MODELLING OPTIONS FOR AUSTRALIA'S RET REVIEW

White Paper

16 May 2014

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SECTION 1. EXECUTIVE SUMMARY

Australia's Renewable Energy Target is once again under review, with sweeping changes on the cards. This White Paper examines five possible scenarios for the policy and analyses the potential impact of these changes on renewable energy investment, capacity, power sector emissions, jobs and the cost to consumers.

- Our modelling indicates that the current 45TWh Renewable Energy Target (RET) is expected to drive AUD 35bn of investment in 14.2GW of new renewable capacity by 2020. This will come at an average nation-wide cost to end-consumers of AUD 0.5bn per annum from 2015-20, with 24,800 workers employed each year in construction and operations. It will also reduce power sector emissions by 8.7MtCO2e (5%) in 2020, compared with 2013 levels.
- Over the longer term (2015-30) the RET will save end-consumers on average AUD 2.0bn per annum, because the costs of the policy are outweighed by the reductions to wholesale electricity prices it achieves. However the scheme could run into trouble if the 10-year tail end of the current design proves too short for projects to obtain financing.
- If the target is abolished, renewables investment will fall by 59% and 63% less capacity will be installed by 2020 than the current set-up. The cost to consumers over 2015-20 will be 22% higher at AUD 0.6bn a year as no savings are made to wholesale power prices but legacy assets continue to be compensated. Incumbent generators (mainly coal) should receive AUD 4.4bn in extra annual revenue. Power sector emissions will be 5% higher and 11,100 fewer people will be employed. Small-scale PV will be the only viable clean energy industry.
- If the target is reduced to 27TWh for large-scale energy and 8TWh for small-scale, investment in renewables will drop by 33%, and 34% less capacity will be installed by 2020 compared with the status quo. The average cost to consumers will be 53% lower to 2020, but 43% higher from 2015-30 as wholesale power prices rise more with less renewable capacity. Power sector emissions will be 3% higher in 2020 and 6,600 fewer jobs will be created each year.
- If the target is deferred to 2025, investment in renewables will be 4% lower than if the current policy is left in place, with 10% less capacity installed by 2020 as build is shifted to 2020-25. The average cost to consumers will be 3% higher than the current arrangement from 2015-20, but will be 15% lower from 2015-30, as wholesale power prices are forced down further than in the current scheme and overall the mechanism works more efficiently.
- If the policy's large- and small-scale components are recombined into one scheme, the system will likely become unworkable, due to the unpredictable nature of the small-scale market. But if large projects can find a way to be viable, the target will be achieved in the long run, but investment, capacity and jobs will be lower to 2020 compared to the status quo.

Table 1: Summary of outcomes under possible RET policy scenario, 2015-20

Scenario	New investment (AUD bn)	Renewable capacity add. (GW)	Power sector emissions from 2015 (MtCO2e)	Approx. cost to consumers per annum (AUD bn)	Avg. annual direct jobs (000s jobs/year)
Current scheme	35	14.2	1,063	0.5	24.8
No target	14.3 (-59%)	5.3 (-63%)	1,121 (+5%)	0.6 (+22%)	13.7 (-45%)
Reduced target	23.4 (-33%)	9.5 (-34%)	1,098 (+3%)	0.2 (-53%)	18.2 (-26%)
Deferred target	33.5 (-4%)	12.8 (-10%)	1,087 (+2%)	0.5 (+3%)	23.1 (-6%)
Recombination of LRET and SRES	28.6 (-18%)	8.1 (-48%)	1,107 (+4%)	1.0 (+97%)	20.5 (-17%)

Source: Bloomberg New Energy Finance

SECTION 2. INTRODUCTION

The Abbott Coalition government is currently conducting a review of Australia's RET, comprising the 41TWh Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES).[1] The terms of reference for the review are broad and allow the expert panel to recommend sweeping changes to the policy (including that it should be unwound) if it believes these are required.[2] To date, much of the public debate about the policy has focussed on the ambition of the target and whether the 41TWh LRET in particular is still appropriate.

This White Paper examines five possible scenarios for the RET and analyses the potential impact of these changes on renewable energy investment, capacity, power sector emissions and the cost of the scheme using the Bloomberg New Energy Finance LRET model and Small-scale PV models.[3] The five scenarios examined are shown in Table 2.

