Modelling illustrative electricity sector emissions reduction policies (iteration with CGE modelling)

Climate Change Authority

Report

26 June 2016

Modelling illustrative electricity sector emissions reduction policies (iteration with CGE modelling)

Project no:	RO016501
Document title:	Final report
Document No.:	Final
Date:	26 June 2016
Client name:	Climate Change Authority
Project manager:	Paul Nidras
Author:	Walter Gerardi, Pan Galanis and Paul Nidras

Jacobs Group (Australia) Pty Limited
ABN 37 001 024 095
Floor 11, 452 Flinders Street
Melbourne VIC 3000
PO Box 312, Flinders Lane
Melbourne VIC 8009 Australia
T +61 3 8668 3000
F +61 3 8668 3001
www.jacobs.com

© Copyright 2016 Jacobs Group (Australia) Pty Limited. The concepts and information contained in this document are the property of Jacobs. Use or copying of this document in whole or in part without the written permission of Jacobs constitutes an infringement of copyright.

Limitation: This report has been prepared on behalf of, and for the exclusive use of Jacobs' Client, and is subject to, and issued in accordance with, the provisions of the contract between Jacobs and the Client. Jacobs accepts no liability or responsibility whatsoever for, or in respect of, any use of, or reliance upon, this report by any third party.

Contents

Abbreviations

AEMO	Australian Energy Market Operator
AETA	Australian Energy Technology Assessment
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CfD	Contract for Differences
CGE	Computable General Equilibrium
CPI	Consumer Price Index
DOGMMA	Distributed On-site Generation Market Model Australia
EITEI	Emission-intensive, Trade-exposed industry
EPC	Engineer-Procure-Construct
ERF	Emissions Reduction Fund
ESOO	Electricity Statement of Opportunities
FiT	Feed-in Tariff
GFC	Global Financial Crisis
IDC	Interest During Construction
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
IMO	Independent Market Operator (WA)
LET	Low Emission Target
LGC	Large-scale Generation Certificate

LNG	Liquefied Natural Gas
LRET	Large-scale Renewable Energy Target
MMAGas	Market Model Australia – Gas
NEFR	National Electricity Forecasting Report
NEM	National Electricity Market
NTNDP	National Transmission Network Development Plan
PED	Price Elasticity of Demand
PPA	Power Purchase Agreement
PV	Photovoltaic
REMMA	Renewable Energy Market Model Australia
RET	Renewable Energy Target
SRES	Small-scale Renewable Energy Scheme
SWIS	South-West Interconnected System
WEM	Wholesale Electricity Market (WA)

Important note about your report

The sole purpose of this report and the associated services performed by Jacobs is to assess the electricity sector impacts of a range of policy scenarios to reduce emissions of greenhouse gases in accordance with the scope of services set out in the contract between Jacobs and the Client. That scope of services, as described in this report, was developed with the Client.

In preparing this report, Jacobs has relied upon, and presumed accurate, any information (or confirmation of the absence thereof) provided by the Client and/or from other sources. Except as otherwise stated in the report, Jacobs has not attempted to verify the accuracy or completeness of any such information. If the information is subsequently determined to be false, inaccurate or incomplete then it is possible that our observations and conclusions as expressed in this report may change.

Jacobs derived the data in this report from information sourced from the Client (if any) and/or available in the public domain at the time or times outlined in this report. The passage of time, manifestation of latent conditions or impacts of future events may require further examination of the project and subsequent data analysis, and re-evaluation of the data, findings, observations and conclusions expressed in this report. Jacobs has prepared this report in accordance with the usual care and thoroughness of the consulting profession, for the sole purpose described above and by reference to applicable standards, guidelines, procedures and practices at the date of issue of this report. For the reasons outlined above, however, no other warranty or guarantee, whether expressed or implied, is made as to the data, observations and findings expressed in this report, to the extent permitted by law.

This report should be read in full and no excerpts are to be taken as representative of the findings. No responsibility is accepted by Jacobs for use of any part of this report in any other context. The scenario results should not be treated as a forecast for commercial purposes.

This report has been prepared on behalf of, and for the exclusive use of, Jacobs's Client, and is subject to, and issued in accordance with, the provisions of the contract between Jacobs and the Client. Jacobs accepts no liability or responsibility whatsoever for, or in respect of, any use of, or reliance upon, this report by any third party.

1. Executive Summary

Under the Climate Change Authority's Special Review of Australia's climate action, the Authority has commissioned Jacobs and Victoria University's Centre of Policy Studies to undertake modelling to investigate the whole-of-economy impacts of several carbon pricing policy options for the electricity sector. This process utilises both Jacobs' detailed electricity sector model and Victoria University's economy-wide computable general equilibrium (CGE) model to examine in detail how the effects of electricity sector policy options would translate to the wider economy. Outputs from the two models were combined through an iterative process to ensure that results across the two models are internally consistent.

The modelling involves three scenarios:

- Cap and Trade (tax cuts), where electricity generators face a cost on emissions through a cap and trade scheme, with all revenue raised from permit sales to electricity generators used to cut personal and company income tax.

- Cap and Trade (lump sum), where generators again face a cost on emissions through a cap and trade scheme and all revenue raised is returned to households in a lump sum manner.

- Emissions Intensity, where generators face an emissions cost but also receive free emissions permits according to an emissions intensity baseline, meaning that generators with intensity below the baseline receive a subsidy and generators above the baseline incur a cost.

All three modelled scenarios are found to have very similar generation mix and capital expenditure through the modelled horizon.

The Emission Intensity scenario has a smaller impact on consumer prices, something that gives rise to a slightly higher demand relatively to the two Cap and Trade scenarios, and that leads to higher cumulative emissions and resource costs through the modelled horizon. This price difference has flow-on effects in the economy-wide modelling undertaken by Victoria University.

The primary purpose of Jacobs' work described in this report is to capture in detail the potential effect of different carbon pricing policies in the electricity sector, and use that detail to inform Victoria University's economy-wide modelling. Key differences in the policies that are not evident in Jacobs' modelling of the electricity sector are likely to be evident in the economy-wide modelling. Readers with an interest in the economy-wide cost effectiveness of different carbon pricing policies should refer to Victoria University's report 'Simulations of the effects of greenhouse gas mitigation policies for the Australian electricity sector'.

Differences between a broad range of policy options affecting the electricity sector were considered in detail in Jacobs' electricity sector modelling for the Authority. Readers with an interest in these results should refer to Jacobs' report 'Modelling illustrative electricity sector emissions reduction policies'.

The modelling is designed to provide insights into the potential impacts of alternative emissions reduction policies in the electricity generation sector. The modelling makes a range of assumptions and simplifications in order to provide information about the relative performance of possible policies to reduce emissions. The results of the modelling should be interpreted carefully to account for the broad context and the limitations of the modelling.

2. Overview

2.1 Methodology and Inputs

The Climate Change Authority is undertaking a Special Review of Australia's climate action, at the request of the Minister for the Environment. As part of this Special Review, the Authority is analysing options for Australia's emissions reduction policies, and considering whether Australia should have an emissions trading scheme.

The Authority commissioned Jacobs to undertake electricity sector modelling to support this work. Jacobs modelled a range of illustrative policy scenarios over the period to 2050, as is outlined in its report 'Modelling illustrative electricity sector emissions reduction policies'. Throughout this report, this work is described to as the 'electricity sector only modelling' to distinguish it from the work described in this report.

To extend this electricity sector only modelling, the Authority also commissioned Jacobs and Victoria University's Centre of Policy Studies to undertake further modelling to investigate the whole-of-economy impacts of several carbon pricing policy options for the electricity sector. This process utilised both Jacobs' detailed electricity sector model and Victoria University's economy-wide computable general equilibrium (CGE) model to examine in detail how the effects of electricity sector policy options would translate to the wider economy.

Outputs from the two models were combined through an iterative process. Typically, Victoria University's initial CGE model runs draw on existing Jacobs' outputs, primarily electricity prices but also technology shares and emissions. Outputs from the initial CGE runs, primarily electricity demand, are then used to update Jacobs' electricity sector results, which in turn are used to update the initial CGE runs, and so on until equilibrium across the two models has been reached.

The scenarios modelled are:

- Cap and Trade (tax cuts), building on Jacobs' modelling of the 2^{o}C Carbon Price scenario in the electricity sector only modelling, and subsequent modelling by Victoria University.
- Cap and Trade (lump sum), building on the revised Cap and Trade (tax cuts) modelling by Jacobs and Victoria University, but with different treatment of revenue recycling in the CGE model, resulting in slightly different levels of economic output and electricity demand.
- Emissions Intensity, building on Jacobs' modelling of the 2^{o}C Emissions Intensity scenario in the electricity sector only modelling and Victoria University modelling.

Jacobs' modelling covers the National Electricity Market (NEM) and the Wholesale Electricity Market of Western Australia (WEM) which together make up about 95% of Australia's electricity demand over the period to 2020[1]. The modelling horizon was from 2017/18 to 2049/50.

Jacobs' modelling approach to support the economy-wide modelling is similar to that adopted in its electricity sector only modelling for the Authority, with the following key differences:

- There is no 'no action' reference case in this exercise. Where necessary for presentation, the Cap and Trade (lump sum) scenario is used as the reference case from which changes in the Cap and Trade (tax cuts) and Emissions Intensity scenarios are shown.

[1] The WEM operates dispatch and delivery in South West Interconnected System (SWIS), which is a grid system with major load centres at Perth/Kwinana and that extends north to Geraldton on the mid-west coast to Kalgoorlie in the east and past Albany in the south-east coast.

- There is no specific emissions constraint within the Australian electricity generation sector in the economy-wide modelling, which contrasts with the electricity sector only modelling. Economy-wide emissions are held constant across scenarios within Victoria University's model to ensure that scenarios can be compared on a like-for-like basis.

- The carbon price used in each scenario is based on the price used in the 2^{o}C Carbon Price scenario in the electricity sector only modelling, with minor differences between exchange rates arising within the Victoria University model. An important difference is that in the electricity sector only modelling the carbon price in the 2^{o}C Carbon Price scenario was lower than the certificate price in the Emissions Intensity scenario, whereas in the economy-wide modelling the effective carbon price is almost exactly the same (in Australian dollar terms) in the two Cap and Trade scenarios and the Emissions Intensity scenario.

- Electricity demand used by Jacobs is based on electricity demand growth rates from Victoria University's CGE modelling. By contrast, the electricity sector only modelling used a fixed demand series for the Reference case, with differences in demand in other scenarios being calculated based on the likely price elasticity of electricity demand.

2.2 Policy scenarios: detailed descriptions

2.2.1 Cap and Trade scheme with tax cuts

A carbon tax sets a price per unit of carbon dioxide equivalent emitted. Generators whose annual emissions exceed a given emissions threshold are required to pay tax on all of their emissions in each compliance period. The tax is an explicit carbon price and the relative price of electricity made from more emissions-intensive sources increases. The tax rate increases over time in real terms.

A carbon tax and a cap and trade scheme operate in essentially the same way (in terms of economic incentives), so they have very similar impacts in deterministic electricity sector models. The differences between the two are driven by the ability to bank and (up to a limit) borrow in emissions trading schemes. This gives a cap and trade scheme some additional flexibility over the timing of emissions reductions that is not available under a carbon tax.

An important element of this scenario is that all revenue raised from permit sales to electricity generators, are used to cut personal and company income tax. These tax cuts have a range of economic effects that are captured in Victoria University's modelling, and which affects electricity demand in Jacobs' modelling. Further detail on these tax cuts and their wider economic effects can be found in Victoria University's report 'Simulations of the effects of greenhouse gas mitigation policies for the Australian electricity sector'.

2.2.2 Cap and Trade scheme with lump sum recycling

As in the Cap and Trade (tax cuts) scenario, this scenario involves a fixed carbon price increasing in real terms. The carbon price is applied within the Jacobs model in the same way as in that scenario.

The primary difference between this scenario and the Cap and Trade (tax cuts) scenario arises within Victoria University's CGE modelling. In this scenario, revenue raised from electricity generators is returned to households in a lump sum manner rather than through tax cuts. Tax cuts enhance economic efficiency in a way that lump sum payments do not, and so this scenario tends to see lower levels of economic activity and electricity demand than the Cap and Trade (tax cuts) scenario. Further detail is outlined in Victoria University's report 'Simulations of the effects of greenhouse gas mitigation policies for the Australian electricity sector'.

2.2.3 Emission Intensity scheme

An emission intensity baseline is set for the electricity supply sector as a whole (based on tonnes of carbon dioxide equivalent per megawatt hour sent out (t CO_2-e/MWh)). All generators are allocated permits (representing one tonne of carbon dioxide equivalent) equal to their own generation multiplied by the emission intensity baseline. At the end of the compliance period all generators surrender permits for each tonne of carbon dioxide equivalent emitted. This effectively means that generators with intensity below the baseline have surplus permits to sell (so receive a subsidy) and generators with intensity above the baseline need to buy additional permits (so incur an extra cost). Emissions permits can also be banked indefinitely for future use or borrowed in limited quantities.

An exogenous certificate price is applied, and the relative price of electricity made from more emissions-intensive sources increases. In contrast to a conventional cap and trade scheme, there is no absolute emissions cap, so in practice overall sectoral emissions will vary depending on electricity demand. In this exercise, the model utilises the previously modelled declining trajectory for emission intensity baselines and is using a certificate price that is exogenous and equal to the carbon price used in the Cap and Trade scenarios.

Economy-wide emissions are held constant between this scenario and the Cap and Trade scenarios within Victoria University's model to ensure that scenarios can be compared on a like-for-like basis.

2.3 Use and limitations of modelling results

The primary purpose of Jacobs' work described in this report is to capture in detail the potential effect of different carbon pricing policies in the electricity sector, and use that detail to inform Victoria University's economy-wide modelling. Key differences in the policies that are not evident in Jacobs' modelling of the electricity sector are likely to be evident in the economy-wide modelling. Readers with an interest in the economy-wide cost effectiveness of different carbon pricing policies should refer to Victoria University's report 'Simulations of the effects of greenhouse gas mitigation policies for the Australian electricity sector'.

Differences between a broad range of policy options affecting the electricity generation sector were considered in detail in Jacobs' electricity sector only modelling for the Authority. Readers with an interest in these results should refer to Jacobs' report 'Modelling illustrative electricity sector emissions reduction policies'.

The modelling is designed to provide insights into the potential impacts of carbon pricing policies in the electricity sector. It is comprehensive and based on standard and long used methods.

The modelling makes a range of assumptions and simplifications in order to provide information about the relative performance of possible policies to reduce emissions. Some features of the electricity system are omitted such as ramp rate constraints and start-up costs that are important for short-term outcomes in the electricity sector, but are small in absolute terms over the longer time horizons that are the focus of this work, so excluding them will not materially affect the comparative projections in this report. Some other assumptions, such as the level of electricity demand and the availability and costs of electricity generation technologies, are important for the results. In these cases, the impact of varying the assumption has been explored through sensitivity analysis in the electricity sector only modelling.

The level of uncertainty around the projections increases over the modelling horizon.

The results of the modelling should be interpreted carefully to account for the broad context and the limitations of the modelling. Important points to note are:

- The results are projections for illustrative scenarios; they are not forecasts of likely future outcomes.

- The modelling assumes perfect foresight with future trends in key assumptions known with certainty. Investment decisions, for example, are made with complete knowledge of future fuel and capital costs. In reality, future trends in key assumptions are not known and investors take into account the uncertainties when making their investment decisions. Varying the assumption is unlikely to affect the answers to the key question the modelling is designed to inform, namely how emissions reduction policies compare to each other on key metrics such as resource costs and costs to consumers.

- In each policy scenario, all policies are assumed to be credible.

- The modelling presumes the policy is announced in 2018, with a start date in 2020. This allows for an immediate reaction in 2020 if required. In reality, reaction times may be longer than presumed as investors and stakeholders consider the uncertainties and there may be constraint on how quickly new builds can occur.

- The scenarios generally result in rapid construction to replace the coal fleet in a short space of time. In practice this rapid construction may increase the price of inputs due to ‘bottlenecks’ in construction. As these increases would be reasonably uniform across scenarios and small relative to the large overall levels of investment across the scenarios, they were not estimated here.

- The modelling does not incorporate the second-round or indirect impacts of these policies on the wider economy. The Authority has commissioned separate modelling from Victoria University to investigate these impacts. In this modelling, some adjustments are made to input assumptions to avoid results in the electricity sector which would be unlikely to obtain if strong emissions reductions applied across more of the economy (for example, generation from biomass is constrained as economy-wide analysis suggests that biomass has higher value in transport rather than the electricity sector when meeting deep emissions reduction target).

- Short run constraints on the availability of gas are assumed not to persist beyond 2019.

3. Scenario comparisons

3.1 Modelling inputs

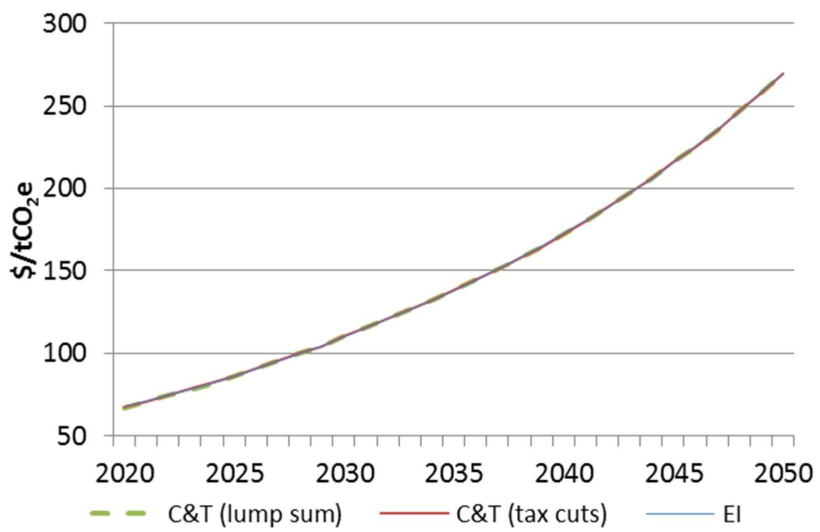
This section compares the Cap and Trade (lump sum), Cap and Trade (tax cuts) and Emission Intensity scenarios and highlights their main differences and similarities. Where relevant the Cap and Trade with lump sum recycling scenario is considered the reference scenario and the other two are compared with it.

3.1.1 Carbon prices and emission intensity baseline

In the two Cap and Trade scenarios, the modelling is conducted with a fixed carbon price based on Climate Change Authority analysis of the Intergovernmental Panel on Climate Change's Fifth Assessment Report (see Appendix C for further detail). In the Emission Intensity scenario, the certificate price used is the same as the carbon price in the Cap and Trade scenarios.

The carbon prices for all three scenarios are illustrated in Figure 1 below. They commence at \$67/t CO_2-e in 2020 and escalate at an average rate of 4.7% per annum in real terms, reaching \$270/t CO_2-e in 2050.

Figure 1: Carbon price path for Cap and Trade and Emission Intensity scenarios

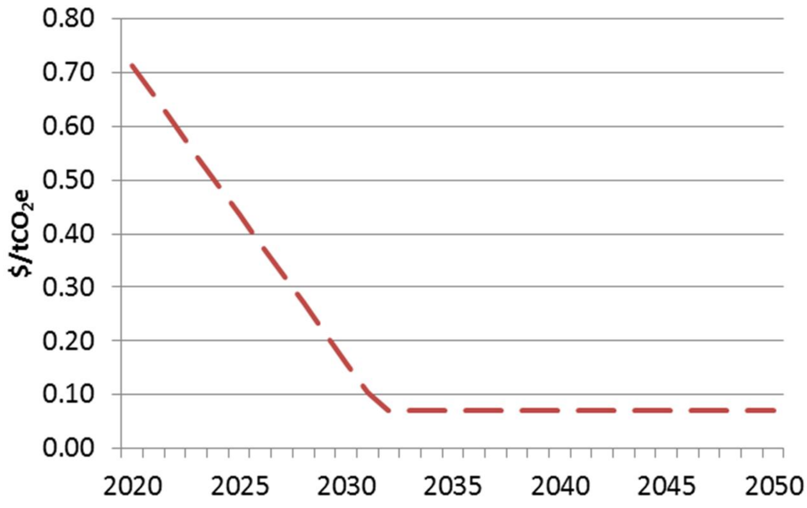


Source: Climate Change Authority calculation from IPCC, 2014. Working Group III Contribution to the Fifth Assessment Report, Climate Change 2014-Mitigation.

Under the Emission Intensity Target (EIT) scheme generators are issued permits calculated as the product of their actual generation and the emission intensity of the year's baseline, and must surrender permits at the end of the year in accordance with their total emissions. The baseline is set to decline linearly over time. The scheme allows for unlimited banking of permits, so that early abatement can be used at a later point in time, but only limited borrowing from future years. A full description of this policy can be found in Jacobs' report 'Modelling illustrative electricity sector emissions reduction policies'.

Figure 2 shows the emission intensity baseline modelled in this scenario. It is identical to the baseline used in the first phase of the modelling, starting at 0.71 t CO_2-e/MWh in 2019/20 and linearly declining to 0.07 t CO_2-e/MWh in 2032, and then staying constant until the end of the modelling horizon.

Figure 2: Emission intensity baseline



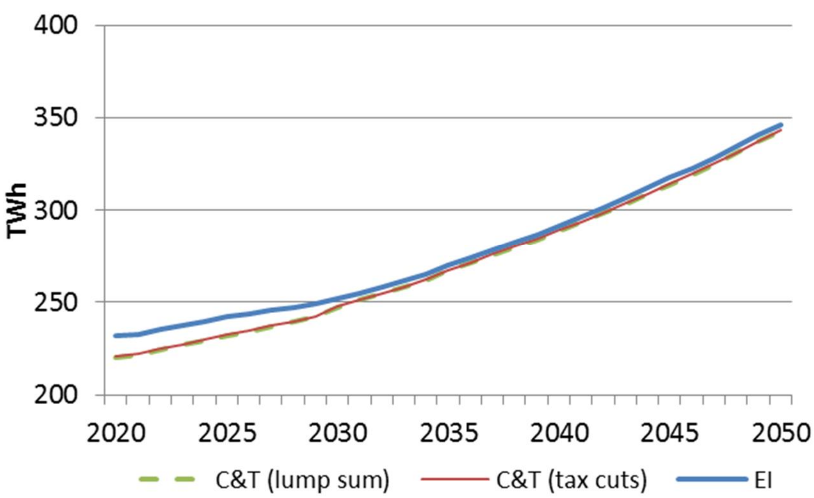
Source: Jacobs

3.1.2 Electricity demand

The demand of electricity for this set of model runs is shown in Figure 3. It is based on Jacobs' analysis of Victoria University CGE model electricity demand outputs (see Appendix C.2). This method is different to that used in the electricity sector only modelling, when a core demand projection was adjusted between scenarios based on differences in electricity prices and assumed demand elasticities.

