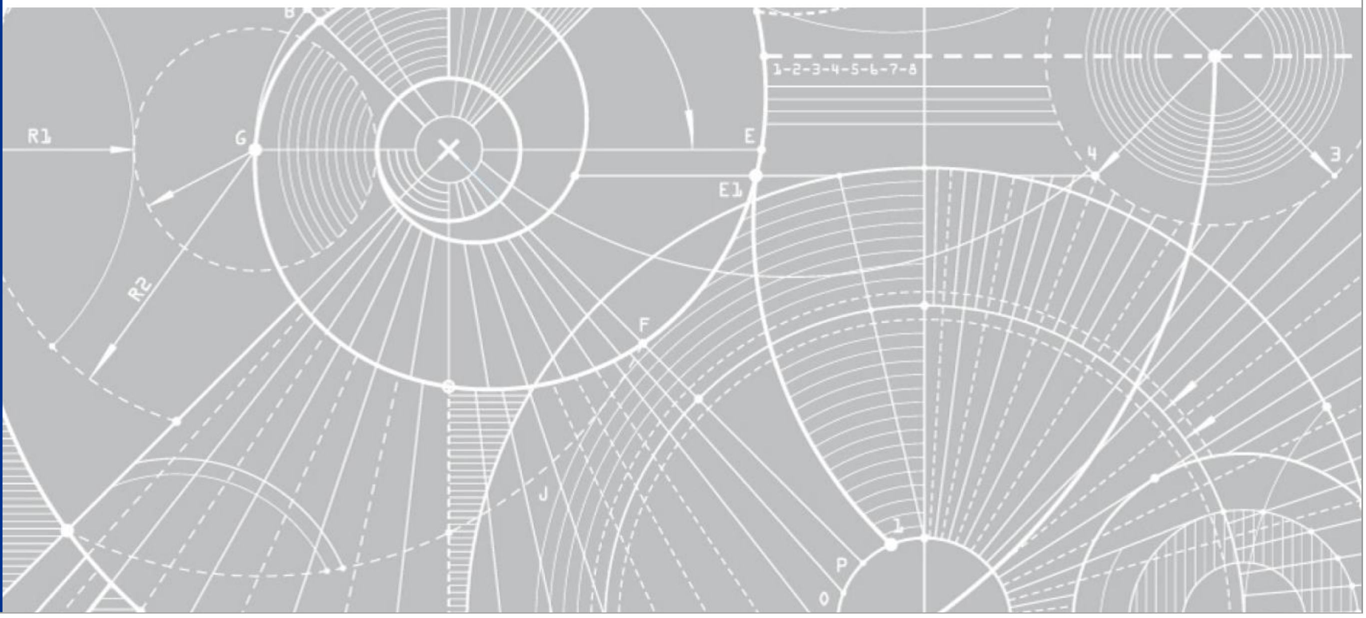
Electricity Sector Impacts of Emission Abatement Policies

THE CLIMATE INSTITUTE

Final

12 April 2016



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Modelling of Electricity Sector Impacts of Emission Abatement Policies

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Client name:	The Climate Institute
Project manager:	Walter Gerardi
Author:	Walter Gerardi

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

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1. Introduction

The electricity sector contributes around 35 per cent of national carbon dioxide emissions. Up until recently, it was the fastest growing source of such emissions in Australia. However, the uptake of renewable energy under various support policies and the development of energy efficiency policies, together with a reduction in demand post the global financial crisis have acted to reduce emissions from this sector over the past five years. However, more recently, emissions from this sector have rebounded.

The Climate Institute has commissioned Jacobs to model the impacts on electricity markets of alternative policies to curb greenhouse emissions in the period after 2020. This study examined a potential mix of emission reduction approaches and compared the impacts with impacts of an “optimal” approach based on carbon pricing alone.

This report outlines the method and assumptions used in predicting electricity market impacts. The key results are also reported and discussed.

2. Scenarios

The policies examined and some key assumptions included:

- Reference scenario: Optimal policy - global carbon price consistent with ensuring global temperatures do not increase by more than 2^{o} Celsius implemented within the Australian economy.
- Suboptimal carbon price scenario: A more politically palatable carbon price trajectory to 2030 and including current RET. From 2030, the carbon price was increased to achieve the same level of cumulative abatement as the reference scenario. The model was “blinded” in the sense that generators before 2030 could not see foresee the carbon price after 2030 – rather investment decisions before 2030 were based on the carbon price trajectory continuing at the slow growth trajectory.
- Technology scenario 1 (referred to as the CET scenario in this report): On top of the suboptimal carbon price scenario, a Clean Energy Target consistent with 50 per cent of generation by 2030 was imposed. The Clean Energy Target operates in the same way as the LRET, but allows CCS or other fossil fuel options with emission intensity less than 200 kilograms CO_2/MWh.
- Technology scenario 2 (referred to as the Closure scenario in this report): On top of the suboptimal carbon price scenario, regulations were imposed on new and existing generation. After 2020, coal based generators more than 45 years old where shut down or retrofitted to full CCS. New build plants to 2030 had to have emission intensities of no more than 450 kilograms CO_2/MWh. After 2030, new build plants had to have emission intensities of no more than 200 kilograms CO_2/MWh.
- Technology scenario 3 (referred to as the CET plus closure scenario in this report): On top of the suboptimal carbon price scenario, impose both Technology scenario 1 and 2 policies.

Sensitively analysis was performed around the 'best' suboptimal scenario using low demand assumptions. Technology scenarios 2 and 3 were also modelled with a 50 year limit on coal generators but it was found that this timeframe for closure had little impact so is not discussed further in this report.

The policy options were assumed to commence in mid-2020 and the simulation of the electricity market impacts was for the period 2020/21 to 2049/50.

In all scenarios, nuclear generation was excluded as an option. However, the modelling allowed biomass based carbon capture and storage generation options. Retrofitting of existing plants was allowed as long as they were economic and met any emission intensity restrictions.

In all scenarios, external (global) fuel and technology costs were equivalent to the assumed rates used by the IEA for its 450 ppm policy simulations[1], implying intense global action to curb emissions being undertaken by all other countries.

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

3. Modelling approach

The objective of the study was to model the impact of the five policy options. The cumulative abatement target was the same for all policy options, but each option differed in the adjustments made to investment in new generation and the timing of that investment. Policy options also had different impacts on wholesale and retail prices.

In this section, a broad outline of the approach taken to model electricity market impacts for each policy scenario is provided. The impacts were determined by comparing outcomes in the policy scenario with those for the (no policy) reference scenario.

The estimated impacts include on:

- Wholesale and retail prices
- Generation mix in each region by technology
- Investment mix in new generation by technology
- Resource cost of electricity supply
- Emission pathway
- Cost of abatement
- Generator profitability
- Supply reliability (through such measures as energy not served and loss of load hours)

The modelling also provided insights into how the policy will affect the electricity sector and what the issues and uncertainties may be with each policy option.

The modelling was confined to National Electricity Market (NEM), which operates on the south-east and eastern seaboard of Australia, and the Wholesale Electricity Market (WEM), which operates on the south-west corner of Western Australia.

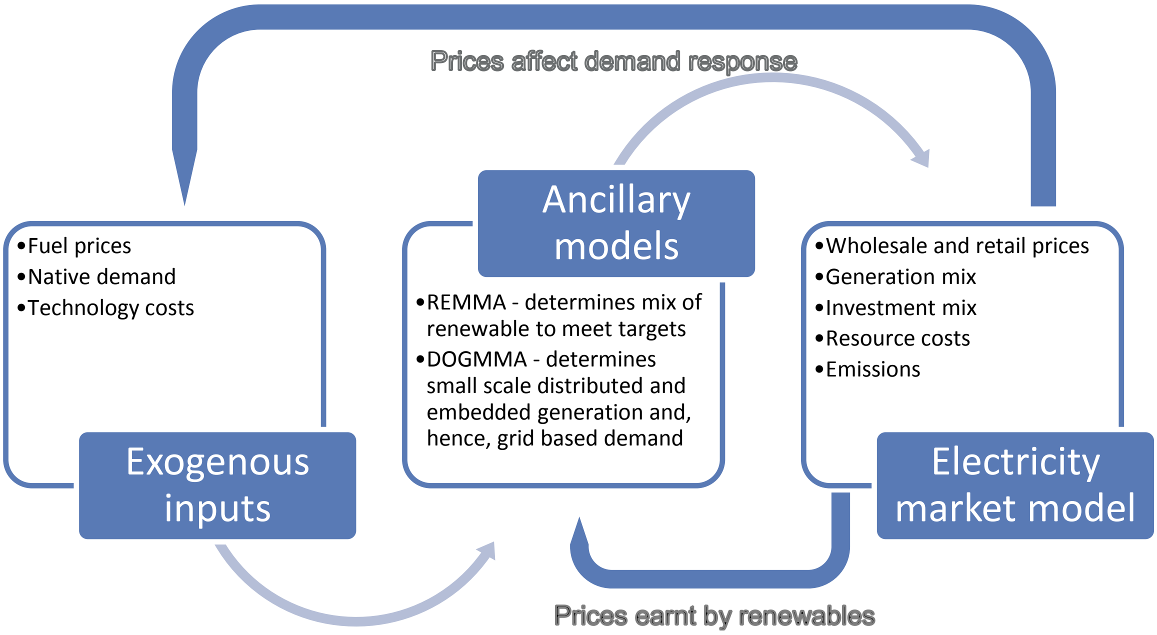
3.1 Overview

Modelling the impact of the abatement policies on the electricity market is a complex process. It requires iteration between a number of models to determine both the direct impacts and interactions between the electricity market and the various ancillary markets used as instruments to meet abatement targets. Figure 1 shows the interactions between the models used.

The approach to modelling the electricity market impacts, associated fuel combustion and emissions is to utilise externally derived electricity demand forecasts (adjusted for embedded generation component) in our STRATEGIST model of the major electricity systems in Australia. 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 method involves an iterative approach. An initial estimate of electricity demand and retail price projections are used to work out the level of embedded generation each year and the level and timing of new large-scale renewable generation. The level of embedded generation determines the net demand for electricity faced by the electricity grid, which is input into the electricity market models. The level and location of new renewable generation is also input into the electricity market models. The electricity market models are then simulated to produce a new set of wholesale and ultimately retail price projections. The whole process is repeated until a stable set of wholesale prices and renewable energy mix by region is achieved.

Figure 1: Modelling approach



3.2 Emission constraints

The optimal policy was modelled with an assumed carbon price designed to ensure global temperatures do not increase by more than 2^o Celsius. The carbon price path was derived from the IPCC (2014) for the scenario where global assumptions are constrained to achieve an atmospheric concentration of 450 ppm. The resulting path of carbon prices (in mid-2014 dollar terms) is shown in Figure 2.

For the other policy scenarios, modelling was undertaken in two phases. The first phase was designed to mimic the lock in of investment in new generation in the period to 2030 based on limited information that investors have on future carbon price paths after 2030. The carbon price path started at $17/t and increase by around 8.0% per annum to reach $40/t CO_2e by 2030 and then by 5% per annum to reach $118/t CO_2e by 2049/50, as shown in Figure 3[2]. The simulation was performed out to 2050 as if investors expect this price path to continue to 2050. In the second phase, the simulations were performed again for the period after 2030, assuming all investment undertaken prior to 2030 was locked in. Simulations of new investment and dispatch after 2030 were performed but with a carbon price that achieved a similar level of abatement as achieved by the optimal policy scenario. In this phase, the carbon price was an outcome of the modelling process as it was progressively altered to achieve the cumulative abatement target.

[2] This is based on the current price for the EU ETS of around $15/t CO_2e increasing by 3% per annum between now and 2020.

Figure 2: Assumed carbon price path for the optimal policy scenario, mid 2014 dollar terms