Table 2: RET scenarios

Scenario	LRET	SRES	Tail*
Current scheme	41TWh	Notional 4TWh uncapped SRES by 2020	To 2030
No target	Capped at 17TWh in 2015 to 2030	Withdrawn	n/a
Reduced target	27TWh	Capped 8TWh SRES by 2020	To 2030
Deferred target	41TWh	Notional 4TWh uncapped SRES by 2025	To 2040
Recombined RET	LRET and SRES recombined to 45TWh RET by 2020		To 2030

*Source: Bloomberg New Energy Finance. Notes: * Tail refers to the period where the target remains at a fixed level and liable entities are still required to purchase certificates under the policy. In our analysis of the current scheme we assume the deeming provisions for small-scale PV under the SRES are reduced from 2015 so that no subsidy is provided from 2030, as recommended by the Climate Change Authority in its 2012 review of the RET.*

2.1. DEMAND THE KEY UNCERTAINTY

The forecast for national electricity demand is the key uncertainty in the RET policy debate. The 45TWh Expanded Renewable Energy Target (the predecessor to the current 41TWh LRET and 4TWh SRES) was designed in 2009 to represent 20% of Australia's forecast 2020 electricity demand of around 300TWh. However, since 2009 the country's power demand has fallen despite significant economic growth, and forecasts for national demand to 2020 are now highly uncertain and vary substantially, ranging from 234TWh to 287TWh (Figure 1). Because much of the debate on the level of the target now centres on what percentage of national generation will be renewable, forecasts for demand are a key uncertainty.

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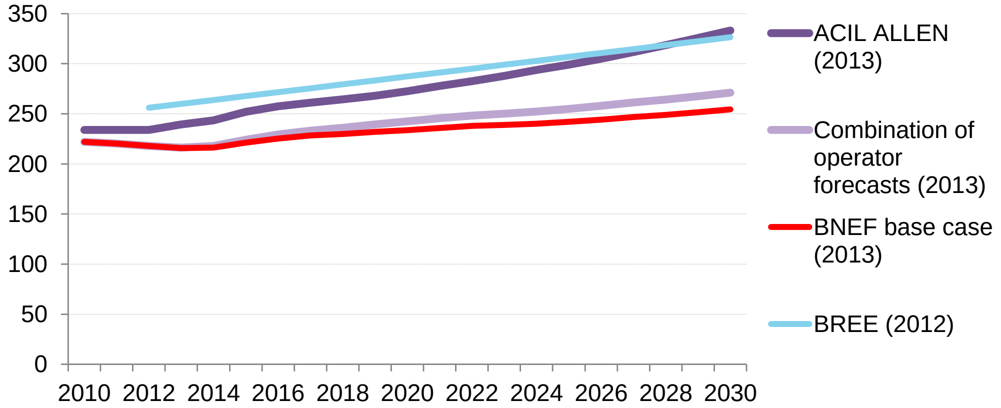
1 For details see: Bloomberg New Energy Finance, Australia's renewable energy target review announced, Asia & Oceania RECs Insight, Analyst Reaction, 17 February 2014.

2 Department of Environment, Renewable Energy Target Review, Terms of Reference.

3 Solar hot water systems and other small-scale technologies are not considered in any part of this analysis.

Figure 1: National gross demand projections (TWh)



Source: Bloomberg New Energy Finance, Australia Energy Market Operator (AEMO), IMO, ACIL ALLEN, Bureau of Resources and Energy Economics (BREE), ROAM Consulting Note: Combination of operator forecasts contains forecasts from AEMO, IMO and NT Power & Water Authority plus estimates for off grid. BNEF demand forecast is based on projections from the operators, with adjustments for higher uptake of PV, greater savings from energy efficiency, and lower load growth in Western Australia.

Forecasts tend to vary depending on:

- When it was constructed (later forecasts tend to be lower)
- Projections for economic growth
- Forecasts for rooftop solar deployment
- Understanding of impacts of energy efficiency
- Inclusion of and forecasts for off- and micro-grid demand.

