REVIEW

Australian Energy Market Commission

FINAL REPORT

Integration of energy and emissions reduction policy

09 December 2016

Reference: SEA0003
Report

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Reference: SEA0003

Citation

AEMC 2016, Integration of energy and emissions reduction policy, Report, 09 December 2016, Sydney

About the AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

Summary

In 2015, the Australian Commonwealth Government committed to reducing Australia's carbon dioxide equivalent (CO_2e) emissions by 26 to 28 per cent below 2005 levels by 2030. As the electricity sector accounts for around one-third of Australia's emissions, efforts to reduce economy-wide emissions efficiently will inevitably involve reducing emissions in the electricity sector. This report examines three emissions reduction mechanisms that could be applied to the wholesale electricity generation sector to assist in the achievement of Australia's 2030 emissions reduction target.

In this context, the Council of Australian Governments (COAG) Energy Council tasked the Senior Committee of Officials (SCO) with preparing advice to allow the COAG Energy Council to better understand the characteristics and potential impact of alternative emissions reduction policy mechanisms on the National Electricity Market (NEM). The Australian Energy Market Commission (AEMC or Commission) and the Australian Energy Market Operator (AEMO) have been asked to assist officials with this work.[1]

While the Commonwealth Government would determine the emissions reduction *target* for the electricity sector, the purpose of this advice is to enable the Energy Council to form a view on the features and impacts of alternative emissions reduction *mechanisms* that can achieve the emissions reduction target. This report examines three emissions reduction mechanisms that could be applied to the wholesale electricity generation sector to assist in the achievement of Australia's 2030 emissions reduction target.

Designing and comparing the impacts of alternative emissions reduction mechanisms involves two key steps. The first step is to confirm the primary objective that governments are seeking to achieve through the policy in question – whether it is emissions reduction, or investment in renewable electricity generation. At the present time, Australia's policies for reducing emissions from the electricity sector at both the Commonwealth and jurisdictional levels are not consistent with emissions reductions as their primary objective. This is demonstrated by the design of the associated mechanisms, which have focused on directly or indirectly promoting the uptake of specific renewable energy technologies. However, in preparing this advice, the AEMC has taken as given – consistent with the terms of reference – that the primary objective of emissions reductions policies is indeed emissions reduction.

The second step in designing and comparing alternative emissions reductions mechanisms is to assess their consistency with governments' existing energy policy objectives. Australia's energy policy objectives focus on promoting the long-term interests of consumers with respect to the price, quality, reliability and security of electricity services.[2] These objectives are encompassed in the National Electricity

1 The terms of reference for this work was provided in February 2016 (Senior Committee of Officials, Modelling of Carbon Emission Reduction Scenarios in the National Electricity Market, Letter to Mr John Pierce and Mr Matt Zema, 18 February 2016), and subsequently expanded in September 2016 (Senior Committee of Officials, Modelling of Carbon Emission Reduction Scenarios in the National Electricity Market, Letter to Mr John Pierce and Dr Tony Marxsen, 20 September 2016).

2 A secure power system is one that is being operated or managed such that all vital technical parameters such as voltage, equipment loading and power system frequency are within design

Objective (NEO)[3], which the AEMC is required to have regard to when undertaking its functions.

Generally speaking, consumers' long-term interests are best served by workably competitive wholesale and retail markets that allocate market and technological risks to commercial parties with the strongest incentives and abilities to manage or mitigate those risks. This helps to ensure that prices to consumers for electricity services are as low as can be sustained. Efficient risk allocation implies that when variables such as demand growth, the rate of technological change or fuel costs diverge from prior expectations, secure and reliable supply remains at the lowest possible cost to consumers.

The promotion of consumers' long-term interests requires the ongoing maintenance of power system security. Australia's electricity industry is undergoing a fundamental transformation, with a rapid rise in the penetration of new generation technologies, such as wind farms and solar, over the past decade. In the past, these technologies accounted for only a small fraction of total electricity supply. Today, they are a critical part of Australia's power system, and their significance is continuing to grow. This growth has implications for maintaining power system security. As discussed below, different mechanisms to support Australia's emissions reduction policy objectives have different system security implications.

Failing to consider Australia's energy policy objectives when designing emissions reduction mechanisms is likely to result in higher prices for consumers in the long run or a less secure power system than would otherwise be achievable. This will inevitably result in calls for emissions reduction mechanisms or policy objectives to be changed. The anticipation of such instability would create uncertainty and raise barriers to achieving both emissions reduction and energy policy objectives.

Conversely, designing the emissions reduction mechanism in a manner that is consistent with governments' energy policy objectives will contribute to the resilience and longevity of both the emissions reduction policy and its associated mechanism. This is one aspect of what the Commission refers to as the successful integration of energy and emissions reduction policy.

The Commission and AEMO were asked by the COAG Energy Council to provide a report to SCO by the end of 2016. This work was undertaken as two tasks:

- **Task 1** required the AEMC to analyse three alternative emissions reduction mechanisms, including the economic impacts of each of these mechanisms and the ability of each mechanism to integrate with the NEM's design and operation.
- **Task 2** required AEMO to consider the outcomes from Task 1 – such as the location and type of new generation investment, retirements and dispatch, which follows from the choice of emissions reduction mechanism – to assess their impact

limits and are stable and all persons are safe. A reliable power system is one that has a high likelihood of supplying all consumer needs.

3 The National Electricity Objective is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to: price, quality, safety, reliability, and security of supply of electricity; and the reliability, safety and security of the national electricity system.

on system security and reliability. AEMO's analysis informed the overall assessment of the emissions reduction mechanisms and is published as an appendix to this report.

The assessment in this report is informed by both qualitative and quantitative indicators that seek to measure and understand costs, risk allocation, incentives, the impacts on wholesale and retail prices, and the ability of the alternative mechanisms to self-correct when the future turns out to be different from today's expectations.

Emissions reduction mechanisms

The Commission was asked to develop mechanisms to test the potential electricity sector outcomes resulting from alternative pathways for achieving an emissions reduction target of 28 per cent on 2005 levels by 2030. The three pathways specified to the Commission were: least-cost abatement, accelerated deployment of renewable energy, and staged generator exit.

There are a range of potential mechanisms that could be devised to assess the impacts under each of these alternative pathways. The Commission has developed the following three mechanisms, corresponding to each of the three alternative pathways towards the 28 per cent emissions reduction target:

1. **Market-based**: the establishment of an emissions intensity target (EIT) for the electricity sector, where generators with an emissions intensity above the target are liable to buy credits and those with an emissions intensity below the target create and sell credits. The emissions intensity target is defined as the amount of CO_2e emissions divided by the amount of electricity generation, and is typically expressed as the number of tonnes of CO_2e per MWh. The target is then applied to all generators in Australia's wholesale electricity markets based on the emissions intensity of their output (in MWh). The emissions intensity target declines over time in a manner consistent with the emissions reduction target.
2. **Technology subsidy**: extension of the existing Large-scale Renewable Energy Target (LRET). The size of the existing target is 33,000 gigawatt hours (GWh) in 2020. In order to meet the emissions reduction target for 2030, and based on AEMO's 2015-year forecasts for electricity consumption in 2030, this target is estimated to equal 86,000 GWh in 2030. That is, based on forecasts for future electricity consumption, the target would need to more than double to achieve the emissions reduction target.
3. **Government regulation**: on the presumption that centralised decision-makers are adept at determining which generators should exit and when, and also adept at implementing this 'optimal closure schedule', this schedule is implemented by government to force certain generators to close in order to meet the emissions reduction target. Regardless of the form and design of this regulation, the decision on which generators would be closed and when would need to be based on a set of expectations of the future; for example, expectations of future electricity demand.

In each case, the mechanism is specified to commence in 2020 and designed so that it is expected to meet the emissions reduction target.

These mechanisms represent the three broad options available for reducing emissions. This report explains the key features and characteristics of each mechanism and evaluates it against the following criteria:

- **Certainty of achieving the emissions reduction objective** – for an emissions reduction mechanism to be sustainable and effective, it needs to be able to meet its objectives in the face of a changing and uncertain future. Without this ability to adapt when the future does not turn out as expected, investors may begin to expect that a emissions reduction mechanism may be changed in light of the actual outcomes, for example if demand is lower than anticipated at the outset of the policy. This can lead to investors not having the confidence to invest in new generation capacity.
- **Technologically-neutral** – a mechanism that recognises abatement brought about through the greatest variety of technology options will help minimise the long term costs to consumers of meeting the emissions target.
- **Geographically-neutral** – a mechanism that is indifferent to where generation technology options are to be located in the NEM, and allows the locations selected to be an outcome of the trade-off between economic costs and benefits, is likely to minimise costs for consumers.
- **Appropriateness of risk allocation** – an emissions reduction mechanism should allocate risks to those parties best-placed to identify and respond to risks in an efficient manner.
- **Contract market liquidity** – a mechanism that, through its effect on the technology of the generation stock, preserves or enhances contract market liquidity will assist participants to manage risks efficiently for the long term benefit of consumers.
- **Implementation flexibility** – the extent to which an emissions reduction mechanism can be implemented in a manner that automatically adjusts or 'self-corrects' in the face of changing demand, cost or other system conditions.
- **Cost estimates and impacts on consumers** – cost estimates of each mechanism include the costs of emissions abatement, while consumer impacts are assessed through wholesale prices. Generator investment, retirement and output changes. As these cost estimates and impacts are sensitive to key input assumptions, such as demand, fuel prices and the determination of generator retirements, it is important to compare the relative differences in outcomes between the mechanisms.
- **Adaptability and sustainability of mechanism design** – investors need a level of confidence that the objectives of any policy can be met and that the mechanism for achieving the objectives is sufficiently robust to deal with changes in energy market conditions or emissions reduction targets without succumbing to calls for the mechanism to be altered or replaced. This requires that the acceptability of outcomes generated by the mechanism should not be predicated on a single view of the future, whether that be a specific demand forecast or relative technology and fuel costs, or the emissions reduction target itself. Rather, investors will need to be satisfied that the mechanism can yield

predictable and politically palatable outcomes given different market conditions and policy objectives. Without confidence in the resilience of the mechanism, investment will not be forthcoming and it is likely that neither the emissions reduction nor wider energy policy objectives (as embodied in the NEO) will be met.

For the market-based mechanism, an **emissions intensity target** is set for the wholesale electricity generation sector, where generators with an emissions intensity above the target face an additional cost, and those with an emissions intensity below the target receive an equal amount of additional revenue, for each unit of output. Whether generation technologies fall above or below the intensity target depends on the level of the emissions reduction target, which is set by government, and how the target changes over time in a manner consistent with achieving the emissions reduction target. This approach encourages the same degree of fuel switching as under a cap-and-trade emissions trading scheme (ETS), but without causing wholesale price increases upon implementation. This is because an ETS penalises all emissions, while an EIT penalises those generators with emissions intensities above the target and rewards those generators with emissions intensities below the target.

An **extended LRET** was considered by the Commission because it is an existing subsidy mechanism for new renewable energy capacity and would therefore be relatively straightforward to implement. Under the existing LRET, the renewable energy target is 33,000 GWh in 2020. In order to meet the 28 per cent emissions reduction target for 2030, and based on AEMO's 2015-year forecasts for electricity consumption in 2030, this target is estimated to equal 86,000 GWh in 2030. That is, based on forecasts for future electricity consumption, the target needs to increase more than two-and-a-half fold to achieve the emissions reduction target. Changes to demand forecasts, which tend to systematically over-predict actual demand, may lead to the size of the renewable energy target differing from that needed to deliver the emissions reduction objective. This, in turn, creates uncertainty about the size of the renewable energy target needed to achieve a given emissions reduction target under the Extended LRET, as has occurred under the existing LRET.

Regulatory Closure has been designed to represent a regulated approach to staged generator exit. Analysis of this mechanism does not consider a specific form of regulation, such as payments made by governments to generators, to implement closures. Instead, the analysis focuses on the market impacts of implementing a closure schedule that is initially based on closures that would occur under an EIT. This schedule specifies the timing and identity of generators to be closed, such that the emissions reduction target is met. Any optimal closure schedule is predicated on a particular forecast of demand, technology costs and fuel costs. Changes to any of these variables would need to be reflected in changes to plant exit timings for the closure schedule to remain optimal.

A **business-as-usual** (BAU) scenario was developed as the counterfactual against which to compare the effect of the three emissions reduction mechanisms. BAU includes the existing LRET, which is a target of 33,000 GWh by 2020, with this target amount remaining the same through to 2030.

The individual design elements of each emissions reduction mechanism were chosen for the purpose of facilitating an analysis of the characteristics and impacts of each mechanism on the wholesale electricity generation sector.

Finally, while the Commission has been asked to consider emission reduction mechanisms that apply to the wholesale electricity generation sector, this does not preclude the implementation of complementary national policies that apply outside the supply side of the sector, such as the National Energy Productivity Plan. A sectoral approach also does not preclude the implementation of different emissions reduction mechanisms outside of the electricity sector that act on other parts of the economy, such as fugitive emissions, agriculture and transport.

Jurisdictional renewable schemes

Pursuant to the expanded terms of reference received by the Commission[4], the AEMC performed an initial assessment of three jurisdictional renewable energy schemes: ACT, Victoria and Queensland based on the information presently available about these schemes (Table 1). These schemes would, if implemented, jointly result in renewable generation comprising just over 40 per cent of electricity output in the NEM by 2030. This is a similar share, in aggregate, to what would occur under Extended LRET.

Table 1 Jurisdictional renewable energy targets and mechanisms

NEM jurisdiction	Renewable energy target		Mechanism to deliver the jurisdictional RET	Proposed or implemented mechanism	Location of new RET-eligible plant
	Percentage of generation	By year			
ACT	100%^	2020	Reverse-auction; 2-way CfD*	Implemented	Anywhere in the NEM
Queensland	50%	2030	Not yet known	N/A	To be determined
Victoria	25% (40%)	2020 (2025)	Reverse-auction; 2-way CfD	Proposed	Victoria only

* CfD stands for Contract for Difference. Source: Jurisdictional websites.

The ACT has implemented a reverse-auction mechanism, under which ActewAGL Distribution, the ACT government-owned distributor, enters into a long-term contract with a renewable energy generator. Any net payments by ActewAGL Distribution under this scheme result in an increase in the prices paid by electricity consumers.[5] Victoria has proposed a similar mechanism to achieve its renewable energy target. Queensland is yet to announce a mechanism to achieve its target.

Under a reverse-auction, renewable energy generators put forward bids for government funding based on a fixed price (or 'strike' price) per MWh of generation.

4 Senior Committee of Officials, Modelling of Carbon Emission Reduction Scenarios in the National Electricity Market, Letter to Mr John Pierce and Dr Tony Marxsen, 20 September 2016.

5 Payments made by ActewAGL Distribution are passed on to consumers as an increase in network charges, which are a significant proportion of retail bills.

The resulting contract-for-difference (CfD) entered into between the relevant government and the renewable generation proponent obliges the parties to make payments to each other based on the difference between the strike price in the CfD and a reference market price[6] (as well as potentially the sale of LGCs). Reverse-auctions differ from the mechanism used to deliver the LRET (and the Extended LRET). In the former case, government directly subsidises the entry of renewable generators; in the latter case, the government obliges retailers, and hence ultimately their customers, and large customers to pay these subsidies via the purchase of LGCs.

Assessment framework for each emissions reduction mechanism

Each of the three NEM-wide emissions reduction mechanisms is assessed against the following criteria:

- The ability to satisfy the emissions reduction policy – the extent to which each mechanism is capable of delivering the emissions reduction target; and
- The ability to satisfy the NEO – the extent to which each emissions reduction mechanism meets the broader energy policy objectives embodied in the NEO.

The assessment of each mechanism's ability to satisfy the NEO is, in turn, undertaken on both qualitative and quantitative grounds:

- A quantitative analysis providing insight into the impact of each mechanism on:
  - Wholesale costs ($/MWh) – referring to the sum of wholesale price outcomes and the cost of large-scale generation credits (LGCs) that are required to be surrendered by retailers under the existing LRET and the Extended LRET mechanisms. The inclusion of LGC costs means that the comparison between the mechanisms is undertaken on a consistent ('like-for-like') basis, in terms of their ultimate impact on retail prices;
  - Resource costs ($) – referring to the sum of generation capital and fuel costs required to meet expected demand. Higher resource costs mean that more of society's scarce resources are expended to serve electricity demand; such resources are diverted from other purposes within the economy; and
  - Abatement costs ($/tonne CO_2e) – referring to the resource costs incurred under the mechanism divided by the volume of emissions reduction or abatement;
- A qualitative analysis is carried out on aspects of the mechanisms that cannot be easily measured, including whether the mechanism:
  - can self-correct when today's expectations turn out to be different to reality;
  - is technologically and geographically neutral;
  - allocates risks to those parties best suited to mitigating such risks and preserves or enhances contract market liquidity; and
  - offers appropriate implementation flexibility; and

6 The reference price is typically based on the NEM settlement price.

- A combined qualitative and quantitative analysis is performed on:
  - the adaptability of the mechanism, meaning whether the relative performance of the mechanism is robust to changes in market conditions and emissions reduction targets; and
  - system security implications of each mechanism, which has been performed by AEMO and is discussed separately to the market and economic analysis.

The Commission has also used its quantitative findings to draw inferences about potential distribution outcomes under each of the mechanisms. These inferences are of interest to policy-makers as they have implications for the stability and longevity of the policy mechanism.

AEMC's findings and analysis[7]

Emissions reduction mechanisms

The Emissions Intensity Target (EIT) has the lowest impact on wholesale prices, the lowest resource costs[8] and the lowest cost of abatement to meet a given emissions reduction target. Prices under an EIT are generally in line with prices under BAU. These results are intuitive because the EIT is technologically-neutral and hence encourages the least-cost form of abatement to be adopted by market participants.

Further, the EIT maintains the standard NEM allocation of risk between generators and consumers regarding future changes in conditions: generators continue to make investment and retirement decisions based on price signals in the spot and contract markets, and face the outcomes of their decisions. If electricity demand, technology costs or fuel costs are higher or lower than expected, the immediate impact is sustained by generators through plant profitability rather than consumers or taxpayers. This is appropriate because generation businesses typically have the expertise, information and commercial incentives to manage market risks more efficiently than consumers or governments.

The Extended LRET has the highest resource costs compared to the other emissions reduction mechanisms. This implies that this mechanism expends the greatest value of resources to simultaneously meet the target and serve electricity demand. This result is intuitive because the mechanism does not reward switching from high emissions fuels to those with lower emissions; it only allows a limited number of technology options to meet the emissions reduction objective. This means that the Extended LRET forgoes the opportunity to utilise potentially lower cost forms of emissions reductions, such as fuel switching from coal to combined-cycle gas turbine (CCGT) generators.

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7 The Commission engaged Frontier Economics to assist the Commission in its assessment of each of the three emissions reduction mechanisms. Frontier Economics modelled the impact of each of the mechanisms on wholesale prices and economic costs, with their findings provided in a separate technical report (Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016).

8 Resource costs are the costs of building new capacity (capital, fuel and labour), as well as the increase in operating costs from switching from lower cost to higher cost fuels (e.g. coal to CCGT), in order to achieve the emissions reduction target.

Under the EIT, CCGT plays a larger role in the generation mix along with renewables. In comparison to the Extended LRET, the EIT generally leads to the highest switching to gas. By contrast, under the Extended LRET, brown coal remains in the market for longer, which deters investment in gas. This is because under the Extended LRET, costs of non-subsidised plants remain the same, which means brown coal remains a cheaper form of generation than CCGT and black coal.

When expressed as a fixed GWh target, the Extended LRET shifts demand and technology cost risk from new entrant renewable generators to existing generators and consumers. If electricity demand is lower than expected – and hence wholesale prices also lower than expected – the subsidy for new entrant renewable generators in the form of the renewable energy certificate price needs to increase to compensate for the lower wholesale prices, if the desired renewable energy target is to be achieved. In the short term, existing generators bear the impact of lower wholesale prices and consumers may benefit if the fall in prices is sufficient to offset the higher cost of the subsidy. However, as existing generators exit the market, wholesale prices can be expected to rise and consumers will face the full cost of the increased subsidy. Likewise, if the cost of renewable technologies does not fall as quickly as expected, renewable generation proponents do not bear this cost. Rather, the renewable energy certificate price rises and consumers again bear the higher costs in the longer term.

Consumer impacts measured by wholesale price increases are highest under Regulatory Closure. This is because as generating units close, supply is reduced, putting upward pressure on wholesale prices. Regulatory Closure is also not least-cost, as it forgoes opportunities to reduce emissions at lower cost by fuel-switching amongst existing plant.

Higher electricity prices under Regulatory Closure are especially likely to occur when regulatory closure policies involve payments to generators to close, irrespective of whether closure payments are made by governments or by those generators that do not close. If closure payments are made by governments, these payments will be recovered from electricity consumers (potentially via levies passed onto retailers or network service providers) or taxpayers. If closure payments are made by other generators, these payments will be recovered from electricity consumers via higher prices.[9]

There are four characteristics of the Regulatory Closure mechanism.

First, Regulatory Closure may not be able to meet emissions reduction targets. There is a risk that remaining high emissions generators increase their output, resulting in emissions rising above the target. Depending on how the closure mechanism is implemented, there is a risk that closed generators reopen at some point in the future if the market environment changes, creating uncertainty for investors in new generation capacity. Separate mechanisms would need to be developed to protect against these

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9 An example of a generator-pays scheme is the reverse-auction scheme proposed by Frank Jotzo and Salim Mazouz, under which plants bid competitively over the payment they require for closure, a centralised decision-maker chooses the most cost effective bid, and closure payments are made by the remaining generators in proportion to their carbon dioxide emissions (Frank Jotzo and Salim Mazouz, *Brown coal exit: a market mechanism for regulated closure of highly emissions intensive power stations*, Economic Analysis and Policy, 48(2015), pp.71-81).

issues for the mechanism to sustainably meet the emissions reduction objective over time.

Second, it presumes that centralised decision-makers are adept at determining and implementing the optimal closure schedule, which relates to which generators should close and when. This not only presumes that centralised decision-makers are fully-informed about generators' costs and revenues, and that non-economic considerations will not affect the closure schedule – it also ignores the possibility that high-emissions generators could take actions that reduce their emissions intensity and thereby defer their socially-optimal closure timing. Furthermore, as noted above, any 'optimal closure schedule' is only optimal by reference to a particular set of assumptions of future electricity demand, technology costs and fuel costs. If these assumptions turn out to differ from reality, the relative performance of the Regulatory Closure mechanism would worsen.

Third, like the Extended LRET, the Regulatory Closure mechanism transfers risks related to the amount of capacity to close and the timing of closure away from the generators best-placed to manage those risks to other parties. In cases where a Regulatory Closure mechanism involves payments to generators to close, the financial and emissions risks around the level of capacity and timing of closure are no longer the concern of the relevant generator. Instead, the cost of sub-optimal closure is borne by government and, ultimately, taxpayers and consumers.[10]

Fourth, when governments indicate they are considering regulatory closure policies that involve payments to generators to close, whether these payments are made by governments or by those generators that do not close, generators that may have exited in response to price signals at their own cost and under their own volition, may instead choose to remain in the market with the expectation of receiving a closure payment. Regulatory closure policies that involve payments to generators therefore risk embedding into the NEM a barrier to exit, with generators no longer responding to price signals, but instead waiting for payment indications from government. Instead of solving a perceived barrier to exit, regulatory closure could in fact create one.

Figure 1 shows national weighted average wholesale prices for the three emissions reduction mechanisms from commencement in 2020 until 2030. In order to compare the mechanisms on a like-for-like basis in terms of consumer impacts, wholesale prices include the price of large-scale generation certificates (LGCs). Retailers are required to purchase LGCs to meet their liability under the LRET, with these costs passed to consumers through retail bills.

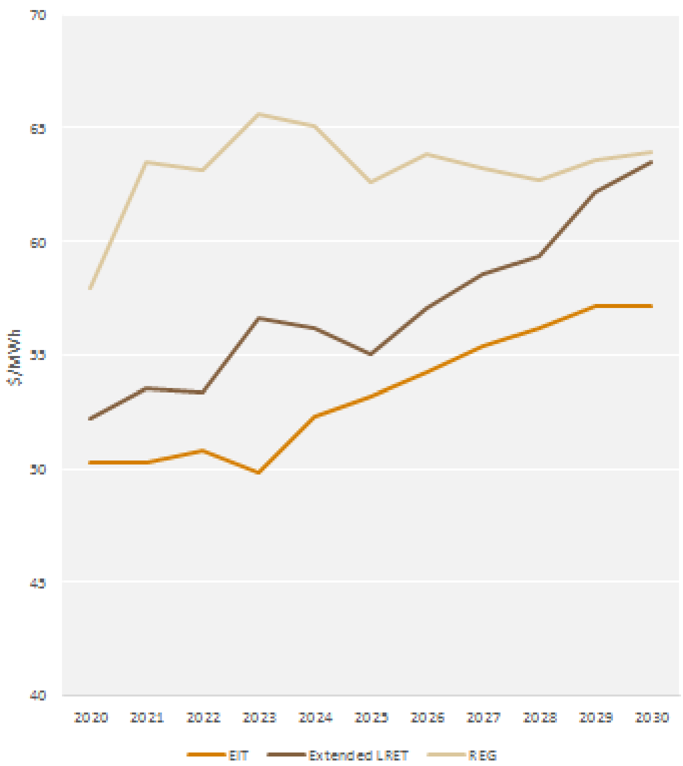
As shown in Figure 1, given an emissions reduction target, wholesale prices paid by consumers are lowest for EIT over the period 2020 to 2030. Under EIT, generators below the target receive a per-MWh credit to produce electricity, which effectively lowers their cost of generation, while generators above the target face an additional cost. This approach results in lower-emission generators being dispatched more, and

10 The factors that inform generator exit decisions are complex and based on future assumptions around a range of variables, including wholesale prices and demand. By entering into a payment for closure, governments implicitly take on some of this uncertainty and risk.

higher-emissions generators being dispatched less, thereby reducing CO_2e emissions from the electricity generation sector.

In order to earn credits, low-emissions generators must be dispatched. To increase the likelihood of being dispatched under an EIT, low-emissions generators offer higher amounts of generation in lower price bands. Under EIT, as existing and new CCGT generators receive credits under a 28 per cent by 2030 emissions reduction target, and are primarily the generators setting the spot price, this results in lower wholesale price increases relative to Extended LRET and Regulatory Closure. The lower wholesale price effects under an EIT are partly attributable to a flattening of the merit order, which means existing generators bear a larger share of the resource cost. The EIT results in lower resource costs as it is technologically-neutral. This is discussed below.

Figure 1 National weighted average wholesale costs - including LGC levy ($/MWh)



Source: Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

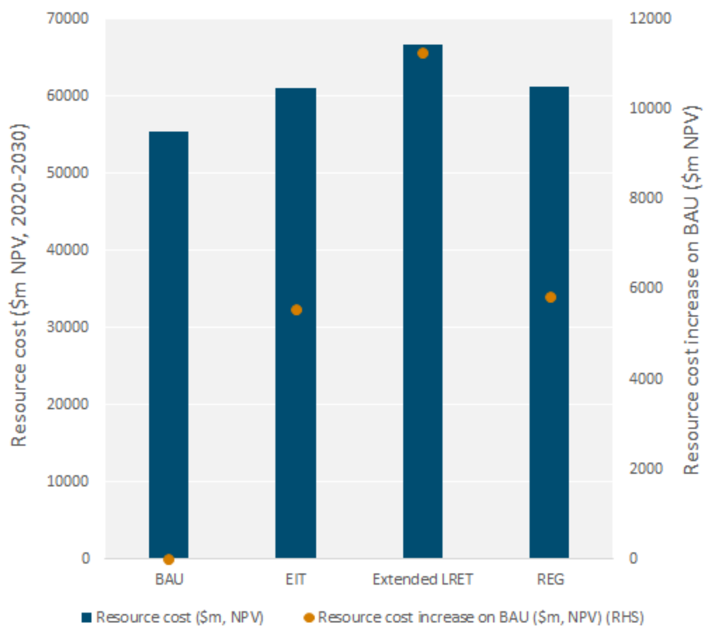
Resource costs represent the cost to the electricity sector as a whole of meeting forecast electricity consumption under the emissions reduction constraint, given a set of future assumptions around technology and fuel costs. They are the capital costs of building new capacity (the sum of capital and labour costs) plus the operating costs (including fuel, variable and fixed operating and maintenance costs) from dispatching new and existing generation to meet demand, subject to any policy constraints such as renewables or emissions targets.

Resource costs are shown in Figure 2. They are highest for Extended LRET ($66.6 billion) for two reasons. First, because the mechanism is not technologically-neutral, more expensive technologies are required to meet the emissions reduction target compared with EIT and Regulatory Closure. Second, more new generation capacity in total is built under Extended LRET than the other mechanisms. Resource costs for EIT ($59.1 billion) are lower than for Regulatory Closure[11] ($61.2 billion) because the incremental fuel switching between existing generators that occurs under EIT is lower cost than building the new capacity required under Regulatory Closure. By contrast, resource costs incurred under the BAU scenario are $55.4 billion, reflecting:

- investment in renewables generation capacity under the existing LRET scheme; and
- investment in gas (in particular, CCGT) capacity to complement the intermittency of renewables and maintain reliability of supply.

As can be seen from Figures 1 and 2, resource cost relativities between the emissions reduction mechanisms do not always correspond to their relative effects on wholesale prices. The incidence of resource costs can fall on consumers through higher wholesale prices, or it can fall on existing generators through lower wholesale prices. The degree to which consumers and generators bear these costs depends on a range of factors such as how the mechanisms operate, generator retirement decisions and the marginal emissions intensity of the electricity generation sector.

Figure 2 Resource costs (2016$m NPV, 2020-2030)



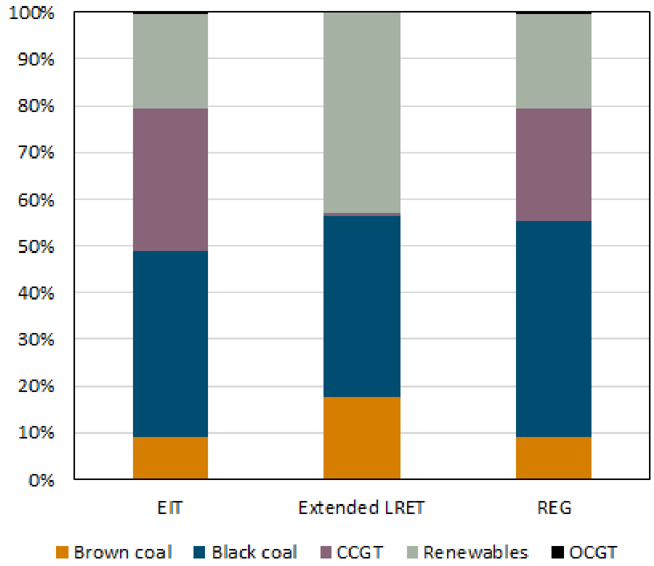
Source: Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

Figure 3 shows the average output mix to achieve the emissions reduction target over the modelling period for the three mechanisms. Renewable output under EIT is supported by CCGT and black coal and has the lowest brown coal output of the mechanisms. Extended LRET has the highest volume of renewable output, but also the highest output from brown coal generation, as there is no penalty on low-cost, high-emissions generation. Regulatory Closure is similar to EIT, but has less CCGT and more black coal output.

11 As previously mentioned, analysis of the Regulatory Closure mechanism does not consider a specific government policy, such as closure payments made to generators, to implement closures.

Wholesale prices and resource costs are lower under EIT because, in addition to the pattern of new investment and retirements, the overall fuel mix gives the system a lower cost of production than the other mechanisms. The reason that Extended LRET has the highest resource cost is due to the higher investment in new generation capacity required to meet the emissions target under this mechanism, compared to the level of investment in capacity under EIT. Over the 2020-2030 period, cumulative investment in capacity under Extended LRET is 70 per cent higher than under EIT. This is partially offset by lower fuel costs, principally due to increased dispatch from brown coal plant and reduced dispatch from CCGT.

Figure 3 Average output mix over the period 2020 to 2030 as a percentage of total output[12]



Source: Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

The average cost per tonne of CO_2e abated reflects the change in resource costs from the BAU scenario divided by the change in emissions from BAU. As the emissions reductions are identical across all mechanisms, differences in the average cost of abatement are driven by differences in resource costs.

Some organisations present abatement costs by discounting resource costs and emissions, while others discount resource costs only. The Commission has presented average cost of abatement estimates for each mechanism both with emissions discounted and not discounted in Table 2. The relative outcomes across the emissions reduction mechanisms are the same under either approach.

Consistent with the resource cost estimates above, EIT has the lowest cost of abatement, followed by Regulatory Closure and Extended LRET.

12 For the purpose of this graph OCGT includes natural gas cogeneration and natural gas steam turbine.

Table 2 Average cost of abatement $/tonne (NPV, Real2016$, 2020-2030)

Emissions reduction mechanisms	Average cost of abatement - base case	
	Discounted	Not discounted
EIT	$30.4/t	$17.5/t
Regulatory Closure	$34.2/t	$19.5/t
Extended LRET	$75.7/t	$42/t

Source: Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016

In designing the existing LRET, the objective was and is to encourage additional renewable electricity generation relative to what would occur in the absence of the LRET.[13] To achieve this objective, baselines were specified for those renewable generators existing prior to the LRET (mostly hydro generators), based on these generators' outputs prior to the LRET. These 'legacy' renewable generators (mostly hydro) were ineligible to create LGCs for generation up to their baseline, which for all hydro generators collectively is around 15 terawatt hours (TWh) per annum.[14] Legacy hydro generators' decisions to generate are considered to be unaffected by their eligibility (or otherwise) to receive LGCs. This means that making legacy hydro eligible to receive LGCs would result in large windfall gains for these generators, without inducing additional emissions reductions.

This same rationale applies for making legacy hydro generation ineligible to receive LGCs under Extended LRET, and making these generators ineligible to receive credits under EIT.

Under EIT, allowing hydro generators to receive credits for baseline generation results in a windfall gain for these generators, with a significant wealth transfer (a cumulative value of $3 billion over the 2020-2030 period) from consumers to legacy hydro generators. This wealth transfer would occur without inducing any additional reduction in emissions.

It is important to note that the modelling results presented above are based on a range of assumptions regarding future electricity demand, emissions reduction targets, and technology costs. Just as important for the stability of the policy mechanism that is implemented as the ordering of expected outcomes under each emissions reduction mechanism is the robustness of each mechanism's relative performance if actual conditions diverge from those currently considered most likely.

A mechanism that can successfully achieve the chosen emissions reduction target while minimising electricity sector impacts – on security, reliability and costs to consumers –

13 See http://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target for more information on the Renewable Energy Target

14 The total amount of legacy renewable generation exempt from the LRET is around 16TWh, of which 94 per cent (15TWh) is generation from hydro, with the remaining generation from landfill gas, bagasse, and biomass.

under a wide range of conditions is likely to be sustainable over the long term. Conversely, a mechanism yielding abatement costs or price outcomes that are highly sensitive to the accuracy of particular assumptions is likely to be vulnerable to pressures for redesign if and when the future turns out to be different than previously expected. The likely result is investment uncertainty and higher long-term costs for consumers, with neither the emissions reduction nor energy policy objectives being met.

In order to test the robustness of each mechanism, the Commission considered changes to forecasts of future electricity demand, future technology costs, emissions reduction targets and the timing of the closure of Hazelwood, a Victorian brown-coal generator.[15] The first key assumption varied was the emissions reduction target for the electricity sector. Mechanisms that perform well if the target were to be significantly increased can be described as scalable. To test the scalability of the various mechanisms, a target of 50 per cent below 2005 levels by 2030 for the electricity sector was chosen.

The 50 per cent emissions reduction target for the electricity sector reflects the midpoint of the 40-60 per cent range recommended by the Climate Change Authority (CCA).[16] This target is also between the emissions reduction targets implied by the CCA's 3-degree and 2-degree Celsius warming scenarios, presented in their recent report[17], which are around 40 per cent and 83 per cent, respectively.

