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MEMBER BRIEFING

MODELLING FOR THE FINKEL REVIEW – IMPLICATIONS FOR CCS IN THE AUSTRALIAN POWER SECTOR

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Summary

The emissions reduction trajectory used in the Finkel Review modelling, by accommodating the Australian Government's current 2030 target, is not consistent with a 2 or 1.5 degree outcome on which the business case for large scale CCS deployment heavily depends. This is the key element of the modelling that resulted in CCS (and other technologies) not being deployed. The significance of this and other aspects of the Finkel modelling to CCS deployment are summarised as follows:

Modelling aspect	Description	Significance to CCS	comments
Emissions trajectory	Not consistent with 2 degree outcomes	High	Targets using the Government's 2030 commitment are inadequate for CCS deployment
Cost assumptions	Small differences from other studies	Low	Immaterial
Retrofits, coal vs gas	Retrofits may not be appropriately modelled; gas with CCS may be more viable	High	Coal plant capital intensities are a deployment barrier in high variable renewable systems
Operational constraints	Modelling reflects minimum operational times/ utilisation of coal plant	Medium	Coal plant inflexibility may be a deployment barrier in systems with much variable renewables
CET vs EIS	EIS shown to have lower overall resource costs	Low	Immaterial – emission target more important than mechanism choice
total resource cost adjustment	Accounting for deadweight losses may alter policy recommendation	Low	Immaterial
Risk premia	Higher required rates of return assumed for coal	Medium	Could be applied to CCS plant in future exercises
System integration costs	Various integration costs not reflected in modelling	Low to medium	Studies suggest that costs aside from utilisation/ backup are less material

Source: Institute.

Background

In response to various issues and events occurring in the Australian electricity sector, the Energy Ministers of the Council of Australian Governments requested Australia's Chief Scientist, Dr Alan Finkel, to examine current security and reliability the national electricity market and to provide advice to governments on a coordinated, national reform blueprint. This "Finkel Review" blueprint was published on 9 June 2017.[1]

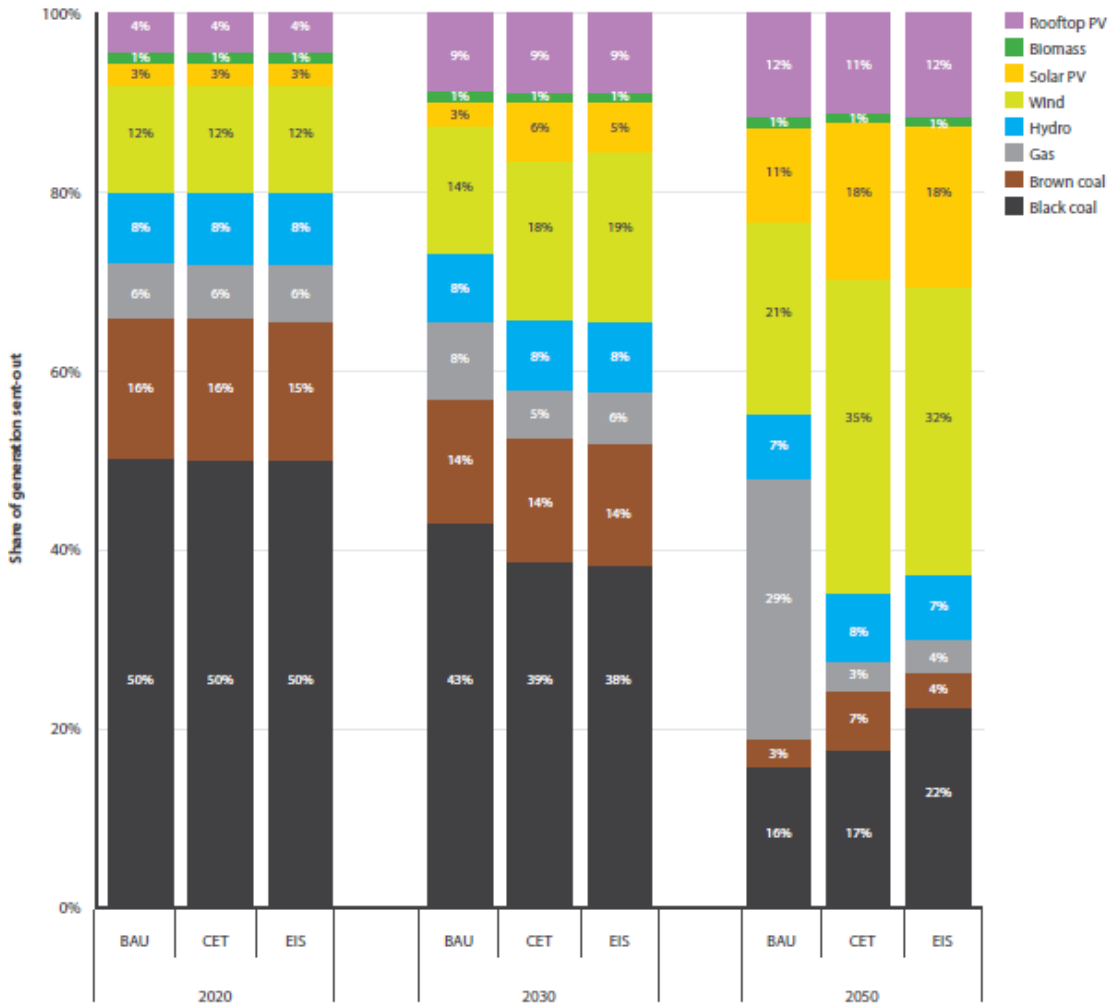
Comments made at the Institute's APAC CCS Forum on 19 June (e.g. by Tony Wood, Paul Dougas, Barry Hooper) and continuing (e.g. at a policy reference group meeting on 27 June

[1] http://www.environment.gov.au/energy/national-electricity-market-review

hosted by the CO2CRC) indicate some misunderstanding of the modelling undertaken for the Finkel review, including as it relates to CCS deployment in the Australian power sector:

- some have interpreted Jacobs' modelling as an indication that CCS would not be deployed under the Finkel recommendations, reflecting the cost assumptions used
- the Mineral's Council of Australia (MCA) criticised the recommended Clean Energy Target on the basis that the modelled emissions intensity threshold of 0.6 tonnes/MWh would exclude unabated high efficiency, low emissions (HELE) coal plant
- some renewables advocates criticised the report for suggesting it was favourable to coal, noting that more coal would supply the market under the Clean Energy Target (CET) relative to business as usual.

Some confusion about the outputs and role of the modelling appears to have arisen because the supporting Jacobs report[2] was released in the week after the Finkel report, which contained very little modelling details. This chart shows the relevant Jacobs modelling outputs in the main Finkel Report. CCS is not deployed under any of the scenarios:



Source: Finkel Review Report, Figure 3.8.

[2] Jacobs, *Report to the Independent Review into the Future Security of the National Electricity Market - Emissions mitigation policies and security of electricity supply*, 13 June 2017 [Jacobs for the Finkel Review].