In our assessment, the forecasts above by ACIL Allen and BREE were produced when national power demand was expected to return to trend or near-trend growth, and are thus too high. The combination of operator forecasts (AEMO, IMO and NT Power & Water Authority plus estimates for off-grid) are also likely to be revised down in 2014 updates. Our demand forecast (BNEF) is based on projections from the operators, deeper energy efficiency savings, and lower load growth in Western Australia. However estimates for off-grid demand may be too conservative in the BNEF and combination of operator forecasts, as little information exists on this segment.

Modelling workshops held by the secretariat responsible for the RET review have indicated the review will utilise a forecast compiled from a combination of the market operator forecasts, but with a pre-release of AEMO's 2014 projections, which are expected to be lower than its 2013 figures. This is likely to bring projections used by the review close to the BNEF forecast.

SECTION 3. HOW CHANGES AFFECT SCHEME FUNDAMENTALS

Any modifications to the LRET and SRES are likely to change the fundamentals of the two markets. In the LRET, fundamentals could change in three ways: the most obvious one is that amendments to the target will affect the amount of overall demand for certificates in the market (net demand). However scheme settings can also influence the cost of new renewable projects and wholesale electricity prices. In the SRES, changes to the scheme can affect (or remove) the amount of subsidy provided, having a minor impact on rates of uptake.

3.1. NET DEMAND

Net demand for Large-scale Generation Certificates (LGCs) is the difference between gross demand (from compliance targets and voluntary sources), and supply from existing and committed projects. Net demand changes depending on the assumed target in each scenario are shown in Table 3.[4] The *No target* scenario assumes that liability to purchase certificates is maintained at 17TWh from 2015 to provide ongoing revenue to legacy projects. This is sufficient to accommodate existing assets and projects that are currently under construction.[5]

Table 3: Assumed target in each RET scenario (GWh)

Scenario	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025-30
Current scheme	16,100	18,000	20,581	25,181	29,781	34,381	41,000	41,000	41,000	41,000	41,000	41,000	41,000
Reduced target	16,100	17,917	19,733	21,550	23,367	25,183	27,000	27,000	27,000	27,000	27,000	27,000	27,000
Deferred target	16,100	18,364	20,627	22,891	25,155	27,418	29,682	31,945	34,209	36,473	38,736	41,000	41,000*
Recombined RET	16,100	20,917	25,733	30,550	35,367	40,183	45,000	45,000	45,000	45,000	45,000	45,000	45,000
No target	16,100	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000

*Source: Bloomberg New Energy Finance Note: * Target in the* Deferred target *scenario is maintained until 2040. In the* No target *scenario liability to purchase certificates is maintained at 17TWh from 2015 to provide ongoing revenue to legacy projects.*

3.2. COST OF NEW PROJECTS

The price at which new projects can supply electricity – represented by the levelised cost of electricity (LCOE) – is also affected by policy settings due to the impact of policy certainty and duration on the cost of finance (Table 4). In general, new projects must have enough bankable revenue via a long-term (usually 15-year) power-purchase agreement in order to receive low-cost finance. If bankable revenue is less than 15 years, financing costs rise.

In all scenarios, except the *Deferred target* case, only 10 years of bankable revenue is likely to exist by 2020 because the tail of the policies (the period where the target remains at a fixed level and liable entities are still required to purchase certificates) only runs to 2030.[6] A survey of project

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4 In this analysis we assume that voluntary demand does not change under different RET scenarios.

5 A RET of 0TWh would undermine existing investments; introducing significant perception of sovereign risk for investors in Australia, as such we view a complete removal of the target with no arrangements for ongoing compensation to existing assets as highly unlikely.

6 The RET was originally designed to work in combination with a carbon price, which was expected to provide enough revenue for renewable projects to be economically viable after 2030. In this analysis we assume no carbon price from 1 January 2015 in all scenarios.

financiers at Australia's four major banks conducted by BNEF in December 2013 reveals that this is likely to increase the cost of finance as gearing ratios decline and loan amortisation times contract, increasing the costs of finance and LCOE of new projects.[7]

In the *Deferred target* case however, the tail of the scheme is assumed to run for 15 years, allowing low-cost finance to be extended to projects for the life of the scheme.

