ACIL ALLEN CONSULTING

REPORT TO
THE DEPARTMENT OF INNOVATION, INDUSTRY, CLIMATE CHANGE, SCIENCE, RESEARCH AND TERTIARY EDUCATION

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ELECTRICITY SECTOR EMISSIONS

MODELLING OF THE AUSTRALIAN ELECTRICITY GENERATION SECTOR

ACIL ALLEN CONSULTING PTY LTD
ABN 68 102 652 148

LEVEL FIFTEEN
127 CREEK STREET
BRISBANE QLD 4000
AUSTRALIA
T+61 7 3009 8700
F+61 7 3009 8799

LEVEL TWO
33 AINSLIE PLACE
CANBERRA ACT 2600
AUSTRALIA
T+61 2 6103 8200
F+61 2 6103 8233

LEVEL NINE
60 COLLINS STREET
MELBOURNE VIC 3000
AUSTRALIA
T+61 3 8650 6000
F+61 3 9654 6363

LEVEL ONE
50 PITT STREET
SYDNEY NSW 2000
AUSTRALIA
T+61 2 8272 5100
F+61 2 9247 2455

SUITE C2 CENTA BUILDING
118 RAILWAY STREET
WEST PERTH WA 6005
AUSTRALIA
T+61 8 9449 9600
F+61 8 9322 3955

ACILALLEN.COM.AU

For information on this report please contact:

Owen Kelp
Principal
Telephone (07) 3009 8711
Mobile 0404 811 359
Email o.kelp@acilallen.com.au

Guy Dundas
Senior Consultant
Telephone (02) 6103 8208
Mobile 0405 169 116
Email g.dundas@acilallen.com.au

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Glossary

Acronym or term	Explanation
AEMO	Australian Energy Market Operator, the entity that manages dispatch and planning in the National Electricity Market.
AETA	Australian Energy Technology Assessment, an analysis of future generation costs from various electricity supply technologies undertaken by BREE in 2012.
ARENA	The Australian Renewable Energy Agency, a statutory authority of the Commonwealth Government to support renewable energy
Bagasse	A renewable fuel produced from sugar cane waste.
BREE	Bureau of Resources and Energy Economics, a Commonwealth Government research agency.
Capacity factor	A measure of the intensity with which a generator operates, calculated as the generator's average output divided by its maximum possible output, and typically expressed as a percentage.
CCGT	Combined-cycle gas turbine, a gas turbine generator where waste heat from the turbine exhaust is captured and used to drive an auxiliary steam turbine.
CCS	Carbon capture and storage, the capturing of carbon dioxide produced in the process of generating electricity (or some other industrial process) and storing
CGE	Computable General Equilibrium modelling, a form of modelling that relates the inputs and outputs of different industries within an economy to determine a 'general equilibrium' outcome across all industries when inputs or assumptions are varied.
CLFR	Concentrated Linear Fresnel Reflector, a form of solar thermal generation technology.
Cogeneration, or 'cogen'	A cogeneration plant generates both electricity and steam, with the steam typically being used for industrial process applications. Cogeneration plants can be based on either a typical steam turbine, with lower pressure steam being diverted for use as heat rather than for electricity generation, or on a gas turbine, where the gas turbine itself generates electricity but waste heat is captured to generate steam for use as process heat.
CO_2	Carbon dioxide, the most common greenhouse gas
CO2CRC	The Cooperative Research Centre for Carbon Capture and Storage.
CSIRO	The Commonwealth Scientific Industrial and Research Organisation, an Australian Government scientific research agency
DKIS	Darwin-Katherine Interconnected System, the interconnected electricity grid servicing the main population centres of the northern part of the Northern Territory.
Dual axis	In the context of solar PV generation, this refers to solar PV plates that can change angle to track the sun on two axes, an axis to track daily east-west movement of the sun across the sky and a second axis to adjust to changes in the sun's angle (north-south) with the seasons. See also 'fixed axis' and 'single axis'.
EGS	Engineered geothermal system, a form of geothermal generation technology also sometimes known as 'hot fractured rocks'.
Fixed axis	In the context of solar PV generation, this refers to solar PV plates that are mounted in a fixed position and do not track the sun. See also 'single axis' and 'dual axis'.
FOM	Fixed operating and maintenance costs. These are represented in ACIL Allen's modelling as a fixed annual payment required to keep a power station operational.
GALLM	Global and Local Learning Model, CSIRO's model of generation technology costs.
GGAS	Greenhouse Gas Abatement Scheme, the NSW Government's former emissions reduction scheme
GWh	Gigawatt-hour, a unit of electricity output or consumption measured over time, which is equivalent to one gigawatt being produced/consumed continuously for one hour, or one thousand megawatt-hours.
HEGT	High efficiency gas turbine.
HSA	Hot sedimentary aquifer, a form of geothermal generation technology.
IGCC	Integrated gasification combined cycle, a form of generation technology that uses coal as the fuel, and which converts the coal to a synthetic gas to drive a gas turbine through an integrated process.
IMO	Independent Market Operator, the the entity that manages dispatch and planning in the South-West Interconnected System.

Acronym or term	Explanation
kW	Kilowatt, a unit of (instantaneous) electricity output or consumption, equal to one one-thousandth of a megawatt.
LDC	Load duration curve, a representation of the variation in electricity demand over a period of time created by ordering the electricity demand (or 'load') in descending order.
LGC	Large-scale Generation Certificate, the certificate that can be created and traded by renewable generators under the LRET. Sometimes referred to as a 'REC', or Renewable Energy Certificate. LGCs are different from the 'Small-scale Technology Certificates' or STCs created under the SRES.
LP	Linear programming
LRET	Large-scale Renewable Energy Target, the Commonwealth Government's scheme to promote large-scale renewable electricity generation. Formerly known as the Mandatory Renewable Energy Target (MRET), and sometimes referred to simply as the RET.
MLF	Marginal loss factor, the level of transmission losses between a given generator and the point of market settlement attributed in dispatching bids for electricity supply and therefore in calculating electricity prices.
MW	Megawatt, a unit of (instantaneous) electricity output or consumption, equal to one thousand kilowatts.
MWh	Megawatt-hour, a unit of electricity output or consumption measured over time, which is equivalent to one megawatt being produced/consumed continuously for one hour.
NEM	National Electricity Market, the interconnected electricity grid covering most of Queensland, New South Wales, Victoria, Tasmania and South Australia.
NWIS	North-West Interconnected System, the interconnected electricity grid covering the Pilbara region of north-western Western Australia.
O&M	Operating and maintenance costs – see also FOM and VOM.
OCGT	Open cycle gas turbine, a gas turbine generator where waste heat is vented to the atmosphere rather than captured to generate electricity or steam, as in a combined-cycle gas turbine (CCGT) or cogeneration plant.
Oxy combustion	A technique used to improve the efficiency of CCS, by firing coal in a primarily oxygen and non-combustible gases (importantly, in the absence of nitrogen), so as to produce a relatively pure stream of CO_2 suitable for capture and storage.
PC	Pulverised coal. See also 'pf'
pf	Pulverised fuel, typically coal. See also 'PC'.
POE	Probability of exceedence, representing a the probability that a given forecast will be exceeded in the relevant forecast period.
PV	Photovoltaic, a form of generation that converts solar radiation to direct current electricity using semi-conductors that exhibit the photovoltaic effect.
QGAS	Queensland Gas Scheme
SF	Solar Flagships, the Commonwealth Government's program to promote large-scale solar generation projects.
Single axis	In the context of solar PV generation, this refers to solar PV plates that can change angle to track the east-west daily movement of the sun across the sky. See also 'fixed axis' and 'double axis'.
SRES	Small-scale Renewable Energy Scheme, the Commonwealth Government's scheme to promote small-scale renewable energy technologies, principally solar PV and solar water heaters. The incentives for these technologies were formerly combined with those for large-scale renewables through the MRET.
SRMC	Short-Run Marginal Cost, an economic interpretation of the extent to which production costs, in this case electricity generation costs, vary at the margin when key inputs, particularly the capital equipment comprising the generator, cannot be varied.
SWCJV	South-West Cogeneration Joint Venture
SWIS	South-West Interconnected System, the interconnected electricity grid covering south-western Western Australia. Also known as the Wholesale Electricity Market, or WEM.
VOM	Variable operating and maintenance costs. These are represented in ACIL Allen's modelling as costs which vary linearly with the amount of electricity produced by a given power station (i.e. as a cost in $/MWh).
WACC	Weighted average cost of capital, a benchmark rate of return on capital investments representing an assumed level of equity and debt financing, and specific rates of return to each of equity and debt.
WCMG	Waste coal mine gas

Executive summary

The Department of Industry, Innovation, Climate Change, Science, Research and Tertiary Education (DIICCSRTE) commissioned ACIL Allen Consulting (ACIL Allen) to model greenhouse gas emissions from Australia's electricity generation sector over the period to 2049-50 for its national emissions projections.

ACIL Allen estimated emissions from Australia's electricity generation sector under two scenarios: a Central Policy scenario including the effect of a carbon price and a No Carbon Price scenario with no carbon price in effect. ACIL Allen's *PowerMark LT* and *RECMark* models were used to estimate effects in Australia's major electricity markets, as well as from embedded and off-grid generation.

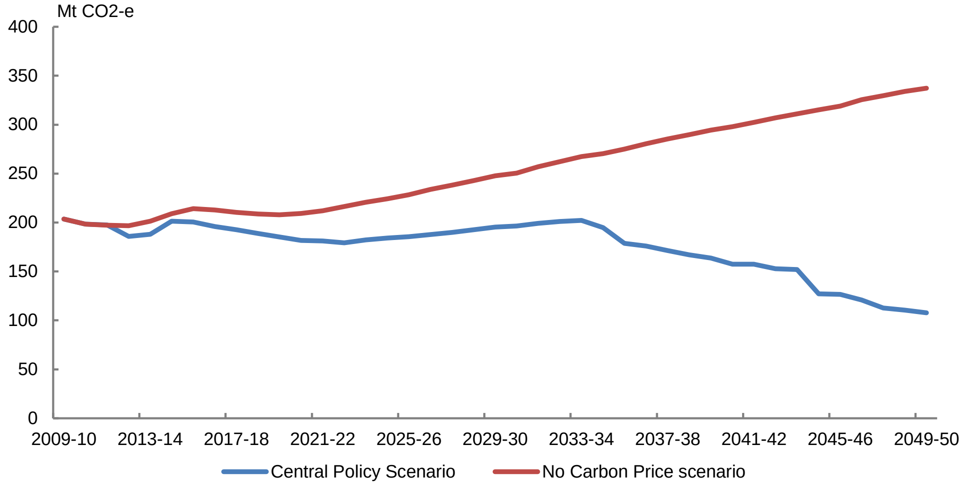
Electricity demand and other assumptions were derived from computable general equilibrium (CGE) modelling of the Australian and world economies undertaken by the Treasury.

The change in emissions between the Policy and No Carbon Price scenarios is illustrated in Figure ES 1. In both scenarios, emissions are relatively flat in the period to around 2020, due to muted demand growth in increasing penetration of large-scale renewables and rooftop solar generation. However, the path of emissions increasingly diverges from that point as demand growth and ongoing use of coal-fired generation sees substantial growth in emissions in the No Carbon Price scenario. Emissions rise from just over 200 Mt CO_2-e in 2009-10 to 248 Mt CO_2-e in 2029-30, and 337 Mt CO_2-e in 2049-50.

By contrast, emissions in the Central Policy scenario are essentially flat from 2009-10 to around 2029-30 at 195 Mt CO_2-e (53 Mt CO_2-e lower than the No Carbon Price scenario) as the carbon price motivates a move towards lower-emissions generators, offsetting the effect of (slowly) growing electricity demand.

After 2029-30 the scenarios diverge even more dramatically. Emissions under the Central Policy scenario reduce substantially as the higher carbon price and reductions in costs for technologies such as solar PV motivate large-scale adoption of low emissions generation technologies. The associated reduction in the emissions-intensity of electricity supply sees Australia's electricity sector emissions reduce to 108 Mt CO_2-e by 2049-50, or around 229 Mt CO_2-e lower than in the No Carbon Price scenario.

Figure ES 1 **Aggregate emissions – No Carbon Price and Central Policy scenarios**



In principle, emissions reductions can be driven by one of two processes: demand reductions or reductions in the emissions intensity of electricity supply. Until around 2033-34, this reduction in emissions in the Central Policy scenario relative to the No Carbon Price scenario is driven in broadly equal amounts by the relative demand reductions and reductions in the emissions intensity of supply. However, after 2033-34, the substantial reduction in emissions under the Central Policy scenario is overwhelmingly driven by adoption of low emissions generation technologies and the associated reduction in the emissions-intensity of electricity supply.

The substitution of high emissions generation technologies with lower emissions alternatives can be seen by comparing the generation shares by fuel type between the scenarios. Figure ES 2 shows this for the Central Policy scenario, whilst Figure ES 3 illustrates the No Carbon Price scenario. These figures illustrate how the introduction of a carbon price results in an absolute decline in conventional coal-fired generation, whilst promoting gas-fired, CCS, wind, solar and geothermal generation as lower-emissions alternatives. This occurs primarily because the introduction of a carbon price increases the cost of high-emissions generation technologies relative to low-emissions alternatives.

Figure ES 2 **Generation by fuel type – Central Policy scenario**

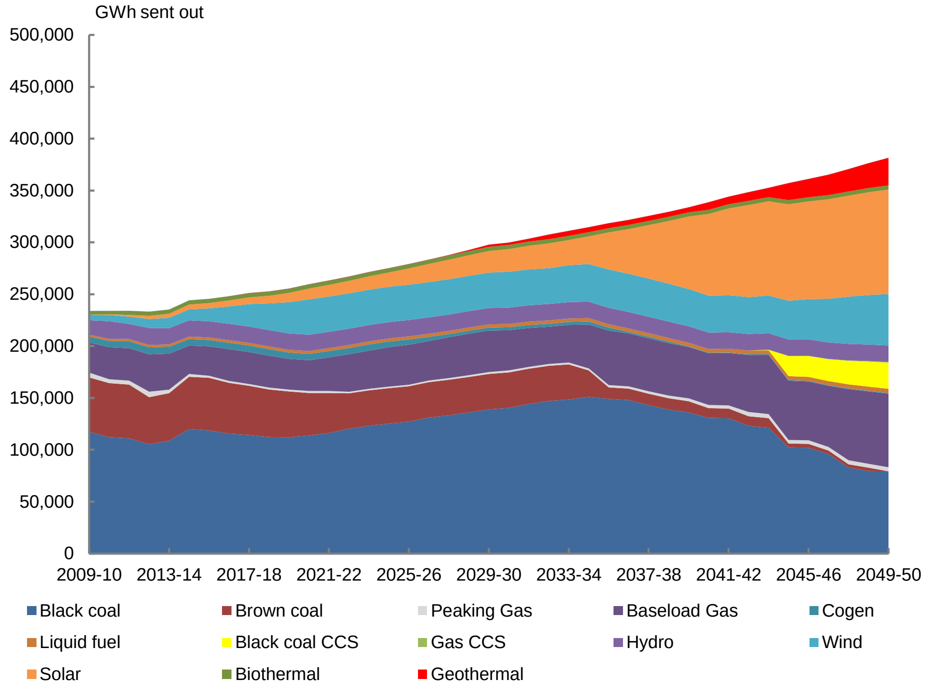
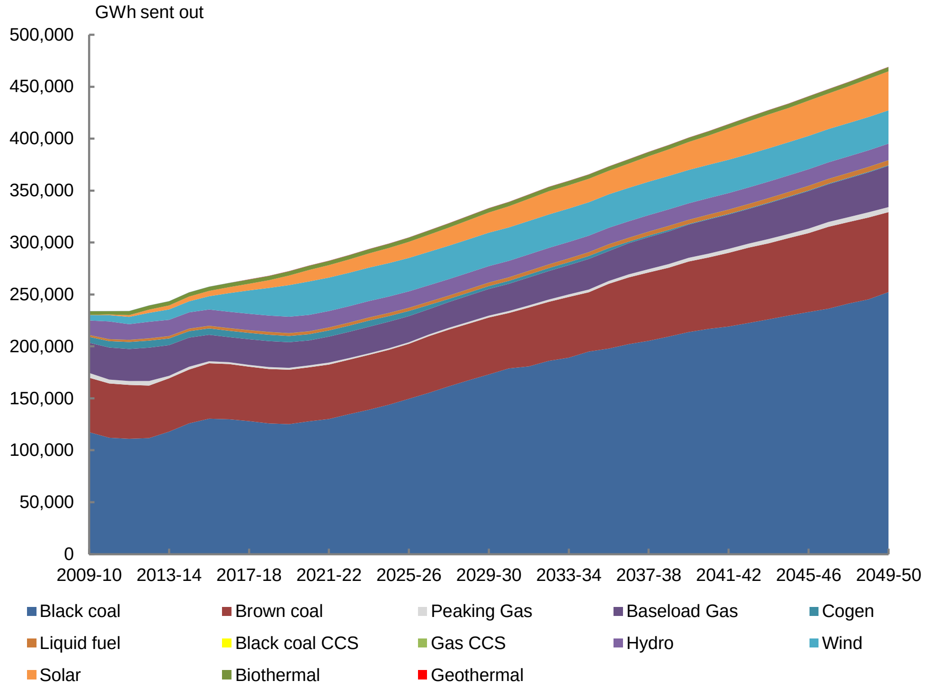


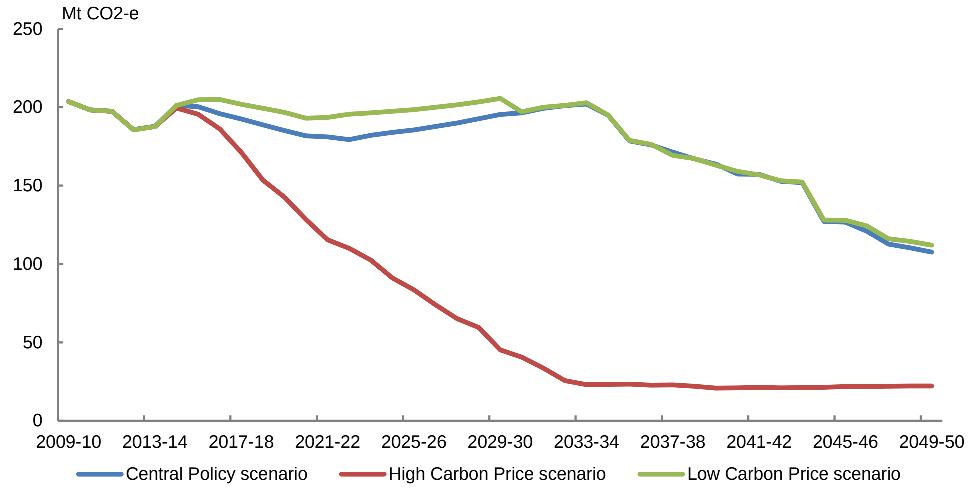
Figure ES 3 **Generation by fuel type – No Carbon Price scenario**



In addition to the two core scenarios, ACIL Allen also modelled High and Low Carbon Price scenarios, and a range of sensitivities, to test the effect of policy and other parameters on emissions from Australia's electricity generation sector.

The High Carbon Price scenario adopted a substantially higher carbon price and consequently resulted in dramatically lower emissions than the Central Policy scenario, as is shown in Figure ES 4. Conversely, there were only minimal differences between both the assumed carbon price and the modelled emissions trajectory between the Low Carbon Price and Central Policy scenarios.

Figure ES 4 **Aggregate emissions – carbon price scenarios**

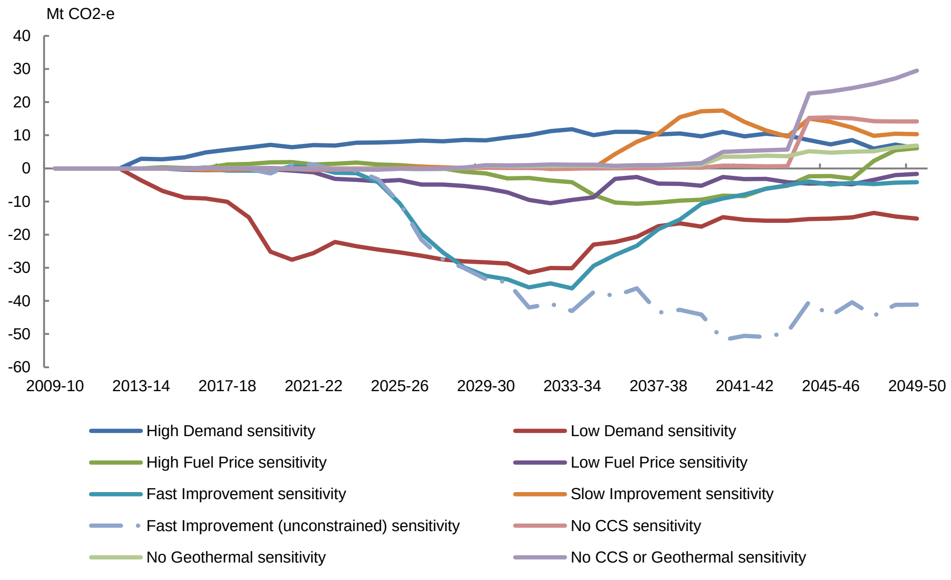


In addition to the carbon price scenarios, various sensitivities were modelled, involving:

- Higher and lower electricity demand growth
- Higher and lower fuel prices
- Faster and slower rates of capital cost reductions for key renewable technologies, particularly solar PV
- Restrictions on technology availability, with geothermal, CCS and both technologies made unavailable across three separate model runs.

The change in emissions in each of these sensitivities relative to the Central Policy scenario is shown in Figure ES 5.

Figure ES 5 **Change in emissions from Central Policy scenario – all sensitivities**



1 Introduction

The Department of Industry, Innovation, Climate Change, Science, Research and Tertiary Education (DIICCSRTE) commissioned ACIL Allen Consulting (ACIL Allen) to model greenhouse gas emissions from Australia's electricity generation sector over the period to 2049-50 for its national emissions projections.

ACIL Allen estimated emissions from Australia's electricity generation sector under two scenarios: a Central Policy scenario including the effect of a carbon price and a No Carbon Price scenario with no carbon price in effect. ACIL Allen's *PowerMark LT* and *RECMark* models were used to estimate effects in Australia's major electricity markets: the National Electricity Market, the South-West Interconnected System centred on Perth, the North-West Interconnected System in the Pilbara region, the Darwin-Katherine Interconnected System and the grid serving Mount Isa. Emissions from embedded and off-grid generation were also estimated.

Electricity demand and other assumptions were derived from Computable General Equilibrium (CGE) modelling of the Australian and world economies undertaken by the Treasury.

In addition to the two core scenarios, ACIL Allen also modelled low and high carbon price scenarios, and a range of sensitivities, to test the effect of policy and other parameters on emissions from Australia's electricity generation sector.

This report is structured as follows:

- Section 2 gives an overview of the project, including methodology, the models used, and a description of the scenarios and sensitivities modelled
- Section 3 sets out the key modelling assumptions, including those derived from CGE modelling and those adopted within the electricity sector modelling
- Section 4 highlights the key modelling results for the Central Policy and No Carbon Price scenarios
- Section 5 outlines the results from the modelled scenarios and sensitivities.

2 Project overview

2.1 Methodology

ACIL Allen's modelling of the Australian electricity generation sector uses two detailed sectoral models, *PowerMark LT* and *RECMark*, as well as inputs derived from the Treasury's CGE modelling of the wider Australian and international economies.

PowerMark LT is ACIL Allen's dynamic least cost model of the Australian electricity sector and is designed to optimise dispatch, investment and retirement decisions over long modelling horizons, given demand, carbon price and other assumptions. More detail on *PowerMark LT's* model structure is provided in section 2.2.1 below and Appendix A. *RECMark* is ACIL Allen's model of how renewable generation responds to broader electricity market outcomes and renewable energy policy settings, particularly the Large-scale Renewable Energy Target (LRET). More detail on *RECMark's* model structure is provided in Section 2.2.2 below and Appendix B.

The key inputs from the Treasury CGE modelling for use in ACIL Allen's electricity sector modelling include:

- electricity demand growth rates
- international fuel prices, which affect domestic prices of fuels used in electricity generation, such as gas and coal
- steel prices and Australian labour costs, which affect the cost of building new electricity generators
- the Australian real exchange rate, which affects the cost of imported components used in building new electricity generators.

2.2 Model suite

2.2.1 PowerMark LT

PowerMark LT is a dynamic least cost model, which optimises existing and new generation operation and new investments over a chosen model horizon, given a range of input assumptions regarding demand growth, incumbent plant costs, interconnectors, new development costs and government policy settings (particularly carbon pricing and the LRET). *PowerMark LT* utilises a large scale commercial LP solver. *PowerMark LT* solves efficiently providing the solution for a single long term scenario (technology, policy settings etc.) within a few minutes. This means that multiple scenario comparisons (for example to compare the effect of different technology futures) are practical within a single set of model runs with the full comparison suite available quickly.

To aid computation, *PowerMark LT* uses fewer dispatch periods per model year than a simulation model such as *PowerMark* (typically 100 for *PowerMark LT*, compared to 8760, or one per hour, for *PowerMark*). Accordingly, *PowerMark LT* solves more quickly and can automatically optimise generation new entry and dispatch outcomes over long time horizons on an inter-temporal basis (that is, adjusting outcomes in all periods based on outcomes in all other dispatch periods). By contrast, the more data intensive *PowerMark* is not solved inter-temporally: it optimises each dispatch period separately and requires manual adjustment of plant mix to reflect new entry and retirement over time.

For this exercise, *PowerMark LT* models five physically separate electricity grids comprising nine distinct electricity market regions simultaneously in a single model. The grids and regions modelled are the National Electricity Market (NEM), comprising the five interconnected regions of NSW, QLD, VIC, SA and TAS, the South-West Interconnected System (SWIS) covering south-western Western Australia, the North-West Interconnected System (NWIS) covering the Pilbara region of Western Australia, the Darwin-Katherine Interconnected System (DKIS) covering the northern part of Northern Territory, and the grid servicing the area around Mt Isa in Queensland. The structure and impact of the LRET is integrated into the model to ensure internal consistency.

PowerMark LT models the supply side at the power station level (as opposed to the generating unit level). Inputs for each station include:

- sent-out capacity
- planned and unplanned outage rates
- fuel costs
- thermal efficiency
- emission intensity.

Further details on these inputs are provided for existing and committed generators in Section 3, and for new entrant generation technologies in Section 3.4.

The model is not strictly a least cost Short-Run Marginal Cost (SRMC) model, in that each plant is represented by two or three offer bands:

- minimum generation level at the market floor price (for thermal plant where appropriate)
- SRMC for assumed contracted capacity
- opportunistic band at a defined multiple of SRMC.

This is an approximation of the complex bidding behaviour observed in the competitive wholesale electricity markets as simulated within ACIL Allen's detailed *PowerMark* model. The SRMC offer band represents a proxy for the plants level of contract cover, which owners are incentivised to offer to the market at its marginal cost of generation. The second, higher offer band reflects the uncontracted portion of the stations output.

Further detail on *PowerMark LT* is in Appendix A.

2.2.2 RECMark

RECMark is ACIL Allen's model of the Commonwealth Government's Large-Scale Renewable Energy Target (LRET). The model utilises a large-scale linear programming solver with an objective function to comply with the LRET in a rational, least cost manner. It operates on an inter-temporal least cost basis, under the assumption of perfect certainty.

The model horizon covers the period from 2010 to 2060. This extends well beyond the end of the LRET (2030) in order to account for the economics of renewable plant installed within the period of the scheme, but beyond the end of the subsidy. In essence the model develops new renewable projects on a least cost basis across Australia and projects the marginal LGC price required to ensure all projects that are projected to be developed are commercially viable. In this sense the Large-scale Generation Certificate (LGC) price reflects the subsidy required to make the most marginally developed project just profitable over the life of the LRET scheme. The LGC price series extends through to 2030 and takes into account all inputs and constraints.

The model simulates the development and operation of new entrant plant based on technology cost settings and project specific parameters within the inputs. The model will naturally develop the lowest cost projects first, subject to any build and capacity limitations applied. Once developed, each of these new entrant projects creates LGCs over its economic life, based on its maximum capacity factor and marginal loss factor (MLF). Combined with output assumptions for existing projects, this allows results to be reported on LGC creation by technology and fuel mix. As certificate creation levels for 2010 and 2011 are already known, these are hard wired within the model.

The annual holding cost assumption is 5% real (approximately 7.5% nominal). The discount rate for project evaluation (WACC) is 10% on a pre-tax real basis.

Further detail on *RECMark*, particularly on how it incorporates the specific policy settings of the LRET, is outlined in Appendix B.

2.3 Scenarios

2.3.1 Central Policy scenario

The Central Policy scenario modelled for the emissions projections incorporate a fixed carbon price for the period 2012-13 to 2013-14, and a floating price from 1 July 2014. The carbon price provided by Treasury is consistent with global efforts to reduce greenhouse gas emissions to 550 parts per million (ppm) of carbon dioxide equivalent (CO_2-e). The Treasury modeled the pattern of Australian economic activity under this scenario within a CGE framework. Electricity demand and other economic variables were derived from this modeling for use within ACIL Allen’s electricity sector modeling as outlined in section 3.5 and 3.6.

The Central Policy scenario includes the effects of a range of specific greenhouse gas abatement measures, including the LRET, the Small-scale Renewable Energy Scheme (SRES), and renewable energy projects supported by the Australian Renewable Energy Agency (ARENA).

Modelling results for the Central Policy scenario are presented in Section 4.

2.3.2 No Carbon Price scenario

The No Carbon Price scenario includes the LRET, SRES, ARENA projects and other miscellaneous greenhouse gas abatement measures, but excludes the carbon price itself. The Treasury CGE modeling for this scenario depicts the period from 2012-13 to 2019-20 where regions act either unilaterally or as a bloc to meet their pledges under the Cancun Agreement to reduce or limit emissions by 2020, with coordinated global action after 2019-20 to reduce greenhouse gas emissions targeting a reduction of 550 ppm CO_2-e, and no carbon price for Australia.

Due to the difference in international economic conditions, and the difference in Australian greenhouse gas abatement policies, economic parameters derived from the No Carbon Price scenario vary slightly from those for the Central Policy scenario. In particular, Australian electricity demand is substantially different, reflecting the absence of the price signal created by the carbon price. These different assumptions contribute to the difference in electricity sector outcomes between the two scenarios. Modelling results for the No Carbon Price scenario are presented in Section 4.

2.3.3 High and Low Carbon Price scenarios

The High and Low Carbon Price scenarios are similar to the Central Policy scenario described above, except they adopt higher and lower carbon prices respectively. Further, due to the changes in international abatement ambition that generate the different carbon prices, international and Australian economic parameters vary, flowing through to fuel prices, electricity demand, exchange rates and labour costs.

Modelling results for these scenarios are presented in section 5.

2.4 Sensitivities

Several sensitivities were also modelled for this exercise. Each sensitivity involved a small change to a key parameter from that assumed for the Central Policy scenario. In each case, the parameter was estimated to vary both above and below the Central Policy scenario value. The sensitivities modelled involve:

- Higher and lower electricity demand growth
- Higher and lower fuel prices
- Faster and slower rates of capital cost reductions for key renewable technologies, particularly solar PV
- Restrictions on technology availability, with geothermal, CCS and both technologies made unavailable across three separate model runs.

Modelling results for the sensitivities are presented in Section 5.

3 Assumptions

3.1 Demand

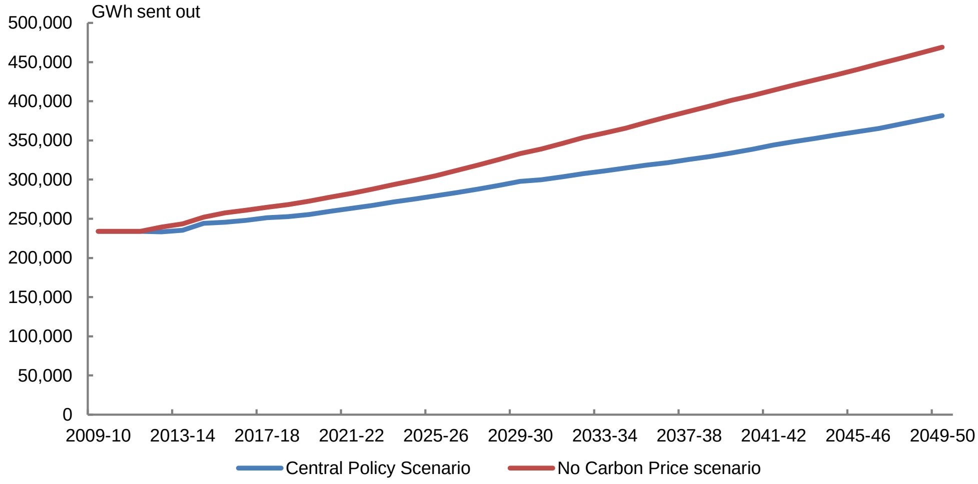
3.1.1 Aggregate demand

Demand is an exogenous input to ACIL Allen's electricity sector modelling. To determine the level of aggregate demand to model, ACIL Allen calibrated initial levels of demand to observed market data where possible. Demand in the years 2009-10 to 2011-12 inclusive for the NEM, SWIS and DKIS was calibrated using market data published by the Australian Energy Market Operator (AEMO), the Independent Market Operator (IMO) and the Northern Territory Utilities Commission respectively. For the NWIS and Mount Isa grids, and for embedded and off-grid generation, baseline demand was estimated based on bottom-up estimates of fuel use and generation of the various plant on the respective grids.

For the NEM, demand in 2012-13 was also calibrated to market data. Specifically, AEMO estimates of 'operational demand' for 2012-13 were available from the 2013 National Electricity Forecasting Report (NEFR) and were used to calibrate demand for 2012-13 in the Central Policy scenario (which incorporates a carbon price as was in effect during 2012-13). For the No Carbon Price scenario, the 2012-13 AEMO estimates of operational demand were scaled upwards to reflect the difference in Treasury estimated growth rates from 2011-12 to 2012-13 between the Policy and No Carbon Price scenarios.

Once demand was calibrated to actuals in this way, it was grown year-on-year in accordance with demand growth rates from the Treasury CGE modelling. Treasury's demand estimates were based on final demand by consumers, which ACIL Allen converted into the equivalent rate of growth in demand expressed on a sent out basis. Aggregate demand assumptions for the Policy and No Carbon Price scenarios are shown in Figure 1 (on a sent out basis).