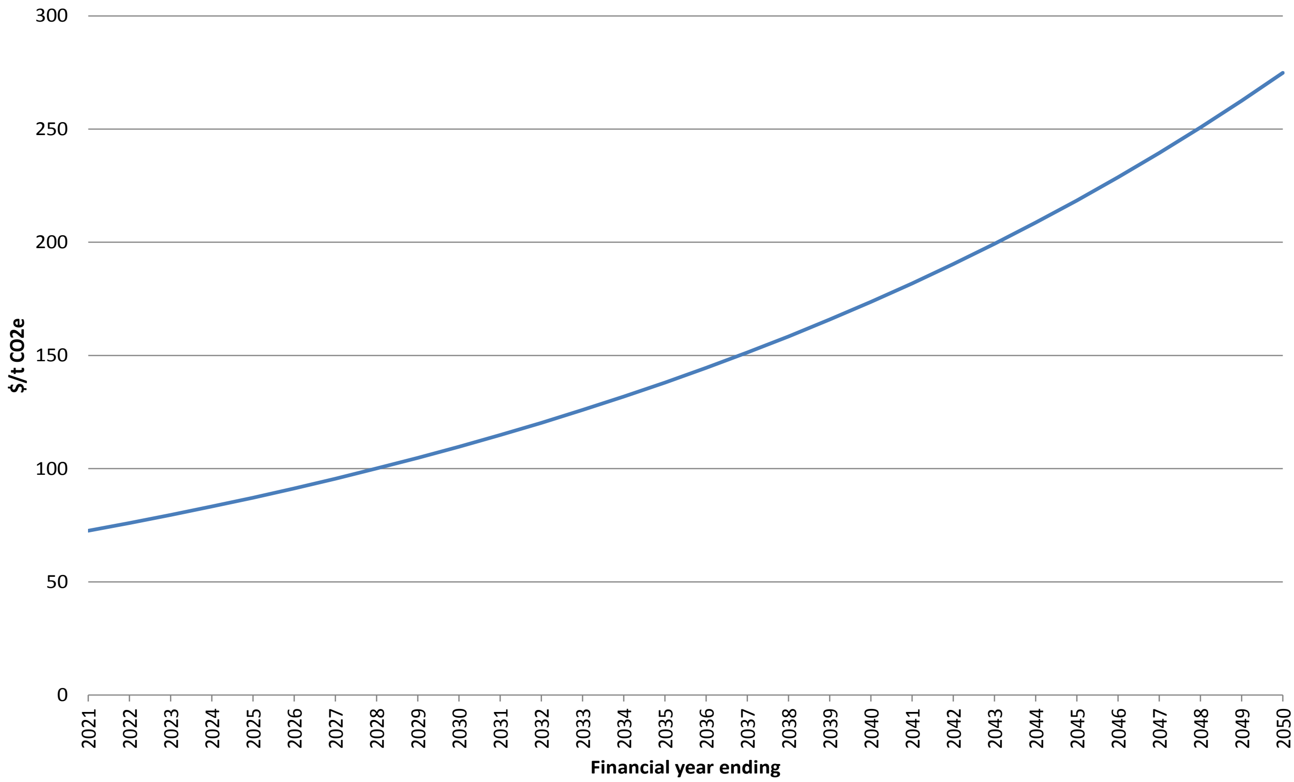
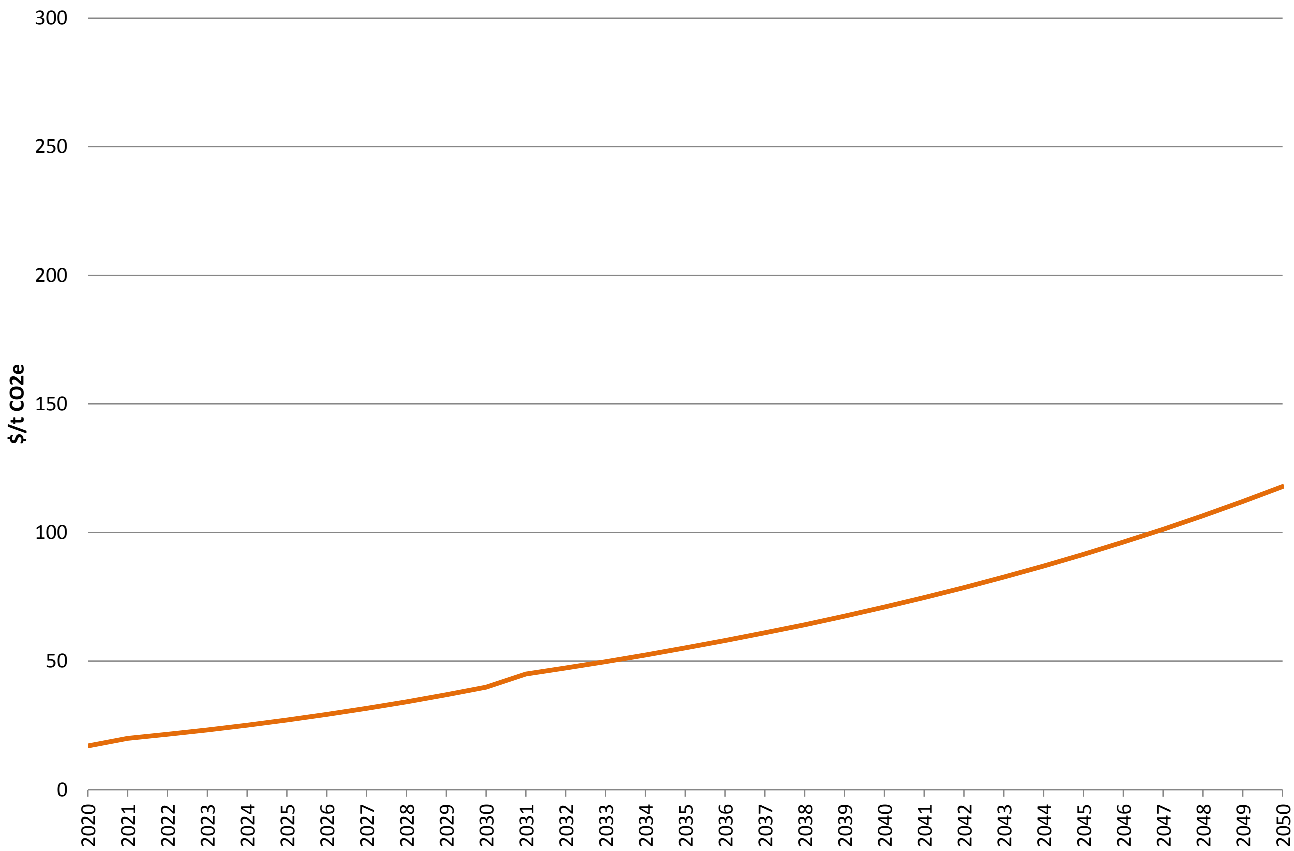


Figure 3: Assumed carbon price path expected by investors in the suboptimal policy scenarios, mid 2014 dollar terms



3.3 Demand

The following demand forecasts were used:

- AEMO's median demand projections published in its NEFR 2015 report
- IMO's latest median demand projections published late 2014.

Jacobs adjusted the forecasts to add back in the "buy-back" component of the embedded generation. Jacobs' Strategist model was then used in conjunction with a renewable energy model to explicitly project the renewable energy uptake. Some embedded generation, such as small scale cogeneration was not included in the Strategist model, and the native load forecasts were adjusted accordingly.

The modelling used the 50% POE peak demand projections to represent typical peak demand conditions and thereby provided an approximate basis for median price levels and generation dispatch.

3.4 Other assumptions

3.4.1 General assumptions

Structural assumptions used in the modelling included:

- Capacity is installed to meet the reserve requirements for the NEM in each region and if revenues post entry is sufficient to recover costs of generation including a return to capital. 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 was based on 2010/11 load profile for the NEM regions, with this being representative of a normal year in terms of weather patterns.
- Generators behave rationally, with uneconomic capacity withdrawn from the market and bidding strategies limited by the cost of new entry. This is a conservative assumption as there have been periods when prices have exceeded new entry costs when averaged over 12 months.
- Infrequently used peaking resources are bid near Market Price Cap (MPC) or removed from the simulation to represent strategic bidding of these resources when demand is moderate or low.
- The LRET scheme continues. The current target of 33,000 GWh of large-scale renewable generation by 2020 has been assumed.
- The Consumer Price Index (CPI) is assumed to be 2.5% per annum in line with the mid-point of target rates by the Reserve Bank. The CPI is used to calculate real fuel prices and network tariff escalations.

3.4.2 Market structure

We assume that the market is structured to remain largely competitive. We assume the current market structure continues under the following arrangements:

- Victorian generators are not further aggregated
- The generators' ownership structure in Queensland remains as public ownership
- The SA and NSW assets continue under the current portfolio groupings.
- Synergy generation assets remain publically owned.

In the NEM, Generators are assumed to behave rationally, with uneconomic capacity withdrawn from the market and bidding strategies limited by the cost of new entry. In the modelling of energy market impacts intra-regional marginal loss factors are assumed to be unchanged from those set by AEMO/IMO in 2014/15. That is, the loss factors are assumed to be the same across all years and across all scenarios. 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.

In the WEM, generators are assumed to bid into the wholesale market at short run marginal cost in accordance with the market rules.

3.4.3 Generator cost of supply

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 1. We also include the net present value of changes in future capital expenditure that would be driven by fuel consumption for open cut mines that are owned by the generator. This applies to brown coal in Victoria and for Leigh Creek coal in South Australia.

Table 1: Indicative average variable costs for existing thermal plant (mid 2014 dollars)

Technology	Variable Cost $/MWh	Technology	Variable Cost $/MWh
Brown Coal – Victoria	$3 - $10	Brown Coal – SA	$24 - $31
Gas – Victoria	$46 - $64	Black Coal – NSW	$20 - $23
Gas – SA	$37 - $111	Black Coal - Qld	$9 - $31
Oil – SA	$250 - $324	Gas - Queensland	$25 - $56
Gas Peak – SA	$100 - $164	Oil – Queensland	$241 - $295

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 at generator are shown in Appendix C.

3.4.4 Gas prices

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
- Domestic market growth driven by gas-fired generation and large industrial projects.

The gas market model assumes that the $A is equal to US80c and declines over 6 years to US70c and holds that value.

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 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 (as is occurring at the moment in the Queensland market).

- Import prices set at the energy equivalent of oil or liquid fuels, being the main substitute for gas in most end-uses.

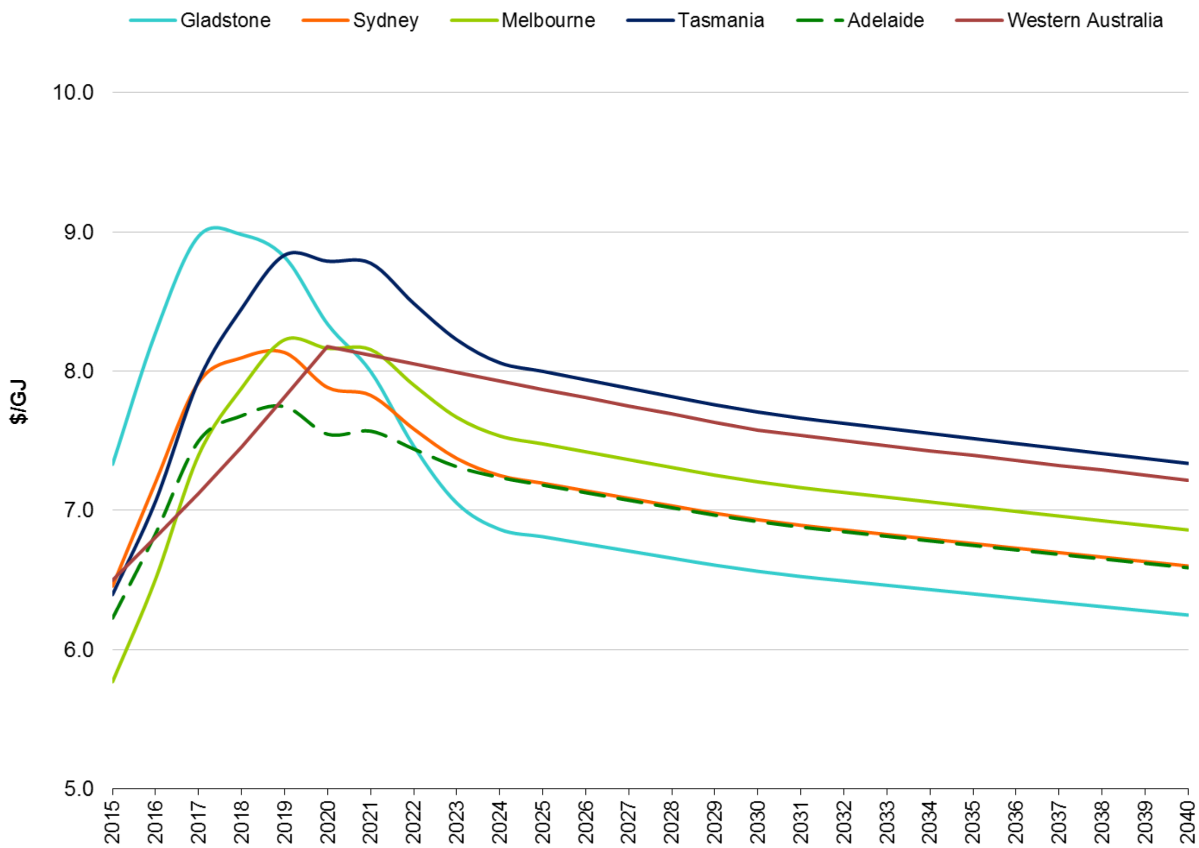
We have used Jacobs's medium gas price projections, which assume gas prices rise above world parity levels over the period to 2018/19 due to a shortage of gas to meet contracted commitments for LNG. Thereafter prices fall to world parity level and rise only gradually from those levels.

Prices are affected by the following factors:

- Over the next year, a shortage of gas is likely to emerge as LNG trains come on line and gas is required to meet export commitments. Currently there are not enough coal seam wells developed to meet the export requirements so gas is being sourced from conventional fields
- This shortage is not likely to dissipate until 2019 at the earliest due to time required to attain approval and develop additional coal seam gas wells.
- Thereafter, gas prices follow world price trends with price movements determined using assumptions by the IEA (2014) for its 450 ppm target simulation.

The prices are shown in the following chart.

Figure 4: Gas price assumptions, city gate prices (mid 2014 dollars)



Source: Jacobs' MMAGas model, IEA 450 ppm scenario

3.4.5 Coal prices

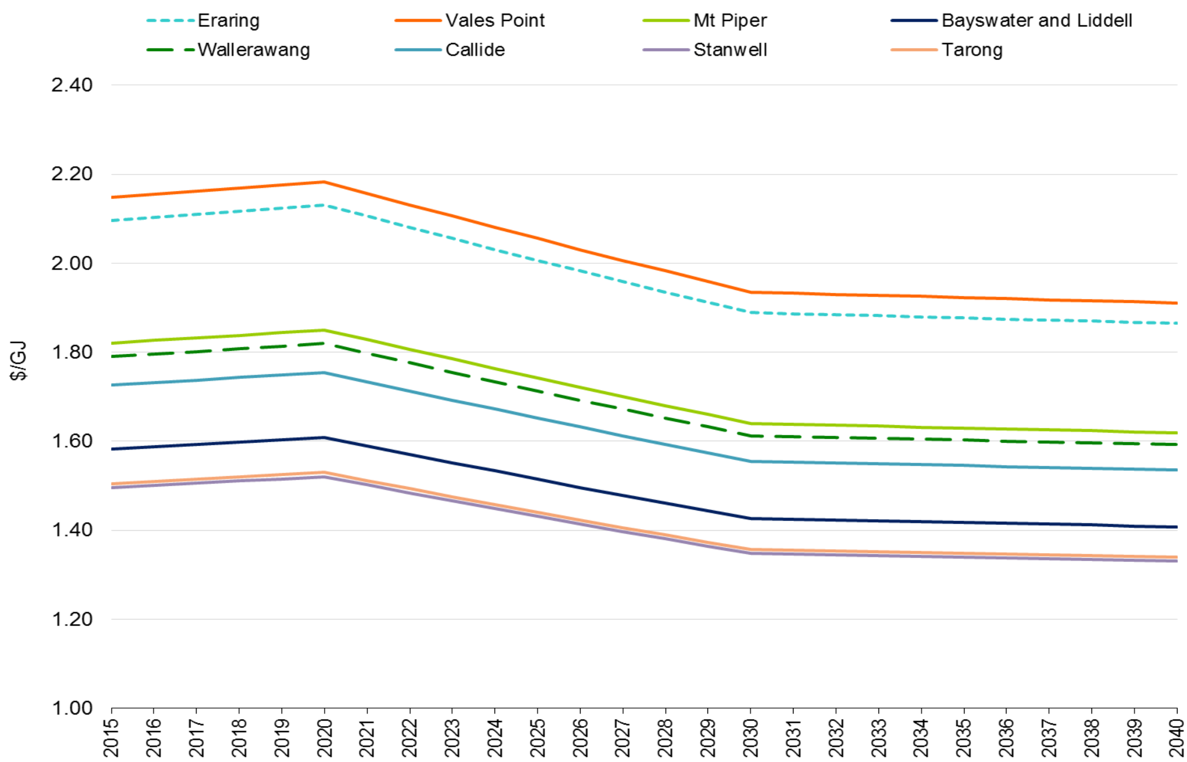
Coal prices are treated in three ways:

- To be equal to the long run average cost of production for those mines containing coal that are unlikely to be exported (typically brown coal plant in Victoria and South Australia)

- 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[3]. Thereafter, world coal prices are assumed to move 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[4].