Electricity demand in both the Cap and Trade scenarios is very similar, starting at around 220 TWh in 2019/20 and reaching 343 TWh in 2049/50. Demand is slightly higher in the Emission Intensity scenario due to its lower electricity prices (see section 3.2.3), starting at around 232 TWh in 2019/20 and reaching 346 TWh at the end of the modelling horizon.

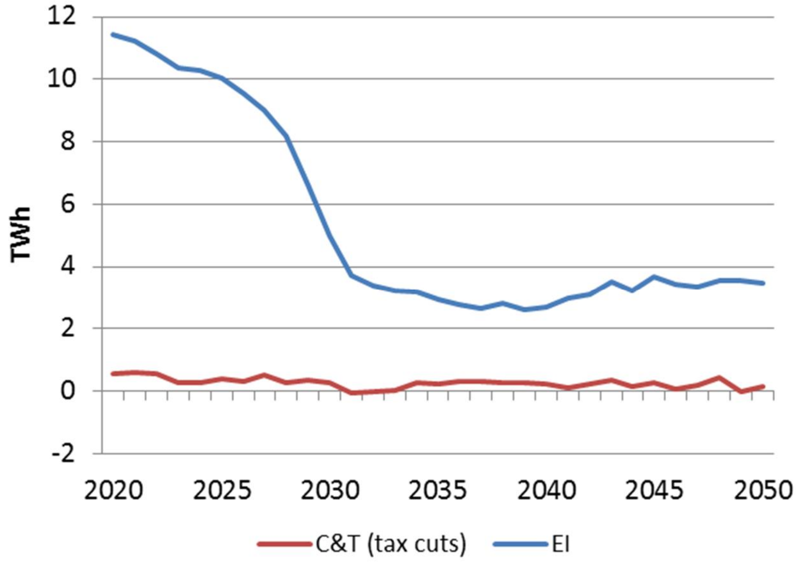
Figure 3: Electricity demand for Cap and Trade and Emission Intensity scenarios



Source: Victoria University and Jacobs Note: In this and all subsequent figures" C&T" stands for "Cap and Trade " and "EI" stands for "Emission Intensity"

Figure 4 shows the demand of electricity for the Cap and Trade (tax cuts) and Emission Intensity scenarios relative to the Cap and Trade (lump sum) scenario. The two Cap and Trade scenarios have almost identical demand, while the electricity demand for the Emission Intensity scenario is around 5% higher for the first eight years falling to only 1% higher after 2029/30. This is because the Emission Intensity policy causes smaller increases to consumer prices than a cap and trade scheme (see section 3.2.3).

Figure 4: Electricity demand for Cap and Trade (tax cuts) and Emission Intensity scenarios relative to the Cap and Trade (lump sum) scenario



Source: Jacobs

3.2 Results

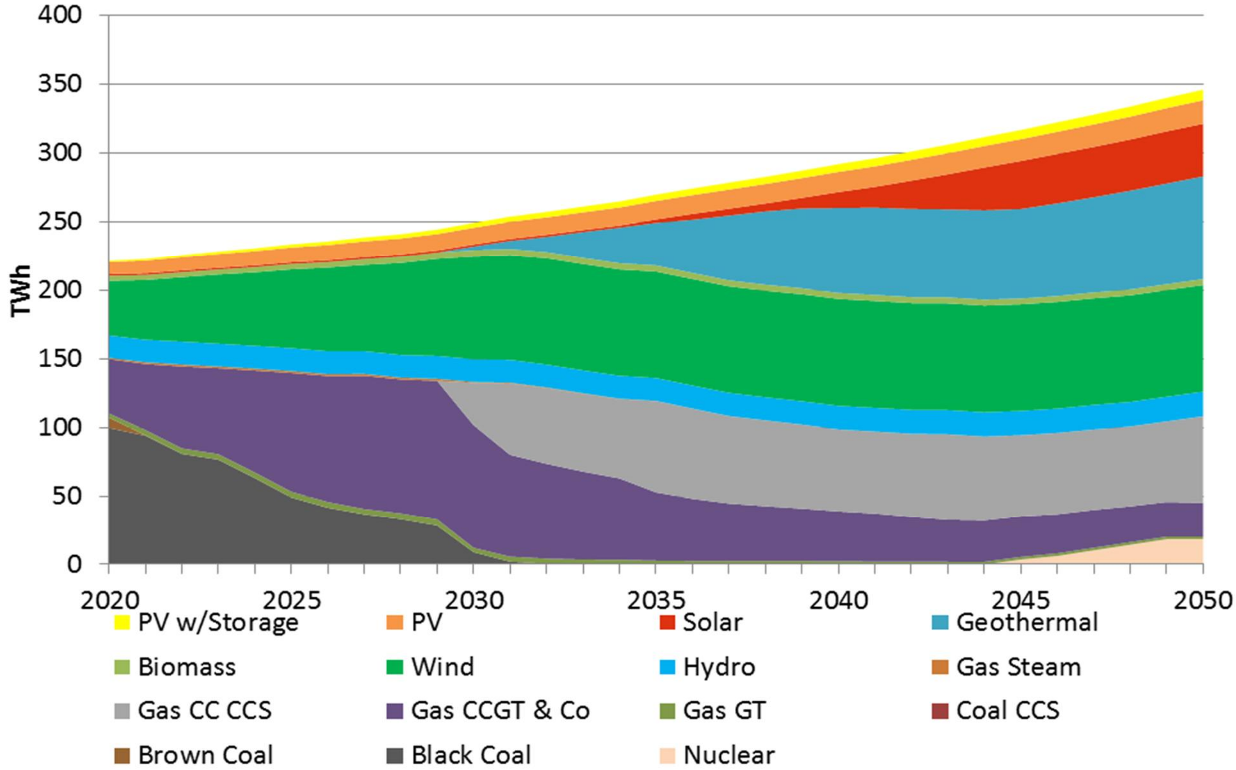
3.2.1 Generation and capacity

Figure 5, Figure 6 and Figure 7 show the generation mix across the modelling horizon in the Cap and Trade (lump sum), Cap and Trade (tax cuts) and Emission Intensity scenarios respectively. Some key features are the sharp and steadily diminishing role played by coal fired generation throughout the 2020s and the transitional role played by CCGTs in the 2020s, where they act as a partial substitute for retiring coal fired capacity. They in turn get displaced post 2030 by newly available low emission technology[2], such as CCGTs with CCS and geothermal. Wind remains a key technology throughout the modelling horizon, by steadily increasing its generation share in the NEM and WEM in the 2020s and providing around a quarter of all grid generation in 2049/50. The four technologies with largest growth post 2030 are CCGTs with CCS, followed by geothermal, large-scale solar and nuclear.

The higher demand in the EI scenario relative to the Cap and Trade cases brings forward some additional investment to low emissions generators. This results in slightly higher generation in the EI scenario from gas plants and wind generators during the first decade. For the subsequent modelled years the generation from gas with CCS is marginally higher relative to the Cap and Trade cases, substituting some geothermal and solar generation.

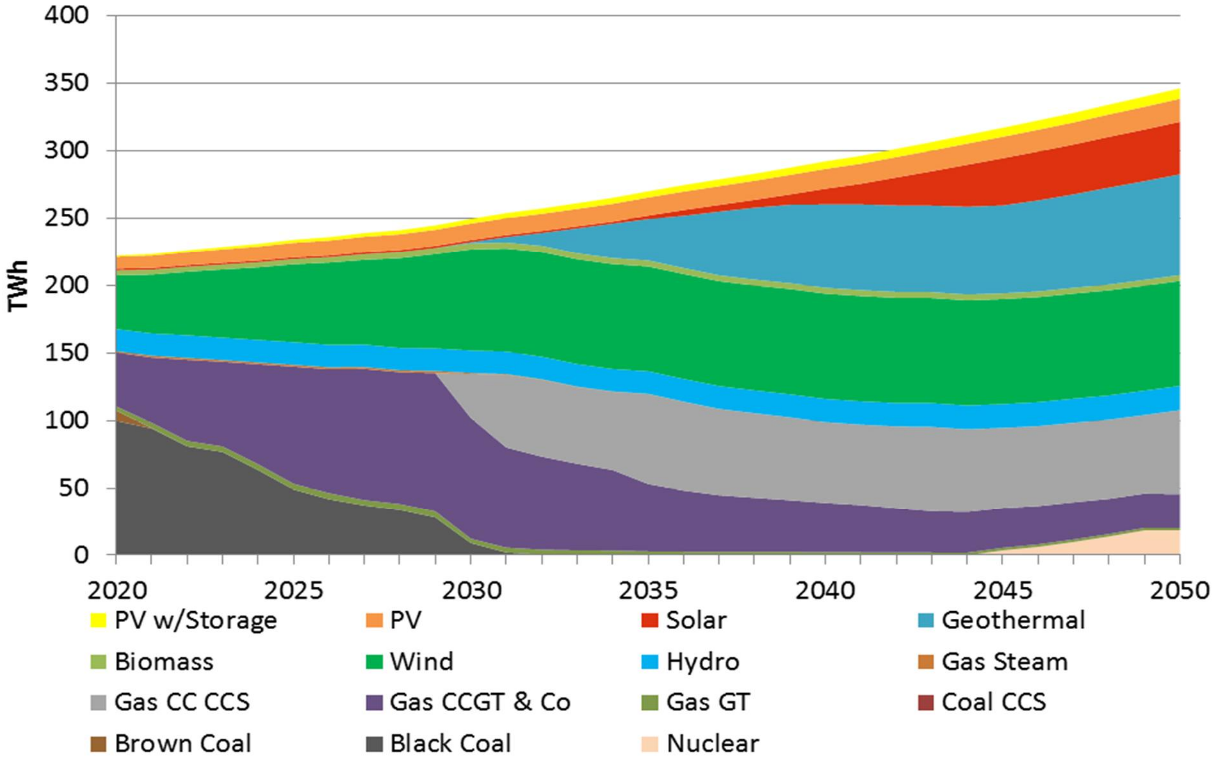
[2] The technology-specific restrictions are the same as in those applied in the 'Modelling illustrative electricity sector emissions reduction policies' report and are given in detail in Appendix C.4.8

Figure 5: Generation mix, Cap and Trade (lump sum) scenario



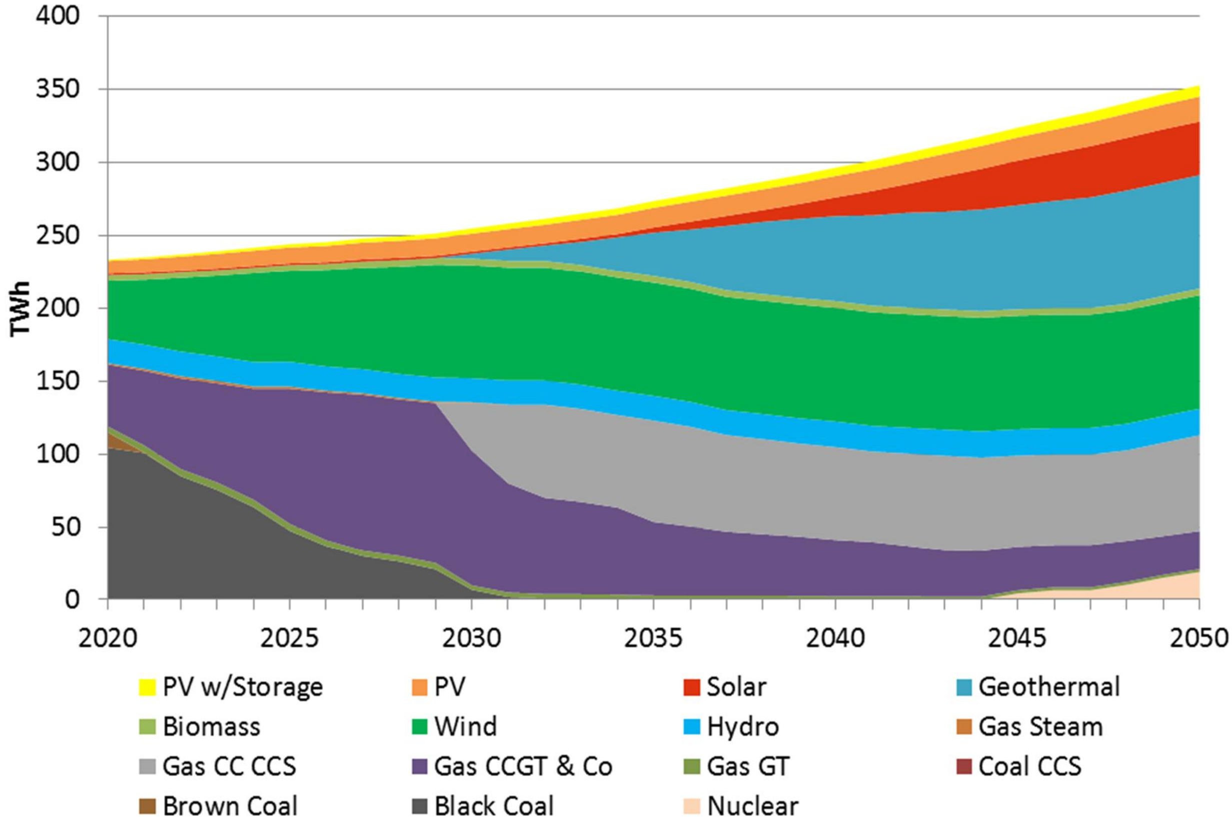
Source: Jacobs Note: In this and all subsequent figures, ‘PV’ and ‘PV w/storage’ are small scale solar PV, while ‘Solar’ comprises large-scale solar PV and solar thermal plants.

Figure 6: Generation mix, Cap and Trade (tax cuts) scenario



Source: Jacobs

Figure 7: Generation mix, Emission Intensity scenario



Source: Jacobs

The share of generation by technology type, as shown in Table 1, is similar for all three scenarios, reflecting the similar carbon price that is applied to the modelled schemes.

Table 1 Share of generation by technology type, % of total generation

Scenario	2030				2050			
	Coal	Gas	Renewable	Other low emission	Coal	Gas	Renewable	Other low emission
Cap and trade (lump sum)	4%	37%	47%	12%	0%	8%	69%	24%
Cap and trade (tax cuts)	4%	38%	46%	13%	0%	8%	69%	23%
Emission Intensity	3%	38%	47%	13%	0%	8%	68%	24%

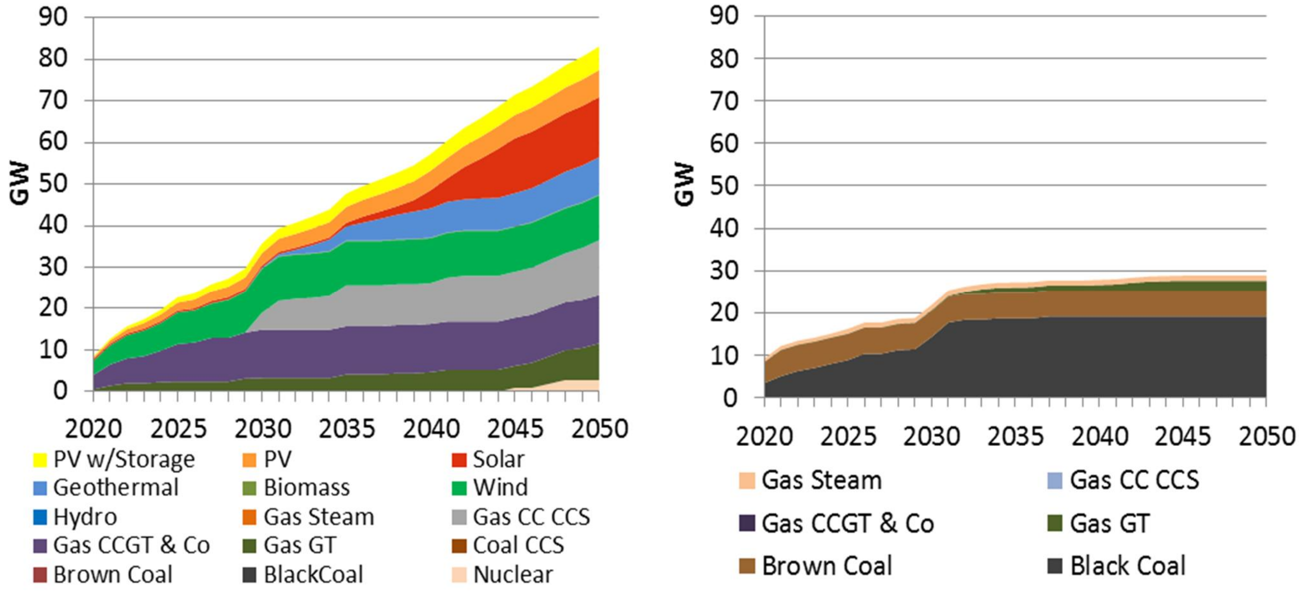
Source: Jacobs. Sums across the rows may not add up to 100 due to rounding, 'Other low emission' is gas CCS and nuclear (coal CCS was available but not deployed in any scenario).

The cumulative new generation capacity across the NEM and WEM on the left and retired capacity on the right for the three scenarios is shown in Figure 8, Figure 9, and Figure 10. The same trends are evident as those mentioned above, but in capacity terms it is notable that the solar generation (large-scale and rooftop) has higher growth than the other low emission technologies.

Trends across all three scenarios are very similar. Regarding the retirement of the high emission intensity generation fleet, all brown coal plants have retired by 2021, while almost all the black coal generators retire gradually in the 2020s. Some older and inefficient gas plants are also mothballed especially after 2030 when new low emission generators such as CCGTs with CCS and geothermal become available.

Figure 8: Cumulative new and retired capacity by technology type, Cap and Trade (lump sum) scenario

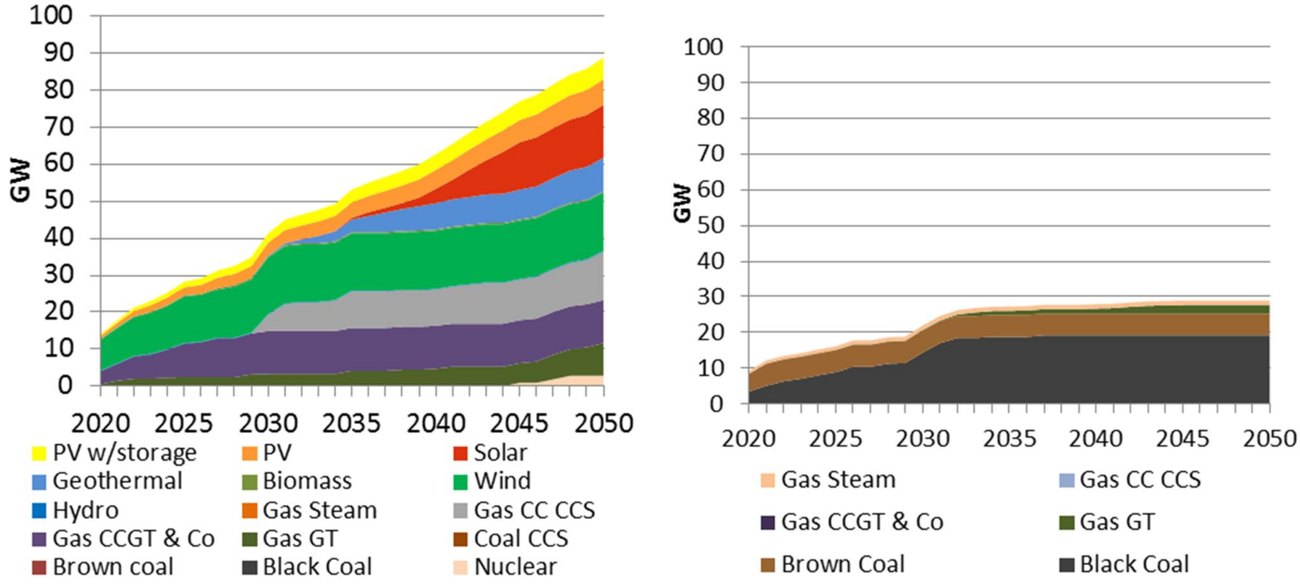
The left graph shows absolute new cumulative capacity. The right graph shows retired capacity.



Source: Jacobs

Figure 9: Cumulative new and retired capacity by technology type, Cap and Trade (tax cuts) scenario

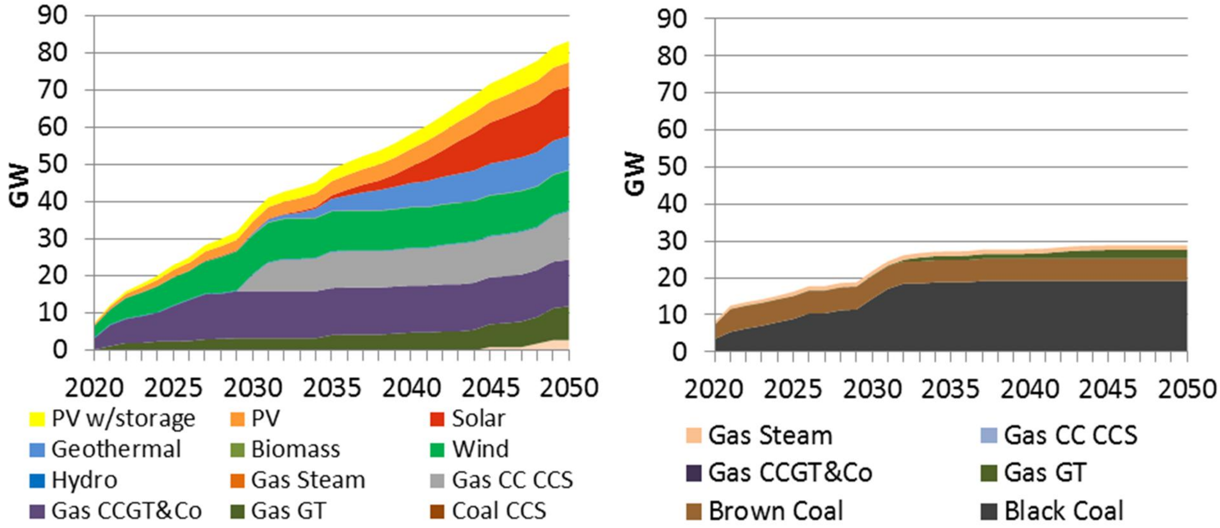
The left graph shows absolute new cumulative capacity. The right graph shows retired capacity.



