Modelling illustrative electricity sector emissions reduction policies

Climate Change Authority

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Executive Summary

Purpose of study

The Climate Change Authority (CCA) is undertaking a Special Review of Australia's climate action, at the request of the Minister for the Environment. As part of this review, the CCA commissioned Jacobs to examine the impacts of different illustrative policy approaches in the electricity sector. The electricity sector contributes just over one-third of national emissions and is characterised by long-lived capital investments. These factors mean that the sector provides a case study for comparing policy options to reduce emissions.

Specifically the objectives of this study are to compare 7 alternative policies to meet a common emission reduction target. The policies examined are:

- Explicit carbon price via a carbon tax.
- Emissions intensity target.
- Three 'technology pull' policies:
  - Renewable Energy Target (RET), which expands on the existing LRET scheme.
  - Low emissions target (LET), which operates in a similar manner to the RET scenario but with an expanded set of eligible technologies including more efficient gas generation.
  - Feed-in Tariffs (FiT) where incentives are provided for eligible low emission generation.
- Regulated closure where standards are applied for existing and new coal generators. Existing generators either retrofit with carbon capture and storage (CCS) or close in order of age.
- Absolute baselines where total emissions from existing generators are limited to specified baselines which decline over time.

The analysis conducted by Jacobs was focused on comparing the relative economic costs of the policies and to examine their impact on key metrics such as retail prices, investment patterns and generator returns.

The robustness of the results from this analysis was tested by variations in the emission target, electricity demand, uptake of embedded generation technologies, and technology costs and availability. Sensitivity analysis was also undertaken to test the impact of a combination of policies.

Approach

An interactive and iterative approach was used using three models that modelled unique aspects of the electricity supply sector:

- An electricity market dispatch and investment model, which simulates dispatch and investment behaviour at the wholesale market level
- A embedded generation uptake model which simulates customer uptake of embedded PV and battery storage systems
- A model simulating uptake of renewable energy and low emission technologies under the specific investment incentives provided under each policy.

The modelling was interactive in that outputs from each model where used as inputs into the other models. Uptake of embedded generation determines net demand faced by the central grid system. Wholesale electricity prices are an important determinant in uptake of renewable energy and low emission technologies.

A unique feature of the modelling approach was the inclusion of a demand response to changes in retail prices. This meant that the direct impact of changes in prices brought about by a policy was estimated.

The modelling approach was adopted because it enabled the simulation of direct impacts and interactions between the electricity market and the various ancillary markets used as instruments to meet the emissions constraint. The approach enabled modelling of specific behaviours affecting investment in new generation and dispatch of plant in response to the different incentives provided by the policies.

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 modelling also assumes perfect foresight with future trends in key assumptions known with certainty. Further, the modelling does not incorporate the second-round or indirect impacts of these policies on the wider economy.

The modelling was confined to the National Electricity Market (NEM), covering the integrated grid extending from northern Queensland to South Australia and Tasmania, and Western Australia's Wholesale Electricity Market (WEM). The modelling horizon is 2014/15 to 2049/50.

Assumptions used in the modelling are detailed in the body of the report and the Appendices. Underpinning the analysis is the assumption of global action to curb greenhouse gas emissions which drives assumptions on exogenous inputs across all scenarios: assumptions on carbon price, fuel costs, and technology cost. The context for this approach is that meeting international targets requires global action.

The emission target for the electricity sector was derived as follows. The carbon pricing simulation was run using the assumed exogenous global carbon price. The cumulative emission to 2050 that resulted was used as the target for all other policy scenarios.

There were two phases to this study. In Phase 1, the policies were examined using a common emissions constraint and modelling inputs consistent with strong global action to limit global average warming to no more than 2°C. Each policy scenario requires a large reduction of emissions, with emissions limited to 1,580 Mt CO_2-e over the period to 2050. Alternative consistent sets of emissions constraints and global inputs were examined in Phase 2. Sensitivity analysis to key assumptions was also undertaken in Phase 2.

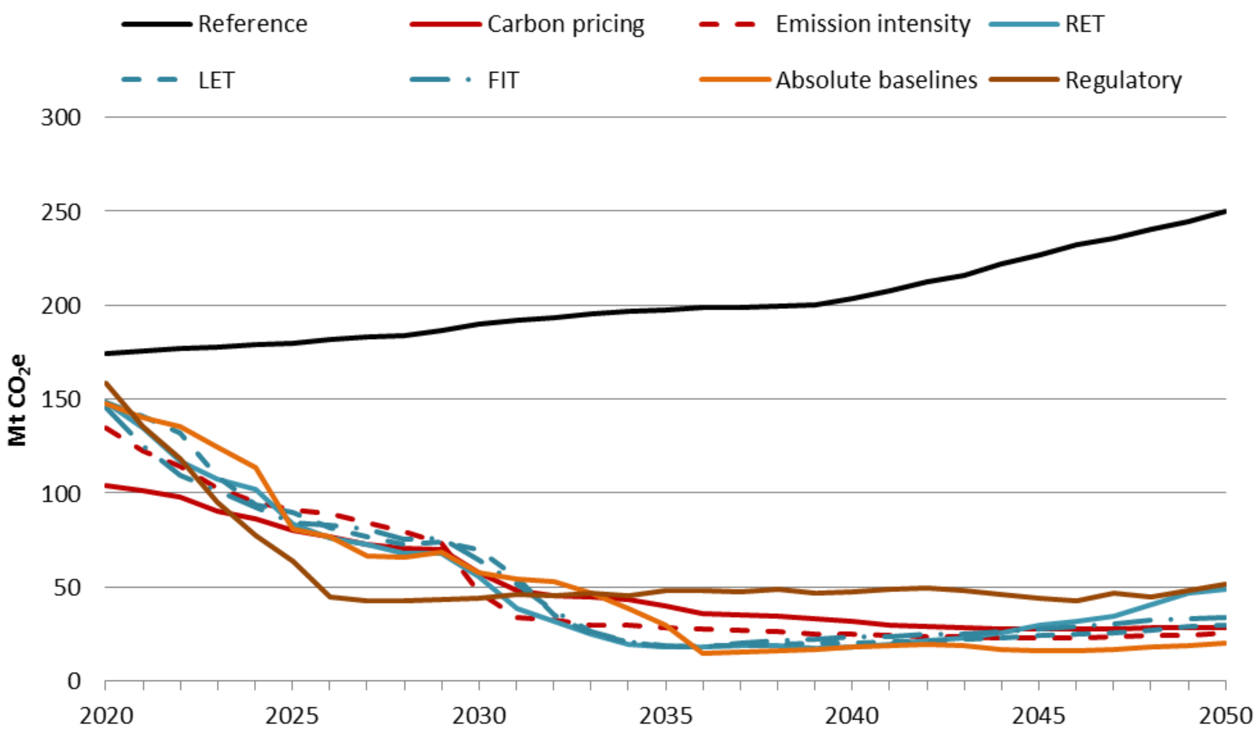
Economic costs

Emissions decrease but at different rates

All policies except regulatory closure achieved the cumulative target. Emissions are projected to fall sharply for the policy scenarios (see Figure 1) with the bulk of the reduction occurring in the period to 2030. The trajectory of the reduction is similar across the scenarios with any difference due to differences in demand and the rate at which low emission technologies are deployed. The policy's influence on gas fired generation also influences the pathway of decline in emissions.

The carbon pricing scenario has a sharp fall in emissions in 2020. This is due to the impact of the high starting price ($69/t CO_2e) on the relative dispatch costs across technologies and through retirements of coal fired plant. Emissions fall rapidly in the regulated closure scenario due to the rapid phase out of coal generators. Despite this, cumulative emissions in this scenario exceed the emissions constraint. Emissions reduction patterns in the other scenarios are broadly similar. Emissions in the RET scenario increase in the late 2040s as the policy imposes no constraint on the emissions of new entrants. Once the RET target is met, new coal (as the lowest-cost generator) plant is deployed to meet growing demand.

Figure 1: Emissions, 2°C emissions constraint



Source: Jacobs

Market based policies lead to lower economic costs

All policies lead to higher economic costs. The economic costs (relative to the reference case) are shown in Table 1. The economic cost is represented by the cost of resources deployed adjusted by the impact on economic welfare of variations in demand (relative to the reference case).

Table 1: Economic costs, 2°C emissions constraint, $ billion

Discount rate	Carbon	Emission intensity	Absolute baselines	FiT	LET	RET	Regulated closures
10%	116	121	136	139	137	163	165
7%	133	136	158	150	150	180	190
3%	158	159	192	166	168	200	233

Source: Jacobs

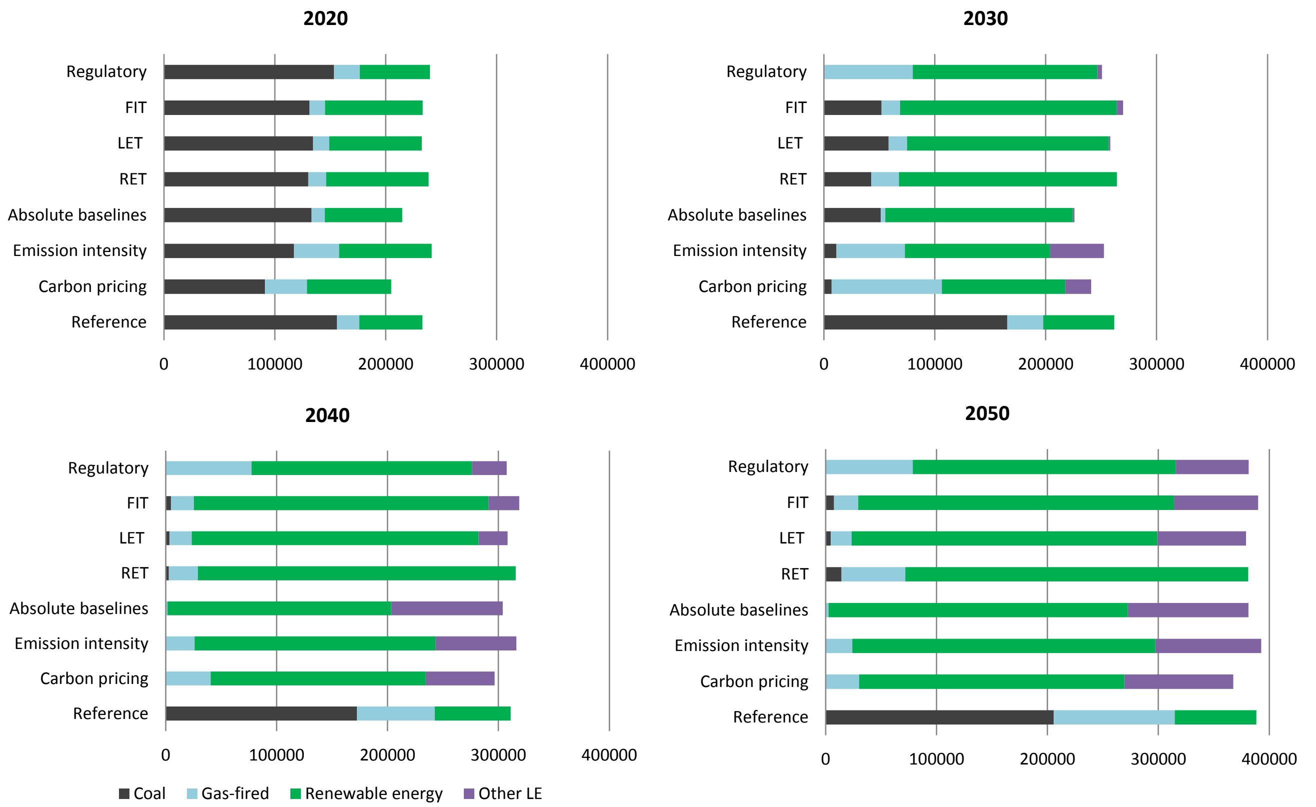
The results indicate the lowest demand adjusted resource costs occurred with the emissions pricing policies (such as carbon pricing and the emission intensity target). The demand adjusted resource cost for the emission intensity scheme is slightly higher due to the higher demand for this policy scenario and the limits to borrowing which required more early abatement.

The technology pull and the regulatory policies (regulated closures and absolute baselines) had similar resource costs with the highest cost occurring for the RET and regulatory closures policy.

Generation mix shifts to low emission technologies

The generation mix changes as a result of the adoption of emission mitigation policies (see Figure 2). The level and the time path of change differ across the policies.

Figure 2: Generation shares, 2°C emissions constraint, GWh



Source: Jacobs. Other LE covers other low emission technologies such as gas-fired CCS and nuclear.

Across the policy scenarios:

- Coal-fired generation reduces with the rate differing across the scenarios. By 2030, the brown coal fleet is decommissioned along with over two-thirds of the black coal fleet. In the technology pull scenarios (the RET, FiT, and LET) scenarios, generation from conventional coal plant picks up slightly after 2040 as the incentive to invest in low emission plant has ceased. There is no investment in coal-fired CCS, which is driven by the high capital cost assumed for this technology.
- Gas-fired generation has an important role and the level of gas-fired generation increases in the period to 2030. The ongoing requirement to reduce emissions means that conventional gas-fired has a minor role after 2030, mainly confined to peaking duties and supporting the high level of intermittent generation. There is, however, uptake of gas-fired CCS generation after 2030.
- Renewable energy generation grows to be the largest component of generation in all policy scenarios. Up to 2030, there is a high level of wind and solar generation induced by the policy measures. After 2030, generation by new and dispatchable renewable technologies (such as geothermal) also increases. By 2050, renewable generation contributes at least 50% of total generation in most policy scenarios.

The level of low emission generation varies amongst the scenarios. There is more gas-fired generation in the market based policies (carbon pricing, emission intensity) particularly in the period to 2030. The technology pull policies have less gas-fired generation for two reasons. For all the technology pull policies, the need to incentivise investment in new low emission technologies means a higher level of investment in these technologies than in the market based scenarios. As the CCS technologies are not assumed to be available until after 2030, all the uptake to 2030 is in renewable energy under the technology pull policies and this locks out gas-fired generation (although there is some additional generation for incumbent gas-fired generators under the LET scheme). In the technology pull scenarios, there are limited direct incentives that influence the pattern of dispatch and this means there is a higher level of coal-fired generation up to 2030.

There is a rapid reduction in conventional coal-fired generation under all policy scenarios. The level and rate of decline differs amongst the policies. The coal fired generation is replaced by a mix of gas-fired and renewable energy generation but there is a partial link between the economic cost of the policy and the mix of generation that replaces coal-fired generation. In the lowest cost policies (market based policies) there is a higher level of gas-fired generation (both from conventional and CCS technologies) and a higher level of renewable energy in highest cost policy scenarios (the regulated closures and RET policies).

The economic cost is also affected by choices on what technologies are eligible under each policy. Under the technology pull policies, the uptake of low emission technologies to 2030 locks out lower costs low emission technologies that might be available in the long term. The results suggest how low emission technologies are incentivised before 2030 also impacts on the investment patterns on low emission technologies after 2030. The regulated closure policy and the technology pull policies do not directly affect the dispatch of the existing generation fleet (that is, does not allow for fuel switching amongst existing generators) and therefore there is a higher level of investment in low emission technologies required to meet the emission target.

The absolute baselines policy does directly limit emissions from existing generators and provides both direct (through an emission standard on new generation) and an indirect incentive (through higher wholesale prices) for new low emission generators.

Supply reliability unaffected

Under all scenarios modelled all reliability of supply criteria assumed[1] were met. Where there was a high level of intermittent generation, AEMO's deterministic rules were deployed to ensure sufficient back-up generation was available. This meant that in some scenarios, there was a higher level of investment in open cycle gas turbines to ensure sufficient back-up. These plants were bid in at the maximum price levels and earnt sufficient revenues to cover their variable and fixed costs.

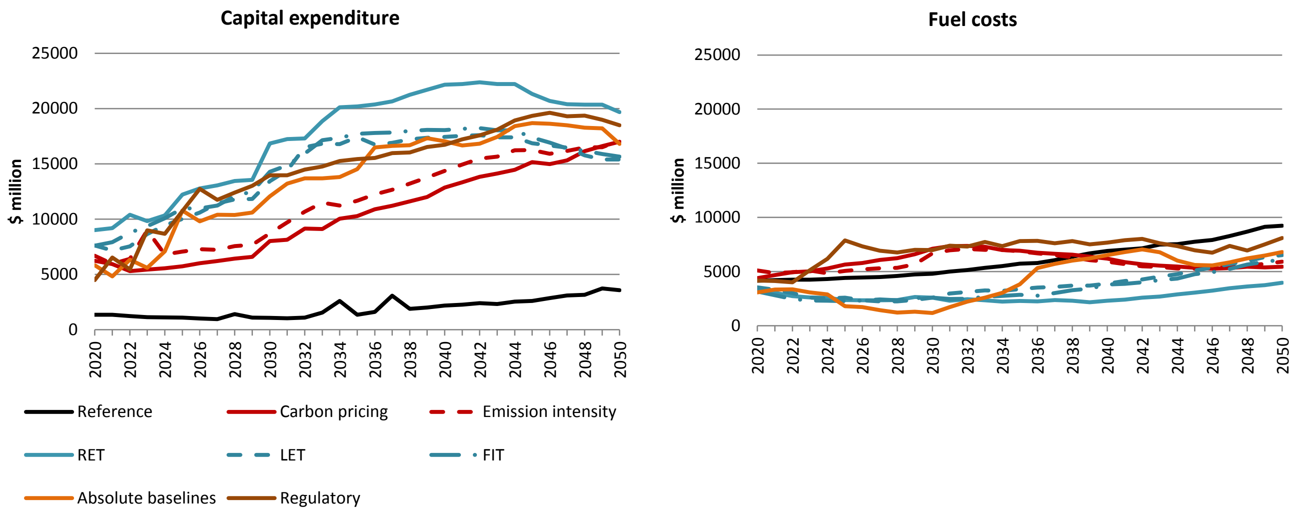
Investment costs increase but fuel costs decrease

The level of investment in generation is higher under each policy scenario relative to the reference case. With the reduction of high-emissions plant there is an immediate need to invest in low emission plant under most policy scenarios. Investment tends to be highest under the technology pull policies as investment in new technologies is the main form of abatement under these policies. The level of investment is lowest under the market pricing policies due to a higher reliance on fuel switching amongst the existing generation fleet under these scenarios.

Fuel costs are lower than for the reference case for the technology pull and absolute baseline policy due to the high level of renewable generation under these policies. For other policy measures fuel costs are initially higher relative to the reference case due to the higher level of gas-fired generation under these scenarios.

[1] The supply reliability criteria were set at an maximum energy not served criteria of 0.002% of energy demand.

Figure 3: Capital and fuel costs, 2°C emissions constraint



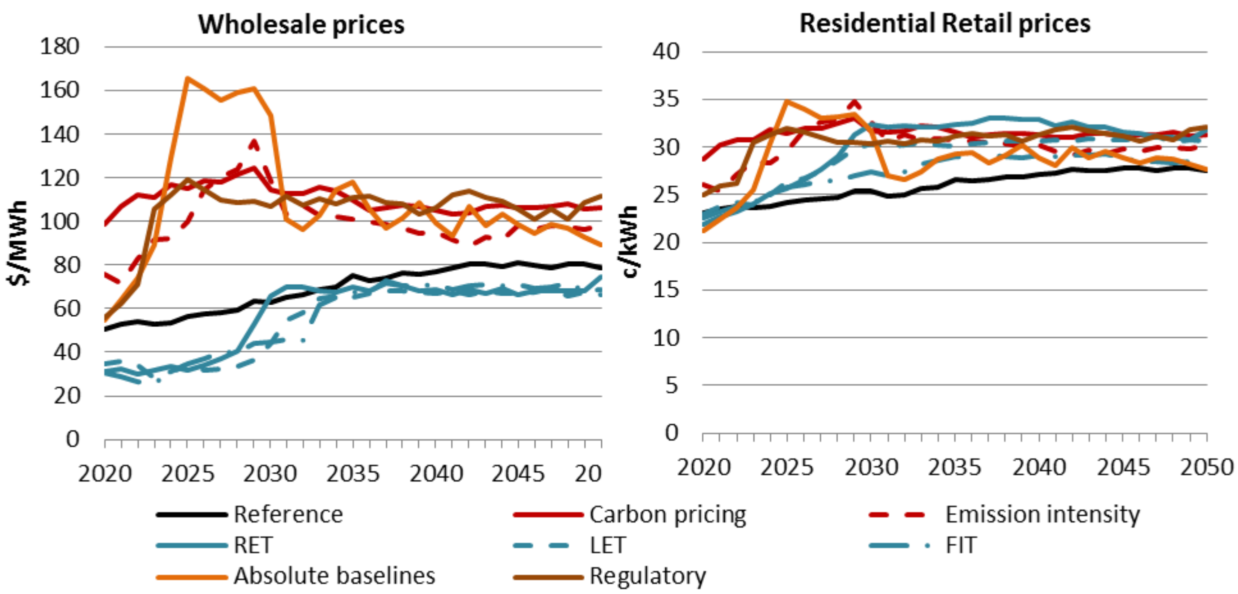
Source: Jacobs

Distributional impacts

Retail prices

Retail prices are generally higher under the policy scenarios compared to the reference case. This is due either to higher wholesale prices or the pass through of certificate costs under the technology pull policies. Residential retail prices have an average increase of around 12% to 23% relative to the reference case, with the smallest increase for the technology pull policies (except for the RET) and highest for the regulatory policies (regulated closures and absolute baselines).

Figure 4: Wholesale and residential retail prices, 2°C emissions constraint



Source: Jacobs

Wholesale prices generally increase for the market based and regulatory policies, with the largest increase occurring for carbon pricing scenario where prices rise by 60% on average. Wholesale prices under the technology pull policies tend to be lower (by about 20% on average) than the reference case due to the high level of low marginal cost renewable energy and the decrease in dispatch cost for eligible gas-fired generation.

Representative customer bills are higher under the policy scenarios. As shown in Table 2, bills increase by over $150 per annum for the carbon pricing and the regulatory policies. The rises tend to be smaller for the emission intensity and FiT policies. The rise in bill represents less than 0.35% of average household disposable incomes.

Table 2: Residential bill impacts

Policy scenario	Annual increase in bill, $/annum	Portion of household disposable income
Carbon pricing	161	0.25%
Emission intensity	116	0.18%
RET	136	0.21%
LET	109	0.17%
FIT	55	0.08%
Absolute baselines	171	0.26%
Regulatory	222	0.34%

Source: Jacobs

Incumbent generator profits

Gross profits were lower by between $40 to $50 billion for the carbon pricing and technology pull scenarios. For carbon pricing, costs of generation are higher for existing high emission plants and volumes of generation are lower. The loss in profits for these generators is partly offset by higher profits for existing low emission generators. The loss in profits in the technology pull scenarios is due to lower wholesale prices and low generation levels. The lowest loss in profits occurs for the emission intensity scenario.

For the absolute baselines scenario, some incumbent generators have higher profits than in the reference case due to the higher wholesale prices earnt by plant not affected by the need to reduce emissions and hence generation levels.

Sensitivity analysis

The robustness of the findings was tested against changes in key assumptions. Sensitivities were performed on weaker carbon constraint, the use of policy combinations, lower and higher demand and technology costs and availabilities.

Weaker emissions constraint

Under the weaker emissions constraint, the emission constraint applied to the electricity sector is consistent with Australia contributing to global action giving a likely chance of limiting global temperature increases to 3°C. The weaker emissions constraint for the electricity sector was determined to be around 2,800 Mt CO_2-e over the period to 2050, around 80% greater than for the 2°C scenarios.

The key results for a weaker emission constraint are shown in Table 3.

Table 3: Key results, weaker emission constraint

	Reference	Carbon pricing	Emission intensity	Absolute baselines	FiT	LET	RET	Regulatory
Economic cost relative to reference case, NPV at 7% discount rate, $ billion	-	71	78	79	104	104	110	84
Wholesale prices, average over 2020 to 2050, $/MWh	67	101	84	60	61	61	98	97
Retail prices, average over 2020 to 2050, c/kWh	27	30	28	28	28	28	30	30
Generation shares, % of total, 2050								
Coal	45%	0%	2%	0%	21%	15%	16%	0%
Gas	36%	6%	10%	1%	16%	8%	10%	12%
Renewable energy	19%	39%	48%	39%	63%	56%	57%	38%
Other low emission	0%	55%	41%	59%	0%	20%	17%	49%

Source: Jacobs

As under the 2°C constraint, emission mitigation incurs an economic cost. The economic cost ranges from $70 billion to $110 billion, significantly lower than in the 2°C simulations. This is because there is less investment in low emission plant.

The relativities in economic costs are similar as in the 2°C with exception of regulatory closures policy. The emission pricing policies still have the lowest economic costs, whilst the technology pull policies have the highest cost due to the high level of investment in low emission plant. The regulatory approaches have costs midway between the emission prices and technology pull policies. For the regulatory approaches, there was less need to constrain gas fired generation through regulatory measures.

Wholesale and retail price impacts are also lower with the weaker emissions constraint. Retail prices still increase but by less than 15%. The technology pull policies were projected to have lower wholesale and retail prices than the emissions pricing and regulatory policies.

Residential electricity bills increase by between $40/annum to $150/annum on bills paid under the reference case, or around 0.1% to 0.2% of average household income levels.

Policy combinations

Under the policy combination simulations, there is a combination of policies enacted to achieve the emissions constraint rather than just using a single policy. The combinations of policies were crafted to achieve the 2°C emissions constraint. The policy combinations considered were:

- A carbon price and low emissions target option. The carbon price was fixed to the carbon price used with the weaker (3°C) emissions constraint. The low emissions target was set at the level required to achieve the emissions constraint.
- A carbon price and regulated closures. The carbon price was fixed to the carbon price used with the weaker 3°C emissions constraint. Regulations were applied to force the closure of coal fired generation.

- A regulatory approach with a low emissions target. The regulations entailed closing the entire coal fired fleet over a 10 year period, with the sequence of closure based on plant age. The low emissions target was then set at the level required to meet the emissions constraint.

The key results are shown in Table 4. The results are compared to the analogous single policy simulations. Generally combining policies resulted in intermediate impacts between the constituent single policies.

Table 4: key results, policy combinations

	Reference	2°C Carbon pricing	3°C Carbon pricing plus LET	3°C Carbon pricing plus regulations	Regulatory plus LET	LET
Economic cost, NPV at 7% discount rate, $ billion	-	$133	$140	$130	$156	$150
Wholesale prices, average over 2020 to 2050, $/MWh	67	110	93	100	64	55
Retail prices, average over 2020 to 2050, c/kWh	27	32	29	29	28	30
Generation shares, % of total, 2050						
Coal	53%	0%	0%	0%	0%	1%
Gas	28%	8%	9%	12%	14%	5%
Renewable energy	19%	65%	76%	61%	67%	73%
Other low emission	0%	27%	14%	27%	19%	21%

Source: Jacobs. 3°C Carbon pricing plus regulations did not achieve the emission target

All policy combinations resulted in higher economic costs than emissions pricing policies operating alone but lead to lower costs than either technology pull policies or regulatory policies. The lower cost compared to the technology pull or regulatory policies acting alone is due to the policy combinations providing direct incentives for a wider range of abatement options than the individual policies.

The wholesale and retail prices for the policy combinations are lower than for the carbon pricing or regulatory policy acting alone and comparable to the regulatory and LET policy.

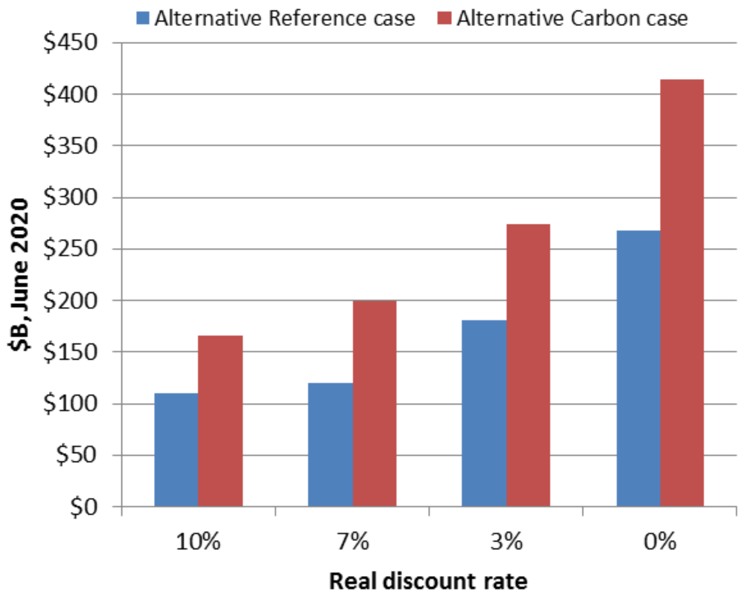
Alternative reference case

The alternative reference case simulations explore a scenario with lower than expected demand for grid supplied electricity. The lower demand is driven by two factors: (1) lower rate of growth in usage of electricity; and (2) higher level of uptake of small-scale embedded generation systems.

The lower demand and increased photovoltaics adoption defers the need for investment for new plant, resulting in flat wholesale prices out to around 2035 and reduced resource costs.

Emissions are lower than in the 2°C reference case in the first decade due to flat demand, high uptake of small-scale PV and the renewables built to meet the existing LRET. As a result the resource cost impacts of the mitigation policies are lower. Figure 5 shows the net present value of the resource costs for the carbon pricing scenario relative to the alternative reference case for four separate discount rates. The resource costs range from 51% (at 10% real discount rate) to 54% (without discounting) higher than that of the reference case.

Figure 5: NPV of resource costs, carbon pricing with alternative reference case assumptions



Source: Jacobs. The resource costs here exclude the demand adjustment. See Appendix B.3.2 for further detail.

Higher demand

The high demand sensitivity explored the case where growth in demand for electricity is higher than expected. Only carbon pricing and the LET policy scenarios were tested in this sensitivity. The same policy settings were applied as in 2^{o}C policy scenarios. Under the high demand sensitivity, demand growth is approximately double the rate.

The key difference under the high demand sensitivity occurs in the projected emissions. Specifically:

- A fixed LET with high demand leads to much higher emissions than in the base 2°C scenario. Once the LET target is met, all new demand is met by the least-cost generator – fossil fuels in this scenario.
- A fixed carbon price with high demand leads to only slightly higher emissions than in the base case, because the carbon price is sufficient to drive rapid retirement of fossil fuel generators and ensure additional demand is met by low emission technologies.

Under the carbon pricing scenario, cumulative emissions reach 1,760 Mt CO_2-e over the period from 2020 to 2050. Under LET policy scenario, cumulative emissions are projected to be 3,210 Mt CO_2-e or nearly double the level under carbon pricing.

The impact of policy measures on wholesale prices is relatively similar across the base and high demand scenarios. Higher demand would tend to put upward pressure on prices but the wholesale price is still ultimately limited by the long run marginal costs of new entry, which are assumed to be the same across both sets of policy scenarios.

The economic costs are higher for the policy scenarios in the high demand case. The costs are only marginally higher for the carbon pricing scenario, but are substantially higher for the LET scenario. For the latter, the emission target was not met and, hence, the estimated cost estimated is an underestimate of the cost of this policy.

Technology costs and availability

Results are presented for three policy scenarios and one reference case modelled with differing assumptions on technology availability and costs. The differing technology assumptions include:

- The CCS, nuclear and geothermal options are assumed not to be available.
- Battery storage costs estimated by CSIRO are used, with lower storage costs over time

The technology sensitivity was conducted with the reference, carbon pricing, LET and RET policy scenarios. The same emissions constraint as for the 2^{o} C simulations was applied to each policy scenario.

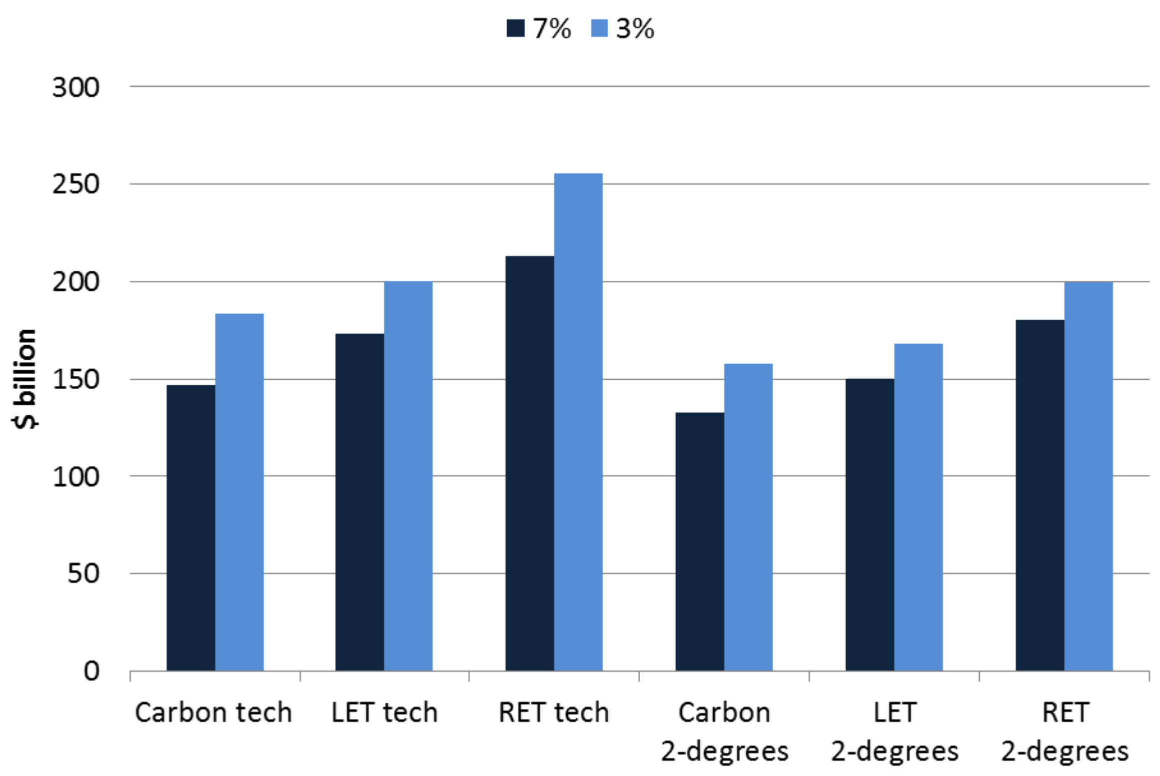
The changed technology assumptions mean existing renewable generation technologies play a bigger role in all scenarios. The outcomes in the reference case are similar under the alternative technology assumptions, although with lower battery storage costs there is a large uptake of large-scale battery storage rather than new open cycle gas turbines from 2035 onwards.

For the carbon pricing scenario, a higher carbon price is required to meet the emissions constraint. Because new dispatchable fossil fuel and nuclear technologies are not available, renewable forms of dispatchable generation (such as solar and wind with battery storage) are deployed. The higher carbon price is required so that wholesale prices are high enough to recover the costs of these higher cost options.

Outcomes under the RET and LET scenarios are very similar as the only difference between the scenarios is that conventional gas fired generation can earn certificates under the LET. Providing certificates to gas significantly lowers the resource cost of meeting the emissions constraint.

Carbon pricing still has the lowest demand adjusted resource costs. The ranking in resource costs, as shown in Figure 6, are preserved across the policy scenarios, but the difference between the policies is reduced. This is because a greater proportion of higher cost low emission technology is required under the technology sensitivity cases.

Figure 6: Resource costs relative to reference, technology sensitivities



Source: Jacobs

Prices (at both the wholesale and retail levels) are higher with the alternative technology assumptions. The greatest increase occurred with the carbon pricing scenarios due to the higher carbon prices required to meet the emissions constraint. The restricted availability of technologies reduces wholesale prices in the LET relative to the reference case because more plant with a SRMC of zero (wind and solar) are deployed.

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
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 Emissions 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)

JACOBS

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 Climate Change Authority (the Client). The scope of services, as described in this report, was developed with the Client.

In preparing this report, Jacobs has relied upon, and presumed accurate, information 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 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 analysis undertaken, 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.

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1. Overview

1.1 Climate Change Authority's Special Review and the electricity sector

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 electricity sector accounts for the largest share - around one-third - of Australia's total greenhouse gas emissions. Previous analysis has highlighted the important role that the electricity sector is likely to play in achieving deep emissions reductions in Australia and globally.[2] As the sector is characterised by long-lived capital investments, credible and consistent policy is important to providing the signals required for reducing the emission intensity of electricity supply over time. These factors mean the sector provides a case study for comparing policy options to reduce emissions, including their relative costs and benefits, effectiveness in reducing emissions and impacts on different groups.

The Authority commissioned Jacobs to undertake modelling to support this work. The purpose of the modelling is to help compare a range of illustrative policy scenarios over the period to 2050 using common sets of input assumptions, including a common emissions constraint.

This document outlines the results of the modelling for the purpose of assessing the potential impacts of alternative policies for reducing carbon emissions in the electricity sector.

The proposed policies, modelling assumptions and approach were released for public feedback in the paper "Consultation Paper: Modelling illustrative electricity sector emissions reduction policies", which was published on 29 May 2015 on the Authority's website. Material from that paper, updated as appropriate, is included in this report for completeness.

In interpreting the previous consultation document on the modelling assumptions and this modelling:

- Readers should not interpret any of the scenarios in this exercise as the Authority's proposals or preferred policy positions or designs.
- The scenario results should not be treated as a forecast for commercial purposes. Modelling is a helpful input to policy analysis, but necessarily requires many assumptions and simplifications.
- Readers should not interpret the sectoral (rather than economy-wide) focus of this modelling as a preference for sector-specific emissions reduction policies in the electricity or any other sector. The Authority is considering questions of policy scope and coverage as part of its broader review, as set out in its November draft report (CCA 2015).

The rest of this document presents the modelling approach and results, and draws out key findings. The views presented in this work are solely those of the Jacobs team who conducted this analysis.

1.2 Aims of the modelling

The work has two broad phases:

- Phase 1 - which analyses the performance of individual policies; and
- Phase 2 - which explores policy combinations and sensitivity analyses.

The seven policies compared in Phase 1 are broadly representative of those proposed and discussed in recent years. The impacts of each policy scenario are determined by comparing outcomes in each of the scenarios with those for the reference case. The results for each policy scenario include the estimated impacts on:

- Wholesale and retail prices.

[2] See for example Climate Change Authority 2014 *Renewable Energy Target Review report;* Climate Change Authority 2014 *Reducing Australia's Greenhouse Gas Emissions—Targets and Progress Review Final Report.*

- Generation mix in each region by technology.
- Investment mix in new generation by technology.
- Resource cost of electricity supply.
- Emissions pathway.
- Cost of abatement.
- Generator profitability and change in gross profits for incumbent plant.
- Supply reliability (through such measures as energy not served and loss of load hours).

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

1.3 Modelling approach

The modelling covered 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[3].The cumulative emissions constraint is the same for all scenarios, but each scenario differs in their effects on existing generation, nature and timing of new investment, wholesale and retail prices, and electricity demand. The rest of this section provides an overview of the models used, and the key input assumptions of electricity demand and the emissions constraint.

Further information on these and all other input assumptions is included in Appendix C.

1.3.1 Software tools and method

Jacobs used a suite of three models to determine the least cost generation mix in the electricity sector - that is, the electricity sector investments required to satisfy demand at least cost for society as a whole given input prices, policies and the emissions constraint. This required iterations between the three models to determine both the direct impacts and interactions between the electricity market and the various ancillary markets used as instruments to meet the emissions constraint.

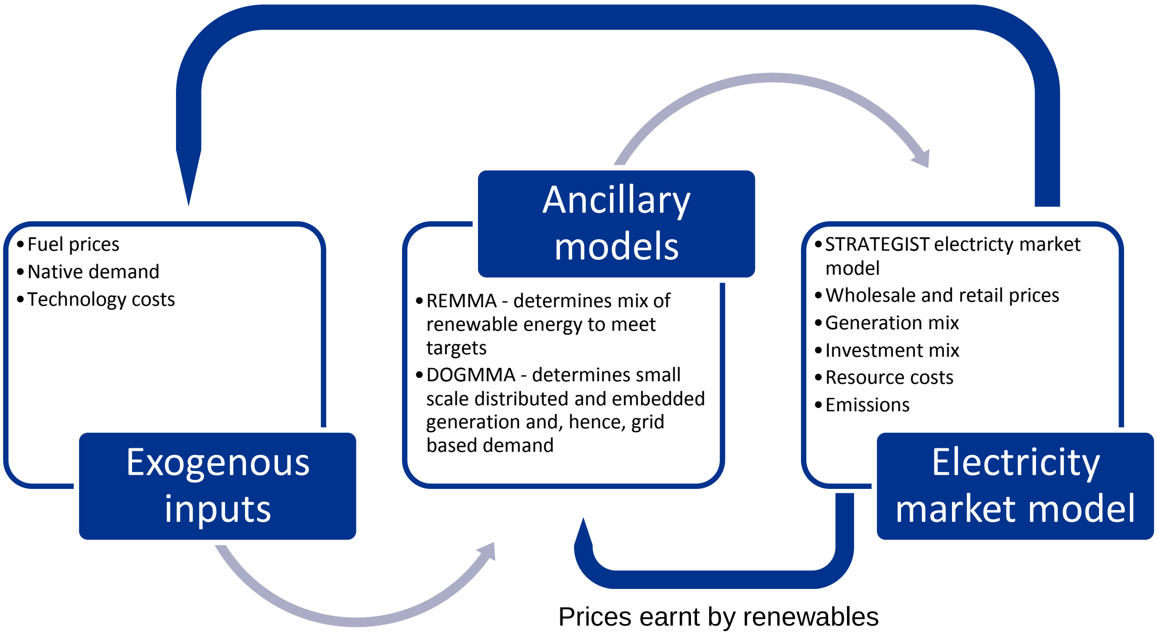
The three models are:

- Strategist - the electricity sector dispatch and investment model;
- REMMA - the renewable energy market model; and
- DOGMMA - a model that projects the uptake of small-scale embedded generation and storage technologies.

Figure 7 shows the interactions between the models.

[3] 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.

Figure 7: Modelling approach



Source: Jacobs

The approach to modelling the electricity market impacts, associated fuel combustion and emissions is to utilise externally derived electricity demand forecasts (adjusted for the embedded generation component) in our Strategist model of the major electricity systems in Australia. Strategist accounts for the economic relationships between generating plants in the system. In particular, Strategist 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 to match the demand profile, assuming a sufficient level of competition to drive efficient dispatch.

The iterative approach is as follows:

- An initial estimate of total 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 (from REMMA) is also input into Strategist.
- Strategist then simulates the response of the thermal generation sector 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.

Further details on Jacobs' models are included in Appendix A.

1.3.2 Emissions constraint

To facilitate a like-for-like comparison of policies, the modelling constrained each policy scenario to achieve the same cumulative emissions. The Authority specified that the emissions constraint be set at a level consistent with Australia contributing to global action giving a likely chance (two-thirds) of limiting global average warming to no more than 2°C. This implies deep cuts in electricity sector emissions by 2050. A weaker emissions constraint consistent with global action to limit global average warming to 3°C was examined as part of the sensitivity analysis in Phase 2 of the work.

There is no single 'correct' level of emissions within Australia's electricity sector consistent with limiting warming to 2°C - it will depend on future economic conditions, technology costs and policies across the economy.

For the purposes of this modelling exercise, the constraint was determined by using the explicit carbon price scenario. This involves:

- Using a carbon price projection consistent with global action giving a likely chance of achieving the 2°C goal as an input into the carbon price scenario in the modelling; and
- Using the resulting emissions over the period from 2020 to 2050 as the cumulative sectoral emissions constraint for all other policy scenarios.

The Authority has specified the carbon price projection should be the relevant median estimates from the Intergovernmental Panel on Climate Change's (IPCC's) Fifth Assessment Report[4]. See Appendix C for details.

The paths for modelling inputs determined by global rather than domestic factors (for example the prices for internationally traded coal and LNG) are likely to be influenced by the strength and pace of global action to reduce emissions. In Phase 1, their values were chosen to be consistent with strong global action to limit global average warming to no more than 2°C. Alternative consistent sets of emissions constraints and global inputs were used in the weaker (3°C) sensitivity scenarios in Phase 2.

1.3.3 Electricity demand

Jacobs' models take total projected electricity demand as an input and forecasts grid based and embedded generation.

The core electricity demand projection for the modelling, used in all reference cases except the low and high demand sensitivities, is based on the series from the Department of the Environment's 2014/15 emissions projections. These official projections use a total electricity demand series developed by Pitt & Sherry and ACIL Allen. For the purpose of this modelling, the original series was extended to 2050 by applying the trend growth rate of the original projection and restricted to areas covered by the NEM and WEM[5]. In these projections:

- Residential demand increases slightly from 2017 onwards as retail prices are projected to level off. Per capita consumption continues to decline slightly as energy efficiency standards for buildings and appliance drive increases in end use efficiency.
- General business demand is projected to grow in line with, but less quickly than, economic activity.
- Large industrial demand is projected to decrease slowly over the projection period after an initial increase driven by gas developments in Queensland.

Phase 2 explores high and low demand sensitivities. The low demand sensitivity combines both low total demand and a rapid increase in uptake of distributed generation and storage technologies that reduces the share of demand met by large-scale generation plant.

In Phase 1, for each of the policy scenarios, the core demand path was adjusted to reflect the impact of each policy on demand through its impact on electricity prices. The size of the expected change in electricity demand depends on:

- How much and in what direction each policy affects the overall prices faced by consumers, and
- How responsive demand is assumed to be to a price change (the estimated own price elasticity of demand).

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[4] IPCC, 2014. *Working Group III Contribution to the Fifth Assessment Report, Climate Change 2014 - Mitigation,* Cambridge University Press, Cambridge.

[5] 'Grid exempt' demand (for example, methane generation at coal mines) is also removed as this component of demand is not projected in Jacobs' modelling.

The demand impacts for alternative policy scenarios were estimated by adjusting the core demand path with the long-run own Price Elasticities of Demand (PED) using the reference price outputs as the base price. Energy price elasticities used are outlined in Table 5). These elasticities apply to all loads (residential, commercial, industrial and large loads) in each state because the underlying price used to derive the elasticities is the average customer electricity price weighted across all classes. These PEDs represent the percentage change in energy demand expected for a 1% increase in electricity price.

Table 5: Assumed regional price elasticity of demand

State	Energy price elasticity (%)	Demand price elasticity (%)
New South Wales	-0.372	-0.242
Victoria	-0.212	-0.131
Queensland	-0.323	-0.184
South Australia	-0.232	-0.179
Tasmania	-0.403	-0.351
Western Australia	-0.230	-0.147

Source: AEMO NEFR 2015 Forecast Methodology Information Paper for the NEM states[6]. The Western Australian elasticity is based on information from Synergy.

These elasticities are defined on an 'energy over time' basis. Peak demand is less elastic. We have assumed that the peak demand elasticity will be reduced by the proportion of air conditioning demand in the peak demand. This is because air conditioning demand is observed to be relatively inelastic. Table 5 shows the estimated peak demand elasticities applicable from 2020 until 2050.

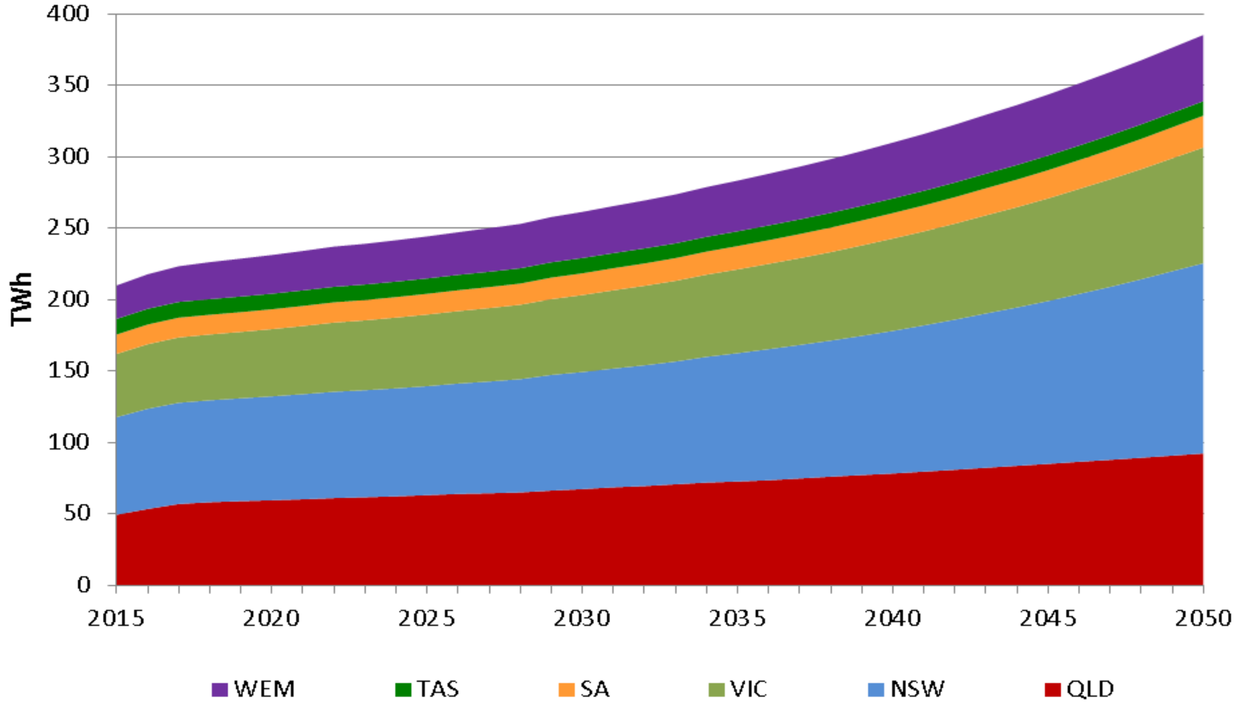
Figure and Figure 9 show the total demand and non-coincident peak demand (that is, the sum of the regional peak demands[7]) respectively across the NEM and WEM for the reference case. Higher growth over the period occurs in Victoria and NSW, with lower growth in the other large states. Demand in Tasmania is stable over this period. The energy demand growth is 1.7% pa over the NEM and WEM as a whole whereas the non-coincident peak demands increase by 1.6%.

Further material on demand is provided in Appendix C.2.

[6] There are many sources of estimates of the own price elasticity of electricity demand in the NEM, but all estimates are characterised by relatively low price elasticities (see M. O'Gorman and F. Jotzo (2014), "Impact of the carbon price on Australia's electricity demand, supply and emissions", *Centre for Climate Economics and Policy Working Paper 1411*, Canberra). A review study has found these elasticities reducing over time (A. Rai, L. Reedman and P. Graham (2014), *Price and income elasticities of residential electricity demand: the Australian evidence)*. Given the broad similarities across estimates, the likely changes in demand response from using alternative estimates are likely to be minimal.

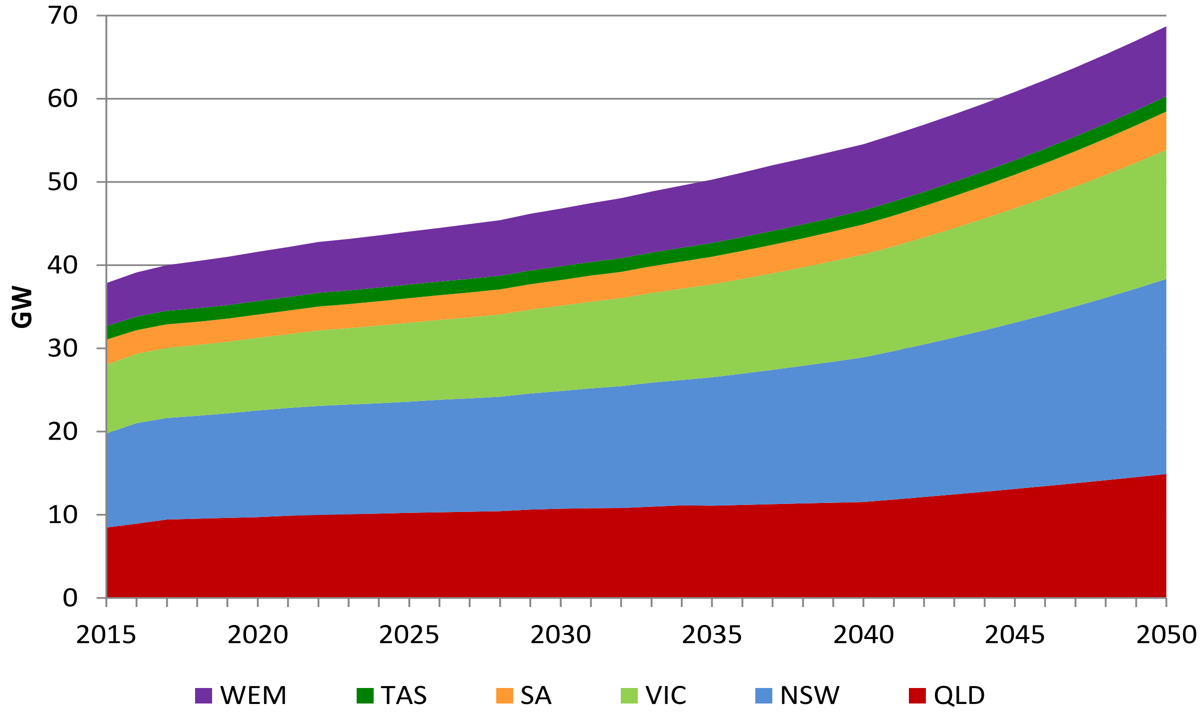
[7] As opposed to the coincident (occurring at the same time) peak demand across all the regions of the NEM

Figure 8: Total energy sent out, reference case



Source: Pitt & Sherry, ACIL Allen and Jacobs

Figure 9: Non-coincident peak demand, reference case



Source: Pitt & Sherry, ACIL Allen and Jacobs

1.4 Using and interpreting this modelling

The modelling is designed to provide insights into the potential impacts of alternative policy measures to achieve a given emissions constraint. 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 assumptions omit features 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 is explored in the sensitivity analyses in Phase 2.

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. In particular, the reference cases for each set of results are not projections of the sector under 'business as usual' but designed so that differences between the policy cases are due specifically to the policies rather than the policies and other features. For example, the Phase 1 reference case assumes strong global action to reduce emissions, without any additional policies in the Australian electricity sector.
- 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. For example, the certainty of policy (or its absence), combined with the low capital costs of new coal plant, mean that some new coal plant is constructed in the Phase 1 reference case. 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 perfectly credible. For example, the reference case does not include any new post 2020 climate policy, and investors choose generation on the basis that this will hold.
- 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.
- Many of the policies 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 designs policies to meet an emissions constraint over the period from 2020 to 2050. The policies are set for that period. In reality, the policies may evolve over time as attention is given to meeting emissions constraints beyond 2050.
- 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 Jacobs and Victoria University to investigate these impacts for some of the policies. 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). While the impacts of energy productivity or electrification are not modelled explicitly, the sensitivities in Phase 2 explore higher and lower levels of electricity demand and the 'high demand' scenario is broadly based on electricity

demand under a scenario with high rates of electrification (including electric vehicle uptake) and energy efficiency. The former effect (electrification) dominates, leading to higher overall demand despite large efficiency improvements.

- Offsets from other sectors cannot be used to meet the emissions constraint in electricity generation. The ability to surrender such units can reduce compliance costs and is an important potential design feature of some of the policies analysed. However, if offsets were included in the modelling, the results could be dominated by expected future offset prices and not be informative about the relative effects of the policies themselves.
- In some phase two scenarios the underlying cost assumptions change in the phase two reference cases compared to the phase one reference case. Accordingly, care should be taken when comparing the relative costs of the phase one and phase two scenarios.
- Short run constraints on the availability of gas are assumed not to persist beyond 2019.

1.5 Report structure

The remainder of the report is structured as follows:

- Section 2 provides a description of the reference and policy scenarios and the sensitivities on key assumptions modelled.
- Section 3 outlines the results of the simulations of the policies in meeting an emissions constraint consistent with limiting emissions to limit global temperature rises to 2°C.
- Section 4 provides an overview of the results on policy combinations and sensitivities.
- Section 5 outlines and discusses the results of the simulations of the policies in meeting a weaker emissions constraint consistent with limiting global temperature rises to 3°C.
- Section 6 outlines and discusses the results of the simulations where a combination of policies (rather than a single policy) is used to meet the 2°C emissions constraint.
- Section 7 discusses the results of the simulations where there is a lower demand for electricity and where there is a significant shift to self-generation or embedded generation, with less reliance on grid-based generation. These assume the 2°C emissions constraint.
- Section 8 examines the impact under two policy measures representative of emissions pricing and technology pull policies under the situation where demand growth is higher than expected. The policy parameters are kept the same as required for the 2°C emissions constraint scenarios.
- Section 9 examines the simulated outcomes under the policies when the technology options are constrained.
- The Appendices provides detail on the modelling inputs and assumptions.

Each set of modelling results begins with a section comparing the policies, then presents results for each of the scenarios in more detail.

2. Scenarios and sensitivities

2.1 Overview of reference and policy scenarios

This chapter describes the eight scenarios (one reference case and seven policy scenarios) that were modelled in Phase 1 of the analysis and for which sensitivities were considered in Phase 2.

The modelling horizon of interest is the period to 2049/50. The geographical scope of the modelling is 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[8].

In phase one of the work, both the common emissions constraint and modelling inputs were determined by global rather than domestic factors (for example technology costs and the prices for internationally traded coal and LNG) and were consistent with strong global action to limit global average warming to no more than 2°C. Alternative consistent sets of emissions constraints and global inputs were examined in Phase 2.

The illustrative policy scenarios were compared to a reference case which incorporates:

- The current Renewable Energy Target (both Large-scale Renewable Energy Target and Small-scale Renewable Energy Scheme) and state-based policies affecting the sector (see Appendix D for a list of the state-based policies included)
- Assumptions about the speed and nature of changes in network pricing resulting from recent Australian Energy Market Commission rule changes encouraging cost-reflective network pricing (see Appendix C.11).

Other assumptions, such as the technology costs and level of electricity demand, vary according to the scenario.

Each policy scenario:

- Matches the reference case to 2019/20 by locking in the commitments that are made in the reference case to 2019/20.
- Like the reference case, includes the current Large-scale Renewable Energy Target (LRET) and Small-scale Renewable Energy Scheme (SRES) trajectories from 2020 to 2030.
- Assumes all prospective zero and low-emissions technologies - including nuclear energy - are available to achieve the emissions constraint.
- Excludes the sector from the Emissions Reduction Fund's safeguard mechanism.
- Models the impacts of the policy on electricity users prior to any assistance being provided (for example, for the impacts of increased electricity prices on households or large electricity users). This highlights groups affected by each policy and how these differ across the scenarios examined.
- Generally applies the same design for policy features such coverage thresholds, limits on banking and borrowing of permits,[9] and so on. This helps ensure that differences in the policy scenarios are driven by material differences between the policies.
- Excludes the use of 'offsets' from other sectors or overseas to acquit liabilities under the policy.

The seven illustrative policy scenarios are:

[8] 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 extends north to Geraldton on the mid-west coast to Kalgoorlie in the east and past Albany in the south-east coast.
[9] The carbon tax does not incorporate banking and borrowing.

1) Explicit carbon price via a carbon tax.
2) Emissions intensity target: the sector is subject to a declining sector-wide emission intensity baseline. All generators receive an allocation of permits at the baseline level of intensity in proportion to their generation. At the end of the compliance period, all generators surrender permits for each tonne of carbon dioxide equivalent emitted (t CO_2-e).
3) Renewable energy target (RET): Large-scale RET expanded.
4) Low emissions target (LET): operates in a similar manner to the RET scenario but with an expanded set of eligible technologies including more efficient gas generation and carbon capture and storage (CCS).
5) Feed-in Tariffs (FiT) with Contracts for Difference (CfD): incentives are provided for specific forms of low emission generation through feed-in tariffs with contracts for difference (broadly based on policy design in the United Kingdom and Australian Capital Territory).
6) Regulated closure: standards for existing and new generators. Existing generators are closed in order of age. Maximum allowable emission intensity standards apply for new generators and existing gas generators are limited in the amount of emissions.
7) Absolute baselines: total emissions from existing generators are limited to specified baselines which decline over time. There are emission standards on new entrants.

The modelling assumes that:

- Each illustrative policy remains in place over the whole study period with no expectation of regulatory change by market participants.
- All market participants have perfect foresight about future costs and electricity demand.
- Regulatory settings are designed to achieve efficient outcomes over the study period with perfect foresight about future costs.

2.2 Policy scenarios: detailed descriptions

2.2.1 Carbon price

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 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. The carbon price is modelled as a tax so does not allow banking or borrowing.

2.2.2 Emission intensity target

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 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.

Demand for permits available in each year creates an explicit carbon price, 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 is used to identify the declining trajectory for emission intensity baselines required to meet the emissions constraint.

2.2.3 Renewable energy target

A new large-scale renewable energy target (RET) operates from 2020 through to 2050 such that renewable energy generation takes sufficient market share to achieve the emissions constraint.

The bulk of the scheme would operate in the same way as the current LRET (see Box 1). To avoid creating windfall gains for pre-existing renewables, generators constructed prior to 2020 and eligible for the current LRET would be excluded from the new policy except if refurbished at the end of their life. A new RET trajectory over and above the existing one would start in 2020, and would follow the same rough shape as the current LRET (that is, rise linearly until 2040 and then stay flat for 10 years to stabilise investments prior to end of the policy horizon). This shape is intended to accelerate investments ahead of 2040 as later investments would have limited effect on cumulative emissions to 2050. The current SRES would phase out as currently legislated, ending in 2030.

Box 1: How the LRET works

The LRET works by creating a market for additional renewable electricity that supports investment in new renewable generation capacity. It places a legal obligation on entities that purchase wholesale electricity (mainly electricity retailers) to surrender a certain number of certificates to the regulator each year. These certificates are created by accredited renewable generators. Each certificate represents one megawatt hour (MWh) of additional renewable energy for compliance purposes. The certificates are tradable and can be banked in unlimited quantities for use in later compliance years. Liable entities can also effectively borrow from future surrenders (this is limited to 10% of an entity's annual liability).

2.2.4 Low emissions target

The low emissions target (LET) would operate in the same way as the RET but with wider eligibility. The target has the same shape as in the RET scenario (increasing from 2020 to 2040 then flat to 2050). Eligibility is extended to all new zero- and low-emissions generation below a threshold level of emission intensity. Carbon capture and storage (CCS) retrofits to existing plant would also be eligible. Eligible generators receive certificates adjusted by how much the generation outperforms the threshold intensity, such that a zero emissions generator would receive one certificate for every MWh of output, while a generator with half the threshold intensity would receive half a certificate.

To avoid windfall gains for pre-existing generation, zero- and low-emissions generators existing at 2020 would be eligible to produce LET certificates only for any generation above pre-specified historic baselines (similar to pre-existing renewable generation under the current LRET).

2.2.5 Feed-in tariffs with Contracts for Differences

Feed-in tariff (FiT) schemes set prices rather than quantities for electricity generated by eligible technologies. The FiT scenario is broadly based on the scheme recently introduced into the United Kingdom and the Australian Capital Territory.[10] In this approach, the government holds periodic reverse auctions to encourage new low emission capacity at the lowest acceptable tariff. The tariff for the successful bidders is realised through a Contract for Difference (CfD), a long-term contract between the government and the generator under which the generator receives the difference between a premium ('strike' price) and reference wholesale electricity price for each unit of electricity generated. If the reference wholesale price exceeds the strike price, generators

[10] The UK policy incorporates some technology-specific assistance or 'banding'. For the purposes of comparability, this exercise models an unbanded scheme.

pay back the difference (Figure 10). The payments to generators are recovered from electricity consumers via a customer levy.

Figure 10: Operation of Contracts for Difference (CfD)

Source: United Kingdom Department of Energy and Climate Change 2011, *Planning our electric future: a White Paper for secure, affordable and low-carbon electricity*, July 2011, London.

2.2.6 Regulated closures

Regulations force the closure or retrofit with carbon capture and storage (CCS) of existing high-emitting generators. Closure is in order of age. New coal plant without CCS is prohibited.

Existing coal capacity is closed in a roughly linear fashion starting with the oldest, with the order of plant closure publicly announced at the time the policy is introduced. Each plant identified for closure would be legally required to either close or retrofit with CCS by its closure date.

The Phase 1 emissions constraint also requires limits on gas generation. Simply closing the most emissions intensive gas generators would be an unnecessarily costly approach, as it may prohibit less efficient but more flexible open-cycle gas turbines to continue to provide a peaking role. For this reason the constraint on existing gas plants takes the form of a maximum level of emissions per MW capacity per year, starting in 2020 at the level of a best-practice base-loading combined cycle plant (i.e. 2,200 tonnes per MW installed per year).

For the purposes of simplicity, the modelling assumes closure requires complete withdrawal of the whole generator at a specific date (or complete conversion to CCS). In practice, if a regulatory approach were adopted it might incorporate more efficient approaches where plants are retired more gradually (for example, unit by unit).

2.2.7 Absolute baselines

Under this policy scenario individual facility baselines are set using facility specific annual emissions between 2009/10 and 2013/14. These baselines then decline at the rate necessary to achieve the emissions constraint.

Baselines only apply to generators above the industry average emission intensity. This intensity threshold declines over time.

Emission standards for new facilities are set at a level to encourage facilities to achieve and maintain best practice. This standard prohibits new fossil fuel generators (both coal and gas) from being built without CCS.

2.3 Sensitivities and policy combinations in Phase 2

Phase 2 of the work shed further insights on the relative performance of policies by testing the performance of combinations, and robustness of individual policies to changes in key assumptions. Table 6 sets out the key questions explored in Phase 1 and Phase 2 and the policy scenarios investigated for each sensitivity.

An expanded version of this table listing key input assumptions and sources for each sensitivity are provided in Appendix D.

Table 6: Relationship between modelling questions, sensitivities and policy scenarios

Question	Explore through	Policy scenarios investigated
How do individual policies compare on key metrics when meeting the same cumulative emissions budget?	Phase one: modelling each policy separately with common inputs and common emissions constraint	All
Would less ambitious emissions targets change the relative performance of policies?	Weaker emissions constraint	All
Will combinations of policies perform better than individual policies?	Policy combinations	Carbon price and low emissions target Carbon price and regulated closures Regulated closures and low emissions target
Does a large shift to distributed generation and storage change the relative performance of policies? If actual electricity demand is lower than projected, does this change the relative performance of policies?	Alternative reference case (higher penetration of PV and storage; lower underlying electricity consumption)	Reference case Carbon price Low emissions target (planned but not run as LET targets exceeded electricity demand)
If actual electricity demand is higher than projected, does this change the relative performance of policies?	High electricity demand	Reference case Carbon price Low emissions target
Does changing costs and/or availability of key large-scale technologies change the relative performance of policies?	Technology sensitivities	Reference case Carbon price Low emissions target Renewable energy target

Source: Climate Change Authority and Jacobs

3. Results: 2°C emissions constraint scenarios

3.1 Scenario comparisons

3.1.1 Key similarities and differences

This section compares the seven policy scenarios modelled using assumptions consistent with global action to limit warming to 2°C. The subsequent sections provide more detailed results for each scenario. Further information about the method and input assumptions are in the Appendices C and D.

Each policy scenario requires a large reduction of emissions, with emissions limited to 1,580 Mt CO_2-e over the period to 2050. To put this in some context, it is equivalent to 10 years of electricity generation emissions at 2014/15 levels.

Achieving the emissions constraint requires a transformation of the electricity supply sector, with a shift from predominantly coal fired generation to a mix of low emission technologies. Looking across the scenarios:

- Three ‘families’ of policies could be identified with similarities within the family but differences between families:
  - The ‘emissions pricing’ policies that price emissions directly (carbon pricing and emission intensity target)
  - The ‘technology pull’ policies that work through creating incentives for new low-emissions generation (the RET, LET and FiT)
  - Two other policies, regulated closure and absolute baselines. These two policies are similar in their broad design (they are both regulatory), but less similar in their projected impacts than are the policies in the other two families.
- All policies met, or came close to meeting, the demanding emissions constraint, with the exception of the regulated closure policy.
- Emissions pricing policies (carbon pricing and the emission intensity target) have the lowest resource cost.

To achieve the emissions constraint, each policy had to encourage a high level of investment in low emission technologies, as well as change the pattern of dispatch away from high emissions to low emission sources. The particular outcomes such as the generation mix, wholesale and retail prices under each policy differed based on the incentives provided.

The differences are as follows:

- The mix of low emission technologies: Gas fired generation was more predominant in the emissions pricing policies (carbon pricing, emission intensity) than for the regulatory based or technology pull policies. All policies engendered a high level of renewable generation, but the level and timing differed. The emissions pricing policies entailed a more even level of investment in new renewable generation. The technology pull and regulatory policies all required greater levels of investment in low emission technologies in the period to 2030, which increased the cost of abatement, with the locked in investment muting the uptake of lower cost options that became available after 2030.
- Constraints on choices in dispatch and/or investment: Under the regulatory policies the choice of new entrant technology was restricted. Regulated closures prohibited the entry of new coal without CCS. Absolute baselines prohibited entry of new coal and gas plant without CCS[11]. The RET policy scenario

[11] The absolute baselines restriction allowed the building of gas plants in peaking roles in the 2020s prior to the entry of gas plant with CCS.

restricted certificate incentives to renewable energy technologies. The LET policy scenario provides some incentive to new plant with emission intensity below 0.6 t CO_2e/MWh, which encourages gas fired options. Eligible plants received certificates prorated to the level of emissions saved: for example, a plant with an emission intensity of 0.3 t CO_2e/MWh would receive half a certificate for each MWh of generation, while a zero emissions plant would receive full certificates.

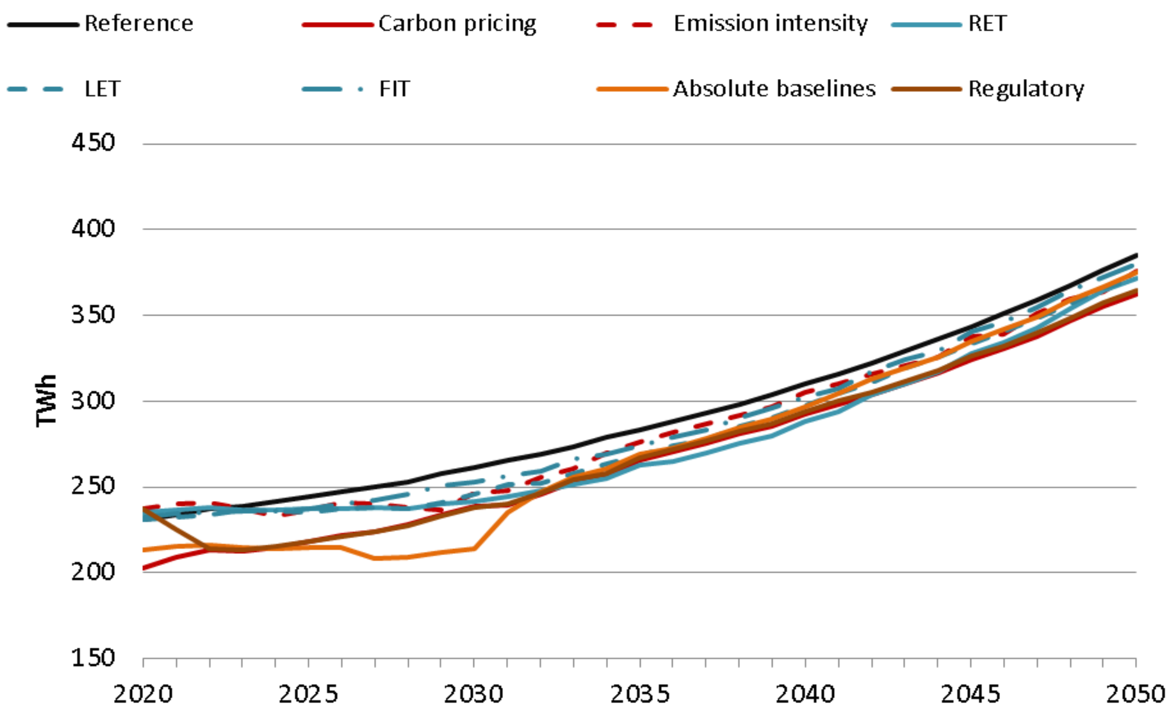
- Impacts on wholesale and retail prices. As a result of variations in retail prices across the policies demand was relatively higher or lower and this led to more or less investment in low emission technologies to achieve the same emissions constraint.

3.1.2 Demand

The demand for electricity is affected by the retail price. For scenarios with higher retail prices, the demand for electricity was lower.

Electricity demand across the scenarios is compared in Figure 11. Demand is generally highest for the reference case, being the scenario with the lowest prices across the period to 2050. In the early years, the price suppression caused by additional renewable energy generation means that demand in the technology pull policies is higher than in the reference case.

Figure 11: Electricity demand, sent out basis, 2°C emissions constraint



Source: Jacobs. These figures include consumption from on-site generation.

The relative change in demand across the scenarios reflects relative prices:

- The lowest demand occurs for the carbon pricing and regulatory scenarios. The carbon price leads to higher wholesale prices and retail prices, which then induces a demand response. Demand in the carbon price scenario is 8% lower on average than in the reference scenario, which means carbon pricing delivers a relatively greater share of demand-side abatement.

- For the technology pull and emission intensity target scenarios, demand is around 2% to 3% lower than the reference case on average. The technology pull policies have demand converging to reference case levels after 2040, when the targets flatten out and the cost of certificates reduces. Demand in the emission intensity target is higher than carbon pricing due it causing smaller increases in consumer prices.

- For the regulatory and absolute baseline policy scenarios, demand is lower than the reference case by around 7% on average over the study period. Both policies entail higher wholesale prices due to restrictions on generation from conventional plant. In the absolute baseline scenario, demand is substantially lower than all other scenarios in the period to 2030 due to the price spike that occurs in the late 2020s.[12]

3.1.3 Generation and capacity

Meeting the emissions constraint significantly changes the mix of generating plant. In the reference case, coal fired generation continues to comprise the largest contribution to generation and capacity installed (see Figure 12). In the policy scenarios, however, coal generation and capacity reduces to zero contribution by between 2025 and 2040. Coal closure is fastest in the regulated closure scenario, where closure is the main lever used to reduce emissions. It is next fastest in the carbon pricing and emission intensity target scenarios, where the carbon price makes coal uncompetitive. It is slowest in the absolute baselines scenario, which allows existing plant to continue to emit (at progressively lower levels) until about 2040.

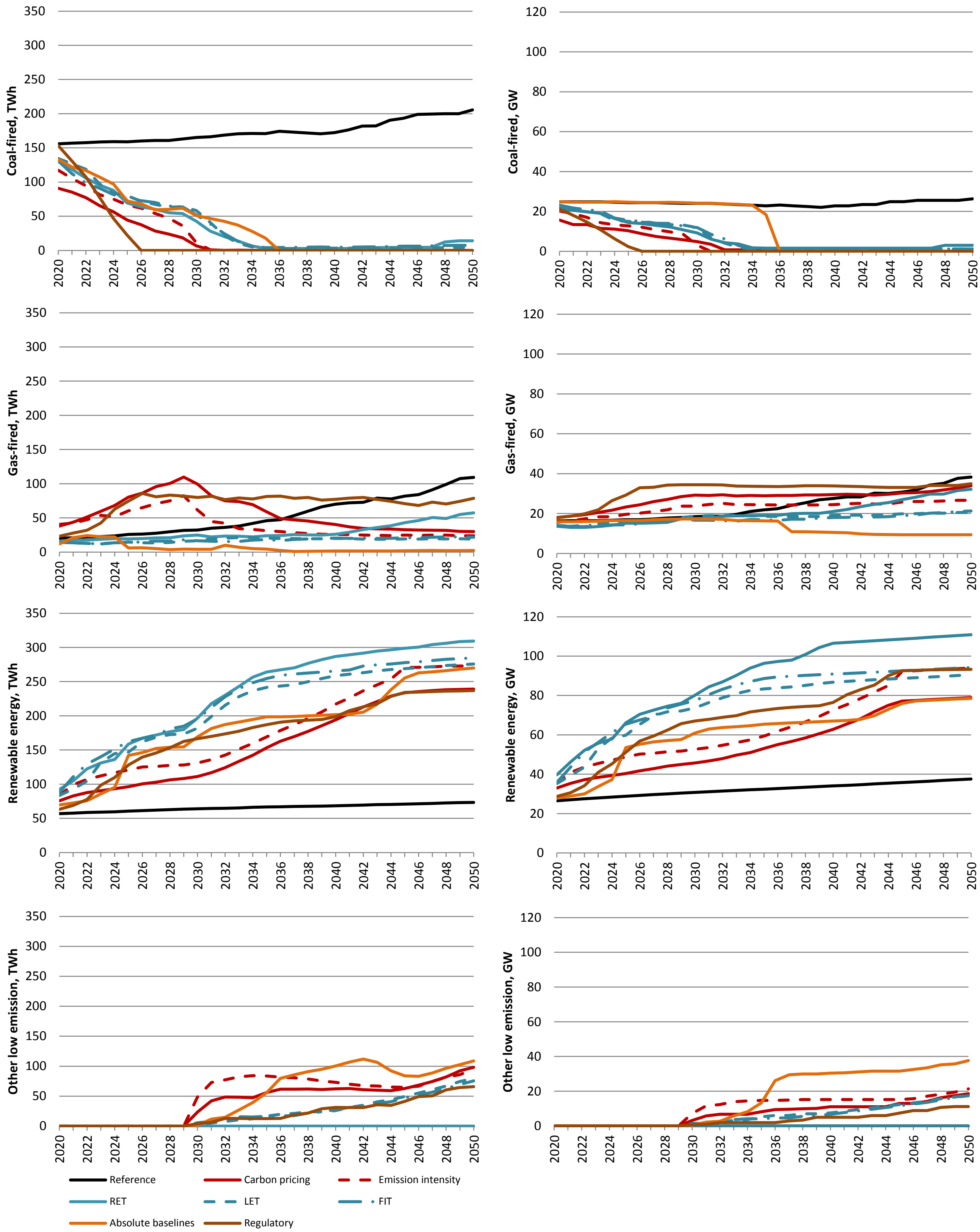
In the reference case, the level of renewable generation stabilises after the capacity required to meet the LRET target is installed (in 2020). There is some growth in capacity and generation from continuing uptake of small-scale PV systems but there is no growth in large scale renewable energy generation. Conventional coal and gas generation remain the lowest cost option, given the assumptions on fuels and capital costs.

In all the policy scenarios, renewable energy eventually becomes the dominant form of generation, with the proportion of renewable energy reflecting the impact of policy measures on generation costs and any restrictions limiting the type of technologies available. The level of renewable energy is highest in the technology pull scenarios due to policy directly providing a subsidy for those technologies. Renewable generation is lower in the emissions pricing scenarios, where gas plays a more significant role in the early years, and low emission technologies (such as CCS and nuclear) play a role later.

Gas fired generation is higher in the emissions pricing policy scenarios than most of the other policy scenarios. Only the regulatory policy scenario has a higher level of gas fired generation mainly due to forced closure of coal fired generators. However, in most policy scenarios the level of conventional gas fired generation falls after 2030. After 2030, gas fired peaking plants are found to have an important role providing reserve capacity to meet supply reliability requirements and to provide support for the level of intermittent generation.

[12] Wholesale and retail prices for absolute baselines are projected to be highest of all the scenarios over 2025-2030, but are broadly similar to carbon pricing after that. Over 2025-2030, new renewables are required to replace the declining output from existing plant. These renewables cause sharp increases wholesale prices because they have only a short window to recover enough of their fixed costs before lower-cost technologies (gas CCS and geothermal) are deployed from 2030.

Figure 12: Generation and capacity by technology type, 2° C emissions constraint



Source: Jacobs

Table 7: Share of generation by technology type, % of total generation, 2°C emissions constraint

Scenario	2030				2050			
	Coal	Gas	Renewable	Other low emission	Coal	Gas	Renewable	Other low emission
Reference	63%	12%	24%	0%	53%	28%	19%	0%
Carbon pricing	3%	41%	46%	10%	0%	8%	65%	27%
Emission intensity	5%	24%	52%	19%	0%	6%	69%	25%
Absolute baselines	21%	3%	76%	1%	0%	1%	71%	28%
RET	16%	9%	74%	0%	4%	15%	81%	0%
LET	20%	5%	70%	5%	1%	5%	72%	22%
FiT	19%	6%	72%	2%	2%	6%	73%	19%
Regulatory	0%	32%	66%	2%	0%	21%	62%	17%

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).

3.1.4 Prices

The type of carbon mitigation policy has a significant effect on wholesale prices. In the reference case, the gradual reduction of surplus generating capacity see wholesale prices gradually rise to the long run marginal costs of new entrants, reaching that level around 2035. For the policy scenarios:

- For the carbon pricing scenario, wholesale prices are significantly higher than in the reference case reflecting the impact of the carbon price on dispatch costs of thermal plant. The rise in wholesale price is tempered by the long run marginal cost of low emission plant, with the wholesale prices reaching the long run marginal cost of new entrants in 2020, and gradually falling over time in line with assumed cost decreases for new low emission generation. Wholesale prices in this scenario are generally the highest across all the policy scenarios.

- Wholesale prices also rise in the emission intensity scenario but by not as much as for the carbon pricing scenario. Prices in this scenario are 12% lower than for the carbon pricing scenario[13].

- Wholesale prices also rise for the regulatory and absolute baseline scenarios as they restrict dispatch of low cost but high emissions plant. In the absolute baseline case, there is a sustained price spike after 2024[14]. Prices lower than the price spike would discourage new low emission plant[15] from coming into the market to cover generator shortfalls during this period. Low emission plant entering into this period need prices higher than their long run marginal cost because prices after 2030 reflect the long run marginal cost of new low emission options that become available.

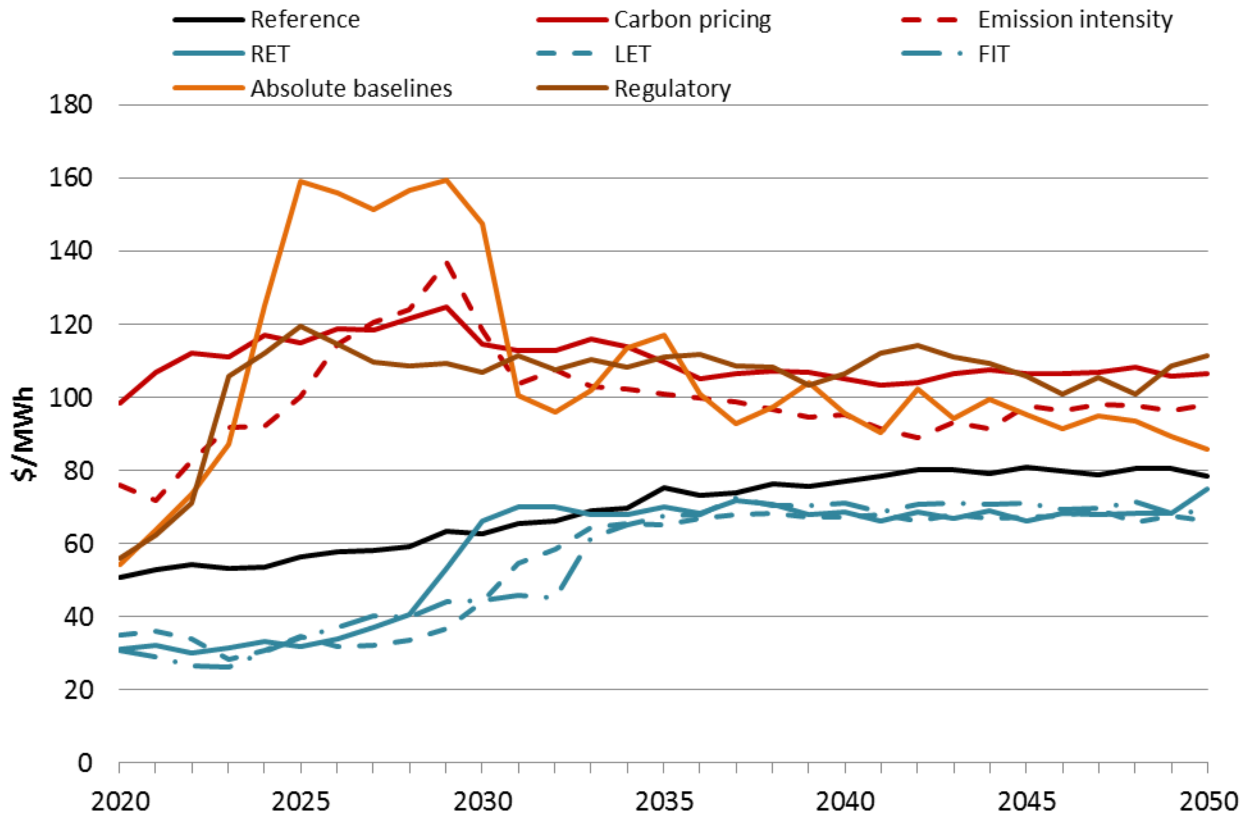
- Wholesale prices are below or around the reference case prices for the technology pull scenarios. Downward pressure on prices occur because of the amount of plant with low short run marginal cost and the implied subsidy on dispatch costs provided by the certificates earnt under these schemes. The RET scenario sees relatively rapid increase in prices in the late 2020s because of the retirements of fossil fuel plants and load growth.

[13] There is a short spike in prices just before 2030, mainly due the assumption of availability of new low cost options for low emissions generation in 2030. Under the assumptions of perfect foresight, the availability of lower cost geothermal and CCS after 2030 is foreseen and hence there is reduced incentive to invest in low emissions plant just before 2030.

[14] For this period wholesale prices are projected to be higher than under any other policy. These higher prices are required to support profitable entry of new low emissions plant before 2030, with these plant earning prices below their long run marginal costs after 2030 when new low cost low emissions options become available.

[15] There is a policy restriction in this scenario to limit entry of new plant to low emissions options

Figure 13: Wholesale prices, volume weighted average, 2° C emissions constraint



Source: Jacobs. Volume weighted prices are average the hourly prices weighted by hourly generation proportions. Volume weighted prices are derived for each region of the NEM and the WEM and a system wide average is then derived by weighting each region price by the proportion of each regions energy demand to total energy demand. Regulated closure in the 2°C scenario breaches emissions budget by about 200 Mt.

On average, retail tariffs are projected to be around 10% to 20% higher in the policy scenarios than for the reference case. Retail tariffs are generally higher for the carbon pricing and regulatory scenarios. The technology pull scenarios have the lowest retail price impact driven mainly by the effects of these policies on reducing wholesale prices.

The mitigation policies all increase residential customer bills (see Figure 14). Residential electricity bills increase by between $50 and $200 per annum compared to the reference case, or 0.1% to 0.3% of projected average household disposable income levels. The largest impact on bills occurs under the regulatory scenario and the least impact under the technology pull scenarios. The high retail prices in the 2020s in the absolute baselines scenario reflect the flow-on effect of the wholesale price spike discussed above.

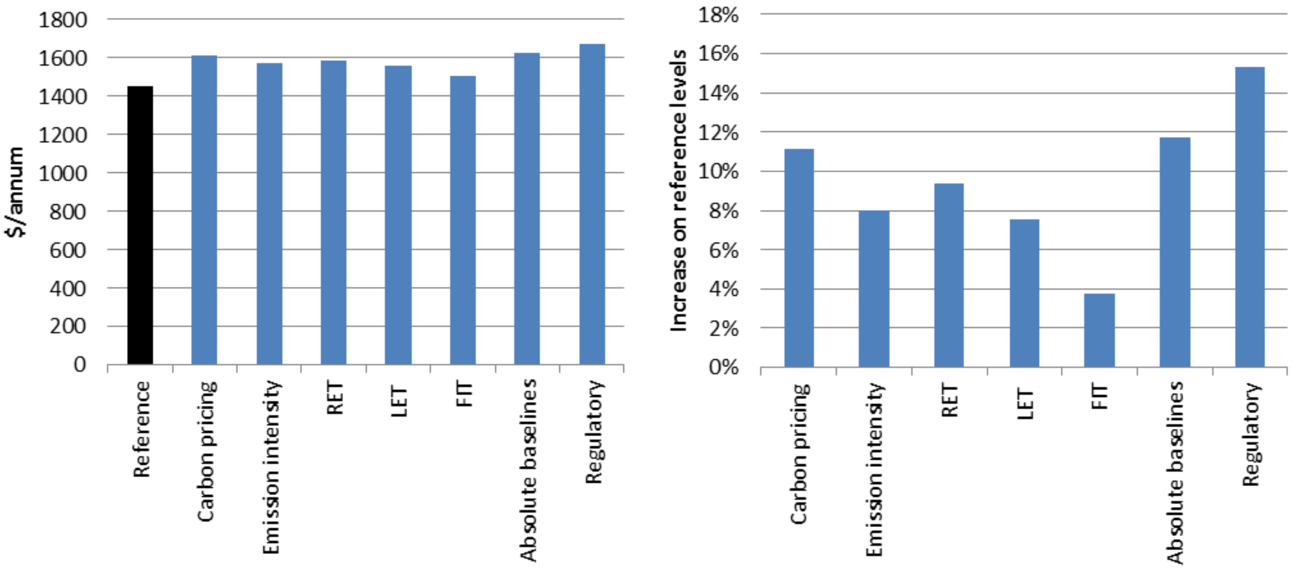
Table 8: Retail tariffs, 2°C emissions constraint

Customer type/scenario	c/kWh				% change from reference			
	2020-2030	2031-2040	2041-2050	2020-2050	2020-2030	2031-2040	2041-2050	2020-2050
Residential								
Reference	24	26	28	26				
Carbon pricing	31	32	31	31	29%	21%	13%	21%
Emission intensity	30	31	30	30	24%	17%	7%	16%
RET	26	33	32	30	9%	24%	15%	16%
LET	26	30	31	29	9%	16%	11%	12%
FiT	25	28	29	27	4%	9%	4%	6%
Absolute baselines	29	28	29	29	21%	9%	4%	11%
Regulatory	30	31	31	31	22%	18%	14%	18%
SME								
Reference	23	24	26	24				
Carbon pricing	29	29	29	29	27%	19%	12%	19%
Emission intensity	28	28	27	28	22%	16%	7%	15%
RET	25	31	30	28	10%	27%	17%	18%
LET	25	29	29	28	10%	18%	15%	14%
FiT	24	27	27	26	5%	12%	7%	8%
Absolute baselines	29	28	29	29	30%	17%	12%	20%
Regulatory	27	29	29	28	21%	18%	15%	18%
Industrial								
Reference	10	12	13	12				
Carbon pricing	17	17	16	16	61%	41%	28%	43%
Emission intensity	16	16	15	15	49%	34%	17%	33%
RET	13	17	16	15	22%	46%	27%	32%
LET	13	15	15	14	22%	29%	18%	23%
FiT	12	13	13	13	13%	12%	3%	9%
Absolute baselines	18	16	16	17	70%	37%	25%	43%
Regulatory	15	16	16	15	43%	33%	24%	33%

Note: residential prices include GST; SME and industrial prices do not. Regulated closure in the 2°C scenario breaches emissions budget by about 200 Mt.

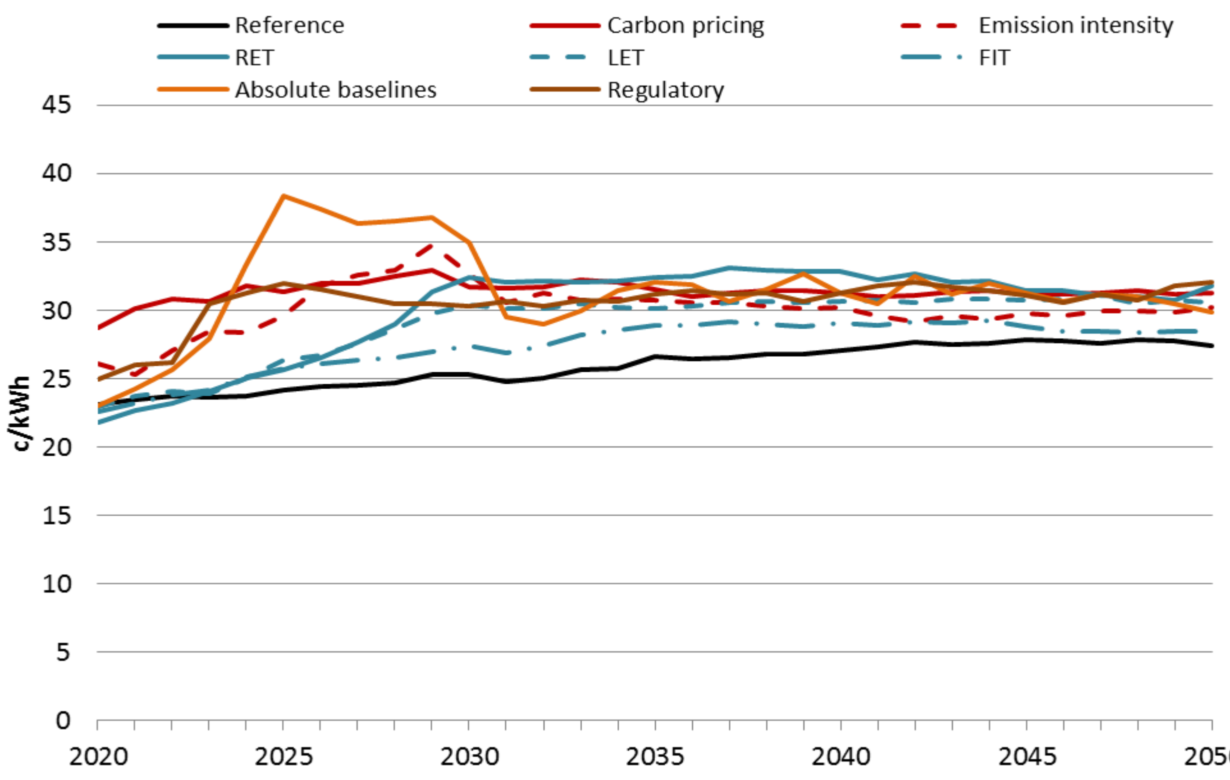
Source: Jacobs

Figure 14: Changes in residential customer bills and additional expenditure on bills, 2° C emissions constraint



Source: Jacobs. Residential bills calculated by taking the net present value of annual bills from 2020 to 2050, discounted using a 7% discount rate, and then dividing by the number of years. Additional expenditure is the average additional residential bill (relative to the reference case) divided by average household incomes over the period from 2020 to 2050. Projected real income is the same across policies. Regulated closure in the 2°C scenario breaches emissions budget by about 200 Mt.

Figure 15: Residential retail tariffs, volume weighted average, 2° C emissions constraint



Source: Jacobs. Volume weighted prices are average the hourly prices weighted by hourly generation proportions. They are also weighted for the hourly profile of electricity use by typical residential customers. Volume weighted prices are derived for each region of the NEM and the WEM and a system wide average is then derived by weighting each region price by the proportion of each regions energy demand to total energy demand. Regulated closure in the 2°C scenario breaches emissions budget by about 200 Mt. So the impact on prices for this scenario should be interpreted with this in mind.

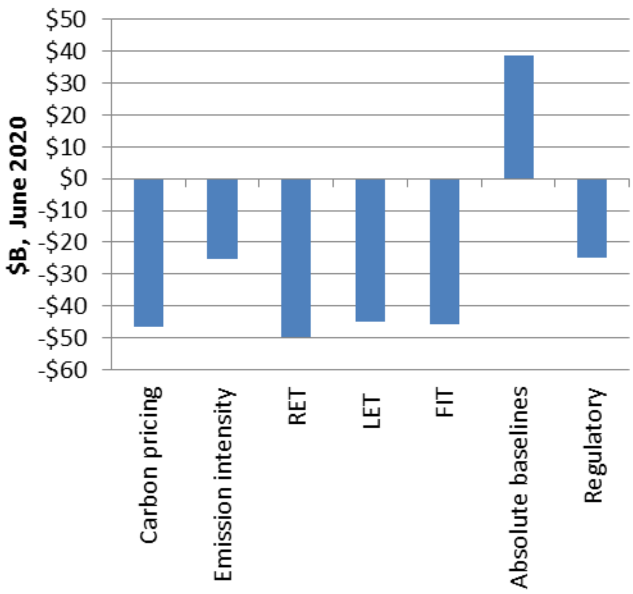
3.1.5 Change in gross profits

Gross profit is a concept related to costs, and for a generator is the difference between total revenue, which consists of pool revenue, contract revenue and certificate revenue (where applicable), less all operating costs, including fuel costs, fixed and variable operating costs and emissions costs.

Each policy affects the gross profits of incumbent generators, except for the absolute baseline policies (see Figure 16). Gross profits were lower by $40 to $50 billion for the carbon pricing and technology pull scenarios. For carbon pricing, costs of generation are higher for existing high emission plants and volumes of generation are lower. The loss in profits for these generators is partly offset by higher profits for low emission generators. The loss in profits in the technology pull scenarios is due to lower wholesale prices and low generation levels. The lowest loss in profits occurs for the emission intensity scenario.

For the absolute baselines scenario, some incumbent generators have higher profits than in the reference case due to the higher wholesale prices earnt by plant not affected by the need to reduce emissions and hence generation levels.

Figure 16: Change for incumbent generators profits by scenario, 2°C emissions constraint



Source: Jacobs.

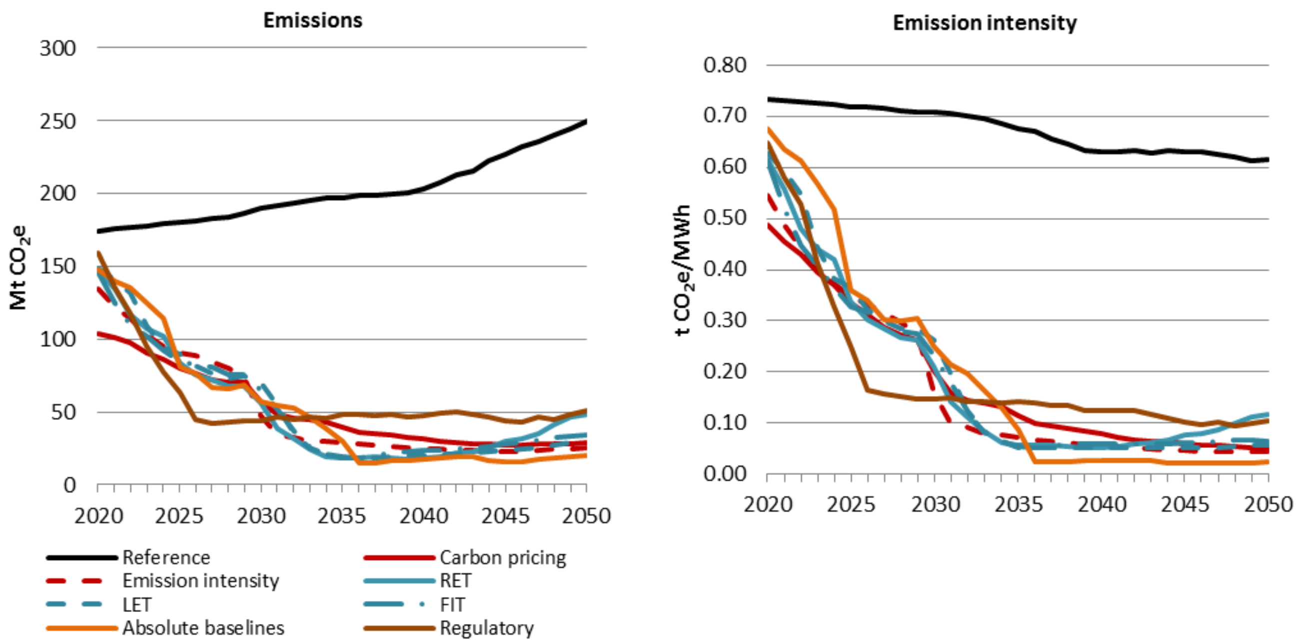
3.1.6 Emissions

Emissions rise in the reference case by around 1.2% per annum, lower than the rate of growth in demand for that scenario. The emission intensity of generation falls due to the increasing proportion of gas fired generation projected.

In contrast, emissions are projected to fall sharply for the policy scenarios (see Figure 17). The bulk of the reduction in emissions occurs in the period to 2030, when there is significant retirement of coal fired generation. The trajectory of the reduction is similar across the scenarios with any difference due to differences in demand and the rate at which low emission technologies are deployed. The policy's influence on gas fired generation also has a significant influence on the pathway of decline in emissions.

The carbon pricing scenario has a sharp fall in emissions in 2020. This is due to the impact of the high starting price ($70/t CO_2e) on the relative dispatch costs across technologies and through retirements of coal fired plant. Emissions fall rapidly in the regulated closure scenario due to the rapid phase out of coal generators. Despite this, cumulative emissions in this scenario exceed the emissions constraint. Emissions reduction patterns in the other scenarios are broadly similar. Emissions in the RET scenario increase in the late 2040s as the policy imposes no constraint on new entrants. Once the RET target is met, new coal (as the lowest-cost generator) plant is deployed to meet growing demand.

Figure 17: Emissions and emission intensity, 2°C emissions constraint



Source: Jacobs. Emissions included direct emissions (from combustion of fuels in electricity generation) and indirect emissions (emitted during processing and supply of fuel to power stations). The emission intensity only includes direct emissions. Regulated closure in the 2°C scenario breaches the emissions budget by about 200 Mt.

3.1.7 Resource costs and cost of abatement

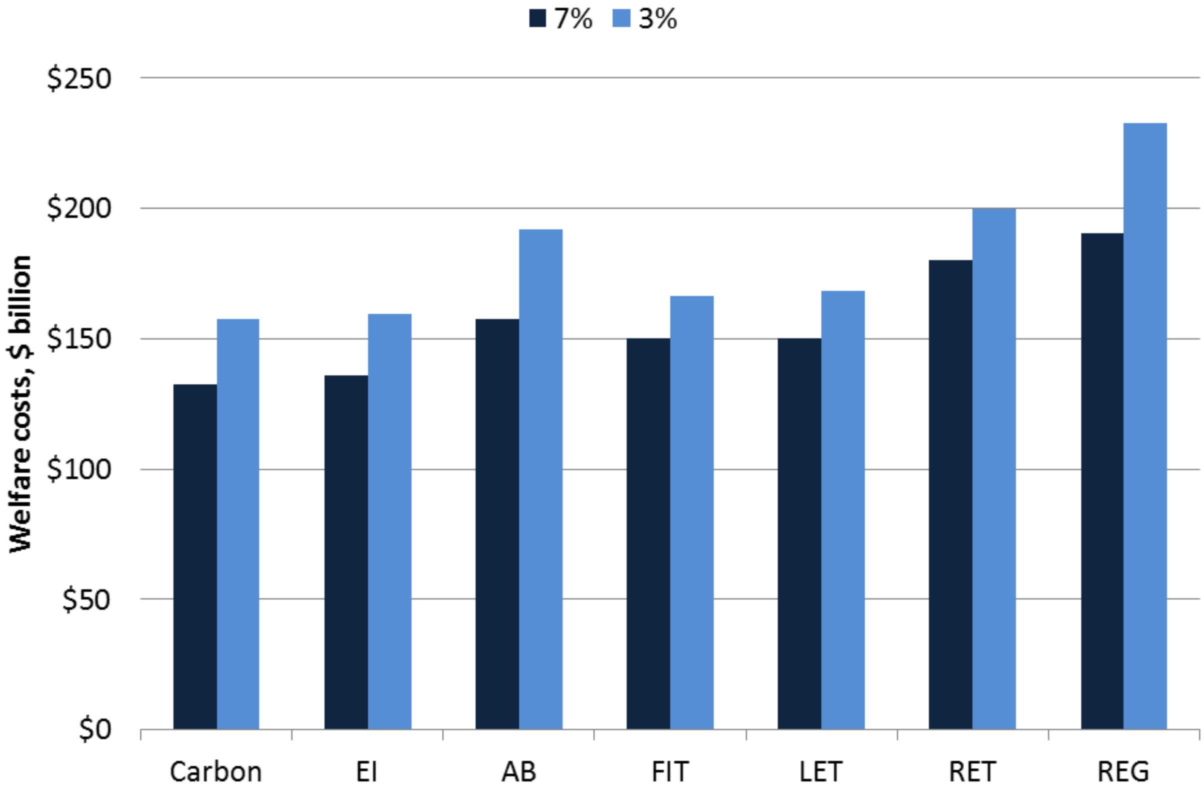
The resource costs of the policy, adjusted for the reductions in demand due to the impacts of each policy on retail prices, are shown in Figure 18. Throughout this report resource costs relative to the reference case are the demand adjusted resource costs. Where resource costs exclude the demand adjustment this is outlined in the notes accompanying the relevant graph.

This ‘demand adjusted resource cost’ is equivalent to the welfare cost of the policy, before the emissions reductions are valued.

The results indicate the lowest resource costs occurred with the emissions pricing policies (such as carbon pricing and the emission intensity target). The resource cost for the emission intensity scheme is slightly higher due to the higher demand in this policy scenario (effectively requiring additional low emission generation to be deployed to meet the same budget constraint) and the limits to borrowing in the emission intensity scenario which required more early abatement.

The technology pull and the regulatory policies had similar resource costs with the highest cost occurring for the RET and regulatory policy measures.

Figure 18: Resource costs relative to the reference case, 2° C emissions constraint



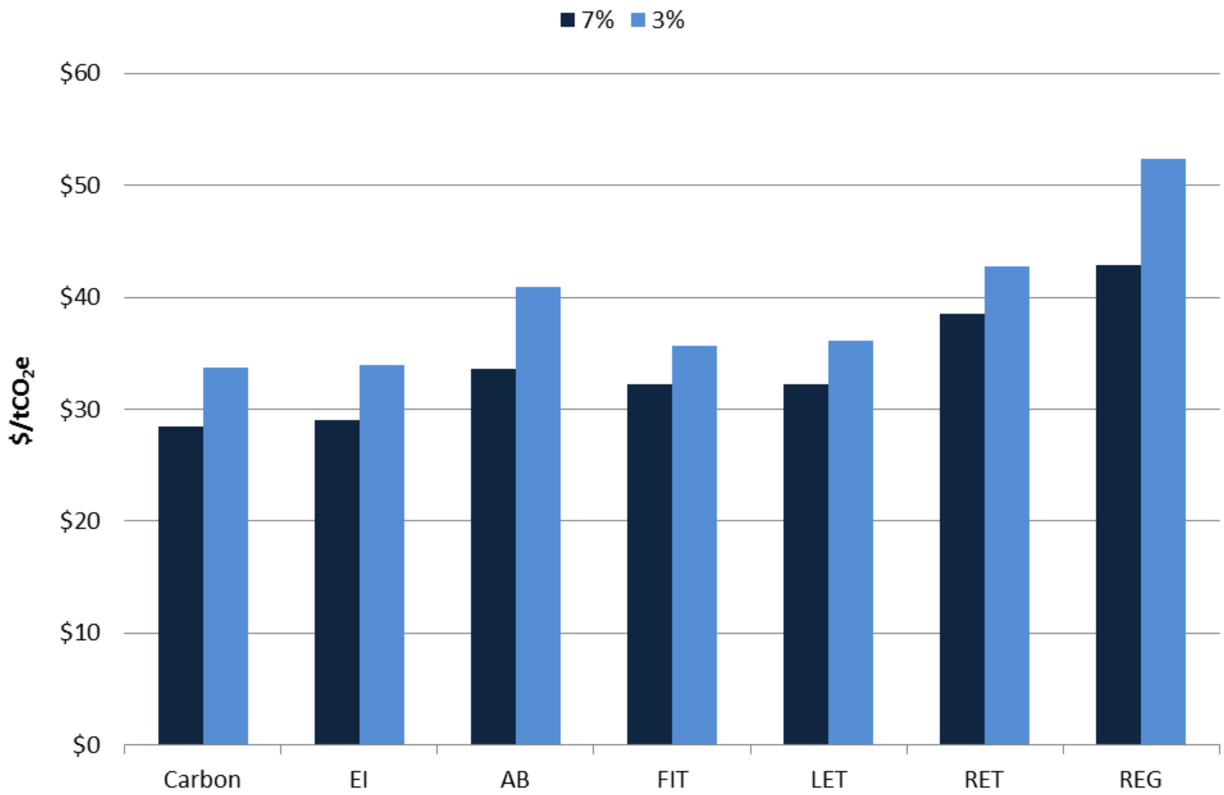
Source: Jacobs. Each bar represents the net present value of the annual change in resource costs relative to the reference case, adjusted for the reduction in demand due to the increase in electricity prices. This is equivalent to the welfare costs of the policy (relative to the reference case) before emissions reduction benefits are considered from 2020 to 2050, discounted by the discount rate shown. For further detail on the method see Appendix B.3. Regulated closure in the 2°C scenario breaches the emissions budget by about 200 Mt.

The cost of abatement is a measure of the cost effectiveness of the differing policy measures. It allows for comparison of the unit cost of a carbon mitigation policy with reference to the goal of reducing emissions. Policies with a lower cost of abatement are more economically efficient. The cost of abatement measures the difference in resource costs and emissions with and without the policy[16].

The cost of abatement for the policy scenarios are shown in Figure 19. Abatement costs tend to be lowest for the market based policies. The highest abatement cost occurs with the RET scheme as this policy requires more expensive abatement options to meet the target. The abatement cost for the regulated closure needs to be interpreted carefully as the abatement target was not met under this policy scenario.

[16] Experts take different views on whether future emissions reductions should be discounted or not. The Authority has directed Jacobs not to discount future emissions reductions. The rationale for this approach is that, unlike money, over the timeframes and volumes of emissions reductions considered, a tonne of emissions reductions in the future is as valuable as a tonne now. Further information on the cost of abatement method is in Appendix B 3.3.

Figure 19: Cost of abatement relative to the reference case, 2°C emissions constraint



Source: Jacobs

3.2 Reference case

3.2.1 Scenario description

The reference case provides a projection of the future and the starting point to compare the performance of the policy scenarios. Emissions were not constrained. However for the purposes of comparison with the policy cases to follow, the 2°C global assumptions were applied (including fossil fuel prices and learning rates affecting technology costs). Otherwise, the scenario represents a continuation of existing policies with no policy change affecting the Australian electricity sector, nor any expected by market participants.

Recent policy considerations included in the reference and other cases were:

- The current Renewable Energy Target (both Large-scale and Small-scale) as legislated in mid-2015.
- State-based policies affecting the sector such as feed-in-tariffs for solar photovoltaic (PV) systems.
- The reference case also incorporates assumptions about the speed and nature of changes in network pricing resulting from recent rule changes encouraging cost-reflective network pricing.

For a full range of the policy and associated assumptions, see Appendix D.

3.2.2 Key findings

Key findings in the reference case include:

- Retail prices and average bills stabilise by around 2035 as the current supply surplus dissipates, and as wholesale prices reach the levels required for new generators.
- Emissions costs are not included in the electricity market and therefore do not influence customer prices.
- Carbon emissions continue to rise as coal generation increases and electricity demand grows, with little further growth in large-scale renewable energy generation beyond that occurring under the LRET scheme.
- A high and stable proportion of coal fired generation due to relatively lower fuel costs and no constraints on plant with high emission intensity.
- Uptake of roof-top solar PV installations continues, eventually reaching saturation[17], with a partial transition to systems with local battery storage that enhance the value of the energy by making it available for later use rather than immediate export at lower value.

3.2.3 Demand

Total energy consumed reaches 383 TWh in 2049/50. The non-coincident peak demand across these regions reaches 69,400 MW. The demand profile for the reference case was discussed in Section 1.3.3.

3.2.4 Generation and capacity

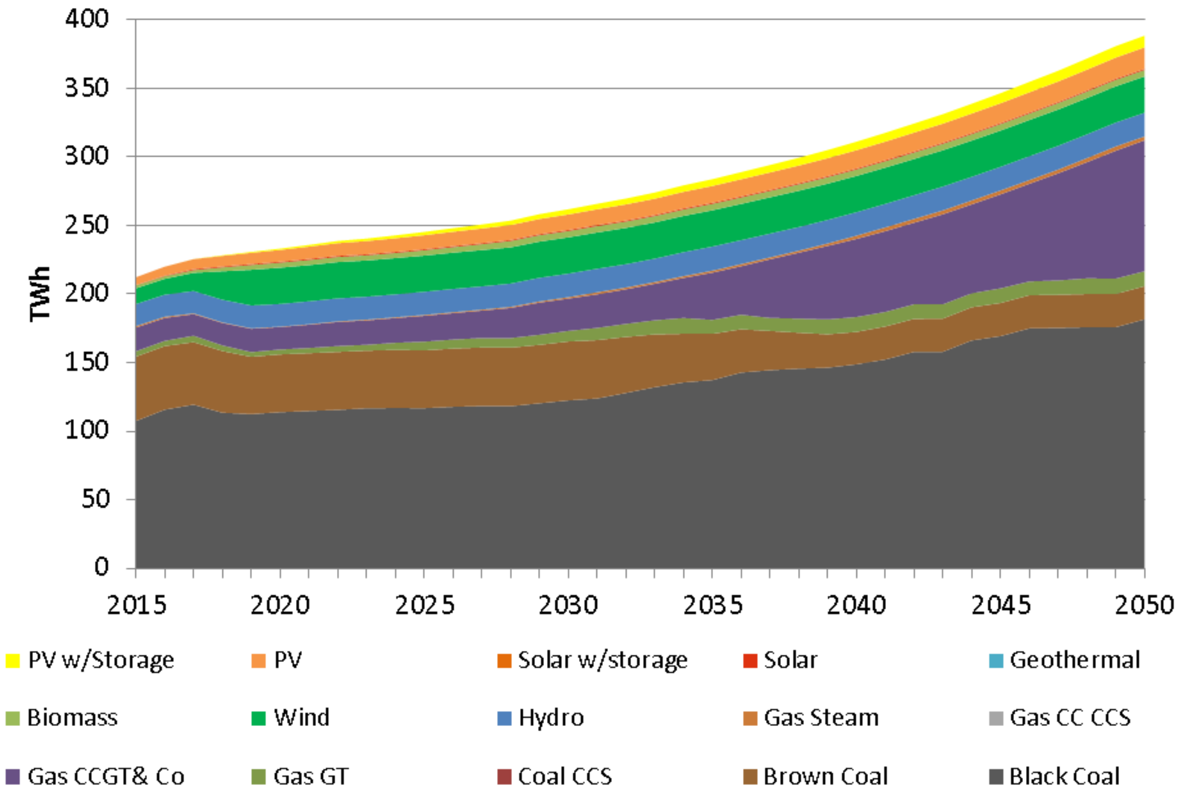
In the reference case, coal continues to maintain its role in power generation. Coal fired generation remains relatively stable until after 2030, after which coal generation increases in line with demand growth and the entry of new coal plant (see Figure 20). Gas fired generation also increases steadily after 2020 mainly due to the growth in demand. Gas fired generation at the gas prices assumed fills in more of the mid-merit role, although in some regions it also undertakes base load duty. Large-scale renewable generation increases to 2020 mainly to meet the LRET target. After 2020, generation from large-scale renewable energy remains flat with no additional entry of new plant. However, renewable generation from small-scale sources is projected to continue to grow over the forecast period to be around 24 TWh by 2050. By 2050, renewable generation comprises around 19% of total generation, with gas comprising 28% and coal 53%.

Figure 21 shows projected entry of new plant and retirement and/or mothballing of capacity. Some brown coal generation closes based on the remaining life of the plant and exhaustion of the associated coal reserves (see Appendix C). Under the assumptions employed in the 2˚C scenarios, black coal is the preferred new coal technology due to lower capital cost than brown coal and the assumption that globally traded black coal prices fall in real terms. Gas fired plant is more economic for the southern regions of the NEM and the WEM.

Under the reference case there are 9 transmission interconnector upgrades totalling 3,450 MW. These were assessed as being economic under the interconnector upgrade approach described in Appendix B.6.

[17] See Appendix C3 for assumptions on saturation.

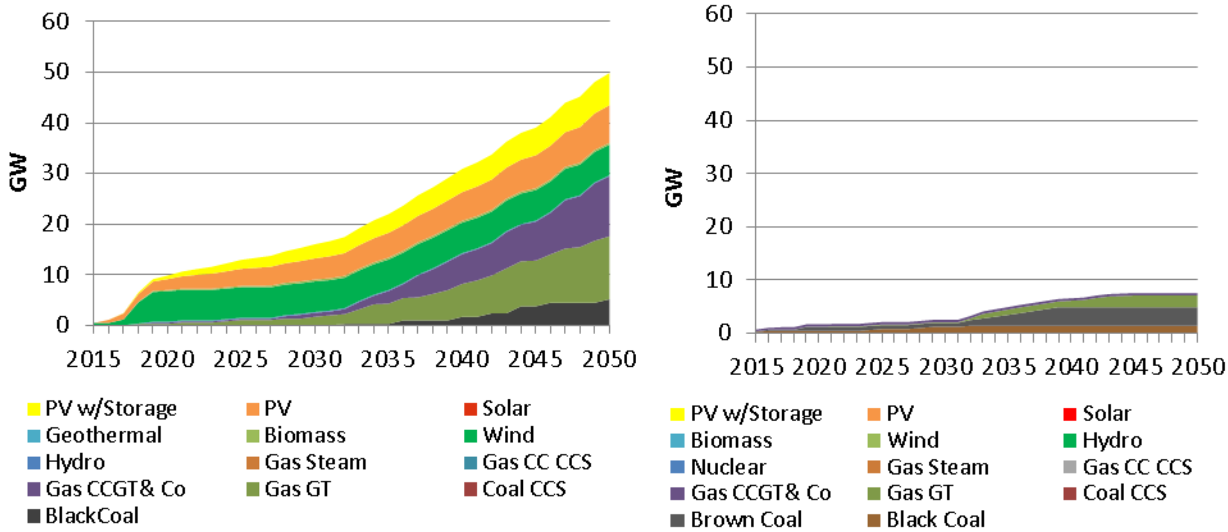
Figure 20: Generation mix, reference case



Source: Jacobs. In this and all subsequent figures, 'Solar' comprises large-scale PV and CST solar plants.

Figure 21: Cumulative new and retired capacity, reference case

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



Source: Jacobs

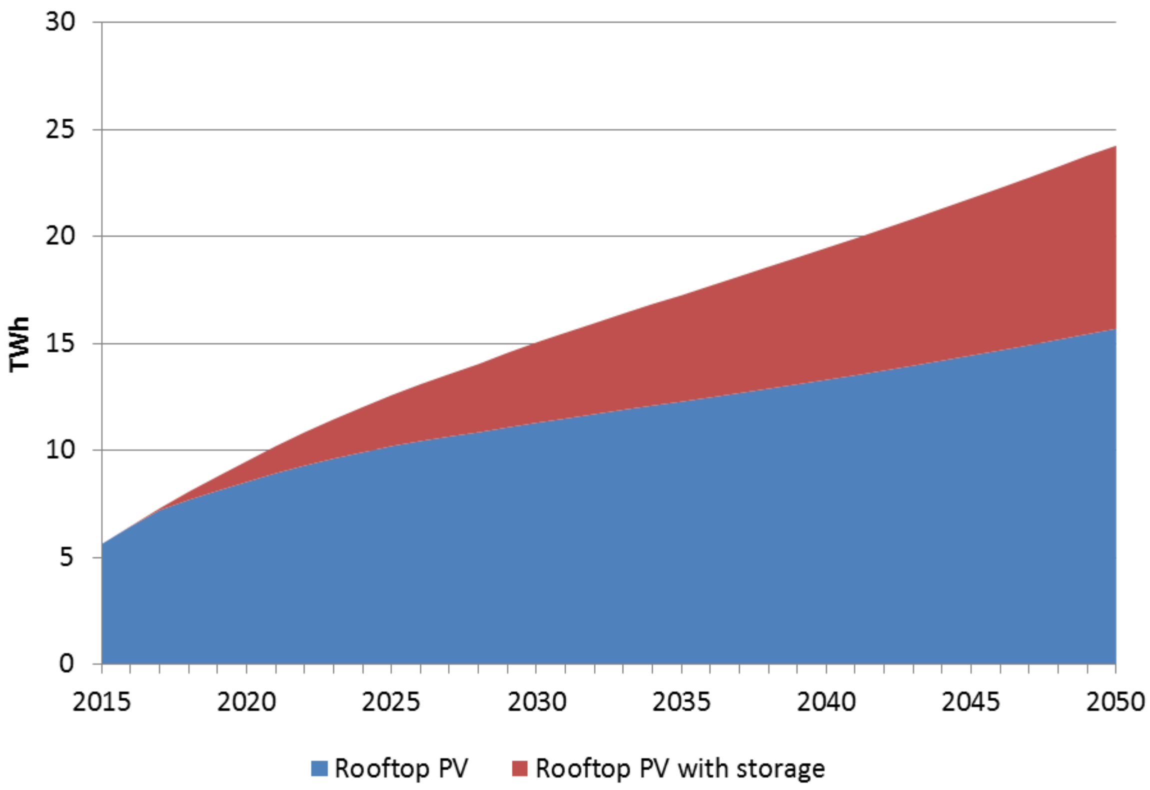
No renewable energy projects are retired under the reference case. The wholesale energy prices rise to levels which would keep existing renewable energy projects operating after 2030 based on their avoidable operation and maintenance costs. As the older wind farms reach their assumed refurbishment age of 25 years, the wholesale prices have returned to a level sufficient to justify refurbishment.

3.2.5 Small scale renewable energy

Small scale renewable generation continues to grow. Growth in uptake follows recent trends until around 2030 to 2035, when assumed saturation levels for the residential and commercial sectors are reached. The small scale sector development slows down in the reference case after 2030 due to the end of direct support for small scale technology and changes to network tariff structures that reduce the financial benefits of generating electricity on site. The figure below shows the energy contribution of roof-top PV by region, including the subsequent development of PV installations with storage. Uptake from storage technology continues growing throughout the modelling horizon. However, uptake of storage technologies is more dominant later in the period.

Small scale generation supplies around 6.5% of total demand by 2050.

Figure 22: Small-scale solar PV generation, reference case



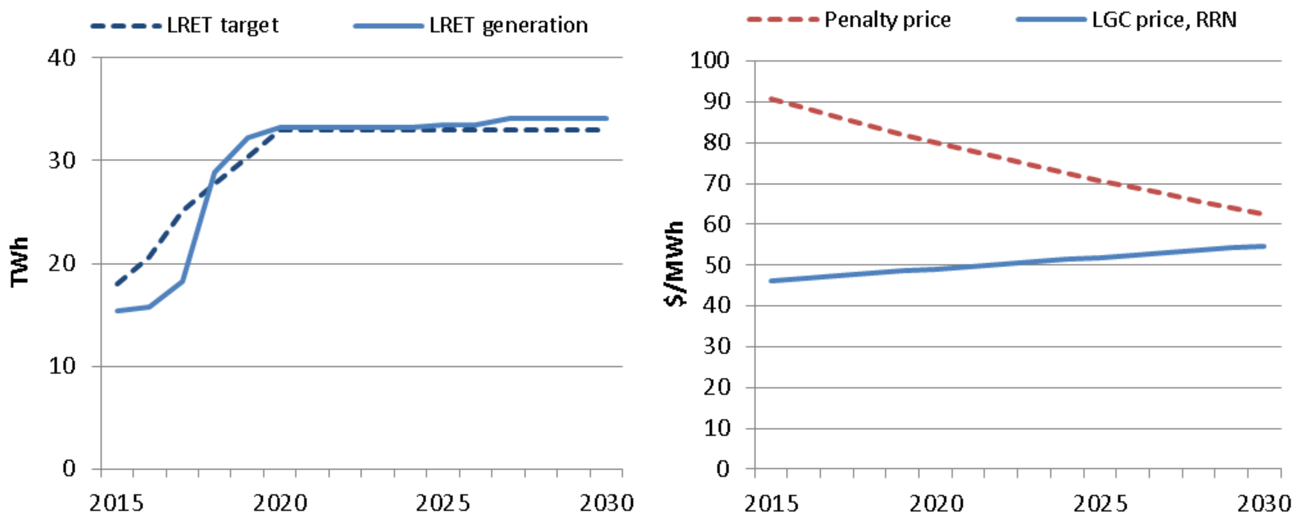
Source: Jacobs

3.2.6 Large-scale Renewable Energy Target

The Large-scale Renewable Energy Target stipulates 33 TWh of energy must be supplied from eligible new renewable generation in 2020. The target is projected to be met under the assumptions used for the reference case, although the accumulated certificates banked from previous years are used to meet the target in the period to 2019. Some of the new renewable generation is also used to meet projected obligations under the Green Power Schemes.

The certificate price is projected to rise over the period to 2030 reaching around $54/MWh in 2030. The price never breaches the penalty price.

Figure 23: LRET target, eligible renewable generation and projected LGC price, reference case



Source: Jacobs

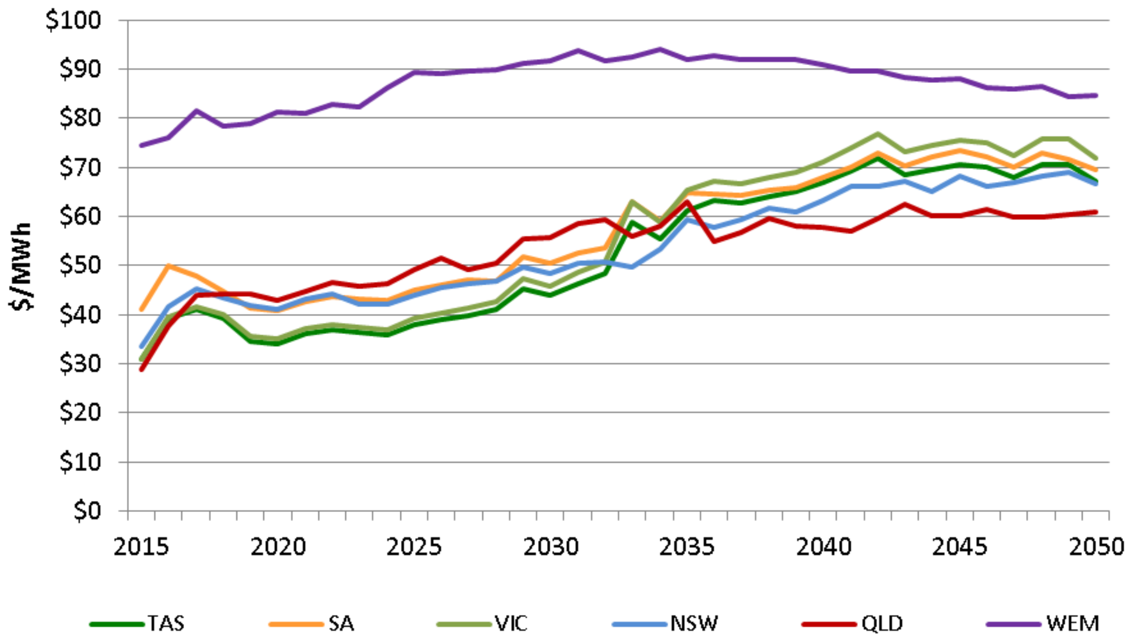
3.2.7 Prices

The wholesale prices for the reference case are shown in Figure 24. In the NEM, the current oversupply of generation capacity reduces slowly to around 2035 and accordingly prices gradually increase to new entry levels to around 2035. Prices in the WEM are higher due to the impact of the higher marginal costs for gas and coal fired generation and the inclusion of capacity market payments in wholesale prices.

The retail price trends are shown in Figure 25 for the regions and for three types of customers: residential, small and medium enterprises and large industrial with fixed and capacity network charges amortised into the energy rate. The price trends follow the wholesale price trend.

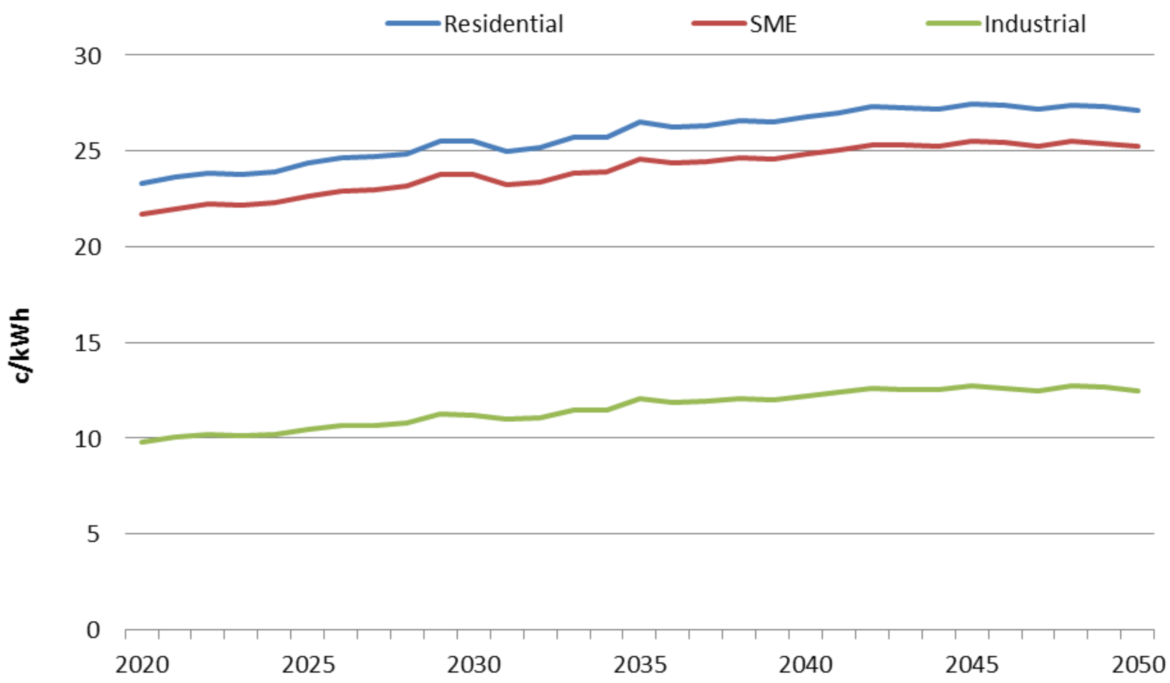
The average residential bill is shown for each region in Figure 26. Bills are projected to slowly increase in real price terms over the period to 2035 and stabilise thereafter. In Western Australia, the stabilisation occurs earlier from 2030.

Figure 24: Wholesale electricity time-weighted prices, reference case



Source: Jacobs

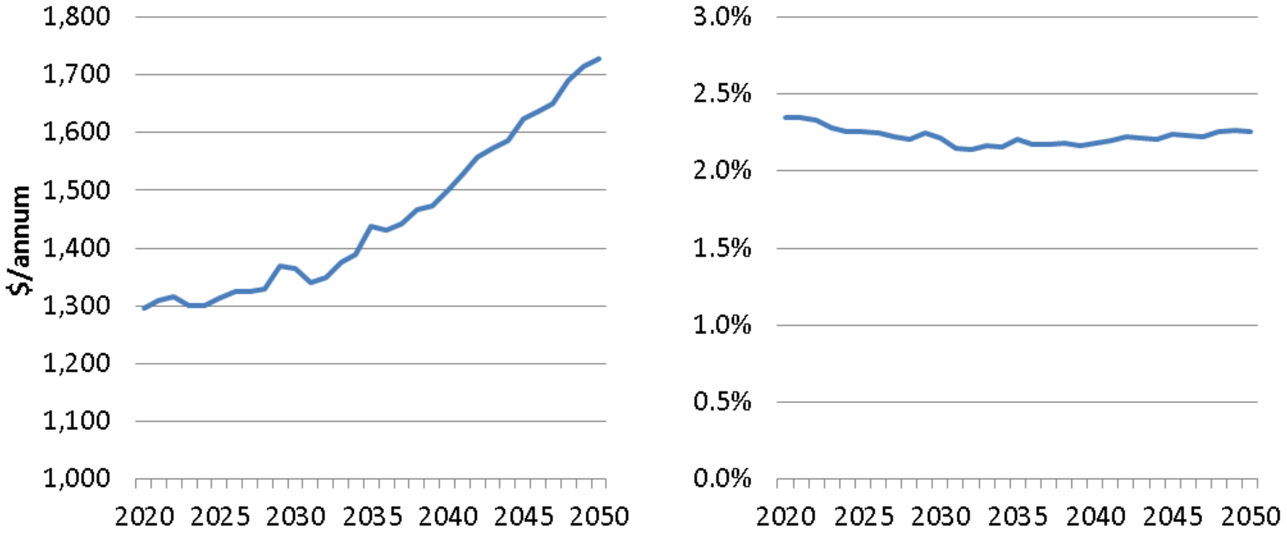
Figure 25: Average retail prices by customer class, reference case



Source: Jacobs. Residential prices include GST; others do not.

Figure 26: Average residential bill cost, reference case

The left graph shows the absolute residential bill. The right graph shows the residential bill as a % of disposable income.



Source: Jacobs based on household disposable income projection from Climate Change Authority based on Australian Bureau of Statistics (ABS) and the Productivity Commission. See Appendix B for further details.

3.2.8 Emissions

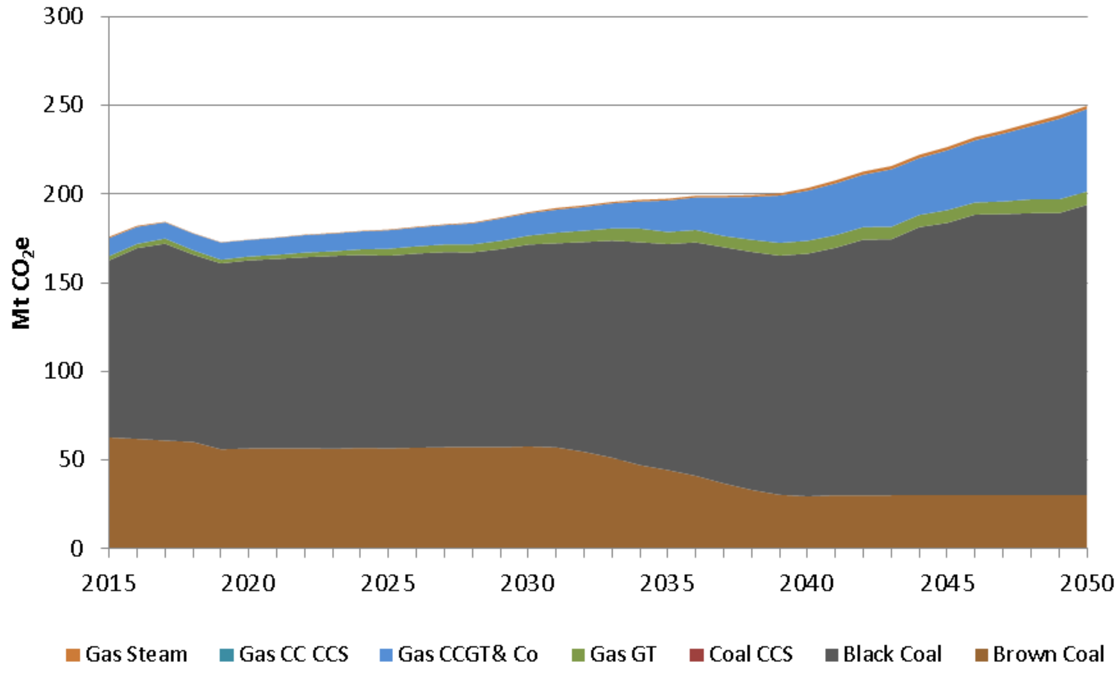
The emissions by technology type are shown in Figure 27. These include both direct emissions, due to on-site fuel combustion, and also indirect upstream emissions generated by fuel transport, including fugitive mine and pipeline emissions. After declining with increased penetration of renewable energy, emissions grow steadily from 2019 onwards. Emissions grow more strongly after 2035 as new black coal plant enter the market. The dominant emissions are in Queensland, New South Wales and Victoria. South Australia's emissions are much lower due to a much higher proportion of gas fired and renewable generation. Similarly, Tasmania has negligible emissions from power generation.

Coal fired power contributes the bulk of the emissions. The reduction in emissions from the closure of brown coal power generation is offset by increased emissions from new black coal fired generation. Gas fired generation also makes an increasing contribution to the aggregate emissions. During the period to 2020, the growth in renewable energy generation reduces emissions. After 2020, the growth in carbon emissions resumes but is moderated by the additional growth in small scale renewable energy generation.

Over the period from 2019/20 to 2049/50, the aggregate carbon emissions are 6,253 Mt CO_2e in the NEM and WEM.

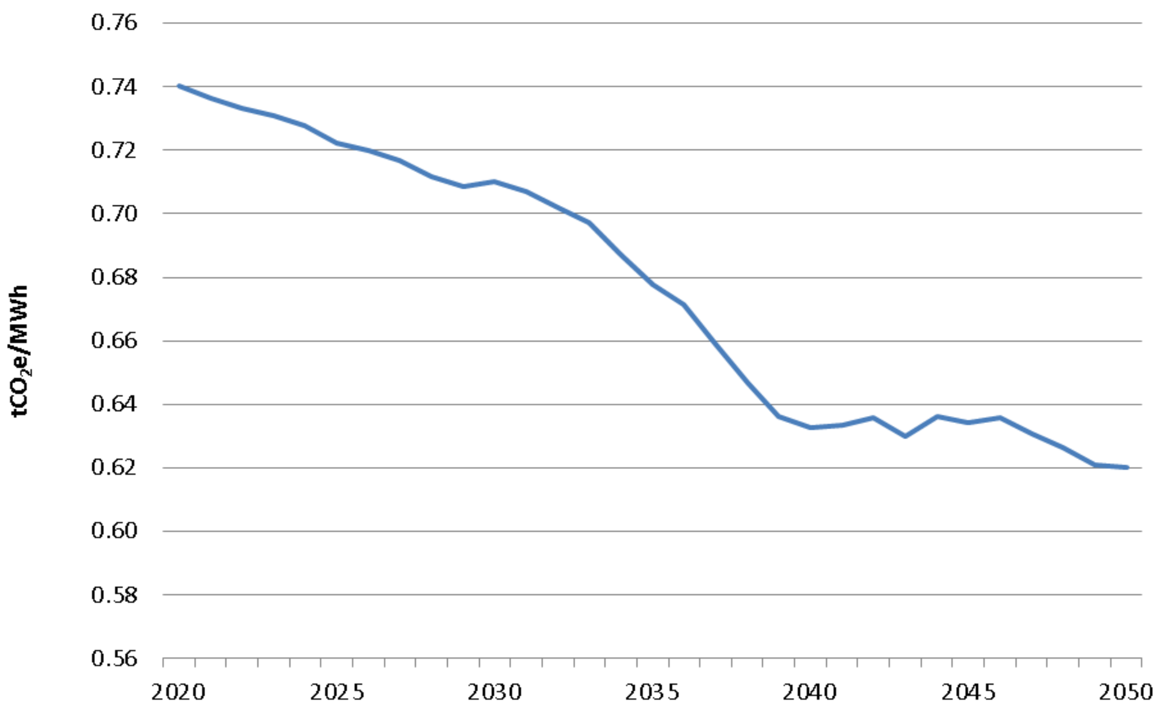
The generation emission intensity is shown in Figure 28. The average emission intensity generally declines throughout the period except for New South Wales after 2035 when new black coal fired generation is added and used to export to other regions. Tasmania's emission intensity increases from a very low base due to additional operation of gas fired generation to meet increased demand and to respond to increased price of import from the Victorian region.

Figure 27: Annual carbon emissions by fuel type, reference case



Source: Jacobs. Includes both direct and indirect emissions.

Figure 28: Generation emission intensity, reference case

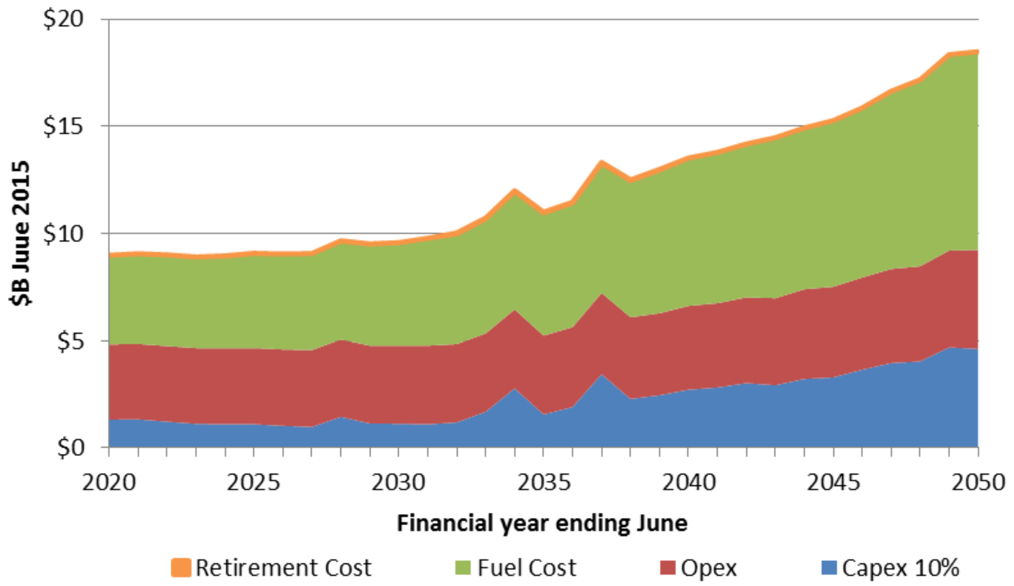


Source: Jacobs. Includes direct emissions only.

3.2.9 Costs

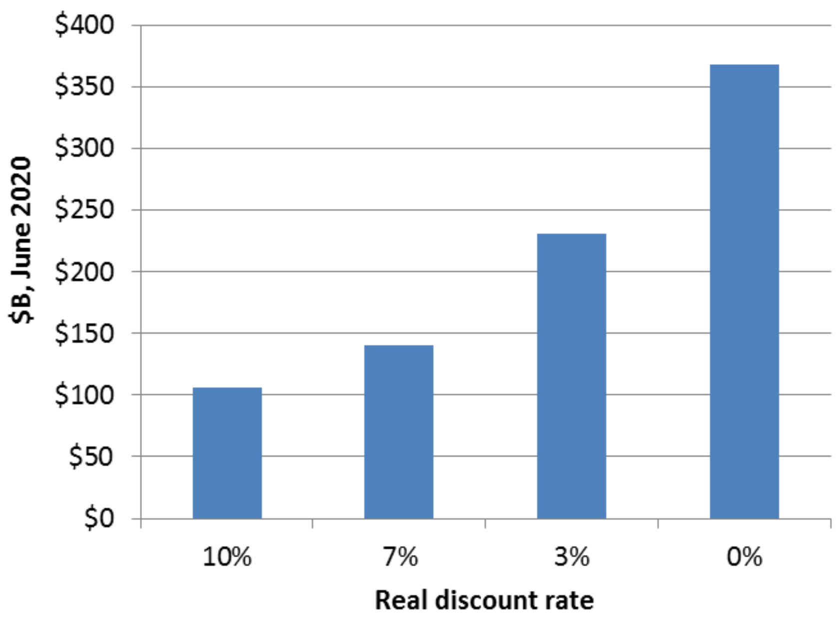
The figure below shows the annual costs for the reference case including operational, capital, fuel and retirement costs. The costs include those for both thermal and renewable energy resources including the fixed costs of incumbents. New capital expenditure is modest compared to operating expenditure due to the low demand growth. The present value of these costs in June 2020 at various discount rates from 4% to 10% is shown in Figure 30.

Figure 29: Annual costs, reference case



Source: Jacobs

Figure 30: Present value of generation costs in June 2020, reference case



Source: Jacobs

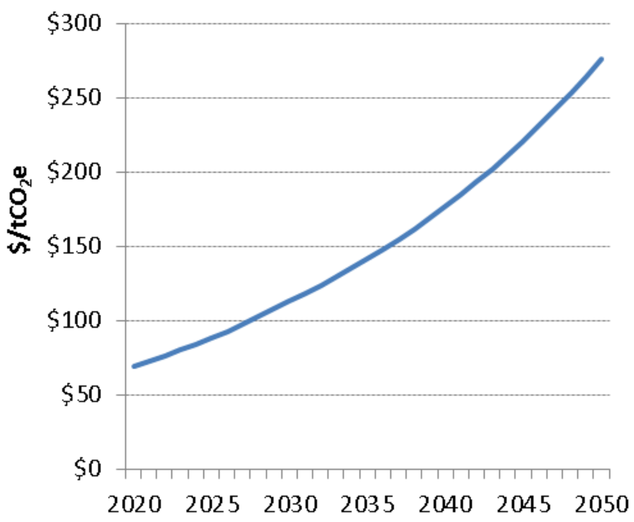
3.3 Carbon pricing

3.3.1 Scenario description

Under carbon pricing, all generators with emissions exceeding a given threshold are liable for surrendering permits to cover all of their emissions each year. The carbon price has been implemented as a carbon tax, that is, with no banking or borrowing of emissions permits. Its impacts are very similar to a cap and trade emissions trading scheme.

