Renewable Energy Laboratory's Western Wind and Solar Integration Study found that the integration of 35% wind and solar energy into the electric power system will not require extensive infrastructure if changes are made to operational practices (National Renewable Energy Laboratory 2010).

This research results showed that in the NEM, the variable wind and solar PV generation together accounted for around 9.9%, 18.2%, 31.8% and 16.0% of total energy generation in the BAU Scenario, the Carbon Reduction Scenarios, the RETs Only and the CCS Only Scenarios respectively in 2049-50.

In the WEM, the variable wind and solar PV generation together contributed to approximately 8.6%, 29.7%, 31.3% and 21% of total energy generation in the BAU Scenario, the Carbon Reduction Scenarios, the RETs Only and the CCS Only Scenarios respectively in 2049-50.

Nevertheless, further research could be done to investigate grid expansion requirements and costs to accommodate the capacity expansion pathways projected by this study.

# APPENDIX 1 Australian Electricity Markets

The NEM is also one of the longest continuous alternating current systems in the world, which covers a distance of 45000 kilometres. The establishment of the NEM was the result of the deregulation movement that occurred in the Australian electricity sector since the early 1990s (Roarty 1998). In December 1998, the NEM commenced its operation as a wholesale spot market for electricity supply with initial physical coverage excluding TAS (Outhred 1998). TAS eventually joined the NEM via the undersea Basslink direct current link connected to Victoria in 2005 and became the sixth region of the NEM operation (NERA 2007). The Australian Energy Regulator (AER) was set up in 2005 to perform economic regulation and enforce the National Electricity Law and the National Electricity Rules in the NEM. In 2009, an integrated system operator the AEMO was created to manage the NEM and gas markets in eastern and southern Australia with the duty to ensure power system security, generate pricing for network service, and execute the national transmission planning (KPMG 2013).

The restructuring of the electricity sector in WA was commenced in the early 2000s. The central reform was the disaggregation of a single state electricity utility into entities responsible for generation, transmission and distribution, and retail individually in 2006 (AER 2009). The WEM as established in the same year operated by the IMO under the governance of the Wholesale Electricity Market Rules (AEMO 2012e). In conjunction with the IMO, independent state regulator the Economic Regulation Authority (ERA) is responsible for performing surveillance on the WEM (Energy Supply Association of Australia 2014). In January 2014, the WA government merged the state-owed electricity generation and retail business. This merging has been criticised as one contributor to the high electricity price since in the WEM. Further restructure to the WEM has been discussed and recommended by the ERA (ERA 2014).

Because of relatively small population and remoteness, the electricity supply in NT is dominated by a state-owed integrated electric utility: Power and Water Corporation. It was established in 1997 covering operations of electricity generation, transmission and distribution, and retailing (Roarty 1998). A wholesale electricity spot market was not considered feasible for the NT given its small scale. Nevertheless, NT State Utilities Commission has recommended the wholesale electricity market arrangement in the state for improving the efficiency and competitiveness of electricity supply service (Yuan and Lyon 2012).

In July 2014, the Power and Water Corporation in the NT was separated into three government owned corporations: Power and Water Corporation, a Power Retail Corporation (Jacana Energy) and a Power Generation Corporation (Territory Generation). Currently, Territory Generation is now the largest electricity producer in NT, owning 592 MW of installed capacity and contracting an additional 114.5 MW from Independent Power Producers for supplying power to its customers (Northern Territory Government 2014).

# APPENDIX 2 Australian Climate Change Policies

## The Renewable Energy Target

The implementation of the Renewable Energy Target aims at driving investments in renewable industry, increasing renewable penetration in Australian electricity generation, and reducing carbon emissions. The Renewable Energy Target allows both large and small-scale renewable power generators to create renewable energy certificates for every MWh of power they generate. The electricity retailers must purchase the certificates to a specified percentage of their electricity. This creates a mandatory demand for electricity generated from renewable sources and provides financial incentives for renewable generators and investors (CER 2014a).

The evolution of current Renewable Energy Target was commenced in 2001 through the establishment of the Mandatory Renewable Energy Target (MRET) by the Howard Government under the Renewable Energy (Electricity) Act 2000. The MRET created a target of 9,500 GWh of new renewable electricity generation by 2010. In 2009, the Renewable Energy (Electricity) Amendment Act 2009 was passed and the Rudd Government has increased the MRET from 9,500 GWh by 2010 to 45,000 GWh by 2020 to achieve 20 per cent penetration of renewable generation (through to 2030) to established the enhanced Renewable Energy Target scheme.

In 2011, the 45,000 GWh renewable energy target was split into two schemes to establish current enhanced Renewable Energy Target: the LRET, consisting of 41,000 GWh by 2020; and the Small-Scale Renewable Energy Scheme (SRES), with a notional, but uncapped, target of 4,000 GWh (CER 2014a).

The Renewable Energy Target has encouraged significant renewable electricity generation. The capacity of renewable generation has almost doubled as a result of the scheme since 2001 (Climate Change Authority 2012). Although the net impact of the Renewable Energy Target on the retail energy prices is not clear, it has and will likely continue to suppress wholesale pool energy price via the merit order effect. At the same time, it has reduced the carbon emissions by displacing existing or new entrant thermal generation that would otherwise have operated to meet demand (Frontier Economics 2014b). Between 2001 and 2012, the Renewable Energy Target scheme reduced emissions by an estimated 20 Mt $CO_2$-e (SKM 2012).

## The Carbon Pricing Mechanism

In July 2011, the Australian Government published a comprehensive package of clean energy proposals that included the introduction of a revised CPM and the provision of significant levels of financial support for innovation in clean energy technologies. Its associated legislation *the Clean Energy Act 2011* has established in November of the same year, which provided a legal framework for a carbon emissions trading system starting with a three-year fixed carbon price phase from July 2012 (Talberg, Hui and Loynes 2013).

The CPM put a price of AU$23 per tonne on $CO_2$-e, rising by 2.5% per year until 2015. On 1 July 2015, this would transit to a flexible market determined price. This scheme has been repealed on 17 July 2014 (Department of Employment 2014).

The CPM required Australia's largest GHG emitters to acquire and surrender eligible units for each tonne of $CO_2$-e they emit. This created financial incentives for liable emitters to take actions to reduce emissions. The CPM covered more than half of Australia's emissions, including emissions from electricity generation, direct combustion, landfills, wastewater, industrial processes and fugitives (CCA 2014a). For the first two years of implementation of the CPM (1 July 2012 to 30 June 2014), it was estimated that the CPM reduced between 11 and 17 Mt $CO_2$ emissions from electricity generation (O'Gorman and Jotzo 2014).

## The Emissions Reduction Fund

Functioning as a climate change policy for replacing the scrapped CPM, the ERF gained the legislative effect as an amendment in *the Carbon Farming Initiative Amendment Bill 2014* which passed the Senate on 31 October, 2014. It built on the CFI by offering emissions reduction opportunities to a range of sources beyond the land sector (Australian Government 2014c). With a total amount of AU$2.55 billion, the fund has been being used to purchase lowest cost abatement from a wide range of sources, providing an incentive to businesses, households and landowners to proactively reduce their emissions (CER 2014b). Further modelling work on the ERF is required to identify its effectiveness in achieving a 5% emissions reduction target based on 2000 level by 2020 (Department of the Environment n.d.).

## Funding Mechanism

In addition to the previously mentioned climate change policies, the Australian Government has also established major funding bodies in 2012: the CEFC and the ARENA to facilitate the development of low carbon energy technologies. The CEFC is a clean energy investment fund working together with the private sector to fund emission reduction projects. As at 30 June 2014, the CEFC has contracted investments of over AU$900 million in projects, a total value of which was over AU$3 billion. It estimated its portfolio achieved about 4 Mt $CO_2$-e of emissions reductions annually at a negative cost (or a net return or benefit) of AU$2.40/t $CO_2$-e (Clean Energy Finance Corporation 2014).

The ARENA is the renewable energy investment fund with targets of improving the competiveness of renewable energy technologies and increasing the supply of renewable energy in Australia. Until 30 June 2014, the ARENA has provided or committed AU$1.2 billion supporting more than 200 projects with a total project value of around AU$3.5 billion. ARENA attracted AU$1.90 in additional financial support for projects, and AU$1.60 for studies and research and development activities for every dollar it spent (ARENA 2014).

# APPENDIX 3 Chapter 5 Modelling Results

This appendix reports the detailed simulation results of the NEM PLEXOS Model. It includes modelling results of carbon emissions, electricity generation, capacity installation and system levilised costs for the NEM's capacity system expansion from 2012-13 to 2049-50. The results reporting is categorised by the modelling scenarios, including the BAU Scenario, the 5% Reduction Scenario, the 25% Reduction Scenario, the 5%-26%_2030 Reduction (CGP) Scenario, the 5%-RETs Only Scenario, the 25%-RETs Only Scenario, the 5%-26%_2030-RETs Only Scenario, the 5%-CCS Only Scenario, the 25%-CCS Only Scenario and the 5%-26%_2030-CCS Only Scenario.