Figure 1 **Aggregate demand**



Note: Estimates include off-grid and embedded generation

Source: ACIL Allen estimates based on Treasury, AEMO, IMO and other sources.

3.1.2 Demand profiles

While aggregate demand is important, the way demand varies over the course of a year also affects dispatch and emissions outcomes. Accordingly, the aggregate demand assumptions described above need to be transformed into a demand profile suitable for modelling. This demand profile will reflect both the level of peak demand in the relevant energy market or market region, and the way the aggregate energy demand is distributed across the year.

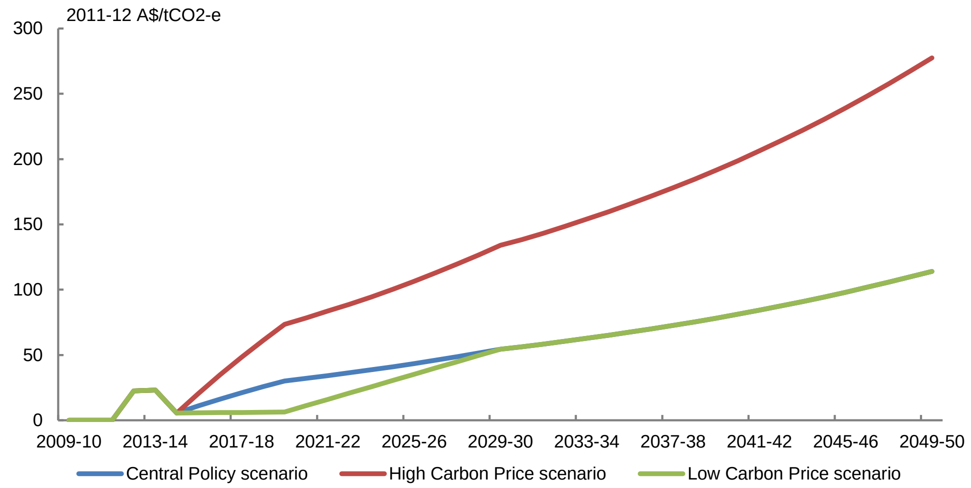
This is done through a number of steps as follows:

- Adjust total electricity demand estimated as described in section 3.1.1 into electricity sent-out for each modelled region (which is the basis on which demand is modelled in *PowerMark LT*). Forecasts of rooftop PV generation are adopted from market forecasts by AEMO in the NEM and the IMO in the SWIS, and deducted from total electricity demand. Embedded generation is held constant, such that incremental changes in electricity demand are competitively supplied from the grid.
- For grid-supplied electricity, determine 50% and 10% probability of exceedence (POE) peak demand levels which correspond to the energy values. These are taken from implied load factors (ratio of peak to average demand) from official forecasts for the NEM regions, the SWIS and the DKIS, and assumed for the NWIS and Mount Isa. Beyond the forecast periods load factors are assumed to stabilise (i.e. the rate of growth for both peak demand and energy are identical).
- Construct initial year 30 minute resolution demand traces for each region which have been weather corrected (i.e. which reflect weather conditions in stylised 'normal' year). Due to no data being available for the DKIS, NWIS and Mt Isa, a Queensland load profile was used and adjusted to the appropriate load factor.
- Grow these demand traces to accord with the peak demand and energy forecasts for each year to 2050
- Grow 30 minute resolution traces for output from intermittent sources and deduct this from the grid profiles to ensure that impacts upon the time-of-day load shapes is preserved
- Sample the final 30 minute resolution grid-based demand profiles down to a weighted 50 point profile for inclusion into *PowerMark LT*.

3.2 Other CGE inputs

The carbon prices modelled in the High Carbon Price, Low Carbon Price and Central Policy scenarios are compared in Figure 2.

Figure 2 **Carbon price assumptions**



Source: Treasury

Steel prices, real wages and real exchange rates were also modelled by the Treasury, and affected the capital cost of generation technologies. The Treasury's modelled series for these inputs are presented in the joint DIICCSRTE/Treasury report to the Climate Change Authority on emissions projections. In terms of generation capital costs, the key driver from these assumptions was the broad real depreciation of the Australian dollar over the model period, which makes final installed generation costs more expensive due to the increased cost of imported components.

3.3 Existing generators

The modelling incorporates a total of 190 existing generators across the nine regions modelled as shown in Table 1. For the NEM, these generators represent those that are scheduled and semi-scheduled (i.e. those that report and participate in AEMO's central dispatch functions). Non-scheduled, embedded 'behind the meter' and off-grid generation are handled outside of *PowerMark LT*.

For the SWIS, the generators and their capacity corresponds with capacity offered to the IMO as part of the wholesale markets net pool functions. This means that capacity and energy related to own-use consumption (most notably from cogeneration projects) is not included explicitly and is handled outside the modelling.

For NWIS, DKIS and Mt Isa regions no formal market structure exists and generators include all major grid-connected plants.

Table 1 **Existing and committed generators: type, capacity and life**

Region	Generator	Plant type	Fuel type	Commissioned	Technical Life (Years)	Technical Retirement Year	Capacity (gross MW)
NSW	AGL SF PV Broken Hill	Solar PV	Solar	2014	30	2044	53
	AGL SF PV Nyngan	Solar PV	Solar	2014	30	2044	106
	Bayswater	Subcritical pf	Black coal	1983	53	2036	2,720
	Bendeela Pumps	Pump	n/a	1977	150	2127	240
	Blowering	Hydro	Hydro	1969	150	2119	80
	Colongra	OCGT	Natural gas	2009	30	2039	664
	Eraring	Subcritical pf	Black coal	1983	50	2033	2,880
	Gunning Wind Farm	Wind turbine	Wind	2011	25	2036	47
	Guthega	Hydro	Hydro	1955	150	2105	60
	Hume NSW	Hydro	Hydro	1957	150	2107	29
	Hunter Valley GT	OCGT	Liquid fuel	1988	30	2018	51
	Liddell	Subcritical pf	Black coal	1972	60	2032	2,100
	Mt Piper	Subcritical pf	Black coal	1993	50	2043	1,340
	Munmorah [a]	Subcritical pf	Black coal	1969	50	2019	600
	Redbank	Subcritical pf	Black coal	2001	50	2051	150
	Shoalhaven Bendeela	Hydro	Hydro	1977	150	2127	240
	Smithfield	CCGT	Natural gas	1997	30	2027	176
	Tallawarra	CCGT	Natural gas	2009	30	2039	430
	Tumut 1	Hydro	Hydro	1959	150	2109	616
	Tumut 3	Hydro	Hydro	1973	150	2123	1,500
	Tumut 3 Pumps	Pump	n/a	1973	150	2123	400
	Uranquinty	OCGT	Natural gas	2009	30	2039	664
	Vales Point B	Subcritical pf	Black coal	1978	50	2028	1,320
	Wallerawang C	Subcritical pf	Black coal	1978	45	2023	960
	Woodlawn Wind Farm	Wind turbine	Wind	2011	25	2036	48
QLD	Barcaldine	CCGT	Natural gas	1996	30	2026	55
	Barron Gorge	Hydro	Hydro	1963	150	2113	60
	Braemar 1	OCGT	Natural gas	2006	30	2036	504
	Braemar 2	OCGT	Natural gas	2009	30	2039	459
	Callide B	Subcritical pf	Black coal	1989	50	2039	700
	Callide C	Supercritical pf	Black coal	2001	50	2051	810
	Collinsville [a]	Subcritical pf	Black coal	1998	30	2028	190
	Condamine	CCGT	Natural gas	2009	30	2039	140
	Darling Downs	CCGT	Natural gas	2010	30	2040	630
	Gladstone	Subcritical pf	Black coal	1980	50	2030	1,680
	Kareeya	Hydro	Hydro	1958	150	2108	81
	Kogan Creek	Supercritical pf	Black coal	2007	50	2057	750
	Mackay GT	OCGT	Liquid fuel	1975	45	2020	34
	Millmerran	Supercritical pf	Black coal	2002	50	2052	851
	Mt Stuart	OCGT	Liquid fuel	1998	40	2038	418
	Oakey	OCGT	Natural gas	2000	30	2030	282
	Roma	OCGT	Natural gas	1999	30	2029	80
	Stanwell	Subcritical pf	Black coal	1995	50	2045	1,440
	Swanbank B [a]	Subcritical pf	Black coal	1972	45	2017	480
	Swanbank E	CCGT	Natural gas	2002	30	2032	385
	Tarong	Subcritical pf	Black coal	1985	50	2035	1,400
	Tarong North	Supercritical pf	Black coal	2002	50	2052	443
	Townsville	CCGT	Natural gas	2005	30	2035	240
	Wivenhoe	Hydro	Hydro	1984	150	2134	500
	Wivenhoe Pump	Pump	n/a	1984	150	2134	480
	Yarwun	Cogeneration	Natural gas	2010	30	2040	168
SA	Angaston	Reciprocating engine	Liquid fuel	2006	30	2036	50
	Bluff WF	Wind turbine	Wind	2011	25	2036	53
	Clements Gap Wind Farm	Wind turbine	Wind	2008	25	2033	57
	Dry Creek	OCGT	Natural gas	1973	45	2018	156
	Hallett	OCGT	Natural gas	2002	30	2032	200
	Hallett 2 Wind Farm	Wind turbine	Wind	2008	25	2033	71
	Hallett Wind Farm	Wind turbine	Wind	2007	25	2032	95

Region	Generator	Plant type	Fuel type	Commissioned	Technical Life (Years)	Technical Retirement Year	Capacity (gross MW)
	Ladbroke Grove	OCGT	Natural gas	2000	30	2030	80
	Lake Bonney 2 Wind Farm	Wind turbine	Wind	2008	25	2033	159
	Lake Bonney 3 Wind Farm	Wind turbine	Wind	2010	25	2035	39
	Mintaro	OCGT	Natural gas	1984	30	2014	90
	North Brown Hill Wind Farm	Wind turbine	Wind	2011	25	2036	132
	Northern	Subcritical pf	Brown coal	1985	50	2035	530
	Osborne	CCGT	Natural gas	1998	30	2028	180
	Pelican Point	CCGT	Natural gas	2000	35	2035	485
	Playford B [a]	Subcritical pf	Brown coal	1960	60	2020	231
	Port Lincoln	OCGT	Liquid fuel	1999	30	2029	74
	Quarantine	OCGT	Natural gas	2002	30	2032	216
	Snowtown 2 Wind Farm	Wind turbine	Wind	2014	25	2039	270
	Snowtown Wind Farm	Wind turbine	Wind	2008	25	2033	99
	Snuggery	OCGT	Liquid fuel	1997	30	2027	63
	Torrens Island A	Steam turbine	Natural gas	1967	52	2019	480
	Torrens Island B	Steam turbine	Natural gas	1977	50	2027	800
	Waterloo Wind Farm	Wind turbine	Wind	2011	25	2036	111
TAS	Bastyan	Hydro	Hydro	1983	150	2133	80
	Bell Bay	Subcritical pf	Natural gas	1971	38	2009	240
	Bell Bay Three	OCGT	Natural gas	2006	30	2036	120
	Cethana	Hydro	Hydro	1971	150	2121	85
	Devils Gate	Hydro	Hydro	1969	150	2119	60
	Fisher	Hydro	Hydro	1973	150	2123	43
	Gordon	Hydro	Hydro	1978	150	2128	432
	John Butters	Hydro	Hydro	1992	150	2142	144
	Lake Echo	Hydro	Hydro	1956	150	2106	32
	Lemonthyme_Wilmot	Hydro	Hydro	1970	150	2120	82
	Liapootah_Wayatinah_Catagunya	Hydro	Hydro	1960	150	2110	170
	Mackintosh	Hydro	Hydro	1982	150	2132	80
	Meadowbank	Hydro	Hydro	1967	150	2117	40
	Musselroe Wind Farm	Wind turbine	Wind	2013	25	2038	168
	Poatina	Hydro	Hydro	1964	150	2114	300
	Reece	Hydro	Hydro	1986	150	2136	231
	Tamar Valley	CCGT	Natural gas	2010	30	2040	200
	Tamar Valley GT	OCGT	Natural gas	2009	30	2039	58
	Tarraleah	Hydro	Hydro	1938	150	2088	90
	Trevallyn	Hydro	Hydro	1955	150	2105	80
	Tribute	Hydro	Hydro	1994	150	2144	83
	Tungatinah	Hydro	Hydro	1953	150	2103	125
VIC	Anglesea	Subcritical pf	Brown coal	1969	52	2021	160
	Bairnsdale	OCGT	Natural gas	2001	30	2031	92
	Dartmouth	Hydro	Hydro	1960	150	2110	158
	Eildon	Hydro	Hydro	1957	150	2107	120
	Energy Brix	Subcritical pf	Brown coal	1960	58	2018	195
	Hazelwood	Subcritical pf	Brown coal	1968	63	2031	1,640
	Hume VIC	Hydro	Hydro	1957	150	2107	29
	Jeeralang A	OCGT	Natural gas	1979	50	2029	228
	Jeeralang B	OCGT	Natural gas	1980	50	2030	255
	Laverton North	OCGT	Natural gas	2006	30	2036	312
	Loy Yang A	Subcritical pf	Brown coal	1986	50	2036	2,180
	Loy Yang B	Subcritical pf	Brown coal	1995	50	2045	1,050
	Macarthur Wind Farm	Wind turbine	Wind	2013	25	2038	420
	McKay	Hydro	Hydro	1980	150	2130	300
	Mortlake	OCGT	Natural gas	2011	40	2051	566
	Mt Mercer Wind Farm	Wind turbine	Wind	2014	25	2039	131
	Murray	Hydro	Hydro	1968	150	2118	1,500
	Newport	Steam turbine	Natural gas	1980	50	2030	500
	Oaklands Hill Wind Farm	Wind turbine	Wind	2011	25	2036	63
	Somerton	OCGT	Natural gas	2002	30	2032	160

Region	Generator	Plant type	Fuel type	Commissioned	Technical Life (Years)	Technical Retirement Year	Capacity (gross MW)
	Valley Power	OCGT	Natural gas	2002	30	2032	300
	West Kiewa	Hydro	Hydro	1956	150	2106	62
	Yallourn	Subcritical pf	Brown coal	1980	55	2035	1,538
SWIS	Albany	Wind turbine	Wind	2001	25	2026	22
	Alcoa Kwinana Cogen	Cogeneration	Natural gas	1998	30	2028	5
	Alcoa Pinjarra Cogen	Cogeneration	Natural gas	1985	35	2020	10
	Alcoa Wagerup Cogen	Cogeneration	Natural gas	1990	30	2020	25
	Bluewaters	Subcritical pf	Black coal	2009	40	2049	441
	BP Cogen	Cogeneration	Natural gas	1996	30	2026	81
	Canning/Melville LFG	Reciprocating engine	Landfill gas	2007	15	2022	9
	Cockburn	CCGT	Natural gas	2003	30	2033	246
	Collgar Wind Farm	Wind turbine	Wind	2012	25	2037	206
	Collie	Subcritical pf	Black coal	1999	40	2039	333
	Emu downs	Wind turbine	Wind	2006	25	2031	80
	Geraldton	OCGT	Distillate	1973	40	2013	21
	Grasmere	Wind turbine	Wind	2012	25	2037	14
	Greenough River	Solar PV	Solar	2012	30	2042	10
	Kalgoorlie	OCGT	Distillate	1990	30	2020	63
	Kalgoorlie Nickel	OCGT	Natural gas	1996	30	2026	10
	Kemerton	OCGT	Natural gas	2005	30	2035	310
	Kwinana A	Steam turbine	Natural gas	1970	41	2011	245
	Kwinana B	Steam turbine	Natural gas	1974	34	2008	0
	Kwinana C	Steam turbine	Natural gas	1976	39	2015	385
	Kwinana GT	OCGT	Distillate	1975	40	2015	21
	Kwinana HEGT	OCGT	Natural gas	2011	30	2041	201
	Muja A&B	Subcritical pf	Black coal	1968	40	2008	240
	Muja C	Subcritical pf	Black coal	1981	40	2021	398
	Muja D	Subcritical pf	Black coal	1986	40	2026	454
	Mumbida	Wind turbine	Wind	2012	25	2037	55
	Mungarra	OCGT	Natural gas	1991	30	2021	113
	Namarkkon	OCGT	Distillate	2012	30	2042	70
	Neerabup Peaker	OCGT	Natural gas	2009	30	2039	330
	Newgen Power	CCGT	Natural gas	2007	30	2037	314
	Parkeston SCE	OCGT	Natural gas	1996	30	2026	68
	Pinjar A B	OCGT	Natural gas	1990	30	2020	228
	Pinjar C	OCGT	Natural gas	1992	30	2022	233
	Pinjar D	OCGT	Natural gas	1996	30	2026	124
	Pinjarra Alinta Cogen	Cogeneration	Natural gas	2007	30	2037	280
	Tesla (various sites)	OCGT	Distillate	2012	30	2042	40
	Tiwest Cogen	Cogeneration	Natural gas	1999	30	2029	37
	Wagerup Alinta Peaker	OCGT	Distillate	2007	30	2037	323
	Walkaway	Wind turbine	Wind	2005	25	2030	89
	Western Energy Peaker	OCGT	Natural gas	2011	30	2041	106
	Worsley	Cogeneration	Black coal	1990	40	2030	0
	Worsley SWCJV	Cogeneration	Natural gas	2000	25	2025	116
NWIS	Burrup Peninsula	OCGT	Natural gas	2006	30	2036	74
	Cape Lambert [a]	Steam turbine	Natural gas	1996	30	2026	105
	Cape Preston	CCGT	Natural gas	2009	30	2039	450
	Dampier [a]	Steam turbine	Natural gas	2000	50	2050	120
	Karratha	Steam turbine	Natural gas	2005	50	2055	44
	Karratha ACTO	OCGT	Natural gas	2010	30	2040	86
	Paraburdoo	Reciprocating Engine	Liquid fuel	1985	30	2015	20
	Port Hedland	OCGT	Natural gas	1997	30	2027	180
DKIS	Berrimah	OCGT	Liquid fuel	1979	30	2009	30
	Channel Island u1-3	OCGT	Natural gas	1986	30	2016	95
	Channel Island u4-6	CCGT	Natural gas	1998	30	2028	95
	Channel Island u7	OCGT	Natural gas	2006	30	2036	42
	Channel Island u8-9	OCGT	Natural gas	2012	30	2042	90
	Katherine	OCGT	Natural gas	1987	30	2017	34

Region	Generator	Plant type	Fuel type	Commissioned	Technical Life (Years)	Technical Retirement Year	Capacity (gross MW)
	LMS Shoal Bay	Reciprocating engine	Landfill gas	2005	15	2020	1
	Pine Creek CCGT	CCGT	Natural gas	1989	30	2019	27
	Weddell	OCGT	Natural gas	2008	30	2038	128
	APA Xstrata OCGT	OCGT	Natural gas	2008	30	2038	30
	Diamantina CCGT	CCGT	Natural gas	2014	30	2044	242
	Diamantina OCGT	OCGT	Natural gas	2014	30	2044	60
	Ernest Henry	Reciprocating Engine	Liquid fuel	1997	30	2027	32
Mt Isa	Mica Creek A CCGT	CCGT	Natural gas	2000	30	2030	103
	Mica Creek A GT	OCGT	Natural gas	2000	30	2030	132
	Mica Creek B	OCGT	Natural gas	2000	30	2030	35
	Mica Creek C	CCGT	Natural gas	2000	30	2030	55
	Mt Isa Mines Station	Steam turbine	Natural gas	1974	50	2024	38
	Phosphate Hill	OCGT	Natural gas	1999	30	2029	42

[a] These generators are mothballed as of April 2013 but have been operational during the model period (starting 1 July 2009).
Source: ACIL Allen

Table 2 provides the assumed thermal efficiencies, auxiliary use, emissions factors, O&M costs, outage rates and marginal loss factor (MLF) values for each existing and committed generator. These values are taken from ACIL Allen's generator database.

Table 2 Existing and committed generators: efficiency, emissions and O&M costs

Region	Generator	Thermal efficiency	Auxiliaries	Scope 1 emission factor	Scope 1 emission intensity	Fixed O&M	Variable O&M	Forced outage rate	Planned outage rate	Marginal Loss Factor
		HHV (%) sent-out	%	(kg CO_2-e/GJ of fuel)	(tonnes CO_2-e/MWh sent-out)	($/MW gross/year)	$/MWh sent-out	%	%	
	AGL SF PV Broken Hill		0.00%	0	0	34,833	0	0.00%	0.00%	1.1026
	AGL SF PV Nyngan		0.00%	0	0	34,833	0	0.00%	0.00%	1.1026
	Bayswater	35.90%	6.00%	90.2	0.905	46,039	1.11	3.00%	4.00%	0.9552
	Bendeela Pumps		0.00%	0	0	48,858	8.67	0.00%	0.00%	1.0017
	Blowering		0.00%	0	0	48,858	4.82	0.00%	4.00%	0.9709
	Colongra	32.00%	3.00%	51.3	0.577	12,214	9.38	1.50%	0.00%	0.986
	Eraring	35.40%	6.50%	89.5	0.91	46,039	1.11	3.00%	4.00%	0.9859
	Gunning Wind Farm		0.00%	0	0	32,083	0	0.00%	0.00%	0.9852
	Guthega		0.00%	0	0	48,858	6.74	0.00%	4.00%	0.9484
	Hume NSW		0.00%	0	0	48,858	5.78	0.00%	4.00%	0.9704
	Hunter Valley GT	28.00%	3.00%	69.7	0.896	12,214	8.93	2.50%	0.00%	0.9641
	Liddell	33.80%	5.00%	92.8	0.988	48,858	1.11	3.00%	8.00%	0.9556
NSW	Mt Piper	37.00%	5.00%	87.4	0.85	46,039	1.23	3.00%	4.00%	0.9629
	Munmorah [a]	30.80%	7.30%	90.3	1.055	51,676	2.05	7.00%	4.00%	0.9857
	Redbank	29.30%	8.00%	90	1.106	46,509	1.11	4.00%	4.00%	0.9572
	Shoalhaven Bendeela		0.00%	0	0	48,858	8.67	0.00%	4.00%	0.9798
	Smithfield	41.00%	5.00%	51.3	0.45	23,489	2.23	2.50%	2.00%	1.0053
	Tallawarra	50.00%	3.00%	51.3	0.369	30,249	1.1	3.00%	2.00%	0.9934
	Tumut 1		0.00%	0	0	48,858	6.74	0.00%	4.00%	0.9453
	Tumut 3		0.00%	0	0	48,858	10.6	0.00%	4.00%	0.9233
	Tumut 3 Pumps		0.00%	0	0	48,858	0	0.00%	0.00%	1.0069
	Uranquinty	32.00%	3.00%	51.3	0.577	12,214	9.38	1.50%	0.00%	0.9665
	Vales Point B	35.40%	4.60%	89.8	0.913	46,039	1.11	3.00%	8.00%	0.9877
	Wallerawang C	33.10%	7.30%	87.4	0.951	48,858	1.23	3.00%	8.00%	0.9633
	Woodlawn Wind Farm		0.00%	0	0	32,083	0	0.00%	0.00%	0.9845
	Barcaldine	40.00%	3.00%	51.3	0.462	23,489	2.23	2.50%	4.00%	1.0235
	Barron Gorge		0.00%	0	0	48,858	10.6	0.00%	4.00%	1.1135
QLD	Braemar 1	30.00%	2.50%	51.3	0.616	12,214	7.33	1.50%	0.00%	0.9471
	Braemar 2	30.00%	2.50%	51.3	0.616	12,214	7.33	1.50%	0.00%	0.9471
	Callide B	36.10%	7.00%	93	0.927	46,509	1.12	4.00%	4.00%	0.9471

Region	Generator	Thermal efficiency	Auxiliaries	Scope 1 emission factor	Scope 1 emission intensity	Fixed O&M	Variable O&M	Forced outage rate	Planned outage rate	Marginal Loss Factor
		HHV (%) sent-out	%	(kg CO_2-e/GJ of fuel)	(tonnes CO_2-e/MWh sent-out)	($/MW gross/year)	$/MWh sent-out	%	%	
	Callide C	36.50%	4.80%	95	0.937	46,509	2.54	6.00%	5.00%	0.9476
	Collinsville [a]	27.70%	8.00%	89.4	1.162	61,072	1.23	4.00%	2.00%	1.0389
	Condamine	48.00%	3.00%	51.3	0.385	30,249	1.1	1.50%	4.00%	0.8895
	Darling Downs	46.00%	6.00%	51.3	0.401	30,249	1.1	3.00%	4.00%	0.9471
	Gladstone	35.20%	5.00%	92.1	0.942	48,858	1.11	4.00%	4.00%	0.9885
	Kareeya		0.00%	0	0	48,858	5.78	0.00%	4.00%	1.1055
	Kogan Creek	37.50%	8.00%	94	0.902	45,099	1.17	4.00%	4.00%	0.9464
	Mackay GT	28.00%	3.00%	69.7	0.896	12,214	8.4	1.50%	0.00%	1.0674
	Millmerran	36.90%	4.70%	92	0.898	45,099	2.64	5.00%	8.00%	0.9578
	Mt Stuart	30.00%	3.00%	69.7	0.836	12,214	8.4	2.50%	2.00%	0.9813
	Oakey	32.60%	3.00%	51.3	0.567	12,214	8.93	2.00%	0.00%	0.9395
	Roma	30.00%	3.00%	51.3	0.616	12,214	8.93	3.00%	0.00%	0.864
	Stanwell	36.40%	7.00%	90.4	0.894	46,039	2.99	2.50%	4.00%	0.9876
	Swanbank B [a]	30.50%	8.00%	90.4	1.067	51,676	1.11	7.00%	4.00%	1.0011
	Swanbank E	47.00%	3.00%	51.3	0.393	30,249	1.1	3.00%	2.00%	0.9963
	Tarong	36.20%	8.00%	92.1	0.916	46,509	6.98	3.00%	4.00%	0.9631
	Tarong North	39.20%	5.00%	92.1	0.846	45,099	1.33	3.00%	4.00%	0.9633
	Townsville	46.00%	3.00%	51.3	0.401	30,249	1.1	3.00%	2.00%	1.0524
	Wivenhoe		0.00%	0	0	48,858	0	0.00%	4.00%	0.9871
	Wivenhoe Pump		0.00%	0	0	28,187	0	0.00%	0.00%	0.9933
	Yarwun	34.00%	2.00%	51.3	0.543	23,489	0	3.00%	0.00%	0.9934
	Angaston	26.00%	2.50%	67.9	0.94	12,214	8.93	1.50%	0.00%	0.999
	Bluff Wind Farm		0.00%	0	0	32,083	0	0.00%	0.00%	0.9718
	Clements Gap Wind Farm		0.00%	0	0	32,083	0	0.00%	0.00%	0.9589
	Dry Creek	26.00%	3.00%	51.3	0.71	12,214	8.93	3.00%	0.00%	1.0009
	Hallett	24.00%	2.50%	51.3	0.77	12,214	8.93	1.50%	0.00%	0.9705
	Hallett 2 Wind Farm		0.00%	0	0	32,083	0	0.00%	0.00%	0.9718
	Hallett Wind Farm		0.00%	0	0	32,083	0	0.00%	0.00%	0.9705
	Ladbroke Grove	30.00%	3.00%	51.3	0.616	12,214	3.34	3.00%	4.00%	0.9626
	Lake Bonney 2 Wind Farm		0.00%	0	0	32,083	0	0.00%	0.00%	0.9404
	Lake Bonney 3 Wind Farm		0.00%	0	0	32,083	0	0.00%	0.00%	0.9404
	Mintaro	28.00%	3.00%	51.3	0.66	12,214	8.93	1.50%	0.00%	0.9778
	North Brown Hill Wind Farm		0.00%	0	0	32,083	0	0.00%	0.00%	0.9694
SA	Northern	34.90%	5.00%	91	0.939	51,676	1.11	5.00%	8.00%	0.9638
	Osborne	42.00%	5.00%	51.3	0.44	23,489	4.72	3.00%	2.00%	0.9997
	Pelican Point	48.00%	2.00%	51.3	0.385	30,249	1.1	3.00%	4.00%	0.999
	Playford B [a]	21.90%	8.00%	91	1.496	65,770	2.79	10.00%	8.00%	0.9573
	Port Lincoln	26.00%	8.00%	67.9	0.94	12,214	8.93	1.50%	0.00%	0.9038
	Quarantine	32.00%	5.00%	51.3	0.577	12,214	8.93	2.50%	0.00%	1
	Snowtown 2 Wind Farm		0.00%	0	0	32,083	0	0.00%	0.00%	0.9154
	Snowtown Wind Farm		0.00%	0	0	32,083	0	0.00%	0.00%	0.9154
	Snuggery	26.00%	3.00%	67.9	0.94	12,214	8.93	2.00%	0.00%	1.0289
	Torrens Island A	27.60%	5.00%	51.3	0.669	36,666	2.05	4.50%	4.00%	0.9999
	Torrens Island B	30.00%	5.00%	51.3	0.616	36,666	2.05	4.50%	4.00%	0.9999
	Waterloo Wind Farm		0.00%	0	0	32,083	0	0.00%	0.00%	0.9747
	Bastyan		0.00%	0	0	48,858	5.78	0.00%	4.00%	0.9436
	Bell Bay	29.00%	2.50%	51.3	0.637	36,666	2.05	12.00%	8.00%	0.9994
	Bell Bay Three	29.00%	2.50%	51.3	0.637	12,214	7.33	3.00%	0.00%	0.9994
	Cethana		0.00%	0	0	48,858	5.78	0.00%	4.00%	0.9668
	Devils Gate		0.00%	0	0	48,858	5.78	0.00%	4.00%	0.9715
TAS	Fisher		0.00%	0	0	48,858	4.82	0.00%	4.00%	0.9717
	Gordon		0.00%	0	0	48,858	4.82	0.00%	4.00%	0.9672
	John Butters		0.00%	0	0	48,858	5.78	0.00%	4.00%	0.942
	Lake Echo		0.00%	0	0	48,858	5.78	0.00%	4.00%	0.9428
	Lemonthyme_Wilmot		0.00%	0	0	48,858	5.78	0.00%	4.00%	0.9746
	Liapootah_Wayatinah_Catagunya		0.00%	0	0	48,858	5.78	0.00%	4.00%	1.0062

Region	Generator	Thermal efficiency	Auxiliaries	Scope 1 emission factor	Scope 1 emission intensity	Fixed O&M	Variable O&M	Forced outage rate	Planned outage rate	Marginal Loss Factor
		HHV (%) sent-out	%	(kg CO_2-e/GJ of fuel)	(tonnes CO_2-e/MWh sent-out)	($/MW gross/year)	$/MWh sent-out	%	%	
	Mackintosh		0.00%	0	0	48,858	5.78	0.00%	4.00%	0.927
	Meadowbank		0.00%	0	0	48,858	5.78	0.00%	4.00%	1.0064
	Musselroe Wind Farm		0.00%	0	0	32,083	0	0.00%	0.00%	0.9974
	Poatina		0.00%	0	0	48,858	5.78	0.00%	4.00%	0.9758
	Reece		0.00%	0	0	48,858	5.78	0.00%	4.00%	0.9348
	Tamar Valley	48.00%	3.00%	51.3	0.385	30,249	1.1	3.00%	2.00%	0.9989
	Tamar Valley GT	28.00%	2.00%	51.3	0.66	12,214	8.93	3.00%	2.00%	0.9994
	Tarraleah		0.00%	0	0	48,858	5.78	0.00%	4.00%	0.9522
	Trevallyn		0.00%	0	0	48,858	5.78	0.00%	4.00%	0.9974
	Tribute		0.00%	0	0	48,858	5.78	0.00%	4.00%	0.9378
	Tungatinah		0.00%	0	0	48,858	5.78	0.00%	4.00%	0.9395
	Anglesea	27.20%	10.00%	91	1.204	124,962	1.11	3.00%	2.00%	1.0135
	Bairnsdale	34.00%	3.00%	51.3	0.543	12,214	2.09	2.50%	0.00%	0.9701
	Dartmouth		0.00%	0	0	48,858	5.78	0.00%	4.00%	0.9885
	Eildon		0.00%	0	0	48,858	8.67	0.00%	4.00%	0.9902
	Energy Brix	24.00%	15.00%	99	1.485	93,957	2.05	2.50%	4.00%	0.9619
	Hazelwood	22.00%	10.00%	93	1.522	131,539	1.11	3.50%	8.00%	0.9685
	Hume VIC		0.00%	0	0	48,858	5.78	0.00%	4.00%	1.0912
	Jeeralang A	22.90%	3.00%	51.3	0.806	12,214	8.4	2.50%	0.00%	0.964
	Jeeralang B	22.90%	3.00%	51.3	0.806	12,214	8.4	2.50%	0.00%	0.964
	Laverton North	30.40%	2.50%	51.3	0.608	12,214	7.33	1.50%	2.00%	0.998
	Loy Yang A	27.20%	9.00%	91.5	1.211	122,144	1.11	3.00%	2.00%	0.9709
VIC	Loy Yang B	26.60%	7.50%	91.5	1.238	87,738	1.11	4.00%	2.00%	0.9709
	Macarthur Wind Farm		0.00%	0	0	32,083	0	0.00%	0.00%	1.005
	McKay		0.00%	0	0	48,858	6.74	0.00%	4.00%	0.9993
	Mortlake	32.00%	3.00%	51.3	0.577	12,214	7.73	2.50%	0.00%	0.9709
	Mt Mercer Wind Farm		0.00%	0	0	32,083	0	0.00%	0.00%	0.956
	Murray		0.00%	0	0	48,858	5.78	0.00%	4.00%	1.011
	Newport	33.30%	5.00%	51.3	0.555	37,583	2.09	2.00%	4.00%	0.9969
	Oaklands Hill Wind Farm		0.00%	0	0	32,083	0	0.00%	0.00%	1.0252
	Somerton	24.00%	2.50%	51.3	0.77	12,214	8.93	1.50%	0.00%	0.996
	Valley Power	24.00%	3.00%	51.3	0.77	12,214	8.93	1.50%	0.00%	0.9709
	West Kiewa		0.00%	0	0	48,858	6.74	0.00%	4.00%	1.0191
	Yallourn	23.50%	8.90%	92.5	1.417	126,842	1.11	4.00%	4.00%	0.9494
	Albany		0.00%	0	0	42,000	1.05	0.00%	0.00%	1.072
	Alcoa Kwinana Cogen	30.00%	1.00%	51.3	0.616	25,000	0	3.80%	5.20%	1.0199
	Alcoa Pinjarra Cogen	30.00%	1.00%	51.3	0.616	25,000	0	3.80%	5.20%	0.9964
	Alcoa Wagerup Cogen	30.00%	1.00%	51.3	0.616	25,000	0	3.80%	5.20%	0.9848
	Bluewaters	36.10%	7.50%	93.1	0.928	52,000	1.58	3.00%	4.90%	0.9949
	BP Cogen	33.00%	2.00%	51.3	0.56	23,489	0	5.00%	4.10%	1.0199
	Canning/Melville LFG	30.00%	0.00%	0	0	50,000	3.68	5.00%	0.00%	1.0284
	Cockburn	48.00%	2.40%	51.3	0.385	30,249	4.73	4.20%	10.10%	1.0164
	Collgar Wind Farm		0.00%	0	0	42,000	1.05	0.00%	0.00%	1.1229
	Collie	36.00%	7.90%	93.1	0.931	52,000	1.58	3.20%	8.50%	0.9949
SWIS	Emu downs		0.00%	0	0	42,000	1.05	0.00%	0.00%	0.9945
	Geraldton	29.00%	0.50%	67.9	0.843	12,214	9.46	5.90%	9.00%	1.037
	Grasmere		0.00%	0	0	42,000	1.05	0.00%	0.00%	1.072
	Greenough River		0.10%	0	0	50,000	0	0.00%	0.00%	1.037
	Kalgoorlie	33.00%	0.50%	67.9	0.741	12,214	9.46	5.90%	4.10%	1.0782
	Kalgoorlie Nickel	33.00%	0.50%	51.3	0.56	12,214	9.46	5.20%	4.70%	1.2253
	Kemerton	34.00%	0.50%	51.3	0.543	12,214	9.46	6.00%	7.90%	1.0057
	Kwinana A	32.00%	9.00%	51.3	0.577	40,000	8.41	5.40%	14.80%	1.0164
	Kwinana B	32.00%	9.00%	51.3	0.577	40,000	8.41	5.40%	14.80%	1.0164
	Kwinana C	33.00%	4.00%	51.3	0.56	40,000	7.35	5.20%	9.90%	1.0164
	Kwinana GT	32.00%	0.50%	67.9	0.764	12,214	9.46	5.20%	9.90%	1.0164
	Kwinana HEGT	40.00%	0.50%	51.3	0.462	12,214	1.31	5.20%	4.10%	1.0164

