Modelling the Future Grid Forum scenarios

CSIRO and ROAM Consulting

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## Contents

1  Introduction ........................................................................................................................................ 12
2  Modelling framework.......................................................................................................................... 13
3  Scenarios ............................................................................................................................................. 17
   3.1  Core scenarios........................................................................................................................... 17
   3.2  Sensitivity cases ........................................................................................................................ 19
   3.3  Scenario and sensitivity case summary .................................................................................... 19
4  Assumptions ........................................................................................................................................ 21
   4.1  Renewable energy output profiles ........................................................................................... 21
   4.2  Demand projections .................................................................................................................. 21
   4.3  Proxy carbon abatement policy measures ............................................................................... 29
   4.4  Fuel cost projections ................................................................................................................. 31
   4.5  Centralised generation capital cost assumptions ..................................................................... 33
   4.6  Other centralised generation assumptions ............................................................................. 34
   4.7  Distributed (on-site) generation capital cost assumptions ....................................................... 35
   4.8  Reconciling centralised and distributed generation solar photovoltaic plant cost projections .......................................................................................................................................... 37
   4.9  Transmission capital cost assumptions ....................................................................................... 37
   4.10  Storage cost assumptions ......................................................................................................... 37
   4.11  Disconnection costs .................................................................................................................. 40
   4.12  Distribution system assumptions ............................................................................................. 44
   4.13  Non-grid system costs .............................................................................................................. 45
   4.14  Electric vehicle assumptions ..................................................................................................... 45
   4.15  2-4-C specific assumptions ........................................................................................................ 46
5  Modelling results ................................................................................................................................. 49
   5.1  Scenario 1: ‘Set and forget’ ....................................................................................................... 50
   5.2  Scenario 2: ‘Rise of the prosumer’ ............................................................................................ 65
   5.3  Scenario 3: ‘Leaving the grid’ .................................................................................................... 80
   5.4  Scenario 4: ‘Renewables thrive’ ............................................................................................... 95
   5.5  Scenario 1 sensitivity case: Zero carbon price ........................................................................ 114
   5.6  Scenario 1 sensitivity case: High carbon price ........................................................................ 117
   5.7  Scenario 1 sensitivity case: Uncertain carbon price ............................................................... 120
   5.8  Scenario 1 sensitivity case: High gas price ............................................................................. 131
   5.9  Scenario 1 sensitivity case: Nuclear ........................................................................................ 134
   5.10  Scenario 1 sensitivity case: Demand response counterfactual .............................................. 137
   5.11  Scenario 1 sensitivity case: climate impacts adaptation .......................................................... 139
6  Consolidated modelling results and scenario comparisons ...................................................................... 142
   6.1  Consolidating results from multiple models ............................................................................ 142
   6.2  Scenario results comparisons .................................................................................................... 143
Figures

Figure 1: The Future Grid Forum modelling framework .................................................................14
Figure 2: Future Grid Forum core scenarios..................................................................................17
Figure 3: Summary of core scenarios and sensitivity cases.............................................................20
Figure 4: Snapshot of summer and winter demand profiles for unadjusted projected demand for Queensland in 2047 with (light blue) and without (dark blue) the impact of rooftop solar panel uptake ..........23
Figure 5: Adjusted projected demand (one week snapshot) for Queensland in 2047 with additional commercial HVAC management (dark green), very light blue shows the rooftop solar panel adjusted load (without commercial HVAC management) .................................................................................................................................25
Figure 6: Adjusted projected demand (one week snapshot) for Queensland in 2047 without (light green) and with (dark green) additional industrial demand reduction: very light blue shows the rooftop solar panel adjusted load only ..........................................................................................................................................................................................26
Figure 7: Adjusted projected demand (one week snapshot) for Queensland in 2047 without (light green) and with (dark green) additional residential HVAC: very light blue shows the rooftop solar panel adjusted load only ..........................................................................................................................................................................................27
Figure 8: Adjusted projected demand (one week snapshot) for Queensland in 2047 without (light green) and with (dark green) additional smart EV charging: very light blue shows the rooftop solar panel adjusted load only ..........................................................................................................................................................................................28
Figure 9: Adjusted projected demand (one week snapshot) for Queensland in 2047 without (light green) and with (dark green) additional battery storage: very light blue shows the rooftop solar panel adjusted load only ..........................................................................................................................................................................................29
Figure 10: SGLP and modified carbon prices used in this report .......................................................30
Figure 11: Medium projected natural gas price assumption .............................................................31
Figure 12: Medium projected black (NSW and Qld) and brown (Vic) coal price assumption ..........32
Figure 13: Medium projected uranium price assumptions ...............................................................32
Figure 14: Cost multiplier for battery technologies based upon the projected wind turbine and solar PV cumulative capacity in Australia, following Hayward and Graham (2012a) ................................................................................................................38
Figure 15: Projected percentage reductions in storage costs ............................................................39
Figure 16: Assumed percentage of stock to exist in age cohorts between one and 50 years by state ........44
Figure 17: Map of the National Electricity Market zones modelled in 2-4-C ........................................47
Figure 18: Assumed centrally supplied electricity consumption and peak demand in NEM states under Scenario 1 ........................................................................................................................................................................................................50
Figure 19: Projected central and on-site electricity generation by technology in Scenario 1 ..........52
Figure 20: Projected on-site electricity generation by technology in Scenario 1 ..........53
Figure 21: Projected cumulative capital investment in central and on-site generation plant in Scenario 1 ........53
Figure 22: Projected average wholesale electricity unit cost in Scenario 1 ................................54
Figure 23: Projected electricity sector greenhouse gas emissions in Scenario 1 ....................................55
Figure 24: Projected uptake of internal combustion and alternative road vehicle drivetrains in Scenario 1 .56
Figure 25: Projected transport sector fuel consumption by fuel in Scenario 1 ....................................57
Figure 26: Illustration of Scenario 1 projected transmission augmentation........................................58
Figure 144: An imaginary demand profile (solid line) for a residential building, and a demand response (dashed line) achieved using a battery and inverter system. This demand response is effectively smoothing the peaky demand.

Tables

Table 1: Desirable model features and their limitations ................................................................. 13
Table 2: Key functions and dependencies of the Future Grid Forum modelling framework ............... 15
Table 3: Main assumptions of the core scenarios ............................................................................. 18
Table 4: 2030 fuel prices ($/GJ) for low and high cases, averaged across states ................................. 33
Table 5: Medium capital costs assumptions based on AETA (2012) ................................................ 33
Table 6: Accelerated capital costs assumptions based on Hayward and Graham (2012) .................... 34
Table 7: Summary of AETA technology assumptions (for representative states) and CSIRO data for current power ........................................................................................................ 35
Table 8: Medium projection of distributed generation capital costs ($/kW) applicable to Scenario 1 .... 35
Table 9: Accelerated projection of distributed generation capital costs applicable to Scenarios 2, 3 and 4 . 36
Table 10: Current cost (in AUD 2012) and performance assumptions for residential scale zinc-bromine batteries assuming they are manufactured at mass market scale ........................................ 38
Table 11: Detailed assumptions, notes and calculations for residential disconnection ....................... 41
Table 12: Two sources for assumed average aggregate costs of investment in distribution system capacity .......................................................................................................................... 45
Table 13: Electric vehicle uptake drivers and assumptions ................................................................. 46
Table 14: Models applied in each scenario or sensitivity case ......................................................... 49
Table 15: Comparison of Initial TNEP and modified 2-4-C transmission augmentation projections ........ 62
Table 16: Projected transmission augmentations in Scenario 2 ......................................................... 71
Table 17: Comparison of 2-4-C modified and TNEP initial projected transmission augmentation in Scenario 2 ............................................................................................................. 77
Table 18: Projected transmission augmentation in Scenario 4 .......................................................... 103
Table 19: Solar generation capacity by NTNDP zone in Scenario 4 .................................................. 106
Table 20: Wave generation capacity by NTNDP zone in Scenario 4 .................................................. 106
Table 21: Wind generation capacity by NTNDP zone in Scenario 4 .................................................. 108
Table 22: Geothermal generation capacity by NTNDP zone in Scenario 4 ......................................... 108
Table 23: Forecasts and ranges for levelised costs of electricity generation; selected years ............ 124
Table 24: Profitability of alternative electricity generation technologies ........................................ 125
Table 25: Projected transmission augmentation across the scenarios .............................................. 149
Table 26: Generation Technologies .................................................................................................. 178
Table 27: TNEP Standard Transmission Options .............................................................................. 180
Table 28: NNS-SWQ interconnector augmentation options ............................................................ 182
Table 29: Nominal flow limits for the DC load flow model ................................................................. 195
Table 30: Generator outage modelling assumptions ......................................................................... 197
Table 31: The total life-cycle cost in AUD 2012 of 5 percent residential battery deployment by 2030 for alternative discount rates ......................................................................................... 202
1 Introduction

This report provides the detail behind the scenarios explored by the Future Grid Forum and how they were modelled. The quantitative analysis in this report has been used to support the discussion and conclusions of the Future Grid Forum which are published separately in *Change and choice*. Besides exploring scenarios and developing policy and technological options for public debate, a key objective of the Future Grid Forum was to develop credible, whole of system modelling of the electricity sector.

In the past decade electricity futures have been modelled in increasingly finer detail by more and more sophisticated models. Electricity sector modelling has received a large amount of resources and in-depth treatment for three reasons. The first is because electricity assets are expensive and long lived so it is an essential to understand more about what futures the assets will be operating in. The second is that Australia’s National Electricity Market commenced in 1998 and so there was a need for companies to have tools in which to strategise their involvement in this new competitive wholesale electricity market environment. The third key driver of the last decade has been the need to understand how the sector can transform, under different policy settings, to meet the long term goal of substantial greenhouse gas emissions reduction.

Given this focus, it is understandable that the vast majority of modelling resources have been targeted at the generation sector. However, more recently given the majority of retail electricity price increases originated outside the generation sector, it has been clear that other parts of electricity supply chain need equal attention to understanding their operation and future changes. Indeed, the approach presented in this report is whole of electricity system modelling. This approach fundamentally recognises that one cannot optimise electricity sector outcomes without studying the whole system.

In the next section of this report we explain what is meant by a whole-of-system modelling approach. The scenarios are then outlined. General and scenario specific model assumptions follow and we conclude with modelling results and appendices.
### 2 Modelling framework

As stated in the introduction one of the objectives of the Future Grid Forum was to present a new whole of system modelling approach that would avoid the potential pitfalls of focussing on only one part of the system. The ambition of whole of sector modelling must inevitably be tempered by the practical limits of modelling. Below are some ideal model features and the problems they create:

<table>
<thead>
<tr>
<th>Desired feature</th>
<th>Requirements and limitations</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Temporal disaggregation</strong></td>
<td>The electricity system has to work on scales of around 50 years (which is the life of most assets) down to sub-five minutes where the extremes of reliability occur.</td>
</tr>
<tr>
<td></td>
<td>It is not feasible to build a single model that optimises 50 years ahead and takes account each five minute interval</td>
</tr>
<tr>
<td><strong>Spatial disaggregation</strong></td>
<td>The electricity system needs to be understood at the national level (e.g. national renewable targets and state trading) and down to the substation or suburb level where load profiles and system stressors must be matched to local solutions.</td>
</tr>
<tr>
<td></td>
<td>Substation level or below data is confidential, poor (only collected intermittently) or not collected. It can be synthesised in some cases. Even if available, it may stretch model size limits.</td>
</tr>
<tr>
<td><strong>Automation</strong></td>
<td>For this project each of the models needs to be run many times to problem solve in the stages of setting up scenario runs and also in a feedback loop with participants and with other models. All of these “runs” need to occur in around two weeks between Forum workshops.</td>
</tr>
<tr>
<td></td>
<td>In practice, given the compromises that have to made to meet the first two challenges there can be a high need for iterations requiring manual rather than automated checks, consuming project resources.</td>
</tr>
<tr>
<td><strong>Technological depth</strong></td>
<td>A large number of technologies, existing and emerging, represented. A higher technological depth increases the size of the model.</td>
</tr>
<tr>
<td><strong>Strong behavioural underpinnings</strong></td>
<td>The goal of a model is to approximate real world behaviour. To do that may require employing multiple theories of human behaviour which vary in different contexts. Economic theory is strongly verified but narrow in scope. Incorporating other theories can improve realism but at the cost of appearing ad hoc. The major decisions we are seeking to model are technology choices and investment. Models vary in the degree to which they attempt to represent and project realistic human behaviours.</td>
</tr>
</tbody>
</table>

Given how spatially and temporally disaggregated we would ideally like each part of the supply chain to be represented implies each segment will need at least one model. If we think of the electricity supply chain as having five circular stages – generation, transmission, distribution, retail and consumer demand – then we need at least five models.
Figure 1 shows the models that were deployed. It includes five models that solve a traditional programming type problem such as minimising costs (GALLM, ESM, TNEP, 2-4-C and DiSCoM) and two other activities which are manipulating data sets through various means to calculate key data inputs and outputs. While there are many data inputs and outputs, the Demand model and Customer impact model are significant enough to deserve special attention and “model” status in their own right.

Notes: GALLM: Global and Local Learning Model; ESM: Energy Sector Model; TNEP: Transmission Network Expansion Planning; 2-4-C: “To foresee”; DiSCoM: Distribution cost model

Figure 1: The Future Grid Forum modelling framework

The arrows in Figure 1 indicate the flow of information and dependency. In some cases models are required to iterate to reach a consistent or feasible point before moving to the next step. These key dependencies are described in Table 2 along with the key function and supply chain segment that each model addresses.

Implicit in the design of this modelling framework is the assumption that it is not possible to build one model to cover all the desirable detail. Even in using multiple models there remains some compromises and gaps. As a result the following limitations in the modelling framework should be noted:

- While the generation and transmission sector are modelled in hourly detail and with reasonable sub-state spatial resolution, the distribution sector receives no treatment below an annual and state distributor level. This aggregated approach to modelling the distribution sector reflects the practical difficulties of access to data. To model at this level each distributor would need to provide details of their network topology and sub-station demand data (or alternatively a methodology for synthesising such data from more aggregate data sets).
- Whilst the framework allows us to estimate the whole of system cost and therefore the implied retail price we do not conduct any analysis of the retail component of the retail price. That is, we do not estimate the margin taken by retailers in the retail price. This component of the retail price is assumed to be constant at the most recent observed level
- We can provide no detail of the location of new generation and transmission assets within NTNDP zones. We can safely assume brown field sites will be re-used but the modelling does not specifically seek to identify the exact location of new assets within NTNDP zones. Transmission distances and generation connection points are averaged within NTNDP zones.
- Except where imposed by a scenario assumption, the major driving human behavioural assumption is cost minimisation/profit maximisation based on economic theory. This is a fairly safe assumption for projecting large asset purchases. However, it is less reliable as we come closer to consumer goods purchases such as electric vehicles and solar panels where other decision making factors can play a large role in reality. The use of scenarios to explore and impose alternative human development pathways partly overcomes the narrow underlying human behavioural assumptions.

<table>
<thead>
<tr>
<th>Model</th>
<th>Supply chain segment</th>
<th>Key function</th>
<th>Key dependencies</th>
</tr>
</thead>
<tbody>
<tr>
<td>GALLM</td>
<td>Technology supply</td>
<td>Calculate the rate of change in electricity generation technology costs over time</td>
<td>Consistency with Australian policy settings in ESM, TNEP and 2-4-C</td>
</tr>
<tr>
<td>Demand model</td>
<td>Consumer demand</td>
<td>Calculate hourly electricity demand profiles by state to 2050 modifying the profile to take account of energy efficiency, electric vehicles, solar panels and demand management activities</td>
<td>Requires ESM to estimate electric vehicle and distributed (on-site) generation uptake.</td>
</tr>
<tr>
<td>ESM</td>
<td>Generation</td>
<td>Project long term generation investment, retirement and augmentation decisions for centralised and decentralised technologies and co-optimise electric vehicle uptake with other transport fuel and vehicle choices to the state level in annual time steps</td>
<td>Requires annual energy and peak demand projections from the demand model. Inputs GALLM technology costs</td>
</tr>
<tr>
<td>TNEP</td>
<td>Generation and transmission</td>
<td>Project the co-optimised generation and transmission investment, retirement and augmentation decisions by NTNDP zone and annual time steps but based on a subset of detailed “stress test” load blocks across the projection period</td>
<td>ESM’s projected generation mix is used as a non-binding starting envelope for generation investment decisions. Information from TNEP about the amount of unserved energy is used to refine TNEP’s load block stress tests. Inputs GALLM technology costs</td>
</tr>
<tr>
<td>2-4-C</td>
<td>Generation and transmission</td>
<td>Project the dispatched generation mix and use of transmission system for each half-hourly period for a cross section of selected years (2030,)</td>
<td>The generation and transmission capacity from TNEP is imposed on 2-4-C and detailed hourly demand profiles are inputted from</td>
</tr>
<tr>
<td>Model</td>
<td>Supply chain segment</td>
<td>Key function</td>
<td>Key dependencies</td>
</tr>
<tr>
<td>----------------------------</td>
<td>----------------------</td>
<td>------------------------------------------------------------------------------</td>
<td>------------------------------------------------------------</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2040 and 2050) and calculate the amount of unserved energy</td>
<td>the Demand Model. Inputs GALLM technology costs</td>
</tr>
<tr>
<td>DiSCoM</td>
<td>Distribution system</td>
<td>Project the investment and total distribution system costs required to meet</td>
<td>The required demand is inputted from the Demand model</td>
</tr>
<tr>
<td></td>
<td></td>
<td>projected consumer demand by state, distributor and year</td>
<td></td>
</tr>
<tr>
<td>Customer impact model</td>
<td>Retail</td>
<td>Project the national annual whole of system cost and unit price and household</td>
<td>Generation expenditure and unit price is inputted from</td>
</tr>
<tr>
<td></td>
<td></td>
<td>electricity costs for average and alternative end-use cases</td>
<td>ESM. Transmission costs are inputted from TNEP. Distribution</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>costs are inputted from DiSCoM. End-use cases are inputted</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>from the Demand model (e.g. storage and smart appliance</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>ownership)</td>
</tr>
</tbody>
</table>

Each model is outlined in more detail in their own appendix to this report.
3 Scenarios

3.1 Core scenarios

The participants in the Future Grid Forum developed four major scenarios to be explored by the modelling. They each explore a set of distinct themes around the topics of peak demand control, distributed (on-site) generation, passive and active customer engagement, use of storage, energy efficiency, electric vehicles and customer disconnection (Figure 2).

**Scenario 1: Set and forget**
- Consumers sign up to voluntary demand control schemes, but rely on utilities for the solutions for integrating and operating them. ‘Set and forget’.
- A niche of customers take up distributed generation and electric vehicles, but most rely on centralised power and liquid-fuelled transport.

**Scenario 2: Rise of the prosumer**
- A tide of customers take up distributed generation and electric vehicles. The role of centralised power and liquid fuel declines considerably.
- The distribution system becomes a hub for user electricity trading.

**Scenario 3: Leaving the grid**
- Around a third of consumers completely disconnect from the grid using a combination of gas generation, solar panels, storage and energy efficiency.
- The remaining consumers on the system are those with poor access to capital and are faced with maintaining an underutilised system.

**Scenario 4: Renewables thrive**
- Storage plays a large role in all aspects of the electricity system supporting a very high share of renewables in centralised power supply, high electric vehicle uptake and strong demand control.

Figure 2: Future Grid Forum core scenarios

These brief scenario narratives give an indication of the broad area of interest explored in the scenarios. However, Table 3 provides more detail on the main assumptions of each scenario.
<table>
<thead>
<tr>
<th></th>
<th>Scenario 1</th>
<th>Scenario 2</th>
<th>Scenario 3</th>
<th>Scenario 4</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>DG share</strong></td>
<td>Low</td>
<td>High</td>
<td>High</td>
<td>High</td>
</tr>
<tr>
<td><strong>EV uptake</strong></td>
<td>Modest</td>
<td>Medium-high</td>
<td>Medium-high</td>
<td>High</td>
</tr>
<tr>
<td><strong>Demand response</strong> (storage)</td>
<td>Equivalent to Resi. 1kW for 5 hours 0-20% 2015-2030 but centrally located in suburb</td>
<td>Resi. 1kW for 5 hours 0-20% 2015-2030 In individual homes</td>
<td>Used off-grid. 5kW batteries plus 2.2kW diesel back-up</td>
<td>Resi. 1kW for 5 hours 0-20% 2015-2030 In individual homes</td>
</tr>
<tr>
<td><strong>Demand response</strong> (HVAC)</td>
<td>Both resi. and comm. managed</td>
<td>Both resi. and comm. managed</td>
<td>Unmanaged, remaining customers can’t afford upfront costs</td>
<td>Both resi. and comm. managed</td>
</tr>
<tr>
<td><strong>Demand response</strong> (Industrial)</td>
<td>Managed</td>
<td>Managed</td>
<td>Unmanaged, remaining customers can’t afford actions</td>
<td>Managed</td>
</tr>
<tr>
<td><strong>Disconnections</strong></td>
<td>RAPS only</td>
<td>RAPS only</td>
<td>All existing and new DG owners by 2020</td>
<td>RAPS only</td>
</tr>
<tr>
<td><strong>GHG reduction commitment</strong></td>
<td>Moderate carbon price</td>
<td>Moderate carbon price</td>
<td>Moderate carbon price</td>
<td>Moderate carbon price plus extended RET to 100%</td>
</tr>
<tr>
<td><strong>Technology costs</strong></td>
<td>AETA projections for CG, CSIRO for DG, storage, large scale solar PV</td>
<td>AETA projections for CG, CSIRO for DG, storage, large scale solar PV</td>
<td>AETA projections for CG, CSIRO for DG, storage, large scale solar PV</td>
<td>Accelerated based on stronger global abatement commitment</td>
</tr>
<tr>
<td><strong>Energy efficiency</strong></td>
<td>AEMO moderate growth case based on current price pressures</td>
<td>AEMO moderate growth case based on current price pressures</td>
<td>Low energy consumption due to relatively higher costs for those left on grid</td>
<td>Low energy consumption based on expected higher prices due to lower emissions</td>
</tr>
<tr>
<td><strong>Network</strong></td>
<td>Modest expansion. Load factor maintained</td>
<td>Flat. Significant decline in load factor</td>
<td>Flat. Significant decline in load factor</td>
<td>Load factor declining. Expansion to connect renewables</td>
</tr>
<tr>
<td><strong>Gas price assumption</strong></td>
<td>AETA medium</td>
<td>AETA low supporting gas on-site generation</td>
<td>AETA low supporting gas on-site generation</td>
<td>AETA medium</td>
</tr>
<tr>
<td><strong>Customer pricing framework</strong></td>
<td>Cost reflective supporting engagement</td>
<td>Cost reflective supporting engagement</td>
<td>Non-cost reflective encouraging disconnection</td>
<td>Cost reflective supporting engagement</td>
</tr>
<tr>
<td><strong>Large scale renewables</strong></td>
<td>Substantial but some technologies limited by cost of back-up</td>
<td>Substantial but some technologies limited by cost of back-up</td>
<td>Substantial but some technologies limited by cost of back-up</td>
<td>Very high supported by storage and lower costs</td>
</tr>
</tbody>
</table>

3.2 Sensitivity cases

The core scenarios do not represent all the possible drivers of change impacting the electricity sector and nor are they intended to. The Future Grid Forum discussed a wide range of drivers, not all of which were selected to be part of the core scenarios. However, it was decided to explore some drivers as sensitivity cases. Briefly, the key sensitivity cases selected to be explored were as follows:

- **NSC**: A nuclear sensitivity case exploring the impact if nuclear power was permitted in the future
- **HCP**: A high carbon price sensitivity case exploring the impact if Australia chose to accelerate the rate at which it reduces greenhouse gas emissions
- **ZCP**: A zero carbon price case exploring the impact if Australia chose to reduce the rate at which it decarbonised
- **CI**: An exploration of the impact on modelling results if the impact of climate change was explicitly included in the modelling
- **UCP**: An exploration of the impact on the electricity sector of having ongoing uncertainty about Australia’s future carbon abatement pathway
- **DRCF**: A peak demand reduction counterfactual which explores the impact of maintaining peak demand growth at trend levels, rather than reducing it.
- **HGSC**: An exploration of the impact of high gas prices

The assumptions of each of these sensitivity cases and how they differ from the core scenarios is explained in more detail in the assumptions section of this report.

3.3 Scenario and sensitivity case summary

The following diagram summarises the core scenario and sensitivity cases in a single diagram. It indicates that our core scenarios are mostly driven off three axes of centralised and decentralised electricity mix, peak demand and deployment of large scale renewables. The sensitivity cases mainly explore issues of carbon prices, gas prices, climate impacts and nuclear power. One sensitivity case is a function of the peak demand axes.
Figure 3: Summary of core scenarios and sensitivity cases

- **Mix of centralised (CG) and distributed (on-site) generation (DG)**
- **Other uncertainties**
  - Nuclear power
  - Carbon price
  - Climate impacts
  - Gas price

- **Large scale renewables (LSR)**
  - High LSR
  - Moderate LSR with gas back-up
  - Low peak response
  - High peak demand response

- **Peak demand management**
  - Low peak response
  - High peak demand response
  - Loss of demand

- **Core scenarios**
  - S1: Nuclear power, Green hydrogen cogeneration
  - S2: Carbon price, Climate impacts, Nuclear power
  - S3: Climate impacts, Gas price, Nuclear power
  - S4: Gas price, Climate impacts, Nuclear power

- **Sensitivity cases**
  - NSC
  - HCP
  - ZCP/CI
  - UCP
  - DRCF
  - HGSC
  - E.g. solar panels, gas cogeneration
  - Large scale renewables (LSR)
4 Assumptions

4.1 Renewable energy output profiles

Hourly profiles for renewable electricity generation technology are used throughout the modelling steps but primarily in developing the demand profiles and adjusting them for solar panel output and for establishing the required generation and transmission investment and operating strategies that meets the reliability requirements of the system.

Renewable energy output profiles are sourced from the AEMO 100% renewable study web page which makes this data available in Excel files for several historical years. The data was developed by CSIRO and ROAM Consulting for that project and was documented in multiple reports that are also published on the same site. A desired outcome of that project was to make the data available for future projects such as this one.

The relevant link is as follows:

4.2 Demand projections

4.2.1 OVERVIEW

Average and peak demand projections for various scenarios were calculated based on AEMO (2013) projections applying their medium case (Scenarios 1 and 2) and low case (Scenarios 3 and 4). AEMO annual projections to 2032-33 were extrapolated to 2050, and half hourly demand trajectories that are compatible with the extrapolated annual projections were constructed based on past history. These half hourly trajectories were modified to simulate demand side management interventions designed to reduce peak demand. These average and peak demand values for these modified trajectories were then derived.

4.2.2 UNADJUSTED ANNUAL AVERAGE ENERGY AND PEAK POWER DEMAND PROJECTIONS

AEMO projections describe annual average energy demand to 2032-33. For this project, the AEMO scenarios of interest are the medium and low case. These include projections of (centralised) “as generated” electricity, auxiliary demand (the electricity consumed within power stations), total sent out electricity (as generated less auxiliary demand), transmission losses, and energy generation from rooftop photovoltaics. Peak power projections are provided on an as generated basis, but auxiliary power demand and solar PV summer peak power projections are also provided.

We constructed time series extrapolated to 2050 of annual electricity consumption (total centralised sent out electricity including photovoltaic generation, to represent electricity consumption requirements though ignoring transmission losses), for each state in the NEM and each of the two growth scenarios by determining the 10 year average annual percentage growth implied by the AEMO projections from 2020-2030 and holding that growth rate constant to 2050.

CSIRO projections show electricity demand for electric vehicles to be quite high between 2025 and 2035, so in order to reduce the effect of this component of demand on demand growth trends, these projections
were subtracted from the energy demand forecasts before extrapolation, after which electric vehicle demand projections were replaced. The rationale for doing this is based on an understanding that the AEMO (2013) projections include EV demand.

The corresponding peak power demand for each of winter and summer (in this case, as generated less auxiliary demand plus summer photovoltaic power generation at peak) were extrapolated in a similar manner, with the exception that no particular adjustments were made for additional peak power demand owing to electrical vehicle charging. In particular, the peak to average ratio (for summer and winter) implied in the AEMO projections was calculated to 2030, and the 10 year average annual percentage growth in this ratio was calculated, and that growth rate kept constant to 2050. The corresponding seasonal peak power demands were then determined from the projected energy requirements and peak to average ratios (leading to a peak power growth rate that is constant over time- before any adjustment to the projections are made for the Future Grid Forum scenario purposes).

4.2.3 UNADJUSTED HALF-HOURLY DEMAND PROJECTIONS

Annual average energy and seasonal peak power demand projections as derived above were used to construct half-hourly demand projections as follows. Historical half-hourly demand were collected and scaled in a non-linear way so that the annual average energy and seasonal peak power demands coincided very closely. Again, demand owing to electric vehicles was treated in a particular way, a charging profile with hourly resolution for each of weekdays and weekends was scaled to reproduce the CSIRO electric vehicle annual energy demand projections (generated from ESM, the assumptions for which are discussed below).

Historical demand traces are associated with both a day of the week and date within the year. We aim to construct a half-hourly resolution demand trace for years to 2050 that have a similar shape to historical demand patterns. To this end for each year in the future we associate with each calendar date some corresponding historical daily demand which is the same day of the week and a similar date within the year. We then scale that year’s half-hourly data so that, after adding the electric vehicle charging demand trajectory as identified above, the resulting year’s data has close to the projected average annual energy demand and the projected seasonal maximum power demands. The scaling is selected so that the growth in the minimum demand each year matches the average energy demand growth. Interpolation is applied at the beginning and end of each artificially constructed year in order to reduce the likelihood of large jumps in the daily average demand from one calendar year to the next.

The scaling that has been applied is a nonlinear (quadratic) function from historical demand quantity to projected future demand quantity. Observe that a linear scaling function, which has only two parameters, is completely determined by two constraints, such as a requirement to meet projected average energy demand and one of two seasonal maximum demand constraints. However, it was noted that such a scaling transformation, applied to each six month period to avoid over-determination, would invariably result in the unrealistic projection in some of the later years of a future demand that is negative for some time periods. This is a consequence of maximum demands that grow significantly faster than average demand. With a linear scaling, higher maximum demands imply correspondingly lower minimum demands for the same average. Instead a quadratic scaling was applied to each six-month period such that the potential for unrealistic outcomes is minimised.

In principle, any historical year could be used as a template half-hourly demand trace for any future projected year. We decided to use the year 2010-11 as a repeating template for each future year given it was the only year in which potential renewable output by region was available for all renewable generation technologies.

4.2.4 ACCOUNTING FOR ROOFTOP SOLAR PANELS

Although AEMO (2013a) provides its own roof-top solar panel uptake projection, as we will be modifying this during each scenario we have replaced it with the rooftop solar panel projections from ESM. Error!
Reference source not found. shows the impact of roof-top solar panels in the year 2047\(^1\) in Queensland for some arbitrary winter and summer days. The darker blue line shows the demand projection not accounting for the impact of solar panels. The light blue line shows how this profile is modified when the solar panel impact is taken into account. As expected it hollows out or reduces the load profile in the middle of the day. In summer it will reduce the state aggregate peak in some cases. In winter, because the peaks occur in the morning and evening, they are not impacted. The summer profile begins to look more like a winter profile.

![Graph showing summer and winter demand profiles](image)

**Figure 4**: Snapshot of summer and winter demand profiles for unadjusted projected demand for Queensland in 2047 with (light blue) and without (dark blue) the impact of rooftop solar panel uptake

### 4.2.5 DEMAND SIDE MANAGEMENT ADJUSTED HALF-HOURLY DEMAND PROJECTIONS

The effects of up to five demand side management measures on the half-hourly demand trace, and therefore on annual average and peak demand is calculated to implement Scenarios 1, 2 and 4 which include demand side measures. These measures include HVAC operational management by commercial customers (commercial HVAC), demand reduction measures by industrial customers (Industrial DR), HVAC operational management by residential customers (residential HVAC), management of the charging cycle of electric vehicles (smart EV charging) and the management of the operations of batteries (battery storage).

\[^1\] We have chosen a year which most clearly demonstrates the impact of roof-top solar panels and different demand side measures. As grid-supplied consumption and peak demand is changing according the scenario assumptions, the impacts are different each year.
Note that residential HVAC management could also proxy management of other large household loads. Selection of this measure is not to imply this is the only prospective household demand management option.

Although in practice the various measures listed below would be applied concurrently, with a varied mix of co-ordination versus independence, the measures are simulated here as being applied consecutively, each consecutive measure being applied to maximise the remaining net impact on the peak power demand. This approach underestimates the impact of DSM to the extent that the five DSM measures are not applied concurrently to optimise the net impact. This effect is ameliorated by the fact that the order of consecutive application of these measures is selected such that the measures whose optimised operations are expected to be least affected by the application of the remaining measures are applied earlier.

On the other hand, the approach overestimates the impact of DSM to the extent that the DSM measures are applied retrospectively, in full knowledge of both half-hourly projected demand and the operations of the other previously applied measures (that is, the measures are somewhat co-ordinated). This effect is ameliorated by the fact that the operations of each measure are constrained to fairly simplistic algorithms dependent upon only aggregate information that is reasonably predictable, and that co-ordination is only partial (measures applied earlier do not depend on those applied later in the chain).

Since the order of consecutive application of these measures is selected such that the measures whose optimised operations are expected to be least affected by the application of the remaining measures are applied earlier, the chosen order of implementation was commercial HVAC, Industrial DR, residential HVAC, smart EV charging, battery storage. These measures are discussed in greater detail below.

### 4.2.6 DSM MEASURES

Where a scenario has assumed demand side management measures are deployed (Scenarios 1, 2 and 4) the following measures have been implemented.

**Commercial HVAC**

We assume that demand response measures amounting to a 3 degrees Celsius change in set-point may be for each building on only the five highest peak demand days of the year, after 2020. According to Zavala et al (2011) this permits a reduction of 45%, which is certainly greater than a conservative assumption of a 30% reduction. It is assumed that 50% of the peak is due to commercial buildings so that there is the equivalent of up to 15% demand reduction capacity in commercial buildings, for up to five days. We do not necessarily assume that the full 15% reduction capacity will be always implemented simultaneously. Instead we assume that peak demand can be reduced in 1% blocks up to 45 times (days) throughout the year. Sometimes these 1% demand reduction blocks may occur simultaneously (on the same day) up to a maximum of 15% at any one time.
Industrial DR

We assume that industrial load shifting measures are available at each site for up to 40 half-hour periods for each site from the year 2015. It is assumed that load deferred at one particular point in time is required to be provided within the next ten hour time period. For the purposes of identifying an operational deployment trajectory, we assume that industrial load shifting can be reduced in blocks of 10% of total load shifting power capacity up to 400 dispatch periods throughout the year. Again, sometimes these load shifting blocks may occur simultaneously, but only up to a maximum of 100% of the total available capacity.
Residential HVAC

We assume that residential HVAC load shifting measures are available for 0% of residences in 2015 increasing to 20% of houses in 2020. The number of dwellings in each state was sourced from ABS (2012) Census statistics and it was assumed that up to 1kW load deferral for each residence was available. It is assumed that 1kW of deferral over one particular dispatch period must be followed by an increased load of 0.25 kW for the next four dispatch periods, and up to 40 dispatch periods per dwelling per year is available.