The coal prices assumed for key NEM power stations are shown in Figure 5.

Figure 5: Projected variable coal price for NEM black coal power stations ($June 2014)



Source: Jacobs, IEA 450 ppm scenario

3.4.6 Interconnection and losses

Assumptions on interconnect limits are shown in Table 2 and their current operating levels are illustrated in Figure 6. 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.

[3] Source: Bureau of Resources and Energy Economics, *Resource and Energy Quarterly*, March 2015
[4] 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.

Table 2: Interconnection limits

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	

The actual limit in a given period can be much less than these maximum limits, depending on the load in the relevant region and the operating state of generators at the time. For example, in the case of the transfer limit from NSW to Queensland via QNI and Terranora, the capability depends on the Liddell to Armidale network, the demand in Northern NSW, the output from Millmerran, Kogan Creek and Braemar, and the limit to flow into Tarong[5].

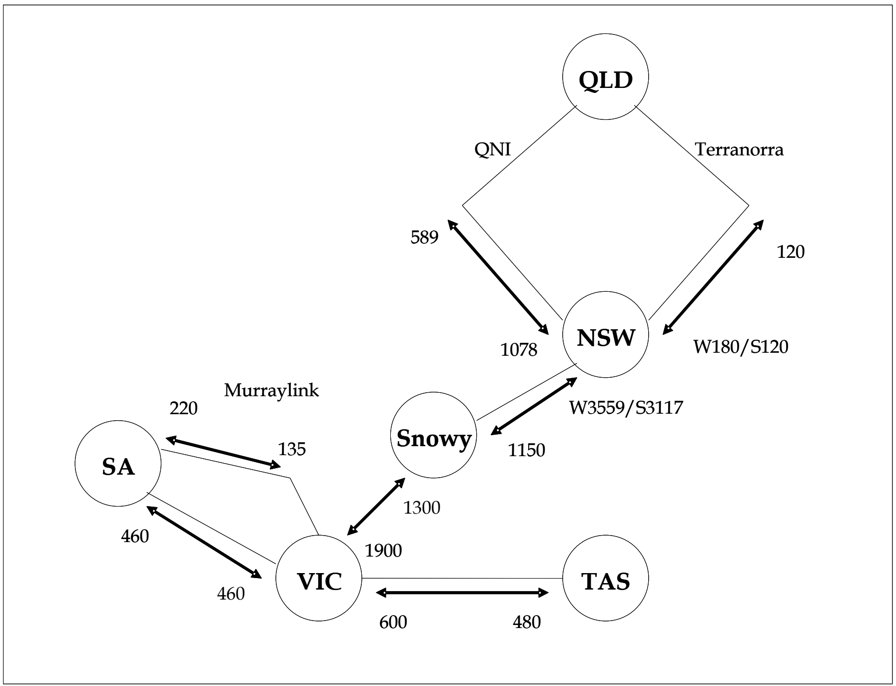
Basslink has a continuous capacity of 480 MW and a short-term rating up to 600 MW. Prior to the carbon pricing, Basslink had been modelled with an optimised export limit that best used the available thermal capacity of the cable to maximise the value of export trade. The optimisation was performed using a Strategist simulation to assess Victorian price versus export. The import limit was represented as a function of Tasmanian load according to the equation published by AEMO. This allowed 323 MW of import at 800 MW and 427 MW at 1,100 MW of load.

After carbon pricing the increase in off-peak prices tends to negate any consistent use of short-term rating in peak periods due to the value of the loss of transfer capability in off-peak periods necessary for cooling the cable thereafter. We therefore model Basslink after carbon pricing is introduced as having 480 MW continuous capacity in each direction.

A proposal to develop a second Basslink from north-west Tasmania via King Island to Victoria (near Anglesea) has recently been included in the modelling as an expansion option to be chosen only if it is more economic than other options.

[5] There is currently expected to be a limit of about 900 MW for flow into Tarong. This is not a fixed limit and could be increased with additional load shedding in Queensland.

Figure 6: Representation of interconnectors and their limits



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.

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.

There are a number of possible interconnection developments that were being considered at that time including:

- An upgrade of the QNI flow limit by an additional 400 MW in both directions.
- A further 600 MW upgrade of the Snowy to Victoria transmission link over time which would enable additional imports from Snowy/NSW into Victoria. The modelling has assumed options with augmentation of up to 2,500 MW total transfer capacity from Snowy to Victoria is available if economic.

An upgrade of Heywood interconnect (between Victoria and South Australia) has been assumed. The capacity increase is approximately 190 MW in both directions which would increase maximum transfer from 460 MW to 650 MW. This upgrade is assumed to be in service by 1 July 2016. The amount of wind capacity under consideration in South Australia is substantial and the extent of further uptake of wind in this State is heavily dependent on further upgrades of this interconnect proceeding.

In modelling the NEM, we augment the existing interconnections according to these conceptual augmentations as required. Further upgrades to relax the Tarong limit are assumed to proceed as required to ensure that capacity in the Tarong region can reach the South East Queensland load.

4. Benefits and costs

Impacts on resource costs and benefits are discussed in this section. The costs are in the form of changes in resource costs, or changes in capital, operating and fuel costs. Benefits are measured in the form of emissions abated. As emission outcomes are largely the same across all scenarios, the benefits are largely the same across all scenarios. Therefore the focus is on resource costs.

The cumulative target to be met in all scenarios is around 1,760 Mt CO_2e for the period 2020-2050 (for both direct emissions and indirect emissions which occur during fuel supply).

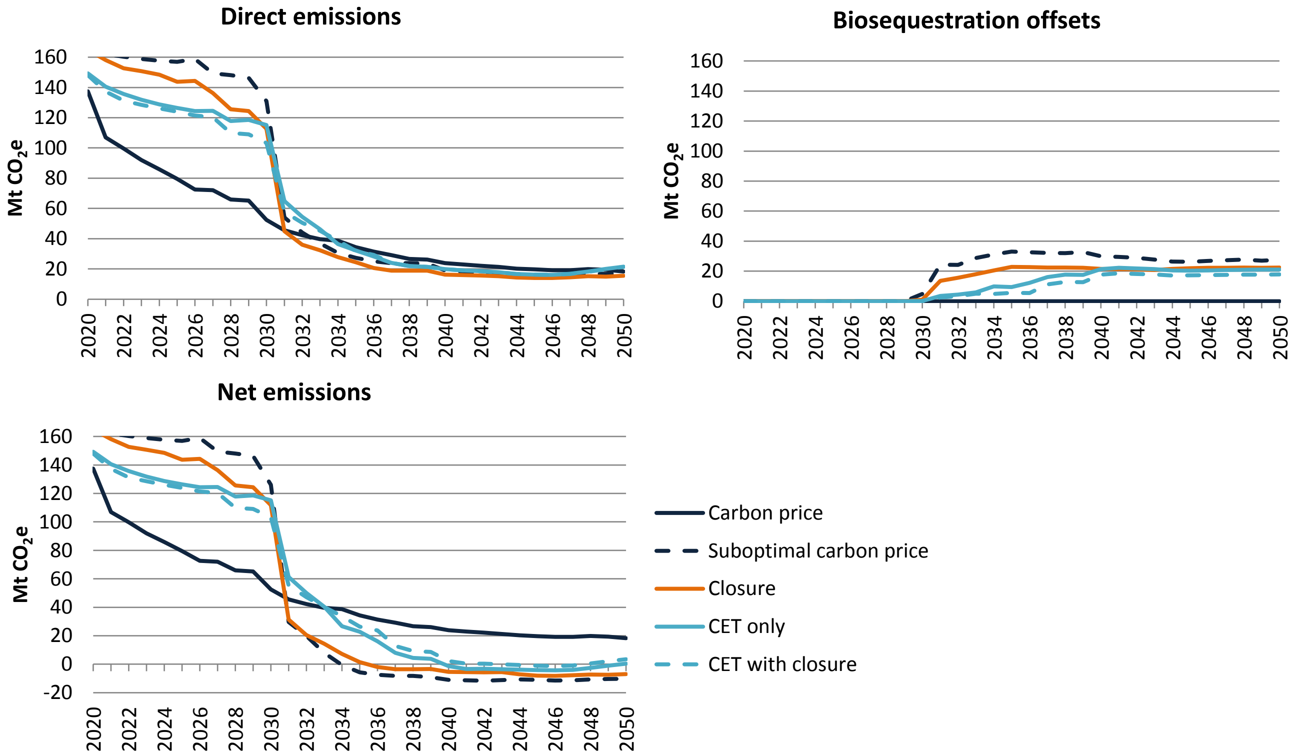
4.1 Emission

Projected annual emissions under the policy scenarios are shown in Figure 7. Two insights become apparent:

- Under the optimal policy case, there is an immediate sharp reduction in emissions and they continue to reduce. Emissions under this scenario fall from around 170 Mt CO_2e in 2019 to 137 Mt CO_2e as the starting carbon price of $70/t CO_2e is high enough to change the merit order and to cause immediate retirements of coal fired plant. By 2030, emissions have reduced to 52 Mt CO_2e. Direct emissions continue reducing until flattening out at around 20 Mt CO_2e. Over the entire period, direct emissions amount to 1,470 Mt CO_2e.

- For other policy scenarios, direct emissions fall less rapidly during the period to 2030. By 2030, direct emissions in these alternative scenarios exceed the total emissions over the period to 2050 for the optimal policy scenario. When including indirect emissions (fugitive emissions on fuel supply), the cumulative emissions to 2030 in the other policy scenario are 71% to 89% of the cumulative target. As a result, all other policy scenarios require offsets to meet the cumulative target (see Table 3), which in this modelling is created by biomass based carbon capture and storage[6].

Figure 7: Emissions and offsets



[6] As biomass generation does not incur any direct emissions, the carbon stored means a net reduction of emissions in the atmosphere.

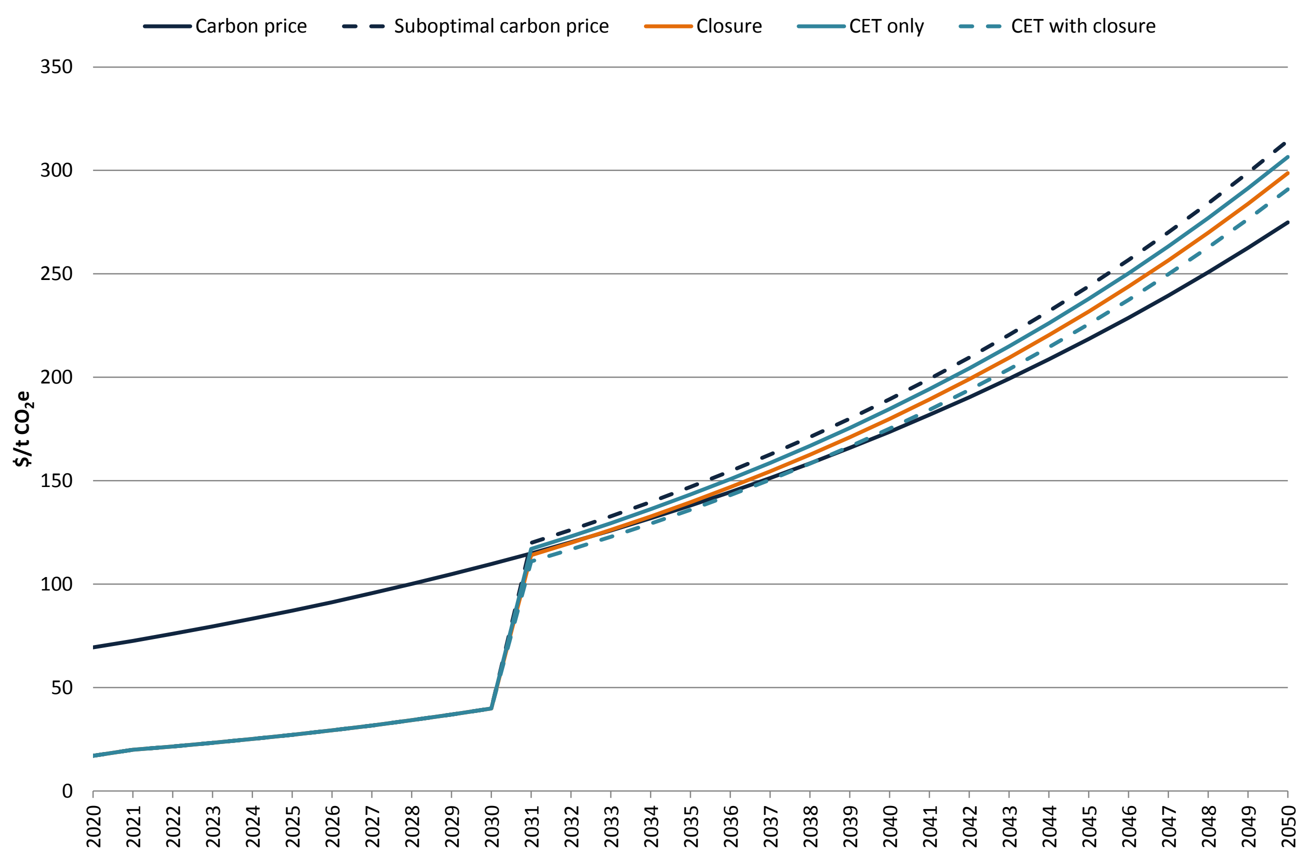
Table 3: Cumulative emissions, Mt CO_2e

	Direct emissions				Indirect emissions, 2020 to 2050	Offsets required, 2020 to 2050	Net emissions, 2020 to 2050
	2020 to 2030	2031 to 2040	2041 to 2050	2020 to 2050			
Carbon price	930	338	202	1,469	291	0	1,760
Suboptimal carbon price	1,695	308	165	2,168	146	581	1,733
Closure	1,562	259	149	1,970	183	422	1,732
CET only	1,413	350	181	1,944	172	329	1,787
CET with closure	1,359	340	180	1,879	177	258	1,799