The critical aspect of this modelling and indeed Finkel's recommendations was that the CET and an agreed long-term emissions reduction target provides an appropriate *framework* for managing the grid. Key decisions, including the actual emissions target and trajectory, were left for governments, including as part of the Federal Government's current review of Climate Change Policies:

> In terms of the specific emissions reduction target that should be set for the electricity sector, the Panel acknowledges that this is a question for governments. At a minimum, the electricity sector should have a target that reflects a direct application of the 2030 commitment of 26 to 28 per cent reduction on 2005 levels, as per the Paris Agreement. The target should anticipate a continuing emissions reduction trajectory out to 2050. A CET or EIS provides a credible mechanism by which both governments and industry can have confidence that the electricity sector will meet its emissions reduction requirements.[3]

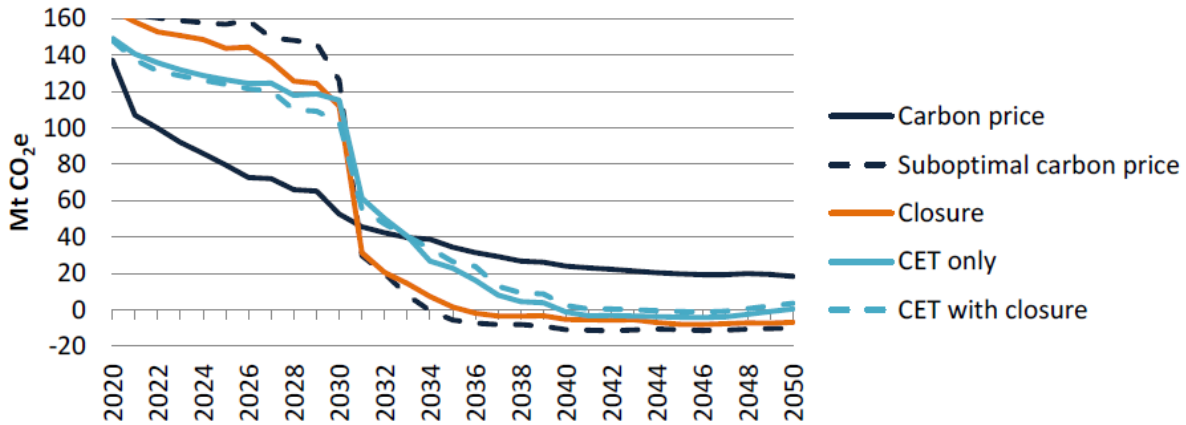
While there is obviously some controversy around the Panel's decision to do so, Finkel's approach was therefore to simply model the Federal Government's 2030 commitment, with a glide path to zero emissions by the second half of this century (2070 was the chosen year).

The remainder of this note examines this and other modelling aspects in more detail, including 2 degree compliant scenarios examined earlier by the Climate Change Authority[4] and by CSIRO[5].

Finkel's emissions trajectory is too weak

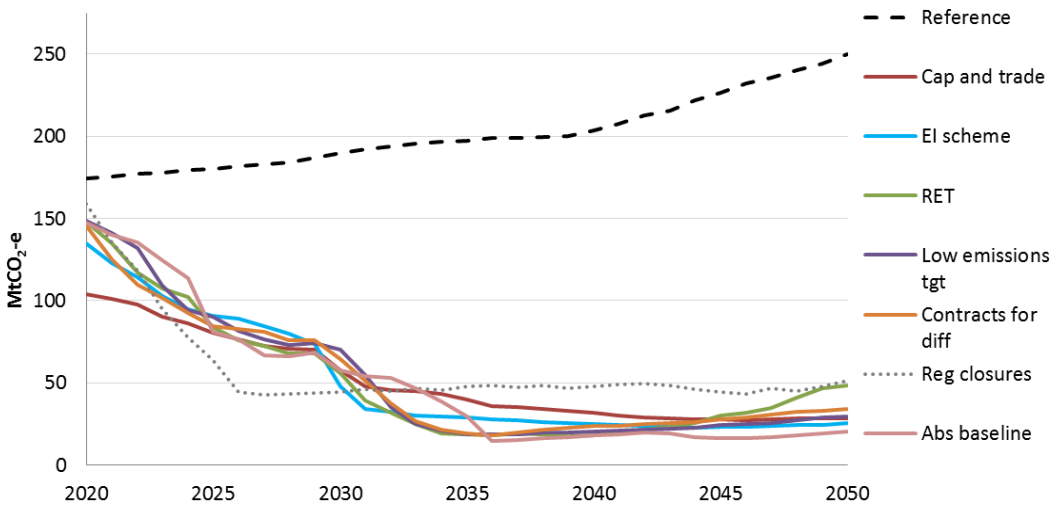
Jacobs for The Climate Institute[6] (TCI) in 2016 modelled a 2 degree compliant carbon budget for the electricity sector of 1760 Mt CO_2e to 2050. Policy scenarios were modelled that kept within this budget but also allowed for weaker or "slow start" policies to 2030, in line with the Government's commitment to a 28% reduction on 2005 emissions. The chart below illustrates that, as argued by the TCI, this 2030 target is inconsistent with 2 degree outcomes. If this 2030 target is maintained the electricity sector, to stay within the carbon budget, would need to produce net negative emissions, achieved in the modelling via offsets of 250Mt to 580Mt in total from 2020 to 2050.

[3] Commonwealth of Australia, *Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future*, June 2017 [Finkel Review Report], p. 96.
[4] http://climatechangeauthority.gov.au/reviews/special-review/special-review-electricity-research-report
[5] Campey, T. et al, *Low Emissions Technology Roadmap*, 2017. CSIRO, Australia.
[6] Jacobs, *Electricity Sector Impacts of Emission Abatement Policies*, 12 April 2016 [Jacobs for The Climate Institute].



Source: Jacobs for The Climate Institute, Figure 7.

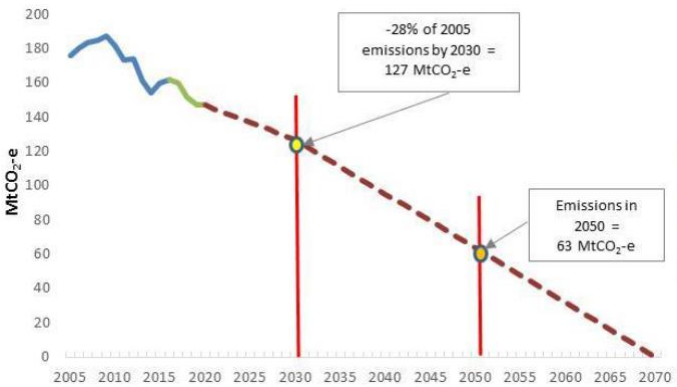
Jacobs modelling for the Climate Change Authority[7] (CCA) was similarly constrained to an interpretation of the Paris temperature goals, equating to a carbon budget of 1580 Mt CO_2e in each of its policy scenarios. The model was not constrained to the Government's 2030 target and so various policy options and emission reductions were found to come into effect immediately.



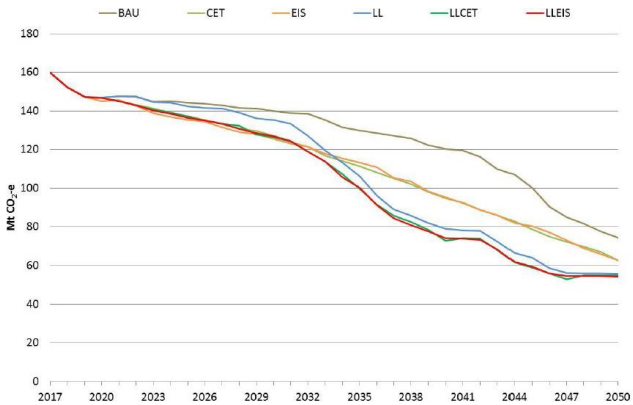
Source: Jacobs for the Climate Change Authority, Figure 1.

The emissions trajectories modelled for Finkel (outside of BAU) reflected the government's 2030 target and a linear decline in emissions of around 1% or 3Mt per year to 2070. This trajectory would result in the 2 degree carbon budget (as reflected in prior modelling) being blown by the early 2030s, and a doubling of this budget by 2050.