For the purposes of identifying an operational deployment trajectory, we approximate residential HVAC load as being able to be shifted in blocks of 10% of total residential HVAC power capacity up to 400 dispatch periods throughout the year. As in the above measures, some of these load shifting blocks may occur simultaneously, up to a maximum of 100% of the total available capacity during any one dispatch period.
Figure 7: Adjusted projected demand (one week snapshot) for Queensland in 2047 without (light green) and with (dark green) additional residential HVAC: very light blue shows the rooftop solar panel adjusted load only

**Smart EV charging**

Instead of the EV demand charging profile assumed in the projection of unadjusted half-hourly demand, it is instead assumed that the energy required for charging electric vehicles overnight in the period from 7pm to 7am may alternatively be sourced during any other time of the day. For the purposes of identifying a deployment trajectory, we approximate electric vehicle demand as being able to be shifted in blocks of 1% of total electric vehicle energy requirements. The impact of this measure is shown in Figure 8.
Figure 8: Adjusted projected demand (one week snapshot) for Queensland in 2047 without (light green) and with (dark green) additional smart EV charging: very light blue shows the rooftop solar panel adjusted load only

Battery Storage

We assume that domestic scale battery systems are available in 0% of detached dwellings in 2015 increasing to 20% of houses in 2030. The number of detached dwellings in each state was sourced from ABS (2012) Census statistics and it was assumed that up to 1kW of batteries with five hours of storage is available in each. Demand shifting within each day is assumed to take place such that the currently estimated maximum demand in the day is shifted in 1% blocks to the minimum demand time period, such that the total power capacity of the batteries is not exceeded at any time. The impact of this measure is shown in Error! Reference source not found..
4.3 Proxy carbon abatement policy measures

The scenarios generally assume there will be some mechanism in Australia to provide incentives to reduce greenhouse gas emissions under the different governments and policies that might prevail over time. Rather than try and anticipate or test different mechanisms the modelling uses a carbon price as a proxy for any type of targeted greenhouse gas reduction policy.

Estimation of a carbon price usually start with consideration of a global target for limiting climate change (such as radiative forcing, temperature increases) and a subsequent target for greenhouse gas concentration in the global atmosphere such as 550ppm CO₂e. The Future Grid Forum modelling team has not conducted new modelling of this type. Instead we have chosen to modify existing modelling of this nature for our purposes.

The most recent modelling of this type in Australia was for the purposes of calculating the impact of the Clean Energy Future carbon price policy. That analysis examined two global scenarios of 550 and 450ppm CO₂e. These were published in the report *Strong Growth Low Pollution*. We shall refer to them as SGLP550 and SGLP450.

We are primarily interested in SGLP550 in the core scenarios but explore the impact of SGLP450 as a sensitivity case. The SGLP550 case was recently modified by the announcement in the May 2013 commonwealth budget that the outlook for carbon prices in the short-term has weakened:
“Deferring the Clean Energy Future personal income tax cuts that were scheduled to commence on 1 July 2015. These tax cuts were designed to assist households with the effects of an increase in the carbon price from $25.40 in 2014-15 to $29 in 2015-16. The carbon price in 2015-16 is now projected to be lower ($12.10) than the fixed price in 2014-15. As a result, households will not experience the impact of an additional rise in the carbon price and the 2015-16 tax cuts will be deferred until the carbon price in the Budget is estimated to rise above $25.40. This is currently projected to occur in 2018-19. Households will receive more assistance than was anticipated to be necessary to assist them with the cost of living impact of the carbon price in 2015-16. This measure is expected to increase tax receipts by $1.5 billion over the forward estimates period.”

http://www.budget.gov.au/2013-14/content/bp1/html/bp1_bst5-03.htm

Based on this revision to the short-term outlook for carbon prices we have developed a modified “FGF moderate pathway” for the carbon price to be used in this study as follows:

- Adjust the 2015-16 nominal carbon price down by $12.10
- Adjust the 2018-19 nominal carbon price to $25.40
- Interpolate for 2016-17 and 2017-18
- Set the 2019-20 carbon price to the original 2015-16 internationally linked carbon price
- Re-join the original carbon price trajectory a few years later
- Adjust all numbers to real dollars.

The similar process is carried out for SGLP450 to adjust the series to recognise the current low international carbon prices.

![Figure 10: SGLP and modified carbon prices used in this report](image-url)
4.4 Fuel cost projections

The assumed fuel costs were published in the 2012 Australian Energy Technology Assessment, and developed by ACIL Tasman (see Table 2.3.1 of BREE, 2012). These are graphed in Figure 11, Figure 12 and Figure 13.

The cost for biomass is constant at $0.83/GJ for bagasse and $1.5/GJ for other biomass to 2050.

Figure 11: Medium projected natural gas price assumption
Figure 12: Medium projected black (NSW and Qld) and brown (Vic) coal price assumption

Figure 13: Medium projected uranium price assumptions
4.4.1 HIGH AND LOW FUEL COST CASES

To recognise the fundamental uncertainty in future fuel prices, particularly gas, we also employ low and high fuel price cases. Scenario 2 and 3 in particular assume low fuel costs as this supports the plausibility of high gas fired distributed (on-site) generation adoption, particularly in Scenario 3 where customers are disconnecting. The high case is used in sensitivity testing and acknowledges that the medium price range might underestimate prices if international prices are high and strongly drive domestic prices via “net-back” pricing arrangements.

The high and low cases are sourced from ACIL Tasman (2012).

Table 4: 2030 fuel prices ($/GJ) for low and high cases, averaged across states

<table>
<thead>
<tr>
<th></th>
<th>Low</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural gas</td>
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</tr>
<tr>
<td>Black coal</td>
<td>1.78</td>
<td>1.99</td>
</tr>
<tr>
<td>Brown coal</td>
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<td>0.85</td>
</tr>
<tr>
<td>Bagasse</td>
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<tr>
<td>Other biomass</td>
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<tr>
<td>Uranium</td>
<td>0.48</td>
<td>0.96</td>
</tr>
</tbody>
</table>

4.5 Centralised generation capital cost assumptions

The centralised electricity generation capital cost assumptions are primarily drawn from the Australian Energy Technology Assessment published by BREE (2012). However, we have also developed an accelerated cost projection case which is derived from existing application of CSIRO’s Global and Local Learning Model (GALLM). Hayward and Graham (2012b) applied a stronger global environment for low emission technology deployment and stronger local commitment to deployment of renewable. Combined with local and global learning rates, this results in generally lower costs for particularly low emission technologies in this case.

The medium capital cost assumptions apply to Scenarios 1, 2 and 3 and the accelerated capital cost assumptions apply to Scenario 4. The only exception to this rule is that in Scenarios 2 and 3, since these experience accelerated improvements in distributed (on-site) generation costs, particularly solar panels, we assume improvements in rooftop solar panels are partly in the PV modules and are therefore applicable to large scale solar PV.

Table 5: Medium capital costs assumptions based on AETA (2012)

<table>
<thead>
<tr>
<th>Technology</th>
<th>2013</th>
<th>2020</th>
<th>2030</th>
<th>2040</th>
<th>2050</th>
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<td>Brown coal IGCC</td>
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<td>Brown coal CCS</td>
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<td>Black coal IGCC</td>
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<td>Black coal CCS</td>
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<td>5656</td>
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<td>4385</td>
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<td>Nuclear</td>
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<td>3682</td>
<td>3729</td>
<td>3839</td>
<td>3856</td>
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<tr>
<td>Gas CCGT</td>
<td>1090</td>
<td>1097</td>
<td>1113</td>
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<td>Gas CCS</td>
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<td>Gas OCGT</td>
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<td>5349</td>
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<td>5457</td>
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### Table 6: Accelerated capital costs assumptions based on Hayward and Graham (2012)

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<th>2030</th>
<th>2040</th>
<th>2050</th>
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<td>3257</td>
<td>3098</td>
<td>2946</td>
<td>2802</td>
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<td>Wind - onshore</td>
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<td>1799</td>
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<td>1848</td>
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<td>Wind - offshore</td>
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<td>3978</td>
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<td>4026</td>
<td>4119</td>
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<td>Hot fractured rocks</td>
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<td>7453</td>
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<td>5511</td>
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<td>PV - utility scale</td>
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<td>Wave</td>
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<td>6193</td>
<td>3807</td>
<td>3800</td>
<td>3651</td>
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4.6 Other centralised generation assumptions

The modelling uses the other BREE (2012) centralised electricity generation technology assumptions which are detailed in the sense that many change year by year and are also state disaggregated. They are therefore not repeated here in detail. However, the following summary table provides a guide. Note, assumptions for Current power in Table 7 are CSIRO estimates as this technology was not covered in BREE (2012).
Table 7: Summary of AETA technology assumptions (for representative states) and CSIRO data for current power

<table>
<thead>
<tr>
<th>Technology</th>
<th>Capacity factor %</th>
<th>Fuel efficiency % HHV</th>
<th>CO₂e emissions kt/MWh</th>
<th>Capture Rate %</th>
<th>Year available</th>
<th>Fixed O&amp;M $/MW</th>
<th>Variable O&amp;M $/MWh</th>
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<tbody>
<tr>
<td>Brown coal</td>
<td>83</td>
<td>32</td>
<td>1024</td>
<td>0</td>
<td>2015</td>
<td>60500</td>
<td>8</td>
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<td>Brown coal IGCC</td>
<td>83</td>
<td>33</td>
<td>1008</td>
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<td>2015</td>
<td>99500</td>
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<td>Brown coal CCS</td>
<td>83</td>
<td>201</td>
<td>156</td>
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<td>2023</td>
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<td>Brown coal DICE</td>
<td>83</td>
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<td>700</td>
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<td>Black coal</td>
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<td>Black coal IGCC</td>
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<td>60</td>
<td>85</td>
<td>2023</td>
<td>17000</td>
<td>9</td>
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<tr>
<td>Gas OCGT</td>
<td>10</td>
<td>35</td>
<td>515</td>
<td>0</td>
<td>2012</td>
<td>4000</td>
<td>10</td>
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<td>Biomass thermal</td>
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<td>2012</td>
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<td>2012</td>
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<td>Wind - offshore</td>
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<td>Solar thermal</td>
<td>23</td>
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<td>2012</td>
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<td>Solar thermal (6 hours storage)</td>
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<td>0</td>
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<td>2012</td>
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<td>0</td>
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<td>Wave</td>
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<td>0</td>
<td>0</td>
<td>2020</td>
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<td>0</td>
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<td>Current</td>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>2012</td>
<td>1000</td>
<td>10</td>
</tr>
</tbody>
</table>

Notes: HHV: Higher heating value

4.7 Distributed (on-site) generation capital cost assumptions

The CSIRO distributed (on-site) generation cost assumptions are partly derived from a previous project called the Intelligent Grid which was a major report analysing the value proposition for distributed energy in Australia (CSIRO, 2009). The data has been updated where new information has become available and indeed two cases have been developed- medium and accelerated. The medium case is applied in Scenario 1 while the accelerated case is applied in Scenarios 2 to 4. The data applied are shown in Table 8 and Table 9.

Table 8: Medium projection of distributed generation capital costs ($/kW) applicable to Scenario 1

<table>
<thead>
<tr>
<th>Technology</th>
<th>2013</th>
<th>2020</th>
<th>2030</th>
<th>2040</th>
<th>2050</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV rooftop - Residential</td>
<td>3163</td>
<td>1880</td>
<td>1574</td>
<td>1147</td>
<td>1063</td>
</tr>
<tr>
<td>PV rooftop - Commercial</td>
<td>2531</td>
<td>1504</td>
<td>1259</td>
<td>917</td>
<td>850</td>
</tr>
<tr>
<td>Technology</td>
<td>2013</td>
<td>2020</td>
<td>2030</td>
<td>2040</td>
<td>2050</td>
</tr>
<tr>
<td>------------------------------------------------</td>
<td>-------</td>
<td>-------</td>
<td>-------</td>
<td>-------</td>
<td>-------</td>
</tr>
<tr>
<td><strong>Reciprocating engine based systems:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas cogeneration - Industrial (30 MWe)</td>
<td>1886</td>
<td>1821</td>
<td>1732</td>
<td>1647</td>
<td>1567</td>
</tr>
<tr>
<td>Gas cogeneration - Industrial (1 MWe)</td>
<td>1775</td>
<td>1714</td>
<td>1630</td>
<td>1550</td>
<td>1475</td>
</tr>
<tr>
<td>Gas cogeneration - Commercial (500 kWe)</td>
<td>1997</td>
<td>1928</td>
<td>1834</td>
<td>1744</td>
<td>1659</td>
</tr>
<tr>
<td>Gas trigeneration - Commercial</td>
<td>2496</td>
<td>2410</td>
<td>2292</td>
<td>2180</td>
<td>2074</td>
</tr>
<tr>
<td>Gas trigeneration - Residential</td>
<td>2496</td>
<td>2410</td>
<td>2292</td>
<td>2180</td>
<td>2074</td>
</tr>
<tr>
<td>Landfill or biogas cogeneration (200 kWe)</td>
<td>2068</td>
<td>2068</td>
<td>2068</td>
<td>2068</td>
<td>2068</td>
</tr>
<tr>
<td>Gas engines - Industrial (1 MWe)</td>
<td>1263</td>
<td>1263</td>
<td>1262</td>
<td>1261</td>
<td>1261</td>
</tr>
<tr>
<td>Diesel engines - remote (1 MWe)</td>
<td>552</td>
<td>552</td>
<td>552</td>
<td>552</td>
<td>552</td>
</tr>
<tr>
<td><strong>Fuel cell based systems:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas cogeneration - Residential (2 kWe)</td>
<td>7456</td>
<td>7456</td>
<td>7456</td>
<td>2801</td>
<td>2801</td>
</tr>
<tr>
<td><strong>Micro turbine based systems:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas turbine - Commercial (65 kWe)</td>
<td>1603</td>
<td>1545</td>
<td>1528</td>
<td>1528</td>
<td>1528</td>
</tr>
<tr>
<td>Gas cogeneration - Commercial (65 kWe)</td>
<td>3883</td>
<td>3749</td>
<td>3566</td>
<td>3392</td>
<td>3226</td>
</tr>
<tr>
<td>Gas trigeneration - Commercial (65 kWe)</td>
<td>4438</td>
<td>4285</td>
<td>4075</td>
<td>3876</td>
<td>3687</td>
</tr>
</tbody>
</table>

Table 9: Accelerated projection of distributed generation capital costs applicable to Scenarios 2, 3 and 4

<table>
<thead>
<tr>
<th>Technology</th>
<th>2013</th>
<th>2020</th>
<th>2030</th>
<th>2040</th>
<th>2050</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Reciprocating engine based systems:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PV rooftop - Residential</td>
<td>3142</td>
<td>1779</td>
<td>1390</td>
<td>945</td>
<td>818</td>
</tr>
<tr>
<td>PV rooftop - Commercial</td>
<td>2513</td>
<td>1424</td>
<td>1112</td>
<td>756</td>
<td>654</td>
</tr>
<tr>
<td><strong>Fuel cell based systems:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas cogeneration - Residential (2 kWe)</td>
<td>7456</td>
<td>7456</td>
<td>7456</td>
<td>2801</td>
<td>2801</td>
</tr>
<tr>
<td><strong>Micro turbine based systems:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas turbine - Commercial (65 kWe)</td>
<td>1603</td>
<td>1545</td>
<td>1528</td>
<td>1528</td>
<td>1528</td>
</tr>
<tr>
<td>Gas cogeneration - Commercial (65 kWe)</td>
<td>3883</td>
<td>3749</td>
<td>3566</td>
<td>3392</td>
<td>3226</td>
</tr>
<tr>
<td>Gas trigeneration - Commercial (65 kWe)</td>
<td>4438</td>
<td>4285</td>
<td>4075</td>
<td>3876</td>
<td>3687</td>
</tr>
</tbody>
</table>
4.8 Reconciling centralised and distributed generation solar photovoltaic plant cost projections

There is some conflict in the estimates of distributed and centralised photovoltaic cost estimates. The rooftop solar photovoltaic panels estimated by CSIRO (2009) are lower cost than the large scale technology costs projected by BREE (2012). In the past, as a general rule, the large scale technology would have been expected to be lower cost due to economies of scale. However it is the smaller scale technology that has reduced costs in recent years and, with far fewer large scale plant being deployed, it is not yet clear if the reduction in roof top solar panels will flow through to the large scale technology. Anecdotally there have emerged some differences in quality which could mean that large scale solar plant remain at a higher capital cost level (albeit with a much better capacity factor due to better location and tracking)².

Given the link between the cost of small scale and large scale solar panels is still emerging we have chosen not to modify either technology projection with one exception. The exception is that, when the accelerated distributed generation cost assumptions are in place (Scenarios 2 and 3) we also use the accelerated cost for large scale solar photovoltaic plant. This is to recognise that if the rate of reduction in cost of roof top solar panels changes, then the cost of large scale panels should also change (although whether by the same amount is unknown).

As we shall see later, both rooftop and large scale solar photovoltaic plant are deployed across all scenarios and so it does not appear this assumption has disadvantaged either technology.

Note that one of the response options that Future Grid Forum consider is for the Australian Energy Technology Assessment process to extend to on-site generation in the future, in which case, if adopted, that process might resolve how best to integrate small and large scale generation cost projections for future studies.

4.9 Transmission capital cost assumptions

These assumptions are outlined in Appendix B: TNEP.

4.10 Storage cost assumptions

Local storage is included in a number of the core scenarios for peak demand management (Scenarios 1, 2 and 4) and for grid disconnection (Scenario 3). Large scale storage is also deployed in Scenario 4.

There are number of different technologies which can provide storage services – compressed air, flywheels, batteries and thermal masses such as molten salt. In this study we focus on batteries because they suit all of the applications and their costs are in the same range of the major alternatives (see James and Hayward, 2012 for a comparison).

The current high levels of investment in battery technology for various applications, such as electric vehicles, makes it reasonable to assume that electricity storage will cost less in future, but how much less is uncertain. The International Energy Agency (IEA, 2012) project that the cost of batteries for electricity vehicles will halve by 2020. MHC (2012) provides a medium, optimistic and pessimistic case (Figure 15). The pessimistic case recognises the potential for some raw materials (such as rare earths) in storage devices to become more expensive. The optimistic case includes a greater than 50 percent reduction by 2020 and the medium case lies between the two extremes.

James and Hayward (2012) considered three technologies presently available at MW scale: advanced lead-acid, zinc-bromine, and repurposed lithium-ion batteries. Of these, zinc-bromine flow batteries are both

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² Diesel generators follow a similar pattern whereby small (e.g. 2.2 kW), lower quality units can be purchased by consumers for their own use for around $140/kW whilst larger units (1 MW) are around 4 times that cost.
the cheapest, in terms of capital cost, and the most suitable for energy shifting when considered separately from other applications. Vanadium-redox flow batteries were not analysed but are another example of a suitable technology. This is not to say that zinc-bromine batteries will be the best overall choice for residential use; rather, they provide a realistic example.

As discussed, James and Hayward (2012) assumed the uptake of batteries to be largely driven by increasing use of intermittent renewable generation. This suggests that battery installations will scale approximately according to the projected wind turbine and solar PV cumulative capacity in Australia. Battery cost reductions are modelled using a learning rate (Hayward and Graham, 2012a) resulting in the multiplier graphed in Figure 14. A steep reduction is anticipated during the remainder of this decade, followed by a steady but slower annual reduction until 2030 (resulting in a 50 percent reduction overall).

![Figure 14: Cost multiplier for battery technologies based upon the projected wind turbine and solar PV cumulative capacity in Australia, following Hayward and Graham (2012a)](image)

The cost and performance of zinc-bromine batteries were estimated from the open literature, notably by the US Electric Power Research Institute and Sandia National Laboratories, as described by James and Hayward (2012). This cost estimate is for battery systems deployed at utility or transmission scale, say 1-100 MW, and allowance must be made for additional costs for manufacturing, delivering, and commissioning thousands of much smaller battery systems which are purchased through a retail chain rather than ordered directly from a vendor. The analysis assumes a 30% mark-up on capital and operating when batteries are applied at residential-scale. Their performance characteristics are summarised in Table 10; note that the energy and power related components are usually summed to obtain the total capital cost estimate. However, when applied in tandem with a solar photovoltaic system, it may be appropriate to assume that batteries and solar panels share a single power conversion unit, saving costs.

Table 10: Current cost (in AUD 2012) and performance assumptions for residential scale zinc-bromine batteries assuming they are manufactured at mass market scale

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy-related cost</td>
<td>520 $/kWh</td>
</tr>
<tr>
<td>Parameter</td>
<td>Value</td>
</tr>
<tr>
<td>-------------------------</td>
<td>-----------</td>
</tr>
<tr>
<td>Power-related cost</td>
<td>520 $/kW</td>
</tr>
<tr>
<td>O&amp;M cost</td>
<td>36 $/kW/year</td>
</tr>
<tr>
<td>Cycle life</td>
<td>10,000</td>
</tr>
<tr>
<td>Round-trip efficiency</td>
<td>70%</td>
</tr>
<tr>
<td>Useable charge range</td>
<td>80%</td>
</tr>
</tbody>
</table>

The estimated cycle life is sufficient for 27 years\(^3\) of full daily cycles so cell replacement is ignored in this analysis – otherwise, cell replacement would at intervals require approximately one third of the original capital outlay. If the batteries are multi-purposed, and serve other applications as well as peak shifting, the cell lifetime and that of some other components would be reduced. The round-trip efficiency is a typical value for present zinc-bromine batteries; in fact, some improvement may be anticipated when there is more experience with the technology and system designs are refined. The useable charge range accounts for the reduced power capacity at very low charge levels although, in principle, flow batteries can be completely discharged and zinc-bromine batteries benefit from this treatment.

For this modelling study we require estimates of costs out to 2050. Extending the estimates from studies in the literature, with particular reliance on the James and Hayward (2012) study, this report assumes a cost reduction trajectory to 2050 as shown in Figure 15.

\(^3\) Note for amortisation purposes, this would be too long as a payback period
**4.11 Disconnection costs**

The following outlines the estimated cost of disconnecting a residential customer. Large commercial and industrial customers also disconnect in Scenario 3 but primarily use existing technologies such as gas co- and tri-generation which are established. The purpose of the following analysis is to establish the cost of disconnection using a combination of storage, solar and small engine back-up.

Table 11 presents the assumptions, rationales and calculation methods for residential disconnection. Note that the solar panel and battery costs reflect the costs already described above. The table shows that the projected costs for a medium consumption household to disconnect are 46 c/kWh in 2030 and 21 c/kWh in 2050. It assumes that electricity supply is primarily managed through a solar panel and battery combination. However, a back-up generator (running on diesel, natural gas or LPG) is assumed to be required for several days per year, depending on outages and household characteristics.

Disconnection costs for small commercial customers would be similar to households. We do not find a strong correlation between larger electricity requirements and cost (the setup is fairly scalable). We sensitivity tested the additional cost to cover the additional electricity needs of an electric vehicle – this was only 1-3 c/kWh higher. There could be limits on roof space for large customers. However, we would also expect solar products more integrated into building structures to emerge and other innovations which might address this limit.
Table 11: Detailed assumptions, notes and calculations for residential disconnection

<table>
<thead>
<tr>
<th></th>
<th>Cost</th>
<th>2013</th>
<th>2030</th>
<th>2050</th>
<th>2013</th>
<th>2030</th>
<th>2050</th>
<th>2013</th>
<th>2030</th>
<th>2050</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Consumption</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>6000 kWh per household is the current national average, assume low is third more energy efficient and high a third less.</td>
</tr>
<tr>
<td><strong>Household type</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Informs the consumption requiring storage in relation to how much the owners try to shift demand but does not impact cost of software and control devices.</td>
</tr>
<tr>
<td><strong>Annual consumption</strong></td>
<td>kWh</td>
<td>3960</td>
<td>3960</td>
<td>3960</td>
<td>6000</td>
<td>6000</td>
<td>6000</td>
<td>7980</td>
<td>7980</td>
<td>7980</td>
<td></td>
</tr>
<tr>
<td><strong>Demand management</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>This should be similar to their home loan interest rate e.g. they might fund it via a redraw or borrow against house equity</td>
</tr>
<tr>
<td><strong>Discount rate</strong></td>
<td></td>
<td>0.07</td>
<td>0.07</td>
<td>0.07</td>
<td>0.07</td>
<td>0.07</td>
<td>0.07</td>
<td>0.07</td>
<td>0.07</td>
<td>0.07</td>
<td>Some equipment will last 20 years but, like vehicles and houses, banks will require pay back well before the end of their useful life.</td>
</tr>
<tr>
<td><strong>Amortisation</strong></td>
<td>years</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>Needs to produce daily average consumption plus 25% buffer</td>
</tr>
<tr>
<td><strong>Solar PV kit</strong></td>
<td>$/kW</td>
<td>2940</td>
<td>1190</td>
<td>600</td>
<td>2940</td>
<td>1190</td>
<td>600</td>
<td>2940</td>
<td>1190</td>
<td>600</td>
<td>In most cases roof constrained so average of 0.15 is downgraded 10% for poorer angle/direction</td>
</tr>
<tr>
<td><strong>Size</strong></td>
<td>kW</td>
<td>4.2</td>
<td>4.2</td>
<td>4.2</td>
<td>6.3</td>
<td>6.3</td>
<td>6.3</td>
<td>8.4</td>
<td>8.4</td>
<td>8.4</td>
<td>Low-high sensitivity around 25</td>
</tr>
<tr>
<td><strong>Capacity factor</strong></td>
<td></td>
<td>0.135</td>
<td>0.135</td>
<td>0.135</td>
<td>0.135</td>
<td>0.135</td>
<td>0.135</td>
<td>0.135</td>
<td>0.135</td>
<td>0.135</td>
<td>Low-high sensitivity around 25</td>
</tr>
<tr>
<td><strong>O&amp;M</strong></td>
<td>$/kW/year</td>
<td>35</td>
<td>25</td>
<td>15</td>
<td>35</td>
<td>25</td>
<td>15</td>
<td>35</td>
<td>25</td>
<td>15</td>
<td>Low-high sensitivity around 25</td>
</tr>
<tr>
<td><strong>Generator back-up</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>2.2 kW, 240AC. Will not allow you to run all appliances but will cover cooking, lighting and entertainment until normal services resume. Assume high energy users need a large system of 4kW and pay 50% more for</td>
</tr>
<tr>
<td>Cost</td>
<td>2013</td>
<td>2030</td>
<td>2050</td>
<td>2013</td>
<td>2030</td>
<td>2050</td>
<td>2013</td>
<td>2030</td>
<td>2050</td>
<td></td>
<td></td>
</tr>
<tr>
<td>----------------------</td>
<td>------</td>
<td>------</td>
<td>------</td>
<td>------</td>
<td>------</td>
<td>------</td>
<td>------</td>
<td>------</td>
<td>------</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Diesel equivalent fuel</td>
<td>$/Le</td>
<td>2.5</td>
<td>2</td>
<td>1.5</td>
<td>2</td>
<td>1.5</td>
<td>2</td>
<td>1.5</td>
<td>2</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Generator efficiency</td>
<td></td>
<td>0.4</td>
<td>0.3</td>
<td>0.2</td>
<td>0.4</td>
<td>0.3</td>
<td>0.2</td>
<td>0.3</td>
<td>0.2</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Generator time on</td>
<td>Days</td>
<td>45</td>
<td>30</td>
<td>15</td>
<td>45</td>
<td>30</td>
<td>15</td>
<td>45</td>
<td>30</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fuel consumption</td>
<td>MJ</td>
<td>1758</td>
<td>1562</td>
<td>1172</td>
<td>3662</td>
<td>3255</td>
<td>2441</td>
<td>6198</td>
<td>5509</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Diesel fuel</td>
<td></td>
<td>$114</td>
<td>$81</td>
<td>$46</td>
<td>$237</td>
<td>$169</td>
<td>$95</td>
<td>$401</td>
<td>$285</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annual cost</td>
<td>$</td>
<td>2226</td>
<td>1037</td>
<td>509</td>
<td>3327</td>
<td>1544</td>
<td>774</td>
<td>4548</td>
<td>2139</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

| Storage costs        |      |      |      |      |      |      |      |      |      |
| Discount rate        | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 |
| Amortisation years   | 10   | 10   | 10   | 10   | 10   | 10   | 10   | 10   | 10   |
| Batteries, power conversion & housing/ installation | $/kW h | 520 | 260 | 130 | 520 | 260 | 130 | 520 | 260 | 130 |
| Size                 | kWh  | 7.75 | 7.75 | 7.75 | 16.14 | 16.14 | 16.14 | 27.33 | 27.33 | 27.33 |
|                      | kW   | 5    | 5    | 5    | 5     | 5     | 5     | 5     | 5     | 5     |

Notes:
- large model.
- The fuel might not be diesel but we will use a diesel equivalent fuel price for the sake of the calculations.
- Assume more expensive generator is more efficient.
- Besides back-up, this also allows for meeting some loads of larger energy users.
- Days multiplied by ratio of day requiring storage multiplied by daily energy use divided by efficiency and multiplied by 3.6 to convert watt hours to joules.
- Consumption multiplied by diesel cost converted to $/MJ/L via diesel equivalent energy content of 38.6MJ/L.
- Basic amortisation formula for capital is r(1+r)^t/((1+r)^t-1) where r is the discount rate and t is the amortisation period.
- These costs reflect the assumed battery cost trajectory from current to 2050.
- A function of the assumptions below.
- Low case allows for operation of a small air conditioner, oven, entertainment devices and lighting simultaneously although some preloading of air conditioning before
<table>
<thead>
<tr>
<th>Cost</th>
<th>2013</th>
<th>2030</th>
<th>2050</th>
<th>2013</th>
<th>2030</th>
<th>2050</th>
<th>2013</th>
<th>2030</th>
<th>2050</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Consumption Low</td>
<td>0.4</td>
<td>0.4</td>
<td>0.4</td>
<td>0.55</td>
<td>0.55</td>
<td>0.55</td>
<td>0.7</td>
<td>0.7</td>
<td>0.7</td>
<td>With demand management shifting loads into middle of the day, this ratio is the fraction of daily consumption that storage must provide.</td>
</tr>
<tr>
<td>Consumption Medium</td>
<td>0.7</td>
<td>0.7</td>
<td>0.7</td>
<td>0.7</td>
<td>0.7</td>
<td>0.7</td>
<td>0.7</td>
<td>0.7</td>
<td>0.7</td>
<td>Round trip efficiency for storing and discharging.</td>
</tr>
<tr>
<td>Consumption High</td>
<td>0.8</td>
<td>0.8</td>
<td>0.8</td>
<td>0.8</td>
<td>0.8</td>
<td>0.8</td>
<td>0.8</td>
<td>0.8</td>
<td>0.8</td>
<td>The capacity of the battery that can be accessed.</td>
</tr>
<tr>
<td>O&amp;M $/kW/year</td>
<td>100</td>
<td>36</td>
<td>10</td>
<td>100</td>
<td>36</td>
<td>100</td>
<td>36</td>
<td>10</td>
<td>10</td>
<td>Essentially meant to be maintenance free but there could be some service call outs.</td>
</tr>
<tr>
<td>Annual cost $</td>
<td>1349</td>
<td>566</td>
<td>221</td>
<td>2810</td>
<td>1179</td>
<td>460</td>
<td>4756</td>
<td>1995</td>
<td>779</td>
<td>Formula as above.</td>
</tr>
<tr>
<td>Operating $</td>
<td>60</td>
<td>40</td>
<td>20</td>
<td>60</td>
<td>40</td>
<td>20</td>
<td>60</td>
<td>40</td>
<td>20</td>
<td>E.g. software updates.</td>
</tr>
<tr>
<td>Annual cost $</td>
<td>86</td>
<td>66</td>
<td>46</td>
<td>86</td>
<td>66</td>
<td>46</td>
<td>86</td>
<td>66</td>
<td>46</td>
<td>Formula as above.</td>
</tr>
</tbody>
</table>

### Notes
- Other customers (medium and high) might require additional air conditioning but they are not adjusted here. Instead we allow for the generator to be available more days to cover that need.
- The capacity of the battery that can be accessed.
- Essentially meant to be maintenance free but there could be some service call outs.
- Formula as above.
4.12 Distribution system assumptions

The distribution system costing model (DiSCoM) factors in the age of the existing capital stock by state and applies a cost of investment for replacing retiring stock or augmenting the system with new stock. The age profile of the stock is based on historical data of the real rate of expenditure on the network. More detailed data is available that could break that down further into specific items such as lines and poles. However, since there is no readily available set of data that would provide a cost for each of those items, we have not sought to make use of more detailed stock data. In essence, we use an aggregate cost for an aggregate stock of distribution assets.

Based on the data applied there is a definite trend in the age profile of the stock. Under a system that is expanding over time such as Australia’s electricity network we would expect the stock to be skewed towards being younger on average – the stronger the growth the more skewed in this way. The assumed age profile shows this characteristic but with a definite jump around the 40 year age cohort and a slump in around the 25 year age group. There are some differences by state but this pattern generally recognises the strong growth in network building in the post World War II boom period of increasing uptake of home electrical appliances. The subsequent slump may indicate a subsequent post-boom saturation effect where new asset deployment stabilised at a steadier growth rate.

This pattern in the age of distribution assets is important because it implies there will be a faster rate of investment required in the present decade to address retirement of assets.

Aggregate distribution asset costs have been developed from two sources - Langham et al. (2011) and de-identified data provided by the Australian Energy Regulator (AER). Table 12 shows the projected ranges of costs from both sources. Given the two data sources accord fairly well (the Langham et al. (2011) data sits within the AER range), the AER data was chosen as the primary source of capital costs.
Table 12: Two sources for assumed average aggregate costs of investment in distribution system capacity

<table>
<thead>
<tr>
<th>$/kW/a (amortised)</th>
<th>Minimum</th>
<th>Maximum</th>
</tr>
</thead>
<tbody>
<tr>
<td>De-identified actual investment data</td>
<td>141</td>
<td>449</td>
</tr>
<tr>
<td>Langham et al. (2011)</td>
<td>110</td>
<td>373</td>
</tr>
</tbody>
</table>

### 4.13 Non-grid system costs

Non-grid system costs include items such as smart meters and smart appliances. Costs for local energy storage have already been discussed separately.

The key source of other non-system costs is E3 (2013) which examined the cost of mandating smart appliances and interfaces. Based on their analysis it appears that a smart meter plus smart appliances such as controllable HVAC system would cost an additional $180 up front plus ongoing costs of around $20 per year. The cost of the appliance itself is not included – it is assumed these are purchased when older systems are no longer functioning. Amortising these upfront costs over five years would be equivalent to around $65 per year in annual non-grid costs (including the assumed $20 operating fee).