Table 4: LCOE under different RET scenarios (real AUD/MWh)

Technology	High-cost financing due to short policy tail *(Current scheme, Reduced target, Recombined RET)*			Low-cost financing due to longer policy tail *(Deferred target)*		
	2014	2020	2030	2014	2020	2030
Wind	81-139	83-138	79-133	81-139	75-124	64-106
Large-scale PV	139-175	115-164	111-158	122-174	95-136	81-116

Source: Bloomberg New Energy Finance Note: Prices are depicted in real 2014 AUD so that relative comparisons of technology costs can be easily made. Large-scale PV includes all projects above the 100kW SRES threshold.

3.3. WHOLESALE ELECTRICITY PRICES

RET policy settings also have an impact on wholesale electricity prices because renewable generation tends to exert downward pressure on market prices due to its zero (or near-zero) short-run marginal cost. Greater renewable generation and lower utilisation of existing fossil assets are likely to reduce wholesale electricity prices as average and marginal short-run costs in the market decrease.

Downward price pressure in the wholesale market is amplified at present because the rate of renewable generation additions has exceeded electricity demand growth, resulting in greater competition among fossil generators that supply the remaining market share. We expect this trend to continue, meaning wholesale prices will remain low for as long as renewable policy promotes new build capacity above, or in line with, demand growth. These low prices place pressure on the earnings – and in extreme cases viability – of fossil generators.

A reduction or deferral of renewable targets is likely to result in less competition among fossil-fuel power assets and increased wholesale power prices. This helps to explain why many companies involved in thermal generation advocate for a reduction in the target. Furthermore, total withdrawal of the RET may necessitate new capacity around 2020, leading to a significant uplift in power prices in order to support the entry of new assets, which may be renewable or thermal.

Electricity market modelling conducted by ROAM Consulting suggests wholesale power prices will increase by an average of 7.2% per annum over 2015-20 (in nominal terms) under the current scheme arrangements (Figure 2).[8] The current set-up is forecast to result in a national (volume weighted-average) power price of AUD 63.2/MWh in 2020 – at least AUD 10/MWh lower than the policy alternatives assessed in this analysis (Figure 3).[9]

The modelling illustrates that wholesale prices would tend to increase faster if the RET is repealed (13.5% per annum) or reduced to 27TWh (11.1% per annum). The proposals to push the 41TWh target out to 2020 or recombine the LRET and SRES would also result in higher

7 For more details see: Bloomberg New Energy Finance, Q4 2013 Australia REC Market Outlook, 19 December 2013. Or visit about.bnef.com for further information.

8 Electricity market modelling based on: ROAM Consulting, *RET policy analysis, Report to the Clean Energy Council*, 29 April 2014.

9 Wholesale spot price projections are based on ROAM Consulting's analysis for the Clean Energy Council, adjusted for changes in renewable energy generation in each of our chosen scenarios. Power price forecasts weighted by AEMO and IMO most recent medium demand scenarios.

wholesale prices than the current scheme. We estimate these scenarios would see wholesale prices increase by an average of 10.5% and 9.3% per annum respectively over 2015-20.

Figure 2: Forecast average annual increase in weighted-average wholesale prices, 2015-20 (nominal)

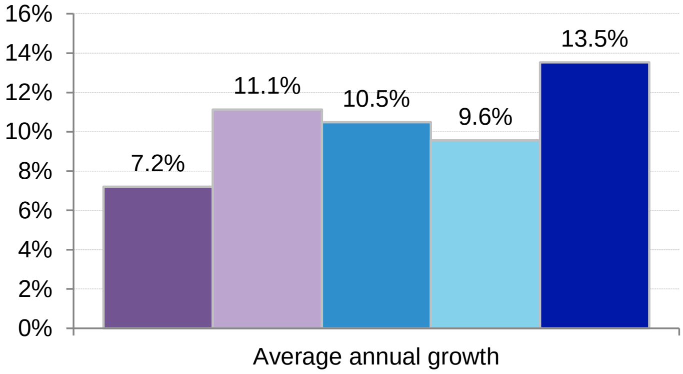
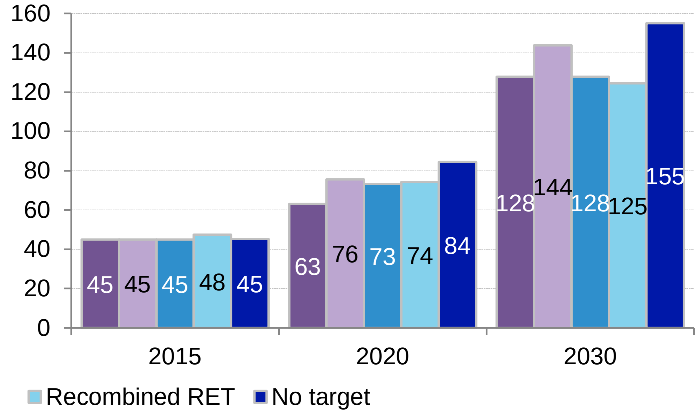


