Peer review of electricity modelling for the Climate Change Authority

Comparing the performance of policies for emissions reduction

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Contents

Figures

Tables

Boxes

1. Introduction

The Climate Change Authority ('the Authority') is conducting a Special Review at the request of the Minister for the Environment. As part of its review, the Authority is comparing the performance of alternative policies aimed at reducing emissions in the electricity sector. It commissioned Jacobs to undertake modelling of seven potential electricity sector policies to inform this assessment.

To test the robustness of this modelling, the Authority has asked HoustonKemp to undertake an independent peer review. The scope of the peer review sought by the Authority is:

1. To assess the implementation of the emissions reduction policies in Jacobs' modelling, providing an opinion on whether the instructions provided to Jacobs, or their translation into the modelling, may have resulted in some policies being more or less advantaged relative to others.
2. To review the sources and approach used to determine the main input assumptions for the electricity modelling.

We were not asked to conduct, and did not conduct, a detailed review of Jacobs' electricity market modelling. We note that, in general, modelling choices that are not specific to any one policy scenario are not likely to materially affect a comparison of the results. However, it nonetheless remains possible that these comparisons could be affected, so our review also assesses modelling choices made by Jacobs where we consider that the choice of these could be relevant to comparing results between policy scenarios.

This peer review has been informed by:

- a draft version of Jacobs' modelling report and the instructions provided to Jacobs by the Authority;[1]
- spreadsheets providing the outputs of each of Jacobs' model runs relied upon in its draft report;
- minutes of previous meetings between Jacobs and the Authority conducted during the development of the modelling;
- a meeting with Jacobs and the Authority in Melbourne on 7 January 2016; and
- emailed responses to subsequent written questions to Jacobs and the Authority.

Unless otherwise stated, all facts stated in relation to the electricity market modelling reviewed in this report are sourced from Jacobs' draft report.

Based on our consideration of these materials, in our opinion the approach to comparing emissions reduction policies is sound, and the input assumptions used in Jacobs' modelling are generally appropriate. Our overall view is that the modelling has been conducted to a high standard of rigour and that the critical policy comparisons drawn by the report are robust.

Throughout this report we offer commentary on specific approaches adopted and input assumptions used. The process that we apply in each case is to assess whether the approach or assumption adopted is reasonable, and whether there might be alternative approaches or assumptions that could have been considered. Consistent with our views about the robustness of the modelling process undertaken by the Authority and Jacobs, in the large majority of areas we conclude that the approach taken is reasonable and appropriate. In a small number of cases we identify what we consider to be preferable alternatives to the approach adopted in the modelling.

The remainder of this report is set out as follows:

[1] Jacobs, *Modelling illustrative electricity sector emissions reduction policies*: *draft version 4.1*, 17 December 2015. The instructions provided by the Authority are set out at appendix D to Jacobs' draft report.

- section 2 describes the implementation of specific policies as modelling scenarios, the basis of comparison between policies and the modelling framework; and
- section 3 details our assessment of the general assumptions and input data used in the model.

2. Translation of policies into modelling scenarios

The Authority has asked us to review the manner in which emissions reduction policies were translated into a modelling context, and in particular, whether the implementation of modelling scenarios has resulted in some policies being advantaged relative to others.

Overall, we are satisfied that Jacobs' modelling decisions do not materially misrepresent the merits of different policies relative to one another.

This conclusion was informed by two types of assessment. First, whether the results of the modelling pass a "sanity check" based on a comparison against *a priori* expectations derived from our previous experience and other modelling results. Second, whether the approach taken by Jacobs converting the policies to modelling scenarios appears reasonable and consistent with best practice modelling.

The following subsections assess high level modelling framework decisions, the means by which policies are compared, and the adaptation of specific policies into modelling scenarios.

The policies that Jacobs were asked to model are outlined briefly in Box 1 below, and in more detail at section 2.1.

Box 1: Policy scenarios modelled by Jacobs

Carbon price ('CP'): a tax is applied to every unit of carbon equivalent emissions produced from electricity generators.

Emissions intensity target ('EIT'): emission permits are allocated to generators every year at a baseline emissions intensity, which decreases over time. The baseline is set such that high emission intensity generators will have a deficit of permits, and will need to purchase permits from low intensity generators, giving rise to a price for emissions.

Renewable energy target ('RET'): new renewable generators can issue certificates. The number of certificates that retailers are required to purchase increases between 2020 and 2040, remaining constant thereafter.

Low emissions target ('LET'): operates similarly to the RET, except that the issue of certificates is not restricted to renewable generators. Certificates may be issued to all new and augmented generators with emissions intensity under 0.6 tCO2-e per MWh – generators with lower emissions can issue proportionately more certificates. Existing eligible fossil and renewable generators are eligible for generation that exceeds historic baseline levels.

Feed in tariff ('FiT'): new low emissions generators are eligible to tender for a contract for difference with the government, equivalent to the generator receiving a fixed price for their output and the government receiving the pool price.

Regulated closures ('RC'): emissions are reduced by mandating the closure of all coal facilities on a pre-determined schedule, while prohibiting investment in new coal facilities without carbon capture and storage. Limits are placed on emissions from gas-fired generators.

Absolute baselines ('AB'): a facility-specific cap on emissions is mandated for incumbent facilities with above-average emissions intensity, with the cap reducing over time.

Source: Climate Change Authority

The policies may be classified into three broad categories:

- the 'emissions pricing' policies, CP and EIT;
- the 'technology pull' policies, RET, LET and FiT; and
- the 'regulatory based' policies, RC and AB.

This nomenclature for referring to policies is used throughout this report.

Jacobs modelled these policies in two phases and four parts:

- in Phase 1 the policies were modelled to achieve emissions reductions consistent with limiting worldwide warming to two degrees;
- in Phase 2 the same policies were modelled, with the implementation varied to achieve emissions reductions consistent with warming of three degrees;
- in Phase 2 various policy combinations were modelled, with the combinations configured to achieve emissions reductions consistent with warming of two degrees; and
- in Phase 2 sensitivity analyses of key assumptions were performed, including high and low demand scenarios and technology sensitivities.

Much of the discussion in this review is focused on Phase 1 results as the prism through which we examine the robustness of the modelling approach taken. In our opinion, if the approach and modelling used to generate the Phase 1 results is robust, then we can be reasonably confident that the results for Phase 2 are produced on a similarly robust basis.

2.1 Policy implementation

In this section we set out our understanding of how each policy scenario was implemented in Jacobs modelling, and what assumptions were made in this process. We discuss how the results of the modelling for each policy scenario are compared at section 2.2 below.

2.1.1 Carbon price (CP)

The CP policy sources series of prices for carbon-equivalent emissions between 2020 and 2050 from the Intergovernmental Panel on Climate Change (IPCC). This includes emissions prices consistent with:

- a two degree target for global warming, modelled in Jacobs' Phase 1 results; and
- a three degree target for global warming, modelled in Jacobs' Phase 2 results.

Emissions prices are implemented in the modelling as a levy on the unit cost of each source of generation calculated as the product of the emissions price and the emissions intensity of the generation unit. The effect of implementing an emissions price in this way is to change the merit order of dispatch, so that the cost of high emissions intensity generation is made more expensive relative to low or zero emissions intensity generation.

The CP scenario is used to calculate the total emissions constraint for all other policy scenarios over the period from 2020 to 2050. Section 2.2 gives closer consideration to this method for comparing policies. It results in an emissions budget of approximately:

- 1,581 Mt for the Phase 1 modelling in which emissions prices consistent with two degree warming are used;[2] and
- 2,823 Mt for the Phase 2 'weaker emissions constraint' modelling in which emissions prices consistent with three degree warming are used.[3]

[2] Calculated based on Jacobs' modelling results for Phase 1 carbon price scenario.

[3] Calculated based on Jacobs' modelling results for Phase 2 weaker emissions constraint carbon price scenario.

2.1.2 Emissions intensity target (EIT)

The EIT operates as an emissions price determined by trading within the wholesale electricity sector. Under the EIT modelled by Jacobs, emissions permits are:

- issued to generators in line with a baseline level of intensity; and
- surrendered by generators in line with their actual level of intensity.

Generators that face a deficit of permits need to buy permits from those with a surplus. These imbalances give rise to a market for permits, and in turn a price on emissions determined by trade within the Australian wholesale electricity industry. Generators may bank permits in unlimited quantities, and may also borrow up to 10 per cent of their permits from future periods.

The baseline level of intensity in 2020 is set as the average level of emissions intensity across all generators for the reference scenario. This baseline is reduced so that the cumulative level of emissions between 2020 and 2050 matches that for the CP policy scenario.

In a practical implementation of the policy, permits would likely be issued based on some expected level of output (such as output in the previous year) and surrendered based on actual output. Differences in these levels of output requires true-up mechanisms to refund or recover in future charges any differences due to output changes. In the modelling, there is no uncertainty and no deviation between expected and actual output, so the actual level of output is used both to issue and to surrender permits. This simplifying assumption serves to eliminate the need to model true-up mechanisms and appears to be a reasonable approximation that is unlikely to have significant consequences for assessing the policy.

The EIT policy operates in a similar way to the CP policy in that both place a direct price on emissions. However, these prices are not the same. The CP policy scenario sources a price exogenously to the Australian wholesale market context (such as an international emissions price). By contrast, the EIT price is determined by a variant of a ‘cap and trade’ system particular to the Australian wholesale electricity market – which allows banking and borrowing as noted above.

A further difference between the policies is that the CP scenario collects revenue from the electricity wholesale sector through the emissions price, whereas under the EIT emissions permits are traded between market participants. We discuss this aspect of the CP policy in more detail in section 2.2. The CP policy would generally be expected to give rise to higher final electricity prices than the EIT scenario and also accrue a significant amount of government revenue.

Notwithstanding these differences, we would expect the CP and EIT policy scenarios to have broadly similar outcomes on the wholesale market and the mix of generation, since both impose price signals as the means of changing the behaviour of emitters. Any differences in outcomes between the policies appear likely to be due to:

- the different path of emissions prices modelled, and the implications of banking and borrowing for the EIT certificate price;[4] and
- the different prices resulting from the policies, which gives rise to different levels of demand and therefore differing mixes of demand and supply side abatement – both policies have the same cumulative emissions from the same reference scenario; with lower end user prices by design, the EIT policy will have less demand side and more supply side abatement than CP.

[4] Section 3.4.2 of Jacobs’ draft report, ‘Emissions intensity target: key findings’ reports that there were differences between the EIT scenario and the carbon pricing scenario in terms of permit prices required to achieve the cumulative emission constraint and the costs in doing so. These can be explained by the impacts of the borrowing constraint, and the lower wholesale and retail prices under the EIT. On the first, the EIT borrowing constraint allowing only limited future borrowing was binding when adopting the carbon pricing scenario’s permit price path. This makes the carbon pricing scenario’s emissions trajectory infeasible under the EIT scheme. Higher prices were required in the early years to allow enough banking to occur so that the borrowing that is inevitably required in the later years draws on the permit bank, and not, more than was allowed, from future permits.