Region	Generator	Thermal efficiency	Auxiliaries	Scope 1 emission factor	Scope 1 emission intensity	Fixed O&M	Variable O&M	Forced outage rate	Planned outage rate	Marginal Loss Factor
		HHV (%) sent-out	%	(kg CO_2-e/GJ of fuel)	(tonnes CO_2-e/MWh sent-out)	($/MW gross/year)	$/MWh sent-out	%	%	
	Muja A&B	26.40%	8.50%	93.1	1.27	60,000	1.58	4.20%	10.00%	1
	Muja C	34.60%	8.00%	93.1	0.97	52,000	1.58	4.20%	9.90%	1
	Muja D	35.60%	8.00%	93.1	0.942	52,000	1.58	4.90%	9.90%	1
	Mumbida		0.00%	0	0	42,000	1.05	0.00%	0.00%	1.037
	Mungarra	29.00%	0.50%	51.3	0.637	12,214	9.46	5.20%	9.90%	1.0181
	Namarkkon	30.00%	1.00%	67.9	0.815	12,214	9.46	4.00%	4.00%	1.1229
	Neerabup Peaker	32.00%	2.00%	51.3	0.577	12,214	9.46	3.90%	2.20%	1.0164
	Newgen Power	48.00%	2.00%	51.3	0.385	30,249	1.1	4.00%	3.30%	1.0164
	Parkeston SCE	33.00%	0.50%	51.3	0.56	12,214	9.46	5.20%	4.90%	1.2429
	Pinjar A B	29.00%	0.50%	51.3	0.637	12,214	9.46	5.20%	9.90%	1.0295
	Pinjar C	29.00%	0.50%	51.3	0.637	12,214	9.46	5.20%	9.90%	1.0295
	Pinjar D	29.00%	0.50%	51.3	0.637	12,214	9.46	5.20%	9.90%	1.0295
	Pinjarra Alinta Cogen	34.10%	2.40%	51.3	0.542	25,000	0	3.90%	4.10%	0.9898
	Tesla (various sites)	28.00%	1.00%	67.9	0.873	12,214	9.46	4.00%	4.00%	1.1229
	Tiwest Cogen	32.00%	1.50%	51.3	0.577	25,000	0	5.90%	4.10%	1.0177
	Wagerup Alinta Peaker	34.10%	0.50%	67.9	0.717	12,214	9.46	3.90%	4.10%	1.012
	Walkaway		0.00%	0	0	42,000	1.05	0.00%	0.00%	0.9444
	Western Energy Peaker	32.00%	0.50%	51.3	0.577	12,214	9.46	5.20%	4.10%	1.0164
	Worsley	28.00%	0.00%	93.1	1.197	25,000	0	4.80%	4.10%	0.9836
	Worsley SWCJV	33.00%	2.00%	51.3	0.56	25,000	0	5.00%	4.10%	0.9836
	Burrup Peninsula	29.00%	2.00%	51.3	0.637	12,214	9.61	3.00%	8.00%	1
	Cape Lambert [a]	30.00%	5.00%	51.3	0.616	40,000	2.25	3.00%	4.00%	1
	Cape Preston	50.00%	3.00%	51.3	0.369	30,249	1.1	3.00%	8.00%	1
NWIS	Dampier [a]	30.00%	5.00%	51.3	0.616	40,000	2.25	3.00%	4.00%	1
	Karratha	30.00%	5.00%	51.3	0.616	40,000	2.25	3.00%	4.00%	1
	Karratha ATCO	40.00%	2.00%	51.3	0.462	12,214	9.61	3.00%	8.00%	1
	Paraburdoo	29.00%	2.00%	67.9	0.843	13,000	9.61	3.00%	4.00%	1
	Port Hedland	29.00%	2.00%	51.3	0.637	12,214	9.61	3.00%	8.00%	1
	Berrimah	24.00%	1.00%	67.9	1.019	12,214	9.61	3.00%	8.00%	1
	Channel Island u1-3	27.00%	1.00%	51.3	0.684	12,214	9.61	3.00%	8.00%	1
	Channel Island u4-6	48.00%	2.00%	51.3	0.385	30,249	1.1	3.00%	8.00%	1
	Channel Island u7	37.00%	1.00%	51.3	0.499	12,214	9.61	3.00%	8.00%	1
DKIS	Channel Island u8-9	37.00%	1.00%	51.3	0.499	12,214	9.61	3.00%	8.00%	1
	Katherine	25.00%	1.00%	51.3	0.739	12,214	9.61	3.00%	8.00%	1
	LMS Shoal Bay	40.00%	2.00%	0	0	80,000	4	3.00%	5.00%	1
	Pine Creek CCGT	47.00%	2.00%	51.3	0.393	30,249	1.1	3.00%	8.00%	1
	Weddell	35.00%	1.00%	51.3	0.528	12,214	9.61	3.00%	4.00%	1
	APA Xstrata OCGT	36.00%	1.00%	51.3	0.513	12,214	9.61	3.00%	8.00%	1
	Diamantina CCGT	48.00%	2.00%	51.3	0.385	30,249	1.05	3.00%	4.00%	1
	Diamantina OCGT	32.00%	2.00%	51.3	0.577	12,214	9.61	3.00%	5.00%	1
	Ernest Henry	29.00%	2.00%	67.9	0.843	13,000	9.61	3.00%	4.00%	1
Mt Isa	Mica Creek A CCGT	43.00%	2.00%	51.3	0.429	30,249	1.05	3.00%	8.00%	1
	Mica Creek A GT	27.00%	3.00%	51.3	0.684	12,214	9.61	3.00%	8.00%	1
	Mica Creek B	27.00%	3.00%	51.3	0.684	12,214	9.61	3.00%	8.00%	1
	Mica Creek C	43.00%	2.00%	51.3	0.429	30,249	9.61	3.00%	8.00%	1
	Mt Isa Mines Station	25.00%	1.00%	51.3	0.739	40,000	9.61	3.00%	8.00%	1
	Phosphate Hill	27.00%	3.00%	51.3	0.684	12,214	1.05	3.00%	8.00%	1

[a] These generators are mothballed as of April 2013 but have been operational during the model period (starting 1 July 2009).
Note: O&M cost values are in 2009-10 dollars
Source: ACIL Allen

3.4 New entrant generators

A range of new entrant generating technologies are made available within the modelling over the period to 2050. *PowerMark LT* determines a least cost plant mix for each modelled region on a dynamic inter-temporal basis.

New capacity is introduced to each region through the use of continuous capacity variables, that is, generation increments are not set to predetermined sizes and the model allows entry of any optimal increment.[1]

A range of cost and generation characteristics are required for each new entrant technology to solve the model in a way that minimises overall resource costs on a net present value basis. The key proposed inputs for each of these elements is discussed in the following sections.

3.4.1 Starting capital costs

Capital costs comprise one of the key inputs for long-term electricity sector modelling as capital is the largest cost component for most generation technologies.

The methodology employed for this study is to commence with a starting capital cost value (termed the 'base' capital cost) and break this down into its component parts: local labour; local equipment and commodities; and foreign equipment and commodities.

These component parts are then projected forward individually before being recombined into a final capital cost estimate. This process allows for the influences of learning rates (both foreign and local), labour costs, and exchange rates to be properly incorporated into the final cost estimates.

For the most part, the base capital cost estimates for most technologies were taken from the 2012 Australian Energy Technology Assessment (AETA) published by the Bureau of Resource and Energy Economics (BREE). ACIL Allen has selected a sub-set of 29 of the 40 technologies examined within the AETA study. Technologies excluded include exotic coal-based technologies that do not employ carbon capture and storage (IGCC, oxy-fuel and direct injection), solar hybrids, offshore wind, landfill gas, bagasse and nuclear options.

Table 3 presents the proposed capital costs for each of the technologies for use within the emission projection modelling. The table also includes the headline splits for the cost components taken from the AETA study.

These capital costs are presented on an 'overnight' basis – interest during construction and financing costs are excluded.[2] For plants that employ carbon capture, the capital costs include capture and compression of CO_2, but exclude transport and storage costs.

ACIL Allen has proposed some minor modifications to base capital costs for a number of selected technologies where it has direct recent experience with actual proposed projects in Australia. Figure 3 shows a comparison of the proposed capital cost figures against those within the AETA 2012 study.

Modifications to the base capital costs were made for the following technologies:

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[1] The *PowerMark LT* model is formulated as a linear program. A mixed integer linear program (MILP) formulation is required to introduce standard increments of new entrant capacity however this increases solution time enormously.

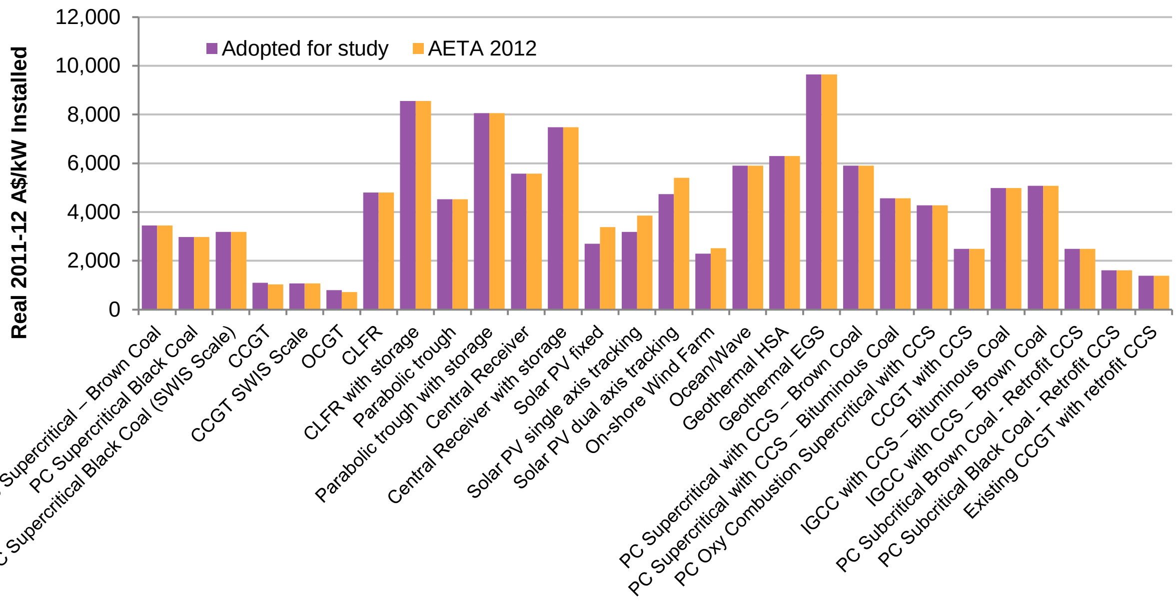
[2] Interest during construction represents the financial cost associated with incurring a portion of construction costs in advance of the commissioning date. Accordingly, these costs are assumed to incur interest until the commissioning date. Interest during construction costs are added to the total capital cost within the modelling based on the time profile of construction for each technology.

- Natural gas-fired CCGT (7% higher)
- Natural gas-fired OCGT (12% higher)
- Solar PV (20% lower) including corresponding changes to tracking options
- Onshore wind (9% lower).

Biomass technologies were not adopted as a new entrant in the modelling, despite being included in the AETA study, due to the miscellaneous nature of the fuel resource for biomass generation and the associated variation in generation costs. In a long-term planning modelling exercise of the type used here, capturing such variety would require applying strict uptake limitations on lower-cost biomass options, and the appropriate limits are, in turn, quite uncertain. Given this, for simplicity, this class of generation was not included in the wholesale market modelling. Existing bagasse, landfill gas and other biomass generation was incorporated as embedded generation (see section 3.8).

Hydro-electric generation is not included as a model as a new entrant technology. This reflects the fact that few commercially viable large-scale hydro-electric sites remain in Australia for exploitation.

Figure 3 **Base capital cost comparison with AETA 2012**



Source: ACIL Allen, BREE

Table 3 **Base capital costs and cost component splits**

Category	Technology	2011-12 Base capital cost (2011-12 A$/kW installed)	2011-12 Base capital cost (A$/kW net)	Labour	Foreign equipment and commodities	Local equipment and commodities
Coal	PC Supercritical – Brown Coal	3,451	3,788	29%	38%	33%
	PC Supercritical Black Coal	2,974	3,124	30%	39%	31%
	PC Supercritical Black Coal (SWIS Scale)	3,192	3,381	31%	40%	29%
Natural gas	CCGT	1,100[a]	1,127[a]	26%	56%	18%
	CCGT SWIS Scale	1,078[a]	1,111[a]	26%	56%	18%
	OCGT	800[a]	808[a]	11%	79%	10%
Solar	CLFR	4,802	5,220	20%	55%	25%
	CLFR with storage	8,550	9,500	25%	55%	20%
	Parabolic trough	4,526	4,920	20%	55%	25%

Category	Technology	2011-12 Base capital cost (2011-12 A$/kW installed)	2011-12 Base capital cost (A$/kW net)	Labour	Foreign equipment and commodities	Local equipment and commodities
	Parabolic trough with storage	8,055	8,950	25%	55%	20%
	Central Receiver	5,570	5,900	30%	55%	15%
	Central Receiver with storage	7,477	8,308	25%	55%	20%
Solar PV	Solar PV fixed	2,700[a]	2,700[a]	15%	70%	15%
	Solar PV single axis tracking	3,180[a]	3,180 [a]	15%	70%	15%
	Solar PV dual axis tracking	4,730[a]	4,730[a]	15%	70%	15%
Wind	On-shore Wind Farm	2,300[a]	2,312[a]	15%	72%	13%
Wave	Ocean/Wave	5,900	5,900	30%	40%	30%
Geothermal	Geothermal HSA	6,300	7,000	34%	23%	43%
	Geothermal EGS	9,646	10,600	37%	17%	46%
CCS	PC Supercritical with CCS – Brown Coal	5,902	7,766	29%	35%	36%
	PC Supercritical with CCS – Bituminous Coal	4,559	5,434	29%	35%	36%
	PC Oxy Combustion Supercritical with CCS	4,274	5,776	33%	35%	32%
	CCGT with CCS	2,495	2,772	19%	67%	14%
	IGCC with CCS – Bituminous Coal	4,984	7,330	27%	52%	21%
	IGCC with CCS – Brown Coal	5,083	8,616	27%	52%	21%
CCS retrofit	PC Subcritical Brown Coal - Retrofit CCS	2,493	3,945	30%	30%	40%
	PC Subcritical Black Coal - Retrofit CCS	1,611	2,244	30%	30%	40%
	Existing CCGT with retrofit CCS	1,392	1,547	12%	78%	10%

Note: CCS capital costs are inclusive of capture, but exclude transport and storage costs. These are treated separately, as discussed in section 3.5. Real 2011-12 dollars

Source: BREE (AETA 2012) unless marked; a indicates ACIL Allen assumption

3.4.1 Learning rates

Learning rates are applied to the base capital costs to reflect cost changes over time through technology and manufacturing improvements and learning by doing.

Learning rates for each major technology have been taken from CSIRO’s Global and Local Learning Model (GALLM) as part of the AETA 2012 study. For some technologies differential learning rates were provided for foreign and local content components and these have been applied to the respective foreign equipment and local equipment/local labour components respectively.

Learning rates in the GALLM model are endogenous and respond to the rate of deployment of each technology both locally and internationally. The learning rates used in deriving capital costs assumptions presented here are consistent with carbon prices and global mitigation outcomes in the Commonwealth Government’s 2011 modelling of the *Clean Energy Future*. As most learning occurs internationally rather than domestically, these rates are appropriate to both the No Carbon Price (no local carbon price, but with international action targeting emissions stabilisation at 550 ppm), and the Central Policy scenario (with a local carbon price and the same level of international action as the No Carbon Price scenario). Higher learning rates would be expected for low-emissions technologies in the event of more ambitious global action and correspondingly faster deployment of these technologies. GALLM learning rates for a scenario consistent with a 450 ppm stabilisation target are available and will be adopted where appropriate.

A complication in this process is the adjustments made by ACIL Allen to the base capital costs for solar PV and wind technologies from the AETA figures. As these represent a reduction in the starting base capital cost, it was decided that the learning rates should be reduced in the early years such that the capital cost for 2020 remained unchanged from the AETA work. The reported learning rates for these technologies in the period to 2020 will therefore differ due to the lower starting value.

Table 4 presents a summary of the learning rates used from the AETA work. Where available the differentiated learning rates that apply to foreign and local components have been used within the capital cost projections.

Table 4 **Learning rates from GALLM for various technologies from AETA 2012 (cost index relative to 2011-12)**

	Brown coal pf	Brown coal IGCC	Brown coal CCS	Black coal pf	Black coal IGCC	Black coal with CCS	Gas combined cycle	Gas with CCS	Gas open cycle	Nuclear	Solar thermal	Large scale PV	Wind	Hot fractured rocks	Wave
2011-12	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2014-15	0.991	0.97	0.995	0.948	0.981	0.995	0.998	0.995	0.992	0.999	0.816	0.877	0.88	1	1
2019-20	0.977	0.919	0.985	0.86	0.95	0.985	0.993	0.986	0.979	0.997	0.509	0.672	0.68	1	1
2024-25	0.963	0.918	0.763	0.849	0.948	0.763	0.988	0.757	0.966	0.992	0.413	0.611	0.675	1.002	0.497
2029-30	0.949	0.918	0.711	0.839	0.948	0.711	0.982	0.696	0.954	0.982	0.409	0.551	0.673	0.977	0.469
2034-35	0.936	0.918	0.698	0.828	0.948	0.698	0.977	0.683	0.942	0.981	0.406	0.447	0.671	0.976	0.467
2039-40	0.923	0.918	0.685	0.818	0.948	0.685	0.972	0.669	0.93	0.98	0.404	0.344	0.668	0.975	0.466
2044-45	0.91	0.918	0.676	0.808	0.948	0.675	0.971	0.66	0.918	0.963	0.403	0.333	0.657	0.975	0.453
2049-50	0.898	0.918	0.666	0.799	0.948	0.666	0.97	0.651	0.907	0.946	0.402	0.321	0.646	0.975	0.439
2011-12	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2014-15	0.991	0.97	0.998	0.948	0.981	0.998	0.998	0.995	0.992	0.999	0.816	0.838	0.875	1	1
2019-20	0.977	0.919	0.995	0.86	0.95	0.995	0.993	0.988	0.979	0.997	0.509	0.554	0.669	1	1
2024-25	0.963	0.918	0.689	0.849	0.948	0.689	0.988	0.777	0.966	0.992	0.413	0.451	0.662	1	0.497
2029-30	0.949	0.918	0.569	0.839	0.948	0.569	0.982	0.691	0.954	0.982	0.409	0.398	0.66	0.955	0.469
2034-35	0.936	0.918	0.558	0.828	0.948	0.558	0.977	0.678	0.942	0.981	0.406	0.323	0.657	0.954	0.467
2039-40	0.923	0.918	0.546	0.818	0.948	0.546	0.972	0.665	0.93	0.98	0.404	0.249	0.653	0.952	0.466
2044-45	0.91	0.918	0.539	0.808	0.948	0.539	0.971	0.656	0.918	0.963	0.403	0.234	0.645	0.952	0.453
2049-50	0.898	0.918	0.532	0.799	0.948	0.532	0.97	0.647	0.907	0.946	0.402	0.219	0.636	0.952	0.439
2011-12	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2014-15	0.991	0.97	0.992	0.948	0.981	0.992	0.998	0.994	0.992	0.999	0.816	0.918	0.897	1	1
2019-20	0.977	0.919	0.98	0.86	0.95	0.98	0.993	0.983	0.979	0.997	0.509	0.795	0.716	1	1
2024-25	0.963	0.918	0.808	0.849	0.948	0.808	0.988	0.716	0.966	0.992	0.413	0.779	0.717	1.005	0.497
2029-30	0.949	0.918	0.796	0.839	0.948	0.796	0.982	0.706	0.954	0.982	0.409	0.712	0.717	1.005	0.469
2034-35	0.936	0.918	0.782	0.828	0.948	0.782	0.977	0.692	0.942	0.981	0.406	0.577	0.717	1.005	0.467
2039-40	0.923	0.918	0.768	0.818	0.948	0.768	0.972	0.679	0.93	0.98	0.404	0.443	0.718	1.005	0.466
2044-45	0.91	0.918	0.757	0.808	0.948	0.757	0.971	0.669	0.918	0.963	0.403	0.436	0.698	1.005	0.453
2049-50	0.898	0.918	0.746	0.799	0.948	0.746	0.97	0.66	0.907	0.946	0.402	0.429	0.679	1.005	0.439

Note: Where individual learning rates for foreign/local components were not available the same overall learning rate was applied to both. Note learning rates in the period to 2020 for solar PV and wind have been adjusted based on a lower starting base capital cost.

Source: ACIL Allen based on GALLM learning rates

3.4.2 Other cost indices

Various cost indices derived from the Treasury's CGE modelling was used to adjust final capital costs for various technologies:

- the capital cost component relating to local labour was adjusted in line with the modelled real labour cost index
- an index of steel prices was used to adjust 25% and 40% of the local and foreign equipment cost component respectively
- a modelled real exchange rate index was used to convert the foreign equipment and commodities cost component (which are projected in US dollars) back into Australian dollars.

These various cost indices varied slightly from scenario to scenario in line with broader economic changes modelled through the CGE framework.

3.4.3 Final capital costs

Table 5 presents the final capital costs for each of the technologies after all adjustments for learning, labour, metals and exchange rates are made. Capital costs for the core Central Policy scenario are also shown graphically in Figure 4. Due to variations in other assumptions such as metals prices and exchange rates, these assumptions vary slightly from scenario to scenario, but very similar to the Central Policy scenario results presented here.

Table 6 shows the average year-on-year percentage change in capital costs for each decade of the projection in the Central Policy scenario.

Table 5 **Final capital costs for new entrant technologies for selected years – Central Policy scenario (Real 2011-12 $/kW installed)**

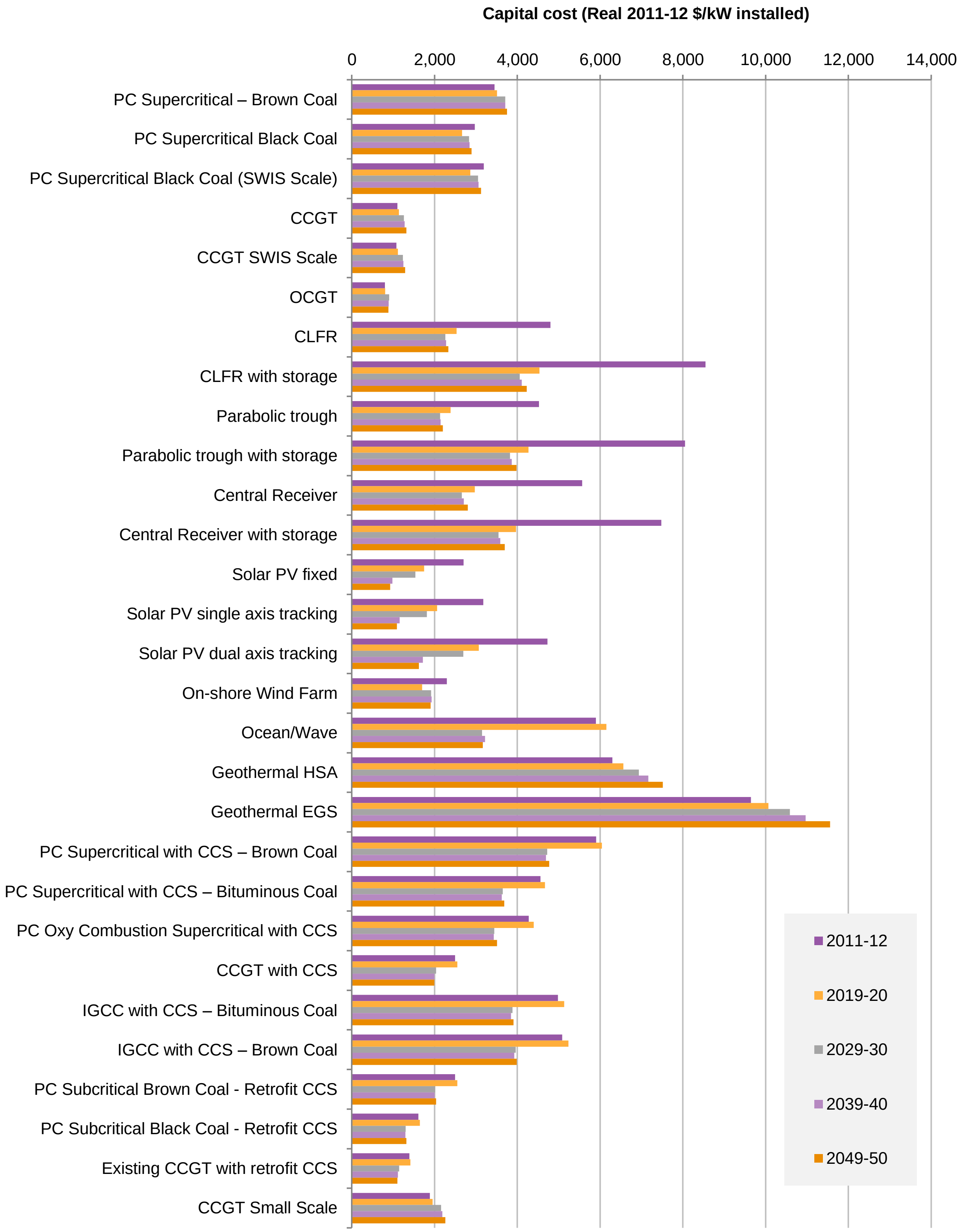
	Technology	2011-12	2019-20	2029-30	2039-40	2049-50
Coal	PC Supercritical – Brown Coal	3,450	3,507	3,708	3,705	3,752
	PC Supercritical Black Coal	2,974	2,667	2,833	2,843	2,892
	PC Supercritical Black Coal (SWIS Scale)	3,191	2,866	3,051	3,064	3,120
Natural gas	CCGT	1,100	1,140	1,258	1,275	1,318
	CCGT SWIS Scale	1,077	1,116	1,233	1,249	1,292
	CCGT small scale (NWIS, DKIS, Mt Isa)	800	807	906	892	883
	OCGT	4,802	2,531	2,261	2,279	2,332
Solar	CLFR	8,549	4,534	4,055	4,105	4,227
	CLFR with storage	4,526	2,385	2,131	2,148	2,198
	Parabolic trough	8,054	4,272	3,820	3,867	3,983
	Parabolic trough with storage	5,569	2,973	2,661	2,705	2,803
	Central Receiver	7,476	3,965	3,546	3,589	3,697
	Central Receiver with storage	2,700	1,751	1,539	980	927
Solar PV	Solar PV fixed	3,179	2,062	1,813	1,154	1,092
	Solar PV single axis tracking	4,729	3,067	2,697	1,716	1,624
	Solar PV dual axis tracking	2,300	1,700	1,917	1,931	1,906
Wind	On-shore Wind Farm	5,899	6,151	3,148	3,219	3,162
	Ocean/Wave	6,299	6,564	6,937	7,164	7,517
Geothermal	Geothermal HSA	5,901	6,043	4,722	4,691	4,772
	Geothermal EGS	4,558	4,668	3,648	3,623	3,686
CCS	PC Supercritical with CCS – Brown Coal	4,274	4,398	3,442	3,433	3,512
	PC Supercritical with CCS – Bituminous Coal	2,494	2,552	2,039	1,998	1,995
	PC Oxy Combustion Supercritical with CCS	4,984	5,131	3,881	3,846	3,908
	CCGT with CCS	5,083	5,233	3,959	3,923	3,986
	IGCC with CCS – Bituminous Coal	2,493	2,550	2,012	2,000	2,037
	IGCC with CCS – Brown Coal	1,611	1,648	1,300	1,293	1,317

	Technology	2011-12	2019-20	2029-30	2039-40	2049-50
CCS retrofit	PC Subcritical Brown Coal - Retrofit CCS	1,392	1,418	1,146	1,116	1,103
	PC Subcritical Black Coal - Retrofit CCS	1,886	1,954	2,157	2,186	2,260
	Existing CCGT with retrofit CCS	3,450	3,507	3,708	3,705	3,752

Note: CCS capital costs are inclusive of capture, but exclude CO_2 transport and storage costs. These are treated separately, as discussed in section 3.5.3.

Source: ACIL Allen based on ACIL Allen, BREE and Treasury inputs.

Figure 4 **Final capital costs for new entrant technologies for selected years – Central Policy scenario**



Source: ACIL Allen based on ACIL Allen, BREE and Treasury inputs.

Table 6 **Average real year-on-year capital cost change for each decade – Central Policy scenario**

	Technology	2011-12 to 2019-20	2019-20 to 2029-30	2029-30 to 2039-40	2039-40 to 2049-50
Coal	PC Supercritical – Brown Coal	0.2%	0.6%	0.0%	0.1%
	PC Supercritical Black Coal	-1.4%	0.6%	0.0%	0.2%
	PC Supercritical Black Coal (SWIS Scale)	-1.3%	0.6%	0.0%	0.2%
Natural gas	CCGT	0.4%	1.0%	0.1%	0.3%
	CCGT SWIS Scale	0.4%	1.0%	0.1%	0.3%
	OCGT	0.1%	1.2%	-0.2%	-0.1%
Solar	CLFR	-7.7%	-1.1%	0.1%	0.2%
	CLFR with storage	-7.6%	-1.1%	0.1%	0.3%
	Parabolic trough	-7.7%	-1.1%	0.1%	0.2%
	Parabolic trough with storage	-7.6%	-1.1%	0.1%	0.3%
	Central Receiver	-7.5%	-1.1%	0.2%	0.4%
	Central Receiver with storage	-7.6%	-1.1%	0.1%	0.3%
Solar PV	Solar PV fixed	-5.3%	-1.3%	-4.4%	-0.6%
	Solar PV single axis tracking	-5.3%	-1.3%	-4.4%	-0.6%
	Solar PV dual axis tracking	-5.3%	-1.3%	-4.4%	-0.6%
Wind	On-shore Wind Farm	-3.7%	1.2%	0.1%	-0.1%
	Ocean/Wave	0.5%	-6.5%	0.2%	-0.2%
Geothermal	Geothermal HSA	0.5%	0.6%	0.3%	0.5%
	Geothermal EGS	0.5%	0.5%	0.4%	0.5%
CCS	PC Supercritical with CCS – Brown Coal	0.3%	-2.4%	-0.1%	0.2%
	PC Supercritical with CCS – Bituminous Coal	0.3%	-2.4%	-0.1%	0.2%
	PC Oxy Combustion Supercritical with CCS	0.4%	-2.4%	0.0%	0.2%
	CCGT with CCS	0.3%	-2.2%	-0.2%	0.0%
	IGCC with CCS – Bituminous Coal	0.4%	-2.8%	-0.1%	0.2%
	IGCC with CCS – Brown Coal	0.4%	-2.8%	-0.1%	0.2%
CCS retrofit	PC Subcritical Brown Coal - Retrofit CCS	0.3%	-2.3%	-0.1%	0.2%
	PC Subcritical Black Coal - Retrofit CCS	0.3%	-2.3%	-0.1%	0.2%
	Existing CCGT with retrofit CCS	0.2%	-2.1%	-0.3%	-0.1%

Source: ACIL Allen based on ACIL Allen, BREE and Treasury inputs.

3.4.1 Other new entrant parameters

Table 7 provides other technical parameters and cost assumptions for the new entrant technologies. For the most part these are aligned with the AETA 2012 study, with a few modifications.