Improved commercial HVAC control is assumed to be available at no extra cost. Commercial buildings already include HVAC control systems but up until recently their control systems have generally been optimised for comfort. New control systems will come with greater functionality and geared more towards energy management.

The cost of demand response for industrial users is nominally assumed to be $1000/MWh sourced from AEMO (2013b). This reflects the observation that there is a significant cost to industrial users shutting down their system. However, that cost may at times be less than the small number of very high peak pricing events that occur in the National Electricity Market each year.

### 4.14 Electric vehicle assumptions

Full details of ESM assumptions for the transport sector are presented in Graham and Smart (2011) and so are not repeated here. Based on previous experience in modelling electric vehicle uptake it is clear that differences in carbon and electricity prices across the scenarios is likely to make very little impact on uptake. Relative to liquid fuel at $1.30/L electricity purchased at an off-peak rate around 15 c/kWh would represent only 12 percent of the liquid fuel running costs of an equivalent size internal combustion road vehicle. Even if electricity is much more expensive (e.g. double) the impact on relative costs is small.

Under 2013 legislation, passenger road transport was exempt from a carbon price. However, even if it were included, each $10 of carbon price only adds 2.5c/L to the cost of liquid fuel. Oil prices, on the other hand, can make a significant difference since they can cause liquid fuel products to vary in a single year by several times that amount.

In this context we need to look for other drivers of electric vehicle uptake to differentiate the scenarios. The logic and key assumptions are set out in Table 13.
## Table 13: Electric vehicle uptake drivers and assumptions

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Drivers and attitudes</th>
<th>Assumption</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Consumer engage where it is convenient to do so without too much disruption to current lifestyles</td>
<td>Maximum 30% passenger vehicle uptake based on 60% of households having two cars and can therefore rely on an alternative for range driving. Maximum 20% uptake in commercial and light rigid truck categories recognises some short haul city applications may be feasible with central charging</td>
</tr>
<tr>
<td>2</td>
<td>Highly engaged consumer is willing to actively explore new technologies at some personal cost – time, inconvenience, effort Enthusiasm offset marginally by moderate oil and gas price increase</td>
<td>Maximum 48% passenger vehicle and 32% light commercial and rigid truck uptake based on distributed charging infrastructure</td>
</tr>
<tr>
<td>3</td>
<td>Same logic as Scenario 2 but tempered by the need to provide their own power given high degree of disconnection or used distributed infrastructure</td>
<td>Maximum 48% passenger vehicle and 32% light commercial and rigid truck uptake based on distributed charging infrastructure</td>
</tr>
<tr>
<td>4</td>
<td>Highly engaged but also driven by strong growth in oil prices</td>
<td>Maximum 60% passenger vehicle and 40% percent light commercial and rigid truck uptake based on distributed charging infrastructure</td>
</tr>
</tbody>
</table>

## 4.15 2-4-C specific assumptions

A number of modelling assumptions are specific to 2-4-C and these are described in this section.

### 4.15.1 MONTE CARLO SIMULATIONS

For each year and scenario modelled, twenty-five Monte Carlo simulations of plant availability were modelled (except where fifty simulations were performed to increase the accuracy of modelling of high renewable uptake in Scenario 4) to capture the risk of plant outages, both in terms of price and unserved energy. To facilitate this, existing generators were modelled as per their existing units and new generation capacity was modelled in discrete units, sized appropriately for the technology. This meant that outages of each unit (both planned (maintenance) and unplanned) could be modelled using technology-specific outage data sourced from AEMO.

### 4.15.2 TRANSMISSION MODELLING

Given the long-term nature of this modelling, the existing NTNDP constraint equations are unlikely to be applicable. Instead, ROAM developed a series of DC load-flow equations to model the intra- and inter-regional flows using the simplified network map shown in Figure 17. These equations were built from full AC power-flow simulations and capture regional transfer limits as inter-regional interconnector losses. In each half-hour, the 2-4-C dispatch engine then dispatched generation according to its bids subject to these constraints.
4.15.3 PEAKING GENERATION

In some scenarios, additional peaking generation greater than that modelled in TNEP was found to be necessary to avoid excessive unserved energy. This captures the specific conditions that occur in some periods, such as a confluence of high demand and low wind and/or solar generation driving the need for additional generation. In these cases, ROAM included sufficient peaking generation in the 2-4-C modelling to maintain the unserved energy level below the reliability standard maximum of 0.002% unserved.

![Figure 17: Map of the National Electricity Market zones modelled in 2-4-C](image)

4.15.4 BIDDING STRATEGIES

Bidding strategies are important for determining how 2-4-C will project future wholesale electricity prices and for ensuring generators are profitable. Most generators should be profitable in order for a projected future generation capacity to be regarded as plausible, within the current electricity market rules.

For existing coal-fired generators the assumed bidding strategy is:

- Bid generation with a must-run component (approximately 40% of their capacity at the market floor of negative $1000/MWh), similar to how they bid today.
- If they are not profitable in step 1, bid them without a must-run component so they will "cycle" when prices are low, such as when there is significant wind and solar generation.
- If they are still not found to be profitable, and their achieved capacity factor is less than 15%, retire them, and potentially replace them with a CCGT (if that CCGT would be profitable).
Variable resource large-scale renewable generators (wind, solar PV, solar thermal and wave) were assumed to be owned by only a few large companies, allowing them to bid strategically. As such, half of the variable resource renewable capacity was bid at $0/MWh and the other half at a price just shadowing the cheapest fossil fuel SRMC (usually a CCGT). While some of the renewable generation might get curtailed with this strategy, the net benefit is positive in terms of pool revenue since they are curtailed when the price is set to the shadow bid, rather than $0/MWh where they wouldn’t have any pool revenue whether they were curtailed or not.

After some trials with different bidding strategies for gas plant (OCGTs and CCGTs) it was found that all CCGTs could bid their generation at their SRMC and maximise their generation and profitability. The OCGT bidding strategy differs between the states. In New South Wales and Queensland, 75% of the OCGT capacity is bid at their SRMC and the other 25% with some strategic higher prices. However, in Victoria and South Australia, the OCGTs bid more aggressively with only around 25% at or near their SRMC and the next 50% bid up to about double their SRMC. All OCGTs have 2.5% of their capacity at $500 and 1.25% at the market price cap. This combination was found to give the most reasonable outcome in terms of profitability to all generators.
5 Modelling results

The modelling results are outlined in this section by each scenario in turn and each sensitivity case after that. Within each scenario/sensitivity case the results from each model is discussed with the exception that only some of the models were applied in the sensitivity cases. The general order in which model results are discussed is ESM, TNEP, 2-4-C, DiSCoM and customer impact model. This reflects the general direction in which information flows between the models. To avoid repetition, the discussion of some scenarios or sensitivity cases assumes the reader has read the modelling results in the order they are presented. That is, Scenario 1 is discussed at greater length as it introduces many of the general trends, some of which also occur in subsequent scenarios. For the other scenarios or sensitivity cases we do not revisit common trends but rather focus attention on the major new trends and results specific to that scenario or sensitivity case.

Table 14: Models applied in each scenario or sensitivity case

<table>
<thead>
<tr>
<th>Scenario/ sensitivity case</th>
<th>Demand</th>
<th>ESM</th>
<th>TNEP</th>
<th>2-4-C</th>
<th>DiSCoM</th>
<th>Customer impact</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Model coverage</strong></td>
<td>All states</td>
<td>All states</td>
<td>NEM</td>
<td>NEM</td>
<td>All states</td>
<td></td>
</tr>
<tr>
<td>Scenario 1: Set and forget</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Scenario 2: Rise of the prosumer</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Scenario 3: Leaving the grid</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Scenario 4: Renewables thrive</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Scenario 1 sensitivity: high carbon price</td>
<td>✓</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Scenario 1 sensitivity: zero carbon price</td>
<td>✓</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Scenario 1 sensitivity: uncertain carbon price</td>
<td>✓</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Scenario 1 sensitivity: high gas prices</td>
<td>✓</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Scenario 1 sensitivity: nuclear</td>
<td>✓</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Scenario 1 sensitivity: demand response counterfactual</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Scenario 1 sensitivity: climate impacts</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

4 However, for ease of comparison we often only report the demand for NEM states.
To conserve resources we do not use the full modelling package in the sensitivity cases. Table 14 sets out which models applied in each case. It also shows the state coverage of the models. The models are roughly split evenly on whether they cover all states or just the NEM states.

Given that we are applying a model ensemble, there are results from different models that overlap and to some extent disagree. Therefore, at the end of this section we make it clear which modelling results we have assumed to be the primary results for the purposes of informing the Future Grid Forum. As a general statement, the models do find reasonable convergence given their inherent differences.

5.1 Scenario 1: ‘Set and forget’

5.1.1 DEMAND PROJECTIONS

Scenario 1 adopts the AEMO (2013) medium electricity forecast, has moderate adoption of on-site generation (determined by ESM) and assumes high adoption of peak demand reduction measures. Figure 18 presents the resulting centrally supplied electricity consumption and peak demand under these scenario assumptions.

![Figure 18: Assumed centrally supplied electricity consumption and peak demand in NEM states under Scenario 1](image-url)
5.1.2 ESM PROJECTIONS

Generation

The key characteristics of Scenario 1 are AEMO (2013) electricity consumption, low peak demand growth, AETA 2012 centralised generation cost inputs, CSIRO on-site generation costs, and moderate carbon price and mid-range natural gas prices.

Figure 19 shows the projected central and on-site generation technology mix to 2050. The first three years of the projection reflect the historical reduction in electricity consumption and subsequent mothballing and retirement of several coal fired electricity plant. In the period 2013 to 2020, most of the growth in electricity consumption is met by wind turbines and some growth in on-site generation. These two sectors have additional price signals driving them.

In the case of wind turbines, the Renewable Energy Target provides a financial incentive in the form of a penalty ($65/MWh) if retailers do not purchase sufficient renewable electricity proportional to their share of the target which increases to 41 TWh by 2020 for large scale renewables (Large-scale Renewable Energy Target). In the modelling the target is met with wind power due to its low cost relative to other renewable technologies. Although not captured, some demonstration projects of other renewable technologies could also be expected to proceed during this period.

In the case of on-site generation, this sector has received a high price signal from recent increases in retail unit costs. Therefore, to some extent investment is proceeding in on-site generation such as solar roof top panels in a way that is somewhat disconnected from the excess supplied generation market to 2020. Solar panels also receive an additional financial incentive from the small scale component of the Renewable Energy target (Small-scale Renewable Energy Scheme) – the penalty for retailers is set at the same level as the large-scale scheme\(^5\).

In the period 2020-2050, ESM projects that with the volume of energy required from renewable by legislation flattening out coal-fired power that has been under-utilised or mothballed will briefly expand to 2025 to meet growth in consumption. However, as many of these plant will be reaching the end of their design life, retirement accelerates and investment in new technologies to replace coal fired power and meet growth in consumption will be primarily from combined cycle gas-fired plant. This simply reflects that this technology is lowest cost under the assumed carbon price. This pattern of changes in large scale generation, up to 2020 and 2030 is largely repeated throughout the scenarios. Differences are strongest beyond 2030.

Large-scale solar photovoltaic plant experiences the next strongest growth in contribution to the electricity supply mix. Wind power also increases its contribution, partly reflecting replacement of end of design life capacity built during the 2010s. Reflecting AETA 2012, at some point beyond 2030, large-scale solar photovoltaic plant is lower cost than wind and begins to be preferred ahead of wind to meet growth in consumption.

Peaking continues to the provided by open cycle gas plant, however, direct injection coal plant make a contribution from around 2025 as that technology’s costs become competitive.

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\(^5\) Note, the model projects a slight decline in roof top solar panel output to 2016. However, this is largely a model artefact to do with how we treat plant depreciation which is more simplified for on-site generation than for large scale plant. A secondary driver is that the rate of investment is lower following reduction in State feed-in tariffs.
Figure 19: Projected central and on-site electricity generation by technology in Scenario 1

A more detailed breakdown of the projected uptake of on-site generation is provided in Figure 20. Current on-site generation in Australia mainly consists of diesel generation in remote locations, particularly related to mining activity, use of sugar cane bagasse in Queensland (QLD) for powering sugar refining, utilisation of land fill gas, roof top solar panels and a small amount of gas cogeneration.

Investment

The bulk of future growth is expected to be in residential, rural and commercial rooftop solar panels, industrial gas cogeneration and commercial co- or tri-generation. The timing of the acceleration of uptake reflects points where the on-site generation is expected to fall below parity with the retail prices paid by different customers groups, opening up the opportunity for lower cost electricity supply subject to local constraints.

Figure 21 shows the breakdown of cumulative investment in both central and on-site generation plant to 2050. The total cumulative capital investment to 2050 is $180 billion. Investment in the centralised sector is the largest comprising 64 percent of the total by 2050 but with a declining trend in share over time.
Figure 20: Projected on-site electricity generation by technology in Scenario 1

Figure 21: Projected cumulative capital investment in central and on-site generation plant in Scenario 1
**Wholesale unit costs**

The projected average wholesale electricity unit cost to 2050 is shown in Figure 22. The unit costs reflects the marginal cost of meeting electricity demand based on the AETA 2012 costs and is indicative of future wholesale prices.

In the period to 2015 the projected wholesale unit costs reflect the introduction of the carbon price and its subsequent reduction in 2014-15 and resumption of a growth trend thereafter. The level of unit costs also reflects the low electricity consumption and subsequent excess supply capacity in the market. Taking away the influence of the carbon price (approximately $20/MWh 2012-2014), then average unit costs are in the $30-40/MWh range which is below the long-run marginal costs of many existing plant.

![Figure 22: Projected average wholesale electricity unit cost in Scenario 1](image)

Unit costs increase most rapidly in the period 2020 to 2030 reflecting the growth in the carbon price and the end of excess supply capacity market conditions which means the underlying unit cost (after taking into account the carbon price) must increase to a level which is equal to the long-run marginal costs of the lowest cost entrant plant that must be built to meet rising electricity consumption. As we see in our zero carbon price sensitivity later in this modelling results section, that level is around $65-70/MWh.

In the period between 2030 and 2050 the unit cost settles at a level which is consistent with the average of the long-run marginal costs of large scale photovoltaic plant and combined cycle gas plant plus the increasing cost of carbon permits for that plant. There is some volatility around 2035 relating to the period when large-scale photovoltaic plant first come into the system and slightly higher unit costs are required to accommodate them, initially.

**Greenhouse gas emissions**

The projected change in greenhouse gas emissions from electricity generation to 2050 is shown in Figure 23. The steep reduction in the first few years reflects the combined impact of the introduction of the carbon price, reduced electricity consumption and retirement or reduced output from coal-fired electricity generation.

![Figure 23: Projected change in greenhouse gas emissions from electricity generation to 2050](image)
generation. The rate of reduction in greenhouse gas emissions is slower for the next decade reflecting stabilisation or slightly increasing total coal-fired electricity generation based around the more efficient, less carbon intensive stock of plant.

Greenhouse gas emissions reduce more rapidly, again, from around 2030 as coal-fired plant retirement accelerates reflecting both the financial disincentive of the carbon price and end of design life for some plant. Between 2040 and 2050, emission reduction slows as coal-fired plant retirement slows and a combination of gas and renewable meets growth in electricity consumption.

By 2050, electricity sector greenhouse gas emissions have reached 54 percent below their 2000 levels.

Figure 23: Projected electricity sector greenhouse gas emissions in Scenario 1

Transport and vehicle electrification

Vehicle electrification was projected in ESM initially and then hardwired into the electricity demand assumptions along with the various other manipulations of demand required to implement Scenario 1. Consumption of electricity for road transport is projected reach 24 TWh by 2050 in Scenario 1 or equivalent to 16 percent of total road kilometres travelled (Figure 24). Hybrid electric vehicles reach a larger share but generate electricity on-board from liquid transport fuel rather than drawing electricity from the grid.

Total consumption of transport fuels is shown in Figure 25. It shows that liquid fuels are still dominant across the transport sector, however, it should be noted that electricity displaces more fuel in equivalent energy terms than is consumed for the same kilometres travelled. The use of biofuels in transport is an important outcome because it has reduced the amount available for use in the electricity sector as fuel. ESM finds that biomass has higher value when converted to biodiesel, ethanol or jet fuel than as an input to electricity generation. The road sector initially consumer most available biomass but over time the air transport sector becomes the dominant user. This is because, as carbon prices increase, the road sector has more fuel options available to reduce emissions (particularly electrification) compared to the aviation sector which is not flexible in its fuel requirements (there is currently no viable alternative to jet fuel which is a type of kerosene which meets the very specific operating requirements of jet aircraft).
Figure 24: Projected uptake of internal combustion and alternative road vehicle drivetrains in Scenario 1
5.1.3 TNEP PROJECTIONS

TNEP loosely imposes the electricity generation mix determined by ESM and co-optimises the required transmission capacity with the location and mix of electricity generation plant.

Transmission augmentation

New capacity of 1000 MW (both directions) is projected to be constructed in Scenario 1 for the CVIC-ADE regions in 2045 (Figure 26). This is the only projected augmentation and reflects the relatively minor expansion in peak demand under this scenario to 2050. Note this does not preclude investment within NTNDP zones.
Centralised generation capacity

The projected trend in installed centralised generation capacity over time is different for each zone. There is a strong tendency for new installation to be close to the major load centres of Sydney (NCEN), Brisbane (SEQ), Melbourne (MEL) and Adelaide (ADE). The few areas that are declining reflect places where coal plants are retired and not replaced on the same site (e.g. NSA, LV). The pattern also reflects an increase in investment in the last two decades compared to 2020 and 2030 reflecting that in the later period, significant existing high load factor capacity is replaced with low load factor renewable technology.
Figure 27: Projected installed centralised generation capacity by NT NDP zone in Scenario 1

5.1.4 2-4-C PROJECTIONS

2-4-C implements the TNEP transmission and generation capacity and modifies it to meet minimum unserved energy (USE) requirements and reasonable levels of generator profitability in the years 2030, 2040 and 2050.

USE performance of the initial capacity

The initial centralised generation capacity that was projected by TNEP and imposed on 2-4-C is shown in Figure 28. Figure 29 shows the resulting USE in each of the three 2-4-C simulation years. The results show that in 2030-31, the USE levels are above the reliability standard (0.002%) in Queensland and New South Wales.
Figure 28: TNEP generation capacity initially imposed on 2-4-C in Scenario 1

Figure 29: 2-4-C estimates of unserved energy under initial TNEP generation and transmission capacity projections in Scenario 1
Modified capacity and price outcomes

The changes to the generation mix implemented in 2-4-C to meet the reliability standard are shown in Figure 30 and Figure 31. After various options to meet the USE were explored 900 MW of OCGT plant in NCEN were brought forward from being installed in 2035 to 2029, and also 900 MW of OCGTs in SEQ. This brought the USE levels in NSW and QLD to low levels (< 0.0005%) in 2030-31.

The bidding strategies of the generators were adjusted so that they each made a profit in the market where possible (see the discussion in the assumptions). This was found to not be possible for some of the coal power plants, largely due to the high carbon price in 2040 and 2050.

1500 MW and 5700 MW of additional coal-fired generation were retired by 2040 and 2050, respectively as shown in Figure 31. This generation was largely replaced by CCGTs and these were found to be profitable. In addition some OCGTs were replaced by CCGTs due to profitability issues.

Figure 30: 2-4-C generation capacity after modifying to meet USE standards in Scenario 1

This means that emissions projected by ESM may be slightly on the high side with 2-4-C indicating they may be replaced by base-load gas which is less emission intensive.
Table 15 presents the changes to augmentation of the transmission system applied for the 2-4-C solution. It was found that wind generators in SA (in 2030-31 and 2040-41) and Tasmania (in all three years) were getting curtailed significantly using the TNEP generation expansion data directly. The installed links were exporting from both of these regions to Victoria at their full capacity for around 40% of the time in the affected years. The new 1000 MW ADE-CVIC link installed by TNEP in 2050-51 was brought forward to be installed before 2030-31 and installed an additional 500 MW link from TAS-LV as detailed in the table. This allowed the wind generation to be curtailed no more than 6% lower than their available generation (i.e. the achieved capacity factor for wind generation in South Australia is around 36% instead of a possible 38.1%).

### Table 15: Comparison of Initial TNEP and modified 2-4-C transmission augmentation projections

<table>
<thead>
<tr>
<th>Link</th>
<th>Year</th>
<th>TNEP (MW)</th>
<th>2-4-C (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>New ADE-CVIC</td>
<td>2030-31</td>
<td>0</td>
<td>1000</td>
</tr>
<tr>
<td>New ADE-CVIC</td>
<td>2040-41</td>
<td>0</td>
<td>1000</td>
</tr>
<tr>
<td>New ADE-CVIC</td>
<td>2050-51</td>
<td>1000</td>
<td>1000</td>
</tr>
<tr>
<td>New TAS-MEL</td>
<td>2030-31</td>
<td>0</td>
<td>500</td>
</tr>
<tr>
<td>New TAS-MEL</td>
<td>2040-41</td>
<td>0</td>
<td>500</td>
</tr>
<tr>
<td>New TAS-MEL</td>
<td>2050-51</td>
<td>0</td>
<td>500</td>
</tr>
</tbody>
</table>

The projected average volume-weighted wholesale electricity prices from 2-4-C are presented and compared with the average ESM projected unit cost in Figure 32. The two projections are in close concordance reflecting that ESM unit cost projections are always close to long run marginal costs (when electricity demand is growing) and 2-4-C’s bidding strategies have been implemented with a view to most plants being profitable (i.e. receiving a return at least covering long run marginal costs).
5.1.5 DISCOM PROJECTIONS

Aggregate load factor

The implied aggregate load factor of the distribution and transmission network (the volume of electricity delivered through the network divided by the maximum volume that could have been supplied) for the National Electricity Market (NEM) states is shown in Figure 33.

The aggregate load factor is improving in the period to 2020 as the deployment of various peak demand reduction measures in this scenario take effect. From 2025, peak demand has started to increase modestly as the assumed peak demand measures have reached their full potential and consequently underlying growth factors begin to exert a stronger influence. At the same, the volume of growth in electricity consumption is slowing and eventually flattens and is in decline by 2040. As a consequence the aggregate load factor exhibits a declining trend over the long run.

---

When applying DiSCoM we also include Western Australia and Northern Territory. However, since we base our consumption and peak demand projections on AEMO (2013) which is NEM state based we report NEM states here to support easier comparison with the original source. In reality, load factors will differ by location within different distribution and transmission sub-state regions. A detailed sub-state spatial study was not carried out and this is a limitation of the study which other studies may consider addressing.
Figure 33: Projected change in aggregate load factor of the network in Scenario 1

Distribution unit costs

Figure 34 shows the projected distribution unit cost for residential customer in Scenario 1. In reality distribution unit costs will be allocated by a variety of measures, however this chart shows the costs if they were equally apportioned by volume of consumption. The change in distribution unit costs reflects the changes in aggregate load factor plus the current arrangements for regulating distribution networks are also assumed to remain unchanged. As the load factor improves from 2015 augmentation expenditure is significantly reduced and consequently there is a slight decline in distribution unit costs. The level of decrease is limited by the fact that augmentation expenditure is a small proportion of distribution costs. The main components are returns on the regulated asset base, operating and maintenance and replacement or refurbishment of retiring capacity.

As the aggregate load factor begins to decline from 2025 the unit distribution costs must increase given that growth in capacity is required to meet peak demand while (grid sourced) consumption is slowing, flattening and eventually declining. Overall an increasing in distribution unit costs of just over 5c/kWh is projected by 2050 in Scenario 1.
5.2 Scenario 2: ‘Rise of the prosumer’

5.2.1 DEMAND PROJECTIONS

Scenario 2 adopts the AEMO (2013) medium electricity forecast, has very high adoption of on-site generation (determined by ESM) and assumes high adoption of peak demand reduction measures. Figure 35 presents the resulting centrally supplied electricity consumption and peak demand under these scenario assumptions.
5.2.2 ESM PROJECTIONS

Generation

In Scenario 2, adoption of on-site generation is very high increasing to almost half of total generation (Figure 36 and Figure 37). This result is achieved by assuming a lower cost of on-site generation as discussed in the assumptions. The growth commences from 2015, cutting short a brief recovery in coal fired generation as consumption begins to increase from 2014. Apart from the wind power that is developed to meet the Renewable Energy Target, on-site generation is responsible for meeting most of the growth in electricity consumption throughout the projection period with the exception of the period between 203 and 2035 when combined cycle gas plant are built to replace some retiring coal-fired electricity generation capacity.

Solar photovoltaic panels and gas co/tri-generation are the main sources of new on-site generation. In the centralised generation sector, gas, wind and large scale solar photovoltaic technologies experience the strongest growth throughout the projection period, but overall the proportion of contribution to consumption is declining.
Figure 36: Projected central and on-site electricity generation by technology in Scenario 2

Figure 37: Projected on-site electricity generation by technology in Scenario 2
Investment

By 2050 it is projected that cumulative capital investment in both on-site generation and centralised generation investment will be almost $250 billion. Cumulative investment in on-site generation will be the largest proportion of that expenditure in contrast to the approach of the last half century which was strongly focussed on investment in centralised electricity generation capacity.

Overall the level of capital investment in Scenario 2 is higher than in Scenario 1. This reflects the major investment in rooftop solar photovoltaic panels which require up-front investment but have very little running costs. Given not all technologies have the same running costs, it cannot be assumed that higher investment means higher unit costs of generation.

![Figure 38: Projected cumulative capital investment in central and on-site generation plant in Scenario 2](image)

Wholesale unit costs

The projected average annual wholesale unit costs for Scenario 2 are shown in Figure 39. Up until 2020, the trend in unit costs closely follows that of Scenario 1 – generally following the changes in the carbon price with a weak underlying unit costs reflecting excess supply while demand growth remains low and new renewable capacity enters the market to meet the Renewable Energy Target.

Reflecting the increasing carbon price and the requirement for the underlying market price to increase for new plant to achieve a return on investments the wholesale unit cost increases in the long run. However, the rate of increase is lower than Scenario 1 such that there is a sustained gap of around $20/MWh lower wholesale unit costs projected between 2030 and 2050.

The lower wholesale unit costs reflect ESM’s assessment that as on-site generation meets most new demand there will be a significant amount of ongoing excess capacity that will be available at below long run marginal cost (plant for whom the investment is sunk can keep operating as long as they achieve revenue above short run marginal cost). The excess supply occurs because demand for centralised power is flat or declining as on-site generation adoption increases.
Projected electricity sector greenhouse gas emissions for Scenario 2 are shown in Figure 40. It is projected that the historical decline in emissions will slow down as consumption growth resumes in this scenario and some underutilised coal-fired power provides a greater contribution to electricity generation at various stages up to 2030 when growth in other plant does not overcrowd the market. Growth in new low emission capacity will mainly come from new wind power (to meet the Renewable Energy Target) and adoption of on-site generation (encouraged by high retail prices relative to falling costs of some on-site generation technologies).

On-site generation lowers emissions by virtue of being less emission intensive than coal, such as in the cases of solar photovoltaic panels or gas-fired engines, or when it is more energy efficient, such as in the cases of using waste heat in cogeneration and tri-generation applications. On-site generation also avoids losses in transmission which contributes to overall efficiency when measured from the perspective of the electricity consumption point (rather than generation point).

As on-site generation begins to dominate new growth in capacity and coal fired power plant retirement accelerates in the 2030s, greenhouse gas reduction goes through another rapid phase.

By 2050, electricity sector greenhouse gas emissions have reached 57 percent below their 2000 levels.
Transport and vehicle electrification

Vehicle electrification was projected in ESM initially and then hardwired into the electricity demand assumptions along with the various other manipulations of demand required to implement Scenario 2. Consumption of electricity for road transport is projected reach 32 TWh by 2050 in Scenario 2 or equivalent to 23 percent of total road kilometres travelled (Figure 41). Hybrid electric vehicles reach a larger share but generate electricity on-board from liquid transport fuel rather than drawing electricity from the grid.

The major trends in the types of fuels consumed across the transport sector are the same as Scenario 1 and so we do not present a figure for Scenario 2. However, the higher adoption of vehicle electrification in Scenario 2 does reduce total road sector fuel consumption by 57 PJ by 2050 relative to Scenario 1.
5.2.3 TNEP PROJECTIONS

TNEP loosely imposes the electricity generation mix determined by ESM and co-optimises the required transmission capacity with the location and mix of electricity generation plant.

Transmission augmentation

Reflecting limited growth in peak demand to 2050, Scenario 2 is projected to include only two major transmission augmentations listed in Table 16. They are projected to occur in the same region 25 years apart (Figure 42). This is from the same regions that augmentation occurs in Scenario 1 partly reflecting wind power development in those regions as well as the need to connect to sources outside their region as existing coal fired power retires. Note investment to maintain capacity within NTNDP zones would also be occurring.

Table 16: Projected transmission augmentations in Scenario 2

<table>
<thead>
<tr>
<th>NEM Interconnector</th>
<th>Year</th>
<th>Nominal Capacity (two way)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CVIC-ADE</td>
<td>2025</td>
<td>500 MW</td>
</tr>
<tr>
<td>CVIC-ADE</td>
<td>2050</td>
<td>1000 MW</td>
</tr>
</tbody>
</table>

Figure 41: Projected uptake of internal combustion and alternative road vehicle drivetrains in Scenario 2
Centralised generation capacity

In Scenario 2, whilst peak demand is similar to Scenario 1 the installed centralised generation capacity is different reflecting the high adoption of on-site generation. On-site generation necessarily follows the population and is adopted more strongly in Melbourne than Sydney and Brisbane. There is no specific advantage for on-site generation in Melbourne (other than high population) and so this result is likely because ESM is optimising the addition of new generation capacity (on-site or otherwise) to replace centralised brown coal fired power. However the connection between price signals in the centralised and on-site generation sectors is currently weak (on-site generation price signals have limited temporal variation and are influenced by retail prices which include network charges and likely by non-price factors). As such, assuming ESM’s solution is optimal it is not clear at present how this type of outcome would be orchestrated by the market in reality. We might rather see a more even distribution of on-site generation and therefore moderated expansion of capacity in near all capital city zones.

As with Scenario 1, higher investment in 2040 and 2050 partly reflects assets replacement and the lower load factor of renewable technologies that are adopted through this period.
5.2.4 2-4-C PROJECTIONS

2-4-C implements the TNEP transmission and generation capacity and modifies it to meet minimum unserved energy (USE) requirements and reasonable levels of generator profitability in the years 2030, 2040 and 2050.

USE performance of the initial capacity

The initial projected centralised generation capacity from TNEP that was imposed on 2-4-C is presented in Figure 44. Figure 45 shows that 2-4-C has calculated that the USE levels were acceptable under this capacity.
Figure 44: TNEP generation capacity initially imposed on 2-4-C in Scenario 2

Figure 45: 2-4-C estimates of unserved energy under initial TNEP generation and transmission capacity projections in Scenario 2
Modified capacity and price outcomes

The modified centralised generation capacity projected by 2-4-C is shown in Figure 46 and compared with the initial TNEP projection in Figure 47. Despite the acceptable USE levels, a larger amount of changes were made to the capacities in Scenario 2 than Scenario 1 due to profitability issues. In Scenario 2:

- All incumbent brown coal generators (4,780 MW) needed to be retired by 2030-31 as they were not profitable.
- Some brown coal DICE technology is introduced by TNEP later by 2040-41 and 2050-51 and this was kept in the 2-4-C simulation.
- Up to 5,000 MW of additional CCGTs are installed each in NSW and QLD, instead of the OCGTs installed by TNEP, while in VIC around 2,000 MW of additional OCGTs are installed instead of TNEP’s 1,270 MW of CCGTs. The latter is due to large amounts of on-site generation in Victoria reducing the net demand significantly in that region making it difficult for CCGTs to be profitable.

Figure 46: 2-4-C generation capacity after modifying to meet USE standards in Scenario 2
Further processing of the projections has also been able to shed further light on a regional aspect of on-site generation in Scenario 2. Due to the significant capacity of on-site generation in Victoria in Scenario 2, significant amounts of the rooftop PV is curtailed due to there being excess supply for the local demand (Figure 48). The amount of rooftop PV that is curtailed in Victoria is 29% in 2040-41 and 43% in 2050-51. NSW has moderate levels of on-site generation installed resulting in 3% of rooftop PV being curtailed in 2050-51. As noted in discussion above, the uneven distribution of on-site generation in Victoria as opposed to other large population centres projected by ESM may be an unrealistic aspect of Scenario 2 modelling. A more even spread across the most populous states is more likely and, as this result highlights, a better use of system assets. This would likely result in no roof-top PV curtailment across the states with less scheduled generation overall.

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8 This is an assumed outcome. One could also argue that other generation would be curtailed in favour of allowing roof-top PV to supply to the grid. However, roof-top PV systems are automatically curtailed by inverter standards which specify a local voltage threshold over which output is curtailed. Therefore, for simplicity we assume these arrangements prevail ahead of other generation curtailment. This issue will require further study.
Table 17 presents the 2-4-C modifications to the TNEP projected transmission augmentations. For Scenario 2, wind generators in SA and TAS (in all three years) were found to be getting curtailed significantly using the TNEP generation expansion data directly. Similar to Scenario 1, the link capacities CVIC-ADE and TAS-MEL were increased (by 500 MW in all years) to allow more wind generation in SA and TAS to be exported rather than curtailed.

Table 17: Comparison of 2-4-C modified and TNEP initial projected transmission augmentation in Scenario 2

<table>
<thead>
<tr>
<th>Link</th>
<th>Year</th>
<th>TNEP (MW)</th>
<th>2-4-C (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>New ADE-CVIC</td>
<td>2030-31</td>
<td>500</td>
<td>1000</td>
</tr>
<tr>
<td>New ADE-CVIC</td>
<td>2040-41</td>
<td>500</td>
<td>1000</td>
</tr>
<tr>
<td>New ADE-CVIC</td>
<td>2050-51</td>
<td>1000</td>
<td>1500</td>
</tr>
<tr>
<td>New TAS-MEL</td>
<td>2030-31</td>
<td>0</td>
<td>500</td>
</tr>
<tr>
<td>New TAS-MEL</td>
<td>2040-41</td>
<td>0</td>
<td>500</td>
</tr>
<tr>
<td>New TAS-MEL</td>
<td>2050-51</td>
<td>0</td>
<td>500</td>
</tr>
</tbody>
</table>

Figure 49 shows the projected 2-4-C average volume weighted wholesale electricity prices and compares them to the projected ESM average wholesale electricity unit costs. In contrast to Scenario 1 where we saw very close alignment in the projected electricity price path, the 2-4-C price is significantly higher than that estimated by ESM. The 2-4-C price is lower than Scenario 1 but not as low as ESM. There were no changes in the bidding strategies implemented in 2-4-C in Scenario 2.

To explain this difference in prices between Scenario 1 and 2 in ESM, the major characteristic that makes Scenario 2 different to Scenario 1 is the flat to declining centralised electricity demand in Scenario 2. When electricity demand is flat or falling it is possible that the market will have excess supply capacity. During such periods, which do exist in Scenario 2, ESM allows that some existing plant (with sunk costs) may have to accept returns that are less than long run marginal costs – that are in fact closer but no lower than short run marginal costs. With this in mind we ideally could have investigated this issue further by iterating alternative bidding strategies in 2-4-C and ruling out the lowest profitability options in ESM to converge.
towards agreement but this fell outside of the scope of the study due to the high time cost of such iterations.