The carbon prices required to ensure the cumulative targets are met are shown in Figure 8. In the carbon price scenario, carbon prices start at around $69/t CO_2e, rising by 4.5% per annum to reach $275/t CO_2e by 2050. To achieve the cumulative target, carbon prices in all other scenarios have to be higher than in the carbon pricing scenario. In 2031, prices in the other scenarios are up to $5/t CO_2e higher than in the carbon pricing scenario and they rise at a greater rate of 5.2% per annum. The scenarios where plants are enticed to close early require lower carbon prices to meet the target.

The carbon prices in these scenarios are higher because an additional incentive is needed to cover the cost of the biomass carbon capture and the storage options required to meet the cumulative target. The higher carbon prices provide an additional revenue stream (offset revenue from carbon sequestered) to help recover their high costs.

Figure 8: Carbon prices required to meet the cumulative emission target



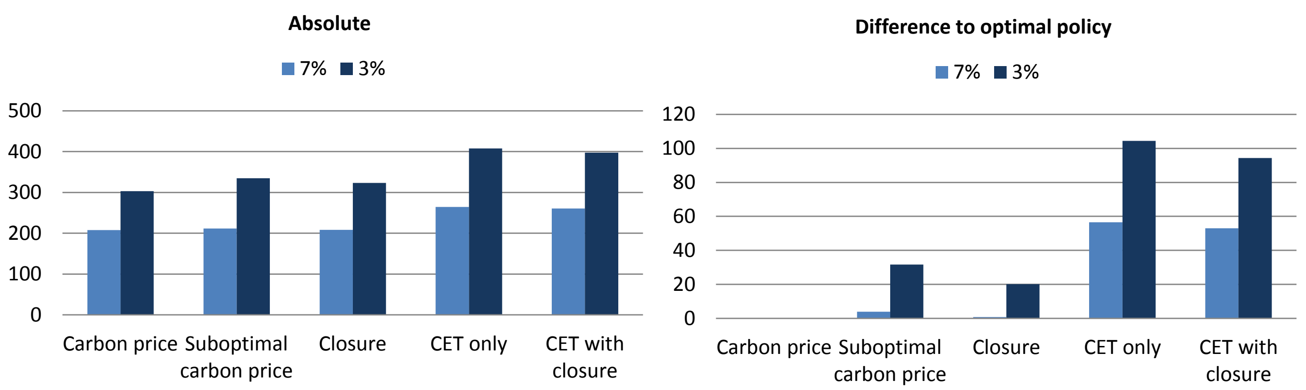
4.2 Net costs

The net present value of the resource costs of each scenario is shown in Figure 9. The resource cost comprises the additional capital expenditure, fuel and operating costs to supply electricity demand under each policy scenario. The optimal policy has the lowest net present cost. The suboptimal carbon pricing policy and the closure policy have broadly similar resource costs (being $2 billion and $1 billion respectively higher) at a 7% discount rate but have substantially higher resource costs at a 3% discount rate (of above $20 billion). The resource cost of these two policies are concentrated in the period after 2030, when more investment in high cost abatement options (e.g. biomass carbon capture and storage) is required to meet the target. At a high discount rate this cost is more heavily discounted. Whereas with the optimal policy case there is a high upfront cost, with higher capital and higher fuel costs in the period to 2030.

The closure scenario has lower resource cost than the suboptimal carbon price. Due to the early closure of the coal plant, there is more abatement in the period to 2030 and therefore less need for offsets from high cost biomass carbon capture and storage to meet the cumulative target.

The clean energy target scenarios have the highest resource cost due to the investment in high cost low emission technologies required to meet the target to 2030. This investment locks out investment in other low emission technologies[7] in the period to 2030, and requires more investment in low emission technologies to 2030 which locks out other low emission options that become available over the long term[8]. Again aligning a clean energy target with a closure regime reduces the resource cost as more abatement occurs in the period to 2030, requiring less need for offsets from biomass carbon capture and storage.

Figure 9: Net present value of resource costs, $ billion, mid 2014 dollar terms

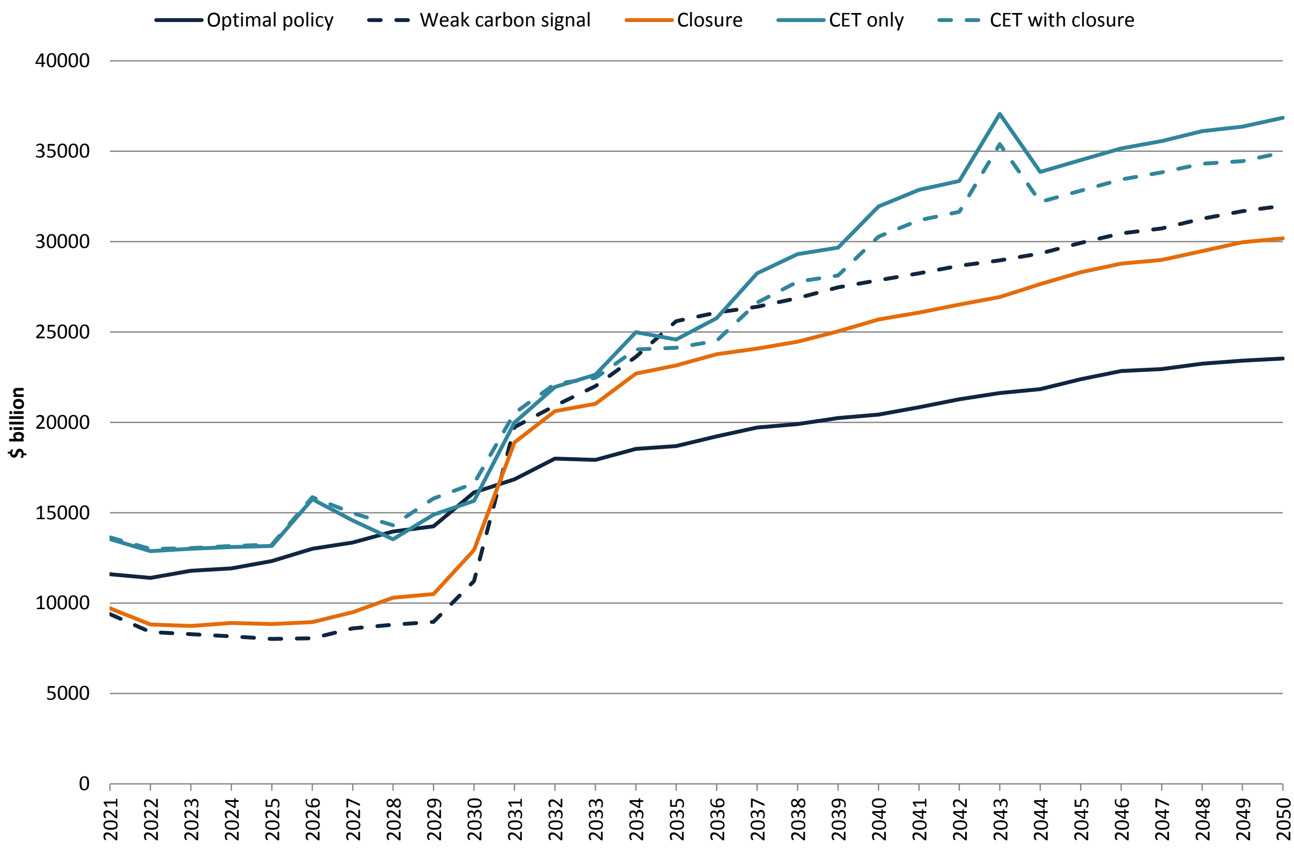


The annual resource costs under each scenario are shown in Figure 10, which shows the total cost of generation in each year under each scenario. For the optimal policy scenario, costs are higher in the period to 2030 compared with other policy scenarios, except for the clean energy target scenarios due to the latter's reliance on investment in new plant to meet the clean energy target. The optimal policy costs are lower than for all other scenarios after 2030. The other policy scenarios require investment in more high cost low emission plant in the period and more investment in biomass carbon capture and storage after 2030.

[7] The specification for this scenario had an emission limit of 0.2 t/MWh to be eligible to participate, preventing CCGT generation (without carbon capture and storage from being eligible)

[8] In this modelling, carbon capture and storage technologies as well as geothermal generation are assumed to become available after 2030.

Figure 10: Electricity generation costs, mid 2014 dollar terms

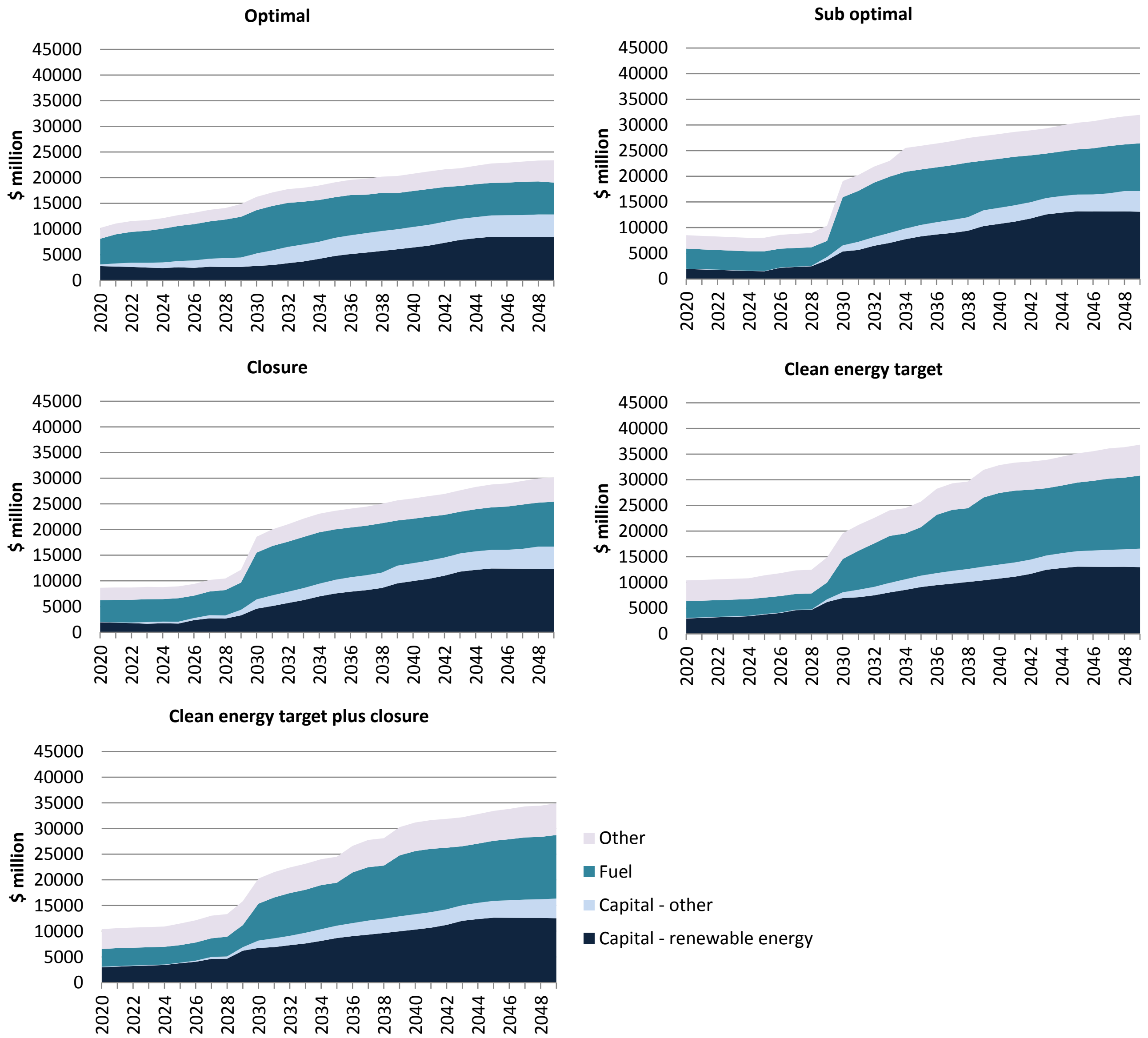


There is a trade-off between capital and fuel costs across the scenarios (see Table 4 and Figure 11). Policies which better utilise the existing gas-fired fleet and invest in new conventional gas plant in the period to 2030 tend to have lower overall resource costs. In the optimal policy scenarios, fuel costs are higher than for other scenarios as there is more gas-fired generation in this scenario in the period to 2030. The lower fuel costs in other scenarios, however, do not compensate for the higher capital costs required in most of these other scenarios. Other operating costs are also higher for other scenarios due to the operating cost of carbon capture and storage technologies, with more of these technologies being adopted for these scenarios.