Table A3.1 reports four sets of carbon emissions results for the BAU Scenario, the scenarios with 5%-80% Reduction Target, the scenarios with 25%-80% Reduction Targets and the Scenarios with 5%-26%-80% Reduction Targets respectively. The carbon emissions results of the BAU Scenario were calculated by the NEM PLEXOS Model. The other three sets of carbon emissions results were calculated by the researcher using the linear extrapolation. The data in Table A3.1 was plotted as Figure 5.1 in Section 5.1, Chapter 5.

**Table A3.1** The NEM's Carbon emissions results by carbon emissions reduction target groups from 2012-13 to 2049-50 (Unit: Mt).

| Year | The BAU Scenario | The Scenarios with 5%-80% Reduction Targets | The Scenarios with 25%-80% Reduction Targets | The Scenarios with 5%-26%-80% Reduction Targets |
|---|---|---|---|---|
| **2012-13** | 186.1 | 186.1 | 186.1 | 186.1 |
| **2013-14** | 188.3 | 188.3 | 188.3 | 188.3 |
| **2014-15** | 201.6 | 183.0 | 177.5 | 183.0 |
| **2015-16** | 194.2 | 177.7 | 166.7 | 177.7 |
| **2016-17** | 194.3 | 172.4 | 155.9 | 172.4 |
| **2017-18** | 195.9 | 167.1 | 145.2 | 167.1 |
| **2018-19** | 196.1 | 161.8 | 134.4 | 161.8 |

| | | | | |
|---|---|---|---|---|
| **2019-20** | 196.4 | 156.6 | 123.6 | 156.6 |
| **2020-21** | 199.8 | 152.4 | 120.6 | 154.0 |
| **2021-22** | 202.2 | 148.3 | 117.6 | 151.4 |
| **2022-23** | 203.2 | 144.2 | 114.5 | 148.9 |
| **2023-24** | 204.6 | 140.1 | 111.5 | 146.3 |
| **2024-25** | 206.6 | 136.0 | 108.5 | 143.8 |
| **2025-26** | 209.9 | 131.8 | 105.5 | 141.2 |
| **2026-27** | 211.8 | 127.7 | 102.5 | 138.7 |
| **2027-28** | 214.5 | 123.6 | 99.4 | 136.1 |
| **2028-29** | 216.3 | 119.5 | 96.4 | 133.6 |
| **2029-30** | 217.7 | 115.4 | 93.4 | 131.0 |
| **2030-31** | 219.1 | 111.3 | 90.4 | 126.1 |
| **2031-32** | 220.4 | 107.1 | 87.4 | 121.2 |
| **2032-33** | 222.4 | 103.0 | 84.3 | 116.3 |
| **2033-34** | 224.4 | 98.9 | 81.3 | 111.4 |
| **2034-35** | 226.1 | 94.8 | 78.3 | 106.5 |
| **2035-36** | 228.7 | 90.7 | 75.3 | 101.6 |
| **2036-37** | 230.8 | 86.5 | 72.3 | 96.7 |
| **2037-38** | 233.0 | 82.4 | 69.2 | 91.8 |
| **2038-39** | 234.8 | 78.3 | 66.2 | 86.9 |
| **2039-40** | 236.9 | 74.2 | 63.2 | 82.0 |
| **2040-41** | 238.2 | 70.1 | 60.2 | 77.1 |
| **2041-42** | 240.6 | 65.9 | 57.2 | 72.2 |
| **2042-43** | 242.3 | 61.8 | 54.1 | 67.3 |
| **2043-44** | 244.7 | 57.7 | 51.1 | 62.4 |
| **2044-45** | 246.1 | 53.6 | 48.1 | 57.5 |
| **2045-46** | 248.0 | 49.5 | 45.1 | 52.6 |
| **2046-47** | 249.8 | 45.4 | 42.1 | 47.7 |

| | | | | |
|---|---|---|---|---|
| **2047-48** | 252.0 | 41.2 | 39.0 | 42.8 |
| **2048-49** | 254.0 | 37.1 | 36.0 | 37.9 |
| **2049-50** | 256.0 | 33.0 | 33.0 | 33.0 |

Table A3.2, Table A3.3, Table A3.4, Table A3.5 and Table A3.6 report the NEM PLEXOS modelling results of electricity generation.

Table A3.2 and Table A3.3 show the electricity generation results of the BAU Scenario in 2012-13 and 2013-14. They were plotted by Figure (5.2-a) and Figure (5.2-b) in Section 5.2.1, Chapter 5 respectively.

**Table A3.2** The NEM's electricity generation results of the BAU Scenario in 2012-13 (unit: TWh).

| Technology | Generation |
|---|---|
| Black Coal | 104.0 |
| Brown Coal | 54.0 |
| CCGT | 13.9 |
| OCGT | 8.5 |
| Liquid Fuel | 0.0 |
| Coal CCS | 0.0 |
| Gas CCS | 0.0 |
| Hydro | 15.5 |
| Wind | 8.1 |
| Biomass | 0.0 |
| Geothermal | 0.0 |
| Solar Thermal | 0.0 |
| Solar PV | 0.0 |
| **Total** | **204.0** |

**Table A3.3** The NEM's electricity generation results of the BAU Scenario in 2013-14 (unit: TWh).

| **Technology** | **Generation** |
|---|---|
| Black Coal | 119.9 |
| Brown Coal | 58.7 |
| CCGT | 5.3 |
| OCGT | 2.6 |
| Liquid Fuel | 0.0 |
| Coal CCS | 0.0 |
| Gas CCS | 0.0 |
| Hydro | 15.8 |
| Wind | 10.6 |
| Biomass | 0.0 |
| Geothermal | 0.0 |
| Solar Thermal | 0.0 |
| Solar PV | 0.0 |
| **Total** | **213.0** |

The data in Table A3.4, Table A3.5 and Table A3.6 display the electricity generation results of all scenarios in 2019-20, 2029-30 and 2049-50 by technology. These results were plotted accordingly in Figure 5.3, Figure 5.4 Figure 5.5, Figure 5.6, Figure 5.7, Figure 5.8, Figure 5.9, Figure 5.10, Figure 5.11, Figure 5.12 and Figure 5.13 in Section 5.2.2 and Section 5.2.3, Chapter 5.

**Table A3.4** The NEM's electricity generation results of in 2019-20 by technology and scenario (unit: TWh).

| **Technology** | **BAU** | **5% Reduction** | **25% Reduction** | **5%-RETs Only** | **25%-RETs Only** | **5%-CCS Only** | **25%-CCS Only** | **5%-26% _2030 Reduction** | **5%-26% _2030-RETs Only** | **5%-26% _2030-CCS Only** |
|---|---|---|---|---|---|---|---|---|---|---|
| Black Coal | 124.1 | 115.8 | 100.3 | 116.3 | 99.2 | 112.3 | 106.7 | 116.2 | 116.0 | 116.5 |
| Brown Coal | 54.6 | 29.3 | 6.7 | 29.1 | 10.5 | 35.8 | 6.6 | 29.0 | 29.2 | 34.7 |
| CCGT | 4.4 | 23.7 | 34.2 | 23.7 | 29.2 | 4.4 | 25.5 | 23.7 | 23.7 | 4.4 |
| OCGT | 0.2 | 0.8 | 5.3 | 0.6 | 5.2 | 1.1 | 4.8 | 0.7 | 0.8 | 0.2 |
| Liquid Fuel | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Coal CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Gas CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Hydro | 15.9 | 15.9 | 15.9 | 15.9 | 15.9 | 15.9 | 15.9 | 15.9 | 15.9 | 15.9 |
| Wind | 27.8 | 38.7 | 52.3 | 36.9 | 52.1 | 53.3 | 53.5 | 38.6 | 38.6 | 52.1 |
| Biomass | 1.3 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 |
| Geothermal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Solar Thermal | 0.0 | 0.5 | 8.1 | 2.4 | 11.1 | 1.7 | 10.1 | 0.5 | 0.5 | 0.9 |
| Solar PV | 1.7 | 1.7 | 2.0 | 1.7 | 2.0 | 1.7 | 2.0 | 1.7 | 1.7 | 1.7 |
| **Total** | **230.1** | **227.8** | **226.2** | **228.0** | **226.6** | **227.7** | **226.4** | **227.8** | **227.8** | **227.7** |