As discussed in Section 1.3.2, the carbon price path determines the emissions budget for the other scenarios. The carbon price is calculated from median estimates consistent with a likely (67%) chance of limiting warming to 2°C from the Intergovernmental Panel on Climate Change's Fifth Assessment Report, and is illustrated in the figure below. It commences at \$69/t CO_2-e in 2020 and escalates at an average rate of 4.7% per annum in real terms, reaching \$277/t CO_2-e in 2050.

Figure 31: 2°C carbon price path



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

3.3.2 Key findings

The relatively high starting value of the carbon price has two immediate impacts: it forces the rapid closure of the Victorian brown coal fleet (all brown coal generators are closed by the end of 2019/20), and it also causes the wholesale price to reach the new entry price for thermal generation, namely CCGT technology, in both the NEM and the WEM. The Victorian brown coal fleet is affected by a carbon price earlier than other generators because it has the highest emission intensity of all generation technologies used in Australia and therefore faces the highest carbon impost. However, 23% of Australia's black coal generation capacity also closes in anticipation of the carbon price and over half is closed by 2025/26. All coal fired generation in Australia ceases by 2036/37 under the assumed carbon price.

Wholesale prices are high enough in 2019/2020 to encourage the immediate entry of large volumes of renewable generation capacity, mainly in the form of wind generation, but new gas fired generation also proves to be an important part of the energy mix and serves as a key transitional technology until low emission dispatchable technologies become available from 2030.

After 2030 the key dispatchable technologies entering the market are CCGTs with CCS and geothermal. Nuclear is available from 2034/35, but its market entry only becomes economic in 2039/40 owing to the rapid learning rate assumed for CCGT with CCS in a world with a 2°C global emissions target. Large-scale solar technology does not materially emerge until after 2040 because until then it is directly competing with small-scale rooftop PVs, which already have a strong foothold in the market and have suppressed the load-weighted wholesale price received by large-scale solar technology.

Cumulative emissions under the carbon pricing scenario from 2020 to 2050 are 1,581 Mt CO_2-e. This represents only 9 years of the 2019/20 emissions observed in the reference case. The results also show that the carbon price drives rapid reductions in emissions. By 2023/24 emissions under carbon pricing are half that of the 2019/20 emissions of the reference case.

Carbon pricing is the only policy scenario to raise revenue. On average, it raises about $6.5 billion in revenue per annum.

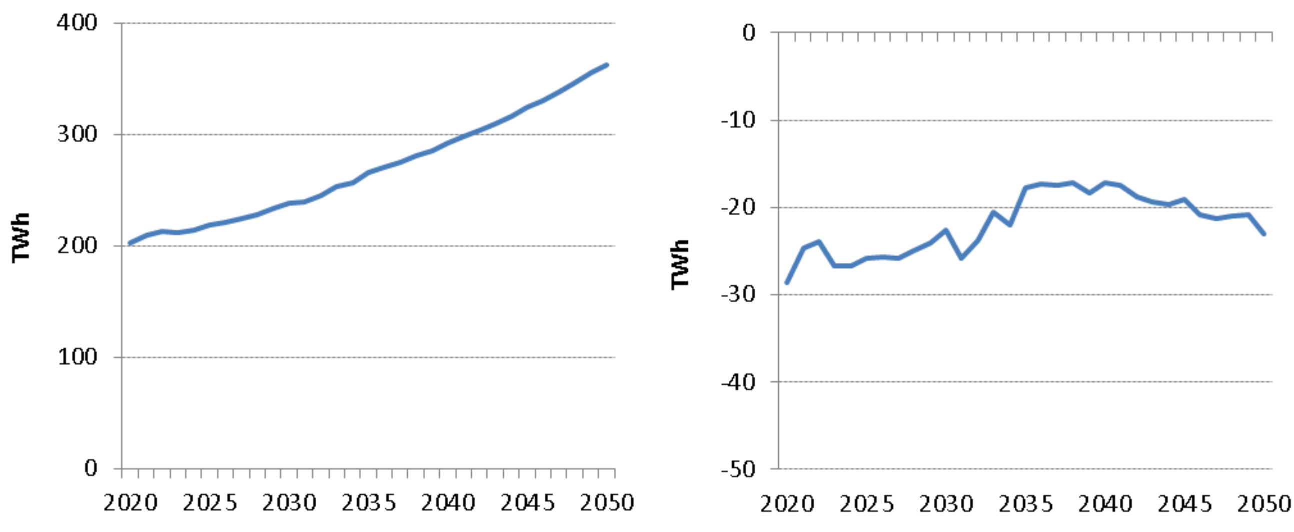
A key finding of the study is that rising carbon price does not drive ever-rising electricity prices for end users. While the carbon price is relatively high and grows at an average rate of 5% per annum over the period to 2050, consumer prices are roughly flat in real terms from around 2030 onwards. This is because, as the price path encourages investment in low- and zero-emissions technologies, the proportion of generation affected by the carbon price is small.

3.3.3 Demand

The figure below shows sent-out energy demand for the carbon pricing scenario and relative to the reference case. Total energy consumed reaches 362 TWh in 2049/50, 21 TWh lower than the reference case due to higher wholesale prices flowing through to higher retail prices and thereby reducing demand relative to the reference case.

Figure 32: Sent-out energy, carbon pricing

The left graph shows sent out energy. The right graph shows the difference from the reference case.



Source: Pitt & Sherry, ACIL Allen and Jacobs

3.3.4 Generation and capacity

Figure 33 shows the generation mix across the modelling horizon both in absolute terms and relative to the reference case. Key features are the steadily diminishing role played by coal fired generation and the transitional role played by CCGTs from 2020 to 2030, where they act as a partial substitute for retiring coal fired capacity. Their role diminishes after 2030 as they are displaced by newly available low emission technology, such as CCGTs with CCS and also geothermal. Wind is also a key technology, providing almost one quarter of all grid generation in 2029/30. Its growth is limited to the 2020s because cheaper low emission technologies become available after 2030. The four technologies with largest growth after 2030 are CCGTs with CCS, followed by geothermal, large-scale solar and nuclear.

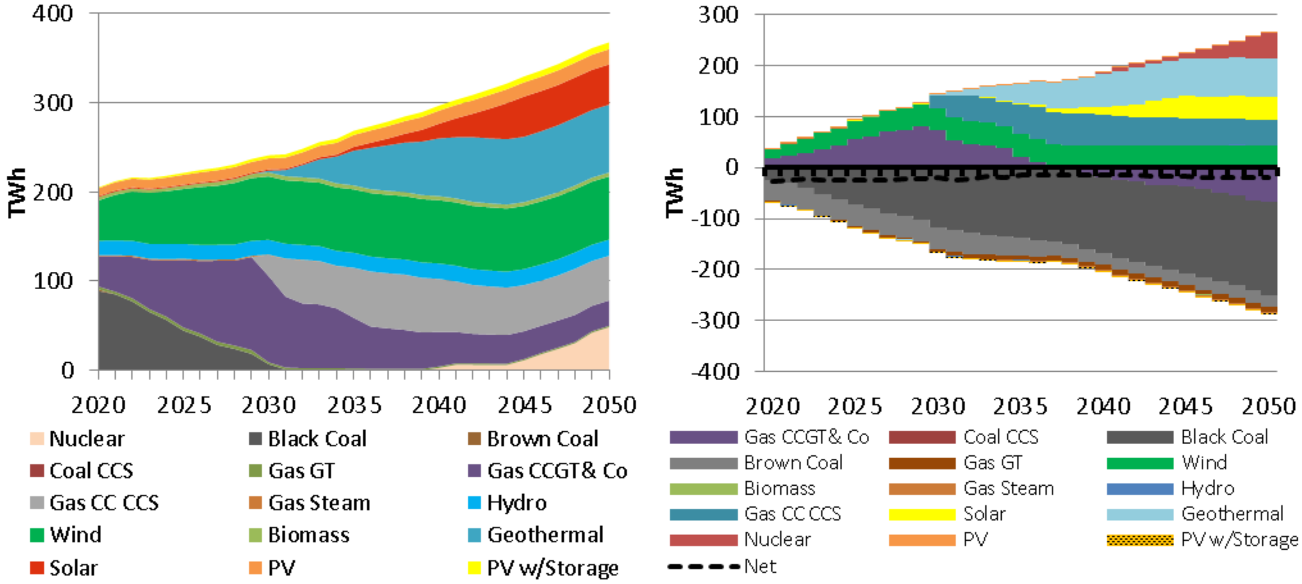
Relative to the reference case there is much less coal generation, and initially there is more CCGT generation although this diminishes by 2040, when CCGTs do not play as significant a role in the carbon pricing scenario. Low emission technologies also feature more prominently in the carbon pricing scenario, and some of these technologies are not present at all in the reference case, such as CCGTs with CCS, geothermal and nuclear.

Figure 34 shows cumulative new generation capacity across the NEM and WEM. Trends in capacity are similar to the trends in generation mentioned above. However, in capacity terms rooftop PV both with and without storage make notable contributions, and gas turbines capacity is also progressively growing throughout the modelling horizon. Gas turbines play an important role in the market as they are a cheap source of backup capacity for intermittent generation, namely wind and solar plant without storage.

Under the carbon pricing scenario there are five transmission interconnector upgrades totalling 2,120 MW. This is around 1,300 MW less than what is required for the reference case. This appears to be due to diverse spread of renewable energy options across the regions.

Figure 33: Generation mix, carbon pricing

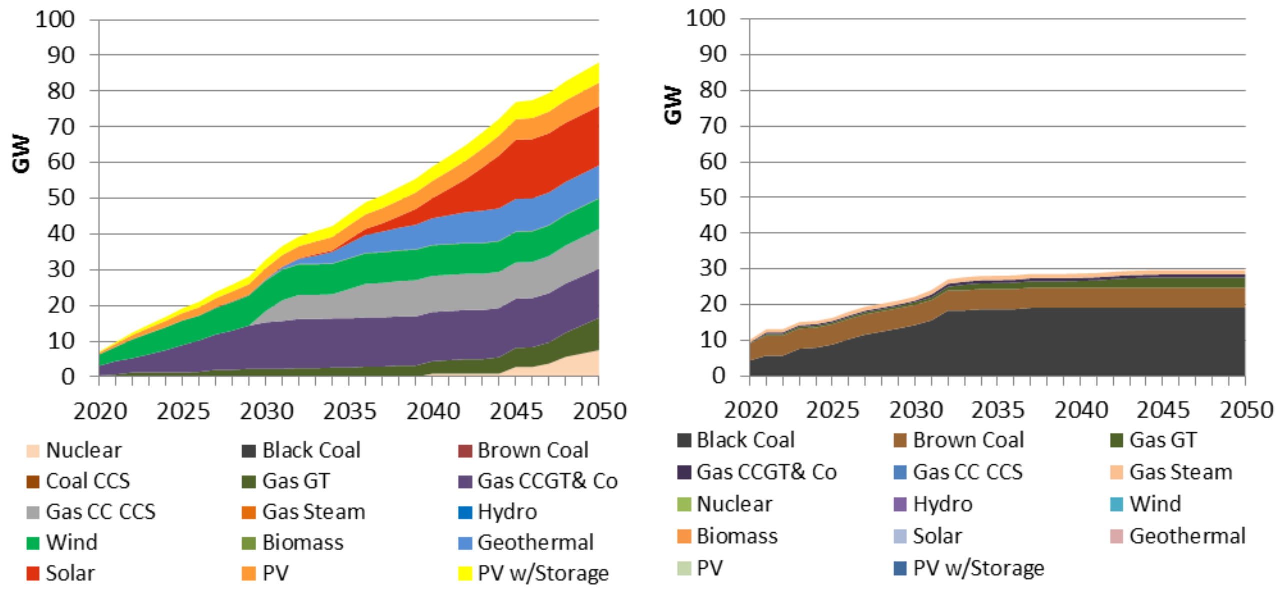
The left graph shows absolute figures for generation. The right graph shows figures relative to the reference case.



Source: Jacobs

Figure 34: Cumulative new and retired capacity, carbon pricing

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



Source: Jacobs

3.3.5 Prices

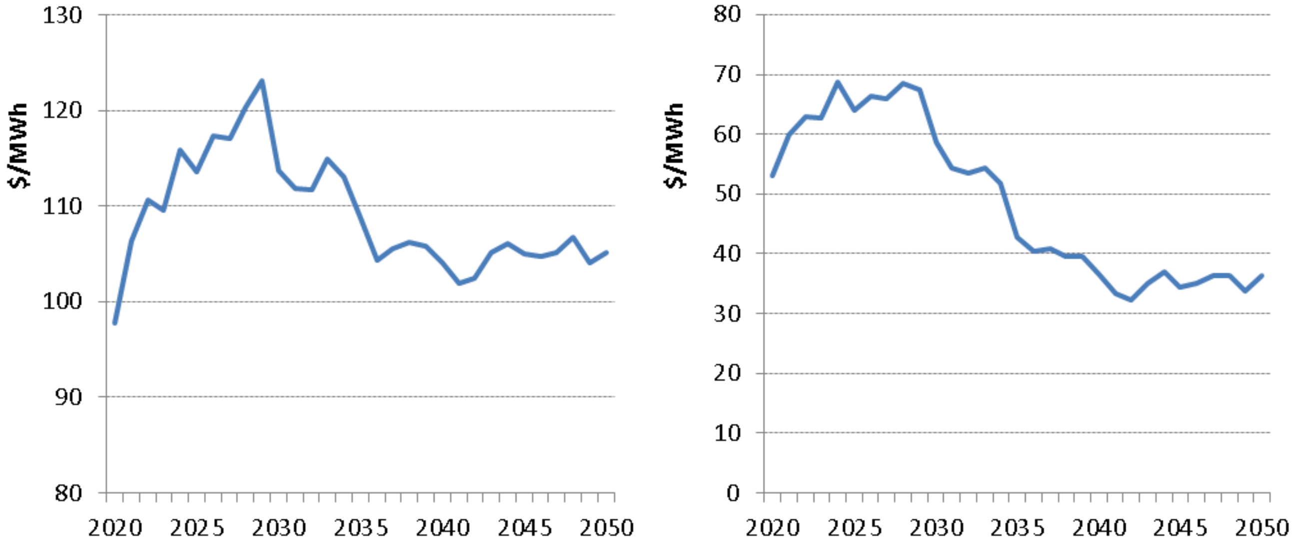
Figure 35 shows wholesale electricity prices on a time-weighted basis. Prices start in 2019/20 from a high level compared to current wholesale prices, trend upward until 2029/30 and then converge to a price that represents the long-run marginal cost (LRMC) of the most economic new entrant technology. The price in the 2020s is set by new CCGTs, and the initial upward price trend is driven by the rapidly escalating carbon price. Prices in the latter half of the 2020s tend to rise above the long run marginal cost (LRMC) of new CCGTs since new entrant CCGTs only have a short window to recover all of their costs as they are displaced by newly available low emission technologies after 2030, which face a much lower carbon impost. From 2029/30 onwards prices are set by low emission CCGTs with CCS, and in some cases from 2039/40, nuclear generation technology. New entrant prices after 2030 are relatively insensitive to the carbon price due to the low emission factors of the technologies setting the price, but in the case of CCGTs with CCS their rapid reduction in capital costs tends to offset the effect of the increasing carbon price.

Carbon price pass through starts at about 80% in 2019/20 and declines to 13% in 2049/50. The reason for the relatively low level of pass through in the early years is that prices are effectively constrained by the CCGT new entry price, which has lower emission intensity than coal fired generation. The observed pass through in 2019/20 is therefore a weighted average of coal fired and efficient gas fired emission intensities. The pass through rates in later years reflects the low emission intensities (including indirect emissions) of the marginal new entrant technologies, namely, nuclear and CCGT with CCS.

In addition, effective decarbonisation is largely achieved prior to the carbon price reaching \$142/t CO_2-e, so the wholesale price becomes relatively insensitive to further increases. This is supported by the assumptions that the technology cost learning rates for low carbon technologies such as geothermal, gas CCS and nuclear make them only slightly more expensive than conventional coal fired technologies in the later years.

Figure 35: Wholesale electricity time-weighted prices, carbon pricing

The left graph shows absolute figures. The right graph shows figures relative to the reference case.

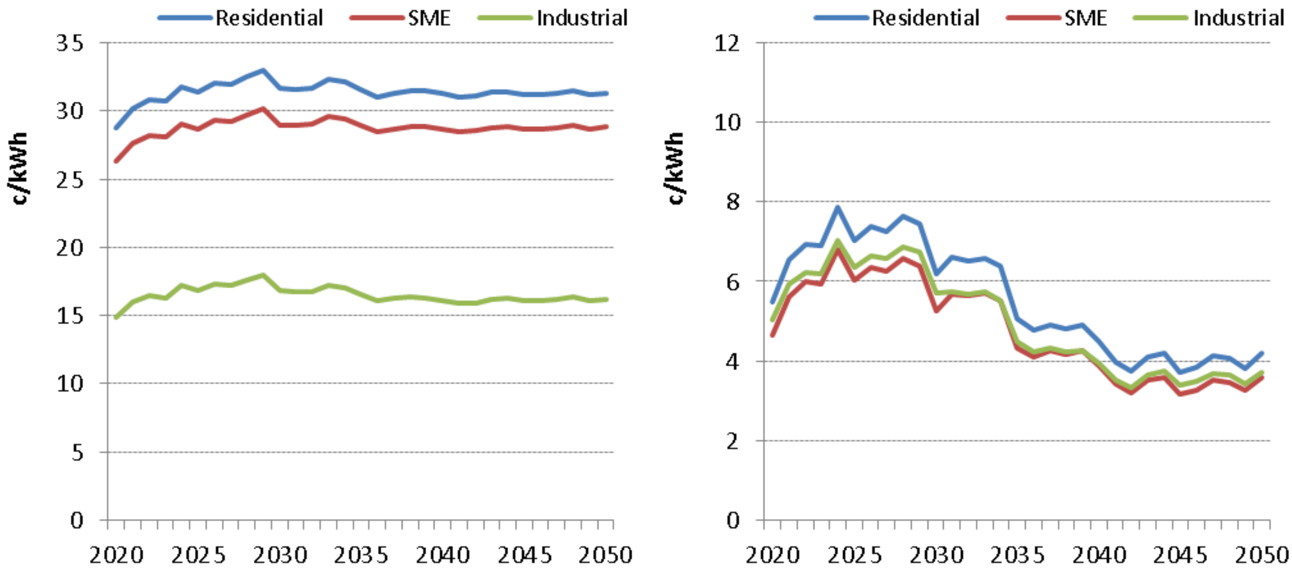


Source: Jacobs

Figure 36 shows weighted average retail prices by customer class. They show the same trends as the wholesale prices, but the relative price movements are more muted since the wholesale price only comprises typically 30% to 40% of the retail price. Figure 37 shows the Australian weighted average residential bill relative to the reference case, as well as the bill as a percentage of average expected disposable income.

Figure 36: Retail prices by customer class, carbon pricing

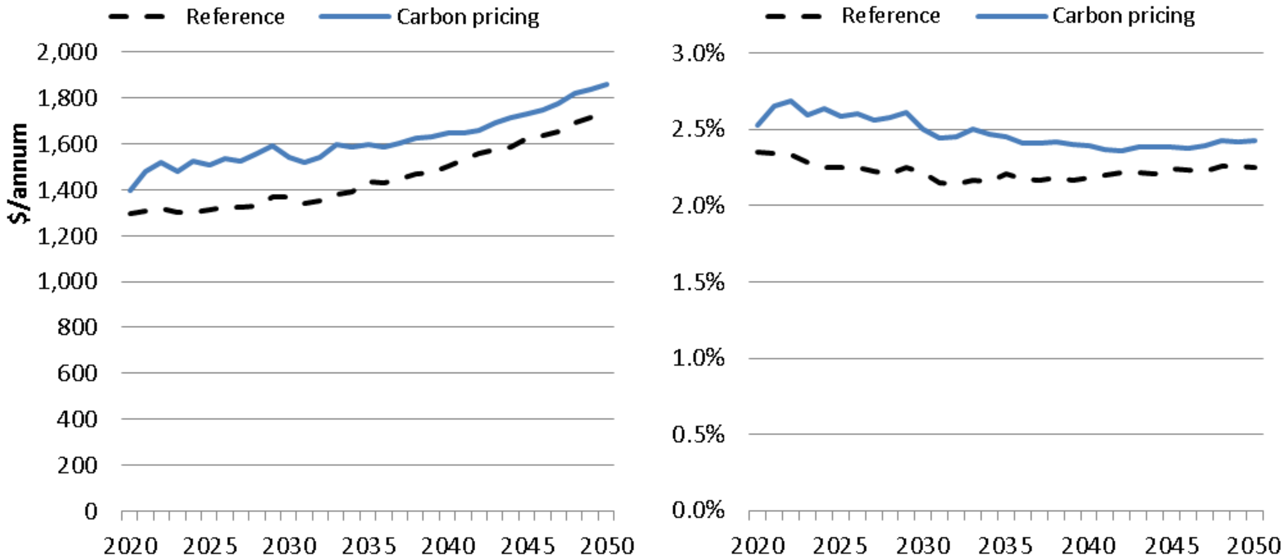
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs. Residential prices include GST; others do not. The chart on the right hand side shows the change from the reference case retail tariff for each customer class.

Figure 37: Residential bills, carbon pricing relative to the reference case

The left graph shows the absolute residential bills. The right graph shows the residential bill as a % of disposable income.



Source: Jacobs

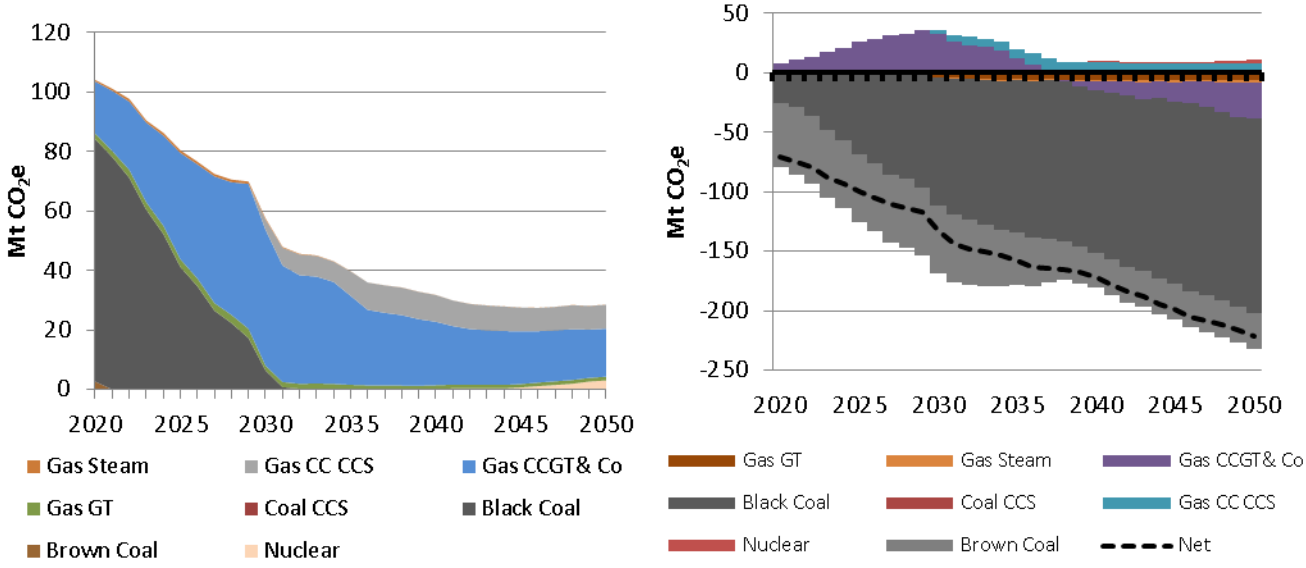
3.3.6 Emissions

Figure 38 shows annual emissions by technology and includes both direct and indirect emissions resulting from electricity generation. Cumulative emissions, both direct and indirect, amount to 1,581 Mt CO_2e across the modelling horizon. In 2019/20 total emissions are 104 Mt CO_2e, which represents just 60% of the 2019/20 reference case emissions. The largest contributor to emissions reductions in the 2020s comes from the rapid closure of brown coal generation. The continuing drop in emissions to 2030 comes from the shutdown of the remaining black coal generation fleet. The large drop in emissions in 2029/30 occurs with the introduction of CCGT with CCS technology. Its introduction displaces CCGT generation, which is the chief source of emissions from the electricity sector at that point in time. Emissions eventually settle at 30 Mt CO_2-e per annum after 2040, and over 25% of these emissions are indirect, meaning that they originate upstream in the fuel supply chain rather than from the fuel combustion process.

Figure 39 shows the generation emission intensity both in absolute terms and relative to the reference case.

Figure 38: Emissions by technology, carbon pricing

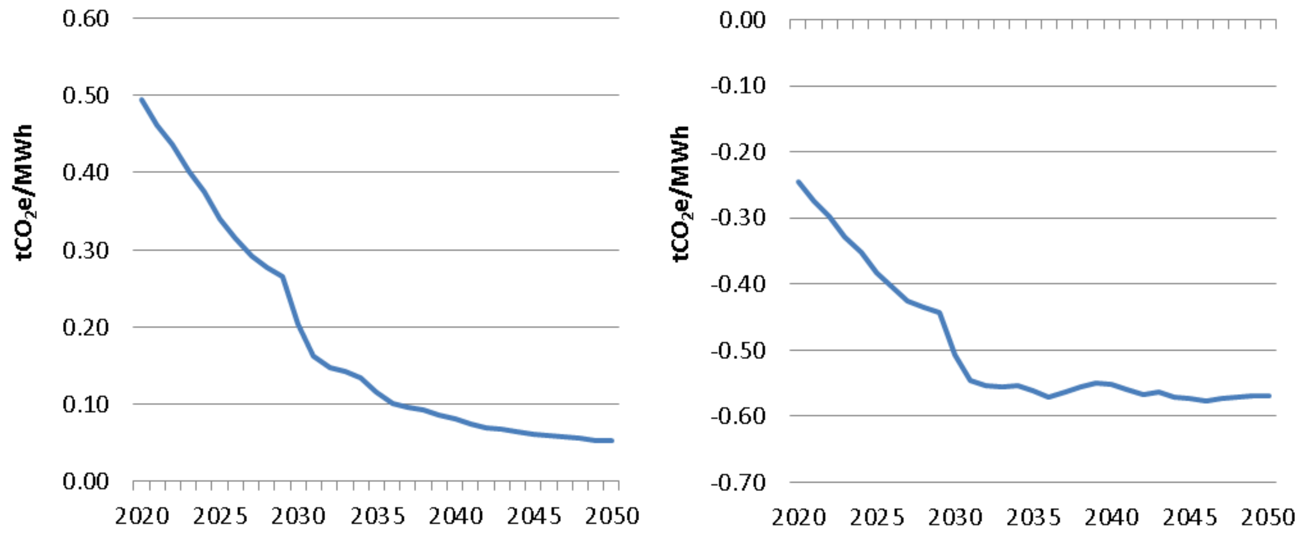
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs. Includes both direct and indirect emissions. The chart on the right hand side represents the change in emissions relative to the reference case. A negative number means reduced emissions from that technology relative to reference case. A positive number means a higher level of emissions from that technology under carbon pricing relative to the reference case. The black dash line is the net change in emissions relative to the reference case.

Figure 39: Generation emission intensity, carbon pricing

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs. Includes direct emissions only.

3.3.7 Costs

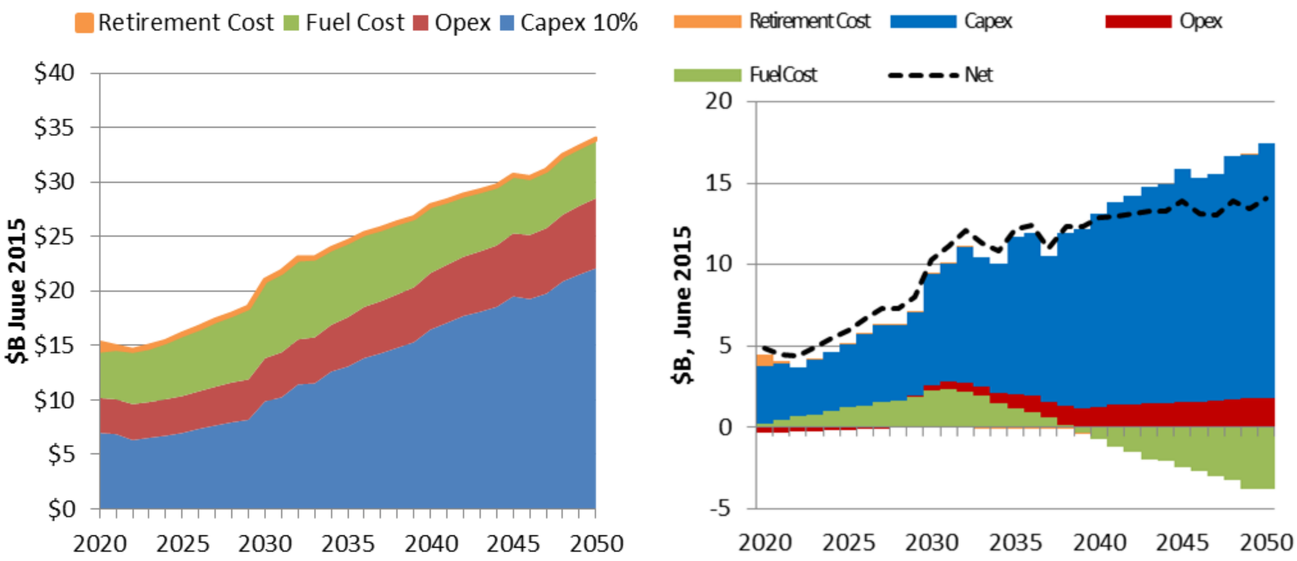
Figure 40 shows annualised resource costs by four cost categories. Costs in 2019/20 are initially about $16 billion per annum and remain at a similar level until 2022/23. Total costs escalate in a pattern that is approximately linear thereafter. Capital expenditure is the largest contributor to cost, comprising 42% of the total cost on average in the first ten years, and then escalating to 64% of the total resource cost by 2049/50. There is growth in all of the cost categories, with the exception of retirement costs, across the modelling horizon, but the growth in capital expenditure is the dominant driver of resource cost growth. This is essential in any large scale decarbonisation scenario as the incumbent generation fleet, which has high average emission intensities, must ultimately be replaced by new zero, or low emission generation technology.

Gross profit is a concept related to costs, and for a generator is the difference between total revenue, which consists of pool revenue, contract revenue and certificate revenue (where applicable), less all operating costs, including fuel costs, fixed and variable operating costs and emissions costs. Gross profit is lower for black coal generating plant due to the reduced level of generation and the added cost of carbon pricing[18]. Brown coal plant averages almost no gross profit under the carbon scenario due to the early closure of the fleet of brown coal generators.

Figure 41 shows the net present value of the resource costs for carbon pricing relative to the reference case for four separate discount rates. The total resource cost for carbon pricing ranges from 97% (at 10% real discount rate) to 37% (without discounting) higher than that of the reference case.

Figure 40: Annualised costs by category, carbon pricing

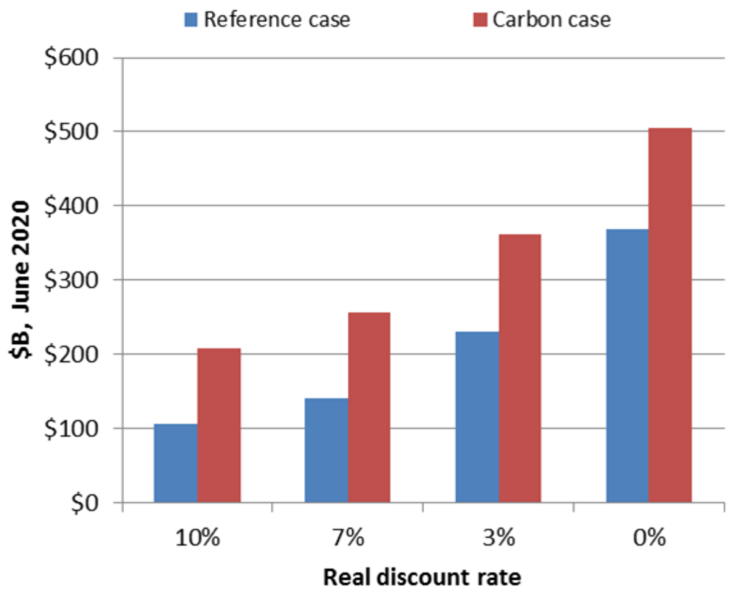
The left graph shows the absolute costs. The right graph shows the costs relative to the reference case.



Source: Jacobs

[18] Note that no black coal fired plant remains operating after 2036.

Figure 41: NPV of resource costs, carbon pricing



Source: Jacobs. Excludes demand adjustment. See Appendix B.3.2 for further detail.

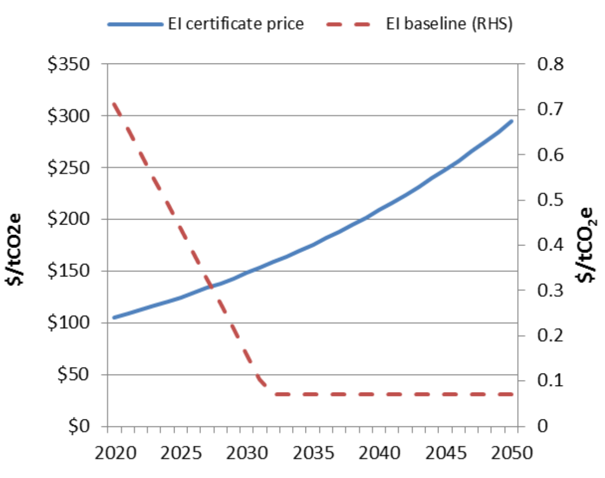
3.4 Emission intensity target

3.4.1 Scenario description and policy parameters

Under the emission intensity target (EIT) scheme generators are issued permits at 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.

Figure 42 shows the final parameters of the emission intensity scheme that met the cumulative emissions constraint. The permit price is higher than the carbon price path. The emission intensity baseline commences from the emission intensity of the reference case in 2019/20, declines linearly and levels out in 2032.

Figure 42: Emission intensity permit price and baseline



Source: Jacobs

For further discussion of the policy see Chapter 2.

3.4.2 Key findings

The EIT scheme impacts are very similar to the carbon pricing scenario, but with slightly higher resource costs and lower wholesale and retail price impacts.

In theory, the supply-side incentives and penalties associated with this scheme for a given permit price are equivalent to those of carbon pricing, regardless of the emission intensity baseline that is set. Revenue for high cost but low emission generators is supported by the value of the volume of permits that they can earn[19].

There were differences between the EIT scenario and the carbon pricing scenario in terms of permit prices required to achieve the cumulative emissions constraint and the costs in doing so. This can be explained by two key points:

- The primary point of difference is that the scheme's constraint allowing only limited future borrowing was binding when adopting the carbon pricing scenario's permit price path. This makes the carbon pricing scenario's emissions trajectory infeasible under the EIT scheme as the borrowing limit would have been breached in some years. Higher prices were required in the early years to allow enough banking to occur so that the borrowing that is inevitably required in the later years draws on the permit bank, and not (more than was allowed) from future permits. This is illustrated in Figure 43, which shows that under the final EIT solution certificates are borrowed from 2027 until 2043.

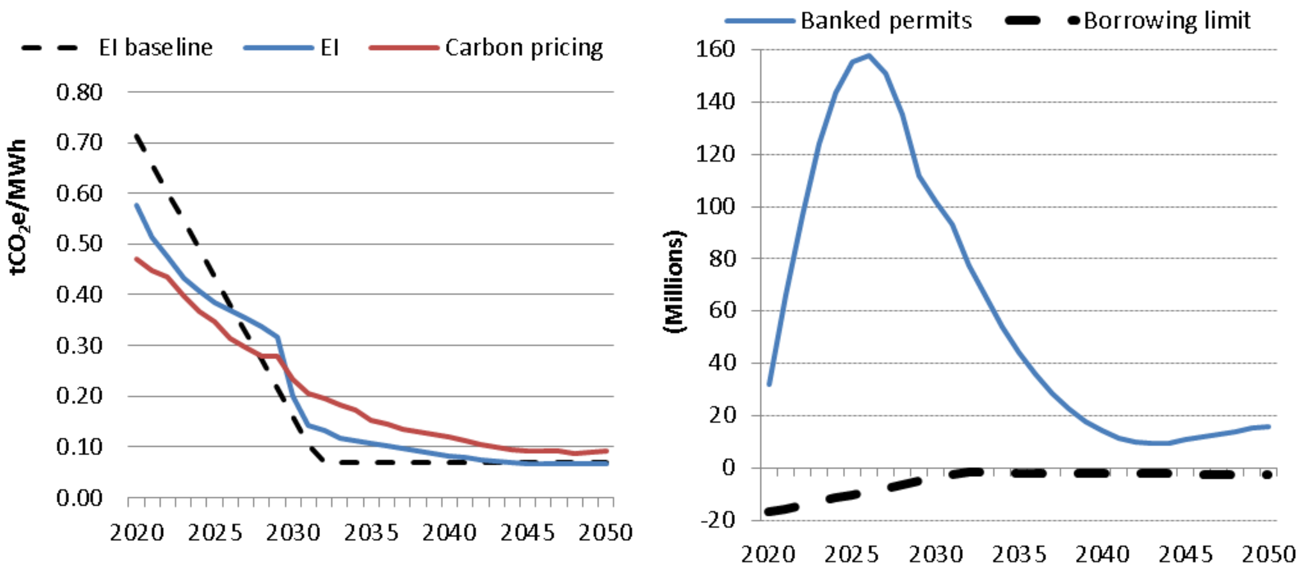
- The built-in price response of demand meant that demand under the EIT was higher relative to the carbon pricing scenario. The high initial baseline under the EIT scenario[20] resulted in lower market prices than in the carbon pricing scenario, and hence a higher level of demand.

The higher permit prices in the earlier years relative to carbon pricing makes the entry of renewables more attractive. This results in a higher level of new renewable investment relative to the carbon scenario throughout the early 2020s, and this also translates to lower levels of new CCGT build. This re-balancing of the plant mix is required under the EIT scenario to achieve the cumulative emissions constraint because demand is higher than the carbon pricing scenario and therefore the generation mix needs to have lower average emission intensity. After 2030 the generation mix, resource cost and wholesale and retail prices are similar to the carbon pricing scenario due to the emission intensity baseline falling to a low level (below 0.1 t CO_2-e/MWh).

[19] Under SRMC bidding with perfectly inelastic demand, a generator's pool revenue is perfectly compensated by the value of the additional volume of allocated permits.

[20] As with all scenarios, the Authority provided guidance on the policy parameters and Jacobs' calibrated the policy and adjusted as required to meet the emissions constraint. The form of the EIT emission baseline was part of the EIT scheme design. The Authority's guidance (see Appendix D) specified a linearly declining emission baseline with the starting point being the grid emission intensity of the reference case. Jacobs chose the rate of decline and the level of this was followed by a flat emission baseline, which Jacobs selected to reflect the long-term emission intensity of the grid.

Figure 43: Emission intensity trajectories for EIT and carbon pricing, and banking/borrowing of permits under EIT



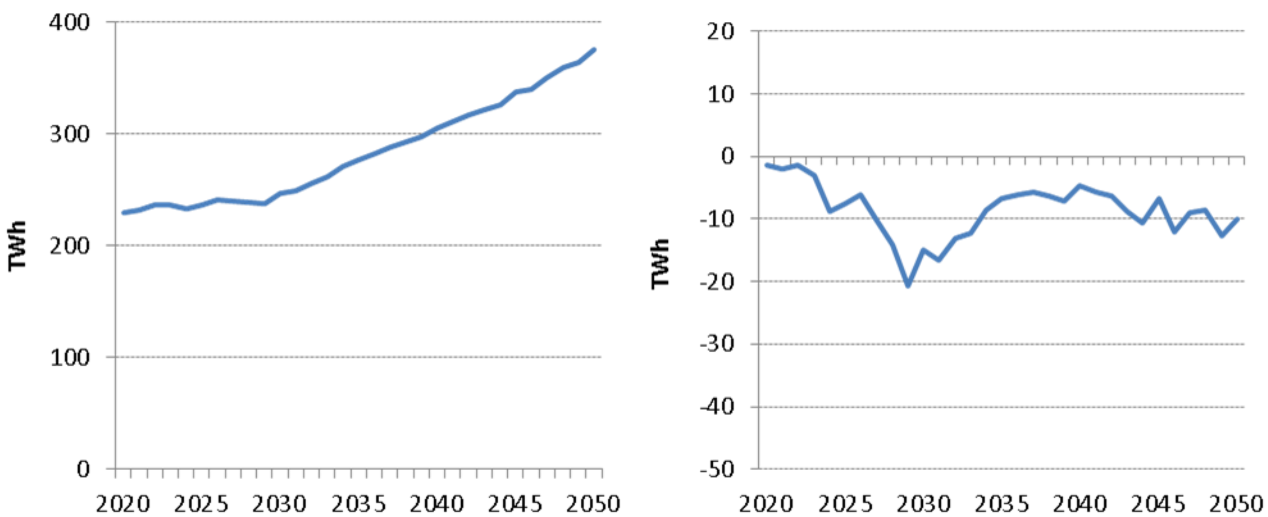
Source: Jacobs

3.4.3 Demand

The following figure shows sent-out energy demand for the emission intensity target scenario in absolute terms and relative to the reference case. Total energy consumed reaches 376 TWh in 2049/50, 10 TWh lower than the reference case due to higher wholesale prices reducing demand.

Figure 44: Sent-out energy, emission intensity target

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Pitt & Sherry, ACIL Allen and Jacobs

3.4.4 Generation and capacity

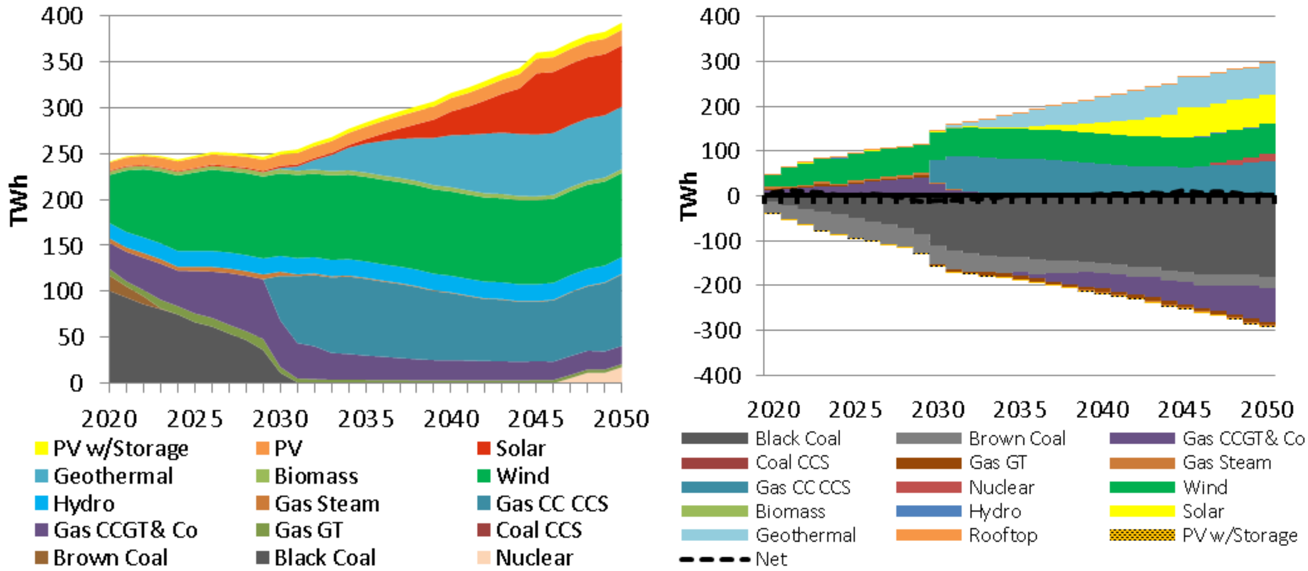
Figure 45 shows the generation mix in both absolute terms and relative to the reference case. During the first decade all coal-fuelled plants are shut-down as a result of the imposed policy, with mostly wind generators and

CCGTs replacing the retired capacity. After 2030, CCGTs coupled with CCS and geothermal generators are the main power generation technologies built, with some nuclear contributing to the generation mix during the last five modelled years. The key difference between the EIT scenario and the carbon pricing scenario in the generation mix is the role played by wind and CCGTs in the 2020s. A lot more wind investment occurs under the EIT scenario, largely driven by the higher certificate prices between 2020 and 2030. Conversely, CCGT investment under EIT is reduced relative to the carbon pricing scenario. As mentioned above, investment in dispatchable low emission technologies after 2030 under EIT is similar to that of carbon pricing as the two schemes are almost identical when the emission baseline is very low (see footnote 18).

Under the EIT scenario there are six transmission upgrades totalling 3,920 MW. This is almost 500 MW more than what was required for the reference case.

Figure 45: Generation mix, emission intensity target

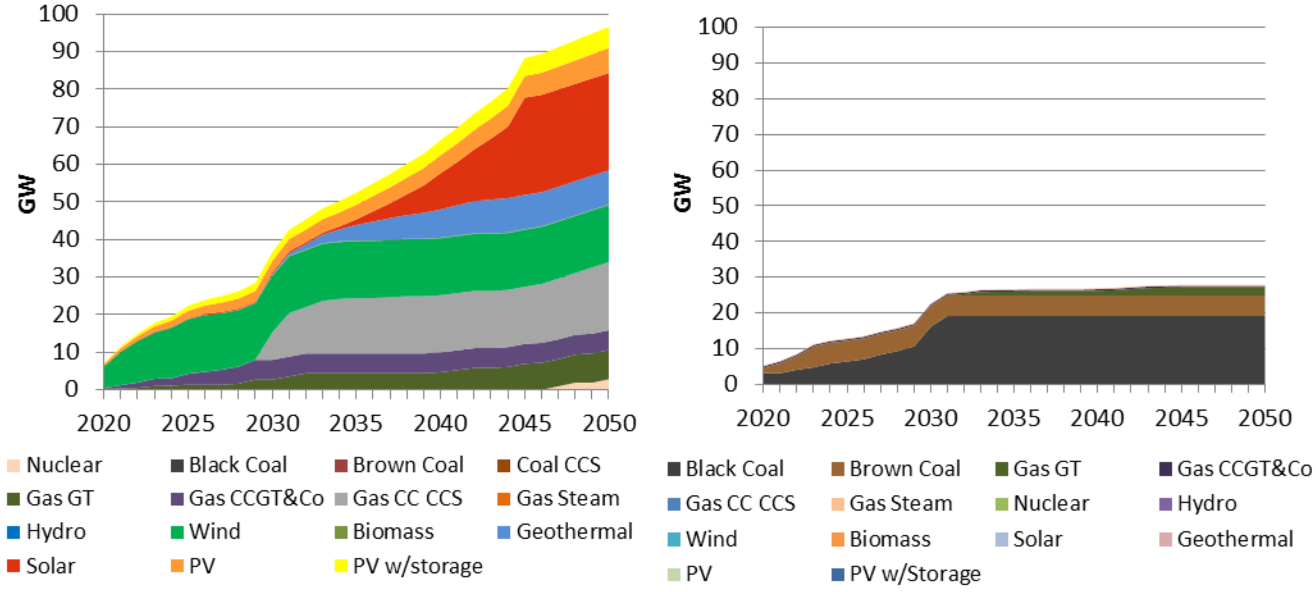
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs

Figure 46: Cumulative new and retired capacity, emission intensity target

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



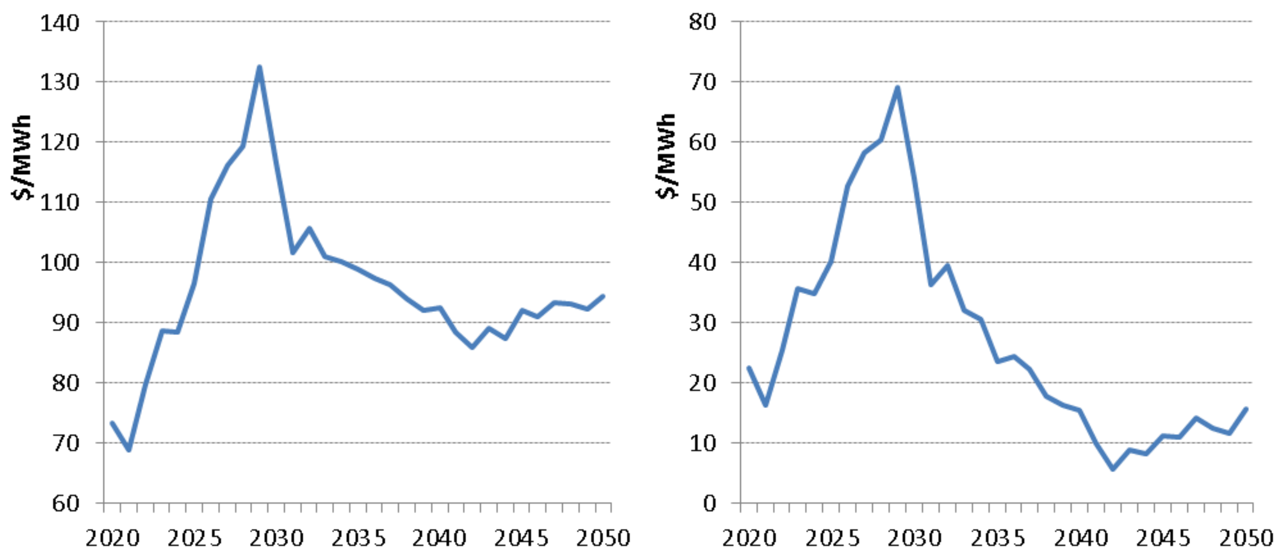
Source: Jacobs

3.4.5 Prices

Figure 47 shows average wholesale prices weighted by region. The upward linear trend in the wholesale price that persists throughout the 2020s is mainly driven by the downward linear trend in the emission baseline (see section 3.4.2 on the relationship between the market price and the emission baseline). Prices decline sharply after 2030 when two of the low emission dispatchable technologies (CCGT with CCS and geothermal) become available, as the emission-related impost on these technologies is much lower owing to their low emission intensities. Long term prices are slightly lower than the carbon price scenario 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 obtain under a carbon tax.

Figure 47: Wholesale electricity time-weighted prices, emission intensity target

The left graph shows absolute figures. The right graph shows figures relative to the reference case.

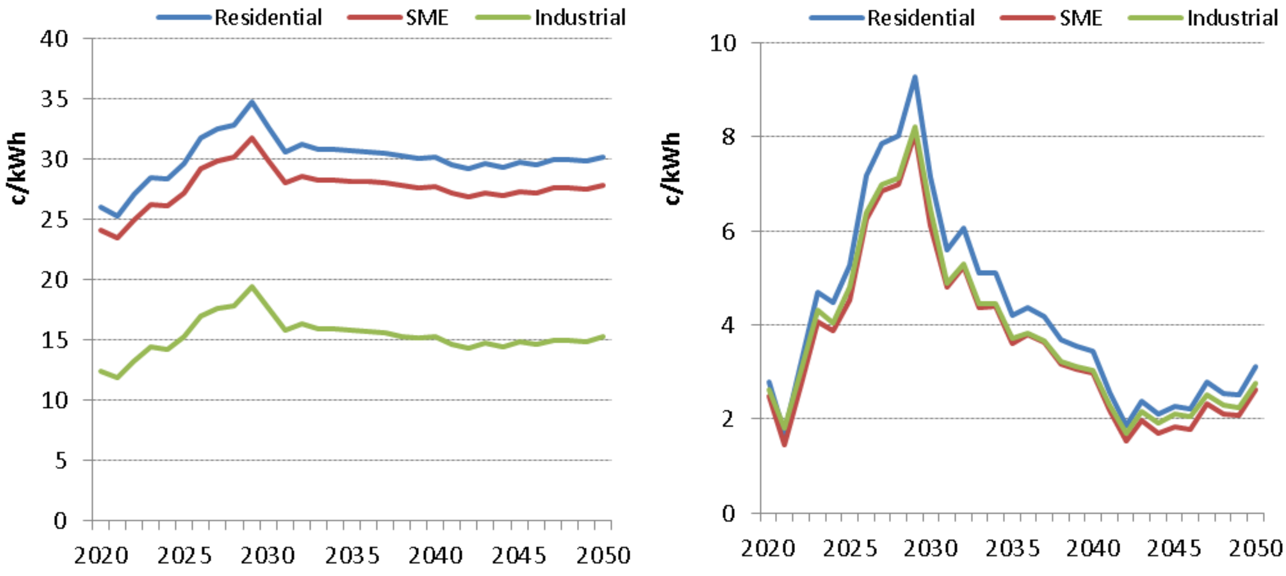


Source: Jacobs

Figure 48 shows weighted average retail prices by customer class. They contain the same trends as the wholesale prices but are more muted on a relative basis.

Figure 48: Retail prices by customer class, emission intensity target

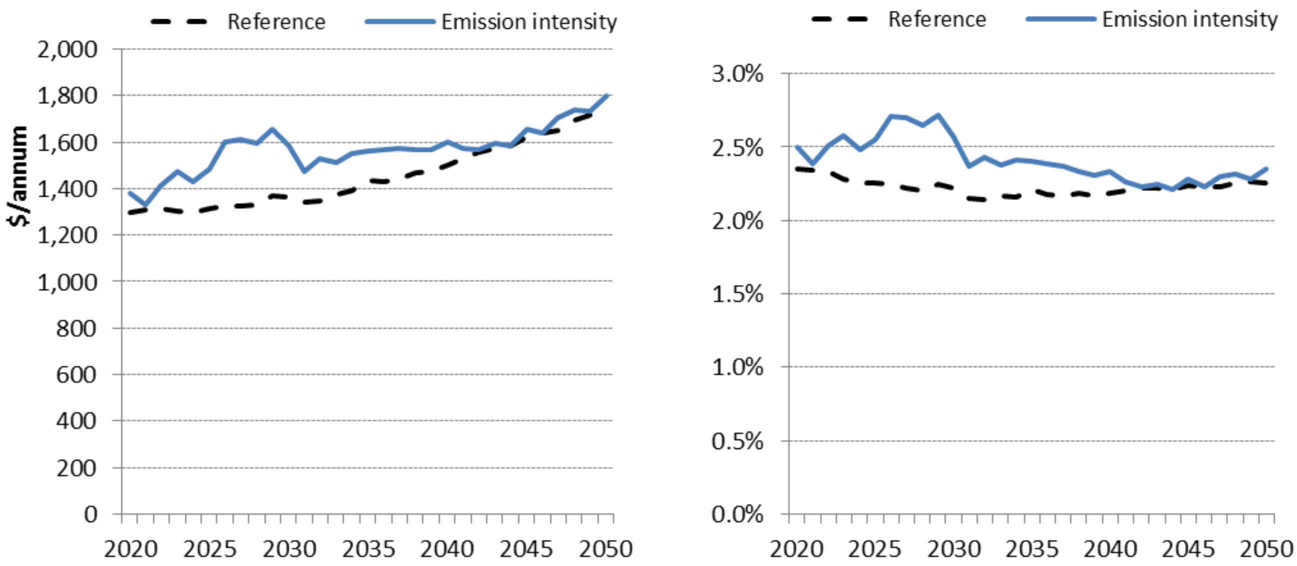
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs

Figure 49: Residential bills, emission intensity target

The left graph shows the absolute residential bill. The right graph shows the residential bill as a % of disposable income.



Source: Jacobs

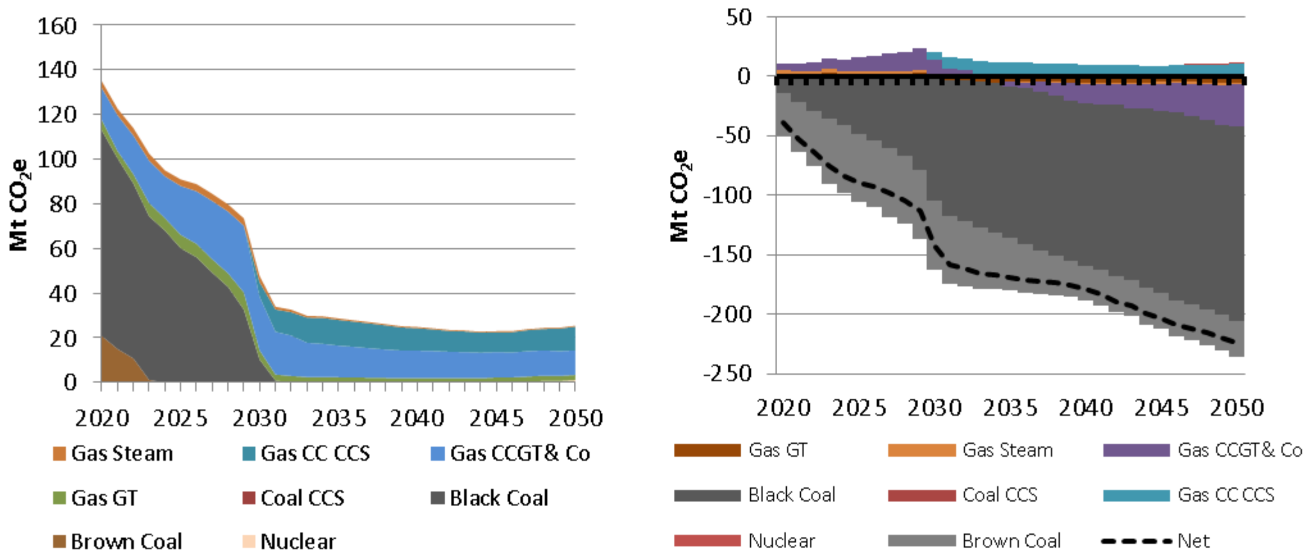
3.4.6 Emissions

Figure 50 shows emissions by generation technology, and the difference relative to the reference case. The initial drop in emissions in 2019/20 is not as sharp as that of carbon pricing, with emissions at 135 Mt CO_2-e for the emission intensity target compared to 104 Mt CO_2-e for carbon pricing. The difference is driven by the additional demand under EIT, which provides additional support to wholesale prices and is enough to delay the retirement of black coal fired generation in New South Wales in particular by about 3 years on average. Some of the brown coal fired generation also retires about 3 years later under the EIT relative to carbon pricing.

Figure 51 presents the grid emission intensity in absolute and relative to the reference case terms, and shows the intensity starting in 2020 around 0.58 t CO_2-e/MWh and dropping sharply for the next 12 years until reaching of 0.1 t CO_2-e/MWh in 2032 and declining very slightly after that for the remaining modelled years.

Figure 50: Emissions by technology, emission intensity target

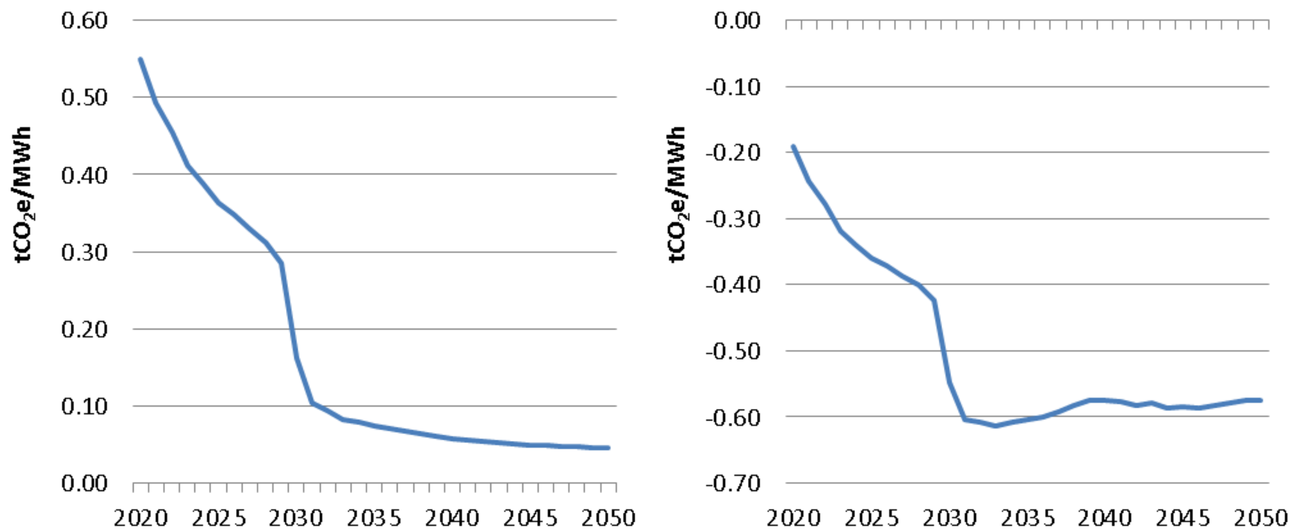
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs. Includes both direct and indirect emissions.

Figure 51: Generation emission intensity, emission intensity target

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



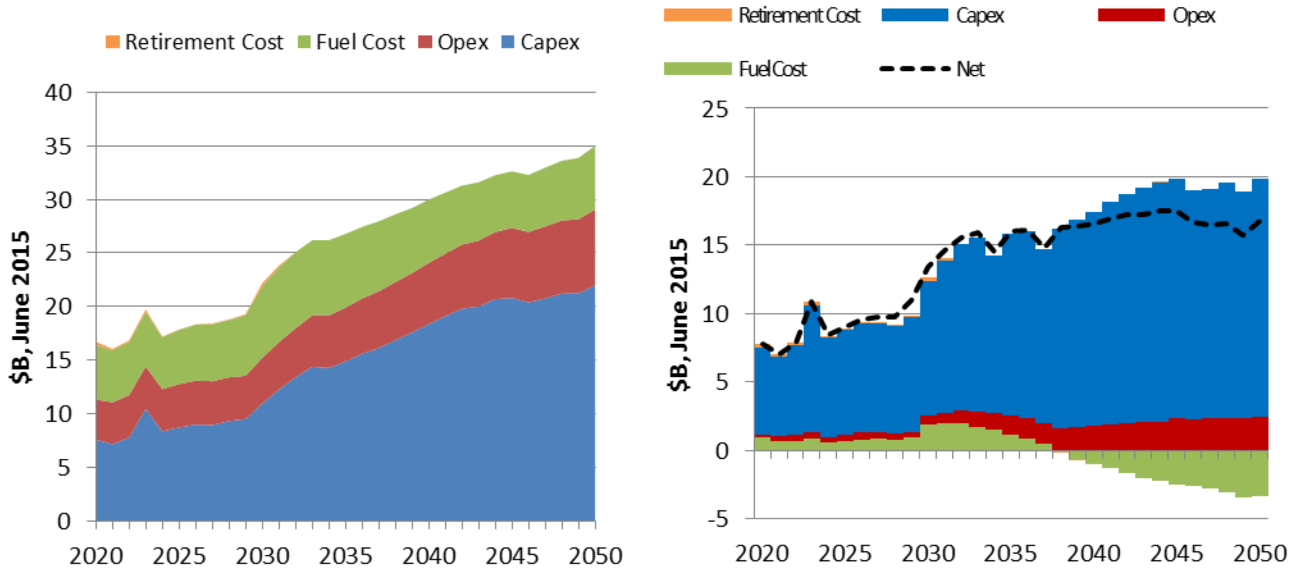
Source: Jacobs. Includes direct emissions only.

3.4.7 Costs

Figure 52 shows annualised resource costs by four cost categories. The cost profile is similar to that of carbon pricing in both magnitude and trend, with capital expenditure being the dominant resource cost.

Figure 52: Annualised costs by category, emission intensity target

The left graph shows the absolute costs. The right graph shows the costs relative to the reference case.

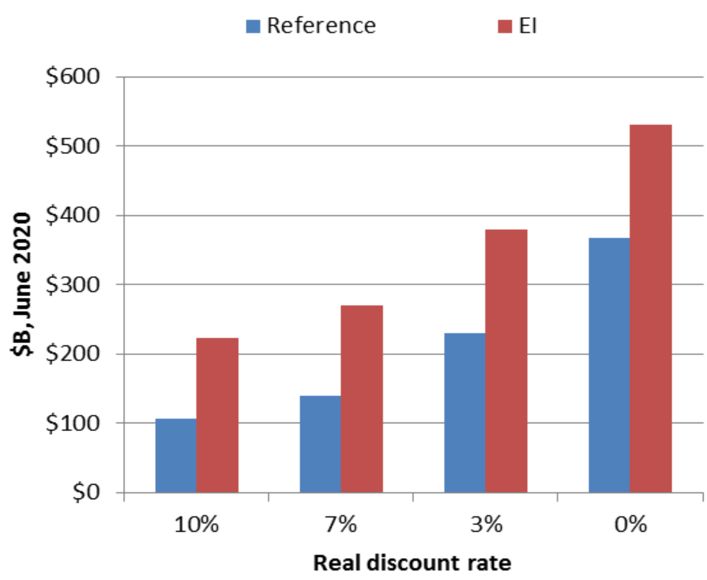


Source: Jacobs

In general, a carbon tax and equivalent EIT would be expected to have the same impacts on gross profits and therefore retirement decisions: the EIT has smaller wholesale price increases and smaller carbon cost increases. In this modelling, the results are similar but not identical due to the small differences in the schemes discussed above. Gross profit under EIT is similar for the brown coal plant under carbon pricing. However black coal plant are in aggregate as profitable under EIT as the reference case in the first decade, and then their profitability deteriorates to a level similar to carbon pricing after 2030.

Figure 53 shows the net present value of the resource costs for EIT in absolute terms and relative to the reference case. The total resource cost for EIT ranges from 110% (at 10% discount rate) to 44% (without discounting) higher than that of the reference case. This is about 10% higher than carbon pricing, with the higher cost reflecting the impact of the aforementioned borrowing constraint and lower demand-side abatement.

Figure 53: NPV of resource costs, emission intensity target



Source: Jacobs. Excludes demand adjustment. See Appendix B.3.2 for further detail.

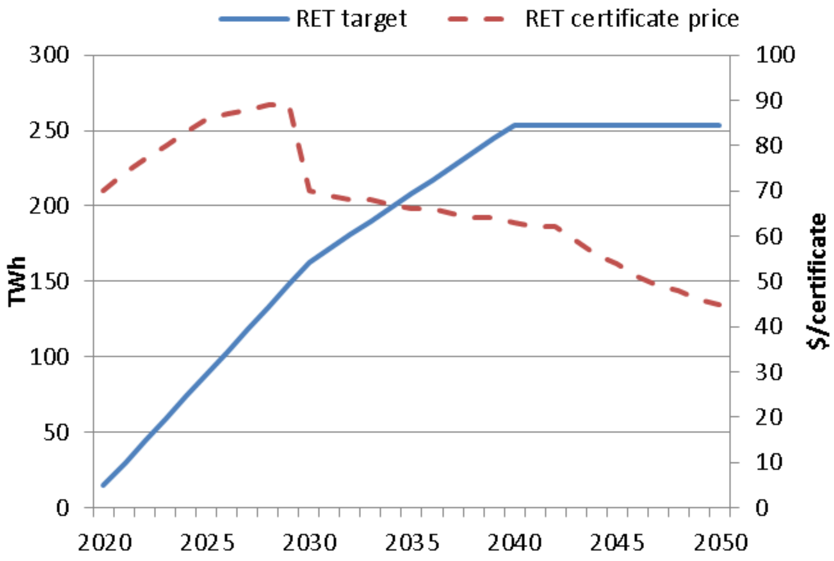
3.5 Renewable energy target

3.5.1 Scenario description

The renewable energy target (RET) scenario is essentially a much larger version of the current LRET scheme, except that there are no exemptions for large energy intensive loads. The LRET works by creating a market for additional renewable electricity that supports investment in new renewable generation capacity. It places a legal obligation on entities that purchase wholesale electricity (mainly electricity retailers) to surrender a certain number of certificates to the regulator each year. These certificates are generated by accredited renewable power stations. Figure 54 shows the final RET trajectory, incorporating the existing targets to 2030, and the corresponding RET certificate price required to satisfy the cumulative emissions constraint. In the course of the modelling it was found that a dual linear form for the RET trajectory was necessary to achieve a least cost solution.

The stringent cumulative emission target set by the carbon pricing scenario dictates that strong action is required in the 2020s to achieve it. For the RET scenario this action is effected by choosing a steep trajectory in the renewable target from 2020 to 2030, followed by a gentler slope from 2030 until 2040. The aim of the initial steep trajectory is to drive the retirement of the incumbent fossil generators by suppressing the wholesale price, and effectively substituting the incumbents with new renewable plant. After 2030, when most of the fossil generators have retired, the trajectory increases at a slower rate essentially to keep pace with load growth.

Figure 54: RET target and RET certificate price



Source: Jacobs

For further discussion see Chapter 2.

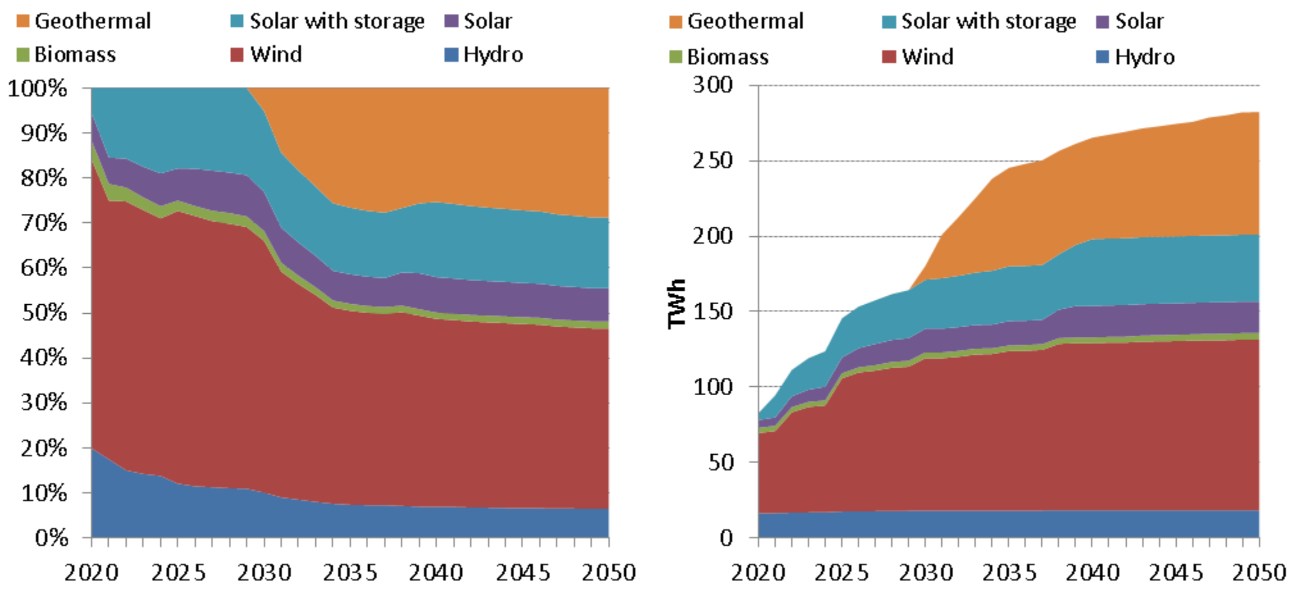
3.5.2 Key findings

Using a scheme such as the RET to de-carbonise the electricity sector presents some challenges. From a broader perspective, two key mechanisms are required for a scheme to efficiently de-carbonise the electricity sector. Firstly an incentive mechanism is required to encourage investment in low emission generation technologies. The RET scheme itself serves as such a mechanism, where the incentive is in the form of certificate revenue for eligible technologies. Secondly a penalty mechanism is required to facilitate the closure of incumbent fossil generators. The RET scheme does not have a direct mechanism to do this. It can only effect the retirement of fossil generators indirectly by reducing their revenue, which it achieves by creating an oversupply of very low marginal cost plant that suppresses the market price and also displaces incumbent high emitting plant.

Figure 55 shows the contribution of each large-scale renewable energy technology in both relative and absolute terms. The key technology in the 2020s is wind generation, which is generating 100 TWh by 2029/30. Large scale PV both with and without storage also plays an important role in the early years, and PV with storage in particular is required in greater quantity to avoid excessive amounts of curtailed energy. After 2030 when geothermal technology becomes available a large amount of it is built due to its cost effectiveness, which is driven by its high learning rate in a 2°C world. Consistent with other studies of very high renewable penetration, considerable volumes of curtailed energy occurred due to occasional surpluses.

A consequence of the RET scheme not having a direct penalty on emissions is that after 2040, when the RET target is no longer growing, the least-cost new entrant options are either supercritical black coal plant or CCGTs, depending on the region. Total emissions therefore begin to increase post 2040 when these new fossil generators start to enter the market. This means that a greater level of abatement needs to be achieved before 2040 in order to satisfy the cumulative emissions constraint. This result is an artefact of the formulation of the RET policy, which effectively treats 2050 as the end of time with no provision for effective emission controls beyond 2050. While this result shows the risk that new high-emissions plant can be built if policies do not directly penalise emissions, if this policy were implemented in practice, investors would likely expect further strong climate policy to continue after 2050, so may be unlikely to construct new coal plant even if it were the lowest cost plant.

Figure 55: Contribution of large-scale renewable generation by technology, renewable energy target



Source: Jacobs. The graph includes new RET target and existing LRET

This policy met the emissions target at higher costs than most other policies. This is mainly because:

- Its policy mechanism was limited to the high use of renewable energy, and was unable to explore potentially lower cost low-emissions non-renewable generation.
- It was unable to adjust the relative dispatch order of fossil fuel plants.
- The flat RET trajectory from 2040 to 2050 permitted the re-introduction of some coal plant late in the period.

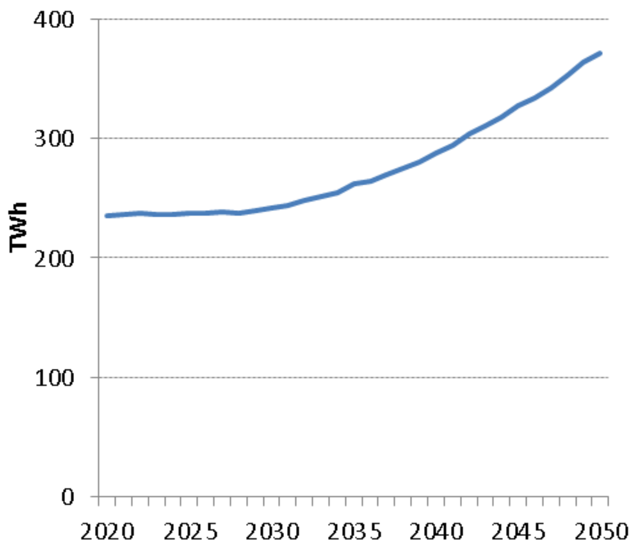
These factors mean that more renewable investments were required earlier to meet the emissions target.

3.5.3 Demand

Figure 56 shows sent-out energy demand for the RET scenario in absolute terms and relative to the reference case. Total energy consumed reaches 376 TWh in 2049/50, 9 TWh lower than the reference case due to high certificate prices inflating retail prices above those of the reference case, thus reducing demand.

Figure 56: Sent-out energy, renewable energy target

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Pitt & Sherry, ACIL Allen and Jacobs

3.5.4 Generation and capacity

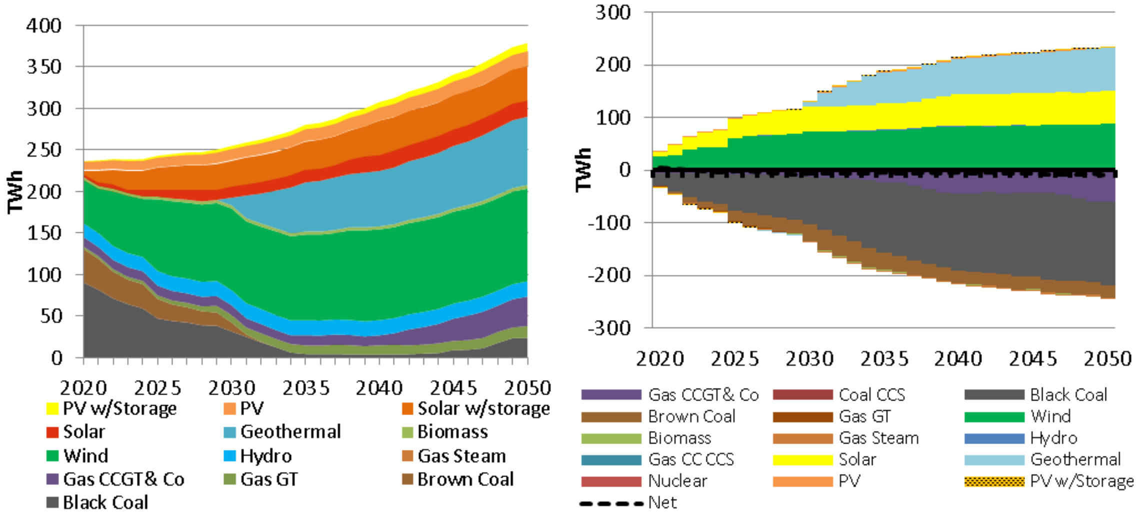
Figure 57 shows the generation mix across the modelling horizon in absolute terms and relative to the reference case. Noteworthy trends for the fossil generators are that brown coal generation continues to generate much longer than it does under the carbon pricing and EIT scenarios. This occurs as brown coal generators have lower marginal costs than black coal generators because emissions are not penalised directly under this policy. As a result, black coal plant tends to be the marginal plant and is the first to be displaced by the new entrant renewable generators. Fossil generation increases from 2040, largely driven by new CCGTs, although some supercritical black coal generators are also built. The share of renewable energy in generation is 74% in 2030, peaks at 91% in 2039 and drops to 81% in 2050.

In the 2020s at times wind and solar produce energy that exceeds local demand plus the region's export limit. In these instances the model forces this energy to be curtailed, which means that it does not contribute to the supply of demand and generators do not earn any revenue for this energy, nor does it contribute to the RET target. This issue lessens after 2030 when the slope of the RET trajectory is not as steep, and demand grows. Notwithstanding the occurrence of curtailed energy, installing this mix of renewable energy plant is still the least cost option because other available alternatives require expensive transmission upgrades which have higher cost imapcts, and which would not necessarily solve the issue.

In the NEM, South Australia has the best renewable resources, mainly in the form of wind generation. Under the RET scenario it was found to be economic to unlock some of these resources by building a 2,000 MW transmission line directly from South Australia to New South Wales. However, these transmission upgrades do not remove all the curtailed energy since there are correlations in the wind profiles across neighbouring regions of the NEM.

Figure 57: Generation mix, renewable energy target

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



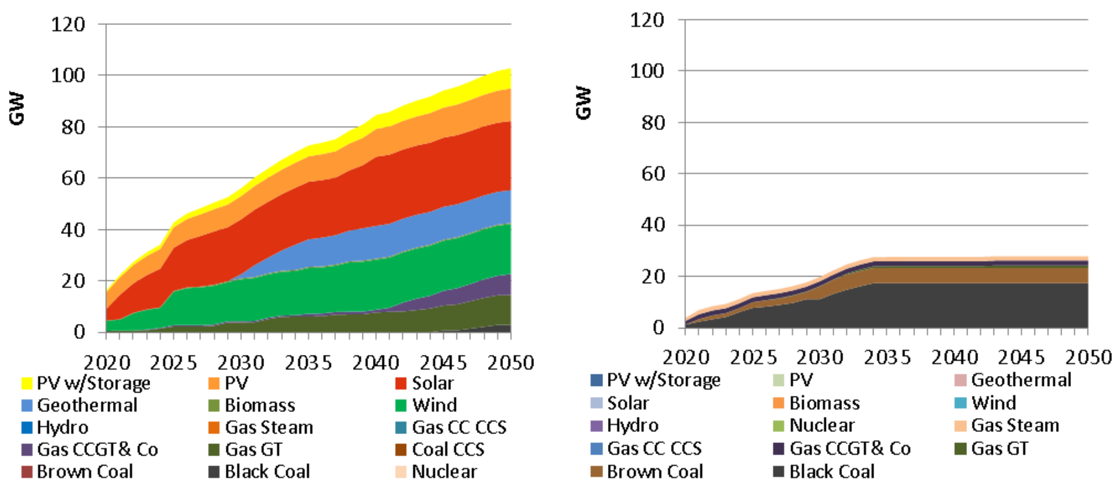
Source: Jacobs

Figure 58 shows cumulative new generation capacity under the RET, with renewable generation technologies dominating new build. A contribution is also made by gas turbines, which is the prevalent fossil generation technology built prior to 2040. The need for gas turbines result from the reliability constraint discussed in Appendix B and they find a market niche in providing back-up capacity for intermittent renewable capacity. Their capacity continues to increase throughout the modelling horizon. Large-scale solar is installed from 2020 because in some regions they face higher wholesale prices during their dispatch relatively to the prices that lower cost wind farms are earning.

Under the RET scenario there are eleven transmission upgrades, including a new transmission line connecting South Australia with New South Wales, totalling 7,380 MW. This is almost 4,000 MW more than the reference case and is required to unlock relatively low cost renewable energy resources, such as those located in South Australia.

Figure 58: Cumulative new and retired capacity, renewable energy target

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



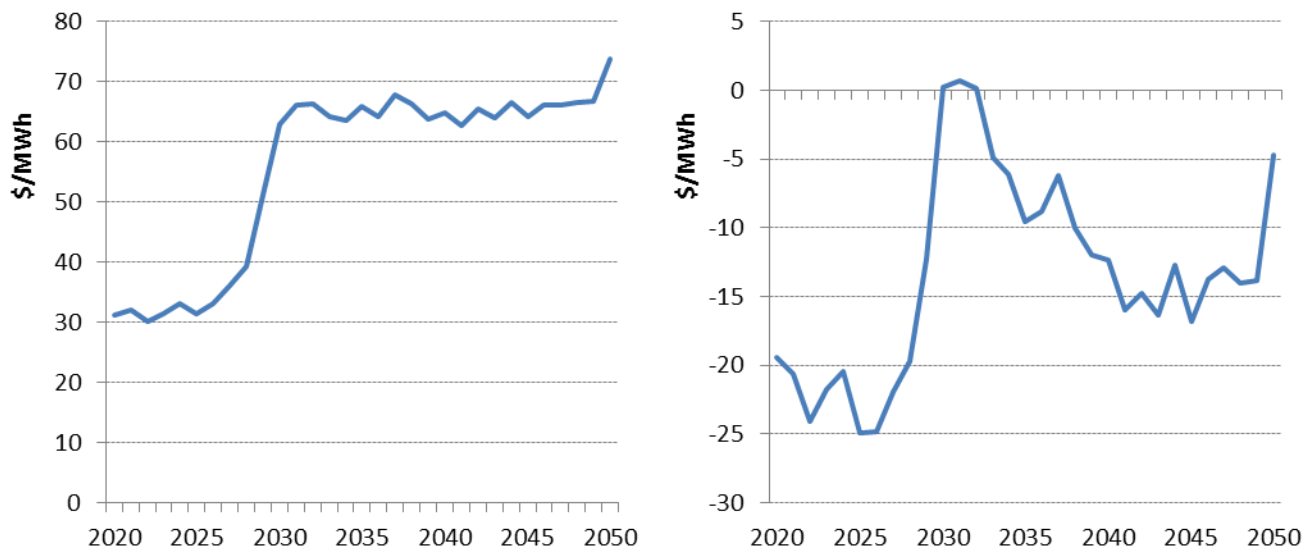
Source: Jacobs

3.5.5 Prices

Figure 59 shows wholesale electricity time-weighted prices. Prices in the early 2020s are suppressed due to the entry of large volumes of renewable generation, and this, coupled with the displacement of coal fired generation, forces the retirement of much of the coal fleet. In 2029/30 prices rebound as a result of most of the coal fleet having retired, which is why prices exceed those of the reference case. Geothermal technology also becomes available at that point for market entry and keeps prices capped below the new entry level of the marginal new entrant fossil technology, namely, supercritical black coal and CCGTs. Post 2040 prices are capped by the new entry level of fossil generators.

Figure 59: Wholesale electricity time-weighted prices, renewable energy target

The left graph shows absolute figures. The right graph shows figures relative to the reference case.

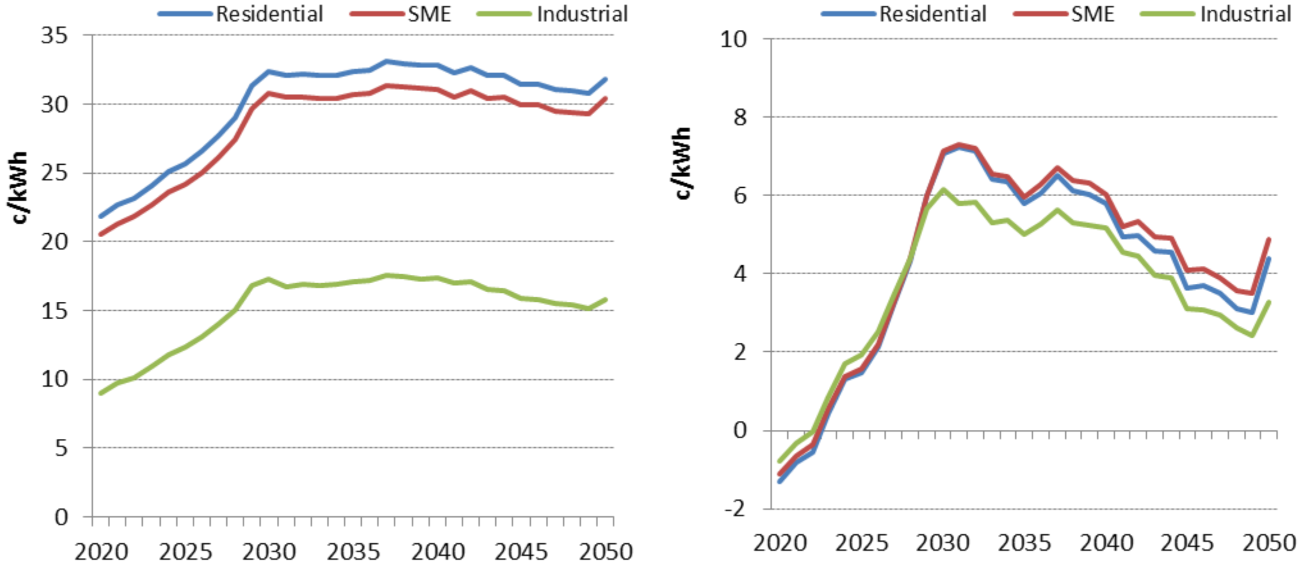


Source: Jacobs

Figure 60 shows weighted average retail prices by customer class. Unlike carbon pricing and an EIT, they do not entirely mirror the trends in the wholesale price because they are also heavily influenced by the renewable certificate costs which more than offset the early wholesale price suppression discussed above. Figure 61 shows the weighted average residential bill relative to the reference case, and also as a percentage of disposable income. The high certificate price and the volume of certificates under the RET required to satisfy the cumulative emissions constraint combine to increase the retail price on average by 4.5 c/kWh per annum.

Figure 60: Retail prices by customer class, renewable energy target

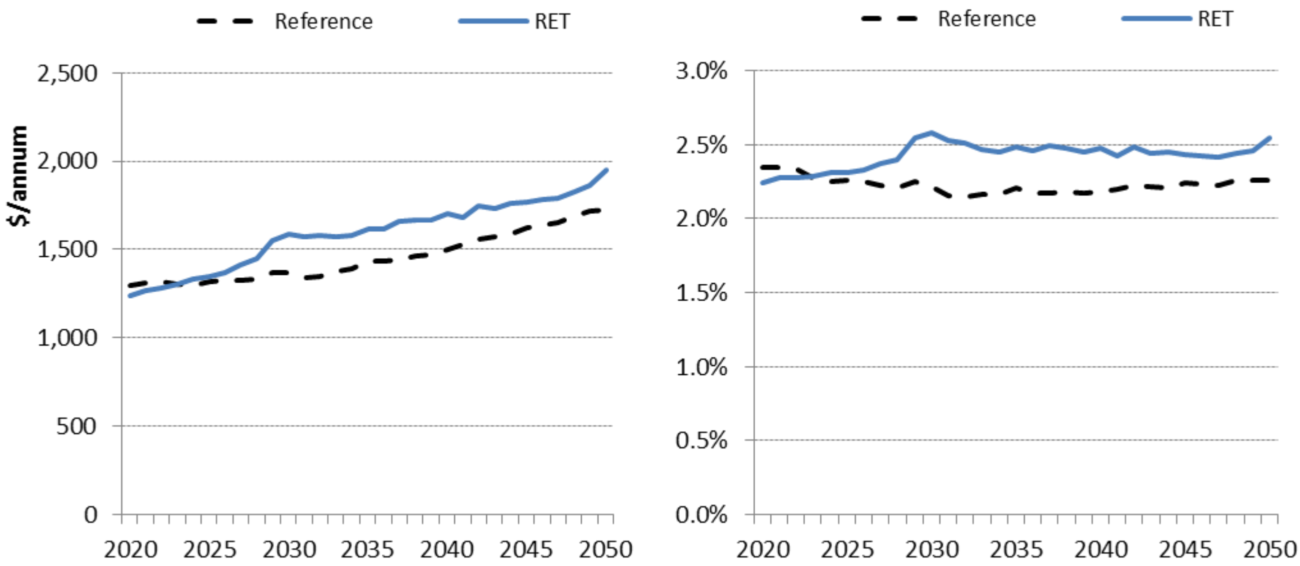
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs

Figure 61: Residential bills, renewable energy target

The left graph shows the absolute residential bill. The right graph shows the residential bill as a % of disposable income.



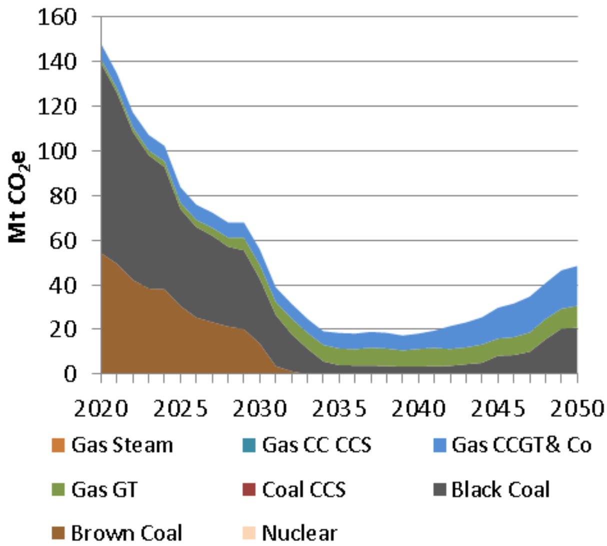
Source: Jacobs

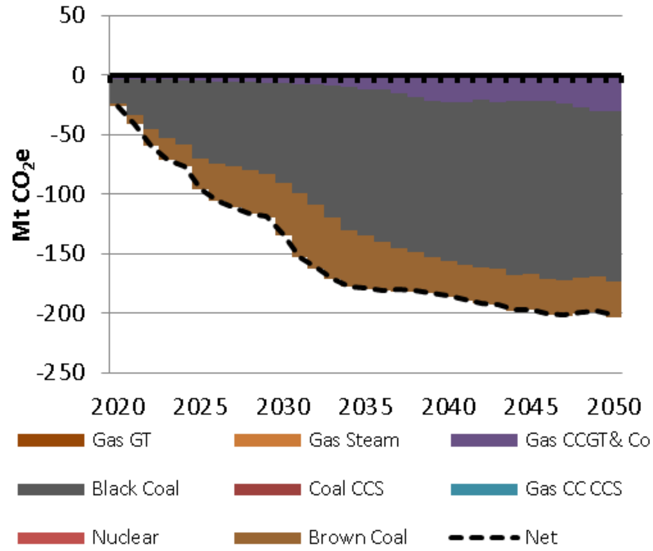
3.5.6 Emissions

Figure 62 shows annual emissions by technology and the difference relative to the reference case. Most of the coal fleet retires by the early 2030s, emissions increase post 2040 with the commissioning of new fossil generators. Figure 63 shows the generation emission intensity both in absolute terms and relative to the reference case.

Figure 62: Emissions by technology, renewable energy target

The left graph shows absolute figures. The right graph shows figures relative to the reference case

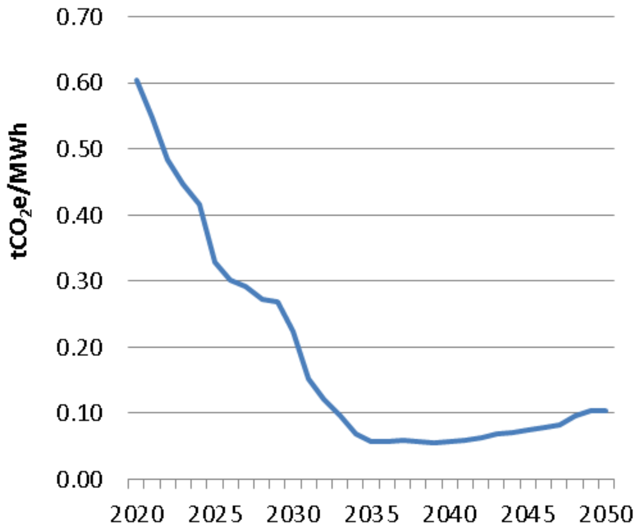


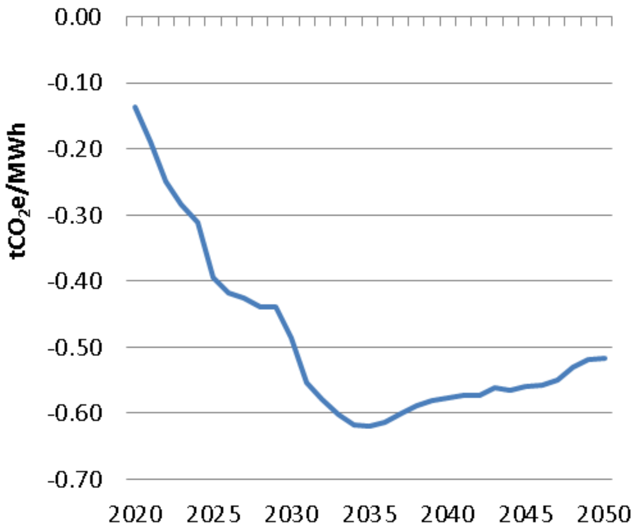


Source: Jacobs. Includes both direct and indirect emissions.

Figure 63: Generation emission intensity, renewable energy target

The left graph shows absolute figures. The right graph shows figures relative to the reference case.





Source: Jacobs. Includes direct emissions only.

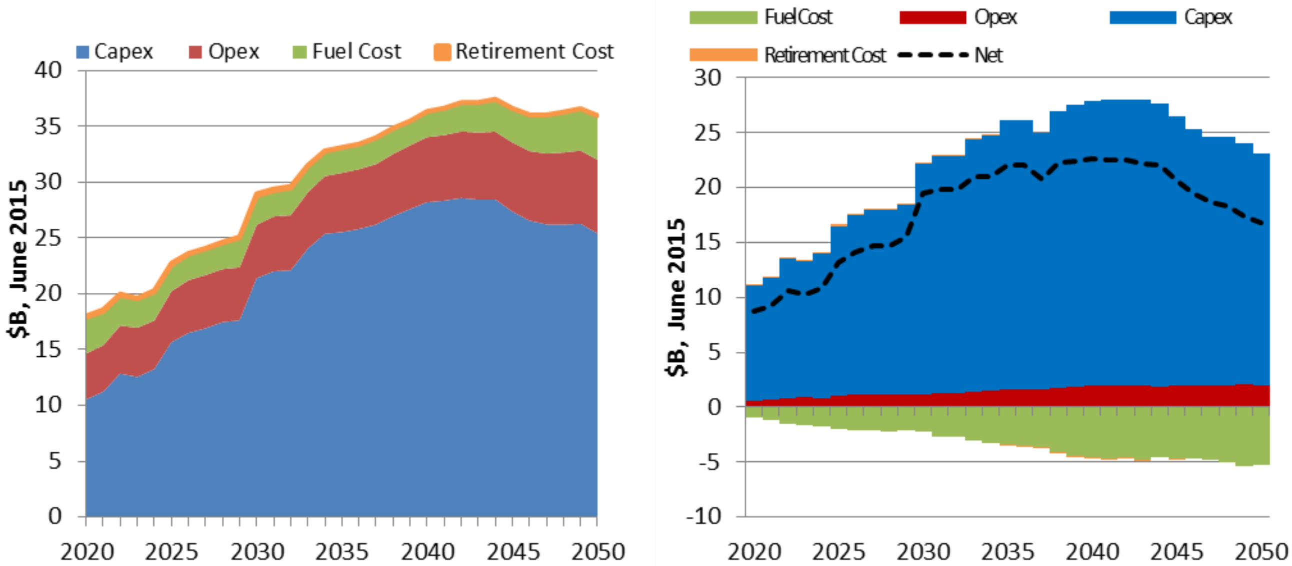
3.5.7 Costs

Figure 64 shows annualised resource costs by four cost categories. Costs in 2019/20 are about $18 billion per annum, and they escalate rapidly from there as new renewable build is required to meet the rapidly escalating RET. Annual costs peak in 2044 at about $38 billion per annum. Capital costs decline thereafter and this is due to wind farm refurbishments of wind farms built in the early 2020s (after their 25 year economic life)[21]. Examining costs relative to the reference case shows a marked reduction in fuel costs, which is a result of a generation fleet that is mostly renewable. Capital costs are considerably higher than carbon pricing, which was at most $17 billion above the reference case.

[21] Capital costs drop because refurbishment cost is assumed to be 60% of the capital cost of new build.

Figure 64: Annualised costs by category, renewable energy target

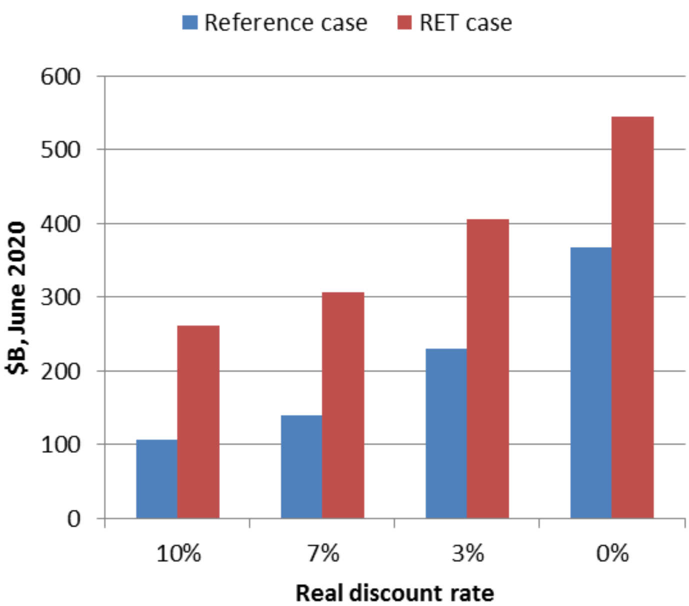
The left graph shows the absolute costs. The right graph shows the costs relative to the reference case.



Source: Jacobs

Figure 65 shows the net present value of the resource costs for the RET scenario relative to the reference case for four separate discount rates. The total resource cost for the RET scenario ranges from 146% (at 10% real discount rate) to 48% (without discounting) higher than that of the reference case. This is driven by the large capital cost required to invest in volumes of renewable generation capacity that are comparable to the current size of the entire electricity sector.

Figure 65: NPV of resource costs, renewable energy target



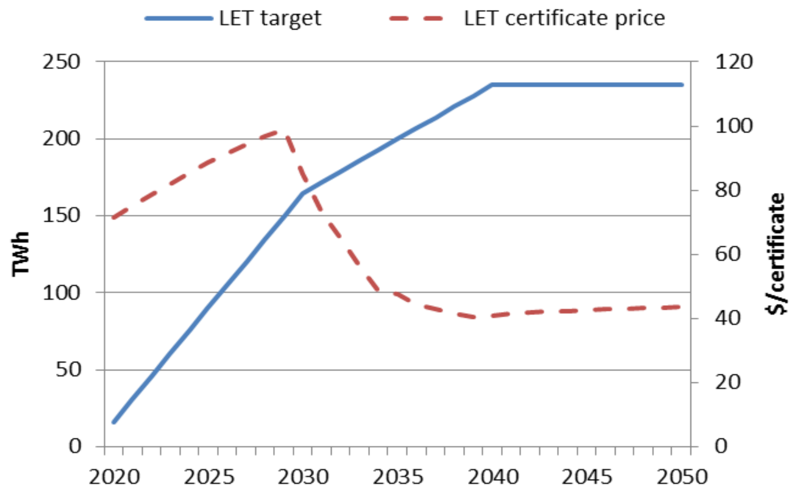
Source: Jacobs. Excludes demand adjustment. See Appendix B.3.2 for further detail.

3.6 Low emissions target

3.6.1 Scenario description

The low emissions target (LET) scenario is very similar to the RET, with the difference being that low emission fossil technologies are also eligible to earn certificates as a fraction of their emissions intensities below an emission intensity threshold of 0.6 t CO_2-e/MWh. This includes CCGTs, CCS plant, both coal fired and gas fired, and also nuclear generation technology. Figure 66 shows the final LET trajectory and the corresponding LET certificate price required to satisfy the cumulative emissions constraint. As with the RET scenario, it was found that a dual linear form for the LET trajectory was necessary to achieve a least cost solution.

Figure 66: LET target and LET certificate price



Source: Jacobs

For further discussion see Section 2.

3.6.2 Key findings

The outcomes of the LET are similar to those of the RET, except that resource costs are lower. Including broader support for low-emissions technologies lowers resource and consumer costs of staying within the emissions constraint. There are two key things driving this outcome:

(i) the contribution from CCGTs in the 2020s prevents locking in more expensive renewable plant, such as large-scale solar with storage; and

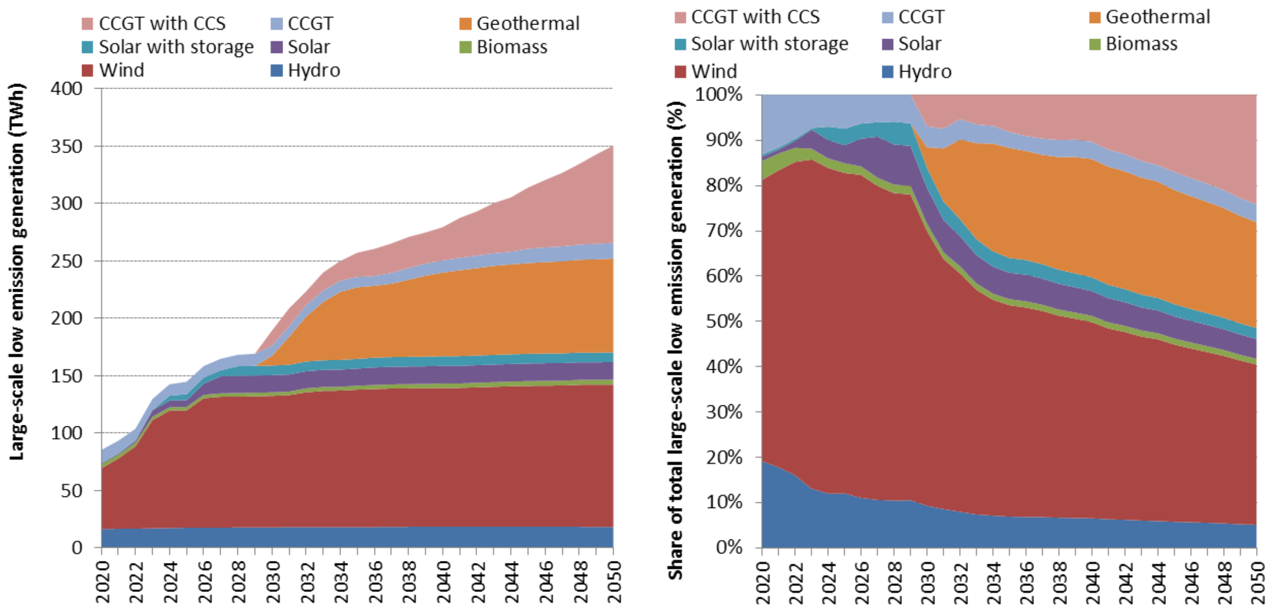
(ii) CCGT with CCS technology makes a notable contribution in the second half of the modelling horizon.

The first point is evident in Figure 67, which shows wind generation playing a larger role in the 2020s when compared with the RET (c.f. Figure 55). The contribution of solar with storage, which is a high cost renewable energy option, is also markedly lower in the LET scenario relative to the RET scenario, and the certificates created by CCGTs under the LET in the 2020s help to make this possible. Post 2030 the contribution of CCGTs with CCS is sizeable, reaching 24% of all large-scale low emission generation by 2049/50. This means that less total renewable energy, curtailed energy and back up gas turbines were required.

Like the RET, the LET can only force incumbent fossil generators to retire indirectly by a combination of suppression of the wholesale price and displacement by low marginal cost plant. As with the RET, the LET requires a steeper initial target trajectory in the 2020s to force the retirement of incumbent coal fired generation. The trajectory in the 2030s does not need to be as steep. The LET trajectory does not need to be quite as high as that of the RET because CCGTs, CCGTs with CCS and nuclear only generate a fraction of a certificate for each MWh generated (thresholds are based on both direct and indirect emissions, see Appendix B for further details). Therefore the actual generation level of eligible low emission plant is higher than the LET target.

Finally, in modelling the LET scheme we had the option of reducing the certificate threshold from the initial value of 0.6 t CO_2e/MWh. However there was no need to exercise this option to achieve the cumulative emissions constraint and therefore the threshold was kept constant.

Figure 67: Contribution of large-scale low emission generation by technology, low emissions target



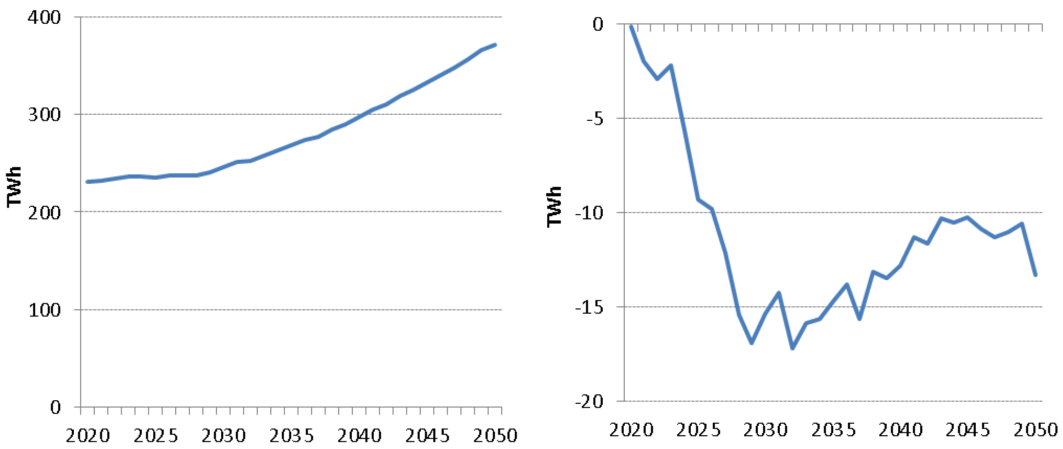
Source: Jacobs. The graph includes new LET target and existing LRET

3.6.3 Demand

Figure 68 shows sent-out energy demand from the LET scenario. Total energy consumption reaches 372 TWh in 2049/50, 13 TWh per annum lower than the reference case.

Figure 68: Sent-out energy, low emissions target

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



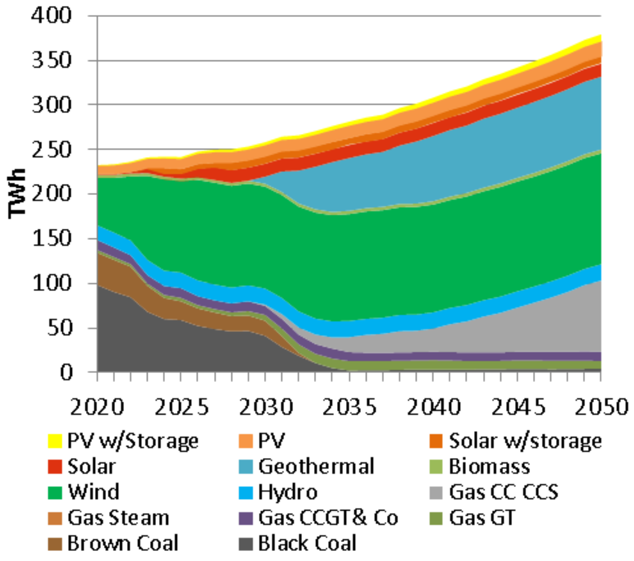
Source: Pitt & Sherry, ACIL Allen and Jacobs

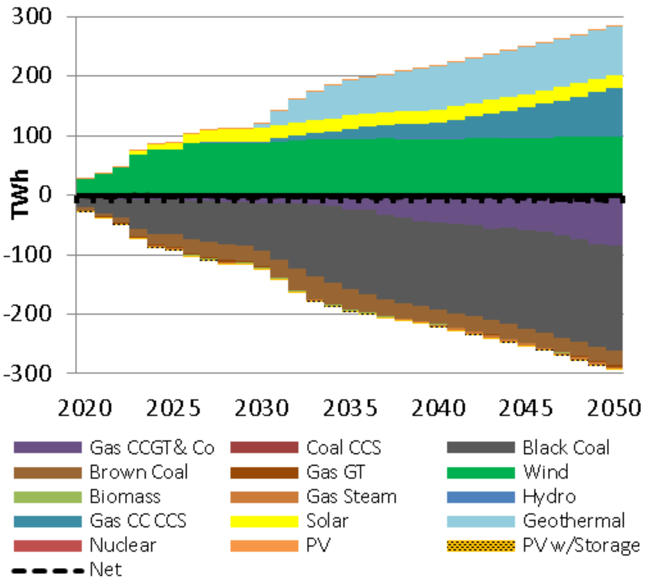
3.6.4 Generation and capacity

Figure 69 shows the generation mix across the modelling horizon. The key trends in the graph are similar to those of the RET scenario, except that solar with storage options are deployed on a much smaller scale than under the RET scenario in the 2020s, and furthermore CCGTs with CCS make a key contribution after 2035.

Figure 69: Generation mix, low emissions target

The left graph shows absolute figures. The right graph shows figures relative to the reference case.





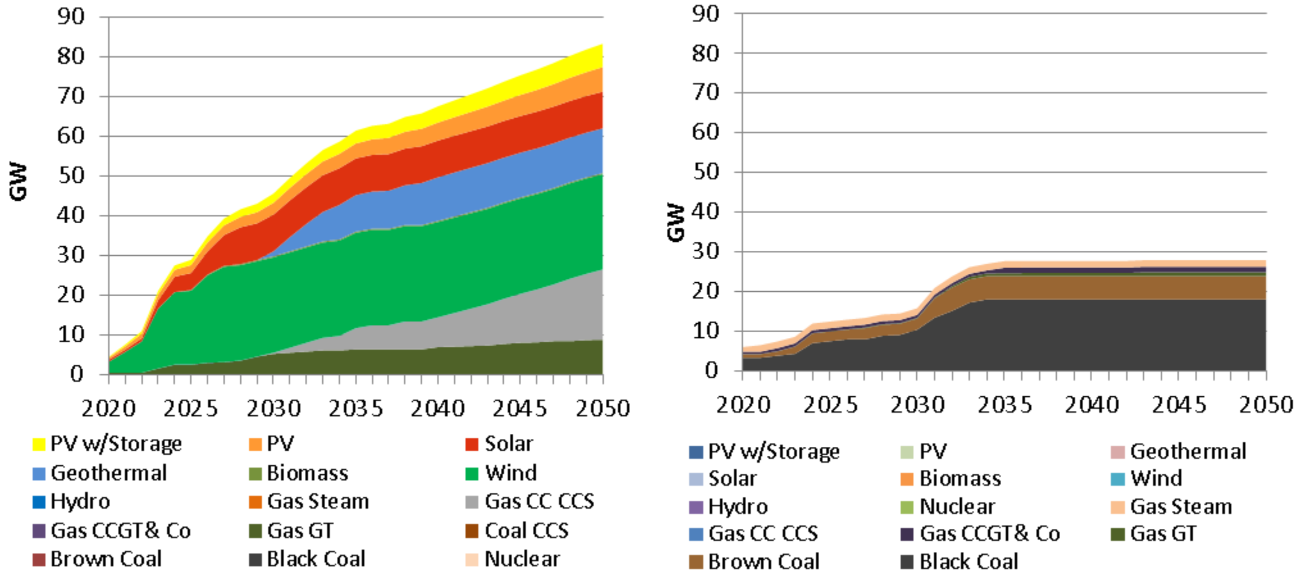
Source: Jacobs

Figure 70 shows cumulative new generation capacity under the LET. Low emission technologies dominate new build, and, as with the RET, gas turbines play an important role as new build plant in providing back-up for the intermittent generation capacity.

Under the LET scenario there are fourteen transmission upgrades, including a new transmission line connecting South Australia with New South Wales, totalling 9,180 MW. This is over 5,700 MW more than the reference case and is required to unlock relatively low cost renewable energy resources, such as those located in South Australia.

Figure 70: Cumulative new and retired capacity, low emissions target

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



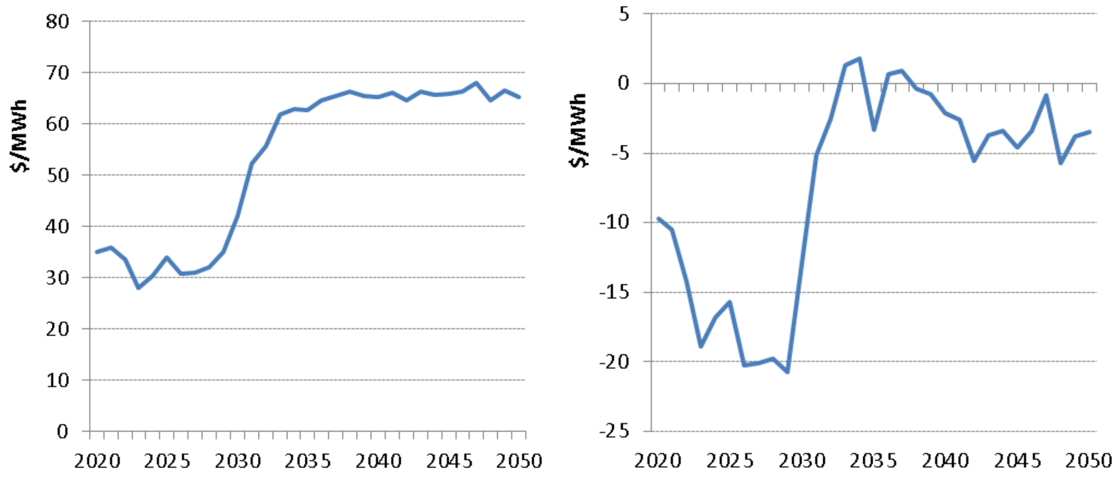
Source: Jacobs

3.6.5 Prices

Figure 71 shows wholesale electricity time-weighted prices. Price trends are similar to those of the RET scenario, except that prices do not materially exceed the reference case at any point in time, especially in the 2030s. The reason for this is that CCGTs are an eligible technology to generate certificates under the LET, whereas they were not under the RET. In the case of the RET, CCGTs were retired before even the coal fired plant was retired because of their higher marginal cost. Under the LET, CCGTs continue to operate, aided by certificate revenue, and contribute to more effectively suppressing the wholesale price. As with the RET scenario, prices after 2040 are capped by the new entry level of fossil generators.

Figure 71: Wholesale electricity time-weighted prices, low emissions target

The left graph shows absolute figures. The right graph shows figures relative to the reference case.

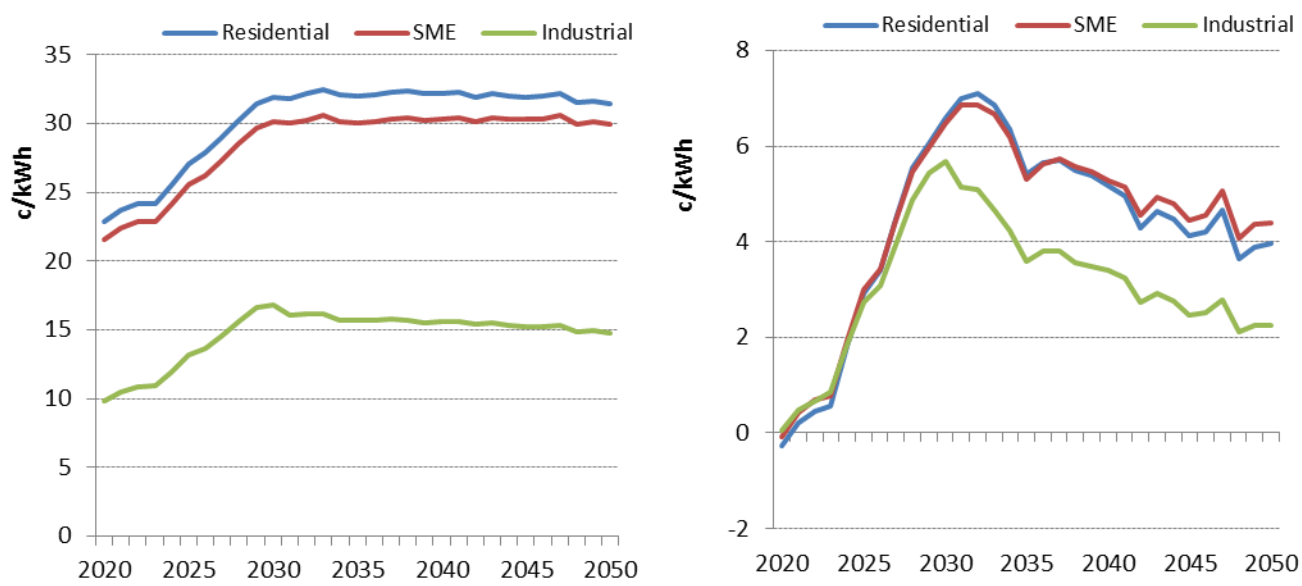


Source: Jacobs

Figure 72 shows weighted average retail prices by customer class. These prices are heavily influenced by the certificate price, especially since the volume of the LET scheme is so large, particularly in the later years. Figure 73 shows the weighted average residential retail bill relative to the reference case, and also as a percentage of disposable income. Overall, residential bills are expected to increase moderately relative to the reference case. The residential bill is also expected to be lower than that of the RET scenario, reflecting the lower expected certificate price of the LET scheme.

Figure 72: Retail prices by customer class, low emissions target

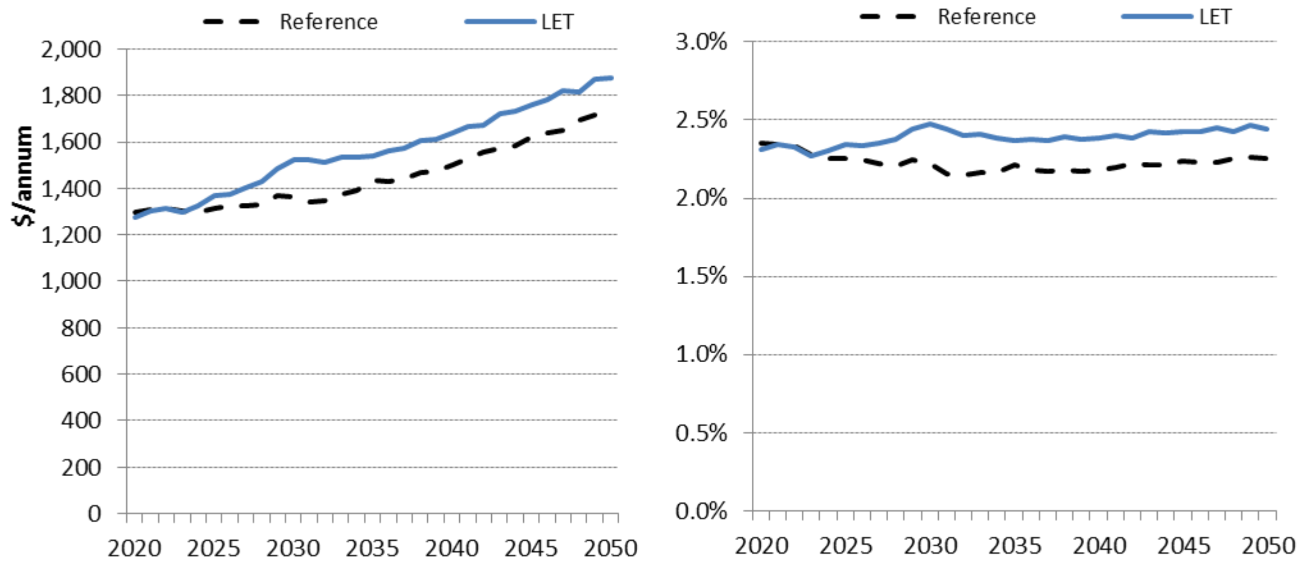
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs

Figure 73: Residential bills, low emissions target

The left graph shows the absolute residential bill. The right graph shows the residential bill as a % of disposable income.



Source: Jacobs

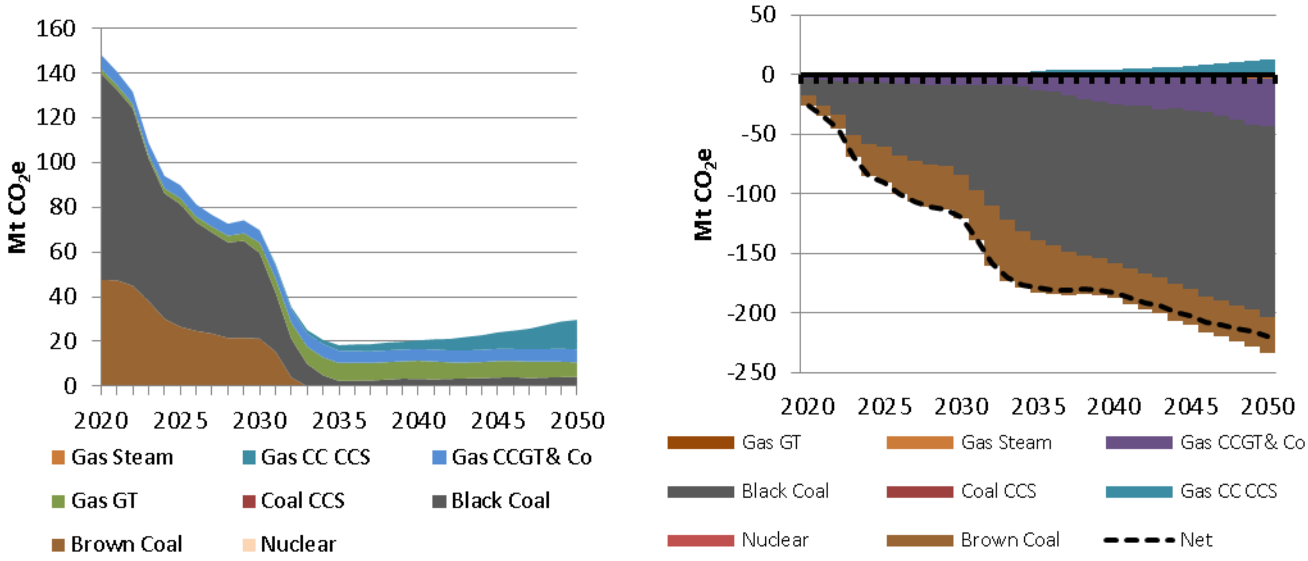
3.6.6 Emissions

Figure 74 shows annual emissions by technology and the difference relative to the reference case. Trends in emissions are very similar to the RET scheme, except that in the 2040s CCGTs with CCS are driving the increase in emissions rather than CCGT and supercritical coal.

Figure 75 shows the generation emission intensity both in absolute terms and relative to the reference case. It follows a very similar trajectory to that of the RET, with a sharp decrease in intensity to 2035 and then a gradual increase to 2050 as the LET target flattens out.

Figure 74: Emissions by technology, low emissions target

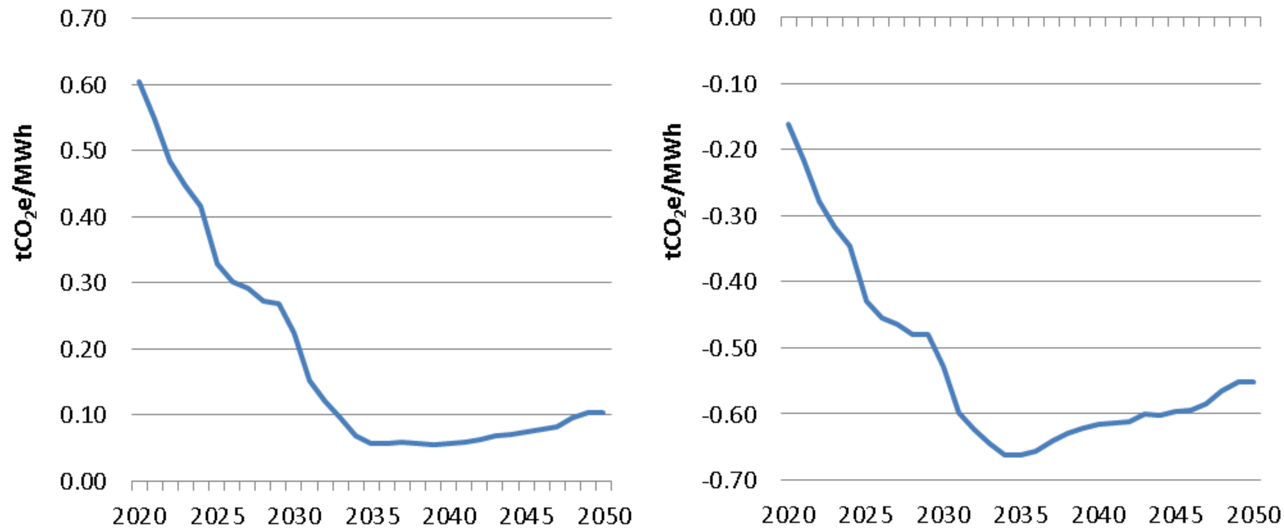
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs. Includes both direct and indirect emissions.

Figure 75: Generation emission intensity, low emissions target

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



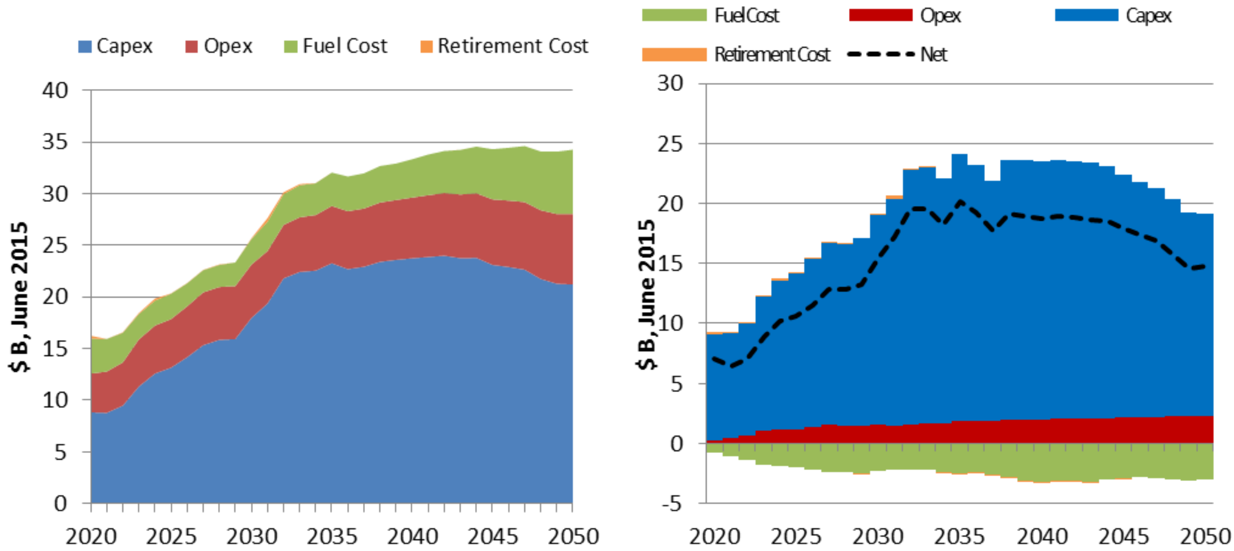
Source: Jacobs. Includes direct emissions only.

3.6.7 Costs

Figure 76 shows annualised resource costs by four cost categories. The trends in these charts are similar to those of the RET scenario. However, capital costs are slightly lower, peaking at $25 billion above the reference case, compared with $29 billion for the RET. Fuel cost savings are lower than in the RET, especially after 2030 when large amounts of CCGTs with CCS plant are deployed.

Figure 76: Annualised costs by category, low emissions target

The left graph shows the absolute costs. The right graph shows the costs relative to the reference case.

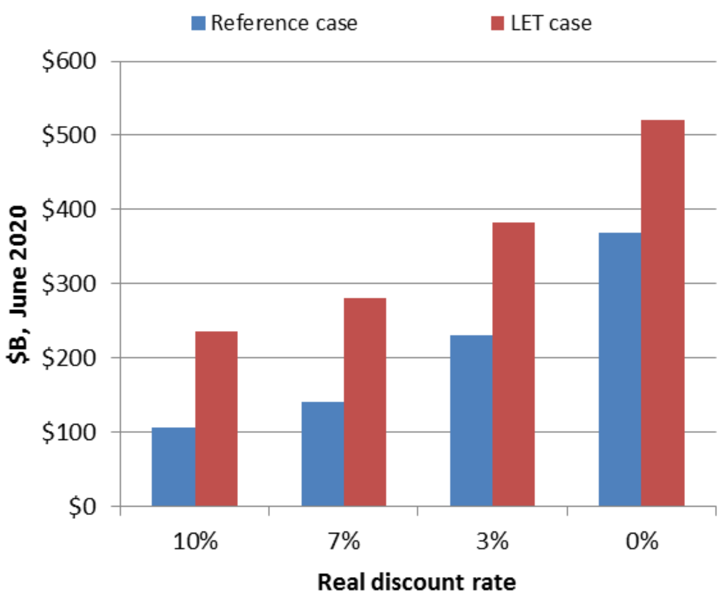


Source: Jacobs

Under the LET black coal fired plant average $2.4 billion per annum less gross profit in the first ten years relative to the reference case, and brown coal fired plant average $0.7 billion per annum less in the same time period. This outcome is more favourable for brown coal-plant owners relative to carbon pricing, and similar to carbon pricing for owners of black coal fired plant. Averaged over the entire modelling horizon, gross profits for owners of coal fired plant are marginally more favourable under the LET relative to the RET.

Figure 77 shows the net present value of the resource costs for the LET scenario relative to the reference case for four separate discount rates. The outcomes are similar to those of the RET, except that the LET has 23% lower costs at a 10% real discount rate and 6% lower costs with no discounting.

Figure 77: NPV of resource costs, low emissions target



Source: Jacobs. Excludes demand adjustment. See Appendix B.3.2 for further detail.

3.7 Feed in tariffs with contracts for differences

3.7.1 Scenario description

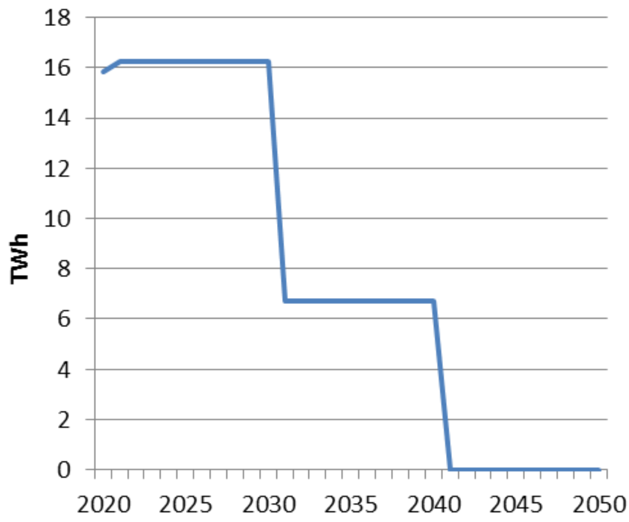
The feed-in tariff approach involves a similar type system as the reverse auction process held for the ACT renewable energy target. Eligible generators bid into an auction for the right to receive a fixed revenue stream per unit of output (the feed-in tariff rate). The feed-in tariff received by each project is equivalent to the project's bid into the auction (pay-as-bid process). In our modelling, it is assumed that each project bids its long run marginal costs and receives an equivalent feed-in tariff over the life of the project.

The feed-in tariffs with contracts for difference (FiT) scenario is very similar to the LET, with two differences.[22] The first is that existing low-emissions gas is not eligible to earn (partial) certificates. The second is that, if generators bid their long run marginal cost (LRMC) of production, customers (who fund the FiT through their bills) pay the average cost of the required subsidy (i.e. the cost of the feed-in tariff for each plant), rather than the (higher) cost of the marginal plant as occurs in the LET (and RET).

Figure 78 shows the annual level of additional contracted eligible capacity required to meet the cumulative emissions constraint. The solution is similar to that of the RET and the LET schemes, in that two different levels of contracting are required to achieve a least-cost solution.

[22] A slightly lower cost of capital (0.5% lower) is used in the FiT scenario due to the lower risk associated with long-term government contracts. Sensitivities on the WACC adjustment have not been conducted. Given the similarity between the FiT and the LET schemes, while variations in the cost of capital may change the ranking of the two schemes their performance on most metrics would likely remain very similar.

Figure 78: Annual incremental FiT volumes



Source: Jacobs

For further discussion see Section 2.

3.7.2 Key findings

The FiT scenario is very similar to the LET scenario as would be expected. Consumer prices are slightly lower than the LET as described above, while resource costs (adjusted for foregone electricity demand) are around the same. The loss of low-cost emissions reductions through subsidising low-emissions gas plant more than offsets the somewhat higher demand due to the smaller consumer price increases.

Generation in the FiT scenario in the 2020s more closely resembles the LET scenario than the RET scenario.

The FiT scenario has the highest investment in wind energy of all scenarios. This is due to the lower weighted average cost of capital under this policy allowing a greater proportion of renewables to be unlocked in the 2020s, most of which is wind. Unlike all other policies, the price stability that results from the contracts for difference do not disadvantage renewables that are built in the late 2020s, before the new low emission technology becomes available.

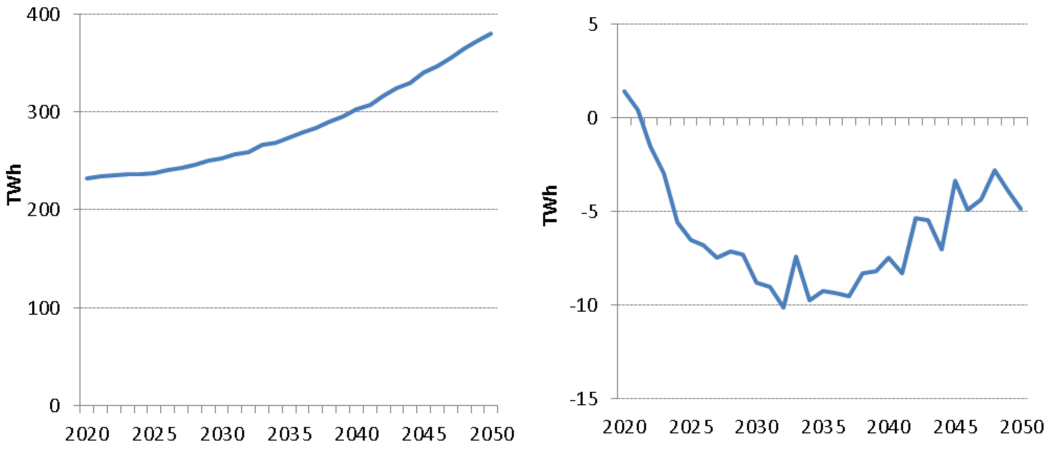
Modelling outcomes after 2030 under the FiT are almost identical to those of the LET.

3.7.3 Demand

Figure 79 shows sent-out energy demand from the FiT scenario. Total energy consumption reaches 380 TWh in 2049/50, 5 TWh per annum lower than the reference case.

Figure 79: Sent-out energy, feed-in tariffs

The left graph shows absolute energy use. The right graph shows figures relative to the reference case.



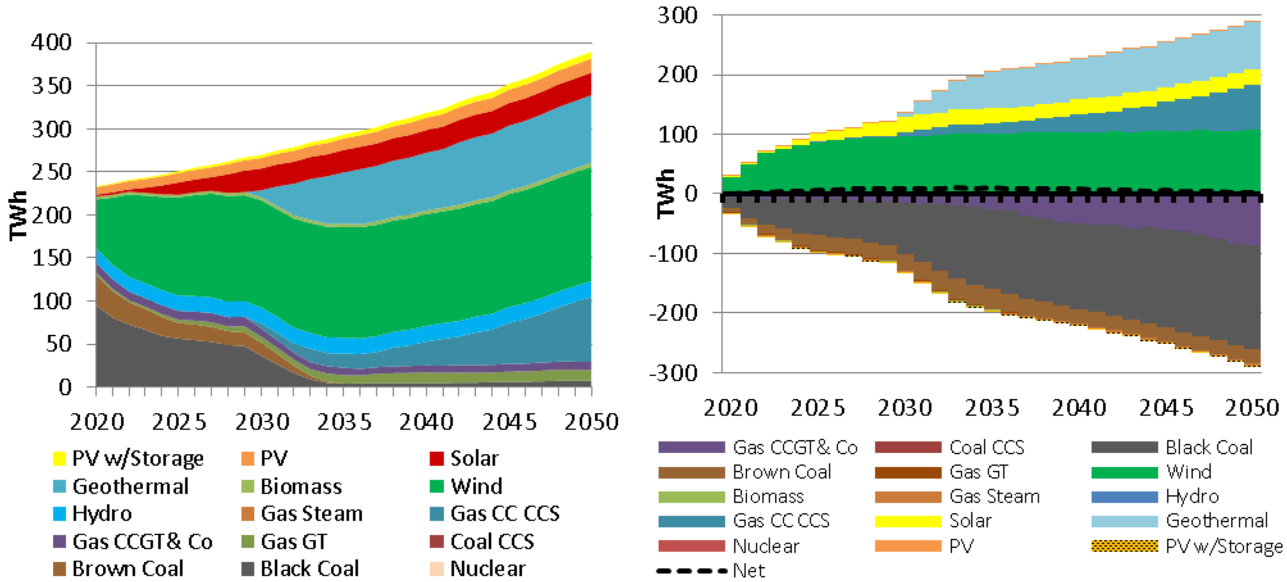
Source: Jacobs

3.7.4 Generation and capacity

Figure 80 shows the generation mix across the modelling horizon. The key trends in the graph are similar to those of the LET scenario.

Figure 80: Generation mix, feed-in tariffs

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



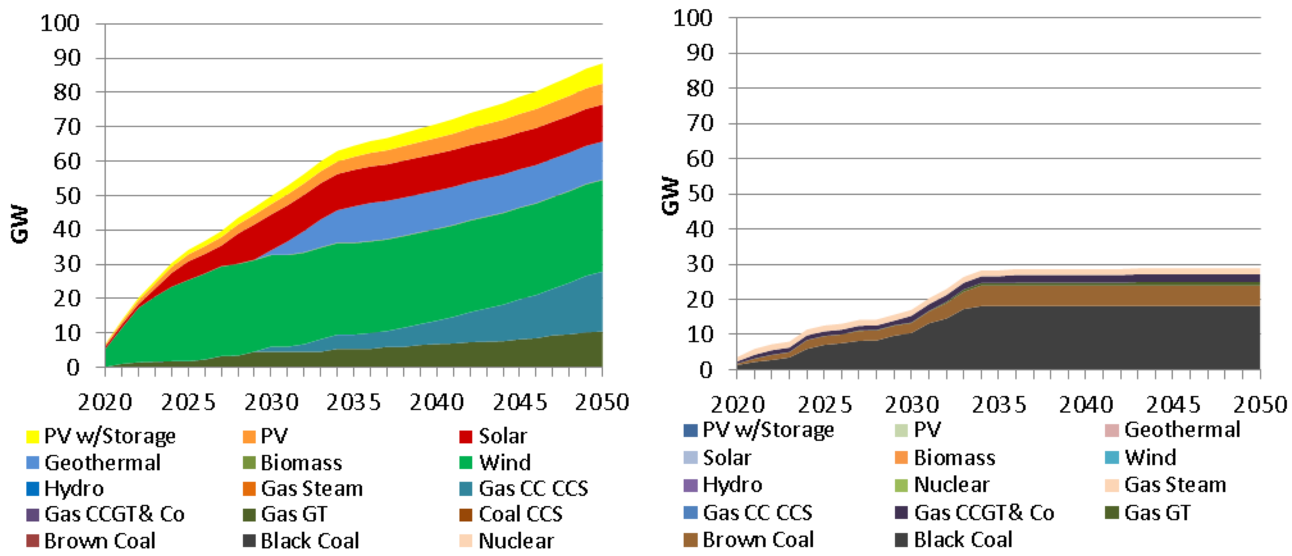
Source: Jacobs

Figure 81 shows cumulative new generation capacity under the FiT. Low emission technologies dominate new build, and, as with the RET and LET, gas turbines play an important role as new build plant in providing back-up for the intermittent generation capacity.

Under the FiT scenario there are nine transmission upgrades, including a new transmission line connecting South Australia with New South Wales, totalling 6,320 MW. This is almost 3,000 MW more than the reference case and is required to unlock relatively low cost renewable energy resources, such as those located in South Australia. The difference in the transmission capacity between the LET and the FiT is that the FiT only applies to new generation (unlike the LET which allows conventional efficient gas turbines to earn certificates) and the pattern of dispatch and investment differs in this scenario.

Figure 81: Cumulative new and retired capacity, feed-in tariffs

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



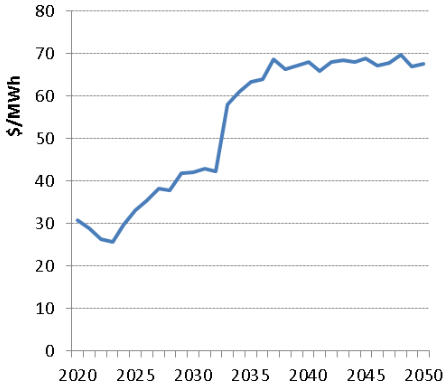
Source: Jacobs

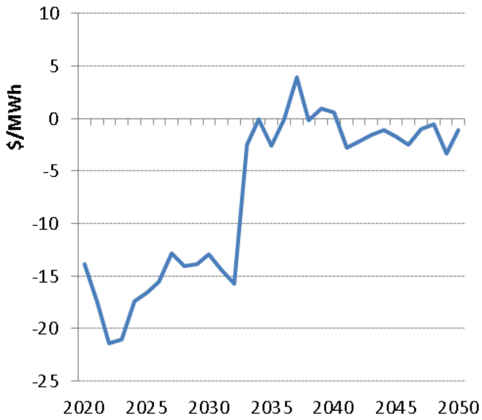
3.7.5 Prices

Figure 82 shows wholesale time-weighted prices. Price trends are similar to those of the LET scenario, although they tend to be slightly higher because CCGTs do not generate as much since they do not earn certificate revenue. As with the RET and LET scenarios, prices after 2040 are capped by the new entry level of fossil generators, which results in prices similar to the reference case.