Table 4: Net present value of cost components, 7% discount rate, mid 2014 dollar terms

	NPV, $million				%of total		
	Capital	Fuel	Other	Total	Capital	Fuel	Other
Optimal policy	83,460	89,945	34,174	207,579	40%	43%	16%
Suboptimal carbon price	83,223	83,688	44,652	211,563	39%	40%	21%
Closure	83,745	85,251	39,430	208,425	40%	41%	19%
CET only	117,890	84,539	61,703	264,132	45%	32%	23%
CET with closure	117,709	81,913	60,956	260,577	45%	31%	23%

Figure 11: Annual costs by component, mid 2014 dollar terms



4.3 Capacity mix

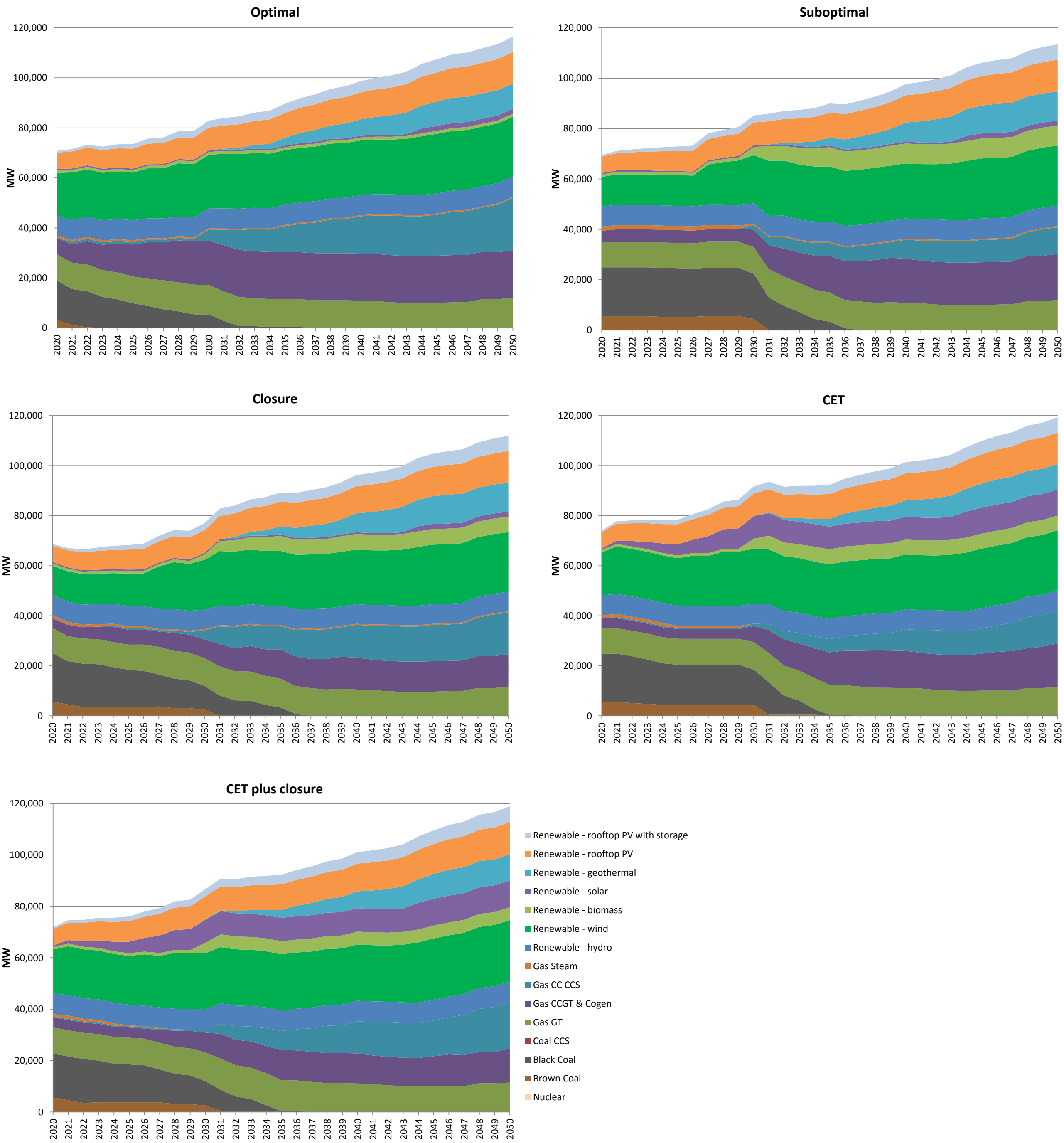
The capacity mix under each policy scenario is shown in Figure 12. Key results are:

- The coal fleet is completely retired by 2032 in the optimal policy scenario, with the brown coal fleet retired by 2025. The retirement of coal plant in this scenario is due to the impact of carbon pricing on operating costs and reduced volumes of generation as efficient gas-fired generation has lower dispatch costs with high carbon prices.

- In other scenarios, the coal fleet is decommissioned later. In the suboptimal policy scenarios, there is little retirement of coal plant until after 2030 when carbon prices are high. This indicates that carbon prices of around $70/t CO_2e are required to significantly affect coal plant costs and dispatch levels to the point where they are no longer economic. In the clean energy target scenarios, there is some retirement of coal plant before 2030 mainly driven by low wholesale prices and reduced volumes of generation due to the high level of zero marginal cost plant. The closure scenario sees coal plant retire after 45 years of operation, which sees some plant closing before 2030 but a less rapid rate than under the optimal scenario.

- In the optimal policy scenario, conventional gas capacity increases as efficient gas plant displace high emission plant. Capacity of high efficient gas plant is twice the level of other scenarios by 2030. In part this is due to the need for plant to replace retiring coal fleet. It is also due to the carbon price making dispatch of efficient gas plant lower cost than for coal plant. In other scenarios where there are some plant closures (e.g. closures scenario) gas capacity does not increase markedly - rather retirement is met by the greater use of the remaining coal capacity. In all scenarios, uptake of gas CCS occurs after 2030, although in scenarios with high levels of biomass CCS, there is less gas-based CCS.

Figure 12: Capacity mix



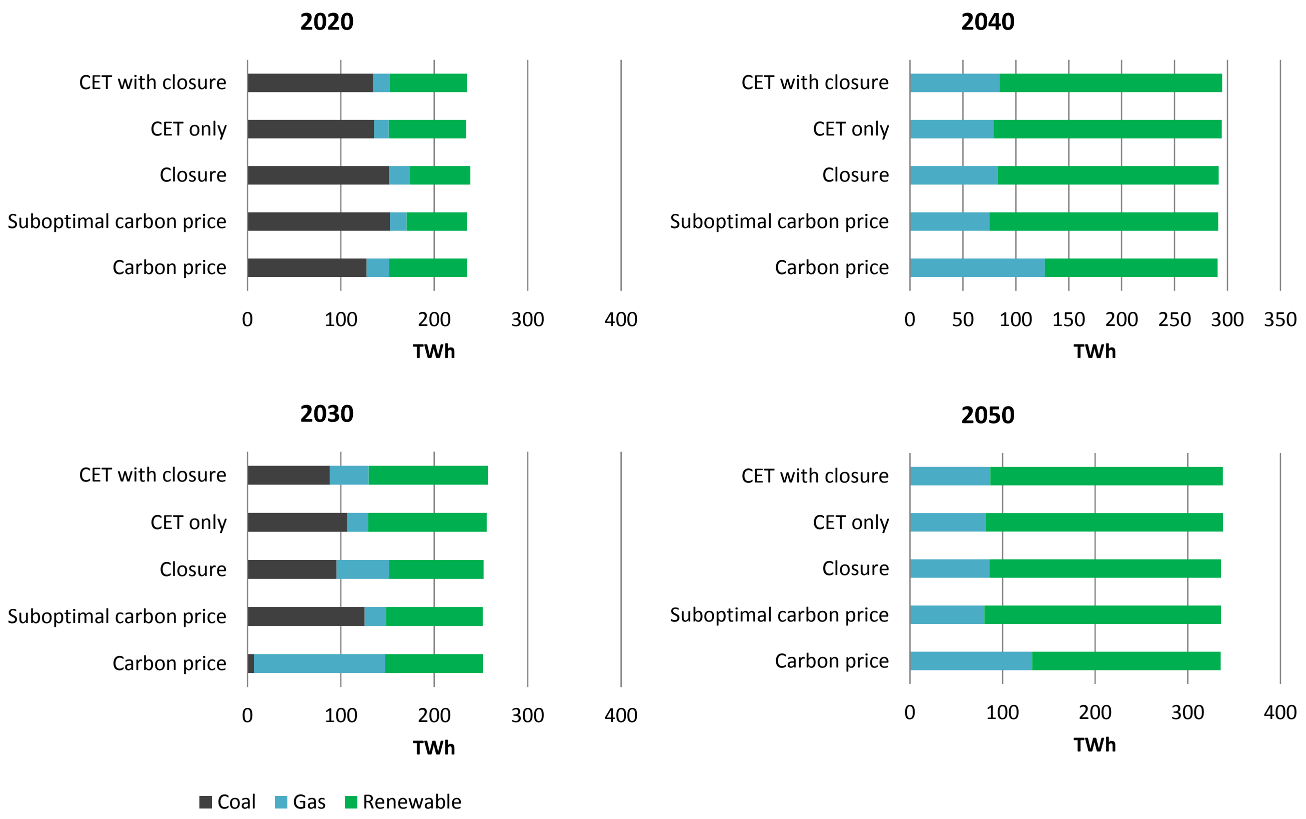
- Wind capacity increases in all scenarios reaching about 20% of total capacity. Wind capacity has the largest share of uptake of renewable energy in the period to 2030. In the CET scenarios, uptake of solar

PV capacity also occurs, but in other scenarios there is less uptake of this technology as it is displaced by newer and lower cost dispatchable options that are assumed to enter the market after 2030.

4.4 Generation levels

Generation shares are shown in Figure 13. Coal-fired share of the generation mix is predicted to reduce in all scenarios, with the most rapid decline occurring in the optimal pricing scenario. By 2040, there is no coal-fired generation. Gas-fired generation increases its share of the generation mix with the largest increase occurring in the optimal pricing scenario. Renewable energy generation also increases in all scenarios and becomes the dominant form of generation.

Figure 13: Generation shares by technology



The results on generation and capacity mix should be treated with caution as they depend heavily on relative technology costs. Coal generation reduces over the long term due to the high capital cost of coal-fired CCS options compared to gas-fired CCS. The modelling assumes the availability after 2030 of new renewable and CCS technologies that are dispatchable. Changes in the relative cost and timing of low emission technologies will impact on the long term generation mix of all scenarios.

4.5 Sensitivity to lower demand

A sensitivity was conducted for three of the policy scenarios to a lower demand growth for grid based electricity. The lower demand growth occurred due to lower growth rates for electricity demand and also greater uptake of small-scale systems. For the carbon price scenario, the same carbon price was used but with a lower demand growth. In the CET scenario, the target was reset to be 50% of the lower demand in 2030. The closure assumptions were also assumed to be the same (45 years).

The results of the sensitivity are presented in Table 5. Emissions are substantially lower in all three policy scenarios with a lower demand growth.

With an assumption of lower demand growth, the impacts of meeting the long term target are reduced. Resource costs are around 30% to 40% lower (even after taking into account the higher level of investment in small-scale generation systems).

Table 5: Sensitivity of key results to lower demand growth

	Carbon price, low demand	Closure, low demand	CET with closure, low demand
Emissions to 2050, Mt CO2e	1045	1465	1417
NPV of resource cost, $ billion			
7%	177	164	189
3%	290	277	304
Generation mix, 2030, GWh			
Coal-fired	18	64	53
Gas-fired	42	19	17
Renewable energy	119	93	107
Generation mix, 2050, GWh			
Coal-fired	0	0	0
Gas-fired	39	46	48
Renewable energy	197	197	197

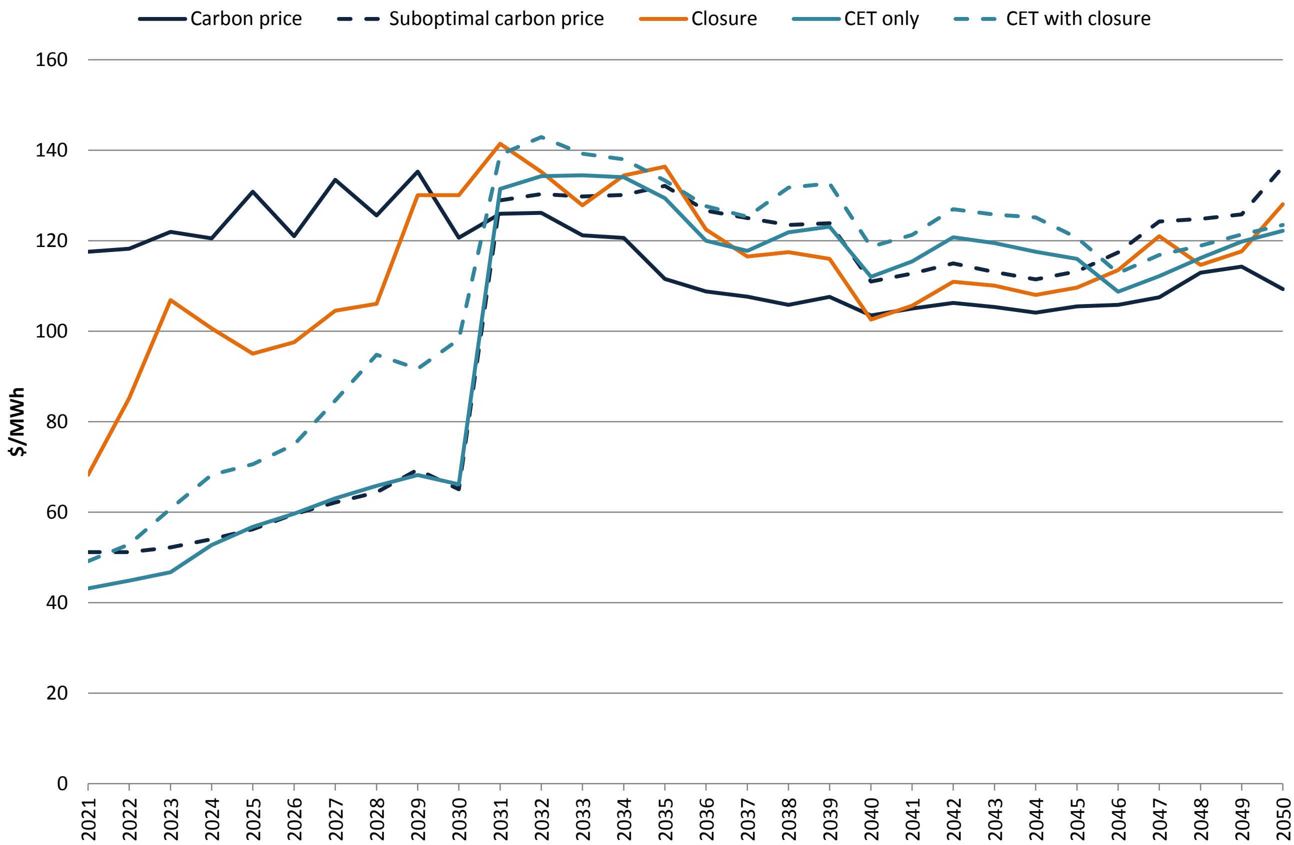
However, the impact on generation shares is similar. Coal-fired generation still reduces and renewable energy generation becomes the dominant form of generation. Gas-generation shares fall due to less need for new gas based plant, particularly gas based CCS plant.