Source: Jacobs

Figure 10: Cumulative new and retired capacity by technology type, Emission Intensity scenario

The left graph shows absolute new cumulative capacity. The right graph shows retired capacity.



Source: Jacobs

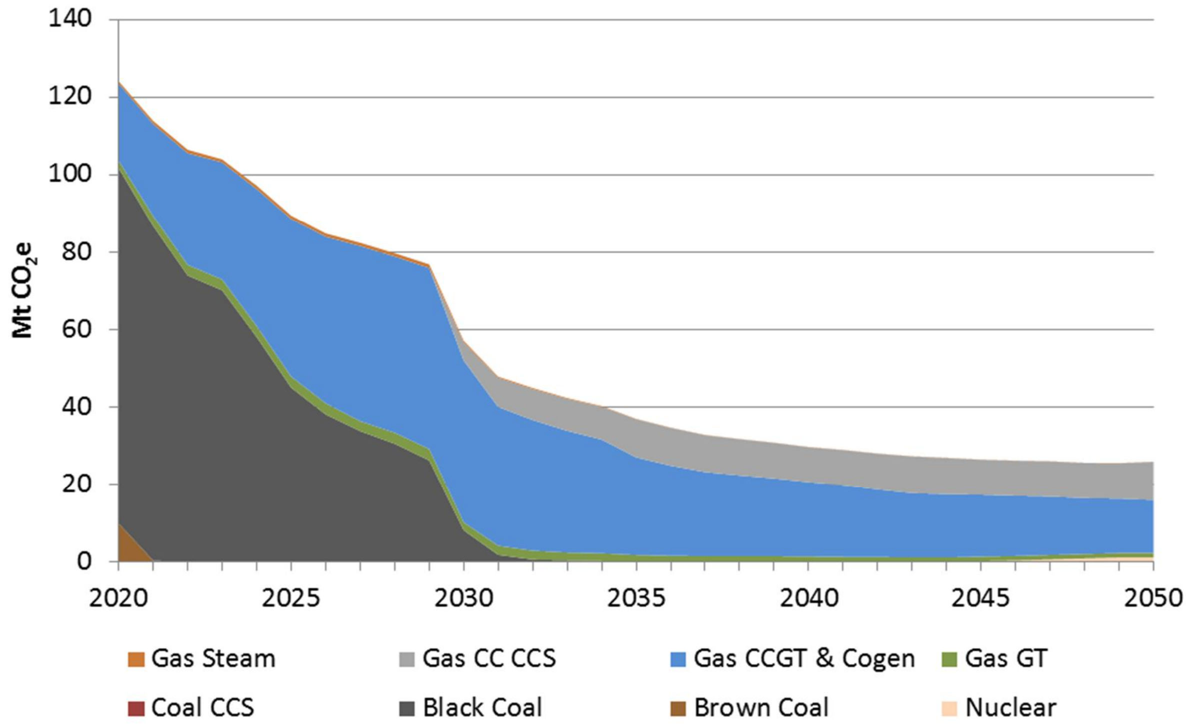
3.2.2 Emissions

The annual emissions by technology are presented in Figure 11, Figure 12, and Figure 13 for the Cap and Trade (lump sum), Cap and Trade (tax cuts) and Emission Intensity scenarios respectively. The figures include both direct and indirect emissions resulting from electricity generation. The cumulative direct and indirect emissions across the modelling horizon amount to 1,655 Mt CO_2-e in the lump sum scenario and 1,661 Mt CO_2-e in the tax cuts scenario mainly due to slightly higher demand. In the Emission Intensity scenario the cumulative emissions to 2049/50 are 1,666 Mt CO_2-e.

In both the Cap and Trade scenarios, the emissions in 2019/20 are around 124 Mt CO_2-e which is significantly lower than today's emissions due to the immediate closure of the brown coal plants in the modelling. A steady decline of emissions continues for the next 10 years following the retirement of the black coal generators. The sharp drop in 2030 is due to the introduction of geothermal and CCGT with CCS technology, displacing CCGT generation. Emissions settle at around at 27 Mt CO_2-e per annum for the last 10 years, with over 35% of these emissions being indirect.

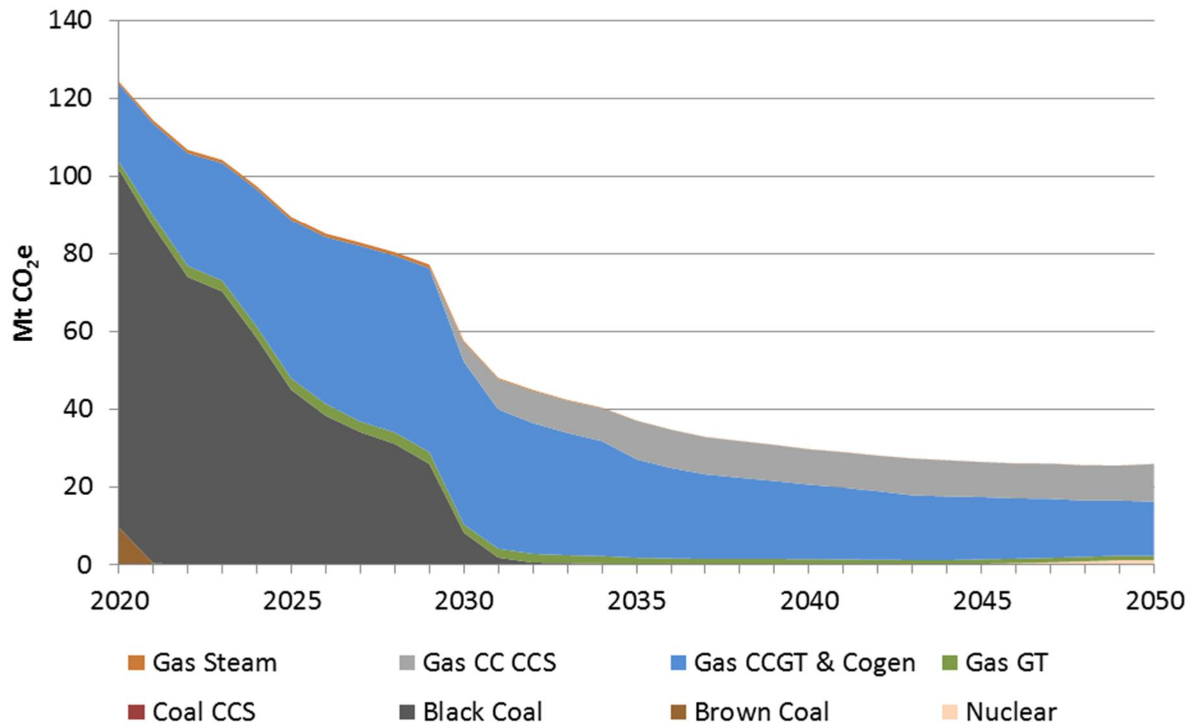
In the Emission Intensity case, the initial drop in emissions in 2019/20 is not as sharp as that of Cap and Trade scenarios, with emissions starting at 133 Mt CO_2-e. The difference is driven by the additional demand under the Emission Intensity scenario, resulting in increased generation from the remaining coal plants in the NEM and WEM.

Figure 11: Emissions by technology, Cap and Trade (lump sum) scenario



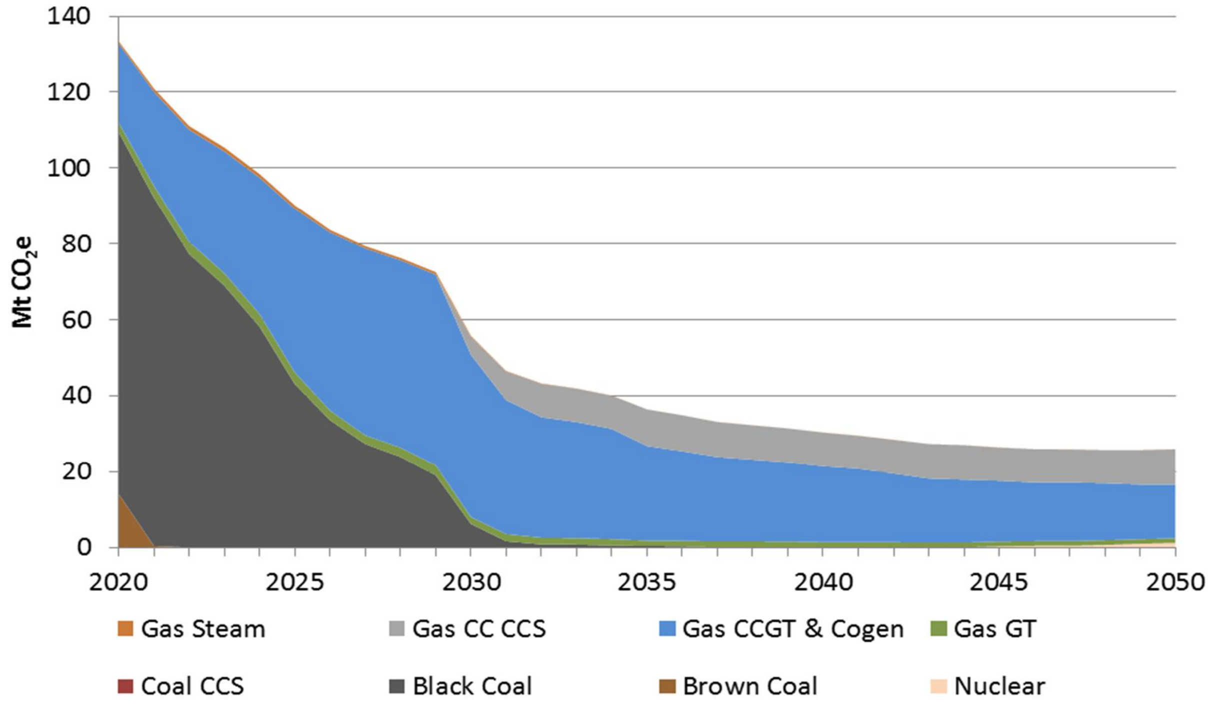
Source: Jacobs. Includes both direct and indirect emissions.

Figure 12: Emissions by technology, Cap and Trade (tax cuts) scenario



Source: Jacobs. Includes both direct and indirect emissions.

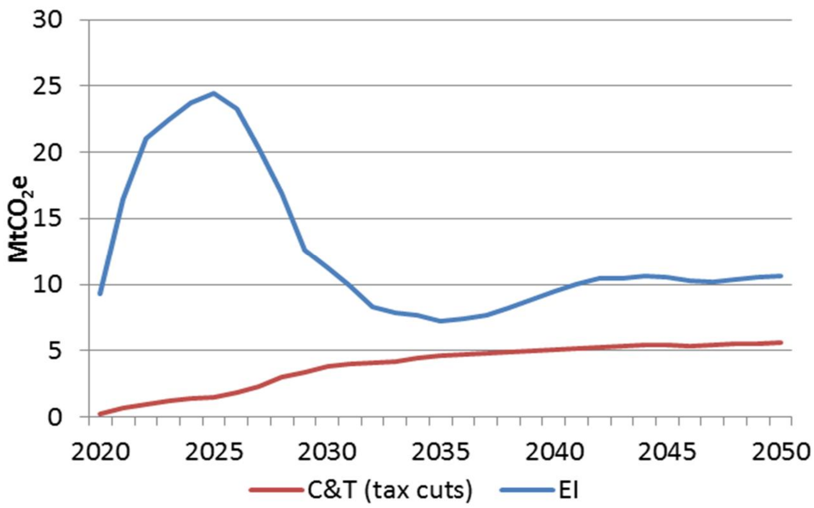
Figure 13: Emissions by technology, Emission Intensity scenario



Source: Jacobs. Includes both direct and indirect emissions.

Unlike in the electricity sector only modelling there is no cumulative emission constraint over the modelled horizon. Figure 14 shows the cumulative emissions of the Cap and Trade (tax cuts) and Emission Intensity scenarios relative to the Cap and Trade (lump sum) scenario. The cumulative emissions in the tax cuts scenario are marginally higher than lump sum recycling, predominantly due to higher electricity demand, ending up 5 Mt CO_2-e higher, which represents only 0.3% of cumulative emissions. In the Emission Intensity case, the higher electricity demand results in higher cumulative emissions relative to the Cap and Trade (lump sum) scenario by around 10 Mt CO_2-e, by the end of the modelling horizon.

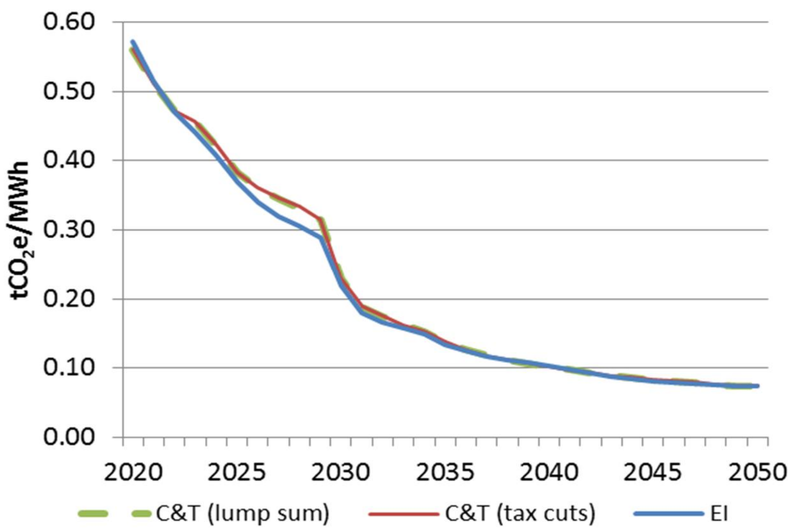
Figure 14: Cumulative emissions of Cap and Trade (tax cuts) and Emission Intensity scenarios relative to the Cap and Trade (lump sum) scenario



Source: Jacobs

Figure 15 presents the generation emission for all three scenarios. It is noticeable that after 2023/24 the average emissions intensity of generation is slightly lower under EI, since the higher demand brings forward some additional low emissions generation, particularly gas and wind, relative to the Cap and Trade scenarios. This effect is temporary because after 2029/30 the marginally higher investment in gas with CCS technology (in the EI scenario) instead of geothermal and solar (in the Cap and Trade scenarios) brings the emission intensity on par for all three cases.

Figure 15: Generation emission intensity



Source: Jacobs

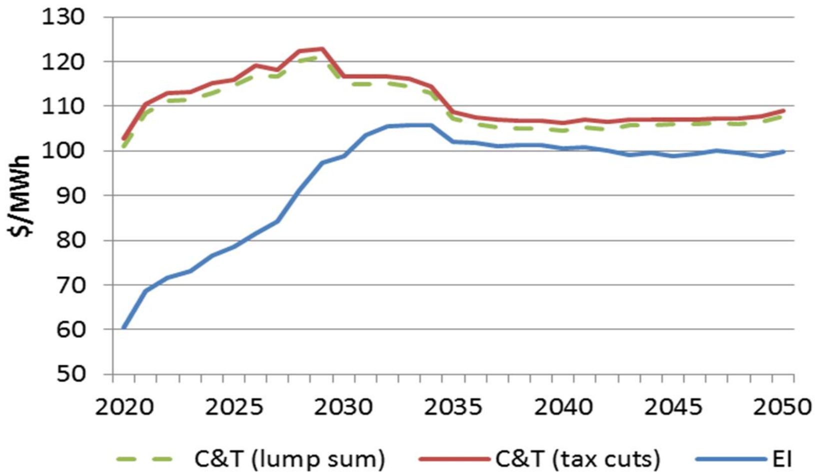
3.2.3 Prices

The wholesale electricity time-weighted prices weighted by regional demand are presented in Figure 16. In the two Cap and Trade cases, the carbon penalty imposed causes prices to immediately rise in 2019/20 compared to current wholesale prices. Following the escalating carbon price the rise in wholesale prices continues to 2029/30 when new low emission technologies become available, causing the wholesale prices to converge to the long-run marginal cost (LRMC) of these technologies. These new technologies are marginally[3] or not at all[4] exposed to the rising carbon price and therefore cause wholesale prices to reach a plateau of around $106 per MWh after 2035. Furthermore, effective decarbonisation is largely achieved in the mid-2030s so the wholesale price becomes relatively insensitive to further carbon price increases. Both the Cap and Trade policies have a very similar impact on prices, with the tax cuts policy scenario giving rise to slightly higher wholesale prices relative to the lump sum recycling scenario, mainly due to the marginally higher demand.

In the Emission Intensity scenario, the apparent upward linear trend in the wholesale price during the first twelve years is mainly driven by the downward linear trend in the emission baseline as shown in Figure 2. Prices start at $61/MWh and rise to $106/MWh in the early 2030s when they eventually reach the LRMC of the newly available low emission plants (CCGT with CCS and geothermal). Long term prices are slightly lower than the carbon price because the long-term emission baseline is non-zero: that is, many generators receive a small subsidy, supressing wholesale prices below the level that would be obtained under a carbon pricing mechanism.

[3] E.g. CCGTs with CCS after 2030 and nuclear after 2035
[4] Geothermal plants

Figure 16: Wholesale prices, volume weighted average

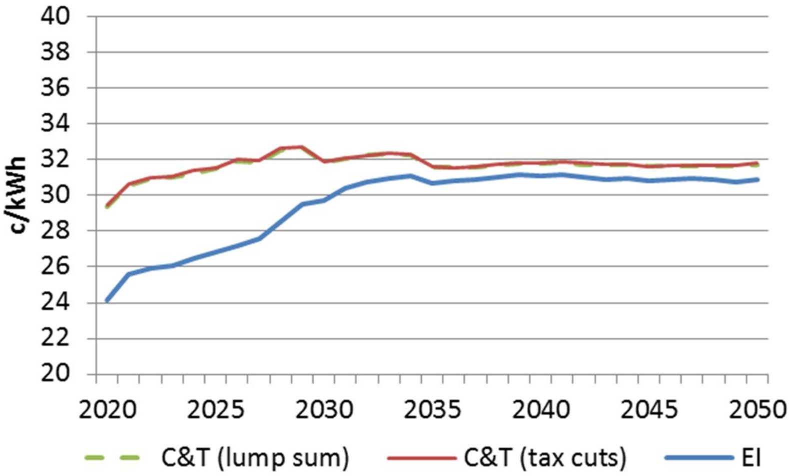


Source: Jacobs

The same trend applies to retail prices but the relative price movements are more muted since the wholesale price only comprises typically 30% to 40% of the retail price over the modelling horizon (more information on other components of retail prices is provided in Appendix B.2). Residential retail prices for the three policies are shown in Figure 17.

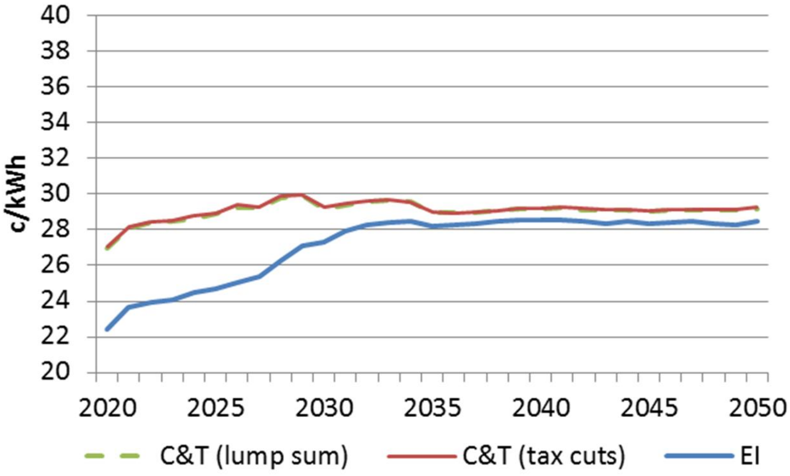
Trends in retail prices for small to medium enterprise (SME) and industrial customers are broadly similar, in that they are initially substantially lower under the Emissions Intensity scenario than the two Cap and Trade scenarios, but converge over time. This is shown in Figure 18 for SME prices and in Figure 19 for industrial retail prices.

Figure 17: Retail residential prices, volume weighted average



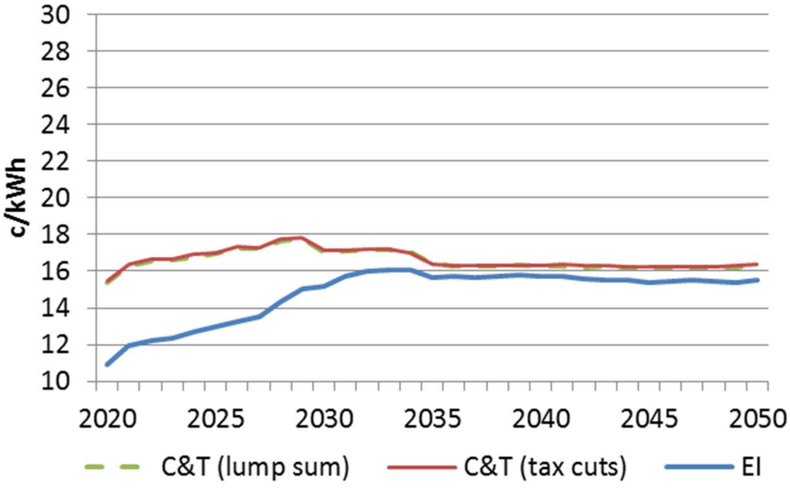
Source: Jacobs

Figure 18: Retail prices for SME customers, volume weighted average



Source: Jacobs

Figure 19: Retail prices for industrial customers, volume weighted average



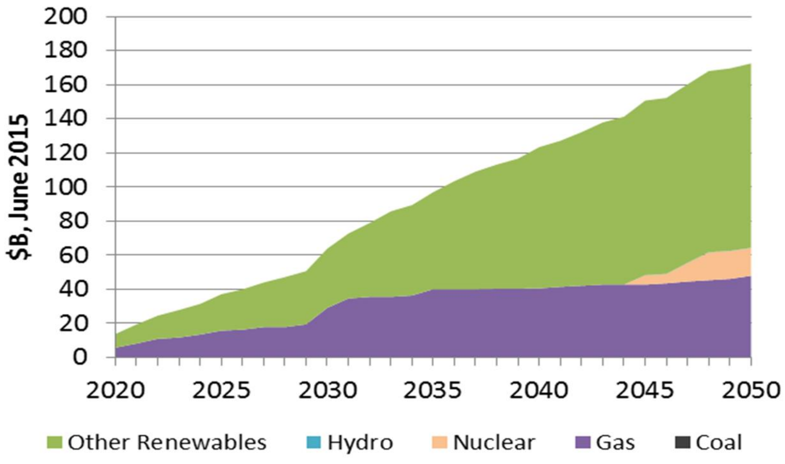
Source: Jacobs

3.2.4 Resource costs

The cumulative capital expenditure by technology for all three scenarios is shown in Figure 20, Figure 21 and Figure 22. In all scenarios there is a substantial capital expenditure in the renewable sector over the modelling horizon. In addition to renewables, some significant investment in gas generation is required over the first ten years, so as to substitute the retired coal fleet and maintain sufficient firm capacity in the NEM and WEM. The introduction of gas CCGTs with CCS in 2030 sees a sharp increase of capital expenditure in gas plants. At the same time the spending for renewable projects becomes steeper, following the introduction of geothermal plants and the further decrease in solar plant costs. Some investment in nuclear plant occurs after 2045.