**Table A3.5** The NEM's electricity generation results of in 2029-30 by technology and scenario (unit: TWh).

| **Technology** | **BAU** | **5% Reduction** | **25% Reduction** | **5%-RETs Only** | **25%-RETs Only** | **5%-CCS Only** | **25%-CCS Only** | **5%-26% _2030 Reduction** | **5%-26% _2030-RETs Only** | **5%-26% _2030-CCS Only** |
|---|---|---|---|---|---|---|---|---|---|---|
| Black Coal | 140.6 | 99.4 | 80.0 | 96.4 | 83.2 | 96.0 | 74.3 | 110.4 | 104.7 | 111.5 |
| Brown Coal | 58.8 | 6.4 | 3.8 | 8.8 | 2.0 | 8.0 | 6.6 | 13.0 | 17.7 | 9.5 |
| CCGT | 4.8 | 25.1 | 25.2 | 25.1 | 24.7 | 25.6 | 25.5 | 22.7 | 22.7 | 25.7 |
| OCGT | 0.3 | 2.5 | 0.8 | 3.3 | 1.8 | 1.7 | 1.8 | 0.3 | 0.3 | 0.9 |
| Liquid Fuel | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Coal CCS | 0.0 | 7.9 | 22.3 | 0.0 | 0.0 | 52.9 | 72.1 | 0.0 | 0.0 | 35.5 |
| Gas CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Hydro | 16.0 | 15.9 | 15.9 | 15.9 | 15.9 | 15.9 | 15.9 | 15.9 | 15.9 | 15.9 |
| Wind | 27.6 | 53.1 | 53.1 | 53.1 | 53.1 | 53.0 | 53.1 | 53.1 | 53.1 | 51.8 |
| Biomass | 1.6 | 8.2 | 8.2 | 8.2 | 8.2 | 1.4 | 1.4 | 8.2 | 8.2 | 1.4 |
| Geothermal | 0.0 | 29.0 | 33.1 | 32.4 | 40.8 | 0.0 | 0.0 | 22.2 | 23.0 | 0.0 |
| Solar Thermal | 0.0 | 0.5 | 8.1 | 2.4 | 12.8 | 2.2 | 10.0 | 0.5 | 0.5 | 0.9 |
| Solar PV | 1.7 | 1.7 | 2.4 | 2.7 | 6.1 | 1.7 | 2.0 | 1.7 | 2.0 | 1.7 |
| **Total** | **251.5** | **249.7** | **253.1** | **248.3** | **248.6** | **258.3** | **262.6** | **247.9** | **248.2** | **254.8** |

**Table A3.6** The NEM's electricity generation results of in 2049-50 by technology and scenario (unit: TWh).

| **Technology** | **BAU** | **5% Reduction** | **25% Reduction** | **5%-RETs Only** | **25%-RETs Only** | **5%-CCS Only** | **25%-CCS Only** | **5%-26% _2030 Reduction** | **5%-26% _2030-RETs Only** | **5%-26% _2030-CCS Only** |
|---|---|---|---|---|---|---|---|---|---|---|
| Black Coal | 171.5 | 18.1 | 19.0 | 23.8 | 23.8 | 11.8 | 13.8 | 18.1 | 23.0 | 11.3 |
| Brown Coal | 61.9 | 0.0 | 0.0 | 0.0 | 0.0 | 1.8 | 1.2 | 0.0 | 0.0 | 1.8 |
| CCGT | 9.5 | 14.6 | 14.6 | 21.7 | 22.2 | 15.5 | 16.3 | 14.6 | 22.3 | 15.5 |
| OCGT | 4.0 | 0.8 | 0.7 | 1.0 | 0.6 | 2.5 | 1.1 | 0.8 | 1.5 | 2.8 |
| Liquid Fuel | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Coal CCS | 0.0 | 175.2 | 163.1 | 0.0 | 0.0 | 234.9 | 223.4 | 175.7 | 0.0 | 238.4 |
| Gas CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Hydro | 19.8 | 17.1 | 16.3 | 15.9 | 15.9 | 18.7 | 18.1 | 17.1 | 15.9 | 18.8 |
| Wind | 27.8 | 53.5 | 53.5 | 53.5 | 53.5 | 53.4 | 53.5 | 53.5 | 53.5 | 52.2 |
| Biomass | 3.1 | 8.9 | 8.9 | 8.9 | 8.9 | 1.4 | 1.4 | 8.9 | 8.9 | 1.4 |
| Geothermal | 0.0 | 30.8 | 33.1 | 47.8 | 47.8 | 0.0 | 0.0 | 30.8 | 47.8 | 0.0 |
| Solar Thermal | 0.0 | 4.2 | 10.4 | 80.2 | 80.4 | 2.2 | 10.0 | 4.2 | 79.2 | 0.9 |
| Solar PV | 1.7 | 6.5 | 6.7 | 39.5 | 39.2 | 1.7 | 2.0 | 6.2 | 40.0 | 1.7 |
| **Total** | **299.3** | **329.7** | **326.2** | **292.3** | **292.2** | **343.9** | **340.9** | **329.9** | **292.2** | **344.7** |

Table A3.7 and Table A3.8 display the results of installed capacity in the NEM's power system by technology and scenario in 2012-2013 and 2014-15 respectively. The data in Table A3.7 were plotted as Figure 5.16 in Section 5.3, Chapter 5.

**Table A3.7** The NEM's installed capacity results by technology and scenario in 2012-13 (unit: GW).

| **Technology** | **BAU** | **5% Reduction** | **25% Reduction** | **5%-RETs Only** | **25%-RETs Only** | **5%-CCS Only** | **25%-CCS Only** | **5%-26% _2030 Reduction** | **5%-26% _2030-RETs Only** | **5%-26% _2030-CCS Only** |
|---|---|---|---|---|---|---|---|---|---|---|
| Black Coal | 20.4 | 20.4 | 20.4 | 20.4 | 20.4 | 20.4 | 20.4 | 20.4 | 20.4 | 20.4 |
| Brown Coal | 7.5 | 7.5 | 7.5 | 7.5 | 7.5 | 7.5 | 7.5 | 7.5 | 7.5 | 7.5 |
| CCGT | 3.1 | 3.1 | 3.1 | 3.1 | 3.1 | 3.1 | 3.1 | 3.1 | 3.1 | 3.1 |
| OCGT | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 |
| Liquid Fuel | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 |
| Coal CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Gas CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Hydro | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 |
| Wind | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 |
| Biomass | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Geothermal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Solar Thermal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Solar PV | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total** | **49.7** | **49.7** | **49.7** | **49.7** | **49.7** | **49.7** | **49.7** | **49.7** | **49.7** | **49.7** |

**Table A3.8** The NEM's installed capacity results by technology and scenario in 2014-15 (unit: GW).

| **Technology** | **BAU** | **5% Reduction** | **25% Reduction** | **5%-RETs Only** | **25%-RETs Only** | **5%-CCS Only** | **25%-CCS Only** | **5%-26% _2030 Reduction** | **5%-26% _2030-RETs Only** | **5%-26% _2030-CCS Only** |
|---|---|---|---|---|---|---|---|---|---|---|
| Black Coal | 20.4 | 20.4 | 20.4 | 20.4 | 20.4 | 20.4 | 20.4 | 20.4 | 20.4 | 20.4 |
| Brown Coal | 7.5 | 7.5 | 7.5 | 7.5 | 7.5 | 7.5 | 7.5 | 7.5 | 7.5 | 7.5 |
| CCGT | 3.1 | 3.1 | 3.3 | 3.1 | 3.3 | 3.1 | 3.3 | 3.1 | 3.1 | 3.1 |
| OCGT | 8.0 | 8.0 | 7.8 | 8.0 | 7.8 | 8.0 | 7.8 | 8.0 | 8.0 | 8.0 |
| Liquid Fuel | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 |
| Coal CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Gas CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Hydro | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 |
| Wind | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 |
| Biomass | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Geothermal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Solar Thermal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Solar PV | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total** | **50.7** | **50.7** | **50.7** | **50.7** | **50.7** | **50.7** | **50.7** | **50.7** | **50.7** | **50.7** |

Table A3.9, Table A3.10 and Table A3.11 show the results of installed capacity in the NEM's power system in 2019-20, 2029-30 and 2049-50 by technology and scenario respectively. The data in these tables were plotted as Figure 5.17, Figure 5.18 and Figure 5.19 in Section 5.3, Chapter 5 respectively.

**Table A3.9** The NEM's installed capacity results by technology and scenario in 2019-20 (unit: GW).

| **Technology** | **BAU** | **5% Reduction** | **25% Reduction** | **5%-RETs Only** | **25%-RETs Only** | **5%-CCS Only** | **25%-CCS Only** | **5%-26% _2030 Reduction** | **5%-26% _2030-RETs Only** | **5%-26% _2030-CCS Only** |
|---|---|---|---|---|---|---|---|---|---|---|
| Black Coal | 19.8 | 18.4 | 17.8 | 18.4 | 17.4 | 18.4 | 18.0 | 18.5 | 18.5 | 18.5 |
| Brown Coal | 7.5 | 4.3 | 1.9 | 4.3 | 2.3 | 4.8 | 1.9 | 4.3 | 4.3 | 4.7 |
| CCGT | 3.1 | 3.1 | 4.6 | 3.1 | 4.5 | 3.1 | 4.4 | 3.1 | 3.1 | 3.1 |
| OCGT | 8.9 | 11.8 | 11.5 | 11.4 | 11.1 | 10.6 | 11.2 | 11.7 | 11.7 | 11.0 |
| Liquid Fuel | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 |
| Coal CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Gas CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Hydro | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 | 7.8 |
| Wind | 8.4 | 12.1 | 17.2 | 11.5 | 17.1 | 17.6 | 17.6 | 12.1 | 12.1 | 17.1 |
| Biomass | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Geothermal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Solar Thermal | 0.0 | 0.2 | 2.8 | 0.8 | 3.8 | 0.7 | 3.4 | 0.2 | 0.2 | 0.3 |
| Solar PV | 1.0 | 1.0 | 1.2 | 1.0 | 1.2 | 1.0 | 1.2 | 1.0 | 1.0 | 1.0 |
| **Total** | **57.3** | **59.7** | **65.7** | **59.2** | **66.2** | **64.9** | **66.5** | **59.6** | **59.6** | **64.4** |