Figure 82: Wholesale electricity time-weighted prices, feed-in tariffs

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



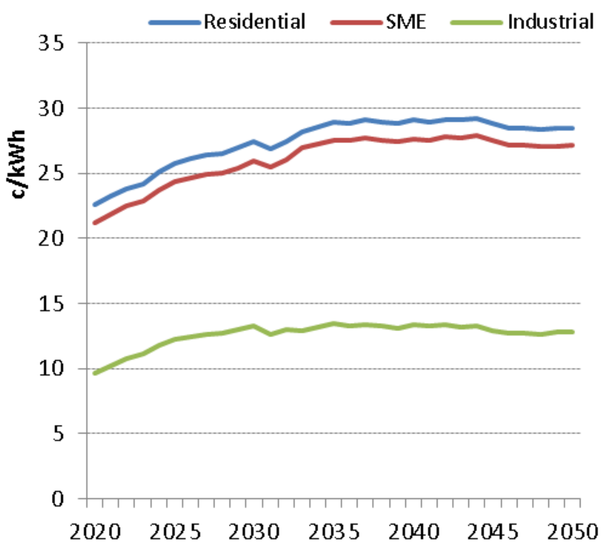


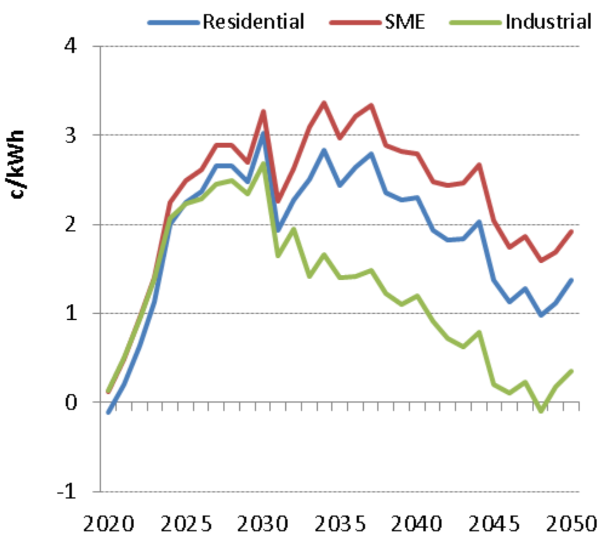
Source: Jacobs

Figure 83 shows weighted average retail prices by customer class which are very similar to the LET's retail prices. These prices are heavily influenced by the FiT subsidy, particularly in the later years, especially since the volume of the FiT scheme is large.

Figure 83: Retail prices by customer class, feed-in tariffs

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



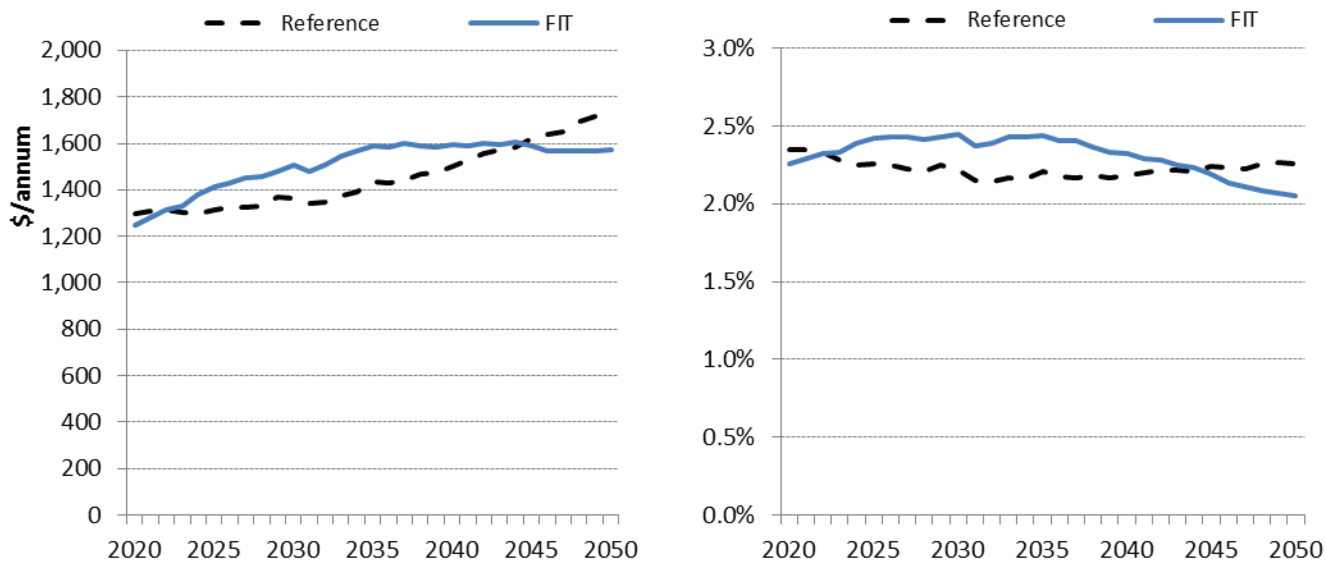


Source: Jacobs

Figure 84 shows the weighted average residential retail bill relative to the reference case, and also as a percentage of disposable income. Overall, residential bills are expected to increase moderately relative to the reference case. The residential bill is also expected to be lower than that of the RET scenario, reflecting the scheme design's lower compliance costs.

Figure 84: Residential bills, feed-in tariffs

The left graph shows the absolute residential bill. The right graph shows the residential bill as a % of disposable income.



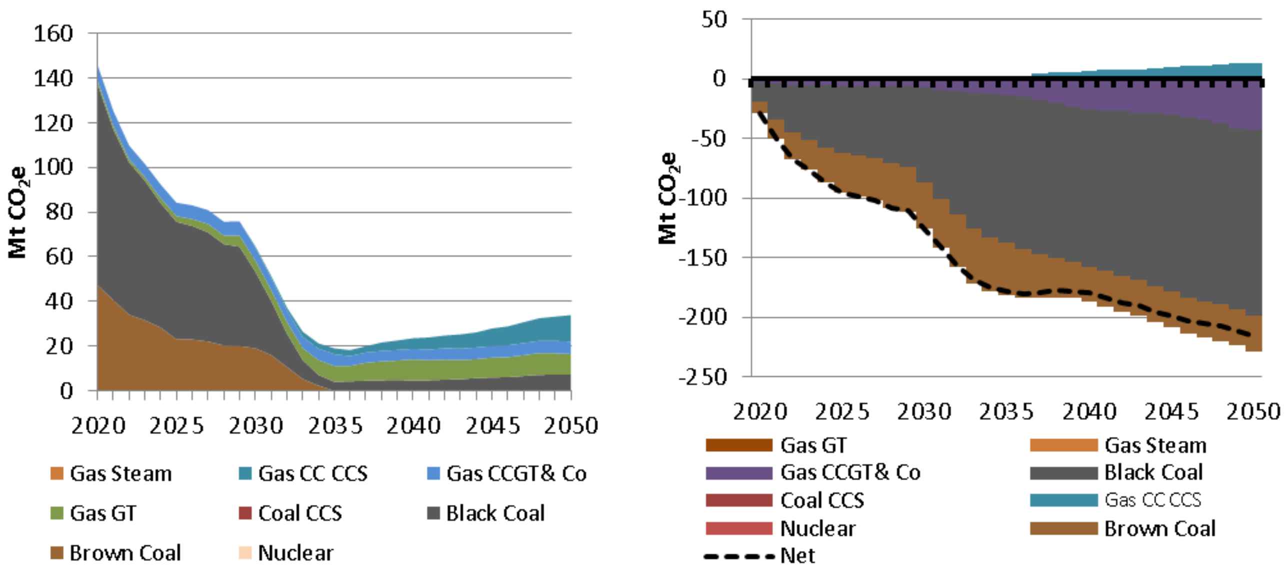
Source: Jacobs

3.7.6 Emissions

Figure 85 shows annual emission by technology and the difference relative to the reference case. The patterns in the charts are very similar to those of the LET scheme. Figure 86 shows the generation emission intensity both in absolute terms and relative to the reference case. It follows a very similar trajectory to that of the LET.

Figure 85: Emissions by technology, feed-in tariffs

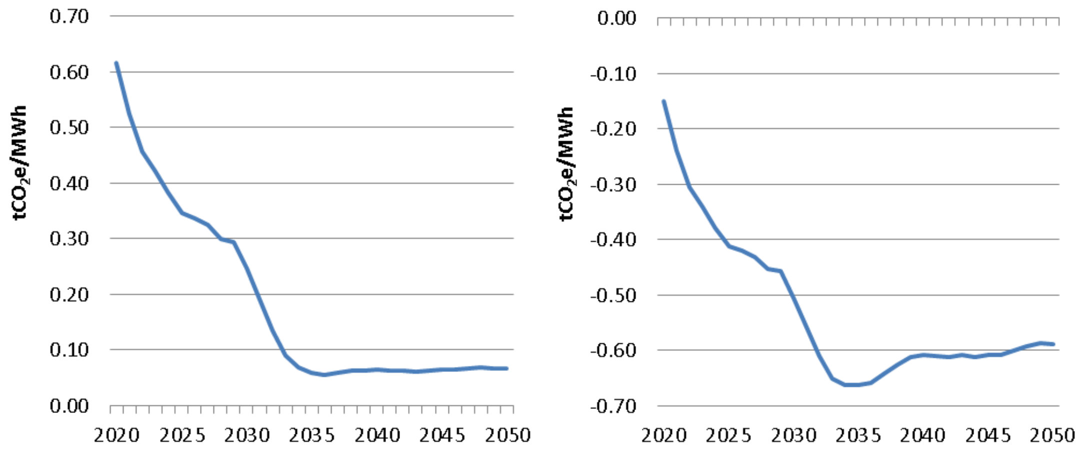
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs. Includes both direct and indirect emissions.

Figure 86: Generation emission intensity, feed-in tariffs

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



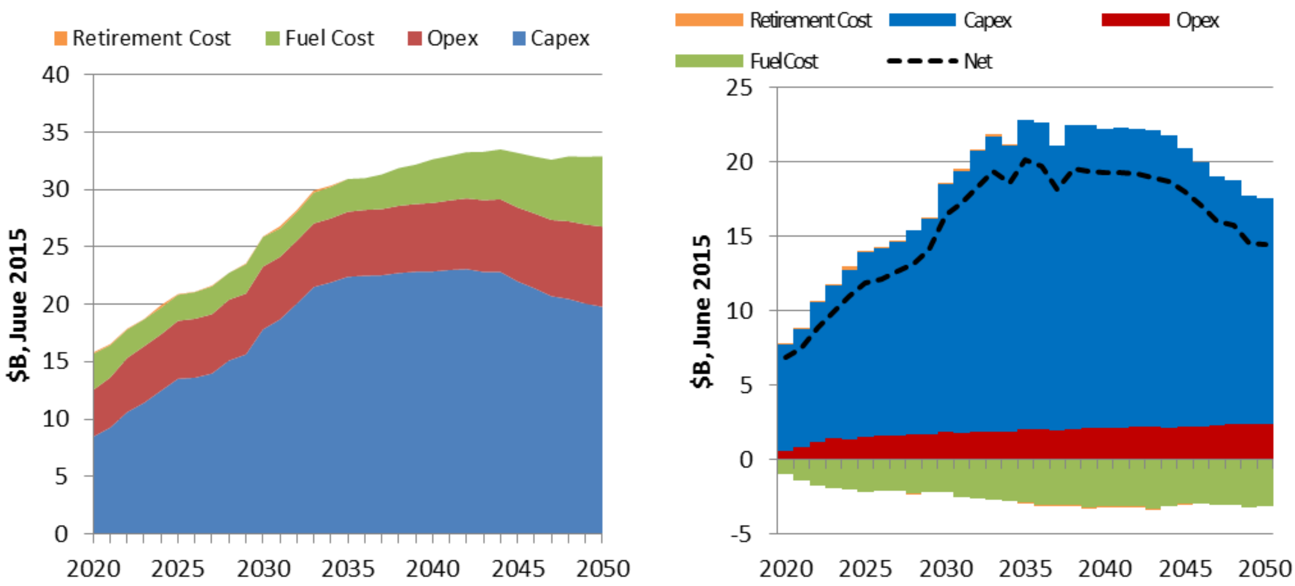
Source: Jacobs. Includes direct emissions only.

3.7.7 Costs

Figure 87 shows annualised resource costs by four cost categories. The trends in these charts are very similar to those of the LET scenario, with capital costs peaking for both scenarios $25 billion above those of the reference case. Fuel cost savings relative to the reference case are also similar to those of the LET scenario.

Figure 87: Annualised costs by category, feed-in tariffs

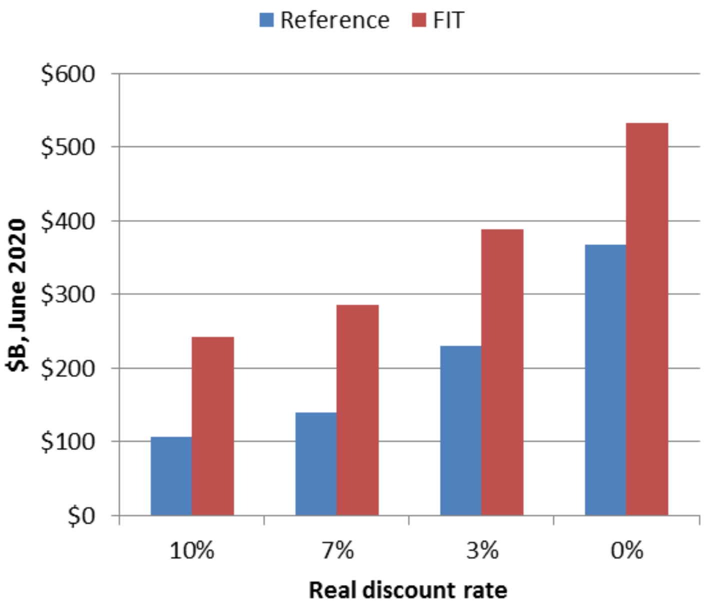
The left graph shows the absolute costs. The right graph shows the costs relative to the reference case.



Source: Jacobs

Figure 88 shows the net present value of the resource costs for the FiT scenario in absolute terms and relative to the reference case for four separate discount rates. The outcomes are very similar to those of the LET, except that the FiT has 5% higher costs at a 10% real discount rate and 3% higher costs with no discounting. Under the FiT there is slightly more demand and existing gas plant do not earn any revenue so the emissions constraint has to be met by more new low emission plant.

Figure 88: NPV of resource costs, feed-in tariffs



Source: Jacobs. Excludes demand adjustment. See Appendix B.3.2 for further detail.

3.8 Regulated closures

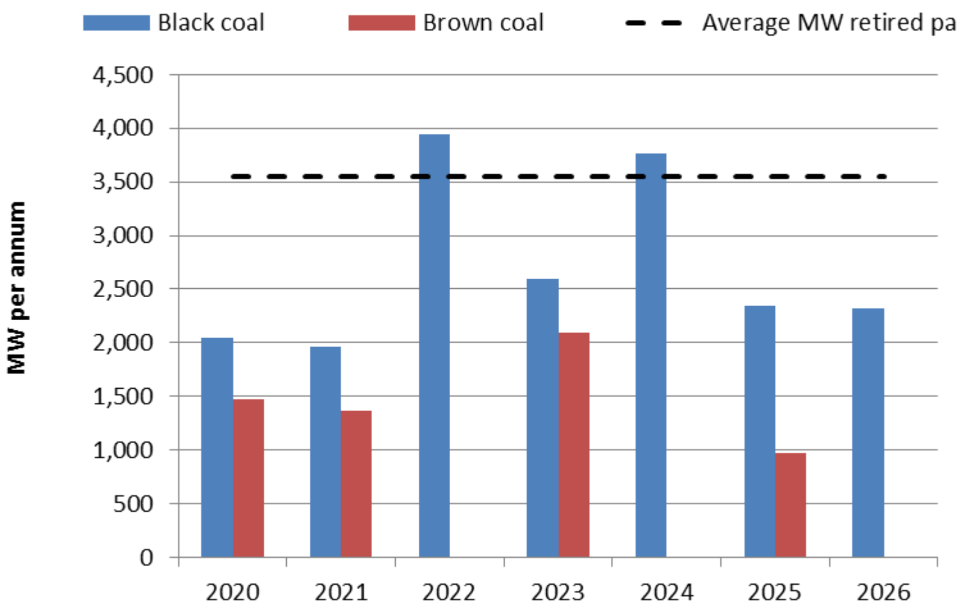
3.8.1 Scenario description

In the regulated closures scenario, coal fired plants are required to close in order of age, starting with the oldest. Two different closure criteria for coal fired generators were originally considered for this scenario: one based on the age of the plant and the other based on the plant's emission intensity. However, it was found that the closure sequences based on these two criteria were 70% correlated, and therefore modelling outcomes were not expected to be materially different. All modelling of this scenario was subsequently conducted based on the age criterion and plant was progressively retired, with the last generator closing in 2027.

No new coal fired generators are permitted under this scheme unless they are fitted with CCS technology. Furthermore, a limit on the annual emissions of gas fired generators was also imposed, restricting their annual emissions to no more than 2,200 t CO_2-e per MW.

Figure 89 shows the final profile of coal fired generation closures used for this scenario. As explained below, this was the only scenario in which the cumulative emissions constraint was not achieved. The final trialled closure rate was just over 3,500 MW of coal fired capacity per annum.

Figure 89: Coal fired generation capacity closures by year, regulated closures policy



Source: Jacobs

For further discussion see Section 2.

3.8.2 Key findings

The regulated closures policy (the "regulated" scenario) was the only Phase 1 policy scenario that did not achieve the cumulative emissions constraint, and also had one of the highest resource costs. Cumulative emissions were 1,808 Mt CO_2-e for the regulated scenario, almost 230 Mt CO_2e over the constraint. The policy relies on increases in wholesale prices to encourage investment in low emission generation. However early prices are not sufficiently high to encourage enough investment in renewable generation over gas generation in the 2020s even if all coal generation is closed by 2027. From 2030 onwards geothermal and CCGTs with CCS become available and are the marginal new entrant technologies given the new entrant constraint on coal without CCS and restriction on conventional gas fired generation. The gas fired emissions restriction effectively raises their long-run marginal cost (they have to recover the same fixed costs over a much lower generation volume) to a level above that of the low emission technologies. However, emissions during the 2020s were high because:

(i) a large volume of new entrant CCGT and GT plant had entered and were heavily dispatched, and

(ii) before they closed, residual coal fired generation levels were elevated.

From this perspective, the regulated scenario has the opposite inefficiencies of the RET, LET and FiT scenarios[23]. Those scenarios directly encourage low emission generation but do not have a direct mechanism to force the closure of high emitting fossil generation. The regulated scenario has this mechanism, but lacks an incentive mechanism to encourage early investment in low emission generation.

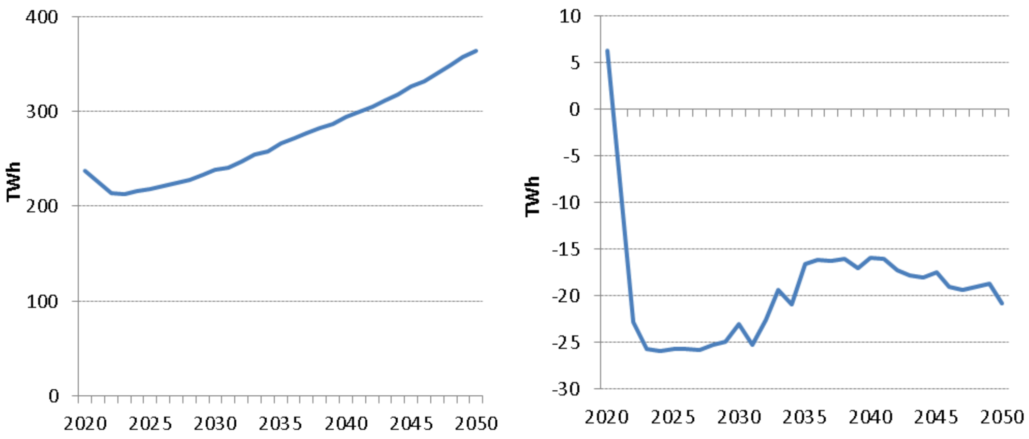
3.8.3 Demand

Figure 90 shows sent-out energy demand for the regulated scenario and relative to the reference case. Total energy consumed reaches 364 TWh in 2049/50, 21 TWh lower than the reference case due to higher wholesale prices reducing demand.

[23] We refer to these three as the "technology pull" schemes.

Figure 90: Sent-out energy, regulated closures

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Pitt & Sherry, ACIL Allen and Jacobs

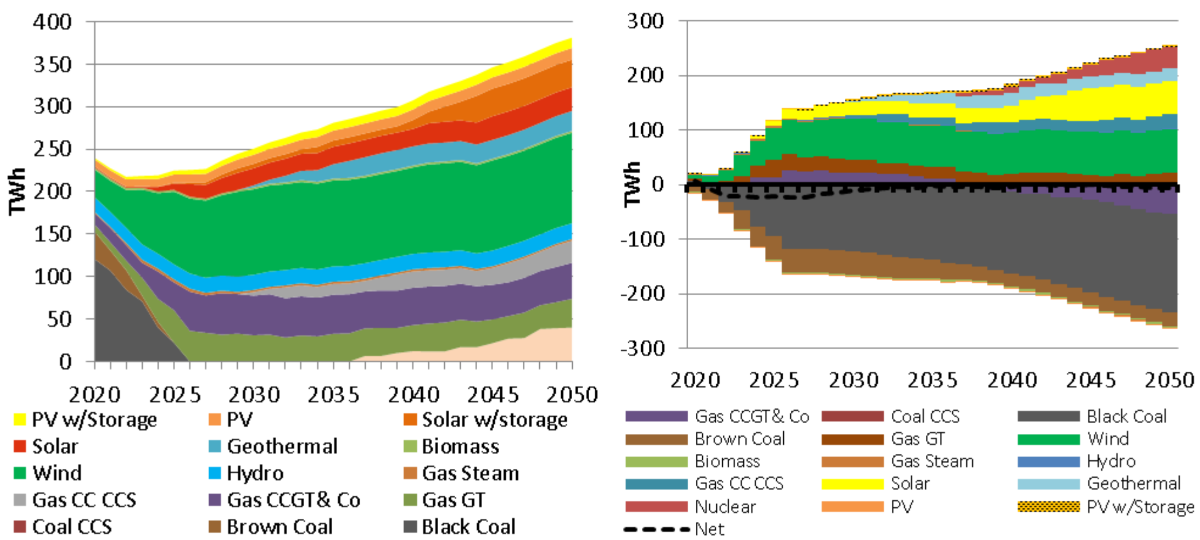
3.8.4 Generation and capacity

Figure 91 shows the generation mix across the modelling horizon both in absolute terms and relative to the reference case. Coal fired generation is closed down within seven years. CCGTs and gas turbines replace this generation through a combination of new investment and elevated generation levels relative to the reference case. By the time new low emission technologies become available post 2030, all of the coal fleet has already been replaced and CCGT and GT investment has been locked in.

Figure 92 shows cumulative new generation capacity across the NEM and WEM. It shows that wind capacity is the dominant new entrant technology in the 2020s, with important contributions from solar, CCGTs and gas turbines.

Figure 91: Generation mix, regulated closures

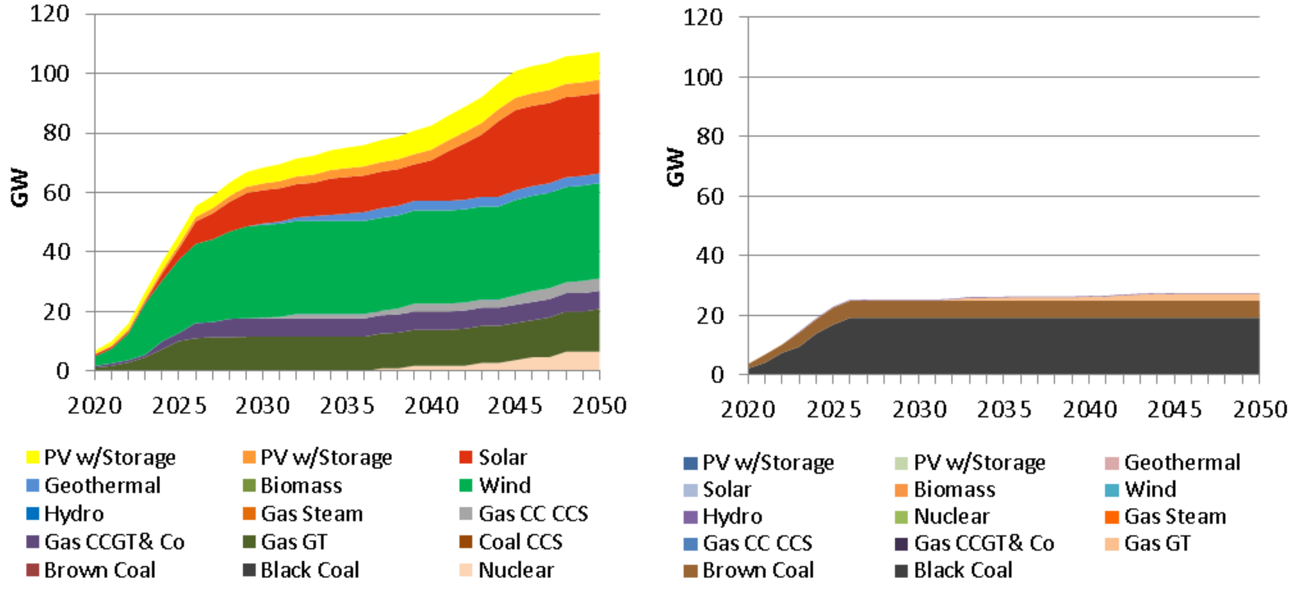
The left graph shows absolute figures. The right graph shows figures relative to the reference case



Source: Jacobs

Figure 92: Cumulative new and retired capacity, regulated closures

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



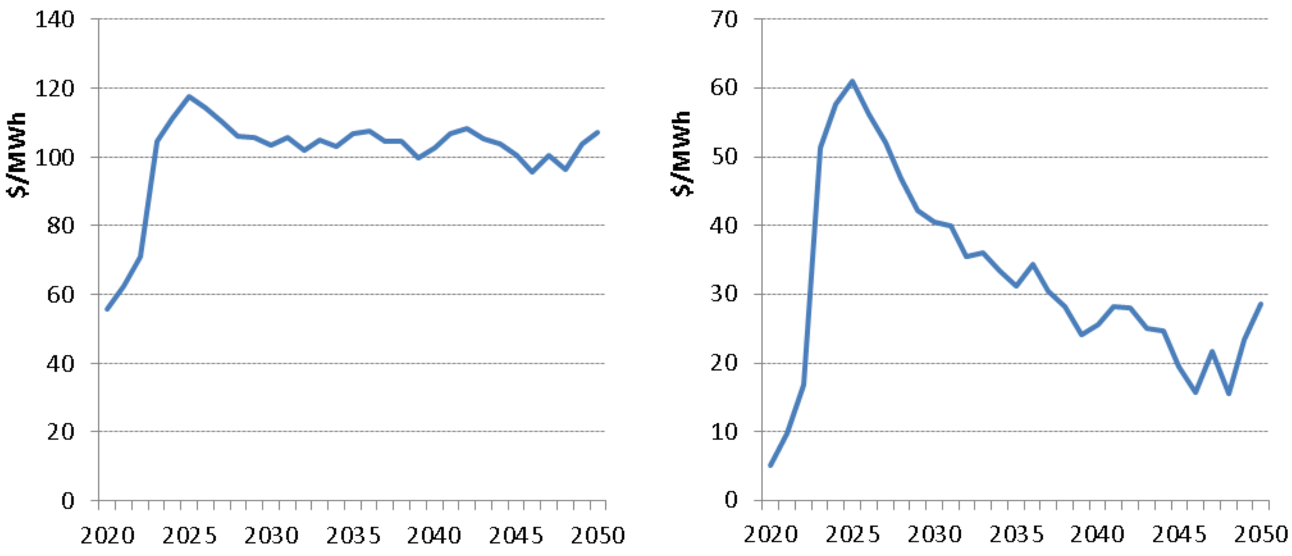
Source: Jacobs

3.8.5 Prices

Figure 93 shows average wholesale prices weighted by region. Prices start from a level that is higher than that of the reference case and escalate rapidly from there, reaching the effective new entrant price of CCGT technology. In the long-term prices trend downwards gently and this reflects the learning rate of CCGT with CCS technology, which is the marginal new entrant technology post 2030.

Figure 93: Wholesale electricity time-weighted prices, regulated closures

The left graph shows absolute figures. The right graph shows figures relative to the reference case.

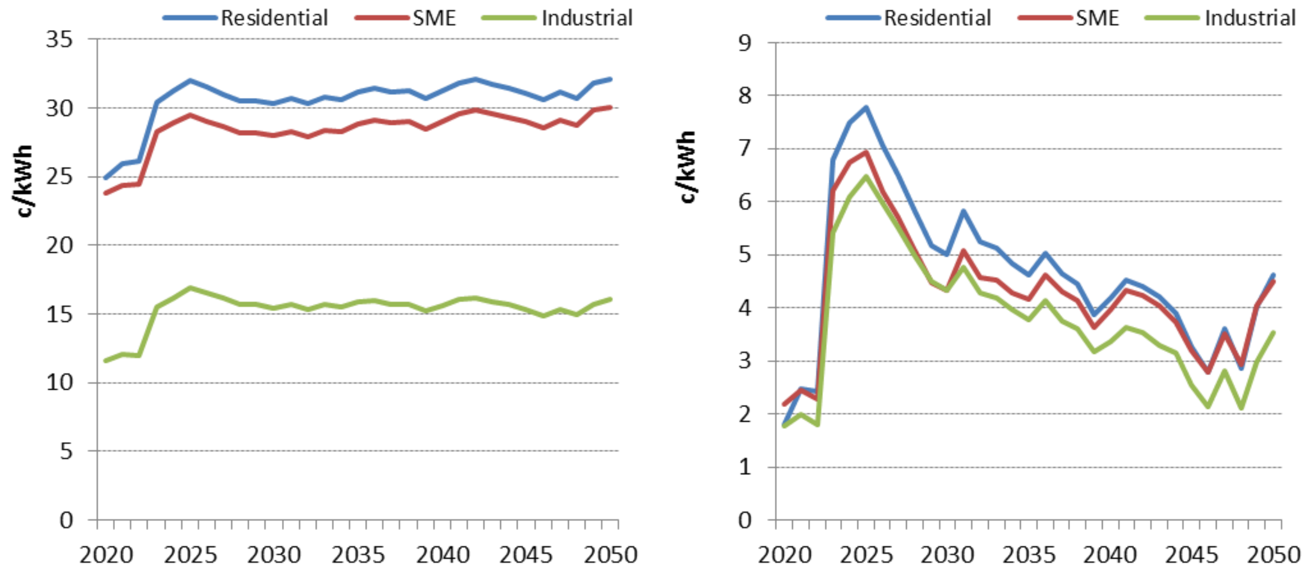


Source: Jacobs

Figure 94 shows weighted average retail prices by customer class. They contain the same trends as the wholesale prices, but the relative price movements are more muted since the wholesale price only comprises typically 30% to 40% of the retail price.

Figure 94: Retail prices by customer class, regulated closures

The left graph shows absolute figures. The right graph shows figures relative to the reference case.

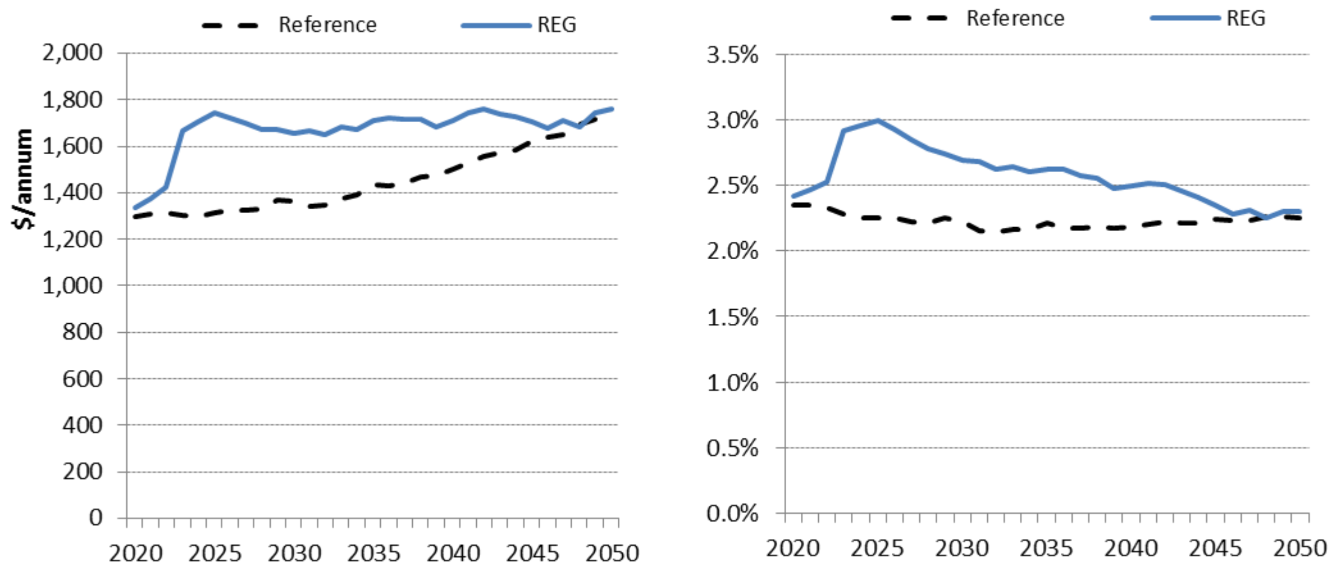


Source: Jacobs

Figure 95 shows the weighted average residential bill relative to the reference case, and also as a percentage of disposable income. The high wholesale prices lead to retail prices that are higher than those of the reference case, and consequently the average residential bill is also higher by an average of $220 per annum.

Figure 95: Residential bill, regulated closures

The left graph shows the absolute residential bill. The right graph shows the residential bill as a % of disposable income.



Source: Jacobs

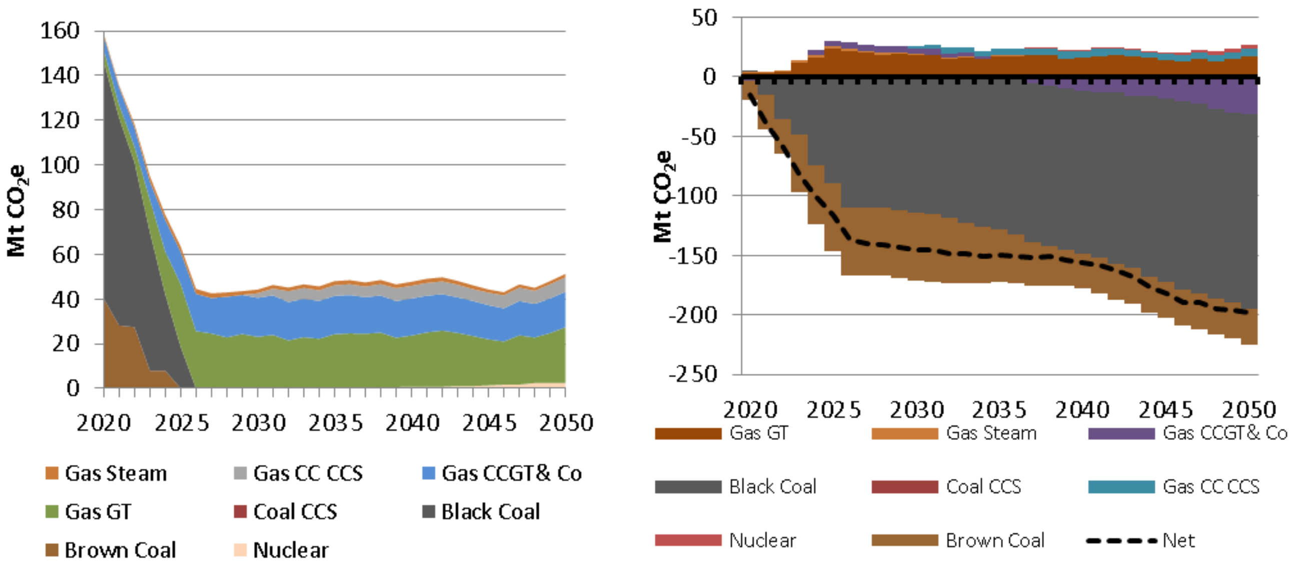
3.8.6 Emissions

Figure 96 shows annual emissions by technology and the difference relative to the reference case. Emissions decline linearly in the 2020s, consistent with the linear closure of coal plant. CCGT and gas turbine emissions both increase markedly in 2025/26, when all coal fired capacity has been retired. The combined emissions from these two technologies are effectively locked in from this date, since they remain fairly constant over the remaining 24 years of the modelling horizon. Gas turbines generate at relative high levels from 2027 to 2050, contributing to about 50% of emissions over this period.

For the regulated closure case, the cumulative emission target was not met. There was an excess to the target of 200 Mt CO_2e.

Figure 96: Emissions by technology, regulated closures

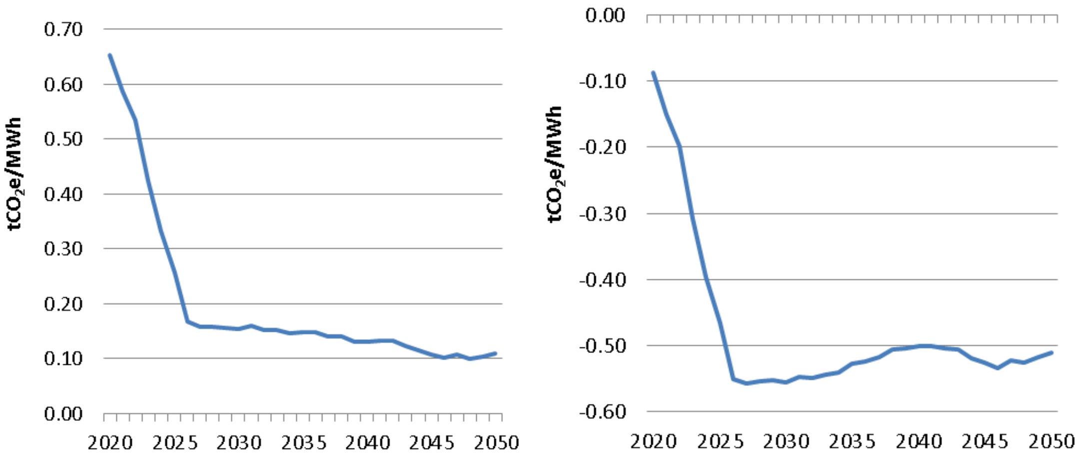
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs. Includes both direct and indirect emissions.

Figure 97: Generation emission intensity, regulated closures

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



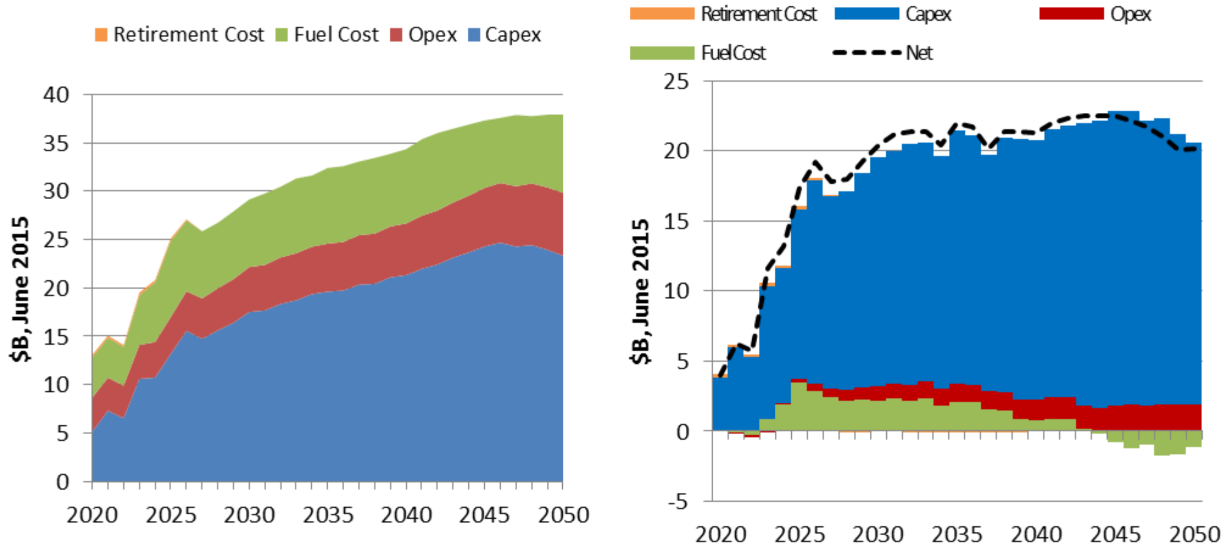
Source: Jacobs. Includes direct emissions only.

3.8.7 Costs

Figure 98 shows annualised resource costs by four cost categories. Costs in 2019/20 are about $13 billion per annum, but they escalate rapidly beginning in 2022/23 when they reach almost $20 billion. Costs peak in 2049/50 when they reach almost $38 billion per annum. Fuel costs, opex costs and capex costs in particular are all higher relative to the reference case. Capex is particularly high and peaks at almost $25 billion per annum, which is slightly higher than that of carbon pricing. The level of annual costs is comparable to that of carbon pricing in the later years, but costs under the regulated scenario are front-loaded due to the rapid closure of the coal fleet, which requires rapid spending on capital.

Figure 98: Annualised costs by category, regulated closures

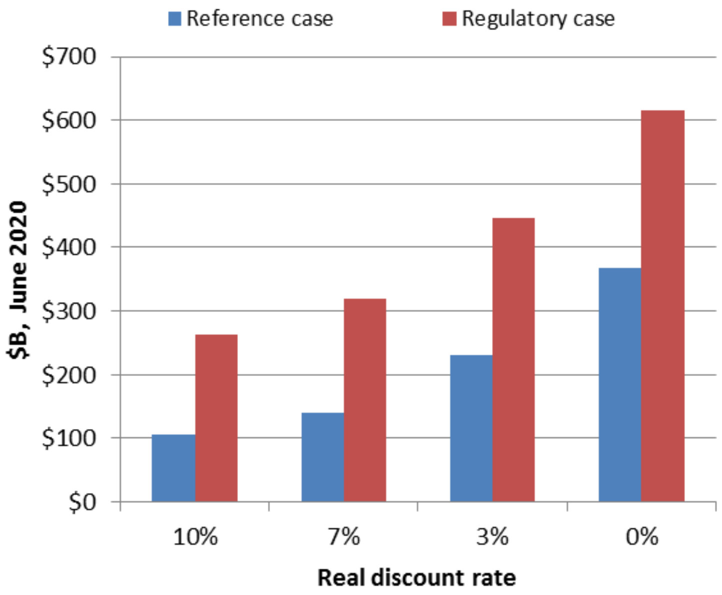
The left graph shows the absolute costs. The right graph shows the costs relative to the reference case.



Source: Jacobs

Figure 99 shows the net present value of the resource costs for regulated closures relative to the reference case for four separate discount rates. The total resource cost for regulated closures ranges from 148% (at 10% real discount rate) to 67% (without discounting) higher than that of the reference case. This is a materially higher cost than for carbon pricing, noting the policy also does not achieve the required level of cumulative abatement.

Figure 99: NPV of resource costs, regulated closures



Source: Jacobs. Excludes demand adjustment. See Appendix B.3.2 for further detail.

3.9 Absolute baselines

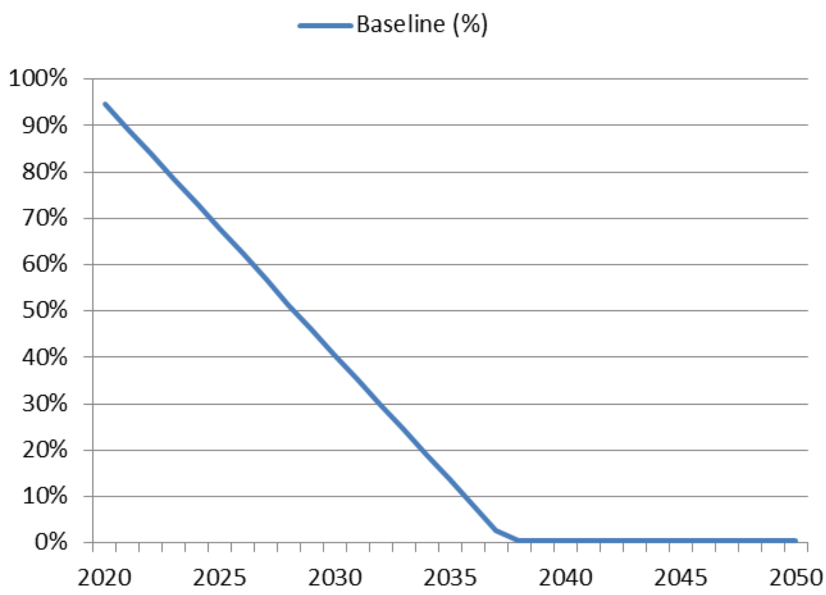
3.9.1 Scenario description

Absolute baselines applies a constraint on emissions output of each incumbent generating facility without certificate trading. The baselines decrease linearly over time for incumbent gas fired and coal fired generators. Generators are not restricted by their baseline if their emission intensity in a given year is lower than the average grid emission intensity. This affects gas fired generation in early years. The final key feature of the scheme is no new fossil generation is permitted without CCS[24].

Figure 100 shows the absolute baseline trajectory required to achieve the cumulative emissions constraint. It implies that all incumbent generators are forced to retire in 2042/43, which is when their baseline is zero. With respect to the retirement requirement, an exception was made for incumbent peaking generators since they still provide a useful role at this point in time serving as back-up generation for intermittent renewable generators such as wind turbines and solar PV.

[24] However, this constraint was relaxed slightly as around 650 MW of gas OCGTs were required in the WEM during the 2020s to meet the system reliability constraints

Figure 100: Absolute baseline trajectory for existing generators



For further discussion see Section 2.

3.9.2 Key findings

The cumulative emissions constraint was assisted by the combination of reducing baselines and the prohibition on new fossil fuel generation. If new CCGTs were allowed to, they would enter the market and limit prices to the CCGT new entry price level, which would be too low to encourage large volumes of renewable energy generation. As CCGTs with CCS cannot be built in the 2020s to bridge the supply gap caused by the declining baselines, the only alternative option to fill this gap is renewable generation.

The early entry of renewable generation in the 2020s causes a large spike in wholesale and retail prices between 2025 and 2030. This is because prices after 2030 are capped by the price of CCGTs with CCS, which is about $80/MWh – too low to support early renewable energy investment. This means that renewable investment in the 2020s can only occur if market prices before 2030 enable this plant to recover all of their costs, given a lower price profile after 2030. After 2030 the broader range of available technologies allows the emissions constraint to be achieved with lower prices.

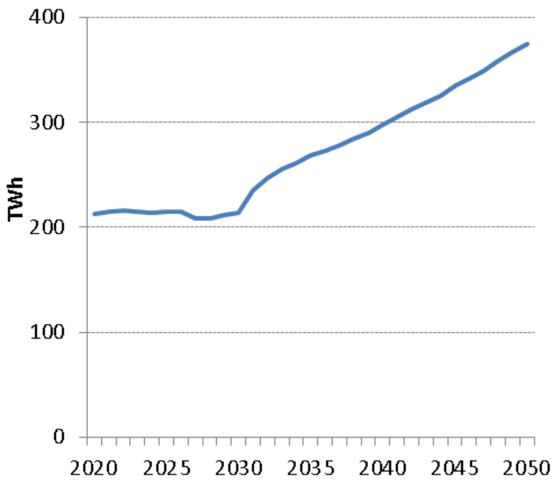
3.9.3 Demand

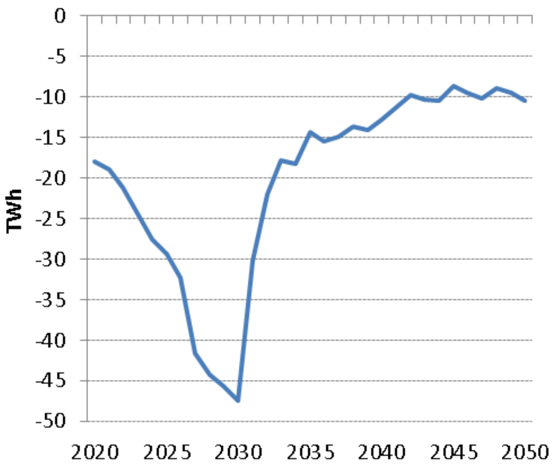
Figure 101 shows sent-out energy demand for absolute baselines and relative to the reference case. Total energy consumed reaches 375 TWh in 2049/50, 10 TWh lower than the reference case due to higher wholesale prices reducing demand. Demand in the 2020s is flat, and this is due to the price spike needed to make early investment in renewable energy generation viable.

The demand changes from increases in prices are applied in one year rather than lagged across multiple years, for simplicity. This means that demand rebounds in full when prices moderate again. In practice, adjustment may occur with more of a lag.

Figure 101: Sent-out energy, absolute baselines

The left graph shows absolute figures. The right graph shows figures relative to the reference case.





Source: Pitt & Sherry, ACIL Allen and Jacobs

3.9.4 Generation and capacity

Figure 102 shows the generation mix across the modelling horizon both in absolute terms and relative to the reference case. Key features include the dominant role played by wind generation in the 2020s as the key new entry technology, and to a lesser extent, large-scale solar generation. The linear decline in generation for the incumbent coal fired and gas fired generation reflects the application of the absolute baselines to these plants. CCGTs with CCS are the dominant new entrant technology post 2030, and geothermal technology only becomes fully competitive as a new entrant in the mid-2040s. The reason for the delayed entry of geothermal is that market prices are lower under absolute baselines relative to the carbon pricing scenario, and one further decade of learning is required to make geothermal competitive with gas fired CCS in the absence of a carbon price or a renewable subsidy.

Figure 103 shows cumulative new generation capacity under absolute baselines. Wind and solar generation technologies clearly dominate new build in the 2020s, followed by CCGTs with CCS in the 2030s and beyond, and finally geothermal from the mid-2040s.

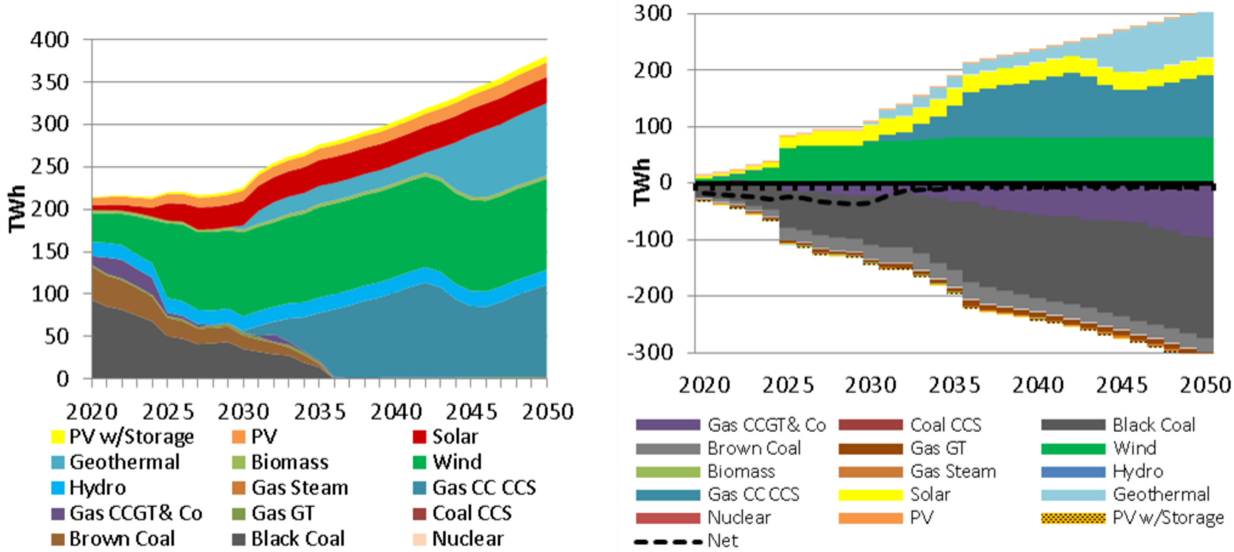
Some coal fired plant experience low capacity factors under the absolute baseline scheme. However, the modelling indicates they remain profitable at these low capacity factors.[25] Essentially generation for these plants is confined to the peak demand periods during summer or other high demand periods. The wholesale prices during these periods are sufficient for these plants to recover their fixed costs as well as short-run marginal costs.

Under the absolute baselines there are nine transmission interconnector upgrades totalling 7,520 MW in transfer capacity, including a new transmission line connecting South Australia to New South Wales. This is over 4,000 MW more than what is required for the reference case and is required to unlock relatively low cost renewable energy resources, such as those located in South Australia.

[25] The affected plants have technical minimum operating capacities. If the plants are dispatched, they are dispatched at or above these minimum capacities. Other constraints such as ramp-rates are ignored as the model dispatches on an hourly basis. In long term studies such as this we assume that the generators' traders will employ anticipatory commitment/de-commitment strategies that avoid technical constraints affecting their operations.

Figure 102: Generation mix, absolute baselines

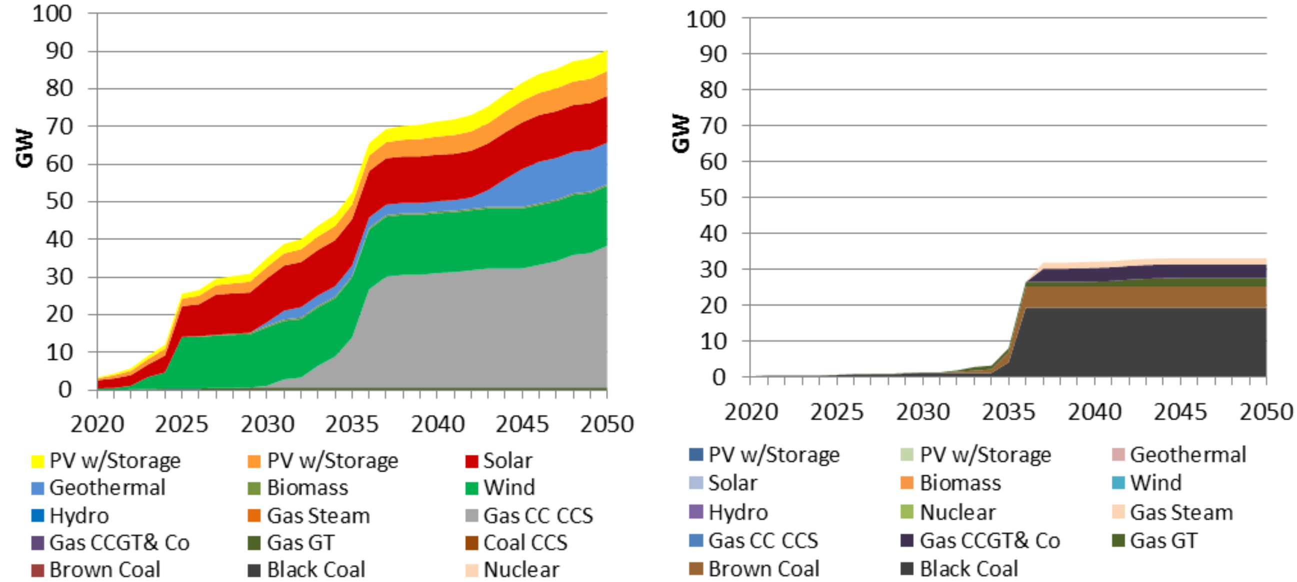
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs

Figure 103: Cumulative new and retired capacity, absolute baselines

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



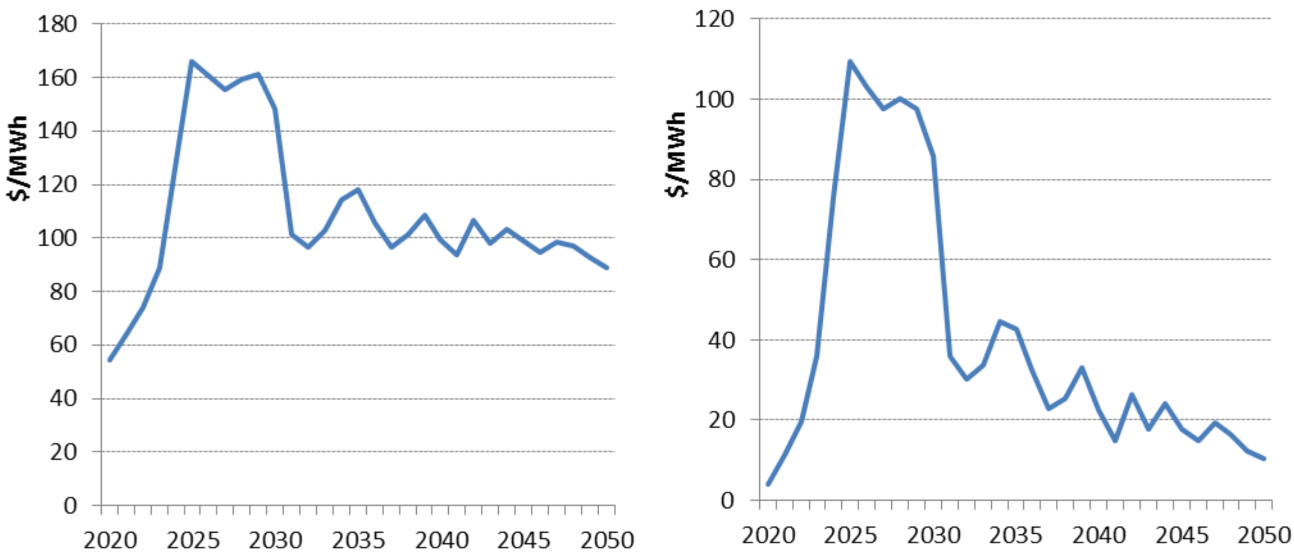
Source: Jacobs

3.9.5 Prices

Figure 104 shows wholesale electricity time-weighted prices. The large price spike in the 2020s is driven by the need for early investors in renewable generation to recover their costs before lower cost dispatchable generation, in the form of CCGTs with CCS, becomes available post 2030. Wholesale prices under absolute baselines are on average $44/MWh higher than those of the reference case across the whole modelling horizon.

Figure 104: Wholesale electricity time-weighted prices, absolute baselines

The left graph shows absolute figures. The right graph shows figures relative to the reference case.

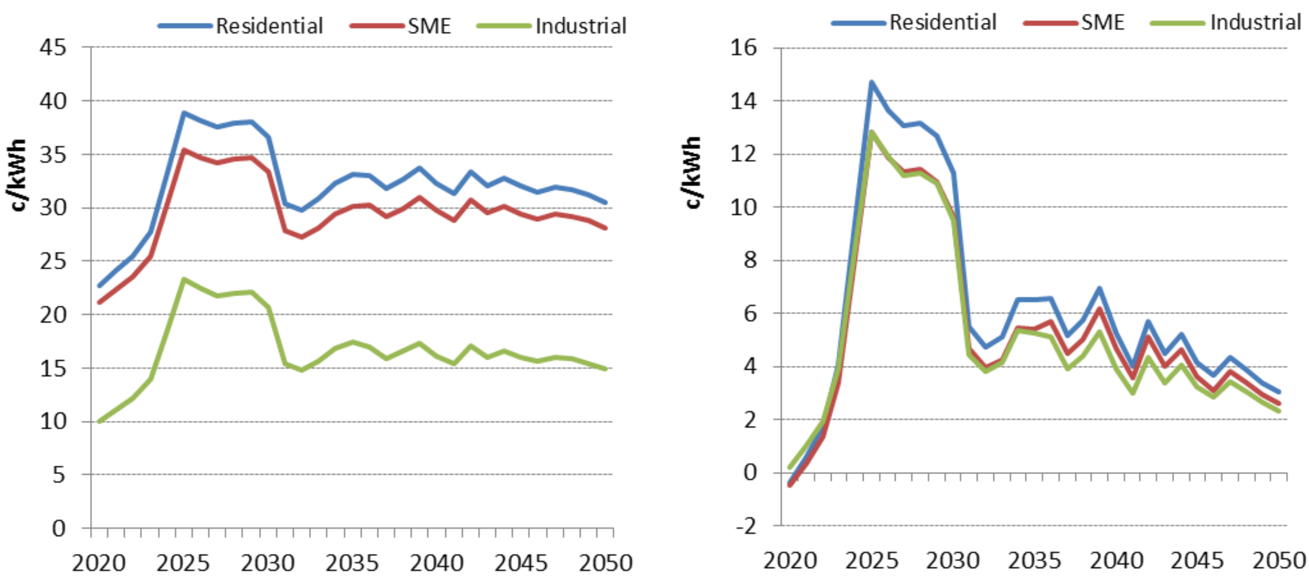


Source: Jacobs

Figure 105 shows weighted average retail prices by customer class. They contain the same trends as the wholesale prices, but the relative price movements are more muted since the wholesale price only comprises typically 30% to 40% of the retail price.

Figure 105: Retail prices by customer class, absolute baselines

The left graph shows absolute figures. The right graph shows figures relative to the reference case.

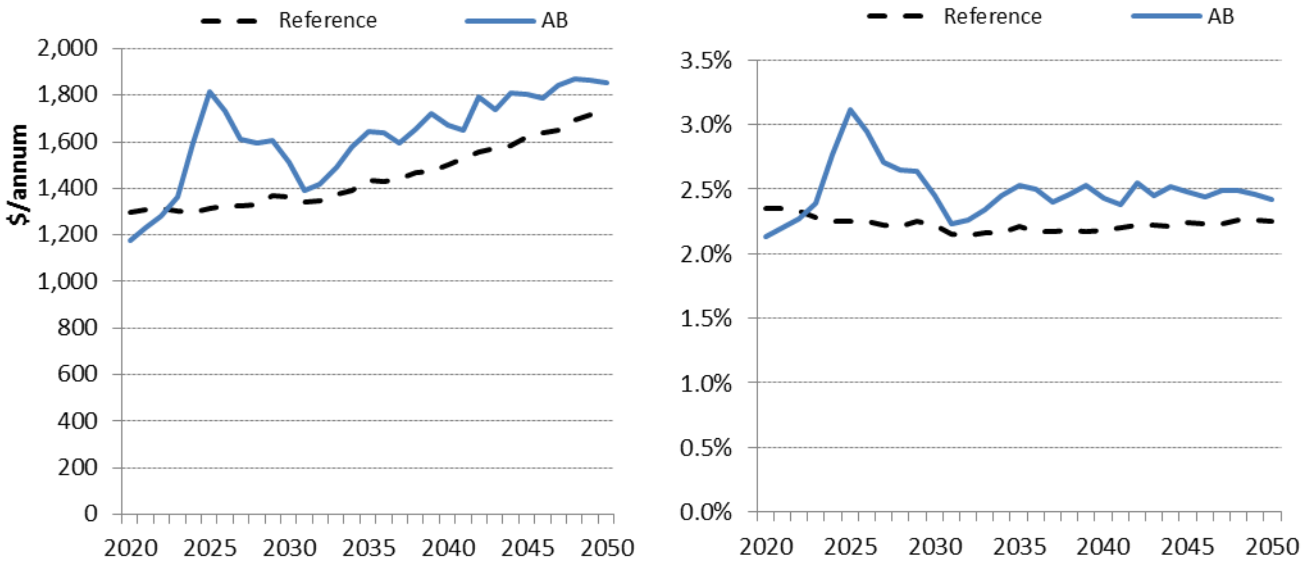


Source: Jacobs

Figure 106 shows the weighted average residential bill relative to the reference case, and also as a percentage of disposable income. The impact of the wholesale price spike on the residential bill stands out, but the spike falls away in the 2030s when the low emission technologies become available. For the first 10 years residential bills are on average $240 per annum higher relative to the reference case and only $130 per annum higher for the remaining modelled years.

Figure 106: Residential bills, absolute baselines

The left graph shows the absolute residential bill. The right graph shows the residential bill as a % of disposable income.



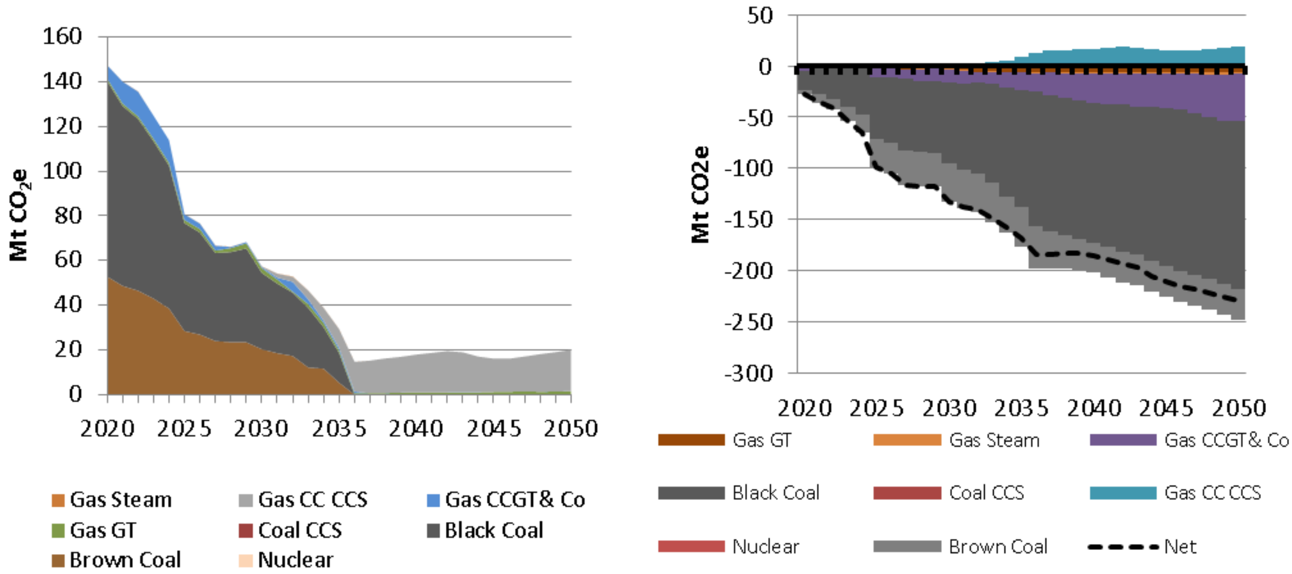
Source: Jacobs

3.9.6 Emissions

Figure 107 shows annual emissions by technology and the difference relative to the reference case. The coal fleet continues to generate until just before 2040, and the main contributor to emissions post 2040 is CCGTs with CCS.

Figure 107: Emissions by technology, absolute baselines

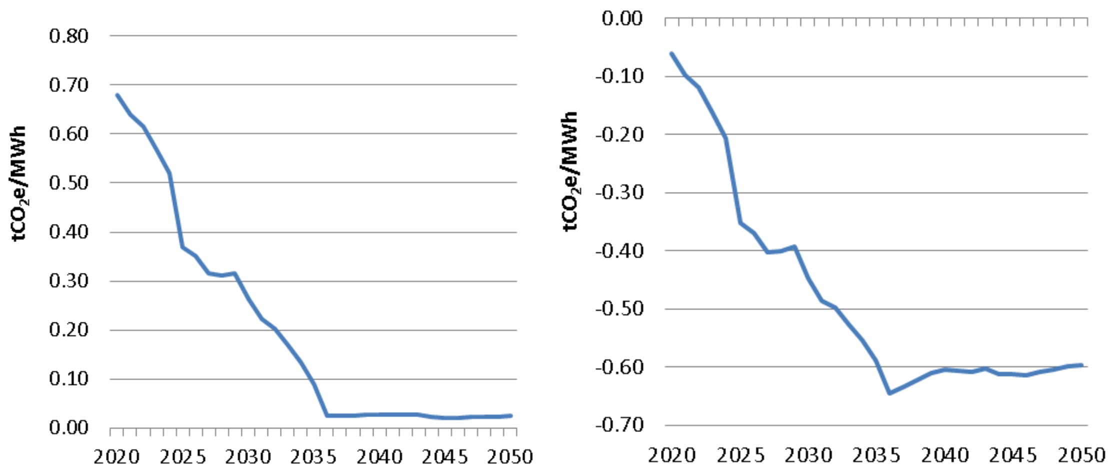
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs. Includes both direct and indirect emissions.

Figure 108: Generation emission intensity, absolute baselines

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



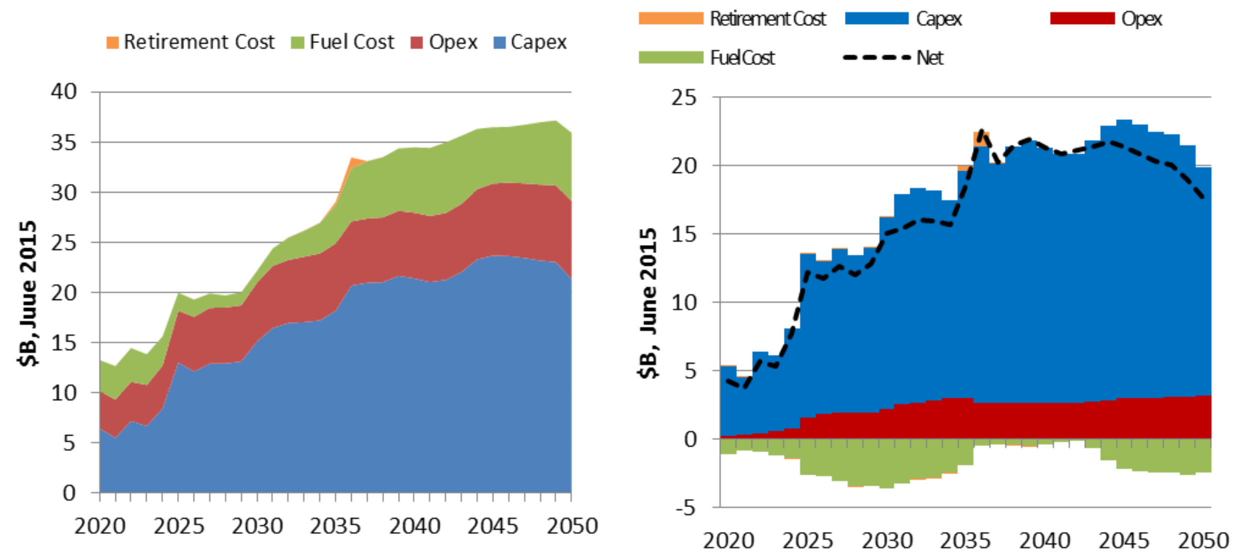
Source: Jacobs. Includes direct emissions only.

3.9.7 Costs

Figure 109 shows annualised resource costs by four cost categories. Costs in 2019/20 are about $14 billion, and they escalate rapidly from there as new renewable build is required to close the supply gap created by the declining baselines. The annual cost peaks in 2043/44 at $36.5 billion, which is about $2 billion more than the peak carbon pricing cost. Costs under absolute baselines are more front-loaded relative to carbon pricing because the supply gap created by the reduction in baselines in the 2020s has to be filled by relatively higher cost renewable energy.

Figure 109: Annualised costs by category, absolute baselines

The left graph shows the absolute costs. The right graph shows the costs relative to the reference case.

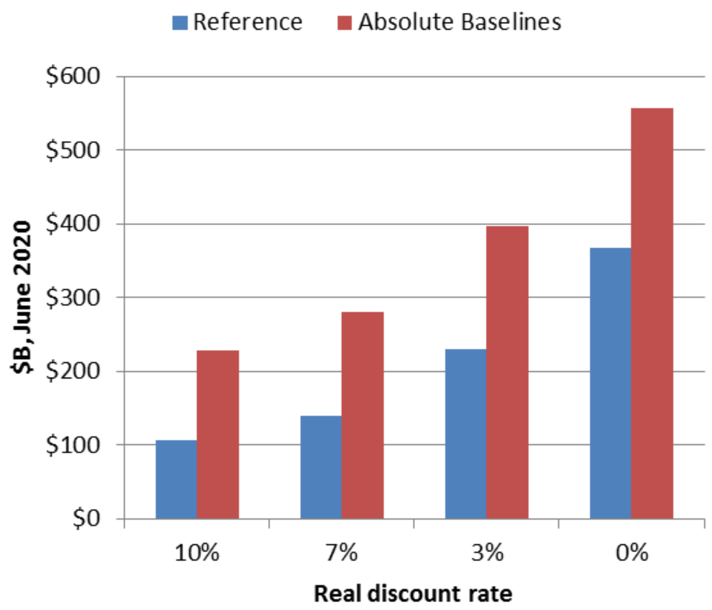


Source: Jacobs

Figure 110 shows the net present value of the resource costs for absolute baselines relative to the reference case for four separate discount rates. The total resource cost for regulated closures ranges from 114% (at 10% real discount rate) to 51% (without discounting) higher than that of the reference case. This is a higher cost relative to carbon pricing, and the reason for this is that the regulation not allowing new build of CCGTs without

CCS means that more expensive renewable plant is built in the 2020s, rather than CCGTs as was the case in the carbon scenario.

Figure 110: NPV of resource costs, absolute baselines



Source: Jacobs. Excludes demand adjustment. See Appendix B.3.2 for further detail.

4. Phase 2 overview

4.1 Introduction

Phase 2 provides further insights on the relative performance of policies by testing the performance of combinations of policies, and the robustness of individual policies to changes in key assumptions. Table 6 sets out the key questions explored in Phase 1 and Phase 2, and the policy scenarios investigated for each sensitivity. The sensitivities investigated were:

1. A weaker emissions constraint consistent with global action giving a likely chance of limiting warming to 3°C.

2. Combinations of policies, with one policy fixed and the other varied to meet the 2°C emissions constraint.

3. Higher overall electricity demand with policies fixed at the 2°C emissions constraint settings.

4. Lower overall electricity demand, coupled with faster reductions in battery storage costs and higher uptake of distributed generation and storage.

5. Technology sensitivity without any of nuclear, CCS and geothermal, in which intermittent renewables and battery storage play important roles in meeting the 2°C emissions constraint.

An expanded version of the table listing key input assumptions and sources for each sensitivity is at Appendix D.

4.2 Key points

The key insights from Phase 2 combinations and sensitivity analyses are:

- Looking across the scenarios, emissions pricing policies are considerably more flexible in adjusting to unexpected change and remain the lowest cost across these scenarios comparing multiple policies.

- The weaker emissions constraint scenario shows that the relative performance of policies is roughly the same. Emissions pricing policies have the lowest resource cost; technology pull policies involve higher resource costs. Regulated closure performs relatively better in this sensitivity.

- The policy combinations show that with a weaker carbon price, technology pull policies are better than regulated closures to achieve the same demanding emissions constraint.

- The high and low demand scenarios illustrate that emissions pricing policies are more robust to uncertain future electricity demand than technology pull policies—at least where the technology targets are fixed well in advance.

- The technology availability scenario shows that the emissions constraint can be met with currently available technologies. However resource costs are around 15% to 25% higher.

5. Results: weaker emissions constraint

Under these sensitivities, a weaker emissions constraint was applied to the electricity sector. The constraint is consistent with Australia contributing to global action giving a likely chance of limiting global temperature increases to 3°C.

The main differences between the 2°C and 3°C scenarios are:

- The carbon price is lower than in the 2°C scenarios, and it is based on the IPCC median carbon prices for stabilising emissions at 530-580 ppm.
- The coal prices are higher following IEA's 2014 WEO "New policies scenario".
- The gas prices are higher following from IEA's 2014 WEO "New policies scenario".
- The deployment rates for low emission technologies are lower based on the IEA's 2014 WEO "New policies scenario". This has the effect of lowering the learning rates for renewable technology such as solar PV and wind.

Appendix C.3 provides further details on the different assumptions used for the weaker emissions constraint sensitivities.

5.1 Scenario comparisons

The weaker emissions constraint for the electricity sector was determined to be around 2,800 Mt CO_2-e over the period to 2050, around 80% greater than for the 2°C scenarios[26].

The policies all achieved the emissions constraint. With the weaker emissions constraint, decarbonisation of the electricity sector occurred over a longer time frame. The weaker emissions constraint allowed for a greater role for gas fired generation as an intermediate fuel. The differences in resource costs across the policies were also slightly reduced. However, the rankings in terms of resource costs remain largely the same as in the 2°C cases, except the ranking of regulated closure and absolute baselines improved.

Key differences between policy scenarios under the weaker emissions constraint included:

- The mix of low emission technologies: Gas fired generation was broadly the same across the policy scenarios, except for the absolute baseline scenario which had a lower uptake than the other 3°C policy cases. Uptake of low emission capacity was again significantly higher for the technology pull policies, where renewable energy contributed over half of the generation mix. In the emissions pricing and regulatory policies, other low emission technologies - such as nuclear and CCGTs with CCS - were a higher proportion of generation than in the 2°C scenarios.
- As with the 2°C scenarios, the policies differed in key outcomes mainly as a result of the characteristics of each policy that constrained choices in dispatch and/or investment. The technology pull policies and the regulatory policies led to high levels of low emission generation particularly before 2030 and this increased the economic costs of these policies. These policies brought forward investment in low emission generation which locked those investments in and changed the pattern of investment after 2030.
- Impacts on wholesale and retail prices: The technology pull policies were projected to have lower wholesale and retail prices than the emissions pricing and regulatory policies. As a result, demand was higher in the technology pull policies and this led to greater investment in low emission technologies to achieve the same emissions constraint.

[26] As with the 2°C scenario, this was determined as equivalent to the emissions occurring under the carbon pricing scenario.

5.1.1 Demand

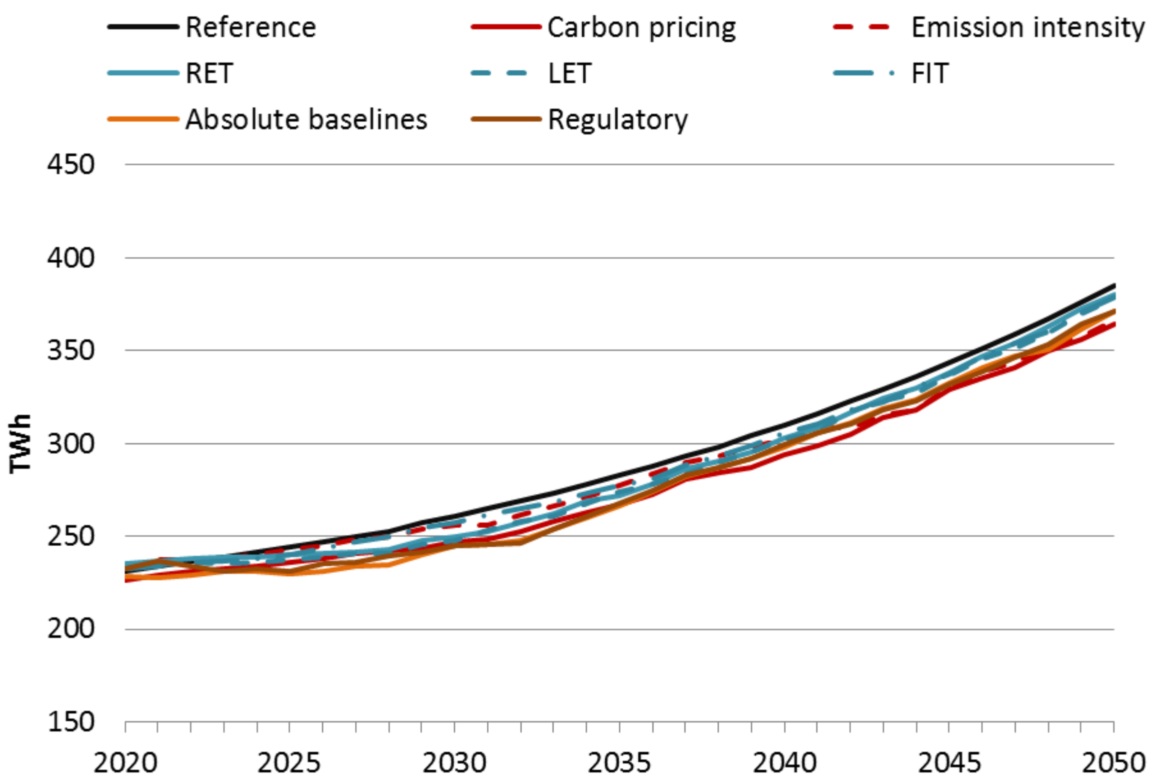
The demand for electricity is affected by the retail price. For scenarios with higher retail prices, the demand for electricity will be lower.

Electricity demand across the scenarios is compared in Figure 111. Demand is generally highest for the reference case, being the scenario with the lowest prices across the period to 2050. Early on the wholesale price suppression resulting from additional renewable energy generation means that demand is higher than in the reference case for the technology pull policies in the early years.

The relative change in demand across the scenarios reflects relative prices:

- The lowest demand occurs for the carbon pricing, regulated closure and absolute baselines cases. The carbon price leads to higher wholesale and retail prices, which then induces a demand response. Demand in the carbon price scenario is 5% lower on average than in the reference case.
- For the technology pull and emission intensity target scenarios, demand is around 1% to 2% lower than the reference case on average. The technology pull policies have demand converging to reference case levels after 2040, when the target flattens out and the cost of certificates reduces.
- For the regulatory policy scenarios, demand is lower than the reference case by around 4% of average over the study period. Both policies entail higher wholesale and retail prices due to restrictions on generation from conventional plant. In the absolute baseline scenario, demand is lower than all other scenarios in the period to 2035 due the slightly higher electricity prices during this period.

Figure 111: Electricity demand, sent out basis, 3°C emissions constraint scenarios



Source: Jacobs

5.1.2 Generation and capacity

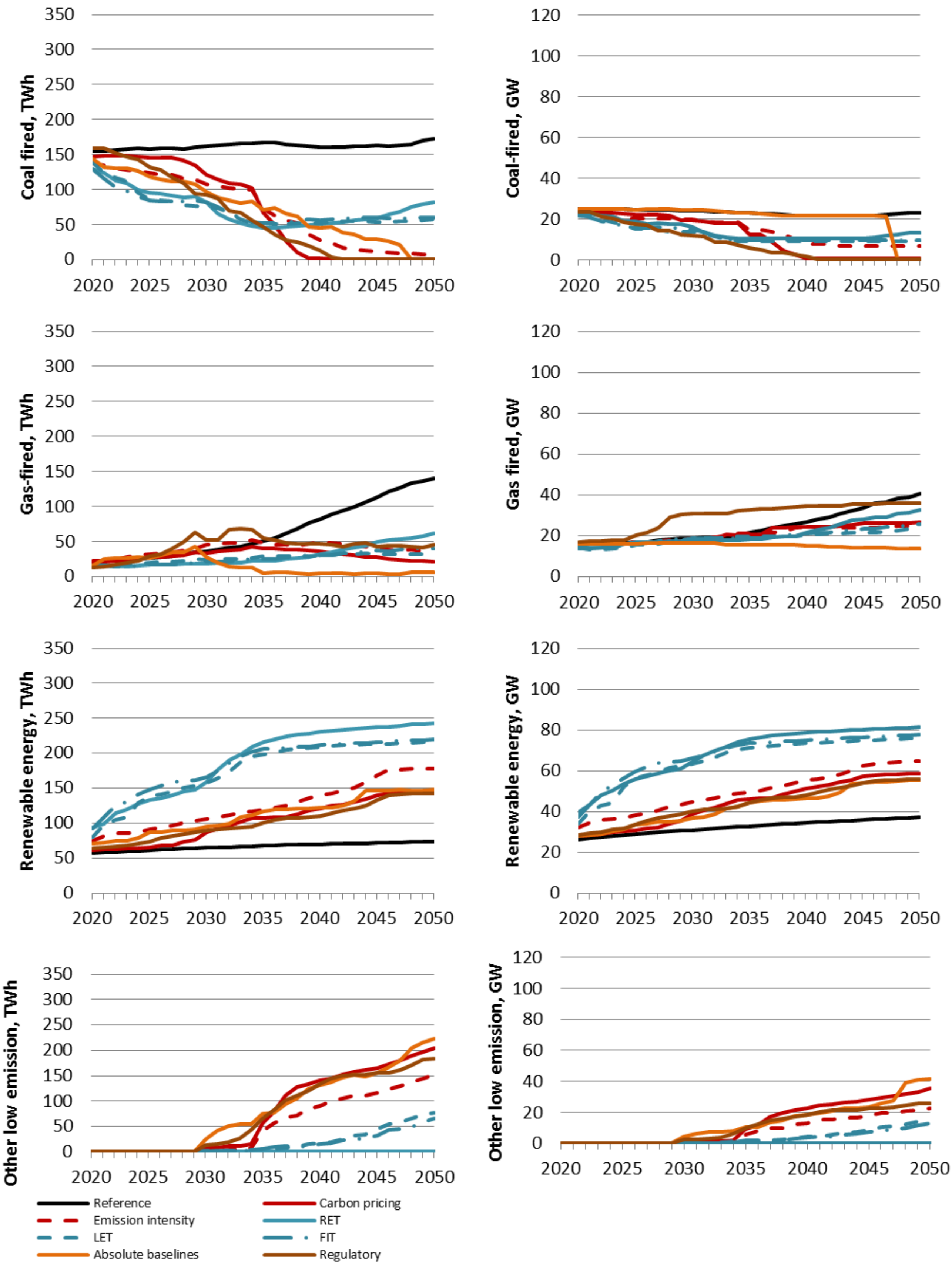
Meeting the emissions constraint changes the mix of generating plant over time. In the reference case, coal fired generation comprises the largest source of generation and capacity installed (see Figure 112). In the policy scenarios, however, coal generation and capacity reduces substantially (and to zero in some scenarios). Coal continues to generate after 2040 in the technology pull scenarios as there is no mechanism preventing new coal fired generation. In this period, demand continues to grow whilst the technology targets do not increase. Therefore any new capacity required is met by the least cost option.

In the reference case, the level of renewable generation stabilises after the capacity required to meet the LRET target is installed (in 2020). There is some growth in capacity and generation from continuing uptake of small-scale PV systems but there is no growth in large scale renewable energy generation. Other forms of generation remain the lowest cost option, given the assumptions on fuels and capital costs.

In all the policy scenarios, renewable energy eventually makes up a large share of the generation mix, with the proportion of renewable energy dependent on the policy impact on conventional forms of fossil fuel generation (see Table 9). The level of renewable energy is highest in the technology pull scenarios due to policy directly providing a subsidy for those technologies. Based on the cost assumptions used in the modelling, in some policy scenarios nuclear power makes up a large and increasing share of the generation mix when it becomes available in 2035. By 2050 nuclear power comprised nearly half of the generation mix across the emissions pricing policy scenarios and regulatory scenarios, replacing the incumbent fossil fleet. The proportion of nuclear generation is lower in the technology pull scenarios because greater entry of renewable energy before 2030 in these scenarios locks out later investment in nuclear energy.

Gas fired generation was broadly similar across the scenarios with the exception of the absolute baseline scenario, which has a lower level due to the impact of the declining baselines and restrictions on new entry of conventional gas plant. After 2030, gas fired peaking plants provide reserve capacity to meet supply reliability requirements and to provide support for the level of intermittent generation.

Figure 112: Generation and capacity by technology type, 3°C emissions constraint scenarios



Source: Jacobs

Table 9: Share of generation by technology type, % of total generation, 3°C emissions constraint

Scenario	2030				2050			
	Coal	Gas	Renewable	Other low emission	Coal	Gas	Renewable	Other low emission
Reference	62%	13%	25%	0%	45%	36%	19%	0%
Carbon pricing	49%	13%	35%	3%	0%	6%	39%	55%
Emission intensity	42%	17%	41%	0%	2%	10%	48%	41%
Absolute baselines	40%	11%	39%	10%	0%	1%	39%	59%
RET	32%	7%	61%	0%	21%	16%	63%	0%
LET	29%	9%	61%	1%	15%	8%	56%	20%
FiT	30%	7%	62%	0%	16%	10%	57%	17%
Regulatory	38%	21%	36%	5%	0%	12%	38%	49%

Source: Jacobs. Sums across the rows may not add up to 100 due to rounding.

5.1.3 Prices

The type of carbon mitigation policy has a significant effect on wholesale prices. In the reference case, the gradual reduction of surplus generating capacity sees wholesale prices gradually rise to the long run marginal costs of new entrants, reaching that level around 2035. For the policy scenarios:

- For the carbon pricing scenario, wholesale prices are significantly higher than in the reference case reflecting the impact of the carbon price on dispatch costs of thermal plant. The rise in wholesale price is tempered by the long run marginal cost of low emission plant. With the assumed carbon prices, wholesale prices in this scenario rise from 2020 in line with carbon prices to reach the long run marginal cost of new entrants just after 2030, and stay relatively stable thereafter. Wholesale prices in this scenario are generally the highest of all the policy scenarios.

- Wholesale prices also rise in the emission intensity scenario but by not as much as for the carbon pricing scenario. Prices in this scenario are around 16% lower than for the carbon pricing scenario.

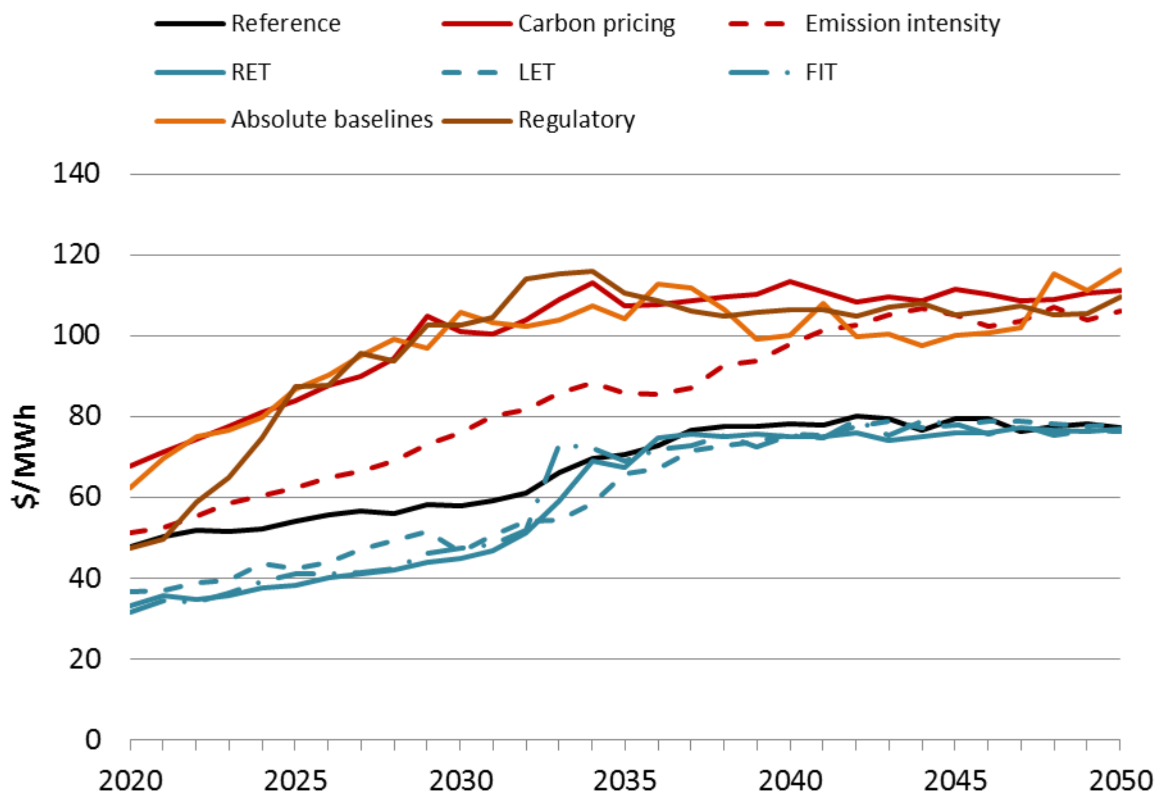
- Wholesale prices also rise for the regulatory and absolute baseline scenarios as the regulations or baselines restrict low cost but high emission generation requiring plant with higher variable costs to be dispatched.

- For the technology pull scenarios, wholesale prices are below or around those of the reference case until about 2030. Downward pressure on prices occur because of the amount of plant with low short run marginal cost and the implied subsidy on dispatch costs provided by the certificates earnt under these schemes. From 2030, wholesale prices converge to reference levels.

Retail tariffs are projected to be around 5% to 15% higher in the policy scenarios than for the reference case (see Table 10). Retail tariffs are highest for the carbon pricing, absolute baselines and regulatory scenarios. The technology pull scenarios have the lowest retail price impact driven mainly by the effects of these policies on reducing wholesale prices.

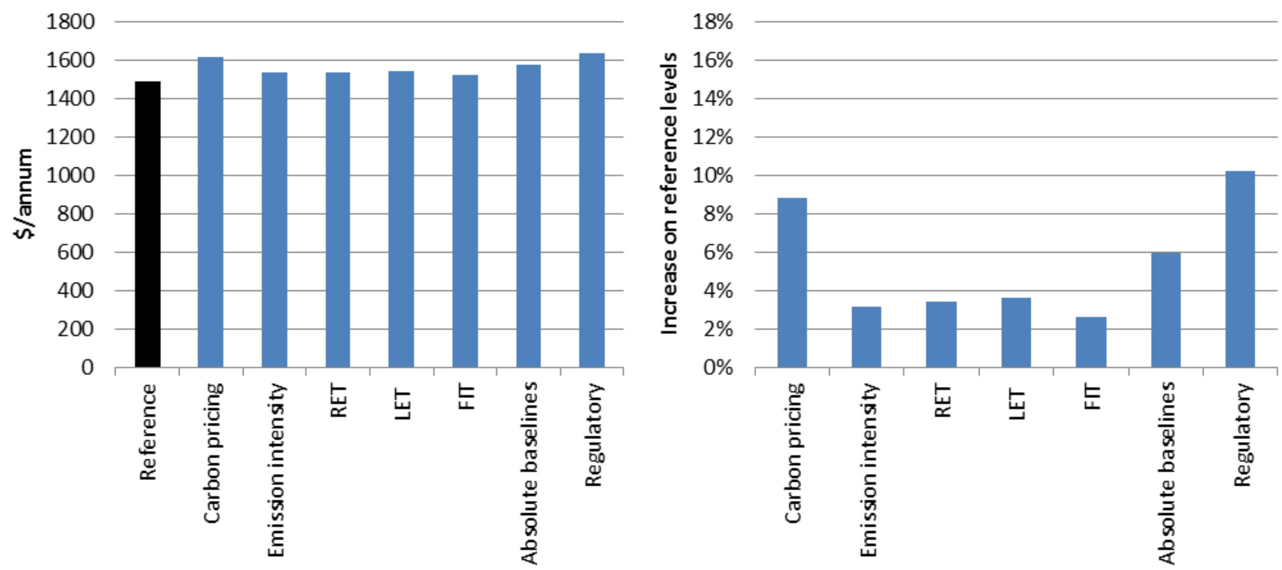
The policies all affect residential customer bills (see Figure 114). Residential electricity bills increase by between $40/annum to $150/annum on bills paid under the reference case, or around 0.1% to 0.2% of average household income levels. The largest impact on bills occurs under the regulatory scenario and the least impact under the technology pull scenarios, reflecting the retail price trends.

Figure 113: Wholesale prices, volume weighted average, 3°C emissions constraint scenarios



Source: Jacobs. Volume weighted prices are average the hourly prices weighted by hourly generation proportions. Volume weighted prices are derived for each region of the NEM and the WEM and a system wide average is then derived by weighting each region price by the proportion of each regions energy demand to total energy demand.

Figure 114: Residential customer bills and percentage increase in bills, 3°C emissions constraint scenarios



Source: Jacobs

Table 10: Average retail tariffs, all regions, 3°C emissions constraint

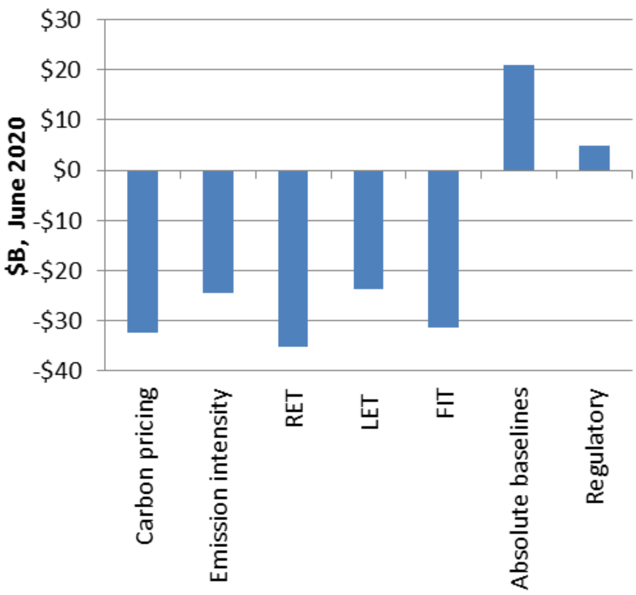
Customer type/scenario	c/kWh				% change from reference			
	2020-2030	2031-2040	2041-2050	2020-2050	2020-2030	2031-2040	2041-2050	2020-2050
Residential								
Reference	25	27	28	27				
Carbon pricing	28	31	32	30	11%	17%	16%	15%
Emission intensity	25	29	32	28	-1%	7%	12%	6%
RET	25	29	30	28	3%	10%	5%	6%
LET	26	29	30	28	6%	8%	6%	7%
FiT	25	29	30	28	1%	7%	6%	5%
Absolute baselines	27	31	32	30	10%	14%	13%	13%
Regulatory	27	31	31	30	10%	17%	12%	13%
SME								
Reference	23	25	26	25				
Carbon pricing	25	29	30	28	10%	16%	15%	14%
Emission intensity	23	26	29	26	-1%	6%	12%	6%
RET	24	28	28	27	4%	13%	8%	8%
LET	25	28	29	27	8%	11%	10%	9%
FiT	24	27	28	26	3%	10%	9%	7%
Absolute baselines	25	28	29	27	9%	13%	13%	12%
Regulatory	25	29	29	28	10%	16%	12%	13%
Industrial								
Reference	11	12	13	12				
Carbon pricing	14	16	17	16	25%	32%	28%	28%
Emission intensity	11	14	16	14	3%	14%	23%	14%
RET	12	14	14	13	10%	13%	5%	9%
LET	12	14	14	13	15%	10%	3%	9%
FiT	12	13	14	13	7%	8%	4%	6%
Absolute baselines	13	16	17	15	24%	28%	24%	25%
Regulatory	13	16	16	15	19%	30%	19%	23%

Source: Jacobs

5.1.4 Change in gross profits

Gross profit is a concept related to costs, and for a generator is the difference between total revenue, which consists of pool revenue, contract revenue and certificate revenue (where applicable), less all operating costs, including fuel costs, fixed and variable operating costs and emissions costs. Each policy affects the gross profits of incumbent generators (see Figure 115).

Figure 115: Change in gross profits for incumbent generators, 3°C emissions constraint scenarios



Source: Jacobs

Gross profits are expected to fall overall by around $20 to $30 billion (compared to what they earn in the reference case) across most policy scenarios. Coal fired generators are predicted to incur greater losses mainly either through increased costs (in the market based policies) or reduced volumes of generation (all policy scenarios). However, these losses are partly compensated for by higher profits (relative to the reference case) for incumbent renewable and some gas-fired generators.

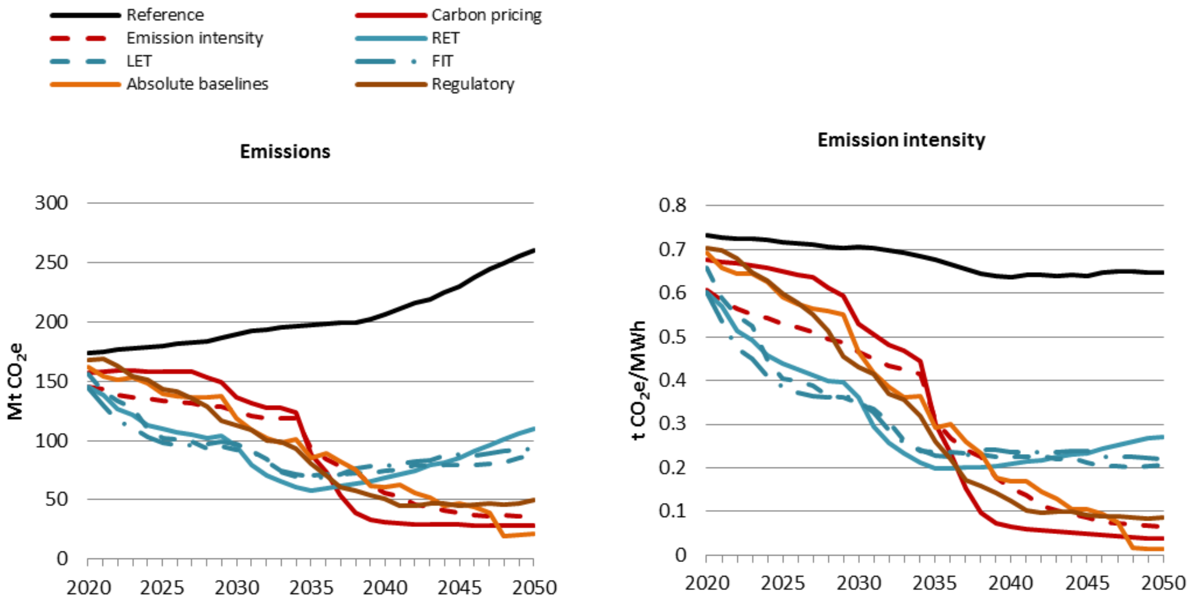
The profits impacts estimated in this study are indicative only. They are based on profits predicted to occur under set assumptions for all scenarios and are highly sensitive to variations in those assumptions.

5.1.5 Emissions

Emissions rise in the reference case by around 1.4% per annum, slightly lower than the rate of growth in demand. The emission intensity of generation falls slightly due to the projected increasing proportion of gas fired generation.

In contrast, emissions are projected to fall for the policy scenarios. The reduction in emissions occurs steadily over the projection period for most policy scenarios, with the exception of carbon pricing scenario where emissions fall sharply after 2035 upon introduction of nuclear generation. For the technology pull scenarios, emissions start to rise after 2040 as the generation targets flatten and there is no other mechanism to limit generation from coal fired plant. This means these scenarios need to achieve a higher amount of abatement earlier on in the modelling period.

Figure 116: Emissions and emission intensity, 3°C emissions constraint scenarios



Source: Jacobs. Emissions included direct emissions (from combustion of fuels in electricity generation) and indirect emissions (emitted during processing and supply of fuel to power stations). The emission intensity only includes direct emissions.

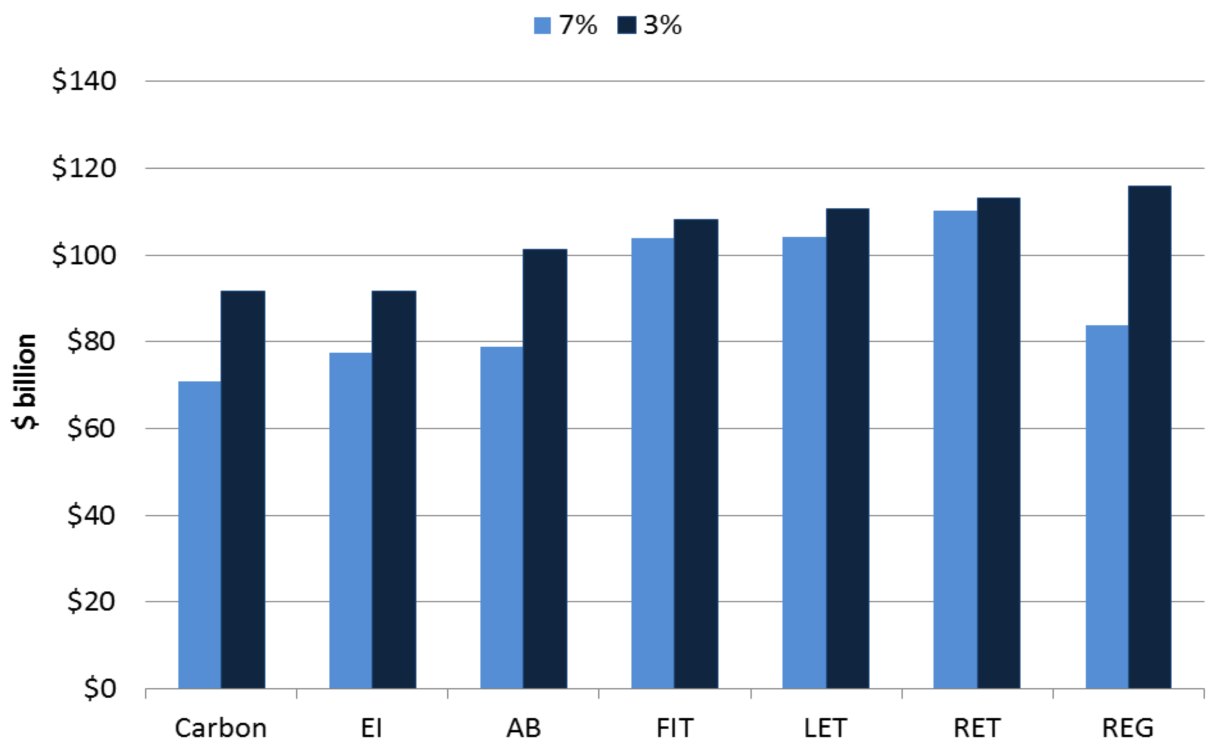
5.1.6 Resource costs and cost of abatement

The estimated resource costs of the policy measures are shown in Figure 117. The resource cost estimates include the adjustment for demand variations across the scenarios (see Appendix B.3.2). The resource costs are similar across the emissions pricing policy scenarios and are the lowest for these scenarios (similar to the 2°C target). The regulatory scenarios have similar costs to pricing scenarios when a lower discount rate is used but higher costs when a low discount rate is used. With a weaker emissions constraint there is less need for new technologies and a more gradual retirement than in the 2° C constraint. In the absolute baselines and regulatory cases, there is less need to bring on new low emission generation early. The level of gas fired generation across these scenarios is also similar, as the constraints on gas fired generation (particularly in the regulatory case) do not bind as strongly.

Resource costs are significantly higher for the technology pull scenarios.

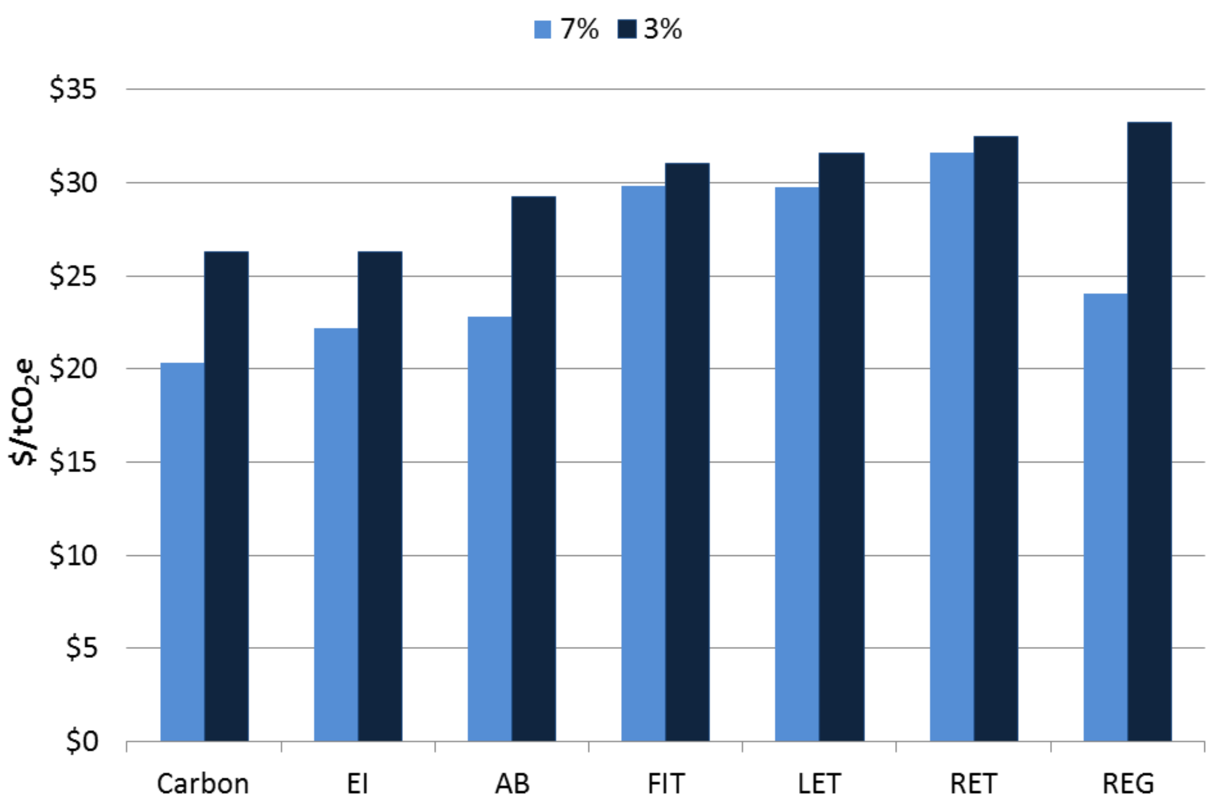
The cost of abatement show a similar ranking to the resource costs (see Figure 118). Cost of abatement is lowest for the emission pricing policy scenarios, with the absolute baselines and regulated scenarios having similar costs at higher discount rates but higher costs at lower discount rates. Technology pull policies have the highest abatement costs.

Figure 117: Resource costs of policies relative to reference case, 3°C emissions constraint scenarios



Source: Jacobs. The resource costs represent the net present value of the annual resource costs from 2020 to 2050 (adjusted for the variations in demand across the policy scenarios), discounted by the discount rate shown

Figure 118: Cost of abatement relative to the reference case, 3˚C emissions constraint scenarios



Source: Jacobs

5.2 Reference case

5.2.1 Scenario description

The reference case provides the starting point of performance comparison of all the other policy scenarios and a projection of the future electricity grid. The main difference to the previous reference case is that it follows the 3°C global assumptions, which affects fossil fuel prices and low emission technology learning rates. Otherwise, it is assumed that no new policy changes are affecting the Australian electricity sector and its market participants and that the existing policies are maintained.

As before, the current Large-scale Renewable Energy Target and the Small-scale Renewable Energy Scheme, and the existing state-based policies given in Appendix D, are preserved. Assumptions on the structure of network changes are the same as for the 2˚C reference case.

5.2.2 Key findings

The main findings are similar to the 2˚C reference case in that:

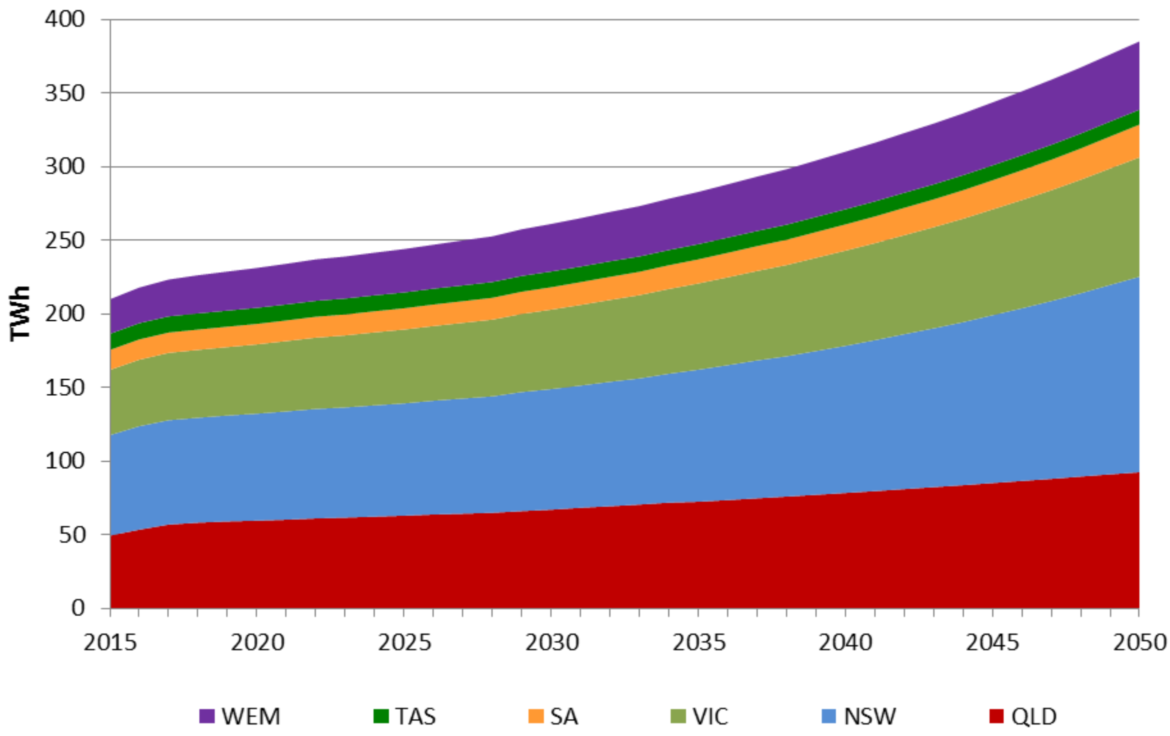
- In the absence of new policies, electricity generation remains dominated by black coal and gas, which make up 80% of generation in 2050.
- Total emissions rise steadily with increasing electricity demand, as the overall emission intensity declines only gradually.
- The uptake of roof-top solar PV installations continues, eventually reaching saturation[27], with a partial transition to systems with local battery storage that enhance the value of the energy by making it available for later use rather than export at lower value.
- The retail prices and average household electricity bills stabilise by around 2035 due to wholesale prices reaching the levels required for new entrant fossil fuel generators to be profitable.
- The new Large-scale Renewable Energy Target of 33,000 GWh is met without the LGC price exceeding the penalty threshold.

5.2.3 Demand

Figure 119 and Figure 120 show the total demand and non-coincident peak demand respectively across the NEM and WEM for the reference case. Total energy demand reaches 385 TWh by 2050, while the non-coincidence peak demand across the regions is 68,700 MW. The energy demand growth is 1.7% pa over the NEM and WEM as a whole whereas the non-coincident peak demands increase by 1.6%.

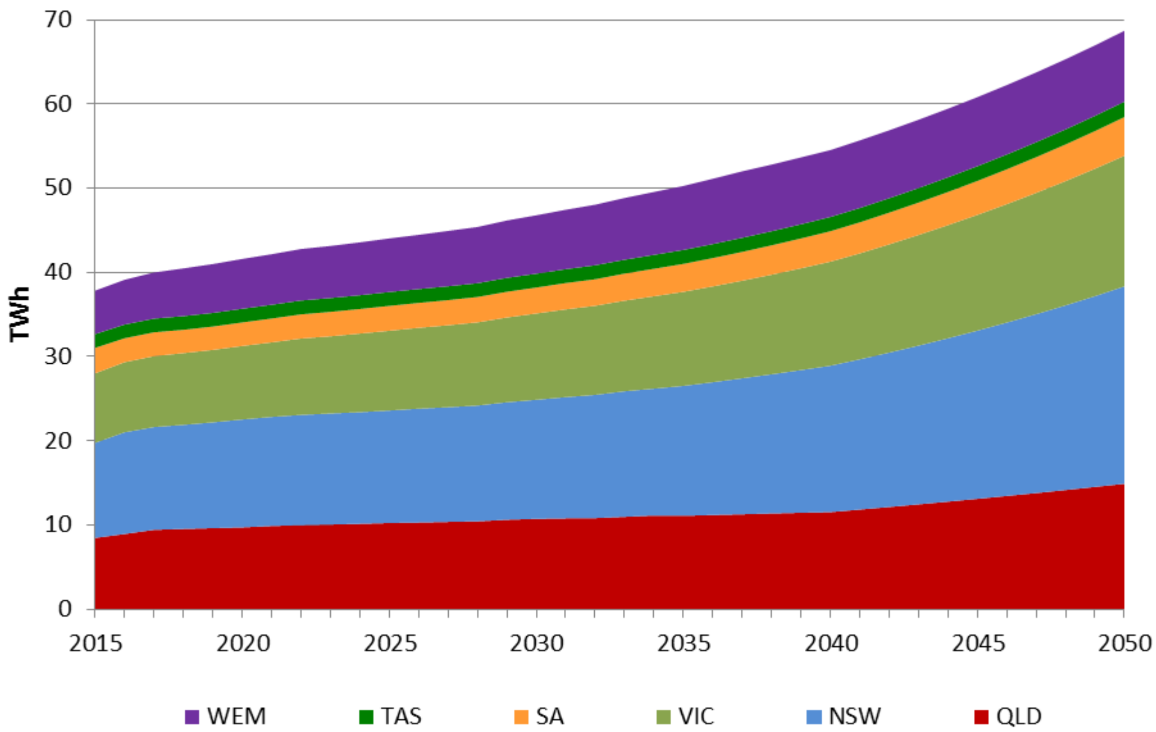
[27] See Appendix C for assumptions on saturation.

Figure 119 Total energy sent out, reference case, 3°C emissions constraint



Source: Pitt & Sherry, ACIL Allen and Jacobs

Figure 120: Non-coincident peak demand, reference case, 3°C emissions constraint

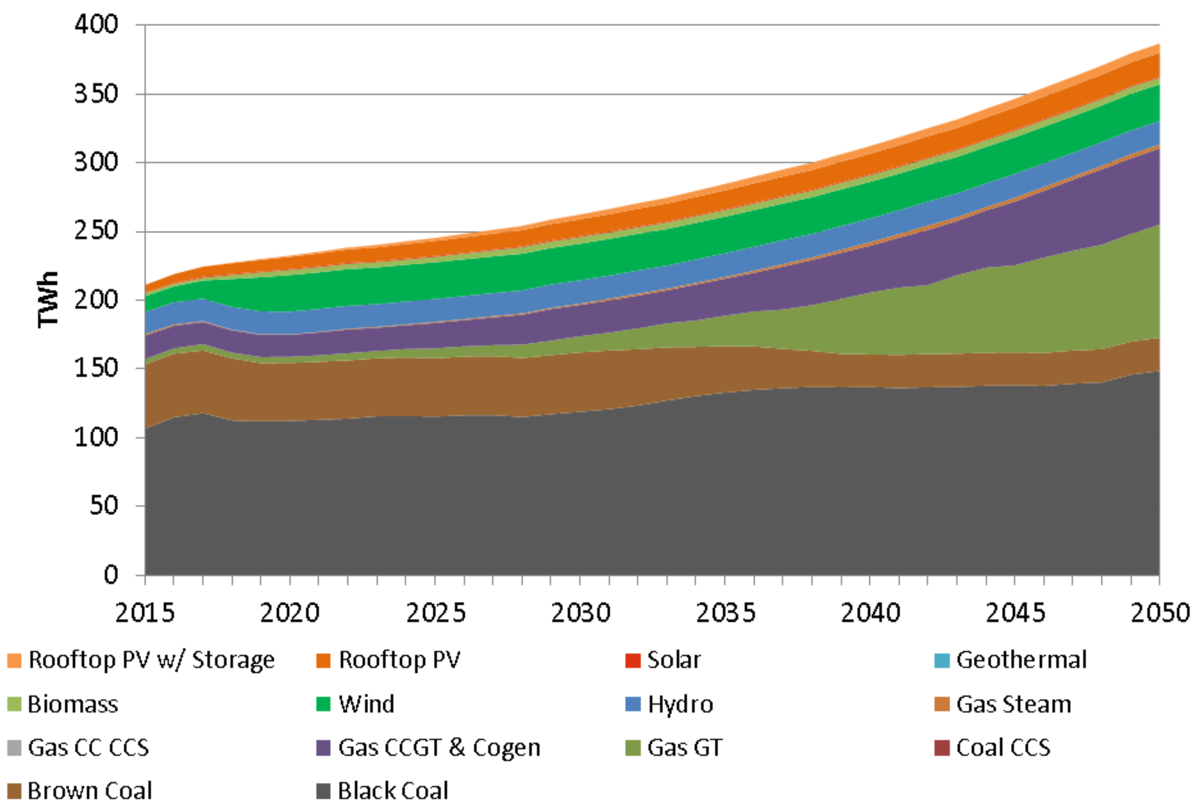


Source: Pitt & Sherry, ACIL Allen and Jacobs

5.2.4 Generation and capacity

Coal retains its principal role in the power generation sector without any significant changes to the level of generation throughout the whole period (Figure 121). Gas fired generation increases in a steady pace after 2020 following the demand growth. Gas fired generation at the gas prices assumed fills in more of the mid-merit role, although in some regions it also undertakes base load duty. Large-scale renewable generation increases to 2020 driven by the LRET target, but remains flat from 2020 once the LRET is met. Small-scale generation continues to grow over the forecasted period reaching saturation levels somewhat later than in the 2°C reference case due to the assumed lower rate of decline in capital costs. By 2050, renewable generation comprises around 19% of total generation.

Figure 121 Generation mix, reference case, 3°C emissions constraint

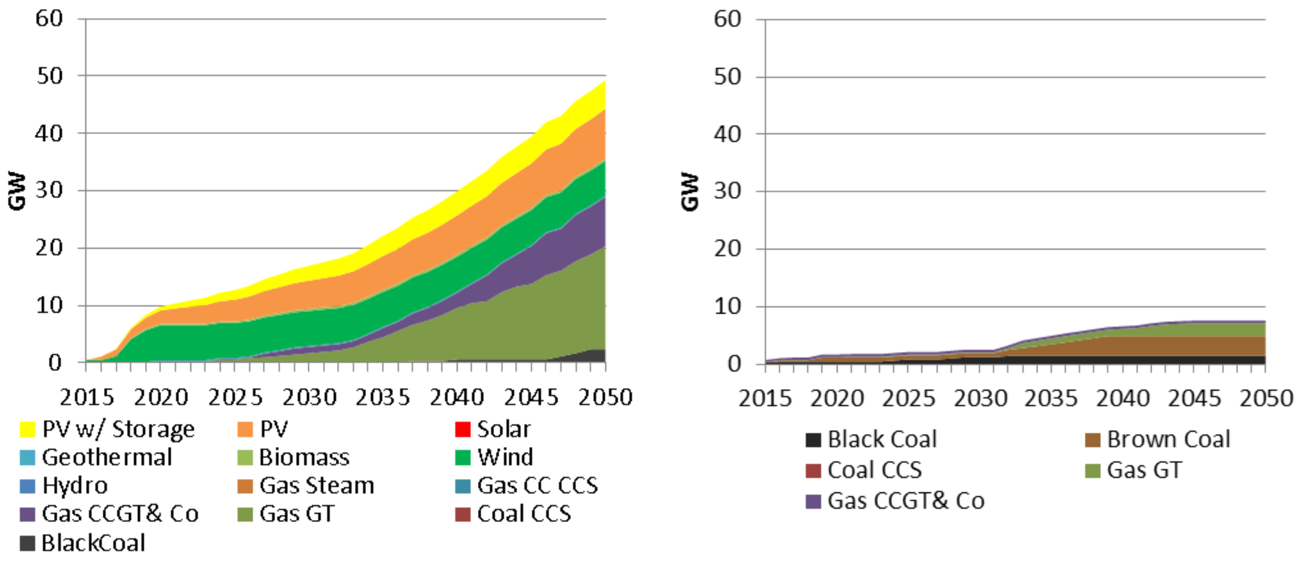


Source: Jacobs

Figure 122 illustrates the projected entry of new plant and retirement of existing plant. Some brown coal generation closes based on the remaining life of the plant and exhaustion of the associated coal reserves (see Appendix C). Based on the assumed capital costs and fuel prices, new conventional gas is preferred to new coal technology, mainly as a result of the lower gas prices assumed in the 3°C scenarios.

Figure 122: Cumulative new and retired capacity, reference case, 3°C emissions constraint

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

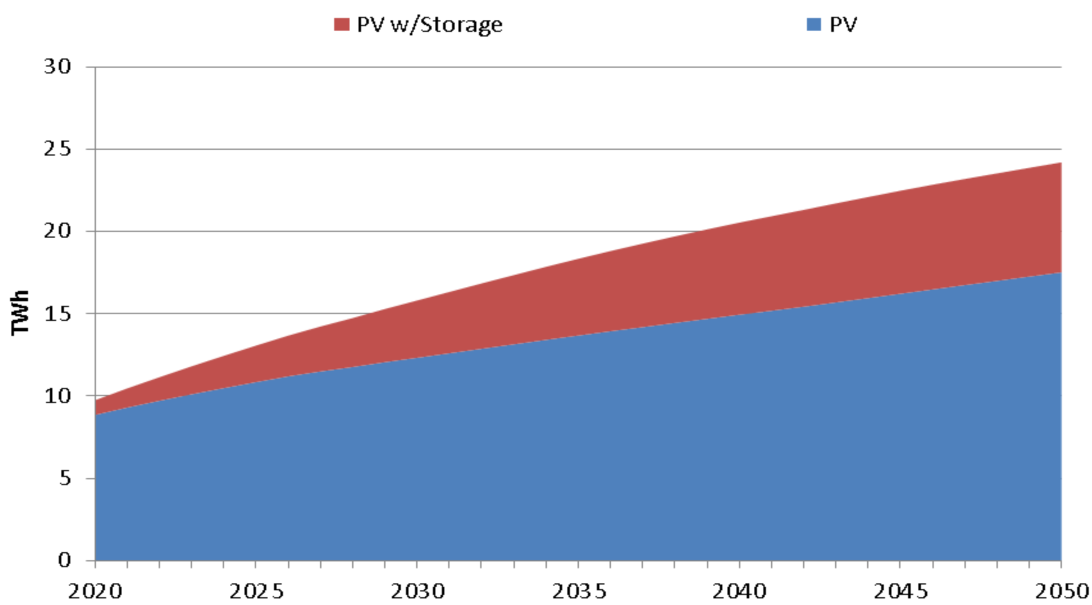


Source: Jacobs

5.2.5 Small scale renewable energy

Small-scale renewable generation continues to grow and reaches the assumed saturation levels for the residential and commercial sectors around 2035. As in the 2°C reference case, small-scale PV uptake slows after 2030 due to the phase-out of the SRES and some changes to network tariff structure. Figure 123 shows the energy contribution of roof-top PV, including the subsequent development of PV installations with storage. Non-storage technology uptake continues throughout the modelling horizon while uptake of storage increases later on in the modelling period.

Figure 123: Small-scale technology development, reference case, 3°C emissions constraint

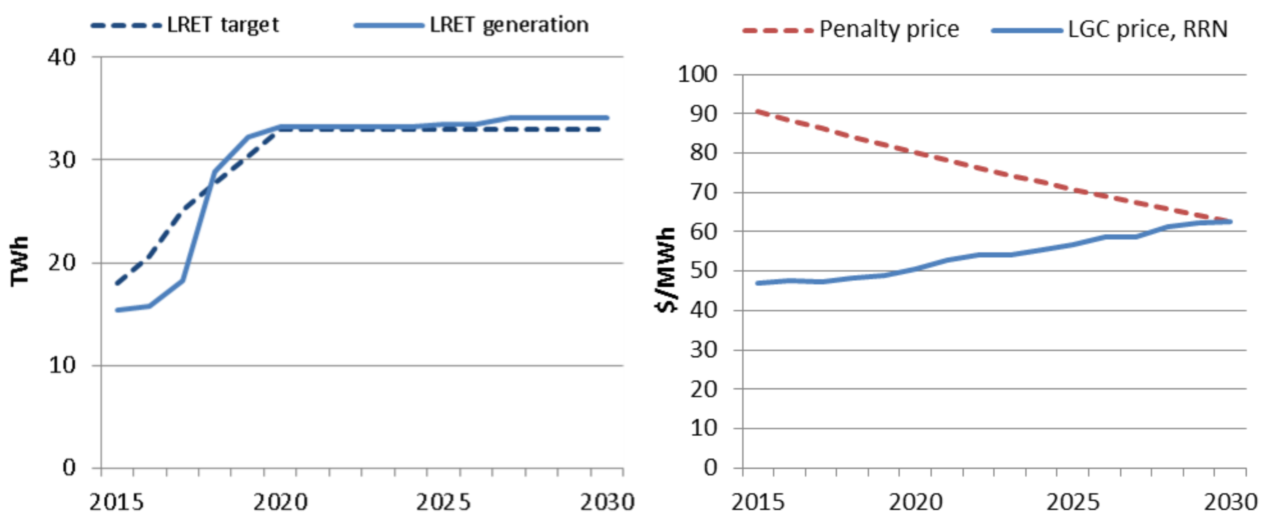


Source: Jacobs

5.2.6 Large-scale Renewable Energy Target

Figure 124 illustrates the LRET targets, the forecasted eligible renewable generation and the projected LGC price. The 33,000 GWh target is projected to be met with the LGC prices expected to rise over the period to 2030.

Figure 124: LRET target, eligible renewable generation and projected LGC price, reference case, 3°C emissions constraint



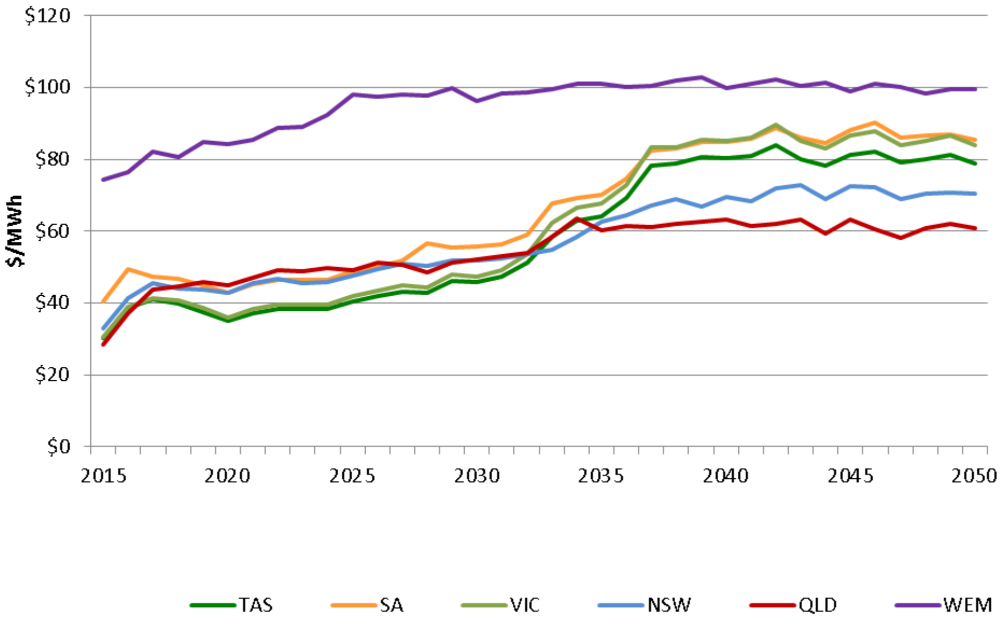
Source: Jacobs. Eligible generation is less than the target in the period to 2018 as a result of the large number of certificates banked by the end of 2014 (around 18 million certificates). The shortfall to target is met by drawing on this bank of certificates during those years.

5.2.7 Prices

Figure 125 shows reference case wholesale prices. These follow the same trends as the 2°C reference case, except that due to the assumed higher fuel prices the prices tend to stabilise around $5 to $10 higher than in the 2°C reference case. Prices in the WEM are higher due to the impact of the higher marginal costs for gas and coal fired generation and the inclusion of capacity market payments.

Retail prices by customer class are illustrated in Figure 127. These follow the wholesale prices trends. The average residential bill is shown in Figure 126. It is projected to remain relatively steady up until 2032 and start rising sharply after, although the percentage of disposable household income for electricity is expected to decline over the forecasted period.

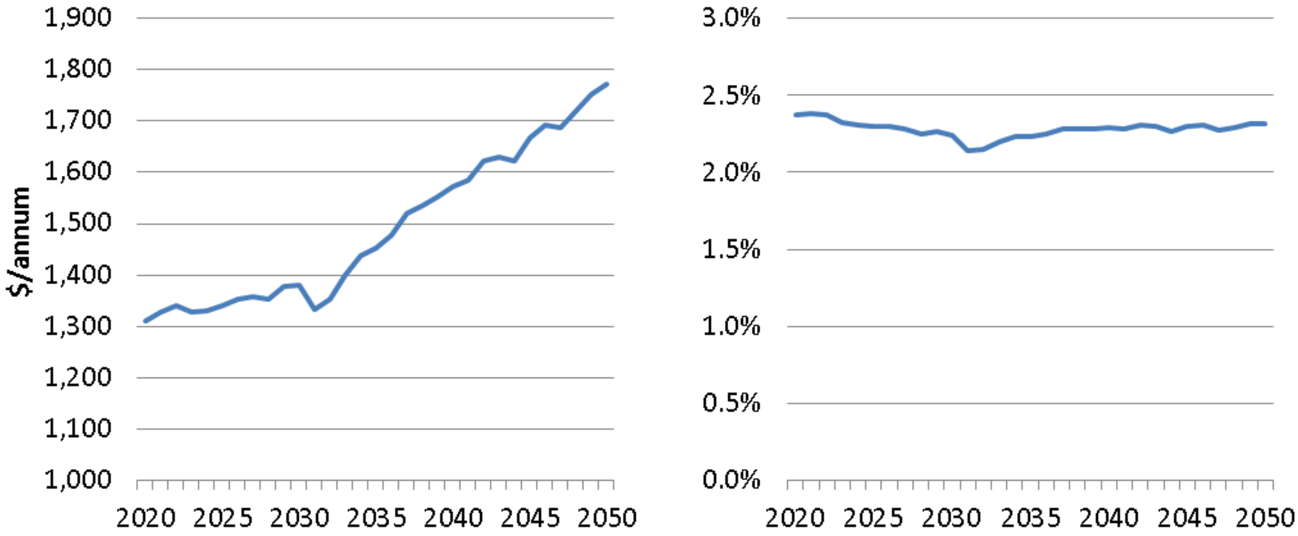
Figure 125: Wholesale electricity prices by region, reference case, 3°C emissions constraint



Source: Jacobs

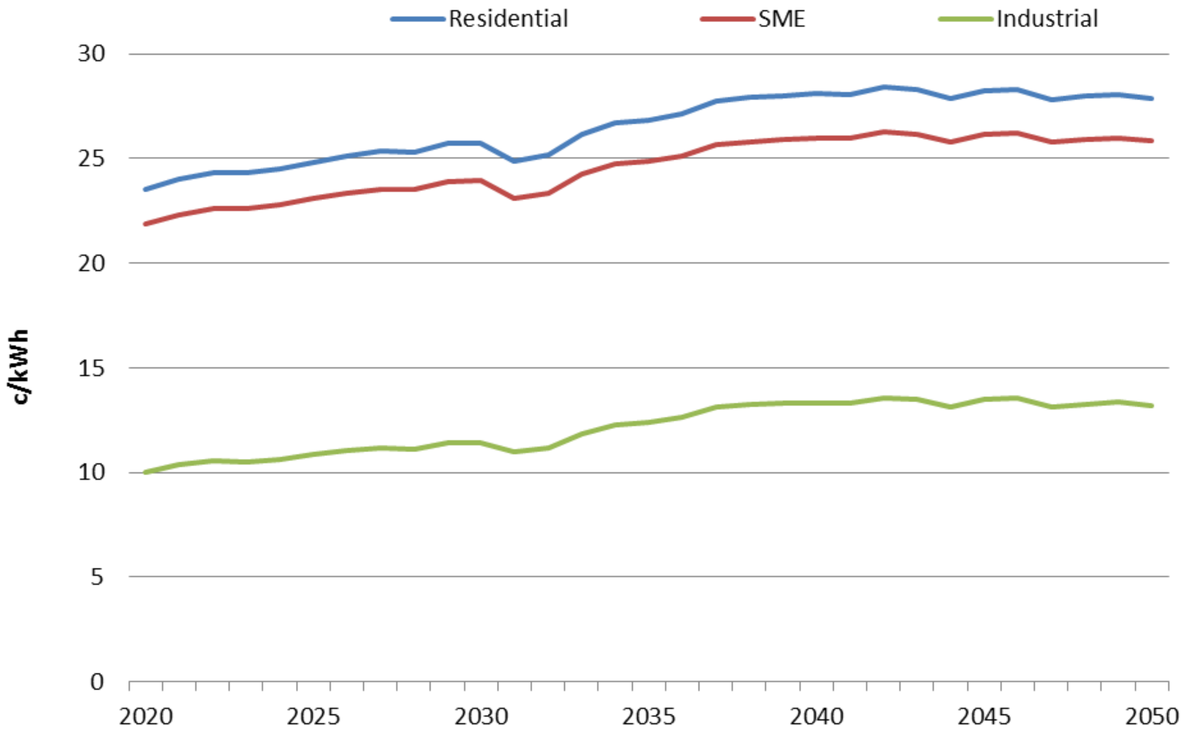
Figure 126: Residential bills, reference case, 3°C emissions constraint

The left graph shows the absolute residential bill. The right graph shows the residential bill as a % of disposable income.



Source: Jacobs

Figure 127: Retail prices by customer class, reference case, 3°C emissions constraint



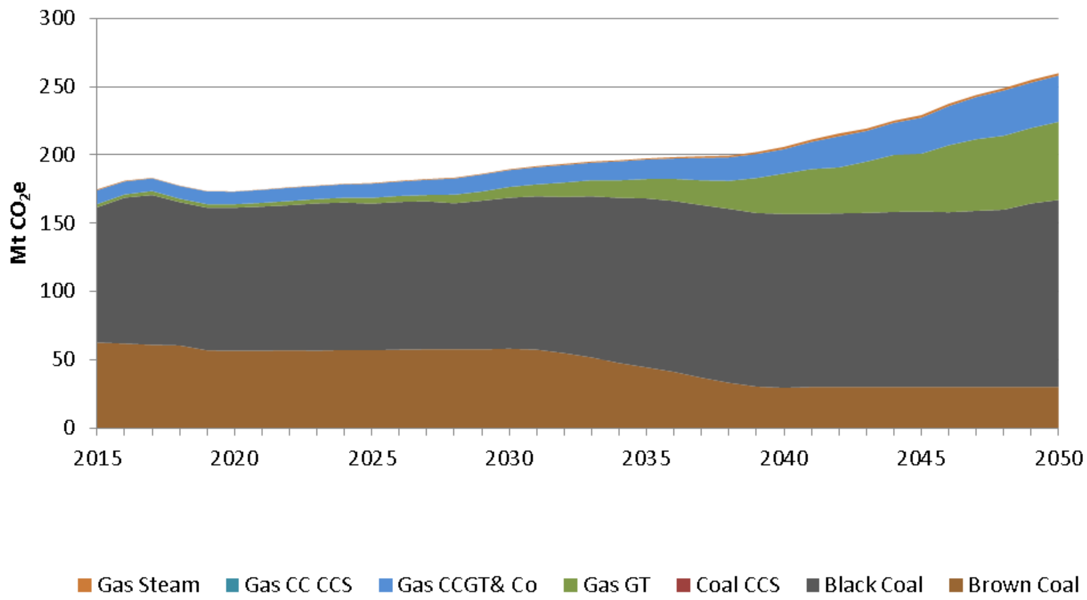
Source: Jacobs

5.2.8 Emissions

Emissions by technology type are shown in Figure 128 and are projected to decline initially due to the increase of renewable energy generation. However, emissions start to rise steadily from 2019 to 2040 when they are projected to have a sharp increase because of new black coal and gas open cycle generators entering the market. Over the period from 2019/20 to 2049/50, the cumulative carbon emissions in the NEM and the WEM are 6,309 Mt CO_2e.

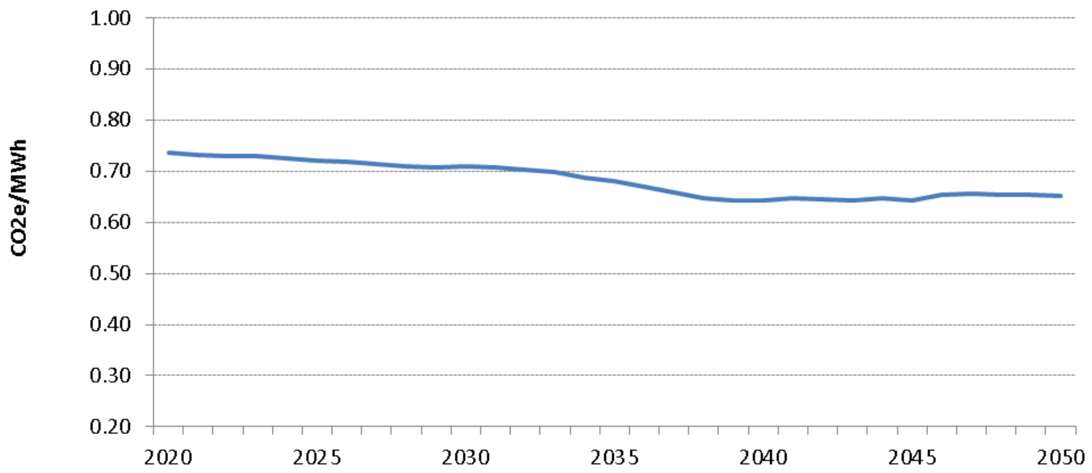
The generation emission intensity is shown in Figure 129. The average emission intensity is initially declining during the period that new renewable plants are added to the electricity grid, but stabilise from 2020 to 2030. There is another drop in emission intensity in the early 2030s due to brown coal retirements and after 2039/2040 the emission intensity settles at around 0.70 t CO_2/MWh.

Figure 128: Emissions by technology, reference case, 3°C emissions constraint



Source: Jacobs. Includes both direct and indirect emissions.

Figure 129: Generation emission intensity, reference case, 3°C emissions constraint

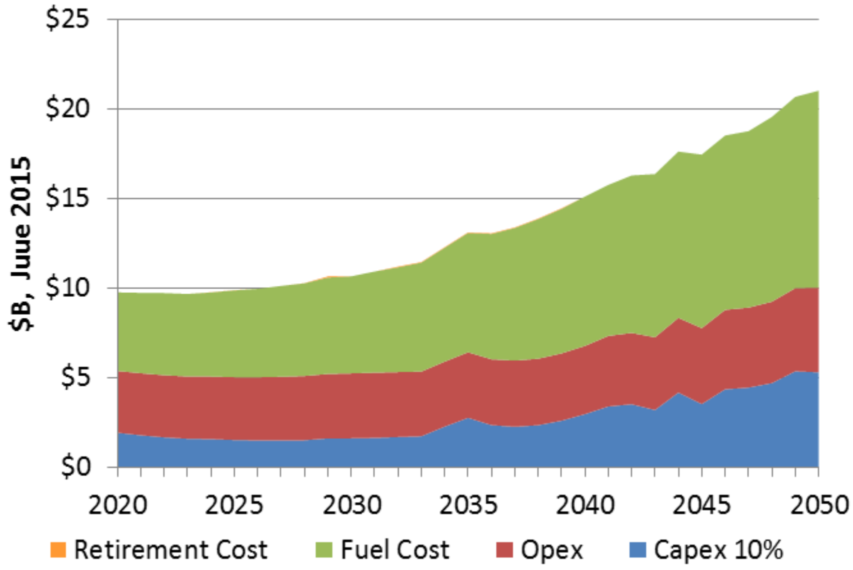


Source: Jacobs. Includes direct emissions only.

5.2.9 Costs

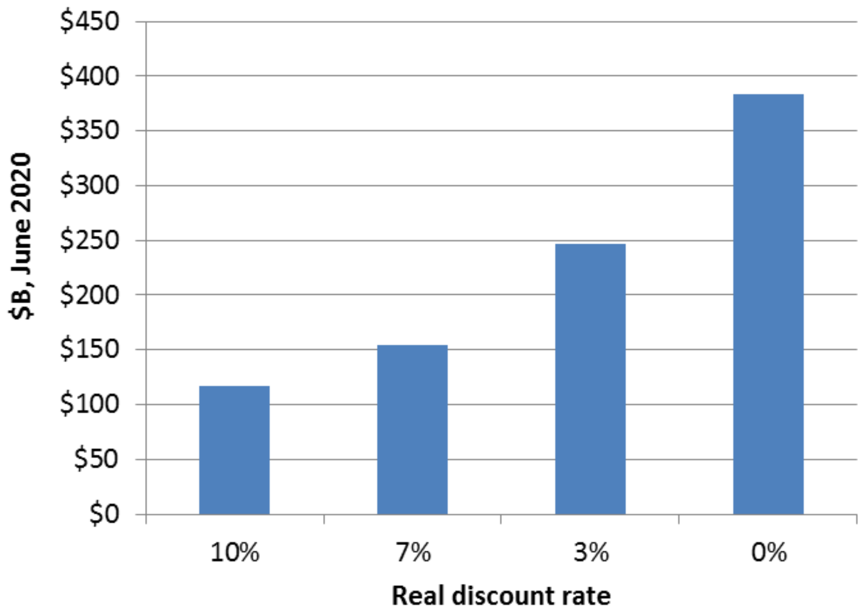
Figure 130 shows the annual operational, capital, fuel and retirement costs for the reference. The costs include those for both thermal and renewable energy resources including the fixed costs of incumbents. Fuel cost is the dominant cost over the period and the proportion of capital costs increases from 2030. The present value of these costs is shown in Figure 131.