[7] Jacobs, *Modelling illustrative electricity sector emissions reduction policies*, 17 February 2017 [Jacobs for the Climate Change Authority].



Source: Jacobs for Finkel Review, Figure 5.



Source: Jacobs for Finkel Review, Figure 1.

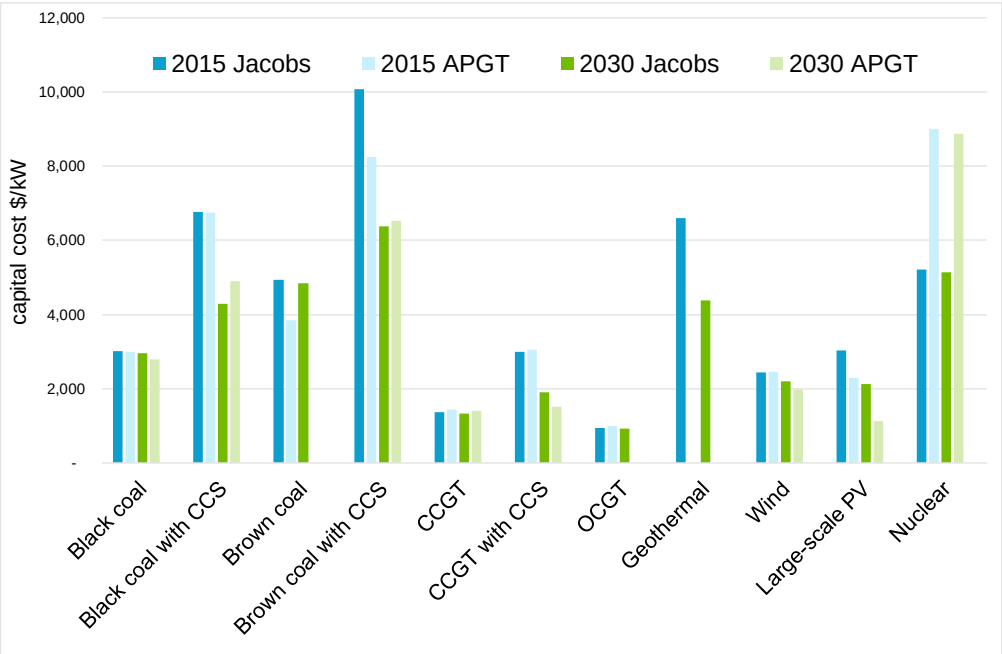
A further element of the emissions trajectory is the translation of the economy-wide 2030 target to the electricity sector. An issue with these modelling exercises is that it has been presumed the electricity sector would contribute a proportionate amount to Australia's total emission reductions. Various bodies/ reviews (e.g. CCA, Garnaut) have argued that this sector should contribute a higher proportion given the emissions intensity of coal and availability of low carbon alternatives, relative to industrial and land use sectors which are harder to decarbonise.

CCS cost assumptions appear largely reasonable

With respect to all CCS plant, Jacobs' modelling for Finkel aligned with the APGT report. Jacobs costs for the CCA (compared to APGT below) were materially higher in the case of brown coal for 2015 costs only. However, its modelling restricted deployment of CCS until 2030 (i.e. 2015 cost estimates were irrelevant for CCS). While some costs in the APGT report are outdated (notably solar PV) it remains a reputable source of estimates for fossil fuel plant in Australia.

Concerns have been raised around Jacobs using values of $2200/kW to $2400/kW for wind and solar PV – values well below $2000/kW and even $1500/kW for some solar PV types has been suggested.[8]

[8] http://reneweconomy.com.au/finkel-modelling-ignores-new-technologies-cheaper-renewables-33626/



Source: Jacobs for CCA, Figure 367.

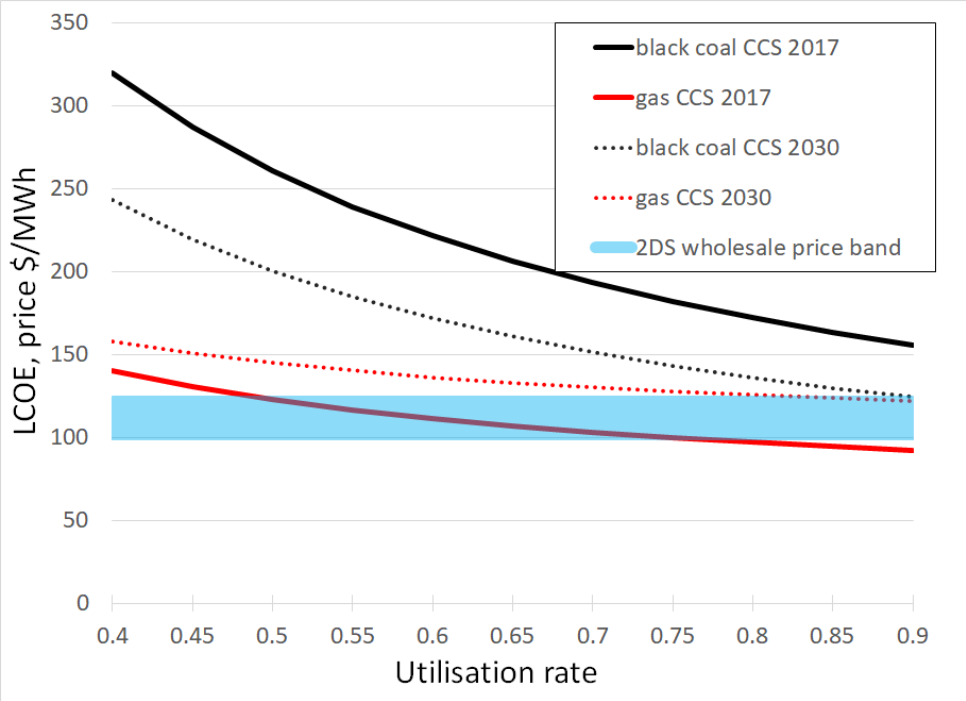
CCS retrofits not really accounted for, but gas CCS is favoured

Some CCS stakeholders have suggested CCS coal retrofits were excluded from the Jacobs modelling. While both the Jacobs reports for Finkel and CCA state retrofits were included, it is unclear how well this was done given detailed information on candidate plant (including site specific conditions and any refurbishment costs) is not in the public domain. CSIRO did not model retrofits "due to the fact that the capital and operating cost can vary significantly depending on the type, age, condition and location of the asset."[9] The CO2CRC has been recently active in pushing coal-fired retrofits as a cost-effective option, and the Institute also put this case to CCA/ Jacobs, however it is incumbent on those advocating the modelling of retrofits to supply data (i.e. identify realistic and actual plant candidates) as the added benefit of seeking such details is not apparent to modelling teams.

For example, one might reasonably expect that any capital cost savings in a retrofit versus new build (i.e. assuming no associated costs for plant life extension) would be offset by a shorter plant life reflecting the age profile of Australian coal plant. The current remaining life of any retrofit candidates would be further diminished with the lead times in certifying geological storage, as well as in approvals and construction. Otherwise, given new and retrofitted plant characteristics are largely identical (e.g. variable costs, minimum operating loads) the modelling algorithms would simply choose the cheaper of new or retrofitted CCS plant without much impact on 'overall' CCS deployment. Even two or three retrofits would not be significant enough to alter the examination of different policy drivers or other exogenous macro factors which are typically the focus of electricity market modelling. Also, some coal plant owners e.g. AGL, Energy Australia, have stated they have no interest in retrofitting or extending the life of existing assets and such strategic decisions (rather than purely economic ones) should be accommodated in the modelling.