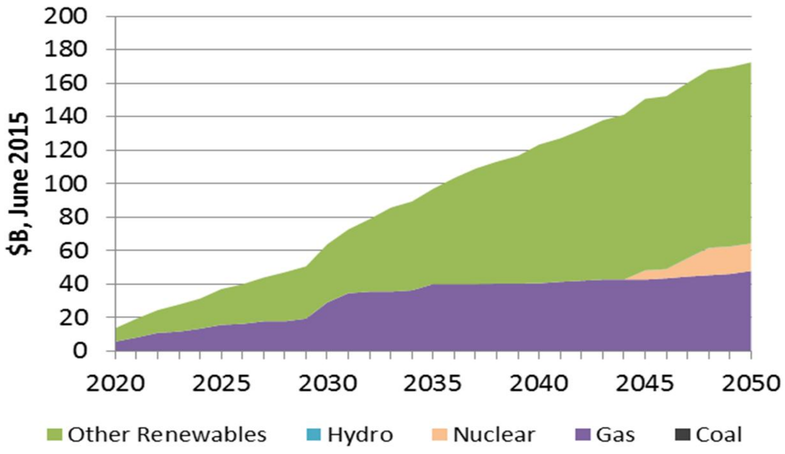
The annualised resource costs by four cost categories are shown in Figure 23, Figure 24 and Figure 25. Costs in 2019/20 are initially about $15.5 billion per annum and remain at a similar level until 2022/23. After that, total costs start to escalate steadily. The capital costs are the main contributor of that increase, while the fuel costs steadily decrease after 2034/5 since most of the fuel intensive generation fleet is replaced by renewable technologies.

Figure 20: Cumulative capital expenditure by technology, Cap and Trade (lump sum) scenario



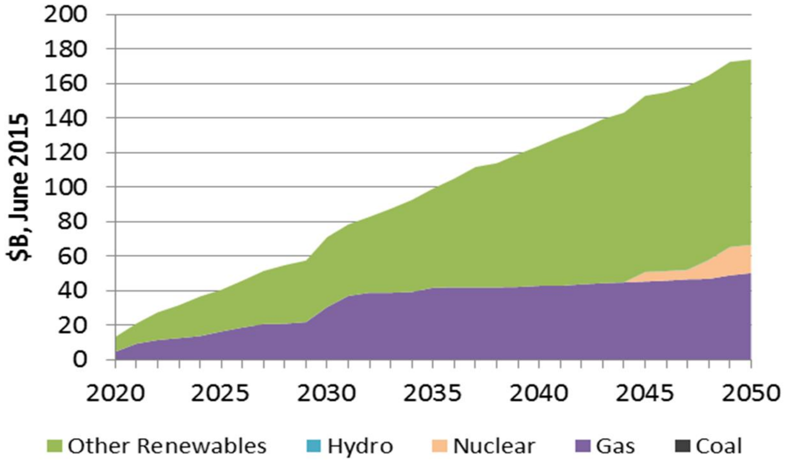
Source: Jacobs

Figure 21: Cumulative capital expenditure by technology, Cap and Trade (tax cuts) scenario



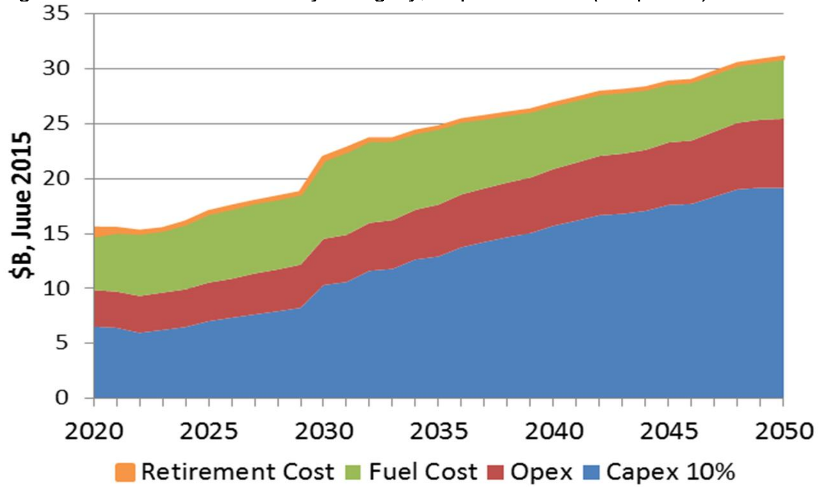
Source: Jacobs

Figure 22: Cumulative capital expenditure by technology, Emission Intensity scenario



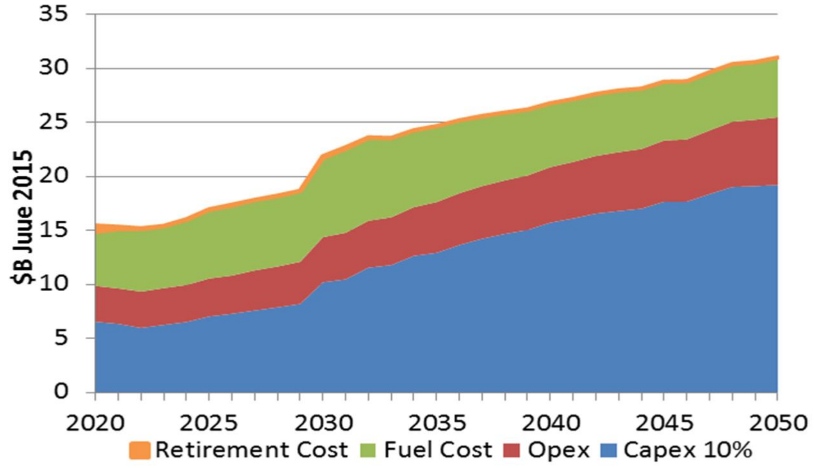
Source: Jacobs

Figure 23: Annualised costs by category, Cap and Trade (lump sum) scenario



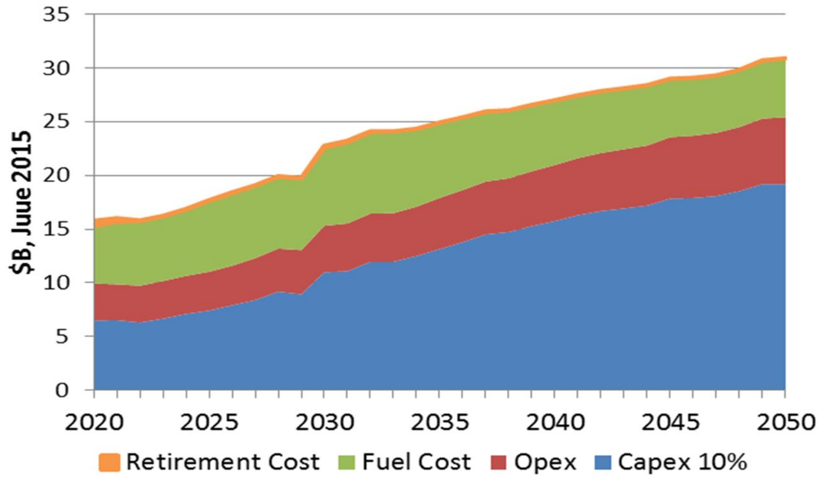
Source: Jacobs. The annualised capital costs are calculated using a discount rate of 10% and so are described as 'capex 10%'

Figure 24: Annualised costs by category, Cap and Trade (tax cuts) scenario



Source: Jacobs. The annualised capital costs are calculated using a discount rate of 10% and so are described as 'capex 10%'

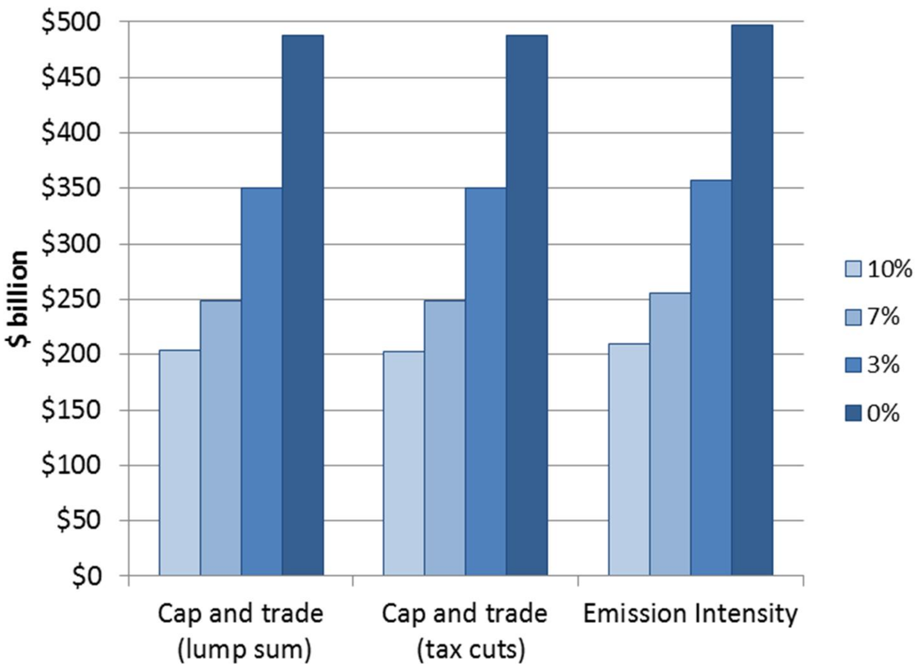
Figure 25: Annualised costs by category, Emission Intensity scenario



Source: Jacobs. The annualised capital costs are calculated using a discount rate of 10% and so are described as 'capex 10%'

As shown in Figure 26 all three policies have very similar resource costs. The two Cap and Trade scenarios range from $203 billion (for 10% discounting) to $488 billion (with no discounting), while the Emission Intensity scenario is slightly higher ranging from $210 billion to $497 billion. The difference is predominantly driven by the higher demand in the Emission Intensity scenario.

Figure 26: NPV of resource costs for different discount rates



Source: Jacobs, Note: Resource costs are not adjusted for differences in demand between scenarios and so are not directly comparable with resource costs presented for the electricity sector only modelling.

3.2.5 Summary

Outcomes for the two Cap and Trade scenarios are very similar, with the main difference being slightly higher electricity demand in the tax cut scenario (due to higher levels of economic activity), which also drives slightly higher prices and slightly higher emissions.

Differences between the Emissions Intensity scenario and the Cap and Trade scenarios are slightly larger, but still modest overall. Lower prices under the Emission Intensity scenario lead to higher electricity demand, resource costs and emissions relative to the Cap and Trade scenarios. The higher demand also brings forward more investment in low emissions generators in the late 2020s, temporarily lowering the emissions intensity of generation in the Emissions Intensity scenario below that in the Cap and Trade scenarios. However, this effect is small and temporary.

In general, differences in the generation mix, emissions intensity and resource costs between the scenarios are very minor. The main difference is the price differential between the Emissions Intensity scenario and the Cap and Trade scenarios. This has flow-on effects in the economy-wide modelling undertaken by Victoria University. Readers with an interest in the economy-wide outcomes for these scenarios should refer to Victoria University's report 'Simulations of the effects of greenhouse gas mitigation policies for the Australian electricity sector'.

Appendix A. Modelling suite

A.1 Strategist

Jacobs uses its market simulation model of the energy markets (NEM and WEM) to estimate the impacts on the electricity markets. Electricity market modelling was conducted using Jacobs' energy market database and modelling tools in conjunction with use of probabilistic market modelling software called Strategist. Strategist represents the major thermal, renewable, hydro and pumped storage resources as well as the interconnections between different regions. Average hourly pool prices are determined within Strategist based on plant bids derived from marginal costs or entered directly.

In terms of selection of new generators and dispatch of generating plant, both the NEM and WEM are modelled in the same way using Strategist.

Market impacts are essentially driven by the behavioural responses of the generators to the incentives and/or regulatory requirements of the policy options being examined and the change in the mix of investment due to the incentives provided by the policy options. Wholesale prices are affected by the supply and demand balance and long-term prices being effectively capped near the long run marginal cost of new entry on the premise that prices above this level provide economic signals for new generation to enter the market. Generation mix and other impacts are also influenced by the incentives or regulations provided by the policy option being examined. Other factors affecting the timing and magnitude of the impacts include projected fuel costs, unit efficiencies and capital costs of new plant.

The market impacts take into account regional and temporal demand forecasts, generating plant performance, timing of new generation including renewable projects, existing interconnection limits and potential for interconnection development.

The primary tool used for modelling the wholesale electricity market is Strategist, proprietary software licensed from Ventyx that is used extensively internationally for electricity supply planning and analysis of market dynamics. Strategist simulates the most economically efficient unit dispatch in each market while accounting for physical constraints that apply to the running of each generating unit, the interconnection system and fuel sources. Strategist incorporates chronological hourly loads (including demand side programs such as interruptible loads and energy efficiency programs) and market reflective dispatch of electricity from thermal, renewable, hydro and pumped storage resources.

The Strategist model is a multi-area probabilistic dispatch algorithm that determines dispatch of plant within each year and the optimal choice of new plant over the period to 2050. The model accounts for the economic relationships between generating plant in the system. In particular, the model calculates production of each power station given the availability of the station, the availability of other power stations and the relative costs of each generating plant in the system. The timing of new thermal generation plant and interconnection upgrades is determined by a dynamic programming algorithm that seeks to minimise total system production and new capital costs.

The model incorporates:

- Chronological hourly loads representing a typical week in each month of the year. The hourly load for the typical week is consistent with the hourly pattern of demand and the load duration curve over the corresponding month.
- Chronological dispatches of hydro and pumped storage resources either within regions or across selected regions (hydro plant is assumed to shadow bid to maximise revenue at times of peak demand).
- A range of bidding options for thermal plant (fixed prices, shadow bidding, average price bidding).
- Chronological dispatch of demand side programs, including interruptible loads.

- Estimated inter-regional trading based on average hourly market prices derived from bids and the merit order and performance of thermal plant, and quadratic inter-regional loss functions.
- Scheduled and forced outage characteristics of thermal plant.

The model projects electricity market impacts for expected levels of generation for each generating unit in the system. The level of utilisation depends on plant availability, their cost structure relative to other plant in the system and bidding strategies of the generators. Bids are typically formulated as multiples of marginal cost and are varied above unity to represent the impact of contract positions and price support provided by dominant market participants.

New plant, whether to meet load growth or to replace uneconomic plant, are chosen on a least cost basis subject to meeting two criteria:

- To ensure electricity reliability are met under most contingencies. The parameters for quality of supply are determined in the model through the loss of load, energy not served and reserve margin. We have used a maximum energy not served of 0.002% on a regional basis, which is in line with planning criteria used by system operators. For this project an additional deterministic reliability constraint is enforced, as outlined in Appendix B.
- Revenues earned by the new plant equal or exceed the long run average cost of the new generator.

Each power plant is considered separately in the model. The plants are divided into generating units, with each unit defined by minimum and maximum operating capacity, heat rates, planned and unplanned outages, fuel costs and operating and maintenance costs. Minimum operating capacities are enforced under all policy scenarios – for policies such as absolute baseline scenario the limit is applied on generation levels across the year not on what can be generated in a dispatch interval. For further details on treatment of minimum capacity under the absolute baseline scenario see Section 2.

Strategist also accounts for inter-regional trading, scheduled and forced outage characteristics of thermal plant (using a probabilistic mechanism), and the implementation of government policies such as the Renewable Energy Target (RET) schemes.

Timing of new generation is determined by a generation expansion plan that defines the additional generation capacity that is needed to meet future load or cover plant retirements by maintaining minimum reserve and reliability standards. As such by comparing a reference case to a policy scenario, we can quantify any deferred generation benefits. The expansion plan has a sustainable wholesale market price path, applying market power where it is evident, a consistent set of renewable and thermal new entry plant and a requirement to meet reserve constraints in each region. Every expansion plan for the reference and policy scenarios in this study has been checked and reviewed to ensure that these criteria are met.

Strategist represents the major thermal, hydro and pumped storage resources as well as the interconnections between the NEM regions. In addition, Jacobs partitions Queensland into three zones to better model the impact of transmission constraints and the trends in marginal losses and generation patterns change in Queensland. These constraints and marginal losses are projected into the future based on past trends.

Average hourly pool prices are determined within Strategist based on thermal plant bids derived from marginal costs or entered directly. The internal Strategist methodology is represented in Figure 27 and the Jacobs modelling procedures for determining the timing of new generation and transmission resources, and bid gaming factors are presented in Figure 28.

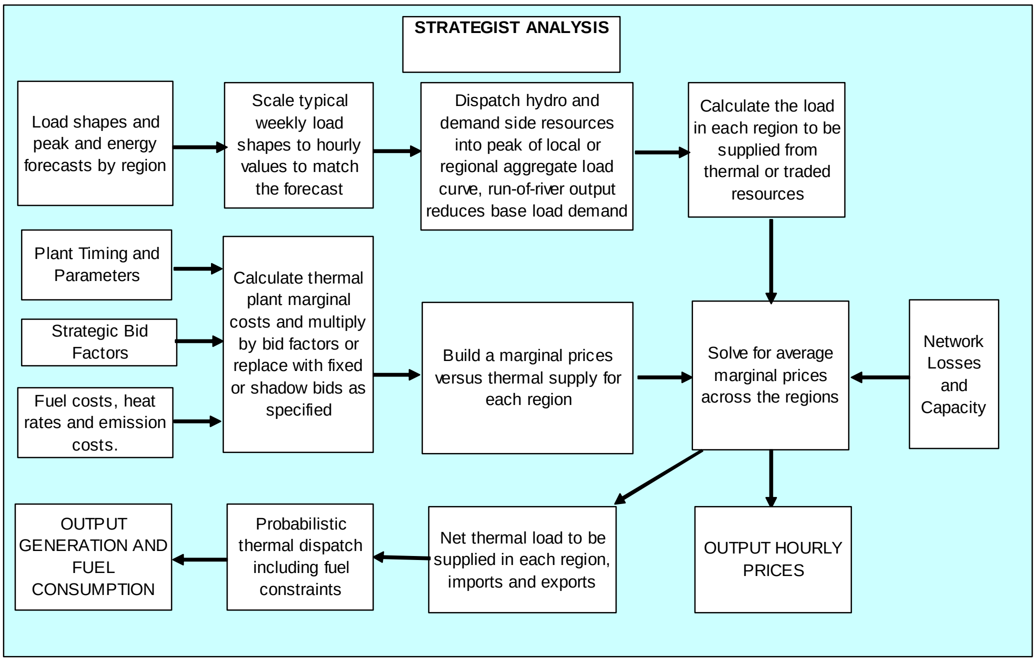
The PROVIEW module of Strategist is used to develop the expansion plan with a view to minimising the total costs of the generation system plus interconnection augmentation. This is similar to the outcome afforded by a competitive market. However due to computational burden and structural limitations of the Strategist package, in one simulation it was not feasible to complete:

- The establishment of an optimal expansion plan (multiplicity of options and development sequences means that run time is the main limitation), and
- A review of the contract positions and the opportunity to exercise market power.

We therefore, conducted a number of iterations of PROVIEW to develop a workable expansion plan and then refined the expansion plan to achieve a sustainable price path applying market power where it was apparent and to obtain a consistent mix of new entry plant.

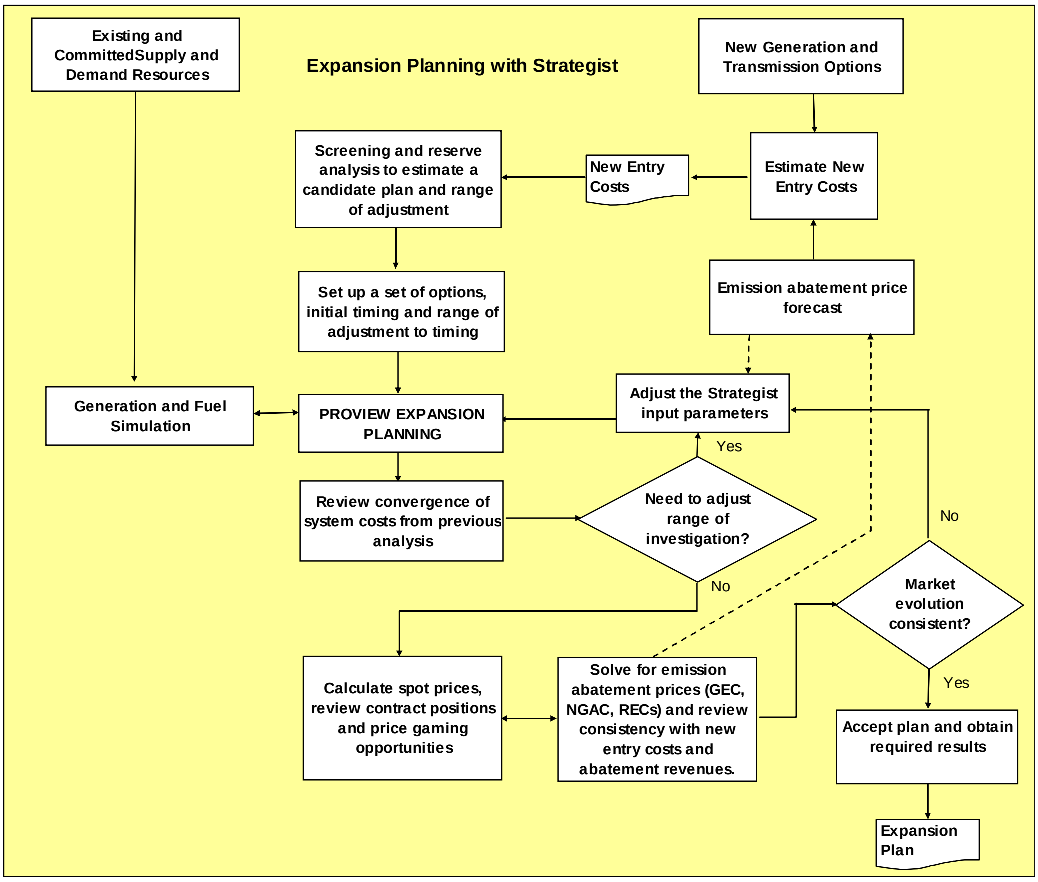
Strategist generates average hourly marginal prices for each hour of a typical week for each month of the year at each of the regional reference nodes, having regard to thermal plant failure states and their probabilities. The prices are solved across the regions of the NEM having regard to inter-regional loss functions and capacity constraints. Interregional capacity is increased in line with capacity needed to avoid prolonged substantial price separation between interconnected regions, with price separation not being greater than typical line losses. It was assumed that these expansions do not change existing interregional marginal losses.

