THE TREASURY

Carbon Pricing and Australia's Electricity Markets

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SKM | MMA

Contents

Abbreviations

AEMO	Australian Energy Market Operator (formerly NEMMCO)
ANTS	Australia's National Transmission Statement
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
DKIS	Darwin-Katherine Interconnected System
DSM	Demand side management
ERA	Economic regulatory Authority
ESOO 2010	Electricity Statement of Opportunities 2010, a document published by AEMO to provide information on the electricity demand and supply situation in the NEM
GEC	Queensland Gas Electricity Certificate
GGAS	Greenhouse Gas Abatement Scheme
IGCC	Integrated Gasification Combined Cycle Gas Turbine
IMO	Western Australian Independent Market Operator
IPART	Compliance Regulator
IPP	Independent Power Producers
LGC	Large-scale Generation Certificate
LNG	Liquefied Natural Gas
LRET	Large-scale Renewable Energy Target
LRMC	Long run marginal cost
MCAP	Marginal Cost Administered Price
MMAGas	Market Model Australia – Gas
MMRF	Monash Multi Regional Forecasting Model
MRET	Mandatory Renewable Energy Target
NEM	National Electricity Market
NGAC	New South Wales Greenhouse Abatement Certificate, which can be earned under the New South Wales Greenhouse Gas Abatement Scheme
NWIS	North-West Interconnected System
OCGT	Open Cycle Gas Turbine
PV	Photovoltaic generation
QNI	Queensland New South Wales interconnect
RET (aka MRET)	(Mandatory) Renewable Energy Target scheme. The scheme established under the Renewable Energy (Electricity) Act 2000
SKM MMA	Sinclair Knight Merz – McLennan Magasanik Associates
SRES	Small-scale Renewable Energy Scheme

SRMC	Short run marginal cost
STEM	Short-term Energy Market
SWIS	South-West Interconnected System in Western Australia
WEM	Wholesale Energy Market (applies to the SWIS in Western Australia)

1. Introduction

The Federal Treasury has engaged SKM MMA, part of the Sinclair Knight Merz Group, to undertake an assessment of the cost and benefits to the electricity market of a national carbon pricing mechanism. The analysis has been directed towards providing insights into the economic costs and benefits to the electricity sector, where cost is defined in terms of a reduction in the productivity of resource use in the sector and benefit is defined in terms of abatement of greenhouse gas emissions. Distributional impacts, such as changes to customer costs, are also examined.

In this report we describe the impacts of the carbon pricing mechanism on the electricity and fuel markets. Section 2 outlines the methodology employed to estimate the impacts. Section 3 summarises the key assumptions used in the modelling, and it also contains a description of the five scenarios and nine sensitivities modelled and an explanation of various other policy measures independent of carbon pricing which are relevant to the exercise.

Sections 4 and 5 present and discuss the key results of the analysis, including:

- Impact on costs of generation
- Impact on generation mix
- Impact on electricity prices

Section 6 presents the results of the nine sensitivity studies also undertaken.

In this report monetary values are in mid 2010 dollar terms and, unless otherwise stated, stated years refer to financial year ending June.

2. Methodology

2.1. Overview: Interaction between Models

Examination of the abatement potential and cost of carbon pricing requires the use of both bottom-up and top-down economic modelling. In this study:

- An initial electricity demand forecast was provided by Treasury
- Using this demand forecast, SKM MMA modelled the impact of different options on the electricity sector. The output of the modelling included: the impacts on energy prices; impacts on the costs of different types of generation; fuel usage; and the interaction of scenarios and policy options with other greenhouse policies such as the Large-scale Renewable Energy Target (LRET) scheme. Timing and type of new investments in generation for each region was also an output of the modelling
- The outputs of the SKM MMA modelling were then fed into the MMRF model to determine the impact of different scenarios and policies on the broader Australian economy
- The iterative procedure between MMRF and SKM MMA continued until there was convergence between demand and supply

2.2. Modelling Impacts on the Electricity Market

Detailed modelling of the Australian electricity markets over the timeframe of the study was undertaken by using SKM MMA's bottom up models of these markets. SKM MMA's model of the National Electricity Market (NEM), South West Interconnected System (SWIS), North West Interconnected System (NWIS) (which represents generating assets in the Pilbara mining region) and the Darwin Katherine Interconnected System (DKIS) simulates the Australian electricity market to determine:

- Dispatch of generating plant and electricity supply costs arising from this dispatch for each year
- Timing and type of new investments in electricity generation and for each region
- Impact of schemes such as Queensland's Gas Electricity Scheme and renewable energy targets on dispatch and electricity prices

Outputs from the bottom up models are then input into the Treasury's MMRF model of the Australian economy.

Modelling the impact of the abatement policies on the electricity market is a complex process. It requires iteration between a number of models to determine both the direct impacts and interactions between the various schemes. For example, carbon pricing will directly impact on the type and cost of renewable generation facilitated under the Renewable Energy Target (RET) scheme.

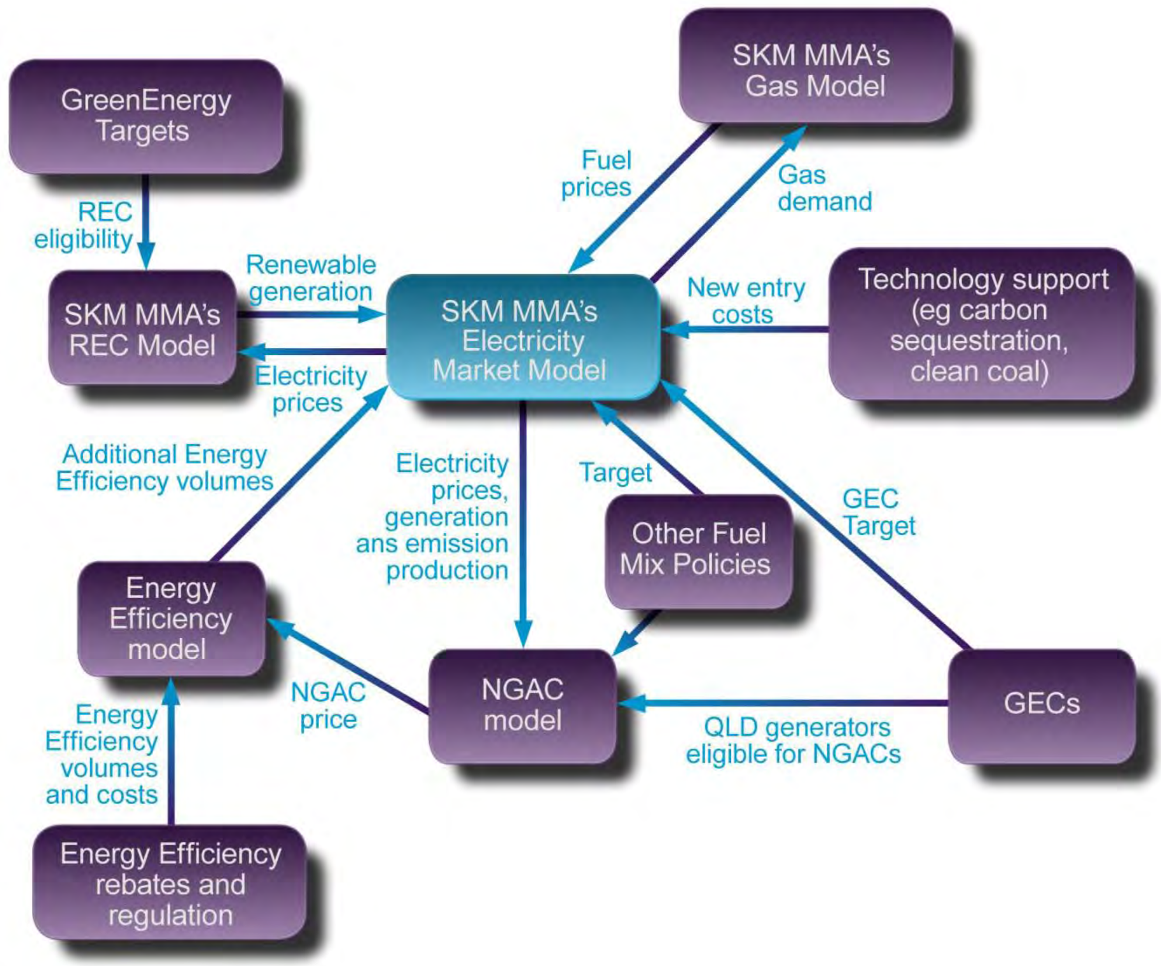
Generally, an abatement policy will directly impact on the electricity market in one of two ways. An abatement policy will:

- Vary the energy demand volume and profile
- Vary the net marginal cost of generation and hence the merit order of dispatch, through a price impost engendered through emissions targets. Carbon pricing impacts on the marginal cost of generation and hence the merit order of power plants. To the extent that these policies impact on electricity prices these policies would also be expected to impact on demand

Energy efficiency programs were not modelled explicitly by SKM MMA. Demand responses were captured in the MMRF modelling.

Figure 1 shows the interactions between the SKM MMA models used, and how the abatement policies were incorporated into the analysis.

- **Figure 1 Diagram of MMA's suite of models for assessing impact on energy sector**



2.3. Strategist Market Modelling Tool

The approach used to model the electricity market, associated fuel combustion and emissions was to utilise electricity demand forecasts derived from the MMRF model in the Strategist[1] database model of the major electricity systems in Australia. The model accounts for the economic relationships between generating plant in the system. In particular, the model calculated production of each power station given the generation availability of the station, the availability of other power stations and the relative costs of each generating plant in the system.

Strategist simulates the electricity market using a multi-area probabilistic dispatch algorithm, which incorporates:

- Chronological hourly electricity loads representing a typical week in each month of the year. The hourly load for the typical week is consistent with the hourly pattern of demand and the load duration curve over the corresponding month
- Chronological dispatches of hydro and pumped storage resources either within regions or across selected regions (hydro-electric plant is assumed to shadow price to maximise revenue at times of peak demand)

[1] Strategist is the market modelling software package used to simulate the various Australian energy markets.

- A range of bidding options for thermal plant to maximise profit from trading in the spot market is assumed up to the time new plant are needed for the region. After new plant is needed for a particular region, all plants in the region are bid at short run marginal cost
- Chronological dispatch of demand side programs
- Estimated inter-regional trading based on average hourly market prices derived from bids and the merit order and performance of thermal plant, and quadratic inter regional loss functions
- Scheduled and forced outage characteristics of thermal plant
- Probabilistic dispatch of interruptible loads to minimise unserved energy after all other resources are dispatched

For any given scenario Strategist represents the major thermal, hydro and pumped storage resources for all of the major grids, as well as the interconnections between the NEM regions. Economic optimisation tools (both internal and external to Strategist) are employed to adjust inter-related elements of the model and iteratively derive a solution that is more economically efficient. These elements may include thermal plant bids, uptake of renewable or thermal generation and appropriate retirement of existing generation. Average hourly pool prices are determined within Strategist based on thermal plant bids derived from marginal costs or entered directly, while renewable energy certificate prices are estimated outside of Strategist in SKM MMA's renewable energy market management model and are based on the net long run average cost of marginal renewable generation options.

2.4. Modelling Methodology

In any modelling study a critical element is obtaining the most realistic and low cost generation expansion plan for the market environment under consideration. This means that each generating unit must run under realistic conditions so that it is modelled to be viable and that new units are brought in only when absolutely necessary. This occurs to keep the system reliable and/or when market prices become unsustainably high relative to the cost of new entry.

Along with bringing in new generation units at the right time, there are also considerations on the correct type of unit to bring in, as well as the most appropriate time to retire older units in the system. The presence of carbon abatement and renewable energy policies in the system can sometimes have a dramatic effect on the most economic dispatch of units within the system. This change to dispatch of existing units can in turn affect the most optimal choice of new unit to bring in when one is required. The introduction of carbon pricing is likely to lead to some retirement of emissions intensive forms of generation in favour of renewable and low emissions intensity alternatives. Timing of retirement of existing units can also have a dramatic effect on dispatch of remaining units in the system and again affect the most optimal choice of new entrant at a given time.

SKM MMA have employed a number of approaches in the past to determining the most optimal generation portfolio over a given time, and occasionally have combined techniques to give a better result. Some of the approaches include iterative techniques and employment of a dynamic programming subroutine in Strategist called Proview to choose the most economic expansion plan among a range of expansion possibilities. What can make the analysis extremely time consuming is that the sheer range of expansion possibilities grows at an exponential rate with regard to timing of new entrants and retirements. The range of possibilities must therefore be limited in an economic manner to keep scenarios running within an acceptable time frame. This is done with a combination of screening curves and limited utilisation of Proview's dynamic programming capability that helps to identify the lowest cost options available in a given year.

The search for an optimal low cost solution requires a consistent set of interactions between:

- Thermal energy and renewable energy so that the cost of meeting the renewable energy is minimised
- The choice of new entry technology as affected by gas and carbon abatement certificate prices
- The retirement of old plants due to their high carbon emission profile or low economic efficiency relative to new plants

- The impact of constraints on new construction to replace retiring plants. This last item has become more critical when considering carbon pricing scenarios because of the additional construction activity required for plant replacement

The search for an economic solution over all of these resources in SKM MMA's models is achieved using an iterative process which converges to a near optimal solution. The following are usually modelled in turn until the lowest cost solution is obtained:

- Application of realistic price bidding behaviour with regard to gaming and dispatch modelling
- Modification of renewable technologies being placed in the market to maximise the return on renewable energy investments
- Minor adjustment of the new entry plan and retirements (i.e. need to move some units in the plan forward or back a small number of years to achieve an optimal level of reliability and to meet reserve margins)
- Adjustment of participation rates in existing abatement programs where participants face a choice

In the longer term the prices also track the estimated long-run new entry costs allowing for the carbon cost and the long-term trends in new entry costs and fuel prices.

The final generator expansion plan must meet minimum reserve constraints in each region, and satisfy maximum emergency energy requirements and maximum loss of load hour's requirements. Generators must behave rationally, with uneconomic capacity withdrawn from the market and bidding strategies limited by the cost of new entry. This is a conservative assumption as there have been periods when prices have exceeded new entry costs when averaged over 12 months. Infrequently-used peaking resources are bid near value of lost load[2] or removed from the simulation to represent strategic bidding of these resources when demand is moderate or low.

[2] (Now "Market Price Cap") currently defined as $12,500/MWh as the maximum half-hourly price in the spot market.

3. Assumptions

3.1. General Assumptions

A number of high level assumptions are employed in the modelling of all scenarios. The following list summarises the high level assumptions while further detail can be found in Appendix A.

The market is assumed to operate to maximise efficiency and is made up of informed, rational participants.

The study period is 2005 to 2050, with carbon pricing policies assumed to commence in July 2012.

Capacity is installed to meet the target reserve margin for the NEM, SWIS, NWIS and the DKIS as long as plant are profitable after entry.

Any changes in pool prices will flow through to retail prices. Price increases are therefore borne by the broad customer base.

Availability, heat rates and capacity factors of all plants in the NEM, SWIS, NWIS and DKIS (including non-renewable generators) are based on historical trends and other published data.

3.2. Additional Policies

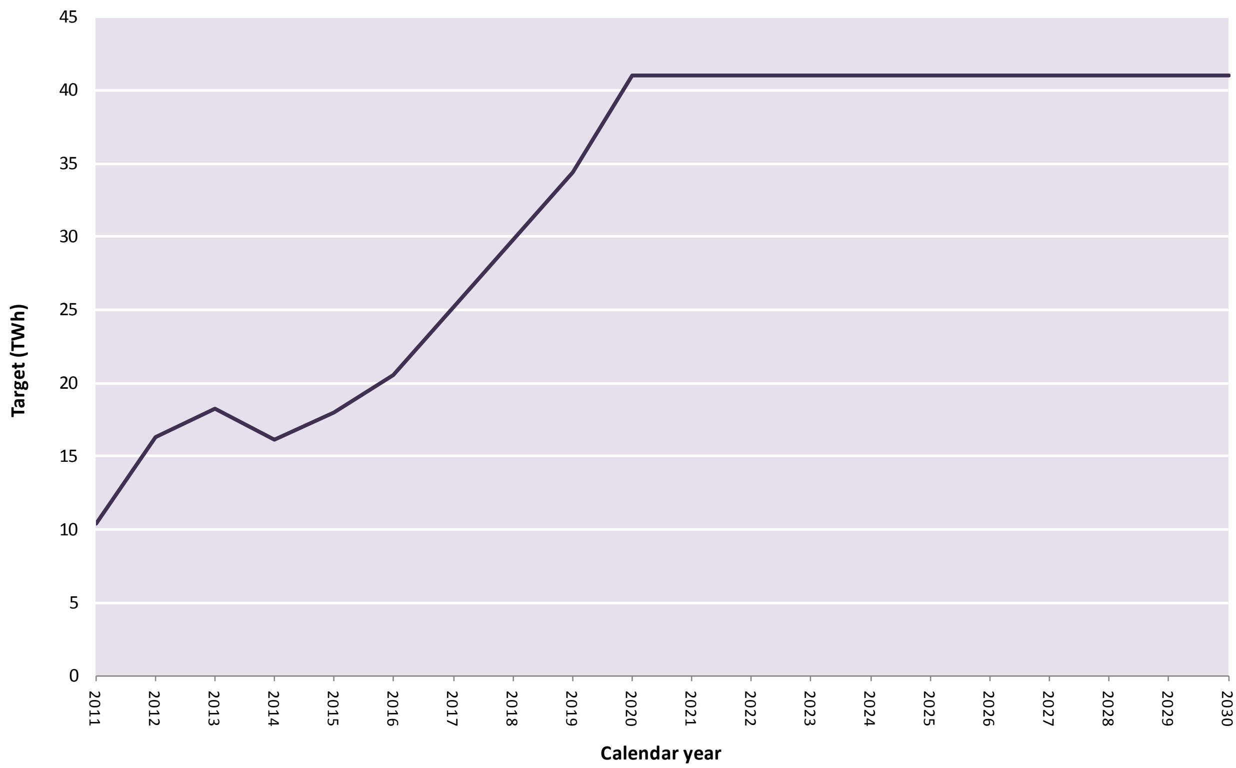
As a general principle in the reference modelling, existing policy measures were retained. In the electricity sector, these included the Queensland Gas Electricity Generation Target (in its expanded form), and the New South Wales and Australian Capital Territory Greenhouse Gas Reduction Scheme (GGAS). The former was also assumed to be in effect for all policy scenarios, although the latter was assumed to expire upon the commencement of carbon pricing. The LRET was also employed for all scenarios. In addition to the existing policy measures, an emissions intensity limit of 0.86 t CO_2e/MWh was imposed for new power stations in all scenarios. A brief description of these schemes follows:

- The **Queensland Gas Electricity Generation Target** is designed to diversify the energy mix for the coal rich state. The scheme began on 1 January 2005 and was to continue for 15 years. It requires electricity retailers to source at least 13% of their energy from gas-fired generation. A Gas Electricity Certificate (GEC) is created for every MWh of eligible gas-fired electricity and is required to be surrendered to the Regulator by Queensland electricity retailers and other parties. The scheme allows for some flexibility, with liable entities able to choose to create either GECs, or alternatively New South Wales Greenhouse Gas Abatement Certificate (NGAC), depending on the respective markets. In later legislation, the target was increased to 15% by 2010, with the option to further raise it to 18% depending on the design of the carbon pricing scheme. In this review, the target was modelled to increase to 15% by 2010 and subsequently increase to an 18% target by 2020 in a linear fashion
- The **New South Wales GGAS** began on 1 January 2003 for New South Wales and 1 January 2005 for the Australian Capital Territory and ceases at the commencement of a carbon pricing scheme. The scheme sets and regulates mandatory emissions abatement targets on both the production and use of energy. A benchmark was established state-wide, initially at 8.65 tCO_2e per capita, with this target dropping linearly to 7.27 tCO_2e from 2007 until the close of the program. Under the scheme, eligible participants can create NGACs by electricity generation activities, carbon sequestration activities, demand side abatement activities or large user abatement activities. These certificates are each worth the equivalent of one tonne of carbon dioxide (CO_2) equivalent emissions. Retailers and other parties involved in the direct sale of electricity are required to surrender certificates to the Compliance Regulator (IPART) for a benchmark amount of CO_2. The penalty for non-compliance is $11.50 per tonne of CO_2. In the absence of any federal emissions scheme, this penalty is due to be raised by $1 per year from 2010 to 2013. The penalty is adjusted annually in line with the consumer price index. Liable parties may surrender renewable energy certificates in substitution for NGACs, and importantly, NGACs can be created anywhere in the NEM
- The expanded **LRET** imposes a target of 41,000 GWh of additional renewable energy from large-scale generation sources by 2020. The targets are given in Figure 2. Generation from small-scale plant such as solar water heaters or

rooftop PV systems contributes to the Small-scale Renewable Energy Scheme (SRES), and the combined renewable generation from the large-scale and small-scale schemes is expected to exceed the 45,000 GWh target of their predecessor, the expanded MRET scheme. For the present modelling, generation output of small-scale systems subsidised by the SRES exceeded 7,600 GWh per annum at its peak (which occurred in 2026), meaning that total renewable generation exceeded 48,600 GWh for the reference cases[3]. The LRET scheme is otherwise similar to the MRET scheme in terms of issues such as banking of certificates and project eligibility periods

- The **Green Power** scheme is a national initiative that complements the RETs. Small-scale consumers may purchase a percentage of their electricity from renewable sources other than those already accredited to the renewable target scheme. The effect of Green Power is explicitly modelled in SKM MMA's renewable model, with future sales projected from current registry data
- An **Emissions Intensity Limit** policy of 0.86 t CO_2e/MWh for new power stations is also assumed to take effect for all scenarios. According to SKM MMA's technical performance assumptions for new plant, under such as policy the only non-CCS coal-fired plant that could be permitted would be supercritical coal-fired technology burning good quality black coal. The same technology burning brown coal would not satisfy the emissions limit under SKM MMA's assumptions, which would mean that, in the absence of a carbon price, new base load in Victoria would either be combined cycle gas turbine (CCGT) plant, or base load power may need to be imported from New South Wales by upgrading the transmission infrastructure if this was a cheaper option. In the policy scenarios the emissions intensity limit policy did not restrict the entry of brown coal plant in Victoria fitted with carbon capture and storage technology

- **Figure 2 Annual LRET target, GWh**



[3] The total number is much higher for the policy cases.

3.3. Scenario Assumptions

A total of four scenarios were modelled for this assignment – two reference scenarios and two policy scenarios, although an additional price sensitivity is also of relevance to the scenario modelling. A summary of the key scenario parameters that define these scenarios is presented in Table 1. The scenario descriptions are as follows:

- The **medium global action** (reference) scenario assumes that the rest of the world sets out to achieve a CO_2 atmospheric concentration target of 550 ppm, while Australia takes no action. This serves as the reference case for the core policy scenario and the low price sensitivity
- The **ambitious global action** (reference) scenario assumes that the rest of the world sets out to achieve a CO_2 atmospheric concentration target of 450 ppm, while Australia takes no action. This serves as the reference case for the high price scenario
- The **core policy** scenario assumes that the world sets out to achieve a CO_2 atmospheric concentration target of 550 ppm, and Australia implements from the outset a carbon price in line with the world target. Carbon pricing commences in July 2012 and the initial carbon price is just under \$20/t CO_2e, expressed in mid 2010 dollars. In FY 2016 the price jumps from \$20/t CO_2e to \$25/t CO_2e and grows at an average rate of 5% per annum thereafter
- The **high price** scenario assumes that the world sets out to achieve a CO_2 atmospheric concentration target of 450 ppm, and Australia implements from the outset a carbon price in line with the world target. Carbon pricing commences in July 2012 and the initial carbon price is just under \$30/t CO_2e. In FY 2016 the price jumps from \$30.5/t CO_2e to \$52/t CO_2e and grows at an average rate of 5% per annum thereafter
- The **low price** sensitivity assumes that the world sets out to achieve a CO_2 atmospheric concentration target of 550 ppm, and Australia implements a soft start in its carbon price for the first decade of the carbon price. Carbon pricing commences in July 2012 and the initial carbon price is just under \$10/t CO_2e. There is a step jump in the Australian carbon price in FY 2023, when it jumps from \$14/t CO_2e to the carbon price trajectory of the core policy case, which is \$35.5/t CO_2e in 2023. The carbon price grows at 5% per annum thereafter

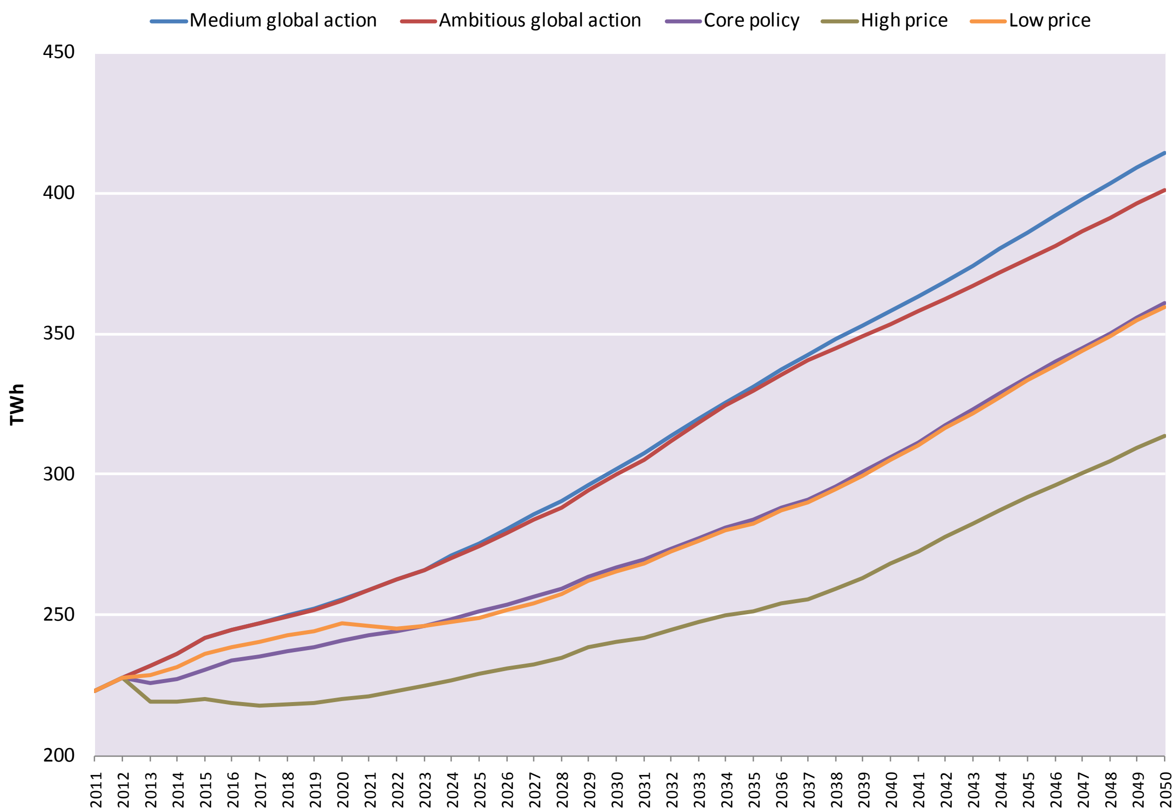
Table 1 Key scenario parameters defining scenarios

SCENARIO PARAMETER	UNITS	MEDIUM ACTION	AMBITIOUS ACTION	CORE POLICY	HIGH PRICE	LOW PRICE
Initial carbon price	\$/t CO_2e	\$0	\$0	\$18.5	\$27.5	\$9.0
Demand growth rate	%	1.6%	1.5%	1.2%	0.9%	1.2%
LRET target	GWh	41,000	41,000	41,000	41,000	41,000
GGAS scheme to 2020	-	Yes	Yes	No	No	No
GEC scheme to 2020	-	Yes	Yes	Yes	Yes	Yes
Emissions intensity limit	-	Yes	Yes	Yes	Yes	Yes

3.3.1. Demand Assumptions

Figure 3 shows aggregate energy demand of all the major Australian grids by scenario, which was provided by the Treasury. Demand for the low price sensitivity tracks back to that of the core policy scenario as soon as the carbon prices of the two cases fall into alignment. The compound average annual growth rates of the demand trajectories are summarised in Table 1.

■ **Figure 3 Aggregate Australian demand by scenario, GWh**



3.3.2. Carbon Price Assumptions

Carbon price assumptions were provided by the Treasury for the two carbon pricing scenarios and for the low price sensitivity case. The carbon price for the core policy scenario commences from July 2012 at $18.5 t/$CO_2$e, and then jumps in FY 2016 from $20/t CO_2e to $25/t CO_2e, and grows at 5% per annum thereafter. Under the high price scenario the initial carbon price is $27.5/t CO_2e, commencing in July 2012. As with the core policy scenario the price steps up in FY 2016, although to a much higher level (from $30.5/t CO_2e to $52/t CO_2e) and it continues to grow at 5% per annum thereafter. The carbon price for the low price sensitivity case also commences from July 2012 at $9/t CO_2e. However, the step jump in price is deferred to FY 2023 when it jumps from $14/t CO_2e to $35.5/t CO_2e, where the latter price is identical to that of the core policy scenario in FY 2023. The carbon price trajectory for the low price sensitivity case then tracks that of the core policy scenario having a growth rate of 5% per annum thereafter.

3.3.3. Technology Learning Rate Assumptions

Table 2 shows the assumed average technology learning rates by scenario, which was provided by Treasury[4]. The key driver in the technology learning rates is evidently the global CO_2 concentration target. In the 450 ppm scenarios (ambitious action and high price) where the target is more stringent, learning rates for the renewable technologies and gas with carbon capture and storage (CCS) are slightly higher, whereas learning rates for coal with CCS technology are highest for the 550 ppm scenarios (medium action, core policy and low price sensitivity). A higher technology learning rate reflects a greater level of global uptake for a particular technology, and therefore more learning by doing is possible as more capacity is built.

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[4] Learning rates for conventional coal and conventional gas were SKM MMA assumptions.

Table 2 Average technology learning rates by scenario[5]

	MEDIUM ACTION	AMBITIOUS ACTION	CORE POLICY	HIGH PRICE	LOW PRICE
Wind	0.30%	0.33%	0.30%	0.33%	0.30%
Solar	0.90%	1.02%	0.90%	1.02%	0.90%
Other renewables	0.47%	0.49%	0.47%	0.49%	0.47%
Coal CCS	0.32%	0.31%	0.32%	0.31%	0.32%
Gas CCS	0.49%	0.54%	0.49%	0.54%	0.49%
Conventional Coal	0.10%	0.10%	0.10%	0.10%	0.10%
Conventional Gas	0.10%	0.10%	0.10%	0.10%	0.10%

3.4. Sensitivity Assumptions

Nine sensitivity cases were also modelled in addition to the four scenarios and the price sensitivity already presented. All sensitivities were relative to either the medium global action scenario or the core policy scenario, and are defined as follows:

- Two **gas price** sensitivities: one relative to the medium action reference scenario and the other relative to the core policy scenario. In both sensitivities the real domestic gas price grows in a straight line to $6.50/GJ by 2030 from current levels and then remains constant in real terms until 2050
- Two **coal price** sensitivities: one relative to the medium action reference scenario and the other relative to the core policy scenario. In both sensitivities the real domestic coal price declines at half the rate of the corresponding scenario
- Two **lower renewable energy technology cost** sensitivities: one relative to the medium action reference scenario and the other relative to the core policy scenario. In these sensitivities technology costs provided by the CSIRO were used as follows:
  - Wind - $1,898/kW installed in 2015 and $1,497/kW in 2030
  - PV (fixed flat plate) - $3,399/kW in 2015 and $2,154/kW in 2030
  - Solar thermal without storage - $2,932/kW in 2015 and $2,037/kW in 2030

These result in effective technology learning rates of 1.57% per annum for wind, 3% per annum for PV and 2.4% per annum for solar, all of which are considerably higher than the base learning rates set out in Table 2.

- Two **lower technology learning rate** sensitivities: one relative to the medium action reference scenario and the other relative to the core policy scenario. In both sensitivities the technology learning rates shown in Table 2 are halved.
- One **no CCS** sensitivity relative to the core policy scenario. In this case CCS technology is assumed not to be commercially and/or technically viable, and therefore CCGT technology becomes the lowest emitting thermal base load technology

[5] These learning rates translate into a per annum capital expenditure reduction in real terms.

4. Benefits and Costs to the Generation Sector

4.1. Overview

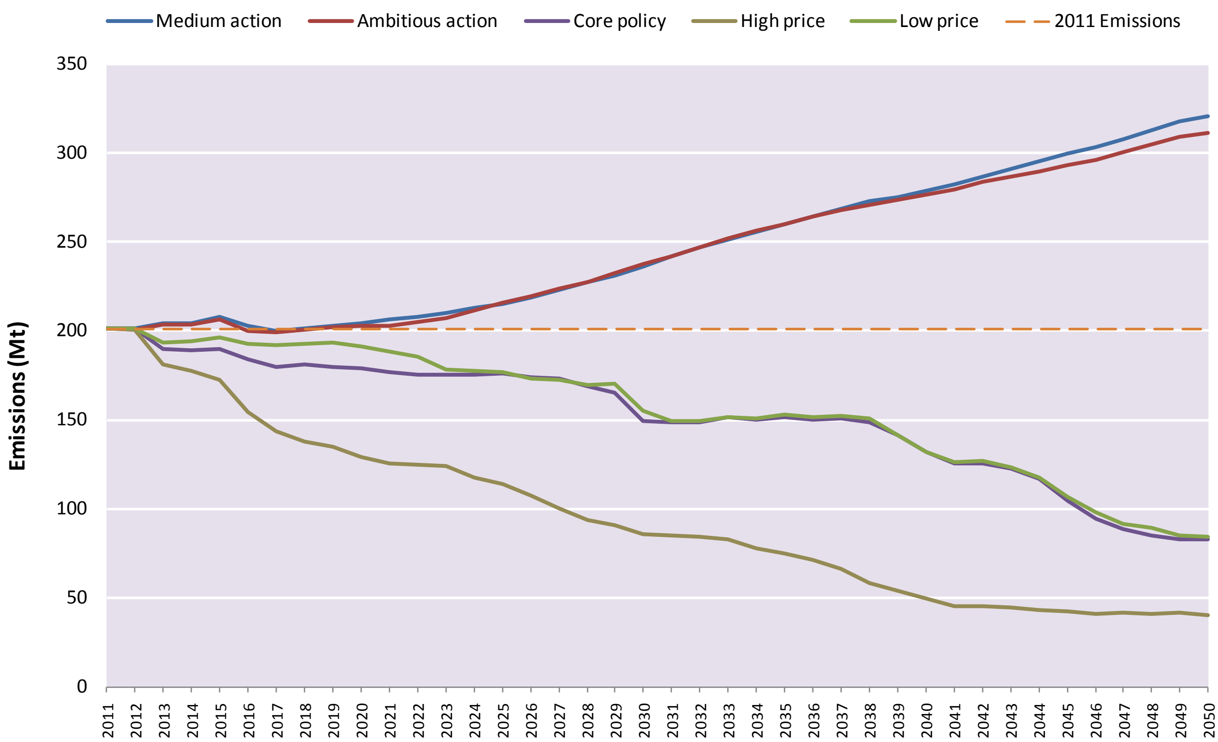
Carbon pricing is designed to reduce the amount of emissions of greenhouse gases. This is done by increasing the cost of activities with high emission rates, and driving investment in or uptake of lower emissions technologies and activities. As low-emission technologies and fuels can be more expensive than those used currently, (or under business as usual), carbon pricing results in some cost to the economy.