Figure 130: Annual costs by category, reference case, 3°C emissions constraint



Source: Jacobs

Figure 131: Present value costs in June 2020 for reference case, 3°C emissions constraint



Source: Jacobs

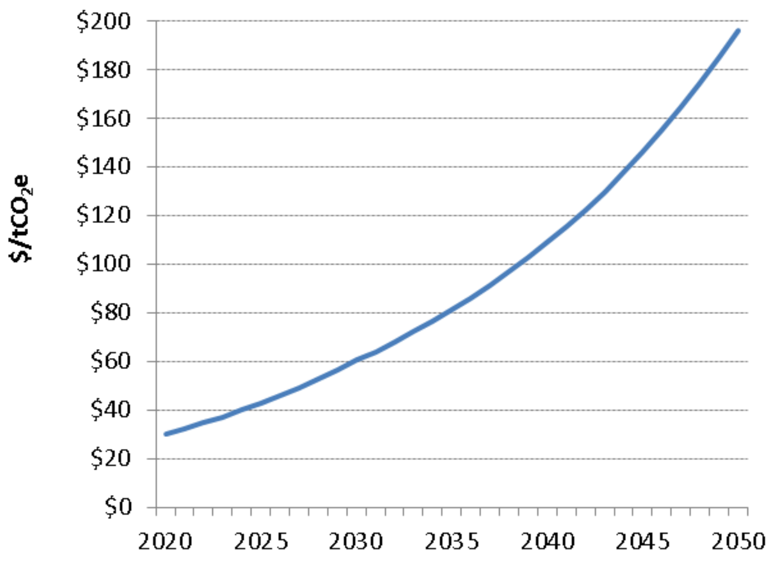
5.3 Carbon pricing

5.3.1 Scenario description

Under carbon pricing, all generators whose emissions exceed a given absolute emissions threshold are liable for surrendering permits to cover all of their emissions each year. The carbon price has been implemented as a carbon tax, that is, with no banking or borrowing of emissions permits. Its impacts are very similar to a cap and trade emissions trading scheme.

The key defining input parameter of the carbon pricing scenario which ultimately determines the cumulative emission target that the other policy scenarios have to achieve is the carbon price path. The 3°C carbon price path was sourced from the IPCC and is illustrated in Figure 132. The carbon price commences at \$30/t CO_2e in 2020 and escalates at an average annual rate of 6.4% per annum in real terms, reaching \$196/t CO_2e in 2050.

Figure 132: 3°C carbon price path



Source: CCA based on IPCC, 2014. Working Group III Contribution to the Fifth Assessment Report, Climate Change 2014-Mitigation,

For further discussion see Section 2.

5.3.2 Key findings

The moderate carbon price in the 3°C world leads to a more gradual reduction in generation and capacity of Australia's incumbent fossil fleet, relative to that of the 2°C carbon price. Wholesale prices increase relative to the reference case, reaching new entry levels in 2028/29 in the NEM and 2023/24 in the WEM. As a result there is little investment in thermal generation throughout the 2020s and almost no renewable generation investment in the 2020s. Only one major brown coal power station shuts down in 2019/20, and the more efficient brown coal plants continue to operate until the mid-2030s. Black coal power stations begin to shut down from 2028/29 with the steadily increasing carbon price. At the costs assumed in the modelling[28], nuclear generation rapidly replaces the coal fleet when it becomes available in 2035.

Gas fired generation does not play the same transitional role as in the corresponding 2°C scenario due the higher gas prices and lower carbon price.

Cumulative emissions under carbon pricing are 2,823 Mt CO_2e, which is around 80% more than the equivalent 2°C scenario.

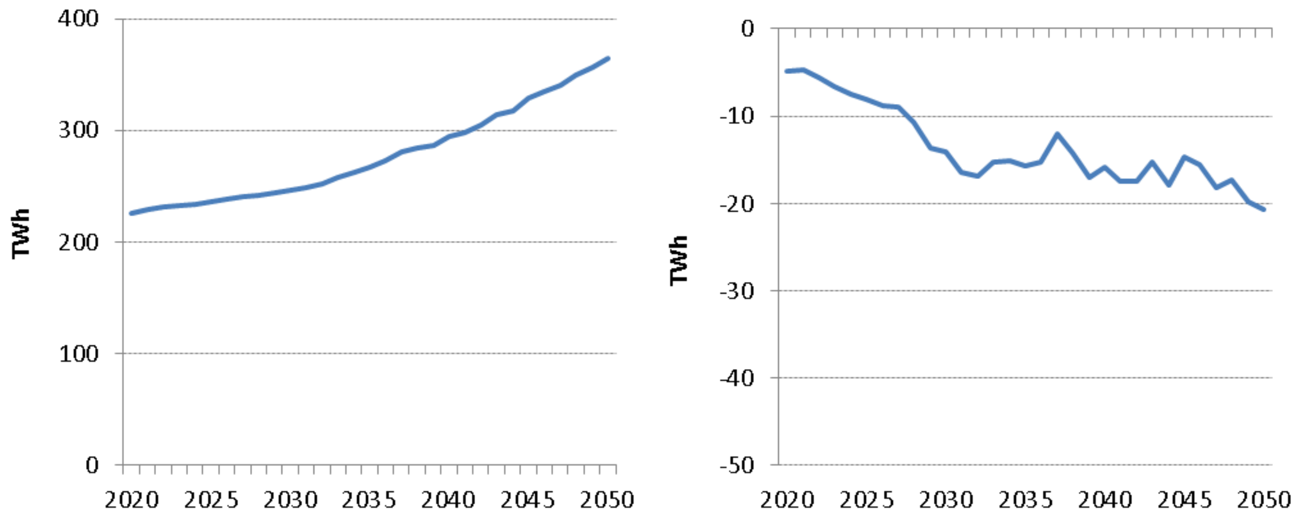
5.3.3 Demand

Figure 133 shows sent-out energy demand. Total energy consumed reaches 364 TWh, which is 21 TWh lower than the reference case due to higher retail prices reducing demand.

[28] In a 3°C world CCGTs with CCS and geothermal are assumed to have a much lower learning rate, and this does not make them competitive with nuclear technology by the mid-2030s. The learning rate for nuclear is unchanged in the weaker emissions constraint.

Figure 133: Sent-out energy, carbon pricing, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Pitt & Sherry, ACIL Allen and Jacobs

5.3.4 Generation and capacity

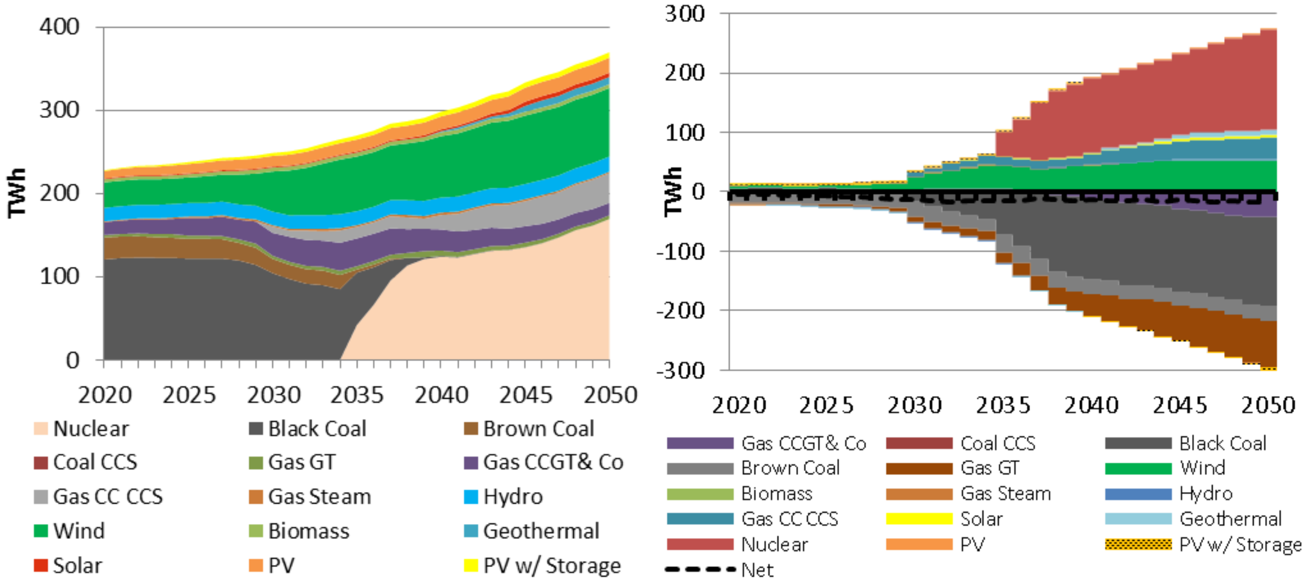
Figure 134 shows the generation mix in absolute terms and relative to the reference case. Coal fired generation does not decline substantially until the 2030s, but declines rapidly from 2035. Wind generation increases in the 2030s when coal fired generation begins declining. Wind makes the second largest contribution to energy supply in all modelled years apart from 2034/35 when it makes the largest contribution. Nuclear generation dominates new entry supply post 2035 and replaces the entire coal fleet in generation terms. CCGTs with CCS also make a contribution in Western Australia, where nuclear is not available, and is also built in eastern Australia between 2029/30 and 2033/34 to replace some retiring coal capacity.

Figure 135 shows cumulative new generation capacity in absolute terms and relative to the reference case. In general, capacity follows a similar trend to generation.

Under the carbon pricing scenario there are three transmission upgrades totalling 1,920 MW. This is over 1,300 MW less than upgrades in the reference case.

Figure 134: Generation mix, carbon pricing, 3°C emissions constraint

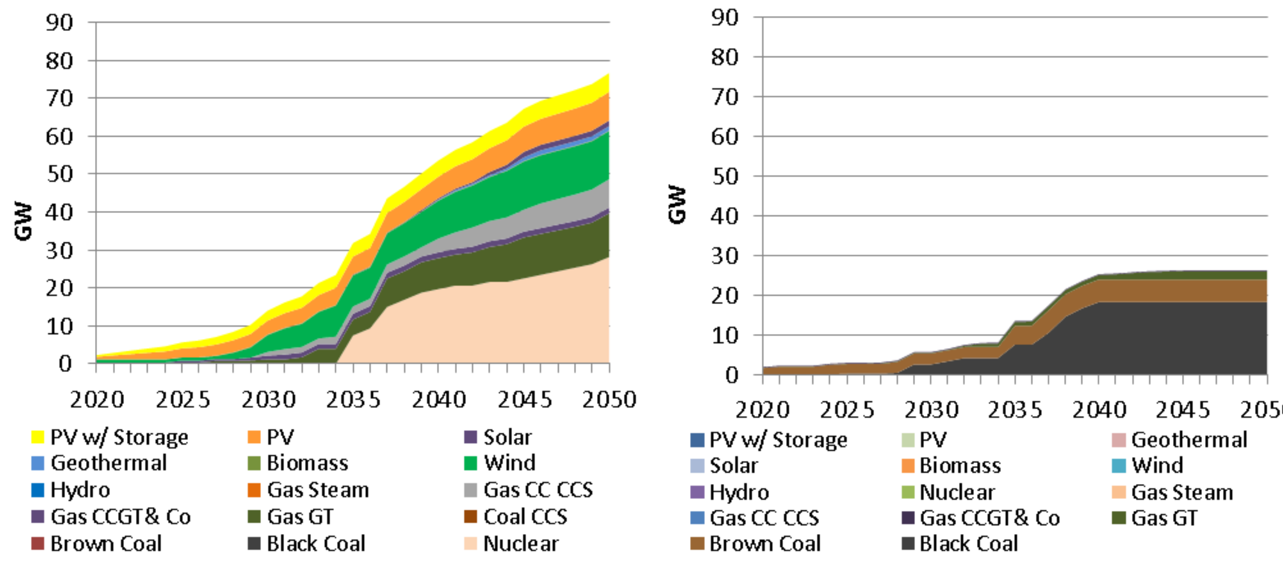
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs

Figure 135: Cumulative new and retired capacity, carbon pricing, 3°C emissions constraint

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



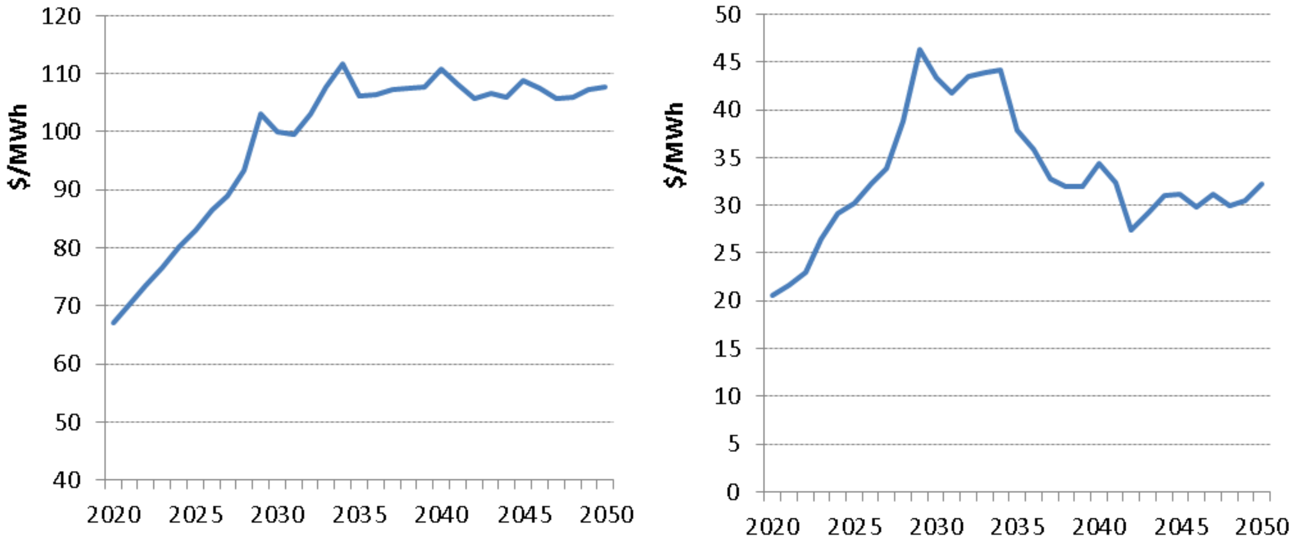
Source: Jacobs

5.3.5 Prices

Figure 136 shows wholesale prices. Prices are elevated relative to the reference case for the entire modelling horizon, due to the carbon price. Prices reach new entry levels in the late 2020s, but continue to increase because the pass-through of the escalating carbon price to CCGTs. Prices stabilise by the mid-2030s when nuclear generation technology becomes available.

Figure 136: Wholesale electricity time-weighted prices, carbon pricing, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows the change in price relative to the reference case.

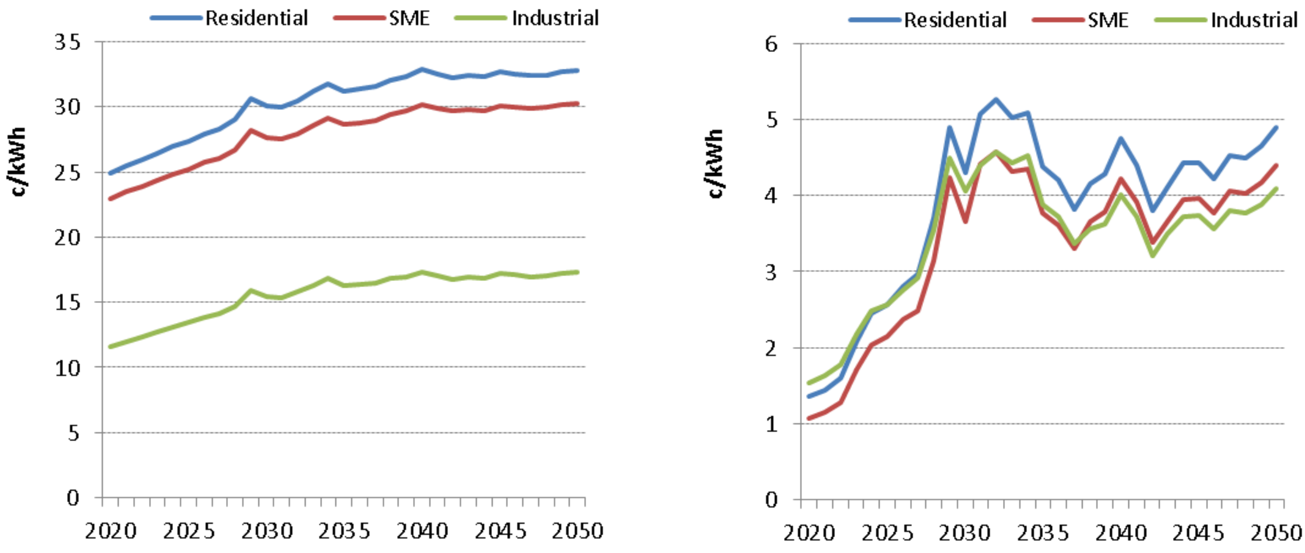


Source: Jacobs

Figure 137 shows weighted average retail prices by customer class. They contain the same trends as the wholesale prices, but the relative price movements are more muted since the wholesale price only comprises typically 30% - 40% of the retail price.

Figure 137: Retail prices by customer class, carbon pricing, 3°C emissions constraint

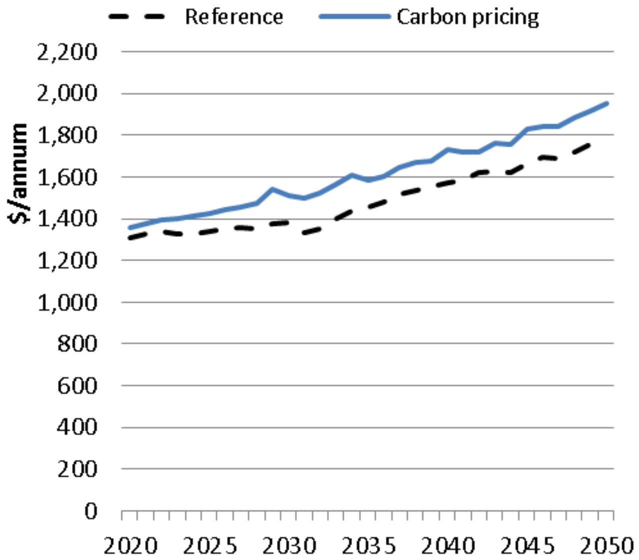
The left graph shows absolute figures. The right graph shows the change in prices relative to the reference case.

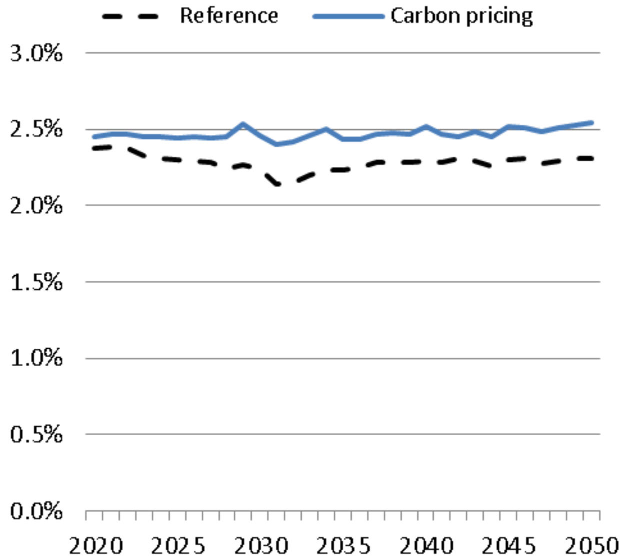


Source: Jacobs

Figure 138: Residential bills, carbon pricing scenario, 3°C emissions constraint

The left graph shows the absolute residential bill. The right graph shows the residential bill as a % of disposable income.





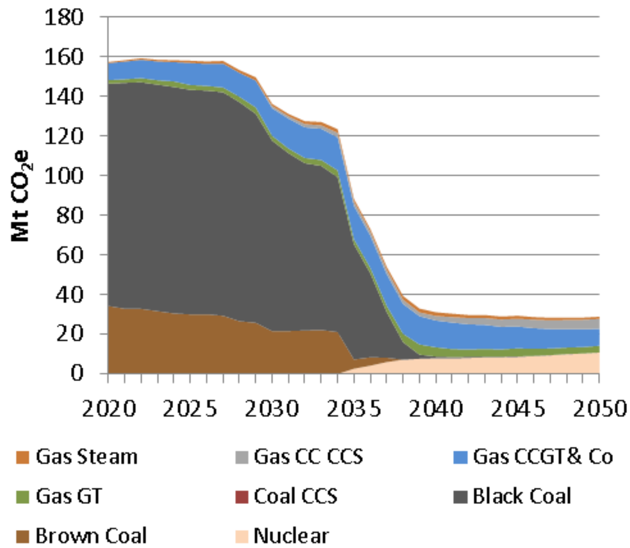
Source: Jacobs

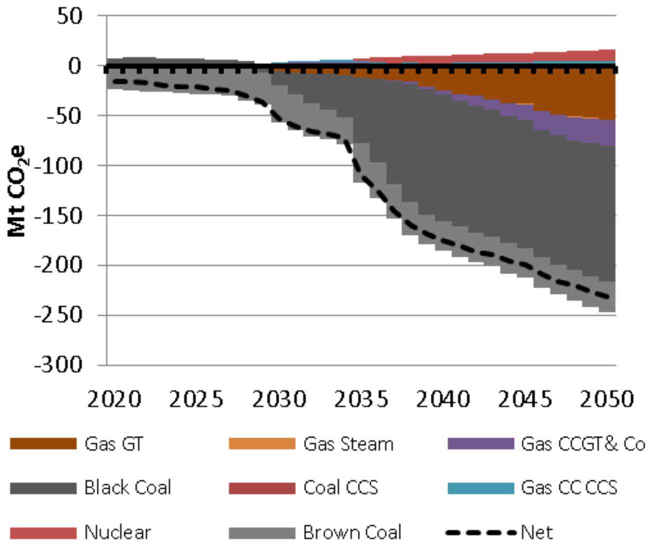
5.3.6 Emissions

Figure 139 shows annual emissions by fuel type. Cumulative emissions, both direct and indirect, amount to 2,823 Mt CO_2e by 2049/50. Emissions are lower than those of the reference case in the 2020s, but are stable for the first eight years of the modelling horizon. Gradual reductions in emissions occur with each retirement of a coal fired unit, with deep cuts occurring from 2034/35, when nuclear generation becomes available. Emissions average 15 Mt CO_2e in the last decade, and 85% of these are indirect emissions mostly produced by the nuclear fuel supply chain.

Figure 139: Emissions by technology, carbon pricing, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



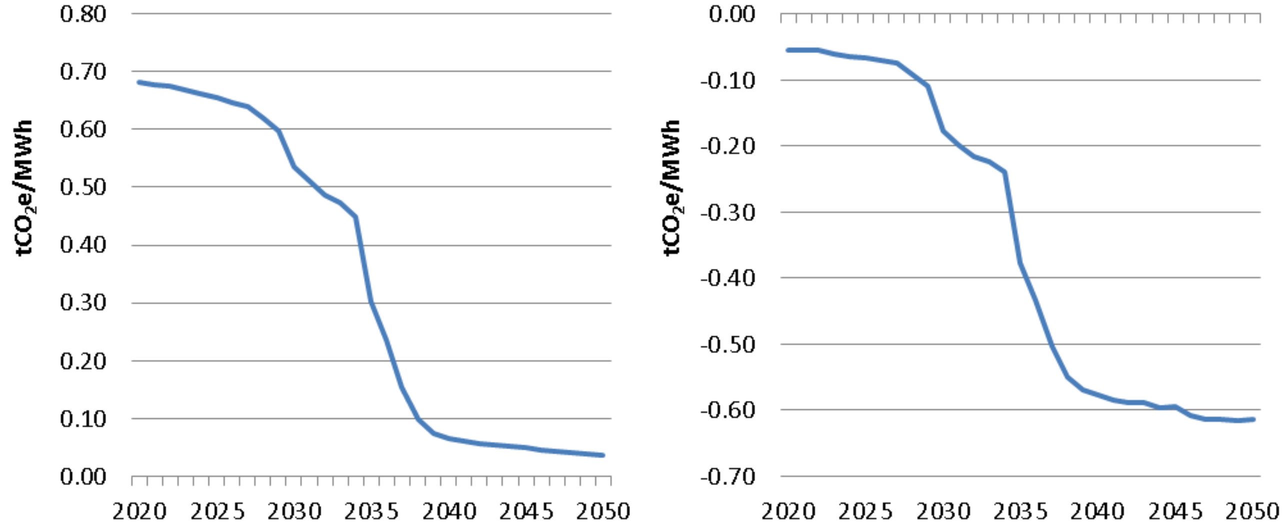


Source: Jacobs. Includes both direct and indirect emissions.

Figure 140 shows the absolute and relative to the reference case emission intensity of the grid. The trajectory shows stable profile of emission s followed by a sharp decrease from late 2020s to late 2030s reaching around 0.05 t CO_2e/MWh.

Figure 140: Generation emission intensity, carbon pricing, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



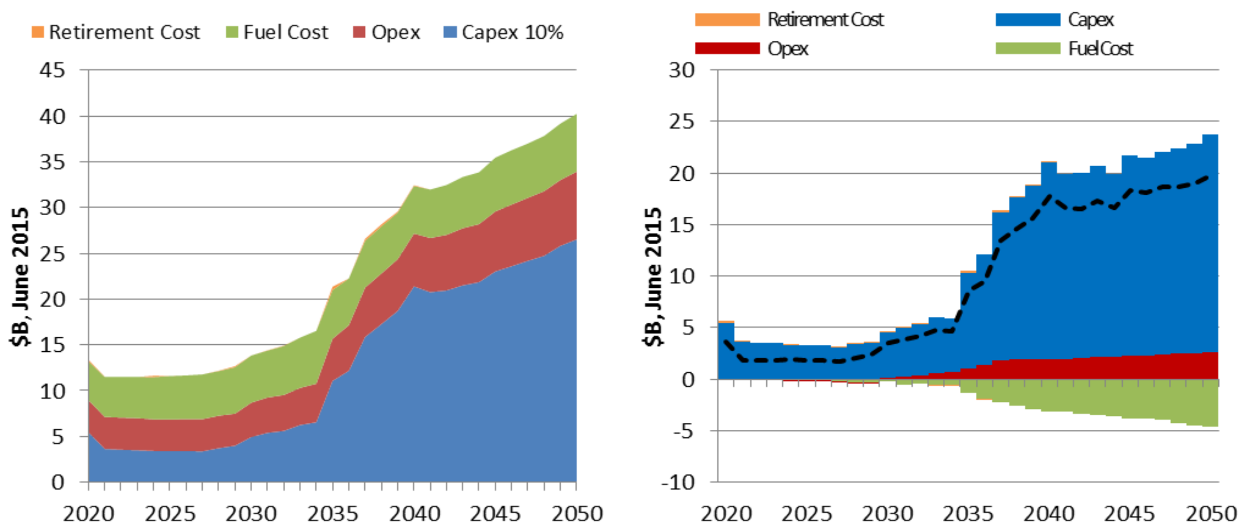
Source: Jacobs. Includes direct emissions only.

5.3.7 Costs

Figure 141 shows the annualised resource cost by four cost categories. Costs are flat over the first decade, only differing noticeably from the reference case in terms of capex. Costs rise from 2029/30 onwards, when retirement of additional coal fired units results in more capital expenditure. When nuclear generation is introduced into the mix in 2034/35 capex rises sharply and continues to rise at a slower rate post 2040. Opex increases relative to the reference case with the introduction of nuclear technology, although fuel costs, particularly from coal fired generation, steadily decrease relative to the reference case.

Figure 141: Annualised costs by category, carbon pricing, 3°C emissions constraint

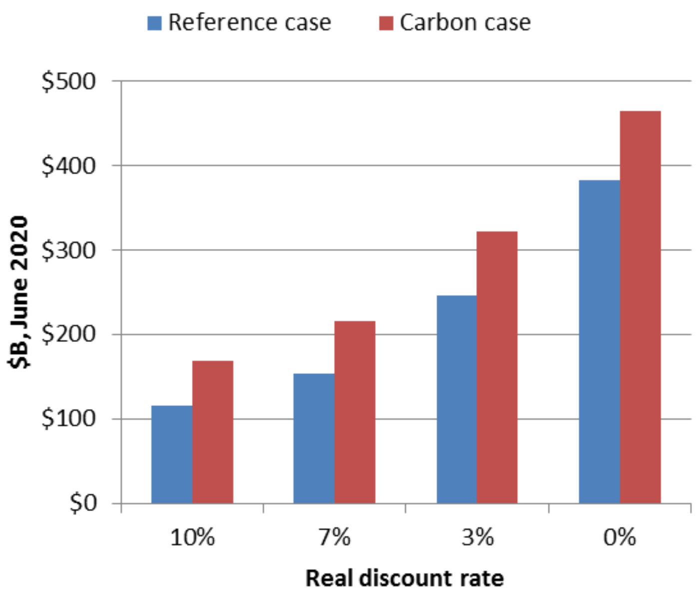
The left graph shows the absolute costs. The right graph shows the costs relative to the reference case.



Source: Jacobs

Figure 142 shows the net present value of resource costs for carbon pricing relative to the reference case. The total resource cost for carbon pricing ranges from 44% (at 10% real discount rate) to 21% (without discounting) higher than that of the reference case.

Figure 142: NPV of resource costs, carbon pricing, 3°C emissions constraint



Source: Jacobs. Excludes demand adjustment. See Appendix B.3.2 for further detail.

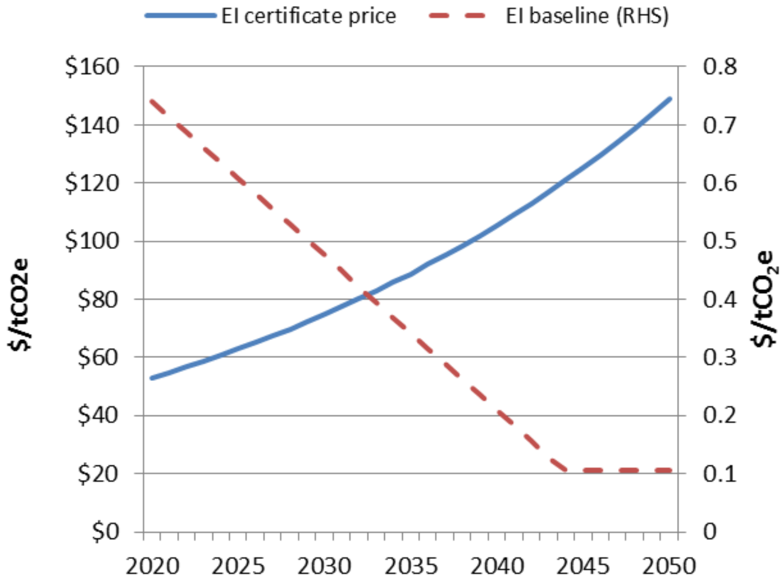
5.4 Emission intensity target

5.4.1 Scenario description

Under the emission intensity target (EIT) scheme generators are issued permits at 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 borrowing from future years is limited to 10%.

Figure 143 shows the final parameters of the EIT scheme that met the cumulative emissions constraint. The permit price is initially higher than the carbon price path, but crosses over with the carbon price in the late 2030s. The emission intensity baseline commences from the emission intensity of the 3°C reference case in 2019/20, declines linearly and levels out at the average emission intensity of the grid from 2045 to 2050.

Figure 143: Emission intensity permit price and baseline, 3°C emissions constraint



Source: Jacobs

For further discussion see Section 2.

5.4.2 Key findings

The EIT scheme impacts are very similar to the carbon price, but with slightly higher resource costs and somewhat lower wholesale and retail price impacts

In theory, the supply-side incentives and penalties associated with this scheme for a given permit price are equivalent to those of carbon pricing, regardless of the emission intensity baseline that is set. Revenue for high cost but low emission generators is supported by the value of the volume of permits that they can earn[29].

There were notable differences between the EIT scenario and the carbon pricing scenario in terms of permit prices required to achieve the cumulative emissions constraint and the costs in doing so. This can be explained by:

- The EIT scenario allows banking and some borrowing, while the carbon pricing scenario does not. The carbon pricing scenario is modelled as a carbon tax, so is equivalent to a cap and trade emissions trading scheme without banking or borrowing of permits. Under the EIT policy banking and borrowing is allowed but future borrowing is constrained by design. Higher certificate prices (compared with the carbon prices in the carbon pricing scenario) were required in the early years to allow enough banking to occur so that the borrowing that is inevitably required in the later years draws on the permit bank, and not from future permits. Figure 147 shows the banking and borrowing of permits over the modelling period.

- The built-in price response of demand meant that demand under the EIT was higher relative to the carbon pricing scenario. The necessarily high initial baseline under the EIT scenario[30] resulted in lower initial market prices, and hence a higher level of demand.

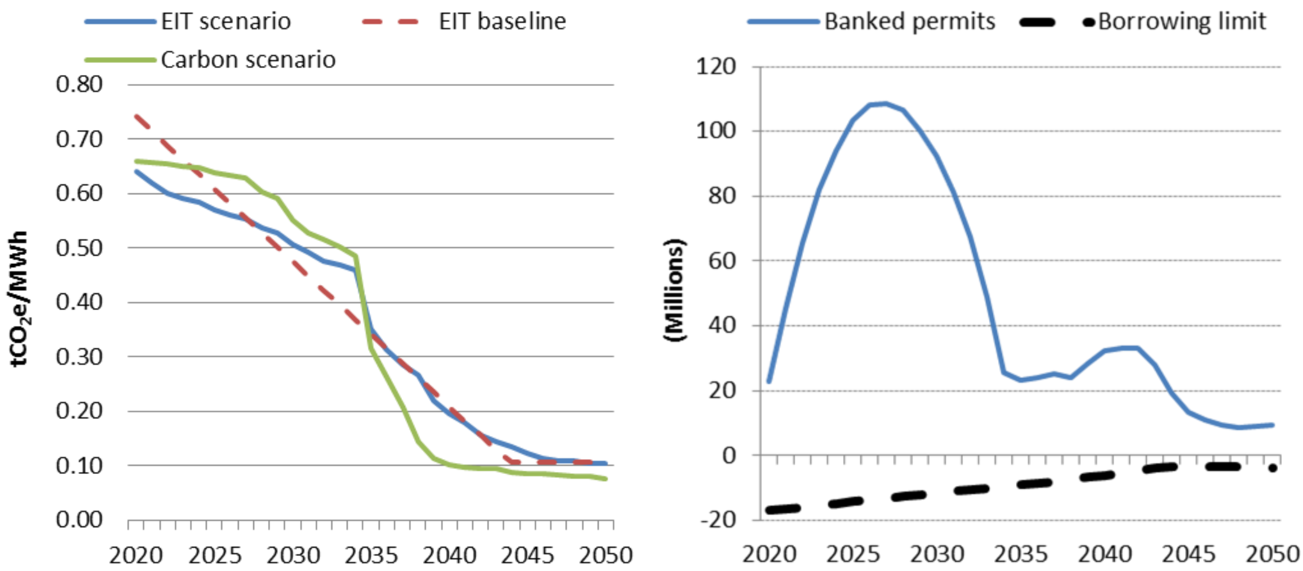
[29] Under SRMC bidding with perfectly inelastic demand, a generator's pool revenue is perfectly compensated by the value of the additional volume of allocated permits.

[30] The form of the EIT emission baseline was part of the EIT scheme design, which called for a linearly declining emission baseline with the starting point being the grid emission intensity of the reference case. This was followed by a flat emission baseline, which was chosen to reflect the long-term emission intensity of the grid.

The higher permit prices in the earlier years relative to carbon pricing makes the entry of renewable energy more attractive. This results in a higher level of new renewable investment relative to the carbon scenario throughout the whole modelling period. This re-balancing of the plant mix is required under the EIT scenario to achieve the cumulative emissions constraint because demand is higher than the carbon pricing scenario from 2020 to 2040 due to lower wholesale prices. Since demand is higher, the generation mix needs to have lower average emission intensity to achieve the cumulative emissions constraint relative to carbon pricing.

Locking in renewables early for the EIT changes the generation mix post 2030 relative to carbon pricing because not as much low emission technology (nuclear and CCGTs with CCS) is required. Moreover, the EIT permit price is lower from 2037/38 resulting in some incumbent coal fired generation surviving until the end of the modelling period, meaning that less generation capacity needs to be replaced.

Figure 144: Emission intensity trajectories for EIT and carbon pricing, and banking/borrowing of permits under EIT, 3°C emissions constraint



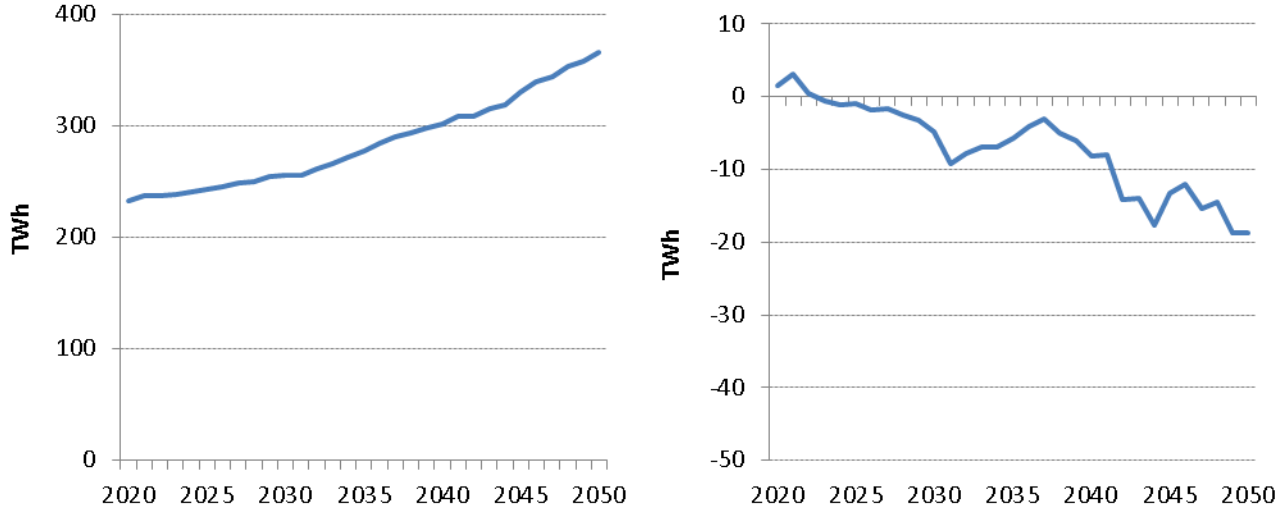
Source: Jacobs

5.4.3 Demand

Figure 145 shows sent-out energy demand for the emission intensity target scenario in absolute terms and relative to the reference case. Total energy consumed reaches 364 TWh in 2049/50, 21 TWh lower than the reference case due to higher wholesale and retail prices reducing demand.

Figure 145: Sent-out energy, emission intensity target, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Pitt & Sherry, ACIL Allen and Jacobs

5.4.4 Generation and capacity

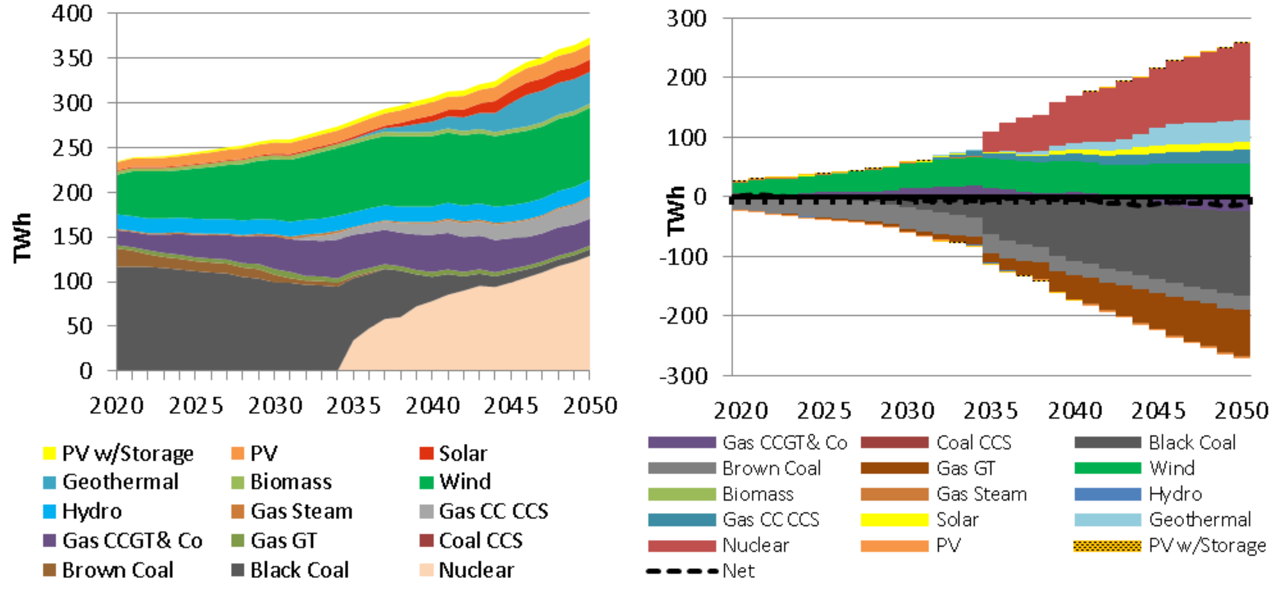
Figure 146 shows the generation mix in both absolute terms and relative to the reference case. The key difference between the EIT scenario and the carbon pricing scenario in the generation mix is the role played by wind in the 2020s. The higher permit prices in the 2020s causes more retirement of coal fired generation in the EIT scenario relative to carbon pricing in this time period. More wind investment occurs under the EIT scenario as a replacement for the retiring coal fired capacity. This early investment in wind effectively locks out some of the low emission replacement capacity (nuclear and CCGTs with CCS) that is used to replace coal fired generation under carbon pricing.

Post 2030, as with carbon pricing, nuclear generation technology dominates new entry. However, the lower level of coal fired retirements under the EIT post 2035, coupled with slightly more demand, enables more geothermal capacity to enter the market as it becomes competitive with nuclear from 2035 onwards. The deferral of some coal fired capacity by a few years is enough to allow geothermal entry in more volume relative to carbon pricing.

Under the EIT scenario there are seven transmission upgrades totalling 4,920 MW. This is 1,660 MW more than what was required for the reference case.

Figure 146: Generation mix, emissions intensity target, 3°C emissions constraint

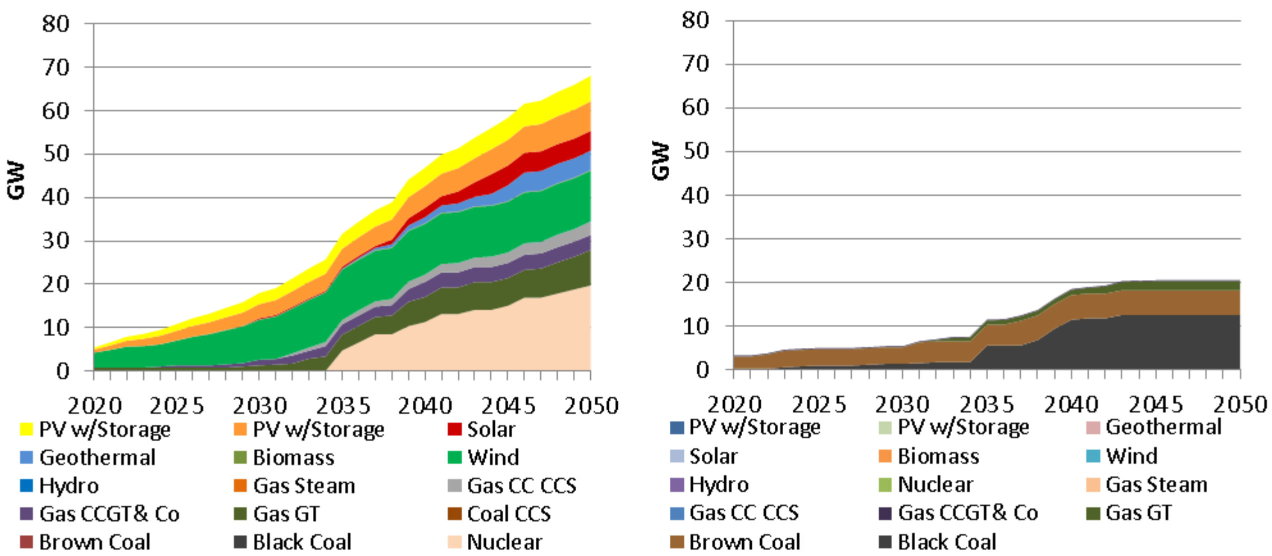
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs

Figure 147: Cumulative new and retired capacity, emission intensity target, 3°C emissions constraint

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



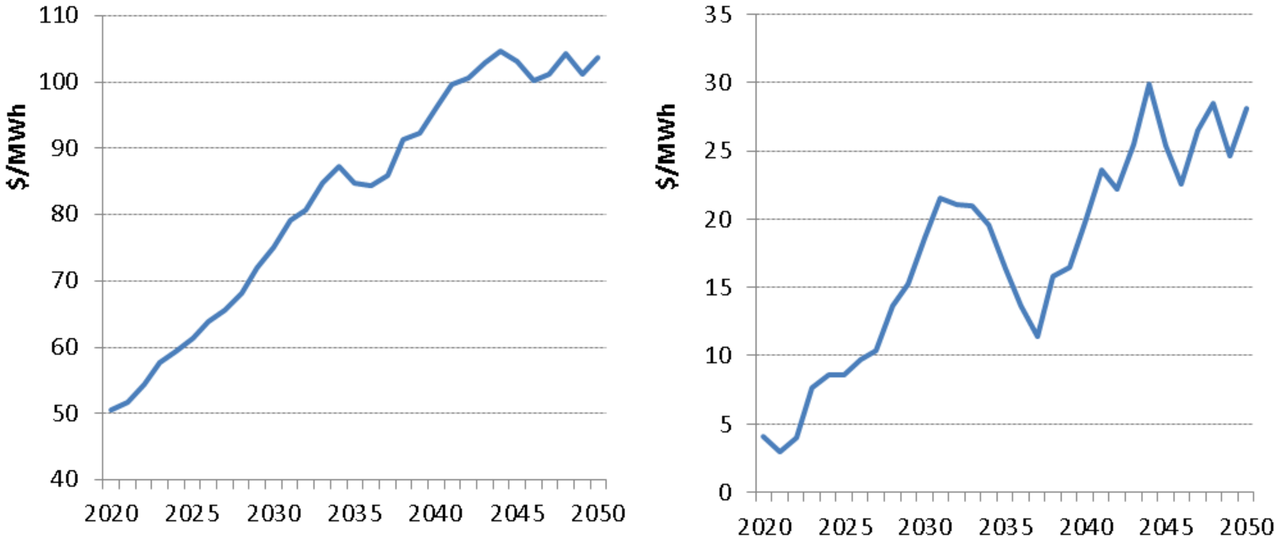
Source: Jacobs

5.4.5 Prices

Figure 148 shows average wholesale prices weighted by region. The upward linear trend in the weighted wholesale price that persists until the mid-2040s is mainly driven by the downward linear trend in the emission baseline (see section 5.4.2 on the relationship between the market price and the emission baseline). Prices level out post 2040 when they reach new entry levels and are slightly lower than carbon pricing because the long-term emission baseline is non-zero.

Figure 148: Wholesale electricity time-weighted prices, emission intensity target, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.

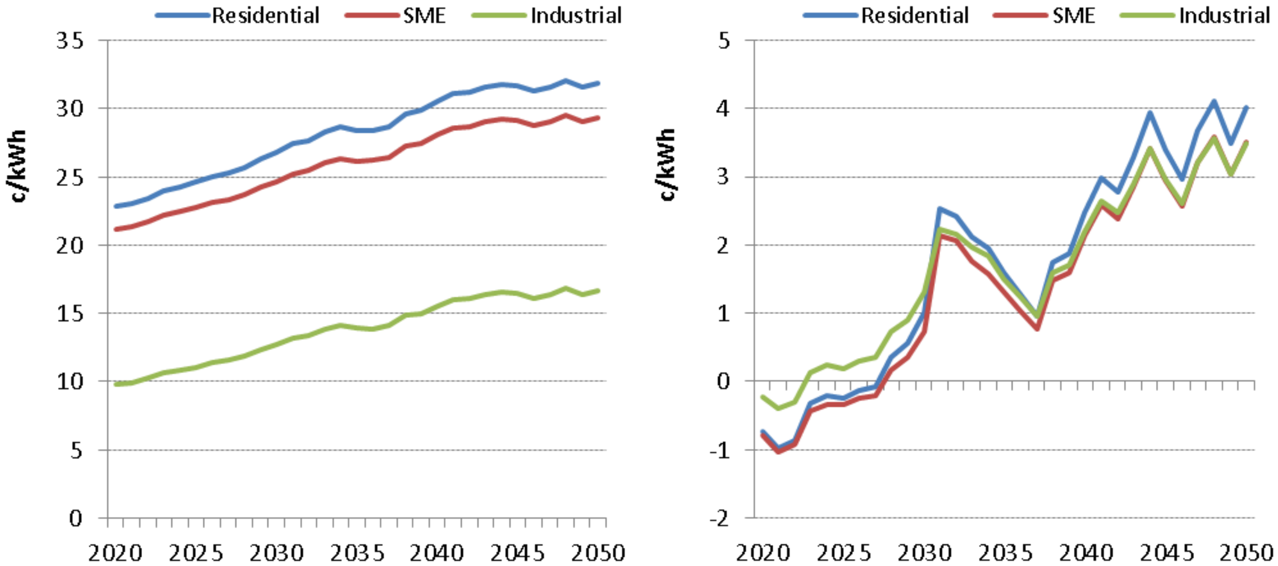


Source: Jacobs

Figure 149 shows weighted average retail prices by customer class. They contain the same trends as the wholesale prices but are more muted on a relative basis. While the same stands for the residential bill costs illustrated in Figure 150.

Figure 149: Retail prices by customer class, emission intensity target, 3°C emissions constraint

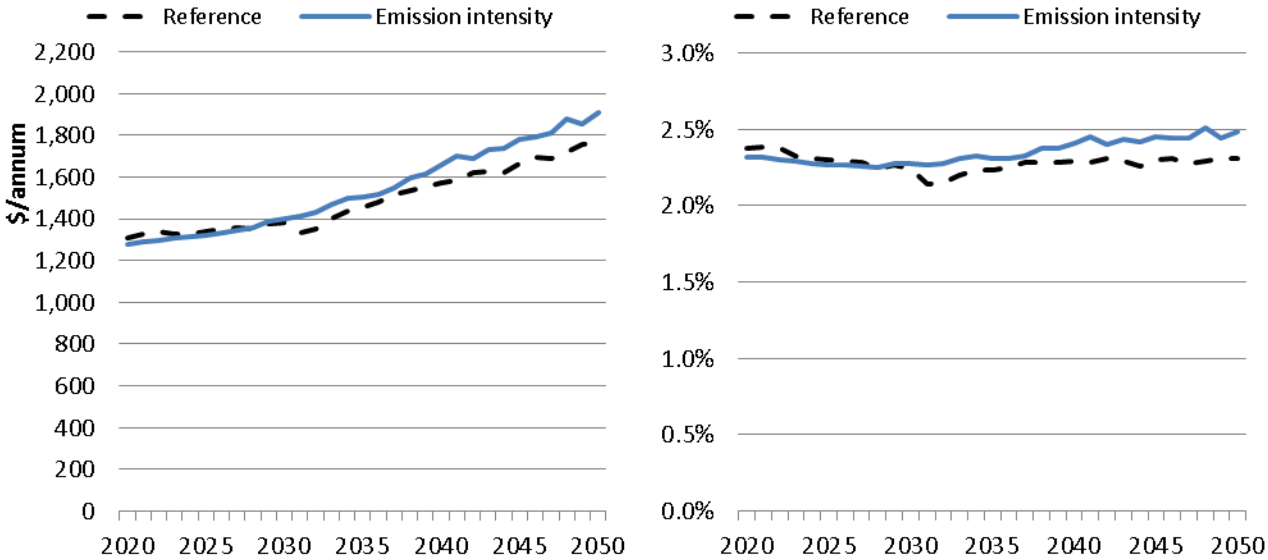
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs

Figure 150: Residential bills, emission intensity target, 3°C emissions constraint

The left graph shows the absolute residential bill. The right graph shows the residential bill as a % of disposable income..



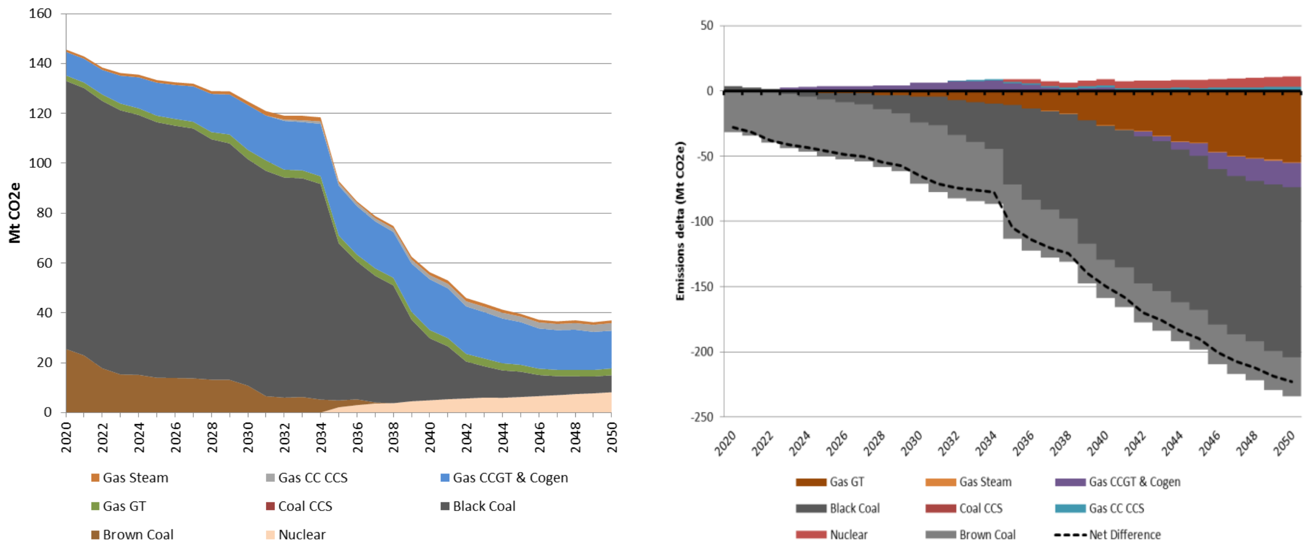
Source: Jacobs

5.4.6 Emissions

Figure 151 shows emissions by generation technology and Figure 152 illustrates the generation emission intensity. Emissions in 2019/20 are lower than those of carbon pricing (146 Mt versus 157 Mt) due to the higher permit price. Also, unlike carbon pricing, emissions steadily reduce from 2019/20 in roughly linear fashion until 2034/35. After 2035 emissions fall away rapidly, as they do under carbon pricing, but the rate of decrease is lower than that of carbon pricing. This is explained by the permit price, which is lower than that of carbon pricing from 2037/38 onwards. Furthermore some coal fired capacity survives until the end of the modelling period, as it remains profitable to operate at shoulder/peaking duties under the certificate prices.

Figure 151: Emissions by technology, emission intensity target, 3°C emissions constraint

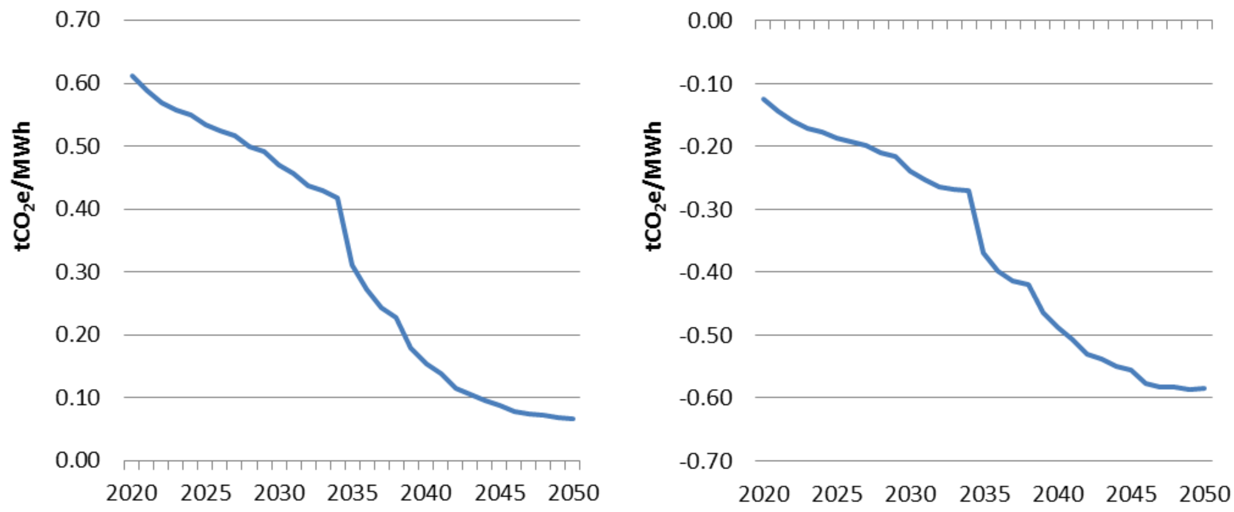
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs. Includes both direct and indirect emissions.

Figure 152: Generation emission intensity, emission intensity target, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



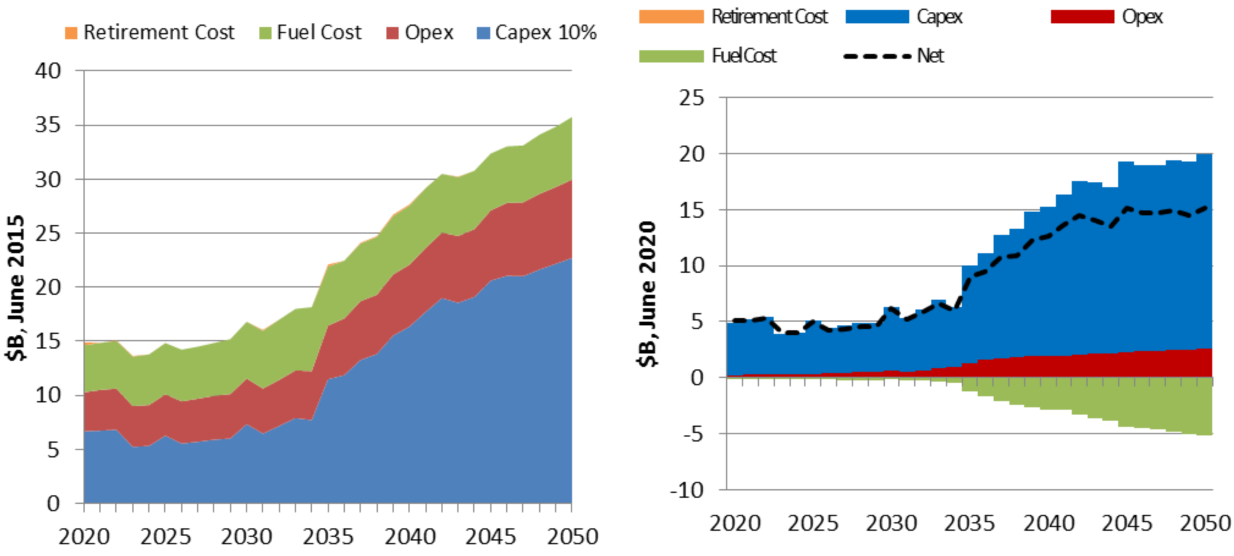
Source: Jacobs. Includes direct emissions only.

5.4.7 Costs

Figure 153 shows annualised resource costs by four cost categories. The cost profile is more front-loaded than that of carbon pricing due to the higher initial investment in wind generation technology in the 2020s. The overall profile is similar to that of carbon pricing in trend, with capex being the dominant resource cost.

Figure 153: Annualised costs by category, emission intensity target, 3°C emissions constraint

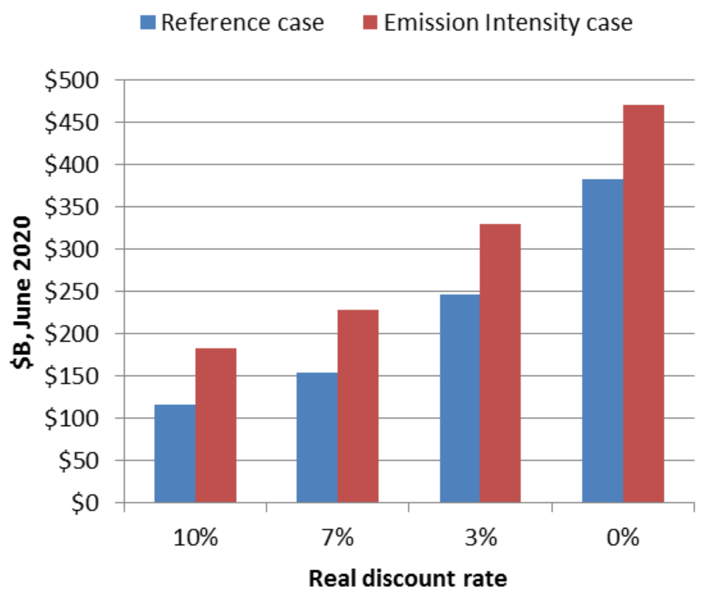
The left graph shows the absolute costs. The right graph shows the costs relative to the reference case.



Source: Jacobs

Figure 154 shows the net present value of resource costs for EIT relative to the reference case. The total resource cost for the EIT scenario ranges from 57% (at 10% real discount rate) to 23% (without discounting) higher than that of the reference case.

Figure 154: NPV of resource costs, emission intensity target, 3°C emissions constraint



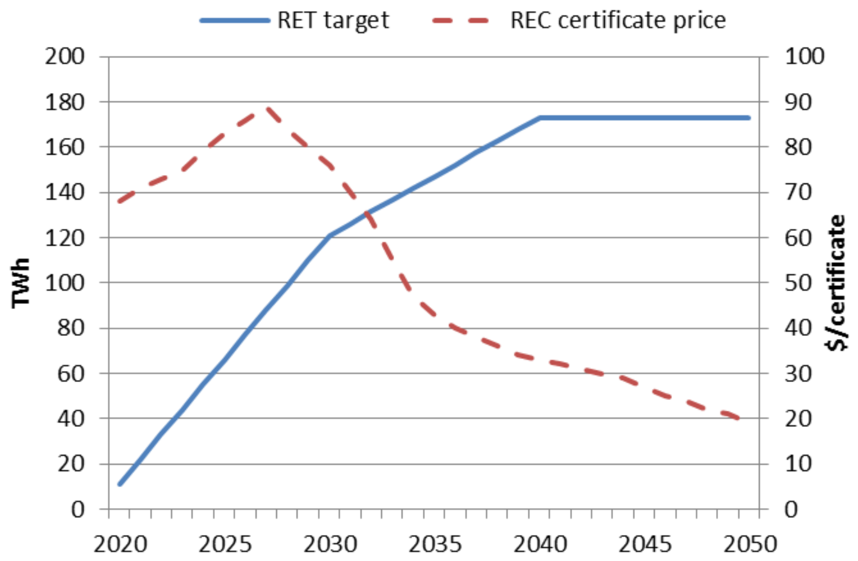
Source: Jacobs. Excludes demand adjustment. See Appendix B.3.2 for further detail.

5.5 Renewable energy target

5.5.1 Scenario description

The RET works by creating a market that supports investment in new renewable generation capacity. It places a legal obligation on entities that purchase wholesale electricity (mainly electricity retailers) to surrender a certain number of certificates to the regulator each year. These certificates are generated by accredited renewable power stations. The renewable energy target (RET) scenario is essentially a much larger version of the current LRET scheme, except that there are no EITE exemptions and there is no price cap on renewable certificates. Figure 155 shows the final RET trajectory and the corresponding RET certificate price required to satisfy the cumulative emissions constraint. In the course of the modelling it was found that a dual linear form for the RET trajectory was necessary to achieve a least cost solution. This is explained in more detail below.

Figure 155: RET target and RET certificate price, 3°C emissions constraint



Source: Jacobs

5.5.2 Key findings

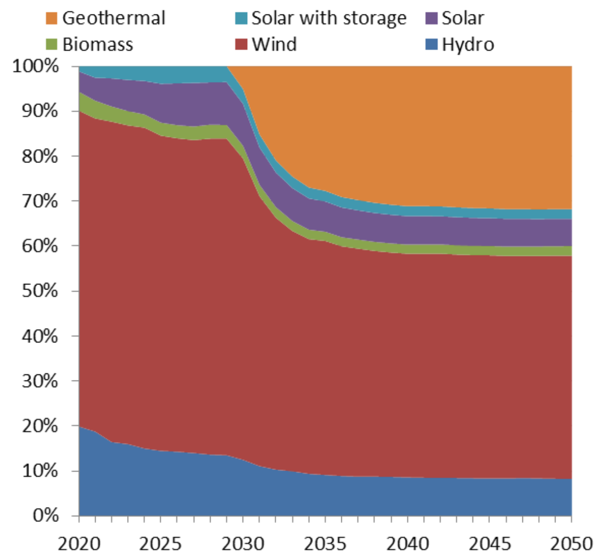
Using a scheme such as the RET to de-carbonise the electricity sector presents some challenges. Two key mechanisms are required for a scheme to efficiently de-carbonise the electricity sector. Firstly an incentive mechanism is required to encourage investment in low emission generation technologies. The RET scheme itself serves as such a mechanism, where the incentive is in the form of certificate revenue for eligible technologies. Secondly a penalty mechanism is required to facilitate the closure of incumbent fossil generators. The RET scheme does not have a direct mechanism to do this. It can only effect the retirement of fossil generators indirectly by reducing their revenue, which it achieves by creating an oversupply of very low marginal cost plant that suppresses the market price and also displaces incumbent high emitting plant.

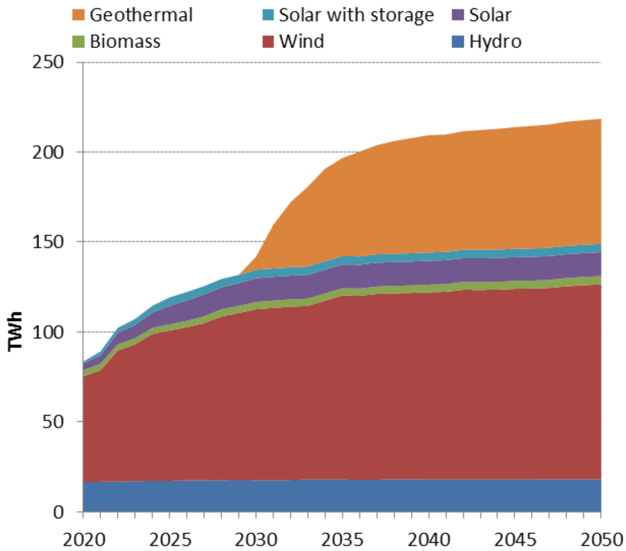
Even with the less stringent cumulative emission target set by the 3°C carbon pricing scenario, strong action is required in the 2020s to achieve the target. This involves a steep trajectory in the renewable target from 2020 to 2030, followed by a gentler slope from 2030 until 2040. The aim of the initial steep trajectory is to drive the retirement of the incumbent fossil generators by suppressing the market price, and effectively substituting the incumbents with new renewable plant. After 2030, when enough fossil generators have retired, the trajectory increases at a slower rate essentially to keep pace with load growth. The initial slope of the RET trajectory to meet the 3°C cumulative emissions target is 26% lower than that of the 2°C scenario.

Figure 156 shows the contribution of each large-scale renewable energy technology in both relative and absolute terms. Renewable generation share peaks in 2035/36 at 76%, which is lower than the 90% peak reached for the corresponding 2°C scenario. The lower peak reflects the smaller abatement task.

A consequence of the RET scheme not having a direct penalty on emissions is that post 2035, when the RET target is not growing as quickly, the least-cost new entrant options are either supercritical black coal plant or CCGTs, depending on the region. Total emissions therefore begin to increase post 2035 quite noticeably when these new fossil generators start to enter the market. This means that a greater level of abatement needs to be achieved pre 2035 in order to satisfy the cumulative emissions constraint compared with the case in which fossil generators are somehow prevented from entering the market (e.g. through the imposition of minimum emission standards). This result is an artefact of the formulation of the RET policy, which effectively treats 2050 as the end of time with no provision for effective emission controls beyond 2050. While this result shows the risk that new high-emissions plant can be built if policies do not directly penalise emissions, if this policy were implemented in practice, investors would likely expect further strong climate policy to continue after 2050, so may be unlikely to construct new coal plant even if it were the lowest cost plant.

Figure 156: Contribution of large-scale renewable generation by technology, renewable energy target, 3°C emissions constraint





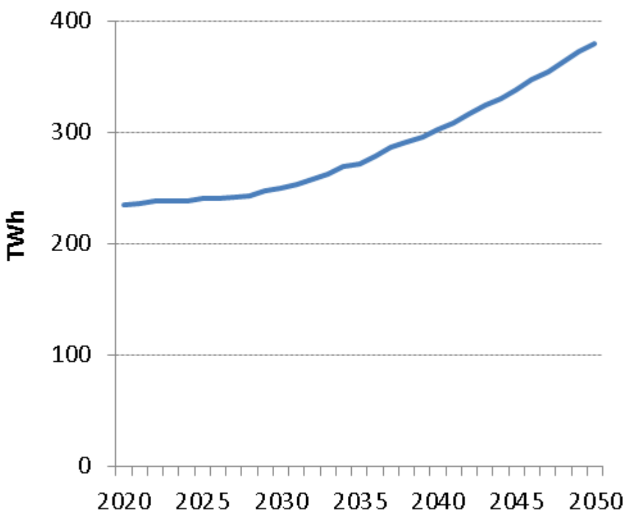
Source: Jacobs

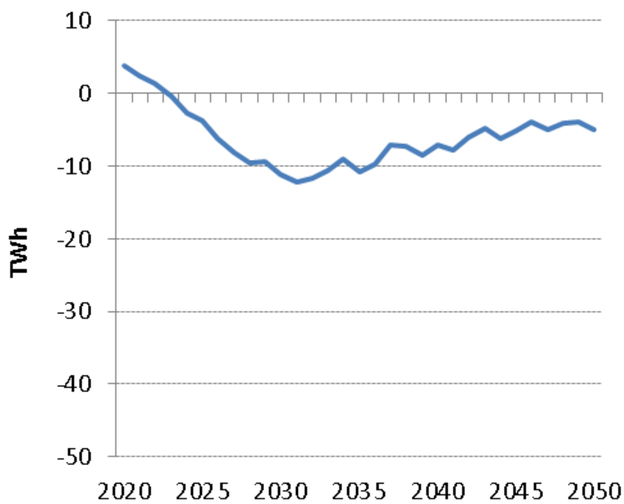
5.5.3 Demand

Figure 157 shows sent-out energy demand for the RET scenario in absolute terms and relative to the reference case. Total energy consumed reaches 385 TWh in 2049/50, which is almost the same as that of the reference case due to low certificate prices.

Figure 157: Sent-out energy, renewable energy target, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.





Source: Pitt & Sherry, ACIL Allen and Jacobs

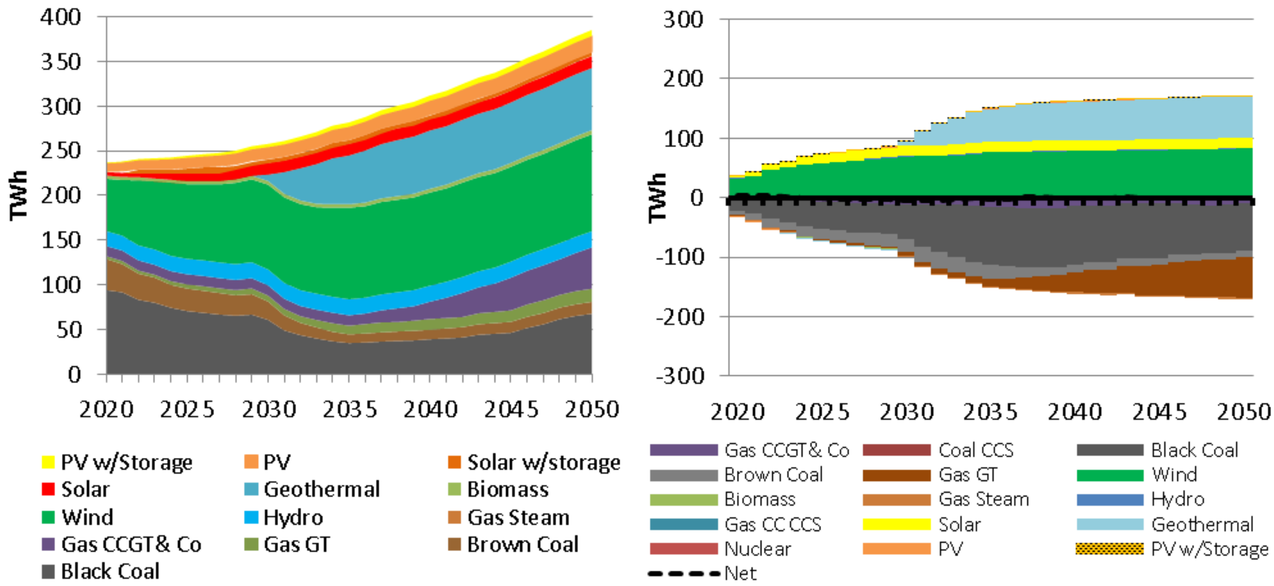
5.5.4 Generation and capacity

Figure 158 shows the generation mix across the modelling horizon in absolute terms and relative to the reference case. The key technology in the 2020s that replaces most of the coal fleet is wind generation, which is generating 94 TWh by 2029/30. Large scale PV without storage plays a small but important role in the early years, and PV with storage plays a much smaller role than it does for the 2°C scenario. The reason for this is that with a lower renewable target curtailed energy is not as critical an issue as it is for the 2°C scenario, and therefore large volumes of PV with storage, which is still a costly technology in the 2020s, can be avoided. After 2030 when geothermal technology becomes available a large amount of it is built even though the rate of decline in its capital cost is half that of the 2°C scenarios.

Brown coal fired generation operate longer than under the carbon pricing and EI scenarios. This occurs because brown coal generators have lower marginal costs than black coal generators and because emissions are not priced directly under this policy. As a result, black coal plants tend to be the marginal plant and are the first to be displaced by the new entrant renewable generators.

Figure 158: Generation mix, renewable energy target, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



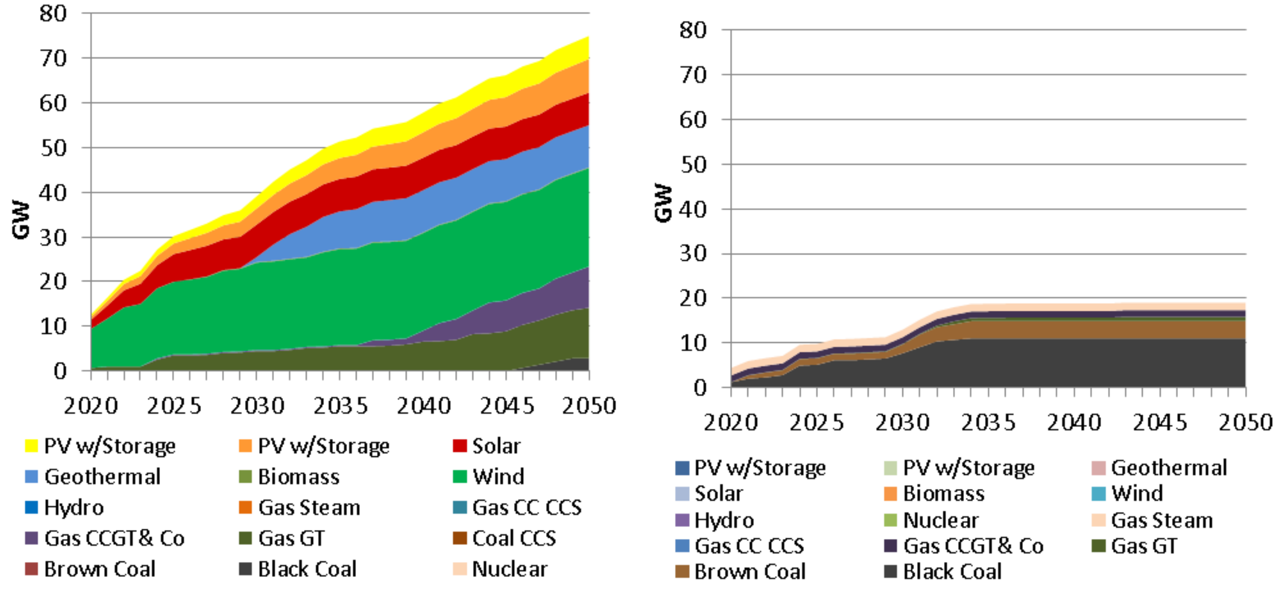
Source: Jacobs

Figure 159 shows cumulative new generation capacity under the RET, with renewable generation technologies dominating new build. A contribution is also made by gas turbines, which is the prevalent fossil generation technology built prior to 2040. Gas turbines are required to meet the reliability constraint discussed in Appendix B and find a market niche in providing back-up capacity for intermittent renewable capacity.

Under the RET scenario there are four transmission upgrades totalling 2,460 MW. This is 800 MW less than the reference case, and stands in contrast to upgrades required for the corresponding 2°C scenario, which were triple in capacity terms.

Figure 159: Cumulative new and retired capacity, renewable energy target, 3°C emissions constraint

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



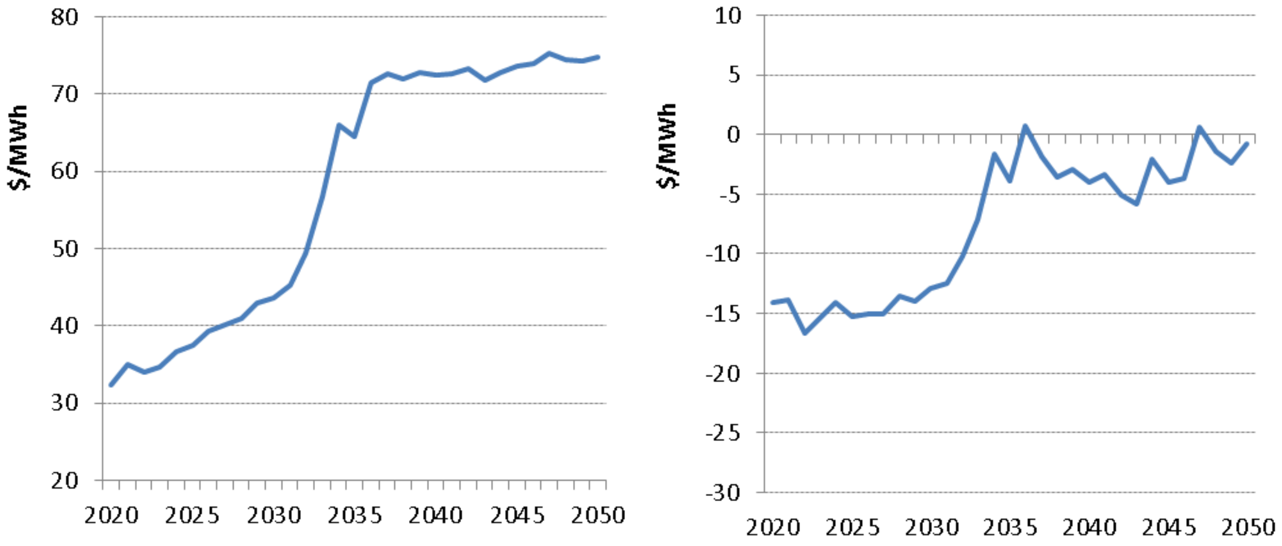
Source: Jacobs

5.5.5 Prices

Figure 160 shows wholesale electricity prices. Prices in the early 2020s are suppressed due to the entry of large volumes of renewable generation, and this force the retirement of much of the coal fleet. In 2033/34 prices rebound after retirement of a significant number of coal fired generators. Prices then track closely to those of the reference case, having reached the new entry level of fossil generation.

Figure 160: Wholesale electricity time-weighted prices, renewable energy target, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



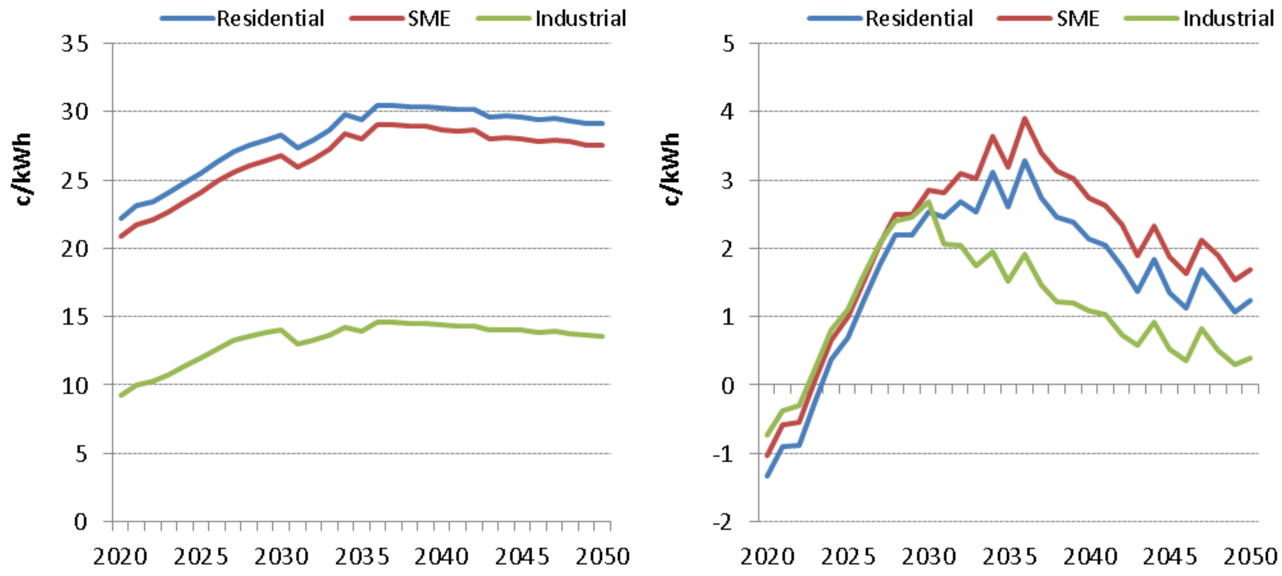
Source: Jacobs

Figure 161 shows weighted average retail prices by customer class. Unlike carbon pricing and EIT, they do not entirely mirror the trends in the wholesale price because they are also heavily influenced by the renewable certificate price. Figure 162 shows the weighted average residential bill relative to the reference case, and also as a percentage of disposable income.

The high certificate price and the volume of certificates under the RET required to satisfy the cumulative emissions constraint combine to have a material impact on retail prices, which in turn results in increases to residential bills.

Figure 161: Retail prices by customer class, renewable energy target, 3°C emissions constraint

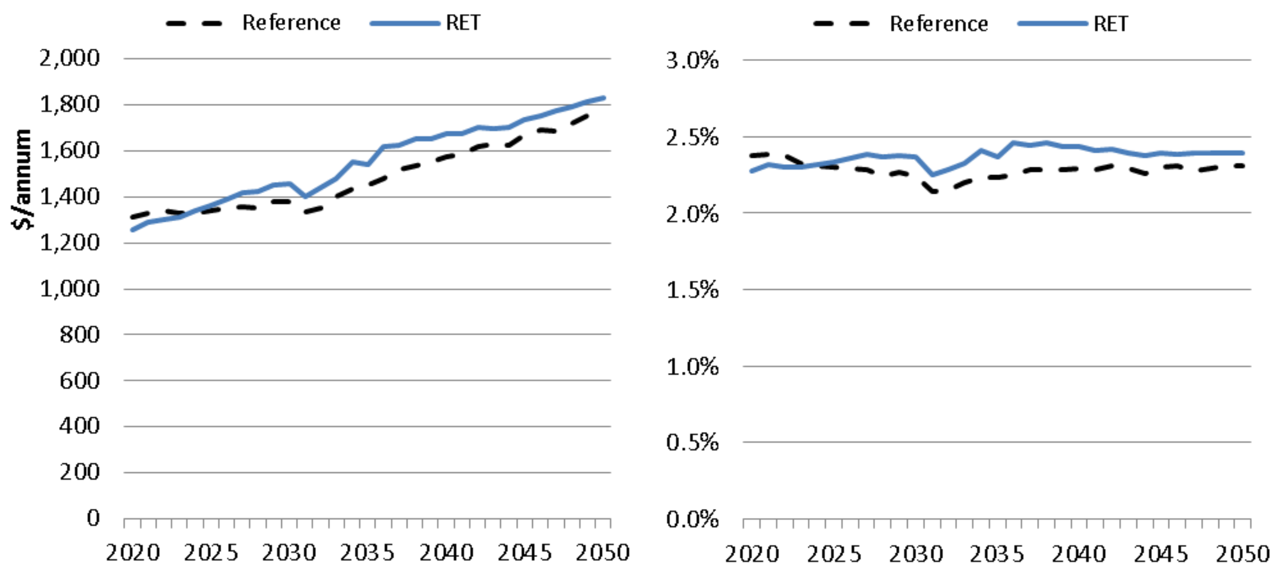
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs

Figure 162: Residential bills, renewable energy target, 3°C emissions constraint

The left graph shows the absolute residential bill. The right graph shows the residential bill as a % of disposable income.



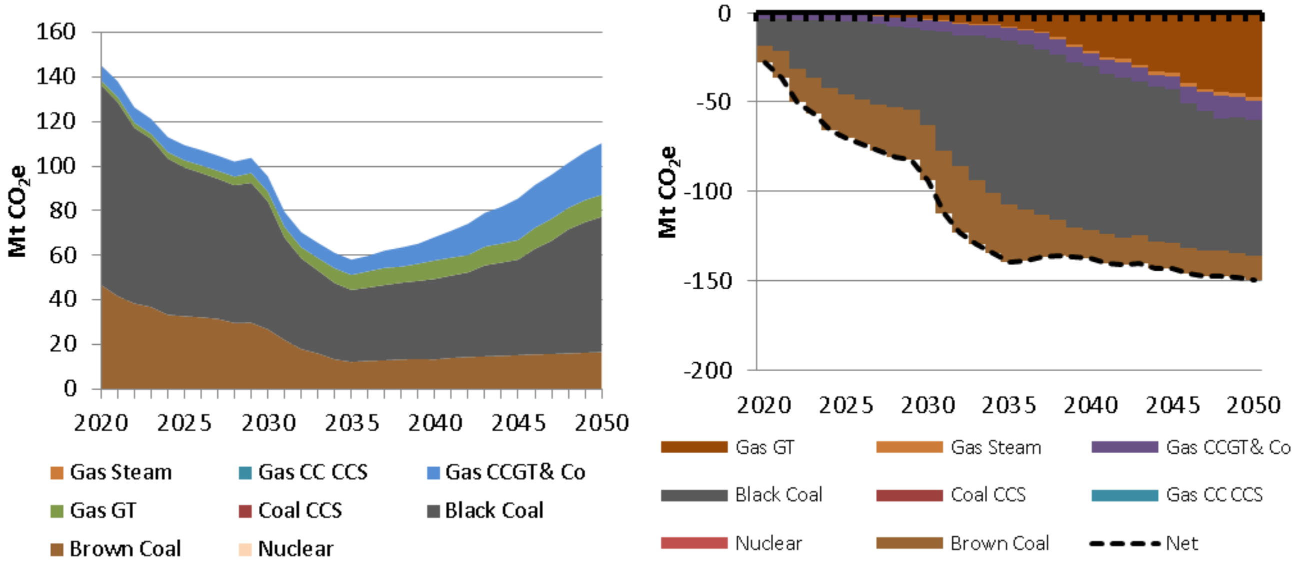
Source: Jacobs

5.5.6 Emissions

Figure 163 shows annual emissions by technology and the difference relative to the reference case. Most of the coal fleet retires by the mid-2030s, and emissions increase post 2035 with the commissioning of new fossil generators. Figure 164 shows the generation emission intensity both in absolute terms and relative to the reference case.

Figure 163: Emissions by technology, renewable energy target, 3°C emissions constraint

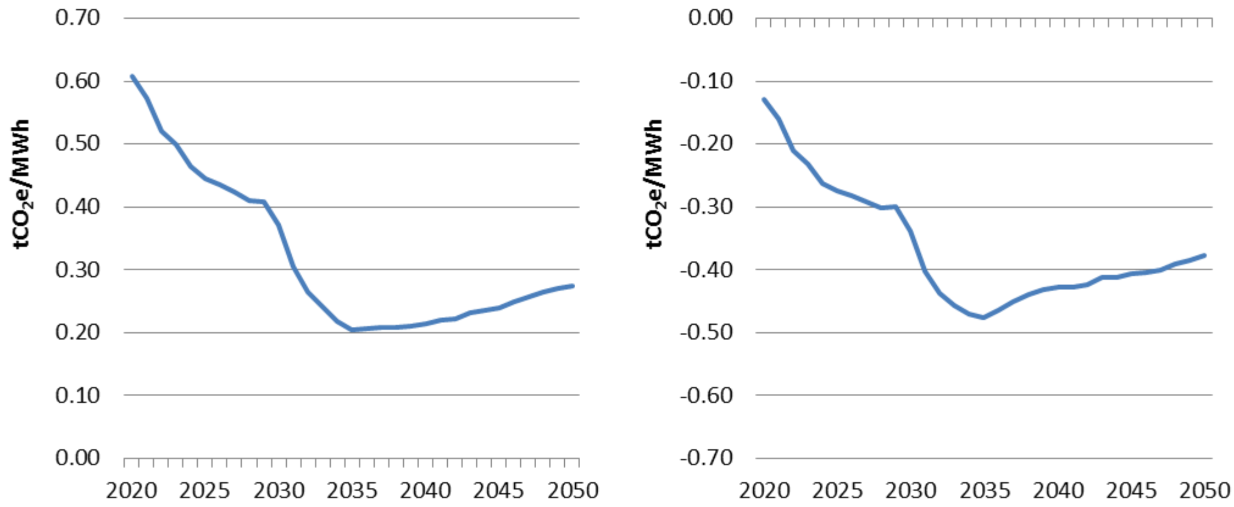
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs. Includes both direct and indirect emissions.

Figure 164: Generation emission intensity, renewable energy target, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



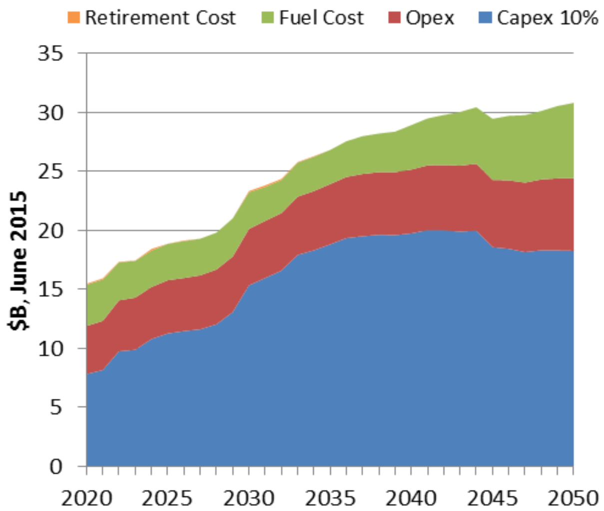
Source: Jacobs. Includes direct emissions only.

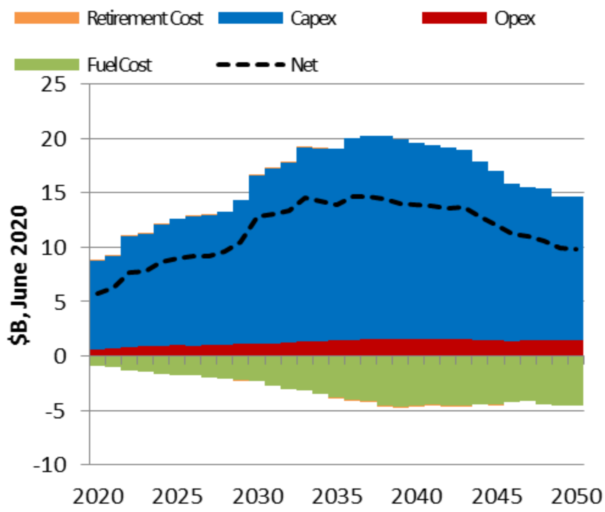
5.5.7 Costs

Figure 165 shows annualised resource costs by four cost categories. Costs in 2019/20 are about $16 billion and they escalate rapidly from there as new renewable build is required to meet the rapidly escalating RET. Annual costs peak in 2049/50 at about $32 billion, which is about 25% lower than that of the carbon pricing scenario. In contrast to the corresponding 2°C scenario, capital costs are lower than those of carbon pricing after 2040.

Figure 165: Annualised costs by category, renewable energy target, 3°C emissions constraint

The left graph shows the absolute costs. The right graph shows the costs relative to the reference case.

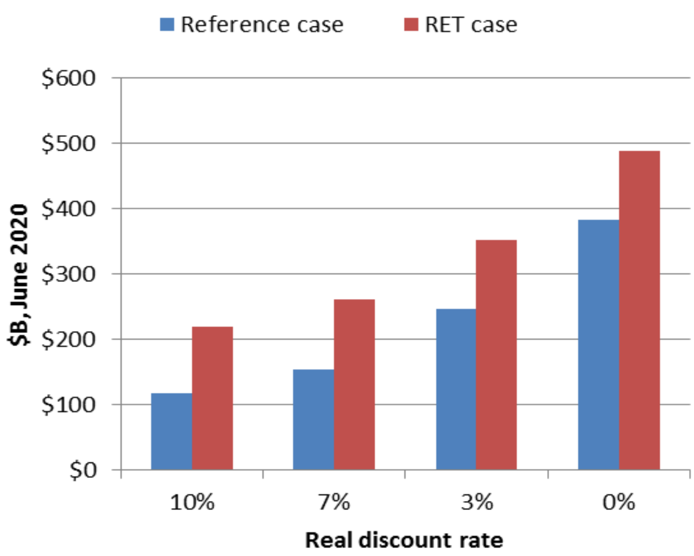




Source: Jacobs

Figure 166 shows the net present value of the resource costs for the RET scenario relative to the reference case for four separate discount rates. The total resource cost for the RET scenario ranges from 88% (at 10% real discount rate) to 27% (without discounting) higher than that of the reference case. This is notably higher than the total resource cost of carbon pricing, and is driven by the large capital cost required to invest in volumes of renewable generation capacity that are comparable to the current and future size of the entire electricity sector.

Figure 166: NPV of resource costs, renewable energy target, 3°C emissions constraint



Source: Jacobs. Excludes demand adjustment. See Appendix B.3.2 for further detail.

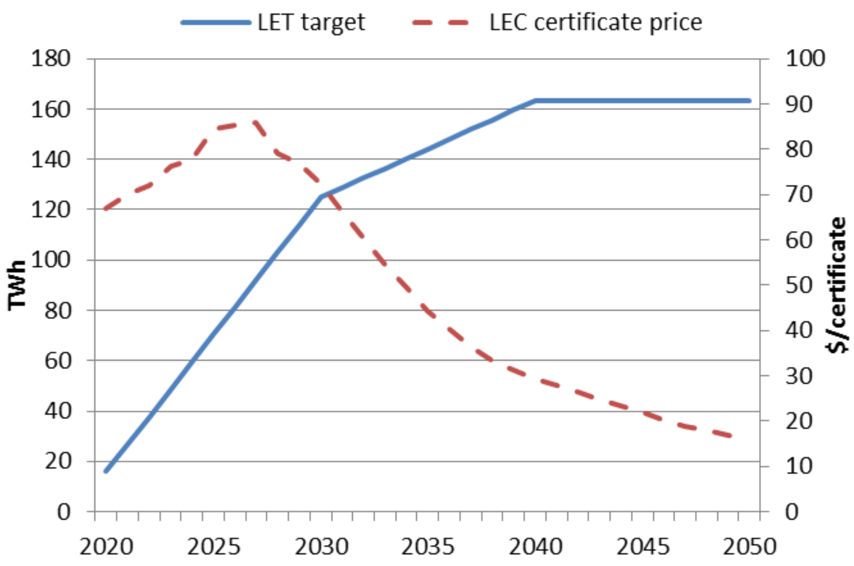
5.6 Low emissions target

5.6.1 Scenario description

The low emissions target (LET) scenario is very similar to the RET, with the difference being that low emission fossil fuel technologies are also eligible to earn certificates. Low emission technologies are those that emit below an emission intensity threshold of 0.6 t CO_2e/MWh. This includes low emission CCGTs, both coal fired and gas fired CCS plants and nuclear generation technology.

Figure 167 shows the final LET trajectory and the corresponding LET certificate price required to satisfy the cumulative emissions constraint. As with the RET scenario, it was found that a dual linear form for the LET trajectory was necessary to achieve a least cost solution. The LET trajectory remains constant from 2040 at 163.5 TWh, which is 5% lower than the stabilisation point of the RET scenario since the LET scenario allows a greater spread of technologies than the RET and issues partial certificates to gas generators.

Figure 167: LET target and LET certificate price, 3°C emissions constraint



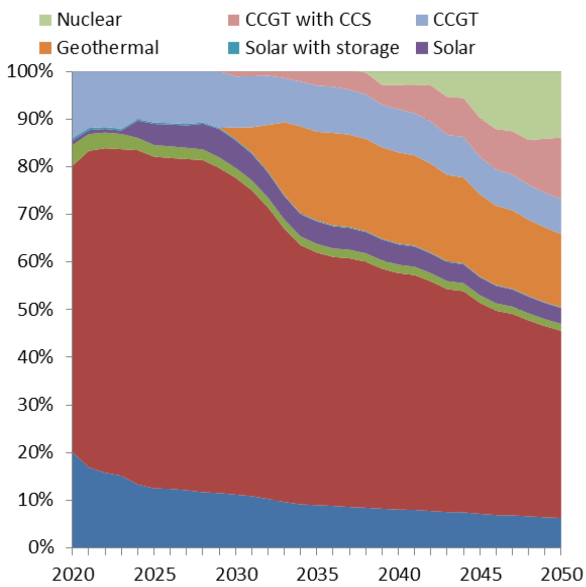
5.6.2 Key findings

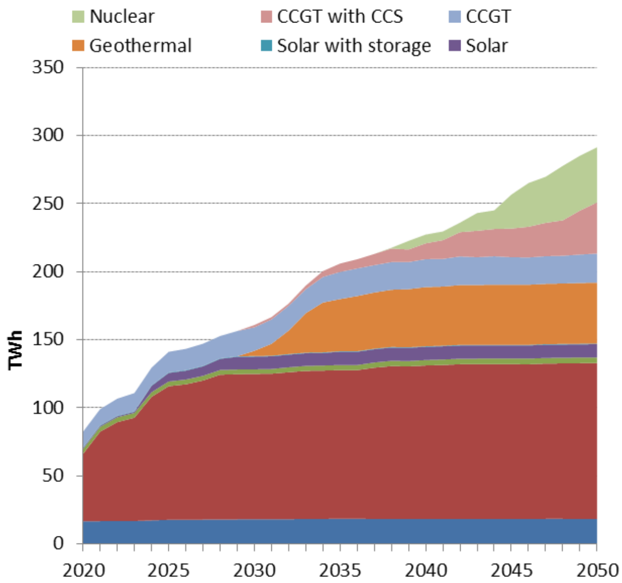
The outcomes of the LET are similar to those of the RET, except that resource costs are lower. There are two key reasons driving this outcome: (i) the contribution from CCGTs in the 2020s helps defer locking in more expensive renewable plant, such as large-scale solar (both with and without storage); and (ii) nuclear and CCGT with CCS technologies make notable contributions in the second half of the modelling horizon.

Figure 168 shows CCGTs contributing about 15% of generation of all LET-eligible technologies. Furthermore, the construction of solar with storage, which is expensive, is less in the LET scenario in contrast to the RET scenario, and the certificates created by CCGTs under the LET in the 2020s displaces certificates created by solar with storage in the RET scenario. The contribution of solar without storage is also lower in the LET scenario relative to the RET. After 2030 the combined contribution of CCGTs with CCS and nuclear is sizeable, reaching 27% of all large-scale low emission generation by 2049/50 and assisting to lower overall costs.

The LET faces the same shortcomings of the RET in that it can only force incumbent fossil generators to retire indirectly by a combination of suppression of the wholesale price and displacement by low marginal cost plant. As with the RET, the LET requires a steeper initial target trajectory in the 2020s when it needs to force the retirement of incumbent coal fired generation. The 3°C trajectory of the LET is proportionally lower than that of the 2°C LET, in accordance with the lower abatement effort required. The LET trajectory in the 2030s does not need to be as steep as the initial trajectory. The LET trajectory does not need to be as high as that of the RET because CCGTs, CCGTs with CCS and nuclear only generate a fraction of a certificate for each MWh generated. Therefore the actual generation level of eligible low emission plant is higher than the LET target. Finally, the LET scheme had the option of reducing the certificate threshold from the initial value of 0.6 t CO_2e/MWh. However there was no need to exercise this option to achieve the cumulative emissions constraint.

Figure 168: Contribution of large-scale low emission generation by technology, low emissions target, 3°C emissions constraint





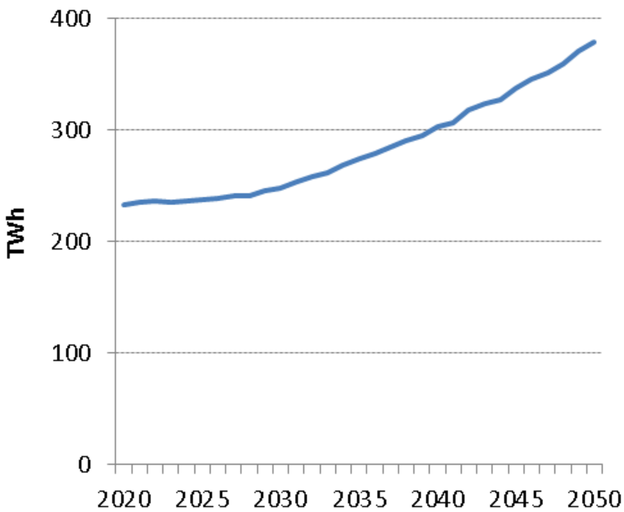
Source: Jacobs

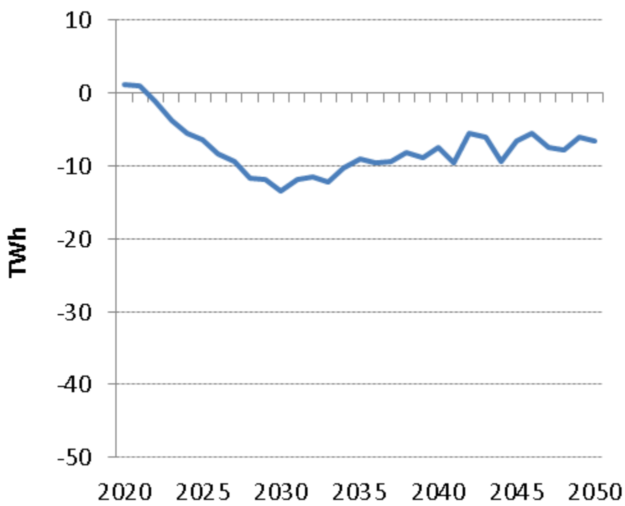
5.6.3 Demand

Figure 169 shows sent-out energy demand from the LET scenario. Total energy consumption reaches 370 TWh in 2049/50, which is 7 TWh per annum lower than that of the reference case.

Figure 169: Sent-out energy, low emissions target, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.





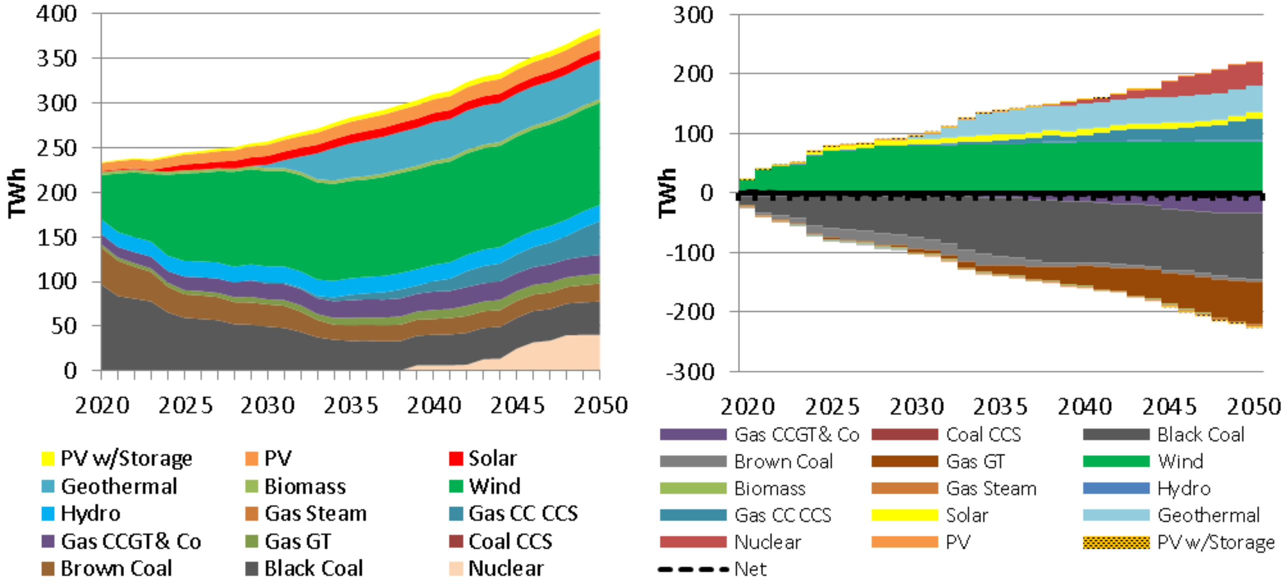
Source: Pitt & Sherry, ACIL Allen and Jacobs

5.6.4 Generation and capacity

Figure 170 shows the generation mix across the modelling horizon. The key trends in the graph are similar to those of the RET scenario, except that expensive solar with storage options are deployed at much lower levels, and CCGTs with CCS and nuclear make a much higher contribution after 2035.

Figure 170: Generation mix, low emissions target, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



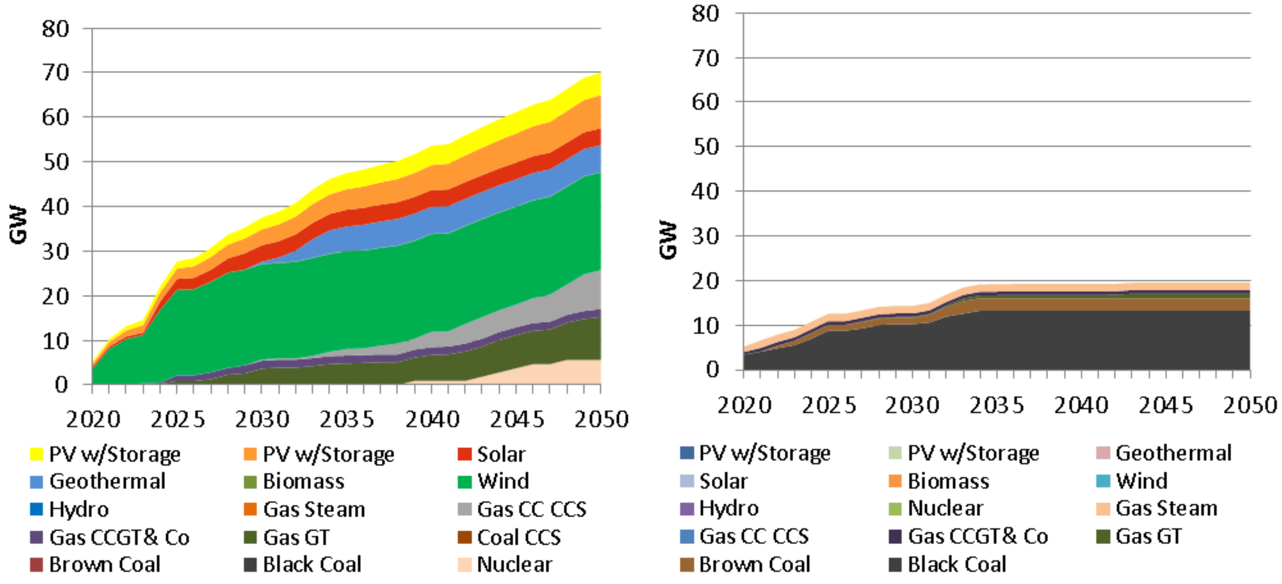
Source: Jacobs

Figure 171 shows cumulative new generation capacity under the LET. Low emission technologies dominate new build, and, as with the RET, gas turbines play an important role in providing back-up for the intermittent generation capacity.

Under the LET scenario there are five transmission upgrades totalling 2,860 MW. This is 400 MW less than the reference case, and stands in contrast to upgrades required for the corresponding 2°C scenario, which are almost four times as great in capacity terms.

Figure 171: Cumulative new and retired capacity, low emissions target, 3°C emissions constraint

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



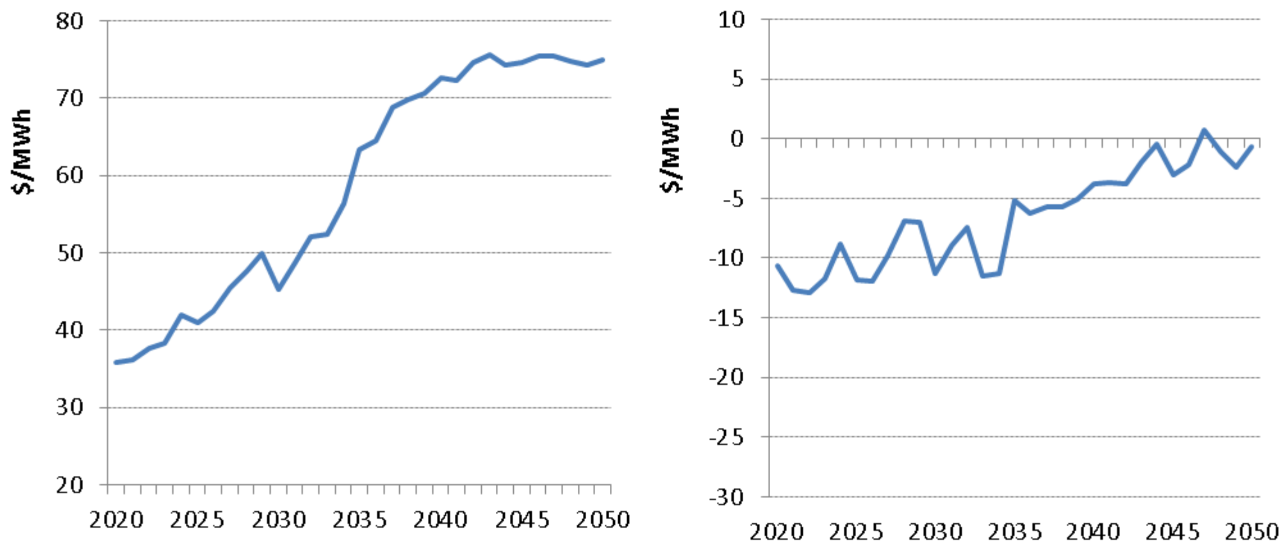
Source: Jacobs

5.6.5 Prices

Figure 172 shows wholesale electricity prices. Price trends are similar to those of the RET scenario, except that prices track lower than the reference case for longer, not reaching reference prices until the mid-2040s. The reason for this is that CCGTs are an eligible technology to generate certificates under the LET, whereas they were not under the RET. Under the LET, CCGTs continue to operate, aided by certificate revenue, and contribute to more effectively suppressing the wholesale price. Prices after 2040 are capped by the new entry level of fossil fuel generators and track reference case prices.

Figure 172: Wholesale electricity time-weighted prices, low emissions target, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.

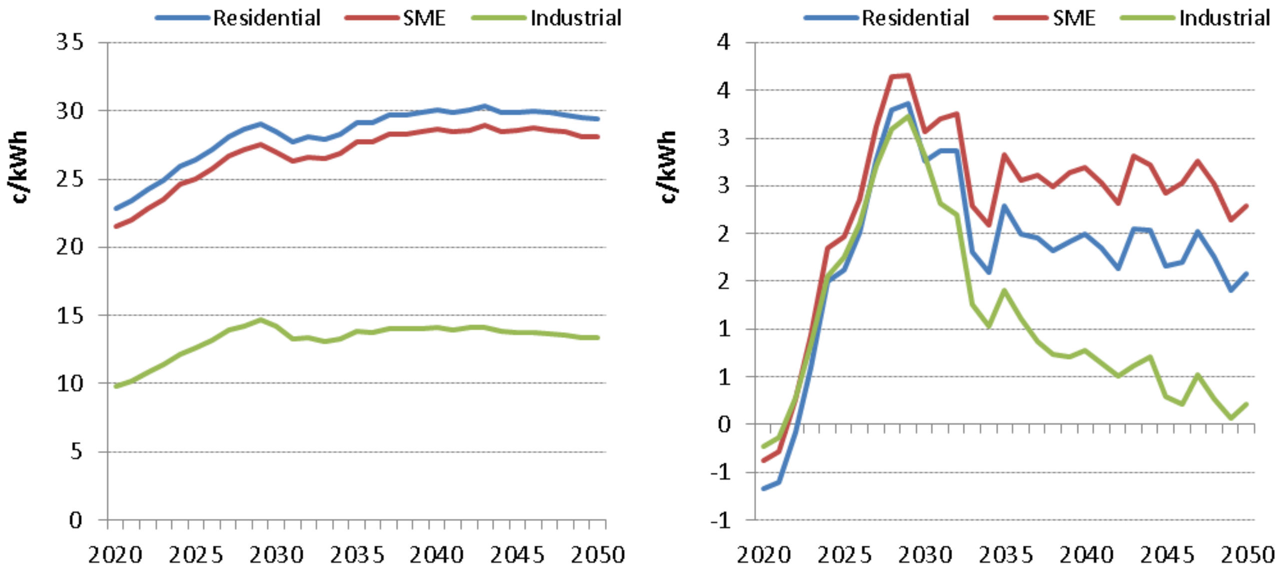


Source: Jacobs

Figure 173 shows weighted average retail prices by customer class. These prices are heavily influenced by the certificate price, especially since the volume of the LET scheme is so large. Figure 174 shows the weighted average residential retail bill, and also as a percentage of disposable income. Overall, residential bills are expected to increase relative to the reference case.

Figure 173: Retail prices by customer class, low emissions target, 3°C emissions constraint

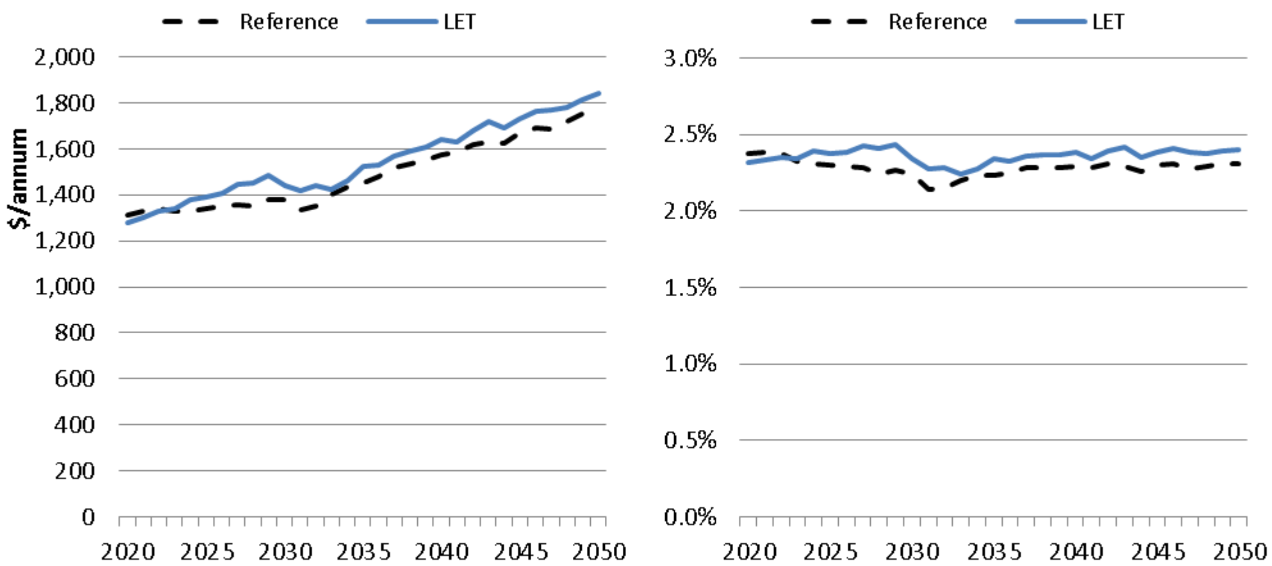
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs

Figure 174: Residential bills, low emissions target, 3°C emissions constraint

The left graph shows the absolute residential bill. The right graph shows the residential bill as a % of disposable income.



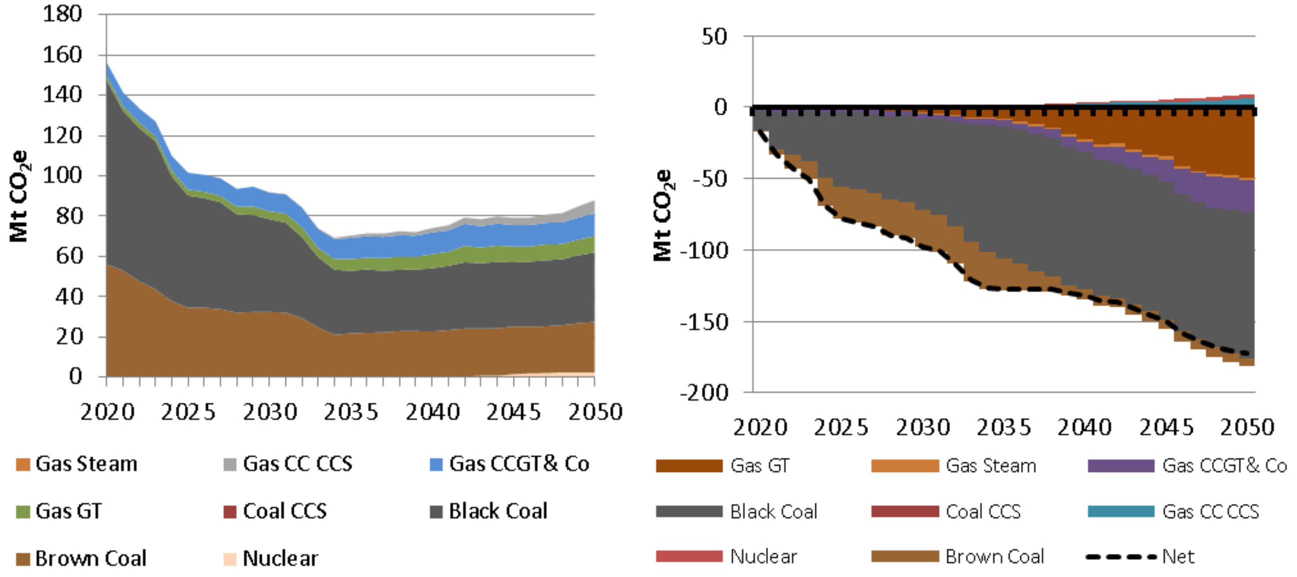
Source: Jacobs

5.6.6 Emissions

Figure 175 shows annual emission by technology and the difference relative to the reference case, and Figure 176 presents the generation emission intensity. Emissions trends are similar to the RET scheme, except that in the 2040s emissions increases are not as steep. The generation emission intensity, both in absolute terms and relative to the reference case, follows a similar trajectory to that of the RET.

Figure 175: Emissions by technology, low emissions target, 3°C emissions constraint

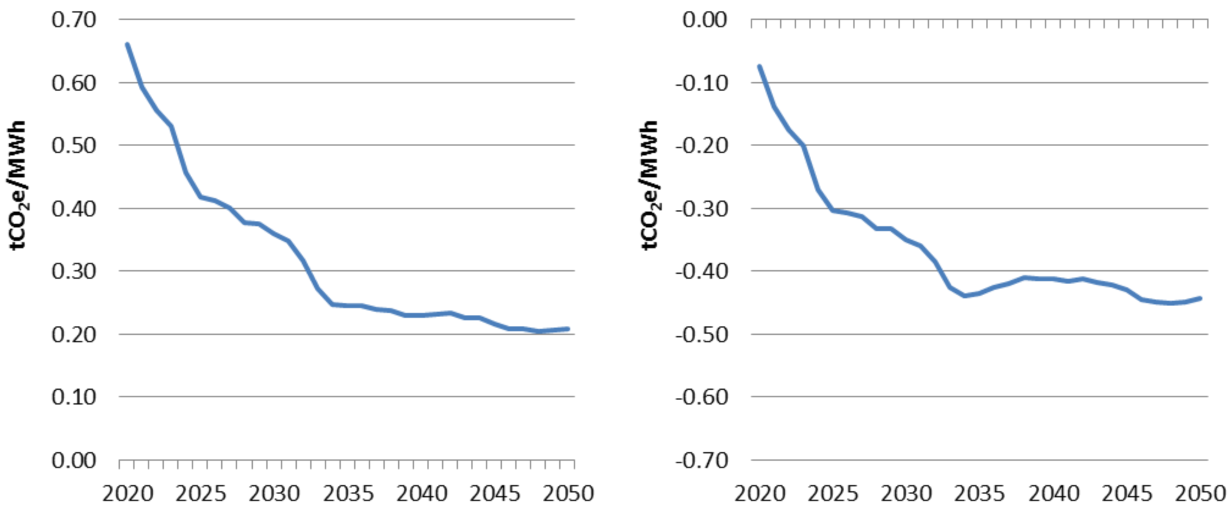
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs. Includes both direct and indirect emissions.

Figure 176: Generation emission intensity, low emissions target, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



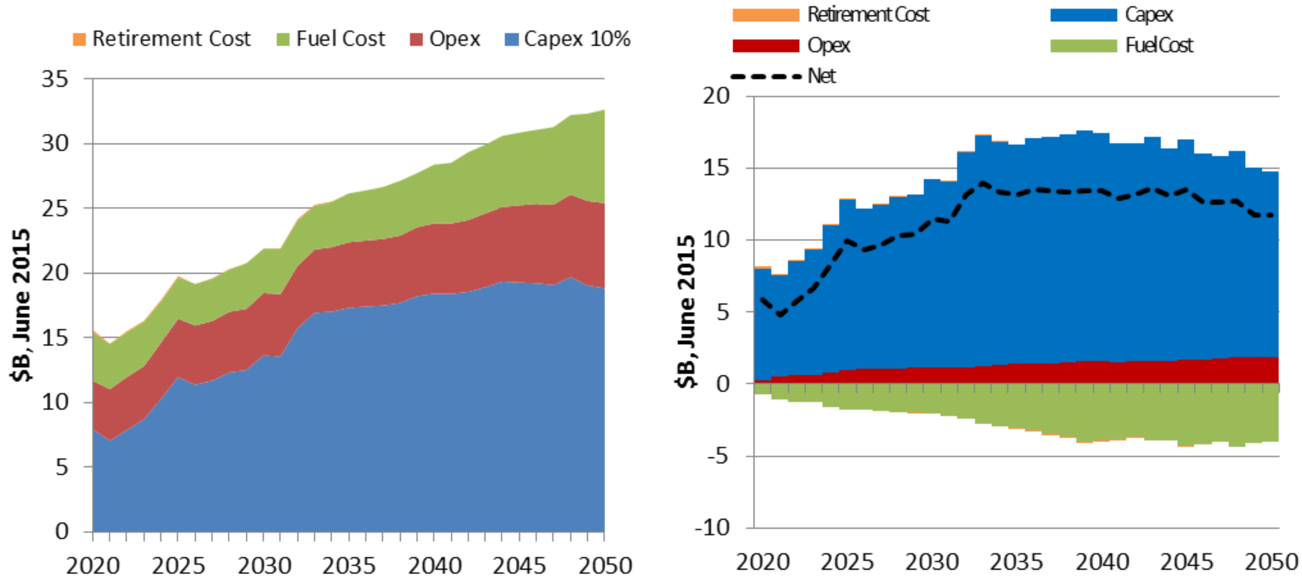
Source: Jacobs. Includes direct emissions only.

5.6.7 Costs

Figure 177 shows annualised resource costs by four cost categories. The trends in these charts are similar to those of the RET scenario. However, capital costs are slightly lower, peaking at $17 billion above the reference case, compared with $20 billion for the RET. Fuel costs are lower than the reference case, due to the reduced fossils fuels needed.

Figure 177: Annualised costs by category, low emissions target, 3°C emissions constraint

The left graph shows the absolute costs. The right graph shows the costs relative to the reference case.

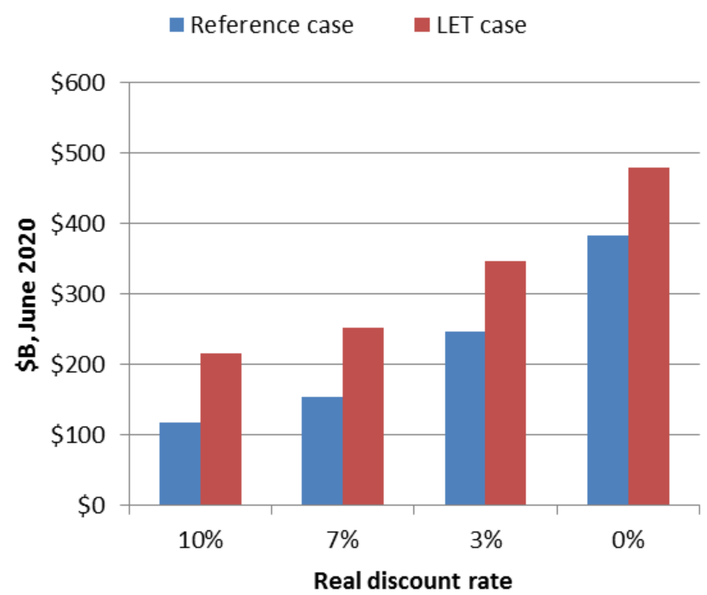


Source: Jacobs

Under the LET black coal fired plant average $2.0 billion per annum less gross profit in the first ten years relative to the reference case, and brown coal fired plant average $0.9 billion per annum less in the same time period. This outcome is less favourable for coal-plant owners relative to carbon pricing. Averaged over the entire modelling horizon, gross profits for owners of coal fired plant are more favourable under the RET relative to the LET.

Figure 178 shows the net present value of the resource costs for the LET scenario relative to the reference case for four discount rates. The outcomes are similar to those of the RET, except that the LET has 4% lower costs at a 10% real discount rate and 2% lower costs with no discounting.

Figure 178: NPV of resource costs, low emissions target, 3°C emissions constraint



Source: Jacobs. Excludes demand adjustment. See Appendix B.3.2 for further detail.

5.7 Feed in tariffs with contracts for differences

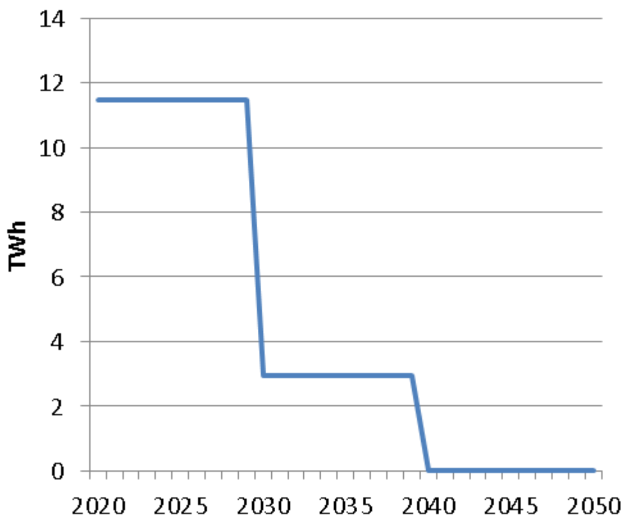
5.7.1 Scenario description

The feed-in tariff approach involves a similar system to the reverse auction process held for the ACT renewable energy target. Eligible generators bid into an auction for the right to receive a fixed revenue stream per unit of output (the feed-in tariff rate). The feed-in tariff received by each project is equivalent to the project's bid into the auction (pay-as-bid process). In our modelling, it is assumed that each project bids its long run marginal costs and receives an equivalent feed-in tariff over the life of the project.

The feed-in tariffs with contracts for difference (FiT) scenario is very similar to the LET, with two differences. The first is that low-emissions gas is not eligible to earn (partial) certificates. The second is that, if generators bid their long run marginal cost (LRMC) of production, customers (who fund the FiT through their bills) pay the average cost of the required low emission subsidy, not the marginal cost as in the LET case.

Figure 78 shows the annual level of additional contracted eligible capacity required to meet the cumulative emissions constraint. The solution is similar to that of the RET and the LET schemes, in that two different levels of contracting are required to achieve a least-cost solution.

Figure 179: Annual incremental FiT volumes, 3°C emissions constraint



Source: Jacobs

For further discussion see Section 2.

5.7.2 Key findings

The FiT scenario is very similar to the LET scenario in that low emission technologies make up a sizeable proportion of the generation mix. FiT scenario outcomes in the 2020s resemble those of the LET scenario rather than the RET scenario. The reason for this is that the average cost subsidy under the FiT allows for new CCGTs to profitably generate during peak periods.

The FiT scenario has the highest investment in wind of all policy scenarios. This is due to the lower weighted average cost of capital (WACC) in the policy resulting in the largest greater proportion of renewables installed during the 2020s. Unlike all other policies, the price stability that results from the contracts for difference do not disadvantage renewables that are built in the late 2020s, before the new low emission technology becomes available.

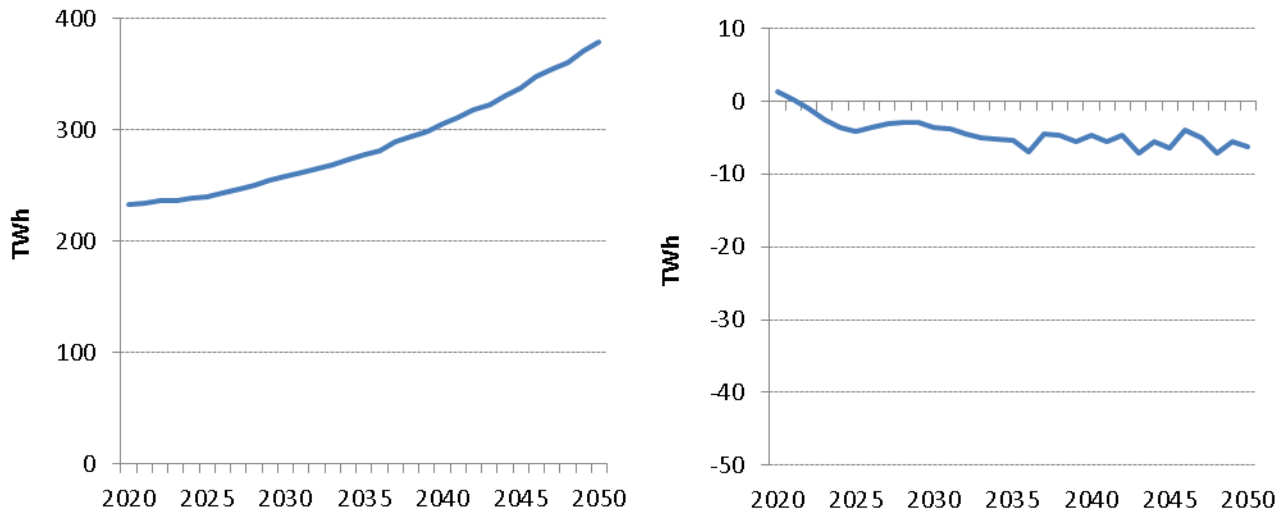
Post 2030 modelling outcomes under the FiT are almost identical to those of the LET.

5.7.3 Demand

Figure 180 shows sent-out energy demand from the FiT scenario. Total energy consumption reaches 379 TWh in 2049/50, 6 TWh lower than the reference case.

Figure 180: Sent-out energy, feed-in tariffs, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



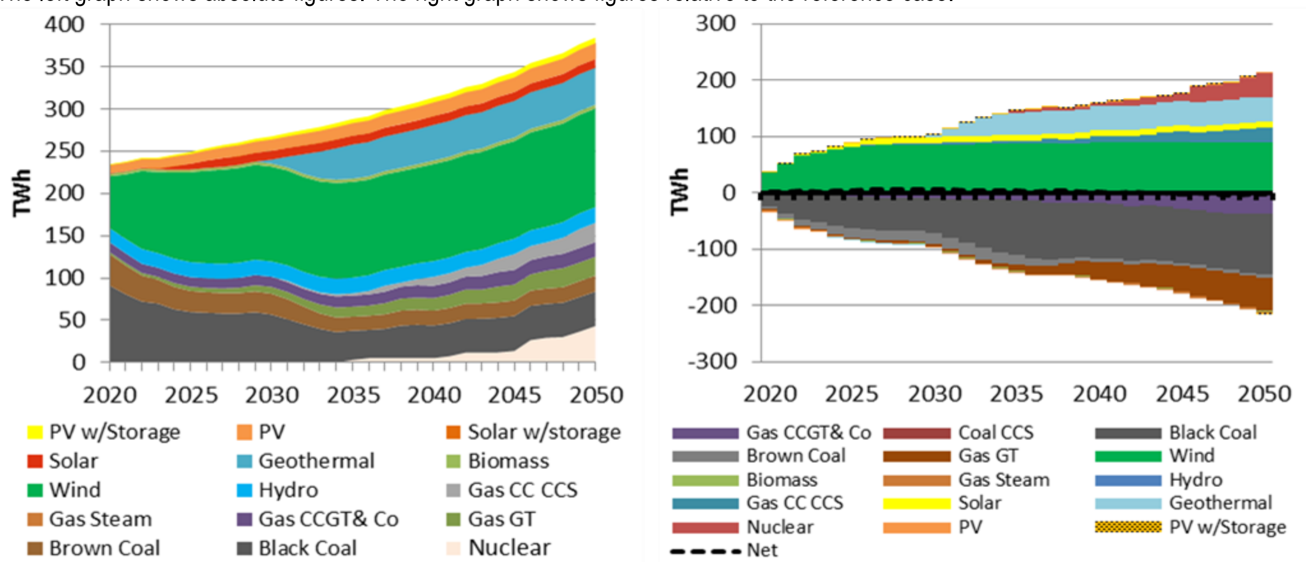
Source: Pitt & Sherry, ACIL Allen and Jacobs

5.7.4 Generation and capacity

Figure 181 shows the generation mix across the modelling horizon. The key trends are similar to those of the LET scenario.

Figure 181: Generation mix, feed-in tariffs, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



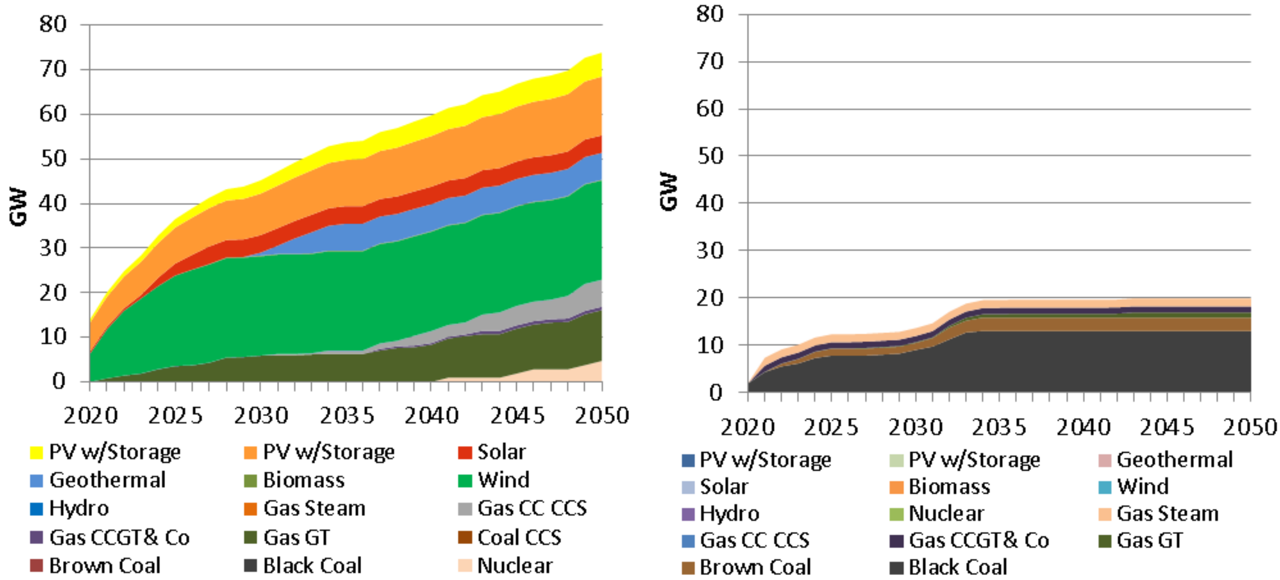
Source: Jacobs

Figure 182 shows cumulative new generation capacity under the FiT. Low emission technologies dominate new build, and, as with the RET and LET, gas turbines play an important role in providing back-up for the intermittent generation capacity.

Under the FiT scenario there are three transmission upgrades totalling 1,360 MW. This is 1,900 MW less than the reference case. The difference in the transmission capacity between the LET and the FiT is that the nature of the FiT delivers a better locational price signal for low emission generation, therefore partly obviating the need for transmission infrastructure.

Figure 182: Cumulative new and retired capacity, feed-in tariffs, 3°C emissions constraint

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



Source: Jacobs

5.7.5 Prices

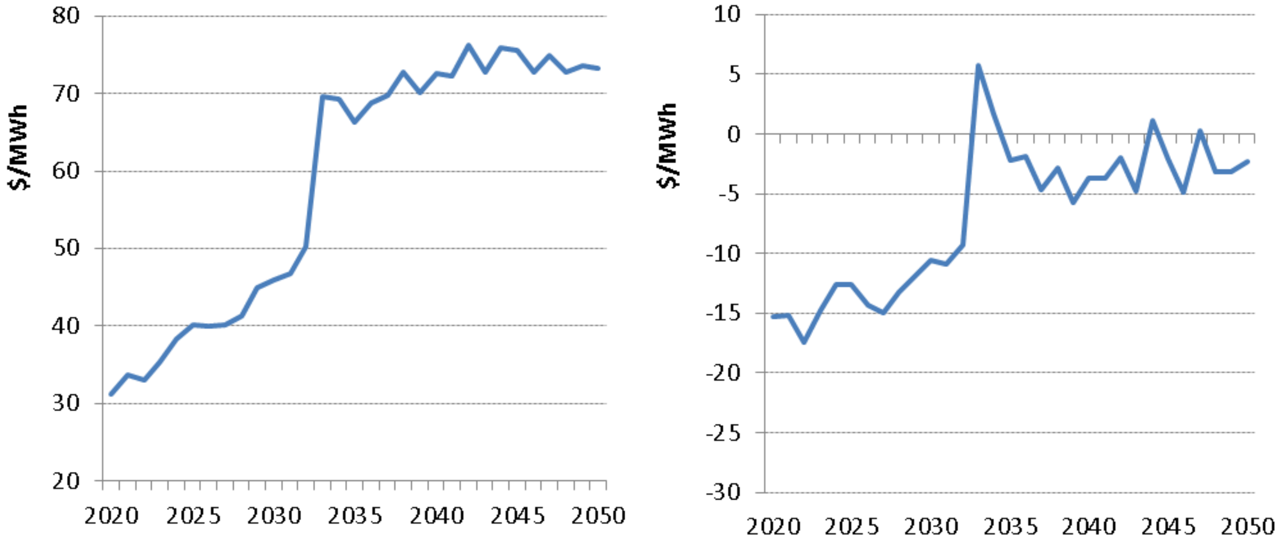
Figure 183 shows wholesale prices. Price trends are similar to those of the LET scenario, although they tend to be slightly higher because CCGTs do not earn certificate revenue and hence do not generate as much. Prices after 2040 are capped by the new entry level of fossil generators, which is why they track the reference case prices.

Figure 184 shows weighted average retail prices by customer class and they are very similar to the LET's retail prices. These prices are heavily influenced by the FiT subsidy.

Figure 185 shows the weighted average residential retail bill relative to the reference case, and also as a percentage of disposable income. Overall, residential bills are expected to increase moderately relative to the reference case.

Figure 183: Wholesale electricity time-weighted prices, feed-in tariffs, 3°C emissions constraint

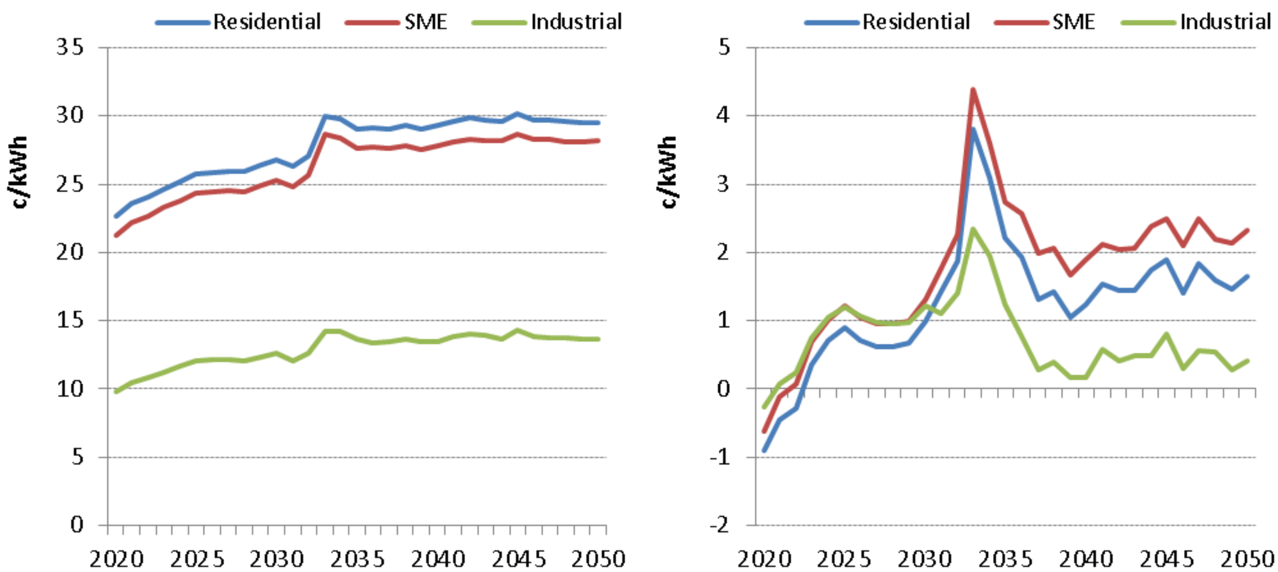
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs

Figure 184: Retail prices by customer class, feed-in tariffs, 3°C emissions constraint

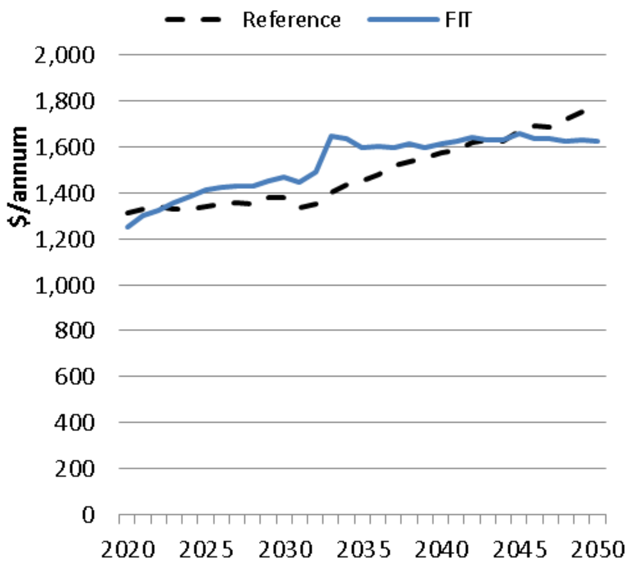
The left graph shows absolute figures. The right graph shows figures relative to the reference case.