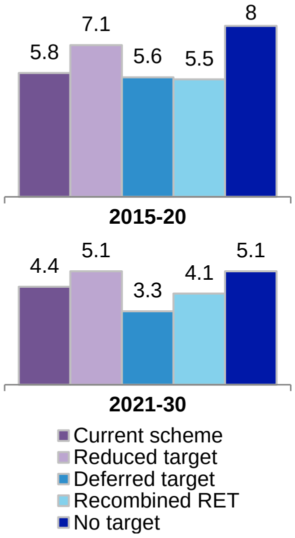
Figure 3: Forecast national weighted-average wholesale electricity spot prices by scenario (nominal AUD/MWh)



Source: Bloomberg New Energy Finance, Roam Consulting. Note: Spot price projections based on ROAM Consulting analysis for the Clean Energy Council adjusted for change in renewable energy generation in each scenario. National weighting is for prices in the NEM and SWIS, based on the medium energy demand projections of AEMO and IMO. Projections assume carbon price is repealed from 1 January 2015 and inflation rate of 2.5% per annum.

3.4. SMALL-SCALE PV

Figure 4: Forecast average payback period for residential solar PV system, 2015-20, 2021-20 (years)



Source: Bloomberg New Energy Finance

The underlying economics of small-scale PV appear strong in light of any potential policy changes. Under the current arrangements, an average residential customer can expect to repay their capital system cost in around 6.8 years, given 15 years of upfront Small-scale Technology Certificate (STC) creation (a process known as deeming). The simple packback period of an average residential system would increase to approximately 9.6 years if the SRES were withdrawn from 2015.

Our residential and commercial market modelling suggests that the total behind-the-meter PV capacity installed by 2030 will vary only slightly in response to policy decisions stemming from the current review. A total withdrawal of the SRES would see approximately 14.6GW of small-scale capacity deployed between now and 2030, compared with 15.8GW under the current arrangements and up to 17.1GW if the SRES and LRET were recombined. This result however conceals the near-term impact on the small-scale market.

An abrupt withdrawal of the upfront subsidy made available by the SRES is likely to reduce installation rates by at least a 24% in the medium term, though the impact on consumer sentiment may cause deeper and more prolonged disruption than the economics alone suggest. Our modelling identifies the residential market, representing 97% of new connections and 74% of new capacity in our base case, as being hit most hard. Suspending the SRES would likely reduce residential installations by 26% over 2015-20. Commercial customers are inclined to perform a more sophisticated assessment of the value proposition of solar, meaning commercial capacity additions may decline by only 10% if the SRES is discontinued.

Placing an absolute limit on eligible small-scale generation would have a similar effect to full withdrawal of the SRES. We anticipate small-scale generation will surpass 8TWh in 2017, at which point restricting SRES eligibility would cause an immediate 20% decline in annual capacity additions.

Proposals to defer the current targets to 2025 would likely bolster small-scale PV installations as new customers would remain eligible for the full 15 years of upfront STC creation until 2025 before tapering to 2040. Similarly, recombining the small- and large-scale schemes is likely to present customers with a stronger price signal than that provided by current STCs. In this case, we anticipate energy retailers would also enter (or re-enter) the small-scale market where the ability to meet scheme liability with the RECs created by installations on customers' rooftops is likely to be more appealing than locking into a PPA with a large-scale project.

SECTION 4. RENEWABLE CAPACITY

Renewable capacity forecasts for each of the scenarios are given below. These include capacity built to meet voluntary demand, but do not include any further large-scale capacity which may be built in addition to the RET to meet growth in energy or power demand.