4.2. Abatement

The level of abatement achieved in the electricity sector depends intrinsically on the carbon price and the complementary policies that are operational. As the scenarios were modelled with a permit price trajectory, the banking of permits to achieve a specific abatement target in the sector was not considered. Rather, measures such as the LRET increase the level of abatement in the sector.

Combined emissions from combustion of fuels in electricity generation are shown in Figure 4. In all scenarios with carbon pricing, emissions are expected to be well below the level projected without the carbon price.

■ **Figure 4 Emissions from electricity generation, Mt CO_2**



Emissions for both reference cases are initially quite flat until about 2022, and then they grow steadily to reach over 300 Mt CO_2 per annum. The initial flatness in emissions growth is due to the LRET scheme, which picks up almost all of the load growth from 2011 to 2020. Once the LRET target flattens out, conventional coal-fired and gas-fired generation meet the load growth, and emissions consequently increase.

Emissions in the scenarios with carbon pricing depend on the permit price as the overall target is set for the economy as a whole. The level of abatement across the sectors of the economy depends on the relativity of the marginal cost of abatement between each sector. Therefore, even if there is a economy wide cap of, say, 5% below 2000 levels by 2020, some sectors with low cost abatement options may achieve more than 5% reduction and other sectors with high costs of abatement may achieve less. In addition, the availability of low cost permits sourced from other countries with large amounts of low cost abatement could potentially contribute to reaching the target.

The emission abatement results for the electricity generation sector show that there is relatively little abatement in the first seven or eight years of the low price sensitivity because the low initial carbon price is not high enough to force the closure of the high emitting coal-fired power stations, whereas in the other two policy scenarios the carbon price is high enough to force some of the high emitting plant to close down over the first decade. The initial decline in emissions for the core policy and low price cases is followed by a gradual decline until about 2030, which coincides with the closure of more high emitting power stations. There is further stabilisation of emissions until about 2038, when the remaining high emitting power stations retire, and this is followed by the gradual retirement of the remaining black coal power stations in both New South Wales and Queensland. The introduction of both coal-fired and gas-fired CCS technology from 2038 onwards also helps to substantially reduce the emissions profile in the 2040s until 2050.

The deepest emissions cuts are achieved in the high price scenario, where the high initial carbon prices ($52/t CO_2e in 2016) force the closure of both brown and black coal-fired power stations as soon as carbon pricing commences. The introduction of both coal-fired and gas-fired CCS technology from as early as 2027 also makes a large contribution to the abatement of CO_2.

Cuts in emissions relative to 2011 levels are shown in Table 3 by scenario. The key feature is that as early as 2020 there are notable emissions reductions for all scenarios relative to 2011, ranging from a 5% reduction for the low price sensitivity case to as much as a 36% reduction for the high price scenario. Further reduction in emissions continues beyond 2020, but the largest reduction in relative terms for the core policy and low price cases occurs between 2040 and 2050. Also noteworthy is that the 2050 emission reduction levels for these two cases are achieved by 2030 under the high price scenario.

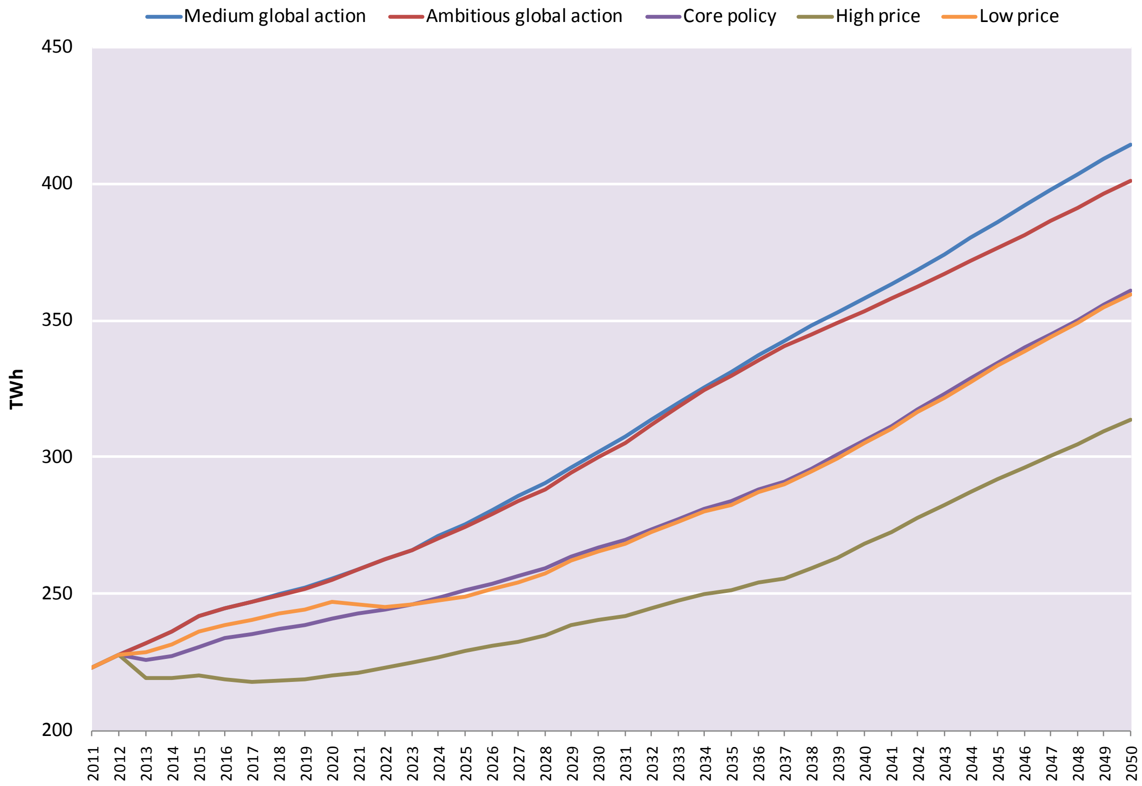
- **Table 3 Emissions in electricity generation by scenario**

	2020	2030	2040	2050
Emissions, Mt				
2011 level	201	201	201	201
Core policy	179	149	132	82
High price	129	87	52	42
Low price	191	155	132	84
Change from 2011 levels				
Core policy	-11%	-26%	-34%	-59%
High price	-36%	-58%	-75%	-80%
Low price	-5%	-23%	-34%	-58%

Three factors are responsible for the rate of change in emissions for the given permit prices. First, there is the response of electricity demand to the higher electricity prices brought about by the carbon price impost[6]. With the onset of carbon pricing, electricity demand either stabilises or falls slightly before recovering to grow at a slower rate than for the reference scenario (see Figure 5). By 2020, electricity demand is some 3% to 14% below reference scenario levels and by 2050 demand is 13% to 22% below reference scenario levels (see Table 4).

The second factor is the switch away from coal-fired generation by incumbents to gas fired and renewable energy generation, which is a function of gas prices and permit prices. By 2020, the most discernable switching occurs for brown coal generation (see Figure 6 and Table 5), although there is also a slight switch away from black coal generation too for the core policy scenario and the low price sensitivity. The level of renewable generation by 2020 is significantly higher only for the high price scenario, which suggests that in the absence of the LRET the carbon prices for the low price and core policy cases at that point ($13/t CO_2e and $29.5/t CO_2e respectively) are not high enough to support widespread new entrant renewable generation. By 2020 renewable generation for the low price sensitivity case is slightly lower than the medium action reference case. This occurred because the optimisation achieved lowest cost by deferring a block of wind generation to 2021 in the low price case, and also deferring a large block of geothermal generation to 2023. Thus by 2021, there are similar levels of renewable generation between the two cases, and by 2023, when the carbon price steps up significantly, the low price sensitivity case clearly has more renewable generation. By 2030 (see Figure 7), the level of incumbent black coal generation is significantly lower for all carbon pricing scenarios, and there is also more renewable generation and gas-fired generation.

▪ **Figure 5 Aggregate Australian demand by scenario, GWh**

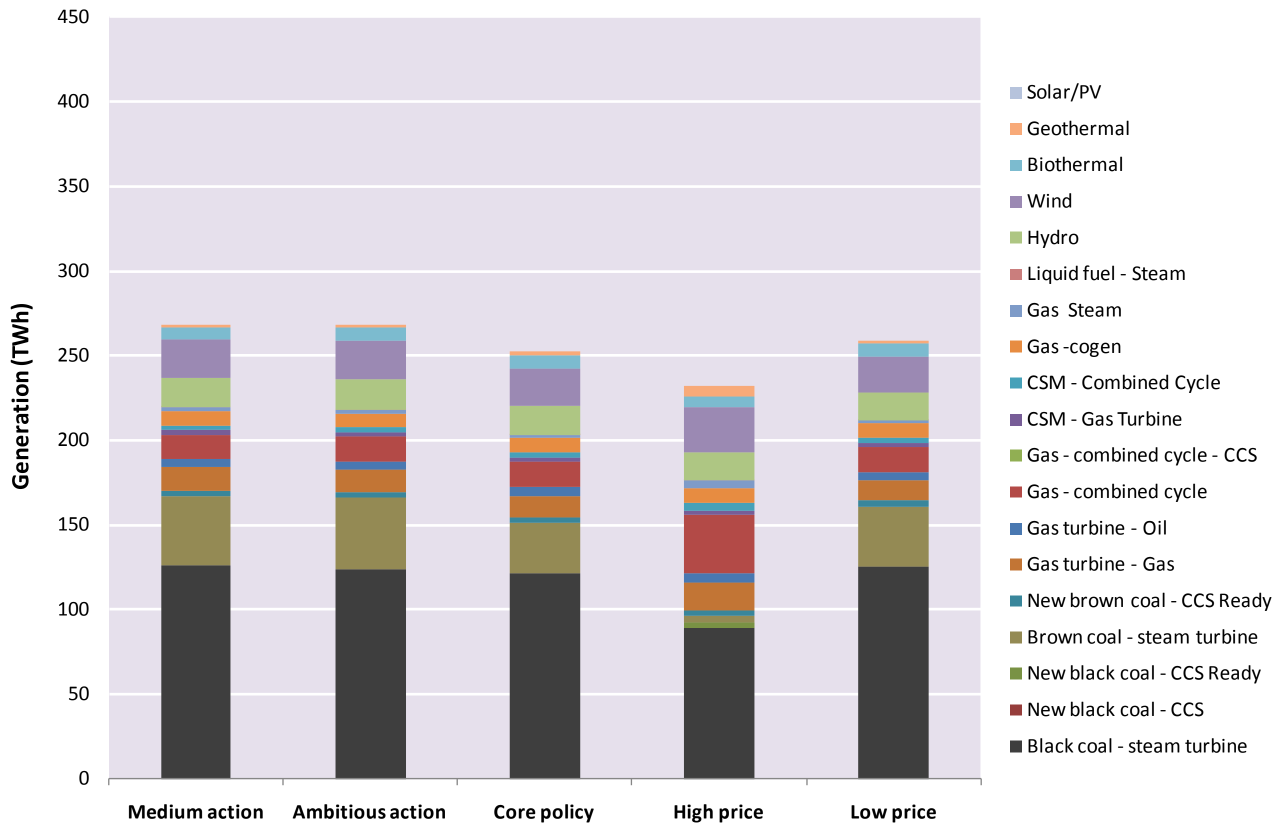


[6] The response of demand to higher electricity prices were determined by the MMRF model through an iteration process with SKM MMA's Strategist model, which provided the pool price rises.

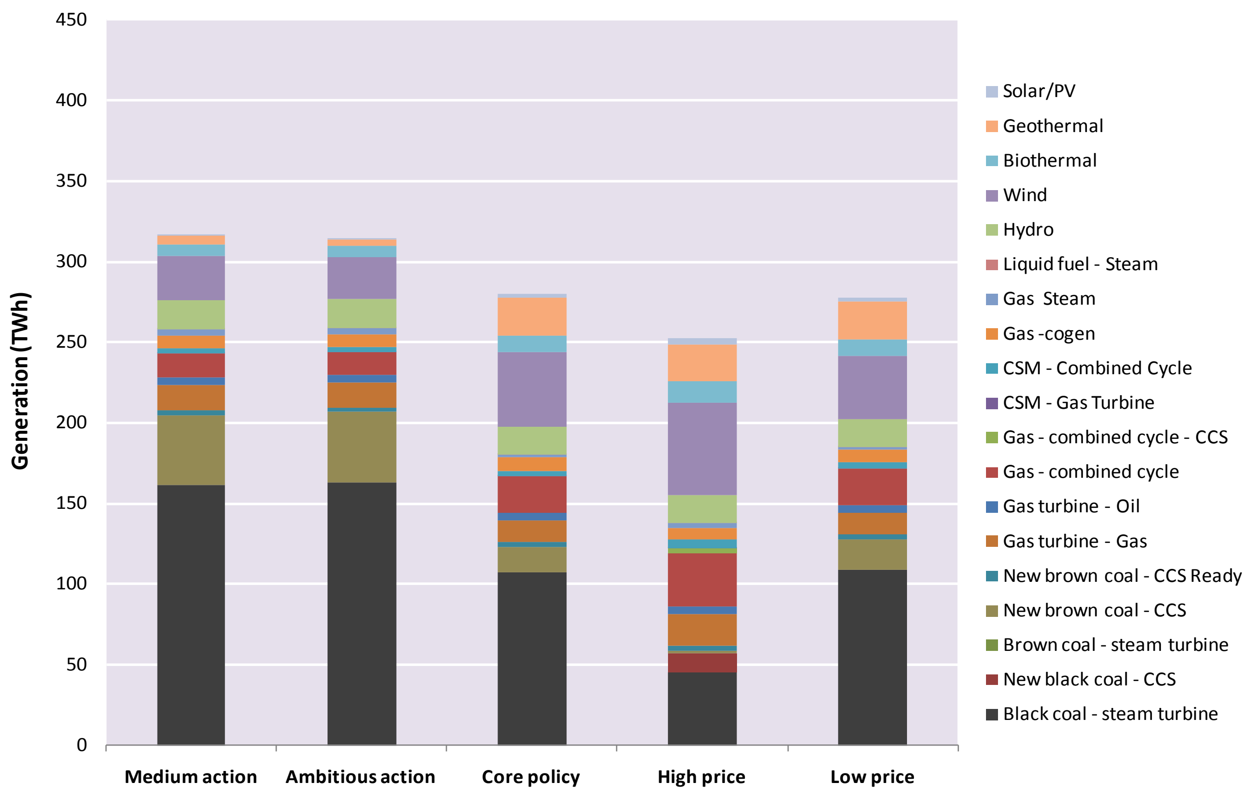
■ Table 4 Change in electricity demand

	2010	2020	2030	2040	2050
Generation (sent out basis), TWh					
Medium action	223	255	302	358	414
Ambitious action	223	255	300	354	401
Core policy	223	241	267	306	361
High price	223	220	240	268	313
Low price	223	247	265	305	360
Change from relevant reference case					
Core policy		-6%	-12%	-14%	-13%
High price		-14%	-20%	-24%	-22%
Low price		-3%	-12%	-15%	-13%

■ Figure 6 National generation mix, 2020, GWh



▪ **Figure 7 National generation mix, 2030, GWh**



▪ **Figure 8 National generation mix, 2050, GWh**

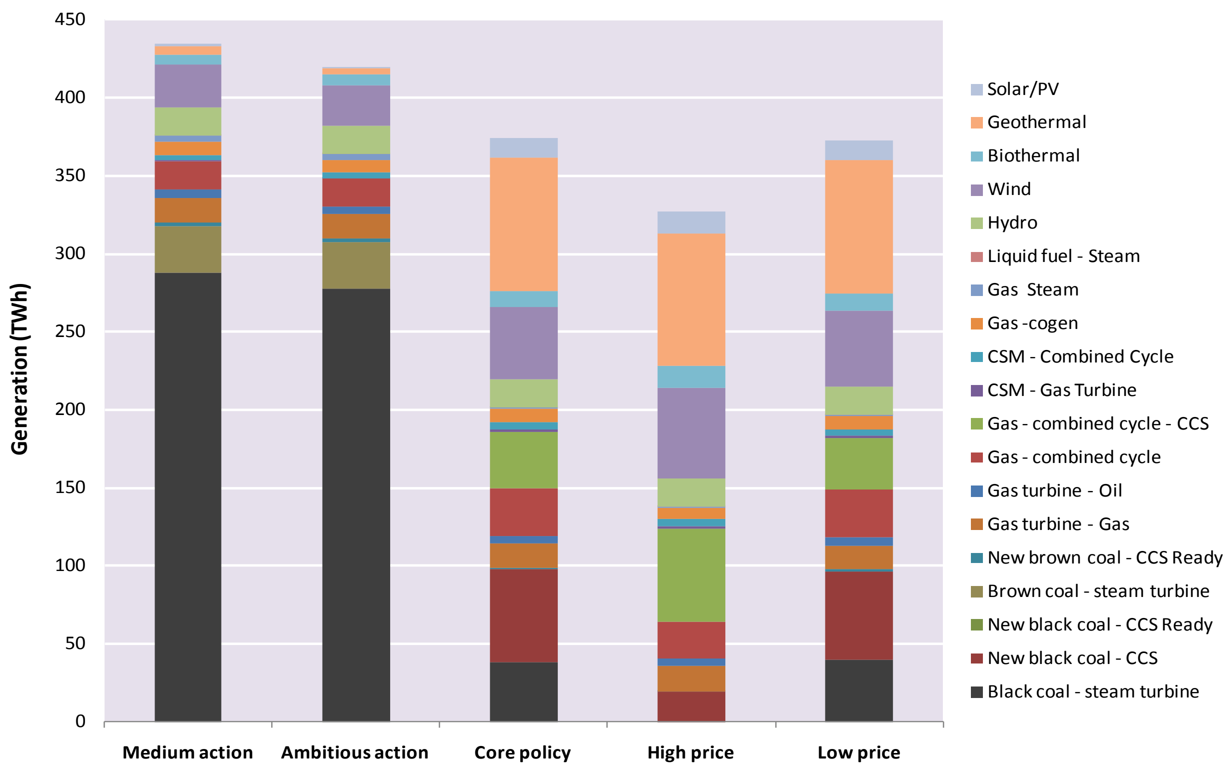


Table 5 Change in generation mix, 2020

	MEDIUM ACTION	AMBITIOUS ACTION	CORE POLICY	HIGH PRICE	LOW PRICE
Generation (sent out basis), TWh					
Black coal	126	124	121	92	125
Brown coal	44	45	33	7	39
Natural gas	44	44	44	72	42
Liquid fuels	5	5	5	5	5
Hydro-electric	18	18	17	17	17
Wind	23	23	23	27	21
Biothermal	7	8	8	6	8
Geothermal	2	2	2	6	1
Solar/PV	0	0	0	0	0

Note: Hydro-electric plant includes generation from pumped storage facilities, and it is at these facilities where the decrease in generation occurs in the carbon pricing scenarios.

The third factor is the change in the mix of new generation. Figure 8 shows the dramatic shift away from coal-fired generation in all three carbon pricing cases by 2050, with renewable generation becoming the dominant energy source. However, thermal generation sources still have their role to play, and black coal generation with CCS is the main thermal base load plant for the core policy scenario and the low price sensitivity, whereas combined cycle plant with CCS is the more dominant thermal technology when the carbon price is higher.

4.3. Cost of Abatement

4.3.1. Resource cost

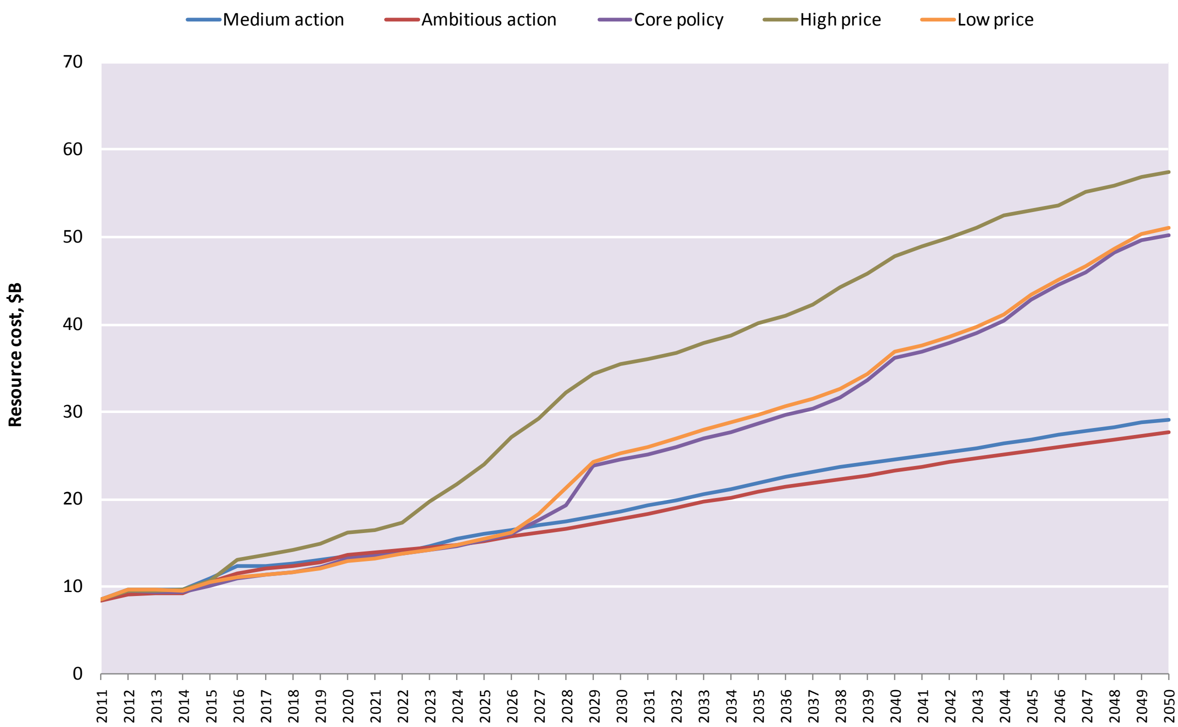
Abatement of greenhouse gases comes at a cost to the economy due to the fact that higher cost forms of generation are deployed to meet the emission targets than would otherwise have been applied.

Predicted trends in resource costs are shown in Figure 9. The resource costs cover the cost of fuel, operating and maintaining plant and the capital costs of new plant.

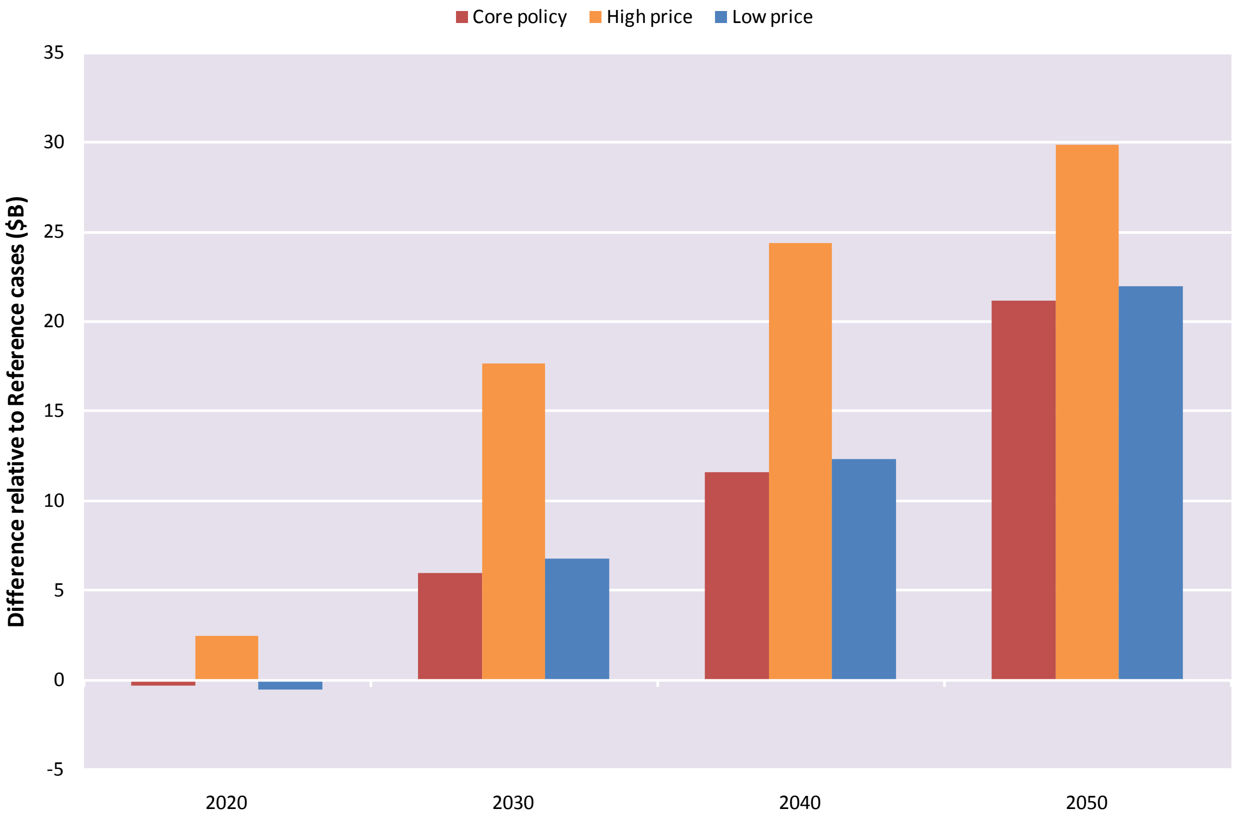
Under carbon pricing, resource costs in electricity generation are actually equal to or slightly lower than those in the reference case in the period to 2026, with the exception of the high price case. This is due to the decrease in demand under carbon pricing, which reduces the need for resources in electricity generation. However, in the carbon pricing scenarios, the lower cost to serve reduced demand is offset by the higher capital cost of new low emission generation. In the high price case, the latter outweighs the former from 2015 onwards. This does not mean that economic costs are low, rather the costs are borne by other sectors of the economy (partly reflected in the electricity sector as less efficient use of resources in other sectors, leading to a reduced demand for electricity).

Over the long-term, resource costs for the carbon pricing cases are significantly higher than in the reference cases. By 2040, resource costs are from $12 billion to $24 billion per annum higher than in the reference cases. By 2050, resource costs are estimated to be between $21 billion to $30 billion higher than the reference cases. The higher cost is mainly due to the higher capital cost of new low emission plant and the additional cost of carbon capture and storage.

- **Figure 9 Resource cost by scenario**



- **Figure 10 Difference in resource costs relative to reference cases**



4.3.2. Investment Cost

Table 6 shows the total amount of capital investment needed in new generation technology for the medium global action scenario and the core policy scenario. The level of capital investment is similar between the two cases until 2020, which is not surprising since the main driver of investment in this time frame is the LRET scheme, which is the same for both cases. However, by 2050 almost twice the capital investment is needed for the core policy scenario relative to the medium global action scenario, even though there is less demand to serve. The generation categories requiring the most investment under the core policy scenario include black coal IGCC technology with CCS, following by geothermal technology and wind technology. In contrast, the medium global action case sees investment predominantly in black coal steam turbine technology, followed by open cycle gas turbines powered on natural gas, and then wind technology.

■ **Table 6 Cumulative cost of new generation investment by generating technology ($B)**

	MEDIUM GOLBAL ACTION		CORE POLICY	
	To 2020	**To 2050**	**To 2020**	**To 2050**
Black coal – steam turbine	0.8	55.7	0.0	0.0
Black coal – IGCC + CCS	0.0	0.0	0.0	66.4
Brown coal – steam turbine	0.0	0.0	0.0	0.0
Brown coal – IGCC + CCS	0.0	0.0	0.0	0.0
OCGT – Gas	1.2	21.3	0.3	24.4
CCGT – Gas	0.8	2.0	1.0	5.8
CCGT + CCS – Gas	0.0	0.0	0.0	18.8
Hydro	0.8	0.8	0.8	0.8
Wind	15.6	18.5	16.6	36.9
Biothermal	2.8	2.8	2.5	3.7
Geothermal	1.3	3.3	2.0	42.6
Solar / PV	0.1	3.7	0.1	12.8
Total	**23.3**	**108.1**	**23.3**	**212.2**

5. Electricity Market Impacts

5.1. Energy Prices

5.1.1. Medium Global Action Scenario

Pool prices are impacted by changes in demand profile and level of demand and the cost of generation technologies.

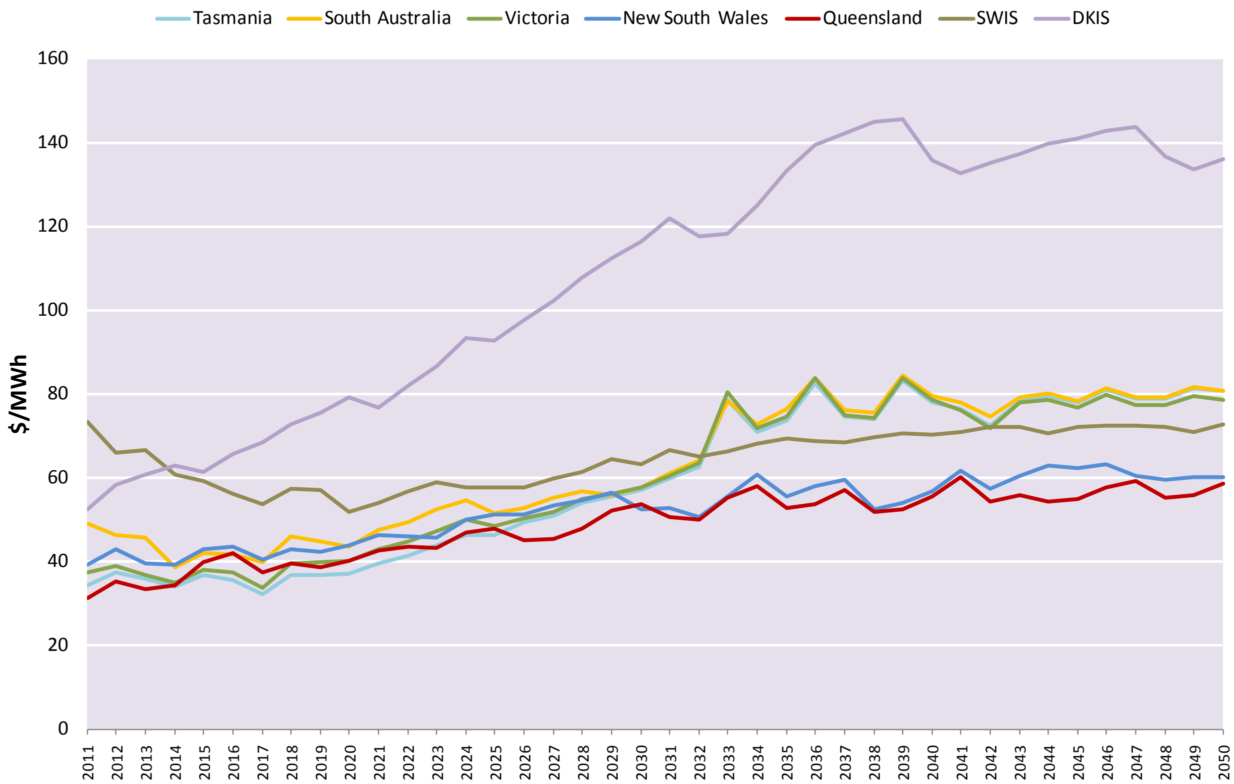
To compare impacts of carbon pricing, pool prices for the medium global action scenario, which serves as a non-carbon price reference scenario, are provided in Figure 11. The medium action case contains a number of features that are likely to impact on price trends:

- Changes to gas prices put upward pressure on pool prices, and this is particularly evident in the DKIS price, where CCGT plant sets the price and is the marginal new entrant
- The assumed emissions intensity limit for new plant of 0.86 t CO_2e/MWh precludes the entry of new brown coal plant in Victoria, and as a result CCGT plant is the marginal plant there because there is no other viable thermal power alternative. However, the escalating cost of gas means that eventually it becomes cheaper to import energy into Victoria from conventional coal-fired base load plant in New South Wales by upgrading the transmission system. This explains the price separation between New South Wales and Victoria post 2030, which is when new base load capacity is required in Victoria
- Inclusion of the New South Wales GGAS and the Queensland GEC Scheme, both of which subsidise low emission generation and put downward pressure on prices
- The gradual weakening of the Australian dollar in the exchange rate assumptions to 2050 places upward pressure on prices since it results in rising capital costs

Prices in the NEM for the medium action case start from about $40/MWh and gradually rise to $60/MWh in the black coal regions of New South Wales and Queensland. The price rise is primarily due to increasing capital costs, which are primarily driven by the falling exchange rate as well as increasing metal prices. However, the Victorian price separates from that of the northern states after 2030 for the reasons already mentioned above. The Tasmanian and South Australian prices follow the Victorian price, and therefore the southern state prices separate from those of the northern states.

Prices in the SWIS remain above those of the northern NEM regions due to higher fuel costs and smaller scale of generation, but are cheaper than the southern NEM regions post 2030 since the SWIS price is set by black coal plant. Prices in the DKIS reflect the international gas price and escalate from $60/MWh in 2011 to $140/MWh by 2050.