2.1.3 Renewable energy target (RET)

The RET policy scenario represents a successor to (rather than a continuance of) the current long-term RET policy. Under the RET, new renewable generators constructed from 2020 are able to issue RET certificates for each unit of output. Purchasers of wholesale electricity, such as retailers, face targets for the number of certificates that they must surrender to the operator of the scheme in each year. Like under the EIT policy, there would be unlimited banking of certificates and borrowing of up to 10 per cent.

The creation of RET certificates and the requirement for purchasers to surrender a certain quantity of these at the end of each year creates a market for the certificates. The price determined in this market represents a cross-subsidy paid by buyers of electricity to generators of renewable electricity that is ultimately paid for by end-users.

A RET reduces emissions by stimulating investment in renewable sources of generation, which would not otherwise be profitable without the additional income from the sale of RET certificates. This gives rise to a surplus of supply, depressing the price of electricity. The lower prices lead some generators that are not eligible for certificates to shut down where either they cannot cover their variable operating costs, or cannot cover fixed costs required to stay operating.

In configuring the RET policy to achieve the overall emissions constraint, a 'dual-linear' path is set for the quantity of certificates that must be surrendered. The trajectory of RET certificates rises steeply between 2020 and 2030, continues rising (but less steeply) between 2030 and 2040, and becomes flat from 2040 to stablise investment. This certificate trajectory brings online a lot of renewable energy resources very quickly, contributing to the early action on emissions required to meet the demanding emissions reduction constraint.

2.1.4 Low emissions target (LET)

The LET policy scenario is a variation on the RET policy scenario that allows a broader class of new generation facilities to be able to issue certificates. The LET scenarios modelled by Jacobs allow all new generators with emissions intensity less than a baseline level 0.6 tCO2-e per MWh to issue LET certificates. Existing plant are eligible for certificates for generation above a historical baseline. This baseline qualifies low emissions gas generators, such as CCGTs to issue certificates. Because the LET policy is focused on emissions, and not the renewable status of generation, other technologies that qualify under this scheme that do not qualify under the RET include CCS (new plant or refits), as well as nuclear generators.

However, the rate at which a generator may issue certificates is in proportion to the extent to which its emissions intensity is under the 0.6 tCO2-e per MWh baseline. A generating facility at or above the baseline level of emissions intensity would generate no certificates. On the other hand generating facilities with no emissions would generate twice the number of certificates per unit of output as one with an emissions intensity of 0.3 tCO2-e per MWh.

The LET achieves emissions reductions in the same way as the RET – by increasing income for qualifying generators. Because the LET also allows some new thermal generators to qualify, it also has the effect of promoting these generators in the merit order relative to non-qualifying generators, an effect more similar to an emissions price policy.

As with the RET scenario, the LET is implemented in Jacobs' modelling with a dual-linear trajectory for the number of certificates that must be surrendered, and which flattens out by 2040.

2.1.5 Feed-in-tariff (FiT)

The FiT policy provides incentives to new low emissions generators through long-term contracts which are allocated through an auction process. The contracts are structured as contracts for differences, in which the government pays contracted generators the difference between a strike price and the market price for their output. Given a quantity of annual output to be auctioned each bidding generator is assumed to bid its LRMC of generation, and successful generators are each contract at their own LRMC. The costs of entering into these contracts is spread across consumers of electricity.

The differences payment is only received by the contracted generator on output that it actually produces. The structure of the contract means that, regardless of the market price, generators with contracts under the scheme will face constant (and positive) incentives to produce across the demand cycle – suggesting that optimal behaviour will be to bid at the market price floor.

Unlike the LET, low emissions gas generators are not eligible to participate in tenders for FiT contracts.

Jacobs was instructed to implement the policy with 20-year contracts, with the volume chosen to meet the emissions constraint. To achieve this objective, Jacobs assumed that contracts are auctioned at the same high level each year between 2020 and 2029, a moderate level per year between 2030 and 2039 and not at all from 2040 onwards.

Jacobs models the price that generators bid at in this auction as their long-run marginal cost (LRMC) of production.[5] We consider that this is a reasonable and appropriate assumption. We note that LRMC incorporates an assumed level of production over time – such that LRMC for the same technology could be lower or higher depending on this assumption. In line with our understanding of the incentives for contracted generators to bid into the market, the level of production used in the calculation of LRMC would reflect a commensurate utilisation of contracted generators.

Jacobs has implemented the FiT scenario with an assumed cost of capital for generators that is 0.5 per cent lower than in other scenarios. The basis for this lower cost of capital is that generators with a FiT contract will be shielded from pricing risk and therefore have greater certainty of cashflows. We agree that it may be reasonable to expect that long-term pricing certainty provided by the FiT may contribute to lower risk for generators that can secure these contracts. On the basis, we consider that a lower cost of capital is reasonable.

A lower cost of capital would be expected to encourage relatively more investment in generators with high capital costs relative to operating costs – including renewable technologies such as wind, large-scale solar or geothermal. It would also be expected to give rise to lower prices, other things being equal – because the long-run costs of generation would be lower than under a higher assumed cost of capital.

2.1.6 Regulated closures (RC)

In the RC policy scenario, coal fired generators are required to retrofit with CCS or shut down in order of age; to meet the constraint the closures occur between 2020 and 2027. No new coal fired generators can be built unless they are fitted with CCS technology. In addition to this restriction, gas-fired generators are restricted to a constraint of 2,200 tCO2-e per MW per year.

The RC scenario lowers emissions by directly closing down or restricting the output of the generators that produce them. However, it does not provide any direct incentives for lower emissions generation to enter to replace the missing generation. Instead, higher prices will be required to incentivise investment in new generation.

Unlike the policies discussed above, the RC scenario does not operate by providing emissions price signals or providing cross-subsidies that encourage low-emissions technologies to produce more. Instead, the gap that is created by the retirement of thermal generation must be filled by sending price signals to bring new generation online.

The RC policy scenario does not meet the emissions constraint in the two degree warming scenario. The RC policy produces 1,814 Mt of CO2-e, 15 per cent higher than the constraint based on the CP policy scenario that is approximately met by all other Phase 1 policy scenarios. This is clearly stated in Jacobs report.

[5] This is distinct from the concept of the LRMC of the market.

However, we consider that the fact that in Phase 1 the RC policy does not achieve the constraint biases the comparison of this policy against all others and should be noted if such comparisons are drawn. We would expect the resource costs and impacts on consumers of this policy to be underestimated relative to policies that achieve the emissions constraint. Under at least one comparison, in Figure 12: 'Resource costs relative to the reference scenario, 2° Celsius emission constraint' of Jacobs' draft report,[6] the resource cost of the RET policy is shown as being higher than the RC policy, when in fact this comparison could very likely be reversed if they were compared on an equal basis.

However, the RC policy scenario does comply with the more relaxed emissions constraint in the three degree warming scenario modelled in Phase 2. On this basis, the RC results under the Phase 2 weaker emissions constraint remain comparable to other policy scenarios.

2.1.7 Absolute baselines (AB)

The AB policy scenario places absolute emissions caps on each individual incumbent generator with higher than average emissions intensity. The cap reduces over time, reaching zero by 2038, by which time all incumbent coal generation is forced to close down. At the same time, the entry of new fossil fuel generators is prohibited unless they are fitted with CCS.

The AB policy is a less direct form of mandated closure than RC. Unlike RC, AB does not require immediate shutdown of thermal plants. The process of phasing out high emissions plant is more gradual and requires less early investment in generation.

2.2 Basis for comparing policies

In this section we discuss how the draft report compares policy scenarios to each other and assess the basis for this comparison. As part of this discussion, we review assumptions that underpin the estimation of the cumulative emissions constraint between 2020 and 2050, which serves as the basis for comparing policies.

2.2.1 Common emissions constraint

Except for RC in Phase 1 (as discussed above), all results for policy scenarios are compared on the basis that the scenarios achieve the same cumulative level of emissions between 2020 and 2050.

We consider that this is a reasonable basis for comparing policies. In particular, in our opinion setting the same emissions constraint for each policy allows each policy to be compared on its cost effectiveness in achieving a common level of emissions abatement. This appears to be reasonable where the level of abatement captured is likely to be targeted at a level similar to those being monitored.

In our view, the approach taken by the Authority and Jacobs to model the emissions constraint as cumulative, and not to discount future emissions, is also reasonable. Discounting is appropriate in circumstances where there is an opportunity cost or benefit associated with incurring a flow at a different time. There is no particular evidence we are aware of that suggests that a unit emission occurring earlier in the 2020 to 2050 period is instrincally more or less costly for the environment than one which occurs later in the period.

We note that the emissions constraint is only approximately met, with Phase 1 emissions (aside from RC) falling between 1,559 Mt CO2-e for EIT and 1,595 Mt CO2-e for RET, as compared to 1,581 Mt CO2-e for the CP policy scenario.[7] These differences are small, and in the order of 1 per cent. This does not seem likely to affect the assessment of policies. However, we note that differences in resource costs between some policies are extremely narrow, and small variances in costs could reverse some comparisons.

[6] Jacobs draft report, section 3.1.6: 'Resource costs and cost of abatement', p 28.

[7] Emissions calculated directly from Jacobs' Phase 1 modelling results.

In order to compare policies on the basis of having the same aggregate level of emissions over 2020 to 2050, Jacobs has 'back-solved' the design of policies other than CP in order to achieve the emissions constraint. For example, as described above:

- the baseline emissions intensity for EIT is reduced over time to a level so that it achieves the overall emissions budget;
- the trajectories of certificates required to be surrendered under the RET, LET and contracts issued under the FiT are selected so as to achieve the emissions budget; and
- the date at which the baseline level of emissions for the AB scenario reaches zero is selected so as to achieve the emissions budget.

While this is an ideal basis for comparing the cost of achieving a particular level of abatement, it may not reflect how policies in practice are designed. A potential alternative basis for comparison could involve explicitly comparing policies that have each been developed based on a specific plan for implementation. For example, a particular policy implementation may be developed to reduce costs, to the extent possible. Reconsidering the design of policies in this way may:

- result in the costliness of each policy reducing to a greater or lesser extent, consistent with a more customised implementation that takes into account the specific attributes of each policy; and
- result in each policy achieving a different level of cumulative emissions abatement over the 2020 to 2050 period.