Figure 49: Comparison of ESM and 2-4-C projected average wholesale prices in Scenario 2

5.2.5 DISCOM PROJECTIONS

Aggregate load factor

Figure 50 shows the projected change in the aggregate load factor of the network in Scenario 2. Scenario 2 includes several peak demand reduction measures which are implemented from 2015. However Scenario 2 also includes very high on-site generation uptake which causes the grid-sourced volume of consumption to decline. Up until 2020 the peak reduction measures are the stronger influence and aggregate load factor improves (with a slight adjustment in 2016 as adoption of on-site generation briefly surges). However, from 2020 the adoption of on-site generation is too rapid and the load factor commences a sustained decline. Overall from 2015 to 2050 the aggregate load factor almost halves declining from 57 percent to 35 percent. The sharp decline in the load factor in the 2040s coincides with a rapid period of on-site generation adoption.
Figure 50: Projected change in aggregate load factor of the network in Scenario 2

Distribution unit costs

Figure 51 shows the projected distribution unit costs for residential customers in Scenario 2. Existing distribution network rules are assumed and unit costs are on the basis of even apportionment of costs by volumed consumed (alternative arrangement are likely to apply in the future).

The projection indicates that there will be a slight fall in distribution unit costs up to 2020 as the load factor improves through this period. The degree of reduction is small because there are significant ongoing distribution costs that form a larger component of total distribution expense than avoided augmentation expenditure. From 2020, distribution unit costs are projected to commence a sustained increasing trend reflecting the sustained decline in aggregate load factor which means that the amount of expenditure that must be undertaken to maintain and grow capacity is increasing faster than the volume of electricity over which distribution expenditure may be recovered.

Overall distribution unit costs are projected to double by 2050 under Scenario 2.
5.3 Scenario 3: ‘Leaving the grid’

5.3.1 DEMAND PROJECTIONS

Scenario 3 adopts the AEMO (2013) low electricity forecast, has very high adoption of on-site generation (determined by ESM) whose customers disconnect completely from the grid. It assumes low adoption of peak demand reduction measures but peak (as seen by the grid) declines with disconnection. Figure 52 presents the resulting centrally supplied electricity consumption and peak demand under these scenario assumptions.
5.3.2 ESM PROJECTIONS

Generation

A major feature of Scenario 3 is that over time a significant portion of consumption is removed from the electricity system via the process of customers disconnecting and, crucially, choosing not to use the grid for back-up in any way – this is disconnection in the sense of a positive choice to be no longer connected rather than just a high reliance on on-site generation (e.g. Scenario 2) or something that might happen to customers who do not pay their electricity bills.

The disconnection commences from around 2015 from a small base and expands at a linear rate to around 2035 (Figure 53). However, after 2035 the rate of disconnection accelerates. This is consistent with our assumptions on the cost of residential disconnection outlined earlier in this report which finds that the cost of disconnection is approaching the retail cost of electricity supply from the grid after 2030 based on a number of input assumptions, particularly in relation to battery costs. We implement the accelerated cost of on-site generation assumptions that were implemented in Scenario 2.

Given that demand for centrally supplied electricity is expected to decline by 2050 there are only two distinct periods of growth in centralised electricity generation capacity. The first is in wind power to meet the Renewable Energy Target up to 2020. The second is in 2030 to 2035 to build base load combined cycle gas plant to replace some retiring coal-fired plant.

Figure 54 shows the amount of on-site generation that remains connected. By 2045 almost all on-site generation disconnects as rising retail unit costs (due to low network utilisation) and the availability of low cost battery storage assumed in this scenario means that all consumer who can use on-site generation choose to disconnect (shown in Figure 55).
Figure 53: Projected central, connected on-site and disconnected on-site electricity generation by technology in Scenario 3

Figure 54: Projected connected on-site electricity generation by technology in Scenario 3
The amount of investment in centralised electricity generation capacity is lower in Scenario 3 than both Scenario 1 and 2 reflecting high adoption of on-site generation (although not as high as Scenario 2) and lower underlying electricity consumption. Grid connected investment in on-site generation is relatively minor. Disconnected on-site generation investment is large and although the volume on-site generation (connected or disconnected) is lower in Scenario 3 compared to Scenario 2, the level of investment is higher due to the additional investment in battery storage and small but infrequently used fossil-fuelled engines required to meet the load in a disconnected system that has a high amount of rooftop solar panels (outlined in the model assumptions earlier in this report).
Wholesale unit costs

Projected wholesale unit costs for Scenario 3 are shown in Figure 57. They follow the same trend to 2020 as Scenarios 1 and 2 reflecting the introduction of carbon pricing, followed by a decrease and then return to rising carbon prices.

After 2020, the Scenario 3 projected average wholesale unit costs follow a similar path to Scenario 2. That is, the growth in wholesale unit costs is below that of Scenario 1 due to weaker demand leading to periods of excess supply capacity persisting into the future. This leads to a stronger reliance on existing generation stock which does not always require returns equal to its long run marginal cost due to the sunk nature of its capital expenditure. The retirement of existing plant would ease this excess supply. However, the increase in prices in the early 2030 due to retirement of coal plant is significantly curtailed in the mid to late 2030s when disconnection via on-site generation rapidly increases, resulting in lower demand for grid supplied electricity.
One of the assumptions of Scenario 3 is that it has lower underlying consumption growth. This assumption was made in anticipation that it would likely be a scenario with relatively high retail prices and that customers would be generally more motivated to implement energy efficiency improvements as it would make the task of disconnecting simpler for those who chose to do so (e.g. fewer solar panels and roof space required).

Therefore, whilst the electricity generation mix of Scenario 3 is much the same as Scenario 2 (dominated by a combination of large scale coal, gas, wind, solar and on-site solar panels and gas co/tri-generation), Scenario 3 has lower greenhouse gas emissions due to lower underlying volume of electricity consumption. By 2050, electricity sector greenhouse gas emissions are 70 percent below 2000 levels in Scenario 3.
Transport and vehicle electrification

By design, the adoption of electric vehicles in Scenario 3 is assumed to be identical to that of Scenario 2 as these scenarios both assume customer have a similar level of interest and engagement with this option. The projections are therefore not repeated here.

5.3.3 TNEP PROJECTIONS

TNEP loosely imposes the electricity generation mix determined by ESM and co-optimises the required transmission capacity with the location and mix of electricity generation plant.

Transmission augmentation

New capacity of 500MW (both directions) is projected to be constructed in Scenario 3 for the SWNSW-NCEN regions in 2035 (Figure 59). This is the only projected augmentation and reflects the relatively minor expansion in peak demand under this scenario to 2050 not due to peak demand management as in the cases of Scenarios 1 and 2 but due to disconnections that occur, particularly in the last two decades. Note investment to maintain capacity within NTNDP zones would also be occurring.
Centralised generation capacity

In Scenario 3, disconnection is so widespread by 2050 that it impacts all NTNDP zones and states. The impact is strongest after 2030 when disconnection is most economically viable, reducing peak demand and consumption on-grid. The centralised electricity generation capacity is therefore significantly curtailed in nearly all zones by 2050 (Figure 60). We do see some limited growth areas. The biggest exception is SEQ. This most likely reflects that growth in this region is one of the strongest and consequently, even with disconnection impact demand, some new centralised capacity is required.
5.3.4 2-4-C PROJECTIONS

2-4-C implements the TNEP transmission and generation capacity and modifies it to meet minimum unserved energy (USE) requirements and reasonable levels of generator profitability in the years 2030, 2040 and 2050.

USE performance of the initial capacity

The initial projected centralised generation capacity from TNEP that was imposed on 2-4-C is presented in Figure 61. Figure 62 shows that the projected generation capacity from TNEP resulted in unacceptable levels of USE in all years in QLD, especially 2040. South Australia also exceeded the standard in 2040.
Figure 61: TNEP generation capacity initially imposed on 2-4-C in Scenario 3

Figure 62: 2-4-C estimates of unserved energy under initial TNEP generation and transmission capacity projections in Scenario 3
Modified capacity and price outcomes

Figure 63 shows the modified 2-4-C projection for generation capacity and it is compared to the initial TNEP projection in Figure 64. Scenario 3 required the least generation capacity changes to the TNEP solution to achieve profitability of all generators and meet the USE standard in 2-4-C. The changes were:

- Similar to other scenarios all brown coal generators and some black coal generators were found to be unprofitable in 2050 and these were retired.
- Additional capacity was required in QLD in all years to reduce the USE to below the reliability standard.
- Due to the significant changes occurring to the demand profile in this scenario due to disconnections, the additional 500 MW CCGT plant installed in QLD was found to be highly profitable in 2040 and 2050, but not profitable in 2030. However, this generator is required in 2030 to meet the reliability standard. This may be an example where an OCGT is installed initially with plans to be later converted into a CCGT.
- An additional 600 MW of OCGT plant was sufficient to reduce the USE in SA to an acceptable level.

![Figure 63: 2-4-C generation capacity after modifying to meet USE standards in Scenario 3](image-url)
Figure 64: Summary of 2-4-C and TNEP generation capacity differences in Scenario 3

No changes to the TNEP transmission augmentations were required in 2-4-C. However there was a change in the average pattern of use of the New South Wales and Queensland transmission link (Figure 65). The net demand is much higher at night than during the day in Queensland in Scenario 3 due to the significant proportion of electric vehicle load which remained on the system for customers who did not disconnect (residential disconnections were lower in Queensland than other states\textsuperscript{9}).

This results in a very different usage of the major transmission link between the two states. In Scenarios 1 and 2 the average flow during the day is northward from NSW to QLD at around 300 MW and 150 MW, respectively. In Scenario 3, however, the average flow during the day is around 700 MW southward from QLD to NSW.

\textsuperscript{9} Disconnections were allocated to states on the basis of where on-site generation was adopted. Differences in on-site generation adoption by state reflect differences in retail prices and costs of on-site and centralised generation.
Figure 65: Average transmission flow by time-of-day in 2050-51 - New South Wales to Queensland - Scenarios 1-3

A comparison of 2-4-C average volume weighted wholesale electricity prices and ESM wholesale electricity unit costs are provided in Figure 66. 2-4-C projects prices to be around $14/MWh higher than ESM in Scenario 3 between 2030 and 2050. The alignment between the two models on price is stronger than under Scenario 2 but not as close as Scenario 1. The difference in Scenario 3 is likely to be for the same reason outlined in the discussion of Scenario 2 – that flat or declining demand for centrally supplied power is leading to periods of excess supply where ESM allows some below long run marginal cost operation of “sunk” generation capacity. Again there was insufficient time to reiterate the models to test alternative approaches to bidding strategies in 2-4-C or thresholds for existing plant retirement in ESM (which would appear to be areas of misalignment).
5.3.5 DISCOM PROJECTIONS

Aggregate load factor

The projected change in the aggregate load factor of the network is presented in Figure 67. Scenario 3 assumes that there are no significant efforts on the part of customer to reduce peak demand growth. On the other hand customers are more electricity efficient than in Scenarios 1 and 2. As a consequence, the aggregate load factor in Scenario 3 starts at a slightly lower point (due to lower consumption) than Scenario 1 and 2 and declines a little further as peak demand growth picks up to 2020. The trends in the remainder of the projection period mainly reflect that Scenario 3 includes a significant number of customers disconnecting. As customers disconnect, consumption falls but so too does peak demand (since the customer is not relying on the grid for back-up as customer with on-site generation in other scenarios do). If customer disconnection is skewed towards peakier customers then the aggregate load factor could in fact improve under these circumstances. This is what occurs in the period between 2020 and 2040. However, as the rate of disconnection accelerates in the period 2040 to 2050 including less peaky customers the aggregate load factor falls.

Overall, the load factor declines from 53 percent in 2015 to 43 percent by 2050.
Figure 67: Projected change in aggregate load factor of the network in Scenario 3

Distribution unit costs

Projected distribution unit costs to 2050 for Scenario 3 are presented in Figure 68. Existing distribution network rules are assumed and unit costs are on the basis of even apportionment of costs by volumed consumed (alternative arrangement are likely to apply in the future).

Up until 2030 distribution unit cost are projected to increase reflecting the relatively stronger growth in peak demand relative to consumption in this period. Distribution unit costs stabilise and fall slightly between 2030 and 2040 as the aggregate load factor improves. However, from 2040, as the aggregate load factor deteriorates, distribution unit costs begin increasing again rapidly to 23c/kWh in 2050.
Figure 68: Projected distribution unit costs for residential customers in Scenario 3

5.4 Scenario 4: ‘Renewables thrive’

5.4.1 DEMAND PROJECTIONS

Scenario 4 adopts the AEMO (2013) low electricity forecast, has moderate adoption of on-site generation (determined by ESM) and assumes high adoption of peak demand reduction measures. Figure 69 presents the resulting centrally supplied electricity consumption and peak demand under these scenario assumptions.
5.4.2 ESM PROJECTIONS

Generation

Scenario 4 implements an extended Renewable Energy Target that increases the share of renewables above the amount set in the existing Renewable Energy Target to 100 percent by 2050. The existing Renewable Energy Target will raise the share of renewables in the centralised electricity system to 41 TWh by 2020 and maintain that level to 2030. We begin ramping up that level from 2035 in a linear fashion to reach 100 percent.

This scenario also includes the assumed lower cost of centralised electricity generation technology as discussed in the assumptions.

It is important to note that the on-site generation sector is not subject to the 100 percent renewable target – the actual share of renewable achieved is around 89 percent.

Given that the centralised electricity sector completely removes both coal and gas fired generation from the technology mix in this scenario, and also considering that many customers would begin to favour electricity over gas in end-use applications as electricity approaches a near emission free fuel, we assume that the distribution of gas will become more and more limited over time. Consequently we do not allow gas based on-site generation as an option in this scenario.

We did test the option for the gas distribution infrastructure to be used to distribute biogas as was explored in AEMO (2013). However, we found that the electricity sector was not able to compete with the transport sector for the use of the biomass resource and as such this option was not taken up (all biomass, in excess of food production, was assumed to be available for the electricity sector in AEMO (2013)). Some natural gas is used in transport, however, this is in the form of LNG at concentrated distribution sites along
the main long haul trucking route of Brisbane-Sydney-Melbourne rather than widely available for other purposes.

We assume diesel is available for use as an on-site generation fuel. It is a more easily distributed fuel and the transport modelling indicates it will still be available for transport purposes in 2050 since there are many transport applications which are difficult to fully electrify such as long distances and/or freight tasks.

The projected electricity sector consumption by technology is shown in Figure 70. It shows that under a 100 percent renewable centralised electricity target, a wide variety of renewable are adopted into the generation mix including hot fractured rocks, large-scale solar photovoltaics, wave and both onshore and offshore wind. In the various trial model runs that were undertaken, solar thermal with storage also appeared in ESM depending on the cost of electricity storage needed to support variable renewables such as wind and solar photovoltaics. However, the aim of the scenario was to explore a scenario with high electrical storage and so ESM was less inclined towards solar thermal power – this does not mean it could not play a significant role in a 100 percent renewable scenario (see AEMO (2013b) for example) and indeed the finer temporal scale models, TNEP and 2-4-C reinstate solar thermal into the mix of Scenario 4 as we discuss later10.

Figure 70: Projected central and on-site electricity generation by technology in Scenario 4

The adoption of on-site generation is lower than Scenarios 2 and 3 but still higher than Scenario 1. This positioning reflects that on the one hand, centralised electricity generation technology is cheaper in this scenario, but on the other, the expanded renewable energy target is forcing in higher costs components of those technology faster than Scenario 1, forcing up wholesale and retail costs therefore making on-site generation attractive to some customers.

Figure 71 shows the mix of on-site generation technology in detail. The two technologies experiencing the strongest growth are solar photovoltaic panels and diesel. Solar panels are assumed to be low cost to be

10 ESM provides a starting point for the generation mix in TNEP and 2-4-C, however those models are also given some latitude to modify the mix if their analysis indicates an improved solution
consistent with lower costs for large scale solar photovoltaic plant. The adoption of diesel fills a niche where use of solar panels is constrained due to space or the nature of the load\textsuperscript{11}.

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{figure71.png}
\caption{Projected on-site electricity generation by technology in Scenario 4}
\end{figure}

**Investment**

Figure 72 presents the cumulative level of capital investment to 2050 in Scenario 4. It shows a much higher level of capital investment than Scenarios 1-3 reflecting the investment in renewable which are capital intensive relative to other choices such as gas fired power whose cost profile is dominated by fuel expenses. However, it should also be acknowledged that there is a greater turnover of capital in this scenario regardless of the differences in the ratio of capital in levelised technology costs. The expanded Renewable Energy Target forces some capital to be discarded that could otherwise have been utilised cost effectively. One consideration is whether there would be less capital discarded if ramping towards the 100 percent target commenced sooner than 2035. Given ESM is a perfect foresight model, it is already minimising the amount of capital that has to be discarded. However, on the other hand, it is likely an early target would mean development of only renewable capacity sooner.

\textsuperscript{11} Diesel may seem an unlikely choice in an urban setting. One advantage is that it is easily converted to renewable generation via biodiesel to be in keeping with the high renewable share in this scenario although this option was not available to be selected in the present on-site generation technology set in ESM. If noise and air pollution restrictions mean that diesel is not viable in an urban setting than this load might be met by some type of gas engine instead.
Projected average wholesale unit costs are presented in Figure 73. As in the previous Scenarios 1-3 the first ten years simply reflects the assumed path of the carbon price. However, from 2020 the increasing price trend is more rapid in Scenario 4 than Scenarios 1-3 reflecting the impact of the expanded Renewable Energy Target. Prior to 2035 the policy settings are the same, however, it is not economically viable to build new fossil plant knowing that it will be required to be closed down later. Consequently some on-site generation and other investment in centralised renewable electricity generation is brought forward when Scenarios 1-3 would have otherwise been investing in gas combine cycle plant.

After 2035 as the Renewable Energy Target tightens, investment broadens out to include a mix of renewables and wholesale unit prices increase more rapidly to reflect their costs. By 2050 when the centralised Renewable Energy Target is fully realised at 100% the wholesale unit cost is projected to reach $176/MWh. This projection is higher than that found in the AEMO (2013b) study which used the same costs assumptions but projected a wholesale unit cost of $111-133/MWh. However, as noted in AEMO (2013b), the cost of reaching a 100% renewable target in that study is underestimated. There are four main reasons. The first is it assumed all renewable technology could be purchased at the price prevailing in the modelled year. In reality, most plant would have been purchased in previous years at higher cost. Second, AEMO (2013b) does not include the cost of transforming from the present system, which would involve implementing a price signal for any fossil units built before 2050 to shut down. This price signal may need to be reasonably high given it is likely the capital costs of any fossil plant would be regarded as sunk once constructed.

Thirdly in AEMO (2013b) demand management was free and optimised to support the contribution of renewables. This is plausible but it is also equally plausible that demand management might be optimised to provide other services such as addressing peak demand to reduced network capacity requirements. In reality demand management will probably address multiple overlapping needs. In this report, demand management is also free (from the generation sector’s point of view but we include it as an off-grid cost.
later in the report) and is optimised for minimising aggregate (state wide) demand peaks which only indirectly beneficial for supporting renewable penetration.

Finally, AEMO (2013) used biomass converted to biogas in peaking plant to back-up to variable renewable. However, ESM modelling finds any available bio-energy resources would be purchased by the transport sector.

When these differences in the studies are taken into account, the ESM projection appears reasonable. TNEP and 2-4-C do not provide further insights on the costs, but they do test the feasibility of a renewable and storage technology mix.

**Figure 73: Projected average wholesale electricity unit cost in Scenario 4**

**Greenhouse gas emissions**

Projected electricity sector emissions for Scenario 4 are presented in Figure 74. As expected, this scenario achieves substantial greenhouse gas reduction reflecting the 89 percent contribution of renewables to total generation following the combination of 100 percent renewable penetration the centralised generation sector and strong contribution of rooftop solar photovoltaic panels in the on-site generation sector by 2050.

By design, Scenario 4 also has slower growth in electricity consumption due to stronger assumptions with regard to electricity energy efficiency improvements. This is consistent with higher electricity prices in this scenario which provide a stronger signal for reduced consumption growth. These assumptions are the same as Scenario 3 except Scenario 4 consumption is slightly higher due to greater electric vehicle uptake.

The period of strongest greenhouse gas emission reduction is from 2030 when renewable electricity generation plant begins to be most rapidly deployed at the same time that coal plant is retiring.

By 2050, electricity sector greenhouse gas emissions are 89 percent below 2000 levels in Scenario 4.
Figure 74: Projected electricity sector greenhouse gas emissions in Scenario 4

Transport and electric vehicle

Scenario 4 was assumed to have the highest level of electric vehicle adoption to reflect the opportunity to take advantage of the low emission intensity of electricity as a transport fuel and the wide availability of competitive battery technology spilling across both sectors. Under this assumption, consumption of electricity for road transport is projected to reach 32 TWh by 2050 in Scenario 2 or equivalent to 31 percent of total road kilometres (Figure 75). Hybrid electric vehicles reach a lesser share but generate electricity on-board from liquid transport fuel rather than drawing electricity from the grid.

In regard to the overall transport fuel mix we see most of the main trends already observed in the other Scenarios 1-3. However, the stronger adoption of electricity as a transport fuel in Scenario 4 reduces demand for petrol and diesel more noticeably. The aviation industry benefits from this by being able to get access to more biomass sooner to convert into bio-derived jet fuel. The higher adoption of vehicle electrification in Scenario 4 reduces total road sector fuel consumption by 123 PJ by 2050 relative to Scenario 1.
Figure 75: Projected uptake of internal combustion and alternative road vehicle drivetrains in Scenario 4

Figure 76: Projected transport sector fuel consumption by fuel in Scenario 4
5.4.3 TNEP PROJECTIONS

TNEP loosely imposes the electricity generation mix determined by ESM and co-optimises the required transmission capacity with the location and mix of electricity generation plant.

Due to the complexity of this scenario, TNEP’s inter-temporal optimisation period was limited to the 2040-2050 to speed up the mathematical solution process.

Transmission augmentation

Due to the 100 percent renewable target and the generally more dispersed location of renewable resources, Scenario 4 has by far the largest projected augmentation of transmission capacity. Table 18 lists the locations, their development year and capacity. Although the model was only run 2040-2050, it is likely augmentation would have commenced from any time after 2035 when the renewable target begins to ramp up from where it had stayed since reaching the 2020 target.

Figure 77 illustrates the location of the new transmission capacity. It indicates that transmission augmentation will be focused on connecting Victoria, Tasmania and South Australia more robustly as well as the western segments of south Queensland, New South Wales and Victoria. The Tasmanian-Victorian connections reflect the increased importance of hydro power for supporting renewable and the adoption of high quality wave resources in that region. Connections between the other regions reflect use of wind, solar and geothermal (the latter particularly between New South Wales and Queensland). Note investment to maintain capacity within NTNDP zones would also be occurring.

Table 18: Projected transmission augmentation in Scenario 4

<table>
<thead>
<tr>
<th>NEM Interconnector</th>
<th>Year</th>
<th>Nominal Capacity (forward / backward)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CVIC-SWNSW</td>
<td>2040</td>
<td>1000 MW</td>
</tr>
<tr>
<td>CVIC-SWNSW</td>
<td>2045</td>
<td>1250 MW</td>
</tr>
<tr>
<td>NCEN-NNS</td>
<td>2040</td>
<td>1500 MW</td>
</tr>
<tr>
<td>NNS-SWQ</td>
<td>2040</td>
<td>1390 MW / 2100 MW</td>
</tr>
<tr>
<td>SESA-MEL</td>
<td>2040</td>
<td>750 MW</td>
</tr>
<tr>
<td>SWNSW-NCE</td>
<td>2040</td>
<td>2000 MW</td>
</tr>
<tr>
<td>SWNSW-NCE</td>
<td>2045</td>
<td>2500 MW</td>
</tr>
<tr>
<td>SWNSW-NCE</td>
<td>2050</td>
<td>3000 MW</td>
</tr>
<tr>
<td>TAS-LV</td>
<td>2040</td>
<td>469 MW / 594 MW</td>
</tr>
<tr>
<td>TAS-MEL</td>
<td>2040</td>
<td>600 MW</td>
</tr>
</tbody>
</table>
Centralised generation capacity

The trend in projected centralised generation capacity in Figure 78 is as we would expect for a scenario which is driving growth in renewable capacity and closing down existing plant. 2050 capacity is higher than 2040 and capacity is high overall reflecting that many renewable electricity generation technologies have a lower load factor than base load coal and gas plant that are replaced.

The distribution of renewable energy generation capacity over space (NTNDP zones) will depend on:

- The location of existing installations;
- The magnitude and temporal pattern of supply in the region/zone;
- The transmission capacity provided to the region/zone;
- In the case of distributed generation, the proximity/presence of suitable customers, structures and demands;
- In the case of centralised generation, the proximity to loads (so as to avoid transmission augmentation costs)

The trade-offs within an optimisation tool will be complex and potentially not easy to explain. The distribution of the generation resources over space is of interest nevertheless.
Figure 78: Projected installed centralised generation capacity by NTNDP zone in Scenario 4

The following tables provide more detail on the location of renewable electricity generation. Wind and solar resources show a fairly static pattern with time, whereas wave and geothermal plant is being installed rapidly and therefore does show change between 5-year intervals.

There is significant growth in solar generation capacity in MEL and SWNSW over 2040-2050 according to the TNEP solution (Table 19). The major amount of solar in SWNSW motivates the building/augmentation of the SWNSW-NCEN transmission link over the period. (Note also that subsequent modelling with 2-4-C indicates that extra solar power generation should be added to the TNEP solution, in the form of centralised PV with additional storage.)
Over the 2040-2050 period, wave power generation is projected to be rapidly installed (Table 20). Wave power is selected by ESM/TNEP as a useful way to supply SEQ in particular. Wave power is not available further North in Queensland. Note also that CAN spans the NSW South Coast.

Table 20: Wave generation capacity by NTNDP zone in Scenario 4

The installations of wave power on the NSW and Queensland coasts are not intuitive results, because the average capacity factor of wave energy converters (WECs, generators) in Victoria and Tasmania is two to four times better than in the Northern states. Through an investigation of the data we have found two main explanations.

Firstly, the correlation in time between WEC output (MW per MW) is not straightforward between Vic/Tas and NSW/QLD, but overall is a negative correlation. The lower capacity factor NSW and Qld WECs will on some occasions generate significant power when Vic/Tas WECs have low output. This can be seen in the plots that follow (Figure 79 and Figure 80), where the demand is taken from the 2040 projection (for the “Renewables Thrive” scenario) and supply is also from a projected series for 2040 (based on 2010, as per other TNEP and 2-4-C modelling).

The conclusion is that there is value in having a portfolio of wave generation regions, even though the average capacity factor in some regions is relatively poor. The value of the NSW and QLD WECs is partly attributable to their ability to support the network under unusual conditions.
It is also observed in data that the correlations in time between demand and wind, solar and wave renewable resources are not straightforward. There are periods where almost all renewable energy conversion is at a minimum. Diversity in supply, in terms of region and of generation type, can be thought of as bringing average-case inefficiency but some extreme-case robustness. The plots of Figure 81 contain observations hours in a year where the solar (utility scale single axis tracking PV) generator output is less than 10% of nameplate capacity (i.e. night, evening or a gloomy day). The Polygon 31 (NCEN)\textsuperscript{12} wave

\textsuperscript{12} polygons refer to the regions for which renewable output data is made available by AEMO. They do not perfectly coincide with NTNDP zones but we show the closest relevant polygon.
output is slightly positively correlated with NCEN demand (the right-hand plot in Figure 81). The wind and wave power outputs are almost unrelated according to this data. The left-hand plot in Figure 81 is a plot of data for only the lowest wind dynamic capacity factor values (up to 10%), and it is evident that there are times when NCEN wave would be contributing to supply in a significant way, and other times where the WECs would be idle along with the wind generators.

The second explanation for the uptake of NSW and QLD wave resources is transmission construction is expensive, and augmentation is considered by the TNEP model to be available in discrete increments (250 MW to 500 MW). This means that lower-grade renewable resources may be harvested locally in preference to commissioning a discrete-step augmentation of a series of links in the network in order to enable transmitting energy over possibly several NTNDP zone boundaries (so as to reach SEQ and NCEN demand centres from the Southern states).

Wind power installations have essentially matured by 2030-2040 in all scenarios. For Scenario 4, some growth in installed capacity in MEL is selected by TNEP (Table 21).

Table 21: Wind generation capacity by NTNDP zone in Scenario 4

<table>
<thead>
<tr>
<th>Year</th>
<th>NTNDP Zone</th>
<th>Energy (TWh)</th>
<th>Capacity (MW) (nearest 25 MW)</th>
<th>Year</th>
<th>NTNDP Zone</th>
<th>Energy (TWh)</th>
<th>Capacity (MW) (nearest 25 MW)</th>
<th>Year</th>
<th>NTNDP Zone</th>
<th>Energy (TWh)</th>
<th>Capacity (MW) (nearest 25 MW)</th>
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<tr>
<td>2040</td>
<td>ADE</td>
<td>0.9</td>
<td>275</td>
<td>2045</td>
<td>ADE</td>
<td>0.4</td>
<td>275</td>
<td>2050</td>
<td>ADE</td>
<td>0.7</td>
<td>275</td>
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<td>CAN</td>
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<td>225</td>
<td>2045</td>
<td>CAN</td>
<td>0.8</td>
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<td>CAN</td>
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<td>225</td>
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<td>CQ</td>
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<td>825</td>
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<td>CVIC</td>
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<td>CVIC</td>
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<td>825</td>
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<td>LV</td>
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<td>MEL</td>
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<td>MEL</td>
<td>11.4</td>
<td>2900</td>
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<td>NCEN</td>
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<td>NCEN</td>
<td>2.3</td>
<td>750</td>
</tr>
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<td>4550</td>
<td>2045</td>
<td>NNS</td>
<td>17.2</td>
<td>4550</td>
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<td>NNS</td>
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<tr>
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<td>NSA</td>
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<td>925</td>
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<td>2050</td>
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<tr>
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<td>350</td>
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<td>1.1</td>
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<td>0.3</td>
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<td>0.0</td>
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<tr>
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<td>SWQ</td>
<td>0.0</td>
<td>25</td>
<td>2050</td>
<td>SWQ</td>
<td>0.0</td>
<td>25</td>
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<tr>
<td>2040</td>
<td>TAS</td>
<td>2.9</td>
<td>850</td>
<td>2045</td>
<td>TAS</td>
<td>2.7</td>
<td>850</td>
<td>2050</td>
<td>TAS</td>
<td>2.8</td>
<td>850</td>
</tr>
</tbody>
</table>

Table 22: Geothermal generation capacity by NTNDP zone in Scenario 4

<table>
<thead>
<tr>
<th>Year</th>
<th>NTNDP Zone</th>
<th>Energy (TWh)</th>
<th>Capacity (MW) (nearest 25 MW)</th>
<th>Year</th>
<th>NTNDP Zone</th>
<th>Energy (TWh)</th>
<th>Capacity (MW) (nearest 25 MW)</th>
<th>Year</th>
<th>NTNDP Zone</th>
<th>Energy (TWh)</th>
<th>Capacity (MW) (nearest 25 MW)</th>
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<tr>
<td>2040</td>
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<td>3.2</td>
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<td>ADE</td>
<td>3.2</td>
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<td>ADE</td>
<td>3.2</td>
<td>425</td>
</tr>
<tr>
<td>2040</td>
<td>MEL</td>
<td>2.9</td>
<td>375</td>
<td>2045</td>
<td>MEL</td>
<td>6.1</td>
<td>800</td>
<td>2050</td>
<td>MEL</td>
<td>9.0</td>
<td>1150</td>
</tr>
<tr>
<td>2040</td>
<td>NVIC</td>
<td>25.5</td>
<td>3275</td>
<td>2045</td>
<td>NCEN</td>
<td>33.4</td>
<td>4325</td>
<td>2050</td>
<td>NCEN</td>
<td>38.6</td>
<td>4975</td>
</tr>
<tr>
<td>2040</td>
<td>NQ</td>
<td>16.0</td>
<td>2025</td>
<td>2045</td>
<td>SEQ</td>
<td>17.7</td>
<td>2250</td>
<td>2050</td>
<td>SEQ</td>
<td>32.5</td>
<td>4125</td>
</tr>
</tbody>
</table>

Geothermal power is specified to develop over 2035-2050 by ESM, and this pattern is followed by TNEP. This form of power has a rather high capacity factor, and displaces fossil-fuelled generation in NCEN in particular (Table 22). The centrality of NCEN to the NEM, as well as the presence of existing transmission assets, helps to drive TNEP to install the Geothermal (HSA) generation capacity in NCEN rather than
elsewhere in NSW. There are also significant installations in SEQ, undoubtedly assisting with meeting demand in that zone (which includes Brisbane): whether this amount of generation capacity can actually be installed in SEQ could be the subject of further study.

Electricity storage

Some energy storage is implied for certain technologies. The use of storage for the technology “Solar Thermal with 6-hr Storage” is modelled explicitly in data pre-processing for TNEP, with a daily charge-discharge profile set to blend a baseload (constant output) and peak (evening peak output) emphasis. Network-level storage is only explicitly considered in TNEP for Scenario 4.

TNEP is not a time-sequential model, so it cannot track electricity inventories in storages. For this reason, it can grossly overestimate the utility of a certain amount of storage capacity, especially on timeframes of three to six hours. TNEP seeks to select sufficient storage capacity to hold a net excess/surplus of electricity over specified periods (the excess/surplus being calculated as the balance of electricity charge and discharge, accounting for roundtrip efficiency over the period). The periods used within the model are day-times (16 hrs, 5am to 9pm), night-times, days (24 hrs), weekdays (5 days), weekends (2 days), weeks (7 days), and seasons (summer, winter). TNEP cannot consider the dynamics of charge-and-discharge, and this leads to optimistic estimates, or lower bounds, on the storage capacity required for fulfilment of demand.

Figure 82 graphs the (lower bound) standalone storage capacity in each NT NDP zone according to the TNEP model for Scenario 4. Given the zone-by-zone generation mix and transmission capacities determined by TNEP in parallel, at least this amount of storage is needed in each of the (noted) zones in order for demand to be satisfied.

![Figure 82: Minimum levels of electricity storage estimated in Scenario 4](image_url)

The function of this storage is mainly to act as peak demand (and/or low renewable energy supply) support - this being a function that is also fulfilled by hydro-electric plant in the TNEP solution for this scenario. By 2050 in Scenario 4, no centralised fossil-fuelled generators are available for use. If the level of renewable energy supply (wind, solar, wave) is low across a region and/or the NEM, then storage, Geothermal
(approximately 11.5 GW, 90 TWh p.a.) and Hydro power (approximately 8 GW, 16 TWh p.a.) are the available alternatives in 2050\textsuperscript{13}.