- **Figure 11 Electricity pool prices, medium global action scenario, $/MWh**

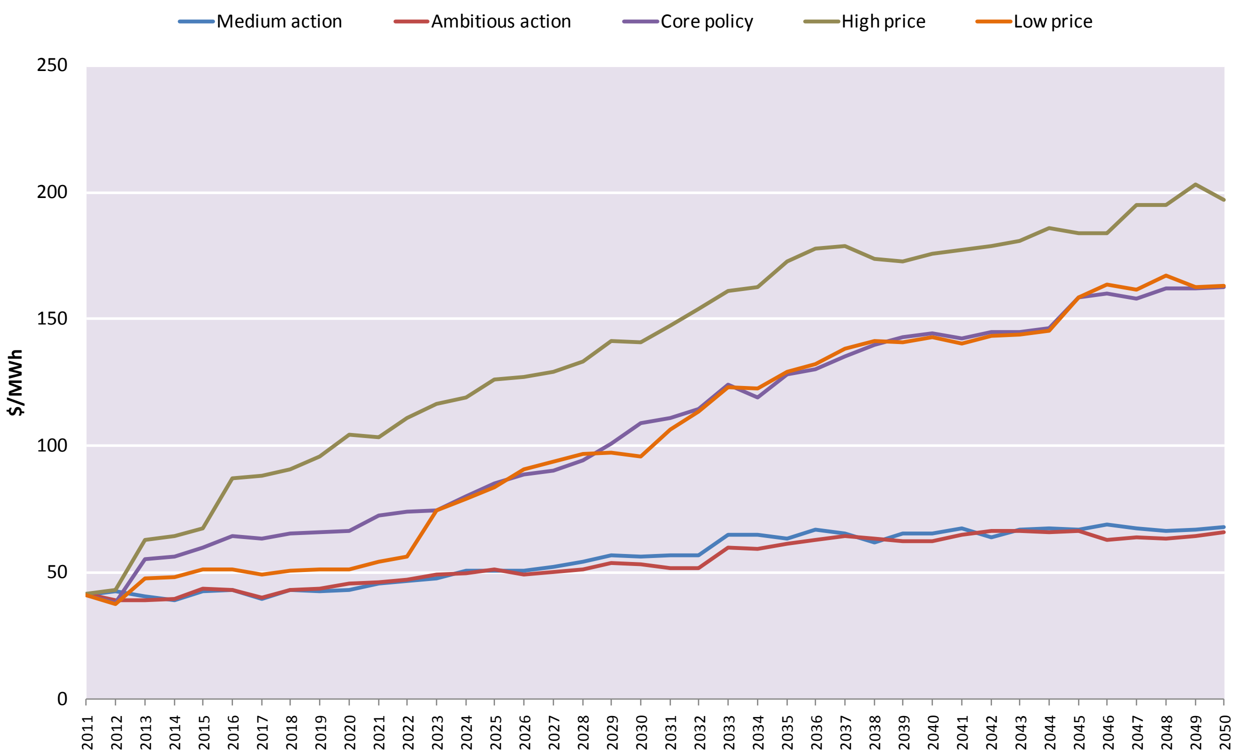


5.1.2. Pool Prices by Scenario

Average pool prices for Australia under carbon pricing are shown in Figure 12. Pool prices are driven by two major factors: the permit price and the escalating price of gas. The higher the permit price, the higher the pool price, although the relative increase diminishes as permit prices increase and more lower emissions plant enter the system, displacing higher emitting incumbents. Gas prices also play a central role in determining pool prices since under a sufficiently high permit price, CCGT technology becomes the marginal new entrant. The RET tends to place downward pressure on prices in the short to medium term due to excess generation capacity entering the market, but has little impact on prices in the long-term as renewable energy is taken up under carbon pricing.

High gas prices are a factor in the continual and rapid escalation of pool prices under the carbon pricing scenarios evident in Figure 12, potentially contributing to the prolonged viability of incumbent coal plant since the higher pool prices afford them greater income. It turns out that this is not the case for the high price scenario, because the high initial carbon price outweighs the benefit of the high gas price for incumbent coal plants. However, for the core policy scenario and the low price sensitivity, the high gas price does support the profitability of the incumbent coal plant, to the extent that the most efficient incumbent Victorian brown coal plant operates until 2040. Moreover, the first incumbent black coal plant retirement in New South Wales occurs in 2029, although the larger plants do not start retiring until the mid 2040s. In Queensland, incumbent black coal plant retirements do not commence until the 2040s, although the majority of the existing fleet does retire by 2050 for these two cases.

- Figure 12 Electricity pool prices (time weighted average), Australia, $/MWh



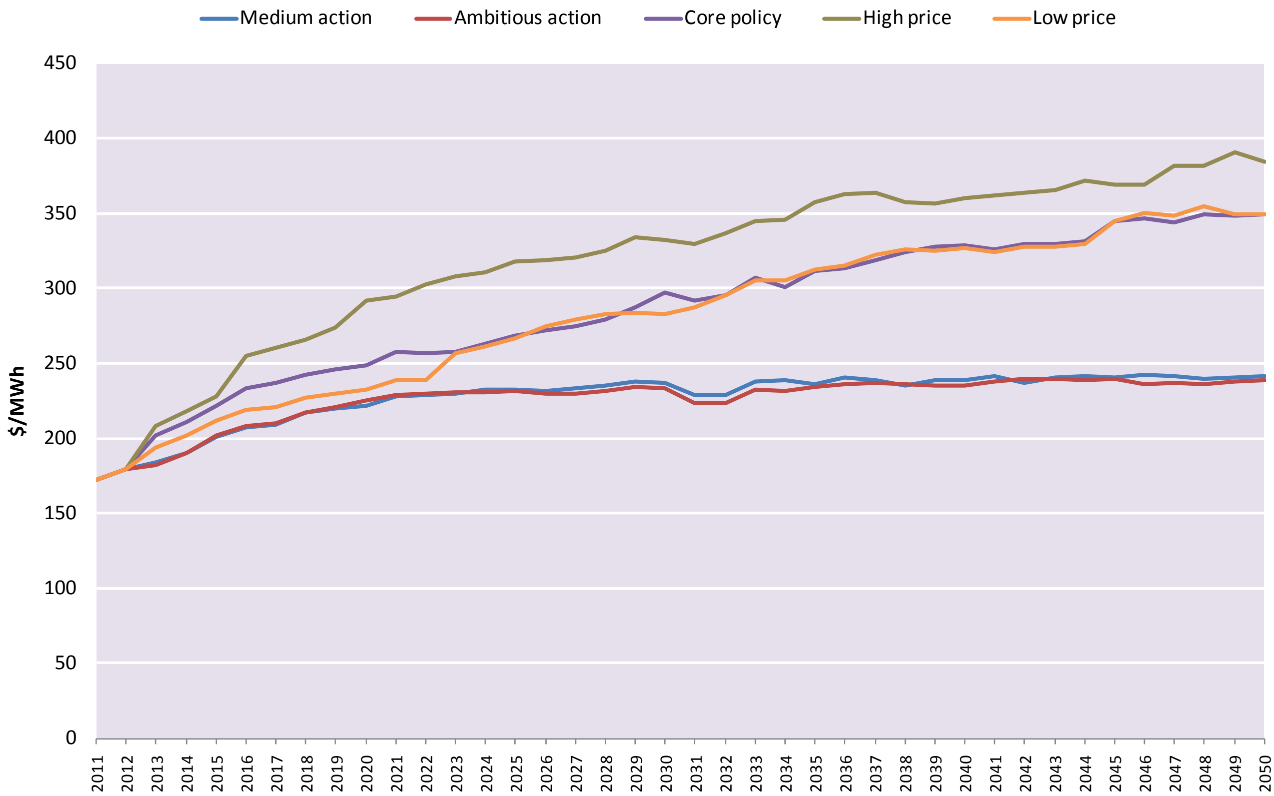
5.1.3. Retail Prices

Retail prices comprise the pool price multiplied by the marginal loss factor in transmission and distribution, and also adjusted by the contract margin and the cost of the load profile, plus network fees plus gross retail margins, market fees, ancillary service charges and the cost of administering various government schemes such as LRET, the SRES and the carbon pricing mechanism.

Retail prices in the reference cases are projected to change from current levels for two reasons. First, changes in pool prices are assumed to flow through to retail prices. Second, network costs are assumed to increase by around 4% per annum in real terms in the short term. While the pool price will change with carbon pricing, network charges are assumed to be the same under carbon pricing as for the reference scenarios.

Figure 13 shows retail prices for the residential sector. The increase in price for the carbon price scenarios relative to the reference scenarios follows the same pattern as for wholesale prices, although the increase is less in percentage terms. The percentage increase relative to the reference case rises from 5% for the smallest cut in emissions to 30% for the deepest cut in the period to 2020. After 2020, retail prices for the carbon price scenarios relative to the reference case are expected to increase on average by about 30% for the core policy scenario and the low price sensitivity, and around 48% for the high price scenario.

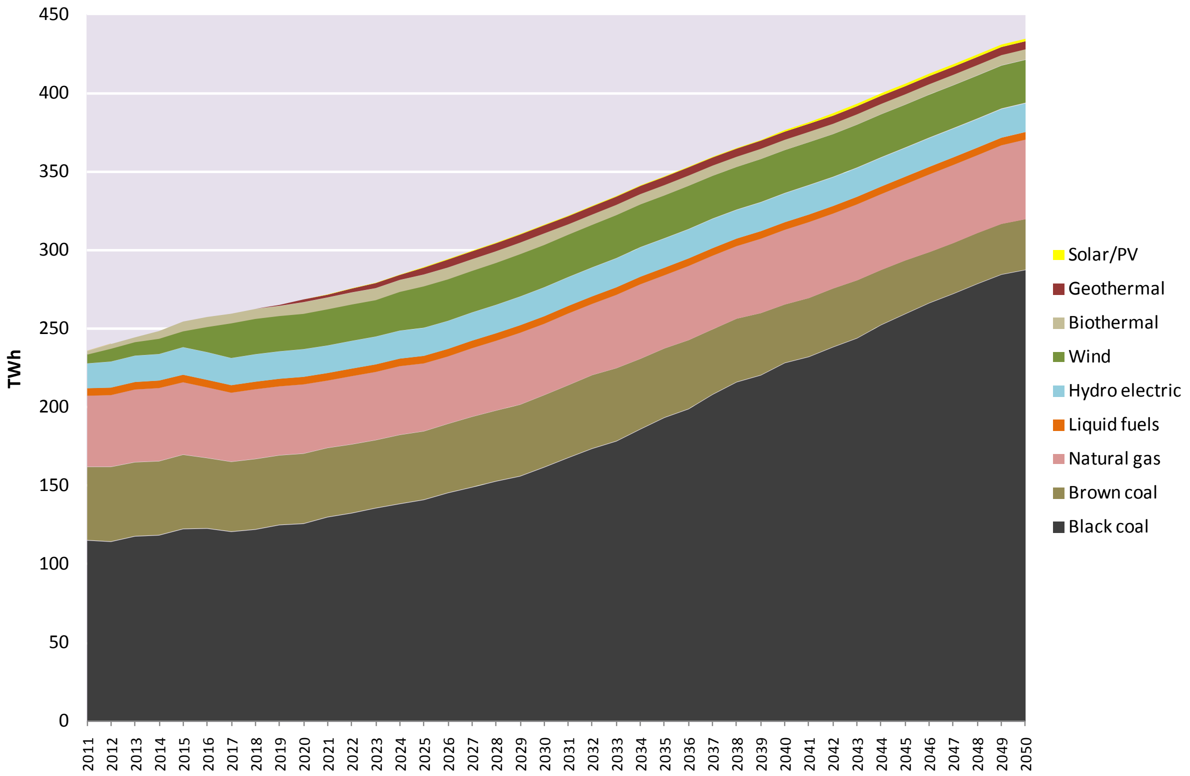
- **Figure 13 Australian residential retail prices, $/MWh**



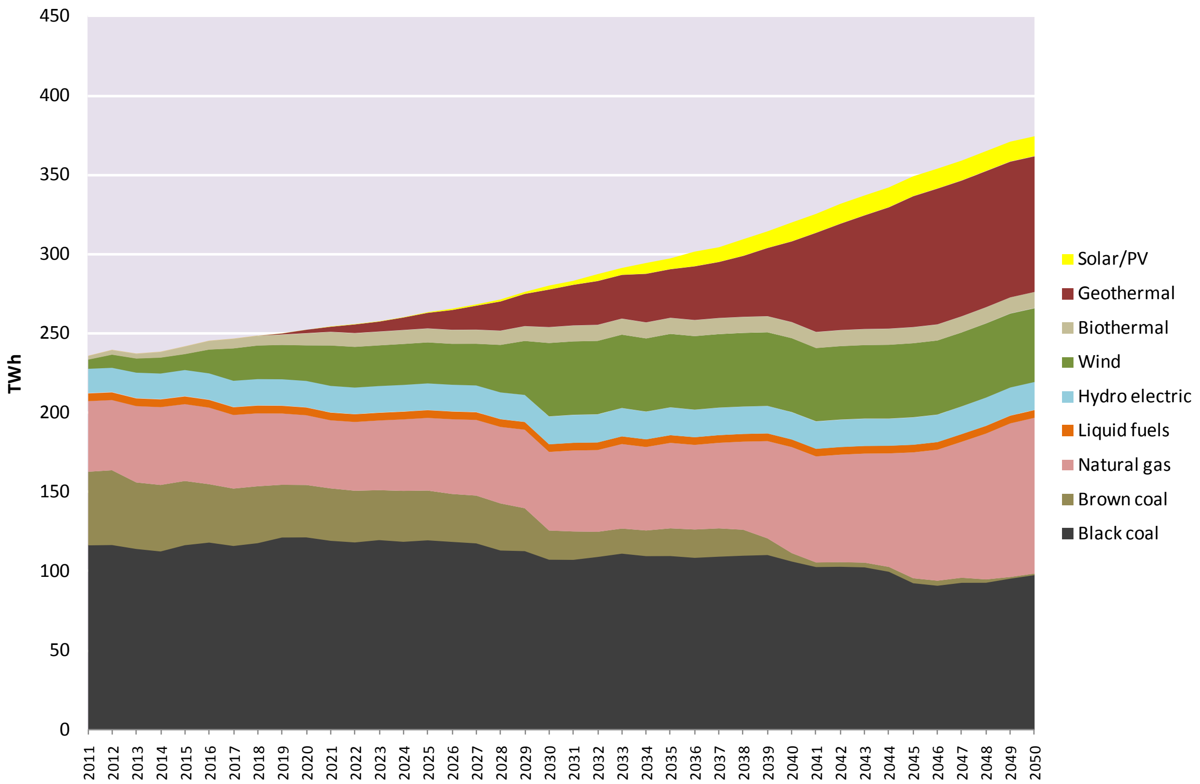
5.2. National Generation Mix

Under carbon pricing, coal-fired generation is predicted to decline slowly over time for the core policy scenario and the low price sensitivity (see Figure 15) and much more rapidly for the high price scenario (see Figure 16). Both black and brown coal fired generation falls relative to levels predicted with no carbon pricing, although in both cases brown coal generation falls at a much faster rate. Most of the reduction occurs in Victoria, Queensland and New South Wales since coal fired generation is limited in the other eastern states and the high gas price in Western Australia provides market support for coal-fired generation located there.

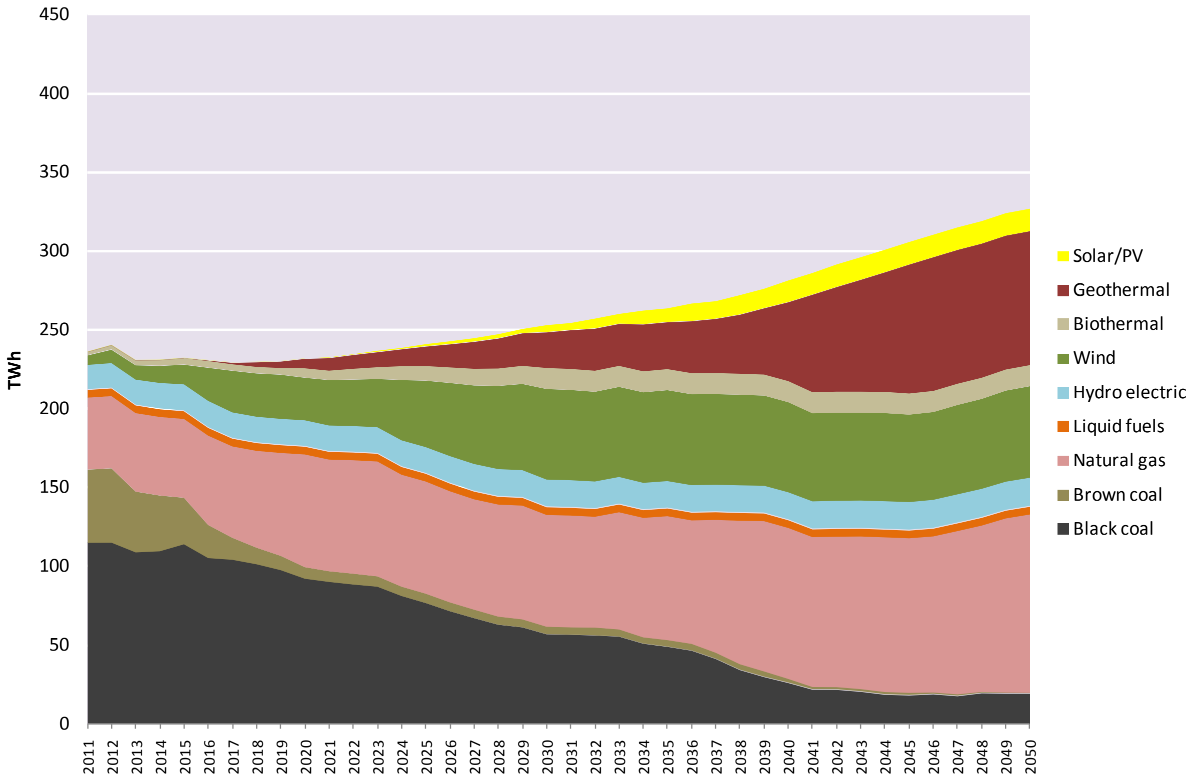
- **Figure 14 Generation trends for the medium global action scenario, GWh**



- **Figure 15 Generation trends for the core policy scenario, GWh**



▪ **Figure 16 Generation trends for the high price scenario, GWh**



The permit price at which fuel switching from coal to gas occurs is high due to the much higher gas prices relative to those in the market at the moment. For the short-term period it is still economically viable for the coal plants to generate as they are still setting the price for a large proportion of the time and thus are able to pass through carbon pricing costs onto the electricity price.

Without the assumed development of carbon capture and storage technologies, coal fired generation could be even lower than predicted. Capture and storage technology was assumed not to be available until 2026 and, aside from renewable generation, dominates the landscape of new entrants after 2030. Figure 17 shows the annual level of CO_2 captured and sequestered by the carbon pricing scenarios. The higher permit prices under the high price scenario allow CCS technology to enter the market earlier than the core policy scenario. The fact that captured CO_2 emissions for the core policy scenario and the low price sensitivity eventually exceed those of the high price scenario post 2045 reflects that coal-fired CCS is more economic in the former cases, whereas gas-fired CCS is more economic in the high price case, which has much higher permit prices.

Figure 17 Annual CO_2 emissions captured and sequestered by scenario

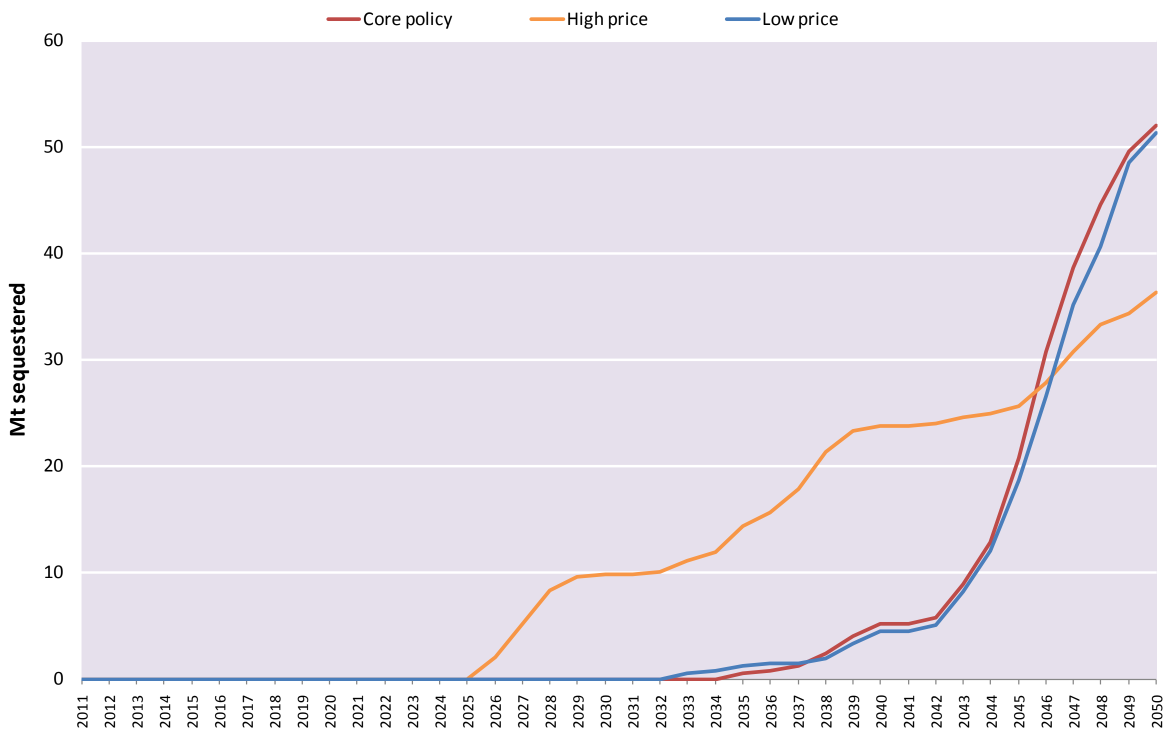
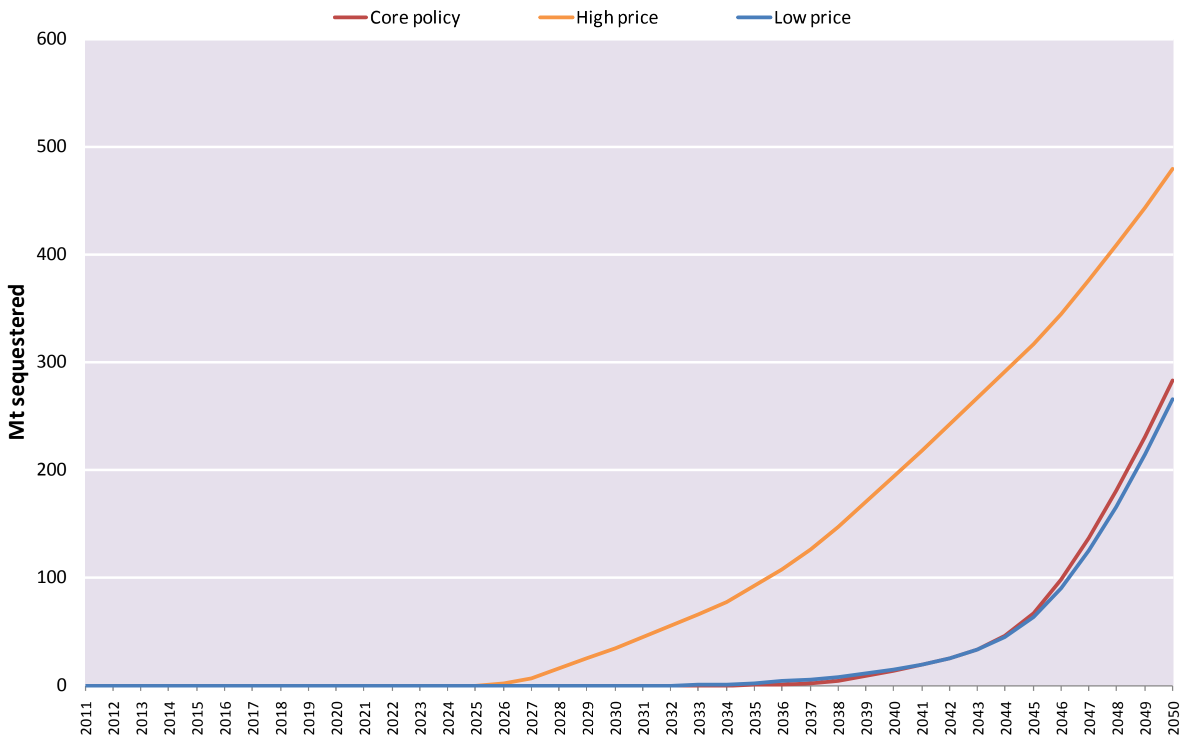


Figure 18 Cumulative CO_2 emissions captured and sequestered by scenario



5.3. Regional Generation Mix

The analysis has shown that the mix of generation changes over time, with increasing levels of renewable energy and gas fired generation with carbon pricing. Coal-fired generation falls over time until CCS technology becomes available.

The change in generation mix is also felt at a regional level as regions differ in their endowments of renewable energy, natural gas and coal resources.

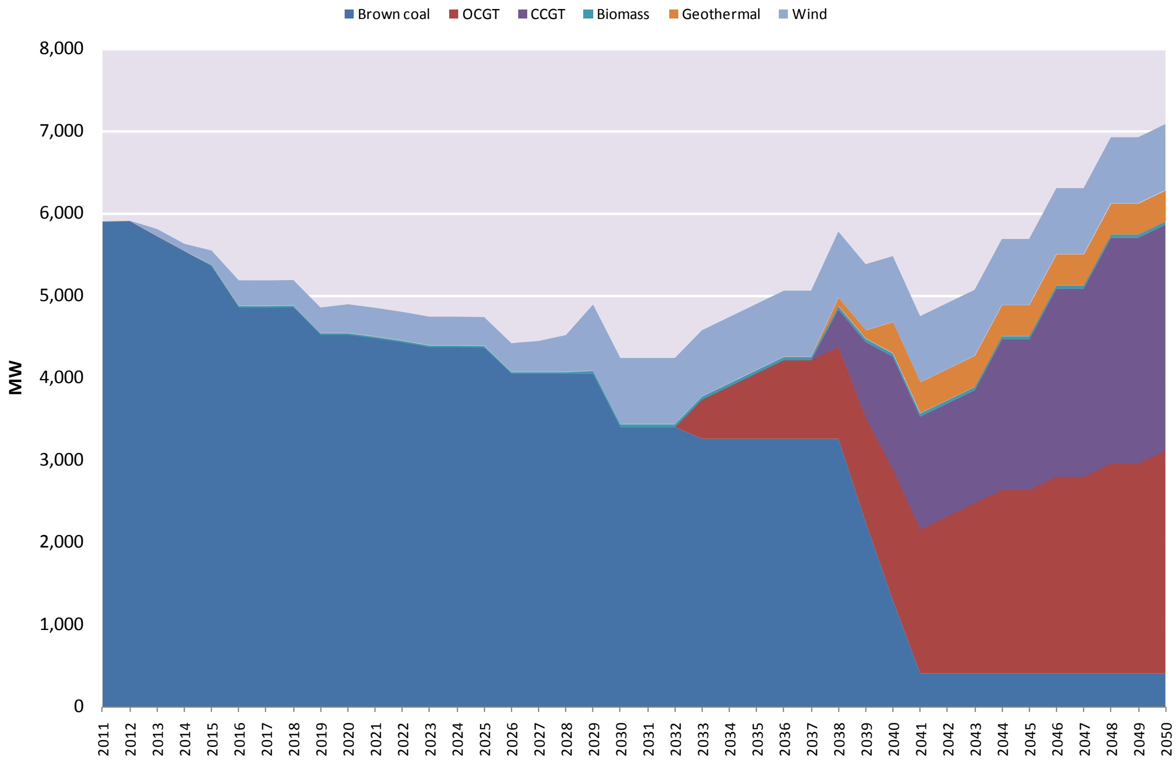
Coal generation has traditionally been concentrated in the Latrobe Valley in Victoria, the Hunter Valley, Collie, Darling Downs and central Queensland regions, close to indigenous coal resources. However, the fact that coal generation is likely to fall under carbon pricing does not necessarily mean that electricity generation in these regions will diminish, leading to an inevitable shift in employment to other sectors or to other regions. Some of these regions enjoy close proximity to renewable energy or natural gas resources, and with the availability of existing transmission infrastructure, these resources can be exploited for generation under a carbon pricing regime.

The Latrobe Valley and Gippsland region of Eastern Victoria is an example. This region is the centre of brown coal generation. Under the assumptions used in this analysis, the level of generation with brown coal falls with a carbon pricing regime. However, as shown in Figure 19, other forms of generation are likely to expand. The region has close proximity to a major natural gas resource and parts of Eastern Victoria have access to good wind, biomass and potentially geothermal resources. This leads to increased investment in generation exploiting these resources, particularly natural gas resources. The exploitation of these resources under carbon pricing means that the overall level of electricity generation may not fall.

Other coal dominant regions experience similar trends although the fall off in coal fired generation is not expected to be as rapid as in the Latrobe Valley. Natural gas and some renewable energy generation are expected to occur in the Hunter Valley. Gas-fired generation is also expected to occur in the central Queensland region, in combination with coal-fired generation with carbon capture and storage. Development of CCS technologies should also lead to continuing coal-fired generation in the Collie region.

Regional impacts should be interpreted with care. Small changes in the underlying assumptions on resource costs at a regional level could lead to large swings in the regional distribution of new generation. Nonetheless, the availability of other resources in currently coal-dominated regions would help to buffer the impact of carbon pricing on coal-fired generation in these regions. Moreover, there is likely to be a more dispersed distribution of generation across the regions, particularly with the growth of renewable generation under carbon pricing.

▪ **Figure 19 Generation capacity in Latrobe Valley and Gippsland regions in Victoria, core policy scenario**

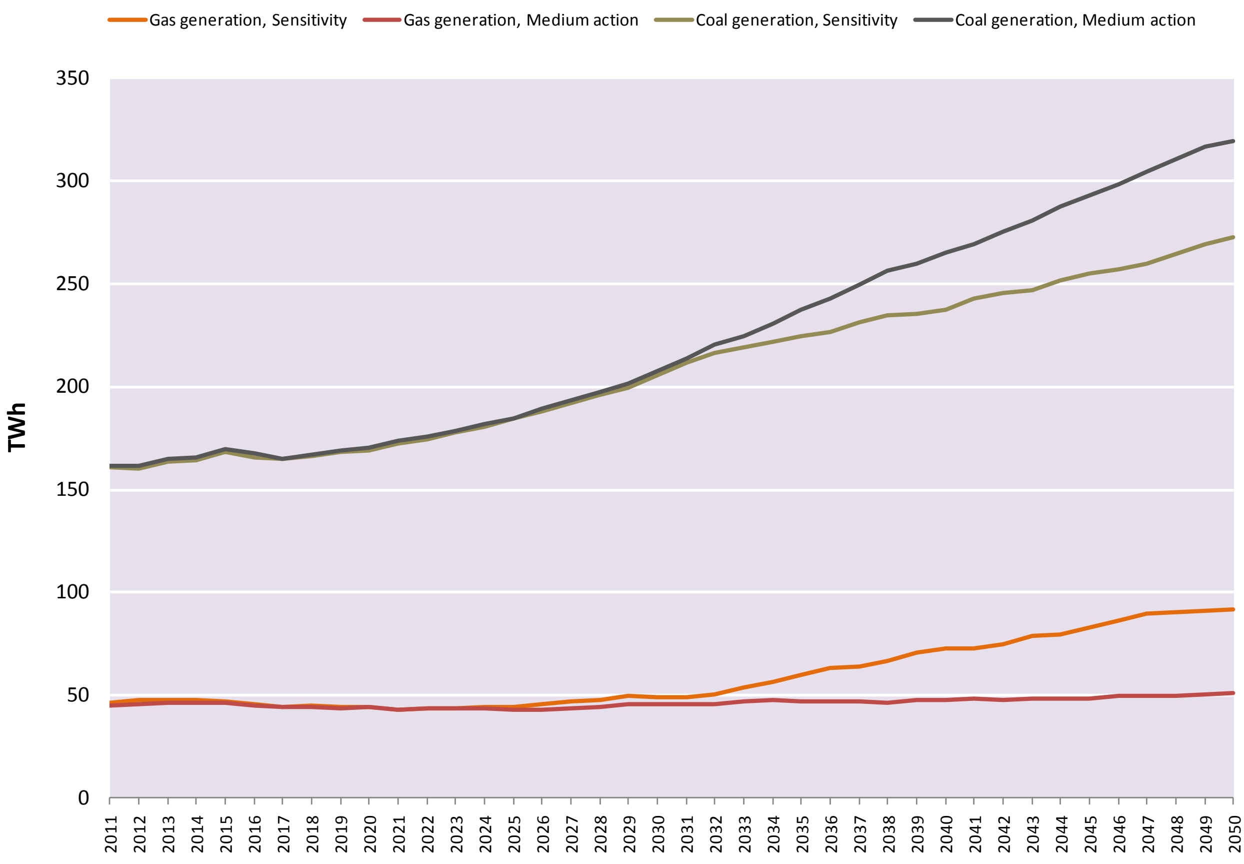


6. Sensitivity Analysis

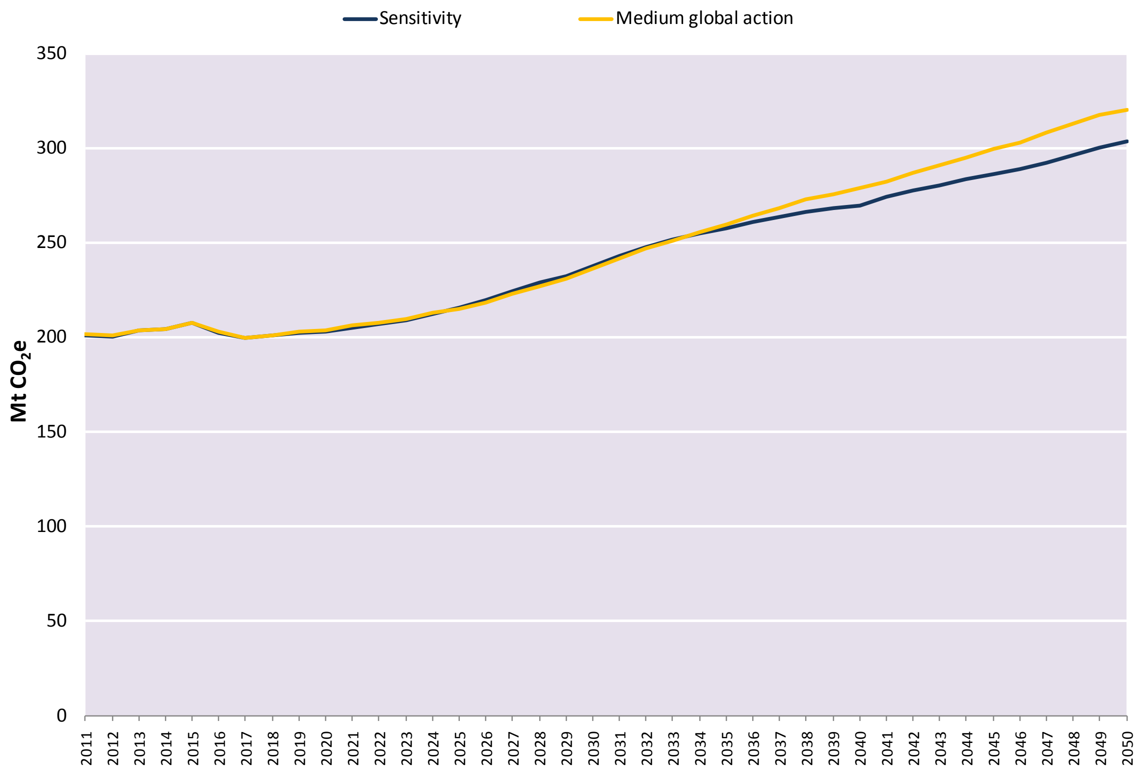
6.1. Gas Price Sensitivity, Medium Global Action

The major effect in lowering the gas price under the gas price sensitivity case for the medium action case is that CCGT technology in Victoria becomes cheaper than upgrading the transmission system between Victoria and New South Wales. Thus, there is significantly more gas-fired generation entering the market as soon as base load generation is required in Victoria, and this displaces coal-fired generation in New South Wales that would have otherwise been built to supply Victoria and, to a lesser extent, South Australia and Tasmania. This outcome is evident in Figure 20. A benefit of this is lower emissions, as shown in Figure 21. Lowering the gas price also translates into lower pool prices, which are shown in Figure 22.