Modelling conducted on this basis may better forecast the effect of potential policy implementations. However, forecasting is explicitly noted by the Authority as something that the modelling is not designed to achieve.[8] In our view, these finer details of policy implementation are unlikely to fundamentally affect the comparison between policies, unless very different levels of abatement are being considered. For instance, Jacobs' draft reports suggests that the RC policy scenario is significantly less costly (in a relative sense) at achieving the weaker emissions constraint than under the two degree warming scenario – in which it is unable to achieve the constraint.[9]

2.2.2 Emissions price path

We consider the use of emissions prices sourced from IPCC findings is an appropriate basis for sourcing international emissions prices.

The emissions prices estimated by the IPCC are denominated in United States dollars and estimated as 2010 real prices. Prices for 2020, 2030 and 2050 have been visually read from charts provided in the IPCC report. To convert these prices to an Australian dollar 2012/13 real basis, the Authority has:

- used average exchange rates for the 2009/10 financial year sourced from the Reserve Bank of Australia (RBA) of $A1.13 for each United States dollar (or equivalently, US$0.88 for each Australian dollar); and
- inflated these to a 2012/13 real basis using an uplift of 4.8 per cent, based on quarterly data on the consumer price index (CPI) sourced from the Australian Bureau of Statistics (ABS).

Overall we consider that these adjustments represent a reasonable basis for determining Australian dollar emissions price inputs from the original emissions prices sourced from the IPCC report. However, we note that given the volatility of exchange rates, and the potential importance of the IPCC emissions price series to the modelling, it would be valuable to also consider sensitivities to this adjustment. In particular, the use of the 2009/10 exchange rate assumes that the emissions price forecasts made by the IPCC have remained constant in Australian dollar terms, even while the Australian dollar has depreciated significantly against the United States dollar since this time. An alternative basis for converting IPCC emissions prices into Australian

[8] Jacobs draft report, section 1.4: 'Using and interpreting this modelling', pp 12-13

[9] Jacobs draft report, section 3.1.6: 'Resource costs and cost of abatement', p 28 and section 5.1.5: 'Welfare costs', p 99

dollars could use a current estimate of the exchange rate, or even forward measures or forecasts of the future exchange rate.

We have looked at one potential alternative basis for developing Australian dollar forecasts of emissions prices that:

- inflates the United States dollar IPCC emissions prices to 2012/13 terms using United States inflation of 7.1 per cent over this period; and
- converts prices to Australian dollars using a recent June 2020 forward rate of US$0.67 for each Australian dollar.[10]

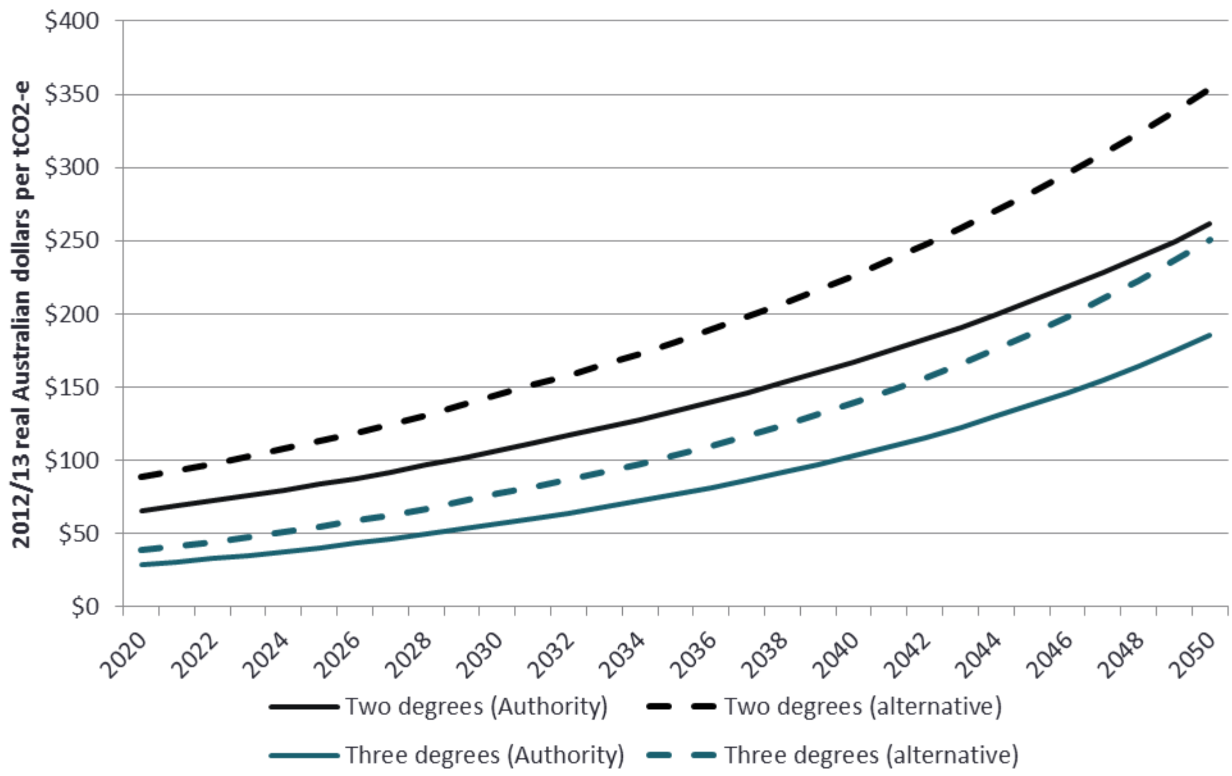
This basis for converting takes the United States dollar emissions prices from IPCC as an estimate of internationally traded emissions prices and assumes that changing exchange rates will affect the emission price experienced in Australian dollars. It also results in future emissions prices that are significantly (35 per cent) higher than those used in the CP scenario and subsequently used to set emissions constraints for all other scenarios. Higher emissions prices in the CP scenario would:

- result in a more rapid reduction in emissions under that policy scenario, and consequently a lower emissions constraint under all modelled scenarios; and
- potentially make some policy options under the two degrees warming scenario infeasible, and may make the RC policy scenario infeasible even under the weaker emissions constraint.

Figure 1 below compares the path of emissions prices under the Authority's basis for converting to Australian dollars and using the basis described above.

[10] We are not able to source forward rates to 2030 or 2050. However, we observe that the forward rate curve is close to flat around 2020.

Figure 1: Comparison of emissions prices under alternative exchange rate assumptions



Source: Climate Change Authority, IPCC, HoustonKemp modelling

As we note above, it appears that the effectiveness of some scenarios is affected by the level of the emissions constraint. In particular, the AB and RC scenarios appear to perform better under the weaker constraint than under the Phase 1 modelling results. If this result is consistent with even tighter constraints, it would suggest that modelling the effect of even higher emissions prices (and tighter emissions constraints) would be expected to promote the 'technology pull' scenarios at the expense of the 'regulated' scenarios on a comparison of resource costs, with the 'emissions pricing' policies remaining least cost.

2.2.3 Resource costs

Resource costs are a key measure used to compare policies in Jacobs' draft report. Resource costs estimate the cost of meeting electricity demand under each of the policy scenarios over the 2020 to 2050 period.

Jacobs explains that it calculates resource costs as the sum of:

- fuel costs including delivery costs;
- variable operating and maintenance costs;
- fixed operating and maintenance costs; and
- annualised capital costs.

Resource costs are calculated between 2020 and 2050 and discounted using a cost of capital of 7 per cent, prescribed as the central rate by the Office of Best Practice Regulation (OBPR) for assessing regulatory interventions, with sensitivities of 3 per cent and 10 per cent.[11]

We consider that using resource costs, so defined, is a reasonable basis for assessing the direct costs of meeting electricity demand under each policy scenario. In particular, annualising capital costs is an appropriate adjustment to make to ensure that capital investments made close to 2050 do not weigh unreasonably on the comparison between policy scenarios. That is, annualising capital costs is a simplification that avoids the need to estimate a longer time horizon and discount using the OBPR rate over this horizon. Consistent with this observation, in our opinion the OBPR discount rate used to calculate the present value of resource costs should also be the same rate used to annualise capital costs. We understand from email correspendance with Jacobs that the cost of capital for generators is used for this purpose.

We consider the effect of the difference is likely to be modest. This is because the capital costs that are being annualised tend to occur later in the 2020 to 2050 period and therefore weigh less on the overall present value resource cost. We also understand from emails with Jacobs that the ranking of policies is not likely to be affected by this change in the cost of capital. However, we recommend that Jacobs revise its basis for calculating annualised capital costs in its measure of resource costs to use the OBPR discount rate consistent with the overall present value calculation.

2.2.4 Demand adjustment

An adjustment is applied to resource costs that captures the welfare consequences of changes in electricity demand as a result of the implementation of policy options.

We agree that taking into account deadweight losses in the overall costs of any particular policy scenario is appropriate. It is important to be careful in making assessments of deadweight loss to consider what the assumed counterfactual ‘efficient’ level of consumption is. For example, if application of an emissions price sends appropriate signals to users of electricity about the social costs of their consumption, then instituting an emissions price will:

- result in a decline in consumption compared to where an emissions price is not applied; but
- give rise to a decrease in deadweight loss in the wholesale market for electricity, since consumers will no longer consume electricity for which their valuation of use is less than the social costs of its consumption.

We are not able to directly observe what baseline level of efficient demand Jacobs assumes in its calculation of the demand adjustment. However, we recommend that it give consideration to the factors discussed above in assessing what a reasonable basis for calculating deadweight loss might be. We expect that the effect of any changes to assumptions in this area will be low, since the deadweight losses are likely to be small relative to the overall resource costs.

2.2.5 Abatement cost

Comparisons of demand-adjusted resource costs between scenarios take into account the overall cost of implementing the scenario, but not the cost effectiveness of abatement, since different policies may achieve different emissions reductions. Abatement costs can be summarised as the present value cost of achieving a unit of emissions reduction.

Jacobs has been directed by the Authority to calculate the abatement cost for each policy according to the following formula:[12]

[11] Office of Best Practice Regulation, *Guidance note: Cost-benefit analysis*, July 2014, p 7.

[12] This is our restatement of the formula in Jacobs’ draft report, section B.3.3: ‘Cost of abatement’, p 276.

$$Abatement\ cost = \frac{\sum_{t=0}^{n} \frac{Demand\ adjusted\ resource\ cost_t}{(1 + OBPR\ discount\ rate)^t}}{\sum_{t=0}^{n} Emissions\ reduction_t}$$

This method produces an average unit cost of abatement, consistent with the Authority's view that emissions reductions should not be discounted. This differs from the methodology that would properly be used to calculate the marginal cost of abatement, which would require a more complex calculation which would include discounting the associated emissions reduction.

After careful consideration, we consider that the formula used by Jabobs represents an appropriate basis for calculating the unit abatement cost.