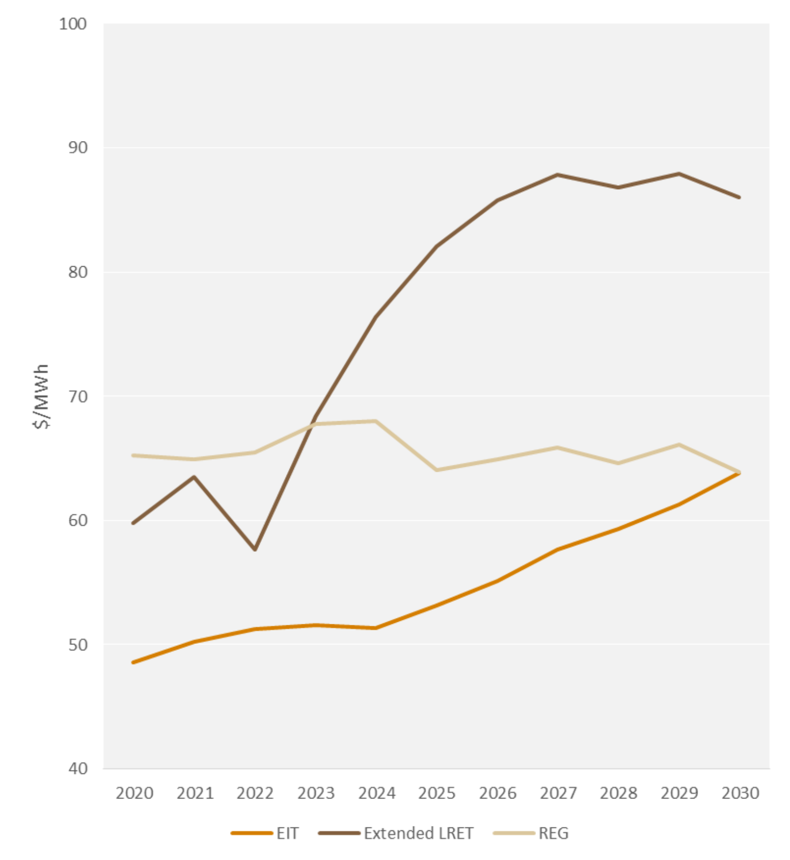
The impact on wholesale electricity prices and on abatement costs is shown in Figure 4 and Table 3, respectively, for each of the three emissions reduction mechanisms, under the 50 per cent emissions reduction target.

15 Specifically, we examine each emissions reduction mechanism's impact on wholesale prices and abatement costs if Hazelwood were to close in mid-2017. Under BAU, Hazelwood remains open throughout the 2020-2030 period.

16 Climate Change Authority, *Reducing Australia's Greenhouse Gas Emissions*, Targets and Progress Review, February 2014.

17 Climate Change Authority, *Policy Options for Australia's Electricity Supply Sector*, Special Review Research Report, August 2016.

Figure 4 **National weighted-average wholesale costs (including LGC levy) under 50 per cent emissions reduction target**



Source: Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

In contrast to a 28 per cent emissions reduction target, in which Regulatory Closure resulted in the highest wholesale prices (see Figure 1), under a 50 per cent emissions reduction target, Extended LRET generally results in the highest wholesale prices. This is because the high price of LGCs and the higher volume of LGCs required more than offsets the downward pressure on wholesale prices from increasing the supply of renewable generation capacity.

Figure 4 also reveals that of the three emissions reduction mechanisms, EIT results in the lowest wholesale prices. This result reflects this mechanism's technological-neutrality, which allows greater fuel switching from high-emissions to low-emissions plant in addition to investment in new zero-emissions (renewables) plant. By contrast, only the latter is possible under the Extended LRET. This means that in the event that the government's abatement target became more ambitious, the EIT would minimise price shocks to consumers under the new target.

Under a 50 per cent emissions reduction target, EIT has the lowest cost of abatement, with Extended LRET the highest (Table 3). This ranking is the same as in Table 2. Comparing Tables 2 and 3 reveals that the average cost of abatement rises under a higher emissions reduction target. This requires more costly forms of abatement.

Table 3 **Average cost of abatement under different emissions reduction targets (NPV, Real2016$, 2020-2030)**

Emissions reduction mechanisms	28% emissions reduction target		50% emissions reduction target	
	Discounted	Not discounted	Discounted	Not discounted
EIT	$30.4/t	$17.5/t	$34.7/t	$20.5/t
Regulatory Closure	$34.2/t	$19.5/t	$37.9/t	$22.1/t
Extended LRET	$75.7/t	$42/t	$85.3/t	$48.3/t

Source: Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

Table 3 also reveals that the increase in abatement cost is highest for Extended LRET, and lower for the EIT mechanism.

The above analysis reveals that of the three emissions reduction mechanisms, the EIT mechanism results in the lowest resource costs, costs of abatement and increase in wholesale prices, even under a higher emissions reduction target. This demonstrates the scalability of the EIT mechanism.

The robustness of the EIT mechanism is also demonstrated when considering other ways in which the future may differ from what is currently expected, as discussed in the body of this report. Collectively, these results demonstrate that of the three emissions reduction mechanisms, the EIT has greater self-correcting features, which enables it to better accommodate changes to policy and non-policy variables. This should, in turn, minimise pressures for redesign and policy instability.

Jurisdictional renewable schemes

As noted above, the announced jurisdictional energy schemes in the ACT, Queensland and Victoria would, if implemented, jointly result in renewable generation comprising just over 40 per cent of electricity output in the NEM by 2030. This is a similar share, in aggregate, to what would occur under Extended LRET. Therefore, the Commission considers that if the announced jurisdictional schemes were implemented, the aggregate outcomes would broadly resemble those under Extended LRET. However, while the aggregate outcomes may be similar, the geographical distribution of renewable generation under the jurisdictional targets may differ from that resulting from Extended LRET, particularly for those schemes (such as Victoria's) that require renewables under the scheme to locate solely in that jurisdiction. Therefore, the jurisdictional schemes may result in higher resource costs being incurred and higher prices for consumers of that jurisdiction than under the Extended LRET, which is geographically-neutral.

These three jurisdictional schemes in effect make investment and labour market outcomes – the increase in jobs in the renewable energy sector – the primary objective, with emissions reductions a secondary objective.[18] A scheme with the primary objective of creating new renewable energy jobs is likely to deliver emissions reductions at a higher cost to consumers than a scheme with a primary objective of efficient emissions reduction. This is because schemes with a primary objective of encouraging investment in renewables will not (by implication) encourage other, lower cost, forms of emissions abatement, such as fuel switching from coal to gas.

The jurisdictional renewable energy targets, like the LRET, is expressed as a fixed amount (in GWh), and these amounts are government-determined. A key rationale for introducing competition in the wholesale electricity sector was the decentralisation of operational and investment decisions away from central authorities to commercial parties operating in a competitive market. Generation businesses may be no better at forecasting the future than governments; however, the important difference is that in a workably competitive market equity and debt holders of generation businesses bear the cost of excess supply, rather than consumers. The combination of competition and capital market discipline, provide incentives to businesses to manage their risks. Under a regulatory approach, such as that used in the Extended LRET and jurisdictional renewable energy schemes, investment decisions are taken by a central authority that does not have the same incentives or ability to manage the associated risks. This means that the costs of any overinvestment are borne by consumers or taxpayers.

Distributional impacts of each emissions reduction mechanism

Distributional impacts relate to how resource costs are allocated between generators and consumers. To the extent that generators can pass on the increase in resource costs incurred under a particular emissions reduction mechanism to consumers in the form of higher wholesale prices, consumers will bear more of the resource costs arising under that emissions reduction mechanism.

The allocation of resource costs between generators and consumers depends on a complex range of factors, including how the emissions reduction mechanism works, the emissions intensity of the marginal generator, the degree of competition between generators, and decisions by generators on when to exit the market.

At a high-level the effects of each of the policy mechanisms on both consumers and generators are summarised in Table 4 below.

18 For example, the Victorian Government's Fact Sheet on its renewable energy targets estimates that there will be over 4000 additional people employed in the construction and operation of new Victorian renewable energy projects, at the peak of construction. As of the time of this report's publication, information on the methodology used to calculate job numbers or the level of net job growth (new jobs created *less* jobs lost) are not available. For more information, see Victoria State Government (2016) Fact Sheet: New Energy. New Jobs., available from: http://earthresources.vic.gov.au/__data/assets/pdf_file/0006/1317597/540889_ELWP-0004_RenewNRG.pdf

Table 4 Summary of distributional impacts of each policy mechanisms

Emissions reduction mechanisms	Consumer impacts	Generator impacts
EIT	Of the three mechanisms, EIT is best for consumers. Wholesale prices remain similar to BAU levels.	High emissions generators pay a penalty, low-emissions generators receive a credit. Transfers are confined to within the supply side of the energy industry.
Regulatory Closure	Highest price increases of the three mechanisms. This means that the cost of the mechanism is borne by consumers, rather than generators.	The withdrawal of capacity through a closure policy means that remaining generators are better off than under BAU, at the expense of consumers.
Extended LRET	Consumer prices increase due to the increasing cost of LGCs, which offsets any (short-term) reduction in wholesale prices. The merit-order effect is unlikely to persist; in the longer term, generator retirements mean consumers face the full cost of the LGC subsidy.	Renewable generators are better off as they receive a subsidy and are not exposed to demand risk. As there is no change to the variable costs of those generators that do not receive the subsidy, the reduction in wholesale prices due to the merit-order effect has largest adverse impact on lower-emitting (but higher-cost) gas (rather than brown coal) plant which exit, rather than higher-emitting brown coal.

In terms of the distributional impacts under each of the emissions reduction mechanisms, Extended LRET has the highest resource costs, but not the highest electricity prices which occurs under Regulatory Closure. This means that under Extended LRET, more of the resource costs fall on existing generators in the form of lower electricity prices.

It is worth reiterating that the resource costs associated with Regulatory Closure exclude any closure payments that may be made to generators that are closing. Likewise, the higher electricity prices for consumers under Regulatory Closure exclude any consumer levies or taxes that may be charged to recover closure payments made by governments. In other words, abatement costs under Regulatory Closure would be the same irrespective of how the policy is funded, but the impact on electricity prices may be different depending on the policy design. Even though closure payments are not an economic cost (rather they are a transfer from taxpayers to generators), such payments shift more of the cost of Regulatory Closure onto taxpayers/consumers and away from generators.

System security impacts

The AEMC and AEMO are working together to address the challenges for maintaining power system security in the NEM associated with the shift from synchronous generation to non-synchronous and intermittent generation. Each market body will, within the scope of their respective roles, bring expertise to bear to address the related technical, regulatory and market framework challenges that arise. The work undertaken by AEMO for the integration of energy and emissions reduction policy project is an extension of the collaborative project between AEMO and the AEMC.

The emissions reduction mechanisms discussed above were also examined for their implications for power system security. As highlighted above, to achieve the emissions reduction target for the electricity sector, the share of generation from low- and zero-emissions generators needs to increase, with a corresponding reduction in the share of generation from high-emission generators. This is likely to reduce the level of inertia[19] of the power system, as inertia is naturally provided by large spinning (fossil-fuel and hydro) generators that are synchronised to the frequency of the system. By contrast, wind and large-scale solar PV are currently examples of non-synchronous generators. As conventional generators exit the market, investment at the generation and/or transmission network level may be needed to control power system frequency in an environment of reduced power system inertia.

As each of the three emissions reduction mechanism results in a different mix of synchronous and non-synchronous generation, the impact on power system inertia, and the potential implications for controlling power system frequency, is likely to differ under each of the mechanisms. In accordance with the scope of Task 2, AEMO has provided an analysis of the potential impacts of each of the three emissions reduction mechanisms on key elements of power system security (such as frequency). AEMO's analysis was conducted on the basis of no change to existing market and regulatory arrangements. In the event that one of the three emissions reduction mechanisms were to be selected to reduce electricity sector emissions, the impacts of that mechanism on power system security would need to be examined more closely.

AEMO's analysis is provided in Appendix A of this report. It reveals that, of the three emissions reduction mechanisms, the security-related implications are lowest under EIT and highest under Extended LRET. This is because Extended LRET results in the highest share of non-synchronous generators in the generation mix. A greater share of non-synchronous generation reduces power system inertia, which results in a higher rate of change of frequency following a disturbance. This may mean the change in frequency cannot be arrested by post-contingent control systems or other mechanisms before the power system collapses across a wide area. It is worth noting that currently these challenges appear relatively minor outside of South Australia and Tasmania.

It is also important to note that AEMO's analysis reveals that the frequency-related challenges projected for South Australia in 2030 are, to a material and growing extent,

19 The ability of the power system to resist large changes in frequency arising from the unexpected loss of a generator, transmission line or large industrial load is determined by the inertia of the power system. The higher the level of inertia, the lower the impact on frequency when unexpected changes in electricity demand or supply occur.

present today. As discussed in Appendix A, AEMO's studies of South Australia have focussed upon the loss of the Heywood interconnector to Victoria at a time of high flow into, and low system inertia present in, South Australia. If the interconnector is lost, this can cause a very rapid drop in frequency that cannot be arrested by automatic under-frequency load shedding, resulting in a state-wide power outage. The lack of inertia in South Australia reflects its high penetration of non-synchronous generation, chiefly wind, that has occurred in response to the incentives provided by the LRET.

On 14 July 2016, the Commission announced it was undertaking a review, the System Security Market Frameworks Review, of whether wholesale energy market frameworks are suitable to complement increasing volumes of renewable energy and to maintain power system security as the industry transforms.[20]The review will provide a holistic consideration of various technical issues, including the minimum level of inertia required to effectively stabilise the power system, thereby allowing it to cope with rapid changes in frequency due to significant movements in supply and demand. Other aspects include fast frequency response and localised impacts on fault levels within certain areas of the electricity grid. As part of this system security work, the Commission is also considering rule changes on emergency under- and over-frequency control schemes.[21]

The review addresses the need for possible changes to market arrangements that lead to more efficient outcomes for energy consumers while delivering a secure operating system, and will provide recommendations on any necessary changes to the COAG Energy Council with an interim report to the nation's energy ministers due by end-2016.

In undertaking this review, the AEMC is working with AEMO and extending its collaboration with AEMO in relation to the challenges with maintaining power system security in the context of a changing generation mix. The AEMC is involved in AEMO's Future Power System Security Program[22], which is an extensive body of work aimed at identifying and prioritising these system security challenges. Potential technical solutions to the challenges are also being identified by AEMO.

A final point to note is that, while the quantitative aspects of the analysis do not include transmission investment in the estimates of resource costs under BAU and each of the emissions reduction mechanisms, the amount of transmission investment required is likely to be highest under Extended LRET and lowest under EIT. This is because of the amount of non-synchronous generation that is installed under Extended LRET, which is likely to require investment in transmission assets to maintain system security. Conversely, under EIT, as emissions abatement is also delivered through fuel switching

20 More details on this work can be found on the AEMC's website at: http://www.aemc.gov.au/Markets-Reviews-Advice/System-Security-Market-Frameworks-Review

21 More details on this work can be found on the AEMC's website, at: http://www.aemc.gov.au/getattachment/6030aedb-cade-4eb0-8136-411ed89b4851/Consultation-Paper.aspx

22 More details on AEMO's work can be found at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/FPSSP-Reports-and-Analysis

from coal to gas, and as gas-fired generation is a synchronous form of generation, a relatively lower transmission investment is required.

Summary assessment and timeline

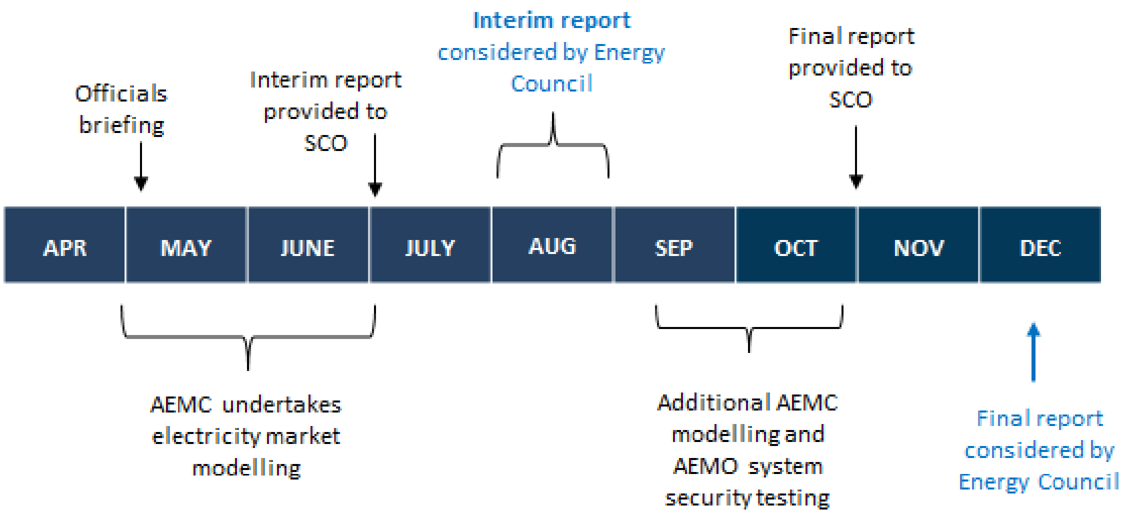
A summary of the analysis and outcomes as they relate to achieving the emissions reduction and electricity objectives is provided in Table 5.

Table 5 Summary assessment of emissions reduction mechanisms

Mechanisms	Emissions Reduction Objective	National Electricity Objective
EIT	As the mechanism for reducing emissions under EIT is embedded in the wholesale electricity price, the emissions reductions are more certain over the long term relative to Extended LRET and Regulatory Closure, contributing to the mechanism's sustainability.	EIT maintains the allocation of risk between generators and consumers and supports the existing pricing mechanisms in the NEM. It does this by changing the relative costs of different technologies to achieve the emissions reduction task. Wholesale prices are lowest under this approach and there are no negative impacts on the contract market,
Extended LRET	If the Extended LRET is expressed in fixed GWh terms, then emissions may under or over shoot the target depending on changes in energy consumption. Unless the LRET is continually extended, there is a risk that higher emissions generators increase output and/or retired generators return to the market when the LRET is met.	The Extended LRET is not a technology neutral mechanism and has mostly subsidised one form of technology to-date: wind. Because of this, it is not the lowest cost way of achieving the emissions target, being over **twice** as expensive on a cost of abatement measure as EIT. The Extended LRET mechanism is also likely to negatively impact the ability of market participants to source and enter into contracts.
Regulatory Closure	Regulatory Closure provides certainty in the short term that generators will close. However, there is a risk that the remaining high emissions generators increase their output. This mechanism is less responsive to uncertainty around future emissions reduction targets as it requires administrative intervention.	Regulatory Closure has the potential to embed a barrier to exit in the NEM, with generators no longer responding to price signals, but instead waiting for announcements from government for payment to close. Wholesale prices are highest under this approach.

The timeline for delivering the advice to the COAG Energy Council is shown in Figure 5. The first stage of the advice was an interim report prepared for SCO and the COAG Energy Council in July 2016, which related to Task 1. The second and final stage is this report, the final report, for consideration by SCO and the COAG Energy Council, which contains the analysis for Tasks 1 and 2, as well as incorporating feedback on the interim report.

Figure 5 Timeline for completing the advice



A key theme of this report is that, while energy and emissions reduction policies may have different objectives, the mechanisms to achieve these objectives can be designed in a manner that minimises the required trade-off between these objectives. Emissions reduction policies that are appropriately designed and integrated with energy policies can achieve emissions reduction benefits and minimise costs and risks faced by consumers in energy markets. Recent evidence in the NEM suggests that if this does not occur, the result is likely to be policy instability, investment deferral, and a failure to achieve one or more policy objectives.

The Commission's analysis has shown that the EIT is the most cost-effective, scalable, and robust emissions reduction mechanism, of the three broad pathways available to policy-makers. Of central importance is that its performance regarding economic efficiency and prices payable by consumers is not predicated on one view of the future. The technological and geographic neutrality of the EIT mechanism gives it the flexibility to cost-effectively adapt to whatever the future holds, allowing emissions reduction and energy policy objectives to be simultaneously achieved at the lowest cost to consumers. This enhances the longer-term sustainability of emissions reduction policies, and facilitates the effective and efficient integration of energy and emissions reduction policy.

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1 Introduction

On 18 February 2016, the Senior Committee of Officials (SCO) of the Council of Australian Governments (COAG) Energy Council wrote to the Australian Energy Market Commission (AEMC or Commission) and the Australian Energy Market Operator (AEMO) requesting advice on the interaction between energy and carbon dioxide or equivalent (CO_2e) emissions reduction policies in the National Electricity Market (NEM).[23]

The request for advice was an outcome of the December 2015 Energy Council meeting, where Energy Ministers noted the following:[24]

> "The successful integration of carbon and energy policies will be critical to meeting Australia's emissions reduction target of 26 to 28 per cent below 2005 levels by 2030. Ministers will develop a national approach to connect environmental outcomes and energy policy in the interests of consumers."

Energy Ministers tasked SCO with preparing advice to allow the COAG Energy Council to better understand the potential impact of emissions reduction policies on the NEM. The AEMC and AEMO have been asked to assist officials with this work.

At its 19 August 2016 meeting, the COAG Energy Council agreed to expand the Terms of Reference for the AEMC and AEMO's work to include consideration of the economic and operational impacts of existing state and territory emission reduction policies.[25] This expansion of scope was provided in a 20 September 2016 letter from SCO to the AEMC and AEMO.[26]

While the Commonwealth Government would determine the emissions reduction target for the electricity sector, the purpose of the AEMC's and AEMO's advice is to enable the COAG Energy Council to form a view on the features and impacts of alternative emissions reduction mechanisms that can achieve the emissions reduction target, highlighting those mechanisms that enable the achievement of both emissions reduction and energy policy objectives.

Designing and comparing the impacts of alternative emissions reduction mechanisms involves two key steps. The first step is to confirm the primary objective that governments are seeking to achieve through the policy in question – whether it is emissions reduction, or investment in renewable electricity generation. At the present time, Australia's policies for reducing emissions from the electricity sector at both the Commonwealth and jurisdictional levels are not consistent with emissions reductions as their primary objective. This is demonstrated by the design of the associated mechanisms, which have focused on directly or indirectly promoting the uptake of specific renewable energy technologies. However, in preparing this advice, the AEMC

23 Senior Committee of Officials, Modelling of Carbon Emission Reduction Scenarios in the National Electricity Market, Letter to John Pierce and Matt Zema, 18 February 2016.

24 COAG Energy Council, Meeting Communique, Canberra, 4 December 2015, p. 2.

25 COAG Energy Council, Meeting Communique, Canberra, 19 August 2016, p. 2

26 Senior Committee of Officials, Modelling of Carbon Emission Reduction Scenarios in the National Electricity Market, Letter to Mr John Pierce and Dr Tony Marxsen, 20 September 2016.

has taken as given – consistent with the terms of reference – that the primary objective of emissions reductions policies is indeed emissions reduction.

The second step in designing and comparing alternative emissions reductions mechanisms is to assess their consistency with governments' existing energy policy objectives. Australia's energy policy objectives focus on promoting the long-term interests of consumers with respect to the price, quality, reliability and security of electricity services. These objectives are encompassed in the National Electricity Objective (NEO)[27], which the AEMC is required to have regard to when undertaking its functions.

Australian energy policy has focussed on promoting the long term interests of consumers with respect to the price, quality and reliability of electricity and gas services through an overarching governance framework based on the *Australian Energy Market Agreement*[28]. Similarly, the National Electricity Objective (NEO) in section 7 of the National Electricity Law refers to the promotion of efficient investment in, and efficient operation and use of electricity services for the long term interests of consumers with respect to:

- price, quality, safety, reliability and security[29] of supply of electricity; and
- the reliability, safety and security of the national electricity system.

Generally speaking, consumers' long-term interests are best served by workably competitive wholesale and retail markets that allocate market and technological risks to commercial parties with the strongest incentives and abilities to manage or mitigate those risks. This helps to ensure that prices to consumers for electricity services are as low as can be sustained. Efficient risk allocation implies that when variables such as demand growth, the rate of technological change or fuel costs diverge from prior expectations, secure and reliable supply remains at the lowest possible cost to consumers.

Failing to consider Australia's energy policy objectives when designing emissions reduction mechanisms is likely to result in higher prices for consumers in the long run or a less secure power system than would otherwise be achievable. This will inevitably result in calls for emissions reduction mechanisms or policy objectives to be changed. The anticipation of such instability would create uncertainty and raise barriers to achieving both emissions reduction and energy policy objectives.

Conversely, designing the emissions reduction mechanism in a manner that is consistent with governments' energy policy objectives will contribute to the resilience and longevity of both the emissions reduction policy and its associated mechanism.

27 The National Electricity Objective is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to: price, quality, safety, reliability, and security of supply of electricity; and the reliability, safety and security of the national electricity system.

28 Australian Energy Market Agreement, 9 December 2013, page. 9.

29 A *secure* power system is one that is being operated or managed such that all vital technical parameters such as voltage, equipment loading and power system frequency are within design limits and are stable and all persons are safe. A *reliable* power system is one that has a high likelihood of supplying all consumer needs

This is one aspect of what the Commission refers to as the successful integration of energy and emissions reduction policy.

1.1 High-level principles for integrating energy and emissions reduction policies

The AEMC, as rule maker, oversees the development of the market mechanisms and regulatory frameworks for the NEM. In doing so, the AEMC seeks to ensure that:

- Natural monopoly activities are undertaken by parties subject to appropriate economic regulation;
- Potentially competitive activities are undertaken by market participants and consumers; and
- Responsibilities and risks are allocated to those best-placed to manage them.

The final point is particularly relevant to how energy and emissions reduction policies should be integrated. In the competitive wholesale electricity market, risk around whether an investment in new generation capacity will be profitable rests with the generation businesses that supply the market. This is appropriate because generation businesses have the expertise, information and commercial incentives to manage the market risks prudently.

More generally, the objective of the last two decades of energy market reform has been to move away from central planning of the electricity sector as much as practicable, to avoid consumers bearing the risks, and ultimately the costs, of inefficient decisions to invest in or retire plant.

Box 1.1 discusses the background to electricity market reform in Australia.

Designing market and regulatory frameworks in this manner should promote energy policy objectives: achieving reliability, security and safety of supply at the lowest cost to consumers over the long term.

For similar reasons, emissions reduction policies are likely to impose the lowest cost burden on electricity consumers in the long term if the mechanism used to achieve those policies:

- decentralises decision-making regarding the means by which abatement occurs to those with the expertise, information and commercial incentives to make those decisions most efficiently. This, in turn, suggests that the mechanism adopted should be technologically and geographically neutral rather than technologically or geographically specific – because a neutral mechanism would allow participants to identify and utilise the least-cost way of achieving the required abatement; and
- allocates the risks of unanticipated changes in demand, cost and other variables to those best-equipped and commercially motivated to manage those risks. Efficient management of risks allocated to participants requires access to liquid contract markets.

These high-level principles inform the mechanism design principles discussed in Section 3.1.

Box 1.1 Background to Australian electricity market reform[30]

The formal process to reform the electricity sector and develop the NEM began in 1991 with a decision by COAG to establish a National Grid Management Council to coordinate the planning, operation and development of a competitive electricity market. COAG took this decision in response to a report by the Industry Commission that found significant increases in Australia's Gross Domestic Product could be realised by introducing competition into the generation and retail sectors.

Prior to the reform of the electricity industry in the 1990s, decisions to invest in new generation capacity were centrally made by vertically integrated authorities. One of the major motivations in a number of jurisdictions for supporting the reform was the strong desire to avoid any government involvement in decision making on the next increments of generating capacity. This was to avoid the mistakes of the 1970s and 1980s over expansion in capacity.

An objective of introducing competition in the wholesale electricity sector was to decentralise operational and investment decisions away from central authorities to commercial parties operating in a competitive market. Generation businesses may be no better at forecasting the future than were governments, however, the important difference is that equity and debt holders bear the cost of overinvestment, rather than consumers. This is a very different way of allocating risk and one which provides very different incentives for efficiency.

Under competition, price signals guide participants as to how they should run their plant, when maintenance should be carried out and when and what type of technology to invest in. Profit, competition and capital market discipline provide incentives to manage risk. Under a regulatory approach, such as a capacity mechanism or through technology subsidies, price signals are weakened and these decisions are taken by a central authority that does not have the same incentives or exposure to risk, and that risk is borne by consumers.

However, as noted above, the mechanisms employed to reduce CO_2e emissions in the electricity sector to date have relied on subsidising specific technology choices.[31] Such an approach pre-determines how emissions are reduced rather than allowing commercial agents to identify the least-cost options. Subsidising specific technologies has also generally involved reallocating risk from investors in those technologies to investors in other generation technologies, consumers and taxpayers.

1.2 Importance of integrating energy and emissions reduction policy

Emissions from the Australian electricity sector were 187.5 megatonnes (Mt) of CO_2e for the year to December 2015. This is equivalent to around 35 per cent of total emissions

30 This discussion is based on: KPMG, National Electricity Market - A case study in successful microeconomic reform, 2013.

31 An example of this has been the small-scale and large-scale Renewable Energy Target and various jurisdictional solar PV feed-in tariff schemes and reverse auctions for renewable generation capacity.

from the economy.[32] As the electricity sector is such a large contributor to national emissions, at some point in the future a sustainable transformation of the generation capital stock will need to occur to meet the emissions reduction targets set by government.

In August 2015 the Commonwealth Government announced an emissions reduction target of 26 to 28 per cent on 2005 levels by 2030.[33] Later in the same year, a global agreement post-2020 was concluded at the Conference of the Parties (COP21) to the United Nations Framework Convention on Climate Change, which provided for five yearly reviews of national emissions reduction targets.[34]

At the same time, a reliable, secure and low-cost supply of electricity has supported decades of Australian economic growth. Australian households spend around $16 billion annually on electricity, while the manufacturing sector's annual electricity expenditure is around $7 billion. The widespread use of electricity throughout the economy reinforces the need to maintain the focus on efficiency within the electricity supply industry as it transforms in response to the need to reduce CO_2e emissions.

As the electricity sector accounts for around one-third of Australia's emissions, efforts to reduce national emissions will inevitably involve reducing emissions in the electricity sector. Therefore, energy and emissions reduction policies are inextricably linked. For an emissions reduction policy to be sustainable over the long term, two policy objectives need to be jointly met:

1. Government-set emissions reduction target; and
2. Reliable and secure supply of electricity.

Emissions reduction mechanisms that are appropriately designed in accordance with the design of the NEM can meet both of these objectives at the lowest long-term cost to consumers. This is the focus of our analysis and mechanisms to reduce emissions will be tested against the framework set out in Chapter 3, which reflects these principles.

1.3 Scope and process for this advice

The Commission has been asked to develop emissions reduction mechanisms for achieving a 28 per cent emissions reduction target that include least-cost abatement, staged generator exit and accelerated deployment of renewable energy. The mechanisms are to be assessed in terms of their impacts on efficient outcomes and the ability for:

- The wholesale market to continue to provide appropriate incentives to ensure supply and demand balances across the NEM with an appropriate level of reliability;

32 Quarterly Update of Australia's National Greenhouse Gas Inventory: September 2015, Commonwealth of Australia 2016, p. 8.

33 Department of the Environment 2016, Australia's 2030 climate change target fact sheet, viewed 26 May 2016, http://www.environment.gov.au/climate-change/publications/factsheet-australias-2030-climate-change-target

34 Department of the Environment 2016, International activities, viewed 26 May 2016, http://www.environment.gov.au/climate-change/international

- The wholesale market to foster liquidity and provide opportunities for long term contracting by market participants; and
- Appropriate frameworks and incentives to be in place to support network investment and investment in energy storage.

The Commission has developed the following mechanisms in response to the request for advice:

- **Market-based**: the establishment of an emissions intensity target (EIT) for the electricity sector, where generators with an emissions intensity above the target are liable to buy credits and those with an emissions intensity below the target create and sell credits. The emissions intensity target declines over time in a manner consistent with the emissions reduction target.
- **Technology subsidy**: extension of the existing Large-scale Renewable Energy Target (LRET). The size of the existing target is 33,000 gigawatt hours (GWh) in 2020. In order to meet the emissions reduction target for 2030, and based on AEMO's 2015-year forecasts for electricity consumption in 2030, this target is estimated to equal 86,000 GWh in 2030.
- **Government regulation**: centralised decision-makers determine which generators should exit and when, and implement this 'optimal closure schedule' to force certain generators to close in order to meet the emissions reduction target. The decision on which generators would be closed and when would need to be based on a set of expectations of the future; for example, expectations of future electricity demand.

In each case, the mechanism is specified to commence in 2020. Further details on the mechanisms and the business-as-usual (BAU) scenario, which is used as the counter-factual, are set out in Chapter 2.

The Commission and AEMO were asked to provide a report by the end of 2016. This work is being undertaken as two main tasks:

- **Task 1** required the AEMC to analyse three alternative emissions reduction mechanisms, including the economic impacts of each of these mechanisms and the ability of each mechanism to integrate with the NEM's design and operation.
- **Task 2** required AEMO to consider the outcomes from Task 1 – such as the location and type of new generation investment, retirements and dispatch, which follows from the choice of emissions reduction mechanism – to assess their impact on system security and reliability. AEMO's analysis informed the overall assessment of the emissions reduction mechanisms and is published as an appendix to this report.

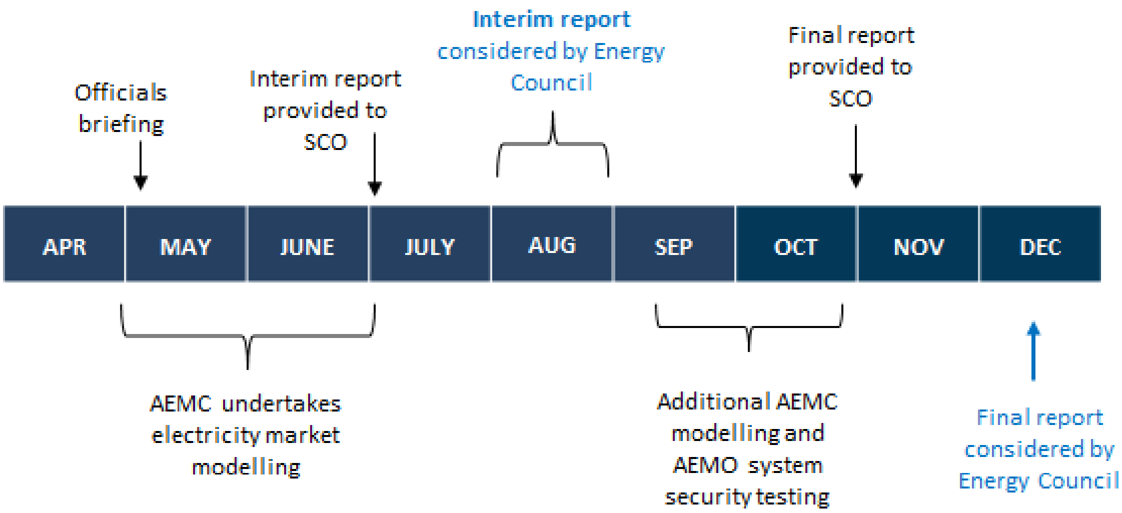
The approach to the interim and final reports is set out in Table 1.1.

Table 1.1 Approach to interim and final reports

Interim report: discussion and analysis of economic impacts	Final report: holistic assessment of economic and system security and reliability impacts
• Discuss the emissions reduction mechanisms, what they are and how they differ • Drawing on the electricity market modelling, outline the strengths and weaknesses of each mechanism • Undertake literature review of similar work in the public domain to highlight similarities and differences	All elements from the interim report, *plus*: • Address comments provided on the interim report, including the scope of additional analyses • Qualitative analysis of the characteristics and impacts of jurisdictional renewable targets and mechanisms • Incorporate AEMO's system security analysis

The timeline for delivering the advice to the Energy Council is shown in Figure 1.1. The first stage of the advice was an interim report prepared for SCO and the COAG Energy Council in July 2016, which related to Task 1. The second and final stage is this report, the final report, for consideration by SCO and the COAG Energy Council, which contains the analysis for Tasks 1 and 2, as well as incorporating feedback received from jurisdictional officials on the interim report.

Figure 1.1 Timeline for completing the advice



The remainder of this report is set out as follows:

- Chapter 2 outlines the emissions reduction mechanisms considered by the Commission.
- Chapter 3 sets out the framework used to assess the mechanisms.
- Chapter 4 includes the analysis and outcomes from the emissions reduction mechanisms.