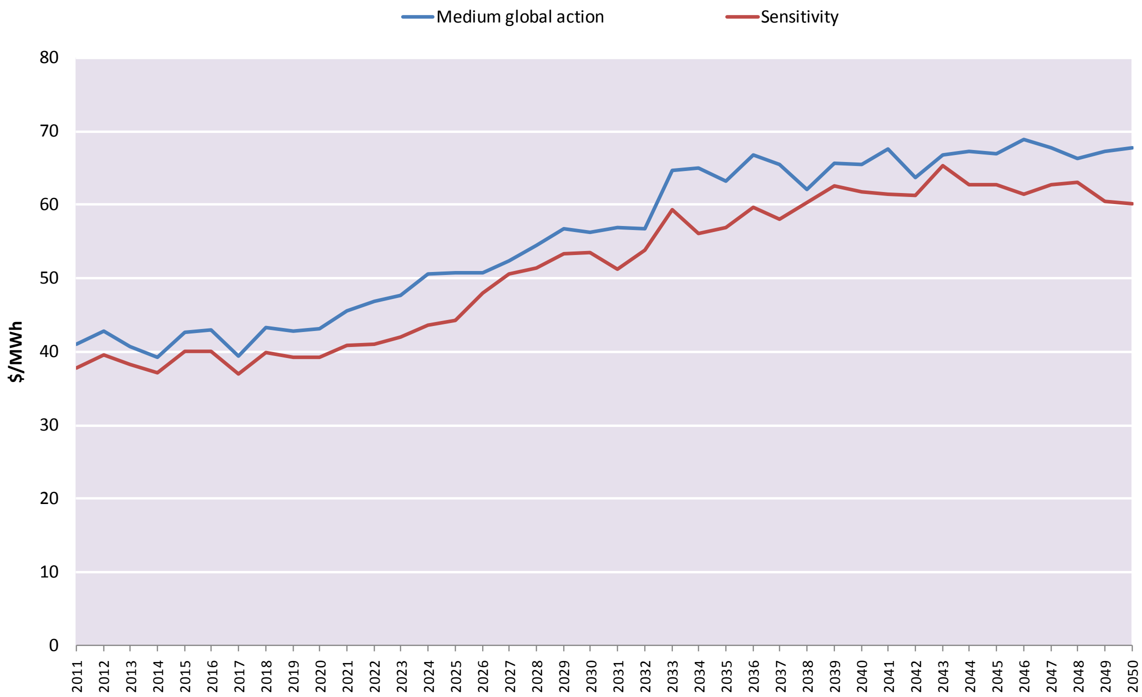
▪ **Figure 20 Gas and coal generation, medium action gas price sensitivity**



■ **Figure 21 Emissions, medium action gas price sensitivity**



■ **Figure 22 Electricity pool prices, medium action gas price sensitivity**



6.2. Gas Price Sensitivity, Core Policy

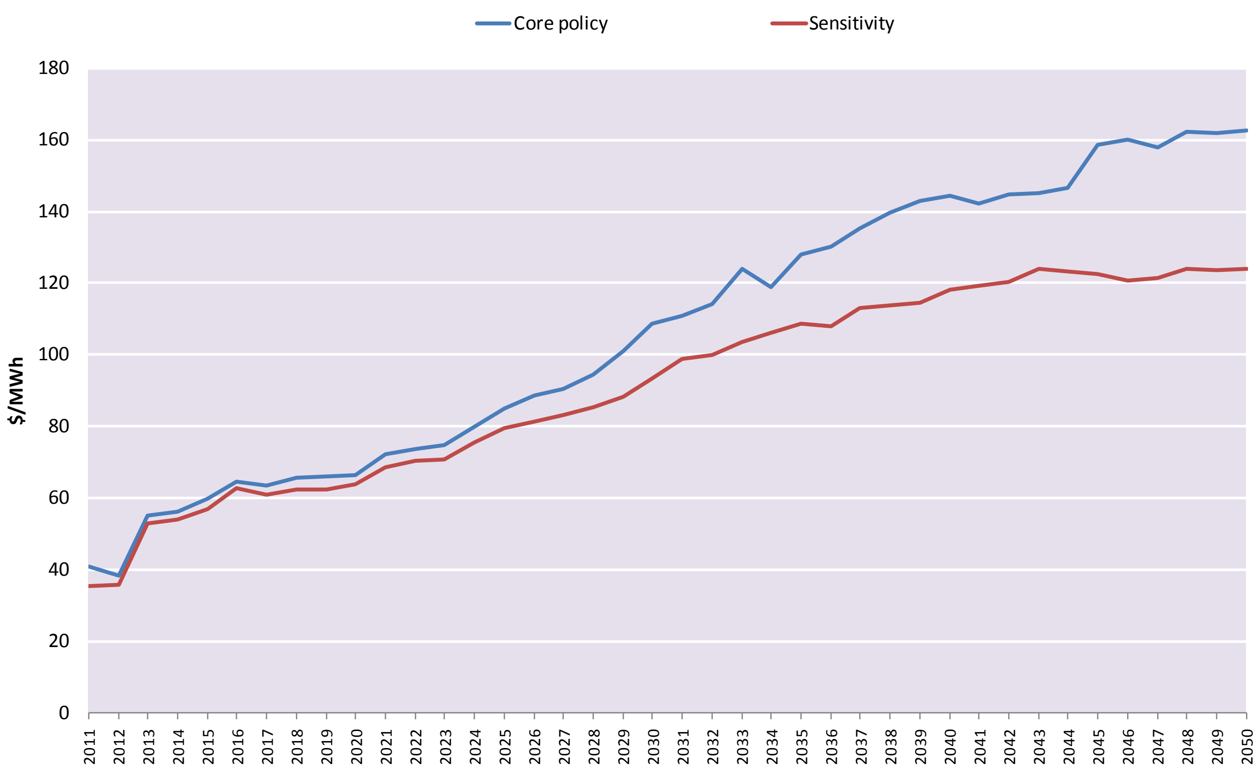
There are two major effects of lowering gas prices under a carbon price regime:

i. Pool prices are significantly lower, since CCGT technology is the marginal new entrant technology. Incumbent coal plants therefore receive less income as a result of lower pool prices and are forced to retire earlier since they are not as financially viable

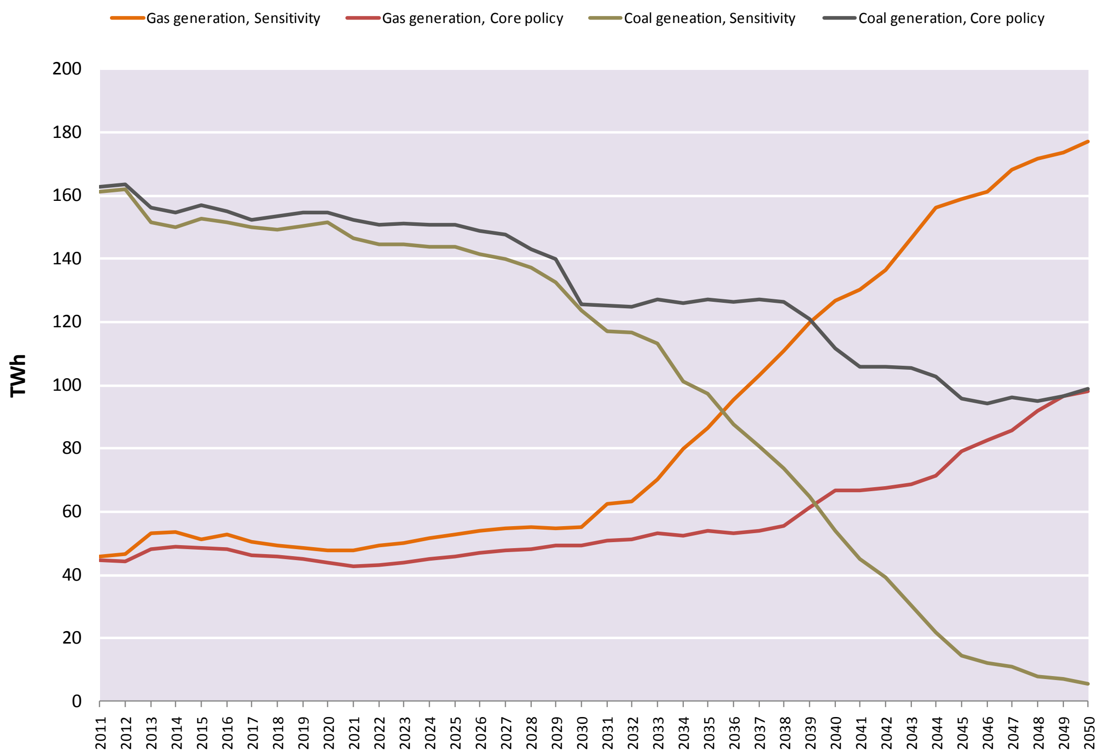
ii. CCGT with CCS technology becomes cheaper than integrated gasification combined cycle gas turbine (IGCC) with CCS technology, resulting in more gas-fired generation and therefore lower emissions

The first effect is illustrated in Figure 23, whereas the second effect is evident in Figure 24 and Figure 25. Figure 24 shows gas-fired generation increasing markedly from about 2031 onwards, which is when the first CCGT with CCS plant is projected to be commissioned in Victoria. The rise in gas-fired generation corresponds with a significant drop in coal-fired generation, and the two are almost perfectly negatively correlated. Emissions under the sensitivity also begin to diverge significantly from the core policy scenario at around 2031, and the difference is maintained to beyond 2050.

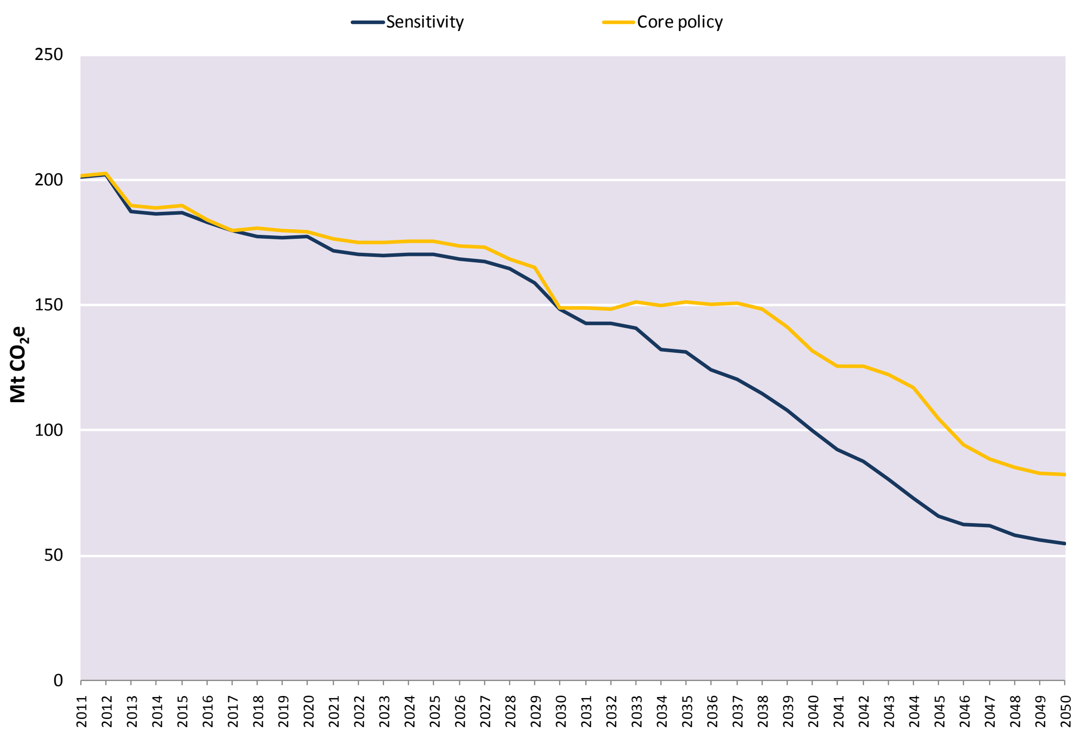
■ **Figure 23 Electricity pool prices, core policy gas price sensitivity**



- **Figure 24 Gas and coal generation, core policy gas price sensitivity**



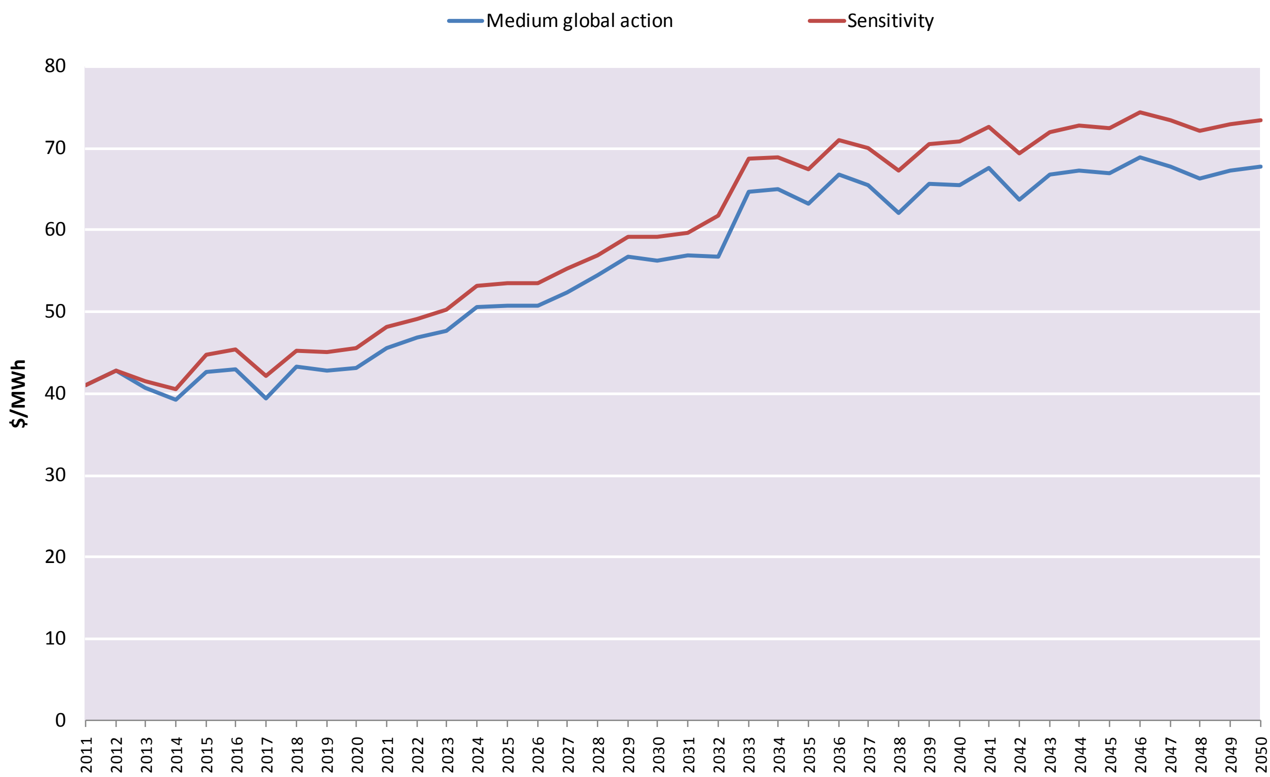
- **Figure 25 Emissions, core policy gas price sensitivity**



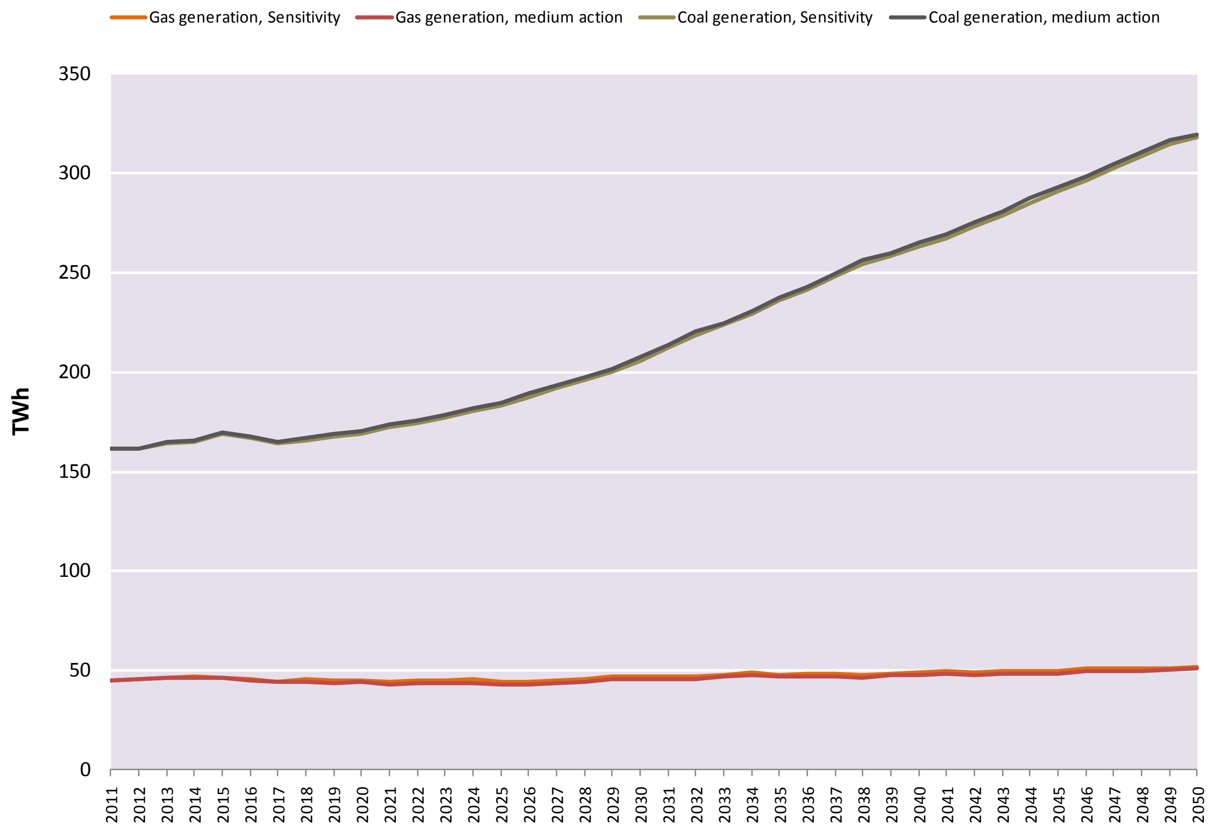
6.3. Coal Price Sensitivity, Medium Global Action

Figure 26 shows a sizeable increase in pool prices as a result of higher coal prices. Pool prices are especially sensitive to coal prices in off-peak periods, when coal-fired generation is marginal. However, coal-fired generation can also be marginal in New South Wales during peak periods, and since New South Wales is the largest NEM region in terms of demand and also lies in the centre of the NEM, changes in its coal price would also have a considerable impact on the NEMs average peak period price. Figure 27 shows that the higher coal prices result in only slightly less coal-fired generation and slightly more gas-fired generation. Therefore, the effect on emissions would also be very slight.

- **Figure 26 Electricity pool prices, medium action coal price sensitivity**



■ **Figure 27 Gas and coal generation, medium action coal price sensitivity**



6.4. Coal Price Sensitivity, Core Policy

The effect of higher coal prices on pool prices under the core policy scenario is illustrated in Figure 28. The difference between the sensitivity and the core policy scenario is slightly higher than the difference between the corresponding sensitivity and the medium action scenario. This occurs because coal-fired generation is the marginal generator for longer periods of the day under a carbon price, and therefore the increase in coal price in passed through more effectively into pool prices.

Figure 29 shows that there is only slightly more gas-fired generation and slightly less coal-fired generation in the sensitivity up until about 2040. From that point onwards there is a notable increase in gas-fired generation under the sensitivity, and the reason for this is with higher coal prices, CCGT with CCS technology is cheaper than IGCC with CCS technology, which was the marginal new entrant in the core policy case. As expected, this switch to lower emissions technology translates into lower emissions, as shown in Figure 30.

Figure 28 Electricity pool prices, core policy coal price sensitivity

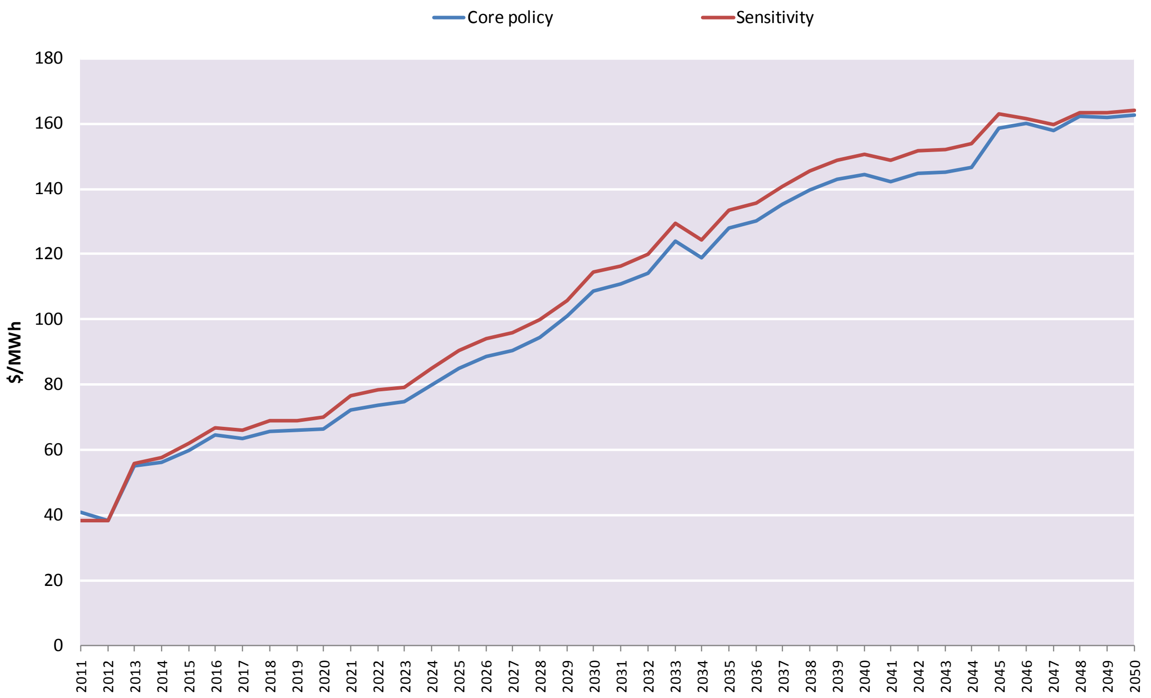


Figure 29 Gas and coal generation, core policy coal price sensitivity

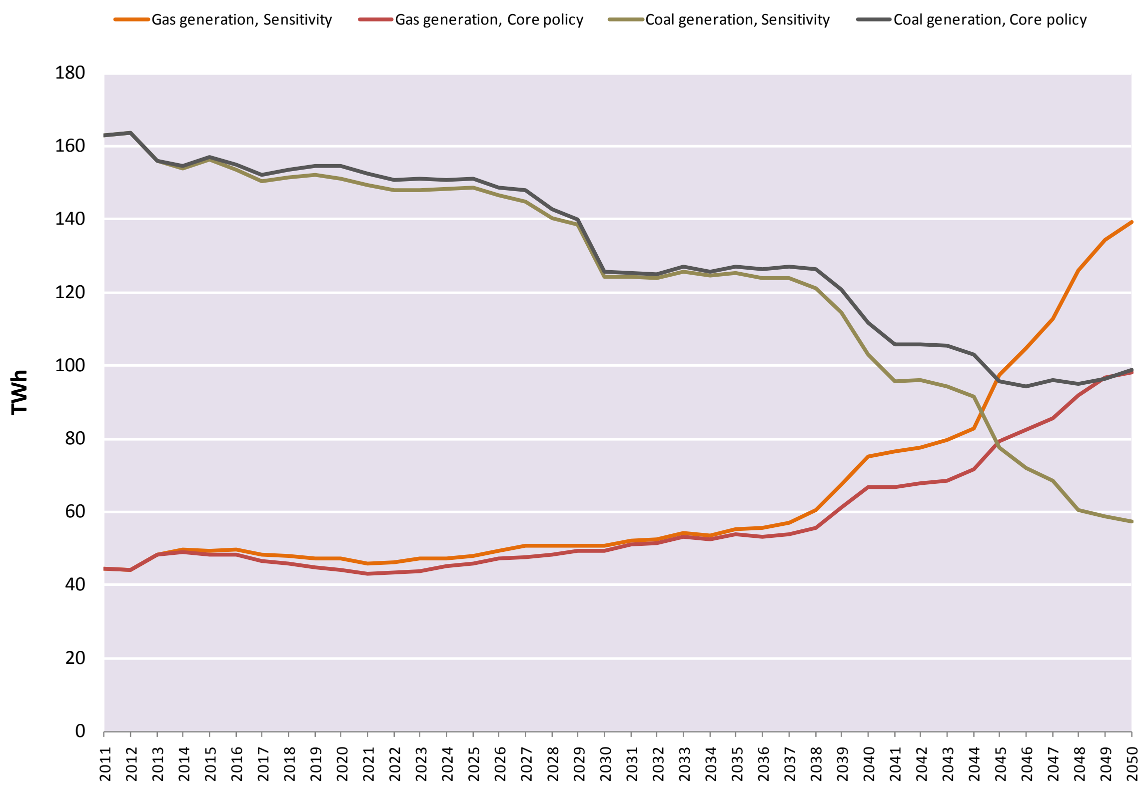
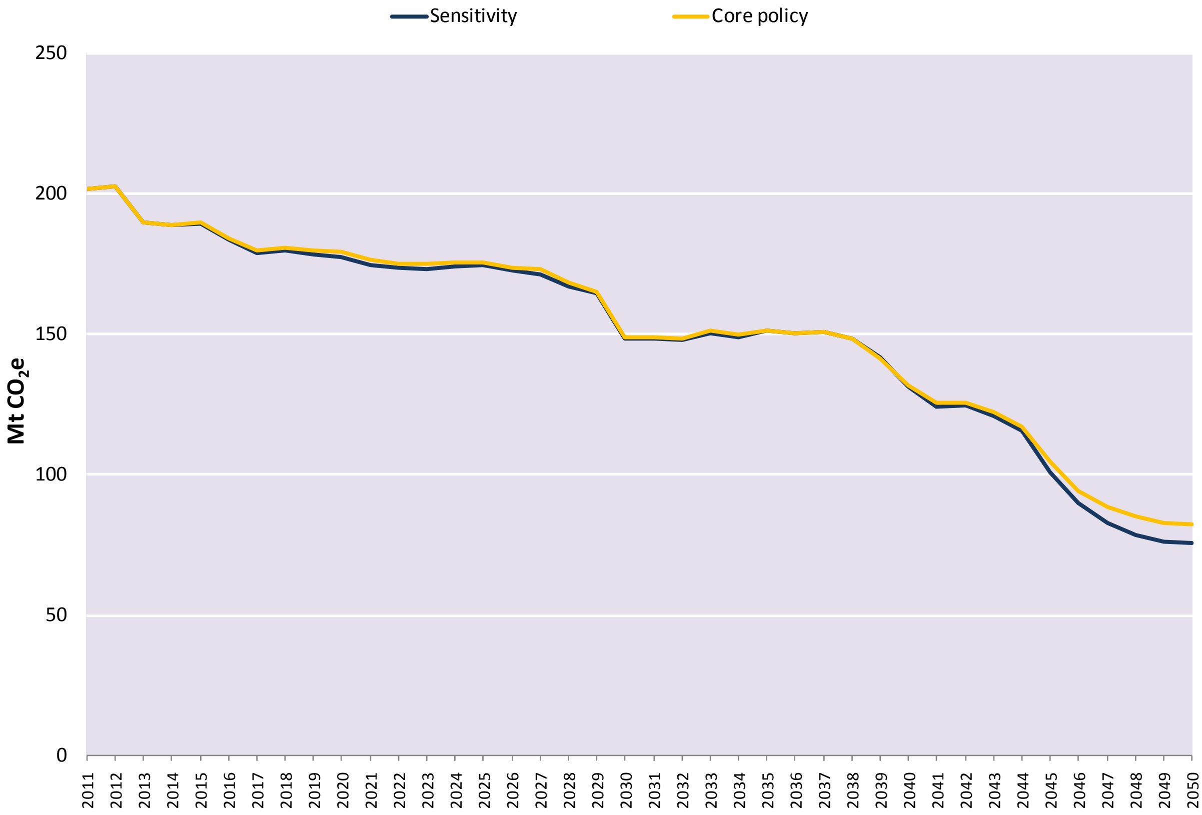


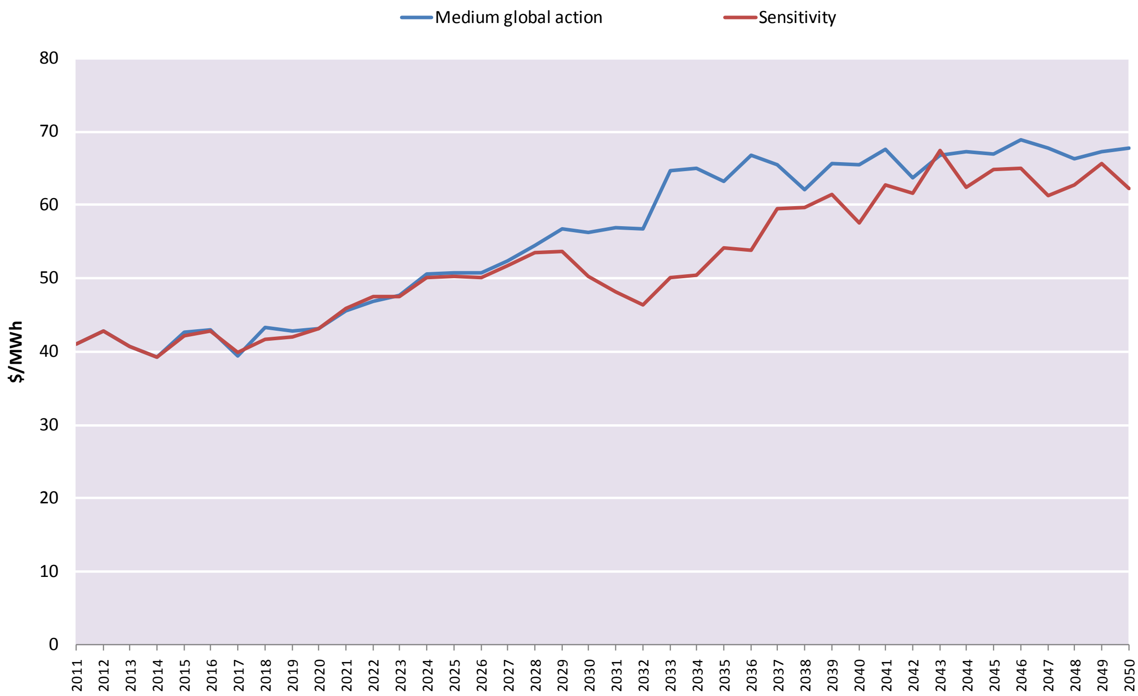
Figure 30 Emissions, core policy coal price sensitivity



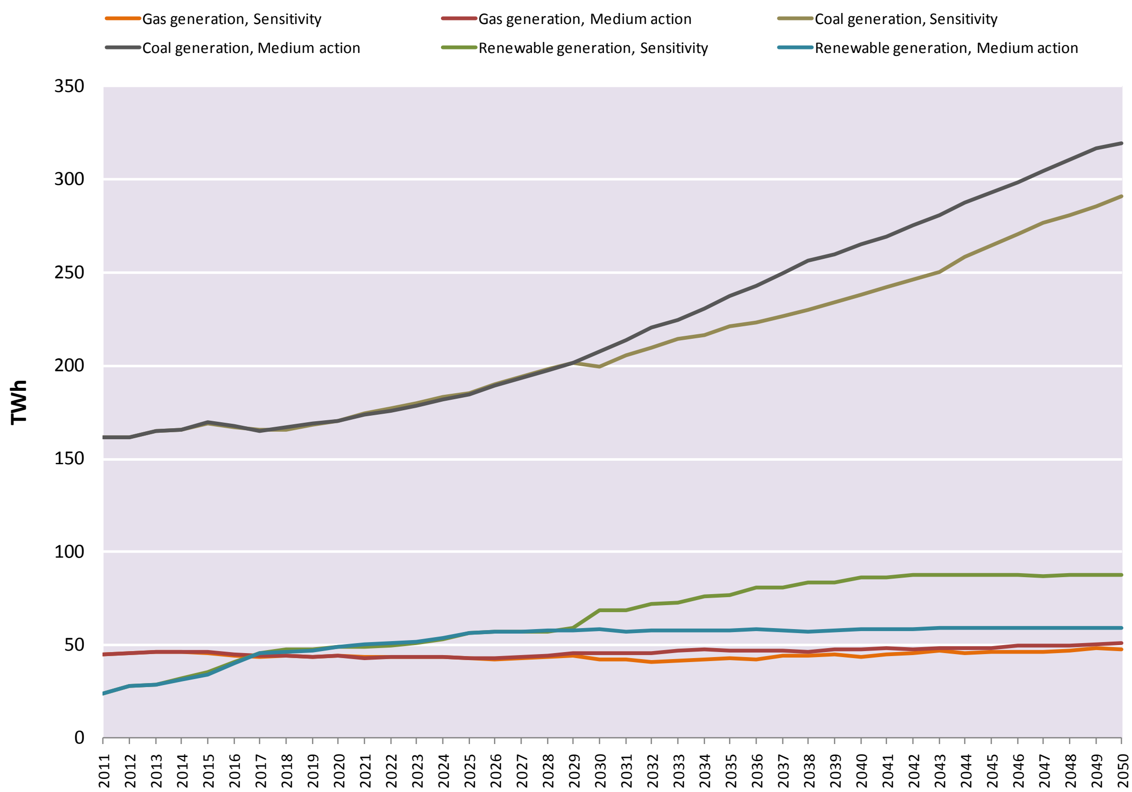
6.5. Lower Renewable Energy Technology Cost Sensitivity, Medium Global Action

Pool prices under the lower renewable energy technology cost sensitivity diverge from the underlying scenario from about 2029 onwards, as shown in Figure 31. This is the point where there is significantly more uptake of large-scale renewable generation, as shown in Figure 32, and is the point in time where renewable energy becomes economic due to the faster learning rates assumed in this sensitivity. The additional renewable generation predominantly displaces coal-fired, but also some gas-fired generation. Figure 33 also shows a significant reduction in emissions, due to the displacement of coal-fired generation.