2.2.6 Network and retail prices

Jacobs has translated wholesale market outcomes into end-user impacts using assumed price structures for electricity networks and for electricity retailers. A number of simplifying assumptions have been adopted to achieve this, including:

- representative network tariffs for each customer class (residential, SMEs, large commercial and industrial) in each distribution network area, using the most common tariff class;
- where inclining block tariffs are applied, assuming that only the price of the first block is taken;
- where more complex time of day pricing is applied, assuming equal consumption of energy across the charging periods; and
- retailers pass through load-weighted average wholesale prices, with a 10 per cent markup to reflect contract premiums.

Some of these assumptions do not reflect reality. However, we consider that they are broadly reasonable in achieving a 'snapshot' of the final tariff impact of alternative policy scenarios. An analysis focused on impacts on specific types of customers would require more detailed and accurate modelling of network and retail tariff structures.

2.3 Assessment of modelling results

Apart from directly assessing the modelling methodology, reviewing the results of Jacobs' modelling provides another method that can be applied to test the implementation of the policy scenarios. In this section, we set out our *a priori* views about how modelling results should compare on these measures and whether these expectations are confirmed in the modelling results.

Overall, we find that our expectations are consistent with the modelling results. This provides a level of assurance that the overall modelling methodology is sound, and that any simplifications that have been made in the modelling process are not material to the ability of the model to produce economically rational outcomes.

2.3.1 Resource costs

We formed some preliminary expectations of how resource costs would likely vary across the policy options modelled by Jacobs. Based on our review of the policies, we consider that:

1. CP and EIT, which signal the cost of emissions directly and allow the industry freedom of action in responding to these signals, will likely have the lowest resource costs of the policy scenarios.
2. The LET will always have a lower resource cost than the RET, due to the RET being more restrictive in its requirement to use renewable technologies rather than low carbon technologies.
3. FiT will have a similar resource cost to the LET because for the most part it is incentivising the same type of generation to enter.

4. RC and AB will likely have amongst the highest resource costs because they select a particular approach to emissons reduction but do not provide any basis for incentivising low emissions generators.

With some exceptions, these expectations were generally reflected in the modelling results.

In particular, Figure 12: 'Resource costs relative to the reference scenario, 2° Celsius emission constraint' and Figure 109: 'Welfare costs of policies relative to reference case, $billion' from Jacobs' draft report show that CP and EIT are the policy alternatives that achieve the lowest resource costs in meeting the emissions constraints. This is not surprising since, from an optimisation perspective, setting a price for emissions is consistent with providing electricity at least cost whilst meeting an emissions constraint. It is likely that CP and EIT provide some level of approximation for an emissions price that solves this optimisation problem, noting that:

- the IPCC emissions price used in the CP policy scenario is the median of prices calculated in studies that solve exactly such an optimisation problem but for more sectors and countries; and
- the endogenous emissions price estimated under the EIT solves the same optimisation problem for the NEM and the WEM for an emissions budget, given the choice of trajectory for emissions intensity and constraints on borrowing.

Our expectations that the LET were lower cost than the RET were met. The cost of the LET was similar to the FiT, although this varied depending on the tightness of the emissions constraint.

Our expectations with respect to the regulated policies were not entirely borne out. While RC was amongst the most expensive policies under the two degree warming scenario, AB performed relatively well under both comparisons. Both were less expensive than the technology pull scenarios under the weak emissions constraint. This is an interesting result. It is potentially reconcileable if the regulated approaches are reasonably well-specified such that, although they represent a heavy intervention in selecting the generators that are to shut down, they do this in a way that is not altogether inconsistent with how a competitive market provided with appropriate pricing incentives would respond. This interpretation suggests that the results of the regulated policies may be sensitive to how the policies are implemented.

Overall, we are satisfied that the comparison of the resource costs estimated in the modelling are robust and broadly consistent with our *a priori* expectations, or at least capable of being explained having regard to the characteristics of the policies.

2.3.2 Comparison of prices and bills

Jacobs' report shows comparisons of the effect of different policies on wholesale market prices and on residential retail tariffs. As with resource costs, we formed initial expectations of how these would compare across scenarios and compared these to actual outcomes reported by Jacobs.

Based on our review of the policies, we expect that:

1. CP will have higher wholesale and retail prices than most scenarios, and particularly EIT. This is because CP collects tax revenue for the government, and Jacobs does not model the return of this to consumers in lower electricity prices – that is, the relative price change induced by the emissions price is preserved.
2. Wholesale and retail prices for the technology pull scenarios (RET, LET and FiT) will initially be lower than for other scenarios. These scenarios work by incentivising entry of new generation. This in turn should lead to lower prices until incumbent generators exit.
3. Wholesale and retail prices for regulated scenarios (RC and AB) will initially be higher than for other scenarios (except potentially CP). This is because these scenarios work by enforcing exit of existing generation, but do not provide specific incentives for new entry. Wholesale market prices will increase as generators exit or produce less output, and will only reduce in response to new entry brought online by the resulting price signals.

Based on our inspection of Figure 8: 'Wholesale prices, volume weighted average, 2° Celsius emission constraint' and Figure 9: 'Changes in residential customer bills and additional expenditure on bills, 2° Celsius emission constraint' of Jacobs' draft report, the pattern of prices from the Phase 1 modelling is generally in line with our expectations. This is also the case with the Phase 2 results shown in Figure 106: 'Wholesale prices, volume weighted average, all regions' and Figure 107: 'Changes in residential customer bills and percentage increase in bills, all scenarios'. These results suggest that the modelling of the scenarios is consistent with our understanding of them based on the Authority's instructions to Jacobs.

The AB scenario has an extreme period of high prices from about 2023 to 2028 under the tighter emissions constraint. The rationale for these high prices is explained in Jacobs' draft report as being required to provide for entry of new generation given the lower prices that will persist after 2030 due to the entry of new lower cost low emissions technologies.[13] This result and the explanation is consistent with our expectations above.

The CP policy is different from all others in that it generates government revenues. These are available for a range of possible uses. It is appropriate that these tax revenues are reflected in higher wholesale and retail prices and we consider that the modelled impact on prices and bills appropriately captures this, showing prices under the CP policy that are higher than those for most other scenarios. The draft report does not include a comparison between scenarios that reflects the net impact on consumer welfare, which would capture the return of government revenue raised under the CP policy scenario.[14]

Revenue that is raised by the government under the CP policy scenario could be returned to consumers, either directly under a compensation package, or in additional general spending or avoided taxation in other areas, assuming a balanced budget over the long run. We suggest that this be highlighted in the report so as to be clear that the comparisons of wholesale prices and bills does not reflect a comparison of total consumer welfare. Assuming revenue recycling, the CP policy scenario would perform more favourably under a comparison of total consumer welfare than it does under the comparisons of wholesale prices and bills.

2.4 Summary of findings

Table 1 below summarises the findings of our review of the implementation of the policy scenarios in Jacobs' electricity market modelling. Overall, we consider that the approach taken and assumptions made are generally robust and will give rise to a fair comparison of policies.

There are some areas in which we consider that the assumptions taken were reasonable, but that alternative assumptions could have been available.

We identified two areas in which we though that an unreasonable assumption or basis for comparison was established:

1. The RC policy under the two degrees warming scenario did not achieve the emissions constraint. Although this is acknowledged in the draft report, we consider that this invalidates comparisons of outcomes with other policies. This could be addressed by removing RC from policy comparisons, or signalling the lack of comparability in each figure.
2. The cost of capital used for annualising capital costs in calculating resource costs should be the OPBR discount rate used to calculate present values and not the generator WACC.

[13] Jacobs draft report, p 23

[14] Arguably the change in demand modelled in response to higher prices under the CP policy scenario captures an implicit income transfer back to consumers since only the substitution effect of higher prices is modelled. This adjustment implicitly assumes that consumers are completely 'made good' for the higher prices through a lump sum transfer from the government because it does not incorporate an income effect caused by higher prices for electricity – that is, that all real incomes are maintained at their pre-policy level. Despite this, no clear basis for comparison of total consumer welfare exists because all other scenarios are also modelled in this way. A comparison of electricity as a percentage of disposable income that is comparable across scenarios might assume a constant disposable income under the CP scenario but take into account the extent to which disposable income is affected by changing electricity prices under other scenarios, in which there would be no government compensation package.

For each item that we considered, where we identified a potential alternative approach or assumption, we assessed the effect on comparison between scenarios that adopting this action would be likely to have. In our view, there are no items that are highly likely to affect the comparison between policy scenarios.

Table 1: Summary of policy modelling decisions

Approach or assumption	Reasonable	Observations and/or potential actions	Potential to misrepresent policy comparisons
Cumulative emissions budget as a basis for comparing policies	Yes	None	None
No discounting of emissions	Yes	None	None
Specification of policy scenarios	Yes	Policy scenarios could be developed with cost minimisation in mind	Low, there may not be much scope to vary policies given emissions constraint
Emissions prices sourced from IPCC	Yes	None	None
Basis for calculating Australian dollar emissions prices	Yes, 2009/10 exchange rates are used	Could use up-to-date forecasts of exchange rates, which are much lower than in 2009/10	Medium, higher emissions prices might be expected to favour “technology pull” scenarios over “regulated” scenarios
Lower WACC for FiT scenario	Yes, but the extent of difference is not clear	Could vary WACC adjustment for FIT scenario	Low, but could affect comparison with LET which is very similar in cost
Inclusion of RC scenario in Phase 1	No, it did not meet the emissions constraint and cannot be directly compared to other policies	Could remove from comparison or signal lack of comparability	Low, this is already signposted in Jacobs’ report but could be highlighted further
Formulation of resource costs	Yes	None	None
Basis for annualising capital costs used in resource costs	No, generator WACC is used	OPBR WACC should be used to annualise capital costs.	Low, based on email communication from Jacobs who have already performed this calculation.
Calculation of demand adjustment	Unclear, but adjusting for dead weight loss appropriate	Could take into account social costs of emissions in calculating deadweight loss	Low, deadweight loss is likely to be small relative to resource costs
Calculation of unit abatement cost	Yes	None	None
Network and retail tariffs	Yes, simplifying assumptions are made	Could take into account finer detail of tariffs	Low, detail unlikely to be important in assessing overall bill impacts
Comparison of resource cost outcomes between policies	Yes, conforms with expectations	None	None
Comparison of price outcomes between policies	Yes, conforms with expectations	Report does not include a comparison of net consumer outcomes after possible government compensation for CP.	Low, this doesn’t affect comparison of resource or abatement costs within the electricity sector

3. Input assumptions

In addition to assessing the manner in which emissions reduction policies were translated into a modelling context, HoustonKemp was instructed to peer review the input assumptions used in Jacobs' electricity modelling. The Authority provided an indicative list of 18 key assumptions for review, including sources for some input assumptions.[15] Each of these key assumptions are assessed in this section.

Our review of Jacobs' input assumptions has been informed by:

- how the data and assumptions have been sourced, ie the credibility of the source and whether this is consistent with best practice modelling; and
- the assumptions themselves, given our previous modelling experience and our knowledge of other models.