Table 7 **New entrant parameters**

Category	Technology	Thermal efficiency (% higher heating value sent-out)	Emissions factor – Scope 1 (tCO_2-/MWh sent out)	Auxiliary load (%)	Fixed O&M ($/MW/year)	Variable O&M ($/MWh)
Coal	PC Supercritical – Brown Coal	32.3%	1.038	8.9%	85,000	1
	PC Supercritical Black Coal	41.9%	0.760	4.8%	52,000	1
	PC Supercritical Black Coal (SWIS Scale)	41.4%	0.769	5.6%	55,500	8
Natural gas	CCGT	49.5%	0.373	2.4%	33,000	1
	CCGT SWIS Scale	49.3%	0.375	3.0%	10,000	4
	OCGT	32.0%	0.577	1.0%	14,000	8
Solar	CLFR	0.0%	0.000	8.0%	60,000	15
	CLFR with storage	0.0%	0.000	10.0%	60,000	15
	Parabolic trough	0.0%	0.000	8.0%	60,000	15
	Parabolic trough with storage	0.0%	0.000	10.0%	65,000	20
	Central Receiver	0.0%	0.000	5.6%	70,000	15
	Central Receiver with storage	0.0%	0.000	10.0%	60,000	15
Solar PV	Solar PV fixed	0.0%	0.000	0.0%	38,000	0

Category	Technology	Thermal efficiency (% higher heating value sent-out)	Emissions factor – Scope 1 (tCO_2-/MWh sent out)	Auxiliary load (%)	Fixed O&M ($/MW/year)	Variable O&M ($/MWh)
	Solar PV single axis tracking	0.0%	0.000	0.0%	38,000	0
	Solar PV dual axis tracking	0.0%	0.000	0.0%	47,000	0
Wind	On-shore Wind Farm	0.0%	0.000	0.5%	40,000	0
	Ocean/Wave	0.0%	0.000	0.0%	190,000	0
Geothermal	Geothermal HSA	0.0%	0.000	10.0%	200,000	0
	Geothermal EGS	0.0%	0.161	9.0%	170,000	0
CCS	PC Supercritical with CCS – Brown Coal	20.8%	0.101	24.0%	91,500	15
	PC Supercritical with CCS – Bituminous Coal	31.4%	0.000	16.1%	73,200	12
	PC Oxy Combustion Supercritical with CCS	32.5%	0.064	26.0%	62,000	14
	CCGT with CCS	43.1%	0.110	10.0%	17,000	9
	IGCC with CCS – Bituminous Coal	28.9%	0.131	32.0%	98,700	8
	IGCC with CCS – Brown Coal	25.5%	1.038	41.0%	123,400	10
CCS retrofit	PC Subcritical Brown Coal - Retrofit CCS	21.6%	Varies	36.8%	37,200	8
	PC Subcritical Black Coal - Retrofit CCS	30.1%	Varies	28.2%	31,000	7
	Existing CCGT with retrofit CCS	43.0%	Varies	10.0%	17,000	9

Note: Fixed O&M costs for CCS technologies do not include CO_2 storage and transport costs, which vary by location and hence cannot be presented generically. CO_2 transport and storage costs are detailed in section 3.5.3. Real 2011-12 dollars

Source: ACIL Allen, AETA 2012

Both fixed and variable O&M charges are assumed to escalate at the rate of inflation (i.e. they are constant in real terms).

Table 8 shows the availability and construction profiles for each of the technologies. It is assumed that CCS based plant would not be available prior to 2030 based on slow international progress on demonstration plants.

Table 8 **Technology availability and construction profiles**

Category	Technology	First year available for start-up	Construction period (years)	Yr1	Yr2	Yr3	Yr4
Coal	PC Supercritical – Brown Coal	2018	4	35%	35%	20%	10%
	PC Supercritical Black Coal	2018	4	35%	35%	20%	10%
	PC Supercritical Black Coal (SWIS Scale)	2018	4	35%	35%	20%	10%
Natural gas	CCGT	2016	2	60%	40%		
	CCGT SWIS Scale	2016	2	60%	40%		
	OCGT	2015	1	100%			
Solar	CLFR	2017	3	50%	30%	20%	
	CLFR with storage	2017	3	50%	30%	20%	
	Parabolic trough	2017	3	50%	30%	20%	
	Parabolic trough with storage	2017	3	50%	30%	20%	
	Central Receiver	2017	3	20%	60%	20%	
	Central Receiver with storage	2017	3	50%	30%	20%	
Solar PV	Solar PV fixed	2016	2	70%	30%		
	Solar PV single axis tracking	2016	2	70%	30%		
	Solar PV dual axis tracking	2016	2	70%	30%		
Wind	On-shore Wind Farm	2016	2	80%	20%		
	Ocean/Wave	2025	2	60%	40%		
Geothermal	Geothermal HSA	2020	3	40%	40%	20%	
	Geothermal EGS	2020	3	40%	45%	15%	
CCS	PC Supercritical with CCS – Brown Coal	2030	4	35%	35%	20%	10%
	PC Supercritical with CCS – Bituminous Coal	2030	4	35%	35%	20%	10%
	PC Oxy Combustion Supercritical with CCS	2030	4	35%	35%	20%	10%
	CCGT with CCS	2030	2	60%	40%		
	IGCC with CCS – Bituminous Coal	2030	3	20%	60%	20%	
	IGCC with CCS – Brown Coal	2030	3	20%	60%	20%	

Category	Technology	First year available for start-up	Construction period (years)	Yr1	Yr2	Yr3	Yr4
CCS retrofit	PC Subcritical Brown Coal - Retrofit CCS	2030	3	25%	60%	15%	
	PC Subcritical Black Coal - Retrofit CCS	2030	3	25%	60%	15%	
	Existing CCGT with retrofit CCS	2030	3	25%	60%	15%	

Source: ACIL Allen, AETA 2012

Table 9 shows the assumed economic life for each technology taken from AETA. As with incumbent generation, refurbishments are also applied to new entrants with the refurbishment capital cost expressed as a percentage of a new facility and resulting in a life extension expressed as a percentage of the original life. Installations can undergo multiple refurbishments within the projection horizon.

Table 9 **Technology life and refurbishment costs**

Category	Technology	Economic life (years)	Refurbishment cost (% of new)	Additional life (% of original life)	Additional life from refurb (years)
Coal	PC Supercritical – Brown Coal	50	25%	30%	15
	PC Supercritical Black Coal	50	25%	30%	15
	PC Supercritical Black Coal (SWIS Scale)	50	25%	30%	15
Natural gas	CCGT	30	70%	100%	30
	CCGT SWIS Scale	30	70%	100%	30
	OCGT	30	85%	100%	30
Solar	CLFR	40	75%	100%	40
	CLFR with storage	40	75%	100%	40
	Parabolic trough	35	75%	100%	35
	Parabolic trough with storage	35	75%	100%	35
	Central Receiver	35	75%	100%	35
	Central Receiver with storage	40	75%	100%	40
Solar PV	Solar PV fixed	35	75%	100%	35
	Solar PV single axis tracking	35	75%	100%	35
	Solar PV dual axis tracking	35	75%	100%	35
Wind	On-shore Wind Farm	25	50%	100%	25
	Ocean/Wave	25	75%	100%	25
Geothermal	Geothermal HSA	40	75%	100%	40
	Geothermal EGS	40	75%	100%	40
CCS	PC Supercritical with CCS – Brown Coal	50	25%	30%	15
	PC Supercritical with CCS – Bituminous Coal	50	25%	30%	15
	PC Oxy Combustion Supercritical with CCS	50	25%	30%	15
	CCGT with CCS	45	50%	50%	23
	IGCC with CCS – Bituminous Coal	30	50%	50%	15
	IGCC with CCS – Brown Coal	30	50%	50%	15
CCS retrofit	PC Subcritical Brown Coal - Retrofit CCS	30	25%	30%	9
	PC Subcritical Black Coal - Retrofit CCS	30	25%	30%	9
	Existing CCGT with retrofit CCS	30	50%	50%	15

Source: ACIL Allen, AETA 2012

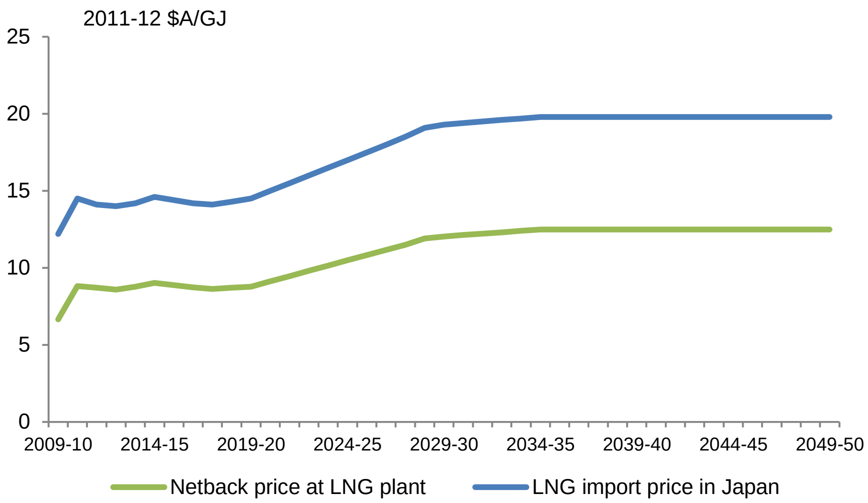
3.5 Fuel and CCS costs

3.5.1 Natural gas

Natural gas costs were based on an international landed LNG price series provided by the Treasury, which were then adjusted to a 'netback' equivalent price for each consumption location in Australia by adjusting for liquefaction and shipping costs.

The landed LNG price in Japan and the equivalent netback price at an Australian LNG plant are compared for the Central Policy scenario in Figure 5.

Figure 5 **International and netback gas price – Central Policy scenario**



Source: ACIL Allen using Treasury gas price and foreign exchange assumptions

Given the absence of operating LNG plants in eastern Australia at the present time, gas prices for power stations on the NEM and Mt Isa transitioned to the netback price series gradually, reaching parity in 2016-17. Further adjustments must be made to the netback price to represent transport cost differentials between each power station and the nearest LNG plant. For locations that are closer to some gas production centres than the nearest LNG plant, they will receive a discount to the netback price to represent the transport cost that gas producers can avoid by transporting the gas to that power station rather than to the LNG plant. Conversely, for power stations that are located further away from major production basins than the nearest LNG plant, they would need to purchase gas at a premium to the netback price to overcome the associated transport cost. This occurs in the SWIS, NWIS, DKIS and Mt Isa.

The transport differentials (constant in real terms) adopted in this study are presented in Table 10.

Table 10 **Gas transport costs (relative to nearest LNG plant)**

Region	Transport cost (real 2011-12A$/GJ)
QLD (excl. Mt Isa)	-$0.16
SA	-$0.79
NSW	-$0.84
VIC	-$1.93
TAS	-$1.44
SWIS	$1.50
NWIS	$0.44
DKIS	$0.00
Mt Isa	$0.25

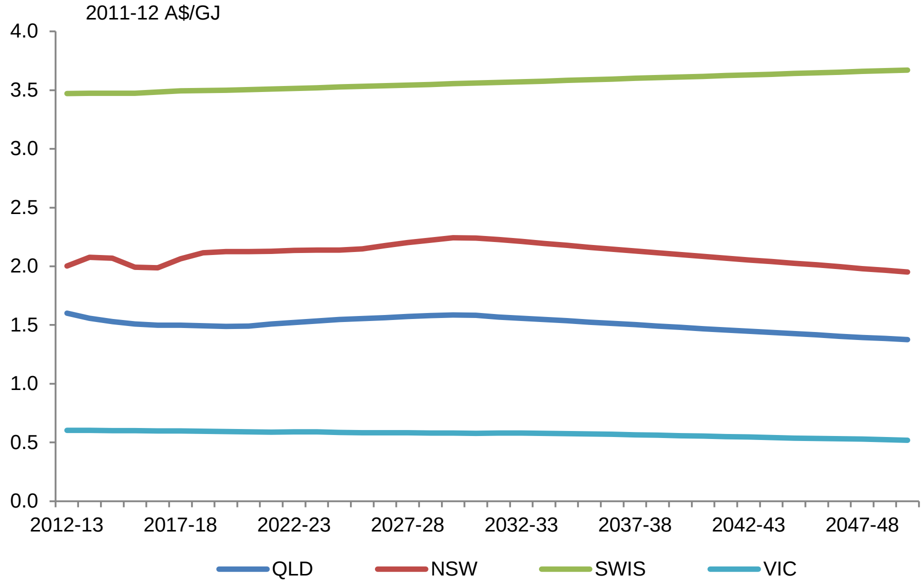
Source: ACIL Allen

The gas price in the Central Policy and No Carbon Price scenarios are essentially identical. Different gas prices were adopted in the High and Low Fuel Price sensitivities, discussed further in section 5.3.

3.5.2 Coal

Due to the variety of mine mouth coal-fired power stations in Australia, a simple 'netback' international coal prices (i.e. adjusted for international shipping costs) is not appropriate for this exercise. Accordingly, ACIL Allen adopted a range of estimates for existing and new entrant generators. The range of coal costs are best represented by the coal costs faced by new entrant generators in the four core coal generating regions, QLD, NSW, VIC and the SWIS, which are shown in Figure 6.

Figure 6 **New entrant coal prices**



Source: ACIL Allen

The coal price in the Central Policy and No Carbon Price scenarios are essentially identical. Different coal prices were adopted in the High and Low Fuel Price sensitivities, discussed further in section 5.3.

3.5.3 Carbon transport and storage costs

For plant that utilise carbon capture, transport and storage costs are applied separately. As the majority of costs related to transport and storage of CO_2 are large upfront fixed costs (pipeline construction and drilling costs), it is appropriate for these to be levied to new entrant technologies as a fixed charge rather than through variable charges. This can be done either through an addition to the capital cost or through an addition charge to the fixed O&M cost. In this modelling, these costs are incorporated as a fixed O&M cost.

Costs for CO_2 transport and storage are uncertain and highly dependent upon the scale of the development for both transmission pipelines and injection infrastructure. A larger CO_2 pipeline grid would result in significant economies of scale over a single coal-fired power station development.

ACIL Allen's assumed transport and storage costs are presented in Table 11. These assumptions have been informed by work done for the Department of Resources, Energy and Tourism Carbon Storage Taskforce in 2009.[3] Costs are assumed to remain constant in real terms over the modelling period.

Table 11 **Assumed CO_2 transport and storage costs**

Region	Real 2011-12 \$/tonne CO_2-e
NSW	30
QLD	25
SA	30
TAS	25
VIC	15
SWIS	25
NWIS	n/a
DKIS	n/a
Mt Isa	n/a

Source: ACIL Allen

3.6 Energy constrained and intermittent generation

3.6.1 Hydro

Within *PowerMark LT* the annual output of hydro stations can be constrained explicitly to desired levels.[4] Aside from run of river output which occurs independently of wholesale prices, the model will naturally schedule hydro output during high priced periods in order to minimise system production costs.

It should be recognised that hydro output does fluctuate considerably year to year and is also susceptible to drought and flood events as witnessed over the last decade. Whilst the modelling can account for changes to long-term averages, it is not typically used to predict fluctuations due to cyclical changes in weather conditions.

Output from the Snowy Mountains Hydro-electric Scheme (Snowy Hydro) has averaged around 4,000 GWh over the last 10 years. ACIL Allen assumes that over the long-term output averages 4,700 GWh with a 60/40 split between NSW and Victorian regions, which is slightly higher than the recent average reflecting prevailing drought conditions for much of the past decade. Similarly, Tasmanian hydro output has averaged approximately 8,000 GWh over the same period. The modelling assumes 9,100 GWh of output which corresponds to Hydro Tasmania's long-term assumption.

3.6.2 Wind

For wind farms, annual output is limited to capacity factors which approximate recent actual outcomes (if available) or assumed levels based on corresponding nearby operating facilities. Wind output is profiled according to 30 minute resolution wind traces for a rage of wind regimes across Australia. These wind traces are then mapped back to the sampled demand profiles in order to ensure wind output correlates properly with demand.

[3] CO2CRC Technologies, The Costs of CO_2 Transport and Injection in Australia, 2009

[4] Simulation models typically use the notion of an opportunity cost for the water which attempts to maximise the net revenue of the plant but not break the energy constraint.

3.6.3 Solar

Solar plants are also limited by annual capacity factor constraints according to the technologies capability. The only committed large-scale solar systems within the modelling are AGL Energy's 159 MW solar flagship developments in NSW and the 10 MW Greenough River project in the SWIS.[5]

ACIL Allen incorporates representative solar PV output profiles for these projects which vary by time of day and month.

Reflecting the correlated nature of solar generation, ACIL Allen also applied an aggregate solar capacity constraint in each generation region. This constraint was calculated as being equal to the expected average midday demand in each region, with this level being estimated approximately based on the ratio of midday to average demand in each region over the period 2009-2011. With this ratio held constant, the implied aggregate limit on solar generation capacity grows in proportion to average demand. This constraint typically only was binding very late in the model horizon, typically after 2040.

3.7 End of life and refurbishment

3.7.1 Retirement criteria

Existing plant may cease operating if net operating revenues from the market (revenue less variable O&M) fail to cover their overhead costs (often termed 'fixed O&M costs'.[6] The profitability of each generator can be most readily analysed by assessing its profit (revenue less variable and fixed O&M) per kW. Once this metric turns negative on a sustained basis, the station is retired regardless of its remaining technical asset life. Retirement may be staged over a number of years to avoid large single year shocks to the market and reflects gradual unit retirement.

3.7.2 Refurbishment

All generating plant have a technical design life for which an allowance of 'stay-in-business' capital expenditure is provided through annual fixed operating and maintenance costs. The fixed operating and maintenance cost assumptions however do not provide for abnormal capital expenditure required for life extension.

Design lives range from 20-30 years for wind and solar, 30 years for gas and 40+ years for coal. However, as has often been the experience in Australia, most generating plant have had operational lives extended through refurbishment programmes. Refurbishment requires a large lump of capital expenditure to refresh/upgrade various components of the power station. The decision on whether to proceed with a refurbishment is an economic one and is dependent upon the commercial outlook (present value of expected net revenues against upfront capital expenditure).

The capital costs for refurbishment will vary greatly across technologies and, often, be site specific. Therefore some simplifying generic assumptions are required.

Table 12 provides the proposed refurbishment capital costs for plant which reach the end of their stated technical life. Capital expenditure for the refurbishment is expressed as a

[5] Other smaller existing solar developments are treated as non-scheduled or embedded generation and are therefore handled outside of the *PowerMark LT* modelling.

[6] For integrated mine mouth brown coal power stations, fixed O&M costs also include mine overheads as in most cases the closure of the power station would also result in closure of the mine.

percentage of new entry costs for the same technology and results in the plant being operational beyond its technical retirement date for a set number of years. The modelling allows for more than one refurbishment so for example, a subcritical coal plant would incur a refurbishment cost every 15 years after the end of its technical retirement date. Reflecting the progressive technical deterioration of a plant, refurbishment costs were escalated by 50% of the original refurbishment cost for each subsequent refurbishment.

Table 12 **Refurbishment costs for incumbent plant**

Technology	Economic life of new plant (years)	Refurbishment cost – first refurbishment only (% of new)	Additional life (% of original life)	Additional life from refurb (years)
CCGT	30	70%	100%	30
Cogeneration	30	70%	100%	30
OCGT	30	85%	100%	30
Solar PV	35	75%	100%	35
Steam turbine	50	25%	30%	15
Subcritical pf	50	25%	30%	15
Supercritical pf	50	25%	30%	15
Wind turbine	25	50%	100%	25

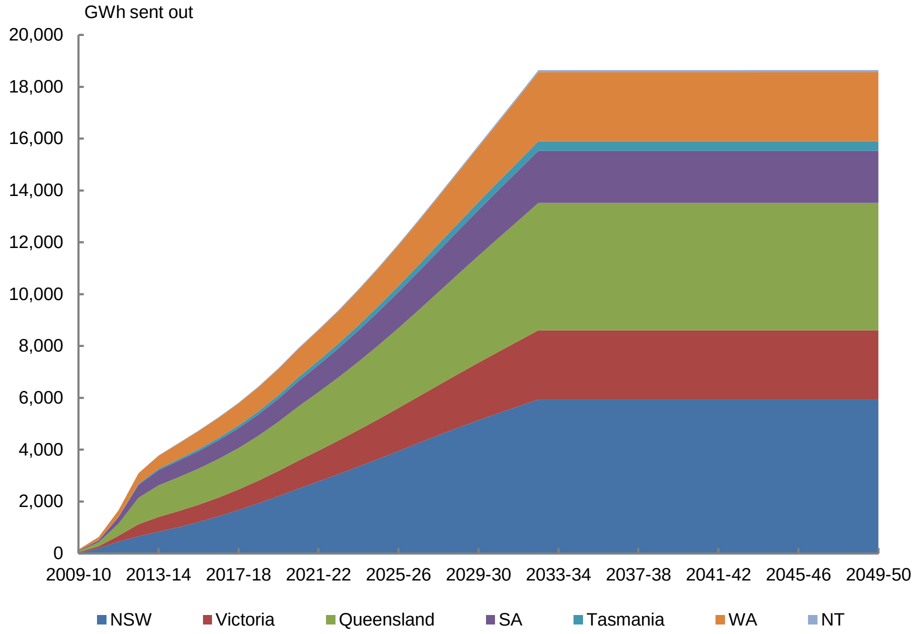
Source: ACIL Allen

3.8 Embedded and off-grid generation

In addition to electricity supplied by and emissions created by generators that are connected to the major grids of the NEM, SWIS, NWIS, DKIS and Mt Isa, ACIL Allen incorporated a range of small-scale embedded (i.e. connected to the distribution network), 'behind the meter' (i.e. connected on a customer's premises) and off-grid generation to develop a comprehensive picture of electricity sector emissions.

A key category of 'behind the meter' generation is rooftop solar, the overall level of which was estimated for the NEM and SWIS based on AEMO (2013 NEFR) and IMO (2012 forecasting study by NIEIR) forecasts. Beyond 2032-33 (the AEMO forecasting horizon) small-scale solar generation was assumed to hold constant on the assumption that if solar PV was not viable at the wholesale level at that point in time it would have reached an effective saturation point and would not be widely deployed at the small-scale level beyond that time. IMO forecasts were extrapolated to 2032-33 to match the AEMO forecasting horizon. The growth of assumed small-scale PV generation, and subsequent flat-lining, can be seen in

Figure 7 **Small-scale solar generation output assumptions**



Source: AEMO; IMO

With the exception of rooftop PV generation, all other embedded and behind the meter generation was assumed to hold constant with a static technology mix and emissions profile based on estimates of the current mix of this generation. This means that all additional generation was met either by rooftop solar generation or generation selected within the wholesale market modelling discussed above.

Off-grid generation was assumed to have a constant technology profile as the current estimated mix of off-grid generation, but to grow in proportion with the general level of demand growth in each state/territory. Whilst this static technological assumption for non-grid generation represents a stylistic simplification and could, for example, under-estimate the growth in renewable generation in off-grid applications, it only has a small effect in the context of Australia's total electricity emissions.

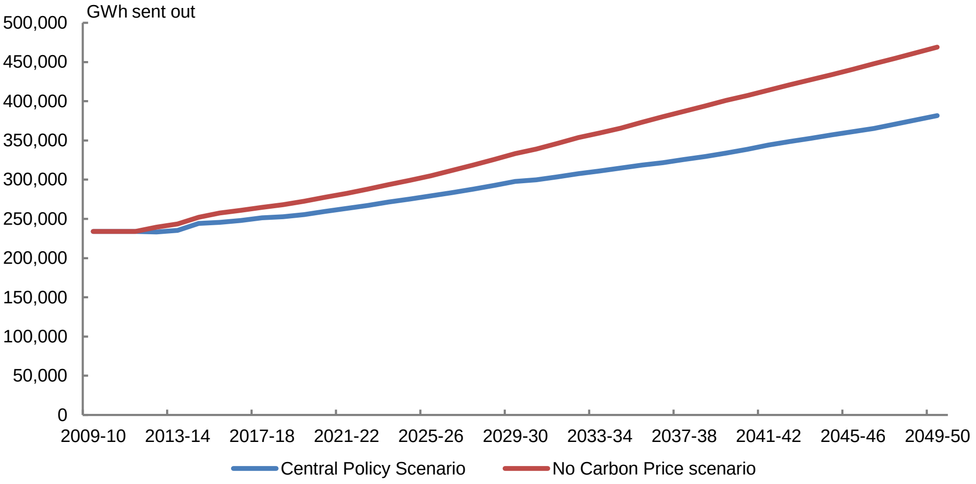
Given estimates of on-grid electricity demand and generation developed as described in section , the overall volume of embedded, behind the meter and off-grid electricity in 2011-12 was calibrated to accord with estimates of total Australian electricity output and emissions from the Australian Government's National Greenhouse Gas Inventory.

4 Policy and No Carbon Price scenario results

4.1 Demand

As discussed in section 3.1, aggregate demand assumptions vary between the Central Policy and No Carbon scenarios, based on demand growth rates modelled by the Treasury. These assumptions are presented again for completeness in Figure 8.

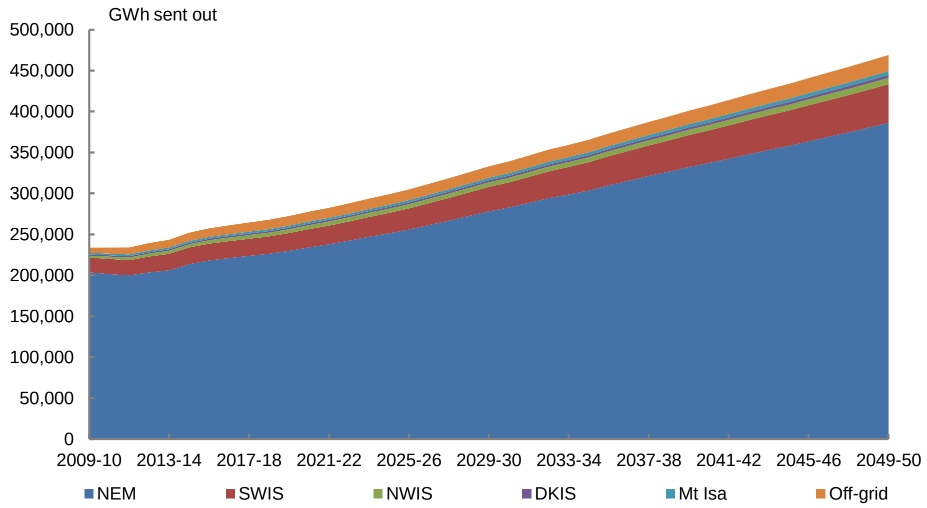
Figure 8 **Aggregate demand**



Note: Estimates include off-grid and embedded generation
Source: ACIL Allen estimates based on Treasury, AEMO, IMO and other sources.

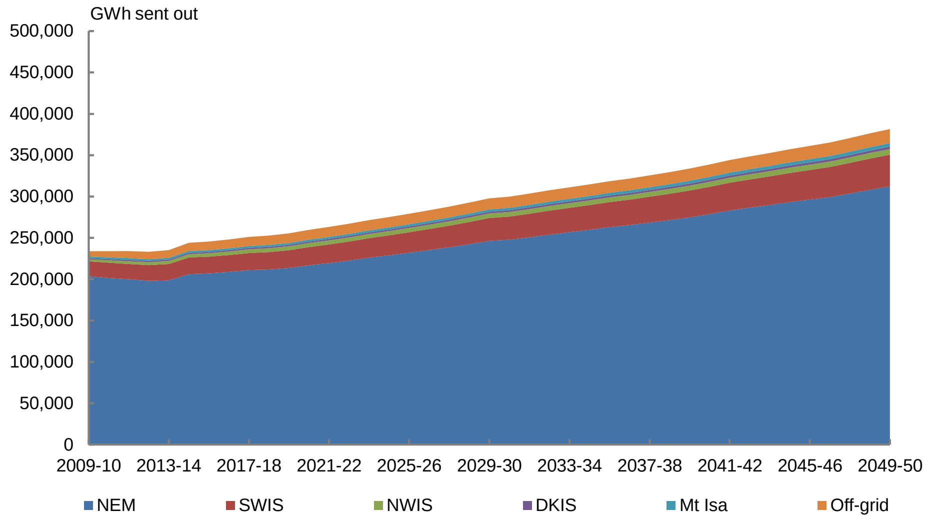
The composition of this demand can be understood more completely by analysing its composition by grid, as in Figure 9 and Figure 10.

Figure 9 **Demand by grid – No Carbon Price scenario**



Source: ACIL Allen based on Treasury, AEMO, IMO and other sources

Figure 10 **Demand by grid – Central Policy scenario**



Source: ACIL Allen based on Treasury, AEMO, IMO and other sources

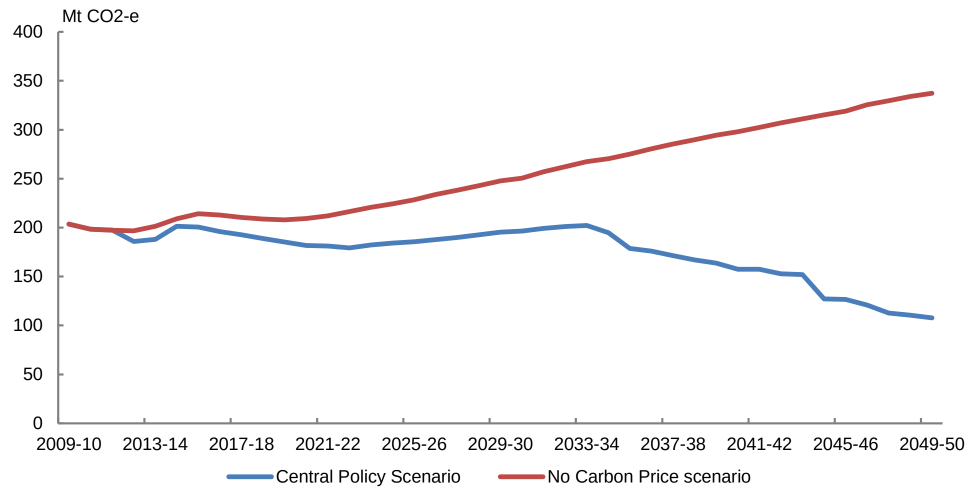
4.2 Emissions and generation outcomes

The introduction of a carbon price in the Central Policy scenario results in a substantial reduction in emissions relative to the No Carbon Price scenario, as illustrated in Figure 11. In both scenarios, emissions are relatively flat in the period to around 2020, due to muted demand growth and increasing penetration of large-scale renewables and rooftop solar generation. However, the path of emissions increasingly diverges from that point as demand growth and ongoing use of coal-fired generation sees substantial growth in emissions in the No Carbon Price scenario. Emissions rise from just over 200 Mt CO_2-e to 248Mt CO_2-e in 2029-30, and 337 Mt CO_2-e in 2049-50.

By contrast, emissions in the Central Policy scenario are essentially flat to 2029-30, reaching 195 Mt CO_2-e in that year (53Mt CO_2-e lower than the No Carbon Price scenario) as the carbon price motivates a move towards lower-emissions generators, offsetting the effect of (slowly) growing electricity demand.

After 2029-30, particularly from around 2033-34, the scenarios diverge even more dramatically. Emissions under the Central Policy scenario reduce substantially as the higher carbon price and reductions in costs for technologies such as solar PV motivate large-scale adoption of low emissions generation technologies. The associated reduction in the emissions-intensity of electricity supply sees Australia's electricity sector emissions reduce to 108 Mt CO_2-e by 2049-50, or around 229 Mt CO_2-e lower than in the No Carbon Price scenario.

Figure 11 **Aggregate emissions – No Carbon Price and Central Policy scenarios**



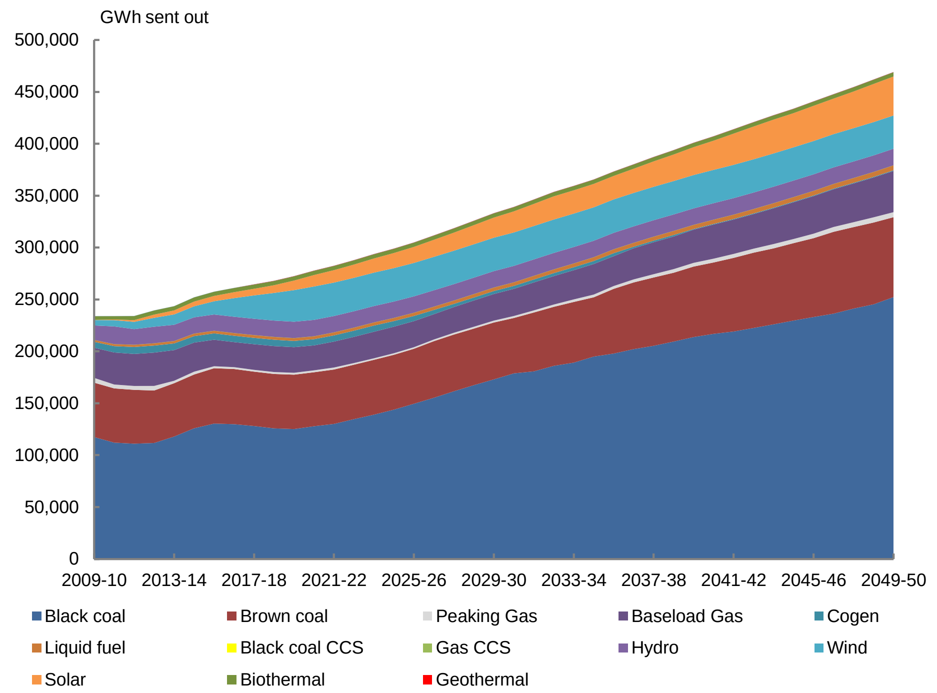
Source: ACIL Allen

The carbon price has two key effects on emissions. Firstly, it reduces electricity demand relative to the No Carbon Price scenario (see Figure 8). Secondly, and in the long-run more significantly, it changes the mix of generation technologies employed towards lower-emissions technologies. Whereas in the No Carbon Price scenario the ongoing growth in electricity demand is largely met by coal-fired generation, in the Central Policy scenario gas, wind, solar, geothermal and CCS technologies are employed to a greater extent. This occurs because the carbon price changes the relative price of high- and low-emissions technologies, encouraging substitution towards the latter.

This can be seen by examining the generation trends by fuel type in the No Carbon Price and Central Policy scenarios separately.