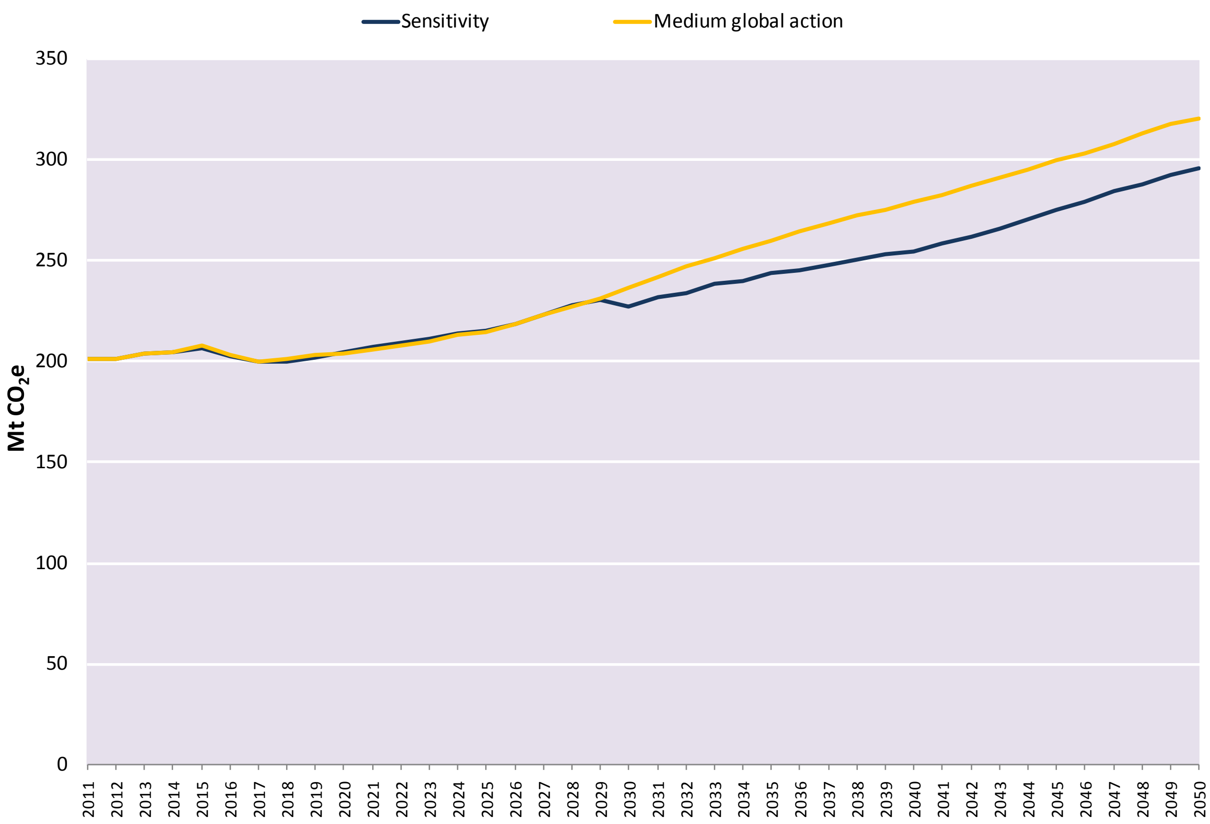
▪ **Figure 31 Electricity pool prices, medium action low renewable cost sensitivity**



▪ **Figure 32 Gas, coal and renewable generation, medium action low renewable cost sensitivity**



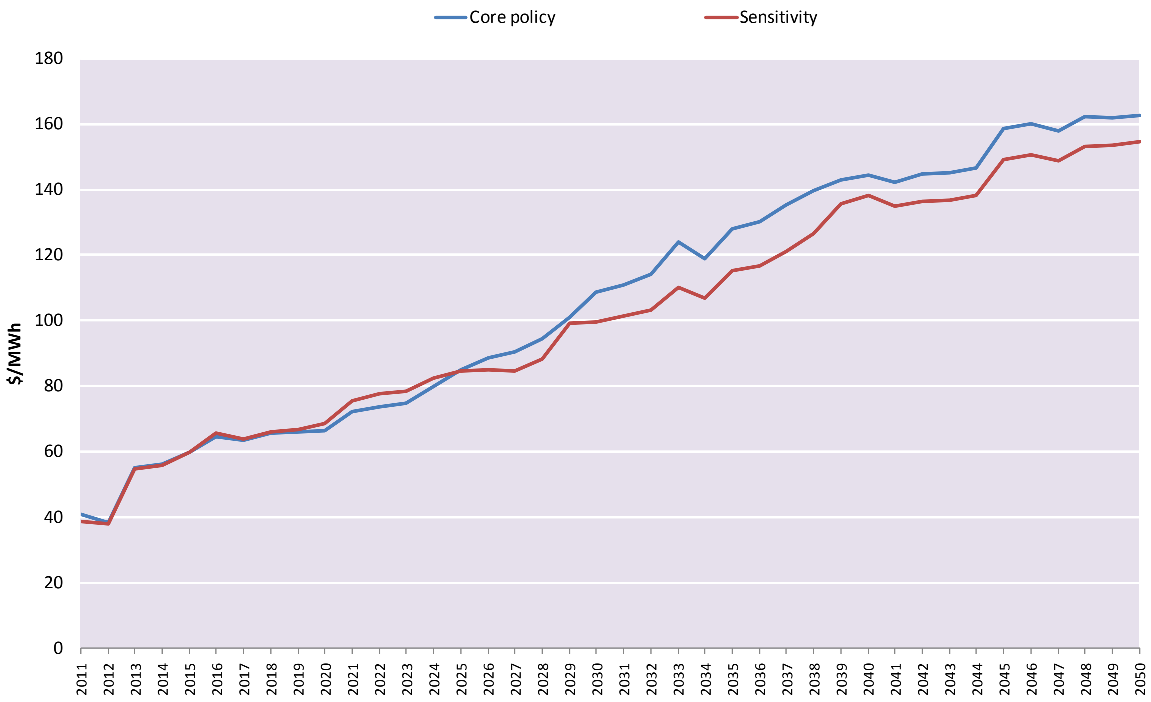
■ **Figure 33 Emissions, medium action low renewable cost sensitivity**



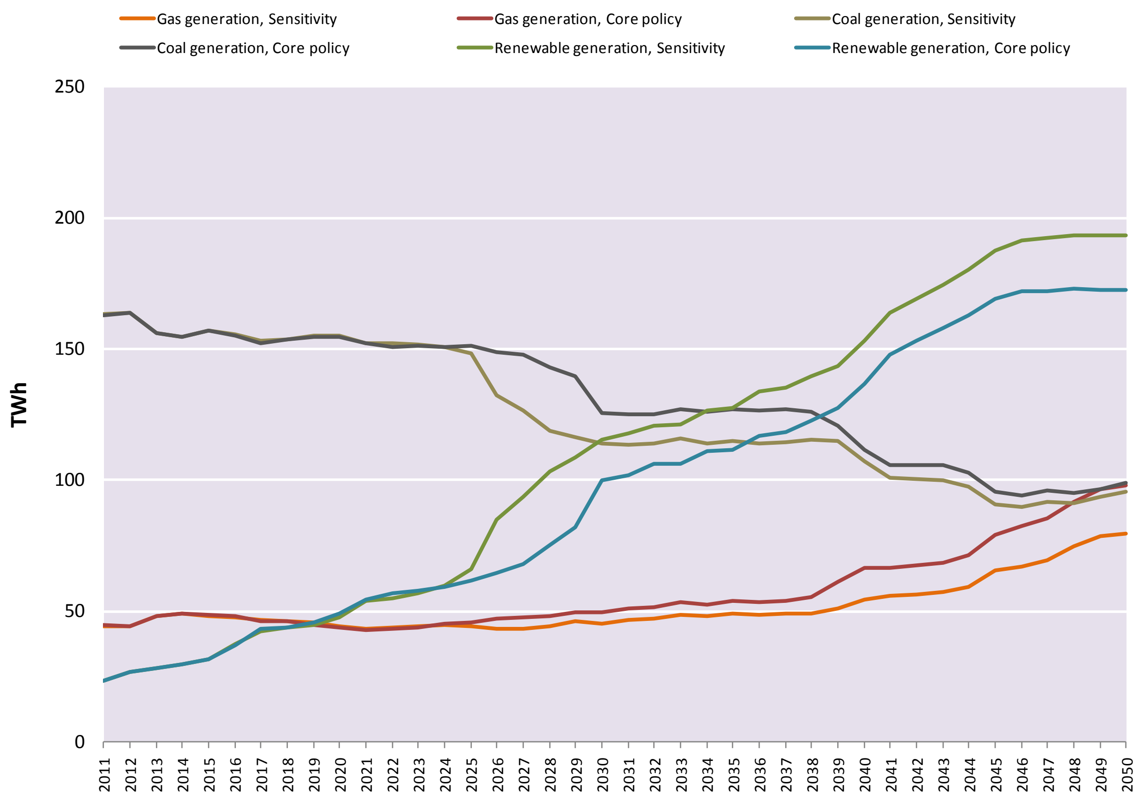
6.6. Lower Renewable Energy Technology Cost Sensitivity, Core Policy

Pool prices under the lower renewable energy technology cost sensitivity diverge from the core policy scenario from about 2025 onwards, as shown in Figure 34. This is once again the point where there is significantly more uptake of large-scale renewable generation, as shown in Figure 35. There is not as much of a difference in the uptake between this sensitivity and the underlying scenario when compared to the medium action case. The reason for this is that under the core policy case more renewable projects are taken up because of the carbon price support, however the lower renewable costs mean that the projects are taken up earlier in the sensitivity (divergence in uptake occurs in 2025, whereas for the medium action sensitivity the divergence from the underlying scenario occurs in 2029). Figure 35 also shows that the additional renewable generation initially displaces coal-fired generation, but from 2040 onwards it displaces mainly gas fired generation since at this point the coal-fired generation begins to retire en masse. This is also evident in the emissions profile, shown in Figure 36, where emissions under the sensitivity are significantly below those of the underlying scenario from 2025 until about 2040, and then the two emissions profiles converge, although the sensitivity's emissions are still lower.

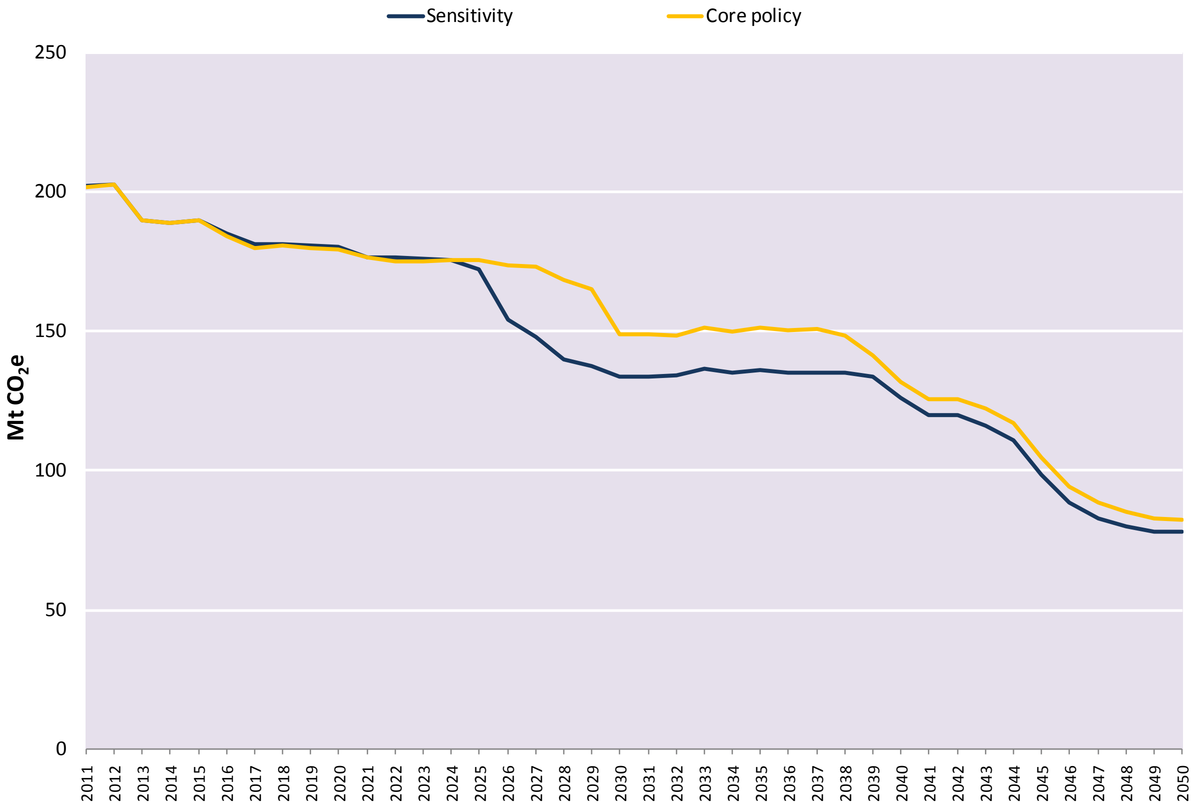
▪ **Figure 34 Electricity pool prices, core policy low renewable cost sensitivity**



▪ **Figure 35 Gas, coal and renewable generation, core policy low renewable cost sensitivity**



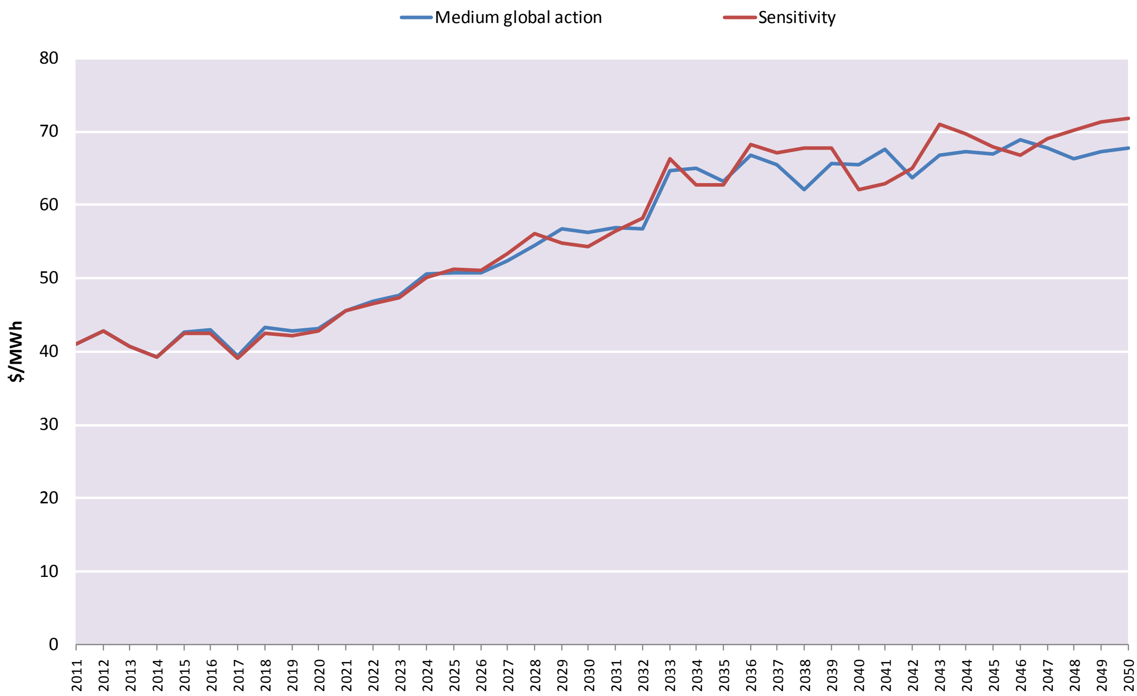
- **Figure 36 Emissions, core policy low renewable cost sensitivity**



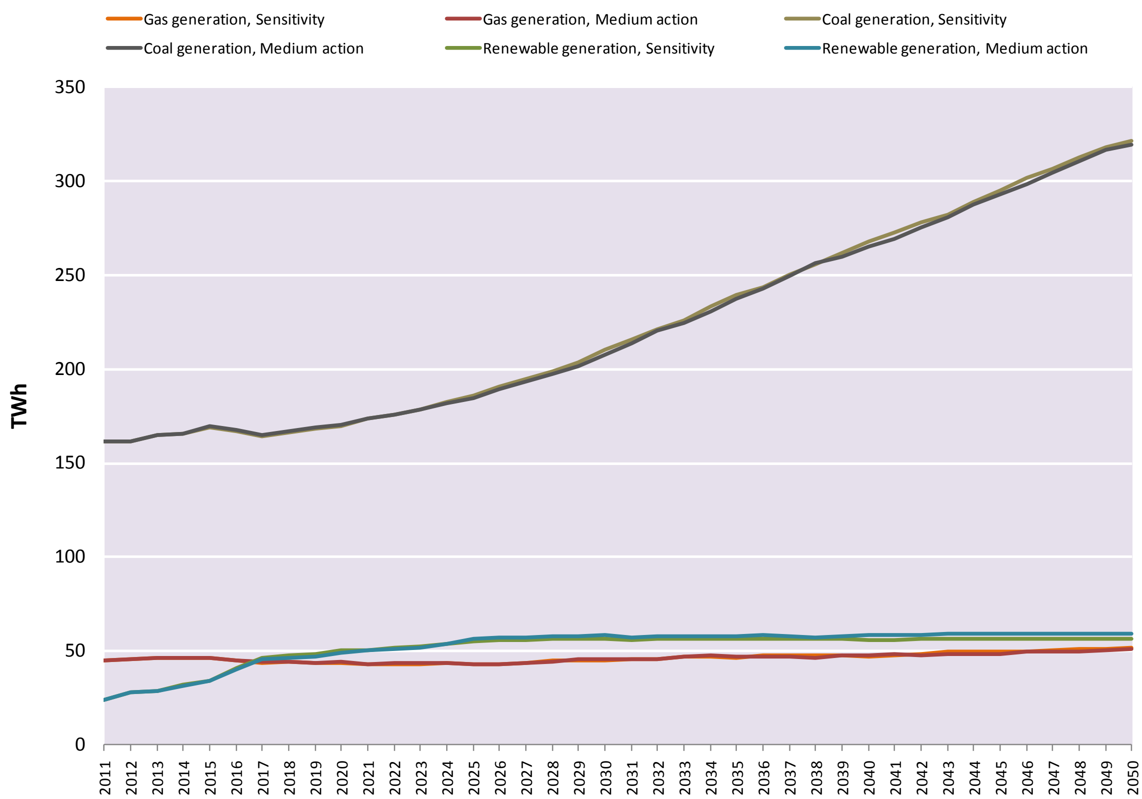
6.7. Lower Technology Learning Rate Sensitivity, Medium Global Action

It is evident from Figure 37 and Figure 38 that halving the technology learning rate for all technologies does not have a dramatic effect on market outcomes. Electricity pool prices tend to be slightly higher, and one can discern that there is slightly less renewable technology and slightly more coal-fired generation, whereas gas-fired generation is more or less the same. The fact that there is less renewable uptake is because the LRET target is the same for both scenarios, but there are fewer projects in the sensitivity run that are supported solely by the electricity price post 2030 since they are more expensive. Coal-fired generation therefore makes up the difference in the sensitivity case since it is the cheapest technology. As a result, emissions are also slightly higher for the sensitivity run.

- **Figure 37 Electricity pool prices, medium action low technology learning rate sensitivity**



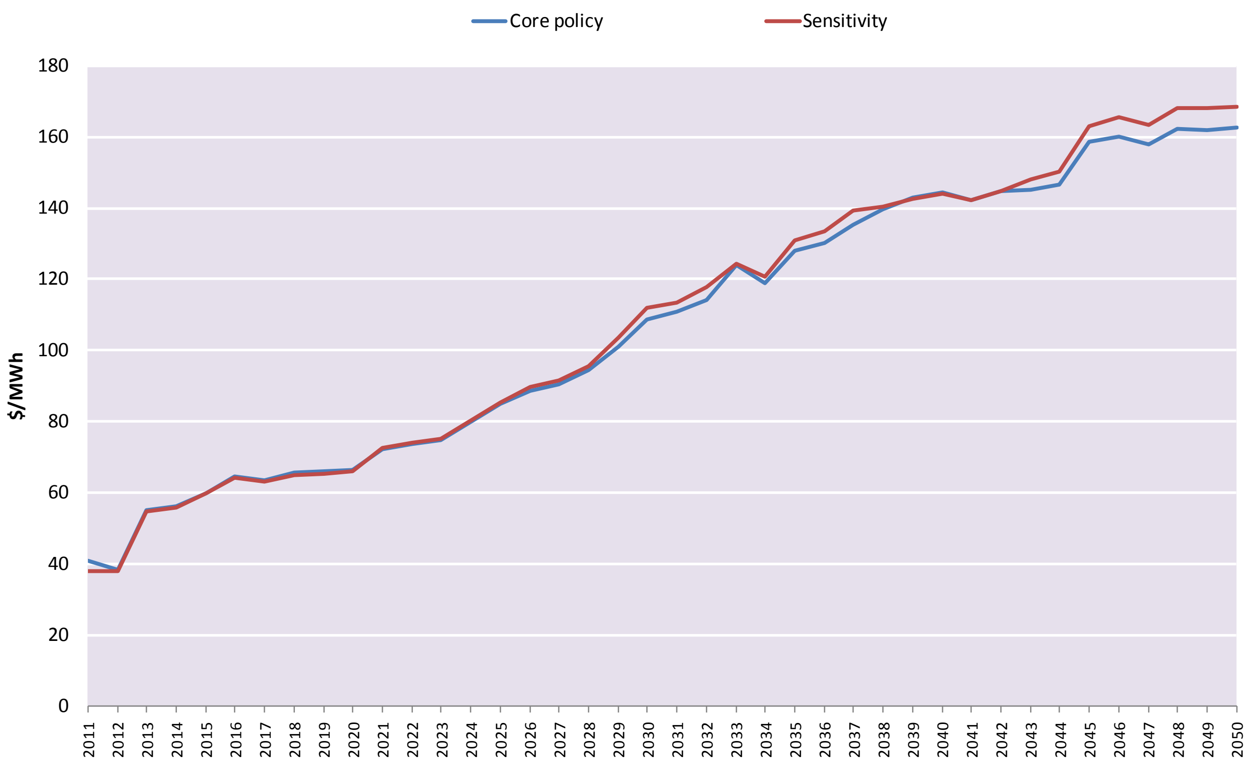
- **Figure 38 Gas, coal and renewable generation, medium action low technology learning rate sensitivity**



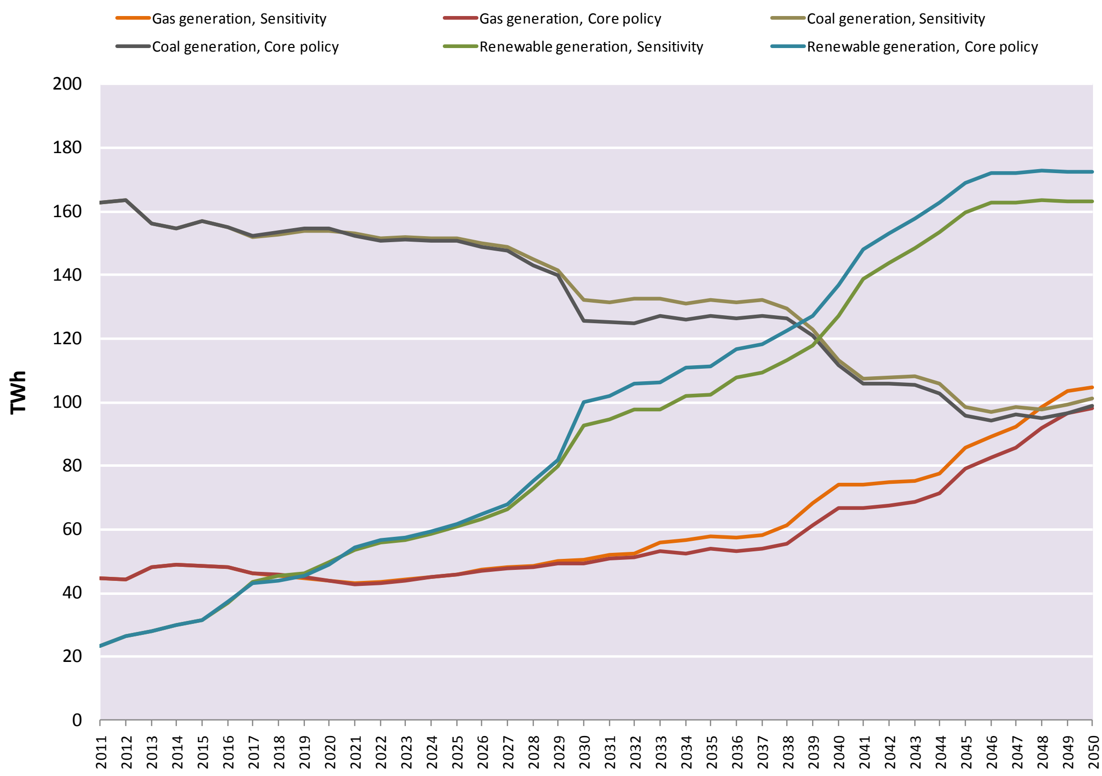
6.8. Lower Technology Learning Rate Sensitivity, Core Policy

Under the core policy case, market outcomes are more sensitive to a lower technology learning rate. Figure 39 shows that pool prices are slightly higher for a lower technology learning rate, since capital costs are more expensive relative to the underlying scenario. Figure 40 shows that there is less renewable technology uptake under the sensitivity, and both coal-fired and gas-fired generation make up the shortfall, although the contribution of each to the shortfall varies over time. Initially coal-fired generation displaces the more expensive renewable technology, but as incumbent coal-fired generation begins retiring from about 2040 onwards, gas-fired generation makes up the shortfall. The reason for renewable technology being disadvantaged when the technology learning rate is halved is that it has higher learning rates relative to the thermal technologies, and therefore it becomes more expensive in relative terms. Figure 41 shows that emissions under the sensitivity are significantly higher than the underlying scenario in the period between 2025 and 2040, when coal-fired generation displaces renewable energy.

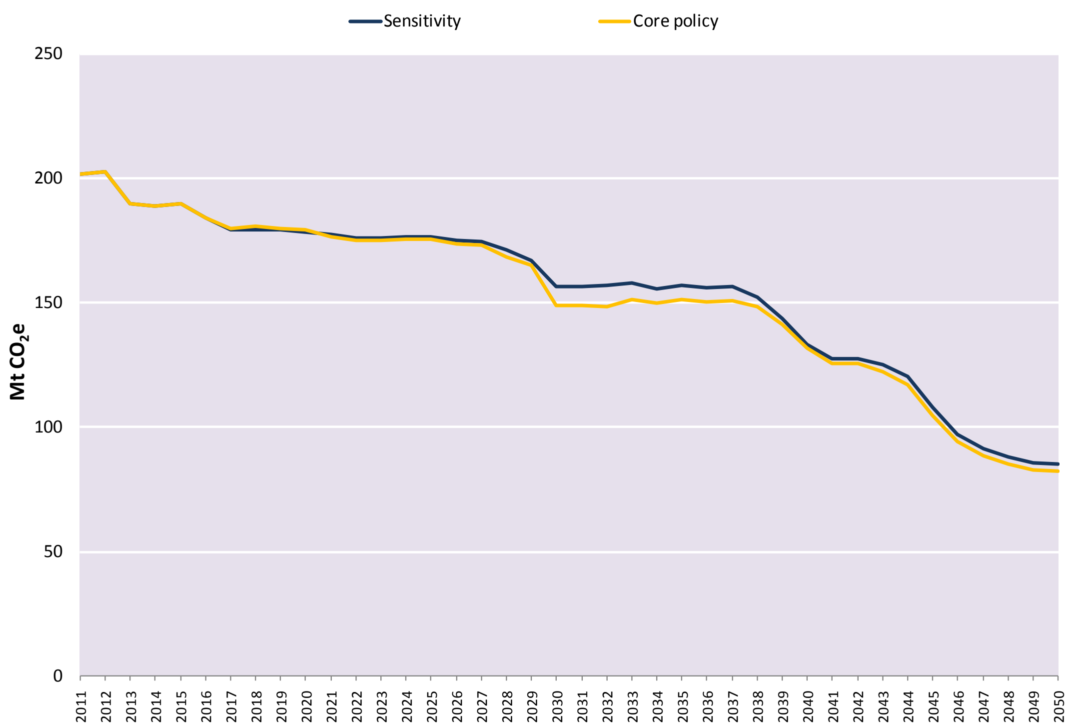
- **Figure 39 Electricity pool prices, core policy low technology learning rate sensitivity**



■ Figure 40 Gas, coal and renewable generation, core policy low technology learning rate sensitivity



■ Figure 41 Emissions, core policy low technology learning rate sensitivity



6.9. No CCS Sensitivity, Core Policy

Figure 42 shows gas-fired and coal-fired generation under the sensitivity case. Gas-fired generation under the sensitivity case rises dramatically from about 2040 onwards, which is when the incumbent black coal-fired generation fleet begins to retire and is replaced by CCGTs. Thus, coal-fired generation falls away, whereas in the underlying scenario the volume of coal-fired generation stabilises since black coal-fired IGCC plant with CCS serves as the replacement plant.

Figure 43 shows that the emissions impact of not having CCS plant available is quite substantial. Whereas emissions in the core policy scenario fall from 150 Mt CO_2e in 2036 to 82 Mt CO_2e in 2050, in the sensitivity case they only fall to 112 Mt CO_2e by 2050.