Where appropriate, we have compared input assumptions to other authoritative sources to assess the reasonableness of inputs used.

3.1 Current technology generation assumptions

3.1.1 Existing generator costs

Appendix E of Jacobs' draft report sets out costs and performance inputs for existing thermal plants used in Jacobs model. Costs and performance inputs include:

- total sent out capacity;
- available capacity;
- full load heat rate (GJ/MWh sent out);
- fixed O&M ($/kW/year);
- variable O&M ($/WMh);
- variable fuel cost ($/GJ); and
- total variable cost ($/MWh).

These data inputs are sourced from Jacobs' database of generation costs, which in turn is based on data from the Australian Energy Market Operator (AEMO), the former Independent Market Operator (IMO), annual reports of generators and fuel suppliers, Australian stock exchange announcements and other media releases. Fixed operating cost data are based on available data from market operators for their planning processes. For generators in the NEM, fixed operating costs are based on publically available data from AEMO. We consider these sources to be appropriate as they are authoritative (ie, AEMO) or are directly from companies operating the generators.

We have compared input assumptions listed in Appendix E: 'Costs and performance of existing and prospective thermal plants' with those from ACIL Allen's Fuel and Technology Review data file[16] to assess the reasonableness of existing generator cost used by the model. ACIL Allen's Fuel and Technology Review data file is used by the AEMO for the National Transmission Network Development Plan (NTNDP). In

[15] The scope of work invited HoustonKemp to suggest additions or removals for material or assumptions excluded or immaterial ones included, respectively. HoustonKemp assessed the indicative list as satisfactory given the aims and timeframe for the review.

[16] ACIL Allen's Fuel and Technology Review data file is available from AEMO's website: http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions.

general, Jacobs' data appear to be consistent with the ACIL Allen data. Although some differences exist, overall they appear not to be materially different from the ACIL Allen assumptions.

3.1.2 New entrant technology costs

Jacobs provides inputs for new entrant technology costs in Appendix E of its draft report. In general, Jacobs derives new entrant technology costs by estimating current costs and applying learning curves and adjusting for foreign exchange movements.

Jacobs have provided core technology cost assumptions in Appendix F, setting out for each technology type:

- asset life (years);
- nominal capacity (MW);
- auxiliary load (per cent);
- capital cost ($/kW sent out);
- capital cost de-escalator from 2020 (per cent per annum);
- heat rate at maximum capacity (GJ/MWh);
- variable non-fuel operating cost ($/MWh); and
- fixed operating cost ($/kW).

Input assumptions for thermal generation technologies are based on cost estimating tools in the Thermoflow Inc software suite. Thermoflow is a leading developer of thermal engineering software for the power and cogeneration industries and is widely used in the power generation industry. Australian users of Thermoflow software include significant electricity businesses, consultancies and research institutes.[17] Given the widespread use of Thermoflow, we consider it to be an appropriate source of input data for generator parameters.

We compared the input assumptions in Appendix F with those from ACIL Allen's Fuel and Technology Review data file, as used by the AEMO for its NTNDP. As noted above, we regard ACIL Allen's Fuel and Technology Review data file as an authoritative source for input assumptions. While there are some differences between the ACIL Allen data and Jacobs' assumptions, input assumptions are of the same magnitude and differences between them are generally small and not unreasonable.

In addition to assessing the overall reasonableness of generator input assumptions, we also reviewed capital costs in more detail. Our assessment of capital cost inputs for each generation technology group is set out below.

Thermal

Estimates of capital costs for gas turbine plants, Rankine cycle plants, and variations of these with carbon-capture were estimated using Thermoflow. As mentioned previously, we consider Thermoflow to be an appropriate source given its widespread use and acceptance.

Photovoltaics

Jacobs based its photovoltaic cost inputs (shown in Table 2 below) on recent observations from its own projects and from publically available information.

[17] Thermoflow website, http://www.thermoflow.com/thermoflow_customerList.html, accessed 14 January 2016.

Table 2: Assumed cost inputs for photovoltaics

Technology	Jacobs' capital cost ($/kW)	Capital cost ($/kW) - external sources
Concentrating PV	$6,175/kW	N/A[18]
Flat panel PV	$2,990/kW	$2,900/kW for single axis tracking[19]
Roof-top PV	$2,400/kW	$2,160kW[20]

Source: Jacobs

We are unable to assess the reasonableness of the capital cost for concentrating PV as this technology is not yet deployed commercially.

Jacobs' flat panel PV capital costs align with ACIL Allen's – on this basis we consider that they are likely to be reasonable.

Capital cost inputs for roof-top PV generation were sourced from Jacobs' analysis of both publicly available information and information from their previous projects. We have estimated roof-top PV costs using publicly available data that are modestly lower than the estimates used by Jacobs. We consider that Jacobs' roof-top PV capital costs are reasonable, given that the extent of this difference is not material in the context of the overall uncertainty about costs,

We understand Jacobs have used Solar Choice and Climate Spectator data[21] to source roof-top PV costs for May 2015. We consider these to be appropriate sources for prices that reflect the current state of the PV market. Cost data from Solar Choice/Climate Spectator are inclusive of:

- the cost of panels;
- the cost of a DC to AC inverter;
- goods and services tax (GST); and
- an amount for STC incentive.[22]

We consider the Solar Choice/Climate Spectator provides an appropriate basis for comparison to roof top PV costs noted in Figure 348: 'Installed total cost assumptions for PV small scale systems' of Jacobs' draft report. Both sets of costs exclude STC incentives and a factor for converting DC to AC (being the cost of the inverter).

Using the May 2015 Solar Choice system costs used by Jacobs, we calculate roof-top PV costs for a 10kW system to be $2,160/kW after adding back the STC subsidy ($8,073) and removing GST ($2,160). Our calculation is set out in Table 3 below. This estimate is modestly lower than the estimate of $2,400/kW reported in Figure 348: 'Installed total cost assumptions for PV small scale systems', but the difference does not appear to be material.

[18] We were not able to find authoritative sources for the capital cost of concentrating PV as the technology is not yet commercialised and currently in the demonstration phase. See IRENA, *Renewable Power Generation Costs in 2014*, January 2015, p 76.

[19] ACIL Allen, *Fuel and technology cost review final report*, June 2014, p 40.

[20] $2,160/kW is based on a 10kW system costing $15,689 and excluding a STC subsidy of $8,073 (207 credits at $39 each). Cost for the 10kW system is from the Solar Choice website, http://www.solarchoice.net.au/blog/residential-solar-pv-system-prices-may-2015.

[21] Climate Spectator data is the same as those from Solar choice. See: http://www.businessspectator.com.au/article/2015/5/11/solar-energy/solar-pv-price-check-may for Climate Spectator and http://www.solarchoice.net.au/blog/residential-solar-pv-system-prices-may-2015 for Solar Choice.

[22] See Solar Choice website: http://www.solarchoice.net.au/blog/residential-solar-pv-system-prices-may-2015.

Table 3: Roof-top PV capital cost calculation

	Capital cost of roof-top PV
Solar choice system cost	15,689
Add: value of STC	8,073[23]
Less: GST[24]	(2,160)
Cost of the system	21,602
Cost per kW	**2,160**

The calculation shown above calculates the cost of solar PV on a GST exclusive basis. This would be appropriate for estimating capital cost inputs for businesses. However, capital costs for assets deployed by the final consumer should be expressed on a GST inclusive basis, and this estimate would be even more closely aligned with Jacobs'. However, we are unable to determine whether the model currently distinguishes capital costs between those incurred by final consumers and those incurred by businesses.

Wind

Jacobs uses capital costs for wind generation of $2,400/kW, based on previous experience and analysis of publicly available information. This is comparable to $2,250/kW[25] as used in AEMO's NTNDP, which is also used by AEMO in the Electricity Statement of Opportunities (ESOO), the Victorian Annual Planning Report (VAPR) and South Australian Advisory Function report. We therefore consider this assumption to be appropriate and reasonable.

Solar thermal

Jacobs' modelling assumes capital costs of $6,500/kW for solar thermal without storage, and $9,500/kW for solar thermal with storage. We have compared these costs to those estimated by ACIL Allens and used by AEMO as its planning assumptions.[26]

Table 4: Capital cost assumptions for concentrated solar thermal plants

Technology	Modelling assumption	ACIL Allen for AEMO
Concentrated solar thermal plant – without storage	$6,500/kW	$4,500/kW for compact linear Fresnel technology
Concentrated solar thermal plant – with storage	$9,500/kW	$9,100/kW for parabolic trough with thermal storage

Source: Jacobs

We understand Jacobs have sourced their modelling assumption from previous work and note that Jacobs' assumed capital cost of solar thermal without storage is materially higher than ACIL Allen's. However, assumed costs are in line with those from Alinta who estimates a stand alone linear Fresnel plant would cost

[23] A 10kW system is entitied to 207 STC, based on the Clean Energy Regulator's small generation unit STC calculator (https://www.rec-registry.gov.au/rec-registry/app/calculators/sgu-stc-calculator, accessed 8 February 2016). Jacobs have used a value of $39 for each STC to calculate the value of STC, which equiates to $8,073.

[24] GST is calculated as 10 per cent of the of the GST exclusive amount of the sum of Solar choice system cost and value of STC.

[25] ACIL Allen, *Fuel and technology cost review final report*, June 2014, p 55.

[26] ACIL Allen, *Fuel and technology cost review final report*, June 2014, pp 43-46. See AEMO website: http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions, accessed 8 February 2016.

approximately $6,969/kW,[27] which suggests costs are reasonable. Jacobs' may wish to include additional material in the final report to support its preferred input assumption in respect of solar without storage.

Geothermal

Jacobs' modelling assumes capital cost inputs of $6,500/kW to $7,000/kW for geothermal generation. This is at the low end compared to costs reported by the International Renewable Energy Agency (IRENA) that range from US$5,000/kW to US$10,000/kW for binary plants, which are relatively expensive and are employed primarily in the absence of excellent geothermal reservoirs.[28] Given that Australia has no volcanic geothermal resources[29] and limited availability of hot sedimentary aquifiers (HSA),[30] it is expected that most of Australia's geothermal power would be produced through enhanced geothermal systems (EGS). EGS relies on fracking and other engineering techniques to create an artificial reservoir, which generally results in much higher production costs than in volcanic reservoirs. In that context, it is reassuring to note that the assumed capital costs are higher than for recent projects in New Zealand, which have been around A$6,000/kW.[31]

We therefore consider that the assumed costs of $6,500/kW to $7,000/kW for geothermal generation are reasonable. However, we caution that unlike some other technologies, the capital cost of geothermal power can increase dramatically as more plants are commissioned while using the most efficient harvestable resources first. Our preferred approach to constructing an approximate geothermal energy supply curve for Australia would give consideration to the quality of individual geothermal fields. We note that Jacobs have included a step change in geothermal generation costs to model for higher connection costs after the first 12,800 MW of geothermal generation capacity.