Figure 27: Strategist Analysis Flowchart



Source: Jacobs

Figure 28: Jacobs Strategist Modelling Procedures



Source: Jacobs

A.2 DOGMMA

Uptake of small-scale renewable technologies is be affected by a number of factors. *DOGMMA* (Distributed On-site Generation Market Model Australia) determines the uptake of renewable technologies with and without storage based on net cost of generation (after FiT revenue and other subsidies are deducted from costs) versus net cost of grid delivered power. Because the cost of small-scale generation will vary by location and load factors, the model estimates uptake based on renewable and fuel resources and load levels within distribution regions.

The cost of small scale renewable energy technologies is treated as an annualised cost where the capital and installation cost of each component of a small scale generation system is annualised over the assumed lifespan of each component, discounted using an appropriate weighted average cost of capital. Revenues include sales of electricity to the grid using time weighted electricity prices on the wholesale and retail market (as affected by the emissions reduction policy), avoidance of network costs under any type of tariff structure, including upgrade costs if these can be captured, and the cost of avoided purchases from the grid.

The DOGMMA model determines uptake of small-scale renewable technologies which are then input into the Strategist model, where the level of small-scale technology uptake, especially that of rooftop PV, will effectively changes the load shape faced by the grid.

A.2.1 Optimisation approach

For each region, the model determines uptake of small-scale systems based on the level of uptake that minimises the cost of supplying electricity to the region. In other words, the model selects the level of small-scale generation that minimises electricity supply costs to the region. The level of uptake of small scale systems increases to the point where any further uptake leads to higher costs of electricity supply than the PV systems costs plus a premium for roof-top systems willing to be paid by consumers[5]. The optimisation matches the cost of small scale systems (capital costs and any operating costs) to the avoided grid supplied electricity costs (as seen by the customer). The costs of small-scale systems may be reduced by being eligible for a subsidy (for example, the sale of certificates generated under the SRES scheme), or the ability to earn revenue either through sale of surplus electricity generation (surplus to the needs of the householder or commercial business) or from enacted feed-in tariffs.

The optimisation is affected by a number of constraints, which are as follows:

- There is a limit to the maximum number of householders and commercial businesses that can install a system.

- The maximum proportion of residential households that can purchase the system is currently the same for each region and it is set at 55% of all households in the region[6]. This limit was determined by the number of separate dwellings (on the assumption that only separate dwellings would install systems) that are privately owned (on the assumptions that only privately owned dwellings would install systems), and allowing for some limits on installations for heritage or aesthetic reasons.

- The maximum proportion of commercial businesses that can install a system is 65% of electricity demand. Commercial customers are those in the wholesale and retail trade, schools, hospitals and government offices.

There are limits on the rate of uptake of each technology in each region. This constraint is designed to ensure there is not a sudden step up in installation rates once a flip point is reached (the point at which the cost of PV becomes cheaper than grid supplied electricity) and to account for any logistic constraints. Once the initial simulation is performed, these constraints are progressively relaxed if it appears the constraint is binding uptake unreasonably.

There are limits on the number of homes and business premises that can accommodate the large sized systems of above 10 kW. We do not have data on the distribution of size of household roof space by region, so this constraint is enforced to limit uptake to around 20% of total households in most regions

Each household or business is assumed to make only one investment, reflecting a rule of thumb that roof space is relatively scarce. This means that, where multiple investments have lower discounted net costs than would grid-sourced electricity only, that each household or business chooses the investment with the largest positive net present value given paths for retail electricity prices and system costs. This has the effect of limiting uptake of solar PV as households that install solar hot water systems cannot subsequently install solar PV. This assumption was relaxed in the alternative reference case.

The technology costs are also adjusted with premiums so that uptake predicted by the model matches historical uptake more closely. The premium reflects the willingness of some consumers to purchase PV systems even if the cost is above grid supply costs. We calculate the premium based on market survey data and other published market data. The premium is also one of the variables used to match modelled uptake

[5] The model allows a premium above grid supply costs for PV systems to account for the purchase behaviour of customers who are willing to pay more for their systems. The premium diminishes to zero as uptake increases on the assumption that only a portion of customers are willing to pay this premium.

[6] According to the ABS (see ABS (2013), *Household Energy Consumption Survey, Australia: Summary of results, 2012*, Catalogue No. 4670.0, Canberra, September), there are 8.7 million households in 2012 in Australia. Around 89.2% of these households where either separate dwellings or semi-detached dwellings (townhouses, flats). Around 67% of dwellings are privately owned. Assuming that this number is applied to separate dwellings means that around 59.2% of households could install PV systems under our assumptions. We allowed an extra 4% to cater for other constraints on installation.

data with historical uptake data. The premium is assumed to decrease as the rate of uptake increases (reflecting the fact that the willingness to pay will vary among customers).

The costs avoided by a small-scale PV systems comprises wholesale electricity purchase costs (including losses during transmission and distribution), market and other fees, network costs (to the extent they can be avoided) and retail margins.

A.2.2 Model Structure

DOGMMA is characterised by:

- A regional breakdown, where each region is defined by transmission or distribution connection point zones. The number of regions modelled is determined by the availability of energy demand data at a regional level[7] and the availability of data on key determinants. Currently the model comprises 56 regions (see Table 2)

Table 2: Number of regions modelled in DOGMMA

State	No of regions
Queensland	10
NSW	5
Victoria	22
South Australia	1
Tasmania	1
Western Australia	13
Northern Territory	3

Source: Jacobs based on data provided by AEMO, IMO and ABS

- The handling of different technologies of differing standard sizes including PV systems, solar water heaters, small-scale wind and mini-hydro systems with and without battery storage systems. The sizes depend on typical sized units observed to be purchased in the market. For this study the technologies and systems used include:
- For the residential sector: solar water heater, 1.0 kW PV system, 1.5 kW PV system, 3 kW PV System, 5 kW PV system, and 3 kW or 5 kW systems with battery storage.
- For the commercial sector: 5, 10, 30 and 100 KW PV systems; 10, 30 and 100 kW systems with storage
- Differentiation between the commercial and residential sectors where each sector is characterised by standard system sizes, levels of net exports to the grid, tariffs avoided, funding approaches and payback periods. The assumptions on these used for this study are shown in Table 3.

Table 3: System characteristics by customer sector

Sector	% of output exported	Funding approaches	Payback period
Residential	20% for smaller systems to 30% for larger systems	Upfront purchase either by debt financing or outright purchase	10 years
Commercial	20% to 40%	10 year leases	10 years

Source: Jacobs

[7] For example, regional sub transmission peak demand data published by AEMO. AEMO has recently published more extensive regional demand data which has not been incorporated into the modelling.

- The ability to test implications of changing network tariff structures and changes to Government support programs including the proportion of network tariffs that are not 'volume based' (that is, that are independent of average energy use). In practice such tariffs could be fixed supply charges, or linked to peak demand ('capacity charges'). These are not differentiated within Jacobs' model, which assumes that all Victorian customers move away from volume-based network tariffs over the period to 2020. All customers in other States and Territories move away from volume-based network tariffs in the period to 2030. In this study, capacity and supply charges are assumed to make up 50% of network tariffs by 2020 (Victoria) and 2030 (other states), respectively. That is 50% of network tariffs are independent of energy use.

A.2.3 Capacity factors

By design, the model can vary capacity factors by region, reflecting for example differing insolation levels by region. However, a lack of regional data means that currently the model applies State wide capacity factors for the selected technology options. The data on capacity factor is obtained from two sources: the capacity factors implied by the zone ratings derived by the Clean Energy Regulator to determine deemed certificates by region[8]; some data on metered energy production available from Ausgrid[9].

The average capacity factor over all capacity for each technology in each State diminishes as the level of capacity increases in each region. This is based on the notion that as more systems are installed, they are progressively in less favourable roof spaces (for example, roof spaces facing other than north or due to shading). The parameters of the function determining average capacity factors are varied so that the projected uptake rates for the first year match actual installation data for each region[10].

The initial capacity factors applying in each State are shown in Table 4. PV systems with storage are assumed to have a lower initial capacity factors due to energy losses occurring during charging and discharging cycles.

Table 4: Initial load factors for small-scale PV systems by region

	Victoria	New South Wales	Tasmania	South Australia	Queensland	Western Australia	NT
PV	14.8%	15.8%	13.7%	15.8%	15.8%	15.8%	15.8%
PV plus storage	13.7%	14.6%	12.7%	14.6%	14.6%	14.6%	14.6%

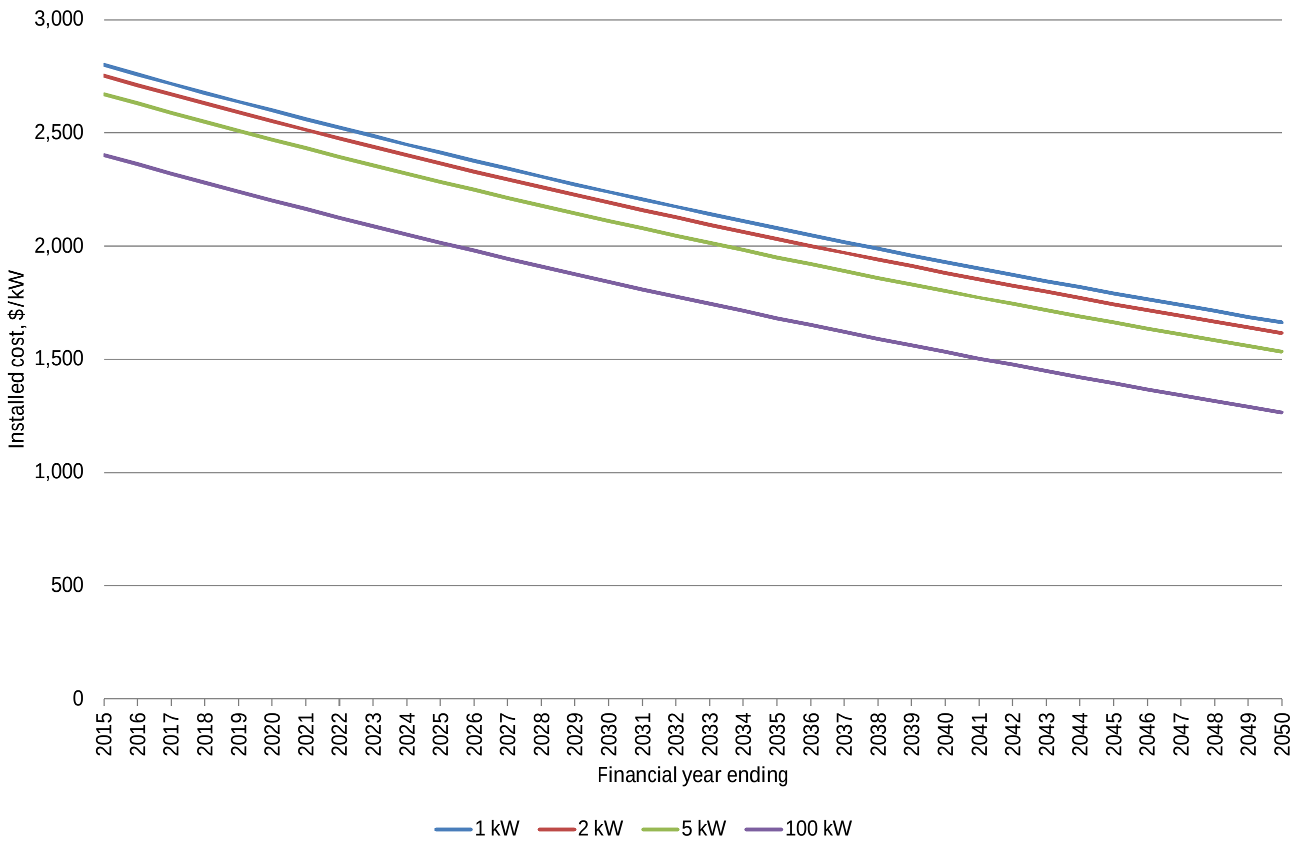
Source: Jacobs based on data provided by CER, Ausgrid and Energex[11].

A.2.4 Capital costs

Capital cost assumptions are shown in Figure 29. Costs in 2015 are sourced from trade data and include balance of system and installation costs. The costs are projected to decline by around 2.5% per annum. Costs are lower for larger system sizes reflecting economies associated with installing larger systems.

[8] The CER divides each State in 4 regions with each zone with a different capacity factor.
[9] Ausgrid (29th May 2013), *Solar Homes Electricity Data*, which contains data on energy production and system capacity for 300 systems;
[10] Postcode data on the number of installations is published by the Clean Energy Regulator.
[11] CER zonal capacity factors, Ausgrid (op. cit.), Energex

Figure 29: Installed total cost assumptions for PV small scale systems



Source: Jacobs based on 2015 data on installed cost supplied in Climate Spectator (2015), "Solar PV price check", 11 May 2015 edition. Installed costs obtained by adding back the rebate obtained from Small-scale Technology Certificates to published data on total system costs, which provide costs to consumers after this rebate has been applied.

A.2.5 Avoided costs

Costs avoided by customers are in one of two ways:

- Avoided retail tariffs on electricity produced by the PV system and used in the premise. As it is difficult to obtain actual retail tariff data and because the proposed policy changes will impact on wholesale prices, retail tariffs are calculated from the components that make up the retail tariff (wholesale price adjusted for network losses, market and other fees, variable network tariffs and gross retail prices. There are regional variations in all these components so that retail tariffs may vary by region.
- Revenue earnt from exports of electricity that is not used on the premises. This price for exported electricity is equal to the wholesale price weighted to the hourly profile of PV generation plus network losses. This revenue acts a negative cost in the model.

A.3 REMMA

The renewable energy market under any renewable energy target scheme was modelled in REMMA, Jacobs' renewable energy model. REMMA is a tool that estimates a least cost renewable energy expansion plan, and solves the supply and demand for LGCs having regard to the underlying energy value of the production for each type of resource (base load, wind, solar, biomass with seasonality).

Strategist was run in conjunction with the renewable energy market model to determine the wholesale market solution that is also compatible and most efficient with regard to renewable energy markets. Additional renewable generation has the effect of reducing wholesale prices while reduced wholesale prices typically have the effect of reducing investment in renewable generation. Iteration of these models typically allows the overall solution to converge to a stable model of consistent wholesale and renewable energy markets.

The REMMA model allows Jacobs to model the impact of policies affecting an expanded target or through external price incentives. Uptake of renewable generation, both its timing and location, is affected both by mandated targets and the impacts of other policies designed to reduce emissions of greenhouse gases.

A.3.1 Model Structure

Projecting certificate prices with the REMMA model is based on the assumption that the price of the certificate will be the difference between the cost of the marginal renewable generator and the price of electricity achieved for that generation. The basic premise behind the method is that the certificate provides the subsidy, in addition to the electricity price, that is required to make the last installed (marginal) renewable energy generator to meet the mandatory target economic without further subsidisation. The REMMA uses a linear programming algorithm to determine least cost uptake of renewable technologies to meet the target, subject to constraints in resource availability and regulatory limits on uptake. The optimisation requires that the interim targets are met in each year (by current generation and banked certificates) and generation covers the total number of certificates required over the period to 2030 when the program is scheduled to terminate. The certificate price path is set by the net cost of the marginal generators, which enable the above conditions to be met and result in positive returns to the investments in each of the projects. Jacobs has a detailed database of renewable energy projects (existing, committed and proposed) that supports our modelling of the renewable uptake. The database includes estimation of capital costs, likely reductions in capital costs over time, operating and fuel costs, connection costs, and other variable costs for over 900 individual projects. Two snapshots of the supply curve used in the REMMA model (which represents all available new renewable energy projects in Australia) are shown in Figure 33 (see Appendix E).

The model can be readily extended to include other forms of low emission generation. The model already includes waste coal mine gas as an option to meet a separate target.

Appendix B. Modelling methodology

B.1 Overview

Jacobs' electricity sector model was iterated with Victoria University's CGE model. The iterative process is described below.

Victoria University's initial CGE model runs drew on existing Jacobs' outputs from the 'Modelling illustrative electricity sector emissions reduction policies' work. The inputs to the CGE model were primarily electricity prices but also technology shares, capital expenditure, unit revenue and emissions. Outputs from the initial CGE runs, primarily electricity demand, are then be used to update Jacobs' electricity sector results, which in turn are used to update the initial CGE runs, and so on until equilibrium between Jacob's model and CGE model was reached.

B.2 Retail prices

Retail prices by customer class (residential, commercial, large business, energy intensive industrial) and state are built up by adding the various components as follows:

- Wholesale prices at the regional reference node weighted by the average hourly demand profile for the customer class, with a 10% margin added to reflect contract premiums.
- Multiplying regional reference node prices by marginal network loss factors to arrive at customer busbar wholesale prices.
- Adding market fees.
- Adding costs of meeting policy targets, as relevant. These will vary by scenario, examples include the costs of the RET or LET certificates, the costs of energy efficiency schemes operating in the reference case, and so on.
- Adding typical network fees using published data for typical voltage levels for each customer class in each State.
- Adding a gross margin for retailing, which is expressed as a percentage mark-up on the other costs.
- For residential customers, a GST rate of 10% was added. GST was not added to commercial and industrial tariffs.

B.3 Reliability and stability

The modelling of plant entry was subject to a reliability constraint of two forms:

- A maximum allowable modelled unserved energy equal to the NEM's and WEM's output based reliability standard of 0.002% of demand.
- For the mainland NEM regions, a deterministic check that installed generating capacity exceeded the maximum demand forecast plus the Minimum Reserve Levels[12] as currently applicable and published by AEMO. Wind and non-storage solar generation capacities were discounted by AEMO's existing firmness percentages.[13] For the WEM, a reserve margin constraint was applied on top of firm capacity where firm capacity for intermittent plant was defined as under rules governing operation of the reserve capacity mechanism.

[12] The Minimum Reserve Levels incorporate the ability to import reserves from other regions. This means they may be negative.
[13] AEMO (2015), *Electricity Statement of Opportunities*

The latter constraint was applied for additional confidence in the acceptability of the reliability outcome in the presence of a very high penetration of intermittent generation. In all modelled cases, the least-cost investment profile met the first constraint, but in those policy scenarios heavily reliant on intermittent generation, additional dispatchable plant was introduced to meet the second constraint. The resulting build was not least-cost, as these additional plants were modelled as bidding at the market price cap in the case of the NEM and to earn capacity credits in the case of the WEM, they were observed to earn sufficient profit to recover their capital costs even with very low operating hours.

Some scenarios invest heavily in wind and PV generation and, to a lesser extent, battery storage. These technologies do not directly synchronise to power system frequency which has implications for power system stability, necessitating new technical solutions. These solutions include mandated technical standards upon these generators, investment in transmission stabilising equipment and the purchase of additional ancillary services from synchronised generators. The solutions are complex and difficult to quantify but appear to be of a much lower total cost than the capital costs of the generators themselves. Therefore these issues and costs were not taken into account in the modelling.

B.4 Network costs and pricing

B.4.1 Overview

Network charges are the summation of distribution and transmission charges. The financial impact on distribution and transmission network service providers of the policy measures will largely depend on the following factors:

- The impact of a policy on load shape, such that reductions in peak demand will defer investment in capital expenditure.
- The impact of a policy to reduce energy usage (in GWh) so that tariffs have to be adjusted to recover the regulated revenue as predicted ahead of time.
- Structural tariff considerations, such as recent trends to increase capacity charges for networks rather than energy consumption charges.

Current network tariffs were collected for each distribution area, and representative tariffs were chosen for each of the residential, Small to Medium Enterprises (businesses with less than 200 employees, also known as SMEs), Low voltage (LV) and High Voltage (HV) customers. Representative tariffs were chosen on the basis that they serve the majority of customers.

For the modelling, all network tariffs were converted to a representative standing or supply charge, a capacity charge and a variable energy use charge.

In most cases residential and SME tariffs consisted simply of a supply charge and a simple or inclining block tariff rate, and did not include a capacity charge. Where inclining block tariffs apply, only the price of the first block was taken, on the basis that some customers would not have large enough loads to meet higher blocks.

Large commercial and industrial customer tariffs are more complex, and consist of a supply charge, a capacity charge, and an energy charge typically split into peak, shoulder and off-peak time periods. The capacity charge is applied to the estimate of peak demand reduction for each distributor. The variable energy charge, if on a time-of-use basis, is converted to a single figure based on an assumed typical usage pattern. The pattern of usage chosen was 33% energy in each of the peak, shoulder and off-peak time periods.

Network tariffs are adjusted in two ways in order to gauge how changes in demand under each policy scenario affect network returns:

- Estimate energy impact; i.e. the impact on total revenue under reduced energy use compared to reference case. It would be expected that fixed revenue requirements and reduced energy use could lead to higher network charges unless the utilisation of the network also improves.
- Estimate peak impact; i.e. the impact of deferred network upgrades resulting from reduced network peak load, if any. It would be expected that some reduction to network peaks would be likely to occur, providing some benefit that will reduce network charges.