- Chapter 5 analyses the ability of each of the mechanisms to adjust to alternative assumptions about future demand, emissions reductions targets, and other key variables.
- Chapter 6 provides a literature review of recent analysis of electricity sector emissions reduction policies.
- Appendix A: AEMO's system security analysis
- Appendix B: Terms of reference.

2 Emissions reduction mechanisms

The Commission was asked to develop scenarios to test the likely outcomes of implementing different types of mechanisms to achieve an emissions reduction target of 28 per cent below 2005 levels by 2030 for the electricity sector. The emissions reduction mechanisms are to commence in 2020 and cover least-cost abatement, accelerated deployment of renewable energy and staged generator exit.[35]

There are a range of potential mechanisms that could be devised to assess the impacts under each of these alternative pathways. The Commission has developed the following three mechanisms, corresponding to each of the three alternative pathways towards the 28 per cent emissions reduction target:

1. **Market-based**: the establishment of an emissions intensity target (EIT) for the electricity sector, where generators with an emissions intensity above the target are liable to buy credits and those with an emissions intensity below the target create and sell credits. The emissions intensity target is defined as the amount of CO_2e emissions divided by the amount of electricity generation, and is typically expressed as the number of tonnes of CO_2e per MWh. The target is then applied to all generators in Australia's wholesale electricity markets based on the emissions intensity of their output (in MWh). The emissions intensity target declines over time in a manner consistent with the emissions reduction target.
2. **Technology subsidy**: extension of the existing Large-scale Renewable Energy Target (LRET). The size of the existing target is 33,000 gigawatt hours (GWh) in 2020. In order to meet the emissions reduction target for 2030, and based on AEMO's 2015-year forecasts for electricity consumption in 2030, this target is estimated to equal 86,000 GWh in 2030. That is, based on forecasts for future electricity consumption, the target would need to more than double to achieve the emissions reduction target.
3. **Government regulation**: on the presumption that centralised decision-makers are adept at determining which generators should exit and when, and also adept at implementing this 'optimal closure schedule', this schedule is implemented by government to force certain generators to close in order to meet the emissions reduction target. Regardless of the form and design of this regulation, the decision on which generators would be closed and when would need to be based on a set of expectations of the future; for example, expectations of future electricity demand.

The individual design elements of each emissions reduction mechanism were chosen for the purpose of facilitating an analysis of the characteristics and impacts of each mechanism on the wholesale electricity generation sector.

This chapter outlines the emissions reduction mechanisms considered by the Commission, including how they work and key differences between approaches. A BAU scenario was used as the counterfactual against which the different mechanisms are compared. BAU reflects current policy settings in the electricity sector, including the

35 Senior Committee of Officials, Modelling of Carbon Emission Reduction Scenarios in the National Electricity Market, Letter to John Pierce and Matt Zema, 18 February 2016.

existing LRET (which is a target of 33,000 GWh of renewable energy generation by 2020). The Commission was also subsequently asked to consider the economic and operational impacts of existing State and Territory renewable energy targets.

While the Commission has been asked to consider emission reduction mechanisms that apply to the wholesale electricity generation sector, this does not preclude the implementation of complementary national policies that apply outside the supply side of the sector, such as the National Energy Productivity Plan.[36] A sectoral approach also does not preclude the implementation of different emissions reduction mechanisms outside of the electricity sector that act on other parts of the economy, such as fugitive emissions, agriculture and transport.

2.1 Emissions Intensity Target

Under an Emissions Intensity Target (EIT) mechanism, an emissions intensity target is set for the electricity sector. Each generator faces an emissions liability or credit reflecting their output multiplied by the difference between their actual emissions intensity and the sector emissions intensity. Lower-emitting generators receive more permits than they need, which they can sell; higher-emitting generators need to purchase permits for emissions above the EIT. As discussed in more detail below, the effect is to alter the generation merit-order and influence dispatch in a manner consistent with meeting the abatement target.

Another market-based mechanism is a cap-and-trade emissions trading scheme (ETS). In an ETS, all emissions from generators are penalised, with the difference in the size of the penalty for each generator changing the relative costs of different technologies and driving switching from high-emissions to low-emissions generators. An EIT mechanism encourages the same degree of fuel switching and emissions reductions as a cap-and-trade ETS - and should accordingly result in similar resource costs of meeting an emissions reduction target (that is, a similar cost of abatement) – but without the same degree of wholesale electricity price increases.[37]

An ETS relies on an allocation of credits which are based on historical, rather than current, output. This creates an opportunity cost associated with the use of permits under an ETS, as using these permits forgoes the revenue from selling these permits. This opportunity cost is passed through to consumers in the form of higher wholesale and retail prices. In contrast, since an EIT is output-based, there is no opportunity cost associated with the permits as generators are allocated permits only when they generate. Therefore, an EIT has lower price impacts than an ETS.

Due to the electricity price impacts of a cap-and-trade ETS, this is generally seen as requiring the provision of compensation to consumers. While the Commonwealth Government can use revenue raised from the sale of emissions permits to provide such compensation, it creates a flow of funds through the budget and exposes the budget to movements in the carbon price. Because the carbon price revenue flows through the budget, fiscal policy objectives can become a consideration in the way the ETS is

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36 COAG Energy Council, National Energy Productivity Plan 2015-2030, December 2015.

37 An EIT scheme with a target of 0t CO_2/MWh is equivalent to a cap-and-trade ETS as, in this case, all emissions under the EIT scheme are penalised.

designed and implemented, rather than it being targeted to meet an energy and emissions reduction policy objective. There is also an interaction effect associated with the tax revenue raised by an ETS; this can lead to further efficiency losses, depending on how the revenue raised is used. For example, lump-sum compensation for the increased in electricity prices may be poorly targeted and therefore inefficient.

It is for these reasons that the Commission considers that an EIT mechanism offers the best prospect of being a resilient and sustainable mechanism for securing emissions reductions. A sustainable mechanism is, in turn, most likely to meet emissions reduction objectives in a way that minimises price impacts on consumers in the long run, consistent with governments' broader energy policy objectives.

Implementing the EIT mechanism as an electricity sector-specific mechanism has the advantage of allowing the mechanism to be designed to meet the unique characteristics of the electricity sector, while also potentially being linked with other domestic and international schemes to support least-cost abatement. In this report, the Commission has not modelled the potential electricity market price outcomes from linking an electricity sector-specific EIT mechanism with other domestic or international schemes. This is due to uncertainties regarding the structure of future international and domestic carbon markets. Instead, a qualitative assessment of the implications of linkage to domestic or international schemes is provided.

2.1.1 How the Emissions Intensity Target works

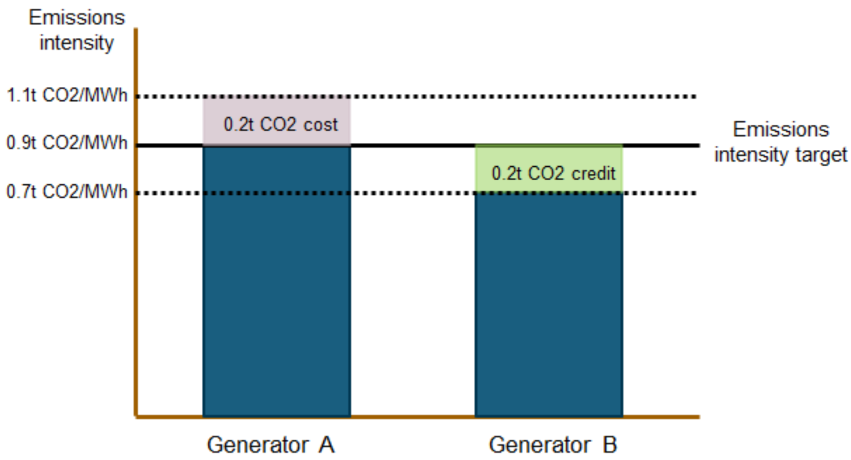
Under the EIT mechanism, the emissions reduction target is reached by setting a sector cap for emissions. This is set by the government in megatonnes (Mt) of CO_2e, and would be converted into an annual emissions intensity target in tonnes of CO_2e per megawatt hour (MWh) of electricity generated. This EIT would be uniform for the sector.

Generators with an intensity below the target would create CO_2e credits – termed Australian Electricity Sector Credits (AESCs) – equal to the difference between their emissions intensity and the EIT, for each and every MWh generated. The demand for credits comes from generators above the target who are required to purchase AESCs to reduce their emissions intensity to the target. For example, if the EIT was 0.8t CO_2e/MWh, combined cycle gas turbine (CCGT) and renewable energy generators would receive credits while black and brown coal generators would be liable to surrender credits. This would drive a change in relative output. One AESC would represent one tonne of CO_2e.

Figure 2.1 shows a stylised example of two generators to illustrate how this approach works given an EIT of 0.9t CO_2e/MWh. Generator A has an emissions intensity above the target and purchases 0.2 AESCs in order to reduce its intensity (1.1t CO_2e/MWh) to the target. Generator B has an emissions intensity of 0.7t CO_2e/MWh and therefore creates 0.2 AESCs which are available for sale to Generator A.

The AESC price would be a function of the supply and demand for credits, which in turn depends on the EIT and output from low- and high-emissions generators. This design results in a generation sector-specific mechanism where generation businesses have the flexibility to reduce the emissions intensity of their portfolios in a least-cost manner by trading credits or investing in technology to reduce the emissions intensity of their plant.

Figure 2.1 Generators below the intensity target create credits that those above must procure



When an EIT is applied to the electricity sector, the relative cost of different generation technologies change. Electricity generation from brown coal, which had the lowest variable costs of generation after renewables, becomes relatively more costly than black coal and CCGT electricity generation, as brown coal generators have the highest emissions intensity and must therefore purchase the most credits.

The shift in the generation merit-order delivered by the EIT delivers the targeted emissions reductions by shifting the generator merit order, with this shift occurring even when market conditions unexpectedly change. For example, if fuel costs for high-emissions generators, (such as brown coal), were to reduce, the inherent self-correcting feature of the EIT mechanism means that there would still be a change in the merit order in order to meet the emissions reduction target. Under EIT, the emissions reductions are achieved by defining an emissions intensity target for the electricity sector. If, for example, high-emissions generators were to increase their output, for example because of a in response to the fall in their fuel costs, for a given level of demand, they will would need to source additional AESCs per MWh for their additional output. At the same time, the supply of AESCs would fall as lower-emissions generators produced less output, since demand is unchanged. The combination of higher demand for, and lower supply of, AESCs would lead to an increase in their price.

This price rise would continue until higher-emissions generators were placed at a cost disadvantage to lower-emissions generators and the required merit order shift occurred. The market would settle at a point where the price of AESCs was sufficiently high so as to meet the target emissions intensity for the industry.

The change in relative costs between different generation technologies under an EIT mechanism is the same as under a cap-and-trade ETS, except that absolute wholesale price increases are lower, as discussed in section 2.1.

The requirement for generators to surrender AESCs could be based on a 12-month compliance period, with generation businesses provided with banking and borrowing flexibility.[38] Banking and borrowing allows generation businesses to optimise the sale and surrender of certificates subject to a range of factors, including current and expected future AESC prices, generation output and time value of money considerations.[39]

An overview of how AESCs could be created and surrendered is in Box 2.1.

Box 2.1 Creating and surrendering AESCs

Certificates could be created and surrendered through the Australian national registry of emissions units administered by the Clean Energy Regulator. This is an electronic registry that facilitates the exchange of certificates and tracks the ownership and creation of all certificates.

Generation businesses would establish a registry account with the Clean Energy Regulator through which to create AESCs, transfer AESCs that have been sold, receive AESCs that have been bought and surrender AESCs to meet any liability.

Determination of the certificate price and financial settlement of a trade occurs outside of the registry. Once a trade takes place, the registry accounts of the generation businesses involved are updated.

As the systems and processes required to create and trade AESCs already largely exists, this minimises implementation costs and risks for industry. AESCs can also be created and sold on a regular basis under this approach, reducing working capital requirements by not having to wait until the end of the compliance period to receive revenue from the sale of certificates.

The existing National Greenhouse and Energy Reporting auditing framework could be developed to support compliance of the EIT mechanism.

2.1.2 Emissions Intensity Target design features

Table 2.1 sets out flexibility measures that could be incorporated into the design of the EIT mechanism. For the mechanism to be sustainable over the long term, it will need to have an ability to adapt to changing energy market conditions and evolving expectations around the magnitude and speed of emissions reductions.

38 For instance, unlimited banking of AESCs for use in future years and a limited ability to borrow AESCs from in the future to meet a liability today.

39 The quantitative analysis assumes that the emissions reduction target is met; therefore no penalty for non-compliance is explicitly modelled. Under this assumption, the carbon price would rise until the market balances.

Table 2.1 Flexibility measures inherent in the design

Flexibility measure	Comment
Setting the emissions intensity target	The design of the target is adaptable to changes in electricity consumption and emissions reduction targets, without modifying the underlying architecture. This is important because it allows the mechanism to continue to meet the emissions reduction objective and NEO at lowest cost.
Integration with the existing LRET	The LRET could be subsumed into the EIT mechanism, which would allow for a technology neutral approach, or operate alongside it.
Domestic linkage	A system to facilitate the trade of AESCs with other domestic emissions reduction mechanisms could be developed.
International linkage	A system to facilitate the trade of AESCs with international emissions reduction mechanisms could be developed.

Setting the emissions intensity target

The ability of the EIT mechanism to respond to future uncertainty around electricity consumption and emissions targets will contribute to its ability to continue to meet the emissions reduction objective and NEO at the lowest cost for consumers.

Setting the emissions intensity trajectory for an extended period of time risks some investment uncertainty due to uncertain demand growth. If electricity consumption turns out to be materially different from the forecast used to calculate the emissions intensity, the trajectory will become detached from what is required to achieve the emissions objective. Where emissions are expected to be notably above or below the target, there will be calls from stakeholders to revise the emissions intensity trajectory, creating uncertainty about the future level of the EIT. However, as the emissions intensity of the sector declines, the level of uncertainty in emissions as a result of demand variations also declines.

Flexibility under an EIT mechanism could be achieved by implementing a transparent and mechanistic gateway process to set the emissions intensity trajectory. The trajectory could be set for five-year periods and potentially carried out alongside the five-yearly reviews of national emissions targets agreed at COP21 and as discussed in Chapter 1.

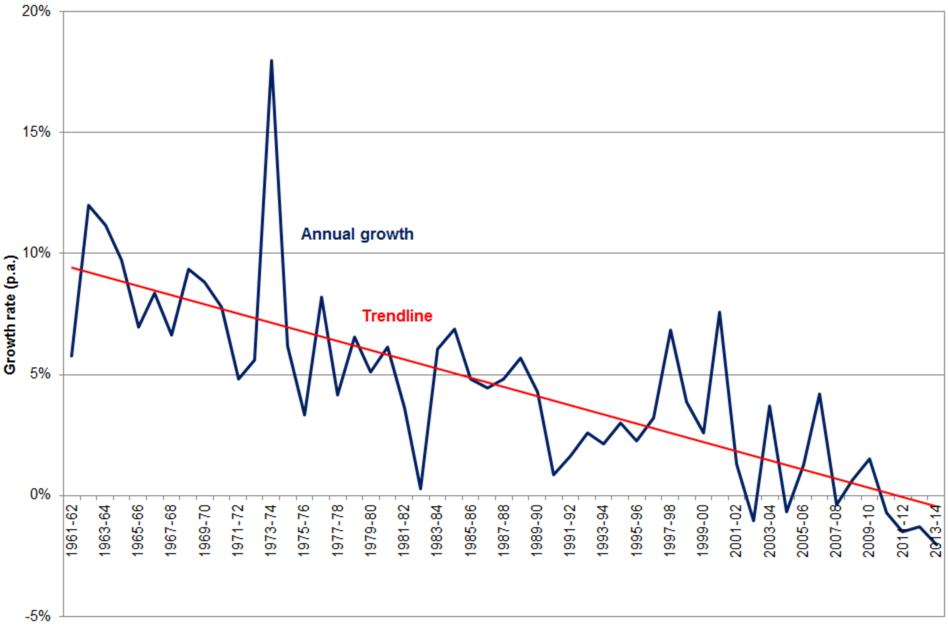
Under a set of requirements that are transparent to industry, an independent body tasked with setting the trajectory could take the absolute emissions target provided by government and determine the emissions intensity using market operator forecasts of annual energy consumption. There would be an opportunity to undertake targeted consultation with industry on the shape of the trajectory and energy forecasts used.

Based on this gateway test process, generators will be able to form expectations, as they currently do for demand and prices, around the likely emissions trajectory over an extended period. As the mechanism can respond to changes in the energy market, this should contribute to investment certainty. Further detail on a potential gateway test is in section 4.4.

The Commission notes that, based on the long-term trend of annual electricity consumption growth, as shown in Figure 2.2, setting the emissions intensity target for a five-year period could result in actual emissions falling below the target if actual electricity consumption growth over the period is lower than expected. For example, say an emissions intensity target of 0.81t CO_2e/MWh was calculated based on an absolute emissions target of 174 Mt divided by forecast energy consumption of 215 TWh. If electricity consumption turned out to be lower at, say, 210 TWh, and the emissions intensity target remained at 0.81, then CO_2e emissions would be 4 Mt **below** the target.

Figure 2.2 shows that annual electricity consumption growth has been decreasing over time. The key structural factor likely contributing to this is the Australian economy moving away from its agricultural and manufacturing origins to one based on less energy-intensive services, such as banking, finance, hospitality, retail, education and health. In recent years, increases in energy efficiency and residential solar PV have also likely contributed to negative growth rates in electricity consumption. The extent to which the historical decline in electricity consumption growth is likely to persist into the future is uncertain and unknown.[40]

Figure 2.2 NEM-states annual energy consumption growth rate 1960/61 to 2013/14 (with trend line)



Source: Department of Industry and Science, Australian Energy Statistics, Table L.

Integration with the existing LRET and legacy renewables

The existing LRET could be incorporated into the EIT mechanism or continue to operate alongside as a separate mechanism. A major benefit of incorporating the LRET into the EIT is to reduce the administrative complexity of operating multiple mechanisms and to promote a technology-neutral approach to emissions reductions. Under this approach,

40 Potential factors that may depress future electricity consumption growth include the ongoing transition to less energy-intensive services from more energy-intensive manufacturing. Potential factors working the opposite way could include the electrification of the transport sector

LRET generators would not receive large-scale generation certificates (LGCs), but instead receive AESCs of equal value.

In designing the existing LRET, the objective was, and is, to encourage additional renewable electricity generation, relative to what would occur in the absence of the LRET. To achieve this objective, baselines were specified for those renewable generators (mostly hydro generators) based on their output prior to the introduction of the LRET. These 'legacy' renewable generators (mostly hydro) were ineligible to create LGCs for generation up to their baseline.[41] Since reservoir sizes and inflows are independent of existing hydro generators' eligibility (or otherwise) to receive LGCs, legacy hydro generators' decisions to generate are unlikely to be impacted by whether or not they are eligible to receive LGCs. Therefore, making legacy hydro generation (in large part, belonging to taxpayers) eligible to receive LGCs would result in large windfall gains for these generators (funded by consumers across the NEM), for little or no additional emissions reductions.

This reason for excluding legacy renewable generation from receiving LGCs also applies to the rationale for excluding legacy renewable generation from receiving AESCs under the EIT mechanism: the need to incentivise additional emissions reductions relative to what currently occurs, as opposed to simply offering windfalls to existing plant.

We note that the treatment of legacy hydro generation is different from the treatment of generation from existing gas-fired generators. While both result in generation from low-emissions technologies, the variable costs of gas-fired generation are much higher than hydro generation (under normal rainfall conditions). A CCGT below an emissions intensity target of, say, 0.8t CO_2e/MWh would receive AESCs for each unit of output. Because of this, the CCGT would decrease its offers into the market to increase its chance of being dispatched and maximise AESC revenue. Unlike legacy hydro generators, existing gas generators' decisions to generate will be impacted by their eligibility to receive AESCs. If existing gas-fired generators were excluded from receiving AESCs, they would not have an incentive to lower their offers to increase output, resulting in higher-cost low-emissions technologies being required to meet the target.

It is worth noting that output from legacy hydro generators would still contribute to reducing the electricity sector's emissions intensity, and any credits generated (or excluded) would need to be considered in setting the emissions intensity target. If output from legacy hydro generators were to be excluded from certificate creation, this would reduce the supply of AESCs created, resulting in higher certificate and wholesale energy prices. One option to offset this price impact is to increase the emissions intensity target.

Another option is for the government to allocate AESCs equivalent to the output from legacy hydro generators to emissions-intensive trade-exposed industries (EITEIs), to provide assistance to EITEIs. EITEIs are Australian businesses competing in an

41 The total amount of legacy renewable generation exempt from the LRET is around 16TWh, of which 94 per cent (15TWh) is generation from hydro, with the remaining generation from landfill gas, bagasse, and biomass. For more details, see Climate Change Authority 2012, *Renewable Energy Target Review*, Final Report, p. 43.

international setting, and comprise businesses engaged in manufacturing activities, such as aluminium smelting, alumina refining, iron and steel manufacturing, packaging and paper manufacturing and others.[42] A further option would be for the government or appropriate regulatory body to sell on the market the credits that would be created by legacy hydro and use the funds generated for other purposes.

In the case that legacy hydro generation was eligible to create AESCs and EITEIs were to receive compensation in the form of AESCs, the emissions intensity target will need to be lowered to take account of the fact that additional AESCs, that do not reflect actual abatement, are needed to be allocated to EITEIs. That is, the emissions intensity target for the sector would need to be reduced in order to achieve the target amount of abatement. Overall, the result of this would be that penalties for high-emissions generation would be higher and, as a result, wholesale prices would also increase.

EITEIs would be allocated compensation in the form of AESCs, which they could then sell to high-emissions generators. This would represent an additional revenue stream for these businesses to compensate them for any increases in electricity prices as a result of the emissions reduction mechanism.

The general rationale for providing assistance to EITEIs is that these businesses are competing in an international setting where their competitors may not face a similar impost.[43] However, under an EIT the price effects would be minimal it would need to be determined the level of compensation that would be appropriate. As discussed in section 4.3.2, there is estimated to be sufficient AESCs to compensate EITEIs for any direct and indirect costs out to 2030.

Allocating AESCs to EITEIs would result in the potential windfall gain to legacy hydro that would occur if these generators were eligible to create AESCs instead flowing to EITEIs, where it would be likely to yield larger economic benefits.

Domestic and international linkage

The EIT mechanism could be linked with other domestic and/or international emissions reduction mechanisms by creating an arrangement through which AESCs are made interchangeable. Domestic and international linkage supports the achievement of an emissions target at the lowest cost for consumers. However, there are a number of potential impacts that are uncertain in nature and need to be considered, including what linkage means for how quickly the Australian electricity sector transforms, the credibility of international certificates imported into Australia, the potential structure of future domestic and international carbon markets, and how policy decisions by international governments could affect the achievement of Australian policy objectives.

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42 For a list of EITEIs exempt from the LRET see: http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/Industry-assistance/Industry-assistance-published-information/Emissions-intensive-trade-exposed-activity-summaries

43 Climate Change Authority 2012, *Renewable Energy Target Review*, Final Report, p. 94.

2.2 Extended LRET

Extending the existing LRET is considered by the Commission as the appropriate technology subsidy mechanism because it is an existing mechanism to support new renewable energy capacity and would therefore be relatively straightforward to implement.

Under the Extended LRET mechanism, the target remains a fixed amount of GWh of generation, reflecting the design of the existing mechanism. The target GWh amount under the Extended LRET mechanism is based on that amount of renewable generation needed to meet the 28 per cent emissions reduction target by 2030. This target amount of renewable generation is 86,000 GWh, based on AEMO's 2015-year forecasts of energy consumption in 2030.

2.2.1 How the Extended LRET works

The LRET works by creating a market for additional renewable energy that supports investment in new renewable generation capacity.

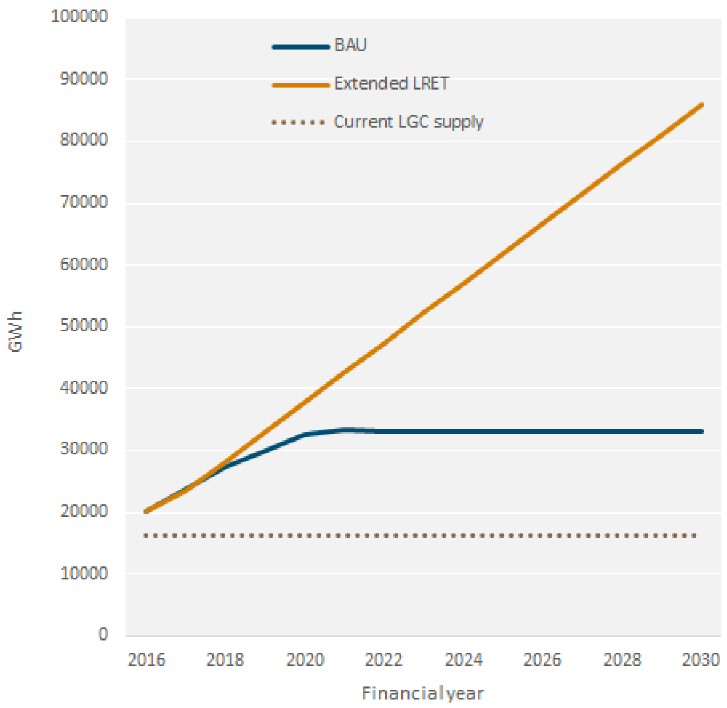
Accredited renewable energy generators create LGCs. Each certificate represents one MWh of additional renewable energy generated. LGCs can be sold or traded to liable entities, in addition to the renewable generator's sale of electricity in the NEM. The LRET places a requirement on liable entities (mainly electricity retailers) to source a percentage of their demand for electricity from renewable energy.[44] Liable entities must purchase and surrender LGCs created by eligible renewable generators to the Clean Energy Regulator each year.

The LRET supports investment in renewable energy projects by bridging the gap between the cost of renewable and thermal generation. The amount of LGCs that must be surrendered by liable entities is determined by the renewable power percentage (RPP). The RPP is a predetermined annual target to achieve the targeted output under the LRET. If a liable entity does not surrender the required number of certificates to the regulator, a shortfall charge applies.

The LRET targets for BAU and the Extended LRET scenario are shown in Figure 2.3. The generation target under the existing LRET (33,000 GWh) is shown in dark blue. As per the design of the existing LRET mechanism, the target peaks in 2020, with the mechanism ending in 2030. The generation target under the Extended LRET mechanism is shown in orange, with the target reaching 86,000 GWh in 2030.

44 Liable entities are classified as an individual or company who is the first person to acquire electricity in a grid which has installed capacity of 100 MW or more.

Figure 2.3 Renewable generation target for BAU and Extended LRET (GWh)



Source: Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

Under the LRET, eligible EITEIs may be issued with an exemption certificate that offsets the cost of purchasing LGCs.[45] The exemption is justified on the grounds that it offsets the reduced price competitiveness of Australian industries that compete in international markets against rivals that may not face a similar price impost.

Exempting EITEIs from any LRET liability also lessens the risk of carbon leakage. Carbon leakage is the shift of production of goods or services, and their associated greenhouse gas emissions, to another country. This can erode the effectiveness of Australia's emissions reduction efforts. While there is no risk of direct carbon leakage from the electricity sector—as there is no export or import of electricity from or to Australia—mitigation policies in the electricity sector can increase prices for electricity consumers. If the electricity price increases result in Australian businesses losing market share to international competitors, this could reduce output (and the associated emissions) in Australia, and increase output in other countries. If those countries do not have binding emissions constraints, the increase in output in those countries could also increase emissions, eroding the effectiveness of Australia's emissions reduction policy.

While the same mechanism could be continued under the Extended LRET, the Commission notes that exempting large users from meeting their liabilities under the mechanism results in the cost burden of the LRET falling on a smaller number of electricity consumers.

45 The exemption rate for EITEIs, the EITE exemption rate, was increased to 100 per cent in 2015, and applies for 2015 and all subsequent years. A 100 per cent exemption rate reduces an EITE's costs of purchasing LGCs to zero. For more details, see: http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/Industry-assistance

2.2.2 Setting the LRET

The current LRET is expressed as a fixed GWh target, as opposed to a percentage of annual energy consumption. When expressed as a fixed target, the LRET shifts demand risk from new entrant renewable generators to existing generators and consumers. It does this because, irrespective of demand and supply and price signals in the wholesale market, additional capacity will be built to meet the target.

In this sense, an Extended LRET policy with a fixed target is more like a capacity payment than allowing a market-based solution to develop, and therefore changes the approach to risk allocation that has been at the heart of the NEM since its inception.

For example, if demand is lower than anticipated when the target was set, and the target is not changed to reflect the lower-than-expected demand, existing generators face the risk of lower wholesale prices, while new entrant renewable generators are kept whole through the LGC subsidy, which is funded by consumers. The two opposing effects of the LRET – higher retail electricity bills due to the direct costs of the mechanism and lower wholesale prices due to an oversupply – can cause a wedge between the wholesale electricity price and the retail price paid by consumers. Over time, a properly functioning market is unlikely to be sustainable when price signals in the upstream segment of the market are not informing choices made by consumers in the downstream segment.

The size of the Extended LRET is based on AEMO's 2015-year forecasts for electricity consumption in 2030.[46] As AEMO's 2016-year forecast for consumption in 2030 is expected to be lower than its 2015-year forecast, this would mean that the target amount under the Extended LRET would need to be lowered below 86,000 GWh in order to meet hit the emissions reduction target. As forecasts of 2030 electricity demand can and do change from one period to the next, this can lead to changes in the size of the renewable energy target. Frequent changes to the target amount can increase investment risk for new- entrant generators. This highlights the inherent instability of the LRET (and Extended LRET) mechanism when used to achieve a specific emissions reduction target, due to the vulnerability of the target to changes in assumptions about future demand..

Conversely, keeping the renewable energy target amount unchanged is likely to result in the Extended LRET mechanism under- or overshooting the emissions reduction target. This creates uncertainty about whether the emissions reduction target can be achieved.

Setting a fixed renewable energy target that becomes detached from actual market outcomes, when actual outcomes differ from what was earlier expected, creates a situation where stakeholders begin calling for a review to adjust the mechanism, which creates investment uncertainty for the electricity sector. There have been numerous,

46 For more details, see Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

wide-ranging reviews of the LRET since its inception, the most recent one having been undertaken in 2014 led by a Commonwealth Government expert panel.[47]

In order to lower costs to consumers, an approach that could better integrate with the competitive wholesale electricity market is to set the target as a percentage of demand. As a percentage, rather than a fixed GWh number, the target automatically adjusts to changes in demand, requiring new entrant renewable businesses to bear the risk of demand being higher or lower than expected, placing them on a more equal playing field with non-subsidised generation.

To further support this approach, a gateway process similar to that discussed above under the EIT mechanism could be adopted to allow the target to be adjusted in line with changes in the energy market. A semi-regular and narrowly-defined process would support greater investment certainty for industry, compared to the unstructured wide-ranging reviews of recent times.

While a percentage-based target is preferable to a fixed-GWh target, even if a percentage-based target had applied during the current LRET, it is likely that it would have provided similar signals for investment in renewable generation as under the existing fixed-GWh target. Under either a fixed-GWh or percentage-based LRET, the wholesale market price is no longer the primary signal for new investment in renewable energy generation. Instead, the price signal is the LGC price and the target amount (or percentage), as generation under the RET is compensated through payments from retailers and other large users, in addition to the wholesale market revenue.

These other price signals, under the LRET, meant that renewable energy generators continued to enter the market, particularly in South Australia, despite lower wholesale market prices.

2.3 Jurisdiction-based renewable energy targets

Pursuant to the expanded terms of reference received by the Commission[48], the AEMC performed an initial assessment of three jurisdictional renewable energy schemes: ACT, Victoria and Queensland based on the information presently available about these schemes (Table 1). These schemes would, if implemented, jointly result in renewable generation comprising just over 40 per cent of electricity output in the NEM by 2030. This is a similar share, in aggregate, to what would occur under Extended LRET.

At this stage there is not sufficient information available on the design and implementation of all the jurisdictional-based renewable energy targets to enable quantitative modelling of their precise geographical impacts. It may be possible to conduct such an analysis in the future, if and when such information becomes available. In the interim, to the extent possible, we have drawn qualitative inferences about the effects of these schemes and indicated where additional modelling may be required.

47 Warburton review (Expert Panel) 2014, Renewable Energy Target Scheme, Report of the Expert Panel, Canberra.

48 Senior Committee of Officials, Modelling of Carbon Emission Reduction Scenarios in the National Electricity Market, Letter to Mr John Pierce and Dr Tony Marxsen, 20 September 2016.

Table 2.2 Jurisdictional renewable energy targets and mechanisms

NEM jurisdiction	Renewable energy target		Mechanism to deliver the jurisdictional RET	Proposed or implemented mechanism	Location of new RET-eligible plant
	Percentage of generation	By year			
ACT	100%^	2020	Reverse-auction; 2-way CfD*	Implemented	Anywhere in the NEM
Queensland	50%	2030	Not yet known	N/A	To be determined
Victoria	25% (40%)	2020 (2025)	Reverse-auction; 2-way CfD	Proposed	Victoria only

*CFD stands for Contract for Difference. Source: Jurisdictional websites

These three jurisdictional schemes appear to make local investment and labour market outcomes – the increase in jobs in the renewable energy sector – the primary objective of these schemes, with emissions reductions a lower-order objective.[49] A scheme with the primary objective of creating new renewable energy jobs is likely to deliver emissions reductions at a higher cost to consumers than a scheme with a primary objective of efficient emissions reduction. This is because schemes with a primary objective of encouraging investment in renewables will not (by implication) encourage other forms of emissions abatement, such as fuel switching from coal to gas, that involve non-renewable technologies and may be lower cost.

The ACT has implemented a reverse-auction mechanism, under which ActewAGL Distribution, the ACT government-owned distributor, enters into a long-term contract with a renewable energy generator. Any net payments by ActewAGL Distribution under this scheme result in an increase in the prices paid by electricity consumers.[50] Victoria has proposed a similar mechanism to achieve its renewable energy target. Queensland is yet to announce a mechanism to achieve its target.

Under a reverse-auction, renewable energy generators put forward bids for government funding based on a fixed price (or 'strike' price) per MWh of generation. The resulting contract-for-difference (CfD) entered into between the relevant government and the renewable generation proponent obliges the parties to make payments to each other based on the difference between the strike price in the CfD and a reference market price[51] (as well as potentially the sale of LGCs). Reverse-auctions differ from the mechanism used to deliver the LRET (and the Extended LRET). In the

49 For example, the Victorian Government's consultation paper on the mechanism to deliver its renewable energy targets estimates that its target will create 4000 jobs in 2024; no information is provided in that consultation paper on the emissions reductions that may be achieved by the scheme. For more details on the proposed mechanism for the Victorian scheme, see The Department of Environment, Land, Water and Planning 2015, Victorian Renewable Energy Auction Scheme, Consultation Paper, The State of Victoria.

50 Payments made by ActewAGL Distribution are passed on to consumers as an increase in network charges, which are a significant proportion of retail bills.

51 The reference price is typically based on the NEM settlement price.

former case, government directly subsidises the entry of renewable generators; in the latter case, the government obliges retailers, and hence ultimately their customers, and large customers to pay these subsidies via the purchase of LGCs.

Reverse auctions differ from the mechanism used to deliver the LRET (and the Extended LRET). In the former case, government directly subsidises the entry of renewable generators; in the latter case, the government obliges retailers, and hence ultimately consumers, and large customers to pay these subsidies via the purchase of LGCs.

The jurisdictional renewable energy targets, like the LRET, is expressed as a fixed amount (in GWh), and these amounts are government-determined. As discussed in Box 1.1 a key rationale for introducing competition in the wholesale electricity sector was the decentralisation of operational and investment decisions away from central authorities to commercial parties operating in a competitive market. Generation businesses may be no better at forecasting the future than governments; however, the important difference is that equity and debt holders of generation businesses bear the cost of any overinvestment, rather than consumers. The pursuit of profit, in combination with competition and capital market discipline, provide incentives to businesses to manage their risks. Under a regulatory approach, such as that used in the Extended LRET and jurisdictional renewable energy schemes, investment decisions are taken by a central authority that does not have the same incentives or ability to manage the associated risks. This means that the costs of any overinvestment are borne by consumers or taxpayers.