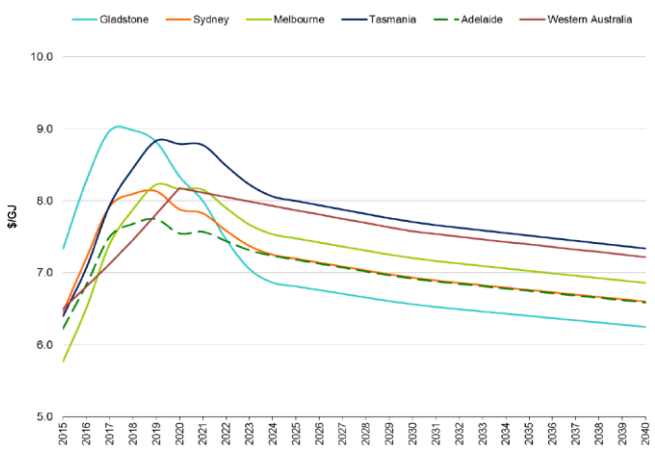
[9] CSIRO, p. 137.

The differences between gas and coal CCS plants are more significant and these show in the modelling results. The modelling of Jacobs for the CCA suggests gas-fired generation fitted with CCS would be deployed but no coal with CCS, reflecting relative SRMCs and fixed versus variable costs. CSIRO's Low Emission Technology Roadmap in its Pathway 3 and Pathway 4 scenarios also suggested gas with CCS would be deployed ahead of coal CCS in Australia. As with Jacobs, it is expected this is a result of lower utilisation of all thermal plant, crowded out by cheaper variable renewables, combined with the higher fixed costs of coal CCS generators making them less profitable under 2 degree wholesale prices.

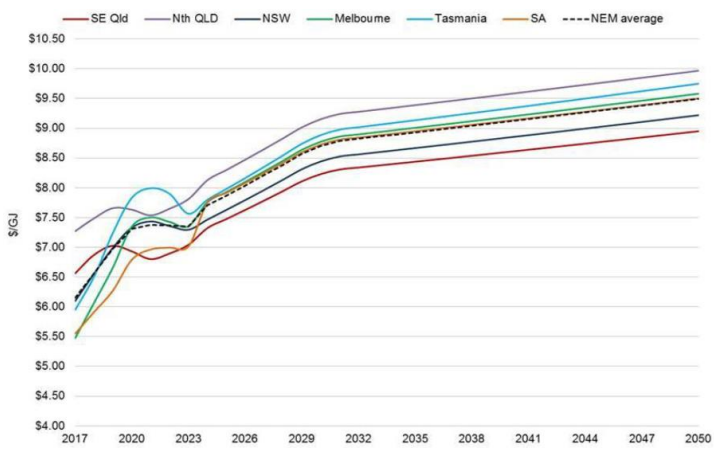


Source: Institute analysis using Finkel Review/ Jacobs assumptions.

This is also obviously dependent on Jacobs' gas price assumptions which have changed dramatically over the last year.

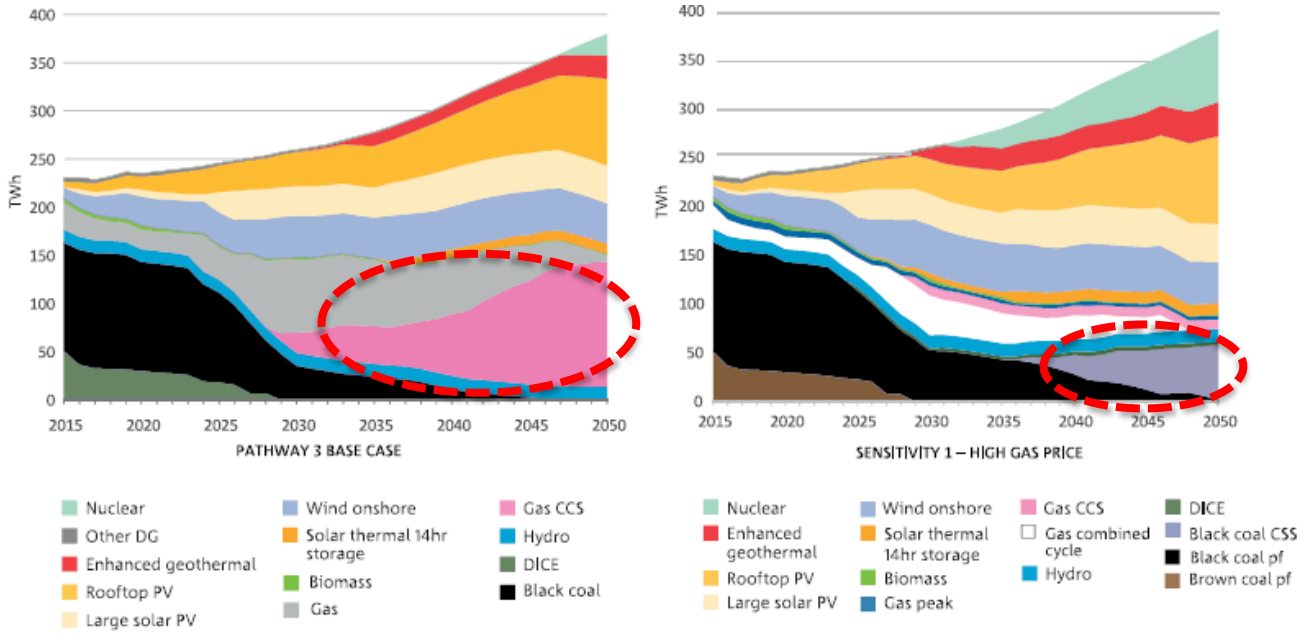


Source: Jacobs for CCA, Figure 369



Source: Jacobs for Finkel, Figure 14

CSIRO also modelled a sensitivity on gas prices in Pathway 3 (i.e. prices of 50% above the base case) which saw a small amount of CCS on coal deployed. Assumed prices were $6.6/GJ in 2015 then rising to $13.2/GJ by 2050 in the base case, but up to $21.7/GJ by 2050 in high price scenario. CSIRO's base case gas prices are well above Jacobs and still show a preference for CCS on gas. Wholesale traded gas prices are currently around $7-9/GJ[10] and, when factoring in pipeline charges, are already having significant adverse impacts on large gas consumers[11], with a second ACCC gas inquiry now commenced[12]. CSIRO's high price scenario suggests nuclear power would be deployed instead of gas generation. However, these prices would have much broader impacts outside of the electricity market, including closure of major industry, and as a reflection of significant gas market dysfunction, would attract very drastic countervailing interventions (e.g. nationalisation of gas supply, construction of import terminals).



Source: CSIRO figure 44

Operational constraints further affecting coal plant

The physical constraints on coal vs gas-fired generation (namely technical minimum operating capacities/ minimum stable load) are likely to also affect the different abilities and profitability of coal and gas CCS in the system. Minimum operating capacities assumed in Jacobs are not listed in the report, however it is understood the modelling reflected a 40% minimum safe/ economic utilisation rate for coal with CCS, consistent with other studies e.g. ACIL, which also applied no minimum (0%) for gas fired technologies.[13]

[10] https://www.aer.gov.au/system/files/AER%20gas%20weekly%20report%20-%2018%20%E2%80%93%2024%20June%202017.pdf
[11] http://cdn.aigroup.com.au/Speeches/2017/Energy_Week_2017_speech_Willox.pdf
[12] https://www.accc.gov.au/media-release/accc-to-investigate-and-report-on-australian-gas-markets-and-market-transparency
[13] https://www.aemo.com.au/-/media/Files/PDF/Fuel_and_Technology_Cost_Review_Report_ACIL_Allen.pdf

Ramp rates are ignored in the Jacobs modelling as it is at an hourly level of granularity. This is common for most, if not all models of the Australian electricity sector given computational limitations.