**Table A3.10** The NEM's installed capacity results by technology and scenario in 2029-30 (unit: GW).

| **Technology** | **BAU** | **5% Reduction** | **25% Reduction** | **5%-RETs Only** | **25%-RETs Only** | **5%-CCS Only** | **25%-CCS Only** | **5%-26% _2030 Reduction** | **5%-26% _2030-RETs Only** | **5%-26% _2030-CCS Only** |
|---|---|---|---|---|---|---|---|---|---|---|
| Black Coal | 19.8 | 17.7 | 16.1 | 18.2 | 16.1 | 16.4 | 15.1 | 18.5 | 18.4 | 17.3 |
| Brown Coal | 7.5 | 2.7 | 1.9 | 2.7 | 1.0 | 2.7 | 1.9 | 3.5 | 3.9 | 3.0 |
| CCGT | 3.1 | 3.1 | 4.6 | 3.1 | 4.5 | 3.1 | 4.4 | 3.1 | 3.1 | 3.1 |
| OCGT | 12.7 | 14.6 | 13.0 | 14.6 | 13.8 | 15.5 | 13.0 | 14.2 | 13.7 | 16.1 |
| Liquid Fuel | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 |
| Coal CCS | 0.0 | 0.9 | 2.5 | 0.0 | 0.0 | 6.0 | 8.2 | 0.0 | 0.0 | 4.1 |
| Gas CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Hydro | 7.9 | 7.9 | 7.9 | 7.9 | 7.9 | 7.9 | 7.9 | 7.9 | 7.9 | 7.9 |
| Wind | 8.4 | 17.6 | 17.6 | 17.6 | 17.6 | 17.6 | 17.6 | 17.6 | 17.6 | 17.1 |
| Biomass | 0.2 | 1.2 | 1.2 | 1.2 | 1.2 | 0.2 | 0.2 | 1.2 | 1.2 | 0.2 |
| Geothermal | 0.0 | 3.3 | 3.8 | 3.7 | 4.7 | 0.0 | 0.0 | 2.5 | 2.6 | 0.0 |
| Solar Thermal | 0.0 | 0.2 | 2.8 | 0.8 | 4.2 | 0.7 | 3.4 | 0.2 | 0.2 | 0.3 |
| Solar PV | 1.0 | 1.0 | 1.4 | 1.6 | 3.6 | 1.0 | 1.2 | 1.0 | 1.2 | 1.0 |
| **Total** | **61.3** | **70.9** | **73.5** | **72.1** | **75.3** | **71.7** | **73.8** | **70.4** | **70.6** | **70.7** |

**Table A3.11** The NEM's installed capacity results by technology and scenario in 2049-50 (unit: GW).

| Technology | BAU | 5% Reduction | 25% Reduction | 5%-RETs Only | 25%-RETs Only | 5%-CCS Only | 25%-CCS Only | 5%-26% _2030 Reduction | 5%-26% _2030-RETs Only | 5%-26% _2030-CCS Only |
|---|---|---|---|---|---|---|---|---|---|---|
| Black Coal | 21.3 | 9.8 | 10.0 | 6.2 | 6.5 | 7.0 | 8.5 | 9.8 | 5.8 | 6.7 |
| Brown Coal | 7.5 | 0.3 | 0.3 | 0.2 | 0.2 | 0.8 | 0.7 | 0.3 | 0.2 | 0.8 |
| CCGT | 3.1 | 3.1 | 4.6 | 3.1 | 4.5 | 3.1 | 4.4 | 3.1 | 3.1 | 3.1 |
| OCGT | 24.6 | 23.1 | 21.3 | 16.9 | 15.5 | 25.7 | 22.7 | 23.0 | 17.4 | 26.0 |
| Liquid Fuel | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 |
| Coal CCS | 0.0 | 20.0 | 18.6 | 0.0 | 0.0 | 27.3 | 25.6 | 20.1 | 0.0 | 27.7 |
| Gas CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Hydro | 7.9 | 7.9 | 7.9 | 7.9 | 7.9 | 7.9 | 7.9 | 7.9 | 7.9 | 7.9 |
| Wind | 8.4 | 17.6 | 17.6 | 17.6 | 17.6 | 17.6 | 17.6 | 17.6 | 17.6 | 17.1 |
| Biomass | 0.5 | 1.3 | 1.3 | 1.3 | 1.3 | 0.2 | 0.2 | 1.3 | 1.3 | 0.2 |
| Geothermal | 0.0 | 3.5 | 3.8 | 5.5 | 5.5 | 0.0 | 0.0 | 3.5 | 5.5 | 0.0 |
| Solar Thermal | 0.0 | 1.2 | 3.4 | 20.8 | 21.7 | 0.7 | 3.4 | 1.2 | 20.5 | 0.3 |
| Solar PV | 1.0 | 3.9 | 4.0 | 23.6 | 23.4 | 1.0 | 1.2 | 3.8 | 24.1 | 1.0 |
| **Total** | **74.9** | **92.4** | **93.5** | **103.8** | **104.8** | **91.9** | **92.9** | **92.3** | **104.0** | **91.6** |

Table A3.12 and Table A3.13 show the data of capacity installed and capacity retired in the NEM's power system from 2012-13 to 2019-20, from 2020-21 to 2029-30, from 2030-31 to 2039-40 and from 2040-41 to 2049-50 respectively by scenario. These data were plotted as Figure 5.15 in Section 5.3, Chapter 5.

**Table A3.12** Capacity installed from 2012-13 to 2019-20, from 2020-21 to 2029-30, from 2030-31 to 2039-40 and from 2040-41 to 2049-50 in the NEM by scenario (unit: GW).

| **Scenario** | **2012-13 to 2019-20** | **2020-21 to 2029-30** | **2030-31 to 2039-40** | **2040-41 to 2049-50** | **Total** |
|---|---|---|---|---|---|
| The BAU Scenario | 7.3 | 3.8 | 7.4 | 6.2 | **24.8** |
| The 5% Reduction Scenario | 14.1 | 13.5 | 13.3 | 18.5 | **59.5** |
| The 25% Reduction Scenario | 23.2 | 9.5 | 11.5 | 16.1 | **60.3** |
| The 5%-RETs Only Scenario | 13.8 | 14.5 | 22.4 | 23.8 | **74.5** |
| The 25%-RETs Only Scenario | 23.7 | 11.7 | 20.6 | 19.2 | **75.2** |
| The 5%-CCS Only Scenario | 18.9 | 10.9 | 12.8 | 18.6 | **61.2** |
| The 25%-CCS Only Scenario | 23.8 | 10.0 | 11.5 | 15.6 | **60.9** |
| The 5%-26%_2030 Reduction Scenario | 14.0 | 11.6 | 14.3 | 19.4 | **59.3** |
| The 5%-26%_2030-RETs Only Scenario | 14.0 | 11.4 | 22.6 | 27.2 | **75.1** |
| The 5%-26%_2030-CCS Only Scenario | 18.4 | 9.1 | 13.7 | 19.9 | **61.1** |

**Table A3.13** Capacity retired from 2012-13 to 2019-20, from 2020-21 to 2029-30, from 2030-31 to 2039-40 and from 2040-41 to 2049-50 in the NEM by scenario (unit: GW).

| Scenario | 2012-13 to 2019-20 | 2020-21 to 2029-30 | 2030-31 to 2039-40 | 2040-41 to 2049-50 | Total |
|---|---|---|---|---|---|
| The BAU Scenario | 0.64 | 0.00 | 0.00 | 0.00 | **0.64** |
| The 5% Reduction Scenario | 5.15 | 2.35 | 2.56 | 7.72 | **17.78** |
| The 25% Reduction Scenario | 8.15 | 1.78 | 1.53 | 6.12 | **17.59** |
| The 5%-RETs Only Scenario | 5.20 | 1.79 | 5.99 | 8.42 | **21.41** |
| The 25%-RETs Only Scenario | 8.11 | 2.68 | 4.39 | 5.96 | **21.14** |
| The 5%-CCS Only Scenario | 4.63 | 4.23 | 2.30 | 8.88 | **20.03** |
| The 25%-CCS Only Scenario | 8.02 | 2.86 | 1.32 | 6.57 | **18.76** |
| The 5%-26%_2030 Reduction Scenario | 5.04 | 0.87 | 3.48 | 8.37 | **17.77** |
| The 5%-26%_2030-RETs Only Scenario | 5.03 | 0.52 | 6.28 | 10.01 | **21.83** |
| The 5%-26%_2030-CCS Only Scenario | 4.64 | 2.93 | 2.77 | 9.97 | **20.31** |

Table A3.14 presents the data of the NEM's power system expansion levilised cost from 2012-13 to 2049-50 by scenario. These data were plotted as Figure 5.21 in Section 5.6, Chapter 5.