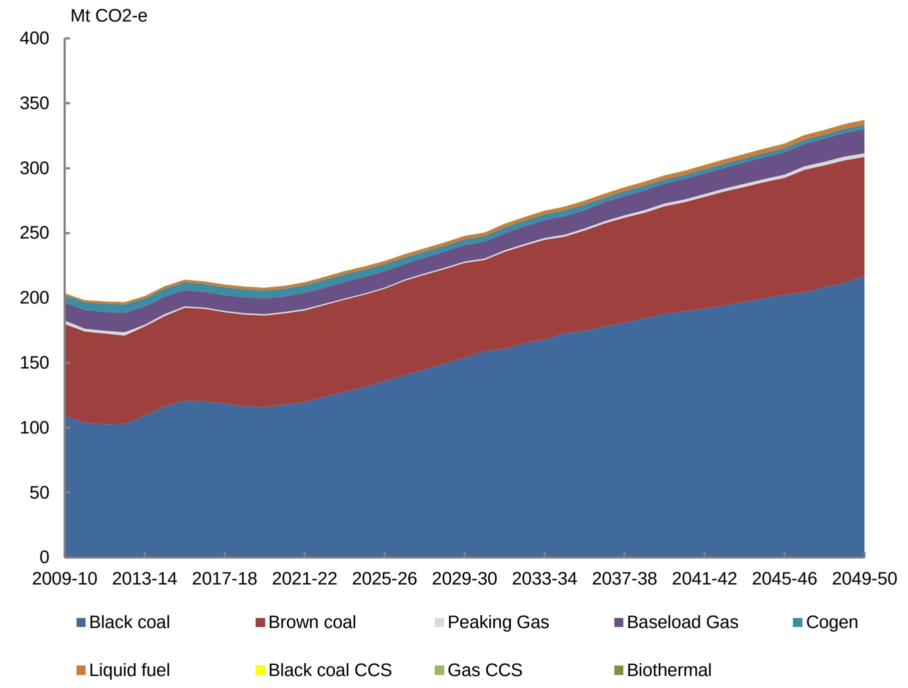
As Figure 12 shows, the predominant trend in generation in the No Carbon Price scenario is ongoing growth in black and brown coal. Whilst growth in wind occurs until around 2020, and there is some growth in solar (largely rooftop) generation, the technology shares remain largely unchanged from the initial supply mix. This in turn implies growing emissions, as shown in Figure 13 (by fuel) or Figure 14 (by major grid).

Figure 12 **Generation by fuel type – No Carbon Price scenario**



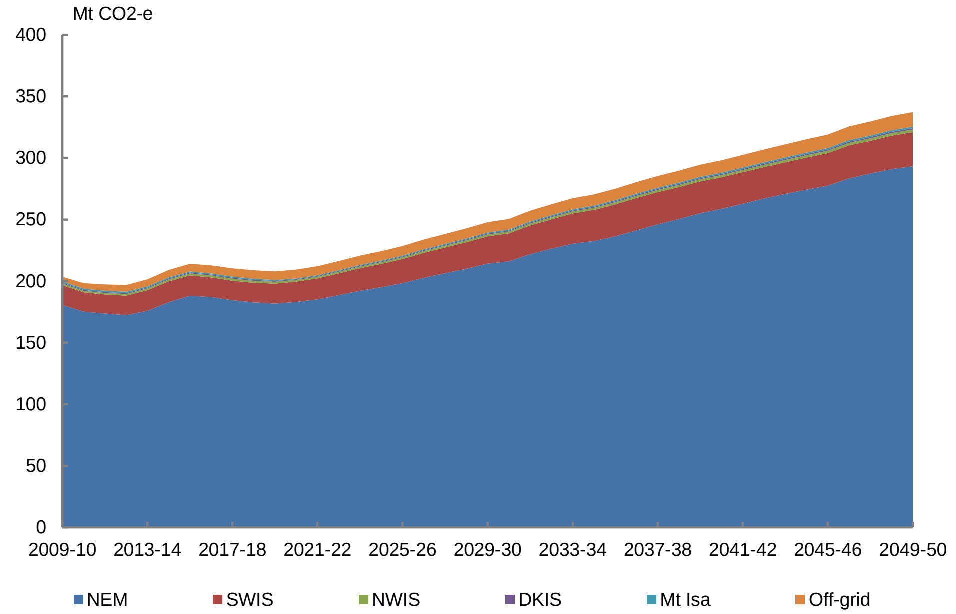
Source: ACIL Allen

Figure 13 **Emissions by fuel type – No Carbon Price scenario**



Source: ACIL Allen

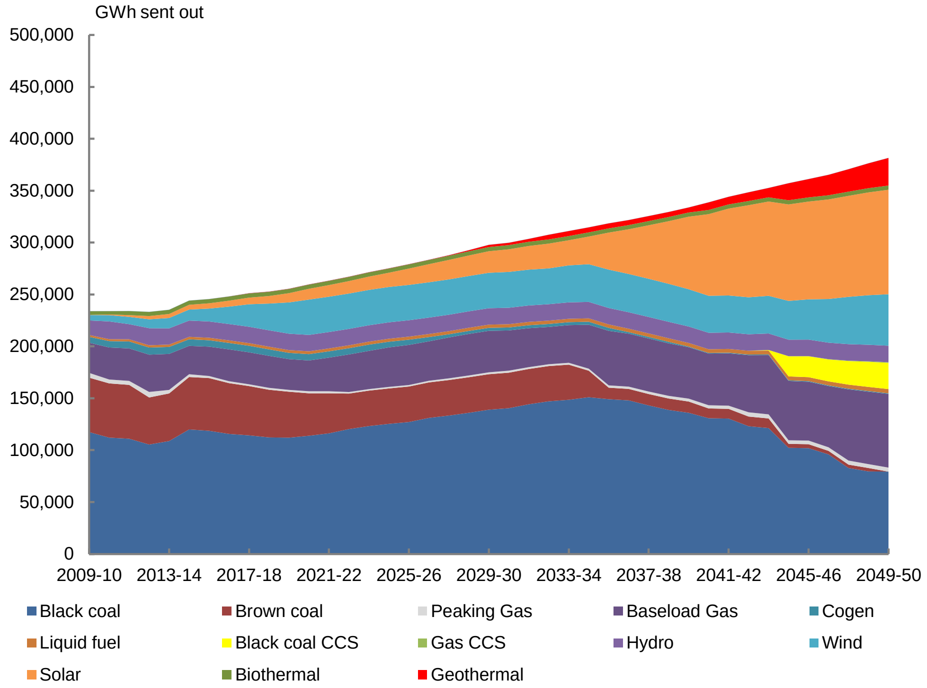
Figure 14 **Emissions by grid – No Carbon Price scenario**



Source: ACIL Allen

By contrast, the Central Policy scenario sees a growing share for baseload gas generation (consisting of new CCGT generation and some incumbent gas plant) after 2019-20, and substantial growth in both wind (up to 2019-20) and solar (after 2034-35). Wind continues to grow beyond the levels required to satisfy the LRET, driven by rising wholesale prices and ongoing cost reductions. Solar initially grows predominantly through rooftop installations, but beyond 2030 dramatic cost reductions see it meet a large share of demand through the wholesale market. Geothermal generation also takes an increasing share of supply, particularly beyond 2040. These trends are illustrated in Figure 15.

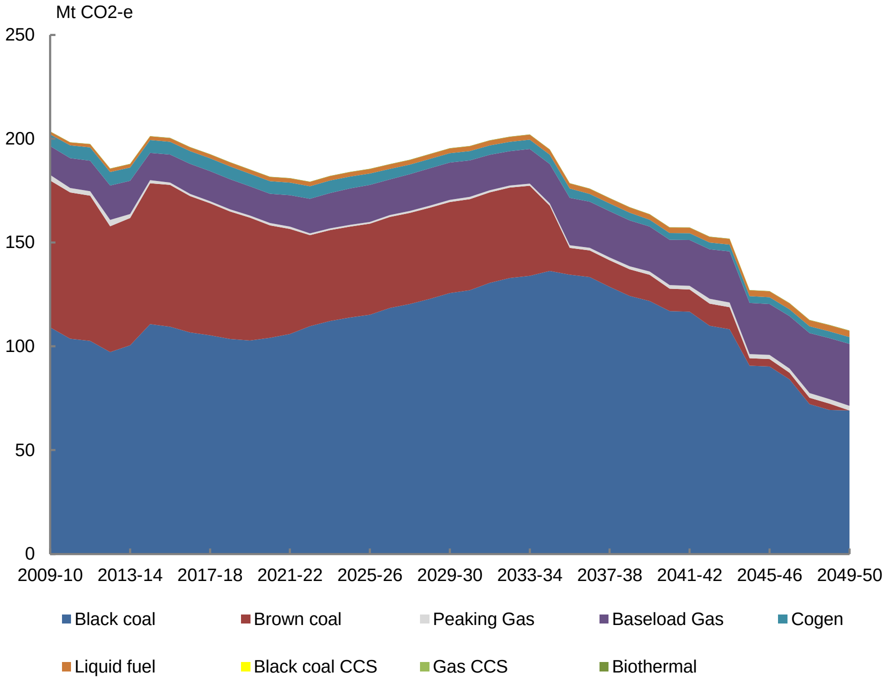
Figure 15 **Generation by fuel type – Central Policy scenario**



Source: ACIL Allen

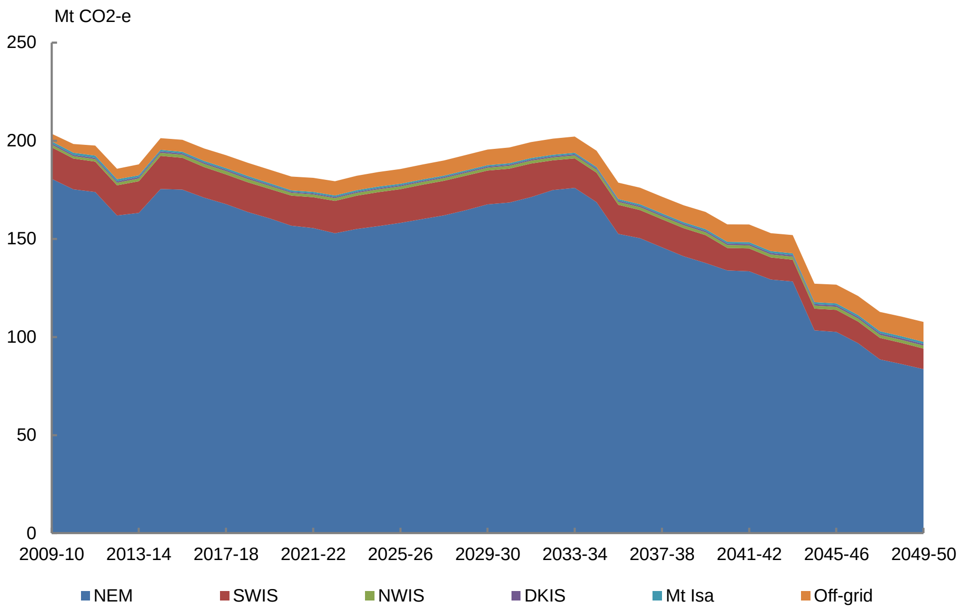
Broadly, this scenario illustrates three distinct periods in terms of emissions trends. Initially, flat electricity demand and the requirements of the LRET cause a slight decline in aggregate emissions, until the early 2020s. For approximately the subsequent decade, the influence of the LRET reduces (as its target is fully met) and the carbon price is insufficient to significantly change the supply mix, resulting in a slight increase in emissions. However, commencing around 2033-34, emissions begin rapidly declining due to increases in baseload gas and solar generation, with wind, black coal with CCS and geothermal also making smaller contributions to the emissions reduction task. This pattern is illustrated in Figure 16 (with emissions broken down by fuel) and Figure 17 (with emissions broken down by grid).

Figure 16 **Emissions by fuel type – Central Policy scenario**



Source: ACIL Allen

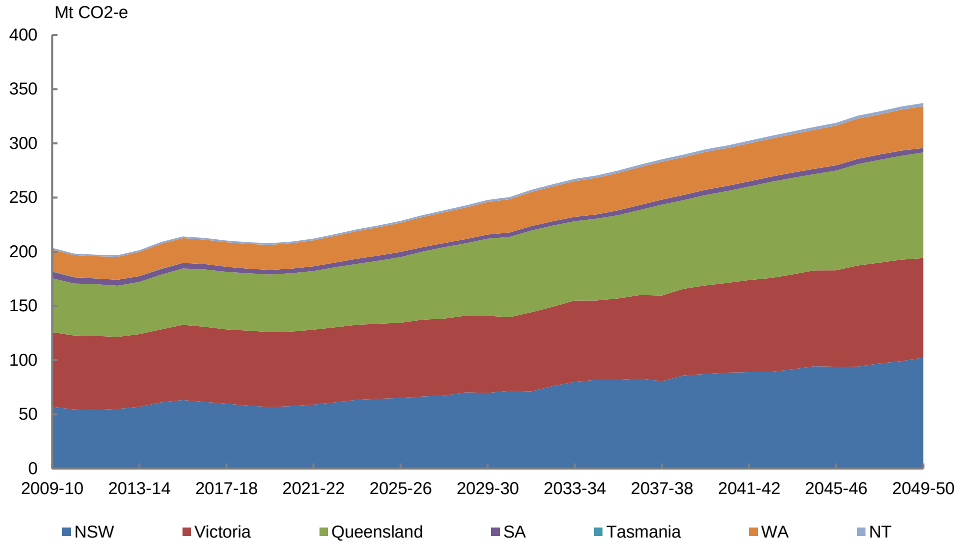
Figure 17 **Emissions by grid – Central Policy scenario**



Source: ACIL Allen

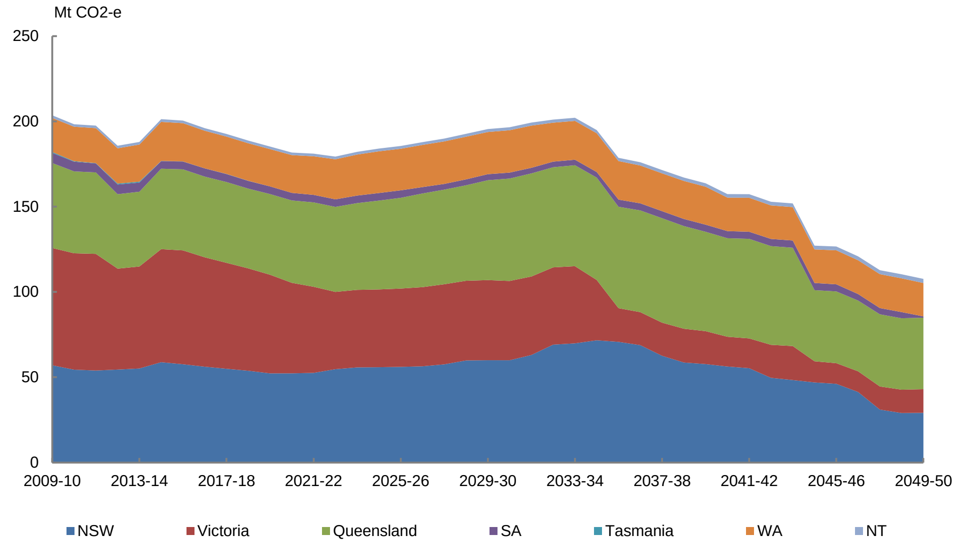
Figure 18 and Figure 19 illustrate the emissions trends by state in the No Carbon Price and Central Policy scenarios respectively. In the No Carbon Price scenario emissions in each state grow broadly in proportion to each other, reflecting the relatively stable supply mix in each state. By contrast the Central Policy scenario sees a dramatic reduction in Victorian emissions, particularly from 2033-34, as high emissions brown coal generation is displaced by lower emissions alternatives.

Figure 18 **Emissions by state – No Carbon Price scenario**



Source: ACIL Allen

Figure 19 **Emissions by state – Central Policy scenario**

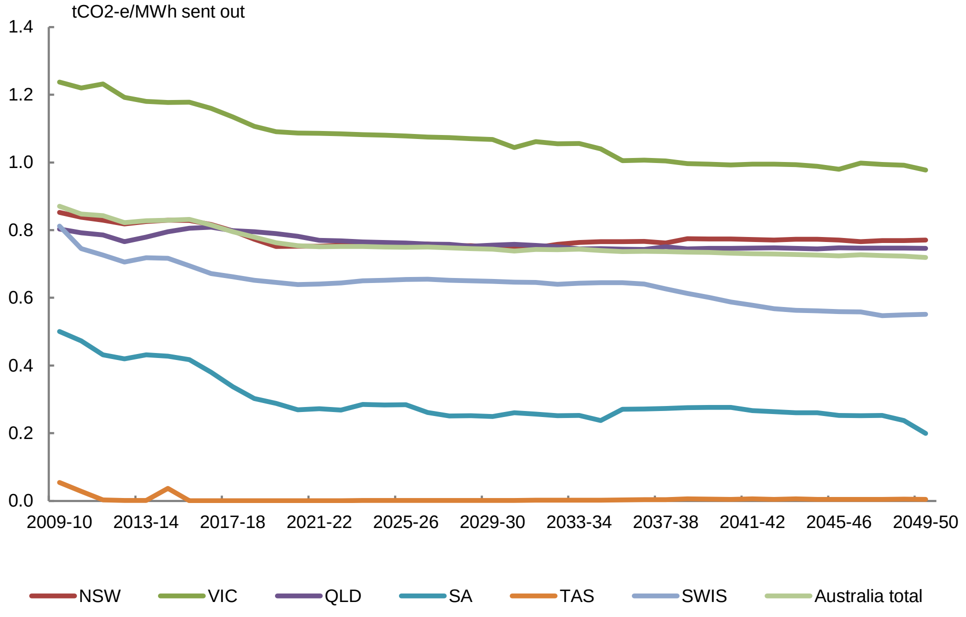


Source: ACIL Allen

A further illustration of the drivers of differences in emissions between the scenarios can be seen by examining trends in emissions intensity. Figure 20 and Figure 21 demonstrate these trends (on a 'sent out' basis) for each state, for the No Carbon Price and Central Policy scenarios respectively. In the No Carbon Price scenario there is an initial decline in most states, due predominantly to growth in renewable generation under the LRET and growth in rooftop solar. Further, new entrant thermal (fossil fuel fired) generators are generally more efficient than the incumbent plant, working to reduce emissions over time. However, this slight decline in emissions intensity largely stops by the mid-2020s, meaning that demand growth after this time directly translates into emissions growth.

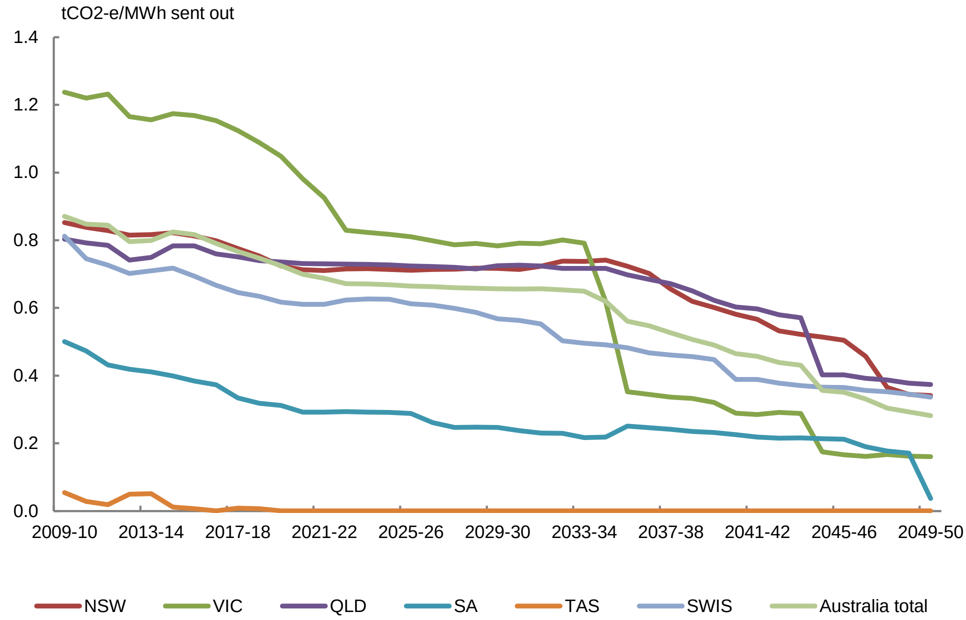
Conversely, the Central Policy scenario sees more consistent and substantial declines in emissions intensity. Initially, trends are similar to the No Carbon Price scenario, except there is a more substantial decline in Victoria as the least efficient and most emissions-intensive brown coal generators lose market share, reinforcing the effect of the LRET and rooftop solar. Importantly, the Central Policy scenario also sees a dramatic decline from around 2033-34 onwards as gas, solar, wind, geothermal and CCS generation begin to displace traditional coal-fired generation. In particular, there is a dramatic fall in the emissions intensity of generation in Victoria as the remaining brown coal generators retire and are replaced with lower emissions sources.

Figure 20 **Emissions intensity by state (sent out) – No Carbon Price scenario**



Source: ACIL Allen

Figure 21 **Emissions intensity by state (sent out) – Central Policy scenario**



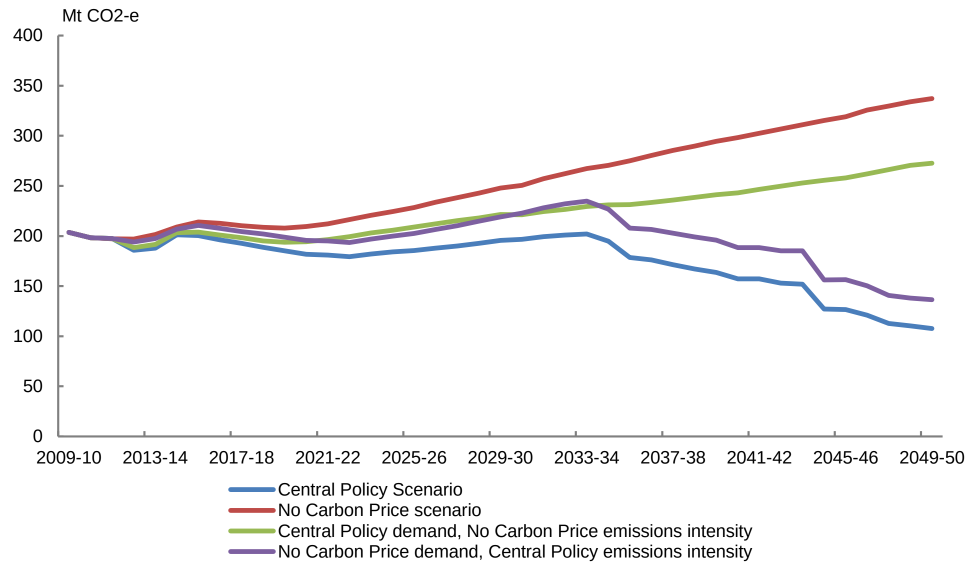
Source: ACIL Allen

The relative effects of differences in demand across the scenarios and of changes in the supply mix and emissions intensity can be examined through counter-factual simulations. Specifically, Figure 22 below augments the previously presented Figure 11 by adding two counter-factuals: a simulation where electricity demand grows as in the No Carbon Price scenario, but emissions intensity changes in line with the Central Policy scenario; and a simulation where demand grows along the lower Central Policy scenario path, but emissions intensity is the same as in the No Carbon Price scenario.

These counter-factuals illustrate broadly that demand reductions and changes in the supply mix have an effect of similar magnitude in the early decades of the simulation. However, from around 2033-34, the carbon price begins to have a dramatic effect on the supply mix and results in a substantial fall in emissions intensity. It is this effect which dominates the long-run emissions trajectory under the Central Policy scenario. Conversely, in the simulation where emissions intensity is held the same as in the No Carbon Price scenario emissions grow in absolute terms through the 2030s and 2040s resulting in emissions substantially above today's level.

Readers should interpret the results of these simulations with caution as the rate of demand growth affects the rate of investment in new generation and hence the emissions intensity of the generation mix. Hence the two trends are, in practice, inter-related. Nevertheless, disaggregating the two effects here can illustrate the broad demand- and supply-side effects of a carbon pricing mechanism in a stylistic way.

Figure 22 **Emissions trends under core scenarios and with counter-factual simulations**

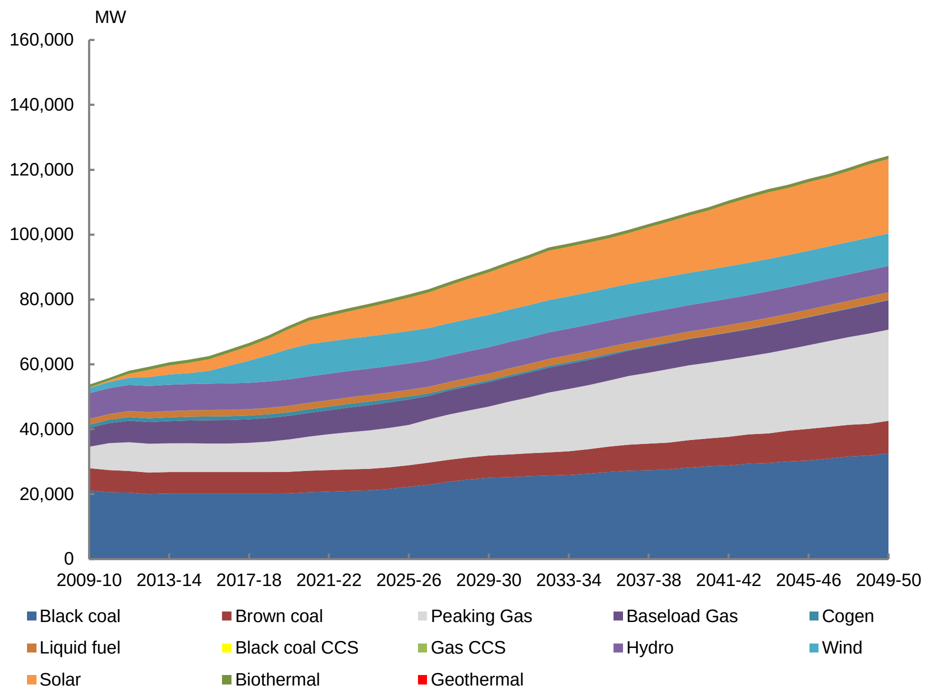


Source: ACIL Allen

4.3 Investment and capacity

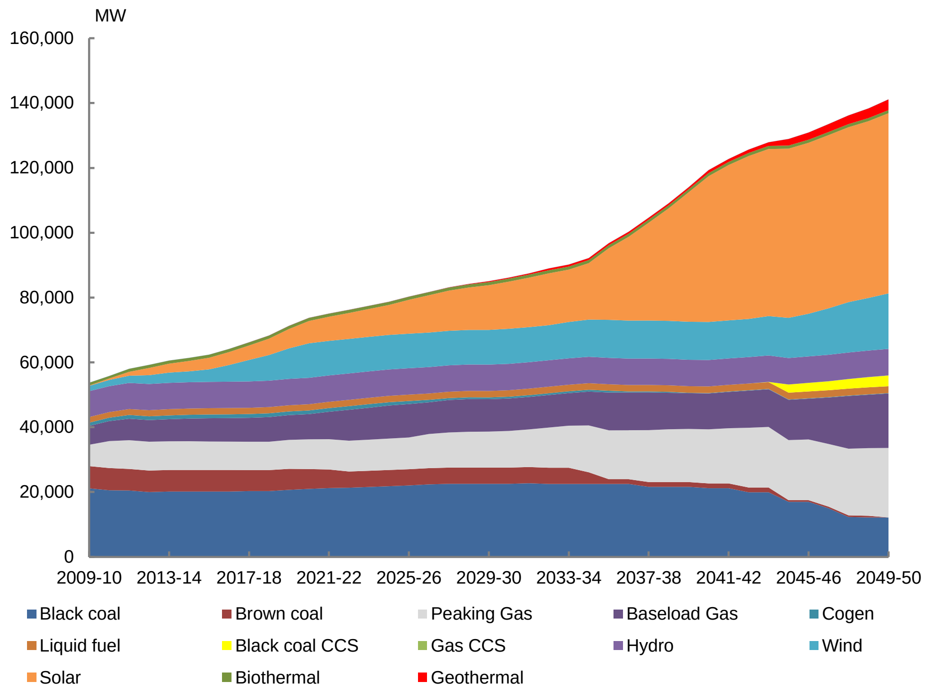
Reflecting the trends in generation described in Section 4.1, Figure 23 and Figure 24 illustrate the share of installed capacity in the No Carbon Price and Central Policy scenarios respectively. Coal and gas retain a dominant share of generation capacity in the No Carbon Price scenario, although wind and solar achieve significant penetration increases by the end of the model horizon. However, given the low capacity factors of peaking gas, wind and solar in particular, their capacity shares greatly over-state their contribution to overall output, as can be seen through a comparison with Figure 12. By comparison, the Central Policy scenario sees a gradual decline in coal capacity, with small increases in peaking and baseload gas capacity, and dramatic increases in solar capacity. In both scenarios the growth in wind capacity occurs primarily prior to 2020 in response to the LRET policy, although there is some ongoing growth in wind later in the model horizon under the Central Policy scenario.

Figure 23 **Generation capacity – No Carbon Price scenario**



Note: Generation capacity presented on same scale as Central Policy scenario for clarity.
Source: ACIL Allen

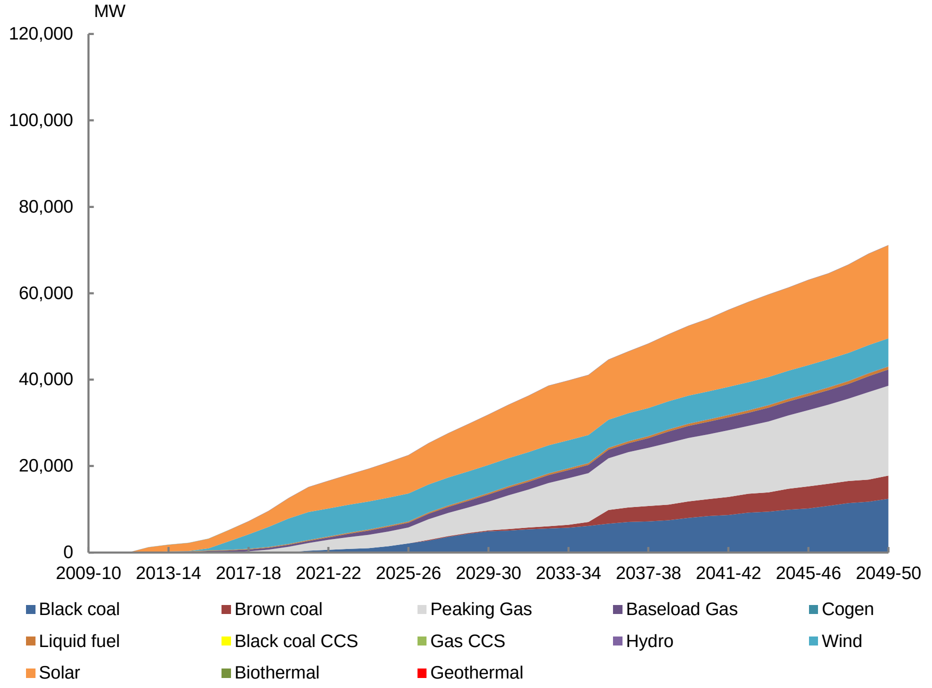
Figure 24 **Generation capacity – Central Policy scenario**



Source: ACIL Allen

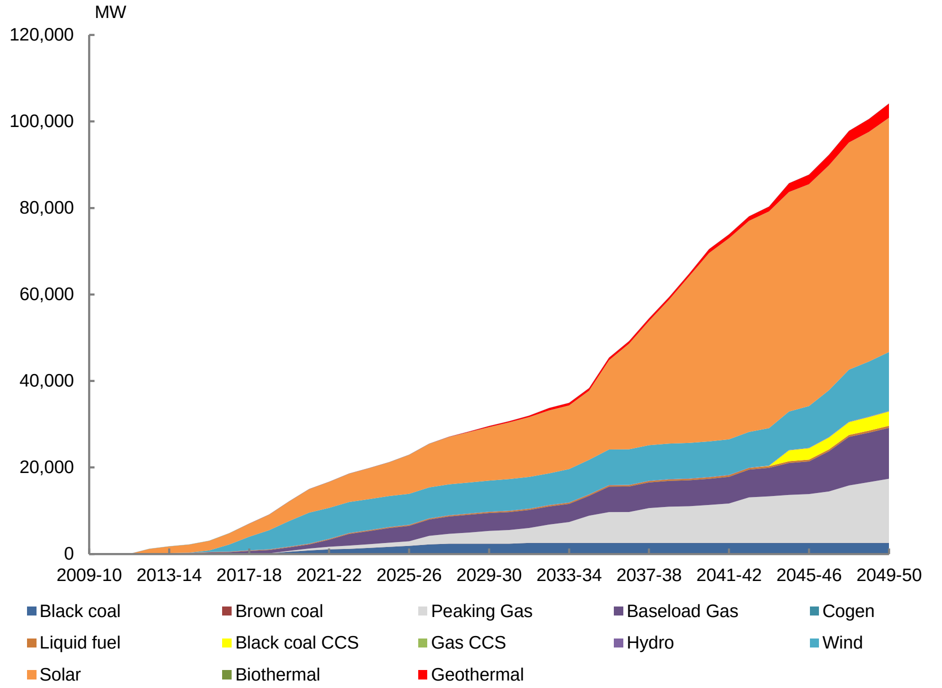
Changes in generation capacity can be more readily analysed by looking at newly installed generation capacity, this being any capacity selected by the model as opposed to being included in the model to represent specific existing or committed generators. Figure 25 shows that while solar represents a surprisingly large share of installed capacity, there is ongoing growth in both brown and black coal generation under the No Carbon Price scenario. Peaking gas also grows strongly in that scenario. By contrast, Figure 26 sees only very low (approximately 2,500 MW) volumes of black coal installation, with greater volumes of baseload gas, wind and, particularly, solar. Over the period from 2033-34 to 2049-50 there is remarkable growth in solar capacity in the Central Policy scenario, from around 15,000 MW to over 50,000 MW.

Figure 25 **Installed generation capacity – No Carbon Price scenario**



Note: 'Installed' generation capacity refers to new generation capacity that was selected by the model rather than being included in the model to represent actual operating or committed generation plant. Installed capacity presented on the same scale as for the Central Policy scenario for clarity.
Source: ACIL Allen

Figure 26 **Installed generation capacity – Central Policy scenario**



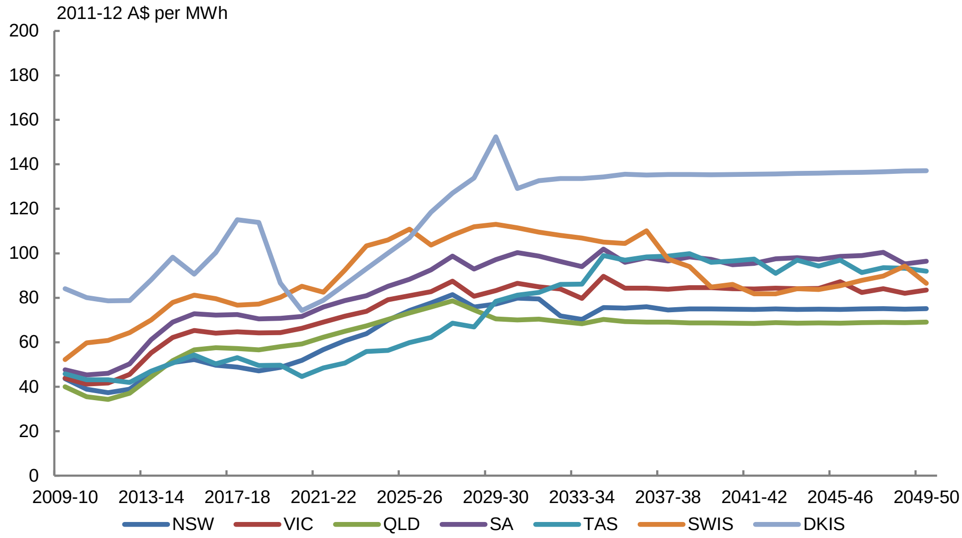
Note: 'Installed' generation capacity refers to new generation capacity that was selected by the model rather than being included in the model to represent actual operating or committed generation plant
Source: ACIL Allen

4.4 Electricity prices

This modelling included analysis of electricity price trends with and without a carbon price at both the wholesale and retail level.