▪ **Figure 42 Gas and coal generation, core policy no CCS sensitivity**

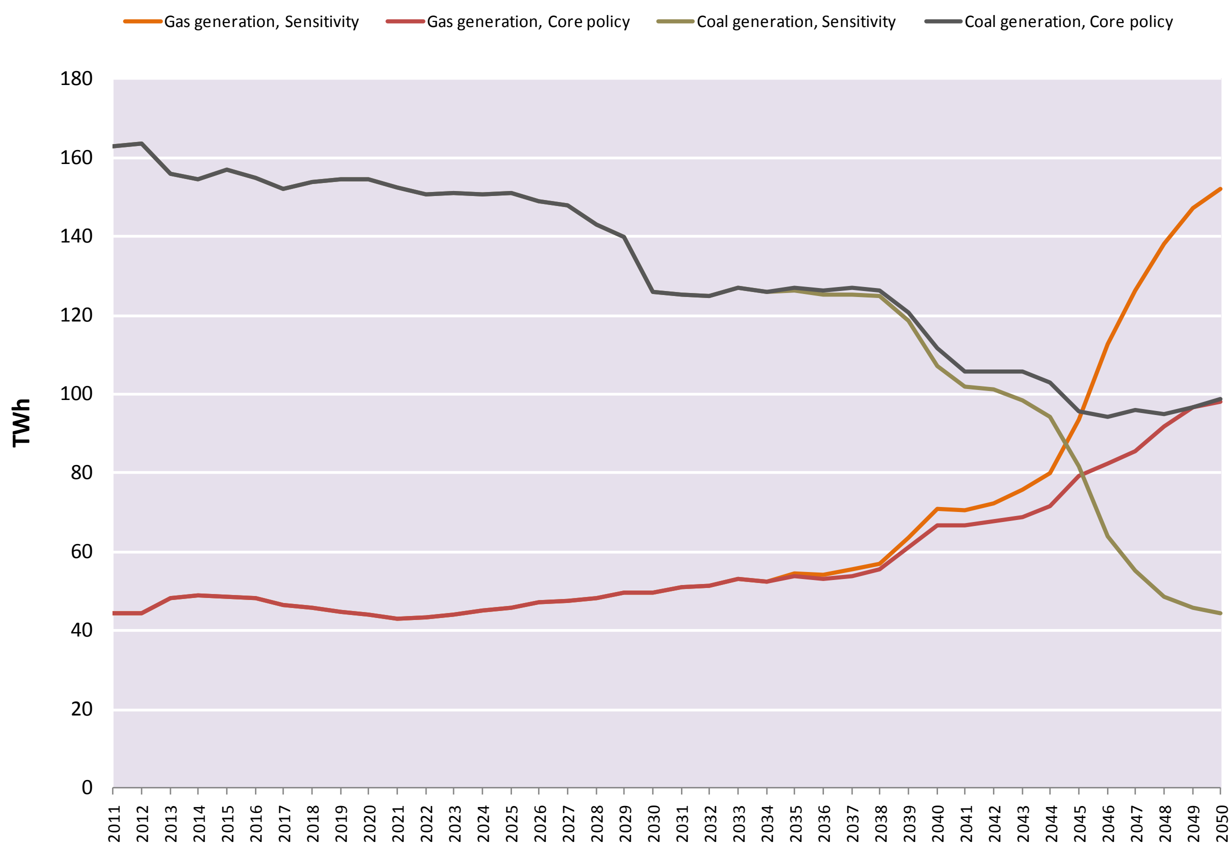
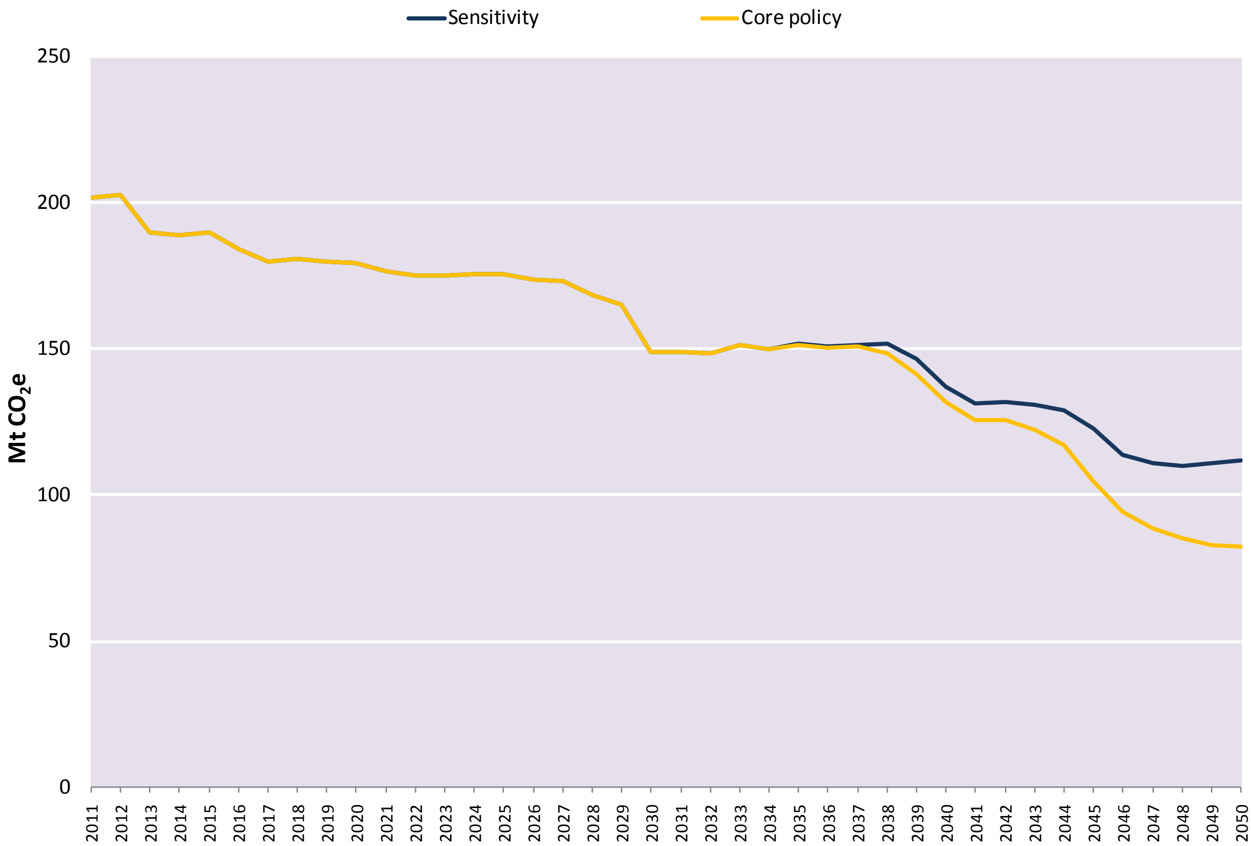


Figure 43 Emissions, core policy no CCS sensitivity



Appendix A General Assumptions

This section details the Australia-wide electricity market assumptions underlying the modelling.

A.1 Demand

Demand projections for the NEM, WEM, DKIS, NWIS and Mt Isa grids are obtained from data provided by the Treasury. The Treasury provides state-wide data, and this data is manipulated to obtain grid-wide data:

- For each state, the grid component is derived by using the ratio of historical grid data to 2008 Treasury data, and applying this ratio to state wide forecasts provided by the Treasury
- Peak demand is derived by taking projected load factors from published forecasts from market operators (AEMO, Western Australia IMO, Northern Territory Utilities Commission, Horizon Power and state government review) and applying these load factor forecasts to Treasury energy consumption data

A.2 Gas Prices

Gas prices used for the modelling were a combination of SKM MMA derived gas prices for eastern Australia, and the world gas price projection, which was provided by Treasury. The broad assumption here was that eastern Australian gas prices would eventually reach import parity with the world price. The assumed import parity date was determined to be around 2020, and the year on year price change of the world gas price thereafter was used to modify eastern Australian gas prices.

Gas prices for Western Australia and Northern Territory were assumed to track the world gas price from the outset.

A.2.1 Eastern Australia

SKM MMA prepares gas price forecasts based on projected demand-supply balance in eastern Australia. The gas resources and delivery infrastructure in this region are illustrated in Figure 44. This section briefly presents in SKM MMA's gas price forecasts, along with the high level assumptions underlying them. SKM MMA's in-house model, Market Model Australia–Gas (MMAGas), replicates the essential features of the Australian wholesale gas market:

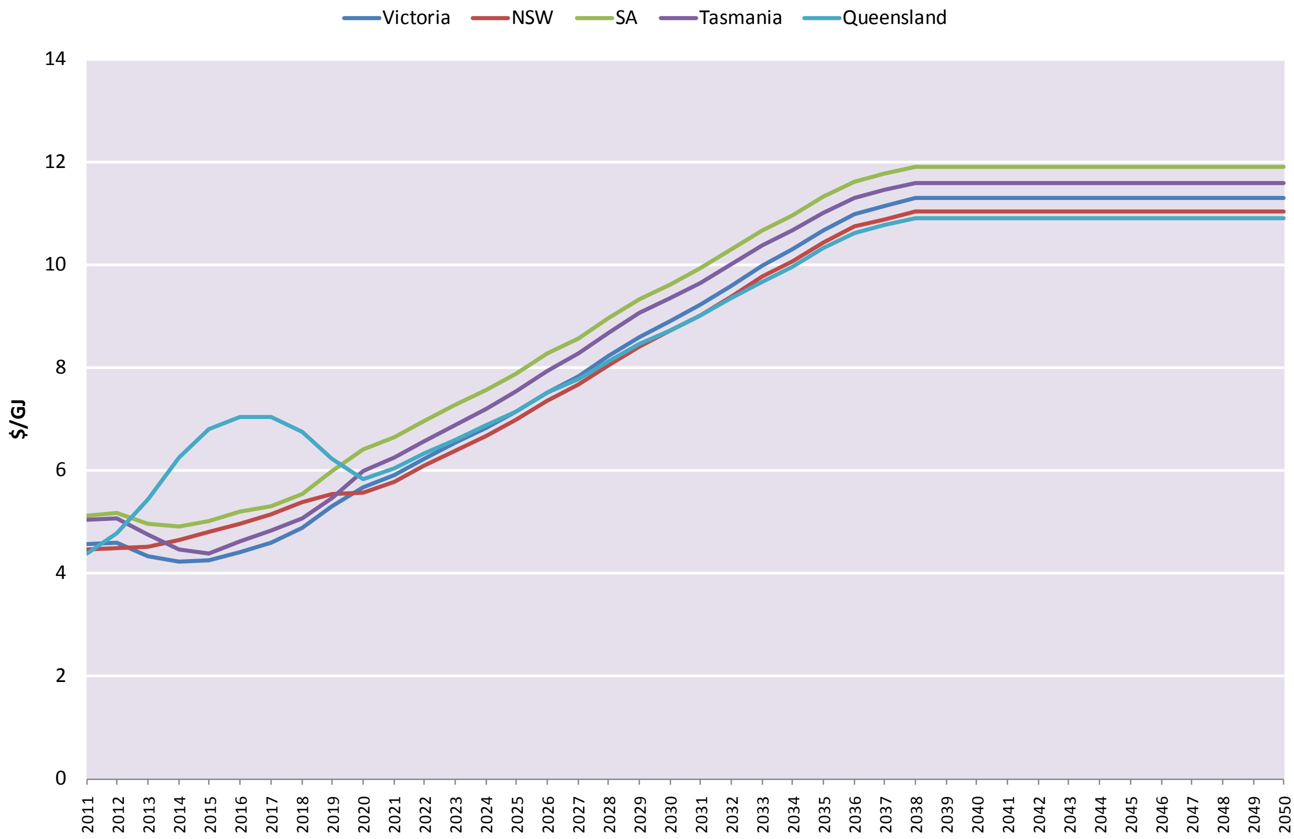
- A limited number of gas producers, with opportunities to exercise market power
- Dominance of long term contracting and limited short term trading
- A developing network of regulated and competitive transmission pipelines
- Market growth driven by gas-fired generation and large industrial projects

MMAGas has been developed to provide realistic assessments of long term outcomes in the Australian gas market, including gas pricing and quantities produced and transported to each regional market. The "gas market" in MMAGas is the market for medium to long-term gas contracts between producers and buyers such as retailers or generators. Competition between producers is represented as a Nash-Cournot game in which each producer seeks to maximise its profit subject to constraints imposed by its competitors. The role of buyers is replicated by modelling the activities of an arbitrage agent. Transmission costs are treated as cost inputs.

- **Figure 44 Gas resources and infrastructure, eastern Australia**

The gas prices for the standard LNG scenario derived from the MMAGas model were input into Strategist by NEM region until the 2020 import parity date. Thereafter, eastern Australian gas prices were modified by the year on year change of the world gas price. Figure 45 shows the final form of gas prices used for new contracts in eastern Australia for the core policy case. The variation in gas price between the scenarios was at most 15%, so these gas prices are fairly representative of the gas price profile for all scenarios. The noticeable bump in the Queensland gas price around 2015 represents the impact of the four committed LNG trains at Gladstone.

▪ **Figure 45 Finalised gas prices by NEM region for new contracts, core policy scenario**



A.2.2 Western Australia Wholesale Energy Market (WEM)

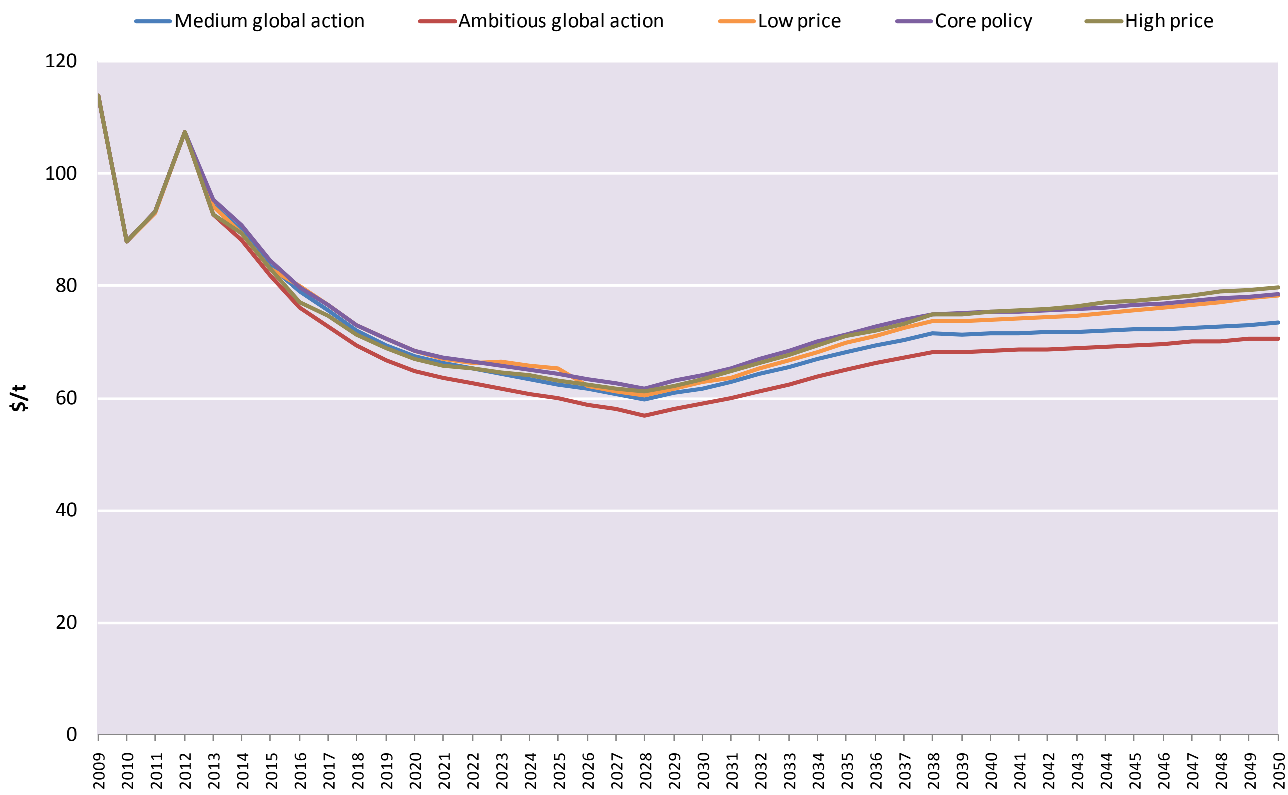
Gas prices in the WEM are not widely published and are often confidential. SKM MMA has assumed that prices range between $6/GJ and $9/GJ for new base load contracts. Existing contracts are at assumed contract price levels. The prices are assumed to change in line with the Treasury's forecasts of world energy prices.

A.3 Coal prices

Coal prices for all coal-fired power stations in Australia, except those located at the mine mouth, were assumed to track the world coal price, which was provided by Treasury (see Figure 46). The exceptions to this were the Victorian brown coal power stations and the mine mouth black coal power stations including Millmerran, Tarong, Tarong North and Kogan Creek. It was also assumed that by 2020 the mine mouth black coal power stations would also begin tracking the world coal price.

Non-mine mouth coal prices in the NEM generally began in the range of $1.9/GJ to $2.8/GJ in 2011, dipped to lows of $1.2/GJ to $2/GJ by 2028, and then recovered to end in the range of $1.5/GJ to $2.4/GJ by 2050. In Western Australia, prices were higher, starting at over $3/GJ, reaching a low of just over $2/GJ in 2028, and then recovering to just under $3/GJ by 2050.

■ **Figure 46 World coal prices by scenario provided by Treasury, $AU/tonne**



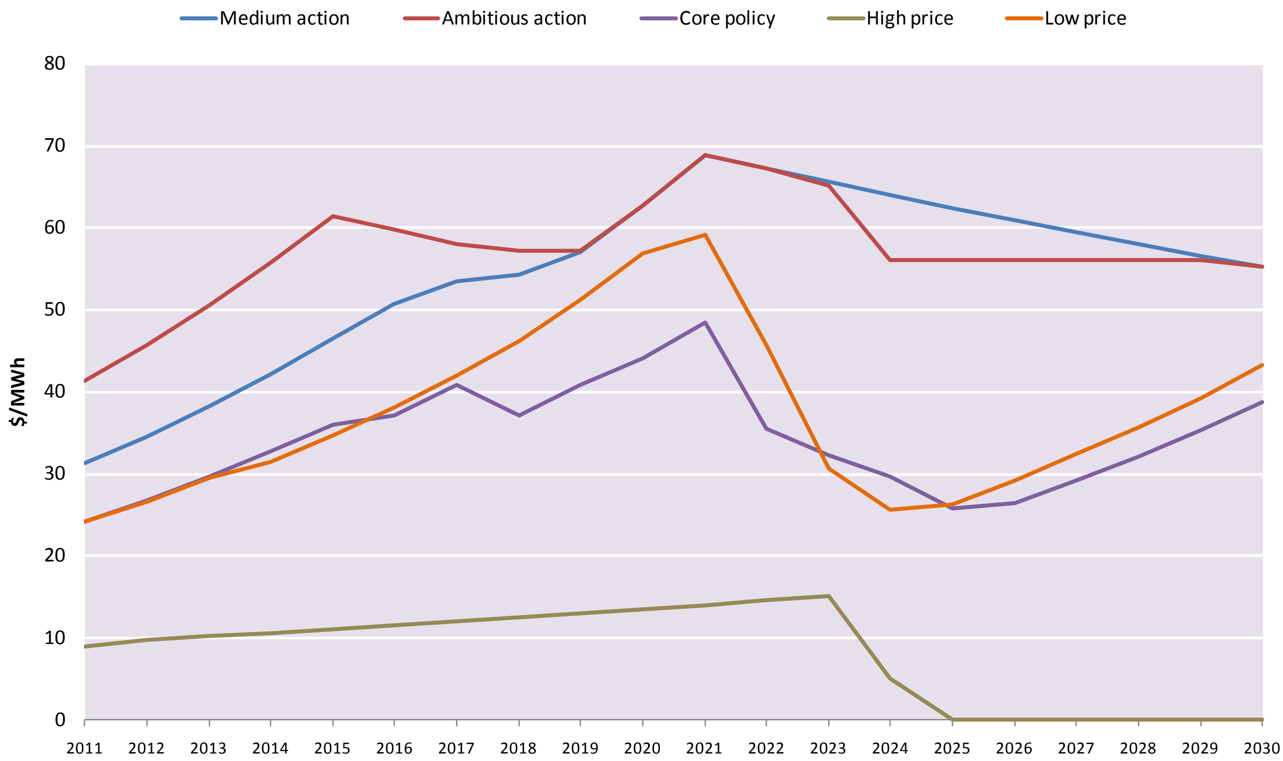
A.4 The Expanded Renewable Energy Target and other Abatement Schemes

A major development with respect to renewable energy generation was the expansion of the RET scheme to 45,000 GWh of additional renewable generation by 2020. The design did not change substantially from the pre-existing MRET, in that unlimited banking of renewable energy certificates is allowed, and there are no restrictions on project eligibility periods. The more recent separation of the scheme into small (SRES) and large scale targets (LRET), as discussed below, will likely see an increase in the adoption of small scale and large scale renewable energy technologies over the period to 2020.

The LRET is likely to bring on significant new wind and biomass capacity over the next decade, which will meet a large proportion of the underlying demand growth. Substantial penetration of wind may require additional open cycle gas turbine plants to provide reserve capacity for when the wind is not blowing. LRET has been legislated as a 41,000 GWh target with a maximum penalty for non- performance of $65/MWh. This penalty is not indexed to the consumer price index. The penalty is also not tax deductible, meaning that under current company tax rates a liable party would be indifferent about the choice of paying the penalty or purchasing certificates at a price of $92.86/MWh. To model the LRET scheme, we have assumed that the current scheme parameters under MRET will continue to operate with an increased target from 2010 onwards, and with an increase in the penalty price for non-compliance. The 41,000 GWh target continues until 2030.

Figure 47 shows projected prices by scenario of large-scale generation certificates (LGCs), which are the certificates produced by the LRET scheme.

▪ **Figure 47 LGC prices by scenario**



The SRES provides a fixed nominal price of $40/MWh for small scale systems such as solar water heaters and roof-top PV systems[7].

Additional to the MRET is Green Power, a scheme enabling any electricity purchaser to ensure that the energy they use is offset against the equivalent amount of renewable generation. This is also the means assumed for electric vehicles to obtain 100% backing of renewable power against all electric vehicle power purchases. The energy covered by this scheme is additional to the MRET.

Other types of schemes operating in Australia are described in Appendix F.

A.5 Capital Costs

A.5.1 Overview

Base capital costs for fossil fuel based technologies (black coal, brown coal and natural gas) were derived using the PEACE software package in conjunction with the GTPro and SteamPro thermodynamic analysis packages distributed by Thermoflow, Inc. A consistent scaling factor was applied to the raw costs calculated by the PEACE package to bring the costs into line with technologies recently quoted and developed (CCGT based technologies). No large scale coal based technology has been developed in Australia since Kogan Creek and hence actual market prices are not observable. The use of the PEACE software with a consistent scaling factor is intended to overcome this lack of data.

Costs derived were compared with those presented in other studies in the literature.

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[7] Uptake of solar and heat pump water heaters and roof-top PV systems under the SRES is treated in the model as a load modifier; that is, it reduces the amount of energy consumption by the energy saved from uptake of these technologies.

It is possible that this method overstates the costs of brown coal IGCC based technologies due to the high reactivity of Victorian brown coal not being fully represented in such generic software, however this is not expected to materially impact the results.

Base capital costs were then modified by the application of technology learning rates, exchange rates and metal prices. All three of these parameters were provided by Treasury for each of the four scenarios and the low price sensitivity, although the technology learning rates were ultimately determined by the 550 ppm or the 450 ppm world CO_2 concentration target. Each of these parameters is described below.

A.5.2 Base Capital Costs

Base capital costs for each technology include:

- The basic cost to procure the power plant on a "turnkey" basis for a generic site
- Where relevant, the costs include the costs of capture and compression of CO_2 but exclude transportation and storage (included elsewhere)
- Connection costs for electricity connection (and gas connection where applicable), and other external infrastructure
- Owner's costs (such as contract supervision, owner's engineering, initial spare parts, start-up costs etc.)

The costs are expressed on an "overnight"[8] basis on the net capacity of the plant. Costs incurred prior to project commitment ("financial closure") are not included.

The base capital costs used for the modelling are summarised below in Table 7.

- **Table 7 Base capital cost and performance assumptions by technology**

GENERATING TECHNOLOGY	BASE CAPITAL COST ($/KW)	THERMAL EFFICIENCY (%)	FIXED O&M COSTS ($/KW/YEAR)
Black Coal Options			
Supercritical coal (dry-cooling)	2,357	40	30
Ultra-supercritical coal (wet cooled)	2,235	41	30
IGCC	3,643	46	45
IGCC with CC	5,418	36	50
Ultra-supercritical with CC and oxy- firing	5,676	30	40
USC with post- combustion capture (wet cooled)	3,828	31	40
Brown Coal Options			
Supercritical coal with drying	2,900	31	36
Supercritical coal	2,900	29	36
Ultra supercritical coal with drying	3,000	32	36
IGCC with drying	6,601	35	50
IGCC with drying and CC	9,816	26	60

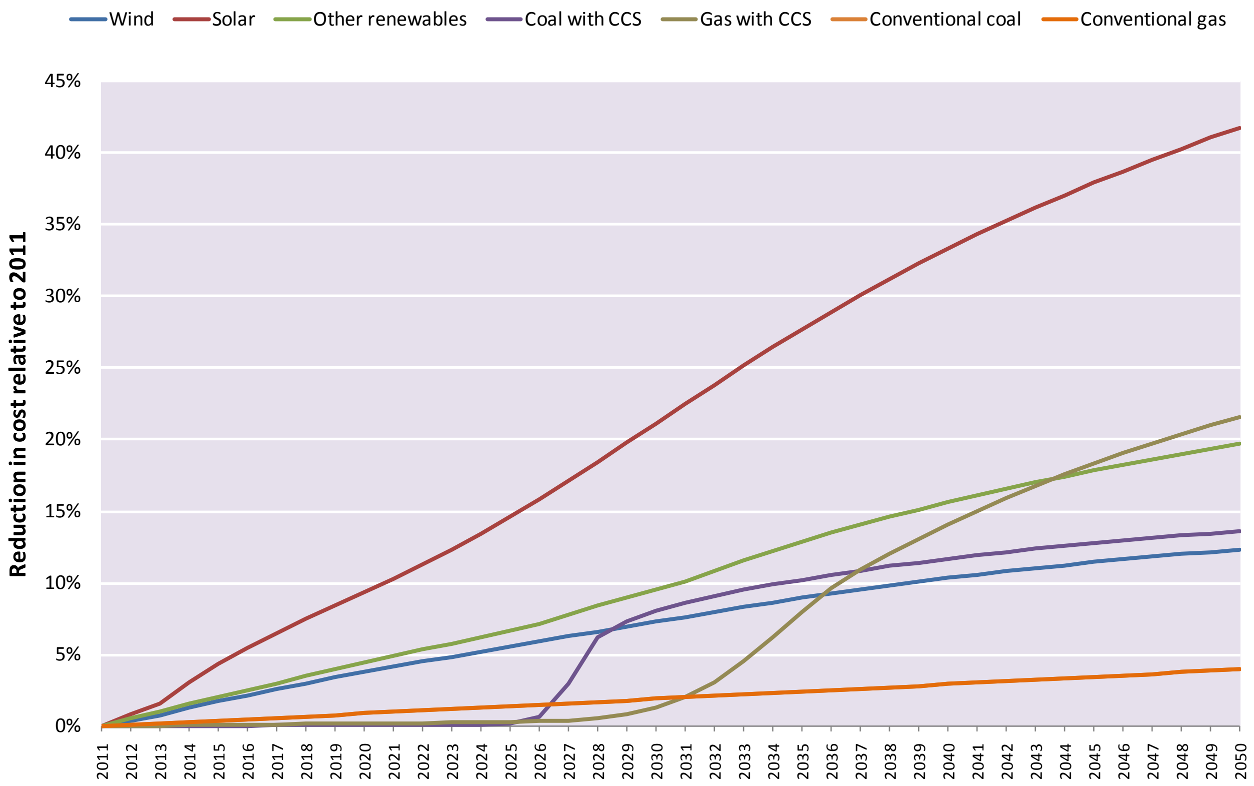
[8] That is, the interest-during-construction costs are not included.

GENERATING TECHNOLOGY	BASE CAPITAL COST ($/KW)	THERMAL EFFICIENCY (%)	FIXED O&M COSTS ($/KW/YEAR)
Natural gas options			
CCGT – small	1,850	43	30
CCGT – medium	1,400	46	25
CCGT – large	1,300	51	18
Cogeneration (large)	1,900	69	25
CCGT with CC (wet cooled)	2,755	44	45
Renewable energy options			
Wind	2,400		40
Biomass - Steam (wood waste used)	6,382	25	60
Biomass - Gasification (wood waste used)	5,361	25	60
Concentrated Solar thermal plant - without storage	6,500		50
Concentrated Solar thermal plant - with storage	9,500		60
Geothermal – HSA	6,500	28	50
Geothermal - Hot Rocks	7,000	26	50
Concentrating PV	6,175		45
Hydro	3,500		35

A.5.3 Technology Learning Rates

Figure 48 shows the projected capital cost reduction relative to 2011 attributable to learning by doing for each technology for the 550 ppm cases (medium action, core policy and low price sensitivity). All learning rates were provided by Treasury, except those for the conventional coal and gas technologies, which were an SKM MMA assumption. Note that the conventional coal and conventional gas learning rates lie on top of each other. The projections show that the most improvement is expected for solar technologies, and the learning is expected to evolve at a fairly steady pace. Learning for CCS technologies is expected to accelerate rapidly from around 2027 for coal-fired technologies and from about 2032 for gas-fired technologies. Learning rates for the 450 ppm scenarios (ambitious action and high price) are slightly higher for all renewable technologies and also for gas-fired generation with CCS, and slightly lower for coal-fired generation with CCS. This is consistent with the more stringent CO_2 concentration target required to be met in a 450 ppm world.

■ **Figure 48 Reduction in capital costs due to learning relative to 2011, 550 ppm world**



A.5.4 Exchange Rates

The Treasury provided assumptions about the movement in the exchange rate over time. The Treasury projects that the Australian dollar will remain at a high level for some time before falling as the terms of trade falls. In the medium global action scenario the exchange rate is projected to trend downwards before stabilising above 70 cents. The exchange rate assumptions for the other scenarios show similar trends. The falling exchange rate will have the effect of increasing capital costs in Australia, and will therefore tend to counter the downward impact of technology learning rates.

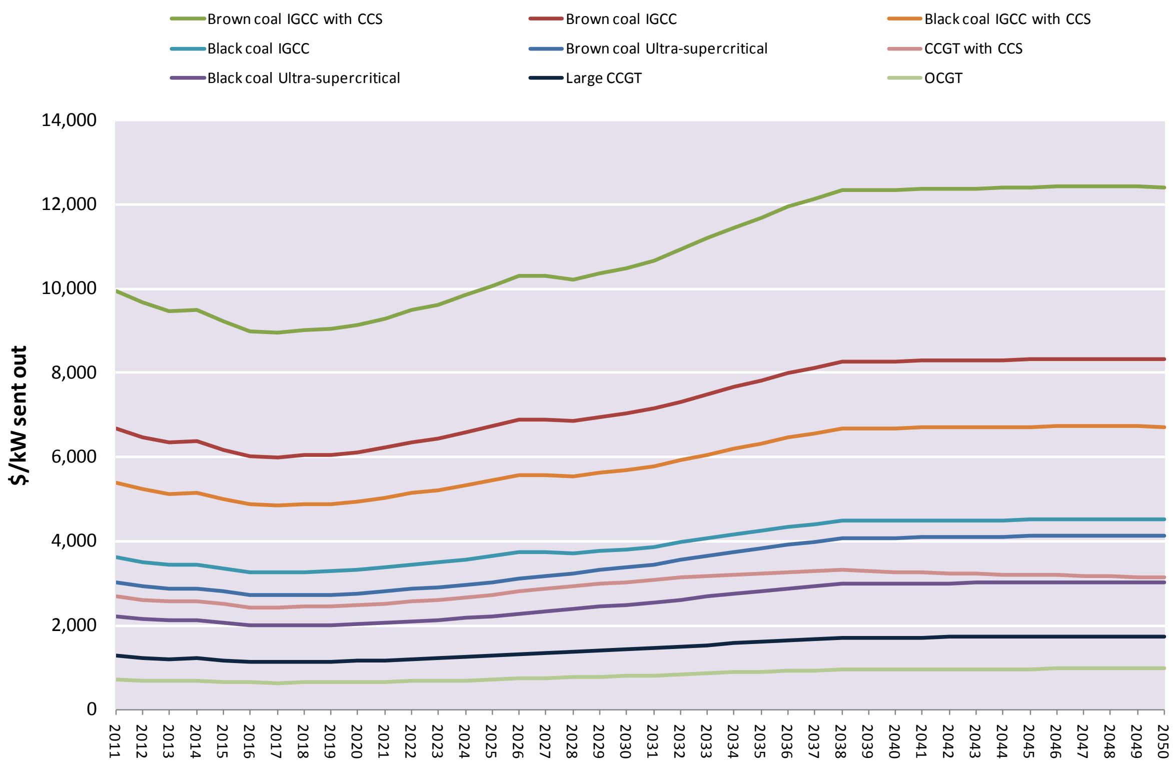
A.5.5 Metal Price Index

Treasury provided price projections for three different types of metals: steel, aluminium and "other metals". The average of the year on year growth rate of the three categories was used to construct a metals price index. This index is used to modify the capital cost of plant, 25% of which is assumed to be sensitive to metal prices – thus the metals index is only applied to 25% of the capital cost, and not to the entire capital cost. Metal prices are higher under the high price scenario, which is consistent with a higher demand for metal, driven by higher power plant construction activity as new low emissions plant is needed to replace high emitting incumbent plant in a relatively small time frame. Metal prices are lower for the core policy scenario and the low price sensitivity, and lower still for the reference cases, where high emissions plant only retire due to aging rather than an increasing carbon price impost.

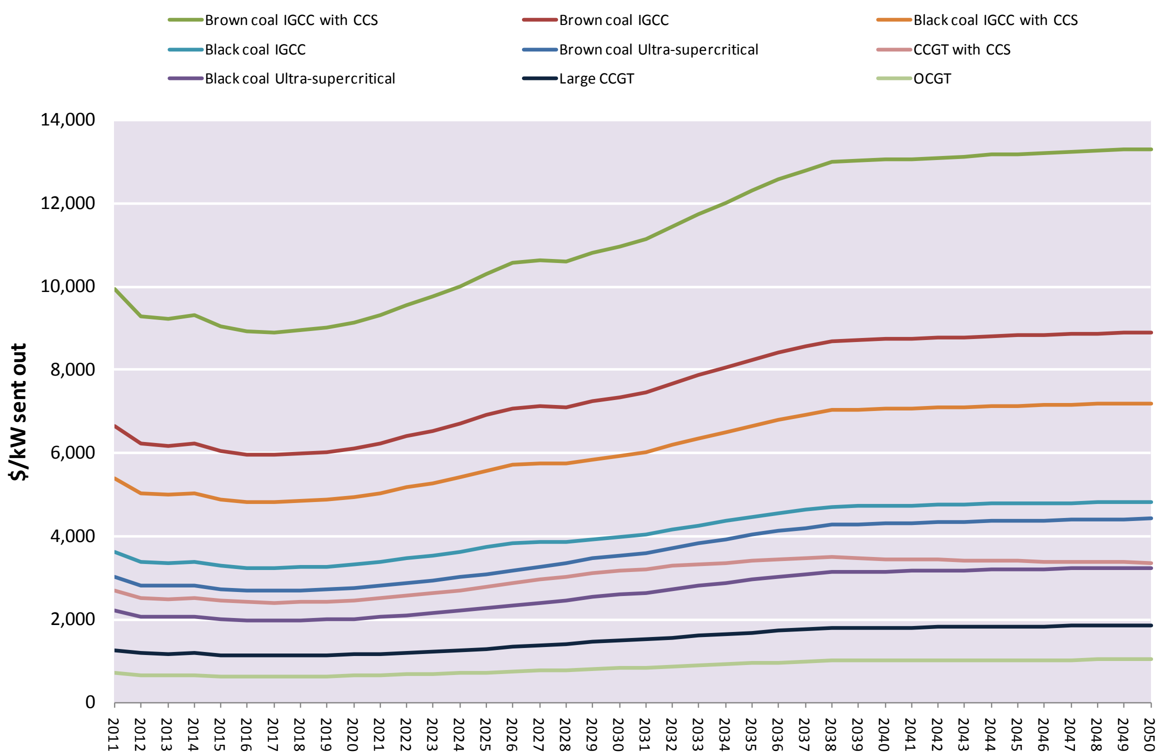
A.5.6 Capital Cost Profiles

Figure 49 shows the final capital cost profiles for the thermal technologies after all modifications to the base capital cost have been carried out, for the medium global action scenario. Figure 50 is the same chart for the core policy scenario. Capital costs are slightly higher in this case, mainly as a result of greater metal prices.

■ **Figure 49 Capital costs for thermal technologies, medium global action scenario**



■ **Figure 50 Capital costs for thermal technologies, core policy scenario**



A.6 Transport and storage costs for carbon capture and storage technology

Table 8 shows SKM MMA's assumptions about the transportation and storage costs associated with carbon capture and storage technology. These are treated as variable costs by the dispatch model because the costs are incurred for every additional tonne of emissions that are produced from the generation process. These costs are assumed to increase in real terms in a linear fashion, which reflects that the lowest cost storage sites would be filled first, and then emissions would have to be sequestered in less favourable (ie. more expensive) storage sites.