Hydro

The model assumed capital cost inputs of $3,500/kW for hydro generation. This is consistent with costs included in IRENA's Hydropower report, which indicate a range from a low of US$1,000/kW to US$3,500/kW.[32] We consider that assumed cost of $3,500/kW for hydro generation is reasonable and in line with authoritative external sources.

Nuclear

Capital costs for nuclear power are assumed to be $5,140/kW based on Generation III reactors in the United States. By comparison, the range of overnight capital costs surveyed by the OECD Nuclear Energy Agency (NEA) in 2015 ranged from US$2,021/kW to US$6,215/kW for OECD countries[33]. Jacobs notes typical capital costs for nuclear energy in the United States range from A$4,780 to A$5,460/kW.

The capital costs of nuclear generation are highly uncertain due to the bespoke nature of nuclear power plant projects. The difficulty and uncertainty of contemporary nuclear power projects is illustrated by the

[27] See https://alintaenergy.com.au/Alinta/media/Documents/Alinta_Solar_Thermal_Stakeholder_Briefing_23_April.pdf, accessed 9 February 2016.

[28] IRENA, *Renewable Power Generation Costs in 2014*, January 2015, p 140.

[29] Australian Geothermal Energy Association. *Geothermal energy frequently asked questions.* Accessed online January 2016, http://www.agea.org.au/geothermal-energy/frequently-asked-questions/

[30] Geoscience Australia. *Geothermal Energy Resources.* Table 1. Accessed online January 2015, http://www.ga.gov.au/scientific-topics/energy/resources/geothermal-energy-resources

[31] IRENA, *Renewable Power Generation Costs in 2014*, January 2015, p 140, Fig 9.2.

[32] IRENA, *Renewable energy technologies: cost analysis series*, Volume 1, Power Sector, Issue 3/5, June 2012, p 18.

[33] Overnight capital costs include engineering, procurement, construction, and owners costs but exclude financing costs

Source: OECD Nuclear Energy Agency, *Executive Summary: Projected Costs of Generating Electricity*, 2015, p 6. See OCED website: http://www.oecd-nea.org/ndd/pubs/2015/7279-proj-costs-electricity-2015-es.pdf, accessed 15 January 2016.

development of the Olkiuoto[34] and Flamanville[35] power plants, which are both facing significant cost overruns and delays. We expect the cost of nuclear generation is more likely to be at the higher end of the range of costs exhibited in the United States, given that Australia does not have experience with construction, regulation and operation of commercial nuclear reactors. While Jacobs' cost assumptions may be slightly low on this basis, we consider them to be reasonable given the inherent uncertainty of nuclear generation.

3.1.3 Biomass availability

Biomass capacity is restricted to not exceed biomass capacity in the reference case. The constraint is based on analysis by the Commonwealth Scientific and Industrial Research Organisation (CSIRO) that biomass resources will be taken up preferentially in the transport and industrial sectors in a carbon constrained world.

We understand that biomass as a technology is relatively mature and is therefore not expected to experience significant improvement in costs that would provide material advantages in generation. In addition, generation would compete for biomass resources with the transport or industrial sector where there are higher value uses for biomass.[36]

In light of limited expected advantages and allocative constraints for biomass resources, we assess that the constraint adopted by Jacobs appears to be reasonable.

3.1.4 Renewable generator capacity factors

Capacity factors refers to the ratio of actual output compared to the output if a generator is able to run at maximum capacity all the time. Jacobs has provided input assumptions for hydro-electric generation, wind generation, and solar PV. We consider the source and reasonableness of capacity factor assumptions (or description of generation output) for each type of renewable energy generation below.

Hydro-electric generation

Output (and therefore capacity factors) from hydro generation is modelled in Strategist with fixed monthly generation volumes. The amount of monthly generation, except for Hydro Tasmania, is based on market information for long term trend of historical observations of monthly hydro output for each of the generators. Hydro Tasmania's generation is based on its stated long term average. We consider this to be a reasonable basis for determining the energy resource of hydro generators.

Wind generation

Capacity factors for wind generation vary by location. Jacobs have obtained inputs from a number of sources for wind generation profiles, which are summarised in Table 5 below.

[34] A European Pressurised Reactor (EPR) reactor is currently under construction at the Olkiluoto Nuclear Power Plant. Areva was to build the unit for a fixed price of €3 billion, but costs were revised to €8.5 billion in 2012. The reactor was initially expected to start operations in 2010. See http://uk.reuters.com/article/tvo-olkiluoto-idUKL6N0LX3XQ20140228, accessed 21 January 2016.

[35] A EPR reactor is currently under construction at the nuclear power plant. Initial costs were expected to be €3.3 billion. Costs have escalated to €10.5 billion. The reactor was expected to start operations in 2012 but is now delayed until 2017. See http://www.wsj.com/articles/edf-postpones-flamanville-nuclear-reactor-startup-to-2018-1441293024, accessed 21 January 2016.

[36] ClimateWorks, *Technical report: Pathways to deep decarbonisation in 2050: How Australia can prosper in a low carbon world*, September 2014, p 35.

Table 5: Sources for wind generation profile input assumptions

State/territory	Source
South Australia	Observed aggregated wind power patterns from the 2013/14 financial year
Victoria	Observed aggregated wind power patterns from the 2013/14 financial year
New South Wales	Observed aggregated wind power patterns from the 2013/14 financial year AEMO's projected wind traces developed for the 2014 NTNDP study
Tasmania	Observed aggregated wind power patterns from the 2013/14 financial year
Queensland	South Queensland area is represented as a fixed wind profile, sourced from AEMO's wind traces. Central and north Queensland wind generation is modelled as an unreliable thermal generator. A partial outage and full outage is used to approximate the availability of wind power
Western Australia	Wind generation profiles based on the major wind regions in the WEM

Source: Jacobs

Aggregate wind power patterns for South Australia, Victoria, Tasmania and New South Wales have been obtained from wind traces released by AEMO. We consider this source of aggregated wind power patterns to be authoritative and appropriate.

Wind generation profile input assumptions for Western Australia are based on major wind regions in the WEM, the source of which Jacobs will confirm in their final modelling report.

Three regions were considered for Queensland wind generation: south Queensland where AEMO wind traces were used as the source of input data, and central and north Queensland where an unreliable thermal generator is used to model wind generation. Although the proxy used for central and north Queensland wind generation profiles are not ideal, we consider that they are reasonable given the lack of actual information for wind traces in these regions.

Solar PV generation

Renewable generator capacity factors are based on two sources: the Clean Energy Regulator (CER) and metered energy production from Ausgrid. The model uses average capacity factors for each state, which diminishes as the level of capacity increases in each region. Initial capacity factors in each state are set out in Table 6 below.

Table 6: Initial capacity factors for small scale PV systems by region

	VIC	NSW	TAS	SA	QLD	WA	NT
PV	14.8	15.8	13.7	15.8	15.8	15.8	15.8
PV plus storage	13.7	14.6	12.7	14.6	14.6	14.6	14.6

Source: Jacobs

We have considered the source of capacity factor input assumptions and compared them to estimates from other sources. We found capacity factors are consistent with other estimates of solar PV capacity factors, which range from 14 per cent to 21 per cent.[37]

The capacity factor for PV plus storage takes into account efficiency losses from charging and discharging into energy storage devices. Battery efficiency is assumed to be approximately 92.4 per cent,[38] which is comparable to the efficiency stated for Tesla's Powerwall, which is 92 per cent.[39]

We consider that using the CER and Ausgrid as a source of capacity factors is appropriate and authoritative.

In addition to capacity factors, Jacobs applies firmness factors sourced from AEMO to intermittent generation when modelling a reliability constraint. We understand that the 28 per cent summer firmness factor for large-scale solar PV was applied, while a winter factor of 0 per cent was used. The firmness factors are consistent with those specified by AEMO and therefore we consider these inputs to be appropriate and authoratively sourced.

3.1.5 Small-scale PV saturation

The model's reference case assumes saturation of 55 per cent for residential households and 65 per cent for commercial businesses.[40] Saturation rates are relaxed for an alternative reference scenario, which assumes saturation rates of 65 per cent for residential households and 75 per cent for commercial businesses.

Reference case saturation rates for households is based on Jacobs analysis of Australian Bureau of Statistics (ABS) of available dwellings that are suitable for installing small-scale PV. We consider ABS statistics are an appropriate and authoritative source to derive small-scale PV saturation rates.

For the purposes of estimating saturation rates for commercial businesses, businesses in wholesale and retail trade, schools, hospitals and government offices have been included. We understand saturation rates for commercial businesses have been derived from the Bureau of Resources and Energy Economics' Fuel and Energy survey and ABS statistics. We consider these sources to be appropriate and authoritative.

3.1.6 Emissions intensities

Emission intensities were obtained from the Department of Environment's workbooks. The emission intensities by power station are set out in Appendix C.7 of Jacobs draft report, including those that relate to new power plants.

We reviewed the Department of Environment's National Greenhouse Accounts Factors[41] and consider that it is to be an appropriate source for emission factors.

3.1.7 Refurbishment costs

Jacobs have assumed that refurbishment of existing generation assets is allowed where refurbishment is economic. Refurbishment costs mainly applies to wind farms and large-scale solar PV plant and is assumed to be 60 per cent of the cost of a new project, which allows for the replacement of key components such as turbines, shafts, gears and panels.

To gauge the reasonableness of this input assumption we have reviewed capital cost breakdowns for ground based solar PV and wind generation from IRENA as a point of reference. The IRENA report indicates that

[37] Bureau of Resources and Energy Economics, *Asia-Pacific Renewable Energy Assessment*, July 2014, p 82.

[38] 92.4 per cent efficiency is derived from the capacity factor for PV plus storage divided the capacity factor for PV.

[39] Tesla website, https://www.teslamotors.com/en_AU/powerwall, accessed 15 January 2016.

[40] Jacobs, *Draft report: Modelling illustrative electricity sector emissions reduction policies*, Dec 2015, p.267.

[41] Department of the Environment, *National Greenhouse Accounts Factors – Australian National Greenhouse Accounts*, December 2014.

capital cost for the generation components of wind generation infrastructure is between 63 per cent and 48 per cent.[42] For solar PV, panels or modules are approximately 51 per cent of capital costs.[43]

Assuming refurbishment requires replacement of components involved in electricity generation, Jacobs' assumption that refurbishment costs are 60 per cent of the cost a new project is reasonable and consistent with the order of magnitude of those implied by capital cost breakdowns from IRENA.