Figure 27 and Figure 28 illustrate wholesale price trends in the No Carbon Price and Central Policy scenario respectively. As can be seen, the prices in the No Carbon Price scenario stabilise in the long-run reflecting relatively stable costs of new entrant thermal generation technologies. Queensland has the cheapest (black coal) new entrant, and hence lower electricity prices than NSW, Victoria and other NEM regions. The Northern Territory has the highest prices, reflecting the absence of coal new entry to compete with gas, which is in turn means that rising gas prices flow through into wholesale electricity prices. The fall in electricity prices in the NT around 2020 reflects the emergence of efficient new entrant CCGT generation with lower costs than the incumbent plant. However, costs and prices subsequently rise with gas prices. The late decline in prices in the SWIS reflects the emergence of competitive solar generation.

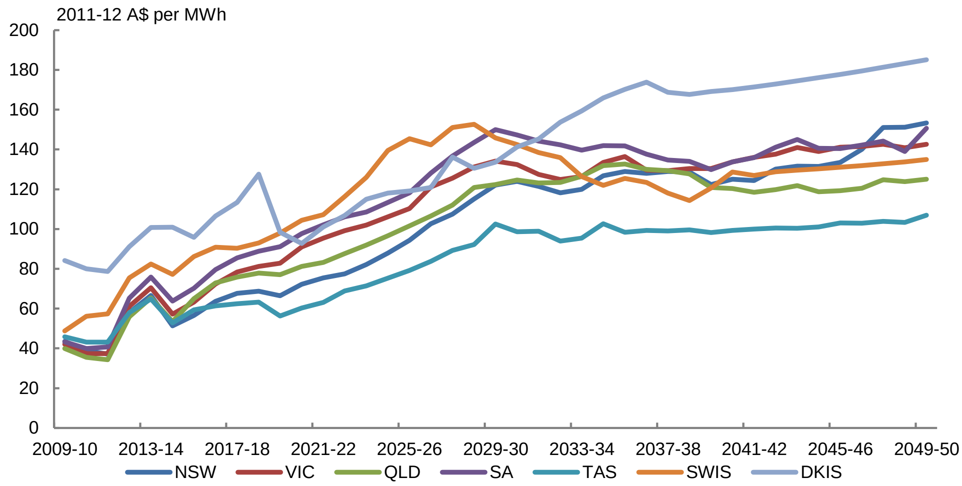
Figure 27 **Wholesale electricity prices – No Carbon Price scenario**



Note: Wholesale prices presented on the same scale as for the Central Policy scenario for clarity.
Source: ACIL Allen

The price path in the Central Policy scenario involves higher initial increases in most regions as the carbon price is passed through into wholesale generation costs. However, in the longer-run, the wholesale price stabilises around a level determined by a mix of low emissions new entrants. In most regions this is a combination of solar, a relatively low cost 'non-intermittent' technology and some flexible gas-fired generation: in Victoria and the SWIS the low cost non-intermittent technology is geothermal, whilst in Queensland it is black coal with CCS. NSW relies on interconnection with other regions to complement increasing solar generation. SA employs a combination of solar, wind, gas-fired generation and interconnection with Victoria. NT is heavily reliant on gas-fired generation to complement intermittent solar generation, and therefore sees electricity prices continue to rise as gas and carbon prices rise.

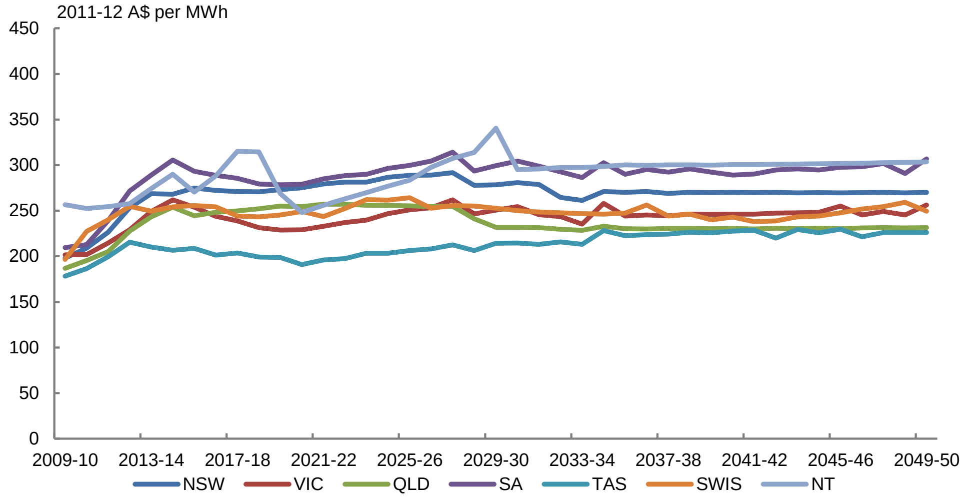
Figure 28 **Wholesale electricity prices – Central Policy scenario**



Source: ACIL Allen

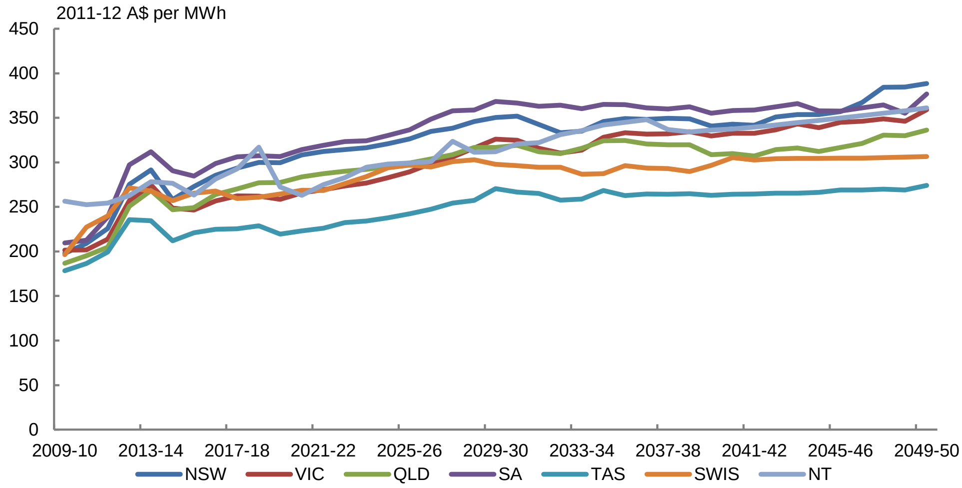
Figure 29 and Figure 30 illustrate retail electricity price trends for residential customers. These prices include a range of components other than the wholesale costs described above, including a load shape and hedging component that reflects the volatile and positively price-correlated nature of residential demand, network costs (which are generally a greater portion of residential retail tariffs than wholesale costs), green scheme costs (principally the LRET and SRES, but also GGAS, QGAS and 'white certificate' energy efficiency schemes in Victoria, NSW and South Australia) and retail operating costs. With these other cost components, residential retail electricity tariffs tend to be relatively stable in both scenarios, and the difference between the two (driven by the carbon price) generally increases over time but rarely exceeds 40% (see Figure 31).

Figure 29 **Residential retail electricity prices – No Carbon Price scenario**



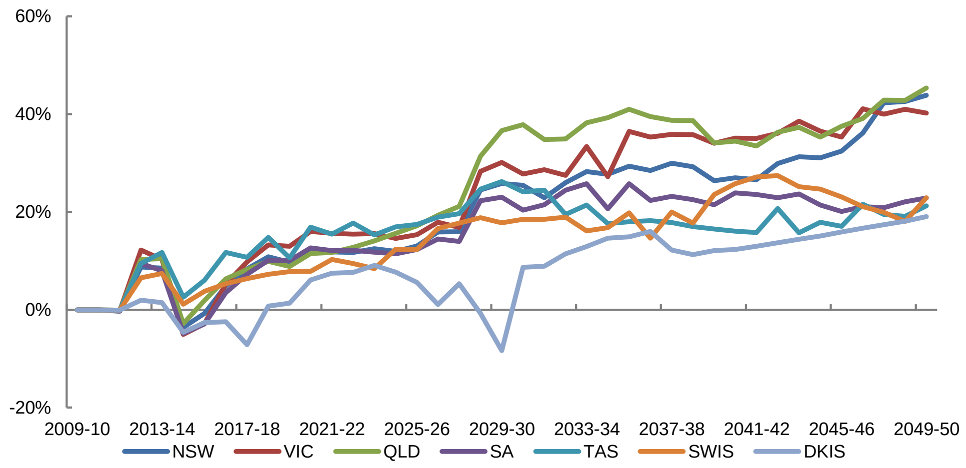
Source: ACIL Allen

Figure 30 **Residential retail electricity prices – Central Policy scenario**



Source: ACIL Allen

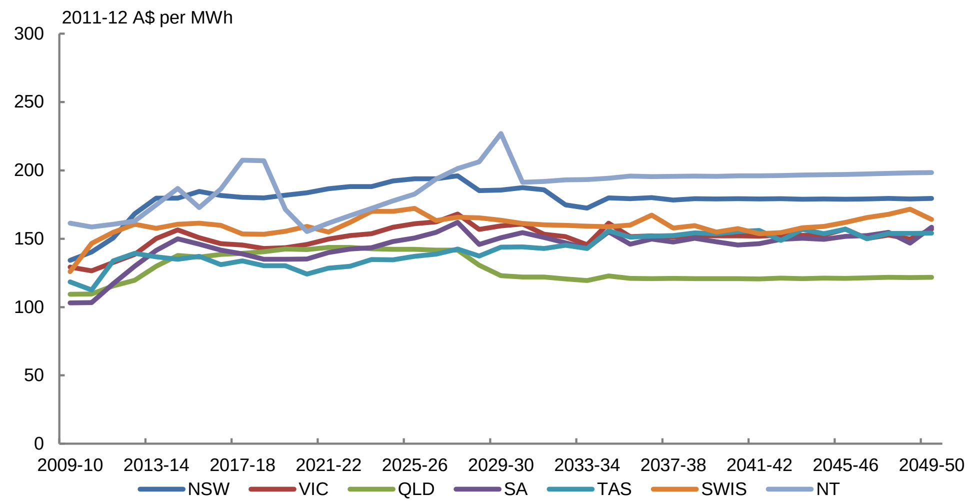
Figure 31 **Percentage change in residential retail tariffs – No Carbon Price scenario to Central Policy scenario**



Source: ACIL Allen

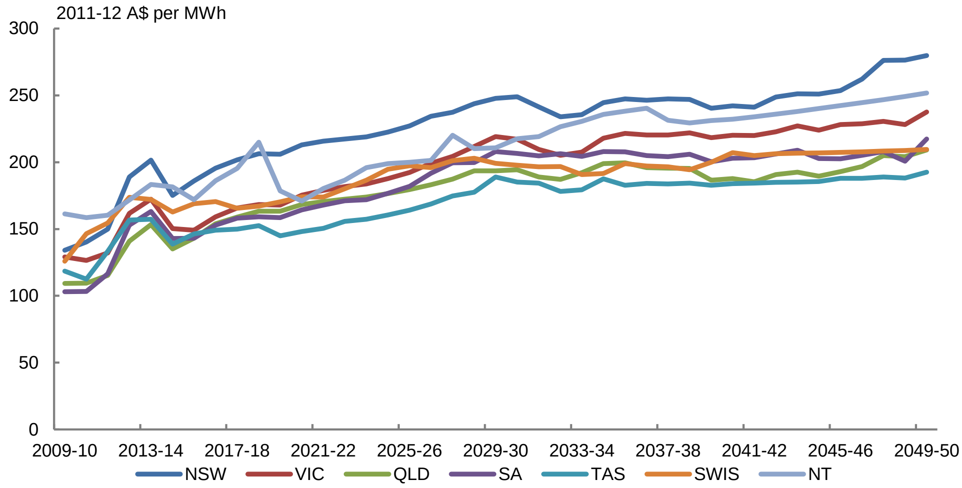
Figure 32 and Figure 33 present retail electricity tariffs (inclusive of wholesale, network, green scheme and retail cost components) for an indicative industrial electricity consumer. These prices are typically lower than for residential users as larger energy users typically pay lower network charges (due to receiving electricity at higher voltages) and have 'flatter' load shapes that are less correlated with price spikes in the wholesale market. The industrial users modelled here are not assumed to receive any partial exemptions from the LRET or any specific assistance to offset the effect of the carbon price on their electricity prices.

Figure 32 **Industrial customer electricity prices – No Carbon Price scenario**



Note: Industrial customers have a great variety of load profiles and network charges, and therefore the series presented here is a stylised price indicative of an industrial customer.
Source: ACIL Allen

Figure 33 **Industrial Customer electricity prices – Central Policy scenario**



Note: Industrial customers have a great variety of load profiles and network charges, and therefore the series presented here is a stylised price indicative of an industrial customer.

Source: ACIL Allen

5 Scenario and sensitivity results

To test the effect of key assumptions on Australia's electricity sector emissions, a range of scenarios and sensitivities were modelled. These were:

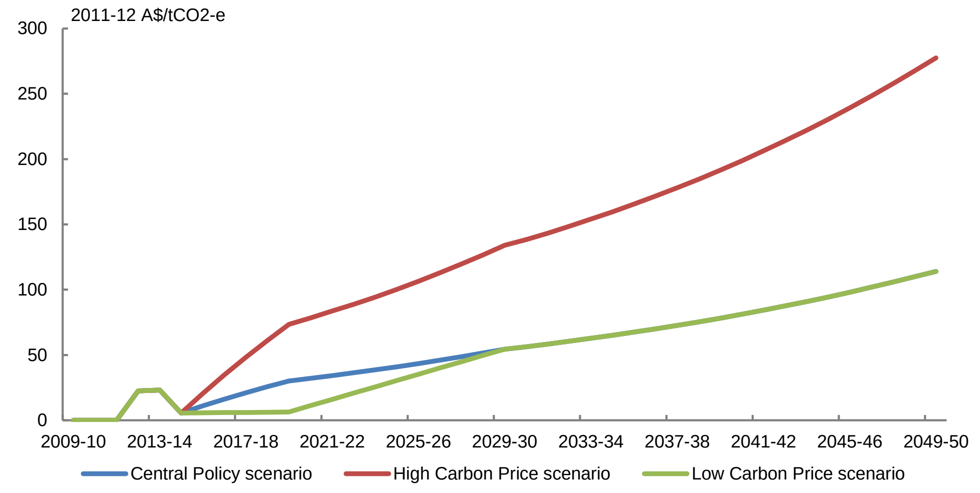
- High and Low Carbon Price scenarios
- High and Low Demand sensitivities
- High and Low Fuel Price (coal, gas and liquid fuel) sensitivities
- Sensitivities with higher and lower rates of technological improvement and capital cost reductions for key low emissions technologies (the Fast Technological Improvement and Slow Technological Improvement sensitivities)
- Sensitivities where CCS and geothermal technologies were excluded from the modelling (the No CCS, No Geothermal and No CCS or Geothermal sensitivities).

The key assumption changes for these scenarios and sensitivities are described in the relevant sections below. The two carbon price scenarios adopted scenario specific modelling assumptions from Treasury's CGE modelling. This occurs because the changes in international abatement ambition that generate the different carbon prices also cause international and Australian economic parameters to vary, and these changes then flow through to fuel prices, electricity demand, exchange rates and labour costs. By contrast the sensitivities left all assumptions identical with the Central Policy scenario other than the assumptions targeted by that sensitivity.

5.1 High and Low Carbon Price scenarios

The High and Low Carbon Price scenarios utilise carbon price trajectories derived from CGE modelling undertaken by the Treasury. The High Carbon Price scenario represents a scenario where slower rates of technological improvement and higher emissions targets drive abatement costs and carbon prices substantially higher than in the Central Policy scenario, whilst the reverse occurs in the Low Carbon Price scenario. The relevant carbon price trajectories are shown in Figure 34.

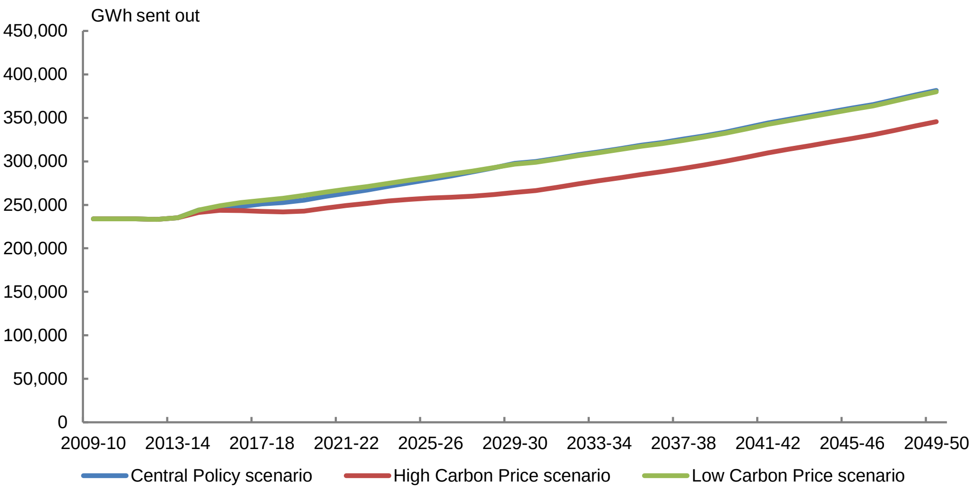
Figure 34 **Carbon price assumptions**



Source: Treasury

Aggregate electricity demand also changes between the scenarios, as illustrated in Figure 35, with only very limited differences between the Policy and Low Carbon Price scenarios, and a substantial drop in the High Carbon Price scenario.

Figure 35 **Aggregate demand – carbon price scenarios**

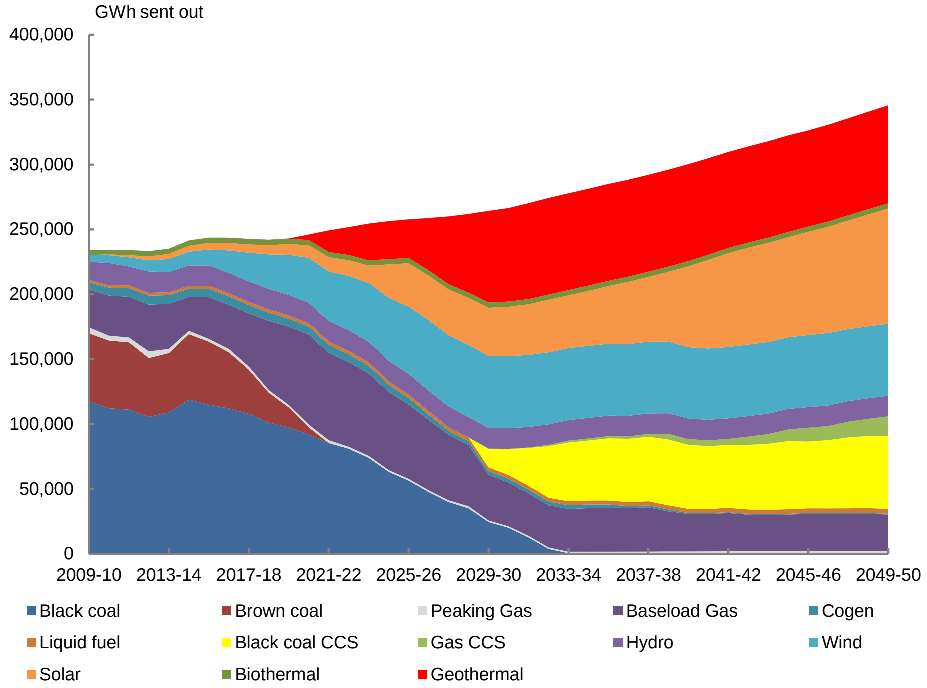


Source: ACIL Allen based on Treasury electricity demand growth rates

As is shown in Figure 36 and Figure 37, the difference in carbon price assumptions drives substantial differences in the generation mix between the carbon price scenarios. In general, the High Carbon Price scenario demonstrates, relative to the Low Carbon Price scenario:

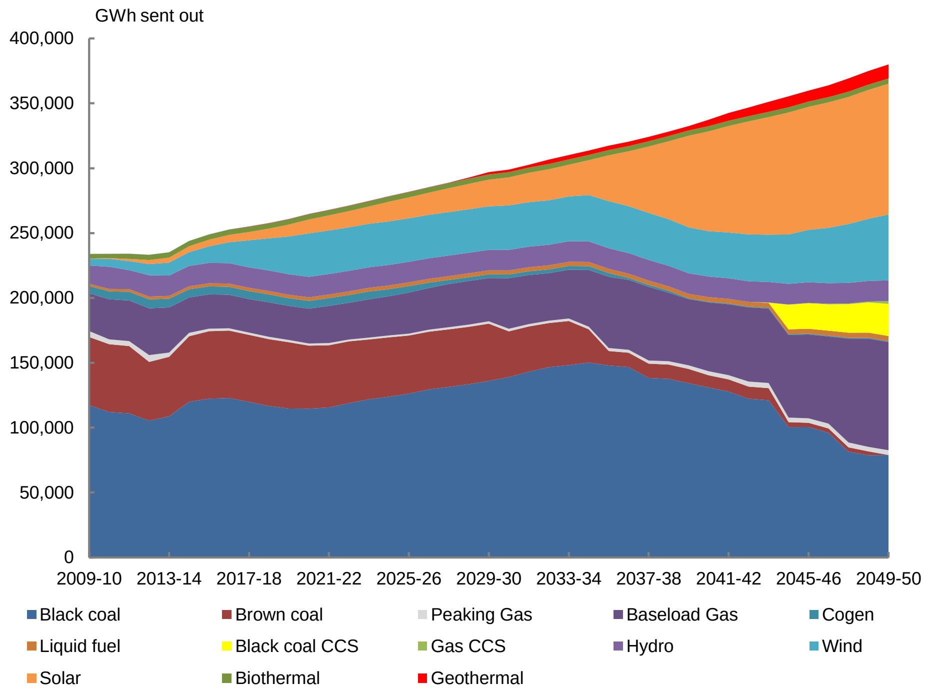
- An earlier and sharper drop off in coal-fired generation
- Earlier growth in gas-fired generation, followed by a lower level later in the model horizon
- Substantially higher levels of geothermal and CCS generation
- Earlier growth in solar generation, albeit to slightly lower ultimate levels (due to solar being displaced by other low-emissions technologies)
- Slightly higher levels of wind generation.

Figure 36 **Generation by fuel type – High Carbon Price scenario**



Source: ACIL Allen

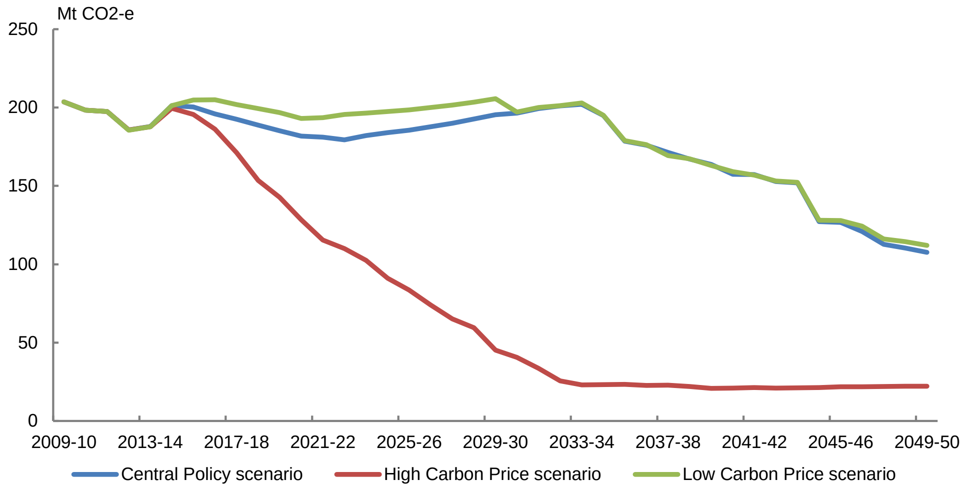
Figure 37 **Generation by fuel type – Low Carbon Price scenario**



Source: ACIL Allen

The generation mix changes illustrated above, along with the slightly reduced level of demand in the High Carbon Price scenario, result in dramatically different emissions profiles between that scenario and the Policy and Low Carbon Price scenarios, as illustrated in Figure 38. The primary difference between the Policy and Low Carbon Price scenarios is in the earlier decades of the modelling, after which time similar levels of demand and similar carbon prices result in almost identical emissions trajectories.

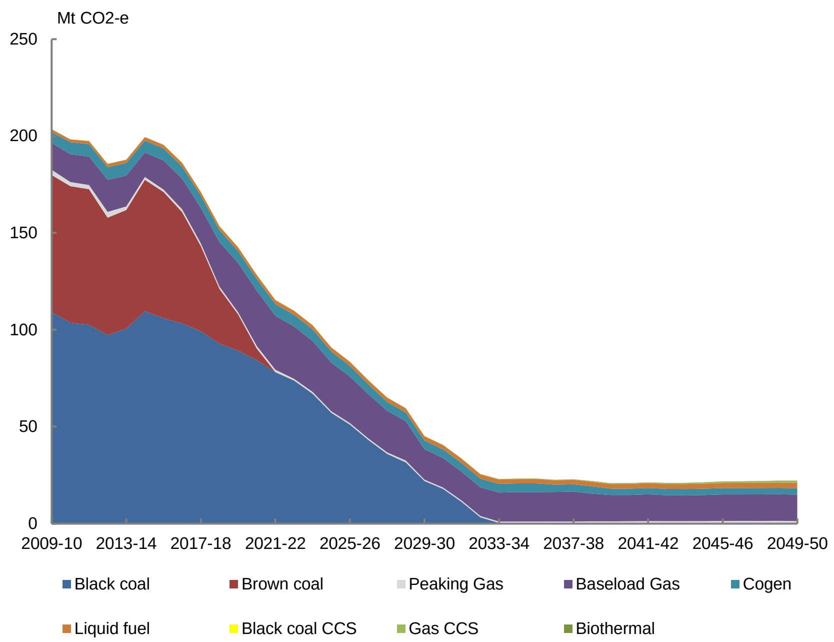
Figure 38 **Aggregate emissions – carbon price scenarios**



Source: ACIL Allen

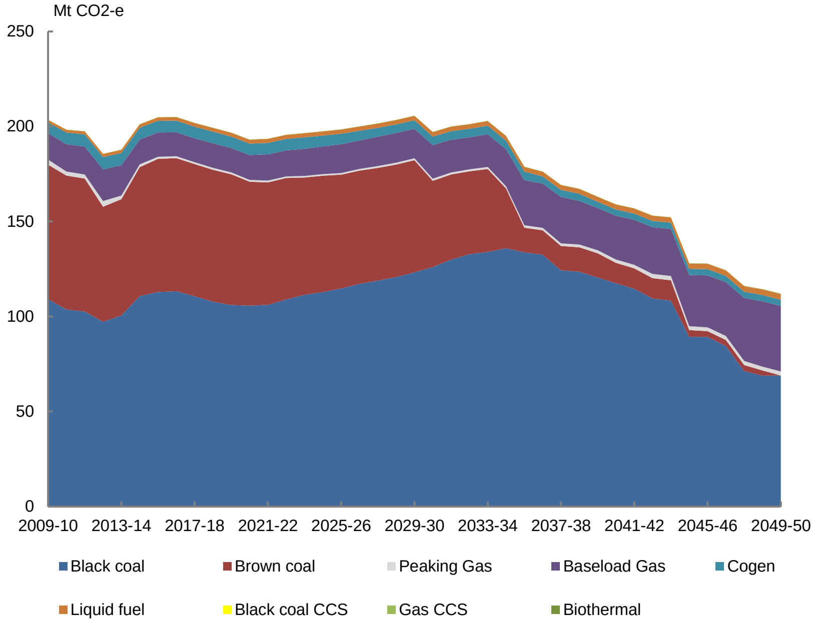
The dramatically different emissions profiles for each scenario are also illustrated by comparing emissions by fuel in the High and Low Carbon price scenarios (Figure 39 and Figure 40 respectively), and emissions by grid in the High and Low Carbon Price scenarios (Figure 41 and Figure 42 respectively).

Figure 39 **Emissions by fuel type – High Carbon Price scenario**



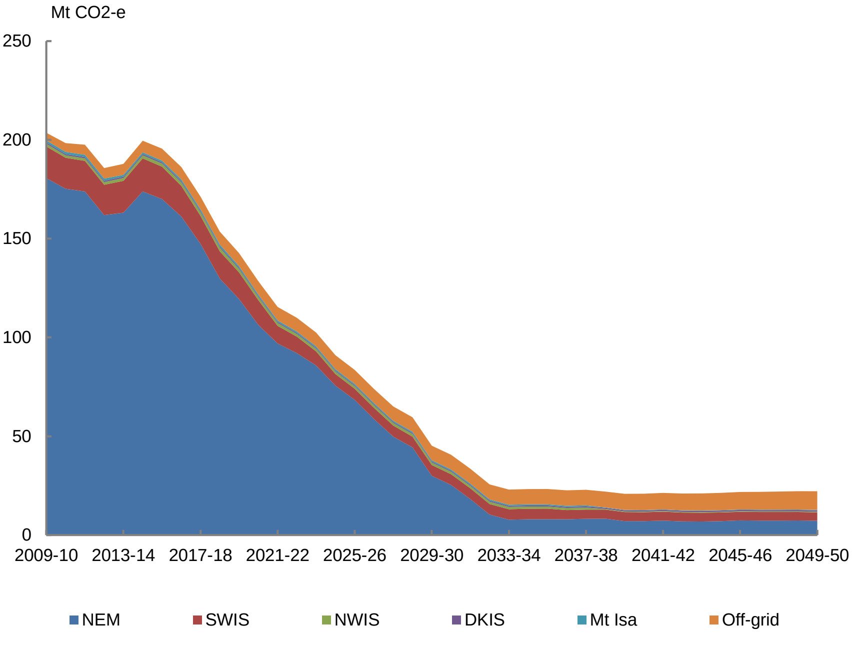
Source: ACIL Allen

Figure 40 **Emissions by fuel type – Low Carbon Price scenario**



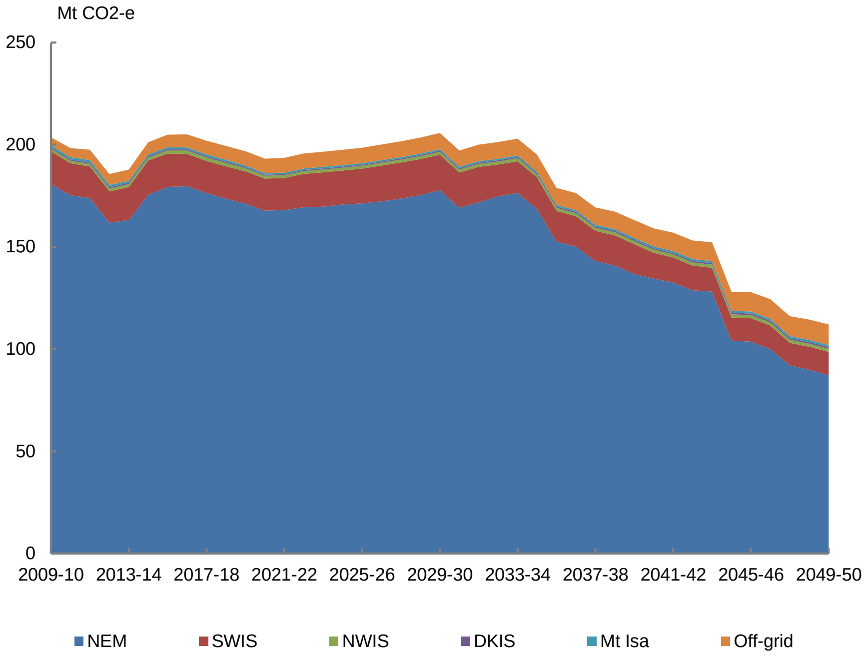
Source: ACIL Allen

Figure 41 **Emissions by grid – High Carbon Price scenario**



Source: ACIL Allen

Figure 42 **Emissions by grid – Low Carbon Price scenario**

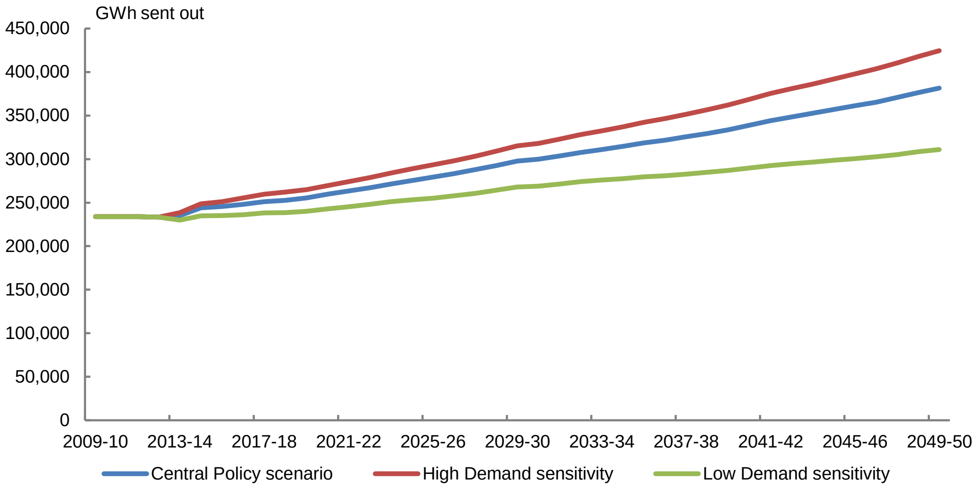


Source: ACIL Allen

5.2 High and Low Demand sensitivities

The High and Low Demand sensitivities were based on a simple variation in aggregate electricity demand from the Central Policy scenario. The percentage difference in demand between the sensitivities and the Central Policy scenario were based on the percentage difference between the high demand (Scenario 2) and low demand (Scenario 6) scenarios analysed by AEMO and its core planning scenario (Scenario 3) from its latest National Electricity Forecasting Report. The rate of divergence between the sensitivities modelled here was held constant beyond AEMO's forecasting horizon (i.e. the sensitivities continue to diverge from the Central Policy scenario at the same average rate as during the AEMO forecasting horizon). The percentage difference in demand for a given year and a given sensitivity was applied to all states and territories, including non-NEM markets. The aggregate demand assumptions thus derived for these sensitivities are illustrated in Figure 43.