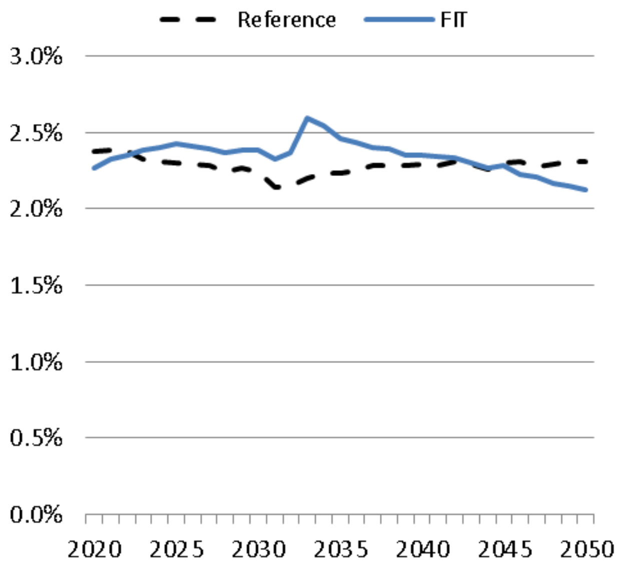


Source: Jacobs

Figure 185: Residential bills, feed-in tariffs, 3°C emissions constraint

The left graph shows the absolute residential bill. The right graph shows the residential bill as a % of disposable income.





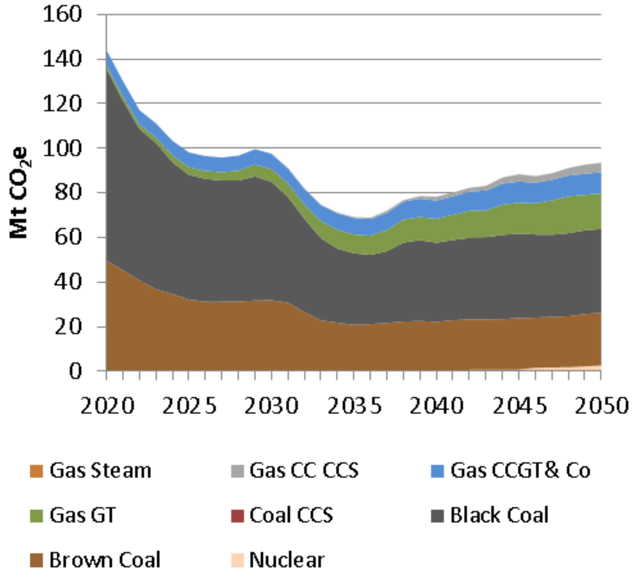
Source: Jacobs

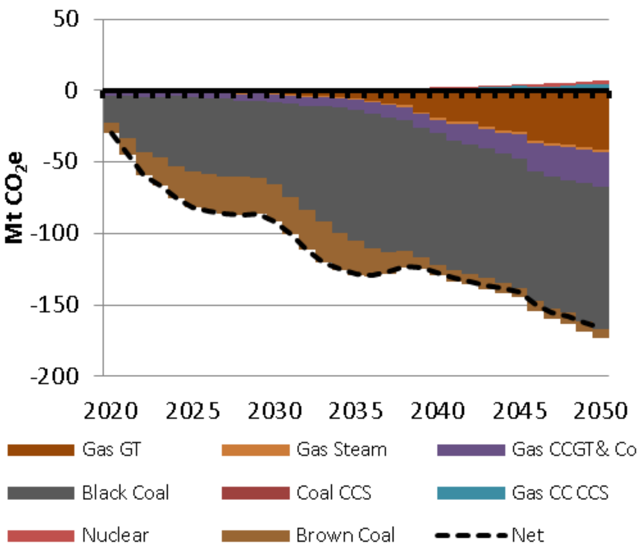
5.7.6 Emissions

Figure 186 shows annual emission by technology and the difference relative to the reference case. Emissions trends are very similar to those of the LET scheme. Figure 187 shows the generation emission intensity both in absolute terms and relative to the reference case.

Figure 186: Emissions by technology, feed-in tariffs, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.

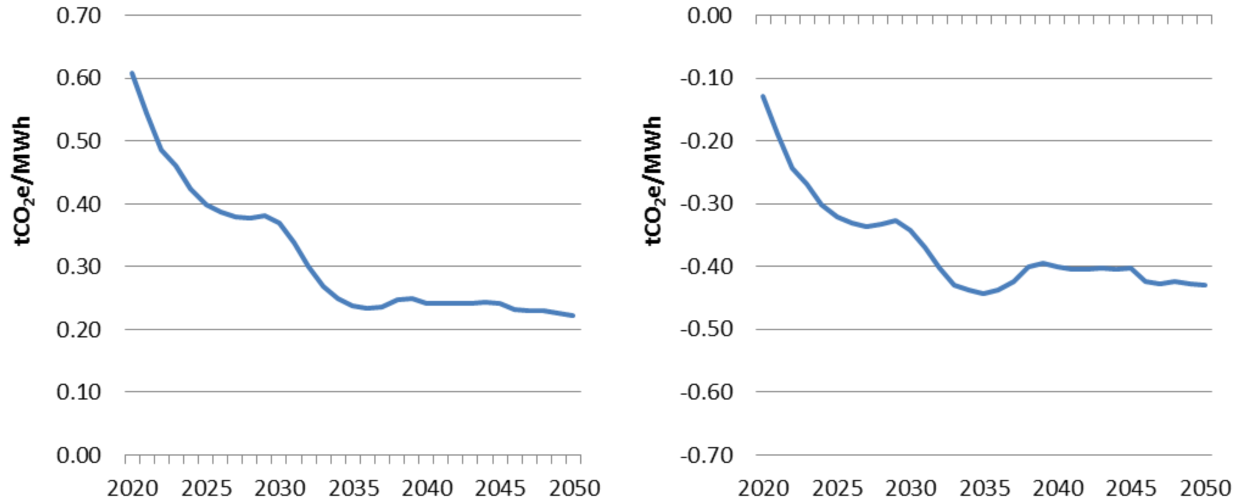




Source: Jacobs. Includes both direct and indirect emissions.

Figure 187: Generation emission intensity, low emissions target, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



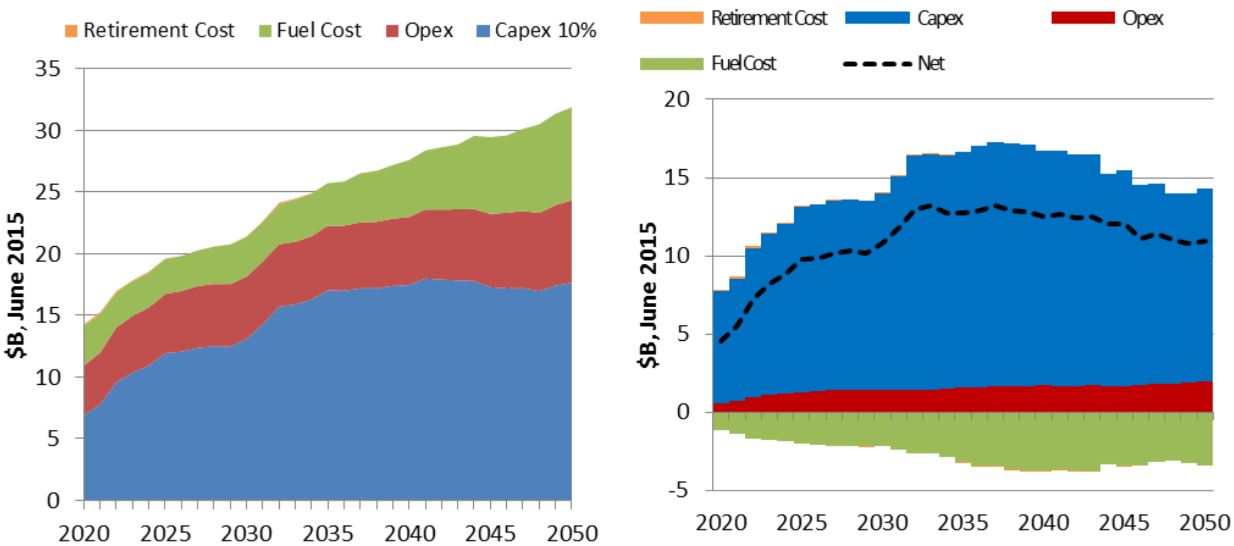
Source: Jacobs. Includes direct emissions only.

5.7.7 Costs

Figure 188 shows annualised resource costs by four cost categories. The trends in these charts are very similar to those of the LET scenario, with capital costs peaking for both scenarios $18 billion above those of the reference case. Fuel cost savings relative to the reference case are also similar to those of the LET scenario.

Figure 188: Annualised costs by category, feed-in tariffs, 3°C emissions constraint

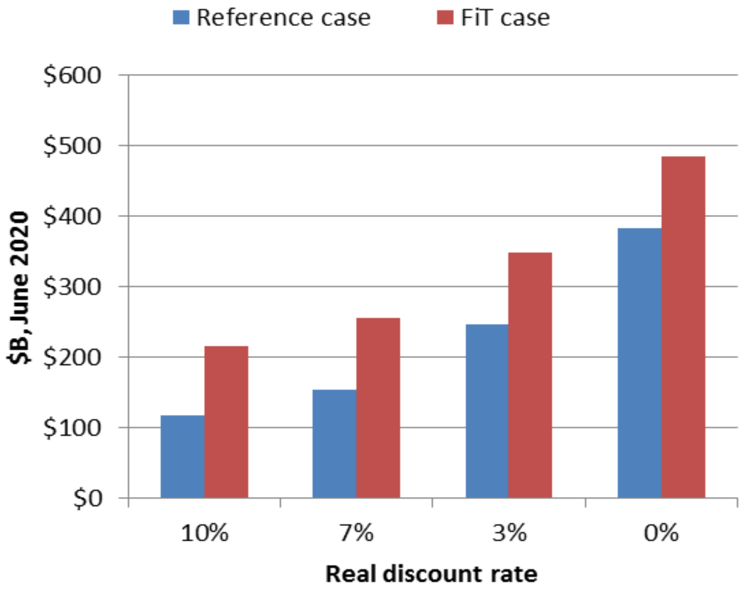
The left graph shows the absolute costs. The right graph shows the costs relative to the reference case.



Source: Jacobs

Figure 189 shows the net present value of the resource costs for the FiT scenario in absolute terms and relative to the reference case for four separate discount rates. The outcomes are very similar to those of the LET, since the FiT has 3% the same costs at a 10% real discount rate and 1% higher costs with no discounting.

Figure 189: NPV of resource costs, feed-in tariffs, 3°C emissions constraint



Source: Jacobs. Excludes demand adjustment. See Appendix B.3.2 for further detail.

5.8 Regulated closures

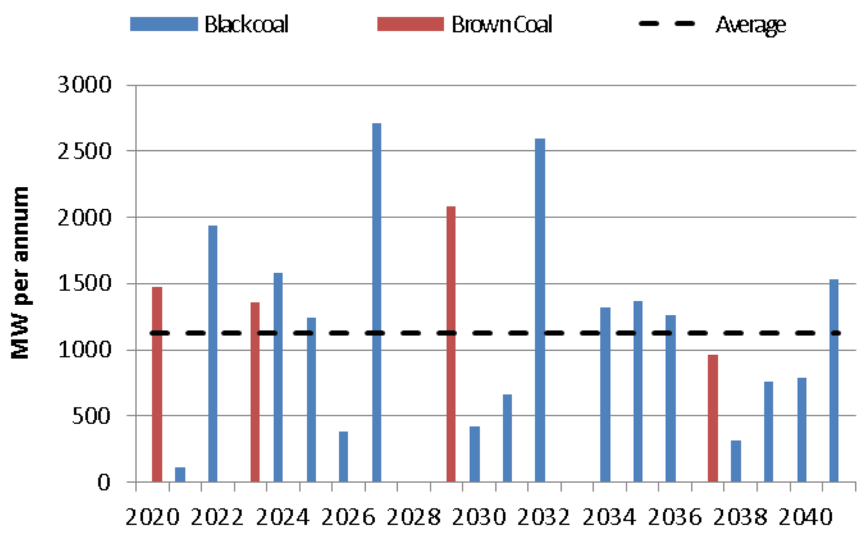
5.8.1 Scenario description

Two different closure criteria for coal fired generators were originally considered for this scenario: one based on the age of the plant and the other based on the plant's emission intensity. However, it was found that the closure sequences based on these two criteria were 70% correlated, and therefore modelling outcomes were not expected to be materially different. All modelling of this scenario was subsequently conducted based on the age criterion. An additional limit on the annual emissions of gas fired generators was also imposed, restricting their annual emissions to no more than 2,200 t per MW. Furthermore, no new coal fired generators are permitted under this scheme unless they are fitted with CCS technology.

Figure 191 shows the final profile of coal fired generation closures used for this scenario. The final closure rate was 1,130 MW of coal fired capacity per annum.

For further discussion see Section 2.

Figure 190: Coal fired generation capacity closures by year, regulated closures, 3°C emissions constraint



Source: Jacobs

5.8.2 Key findings

Unlike the corresponding 2°C scenario, the 3°C cumulative emissions constraint was achieved for the regulated closures policy. The weaker emissions constraint allowed for coal retirements to be stretched out over 22 years. This means a much lower rate of investment in renewable generation is required in the 2020s, with cheaper options such as nuclear generation available in the 2030s.

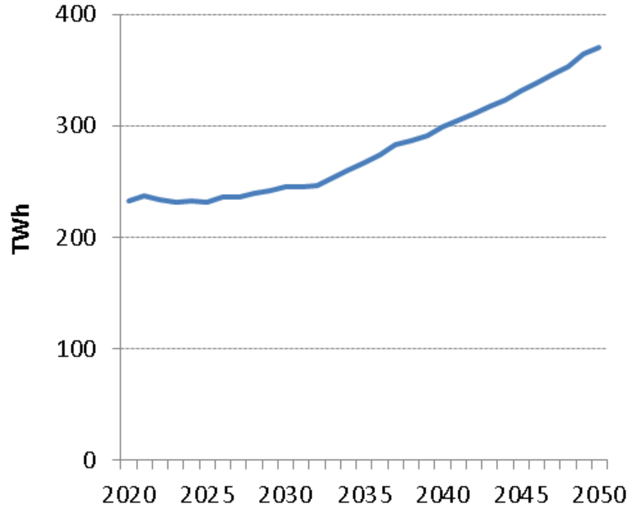
This policy has the opposite inefficiencies of the RET, LET and FiT schemes. The technology pull schemes do not have a mechanism to force the closure of high emitting fossil generation, whereas the regulated scenario has this mechanism, but lacks an incentive mechanism to encourage investment in renewable generation plant. This characteristic, which was the reason for the scheme failing to meet the 2°C cumulative emissions constraint, does not prevent the achievement of the less stringent cumulative emission target in the 3°C case because low emission technologies (nuclear and CCGTs with CCS) are able to be deployed in time to produce the necessary abatement. However, this elevates resource costs relative to carbon pricing because more non-CCS gas fired generation is built in the regulated scenario than all other policy scenarios under the weaker emissions constraint suite. This additional gas fired generation is required in the late 2020s to replace some of the retiring coal fired capacity before low the emissions technologies can be deployed. The optimal build would have been renewable generation capacity, but prices are not high enough to support its entry in the required volume.

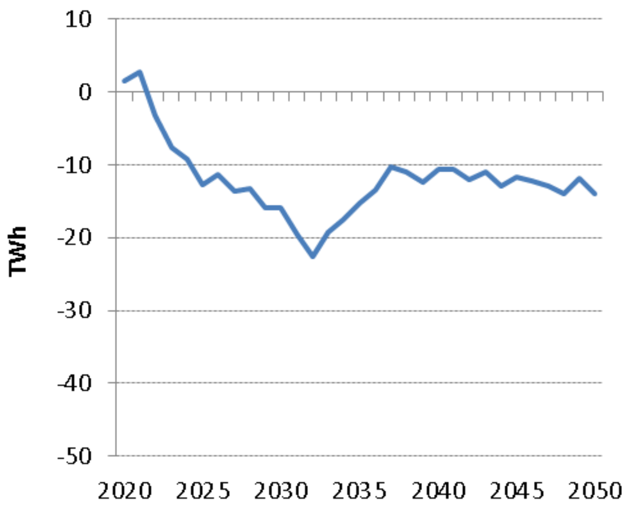
5.8.3 Demand

Figure 192 shows sent-out energy demand for the regulated scenario and relative to the reference case. Total energy consumed reaches 371 TWh in 2049/50, 14 TWh lower than the reference case due to higher wholesale prices reducing demand.

Figure 191: Sent-out energy, regulated closures, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.





Source: Pitt & Sherry, ACIL Allen and Jacobs

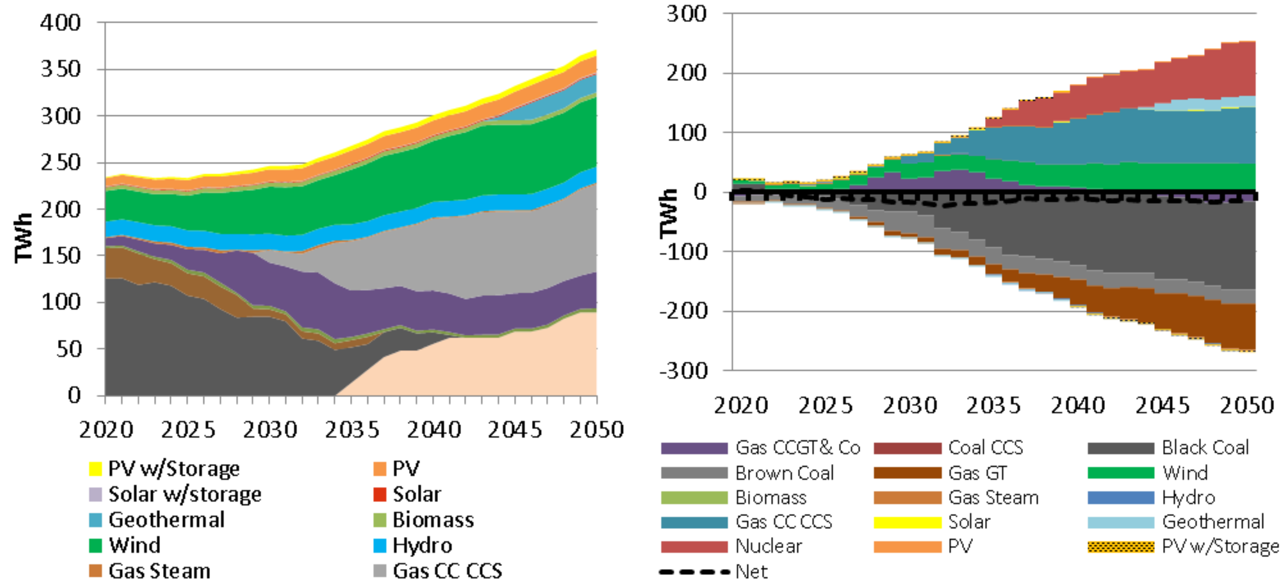
5.8.4 Generation and capacity

Figure 192 shows the generation mix across the modelling horizon both in absolute terms and relative to the reference case. Coal fired generation is closed down over a 22 year period. A supply gap emerges in the late 2020s caused by the steady retirement of coal fired generation at the average rate of 1,130 MW per annum. This gap is filled mainly with CCGTs, even though their annual output is restricted by the regulatory gas constraint, and some low-cost wind resources. Post 2030 low emission technologies, such as CCGTs with CCS and nuclear become available and they are lower cost than stand-alone CCGT technology due to the regulatory gas constraint. These technologies generate at high levels over the 2030s and 2040s. Some geothermal technology is also built in the 2040s, which is a similar result to the carbon pricing scenario.

Figure 193 shows cumulative new generation capacity across the NEM and WEM. It shows that CCGTs and wind generation are the dominant new entrant technologies in the 2020s, with continuing contributions from rooftop solar. Post 2030 CCGTs with CCS and nuclear dominate new entry, although wind capacity also continues to expand through to the 2040s.

Figure 192: Generation mix, regulated closures, 3°C emissions constraint

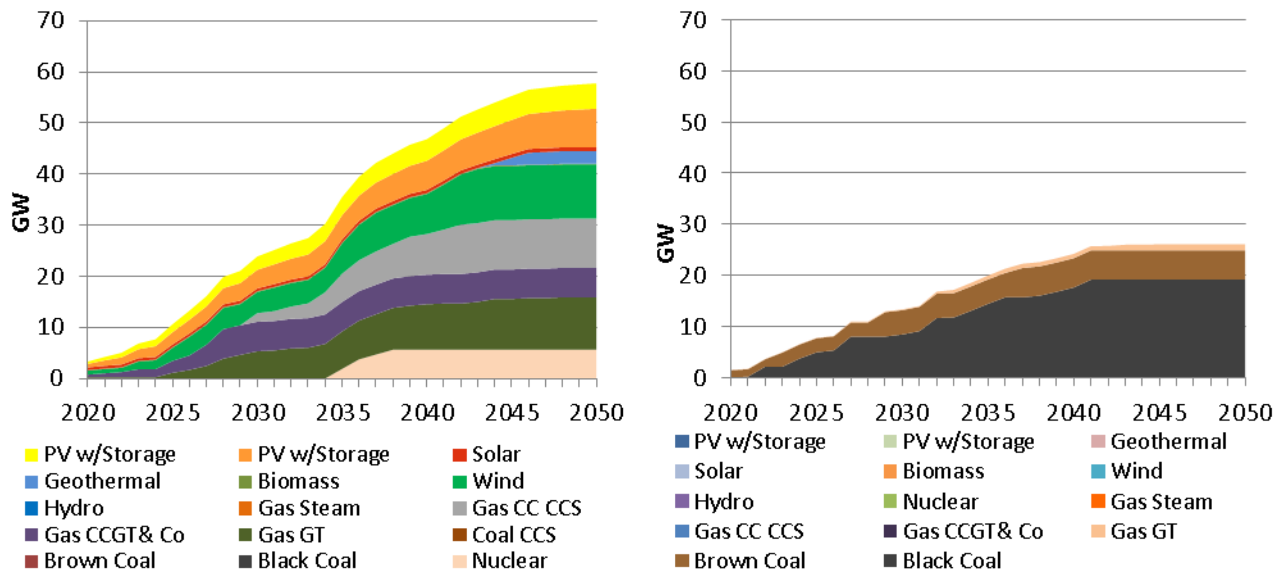
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs

Figure 193: Cumulative new and retired capacity, regulated closures, 3°C emissions constraint

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



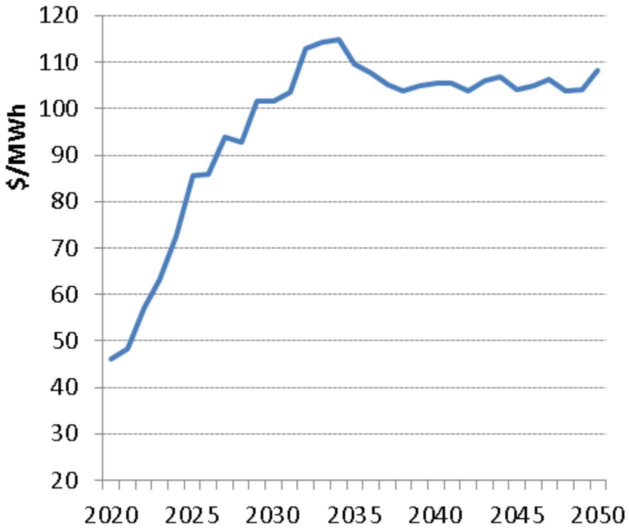
Source: Jacobs

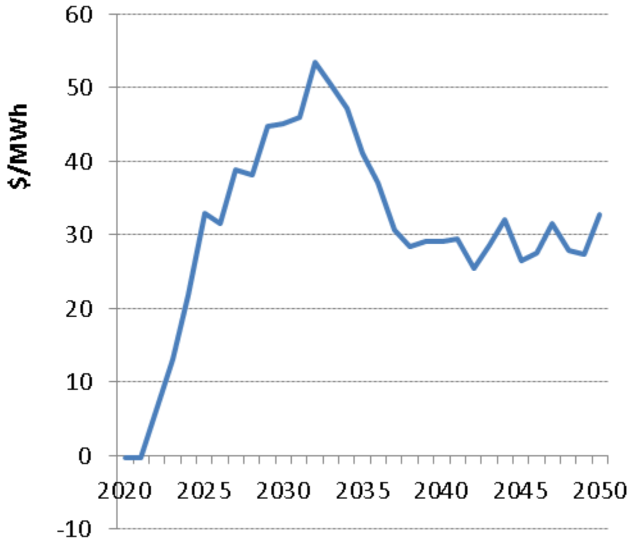
5.8.5 Prices

Figure 194 shows average wholesale prices weighted by region. Prices start from a similar level to that of the reference case, but then escalate rapidly from there, driven by the steady rate of coal fired retirements. In the long-term prices level out at the new entry cost of CCGTs with CCS between 2030 and 2035, and then nuclear generation technology post 2035. Prices are generally elevated relative to the reference case for the whole modelling horizon.

Figure 194: Wholesale electricity time-weighted prices, regulated closures, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



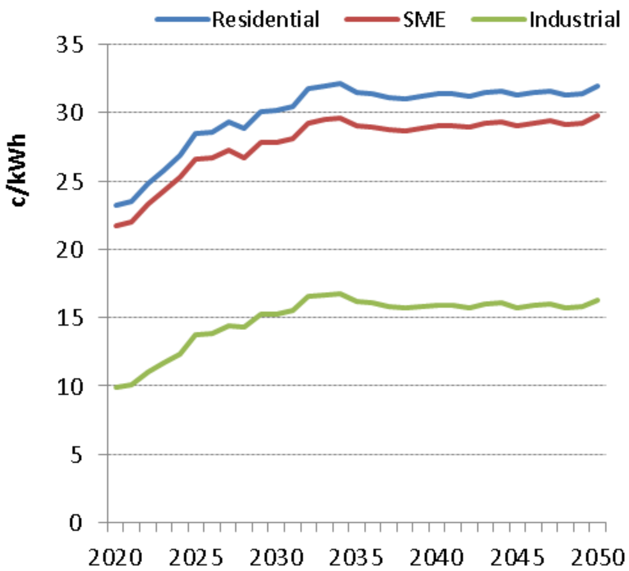


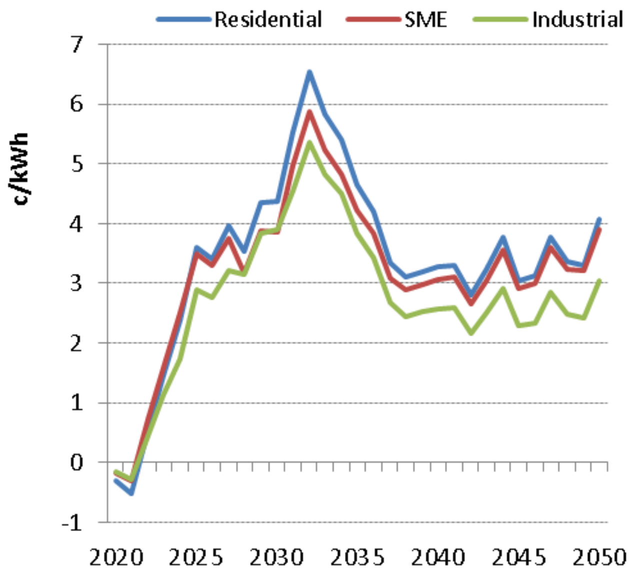
Source: Jacobs

Figure 195 shows weighted average retail prices by customer class. They contain the same trends as the wholesale prices, but the relative price movements are more muted since the wholesale price only comprises typically 30% to 40% of the retail price.

Figure 195: Retail prices by customer class, regulated closures, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



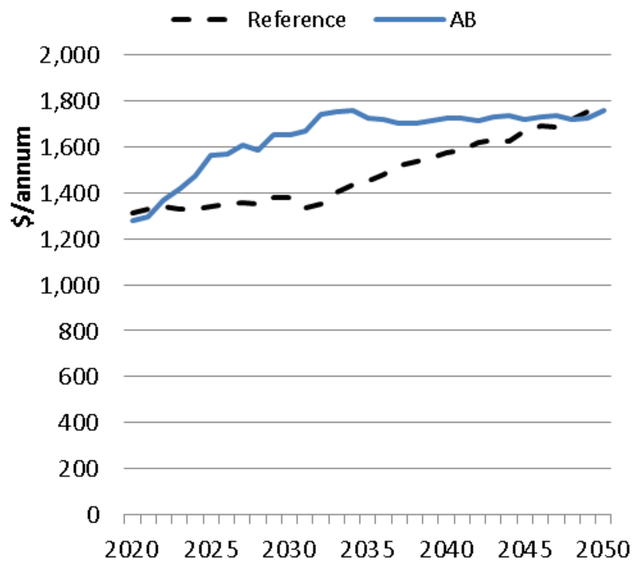


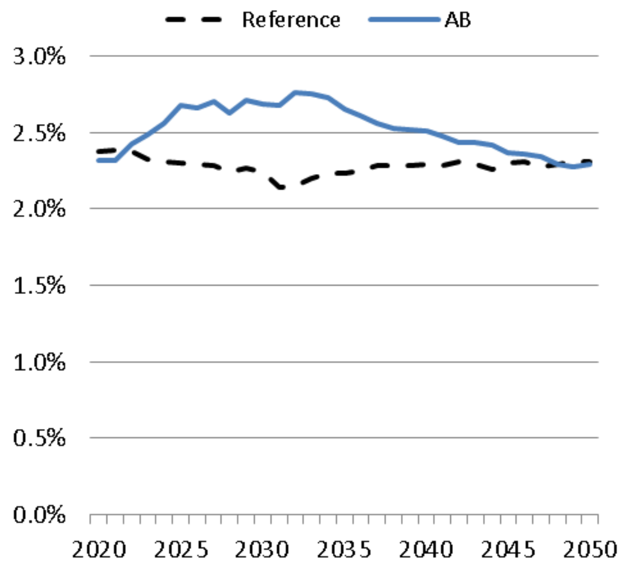
Source: Jacobs

Figure 196 shows the weighted average residential bill relative to the reference case, and also as a percentage of disposable income. The high wholesale prices lead to retail prices that are higher than those of the reference case, and consequently the average residential bill is also higher.

Figure 196: Residential bills, regulated closures, 3°C emissions constraint

The left graph shows the absolute residential bill. The right graph shows the residential bill as a % of disposable income.





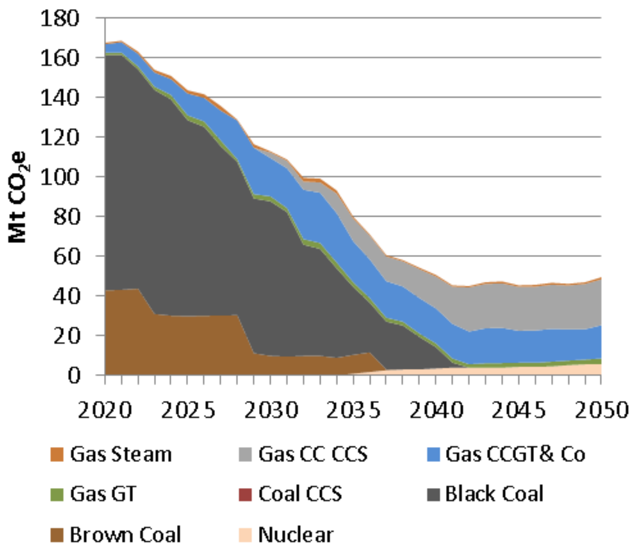
Source: Jacobs

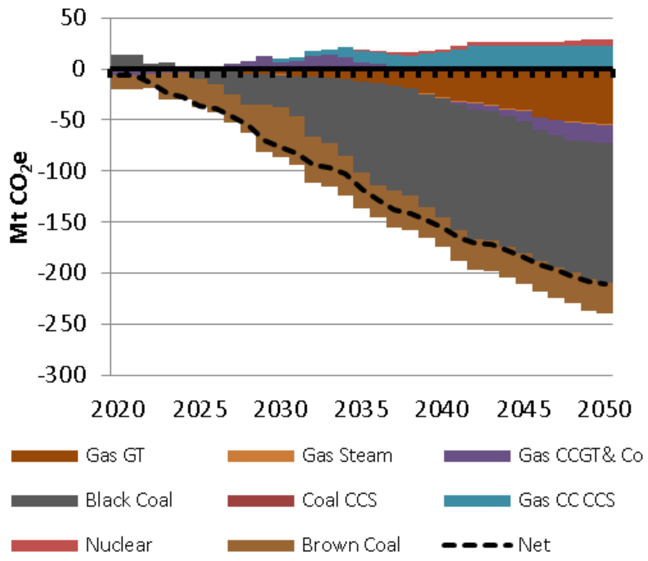
5.8.6 Emissions

Figure 197 shows annual emissions by technology and the difference relative to the reference case. Figure 198 shows the absolute and relative change to the reference case of emission intensity of the grid. The linear form of the coal closure rate is evident in the linear decline of total coal fired emissions. CCGT emissions grow throughout the 2020s and then stay relatively steady post 2030. CCGTs with CCS make the largest emission contribution post 2040, surpassing emissions from CCGTs at around 2040.

Figure 197: Emissions by technology, regulated closures, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.

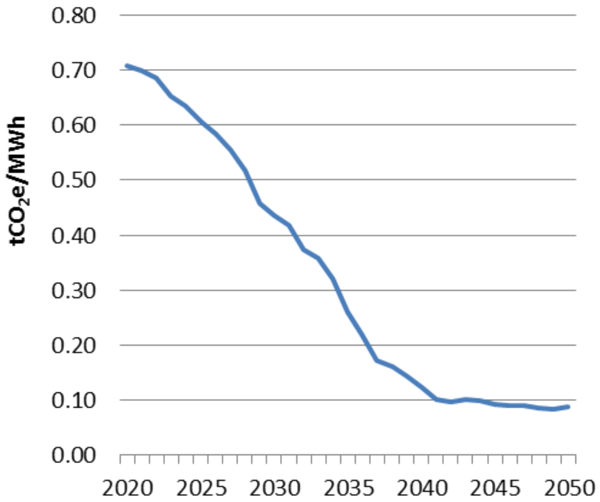


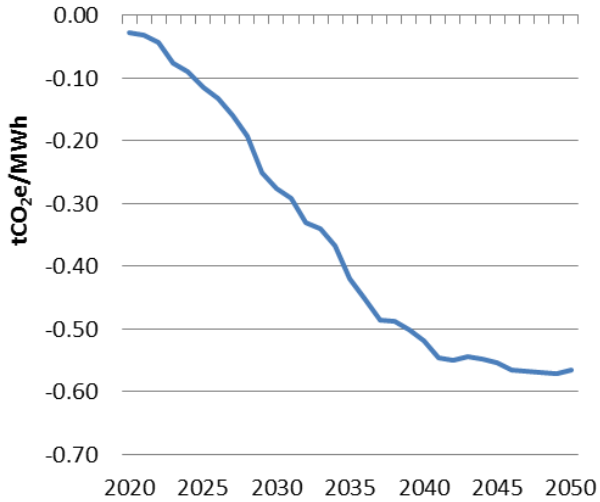


Source: Jacobs. Includes both direct and indirect emissions.

Figure 198: Generation emission intensity, regulated closures, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.





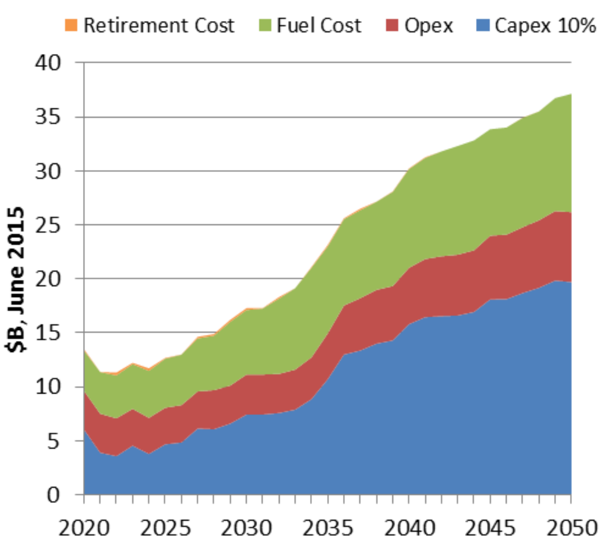
Source: Jacobs. Includes direct emissions only.

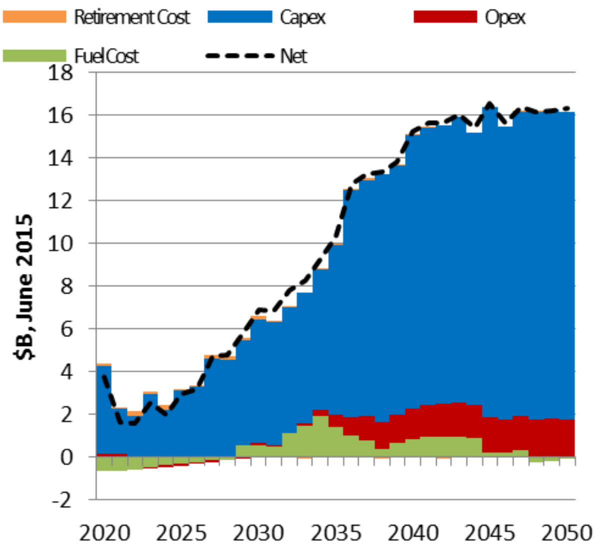
5.8.7 Costs

Figure 199 shows annualised resource costs by four cost categories. Costs in 2019/20 are about $13.5 billion and they escalate at a moderate rate from 2024/25 and then accelerate further in the early 2030s. Costs peak in 2049/50 when they reach $37 billion. Fuel and operating costs are initially lower than the reference case, owing to the coal fired retirements and the lower demand. However, these costs become higher than the reference case from 2028/29 onwards as investment in the new, more expensive technologies accelerates. Fuel costs are also substantially higher than those of the carbon pricing scenario. Capital expenditure is initially higher than carbon pricing, but it peaks at $16 billion per annum, which is well below that of carbon pricing. Capital expenditure is front-loaded relative to carbon pricing because of the early investment required for the regulatory scenario, which is driven by the linear nature of the coal fired retirement schedule.

Figure 199: Annualised costs by category, regulated closures, 3°C emissions constraint

The left graph shows the absolute costs. The right graph shows the costs relative to the reference case.

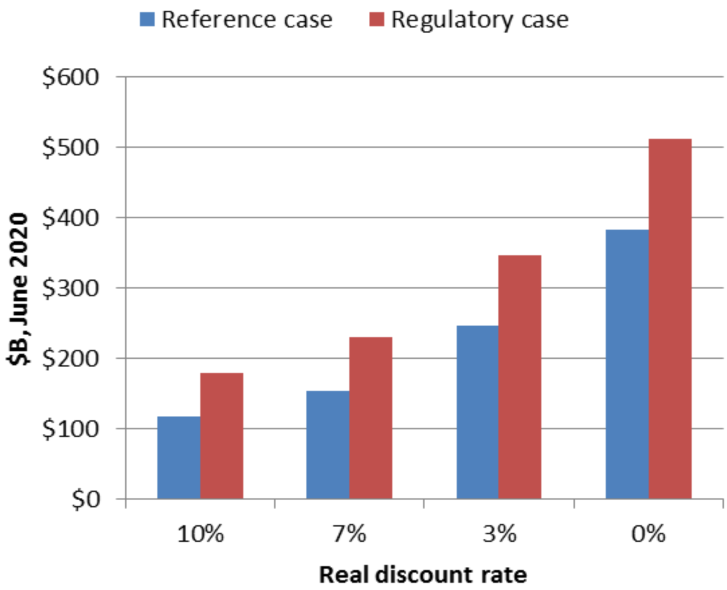




Source: Jacobs

Figure 200 shows the net present value of resource costs for the regulatory scenario relative to the reference case. The total resource cost for the regulatory scenario ranges from 53% (at 10% real discount rate) to 34% (without discounting) higher than that of the reference case. This corresponds to increases of 9% and 13% respectively relative to carbon pricing. The key source of difference in resource costs is the additional spending on CCGT capacity that was not required in any of the other policy scenarios.

Figure 200: NPV of resource costs, regulated closures, 3°C emissions constraint



Source: Jacobs. Excludes demand adjustment. See Appendix B.3.2 for further detail.

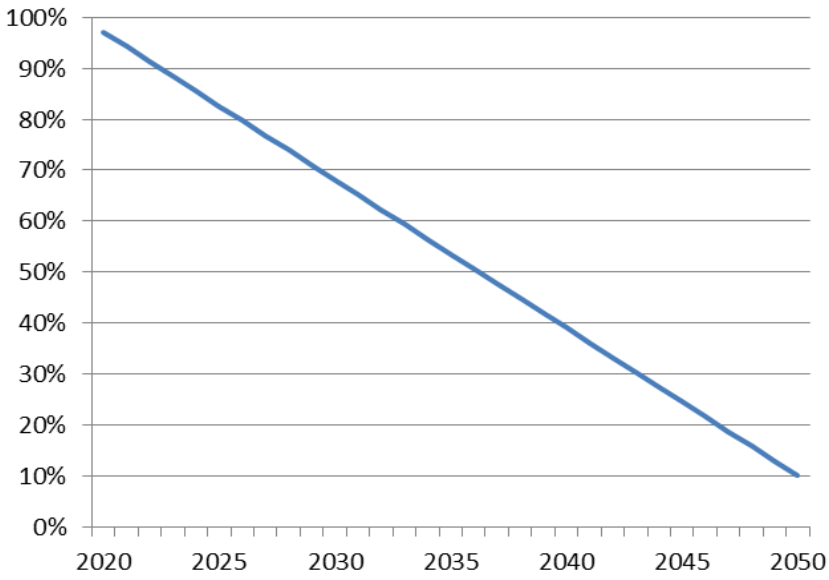
5.9 Absolute baselines

5.9.1 Scenario description

Absolute baselines applies a constraint on emissions output of each incumbent generating facility relative to the historical reference period without certificate trading. The baselines decrease linearly over time for incumbent gas fired and coal fired generators. Generators are not restricted by their baseline if their emission intensity in a given year is lower than the average grid emission intensity which affects gas fired generation in early years. The final key feature of the scheme is no new fossil generation is permitted without CCS.

Figure 201 shows the absolute baseline trajectory required to achieve the cumulative emissions constraint. The baseline decreases by 2.8% per annum, and commences at 97.2% in 2019/20. The baseline trajectory implies that incumbent generators may be able to survive until 2049/50, at which point they are permitted to emit 13.2% of their baseline emissions.

Figure 201: Absolute baseline trajectory, 3°C emissions constraint



Source: Jacobs

For further discussion see Section 2.

5.9.2 Key findings

The absolute baseline approach was a relatively low cost policy scenario in meeting the weaker emissions constraint. The key difference in the solution between absolute baselines and the regulatory scenario is that under absolute baselines renewables are built in the late 2020s to fill in the supply gap caused by the shrinking baselines, and not CCGTs. As a result, the capacity mix is similar to that of emission pricing scenarios at an aggregate level (although the timing of entry of the plant are different), and therefore resource costs for absolute baselines are comparable to those of the carbon pricing and lower than the regulatory scenario.

The price spike that was required under the 2°C absolute baseline solution is absent in the 3°C solution. This is because the lower learning rate of CCGT with CCS technology in the 3°C world results in higher new entry prices post 2030, and these prices are high enough to support early entry of the renewable generation capacity that is required to fill the supply gap caused by the declining baselines.

As no new fossil fuel plants were allowed to be built without CCS, peaking capacity used to support new renewables was provided by incumbent generators and gas generators with CCS until nuclear becomes available. This meant that generators that provided system reliability were also able to generate profits as base load generators, unlike all other scenarios.

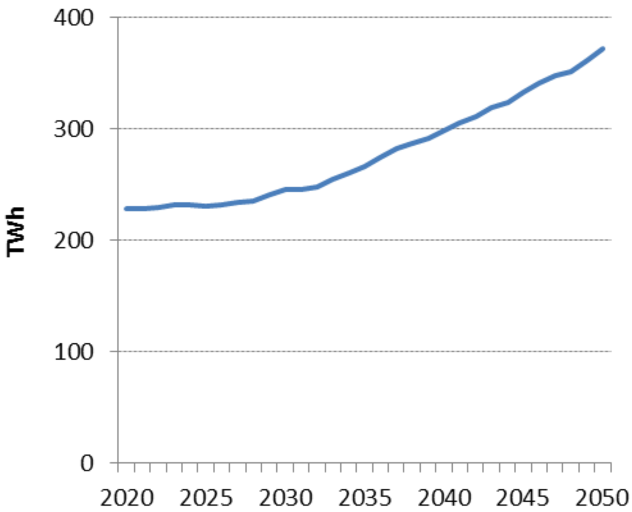
Most coal fired capacity continues to generate into the late 2040s under absolute baselines, even though its generation levels continually decline to satisfy the required baselines. This is advantageous in terms of resource costs because all of the coal fired capacity can be used to provide backup for the intermittent plant, and there is no need to build large amounts of other capacity to fulfil that role.

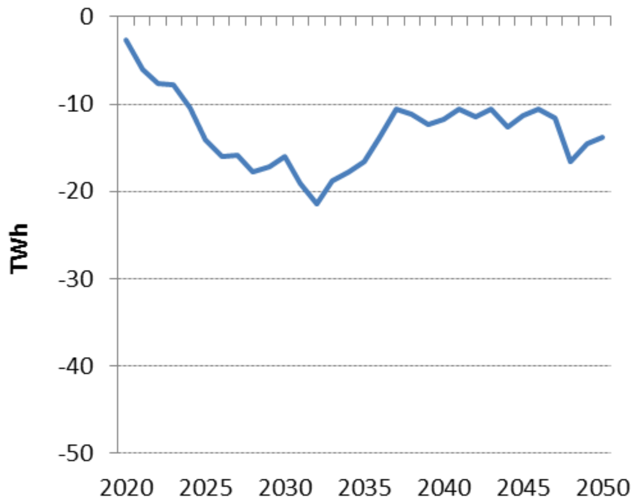
5.9.3 Demand

Figure 202 shows sent-out energy demand for absolute baselines and relative to the reference case. Total energy consumed reaches 371 TWh in 2049/50, 14 TWh lower than the reference case due to higher wholesale prices reducing demand. Demand in the 2020s has a very mild growth rate, and this is due to the escalation of wholesale prices, driven by the supply gap caused by the declining baselines. This situation changes post 2035 with the introduction of nuclear generation technology, which caps prices.

Figure 202: Sent-out energy, absolute baselines, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.





Source: Jacobs

5.9.4 Generation and capacity

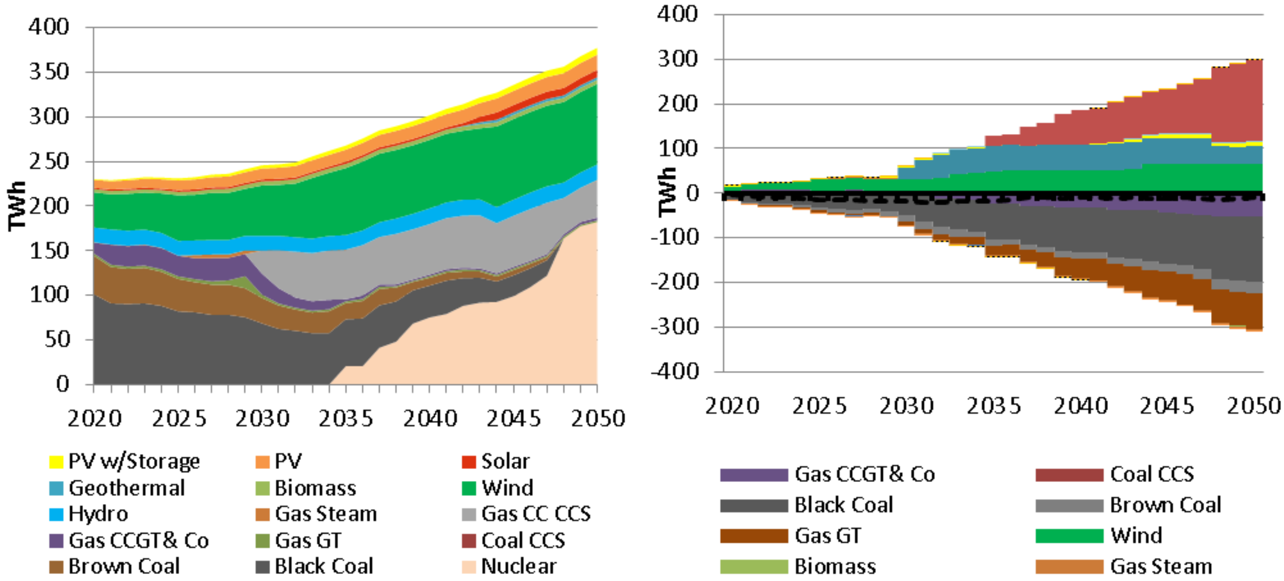
Figure 203 shows the generation mix across the modelling horizon both in absolute terms and relative to the reference case. Key features include the dominant role played by wind generation in the 2020s as the key new entry technology. The gradual linear decline in generation for the incumbent coal fired and gas fired generation reflects the application of the absolute baselines to these plants. CCGTs with CCS are the dominant new entrant technology post 2030, followed by nuclear technology post 2035, which is lower cost than CCGTs with CCS due to the lower learning rate of the latter. Geothermal technology does not enter the market at all under absolute baselines because the lack of any penalty on emissions is enough to make it uncompetitive with nuclear generation.

Figure 204 shows cumulative new generation capacity under absolute baselines which follows similar trends to generation.

Under absolute baselines there are seven transmission upgrades totalling 3,240 MW, including four upgrades that occur between Victoria and South Australia, which are needed to unlock South Australian wind resources. This is almost identical in capacity terms to the requirement for the reference case.

Figure 203: Generation mix, absolute baselines, 3°C emissions constraint

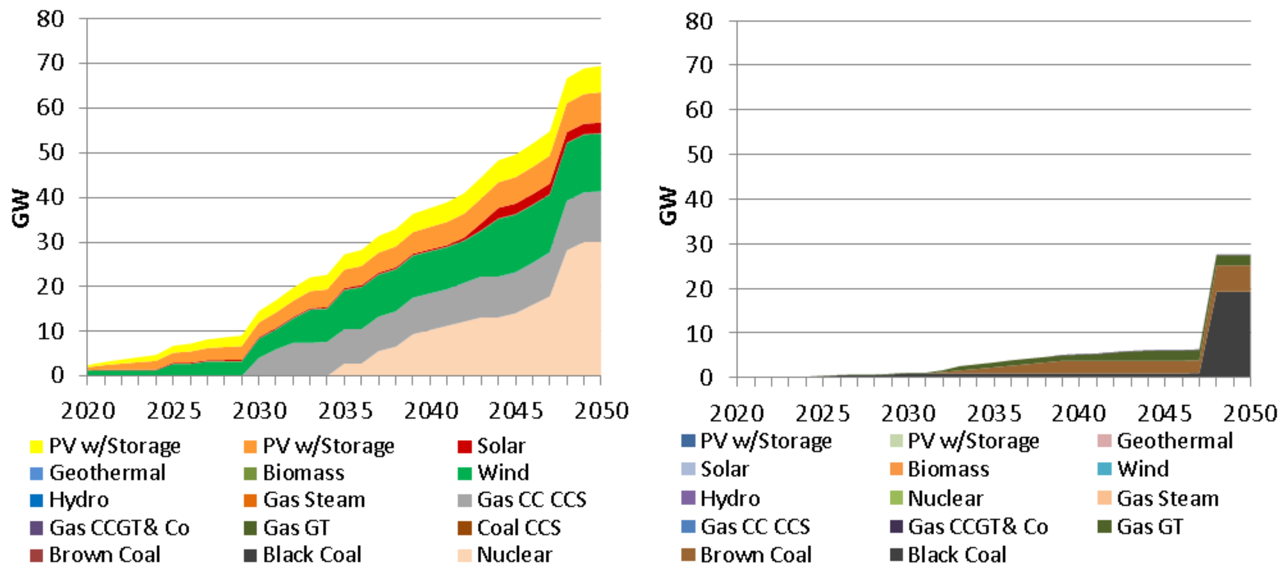
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs

Figure 204: Cumulative new and retired capacity, absolute baselines, 3°C emissions constraint

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



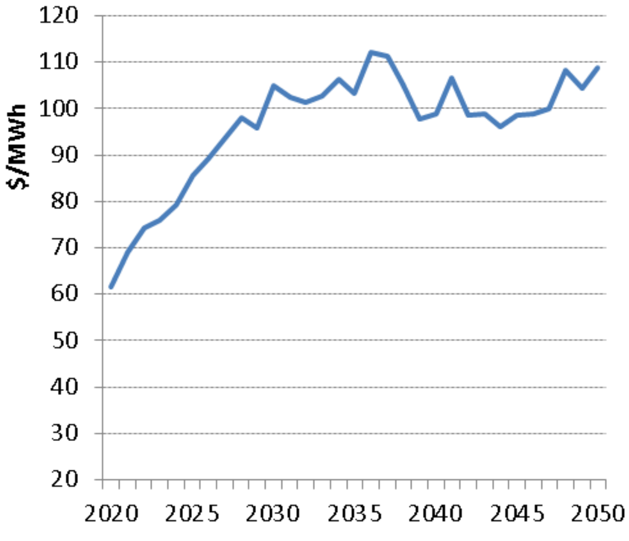
Source: Jacobs

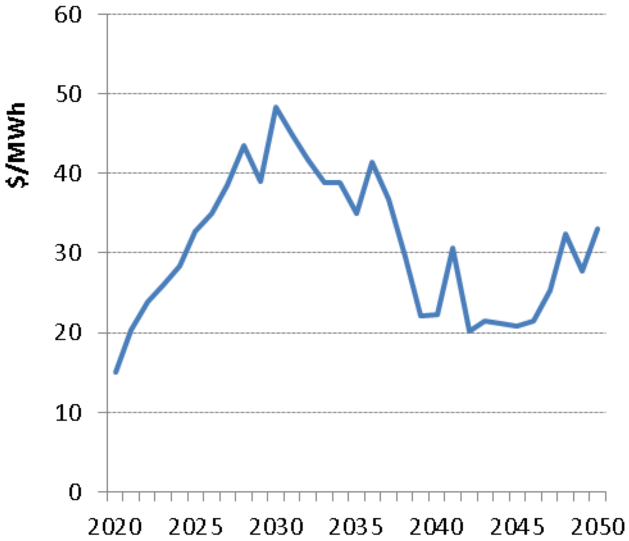
5.9.5 Prices

Figure 205 shows wholesale electricity prices. Prices are higher than those of the reference case across the whole modelling horizon, starting $15/MWh higher and then escalating. This is because cheaper CCGT and coal fired technology that set prices in the reference case are not permitted to be built under absolute baselines. In addition, the declining baselines cause tightness on the supply side as soon as the scheme commences, and this drives the steady increase in prices.

Figure 205: Wholesale electricity time-weighted prices, absolute baselines, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



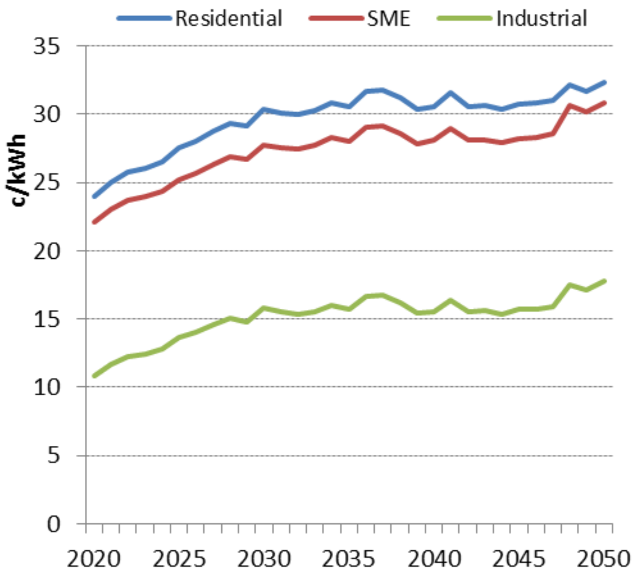


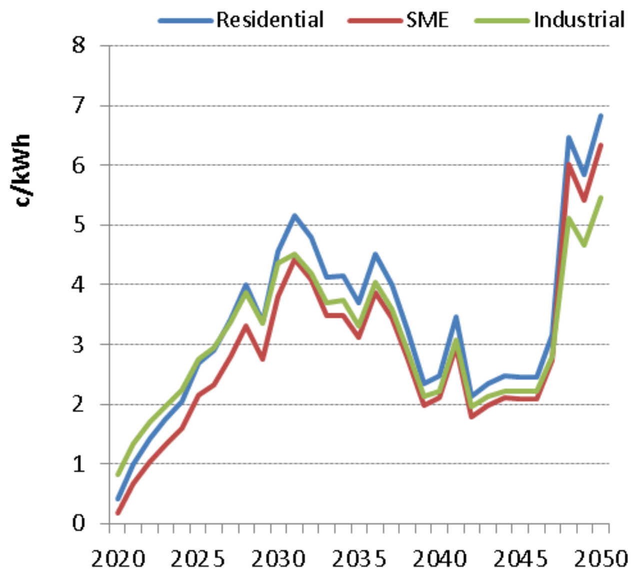
Source: Jacobs

Figure 206 shows weighted average retail prices by customer class. They contain the same trends as the wholesale prices, but the relative price movements are more muted since the wholesale price only comprises typically 30% to 40% of the retail price.

Figure 206: Retail prices by customer class, absolute baselines, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



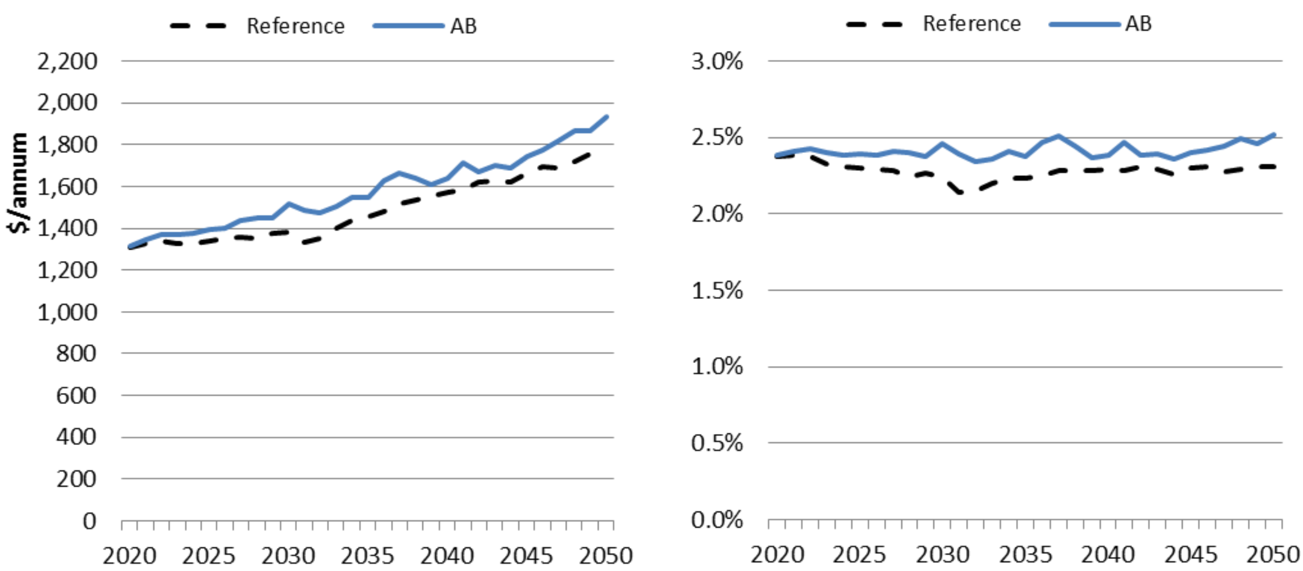


Source: Jacobs

Figure 207 shows the weighted average residential bill relative to the reference case, and also as a percentage of disposable income. Bills are only marginally higher than the reference case.

Figure 207: Residential bills, absolute baselines, 3°C emissions constraint

The left graph shows the absolute residential bill. The right graph shows the residential bill as a % of disposable income.



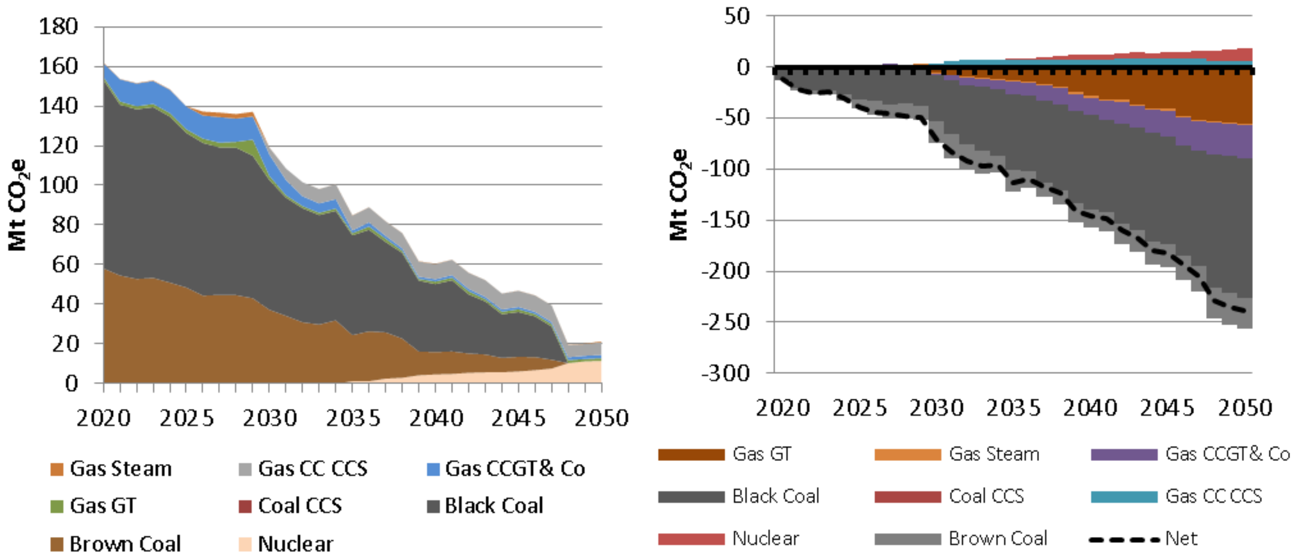
Source: Jacobs

5.9.6 Emissions

Figure 208 shows annual emissions by technology and the difference relative to the reference case. Figure 209 illustrates the generation emission intensity for the scenario and the change from the reference case. The decline in emissions from the incumbent generators is generally linear, which is in accordance with the linear decline of the baselines. The coal fleet continues to generate until the late 2040s and remains the main contributor to emissions until then. CCGTs with CCS and nuclear generation also make a relatively small contribution to emissions in the second half of the modelling horizon.

Figure 208: Emissions by technology, absolute baselines, 3°C emissions constraint

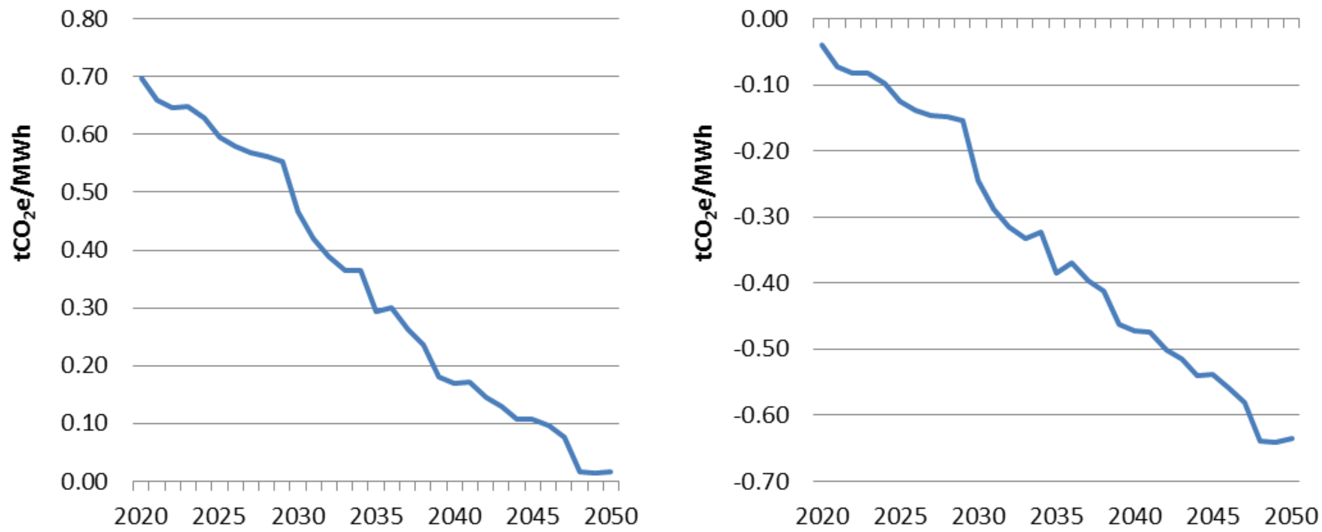
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs. Includes both direct and indirect emissions.

Figure 209: Generation emission intensity, absolute baselines, 3°C emissions constraint

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



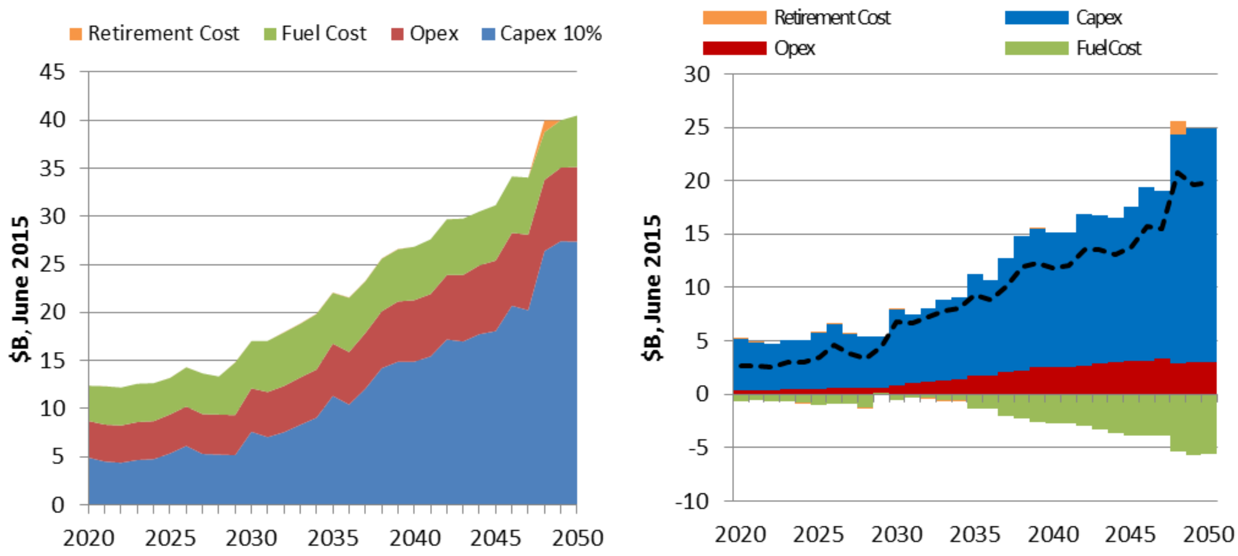
Source: Jacobs. Includes direct emissions only.

5.9.7 Costs

Figure 210 shows annualised resource costs by four cost categories. Costs in 2019/20 are about $12 billion per annum, and they escalate gradually from there with some early new renewable build. Costs accelerate from 2028/29 onwards when greater amounts of investment are required to fill the supply gap caused by the declining baselines. The annual cost peaks in 2049/50 at $41 billion per annum, which is slightly more than the peak carbon pricing cost. Costs under absolute baselines are more front-loaded relative to carbon pricing because the supply gap increases in a linear fashion, whereas under the carbon scenario the reduction in supply is much more sudden, occurring in the mid-2030s.

Figure 210: Annualised costs by category, absolute baselines

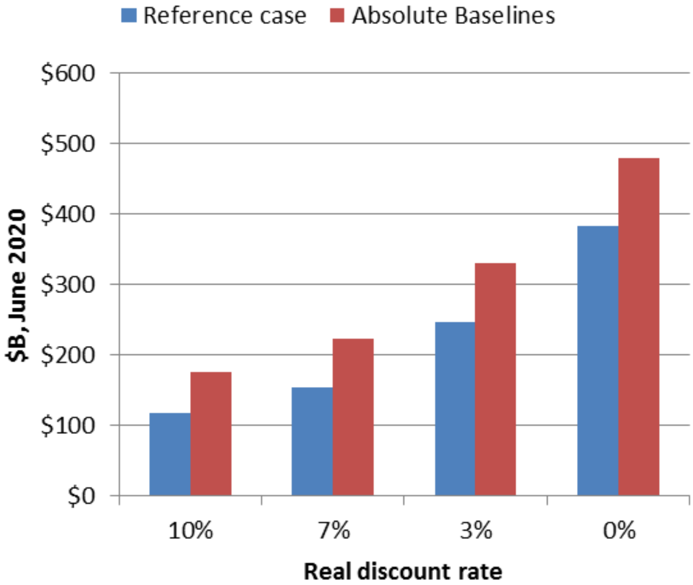
The left graph shows the absolute costs. The right graph shows the costs relative to the reference case.



Source: Jacobs

Figure 211 shows the net present value of the resource costs for absolute baselines relative to the reference case for four separate discount rates. The total resource cost for absolute baselines ranges from 50% (at 10% real discount rate) to 25% (without discounting) higher than that of the reference case. This is a slightly higher cost relative to carbon pricing.

Figure 211: NPV of resource costs, absolute baselines, 3°C emissions constraint



Source: Jacobs. Excludes demand adjustment. See Appendix B.3.2 for further detail.

6. Results: policy combinations with 2°C emissions constraint

In this section, we discuss the results of electricity market simulations where there is a combination of policies enacted to achieve the emissions constraint rather than just using a single policy. Apart from the emissions pricing measures, the individual policy scenarios are only directly acting on one aspect of behaviour in the electricity market. Technology pull policies affect investment patterns toward a higher mix of low emission technologies, but have no direct impact on dispatch pattern of generation. Regulatory measures have no direct impact on either investment or dispatch, although emission standards are imposed on new plant and there is an upper limit on dispatch of conventional coal and gas fired plant

Combinations of policies can target both key behavioural decisions (that is, new investment and dispatch). Three combinations of policies were modelled.

In the series of simulations, the combinations of policies were crafted to achieve the 2°C emissions constraint. The policy combinations considered were:

- A carbon price and low emissions target option. The carbon price was fixed to the carbon price used with the weaker (3°C) emissions constraint. The low emissions target was set at the level required to achieve the stronger 2°C emissions constraint.
- A carbon price and regulated closures. The carbon price was fixed to the carbon price used with the weaker 3°C emissions constraint. Regulations were applied to force the closure of coal fired generation. There was no restriction on gas fired generation from existing plant.
- A regulatory approach with a low emissions target. The regulations entailed closing the entire coal fired fleet over a 10 year period, with the sequence of closure based on plant age. The low emissions target was then set at the level required to meet the 2°C emissions constraint.

6.1 Comparison of policy combinations

6.1.1 Key differences

In some instances, combining policies resulted in intermediate impacts between the constituent parts. All policy combinations resulted in higher costs than emissions pricing policies operating alone but can lead to lower costs than either technology pull policies or regulatory policies. The improvement is due to the policy combinations providing direct incentives for a wider range of abatement options than the individual policies.

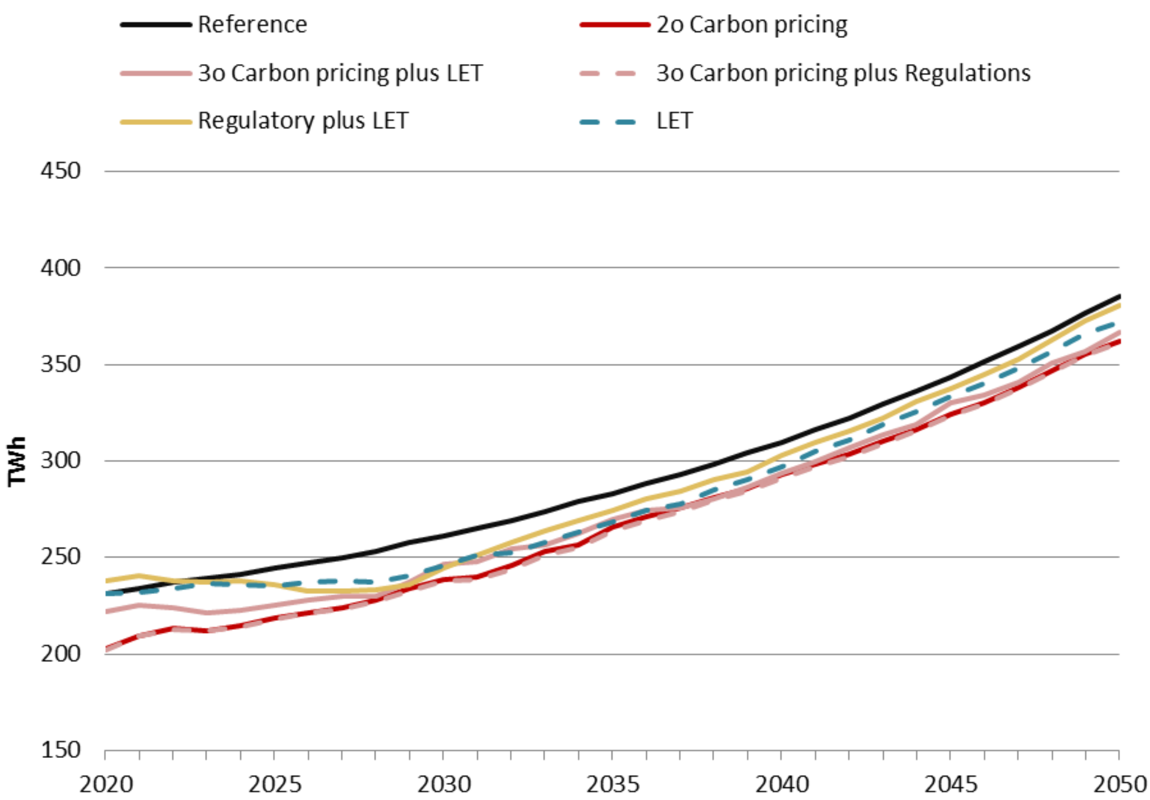
The emissions constraint was not met by the combination of carbon pricing and regulated closure. Regulated closures reduced emissions by closing the coal fleet in the decade to 2030, but the carbon price was not sufficient to incentivise renewable generation over conventional gas. This meant that there was a large increase in generation from existing gas fired units and induced entry of new gas fired plant causing emissions to exceed the emissions constraint.

6.1.2 Demand

Electricity demand across the policy combination scenarios are shown in Figure 212. Demand was generally higher for the policy combinations than for the carbon policy on its own. After 2030, the carbon pricing plus regulations led to a similar demand level as carbon pricing alone mainly due to impact on wholesale prices of the high proportion of gas fired generation.

Of the policy combination scenarios, the regulatory plus LET combination led to the highest demand.

Figure 212: Electricity demand, policy combination scenarios



Source: Jacobs

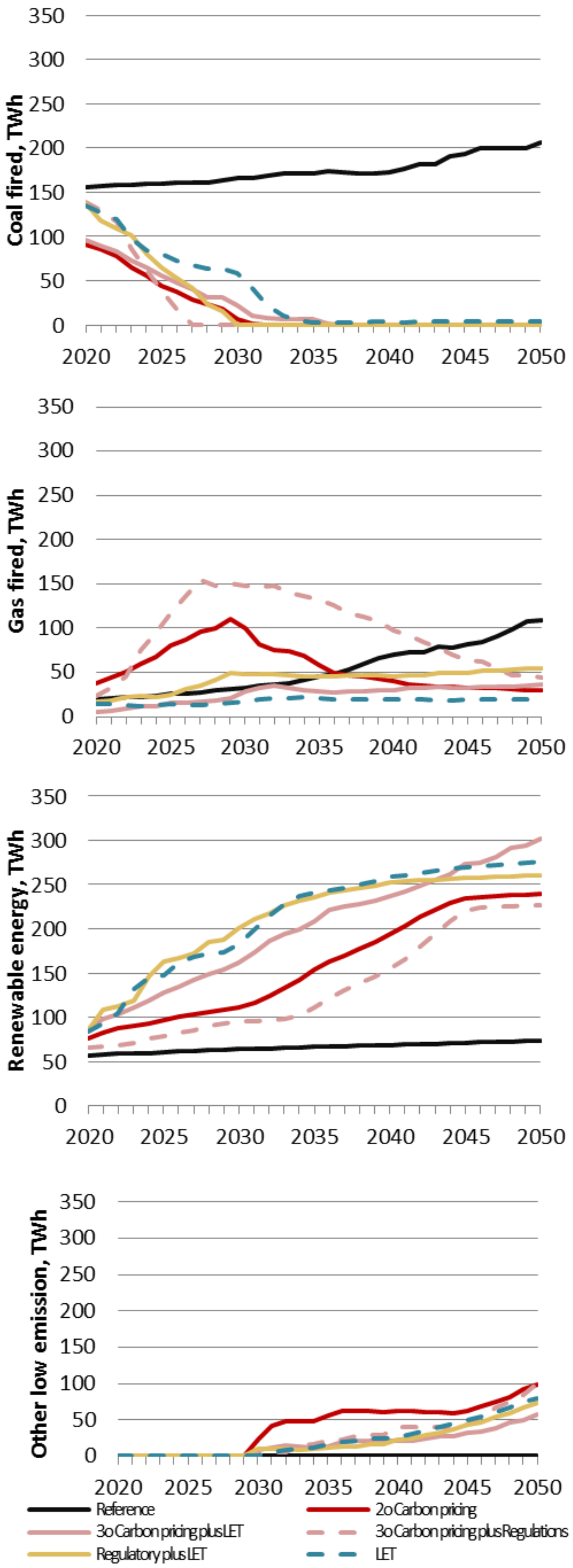
6.1.3 Generation and capacity

Figure 213 shows the generation and capacity mix across the different policy combinations. In all policy combination scenarios there is no coal fired generation after 2035.

Gas fired generation is similar under most of the policy combination scenarios as under the equivalent stand-alone policy scenario. The exception is in the carbon price plus regulated closure scenario where the highest level of gas fired generation occurs. By 2030, gas fired generation comprises 60% of total generation, compared with around 40% in the carbon pricing only scenario. The relatively low carbon prices to 2035 do not lead to high enough wholesale prices to cause a switch from gas fired generation to new renewable generation.

Over the long term (past 2030), renewable energy dominates the generation mix across all the policy combination scenarios (see Table 11). With the exception of the carbon price plus regulated closure scenario, the proportion of renewable generation is higher for the policy combination scenarios than for the carbon pricing only scenario.

Figure 213: Generation and capacity by technology type, policy combination scenarios



Source: Jacobs

Table 11: Share of generation by technology, % of total generation, policy combination scenarios

Scenario	2030				2050			
	Coal	Gas	Renewable	Other low emission	Coal	Gas	Renewable	Other low emission
Reference	63%	12%	24%	0%	53%	28%	19%	0%
2°C Carbon pricing	3%	41%	46%	10%	0%	8%	65%	27%
3°C Carbon pricing plus LET	10%	13%	73%	4%	0%	9%	76%	14%
3°C Carbon pricing plus regulated closure	0%	60%	39%	1%	0%	12%	61%	27%
Regulated closure plus LET	0%	19%	78%	4%	0%	14%	67%	19%
LET	23%	6%	70%	1%	1%	5%	73%	21%
Regulated closure	0%	32%	66%	2%	0%	21%	62%	17%

Source: Jacobs

6.1.4 Prices

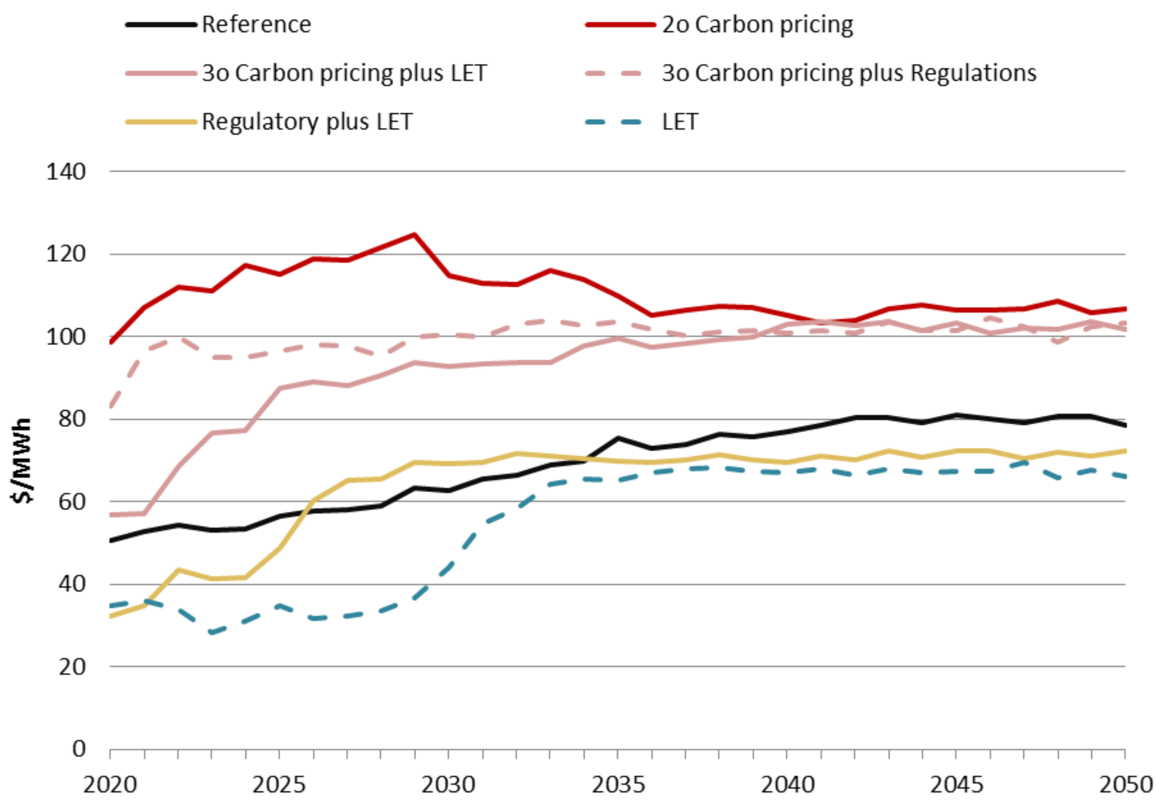
Wholesale price impacts in the policy combinations are affected by the level of the carbon price and/or the amount of low emission generation subsidised under a technology pull policy. However, the results on prices for the carbon pricing plus regulation scenario need to be interpreted with care as the emissions constraint for this scenario was not met.

Across the scenarios:

- Wholesale prices are highest for the policy combinations containing a carbon price but are somewhat lower than for carbon price only scenario. Prices with carbon pricing plus regulated closure reflect the carbon pricing assumptions used plus the level of high cost gas fired generation. Prices for the carbon plus LET scenario has the lowest prices for all the carbon policy combination scenarios. The LET drives higher level of low emission generation (particularly before 2035) putting downward pressure on wholesale prices. After 2035, wholesale prices are broadly similar across the scenarios, tracking the long run marginal cost of new low emission generation.

- Wholesale prices are just above the reference case prices for the regulated closure plus RET combination for most of the period (and are higher than the LET-only scenario). Downward pressure on prices occurs because of the amount of plant with low short run marginal cost and the implied subsidy on dispatch costs provided by the certificates earnt. However, the early closure of coal fired plant leads to a switch to more expensive gas fired generation, limited only by the amount of low emission generation encouraged under the LET.

Figure 214: Wholesale prices, volume weighted average, policy combination scenarios



Source: Jacobs. Volume weighted prices are average the hourly prices weighted by hourly generation proportions. Volume weighted prices are derived for each region of the NEM and the WEM and a system wide average is then derived by weighting each region price by the proportion of each regions energy demand to total energy demand. Prices for the carbon pricing plus regulation scenario need to be interpreted with care as the emissions constraint for this scenario was not met.

Retail tariffs are projected to be around 14% to 18% higher in the policy combination scenarios than for the reference case over the full period to 2050. This compares to a 21% increase over the study period for carbon pricing only scenario, and around 8% higher for the LET only scenario. The retail tariff impacts for the carbon pricing plus regulation scenario need to be interpreted with care as the emissions constraint for this scenario was not met.

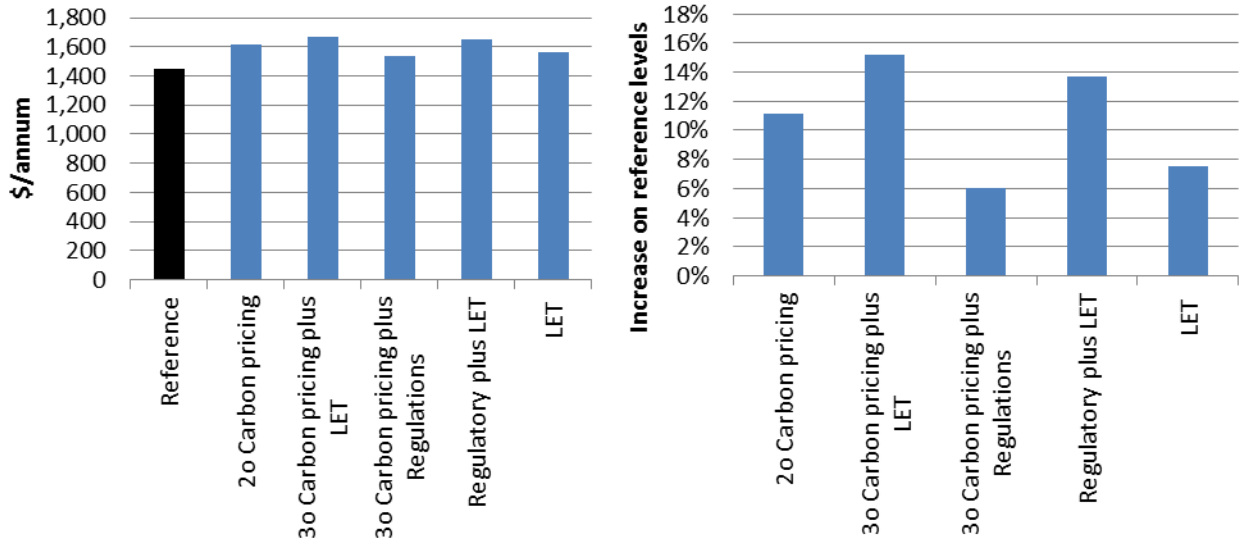
The policy combinations impact on residential customer bills (see Figure 215). Residential electricity bills increase by between $95/annum to $235/annum on bills paid under the reference case, or 0.2% to 0.3% of average household income levels.

Table 12: Retail tariffs, policy combination scenarios

Customer type/scenario	$/MWh				% change from reference			
	2020-2030	2031-2040	2041-2050	2020-2050	2020-2030	2031-2040	2041-2050	2020-2050
Residential								
Reference	24	26	28	26				
Carbon pricing	31	32	31	31	29%	21%	13%	21%
3°C Carbon pricing plus LET	29	31	31	30	20%	17%	14%	17%
3°C Carbon pricing plus Regulations	29	30	31	30	20%	16%	11%	16%
Regulatory plus LET	28	30	30	29	15%	16%	9%	13%
LET	26	30	31	29	9%	16%	11%	12%
SME								
Reference	23	24	26	24				
Carbon pricing	29	29	29	29	27%	19%	12%	19%
3°C Carbon pricing plus LET	27	29	30	28	21%	18%	15%	18%
3°C Carbon pricing plus Regulations	27	28	28	28	18%	15%	10%	14%
Regulatory plus LET	26	29	29	28	16%	18%	11%	15%
LET	25	29	29	28	10%	18%	15%	14%
Industrial								
Reference	10	12	13	12				
Carbon pricing	17	17	16	16	61%	41%	28%	43%
3°C Carbon pricing plus LET	14	15	15	15	39%	27%	21%	29%
3°C Carbon pricing plus Regulations	15	16	16	15	42%	33%	24%	33%
Regulatory plus LET	14	15	15	15	33%	30%	17%	26%
LET	13	15	15	14	22%	29%	18%	23%

Source: Jacobs

Figure 215: Changes in residential customer bills and percentage increase in bills, policy combination scenarios

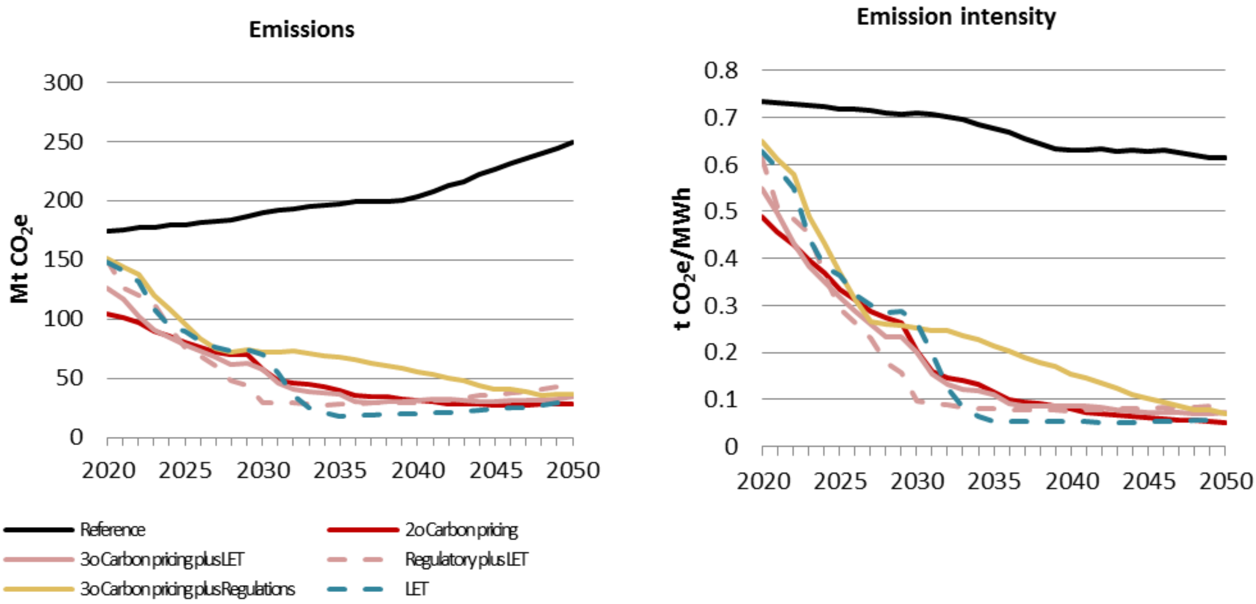


Source: Jacobs

6.1.5 Emissions

Emissions in the policy combination scenarios are projected to follow a similar trend to the carbon pricing only scenario. The reduction in emissions occurs sharply in the period to 2030. The only exception is for the carbon plus regulatory scenario where the emissions constraint is not met due to the lack of sufficient incentives for renewable generation over conventional gas in the 2020s.

Figure 216: Emissions and emission intensity, policy combination scenarios

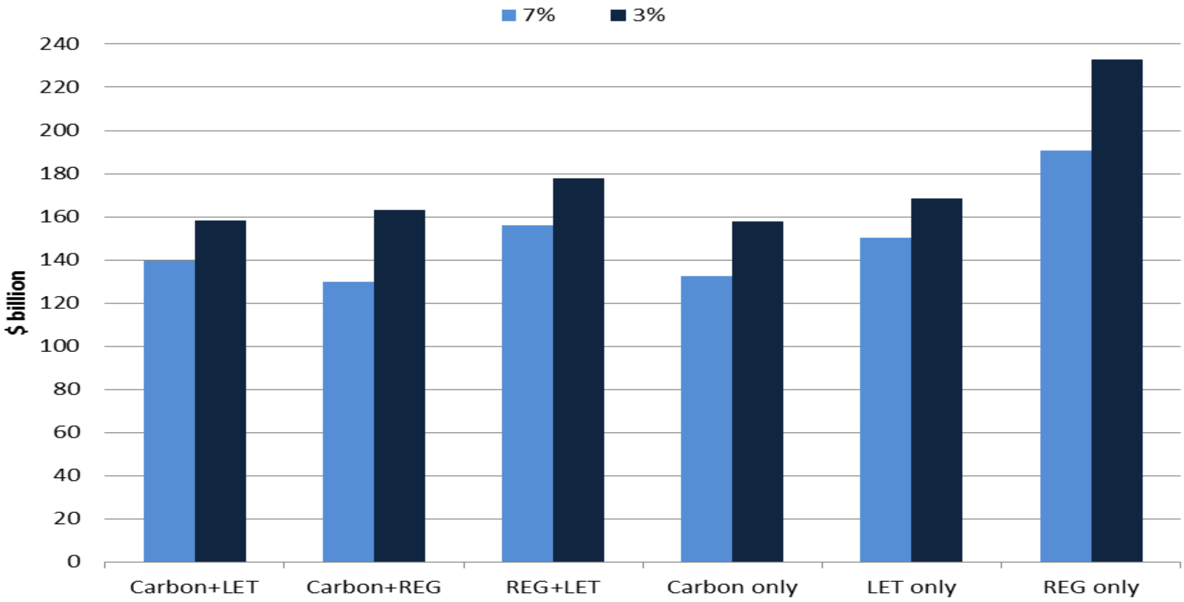


Source: Jacobs. Emissions included direct emissions (from combustion of fuels in electricity generation) and indirect emissions (emitted during processing and supply of fuel to power stations). The emission intensity only includes direct emissions.

6.1.6 Resource costs and cost of abatement

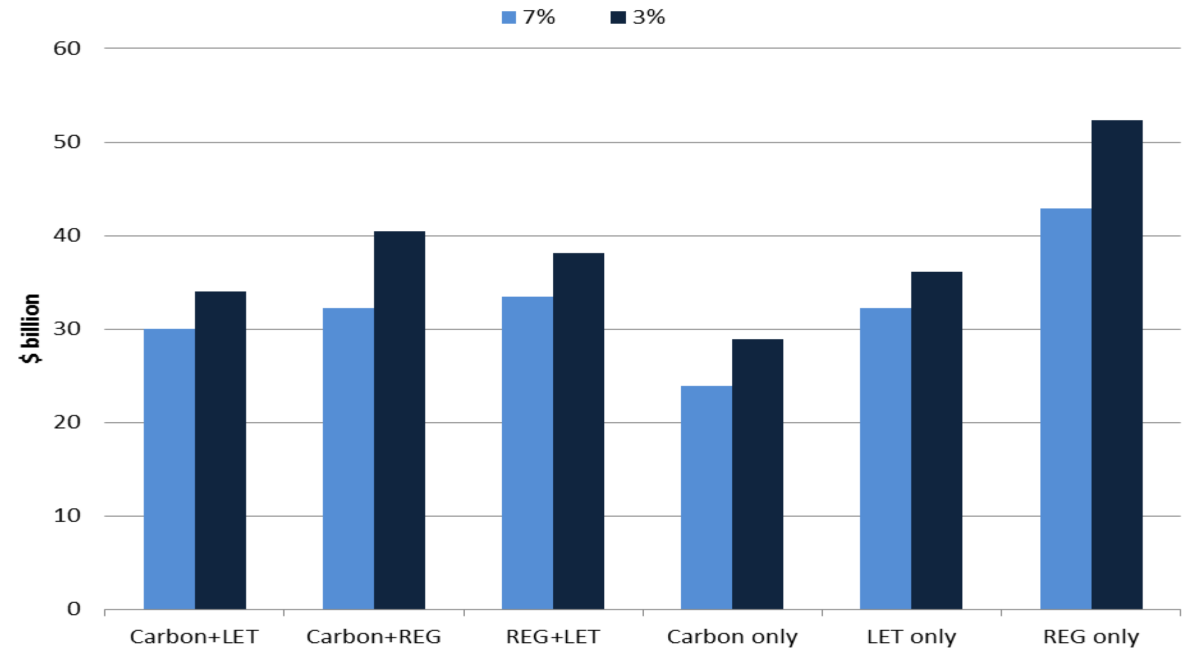
The estimated demand adjusted resource costs of the policy combinations are shown in Figure 216 and the cost of abatement for the policy combinations are shown in Figure 217. The costs are higher than for the carbon only scenario and are lower than for the LET only and Regulatory only scenarios. Costs for the carbon pricing plus regulated closure combination appear low but this scenario does not reduce emissions to the emissions constraint and hence is an underestimate of the cost.

Figure 217: Resource costs relative to reference case, policy combination scenarios



Source: Jacobs. The resource costs represent the net present value of the annual resource costs from 2020 to 2050, discounted by the discount rate shown. The emissions constraint is exceeded by about 650 Mt CO_2e in the carbon pricing and regulated closures policy scenario and 200 Mt CO_2e in the regulated closures scenario.

Figure 218: Cost of abatement relative to the reference case, policy combination scenarios



Source: Jacobs.

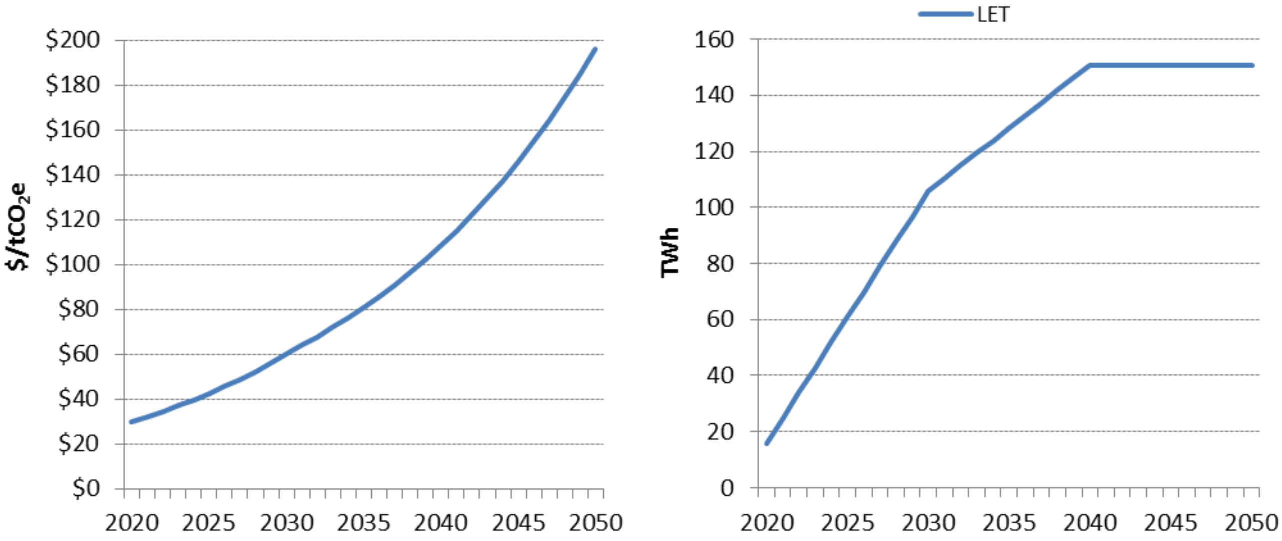
6.2 Carbon pricing and low emissions target

6.2.1 Scenario description

This scenario investigates the combination of the moderate 3°C carbon price with a new low emissions target needed to meet the 2°C emissions target. Figure 219 shows the 3°C world carbon price starting from $30/t CO_2e and reaching $196/t CO_2e in 2050, and the low emissions target needed to incentivise enough low emission investment to meet the emissions constraint. The other assumptions (learning rates, fuel prices etc.) are in agreement with the 2°C world.

For further discussion see Section 2.

Figure 219: 3°C carbon price path and LET target, carbon pricing and low emissions target combination



Source: Jacobs

6.2.2 Key findings

The resource costs, wholesale prices and emissions trajectory all fall about mid-way between the results from the individual carbon price and LET scenarios.

Resource costs are higher than individual carbon pricing scenario.

The carbon pricing plus low emissions target combination is able to meet the emissions constraint since the carbon price facilitates the retirement of coal fired plant and the low emissions target incentivises the entry of renewable and low emission technologies.

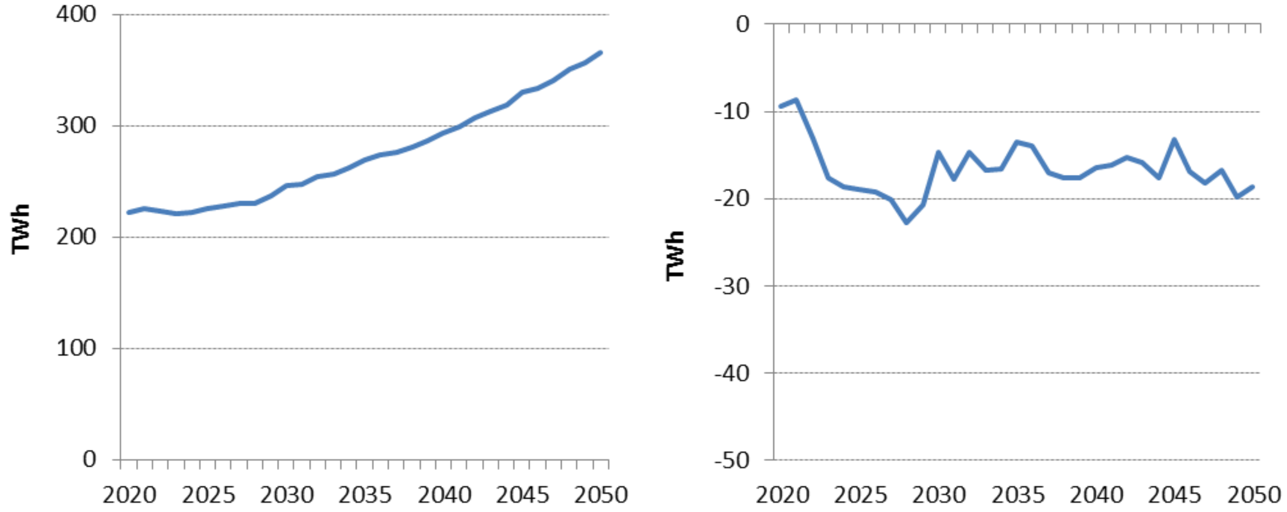
The combination of these policies encourages renewables over gas as the transitional technologies to fill in the retired coal generation in the 2020s and thus meets the 2°C emissions constraint.

6.2.3 Demand

Figure 220 shows sent-out energy demand for carbon pricing and relative to the reference case. Total energy consumed reaches 371 TWh, which is 14 TWh lower than the reference case due to higher wholesale and retail prices reducing demand.

Figure 220: Sent-out energy, carbon pricing and low emissions target combination

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Pitt & Sherry, ACIL Allen and Jacobs

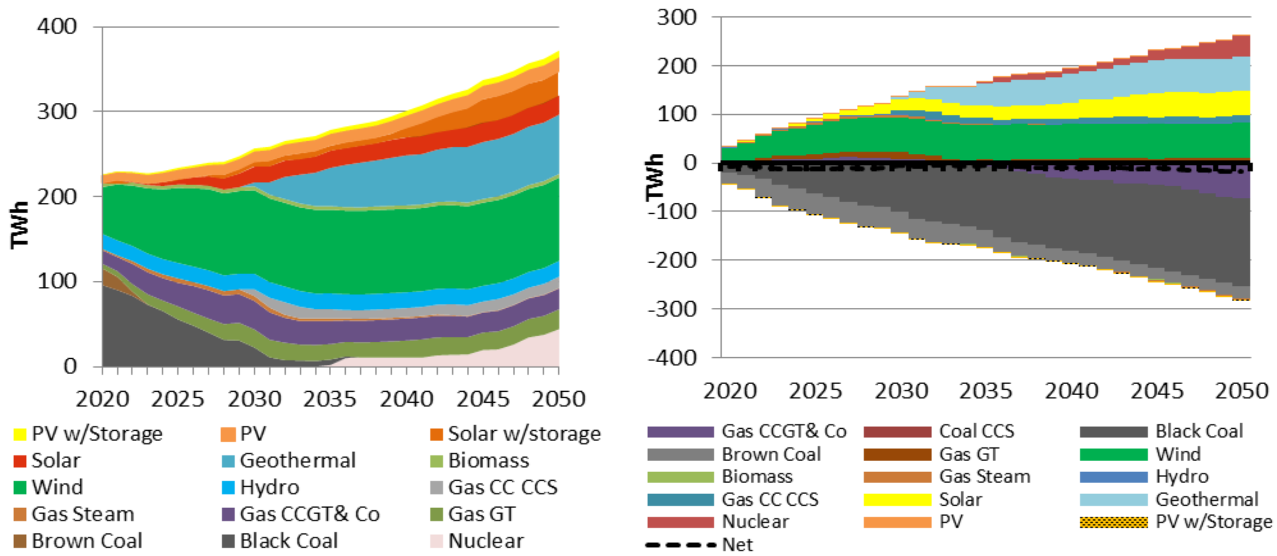
6.2.4 Generation and capacity

Figure 221 shows the generation mix in this policy combination and Figure 222 illustrates the cumulative new generation capacity on the left and the retired capacity on the right. Coal fired generation shows a sharp decline the first ten years as a result of the carbon price cost and renewables-induced wholesale price suppression. The more efficient coal fired plants succeed to continue to generate until closure in 2036.

During the first 15 years wind and solar (backed-up by gas turbines) act as the transitional technologies for the retiring coal fired capacity. After the early 2030s, geothermal generation starts to grow strongly supported from the certificates' revenue and the higher wholesale prices resulting from the carbon price. From 2035, nuclear becomes the marginal low emission technology to be added to the generation mix so as to meet the growth of demand within those years.

Figure 221: Generation mix, carbon pricing and low emissions target combination

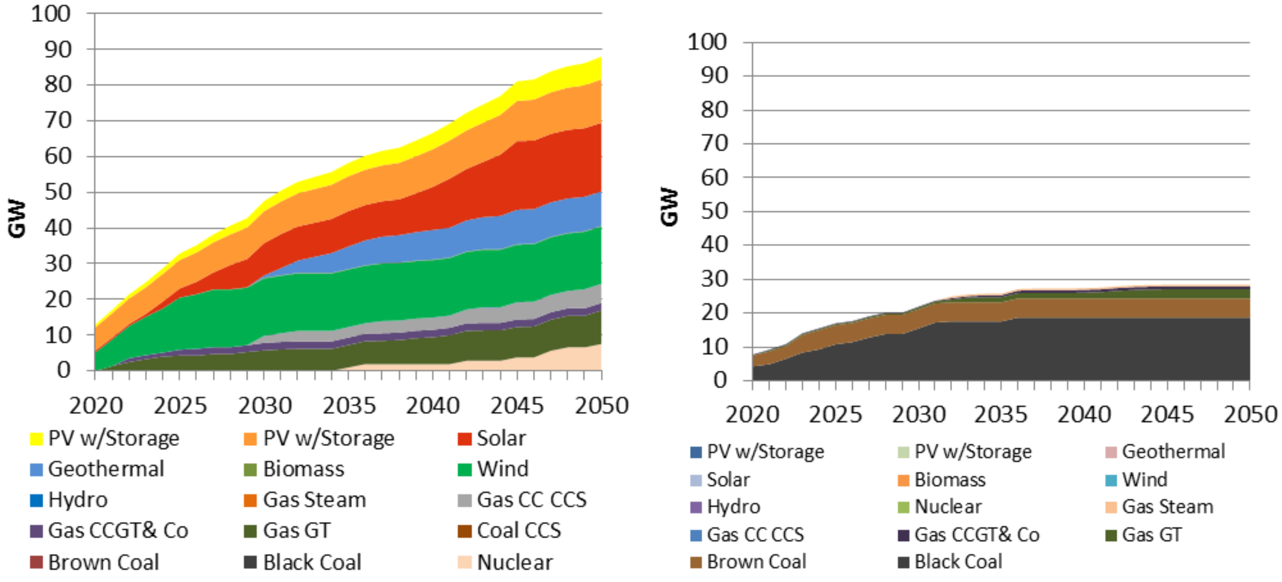
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs

Figure 222: Cumulative new and retired capacity, carbon pricing and low emissions target combination

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



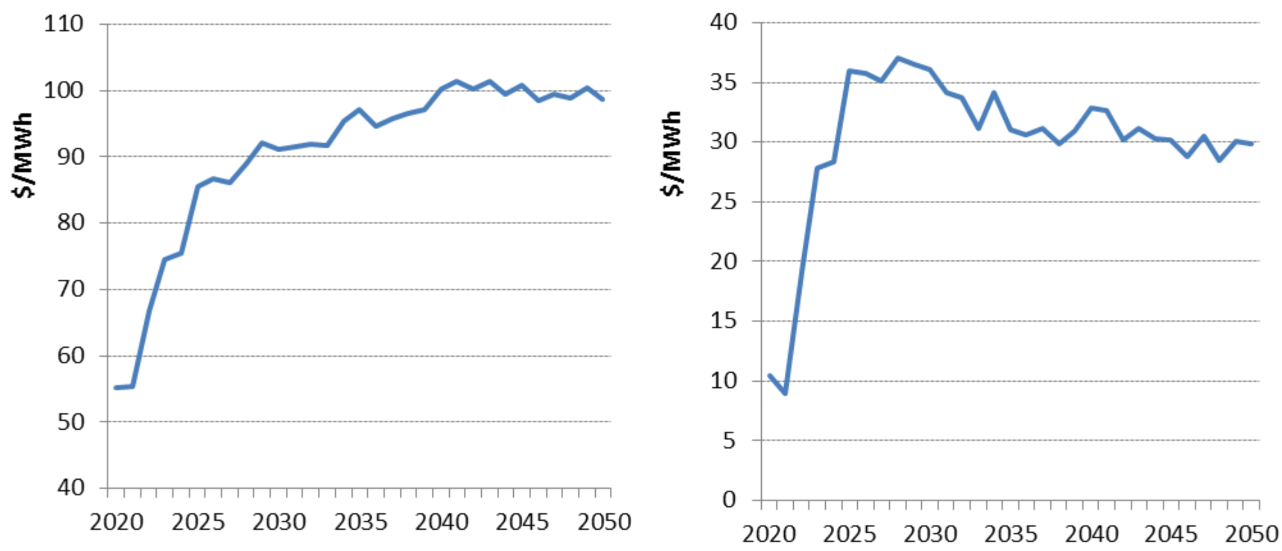
Source: Jacobs

6.2.5 Prices

Figure 223 shows wholesale prices, including price relative to the reference case. Prices are higher relative to the reference case for the entire modelling horizon, due to the carbon price. Wholesale prices reach new entry levels in the mid-2020s, but they keep climbing because the escalating carbon price continues to increase the marginal cost of CCGTs. Prices stabilise by the mid-2030s when nuclear generation technology becomes available and sets the new entry price.

Figure 223: Wholesale electricity time-weighted prices, carbon pricing and low emissions target combination

The left graph shows absolute figures. The right graph shows figures relative to the reference case.

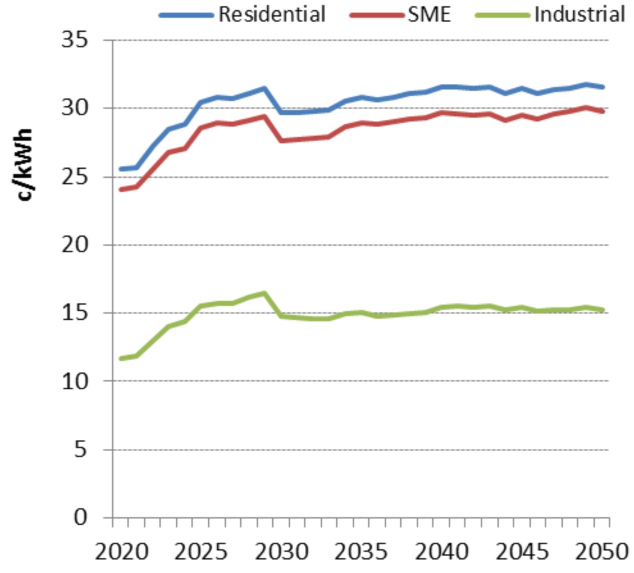


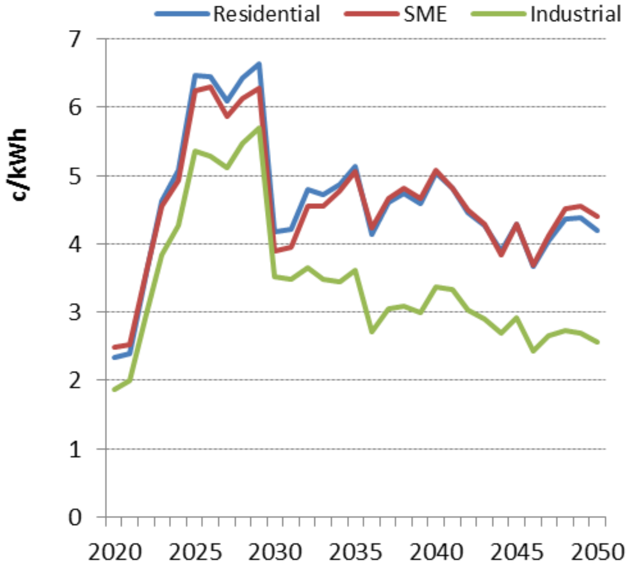
Source: Jacobs

Figure 224 shows the retail prices by customer class. This reveals an upward trend during the first 10 years as a result of the increasing wholesale prices, while they are also influenced from the low emission certificate prices. After 2030, a slight drop to the retail prices results due to the sharp decrease of the LET certificate prices, while the prices become more stable after the mid-2030s. The residential bill impacts are shown in Figure 225. Throughout the whole period both the residential bill cost and the percentage of disposable income are significantly higher than the reference case.

Figure 224: Retail prices by customer class, carbon pricing and low emissions target combination

The left graph shows absolute figures. The right graph shows figures relative to the reference case.

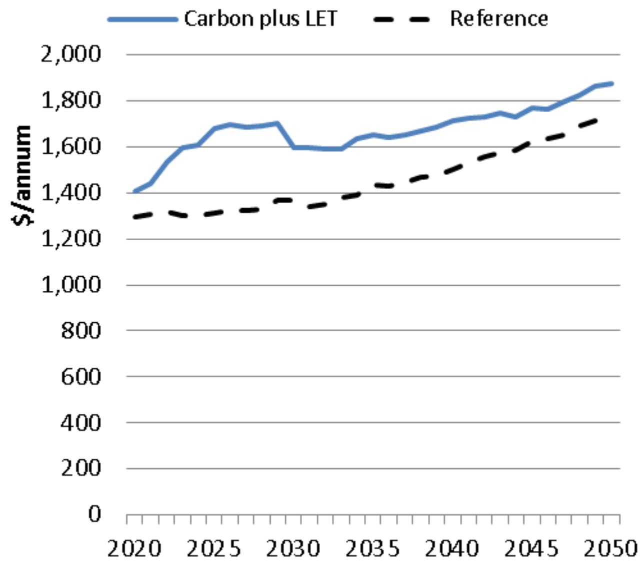


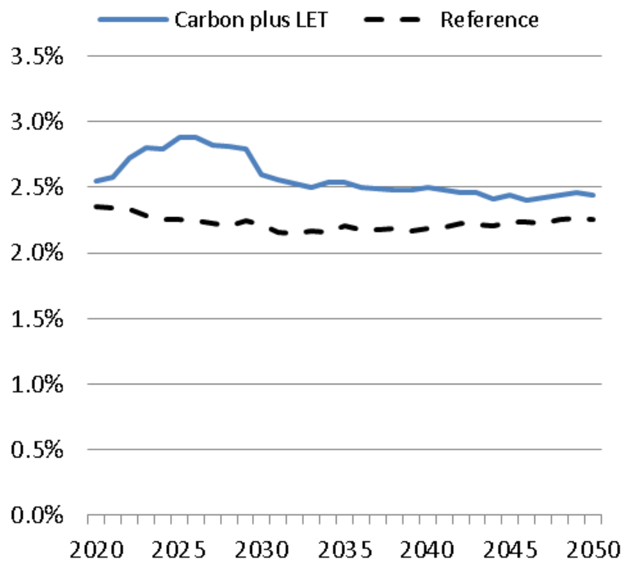


Source: Jacobs

Figure 225: Residential bills, carbon pricing and low emissions target combination

The left graph shows the absolute residential bill. The right graph shows the residential bill as a % of disposable income.





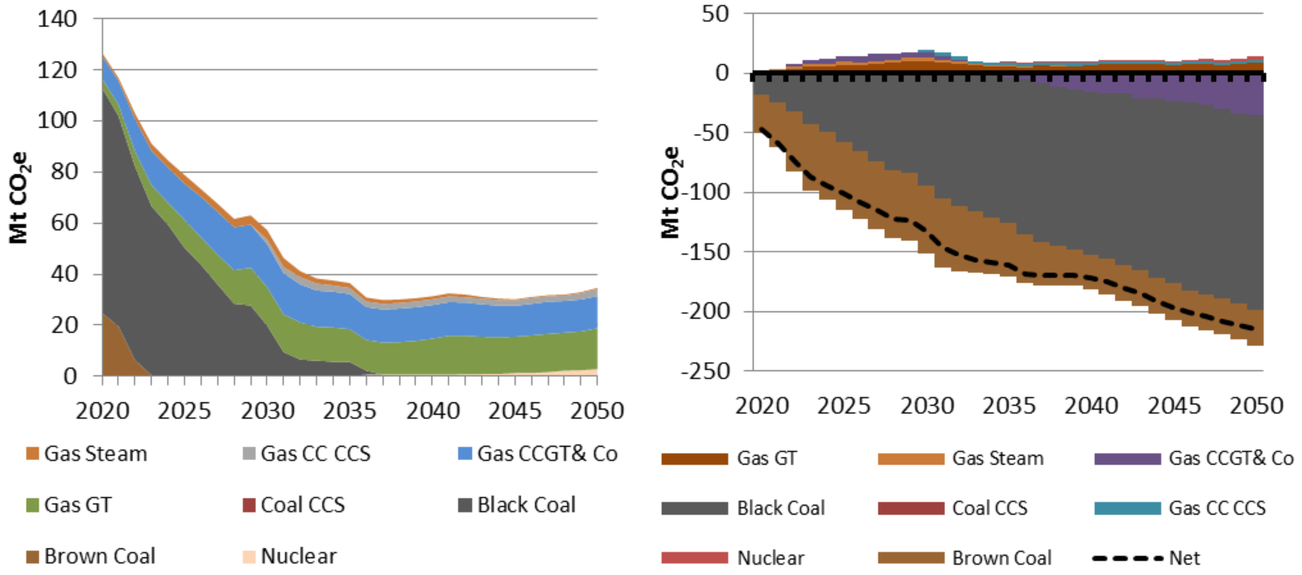
Source: Jacobs

6.2.6 Emissions

Figure 226 illustrates the emissions by fuel type resulting from electricity generation. Emissions decline sharply during the first 10 years when most of the coal fleet retires, then remain relatively stable after 2035. Figure 227 shows the generation emission intensity both in absolute terms and relative to the reference case.

Figure 226: Emissions by technology, carbon pricing and low emissions target combination

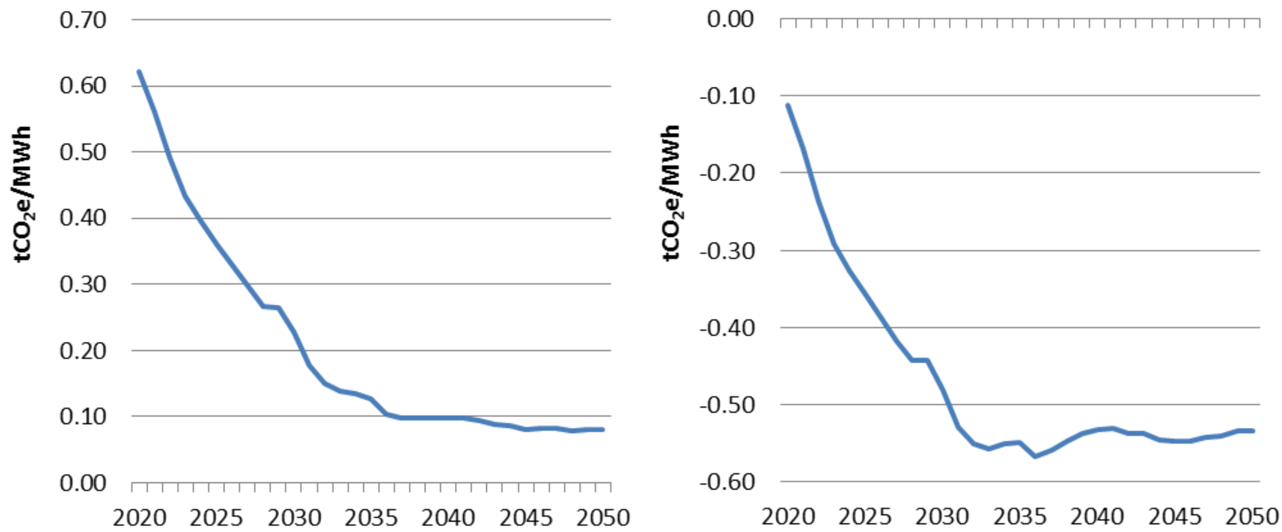
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs. Includes both direct and indirect emissions.

Figure 227: Generation emission intensity, carbon pricing and low emissions target combination

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs. Includes direct emissions only.

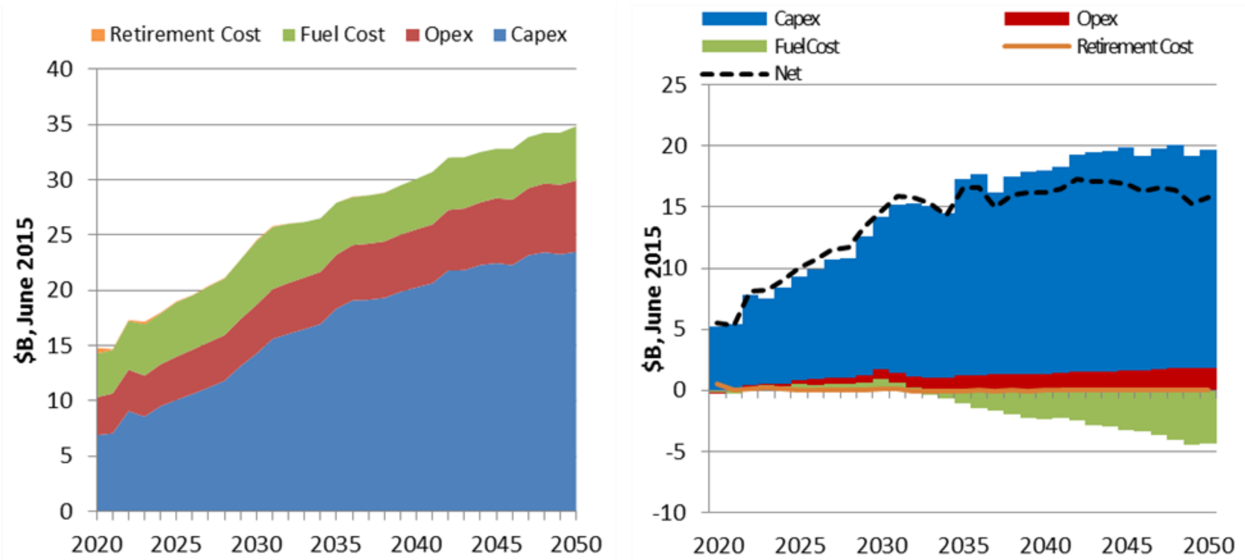
6.2.7 Costs

Figure 228 shows annualised costs by four categories. Capital costs escalate steadily throughout the modelling period, driven by the need to build new low emission plants to substitute the retired capacity in the first 10 years.

When compared to the reference case a distinctive reduction in fuel costs is observed, an outcome of more renewable generation. On the other hand, the higher assets costs of the low emission technologies deployed in the scenario cause overall capital costs to be almost $18 billion above the reference case.

Figure 228: Annualised costs by category, carbon pricing and low emissions target combination

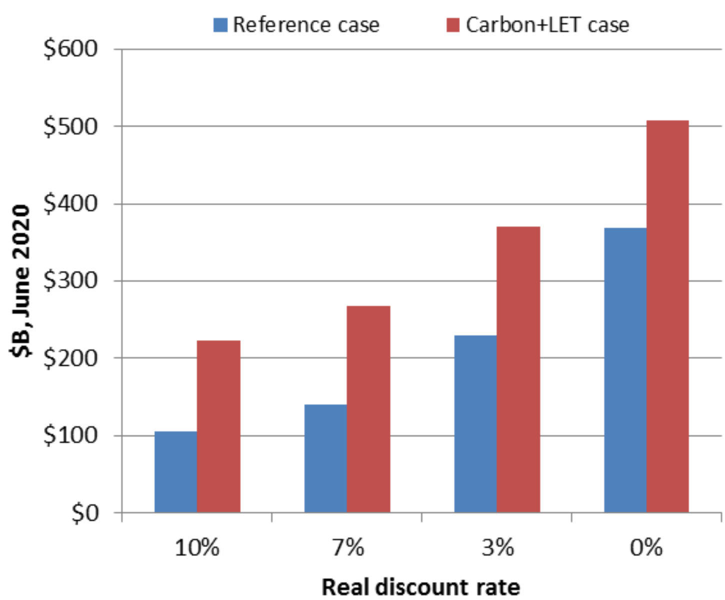
The left graph shows the absolute costs. The right graph shows the costs relative to the reference case.



Source: Jacobs

Figure 228 illustrates the net present value of the resource costs when a combination of a carbon price and low emissions target policies are applied relative to the reference case. Regardless, of the real discount rate used for the calculation the resource costs is approximately double the one derived in the reference case, a cost that is mainly driven by the higher capital costs of the low emission technologies that have entered the market.

Figure 229 NPV of resource costs, carbon pricing and low emissions target combination



Source: Jacobs. Excludes demand adjustment. See Appendix B.3.2 for further detail.

6.3 Carbon pricing and regulated closures

6.3.1 Scenario description

For this scenario a moderate 3°C carbon price is applied in combination with regulated closures based on the age of the plant and timed in such a sequence so as to meet the 2°C emissions target. No restriction on emissions is imposed on gas fired plants. The modelled period of regulated closures was 7 years. For further discussion see Section 2.

6.3.2 Key findings

Carbon pricing plus regulated closures combination was not able to achieve the emissions constraint. The rapid closure of the coal fired fleet and the lack of any restriction to emissions generated from gas plants brought in and locked in too much gas fired generation during the first decade. The resulting emissions constraint is about 650 Mt CO_2e over the 2°C emissions constraint even when all coal plant closes within seven years.

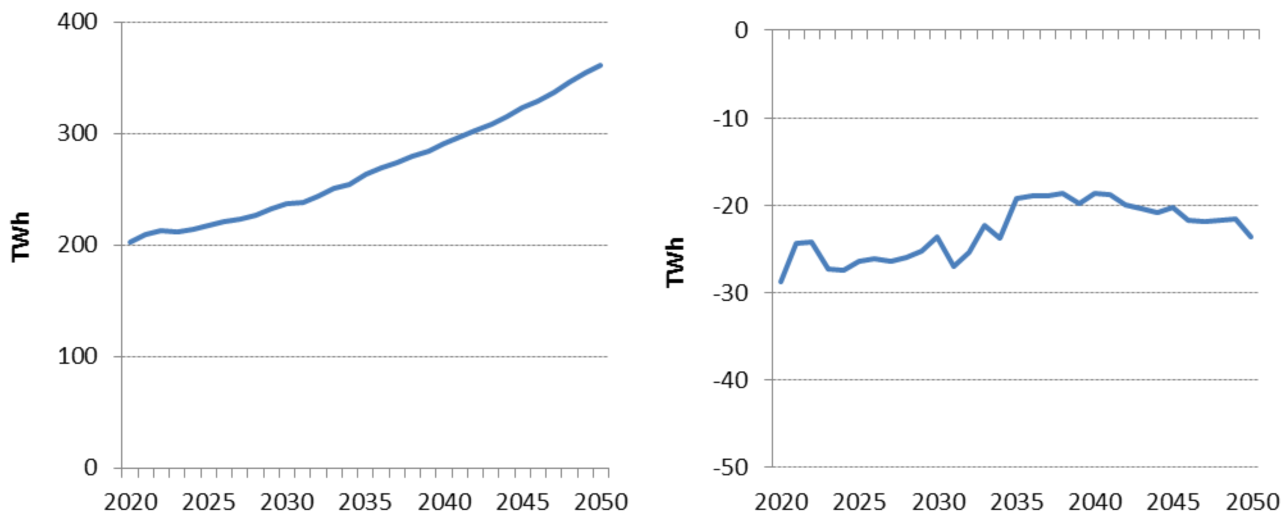
- The marginal cost plants for these initial ten years are the CCGT generators and there are no other incentives or revenue stream for the lower emission and renewable technologies to enter the market.
- If the regulated closures were done in a longer time period the accumulated emissions would be even higher.
- A complementary policy lowering the emission intensity of new plant is needed to reach the demanding emissions constraint.

6.3.3 Demand

Figure 230 shows sent-out energy demand for the carbon pricing and regulated scenario and relative to the reference case. Total energy consumed reaches 362 TWh in 2050, 24 TWh lower than the reference case due to higher wholesale and retail prices reducing demand.

Figure 230: Sent-out energy, carbon pricing and regulated closures combination

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Pitt & Sherry, ACIL Allen and Jacobs

6.3.4 Generation and capacity

Figure 231 shows the generation project in this scenario. The coal fleet is closed down within seven years and the dominant technology replacing the retired capacity are CCGTs. CCGT generation increases from around 17

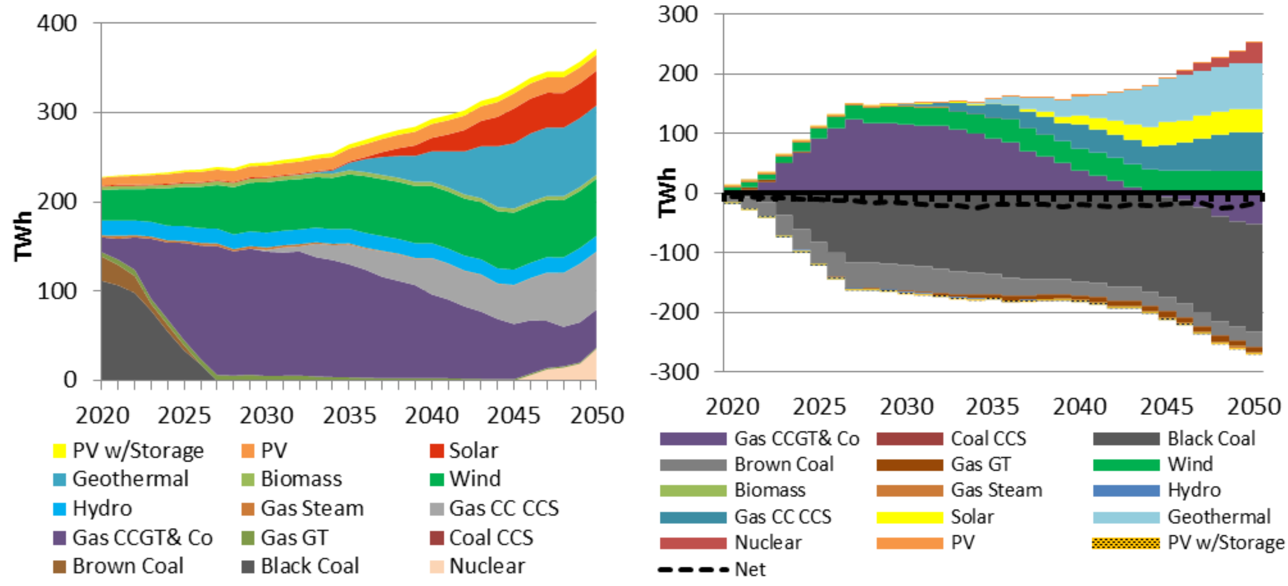
GWh in 2020 to 140 GWh in the 2030s. After 2030 their role start to diminish as the carbon price increases and a transition to CCGTs with CCS occurs.

During the mid-2030s the geothermal and solar plants become the marginal cost technologies and have higher generation growth, while after 2045 some nuclear generation is also added to the generation mix so as to meet the growth of demand within those years.

Figure 232 shows the cumulative new generation capacity across the NEM and WEM. CCGT capacity is the dominant new entrant technology for the first 10 years, with only minor contributions from wind and solar during that period.

Figure 231: Generation mix, carbon pricing and regulated closures combination

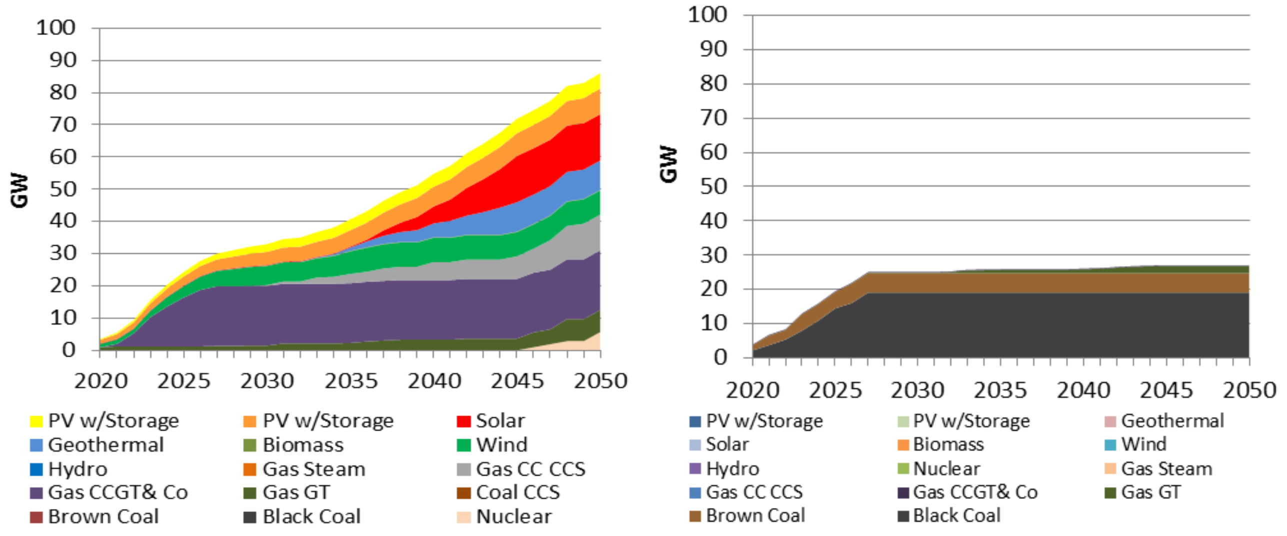
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs

Figure 232: Cumulative new generation capacity, carbon pricing and regulated closures combination

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



Source: Jacobs

6.3.5 Prices

Figure 233 shows the wholesale prices. The prices have a higher starting point than the reference case due to the carbon price and escalate rapidly due to the regulated coal closures reaching the new entrant price of CCGT technology. From mid-2020s they continue to rise at a moderate pace following the carbon price increase until mid-2030s when low emission plants become the marginal new entrant technologies.

Figure 233: Wholesale electricity time-weighted prices, carbon pricing and regulated closures combination

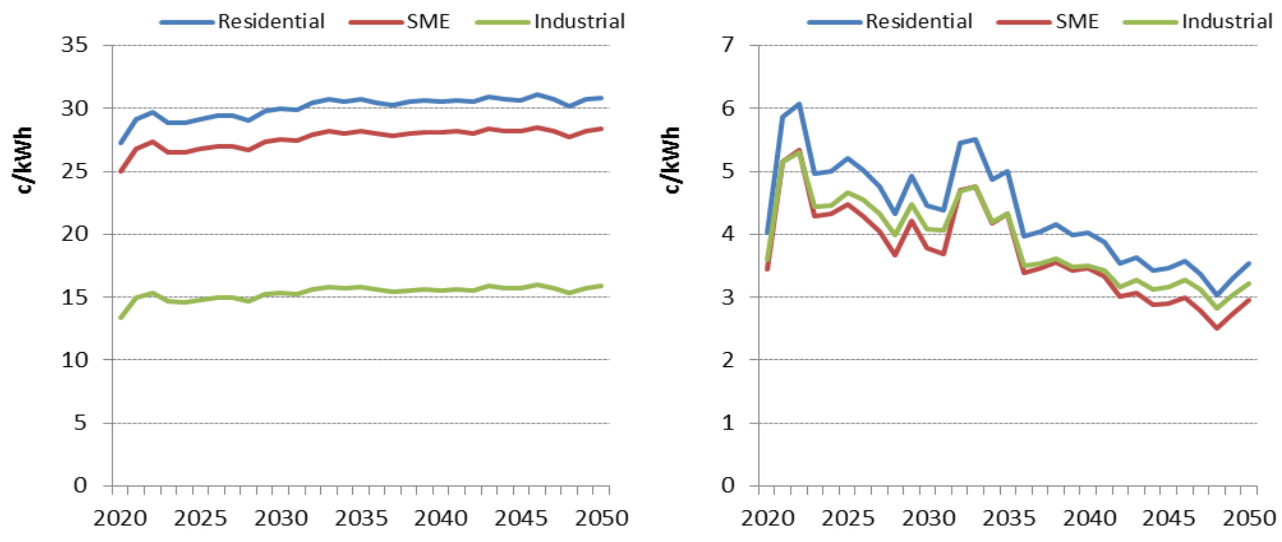
The left graph shows absolute figures. The right graph shows figures relative to the reference case.

Source: Jacobs

Figure 234 shows the that weighted average retail prices by customer class contain the same trends as the wholesale prices, but the relative price movements are more subtle since the wholesale price only comprises typically 30% to 40% of the retail price. In Figure 2366 the weighted average residential bill and its percentage of disposable income relative to the reference case is given, showing a sharp increase during the first years followed by a drop later since the retail prices in this increase at a lower rate than in the reference case.

Figure 234: Retail prices by customer class, carbon pricing and regulated closures combination

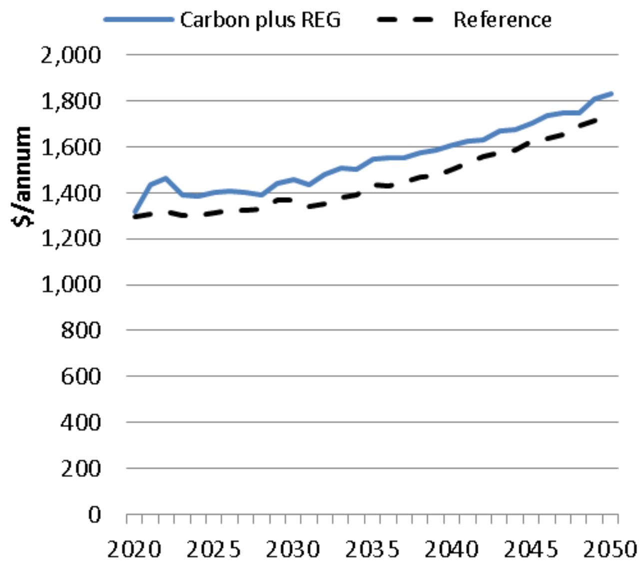
The left graph shows absolute figures. The right graph shows figures relative to the reference case.

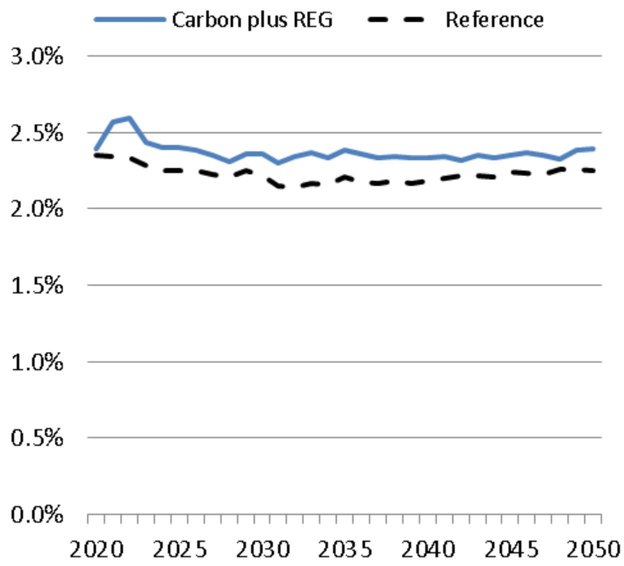


Source: Jacobs

Figure 235: Residential bills, carbon pricing and regulated closures combination

The left graph shows the absolute residential bill. The right graph shows the residential bill as a % of disposable income.





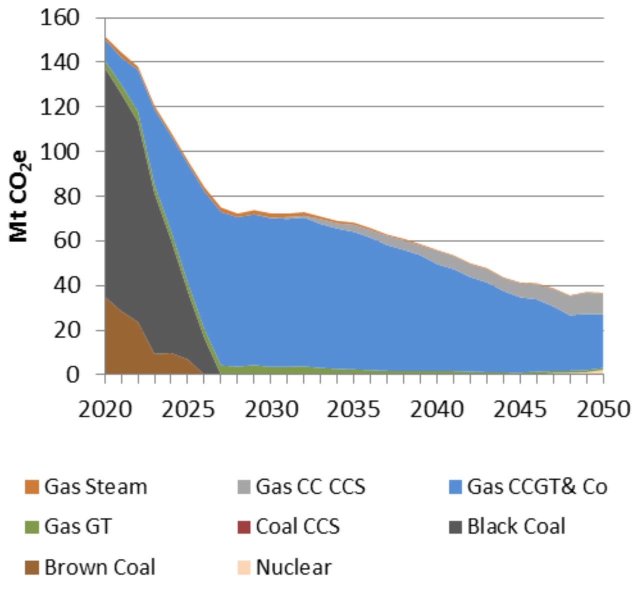
Source: Jacobs

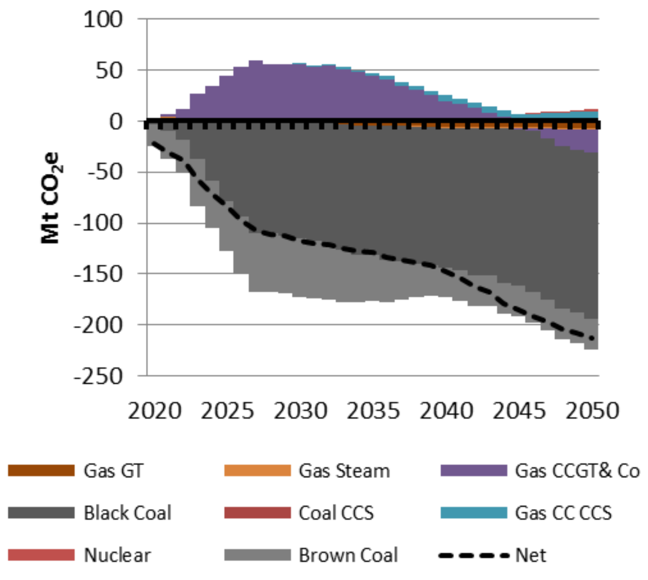
6.3.6 Emissions

The annual emissions by technology and their difference to the reference case are illustrated in the following Figure. It shows the sharp linear decline of coal fired emissions during the first 7 years follows the regulated closure of coal plant. The rapid transition to CCGTs during that period results in a substantial increase in emissions from this technology. These emissions are effectively locked in from this date and therefore they remain relatively stable for the next 8 years when the increased carbon pricing starts to gradually limit the CCGTs dispatch. The accumulated emissions for the studied period are 2220 Mt CO_2e which is 640 Mt CO_2e higher than the emissions constraint. The generation emission intensity and its difference to the reference case shown in Figure 237 reveal the same trends.

Figure 236: Emissions by technology, carbon pricing and regulated closures combination

The left graph shows absolute figures. The right graph shows figures relative to the reference case.