5. Distributional impacts

5.1 Wholesale prices

The impact of the policy measures on wholesale prices are shown in Figure 14. In the period to 2030, prices are generally highest in carbon pricing scenario and lowest for the suboptimal and CET only scenarios. Carbon pricing increases the dispatch cost of all fossil fuel generation and hence will increase wholesale prices. In the CET scenarios, the high level of low emission capacity entering the market creates a capacity surplus which tends to depress wholesale prices. As much of this capacity to 2030 is wind and solar, prices are also lower due to the high level of low short-run marginal cost plant.

Figure 14: Wholesale prices, time weighted average for the NEM, mid 2014 dollar terms

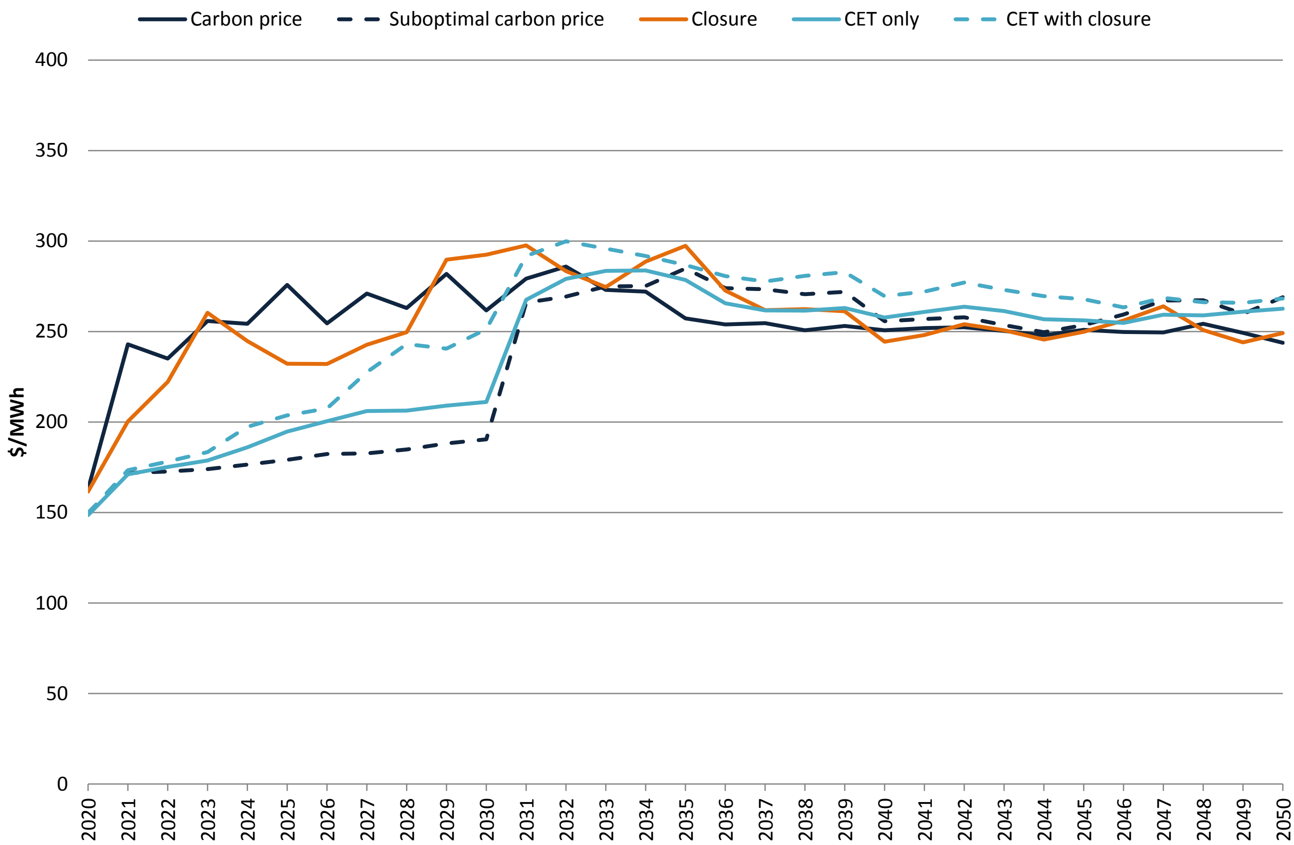


Prices after 2030 tend to converge to the long run marginal cost of low emission generation (around $100/MWh to $120/MWh). Prices for the optimal pricing scenario tend to be lower than for all other scenarios due to the higher carbon prices required to meet the cumulative target in these other scenarios.

5.2 Retail prices

Retail price impacts are shown in Figure 15. Average retail price movements are shown as well as an index of nominal tariffs. Retail prices rise by over 40% in all scenarios with the exception of the suboptimal carbon pricing scenario. The movements reflect the increases in wholesale prices. In the CET scenarios, retail prices also increase due to the cost of the certificates required.

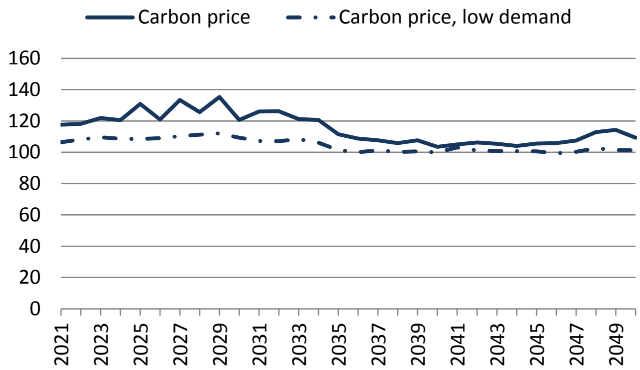
Figure 15: Movements in average retail prices, mid 2014 dollar terms

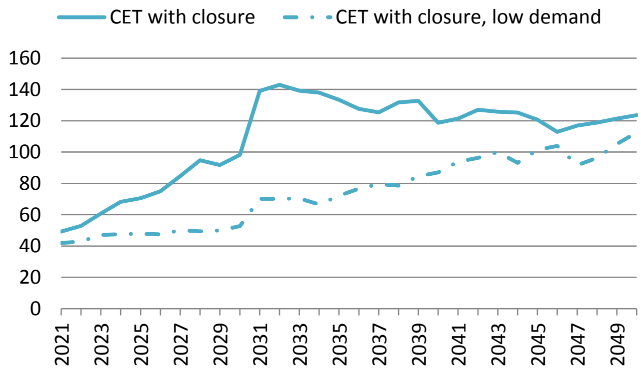


5.3 Sensitivity to lower demand

Figure 16 shows the sensitivity of wholesale price impacts with lower demand for two policy scenarios. Wholesale price are lower with the lower level of electricity demand. In the carbon pricing scenario, wholesale prices are only around 10% lower since the same carbon price is assumed. Thus the long run marginal cost of new low emission plant are the same despite the demand growth rate and any change in price is due to differences in timing for the need for new plant. In the CET with closure scenario, prices are substantially lower, especially to 2035, as the CET target induces a large surplus of capacity, which is relatively larger in the lower demand sensitivity.

Figure 16: Sensitivity of wholesale price impacts to lower demand





Appendix A. Modelling suite

A.1 Strategist

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.

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.

Jacobs's market models are designed to create predictions of wholesale electricity price and generation driven by the supply and demand balance, with long-term prices capped near the cost of the cheapest new market entrant (based on the premise that prices above this level provide economic signals for new generation to enter the market). Price drivers include carbon prices, fuel costs, unit efficiencies and capital costs of new plant.

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 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).
- Where an auction market exists, a range of bidding options for thermal plant (fixed prices, shadow bidding, average price bidding).
- Chronological dispatch of demand side programs, including interruptible loads and energy efficiency programs.
- 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.
- Energy efficiency and interruptible loads as a dispatchable resource.

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 or energy efficiency programs, whether to meet load growth or to replace uneconomic plant, are chosen on two criteria:

- To ensure electricity supply requirements 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%, which is in line with planning criteria used by system operators.
- Revenues earned by the new plant/energy efficiency program 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.

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 expanded 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. As such by comparing a reference case to a test case, 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 must meet reserve constraints in each region. Every expansion plan for the reference and policy scenarios in this study is 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 17 and the Jacobs modelling procedures for determining the timing of new generation and transmission resources, and bid gaming factors are presented in.

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, it is not feasible to complete in one analysis:

- The establishment of an optimal expansion plan (multiplicity of options and development sequences means that run time is the main limitation)
- A review of the contract positions and the opportunity for strategic bidding the spot market prices.

We therefore, conduct a number of iterations of PROVIEW to develop a workable expansion plan and then refine the expansion plan to achieve a sustainable price path applying market power where it is apparent and to obtain a consistent set of emission abatement prices and new entry plant mix.

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. Failure of transmission links is not represented although capacity reductions are included based on historical chronological patterns. Constraints can be varied hourly if required and such a method is used to represent variations in the capacity of the Heywood interconnection, between Victoria and South Australia, which have been observed in the past when it was heavily loaded. Such variations in interconnection capacity occur during the threat of thunderstorms in proximity to the interconnecting transmission line to enhance system security, and during transmission line outages.

Bids are generally formulated as multiples of marginal cost and are varied by ratios above unity to represent the impact of contract positions and the price support provided by dominant market participants. Some capacity of cogeneration plants is bid below short run marginal cost to represent the value of the steam supply which is not included in the power plant model. The modelling of Smithfield allows for the typical peak and off-peak dispatch levels having regard to the cogeneration requirements.

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.