3.1.8 Decommissioning costs

Decommissioning costs relate to mine rehabilitation plus the cost of removing equipment and site rehabilitation. Decommissioning costs are based on retirement cost estimates provided by ACIL Allen in its Fuel and Technology Cost data file.[44]

ACIL Allen has included the cost of end of life plant remediation and site rehabilitation in its estimate of decommissioning/retirement costs. It notes that these costs are often plant and technology specific and are significantly influenced by local stator rules and regulations.[45]

We reviewed costs and recalculated retirement costs for a selected number of plants and found that the retirement costs listed in Appendix C.4.7 were consistent with per-megawatt costs from ACIL Allen's Fuel and Technology Cost data file. We consider that ACIL Allen as an appropriate source as it has demonstrated expertise and consulting experience in the electricity industry.

3.2 New technology generation assumptions

3.2.1 Technology availability

Jacobs made a number of assumptions regarding when certain technologies were available. These assumptions are set out in Table 7 below.

Table 7: Technology availability

Technology	Technology availability restrictions
Carbon capture storage (CCS)	Not available until 2030.
Geothermal	Not available until 2030. Low cost geothermal options were limited to 12,800 MW. After this time, the cost of geothermal was increased to account for higher connection costs.
Nuclear	Not available until 2035.
Biomass	Biomass capacity in policy scenarios was not to exceed biomass capacity built in the reference case.[46]

Source: Jacobs

There is a high degree of uncertainty concerning the timing of when new technologies will be available – let alone when those technologies will be commercially viable in the Australian context. Consequently, we do

[42] IRENA, *Renewable Energy Technologies: Cost Analysis Series - Wind Power*, Volume 1: Power Sector, Issue 5/5, June 2012, p 18. 63 per cent and 48 per cent replacement costs is derived from capital cost of wind turbines less the cost of the tower. This cost of the tower constitutes approximately 25 per cent the cost of wind turbines.

[43] IRENA, *Renewable Energy Technologies: Cost Analysis Series - Solar Photovoltaics*, Volume 1: Power Sector, Issue 4/5, June 2012, p 20. The installed cost of ground mounted PV is $3.50/W of which approximately $1.80/W relates to the module. This gives a replacement cost of the module of approximately 51 per cent.

[44] Available from AEMO website, http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions, accessed 15 January 2016.

[45] ACIL Allen, *Final report: Fuel and technology cost review*, June 2014, p 15.

[46] See section 3.1.3**Error! Reference source not found.**.

not have a basis to assess whether the technology availability input assumptions presented in Jacobs' report are reasonable.

However, we note Jacobs performs sensitivity testing for its technology availability assumptions by excluding nuclear, CCS and geothermal generation as options. The sensitivity testing shows that resource costs are higher with lower technological availability but the relative ranking of policy options does not change. We consider that these results provide some comfort that the results of Jacobs' modelling do not hang on particular entry assumptions for new technologies.

3.2.2 Battery costs

Jacobs' cost assumptions for energy storage are modestly higher than those that we have been able to establish from publicly available sources. The higher costs used by Jacobs appear to be due to conservative price and performance assumptions.

We are satisfied that Tesla's Powerwall is an appropriate standard for the cost of home battery systems. We consider the small-scale costs used by Jacobs to be broadly reasonable given the significant uncertainty surrounding purchase and balance of system prices.

Continued use of Tesla's battery products as a point of comparison would suggest that a 30 per cent discount for large-scale storage might be more appropriate than the 10 per cent discount used by Jacobs. We consider the use of CSIRO estimates for the alternative reference scenario to be reasonable.

Jacobs used Tesla's Powerwall energy storage product as a proxy to estimate small scale battery costs. For large scale storage costs, Jacobs applied a 10 per cent discount to small scale battery costs to arrive at the cost of large scale batteries. Table 8 below sets out Jacobs' assumed battery costs for small and large scale storage based on Tesla's Powerwall.

Table 8: Energy storage costs per usable MWh over the life of the battery

Technology	LCOE ($/MWh)
Small scale storage	325
Large scale storage	293

Source: Jacobs

Based on Telsa's press release,[47] there are two Powerwall models available:

- a 7kWh model costing US$3,000 (A$3,896); and
- a 10kWh model costing US$3,500 (A$4,545).

Both costs exclude the inverter and installation. It is notable that the two products have very different intended purposes. While both are expected to last 10 years or more, the 7kWh model is capable of daily cycling (5000 cycles total), while the 10kWh model is intended for backup use in the order of 70 cycles per year (1000-1500 cycles).[48]

Our calculations (shown in Table 9 below) suggest that using the 7kWh model gives rise to a levelised cost of energy storage of $257 per MWh, compared to $325 per MWh as calculated by Jacobs.

[47] Tesla website, https://www.teslamotors.com/en_AU/presskit/teslaenergy, accessed 13 January 2016. See http://www.theaustralian.com.au/business/technology/tesla-flicks-the-switch-on-powerwall-sales/news-story/ce87cb33129937c7eab808f3a8fe4215 for historical prices.

[48] Tesla website, http://www.thestreet.com/story/13142191/4/tesla-motors-tsla-earnings-report-q1-2015-conference-call-transcript.html, accessed 13 January 2016.

Table 9: Levelised cost of energy of Tesla Powerwall models, GST inclusive

Powerwall	Price (AUD)[49]	Capacity (kWh)[50]	Round trip efficiency[51]	Cycles per annum[52]	Lifespan	**LCOE ($/MWh)[53]**
10kWh	10,000	9	0.9	70	13.7	1,030
7kWh	7,286	6.3	0.9	365	13.7	257

Source: Tesla

Most of the difference between the calculations is due to the use of higher installation or other balance of system costs in Jacobs' calculations than in our own, which were already high relative to UBS and Morgan Stanley estimates cited by AEMO. It also appears that Jacobs assumed both a greater rate of efficiency and capacity degradation over the lifespan of the battery than assumed in other estimates.[54] However, we would not conclude that Jacobs' cost per MWh for small-scale storage is unreasonable, particularly because of the high uncertainty surrounding battery prices at present.

Tesla also sells a scaleable commercial battery called the Powerpack[55], which was publicly announced alongside the Powerwall in April 2015.[56] Using Tesla's Powerpack as an indication of prices for larger scale storage, the ten per cent discount for large scale storage used by Jacobs seems conservative. On a simple capacity basis, the Powerpack sells for US$250 per kWh[57], almost a 30 per cent discount to the 10 kWh Powerwall at $US350 per kWh. Additionally, Eos Energy expects to make its megawatt-scale battery system available in 2016 at $US160 per kWh.[58] Given this, and the scalability of certain large-scale technologies such as flow batteries, we suggest that Jacobs consider a discount of greater than ten per cent for large scale energy storage.

For an alternative reference scenario for battery storage costs, Jacobs uses parameters from CSIRO's report on future energy storage trends where the minimum cost for Li-ion (LFP and NMC) is $443/kWh and assumes 4,000 cycles, a useful life of 10 years and discharge/recharge efficiency of 90 per cent.[59]

[49] Prices as per Tesla's media release, converted to AUD and with $3,000 allowed for inverter and installation costs. Actual prices including balance of system costs are highly uncertain; AEMO recently cited estimates of $5,175, $4,179 and $8,901 for the 7 kWh Powerpack including the inverter and installation. These estimates were by UBS, Morgan Stanley and SunWiz, respectively. While the total price for the very first installations may be higher, we consider the estimates cited by AEMO to be reasonable and credible for short to medium term prices.

Souce: AEMO. (June 2015). *Emerging Technologies Information Paper*. p.29.

[50] A 90% discount was applied to the nominal capacity stated in the Powerwall specifications in order to account for degradation over time, based on 80% capacity at end of life.

[51] Round trip efficiency was discounted from the nominal 92.5% efficiency stated in the Powerwall specifications in order to account for degradation over time.

[52] 7 kWh model: daily cycling for 5000 cycles or 13.7 years. 10 kWh model: 60-70 cycles per year over a similar total lifespan.

Source: Tesla (2015). *Q1 2015 Earnings Report conference call transcript,* http://www.thestreet.com/story/13142191/4/tesla-motors-tsla-earnings-report-q1-2015-conference-call-transcript.html, accessed 13 January 2016.

[53] Calculated as: LCOE = price / (capacity x efficiency x cycles per annum x lifespan).

[54] UBS, Morgan Stanley and SunWiz did not discount battery capacity for their payback analysis, while only UBS used a lower round-trip efficiency (89 per cent) than specified by Tesla (92 per cent).

Souce: AEMO. (June 2015). *Emerging Technologies Information Paper*. p.29.

[55] Tesla website, https://www.teslamotors.com/en_AU/presskit/teslaenergy, accessed 9 February 2016.

[56] Tesla website, https://www.teslamotors.com/en_AU/powerwall, accessed 9 February 2016.

[57] Bloomberg website, http://www.bloomberg.com/news/articles/2015-05-08/tesla-s-battery-grabbed-800-million-in-its-first-week, accessed 9 February 2016.

[58] Eos Energy Storage website, http://www.eosenergystorage.com/products/, accessed 9 February 2016.

[59] CSIRO, *Future energy storage trends*, September 2015, p 21 and p 31.

We consider using the CSIRO report as a source for the alternative reference scenario to be appropriate and the inputs reasonable.

3.2.3 Technology learning rates

Technology learning rates refers to the rate that costs decrease as a result of a learning process that may include learning by doing or learning by research. Technology learning rates are expressed as a percentage cost reduction for each doubling of capacity.

Jacobs has sourced learning rates used in the model from literature published by:

- the **European Commission Joint Research Centre** (ECJRC), which is a research organisation supporting policy making by the European Commission with independent, evidence based scientific and technical advice and analysis. Jacobs have cited ECJRC's report titled '*Technology Learning Curves for Energy Policy Support*' that describes different approaches to characterising learning curves. However, the report does not provide estimates of the learning rate for different generation technologies; and
- the **Electric Power Research Institute** (EPRI), which is an independent not for profit organisation made up of members from mainly electricity utilities. The EPRI conducts research relating to generation, delivery and use of electricity for the benefit of the public. Jacobs has cited the Phase I Report titled *'Modeling Technology Learning for Electricity Supply Technologies'* authored by researchers at Carnegie Mellon University and the University of California. The report reviews literature on learning rates for different electricity supply technologies.

Learning rates were used to calculate annual capital cost de-escalators from 2020 onwards as set out in Appendix F.[60] Learning rates have been adjusted for projected global deployment rates consistent with global action to limit temperature increases to two degrees. The cost reduction is converted to percentage reduction per annum and applied to the 'Australian component' of capital costs (that is, the Australia-specific estimate of the share of international capital costs in total capital costs for each technology).

Projected global rates were sourced from the International Energy Agency (IEA), which we consider to be an authoritative source.