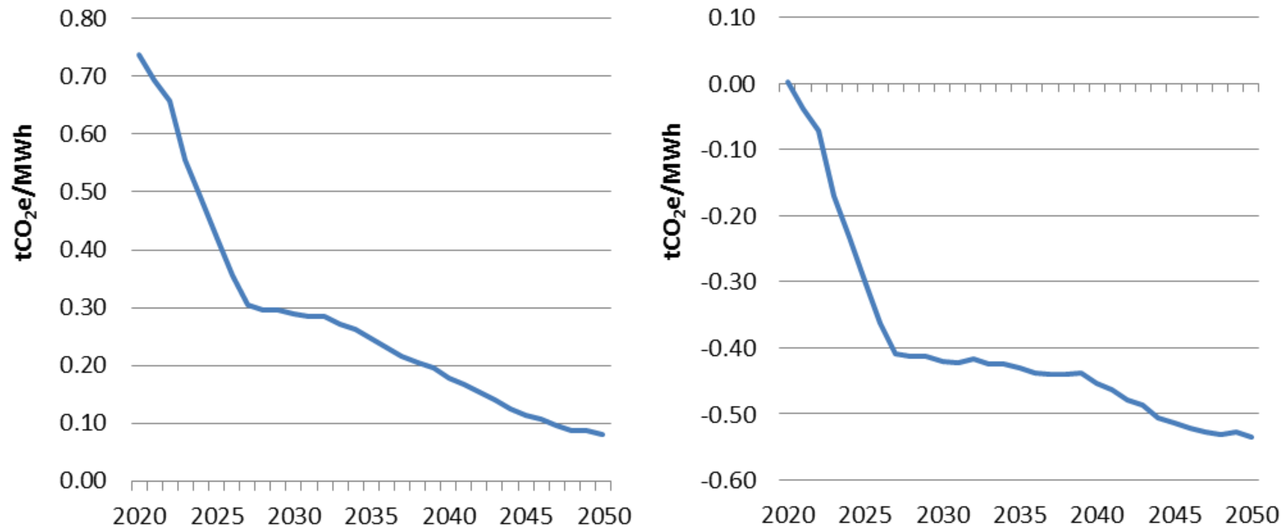




Source: Jacobs. Includes both direct and indirect emissions.

Figure 237: Generation emission intensity, carbon pricing and regulated closures combination

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



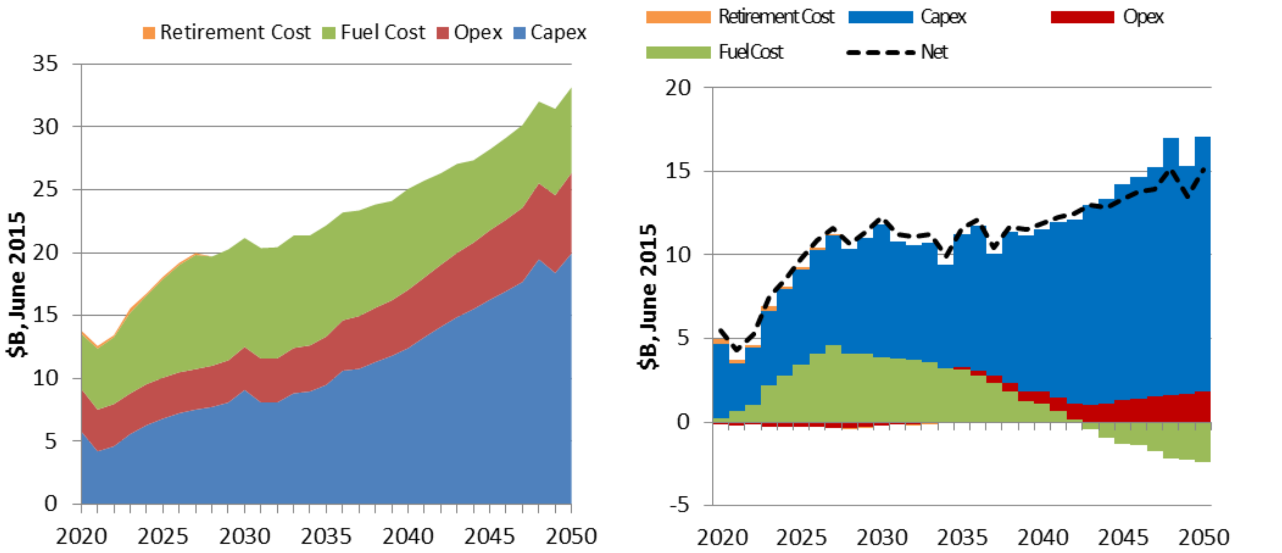
Source: Jacobs. Includes direct emissions only.

6.3.7 Costs

The annualised costs by category and their difference relative to the reference case are shown in Figure 238. During the first 15 years both capital and fuel costs increase rapidly, driven by new fuel intensive CCGTs entering the market to fill in the supply gap left from the closed coal fired plants. That trend changes after 2035 when more capital intensive low emission technologies with high operating costs become the marginal new entry plants.

Figure 238: Annualised costs by category, carbon pricing and regulated closures combination

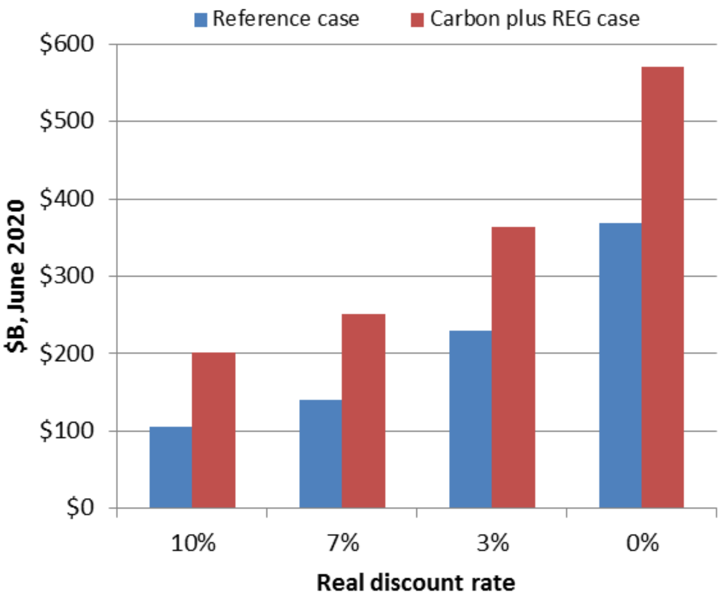
The left graph shows the absolute costs. The right graph shows the costs relative to the reference case.



Source: Jacobs

Figure 239 shows the net present value of the resource costs for carbon pricing plus regulated closures scenario relative to the reference case for four separate discount rates. The total resource cost for regulated closures is from 90% to 55% higher than that of the reference case depending on the discount rate. This is materially higher in cost than carbon pricing, and the policy does not achieve the required level of cumulative abatement.

Figure 239: NPV of resource costs, carbon pricing and regulated closures combination



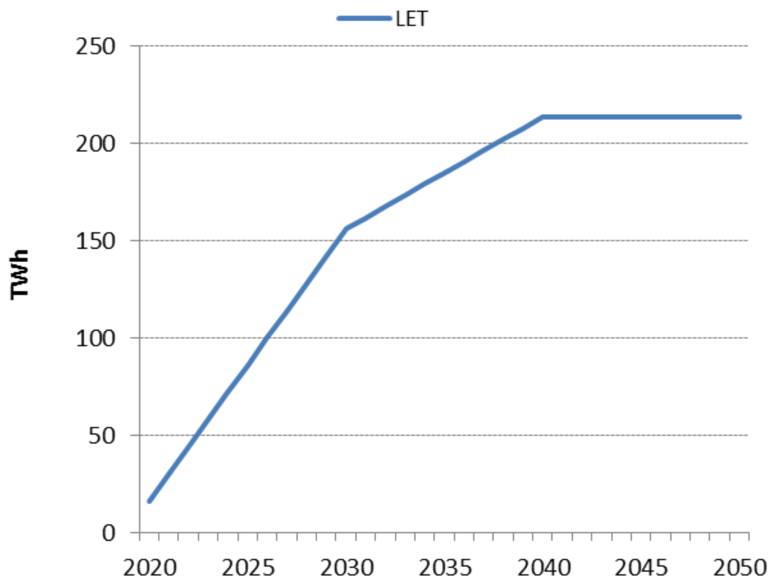
Source: Jacobs. Excludes demand adjustment. See Appendix B.3.2 for further detail.

6.4 Regulated closures and low emissions target

6.4.1 Scenario description

The combination of the following two policies is investigated: regulated closure of coal plants within 10 years based on age, and the introduction of a new low emissions target to meet the 2°C emissions constraint. Figure 240 shows the LET target required to meet the emissions constraint. The LET has the same starting point and shape as the regular LET and is slightly lower since the regulated carbon plant closures are principally driving the reduction of emissions while the LET’s primary target is to incentivise the low emission plants to become the key transitional technologies instead of CCGTs. For further discussion, refer to section 2.2.

Figure 240: LET target, regulated closures and low emissions target combination



Source: Jacobs

6.4.2 Key findings

The combination of the regulated closures and the LET meets the emissions constraint. Regulated closures facilitates the early retirement of the coal fired plant while the LET enables the entry of renewables and other low emission technologies in the generation mix.

The additional revenue stream to renewables and low emission technologies coming from the LET certificates set these technologies as the transitional technologies to replace the retired coal-fleet instead of CCGTs. Therefore the policy does not have the investment in CCGTs during the first decade that would be locked-in throughout the whole horizon.

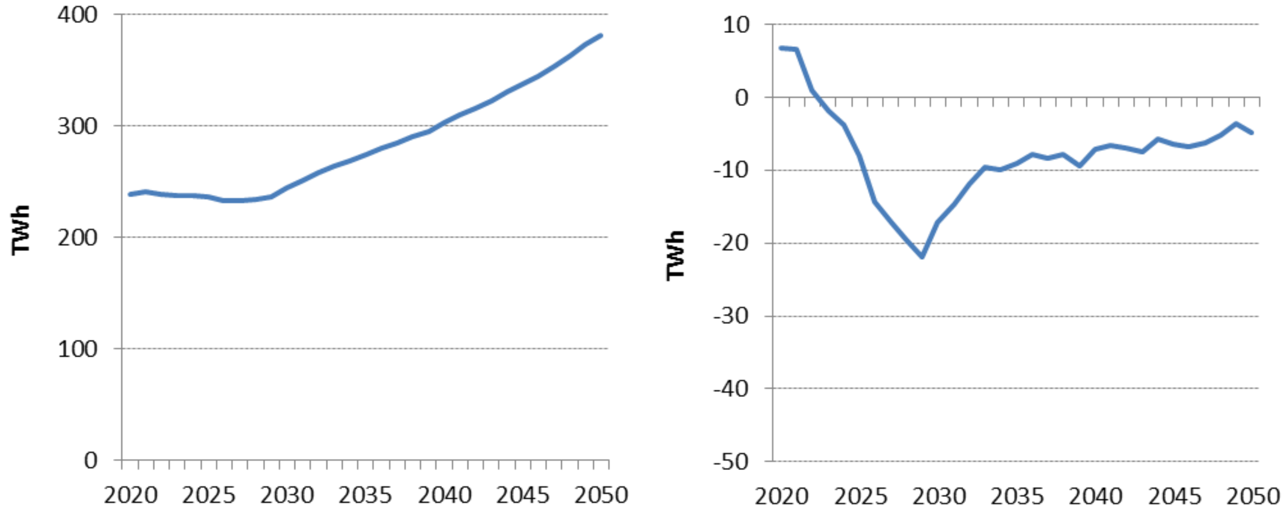
This combination has similar resource costs and cost of abatement than the cheaper of its components (the LET).

6.4.3 Demand

Figure 241 shows the sent-out energy demand for the regulated closures and low emissions target scenario and relative to the reference case. Total energy consumed reaches 380 TWh in 2049/50, 5 TWh lower than the reference case due to higher wholesale prices reducing demand. Demand in the 2020s is flat, and this is due to the price spike originated due to the coal-fleet retirement.

Figure 241: Sent-out energy, regulated closures and low emissions target combination

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



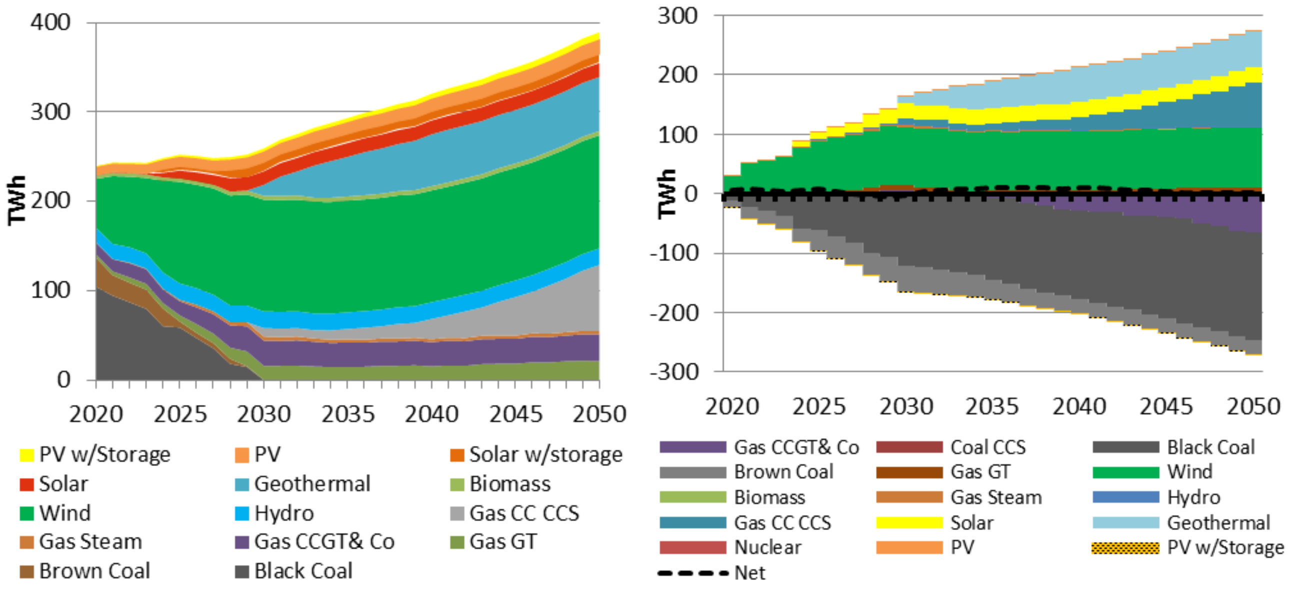
Source: Pitt & Sherry, ACIL Allen and Jacobs

6.4.4 Generation and capacity

Figure 242 shows the generation mix across the modelling horizon while Figure 243 illustrates the cumulative new generation capacity. In this scenario the supply shortage resulted from the regulated closures during the first decade is filled-up predominantly by wind and solar technologies, supported by the low emission certificate and the increase of wholesale prices. New GTs are also needed during the 2020s to facilitate the take–up of these intermittent renewable technologies. Moreover, generation from geothermal plants is added to the mix after 2030, while the last 10 years CCGTs with CCS become the marginal cost entry technology needed to meet the growing demand.

Figure 242: Generation mix, regulated closures and low emissions target combination

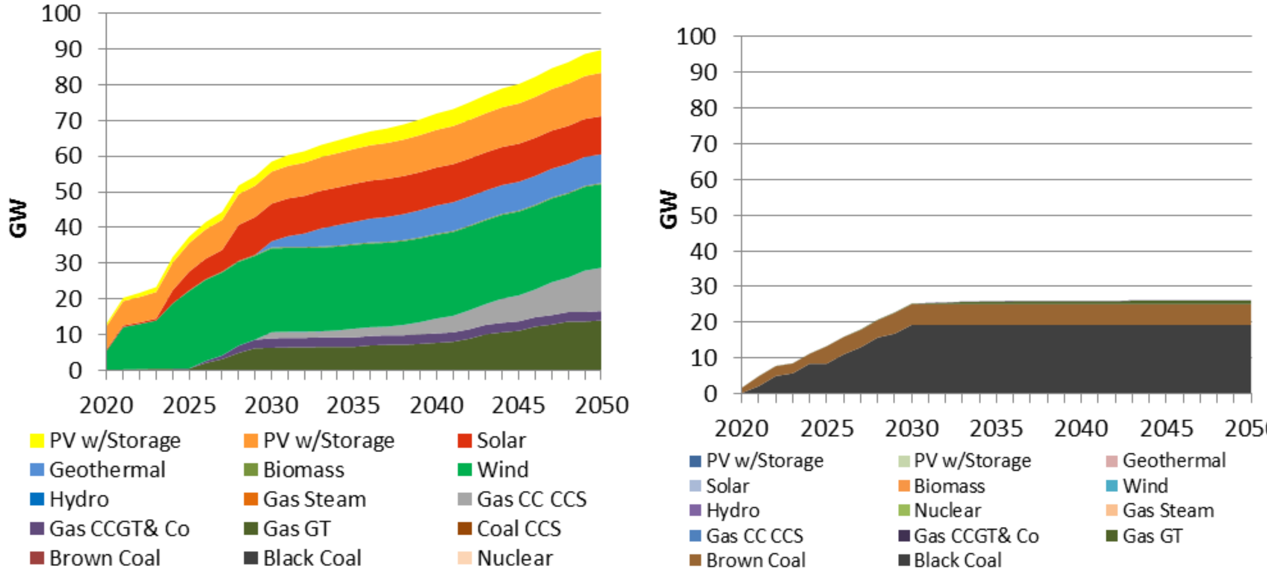
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs

Figure 243: Cumulative new and retired capacity, regulated closures and low emissions target combination

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



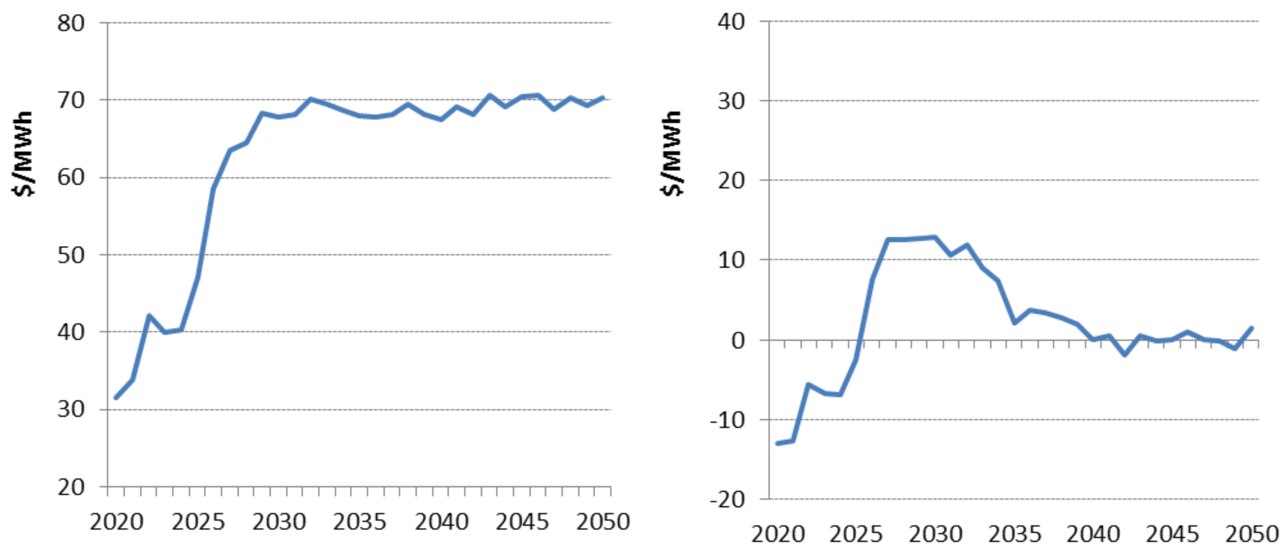
Source: Jacobs

6.4.5 Prices

Figure 244 shows wholesale time-weighted prices. The price is initially lower than the reference case driven by the new renewables built, but then it rapidly increases following the regulated closure of the coal-fleet, reaching within 10 years the entry cost price of CCGTs. The wholesale prices remain stable after 2030 capped by the CCGTs new entry cost price initially and the CCGT with CCS later on since they are both eligible to generate low emission certificates.

Figure 244: Wholesale electricity time-weighted prices, regulated closures and low emissions target combination

The left graph shows absolute figures. The right graph shows figures relative to the reference case.

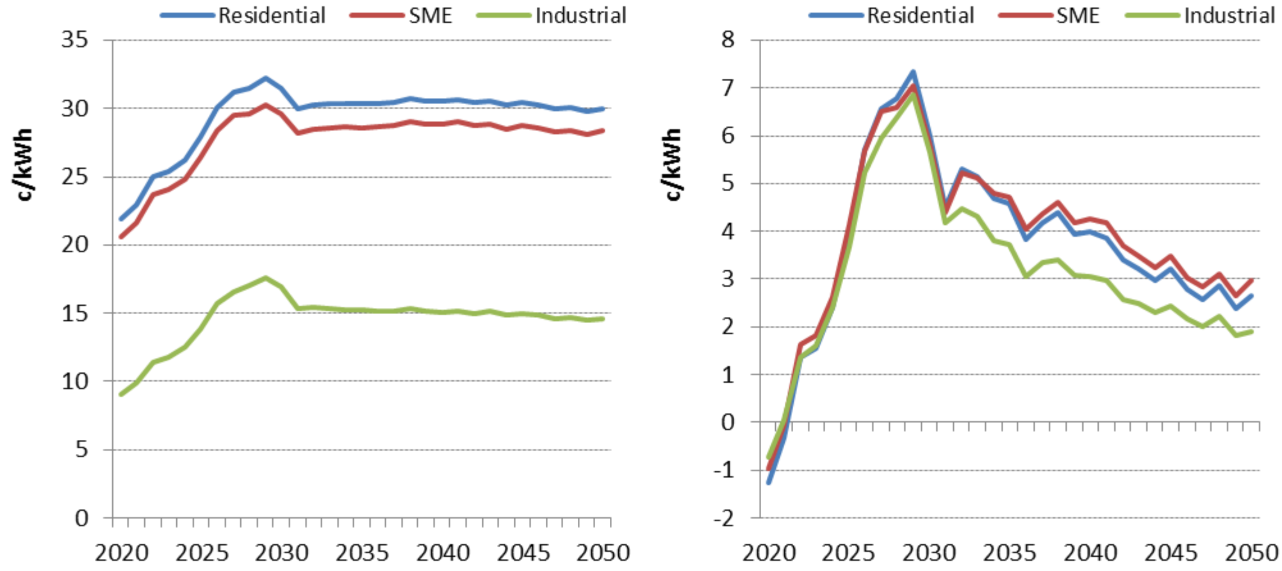


Source: Jacobs

Figure 245 shows weighted average retail prices by customer class. They contain the same trends as the wholesale prices, but are also influenced by the low emissions target certificate price resulting in a slight drop during the early 2030s.

Figure 245: Retail prices by customer class, regulated closures and low emissions target combination

The left graph shows absolute figures. The right graph shows figures relative to the reference case.

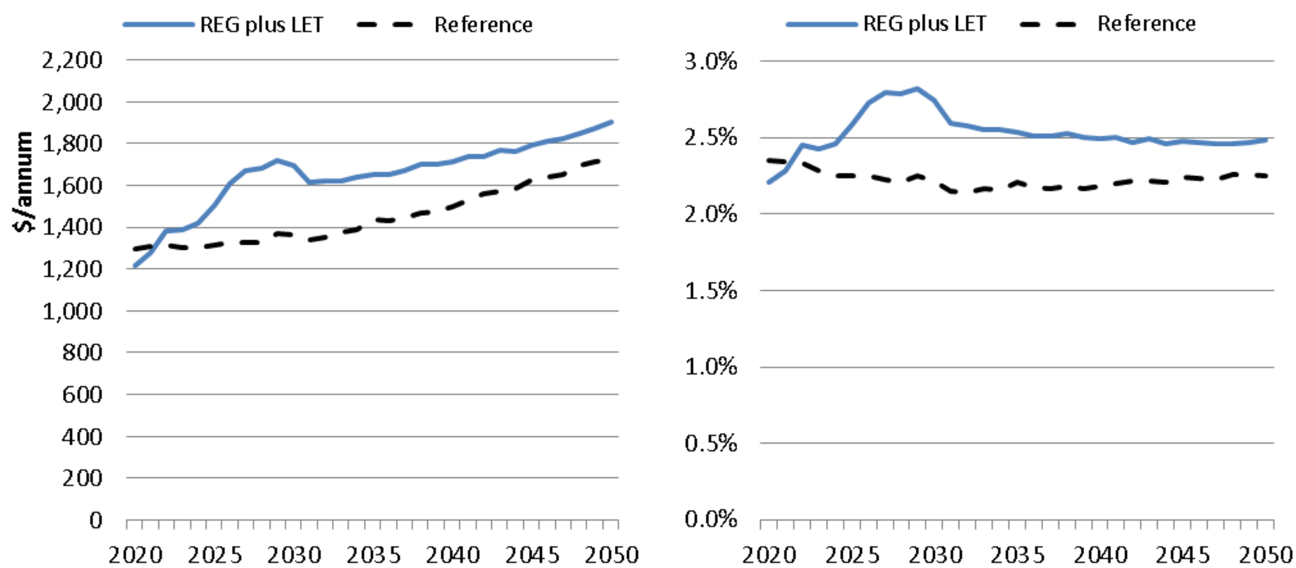


Source: Jacobs

Figure 246 shows the weighted average residential bill relative to the reference case, and also as a percentage of disposable income. After the initial lower prices driven by the new renewables, the high wholesale prices lead to retail prices that are higher than those of the reference case, and consequently the average residential bill is also higher.

Figure 246: Residential bills, regulated closures and low emissions target combination

The left graph shows the absolute residential bill. The right graph shows the residential bill as a % of disposable income.



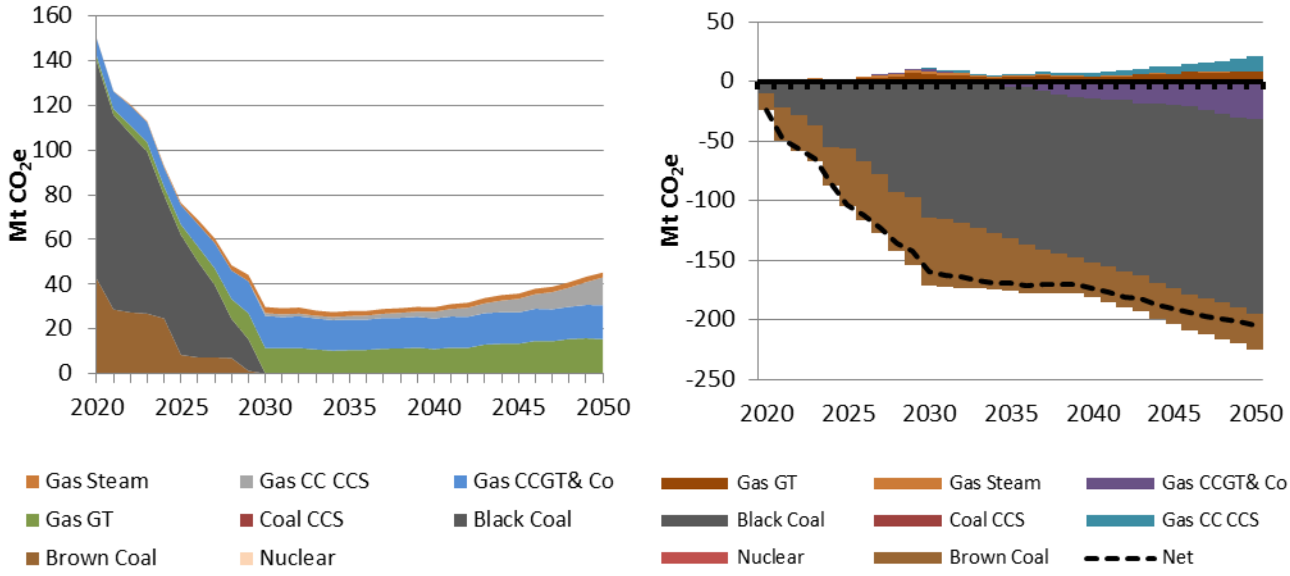
Source: Jacobs

6.4.6 Emissions

Figure 247shows annual emissions by technology and the difference relative to the reference case, while in Figure 248 the generation emission intensity and their relativeness to the reference case are shown. The regulated closure of the coal fired fleet is driving the linear decline of emissions the first decade. Some rise in emissions from CCGTs and gas turbines is evident in the early 2030s, although when compared to the reference case this increase is only marginal. This occurs due to the additional renewables driven in the generation mix by the LET scheme. A slight escalation in emissions is shown during the last decade of the horizon following the end of the LET scheme and the build of some new CCGTs with CCS.

Figure 247: Emissions by technology, regulated closures and low emissions target combination

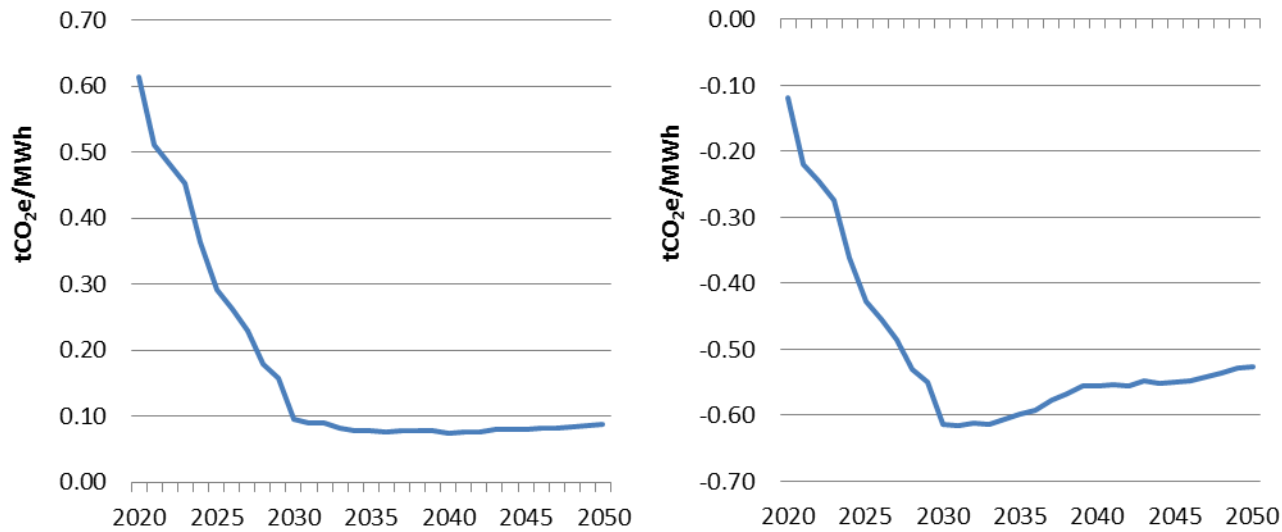
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs. Includes both direct and indirect emissions.

Figure 248: Generation emission intensity, regulated closures and low emissions target combination

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



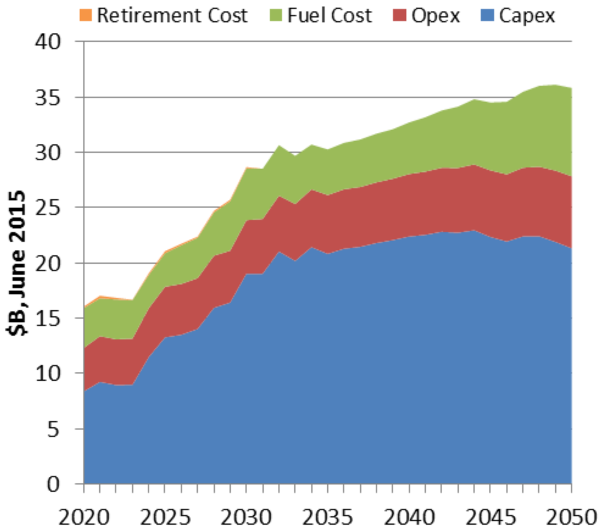
Source: Jacobs. Includes direct emissions only.

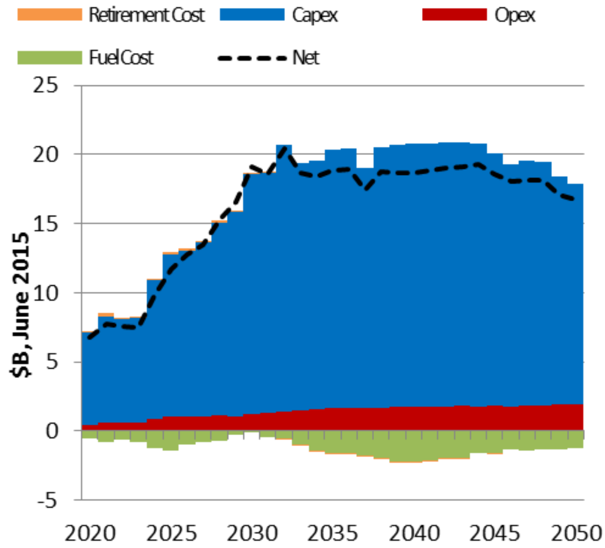
6.4.7 Costs

Figure 249 displays the annualised resource costs for the policy. The costs start from about $15 billion per annum in 2019/20 and escalate rapidly after 2022/2023 peaking at the end of the studied horizon to around $36 billion. The prevailing cost category for that case is the capex, since the closure of the coal generation and the adoption of the LET scheme encourages the investment to cost intensive renewable technologies. The fuel costs on the other hand are lower relative to the reference case since all the coal-fuelled fleet is shut off.

Figure 249: Annualised costs by category, regulated closures and low emissions target combination

The left graph shows the absolute costs. The right graph shows the costs relative to the reference case.

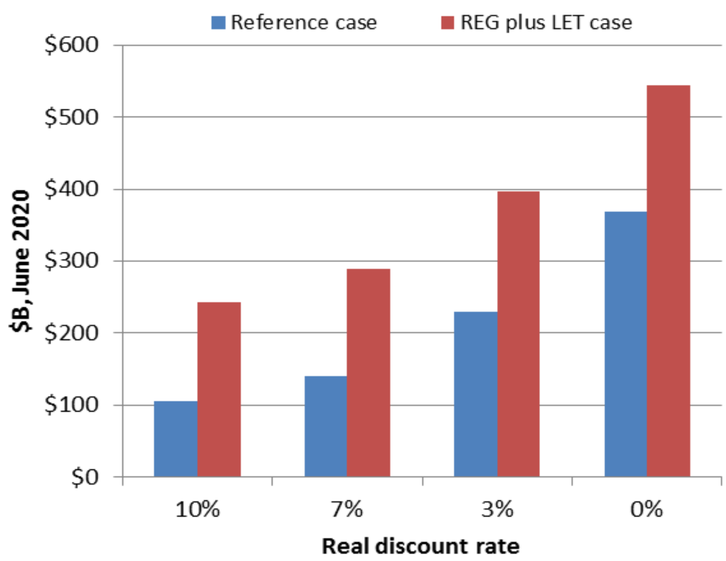




Source: Jacobs

The net present value of the resource costs presented in Figure 250 demonstrates that the combination of the regulated closures policy and the LET scheme require a total resource cost ranging from 129% (at 10% real discount rate) to 48% (without discounting) higher than the reference case so as to achieve the 2°C emissions constraint.

Figure 250: NPV of resource costs, regulated closures and low emissions target combination



Source: Jacobs. Excludes demand adjustment. See Appendix B.3.2 for further detail.

7. Results: alternative reference case

7.1 Alternative reference case

7.1.1 Scenario description

The alternative reference simulations explore a scenario with lower than expected demand for grid supplied electricity. The lower demand is driven by two factors: (1) lower rate of growth in usage of electricity; and (2) higher level of uptake of small-scale embedded generation systems. In this scenario there is a substantial shift to distributed generation with increased penetration of rooftop photovoltaics in the generation mix.

The higher uptake of embedded generation is driven by:

- Relaxed constraints on the saturation levels of uptake of small-scale systems in the commercial and residential sectors.
- Allowing owners of solar water heaters to install a small-scale system.
- Lower capital costs for systems particularly for battery storage. Assumptions on battery costs were based on a CSIRO study, that indicate higher initial capital costs than assumed in the 2°C scenarios, but with a much steeper decrease in costs over time making the battery prices lower than the 2°C degree reference case after 2025. The detailed assumed battery costs are given in Appendix C. All other global assumptions have remained the same. The policy scenarios in this set of simulations had the same emissions constraint as for 2°C scenarios.

7.1.2 Key findings

The lower demand and increased photovoltaics adoption defers the need for investment for new plant, resulting in flat wholesale prices of around $30/MWh out to around 2035 and reduced resource costs.

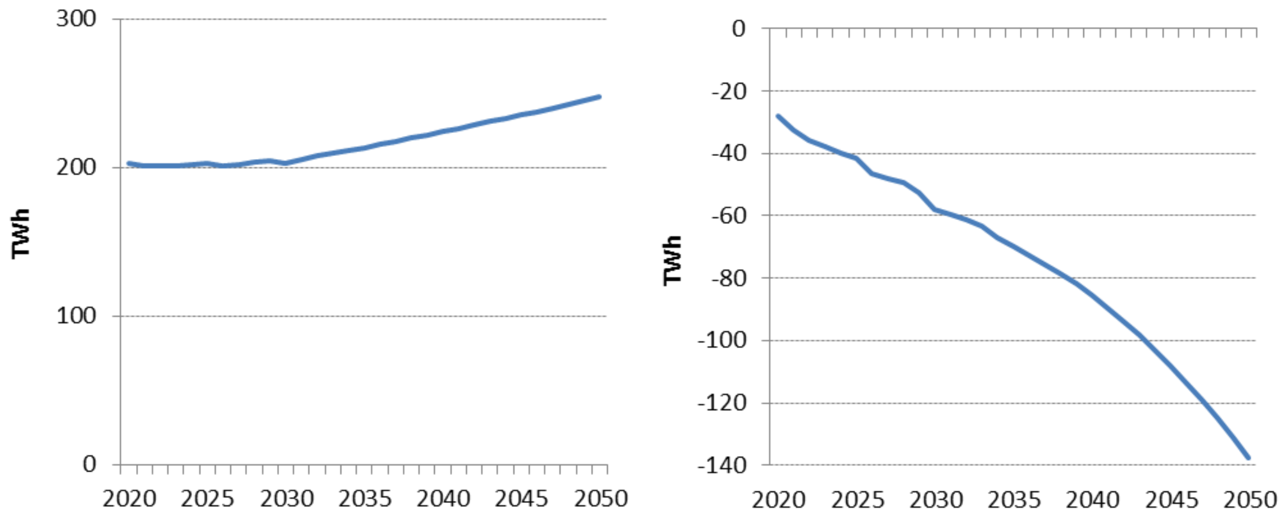
Emissions are lower than in the 2°C reference case in the first decade due to flat demand, high uptake of small-scale PV and the renewables built to meet the existing LRET.

7.1.3 Demand

The demand of NEM and WEM in the alternative reference case as shown in Figure 251 starts at 203 TWh in 2020, around 28 TWh lower than the reference case, and remains flat for the first decade, with a moderate rise over the next modelled years. It reaches 247 TWh in 2050 which is 138 TWh lower than the total energy consumed during the same year in the reference case.

Figure 251: Sent-out energy, alternative reference case

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Pitt & Sherry, ACIL Allen and Jacobs

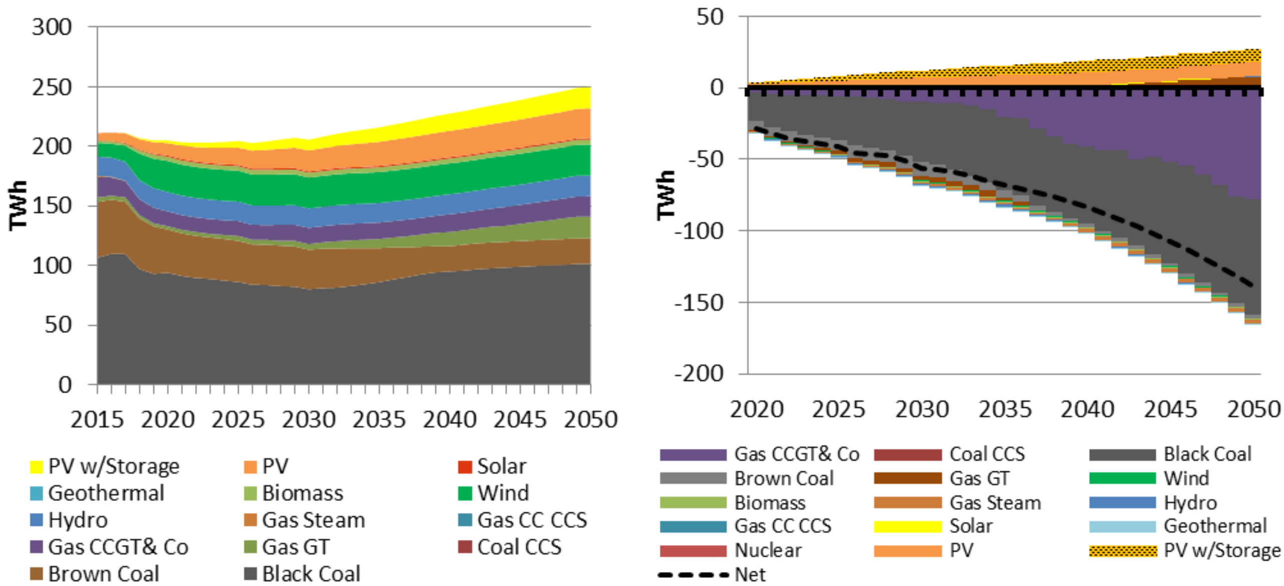
7.1.4 Generation and capacity

As shown in Figure 252 in the alternative reference case, coal retains its dominant role in the generation mix but the flat demand and the build of more photovoltaics during the first ten years forces some of the most inefficient coal plants to retire. When compared to the reference case, the growth of small scale solar generation is displacing the need for new gas fired plants throughout the modelled horizon.

Rooftop photovoltaics demonstrate a noticeable growth generating around 43 TWh at the end of the modelled horizon. On the other hand, large scale renewables increase their installed capacity (as shown in Figure 253) mainly to meet the LRET target by 2020, and remain flat after that. Some new gas turbines are also needed from the mid-2030s to back-up the increased intermittent generation capacity built.

Figure 252: Generation mix, alternative reference case

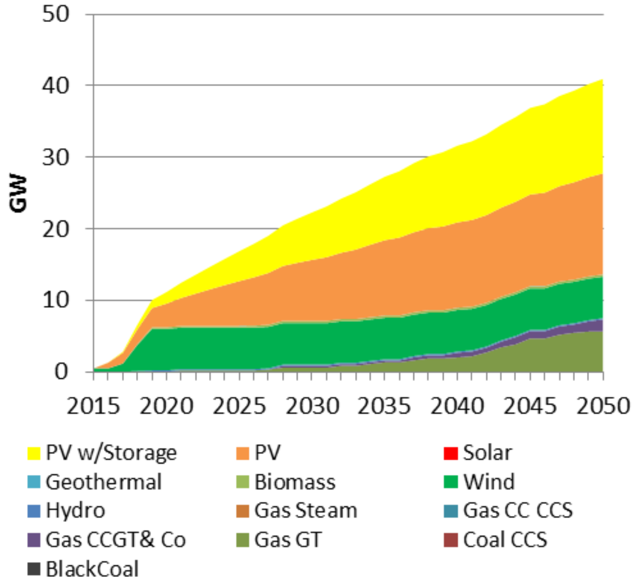
The left graph shows absolute figures. The right graph shows figures relative to the reference case.

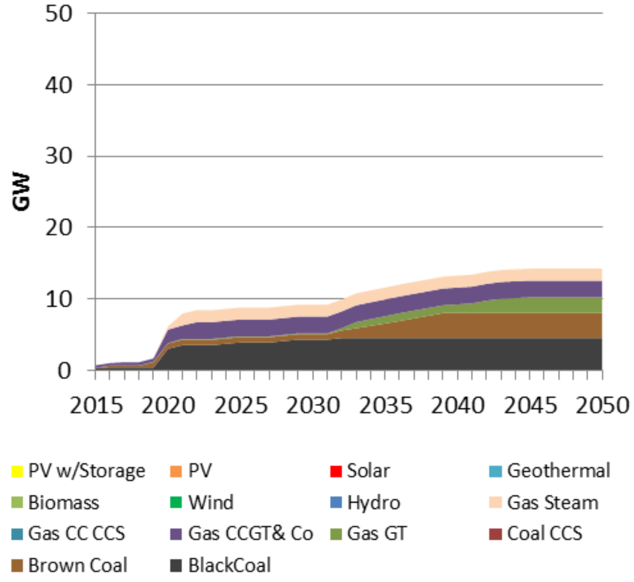


Source: Jacobs

Figure 253: Cumulative new and retired capacity, alternative reference case

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





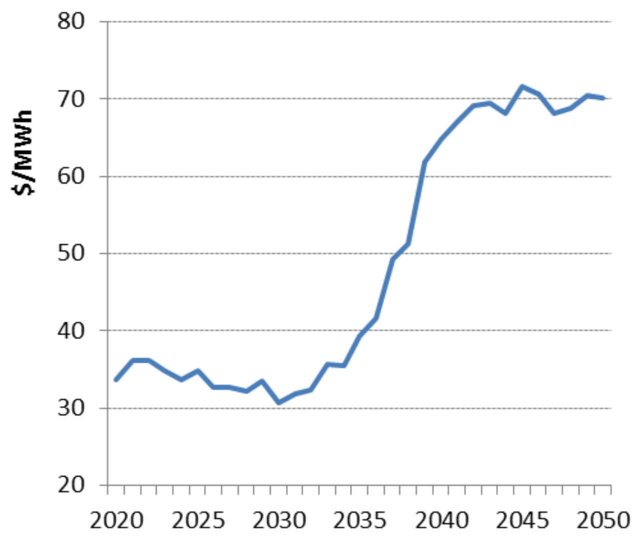
Source: Jacobs

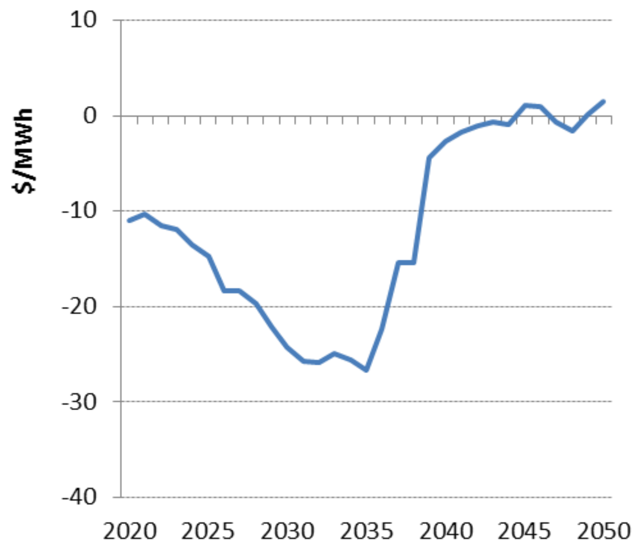
7.1.5 Prices

The wholesale prices for the alternative reference case and their difference to the reference case are illustrated in Figure 254. The prices remain flat for the first 15 years ranging from $30/MWh to $35/MWh, due to the lower demand and the increased adoption of small-scale photovoltaic systems. The retirement of some incumbent coal and gas units around 2035 accelerates the prices to new entry levels around 2040.

Figure 254: Wholesale electricity time-weighted prices, alternative reference case

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



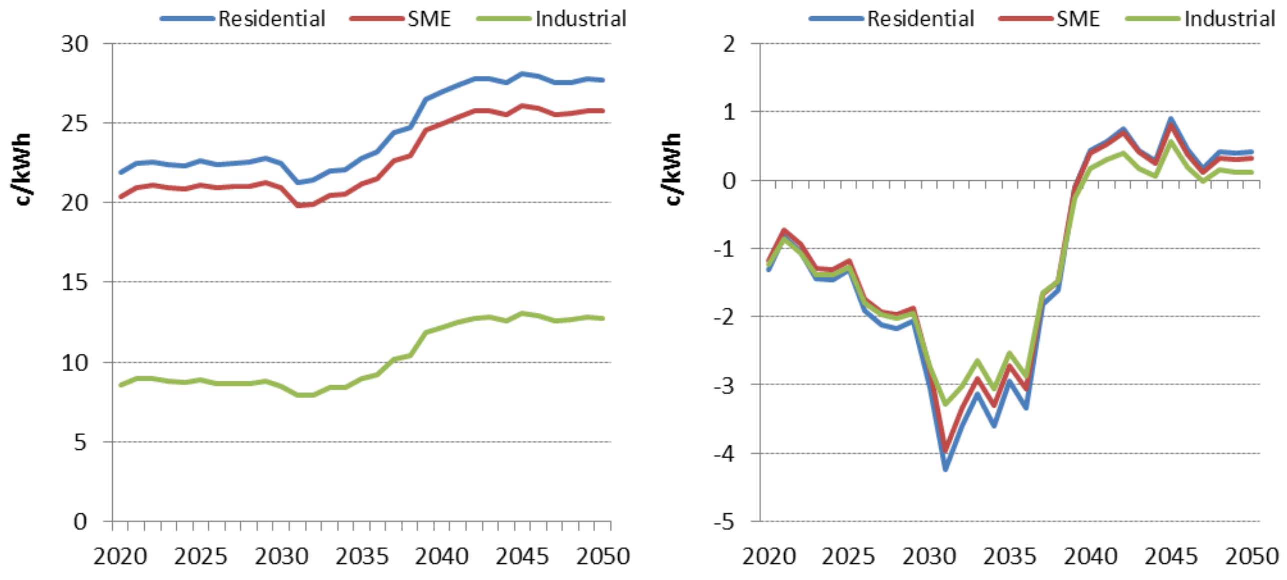


Source: Jacobs

Figure 255 shows that the retail prices for the three customer types are following the wholesale price trends. Both the residential bill and the percentage of disposable income in that scenario are lower than the reference case as shown in Figure 256, following the decreased retail prices.

Figure 255: Retail prices by customer class, alternative reference case

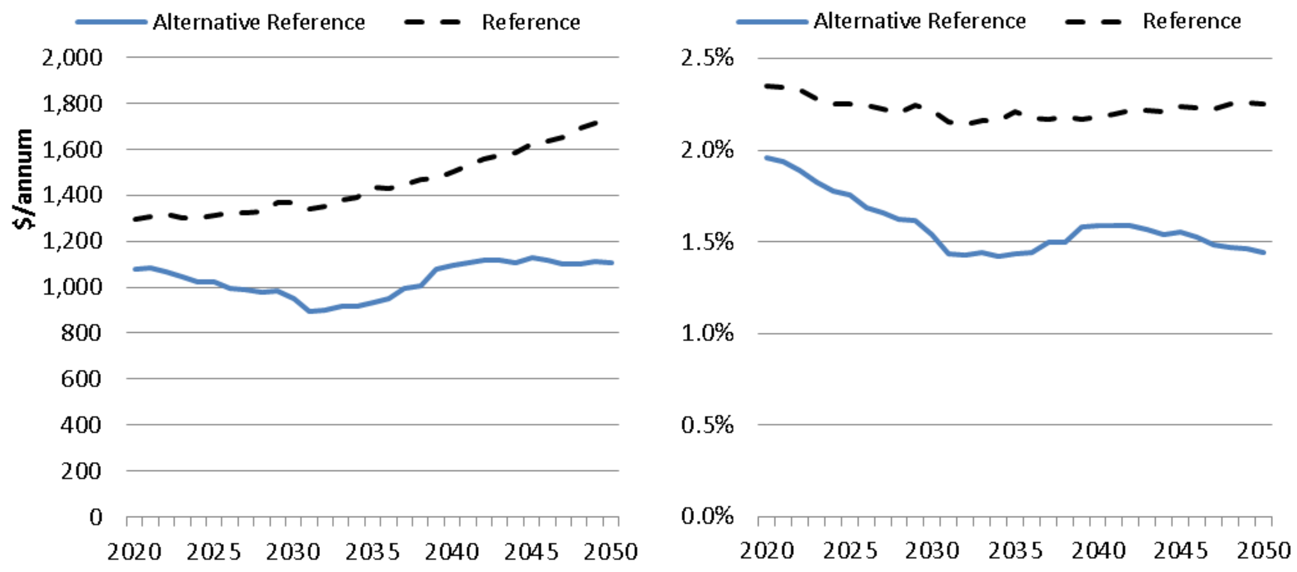
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs

Figure 256: Residential bills, alternative reference case

The left graph shows the absolute residential bill. The right graph shows the residential bill as a % of disposable income.



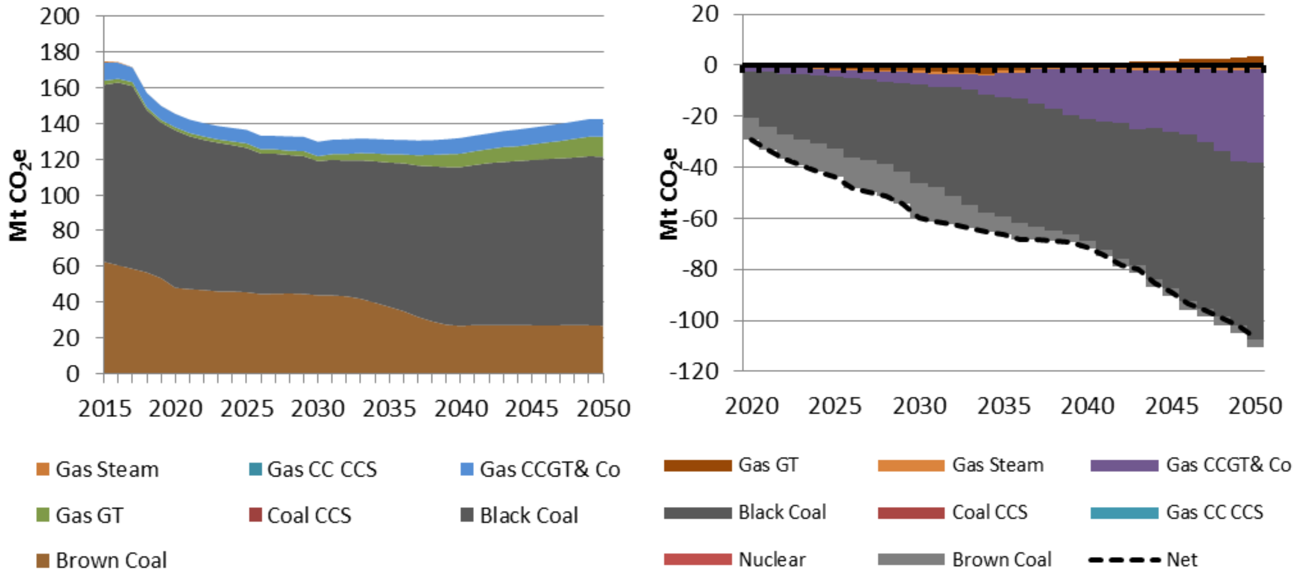
Source: Jacobs

7.1.6 Emissions

The annual direct and indirect emissions by technology for the alternative reference case and their relativity to the reference case are presented in Figure 257. After a relative steep reduction of the emissions over the first 5 years due to the new renewables built to meet the LRET target and the increase of small-scale PV, they show a milder decline reaching a plateau at around 135 Mt CO_2e in the early 2030s. The annual emissions are showing a slight increase during the last 10 years of the studied period mainly due to the new gas turbines coming into operation during this period. When compared to the reference case, the retirement of some coal plants initially and the limited need for new CCGTs after 2030 reduces emissions relative to the reference case.

Figure 257: Emissions by technology, alternative reference case

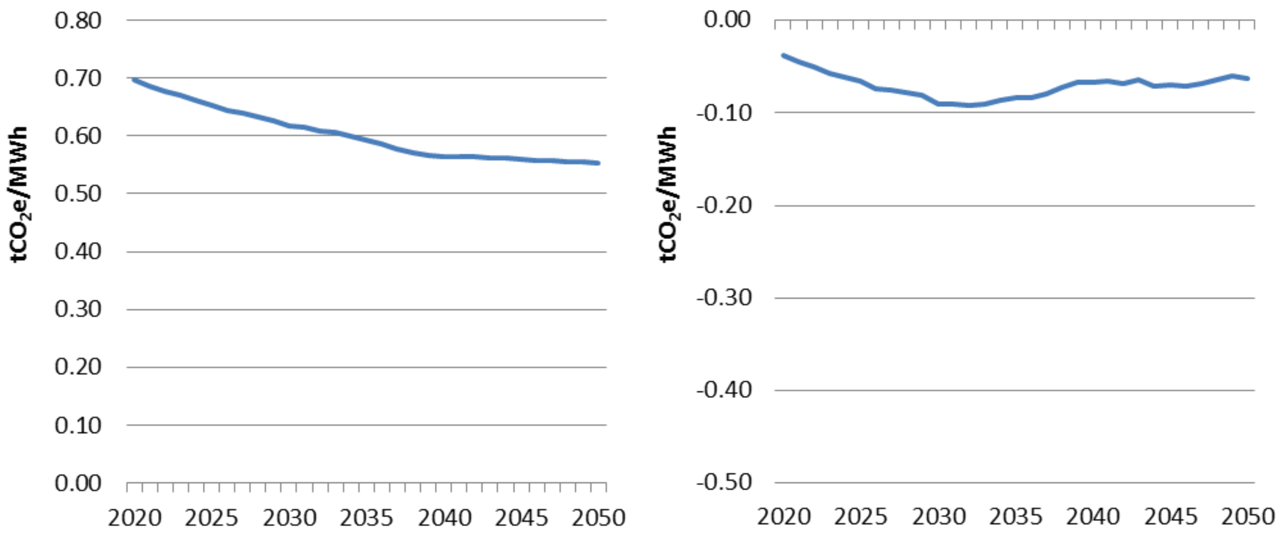
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs. Includes both direct and indirect emissions.

Figure 258: Generation emission intensity, alternative reference case

The left graph shows absolute figures. The right graph shows figures relative to the reference case.



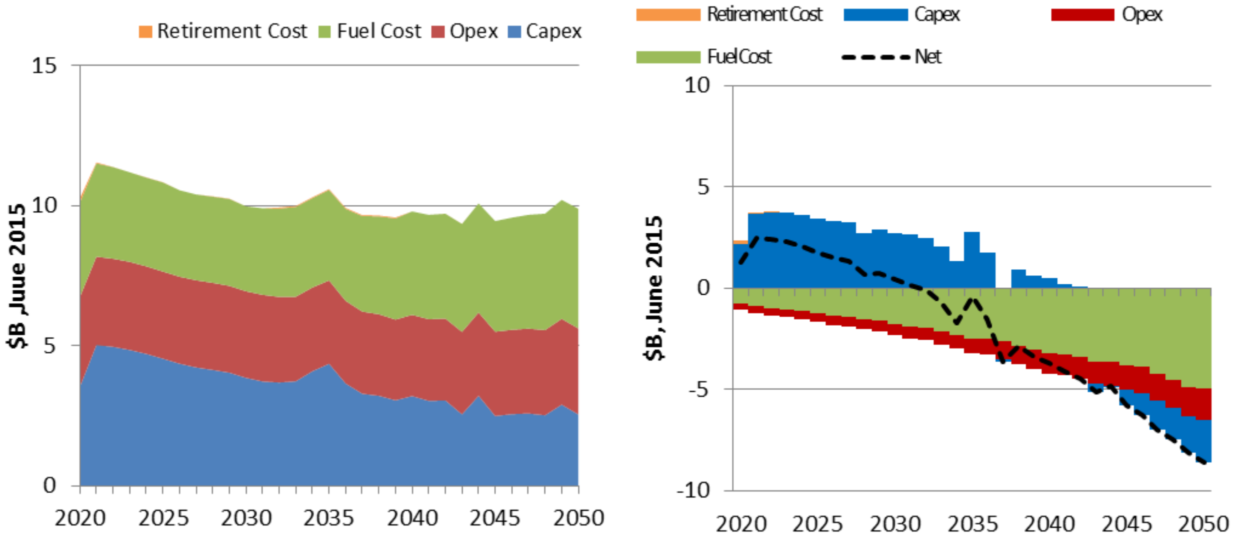
Source: Jacobs. Includes direct emissions only.

7.1.7 Costs

The annualised costs shown in Figure 259 reveal that the prevailing costs in this scenario are fuel costs followed closely by operation costs, while the reduced demand and the increased rooftop photovoltaic generation defer the need for new capital expenditure until after the mid-2030s. The annual costs start from around $6.5 billion in 2020 and remain relatively stable for the next 15 years, when there is a need for some additional investment.

Figure 259: Annualised costs by category, alternative reference case

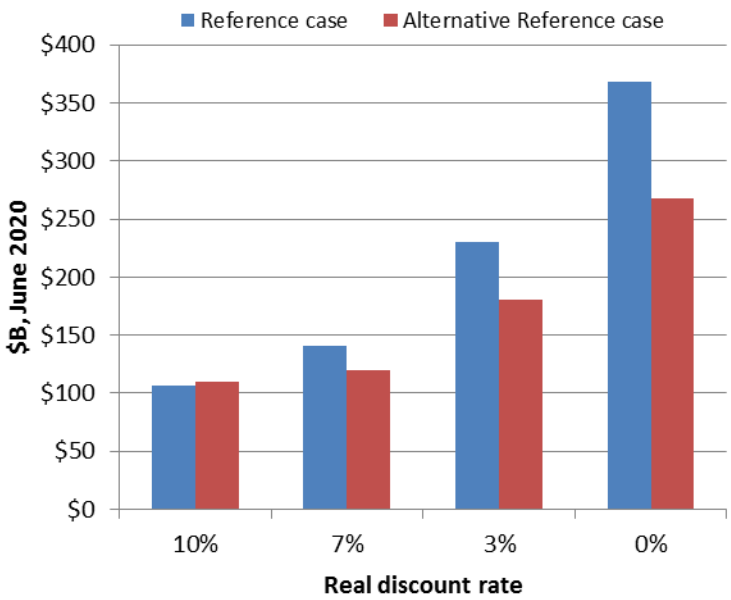
The left graph shows the absolute costs. The right graph shows the costs relative to the reference case.



Source: Jacobs

The net present value of the resource costs in that scenario is around 27% lower than that of the reference when undiscounted (see Figure 260) since the lower demand and higher penetration of small-scale photovoltaics defers some investment.

Figure 260: NPV of resource costs, alternative reference case



Source: Jacobs. Excludes demand adjustment. See Appendix B.3.2 for further detail.

7.2 Carbon pricing (alternative reference case)

7.2.1 Scenario description

This scenario applies the 2°C carbon price to the alternative reference case. The scenario assumes the same carbon price used in the 2°C scenario.

7.2.2 Key findings

Total emissions over the modelling period are around 1,065 Mt CO_2e less than a quarter of emissions in the alternative reference case (which are around 4,250 Mt CO_2e). This compares to 1,580 Mt CO_2e in the 2°C carbon pricing policy scenario.

Wholesale prices are very similar to those projected in the regular carbon pricing run, driven by the cost required to incentivise the entry of new low emission plant.

Changing the input assumptions for small-scale solar results in small-scale generation making up around 20% of generation by 2050 (up from 10% in the 2°C policy simulation). This indicates that even with a substantial shift to distributed generation, large-scale generation will continue to play a major role in electricity supply.

Large-scale solar with storage becomes more economic than large-scale solar without storage from around 2040.

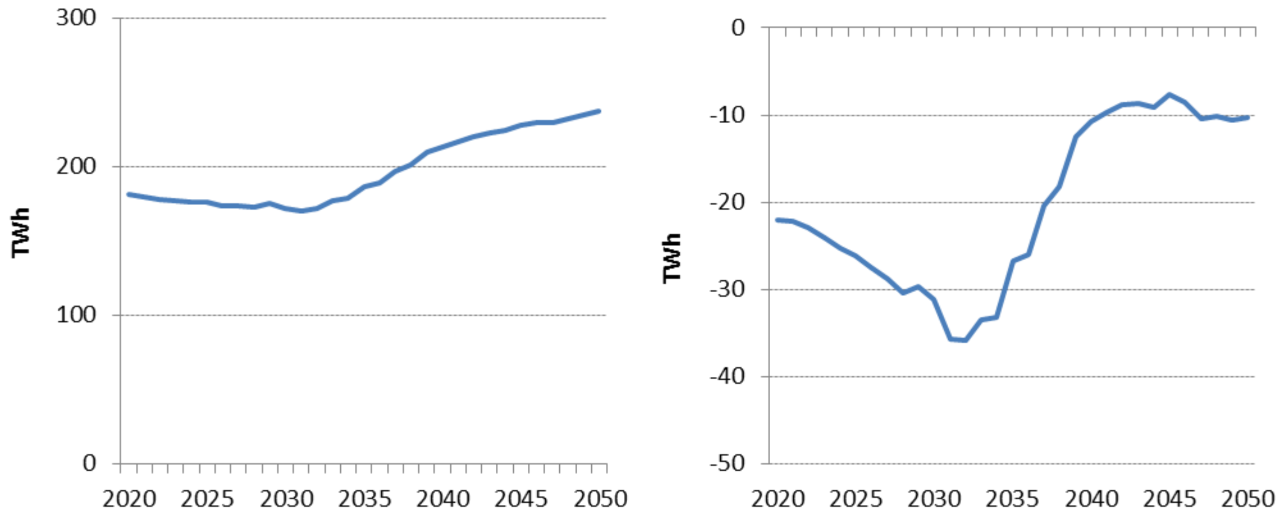
Resource costs are also lower, around $210 billion compared with $290 billion in the 2°C policy scenario (using a 7% discount rate). Resource costs are around 140% higher than for the alternative reference case.

7.2.3 Demand

In Figure 261 the electricity demand of the policy scenario compared with the alternative reference case are presented. The total energy consumed shows a slight decrease for the first 15 years starting from 181 TWh, which is 22 TWh lower than the alternative reference case due to the imposed carbon price. Demand starts to steadily rise from the mid-2030s reaching 237 TWh at the end of the studied period.

Figure 261: Sent-out energy, carbon pricing with alternative reference case assumptions

The left graph shows absolute figures. The right graph shows figures relative to the alternative reference case.



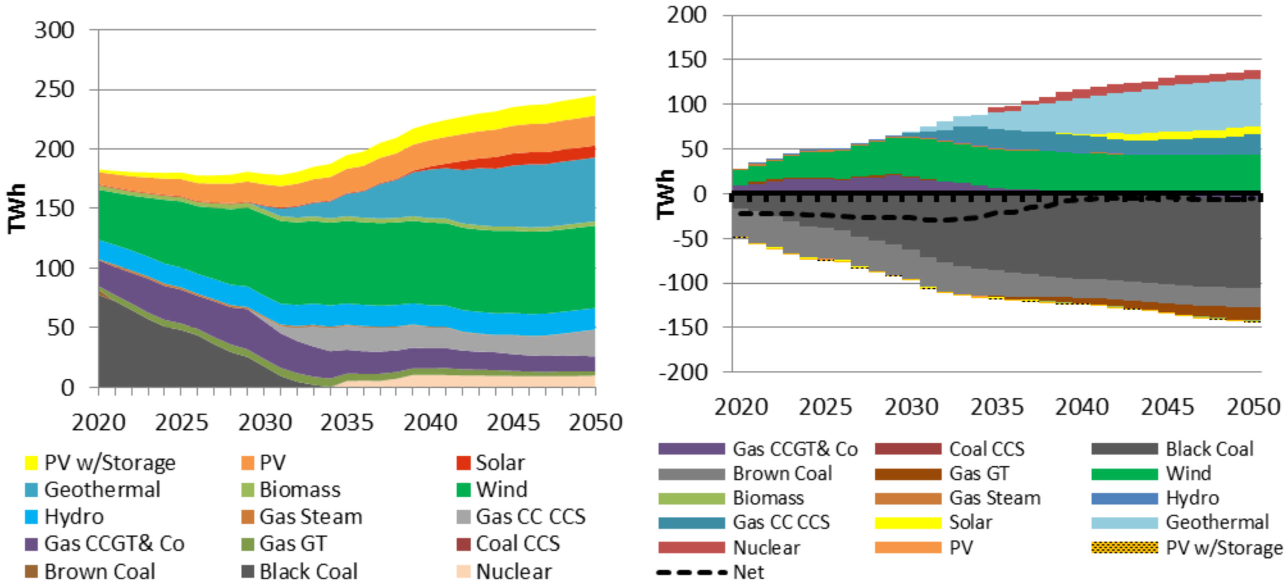
Source: Pitt & Sherry, ACIL Allen and Jacobs

7.2.4 Generation and capacity

Figure 262 illustrates the generation mix of the NEM and WEM in absolute terms and relative to the alternative reference case. The high carbon prices and the flat demand over the first 15 years forces the retirement of the coal fired fleet during that period. Rooftop photovoltaics are the key transitional technology that substitutes the retired coal capacity, with wind generation contributing to a lesser degree. The incumbent CCGTs remain in the generation mix and help to back-up the renewable generation built and some new CCGTs coupled with CCS are also built in the early 2030s as shown in Figure 263. After 2030, the geothermal pants are becoming the marginal cost generators built to meet the increased demand. Finally, some nuclear plants and large-scale solar also contribute to the generation mix with almost 10 TWh generated by each technology at the end of the modelled horizon.

Figure 262: Generation mix, carbon pricing with alternative reference case assumptions

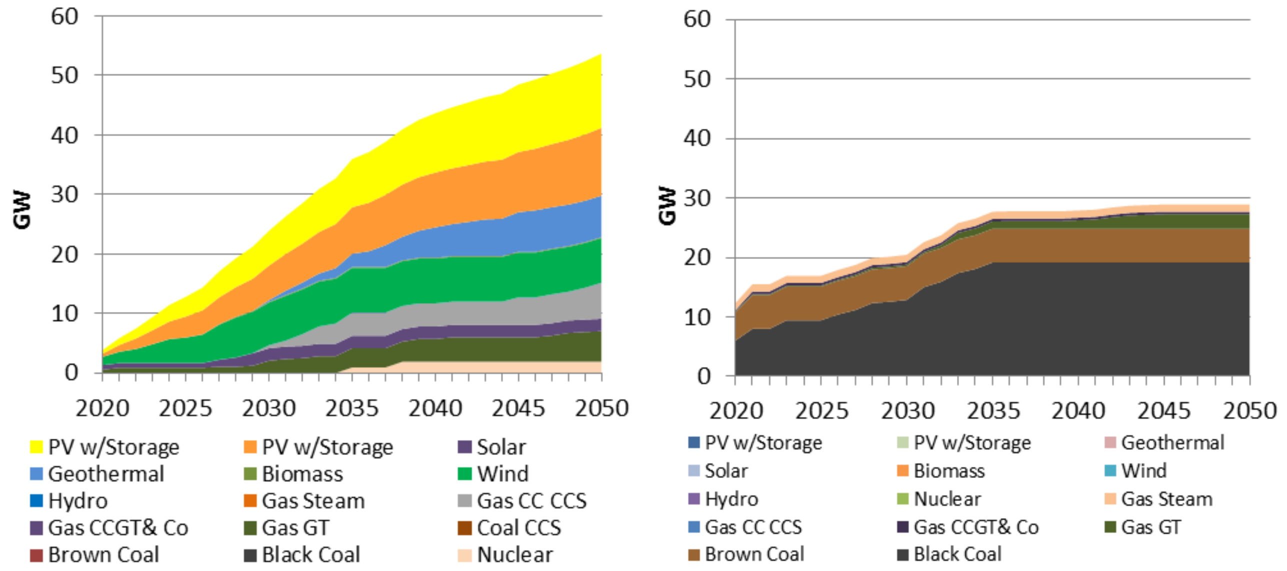
The left graph shows absolute figures. The right graph shows figures relative to the alternative reference case.



Source: Jacobs

Figure 263: Cumulative new and retired capacity, carbon pricing with alternative reference case assumptions

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



Source: Jacobs

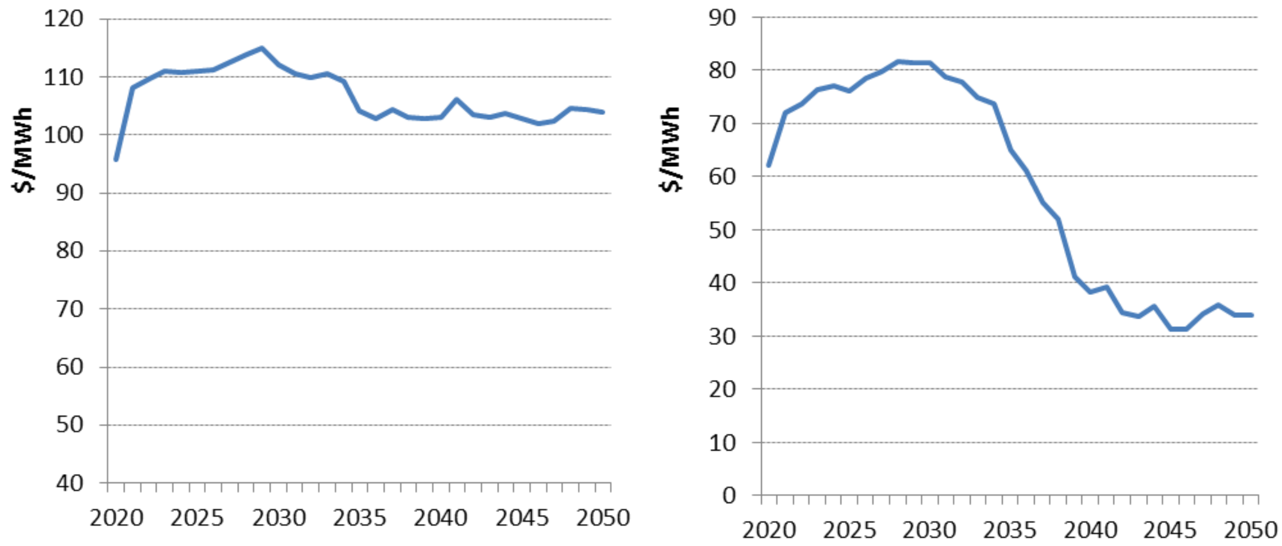
7.2.5 Prices

Figure 264 shows wholesale electricity time-weighted prices. The prices start from $96/MW in 2020, which is around $63/MWh higher than the alternative reference case due to the imposed carbon price. They trend upward steeply until early 2030s when they converge to a price representing the LRMC of CCGTs with CCS.

After 2030, prices remain relatively stable as they are insensitive to the carbon price due to the low emission factors of the technologies setting the price. Also the reduction in capital costs for these technologies offsets the effect of the increasing carbon price. A slight drop in the price in the mid-2030s reflects the entry of nuclear technology.

Figure 264: Wholesale electricity time-weighted prices, carbon pricing with alternative reference case assumptions

The left graph shows absolute figures. The right graph shows figures relative to the alternative reference case.

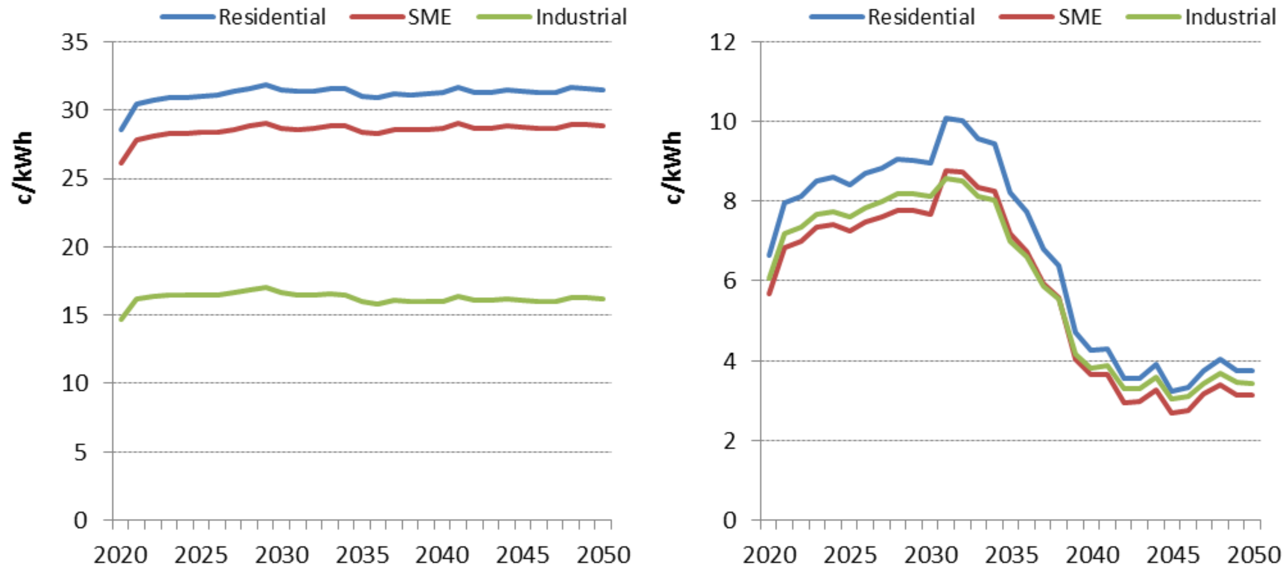


Source: Jacobs

The weighted average retail prices by customer category and their difference from the alternative reference case are illustrated in Figure 265. Prices start from around 6 to 6.5 cents per kWh higher than the alternative reference case (depending on the customer class) and then follow the wholesale price trends. The same stands for the residential bill presented in Figure 266.

Figure 265: Retail prices by customer class, carbon pricing with alternative reference case assumptions

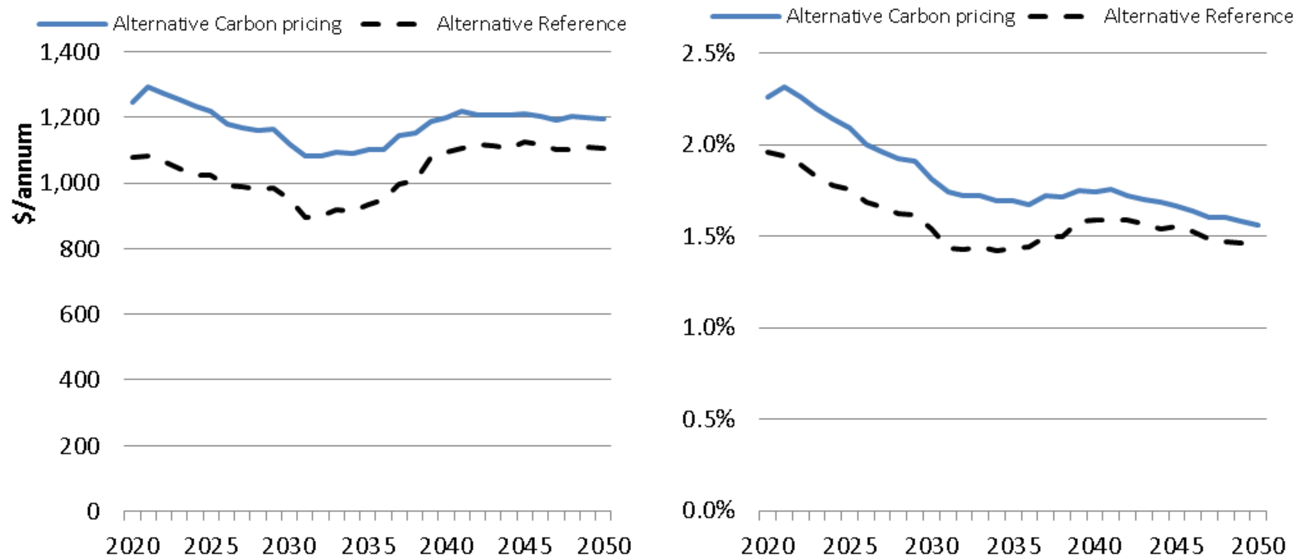
The left graph shows absolute figures. The right graph shows figures relative to the alternative reference case.



Source: Jacobs

Figure 266: Residential bills, carbon pricing with alternative reference case assumptions

The left graph shows the absolute residential bill. The right graph shows the residential bill as a % of disposable income.



Source: Jacobs

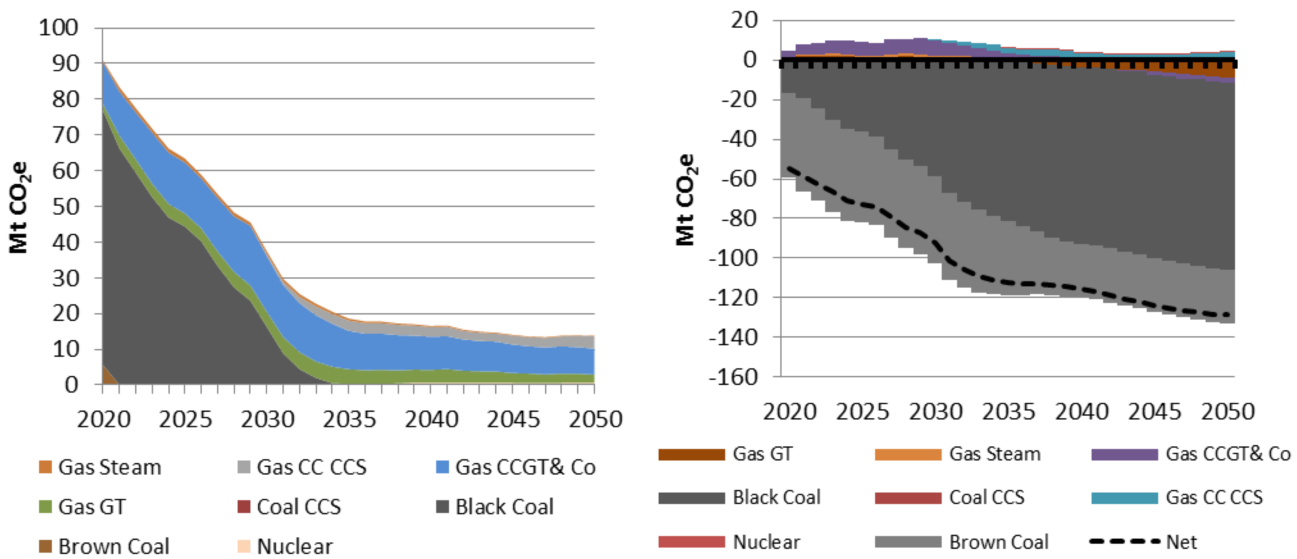
7.2.6 Emissions

The sum of direct and indirect emissions is shown in Figure 267 while the generation intensity including only the direct emissions is illustrated in Figure. The emissions show a steep decline from 97 Mt CO_2e in 2020 to 19 Mt CO_2e in the mid-2030s due to retirement of the coal fired generation and the adoption of renewable generation technologies. After 2035 the emissions continue to marginally decrease since some CCGT generation is displaced by other low emission technology and renewable generation.

Cumulative emissions, over the studied period, are 1,065 Mt CO_2e, which is 516 Mt CO_2e lower (roughly a third) than the emissions constraint achieved under the base (2°C) policy scenarios.

Figure 267: Emissions by technology, carbon pricing with alternative reference case assumptions

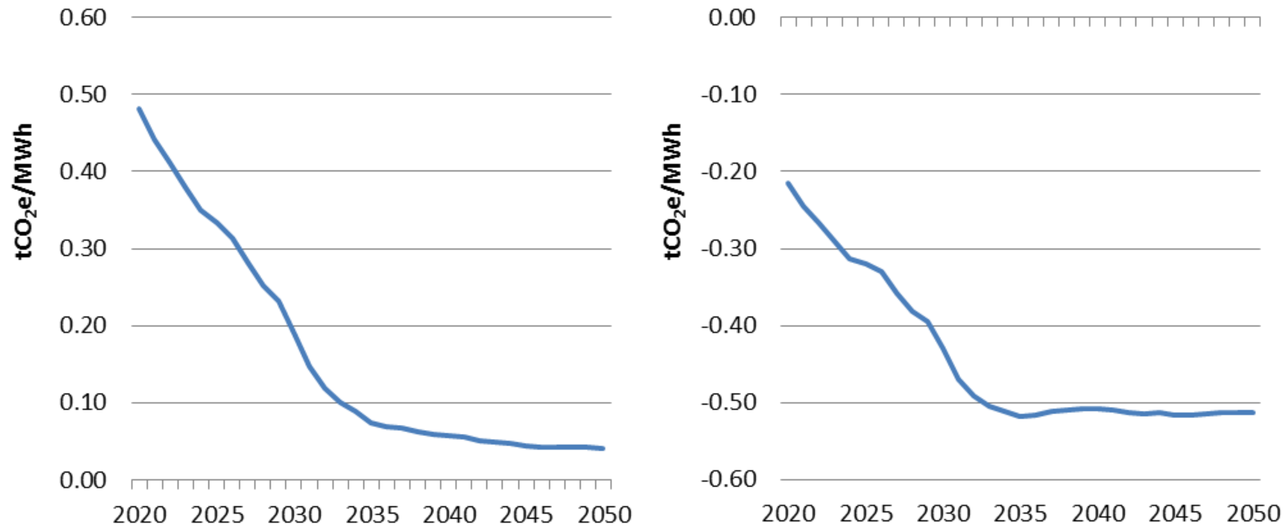
The left graph shows absolute figures. The right graph shows figures relative to the alternative reference case.



Source: Jacobs. Includes both direct and indirect emissions.

Figure 268: Generation emission intensity, carbon pricing with alternative reference case assumptions

The left graph shows absolute figures. The right graph shows figures relative to the alternative reference case.



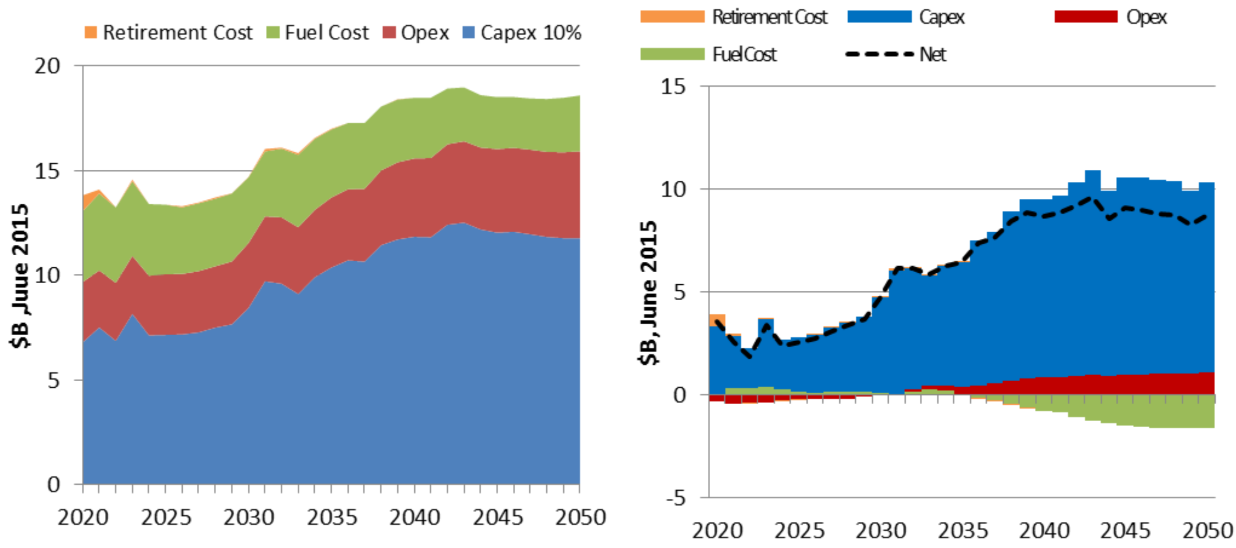
Source: Jacobs. Includes direct emissions only.

7.2.7 Costs

The annualised resource costs in this scenario shown in Figure 269 start from around $13.5 billion and remain relatively stable for the first decade, since the lower demand and the increased generation from small-scale photovoltaics defer the need for any other new investment. After 2030 and for the next 10 years, some additional capital expenditure is needed to replace the retired coal capacity and the growing demand and thus increasing the overall costs. During the last decade of the modelled horizon the resource costs remain relatively stable at around $18 billion per annum since the growing demand is met predominantly by solar and wind farm refurbishments built in the early 2020s. These refurbishments are assumed to cost 40% less than the capital investment needed for a new plant.

Figure 269: Annualised costs by category, carbon pricing with alternative reference case assumptions

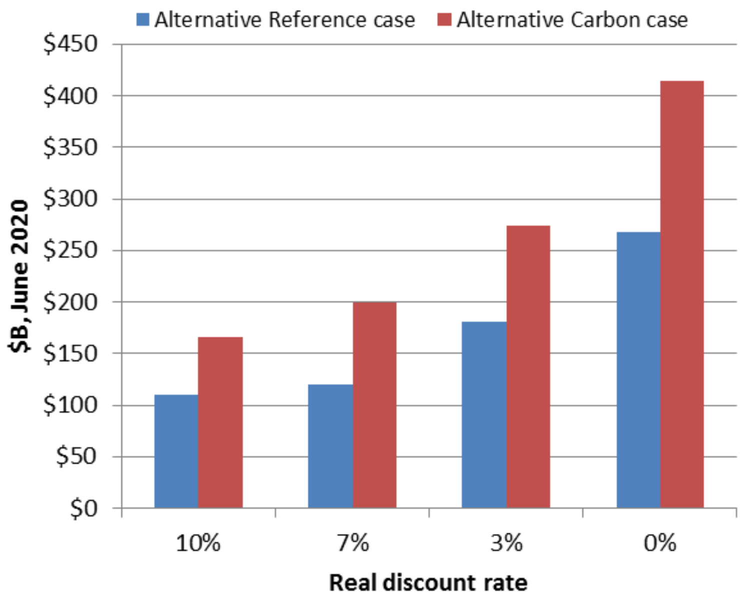
The left graph shows the absolute costs. The right graph shows the costs relative to the alternative reference case.



Source: Jacobs

Figure 270 shows the net present value of the resource costs for the carbon pricing scenario relative to the alternative reference case for four separate discount rates. The resource costs range from 51% (at 10% real discount rate) to 54% (without discounting) higher than that of the reference case.

Figure 270: NPV of resource costs, carbon pricing with alternative reference case assumptions



Source: Jacobs. Excludes demand adjustment. See Appendix B.3.2 for further detail.

8. Results: high demand sensitivity

The high demand sensitivity explored the case where growth in demand for electricity is higher than expected. Only carbon pricing and the LET policy scenarios were tested in this sensitivity. The same policy settings were applied as in 2^{o}C policy scenarios. That is, the same carbon price path was adopted in the carbon pricing scenario and the same target trajectory under the LET was applied.

Under the high demand sensitivity, demand growth is approximately double the rate than in the reference case – 2.7% per annum compared with 1.4% per annum. As a result there is also a higher level of emissions under this scenario.

8.1 Comparison of demand sensitivities

8.1.1 Key differences between policy scenarios

The key difference under the high demand sensitivity occurs in the projected emissions. Specifically:

- A fixed LET with high demand leads to much higher emissions than in the base 2°C scenario. Once the LET target is met, all new demand is met by the least-cost generator – fossil fuels in this scenario.

- A fixed carbon price with high demand leads to only slightly higher emissions than in the base case, because the carbon price is sufficient to drive rapid retirement of fossil fuel generators and ensure additional demand is met by low emission technologies.

Under the carbon pricing scenario, cumulative emissions reach 1,760 Mt CO_2-e over the period from 2020 to 2050. Under LET policy scenario, cumulative emissions are projected to be 3,210 Mt CO_2-e or nearly double the level under carbon pricing.

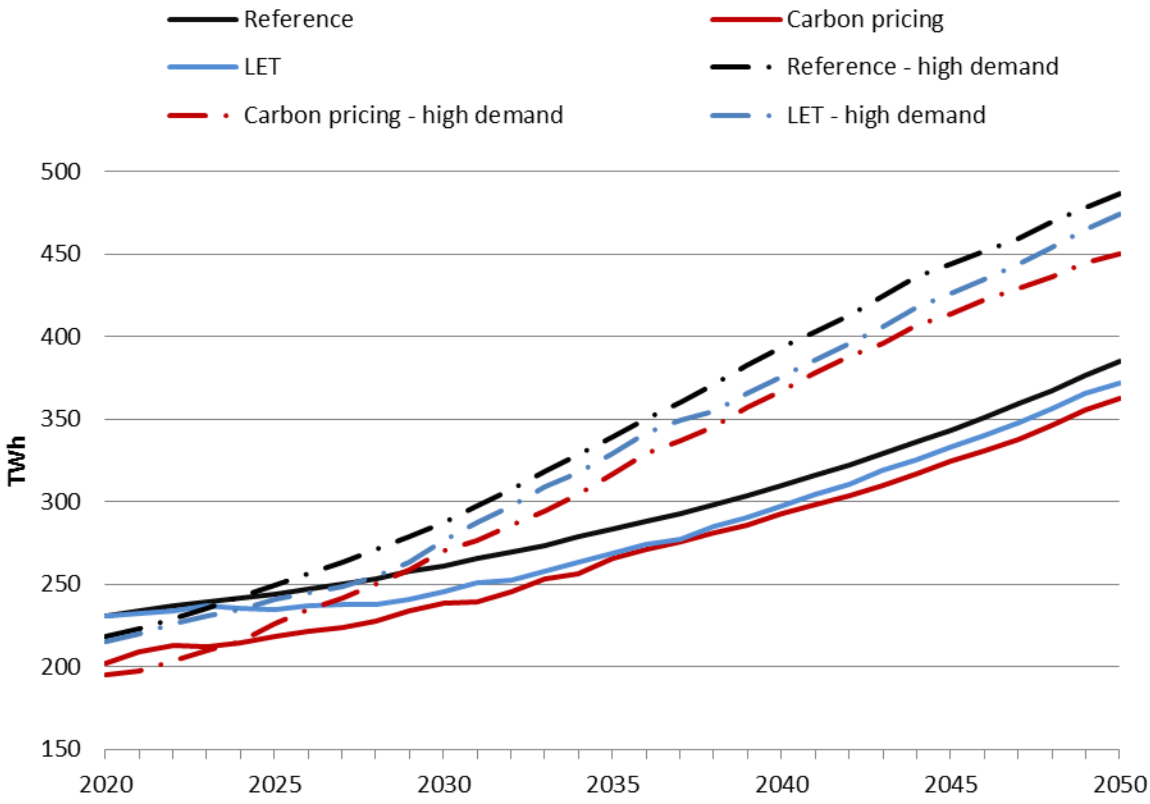
The impact of policy measures on wholesale prices is relatively similar across the base and high demand scenarios. Higher demand would tend to put upward pressure on prices but the wholesale price is still ultimately limited by the long run marginal costs of new entry, which are assumed to be the same across both sets of policy scenarios.

8.1.2 Demand

Demand is significantly higher in these set of simulations with growth in demand being around 2.7% per annum, compared with 1.4% per annum for all other simulations (except for the alternative reference case simulations).

However, as for the core 2°C scenarios, the ranking of demand impact from the policy scenario remains the same with the lowest demand occurring with the carbon pricing case and demand for the LET scenario remaining just under the reference case.

Figure 271: Electricity demand, high demand sensitivity, reference and select policy scenarios



Source: Jacobs

8.1.3 Generation and capacity

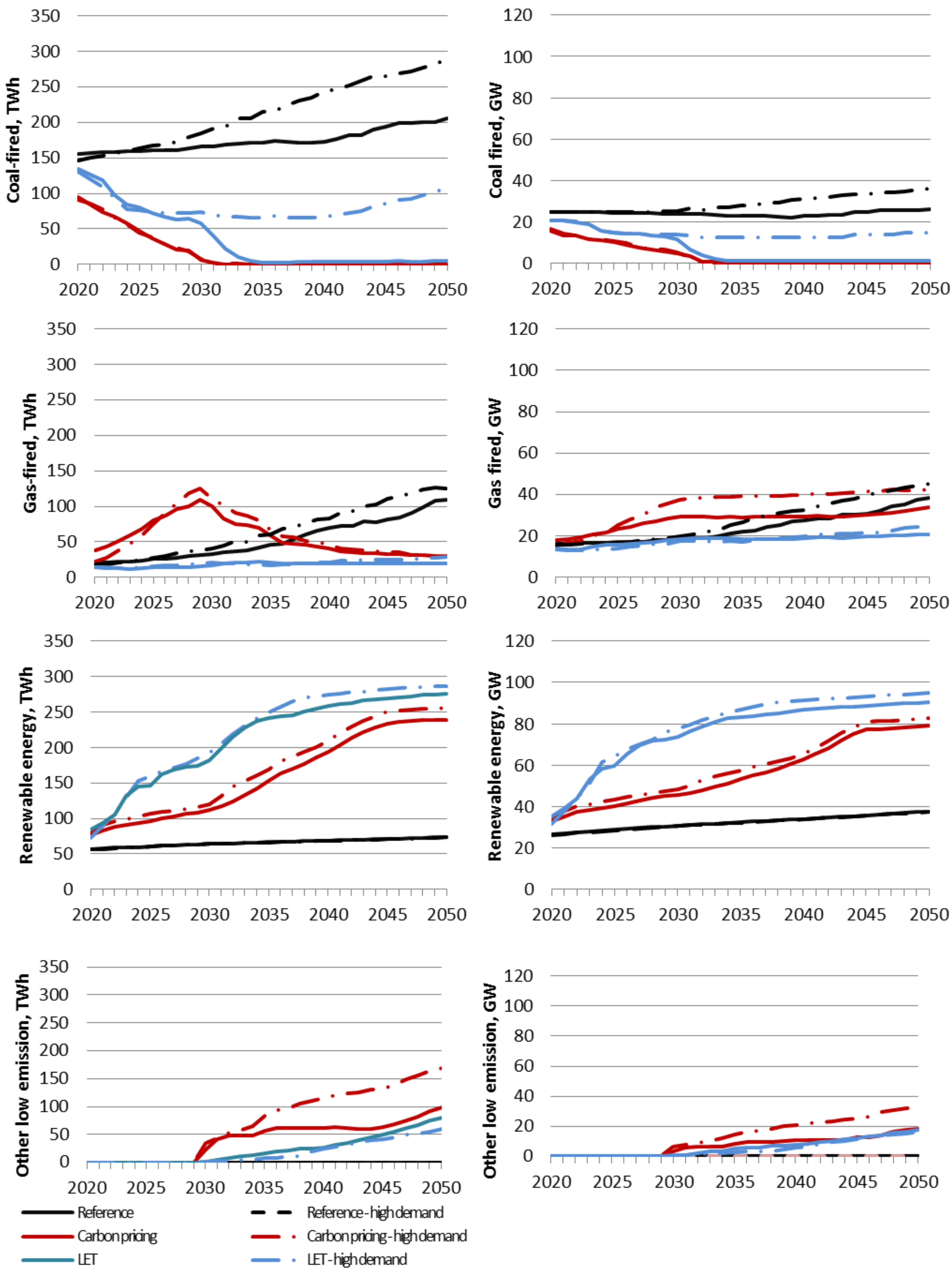
Generation and capacity mix are shown in Figure 272. Generation and capacity by technology type is shown for both the high demand and base demand scenarios.

Coal fired generation is significantly greater with higher demand growth in the reference case. Under the LET policy scenario, coal fired generation maintains a significant share through the 2020s and grows again from 2035 onwards. Because the LET target is the same across the demand simulations, once the target is met any further demand growth is met by the lowest cost options, which is typically coal fired generation. There are fewer retirements of coal plant and more new coal plant entering in the high demand LET scenario.

Coal fired generation under the carbon pricing scenario is almost the same under both demand growth rates. The carbon price increases coal fired generation dispatch costs and a higher demand growth does not improve the profitability of coal plant.

Gas fired and renewable energy generation under the carbon pricing scenario is slightly higher with high demand growth. However, generation from CCS and nuclear technologies significantly increases with higher demand.

Figure 272: Generation and capacity by technology, high demand sensitivity, reference and select policy scenarios



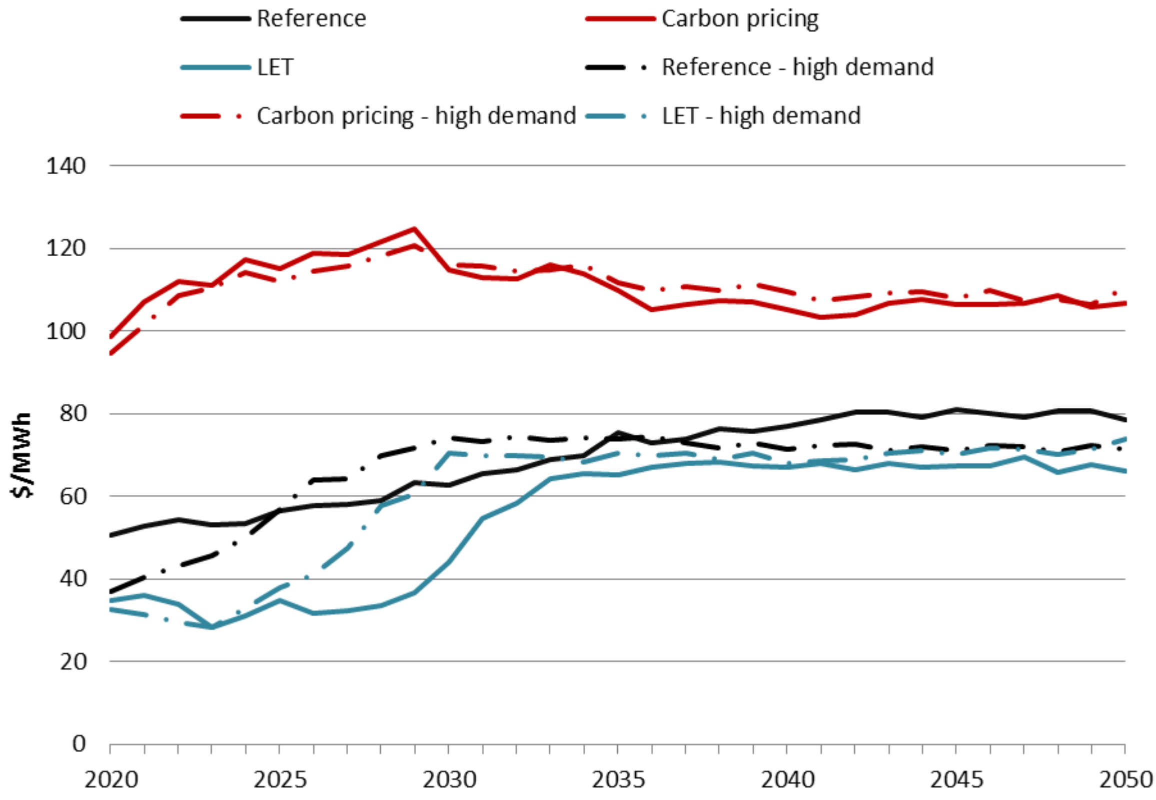
Source: Jacobs

8.1.4 Prices

The impact of policy measures on wholesale prices is relatively similar across the base and high demand scenarios. Wholesale prices under carbon pricing remain the highest: the price level is slightly lower in the 2020s and slightly higher over the long term with higher demand. Prices are limited by the long run marginal costs of new low emission plant, which are assumed to be the same across the scenarios. The higher demand will require some more low emission generation and this will likely be more expensive but only slightly so.

Wholesale prices under the LET start out and end at the same levels as the core 2°C scenarios. However, in the period from 2025 to 2035, prices are significantly higher with higher demand growth because thermal plants are setting the price more frequently and the period of wholesale price suppression is shorter.

Figure 273: Sensitivity of wholesale prices to higher demand growth rate



Source: Jacobs

Retail price impacts are mixed (see Table 13):

- Retail prices are higher in the reference case with higher demand growth due to higher wholesale prices.
- Under carbon pricing, as wholesale prices are broadly the same under the base and high demand growth rates, there is less of a price increase with higher demand growth rates.
- Under the LET retail price impacts are relatively greater as the period of wholesale price suppression is shorter.

Table 13: Retail price impacts under differing demand growth assumptions

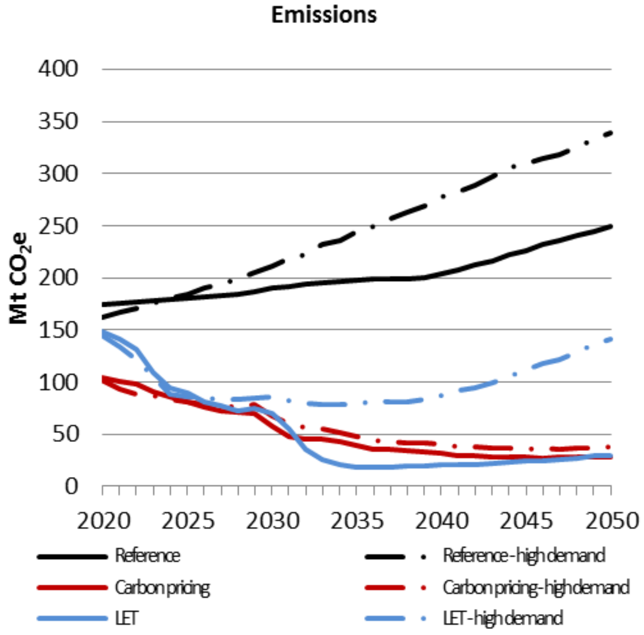
Customer type/scenario	c/kWh				% change from reference			
	2020-2030	2031-2040	2041-2050	2020-2050	2020-2030	2031-2040	2041-2050	2020-2050
Residential								
Reference	24	26	28	26				
Carbon pricing	31	32	31	31	29%	21%	13%	21%
LET	26	30	31	29	9%	16%	11%	12%
Reference – high demand	25	27	27	27				
Carbon pricing – high demand	31	32	32	32	23%	17%	16%	18%
LET – high demand	27	30	31	29	7%	11%	12%	10%
SME								
Reference	23	24	26	24				
Carbon pricing	29	29	29	29	27%	19%	12%	19%
LET	25	29	29	28	10%	18%	15%	14%
Reference – high demand	23	25	25	25				
Carbon pricing – high demand	28	29	29	29	21%	15%	15%	17%
LET – high demand	26	29	29	28	9%	14%	16%	13%
Industrial								
Reference	10	12	13	12				
Carbon pricing	17	17	16	16	61%	41%	28%	43%
LET	13	15	15	14	22%	29%	18%	23%
Reference – high demand	11	13	13	12				
Carbon pricing – high demand	16	17	17	17	48%	31%	30%	36%
LET – high demand	13	14	15	14	18%	12%	15%	15%

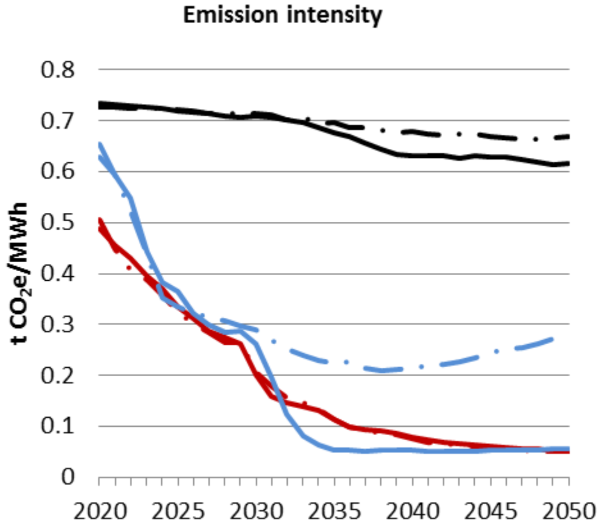
Source: Jacobs

8.1.5 Emissions

Higher demand growth leads to significant differences in emissions under the policy scenarios. Emissions under carbon pricing are slightly higher, but emissions under the LET are much higher especially after 2035.

Figure 274: Emissions under differing demand growth rates, reference and select policy scenarios



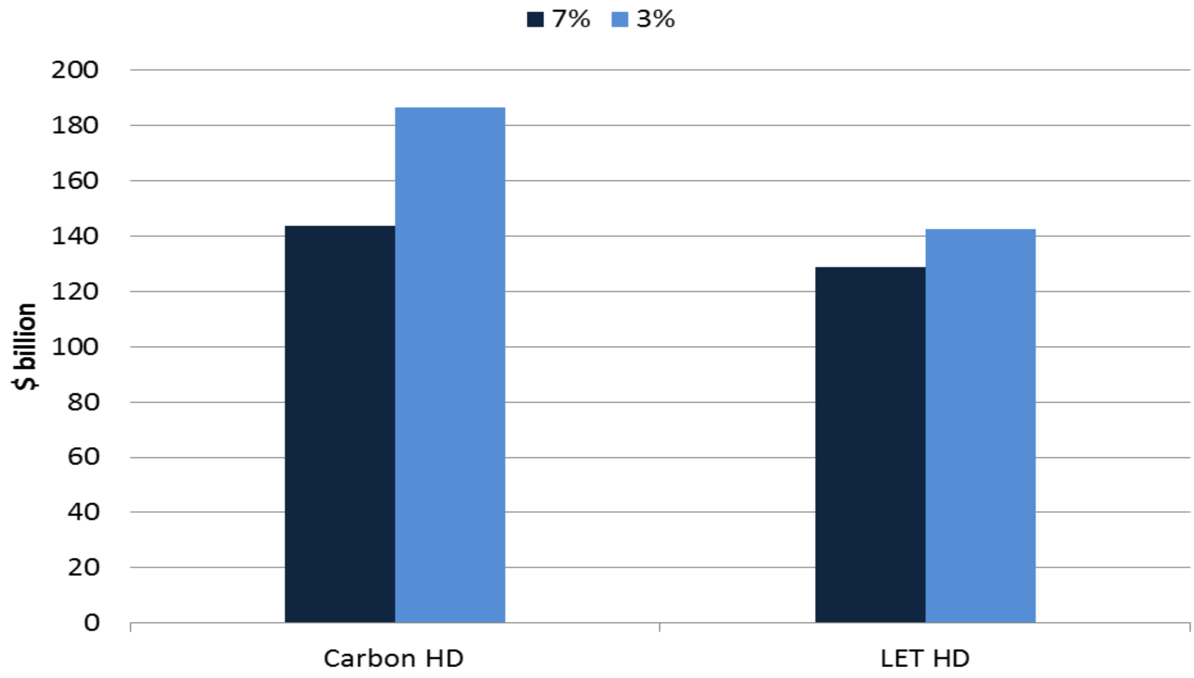


Source: Jacobs. Includes both direct and indirect emissions.

8.1.6 Resource costs and cost of abatement

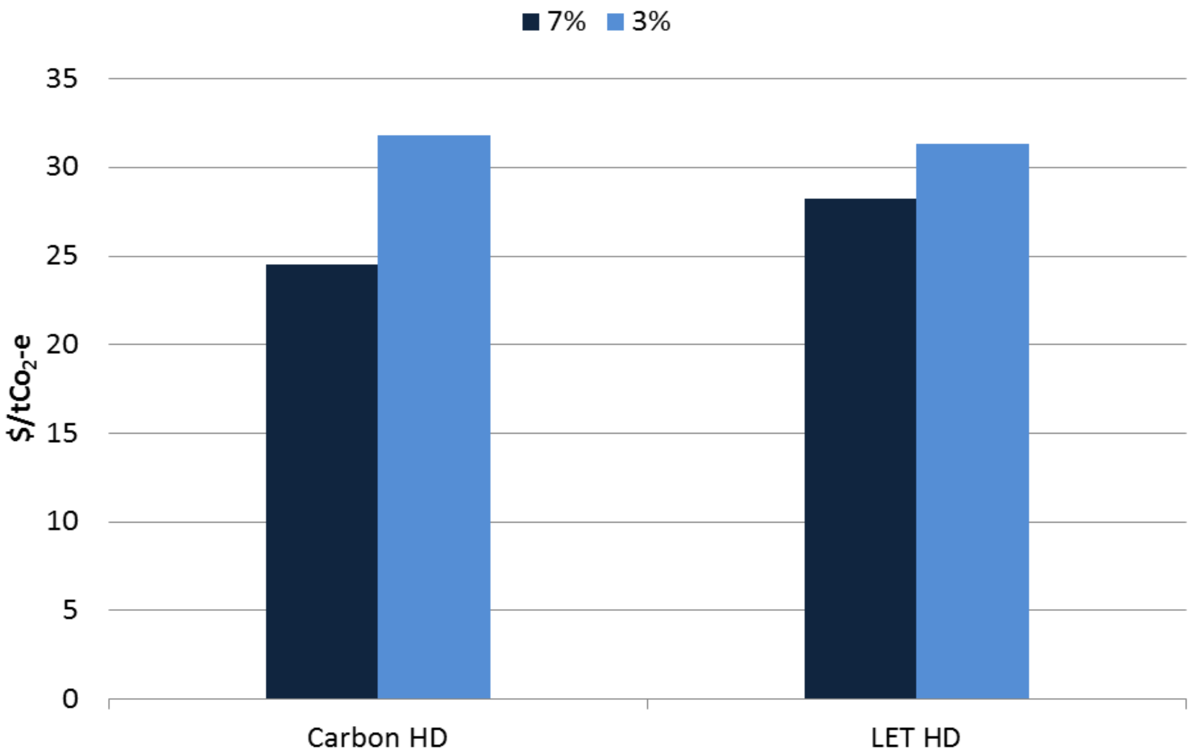
The resource costs are higher for the policy scenarios in the high demand case. The demand adjusted costs are higher for the carbon pricing scenario than LET scenario in the high demand case since the carbon scheme drives additional investment.

Figure 275: NPV of demand adjusted resource costs relative to the reference case, high demand sensitivity



Source: Jacobs

Figure 276: Cost of abatement relative to the reference case, high demand sensitivity



Source: Jacobs

8.2 Reference case (high demand)

8.2.1 Scenario description

In this scenario a higher electricity demand is assumed while all the other inputs have remained the same as in the core 2°C scenarios.

8.2.2 Key findings

The key findings are:

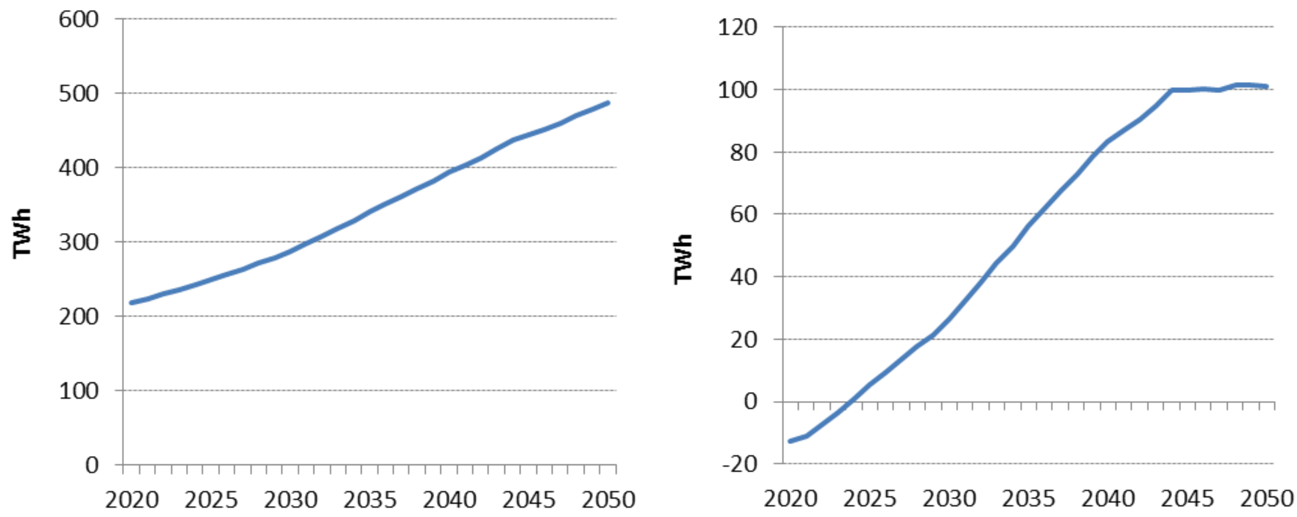
- The higher demand scenario increases generation from fossil fuel generators, particularly black coal and CCGT plant.
- The emission intensity of grid based generation declines slightly over time due to the entry of new winds farms to meet the LRET and replacement of older coal plants with more efficient supercritical generators. Increasing electricity demand offsets the slight reduction in emission intensity, causing emissions to be significantly higher than in the regular reference case.
- Renewables technologies have no additional incentive to grow more than in the regular reference case and therefore their generation capacity remains similar for both cases.

8.2.3 Demand

The total electricity consumed in the NEM and WEM for the high demand reference case (see Figure 277) is projected to be 210 TWh in 2020 and rapidly grows reaching 486 TWh at the end of the modelled horizon. When compared to the (base demand) reference case the sent-out demand starts 13 TWh lower in that scenario[31], but quickly rises above the base case demand to settle around 100 TWh higher for the last seven years.

Figure 277: Sent-out energy, high demand reference case

The left graph shows absolute figures. The right graph shows figures relative to the (base demand) reference case.



Source: Climate Works (2015) and Jacobs

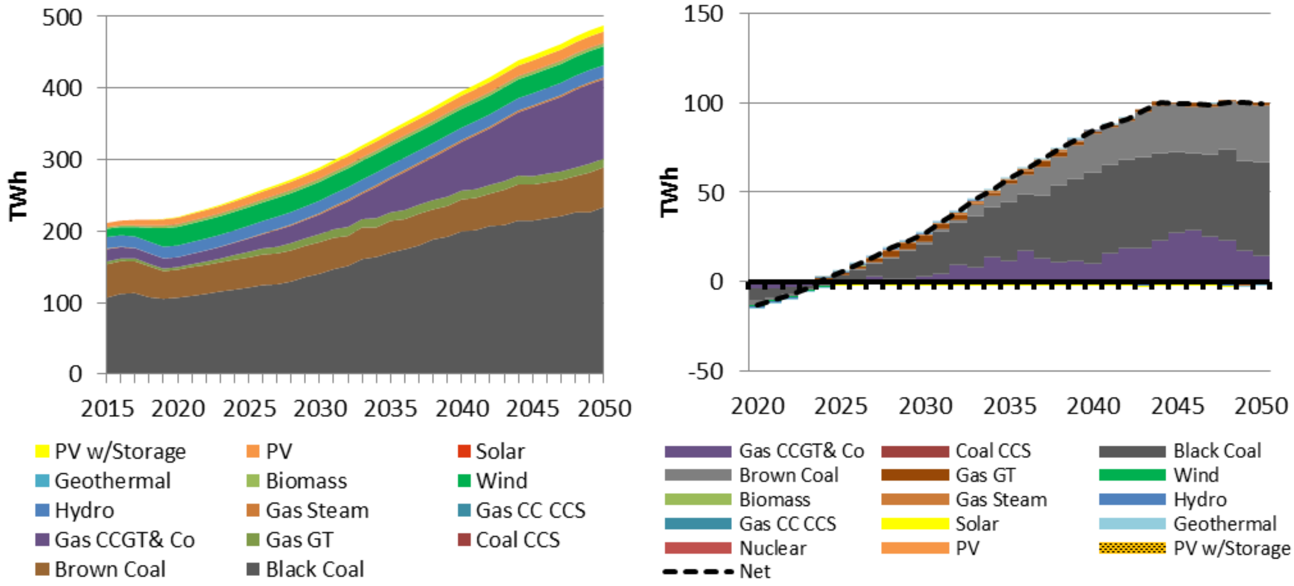
8.2.4 Generation and capacity

Figure 278 shows the generation mix in the NEM and WEM for high demand reference scenario in absolute terms and relative to the (base demand) reference case. Coal fired plants hold their key role in power generation having a relatively stable output for the first ten years as the current oversupply of generation is being reduced and steadily increasing their generation for the rest of the modelled period with new supercritical coal plants (see Figure 279) substituting some older brown coal capacity. More CCGTs are also built since this technology becomes the marginal cost technology in many of the regions, undertaking higher levels of duty. The rapid growth of demand brings in more gas turbines needed for the peak demand hours. Large-scale renewable generation grows until 2020 to meet the LRET target and remains flat after that since no economic incentives exist in the market for additional investment. Small-scale photovoltaics deployment continues to grow steadily reaching similar capacity to the reference case. Both small and large-scale renewable generation in 2050 comprises around 15% of total generation in the high demand reference case compared to 19% in the reference case.

[31] The demand forecasts for the high scenario were based on a study undertaken by ClimateWorks (2015). Op.cit. This study had a different demand trajectory and hence the reason for the lower demand for the first two years of our study

Figure 278: Generation mix, high demand reference case

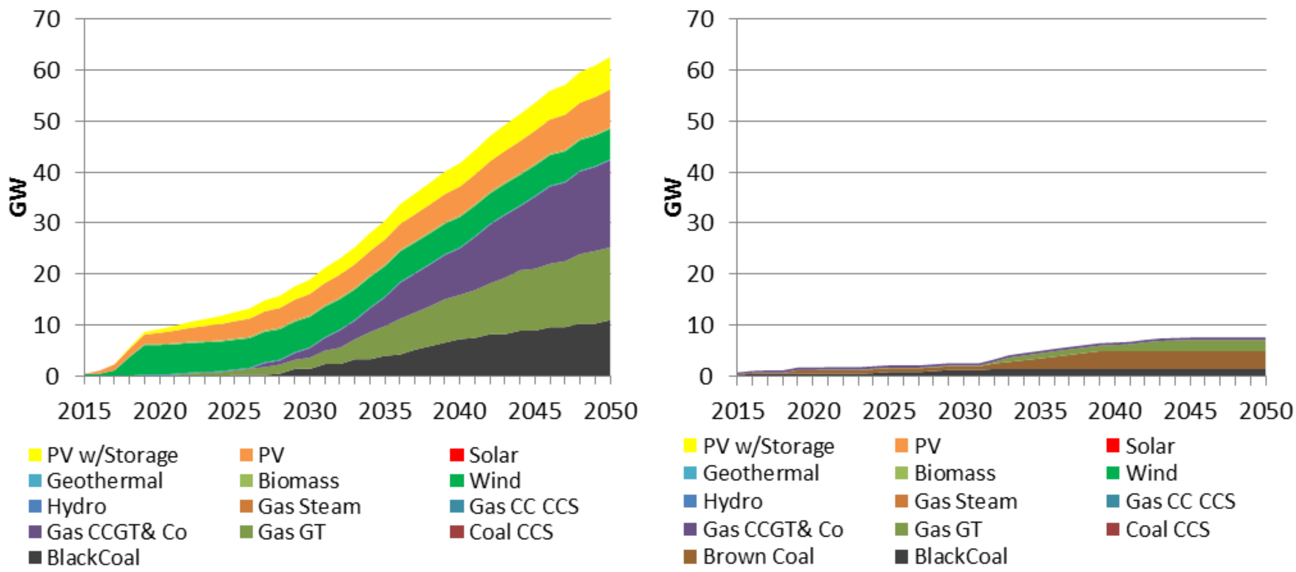
The left graph shows absolute figures. The right graph shows figures relative to the (base demand) reference case.



Source: Jacobs

Figure 279: Cumulative new and retired capacity, high demand reference case

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



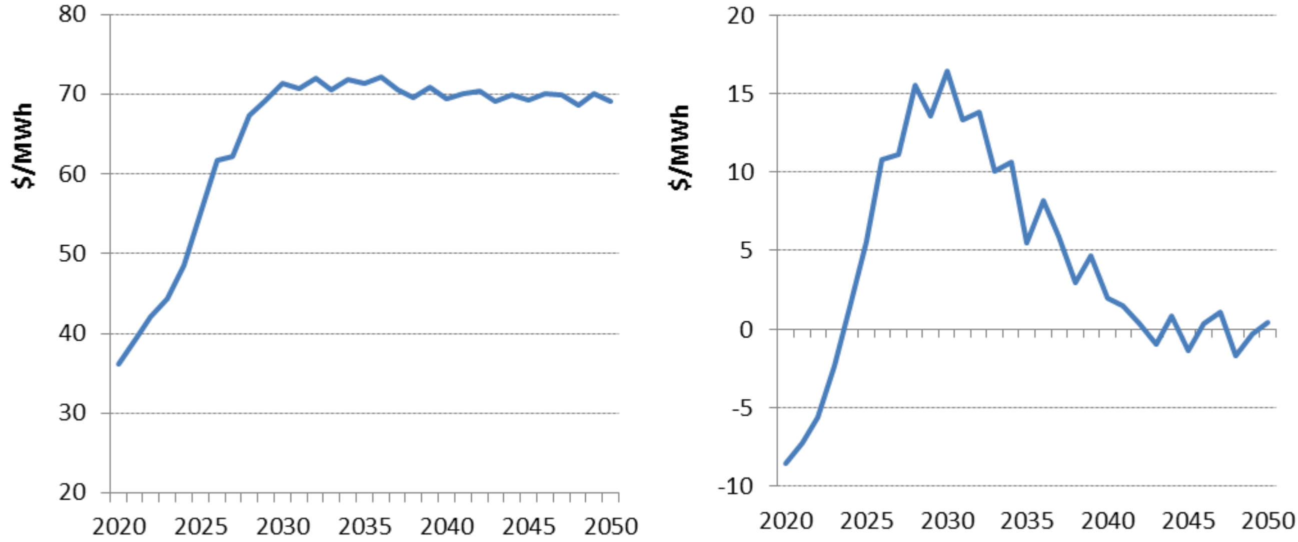
Source: Jacobs

8.2.5 Prices

The wholesale prices in the high demand reference case are gradually rising following the growth of electricity demand and reaching the new entry price levels in the early 2030s (Figure 280). When compared to the reference case the wholesale prices have a lower starting point due to the initial lower demand assumed, but quickly rise to around $15/MWh higher during the early 2030s. After 2030, the prices start to gradually converge, reaching similar levels for the last 10 years.

Figure 280: Wholesale electricity time-weighted prices, high demand reference case

The left graph shows absolute figures. The right graph shows figures relative to the reference case.

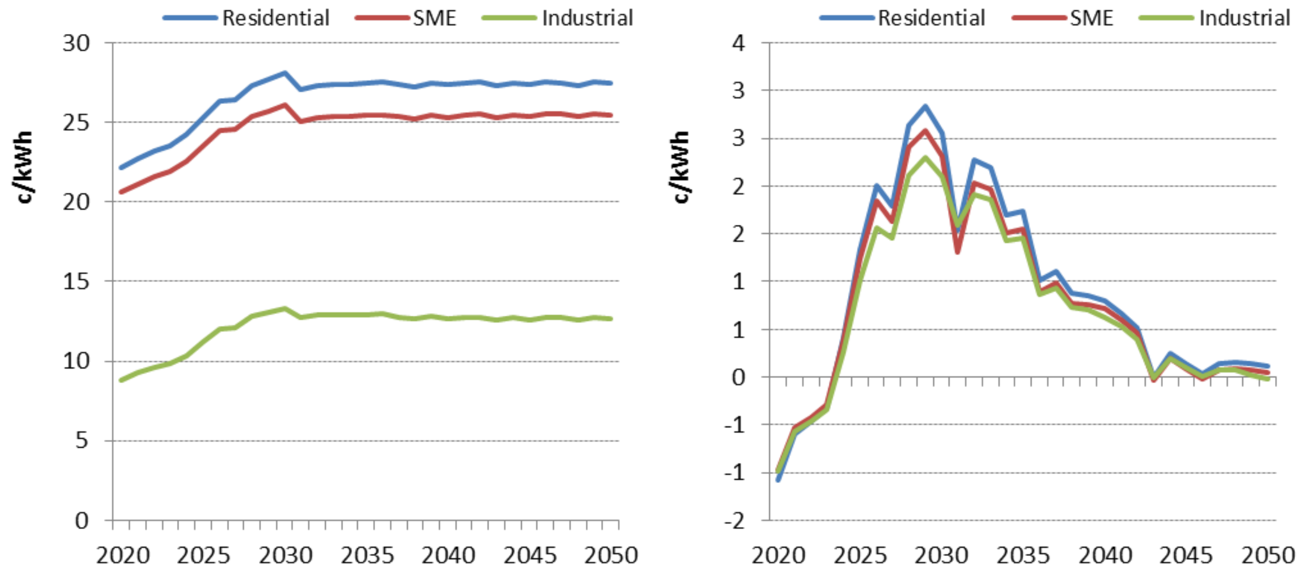


Source: Jacobs

The retail prices and the residential bill shown in Figure 281 and Figure 282 respectively, follow the wholesale price trend.

Figure 281: Retail prices by customer class, high demand reference case

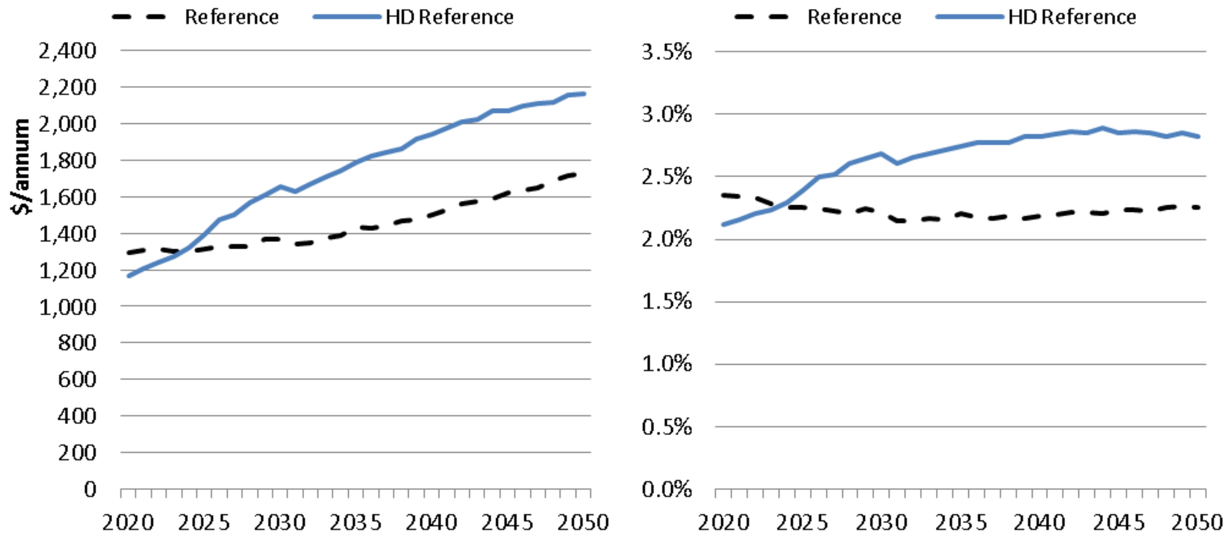
The left graph shows absolute figures. The right graph shows figures relative to the reference case.



Source: Jacobs

Figure 282: Residential bills, high demand reference case

The left graph shows the absolute residential bill. The right graph shows the residential bill as a percent of disposable income.



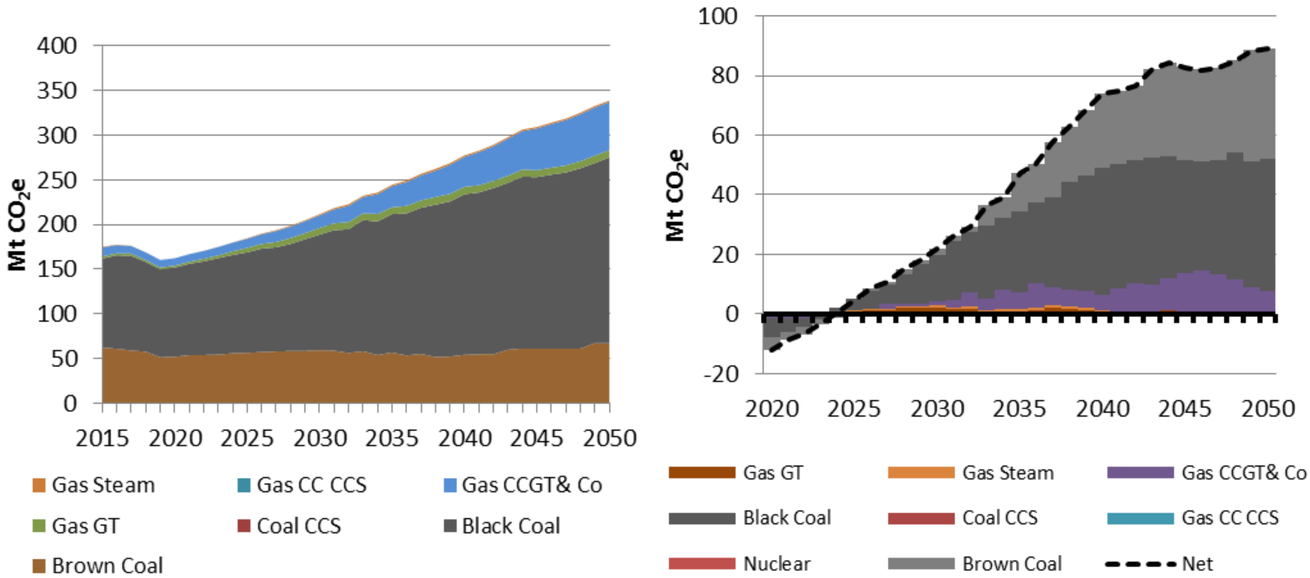
Source: Jacobs

8.2.6 Emissions

Emissions of greenhouse gases in the high demand reference case are initially declining due to the penetration of renewable generation while gradually increasing from 2019 onwards following the growing generation (as shown in Figure 283). The key reason for this increase of emissions is the higher generation from coal fired plants. When compared to the reference case black-coal plants start to emit more from the mid-2020s onwards while the retired brown coal plants are replaced with new more efficient supercritical brown coal generators that contribute significantly to the amount of CO_2e emitted. Total emissions in the high demand reference case for the studied period are projected to be 7,626 Mt CO_2e which is 22% higher than the reference case.

Figure 283: Emissions by technology, high demand reference case

The left graph shows absolute figures. The right graph shows figures relative to the reference case.

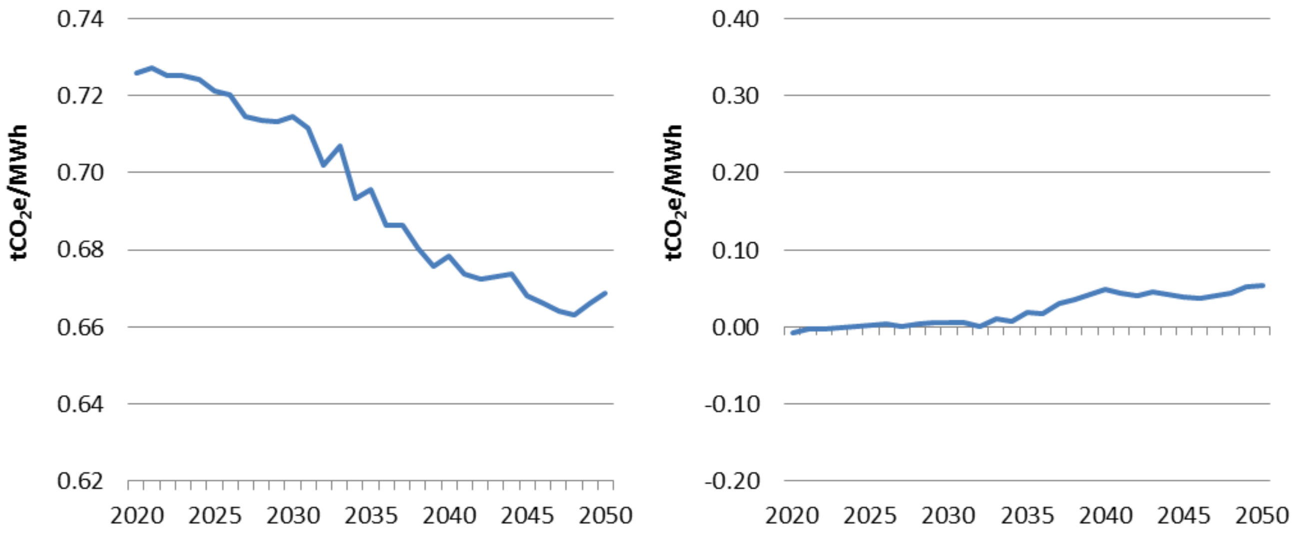


Source: Jacobs. Includes both direct and indirect emissions.

The average generation emission intensity, as shown in the figure below, declines throughout the modelled period since small and large-scale renewables are added in the generation mix and some high polluting coal fired plants are being replaced with new supercritical generators.

Figure 284: Generation emission intensity, high demand reference case

The left graph shows absolute figures with high demand. The right graph shows figures relative to the (base demand) reference case.



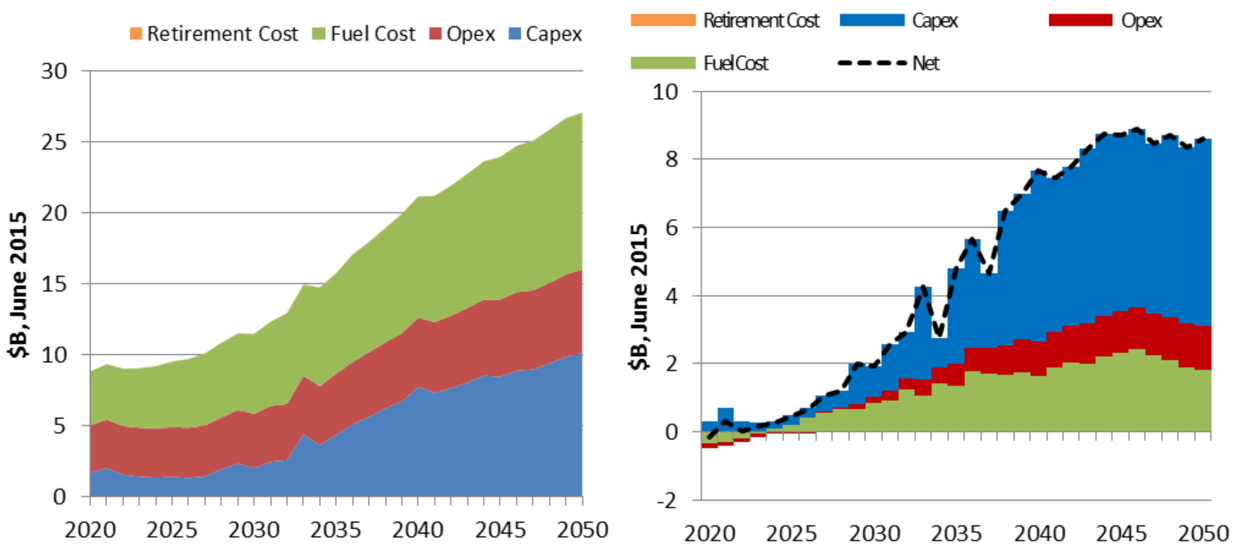
Source: Jacobs. Includes direct emissions only.

8.2.7 Costs

The annual resource cost illustrated in Figure 285 start from around $7 billion with limited capital expenditure needed until the late 2020s. After that, the sharp growth in demand leads to gradually increased investment in new fossil fuel generators. Furthermore, the fuel costs are progressively rising following the increased fuel consumption of the coal and gas fired generators.

Figure 285: Annualised costs by category, high demand reference case

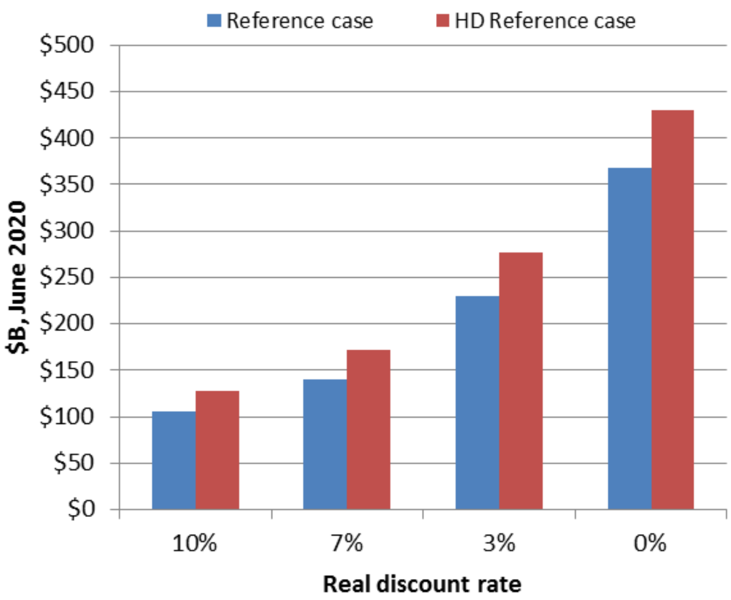
The left graph shows the absolute costs. The right graph shows the costs relative to the (base demand) reference case.



Source: Jacobs

The net present value of the resource costs in that scenario are higher from those in the reference case due to the increased capital expenditure needed to meet the higher demand and is ranging from $22 billion higher for 10% discount rate to $61 billion higher when no discount is applied (see Figure 286).

Figure 286: NPV of resource costs, high demand reference case



Source: Jacobs. Excludes demand adjustment. See Appendix B.3.2 for further detail.

8.3 Carbon pricing (high demand)

8.3.1 Scenario description

The scenario investigates how the carbon policy outcomes will be affected if the electricity demand is much higher than expected in the regular carbon case. All the other assumptions have remained the same as in the base case.

8.3.2 Key findings

Key findings are:

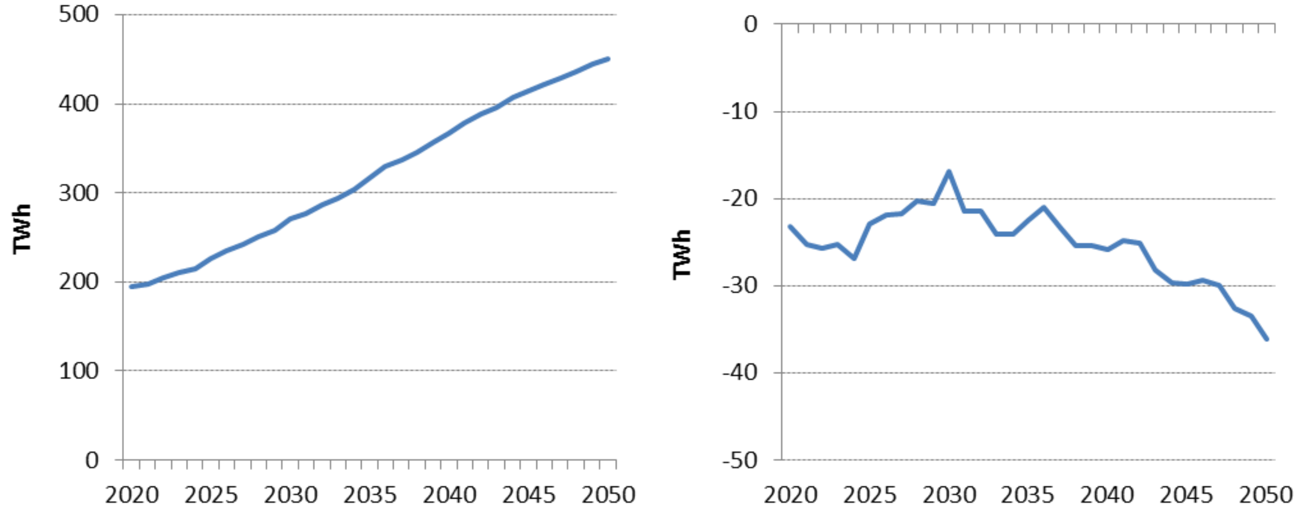
- The generation mix remains similar to the one in the regular carbon pricing scenario with most of the additional demand being met with the build of new low emission technologies such as CCGTs with CCS and nuclear plants.
- The wholesale prices are very similar to those projected in the regular carbon pricing run since they are driven by the cost required to incentivise the entry of new low emission plant.
- The higher assumed demand resulted in cumulative emissions of around 1,764 Mt CO_2e, which is 11.5% higher than the 2°C emissions constraint of 1,580 Mt CO_2e.

8.3.3 Demand

Figure 287 shows sent-out energy demand for the high demand carbon pricing scenario in absolute terms and relative to the reference case. Total energy consumed reaches 450 TWh in 2050, 36 TWh lower than the high demand reference case due to higher wholesale prices reducing demand.

Figure 287: Sent-out energy, carbon pricing with high demand

The left graph shows absolute figures. The right graph shows figures relative to the high demand reference case.