In addition, the reverse-auction mechanism, used to achieve jurisdictional renewable energy targets, reallocates price risk, and therefore much of the investment risk, from renewable energy generators to governments. This means that taxpayers or consumers ultimately bear the risk of wholesale price volatility in respect of the output of renewable generators underwritten by the CfDs.

In addition to differences in the size of the various jurisdictional targets shown in Table 2.2, another key difference between the jurisdictional schemes is the extent to which the respective targets and mechanisms are geographically-neutral. The proposed Victorian mechanism is based on renewable energy generators being developed in Victoria, while renewable energy generators under the ACT's RET can be located anywhere in the NEM. A non-geographically neutral scheme is likely to lead to higher resource costs being incurred, and higher prices for consumers of that jurisdiction, than a geographically-neutral LRET. It will also lead to the geographical distribution of renewable generation resulting from the jurisdictional schemes differing from the geographical distribution under the Extended LRET.

The potential impact of the Extended LRET, including the potential impact of the jurisdictional RETs, on the achievement of the energy and emissions reduction objectives is discussed in Chapter 4.

2.4 Regulatory Closure

The Regulatory Closure mechanism has been designed to represent a forced closure approach to staged generator exit. The modelling to support the analysis for this approach does not consider a specific government policy chosen to implement closures.

Instead, the modelling focuses on the market impacts of a closure policy relative to BAU and the other mechanisms.

2.4.1 How Regulatory Closure works

The closure of existing high-emissions thermal generators can be managed by government regulation in a number of different ways. Two policies in particular that have been publicly discussed are the Contract for Closure Program and a voluntary auction process.

In 2011/12, the Commonwealth Government implemented the Contract for Closure Program, which aimed to negotiate the orderly exit of around 2,000 MW of high emissions-intensive coal-fired generation capacity from the NEM. The program consisted of a voluntary process, where a generator negotiated a price with the Commonwealth Government, and entered into a contract with the Government under which that generator received a payment from the Government to close down.

The objective of Contract for Closure Program was to:

- provide certainty about the timing of retirements which can allow participants to make informed investment decisions about new capacity;
- manage retirements in an orderly fashion to ensure that sufficient generation capacity was available to meet demand; and
- achieve value for money from negotiated closures.

Ultimately, the Commonwealth Government did not pay any generators to close as it was unable to agree on a price that, from the Government's perspective, represented value for money. It should be noted that, of the five generators that entered into negotiations to close, three have subsequently left the market without government payment.[52]

Attention has recently been given to a regulatory closure mechanism which would operate through a reverse-auction process.[53] Under this approach, coal-fired plant would bid competitively over the payments they would require for closure. The regulator would determine the auction result based on the most cost-effective bid. The payment required to close the power station is made via a tax or a vey on the remaining power stations, rather than government, in proportion to their CO_2e emissions.

Irrespective of the closure policy implemented by government, there would likely need to be complementary policies in place to safeguard the emissions reductions. Measures would need to be developed to prevent the high-emitting generators that exited the market from returning at a later date and the remaining high-emissions plant from increasing output to compensate for the closed generators, i.e., an intervention in the market.

The assessment of the Regulatory Closure emissions reduction mechanism assumes a mechanism is in place such that a sufficient number of high-emitting power stations are

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52 These generators are Playford B, Collinsville and Energy Brix.

53 Frank Jotzo and Salim Mazouz, *Brown coal exit: a market mechanism for regulated closure of highly emissions intensive power stations*, Economic Analysis and Policy, 48(2015), pp.71-81.

closed in order to meet the emissions reduction target. Compensation that governments or other generators may need to pay generators to close has not been estimated or incorporated into the results. Compensation is not an economic cost, rather it is a transfer from taxpayers to generators, or a transfer between generators. Nevertheless, the extent of these distributional impacts may be relevant to policy-makers when comparing the various mechanisms.

2.4.2 Determining the level of capacity to close

Under the Regulatory Closure mechanism, a central authority is required to determine the level of capacity to close and the timing of when that capacity should close. Such decisions necessarily depend on forecasts of a range of variables. For example, a key variable is future energy consumption. If actual energy consumption turns out to be lower than forecast, then governments may have paid for more capacity to close than was required to meet the emissions reduction target. In this way, the risk associated with disinvestment is partly transferred from generators to taxpayers.

The timing of closures is also important. Under a market-based mechanism, generation businesses optimise the closure of their generation units based on a wide range of factors, including fixed and variable costs and the prices they are able to achieve in the contract and spot markets. Closure may be brought forward or delayed in response to market signals, resulting in the lowest-resource cost outcomes for consumers. This type of flexibility may not be available when a regulatory approach is adopted.

When governments indicate they are considering regulatory closure policies, generators that may have exited in response to price signals may choose to remain in the market with the expectation of receiving a payment. In this sense, regulatory closure policies risk embedding within the NEM a barrier to generator exit. Instead of solving a perceived barrier to exit, regulatory closure could in fact create one, resulting in higher costs for consumers in the long run.

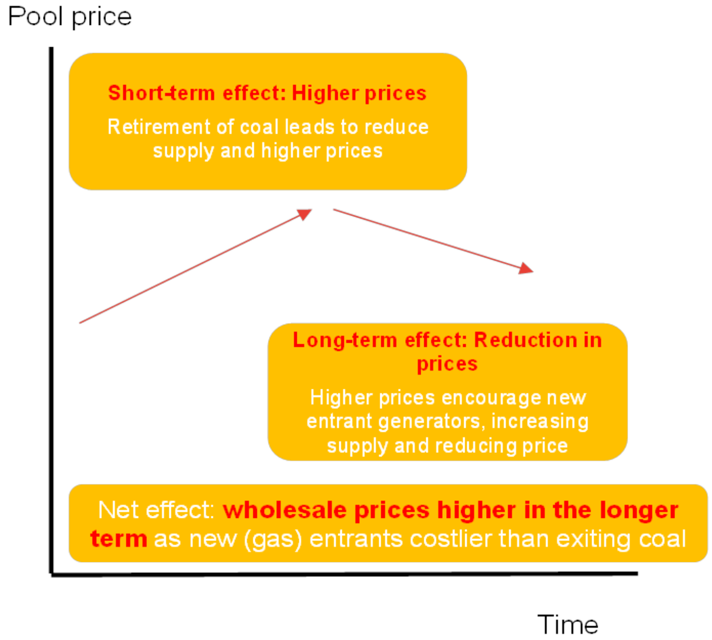
2.5 Effects of the LRET and Regulatory Closure on wholesale prices

Both the Extended LRET and Regulatory Closure policies ultimately increase wholesale electricity prices relative to BAU. In the short term, the direction and trajectory of the wholesale price effect associated with each of these policies is, however, in opposite directions, given the impact on the amount of generation capacity in the market.

Regulatory Closure forces high emissions plant to exit and therefore reduces the generation capacity in the market. This leads to a reduction in the supply of available generation, increasing wholesale prices. The increase in the wholesale price can be expected to induce new capacity (such as gas and renewables) to enter the market. In the long term, it is expected that new capacity will continue to enter the market until supply is sufficient to meet demand.

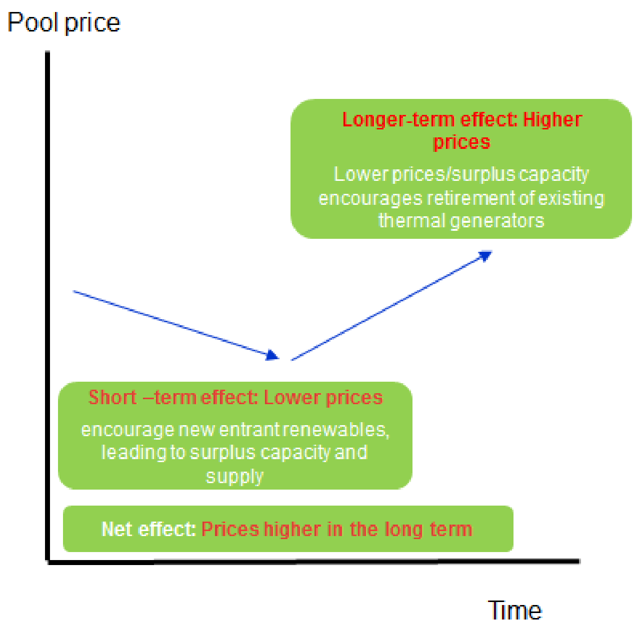
The wholesale price trajectory associated with the regulated closure policy is illustrated in Figure 2.4.

Figure 2.4 Mechanics of Regulated Closure



The wholesale price trajectory associated with the LRET policy is illustrated in Figure 2.5.

Figure 2.5 Mechanics of the LRET



Under the LRET (and the Extended LRET), it is the availability of LGC revenue (which can be earned in addition to revenue earned through the wholesale price) that encourages renewable generation to enter the market. The new entrant renewable generators increase the supply of generation capacity, which causes the wholesale electricity price to fall in the short term. New entrant renewable generators, such as wind generation, typically have low variable costs, which mean they displace higher-cost thermal plant in the merit order. This 'merit-order effect', in combination with extra capacity, can lead to a fall in the spot price in the short term. Lower spot prices, in turn, may encourage the exit of some existing thermal generators that do not receive LGC revenue if they cannot recover fixed operating and maintenance costs.

The retirement of these thermal generators reduces the supply of generation capacity in the market and leads to an eventual increase in the wholesale price. This will tend to reverse the previous reduction in wholesale prices.

It is worth noting that the effects on wholesale prices under the LRET do not determine outcomes for end-consumers. This is because retailers are also liable for the costs associated with purchasing LGCs, a cost which is passed on to consumers through increases in retail prices. Therefore, in order to understand the consumer impacts of the LRET mechanism, it is necessary to consider the wholesale price combined with the LGC price. It may well be the case that the LRET leads to a net increase in retail prices, even in the short term, as the cost of the LGCs more than offset the fall in wholesale prices. Furthermore, as noted above, any reduction in wholesale (and potentially also retail) prices is unlikely to be a longer-term phenomenon. This is because generator retirement leads to an increase in both wholesale and retail prices, imposing higher long-term costs on consumers than potentially would occur under other emissions reduction mechanisms. The estimates of the costs of the various emissions reduction mechanisms are discussed in Chapter 4.

The jurisdictional-based renewable energy targets are likely to affect wholesale market prices in a similar way as the Extended LRET, in both the short and longer term. The increase in net renewables targets brought about by these schemes (where the scheme targets are additional to the national LRET) are unlikely to result in continued falls in wholesale prices. This is because any further reductions in expected wholesale prices would be likely to bring forward retirement decisions by existing thermal generators, offsetting any short-term merit-order effect.

As discussed in section 2.2.2, governments are not as well-placed as market participants to manage wholesale market investment risks faced by generators. This means that government takes on generators' investment risk through the CfD mechanism. This is likely to lead to greater long-run costs for consumers than a market-based emissions reduction mechanism.

3 Assessment framework

The AEMC's role is to promote efficient, reliable and secure energy markets that serve the long-term interests of consumers, in accordance with the National Electricity Objective (NEO).

When analysing the impacts of emissions reduction mechanisms on consumers and the NEM, the Commission has applied the NEO as well as several market design principles that support satisfaction of the NEO. These principles are discussed further below and include technological and geographical neutrality, appropriateness of risk allocation, implementation flexibility, and the adaptability and sustainability of the mechanism to be able to meet its policy objective over time.

The assessment in this report is informed by both qualitative and quantitative indicators that seek to measure and understand costs, risk allocation, incentives and impacts on wholesale and retail prices. Qualitative analysis on these indicators was undertaken in order to understand likely outcomes, with electricity market modelling used to confirm and estimate the results where possible.

Electricity market modelling provides a simplified environment within which the impacts of emissions reduction policies on the electricity sector can be assessed. Market modelling is best suited to understanding factors such as changes in wholesale prices, resource costs, cost of abatement and investment and retirements from a counterfactual - in this case BAU. Because the modelling results are dependent on input assumptions, it is more reliable to assess the *relative change* in outcomes from BAU and not the absolute levels of the outcomes.

3.1 National Electricity Objective

When undertaking rule changes, reviews and advice related to the NEM, the Commission is guided by the NEO which is set out in section 7 of the National Electricity Law:

> "The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.""

The NEO is structured to encourage energy market development in a way that supports the:[54]

1. efficient allocation of electricity services to consumers that value them the most, typically through price signals that reflect underlying costs;
2. provision of, and investment in, electricity services at lowest possible cost through employing the least-cost combination of inputs; and

54 These three outcomes are commonly referred to as allocative, productive and dynamic efficiency, respectively.

3. ability of the market to readily adapt to changing supply and demand conditions, and the preferences of consumers, over the long-term by achieving outcomes 1 and 2 over time.

The three limbs of efficiency described above are generally observable in a well-functioning, workably competitive market. Together they work to promote the long-term interests of consumers by supplying safe, secure and reliable electricity services at the lowest possible cost, over time.

The Commission considers that the effective integration of electricity and emissions reduction policy is most likely to occur in accordance with the NEO where the following supporting mechanism design principles are adopted:

- **Technologically-neutral** - an emissions reduction mechanism that recognises abatement brought about through the greatest variety of technology options will help minimise the long term costs to consumers of meeting the emissions target.
- **Geographically-neutral** - an emissions reduction mechanism that is indifferent to where generation technology options are to be located in the NEM, and allows the locations selected to be an outcome of the trade-off between economic costs and benefits, is likely to minimise costs for consumers.
- **Appropriateness of risk allocation** - an emissions reduction mechanism should allocate risks to those parties best-placed to identify and respond to risks in an efficient manner.
- **Contract market liquidity** – an emissions reduction mechanism that, through its effect on the technology of the generation stock, preserves or enhances contract market liquidity will assist participants to manage risks efficiently for the long term benefit of consumers.
- **Implementation flexibility** - the extent to which an emissions reduction mechanism can be implemented in a manner that automatically adjusts or ‘self-corrects’ in the face of changing demand, cost or other system conditions.
- **Adaptability and sustainability of mechanism design** - investors need a level of confidence that the objectives of any policy can be met and that the mechanism for achieving the objectives is sufficiently robust to deal with changes in energy market conditions or emissions reduction targets without succumbing to calls for the mechanism to be altered or replaced. This requires that the acceptability of outcomes generated by the mechanism should not be predicated on a single view of the future, whether that be a specific demand forecast or relative technology and fuel costs, or the abatement target itself. Rather, investors will need to be satisfied that the mechanism can yield predictable and politically palatable outcomes given different market conditions and policy targets. Without confidence in the resilience of the mechanism, investment will not be forthcoming and it is likely that neither the emissions reduction nor wider energy policy objectives (as embodied in the NEO) will be met.

3.2 Assessment framework indicators

When applying the NEO and market design principles, the analysis will be informed by quantitative and qualitative indicators, such as those set out in Table 3.1.

Qualitative analysis is carried out on aspects of the policies that cannot be easily measured. These include whether emissions reduction mechanisms operate in a technologically- and geographically-neutral manner, how incentives to enter and exit the market may have changed, and how investment risks have been allocated.

Quantitative outputs from electricity market modelling provide insights into changes in prices faced by consumers across the scenarios, as well as resource costs, the cost of abatement and other indicators.

The adaptability – and hence sustainability – of an emissions reduction mechanism to dealing with changes in market conditions and policy targets is another key criterion which will be informed by both quantitative and qualitative analysis.

Table 3.1 Scenario analysis indicators

Indicators	Type of analysis	Section of report
Certainty of achieving the emissions reduction objective	Qualitative	4.1
Technological and geographical neutrality		4.2
Risk allocation and contract market liquidity		4.3
Implementation issues		4.4
Wholesale price impacts	Quantitative	4.5.2
Investment, retirement and output		4.5.3
Resource costs		4.5.4
Cost of abatement		4.5.5
Adaptability and sustainability assessment	Qualitative and quantitative	5
Achievement of the National Electricity Objective	Qualitative	4.6

4 Base case findings and analysis

This chapter provides a qualitative and quantitative assessment of the three emissions reduction mechanisms against BAU using the framework outlined in Chapter 3.

Sections 4.1 to 4.4 provide a qualitative assessment around the degree to which each mechanism contributes to the achievement of the emissions reduction objective and satisfies the key market design principles that support the NEO.

Section 4.5 presents and discusses quantitative estimates of the impacts of different emissions reduction mechanisms, informed by electricity market modelling. The modelling presented includes a base case, which represents the most likely view of the future in the absence of any new emissions reduction mechanism. Section 4.6 summarises the base case findings and analysis, and discusses which of the three emissions reduction mechanisms best contribute to the achievement of the emissions reduction and energy objectives.

In addition, Chapter 5 provides a qualitative and quantitative assessment of the adaptability of each of the emissions mechanisms to alternative assumptions about future demand, emissions reduction targets, and other key variables.

4.1 Certainty of achieving of the emissions reduction objective

For an emissions reduction mechanism to be successful, it needs to be able to meet its objectives in the face of a changing and uncertain future. Without this ability to adapt when the future does not turn out as expected, investors may begin to expect that a emissions reduction mechanism may be changed in light of the actual outcomes, for example if demand is lower than anticipated at the outset of the policy. This may lead to investors not having the confidence to invest in new generation capacity.

While the three emissions reduction mechanisms have been designed to achieve a electricity sector target consistent with a national reduction of 28 per cent on 2005 level emissions by 2030, how the different mechanisms work influences how certain the emissions reductions will likely be.

While the Commission has been asked to consider emission reduction mechanisms that apply to the wholesale electricity generation sector, this does not preclude the implementation of complementary national policies that apply outside the supply side of the sector, such as the National Energy Productivity Plan. A sectoral approach also does not preclude the implementation of different emissions reduction mechanisms outside of the electricity sector that act on other parts of the economy, such as fugitive emissions, agriculture and transport.

4.1.1 Emissions Intensity Target

EIT is a mechanism where generators below the target receive a market payment for producing electricity in the form of AESCs, while generators above the target face an additional cost of having to purchase AESCs. This results in a relative shift in the merit order, with renewable energy and CCGT generation becoming less expensive and displacing higher emissions black and brown coal.

Under EIT, as the mechanism for reducing emissions is embedded in the wholesale electricity price, the emissions reductions are certain over the long term. For instance, if the emissions intensity target was to plateau at 2030, the mechanism would effectively act as a cap on emissions in the electricity sector. If the target continued to reduce, emissions would decrease as well.

A key challenge for the EIT mechanism is uncertainty around future annual energy consumption, as this is used to calculate the emissions intensity target as follows:[55]

$$\frac{Absolute\ annual\ emissions\ target\ (tonnes\ \ CO_2)}{Forecast\ annul\ energy\ consumption\ (MWh)}$$

While the absolute annual emissions target is known and set by government, annual energy consumption forecasts are subject to error. If an emissions intensity target trajectory is set for, say, 10 years into the future to provide certainty for investors, then to the extent actual energy consumption is different to forecast, emissions will be above or below the target.

For example, say an emissions intensity target of 0.81t CO_2e/MWh was calculated based on an absolute emissions target of 174 Mt divided by forecast energy consumption of 215 TWh. If energy consumption turned out to be lower at, say, 210 TWh, and the emissions intensity target remained at 0.81, then CO_2e emissions would be 4 Mt below the target. If energy consumption turned out to be 220 TWh, then emissions would be 4 Mt above the target.

As discussed further in section 4.4, this issue can be resolved by utilising gateways to mechanistically adjust the emissions intensity trajectory in response to changing energy consumption.

The Commission notes that AEMO's annual energy consumption forecasts in the NEM have tended to historically overestimate future demand, with Queensland and New South Wales showing the strongest bias[56]. When annual energy consumption is lower than forecast, this results in actual emissions reductions exceeding those required to meet the emissions objective, as the emissions intensity target will be set lower than required.

Figure 4.1 shows the percentage error for AEMO's annual energy consumption forecasts for New South Wales, which is currently the largest NEM region by energy consumption. Negative values indicates an overestimate (that is, actual demand is less than forecast), and positive values indicate an underestimate.

Based on these outcomes, it is most likely that emissions within the five-year periods where the intensity trajectory is fixed will be lower than expected. This means that the EIT is likely to deliver more emissions reductions than was the target in a given period. If this trend was to reverse and future forecasts were to underestimate actual energy consumption, the use of international permits could also be considered as a mechanism

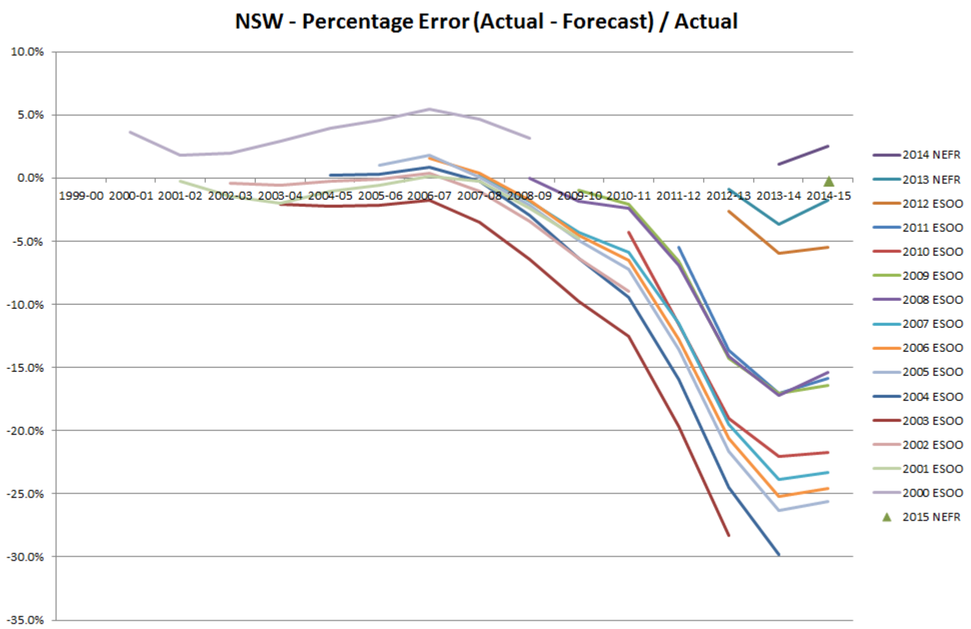
55 'Demand' and 'energy consumption' are referred to interchangeably in this report.

56 It should be noted that, given the asymmetric risk involved with forecasting electricity demand, there is a tendency in the electricity industry to be conservative in any assumptions used to forecast electricity demand.

to make up for the shortfall of emissions reductions, alongside the gateway review process.

As the emissions intensity of the sector declines, any risk associated with demand forecasting errors should also decline as variations in demand will lead to smaller variations in emissions.

Figure 4.1 Annual electricity consumption forecast error - New South Wales



Source: AEMC analysis based on AEMO ESOO and NEFR data.

4.1.2 Extended LRET

Under the Extended LRET, the target for renewable energy is increased to 86,000 GWh in 2030 such that emissions in 2030 are 28 per cent below 2005 levels. As mentioned above, the size of the Extended LRET is based on AEMO's 2015-year forecasts for electricity consumption in 2030[57].

Outside of a modelling environment, the ability for Extended LRET to meet and sustain an emissions reduction target is less certain than under EIT. If the target is expressed in fixed GWh terms, then emissions may under or over shoot depending on changes in demand. In a situation where actual demand turns out to be lower than forecast, a fixed GWh target risks consumers facing substantial costs of building new renewable capacity that is not required to meet a given emissions reduction target. For example, as AEMO's 2016-year forecast for consumption in 2030 is lower than its 2015-year forecast. If the target amount under the Extended LRET were to be based on AEMO's 2016-year forecasts, then the target amount would need to be lowered below 86,000 GWh in order to meet the emissions reduction target.

To resolve this issue, setting the Extended LRET as a percentage of demand, as opposed to a fixed GWh number, will increase the likelihood of the emissions reduction target being met. Under this approach, a calculation is made as to what percentage of

57 For more details, see Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

renewable energy in the power system is expected to result in the emissions target being achieved. As the target is set as a percentage of demand, the level of renewable energy required automatically adjusts to demand, while also appropriately allocating demand risk to the generators and not consumers. This approach, along with the implementation of structured reviews to make the mechanism more flexible, is discussed further in section 4.4.

A positive feature of Extended LRET is the certainty that a level of renewable energy will be produced and the required capacity to deliver this output will be built. However, unless the mechanism continues to be extended, there is a risk that, when the target plateaus, existing higher emissions generators increase output and/or retired plant come back online to meet any growth in demand.

As meeting and sustaining the emissions target is less certain, the Extended LRET also results in uncertainty for investors. This uncertainty exists because the target will likely need to be updated on a regular basis to continue achieving the emissions objective. Without an existing process in place that has a specific and targeted terms of reference, these reviews will likely happen on an ad-hoc basis, with the entire scheme up for review and subject to influence by competing interest groups.

4.1.3 Jurisdiction-based renewable energy targets

As discussed in section 2.2.3, three NEM jurisdictions (ACT, Queensland, and Victoria), have either introduced or proposed renewable energy targets, and mechanisms to deliver these targets. These jurisdictional-based targets and supporting mechanisms are outside of the existing LRET, and therefore provide additional support to investment in new renewable generation technologies.

The ACT's reverse-auction mechanism and two-way CfD is likely to be successful in achieving the ACT's renewable energy target, because it directly underwrites the entry of sufficient renewable generation to meet the target. Although its details are less certain, Victoria's proposed two-way CfD reverse-auction scheme is also likely to achieve the relevant target. However, given that Queensland is yet to announce a mechanism to deliver their renewable energy target, it is too early to say whether it is likely to be successful.

In future, these state-based schemes could be modelled as separate additional policies to the LRET once full details are known regarding (a) any technology quotas between large scale wind and solar within the state targets and (b) the extent to which any LGCs created by projects eligible for the Victorian and Queensland schemes are used to contribute to the LRET, or are voluntarily surrendered.

4.1.4 Regulatory Closure

Regulatory Closure is not well-suited to meeting specific emissions reduction targets, as it has similar issues to the Extended LRET in terms of certainty of achieving the emissions reduction objective. While Regulatory Closure provides certainty in the short term that generators will close, there is a risk that remaining high emissions generators increase their output, resulting in emissions rising above the target.

Depending on how the closure mechanism is implemented, there is a risk that closed generators reopen at some point in the future if the market environment changes, creating uncertainty for investors in new generation capacity. Separate mechanisms would need to be developed to protect against these issues for the mechanism to sustainably meet the emissions reduction objective over time.

Where governments pay generators to close, there is a risk that governments could pay for too much or too little capacity to retire if demand is lower or higher than expected, respectively. This could result in either a costly outcome for consumers, or alternatively, in the emissions reduction objective not being met[58].

A further concern is that government payments to close generators risks embedding a barrier to exit, with generators no longer responding to price signals, but instead responding to, and waiting for, announcements from government. There may also be questions of additionality, which relates to whether the closure payments deliver closures additional to what would be expected in the absence of any payments. This issue is discussed further in section 4.3.3.

4.2 Technological and geographical neutrality

An emissions reduction mechanism that recognises abatement brought about through the greatest range of technology options will help minimise the long-term costs to consumers of meeting the emissions reduction target, compared to mechanisms that restrict the range of options. Long-term costs will also be minimised by those emissions reduction mechanisms that are indifferent to where generation technologies are to be located, and allows the locations selected to be an outcome of the trade-off between economic costs and benefits.

4.2.1 Emissions Intensity Target

The EIT mechanism is technologically-neutral, as it supports the lowest-cost technology to meet the emissions constraint, whether that is fuel switching from coal to CCGT and/or building renewable energy capacity. This is a no-regrets option[59], so even under different gas and renewable cost assumptions, this will still favour the lowest-cost options. The EIT mechanism is also geographically-neutral, as the choice of locations for the new generation capacity in the NEM (or the SWIS) is selected solely on the basis of a cost-benefit trade-off.

4.2.2 Extended LRET

While the Extended LRET mechanism is geographically-neutral, it is not technologically-neutral as it incentivises investment only in renewable energy generation technologies, to meet the emissions reduction target. To date, the existing LRET has mostly subsidised growth in wind capacity, which is currently the lowest-cost

58 Regulatory closure is not a market-based mechanism for emissions. Even if, for example, a tender for closure is conducted, there is no direct market for emissions. Hence, decisions around the MW of capacity to close (and when) require an administrative intervention.

59 A no-regrets option is an emissions reduction option that has negative net costs. That is, the direct or indirect benefits that it creates are large enough to offset the costs of implementation.

renewable technology, though the LRET is designed to encourage investment in all forms of renewables, such as solar and hydro plant.

Investment in reducing the emissions intensity of CO_2e -emitting generation technologies, such as fuel switching from coal to CCGT, is not supported under Extended LRET. As these forms of abatement (especially fuel switching) can be relatively low-cost, yet are not supported by the Extended LRET, this means that this mechanism is likely to result in higher longer-term costs to consumers compared to EIT.

Results from electricity market modelling indicate that onshore wind will likely continue being built to meet an Extended LRET. As the mechanism is not technology neutral, it is not the lowest cost way of achieving the emissions target, being over twice as expensive on a cost of abatement measure as EIT, as discussed in section 4.5.

4.2.3 Jurisdiction-based renewable energy targets

Unlike the LRET and the ACT renewable energy target, the Victorian scheme relates to new renewable energy generation capacity being installed solely in Victoria. Under the proposed design of the Victorian scheme, up to 20 per cent of generation will be reserved for large-scale solar. However, Victoria is unlikely to be the best location for most of this solar generation. This is borne out by submissions to the Australian Renewable Energy Agency (ARENA)'s latest competitive funding round for large-scale solar projects, where no Victorian sites were provided funding.[60]

Mandating solar to be installed solely in Victoria to satisfy the 20 per cent generation mix target is likely to result in higher costs than if the Victorian scheme was to award funding on a geographically-neutral basis. Costs are likely to be lower if this 20 per cent target allowed new solar capacity to be installed anywhere in the NEM.

If the Victorian mechanism was geographically-neutral, it could also allow renewable generation capacity to be built in those locations where there are relatively few network constraints or congestion, especially if the costs of network augmentation are factored into the reverse auction bids. This would be likely to lead to better outcomes, in the form of lower resource costs, for consumers. The Commission supports the need, as reflected in the auction evaluation principles for the proposed Victorian mechanism, for government, when considering alternative tenders, to take account of the network and broader system costs from installing more intermittent generation capacity at a particular location[61].

4.2.4 Regulatory Closure

Regulatory Closure can be both technologically- and geographically-neutral as it does not place restrictions on the types of generation technologies that could enter the market to replace those high-emissions generators that close under the mechanism.

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60 Victorian sites comprised less than 15 per cent (in MW terms) of submissions. Queensland-located sites were the highest share (48 per cent, in MW terms), followed by New South Wales-located sites (33 per cent). For more details, see: http://arena.gov.au/programs/advancing-renewables-program/large-scale-solar-pv/

61 The Department of Environment, Land, Water and Planning 2015, Victorian Renewable Energy Auction Scheme, Consultation Paper, The State of Victoria, p. 13

However, as discussed in section 4.1.3, Regulatory Closure is not well-suited to meeting specific emissions reduction targets, as there is a risk that remaining high-emissions generators increase their output, resulting in emissions rising above the target. As this does not establish a direct market for emissions (or intensity), it still requires administrative decisions on the level of capacity to be closed to meet approximate emissions goals.

4.3 Risk allocation

The NEM is designed in a manner such that generators make investment and retirement decisions based on price signals in the spot and contract markets, and face the outcomes of their decisions. If electricity demand, fuel costs, or other variables are higher or lower than expected, the primary implications for plant profitability are borne by generators, rather than consumers or taxpayers. This is appropriate because generation businesses have the expertise, information and commercial incentives to manage such risks efficiently. In this way, the risk of changes in different variables is appropriately allocated to generators, rather than customers, which helps promote the NEO.

4.3.1 Emissions Intensity Target

The EIT maintains the existing pricing and risk management mechanisms in the NEM for signalling whether new investment is required and whether generators should exit. It does this by changing the *relative* costs of different generation technologies on the basis of each technology's emissions intensity, thereby maintaining the balance of incentives and risks that ordinarily prevail in the wholesale market. While the EIT will change the relative costs of the generation technologies in line with their respective emissions intensities, investors will continue to be responsible for managing risks associated with demand, fuel costs and plant fixed costs diverging from forecast levels.

As the efficacy of the price signal in the wholesale market is preserved, the allocation of risk between generators and consumers does not change. Generators continue to make investment and retirement decisions based on price signals in the wholesale spot and contract markets. Furthermore, the EIT does not negatively impact the liquidity or availability of hedging contracts for market participants, as this emissions reduction mechanism does not directly subsidise investment in new renewables. In contrast, Extended LRET is likely to negatively impact contract market liquidity, as discussed below.

4.3.2 Extended LRET

The LRET provides an incentive for investment in renewable energy technology by requiring liable entities to source a proportion of their electricity consumption from renewable sources. Eligible generators create LGCs that liable entities, such as retailers and large direct wholesale market customers, purchase, with this additional cost passed through to consumers through retail electricity bills.

If growth in annual energy consumption is low, subsidising the uptake of renewable energy generation can be expected to place downward pressure on wholesale electricity prices in the short term. As wind generation has low variable costs, it displaces higher cost thermal plant in the merit order of generators. This is known as the 'merit-order effect'.[62]

The net cost to consumers will depend on the extent to which the merit-order effect offsets the additional LGC cost, which also depends on the behaviour of existing generators in the market. If some of these generators close, as we have recently seen in the NEM, then this will reduce supply and put upward pressure on wholesale prices, increasing the costs faced by consumers.

Depending on the design, Extended LRET could also change the risk allocation and incentives faced by existing generators, consumers and new entrant renewable generators. If the LRET is expressed as a fixed GWh number, then irrespective of demand and supply and price signals in the wholesale market, additional capacity will be built. This takes the demand risk away from new entrant renewable generators and transfers it to existing generators and consumers.

For example, if demand is lower than anticipated, existing generators face the risk of lower wholesale prices, while new entrant renewable generators are kept whole through the LGC subsidy, which is funded by consumers. This may lead to pressures for the Extended LRET to be reduced. Conversely, if demand is higher than anticipated, this may lead to pressures for the Extended LRET to be increased. It is extremely difficult for investors in the thermal generation, such as combined cycle gas turbines – which are needed to complement wind and other forms of intermittent generation - to manage these kinds of regulatory risks. Investors in such assets require a reasonable degree of market, policy and regulatory certainty, given the long lives of power stations and the high level of capital involved. The greater the uncertainty, the higher the risk premium and rate of return required by investors, and therefore the higher the cost for consumers. If the risk is deemed too high, it is possible that investment may not occur. It can also raise the cost of maintaining power system security, as discussed below.

When new investment is required, investors may not be forthcoming without government support through a subsidy. Investment risk becomes gradually transferred to consumers, where governments determine renewable energy targets and consumers face the costs of inefficient decisions.

Under the LRET, the wholesale market price is no longer the primary signal for new investment in renewable energy generation. Instead, the price signal is the LGC price and the target amount (or percentage), as generation under the RET is compensated through payments from retailers and other large users, in addition to the wholesale market revenue.

These other price signals have meant that renewable energy generators have continued to enter the market, particularly in South Australia, despite lower wholesale market prices. The resulting exit of existing generators has had significant impacts on wholesale market prices in both the energy and ancillary services markets. These impacts have been as follows:

62 It is important to note that the merit-order effect does not decrease the total cost of the LRET; it represents a transfer from existing generators, who receive lower pool prices, to consumers.

- An increase in both the level and volatility in wholesale energy prices, due to a combination of lower supply, increased reliance on more expensive gas generation (particularly in South Australia), and a greater share of intermittent generation in the generation mix. Higher and more volatile market prices have increased the price of forward contracts, and have also offset the short-term merit order effect.
- A lack of liquidity in the forward contract market, which has exacerbated the rise in forward prices. Retailers and generators are typically incentivised to enter into long-term contracts to minimise price risk. However, generators that also receive LGC revenue have less incentive than other generators to enter into contracts, as the LGC revenues mitigate these generators' exposure to wholesale energy prices. Furthermore, as traditional generators retire, and more capacity comes from renewables, fewer generators are available to offer contracts, further raising the cost of forward contracts.