**Table A3.14** The NEM's levilised cost results by scenario from 2012-13 to 2049-50 (unit: $/MWh).

| Technology | BAU | 5% Reduction | 25% Reduction | 5%-RETs Only | 25%-RETs Only | 5%-CCS Only | 25%-CCS Only | 5%-26% _2030 Reduction | 5%-26% _2030-RETs Only | 5%-26% _2030-CCS Only |
|---|---|---|---|---|---|---|---|---|---|---|
| **2012-13** | 42.5 | 47.4 | 46.7 | 48.3 | 46.6 | 47.7 | 46.1 | 47.5 | 48.1 | 47.5 |
| **2013-14** | 43.4 | 52.8 | 51.4 | 53.3 | 51.3 | 53.1 | 51.7 | 52.8 | 52.8 | 52.9 |
| **2014-15** | 15.3 | 34.2 | 52.0 | 34.3 | 51.6 | 33.6 | 51.6 | 33.5 | 35.6 | 33.6 |
| **2015-16** | 15.2 | 29.5 | 60.7 | 29.5 | 60.8 | 29.6 | 61.2 | 29.3 | 29.5 | 29.1 |
| **2016-17** | 16.3 | 27.2 | 43.6 | 27.2 | 43.9 | 27.3 | 44.9 | 26.5 | 27.0 | 26.2 |
| **2017-18** | 17.5 | 33.4 | 42.6 | 33.0 | 42.1 | 39.2 | 42.6 | 36.1 | 34.4 | 37.6 |
| **2018-19** | 18.1 | 39.7 | 46.6 | 38.2 | 47.2 | 31.4 | 45.7 | 37.8 | 36.1 | 30.3 |
| **2019-20** | 18.2 | 37.1 | 50.6 | 35.7 | 48.4 | 29.1 | 48.7 | 35.9 | 34.6 | 29.8 |
| **2020-21** | 18.5 | 35.3 | 65.8 | 34.6 | 61.6 | 35.0 | 54.2 | 33.9 | 33.3 | 33.7 |
| **2021-22** | 18.7 | 38.4 | 60.1 | 37.7 | 53.5 | 40.0 | 56.0 | 37.1 | 36.2 | 37.9 |
| **2022-23** | 18.9 | 40.3 | 54.5 | 39.7 | 52.2 | 49.5 | 59.2 | 38.4 | 37.4 | 40.0 |
| **2023-24** | 19.0 | 41.9 | 51.0 | 41.2 | 50.7 | 51.1 | 60.2 | 39.8 | 38.9 | 47.0 |
| **2024-25** | 19.2 | 44.7 | 54.6 | 43.4 | 53.5 | 57.2 | 63.7 | 41.5 | 40.8 | 51.0 |
| **2025-26** | 20.0 | 50.4 | 63.1 | 48.2 | 58.3 | 56.8 | 65.3 | 47.6 | 45.6 | 53.4 |
| **2026-27** | 21.2 | 54.1 | 66.3 | 51.5 | 62.9 | 58.6 | 64.9 | 49.8 | 47.9 | 55.1 |
| **2027-28** | 22.5 | 59.2 | 67.0 | 55.1 | 65.6 | 59.3 | 66.2 | 51.1 | 49.1 | 55.2 |
| **2028-29** | 23.1 | 67.0 | 71.2 | 61.8 | 73.5 | 63.2 | 69.5 | 54.6 | 52.0 | 59.1 |
| **2029-30** | 23.4 | 66.4 | 70.6 | 63.1 | 73.2 | 62.6 | 69.9 | 54.5 | 52.9 | 58.2 |
| **2030-31** | 23.6 | 65.0 | 71.1 | 64.6 | 72.5 | 62.4 | 69.1 | 59.5 | 56.9 | 57.9 |
| **2031-32** | 24.2 | 68.7 | 71.3 | 68.8 | 76.4 | 64.8 | 70.3 | 65.1 | 63.3 | 60.6 |
| **2032-33** | 24.7 | 68.7 | 73.2 | 75.6 | 82.9 | 66.2 | 72.2 | 66.1 | 66.3 | 61.8 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **2033-34** | 25.6 | 70.5 | 74.7 | 78.9 | 87.3 | 68.1 | 73.9 | 68.1 | 71.9 | 64.0 |
| **2034-35** | 26.5 | 74.0 | 78.3 | 87.7 | 92.1 | 71.4 | 76.9 | 71.5 | 81.9 | 67.8 |
| **2035-36** | 23.4 | 71.2 | 74.9 | 85.4 | 90.4 | 69.3 | 75.1 | 69.0 | 78.1 | 65.1 |
| **2036-37** | 24.1 | 71.4 | 75.4 | 90.9 | 95.7 | 69.5 | 75.2 | 68.7 | 86.5 | 66.4 |
| **2037-38** | 24.4 | 73.6 | 74.2 | 96.9 | 97.3 | 72.4 | 73.6 | 72.2 | 92.2 | 69.0 |
| **2038-39** | 33.4 | 73.9 | 73.0 | 89.1 | 86.0 | 70.6 | 72.8 | 72.2 | 85.1 | 68.5 |
| **2039-40** | 34.1 | 75.7 | 74.4 | 90.7 | 90.1 | 70.2 | 73.6 | 73.7 | 86.2 | 67.9 |
| **2040-41** | 37.4 | 75.9 | 76.5 | 99.0 | 97.0 | 73.5 | 76.2 | 74.4 | 97.4 | 71.5 |
| **2041-42** | 36.5 | 76.8 | 78.4 | 95.6 | 97.7 | 75.7 | 77.8 | 75.5 | 92.5 | 74.0 |
| **2042-43** | 38.6 | 79.4 | 80.4 | 104.0 | 104.0 | 78.6 | 80.2 | 78.6 | 102.7 | 77.3 |
| **2043-44** | 39.3 | 81.8 | 82.2 | 99.4 | 103.8 | 81.0 | 82.2 | 80.9 | 98.5 | 80.3 |
| **2044-45** | 40.3 | 85.6 | 85.5 | 115.1 | 110.4 | 84.2 | 85.8 | 85.3 | 113.4 | 84.0 |
| **2045-46** | 41.7 | 89.4 | 88.7 | 116.3 | 115.6 | 88.0 | 89.0 | 89.8 | 118.9 | 87.5 |
| **2046-47** | 45.5 | 93.0 | 91.9 | 121.9 | 118.5 | 91.8 | 90.9 | 93.7 | 123.7 | 91.6 |
| **2047-48** | 47.5 | 97.7 | 95.3 | 126.8 | 120.3 | 97.3 | 94.6 | 98.5 | 128.8 | 97.9 |
| **2048-49** | 49.3 | 106.4 | 101.6 | 138.8 | 132.1 | 107.1 | 100.9 | 108.6 | 145.0 | 109.0 |
| **2049-50** | 54.4 | 122.4 | 116.5 | 151.1 | 145.4 | 126.8 | 116.3 | 125.5 | 158.3 | 131.3 |

# APPENDIX 4 Chapter 6 Modelling Results

This appendix reports the detailed data of the WEM PLEXOS Model simulation results. It presents data of carbon emissions results, electricity generation results, capacity installation results, power system levilised costs results for the WEM from 2013-14 to 2049-50.

Similar as in the APPENDIX 3, the results data are reported by the modelling scenarios, including the BAU Scenario, the 5% Reduction Scenario, the 25% Reduction Scenario, the 5%-26%_2030 Reduction (CGP) Scenario, the 5%-RETs Only Scenario, the 25%-RETs Only Scenario, the 5%-26%_2030-RETs Only Scenario, the 5%-CCS Only Scenario, the 25%-CCS Only Scenario and the 5%-26%_2030-CCS Only Scenario.

Table A4.1 lists carbon emissions results of the BAU Scenario, the scenarios with 5%-80% Reduction Target, the scenarios with 25%-80% Reduction Targets and the Scenarios with 5%-26%-80% Reduction Targets respectively for the WEM simulation. The WEM PLEXOS Model generated the carbon emissions results of the BAU Scenario based on the inputs. The other three sets of carbon emissions results were computed by the researcher using the linear extrapolation.

The data in Table A4.1 was reflected as Figure 6.1 in Section 6.1, Chapter 6.

**Table A4.1** The WEM's Carbon emissions results by carbon emissions reduction target groups from 2013-14 to 2049-50 (Unit: Mt).

| **Year** | **The BAU Scenario** | **The Scenarios with 5%-80% Reduction Targets** | **The Scenarios with 25%-80% Reduction Targets** | **The Scenarios with 5%-26%-80% Reduction Targets** |
|---|---|---|---|---|
| **2013-14** | 13.8 | 13.8 | 13.8 | 13.8 |
| **2014-15** | 16.1 | 13.7 | 13.2 | 13.7 |
| **2015-16** | 16.0 | 13.6 | 12.7 | 13.6 |
| **2016-17** | 16.0 | 13.6 | 12.2 | 13.6 |
| **2017-18** | 16.0 | 13.5 | 11.6 | 13.5 |
| **2018-19** | 16.0 | 13.4 | 11.1 | 13.4 |