For each scenario modelled, it was assumed that some proportion of peak impact from 2020 will be passed through to customers.

Reductions to network charges were applied only to the energy component of the network tariff, to replicate the existing trend for networks to reduce their risk by increasing fixed charges and reducing consumption charges. However, the analysis assumes that the proportion of energy based charges will decline over time, so that for all customers at most 50% of network tariffs are energy based by 2030.

B.4.2 Interconnection and losses

The model begins with a representation of the existing network capacity. Interregional capacity is increased in line with capacity needed to avoid prolonged substantial price separation between interconnected regions, with price separation not being greater than typical line losses.

Assumptions on initial interconnect limits are shown in Table 5. We have retained a Snowy zone in our Strategist model to better represent the impact of intra-regional constraints on each side of the Victoria/NSW border.

Table 5: Interconnection limits – based on maximum recorded flows in 2011/12

From	To	Capacity	Summer
Victoria	Tasmania	480 MW	
Tasmania	Victoria	600 MW	
Victoria	South Australia	630 MW	
South Australia	Victoria	630 MW	
South Australia	Redcliffs	135 MW	
Redcliffs	South Australia	220 MW	
Victoria	Snowy	1,300 MW	
Snowy	Victoria	1,900 MW	
Snowy	NSW	3, 559 MW	3,117 MW
NSW	Snowy	1,150 MW	
NSW	South Queensland	120 MW	
South Queensland	NSW	180 MW	120 MW
NSW	Tarong	589 MW	
Tarong	NSW	1,078 MW	

Source: Combination of ESOO and historical market data

Inter-regional loss equations are modelled in Strategist by directly entering the Loss Factor equations published by AEMO except that Strategist does not allow for loss factors to vary with loads. Therefore we allow a typical area load level to set an appropriate average value for the adjusted constant term in the loss equation. The losses currently applied are those published in the AEMO report entitled “List of Regional Boundaries and Marginal Loss Factors for the 2014-15 Financial Year”.

Negative losses are avoided by shifting the quadratic loss equation so that the minimum passes through zero loss.

Benefits due to lower losses across the inter-regional interconnects are modelled directly in the Strategist model using equations that mimic the transfer equations used in AEMO/IMO dispatch algorithms.

Intra-regional losses are applied as detailed in the AEMO report entitled “List of Regional Boundaries and Marginal Loss Factors for the 2014-15 Financial Year”.

The long-term trend of marginal loss factors is extrapolated for two more years and then held at that extrapolated value thereafter.

Generalised estimates of interconnector expansion sizes and costs have been derived from AEMO’s National Transmission Network Development Plan 2014.

B.5 Refurbishment

Refurbishment of existing generation assets is allowed in the modelling if economic. This mainly applies to wind farms and large-scale solar PV plant, which have 25 year lives. Small-scale solar PV at the end of their lives are assumed to be automatically replaced by owner.

The assumption is that the refurbishment cost is some 60% of the cost of a new project. This assumption is used on the basis that only parts of the generator will need to be replaced (turbines, shafts, gears, panels) whilst other elements such as footings and electrical elements will not need to be replaced. Refurbishment costs are included in the capital cost reporting.

In most cases, it will be economic to refurbish plant on the basis of the electricity prices earnt alone. However, in the RET and LET policy measures, refurbished plant are allowed to earn certificates under the measure due to the possibility that electricity prices are lower than prices required for refurbishment to occur.

B.6 Emissions

The cost of direct emissions in the generation sectors are incorporated through either a cap and trade or emissions intensity scheme depending on the scenario. All scenarios apply the prevailing carbon price to indirect emissions associated with electricity generation from the transport and extraction of fuel. This reflects the assumption in Victoria University’s CGE modelling that emitting sectors outside electricity generation must pay the prevailing carbon price for all emissions. Accordingly, the cost of indirect emissions will be included in the price of fossil fuels used by electricity generators, which in turn will affect the generation mix.

Appendix C. Modelling assumptions

C.1 Carbon price assumptions

The Authority specified that the carbon price be set at a level consistent with Australia's contribution to a likely chance (two-thirds) of limiting global average warming to no more than 2^{o} C. The Authority chose the median carbon price associated with an atmospheric concentration of 450 ppm carbon dioxide equivalent observed in a meta-analysis of global carbon prices in the Intergovernmental Panel on Climate Change's Fifth Assessment Report[14]. The meta-analysis presented global carbon prices in 2020, 2030, 2050 and 2100 (in 2010 US dollars) and the atmospheric concentrations that would result from each price. The Climate Change Authority inflated median values from the analysis to 2014 US dollars based on the US GDP price deflator published by the US Federal Reserve. Uniform growth rates were calculated to interpolate the carbon price between 2020, 2030 and 2050.

The US dollar carbon price series was used as an input to Victoria University's CGE model, which then provided an Australian dollar series as an output for each model run. The Australian dollar series varied very slightly between the scenarios due to differences in the terms of trade and exchange rate between the scenarios, as shown in Figure 1.

C.2 Electricity demand

The calculation of the electricity demand in the NEM and WEM was done by using for each state as a starting point in financial year 2014/15 the actual electricity demand as given in AEMO's NEFR 2015, and implementing for the subsequent modelled years the annual growth rate of demand coming from Victoria University's CGE modelling.

The peak demand for the two Cap and Trade scenarios was calculated by using the ratio of peak demand to average demand from the 2^{o}C Carbon Price scenario as given in Jacobs' 'Modelling illustrative electricity sector emissions reduction policies' report. Similarly, for the Emission Intensity scenario, the ratio of peak demand to average demand from the Emission Intensity scenario from that report was used.

C.3 General assumptions

C.3.1 Structural assumptions

Structural assumptions used in the modelling include:

- Capacity is installed to meet the reserve requirements for the NEM in each region. Unless induced by policy (for example the RET), additional capacity on top of what is required to meet reliability criteria is unlikely as this would tend to depress prices below levels to recover costs of new plant
- Annual demand shapes consistent with the relative growth in summer and winter peak demand. The native load shape is based on 2010/11 load profile for the NEM and WEM regions, with this being representative of a normal year in terms of weather patterns. The load profile presented to the thermal generation plant is modified by two factors: the small scale solar and wind resources added to the market since 2010/11 and forecast by the modelling to be added; and the changing trend in growth of peak demand relative to average demand implicit in the forecasts.

C.3.2 Wind assumptions

Modelling of wind generation varies by location:

[14] IPCC, 2014. *Working Group III Contribution to the Fifth Assessment Report, Climate Change 2014—Mitigation,* Cambridge University Press, Cambridge, *Figure 6-21, p.450*.

- Wind generation profiles in South Australia, Tasmania, Victoria and New South Wales are based on the observed aggregate wind power patterns for each region from the 2013/14 financial year. Where historical data is limited (for example in New South Wales), we will use AEMO's projected wind traces, developed for the 2014 NTNDP study[15].
- Wind power in Queensland is less significant than in other states over the modelling horizon and is modelled as an unreliable thermal generator. A partial outage and full outage model is used to approximate the availability of wind power.
- Wind generation profiles in Western Australia are based on the major wind regions in the WEM.

C.3.3 Generator profits

Gross generator profits and losses were calculated based on the revenue earnt by each unit minus the fixed and variable operating costs. They are equivalent to earnings before tax (that is, they include interest as part of fixed costs, depreciation and amortisation). Profits obtained in the short run through trading in wholesale markets ('trading profits') will differ from these estimated gross profits.

Generator revenues included:

- Spot market revenue plus a 10% inflator for contract price premiums.
- For WEM generators, capacity market income.
- For eligible plants, the market value of existing RET certificates.
- For eligible plants, the annual value of the new policy instruments being considered.

Generator costs included:

- Variable operating and maintenance costs
- Fixed operating and maintenance costs.
- Emissions cost (if any).
- The amortised capital cost of new plant
- Decommissioning costs when the unit is permanently closed.

Gross profits are indicative estimates only and are based on the expected wholesale prices predicted in the modelling. They do not include returns on existing contract positions. The profits are based on the assumptions used in the modelling and are not a forecast of expected profits of incumbent generators.

C.3.4 Generator behaviour

Bidding strategies are limited by the cost of new entry. This is a conservative assumption (that is, it may underestimate wholesale prices) as there have been periods when prices have exceeded new entry costs when averaged over 12 months, typically when there are prolonged periods of high temperatures and/or when there has been major supply constraints such as major outages or water shortages. In the WEM, generators are assumed to bid into the wholesale market at short run marginal cost in accordance with the market rules.

Infrequently used peaking resources are bid near market price cap or removed from the simulation to represent strategic bidding of these resources when demand is moderate or low.

Units close and/or shut down under the following conditions:

[15] These are available at http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions.

- Units that recorded operating losses (disregarding their amortised capital costs) for greater than two years were mothballed for the period. If the losses extended beyond 10 years then the affected units were permanently shut down.
- Where a mine-mouth coal supply is exhausted and, based on general understanding of economic and physical constraints, appears unlikely to be extended. In practice this applies to only two brown coal power stations.
- Generating units were shut down sequentially and the model rerun to gauge how profitability of the remaining units changed. This process was repeated until there was no unit recording operating losses

Some modelling projects close units if they are observed to operate less than a specific number of hours in a year. However this project applied no minimum run-time rule. Plant profitability is the over-riding driver and it is unclear what minimum run-time would be appropriate in a market operating under these policies. Recent NEM experience includes some coal and combined-cycle gas turbine units achieving low-duty operation and similar market conditions are expected in the transition period to decarbonisation.

C.3.5 Weighted average cost of capital

Generally, the long run marginal costs of new investments were calculated using a weighted average cost of capital of 8.8% in real terms. This rate reflected a premium for the uncertainty inherent in any investment in generation capacity. This assumes debt: equity share of 60:40 and nominal debt rate of 7%.

In both cases, these capital costs are the private financing costs faced by investors in new generation. The resource costs from the perspective of society as a whole are calculated by incorporating the time value of money by discounting future costs in real terms (in this case, at the rate prescribed by the Office of Best Practice Regulation using the social discount rate recommended by the Office of Best Practice Regulation (7%).

C.3.6 Market structure

Existing market arrangements and regulations for the wholesale electricity markets were assumed to continue to the end of the study period. That is, the NEM remains region based energy only market, whilst the WEM has and energy market (balancing market, Short Term Energy Market) plus a capacity market.

We assume that the market is structured to remain largely competitive and continues the following arrangements:

- Victorian generators are not further aggregated
- The generators' ownership structure in Queensland remains as public ownership
- The South Australia, Tasmanian and New South Wales assets continue under the current portfolio groupings
- Synergy generation assets (Western Australia) remain publically owned.
- Arrangements for setting existing maximum price caps are assumed to continue to apply during the study period.

C.3.7 Baseline hydro-electric generator output

The total projected generation from renewables pre-dating the Mandatory Renewable Energy Target is 14,600 GWh.

Hydro plants are set up in Strategist with fixed monthly generation volumes. Strategist dispatches the available energy to take the top off the load curve within the available capacity and energy. Any run-of-river component is treated as a base load subtraction from the load profile. Table 6 and Table 7 show the monthly energy used in our model for the smaller hydro schemes.

Based on our market information we have produced monthly and annual monthly energy values for the Snowy Hydro units. This information has been incorporated into the Strategist simulation as monthly energy generation. The monthly minimum generation for Blowering and Guthega are based on market information acquired by Jacobs, largely driven by the irrigation requirements of these hydro systems. Table 8 shows the monthly generation for Murray, the Tumut power stations and for Hydro Tasmania. Hydro Tasmania's generation is set to the stated long-term average of 8,700 GWh.

Table 6: Monthly energy for small hydro generators, GWh

Month	Barron	Hume	Kareeya
Jan	15.93	7.62	26.83
Feb	30.92	8.60	13.45
Mar	20.80	9.27	21.48
Apr	18.74	8.41	20.59
May	11.80	6.04	36.35
Jun	15.93	0.00	47.36
Jul	11.80	0.00	26.24
Aug	17.05	0.00	32.78
Sep	13.49	6.04	28.91
Oct	19.11	10.84	28.62
Nov	4.87	9.91	28.32
Dec	6.93	8.54	26.54
Total	187.38	75.26	337.46

Table 7: Monthly energy for Victorian hydro units, GWh

Month	Dartmouth	Eildon 1-2	Kiewa/ McKay
January	26.78	42.37	8.27
February	23.56	33.25	7.23
March	21.42	31.32	7.23
April	10.71	27.54	12.40
May	5.36	1.57	24.80
June	5.36	0.00	33.07
July	8.57	1.13	36.17
August	10.71	4.22	43.40
September	10.71	13.17	47.54
October	12.85	14.14	51.67
November	21.42	14.30	44.44
December	23.56	22.56	28.94
Total	181.00	205.57	345.16

Table 8 Monthly energy limits for Snowy Hydro and Hydro Tasmania, GWh

Month	Murray	Upper Tumut	Lower Tumut	Hydro Tasmania
January	114.74	134.21	46.20	716.53
February	178.19	192.44	43.67	508.08
March	172.03	148.78	43.84	677.22
April	149.48	121.72	45.78	708.18
May	166.52	164.12	51.16	783.00
June	195.22	196.68	39.57	957.00
July	238.83	261.92	44.58	783.01
August	207.94	153.79	47.54	696.00
September	42.00	8.84	47.69	870.00
October	125.00	10.00	43.60	835.53
November	91.60	115.64	46.88	568.80
December	114.39	121.64	44.50	596.67
Total	1795.93	1629.79	545.00	8700

Source: Jacobs based on market data published by AEMO

C.4 Technology costs

C.4.1 Existing generators

The marginal costs of thermal generators consist of the variable costs of fuel supply including fuel transport plus the variable component of operations and maintenance costs. The indicative variable costs for various types of existing thermal plants are shown in Table 9. For brown coal in Victoria, where the open-cut mine is owned by the generator, the variable costs also include the net present value of changes in future capital expenditure.

Fixed operating cost data are based on available data on operating cost for like plant and data published by the market operators for their planning processes. For the NEM, fixed operating costs are based on publically available data from AEMO[16]. Fixed operating cost data change over time in accordance with assumptions on projections of growth in wage rates, which are sourced from Treasury budget projections. Details of fixed operating cost by plant are provided in Appendix D.

Thermal power plants are modelled with planned and forced outages with overall availability consistent with current performance. Coal plants have available capacity factors between 86% and 95% and gas fired plants have available capacity factors between 87% and 95%. Capacity, fuel cost and heat rate data by generator type are shown in Appendix D.

[16] Jacobs uses the Australian Energy Market Operator's publicly available data to develop fixed costs for conventional coal and gas plant as well as renewable energy technologies. Jacobs' database was used as the source for the avoidable operating and maintenance costs.

Table 9: Indicative average variable costs for existing thermal plant ($June 2014)[17]

Technology	Variable Cost $/MWh	Technology	Variable Cost /MWh
Brown Coal – Victoria	3 - 10	Black Coal – NSW	20 - 23
Gas – Victoria	46 - 64	Black Coal - Queensland	9 - 31
Gas – SA	37 - 111	Gas - Queensland	25 - 56
Oil – SA	250 - 324	Oil – Queensland	241 - 295
Gas Peak – SA	100 - 164	Gas - WA	52 - 59
Black coal – WA	25 - 31		

Source: Jacobs data base of generation costs, which in turn is based on market data published by AEMO and IMO, annual reports of generators and fuel suppliers, ASX announcements and other media releases.

C.4.2 New entrant generators: cost and availability

Method

Jacobs' modelling selects new capacity from a range of currently available fossil fuel and renewable technologies that could be considered in the Australian market. Parameters for technologies that are not presently commercially available are included where an estimate can be made of their performance and costs for use in the modelling. In each scenario the least cost mix of plant is dispatched to meet demand, conditional on the emissions constraint, fuel and capital costs, and any policy constraints (for example prohibitions on new coal without CCS).

New entrant technology costs are derived at a-point-in-time (generally an estimate of current costs) and future costs are handled within the modelling using learning curves and adjustments for changes in exchange rates.

For gas turbine based plants (including open cycle, combined cycle, cogeneration and Integrated Gasification Combined Cycle (IGCC) plants) and conventional Rankine Cycle (or "thermal") plants (including sub-critical, supercritical and ultra-supercritical, and biomass), and for variations of these with carbon-capture, Jacobs' method is generally to use the capital cost estimating tool within the Thermoflow Inc suite of software (including GTPro, SteamPro and PEACE) for the Engineer-Procure-Construct (EPC)[18] base power-island cost. This model estimates capital costs based on technical configurations of each plant design selected by Jacobs that is considered to be appropriate for Australian conditions and fuels. Jacobs applies local factors (such as the unit sizing, suitability for Australia's climate and fuel alternatives) for the configuration of the plants and for regional factors (such as plant costs for Australian construction versus cost in, for example, South East Asia). These factors are based on Jacobs' experience and judgement.

Jacobs refines the cost estimates using adjustment factors where considered appropriate based on market soundings and information from other projects (such as overseas).

The Thermoflow database used is dated May 2014. Adjusted for changes in exchange rates, the resulting EPC costs per kW of power plant capacity appear reasonable against current prices being seen in Asia (adjusting as necessary for local Australian cost factors).

[17] The variable cost of gas based peaking plant assumes that the fixed cost of pipelines and processing assets are converted into a variable cost to reflect opportunity cost of using assets at low levels of utilisation and to enable bids for these plants to be set at a rate that will recover their fixed costs for the limited time they are typically dispatched.
[18] Engineer-Procure-Construct turnkey project delivery.

In addition to the EPC costs, allowances have been made for coal drying plant costs (where relevant for brown coal), connection costs (for electricity and gas where applicable) and owner's costs. Interest during Construction (IDC) costs are handled separately in the modelling.

Wind and PV costs have been updated using observed recent costs for Australia.

Solar thermal, geothermal, hydro and nuclear costs are subject to limited new data in the Australian context and remain as assumed in previous Jacobs' studies.

Current estimates for capital costs of new technologies are shown in Appendix E. These are based on 0.77 USD/AUD.

Learning rates

Learning rates represent the impact that rapid adoption of new technologies has in lowering future installation costs. Typically, the first plant of any new technology may be over engineered to ensure successful operation – as installation and operating time increases, people learn how to reengineer the technology and reduce costs of installation (or of operation).

Rates are considered in two parts. First learning rates are applied as a result of uptake of generation technologies due to global action. This means that, other things equal:

- Faster rates of global deployment reduce the per-unit costs of a technology more rapidly, and
- The per-unit technology costs at a given time will depend on the learning rate for the technology and the cumulative amount of globally deployed capacity.

For this exercise, learning rates are sourced from the international literature[19], adjusted for projected global deployment rates consistent with global action with a likely chance (two-thirds) of limiting global average warming to no more than 2^{o} C, as sourced from the IEA[20]. These values are applied to the equivalent of the equipment costs, which typically comprises 50% to 70% of total capital costs.

Second, learning rates are applied to the domestic component of these investments reflecting learnings from domestic deployment of these technologies. These rates only apply to novel technologies in Australia – typically geothermal, solar thermal, wave, CCS and some biomass technologies. The rates apply to the domestically sourced components of capital costs which vary from 30% to 50% of total costs. The learning rates for this component are assumed to be around 20% for each doubling of capacity[21]. An iterative approach is adopted to translate this learning rate to final capital costs.

The table below shows the projected deployment and learning rates and resulting projected Australian capital cost reductions for four major emerging technologies. The learning rates for all technologies and both emissions constraint are shown in Appendix E (as capital cost de-escalators).

[19] SETIS (2012), *Technology learning curves for energy support policies*, Joint Research Centre Scientific and Policy Reports; EPRI (2013), PRISM: Modelling Technology Learning Rates for the Electricity Supply Sector: Technical Update, Palo Alto, California (Table 5.1). For the latter we used the mid-point of the learning by doing rate range cited. No learning rates for geothermal were provided so we used the learning rates for biomass steam technologies as a proxy.

[20] IEA (2014), *World Energy Outlook: 2014*, Paris

[21] ATA, CSIRO

Table 10: Learning rates and technology cost reductions

	IEA growth in generation, 2020 to 2040 (%) (450 ppm scenario (2 degree target))	Learning rate, cost reduction per doubling, mid point estimate	Per cent per annum reduction	* Australian component, reduction per cent per annum
Biomass	194%	12%	1.2%	0.7%
Wind	260%	14%	1.8%	0.9%
Geothermal	360%	12%	2.2%	1.3%
Solar PV	332%	30%	5.0%	2.5%

* Reflects international equipment costs. That is, the 'Australian component' is the Australia-specific estimate of the share of international capital costs in total capital costs for each technology. Source: Jacobs using technology deployment projections from the IEA (2014), methodological notes from SETIS (2012) and learning rates from EPRI (2013). See footnotes 20 and 21.

C.4.3 Trends and comparisons

This exercise was conducted when Australia-specific technology costs from the Australian Energy Technology Exercise[22] (AETA) were a few years old, and the Australian Power Generation Technology[23] (APGT) costs (published in November 2015) were not yet available. This section provides a comparison with the technology costs across the three exercises.

Technology costs in AETA 2012 were based on the exchange rate trending to 1.13 USD/AUD in 2016/17 and then declining to 0.86 USD/AUD by 2031-32. The AETA assessments used Thermoflow Version 21; for this review Jacobs is using the current version (i.e. Version 24). Considering the changes in the market between 2012 and the present, the differences in assumptions such as exchange rate, and likely differences in configurations selected, the AETA data does not suggest that the proposed parameters are inappropriate. Technologies with larger differences have a larger share of imported components.

The APGT study used consultants including the Electric Power Research Institute (EPRI) to review technology costs in Australia and abroad. These cost estimates were projected to 2030 using the CSIRO's GALLM model, which uses learning curves for each technology in a global context and projects future costs under various scenarios.

Figure 30 compares the full set of technologies in both 2015 and 2030 across all three studies. The capital costs across all three studies are broadly similar with the exception of nuclear, brown coal and large-scale solar generators.