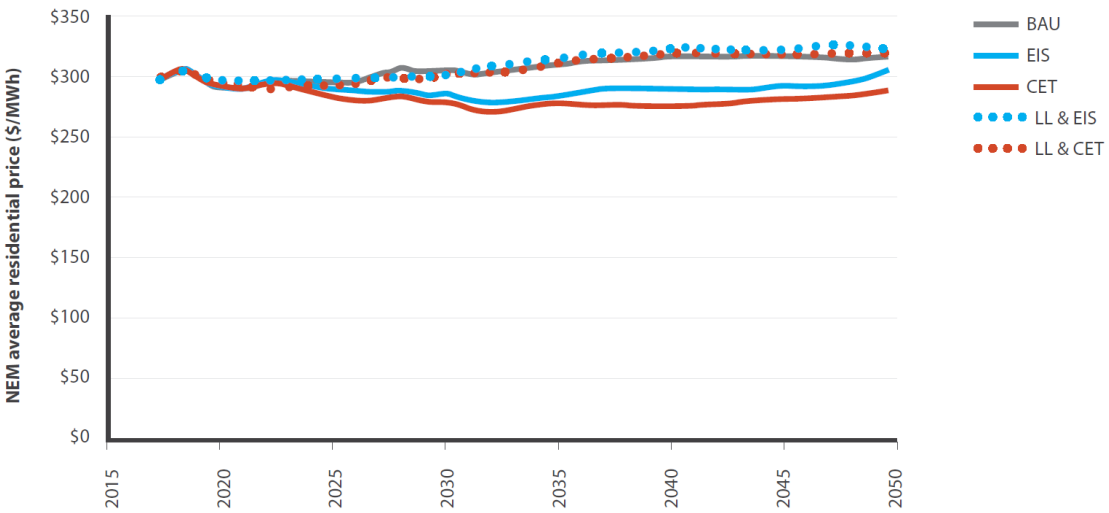
EIS found to be cheaper than the CET

The Finkel report recommendation of a CET over an EIS was not a strong one:

> According to the modelling undertaken for this Review, there was a small difference in price between the CET (Clean Energy Target) and EIS (Emissions Intensity Scheme) scenarios… In the Panel's view, the single most important characteristic of any emissions reduction mechanism to be adopted by governments is that it is agreed expeditiously and with sufficient broad-based support that investors can be confident it will endure through many electoral cycles.
>
> Experience both here and overseas has shown that mechanisms of this kind rarely operate as originally designed… As a consequence, mechanisms with any longevity are subject to adjustment in both target parameters and substantive design features…
>
> For these reasons, the Panel is hesitant to argue definitively that one mechanism, between the EIS and the CET, is superior to the other. The differences in theory may be less significant than how well the chosen scheme is implemented and aspects of its detailed design, such as a predictable process for parameter changes and a robust and proportionate compliance and enforcement regime…
>
> An EIS, though widely discussed in recent months in Australia, would be a new scheme and require detailed development and design. By contrast, a CET could build directly on the experience of the Renewable Energy Target and its operations are well understood by participants. The Clean Energy Regulator would be well placed to administer the CET drawing on well-developed skills, procedures and infrastructure such as the Renewable Energy Certificate Registry system…
>
> A CET or EIS provides a credible mechanism by which both governments and industry can have confidence that the electricity sector will meet its emissions reduction requirements.[14]

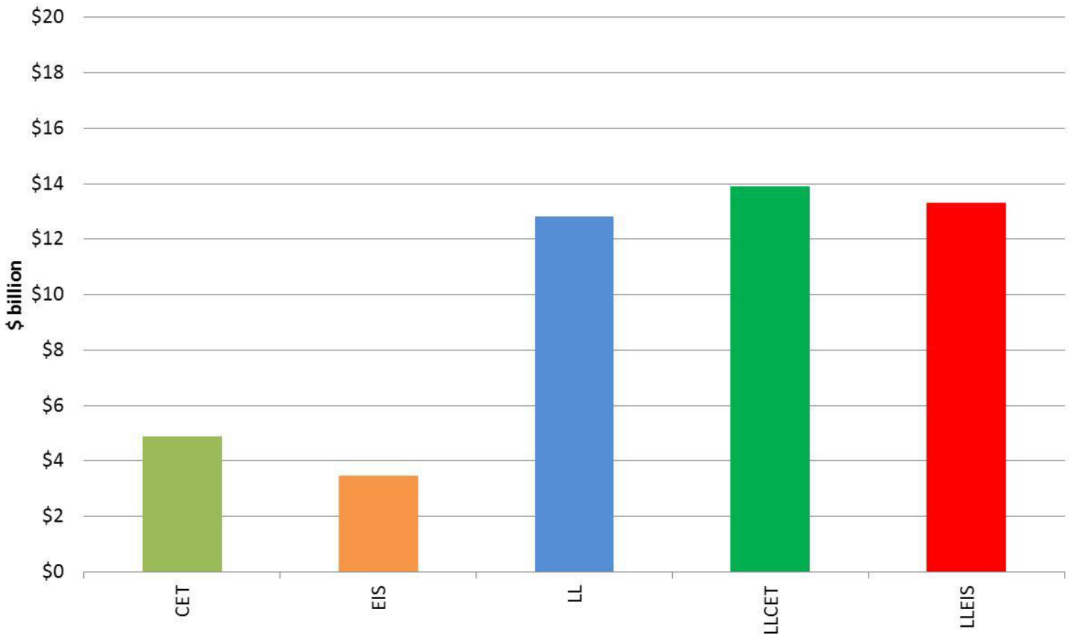
Finkel's finding that there would be a small difference in impact between the CET and EIS appear to be largely based on average price impacts. Total resource/ welfare costs and average abatement costs per tonne of CO_2 are around 25% lower under the EIS.

[14] Finkel Review Report, p. 96.



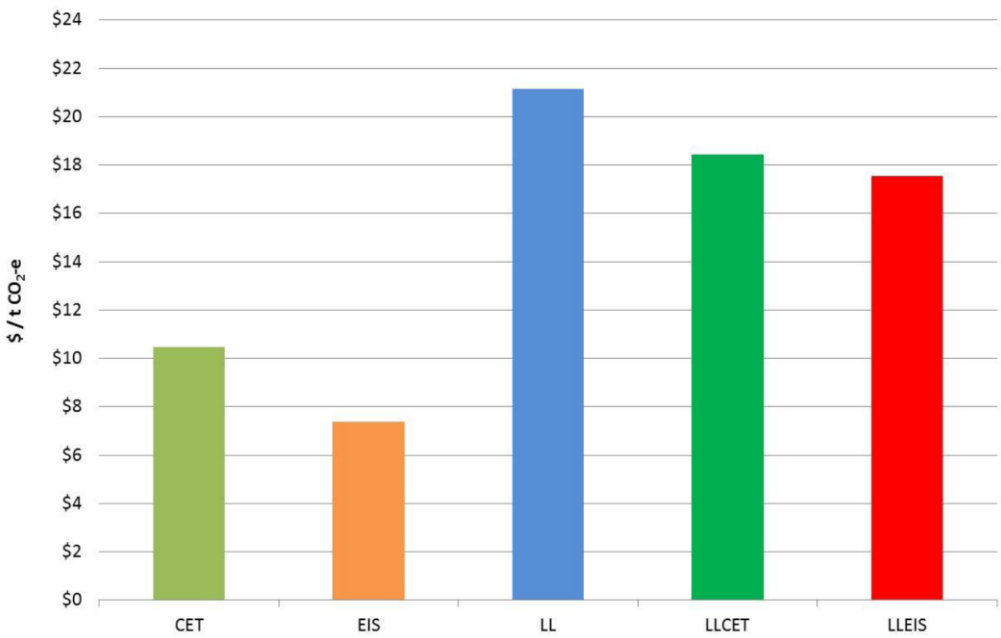
Source: Finkel, Figure 3.9

Figure 2: Resource costs relative to the Business as Usual, all scenarios (2017-2050)



Source: Jacobs for Finkel, p. 13.