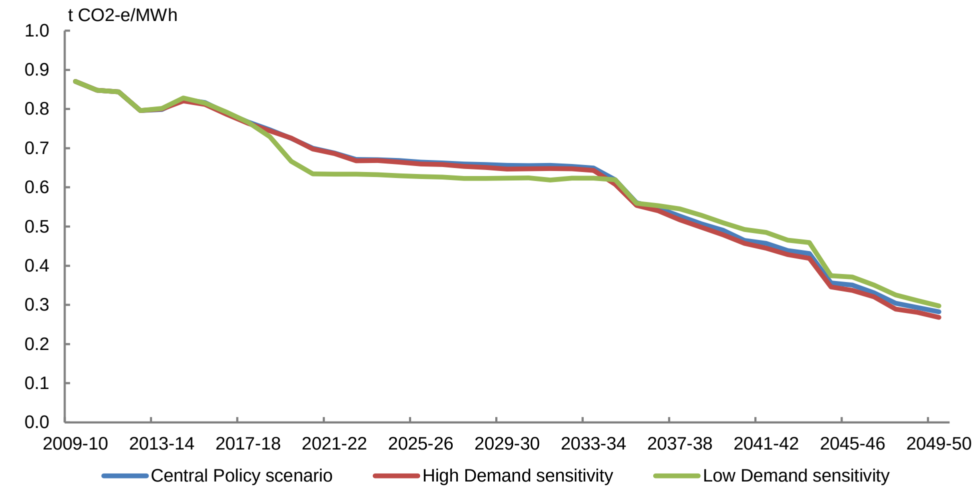
Figure 43 **Demand assumptions – demand sensitivities**



Source: ACIL Allen

Incremental changes in demand can affect the emissions intensity of the generation mix, either by promoting the early retirement of emissions-intensive generators (in the case of lower demand) or bringing in additional new entrant generators that are (typically) less emissions-intensive than incumbent generators on average (in the case of higher demand). However, as is illustrated in Figure 44, the emissions intensity of generation on average does not vary materially between the sensitivities and the Central Policy scenario. Accordingly, the primary effect of changes in demand on emissions is a direct reduction through lower levels of aggregate generation.

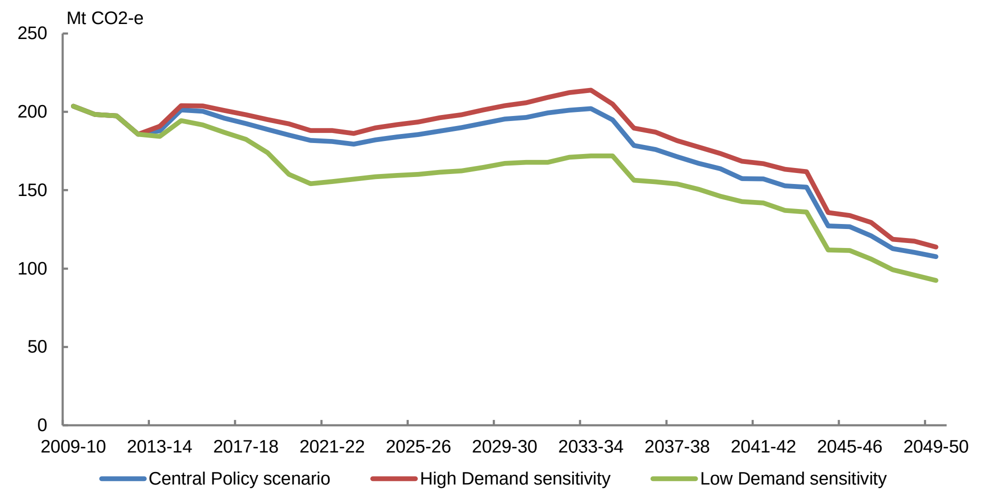
Figure 44 **Emissions intensity of generation – demand sensitivities**



Source: ACIL Allen

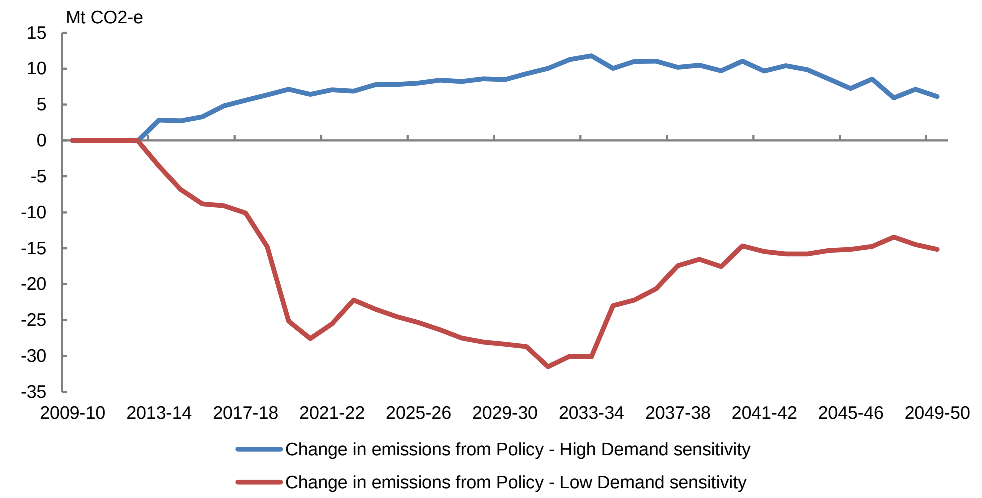
Reflecting the relatively stable emissions intensity of generation in the demand sensitivities, the change in emissions relative to the Central Policy scenario tend to be relatively minor, as is illustrated in Figure 45. These changes are more clearly expressed as a change relative to emissions in the Central Policy scenario, as is shown in Figure 46.

Figure 45 **Aggregate emissions – demand sensitivities**



Source: ACIL Allen

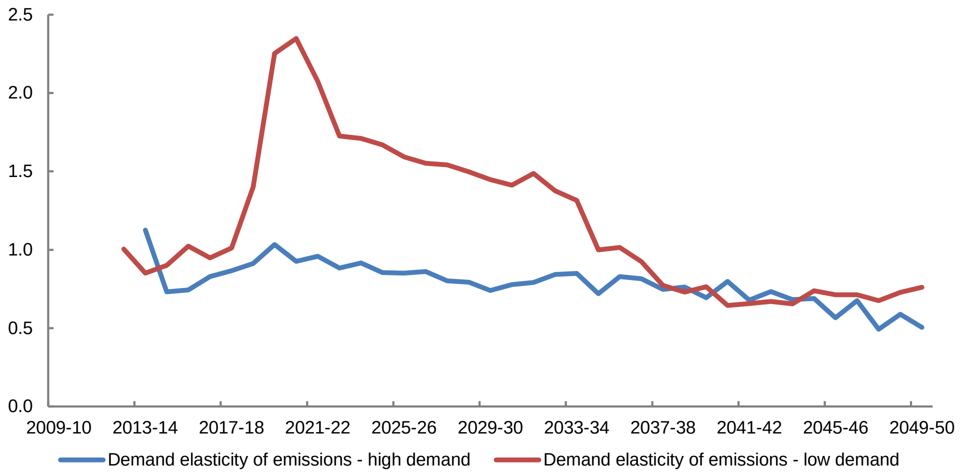
Figure 46 **Change in emissions relative to Central Policy scenario – demand sensitivities**



Source: ACIL Allen

This modelling can be used to estimate a demand elasticity of emissions, that is, the percentage change in emissions that results from a percentage change in demand. This is illustrated for both demand sensitivities in Figure 47 below. The demand elasticity of emissions tends to be lower in the high demand sensitivity, especially prior to 2033-34. This result is driven by the fact that reductions in demand particularly affect the output of emissions-intensive brown coal generators resulting in percentage changes in emissions that are greater than the relevant percentage change in demand. Conversely, when demand is marginally higher, the additional demand is met by a combination of generators that is broadly reflective of the existing (incumbent) generation mix, such that the percentage increase in emissions is only slightly lower than the percentage increase in emissions. This can occur because many existing coal and other plant have excess generation capacity that they can employ if demand increases. However, later in the modelling horizon in both sensitivities, incremental changes in demand are met increasingly by changes in the level of new entrant generation. These new entrants have a lower emissions intensity than the average fleet, and so the demand elasticity of emissions falls below one.

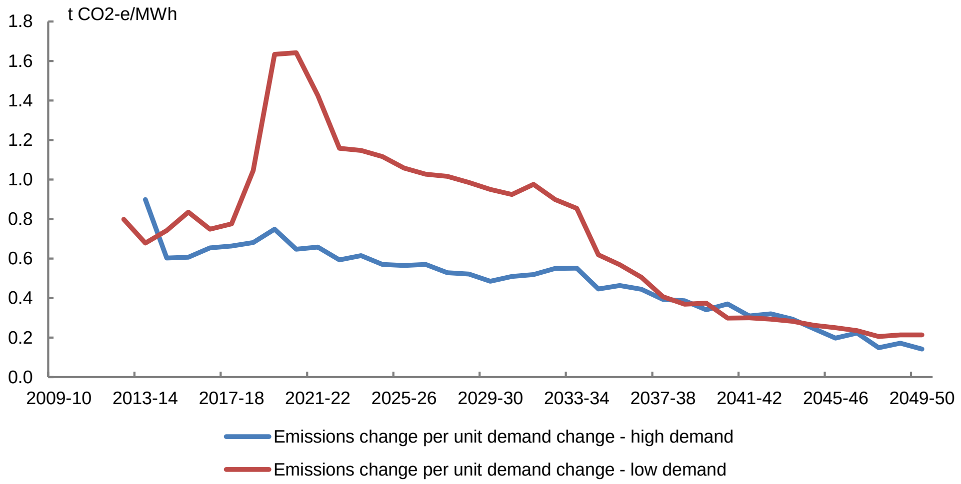
Figure 47 **Demand elasticity of emissions**



Note: Demand elasticity of emissions was negative for the high demand sensitivity in 2012-13 and so is not presented for clarity.
Source: ACIL Allen

An alternative expression of the effect of changes in demand on emissions can be illustrated through the change in emissions per unit of demand, i.e. the relative change in emissions expressed as tonnes of CO_2-e per megawatt-hour of electricity (see Figure 48). This broadly reflects the emissions-intensity of the generators that increase or reduce output in response to changes in demand. As was seen in the presentation on the demand elasticity of emissions above, the change in emissions per unit of electricity demand is higher in the low demand sensitivity, reflecting the significant effect of demand reductions on emissions-intensive brown coal plant. In the long-run the sensitivity of emissions to demand changes reduces as the average emissions-intensity of the generation fleet reduces.

Figure 48 **Change in emissions per unit change in demand**

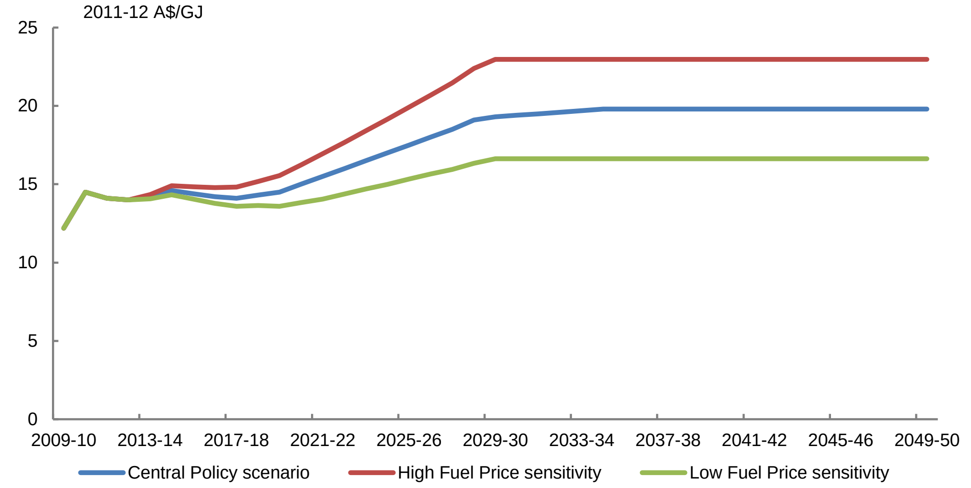


Note: Change in emissions per unit of demand was negative for the high demand sensitivity in 2012-13 and so is not presented for clarity.
Source: ACIL Allen

5.3 High and Low Fuel Price sensitivities

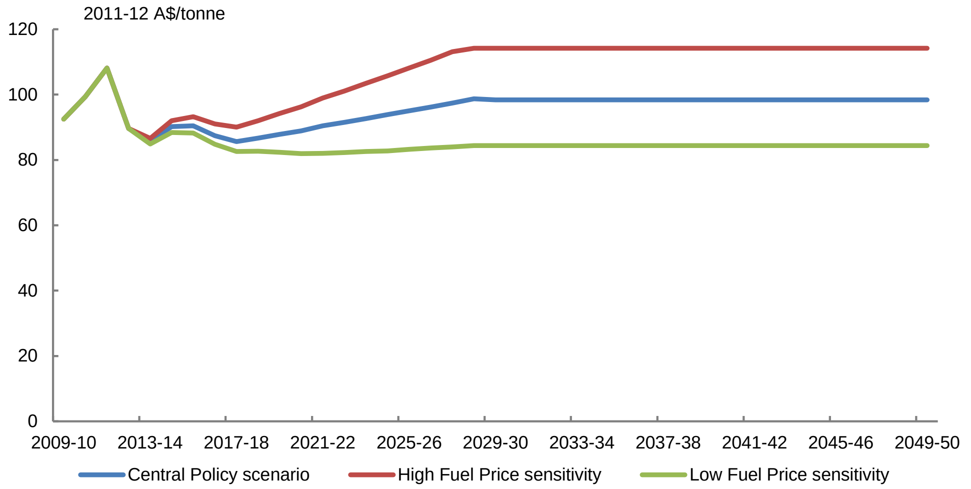
The Treasury provided fuel price trajectories for gas, coal and oil for both High and Low Fuel Price sensitivities. These trajectories reflect internationally traded prices for these fuels and were translated to domestic prices for each power station as described in Section 3.5. The international fuel price assumptions for gas and coal are presented in Figure 49 and Figure 50 respectively (oil prices have a negligible effect on this modelling).

Figure 49 **Gas price assumptions – fuel price sensitivities**



Note: prices presented represent internationally traded (landed LNG) prices for gas.
Source: Treasury

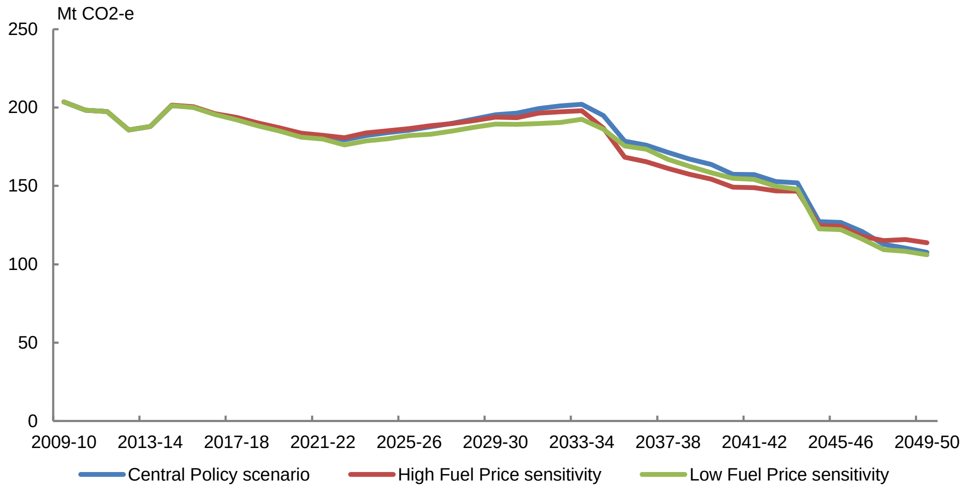
Figure 50 **Coal price assumptions – fuel price sensitivities**



Note: Prices presented represent internationally traded (landed) coal prices.
Source: Treasury

The co-movement of coal and gas prices has an ambiguous effect on emissions. As fuel prices tend to comprise a greater portion of total generation costs for gas-fired generators than coal-fired generators, lower (higher) fuel prices would be expected to advantage (disadvantage) gas-fired generation over coal-fired generation decreasing (increasing) emissions. However, lower (higher) fuel prices would also tend to advantage (disadvantage) thermal generators over renewable generators, increasing (decreasing) emissions. The outcome of these changes, therefore, is complex and sensitive to the incumbent plant mix, new entrant costs and a range of other assumptions. This is reflected in the relatively minor and unstable changes in emissions between the Central Policy scenario and the fuel price sensitivities, as illustrated in Figure 51.

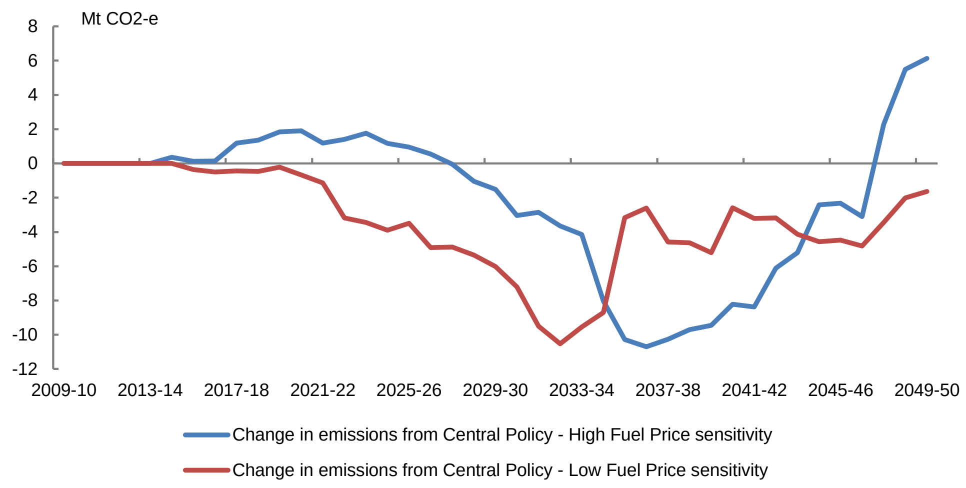
Figure 51 **Aggregate emissions – fuel price sensitivities**



Source: ACIL Allen

Due to the small change in emissions under the fuel price sensitivities, the change in emissions relative to the Central Policy scenario is presented in Figure 52.

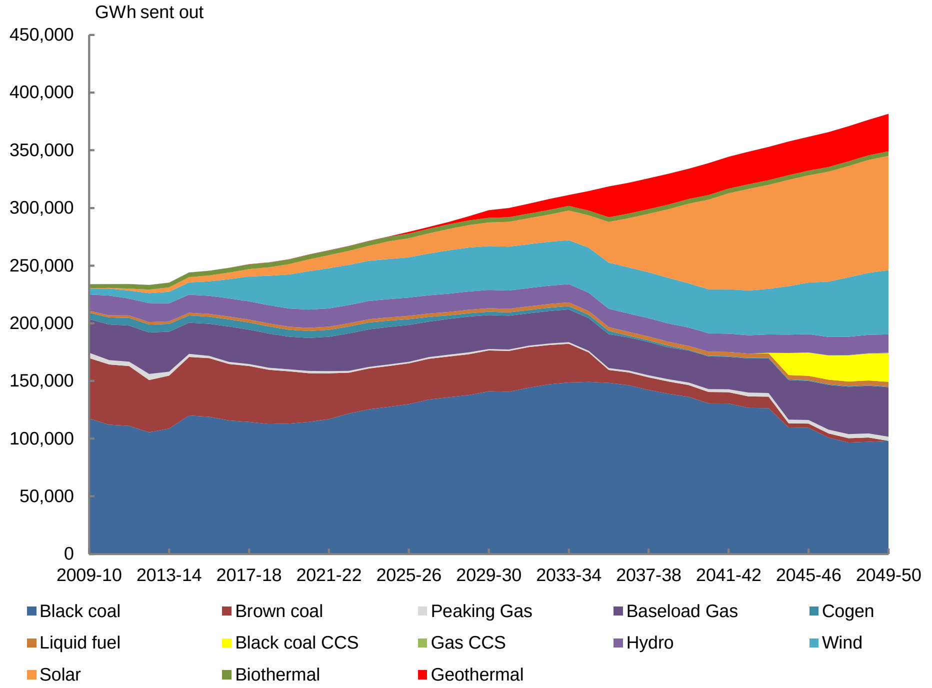
Figure 52 **Change in emissions relative to Central Policy scenario – fuel price sensitivities**



Source: ACIL Allen

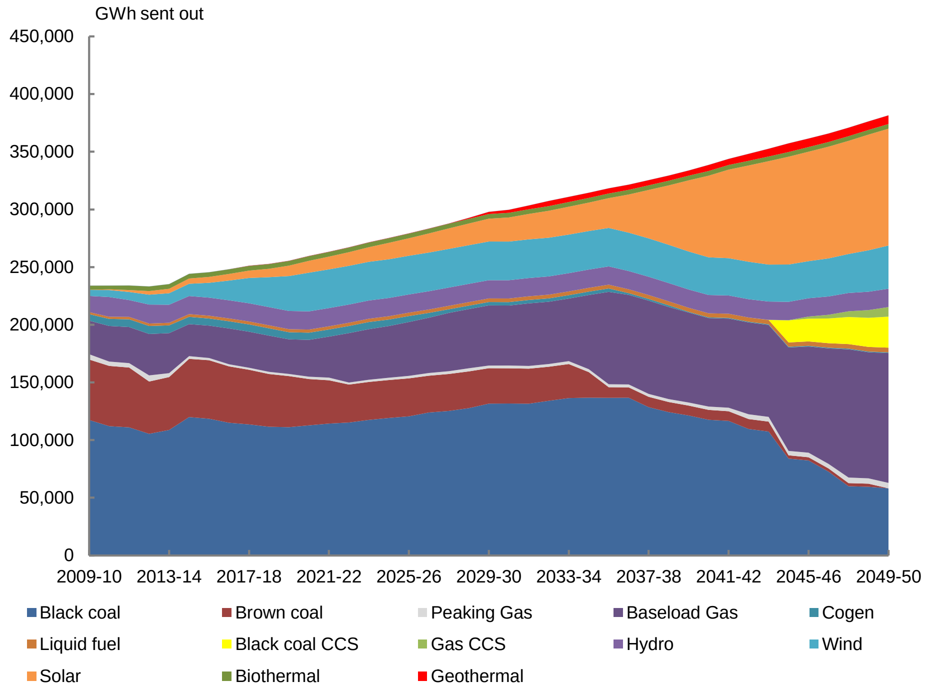
Changes in the generation mix are critical in driving emissions differences in the fuel price sensitivities, as can be seen by comparing Figure 53 and Figure 54, which illustrate the generation mix in the High and Low Fuel Price sensitivities respectively.

Figure 53 **Generation by fuel type – High Fuel Price sensitivity**



Source: ACIL Allen

Figure 54 **Generation by fuel type – Low Fuel Price sensitivity**

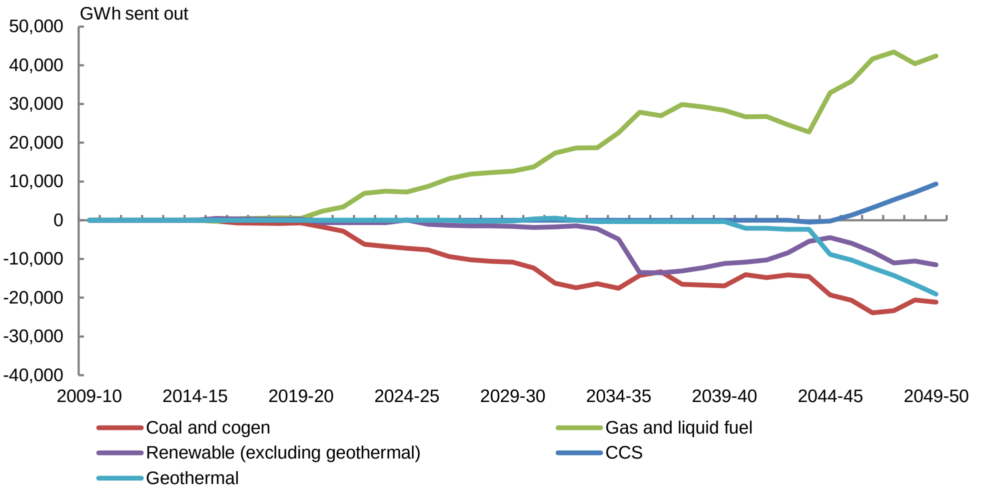


Source: ACIL Allen

An even clearer illustration of how the change in the generation mix drives emissions results can be seen by displaying the change in output by generation technology between the Central Policy scenario and each sensitivity, with generators grouped into five categories:

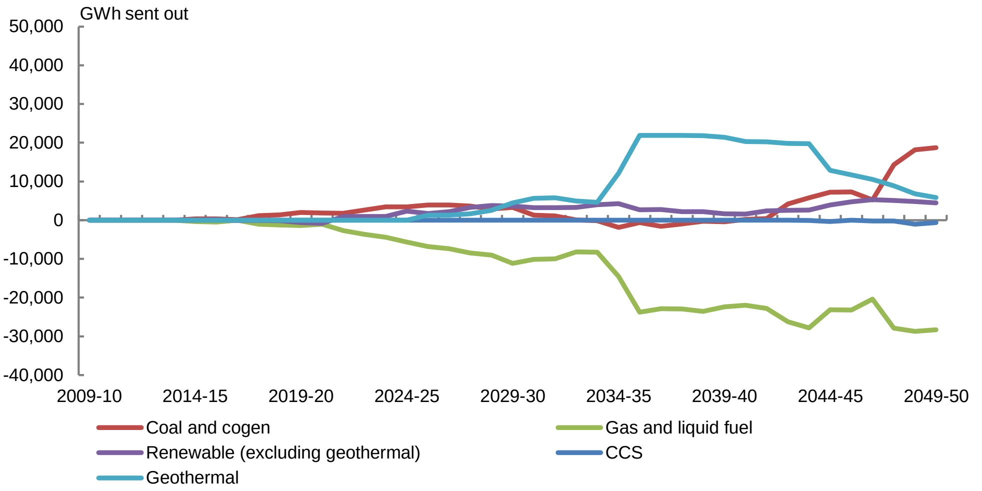
coal and cogeneration; natural gas and liquid fuel; renewable (excluding geothermal); CCS; and geothermal (see Figure 55 and Figure 56).

Figure 55 **Change in output by generation grouping – High Fuel Price sensitivity**



Source: ACIL Allen

Figure 56 **Change in output by generation grouping – Low Fuel Price sensitivity**



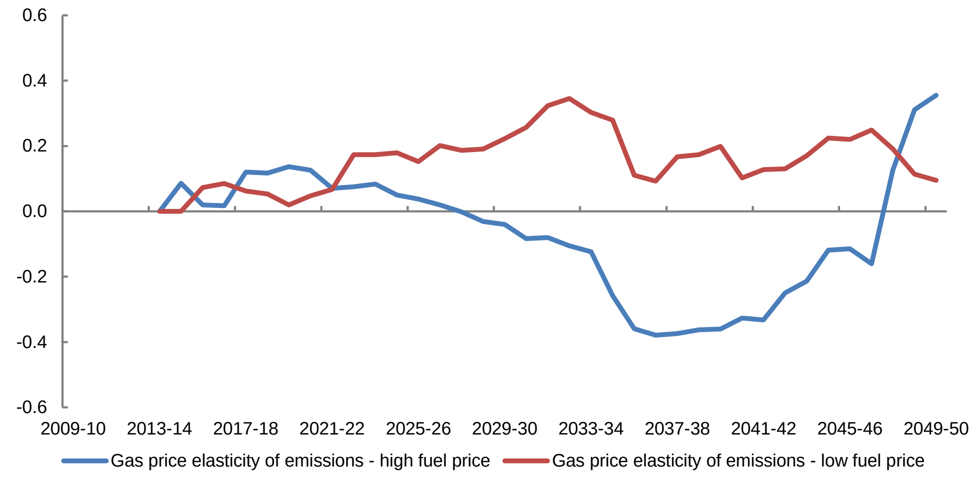
Source: ACIL Allen

In the High Fuel Price sensitivity, the increase in fuel prices initially favours coal-fired generation over gas-fired generation and therefore marginally increases emissions. However, from the late 2020s, the higher fuel prices favour renewable, particularly geothermal, generation over both coal and gas, reducing emissions. This means that, at this point, the fuel price elasticity of emissions is negative, as shown in Figure 57. Very late in the High Fuel Price sensitivity, an increase in coal-fired generation at the expense of gas-fired generation results in an overall increase in emissions relative to the Central Policy scenario. This occurs where, in the Central Policy scenario, a large volume of coal-fired generation retires in the late years of the model, whereas in the presence of higher gas prices it is viable for this coal-fired generation to continue in the sensitivity.

Conversely, the Low Fuel Price sensitivity sees much higher levels of gas-fired generation, coming largely at the expense of coal-fired generation and with relatively low displacement of renewable generation. This drives the result that emissions are lower throughout the Low Fuel Price sensitivity relatively to the Central Policy scenario, and therefore that the fuel price elasticity of emissions is positive.

Given that gas-fired generation is more sensitive to fuel prices than coal-fired generation, Figure 57 presents the gas price elasticity of emissions based on these two sensitivities (rather than the coal price elasticity of emissions), that is, the percentage change in emissions in response to a percentage change in gas prices. As discussed above, this elasticity is negative for the middle period of the high fuel price sensitivity, as the displacement of gas and coal-fired generation by renewable generation results in a decrease in emissions when gas prices increase. However, in all other cases, emissions reduce when gas prices reduce and vice versa, i.e. the gas price elasticity of emissions is positive.

Figure 57 **Gas price elasticity of emissions**



Source: ACIL Allen

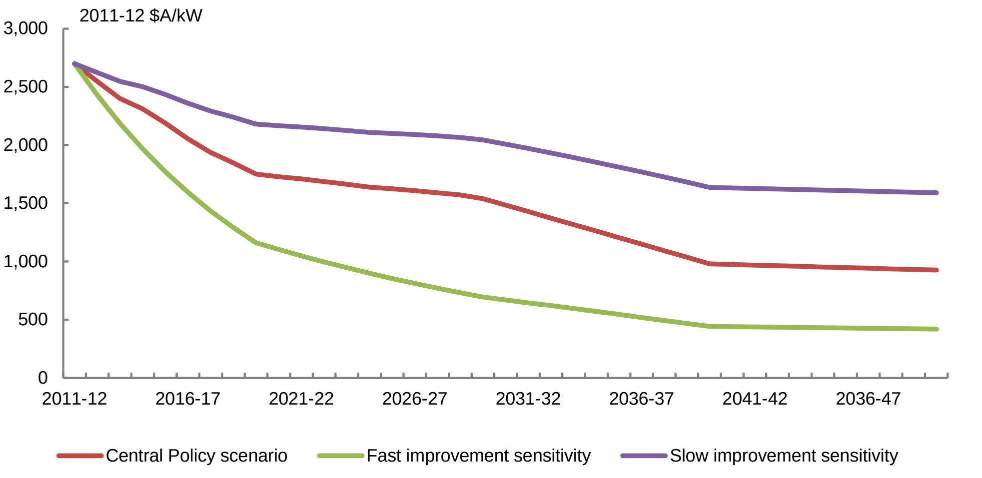
5.4 Technology cost sensitivities

To test the potential effect of technological learning on emissions, particularly associated with improvements in solar and other renewable technologies, ACIL Allen modelled three technology cost sensitivities:

- A Fast Improvement sensitivity, where capital costs for solar PV reduced substantially faster than in the Central Policy scenario (i.e. the technology improved at a fast rate)
- A Slow Improvement sensitivity, where capital cost for solar, wave, and CCS technologies reduced more slowly than in the Central Policy scenario
- A Fast Improvement (unconstrained) sensitivity, adopting the same solar PV capital costs as the Fast Improvement sensitivity but where the total build constraints on solar PV were relaxed (see Section 3.6.3 for more information on these constraints).

Specifically, DIICCSRTE requested that real Australian dollar capital costs for solar PV in the Fast Improvement sensitivity reduce by 10% per annum over the period to 2019-20, and then by 5% over the period to 2029-30. After that period costs were assumed to reduce by the same annual rate as in the Central Policy scenario. In the Slow Improvement sensitivity, DIICCSRTE requested that real Australian dollar capital costs for all solar, wave and CCS technologies reduce by half the rate assumed in the Central Policy scenario. As solar PV is the critical technology in terms of technological learning, the capital cost for solar PV in the Central Policy, Fast Improvement and Slow Improvement sensitivities is presented in Figure 58.