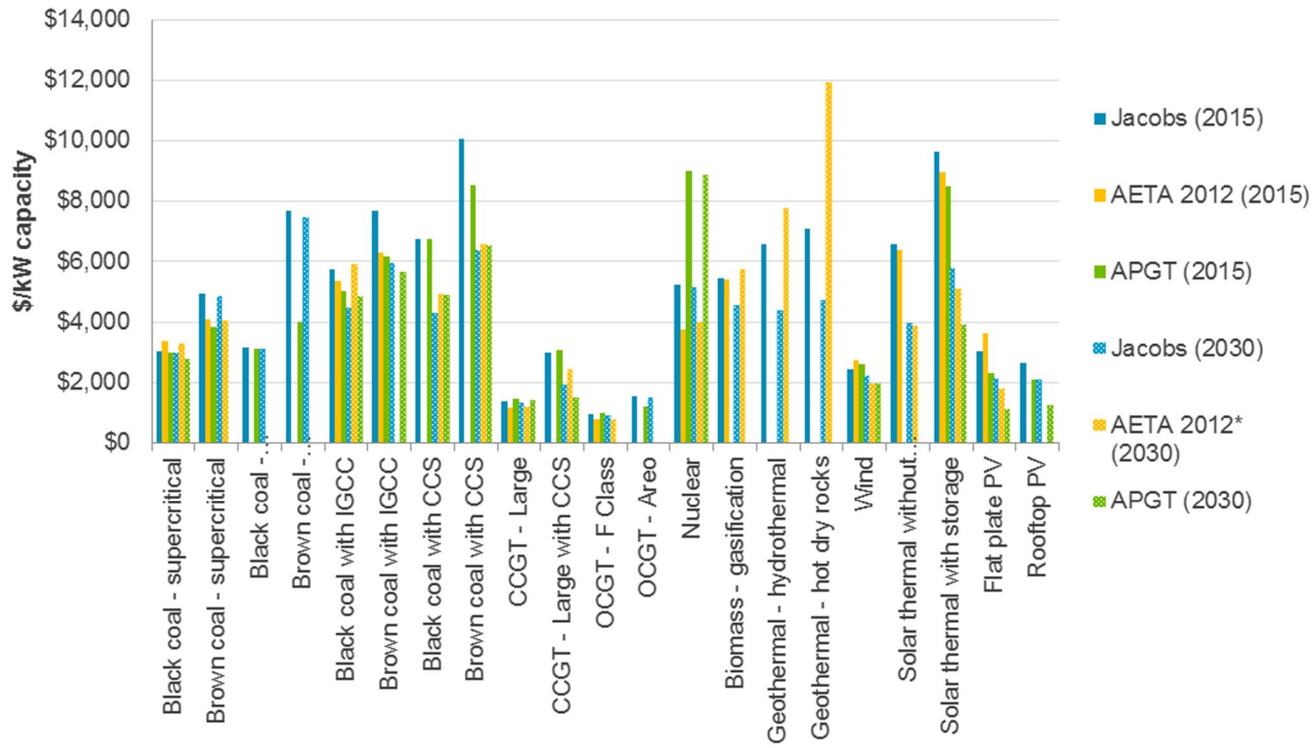
Relative to this study, the 2015 capital costs of a brown coal plant is around 20% lower in the APGT study and 15% lower in AETA 2012.

Jacobs' nuclear capital costs were about half that suggested by the APGT study. APGT costs were based on the upper bound of a range presented in a 2012 EPRI report[24]. Further discussion on Jacobs' nuclear cost assumptions is in Appendix C 4.6.

The capital costs for large-scale solar were around 20% lower in the APGT study and were projected to fall by 50% between 2015 and 2030. Jacobs' projected capital costs to fall by 30% over the same period.

[22] Bureau of Resources and Energy Economics, "Australian Energy Technology Assessment", 2012.
[23] CO2CRC, Australian Power Generation Technology Report, 2015.
[24] EPRI (2013), *Program on Technology Innovation: integrated generation technology options 2012*, EPRI, Palo Alto, California, product ID 1026656.

Figure 30: Capital cost in 2015 and 2030: comparison across studies



Source: Jacobs 2015, AETA 2012, APGT 2015. Note: Jacobs and APGT costs use global costs derived from a strong climate action scenario, AETA 2012 does not.

C.4.4 CCS

CCS retrofits of existing fossil-fuel plants were not included as an investment option based on Jacobs' understanding of the relative costs of these options against new CCS plants.

Table 11 provides an overview of carbon transport and storage costs. The storage and transport declined over time to be some $6/t CO_2-e less in real terms in 2050.

Table 11: Carbon capture and storage cost assumptions

Region	Storage and transport cost, $/t CO_2-e, 2030
Queensland South	25
Queensland Central	30
Queensland North	25
Tarong	25
Mt Isa	25
New South Wales	30
Victoria	20
South Australia	30
SWIS	25

Region	Storage and transport cost, \$/t CO_2-e, 2030
Darwin	25
Katherine	25
NWIS	25
Tasmania	30

Source: Jacobs. Based on data sourced from CO_2 CRC

C.4.5 Storage costs

Small-scale storage costs are based on Tesla's recently released Powerwall product, which is based on Lithium Ion battery technology. The current literature shows that large-scale battery costs are significantly higher than the cost of the Powerwall product. Our understanding is that the technology underpinning the Powerwall product is scalable, and therefore for the large-scale costs we propose to apply a further 10% discount relative to the small-scale cost, to represent economies of scale that should be achievable for a larger system size.

Table 12: Technology cost assumptions for storage by scale

Technology	\$/kWh net
Small-scale storage	612
Large-scale storage	551

Source: Jacobs analysis

C.4.6 Nuclear energy

The nuclear cost assumptions in this modelling were finalised in May 2015; since then the South Australian Nuclear Royal Commission has conducted extensive research into the costs of nuclear power in Australia; finding higher capital costs.

Nuclear energy, like other plant types, will be constructed and dispatched if it is part of the least cost generation mix to meet total electricity demand given technology costs, fuel prices and the emissions constraint. This assumes that the regulatory and support frameworks are in-place at the necessary time to allow the consideration of this technology. These frameworks are not in-place at the present time in Australia and there are no current proposals to put these in place. The necessary requirements would include:

- The political and legislative framework at the Commonwealth and (where relevant) the State level. The larger States each have legislation prohibiting the construction of a nuclear power station (the Lucas Heights facility operates under a Commonwealth framework). Bi-partisan support and broad social acceptance is likely to be a pre-requisite to nuclear development. This would take some time to establish. The most commercially developed and cost effective technologies presently available are large unit sizes that could only practically be installed in NSW, Victoria or Queensland.
- An institutional framework would be required to supervise the industry in its construction and operational phases.
- A siting study would be required necessitating significant political and consultative processes.
- An environmental assessment framework specific to nuclear power in Australia would need to be established and undertaken.

- An insurance framework would need to be established to address the insurer-of-last-resort issues of a nuclear power plant.

The costs of these processes have not been incorporated into the analysis.

Should an Australian nuclear plant be considered, it would be envisaged that a proven design would be selected from an international vendor. Accordingly, although some of the specialised construction techniques would be first-of-a-kind in Australia they would not be first-of-a-kind for the vendor nor for the global industry. It is assumed that the Australian regulatory regime would not require different or additional design or construction requirements than would apply in other jurisdictions where the vendor(s) have previously applied the design.

In this analysis it is assumed that the design and construction arrangement would be able to apply the benefits of prior learning on other plants overseas.

Costs allowed are based on the "N"-of-a-kind cost for a large scale Generation III reactor (1000 MW) in the US of $3,750/kW ($2013), which is the average cost reported by the World Nuclear Association. These do not include decommissioning costs and an allowance has been included of $20/kW (based on $1,000/kW discounted for 60 years at 7% real). An assumed cost of $5,140/kW is allowed ($2015, and reflecting exchange rate differences).

Nuclear costs will always be a highly debatable point in the Australian context until proposals are developed and the framework that they would be built under is established.

Overseas, the experience has been varied.

Indicative contemporary costs as reported by the World Nuclear Association for Generation III plants are approximately US$3,500/kW to US$4000/kW in USA, US$2,300-3,000/kW in China and for Hinkley C in UK US$7,750/kW. The UK industry has always had costs significantly higher than elsewhere for nuclear plants.

These are typically $2013 to present and all are overnight basis (that is as if construction costs were paid in full at once, so excluding interest during construction). If we are to compare these to capital costs quoted above, then they should be escalated by 36% to be converted from US to Australian dollars and inflated to $2015. Thus, typical capital costs for nuclear energy in the USA are $A4780-5460/kW, $A3140-4090/kW in China and $10,570/kW for the Hinkley C plant in the UK.

The Climate Change Authority requested Jacobs to model an earliest date of entry for nuclear energy of 2035. This is based on the significant time for the processes described above to be implemented and accepted.

Other nuclear technologies may become available in the future however their technical and cost parameters are not presently known.

C.4.7 Decommissioning costs

The cost of decommissioning generating plant was included in the study. The cost covered mine rehabilitation (if a mine mouth power station) plus the cost of removing equipment and site rehabilitation.

Table 13 provides an overview of the decommissioning cost assumptions for coal plant. These are from retirement and/or rehabilitation costs as estimated for AEMO by ACIL Allen.

Table 13: Retirement cost assumptions

Unit Name	Retirement Costs ($'000)
Tamar Valley	2,080
Northern	43,680
Pelican Point	4,740
Torrens Island	4,100
Loy Yang A	181,600
Loy Yang B	80,000
Yallourn	118,720
Hazelwood	128,000
Bayswater	138,000
Eraring	144,000
Mt Piper	70,000
Liddell	104,000
Vales Point	66,000
Millmerran	42,600
Tarong	87,500
Kogan Creek	37,200
Callide C	45,000
Callide B	35,000
Stanwell	73,000
Gladstone	84,000
Muja C	16,848
Muja D	18,230
Collie	14,274
Bluewaters	18,720

Source: Jacobs analysis based on unit ($/MW) retirement cost estimates provided by ACiL Allen (2014), *Fuel and Technology Cost Data*.

C.4.8 Technology-specific restrictions

Several restrictions were assumed to apply to the cost or availability of new technologies:

- CCS options were not available until 2030
- Geothermal options were not available until 2030. Low cost geothermal options were limited to 12,800 MW. After this the cost of geothermal was increased to account for higher connection costs.
- Nuclear generation was not available until 2035.

- Transmission connection costs were included as part of the capital cost of each option. For options located in remote region (e.g. geothermal in central Australia), the full cost of connecting to the grid were included in the capital cost of the option.
- Biomass capacity in the policy scenarios is restricted to not exceed biomass capacity built in the reference case. This is based on analysis by CSIRO that projects biomass will be taken up preferentially in the transport and industrial sectors in a carbon constrained world[25].

C.5 Gas prices

C.5.1 Gas prices under 2°C emissions constraint

Jacobs prepares gas price forecasts based on projected demand-supply balance in Eastern Australia using Jacobs' proprietary model, MMAGas (Market Model Australia – Gas), which intends to replicate the essential features of Australian wholesale gas markets:

- A limited number of gas producers, meaning that prices can rise above export parity levels when producers can exercise market power.
- Dominance of long term contracting and limited short term trading.
- A developing network of regulated and competitive transmission pipelines[26].
- Domestic market growth driven by gas fired generation and large industrial projects.

The model is structured around some fundamental principles:

- With the export market being the predominant market from 2016/17, gas prices converge to between the export parity and import parity levels. The degree to which prices are above export parity levels depends on the degree of competition in the domestic gas market.
- Export parity levels are set at the LNG net back prices (that is, world prices for LNG - assumed to be set at export prices for natural gas in major markets - after shipping, processing and handling costs are deducted). Prices can go below export prices for short periods due to the fact that coal shale gas wells cannot be plugged or turned down easily so there may be short periods with a glut of gas. Price projections are based on US Energy Information Agency or the International Energy Agency on world gas prices in these markets. Shipping and other costs are based on the historical differential between cost insurance and freight (c.i.f) prices in Japan and free on board (f.o.b) export prices.
- Import prices are set at the energy equivalent of oil or liquid fuels, being the main substitute for gas in most end-uses.

For the period to 2020 we have used our medium gas price projections, which assume gas prices rise above world parity levels over the period to 2018/19 due to a shortage of gas to meet contracted commitments for LNG. Thereafter prices fall to world parity level. Figure 31 shows the gas price assumptions used.

Prices are affected by the following factors:

- Over the next few years, supply of gas will remain tight as LNG trains come on line and gas is required to meet export commitments.
- The tightness of supply is not likely to dissipate until 2019 at the earliest due to time required to attain approval and develop additional coal seam gas wells.

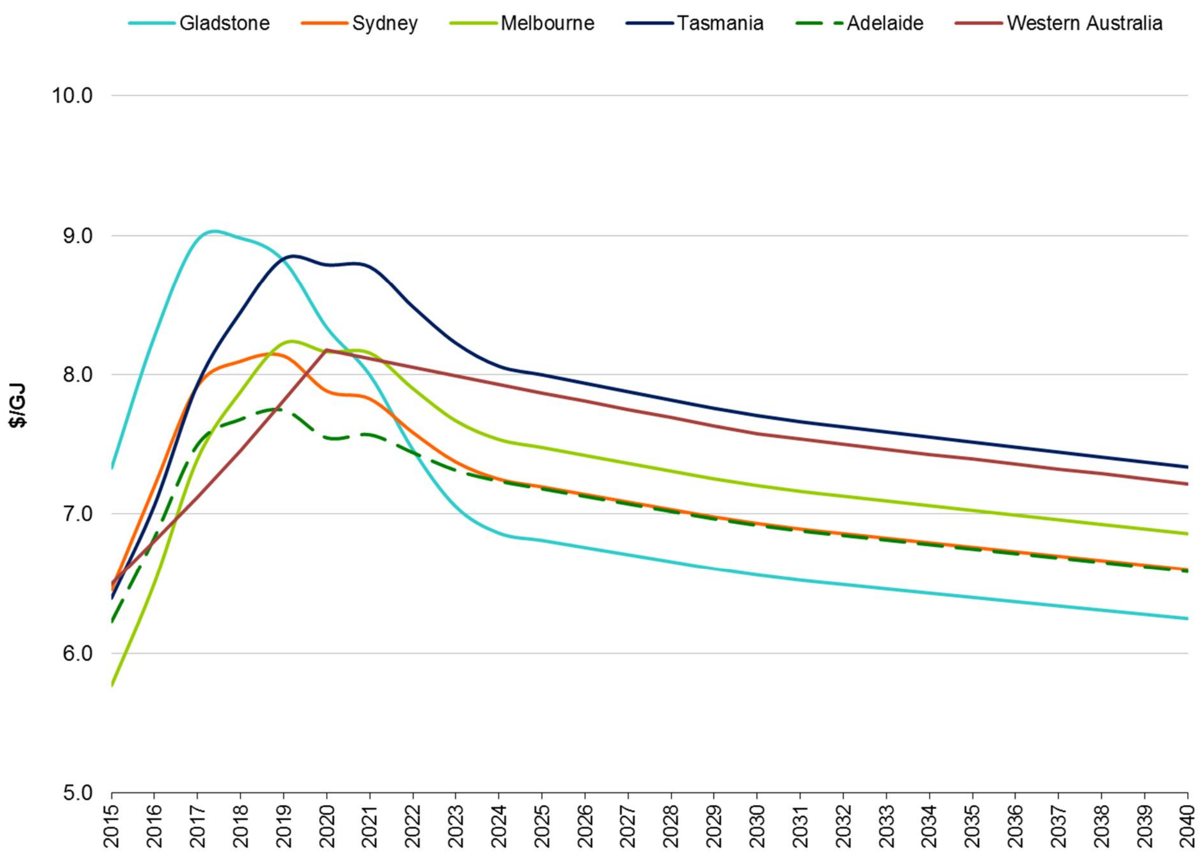
---

[25] ClimateWorks 2015, *Pathways to deep decarbonisation in 2050 – Technical Report*

[26] The modelling does not consider the possibility of building a pipeline to link Queensland with the Northern Territory. The impact of this assumption on gas prices in the NEM is considered to be immaterial.

- Thereafter, gas prices follow world price growth rate trends. From 2020, world prices follow the trajectory predicted by the IEA for a scenario involving concerted global action to curb emissions so that atmospheric concentration of greenhouse gas do not exceed 450 ppm CO_2-e[27]. This sees prices for natural gas on world markets decreasing by around 0.5% per annum in real terms.

Figure 31: Gas price assumptions (2°C emissions constraint), city gate prices



Source: Jacobs' MMAGas model, IEA 450 ppm scenario

C.6 Coal prices

Coal prices are treated in three ways depending on the plant characteristics:

- For those mines containing coal that is unlikely to be exported (typically brown coal plant in Victoria), prices are equal to the long run average cost of production including expected continuing mine development
- For plant with long term coal contracts, prices remain at contract price terms (as we understand them) until the contracts expire. Once they expire the prices increase to concurrent market levels
- All other coal prices are linked to trends in world market prices which are assumed to grow slowly to 2020 due to stable world demand for coal[28]. Thereafter, world coal prices are assumed to move

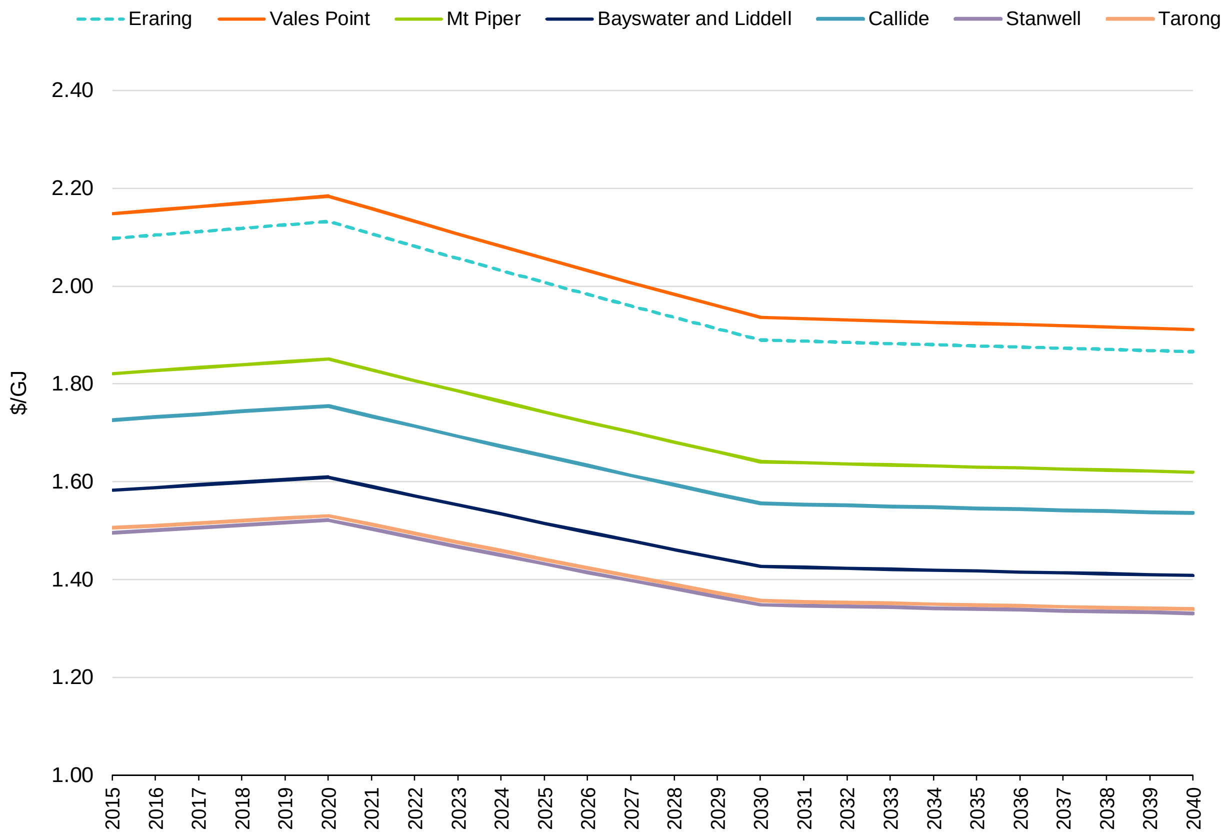
[27] International Energy Agency, *World Energy* Outlook, 2014, p.48. More recent gas price projections became available after the modelling was largely complete (International Energy Agency, *World Energy* Outlook, 2015). The gas price growth rates were very similar.

[28] Source: Bureau of Resources and Energy Economics, *Resource and Energy Quarterly*, March 2015

in line with projections by the IEA for a scenario involving concerted global action to curb emissions so that atmospheric concentration of greenhouse gas do not exceed 450 ppm CO_2-e[29].

The coal prices assumed under stronger emissions constraint runs for key NEM power stations are shown in Figure 32. Coal prices are expected to be depressed over the long term and are forecast to continue decreasing if there is concerted action to curb greenhouse emissions.

Figure 32: Projected variable coal price for NEM black coal power stations (2°C emissions constraint), $June 2014



Source: Jacobs's analysis, IEA *World Energy Outlook*.

C.7 Emission factors

Emission factors are obtained from the workbooks supporting the National Greenhouse Accounts published by the Department of Environment. The direct emission factors assumed for existing power stations are listed in Table 14. The direct emissions factors assumed for new power stations are listed in Table 15. These factors are sourced from the Department of the Environment's workbooks containing assumptions behind the derivation of historical emissions[30].

[29] International Energy Agency, *World Energy* Outlook, 2014, p.48. More recent coal price projections became available after the modelling was largely complete (International Energy Agency, *World Energy* Outlook, 2015). The growth rates were largely similar.
[30] Department of the Environment (2014), *National Greenhouse Account Factors: 2014*, and previous issues.