Figure 17: Strategist Analysis Flowchart

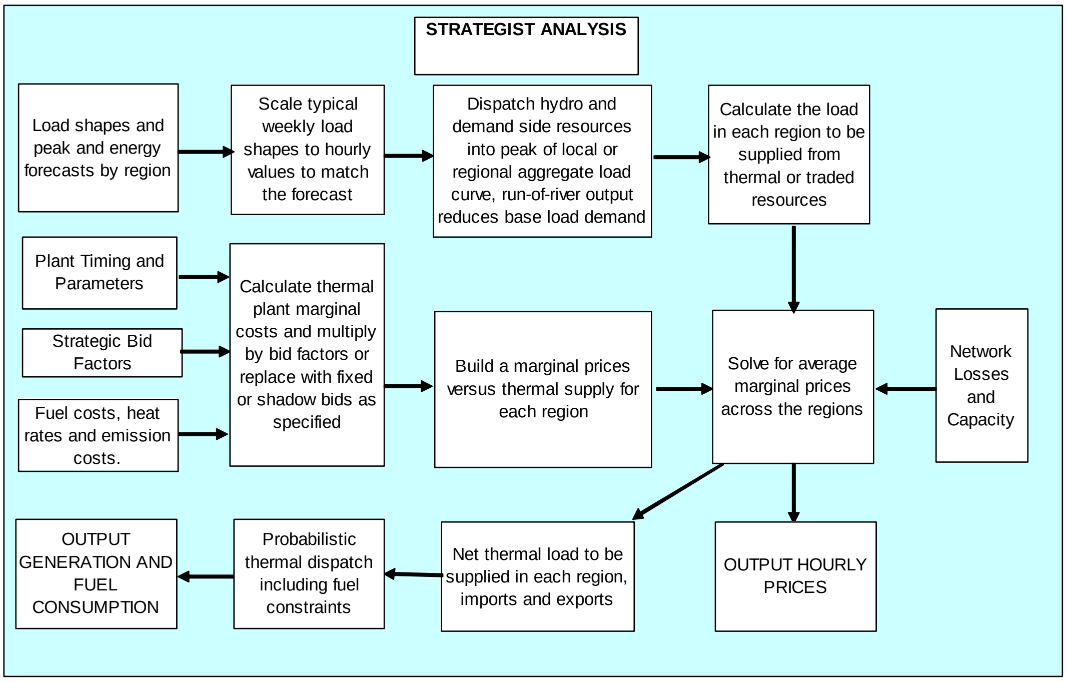
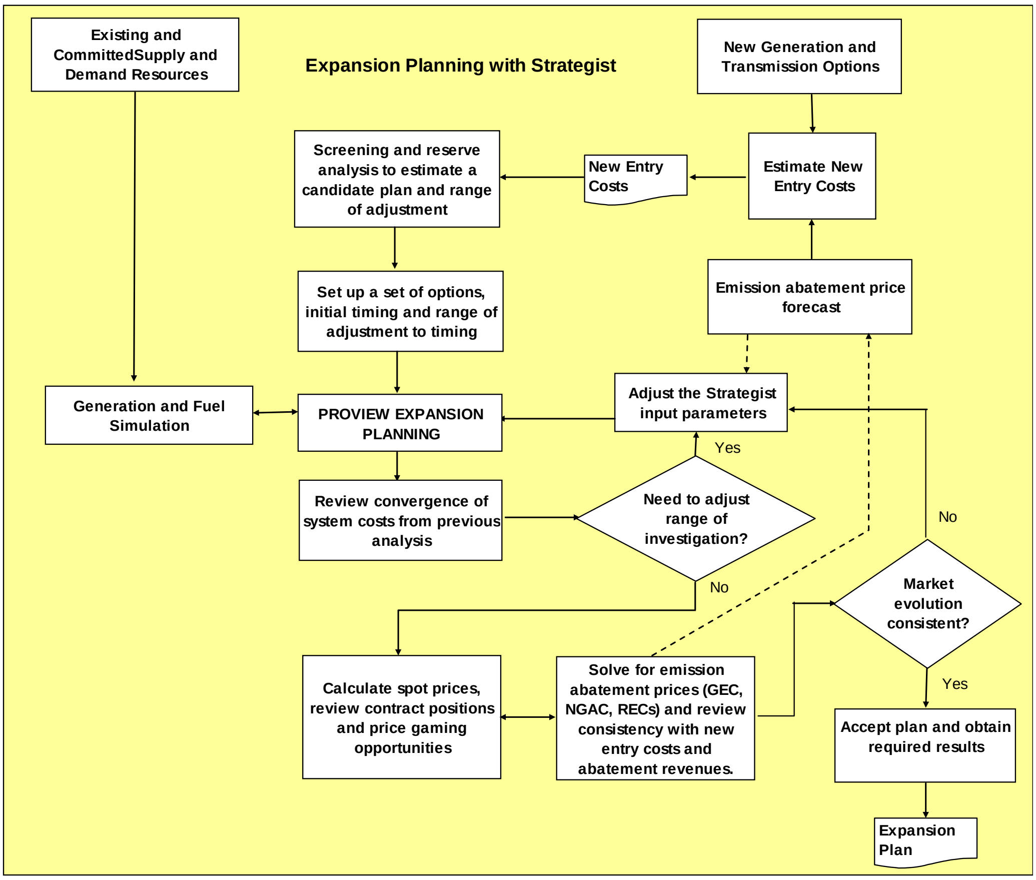


Figure 18: Jacobs Strategist Modelling Procedures



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. Other factors that may impact on the decision are modelled such as a premium prepared to be paid for small scale renewable generation. We calculate the premium based on market survey data and other published market data. The premium will be assumed to decrease as the rate of uptake increases (reflecting the fact that the willingness to pay will vary among customers).

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 and these will then be fed into the Strategist model, where the level of small-scale technology uptake, especially that of rooftop PV, will effectively distort the load shape seen 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 further any uptake leads to higher costs of electricity supply. 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 latter comprises wholesale electricity purchase costs (including losses during transmission and distribution), market and other fees, network costs (to the extent they are avoided, which is reflected through the variable component of network tariffs) and retail margins. The costs of small-scale systems may be reduced either 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:

- 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 is set at 55% of all households in the region[9]. 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.

- 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 rate of installation 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. 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

A.2.2 Model Structure

The model 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[10] and the availability of data on key determinants. Currently the model comprises:

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

[9] 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, etc). 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.

[10] 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 handling of different technologies of differing standard sizes including PV systems, solar and heat pump 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: 1.0 kW PV system, 1.5 kW PV system, 3 kW PV System, 5 kW PV system, 3 kW and 5 kW systems with battery storage and solar water heaters.
  - For the commercial sector: 5, 10, 30 and 100 kW PV systems; 10, 30 and 100 kW systems with storage
- Differentiation into 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 include:

Sector	% of output exported	Funding approaches	Payback period
Residential	20% for smaller systems to 30% for larger systems	Purchase	10 years
Commercial	20% to 40%	10 year leases	10 years

- The ability to test implications of changing network tariff structures and changes to Government support programs. The proportion of network tariffs charged as fixed, and hence unavoidable, fees. Currently it is assumed that all customers go towards capacity payments over a 10 year period. In this study, capacity payments are assumed to make up 50% of network tariffs. This can be varied to reflect different assumptions on network tariff structures.

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[11]; some data on metered energy production available from Ausgrid and Energex.

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[12].

The initial capacity factors applying in each State are shown in Table 6. Data on capacity are sourced from a number of sources.

Table 6: Assumed starting capacity factors for small-scale systems

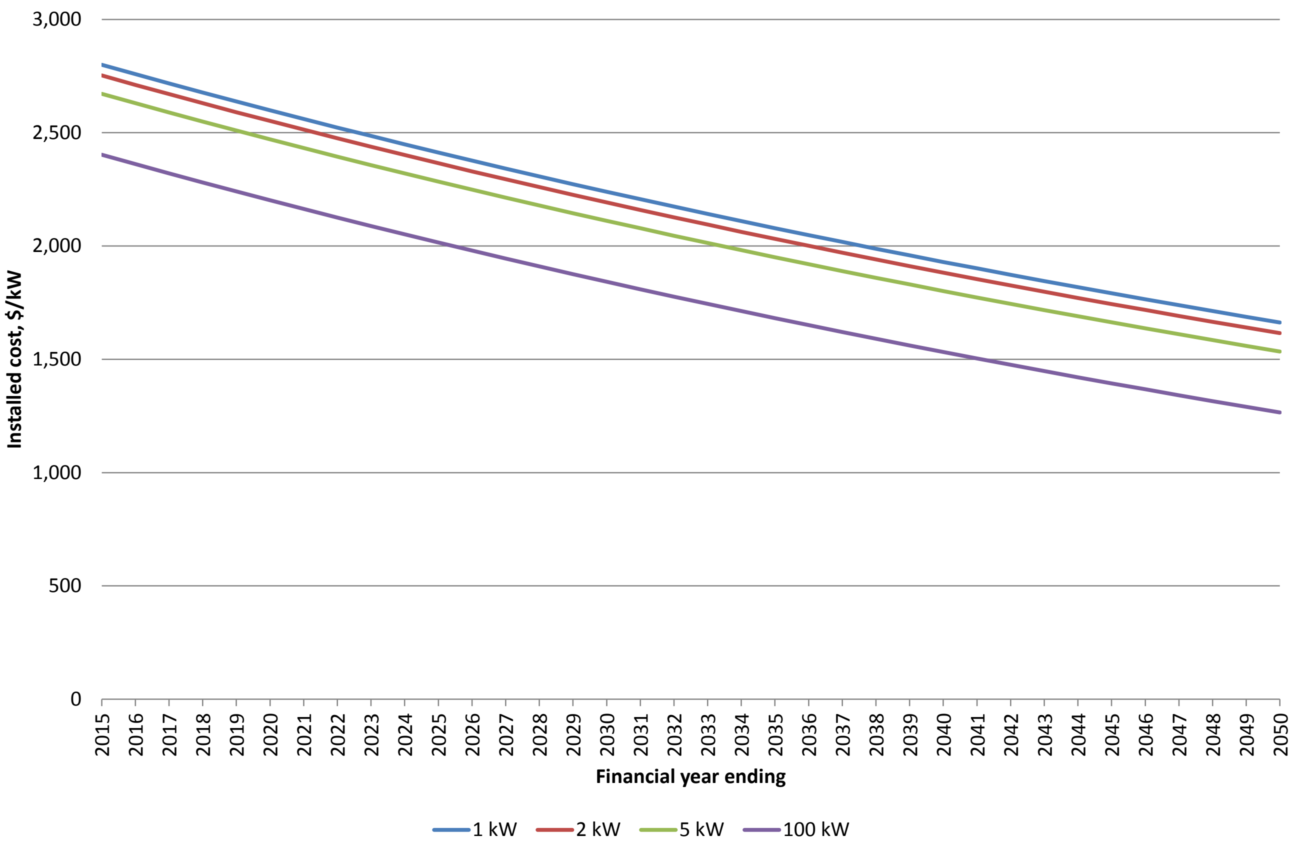
	VIC	NSW	TAS	SA	Qld	WA	NT
PV starting load factor	14.8%	15.8%	13.7%	15.8%	15.8%	15.8%	15.8%
PV + 5kWh storage	13.7%	14.6%	12.7%	14.6%	14.6%	14.6%	14.6%
PV + 10 kWh storage	13.7%	14.6%	12.7%	14.6%	14.6%	14.6%	14.6%
PV + 20 kWh storage	13.7%	14.6%	12.7%	14.6%	14.6%	14.6%	14.6%

[11] The CER divides each State in 4 regions with each zone with a different capacity factor.
[12] Postcode data on the number of installations is published by the Clean Energy Regulator.

A.2.4 Capital costs

Capital cost assumptions are shown in Figure 19. Costs in 2015 are sourced from trade data. The costs are projected to decline by around 1.5% per annum. Costs are lower for larger system sizes reflecting economies associated with installing larger systems

Figure 19: Installed 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. (adjusted by adding back the STC rebate).

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 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 will be 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). REMMA is an Excel application based on a database of nearly 900 existing, committed, proposed and generic projects across Australia.

Strategist will be 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.

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.

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. Technology costs

Technology cost assumptions for new plant are shown in the following table.

The capital cost de-escalators follow published trends in capital cost reductions including capturing the impact of learning by doing. Implicit in the assumptions is that there are active policies (globally) to undertake R&D, promote development and support initial deployment of these new technologies.

Technology costs proposed for this review are compared against costs shown in the AETA 2012[13]. The AETA was 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 Version 24. A comparison is shown in Table 7.

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.

Table 7: Selected new technology cost comparisons, including connection and owner's costs

Technology	AETA $/kWnet[14]	Proposed $/kWnet
Black coal, supercritical	3,357	2,966
Brown coal, supercritical	4,071	4,860
Large CCGT	1,141	1,341
Black coal with carbon capture	7,877	6,665
Wind	2,719	2,400
Large-scale PV (net AC basis)*	3,632	2,987
Concentrated solar thermal with storage	8,928	9,500
Geothermal (hydrothermal)	7,522	6,500

* Note: $/kW costs for PV are usually quoted on a DC basis. We have applied a DC to AC conversion factor which makes the PV costs comparable to other large-scale technologies. Source: Jacobs, AETA 2012

Table 8: Technology cost assumptions for storage by scale

Technology	Proposed $/MWh net
Small-scale storage	325
Large-scale storage	293

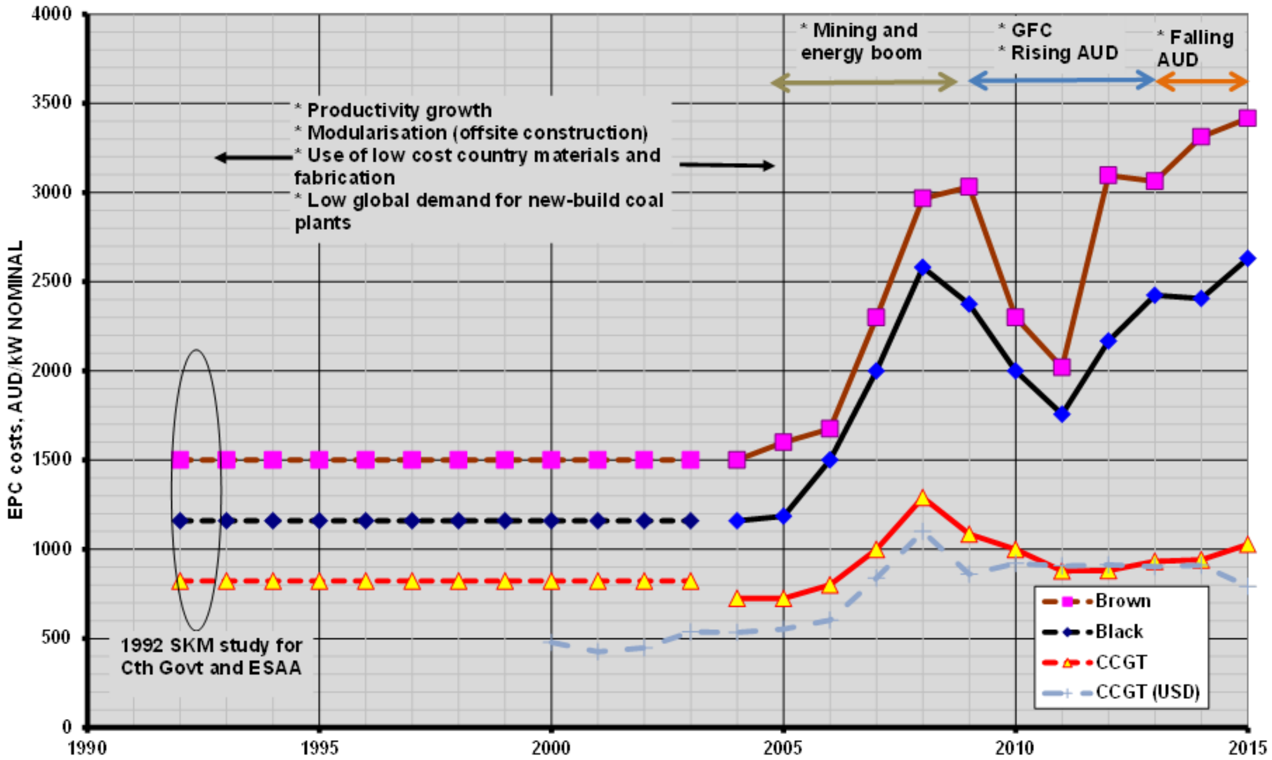
Source: Jacobs

Post combustion capture options for coal have been excluded because generally the parasitic loads for these options are high and this generally makes these options less economic than other coal CCS options.