The large investment in transmission system augmentation reflects the result of a trade-off between storage, generation and transmission investment costs. Rather than more storage, TNEP prefers a “parallel” investment in transmission so that both the highly variable renewable energy supplies and the less variable renewable supplies (hydro and geothermal) can be moved between regions when required.

5.4.4 2-4-C AND H\textsubscript{2}OPT PROJECTIONS

2-4-C implements the TNEP transmission and generation capacity and modifies it to meet minimum unserved energy (USE) requirements and reasonable levels of generator profitability in the years 2030, 2040 and 2050. A special 2-4-C module called H\textsubscript{2}Opt was utilised for this scenario in order to better represent storage, which plays a key role in this scenario.

USE performance of the initial capacity

As noted in the TNEP discussion, it is very difficult to optimise the generation capacity and use of storage in a 100 percent renewables scenario without time-sequential modelling of every period. In Scenario 4 ROAM’s H\textsubscript{2}Opt module was applied to dispatch the storage devices in a realistic manner. H\textsubscript{2}Opt was run in its weekly mode, where the storage devices are operated optimally one week at a time. This operation assumes the storage devices have perfect foresight to plan their charge and dispatch up to a week ahead, but not longer. Figure 83 shows the unserved energy (USE) in 2050 in 2-4-C with H\textsubscript{2}Opt using the generation expansion data directly from TNEP for Scenario 4. The USE levels are extremely high showing that TNEP has underestimated the required storage and generation capacity – this was an expected outcome given neither ESM nor TNEP is able to sequentially monitor storage levels.

\textsuperscript{13} Demand side management including control of electric vehicle charging has already been optimised to reduce peak demand and can provide no further support. As discussed, an alternative approach could have allowed for demand management to be optimised for renewable back-up.
Modified generation and storage capacity outcomes

Figure 84 presents the TNEP initial centralised generation capacity and the modified 2-4-C generation capacity. To help reduce the USE, 7 GW of large-scale solar PV was installed in 2-4-C across all the states. In addition, after several trials with different amounts of storage, to reduce the USE below 0.002% in every region, the following storage installation was implemented:

- 50 times the storage capacity TNEP assigned to SEQ,
- 32 times the capacity in NCEN,
- 21 times in ADE and
- 15 times in MEL.

New storage capacity in other smaller zones was also required as shown in the Figure 85. Despite the apparent large increase in storage needed, the total size of all reservoirs for the 2-4-C solution is only 771 GWh, which is equivalent to about 1.5 average days of total demand in the NEM in this scenario (the annual demand energy is 166,000 GWh).
As a point of interest, the most stressed iteration of the 50 that were run for Scenario 4 is the iteration shown in Figure 86 (the iterations were to examine the impact of forced outages of the geothermal plant). In this iteration, the reservoir levels in the storage reached near zero in SEQ to meet USE.
Summary of TNEP and 2-4-C findings on Scenario 4

The deployment of storage with renewables can be readily tuned to achieve a reliable 100 percent renewable electricity generation mix. However, the modelling is not able to say whether storage was better than other options for supporting variable output such as more transmission or more renewable capacity or more targeted demand management. It is noted that AEMO (2013b) used a significant amount of biogas peaking plant to support other variable renewable however ESM did not allow that solution in TNEP and 2-4-C, finding bioenergy resources were allocated to transport.

The difficulty with finding an optimal 100 percent renewable scenario is that models that select generation plant and transmission (ESM/TNEP) are not temporally fine grained enough to determine if the solution is reliable such as in 2-4-C (but on its own, 2-4-C cannot project plant and transmission builds). Finding an optimal scenario necessarily requires multiple iterations of several models – which were not possible in the time available for this process. We therefore characterise the results presented as feasible but not necessarily least cost. They should therefore be interpreted as only indicative of the potential outcomes under Scenario 4.

5.4.5 DISCOM PROJECTIONS

Aggregate load factor

Figure 87 shows the change in the aggregate network load factor for Scenario 4. Scenario 4 assumes several peak demand measures are adopted by customers and this slightly improves the load factor to 2020. However, from 2020 the assumed slow underlying growth in electricity consumption (due to improved energy efficiency) and adoption of on-site generation mean that grid supplied consumption is falling in the long term against rising peak demand. Consequently the aggregate load factor declines to 44 percent by 2050.

Figure 87: Projected change in aggregate load factor of the network in Scenario 4
**Distribution unit costs**

The projected change in Distribution unit costs for residential customers is presented in Figure 88. Existing distribution network rules are assumed and unit costs are on the basis of even apportionment of costs by volumed consumed (alternative arrangement are likely to apply in the future).

Distribution unit costs are projected to be flat in the period to 2023 reflecting little need for new capacity investment with peak demand measures in place and no decline in the network load factor. However, as peak demand begins to increases and the aggregate load factor declines increasing costs must be apportioned over consumption that is not growing as fast. This trend continues to 2050 where distribution unit costs reach just under 21c/kWh.

![Figure 88: Projected distribution unit costs for residential customers in Scenario 4](chart)

**5.5  Scenario 1 sensitivity case: Zero carbon price**

For this sensitivity case, we are primarily concerned with how the absence of a carbon price from 2015 impacts the technology mix, wholesale unit prices and greenhouse gas emissions. ESM was the only model applied to determine these outcomes.

**5.5.1  ESM PROJECTIONS**

**Generation**

In the absence of a carbon price from 2015 coal-fired power is not projected to immediately expand (Figure 89). The Renewable Energy Target is still in place and consequently most new growth in consumption up to 2020 is met by wind power (in fact beyond meeting new demand wind power is also displacing coal-fired generation). After 2020, coal fired power begins to expand. Black coal capacity expands, particularly in QLD to support stronger growth in consumption in that state. In the south direct injection coal engines (DICE)
are preferred for new brown coal capacity – this is because most wind power is installed in this region and DICE is better suited to backing up that capacity than traditional pulverised fuel boilers.

It should be noted that while liquefied coal diesel engines are an old technology they have not been deployed at this scale before in Australia and so there is some uncertainty attached to this modelling result. More than likely, if DICE was not deployed then a more conventional brown coal plant would occupy its position in the technology mix.

Compared to Scenario 1 other major changes are significantly reduced adoption of gas combined cycle and large-scale solar photovoltaic plant. Also, wind power is not fully replaced or expanded after capacity built for the Renewable Energy Target is due for retirement.

On-site generation is slightly higher under this sensitivity case compared to Scenario 1 reflecting lower costs for gas fuelled on-site generation technologies in the absence of a carbon price. The major sources of the growth in on-site generation are rooftop solar photovoltaic panels and gas co-generation.

![Figure 89: Projected central and on-site electricity generation by technology in Scenario 1 sensitivity: zero carbon price (effective 2015)](image)

**Wholesale unit costs**

Figure 90 compares the projected average wholesale unit cost in Scenario 1 and in the Scenario 1 sensitivity case with a zero carbon price from 2015. As we would expect the sensitivity case shows the wholesale unit costs dropping back to $40/MWh as is implied by current prices as the underlying wholesale unit cost if you take away the current impact of the carbon price (around $20/MWh) from the current wholesale unit cost ($60/MWh as a national average, but there are significant differences between states).

However, more importantly, what the zero carbon price sensitivity case shows is that the wholesale unit costs cannot be maintained at this level. $40/MWh is below the cost of new plant and therefore not sustainable in a system that requires new capacity to be built at a reasonable return to investors. The projection indicates that the long term sustainable level average wholesale unit cost is around $70/MWh which would closely match the projected future cost of new coal-fired plant (in real terms).
As such, even with no carbon price, wholesale electricity unit costs in Australia are projected to increase. The increase is projected to commence in the 2020s after the influence of the Renewable Energy target and subdued growth in consumption, which in combination is keeping wholesale unit costs low, has waned.

Figure 90: Projected average wholesale electricity unit cost in Scenario 1 and Scenario 1 sensitivity: zero carbon price (effective 2015)

**Greenhouse gas emissions**

With a zero carbon price from 2015 this Scenario 1 sensitivity is projected to still result some continuing greenhouse gas emissions reduction. This is driven by the Renewable Energy Target bringing in wind power which replaces the contribution of some existing coal fired electricity generation capacity. However, after 2020 when the Renewable Energy Target reaches its peak, greenhouse gas emissions are projected to stabilise for several decades and reach 166 MtCO₂e by 2050.

The lack of increase in emissions from 2020 reflects two factors. The first is that growth in electricity consumption is assumed to the slowing over time to close to a near zero rate of growth by 2050. The second is that new electricity generation plant is projected to be less greenhouse gas emissions intensive than existing coal-fired plant. Roof-top solar photovoltaic panels, gas cogeneration, high efficiency direct injection coal engines and new more efficient black coal fired power plants are all less greenhouse gas intensive than the current stock.

Nevertheless, by 2050, electricity sector greenhouse gas emissions are 87 MtCO₂e higher than Scenario 1: set and forget if there is no carbon price (or equivalent mechanism). This represents an emission level only 6 percent below 2000 levels.
5.6 Scenario 1 sensitivity case: High carbon price

In this sensitivity case we explore the impact on greenhouse gas emissions, the technology mix and wholesale unit prices if we impose the higher carbon price path (associated with a global greenhouse gas concentration target of 450ppm set out in the assumptions section). The results are all sourced from ESM.

5.6.1 ESM PROJECTIONS

The projected electricity generation technology mix is shown in Figure 92. Under a high carbon price there is projected to be a much faster retirement of existing black and brown coal-fired electricity plant. Replacing this retiring plant is a much more diverse set of technologies than we have seen in Scenario 1. Coal and gas with carbon capture and storage are projected to play a significant role in electricity generation from around 2030 with gas with carbon capture and storage the reaching the larger share of these two.

The high carbon price sensitivity case also includes significantly more renewable electricity including expanded biomass and wind compared to Scenario 1 and the addition of solar thermal and hot fractured rocks electricity generation plant. Rooftop and large-scale solar photovoltaic technologies have around the same contribution as Scenario 1.

On-site generation has a significantly lower share in this sensitivity case reflecting the reduced competitiveness (through higher compliance costs) of some gas and diesel consuming on-site generation technologies under a high carbon price.
Figure 92: Projected central and on-site electricity generation by technology in Scenario 1 sensitivity: high carbon price

Wholesale unit costs

Figure 93 shows that average wholesale electricity unit costs are consistently $25/MWh higher under the high carbon price sensitivity case from around 2025. We can infer from this that this is the gap in the costs for technologies such as carbon capture and storage to be competitive with technologies such as wind and large scale solar photovoltaics which do not require a high carbon price to be competitive.

Both Scenario 1 and the high carbon price sensitivity case have identical carbon prices before 2020 which explains why that is the point where unit costs diverge.
Greenhouse gas emissions

A comparison of projected greenhouse gas emissions from Scenario 1 and this high carbon price sensitivity case is shown in Figure 94. It indicates that, under this high carbon price sensitivity, greenhouse gas emissions begin to decline faster from just after 2025. The decline accelerates most rapidly in 2030 when a substantial amount of coal fired electricity without carbon capture and storage is retired in favour of low emission intensive generation. In Scenario 1 the main replacement technology was gas combined cycle which provides electricity at an emission intensity of 0.5-0.6 tCO₂e/MWh (depending on source and associated upstream fugitive emissions). However, in the high carbon price sensitivity the replacement plant is gas combined cycle and coal with carbon capture and storage which is significantly less greenhouse gas emission intensive (less than 0.15tCO₂e/MWh).

By 2050, electricity sector greenhouse gas emissions are 89 percent below 2000 levels in the high carbon price sensitivity case.
Figure 94: Projected electricity sector greenhouse gas emissions in Scenario 1 and Scenario 1 sensitivity: high carbon price

5.7 Scenario 1 sensitivity case: Uncertain carbon price

ESM assumes perfect knowledge of the future carbon price and is therefore not suitable on its own to model this sensitivity case. The methodology chosen to model this sensitivity is to apply a real options model to determine what technologies would be prioritised for investment under carbon price uncertainty. A real options model is ideal for this problem because it considers the carbon price uncertainty range rather than a single carbon price path in making the technological investment choice. Once the real options model has chosen which technologies and when to invest we impose those choices on ESM to find out what the impact of carbon price uncertainty might be in the generation mix, emissions and wholesale unit costs.

5.7.1 REAL OPTIONS MODEL PROJECTION

Assessing the expected profitability of alternative generation technologies under price uncertainty

While Australia has adopted a carbon-pricing regime, the carbon price is not fixed indefinitely and it may be removed, replaced by a different mechanism or converted to a cap and trade scheme where the price is determined by the market (and potentially linked with other carbon permit markets outside of Australia). Thus, there is uncertainty for electricity generation technology investor about the future level of carbon prices, in addition to the ‘usual’ risks over future wholesale electricity prices and future project costs (capital, fuel and other operating expenses). While the latter two risks can be, and typically are, mitigated by using various hedging instruments, the domestic market for carbon price risk is still in its infancy, with a limited range of hedging instruments.
When investment is made under uncertainty, the rationale response by large-scale electricity generators, when faced with ( uninsurable) uncertainty, is to wait until the uncertainty is resolved before committing to projects that have high up-front costs and are largely irreversible once initiated. However, while carbon (and electricity) prices are uncertain, they are not totally unpredictable, since committed bi-partisan political support for greenhouse gas emissions reduction can ensure that carbon prices (or an equivalent carbon pricing mechanism) never reach the zero bound. Consequently, electricity generators can forecast, to some degree, the profitability of adopting alternative generation technologies even when future prices are uncertain. As a result, it can be profitable for electricity producers to adopt a certain generation technology, even if future revenues and costs are not certain and can only be forecast.

The approach adopted here is to consider which electricity generation technologies are (forecast to be) profitable, given uncertainty about future carbon and electricity prices. Furthermore, in the event that a certain technology is (forecast to be) profitable at multiple future times, we also consider when the technology should be adopted; that is, when is it most profitable to adopt a specific technology?

**Methodological framework**

The framework used to address the above questions involves three elements:

1. Generating forecasts of future carbon prices, electricity prices, and levelised electricity costs. While the first two prices are ‘technology-independent’, the last (levelised costs) does vary by the type of generation technology;
2. Generating multiple realisation paths for the three prices in point 1, using a mathematical model that reflects both the uncertainty and predictability about future prices and costs; and
3. Given a potential realisation of carbon and electricity prices, and levelised costs, calculating the profitability of each generation technology.

More details about the mathematical framework used are provided in Section 14.

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14 Other sources of predictability include bi-partisan support for renewable energy targets and a commitment to limit the increase in future atmospheric temperatures.
Forecasts and uncertainty ranges

Figure 95: Forecasts and uncertainty ranges for carbon prices

Figure 95 reveals the assumed conditional mean path followed by the carbon price (or equivalent pricing mechanism), and the range of potential values (the “uncertainty range”) the carbon price can take in each year. Consistent with Commonwealth of Australia (2011) and Zhu et al. (2009) both the conditional mean and conditional volatility of carbon prices are forecast to rise over the next 37 years. The conditional mean is forecast to rise from A$26/tCO₂e in 2013 to A$40/tCO₂e in 2023, after a decline in 2015 (to A$5.1/tCO₂e), with a sustained increase thereafter, reaching A$160/tCO₂e by 2050.

Furthermore, the probability of a zero carbon price quickly becomes zero as the forecast horizon increases; beyond 2015, the probability of a zero carbon price is zero. This is a consequence of the mean-reverting property of carbon prices, and the upward trajectory of the conditional mean, which implies that potential realisations of future carbon prices are not that “far away” from the conditional mean. From a policy point of view it also reflects that most major political parties are committed to emission reduction (although disagree on aspects such as the policy mechanism). A positive (implied or explicit) carbon price is a necessary condition to achieve emission reduction under current knowledge of electricity generation technologies.

The projected carbon price uncertainty range depends itself on the results of Australian modelling of long term carbon prices. There have only been a limited number of these published. Therefore it is possible that the “true” uncertainty range is wider than that modelled here. This type of analysis should therefore ideally be updated as new information about future carbon price paths becomes available.
As is the case for carbon prices, the conditional mean and standard deviation for wholesale electricity prices also follow an upward trajectory, though to a lesser extent than the carbon price (Figure 96). The conditional mean is forecast to rise to $89/MWh in 2030, and then to $123/MWh in 2050.

Similar to Figure 95, the range of potential wholesale electricity prices is dependent on the degree of mean-reversion and the conditional standard deviation; all else being equal, a higher degree of mean-reversion implies a lower range, while a higher conditional standard deviation implies a higher range, all else equal.

Table 23 shows the conditional mean and range of levelised costs, for each of the twenty generation technologies, for two years: 2025 and 2050. For most technologies, both renewable and non-renewable, expected levelised costs’ decline over time; in terms of non-renewables, only the two combined cycle natural gas technologies have an increase in expected levelised costs between 2025 and 2050. In terms of renewables, levelised costs are forecast to not decline only for the two geothermal technologies, between 2025 and 2050.

Of the selected non-renewable technologies in Table 23, nuclear is forecast to have the lowest levelised costs, of $79/MWh and $83/MWh in 2025 and 2050, respectively; of the renewable technologies, onshore wind has the lowest expected levelised cost ($88/MWh and $73/MWh in 2025 and 2050, respectively).
### Table 23: Forecasts and ranges for levelised costs of electricity generation; selected years

<table>
<thead>
<tr>
<th>Technology</th>
<th>Year 2025</th>
<th></th>
<th>Year 2050</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Min</td>
<td>Mean</td>
<td>Max</td>
<td>Min</td>
</tr>
<tr>
<td>Pulverised brown coal supercritical plant</td>
<td>99</td>
<td>114</td>
<td>125</td>
<td>95</td>
</tr>
<tr>
<td>Integrated gasification combined cycle (IGCC) plant based on brown coal</td>
<td>111</td>
<td>127</td>
<td>140</td>
<td>112</td>
</tr>
<tr>
<td>IGCC brown coal plant with carbon capture and storage (CCS)</td>
<td>149</td>
<td>172</td>
<td>189</td>
<td>149</td>
</tr>
<tr>
<td>Pulverised bituminous coal supercritical plant</td>
<td>99</td>
<td>113</td>
<td>125</td>
<td>94</td>
</tr>
<tr>
<td>IGCC bituminous coal plant</td>
<td>118</td>
<td>136</td>
<td>150</td>
<td>117</td>
</tr>
<tr>
<td>IGCC bituminous coal plant with CCS</td>
<td>144</td>
<td>165</td>
<td>182</td>
<td>138</td>
</tr>
<tr>
<td>Combined cycle natural gas plant</td>
<td>154</td>
<td>177</td>
<td>199</td>
<td>164</td>
</tr>
<tr>
<td>Combined cycle natural gas plant with CCS</td>
<td>208</td>
<td>239</td>
<td>268</td>
<td>218</td>
</tr>
<tr>
<td>Natural gas co-generation (heat and electricity)</td>
<td>256</td>
<td>295</td>
<td>324</td>
<td>255</td>
</tr>
<tr>
<td>Nuclear (Small Modular Reactor)</td>
<td>69</td>
<td>79</td>
<td>87</td>
<td>72</td>
</tr>
<tr>
<td>Sugar cane waste power plant (‘biomass’)</td>
<td>134</td>
<td>155</td>
<td>170</td>
<td>121</td>
</tr>
<tr>
<td>Solar thermal plant with storage</td>
<td>152</td>
<td>175</td>
<td>144</td>
<td>99</td>
</tr>
<tr>
<td>Solar PV - Single axis tracking</td>
<td>132</td>
<td>152</td>
<td>92</td>
<td>79</td>
</tr>
<tr>
<td>Wind onshore</td>
<td>77</td>
<td>88</td>
<td>88</td>
<td>63</td>
</tr>
<tr>
<td>Geothermal - engineered geothermal system (EGS)</td>
<td>86</td>
<td>99</td>
<td>109</td>
<td>88</td>
</tr>
<tr>
<td>Geothermal - hot sedimentary aquifer (HSA)</td>
<td>89</td>
<td>102</td>
<td>112</td>
<td>88</td>
</tr>
<tr>
<td>Hydropower</td>
<td>146</td>
<td>168</td>
<td>184</td>
<td>129</td>
</tr>
<tr>
<td>Wave</td>
<td>124</td>
<td>142</td>
<td>156</td>
<td>87</td>
</tr>
<tr>
<td>Tidal</td>
<td>115</td>
<td>132</td>
<td>146</td>
<td>93</td>
</tr>
</tbody>
</table>

Note: these costs are slightly higher than that modelled in ESM reflecting the fact that these represent amortised costs for a fixed pay-back period. However, in ESM, plant will have a useful life that is longer than the amortisation period (and in reality plant may be refinanced several times) which tends to reduce the long run marginal costs of generation in the model.

### Results

Applying the above framework, forecasts and uncertainty ranges to twenty different generation technologies\(^\text{15}\) leads to the following findings:

- Given the forecasts of carbon and electricity prices, and levelised costs of electricity, options on each of the fossil-fuelled technologies are not expected to be profitable at any time between 2013 and 2050 (the investment horizon under consideration);
- Nuclear and all renewable technologies have positive option values, with onshore wind and nuclear having the highest option values ($44.5/MWh and $42/MWh, respectively). Furthermore, for all

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\(^{15}\) The complete list is in Appendix F: Real-options model description.
these technologies, optimal exercise occurs during the decade spanning the mid-2020s and mid-2030s; the technologies for which options are exercised earliest are onshore wind (2026), solar PV (2027), and geothermal-EGS (2028).

The results are summarised in Table 24.

Table 24: Profitability of alternative electricity generation technologies

<table>
<thead>
<tr>
<th>Technology</th>
<th>Option value ($/MWh)</th>
<th>Optimal exercise year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind onshore</td>
<td>44.5</td>
<td>2026</td>
</tr>
<tr>
<td>Nuclear (Small Modular Reactor)</td>
<td>42.0</td>
<td>2036</td>
</tr>
<tr>
<td>Solar PV - Single axis tracking</td>
<td>12.0</td>
<td>2027</td>
</tr>
<tr>
<td>Wave</td>
<td>6.7</td>
<td>2033</td>
</tr>
<tr>
<td>Geothermal - engineered geothermal system (EGS)</td>
<td>6.4</td>
<td>2028</td>
</tr>
<tr>
<td>Tidal</td>
<td>5.1</td>
<td>2035</td>
</tr>
<tr>
<td>Geothermal - hot sedimentary aquifer (HSA)</td>
<td>4.6</td>
<td>2030</td>
</tr>
<tr>
<td>Sugar cane waste power plant ('biomass')</td>
<td>1.7</td>
<td>2030</td>
</tr>
<tr>
<td>Hydropower</td>
<td>1.0</td>
<td>2035</td>
</tr>
<tr>
<td>Solar thermal plant with storage</td>
<td>0.9</td>
<td>2033</td>
</tr>
</tbody>
</table>

5.7.2 ESM PROJECTIONS

Generation

The limited generation technology choices and timings from the real option modelling were imposed on ESM with four exceptions. The first is to ensure that there is always sufficient capacity we allow ESM to invest in gas peaking plant at any time. Being the lowest capital cost technology we expect that investment in gas peaking plant would take place to meet demand if delays in investment in other technologies meant there was a risk of a shortfall in supply.

The second exception is that no particular constraints were placed on investment in on-site generation since the impact of uncertainty and investment on on-site generation was not explored in the real options analysis (we offer an alternative to this assumption below).

The third is that nuclear was excluded on the basis that it is prohibited under current legislation (however, we explore a dedicated sensitivity case on this separately).

Finally, we allow investment in wind before the optimal exercise year to meet the Renewable Energy Target. However, in reality there is some risk that wind projects are delayed.

Figure 97 shows the projected electricity generation technology mix in ESM. The technology mix reflects the constraints just discussed – all new capacity is either renewable (based on the real options analysis), gas peaking or on-site generation. Reflecting trends we have seen in Scenario 1: Set and forget wind, large-scale solar photovoltaic plant and rooftop solar photovoltaic panels are the most competitive renewable electricity generation technologies.
Figure 97: Projected central and on-site electricity generation by technology in Scenario 1 sensitivity: uncertain carbon price

Figure 98: Projected on-site electricity generation by technology in Scenario 1 sensitivity: uncertain carbon price
Figure 98 presents further detail on the technologies adopted in the projected increase in on-site generation. It shows that gas co- or tri-generation is a substantial source of new on-site generation from around 2030. Given that gas combined cycle generation was not expected to be profitable in the large scale sector this raises the question whether this investment is consistent with this sensitivity case. On the other hand, the adoption of on-site generation is driven by different uncertainties. It is likely, given the increasing network unit costs we have observed in Scenarios 1-4, that the retail price signal will be different to the wholesale price signal under carbon price uncertainty. Stronger increase in retail prices could mean that on-site base load gas plant investment proceeds even where large scale base load gas plant does not.

To explore the alternative, Figure 99 and Figure 100 present the projected electricity generation technology mix if no new investment in fossil (gas and diesel) fuelled on-site generation is allowed after 2030. In this case, there is an increase in renewable on-site generation such as rooftop solar photovoltaic panels but overall on-site generation is substantially reduced. Consequently there is a need for significantly more centralised electricity generation.

ESM projects that additional capacity will be sourced from onshore wind and solar but also additional renewable electricity generation technologies such as wave, offshore wind and hot fractured rocks between 2035 and 2040.

Figure 99: Projected central and on-site electricity generation by technology in Scenario 1 sensitivity: uncertain carbon price including limits on fossil on-site generation
Figure 100: Projected on-site electricity generation by technology in Scenario 1 sensitivity: uncertain carbon price including limits on fossil on-site generation

Wholesale unit costs

Figure 101 compares the projected wholesale electricity unit costs for Scenario 1 and two versions of the Scenario 1 sensitivity: uncertain carbon price with and without a constraint on fossil (gas and diesel) on-site generation. In the two sensitivity case versions, we have assumed that a carbon price signal of some sort consistent with Scenario 1 stays in place until 2020 and so wholesale unit costs track Scenario 1 to that point. After 2020, there is no carbon price signal in the sensitivity cases – increasing unit costs simply reflect the technology choices and the unit costs required to make those investments economically viable.

In both versions of sensitivity case, the wholesale unit cost drops away after 2020 since there is excess generation capacity immediately following the end of the Renewable Energy Target which has expanded supply capacity by 41 TWh to that point. However, it is only around 3 years before new capacity is needed and the wholesale unit costs must increase to support the profitability of that new capacity. Under the two sensitivity case versions the wholesale unit costs increases until it is above the Scenario 1 unit cost price path – the cross-over point differs between the sensitivity case versions by 15 years.

The reason that wholesale unit costs must eventually increase above that of Scenario 1 is because, in general, any limitation on the choice of technology has the potential to increase costs. If the carbon price were more certain, Scenario 1 indicates investors would prefer to take up combined cycle gas generation. Alternatively the zero carbon price sensitivity indicates they might also like to take up coal-fired electricity generation. However, those technologies have a reduced expected profit under carbon price uncertainty and therefore are not taken up in our uncertain carbon price sensitivity case. In their place are higher cost technologies forcing the wholesale unit costs to be higher than Scenario 1 (or the zero carbon price sensitivity).

The “on-site-generation constrained” version of the sensitivity case, wholesale unit costs increase and rise above Scenario 1 more quickly because the technology mix is even more constrained. Lower cost co-/tri-generation is replaced with higher cost centralised electricity generation technologies.
Figure 101: Projected average wholesale electricity unit cost in Scenario 1, Scenario 1 sensitivity: uncertain carbon price and Scenario 1 sensitivity: uncertain carbon price with constrained on-site generation

For the purposes of delivering a consolidated modelling result, we combine the results of the two versions of this sensitivity case in Figure 102. Since the real options modelling was not conducted for on-site generation and there are equally plausible arguments for whether fossil fuel investment would be less or equally constrained in the on-site generation sector as the centralised generation sector, a simple average over the two price paths are applied to calculate this result.
Figure 102: Projected average wholesale electricity unit cost in Scenario 1 and Scenario 1 sensitivity: uncertain carbon price (consolidated modelling result)

**Greenhouse gas emissions**

The greatest impact of any carbon price scheme is in the way it impacts future investment choices. It should therefore be perhaps no surprise that Figure 103 shows that carbon price uncertainty is equally effective at reducing emissions as an actual carbon price (to be clear, no carbon price is implemented in this scenario beyond 2020). As discussed earlier in the real options modelling, carbon price uncertainty reduces the expected profitability of fossil (gas, coal, petroleum) fuelled plant such that they are no longer viable investment choices. With only low emission technologies offering expected profits and given electricity consumption must be met, low emission technologies are deployed and as existing coal- and gas-fired technologies retire, greenhouse gas emissions are significantly reduced.
Important caveats on modelling carbon price uncertainty

There are several important caveats on this analysis. The analysis is only valid in the case that investors face the carbon price uncertainty, electricity price uncertainty and technology costs applied in the real options modelling. The future view of the carbon price uncertainty range is always changing depending on domestic and global government policy and public support for addressing the risk of climate change through greenhouse gas emissions reduction. The uncertainty ranges might therefore change – although the analysis can be easily updated in that case.

These parameters could also change in ways that cannot be easily predicted or incorporated into this analysis. For example, this analysis assumes all new investment is from the private sector, however, governments could intervene in various ways to ensure certain types of plant are built. Secondly alternative carbon pricing mechanisms might provide different signals to different investors and that might also change some investment choices.

Finally, our own experience here indicates that the analysis should ideally be expanded to include impacts of carbon price uncertainty on on-site generation.

5.8 Scenario 1 sensitivity case: High gas price

In this sensitivity case Scenario 1 is modelled using the high gas price path outlined in the modelling assumptions. The modelling results for generation technology mix, greenhouse gas emissions and wholesale unit prices are sourced from ESM.
5.8.1 ESM PROJECTIONS

Generation

Scenario 1: Set and Forget included a significant amount of combined cycle natural generation in the technology mix. Under a high gas price we would expect to see that significantly reduced. Figure 104 shows that is the case. Under a high gas price we do not observe a significant expansion of gas combined cycle electricity generation plant. Instead, ESM projects a stronger continuing role for coal-fired electricity generation, including both conventional and more advanced technologies such as direct injection coal engines and carbon capture and storage.

There are two aspects to this outcome. The first is that a high gas price makes gas fired electricity plant more expensive. However, the second aspect is that a high gas price makes it more costly to support variable renewable electricity generation. As we have seen throughout the scenarios the two most preferred renewable electricity generation plant are wind and solar photovoltaics which both have variable generation output. Accordingly, high gas prices increase both the cost of gas fired plant and some renewable plant (when you take into account the cost of backing-up their variable output). A major caveat on this analysis is that we do not fully explore in this sensitivity the full range of options for backing up variable renewables. Demand management is targeted at minimising peak demand and only partially supporting renewables, and we do not include storage at all (there were explored in Scenario 4). Therefore, this result should not be considered the only possible outcome of high gas prices.

High gas prices also reduce the uptake of gas fired on-site generation technologies. Non-solar on-site generation is declining over time.

Figure 104: Projected central and on-site electricity generation by technology in Scenario 1 sensitivity: high gas price

Wholesale unit costs

Figure 105 compares average wholesale electricity unit costs for Scenario 1 and the high gas price sensitivity. It indicates that wholesale unit prices will be higher under a high carbon price. This reflects the
assumption that the cost of non-gas consuming technologies which ESM chooses to switch to are higher than that of gas combined cycle plant. By 2050 the difference in average unit costs is $11/MWh.

Figure 105: Projected greenhouse gas emissions in Scenario 1 and Scenario 1 sensitivity: high gas price

**Greenhouse gas emissions**

The projected greenhouse gas emissions for Scenario 1 and the high gas price sensitivity case are compared in Figure 106. It indicates that greenhouse gas emissions under a high gas price are higher. This reflects the projected generation mix having a stronger contribution of coal and less renewable. Although some of the coal-fired generation includes capture and storage which can be very low emission and high efficiency direct injection coal engines, this is not large enough to offset the stronger contribution of conventional coal-fired generation and reduced renewable generation.

By 2050, electricity sector greenhouse gas emissions are 40 percent below 2000 levels in the high gas price sensitivity case.
In this sensitivity case we model Scenario 1 with nuclear power included as an allowable electricity generation technology. In all other modelling we enforce the existing Australian government policy which is to prohibit its use. This sensitivity case is included to acknowledge that whilst existing government policy prohibits its use attitudes may change in the future that result in a policy change\textsuperscript{16}. It is important to note that the costs of nuclear power do not including decommissioning as they were sourced from BREE (2012) which does not included that element. However, it is not expected inclusion of decommissioning costs would change the results significantly. Although decommissioning costs may be considerable in the future, the necessary discounting of those costs (at least 50 years into the future at the end of plant design life\textsuperscript{17}) to the present day would render them a small component of operating costs. The decommissioning costs of other technologies have also not been included in any of the modelling.

A key assumption is that nuclear power cannot be immediately implemented. We include a considerable delay before the first nuclear plant could be built to recognise the significant ramping up in skills, regulation and construction that would be necessary. The earliest allowable date for nuclear electricity generation is 2025.

No specific assumptions have been made about additional transmission costs. The analysis has not considered possible sites in any depth.

The results for this sensitivity case were sourced from ESM.

\textsuperscript{16} This is not to say there is currently any evidence that attitudes are changing.

\textsuperscript{17} And possibly further into the future if a new or refurbished plant is built on the same site.
5.9.1 ESM PROJECTIONS

Generation

Figure 107 show the projected electricity generation technology mix for Scenario 1 with nuclear electricity generation plant allowed. The first nuclear plant commences generation from 2025 and dominates new investment in electricity generation. The dominance of nuclear power reflects the fact that BREE (2012) estimates its future costs to be the lowest by 2050. The costs are so low that it is preferable to not use some existing black and brown coal fired power than the generate from those plant at short run marginal cost (inclusive of pay for carbon costs under the prevailing carbon price).

In addition to nuclear plant there are some new investments in on-site generation, mainly limited to rooftop solar photovoltaics, as well as large scale solar photovoltaics, and peaking technologies such as open cycle gas turbines and direct injection coal engines.

![Figure 107: Projected central and on-site electricity generation by technology in Scenario 1 sensitivity: nuclear](image)

Wholesale unit costs

A comparison of the average wholesale electricity unit costs for Scenario 1 with and without nuclear plant is shown in Figure 108. It indicates that from the time nuclear plant are built wholesale unit costs are lower in this sensitivity case, reflecting the assumed lower cost of nuclear technology. By 2050, the wholesale unit costs of electricity is $35/MWh lower with nuclear.
Greenhouse gas emissions

Figure 109 compares the projected greenhouse gas emissions for Scenario 1 with and without nuclear power. Given that nuclear power has no direct greenhouse gas emissions associated with its production of electricity and under the sensitivity it occupies a large share of electricity generation we would expect this sensitivity to have a low emission profile. Figure 109 shows that is the case with emission falling more rapidly from 2025 when the nuclear electricity generation commences.