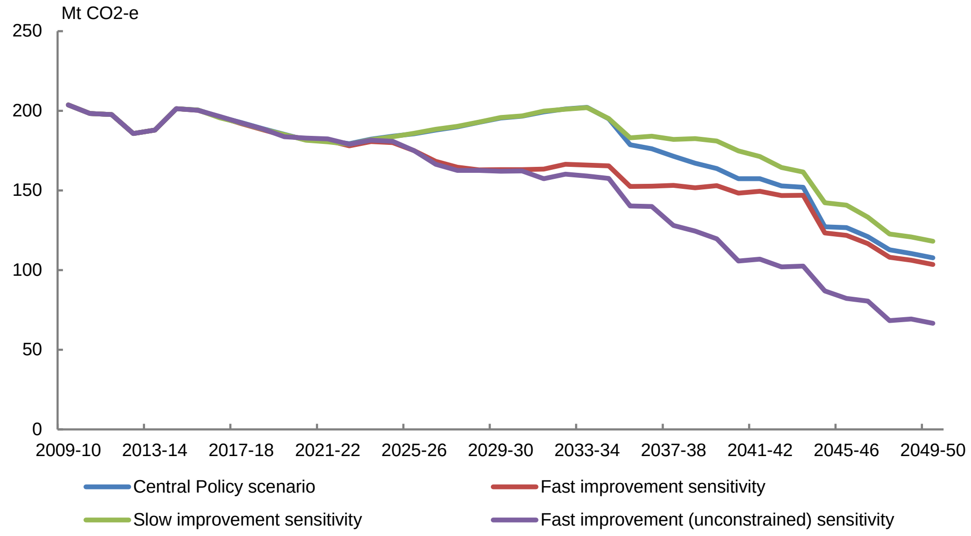
Figure 58 **Solar PV cost assumptions – technology cost sensitivities**



Source: DIICCSRTE

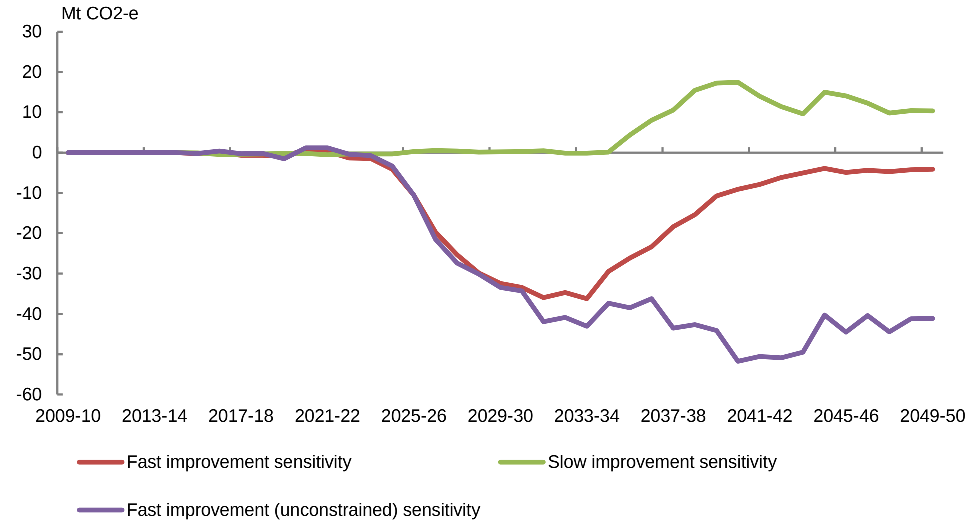
Unsurprisingly, emissions reduce relative to the Central Policy scenario in the Fast Improvement and Fast Improvement (unconstrained) sensitivities, and increase in the Slow Improvement sensitivity (with some minor exceptions early in the modelling period). The relative emissions trajectories are presented in Figure 59 in absolute terms, and expressed as a variation from the Central Policy scenario in Figure 60. In the Fast Improvement sensitivity, emissions initially reduce substantially relative to the Central Policy scenario, but then return to very similar levels to the Central Policy scenario as absolute build limits on solar PV are reached. In the Central Policy scenario, these limits are generally reached around the mid-2040s, whereas they bind in the early to mid-2030s in the Fast Improvement sensitivity. Together, this means that the difference in emissions between the two model runs peaks at around 40 Mt CO_2-e in the early to mid-2030s but broadly converges by the mid-2040s. In the Slow Improvement sensitivity, the increase in emissions is fairly modest, and steady at around 10 Mt CO_2-e from the mid-2030s onwards. In the Fast Improvement (unconstrained) sensitivity, the difference in emissions is similar to the constrained Fast Improvement sensitivity until the early to mid-2030s. After that point, the emissions difference between the Central Policy and Fast Improvement (unconstrained) sensitivity remains relatively stable at around 50 Mt CO_2-e for the remainder of the model horizon.

Figure 59 **Aggregate emissions – technology cost sensitivities**



Source: ACIL Allen

Figure 60 **Change in emissions relative to Central Policy scenario – technology cost sensitivities**

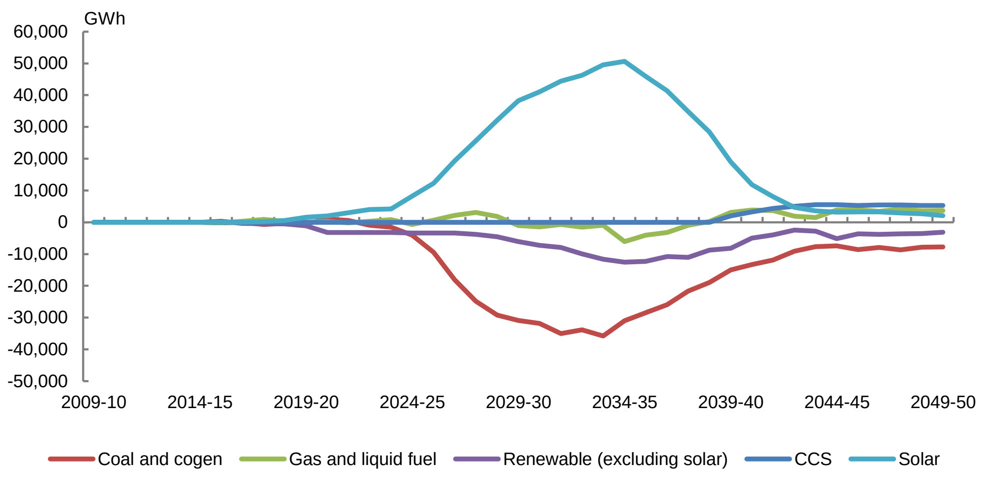


Source: ACIL Allen

The changes in emissions can be explained by analysing the changes in different generation categories (relative to the Central Policy scenario), as illustrated below. In the Fast Improvement senstivity (Figure 61), the initial growth in solar relative to the Central Policy scenario is largely at the expense of coal, resulting in substantial emissions reductions. However, the additional volume of solar reduces beyond the mid-2030s, driving the convergence of emissions with the Central Policy scenario. In the Slow Improvement sensitivity (Figure 62) there is a substantial reduction in solar generation, but much of this is replaced with other renewables (principally wind and geothermal), and therefore the emissions impact is modest. Finally, in the Fast Improvement (unconstrained) sensitivity (Figure 63) the volume of solar increases substantially (by over 100,000 GWh by the late

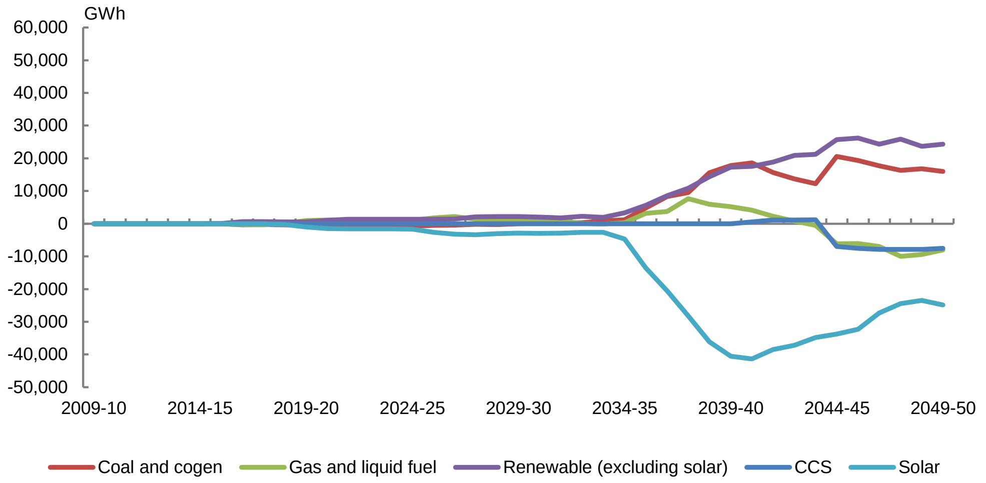
2040s), but increasingly displaces CCS and other renewable generation, therefore having only reducing emissions to a modest extent.

Figure 61 **Change in output by generation grouping – Fast Improvement sensitivity**



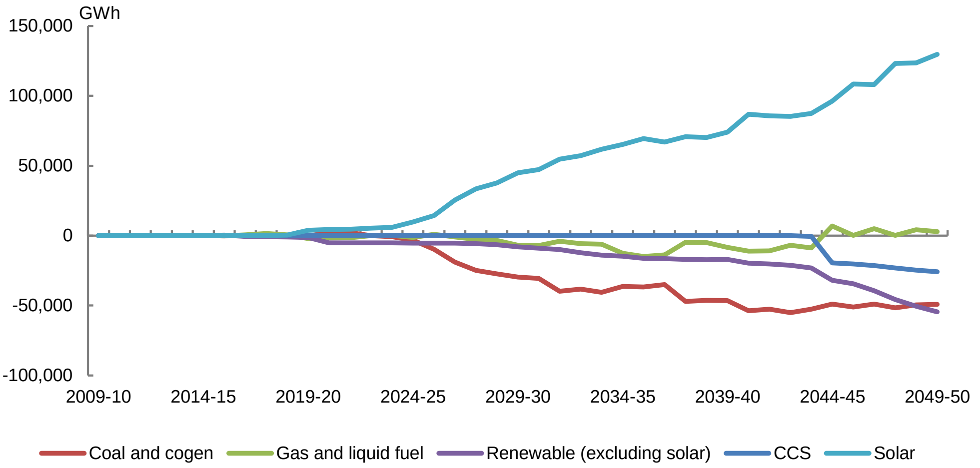
Source: ACIL Allen

Figure 62 **Change in output by generation grouping – Slow Improvement sensitivity**



Source: ACIL Allen

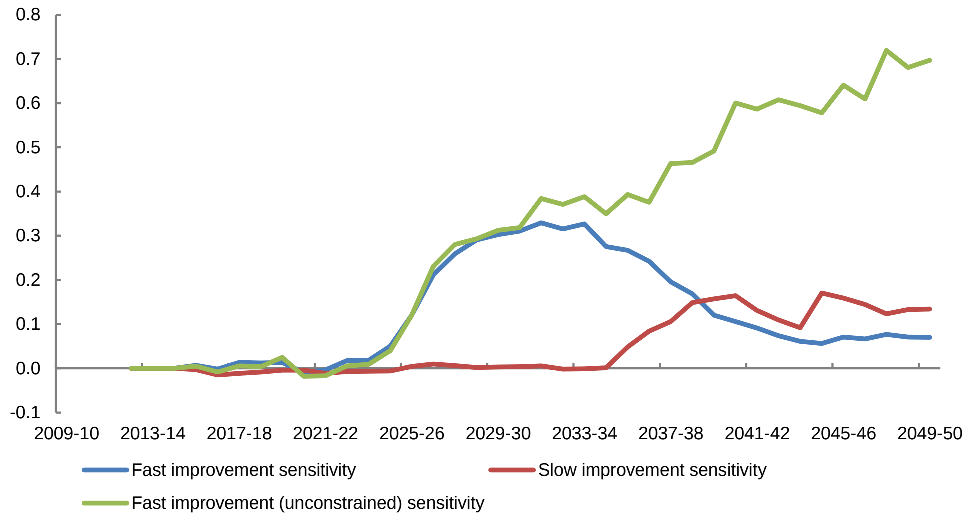
Figure 63 **Change in output by generation grouping – Fast Improvement (unconstrained) sensitivity**



Source: ACIL Allen

The change in emissions relative to the Central Policy scenario can be used to derive a solar PV capital cost elasticity of emissions, that is, the percentage change in emissions for a percentage change in solar PV capital costs. The figures presented below should be interpreted with caution due to the effect of build constrains on solar uptake. In all sensitivities in most years the elasticity is positive, as expected (that is, a reduction in solar capital costs results in a reduction in emissions, and vice versa). The elasticity in the Fast Improvement (constrained and unconstrained) sensitivities is initially similar until build constraints bind, at which time the elasticity in the constrained sensitivity reduces rapidly. The elasticity in the Slow Improvement sensitivity is generally lower, reflecting that the widespread adoption of solar is generally fairly late in the model period in the Central Policy scenario. Accordingly, solar output and emissions are only materially affected from the mid-2030s onwards, by which time other low-emissions technologies are relatively cost competitive with coal, and therefore a reduction in solar capital costs has a relatively small effect on emissions as solar can be substituted with other low-emissions technologies. Overall, this means that the increase in emissions for an increase in solar PV costs is relatively small in the Slow Improvement sensitivity.

Figure 64 **Solar PV capital cost elasticity of emissions**



Source: ACIL Allen

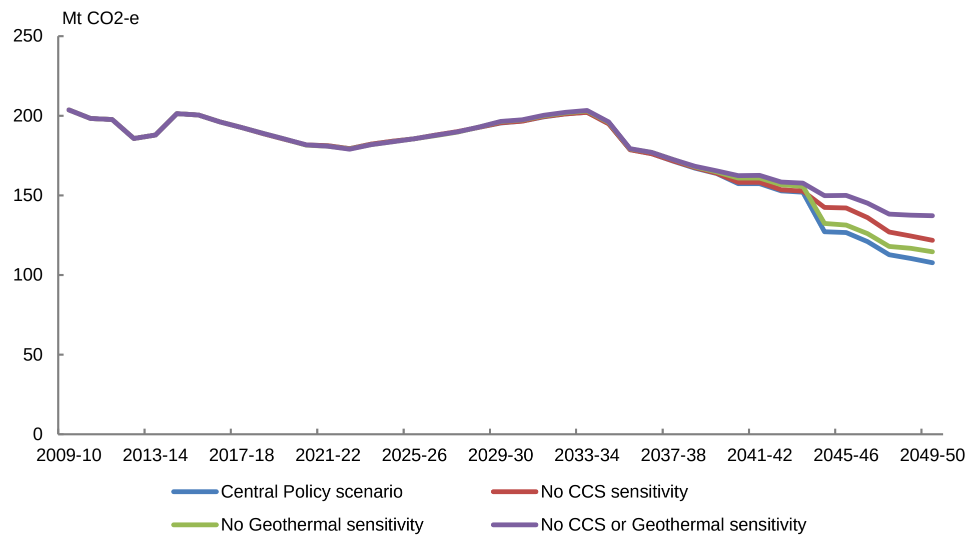
5.5 Restrictions on geothermal and CCS

Three sensitivities were modelled to assess the importance of geothermal and CCS generation technologies on future emissions trajectories:

- A No CCS sensitivity, where all CCS technologies were excluded from the modelling
- A No Geothermal sensitivity, where geothermal generation was excluded from the modelling (with the exception of ARENA supported geothermal pilot projects, which were assumed to go ahead)
- A No CCS or Geothermal sensitivity, which excluded both technologies (whilst retaining the ARENA geothermal pilot projects).

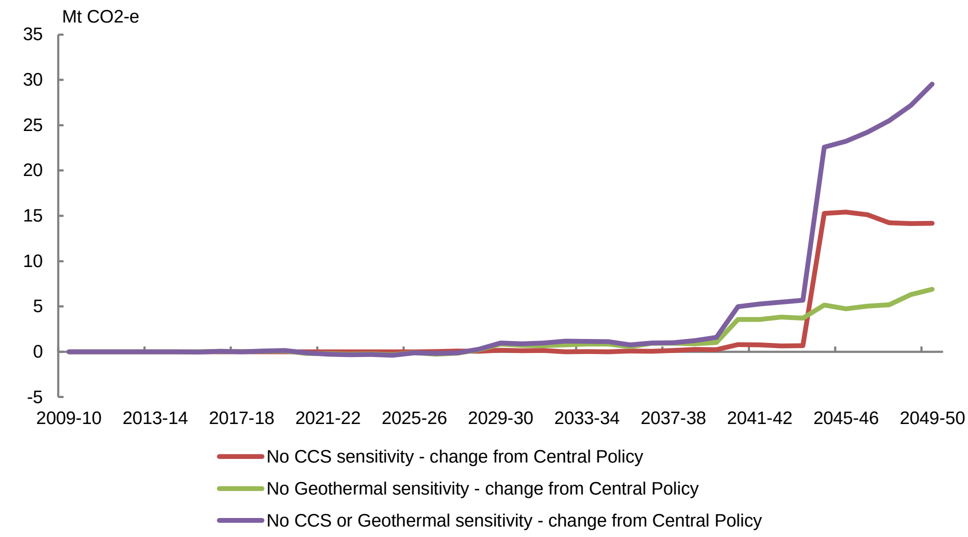
The effect of these technology restrictions on emissions are presented in aggregate in Figure 65, and expressed as a difference from the Central Policy scenario in Figure 66.

Figure 65 **Aggregate emissions – technology restriction sensitivities**



Source: ACIL Allen

Figure 66 **Emissions change relative to Central Policy scenario – technology restriction sensitivities**

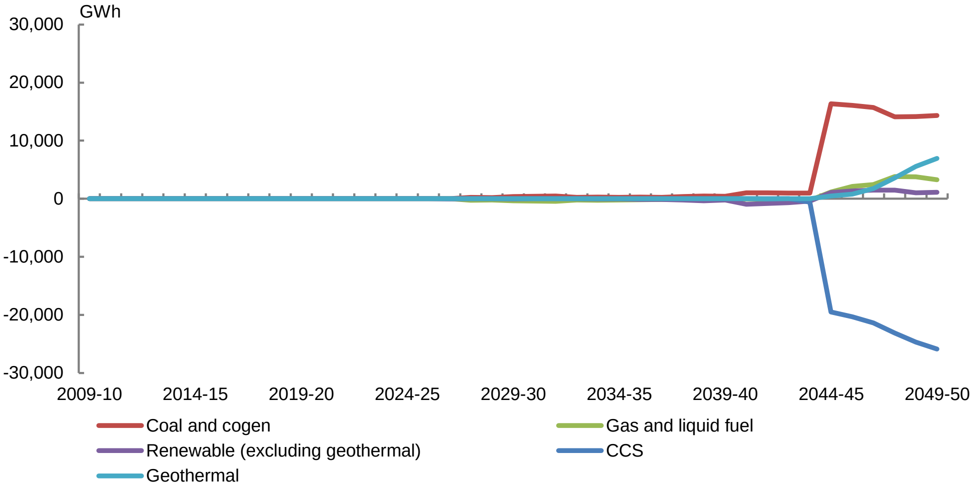


Source: ACIL Allen

The drivers of these changes in emissions can be seen by which technologies displace CCS and/or geothermal in each sensitivity. The following three figures group display the change in output by generation technology between the Central Policy scenario and each sensitivity, with generators grouped into five categories: coal and cogeneration; natural gas and liquid fuel; renewable (excluding geothermal); CCS; and geothermal.

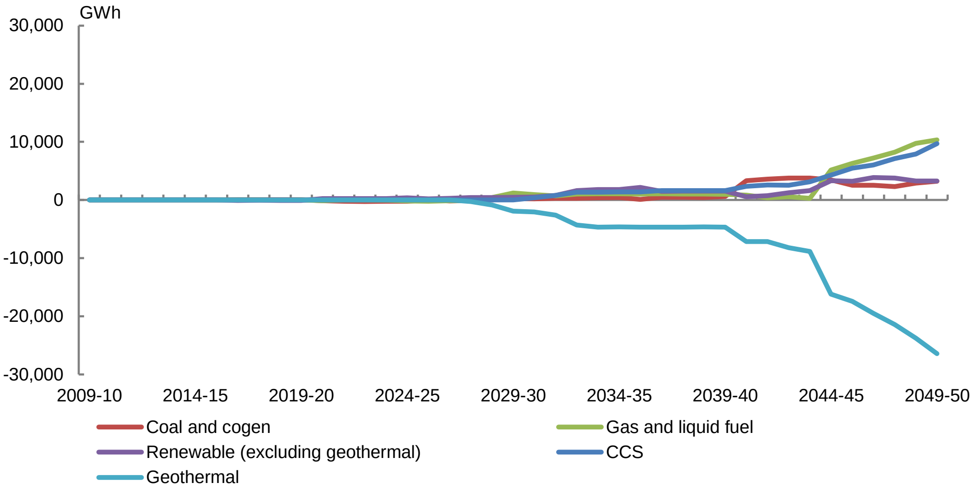
Figure 67 illustrates how coal plays the key role in replacing CCS generation when it is excluded from the modelling, resulting in a relatively sharp increase in emissions. Conversely, when geothermal is excluded, all the other major generation groupings play a significant role in replacing it (see Figure 68), with a correspondingly more muted effect on emissions. When both geothermal and CCS are excluded, other renewables play only a limited role in replacing their output, with the thermal (and relatively emissions-intensive) generation types increasing substantially (Figure 69).

Figure 67 **Change in output by generation grouping – no CCS sensitivity**



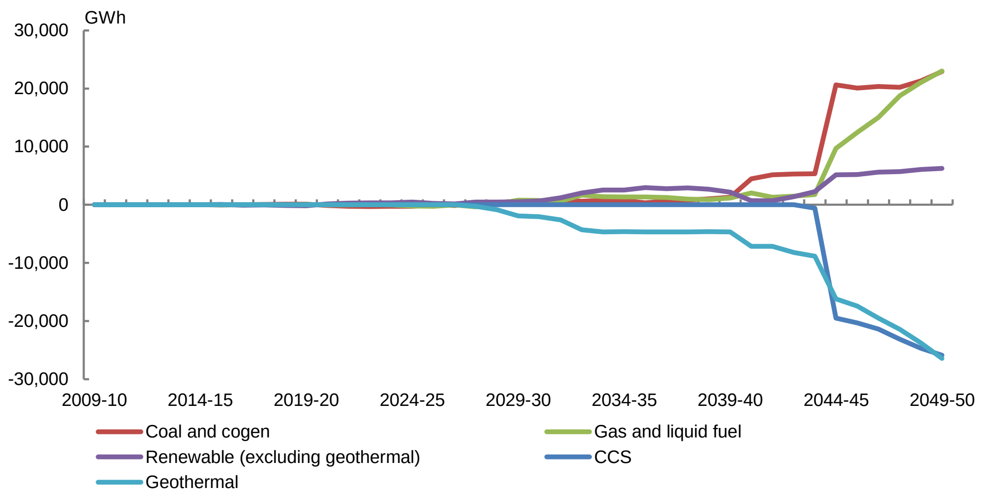
Source: ACIL Allen

Figure 68 **Change in output by generation grouping – no Geothermal sensitivity**



Source: ACIL Allen

Figure 69 **Change in output by generation grouping – no CCS or Geothermal sensitivity**

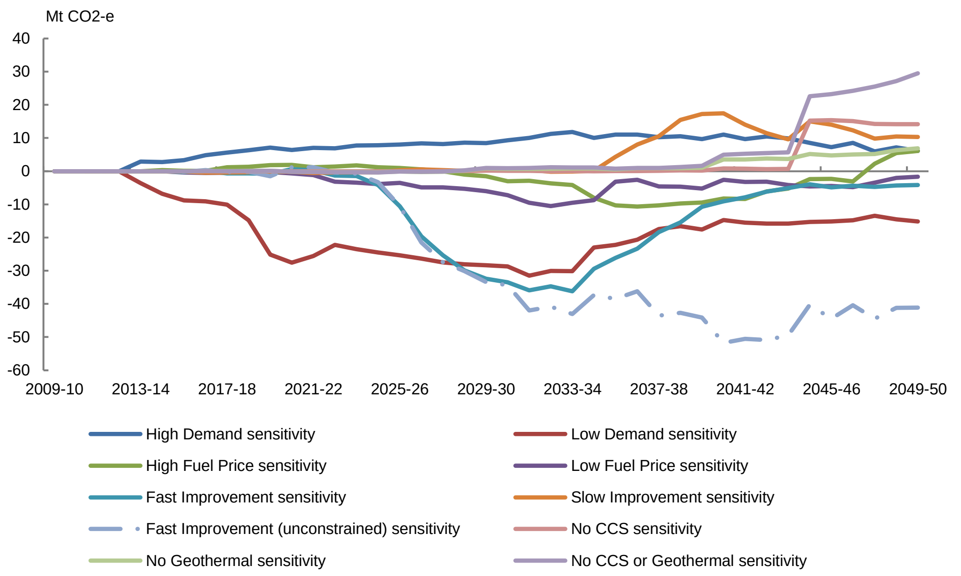


Source: ACIL Allen

5.6 Summary of sensitivities

Figure 70 summaries the change in emissions from the Central Policy scenario for each of the sensitivities.

Figure 70 **Change in emissions from Central Policy scenario – all sensitivities**



Source: ACIL Allen

Appendix A PowerMark LT

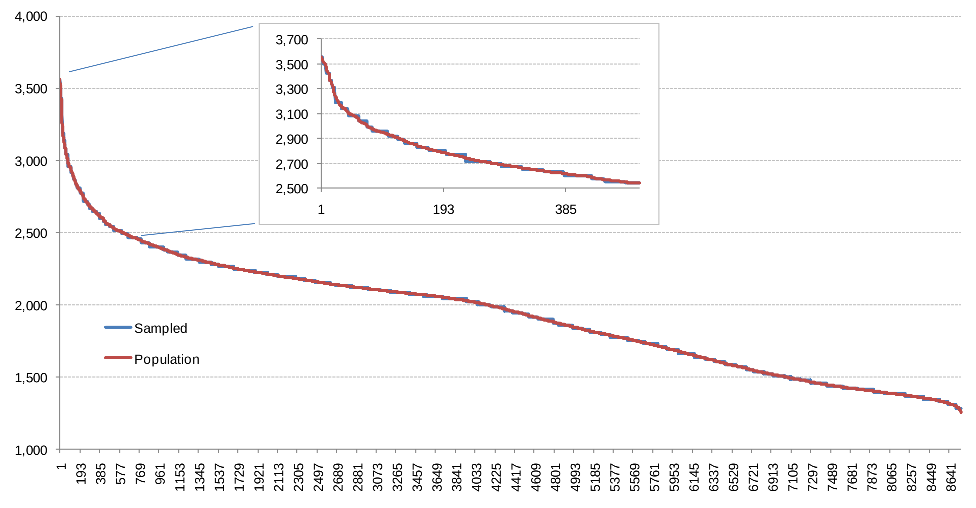
Unlike a detailed simulation model, *PowerMark LT* utilises a sampled 50 or 100 point sequential representation of demand in each year, with each point weighted such that it provides a realistic representation of the demand population. A 100 point demand sample is used in this analysis. The sampling utilises a tree clustering process with a weighted pair-group centroid distance measure.

Figure A1 below shows the fit between a 100 point sampled Load Duration Curve (LDC) with an hourly load trace for a single region. The sampled series exhibits an extremely close fit with the population LDC. In this example, the average sampling error was only 0.36 MW (max 57 MW, min -53 MW).

It is important to maintain demand diversity across multiple regions. For this reason the sampling process described above is done for all regions simultaneously such that the resulting sampled demand curve is the closest possible representation for the whole market and preserves demand diversity. The process ensures that the peak demands for each region are preserved as well as the annual energy.

Given the propensity for changes to the underlying load shapes in each region (from influences such as embedded PV etc.), the sampling process is undertaken on grown half hourly demand traces for each year of the projection period which take account of these influences.

Figure A1 **Comparison of 100 point sampled LDC with hourly trace (MW)**



Source: *PowerMark LT*

Appendix B RECMark

B.1 LRET implementation

The key features of the LRET are implemented within *RECMark* as discussed in the following sections.

Banking/borrowing

As per the schemes design, unlimited banking of permits is allowed. That is, permits created can be created and withheld for surrender in later years. *RECMark* allows an unlimited number of LGCs to be banked throughout the scheme. Note that all banked LGCs up until the end of calendar year 2010 will be eligible to be used against the LRET, regardless of how they were created.

Borrowing under the scheme is effectively limited to 10% of each liable entities liability.[7] This provision is provided because it is often difficult for a retailer to accurately predict what its liability will be. The 10% provides liable parties some leeway in estimating liabilities. With perfect foresight, this provision could be gamed, with liable parties only surrendering 90% of required LGCs and carrying forward the shortfall.

Shortfall penalty

The shortfall charge as specified within the regulation is $65 per MWh not-indexed (constant in nominal terms over the life of the scheme). This represents a significant increase over the $40/MWh shortfall charge under the old MRET scheme.

As penalties paid are not deductible business expenses (they are treated as fines), the effective pre-tax penalty is therefore $92.86/REC ($65/(1-30%), assuming a 30% marginal tax rate). The penalty is not indexed so it declines in real terms over the period to 2030.

B.2 Certificate demand

There are three sources of demand for LGCs: demand for LGCs to offset mandatory obligations under the scheme, LGCs to acquit GreenPower sales and certificates associated with desalination plants/other voluntary schemes. While there is a good deal of uncertainty in relation to GreenPower and desalination volumes, in aggregate these make up a small proportion of overall demand and variations to these assumptions are unlikely to alter the outlook significantly.

While the requirement to surrender LGCs applies to each individual entity, *RECMark* treats the demand-side as a single entity. As such, it does not distinguish between parties and their respective LGC positions.[8]

RECMark assumes there is zero mandated demand for LGCs at prices above the tax-adjusted shortfall penalty price. While some have suggested liable entities may be willing to buy certificates at prices above these levels to avoid reputational damage, *RECMark* does not explicitly account for this.

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[7] Renewable Energy (Electricity) Act 2000, Section 36(2)

[8] Another way of thinking of this is that all parties freely trade with one another without any transaction costs.

Note that the demand figures include the 850 GWh allowance for waste coal mine gas (WCMG) to 2020. This is offset by an 850 GWh supply-side assumption for pre-existing WCMG operators, such that the inclusion has no impact upon LRET outcomes.

B.3 Certificate supply

The modelling considers two types of certificate supply: existing/committed accredited generators and potential new entrants.

Existing generators

Contribution from existing accredited generators and those under construction are done at the individual power station level. For most, this involves projecting LGC creation rates at levels similar to recent history. Those that are currently under construction have assumptions about commissioning timing and production ramp up.

New entrants

A range of specific projects and various generic new entrant technologies are presented to the model for deployment. Capital costs for these technologies are discussed further in Section 3.4.

With a number of the smaller, niche renewables technologies, it is difficult to project deployment when modelling the LRET at the macro level. These include:

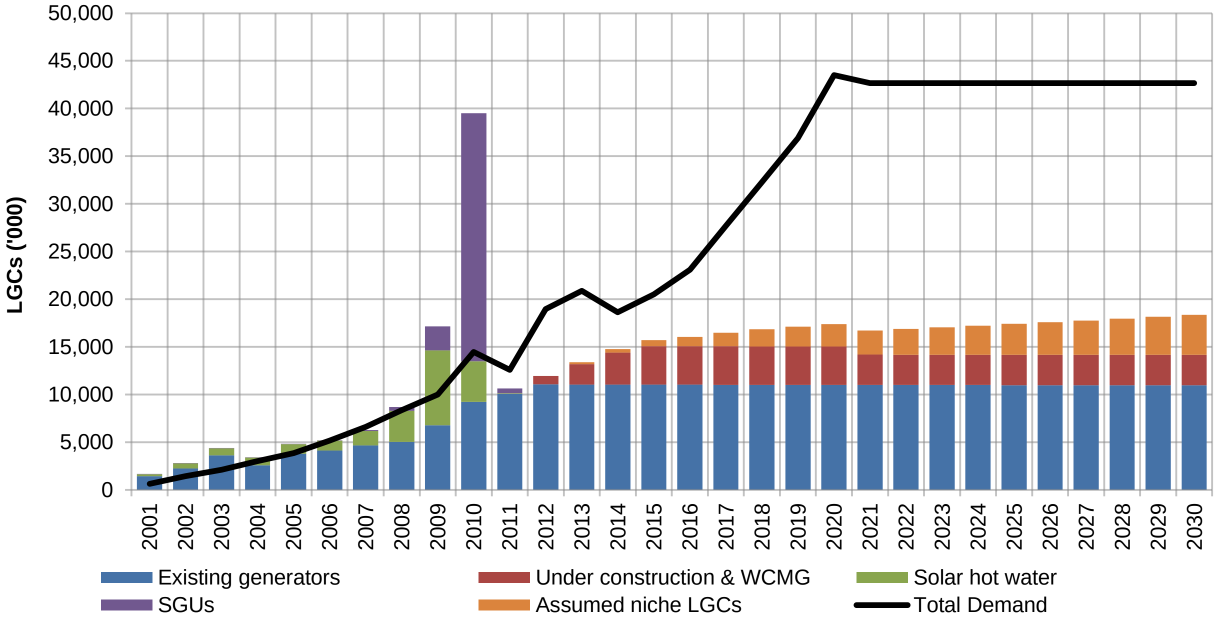
- Landfill gas where projects are very site specific and local transmission connection costs can be a significant component of capital costs. Ultimately the resource base is limited by suitable landfill sites
- Bagasse where projects are mill specific and the timing of which, is determined by the need for mill refurbishment more so than the economics of the cogeneration units. The resource base is also limited by the amount of sugar cane crop processed.
- Wood and wood waste plants which are typically small-scale developments where feedstock availability and network connection are key variables. Lager projects (such as Gunns' Bell Bay) are reliant upon the underlying paper mill development rather than the economics of generation. Fuel transport and handling costs typically are constraining factors.
- Embedded solar PV systems above the current 100 kW LRET cut-off (but not considered utility scale)
- Other technologies such as those using agricultural/food wastes and municipal wastes which are small and it is often difficult to obtain representative capital cost estimates.

To account for uptake of these technologies, ACIL Allen makes projections of LRET contribution based on historical growth and ultimate resource potential rather than explicitly 'modelling' deployment through *RECMark*.

B.4 Supply-demand balance

Figure B1 shows historical and projected LGC creation from existing renewable generators, generators that are under construction, from WCMG generators entitled to create LGCs, and from niche small-scale generators such as landfill gas, bagasse and small-scale solar above 100 kW but below utility scale. Figure B1 also shows aggregate demand for LGCs over the period to 2030 as defined by the annual legislated LRET target. *RECMark* seeks to fill the gap between committed and assumed future supply and demand by deploying further LGC-eligible generation at least cost over the period to 2030 and explicitly considers the economics of those installations for the period beyond 2030.

Figure B1 **LGC supply demand balance 2001 to 2030**



Note: Assumed new LGCs represent contributions from niche technologies (Landfill gas, Bagasse, Wood, Sewage Gas, and embedded solar PV above 100 kW in size). Historical REC Registry data current to 20 March 2013

Source: ACIL Allen analysis