Figure 3: Cost of abatement relative to the Business as Usual, all scenarios (2017-2050)



Source: Jacobs for Finkel, p. 14.

The imposition of a more stringent carbon constraint may magnify these differences. However, over a 50+ year time horizon the results for the CET and EIS are arguably immaterial. Finkel reasonably places a higher priority on getting bipartisan support for either mechanism and implies that a CET has better prospects given the existing institutions managing the RET which is similar.

Finkel has been criticised by some for excluding carbon pricing as a policy option, which has been demonstrated by previous analysis to deliver optimal outcomes in terms of customer impact and resource costs. However, the exclusion of this option is entirely pragmatic.

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

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

Source: Jacobs for CCA, p. 3.

‘Demand adjusted’ resource costs

In calculating net welfare/ resource costs, Jacobs for CCA and for Finkel appears to have taken different approaches:

- For the CCA, Jacobs made an adjustment (increase) to resource costs to reflect the deadweight loss typically associated with lower demand and supply in response to policy-induced price increases
- For Finkel, it is not clear if resource costs were adjusted in this way, arguably understating true resource costs.

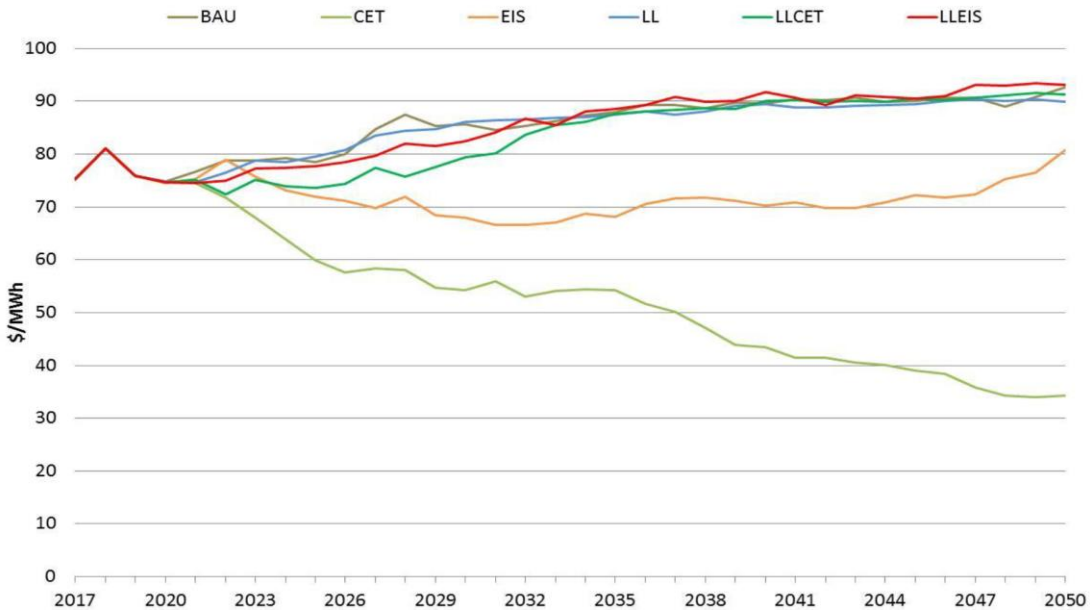
One commentator has suggested not using such “demand adjusted” resource costs would overstate the benefits of the CET: “Finkel told his consultants to assume that demand does not respond to price… As demand reductions are an important part of the least-cost way to reduce some emissions, Finkel has understated his CET’s cost disadvantage versus an emissions intensity scheme.”[15] However this appears to confuse at least two separate but related elements of the modelling, namely general price elasticity feedbacks versus welfare/ deadweight losses, as well as the modelled change in wholesale prices.

The wholesale price impact under the CET is lower than the EIS because generators are only rewarded and not penalised. In a situation of price increases and a reduction in demand, as this commentator suggests, the CET would therefore result in a lower deadweight loss, and would actually seem less favourable if welfare losses were ignored.

The second relevant aspect of the Finkel modelling here is that wholesale prices were shown to decrease, and moreso under the CET. If this is correct, it implies an expansion in demand and supply, and a net welfare gain that should be netted from total resource costs. Again, ignoring such an adjustment makes the CET look worse, not better, relative to an EIS.

[15] http://www.theaustralian.com.au/business/mining-energy/finkel-numbers-dont-add-up/news-story/6ccc0f3fc6ed4ce67dd58037e4d70eec

Figure 22: NEM wholesale prices, all scenarios



Source: Jacobs for Finkel, p. 51.

Contemplating price decreases and welfare gains is counter-intuitive given market interventions are typically associated with price increases and deadweight losses. This potentially counter-intuitive or confusing situation may be the reason why the welfare adjustment was not done for Finkel (or at least not discussed in the reports). More likely, Finkel recommended a range of measures that would impact on demand and prices outside of the CET/ EIS modelling results, making it a very difficult and largely academic exercise to accommodate welfare losses/ gains.

Addressing directly the notion that general retail price/ demand feedbacks should have been modelled (which is a separate but valid question), it is unlikely the Finkel scenarios would have produced much demand response to differentiate total resource costs for the CET versus the EIS. Price changes for both mechanisms (at least on an average basis) were small and of a similar direction and magnitude. Jacobs' modelling accounts for these price/ demand feedback effects in any case.

Risk premia further disadvantage coal

Jacobs' modelling for Finkel applied different risk premia across scenarios and technology types to reflect expected plant size (relative to demand growth) and complexity giving rise to different project risk. Coal was further disadvantaged with a lower assumed gearing ratio, allowing only 40% debt financing relative to 75% for other technologies. It is not clear if these assumptions were applied to plant fitted with CCS.

Different financing assumptions are a departure from Jacobs' prior modelling but are not unreasonable and appear to reflect feedback from financiers (e.g. the CEFC) to the Finkel review.

By way of illustration, increasing the WACC on a typical unabated black coal generator from 10 to 15% to reflect policy risk (as per the figures below), assuming 85% utilisation and Jacobs other assumptions, would increase its LCOE from around $85/MWh to $115/MWh. If the same plant was deemed to have the same risk as gas/ renewables, with policy uncertainty its LCOE would fall from around $85/MWh to $65/MWh.

Arguably these coal figures are academic as, even with policy certainty, there are unlikely to be any private investors willing to fund unabated coal-fired power stations in Australia for the foreseeable future.

Table 5: Weighted average cost of capital in the policy scenarios

Generator	Coal	Gas CCGT	Renewables
Debt to equity ratio	40:60	75:25	75:25
Cost of debt	5.3%	4.4%	4.4%
Cost of equity	13%	11%	11%
WACC	9.9%	6.1%	6.1%

Table 6: Weighted average cost of capital in the BAU scenario

Generator	Coal	Gas CCGT	Renewables
Debt to equity ratio	40:60	75:25	75:25
Risk premium	5%	2%	1%
Cost of debt	5.3%	4.4%	4.4%
Cost of debt (including risk premium)	10.3%	6.4%	5.4%
Cost of equity	13%	11%	11%
Cost of equity (including risk premium)	18%	13%	12%
WACC	14.9%	8.1%	7.1%

Source: Jacobs for Finkel, p. 32.