By 2050, electricity sector greenhouse gas emissions are 87 percent below 2000 levels in the nuclear sensitivity case.
5.10 Scenario 1 sensitivity case: Demand response counterfactual

A counterfactual sensitivity case tells us what would have happened if we had not done something. In this case we wish to calculate what would have been the impact if we had not implemented the peak demand management measures that we implemented in Scenario 1 (and also Scenarios 2 and 4). Accordingly this sensitivity case is identical to Scenario 1 except that it has higher peak demand.

We model this scenario using both ESM and DiSCoM.

5.10.1 ESM PROJECTIONS

For brevity we do not present the ESM modelling results in detail. There is little visible difference in the ESM projections for generation, wholesale unit costs and greenhouse gas emissions under the demand response counterfactual compared to Scenario 1. The main reason for this is that the cost of servicing peak demand with electricity generation has been assumed to be largely independent of the scale of peak demand. The price of fuels (particularly gas) and various technologies which provide flexible supply to meet peaks do not change with the scale of peak demand – the marginal cost of peak generation is fairly constant with scale. Within ESM we might still expect some differences in the utilisation of peaking plant – it might decline or improve as the number of peak hours expands depending on how well they are utilised in Scenario 1. We might also expect a higher use of peaking plant to increase the average cost of electricity.

Another reason that additional peak demand may not have a significant impact on generation is because some peaking generation capacity is required to support variable renewable output. Therefore, peak demand is not necessarily the main drive of the need for flexible generation once renewable increase their contribution to electricity generation.
Other models with a greater temporal and spatial disaggregation may be able to find stronger price impacts if peaks coincide with constrained networks or if there is some non-linearity around the bidding strategies that can be deployed when peak demand is higher. Modelling which includes a wider variety of methods for supporting renewable variability might also provide different results.

Accepting the limitations of ESM on this question, average wholesale electricity unit costs are projected to be $3/MWh higher by 2050 under the demand response counterfactual. Greenhouse gas emissions are projected to be 7 MtCO$_2$e higher by 2050 in the demand response counterfactual reflecting that some plants deployed to meet peak demand are less fuel efficient.

### 5.10.2 DISCOM PROJECTIONS

#### Aggregate load factor

The projected aggregate load factors of the network for Scenario 1 and the Scenario 1 demand response counterfactual to 2050 is presented in Figure 110. Given that the peak demand management measures implemented in Scenario 1 commence from 2015 the counterfactual which does not include these measure commences with a lower load factor than Scenario 1. The difference in the load factor continues to widen as the full impact of the peak demand measures is deployed in Scenario 1 over the next decade and then stabilises thereafter at a consistent difference in load factor of 15 percentage points to 2050.

![Figure 110: Projected change in aggregate load factor of the network in Scenario 1 and Scenario 1 demand response counterfactual](image)

#### Distribution unit costs

Figure 111 compares the projected distribution unit costs between Scenario 1 and the Scenario 1 demand response counterfactual. These are the costs for residential customers if they were evenly apportioned.
across residential customers by volume of electricity consumed (alternative arrangements for distributing these costs to customers may be occur in reality).

The projections reflect that due to a declining aggregate load factor the costs of a larger network must be shared over lower consumption in the demand response counterfactual. Consequently, projected distribution unit costs are increasing faster than under Scenario 1 and maintain a consistently higher level. From around the 2020s and continuing through to 2050, distribution unit costs are 2c/kWh higher under the demand response counterfactual.

![Figure 111: Projected distribution unit costs for residential customers in Scenario 1 and Scenario 1 demand response counterfactual](image)

5.11 Scenario 1 sensitivity case: climate impacts adaptation

The electricity sector is especially vulnerable to climate change because the climate impacts nearly every aspect of the electricity systems operation. If there is a significant change in the climate due to increased concentration of greenhouse gas in the atmosphere then the various parts of the electricity system may be subject to higher costs of procurement, reinforcement and redundancy to adapt to those changes. To fully estimate these impacts would be an enormous task which is beyond the scope of this report. However, what we aim to do is at least provide a preliminary indication of the scale of costs that the sector might be subject to.

Our aim is to do this as simply as possible, applying the models and approaches already used in other scenarios and sensitivity cases. We do not seek to choose a specific climate change scenario nor cover all possible climate impact adaptations that might occur. Instead, we focus on the potential for higher peak demand under climate change. Increased frequency of periods of higher than average temperature would be expected to increase peak demand in the electricity system. If investors knew that there was an increased risk of higher peak demand events then they would need to build more generation and network
capacity. This is the sensitivity case that we explore in order to provide a simple proxy for the cost of climate impacts adaptation.

The key assumption to implement this sensitivity case is that we assume the electricity system must be built to meet POE10 projected peak demand (AEMO 2013a) instead of the POE50 peak demand that was assumed as the underlying trend in peak demand for Scenario 1. The POE10 projection is phased in gradually to 2050. The sensitivity assumes no peak demand response – although that would be a plausible adaptation – the risk of higher peaks is met by a building more capacity.

Given peak demand changes did not significantly impact ESM modelling results in the demand response counterfactual sensitivity case, only DiSCoM projections are presented for the climate impacts adaption sensitivity.

### A.1.1 DISSCOM PROJECTIONS

**Aggregate load factor**

A comparison of the aggregate network load factor in Scenario 1 and the Scenario 1 sensitivity: climate change adaptation is provided in Figure 112. It indicates that if we expect peak demand growth to be higher due to climate change than we can also expect the network aggregate load factor to decline faster. By 2050, the aggregate load factor is projected to decline by 20 percentage points relative to Scenario 1, at 40 percent.

![Figure 112: Projected change in aggregate load factor of the distribution network in Scenario 1 and Scenario 1 sensitivity: climate impact adaptation](image)

**Distribution unit costs**

Figure 113 compares the projected distribution unit costs between Scenario 1 and the Scenario 1 sensitivity: climate impacts adaptation. These are the costs for residential customers if they were evenly apportioned across residential customers by volume of electricity consumed (alternative arrangements for distributing these costs to customers may be occur in reality).
The projections reflect that due to a declining aggregate load factor the costs of a larger network must be shared over the same consumption levels as Scenario 1. Consequently projected distribution unit costs are increasing faster than under Scenario 1 and maintain a consistently higher level. On average, through the period 2025 to 2050, distribution unit costs are 2.8c/kWh higher under the climate impacts adaptation sensitivity.

Figure 113: Projected distribution unit costs for residential customers in Scenario 1 and Scenario 1 sensitivity: climate impact adaptation
6 Consolidated modelling results and scenario comparisons

6.1 Consolidating results from multiple models

The package of models employed in this study sometimes offer overlapping and conflicting views on some outputs. This reflects their different scope, temporal and spatial aggregation and mathematical solution procedure. This short section provides a guide to how these inconsistencies were handled in order to provide the Future Grid Forum with a single robust result (where required).

6.1.1 GENERATION MIX

ESM, TNEP and 2-4-C consistency

TNEP is constrained for most centralised generation technologies to have the total delivered energy that is at least 80% of that for the ESM solution, and up to 150% of the ESM solution, in each state. The same lower and upper percentage limits are also applied for installed capacity, except that for centralized gas plant, the lower installed capacity limit is 60% of the ESM solution and the constraints are applied over all CG gas plant, not each individual technology (on account of Gas OCGT potentially being usable at a higher capacity factor than what is assumed in ESM, and replacement (in TNEP and 2-4-C models) of some Gas OCGT by Gas CCGT being cost-favourable). Notwithstanding these limits, any renewable centralised generation technology may be used by TNEP to deliver at least 2 TWh per year (this is allowed to help manage variability), and any centralised generation technology can deliver up to 1 TWh if ESM states that at least some energy is supplied. For on-site generation, TNEP adheres to the ESM solution’s installed capacity. Further rules are applied to ensure that a set of limits do not rule out a feasible solution for TNEP.

Due to these constraints, TNEP and ESM solutions are not significantly different. The most interesting and significant differences between the ESM solution provided to TNEP and the TNEP solution was observed for Scenario 4, where:

- TNEP selects less onshore wind in the early 2040s, but 60% more than ESM in the late 2050s. The additional wind power installations presumably help deal with supply variability.
- TNEP selects 40% more wave generation compared to ESM in the period 2040-2050.
- TNEP selects on-average 20% more geothermal generation compared to ESM, but 30% less solar generation resources.

We speculate that these differences are driven by the greater temporal detail in TNEP, and in particular by the use of the “stress” load blocks.

A major 2-4-C difference was that coal was unprofitable in the long run indicating that some coal fired power in the ESM solution may need to close sooner than projected. It also indicated that more solar photovoltaic electricity generation capacity was appropriate in Scenario 4. Some modifications were made to ESM to re-run Scenario 4 so that it was closer to both the final TNEP and 2-4-C model runs. However, other scenarios were not modified.

The differing generation mixes across the models are ultimately not resolved due to the high cost of iterations achieve that outcome. The differing results should be viewed as indicating some of the uncertainty in the modelling.
6.1.2 WHOLESALE ELECTRICITY PRICES

ESM and 2-4-C projected electricity prices for Scenarios 1 to 4 and 1 to 3 respectively. In the case of ESM these are in fact average electricity generation unit costs based on long run costs of meeting electricity demand, whereas 2-4-C models price outcomes from hourly bidding processes.

ESM and 2-4-C projections were strongly align in Scenario 1 with negligible differences in 2030, 2040 and 2050 which were the snapshot years modelled in 2-4-C. However, projections differed in Scenarios 2 and 3 with 2-4-C projections being generally $14/MWh higher.

To explain this difference in prices between, the major characteristic that makes Scenario 2 and 3 different to Scenario 1 is the flat to declining centralised electricity demand. When electricity demand is flat or falling it is possible that the market will have excess supply capacity. During such periods, which do exist in Scenario 2 and 3, ESM allows that some existing plant (with sunk costs) may have to accept returns that are less than long run marginal costs – closer to but no lower than short run marginal costs. To test whether this scenario feature is driving the difference, we ideally could have investigated this issue further by iterating alternative bidding strategies in 2-4-C and ruling out the lowest profitability options in ESM to converge towards agreement. However, this fell outside of the scope of the study due to the high time cost of such iterations.

For the purposes of the Future Grid Forum analysis we assume the ESM prices prevail as the outcome of the modelling package. This is not say that ESM prices are likely more correct than 2-4-C. Rather it reflects the practical concern that adjusting some ESM scenario prices would make the sensitivity case price comparison more fraught.

It is likely the ‘best’ price estimate lies somewhere between ESM and 2-4-C projections. ESM may over-estimate the willingness of sunk plant to continue operating below long-run marginal cost. 2-4-C’s bidding strategies could possibly shift to a more a more ‘competitive’ mode when a scenario has sustained weak demand.

6.2 Scenario results comparisons

The following figures provide comparisons of key model projections across the scenarios in a single chart.

6.2.1 DEMAND

Scenario 1 and 2 are based on the medium AEMO (2013a) electricity consumption forecast while Scenarios 3 and 4 are based on the low forecast (Figure 114). The AEMO (2013a) forecasts are extrapolated and modified to incorporate the electric vehicle projections in Figure 115. Figure 116 shows the level of centrally supplied electricity consumption by scenario after the on-site generation shown in Figure 117 is adopted.

Figure 118 demonstrates that Scenarios 1, 2 and 4 have assumed a significant amount of demand management is adopted to reduce and slow the rate of growth in peak demand that must be met by the grid. Scenario 3 assumed no peak demand reduction measures. However, peak demand falls later in the projection period as consumers disconnect and take their contribution to peak demand with them.
Figure 114: Assumed level of electricity consumption by scenario based on AEMO (2013a) medium and low forecasts

Figure 115: Projected consumption of electricity by the road transport sector by scenario
Figure 116: Projected level of centrally supplied electricity consumption by scenario

Figure 117: Projected share of on-site generation by scenario
Figure 118: Projected level of centrally met peak demand by scenario

6.2.2 GENERATION

The share of renewable generation in total central and on-site generation across the scenarios is presented in Figure 119. The share of on-site generation was also presented in the previous section. Refer to individual scenario results for further detail.
6.2.3 DISTRIBUTION

The projected distribution unit costs expressed as they might appear in a residential volume based contract are shown in Figure 120 for each scenario and sensitivity cases where DiSCoM was applied. Refer to individual scenario and sensitivity results for discussion of these trends.
The trend in installed capacity over time is different for each zone, and differs between scenarios (Table 25). For all scenarios there is a strong tendency for new centralised generation installation to be close to the major load centres of Sydney and Brisbane, i.e., in NCEN and SEQ. Due to the high penetration of on-site generation in Victoria in some scenarios, the growth in installed generation capacity is not strong in MEL, and over time the installed capacity is not of a comparable magnitude to that in NCEN and SEQ except in the Scenario 1 and Scenario 4.

There is little investment in new generation in CQ and NQ under all of the scenarios. With the decline in fossil fuels over time, CQ generation capacity heads towards minor levels in all scenarios. Only one or two coal and/or gas plants remain in operation in 2050 across the scenarios, and in Scenario 4 these plants are not used. For NQ, being at one end of the NEM could make investments less attractive due to the potential need to augment more transmission compared to developments in SWQ, NSW and Victoria. Nevertheless, except in Scenario 3, NQ does see modest growth in installed capacity, consistently to around 2 GW. In addition to the existing Hydro-electric plant, by 2050 in Scenario 4 we see Geothermal HSA (900 MW) and Onshore Wind (1200 MW), in the Engaged scenario there is Gas OCGT and CCGT (1200 MW), Large-Scale PV (350 MW) and Onshore Wind (250 MW), and in Scenario 1 the gas share is higher (1450 MW), no wind is installed, and 450 MW of Large-Scale PV is installed. In Scenario 3, only 1000 MW of Gas OCGT and CCGT are installed alongside the existing Hydro plant.

The projections for Tasmania are relatively consistent across the scenarios, with the existing Hydro plant being supplemented by between 500 MW and 1200 MW of wind power by 2050 (with this generation mix often being present in full by 2030). Somewhat surprisingly given the proposed investment in Transmission between Victoria and Tasmania, it is in the Scenario 4 that the installation of wind in Tasmania is at its lowest value (just over 500 MW in 2040-2050). Considering the TNEP results in isolation, this suggests that Tasmanian hydro-electric generators are being relied upon for meeting peak demand on the mainland under Scenario 4. (In other scenarios, Gas OCGT is favoured as peaking plant.)
In South Australia, SESA and NSA are generally projected by TNEP to decline in importance as generation centres in 2035-2050, whereas ADE increases in importance. This is not in keeping with current trends and activity, and different assumptions about renewal/re-powering of wind power could lead to different outcomes. For transmission of electricity originating in South Australia, the ADE-CVIC interconnector augmentation is favoured by TNEP in Scenarios 1 and 2, possibly because this saves building two interconnectors SESA-MEL-CVIC to give increased transmission access to NSW and Qld.

In general, because TNEP does not consider the social and environmental aspects of migrating wind power from one region to another, from a minimum total system cost standpoint the benefits of being close-to-load appear to outweigh the savings from re-powering (compared to building on new sites: in the modelling, re-powering is achieved at 70% of new-build cost). In practice, the SA wind power fleet might not migrate towards ADE, but rather some alternative transmission augmentation might occur. It can also be noted that the share of wind in the overall NEM generation mix either stagnates or declines from around 2030 (because relative technology costs change, and on-site generation adoption accelerates). The retirement of life-expired wind plant can be centred on SA zones simply as a result of turbine age at the time that these NEM-wide trends occur.

In Victoria, the general trends across the scenarios are:

- NVIC and CVIC total generation capacity (Hydro and Onshore Wind) is relatively stable over time;
- Existing brown coal plants give way to Gas OCGT and CCGT in the Latrobe Valley (e.g., 1550 MW is present in 2040 in Scenario 2), except for Scenario 4 where all fossil-fuelled plant is phased out, and 225 MW of offshore wind is installed instead.
- Some significant installations of DICE plant occur in LV (Engaged: 850 MW in 2040 and 1350 MW in 2050; Reference: 850 MW to 950 MW over late 2020s through to 2050; Disconnected: 100 MW until late 2040s)
- Gas-fuelled on-site generation is influential in MEL for scenarios other than Scenario 4, and in Scenario 2 in particular (e.g., over 6.2 GW in 2050). This curtails some of the need for centralized generation investment in Victoria.

Table 25: Projected transmission augmentation across the scenarios

<table>
<thead>
<tr>
<th>Scenario</th>
<th>NEM Interconnector</th>
<th>Augment by Year</th>
<th>Nominal Capacity (fwd / bwd)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>CVIC-ADE</td>
<td>2045</td>
<td>1000 MW</td>
</tr>
<tr>
<td>2</td>
<td>CVIC-ADE</td>
<td>2025</td>
<td>500 MW</td>
</tr>
<tr>
<td>2</td>
<td>CVIC-ADE</td>
<td>2050</td>
<td>1000 MW</td>
</tr>
<tr>
<td>3</td>
<td>SWNSW-NCEN</td>
<td>2035</td>
<td>500 MW</td>
</tr>
<tr>
<td>4</td>
<td>CVIC-SWNSSW</td>
<td>2040</td>
<td>1000 MW</td>
</tr>
<tr>
<td>4</td>
<td>CVIC-SWNSSW</td>
<td>2045</td>
<td>1250 MW</td>
</tr>
<tr>
<td>4</td>
<td>NCEN-NNS</td>
<td>2040</td>
<td>1500 MW</td>
</tr>
<tr>
<td>4</td>
<td>NNS-SWQ</td>
<td>2040</td>
<td>1390 MW / 2100 MW</td>
</tr>
<tr>
<td>4</td>
<td>SESA-MEL</td>
<td>2040</td>
<td>750 MW</td>
</tr>
<tr>
<td>4</td>
<td>SWNSW-NCEN</td>
<td>2040</td>
<td>2000 MW</td>
</tr>
<tr>
<td>4</td>
<td>SWNSW-NCEN</td>
<td>2045</td>
<td>2500 MW</td>
</tr>
<tr>
<td>4</td>
<td>SWNSW-NCEN</td>
<td>2050</td>
<td>3000 MW</td>
</tr>
<tr>
<td>4</td>
<td>TAS-LV</td>
<td>2040</td>
<td>469 MW / 594 MW</td>
</tr>
<tr>
<td>4</td>
<td>TAS-MEL</td>
<td>2040</td>
<td>600 MW</td>
</tr>
</tbody>
</table>
6.2.5  WHOLESALE UNIT COSTS

Figure 121 shows the full range of average wholesale unit prices by scenario and sensitivity case. As each price path is explained in the body of this report, we do not describe them further here.

![Comparison of projected average wholesale electricity unit costs by scenario and sensitivity case](image)

6.2.6  GREENHOUSE GAS EMISSIONS

Figure 122 shows the projected greenhouse gas emissions across the scenarios and sensitivity cases. As each emission pathway is explained in the body of the report, we do not describe them further here.
Another way of expressing greenhouse gas emission outcomes is their level of achieved reduction below 2000 levels which were 176 MtCO₂e for the electricity generation sector. If we combine this with projected wholesale unit costs we can plot the costs of achieving different levels of abatement across the scenarios. Figure 123 shows that there is generally a rising wholesale unit cost for a higher level of abatement. However it also shows some examples where the same level of abatement might be reached at different costs (Scenario 4 and Scenario 1 with a high carbon price) or different levels of abatement might be reached at the same wholesale unit cost (Scenario 2 and Scenario 3). Clearly different assumptions are driving these outcomes.
Figure 123: Wholesale unit cost and projected greenhouse gas abatement relative to 2000 levels by scenario or alternative carbon price scenario (the abatement and unit costs at 2013 is shown for comparison)
7 Whole of system costs and customer impacts

7.1 Whole of system costs

The modelling package deployed provides the opportunity to sum up the whole of system costs from generation through to distribution. We can express system costs in two ways: as unit costs of retail supply; or, as total system expenditure.

Retail unit costs

To develop a residential retail unit cost measure the generation component (inclusive of carbon and Renewable Energy Target costs) was directly sourced from ESM (adding a cost of hedging based on current observed differences in wholesale prices and wholesale costs to retailers) and the distribution network component from DISCoM. Retail margins are assumed to remain unchanged from their current average levels estimated by AEMC (2013). The transmission component was partially based on TNEP output and an extrapolation of average AEMC (2013) costs based on projected changes in average load factor (i.e. unit transmission costs increase if the load factor is declining). Despite these assumptions the modelled retail unit costs will still not align with regulated retail prices. This is mainly due to the treatment of wholesale prices. Some regulatory models require the wholesale component to take into account the current cost of replacement of generation assets. However, the wholesale market can experience extended periods, such as now, when the average wholesale price is below the cost of replacement. The methodology here uses projected wholesale prices rather than costs of replacement.

The projected change in residential retail unit costs is shown in Figure 124. Up until the 2040s Scenarios 1 to 3 are fairly close. This is because the scenarios with higher distribution and transmission costs (Scenarios 2 and 3) due to weak demand for centrally supplied electricity tend to also have lower generation costs for the same reason. The outcome for Scenario 4 from 2030 onwards is dominated by higher generation costs. The 2050 outcomes for Scenarios 2 and 3 are dominated by high distribution and transmission costs. Although experiencing higher generation costs than Scenarios 2 and 3, the low distribution and transmission costs of Scenario 1 make it the lower residential retail price by 2050.
System expenditure

The retail unit cost does not take account of the scale of the system nor any end-user off-grid costs. The total level of system expenditure can alternatively be expressed as the total level of system expenditure. Expenditure includes investment, fuel expenses and operating and maintenance expenses and in Figure 125 by sub-sector and scenario.

Viewed from the perspective of system expenditure the ranking of the scenarios in terms of whole of system costs changes compared to retail unit costs. Scenario 3 is high cost reflecting the duplication of resources that occurs when consumers disconnect. Scenario 4 is not high cost from an expenditure perspective because it has lower electricity consumption. However, Scenario 1 remains lowest cost from both a unit cost an expenditure perspective.
7.2 Customer impact modelling results

Customer impact depends on both the unit cost and the volume of electricity consumed net of any exports from on-site generation. It also depends on changes in consumer’s income.

7.2.1 RESIDENTIAL

Projected changes in residential electricity bills in 2030 and 2050 are shown in Figure 126 relative to 2013 electricity bills. The electricity bill is calculated for a single customer with the national average level of consumption for three choices about their electricity supply: retail only, retail with rooftop solar panels and disconnection. It is assumed on-site generation, if connected, is sold back to the electricity grid at a price consistent with the retail unit cost minus retail and distribution cost components (and this reduces annual electricity costs). Scenarios 3 and 4 include their existing assumption of 0.7 percent per annum lower electricity consumption per household, while Scenarios 1 and 2 have a slower 0.3 percent per annum improvement over the current average rate of electricity consumption of 6,000 kWh per annum.
Figure 126: Projected net annual electricity cost (retail bill minus PV export payments plus amortised on-site costs where relevant) under alternative scenarios and household types

The analysis shows that by 2030, the best outcome for the residential consumer is to have a reduced rate of electricity consumption and either contract all of their electricity supply from the grid or adopt solar panels if the retail electricity price is higher, as is the case under Scenario 4. Under Scenarios 3 and 4, there is almost no increase in the household electricity bill compared with today. However, if the residential consumer is unable to achieve a high rate of electricity efficiency improvement (as in Scenarios 1 and 2), the best option for the household is to adopt solar panels because this will result in a modest reduction in costs relative to retail supply only. Note, the difference in owning and not owning connected solar panels is not large in 2030 and would depend on specific feed-in tariffs secured and the profile of household electricity use (as it does now).

By 2050, the projections indicate it is financially preferable for all residential consumers to have some type of on-site generation rather than grid supply only. The lowest cost outcome for grid-connected households with on-site generation occurs under Scenario 1: ‘Set and forget’ followed by Scenario 4: ‘Renewables thrive’; however, if more households choose on-site generation to reduce net electricity bills then the assumptions of these scenarios are violated and consumers shift into the world of Scenario 2: ‘Rise of the prosumer’ where there is much broader uptake of on-site generation and subsequent higher unit retail costs due to lower network utilisation.

If, however, the assumed 75 percent reduction in battery costs by 2050 emerges, then complete disconnection will potentially be a preferable option than remaining connected as in Scenario 3: ‘Leaving the grid’. If, however, those circumstances do not arise then, again, remaining connected with some on-site generation is the preferred outcome. From a big picture point of view, there is a sense that, over time, circumstances will tend to push consumers from Scenario 1/4 into Scenario 2 and finally into the disconnection described in Scenario 3, with the plausibility of this latter step highly dependent on the costs of storage systems relative to any changes in the cost of network connection charges.
Of course, all of the scenarios represent an increase in electricity bills by 2050, but does this mean electricity is a greater share of our household budget? To determine that, the Forum needed to consider whether there were compensating increases in income. The most appropriate projections of future increases in real wages are from the Commonwealth of Australia (2011), which considered how the economy grows under a carbon price. In that analysis, real wages increased by around 37 percent to 2050 under a 550 parts per million consistent carbon price regime.

The current share of the electricity bill in an average wage is 2.5 percent. This share slightly improves (declines) or is maintained by 2030; however, the projected 37 percent increase in real wages from 2013 to 2050 is not enough to offset the increases in electricity bills to 2050 across all scenarios. The future share of the electricity bill in the real wage is projected to be between 2.3 and 2.9 percent depending on the scenario.

![Figure 127: Projected share of electricity bill in the average wage in 2030 and 2030 compared to 2013](image)

For a pensioner, the current share of an electricity bill in the pension payment (assuming average consumption) is 9 percent and this is projected to be between 8 and 10 percent across the scenarios assuming no real increase in pensions (inflation indexation only).

7.2.2 LARGE COMMERCIAL AND INDUSTRIAL

Information on the tariff structures of large commercial and industrial customers is confidential between retailers and customers. However we need to know the structure in order to understand how changes in the different system component costs are likely to impact large commercial and industrial customers. The assumption that was used was that network (distribution and transmission use of system charges) would be based on an average of those reported in SKM MMA (2013). Generation costs were added to retail charges as projected in the modelling and a nominal retail charge scaled to the customer size was also added (given the large volume consumed by these customer groups this is a small component). Standing charges vary
considerably and can be zero for industrial customers depending on the network. Based on these inputs the assumed tariff structure is shown in Figure 128.

Figure 128: Assumed commercial and industrial tariff structures

A representative large commercial customer was assumed to have annual consumption of 525 MWh and peak demand of 100 kW. The equivalent assumptions for an industrial customer were 700,000 MWh annual consumption and 100 MW peak demand.

Applying these consumption profiles and tariff structures results in the equivalent industrial and commercial electricity bill customer impact diagram in Figure 129 to what was calculated for the residential sector. For simplicity, unlike residential it does not include options for on-site generation as there are too many to include and costs for customers of this scale are very site specific. It shows real costs increases to a moderate level in 2030 and higher in 2050. The trends overall and between scenarios reflect the impact of increasing generation costs. Reflecting the tariff structure above, generation contributes a much larger share of the tariff. Accordingly, electricity bill increases are closely in line with increase in generation costs and are highest in Scenario 4 which experiences the largest increase in generation costs.

We are not able to project whether any increases in industry revenue are likely to offset these increasing electricity bills. Analysis of industry income was outside of the scope of this study.
Figure 129: Projected impact on commercial and industrial electricity bills

- **Scenario 1: Set and forget**
  - 0.3% p.a. reduction in electricity intensity of commercial and industrial sector, respectively

- **Scenario 2: Rise of the prosumer**

- **Scenario 3: Leaving the grid**
  - 0.7% p.a. reduction in electricity intensity of commercial and industrial sector, respectively

- **Scenario 4: Renewables thrive**

Index: 2013 electricity costs = 100
8 References


Appendix A: ESM description

This appendix provides summary information about the Energy Sector Model (ESM).

9.1 Structure and theoretical underpinnings

Energy Sector Model (ESM) is solved as a linear program where the objective function to be maximised is welfare, which is calculated as the discounted sum of consumer and producer surplus over time. The sum of consumer and producer surplus is calculated as the integral of the demand functions minus the integral of the supply functions, each of which is disaggregated into many components across the electricity and transport markets. The objective function is maximised subject to constraints that control for the physical limitations of fuel resources, the stock of electricity plant and transport vehicles, greenhouse gas emissions as prescribed by legislation, and various market and technology specific constraints such as the need to maintain a minimum number of peaking plants to meet rapid changes in the electricity load.

9.2 Main components

The main components of ESM include:

- Coverage of all States and the Northern Territory (Australian Capital Territory is modelled as part of New South Wales)
- 22 centralised generation (CG) electricity plant types: black coal pulverised fuel; black coal integrated gasification combined cycle (IGCC); black coal with CO₂ capture and sequestration (CCS) (90 percent capture rate); brown coal pulverised fuel; brown coal IGCC; brown coal direct injection coal engine; brown coal with CCS (90 percent capture rate); natural gas combined cycle; natural gas peaking plant; natural gas with CCS (90 percent capture rate); biomass; hydro; onshore wind; offshore wind; large scale photovoltaic (PV); solar thermal; solar thermal with 6 hours storage; integrated solar and gas; hot fractured rocks (geothermal), wave, ocean current and nuclear
- 17 distributed generation (DG) electricity plant types: internal combustion diesel; gas reciprocating engine; gas turbine; gas micro turbine; gas combined heat and power (CHP); gas micro turbine CHP; gas micro turbine with combined cooling, heat and power (CCHP); gas reciprocating engine CCHP; gas reciprocating engine CHP; solar photovoltaic; bagasse CHP; biomass steam; biogas reciprocating engine; landfill gas reciprocating engine; wind; natural gas fuel cell CHP and hydrogen fuel cell CHP
- Trade in electricity between National Electricity Market (NEM) regions
- Four electricity end use sectors: industrial; commercial & services; rural and residential
- Nine road transport modes: small, medium and large passenger cars; small, medium and large commercial vehicles; rigid trucks; articulated trucks and buses
- Five engine types: internal combustion; hybrid electric/internal combustion; hybrid plug-in electric/internal combustion; fully electric and fuel cell
14 road transport fuels: petrol; diesel; liquefied petroleum gas (LPG); natural gas (compressed (CNG) or liquefied (LNG)); petrol with 10 percent ethanol blend; diesel with 20 percent biodiesel blend; ethanol and biodiesel at high concentrations; biomass to liquids diesel; gas to liquids diesel; coal to liquids diesel with upstream CO₂ capture; shale to liquids diesel with upstream CO₂ capture, hydrogen (from renewables) and electricity

All vehicles and centralised electricity generation plants are assigned a vintage based on when they were first purchased or installed in annual increments; and

Time is represented in annual frequency.

All technologies are assessed on the basis of their relative costs subject to constraints such as the turnover of capital stock, existing or new policies such as subsidies and taxes. The model aims to mirror real world investment decisions by simultaneously taking into account:

- The requirement to earn a reasonable return on investment over the life of a plant or vehicle
- That the actions of one investor or user affects the financial viability of all other investors or users simultaneously and dynamically
- That consumers react to price signals (price elastic demand)
- That the consumption of energy resources by one user affects the price and availability of that resource for other users, and the overall cost of energy and transport services, and
- Energy and transport market policies and regulations.

The model projects uptake on the basis of cost competitiveness but at the same time takes into account constraints on the operation of energy and transport markets, current excise and mandated fuel mix legislation, GHG emission limits, existing plant and vehicle stock in each State, and lead times in the availability of new vehicles or plant. It does not take into account issues such as community acceptance of technologies but these can be controlled by imposing various scenario assumptions which constrain the solution to user provided limits.

9.3 ESM model inputs

ESM requires both economic and biophysical data in order to support the selection of a least cost solution that is within biophysical limits of the technologies and energy resources that are employed. Key economic data include:

- National carbon price or emission limit
- Electricity generation technology cost changes
- Fuel prices to electricity generators
- Road vehicle costs
- Transport fuel prices
- Net excise, charges, registration and insurance fees by state.

Key biophysical data includes:

- Existing stock and age of generators by state
• Road vehicle fuel efficiencies & emission factors by mode
• State resource or technology constraints
• Electricity technology capacity factor and supply constraints
• Transmission losses or premiums
• Air, marine, road and rail transport demand
• State electricity energy consumption and peak demand growth.

Some social considerations include:
• Road vehicle size preferences
• Social constraints on land use
• Number of houses with two vehicles.

9.4  ESM model outputs

For given time paths of the exogenous (or input) variables that define the economic environment, ESM determines the time paths of the endogenous (output) variables. Key output variables include:

• Fuel, engine, and electricity generation technology uptake
• Fuel consumption
• Price of fuels
• GHG and criteria air pollutant emissions
• Wholesale and retail electricity prices, and
• Demand for transport and electricity services.

Some of these outputs can also be defined as fixed inputs depending upon the design of the scenario.

The endogenous variables are determined using demand and production relationships, commodity balance definitions and assumptions of competitive markets at each time step for fuels, electricity and transport services, and over time for assets such as vehicles and plant capacities. With respect to asset markets, the assumption is used that market participants know future outcomes of their joint actions over the entire time horizon of the model.
10 Appendix B: DiSCoM model description

The Distribution System Costing Model (DiSCoM) is designed to be a very high level tool for projecting future changes in the average cost of distribution system. This appendix provides summary information about DiSCoM.

10.1 Mathematical structure and theoretical underpinnings

DiSCoM is solved as a stock turnover model where the existing stock is depreciated through age or damage and investment must take place to both replace old stock and meet any growth in demand. It is similar in this sense to a car fleet where vehicles either break down after a given expected life or they are retired early by a collision (where in both cases repair or additional maintenance is not cost effective according to the owner’s judgement). In the case of distribution infrastructure early retirement of well functioning assets might occur due to weather damage events for example.

The basic equation structure is as follows where $D$ is demand, $K$ is the stock of supply capacity and $I$ is investment over time, $t$, region $r$ and age of assets $a$:

If expected demand is greater than the supply capability of the existing stock as per

Then the required amount of investment is:

Prior to calculating investment for the next period, the stock of existing capital is updated such that assets ready for retirement are removed and assets invested in last period are now aged one period:

Investment for unexpected retirement through damage is added as a constant although in reality it will be highly variable across each year and region. Operating, non-network costs and return on investment are also added before calculating total annual distribution system costs.

Once replacement and augmentation investment are determined, the model calculates the payments to distribution network providers, adding in operating and maintenance costs, non-network expenses (both according to historical levels) and allowable returns on the regulated asset base (RAB) (updating the RAB as the model projects forward in time).

10.2 DiSCoM model inputs

DiSCoM requires data on the physical capacity of the distribution system, the cost of maintaining it and its age distribution:

- Existing stock of assets and average cost of replacement/new build for nine existing de-identified distribution regions. These are supplied by the AER.
- Age distribution of network assets. These were taken from the ESAA historical time series of network investment
• Projections of peak demand and energy consumption. These are dependent upon the scenario

10.3 DiSCoM model outputs

The goal of DiSCoM is to provide a guide to the average change in distribution system costs under different scenarios of the level of peak demand, energy consumption and uptake of distributed generation.