The exit of synchronous generators in South Australia has reduced competition amongst suppliers of frequency control and ancillary services (FCAS), raising the market price of FCAS. The exit of synchronous generators has also reduced the system's inertia, making it more susceptible to large changes in frequency from unexpected changes in electricity demand or supply. These impacts on risk management and risk allocation are unintended consequences of the LRET, and are impacts likely to be even more consequential under the Extended LRET due to the even higher rates of penetration of non-synchronous generation under that emissions reduction mechanism.

4.3.3 Jurisdiction-based renewable energy targets

The above impacts on the energy and ancillary services markets are likely to also occur, perhaps to an even greater extent, under the jurisdictional renewable energy targets. Where jurisdictional-based renewable energy targets are additional to the LRET the cumulative target for renewable generation is increased, leading to more renewable capacity entering the market.

For a renewable energy generator, the CfD payment associated with generating one MWh of electricity should represent the cost of investing in the most efficient renewable energy technology, net of the expected wholesale market price (and the LGC price). For instance, if the cost of new entrant wind is $100/MWh and the wholesale spot price is $60/MWh (including the LGC price), then the CfD payment will be $40/MWh. If investment in renewable energy continues to be made in an already oversupplied market, the wholesale price can be expected to continue to fall. However, LGC-eligible new entrants will be largely insulated from this impact, as the CfD payment rises to offset the falling wholesale price.

In this respect, the risk of lower wholesale prices as a result of an over-supplied market is transferred to existing thermal generators, and also transferred to customers in the form of rising CfD payments (which is the difference between the fixed price and the wholesale price) from government to generators.

The ACT and Victorian renewable energy mechanisms seek to award funding on a CfD basis, under which the price that a successful renewable energy generator receives would be effectively fixed. By fixing the price for generation, a CfD reduces the investment and financing risk for generators. However, this risk is not eliminated; instead, this reduced risk is simply transferred from the relevant renewable generators to government and, through changes to retail prices, to consumers. Consumers face the risk of high and rising CfD payments in the event that the strike price remains above the reference price. This is likely to occur, at least in the short term, due to the merit-order effect.

The Commission considers that market participants are better-placed than government or consumers to manage the risks faced by renewable energy generators wishing to enter the wholesale electricity market. Market participants, like retailers, manage wholesale price and volume risks as a natural part of their business, and are the more appropriate counterparty to generators than governments. Risk-sharing amongst market participants is common practice in the NEM, through the use of power-purchase agreements, forward contracts, and other derivatives.

4.3.4 Regulatory Closure

Like the Extended LRET, Regulatory Closure transfers risks away from the relevant generators to other parties. In cases where Regulatory Closure results in payments made to generators to close, the financial and emissions risks around the level of capacity and timing of closure are no longer the concern of the relevant generator, who becomes indifferent to whether its closure timing minimises overall costs. Instead, the cost of sub-optimal closure is borne by government and, ultimately, taxpayers and consumers.

The factors that inform generator exit decisions are complex and based on future assumptions around a range of variables, including wholesale prices and demand. By entering into a payment for closure, governments implicitly take on some of this uncertainty and risk. Governments are at a commercial disadvantage when negotiating the closure of generating units due to information asymmetries. This can result in consumers paying above the efficient level for closures to occur.

In recent times, the following power stations have closed of their own volition and cost: Munmorah, Swanbank B and E, Collinsville, Playford B, Energy Brix, Wallerawang units 7 and 8 and Northern, indicating that wholesale price signals in the market are working as intended. In advice to Energy Ministers in June 2015, the Commission found that there is nothing in the National Electricity Law or Rules which would constitute a barrier to efficient exit decisions by generators.[63]

Furthermore, generators that may have closed in response to price signals at their own cost and under their own volition, may choose to keep generating if there is a possibility of receiving a closure payment. This could embed a barrier to exit into the market, with generators no longer responding to price signals, but instead responding to, and waiting for, the possibility of closure payments from government.

If a regulatory closure mechanism were to be implemented in combination with Extended LRET, this could lead to a costly situation for consumers where the government, through taxpayer funds, is subsidising new renewable capacity, while at

63 AEMC 2015, *Barriers to efficient exit decisions by generators*, Advice to the COAG Energy Council, 16 June 2015, Sydney.

the same time subsidising the exit of high emissions capacity. Once these subsidies are embedded in the market, they will be difficult to remove and result in a fundamental reallocation of risk from generators to consumers.

4.4 Implementation flexibility

Implementation flexibility is a critical design aspect to the sustainability of any emissions reduction mechanism. If the mechanism design is predicated on one view of the future, then it may not be sufficiently resilient to respond to changes in demand, fuel prices, technology costs and other factors that influence electricity market outcomes. This will likely result in the emissions reduction objective and NEO not being met, along with pressure placed on governments to undertake reviews, resulting in investment uncertainty.

4.4.1 Emissions Intensity Target

Under EIT, implementation flexibility can be realised through the development of a transparent and mechanistic gateway process to set the emissions intensity target trajectory. Through this process, which could occur every five years alongside the review of national emissions targets (as discussed in Chapter 1), the emissions intensity trajectory could be set for a five year period.

Box 4.1 provides an example of how a gateway approach could be implemented.

Box 4.1 Setting the emissions intensity target

Say the EIT mechanism was to commence on 1 January 2020 and its objective is to reduce emissions by 28 per cent below 2005 levels by 2030 (34 per cent pro rata electricity sector).

In August 2019, an independent body undertakes a short period of consultation to set the emissions intensity target to apply between 1 January 2020 and 31 December 2024. Consultation focuses on which forecasts to use and the shape of the emissions intensity trajectory.

In October 2019, the independent body sets the emissions intensity trajectory to 31 December 2024 and an indicative trajectory from 1 January 2025 to 31 December 2029. The indicative trajectory would be subject to a gateway test and confirmed in mid-2024.

Based on this gateway test process, generators will be able to form their own expectations, as they do now for demand and prices, around the likely emissions trajectory over an extended period. As the mechanism can respond to changes in the market, this should contribute to investment certainty.

To further reinforce investment certainty, a rule change process administered by an independent body could be developed to continue to evolve the design of the EIT mechanism. For instance, over time if governments make decisions to allow full or partial linking with the domestic economy and/or international schemes, the independent body could make these rules after consulting with industry and other stakeholders on the implementation details.

4.4.2 Extended LRET

In order to lower costs to consumers while maintaining system reliability and security, an approach that could better integrate with the competitive wholesale electricity market is to set the target as a percentage of demand. As a percentage, rather than a fixed GWh number, the target automatically adjusts to changes in demand, requiring new entrant renewable businesses to bear the risk of demand being higher or lower than expected. This would result in there being a consistent allocation of risk across the NEM.

To further support this approach, a gateway process similar to that discussed under the EIT mechanism (see Box 4.1) could be adopted to allow the target to be adjusted in line with changes in the energy market. A semi-regular, but narrowly defined, process would support greater investment certainty for industry than the unstructured wide-ranging reviews of recent times.

While a percentage-based target is preferable to a fixed-GWh target, even if a percentage-based target had applied during the life of the LRET, it is likely that it would have provided similar signals for investment in renewable generation as under the existing fixed-GWh target. Under either a fixed-GWh or percentage-based LRET, the wholesale market price is no longer the primary signal for new investment in renewable energy generation. Instead, as discussed in section 4.3.2, the primary signal for new investment in renewable energy generation is the LGC price and the target amount (or percentage), as generation under the RET is compensated through payments from retailers and other large users, in addition to the wholesale market revenue.

4.4.3 Jurisdiction-based renewable energy targets

It is difficult to say at this stage, given the uncertainty about the design of some of these schemes, what implementation issues would be associated with jurisdictional-based renewable energy targets.

4.4.4 Regulatory Closure

This mechanism presumes that centralised decision-makers are adept at determining and implementing the optimal closure schedule; which generator should close and when. This not only presumes that centralised decision-makers are fully-informed and that political considerations will not affect the closure schedule; it also ignores the possibility that high-emissions generators, in the absence of forced closure, could take actions that reduce their emissions intensity and thereby defer their socially-optimal closure timing.

Generators are heterogeneous goods and there are many complex and detailed technical and legal questions required to be resolved before boards can sign-off on closure agreements.[64] These negotiations can take months and involve multiple governments, institutions and international corporate head offices.

64 For instance, remediation obligations of the power station and mine, phasing of closure, closure dates, options to delay/bring-forward closure, workers obligations, system security implications etc.

There is also the risk that, unless this emissions reduction mechanism is well-designed and well-implemented, closed generators could reopen at some point in the future if the market environment changes, offsetting any short-term reduction in emissions. Separate mechanisms would need to be developed to protect against these issues for the mechanism to sustainably meet the emissions reduction objective over time.

4.5 Cost estimates and impacts on consumers

This section analyses how wholesale prices, resource costs, emissions levels, cost of abatement and generator investment, retirement and output change relative to BAU. It also discusses how robust the mechanisms are to changes in demand and a higher gas price.

The Commission notes that the quantitative assessment outcomes are sensitive to key input assumptions, such as demand and fuel prices, and how generator retirements are determined. Because of this, it is important to compare the relative differences in outcomes between the mechanisms and to use the sensitivities to test the robustness of these relativities to different assumptions.

In terms of the jurisdictional renewable energy schemes, it is worth noting that, for the purposes of modelling the resource costs, and impacts on consumers, of the Extended LRET mechanism, only the ACT scheme is included. The Victorian and Queensland schemes are excluded due to the uncertainty about precisely how these schemes will be implemented. Consequently, a qualitative discussion of the likely impact of including the Victorian and Queensland schemes in the Extended LRET mechanism is provided.

4.5.1 Approach to quantitative assessment

Each of the emissions reduction mechanisms have an electricity sector emissions reduction target consistent with a national target of emissions: 28 per cent below 2005 levels by 2030. The emissions trajectory from 2020 to 2030 was calculated as follows:

- Calculate the absolute emissions target in 2030 of 28 per cent below 2005 levels, which is around 440 Mt of CO_2e.[65]
- Pro rata emissions reduction target for the electricity sector is set at 34 per cent, which equals around 149 Mt and is the 2030 electricity sector target.
- Assume Australia's 2020 national target of 532 Mt is met and the pro rata reduction for the electricity sector is set at 34 per cent, which equals around 180 Mt and is the 2020 electricity sector target.

While only results from the NEM jurisdictions are included in this report, the NEM and Western Australian South West Interconnected System (SWIS) were modelled. This recognises that any mechanism to reduce emissions is likely to be implemented nationally and will be lower cost for consumers as abatement can be optimised across

65 Based on: http://www.environment.gov.au/climate-change/publications/tracking-to-2020

the NEM and SWIS. The NEM and SWIS represent around 97 per cent of total electricity sector emissions in Australia.[66]

Base case input assumptions were established for BAU and three emissions reduction mechanisms. Key variables are set out in Table 4.1, with further detail in a separate technical report.[67] Legacy hydro generation of 15,000 GWh was not eligible to produce AESCs or LGCs for the modelling undertaken in this report.

Table 4.1 Base case input assumptions for BAU and the emissions reduction mechanisms

Emissions target	LRET	Demand	Fuel price	New entrant capital cost
28% below 2005 levels by 2030 (pro rate electricity sector at 34%)	Current policy of 33,000 GWh in 2020 (except Extended LRET where the target is increased to 86,000 GWh in 2030)	AEMO/IMO2015 medium	Frontier Economics internal - see separate technical report	Frontier Economics internal - see separate technical report

After the completion of the market modelling, AEMO released its 2016 energy forecasts, with the 2016 medium forecast being lower than the 2015 medium forecast used for this report. All things equal, lower growth in electricity consumption is likely to result in lower costs of meeting an emissions reduction objective. While demand forecasts will change from year to year, it is important to understand how robust the mechanisms are under different growth assumptions, which has been tested for this report and is discussed in Chapter 5.

4.5.2 Consumer impacts

Consumer impacts of the emissions reduction mechanisms are felt through changes in the wholesale price component of consumer bills, which for the purposes of this modelling include the LGC levy. In order to compare the mechanisms on a like-for-like basis in terms of consumer impacts, wholesale prices include the cost of the LGC levy. Retailers are required to purchase LGCs to meet their liability under the LRET, with these costs passed to consumers through retail bills.

Wholesale prices paid by consumers are lowest under EIT for most of the period to 2030, including with reference to BAU. Under EIT, generators below the target receive a subsidy in the form of AESCs to produce electricity, which effectively lowers their variable costs of operating. To increase the chance of being dispatched and receiving

66 See: http://www.cleanenergyregulator.gov.au/NGER/Published-information/Reported-greenhouse-and-energy-information-by-year/greenhouse-and-energy-information-2014-15

67 Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

credits, low emissions generators are likely to reduce their offers into the market. It also encourages faster entry of low-emissions capacity into the market.

As CCGT generators receive AESCs and are generally the marginal generator setting the price, this puts downward pressure on wholesale prices. Conversely, generators above the emissions intensity target face a higher cost per MWh of output from having to purchase AESCs, reducing their margins. These two effects work together to change the relative costs of the generation technologies, resulting in higher output from low emissions plant displacing output from high emissions plant, and in doing so reducing CO_2e emissions from the sector. It means that although the overall cost of generation increases, this cost increase is borne by existing high emissions generators rather than consumers.

The Commission notes that as the emissions intensity target becomes lower, generators above the target face a larger penalty, while those below the target will earn less AESCs. Over time, this will result in a transition where higher emissions plant generate less and exit the market, replaced by existing and new low emissions plant.

An example of the effect of the EIT on wholesale prices is set out in Box 4.2.

Box 4.2 Illustrative effect of Emissions Intensity Target on wholesale prices

Consider an example where the emissions intensity target is 0.8t CO_2e/MWh and a CCGT power station has an emissions intensity of 0.36t CO_2e/MWh. For every MWh produced the CCGT could create 0.44 AESCs - the difference between the target and the emissions intensity of the CCGT.

If AESCs were around $35, then the CCGT would receive $15.4 for every MWh produced (0.44 AESCs * the AESC price), effectively reducing its variable costs by $15.4/MWh.

If the CCGT's variable costs prior to receiving AESC revenue were around $40/MWh, then this would reduce to $24.6/MWh. To maximise spot price revenue, the CCGT would offer into the market at $15.4/MWh less than before, increasing its output and displacing higher emitting and therefore higher cost coal-fired generation.

If the CCGT was the marginal generator setting the wholesale price before and after the introduction of the EIT mechanism, then wholesale prices would be likely to fall from $40/MWh to around $25/MWh.

The Commission notes that this is a stylised example and industry structure along with generator bidding behaviour will influence actual price outcomes.

Figure 4.2 shows national weighted-average wholesale prices for BAU and the emissions reduction mechanisms. In order to compare the mechanisms on a like-for-like basis, wholesale prices include the cost of the LGC levys. Retailers are required to purchase LGCs to meet their liability under the LRET, with these costs passed to consumers through retail bills. Regional NEM wholesale prices are shown in a separate technical report.[68]

Regulatory Closure results in the highest wholesale prices compared with BAU, EIT and Extended LRET. This is because, as generating units close, supply is reduced, putting upward pressure on wholesale prices to signal the need for new investment. Under EIT, although there is similar levels of coal plant retirement (supply withdrawal) compared with the REG case, this is complemented by large transfers from high emissions coal (reducing their margins) to low emissions gas/renewables as market entrants, which encourages new entry supply at lower cost. This causes a flattening of the merit order, which limits any wholesale price increases despite the increase in overall generation costs. Hence, although overall costs increase, this is mainly at the expense of the producer surplus (generator margins) rather than the consumer surplus. Wholesale prices for Extended LRET are higher than EIT and both above and below BAU. The aggregate NEM-wide wholesale price impacts of the jurisdictional renewable energy targets are likely to be similar to those under the Extended LRET.

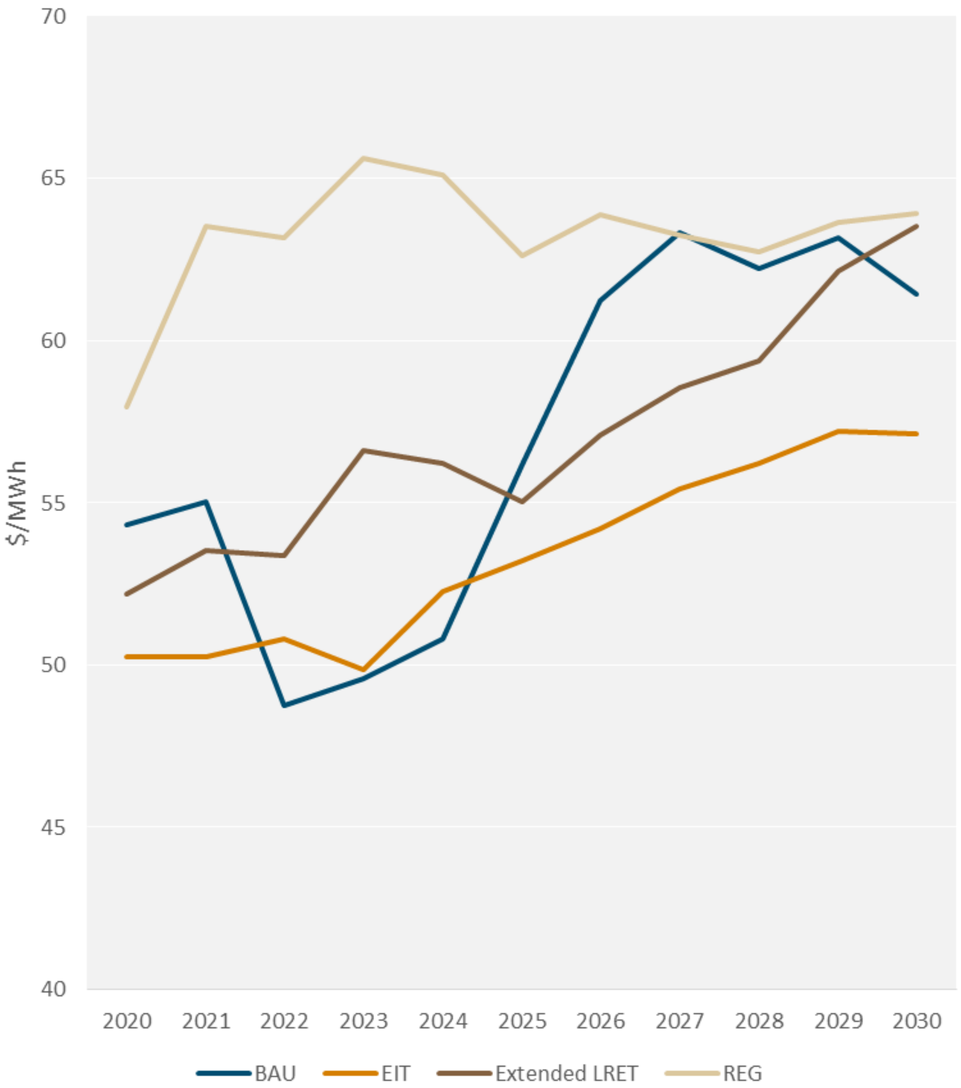
Higher electricity prices under Regulatory Closure are especially likely to occur when regulatory closure policies involve payments to generators to close, irrespective of whether closure payments are made by governments or by those generators that do not close. If closure payments are made by governments, these payments will be recovered from electricity consumers (potentially via levies passed onto retailers or network service providers) or taxpayers. If closure payments are made by other generators, these payments will be recovered from electricity consumers via higher prices.[69]

The price volatility shown in BAU is mostly caused by the surplus of wind being built in order to meet the current 33,000 GWh LRET. As the additional capacity outstrips growth in energy consumption, prices are expected to drop in response. This effect lasts until the LRET is met and demand growth catches up, reducing the surplus generation and resulting in wholesale prices increasing towards a new equilibrium. The price volatility is less obvious in the emissions reduction mechanisms because the investment and retirement mix is changing in order to achieve the emissions reduction constraint.

68 Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

69 An example of a generator-pays scheme is the reverse-auction scheme proposed by Frank Jotzo and Salim Mazouz, under which plants bid competitively over the payment they require for closure, a centralised decision-maker chooses the most cost effective bid, and closure payments are made by the remaining generators in proportion to their carbon dioxide emissions (Frank Jotzo and Salim Mazouz, *Brown coal exit: a market mechanism for regulated closure of highly emissions intensive power stations*, Economic Analysis and Policy, 48(2015), pp.71-81).

Figure 4.2 National weighted average wholesale prices - including LGC levy ($/MWh)



Source: Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

Emission-intensive trade-exposed industries

The below analysis is based on EITEIs being compensated for the direct and indirect costs associated with implementing the EIT mechanism. Direct costs are those passed through by generators that have to purchase AESCs and are under power purchase agreements with EITEIs. Indirect costs relate to any uplift in wholesale prices faced by EITEIs as a result of implementing the EIT mechanism (noting the potential uplift is expected to be low under EIT). The compensation provided to EITEIs is based on the pool of credits that would have been created if legacy hydro generators were eligible to receive credits. The compensation provided to EITEIs under the EIT mechanism is consistent with the compensation provided to EITEIs under the Extended LRET mechanism, which, in turn, continues the exemption granted to EITEIs under the existing LRET[70].

4.5.3 Resource costs

Resource costs represent the cost to the electricity sector as a whole of meeting forecast electricity consumption under the emissions reduction constraint, given a set of future assumptions around technology and fuel costs. They are the capital costs of building new capacity (the sum of capital and labour costs) plus the operating costs (including fuel, variable and fixed operating and maintenance costs) from dispatching new and existing generation to meet demand, subject to any policy constraints such as renewables or emissions targets. Resource costs related to potential additional transmission network investment, which may be needed to support additional generation investment, is not considered as part of this analysis, as these costs tend to be significantly smaller than costs associated with new generation capacity[71].

Resource costs are highest for Extended LRET because the mechanism is not technology neutral - more expensive technologies are required to meet the emissions constraint than under EIT and Regulatory Closure. EIT costs are less than Regulatory Closure because greater fuel switching occurs under EIT, where for Regulatory Closure new plant is required to be built to replace generators exiting.

Resource costs are not always related to wholesale price movements. For instance, Regulatory Closure has the highest wholesale prices but Extended LRET has the highest resource costs. Under Extended LRET, more of the additional resource costs fall on existing generators in the form of lower wholesale prices. However, this may not always be the case. In some instances, consumers will face the increase in resource costs if generators can pass these on through higher wholesale prices.

The allocation of resource costs between generators and consumers depends on a complex range of factors, including how the emissions reduction mechanism works, the emissions intensity of the marginal generator and decisions by generators on when to exit the market[72]. We note that resource costs do not include any payments made to generators under Regulatory Closure. Closure payments are not an economic cost, rather they are a transfer from taxpayers to generators[73].

Resource costs for BAU and the emissions reduction mechanisms are shown in Figure 4.3, with the orange dots representing the change from BAU on the right hand axis. In terms of the jurisdictional renewable energy schemes, as noted above, only the ACT scheme is included in the quantitative analysis. Including the Victorian and Queensland schemes is likely to result in higher resource costs than that shown in

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70 A discussion of EITE compensation under the existing LRET was provided in section 2.2.1

71 For example, AEMO's 2015 National Transmission Network Development Plan estimated the cost of new transmission investment to be around $2.5 billion over the 2015-2035 period under BAU. This compares to resource costs of around $55 billion under BAU over the 2020-2030 period (see Figure 4.3).

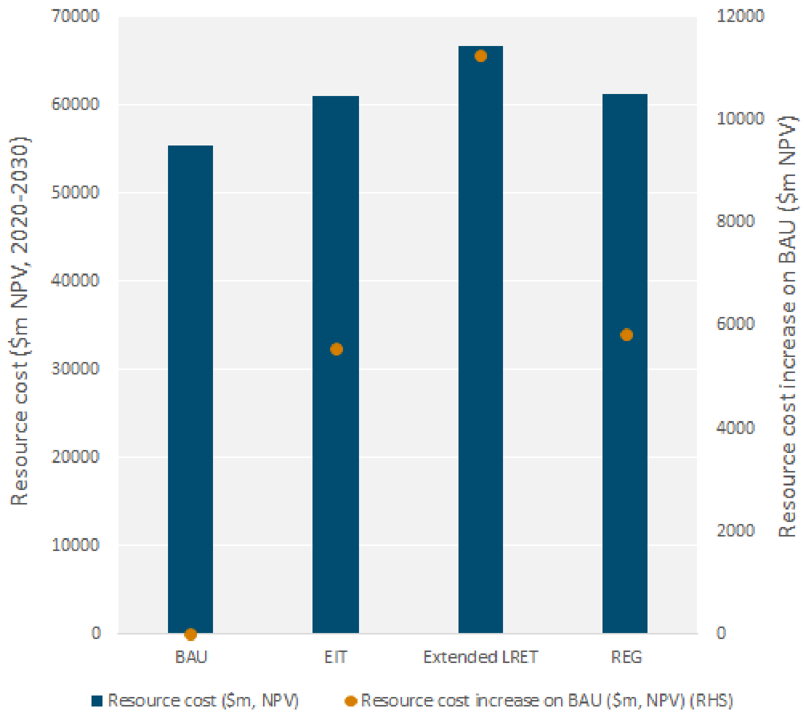
72 Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

73 The extent of these distributional impacts may, however, be of interest in policy-makers when comparing the various policies.

Figure 4.3 ; if these levels of renewable build in these regions were least cost then they would occur without additional policy support.

Higher renewable energy targets, would encourage more renewables into the NEM and therefore raise capital costs in the BAU, EIT and REG cases in particular.– The Extended LRET mechanism will likely see more additional renewables (nationally) than required by these state schemes. The addition of these schemes in the modelling will impose some constraints on technology (solar requirements) and region (Vic/Qld requirements) that would raise costs compared with an unconstrained.

Figure 4.3 Resource costs (2016$m NPV, 2020-2030)



Source: Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

While transmission investment is not included in the estimates of resource costs under BAU and each of the emissions reduction mechanisms, the amount of transmission investment required is likely to be highest under Extended LRET and lowest under EIT. This is because of the amount of non-synchronous generation that is installed under Extended LRET, which is likely to require investment in transmission assets to maintain system security. Conversely, under EIT, as emissions abatement is also delivered through fuel switching from coal to gas, and as gas-fired generation is a synchronous form of generation, a relatively lower transmission investment is required.

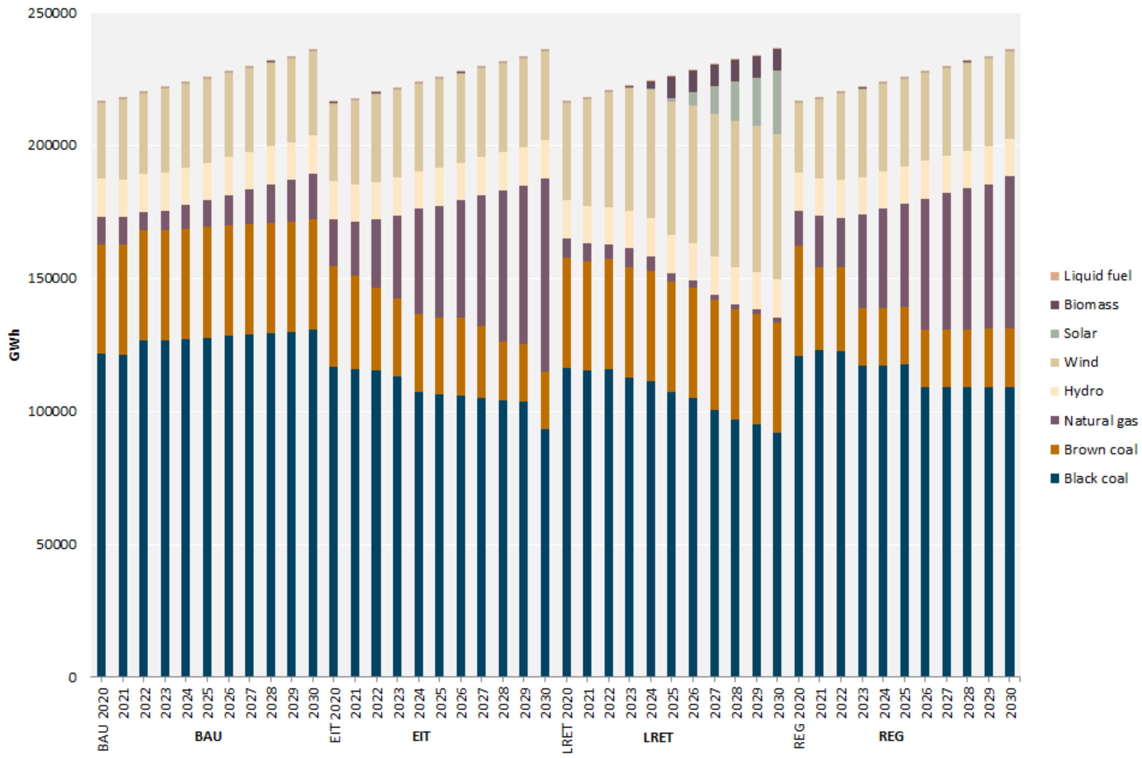
4.5.4 Investment, retirements and output

Under **EIT**, brown and black coal generation decreases, while gas-fired generation increases and output from renewable generation stays relatively constant compared with BAU. New investment is primarily made up of CCGT. Closures under EIT are expected to be as follows: Hazelwood closes between 2021 and 2022[74], followed by Liddell between 2022 and 2024, and Yallourn W in 2028. Gladstone then closes in 2030.

For **Extended LRET**, renewable generation increases, displacing gas-fired generation and black coal. Brown coal generation stays constant relative to BAU. New investment is made up of wind, solar and biomass. Extended LRET has the fewest expected generator closures, with only Vales Point B closing in 2023. This is because the new renewable capacity, combined with a reduction in higher cost black coal and CCGT output, drives the emissions reduction. Brown coal output remains at BAU levels as it remains the least-cost form of thermal generation without any penalties imposed on high emissions.

Regulatory Closure results in lower brown coal generation than in BAU, replaced by CCGT. Black coal is marginally lower and renewable output is constant relative to BAU. New investment is made up of CCGT and wind. As discussed in section 4.1.3, the timing and sequence of generator retirements under Regulatory Closure are assumed to occur in a cost-effective manner, which means retirement outcomes similar to that under EIT, the most cost-effective mechanism. Therefore, under Regulatory Closure, Hazelwood retires in 2021, Liddell between 2022 and 2023, Yallourn W in 2023 and Vales Point B in 2026.

Figure 4.4 National annual generation output 2020 to 2030 (MWh)

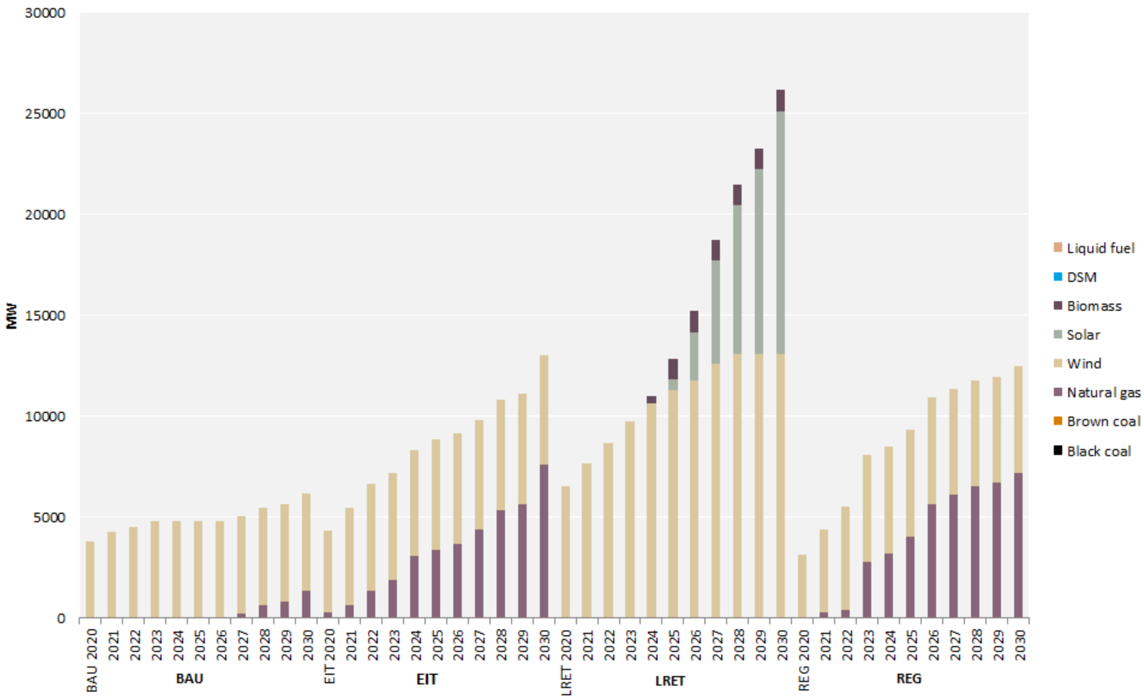


Source: Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

74 A separate analysis of the effect of a pre-2020 closure of Hazelwood has been conducted and is discussed in Section 5.5 of this report.

Annual generation output for each mechanism across the period 2020 to 2030 is shown in Figure 4.4, while new investment in capacity is shown in Figure 4.5.[75] Capacity and output for each NEM region is shown in a separate technical report.[76]

Figure 4.5 National cumulative investment in new capacity 2020 to 2030 (MW)



Source: Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

In terms of the jurisdictional renewable energy schemes, including the Victorian and Queensland schemes in all cases mechanism would likely result in increased investment in new generation capacity and therefore renewables' having a higher share of output. In the Extended LRET case this will likely just impose technology/regional constraints on the renewables that would be built under the extended national scheme.

4.5.5 Emissions and certificate prices

The emissions intensity of the Australian electricity sector needs to fall from 0.81t CO_2e/MWh in 2020 to 0.62t CO_2e/MWh in 2030 to meet the 28 per cent emissions target in the base case. Without any additional policies in place outside of BAU, the emissions intensity of the Australian electricity sector is expected to be around 0.77t CO_2e/MWh in 2030.

To achieve the emissions reduction target, AESC prices are expected to be around $28 when the mechanism begins in 2020 before reaching around $40 in 2030[77]. AESC prices

75 Output and investment in new capacity with respect to gas is predominantly CCGT in the graphs.

76 Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016, Appendix A.

77 Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016, p. 37.

are a function of the supply and demand for credits, which depends on the level of the target, the emissions intensity of the sector and relative costs of generation.

The Commission notes that, while a linear emissions intensity trajectory has been assumed for this analysis, different trajectory shapes could be contemplated. For instance, the trajectory could start off relatively flat and become steeper closer to 2030 or vice versa. The Commission has not considered the merits of how different trajectories might better contribute to meeting the emissions reduction objective and NEO in this report.

4.6 Summary of analysis and outcomes

A summary of the key assessment metrics is set out in Table 4.2, while a summary of the analysis and outcomes as they relate to achieving the dual emissions reduction and electricity objectives is provided in Table 4.3.

Table 4.2 Summary of assessment metrics

	Change in resource cost from BAU (NPV, Real2016$, 2020-2030)	Cost of abatement (emissions discounted)	Total new investment in renewable capacity (MW)	Total retirements (MW)
EIT	$5,546m	$30.4/t	5,441	6,852
Extended LRET	$11,248m	$75.7/t	26,166	2,559
Regulatory Closure	$5,838m	$34.2/t	5,266	6,406

Source: Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

Note: new investment and retirements are totals, not the change from BAU. New investment is from 2017 to incorporate the current LRET.

EIT has the lowest impact on wholesale prices, lowest resource costs and lowest cost of abatement relative to the other emissions reduction mechanisms. These results are intuitive because, as the mechanism is technology neutral, it promotes the least-cost form of abatement. Importantly, EIT maintains the allocation of risk between generators and consumers, where generators continue to make investment and retirement decisions based on price signals in the spot and contract markets, and face the outcomes of their decisions.

The **Extended LRET** has the highest resource costs and cost of abatement. This result is also intuitive because, as the mechanism only allows a limited number of technology options to meet the emissions constraint, lower cost forms of emissions reductions do not take place. The Extended LRET results in low cost brown coal remaining in the market, while higher cost but lower emissions black coal exits in response to low wholesale prices depressed by the new renewable capacity.