System integration costs not fully accounted for

Various submissions to the Finkel Review (including the Institute's) argued that CCS equipped power plants could deliver benefits via providing low carbon, controllable synchronous generation that would complement variable renewable output.

The MCA has gone further to argue that integrating large amounts of variable renewable generation involves significant costs:

> The BAEconomics research shows that as the share of intermittent wind and solar power rises, electricity systems face significant integration costs including the need to maintain back-up generation capacity in the system to meet demand when the wind is not blowing or the sun is not shining. Other integration costs include the need for conventional generators to ramp output up and down at short notice as wind power supplies fluctuate and the impact of difficulties in

> forecasting the output of wind generators on planned schedules for dispatching electricity to the grid.[16]

BAEconomics[17] estimated integration costs for wind, and examined two main types:

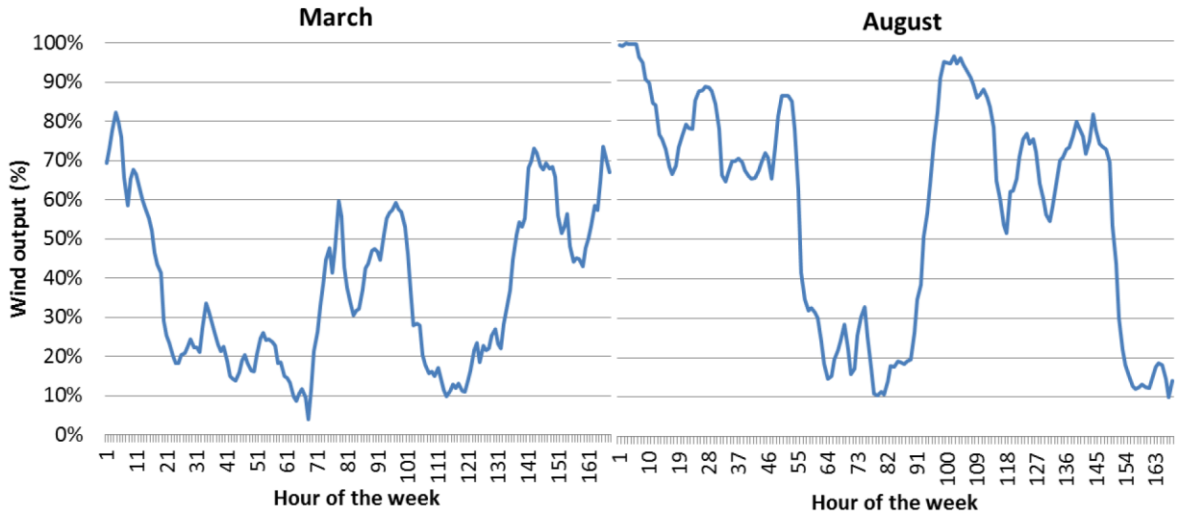
> System 'balancing' costs, which arise due to wind forecasting errors. Wind forecasting errors require more costly conventional generating plant to be dispatched than would otherwise be the case, and require additional operating reserves to be held to account for the increased uncertainty. A trend estimate across wind integration studies in thermal power systems suggests that wind balancing costs increase from a base of around $2.7/MWh by around 8 ¢/MWh for each percentage point increase in the share of wind generation.
>
> System 'utilisation' (or back-up) costs, which arise due to the fluctuating output of wind. While the utilisation of conventional power stations falls as the share of wind increases, these plants remains essential for the reliable and secure operation of the power system, and their capacity must be maintained and paid for. The need to carry additional conventional generation capacity (or equivalent technologies, such as storage) to compensate for the intermittency of many renewable resources represents a significant cost to the system. In the short run, given the existing fleet of generation resources in a power system, utilisation costs increase from a base of around zero by around $1/MWh for each percentage point increase in the share of wind generation.[18]

A survey of renewables integration cost studies undertaken by UKERC this year (updated from a 2006 survey) found similar values, namely that 'utilisation' or 'reserve' costs are around £10/MWh at penetration rates of 20%, rising to between £15 and £45 per MWh at 50% penetration.[19] Costs at the lower end reflect 'flexible' systems which refer to technical and economic aspects, including flexible demand, storage, increased interconnection capacity, changes to system operation, regulatory frameworks and the design of electricity markets. UKERC further points out that many studies double count or poorly identify different types of integration costs.

Reserve or utilisation costs are captured (albeit not perfectly) in Jacobs modelling. Jacobs (and others) account for wind and solar variability through observed, historical loading profiles at a regional level. Indeed, a key point of this type of modelling is to examine how the system maintains such variable energy balances within AEMO's reliability and technical constraints, including minimum firm reserve requirements. Jacobs modelling also accounts for the cost and location of transmission and interconnection upgrades required to meet new/ changing power flows. It is precisely because of these cost impacts and technical constraints that CCS is deployed in the modelling scenarios alongside renewables, and why the modelling does not suggest a full 100% renewables solution.

[16] http://www.minerals.org.au/news/minerals_council_submission_to_finkel_review
[17] http://www.baeconomics.com.au/wp-content/uploads/2017/03/Intermittent-generation-technologies-13Feb17.pdf
[18] BAEconomics, pp. iii-iv.
[19] http://www.ukerc.ac.uk/programmes/technology-and-policy-assessment/the-costs-and-impacts-of-intermittency-ii.html

Figure 9: South Australian wind profiles



Source: Jacobs for Finkel, p. 30.

Jacobs modelling overlooks a range of real-time complexities such as ramp rates and costs of procuring frequency stability and other ancillary services:

> Some scenarios invest heavily in wind and PV generation and, to a lesser extent, battery storage. These technologies do not directly synchronise to power system frequency which has implications for power system stability, necessitating new technical solutions. These solutions include mandated technical standards upon these generators, investment in transmission stabilising equipment and the purchase of additional ancillary services from synchronised generators. The solutions are complex and difficult to quantify but appear to be of a much lower total cost than the capital costs of the generators themselves. Therefore these issues and costs were not taken into account in the modelling.[20]

The model's constraints ensure there is a sufficient reserve margin of firm capacity installed and connected to the system. However, it is not known whether this capacity was in operation at all times such that it could provide sufficient inertia or frequency control under very short-run ('real world') conditions:

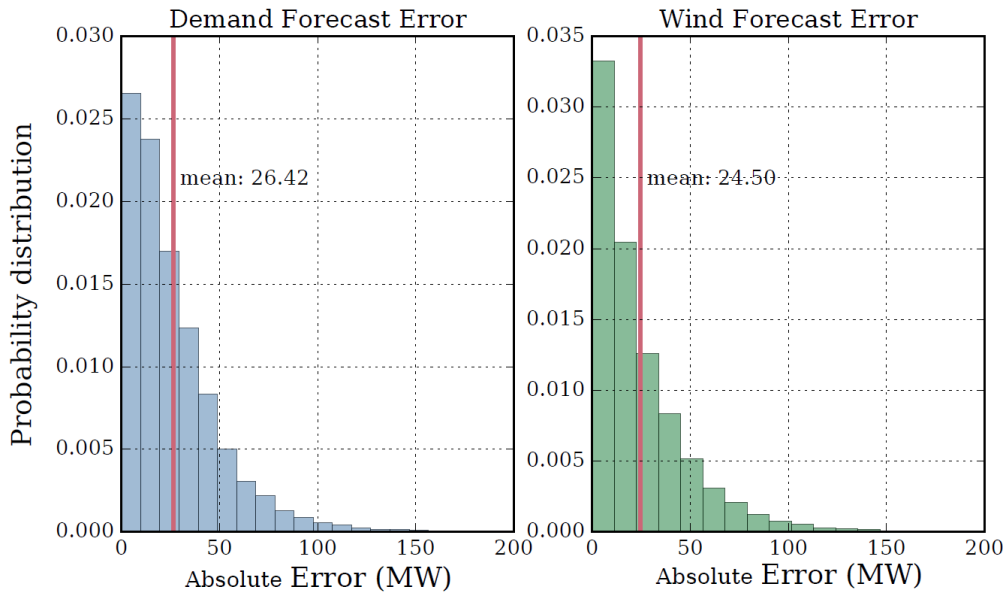
> For the mainland NEM regions, a deterministic check that installed generating capacity exceeded the maximum demand forecast plus the Minimum Reserve Levels as currently applicable and published by AEMO. Wind and non-storage solar generation capacities were discounted by AEMO's existing firmness percentages. For the WEM, a reserve margin constraint was applied on top of firm capacity where firm capacity for intermittent plant was defined as under rules governing operation of the reserve capacity mechanism.
>
> …[This] constraint was applied for additional confidence in the acceptability of the reliability outcome in the presence of a very high penetration of intermittent generation…. in those policy scenarios heavily reliant on intermittent generation, additional dispatchable plant was introduced to meet [this] constraint. The resulting build was not least-cost, as these additional plants were

[20] Jacobs for CCA, p. 281.

> modelled as bidding at the market price cap in the case of the NEM and to earn capacity credits in the case of the WEM, they were observed to earn sufficient profit to recover their capital costs even with very low operating hours[21]

The likely small scale of integration costs not captured in the modelling is demonstrated by using BAEconomics' own estimates: a system with 50% wind penetration would incur an additional $6.7/MWh of 'balancing' costs to deal with wind forecast errors via short-run dispatch of backup generation. Allocating these costs to wind generators would likely have a small impact on the modelling results, especially for CCS plant, given wind has a very low capital cost and zero marginal cost.

System balancing in the face of uncertainty is also not a problem unique to or solely introduced by wind generation. Analysis by the Melbourne Energy Institute[22] (MEI) indicates that AEMO's ability to forecast wind output for SA is actually better than its ability to forecast total system demand. MEI also point out that thermal generators also occasionally trip, resulting in instantaneous loss of large increments of supply. These contingencies are managed by ancillary services and minimum reserve requirements, and the costs of doing so are minimised via having a diverse, flexible system, including with transmission interconnection and effective demand management.



Source: Melbourne Energy Institute, p. 26.

The MEI's report on SA events also usefully highlights work by the AER, AEMC and others examining bidder behaviour in a market with large wind generation, the exit of thermal power stations, and a higher reliance on remaining dispatchable generators. How the technology mix affects market power, e.g. through a lack of diversity in technology types or in individual

[21] Jacobs for CCA, p. 281.
[22] http://energy.unimelb.edu.au/__data/assets/pdf_file/0017/2054132/SA_PRICES_FINAL.pdf

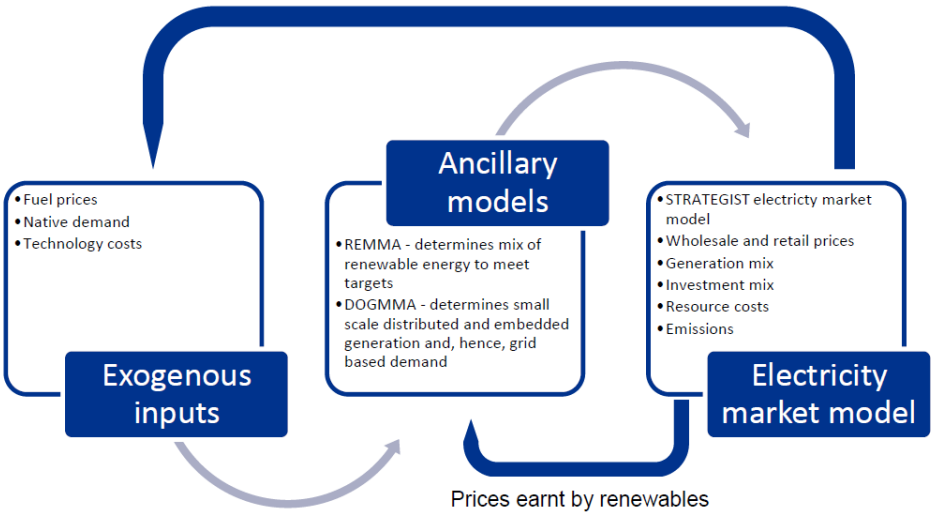
plant, is another potential ‘integration’ issue worth further examination, and is a possible further argument for having some CCS plant in the generation mix.

It may be the case that maintaining (or returning to) a system provided by mostly thermal synchronous generation would be least cost and secure/ reliable, however this does not address the need to decarbonise. The extension of this argument (not made by the MCA and unlikely to be supported by evidence) is that supply mostly by coal (and/or gas) generators with CCS could arguably be a least cost, decarbonised system. However this is an “either/ or” argument with respect to renewables and, given the clear direction of travel of policy and technology, is now hypothetical, at least in most developed countries.

A very compelling and practical counterargument is that integration costs are inevitable but also manageable. Costs incurred from today will be minimised by pursuing a range of solutions (including CCS) led by market incentives, rather than by investing in a pre-determined generation mix. Such a mix, driven by ideology rather than sound policy, would necessarily involve suboptimal resource allocation and costs far in excess of those associated with integrating variable renewables. Indeed, UKERC’s analysis underlines the importance of implementing a host of measures to facilitate rather than block renewables integration. Many of these measures are the same as recommended by Finkel and have widespread support. Some of these, including the ‘system security obligation’ for minimum inertia in each region and the ‘generator reliability obligation’ for new generators to ensure adequate dispatchable capacity, are likely to favour CCS-equipped plant.

Appendix: Jacobs model overview

Jacobs modelling has been extensively used by a variety of stakeholders in the recent Australian policy discussions. Its modelling suite comprises of three separate but connected modules that treat distributed generation (DOGGMA), renewables under the RET (REMMA), and a model of all other generating types in the NEM and WEM (Strategist).



Source: Jacobs for CCA, Figure 7.

The modelling determines least cost deployment outcomes through iterations between the different modules as follows:

- initial estimates of total electricity demand and retail price projections are used to determine embedded generation output each year and the level and timing of new large-scale renewable generation
- The level of embedded generation determines the net demand for electricity faced by the electricity grid, which is input into the electricity market models
- The level and location of new renewable generation is also input into the Strategist model of the NEM/WEM.
- Strategist then simulates the response of the thermal generation sector to produce a new set of wholesale and ultimately retail price projections.
- This process is repeated until a stable set of wholesale prices and renewable energy mix by region is achieved.

The main model, Strategist, represents the optimising behaviour of owners of individual generating units to enter the market and submit price bids relative to short and long run marginal costs. Bidding behaviour reflects expectations about various policy interventions, future wholesale price outcomes, fuel prices, plant cost and performance, and the physical limitations of each generating

unit and of the system. All of this is modelled as chronological hourly loads for a typical week in each month of the year.

Key exogenous inputs are:

- an emission constraint, which takes various forms in the model depending on the form of policy intervention but usually a value on carbon (including penalties or subsidies depending on carbon intensity) or a direct constraint on annual generation (again can depend on emissions intensity)
- energy and maximum demand forecasts
- load profiles (i.e. energy and demand over representative time periods)
- price elasticities of demand
- fuel input cost forecasts
- capital and performance specifications of different plant type, including as these improve over time via assumed learning rates.