| | | | | |
|---|---|---|---|---|
| **2019-20** | 16.0 | 13.4 | 10.6 | 13.4 |
| **2020-21** | 16.3 | 13.0 | 10.3 | 13.1 |
| **2021-22** | 16.5 | 12.7 | 10.1 | 12.8 |
| **2022-23** | 16.6 | 12.3 | 9.8 | 12.5 |
| **2023-24** | 16.8 | 12.0 | 9.5 | 12.2 |
| **2024-25** | 16.9 | 11.6 | 9.3 | 11.9 |
| **2025-26** | 17.2 | 11.3 | 9.0 | 11.6 |
| **2026-27** | 17.4 | 10.9 | 8.8 | 11.3 |
| **2027-28** | 17.6 | 10.6 | 8.5 | 11.0 |
| **2028-29** | 17.8 | 10.2 | 8.2 | 10.7 |
| **2029-30** | 18.0 | 9.9 | 8.0 | 10.4 |
| **2030-31** | 18.2 | 9.5 | 7.7 | 10.0 |
| **2031-32** | 18.4 | 9.2 | 7.5 | 9.7 |
| **2032-33** | 18.7 | 8.8 | 7.2 | 9.3 |
| **2033-34** | 18.9 | 8.5 | 7.0 | 8.9 |
| **2034-35** | 19.2 | 8.1 | 6.7 | 8.5 |
| **2035-36** | 19.4 | 7.7 | 6.4 | 8.1 |
| **2036-37** | 19.7 | 7.4 | 6.2 | 7.8 |
| **2037-38** | 19.9 | 7.0 | 5.9 | 7.4 |
| **2038-39** | 20.2 | 6.7 | 5.7 | 7.0 |
| **2039-40** | 20.5 | 6.3 | 5.4 | 6.6 |
| **2040-41** | 20.8 | 6.0 | 5.1 | 6.2 |
| **2041-42** | 21.1 | 5.6 | 4.9 | 5.9 |
| **2042-43** | 21.4 | 5.3 | 4.6 | 5.5 |
| **2043-44** | 21.7 | 4.9 | 4.4 | 5.1 |
| **2044-45** | 22.1 | 4.6 | 4.1 | 4.7 |
| **2045-46** | 22.5 | 4.2 | 3.9 | 4.3 |
| **2046-47** | 22.9 | 3.9 | 3.6 | 4.0 |

| | | | | |
|---|---|---|---|---|
| **2047-48** | 23.4 | 3.5 | 3.3 | 3.6 |
| **2048-49** | 23.8 | 3.2 | 3.1 | 3.2 |
| **2049-50** | 24.3 | 2.8 | 2.8 | 2.8 |

Table A4.2, Table A4.3, Table A4.4, Table A4.5 and Table A4.6 present the WEM PLEXOS modelling results of electricity generation in 2013-14, 2014-15, 2019-20, 2029-30 and 2049-50 respectively.

Table A4.2 and Table A4.3 show the WEM's electricity generation results of the BAU Scenario in 2013-14 and 2014-15.

They were plotted as Figure (6.2-a) and Figure (6.2-b) respectively in Section 6.2.1, Chapter 6.

**Table A4.2** The WEM's electricity generation results of the BAU Scenario in 2013-14 (unit: TWh).

| **Technology** | **Generation** |
|---|---|
| Black Coal | 8.9 |
| Brown Coal | 0.0 |
| CCGT | 4.9 |
| OCGT | 3.3 |
| Coal CCS | 0.0 |
| Gas CCS | 0.0 |
| Liquid Fuel | 0.0 |
| Hydro | 0.0 |
| Wind | 1.5 |
| Biomass | 0.4 |
| Geothermal | 0.0 |
| Solar Thermal | 0.0 |
| Solar PV | 0.0 |
| Landfill Gas | 0.2 |
| **Total** | **19.2** |

**Table A4.3** The WEM's electricity generation results of the BAU Scenario in 2014-15 (unit: TWh).

| **Technology** | **Generation** |
|---|---|
| Black Coal | 13.6 |
| Brown Coal | 0.0 |
| CCGT | 2.9 |
| OCGT | 0.8 |
| Coal CCS | 0.0 |
| Gas CCS | 0.0 |
| Liquid Fuel | 0.0 |
| Hydro | 0.0 |
| Wind | 1.5 |
| Biomass | 0.4 |
| Geothermal | 0.0 |
| Solar Thermal | 0.0 |
| Solar PV | 0.0 |
| Landfill Gas | 0.0 |
| **Total** | **19.2** |

The data in Table A4.4, Table A4.5 and Table A4.6 display the electricity generation results of all scenarios for the WEM power system simulation. They present energy output data in 2019-20, 2029-30 and 2049-50 respectively by technology and by scenario.

These results were plotted accordingly in Figure 6.3, Figure 6.4 Figure 6.5, Figure 6.6 and Figure 6.7 in Section 6.2.2, Chapter 6, and were plotted as Figure 6.8, Figure 6.9, Figure 6.10 and Figure 6.11 in Section 6.2.3 in Chapter 6.

**Table A4.4** The WEM's electricity generation results of in 2019-20 by technology and scenario (unit: TWh).

| **Technology** | **BAU** | **5% Reduction** | **25% Reduction** | **5%-RETs Only** | **25%-RETs Only** | **5%-CCS Only** | **25%-CCS Only** | **5%-26% _2030 Reduction** | **5%-26% _2030-RETs Only** | **5%-26% _2030-CCS Only** |
|---|---|---|---|---|---|---|---|---|---|---|
| Black Coal | 13.4 | 9.1 | 2.6 | 9.1 | 2.6 | 11.3 | 8.2 | 7.9 | 7.9 | 11.2 |
| Brown Coal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| CCGT | 2.9 | 4.7 | 4.9 | 4.7 | 4.9 | 0.7 | 1.2 | 4.9 | 4.9 | 0.8 |
| OCGT | 1.1 | 2.4 | 7.8 | 2.4 | 7.8 | 2.1 | 2.3 | 4.2 | 4.2 | 2.2 |
| Liquid Fuel | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Coal CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Gas CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Hydro | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Wind | 2.8 | 3.6 | 4.1 | 3.6 | 4.1 | 6.0 | 7.5 | 2.8 | 2.8 | 5.9 |
| Biomass | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4o | 1.0 | 0.4 | 0.4 | 0.4 |
| Geothermal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Solar Thermal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Solar PV | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Landfill Gas | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.0 | 0.0 | 0.2 | 0.2 | 0.0 |
| **Total** | **20.7** | **20.4** | **20.0** | **20.4** | **20.0** | **20.5** | **20.3** | **20.4** | **20.4** | **20.5** |

**Table A4.5** The WEM's electricity generation results of in 2029-30 by technology and scenario (unit: TWh).

| Technology | BAU | 5% Reduction | 25% Reduction | 5%-RETs Only | 25%-RETs Only | 5%-CCS Only | 25%-CCS Only | 5%-26% _2030 Reduction | 5%-26% _2030-RETs Only | 5%-26% _2030-CCS Only |
|---|---|---|---|---|---|---|---|---|---|---|
| Black Coal | 13.7 | 1.8 | 0.7 | 1.5 | 0.7 | 2.6 | 0.1 | 2.6 | 2.1 | 3.4 |
| Brown Coal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| CCGT | 3.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 5.8 | 4.9 | 4.9 | 4.9 |
| OCGT | 2.8 | 7.9 | 6.9 | 8.4 | 6.9 | 6.9 | 7.2 | 7.6 | 8.3 | 6.5 |
| Liquid Fuel | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Coal CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Gas CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Hydro | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Wind | 2.8 | 7.2 | 7.6 | 6.7 | 7.9 | 7.9 | 8.4 | 7.1 | 6.4 | 7.5 |
| Biomass | 0.4 | 0.7 | 2.3 | 1.0 | 2.1 | 0.4 | 1.0 | 0.4 | 0.9 | 0.4 |
| Geothermal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Solar Thermal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Solar PV | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Landfill Gas | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| **Total** | **23.6** | **22.7** | **22.6** | **22.7** | **22.6** | **22.8** | **22.6** | **22.8** | **22.8** | **22.8** |

**Table A4.6** The WEM's electricity generation results of in 2049-50 by technology and scenario (unit: TWh).

| Technology | BAU | 5% Reduction | 25% Reduction | 5%-RETs Only | 25%-RETs Only | 5%-CCS Only | 25%-CCS Only | 5%-26% _2030 Reduction | 5%-26% _2030-RETs Only | 5%-26% _2030-CCS Only |
|---|---|---|---|---|---|---|---|---|---|---|
| Black Coal | 17.5 | 0.1 | 0.1 | 0.1 | 0.1 | 0.0 | 0.0 | 0.1 | 0.1 | 0.0 |
| Brown Coal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| CCGT | 4.6 | 2.1 | 2.1 | 2.7 | 2.7 | 0.8 | 0.8 | 2.0 | 2.7 | 0.7 |
| OCGT | 6.9 | 1.4 | 1.5 | 2.0 | 2.0 | 0.3 | 0.4 | 1.4 | 2.0 | 0.3 |
| Liquid Fuel | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Coal CCS | 0.0 | 9.5 | 8.2 | 0.0 | 0.0 | 27.4 | 25.9 | 10.0 | 0.0 | 27.9 |
| Gas CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.1 | 1.0 | 0.0 | 0.0 | 1.2 |
| Hydro | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Wind | 2.8 | 7.9 | 8.0 | 8.4 | 8.4 | 7.9 | 8.4 | 7.9 | 8.4 | 7.5 |
| Biomass | 0.4 | 3.9 | 3.9 | 3.9 | 3.9 | 0.4 | 1.0 | 3.9 | 3.9 | 0.4 |
| Geothermal | 0.0 | 6.9 | 7.8 | 7.9 | 8.8 | 0.0 | 0.0 | 6.6 | 7.9 | 0.0 |
| Solar Thermal | 0.0 | 0.0 | 0.0 | 5.4 | 4.5 | 0.0 | 0.0 | 0.0 | 5.4 | 0.0 |
| Solar PV | 0.0 | 2.2 | 2.1 | 1.7 | 1.7 | 0.0 | 0.0 | 2.2 | 1.7 | 0.0 |
| Landfill Gas | 0.1 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| **Total** | **32.3** | **34.1** | **33.8** | **32.2** | **32.2** | **38.0** | **37.7** | **34.2** | **32.2** | **38.1** |

Table A4.7 and Table A4.8 display the results of installed capacity in the WEM's power system by technology and scenario in 2013-2014 and 2014-15 respectively. The data in Table A4.7 were plotted as Figure 6.14 in Section 6.3, Chapter 6.