The above impacts on the energy and ancillary services markets are likely to also occur, perhaps to an even greater extent, under the jurisdictional renewable energy targets.

Where jurisdictional-based renewable energy targets are additional to the LRET, the cumulative target for renewable generation is increased, leading to more renewable capacity entering the market.

Table 4.3 Summary assessment of emissions reduction mechanisms

Mechanisms	Emissions Reduction Objective	National Electricity Objective
EIT	As the mechanism for reducing emissions under EIT is embedded in the wholesale electricity price, the emissions reductions are more certain over the long term relative to Extended LRET and Regulatory Closure, contributing to the mechanism's sustainability.	EIT maintains the allocation of risk between generators and consumers and supports the existing pricing mechanisms in the NEM. It does this by changing the relative costs of different technologies to achieve the emissions reduction task. Wholesale prices are lowest under this approach and there are no negative impacts on the contract market,
Extended LRET	If the Extended LRET is expressed in fixed GWh terms, then emissions may under or over shoot the target depending on changes in energy consumption. Unless the LRET is continually extended, there is a risk that higher emissions generators increase output and/or retired generators return to the market when the LRET is met.	The Extended LRET is not a technology neutral mechanism and has mostly subsidised one form of technology to-date: wind. Because of this, it is not the lowest cost way of achieving the emissions target, being over **twice** as expensive on a cost of abatement measure as EIT. The Extended LRET mechanism is also likely to negatively impact the ability of market participants to source and enter into contracts.
Regulatory Closure	Regulatory Closure provides certainty in the short term that generators will close. However, there is a risk that the remaining high emissions generators increase their output. This mechanism is less responsive to uncertainty around future emissions reduction targets as it requires administrative intervention.	Regulatory Closure has the potential to embed a barrier to exit in the NEM, with generators no longer responding to price signals, but instead waiting for announcements from government for payment to close. Wholesale prices are highest under this approach.

When expressed as a fixed GWh target, the Extended LRET shifts demand risk from new entrant renewable generators to existing generators and consumers. For example, if demand is lower than expected, the subsidy for new entrant renewable generators increases to compensate for lower wholesale prices, while existing generators face the impact of lower wholesale prices. In the short term, the fall in wholesale prices may offset the cost of the mechanism on consumers; however, as existing generators exit the market, wholesale prices can be expected to rise and consumers will face the full cost of the subsidy.

Consumer impacts in terms of wholesale price increases are highest under Regulatory Closure. This is because as generating units close, supply is reduced, putting upward pressure on wholesale prices to signal the need for new investment. Regulatory Closure provides less chance for the market to optimise closure decisions as administrative decisions around the level of capacity and timing of closure need to be made, which may not always result in a least-cost outcome. Where payments for closure are made to generators, the mechanism transfers the financial risk around the level of capacity and timing of closure from generators onto consumers, ultimately leading to higher long-term costs for consumers.[78]

In summary, the preceding analysis shows that, of the three emissions reduction mechanisms, the EIT is the mechanism likely to integrate energy and emissions reduction policies most successfully. The EIT mechanism can achieve the desired emissions reductions in a manner that maintains the reliability, security, and economic efficiency of the wholesale electricity market, at the lowest long-term cost to consumers.

78 The factors that inform generator exit decisions are complex and based on future assumptions around a range of variables, including wholesale prices and demand. By entering into a payment for closure, governments implicitly take on some of this uncertainty and risk.

5 Adaptability and sustainability assessment

Chapter 4 provided estimates of the cost and price impacts of the three emissions reduction mechanisms, developed using base case assumptions relating to future electricity demand, emissions reduction targets, and technology costs. However, all of these variables are subject to uncertainty. For example, as the experience of the last decade has revealed, electricity demand may be higher or lower than earlier anticipated. Similarly, technology and fuel costs may or may not evolve in line with present estimates. Emissions reduction targets are set by governments and are subject to change.

As our assessment framework in Chapter 3 explained, a key principle we apply in evaluating whether a mechanism promotes the NEO is whether the mechanism is capable of flexibly adapting to changing circumstances. An adaptable mechanism is one that is capable of yielding efficient and acceptable outcomes under a wide range of conditions. These attributes mean that an adaptable mechanism is less likely to be subject to calls for alteration or replacement and is therefore more likely to endure over time. Perceptions of mechanism sustainability engender confidence amongst investors and help promote the long-term interests of consumers in accordance with both emissions reduction objectives and the NEO. Conversely, a mechanism that is viewed as becoming unfit-for-purpose when conditions change, such as the original LRET, is likely to become vulnerable to pressure on governments to undertake reviews and overhaul the mechanism.

This chapter assesses the ability of each of the emissions reduction mechanisms to yield efficient and acceptable outcomes in the event of changes to key assumptions, including future costs and emissions reduction targets. A list of these potential future changes in conditions is summarised in Table 5.1.

As Table 5.1 shows, the following seven variations to the input or modelling assumptions were performed to assess the adaptability of each of the emissions reduction mechanisms:

- two variations relating to demand forecasts (high and low demand scenarios, respectively;
- a variation to gas price forecasts (a 'high price' scenario);
- a higher emissions reduction target;
- allowing legacy hydro generators to receive AESCs;
- allowing capital costs for utility-scale solar to fall at a faster rate than assumed under the base case; and
- Hazelwood power station closing in 2017, consistent with a recent closure announcement.[79]

79 Engie Media Release, Hazelwood to close in March 2017, 03 November 2016. Available at http://www.gdfsuezau.com/media/UploadedDocuments/News/Hazelwood%20Clousure/Hazelwood%20closure%20-%20Media%20release.pdf

Detailed results of each of the six variations to input or modelling assumptions are set out in a separate technical report, with only a summary of the key findings provided below.[80]

Table 5.1 Alternative future conditions

Input or modelling assumption	Base case	Alternative scenarios
Demand forecast*	AEMO/IMO 2015 Medium scenario	AEMO/IMO 2015 High scenario; AEMO/IMO 2015 Low scenario
Gas price*	Frontier Economics' Base Case	Frontier Economics' High Case
Emissions reduction target	28 per cent below 2005 levels by 2030 (pro-rata electricity sector)	50 per cent below 2005 levels by 2030 (pro-rata electricity sector)
Legacy hydro generators' eligibility to receive AESCs	Ineligible to receive AESCs	Eligible to receive AESCs
Capital costs for utility-scale solar	Frontier Economics' Base Case	Frontier Economics' Low-cost Solar case
Hazelwood power station's presence in pre-2020 period	Remains in the NEM for entire pre-2020 period	Exits the NEM in 2017

*See Frontier Economics report for more details[81]

5.1 Different forecasts for electricity demand and gas prices

5.1.1 Impact on wholesale prices and resource costs

For the purposes of the high gas price scenario, AEMO's National Transmission Network Development Plan (NTNDP) 2015 Medium gas price assumptions were used. AEMO's NTNDP model captures both domestic and foreign factors that influence gas prices. An example of a domestic factor is the increased gas demand from both local gas-powered electricity generation and liquefied natural gas facilities for export. This higher demand is expected to use up existing developed sources of gas supply, requiring the development new sources of gas which are expected to cost more to develop and produce. The rising cost of gas production is in turn boosts the wholesale

80 Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

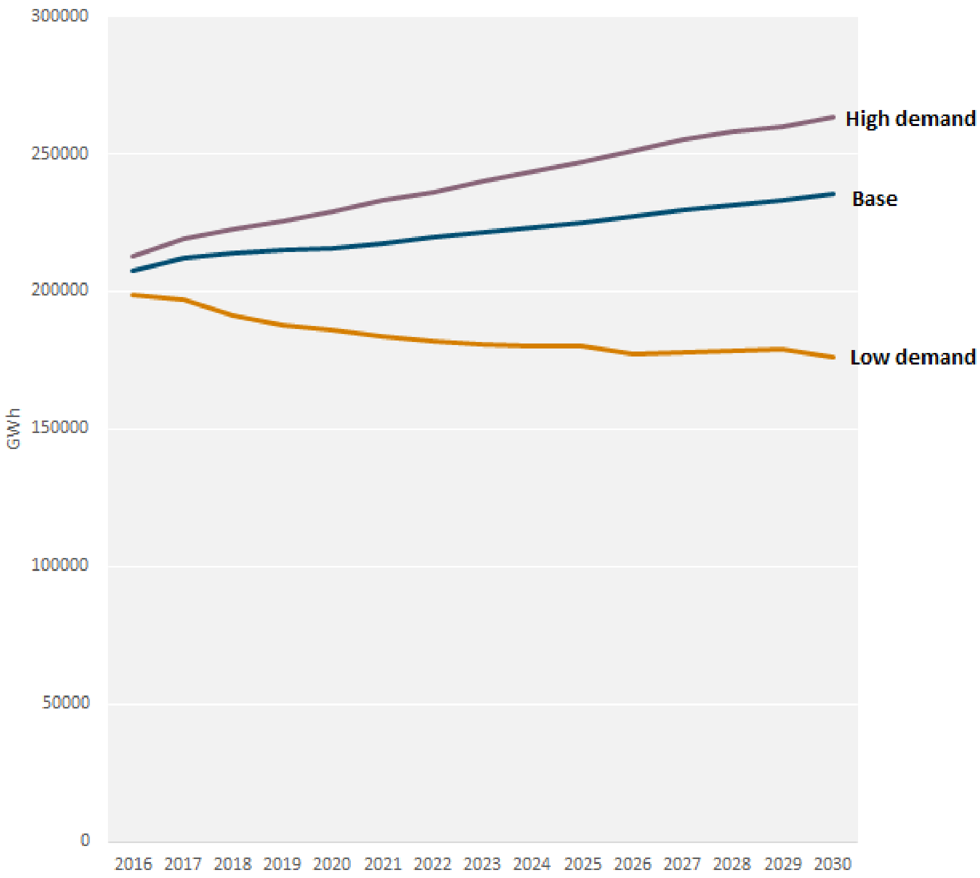
81 Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

gas price.[82] Another example of a domestic factor is the impact of existing restrictions on the local extraction of gas, which also contributes to forecasts of higher gas prices.

Electricity demand is inherently uncertain and therefore the Commission considered it prudent to assess the adaptability of each of the emissions reduction mechanisms, and understand how the relativities between the emissions reduction mechanisms could change, if actual demand was higher or lower than that assumed under the base case.

The different electricity demand profiles under each of the three demand assumptions (including the base case), are shown in Figure 5.1. The low demand scenario assumes annual energy consumption decreases out to 2030, while the high demand scenario has demand increasing between 2016 and 2030 by an average rate of 1.3 per cent per annum. The high demand scenario results in higher BAU emissions projections and larger emissions abatement required to meet the 2030 target.

Figure 5.1 NEM and SWIS annual electricity consumption, by demand scenario



Source: Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

Under the high electricity demand scenario, Extended LRET has materially higher wholesale price outcomes (including LGC prices) compared with the other mechanisms. This is because 124,000 GWh of new renewable energy is required to meet

82 The gas price forecasts used for the base case are sourced from Frontier Economics, and presume that domestic prices converge with global prices. Under this presumption, Australia is a gas price-taker and therefore domestic demand and supply factors do not impact on global prices.

emissions target: this higher target, combined with the resulting in higher LGC prices to achieve this, increases the LGC levy. On the other hand, any merit order effect from increasing the LRET (to cause offsetting reductions in wholesale prices) is limited, as further increases in the LRET are met with plant retirements rather than continued reductions in wholesale prices.

Under the high electricity demand scenario, greater emissions reduction is required to achieve the emissions reduction target, with the emissions intensity needing to fall from 0.76t CO_2e/MWh in 2020 to 0.55t CO_2e/MWh in 2030. Resource cost relativities under this scenario are the same as in the base case, with EIT lowest followed by Regulatory Closure and Extended LRET.

For the low electricity demand scenario, as annual energy consumption is assumed to fall out to 2030, emissions under BAU are below the target by 90 Mt (cumulative from 2020-2030). This means no additional emissions reduction mechanisms, beyond the existing 33,000 GWh LRET, are required to achieve the emissions reduction target.

For the high gas price scenario, the wholesale price relativities are generally the same as in the base case. The relativities change somewhat under a higher gas price, with EIT still having the lowest resource cost, but now followed by Extended LRET then Regulatory Closure.

Resource costs for Regulatory Closure are higher under the high gas price scenario primarily because the variable costs of gas-fired generation have increased and this is what is built to replace the retired generators. While EIT also relies on replacing coal generation with gas-fired generation, EIT can optimise the retirement decisions (similar to a market) unlike Regulatory Closure, where retirements are an exogenous assumption. This reflects how these mechanisms would practically operate. There is more investment in renewables, rather than fuel switching to gas, under Regulatory Closure under the high gas price scenario. For these reasons, resource costs for EIT are lower than for Regulatory Closure, under the high gas price scenario, similar to the ranking of resource costs in the base case.

The above results reveal that the EIT mechanism remains the most cost-effective mechanism and continues to have the lowest consumer impacts and resource costs compared with the other emissions reduction mechanisms, under alternative views about future electricity demand and gas prices. This demonstrates the adaptability and flexibility of the EIT mechanism.

5.1.2 Impact on costs of abatement

Cost of abatement is the cost of each tonne of CO_2e avoided as a result of implementing one of the emissions reduction mechanisms. It is calculated as the change in resource costs from BAU divided by the change in emissions from BAU, for the relevant period.

Some organisations present cost of abatement by discounting resource costs and emissions, while others discount resource costs only. The Commission has presented average cost of abatement estimates with emissions discounted and not discounted for each mechanism in Table 5.2. By discounting emissions, the different time frames in which emissions reductions occur are taken into account. The relativities between the emissions reduction mechanisms are the same under either approach.

Table 5.2 Average cost of abatement $/tonne (NPV, Real2016$, 2020-2030)

Mechanisms	Base Case		High gas price scenario		High demand scenario	
	Disc.	**Not disc.**	**Disc.**	**Disc.**	**Disc.**	**Disc.**
EIT	$30.4/t	$17.5/t	$51.4/t	$28.4/t	$29.8/t	$17.6/t
Extended LRET	$75.7/t	$42/t	$72/t	$40/t	$93.6/t	$50.8/t
Regulatory Closure	$34.2/t	$19.5/t	$73.9/t	$43.6/t	$35.5/t	$20/t

Source: Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

EIT has the lowest cost of abatement, followed by REG and then Extended LRET. These relativities are generally consistent across the sensitivities, although the cost of abatement between Regulatory Closure and Extended LRET reverses under the high gas price scenario. The low demand scenario is not shown as there is no additional cost of abatement required.

5.2 Changes to the emissions reduction target

An emissions reduction target of 50 per cent below 2005 levels by 2030 for the electricity sector was chosen for the purposes of the analysis in this subsection. This target was chosen to assess the scalability of each emissions reduction mechanism. Scalability relates to the extent to which those emissions reduction mechanisms, which are cost-effective for a 28 per cent emissions reduction target, continue to be cost-effective under higher targets.

This target reflects the midpoint of the 40-60 per cent emissions reduction target range recommended by the Climate Change Authority.[83] The 50 per cent target for the electricity sector is also between the emissions reduction targets implied by the Climate Change Authority's (CCA's) 3-degree and 2-degree Celsius warming scenarios, presented in their recent report, which are around 40 per cent and 83 per cent, respectively, on 2005 levels by 2030.[84]

Alternatively, a higher emissions reduction target for the electricity sector may occur if it is considered that the electricity sector should contribute more than its proportionate share to the 28 per cent emissions reduction target for the overall economy.

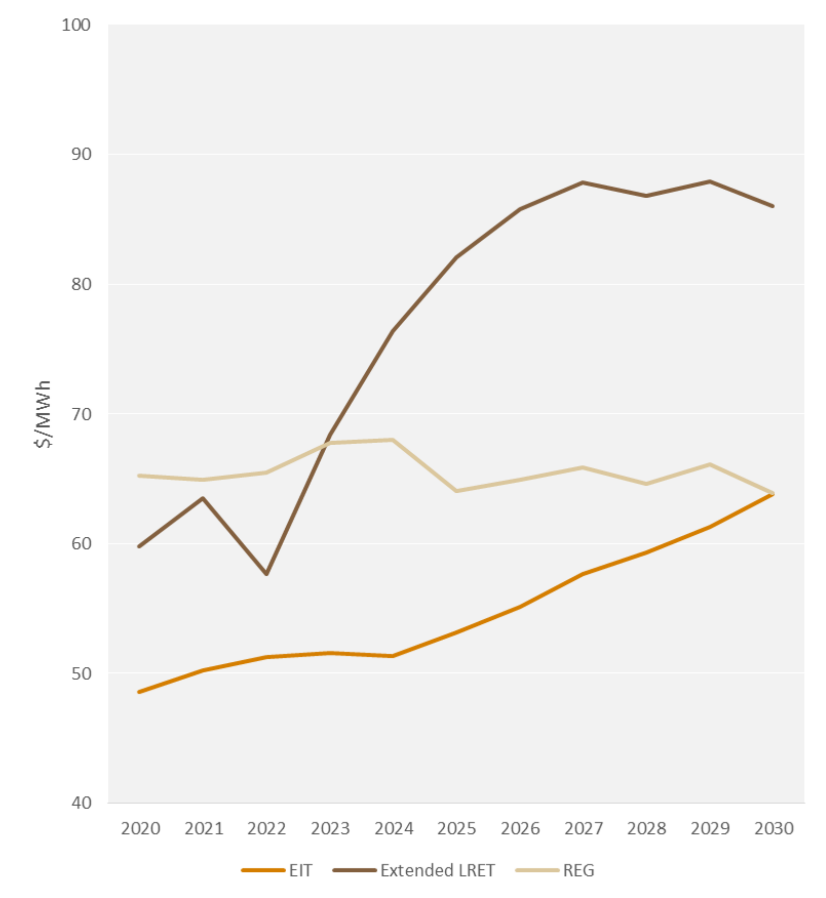
83 Climate Change Authority, *Reducing Australia's Greenhouse Gas Emissions*, Targets and Progress Review, February 2014.

84 Climate Change Authority, *Policy Options for Australia's Electricity Supply Sector*, Special Review Research Report, August 2016. The emissions reduction percentages are determined from the modelling undertaken for the CCA by Jacobs Group (Jacobs Group, *Modelling illustrative electricity sector emissions reduction policies*, Final report for the Climate Change Authority, 25 August 2016).

5.2.1 Impact on wholesale prices and resource costs

Under a 50 per cent emissions reduction target, Extended LRET generally results in the highest wholesale prices (Figure 5.2). This is because of the high price and volume of LGCs, which more than offsets the downward pressure on wholesale prices from increasing the supply of renewable generation capacity. In contrast, under a 28 per cent emissions reduction target, Regulatory Closure resulted in the highest wholesale prices (see Figure 4.2).

Figure 5.2 National weighted-average wholesale prices (including LGC levy) under a 50 per cent emissions reduction target



Source: Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

Of the three emissions reduction mechanisms, EIT results in the lowest wholesale prices. This result reflects this mechanism's technological-neutrality, which allows greater fuel switching from high-emissions to low-emissions plant, in addition to investment in new zero-emissions (renewables) plant. In contrast, only the latter is possible under the Extended LRET.

5.2.2 Impact on costs of abatement

EIT has the lowest cost of abatement, with Extended LRET the highest (Table 5.3). This ranking is the same as in the base case (see Table 5.2). Comparing the base case in Table 5.2 with Table 5.3 reveals that the average cost of abatement rises under a higher emissions reduction target. This result reflects the fact that as the emissions reduction target increases, meeting this target require more costly forms of abatement (such as investment in renewables or replacement of progressively more efficient/less emissions intensive coal plant). Less costly forms of abatement, such as switching from coal to gas, provide a greater proportion of the total emissions abatement under a lower emission reduction target, such as 28 per cent, and need to be supplemented with more costly forms of abatement, to achieve higher emissions reduction targets, thereby raising the average cost of abatement.

Table 5.3 Average cost of abatement under different emissions reduction targets (NPV, Real2016$, 2020-2030)

Emissions reduction mechanisms	Base Case (28% emissions reduction target)		50% emissions reduction target	
	Discounted	Not discounted	Discounted	Discounted
EIT	$30.4/t	$17.5/t	$34.7/t	$20.5/t
Extended LRET	$75.7/t	$42/t	$85.3/t	$48.3/t
Regulatory Closure	$34.2/t	$19.5/t	$37.9/t	$22.1/t

Source: Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

Table 5.3 also reveals that the increase in abatement cost is highest for Extended LRET, at $9.6/t (for the discounted abatement cost). In contrast, the increased (discounted) abatement cost for EIT is $4.3/t.

The results of the higher emissions reduction scenario reveal that the EIT mechanism results in the lowest: resource costs; costs of abatement; and increase in wholesale prices, of the three mechanisms. These results demonstrate that of the three emissions reduction mechanisms, EIT is the most economically efficient and scalable mechanism, due to its inherent flexibility, capable of achieving the specified emissions reduction target at the lowest cost.

5.3 The treatment of legacy hydro generation

As discussed in section 2.1.2, in designing the existing LRET, baselines were specified for those renewable generators (mostly hydro generators) that existed prior to the introduction of the LRET. These 'legacy' renewable generators (mostly hydro) were ineligible to create LGCs for generation up to their baseline, which for all hydro generators is around 15 terawatt hours (TWh).[85] The objective for specifying such baselines, and excluding this output from the LRET, was to encourage additional renewable electricity generation, relative to what would occur in the absence of the LRET. In section 2.1.2, it was also argued that legacy hydro generators' decisions to generate are unlikely to be impacted by their eligibility (or otherwise) to receive LGCs.

85 This amount of generation was termed the 'below baseline generation' from renewable generators that existed before the Commonwealth's RET came into effect. For more details, see Climate Change Authority, *Renewable Energy Target Review*, Final Report, December 2012.

This rationale is also why these generators might not receive credits under the EIT for output up to the baseline.[86] In turn, making legacy hydro eligible to receive AESCs would result in large windfall gains for these generators, as they would not be contributing to additional emissions reductions.

Allowing legacy hydro generators to receive AESCs for their baseline output (15TWh) (in addition to allocating the same volume of credits to EITEI use) reduces the emissions reductions achieved under the existing emissions intensity target path. Therefore, to achieve the emissions reduction target, the emissions intensity target path must be lowered. This adjustment results in a modest increase (around $1.50/MWh) in wholesale prices.

The higher wholesale price does not reflect an increase in resource costs, which remains unchanged. Instead, the higher wholesale electricity price effectively represents a significant wealth transfer (a cumulative value of $3 billion over the 2020-2030 period) from consumers to legacy hydro generators.

5.4 Changes to projections of cost of utility-scale solar

Under this scenario, capital costs for utility-scale solar are assumed by Frontier Economics to be 10-15 per cent lower over the 2016-2030 period, compared to Frontier Economics' assumptions about costs in the base case.[87] All else equal, lower solar costs should be expected to result in a higher uptake of solar under all of the emissions reduction mechanisms, as well as BAU, but especially Extended LRET, as only renewables are likely to enter the wholesale market under Extended LRET.

5.4.1 Impact on wholesale prices and resource costs

Compared to the base case, lower utility-scale solar costs result in a modest to negligible reduction in wholesale prices, with the largest (albeit modest) impact on wholesale prices under the Extended LRET, which are around $2/MWh lower over the 2020-2030 period, compared to the base case (Figure 5.3). The lower wholesale price under Extended LRET is due to the lower LGC price.

Despite the greater reduction in wholesale prices under Extended LRET, Figure 5.3 reveals that wholesale prices remain lower under EIT than under Extended LRET or Regulatory Closure.

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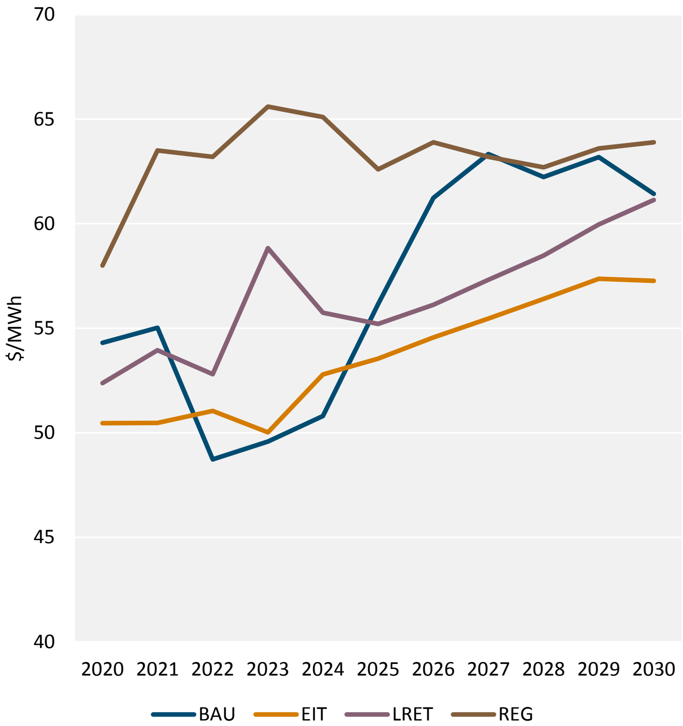
86 Frontier Economics'' modelling of an EIT scenario is agnostic on whether the legacy hydro credits are allocated to legacy hydro or to EITEI: in the modelling, this volume of credits is set aside for use by one of legacy hydro or EITEI (but not both) and the impact on prices and costs are not affected by which party receives these credits.

87 For more details, see Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

Figure 5.3 **National weighted-average wholesale prices (including LGC levy) – alternative utility-scale solar cost scenario**



Source: Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

Resource costs are lower under the assumption of lower costs for utility-scale solar for both EIT and Extended LRET. Of the three emissions reduction mechanisms, resource costs are lowest under EIT, a result which is consistent with the base case (see Figure 4.3).

5.4.2 Impact on costs of abatement

Table 5.4 reveals that average abatement costs remain lowest under EIT, despite the decline in the average cost of abatement for Extended LRET.

Table 5.4 **Average cost of abatement under alternative utility-scale solar cost scenario (NPV, Real2016$, 2020-2030)**

Emissions reduction mechanisms	Base Case		Utility-scale solar cost scenario	
	Discounted	Not discounted	Discounted	Not discounted
EIT	$30.4/t	$17.5/t	$30.3/t	$17.4/t
Extended LRET	$75.7/t	$42/t	$67.5/t	$37.2/t
Regulatory Closure	$34.2/t	$19.5/t	$34.1/t	$19.4/t

Source: Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

5.5 Impacts of pre-2020 Hazelwood retirement

On 3 November 2016, ENGIE, announced that the Hazelwood power station[88] in Victoria would be closed in March 2017.[89]

Under the base case findings presented in Chapter 4, Hazelwood is assumed to remain open throughout the 2020-2030 period under BAU and under Extended LRET and retire in 2021/22 under EIT and Regulatory Closure for economic reasons.[90] Given that Hazelwood has now announced that it will exit the NEM, it is worthwhile examining the emissions abatement required, and the associated costs and price impacts, when Hazelwood closes prior to 2020; that is, prior to the commencement of any of the three emissions reduction mechanisms.

In the following subsections, Hazelwood is assumed to close by the end of June 2017.

5.5.1 Impact on wholesale prices and resource costs

Under an early closure of Hazelwood, wholesale prices are higher, by around $5-10/MWh, under BAU and Extended LRET, relative to their levels under the base case (Figure 4.2 vs. Figure 5.4). A pre-2020 Hazelwood closure leads to a larger increase in BAU and Extended LRET wholesale prices as, under the base case, Hazelwood remains in the NEM over the entire 2020-2030 period under BAU and Extended LRET.

In contrast, wholesale prices under EIT and Regulatory Closure under an early Hazelwood closure are little changed from their corresponding levels under the base case. The negligible wholesale price impacts under EIT and Regulatory Closure reflect the fact that under the base case, Hazelwood exits in 2021/22 under both of these two emissions reduction mechanisms. Therefore, the assumption of a pre-2020 Hazelwood closure is expected to have little to no impact on EIT and Regulatory Closure wholesale prices, as borne out by the comparison between Figure 4.2 and Figure 5.4.

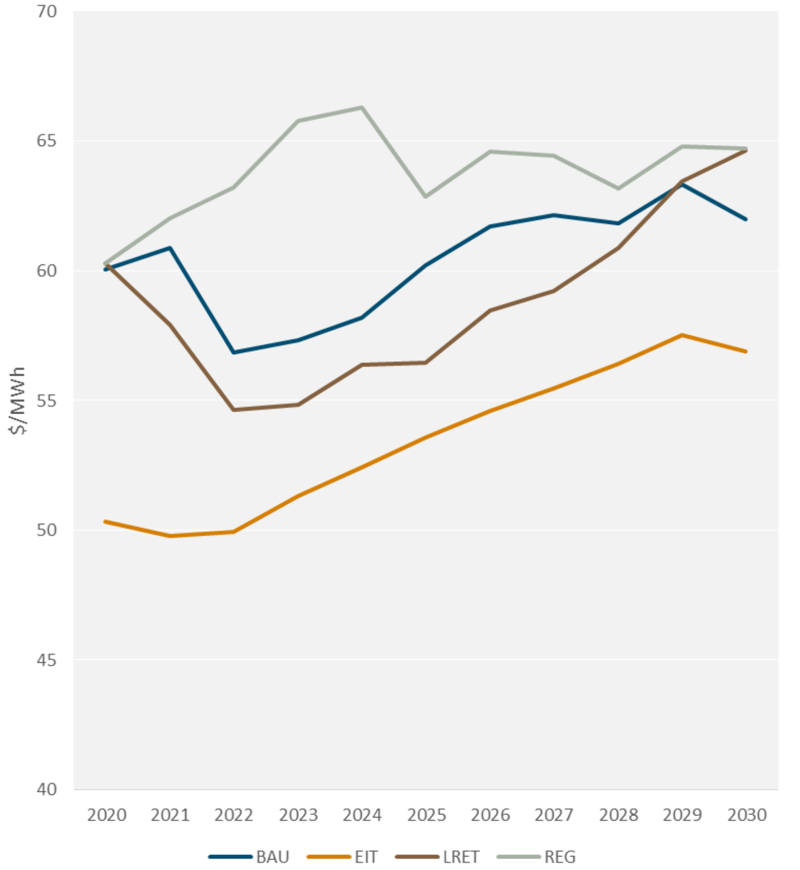
Of the three emissions reduction mechanisms, EIT has the lowest wholesale prices, a finding which is consistent with the base case. Moreover, under a pre-2020 Hazelwood closure, wholesale prices under EIT are even lower than BAU, which contrasts with the base case (Figure 4.2).

88 Hazelwood is a 1,542MW brown coal-fired power station, with annual output around 12 TWh , representing around 5 per cent and 25 per cent of Australia's and Victoria's energy consumption, respectively. Hazelwood is jointly owned by ENGIE (72 per cent) and Mitsui & Co Ltd (28 percent).

89 ENGIE Media Release, Hazelwood to close in March 2017, 03 November 2016. Available at http://www.gdfsuezau.com/media/UploadedDocuments/News/Hazelwood%20Clousure/Hazelwood%20closure%20-%20Media%20release.pdf

90 See Table 6 in Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

Figure 5.4 **National weighted-average wholesale prices (including LGC levy) under pre-2020 closure of Hazelwood ($/MWh)**



Source: Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

Resource costs are higher under BAU in a scenario where Hazelwood closes prior to 2020, compared to resource costs under BAU in the base case (Table 5.5). The higher costs under BAU reflect the costs of switching from low-cost brown coal to higher cost fuels (black coal, and gas).

Table 5.5 **Resource costs under pe-2020 Hazelwood closure and under base case (NPV, Real2016$ billion, 2020-2030)**

Emissions reduction mechanism 2020 onward	Base case	Hazelwood closure pre-2020
BAU (i.e. no emissions reduction mechanism)	$55.3	$57.6
EIT	$60.8	$61.1
Extended LRET	$66.6	$67.8
Regulatory Closure	$61.1	$61.5

Source: Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016

The higher resource costs under BAU in a pre-2020 Hazelwood closure scenario result in higher resource costs for each of the emissions reduction mechanisms compared to the resource costs for each mechanism in the base case: if early closure were a lower-cost outcome, then it would have already occurred in the base case modelling. The smallest increase in resource costs occurs for EIT, and the largest increase for Extended LRET. As Hazelwood exits in 2021/22 in EIT (and Regulatory Closure) under the base case, the assumption of a pre-2020 closure has minimal impact on resource costs for EIT and Regulatory Closure. A pre-2020 closure assumption leads to a larger increase ($1.2 billion) in resource costs for Extended LRET, as Hazelwood remains in the NEM over the entire 2020-2030 period in the base case.

5.5.2 Impact on costs of abatement

Under a pre-2020 closure of Hazelwood, average abatement costs are lowest for EIT and highest for Extended LRET (Table 5.6). This ranking of abatement costs is the same for the base case. Furthermore, abatement costs for Extended LRET increase when moving from the base case to a pre-2020 Hazelwood closure scenario. This increase in abatement costs reflects the fact that resource costs increase the most under Extended LRET ($1.2 billion; see Table 5.5) than under the other two emissions reduction mechanisms.[91]

Table 5.6 Average cost of abatement under pe-2020 Hazelwood closure and under base case (NPV, Real2016$, 2020-2030)

Emissions reduction mechanisms	Base Case		Hazelwood closure pre-2020	
	Discounted	Not discounted	Discounted	Not discounted
EIT	$30.4/t	$17.5/t	$28.8/t	$16.2/t
Extended LRET	$75.7/t	$42/t	$85.1/t	$46.9/t
Regulatory Closure	$34.2/t	$19.5/t	$35.2/t	$19.5/t

Source: Frontier Economics, *Emissions reduction policy options*, A report prepared for the Australian Energy Market Commission, November 2016.

In contrast to Extended LRET, the average cost of abatement under EIT is lower in the pre-2020 Hazelwood closure scenario than under the base case. The findings in Table 5.5 and Table 5.6 further illustrate that EIT remains the most cost-effective emissions reduction mechanism, due to its more adaptable design compared to Extended LRET. The EIT mechanism is technologically-neutral, which encourages the least-cost form of abatement to be adopted by the market. It is also inherently self-correcting as it has the flexibility to cost-effectively adapt to incorporate a future without Hazelwood in the market.

91 The average cost of abatement is defined as the change in resource costs from BAU divided by the change in emissions from BAU.

5.6 Summary of the above findings

A mechanism that can successfully achieve the chosen emissions reduction target while minimising electricity sector impacts – on security, reliability and costs to consumers – under a wide range of conditions is likely to be sustainable over the long term. Conversely, a mechanism yielding abatement costs or price outcomes that are highly sensitive to the accuracy of particular assumptions is likely to be vulnerable to pressures for redesign if and when the future turns out to be different than previously expected. The likely result is investment uncertainty and higher long-term costs for consumers, with neither the emissions reduction nor energy policy objectives being met.

The findings from the base case (see Chapter 4) revealed that the EIT mechanism typically results in the lowest: resource costs; costs of abatement; and increase in wholesale prices, of the three emissions reduction mechanisms. The findings in Chapter 5 reveal that these base case findings are robust to a multitude of alternative views about future emissions reduction targets, technology costs, and electricity demand.

Collectively, the results in Chapters 4 and 5 demonstrate that, of the three emissions reduction mechanisms, the EIT is the most cost-effective, flexible, and scalable, capable of achieving the specified emissions reduction target, irrespective of the future path of input costs, demand growth, and other key parameters. These findings reflect the decentralised nature of decision-making embodied in the EIT mechanism, which give it much greater flexibility and adaptability to alternative views about the future, and adaptability to unexpected changes in non-policy variables, than the other emissions reduction mechanisms.

6 Literature review

This chapter reviews recent analysis of electricity sector emissions reduction policies by the Climate Change Authority, the Climate Institute, the Energy Networks Association and the Grattan Institute. The objective of this chapter is to compare the publically available work of other organisations with the results and analysis in this report.

Analysis conducted by other organisations may not be directly comparable across studies as assumptions or methodologies may differ. However, the relative performance of policies analysed by other parties provides useful context for the results presented in Chapter 4.