Trends observed by Jacobs over time in the estimated costs of the main fossil fuel plant types considered in the Australian market are shown in Figure 20. It is notable that whereas prior to 2005 the estimated capital costs were stable over a long period of time. Subsequently the costs have been volatile and influenced by significant shifts in the global market consequent on the minerals and petroleum boom period leading up to the global financial crises and the period subsequent to the crises with a depressed global market for new power plant sales and volatile exchange rates.

[13] Bureau of Resources and Energy Economics, "Australian Energy Technology Assessment", 2012.
[14] AETA costs are original quoted in $2012. In this table we have escalated these AETA costs to $2014 for comparison purposes.

Figure 20 Trends in power plant EPC costs in Australia[15]



Source: Jacobs' database

There is significant uncertainty around the degree to which technology costs will reduce over time. Jacobs has used a learning by doing approach to setting assumptions on technology cost projections. 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[16], adjusted for projected global deployment rates consistent with strong global action to reduce emissions as sourced from the IEA[17]. These values are applied to the equivalent of the equipment costs, which typically comprises 50% to 70% of total capital costs. The learning rates are shown in Appendix D (as capital cost de-escalators), which are based on strong global action to curb emissions - that is, a reasonably rapid rate of deployment globally.

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

[15] EPC basis costs do not include connection costs and owner's costs, not interest-during-construction costs.
[16] SETIS (2012), *Technology learning curves for energy support policies*, Joint Research Centre Scientific and Policy Reports; EPRI (2013), Modelling Technology Learning Rates for the Electricity Supply Sector: Phase 1 report, Palo Alto, California
[17] IEA (2014), *World Energy Outlook: 2014*, Paris

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[18]. An iterative approach is adopted to translate this learning rate to final capital costs.

Figure 21: Technology cost assumptions

Technology Type	Life	Nominal Capacity	Auxilliary Load	Capital Cost, 2016	Capital Cost Deescalater to 2020	Capital Cost Deescalater from 2021	Heat Rate at Maximum Capacity	Variable Non-Fuel Operating Cost	Fixed Operating Cost	Maintenance Weeks	Mature Forced Outage Rate
	Years	MW	%	$/kW so	% pa	% pa	GJ/MWh	$/MWh	$/kW	Weeks	%
Supercritical	35	743	4.7%	2,966	0.11	0.11	9.16	1.6	84	3.00	2.00
Ultrasupercritical	35	743	4.5%	3,113	0.11	0.11	8.85	1.6	87	3.00	2.00
Black coal IGCC	30	510	10.3%	5,653	3.00	1.00	8.08	4.4	134	3.00	7.00
Black coal with CCS	30	480	17.5%	6,665	3.00	3.00	9.87	4.8	157	3.00	7.00
Brown Coal Supercritical	30	743	6.5%	4,860	0.11	0.11	11.44	1.9	119	3.00	4.00
Brown Coal Supercritical with drying	30	743	6.5%	4,860	0.11	0.11	11.44	1.9	119	3.00	7.00
Brown Coal Ultrasupercritical	30	500	9.4%	7,564	0.17	0.17	9.62	4.4	170	3.00	7.00
Brown Coal IGCC	30	500	9.4%	7,564	3.00	1.00	9.62	4.4	170	3.00	7.00
Brown Coal with CCS	30	470	19.2%	9,924	3.00	3.00	12.61	4.9	221	3.00	7.00
Cogeneration	30	123	1.7%	1,760	0.17	0.17	5.49	5.2	45	2.50	2.00
Combined Cycle Gas Turbine - Large	30	559	2.2%	1,341	0.17	0.17	6.86	3.6	35	2.50	3.00
Combined Cycle Gas Turbine - Large with CCS	30	524	7.9%	2,959	3.00	3.00	7.87	4.5	62	2.50	3.00
CCGT-Medium	30	245	2.3%	1,495	0.17	0.17	7.83	3.6	38	2.50	3.00
Open Cycle Gas Turbine (E Class)	30	167	1.1%	1,106	0.20	0.20	11.36	7.2	17	1.50	2.00
Open Cycle Gas Turbine (F Class)	30	284	1.0%	936	0.20	0.20	10.38	7.2	13	1.50	2.00
Open Cycle Gas Turbine (aero)	30	49	1.2%	1,539	0.20	0.20	10.00	10.3	27	1.50	2.00
Open Cycle Gas Turbine (Brown Field)	30	196	1.4%	1,550	0.66	0.66	9.52	10.3	28	1.50	2.00
Open Cycle Gas Turbine (Green Field)	30	196	1.4%	1,550	0.66	0.66	9.52	10.3	28	1.50	2.00
Wind	25	100	2.0%	2,400	1.00	1.00	3.60	5.0	40	3.00	2.00
Biomass - Steam	30	30	6.3%	6,382	0.50	0.50	14.24	8.0	60	3.00	2.00
Biomass - Gasification	25	79	22.3%	5,361	1.50	1.50	14.14	10.0	60	3.00	2.00
Concentrated solar thermal plant - without storage	35	150	5.0%	6,500	2.50	2.50	3.60	5.0	50	3.00	2.00
Concentrated solar thermal plant - with storage	35	150	5.0%	9,500	2.50	2.50	3.60	10.0	60	3.00	2.00
Geothermal - Hydrothermal	30	50	8.0%	6,500	2.50	2.50	13.00	5.0	50	3.00	2.00
Geothermal - Hot Dry Rocks	25	50	10.0%	7,000	2.50	2.50	14.00	5.0	50	3.00	2.00
Concentrating PV	30	150	3.0%	6,175	2.50	2.50	3.60	5.0	45	3.00	2.00
Flat Plate PV	35	175	2.0%	2,990	2.50	2.50	3.60	2.0	25	3.00	2.00
Roof-top PV	25	1	1.0%	3,100	2.50	2.50	3.60	2.0	0	3.00	2.00
Hydro	35	30	2.0%	3,500	0.50	0.50	3.60	5.0	35	3.00	2.00

[18] ATA, CSIRO

Appendix C. Costs and performance of thermal plants

The following table shows the parameters for power plants used in the Strategist model.

Plant	Total Sent Out Capacity, MW	Scheduled Maintenance (Weeks pa)	Forced Outage Rate	Available Capacity Factor	Full Load Heat Rate, GJ/MWh	Variable O&M, $/MWh	Variable Fuel Cost $/GJ, 2015 values
Tasmania							
Tamar Valley CCGT	201.8	1.9	3%	93.6%	7.54	$2.87	$7.16
Bell Bay GT	119.4	3.0	1%	93.3%	11.50	$4.30	$4.72
Tamar Valley OCGT	57.7	3.0	1%	93.3%	11.50	$4.30	$15.11
New CCGT	195.5	2.5	3%	92.3%	6.93	$3.60	$7.16
New GT	319.2	2.8	2%	93.3%	11.43	$5.80	$15.11
Victoria							
AGL Somerton	161.7	4.0	9%	83.9%	13.50	$2.87	$4.38
Anglesea	145.4	1.0	2%	96.6%	13.00	$1.43	$0.15
Bairnsdale	83.6	3.0	1%	93.3%	11.50	$4.30	$4.52
Energy Brix	95.7	5.0	4%	86.8%	21.25	$2.87	$0.67
Hazelwood	1472.0	4.0	9%	84.0%	13.30	$0.66	$0.67
Jeeralang A	230.8	2.1	1%	95.0%	13.75	$8.61	$4.28
Jeeralang B	253.7	2.1	1%	95.0%	12.85	$8.61	$4.28
Laverton North	338.3	2.0	2%	93.9%	11.55	$4.30	$4.38
Loy Yang A	2043.0	2.5	4%	91.9%	11.58	$1.15	$0.51
Loy Yang B	966.0	2.5	3%	92.3%	11.70	$1.15	$0.51
Valley Power	334.3	2.1	1%	95.0%	13.75	$8.61	$4.28
Yallourn W	1361.6	3.0	6%	88.6%	12.91	$3.43	$0.52
Newport	484.5	2.2	3%	93.0%	10.33	$2.87	$4.38
Mortlake OCGT	550.2	2.5	2%	93.0%	10.78	$3.65	$6.44
Qenos Cogeneration	21.0	2.0	3%	93.3%	11.00	$2.07	$7.94
New CCGT	546.1	2.5	3%	92.3%	6.93	$3.51	$7.94
New GT	281.3	1.5	2%	95.2%	10.38	$7.30	$16.76
South Australia							
Angaston	49.8	0.0	1%	99.4%	9.00	$12.31	$20.41
Dry Creek	147.3	5.6	3%	86.1%	17.00	$8.61	$11.07
Hallett	220.0	4.0	4%	88.3%	9.60	$9.83	$11.07
Ladbroke Grove	83.6	3.0	2%	92.1%	10.00	$7.17	$5.24
Mintaro 1	89.6	4.0	5%	88.1%	16.00	$8.61	$11.07
Northern	505.1	0.0	2%	97.9%	11.50	$2.79	$2.41
Osborne	185.4	2.0	2%	93.9%	10.40	$2.79	$5.24
Pelican Point	462.6	3.0	3%	91.4%	7.71	$2.87	$4.99
Playford B	185.0	6.0	5%	84.1%	15.00	$4.18	$2.41
Port Lincoln	72.6	3.0	3%	91.4%	11.67	$8.61	$20.41

Plant	Total Sent Out Capacity, MW	Scheduled Maintenance (Weeks pa)	Forced Outage Rate	Available Capacity Factor	Full Load Heat Rate, GJ/MWh	Variable O&M, $/MWh	Variable Fuel Cost $/GJ, 2015 values
Quarantine	217.9	4.0	3%	89.1%	10.35	$9.15	$11.07
Snuggery	65.7	4.0	5%	88.1%	15.00	$8.61	$20.41
Torrens Island A	456.0	4.0	5%	87.7%	10.80	$8.61	$9.22
Torrens Island B	760.0	4.0	5%	87.7%	10.50	$2.15	$8.02
New OCGT	164.7	1.5	2%	95.2%	11.36	$7.22	$16.93
NSW							
Bayswater	2592.7	2.5	2%	93.3%	10.00	$2.87	$1.74
Colongra OCGT	720.4	2.5	3%	91.9%	11.84	$9.90	$17.45
Eraring	2707.2	2.5	4%	91.8%	10.08	$2.87	$2.03
Eraring GT	41.8	2.5	3%	91.9%	11.84	$9.90	$20.41
Hunter Valley GT	49.8	4.0	3%	89.1%	23.38	$9.90	$20.41
Liddell	1936.4	2.5	3%	92.3%	10.38	$2.59	$1.74
Mt Piper	1259.6	1.0	1%	97.1%	9.93	$2.73	$1.76
Munmorah	0.0	43.0	10%	15.8%	10.67	$2.85	$1.88
Smithfield	151.2	3.0	3%	91.4%	10.00	$5.45	$5.97
Tallawarra	422.0	2.5	3%	92.3%	7.17	$3.64	$8.27
Uranquinty	660.7	2.5	2%	93.3%	10.98	$3.47	$17.45
Vales Point	1240.8	3.8	4%	89.0%	9.87	$3.59	$2.08
New CCGT	546.1	2.5	3%	92.3%	6.93	$3.56	$8.27
New OCGT	281.3	1.5	2%	95.2%	10.38	$7.15	$17.45
New CCGT CCS	482.5	2.5	3%	92.3%	7.87	$4.38	$8.27
Queensland							
Barcaldine CC	36.8	3.0	3%	91.4%	8.02	$4.30	$5.21
Braemar	1017.9	2.0	2%	94.2%	11.00	$3.61	$1.96
Callide B	658.0	2.0	3%	93.3%	9.88	$2.07	$1.69
Callide C	846.0	1.2	6%	91.9%	9.00	$1.43	$1.69
Collinsville	177.7	3.0	5%	89.5%	13.70	$2.87	$2.07
Darling Downs	898.7	2.3	2%	94.2%	8.54	$5.45	$11.61
Gladstone	1579.2	2.4	5%	91.1%	10.22	$1.26	$1.96
Kogan Creek	699.4	3.0	3%	91.4%	9.50	$1.29	$0.79
Millmerran	787.5	3.0	8%	86.5%	9.88	$1.29	$0.79
Moranbah	45.6	3.0	3%	91.4%	8.02	$4.30	$-
Mt Stuart GT	416.9	2.0	2%	94.2%	11.50	$5.74	$20.41
Oakey GT	338.3	2.0	2%	94.2%	11.50	$5.74	$11.00
QAL Cogeneration	150.0	2.5	1%	94.3%	7.00	$3.60	$-
Roma	67.7	4.0	9%	84.0%	13.50	$5.74	$5.21
Stanwell	1372.4	1.8	1%	95.6%	9.99	$1.15	$1.75
Swanbank E	358.9	2.0	2%	94.2%	8.10	$2.87	$5.21

Plant	Total Sent Out Capacity, MW	Scheduled Maintenance (Weeks pa)	Forced Outage Rate	Available Capacity Factor	Full Load Heat Rate, GJ/MWh	Variable O&M, $/MWh	Variable Fuel Cost $/GJ, 2015 values
Tarong	1316.0	1.0	2%	96.0%	10.50	$1.19	$1.50
Tarong North	416.4	1.0	0%	98.0%	9.50	$1.19	$1.50
Yabulu	235.7	3.0	2%	92.4%	7.44	$2.87	$3.16
New CCGT CCS	482.5	2.5	3%	92.3%	7.87	$4.52	$9.20
New GT	164.7	1.5	2%	95.2%	11.36	$7.22	$19.42
New CCGT	239.4	2.5	3%	92.3%	7.83	$3.61	$9.20