**Table A4.7** The WEM's installed capacity results by technology and scenario in 2013-14 (unit: GW).

| **Technology** | **BAU** | **5% Reduction** | **25% Reduction** | **5%-RETs Only** | **25%-RETs Only** | **5%-CCS Only** | **25%-CCS Only** | **5%-26% _2030 Reduction** | **5%-26% _2030-RETs Only** | **5%-26% _2030-CCS Only** |
|---|---|---|---|---|---|---|---|---|---|---|
| Black Coal | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 |
| Brown Coal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| CCGT | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 |
| OCGT | 2.5 | 2.5 | 2.5 | 2.49 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 |
| Liquid Fuel | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Coal CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Gas CCS | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 |
| Hydro | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Wind | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 |
| Biomass | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Geothermal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Solar Thermal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Solar PV | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Landfill Gas | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total** | **6.0** | **6.0** | **6.0** | **6.0** | **6.0** | **6.0** | **6.0** | **6.0** | **6.0** | **6.0** |

**Table A4.8** The WEM's installed capacity results by technology and scenario in 2014-15 (unit: GW).

| Technology | BAU | 5% Reduction | 25% Reduction | 5%-RETs Only | 25%-RETs Only | 5%-CCS Only | 25%-CCS Only | 5%-26% _2030 Reduction | 5%-26% _2030-RETs Only | 5%-26% _2030-CCS Only |
|---|---|---|---|---|---|---|---|---|---|---|
| Black Coal | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 |
| Brown Coal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| CCGT | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 |
| OCGT | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 |
| Liquid Fuel | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Coal CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Gas CCS | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 |
| Hydro | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Wind | 0.5 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.5 | 0.5 | 0.5 |
| Biomass | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Geothermal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Solar Thermal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Solar PV | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Landfill Gas | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total** | **6.0** | **6.1** | **6.1** | **6.1** | **6.1** | **6.1** | **6.1** | **6.0** | **6.0** | **6.0** |

Table A4.9, Table A4.10 and Table A4.11 display the results of installed capacity in the WEM's power system in 2019-20, 2029-30 and 2049-50 by technology and scenario respectively. The data in these tables were plotted as Figure 6.15, Figure 6.16 and Figure 6.17 in Section 6.3, Chapter 6 respectively.

**Table A4.9** The WEM's installed capacity results by technology and scenario in 2019-20 (unit: GW).

| **Technology** | **BAU** | **5% Reduction** | **25% Reduction** | **5%-RETs Only** | **25%-RETs Only** | **5%-CCS Only** | **25%-CCS Only** | **5%-26% _2030 Reduction** | **5%-26% _2030-RETs Only** | **5%-26% _2030-CCS Only** |
|---|---|---|---|---|---|---|---|---|---|---|
| Black Coal | 1.6 | 1.1 | 0.9 | 1.1 | 0.9 | 1.3 | 0.9 | 1.2 | 1.2 | 1.3 |
| Brown Coal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| CCGT | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 |
| OCGT | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 |
| Liquid Fuel | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Coal CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Gas CCS | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 |
| Hydro | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Wind | 0.8 | 1.1 | 1.2 | 1.1 | 1.2 | 2.3 | 2.5 | 0.8 | 0.8 | 2.2 |
| Biomass | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.0 | 0.0 | 0.0 |
| Geothermal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Solar Thermal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Solar PV | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Landfill Gas | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total** | **6.1** | **6.0** | **5.8** | **6.0** | **5.8** | **7.3** | **7.2** | **5.7** | **5.7** | **7.2** |

**Table A4.10** The WEM's installed capacity results by technology and scenario in 2029-30 (unit: GW).

| Technology | BAU | 5% Reduction | 25% Reduction | 5%-RETs Only | 25%-RETs Only | 5%-CCS Only | 25%-CCS Only | 5%-26% _2030 Reduction | 5%-26% _2030-RETs Only | 5%-26% _2030-CCS Only |
|---|---|---|---|---|---|---|---|---|---|---|
| Black Coal | 1.6 | 1.1 | 0.9 | 1.1 | 0.9 | 1.2 | 0.9 | 1.2 | 1.2 | 1.3 |
| Brown Coal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| CCGT | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 |
| OCGT | 2.9 | 2.8 | 2.8 | 2.8 | 2.9 | 2.7 | 2.8 | 2.9 | 2.9 | 2.7 |
| Liquid Fuel | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Coal CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Gas CCS | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 |
| Hydro | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Wind | 0.8 | 2.1 | 2.3 | 2.0 | 2.3 | 2.3 | 2.5 | 2.1 | 1.9 | 2.2 |
| Biomass | 0.0 | 0.1 | 0.3 | 0.1 | 0.3 | 0.0 | 0.1 | 0.0 | 0.1 | 0.0 |
| Geothermal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Solar Thermal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Solar PV | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Landfill Gas | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total** | **6.5** | **7.4** | **7.5** | **7.3** | **7.5** | **7.5** | **7.5** | **7.4** | **7.2** | **7.5** |

**Table A4.11** The WEM's installed capacity results by technology and scenario in 2049-50 (unit: GW).

| **Technology** | **BAU** | **5% Reduction** | **25% Reduction** | **5%-RETs Only** | **25%-RETs Only** | **5%-CCS Only** | **25%-CCS Only** | **5%-26% _2030 Reduction** | **5%-26% _2030-RETs Only** | **5%-26% _2030-CCS Only** |
|---|---|---|---|---|---|---|---|---|---|---|
| Black Coal | 2.0 | 1.1 | 0.8 | 1.1 | 0.9 | 0.9 | 0.7 | 1.1 | 1.1 | 0.8 |
| Brown Coal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| CCGT | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.7 | 0.7 | 0.6 | 0.6 | 0.7 |
| OCGT | 5.5 | 3.3 | 3.5 | 3.2 | 3.4 | 3.0 | 3.2 | 3.2 | 3.2 | 3.0 |
| Liquid Fuel | 0.0 | 1.1 | 0.9 | 0.0 | 0.0 | 3.6 | 3.4 | 1.1 | 0.0 | 3.7 |
| Coal CCS | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.4 | 0.4 | 0.0 | 0.0 | 0.5 |
| Gas CCS | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 |
| Hydro | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Wind | 0.8 | 2.5 | 2.5 | 2.5 | 2.5 | 2.3 | 2.5 | 2.5 | 2.5 | 2.2 |
| Biomass | 0.0 | 0.5 | 0.5 | 0.5 | 0.5 | 0.0 | 0.1 | 0.5 | 0.5 | 0.0 |
| Geothermal | 0.0 | 0.8 | 0.9 | 0.9 | 1.0 | 0.0 | 0.0 | 0.8 | 0.9 | 0.0 |
| Solar Thermal | 0.0 | 0.0 | 0.0 | 2.1 | 1.8 | 0.0 | 0.0 | 0.0 | 2.1 | 0.0 |
| Solar PV | 0.0 | 1.0 | 0.9 | 0.8 | 0.8 | 0.0 | 0.0 | 1.0 | 0.8 | 0.0 |
| Landfill Gas | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total** | **9.6** | **11.4** | **11.3** | **12.2** | **12.0** | **11.6** | **11.6** | **11.4** | **12.2** | **11.5** |

Table A4.12 and Table A4.13 list the data of capacity installed and capacity retired in the WEM's power system in the periods of 2012-13 to 2019-20, 2020-21 to 2029-30, 2030-31 to 2039-40 and 2040-41 to 2049-50 respectively by scenario. These data were plotted as Figure 6.13 in Section 6.3, Chapter 6.