6.1 The Climate Change Authority

The Minister for the Environment requested that the Climate Change Authority (CCA) conduct a Special Review into Australia's climate action. The Review conducted in several parts. This section will focus on Report Three of the Review which looks at what action Australia should take to deliver on its international commitments following the United Nation's Framework Convention on Climate Change Paris Conference.[92]

As part of the Review, the CCA conducted and published modelling to examine the impacts of different illustrative policy approaches in the electricity sector. As the electricity sector is a significant contributor to national emissions and is characterised by long-lived capital investments it is seen to provide a useful case study for comparing policy options to reduce emissions.[93]

The CCA modelled seven policy under a two degree emissions budget. The work also included sensitivities, including a three degree emissions budget, and policies were also modelled in combination. The seven policy scenarios may be classified into three broad categories:

- **market mechanisms:** A cap and trade scheme and an emissions intensity schemes. These policies put a direct price on emissions in order to change the relative price of high- and low-emissions generation;
- **technology pull policies:** The RET, a low emissions target (LET) and contracts for difference. These policies subsidise renewable or low-emissions generation technologies, thereby changing the generation mix; and
- **regulatory policies:** Regulated closure and absolute baselines. These policies change the generation mix by removing high-emissions generation through regulations.

For each of the seven policy scenarios described above, a number of assumptions were made. These are:

- all policies modelled are announced in 2017-18 and start in 2019-20;

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92 See: http://climatechangeauthority.gov.au/reviews/special-review

93 Climate Change Authority *Modelling illustrative electricity sector emissions reduction policies*, Final report, 25 August 2016.

- the current LRET and SRES trajectories between 2020 and 2030 are included in all modelled policy scenarios and the base case;
- all prospective zero- and low-emissions technologies - including nuclear - are available to meet the emissions budget;
- the Emissions Reduction Fund's safeguard and crediting mechanism are excluded from the modelling; and
- offsets from other sectors or international permits are omitted from the scenarios modelled.[94]

6.1.1 Key findings

All of the emissions reduction mechanisms modelled, except regulated closure, were able to meet the emissions budget consistent with 2°C warming.

All of the emissions reduction mechanisms led to higher economic costs. The results show that emissions pricing policies (including a carbon price and emissions intensity target) were associated with the lowest resource costs. The highest resource costs in the CCA's work occurred under the RET and regulatory closures policy.

The generation mix changed under each policy modelled. Renewable energy is projected to make up between 60 and 80 per cent of the generation mix by 2050. There is a higher proportion of renewable generation under the technology pull policies as they provide a subsidy for this generation. The proportion of renewables in the generation mix is lower under the market mechanisms modelled as gas generation increases.

With respect to wholesale electricity prices the CCA find that:

- wholesale prices are generally highest under the carbon price policy;
- under EIT, wholesale prices also increase but by less than under the carbon price; and
- technology pull policies result in wholesale prices that are below or around those under the reference case (BAU). This is because these policies suppress the wholesale price by providing a subsidy to renewable generators.

The results for retail prices show that:

- market mechanisms and regulatory policies affect the wholesale price (as discussed above), but leave other components of retail prices unchanged;
- technology pull policies cause retail prices to increase as the cost of the subsidy is borne by retailers and passed on to consumers; and
- climate policies are not expected to affect network costs.

The CCA also modelled a number of policy combination scenarios. Under each of these scenarios a combination of policies were enacted to achieve the 2°C emissions constraint rather than just using a single policy. The results of these policy combination scenarios show that all policy combinations resulted in higher economic costs than emissions pricing policies operating alone but lead to lower costs than either technology pull or

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94 This is consistent with the "closed" EIT scheme modelled by the Commission.

regulatory policies alone. The lower cost of the policy combinations relative to the technology pull or regulatory policies is due to the policy combinations providing direct incentives for a wider range of abatement options than the individual policies.[95]

In addition to the modelling results, the CCA recommends a package of measures, or a "policy toolkit" which should be implemented in order for Australia to meet its international commitments to reduce emissions. The CCA's report acknowledges that, in recent years, climate policy in Australia has been characterised by uncertainty and frequent changes in direction. As a result of this previous uncertainty, the CCA recommends that future emissions reduction should be achieved by building on policies currently in operation. An advantage of this approach, according to the CCA, is that it would send a signal to investors and the broader community that climate policy would be stable in the future. Building on existing policies would provide confidence that the policy architecture would endure and would be capable of meeting Australia's emissions reduction commitments.[96]

With respect to the electricity sector, the Authority recommends that a market mechanism, in the form of an emissions intensity scheme, should be part of Australia's policy toolkit. The CCA says that market mechanisms are capable of making a significant contribution to the emissions reduction objective in a way that is both flexible and scalable.[97]

6.1.2 Comparison with AEMC work

This section focuses on comparing the AEMC work with the CCA's 3 degree scenario, which is the most comparable to the AEMC's work.[98] The results of the two modelling exercises differ due to the assumptions and inputs used in the modelling. The main points of difference are:

- The target for emissions reduction is higher in the CCA work. The three degrees scenario implies an emissions reduction of 38 per cent on 2005 levels, compared with 28 per cent in the Commission's work;
- In the AEMC's modelling the gas price used as an input is lower than that used by the CCA. The projected costs of renewable technologies are also slightly higher in the AEMC's work that in the CCA's modelling. Both of these input assumptions will have an impact on the uptake of renewables relative to gas in the AEMC's results.

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95 Climate Change Authority *Modelling illustrative electricity sector emissions reduction policies* Final report, 25 August 2016, p 9.

96 Climate Change Authority *Towards a Climate Policy Toolkit: Special Review on Australia's Climate Goals and Policies* Summary, p5.

97 Climate Change Authority *Towards a Climate Policy Toolkit: Special Review on Australia's Climate Goals and Policies* Summary, p7.

98 It should be noted that the CCA conducted the scenario with a carbon budget consistent with 3 degrees warming as part of its sensitivity analysis. The scenario was conducted purely for the purpose of testing the model sensitivity and does not reflect the CCA's endorsement of a three degree temperature increase as a policy objective.

Despite the differences in modelling inputs and assumptions the CCA and AEMC works produce similar results with respect to the relative performance of emissions reduction mechanisms.

Wholesale prices are generally highest under the carbon price scenario in the CCA work. Under EIT, the increase in wholesale prices is considerably less. This is consistent with the qualitative analysis presented by the Commission.

In addition, the CCA's modelling shows that wholesale prices are generally lowest under the technology pull scenarios, including the RET. This result is because of the downward pressure placed on wholesale prices as a result of increased renewable capacity in the market and the implied subsidy provided by the certificate revenue under these schemes. Again, this result is in agreement with the Commission's modelling of wholesale prices.

The relative performance of the emissions reduction mechanisms in terms of resource costs and costs of abatement are the same in the two studies. The CCA find that resource costs are lowest under the EIT mechanism and highest under the RET. The cost per tonne of CO_2e abated results in the CCA modelling shows that the EIT abatement cost is lower than either the RET or REG mechanisms. Resource costs and cost of abatement are significantly higher in the technology pull scenarios. These findings are both consistent with the AEMC results

6.2 The Climate Institute

The work conducted by the Climate Institute is motivated and informed by the international Paris Agreement, which saw countries agree to limit climate change to 1.5 to 2°C above pre-industrial levels.[99]

The Climate Institute commissioned electricity market modelling to assess policy options to achieve emissions reductions that are consistent with the less than 2°C goal. Five scenarios were considered in the modelling, which included variations around different levels of carbon pricing with and without a clean energy target.

The modelling initially compares a scenario with a carbon price consistent with the less than 2°C increase in global temperatures goal with a policy that prices carbon at a level currently seen in existing international markets. The base scenarios are summarised in Table 6.1.

Additional scenarios are modelled that add a policy similar in design to the LRET and a regulated closure policy to the weak carbon price scenario. The LRET scheme modelled is a certificate scheme that targets 50 per cent clean energy by 2030.[100] The regulated

99 This section is based on The Climate Institute, *A switch in time: Enabling the electricity sector's transition to net zero emissions* Policy Brief, April 2016.

100 For the purposes of this report clean energy is not confined to renewable power, any technology that produces less than 0.2 tonnes of greenhouse gases per megawatt of electricity generated is considered clean energy.

closure scheme modelled is the imposition of a 45 year operating lifetime limit on coal-fired power stations.[101]

Table 6.1 Base case scenarios modelled

	2°C Carbon Price	Weak Carbon Price
Overview	This scenario defines what the electricity sector needs to do for the most efficient transition to meet the <2°C goal	A proxy for a national baseline-and-credit or cap-and-trade scheme set at a level that reflects carbon prices currently seen in existing markets and company disclosures
Carbon Price	Global Carbon Price - $70/t in 2020; $110/t in 2030; and $275/t in 2050	$17/t from 2020, rising 8 per cent per year to reach $40/t in 2030. After 2030, carbon price jumps in order to achieve the carbon budget
Carbon budget	No more than 1,760 million tonnes by 2050	

6.2.1 Key findings

In terms of emissions, the report finds that a weak carbon price alone will exceed the carbon budget by 550 million tonnes.[102] The inclusion of the LRET-like policy and a policy to systematically close coal-fired generators with the weak carbon price will also exceed the chosen carbon budget, however, this is reduced to 290 million tonnes.

In terms of changes to the generation mix, the 2°C Carbon Price scenario drives a sustained decline in coal generation over about 12 years. Under the Weak Carbon Price, very few coal-fired generators retire in the 2020s. This means that in order to meet the carbon budget a large amount of high-emissions generation must exit the market in a short period of time.

In terms of cost, the results show that the 2°C Carbon Price and the Weak Start Carbon Price scenarios are similar. However, the Climate Institute contends there are risks associated with the disruptive economic impact of the latter policy. These costs are not quantified. The scenario in which a LRET and closure policy are added to the weak carbon price is $50 billion more costly than the base scenarios, however, relative to the weak carbon price scenario the Climate Institute consider it could provide significant benefits for that extra cost, in terms of reducing the risks of price and system security shocks.

In all the scenarios modelled, wholesale prices converge around the long-run marginal costs of new investment (around $110-$120/MWh as clean energy replaces coal generation). Where the modelled scenarios differ is in the timing and trajectory of this

101 Coal-fired generation must either close or retrofit carbon capture and storage to comply with an emissions performance standard of 0.2t CO_2e/MWh when they reach a 45 year operating life.

102 The carbon budget in this instance is consistent with limiting the increase in global temperatures to 2 degrees.

price increase. The weak carbon price scenario delays adjustment in the sector, therefore electricity prices are lower for longer during the modelling period, but they jump significantly after 2030. The increases in wholesale prices are more gradual under the other scenarios.

Finally, the report recommends the use of all policy levers available with an awareness of the need to manage the tensions between policies. In the absence of a strong carbon price that has political and public support, the Climate Institute support the use of a package of measures. This package of policies would include a politically sustainable carbon price, policies that incentivise investment in clean energy, policies that ensure timely exit (such as regulations to close coal power stations) and energy efficiency policies.

6.2.2 Comparison with AEMC work

While the Climate Institute's work is not directly comparable with the Commission's analysis, there are some similarities in the results. The outcomes show that the scenarios that establish a market for carbon are the least-cost and most effective at achieve the emissions reduction objective. The Climate Institute emphasises that a price signal is needed to bring about the exit of existing coal generation and the entry of new clean energy.

6.3 The Energy Networks Association

The objective of Energy Networks Association (ENA) study was to quantify the impacts of a number of alternative policy approaches to achieving two different emissions reduction targets: 26 to 28 per cent below 2005 levels by 2030 and 45 per cent on 2005 levels by 2030.

The work focuses on achieving the emissions reduction targets in stationary energy activities through two alternatives to BAU over a modelling period from 2020 to 2035. These are summarised in Table 6.2.

Table 6.2 ENA emissions reduction scenarios

Scenario	Description
Technology neutral framework scenario	• Assumes current abatement initiatives such as LRET are made technology neutral • Safeguard Mechanism evolves to an intensity target scheme where trading among participants is permitted
Explicit carbon price scenario	• Explicit carbon price is established through the equivalent of the whole of economy carbon tax or emissions trading scheme • All other abatement policies are removed.

6.3.1 Key findings

The results of the ENA's modelling with respect to electricity generation are:

- Emissions abatement is realised from switching from coal to a mix of CCGT and renewable energy. The proportion of this fuel switching mix is determined by the policies used.
- Overall fuel usage declines due to a fall in overall demand and, in some scenarios, increase in generation from renewable energy sources.
- Gas usage must increase in all scenarios - the level of this increase ranges from 35 to 61 per cent. Gas usage is highest in the technology neutral scenarios.
- Brown coal decreases and renewable energy increases in all scenarios.
- Under all scenarios, an increase in investment in new gas and renewable generation plant is required.

In terms of costs, the results show that the explicit carbon pricing scenarios have the lowest cost. The relative cost savings associated with the carbon price scenario are larger under the 45 per cent emissions reduction target scenarios. The results are summarised in Table 6.3.

The results with respect to residential electricity bills and residential electricity prices show that the technology neutral framework scenario results in the lowest cost relative to BAU and the explicit carbon price scenarios.[103]

Table 6.3 Resource costs to electricity sector (NPV, Real2016$, 2020-2035)

	Abatement target			
	26 to 28 per cent		45 per cent	
Policy Settings	**Total Cost**	**Savings relative to BAU**	**Total Cost**	**Savings relative to BAU**
Business as usual	$127.9 bn	-	$139.5 bn	-
Technology neutral framework	$127.0 bn	$0.9 bn	$138.2 bn	$1.3 bn
Explicit carbon price	$126.4 bn	$1.5 bn	$135.3 bn	$4.2 bn

Source: Energy Networks Association *Australia's Climate Policy Options: Modelling of Alternate Policy Scenarios* Final Report, 22 August 2016, p13, 17.

103 Energy Networks Association *Australia's Climate Policy Options: Modelling of Alternate Policy Scenarios* Final Report, 22 August 2016, p.17.

6.3.2 Comparison with AEMC work

There are two emissions reduction mechanisms included in the technology neutral framework scenario, the emissions intensity scheme and the low emissions target (LET). The LET provides a subsidy to all generation with an emissions intensity of less than 0.6t CO_2e/MWh. While there are some similarities between the ENA's level playing field scenario and the AEMC's EIT mechanism, they are not directly comparable.

That said, the Commission and the ENA both found that the EIT and technology neutral framework scenarios had lower wholesale prices *relative* to BAU. In contrast to the Commission's findings, the ENA found that resource costs were lower under its technology neutral framework compared with BAU.[104] This difference is likely due to the emissions intensity scheme being combined with a LET, instead of the existing LRET, as included in the Commission's modelling. Because the LRET subsidises a narrower range of technologies compared to a LET, this approach results in resource costs being higher under the Commission's EIT mechanism relative to BAU.

The total cost results from the ENA are not directly comparable with the AEMC's work. It should be noted that the cost results are higher than the AEMC's analysis. This is partly due to the time periods for the analysis: the ENA results are calculated over the period 2018-2035, whereas the AEMC costs are calculated over the period 2020-2030. In addition, the ENA modelling includes both the electricity and direct combustion sectors, while the AEMC work focuses on the electricity sector alone. The costs results in the ENA report also show savings relative to BAU, while the AEMC results show that all emissions reduction mechanisms involves some resource costs. The reason for this difference is that, in the ENA's work, the emissions reduction target is met under BAU. This is modelled to have been achieved through current government policy. In contrast, in the AEMC work there is no emissions reduction target included in the BAU case.

6.4 The Grattan Institute

The work by the Grattan Institute provides a qualitative assessment of a range of policies that could be used to achieve the current, and potential future, emissions reduction objectives.[105] These policies fall into two categories: policies which do and do not explicitly price carbon.[106] Policies that do not explicitly price carbon involve measures that either require or incentivise emissions reductions.[107]

A key message from this report is that all policy options in this area are imperfect and that implementation of a credible policy framework will involve some trade-offs. Therefore, it is necessary to define criteria that an ideal emissions reduction policy

104 It should be noted that the BAU in the ENA modelling is not the same as the BAU in this report. The BAU in the ENA report reflects a case in which a policy is put in place to meet the emissions reduction target without the trade of permits. The BAU in the ENA report is therefore said to reflect the current ERF and Safeguard mechanism, which is excluded from the AEMC's BAU.

105 This section is based on Wood, T., Blowers, D. and Moran G., Post Paris: Australia's climate policy options, Grattan Institute Working Paper, December 2015 and Wood, T. and Blowers, D., Climate phoenix: A sustainable Australian climate policy" Grattan Institute Report No. 2016-6, April 2016.

106 Such as a carbon tax, a cap and trade or an intensity baseline and credit.

107 Such as regulation, emissions purchasing schemes or tradeable green cert schemes such as the RET.

would possess. Criteria to assess policy options are identified including: credibility, political viability, flexibility, adaptability, public acceptability and cost.

The Grattan Institute also provide a "roadmap" for how the existing policy environment could be altered over time in order that Australia can meet "commitments to limit global warming while easing the cost and disruption to Australian households and businesses".

The roadmap outlines three steps which initially strengthens the government's existing policies and builds on them in a manner consistent with the policies and preferences of the Coalition and Labor Parties. This bipartisan approach is said to be necessary to provide predictability that business needs to transition to a low-carbon economy.

6.4.1 Key findings

As mentioned above, this work is of a qualitative nature, therefore there are no modelling results. However, the discussion does include two items of relevance to the Commission's work. These are the recommended approach to the electricity sector and the discussion regarding government intervention to close power stations.

Electricity sector policy approach

The report proposes that the electricity sector be treated differently to the rest of the economy and a separate roadmap for electricity is proposed. This roadmap can be summarised as:

1. Strengthen the Safeguard Mechanism by reducing the existing sector-wide absolute baseline in line with the emissions reduction target;
2. Move to an emissions intensity target scheme; and
3. Evolve the emissions intensity target scheme into a scheme with full auctioning of permits.

The separate treatment of the electricity sector is justified by the Grattan Institute because emissions are dependent on both the amount of electricity produced as well as the emissions intensity of the source of generation. Emissions could be reduced by switching generation from coal to CCGT and there should be no impediment to this fuel switching taking place. Therefore, the report identifies that an appropriate option for the electricity sector would be to set an intensity target for the sector.

Regulated closure

The Grattan Institute argue that, unless the government has perfect foresight and perfect information, it is likely that regulated closures would lead to higher cost emissions abatement than other policies. Generator closure should be based on outcomes that would occur under a credible carbon price. The chances that governments could successfully predict the right order for closures are low.

The report also cautions that government intervention in the market may, by itself, change market dynamics. If government pursues a regulated closure policy, some generators may delay exit because there is a possibility that they may be paid to close.

Again, this would have implications for cost of abatement outcomes and governments may use taxpayers money to pay for closures that may have occurred without payment.

The Grattan Institute note that, in an environment where there is a sustainable policy which has bipartisan support in place, there would be less need for government intervention to address uncertainty and achieve abatement targets.

6.4.2 Comparison with AEMC work

The analysis undertaken by the Grattan Institute focuses on similar areas as the Commission's work. The findings with respect to the relative advantages and disadvantages of policy options are broadly similar to the Commission's analysis.

The Grattan Institute undertook an assessment of an emissions intensity target scheme, similar to that presented in Chapter 2. In this analysis an emissions intensity scheme is said to be more credible than existing policy as it is directly linked to Australia's emissions reduction targets. The scheme is also flexible and would provide political viability and public acceptance as it limits the impact of emissions reduction policies on electricity prices.

The Grattan Institute reiterates the Commission's views that regulatory closure policies risk changing market dynamics and introducing a barrier to exit, with generators delaying exit to potentially receive a payment from government.

Abbreviations

AEMC or Commission	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AESCs	Australian Electricity Sector Credits
BAU	Business-as-Usual
CCGT	Combined-Cycle Gas Turbine
COAG	Council of Australian Governments
EIT	Emissions Intensity Target
EITEs	Emissions-Intensive Trade-Exposed industries
ETS	Emissions Trading Scheme
LGCs	Large-scale Generation Certificates
LRET	Large-scale Renewable Energy Target
NEM	National Electricity Market
NEO	National Electricity Objective
SCO	Senior Committee of Officials
SWIS	South West Interconnected System

ADVICE ON THE INTEGRATION OF ENERGY AND CLIMATE POLICY

AEMO STAGE TWO REPORT

November 2016

AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

AEMO has prepared this document to provide information about the integration of energy and climate policy, as at the date of publication.

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EXECUTIVE SUMMARY

Task

In early 2016 the Council of Australian Governments (COAG) Energy Council sought advice from the Australian Energy Market Commission (AEMC) and AEMO on the interaction between energy and emissions reduction policies in the National Electricity Market (NEM). The institutions were asked to contemplate three policy approaches for meeting Australia's emissions targets within the NEM during the period 2020-2030.

AEMC undertook economic modelling of these three approaches, analysing new investments, costs and customer impacts. AEMO then analysed these model outputs for system security implications.

This is a report into AEMO's work, and is intended to be read as an appendix to AEMC's report.

To our knowledge, this work, and the contemporaneous 2016 National Transmission Network Development Plan (NTNDP), are the first attempts at interpreting system security implications from the outputs of a long-term economic model. Being intended for high-level policy analysis, the modelling commissioned by the AEMC was not designed to produce the type of outputs necessary for this form of analysis. This has required a number of improvised approaches to be used to extend its use for this purpose.

The 2016 NTNDP modelling uses a different approach which, while still not ideal, is more directly useful for system security analysis. Although it does not cover all of the same emissions reduction policies, it was emissions constrained to a similar emissions reduction target. AEMO encourages readers to review the 2016 NTNDP for greater depth of analysis on system security matters. No attempt was made to harmonise AEMC's and 2016 NTNDP modelling, which use different inputs and models, which resulted in significant differences between the two sets of results.

In both this work and the NTNDP modelling, the approach has been to undertake economic or market modelling and then to review the results to assess system security. This linear approach of economic modelling followed by engineering analysis of security outcomes is problematic as the NEM is fundamentally based on security constrained, economic dispatch. This inextricably links the two. It is a requirement of the National Electricity Rules (NER) that the power system be operated in a secure state, and to do so AEMO can constrain network flows or direct generators to achieve this; hence security is always maintained, albiet at an economic cost. In the AEMC modelling, it is assumed that the current network limits are maintained and that AEMO would not otherwise intervene to maintain or restore a secure operating state. However these limits would change in line with the generation changes being modelled. AEMO therefore looked for dispatch outcomes in which applying the assumed network limits could be inconsistent with maintaining a secure operating state, with a view to identifying what would be required to restore security.

AEMO is undertaking a major line of work, the Future Power System Security (FPSS) program, which is exploring what is needed to maintain a secure operating state given similar challenges highlighted in this report and the 2016 NTNDP. FPSS is finding many potential options to resolve many different issues, each with quite different cost and other impacts. Whilst maintaining network capacity through these changes will be technically complex and time consuming, AEMO considers their costs likely to be small compared to the other costs being assessed by the AEMC. AEMO has therefore not attempted to quantify these costs for this report.

The requirement to maintain system security under the current rules is limited to 'credible' contingencies. AEMO's work in the FPSS program has found that the changing generation mix is changing the power systems ability to survive 'non-credible' contingencies which, while unlikely, are plausible. Our assessment for this work considers a limited subset of events which we consider are low probability but which have serious consequences should they occur.

Observations

AEMO undertook Rate of Change of Frequency (RoCoF) analysis from AEMC's 28% carbon reduction scenarios.

As a result of existing policies, South Australia requires actions to be taken prior to 2020. These are underway through FPSS. After 2020, the Emissions Intensity Target (EIT) policy and Regulatory (REG) policy did not worsen South Australian RoCoF. The Large-Scale Renewable Energy Target (LRET) policy marginally deteriorated conditions after 2020, which would require some additional rectification.

Tasmanian RoCoF was observed to worsen in the LRET scenario after 2020, but not in the other policies. Queensland appeared to maintain acceptable RoCoF in all scenarios. New South Wales and Victoria were not studied as they are not significantly exposed to separation from all other regions.

Installation of large-scale solar in Queensland in the LRET case would likely cause AEMO to dispatch a significant volume of Frequency Control Ancillary Service (FCAS) regulation in Queensland pre-separation. Adequate supply is however likely to be available from the remaining fossil generators and potentially from the new renewable plants.

In the 50% emissions reduction cases, the EIT and REG policies achieve their ambitious abatement target mainly through replacing coal fired generation with gas-fired generation. This would involve considerable transitional risks and greater demands on gas infrastructure, but analysing these are beyond the scope of this task. The 50% LRET case includes extended periods in all regions where no synchronous generation is dispatched and some periods where no mainland synchronous generation is dispatched at all. This would require actions, along the same lines as FPSS is promoting for South Australia independently, to be undertaken in all regions.

In the 28% and 50% LRET, some other security related matters could also prove challenging to manage:

- Network voltage control/reactive power.
- Network system strength/fault levels.

These were not analysed in this task as they are strongly location and technology dependent, information which was not readily assessable from the economic model outputs. For more background, please refer to the 2016 NTNDP.

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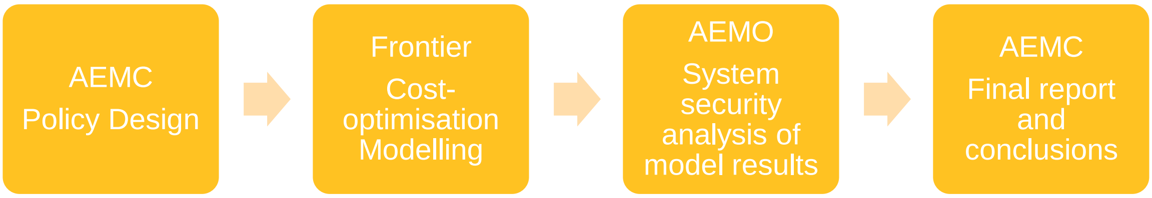
1. INTRODUCTION

On 18 February 2016, the Senior Committee of Officials (SCO) of the COAG Energy Council wrote to the AEMC and AEMO requesting advice on the interaction between energy and emissions reduction policies in the NEM.

This report is intended to be read as an incorporated section within the AEMC's final report which provides background on our respective roles in this project. Consistent with AEMO's functions and the research scope described for AEMO as "Task 2" in the letter, AEMO has only engaged with power system security matters.

The carbon reduction policies were developed by AEMC, who engaged Frontier Economics to perform cost-optimisation modelling to assess the broad economic costs, investments and prices that would result from each of these policies. AEMO has reviewed the investments Frontier has forecast, and assessed this for power system security implications. AEMC have then contemplated Frontier's and AEMO's results for their final report, as described by Figure 1.

Figure 1 Analysis Process



The Frontier work encompassed Western Australia's South West Interconnected System (SWIS) as well as the NEM. Consistent with the COAG request, AEMO's analysis was limited to the NEM.

1.1 The 2016 National Transmission Network Development Plan

AEMO is also applying a 28% pro-rata reduction in carbon emissions from 2005 levels by 2030 in the NEM in its ongoing forecasting and planning processes. To that end, the 2016 National Electricity demand Forecasting Report (NEFR) and 2016 NTNDP are emissions constrained. The 2016 NEFR was published in June, and the NTNDP will be published in mid-December.

The NTNDP incorporates a cost-optimisation model to determine the likely location and type of generation before assessing opportunities for efficient network development. The 2016 NTNDP will, for the first time, also include a system security analysis on the model outputs in a broadly similar approach to what has been attempted for this report.

As these are the NTNDP's major objectives, it employs a more granular approach to modelling generator locations, and also dispatch in specific time periods, than was used by Frontier, who focused on economic analysis. This means the NTNDP should be seen as the more authoritative source on the evolving power system security environment of the NEM. Further, the NTNDP has analysed more power system security themes that this COAG task, such as system strength and voltage stability.

The NTNDP's underlying generation modelling has differences to this work, and AEMO is not harmonising them. Significant known differences include:

- *Policy Design* – The carbon constraint in the NTNDP model has broadly similar effects on generator incentives as the emissions intensity scheme analysed by the AEMC, however wholesale prices will tend to be higher with AEMO's approach, which in turn affects total demand.

- *Demand Forecast* – As the Frontier modelling began in early 2016, it drew its input demand forecast from AEMO's 2015 NEFR. The 2016 NEFR, released in June 2016, notably reduced energy and peak demands in some regions, and the 2016 NTNDP will use this.
- *Gas Prices* – The NTNDP uses a materially higher gas price forecast than was applied by Frontier in their base scenario, who derive their own forecast from a proprietary gas model. Frontier however included a "high gas price sensitivity" which is close to that used by the 2016 NEFR. AEMO paid particular attention to this sensitivity, as the security concerns are expected to be greatest in scenarios with less gas-fired generation.
- *Transmission Development* – As the key output of the NTNDP is network development, it explored numerous potential network upgrades, optimised within the model. Frontier's modelling did not explore shared network augmentations.
- *Model* – A different simulation model is used, which invariably produces different outcomes even for the same inputs. In particular the simplifications associated with time slicing, discussed in section 3.1.1, produce particular challenges in creating a representative distribution of intermittent generation, which become material at the penetration levels being modelled. This is also discussed in section 3.1.2.

2. ASSESSING POWER SYSTEM SECURITY

2.1 Definition

Power system management is assisted by understanding the clear distinction between the concepts of *reliability* and *security*.

Power system *reliability* means the adequacy of installed capacity to meet demand, i.e. “do we have enough total generators built?” Assessing installed capacity against the reliability standard is an arithmetic process, readily captured within cost-optimisation models.

Power system *security* means the robustness of the power system to both maintain quality of supply to customers, and to tolerate foreseeable disturbances without suffering plant damage or widespread interruption. Investigating power system security requires electrical engineering analysis, using tools such as Alternating Current (AC) loadflow and stability modelling. This work then defines a *secure system envelope* within which the market can be dispatched. For example, network limits are set sufficiently conservatively such that the worst credible contingency can be tolerated.

2.2 AEMO’s broad approach

In tasking AEMO with analysing the economic modelling outputs, the SCO letter requested that AEMO study both reliability and security implications. However, Frontier’s model is *reliability constrained*, i.e. it builds the least cost supply needed to meet the reliability standard. This is standard industry practice, being based on a reasonable assumption that market settings will be adjusted to ensure sufficient incentives exist for investment in adequate generation capacity to meet the reliability standard. Thus, by design the Frontier results will always be *reliable*, regardless of policy.

A cost-optimisation model does not directly assess *security*, but it is implicitly recognised. These models incorporate, via simplified constraint equations, a representation of the secure system envelope described earlier. Thus, if the representation is sufficiently accurate, and the envelope does not change over the period of the modelling, then the results of the model would, by design, also be *secure*.

However the secure system envelope is dependent on the plant installed and operating, which the model is adjusting over time. The network constraints used by Frontier were developed for typical 2016 power system conditions. If the services provided by generators that assist security become less plentiful in 2030, then the market must either:

- Tighten the secure system envelope through dispatch constraints which will increase market costs through less economic dispatch.
- Invest in alternative sources of these services.

In reality, the actual outcomes will be a mixture of the two themes above, with numerous discrete decisions trading off these options. If the envelope must be tightened, then so should the constraints in the cost-optimisation modelling. However this implies an extremely complex iterative analysis, which has not been attempted.

Instead, given Frontier has maintained its network constraints as fixed, AEMO has reviewed the outcomes of its investment proposals and dispatch results, and assessed them for security infeasibility.

2.3 Contingencies

Power system limits are determined such that no *credible* contingency will cause plant damage or widespread disruption, such as a black system. Credible contingencies are defined in the NER and relate to the disconnection of a single power system asset, such as a generating unit or a transmission line.

It is, of course, impossible to make a power system secure against every conceivable contingency, and the NER's definitions are written around events that are reasonably probable. However most major power system incidents are triggered by a non-credible event, and so defining the appropriate list of credible events is a crucial part of system security analysis.

If AEMO becomes aware that a particular non-credible event has become more likely due to some unusual circumstance, it can re-classify the event as credible and, as a result, constrain the system such that the event would not lead to plant damage or widespread disruption. A common example is where a bushfire approaches an easement carrying two transmission lines: it then becomes relatively probable that the smoke will fault both lines, and AEMO will constrain dispatch such that the flow on the lines reduces.

Whilst the list of events that are normally considered credible is defined within the NER, this is likely to change over time. Where two transmission lines share towers over a long distance, the risk of simultaneous faults is inherently higher. AEMO expects the approach to some line segments to change over time, examples of which are discussed in section 3.2.1.

2.4 Assessed security matters

In assessing security, many electrical engineering matters must be considered. This includes:

1. Maximum current carrying capacity of assets, often described as "thermal constraints", before and after a contingency.
2. Voltage control: will voltages remain within acceptable limits, and not collapse following a contingency?
3. Fault levels/system strength. Where the network is "weak", i.e. has very high impedances, generators may be unable to remain stably connected as their own output affects local voltages.
4. Steady state frequency control, i.e. is there enough regulation frequency control ancillary services (FCAS) to maintain the normal conditions' frequency standards?
5. Contingency frequency control, i.e. is there enough FCAS available to maintain the system, post-contingency, within contingency frequency standards?
6. Mechanical stability[1], i.e. is there a risk of the power system breaking up through loss of synchronism between generators, either in the steady state (dynamic stability) or post-contingency (transient stability).
7. Fast frequency response/inertia, i.e., is the system heavy enough such that a post-contingent RoCoF can be arrested by FCAS or automatic load shedding?

Matter 1 (thermal constraints) is a relatively predictable characteristic of the network assets and should not change with the nature of generation investment. This has not been investigated.

Matters 2-3 (voltage control and system strength) are related to the network and generation fleet: certain generator types will create greater challenges in regard to these matters. However the challenges are extremely location dependent and the actual technology employed, e.g. the model of wind turbine and the connection equipment, such as reactive power equipment. These are matters for which a long-term model is not well suited to identify and assessment of these matters has not been attempted here. Note that in AEMO's 2016 NTNDP, post-model assumptions were made about the generator locations and models employed, and some assessment of these matters have been attempted.

Matters 4-7 (frequency control, mechanical stability and inertia) are interrelated concepts that are dependent on both the generation fleet and network. These matters do not require very granular

[1] "Mechanical stability" refers to the stability of the rotor angle differences between synchronous machines; i.e. how much each synchronous machine remains in step with each other.

generator investment information as they are usually analysed region-wide. Also, the specific generator/storage models are less important, as performance characteristics can be broadly grouped into:

- Synchronous, high-inertia. This is generally all thermal-based plants[2] except those using reciprocating engines.
- Synchronous, low-inertia. This is generally hydro and reciprocating engines.
- Asynchronous. This is generally wind or wave turbines, photovoltaics, direct current (DC) transmission lines and batteries.

Matters 4 & 5 (FCAS adequacy) is likely to be manageable because all of the above generator groups are technically capable of delivering FCAS, along with demand-side response. Whilst FCAS provision is presently dominated by synchronous generators in the NEM, should their prevalence decline, FCAS market signals would be expected to encourage more demand-side and/or asynchronous generation/storage FCAS participation. However the growth of large-scale photovoltaic generation is likely to create additional demands for regulation. An analysis exploring this likely growth from Frontier's Queensland results has been performed.

Matter 6 (mechanical stability) will change as the generation fleet moves away from large synchronous units and some aspects of mechanical stabilility may actually improve. However the characteristics are complex and it is difficult to infer trends that could be applied to this analysis. .

Matter 7 is a particular matter of interest for the NEM as it moves away from traditional generation sources to more asynchronous. This is because the stringy nature of the transmission grid, which includes interconnection based on long segments of double-circuit transmission towers, means it is reasonably probable that specific events will lead to regional islanding. The ability of the regions to successfully island without collapsing to a system black relates to:

- The amount of inertia in each island, which in turn slows the RoCoF.
- The speed at which post-contingent action, such as under-frequency load-shedding, can act.

This matter is also the issue that AEMO has been specifically studying, for South Australian islanding, in its FPSS work[3]

Matter 7 can be addressed by various actions, each of which involves some cost:

- Reducing pre-contingent interconnector flows, to reduce the shock of separation.
- Creating new ancillary services to retain a minimum quantity of inertia in every region, even where this requires a generator to operate at prices below its Short-Run Marginal Cost (SRMC).
- Installing new automatic load shedding controls which can arrest faster RoCoF.
- Install high inertia synchronous condensing equipment in the network.
- Obtaining very fast FCAS "synthetic inertia" from asynchronous plant.