Table 8 Transportation and storage costs of CCS technology by state ($/t CO_2e)

	2026 COST	2050 COST
South Australia	30	36
Victoria	20	26
Tasmania	20	26
New South Wales	30	36
Queensland	25	31
Western Australia (SWIS)	25	31

Appendix B Assumptions for the NEM

B.1 Supply

B.1.1 Marginal Costs

The marginal costs of thermal generators consist of the variable costs of fuel supply (including fuel transport), plus the variable component of operations and maintenance costs. The indicative variable costs for various types of existing thermal plants are shown in Table 9. The parameters underlying these costs are presented in detail on a plant by plant basis in Appendix C. SKM MMA also include the net present value of changes in future capital expenditure that would be driven by fuel consumption for open cut mines that are owned by the generator. This applies to coal in Victoria and South Australia.

- **Table 9 Indicative average variable costs for existing thermal plant ($June 2010)**

TECHNOLOGY	VARIABLE COST $/MWH	TECHNOLOGY	VARIABLE COST $/MWH
Brown Coal – Victoria	$7 - $11	Brown Coal – SA	$23 - $29
Gas – Victoria	$45 - $65	Black Coal – NSW	$21 - $24
Gas – SA	$38 - $183	Black Coal - QLD	$8 - $23
Oil – SA	$268 - $330	Gas – QLD	$26 - $103
Gas Peak – SA	$103 - $185	Oil – QLD	$258

B.1.2 Plant Performance and Production Costs

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

B.2 Bidding Behaviour

B.2.1 Market structure

We assume the current market structure continues under the following arrangements:

- Victorian generators are not further aggregated
- New South Wales generators remain under the current structure in public ownership
- The generators' ownership structure in Queensland remains with the current level of public ownership
- The South Australia assets continue under the current portfolio groupings (Optima in the TRUenergy portfolio and Synergen in the International Power portfolio with Pelican Point and Hazelwood Power)

Bidding of capacity depends on the contracting position of the generator. Capacity under two-way contracts will either be self-committed[9] for operational reasons or bid at marginal cost to ensure that the plant is earning pool revenue whenever the pool price exceeds the marginal cost. Capacity which backs one-way hedges will be bid at the higher of marginal cost and the contract strike price, again to ensure that pool revenue is available to cover the contract pay out.

SKM MMA formulates future NEM development ensuring that the reserve requirements are met in each region at least cost. The minimum reserve levels assumed for each state are based on values specified in the 2010 ESOO and are summarised

[9] "Self-committed" means that the generator specifies the timing and level of dispatch rather than AEMO and this is taken as a zero bid when setting pool prices. If generators are required to off-load below their self-commitment level, a negative pool price will be declared for generators and customers.

in Table 10 below. The minimum reserve level for Victoria and South Australia combined post 2012 is 60 MW of which -116 MW has been allocated to South Australia by AEMO in an attempt to minimise the local reserve requirement in South Australia. This means that Victoria must carry 176 MW when South Australia is fully relying on Victoria.

Table 10 Minimum reserve levels assumed for each state

REGION	QLD	NSW	VIC	SA	TAS
Reserve Level 2010/11	829 MW	-1,548 MW	653 MW	-131 MW	144 MW
Reserve Level 2011/12	913 MW	-1,564 MW	530MW	-268 MW	144 MW
Reserve Level 2012/13 onwards	913 MW	-1,564 MW	176MW	-116 MW	144 MW

After selecting new entry to meet AEMOs minimum reserve criteria, SKM MMA's pool market solution indicates whether prices would support additional new entry under typical market conditions and these are included in the market expansion if required. We assume that:

- Some 75% of base load plant capacity will be hedged in the market and bid at close to marginal cost to manage contract position
- New entrants will require that their first year cash costs are met from the pool revenue before they will invest
- Infrequently-used peaking resources are bid near value of lost load or removed from the simulation to represent strategic bidding of such resources

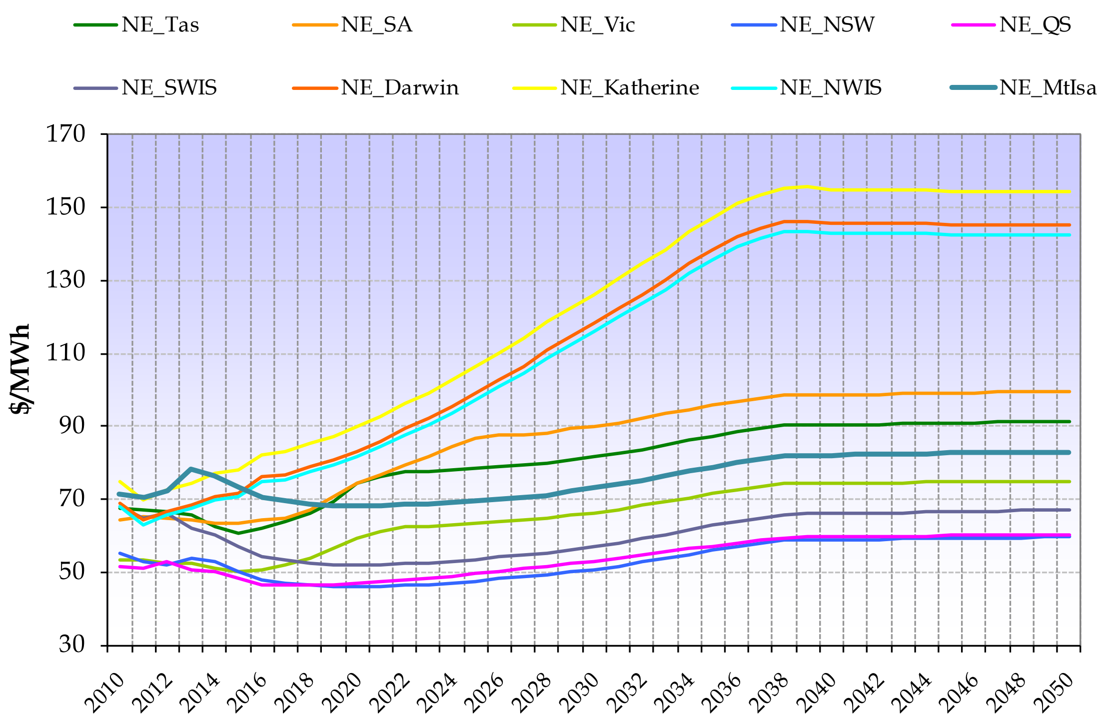
New entry prices for the medium global action scenario are shown in Figure 51 in June 2010 dollars. These new entry prices include the impact of emission abatement schemes such as GECs in Queensland throughout the period and the NGACs until 2020/21.

Cost and financing assumptions used to develop the long term new entry prices are provided in Table 11. New technologies have higher initial costs and greater rates of real cost decline. The real pre-tax weighted average cost of capital[10] was 11.30% pa in 2011, but this declines to the long-term trend of 9.5% pa by 2016.

The capacity factors in Table 11 are deliberately high to allow us to approximate a time-weighted new entry price in each state that can rapidly be compared to the time-weighted price forecasts to determine whether or not new entry would be encouraged to enter the market. These capacity factors do not necessarily reflect the levels of duty that we would expect from the units. The unit's true LRMC measured in $/MWh is higher than this level. For example, we would be more likely to find a new CCGT operating in Victoria with a capacity factor of around 60% to 70% rather than the 92% indicated in Table 11. Ideally, in determining the timing of new entry of such a plant we would compare the new entry cost of a CCGT operating at this level against the time-weighted prices forecast in the top 60% to 70% of hours. However, this would require more detailed and time-consuming analysis, and in our experience it does not yield any significantly different price path.

[10] Weighted average cost of capital, applied in real terms and pre-tax in this report. It is defined as the weighted average cost of debt and equity funds applied, as a proportion of the total investment cost, and adjusted to a pre-tax basis. It is used as a discount rate to annualise the capital costs over the expected technical operating life of the project.

■ **Figure 51 Medium global action scenario new entry prices (June 2010 $/MWh)**



■ **Table 11 New entry cost and financial assumptions ($ June 2010) for 2010/11**

	TYPE OF PLANT	CAPITAL COST	AVAILABLE CAPACITY FACTOR	FUEL COST*	WEIGHTED COST OF CAPITAL	LRMC $/MWH (a)
		$/kW		$/GJ	% real	
SA	CCGT	$1,400	92%	$5.11	11.30%	$65.4
VIC	CCGT	$1,300	92%	$4.57	11.30%	$53.3
NSW	CCGT	$1,300	92%	$4.47	11.30%	$52.9
NSW	Black Coal	$2,235	92%	$1.92	11.30%	$54.6
QLD	CCGT	$1,300	92%	$4.37	11.30%	$51.3
QLD	Black Coal (Tarong)	$2,235	92%	$0.72	11.30%	$44.0
QLD	Black Coal (Central)	$2,235	92%	$2.23	11.30%	$57.3

* The fuel costs shown are indicative only. Gas prices vary according to the city gate prices.
(a) excluding abatement costs or revenues

B.3 Future NEM Developments

B.3.1 Committed and Planned Entry

The recently developing power projects and reserve plant are shown in Table 12. Only projects which have nominated commencement dates are included. The table shows the currently mothballed or reserve capacity in the NEM and the new projects which have been committed for completion within the next four years, as is reported in the 2010 ESOO. It also shows other projects for which planning is well advanced according to the 2010 ESOO. Table 12 demonstrates that new entry is alive and strong in the NEM with plenty of new projects in the pipeline to meet projected demand.

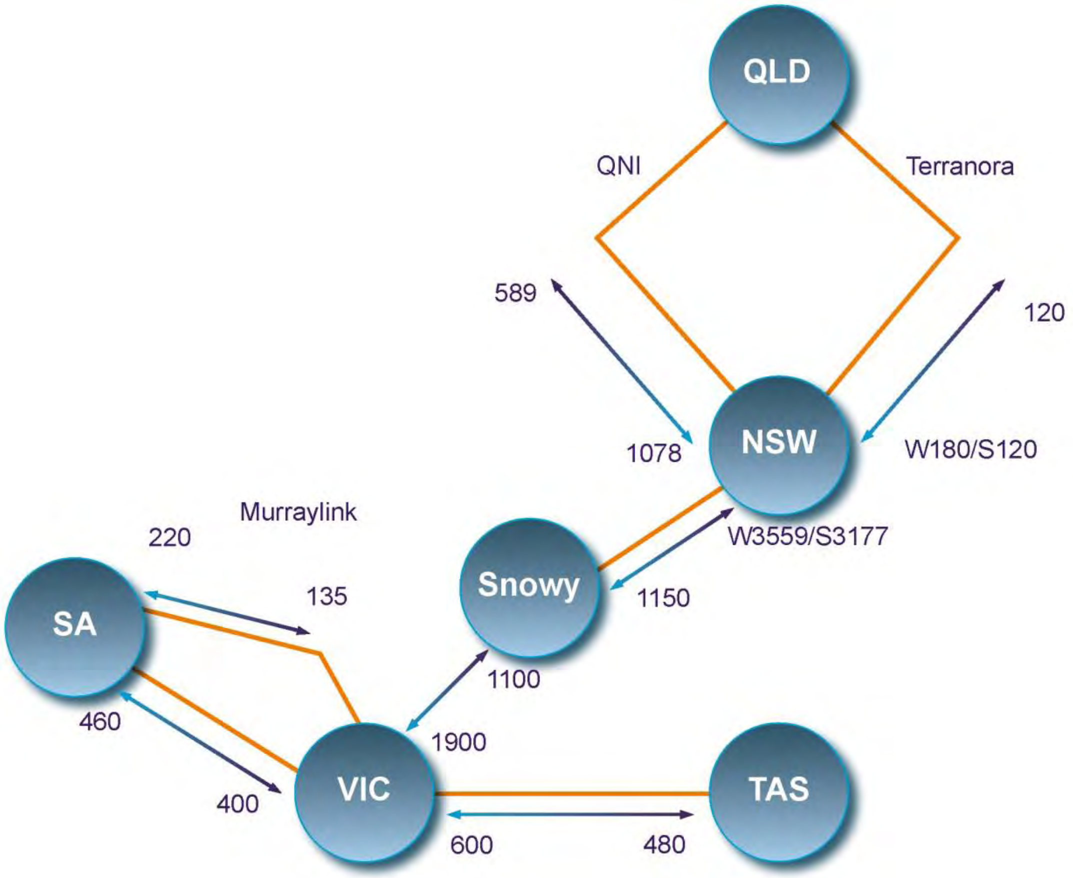
Table 12 Mothballed and reserve capacity and recently developed new plants in the NEM

POWER PLANT	GENERATED CAPACITY (MW)	REGION	SERVICE DATE	STATUS
Callide A	120 (90 long-term)	Central QLD	Originally intended to be refurbished	Mothballed in April 2002. Now in indefinite dry storage. One unit of this plant will be used to test CO_2 sequestration technology as part of low emission technology development. Modelled from 2010/11 to 2015/16.
Munmorah	2 X 300	NSW	Reserve	Both 300 MW units are operable at short notice when other Delta Electricity units are unavailable. They are not normally operated when Mt Piper and Wallerawang are fully available.
TOTAL Reserve	**690**			
Eraring upgrade	4 x 60	NSW	Dec 11 – Nov 12	Advanced proposal
Wellington GT 1-4	4 x 173	NSW	Nov 2011	Publicly announced
Wellington GT 5	300	NSW	Dec 2012	
Leaf's Gully	360	NSW	Jan 2012	Publicly announced
Bamarang OCGT	330	NSW	Nov 2012	Publicly announced
Bamarang CCGT	450	NSW	Nov 2012	Publicly announced
Marulan OCGT	330	NSW	Nov 2013	Publicly announced
Marulan CCGT	420	NSW	Nov 2013	Publicly announced
Mt Piper Coal	1000	NSW	Nov 2015	Publicly announced
Mt Piper Coal	1000	NSW	Nov 2016	Publicly announced
Braemar stage 3	3 x 173	QLD	March 2012	Publicly announced
Braemar stage 4	2 x 236.5	QLD	Dec 2013	Publicly announced
Arckaringa IGCC	560	SA	Nov 2014	Publicly announced
Lonsdale 2	28	SA	Jan 2010	Publicly announced
Kingston	40	SA	2015	Publicly announced
Loy Yang	90	VIC	November 2012	Committed
Mortlake GT	2 x 275	VIC	Q1 2011	Undergoing commissioning
Tarrone GT	500	VIC	Jan 2012	Publicly announced
Shaw River CCGT	500	VIC	June 2012	Publicly announced
HRL IDGCC	500	VIC	2016	Publicly announced
Gunns	176	TAS	2014	Advanced proposal
TOTAL Planned	**9,058**			
TOTAL	9,748			Includes reserve, new and prospective developments with advanced proposal status or likely to proceed.

B.3.2 Interconnections

Assumptions on interconnect limits are illustrated in Figure 52. These limits are based on the maximum recorded inter-regional capabilities for 2005/06. The actual limit in a given period can be much less than these maximum limits, depending on the load in the relevant region and the operating state of generators at the time.

- Figure 52 Representation of interconnectors and their limits



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

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

There are a number of possible interconnection developments being considered including:

- An upgrade of the Queensland New South Wales interconnect export limit by an additional 400 MW in both directions
- An upgrade of the existing Victoria to South Australia export limit from 460 MW to 630 MW

- A further 600 MW upgrade of the Snowy to Victoria transmission link over time which would enable additional imports from Snowy/New South Wales into Victoria

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

B.3.3 Transmission

Inter-regional losses

Inter-regional loss equations are modelled in Strategist by directly entering the loss factor equations published by AEMO except that Strategist does not allow for loss factors to vary with loads. Therefore we allow a typical area load level to set an appropriate average value for the adjusted constant term in the loss equation. The losses currently applied are those published in the AEMO 01 April 2010 Report V1.0 *"List of Regional Boundaries and Marginal Loss Factors for the 2010/11 Financial Year".*

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

Intra-regional losses

Intra-regional losses are applied as detailed in the AEMO 01 April 2010 Report V1.0 *"List of Regional Boundaries and Marginal Loss Factors for the 2010/11 Financial Year".* The long-term trend of marginal loss factors is extrapolated for two more years and then held at that extrapolated value thereafter.

B.3.4 Hydro modelling

Hydro plants are set up in Strategist with fixed monthly generation volumes. Strategist dispatches the available energy to take the top off the load curve within the available capacity and energy. Any run-of-river component is treated as a base load subtraction from the load profile.

These monthly energy limits provided by NEMMCO in the 2003 ANTS have been validated by comparison against historical hydro sequences that are derived from published generation data found at www.erisk.net. Erisk is a live source of combined news, prices, data and analyses for the Australian Energy Market. Where the hydro sequences appear ill-aligned to the NEMMCO energy limits, the average monthly generation levels are used in place of the NEMMCO limits to represent an estimate of the long run monthly energy limits.

Table 13 through to Table 15 show the maximum monthly energy limits used in the model.

Based on market information, we have produced detailed information on monthly and annual maximum and minimum energy limits for the Snowy Hydro units. This information has been incorporated into the Strategist simulation as monthly energy generation. Daily release constraints cannot be modelled in Strategist.

The monthly minimum generation limits for Blowering and Guthega are based on market information acquired by SKM MMA, largely driven by the irrigation requirements of these hydro systems. While the generation from individual hydro units may differ from what has been historically observed over the past couple of years, the long-run average total Snowy generation assumed on a calendar year basis is approximately 500 GWh higher than the average of the actual Snowy generation for calendar years 2004 and 2005.

Murray 1 releases will be progressively reduced with increasing environmental releases, particularly down the Snowy River. Snowy Hydro estimates a reduction of 540 GWh/year after the 10 year programme is completed. Consequently, by July 2012 the Murray annual energy limit will have been reduced to 1,738 GWh per annum.

Table 13 Maximum monthly energy availability for small hydro generators (GWh)

MONTH	BARRON GORGE	HUME NSW	HUME VIC	KAREEYA
January	13.96	4.19	18.75	23.32
February	20.56	3.44	15.19	22.91
March	22.63	0.22	14.53	23.60
April	15.47	0.21	6.53	20.42
May	11.28	0.00	0.62	25.02
June	9.40	0.00	0.09	25.80
July	10.07	0.94	0.01	32.05
August	7.93	4.47	1.09	30.18
September	8.51	7.86	6.97	22.61
October	12.02	6.71	14.61	23.34
November	13.38	3.47	20.25	21.30
December	10.52	5.91	20.66	28.05

Table 14 Maximum monthly energy availability for Southern Hydro units

MONTH	DARTMOUTH	EILDON 1-2	KIEWA/MCKAY
January	24.98	19.13	10.01
February	26.37	14.71	10.6
March	11.87	15.51	5.98
April	3.48	7.49	4.33
May	4.71	1.37	11.44
June	9.58	0.32	19.4
July	36.78	0.88	28.89
August	34.77	3.3	23.06
September	31.76	4.98	30.8
October	33.33	7.4	43.71
November	35.99	8.98	23.03
December	31.14	17.6	15.93

- **Table 15 Maximum and minimum energy limits from Snowy Hydro**

	BLOWERING	GUTHEGA	MURRAY	UPPER TUMUT	LOWER TUMUT
Annual Maximum Limit (GWh)	240	250	2210	1630	745
Monthly Minimum Limits (GWh)					
January	60	9	1	5	
February	50	4	1	5	
March	45	4	1	5	
April	25	4	1	5	
May	10	9	1	5	
June	15	23	2	10	
July	20	24	2	14	
August	20	23	2	15	
September	30	42	3	15	
October	60	125	10	15	
November	80	79	6	10	
December	70	23	2	5	
Daily Maximum (GWh)		13	12	4	

Hydro Tasmania is represented by the aggregate of a 3-storage model:

- Long-term storage, which is assumed to have sufficient storage for at least one year
- Mid-term storage, which is assumed to be managed on a 6-monthly basis
- Run-of-the-river, with storage possible for only one month at a time

Allocation of individual generators to each of these storages has been based on the 2006 ANTS allocation, as shown in Table 16. However, in Strategist the monthly energy and capacity are combined into one equivalent hydro unit for Hydro Tasmania.

- **Table 16 Allocation of units to storage in Tasmania**

STORAGE	STATIONS
Long-term	Gordon, Poatina
Mid-term	Butlers Gorge, Lake Echo,Tarraleah, Tungatinah, Liapootah, Wayatinah, Catagunya, Repulse, Cluny, Fisher, Rowallan, Lemonthyme, Mackintosh, Bastyan, John Butter, Lake Margaret
Run of river	Meadowbank, Trevallyn, Wilmot, Cethana, Devils Gate, Paloona, Reece, Tribute, Parangan, Todds Corner

In the 2006, ANTS energy inflow data was determined for each storage based on historical monthly yield information provided by Transend. These monthly energy inflows are represented in Table 17.

The average annual yield is assumed to increase after the commissioning of Basslink, and so the monthly limits are pro-rated each year in line with this annual yield which appears in Table 18. The generation profile may be distributed over the months of the year to optimise the value of trading according to the requirements of the study.

- **Table 17 Monthly energy inflows for Tasmanian hydro, average monthly yields 1924 to 2002 (GWh)**

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Long-term	77	66	86	197	288	330	399	417	366	292	192	141	2851
Mid-term	147	120	145	325	462	495	601	595	530	435	313	230	4398
Run of river	131	110	125	206	275	311	364	364	320	280	221	177	2884
Total	355	296	356	728	1025	1136	1364	1376	1216	1007	726	548	10133

Source: ANTS 2006.

- **Table 18 Assumed average annual generation from Tasmanian Hydro generators (GWh)**

FINANCIAL YEAR	2010	2011	2012	2013	THEREAFTER
Average annual generation	8,249	8,831	9,309	8,685	8,685

Source: SKM MMA estimate.

Appendix C Costs and Performance of Thermal Plants – NEM

The following table shows the parameters for power plants used in the Strategist model. Costs are reported in June 2010 dollars.

PLANT	NO UNITS	TOTAL SENT OUT CAPACITY	SCHEDULED MAINTENANCE (WEEKS PA)	EFFECTIVE FORCED OUTAGE RATE	AVAILABLE CAPACITY FACTOR	FULL LOAD HEAT RATE (SENT OUT)	VARIABLE O&M COST $/MWH (SENT OUT)	VARIABLE FUEL COST $/GJ	TOTAL VARIABLE COST $/MWH (SENT OUT)
Tasmania									
Tamar Valley CCGT	1	196.9	1.9	3%	93.6%	7.54	$2.77	$5.42	$43.65
Bell Bay GT	3	119.4	3.0	1%	93.3%	11.50	$4.15	$4.73	$58.51
Tamar Valley OCGT	1	57.7	3.0	1%	93.3%	11.50	$4.15	$11.44	$135.73
Victoria									
AGL	4	159.2	4.0	9%	84.0%	13.50	$2.77	$4.07	$57.69
Anglesea	1	146.3	1.0	2%	96.6%	13.00	$1.38	$0.14	$3.23
Bairnsdale	2	91.5	3.0	1%	93.3%	11.50	$4.15	$4.19	$52.42
Energy Brix	5	150.9	5.0	4%	86.8%	21.25	$2.77	$0.64	$16.33
Hazelwood	8	1472.0	4.0	9%	84.0%	13.30	$2.77	$0.64	$11.26
Jeeralang A	4	230.8	2.1	1%	95.0%	13.75	$8.31	$3.97	$62.83
Jeeralang B	3	253.7	2.1	1%	95.0%	12.85	$8.31	$3.97	$59.26
Laverton	2	338.3	2.0	2%	93.9%	11.55	$4.15	$4.07	$51.14
Loy Yang A	4	2043.0	2.5	4%	91.9%	11.58	$1.10	$0.48	$6.72
Loy Yang B	2	966.0	2.5	3%	92.3%	11.70	$1.10	$0.48	$6.78
Valley Power	6	313.4	2.1	1%	95.0%	13.75	$8.31	$3.97	$62.83
Yallourn W	4	1368.0	3.0	6%	88.6%	12.91	$1.38	$0.49	$7.80
Newport	1	484.5	2.2	3%	93.0%	10.33	$2.77	$4.07	$44.80
Mortlake OCGT	2	550.2	2.5	2%	93.0%	10.60	$3.52	$3.60	$41.63

PLANT	NO UNITS	TOTAL SENT OUT CAPACITY	SCHEDULED MAINTENANCE (WEEKS PA)	EFFECTIVE FORCED OUTAGE RATE	AVAILABLE CAPACITY FACTOR	FULL LOAD HEAT RATE (SENT OUT)	VARIABLE O&M COST $/MWH (SENT OUT)	VARIABLE FUEL COST $/GJ	TOTAL VARIABLE COST $/MWH (SENT OUT)
HRL	committed	403.0	2.0	20%	76.9%	7.17	$3.35	$0.48	$6.79
South Australia									
Angaston	1	48.8	0.0	0%	99.5%	9.00	$11.88	$21.03	$201.23
Dry Creek	3	147.3	4.0	3%	89.1%	17.00	$8.31	$9.92	$177.09
Hallett	5	210.1	4.0	5%	87.9%	12.00	$9.48	$21.03	$261.94
Ladbroke Grove	2	85.6	3.0	2%	92.1%	10.00	$6.93	$4.70	$53.95
Mintaro 1	1	89.6	4.0	5%	88.1%	16.00	$8.31	$9.92	$167.16
Northern	2	505.1	2.8	2%	92.6%	11.50	$2.69	$1.55	$20.45
Osborne	1	187.4	2.0	2%	93.9%	10.40	$2.69	$4.70	$51.60
Pelican Point	1	462.6	3.0	3%	91.4%	7.71	$2.77	$4.44	$37.04
Playford B	4	222.0	6.0	5%	84.1%	15.00	$4.04	$1.55	$27.20
Port Lincoln	3	74.6	3.0	3%	91.4%	11.67	$8.31	$21.03	$253.75
Quarantine	5	217.9	4.0	3%	89.1%	10.35	$8.83	$9.92	$111.60
Snuggery	3	65.7	4.0	5%	88.1%	15.00	$8.31	$21.03	$323.88
Torrens Island A	4	478.8	4.0	5%	87.7%	10.80	$8.31	$8.35	$98.49
Torrens Island B	4	779.0	4.0	5%	87.7%	10.50	$2.08	$5.97	$64.70
New South Wales									
Bayswater	4	2592.7	2.5	2%	93.3%	10.00	$2.77	$1.66	$19.32
Colongra OCGT	4	664.7	2.5	3%	91.9%	11.84	$9.55	$12.29	$155.13
Eraring	4	2594.4	2.5	4%	91.8%	10.08	$2.77	$1.94	$22.32
Eraring GT	1	39.8	2.5	3%	91.9%	11.84	$9.55	$21.03	$258.61
Hunter Valley GT	2	74.6	4.0	3%	89.1%	23.38	$9.55	$21.03	$501.43

PLANT	NO UNITS	TOTAL SENT OUT CAPACITY	SCHEDULED MAINTENANCE (WEEKS PA)	EFFECTIVE FORCED OUTAGE RATE	AVAILABLE CAPACITY FACTOR	FULL LOAD HEAT RATE (SENT OUT)	VARIABLE O&M COST $/MWH (SENT OUT)	VARIABLE FUEL COST $/GJ	TOTAL VARIABLE COST $/MWH (SENT OUT)
Liddell	4	1974.0	2.5	3%	92.3%	10.38	$2.50	$1.66	$19.68
Mt Piper	2	1316.0	1.0	1%	97.1%	9.93	$2.64	$1.68	$19.35
Munmorah	2	564.0	43.0	10%	15.8%	10.67	$2.75	$1.79	$21.93
Redbank	1	141.0	2.0	2%	93.9%	11.00	$2.77	$0.34	$6.54
Smithfield	1	151.2	3.0	20%	75.8%	10.00	$5.27	$4.66	$51.83
Tallawarra	1	422.0	2.5	3%	92.3%	7.17	$3.51	$5.82	$45.27
Uranquinty	4	660.7	2.5	2%	93.3%	10.98	$3.35	$12.29	$138.36
Vales Point	2	1240.8	3.8	4%	89.0%	9.87	$3.46	$1.99	$23.07
Wallerawang	2	940.0	4.8	8%	83.9%	11.13	$4.15	$1.66	$22.58
Queensland									
Barcaldine CC	1	48.8	3.0	3%	91.4%	8.02	$4.15	$3.86	$35.11
Braemar	6	964.2	2.0	2%	94.2%	11.00	$3.48	$2.02	$25.72
Callide A	Reserve	120.0	3.0	5%	89.5%	13.70	$2.08	$1.60	$23.95
Callide B	2	658.0	2.0	3%	93.3%	9.88	$1.99	$1.61	$17.88
Callide C	2	846.0	1.2	6%	91.9%	9.00	$1.38	$1.61	$15.86
Collinsville	5	174.9	3.0	5%	89.5%	13.70	$2.77	$1.98	$29.82
Darling Downs	1	617.4	2.0	1%	95.2%	6.70	$3.44	$1.55	$13.78
Gladstone	6	1579.2	2.4	5%	91.1%	10.22	$1.22	$1.87	$20.30
Kogan Creek	1	699.4	3.0	3%	91.4%	9.50	$1.25	$0.75	$8.44
Mackay GT	1	31.8	2.0	2%	94.2%	13.50	$11.08	$21.03	$295.09
Millmerran	2	783.8	3.0	8%	86.5%	9.88	$1.25	$0.75	$8.72
Mt Stuart GT	3	412.9	2.0	2%	94.2%	11.50	$5.53	$21.03	$247.47

PLANT	NO UNITS	TOTAL SENT OUT CAPACITY	SCHEDULED MAINTENANCE (WEEKS PA)	EFFECTIVE FORCED OUTAGE RATE	AVAILABLE CAPACITY FACTOR	FULL LOAD HEAT RATE (SENT OUT)	VARIABLE O&M COST $/MWH (SENT OUT)	VARIABLE FUEL COST $/GJ	TOTAL VARIABLE COST $/MWH (SENT OUT)
Oakey GT	2	328.4	2.0	2%	94.2%	11.50	$5.53	$8.15	$99.26
QAL Cogen	1	150.0	2.5	1%	94.3%	7.00	$3.48	$3.90	$30.78
Roma	2	67.7	4.0	9%	84.0%	13.50	$5.53	$3.86	$57.66
Stanwell	4	1380.9	1.8	1%	95.6%	9.99	$1.10	$1.67	$17.77
Swanbank B	4	448.8	3.0	10%	84.8%	10.81	$2.77	$1.76	$21.82
Swanbank E	1	358.9	2.0	2%	94.2%	8.10	$2.77	$3.86	$34.04
Tarong	4	1316.0	2.2	2%	94.2%	10.06	$1.15	$1.26	$13.76
Tarong North	1	416.4	2.4	2%	93.9%	9.00	$1.15	$1.38	$13.60
Yabulu	1	235.7	3.0	2%	92.4%	7.44	$2.77	$3.26	$27.00

* A very low marginal cost has been assumed for Anglesea to reflect the contractual arrangements for supply to the Pt Henry Smelter which encourages full output from Anglesea irrespective of pool prices.

** Redbank has also been assigned a low marginal cost consistent with its observed base load operation and its use of coal washery waste which otherwise has no value.

Appendix D Western Energy Market Background

D.1 Institutional Arrangements

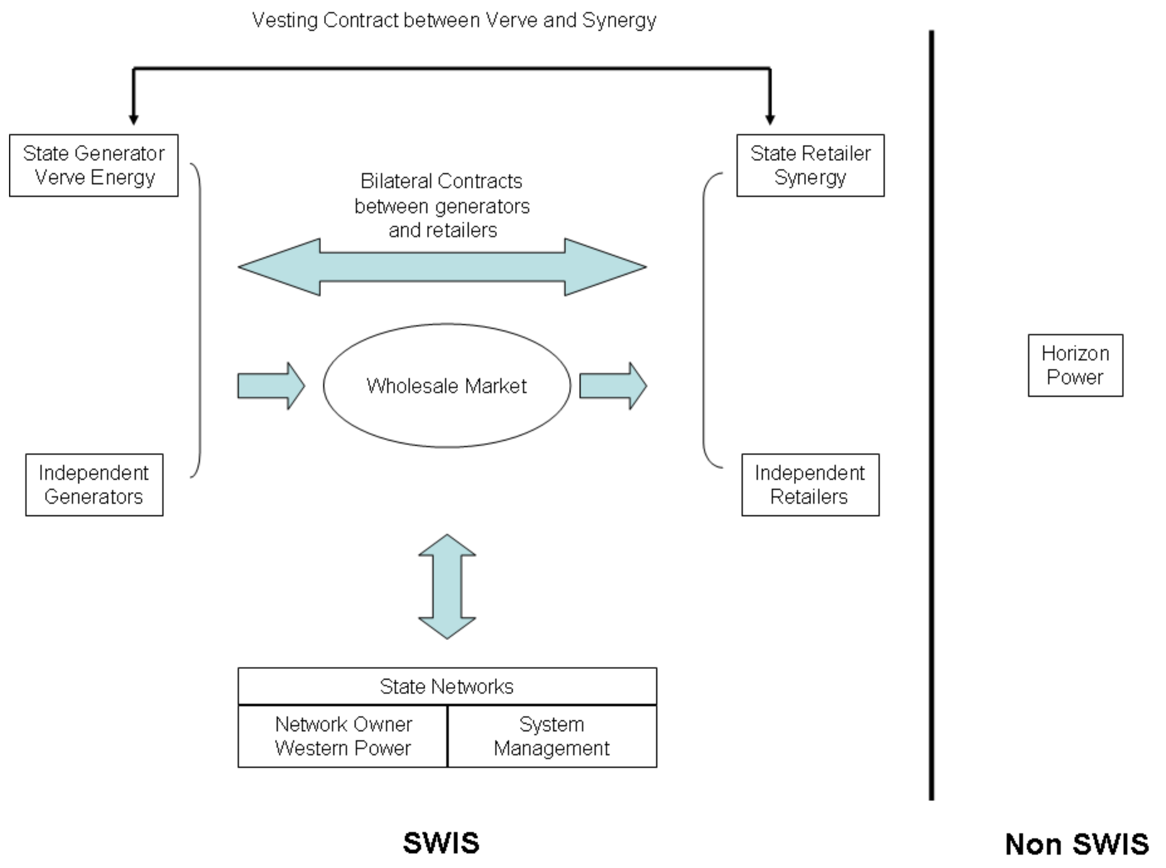
The SWIS is the main electricity grid in Western Australia. Consisting of nearly 88,000 km of power lines, it connects Perth, Geraldton, Kalgoorlie and the South West as shown in Figure 53. The establishment of the WEM for the SWIS, which began on 21 September 2006, followed the passing of the Electricity Act 2004 in March 2004. Amongst other things, the Act established the wholesale electricity market; tariff equalisation fund; network access codes; customer protection measures; and assignment of the regulatory functions to the Economic Regulatory Authority (ERA), which is the relevant state regulator. As part of this agenda the Government disaggregated the Government owned, vertically integrated Western Power into four separate entities: Synergy (responsible for the sale of electricity within the SWIS), Verve Energy (responsible for power generation within the SWIS), Western Power (responsible for operating, maintaining and expanding the electrical transmission and distribution network in the SWIS), and Horizon Power (responsible for the generation, transport and sale of electricity in areas outside of the SWIS).