**Table A4.12** Capacity installed from 2012-13 to 2019-20, from 2020-21 to 2029-30, from 2030-31 to 2039-40 and from 2040-41 to 2049-50 in the WEM by scenario (unit: GW).

| **Scenario** | **2012-13 to 2019-20** | **2020-21 to 2029-30** | **2030-31 to 2039-40** | **2040-41 to 2049-50** | **Total** |
|---|---|---|---|---|---|
| The BAU Scenario | 0.36 | 0.40 | 1.32 | 1.74 | **3.82** |
| The 5% Reduction Scenario | 0.60 | 1.44 | 1.82 | 2.27 | **6.12** |
| The 25% Reduction Scenario | 0.75 | 1.67 | 1.81 | 2.08 | **6.31** |
| The 5%-RETs Only Scenario | 0.60 | 1.36 | 1.75 | 3.27 | **6.97** |
| The 25%-RETs Only Scenario | 0.75 | 1.71 | 1.63 | 2.89 | **6.98** |
| The 5%-CCS Only Scenario | 1.85 | 0.22 | 1.70 | 2.74 | **6.51** |
| The 25%-CCS Only Scenario | 2.09 | 0.40 | 1.71 | 2.50 | **6.69** |
| The 5%-26%_2030 Reduction Scenario | 0.36 | 1.66 | 1.79 | 2.34 | **6.15** |
| The 5%-26%_2030-RETs Only Scenario | 0.36 | 1.52 | 1.78 | 3.30 | **6.95** |
| The 5%-26%_2030-CCS Only Scenario | 1.74 | 0.23 | 1.70 | 2.81 | **6.48** |

**Table A4.13** Capacity retired from 2012-13 to 2019-20, from 2020-21 to 2029-30, from 2030-31 to 2039-40 and from 2040-41 to 2049-50 in the WEM by scenario (unit: GW).

| **Scenario** | **2012-13 to 2019-20** | **2020-21 to 2029-30** | **2030-31 to 2039-40** | **2040-41 to 2049-50** | **Total** |
|---|---|---|---|---|---|
| The BAU Scenario | 0.22 | 0.00 | 0.00 | 0.00 | **0.22** |
| The 5% Reduction Scenario | 0.64 | 0.00 | 0.00 | 0.08 | **0.71** |
| The 25% Reduction Scenario | 0.92 | 0.00 | 0.00 | 0.03 | **0.95** |
| The 5%-RETs Only Scenario | 0.64 | 0.00 | 0.00 | 0.08 | **0.72** |
| The 25%-RETs Only Scenario | 0.92 | 0.00 | 0.00 | 0.00 | **0.92** |
| The 5%-CCS Only Scenario | 0.49 | 0.04 | 0.00 | 0.39 | **0.92** |
| The 25%-CCS Only Scenario | 0.85 | 0.00 | 0.00 | 0.22 | **1.07** |
| The 5%-26%_2030 Reduction Scenario | 0.63 | 0.00 | 0.00 | 0.09 | **0.72** |
| The 5%-26%_2030-RETs Only Scenario | 0.63 | 0.00 | 0.00 | 0.07 | **0.70** |
| The 5%-26%_2030-CCS Only Scenario | 0.50 | 0.00 | 0.00 | 0.45 | **0.95** |

Table A4.14 shows the data of the WEM's power system expansion levilised cost from 2013-14 to 2049-50 by scenario. These data were plotted as Figure 6.19 in Section 6.6, Chapter 6.

**Table A4.14** The WEM's levilised cost results by scenario from 2013-14 to 2049-50 (unit: \$/MWh).

| Technology | BAU | 5% Reduction | 25% Reduction | 5%-RETs Only | 25%-RETs Only | 5%-CCS Only | 25%-CCS Only | 5%-26% _2030 Reduction | 5%-26% _2030-RETs Only | 5%-26% _2030-CCS Only |
|---|---|---|---|---|---|---|---|---|---|---|
| **2013-14** | 50.4 | 50.4 | 50.4 | 50.4 | 50.4 | 50.4 | 50.4 | 50.4 | 50.4 | 50.4 |
| **2014-15** | 32.0 | 34.1 | 34.5 | 34.1 | 34.5 | 34.1 | 34.5 | 33.4 | 33.4 | 33.4 |
| **2015-16** | 32.3 | 35.0 | 36.1 | 35.0 | 36.1 | 35.0 | 36.1 | 33.8 | 33.8 | 33.8 |
| **2016-17** | 32.4 | 34.6 | 35.8 | 34.6 | 35.8 | 34.8 | 35.9 | 33.2 | 33.2 | 33.4 |
| **2017-18** | 33.1 | 35.5 | 37.7 | 35.5 | 37.7 | 35.6 | 37.9 | 34.0 | 34.0 | 34.2 |
| **2018-19** | 33.8 | 36.3 | 40.0 | 36.3 | 40.0 | 36.5 | 40.5 | 34.8 | 34.8 | 35.0 |
| **2019-20** | 34.4 | 37.0 | 41.7 | 37.0 | 41.7 | 47.5 | 50.2 | 35.4 | 35.4 | 46.1 |
| **2020-21** | 34.3 | 37.3 | 42.7 | 37.3 | 42.7 | 46.7 | 49.5 | 36.5 | 36.5 | 45.4 |
| **2021-22** | 34.2 | 38.3 | 43.7 | 38.3 | 43.7 | 46.3 | 49.2 | 37.7 | 37.7 | 45.0 |
| **2022-23** | 34.2 | 39.6 | 44.7 | 39.6 | 44.7 | 45.9 | 49.0 | 38.8 | 38.8 | 44.7 |
| **2023-24** | 34.2 | 41.0 | 45.9 | 41.0 | 45.9 | 45.6 | 49.1 | 40.1 | 40.1 | 44.4 |
| **2024-25** | 34.2 | 42.5 | 47.4 | 42.5 | 47.4 | 45.7 | 49.2 | 41.4 | 41.4 | 44.6 |
| **2025-26** | 34.2 | 44.0 | 48.8 | 44.0 | 48.8 | 45.7 | 49.3 | 42.9 | 42.9 | 44.6 |
| **2026-27** | 34.4 | 45.8 | 50.3 | 45.8 | 50.3 | 45.8 | 49.6 | 44.6 | 44.6 | 44.7 |
| **2027-28** | 34.7 | 47.5 | 51.7 | 47.6 | 51.7 | 46.1 | 50.7 | 46.1 | 46.2 | 44.9 |
| **2028-29** | 35.0 | 49.4 | 53.2 | 49.4 | 53.2 | 47.2 | 52.3 | 48.0 | 47.9 | 45.9 |
| **2029-30** | 35.4 | 51.1 | 54.7 | 51.2 | 54.7 | 49.0 | 55.0 | 49.4 | 49.4 | 47.4 |
| **2030-31** | 35.8 | 52.8 | 56.2 | 52.8 | 56.8 | 51.4 | 57.6 | 51.2 | 51.2 | 49.6 |
| **2031-32** | 36.1 | 54.2 | 57.3 | 54.2 | 58.6 | 54.1 | 59.9 | 52.7 | 52.7 | 52.3 |
| **2032-33** | 36.5 | 55.8 | 59.2 | 56.4 | 60.6 | 57.1 | 62.4 | 54.4 | 55.0 | 55.5 |
| **2033-34** | 36.9 | 57.3 | 61.2 | 58.6 | 62.6 | 60.0 | 64.9 | 56.0 | 57.3 | 58.5 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **2034-35** | 37.3 | 59.3 | 63.2 | 60.8 | 64.5 | 62.8 | 67.2 | 57.6 | 59.5 | 61.4 |
| **2035-36** | 37.8 | 61.4 | 65.5 | 62.9 | 66.4 | 65.4 | 69.4 | 59.8 | 61.7 | 64.0 |
| **2036-37** | 38.3 | 63.7 | 68.0 | 65.1 | 68.4 | 67.9 | 71.7 | 62.1 | 63.9 | 66.8 |
| **2037-38** | 38.7 | 66.2 | 70.1 | 67.1 | 70.4 | 70.3 | 73.7 | 64.6 | 66.0 | 69.2 |
| **2038-39** | 39.1 | 68.8 | 72.3 | 69.2 | 72.6 | 72.8 | 75.8 | 67.3 | 68.2 | 71.8 |
| **2039-40** | 39.6 | 71.3 | 74.4 | 71.6 | 74.6 | 75.0 | 77.6 | 69.8 | 70.4 | 74.1 |
| **2040-41** | 40.3 | 74.3 | 77.0 | 74.5 | 77.1 | 77.7 | 80.1 | 72.9 | 73.3 | 76.9 |
| **2041-42** | 40.9 | 76.9 | 79.4 | 77.1 | 79.7 | 80.4 | 82.5 | 75.7 | 76.0 | 79.6 |
| **2042-43** | 41.5 | 79.3 | 81.6 | 80.3 | 82.9 | 82.6 | 84.4 | 78.2 | 78.5 | 81.8 |
| **2043-44** | 42.0 | 81.6 | 83.5 | 84.0 | 85.9 | 84.8 | 86.3 | 80.6 | 82.4 | 84.2 |
| **2044-45** | 42.7 | 84.3 | 85.7 | 88.4 | 89.5 | 87.8 | 89.1 | 83.4 | 87.0 | 87.3 |
| **2045-46** | 43.4 | 86.9 | 88.0 | 92.7 | 93.0 | 91.2 | 92.1 | 86.2 | 91.6 | 90.7 |
| **2046-47** | 44.1 | 89.4 | 90.2 | 97.0 | 96.5 | 94.7 | 95.2 | 88.8 | 96.1 | 94.3 |
| **2047-48** | 44.8 | 91.8 | 92.2 | 100.7 | 99.7 | 98.5 | 98.4 | 91.3 | 100.1 | 98.3 |
| **2048-49** | 45.4 | 94.0 | 93.9 | 104.4 | 102.6 | 102.1 | 100.4 | 93.6 | 104.0 | 102.3 |
| **2049-50** | 46.1 | 97.4 | 96.7 | 108.1 | 105.7 | 107.5 | 104.9 | 97.2 | 107.8 | 107.8 |

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