Whilst these resolutions all involve some cost, the optimal resolution is likely to be of a lower order than the costs related to the construction of new generation plant, which is directly assessed in Frontier's model.

2.5 Linking to a cost-optimisation model

When considering modelling a power system, it may be helpful to group power system costs as follows, in an order of declining relative cost:

[2] Thermal plants includes all fossil fuel plants, as well as biomass, solar thermal, geothermal.
[3] Refer https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/FPSSP-Reports-and-Analysis

1. Distribution network costs. As these mostly relate to supplying peak demand, when modelling policies targeting large generators, they are not normally assessed as the policies' impacts upon them are second-order.
2. Generator capital and operating costs, including connection costs. These are directly impacted by the policy in question and are assessed within the model, including by Frontier's model.
3. Shared transmission network costs, which includes intra and inter-regional investments, some of which will be justified by the generation investments above. Depending on the form and objective of the modelling task, these may or may not be modelled. Given the expected low level of these costs compared to generation in the timeframe under consideration, the AEMC-Frontier work did not assess these.
4. FCAS and power system security reinforcement costs, i.e. matters discussed in section 2.3. Although they will be affected by policies affecting generator development, due to their technical complexity and low relative costs, these are not assessed in mainstream NEM models, including Frontier's.

The costs of the fourth category are likely to be small compared to a reasonable range of error in the other costs. Therefore AEMO did not approach this work as an analysis of material future "costs", but more as a qualitative alert of the matters that will require addressing by network planners and rule makers as the power system changes over time.

This work, along with the contemporaneous 2016 NTNDP, are the first time, to our knowledge, that the results of a long-term cost-optimisation generation forecast has been assessed for "system security impacts". Frontier's model was not developed for this purpose, and novel approaches were required to draw from its outputs a basis for a meaningful assessment.

3. ANALYSIS

3.1 Cost-optimisation model outputs

3.1.1 Time slicing

To enable workable solution times, cost-optimisation models use market simplifications such as dividing time into large blocks. Frontier's model represents the 8760 hours of a year as 44 time blocks, each of different durations. Some blocks are dedicated to the extreme high and low demand half hours of particular regions, whilst others represent much longer durations of less extreme demand conditions.

Thus the model need only solve 44 "dispatch intervals" every year, and evaluates dispatch quantities, costs, prices and profits in each of these, multiplying them by the length of the interval and sums to find annual values.

3.1.2 Creating an intermittent generation distribution

The dispatch intervals contain a range of intermittent generation outputs, however within each interval, the intermittent generation is fixed. Thus it does not explore the full stochastic distribution of intermittent generation dispatch that will occur at every demand level over a year. Meanwhile, to ensure the solution is reliability constrained (as discussed in section 2.2), the intermittent generation in the high demand intervals is limited to AEMO's "firm" (high confidence of exceedance) levels.

Inertia will be lowest at periods of low synchronous generation, which is likely to occur in periods of high intermittent generation and/or low demand. This required redispatching Frontier's model across a distribution of wind generation outputs: each of the 44 time slices were redispatched with wind generation reflective of 10%, 30%, 50%, 70%, 90% probability of exceedence.

The above approach is appropriate for wind for which, in Australia, shows no particular correlation to time of day or demand level. For solar this is clearly not the case, and the solar generation levels were not varied. This may underestimate the potential variation in the cases with a large penetration of large-scale solar.

3.1.3 Interpolating results over time

This redispatching required intensive model re-running effort, so it was only performed for the 2030 year, i.e. the end of the period of study. This was compared against the "business as usual" policy case for 2020, to determine how security conditions would change over the decade in each policy scenario.

3.1.4 Determining inertia

Frontier's model projects the output by power station, however available inertia depends on the number of synchronised units. This was determined by identifying the least number of synchronised units to meet a dispatch point. For example, if a station with 4*200MW units was dispatched to 450MW, 3 units were considered to be on-line.

In general this would be a conservative assumption for slow-starting units. Historical observation shows that generators usually commit more slow-starting units than is necessary for a particular dispatch level, presumably due to practical constraints relating to startup and shutdown times and costs and managing contract position risks.

3.1.5 Large-scale solar investments

To assess growing FCAS regulation requirements, it was only necessary to assess the investment in large-scale solar in each region. This was readily available from Frontier's results in all modelled years.

3.1.6 Sensitivities tested

The AEMC engaged Frontier to model each of the three policy scenarios with the following sensitivities:

- Base case input assumptions.
- High demand.
- Low demand.
- High gas prices.

AEMO tested the base case and high gas price sensitivity. As noted in section 1.1, Frontier's base case gas price forecast are materially lower than those being assumed in AEMO's other planning processes. The effect of higher gas prices is expected to shift some low emissions generation investments from gas to renewables in technology-neutral policies. Therefore it was considered prudent to investigate a high gas price sensitivity.

3.2 Contingencies tested

In testing for regional inertia adequacy (see explanation, section 2.3), one must first consider the limiting contingency.

In system normal conditions[4], network limits are set such that no credible contingency will cause alternating current (AC) separation[5]. Four AC lines interconnect Victoria and New South Wales. Two AC lines interconnect Victoria and South Australia and also New South Wales and Queensland. Where one of these lines is taken out of service for maintenance, separation becomes credible and flows are heavily restricted, which resolves the inertia problem.

The two lines that make up the Victoria-South Australia and the Queensland-New South Wales interconnectors run on single towers over many hundreds of kilometres. Whilst the simultaneous loss of both lines are considered by the NER as non-credible, experience has shown this event has much greater probability than independent co-incidence. Given this, and the extreme consequences of separation, AEMO considers it is likely that a concept of "protected event" will be introduced for these non-credible events, for which a black system should not be allowed to occur as a direct consequence.

AEMO has tested Frontier's results to determine when, on the occurrence of such a non-credible separation, the existing network would be unable to avoid either South Australia or Queensland collapsing to system black. We have determined this by assessing when the RoCoF would be too great to be arrested by the existing under-frequency load shedding systems. We have also assessed how much FCAS regulation service would need to be operating to maintain Queensland frequency post separation.

For Queensland, the entire state has been analysed as a single region on the loss of New South Wales interconnection. It should be noted that separation of Far North Queensland, from Nebo switching station northwards, is also potentially possible. Such a separation would also currently be considered non-credible.

For Tasmania, the contingency tested was the loss of the single DC interconnector. As this is a credible contingency in system normal conditions, a commercially procured automatic load shedding scheme triggers upon it; the Basslink Special Protection Scheme (SPS). The analysis has however been undertaken assuming SPS is not in service, which is still informative as it indicates the robustness of Tasmania to other, non-credible, contingencies with similar impacts.

Note also that some Tasmanian hydro generators are capable of operating in synchronous condenser mode at low cost during which they provide inertia – but, as there is no existing specific ancillary service designed to procure it, these were presumed to be not providing this in this study.

[4] "System Normal" means there are no transmission assets currently out of service for maintenance.
[5] AC connection is the critical matter here as the mainland direct current lines can transfer energy but not frequency response.

3.2.1 Contingency assumptions

The approach for determining post-contingent RoCoF assumes no change from current day circumstances. Conservative assumptions include:

- The existing automatic post-contingent control schemes remain unchanged for South Australia and Queensland. For these regions, under-frequency load-shedding is triggered on absolute frequency, from 49 Hz down to 47 Hz and does not detect separation or RoCoF. For Tasmania, the SPSS that operates on separation is assumed to be out of service. There is no centralised over-frequency generation tripping schemes in any of these regions.
- No asynchronous plant supplies any inertia of any form. In the future very fast frequency responses, sometimes described as “synthetic inertia”, may be obtainable from Murraylink, windfarms and battery storage. Research continues into how valuable such responses could be in reducing post-contingent RoCoF.
- No new synchronous condensers are installed in the transmission network. These provide inertia in a similar manner as that provided by synchronous generators.
- Inertia support is not explicitly recognised in energy dispatch or ancillary services markets.

The above does not imply AEMO considers these circumstances likely to still hold in 2030. For example, work on automatic control schemes may, at low cost, improve the power system’s ability to withstand higher RoCoF. This report should more be seen as an indicator of the priority that should be used to address these matters should one of the proposed policies be implemented.

Non-conservative assumptions include:

- All Queensland, South Australian and Tasmanian generators that are online at the time of contingency are capable of tolerating 4 Hz/s for up to 0.25s as per the current minimum access standard. Work is on-going in determine plants’ actual tolerances, and more information on this will be published in the FPSS line of work by early 2017. If they are determined to be unable to tolerate 4Hz/s, when on-line, the tolerable RoCoF for the region is likely to be lower.
- New type-fault matters do not emerge in the new plant being installed for these policy futures, such as inability to ride through multiple disturbances.
- Large-scale solar generation do not exceed the fixed dispatch levels presented in Frontier’s 44 time slices (discussed in section 3.1.2).

3.2.2 Network flows

Like many such models, the Frontier model uses a simplified representation of the network, applying static flow path limits relating to ideal conditions. Actual network limits are complex, with intra and inter-regional terms, e.g interconnectors are frequently constrained below their nominal capacity as a result of dispatch patterns within each region.

As networks are the primary focus of AEMO’s NTNDP modelling, it incorporated much of this complexity. The result is that the NTNDP tends to have lower interconnectors flows. This in turn means that RoCoF upon separation be assessed as higher in Frontier’s outputs than in the NTNDP. The results shown below have materially greater RoCoF levels than are being developed in the 2016 NTNDP results.

3.2.3 RoCoF tolerance

The chief danger of having a high RoCoF in an islanded region is that:

- The frequency may rise too fast for high frequency generation protection systems to trip generation in a controlled manner.
- The frequency may fall too fast for under frequency load shedding systems to operate prior to generators interrupting on low frequency protection.

The result of either of the above is that the region is likely to break up into a black system condition. The FPSS line of work is analysing various regions' maximum tolerable RoCoF levels; these values remain uncertain until all existing frequency protection, including that at generating plants, is better understood.

South Australia has had the most analysis to date, which to date indicates that a RoCoF below 1 Hz/s (green shades) can be tolerated with a high degree of confidence, whilst a RoCoF above 3 Hz/s is unlikely to be tolerated (orange and red shades). More analysis on the tolerable South Australian RoCoF will be published by early 2017 and may change these conclusions. Queensland and Tasmania have not yet been assessed, however similar tolerances have been assumed.

3.3 Results

3.3.1 Rate of Change of Frequency

The following figures 2-4 show the percentage of time in 2030 that, based on the dispatch as determined by the process described in section 3.1, these regions are exposed to levels of RoCoF following a contingency as described in section 3.2. Declining RoCoF is shown as increasingly red shades towards the left, and inclining RoCoF is shown as increasingly red shades towards the right. Declining RoCoF occurs when an importing region islands, and inclining RoCoF occurs when an exporting region islands.

A dispatch result from the 2020 Business as Usual (BAU) case is also included, being a model of the situation prior to the new policies taking effect.

Figure 2 Queensland Rate of Change of Frequency post islanding in 2030

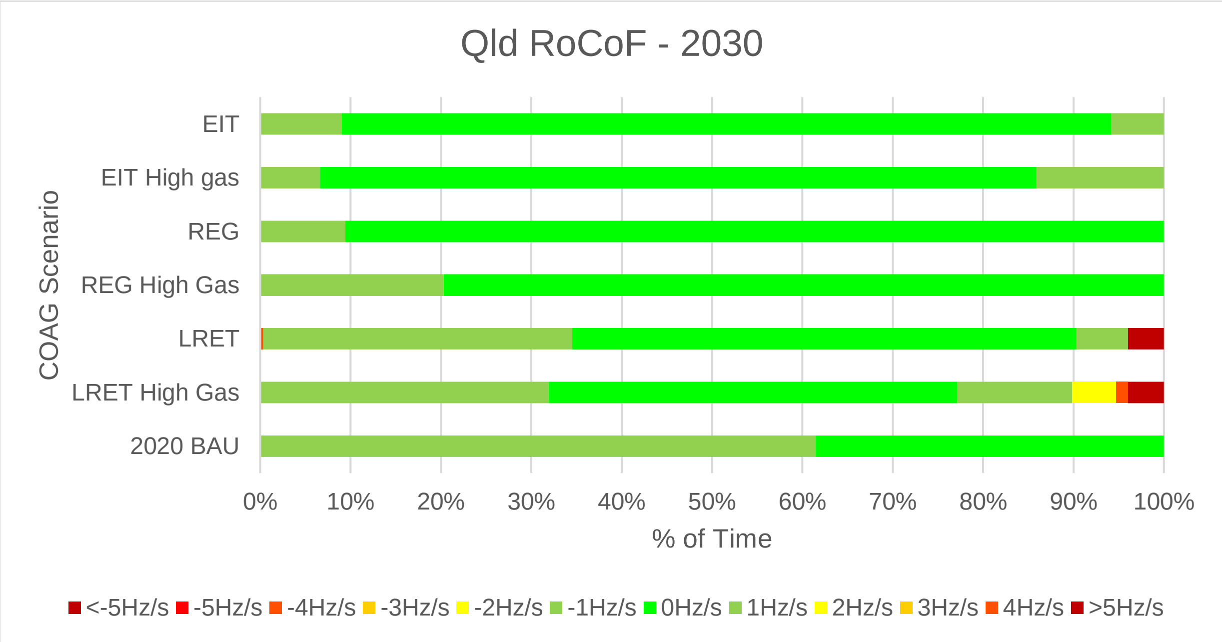


Figure 3 Tasmanian Rate of Change of Frequency post islanding in 2030

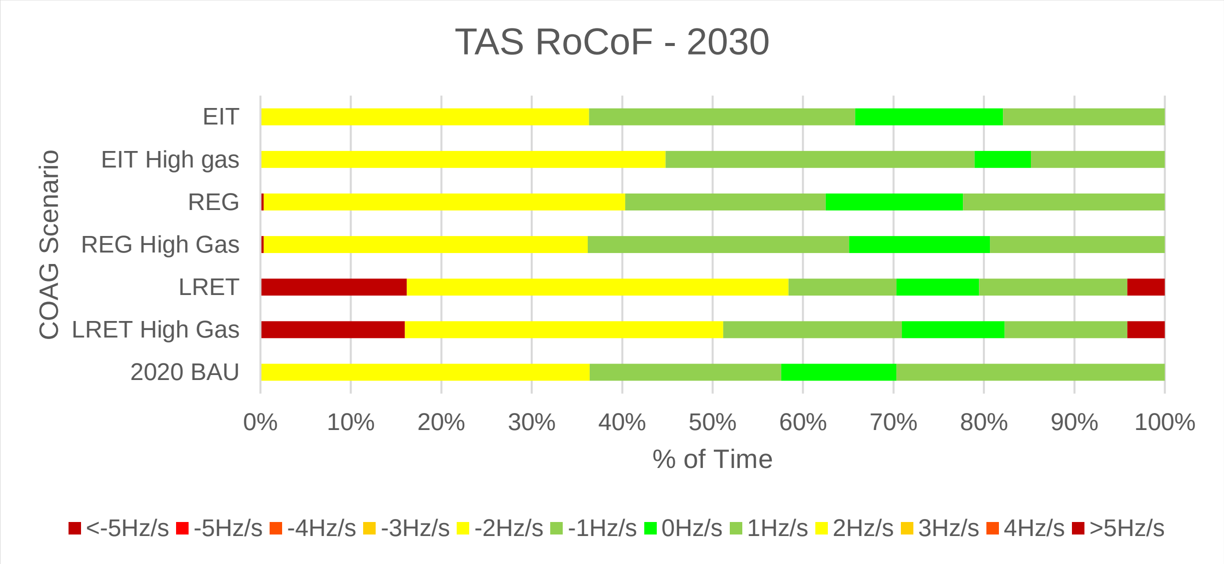
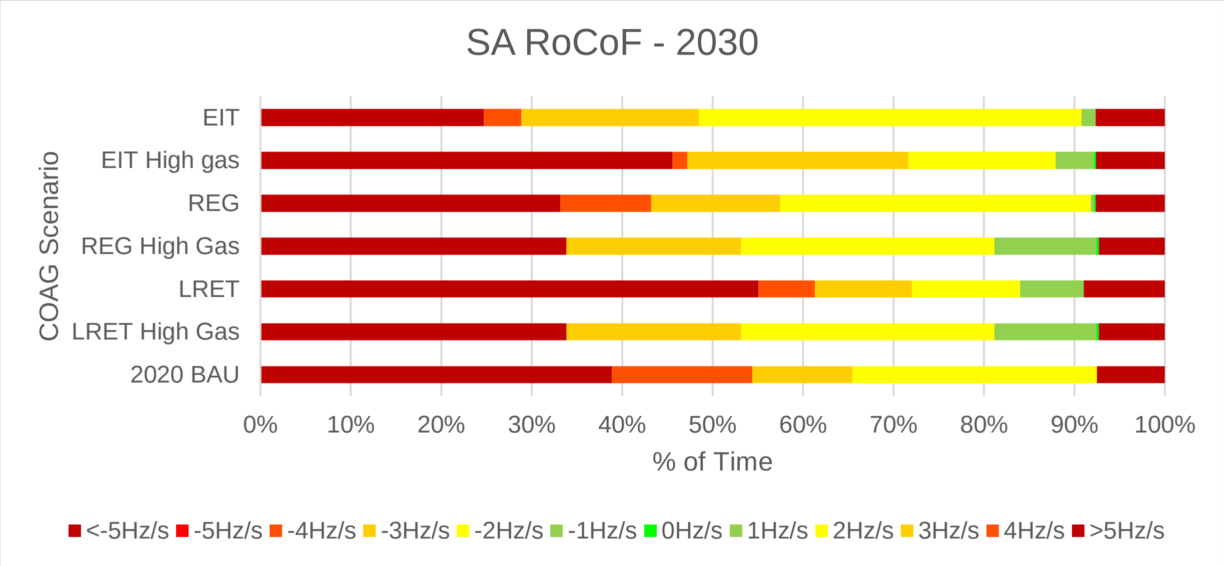


Figure 4 South Australian Rate of Change of Frequency post islanding in 2030



3.3.2 Queensland FCAS regulation requirement

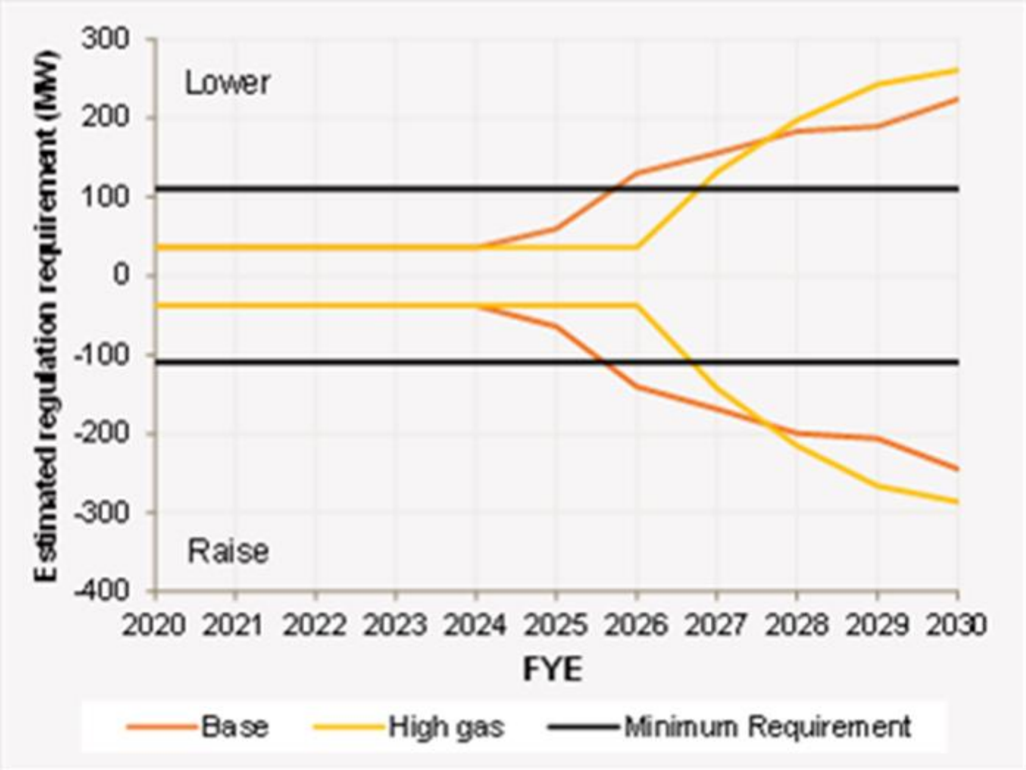
Observation of the NEM's existing large-scale photovoltaic based solar farms show a characteristic of rapid and frequent changes in output caused by passing cloud cover. FCAS regulation service is the appropriate mechanism to manage these variations. An analysis of Frontier's modelled Queensland solar investment was performed to indicate how much service would be required to manage the region post separation.

The presumed solar generator sizes, fluctuations and correlations were extrapolated from the NEM's existing and under construction farms.

Figure 5 is a forward projection of the total amount of regulation FCAS required for utility-scale PV for an islanded Queensland. Only the LRET scenario is shown as the other policy scenarios have no growth in large-scale solar. This can be compared to the 2016 minimum amount of regulation FCAS required in an islanded Queensland, shown in black (110 MW raise, and 110MW lower).

Under the LRET-base scenario large-scale solar is projected to grow to more than 4.1GW in Queensland by 2030, with associated local raise/lower regulation requirements of 244MW/223MW. In the LRET-High gas scenario large-scale solar grows to more than 5.2GW in Queensland by 2030, implying a local raise/lower regulation requirement of 286MW/261MW.

Figure 5 Qld FCAS Regulation requirement: LRET case



3.4 Interpretation

Queensland

RoCoF is not a significant concern in any policy scenarios for any material periods within the 2030 year, except for a small period in the LRET - high gas price scenario. This is intuitive due to that policy's higher investments in asynchronous renewable generation and very low investment in synchronous gas-fired generation. It should be noted that the fixed dispatch approach used for large-scale solar generation discussed in section 3.1.2 may result in a lower indication of RoCoF risk for Queensland LRET scenario than would be the case if a full solar distribution was used.

The installation of a large volume of large-scale solar in Queensland would require increased recruitment of local regulation FCAS to manage islanding. The non-intermittent plant installed in that scenario appears to retain sufficient conventional capacity to provide this requirement, presuming it participates in the FCAS market and remains on-line to sell FCAS even during low energy prices commensurate with sunny conditions. Large-scale solar could potentially become a new regulation provider in these scenarios.

Presently AEMO does not purchase a Queensland local regulation requirement pre-separation. This is because generators typically on-line have more than sufficient regulation capacity for AEMO to confidently predict it will be available post separation. However should the requirement grow and/or the supply decline (both are predicted in this scenario), AEMO will need to purchase a local requirement pre-separation. An equivalent situation has developed in South Australia, and, since 2015 AEMO has been purchasing 35MW of local raise and lower FCAS regulation whenever separation is a credible contingency. Although the South Australian registered local FCAS regulation capacity is considerably larger than 35MW, high FCAS regulation prices have nevertheless been experienced.

Tasmania

All scenarios indicate some periods of potentially high RoCoF, with the highest results occurring in the LRET scenario. This is intuitive as it achieves its abatement via asynchronous renewable energy generation investment, and the exploration of wind diversity discussed in section 3.1.2 gave long periods with negligible Tasmanian synchronous generation dispatched in that scenario. Note the analysis presumes Tasmanian generation is dispatched purely on a cost basis and no units are operated in synchronous condenser mode in order to retain inertia. Some existing Tasmanian hydro units are capable of operating in this mode at low cost and this is likely to be a convenient source of Tasmanian inertia.

Whilst all scenarios have a degree of RoCoF above 1 Hz/s, it should be noted that the existing Special Protection Scheme (SPS) would most likely avert a system black upon the specific contingency being tested: loss of Basslink. However the trends thematically indicate the Tasmania's robustness to other, non-credible, contingencies which are not protected by SPS.

South Australia

All policy scenarios contain very large periods in 2030 with unacceptable RoCoF should the loss of a both existing AC interconnector circuits be a protected contingency event. Whilst, as expected, the LRET scenarios have the greatest duration of risk, all scenarios, including the EIT scenario, will require action to address.

The 2020 BAU line indicates the risk associated with EIT actually emerges prior to 2020, i.e. the concern arises as a consequence of the settings of existing policies such as the Renewable Energy Target rather than EIT's actions post 2020. This is to be expected as that case invested no new renewable energy in South Australia during the period. The LRET 2030 case does however deteriorate somewhat as additional renewable generation is built post 2020 in South Australia.

Despite the alarming nature of the South Australian chart, the concerns are likely to be addressable, by one, or more likely, a combination, of the following actions:

- Contingency control schemes, such as changes to the triggering of the automatic load shedding (ALS) scheme that is supplied by the distribution network as a requirement of the National Electricity Rules. This could be set to act upon the contingency itself, in a similar way to the Basslink SPS or directly upon RoCoF prior to the frequency falling below into the ALS range of 47-49 Hz.
- Installation of high inertia synchronous condensers in the South Australian network, which is also valuable for addressing the system strength and voltage concerns highlighted in the 2016 NTNDP.
- Introduction of an ancillary service or similar mechanism to ensure that high inertia synchronous generation remains committed even when prices are below its operating cost.
- Investment in a new, dual-line, AC interconnector from Victoria or New South Wales, which lessens the likelihood of separation.

- In combination with other actions, the use of very fast frequency response ("synthetic inertia") from asynchronous generators and storage.
- Operation of the Heywood interconnector at reduced capacity (East and West) during periods of low South Australian inertia.

As these investigations are underway, and are required regardless of the post 2020 policy, their costs are not relevant to this study. They are more fully explored in the 2016 NTNDP and the FPSS line of work.

Note that the 2016 NTNDP analysis, when published, predicts a less prolonged exposure to high RoCoF in South Australia in 2020. This is due to a different economic model providing the dispatch pattern, with synchronous units being run more continuously.

3.5 50% emissions reduction case

AEMO qualitatively reviewed the outcomes of Frontier's 50% emissions reduction case for thematic interpretations of system security matters.

These cases clearly involve bigger transitions of the generation fleet than is required for the 28% target. The new investment, costs and prices are presented in Frontier's report.

For the EIT and REG 50% cases, the more aggressive targets are achieved by a much more significant shift from coal to gas-fired generation. Gas-fired generation is technically equally capable of providing equivalent non-energy services to support power system security security challenges as coal-fired generation, noting that:

- Any major replacement of generation plant will entail significant technical challenges and transitional risks.
- The large volumes of gas-fired dispatch will require considerably more gas supply and gas transport infrastructure. Analysis of gas market impacts has not been undertaken for this task.

For the LRET 50% case, very substantial volumes of asynchronous intermittent generation are invested as presented in Table 1.

Table 1 Generation investment LRET 50% case.

Capacity in 2030 (MW)	NSW	QLD	SA	TAS	VIC
Large-scale solar	11,411	7,275	567	0	3,465
Wind	7,306	4,301	2,159	1,427	6,891

These capacities considerably exceed forecast average demand levels in these regions. As a result each region has long periods of zero dispatch of synchronous generation, typically combined with zero or negative energy price. This would require considerable new actions in each region to ensure the system remained secure state during these times. Thematically, the actions would extend those being proposed by the FPSS line of work for South Australia.

For Queensland and Tasmania, as these are separable regions (see discussion in section 3.2), mechanisms to support mechanical stability will be required – likely to be by maintaining synchronous generation or condensers on-line at all times. For Victoria and New South Wales, although the potential for islanding is less severe, there are nevertheless some dispatch periods when all mainland synchronous generation is zero. This implies that mechanisms to also support NEM-wide mechanical stability would be required.

Network system strength would be a concern in every region as the minimum dispatch of synchronous generation declined. This would likely be addressed through a combination of new connection equipment obligations or new shared network assets to increase fault levels, such as synchronous condensers.

The short-term variability of the new generators, particularly large-scale solar (see section 3.3.2) will create significantly increased FCAS regulation requirements both NEM-wide and for separation protection. Geographic diversity however means that the growth in requirements increases less than linearly with investment as indicated in Figure 5. Whilst the requirement for FCAS regulation will increase, it would be expected that these new generators would also participate in supply.

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MODELLING OF CARBON EMISSION REDUCTION SCENARIOS IN THE NATIONAL ELECTRICITY MARKET

Dear Mr Zema and Mr Pierce

I am writing to you in my capacity as the Chair of the Senior Committee of Officials (SCO) on behalf of the COAG Energy Council (the Council).

The Council discussed the interactions between energy and climate change policies in the National Electricity Market (NEM) during its meetings in 2015. The Council recognised the significant implications Australia's carbon reduction policies may have for the NEM and that the successful integration of carbon emissions policy and energy policy will be critical to meeting Australia's emissions reduction targets in the most efficient manner.

At its 4 December 2015 meeting, the Council agreed to task the Australian Energy Market Commission (AEMC) and the Australian Energy Market Operator (AEMO) with modelling the effect of carbon abatement mechanisms on the electricity sector. This is intended to assist the Council in future policy deliberations. This letter sets out the proposed terms for this work.

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I understand that a Power System Issues Technical Advisory Group has been established by AEMO, including representatives from SCO, the AEMC and industry groups, to advise on ongoing power system security matters associated with the changing generation mix in the NEM. The SCO welcomes this initiative given the Council's strong interest in ensuring market systems continue to keep pace with energy technology and policy changes. The SCO welcomes your consideration of how this group could be employed to further refine and advance the modelling tasks detailed below.

Task 1: Scenario modelling – NEM resilience

The modelling should reflect the firm commitment by the Australian Government, with the support of all NEM jurisdictions, that Australia will reduce its emissions by at least 26 to 28 per cent compared with 2005 levels by 2030.

While carbon reduction targets are set at the national level on an economy wide basis, the Council has agreed that the contribution of the electricity sector be consistent with national targets, while acknowledging that it may be economically efficient for the electricity generation sector to make a greater than pro-rata contribution. To clarify this, SCO officials have agreed that a 28 per cent reduction from 2005 levels by 2030 is an appropriate constraint for the AEMC to adopt for its modelling purposes and for AEMO to use in its ongoing forecasting and planning processes. Noting this is the high end of the national target range and may be subject to future upward revision as international agreements develop over time, AEMC may also model higher levels of abatement in the NEM in order to test the sensitivity of the modelling results and to strengthen the modelling of power system security and reliability to be conducted under Task 2.

The Council understands that AEMO has already commenced work on its forecasting and planning processes for 2016 and will base those on achieving the target 28 per cent abatement using AEMO's existing modelling tools.

The AEMC is requested to develop a series of scenarios setting out alternative pathways for achieving a 28 per cent emission reduction target in the NEM, including:

- least cost abatement;
- staged generator exit, whereby generators withdraw from the market on the

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basis of their emissions intensity or publicly notified retirement dates; and

- accelerated deployment of renewable energy, whereby solar and wind energy is pushed into the market by economic or policy drivers.

The output of this modelling is a report to SCO outlining a number of pathways to achieve the 28 per cent emission reduction target in the NEM. The approaches should be assessed and considered in terms of their impacts on efficient outcomes and their ability to ensure that:

- wholesale markets continue to provide appropriate incentives to ensure supply and demand balances across the NEM;
- wholesale markets are liquid and provide opportunities for long term contracting by market participants; and
- appropriate frameworks and incentives are in place for network investment and investment in energy storage.

Outcomes from this modelling are also required to allow AEMO to test the operational power system security and reliability implications of each of the scenarios. The AEMC and AEMO will need to co-ordinate on the specification of the relevant information; however it is expected to include such things as a range of plant mix and location, dispatch outcomes, investment and retirement profiles (task 2 outlined below).

Task 2: Power system security and reliability testing

This task, to be undertaken by AEMO and drawing upon its routine planning work and the work of the AEMC in the first task, is to provide robust stress testing of market rules and systems, as they apply to the generation and transmission sectors for power system security and reliability. This is intended to ensure that AEMO, AEMC, AER and the Council are able to identify the developments required to ensure the NEM continues to function and contribute efficiently in the broader economy wide transition to a low emissions future including in relation to current national emission reduction targets. Of particular concern is the performance of the NEM in ensuring that:

- services, such as system inertia and frequency control, remain adequate to meet appropriate standards; and
- network and interregional constraints do not impede secure and efficient national market operation.

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This phase of the work will be undertaken using the AEMC's modelling from the first phase and used to identify rule changes that could aid in ensuring power system security and reliability under the range of abatement paths developed in Task 1. In doing so, and based on the scenarios developed in Task 1, it may be appropriate to test scenarios in which the NEM contributes a higher than pro-rata contribution to the national emission reduction effort.

SCO understands that Task 2 will be done in parallel and in conjunction with AEMO's normal functions of preparing information to the market based on its scenarios such as:

- the National Electricity Forecasting Report (NEFR);
- the Electricity Statement of Opportunities (ESOO); and
- the National Transmission Development Plan (NTNDP).

The Council requests an interim progress report on this task by mid-2016 and the final report by the end of 2016.

Yours sincerely

Dr Steven Kennedy
Chair
COAG Energy Council Senior Committee of Officials
18 February 2016

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MODELLING OF CARBON EMISSION REDUCTION SCENARIOS IN THE NATIONAL ELECTRICITY MARKET

Dear ~~Mr Pierce~~ and ~~Dr Marxsen~~
John & Tony

I am writing to you in my capacity as the Chair of the Senior Committee of Officials (SCO) on behalf of the COAG Energy Council (the Council).

I refer you to the Council's decision at its 4 December 2015 meeting to task the Australian Energy Market Commission (AEMC) and the Australian Energy Market Operator (AEMO) with modelling the effect of carbon abatement mechanisms on the electricity sector. A letter setting out the Terms of Reference for this work was provided by the Chair of the COAG Energy Council Senior Committee of Officials (SCO) on 18 February 2016. This letter is attached for your reference.

The original Terms of Reference asked AEMC and AEMO to carry out two tasks to be completed by the end of 2016. Under Task 1, the AEMC was requested to develop scenarios setting out alternative pathways for achieving a 28 per cent emission reduction target from 2005 levels by 2030, including:

- least cost abatement;
- staged generator exit, whereby generators withdraw from the market on the basis of their emissions intensity or publicly notified retirement dates; and
- accelerated deployment of renewable energy, whereby solar and wind energy is pushed into the market by economic or policy drivers.

Under Task 2, AEMO was asked to identify power system security and reliability impacts under the alternative emissions reductions pathways examined by the AEMC in Task 1.

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At its 19 August 2016 meeting, the Council agreed that SCO will expand the Terms of Reference for AEMC and AEMO's work to include consideration of the economic and operational impacts of existing jurisdictional renewable energy targets.

My understanding of the various jurisdiction based targets suggest that, if achieved, they would deliver just under 40% renewables in the NEM in 2030. I note that the AEMC's current scenario of the extended LRET (to deliver the 28% reduction of emissions compared to 2005 levels) would deliver just over 40% renewables in the NEM. Of course, while the specific mechanisms individual jurisdictions might choose to use to deliver their renewable energy targets may differ from that used in the LRET, it seems to me that whatever mechanism design they do use would likely have a broadly equivalent effect.

Accordingly, I consider, at least at an aggregate level, the AEMC's and AEMO's current process will substantially deliver what the Council has requested.

It is possible that the actual delivery of renewable energy targets for some jurisdictions, such as Queensland and Victoria, may result in a geographical distribution of renewable energy that requires more finely calibrated modelling to assist Ministers' understanding of the relative costs of alternative emission reduction pathways and their implications for system security. It would, however be premature to commence that additional modelling at this point in time, prior to the relevant jurisdictions finalising their policy positions. When positions are sufficiently finalised, I will write to you commissioning further work, after appropriate consultation with the relevant jurisdictions. Of course this might mean that Council's deliberations of the precise effect of different jurisdiction-based targets might not take place until next year.

In the interim, the AEMC and AEMO are asked to draw qualitative inferences regarding how jurisdictional renewables policies, if achieved, could influence the results and system security. I also request that you provide high level advice on what additional modelling, if any, is required. This should be sufficient for the 2016 December Council meeting and I would be grateful if the report required for this meeting clearly outlined this.

If you would like to discuss any aspects of this request, please do not hesitate to call me.

Yours sincerely

Rob Heferen
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COAG Energy Council Senior Committee of Officials

September 2016

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