Table 14: Emission factors by power station

Power station	Emissions factor (kg/MWh)	Emission factor of fuel (kg/GJ)
Tamar Valley GT	720	62.64
Tamar Valley CCGT	473	62.64
Northern	1111	97.12
Pelican Point CCGT	476	61.64
Osborne	641	61.64
Torrens Island B	654	62.24
Torrens Island A	672	62.24
Dry Creek GT	863	61.64
Mintaro	986	61.64
Snuggery	1105	73.69
Pt Lincoln	791	73.69
Quarantine GT 1-4	863	61.64
Quarantine GT 5	638	61.64
Hallett GT	1200	61.64
Angaston	663	73.69
Loy Yang A	1248	94.58
Loy Yang B	1242	94.58
Yallourn	1445	97.01
Hazelwood	1481	92.01
Anglesea	1419	92.46
Newport	578	61.44
Jeeralang A	845	61.44
Jeeralang B	790	61.44
Bairnsdale	650	61.84
Valley Power	845	61.44
Somerton	829	61.44
Laverton Nth	707	61.44
Mortlake	666	61.74
Qenos Cogeneration	676	61.44
Uranquinty	683	62.24
Bayswater	905	92.37
Eraring	888	91.67
Mt Piper	873	90.23
Liddell	1007	90.68
Vales Point	893	90.73
Wallerawang	897	87.88
Hunter Valley GT	1723	73.69
Smithfield	622	62.24
Tallawarra	447	62.24
Colongra	670	62.24
Millmerran	918	87.59
Tarong	897	90.37
Roma	832	61.64
Oakey	709	61.64

Braemar	593	55.32
Braemar 2	593	55.32
Kogan Creek	866	87.59
Condamine	394	55.32
Swanbank E	499	61.64
Darling Downs	398	55.32
Yarwun	661	61.64
Callide C	970	97.53
Callide B	1020	97.53
Stanwell	980	91.72
Gladstone	1009	93.02
Mt Stuart	847	73.69
Mackay GT	995	73.69
Yabulu CCGT	413	55.52
Muja A/B	1237	95.25
Muja C	1077	95.25
Muja D	1003	95.25
Alinta Pinjarra	391	59.94
Geraldton GT	1072	68.99
Mungarra	798	59.94
Pinjar A/B	792	59.94
Pinjar C	751	59.94
Pinjar D	751	59.94
Collie	955	95.25
Kalgoorlie	1018	68.99
Kemerton	842	68.99
Cockburn	469	59.94
Perth Power Partnership	731	59.94
Goldfields Power	721	61.64
Southern Cross	780	61.64
Alcoa Cogeneration	828	59.94
LMS 100	506	59.94
NewGen CCGT	447	59.94
Tronox	768	59.94
Alinta Wagerup	641	59.94
Bluewaters	871	95.25
Neerabup	731	59.94
Perth GT	659	59.94
Merredin	690	68.99

Source: Department of the Environment (2014), *NGA Factors Workbook*, Canberra.

Table 15: Emission factors applying to new power plant

Region	Power station	Emissions factor (kg/MWh)	Emission factor of fuel (kg/GJ)
Victoria	OCGT	694	61.44
	CCGT	436	61.44
	CCGT with CCS	498	61.44
	Nuclear	63	7.00
New South Wales	OCGT	671	62.24
	CCGT	447	62.24
	CCGT with CCS	504	62.24
	Supercritical coal	827	90.92
	Nuclear	63	7.00
South Australia	OCGT	733	61.64
	CCGT	481	61.64
	CCGT with CCS	499	61.64
Queensland South	OCGT	673	61.64
	CCGT	397	55.32
	CCGT with CCS	448	55.32
	Supercritical coal	797	87.59
	Nuclear	63	7.00
Queensland Central	CCGT	443	61.64
Queensland North	OCGT	696	61.64
	CCGT	493	61.64
	CCGT with CCS	499	61.64

Source: Jacobs analysis based on data from DoE, IPCC

C.8 Federal and State policies

The following policies are included all three scenarios.

C.8.1 National policies

The Renewable Energy Target

The Large-scale Renewable Energy Target (LRET) is a legislated requirement on electricity retailers to source a given proportion of specified electricity sales from renewable generation sources, ultimately creating material change in the Australian technology mix towards renewable alternatives. The target mandates that 33,000 GWh must be derived from eligible renewable sources by 2020 and maintained through to 2030. Emissions Intensive Trade Exposed industry are exempt from paying the liabilities of the LRET.

The LRET scheme is described in further detail in Box 1. Another scheme supporting smaller scale renewable generation options has also been enacted, called the Small-scale Renewable Energy Scheme (SRES).

The costs of sourcing renewable generation under the LRET and SRES are met by an additional cost added to retail electricity bills. The scheme is administered by the Clean Energy Regulator (CER).

The Emissions Reduction Fund

The Emissions Reduction Fund (ERF) purchases accredited emissions reductions. Under Australia's commitment to the Kyoto Protocol[31], Australia must reduce its greenhouse gas emissions to 5% below 2000 levels by 2020. The ERF is administered by enabling creation of Australian Carbon Credit Units (ACCUs) through a reverse auction or tender process.

Sectoral coverage of the ERF is wider than the energy sector, and can include agricultural and forestry activities under the Carbon Farming Initiative, as well as avoided emissions from landfill. Other emissions reduction activity may include industrial and commercial energy efficiency and emissions avoidance projects. It is unlikely under current parameters and allocated budgets to encourage uptake of large-scale low emission generation options. Therefore the ERF is not considered in the modelling.

C.8.2 State and territory policies

Feed in tariffs

Feed-in tariffs are equivalent to payments for exported electricity. Feed-in tariff schemes have been scaled back in most jurisdictions so that the value of exported energy does not provide a significant incentive to increase uptake of solar PV systems. All States now only mandate fair and reasonable tariffs to apply to exports, reflecting the value of equivalent wholesale prices. This approach was assumed in this study.

ACT renewable target

The ACT recently announced that it would extend its existing renewable energy target from 90% to 100% by 2025. The target is achieved by enabling large scale solar and wind auctions which enable the territory to economically undertake power purchase contracts with renewable energy generators in the ACT and other states to produce an equivalent amount of power to what is used within the ACT. This is modelled by Jacobs as a small increase to the RET.

Victorian renewable target

The Victorian government recently announced an initiative to purchase renewable energy certificates from new renewable energy projects in Victoria to offset emissions associated with its own energy use. This initiative is expected to encourage around 100 MW of wind capacity to be built in the state. However, as the certificates to be purchased will not be additional to the RET and as Victoria is likely to achieve in excess of this in the next five years under business as usual conditions, this initiative is not explicitly considered in this analysis.

[31] http://www.aph.gov.au/About_Parliament/Parliamentary_Departments/Parliamentary_Library/pubs/rp/BudgetReview201415/Emissions

In June 2016 the Victorian government announced renewable energy targets of 25% by 2020 and 40% by 2025. This policy was announced after this modelling was complete and so has not been incorporated in this analysis.

Queensland renewable target

The Queensland government has announced support for 60 MW of large scale solar PV, whilst Ergon Energy is concurrently running an Expression of Interest for 150 MW of large scale renewable energy. These projects are treated as a Queensland specific increase to the RET in the modelling.

State and Territory energy efficiency policies

Some states and territories in Australia have implemented energy efficiency policies. To a large extent, energy efficiency schemes are already allowed for in the baseline energy demand projections. However, there are instances where a given scheme has not been allowed for or has been extended, for example if policy has changed since the original demand projections were created. Where this has occurred, the impact on the underlying electricity demand projection was not estimated.

Appendix D. Costs and performance of plants

The following tables show the parameters for power plants used in the Strategist model. Costs are reported in March 2014 dollars for 2014/15. All existing plant included in the model are available for dispatch. Since the modelling commenced there have been announcement of the withdrawal of a small number (for example Liddell) of plants.

Plant	Capital Cost $/kW	Total Sent Out Capacity	Available Capacity factor	Full Load Heat Rate GJ/MWh so	Fixed O&M $/kW/year	Variable O&M $/MWh	Variable Fuel Cost $/GJ	Total Variable Cost $/MWh
Tasmania								
Tamar Valley CCGT		202	93.6%	7.54	38	2.87	7.16	56.86
Bell Bay GT		119	93.3%	11.50	14	4.30	4.72	58.53
Tamar Valley OCGT		58	93.3%	11.50	14	4.30	15.11	178.06
New CCGT	1150	196	92.3%	6.93	38	3.60	7.16	53.20
New GT	903	319	93.3%	11.43	13	5.80	15.11	178.50
New CCGT CCS	2535	483	92.3%	7.87	62	4.51	7.16	60.84
Victoria								
AGL Somerton		162	83.9%	13.50	14	2.87	4.38	61.98
Anglesea		145	96.6%	13.00	54	1.43	0.15	3.37
Bairnsdale		84	93.3%	11.50	14	4.30	4.52	56.33
Hazelwood		1472	84.0%	13.30	93	0.66	0.67	9.56
Jeeralang A		231	95.0%	13.75	14	8.61	4.28	67.44
Jeeralang B		254	95.0%	12.85	14	8.61	4.28	63.59
Laverton North		338	93.9%	11.55	14	4.30	4.38	54.87
Loy Yang A		2043	91.9%	11.58	89	1.15	0.51	7.03
Loy Yang B		966	92.3%	11.70	89	1.15	0.51	7.09
Valley Power		334	95.0%	13.75	14	8.61	4.28	67.44
Yallourn W		1362	88.6%	12.91	90	3.43	0.52	10.15
Newport		485	93.0%	10.33	25	2.87	4.38	48.10
Mortlake		550	93.0%	10.78	14	3.65	6.44	73.06
Qenos Cogeneration		21	93.3%	11.00	28	2.07	7.94	89.40
New CCGT	1150	546	92.3%	6.93	35	3.51	7.94	58.53
New GT	755	281	95.2%	10.38	13	7.30	16.76	181.27
South Australia								
Angaston		50	99.4%	9.00	14	12.31	20.41	196.05
Dry Creek		147	86.1%	17.00	14	8.61	11.07	196.77
Hallett		220	88.3%	9.60	14	9.83	11.07	116.08
Ladbroke Grove		84	92.1%	10.00	14	7.17	5.24	59.60
Mintaro 1		90	88.1%	16.00	14	8.61	11.07	185.70
Northern		505	97.9%	11.50	49	2.79	2.41	30.53
Osborne		185	93.9%	10.40	28	2.79	5.24	57.32
Pelican Point		463	91.4%	7.71	35	2.87	4.99	41.36
Port Lincoln		73	91.4%	11.67	14	8.61	20.41	246.78
Quarantine		218	89.1%	10.35	14	9.15	11.07	123.71
Snuggery		66	88.1%	15.00	14	8.61	20.41	314.83
Torrens Island A		456	87.7%	10.80	39	8.61	9.22	108.17

Plant	Capital Cost $/kW	Total Sent Out Capacity	Available Capacity factor	Full Load Heat Rate GJ/MWh so	Fixed O&M $/kW/year	Variable O&M $/MWh	Variable Fuel Cost $/GJ	Total Variable Cost $/MWh
Torrens Island B		760	87.7%	10.50	58	2.15	8.02	86.34
SA OCGT	903	165	95.2%	11.36	13	7.22	16.93	199.50
Hallett	903	220	88.3%	9.60	13	9.83	11.07	116.08
New South Wales								
Bayswater		2592	93.3%	10.00	58	2.87	1.74	20.22
Colongra OCGT		720	91.9%	11.84	14	9.90	17.45	216.49
Eraring		2707	91.8%	10.08	58	2.87	2.03	23.36
Eraring GT		42	91.9%	11.84	14	9.90	20.41	251.57
Hunter Valley GT		50	89.1%	23.38	14	9.90	20.41	487.20
Liddell		1936	92.3%	10.38	58	2.59	1.74	20.60
Mt Piper		1260	97.1%	9.93	58	2.73	1.76	20.26
Smithfield		151	91.4%	10.00	28	5.45	5.97	65.11
Tallawarra		422	92.3%	7.17	35	3.64	8.27	62.90
Uranquinty		661	93.3%	10.98	14	3.47	17.45	195.08
Vales Point		1241	89.0%	9.87	58	3.59	2.08	24.14
New CCGT	1150	546	92.3%	6.93	35	3.56	8.27	60.85
New OCGT	755	281	95.2%	10.38	13	7.15	17.45	188.30
New CCGT CCS	2535	482	92.3%	7.87	62	4.38	8.27	69.44
New coal CCS	5568	396	87.6%	9.87	157	4.72	2.33	27.74
Queensland								
Barcaldine		37	91.4%	8.02	28	4.30	5.21	46.09
Braemar		1018	94.2%	11.00	14	3.61	1.96	25.19
Callide B		658	93.3%	9.88	59	2.07	1.69	18.72
Callide C		846	91.9%	9.00	59	1.43	1.69	16.61
Darling Downs		899	94.2%	8.54	28	5.45	11.61	104.62
Gladstone		1579	91.1%	10.22	59	1.26	1.96	21.27
Kogan Creek		699	91.4%	9.50	59	1.29	0.79	8.83
Mackay		34	94.2%	13.50	14	11.48	20.41	287.08
Millmerran		788	86.5%	9.88	59	1.29	0.79	9.13
Moranbah		46	91.4%	8.02	14	4.30	-	4.30
Mt Stuart		417	94.2%	11.50	14	5.74	20.41	240.51
Oakey		338	94.2%	11.50	14	5.74	11.00	132.25
Roma		68	84.0%	13.50	14	5.74	5.21	76.08
Stanwell		1372	95.6%	9.99	59	1.15	1.75	18.61
Swanbank E		359	94.2%	8.10	35	2.87	5.21	45.08
Tarong		1316	96.0%	10.50	59	1.19	1.50	16.94
Tarong North		416	98.0%	9.50	59	1.19	1.50	15.44
Yabulu		236	92.4%	7.44	38	2.87	3.16	26.39
North CCGT CCS	2535	485	92.3%	7.87	62	4.52	9.20	76.90
North GT	905	165	95.2%	11.36	13	7.22	19.42	227.80
North CCGT	1270	239	92.3%	7.83	38	3.61	9.20	75.63
South CCGT	1150.0	385	92.3%	6.93	35	3.67	9.67	70.65
South OCGT	905	165	93.3%	11.36	13	7.33	20.40	239.13
South CCGT CCS	2535	485	92.3%	7.87	62	4.59	9.67	80.66

Plant	Capital Cost $/kW	Total Sent Out Capacity	Available Capacity factor	Full Load Heat Rate GJ/MWh so	Fixed O&M $/kW/year	Variable O&M $/MWh	Variable Fuel Cost $/GJ	Total Variable Cost $/MWh
Central CCGT	1150	380	92.3%	6.93	35	3.56	9.68	70.65
Central coal CCS	5570	396	87.6%	9.87	157	4.78	1.69	21.42
WEM								
Albany		22	94.1%	-	0	4	0	4
Mumbida		55	94.1%	-	0	4	0	4
Greenough		10	97.0%	-	0	5	0	5
Collie A		304	92.1%	10.0	12,000	5	3.14	36.40
Muja A/B		240	88.4%	13.0	16,000	9	3.41	53.33
Muja C		171	92.2%	11.0	12,500	6.5	3.41	44.01
Muja D		400	93.1%	10.5	12,000	6	3.41	41.81
Kwinana GT		16	95.1%	15.5	1,000	9	6.5	109.75
Pinjar A, B		174	91.2%	13.5	2,000	5	6.5	92.75
Pinjar C		183	91.2%	12.5	4,000	5.5	6.5	86.75
Pinjar D		123	91.2%	12.5	4,000	5.5	6.5	86.75
Mungarra		87	91.2%	13.5	2,000	5	6.5	92.75
Geraldton		16	95.1%	15.5	500	5	20	315
Kalgoorlie		48	95.1%	14.5	500	5	20	295
Cockburn		240	94.1%	7.5	11,000	3	6.5	51.75
LMS100		200	94.1%	10.8	2,800	5	6.5	75.2
Worsley		70	94.1%	8.0	4,000	5	6.5	57
Alcoa		212	94.3%	12.0	6,000	5	6.5	83
BP/Mission		100	94.3%	8.0	2,800	5	6.5	57
Southern Cross		120	92.4%	12.7	1,680	4	6.5	80.05
Goldfields Power		90	95.2%	9.5	1,260	4	6.5	65.75
Worsley		27	94.3%	8.0	756	4	6.5	56
NewGen		350	95.1%	7.4	11,900	2	6.5	50.1
Kemerton		308	97.5%	12.2	4,312	5	6.5	84.3
Alinta Wagerup		351	95.1%	11.2	9,828	2	6.5	74.8
Alinta Pinjarra		266	96.0%	6.5	7,448	2	6.5	44.25
Bluewaters		400	94.1%	9.7	17,200	2	3.14	32.46

Source: Jacobs' data base of generation costs, which in turn is based on market data published by AEMO and IMO, annual reports of generators and fuel suppliers, ASX announcements and other media releases.

Appendix E. Technology cost assumptions

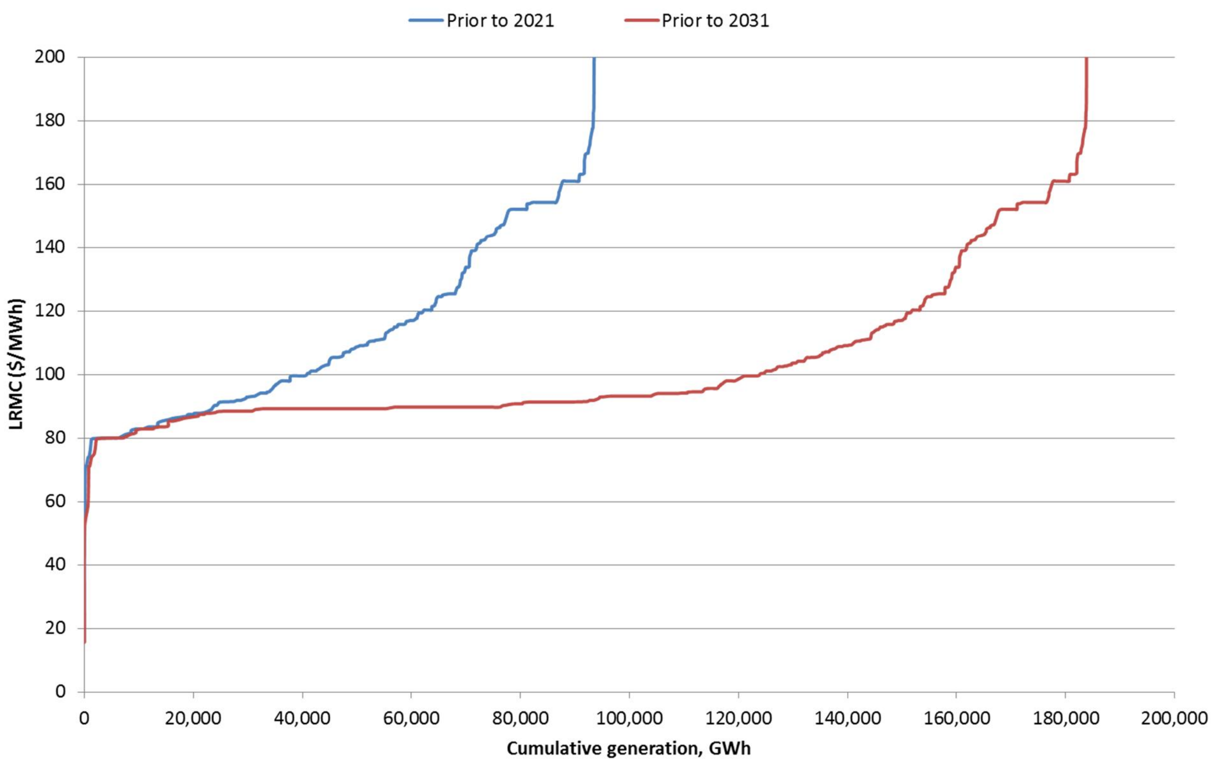
Technology type	Life, years	Nominal capacity, MW	Auxiliary load, %	Capital cost, 2016 $/kW so	Capital cost de-escalator from 2020, % pa	Heat rate at maximum capacity, GJ/MWh	Variable non-fuel operating cost, $/MWh	Fixed operating cost, $/kW
Supercritical	35	743	4.7%	2,966	0.11	9.16	1.6	84
Ultrasupercritical	35	743	4.5%	3,113	0.11	8.85	1.6	87
Black coal IGCC	30	510	10.3%	5,653	1.00	8.08	4.4	134
Black coal with CCS	30	480	17.5%	6,665	3.00	9.87	4.8	157
Brown coal supercritical	30	743	6.5%	4,860	0.11	11.44	1.9	119
Brown coal supercritical with drying	30	743	6.5%	4,860	0.11	11.44	1.9	119
Brown coal ultrasupercritical	30	500	9.4%	7,564	0.17	9.62	4.4	170
Brown coal IGCC	30	500	9.4%	7,564	1.00	9.62	4.4	170
Brown coal with CCS	30	470	19.2%	9,924	3.00	12.61	4.9	221
Cogeneration	30	123	1.7%	1,760	0.17	5.49	5.2	45
CCGT- large	30	559	2.2%	1,341	0.17	6.86	3.6	35
CCGT - large with CCS	30	524	7.9%	2,959	3.00	7.87	4.5	62
CCGT-medium	30	245	2.3%	1,495	0.17	7.83	3.6	38
OCGT (E Class)	30	167	1.1%	1,106	0.20	11.36	7.2	17
OCGT (F Class)	30	284	1.0%	936	0.20	10.38	7.2	13
OCGT (aero)	30	49	1.2%	1,539	0.20	10.00	10.3	27
Wind	25	100	2.0%	2,400	0.50	3.60	5.0	40
Biomass - steam	30	30	6.3%	6,382	1.00	14.24	8.0	60
Biomass - gasification	25	79	22.3%	5,361	1.00	14.14	10.0	60
Concentrated solar thermal plant - without storage	35	150	5.0%	6,500	2.50	3.60	5.0	50
Concentrated solar thermal plant - with storage	35	150	5.0%	9,500	2.50	3.60	10.0	60
Geothermal - hydrothermal	30	50	8.0%	6,500	1.50	13.00	5.0	50
Geothermal - Hot Dry Rocks	25	50	10.0%	7,000	1.50	14.00	5.0	50
Concentrating PV	30	150	3.0%	6,175	2.50	3.60	5.0	45
Flat plate PV	35	175	2.0%	2,990	2.50	3.60	2.0	25

Technology type	Life, years	Nominal capacity, MW	Auxiliary load, %	Capital cost, 2016 $/kW so	Capital cost de-escalator from 2020, % pa	Heat rate at maximum capacity, GJ/MWh	Variable non-fuel operating cost, $/MWh	Fixed operating cost, $/kW
Roof-top PV **	25	1	1.0%	(a)	2.50	3.60	2.0	0
Hydro	35	30	2.0%	3,500	0.50	3.60	5.0	35
Nuclear	40	1,000	6.0%	5,140	0.11	10.97	14.7	34
Small-scale storage	15	-	-	612*	2.50	-	-	-
Large-scale storage	15	-	-	551*	2.50		-	-

* Costs for storage technologies are presented as $/kWh.

** For small scale PV costs per kW by system size were used.

Figure 33: Assumed renewable supply curve for Australia in 2020 and 2030 for new projects



Source: Jacobs' data base of renewable energy projects, which in turn is based on annual reports of generators, ASX announcements and other media releases.