The main outputs of DiSCoM are:

• Investment in supply capacity by MW
• The total level of investment in dollars
• The range of costs per MWh across the nine regions and the average change in costs over time. This can be used to calculate the change in the distribution system’s contribution to future retail prices

In its current form DiSCoM is useful for examining the following issues:

• The need to invest to replace aged infrastructure
• Different rates of investment for different growth in peak demand
• Different revenue needs for different energy volume GWh throughputs
• De-rating of assets due to climate impacts
11 Appendix C: TNEP model description

11.1 Introduction

The Transmission Network Expansion Planning (TNEP) model is part of network optimisation software designed and implemented by CSIRO. The goal in TNEP is to determine an optimal set of energy generation sources and an optimal configuration of the transmission network to support these generation sources.

TNEP can be applied to macro-scale national modelling of the electricity system or to the detailed micro-scale design of transmission and generation in a region. In the macro-scale case, it uses an energy transportation approach, while in the micro-scale case, a DC power flow approximation (i.e., small phase angle) is used. For the Future Grid Forum, the macro-scale model was used.

TNEP is implemented as part of a larger software suite that covers network design and analysis for freight transport, ports, agriculture and electricity. The software suite, known as the Infrastructure Futures Analysis Platform (IFAP), integrates a database system based on SQL Server, a Geographic Information System (GIS) and a scientific computing library developed by CSIRO. In the freight area, IFAP has been used for planning and scenario analysis in several ports and mineral supply chains.

TNEP has been newly developed for the Future Grid Forum. It borrows concepts from some other models developed overseas and uses a commercial mathematical programming solver at its core.

Most software used for electricity system analysis is not suited to considering large numbers of alternatives for generation sources (location, type, and capacity) and transmission network configurations (transmission lines, connection points, and transmission line capacities). More typically the power system and/or market system is modelled in detail but with relatively few network options in play. Other models and studies (including the Energy Sector Model that is also used for the Future Grid Forum) tend to be more economically focussed and/or spatially aggregated than TNEP, this leading to more approximate appraisal of details, costs and energy flows in future networks.

11.1.1 USE OF TNEP IN THE FUTURE GRID FORUM

The development of TNEP has been motivated by the need to study long-range future questions with intermediate levels of detail. For the Future Grid Forum we use it to:

- Disaggregate state-level energy generation mixes into plans for more detailed NTNDP-zone generation sites
- Address intermittency of renewable supply, through considering “load blocks” associated with period of network stress
- Investigate options for interconnector capacity strengthening
- Consider the details of transmission construction required to “harvest” renewable supplies
- Capture information about the evolution of the future network over time, as TNEP makes decisions for every year in the planning horizon
- Undertake a supply-demand balance at a level of detail between that of economic and spot-market models.

TNEP is a data intensive model and also needs to be integrated with the other models used for the Future Grid Forum. To support its use and integration for the forum, an extensive library of data preparation and processing software is being assembled.
11.1.2 PURPOSES OF THIS DOCUMENT

The dual purposes of this document are to form the backbone of the technical documentation of the TNEP model, and to document the model for the purposes of the forum. There are references to some technical details which are not relevant to the forum, due to the former purpose.

11.2 Model Overview

In this section we give an overview of the TNEP model and the way in which is represents the electricity system.

11.2.1 TIME

TNEP addresses time in terms of annual time steps, over a multiple-year horizon (typically 2015 to 2051). TNEP uses calendar years for time steps. Asset capacities are determined for each year (i.e., for each time step) using an Integer Linear Programming mathematical model.

Changes in transmission and generation capacities require one or more time steps to complete, and previously-planned (in the real world) retirement or commissioning events are scheduled to occur at the beginning of each time step, so that an asset has a certain capacity for the duration of a time step.

11.2.2 NETWORK REPRESENTATION

The electricity system is represented by generation facilities, transmission lines, zonal hubs (junctions in the transmission system) and demand centres (one in each zone).

Electricity

The TNEP model in its current form represents energy (power) transport. In the version of the model used for Future Grid Forum, there is no explicit consideration of voltage. The model has the potential to represent a linear approximation to AC power flow, and to consider multiple voltage levels (requiring the model to place transformers between steps) but it is computationally prohibitive to do so at the spatial scale being addressed.

NTNDP Zones

The east coast network is divided into zones, matching the National Transmission Network Development Plan (NTNDP) modelling undertaken annually by AEMO. A representation for the Western Australian SWIS network is under development. Figure 130 shows the NTNDP zones mapped geographically, with the boundaries of each zone coinciding with Statistical Sub-Divisions (SSDs)\(^{18}\) were possible. This approach facilitates calculations such as apportioning state-wide demand according to population data. In Northern Queensland, the independent system centred on Mt Isa is excluded from the Northern Queensland NTNDP zone geographical definition.

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\(^{18}\) Refer Australian Bureau of Statistics
Figure 130: Mapping of NTNDP Zones

Generation
Each electricity generation site in the NEM is located within an NTNDP zone. In general the assignment is not ambiguous. In most cases we have based this on geographic location (latitude and longitude) with respect to the NEM NTNDP zone boundaries shown in Figure 130. In exception cases we have consulted AEMO network diagrams and other information, so as to set the correct NTNDP zone membership.

Potential new facilities that do not represent specific known generation projects are placed in somewhat arbitrary locations, centred on an NTNDP zone hub or a renewable resource polygon (referred to later in this Section). These are typically identified by labels starting with “auto_”, due to the way in which capacity is represented. The set of existing and potential facilities in Tasmania is shown in Figure 131.

![Figure 131: Location of existing generators and new generation options in Tasmania (from TNEP GIS System)](image)

For the purposes of the Future Grid Forum, all generation is connected to NTNDP zone hubs using links that have unrestricted power transmission capacity. This is not a fundamental restriction of the TNEP model, which (subject to computational feasibility) could handle a large network of capacititated links and junctions/buses.

### Hubs and Demand Centres

Each NTNDP has a hub facility, which is a junction for that NTNDP. All electricity flow between NTNDP zones is between these hubs, and all generation facilities in an NTNDP zone are connected to the hub. The location of the hub is simply at the centroid of the zone, and does not represent a facility present in the real world. TNEP could be loaded with a more accurate network representation, but this would not help significantly in the main function of deciding on interconnector and generation capacities.

The electricity demand in a zone is “sunk” at the zone’s demand centre, which is a node located at the position of the main population centre in the NTNDP zone.
Transmission

The transmission system is represented by interconnectors between NTNDP Zone hubs, and therefore matches the approach taken in a number of other studies including those undertaken for the NTNDP. Intra-hub transmission (and the constraints related to it) is not considered explicitly. As noted in preceding sections, connection to the hub from generation and demand centres is done using unrestricted transmission capacity. A version of the TNEP transmission network is illustrated in Figure 132. In the most recent runs of the model, additional NTNDP zone interconnectors (e.g., NSA to SWNSW) are modelled.

Renewable Supply Polygons

For renewable energy supplies we utilise data that was assembled by CSIRO and ROAM consulting for the AEMO “100% Renewable Supply” project in 2012-2013. The spatial resolution of the data is as per Figure 133.
As part of the AEMO 100% Renewable Supply work, 30-minute time series of 1 MW generator output of various technologies was determined for some or all of the years 2003 to 2012. For the Future Grid Forum modelling, we have used the time series from the 2010-2011 financial year to represent future dynamic output from renewable generators. In doing so, whole dates were swapped around within months, so that 2010-2011 weekdays matched future year weekdays, and so on. This preserves the correlations between demand and various forms of supply, at the expense of not exploring supply extremes that were not observed in 2010-2011.

11.2.3 REPRESENTATION OF PROJECTS

Transmission and generation capacity choices are discrete and can be thought of as “projects” that the TNEP model can decide to execute. We refer to discrete options as states, and between years assets transition between these states according to pre-specified permissible paths.
Transmission

Transmission options have transitions between states of increasing capacity that are linear and irreversible. This is illustrated in Figure 134. Typically, the initial state represents current (nominal MW limit) capacity and subsequent states add a fixed multiple (say, 500 MW) of capacity. Multiple capacity-increment steps are available in each decision period: that is, a capacity jump of two or more multiples can be programmed for a year.

![Figure 134: Interconnector transmission capacity states](image)

The actual routes for transmission corridors are not determined by the TNEP model, and are not particularly relevant for the modelling being undertaken.

Generation

Existing and proposed generation plant is represented by four states, one of these representing a “repower” option for plant that becomes life expired during the time horizon of the TNEP model. The four-state representation is illustrated in Figure 135.

New plant, which does not represent existing plant or known proposals, has two states (unbuilt and built) with typically ten graduated capacity levels (refer Figure 136). The size of each capacity increment varies depending on the NTNDP zone and the technology, and is governed by upper limits on generation build in an NTNDP Zone (refer Section 11.3.5) and by the capacity decisions made using the preceding run of the Energy Sector Model (ESM). In some cases, e.g., wind in NSW, the capacity increments can be hundreds of MW.
11.2.4 OPTIMALITY PRINCIPLE

The objective in TNEP is to minimise total system cost. This is comprised of capital costs and direct operating (fixed and variable) costs for transmission and generation. The nature of the model is such that it represents optimal centralised decision making, to minimise total system cost. This provides a lower bound on expected actual future outlays, and does not directly consider the dynamics of the electricity market. For this reason, TNEP solutions are tested using market simulations in order to identify issues with respect to generator financial performance, for example.
A discounting factor is used to discount future costs (usually 8% per annum). Importantly, this ensures that investments are not made until the capacity is needed.

A flavour of least-cost dispatch is implicit with the objective of minimising total system cost, but the TNEP model will effectively dispatch out of merit order if this is demanded by constraints (e.g., LRET in terms of energy delivery). Once again, this motivates post-analysis of the TNEP solutions using market simulation.

11.2.5 CONSTRAINTS

The TNEP model has a range of constraints, to capture the necessary physics, financials and decision-making. The principal constraints are:

- Power balance / current balance at nodes (Kirchoff current constraints)
- Capacity-limited and renewable supply-limited generator output, including addressing graduated-capacity states.
- Minimum and maximum energy delivery limits (from ESM) by state and technology
- Line losses (function of power and line length)
- Pre-specified state transitions (i.e., known commissioning and retirement)
- State transition constraints
- System wide generation reserve constraints
- End-of-life repower/retirement constraints for generation
- MRET energy delivery constraints.

Line losses are modelled as a percentage loss of power flow, per length of interconnector (1% per 100 km). The minimum and maximum energy delivery limits are set at 80% and 500% per year of the corresponding ESM solution, with all centralised generation technologies also having a minimum 1 TWh per year potential contribution per state (i.e., overriding ESM limits).

The TNEP model is a large Integer Linear Program. Typical dimensions are as follows:

- 36 years
- 16 transmission zones (regions)
- 300+ facilities, and their links to hubs
- 24 interconnectors with up to 8 states
- 8 “average load blocks”, each year
- Up to 24 “stress load blocks”, every five years
- 500 resource constraints (energy by state and tech)
- Greater than 2.5M rows and columns
- After pre-solve, 70K binary variables remain.

The model is computationally expensive, and model computation time is a major constraint. CSIRO is continuing development of the model solution process in order to extend TNEP’s capabilities.

11.2.6 CONNECTION WITH OTHER MODELS

The TNEP model sits in a modelling scheme involving other models. This is illustrated in Figure 137.
11.3 Model Assumptions and Capability

11.3.1 POWER TRANSPORT

TNEP, as used for the Future Grid Forum, uses an energy transportation model. This means that no direct attention is paid to the physics of AC power flow.

There is the facility to run TNEP using a “DC approximation” approach (based on ), but this is currently computationally prohibitive for the spatial and temporal scale TNEP addresses. Furthermore, a lack of network detail within NTNDP zones means that susceptances within zones cannot be adequately represented.

11.3.2 TRANSMISSION EXPANSION

We assume that transmission expansions, once undertaken, are never reversed during the time horizon of the model (typically ending in 2051). We also assume that for any given interconnector, that existing corridors can accommodate the expansion options, this avoiding once-off acquisition costs. Corridor limits are imposed: specifically, the line from Terranora cannot be expanded.

11.3.3 DEMAND

All demand data is associated with a particular scenario, and derived using complex procedures in data pre-processing for TNEP. TNEP takes a demand time series at 30-minute resolution, and partitions this into load blocks (refer Section 11.7). The methodology for creating the demand time series is described in other documentation.

The demand data provided TNEP corresponds to Total Sent Out (TSO) by generators. As such, TNEP needs to consider the relationship between Total As Generated (TAG) and TSO: refer Section 11.3.7.
11.3.4 GENERATION TECHNOLOGIES

TNEP considers centralised (CG) and decentralised (DG, distributed/embedded) generation technologies. Capacity decisions are only made with respect to CG, but the DG contributes to demand satisfaction. The amount of DG is dictated by ESM, and varies by NTNDP zone and year. TNEP down-scales the DG data from a state level to NTNDP, based on population. The set of technologies used by TNEP is the same as that used by ESM, and is summarized in Table 26.

11.3.5 GENERATION BUILD

Generation capacity build is represented by states and states transitions (refer Section 11.2.3). The time taken to transition between states is a parameter that can be specified on an asset and state specific basis. That is, we can specify that a certain upgrade takes four years, for example. This will mean that a preceding transition for the asset concerned cannot occur more recently than four years prior to the transition in question. We assume that an asset can generate power at normal capacity level during a transition, so that over the four year construction span cited in this example, the output of the generator is not adversely affected19.

11.3.6 GENERATION RETIREMENT

Each CG technology is associated with an economic life, and plant must be re-powered (typically at around 80% of new build cost) or retired when this economic life is reached. The economic life is a function only of technology, and is applied equally to existing plant (backdated to the commissioning date of the most recent capacity change) and to new plant selected by TNEP.

11.3.7 AUXILLARY POWER REQUIREMENTS

The auxiliary power requirement for certain types of generation can be very significant, and is the difference between power as Total Sent Out (TSO) and Total As Generated (TAG). We apply an auxiliary power requirement multiplier, such as \[ \mu \] where \( \mu \) is less than one and depends only on the technology. The multiplier values are discussed in Section 11.6.4.

The ESM solutions specify energy and installed capacity in terms of TSO, as this model considers generation sufficient to meet demand (which is TSO).

Therefore, in data preparation for TNEP, when making CG facilities, ESM energy and installed capacity are interpreted as TSO, so TNEP installed capacity (which is TAG) is arrived at by multiplying by \( \frac{1}{\mu} \).

For DG facilities, ESM energy and installed cap are interpreted as TAG, in part because TSO and TAG are not very different for the relevant technologies.

![Table 26: Generation Technologies](image)

<table>
<thead>
<tr>
<th>TECHCODE</th>
<th>CGDG</th>
<th>TYPE</th>
<th>REPRESENTATIVE FUEL</th>
<th>REPRESENTATIVE PROCESS</th>
</tr>
</thead>
<tbody>
<tr>
<td>bgas_rec_b</td>
<td>dg</td>
<td>PEAK</td>
<td>Sewerage / Waste Water</td>
<td>Spark Ignition Reciprocating Engine</td>
</tr>
</tbody>
</table>

19 TNEP could have additional states defined so that de-rating during expansion was represented, but it could be computationally expensive, and would require data that we have not gathered.
We do not presently represent network storage. We represent generation-site storage in some cases by incorporating it into the supply time series (notably, this is done for solar thermal with 6-hour storage). The potential exists to modify the model to address storage better.
11.3.9 EMISSIONS AND RENEWABLE ENERGY TARGETS

There is no implicit consideration of emissions in TNEP, as emissions targets (via constraints and/or carbon pricing) is handled by ESM. The LRET, however, is explicitly represented in TNEP until the expiration of this scheme in 2030.

11.4 Assets

11.4.1 TRANSMISSION NETWORK

The transmission network topography is derived from that used by AEMO in NTNDP studies. Additional corridors are also considered by TNEP. Table 27 summarises the set of assets and capacity options usually explored by TNEP.

Potential interconnectors are, at present, derived from the existing NEM plus the options provided under NEMLink where we could extract suitable data. On a MW line limit basis, the current set of available interconnectors is characterised using nominal MW capacity data supplied by ROAM Consulting. For the runs of ROAM’s 2-4-C market model, a more detailed representation of interconnector capacity shall be utilised for existing AC links, and augmentations are modelled as DC.

11.4.2 POWER GENERATORS

Data on existing power generation plant has been drawn from AEMO’s December 2012 published list of scheduled and unscheduled generators, from somewhat similar listing maintained by the Energy Supply Association of Australia (ESAA, 2012), and lists of fossil and renewable plant maintained by Geoscience Australia (GA, 2013a,b). The main use of the latter is to give geo-coding for the facilities listed in the ESAA and AEMO data, as well as for patching missing data (such as some commissioning dates).

These three sources have been supplemented by alternative data such as internet searches on specific plant (e.g., to confirm that certain cogeneration plant is no longer in service, and to locate plant for which coordinates where not given in GA data).

The data was loaded into an SQL Server database, cleansed, linked and then processed (e.g., assigned to NTNDP zone and to ESM technology class) to create a set of 390 generation sites nationally, totalling just under 62 GW nameplate capacity. The 390 sites include new build which is scheduled to come on line during late 2012 and up to 2015.

Fixed operating costs, derived from AETA information (BREE, 2012) and as used in ESM, were also incorporated into the TNEP system over the period.

Supply data has been revised so that the TNEP model can be run for any ‘fixed’ reference year in the range 2003-2010, and revised demand information has also been loaded into the system. The demand data is “downscaled” from a state-wide level to an NTNDP zone level as part of the process.

New generation options are developed using a complicated process driven by the need to provide capacity options enabling fulfilment of energy mixes proposed by ESM. Most technologies end up having a site with 5-10 capacity levels in each NTNDP zone. Between 520 and 650 generation sites, just under half with 5-10 capacity levels, end up being considered in a run of TNEP.

Table 27: TNEP Standard Transmission Options

<table>
<thead>
<tr>
<th>From</th>
<th>To</th>
<th>Present Status</th>
<th>Fwd MW</th>
<th>Augmentation</th>
</tr>
</thead>
<tbody>
<tr>
<td>CQ</td>
<td>NQ</td>
<td>Existing</td>
<td>1501</td>
<td>1501</td>
</tr>
</tbody>
</table>
11.5 Costs and Revenues

11.5.1 COST DISCOUNTING AND BUDGETING

All costs in TNEP are expressed in 2012 Australian dollars. We apply 8% annual discount rate to all costs.

Capital costs are borne in full in the year that the relevant state transition completes. Operating costs (variable and fixed) accumulate annually. No capital or operating budget constraint is applied in TNEP.

Beyond end of horizon, the mathematical objective function charges an additional cost relating to ongoing operating cost for the plant inventory for forward years (25 years). This is done in order to help avoid system run-down (high operating cost, low capital cost) towards the end of the planning horizon.

There is a trajectory of technology, carbon and fuel costs with time. The base data is the same as that used in ESM.
11.5.2 TRANSMISSION CAPACITY EXPANSION COSTS

TNEP has the capability to apply a project and asset-state specific capital costs for every interconnector considered. That is, where specific data is known, it can be utilised.

For the Future Grid Forum however, we have generally followed an approach taken by ROAM Consulting (2011). A fixed cost of A$500,000 per MW of augmentation is applied for most interconnectors, except for new corridors where A$750,000 per MW is charged. Exceptions are: MEL-TAS ($1 B and $2 B for NTNDP 2012 VIC-TAS Option 1 and its duplication, respectively), Basslink duplication ($750 M) and NNS-SWQ where data from NTNDP 2012 is used (Table 28).

Table 28: NNS-SWQ interconnector augmentation options

<table>
<thead>
<tr>
<th>NNS-SWQ Option</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>NTNDP 2012 Option 2</td>
<td>$1025M</td>
</tr>
<tr>
<td>NTNDP 2012 Option 2+5</td>
<td>$1025M + $650M</td>
</tr>
<tr>
<td>NTNDP 2012 Option 2+7</td>
<td>$1025M + $1100M</td>
</tr>
</tbody>
</table>

11.5.3 GENERATION CAPACITY EXPANSION COSTS

For the construction of new plant we use the AETA dataset (BREE, 2012), as per the ESM, for the capital costs.

Generation Connection Costs

Connection costs for technologies in different NTNDP zones have been adopted from IES (2010) developed for AEMO. The five technology classes in that dataset were mapped to the 35 ESM technology classes. For TNEP purposes, we interpret these costs as applying for the connection and for line upgrades excepting interconnectors. Other Future Grid Forum modelling addresses intra-NTNDP zone transmission and distribution costs.

11.5.4 GENERATION RE-POWERING AND DECOMMISSIONING COSTS

Except for wind power, plant re-powering is set to cost 80% of new build-cost, and (the alternative) decommissioning is set to 10% of new-build cost.

For wind, the re-power cost is set to 35%. This is contentious and we have received conflicting advice on this matter. An overriding reason to apply this low figure is that the re-powering of existing wind projects needs to be favoured strongly, due to social and political pressures, even if demand shifts over time would have the model “move wind around” otherwise.

11.5.5 TRANSMISSION OPERATING COSTS

No such costs are modelled at present. TNEP has the capability to apply a model of operating costs that can be a function of existence, capacity, power, energy.

11.5.6 GENERATION OPERATING COSTS

Generation operating costs have fixed and variable components. The fixed component is generally as per AETA data (BREE, 2012). The variable component includes carbon and fuel costs, and therefore varies between scenarios.
11.5.7 REVENUES

In the model we do not currently represent revenue from electricity sales or less conventional streams such as heat provision.

11.6  Capacity and Supply

11.6.1 GENERATION BUILD LIMITS

Limits on the generation capacity that can be installed in each NTNDP zone is derived for renewable sources from data created for the AEMO 100% Renewable Supply project.

TNEP does not consider biomass availability/inventory constraints directly, but it does indirectly through capacity factors and build limits (from the AEMO 100% Renewable Supply project).

TNEP does not presently consider gas (LNG or LPG) supply limitations, except by way of respecting generation mix constraints per state that are derived from ESM.

11.6.2 GENERATION AVAILABILITY

Generation technologies are associated with supply availability data that reflects “mechanical” and “technical” limits on the percentage of time a unit can be in service. For example, wind plant is assumed to be available at 90% long-run and 95% short-run (peak). This availability factor is one component of the traditional “capacity factor” view of generation capacity.

11.6.3 INTERMITTENT GENERATION

The overall capacity factor of intermittent renewable generation is the product of the energy output time series (at 30 or 60 minute time resolution) and the generation availability described to in Section 11.6.2.

11.6.4 GENERATION AUXILLARIES

The percentage of Total As Generated (TAG) power that is consumed by auxiliaries in generation plant, resulting in Total Sent Out (TSO), is computed as described in Section 11.3.7 and uses data provided by ROAM Consulting. The multipliers vary by technology only. We assume that wind and solar traces from the AEMO 100% Renewables Supply project have auxiliary power requirements netted off already.

11.6.5 LINE LOSSES

Line losses are represented simplistically in TNEP, by applying 1% power loss per 100 km of hub-hub interconnector length.

11.6.6 TRANSMISSION DERATING

We do not model seasonal and thermal effects, including consideration of climate change effects with respect to wind and temperature.

As an approximation, we de-rate (by 40%) transmission output from SA due to the high wind proportion in that state. This is done for load blocks of 12 hours duration or more, and is done to prevent severe curtailment of wind generator output due to transmission constraints (which is identified during market simulation runs post-TNEP).
11.6.7 CONTINGENCY

A system-wide reserve of 3 GW excess generation capacity is applied for all years, to approximate generation contingency planning.

11.6.8 DEMAND UNCERTAINTY

The magnitudes in demand time series are inflated by 10% so as to enable TNEP to plan generation and transmission such that there is “headroom” above the (scaled) 2010-2011 demand data. This approximates a conservative PoE approach.

11.6.9 LRET CONSTRAINTS

The data for NEM-wide annual renewable energy delivery, for the LRET, is the same as that used in ESM.

11.7 Load blocks

For computational reasons we cannot have “35 years x 8760 hours x 16 zones” number of supply-demand constraints in our model for network design. Therefore we form “load blocks” that represent either:

- The average case over a subset of hours (energy balance → cost)
- Stress cases for particular hours (power balance → feasibility).

The model solution time is very sensitive to the number of load blocks.

For adequate annual energy representation, we need at least eight average-case load blocks covering the combinations of day/night, weekday/weekend, for each of summer and winter, in each year.

In each year, a stress-case load block of one hour duration is formed by finding the time of maximum demand in each of Adelaide, Melbourne, Sydney and Brisbane.

Because we are deciding on the generation mix, we do not know a-priori how much of each renewable supply we have, nor where it is located (the time series varies by location). For this reason, additional stress-case load blocks are determined by iteratively solving the TNEP model and evaluating hourly supply-demand balance for each hour in the full time horizon. In our current experience, at least 12 stress load blocks (and up to around 24) are needed per year in order to get unserved energy (evaluated by a market simulator) to acceptable levels.

Our heuristic approach, using a previous solution as a starting point, is for each year to find the 1000 highest values of hourly demand minus supply (nationally), and use the top N non-dominated hours as new stress load blocks. In this, N≤8 or thereabouts.
Figure 138: An illustration of average and stress load blocks
12 Appendix D: GALLM model description

This appendix provides summary information about the Global and Local Learning Model (GALLM).

12.1 Mathematical structure and theoretical underpinnings

GALLM is solved as a mixed integer linear program where costs are minimised to reach a given level of electricity demand. GALLM features endogenous technology learning at both the global and local scale. Endogenous technological learning means that the electricity technology mix and the cost of each electricity generation technology are solved simultaneously as outputs from the model based on the learning curves provided as inputs.

Learning curves refer to the observed phenomenon that the costs of new technologies tend to reduce with the cumulative production of the technology – that is, “learning-by-doing”. Furthermore, costs tend to reduce by an approximately constant factor for each doubling of cumulative production (Wright 1936; Arrow 1962; Grübler et al. 1999). This observation allows for the ability to create cost projections based on projections of the future uptake of a technology. Projections can be created from a transparent mathematical equation as follows:

$$IC_t = IC_0 \times CC_t^{-b}$$

where IC is the investment cost of a technology at CC cumulative capacity at a given future point in time t, IC₀ is the investment cost at given starting period and/or capacity, and b is the learning index. The learning index is related to the learning rate LR by: $$LR = 100 - 2^{-b}$$ where LR is represented as a percentage.

Any mathematical equation or model is only as good as the data it applies. For technologies that have already been deployed the learning rate can be observed. For very new technologies, not yet deployed, no historical learning rate can be calculated. In this case assumed values, based on learning rates of similar previously emerging technologies, are often applied. Component learning can be used, where technologies are broken down into their components and when components are shared between different technologies (e.g. steam turbines), the cost reductions are shared among the technologies that use the same component (IEA 2000; Ferioli et al., 2009).

Projections of the global and local uptake of a technology need to be generated to project costs. But then, uptake depends itself on projected costs. Hence, to resolve this interdependency, models like GALLM are applied to simultaneously project cost and uptake in a single step.

The main advantage of the learning curve approach is that it provides an objective and transparent methodology for assigning a timeline to technology cost improvements. It also simultaneously provides a projection of the global technology mix at each point in time.

The disadvantage of the learning curve approach is that it cannot provide any guidance to exactly what processes or material components changed to arrive at the future cost level. It is unable to identify breakthroughs in technological development or bottlenecks that need to be addressed. If not constrained in some way, the learning curve approach can lead to unrealistically low costs. However, this can be addressed by implementing a lower limit (informed by engineering and science estimates of the maximum potential of a technology) or reducing the learning rate over time based on the experience of other technologies.
12.1.1 CHALLENGES FOR THE LEARNING CURVE APPROACH

The price of a technology does not always decrease at a steady rate with an increase in the number of units produced. Various factors can have an influence on the price and thus on the actual slope of a learning curve:

- Technology structural changes, which result in a dramatic improvement in the technology accompanied by a sharp increase in the learning rate and decrease in cost. This may happen for example, in the case of hot fractured rocks, if the promise of plasma drilling techniques are realised.
- Market forces, which can have a large influence when price instead of cost data is used to construct the learning curves. When there is high demand for a product and few suppliers, the price can remain high or increase, leading to a perceived decrease in the learning rate. This has been the case in recent years, for example, for wind turbines and photovoltaic panels.
- Government policy and research and development (R&D) spending, which can help push some technologies down the learning curve when they are given government support for demonstration projects, for example. This type of support is especially important for emerging and early stage technologies which need to move beyond the demonstration phase.
- Compound or component learning, where technologies are a combination of different parts which have different rates of learning. This can result in learning being saturated in one component for example, and as a consequence the learning rate for the technology as a whole reduces.
- The country or region/s in which the learning has occurred can also have an effect as local rates of learning differ from global rates, since uptake of the technology is on a different scale.

12.1.2 LOCAL VERSUS GLOBAL LEARNING

GALLM allows for both local and global learning. For example, wind turbines are developed and sold in a global market, thus one learning curve has been developed for wind turbines in our model. However, as installation happens on a local scale, local/regional learning curves were developed for the installation costs. The data and fitted curves for wind turbines and installation in the developed world are shown in Figure 139. The data for turbines ranges from 1998–2007 and for installations from 2000–2007. Each marker shown on the curves represents the average over one year. The learning rate determined from the turbine data is 4.3%. This means that for every doubling in the number of wind turbines installed globally, the cost of turbines should reduce by 4.3%.
It can be seen from Figure 139 that there is a deviation in the data from the learning curves. This began from the year 2004. This is the result of market forces having an influence on the price of wind turbines and installations. There were increasing costs for the manufacturers in input materials and labour shortages during this period. Given demand for wind turbines was extremely high manufacturers had the freedom to pass on higher costs and in some cases increase their profit margins (Milborrow, 2008).

12.1.3 MARKET FORCES

Not only have higher prices been observed during that period for wind, other electricity generation technologies were and still are affected. If these price increases are temporary, then it is important to have a methodology for including this effect in cost projections of electricity generation technologies, otherwise the price of the technology may be overestimated in the longer term. The problem can be seen in Figure 140, where by estimating prices at the peak of the “bubble”, the projected prices are overestimated.

GALLM includes a so-called “penalty constraint” as a simple methodology for handling these market forces. If demand for construction of a technology in any one year is high, the cost of that technology increases by a percentage in the model. The penalty constraint tends to prevent the model from seeking to rely too heavily on any single technology (and thus avoiding the problem of technology lock-in), while not preventing rapid expansion of some technologies, particularly in the short term when it is more cost-effective to pay more for a low-emissions technology that is more mature (e.g. wind) than a technology which is still emerging and expensive (e.g. wave energy) (Hayward et al. 2011).
12.1.4 TECHNOLOGIES IN EARLY STAGES OF LEARNING

The Grubb curve is a concept that the costs of new technology initially rise, as the challenges are better understood and then fall as the challenges are overcome with learning. Emerging technologies are in the early stages of learning and are those situated on the left-hand side of the Grubb curve. The costs of emerging technologies are not well known and in the majority of cases there have been few installations. A learning curve based on historical data cannot be constructed if there has been no deployment of the technology. Other technologies in the early stages of learning are those which have been deployed, but are still commercialising and expanding rapidly globally. However, because deployment data is available learning rates can be formulated. The learning rates tend to be high for these technologies; a good example is photovoltaics. These technologies would be situated in the “Early” stage as shown in Figure 141 and the high slope of the curve indicates that technologies in this stage tend to have a high learning rate.

The high rate of learning observed in these early-stage technologies does not continue indefinitely. Several rates of learning can be observed for the same technology over its lifespan, and the rate depends on the stage of development of the technology. Typically, the learning rate reduces as the technology matures. For example, during the early commercialisation stages, learning rates may be around 20 percent. During the pervasive diffusion stage or intermediate stage as shown in Figure 141, learning rates may be around 10 percent. When the technology is mature, little or no learning may be observed (Grübler et al. 1999).
Accordingly, we include learning curves with two different learning rates for early-learning and emerging technologies, typically those that begin with a high learning rate. The second rate is half the value of the first rate. The second rate is activated when the technology reaches the diffusion or intermediate stage, referred to as “Transition Capacity” in Figure 141. Once a technology reaches the mature stage, which corresponds to its lower limit, learning is reduced to 0.5%. This is to take account of improvements in materials, for example, which can result in a lower cost.

Only the technology components, not labour components, have a second reduced rate of learning. Experience, particularly from the oil and gas industry, has shown that labour rates of learning tend to remain high even once the technology has become pervasive (Brett and Millheim 1986; Schrattenholzer and McDonald 2001). Labour costs are included in the local component of plant costs.

### 12.2 Main components

The main components of GALLM include:

- Two modes of regional coverage: Three region model with Australia, rest of developed world and developing world; 9 region model with USA, Western Europe, Eastern Europe, China, India, Russia, Australia, rest of developed world and rest of less-developed world

- Nineteen centralised generation (CG) electricity plant types: black coal pulverised fuel; black coal integrated gasification combined cycle (IGCC); black coal with carbon capture and sequestration (CCS) (90 percent capture rate); brown coal pulverised fuel; brown coal IGCC; brown coal with CCS (90 percent capture rate); natural gas combined cycle; natural gas peaking plant; natural gas with CCS (90 percent capture rate); biomass; hydro; wind; solar thermal; large-scale solar photovoltaic; conventional geothermal; hot fractured rocks (geothermal); wave, ocean current/tidal and nuclear

- Three distributed generation (DG) electricity plant types: gas combined heat and power (CHP); rooftop solar photovoltaic and fuel cells

- Time is represented in annual frequency.
All technologies are assessed on the basis of their relative costs subject to constraints such as the turnover of capital stock, existing or new policies such as subsidies and taxes. The model aims to mirror real world investment decisions by simultaneously taking into account:

- The requirement to earn a reasonable return on investment over the life of a plant or vehicle
- That the actions of one investor or user affects the financial viability of all other investors or users simultaneously and dynamically
- That the consumption of energy resources by one user affects the price and availability of that resource for other users, and the overall cost of energy services, and
- Energy market policies and regulations.

The model projects uptake on the basis of cost competitiveness but at the same time takes into account constraints on the operation of energy markets, GHG emission limits, existing plant stock in each region, and lead times in the availability of new plant. It does not take into account issues such as community acceptance of technologies but these can be controlled by imposing various scenario assumptions which constrain the solution to user provided limits.

### 12.3 GALLM model inputs

GALLM requires both economic and biophysical data in order to support the selection of a least cost solution that is within biophysical limits of the technologies and energy resources that are employed. Key economic data include:

- Global and national carbon price or emission limit
- Historical electricity generation technology costs
- Fuel prices to electricity generators

Key biophysical data includes:

- Observed or calculated learning rates
- Existing stock and age of generators by region
- Regional resource or technology constraints
- Electricity technology capacity factor and supply constraints
- Regional electricity energy consumption and peak demand growth

### 12.4 GALLM model outputs

For given time paths of the exogenous (or input) variables that define the economic environment, GALLM determines the time paths of the endogenous (output) variables. Key output variables include:

- The change in the capital cost of electricity generation technologies
- Electricity generation technology uptake
- Fuel consumption
- Greenhouse gas emissions
- Wholesale electricity prices

Some of these outputs can also be defined as fixed inputs depending upon the design of the scenario.