■ **Figure 53 The South West Interconnected System (SWIS)**

Source: Western Power Networks - http://westernpower.com.au/subContent/aboutUs/ourNetwork/swis.html

While the government-owned generator and retailer dominate the Western Australian electricity supply market, there are also a number of independent retailers and generators entering the market. The diagram in Figure 54 shows the structure of the Western Australian electricity supply market.

- **Figure 54 Structure of the Western Australia electricity supply market**



D.2 Generation and DSM

Verve Energy is the dominant generation company in the SWIS, with five major power stations – Muja, Collie, Kwinana, Cockburn and Pinjar (north of Perth) – as well as wind farms at Albany and Esperance, and biomass and solar facilities. As of 30 June 2009, Verve Energy had a total portfolio of 2,907 MW on an as-generated basis[11]. As there are no plans to split Verve Energy, it is expected that it will maintain a dominant position in the wholesale market. According to the Western Australian IMO Statement of Opportunities July 2008[12], as at 30 June 2008 the SWIS had approximately 4,730 MW of generation and 61 MW of DSM in place. A further 1,151 MW of committed plant is scheduled to be completed by the end of 2010, and recently the Western Australian Government approved the refurbishment of the mothballed Muja A/B power station (240 MW). A new gas turbine located north of Perth (300 MW) was recently commissioned.

There is also around 400 MW of proposed renewable energy projects, mostly wind generation but with a major biomass component.

According to the IMO around 300 MW of additional generation will be required to meet demand growth in 2011 and 2012.

Most base-load generation requirements are supplied by coal-fired power stations, but a growing quantity is from gas fired cogeneration plants. Table 19 outlines the principal electricity generation by fuel type in Western Australia.

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[11] Source: Verve Annual Report 2008.
[12] http://www.imowa.com.au/10_5_1_m_stmt_of_opp.htm

Table 19 Principal electricity generation by fuel type (GWh) - year ending June 2009

TYPE OF FUEL	GENERATION, GWH	PROPORTION, %
Black Coal	8,366	50.6
Natural Gas	7,476	45.2
Oil Products	39	0.2
Wind	647	3.9
Total	16,528	100

Source: ESAA, Electricity Gas Australia 2010.

D.3 Retail Market

As in the generation sector, the government-owned incumbent, Synergy, dominates the retail market, supplying over 90% of the load to energy users. In January 2005, customers consuming more than 50 MWh per year became contestable. The timetable for contestability in Western Australia is outlined in Table 20. There has not been any announcement regarding the adoption of full retail contestability in Western Australia.

Table 20 Timetable for contestability in Western Australia

DATE ELIGIBLE	CUSTOMER TRANCHE
July 1997	≥ 10 MW
July 1998	≥ 5 MW
January 2000	≥ 1 MW
July 2001	≥ 230 KW
January 2003	≥ 35 KW
January 2005	≥ 50 MWH/Year

Source: ESAA, Electricity Gas Australia 2010.

According to the ERA there were 10 electricity retail licence holders in Western Australia[13]. These are listed in Table 21.

[13] Source: http://www.era.wa.gov.au/electricity/licenceHolders.cfm

- **Table 21 Generation and retail licence holders in Western Australia**

LICENCE HOLDER	GENERATION	RETAIL
Alcoa of Australia	X	
Alinta Cogeneration (Pinjarra) Pty Ltd	X	
Alinta Cogeneration (Wagerup) Pty Ltd	X	
Alinta Sales Pty Ltd		X
CSBP Limited	X	X
Emu Downs Wind Farm Joint Venture	X	
Goldfields Power Pty Ltd	X	X
Griffin Power Pty Ltd	X	X
Landfill Gas & Power Pty Ltd		X
Newgen Power Kwinana Pty Ltd	X	
Newmont Power Pty Ltd	X	X
Perth Energy Pty Ltd		X
Perth Power Partnership	X	
Premier Power Sales Pty Ltd		X
South West Cogeneration Joint Venture	X	
Southern Cross Energy Partnership	X	X
Synergy		X
Transfield Services Kemerton Pty Ltd	X	
Verve Energy	X	
Walkaway Wind Power Pty Ltd	X	
Worsley Alumina Pty Ltd	X	

Source: Economic Regulation Authority. http://www.era.wa.gov.au/electricity/licenceHolders.cfm

D.4 Regulatory Framework

There are five governance bodies involved in the regulation of the Western Australian electricity industry.

D.4.1 The Economic Regulation Authority

This entity is responsible for (among other matters):

- The economic regulation of transmission and distribution businesses
- Licensing of generators, retailers and covered networks
- Approving maximum prices for reserve capacity mechanism as well as maximum and minimum energy prices

D.4.2 Independent Market Operator (IMO)

The IMO administers and operates the wholesale electricity market including the Short Term Energy Market (STEM) and the reserve capacity mechanism. It compiles the annual Statements of opportunities and monitors compliance with the wholesale market rules.

D.4.3 System Management

System management is the equivalent to the system control function in the NEM. It operates the power system to maintain system security and reliability. It also coordinates planned outages and opportunistic maintenance. The aspects managed by these two are detailed in Figure 54.

D.4.4 The Market Advisory Committee

This is an industry body convened by the IMO that proposes changes to market rules and procedures as well as general market operation issues.

D.4.5 The Energy Review Board

The Energy Review Board is primarily an appeals body. It imposes penalties for serious breaches of the market rules, hears appeals against IMO decisions or claims from participants that it has breached market rules, and conducts procedural reviews of rule changes.

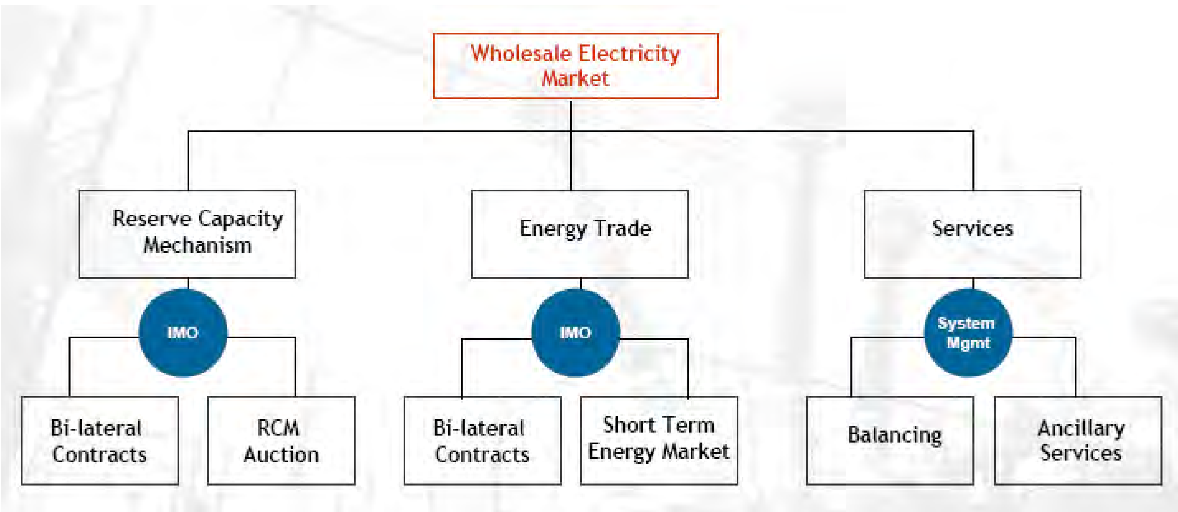
D.4.6 Market Design and Operation

The WEM for the SWIS commenced operation on 21 September 2006. This market, summarised diagrammatically in Figure 55, consists of three components:

- An energy market, which is an extension of the previous bilateral contract arrangements, with a residual day-ahead energy market
- A services component, to balance supply and demand, dispatch spinning reserve and ensure supply reliability and quality
- A reserve capacity mechanism, to ensure that there is adequate capacity to meet demand each year

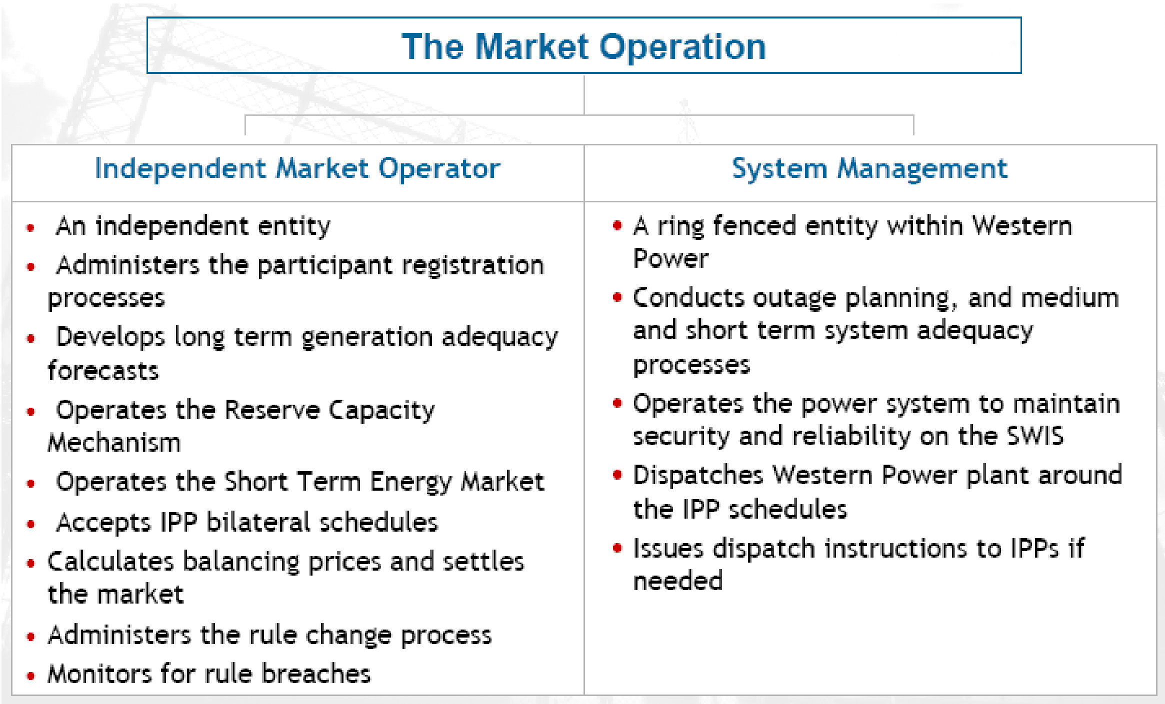
The energy market and the reserve capacity mechanism are operated by the IMO. Other services are controlled by System Management. The roles of the IMO and System Management are summarised in Figure 56.

Figure 55 Structure of the Wholesale Electricity Market



Source: Office of Energy (2004), Wholesale Electricity Market, Reserve Capacity Mechanism, Request for Expressions of Interest

- **Figure 56 Market Operation**



Source: Office of Energy (2004), *Wholesale Electricity Market, Reserve Capacity Mechanism, Request for Expressions of Interest*

D.5 The Energy Trading Market

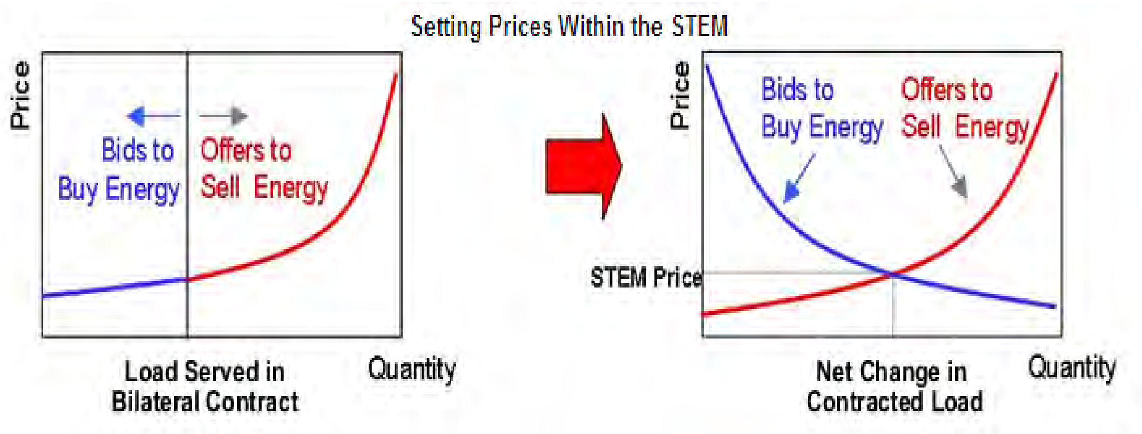
The WEM is relatively small, and a large proportion of the electricity demand is for mining and industrial use, which is supplied under long-term contracts. Considering these features, the Electricity Reform Task Force evaluation determined that it would be most appropriate for a bilateral contracts market to continue to underpin the WEM. Hence, over 90% of energy sales in the SWIS are traded through bilateral contracts that closely follow the individual customer's load.

The STEM is a residual day-ahead trading market that allows contract participants to trade out any imbalances. The STEM also allows small generators, such as renewable generators, to compete despite their inability to secure contracts.

Market participants (both generators and retailers) can submit offers to sell energy to the STEM, or bids to buy energy from the STEM. Market generators may wish to buy energy from the market if the STEM price is lower than its marginal cost of generation. Alternatively, the generator may wish to sell energy in excess of its bilateral contract into the STEM. Similarly, retailers may use the STEM to trade out imbalances between the bilateral contract position and expected demand.

The IMO is responsible for clearing the offers and bids in the STEM. The STEM price is set at the point where the marginal offer price and marginal bid price are equal. The volume at this point represents the net change in contracted load, as shown in Figure 57.

- **Figure 57 Setting prices within the STEM**

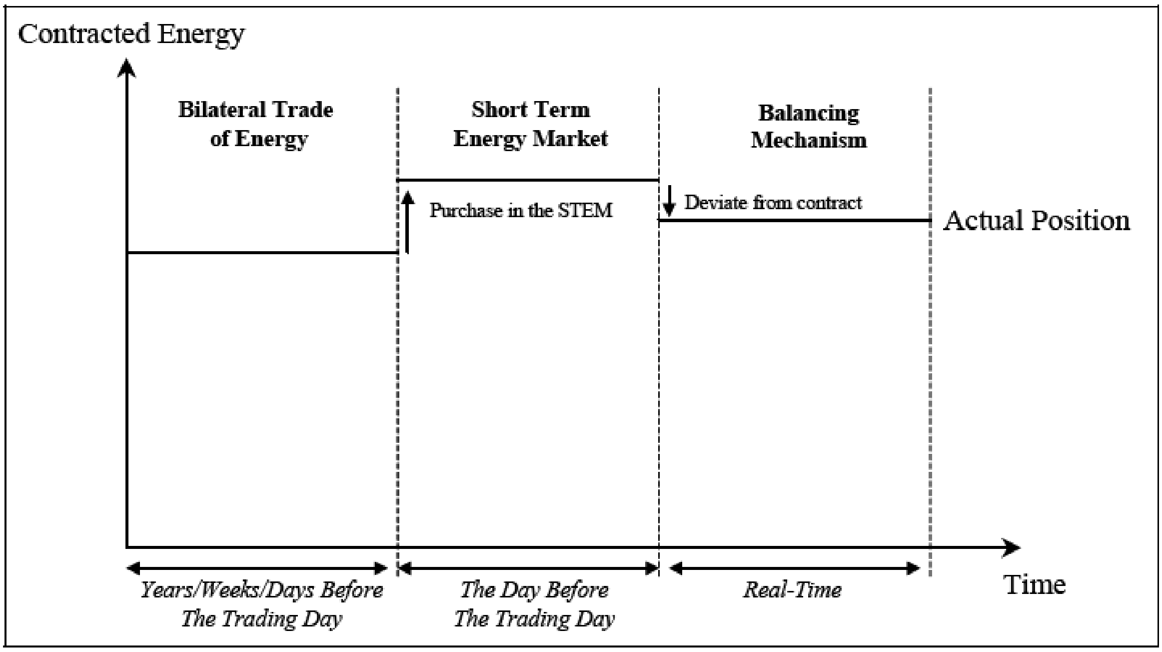


Source: IMO (2007) www.imowa.com.au/market_structure.htm

There will inevitably be slight differences between the day-ahead net contract volumes and the real-time demand. Under the balancing mechanism, System Management may instruct Verve Energy to alter its scheduled dispatch in real time to accommodate these deviations and maintain system security. If necessary, Independent Power Producers (IPPs) may also be instructed to vary generation volumes.

Figure 58 shows the relationship between bilateral trades, the STEM and the balancing mechanism.

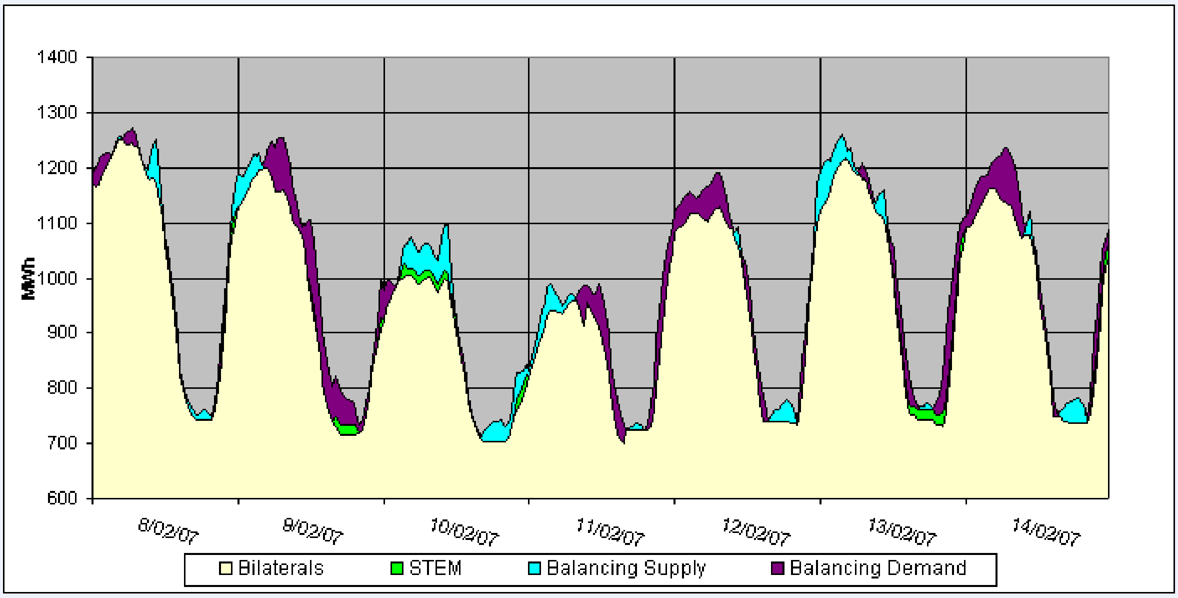
- **Figure 58 Components of the Energy Trading Market**



Source: IMO (2006) *The South West Interconnected System Wholesale Electricity Market: An Overview*

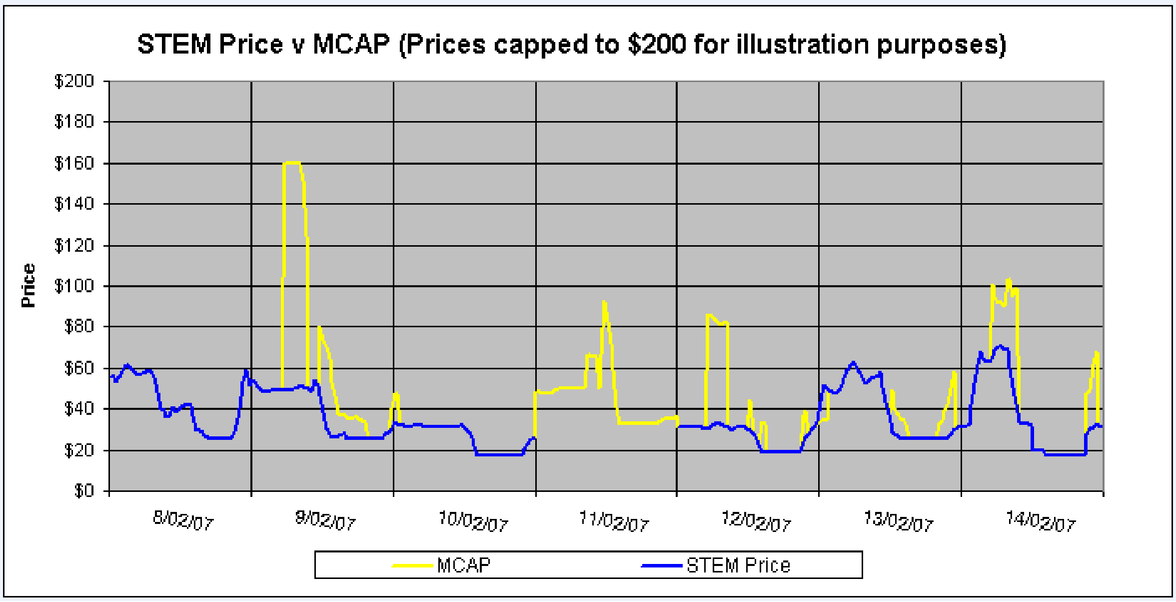
Figure 59 shows the total traded energy from bilateral contracts, STEM trades and the balancing market for the week ending 14 February 2007, while Figure 60 compares the STEM and balancing prices for the same week.

- **Figure 59 Total energy trades in the WEM, week ending 14th February 2007**



Source: http://www.imowa.com.au/WeeklyReport.htm. Note: MWh refers to a half-hourly energy volume.

- **Figure 60 STEM price and balancing price, week ending 14th February 2007**



Source: http://www.imowa.com.au/WeeklyReport.htm

Figure 59 demonstrates that the majority of energy trades are from bilateral contracts. The STEM price and the balancing price (MCAP) are normally equal. However, the MCAP price may be recalculated when relatively large balancing volumes are required, as indicated in Figure 60.

D.5.1 Market Rules

Important features of the market rules include the following.

All generation plants must be self-scheduled to meet their bilateral and STEM contract positions, meaning that they determine when to be committed and de-committed.

Bilateral contracts must be self-dispatched. However, system management may over-ride this dispatch to maintain system security.

Supply and demand will be balanced in the STEM by centrally determining the residual dispatch requirements. A single market-clearing price will exist in the STEM. This price will exclude the effect of network congestion.

Maximum prices in the STEM are capped at the SRMC of gas and distillate peaking plant. The maximum STEM price is currently $336/MWh, and the alternative maximum STEM price is up to $549/MWh. This alternative STEM price applies when more expensive liquid fuels are required for generation. The price is adjusted monthly based on changes in the three-month average Singapore Gas Oil price, and adjusted annually in line with inflation. All price caps are reviewed annually by the IMO.

D.6 Reserve Capacity Mechanism

The reserve capacity mechanism has been designed to ensure there is sufficient capacity installed in the SWIS to meet demand at all times. Each year, the IMO must determine the WEM capacity requirement two years in advance, and ensure that this capacity is facilitated. The capacity requirement covers the loss of the largest generator during peak demand (with 10% probability of exceedance) while still maintaining sufficient ancillary services for frequency control.

Under the reserve capacity mechanism, notional capacity credits are created for a particular year, and are allocated to registered generators or DSM providers. Retailers are assigned capacity credit obligations that are determined based on the expected maximum demand of the retailer during peak system demand and include a contribution to the system reserve margin.

Generators and DSM providers may trade capacity credits with retailers through bilateral contracts, or offer the capacity credits to the IMO via an auction. Retailers that have not been able to procure all capacity credit obligations from suppliers must then purchase their remaining obligations from the IMO.

The price of the capacity credits under auction is capped at the cost of a new OCGT, based on the premise that if the OCGT has not been able to secure bilateral contracts its entry into the WEM may be funded by capacity credits. This maximum reserve capacity price is reviewed each year. As from October 2008, if no reserve auction is run, the reserve capacity price is deemed to be 85% of the maximum reserve price multiplied by an excess capacity adjustment factor.

Each year the IMO is required to conduct a review of the maximum reserve capacity price that sets the cap for the Reserve Capacity Auction[14]. The general steps in this process are:

- IMO conducts a review of the maximum reserve capacity price and produces a draft report
- The IMO publishes the draft report and requests submissions from the public on the review
- The IMO reviews all submissions made and revises the maximum reserve capacity price if appropriate
- The IMO provides a final report which is submitted to the ERA for approval

Following approval or further review, the IMO publishes the approved maximum reserve capacity price.

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[14] The information in this paragraph is sourced directly from http://www.imowa.com.au/mrcp

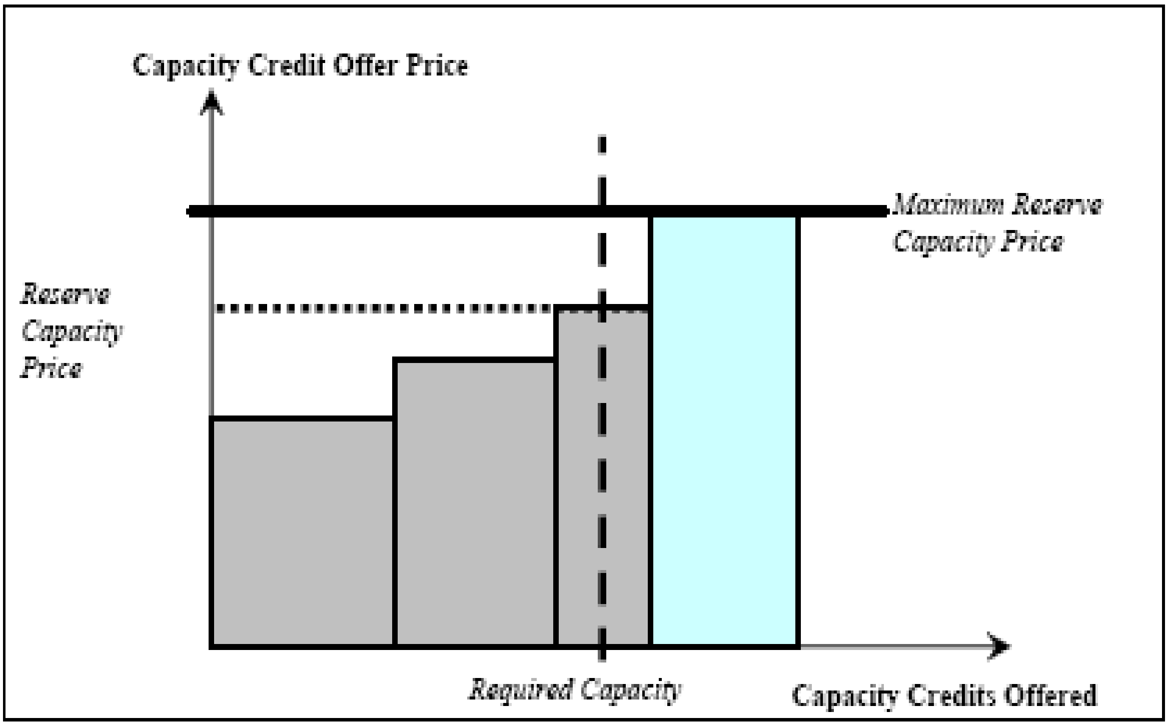
Table 22 shows the maximum and actual reserve capacity prices that have been determined. The increase in the maximum reserve capacity price for the 2009/10 reserve capacity year has been driven by increases in OCGT new entrant costs and transmission costs. The costs are projected to fall leading to a 5% fall in the maximum capacity price in 2011/12. Under auction, the actual reserve capacity price is set according to the marginal capacity credit offer which meets the required capacity, as shown in Figure 61.

Table 22 Maximum and actual reserve capacity prices - market start to October 2014

YEAR	MAXIMUM RESERVE CAPACITY PRICE, $/MW	RESERVE CAPACITY PRICE PER YEAR*, $/MW
Sep 06 – Oct 07	150,000	127,500
Oct 07 – Oct 08	150,000	127,500
Oct 08 – Oct 09	122,500	97,835
Oct 09 – Oct 10	142,200	108,459
Oct 10 – Oct 11	173,400	144,235
Oct 11 – Oct 12	164,100	131,905
Oct 12- Oct 13	238,500	186,001
Oct 13 – Oct 14	240,600	Not available

Source: www.imowa.com.au/max_rc_price.htm. * Note: the reserve capacity price is the price paid by the IMO for capacity not traded bilaterally.

Figure 61 Procuring reserve capacity credits under auction



Source: IMO (2006), *Summary of Wholesale Electricity Market Rules*, Perth, June.

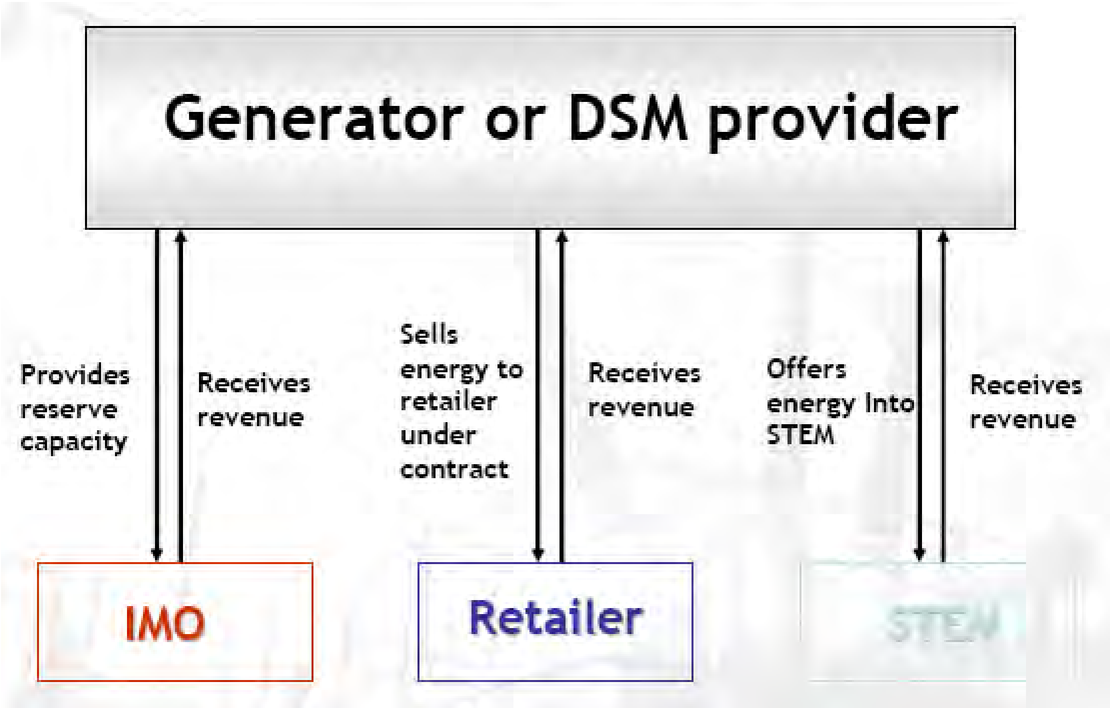
D.7 Revenue Streams

In summary, a generator or DSM provider in the WEM may receive revenue from three streams:

- Capacity payments from IMO resulting from sale of capacity credits at auction
- Energy and capacity payments via bilateral contracts with retailers
- Energy sales (or purchases) in the STEM

Figure 62 provides a visual representation of these potential revenue streams.

Figure 62 Potential revenue streams for generators in the WEM



Source: Office of Energy (2004), *Wholesale Electricity Market, Reserve Capacity Mechanism, Request for Expressions of Interest*.

Appendix E Generation Capacity of Mt Isa, NWIS and DKIS

The following table summarises the existing generation capacity in Mt Isa, the NWIS and the DKIS.

REGION AND POWER STATION	OPERATOR	CAPACITY (MW)	FUEL
Mt Isa			
XStrata	XStrata	30	Natural gas
Mica Creek	CS Energy	325 (10x30-35)	Natural gas
Total[15]		445	
NWIS			
Dampier	Rio Tinto	120	Natural gas
Cape Lambert	Rio Tinto	105	Natural gas
Paraburdoo	Rio Tinto	2x40 aero-derived gas turbine 20 old industrial turbine	Natural gas
Port Hedland	Alinta	90	Natural gas
Newman	Alinta	105	Natural gas
Total		520	
DKIS			
Channel Island	PWC	232	Natural gas or liquid fuel
Weddell	PWC	86	Natural gas or liquid fuel
Berrimah	PWC	30	Natural gas or liquid fuel
Katherine	PWC	21	Natural gas or liquid fuel
Pine Creek	NGD(NT) Cosmo Power	35	Natural gas or liquid fuel
Total[16]		494	

[15] Includes additional 90 MW from onsite diesel or gas fired plants at more remote mines.
[16] Includes additional 90 MW from smaller regions of Alice Springs and Tennant Creek.

Appendix F Environmental Schemes Influencing the Electricity Market

The following table shows a summary of environmental schemes currently influencing the NEM.

SCHEME	OBJECTIVES	SCOPE	NEM IMPACT	FUTURE PROSPECTS
Queensland Gas Electricity Certificates	Increase gas fired electricity supply in Queensland to 13% of electricity consumption excluding some price sensitive large loads greater than 750 GWh per annum. The target has been increased to 18% but the timing is currently unclear.	All gas fired electricity located in Queensland with some limited scope for participation for imported power.	Will encourage some additional capacity into Queensland and lower the bid prices of gas fired generation mainly during shoulder periods when additional Gas Certificates are required.	No change – expected to be made redundant through carbon pricing.
NSW Greenhouse Benchmark	Mandatory targets for GHG emission intensity on a per capita basis from 2003 to 2020 for NSW retailers to reduce GHG emissions from power generation.	All electricity in NSW purchased from the NEM. Generators outside NSW may participate.	Will stimulate gas fired generation throughout the NEM plus some demand side management in NSW. This will have the effect of lowering energy prices.	Will cease when carbon pricing commences.

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