Source: Pitt & Sherry, ACIL Allen and Jacobs

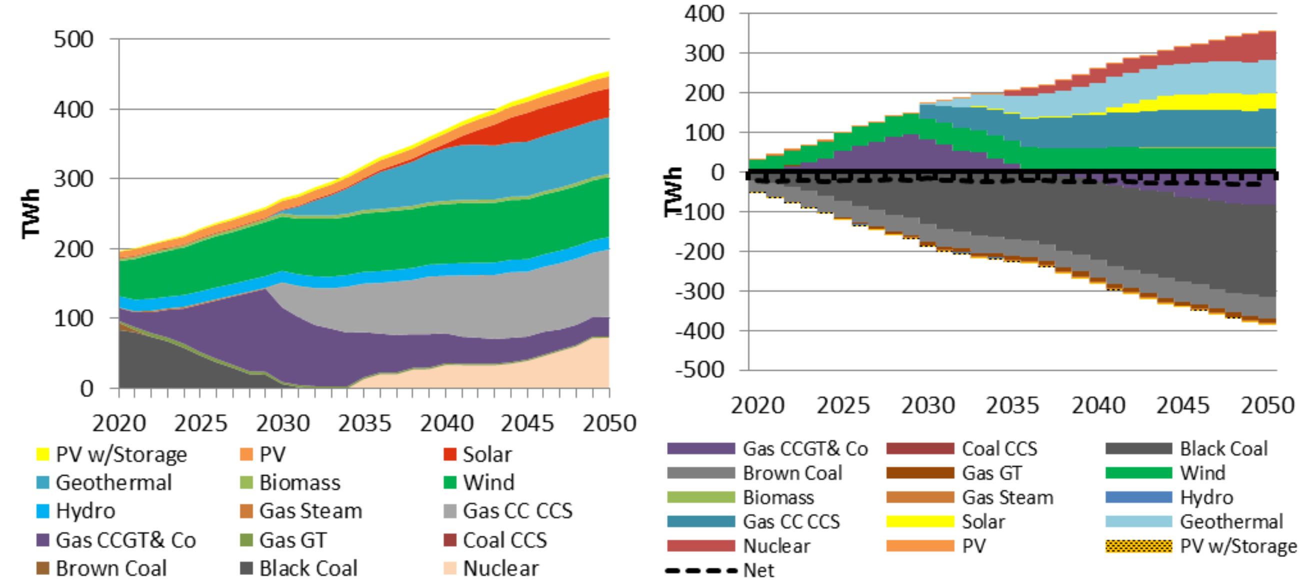
8.3.4 Generation and capacity

The generation mix in the NEM and WEM as shown in Figure 288 is very similar to the one projected in the regular carbon pricing scenario. The coal fired fleet retires during the first 10 years of the horizon due to the high carbon prices imposed while gas fired plants are acting as the main substitute for power supply for that same period. After 2030 and for the next 10 years, the CCGTs with CCS show a significant increase in generation, displacing some of the older conventional gas plants while geothermal generators also have a considerable contribution in the generation mix. Wind remains a key technology during the 2020s but its growth is limited after that when cheaper low emission technologies become available. Finally, nuclear generators have a higher contribution to the electricity supply so as to meet the higher demand assumed. Overall, most of the additional demand modelled is met with new low emission technologies such as CCGTs with CCS and nuclear.

Figure 289 illustrates cumulative new generation and again reveals the foremost role of gas plants when the retirement of the coal-fleet occurs, while CCGTs with CCS, geothermal and nuclear generators are showing a considerable growth when they become available. Finally, capacity of rooftop PV show a similar growth as in the regular carbon pricing scenario while large-scale solar has a notable increase in the early 2040s in capacity terms.

Figure 288: Generation mix, carbon pricing with high demand

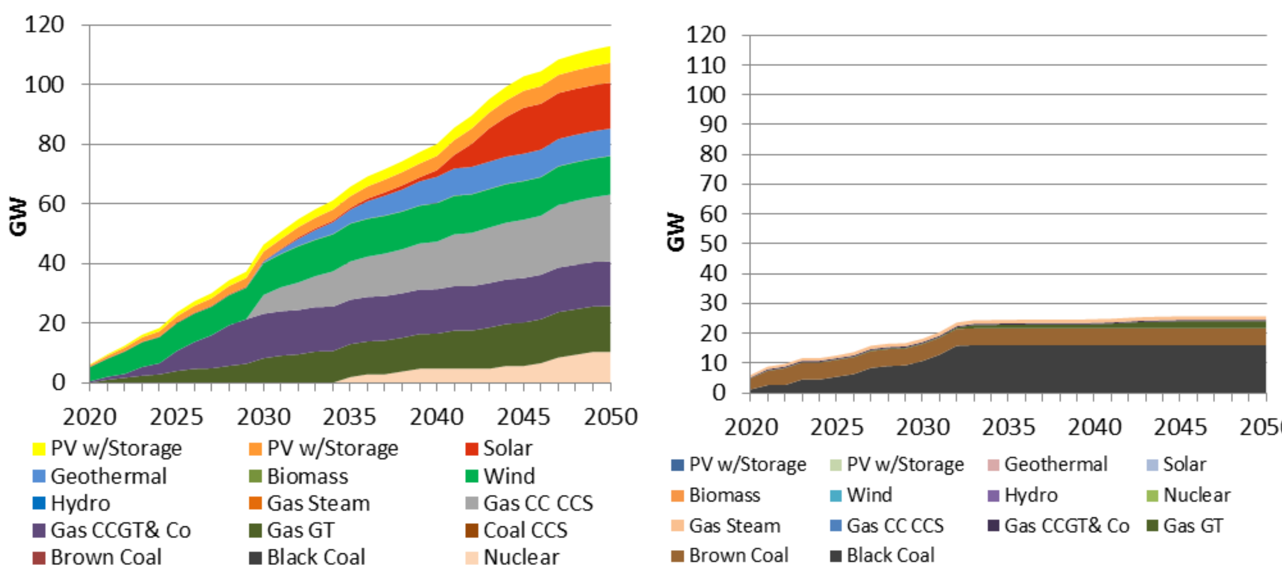
The left graph shows absolute figures. The right graph shows figures relative to the high demand reference case.



Source: Jacobs

Figure 289: Cumulative new and retired capacity, carbon pricing with high demand

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



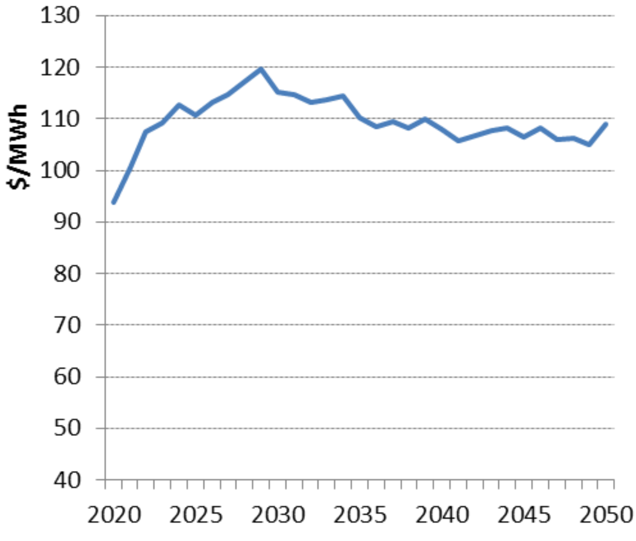
Source: Jacobs

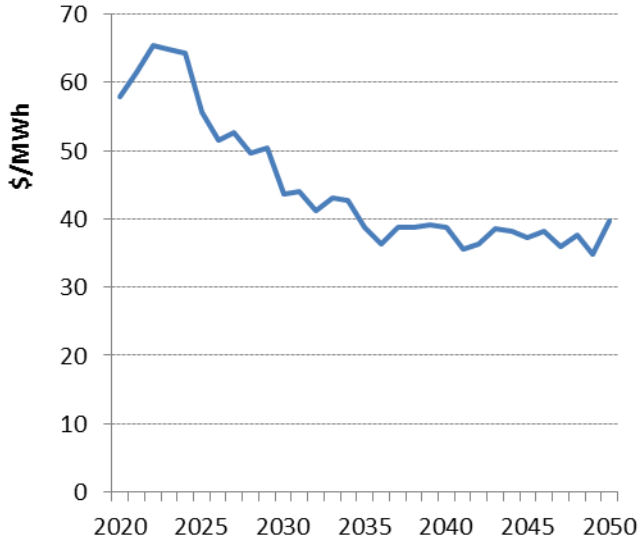
8.3.5 Prices

The time-weighted wholesale prices presented in Figure 290 show a sharp increase during the 2020s finally converging to a price that represents the LRMC of the CCGTs. Post 2030, when new low emission CCGTs coupled with CCS become available the impact of carbon pricing becomes less significant while after 2040 nuclear becomes the marginal cost generation technology and thus the wholesale price is not impacted by the continuously increasing carbon price.

Figure 290: Wholesale electricity time-weighted prices, carbon pricing with high demand

The left graph shows absolute figures. The right graph shows figures relative to the high demand reference case.





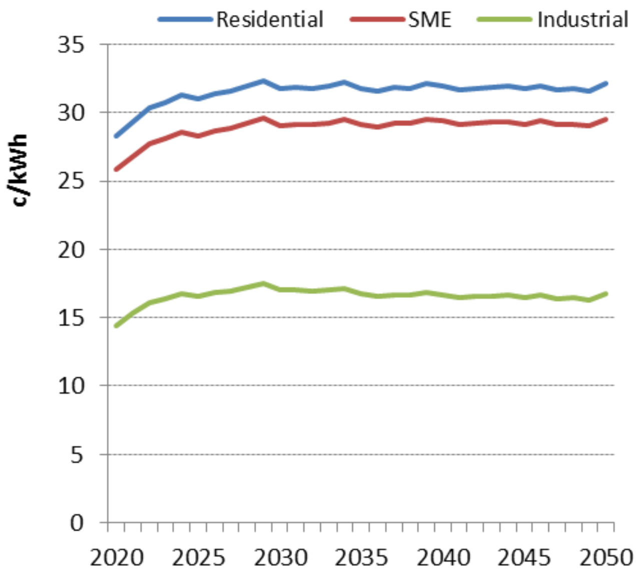
Source: Jacobs

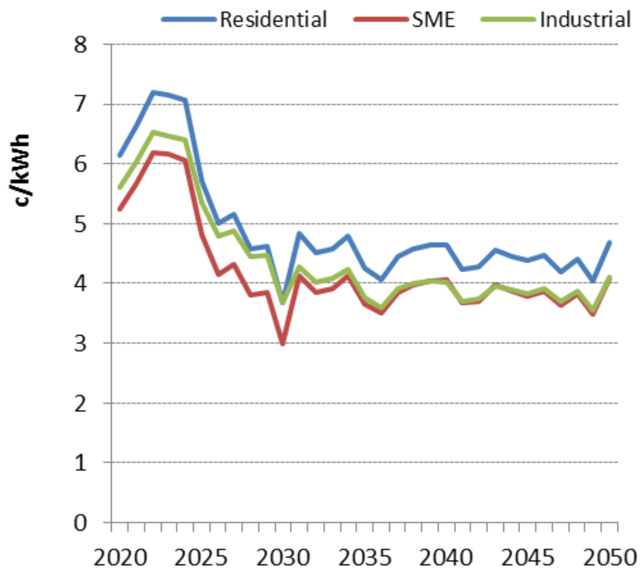
Figure 291 shows weighted average retail prices by customer class. They contain the same trends as the wholesale prices, but the relative price movements are more muted since the wholesale price only comprises typically 30% to 40% of the retail price.

Figure 292 shows the Australian weighted average residential bill relative to the reference case, as well as the bill as a percentage of average expected disposable income.

Figure 291: Retail prices by customer class, carbon pricing with high demand

The left graph shows absolute figures. The right graph shows figures relative to the high demand reference case.

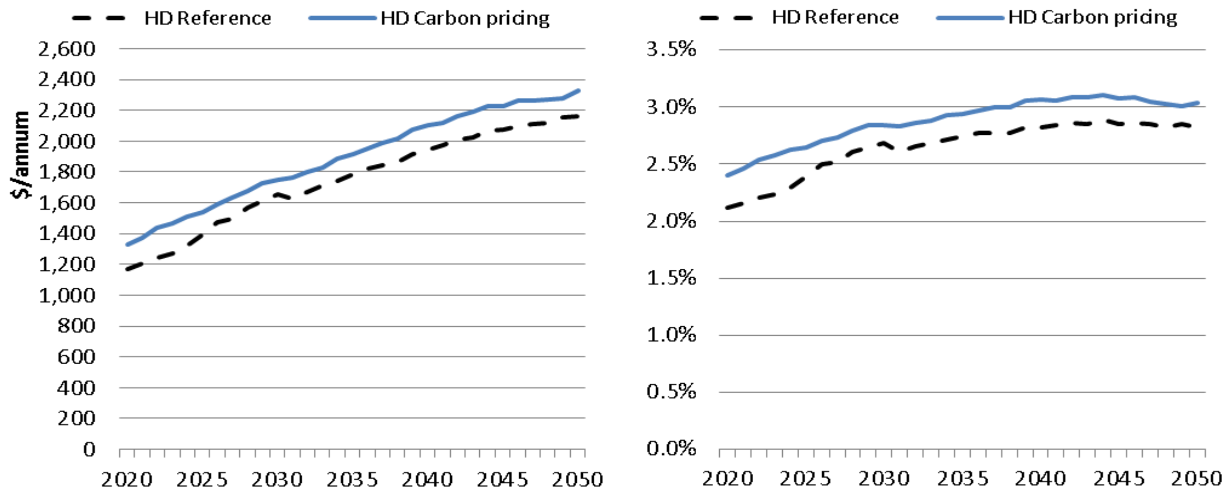




Source: Jacobs

Figure 292: Residential bills, carbon pricing with high demand

The left graph shows the absolute residential bill. The right graph shows the residential bill as a % of disposable income.



Source: Jacobs

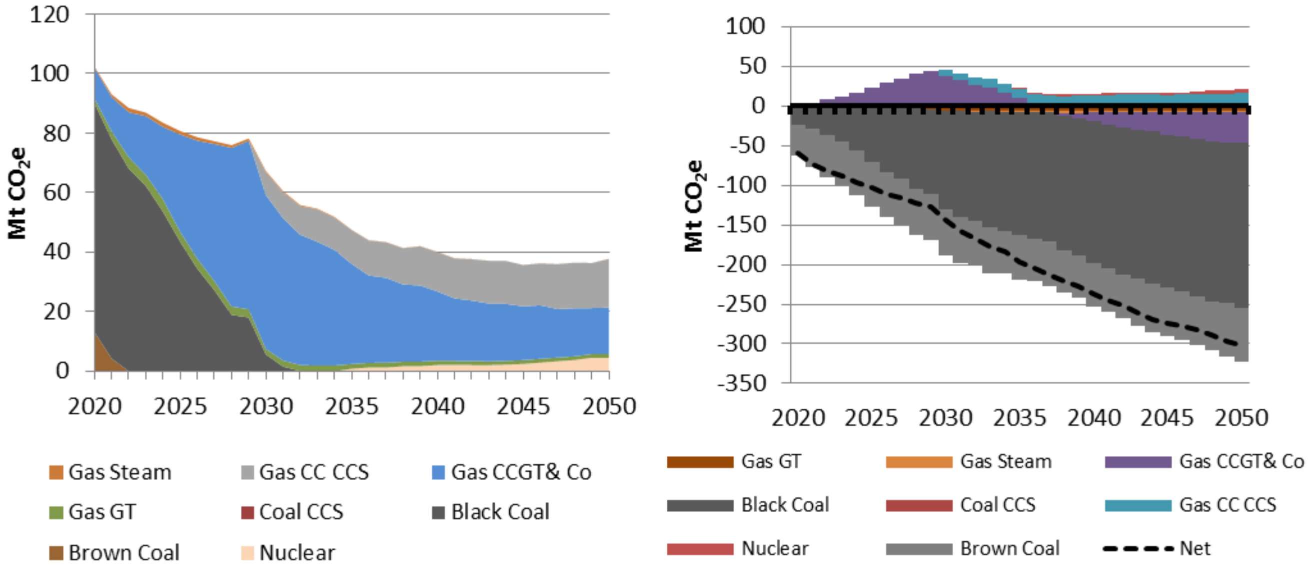
8.3.6 Emissions

The annual direct and indirect emissions by fuel technology are presented in Figure 293. Emissions have the same starting point in 2020 of 100 Mt CO_2e as the regular carbon pricing scenario, but their decline is not as sharp since the increased electricity demand is being met with additional gas generation contributing to total emissions for the first ten years. After 2030, when geothermal and CCGTs with CCS technologies become available, the decrease of emissions is more strongly manifested reaching a plateau of around 38 Mt CO_2e for the last ten years of the horizon. The accumulated emissions projected for this scenario are 1,764 Mt CO_2e, which is around 11.5% higher than the target.

The grid generation emission intensity shown in Figure 294 is similar to the one projected at the regular carbon pricing.

Figure 293: Emissions by technology, carbon pricing with high demand

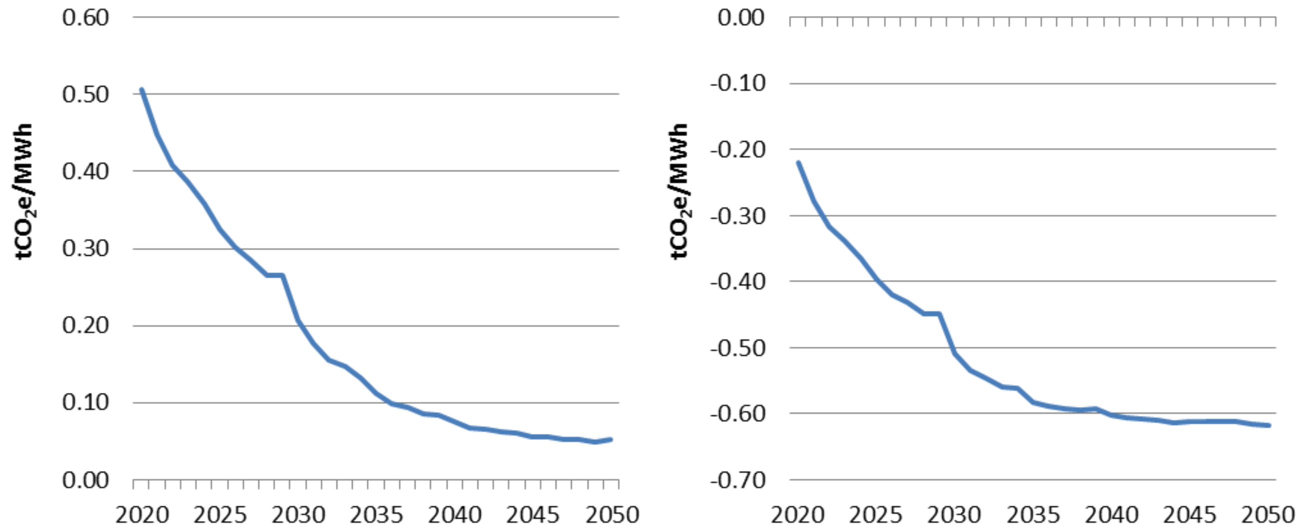
The left graph shows absolute figures. The right graph shows figures relative to the high demand reference case.



Source: Jacobs. Includes both direct and indirect emissions.

Figure 294: Generation emission intensity, carbon pricing with high demand

The left graph shows absolute figures. The right graph shows figures relative to the high demand reference case.



Source: Jacobs. Includes direct emissions only.

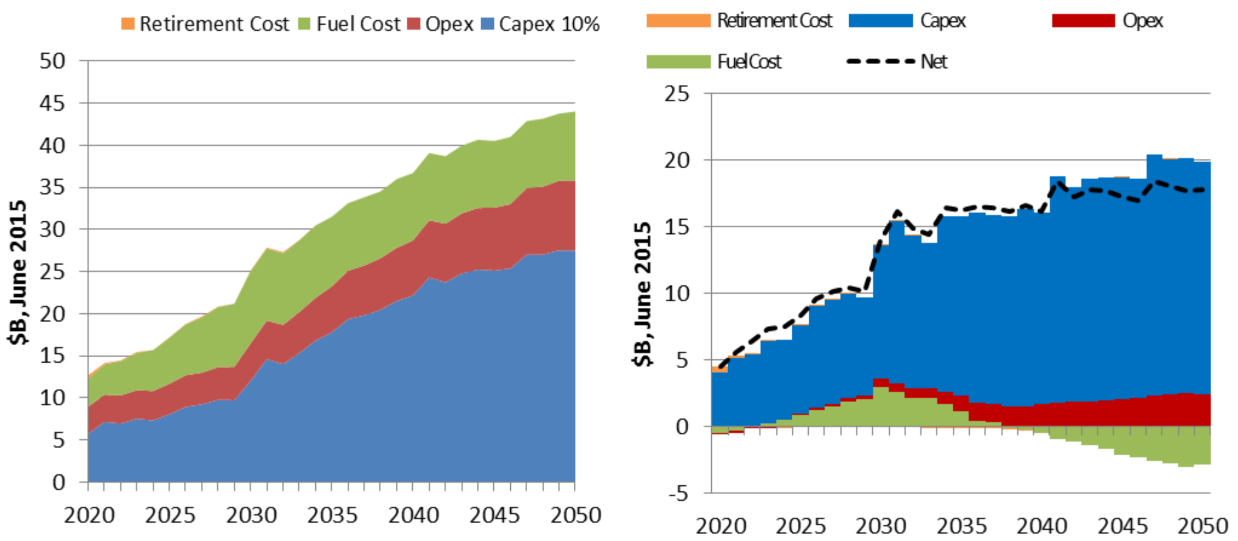
8.3.7 Costs

The annualised resource costs of the four main categories presented in Figure 295 are very similar to those in the regular carbon price scenario, with some additional capital expenditure needed for gas fuel generators to meet the higher demand resulting in increased fuel costs as well.

Figure 296 shows the net present value of the resource costs for carbon pricing relative to the reference case for four separate discount rates. The total resource cost for carbon pricing ranges from 85% (at 10% real discount rate) to 44% (without discounting) higher than that of the reference case.

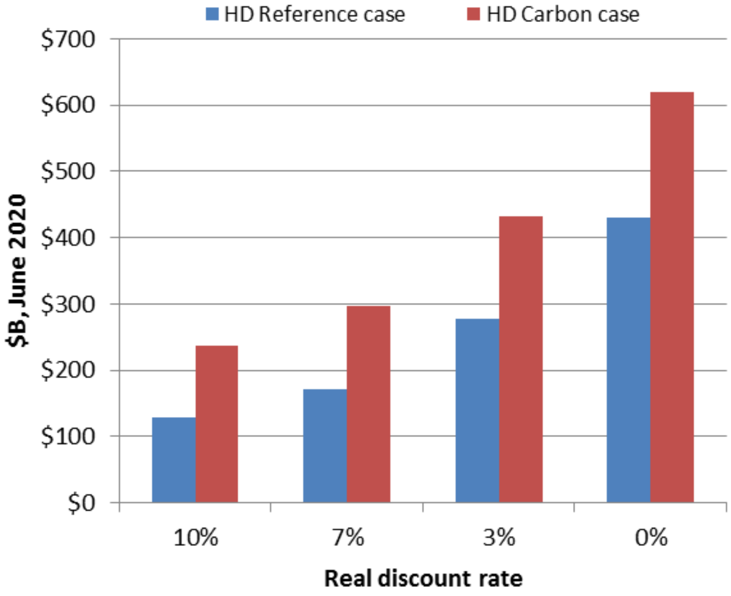
Figure 295: Annualised costs by category, carbon pricing with high demand

The left graph shows the absolute costs. The right graph shows the costs relative to the high demand reference case.



Source: Jacobs

Figure 296: NPV of resource costs, carbon pricing with high demand



Source: Jacobs. Excludes demand adjustment. See Appendix B.3.2 for further detail.

8.4 Low emissions target (high demand)

8.4.1 Scenario description

The high demand low emissions target scenario explores how the policy outcomes will be affected if the electricity demand is much higher than what is assumed in the regular case. Apart from the demand all the other assumptions have remained the same as in the base case. The low emissions target used is the same as in the regular LET policy scenario.

8.4.2 Key findings

The key findings are

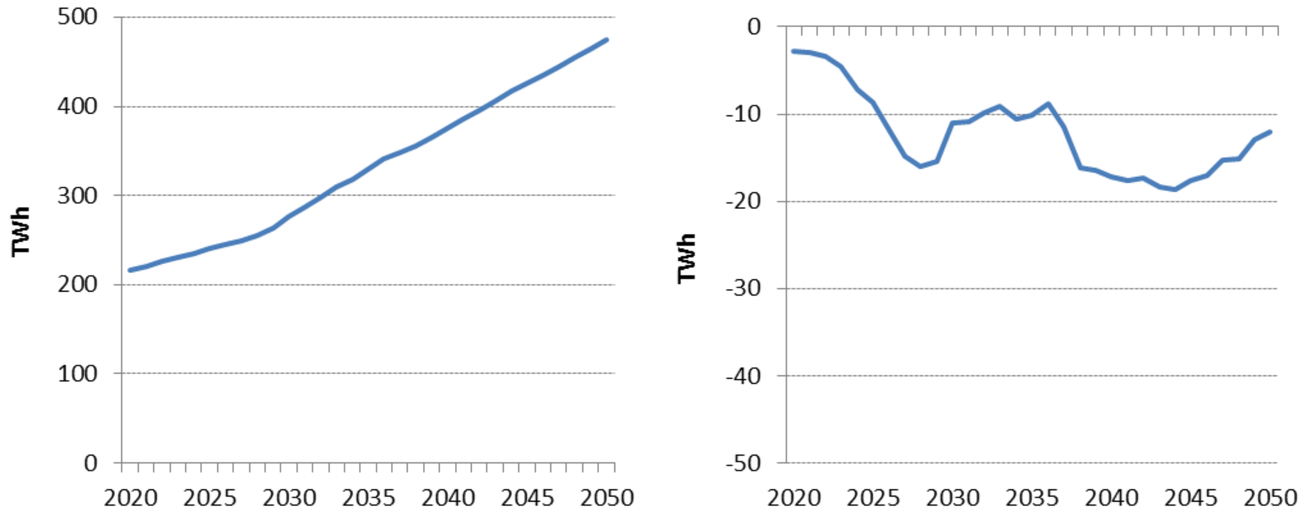
- More coal generators remain in the generation mix because the depressed prices caused by the renewables built are offset by the increased demand.
- Once the LET targets are met in 2040, emission intensity and coal generation increase, with new coal plants added as a result of there being no direct control or penalty on emissions.
- With higher demand but the same LET targets, this scenario results in cumulative emissions of around 3,209 Mt CO_2e which is around double the 2°C emissions constraint of 1,580 Mt CO2e and significantly higher than total emissions projected in the high demand carbon pricing.
- Wholesale prices, retail prices and resources costs (relative to reference) remain similar to those projected in the regular LET scenario.

8.4.3 Demand

Figure 297 shows sent-out energy demand from the high demand LET scenario. Total energy consumption reaches 474 TWh at the end of the modelled period, which is 12 TWh per annum lower than the high demand reference case. The demand is lower throughout the horizon because of the LET certificate price that impacts the retail price in the NEM and WEM.

Figure 297: Sent-out energy, low emissions target with high demand

The left graph shows absolute figures. The right graph shows figures relative to the high demand reference case.



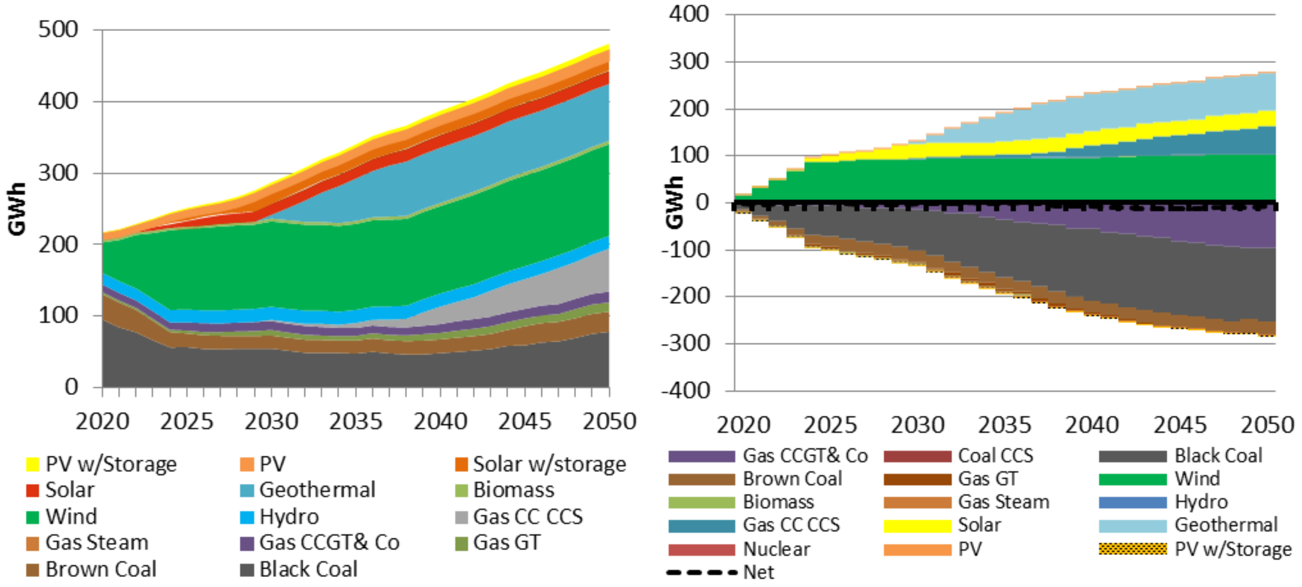
Source: Pitt & Sherry, ACIL Allen and Jacobs

8.4.4 Generation and capacity

Figure 298 shows the generation mix across the modelling horizon. The key difference from the regular LET scenario is that the higher demand helps some of the coal fleet to survive the suppression of prices caused by the renewables during the first decade. These coal generators are contributing significantly to the generation mix throughout the whole modelling period, having a total generation of 120 TWh at the end of the horizon which is a quarter of the total energy supplied. The new renewables built are quite similar to the regular LET case since they are driven by the same target. The cumulative new generation capacity illustrated in Figure 299 also reveals that only a fraction of the CCGTs with CCS built in the regular LET scenario are built in that case, since they are displaced from the incumbent coal plants and some new ones that are built over the last decade.

Figure 298: Generation mix, low emissions target with high demand

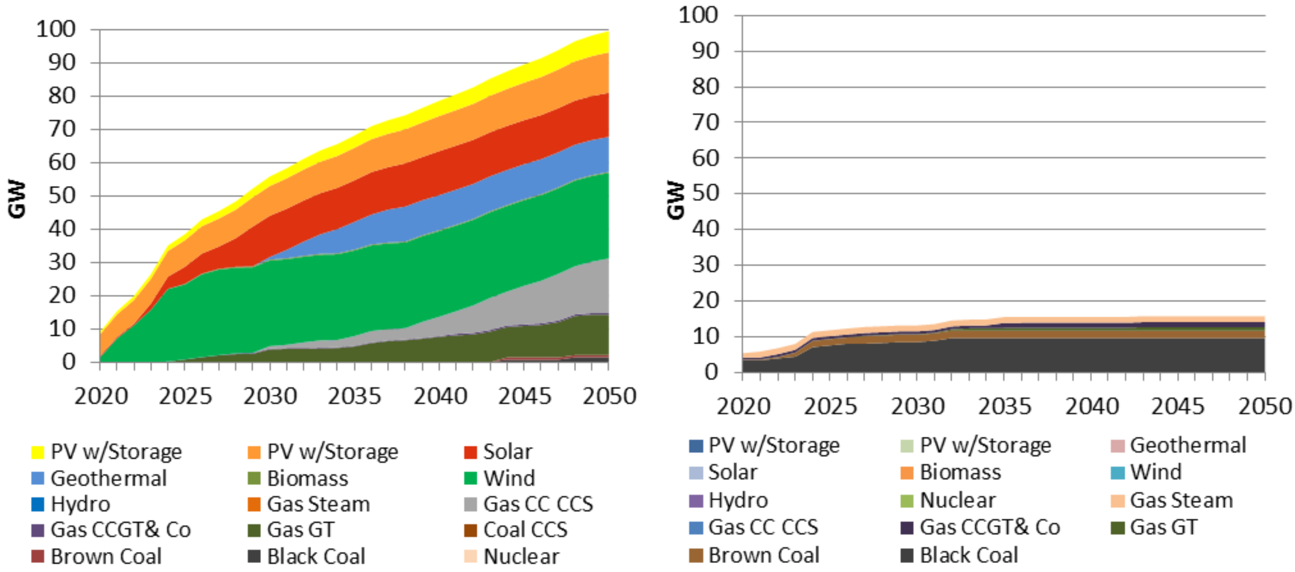
The left graph shows absolute figures. The right graph shows figures relative to the high demand reference case.



Source: Jacobs

Figure 299: Cumulative new and retired capacity, low emissions target with high demand

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



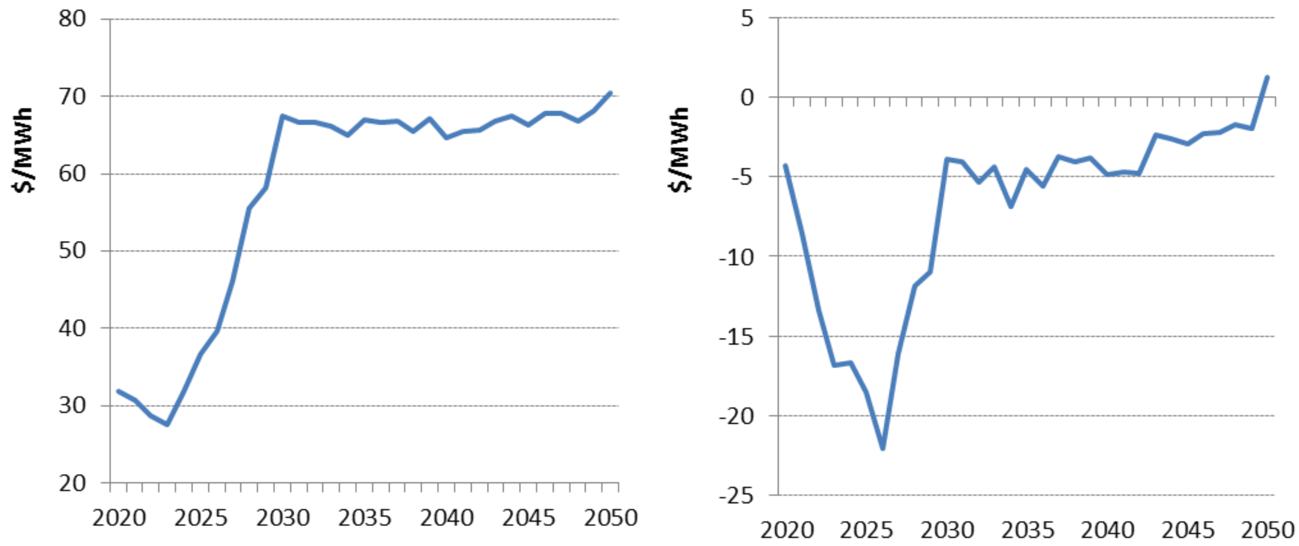
Source: Jacobs

8.4.5 Prices

Figure 300 shows wholesale electricity time-weighted prices. Price trends are similar to those of the LET scenario, except that prices in that scenario reach the marginal new entry cost price earlier on the horizon.

Figure 300: Wholesale electricity time-weighted prices, low emissions target with high demand

The left graph shows absolute figures. The right graph shows figures relative to the high demand reference case.

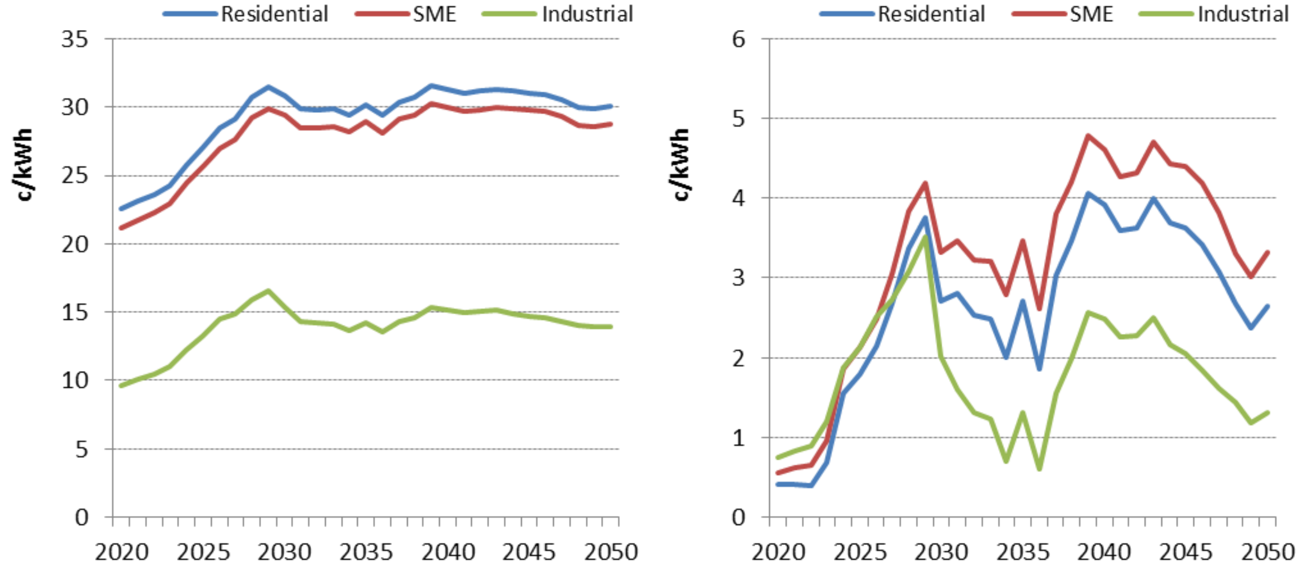


Source: Jacobs

The retail prices presented in Figure 301 and the residential bill in Figure 302 also follow the wholesale price trends while they are also being influenced by the LET certificate prices.

Figure 301: Retail prices by customer class, low emissions target with high demand

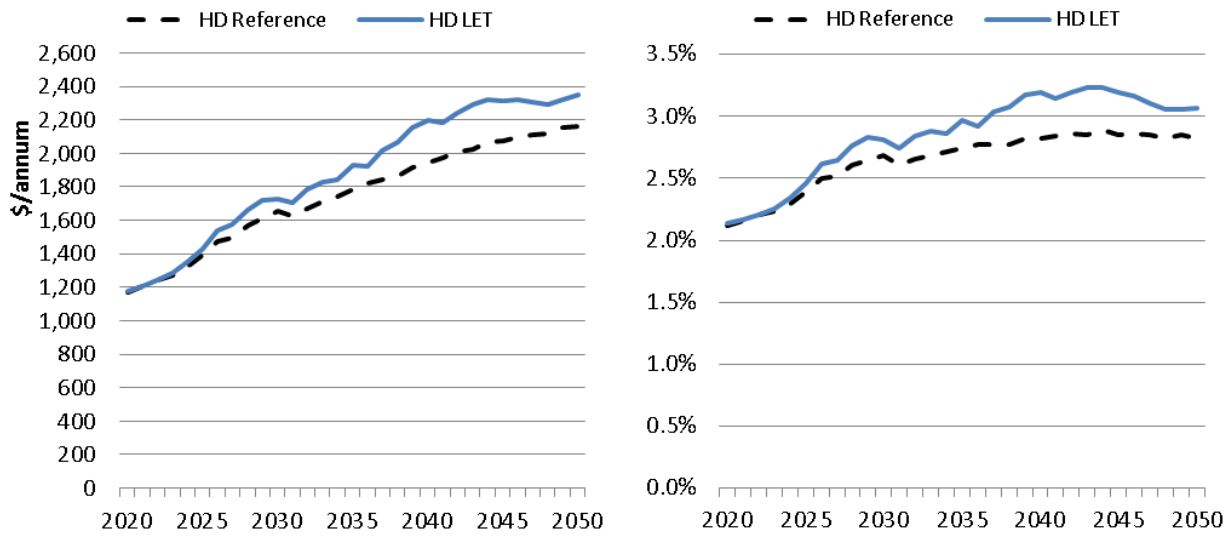
The left graph shows absolute figures. The right graph shows figures relative to the high demand reference case.



Source: Jacobs

Figure 302: Residential bills, low emissions target with high demand

The left graph shows the absolute residential bill. The right graph shows the residential bill as a % of disposable income.



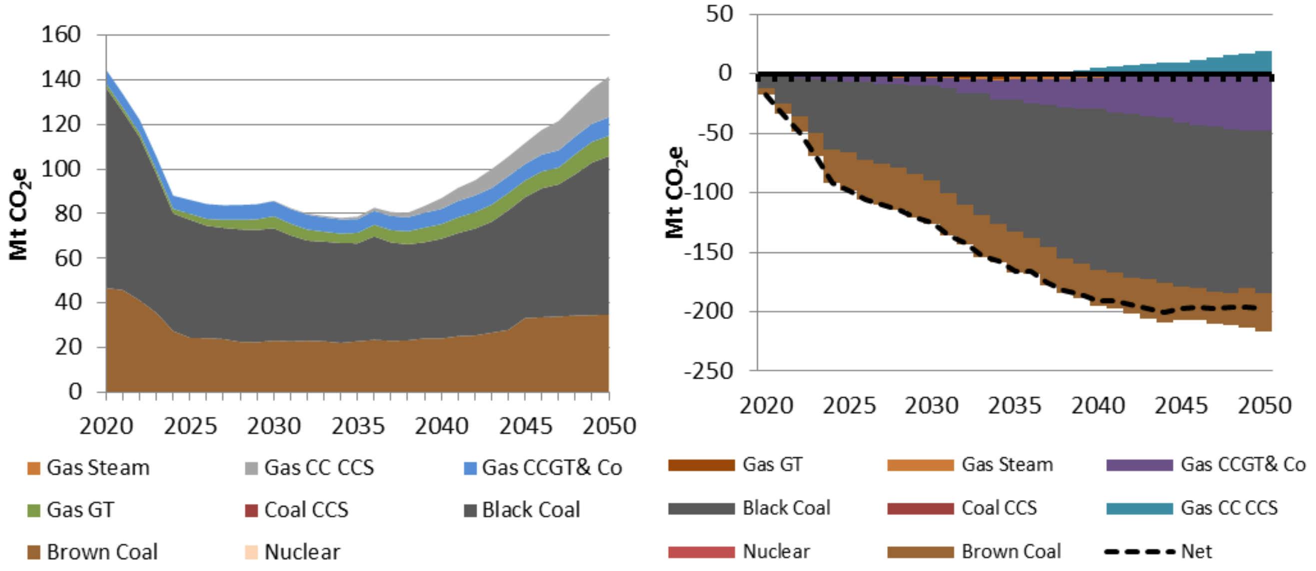
Source: Jacobs

8.4.6 Emissions

Annual emissions in this scenario, shown in Figure 303, are distinctively different than those presented in the regular LET case. While emissions decline sharply during the first half of the 2020s due to the retirement of some coal plants and the penetration of renewable resources, after 2025 emissions remain almost stable for the next 15 years since the surviving coal units are key contributors to the generation supply. In the last 15 years of the modelled horizon the increased demand is causing a higher utilisation of the incumbent coal fleet and the build of new supercritical coal plants, causing a rapid rise in the annual emissions. In 2050 the total direct and indirect emissions are projected to be 150 Mt CO_2e, which is 5 Mt CO_2e higher than the starting point in 2020. The same story is depicted in Figure 304 where the initial drop of generation emission intensity is followed by a gradual rise during the last ten years of the modelled horizon. Overall, the cumulative emissions throughout the modelled period is projected to be 3,209 Mt CO_2e which is more than double the emissions target set in the 2°C scenario.

Figure 303: Emissions by technology, low emissions target with high demand

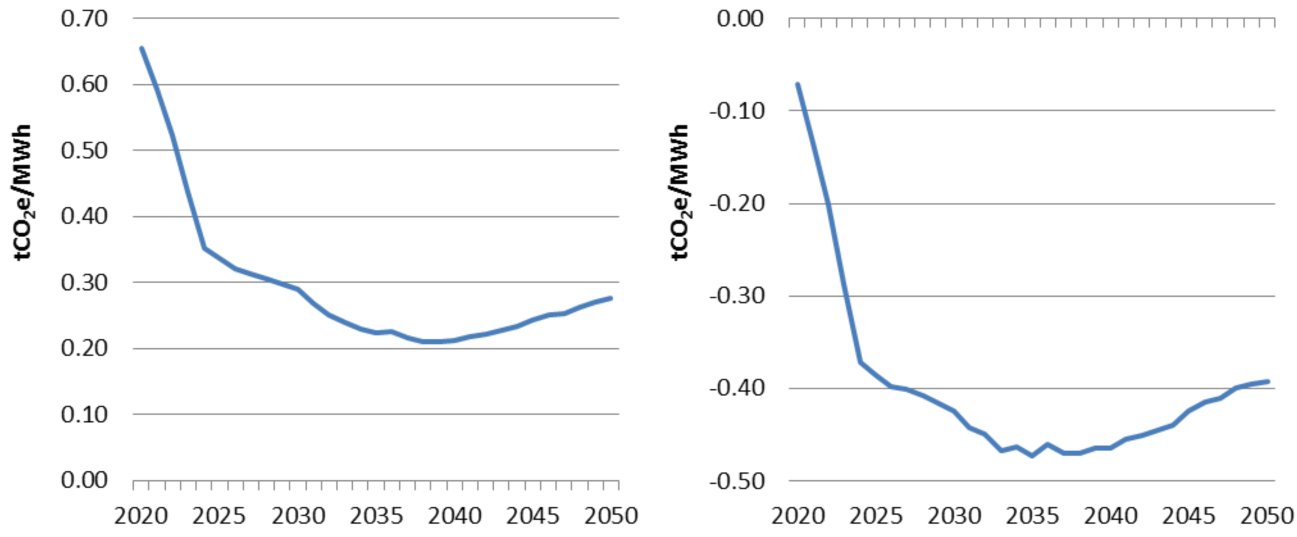
The left graph shows absolute figures. The right graph shows figures relative to the high demand reference case.



Source: Jacobs. Includes both direct and indirect emissions.

Figure 304: Generation emission intensity, low emissions target with high demand

The left graph shows absolute figures. The right graph shows figures relative to the high demand reference case.



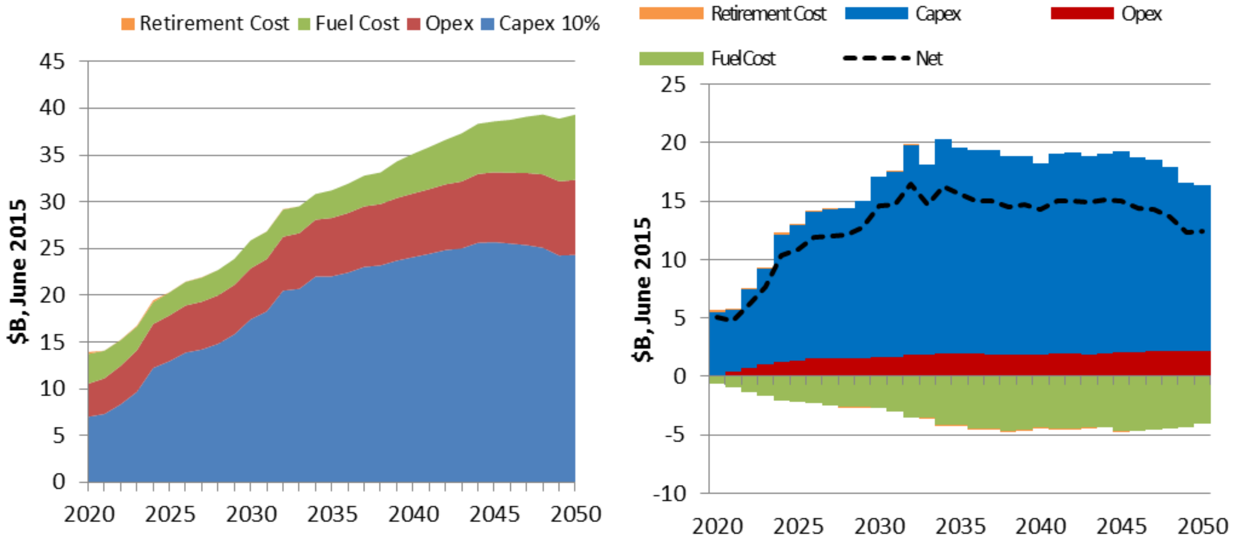
Source: Jacobs. Includes direct emissions only.

8.4.7 Costs

The annualised resource costs shown in Figure 305 are very similar to those in the regular LET case. While some of the capital expenditure is deferred during the 2020s because of the incumbent coal plants continuing to operate in the NEM and WEM, additional investment in fossil fuels is needed later on to meet the increased demand assumed.

Figure 305: Annualised costs by category, low emissions target with high demand

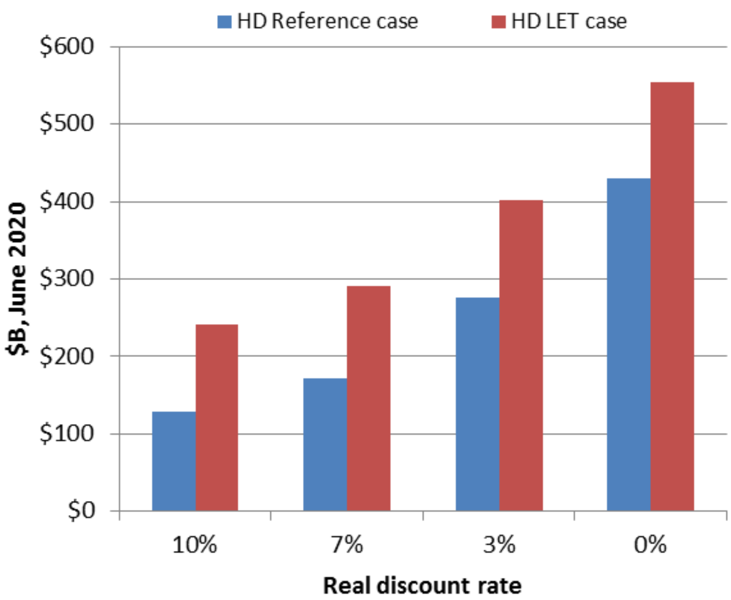
The left graph shows the absolute costs. The right graph shows the costs relative to the high demand reference case.



Source: Jacobs

Figure 306 shows the net present value of the resource costs for the high demand LET scenario relative to the reference case for the four selected discount rates. The difference ranges from 88% higher at 10% discount rate to 29% higher when no discount is applied.

Figure 306: NPV of resource costs, low emissions target with high demand



Source: Jacobs. Excludes demand adjustment. See Appendix B.3.2 for further detail.

9. Results: technology sensitivities

In this section, results are presented for three policy scenarios and one reference case modelled with differing assumptions on technology availability and costs.

The differing technology assumptions include:

- The CCS, nuclear and geothermal options are assumed not to be available.
- Battery storage costs estimated by CSIRO are used, with lower storage costs over time (see Appendix C.4.5 for further details).

The technology sensitivity was conducted with the reference, carbon pricing, LET and RET policy scenarios. The same emissions constraint as for the 2^{o} C simulations was applied to each policy scenario (i.e. 1,580 Mt CO2e over the period from 2020 to 2050). Other than the changes listed above, the assumptions on fuel prices and learning rates consistent with a 2°C world are retained.

9.1 Comparison of technology sensitivities

9.1.1 Key differences between policy scenarios

The changed technology assumptions mean existing renewable generation technologies play a bigger role in all scenarios. The outcomes in the reference case are similar under the alternative technology assumptions, although with lower battery storage costs there is a large uptake of large-scale battery storage rather than new open cycle gas turbines from 2035 onwards.

For the carbon pricing scenario, a higher carbon price is required to meet the emissions constraint. Because new dispatchable low emissions fossil fuel and nuclear technologies are not available, renewable forms of dispatchable generation (such as solar and wind with battery storage) are deployed. The higher carbon price is required so that wholesale prices are high enough to recover the costs of these higher cost options.

Outcomes under the RET and LET scenarios are very similar as the only difference between the scenarios is that conventional gas fired generation can earn certificates under the LET. Providing certificates to gas significantly lowers the resource cost of meeting the emissions constraint. As a result, RET results are shown for resource costs, and only LET results are shown for the other comparative measures.

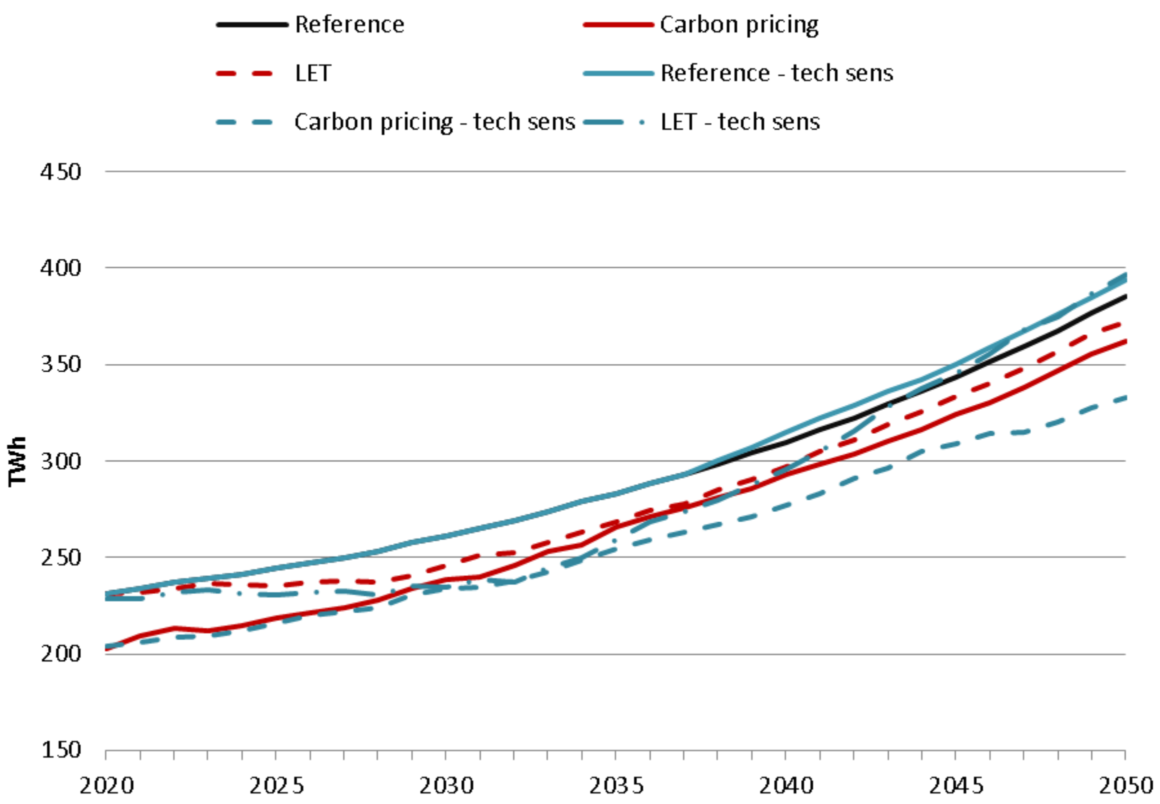
Carbon pricing still has the lowest demand adjusted resource costs.

9.1.2 Demand

Under the reference case, demand is slightly higher with the alternative technology assumptions from 2035 onwards. This is because with lower battery storage costs, more large scale battery storage is adopted resulting in higher levels of purchase of energy in low price period to discharge in high price periods. More energy is used for charging than for discharging (due to losses) and this leads to a slight increase in energy demand.

Demand under the policy scenarios is lower with the alternative technology assumptions. This is because more expensive options are required. This increases the wholesale price in carbon pricing and the certificate price in the technology pull scenarios. Carbon pricing has the largest drop in demand. This effect is larger than in the core 2°C scenario reflecting the higher carbon price and consequent higher retail prices. The electricity demand projections for the technology sensitivities scenarios and for the respective 2^{o}C scenarios are shown in Figure 307.

Figure 307: Demand projections, reference and select policy scenarios, technology sensitivities



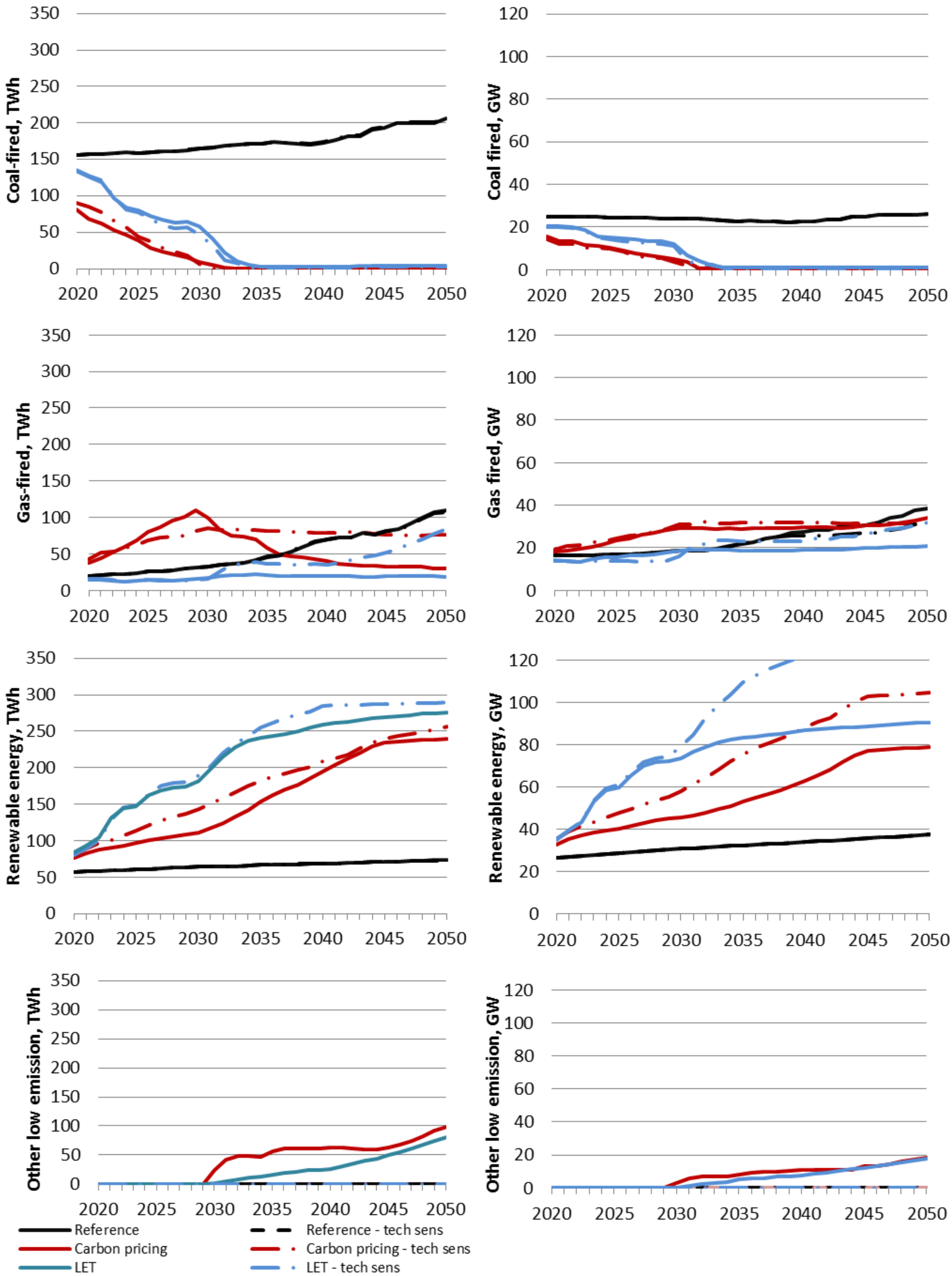
Source: Jacobs

9.1.3 Generation and capacity

Figure 308 shows the generation mix across the technology sensitivities. In these modelling runs there is no generation from nuclear, CCS and geothermal. This means that there is more generation from large-scale solar, wind and CCGTs.

Renewable energy capacity increases markedly with the alternative technology assumptions. There is also additional gas fired generation, although the capacity of gas fired generation installed is similar across the alternative technology assumptions. There is significant uptake of large-scale battery storage technology in all policy scenarios, which replaces the peaking role played by gas from the late 2030s onwards.

Figure 308: Generation and capacity by technology type, technology sensitivities

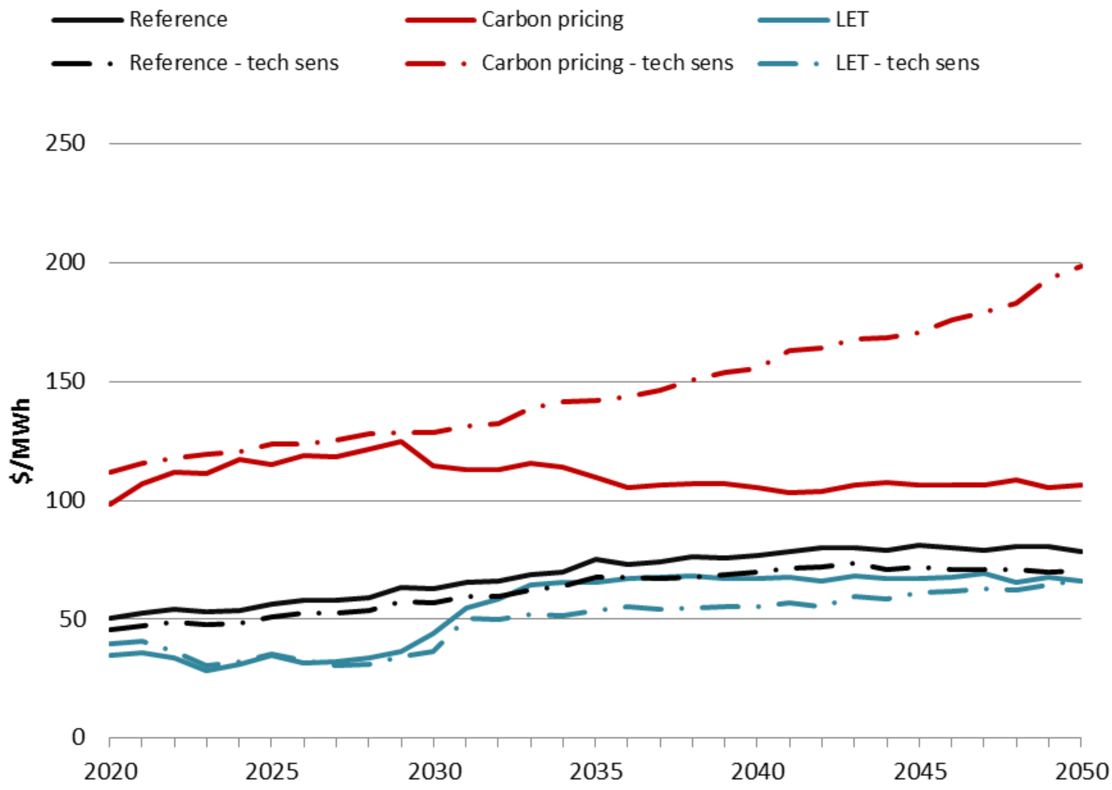


Source: Jacobs

9.1.4 Prices

Prices (at both the wholesale and retail levels) are higher with the alternative technology assumptions. The greatest increase occurred with the carbon pricing scenarios due to the higher carbon prices required to meet the emissions constraint. The restricted availability of technologies reduces wholesale prices in the LET because more plant with a SRMC of zero (wind and solar) are deployed. The wholesale prices are shown in Figure 309 while the retail prices for the different customer categories are given in Table 14.

Figure 309: Wholesale electricity time-weighted prices, technology sensitivities



Source: Jacobs

Table 14: Average retail price impacts, technology sensitivities

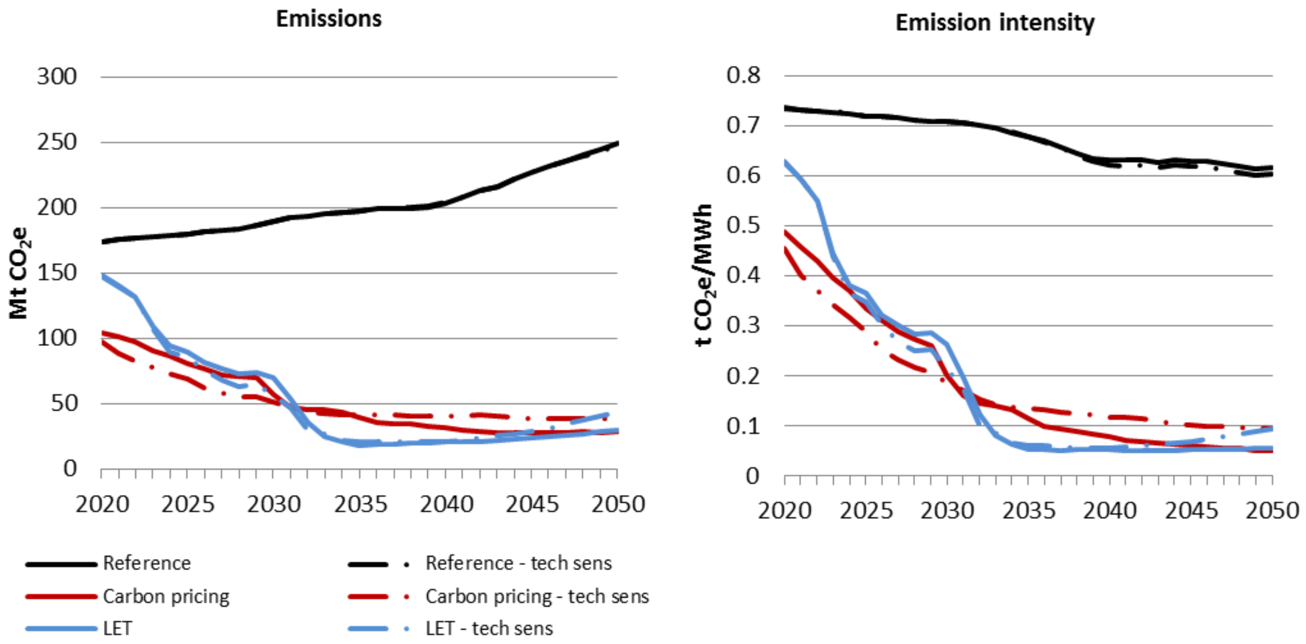
Customer type/scenario	c/kWh				% change from reference			
	2020-2030	2031-2040	2041-2050	2020-2050	2020-2030	2031-2040	2041-2050	2020-2050
Residential								
Reference	24	26	28	26				
Carbon pricing	31	32	31	31	29%	21%	13%	21%
LET	26	30	31	29	9%	16%	11%	12%
Reference – tech sensitivity	24	26	27	26				
Carbon pricing – tech sensitivity	32	36	40	36	33%	36%	46%	38%
LET – tech sensitivity	27	32	31	30	10%	23%	14%	16%
SME								
Reference	23	24	26	24				
Carbon pricing	29	29	29	29	27%	19%	12%	19%
LET	25	29	29	28	10%	18%	15%	14%
Reference – tech sensitivity	23	24	25	24				
Carbon pricing – tech sensitivity	29	32	36	32	30%	34%	43%	36%
LET – tech sensitivity	25	30	29	28	12%	25%	17%	18%
Industrial								
Reference	10	12	13	12				
Carbon pricing	17	17	16	16	61%	41%	28%	43%
LET	13	15	15	14	22%	29%	18%	23%
Reference – tech sensitivity	10	12	12	12				
Carbon pricing – tech sensitivity	18	20	24	20	68%	71%	89%	77%
LET – tech sensitivity	13	18	16	15	25%	49%	27%	34%

Source: Jacobs

9.1.5 Emissions

The emissions constraint is met under all policy scenarios. However, there is more abatement activity in the alternative technology policy scenarios in the period to 2030.

Figure 310: Emissions, technology sensitivities

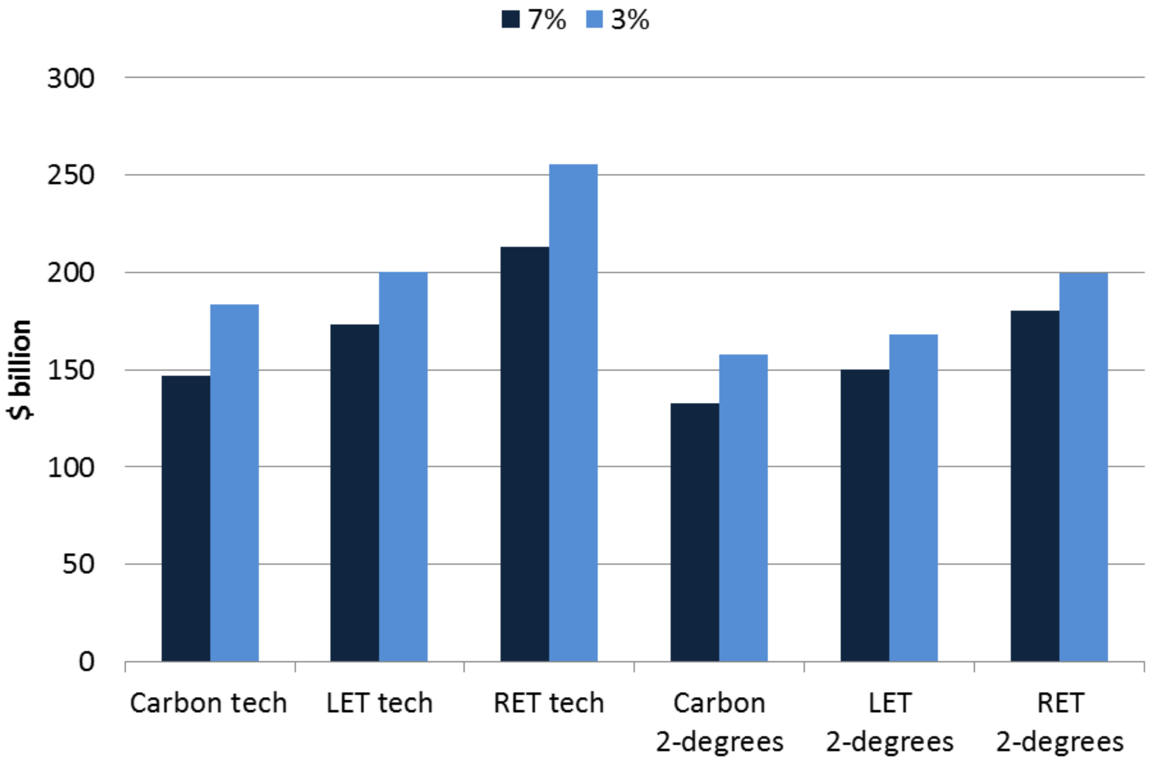


Source: Jacobs. Includes both direct and indirect emissions.

9.1.6 Resource costs and cost of abatement

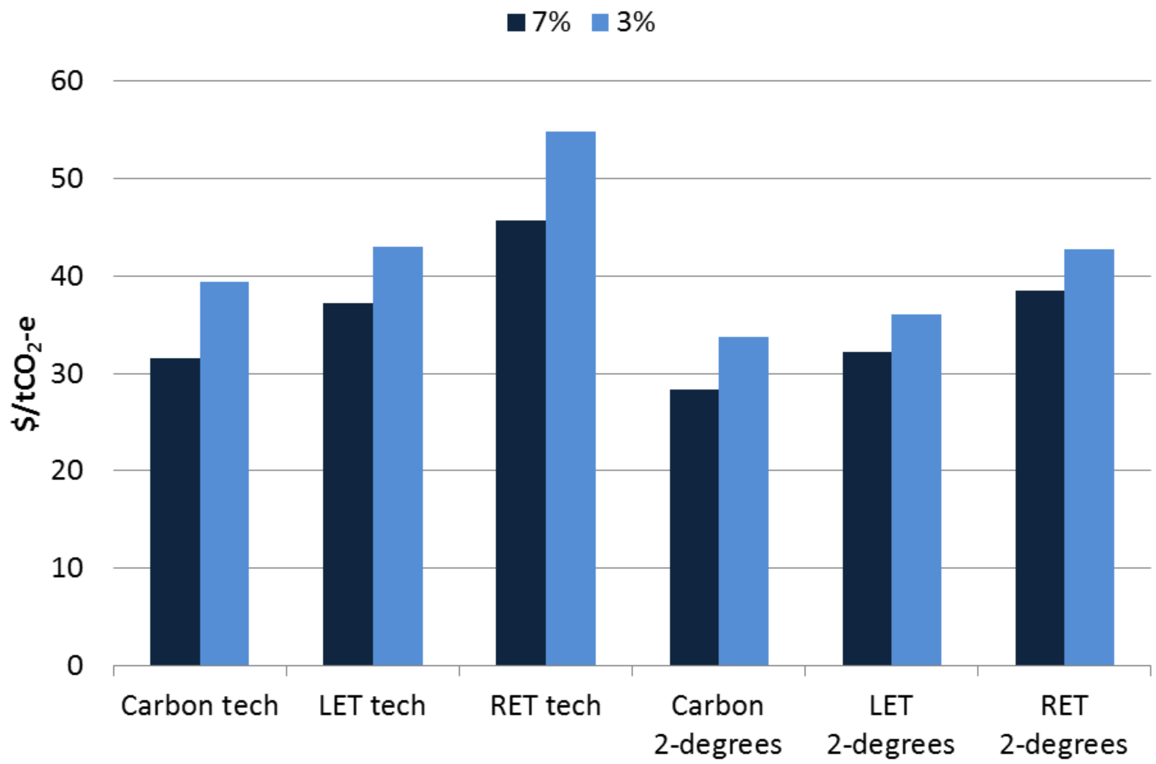
The resource costs and abatement costs are higher under the alternative technology assumptions. The ranking in resource costs are preserved across the policy scenarios, but the difference between the policies is reduced (see Figure 311).Similarly the rankings in abatement costs are preserved across the policy scenarios (see Figure 312). This is because a greater proportion of higher cost low emission technology is required in the LET/RET scenarios under the technology sensitivity cases.

Figure 311: Resource costs relative to reference case, technology sensitivities



Source: Jacobs. The technology sensitivity reference case assumes faster battery cost reductions than the phase one reference case so care should be taken when comparing costs across the two sets of results.

Figure 312 Cost of abatement relative to the reference case, technology sensitivities



Source: Jacobs. The technology sensitivity reference case assumes faster battery cost reductions than the phase one reference case so care should be taken when comparing costs across the two sets of results.

9.2 Reference case

9.2.1 Scenario description

The reference case provides a projection of the future and the starting point to compare the performance of the illustrative policy scenarios under the technology sensitivity, including increased learning rates for battery storage technology. Emissions were not constrained, however for the purposes of comparison with the policy cases to follow, the 2°C global assumptions were retained, which affects fossil fuel prices and low-emissions technology learning rates. Otherwise, the scenario represents a continuation of existing policies with no policy change affecting the Australian electricity sector, nor any expected by market participants.

For a full range of the policy and other assumptions underlying this scenario, see Appendix D.

9.2.2 Key findings

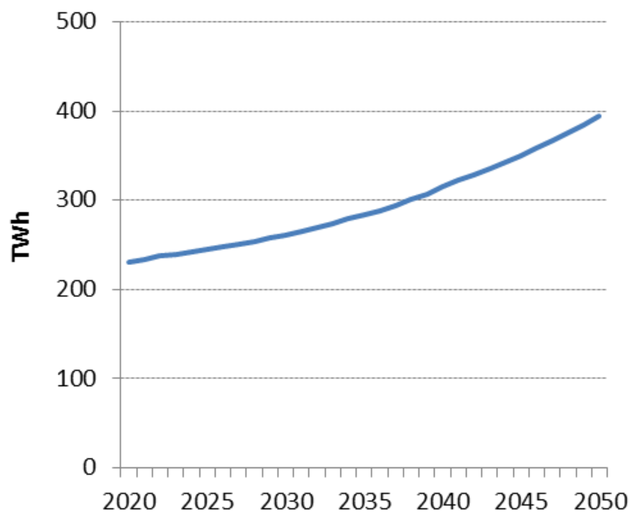
The reference case outcomes were very similar to the unconstrained 2°C reference case. None of the excluded technologies were deployed under the unconstrained scenario, and therefore new capacity is virtually identical with respect to base load and intermediate duty capacity. The key difference to the unrestricted reference case is that battery storage becomes competitive with gas turbine technology for the peaking role in the late 2030s due to its enhanced learning rate. From 2037/38 onwards large-scale stand-alone battery storage enters the market instead of gas turbines to fulfil the peaking role. Almost 7,000 MW is installed by 2049/50 across Australia, and it runs at an average capacity factor of 16%, which is substantially higher than the duty of a typical gas turbine. This battery storage also creates additional demand in off-peak hours during their charging cycle, which encourages additional dispatch of low cost base load generation.

9.2.3 Demand

Figure 313 shows sent-out energy demand for the reference case, and also compares it to the unconstrained 2°C reference case. Demand is almost identical between the two cases until 2037/38[32]. The technology sensitivity has a higher level of demand post 2037, which is created by the charging cycle of the batteries[33].

Figure 313: Sent-out energy, reference case, technology sensitivity

The left graph shows absolute figures. The right graph shows figures relative to the 2°C reference case.



Source: Pitt & Sherry, ACIL Allen and Jacobs

[32] The small 0.4% difference in demand between the cases prior to 2037/38 is due to additional pump storage being dispatched under the technology sensitivity.

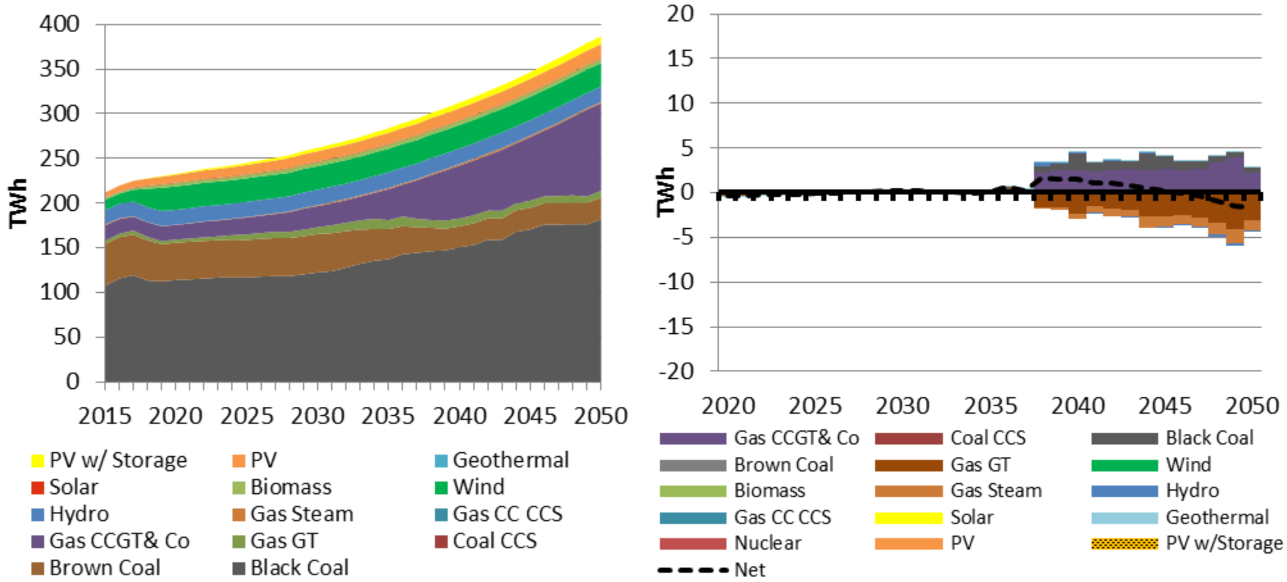
[33] The demand projections shown throughout the report includes the component for "pumping energy" for pumped storage options. In the modelling, large-scale batteries are treated as pumped storages.

9.2.4 Generation and capacity

Figure 314 shows the generation mix across the modelling horizon both in absolute terms and relative to the unconstrained 2°C reference case. The key difference between the two reference cases is that much more large-scale battery generation occurs post 2037 under the technology sensitivity, and less gas turbine and gas steam generation. The additional demand created by battery charging is serviced mainly by CCGT generation and some black coal generation.

Figure 314: Generation mix, reference case, technology sensitivity

The left graph shows absolute figures. The right graph shows figures relative to the 2°C reference case.

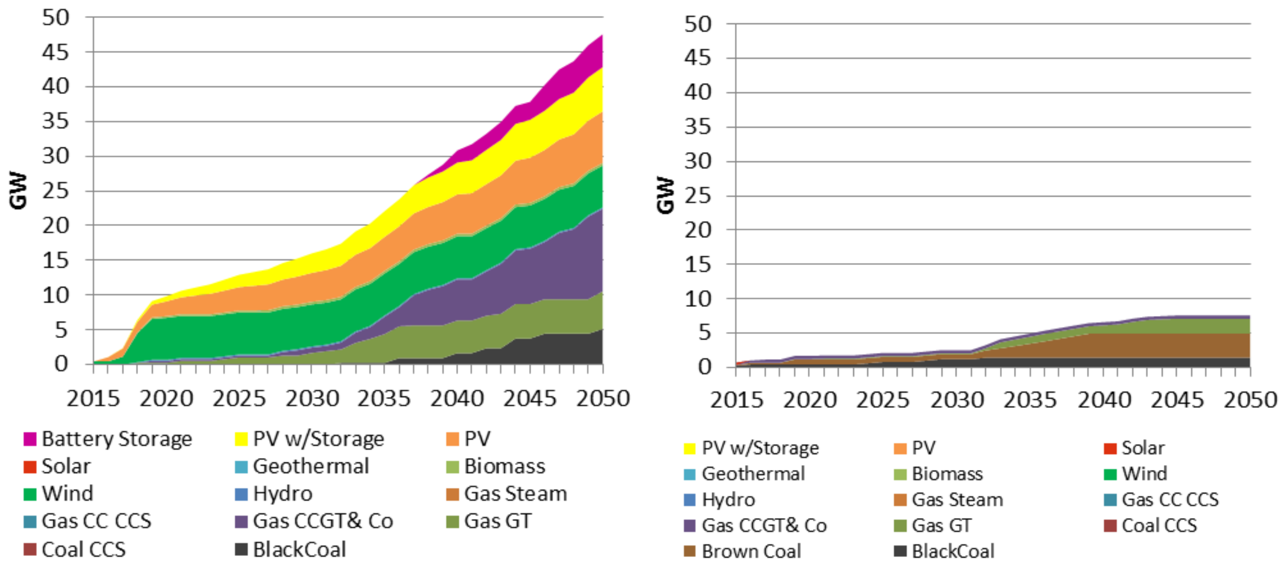


Source: Jacobs

Figure 315 shows cumulative new generation capacity, including generation relative to the unconstrained 2°C reference case. It shows that battery capacity under the technology sensitivity replaces gas turbine capacity from around 2037 due to declining battery costs assumed.

Figure 315: Cumulative new and retired capacity, reference case, technology sensitivity

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



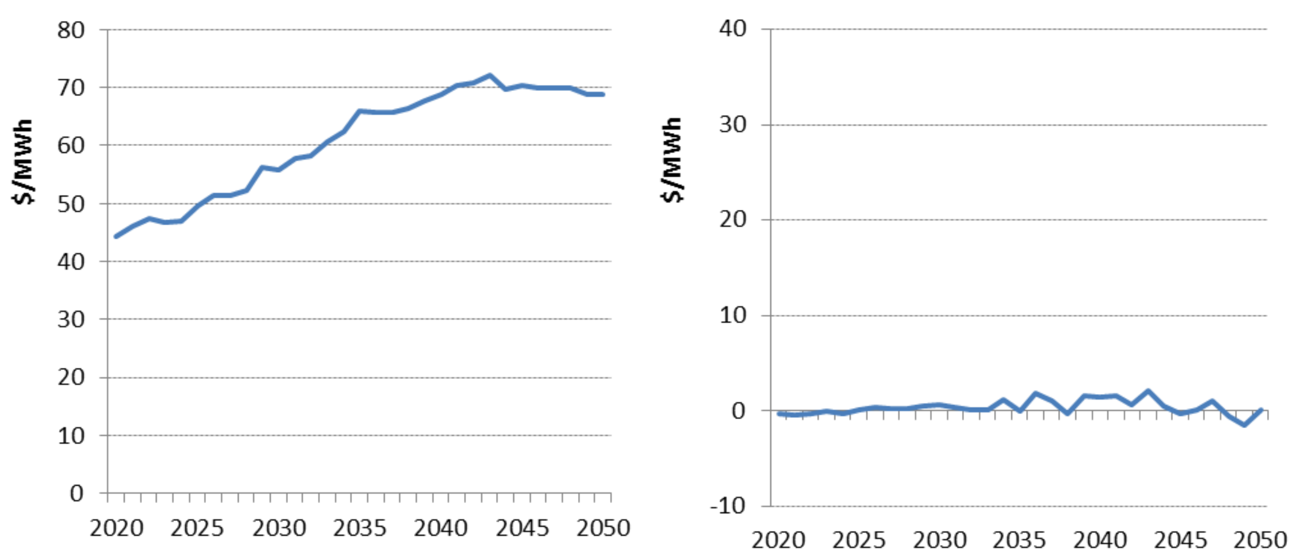
Source: Jacobs

9.2.5 Prices

Figure 316 shows wholesale prices, including the price relative to the unconstrained 2°C reference case. Differences between the two scenarios are very small. Similar trends are observed in the retail prices, shown in Figure 317, with the difference being that there is a small, yet distinct downtrend in the retail price for the technology sensitivity post 2037 when batteries are deployed. This reflects the higher capacity factors achieved by batteries relative to gas turbines, since their influence on price extends to shoulder periods, as well as peak periods.

Figure 316: Wholesale electricity time-weighted prices, reference case, technology sensitivity

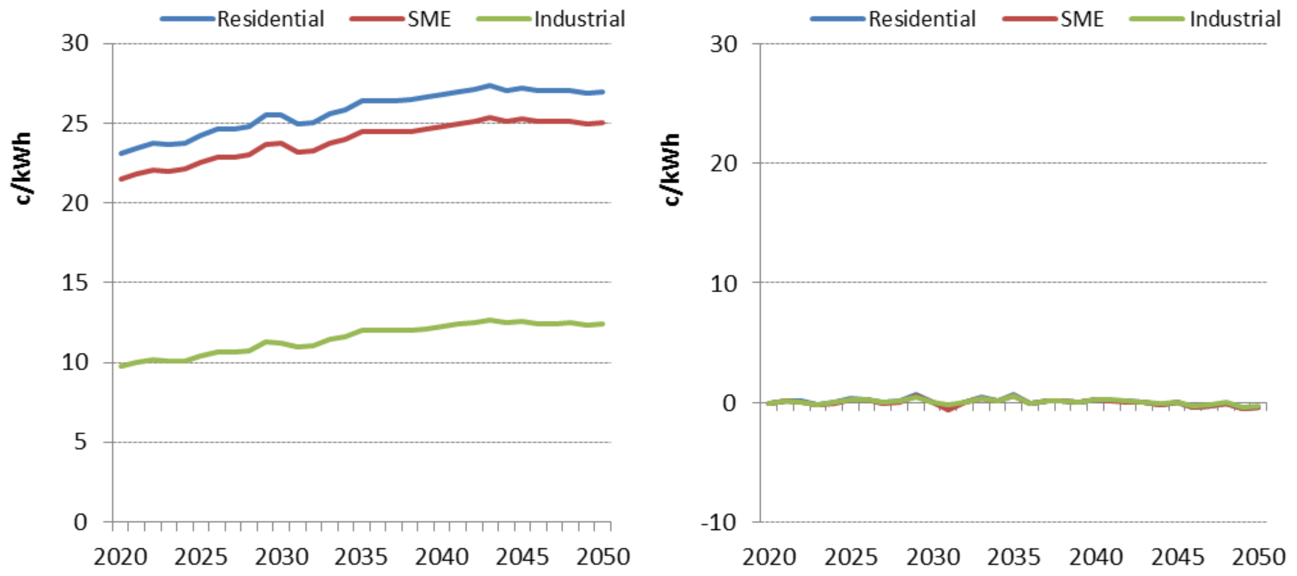
The left graph shows absolute figures. The right graph shows figures relative to the 2°C reference case.



Source: Jacobs

Figure 317: Retail prices by customer class, reference case, technology sensitivity

The left graph shows absolute figures. The right graph shows figures relative to the 2°C reference case.

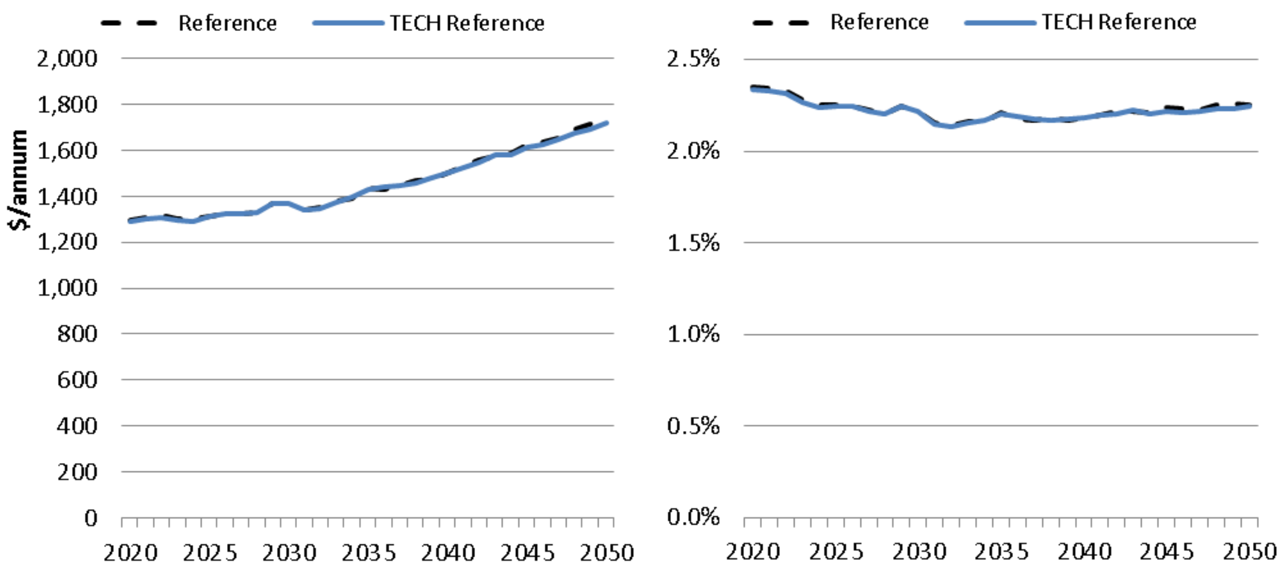


Source: Jacobs

Figure 318 shows the weighted average residential bill relative to the unconstrained 2°C reference case, and also as a percentage of disposable income.

Figure 318: Residential bills, reference case, technology sensitivity

The left graph shows the absolute residential bill. The right graph shows the residential bill as a % of disposable income.



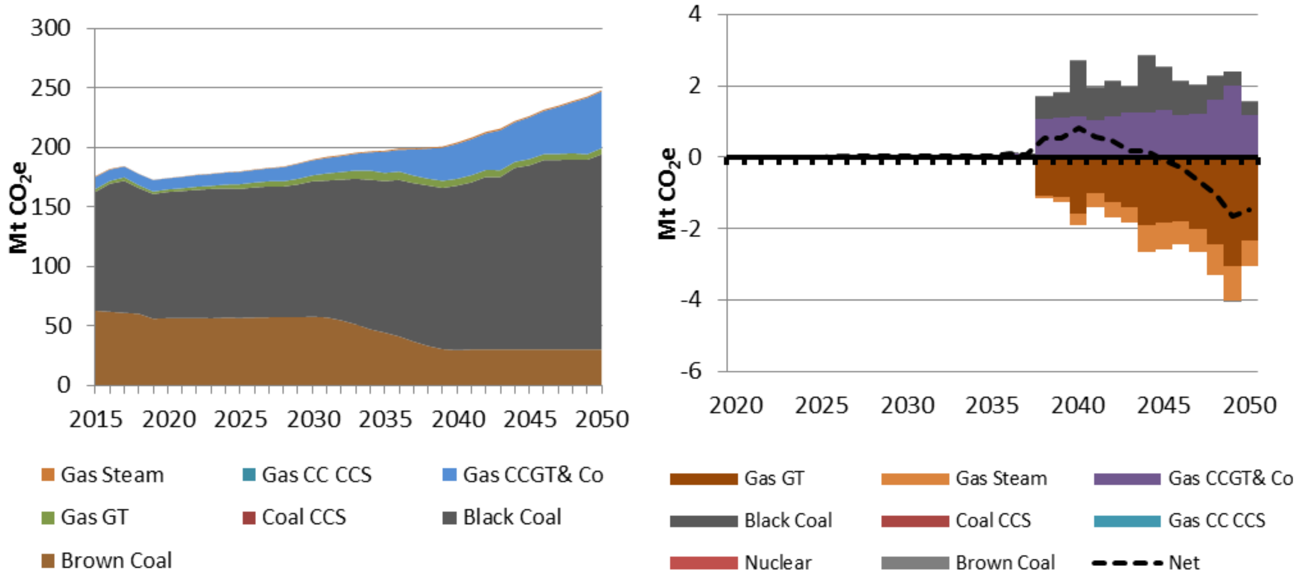
Source: Jacobs

9.2.6 Emissions

Figure 319 shows annual emissions by technology and the difference relative to the unconstrained 2°C reference case, while Figure 320 illustrates the absolute grid emission intensity of the scenario and the difference relative to the reference case. Differences between the two scenarios are very small until 2037/38, and even then there is less than 1% difference in aggregate emissions between the scenarios. The deployment of large-scale batteries post 2037 results in some emission savings because they displace gas turbines and gas steam generation while using mainly CCGT generation to charge.

Figure 319: Emissions by technology, reference case, technology sensitivity

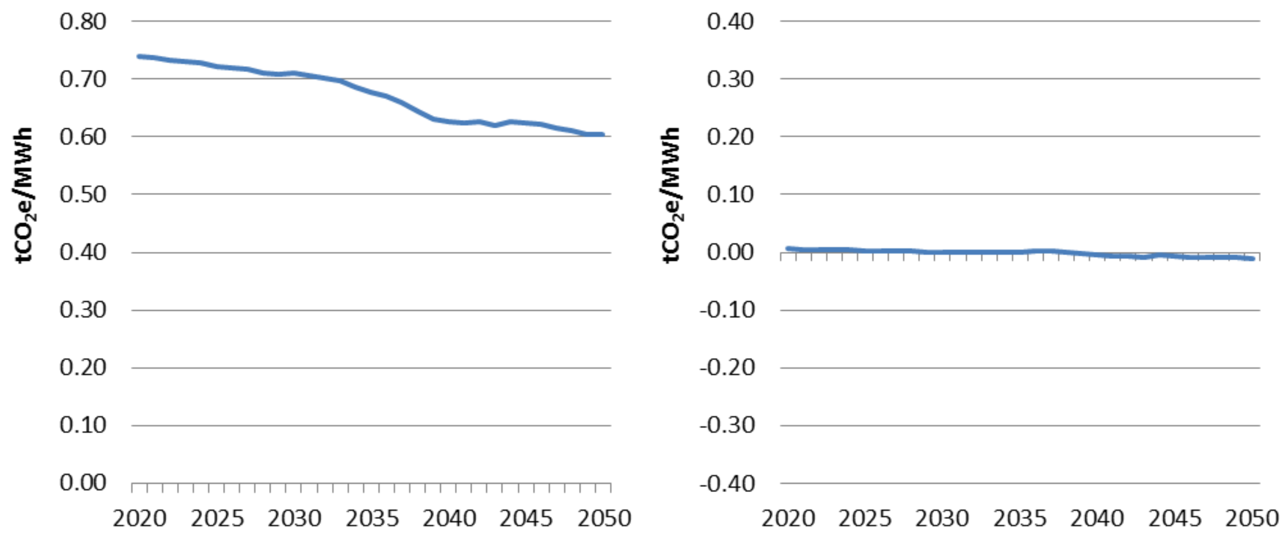
The left graph shows absolute figures. The right graph shows figures relative the 2°C reference case.



Source: Jacobs. Includes both direct and indirect emissions.

Figure 320: Generation emission intensity, reference case, technology sensitivity

The left graph shows absolute figures. The right graph shows figures relative to the 2°C reference case.



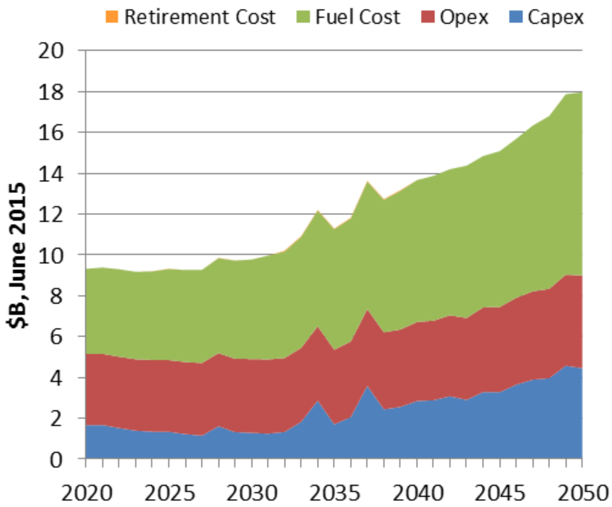
Source: Jacobs. Includes direct emissions only.

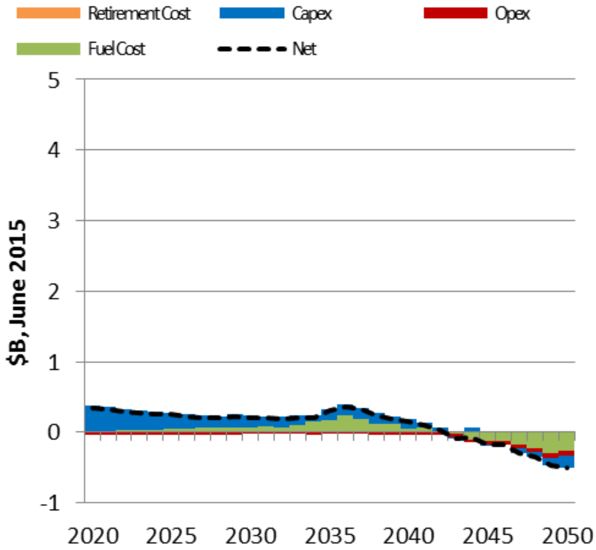
9.2.7 Costs

Figure 321 shows annualised resource costs by four cost categories. The differences between the restricted and unrestricted reference case costs are small, with slightly higher costs in the restricted reference case. Batteries incur higher capital costs, but they also save on fuel costs since they are mainly charged by CCGTs while displacing gas turbines and gas steam generation.

Figure 321: Annualised costs by category, reference case, technology sensitivity

The left graph shows the absolute costs. The right graph shows the costs relative to the 2°C reference case.

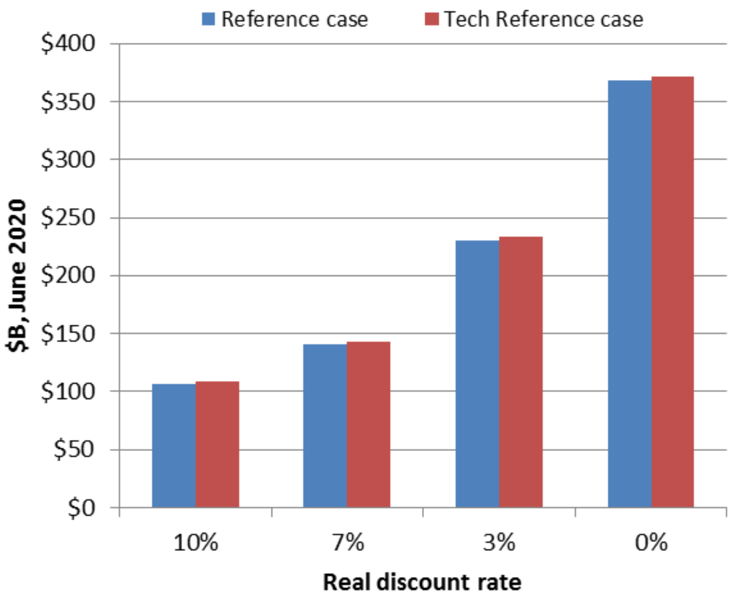




Source: Jacobs

Figure 322 shows the net present value of the resource costs for the technology sensitivity for four separate discount rates. The cost is only 1% to 2% higher than for the unconstrained 2°C reference case.

Figure 322: NPV of resource costs, reference case, technology sensitivity



Source: Jacobs

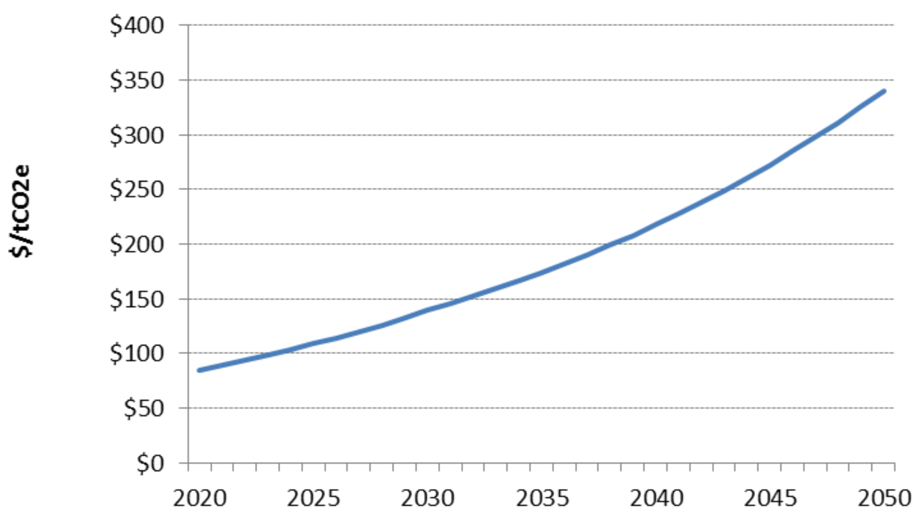
9.3 Carbon pricing

9.3.1 Scenario description

Under carbon pricing, all generators whose emissions exceed a given absolute emissions threshold are liable for surrendering permits to cover all of their emissions each year. The carbon price has been implemented as a carbon tax, that is, with no banking or borrowing of emissions permits.

Under the technology sensitivity, the carbon price was increased until the 2°C cumulative emission target of 1,580 Mt CO_2e was reached. A higher price is necessary to achieve the same emission target because some potentially lower cost technologies that are not presently generating at commercial scale in Australia are excluded from being deployed. Figure 323 shows the carbon price path required to achieve the cumulative emissions constraint. The carbon price commences at $85/t CO_2e in 2020 and escalates at an average annual rate of 4.7% per annum in real terms, reaching $340/t CO_2e in 2050. The escalation rate is identical to that of the unconstrained 2°C scenario.

Figure 323: Technology sensitivity carbon price path



Source: Jacobs

9.3.2 Key findings

The relatively high starting value of the carbon price has two immediate impacts: it forces the rapid closure of the Victorian brown coal fleet (all brown coal generators are closed by the end of 2019/20), and it also causes the wholesale price to reach the new entry price CCGTs in both the NEM and the WEM. The Victorian brown coal fleet is earliest affected by a carbon price because it has the highest emission intensity of all base load generation in Australia and therefore faces the highest carbon impost. However, 26% of Australia's black coal generation capacity also closes in anticipation of the carbon price at the end of 2018/19 and over half is closed by 2025/26. All coal fired generation in Australia ceases by 2033/34 for the assumed carbon price. Most of these outcomes are similar to the corresponding unconstrained scenario, with some effects, such as retirement of all coal fired generation, brought forward two or three years.

As with the unconstrained scenario, prices are high enough in 2019/20 to encourage the immediate entry of large volumes of renewable generation capacity, mainly in the form of wind generation, although large-scale solar generation also plays an increasingly important role. New gas fired generation is also an important part of the energy mix.

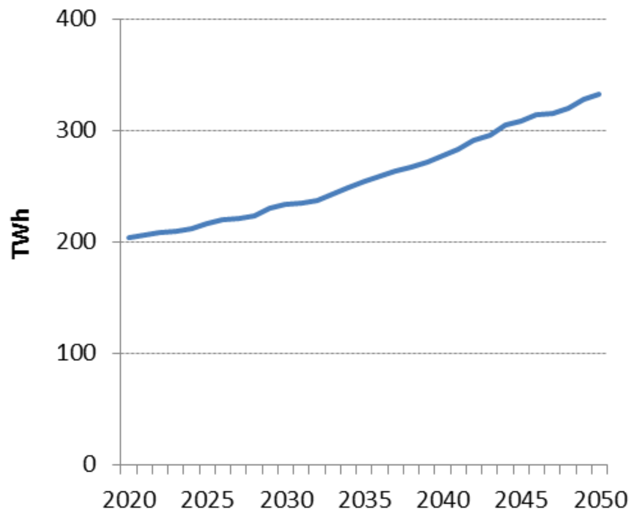
After 2030 the key technologies entering the market are wind generation and large-scale solar generation. The latter technology plays a steadily increasing role, and by 2041/42 is making over half the contribution made by wind generation in energy terms, and the majority of this is from systems with storage. Stand-alone large-scale battery storage begins to appear in the mix from 2036/37 onwards serving in a peaking role but also helping to smooth out the effects of the intermittent nature of wind generation. This particular generation mix necessarily creates more curtailed energy[34] when compared to the unconstrained scenario, due to the intermittent nature of much of the generation technology being deployed. An important consequence of excluding the dispatchable low emission technologies is that wholesale prices continue to increase at about 40% of the rate of growth of the carbon price. This reflects the emission intensity of CCGT technology, which is the thermal technology that sets the new entrant price. As a result, wholesale prices are much higher under the technology sensitivity, and this translates into substantially lower levels of electricity demand.

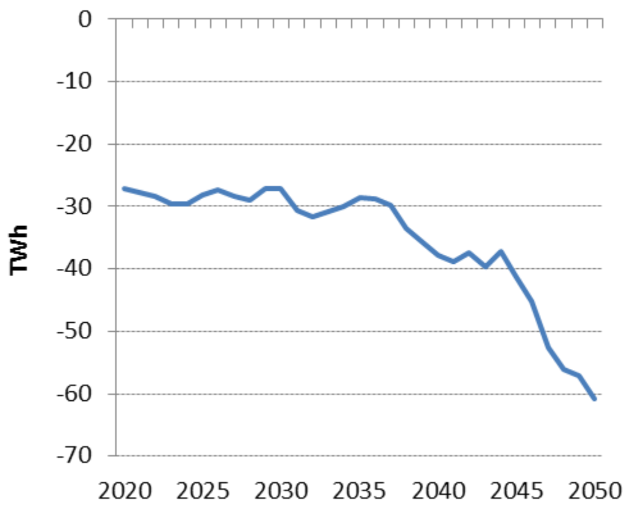
9.3.3 Demand

Figure 324 shows sent-out energy demand for the carbon pricing scenario and relative to the reference case. Total energy consumed reaches 333 TWh in 2050, 63 TWh lower than the reference case due to higher wholesale prices reducing demand. This represents a 16% reduction in demand relative to the reference case.

Figure 324: Sent-out energy, carbon pricing, technology sensitivity

The left graph shows absolute figures. The right graph shows figures relative to the technology sensitivity reference case.





Source: Pitt & Sherry, ACIL Allen and Jacobs

9.3.4 Generation and capacity

Figure 325 shows the generation mix across the modelling horizon both in absolute terms and relative to the reference case. Key features are the rapidly 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. Their role stagnates after 2030 as they are no longer competitive with renewable technologies due to the very high carbon price. Wind is the dominant new entrant technology, providing almost 25% of all grid generation in 2019/20 and peaking at 43% in 2032/33. Large-scale solar also plays an increasingly important role, starting from a small base in 2020, and achieving an average growth rate of 12.1% per annum across the 30-year modelling horizon. Its peak contribution occurs in 2049/50 when it comprises 29% of all grid generation.

Relative to the reference case there is much less coal generation, and initially there is more CCGT generation although this reverses by the late 2040s, when CCGTs do not play as substantial a role in the carbon pricing technology sensitivity.

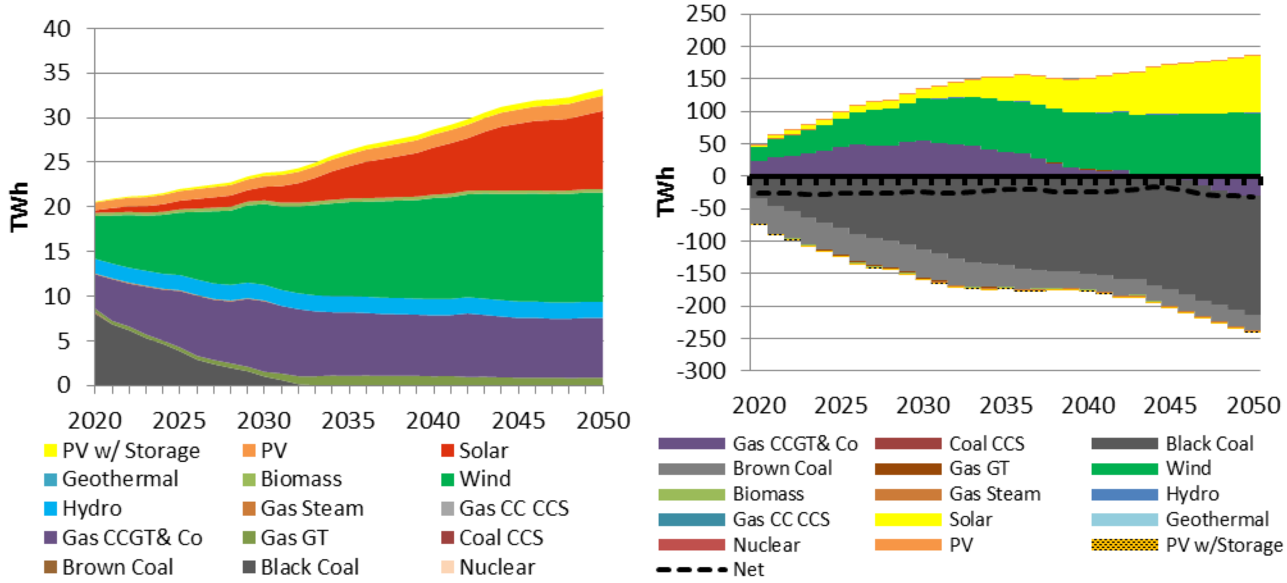
[34] Up to 3.5 times as much.

Figure 326 shows cumulative new generation capacity across the NEM and WEM. It shows that new CCGT and wind capacity are the dominant new entrant technologies in the 2020s. It also shows that in capacity terms rooftop PV both with and without storage make notable contributions to the generation mix, and gas turbine capacity also grows progressively until the late 2030s, when stand-alone battery storage becomes competitive in a peaking role. Gas turbines and batteries play an important role in the market as backup capacity for intermittent generation.

Under the carbon pricing technology sensitivity there are nine transmission upgrades totalling 6,720 MW. This is about double of what is required for the reference case and includes a new transmission line connecting South Australia with New South Wales. This level of transmission upgrades is required to unlock renewable energy resources, especially wind in South Australia, and also helps to mitigate curtailed energy.

Figure 325: Generation mix, carbon pricing, technology sensitivity

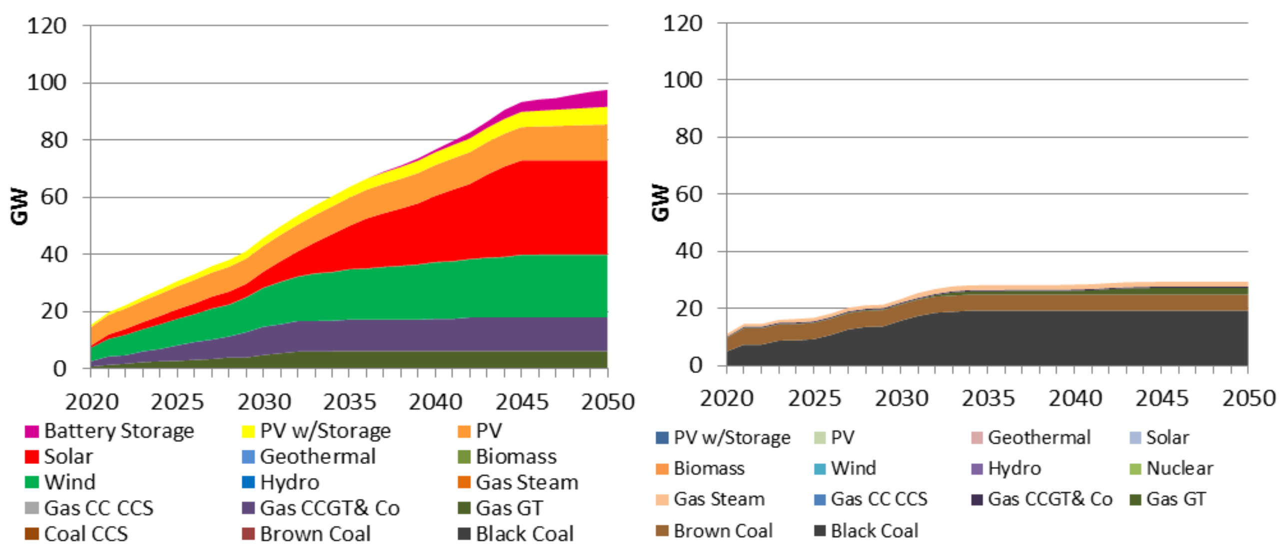
The left graph shows absolute figures. The right graph shows figures relative to the technology sensitivity reference case.



Source: Jacobs

Figure 326: Cumulative new and retired capacity, carbon pricing, technology sensitivity

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



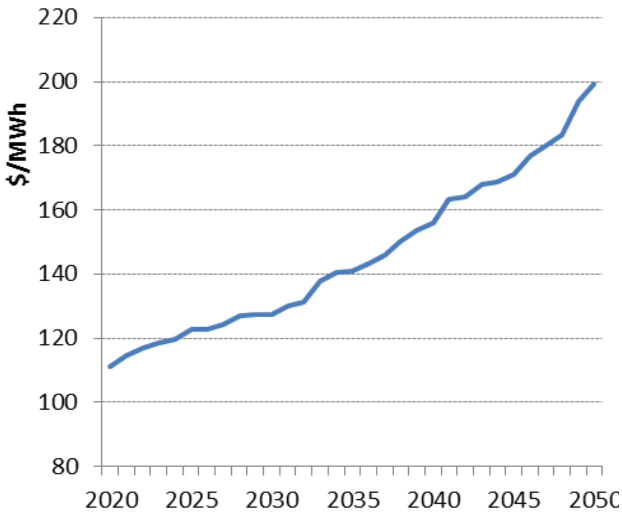
Source: Jacobs

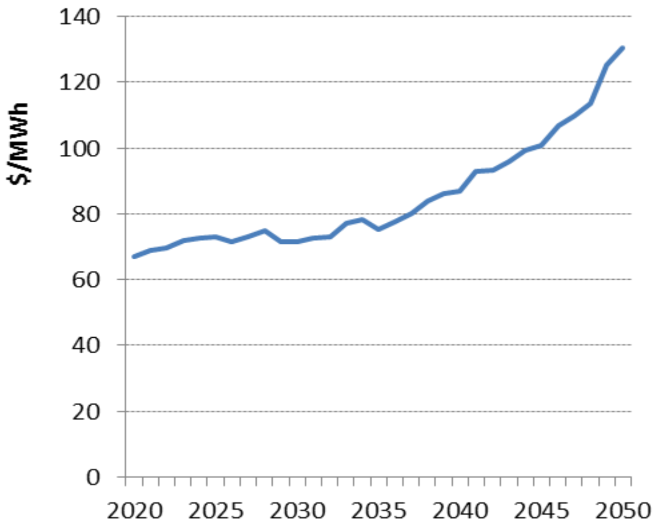
9.3.5 Prices

Figure 327 shows wholesale prices. Prices start in 2020 from a high level compared to current wholesale prices and trend upward over the whole modelling period. The price in the 2020s is set by new entrant CCGTs, and the persistent upward price trend is driven by the rapidly escalating carbon price. Prices continue to climb because under the technology sensitivity there are no low emission dispatchable generation options, and the volume of renewables required to replace the coal fired fleet implies that low cost options are rapidly exhausted and more expensive options are progressively deployed.

Figure 327: Wholesale electricity time-weighted prices, carbon pricing, technology sensitivity

The left graph shows absolute figures. The right graph shows figures relative to the technology sensitivity reference case.



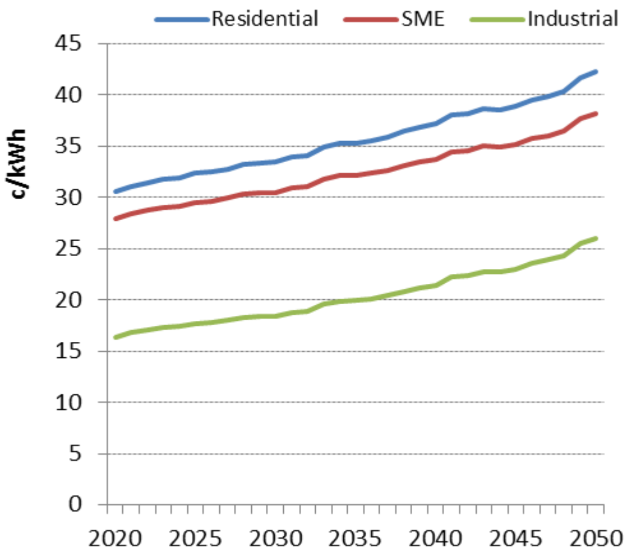


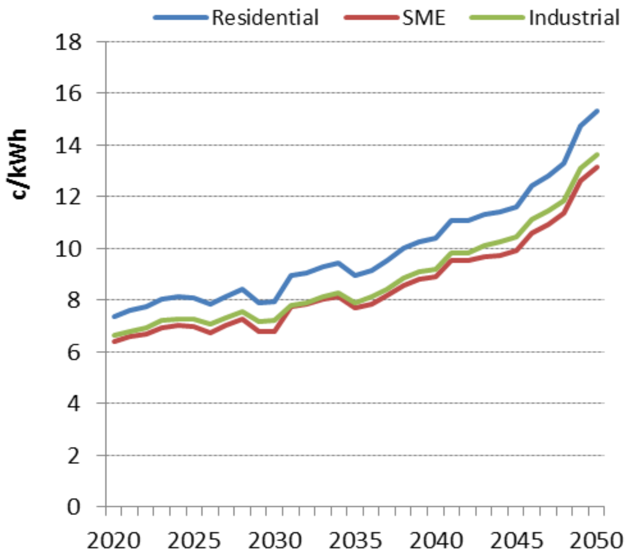
Source: Jacobs

Figure 328 shows weighted average retail prices by customer class. They contain the same trends as the wholesale prices, but the relative price movements are more muted since the wholesale price only comprises typically 30% to 40% of the retail price.

Figure 328: Retail prices by customer class, carbon pricing, technology sensitivity

The left graph shows absolute figures. The right graph shows figures relative to the technology sensitivity reference case.



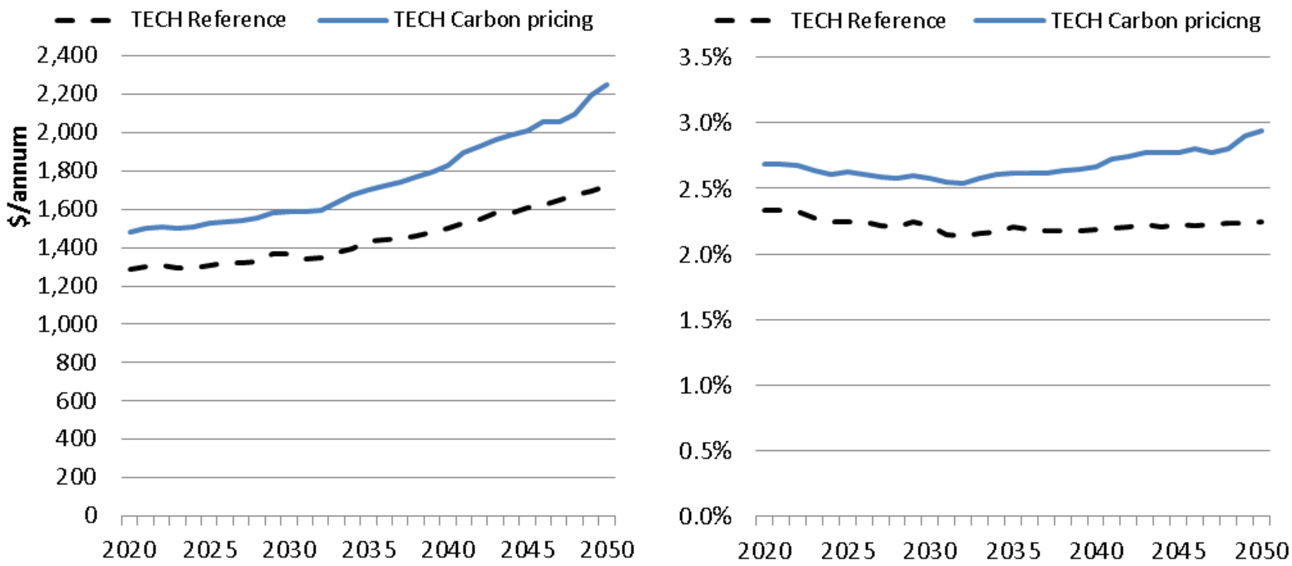


Source: Jacobs

Figure 329 shows the Australian weighted average residential bill relative to the reference case, as well as the bill as a percentage of average expected disposable income. The bill is substantially higher under the technology sensitivity.

Figure 329: Residential bills, carbon pricing, technology sensitivity

The left graph shows the absolute residential bill. The right graph shows the residential bill as a % of disposable income.



Source: Jacobs

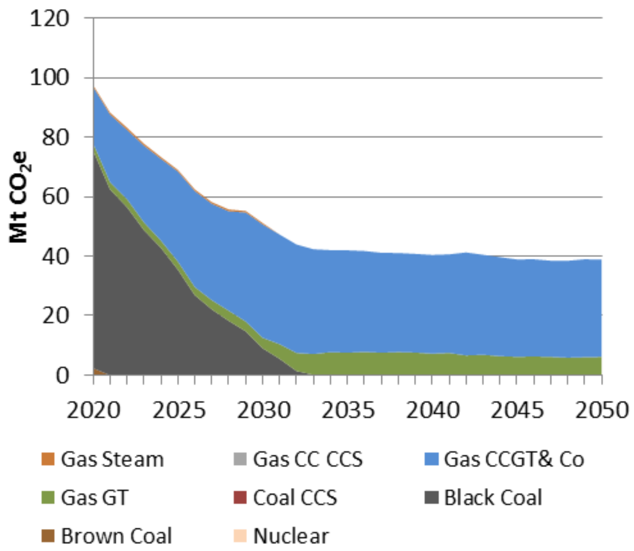
9.3.6 Emissions

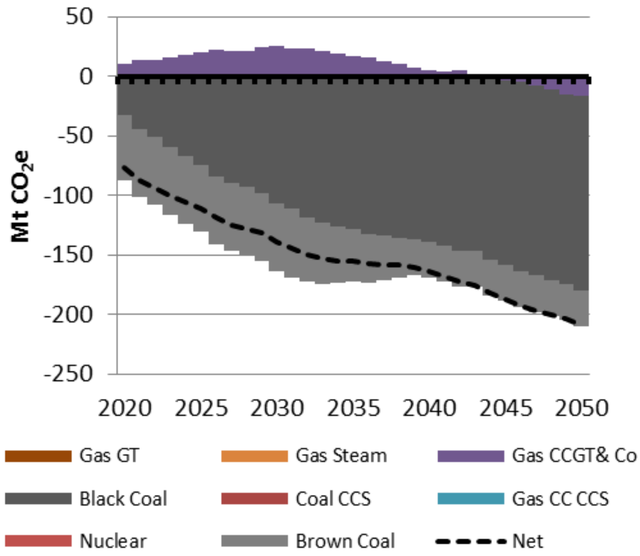
Figure 330 shows annual emissions by fuel type. In 2019/20 total emissions are 97 Mt CO_2e, which represents just 56% of the 2019/20 Reference case emissions. Under the technology sensitivity coal fired emissions comprise just 27% of total cumulative emissions, compared to 31% under the unconstrained scenario. CCGTs are by far the largest contributor to emissions under the technology sensitivity, accounting for 63% of total cumulative emissions. Long-term emissions settle at about 40 Mt CO_2e per annum post 2040, which is 30% more than those of the unconstrained scenario.

Figure 331 shows the generation emission intensity both in absolute terms and relative to the reference case.

Figure 330: Emissions by technology, carbon pricing, technology sensitivity

The left graph shows absolute figures. The right graph shows figures relative to the technology sensitivity reference case.

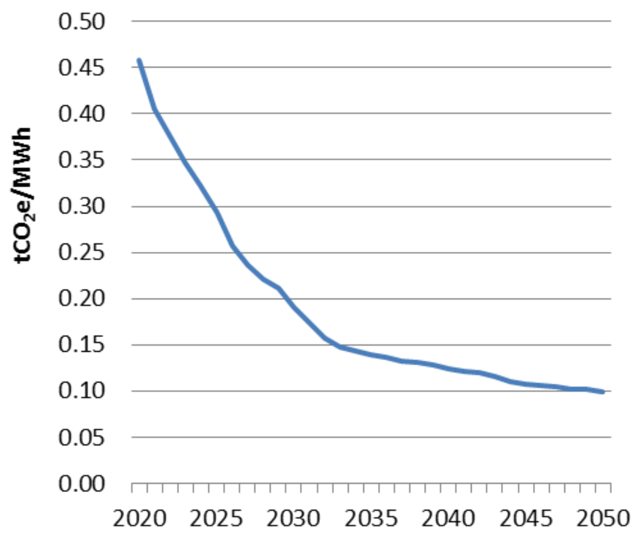


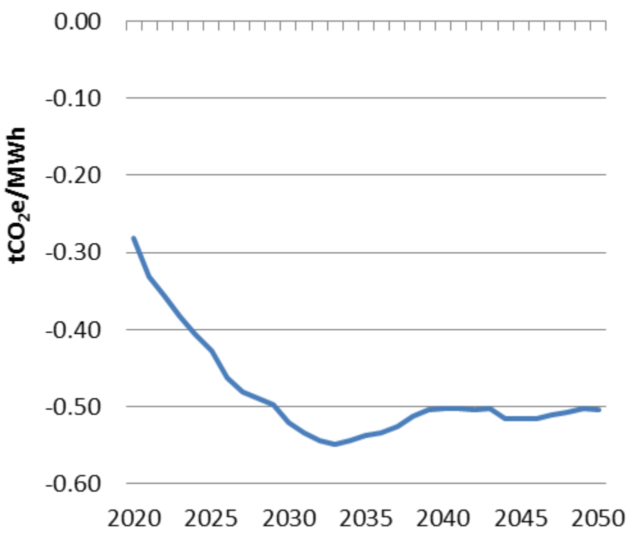


Source: Jacobs. Includes both direct and indirect emissions.

Figure 331: Generation emission intensity, carbon pricing, technology sensitivity

The left graph shows absolute figures. The right graph shows figures relative to the technology sensitivity reference case.





Source: Jacobs. Includes direct emissions only.

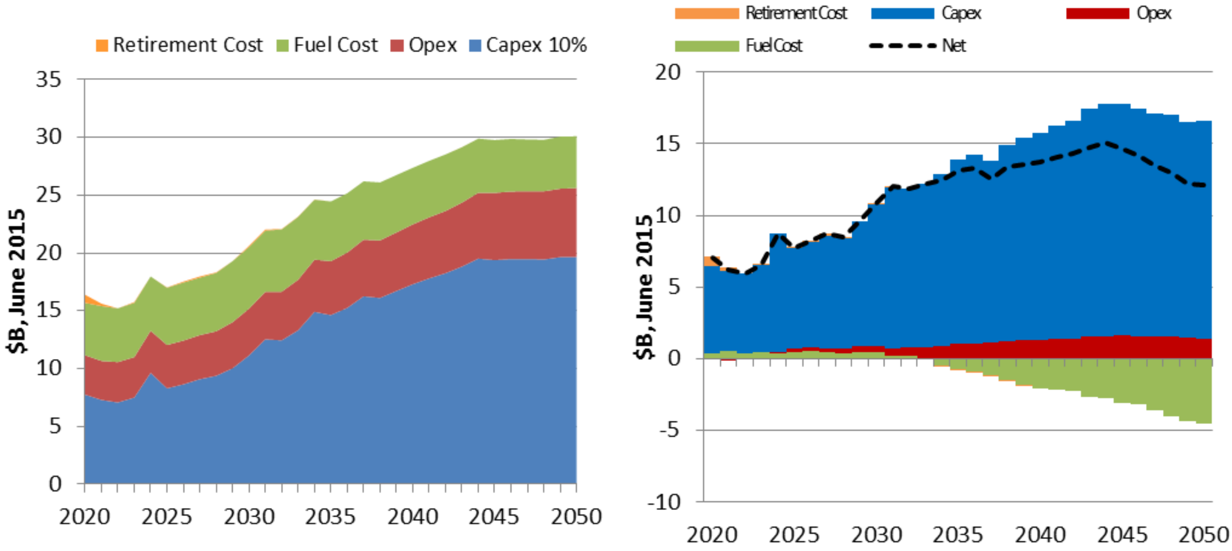
9.3.7 Costs

Figure 332 shows annualised resource costs by four cost categories. Costs in 2019/20 are initially about $17 billion per annum and remain at a similar level until 2023. Total costs escalate rapidly thereafter, and then plateau in the late 2040s. Capital expenditure is the largest contributor to cost, comprising 47% of the total cost on average in the first ten years, and then peaks at 61% of the total resource cost by 2044/45. There is growth in the capital and operating cost categories across the modelling horizon while fuel cost remains relatively flat over this time period.

Figure 333 shows the net present value of the resource costs for carbon pricing relative to the reference case for four separate discount rates. The total resource cost for carbon pricing ranges from 102% (at 10% real discount rate) to 44% (without discounting) higher than that of the reference case. The total resource cost is higher than that of the unconstrained scenario.

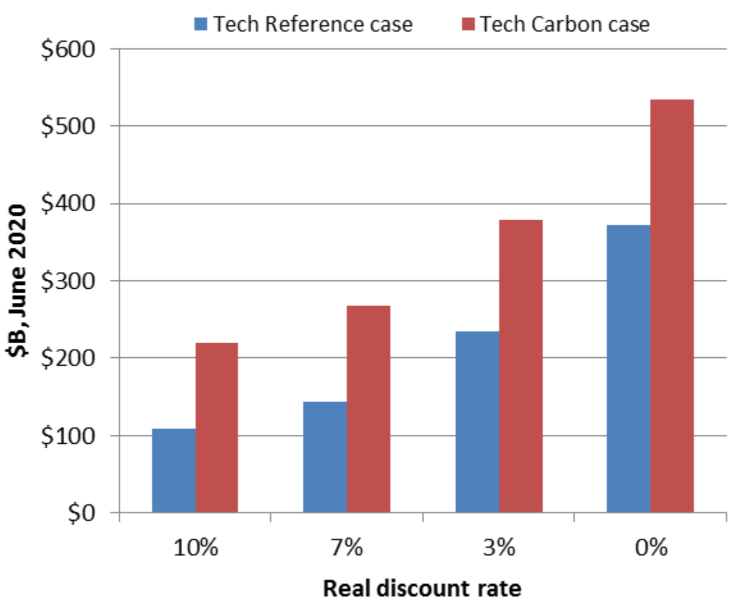
Figure 332: Annualised costs by category, carbon pricing, technology sensitivity

The left graph shows the absolute costs. The right graph shows the costs relative to the technology sensitivity reference case.



Source: Jacobs

Figure 333: NPV of resource costs, carbon pricing, technology sensitivity



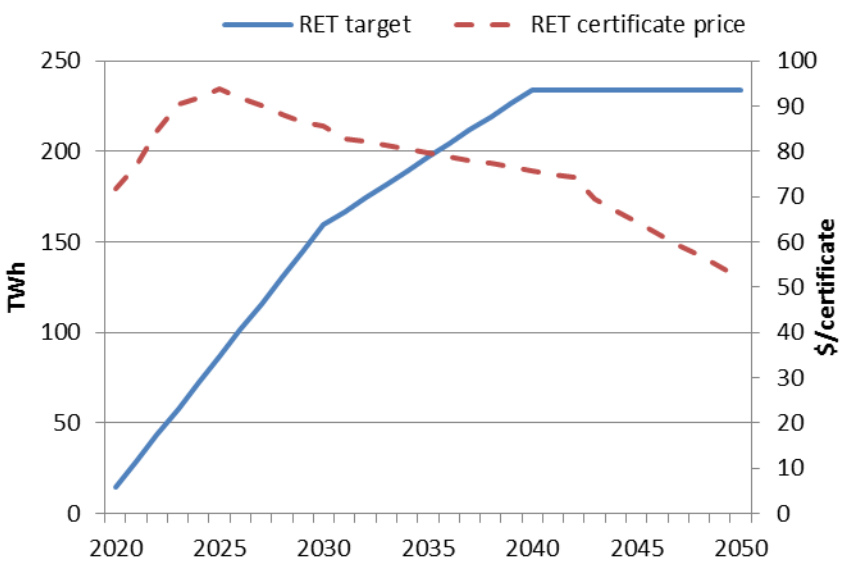
Source: Jacobs. Excludes demand adjustment. See Appendix B.3.2 for further detail.

9.4 Renewable energy target

9.4.1 Scenario description

The RET works by creating a market for additional renewable electricity that supports investment in new renewable generation capacity. It places a legal obligation on entities that purchase wholesale electricity (mainly electricity retailers) to surrender a certain number of certificates to the regulator each year. These certificates are generated by accredited renewable power stations. Figure 334 shows the final RET trajectory and the corresponding RET certificate price required to satisfy the cumulative emissions constraint. In the course of the modelling it was found that a dual linear form for the RET trajectory was necessary to achieve a least cost solution.

Figure 334: RET target and RET certificate price, technology sensitivity



Source: Jacobs

For further discussion see Section 2.

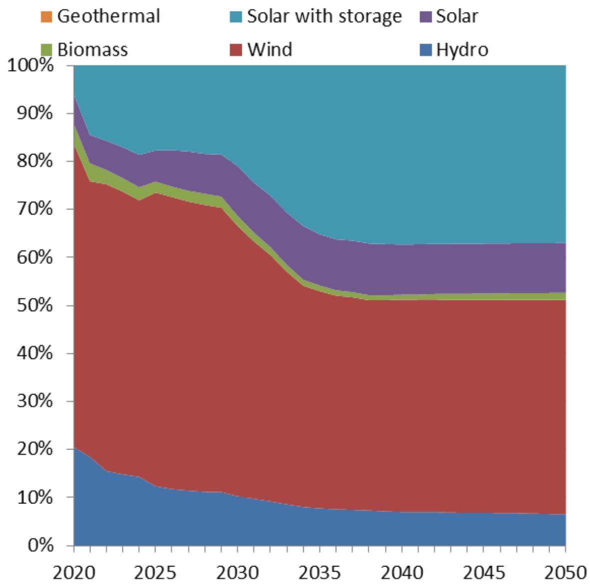
9.4.2 Key findings

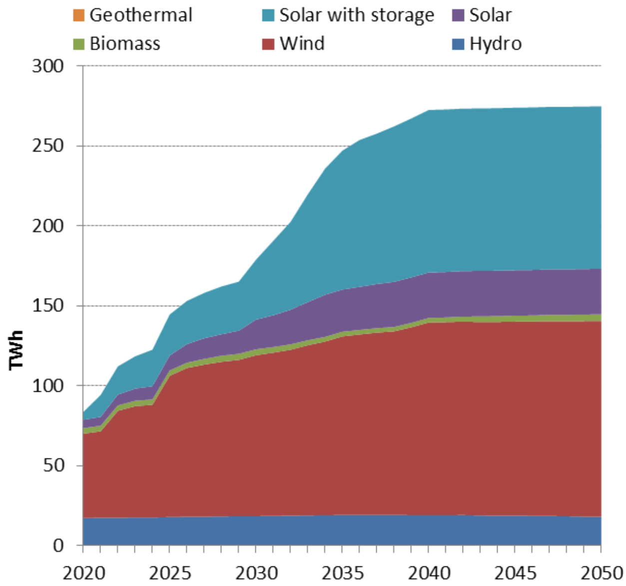
The key difference between the technology sensitivity and the unconstrained RET is that geothermal technology is excluded under the sensitivity. Figure 335 shows the renewable capacity deployed to meet the RET. The modelling shows that solar with storage acts as a substitute for geothermal at slightly higher costs. The other competing substitute would have been additional wind, but this is a higher cost solution due to additional volumes of curtailed energy.

Stand-alone battery storage enters the market in the mid-2030s mainly as a lower cost alternative to gas turbines (much as it does in the reference case), but it also makes a small contribution to reducing curtailed energy from intermittent generation sources.

The costs of this sensitivity are around 20% higher than that of the unconstrained RET.

Figure 335: Contribution of large-scale renewable generation by technology, renewable energy target, technology sensitivity





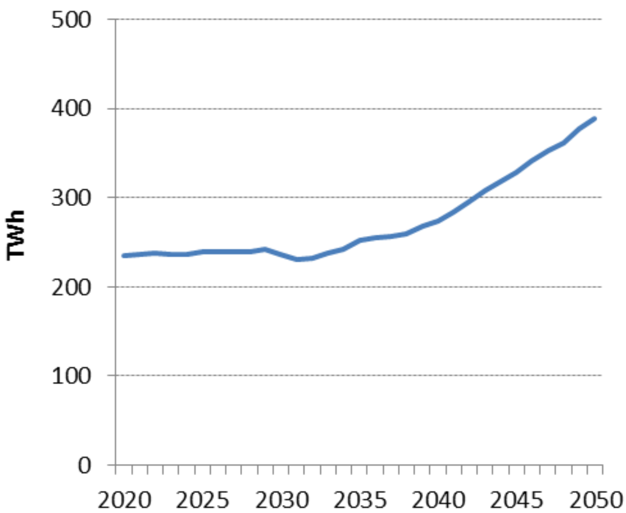
Source: Jacobs

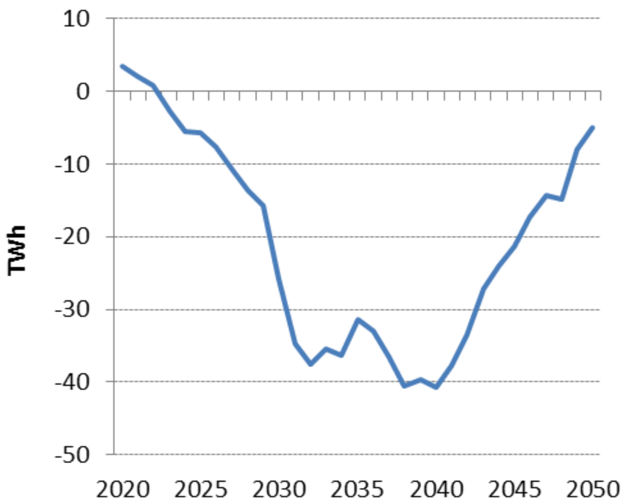
9.4.3 Demand

Figure 338 shows sent-out energy demand for the RET scenario in absolute terms and relative to the reference case. Total energy consumed reaches 389 TWh in 2049/50, 7 TWh lower than the reference case due to high certificate prices inflating retail prices above those of the reference case, thus reducing demand.

Figure 336: Sent-out energy, renewable energy target, technology sensitivity

The left graph shows absolute figures. The right graph shows figures relative to the technology sensitivity reference case.





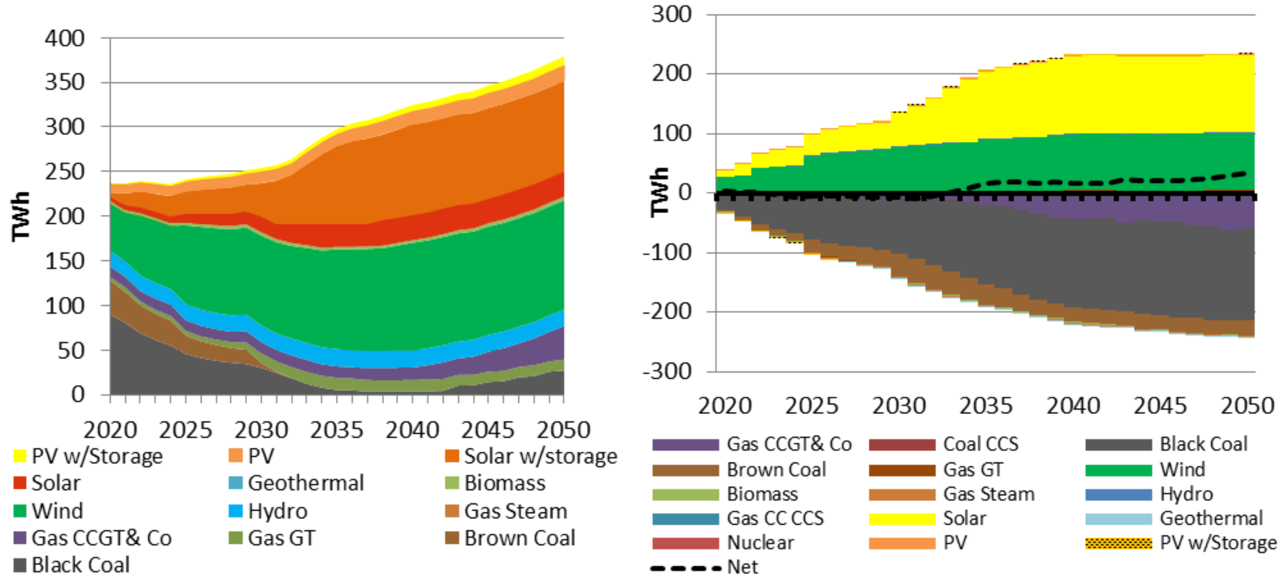
Source: Pitt & Sherry, ACIL Allen and Jacobs

9.4.4 Generation and capacity

Figure 337 shows the generation mix across the modelling horizon in absolute terms and relative to the reference case. The key trends in the graph are identical to the unconstrained RET scenario, with the exception that solar with storage fulfils the role of geothermal generation from the early 2030s. Stand-alone batteries with storage are also in the generation mix, mainly displacing new gas turbine capacity.

Figure 337: Generation mix, renewable energy target, technology sensitivity

The left graph shows absolute figures. The right graph shows figures relative to the technology sensitivity reference case.



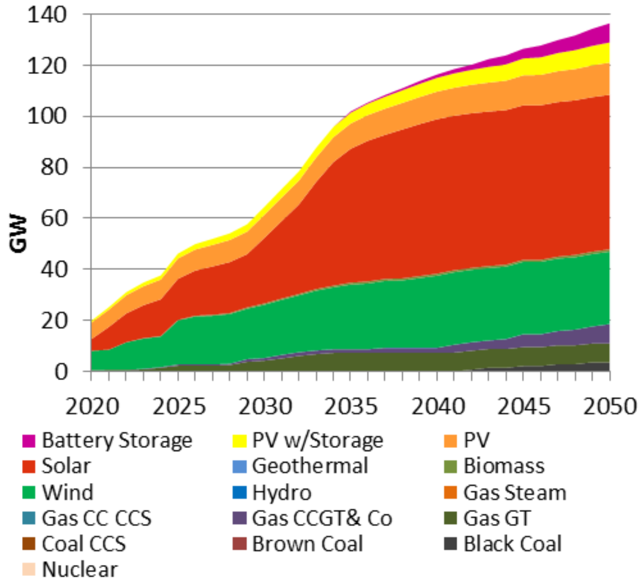
Source: Jacobs

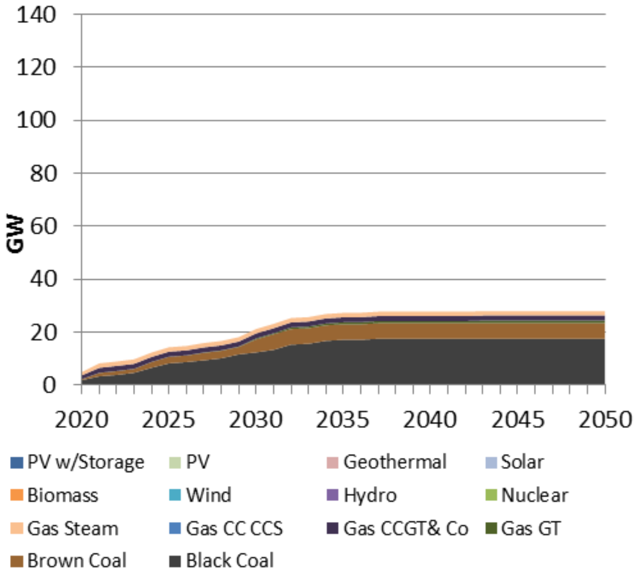
Figure 338 shows cumulative new generation capacity under the RET, and it is clear that wind and solar with storage dominate new build. A contribution is also made by gas turbines, which are the virtually only fossil generation technology built prior to 2040. However, total gas turbine capacity plateaus from the mid-2030s, which is when stand-alone battery storage becomes competitive in the peaking segment of the market.

Under the RET scenario there are fifteen transmission upgrades, including a new transmission line connecting South Australia with New South Wales, totalling 10,780 MW. This is over 7,000 MW more than the reference case and is required to unlock relatively low cost renewable energy resources, such as those located in South Australia.