We have reviewed inputs for capital cost de-escalator rates and by in large consider that the sources of those inputs to be authoritative and appropriate. The capital cost reduction rate inputs follows a trend where mature technologies such as OCGT, CCGT, nuclear and coal fired generation exhibit lower cost de-escalation rates, while newer technologies such as CCS, energy storage, and photovoltaics exhibit higher cost de-escalation rates. This is consistent with the idea that there are more opportunities for learning and cost reduction for new technologies, while potential cost reduction for mature technologies have already been realised.

Overall, the sources of learning rates appear to be appropriate. To enable greater scrutiny in this area, Jacobs might consider providing in its report a transparent description on how learning rates are sourced and calculated.

3.2.4 CCS transport and storage cost

Carbon capture and storage (CCS) encompasses technologies that capture carbon emissions from generators and stores carbon, preventing carbon emissions from being released into the atmosphere.

Projected transport and storage cost of CCS ranges from \$5/t CO_2-e to \$14/t CO_2-e at the low end, to \$70/t CO_2-e at the high end.[61] The large range of projected CCS costs are due to variability in storage site characteristics and uncertainties inherent with an immature technology. These data are sourced from the

[60] There were also capital cost de-escalator rates for pre-2020. See Jacobs, *Consultation Paper: Modelling illustrative electricity sector emissions reduction policies*, May 2015, p.36.

[61] Electric Power Research Institute, *Australian Power Generation Technology Report*, November 2015, p vii.

Australian Power Generation Technology report, which was published in November 2015 and therefore not available to Jacobs at the time that the modelling was conducted.

Jacobs has derived CCS input assumptions from previous studies undertaken for Treasury and range from \$20/t CO_2-e to \$30/t CO_2-e, which we consider to be an appropriate and authoritative source for CCS assumptions.

We note that Jacobs' assumed CCS costs are similar to those used in Treasury's carbon price modelling project published in 2011. The carbon price modelling project used carbon capture costs of \$31/t CO_2-e for coal CCS and \$38.5/t CO_2-e for gas CCS.[62] CCS input assumptions of \$20/t CO_2-e to \$30/t CO_2-e appear to be reasonable as costs are expected to have decreased since 2011.[63]

3.3 Fuel price assumptions

3.3.1 Gas prices

Jacobs has prepared gas price forecasts for East and West coast gas markets for the period prior to 2020. East coast gas prices are based on projected supply and demand balance in Eastern Australia using its proprietary model called Market Model Australia – Gas (MMAGas). A fundamental modelling principle adopted in MMAGas is that gas prices converge to between export parity and import parity levels. West Coast gas prices are based on (the former) IMO's Gas Statement of Opportunities.

As Jacobs notes in Appendix C.5, Australia's gas market is driven by large projects related to generation and large industrial projects. We agree that those industrial projects gives rise to periods of tightness in domestic wholesale gas supplies, especially around the period of time prior to the start-up of LNG gas trains as these look to secure gas supply for export. One element of gas prices Jacobs may wish to update is the effect of these events on gas prices - the model links gas prices to oil prices through the LNG netback price. Given the dramatic decreases in oil prices in 2015 and 2016[64] there is a risk that gas price scenarios adopted in the model may not eventuate in the short to medium term.

Price projections of export parity levels for both the East and West coast markets source either the United States Energy Information Administration (EIA) or the International Energy Agency (IEA) for gas prices. We consider these sources for gas price inputs are authoritative and appropriate.

3.3.2 Coal prices

The main source of information for coal price forecasts is Jacobs' own analysis and the World Energy Outlook 2014 report published by the IEA.

We consider data from the World Energy Outlook 2014 published by the IEA to serve as a basis for coal price inputs to be an authoritative and appropriate source. We note that the IEA published the World Energy Outlook 2015 on 10 November 2015 and recognise that virtually all of the modelling work was performed prior to its publication. This meant that Jacobs did not have the opportunity to use the World Energy Outlook 2015 in its modelling.

To ensure reasonableness of coal price inputs, we compared coal prices in Figure 359: 'Projected variable coal price for NEM black coal power stations (two deggrees emissions constraint) \$June 2014' of Jacobs'

[62] See Treasury website: *http://carbonpricemodelling.treasury.gov.au/content/report/11appendixb.asp#P197_22971*, accessed 14 January 2014. Refer to footnote 2.

[63] Worley Parsons Schlumberger, *Economic Assessment of Carbon Capture and Storage Technologies*, 2011, p.31.

[64] Brent crude decreased to US\$31 on 12 January 2016. Crude oil futures at this date suggest crude oil prices will only recover to slightly over US\$50 by December of 2025. See http://www.cmegroup.com/trading/energy/crude-oil/light-sweet-crude.html, accessed 12 January 2016.

draft report to those published in the World Bank's Commodity Markets Outlook for October 2015[65] and found them to be in the same order of magnitude as those used in the modelling.

3.4 Demand assumptions

Electricity demand projections are based on those developed by Pitt&Sherry and ACIL Allen for the Department of Environment's 2014-15 emissions projections. The projections were extended from 2040 to 2050 by applying the trend growth rate.

We consider electricity demand projections from the Department of Environment to be a reputable and authoritative source and that Pitt&Sherry and ACIL Allen have the expertise to develop reasonable projections given their consulting experience in the electricity infrastructure industry.

As noted by Jacobs in Appendix C.2.1, the electricity demand projections used are consistent with AEMO's 2015 demand projections indicating the magnitude of those projections are reasonable.

Sensitivities for projected demand were based on ClimateWorks for the high demand series, and the relevant market operators' projection of low demand for the low demand series.

Price elasticities are based on those from AEMO for NEM jurisdictions and Synergy for Western Australia. Given that AEMO and Synergy are respectively the market operator and major generator-retailer for their jurisdictions, we conclude that the sources used to obtain sensitivities for projected demand and price elasticities are authoritative and the most appropriate sources available.

3.5 Economic assumptions

3.5.1 Carbon prices

Carbon prices used in the modelling are based on meta-analysis produced by the IPCC, which presented global carbon prices in 2020, 2030, 2050, and 2100. The Authority secretariat provided the carbon price series to Jacobs for use in the modelling. The secretariat used median values from the analysis, which were converted from United States dollars to Australian dollars, applying uniform growth rates to interpolate the carbon price between 2020, 2030 and 2050.

We consider the IPCC is an authoritative source for input carbon prices. In ensuring carbon price inputs are accurate, we reviewed the secretariat's workbooks used to derive carbon price series in Appendix C.1 and assessed it to be a reasonable approach to convert carbon prices sourced from the IPCC into input assumption suitable for use in the model.

3.5.2 Reliability

There are two reliability constraints in the model based on reliability standards published by the AEMO:

- unserved energy equal to the NEM's and WEM's reliability standard of 0.002% of demand; and
- Minimum Reserve Levels (MRL) as currently applicable and published by the AEMO.

We agree with the value of 0.002 per cent for unserved energy, based on the Australian Energy Markets Comission (AEMC) Reliability Panel's reliability standard and reliability settings review 2014.[66]

[65] World Bank, *Commodity Markets Outlook*, October 2015, p 41. A conversion rate of 1 ton of coal to 29.3076 GJ and an exchange rate of AUD/USD 0.77 was used.

[66] AEMC Reliability Panel, *Final Report: Reliability Standard and Reliability Setting Review*, July 2014, p i.

Jacobs have used MRL for NEM jurisdictions based on Table 6.1 of an AEMO report published in 2010 titled 'Final Report for Operational MRLs – 2010 MRL Recalculation'.[67] We conclude that sourcing reliability input assumptions from the AEMO and AEMC and the reserve margin constraint from the WEM is appropriate.

3.5.3 Weighted average cost of capital

A weighted average cost of capital (WACC) of 8.8 per cent in real terms is adopted in Jacobs model. In the case of a feed-in tariff policy the weighted average cost of capital of investment funded under the policy was assumed to be 0.5 per cent lower to reflect reduced risk from use of long term contracts. We discuss this assumption in more detail at section 2.1.5 above.

We understand the WACC of 8.8 per cent is derived based on Jacobs' own analysis. While the overall level of WACC seems plausible, without further information it is not possible for us to assess whether there is a reasonable basis for this assumption.

3.6 Summary of findings

Table 10 below summarises the findings of our review of the input assumptions used in Jacobs' electricity market modelling. Overall, we consider that the input assumptions used are appropriate.

There are some areas in which we consider that the assumptions taken were reasonable, but that alternative assumptions could have been available. We identified two areas in which we consider that potentially preferable input assumptions could be considered:

1. The modelled cost of new solar thermal generation without storage appears to be higher than assumed by ACIL Allen in its work for AEMO.
2. The assumed discount for large-scale battery storage costs in Phase 1 appears to be significantly less than what would be expected based on prices for Tesla's product range.

Overall we believe that the implications of using alternative assumptions for these areas are unlikely to be material to the comparison of policies, since these assumptions pertain equall to all policy scenarios.

[67] AEMO, *Final Report for Operational MRLs – 2010 MRL Recalculation*, June 2010, p 12.

Table 10: Summary of input assumptions

Approach or assumption	Reasonable	Observations and/or potential actions	Potential to misrepresent policy comparisons
Costs for existing generation	Yes	None	None
Costs for new thermal generation	Yes	None	None
Costs for new photovoltaic generation	Yes	None	None
Costs for new wind generation	Yes	None	None
Costs for new solar thermal generation	Mixed, costs with storage are reasonable but without storage appear high	ACIL Allen estimates lower cost for solar without storage	Low, affects all scenarios
Costs for new geothermal generation	Yes	More accurate modelling could take into account geothermal fields	Low, Jacobs already takes into account step changes in resource availability
Costs for new hydro generation	Yes	None	None
Costs for new nuclear generation	Yes	OECD data suggests slightly higher costs	Low, affects all scenarios
Biomass availability	Yes	None	None
Hydro capacity factors	Yes	None	None
Wind capacity factors	Yes	None	None
Solar capacity factors	Yes	None	None
Emissions intensities	Yes	None	None
Refurbishment costs	Yes	None	None
Decommissioning costs	Yes	None	None
Technology availability	Not amenable to assessment	Availability of new technologies is inherently uncertain	Low, based on alternative scenarios modelled by Jacobs
Battery storage costs	Mixed. Small scale battery costs appear high but broadly reasonable. The cost discount for large scale battery appears too low	Calculation of Powerwall costs suggests lower estimates	Low, affects all scenarios. Phase two sensitivity costs are reasonable.
Technology learning rates	Yes	Report could provide more transparency on these assumptions	Low, affects all scenarios
CCS costs	Yes	None	None
Gas prices	Yes	Review against updated gas prices	Low, affects all scenarios
Coal prices	Yes	Review against updated coal prices	Low, there have not been significant changes in coal prices
Demand and elasticities	Yes	None	None
Emissions prices	Yes	None	None
Reliability	Yes	None	None
Weighted average cost of capital	Uncertain, the calculation of WACC is not set out although its level seems plausible	Clarify cost of capital assumptions	Low, the WACC assumption affects all scenarios

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