The endogenous variables are determined using demand and production relationships, commodity balance definitions and assumptions of competitive markets at each time step. With respect to asset markets, the assumption is used that market participants know future outcomes of their joint actions over the entire time horizon of the model.
Appendix E: 2-4-C model description

13.1 Introduction

2-4-C is a complete proprietary electricity market forecasting package. It was originally built to match as closely as possible the operation of the National Electricity Market Dispatch Engine (NEMDE) used for real five-minute dispatch in the NEM. It is now used to model systems ranging from the small North-West Interconnected System (NWIS) of Western Australia to the large 4000 node CalISO system of California.

2-4-C implements the highest level of detail and bases dispatch decisions for individual generating units and transmission links on bidding patterns and availabilities in the same way that the real market operates. Simulations include modelling of generator outages (full, partial and planned), intermittent or inflexible generators and inter-regional transmission capabilities and constraints. Generator bidding strategies are derived from real bid profiles and operational behaviours taken from generators in the relevant system, adjusted over time for any changing market conditions. Such conditions might include water availability, changes in regulatory measures or fuel availability, or under conditions of changing market power.

These processes and features are central to delivering high quality, realistic operational profiles that translate into sound wholesale price forecasts.

2-4-C has been used on projects ranging from week-ahead price forecasts to long term studies of the whole of Australia, in combination with ROAM’s other software tools and expertise or in collaboration with other modelling organisations, such as the CSIRO in this study.

13.2 Realistic dispatch

2-4-C is an LP (linear program) based electricity market dispatch and pricing model. For a given dispatch period, 2-4-C solves for the least cost system dispatch, subject to constraints such as:

- Meeting demand, if possible (unmet demand is recorded as unserved energy, a measure of reliability of supply);
- Transmission constraints;
- Generator ramp rates;
- Water and reservoir limits;
- Energy storage technologies, particularly pumped storage hydro generation;
- Unit operation limits (e.g., inflexibility); and
- Co-optimisation with ancillary services.

2-4-C can operate at any time resolution, such as the 5-minute dispatch period of the NEM or, as was used in this study, the 30-minute price period.

For detailed market operation, 2-4-C can optimise multiple ancillary services markets with the energy market, or incorporate “tie-breaking” behaviour to determine which regions or units are affected by constraints.

13.3 Bidding Strategies

Bidding strategies are important for determining how 2-4-C will project future wholesale electricity prices and for ensuring generators are profitable. Most generators should be profitable in order for a projected future generation capacity to be regarded as plausible, within the current electricity market rules.
Starting bids for generators are typically derived from the operation of existing units, if such market information is available. 2-4-C models up to ten price and capacity bid offers for each generator, which are then called upon as part of the optimised dispatch.

2-4-C can then adjust these bids through a process known as “dynamic bidding”, where portfolios of generation adjust their bidding strategies to maximise revenue in a game theory framework. Alternatively, heuristic bidding strategies can be imposed in scenarios where portfolios are not known or are too uncertain (such as the long-term modelling done in this study, with significantly different market structure). ROAM also employs analysis tools and models such as a Week Ahead Unit Commitment (WAUC) model, which determines whether it is cost effective for generators in the future to cycle during periods of low demand or oversupply of capacity.

Finally, in all bids, 2-4-C incorporates changes to the short-run cost of generation, including:

- Fuel price;
- Carbon costs; and
- Changing unit parameters.

The combination of these inputs allows systematic changes to the dispatch merit order to be observed in long-term modelling.

When additional detail is required, “real time” dynamic bidding can be employed, which can capture effects such as generators competing on volume rather than price, the impact of transient market power and the occurrence of “race to the floor” strategies.

### 13.4 Transmission

As part of a security constrained optimal dispatch, 2-4-C can incorporate transmission limitations through physical transmission limits and more abstract “constraint equations” that place limits on generator dispatch, often to ensure system security in the event of one (or more) network or generation outages. For example, in the NEM, AEMO develops constraint equations (the NTNDP constraints) that transpose intra-regional network issues to the operation of controllable assets: the interconnectors joining the regions of the NEM and the generation of NEM stations. These constraint equations consist of several hundred mathematical expressions which define the interconnector limits in terms of generation, demand and flow relationships. 2-4-C can implement these constraint equations, and then optimise the dispatch of all generators accordingly.

For longer term studies, however, the existing constraint equations may not continue to be valid. Changes in demand, location of generation and transmission flows, or transmission upgrades can mean that the operation of the power system looks very different into the future.
Figure 142: Map of the National Electricity Market zones modelled in 2-4-C in this study

An alternative is to develop a so-called “DC load flow” representation of the existing network and proposed upgrades. This representation captures the physical limits of the transmission system to ensure that half-hourly outcomes could be realistically dispatched in a system. This was the approach taken in this study.

This requires, as inputs, thermal limits and reactance/susceptance values for each transmission path. For example, the thermal limits used in the NTNDP zone transmission representation of this study are listed in Table 29 and illustrated in Figure 142. Additional upgrades suggested by TNEP were also included in the DC load flow model, with both AC and DC links able to be captured.

Table 29: Nominal flow limits for the DC load flow model

<table>
<thead>
<tr>
<th>Line</th>
<th>Flow limit (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CQ-NQ</td>
<td>±1501</td>
</tr>
<tr>
<td>SEQ-CQ</td>
<td>±1421</td>
</tr>
<tr>
<td>SEQ-SWQ</td>
<td>±5288</td>
</tr>
<tr>
<td>SWQ-CQ</td>
<td>±1313</td>
</tr>
<tr>
<td>NCEN-NNS</td>
<td>±929</td>
</tr>
<tr>
<td>CAN-NCEN</td>
<td>±2304</td>
</tr>
<tr>
<td>SWNSW-CAN</td>
<td>±2022</td>
</tr>
<tr>
<td>MEL-NVIC</td>
<td>±1422</td>
</tr>
</tbody>
</table>
### Line Flow limit (MW)

<table>
<thead>
<tr>
<th>Line</th>
<th>Flow limit (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CVIC-NVIC</td>
<td>±284</td>
</tr>
<tr>
<td>MEL-CVIC</td>
<td>±542</td>
</tr>
<tr>
<td>LV-MEL</td>
<td>±8907</td>
</tr>
<tr>
<td>SESA-ADE</td>
<td>±547</td>
</tr>
<tr>
<td>ADE-NSA</td>
<td>±537</td>
</tr>
<tr>
<td>Murraylink (NSA-CVIC)</td>
<td>±220</td>
</tr>
<tr>
<td>SWNSW-NVIC</td>
<td>±1500</td>
</tr>
<tr>
<td>Basslink</td>
<td>594/-469 DC</td>
</tr>
<tr>
<td>Heywood</td>
<td>±460</td>
</tr>
<tr>
<td>QNI</td>
<td>450/-1250</td>
</tr>
<tr>
<td>Terranora</td>
<td>70/-230 DC</td>
</tr>
</tbody>
</table>

#### 13.5 H₂Opt and energy limited plant

One of the most critical aspects of system operation is the dispatch of energy-limited plant, where short-term decisions affect long-term options. This is particularly applicable for future systems with high levels of energy storage, or for detailed modelling of existing hydro plant (either for considering intermittent inflows or for the application of pumped storage).

The highest level of detail can be obtained through the add-on module, H₂Opt, which effectively operates 2-4-C over many dispatch periods such that system cost is minimised not just in a single half-hour but over a day, week or year. In this way, storage can be dispatched in an efficient way (assuming that market participants have strong forecasting capabilities), and the profitability and operation of all plants can correctly inferred. The model is capable of looking ahead at future inflow and demand patterns and simulating all energy limited plant in the NEM in parallel for periods of up to two years at hourly resolution. The outcome is a computed ‘water value’ for each hydro generator or other energy limited generator which provides a strategy for bidding all such assets into the market. This achieves both the highest value for the water and the lowest overall dispatch cost in the NEM (or other system).

#### 13.6 Generator availability

Generators in any market are not always available, due to a combination of “forced” and “unforced” outages.

Forced outages refer to the unavailability of plant due to technical failures, which can be treated as essentially random. Failure to capture this (i.e., to assume 100% availability) overestimates the reliability of a system and underestimates potential electricity price spikes and unserved energy. To capture the risk of plant outages, 2-4-C includes the capability to provide Monte Carlo simulations of plant availability, typically 25 or more simulations with randomly varying plant outages.

Similarly, all generators require maintenance on a regular basis, requiring them to be offline for a period of time. 2-4-C schedules maintenance of all generators in order to minimise supply shortages across the year (thus minimising the risk of unserved energy due to forced outages), while taking into account the availability of defined portfolios of generation. This mimics how generators schedule their maintenance in reality since they will aim to be available during peak times (and thus minimise supply shortages) as this when the price is likely to be highest. Additionally, specific maintenance schedules can be imposed (for example, for generators with historically fixed annual maintenance periods can continue on this basis).
These schedules have been constructed based on information in the public domain and historical generator availabilities. In particular, six key parameters are used in the development of outage schedules, as detailed in the table below.

**Table 30: Generator outage modelling assumptions**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Full forced outage rate</td>
<td>Proportion of time per year the unit will experience full forced outages.</td>
</tr>
<tr>
<td>Partial forced outage rate</td>
<td>Proportion of time per year the unit will experience partial forced outages.</td>
</tr>
<tr>
<td>Number of full outages</td>
<td>The frequency of full outages per year.</td>
</tr>
<tr>
<td>Number of partial outages</td>
<td>The frequency of partial outages per year.</td>
</tr>
<tr>
<td>Derated value</td>
<td>Proportion of the unit’s maximum capacity by which the unit will be derated in the event of a partial outage.</td>
</tr>
<tr>
<td>Full maintenance schedule</td>
<td>Maintenance schedule of planned outages (each planned outage has a start and end date between which the unit will be unavailable).</td>
</tr>
</tbody>
</table>

13.7 Market analysis

Beyond the modelling software itself, the most significant feature of 2-4-C is the analysis tools that allow the user to quickly see results in whatever level of detail is required, from an overview of simulation outcomes and to an examination of the half-hourly transmission flows between regions. These tools incorporate both technical and economic information to allow the economic outcomes for generators to be assessed. These are used to adjust generation development plans and to ensure that outcomes are realistic, not just from a technical perspective, but also from a financial market perspective.

13.8 Uses of 2-4-C

2-4-C forms the core of most of ROAM’s activities, and was used as part of the extensive modelling process in this study to model the half-hourly dispatch of the power system of the future. In other areas, 2-4-C has been used for:

- Forecasting wholesale energy prices, generation volumes and operating patterns;
- Assessment of bidding strategies;
- Determining carbon pricing impacts on volumes, prices and operating patterns;
- System reliability modelling;
- Assessment of rule change impacts or regulatory changes;
- Assessing transmission congestion; and
- Impacts of renewable generators on market prices, transmission flows and congestion.
Appendix F: Real-options model description

14.1 Technical details

An option-pricing approach is used to assess the profitability of competing electricity generation technologies. The use of option-pricing theory reflects two shortcomings of conventional net present value analysis:

1. Choice of discount rates to use – due to the embedded leverage in options, the rate applied to discount the cash flows in an option should be higher than the rate used to discount the cash flows from the actual project; and
2. An investment may have several embedded options (e.g. expansion options; abandonment options; options to defer and/or extend). Discount rates are likely to differ for each option, reflecting their differing embedded leverage and whether the option is a call or a put.

In short, the key limitation of NPV analysis is that one requires knowledge of the (real-world) discount rate in order to discount the option’s expected cash flows. Knowledge of this requires, in turn, knowing investors’ risk aversion, a difficult parameter to estimate.

In contrast, option-pricing theory uses a risk-neutral framework, meaning that an option’s cash flows can be discounted at the (observable) risk-free rate, using a risk-neutral probability measure to obtain expected cash flows. The risk-neutral approach gives the correct price – not just in a risk-neutral “world”, but in all other “worlds” as well.

14.1.1 MATHEMATICAL APPROACH

Existing approaches use multinomial (typically, binomial or trinomial) trees to model the projected paths of the carbon price, and, using these paths, to model the option. Multinomial-trees are useful for valuing American-style options, but become computationally intensive when three or more state variables are involved – as is the case with this sensitivity case.²⁰

An alternative approach, which overcomes this limitation of multinomial trees and is the approach used in this project, is to model carbon prices using Monte Carlo (MC) simulations, which samples several (10,000) paths for each state variable. At each and every time period, and in each and every potential economic state, the option’s payoff has the following form:

\[ \text{(1)} \]

where \( P \) is the payoff of the call option on technology \( g \), in state \( s \) and at time \( t \), and \( \pi(s,k), \epsilon(s,k) \) are, respectively the expected wholesale electricity price and carbon price (in state \( s \) and at time \( k \)), and \( \alpha \) is the levelised electricity cost for technology \( g \), in state \( s \) and time \( k \). Finally, \( \text{CO}_2 \) and \( \text{Elec} \) are, respectively, the emissions generated and electricity generated by technology \( g \) at time \( k \).

These two variables are non-stochastic, so \( \text{CO}_2, \text{Elec} \) are, and \( \pi, \epsilon, \alpha \) are.

For each technology \( g \), the option price today is the arithmetic average of each of the payoffs, averaged over all states \( s \) at time \( t \), and then discounted back to today. There are in total \( T \) number of call options, with each option maturing at time \( t \) (\( t=1,\ldots,T \)). Today’s price of the time-\( t \) call option on generation technology \( g \), \( C(t,g) \), is equal to:

²⁰ The tree approach also has the limitation of assuming that the option’s value depends only on the final value of the state variable(s).
where \( S = 10,000 \) (the number of possible states at time \( t \)), and \( \delta \) is the discount rate.

The advantage of MC simulations is that it becomes relatively more efficient (and relatively less computationally intensive\(^2\)) as the number of state variables increases.\(^2\)

### 14.1.2 STATE VARIABLES

There are three state variables used in the modelling for the Future Grid Forum: (i) the price of carbon (per tonne of CO\(_2\) emitted); (ii) wholesale electricity price (per MWh); and (iii) the levelised electricity cost (per MWh). The first two state variables are independent of the generation technology; the third is technology dependent.

The (future) time horizon adopted is the period from 2013 to 2050 (38 years), with forecasts of conditional means and volatilities based on a range of existing models and data sources (see below).

For each state variable \( \theta = 1, 2, 3 \), the continuous-time stochastic process, used to generate realisations of potential future values, is the following mean-reverting Geometric Brownian motion (GBM) process:

\[
\frac{dS_{\theta}}{S_{\theta}} = \mu_{\theta} dt + \sigma_{\theta} dW_t
\]

where \( \mu_{\theta} \) is the mean-reversion rate of the \( \theta \)th state variable, \( \sigma_{\theta} \) is the continuously-compounded change in the price of state variable \( \theta \), \( \mu_{\theta} \) is the value of the (time varying) mean reversion level multiplied by the reversion rate\(^2\), and \( \sigma_{\theta} \) is the (time- ) volatility of \( \theta \). \( dW_t \) is a Weiner process with zero mean and variance \( \sigma^2_{\theta} dt \). This specification is the same as that used in Zhu et al. (2009). Mean-reversion is consistent with economic theory, reflecting the response by consumers and producers to relatively high and low prices, and is also consistent with the cyclical nature of empirical electricity prices.

The stochastic process specified for each state variable incorporates mean-reversion and stochastic volatility. A discretised version of equation (1) is:

\[
S_{\theta,t+1} = S_{\theta,t} \exp\left( \mu_{\theta} \Delta t + \sigma_{\theta} \sqrt{\Delta t} Z \right)
\]

Details on the practical implementation of equation (4), and the associated parameter values, are provided below.

The benefit of the mean-reverting GBM process (equation (2)) is that it captures the tendency for the state variables to be ‘pulled back’ to their conditional means. Thus, the future paths of the state variables are not completely unpredictable and random, as would be the case under a non-mean-reverting GBM process.\(^2\)

Allowing for mean reversion implies that electricity generators can forecast, to some degree, the profitability of adopting alternative generation technologies even when future prices are uncertain. As a result, it can be profitable for electricity producers to adopt a certain generation technology, even if the future revenues and costs are not known and can only be forecast.

In contrast, in a pure GBM process – which is the model adopted for the price of stocks and other financial instruments -- the rationale response by large-scale electricity generators, when faced with this uncertainty, is to wait until the uncertainty is resolved before committing to projects that have high up-front costs and are largely irreversible once initiated. The incorporation of mean-reversion is a key point of difference between valuing call options on financial instruments, and call options on electricity generation.

\( ^2 \) For example, the time taken to perform a MC simulation increases approximately linearly with the number of state variables, whereas the time taken for tree approaches increases approximately exponentially with the number of state variables.

\( ^2 \) A further advantage of MC simulations is that it can be used to value options whose value depends on the paths followed by the state variables (e.g. when option payoffs depend on the average value of the state variables over the option’s life), in addition to the state variables’ final values.

\( ^2 \) That is, the conditional (i.e. time-varying) mean-reversion level is \( \mu_{\theta} \), for the \( \theta \)th state variable.

\( ^2 \) When \( \delta = 0 \), equations (3) and (4) result in a non-mean reverting GBM process.
A model-consistent expectation of the state variables can be obtained by using equation (4) iteratively:

\[ (5) \]

Equation (5) constructs (conditional) forecasts of each state variable, which are used to value call options on technology \( g \) using equations (1) and (2).

### 14.1.3 MODEL IMPLEMENTATION AND PARAMETER ASSUMPTIONS

There are four steps required for practical implementation of the real options model:

1. For each state variable \( i \), and at each time \( t \), draw 10,000 observations from a \( \text{NID}(0,1) \) distribution. This gives the realisations of

2. The mean-reversion levels, \( \alpha \), for each state variable \( i \), are derived by taking the cross-sectional mean of a range of annual price forecasts obtained from: (i) Commonwealth of Australia (2011) (annual carbon and electricity price forecasts between 2013 and 2050); (ii) CSIRO’s Global and Local Learning Model (GALLM); and (iii) AETA (BREE, 2012) – (ii) and (iii) are used for annual levelised cost forecasts between 2013 and 2050).

3. Following Zhu et al. (2009), the conditional volatilities for each state variable \( \sigma_i \) are equal to the cross-sectional standard deviations of each state variable’s forecasts, using the above data sources to obtain the annual range of forecasts for each state variable. Finally, \( \sigma_i \) are assumed to be \( \text{NID}(0,1) \) distributed, and \( \mu \) is one year.

4. Using the specified parameter values (see below), equation (4) is used to obtain 10,000 realisations of \( \tilde{y}_{it} \) at each time \( t \). For each time \( t \), the average of these 10,000 observations.

The value for \( \alpha \), the mean-reversion parameter, is set at 0.85 for carbon and electricity prices, and 0.7 for each of the levelised electricity generation costs. The lack of empirical data on carbon prices and levelised costs makes it difficult to estimate these parameters with any degree of precision. Consequently, sensitivity analyses were undertaken on the respective values of \( \alpha \).

The key finding from the sensitivity analysis was that higher values of \( \alpha \) for carbon prices increased the profitability of renewable technologies, and decreased the profitability of non-renewable technologies, all else equal.

Intuitively, this finding reflects the fact that, with a higher degree of mean-reversion, there is a higher probability that each state variable will follow their respective conditional mean paths. That is, in the event that the sample realisations, \( \tilde{y}_{it} \), for the \( i \)th state variable, deviate from its forecast path, there is a high probability that the state variable’s future price will move back to that path. As the carbon price path is upward sloping, higher values of \( \alpha \) increase the profitability of zero-emission technologies.

Conversely, lower values of \( \alpha \) reduce the profitability of renewable technologies, and increase the profitability of non-renewable technologies. The intuition behind this result is that lower values of \( \alpha \) reduce the probability that carbon prices follow its conditional mean path, thereby boosting the profitability of emissions-intensive technologies relative to zero-emission technologies.

Changes in the values of \( \alpha \) for wholesale electricity prices and levelised costs did not, all else equal, change the profitability ranking of renewable and non-renewable technologies; in line with intuition, increases in the mean-reversion rate of wholesale electricity prices, all else equal, increased the profitability of all technologies (and vice-versa for decreases in \( \alpha \)).

### 14.2 Choice of electricity generation technologies

The technologies selected for the real-options analysis are made on the basis of those in GALLM (see Appendix D: GALLM model description). The twenty electricity generation technologies analysed are:
1. Pulverised coal supercritical plant based on brown coal
2. Integrated gasification combined cycle (IGCC) plant based on brown coal
3. IGCC plant with carbon capture and storage (CCS) based on brown coal
4. Pulverised coal supercritical plant based on bituminous coal
5. IGCC plant based on bituminous coal
6. IGCC plant with CCS based on bituminous coal
7. Combined cycle plant burning natural gas
8. Combined cycle plant with post combustion CCS
9. Natural gas peaking plant
10. Landfill gas power plant
11. Nuclear (small modular reactor)
12. Solar thermal plant using compact linear fresnel reflectors without storage
13. Solar photovoltaic (PV) - Single axis tracking
14. Wind onshore
15. Geothermal - hot rock (EGS; engineered geothermal system)
16. Geothermal - hot sedimentary aquifer (HSA)
17. Hydropower
18. Wave
19. Tidal
20. Combined heat and power
15 Battery adoption costing example

The number of dwellings in Australia is currently about 8 million, so that a 5% penetration of battery systems would require an estimated 400,000 residential battery installations by 2030. This does not account for an increase in Australia’s population and ignores any influence of the tendency towards higher-density housing in cities with more multi-dwelling buildings.

A cash flow analysis for the growing fleet of battery installations would result in the total life-cycle costs shown in Table 31 and graphed in Figure 143. No financial returns are modelled so the total cost is the negative of the net present value. This calculation assumes discount rates of 7% and 10% during the period of analysis from 2015 to 2030. The cumulative investment is somewhat over $1 billion in AUD 2012. It increases smoothly due to the fixed rate of deployment, and levels out from 2030 onwards when the only expenditure is operation and maintenance costs on the batteries already installed.

Table 31: The total life-cycle cost in AUD 2012 of 5 percent residential battery deployment by 2030 for alternative discount rates

<table>
<thead>
<tr>
<th>Discount rate</th>
<th>2015</th>
<th>2030</th>
</tr>
</thead>
<tbody>
<tr>
<td>7%</td>
<td>$M 104</td>
<td>$M 1,213</td>
</tr>
<tr>
<td>10%</td>
<td>$M 105</td>
<td>$M 1,040</td>
</tr>
</tbody>
</table>

Figure 143: The total life-cycle cost in AUD 2012 of the residential battery deployment anticipated by scenario demand side measures. Blue graph: 7% discount rate; red graph: 10% discount rate
15.1.1 EXAMPLE OF BATTERY APPLICATION TO PEAK REDUCTION

Devolving battery installation to customers means that batteries will be operated in the context of individual customer demand profiles. These are very diverse compared to the load curves seen at substations by distribution utilities.

It is helpful to illustrate this idea with a simple example, unrealistic, but capable of generalisation using statistical methods. Consider a square wave function as an archetypal “peaky” load profile, for a residential building, with constant form for a period of time over which the utility requires a demand response to achieve a peak load reduction. It is characterised by a duty cycle, where is the duration of a peak or “on” pulse, and is the period. The building that has this unusual demand profile is equipped with a grid-connected inverter and battery system, with power capacity that is less than half the peak-to-trough amplitude of the square wave. These parameters are indicated in Figure 144.

The peak demand of this building may be mitigated by discharging the battery during the peaks to offset consumption of grid electricity. This assumes the battery technology is responsive enough to be switched into a discharging state instantaneously with the onset of the peak – otherwise the peak mitigation is not effective. Because the peaks are high compared to the battery capacity, the battery may be recharged during the troughs, partially or fully restoring the battery’s state of charge. Again, rapid switching capability is required, particularly if the trough is fully used for charging as shown in Figure 144.

If this demand profile and these switching actions continue for duration of the demand response, we may calculate the total discharged energy and total charged energy as follows, where is the round-trip efficiency of the battery and inverter system:

\[
\text{Total discharged energy} = \text{peak demand} \times \text{duration} \times (1 - \text{round-trip efficiency})
\]

\[
\text{Total charged energy} = \text{peak demand} \times \text{duration} \times \text{round-trip efficiency}
\]

The difference is the total energy capacity that the battery should have. For a concrete calculation, assign kW and hours according to assumptions used in the scenarios, which shifts 1 kW of demand by 5 hours, and say so that an intermittent load is more often on than off, and which is a typical flow-battery efficiency though low for sealed-cell batteries. Then we can calculate the battery capacity required to reduce the peak demand by 1 kW for 5 hours:

\[
kWh
\]

This should be compared with the battery capacity required to reduce a constant load profile by 1 kW for 5 hours, which is of course 5 kWh, indicating that peakier customers can achieve peak mitigation most efficiently.

Does this reduce the peaks observed by utilities? Assuming customer loads are not perfectly correlated for the duration of the demand response, the average power reduction across a community of residential buildings can be calculated as follows:
This is much less than the kW reduction that would be achieved for constant load profiles. In fact, it can be positive, zero, or negative depending on the final average state of charge achieved across the set of customer batteries.

What we learn from this simple example is that, when residential buildings are equipped with batteries, a peak reduction target specified per customer can have little or even adverse impact on the overall demand response. The response obtained depends on the peakiness of individual customer demand profiles and the sophistication of the battery and inverter controls. A customer incentive scheme to promote the adoption of demand response technology, including batteries, may not produce the desired result if is based on individual peak load reductions.

However, batteries may assist an incentive scheme that caps individual customer demand, as opposed to a demand response at a particular time. Many such schemes exist, generally involving an increased tariff, or a hard limit, or even disconnection when demand exceeds the cap. In principle, although they give some certainty about maximum system demand, they cannot be very efficient because they do not account for diversity – network design would still be based on after-diversity maximum demand (ADMD) rather than the sum of customer demand caps.

Batteries can help such schemes to lead to efficient distribution systems, because they are effective at smoothing demand, and this is the main impact observed in Figure 144. Without smoothing, networks will tend to be over-engineered so they can meet the demand caps of all customers, which most of the time exceed the actual demand. With smoothing, the demand cap can be lowered to a value closer to the average demand, without reducing the individual peak demand that will be supplied by a combination of grid electricity and battery discharge.

Overall, batteries are well suited to smoothing customer demand, and this can be helpful in developing an efficient customer incentive scheme that caps individual customer demand. The business models under which batteries are adopted at scale at residential level – to what extent supported by incentive schemes, to what extent meeting customer needs directly, to what extent owned and operated by aggregation businesses – is not resolved here. The simplistic example above at least demonstrates that a number of influences are at play. Some products oriented to the residential market are already being actively promoted (Parkinson, 2012) and will progress over time.
### ACRONYMS AND ABBREVIATIONS

<table>
<thead>
<tr>
<th>Item</th>
<th>Definition</th>
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</thead>
<tbody>
<tr>
<td>2-4-C</td>
<td>To foresee (ROAM Consulting’s electricity market dispatch model)</td>
</tr>
<tr>
<td>a</td>
<td>Annum</td>
</tr>
<tr>
<td>ABS</td>
<td>Australian Bureau of Statistics</td>
</tr>
<tr>
<td>AC</td>
<td>Alternating current</td>
</tr>
<tr>
<td>ADE</td>
<td>Adelaide zone</td>
</tr>
<tr>
<td>ADMD</td>
<td>After-diversity maximum demand</td>
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<td>AEMC</td>
<td>Australian Energy Market Commission</td>
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<tr>
<td>AEMO</td>
<td>Australian Energy Market Operator</td>
</tr>
<tr>
<td>AER</td>
<td>Australian Energy Regulator</td>
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<tr>
<td>AETA</td>
<td>Australian Energy Technology Assessment</td>
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<tr>
<td>AUD</td>
<td>Australian dollars</td>
</tr>
<tr>
<td>B</td>
<td>Billion</td>
</tr>
<tr>
<td>BREE</td>
<td>Bureau of Resources and Energy Economics</td>
</tr>
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<td>c</td>
<td>Cents</td>
</tr>
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<td>CAN</td>
<td>Canberra zone</td>
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<tr>
<td>CCGT</td>
<td>Combined cycle gas turbine</td>
</tr>
<tr>
<td>CCHP</td>
<td>Combined cooling, heat and power</td>
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<tr>
<td>CCS</td>
<td>Carbon capture and storage</td>
</tr>
<tr>
<td>CG</td>
<td>Centralised generation</td>
</tr>
<tr>
<td>CHP</td>
<td>Combined heat and power</td>
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<tr>
<td>CI</td>
<td>Scenario 1 sensitivity case: Climate impacts adaptation</td>
</tr>
<tr>
<td>CNG</td>
<td>Compressed natural gas</td>
</tr>
<tr>
<td>CO₂e</td>
<td>Carbon dioxide equivalent</td>
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<tr>
<td>Cogen</td>
<td>Cogeneration</td>
</tr>
<tr>
<td>comm.</td>
<td>Commercial</td>
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<td>CQ</td>
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<tr>
<td>CSIRO</td>
<td>Commonwealth Scientific and Industrial Research Organisation</td>
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<tr>
<td>CTL</td>
<td>Coal-to-liquids</td>
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<td>CVIC</td>
<td>Country Victoria zone</td>
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<tr>
<td>DC</td>
<td>Direct current</td>
</tr>
<tr>
<td>DG</td>
<td>Distributed generation</td>
</tr>
<tr>
<td>DICE</td>
<td>Direct injection coal engine</td>
</tr>
<tr>
<td>DiSCoM</td>
<td>Distribution System Cost Model</td>
</tr>
<tr>
<td>DR</td>
<td>Demand response</td>
</tr>
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<td>DRCF</td>
<td>Scenario 1 sensitivity case: Demand response counterfactual</td>
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<tr>
<td>DSM</td>
<td>Demand-side management</td>
</tr>
<tr>
<td>EGS</td>
<td>Engineered geothermal system</td>
</tr>
<tr>
<td>ESAA</td>
<td>Energy Supply Association of Australia</td>
</tr>
<tr>
<td>ESM</td>
<td>Energy Sector Model</td>
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<td>Item</td>
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<tr>
<td>EUR</td>
<td>Euros</td>
</tr>
<tr>
<td>EV</td>
<td>Electric vehicle</td>
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<tr>
<td>FCAS</td>
<td>Frequency control ancillary service</td>
</tr>
<tr>
<td>FCV</td>
<td>Fuel cell vehicle</td>
</tr>
<tr>
<td>GA</td>
<td>Geoscience Australia</td>
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<tr>
<td>GALLM</td>
<td>Global and Local Learning Model</td>
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<tr>
<td>GBM</td>
<td>Geometric Brownian motion</td>
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<tr>
<td>GHG</td>
<td>Greenhouse gases</td>
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<tr>
<td>GIS</td>
<td>Geographic Information System</td>
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<tr>
<td>GJ</td>
<td>Gigajoules</td>
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<tr>
<td>GTL</td>
<td>Gas-to-liquids</td>
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<tr>
<td>GW</td>
<td>Gigawatts</td>
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<tr>
<td>GWh</td>
<td>Gigawatt hours</td>
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<td>H₂Opt</td>
<td>Optional medium term optimisation module</td>
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<td>HCP</td>
<td>Scenario 1 sensitivity case: High carbon price</td>
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<tr>
<td>HGSC</td>
<td>Scenario 1 sensitivity case: High gas prices</td>
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<td>HHV</td>
<td>Higher heating value</td>
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<td>Hour</td>
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<td>hrs</td>
<td>Hours</td>
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<tr>
<td>HSA</td>
<td>Hot sedimentary aquifers</td>
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<tr>
<td>HVAC</td>
<td>Heating, ventilation and air conditioning</td>
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<tr>
<td>IEA</td>
<td>International Energy Agency</td>
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<tr>
<td>IES</td>
<td>Intelligent Energy Systems</td>
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<tr>
<td>IFAP</td>
<td>Infrastructure Futures Analysis Platform</td>
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<tr>
<td>IGCC</td>
<td>Integrated gasification combined cycle</td>
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<td>IMO</td>
<td>Independent Market Operator</td>
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<td>Kilotonnes</td>
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<tr>
<td>kW</td>
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<tr>
<td>kWe</td>
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<tr>
<td>kWh</td>
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<td>L</td>
<td>Litres</td>
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<td>Le</td>
<td>Litre equivalent</td>
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<tr>
<td>LNG</td>
<td>Liquefied natural gas</td>
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<tr>
<td>LPG</td>
<td>Liquefied petroleum gas</td>
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<tr>
<td>LRET</td>
<td>Large-scale Renewable Energy Target</td>
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<td>LSR</td>
<td>Large-scale renewables</td>
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<td>M</td>
<td>Million</td>
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<tr>
<td>MW</td>
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<td>National Electricity Market</td>
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<td>National Electricity Market Dispatch Engine</td>
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<td>Normally and independently distributed</td>
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<td>Net Present Value</td>
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<td>NSC</td>
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<td>O&amp;M</td>
<td>Operating and maintenance</td>
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<tr>
<td>OCGT</td>
<td>Open cycle gas turbine</td>
</tr>
<tr>
<td>p.a.</td>
<td>Per annum</td>
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<tr>
<td>pf</td>
<td>Pulverised fuel</td>
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<td>PHEV</td>
<td>Plug-in hybrid electric vehicle</td>
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<td>PJ</td>
<td>Petajoules</td>
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<tr>
<td>POE</td>
<td>Probability of exceedence</td>
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<tr>
<td>ppm</td>
<td>Parts per million</td>
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<tr>
<td>PV</td>
<td>Photovoltaic</td>
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<td>Queensland</td>
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<td>Research and development</td>
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<td>RAPS</td>
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<tr>
<td>resi.</td>
<td>Residential</td>
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<tr>
<td>S1</td>
<td>Scenario 1 (‘set and forget’)</td>
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<tr>
<td>S2</td>
<td>Scenario 2 (‘rise of the prosumer’)</td>
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<td>S3</td>
<td>Scenario 3 (‘leaving the grid’)</td>
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<td>Scenario 4 (‘renewables thrive’)</td>
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<td>South Australia</td>
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<td>SC-OPF</td>
<td>Security constrained optimal power flow</td>
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<td>SEQ</td>
<td>South East Queensland zone</td>
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<tr>
<td>SESA</td>
<td>South East South Australia zone</td>
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<tr>
<td>SGLP</td>
<td>Strong Growth, Low Pollution</td>
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<td>SGLP450</td>
<td>Strong Growth, Low Pollution 450 ppm scenario</td>
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<tr>
<td>SGLP550</td>
<td>Strong Growth, Low Pollution 550 ppm scenario</td>
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<td>SKM</td>
<td>Sinclair Knight Merz</td>
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<td>SRMC</td>
<td>Short-run marginal cost</td>
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<td>SSD</td>
<td>Statistical sub-division</td>
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<td>Item</td>
<td>Definition</td>
</tr>
<tr>
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<tr>
<td>STL</td>
<td>Shale-to-liquids</td>
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<tr>
<td>SWIS</td>
<td>South West Interconnected System</td>
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<td>UCP</td>
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<td>wk</td>
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