Figure 338: Cumulative new and retired capacity, renewable energy target, technology sensitivity

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





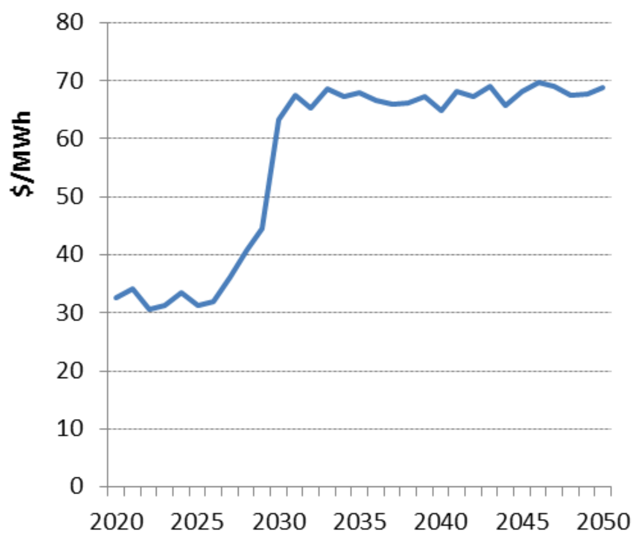
Source: Jacobs

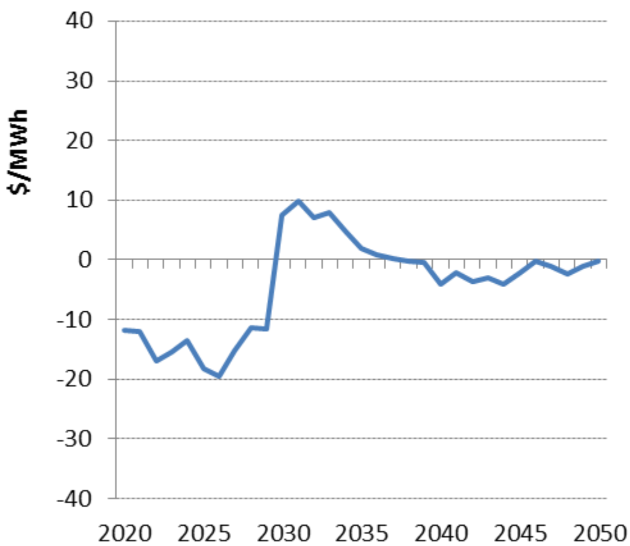
9.4.5 Prices

Figure 339 shows wholesale electricity time-weighted prices. Prices in the early 2020s are suppressed due to the entry of large volumes of renewable generation, and this, coupled with the displacement of coal fired generation, forces the retirement of much of the coal fleet. In 2029/30 prices rebound as a result of most of the coal fleet having retired, which is why prices exceed those of the reference case. Prices after 2030 reflect the new entry level of the marginal new entrant fossil technology, namely, supercritical black coal and CCGTs. After 2035 prices are capped by the new entry level of fossil generators, which is why they track reference case prices.

Figure 339: Wholesale electricity time-weighted prices, renewable energy target, technology sensitivity

The left graph shows absolute figures. The right graph shows figures relative to the technology sensitivity reference case.



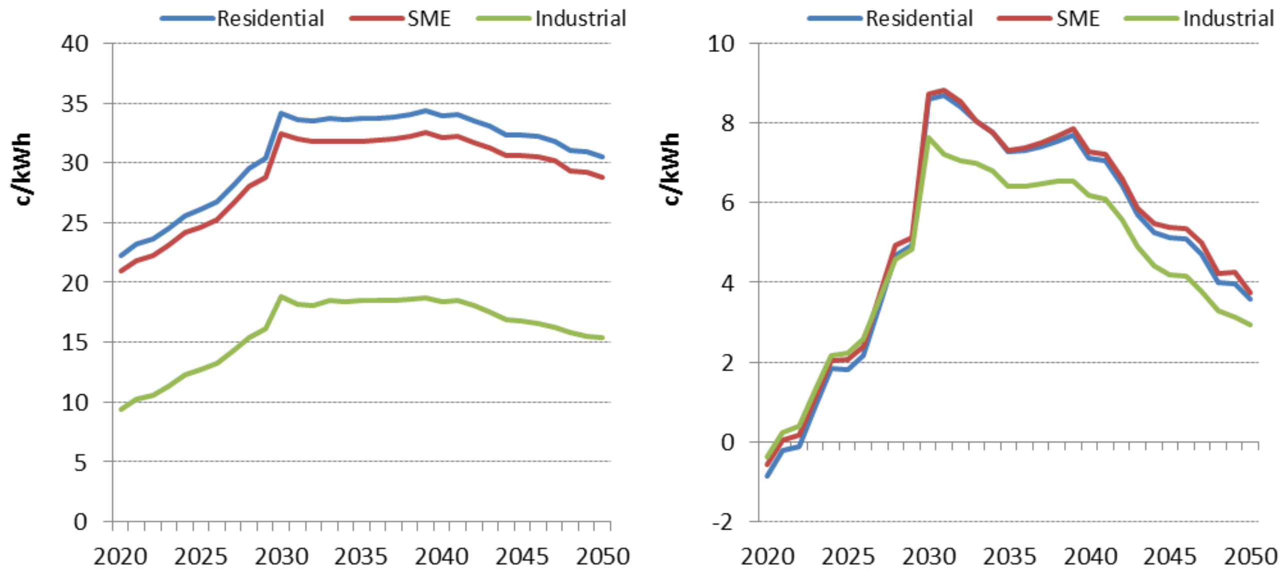


Source: Jacobs

Figure 340 shows weighted average retail prices by customer class. Unlike carbon pricing, they do not entirely mirror the trends in the wholesale price because they are also heavily influenced by the renewable certificate price. Figure 341 shows the weighted average residential bill relative to the reference case, and also as a percentage of disposable income. The high certificate price and the volume of certificates under the RET required to satisfy the cumulative emissions constraint combine to have a material impact on retail prices, which in turn results in increases to residential bills.

Figure 340: Retail prices by customer class, renewable energy target, technology sensitivity

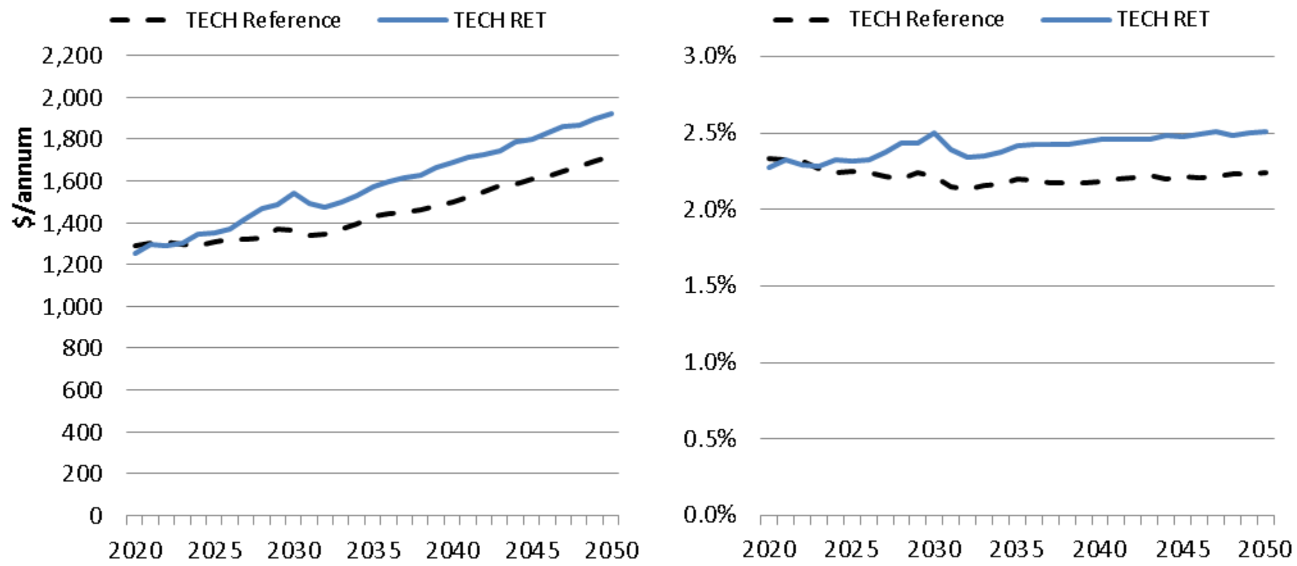
The left graph shows absolute figures. The right graph shows figures relative to the technology sensitivity reference case.



Source: Jacobs

Figure 341: Residential bills, renewable energy target, technology sensitivity

The left graph shows the absolute residential bill. The right graph shows the residential bill as a % of disposable income.



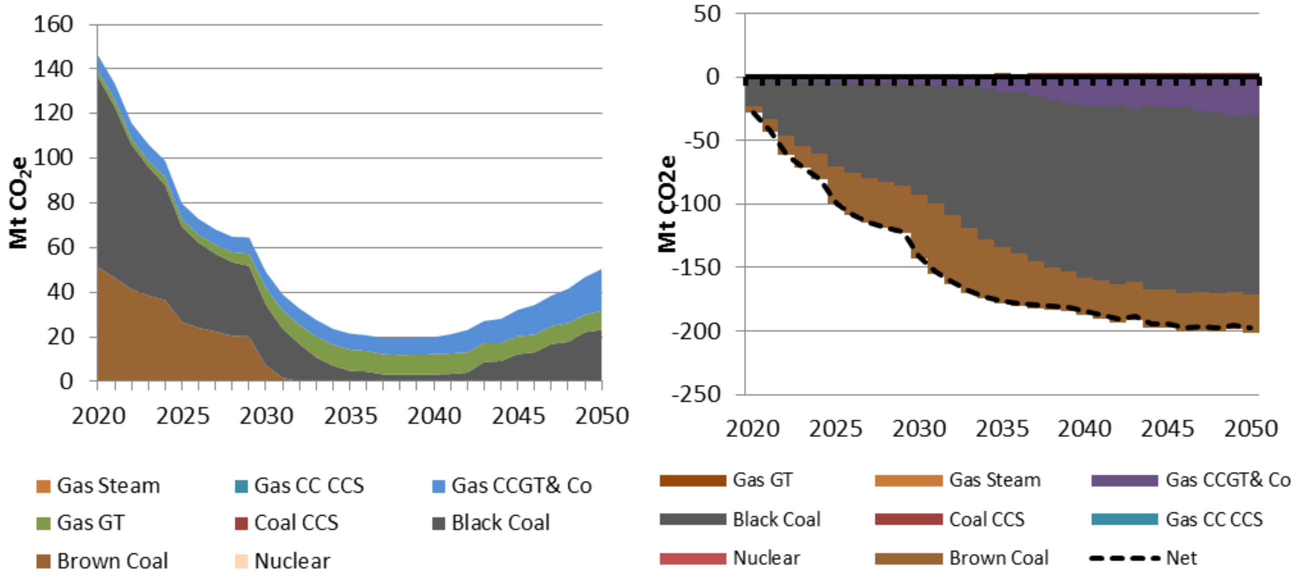
Source: Jacobs

9.4.6 Emissions

Figure 342 shows annual emissions by technology and the difference relative to the reference case. Most of the coal fleet retires by the early 2030s, and as with the unconstrained scenario, emissions increase post 2040 with the commissioning of new fossil generators. Figure 343 shows the generation emission intensity both in absolute terms and relative to the reference case.

Figure 342: Emissions by technology, renewable energy target, technology sensitivity

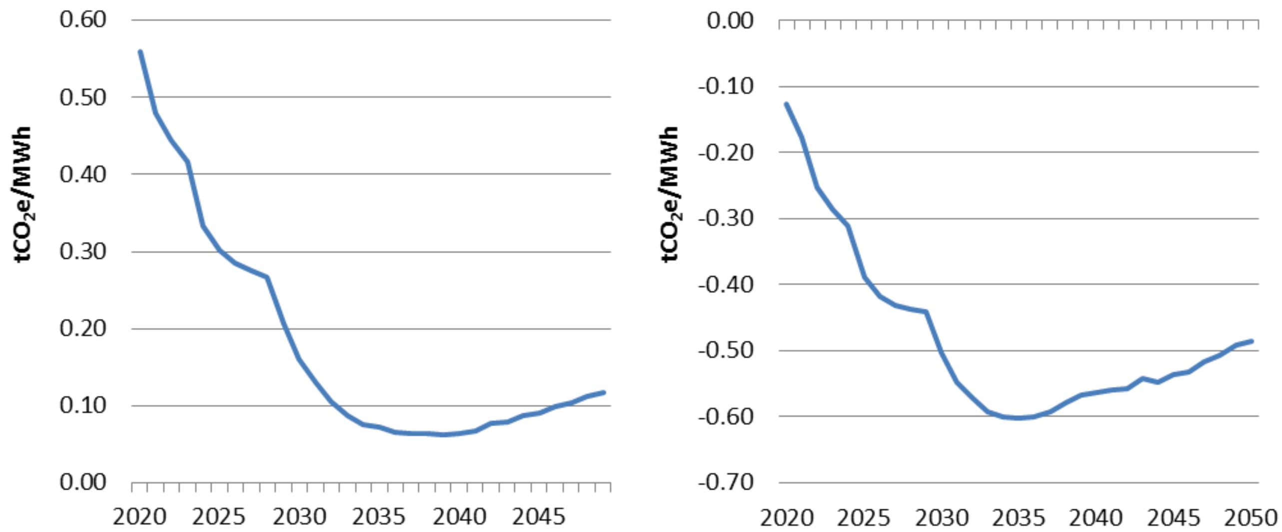
The left graph shows absolute figures. The right graph shows figures relative to the technology sensitivity reference case.



Source: Jacobs. Includes both direct and indirect emissions.

Figure 343: Generation emission intensity, renewable energy target, technology sensitivity

The left graph shows absolute figures. The right graph shows figures relative to the technology sensitivity reference case.



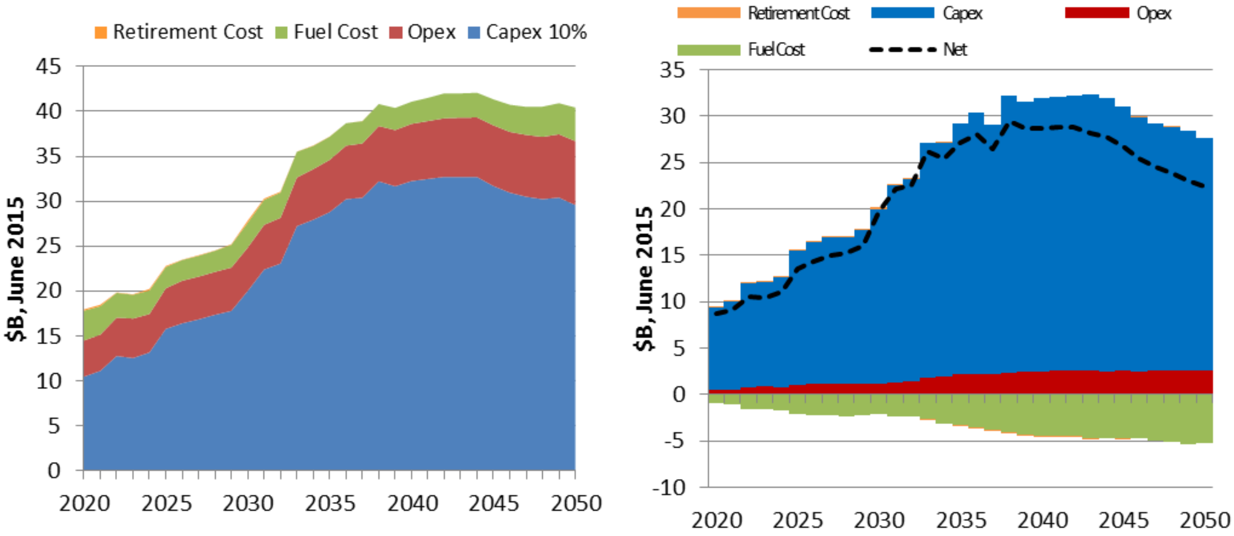
Source: Jacobs. Includes direct emissions only.

9.4.7 Costs

Figure 344 shows annualised resource costs by four cost categories.

Figure 344: Annualised costs by category, renewable energy target, technology sensitivity

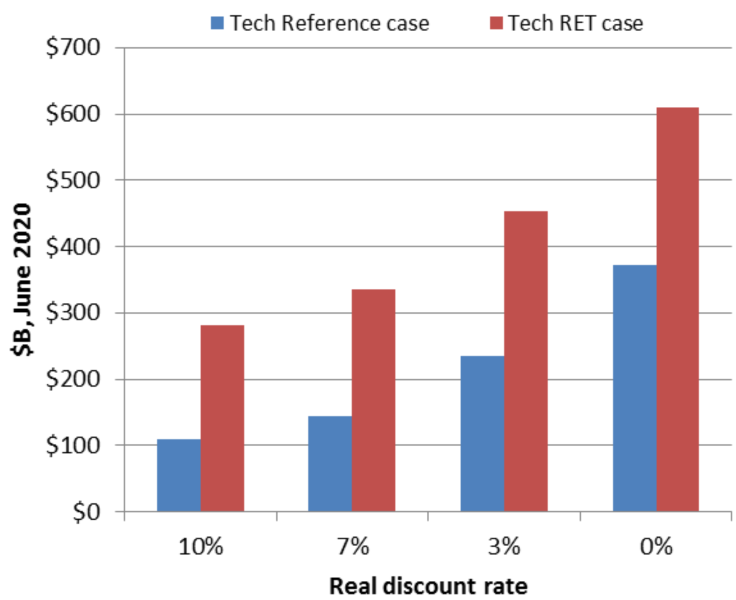
The left graph shows the absolute costs. The right graph shows the costs relative to the technology sensitivity reference case.



Source: Jacobs

Figure 345 shows the net present value of the resource costs for the RET scenario relative to the reference case for four separate discount rates. The total resource cost for the RET scenario ranges from 159% (at 10% real discount rate) to 64% (without discounting) higher than that of the reference case. This is slightly higher than the resource costs of the unconstrained scenario. Properly accounting for the additional demand side abatement widens the cost gap between the technology sensitivity and the unconstrained scenario.

Figure 345: NPV of resource costs, renewable energy target, technology sensitivity



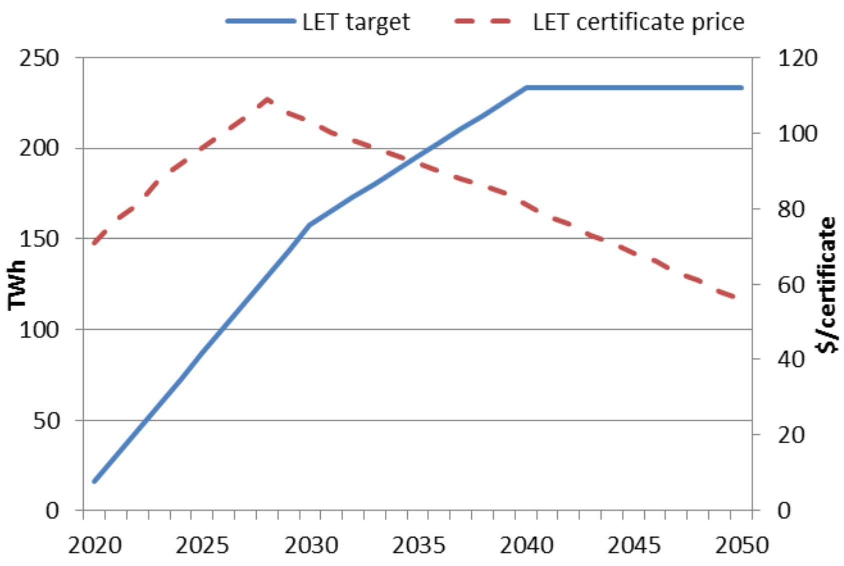
Source: Jacobs. Excludes demand adjustment. See Appendix B.3.2 for further detail.

9.5 Low emissions target

9.5.1 Scenario description

The low emissions target (LET) scenario is very similar to the RET, with the difference being that low emission fossil technologies are also eligible to earn certificates as a fraction of their emissions intensities below an emission intensity threshold of 0.6 t CO_2e/MWh. Under the technology sensitivity CCGTs are the only eligible base load thermal generation technology. Figure 346 shows the final LET trajectory and the corresponding LET certificate price required to satisfy the cumulative emissions constraint. As with the RET scenario, it was found that a dual linear form for the LET trajectory was necessary to achieve a least cost solution.

Figure 346: LET target and LET certificate price, technology sensitivity



Source: Jacobs

For further discussion see Section 2.

9.5.2 Key findings

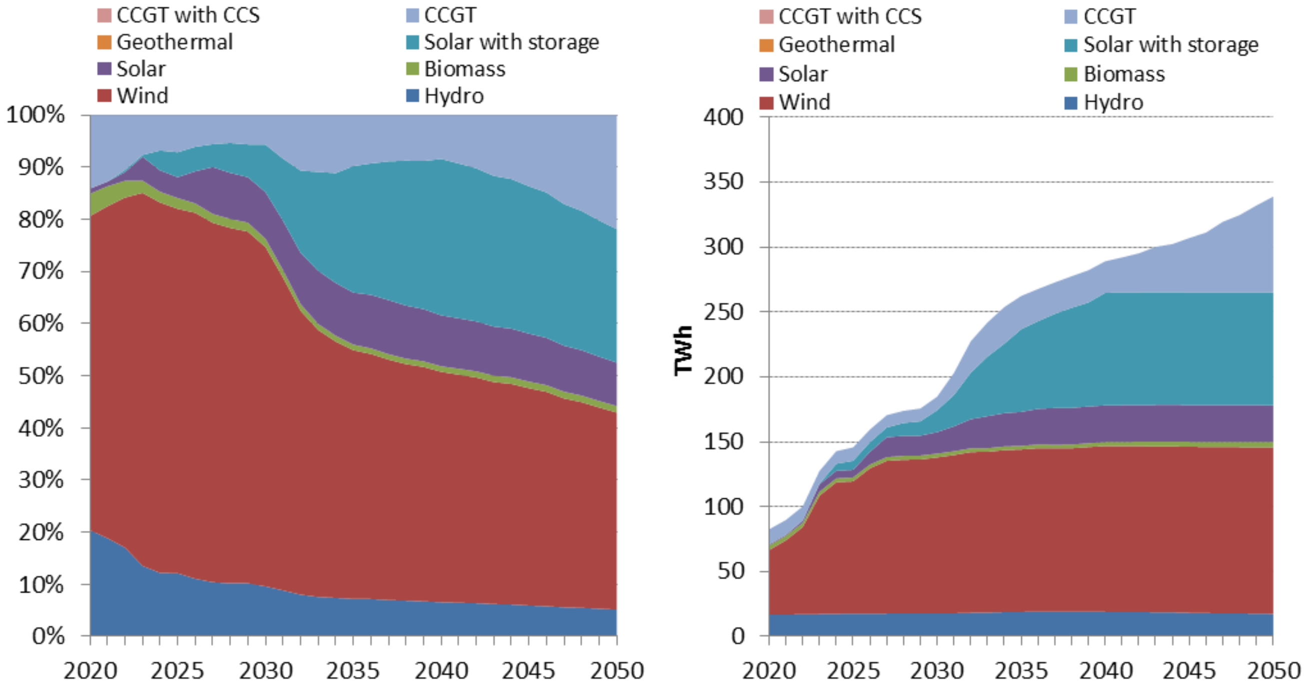
The difference between the technology sensitivity and the unconstrained LET is that geothermal, nuclear and CCGT with CCS generation technologies are excluded under the sensitivity. The conclusion for this sensitivity is an extension of the conclusion drawn for the RET technology sensitivity. Solar with storage substitutes for geothermal, and CCGTs substitute for CCGT with CCS technology. The latter implies that some additional abatement is required to meet the same cumulative emission target because CCGTs have higher emissions than CCGT with CCS technology. This is achieved through a much higher LET certificate price, which has two impacts: (i) it encourages additional CCGT generation, which displaces some coal fired generation in the early years; and (ii) it leads to higher retail prices, which in turn encourages additional demand-side abatement. The LET trajectory of the technology sensitivity is similar to that of the unconstrained LET scenario.

As with all the technology sensitivities, stand-alone battery storage enters the market in the mid-2030s mainly as a lower cost alternative to gas turbines (much as it does in the reference case), and also makes a small contribution to reducing curtailed energy from intermittent generation sources.

The only difference between the RET and LET policies in this scenario is the partial credits issued to CCGT generators. This results in a reduction in total welfare loss of around $30 billion, discounted at 7%. CCGT generators in the LET are more profitable, which leads to considerably more CCGT capacity than the RET case.

The additional CCGT capacity results in the faster retirement of black coal and lower investment in gas turbines, which reduces the total resource cost of the policy.

Figure 347: Contribution of large-scale low emission generation by technology, low emissions target, technology sensitivity



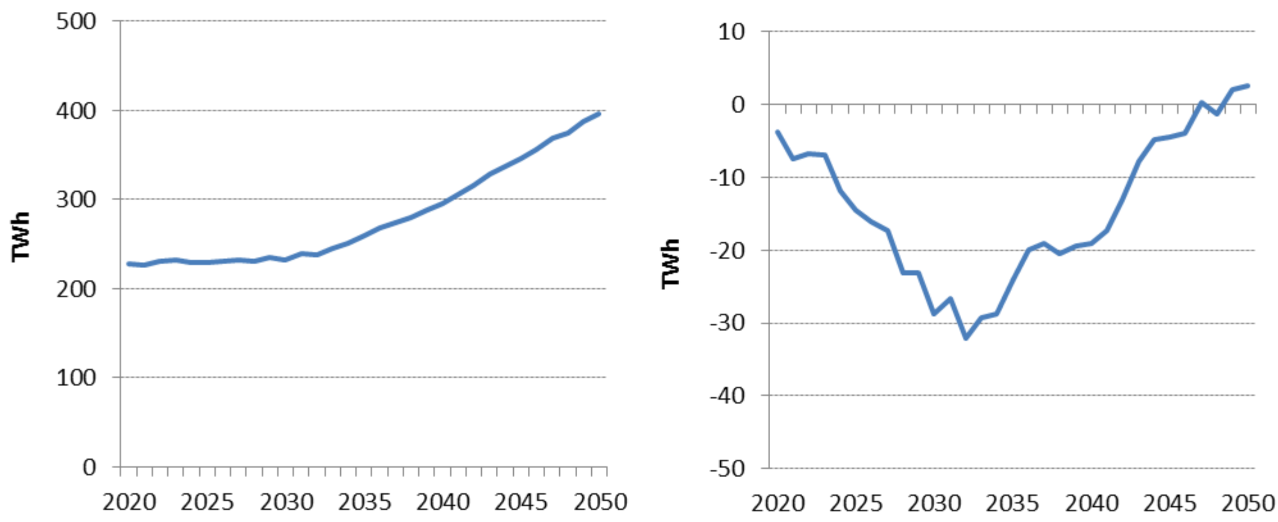
Source: Jacobs

9.5.3 Demand

Figure 348 shows sent-out energy demand from the LET scenario. Total energy consumption reaches 396 TWh in 2049/50, 1 TWh per annum higher than the reference case. However, demand under the LET is lower than that of the reference case for most of the modelling horizon.

Figure 348: Sent-out energy, low emissions target, technology sensitivity

The left graph shows absolute figures. The right graph shows figures relative to the technology sensitivity reference case.



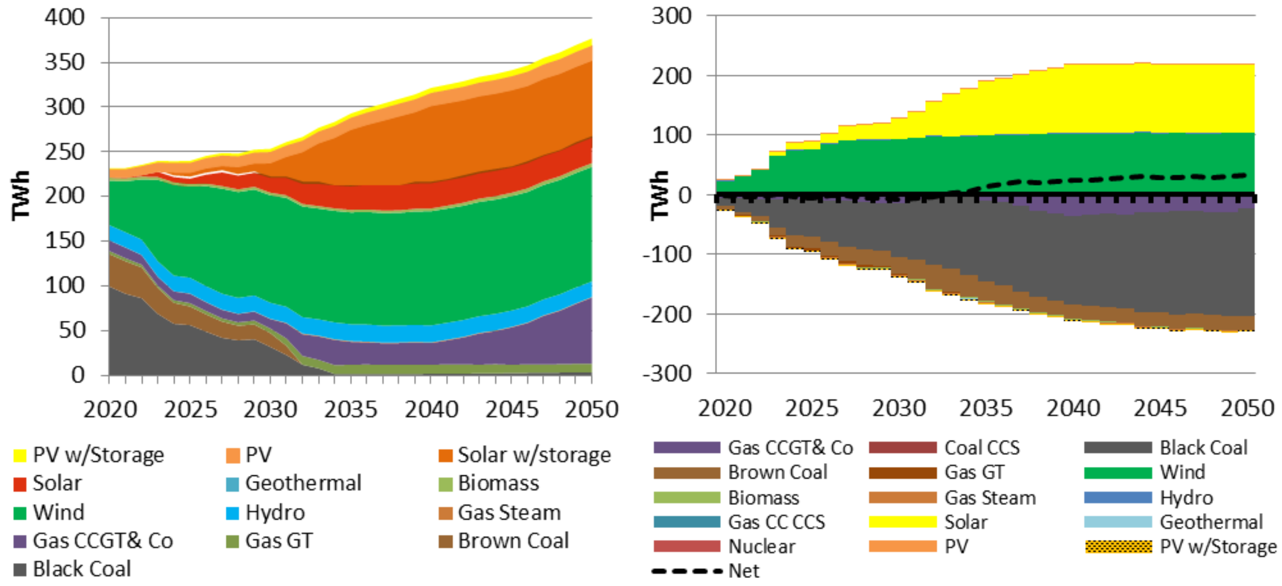
Source: Pitt & Sherry, ACIL Allen and Jacobs

9.5.4 Generation and capacity

Figure 349 shows the generation mix across the modelling horizon in absolute terms and relative to the reference case. The key trends in the graph are identical to the unconstrained LET scenario, with the exception that solar with storage fulfils the role of geothermal generation from the early 2030s and CCGTs replicate the role of CCGTs with CCS from 2030 onwards. Stand-alone batteries with storage are also in the generation mix, mainly displacing new gas turbine capacity.

Figure 349: Generation mix, low emissions target, technology sensitivity

The left graph shows absolute figures. The right graph shows figures relative to the technology sensitivity reference case.



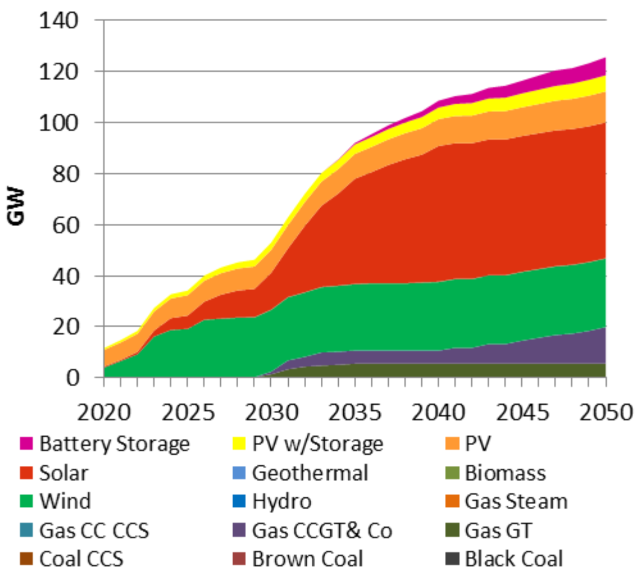
Source: Jacobs

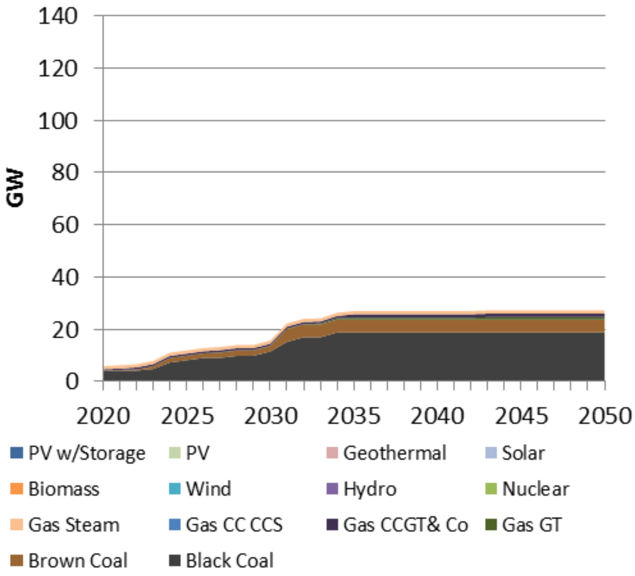
Figure 350 shows cumulative new generation capacity under the LET, and it is clear that wind and solar with storage dominate new build. The contribution of CCGTs in capacity and energy terms is not as great, ranking fourth and third respectively, but this is an essential part of the solution to meet the cumulative emissions constraint as CCGTs are the largest source of emissions across the modelling horizon. The contribution of gas turbines, is not as great when compared with the RET because CCGT capacity performs a similar role. Moreover, total gas turbine capacity plateaus from the mid-2030s, which is when stand-alone battery storage becomes competitive in the peaking segment of the market.

Under the LET scenario there are fifteen transmission upgrades, including a new transmission line connecting South Australia with New South Wales, totalling 10,780 MW. This is over 7,000 MW more than the reference case and is required to unlock relatively low cost renewable energy resources, such as those located in South Australia.

Figure 350: Cumulative new and retired capacity, low emissions target, technology sensitivity

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





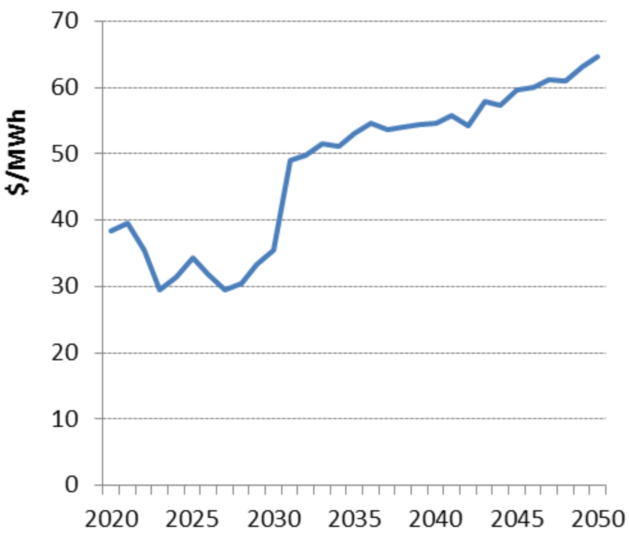
Source: Jacobs

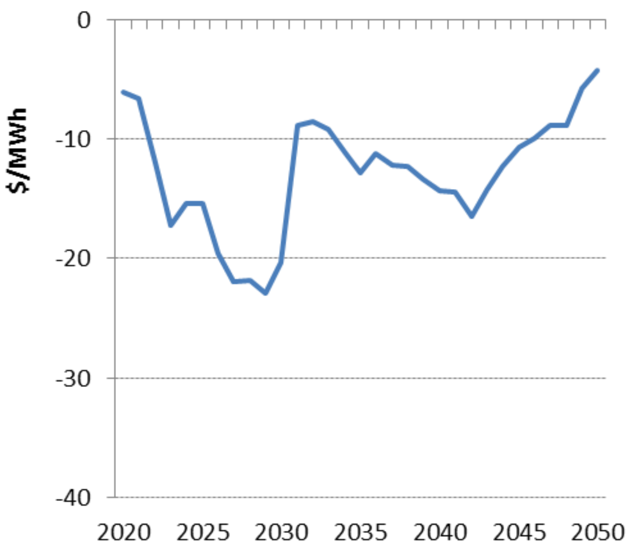
9.5.5 Prices

Figure 351 shows wholesale electricity time-weighted prices. Prices in the early 2020s are suppressed due to the entry of large volumes of renewable generation, and this, coupled with the displacement of coal fired generation, forces the retirement of much of the coal fleet. In 2029/30 prices rebound as a result of most of the coal fleet having retired, which is why prices rebound relative to the reference case. Prices never actually reflect the new entry level of supercritical black coal because the LET certificate price helps to suppress the market price by effectively lowering the marginal cost of CCGT technology. This ultimately prevents more coal fired generation from entering the market and helps achieve the cumulative emission target.

Figure 351: Wholesale electricity time-weighted prices, low emissions target, technology sensitivity

The left graph shows absolute figures. The right graph shows figures relative to the technology sensitivity reference case.



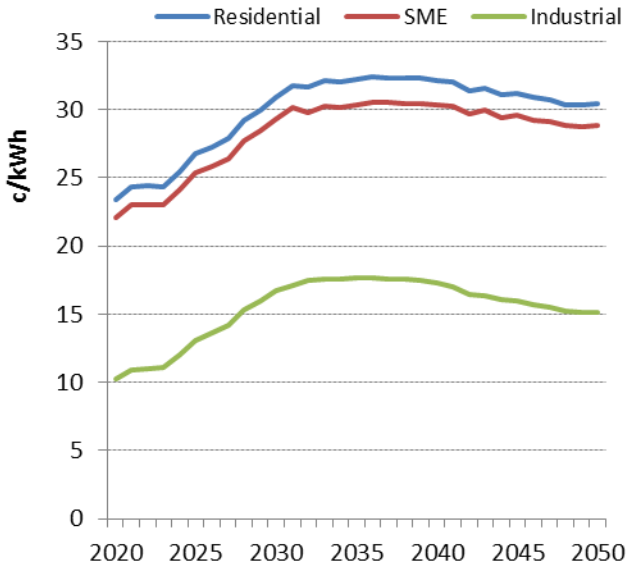


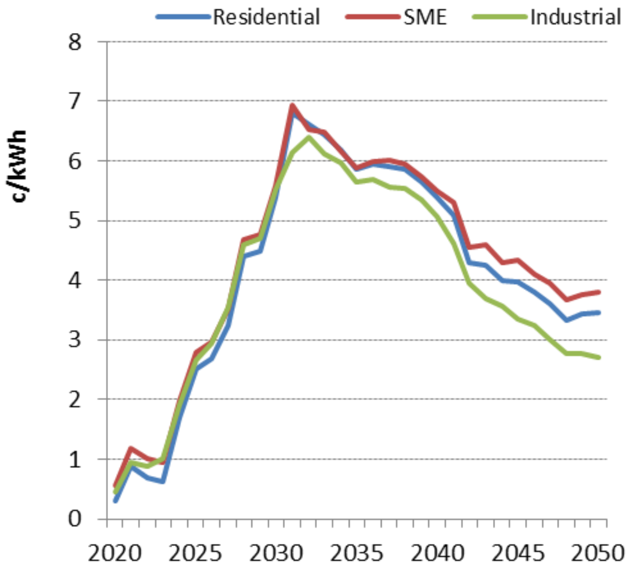
Source: Jacobs

Figure 352 shows weighted average retail prices by customer class. Unlike carbon pricing, they do not entirely mirror the trends in the wholesale price because they are also heavily influenced by the low emission certificate price. Figure 353 shows the weighted average residential bill relative to the reference case, and also as a percentage of disposable income. The high certificate price and the volume of certificates under the LET required to satisfy the cumulative emissions constraint combine to have a material impact on retail prices, which in turn results in increases to residential bills.

Figure 352: Retail prices by customer class, low emissions target, technology sensitivity

The left graph shows absolute figures. The right graph shows figures relative to the technology sensitivity reference case.

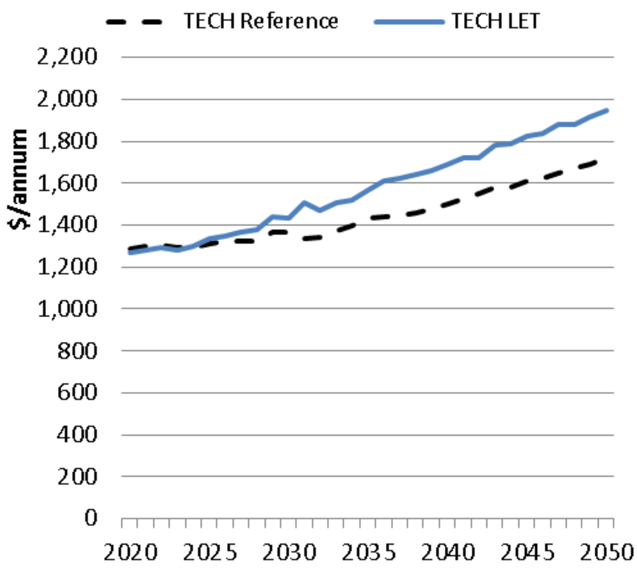


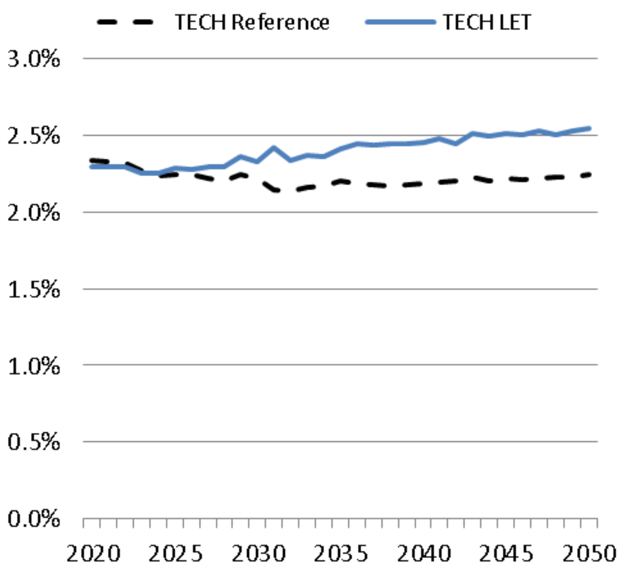


Source: Jacobs

Figure 353: Residential bills, low emissions target, technology sensitivity

The left graph shows the absolute residential bill. The right graph shows the residential bill as a % of disposable income.





Source: Jacobs

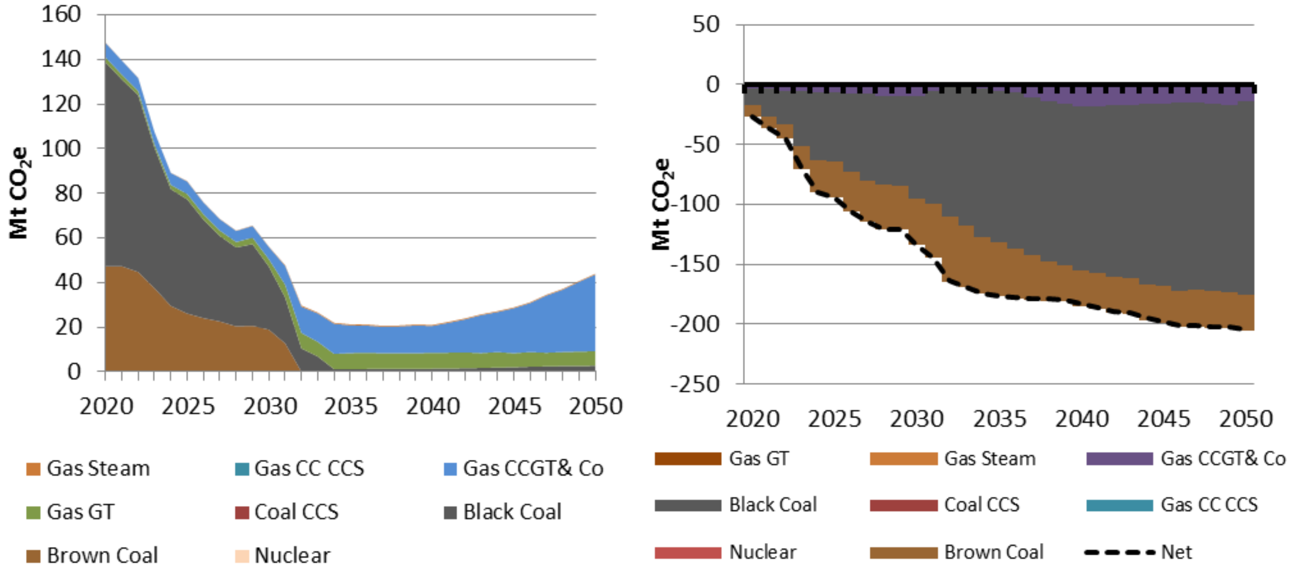
9.5.6 Emissions

Figure 354 shows annual emissions by technology and the difference relative to the reference case. Most of the coal fleet retires by the early 2030s, and as with the unconstrained scenario, emissions increase after 2040 with the commissioning of new fossil generators.

Figure 355 shows the generation emission intensity both in absolute terms and relative to the reference case.

Figure 354: Emissions by technology, low emissions target, technology sensitivity

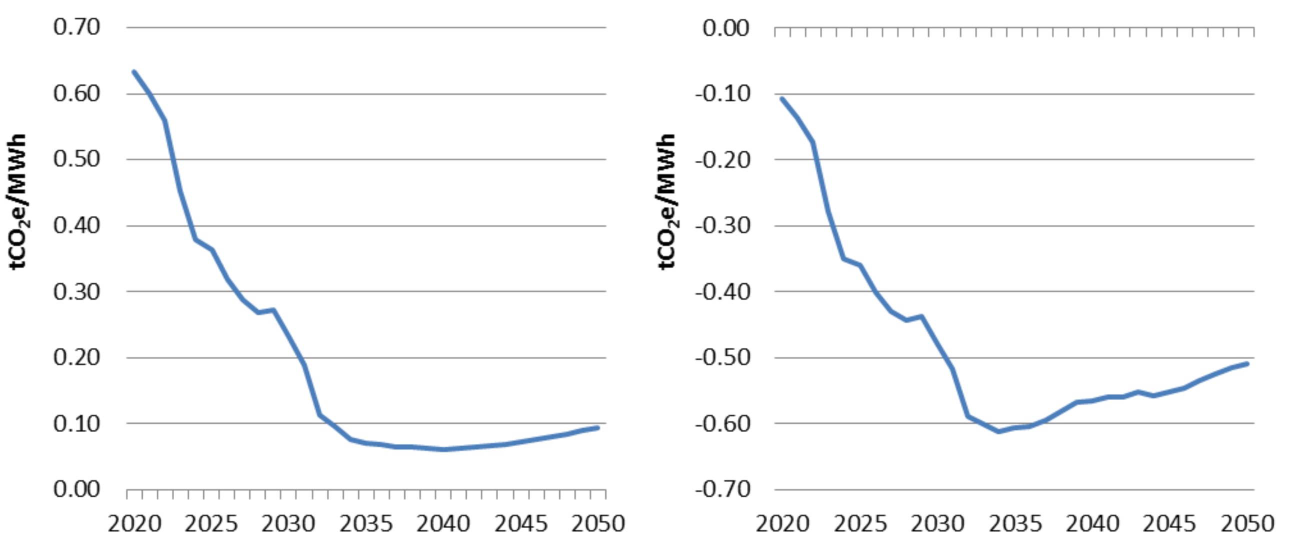
The left graph shows absolute figures. The right graph shows figures relative to the technology sensitivity reference case.



Source: Jacobs. Includes both direct and indirect emissions.

Figure 355: Generation emission intensity, low emissions target, technology sensitivity

The left graph shows absolute figures. The right graph shows figures relative to the technology sensitivity reference case.



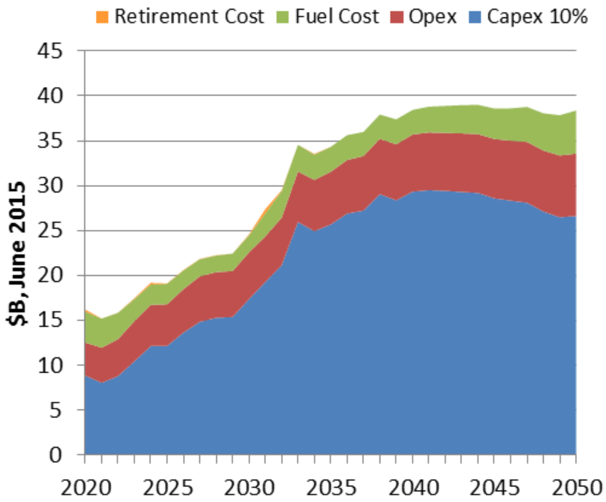
Source: Jacobs. Includes direct emissions only.

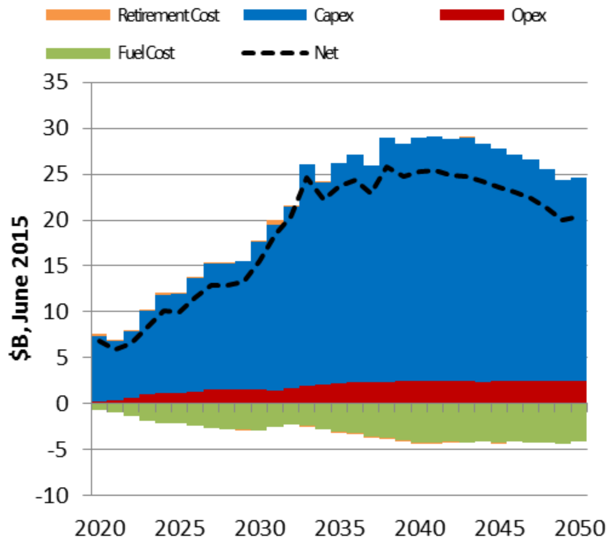
9.5.7 Costs

Figure 356 shows annualised resource costs by four cost categories and illustrates the need for capital investment for the first 15 years.

Figure 356: Annualised costs by category, low emissions target, technology sensitivity

The left graph shows the absolute costs. The right graph shows the costs relative to the technology sensitivity reference case.

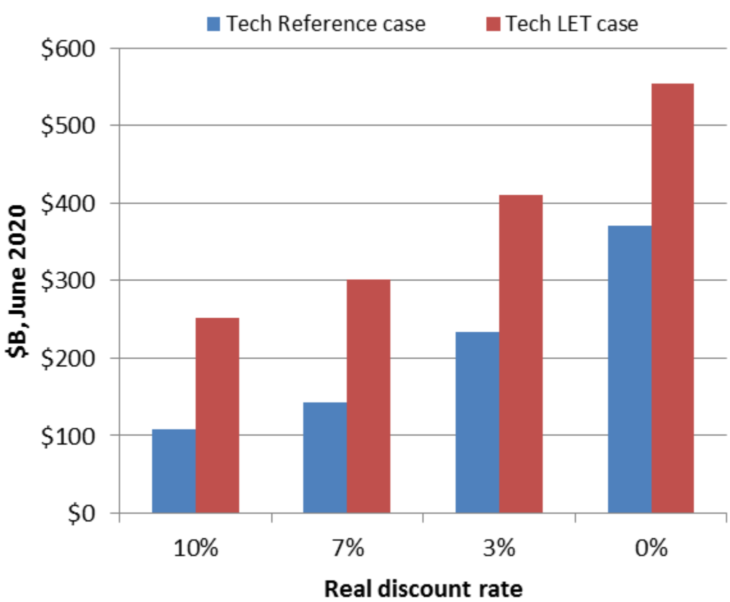




Source: Jacobs

Figure 357 shows the net present value of the resource costs for the LET scenario relative to the reference case for four separate discount rates. The total resource cost for the LET scenario ranges from 132% (at 10% real discount rate) to 49% (without discounting) higher than that of the reference case. This is slightly higher than the resource costs of the unconstrained scenario, but lower than the resource costs for the RET technology sensitivity. Properly accounting for the additional demand side abatement widens the cost gap between the technology sensitivity and the unconstrained scenario.

Figure 357: NPV of resource costs, low emissions target, technology sensitivity



Source: Jacobs. Excludes demand adjustment. See Appendix B.3.2 for further detail.

Appendix A. Modelling suite

A.1 Strategist

Jacobs uses its simulation model of the energy markets (NEM and WEM) to estimate the policy 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 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 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 358 and the Jacobs modelling procedures for determining the timing of new generation and transmission resources, and bid gaming factors are presented in Figure 359.

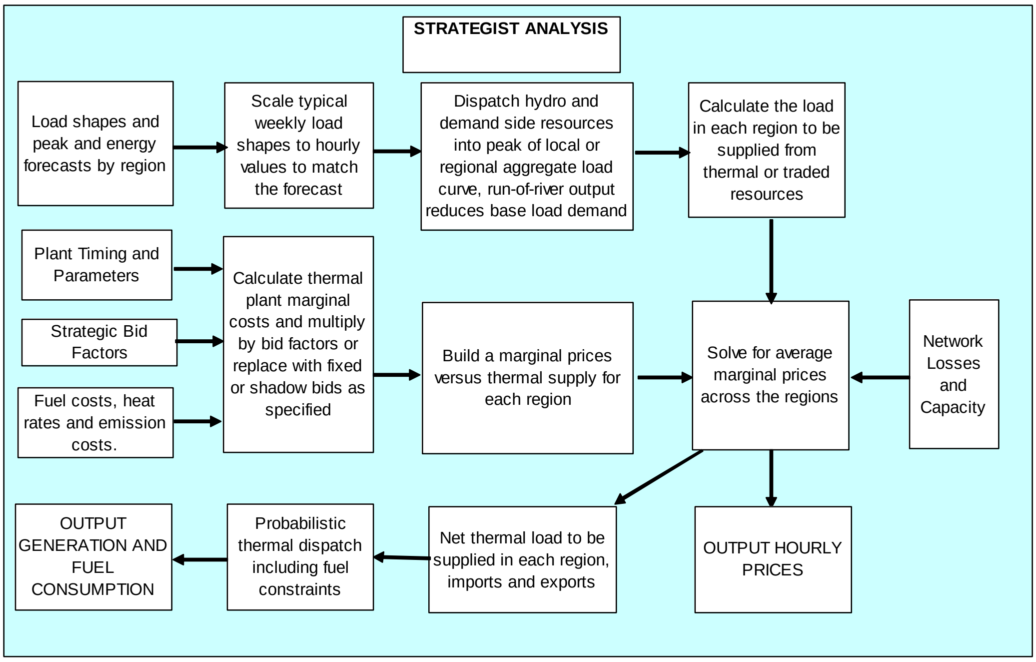
The PROVIEW module of Strategist is used to develop the expansion plan with a view to minimising the total costs of the generation system plus interconnection augmentation. This is similar to the outcome afforded by a competitive market. However due to computational burden and structural limitations 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.

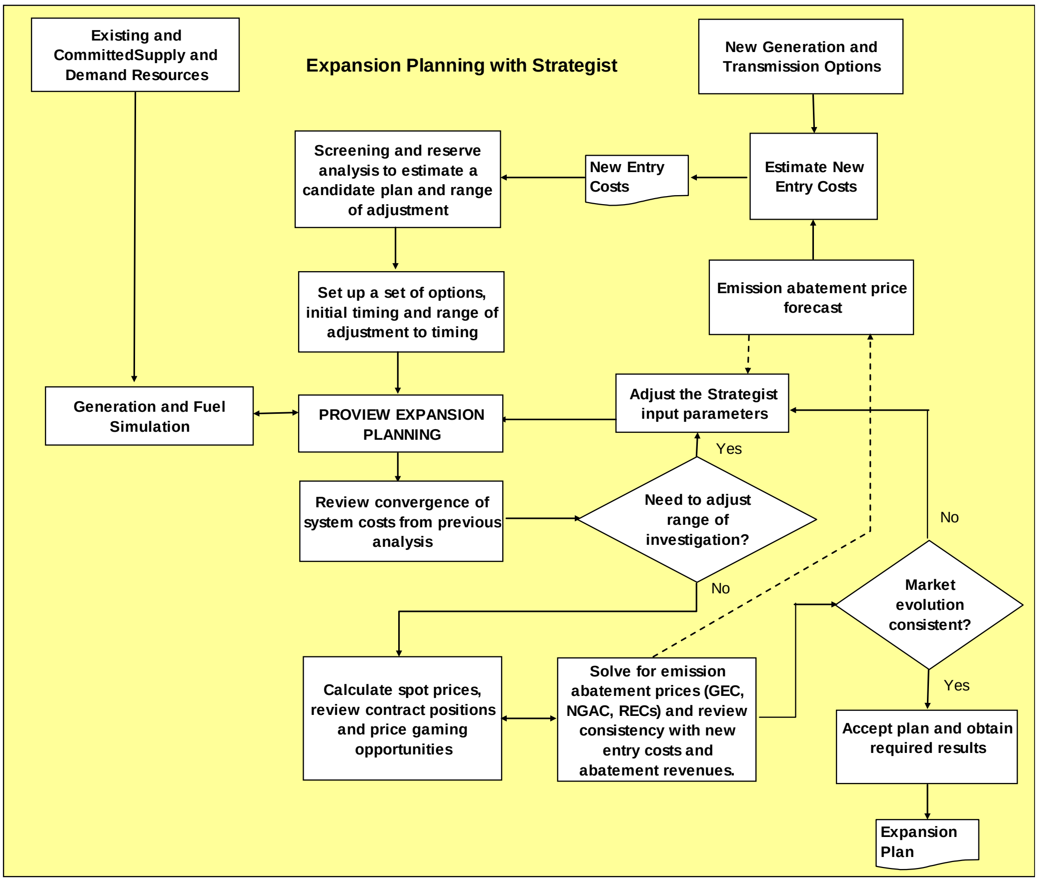
Strategist generates average hourly marginal prices for each hour of a typical week for each month of the year at each of the regional reference nodes, having regard to thermal plant failure states and their probabilities. The prices are solved across the regions of the NEM having regard to inter-regional 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 358: Strategist analysis flowchart



Source: Jacobs

Figure 359: Jacobs modelling procedures



Source: Jacobs

A.2 DOGMMA

Uptake of small-scale renewable technologies is 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 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 change the hourly 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[35]. 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[36]. 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.
  - Both of these limits were relaxed in the alternative reference case.
- 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 5 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, 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 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).

[35] 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.

[36] 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.

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[37] and the availability of data on key determinants. Currently the model comprises 56 regions (see Table 15)

Table 15: 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 16.

Table 16: 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

- 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

[37] 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.

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[38]; and some data on metered energy production available from Ausgrid[39].

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[40].

The initial capacity factors applying in each State are shown in Table 17. PV systems with storage are assumed to have a lower initial capacity factors due to energy losses occurring during charging and discharging cycles.

Table 17: 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%

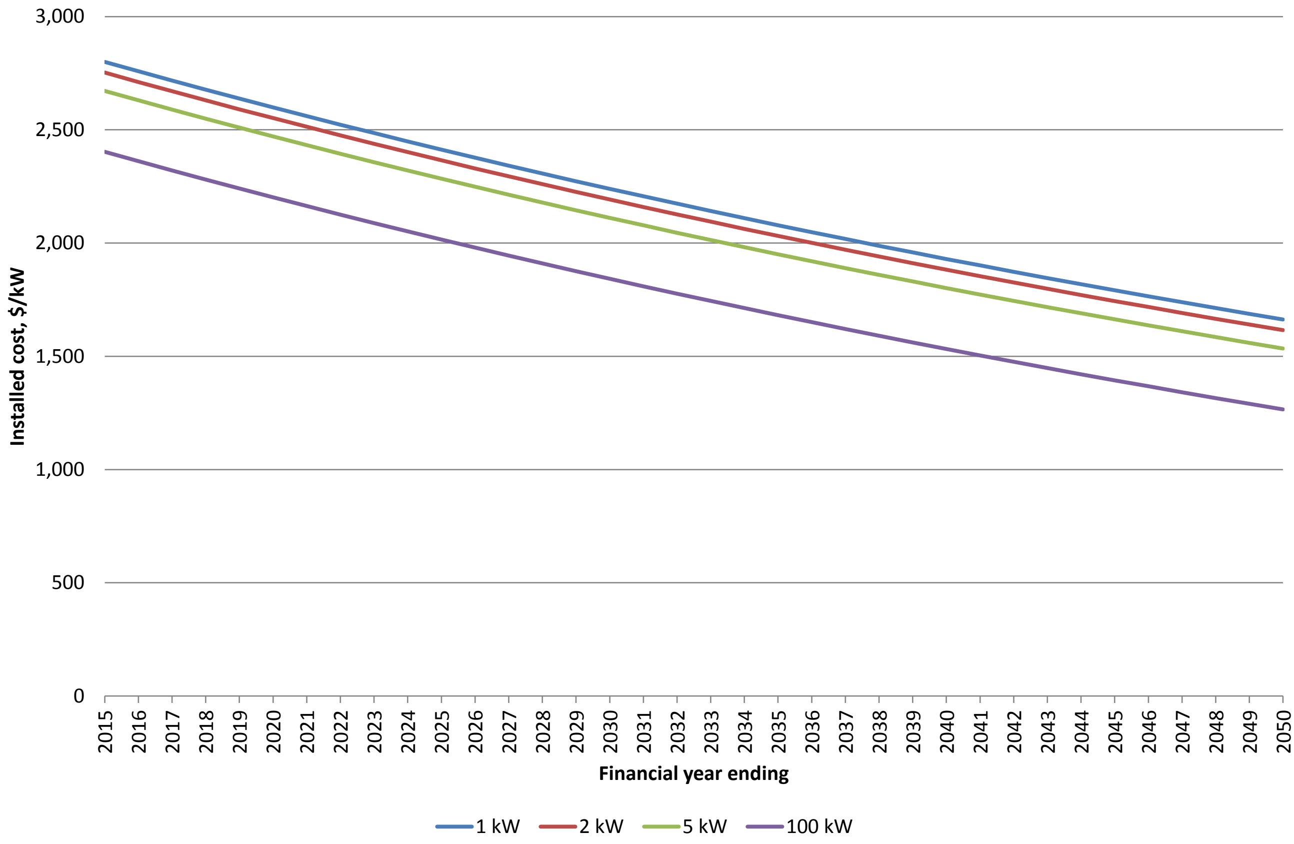
Source: Jacobs based on data provided by CER, Ausgrid and Energex[41].

A.2.4 Capital costs

Capital cost assumptions are shown in Figure 360. 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.

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

Figure 360: 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.2.6 Changes to DOGMMA assumptions for alternative reference case

Five changes to DOGMMA assumptions were made for the alternative reference case (see Section 7). These different assumptions were:

- The saturation level for residential dwellings was increased from 55% to 75% of all dwellings. This allowed for a higher level of panel leasing on rented properties.
- Allowing homes that have installed a solar water heater to also install a PV system. The proportion of homes with solar water heaters that could install a PV system was increased from 10% in 2017 to 100% in 2026.

- The saturation level for the commercial sector increased from 65% of all energy consumption by this sector to 75% of all energy consumption.
- Relaxed the regional build constraints that limited to amount of installations that can be installed in each year (to reflect that there may be limits on available qualified tradesmen). The allowable regional build rates were doubled in the alternative reference case.

Faster reductions in battery storage costs, with the reductions equal to assumptions used in a recent CSIRO study. [42]

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 set of 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 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 373 (see Appendix F).

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.

[42] CSIRO (2015), *Future Energy Storage Trends*, report prepared for AEMC

Appendix B. Modelling methodology

B.1 Overview

The approach to the modelling of the policy scenarios was guided by the cumulative emissions constraint applied in 2^{o} C scenarios. With this emissions constraint, the generation mix was necessarily similar across different scenarios. However, the wholesale prices and/or permit or certificate prices were quite different across the scenarios, giving some differences in timing of entry of new plant, but the essential difference between the scenarios were the distributional impacts. The differences in pricing will lead to moderate differences in demand between the policy options, driven by the assumed price elasticity.

The reference case was the first scenario modelled. This scenario assumed that although the rest of the world enacted carbon reduction policy to meet global targets, there was no such policy in Australia. Instead:

- There was no additional carbon mitigation policy affecting the electricity generation sector beyond the current suite of polices.
- The Large-scale Renewable Energy Target (LRET) is in place until the planned cessation date of the end of 2030. The Small-scale Renewable Energy Scheme (SRES) also continues to the end of 2030.

In this scenario, investments in new generation is based on the combination and timing of entry of the available choices that minimised the net present value of generation costs. The technology choices covered the gamut of coal, gas fired, nuclear and renewable technologies.

The policy scenarios were modelled as different behavioural rules impacting on the dispatch of generation plant and the selection of new plant. The behavioural rules impacted either by affecting the relative costs of dispatch, by prohibiting or constraining dispatch of high emission technologies or by affecting relative costs of new generation options.

B.2 Scenario-specific methodology

The approach used for modelling of each policy scenario was as follows:

- The **Carbon Pricing** scenario was modelled first as this provided both the emissions constraint for all other scenarios and provided the least-cost expansion solution for that constraint. An exogenous carbon price was used consistent with meeting the 2°C global temperature goal based on international studies. After allowing for price elasticity of demand, the least cost expansion and dispatch for the sector was found and total cumulative emissions over the period to 2050 was applied to the other scenarios.

  The optimal carbon price solution was used as the starting basis for the other six policy options, and the solution adjusted to accommodate the specific policy option being considered. Descriptions for how this was done by policy option are as follows:

- **Absolute Baseline** scenario. This scenario had facility-level absolute baselines for liable thermal generators.

  The facility level baselines, which were based on historical generation levels, were applied to thermal plant with an emission intensity above the industry average in a given year. Facility baselines were treated as hard annual generation limits that could not be exceeded by any facility. The facility baselines were uniformly reduced for all thermal plant in the NEM and the SWIS in order to meet the cumulative emission target. Meeting the facility baselines was modelled through an iterative approach by increasing the shadow bid price of incumbent plants using a dummy carbon penalty until each facility does not exceed its individual baseline.

  Low emission new entry was directly encouraged by entrant standards that prohibit new fossil fuel generation without CCS and by the high wholesale prices arising from the generation constraints.

- **RET**. This policy scenario used the renewable energy expansion under the carbon pricing scenario to formulate an initial target trajectory which is constant from 2040. The target trajectory was assumed to have a growth path to the ultimate target which was piecewise linear. The ultimate target in 2040 and piecewise linear growth path was adjusted until the cumulative emissions constraint was met.

  The thermal and renewable energy plant mix in the model was determined by that mix that minimised the cost of the new RET scheme for the given target (the thermal mix was also re-optimised in response to any shifting of renewable capacity). The difference in the generation mix from other scenarios arises due to the fact that the renewable target peaks in 2040 to allow a 10 year period for revenue to be earned to recover costs.

  The original LRET projects were assumed to be refurbished and earn certificates after refurbishment under the new scheme.

- **LET policy**. The same approach was used as for the RET only scenario, but the LET target also included low emission generation with an emission intensity below a specified rate. The LET scheme was implemented in an external spreadsheet model, which is an extension of our current REMMA model by including the volume of low emission certificates derived from thermal sources as a contribution to the LET. This spreadsheet model was directly interfaced with the Strategist model so that the certificate revenue earned by each eligible generator for 1 MWh of generation was used to reduce the marginal cost of that 1 MWh of generation. This mechanism encourages low emission plant to run harder as they would be more competitive.

  This policy option also required an emission intensity threshold to be specified as this defined the eligible low emission plant for a given year. The starting point for the threshold was 0.6 t CO_2-e/MWh sent out.

- **Emission intensity target**. Linear or stepwise linear sectoral intensity targets were developed using the emission results and expansion plan of the carbon pricing scenario. Certificates are created by generators with emission intensities lower than the annual target, and their marginal costs are reduced through the sale of those certificates. Generators with emission intensities above the annual target need to procure certificates from the market, which adds to their marginal costs. Other features of simulation of this policy scenario included:

  - An initial expansion plan based on carbon pricing scenario was used
  - An average annual emission intensity over the period to 2050 was developed and a linear profile of emission intensity consistent with the cumulative emission from carbon pricing was determined
  - The certificate price in each year was adjusted to avoid any mismatches between the target emission allowances and the emissions created noting that the scheme did allow for borrowing above 10% of the annual requirement.
  - The cumulative target was initially achieved, but the borrowing limit was violated
  - This was addressed by increasing the initial carbon price to achieve more abatement earlier on, and also decreasing the escalation rate of the permit price

- The permit price trajectory was adjusted until the emissions constraint was satisfied

- **Regulatory approach**. Regulations force the closure of existing high-emitting generators based on the age of the plants with no new non-CCS coal permitted to enter. A gas generation intensity regime was also applied with emissions on conventional gas fired plant limited to 2000 t CO_2-e/MW. Other features of the simulation of this scenario included:

  - A distribution and an initial time path for closure based on the closure profile determined under the carbon pricing approach was used.

- An initial shadow penalty on gas fired plants was chosen
- The wholesale and retail costs were estimated and an adjustment to the demand forecast was applied.
- An iteration was done and the cumulative emissions target was calculated. If the target was not met the time path for closures was changed and/or the penalty price for gas fired plants was increased or decreased and the process repeated.

- **FiT with contract for differences.** Similar to the RET only approach, except that the average new capacity was assumed to be contracted for 20 years and that CCS and nuclear technologies were also eligible. The electricity price used to calculate payments under the contract for difference is the monthly reference wholesale electricity price of the entire NEM or SWIS.

  A lower WACC (of 0.5 % in real terms) was applied due to the certainty in revenue streams provided under this policy.

  The FiT rate was based on the assumption that a reverse auction will be used so that bidders will bid in their long-run marginal cost.

Whilst the policies all operate from 2020 to 2050, the model's start year will precede 2020. Starting year is important as it determines when expansion can start. Construction was assumed to not begin until the relevant policy could be legislated, which was assumed to be in 2018.

B.3 Cost of abatement

The cost of abatement for a policy scenario is equal to its resource costs divided by its emissions reductions, both measured relative to a reference case without the policy. This section explains each part of the calculation in turn.

B.3.1 Resource costs

Resource costs reflect the cost of actual economic resources used to generate electricity to meet wholesale demand. Resource costs cover the following, for both large-scale and distributed generation:

1. Fuel costs including any delivery (transmission or transport) costs
2. Variable operating and maintenance costs
3. Fixed operating and maintenance costs
4. Capital costs. For large-scale generation, capital costs were annualised as a way of resolving issues in accounting for the cost of new plant that had operating lives beyond 2050 (the last year modelled)

Resource costs exclude all transmission and distribution costs except where these are borne by new entrant generators (for example, if a new geothermal plant was built away from existing transmission infrastructure it would bear the connection costs).

Costs of interconnector upgrades were estimated in the modelling and included in the calculation of resource costs.

The resource cost does not include a value on remaining emissions. The economic cost of achieving the emissions constraint under different policy prescriptions is reflected in the resource costs as modelled.

B.3.2 Demand adjustment

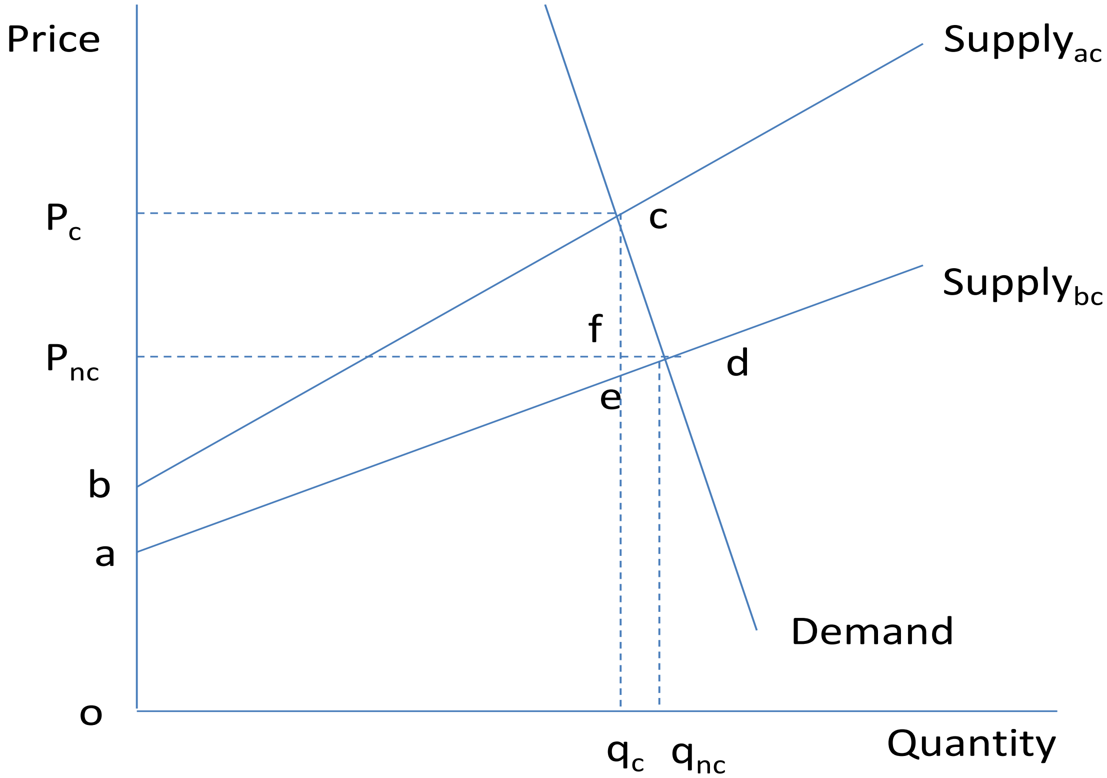
The modelling included changes to electricity demand as a result of changes to retail prices. This means the resource cost of meeting the emissions constraint is not just the change in supply costs. Instead the resource cost is based on the supply cost adjusted for the changes due to the demand response. Throughout the paper, resource costs relative to the reference case include this demand adjustment. Where resource costs exclude this demand adjustment, this is pointed out in the notes accompanying the graph.

An explanation of the economic gains and losses - herein called the demand adjusted resource costs - incurred from meeting the emissions constraint is provided below.

This analysis measures the reduction in welfare before the benefits of emissions reductions are incorporated. The cost-effectiveness of policies can be compared by calculating the cost of abatement as the change in welfare per tonne of greenhouse gas emissions avoided (see next section).

Resource costs can be determined with the use of a representative snap shot of supply and demand with and without the emissions constraint and including the demand response, as shown in Figure 361. The diagram represents the hypothetical market for electricity generation, showing the combinations of demand for and supply of electricity at each price level. Implementing carbon policy shifts the supply curve upwards from Supply_{bc} to Supply_{ac} – the cost of electricity supply is now more expensive.

Figure 361: Illustrative welfare costs



The equilibrium price before carbon is P_{nc} with q_{nc} demanded and supplied at that price. With carbon policy, the equilibrium price rises to P_c and the quantity demanded falls q_c.

The immediate welfare change is the area *abce.* This represents the change in welfare from using more expensive inputs in the production of electricity. If the demand was perfectly inelastic, this area would equal the whole welfare change resulting from the policy.

But the reduction in quantity demand also engenders a welfare change. People now consume less electricity than they previously wanted to. The change in welfare from this is given by the area *cfd*. This is estimated in the modelling using the demand adjustment formula by taking the change in quantity demand from the reference case and multiplying by the price change and taking half of this amount. That is:

$$cfd = 0.5*((q_{nc}-q_c)*(p_c-p_{nc}))$$

There is also a change in producer surplus from the move to a lower quantity of demand. This is measured by the area *dfe*.

The area edq_nq_c does not represent a welfare loss. In a competitive market each point on the supply curve and the area under the supply curve represents the opportunity cost of the inputs used in generation – that is, the value of their most profitable use. These inputs are used elsewhere in some other production activity (for example, coal is exported) so there is no welfare change from them not being used in electricity production.

Thus the demand adjusted resource cost (representing the economic costs of meeting the emissions constraint under each policy) is given by:

$$RCDpt = abce + cfd + efd$$

The modelling measures resource costs from the electricity generation sector, while consumer prices in Figure 361 incorporate generation, network and retailing costs. Network and retailing costs are therefore removed to avoid overstating the welfare loss.

B.3.3 Cost of abatement

The cost of abatement is a measure of the cost effectiveness of the differing policy measures. It allows for comparison of the unit cost of a carbon mitigation policy with reference to the goal of reducing emissions. Policies with a lower cost of abatement are more economically efficient.

The cost of abatement measures the difference in resource costs and emissions with and without the policy. More specifically, it measures the net present value of the resource costs divided by the incremental emissions reductions from the policy, where the net costs and emissions reductions are measured relative to a reference point of expected outcomes in the absence of the policy. Resource costs include capital and operating costs as described above. That is, the cost of abatement includes the demand-adjusted resource costs.

The cost of abatement:

- Considers the net costs of the policy from the perspective of society as a whole (not a particular group such as investors or consumers).
- Incorporates 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 (7%)).
- Incorporates the effectiveness of policy: if emissions are projected to be very similar with and without the policy, abatement is small and the cost of abatement is high, other things equal.

Experts take different views on whether future emissions reductions should be discounted or not. The Authority has directed Jacobs not to discount future emissions reductions. The rationale for this approach is that, unlike money, over the timeframes and volumes of emissions reductions considered, a tonne of emissions reductions in the future is as valuable as a tonne now.

In this study, we have used a measure based on demand adjusted resource cost as defined in the previous section:

$$ACD_p = \frac{\sum_{t=0}^{n}(RCDpt)/(1+i^t)}{\sum_{t=0}^{n}(Ept-Ert)}$$

where *ACDp* is the demand adjusted abatement cost of the policy, *RCDpt* = demand adjusted resource cost change in year *t*, *Ept* = emissions in policy case in year *t*, *Ert* = emissions in reference (no policy case) in year *t* and *i* is the discount rate.

B.4 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.5 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[43] as currently applicable and published by AEMO. Wind and non-storage solar generation capacities were discounted by AEMO's existing firmness percentages.[44] 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.

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.

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

B.6 Network costs and pricing

B.6.1 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.6.2 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 18. 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 18: 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.7 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.

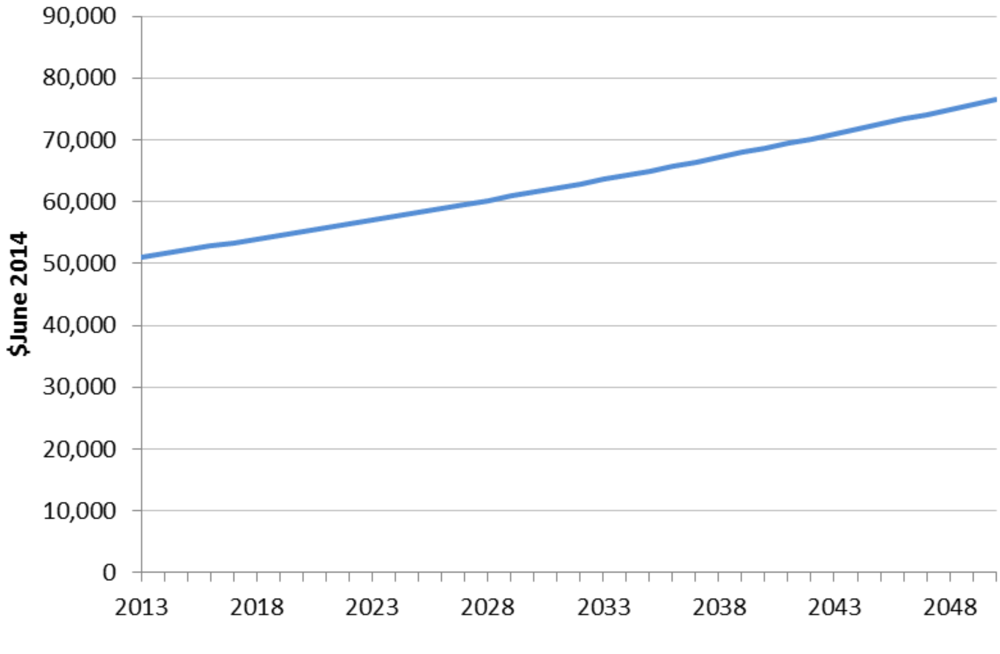
In most cases, it will be economic to refurbish plant on the basis of the electricity prices earnt alone. However, in the RET and LET policy measures, refurbished plant are allowed to earn certificates under the measure due to the possibility that electricity prices are lower than prices required for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

B.8 Households

B.8.1 Method for projecting household disposable income

Figure 362 shows the projected annual equivalised household disposable income used to calculate the impact of electricity price increases on disposable income. Average (mean) equivalised disposable household income is the income that a single person household would require to maintain the same standard of living as the average person living in all private dwellings in Australia. Disposable income better represents the economic resources available to meet the needs of households and derived by deducting estimates of personal income tax and the Medicare levy from gross household income. The series in this analysis was created by applying a disposable income growth rate from the Productivity Commission45 to historical average equivalised disposable income data from the Australian Bureau of Statistics[46]. Projected income is not varied by policy scenario.

Figure 362: Projected equivalised household disposable income in Australia to 2050



Source: CCA analysis based on sources in text.

B.8.2 Method for projecting household electricity consumption

Household electricity consumption was projected as follows:

- ABS population projections were used[47].
- The ABS' projected population share by state was also used (this has to be interpolated as only snapshots were provided).

[45] Productivity Commission 2014, *An ageing Australia: preparing for the future*. Uses a long term growth in disposable income of 1.1%.
[46] Australian Bureau of Statistics 2013, *Household income and income distribution 2011-12*.
[47] ABS (2013), *Population Projections, Australia, 2012 to 2101*, Catalogue No. 3222.0, Canberra

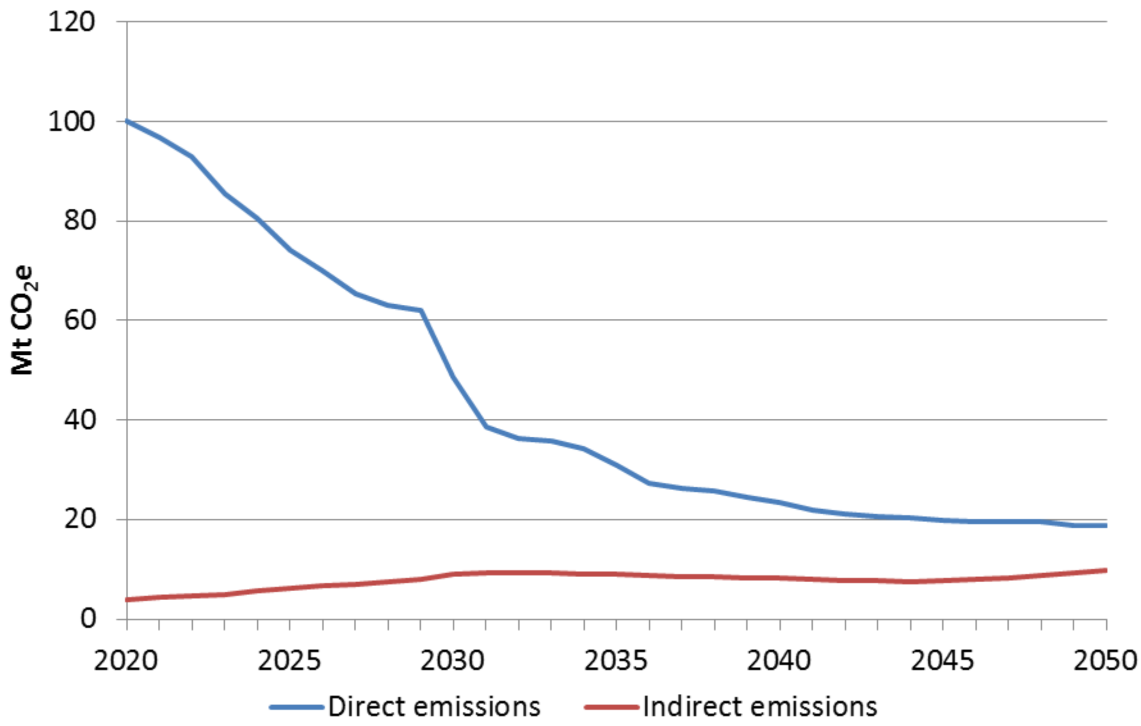
- The long term trend in persons per household across Australia was applied and this was used to calculate number of households by state.
- The residential share of electricity demand was calculated for each region in 2015 based on historical electricity demand and historical number of households.
- This share was assumed to be constant in each region going forward.
- Household consumption could be derived for each region by applying the constant residential share to the electricity demand projection and then dividing by the projected number of households.

B.9 Emissions

All modelling runs use full fuel cycle emissions for electricity generation. These include direct emissions from power station operation (such as emissions from burning fuel to generate electricity), and indirect emissions from the transport and extraction of fuel. Further details include:

- The emissions constraint is based on full fuel cycle emissions (both in direct and indirect emissions).
- In the carbon pricing and emission intensity target policy scenarios the permit price was applied to all emissions, but the model does not have any mechanisms to reduce the indirect emissions in response to these pricing signals (so only the direct emissions can be abated).
- In the other policy scenarios, the emission thresholds and/or constraints were based on both direct and indirect emissions.
- Figure 363 shows the breakdown of direct and indirect emissions in the 2°C carbon pricing policy scenario. Over the modelling period indirect emissions make up an increasing proportion of overall emissions due to the abatement of direct emissions.

Figure 363: Direct and indirect emissions, carbon pricing (2°C)



Source: Jacobs

Appendix C. Modelling inputs and assumptions

C.1 Emissions constraint

C.1.1 Two degree emissions constraint

In order to facilitate a like-for-like comparison of policies, the modelling constrained each policy scenario to achieve the same cumulative emissions. The Authority specified that the emissions constraint 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 2o 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[48]. 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 median values from the analysis were converted from US dollars to Australian dollars and inflated to 2015 dollars. Uniform growth rates were calculated to interpolate the carbon price between 2020, 2030 and 2050. The conversion, conducted by the Authority secretariat, converted from US to Australian 2010 dollars using the average exchange rate for the 2009/10 financial year and inflated these to June 2014 Australian dollars for consistency with other values in the modelling. Using higher or lower exchange rates would change the carbon price and therefore the carbon budget for use in the modelling.

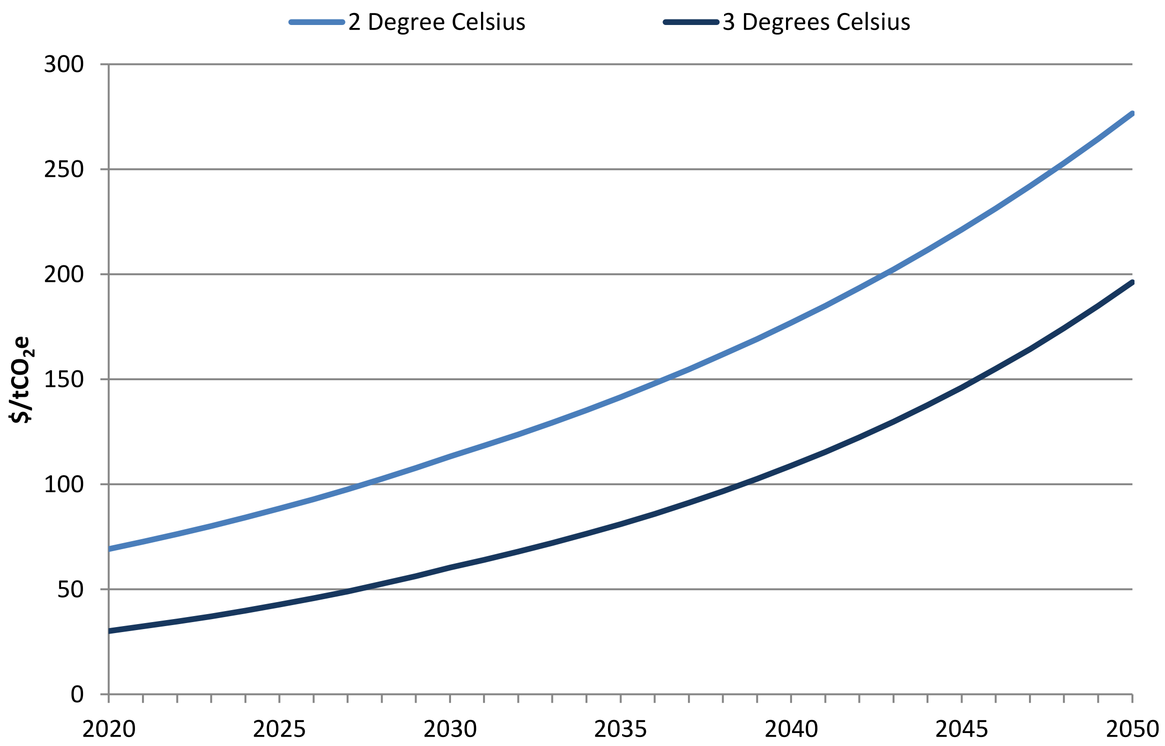
C.1.2 Weaker emissions constraint

One of the sensitivities run was the modelling of each policy scenario with a weaker emissions constraint (see Section 5). The level of cumulative emissions for this constraint was determined in the same way as the 2°C constraint, except with a lower carbon price series obtained using the same source and approach as the 2°C constraint. The Authority specified that the weaker emissions constraint 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 3°C[49]. Figure 364 provides a comparison of the carbon price inputs for the determining the emissions constraints.

The same methodology was used to determine the carbon price as in the 2°C emissions constraint. However the median carbon price associated with a 550 ppm concentration of carbon dioxide equivalent was used to be consistent with a likely chance of limiting warming to 3°C.

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

Figure 364: Carbon price paths for alternative emissions constraints



Source: Jacobs

C.2 Electricity demand

Our models take total projected electricity demand as an input and forecasts grid-based and embedded generation.

The core electricity demand projection for the modelling is based on the series from the Department of the Environment's 2014-15 emission projections. These official projections use a total electricity demand series developed by Pitt & Sherry and ACIL Allen which extends to 2040. For the purpose of this exercise, the original series was extended to 2050 by applying the trend growth rate from 2025 to2040. In the Departments' projections:

- Residential demand increases slightly from 2017 onwards as retail prices are projected to level off. Per capita consumption continues to decline slightly as energy efficiency standards for buildings and appliance drive increases in end use efficiency.
- General business demand is projected to grow in line with, but less quickly than, economic activity.
- Large industrial demand is projected to decrease slowly over the projection period after an initial increase driven by gas developments in Queensland.

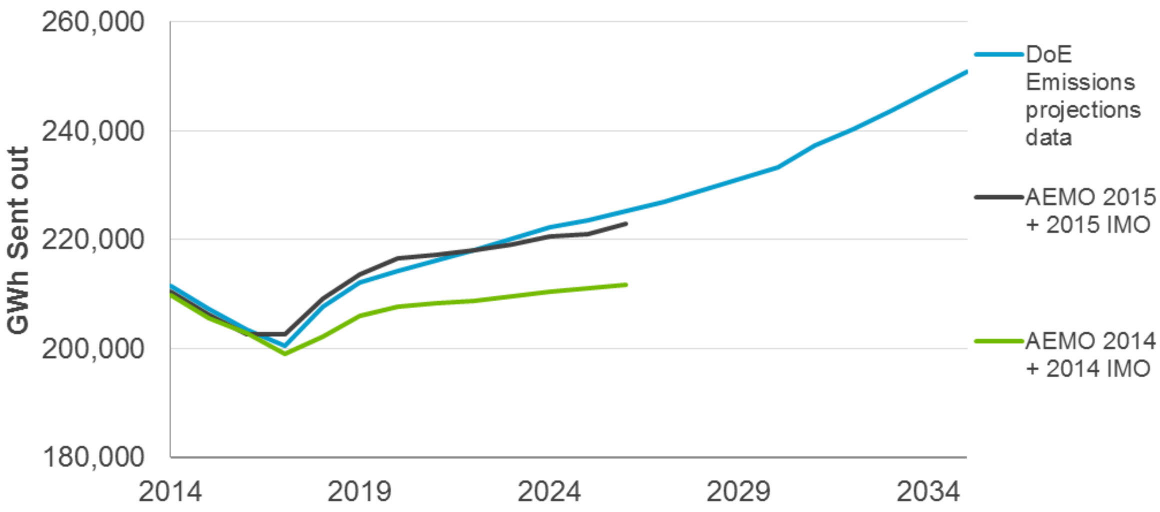
Since embarking on the project, more up-to-date projections of electricity demand have been released by the market operators (AEMO for the NEM and the Independent Market Operator (IMO) in WA, respectively)[50]. Overall, these updated projections move the combined AEMO and IMO series closer to the demand projections used in this modelling exercise (Figure 365).

[50] AEMO (2015), *National Electricity Forecasting Report*; IMO (2015), *2014 Electricity Statement of Opportunities.*

AEMO's and IMO's updated electricity demand forecasts were released in June 2015. Since their 2014 forecasts:

- Actual demand in the NEM has returned to growth while demand in WA has fallen.
- AEMO's demand forecasts have increased somewhat, while IMO's are slightly down.

Figure 365: Comparisons of electricity demand in the NEM and WEM

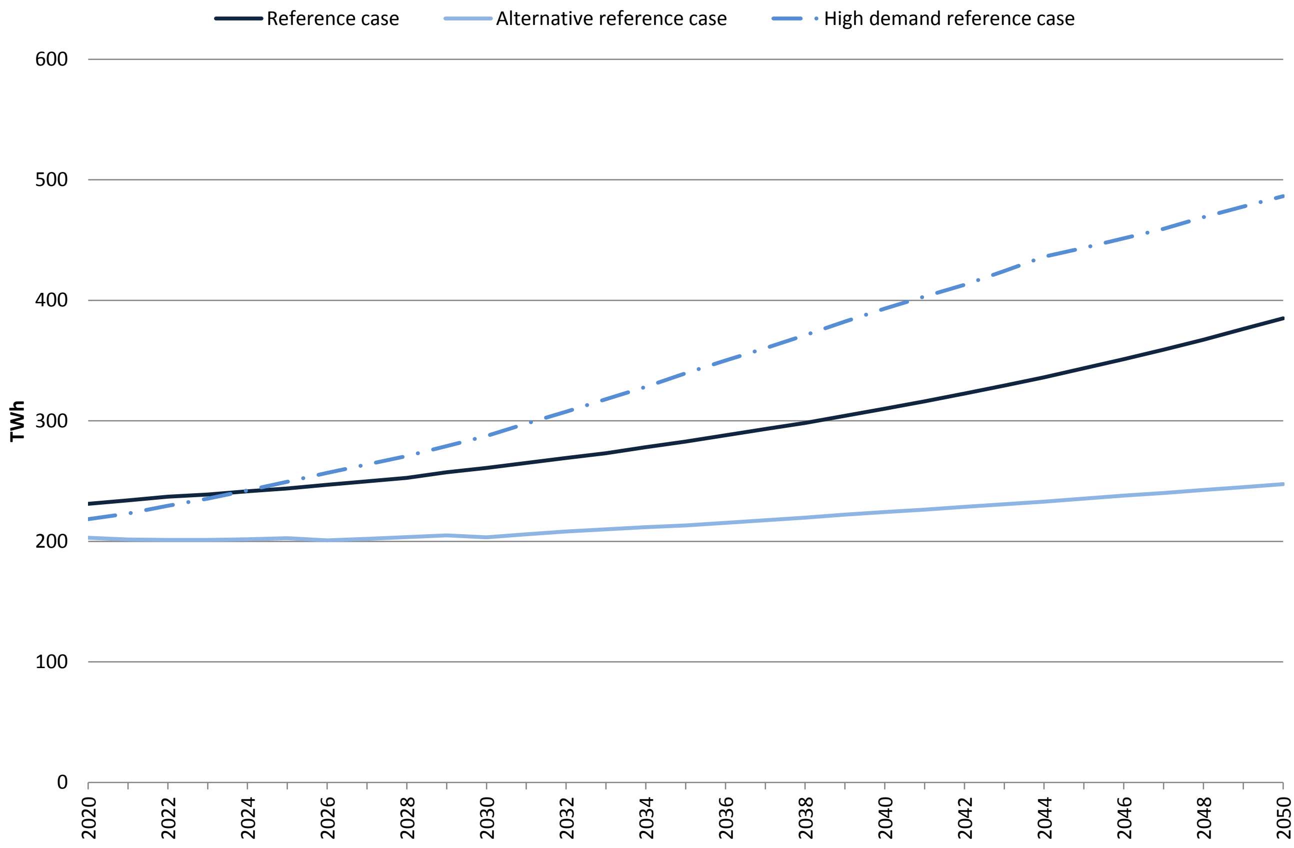


Source: Climate Change Authority based on AEMO, IMO and Department of the Environment. Notes: AEMO and IMO series are the medium demand projections from the National Electricity Forecasting Report and SWIS Electricity Statement of Opportunities, respectively. Both are 'sent out', that is, they include transmission and distribution losses but exclude auxiliary generation. Neither series in this figure includes 'grid exempt' demand (for example, embedded generation such as methane generation at coal mines). Two adjustments have been made to the Department of Environment series for the purposes of this comparison of grid-based demand, but not to the series used in the modelling. First, projected generation from rooftop PV has been removed; it is included in the estimate of total demand used as an initial input into Jacobs' suite of models. Second, the Department of Environment series constructed for this comparison figure includes both on- and off-grid large-scale solar so will slightly overestimate total projected generation from large-scale solar in the NEM and WEM.

C.2.1 Demand sensitivities

A selection of policy scenarios were modelled with high and low demand sensitivities. The low demand series was incorporated in the alternative reference case sensitivity. Figure 366 provides a comparison of the three demand series.

Figure 366: Demand projections for high and low demand sensitivities



Source: Jacobs. Includes demand from on-site generation.

The starting point for both the high and low demand series was the latest demand projections from the relevant market operators[51]. From this starting point, different growth rates were applied to produce demand series to 2050:

- The high demand series used growth rates for NEM demand based on ClimateWorks' 'Pathways to Deep Decarbonisation' study[52]. In ClimateWorks' scenarios, demand is projected to increase significantly, driven by electrification of the road transport, building and industrial sectors.
- The high demand series for the WEM was produced by adding IMO's high demand series for grid-based demand with high uptake of small-scale PV. For the purpose of this exercise, the series was extended to 2050 by applying the average growth rate from the final five years of the projection.
- The low demand series are based on the latest low demand projections published by the relevant market operators[53].
  - For the NEM, the low demand series was produced by adding AEMO's low demand series for grid-based demand with low uptake of small-scale PV. For the purpose of this exercise, the series was extended to 2050 by applying the average growth rate from the final five years of the projection.
  - For the WEM, the low demand series was produced by adding IMO's low demand series for grid-based demand with low uptake of small-scale PV. For the purpose of this exercise, the original series was extended to 2050 by applying the average growth rate from the final five years of the projection.

[51] Australian Energy Market Operator, National Electricity Forecasting Report 2015; Independent Market Operator, 2014 Electricity Statement of Opportunities.
[52] ClimateWorks 2014, Pathways to Deep Decarbonisation in 2050: How Australia can prosper in a low carbon world.
[53] Australian Energy Market Operator, National Electricity Forecasting Report 2015; Independent Market Operator, 2014 Electricity Statement of Opportunities.

C.2.2 Price elasticity

In all modelling runs the core demand path was adjusted to reflect the impact of each policy on demand through its impact on electricity prices. The size of the expected change in electricity demand depends on:

- How much and in what direction each policy affects the overall prices faced by consumers, and
- How responsive demand is projected to be to a price change (the estimated elasticity of demand).

The demand impacts are estimated by adjusting the core demand path with long-run own price elasticities of demand. Elasticities used are based on those from AEMO 2015 (Table 1). These elasticities apply to all loads (residential, commercial, industrial and large loads) in each state because the underlying price used to derive the elasticities, referred to as the Total Price of Elasticity, is essentially the average customer electricity price weighted across all classes. These price elasticities represent the percentage change in demand expected for a 1% increase in electricity price.

Table 19: Assumed regional price elasticity of demand by State

State	Energy price elasticity (%)	Demand price elasticity (%)
New South Wales	-0.372	-0.242
Victoria	-0.212	-0.131
Queensland	-0.323	-0.184
South Australia	-0.232	-0.179
Tasmania	-0.403	-0.351
Western Australia	-0.230	-0.147

Source: AEMO NEFR 2015 Forecast Methodology Information Paper for the NEM states[54]. The Western Australian elasticity is based on information from Synergy.

These elasticities are defined on an ‘energy over time’ basis. Peak demand is less elastic. We assume the peak demand elasticity will be reduced by the proportion of air conditioning demand in the peak demand. This is because air conditioning demand is observed to be relatively inelastic.

C.2.3 Further details on demand

The 2010/11 load shape is used to shape hourly demand profiles as it reflects demand response to normal weather conditions and captures the observed demand coincidence between the States. The energy forecasts were originally developed by Pitt & Sherry and ACIL Allen for the Department of the Environment’s 2014/15 emissions projections. Jacobs derived the peak demand forecast from these energy projections by applying the load factors from AEMO’s 2014 NEFR forecast, and the IMO’s 2014 SWIS Electricity Demand Outlook forecast.

Jacobs adjusts the forecasts to account for small scale embedded generation uptake as projected by the DOGMMA model. Jacobs’ Strategist model is then used in conjunction with REMMA to explicitly project the uptake of renewable energy generation.

The use of the 50% probability of exceedance (POE) peak demand is intended to represent typical peak demand conditions and thereby provide an approximate basis for median price levels, generation dispatch and assessing long-term system costs. Reserve margins allow for coverage of 1 in 10 year peak demands (10% POE).

[54] There are many sources of estimates of the own price elasticity of electricity demand in the NEM, but all estimates are characterised by relatively low price elasticities (see M. O’Gorman and F. Jotzo (2014), “Impact of the carbon price on Australia’s electricity demand, supply and emissions”, *Centre for Climate Economics and Policy Working Paper 1411*, Canberra). A review study has found these elasticities reducing over time (A. Rai, L. Reedman and P. Graham (2014), *Price and income elasticities of residential electricity demand: the Australian evidence)*. Given the broad similarities across estimates, the likely changes in demand response from using alternative estimates are likely to be minimal.

The load is modelled hourly and therefore the peak is applied as an hourly load in Strategist rather than half-hourly as it occurs in the market. Because the Strategist model applies this load for one hour in a modelled typical week it is effectively applied for 4.3 hours per year and therefore it represents a slightly higher peak demand exposure than the pure half-hour 50% POE. This compensates to some degree for not explicitly representing the variation up to 10% POE.

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

Wind generation varies by location:

- 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[55].
- 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

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

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

They do not include financing costs or depreciation of existing capital.

Note that 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; as such they 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:

- 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%. These inputs are based on discussions with major investors (generating companies, investment banks and superannuation funds) in generating plant and lenders (major financial institutions) to the electricity sector.

In the case of the Feed-in Tariff policy the weighted average cost of capital of investments funded under the policy was assumed to be 0.5 percentage points lower as a typical feature of the policy is the provision of long term contracts, which provides a degree of revenue certainty for investors not available under other policy measures.

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 using the social discount rate recommended by the Office of Best Practice Regulation (7%) (see Section B above).

C.3.6 Exchange rates and inflation

All values in the report are in June 2014 dollars unless otherwise specified.

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. The wholesale market models are created in real dollar costs to show trends in real price terms.

The Australian dollar exchange rate in 2014/15 is assumed to be US77c and to decline over 5 years to US76c and hold that value. This is based on Department of Industry and Science's projected exchange rate in its latest quarterly outlook[56].

C.3.7 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.3.8 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 20 and Table 21 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 22 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.

[56] Department of Industry and Science, "Resources and Energy Quarterly", March 2015.

Table 20: Monthly energy for small hydro generators, GWh

Month	Barron	Hume	Kareeya
January	15.93	7.62	26.83
February	30.92	8.60	13.45
March	20.80	9.27	21.48
April	18.74	8.41	20.59
May	11.80	6.04	36.35
June	15.93	0.00	47.36
July	11.80	0.00	26.24
August	17.05	0.00	32.78
September	13.49	6.04	28.91
October	19.11	10.84	28.62
November	4.87	9.91	28.32
December	6.93	8.54	26.54
Total	187.38	75.26	337.46

Table 21: 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 22: 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 23. 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.

Table 23: Indicative average variable costs for existing thermal plant ($June 2014)[57]

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 – South Australia	37 - 111	Gas - Queensland	25 - 56
Oil – South Australia	250 - 324	Oil – Queensland	241 - 295
Gas Peak – South Australia	100 - 164	Gas – Western Australia	52 - 59
Black coal – Western Australia	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.

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[58]. 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 E.

[57] 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.

[58] 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.

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 E.

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)[59] 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).

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 F. 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).

[59] Engineer-Procure-Construct turnkey project delivery.

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[60], adjusted for projected global deployment rates consistent with strong or weaker global action to reduce emissions as sourced from the IEA for the 2°C and weaker emissions constraint, respectively[61]. 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[62]. 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 F (as capital cost de-escalators).

Table 24: Learning rates and technology cost reductions

	IEA growth in generation 2020 to 2040 (%); 450 ppm scenario (2 degree target); New policies scenario (3 degrees target)	Learning rate, cost reduction per doubling, mid point estimate	Per cent per annum reduction	* Australian component, reduction per cent per annum
2°C				
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%
3° C Target				
Biomass	105%	12%	0.6%	0.4%
Wind	151%	14%	1.1%	0.5%
Geothermal	215%	12%	1.3%	0.8%
Solar PV	188%	30%	2.8%	1.4%

* 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 60 and 61.

[60] 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.

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

[62] ATA, CSIRO

C.4.3 Trends and comparisons

This exercise was conducted when Australia-specific technology costs from the Australian Energy Technology Exercise[63] (AETA) were a few years old, and the Australian Power Generation Technology[64] (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 367 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.

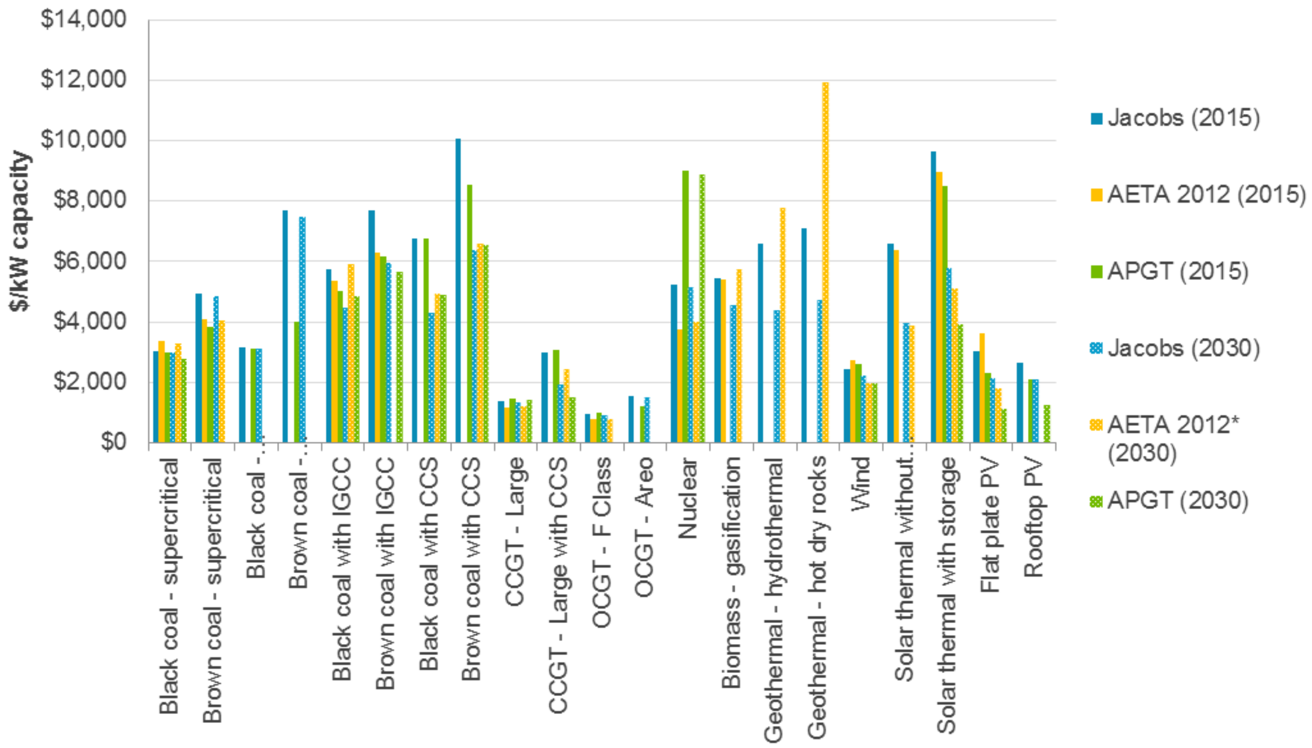
- Relative to this study, the 2015 capital costs of a brown coal plant is around 20% lower in the APGT study and 15% lower in AETA 2012.

- 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[65]. 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.

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

Figure 367: Capital cost in 2015 and 2030: comparison across studies



Source: Jacobs 2015, AETA 2012, APGT 2015 . * 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 25 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 25: 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
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 26: Technology cost assumptions for storage by scale

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

Source: Jacobs analysis

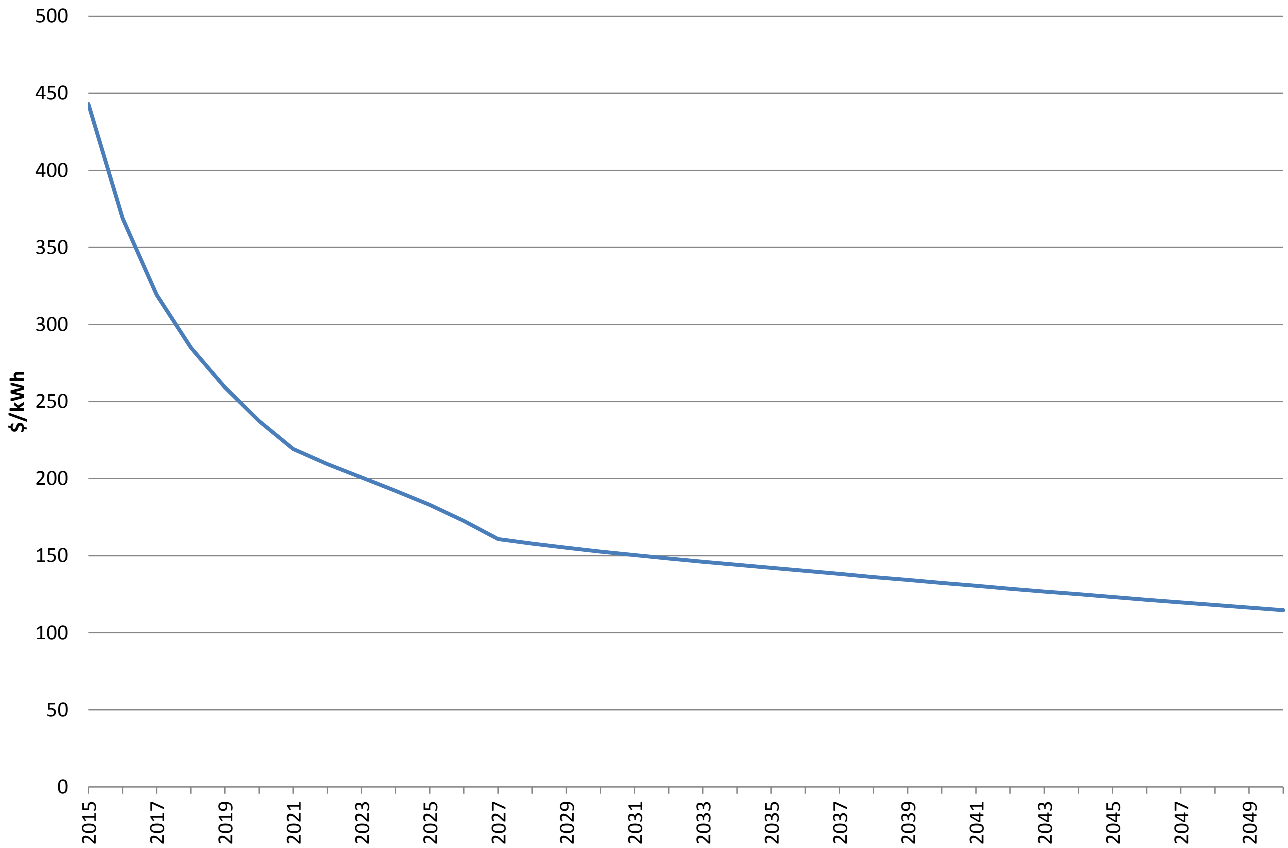
For the alternative reference, different assumptions on storage costs were used. The assumptions were based on a CSIRO study[66]. The assumptions are shown in Figure 368. They indicate higher storage costs than was used in the reference case but these costs decline over time to be lower than reference case storage costs by 2025.

In deriving these costs and storage operating parameters, the following assumptions were used:

- Multiple on capital cost for invertor and balance of plant: 1.7
- Cycles: 4000
- Maximum life: 10 years
- Discharge/recharge efficiency: 90%

[66] CSIRO (2015), *Future Energy Storage Trends*, report prepared for AEMC

Figure 368: Storage costs for the alternative reference case, levelised costs, $/kWh



Source: CSIRO, 2015, ibid.

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. However, the potential for cost reductions through learning by doing mean that the estimates used in this study are still plausible.

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 27 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 27: 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[67].

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[68].
- 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.

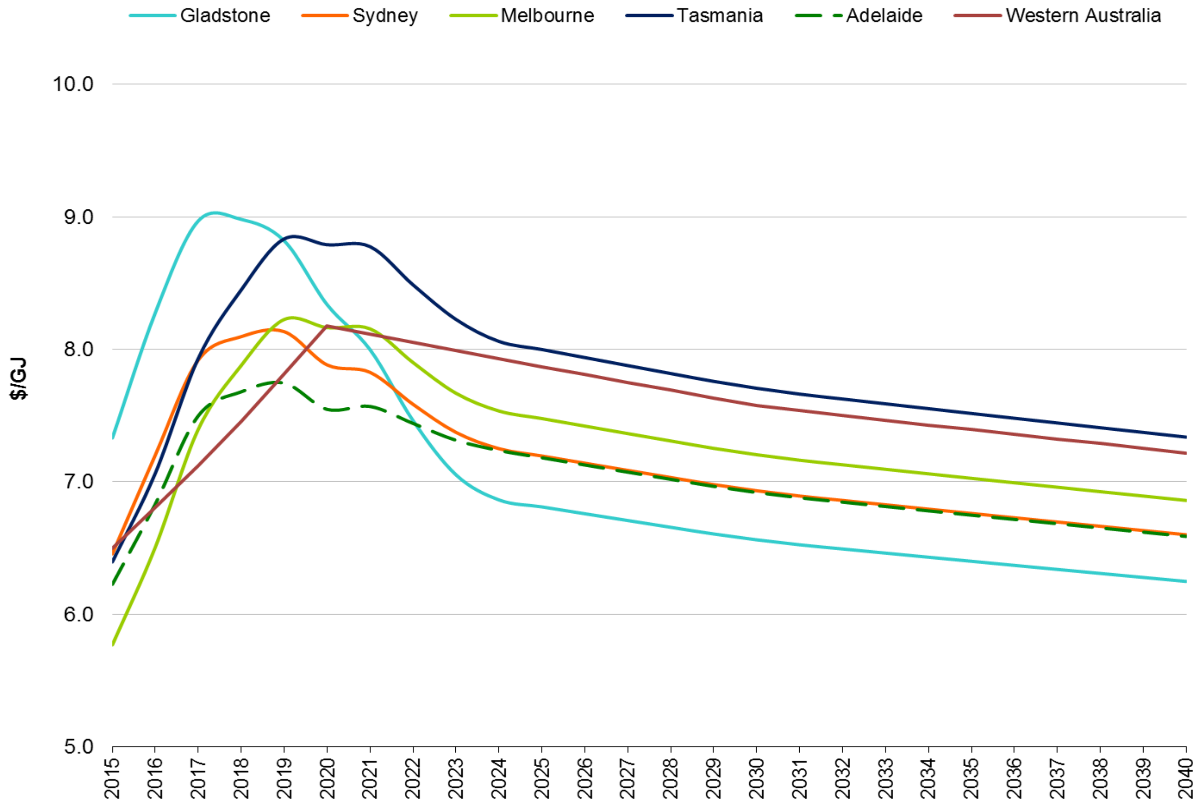
For the period to 2020 we have used our medium gas price projections, which assume gas prices rise above world parity levels over the period to 2018/19 due to a shortage of gas to meet contracted commitments for LNG. Thereafter prices fall to world parity level. Figure 369 shows the gas price assumptions 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.
- 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[69]. This sees prices for natural gas on world markets decreasing by around 0.5% per annum in real terms.

[67] ClimateWorks 2015, *Pathways to deep decarbonisation in 2050 – Technical Report*
[68] 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.
[69] 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.

Figure 369: Gas price assumptions (2°C emissions constraint), city gate prices

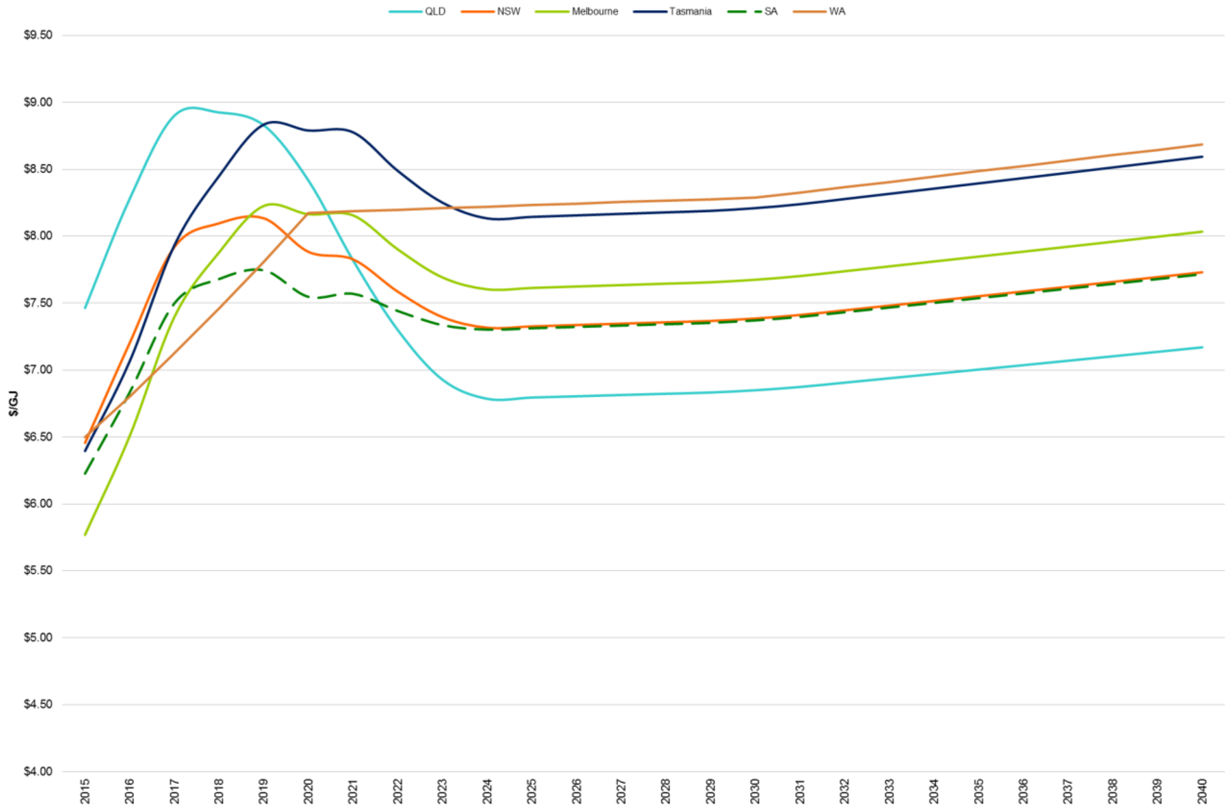


Source: Jacobs' MMAGas model, IEA 450 ppm scenario

C.5.2 Gas prices under weaker emissions constraint

Gas prices for the weaker emissions constraint are derived in the same way as prices under the 2°C constraint, except different assumptions are made about world gas prices. From 2020, world prices follow the trajectory predicted by the IEA for their new policy scenario. Figure 370 shows the gas price assumptions used for the weaker emissions constraint.

Figure 370: Gas price assumptions (weaker emissions constraint), city gate prices



Source: Jacobs' MMAGas model, IEA New policies scenario

C.6 Coal prices

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

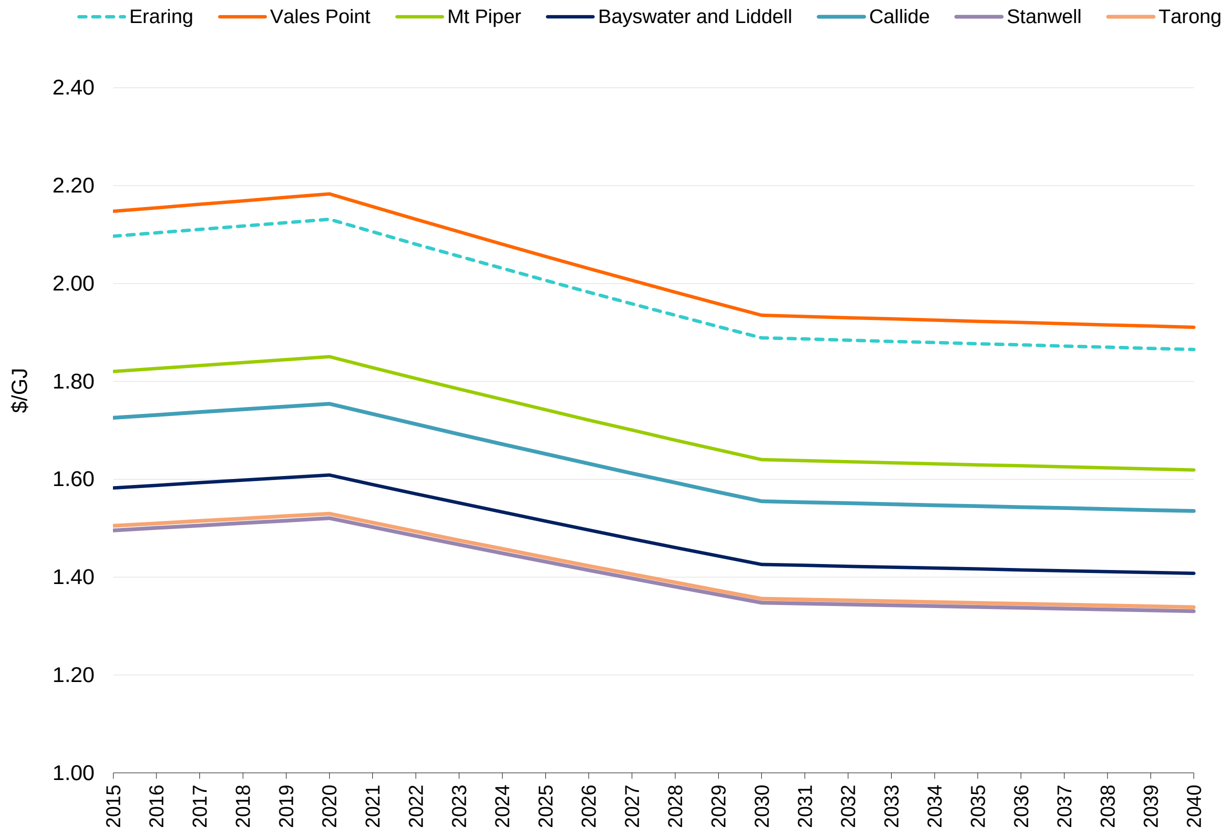
- For those mines containing coal that is unlikely to be exported (typically brown coal plant in Victoria), prices are equal to the long run average cost of production including expected continuing mine development
- For plant with long term coal contracts, prices remain at contract price terms (as we 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[70]. 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[71].

The coal prices assumed under stronger emissions constraint runs for key NEM power stations are shown in Figure 371. 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.

Coal prices for the weaker emissions constraint are derived in the same way as prices under the 2°C constraint, except different assumptions are made about world coal prices. From 2020, world prices follow the trajectory predicted by the IEA for their new policy scenario. This is the IEA scenario most consistent with the world taking action to stabilise greenhouse gas emissions at 550 ppm. Figure 372 shows the coal price assumptions used

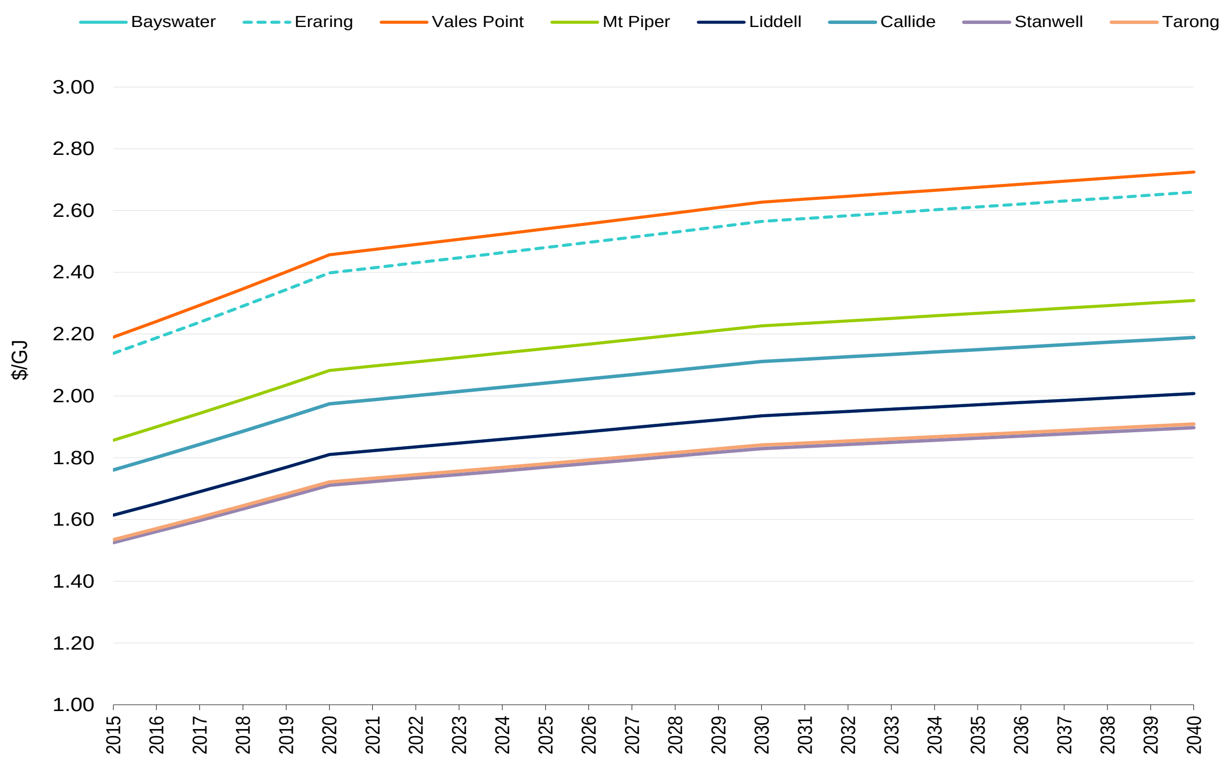
[70] Source: Bureau of Resources and Energy Economics, *Resource and Energy Quarterly*, March 2015
[71] International Energy Agency, *World Energy* Outlook, 2014, p.48. More recent coal price projections became available after the modelling was largely complete (International Energy Agency, *World Energy* Outlook, 2015). The growth rates were largely similar.

Figure 371: Projected variable coal price for NEM black coal power stations (2°C emissions constraint), $June 2014



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

Figure 372: Projected variable coal price for NEM black coal power stations (weaker emissions constraint), $June 2014



Source: Jacobs, IEA (2014), *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 28. The direct emissions factors assumed for new power stations are listed in Table 28. These factors are sourced from the Department of the Environment's workbooks containing assumptions behind the derivation of historical emissions[72].

Table 28: Emission factors by power station

Region	Power station	Emissions factor (kg/MWh)	Emission factor of fuel (kg/GJ)
Tasmania	Tamar Valley GT	720	62.64
	Tamar Valley CCGT	473	62.64
South Australia	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
Victoria	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

[72] Department of the Environment (2014), *National Greenhouse Account Factors: 2014*, and previous issues.

Region	Power station	Emissions factor (kg/MWh)	Emission factor of fuel (kg/GJ)
	Bairnsdale	650	61.84
	Valley Power	845	61.44
	Somerton	829	61.44
	Laverton Nth	707	61.44
	Mortlake	666	61.74
	Qenos Cogen	676	61.44
New South Wales	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 Vallet GT	1723	73.69
	Smithfield	622	62.24
	Tallawarra	447	62.24
	Colongra	670	62.24
Queensland	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

Region	Power station	Emissions factor (kg/MWh)	Emission factor of fuel (kg/GJ)
	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
SWIS	Muja A	1237	95.25
	Muja B	1237	95.25
	Muja C	1077	95.25
	Muja D	1003	95.25
	Alinta Pinjarra	391	59.94
	Kwinana C	668	59.94
	Kwinana GT	928	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
	Worsely	480	59.94
	Goldfields Power	721	61.64
	Southern Cross	780	61.64
	Alcoa Cogen	828	59.94
	LMS 100	506	59.94
	NewGen CCGT	447	59.94

Region	Power station	Emissions factor (kg/MWh)	Emission factor of fuel (kg/GJ)
	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 29: 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 in the reference case for this work.

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[73], 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

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

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.

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. Scenario specific details and summary

Table 30: Policy scenarios: key assumptions

Questions	Explore through	Scenarios	Key assumptions and design
How do individual policies compare on key metrics when meeting the same cumulative emissions budget?	Modelling each policy separately with common inputs and common emissions constraint	All	Strong global action[1] Policies calibrated to meet emissions constraint Technology availability (constant across all scenarios both phases except technology sensitivity) CCS and geothermal can be deployed from 2030 Nuclear can be deployed from 2035
Would less ambitious emissions targets change the relative performance of policies?	Weaker emissions constraint	All	Weaker global action[2] Policies calibrated to meet emissions constraint
Will combinations of policies perform better than individual policies?	Policy combinations	Carbon price and low emissions target Carbon price and regulated closures Regulated closures and low emissions target	Strong global action The first policy in each combination is fixed; the other varies so the combination meets the emissions constraint. When fixed: • Carbon price consistent with likely chance of 3 degrees warming • Regulated closures of all coal capacity by 2030 (regulated closures limited to coal fired generators)
Does a large shift to distributed generation and storage change the relative performance of policies? If actual electricity demand is lower than projected, does this change the relative performance of policies?	Alternative reference case (higher penetration of PV and storage; lower underlying electricity consumption	Reference case Carbon price Low emissions target (planned but not run: LET targets exceed electricity demand)	Strong global action Uses policy parameters from phase one (that is, policies are an input not an output as per most other runs) Lower electricity demand sourced from AEMO and IMO[3]. More demand management leads to flatter profile Faster reductions in battery storage costs[4] Relaxed upper bounds on share of households and businesses that install PV. Relaxed constraints limiting installations per region per year[5]
If actual electricity demand is higher than projected, does this change the relative performance of policies?	High electricity demand	Reference case Carbon price Low emissions target	Strong global action Uses policy parameters from phase one (that is, policies are an input not an output as per most other runs) High electricity demand based on ClimateWorks (for NEM) and IMO high demand scenario (WEM)[6]
Does changing the costs and/or availability of key large-scale technologies change the relative performance of policies?	Technology sensitivities	Reference case Carbon price Low emissions target Renewable energy target	Strong global action Policies calibrated to meet emissions constraint No nuclear, CCS or geothermal deployment Faster reductions in battery storage costs[4]

1. Cumulative emissions constraint: consistent with Intergovernmental Panel on Climate Change's median estimates carbon price consistent with likely (two-thirds) chance of limiting warming to 2 °C (430 to 480 ppm).(IPCC, 2014. Working Group III Contribution to the Fifth Assessment Report, Climate Change 2014—Mitigation). Gas prices to 2020 based on Jacob's MMAGas (Market Model Australia – Gas) medium price projections. Prices from 2020 based on IEA (2014) WEO '450 ppm scenario'. International Energy Agency, World Energy Outlook, 2014, p.48. Coal prices treated in three ways:

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

- For plant with long term coal contracts, prices remain at contract price terms (as understood by Jacobs) 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. 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. International Energy Agency, World Energy Outlook, 2014, p.48.

Projected learning rates are sourced from the international literature, adjusted for projected global deployment rates consistent with strong global action (450 ppm) to reduce emissions as sourced from the IEA. Projected learning rates sourced from 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. Forecasts for deployment sourced from IEA (2014), World Energy Outlook: 2014 (450 ppm scenario).

2. Same as in (1), but with the following changes:

- Cumulative emissions constraint based on IPCCs 530 to 580 ppm scenario.
- Gas and coal prices from 2020 based on IEA's 'new policies scenario'.
- Forecast deployment (for learning rates) based on IEA's 'new policies scenario'.

3. Low electricity demand based on 'low' series from Australian Energy Market Operator (AEMO) (2015) National Electricity Forecasting Report for the National Electricity Market (NEM) and the Independent Market Operator (IMO) (2015) 2014 Electricity Statement of Opportunities for the South-West Interconnected System of Western Australia.

4. Large scale battery storage data from CSIRO (2015) Future Energy Storage Trends. Projected capital cost trajectory of lithium-ion batteries (low cost path).

5. Three of the constraints applied to solar photovoltaics (PV) and solar hot water (SHW) were adjusted in the alternate reference case.

In the reference case a household could choose either PV or SHW (and would choose the system with highest NPV if both were economic). This constraint relaxed over time so that by 2030, 100% of households can choose both PV and SHW.

Saturation rates relaxed for both households and commercial sector. Households: relaxed from all owner-occupiers in separate dwellings to all separate dwellings (allowance in both cases for heritage houses, etc). Commercial deployment of PV was also increased by 10% relative to the Phase 1 reference case. Effects are to raise saturation rates for households from around 55% to 65% and for the commercial sector from around 65% to 75%, respectively.

Maximum installation rates per system per year relaxed.

6. Growth rates from electricity demand in *ClimateWorks (2014) Pathways to Deep Decarbonisation in 2050: How Australia can prosper in a low carbon world* applied to the 2014/15 NEM electricity demand from Phase 1 of the modelling (in turn based on Department of the Environment (2015) Emissions projections 2014/15 electricity demand forecast). WEM demand based on high demand series from IMO (2015) SWIS Electricity Demand Outlook.

Table 31: Scenario design

Policy	Coverage, liability and eligibility	Parameters to meet emissions constraint	Banking and borrowing	New entrants standards	Other*
Carbon price	Coverage/liability: all generators in NEM and WEM with emissions above 25,000 t CO2-e/year.	N/A (carbon price used to derive emissions constraint)	No banking or borrowing.	No explicit standards.	Permit allocation: full auctioning No offsets. New biomass generation: constrained to reference case capacity
Emissions intensity target	Coverage/liability: all registered generators in NEM and WEM. Generators built after 2020 will are only eligible to participate in this scheme rather than the RET.	Baseline trajectory: declining linear emissions intensity baseline starting at grid average intensity in 2020 with level in 2050 chosen to meet the emissions constraint.	Unlimited banking; borrowing limited to 10 per cent of the following year's permits.	No explicit standards.	Permit allocation: free allocation of permits to each generator determined by own output multiplied by the baseline. New biomass generation: constrained to reference case capacity
Renewable energy target	Eligibility: new (from 2020) large-scale renewable generators (generators registered for existing scheme and all coal-mine methane generators ineligible) new commercial-scale PV (systems larger than 10 kW)* brown field projects on existing sites. Liability: same liabilities as existing scheme.	LRET trajectory: a 'new LRET' trajectory additional to the existing LRET trajectory grows from zero in 2020 to the required level in 2040 then flat to 2050. Existing small-scale scheme phases out as planned.	Unlimited banking; borrowing limited to 10 per cent of the following year's permits.	No explicit standards.	Existing LRET: investments unchanged from reference case. Assume investors in existing scheme invest on existing economics (that is, they do not delay to take advantage of new scheme). New biomass generation: constrained to reference case capacity
Low emissions target	Eligibility and liability: same as the RET scenario, with the following additions to eligibility: • all new fossil and nuclear generation with an emissions intensity below the threshold • existing fossil generation that has had a CCS retrofit resulting in an emissions intensity below the threshold • coal-mine methane capture eligible according to emissions intensity of generation only • existing low emissions fossil plant and	A LET trajectory additional to the existing LRET grows from zero in 2020 to the required level in 2040 then flat to 2050.	Unlimited banking: borrowing limited to 10 per cent of the following year's permits.	No explicit standards.	Threshold intensity: 0.6 t CO2-e/MWh (sent-out) to provide a moderate incentive for low emissions generation; for example a combined-cycle gas turbine (the least polluting existing fossil plant has an intensity of 0.4 t CO2-e/MWh). Existing LRET: investments unchanged from reference case. Assume investors in existing scheme invest on existing economics (that is, they do not delay to take advantage of new scheme).

Policy	Coverage, liability and eligibility	Parameters to meet emissions constraint	Banking and borrowing	New entrants standards	Other*
	renewable generators eligible for generation that exceeds historic baseline levels.				New biomass generation: constrained to reference case capacity
Feed-in-tariff	Eligibility: new renewables and new fossil with CCS; CCS retrofits; nuclear. Eligible renewables as per LRET with 10 kW PV threshold (renewables receiving certificates under the existing RET ineligible). Liability: funds for payments to successful generators raised via energy-based customer levy shared across NEM and WEM.	Allocation trajectory: allocate the same volume of 20 year contracts each year from 2020 to 2035 to obtain a progressively increasing volume of low emissions energy. This volume will be chosen to achieve the emission constraint.	Not applicable.	No explicit standards.	Reference price for CfDs: NEM: monthly national average wholesale electricity spot price. SWIS: average monthly wholesale electricity spot price. New biomass generation: constrained to reference case capacity
Regulated closure (age-based)	Coverage: limited to coal-fired and gas generators. For simplicity, complete withdrawal of whole of a generator at a specific date or complete conversion to CCS.	Closure sequence: Generator closure dates set in 2020. Closure dates chosen to remove capacity starting with oldest plant to achieve a roughly linear MW per year total closure to meet the emissions constraint.	Not applicable.	Standards prohibit new coal without CCS.	Closure ranking: Age-based: by date of first unit's commissioning. Plant life extensions ignored. Once determined, the ranking is publicly announced and fixed. New biomass generation constrained to reference case capacity.
Absolute baselines	Coverage/liability: all generators in NEM and WEM with emissions above 25,000 t CO2-e/year (for the sectoral baseline); above average intensity generators (for the individual baselines). The coverage intensity threshold for individual baselines to decline at a fixed rate from commencement of the scheme.	Baselines: individual absolute baselines to meet the emissions constraint.	Not applicable.	Required to be at 'best practice' (that is, no new coal or gas plant without CCS).	No offsets. New biomass generation constrained to reference case capacity.

* In practice policies would have penalties for non-compliance. These are not incorporated into the modelling because the aim is to find the policy parameters under which businesses comply with the policy through mitigation action rather than paying the financial penalty. Policies modelled without offsets: their inclusion may have meant that modelling results were dominated by expected future offset prices, which are particularly uncertain.

Table 32: Changes to modelling assumptions since release of the consultation paper

Change made	Reason for change
Price elasticities for National Electricity Market (NEM) states and load factors for the NEM were updated from the 2014 Australian Energy Market Operator (AEMO) National Electricity Forecasting Report (NEFR) to 2015 AEMO NEFR data	Incorporate latest information
Fixed operating and maintenance costs for existing generators were changed (from Jacobs' database to AEMO's publicly available data), on the basis of GDF Suez's submission.	Public consultation outcome
Generator list updated to incorporate Alcoa's Anglesea (31 August 2015) and Alinta's Northern (March 2018) closure announcements.	Incorporate latest information
Minor updates were made to Western Australia generator information on the basis of Synergy's confidential submission.	Public consultation outcome
New biomass generation capacity is limited by the reference case in order to reflect CSIRO findings that under economy-wide emissions reduction policies highest value use of biomass is likely to be in transport sector. This constraint is applied across all policy scenarios.	Accuracy
The RET and LET trajectories re-phased from a linear trajectory to dual trajectories from 2020-2030 and 2030-2040 to allow convergence with the emissions target.	Allow convergence with emissions budget
Intensity target threshold for issuing LET certificates held constant at it starting value rather than declining	Decline not required to meet emissions budget
Minor change to reference case demand post-2035: Jacobs extended official series from 2035 using trend growth rather than average growth rate from the final five years of the official projections as stated in the consultation document.	This method has proven to be more accurate
Gas constraint in regulated closure policy implemented as stable not declining	During modelling It was found that declining the gas constraint was not resulting to the least cost solution
New commercial-scale rooftop PV (larger than 10 kW) not eligible for RET, LET, FiT	Eligibility not implemented to simplify modelling] Used 100 kW minimum instead

Appendix E. Costs and performance of existing and prospective thermal 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

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
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
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

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
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
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 F. Technology cost assumptions

Technology type	Life Years	Nominal capacity MW	Auxiliary load %	Capital cost, 2015 $/kW sent out	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
Combined Cycle Gas Turbine - Large	30	559	2.2%	1,341	0.17	6.86	3.6	35
Combined Cycle Gas Turbine - 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
Open Cycle Gas Turbine (E Class)	30	167	1.1%	1,106	0.20	11.36	7.2	17
Open Cycle Gas Turbine (F Class)	30	284	1.0%	936	0.20	10.38	7.2	13
Open Cycle Gas Turbine (aero)	30	49	1.2%	1,539	0.20	10.00	10.3	27
Open Cycle Gas Turbine (Brown Field)	30	196	1.4%	1,550	0.66	9.52	10.3	28
Open Cycle Gas Turbine (Green Field)	30	196	1.4%	1,550	0.66	9.52	10.3	28
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

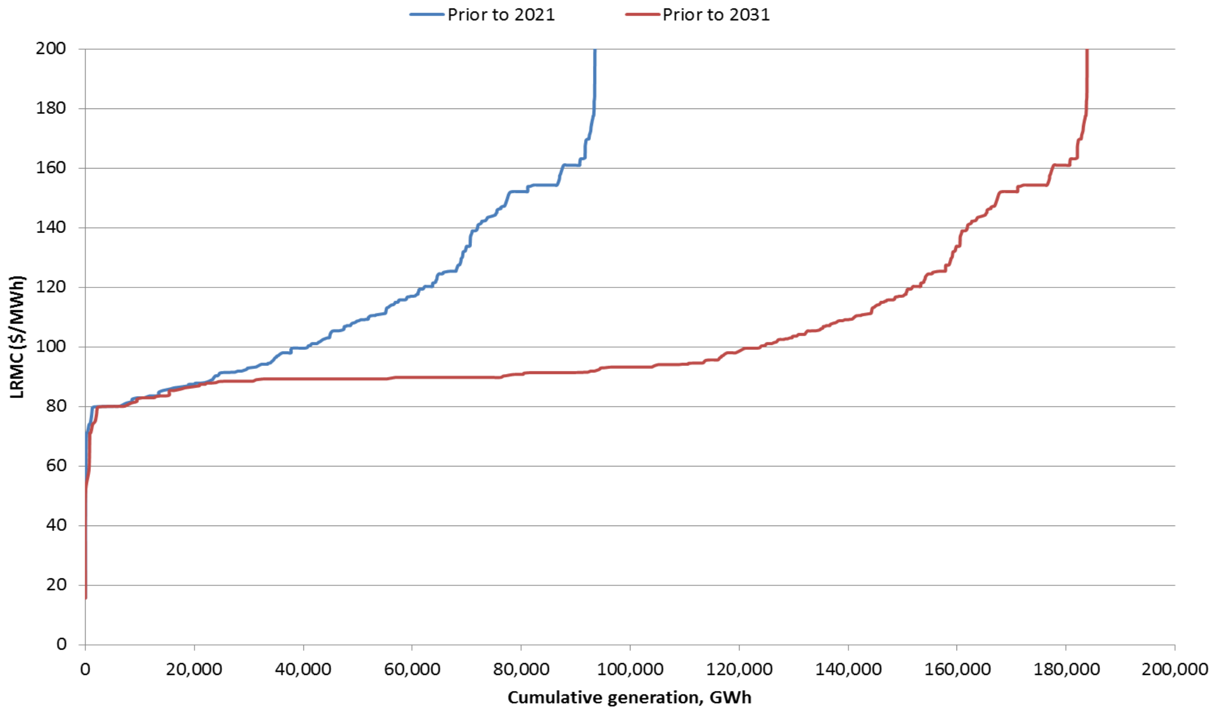
Technology type	Life Years	Nominal capacity MW	Auxiliary load %	Capital cost, 2015 $/kW sent out	Capital cost de-escalator from 2020 % pa	Heat rate at maximum capacity GJ/MWh	Variable non-fuel operating cost $/MWh	Fixed operating cost $/kW
Concentrated solar thermal plant - without storage	35	150	5.0%	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
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: Phase 1	15	-	-	612*	2.50	-	-	-
Small-scale storage: Phase 2 alternative reference case	15	-	-	443	9.00	-	-	-
Large-scale storage: Phase 1	15	-	-	551*	2.50		-	-
Large-scale storage: Phase 2 alternative reference case				399*	9.00	-	-	-

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

** Construction periods are build times only and exclude time required for regulatory approvals.

(a) For small scale PV costs per kW by system size were used. Please see Appendix A.2.4 and Figure 349.

Figure 373: 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.