4.1. CURRENT SCHEME

Under the *Current scheme*, the RET is met in 2021, with 14.2GW of new renewable capacity installed by 2020 (Figure 5 and Figure 6) and 24.6GW by 2030 (Figure 7 and Figure 8). Large-scale capacity rises by 800MW from 2020 to 2030 because the LRET is only met in 2021. Small-scale PV continues to rise throughout the forecast period because of its strong underlying economics, despite a decrease in subsidy levels from reduced deeming. It should be noted however, that the LRET is at risk of not being met in the current scheme: this is because the short tail of policy support from 2020-30 may prevent large-scale projects from achieving finance towards 2020.

Figure 5: New large-scale renewable capacity, 2015-20 (GW)

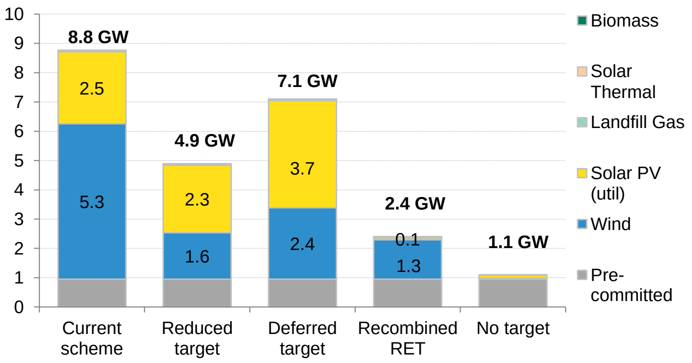
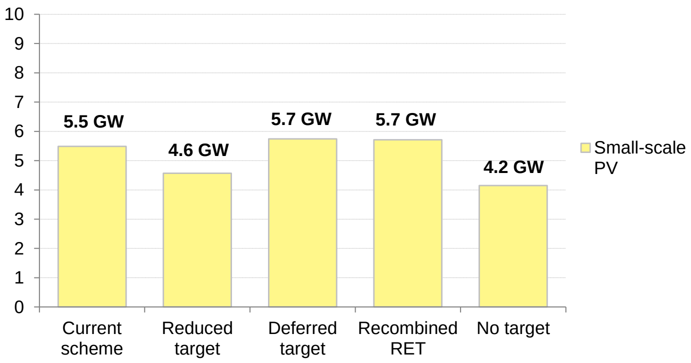


Figure 6: New small-scale renewable capacity, 2015-20 (GW)



Source: Bloomberg New Energy Finance. Note: Pre-committed build of 948MW includes projects with finance secured/under construction, or the subject of government programmes such as the ACT government Climate Change Action Plan 2, which is in addition to the RET.

4.2. REDUCED TARGET

Under the *Reduced target* the RET is also achieved in 2021, with 9.5GW of new renewable capacity installed by 2020 and 19.8GW by 2030. This is 4.7GW less in 2020 and 4.8GW less in 2030 than the current scheme.

As under the status quo, large-scale capacity rises to 2030 because the LRET is only met in 2021. An 8TWh cap is placed on small-scale generation in this scenario, which we forecast will be met in 2017. However restricting SRES eligibility at this point will only reduce small-scale capacity deployed between now and 2030 by 1GW compared with the current scheme, as the underlying economics remain strong without subsidies from 2018. As with the current scheme, due to the short tail of policy support over 2020-30, there is a risk that large-scale projects may not be financed towards 2020, and that the LRET may not be met.

4.3. DEFERRED TARGET

Under the *Deferred target* the RET is met in 2025. Some 12.8GW of new renewable capacity is installed by 2020 and 28.1GW a decade later – 1.4GW less in 2020 and 3.5GW more in 2030 than the current scheme.

Renewable capacity build is less to 2020 because of the lower target trajectory, but higher in 2030. This is for two reasons; firstly more large-scale PV is built because by 2020-25 the technology should be more competitive than wind, but due to its lower capacity factor more capacity is required. Secondly, more small-scale PV is also installed, as subsidy levels are high until 2025 because deeming arrangements are not assumed to reduce until this time. By extending the scheme, the risk of target failure is low due to an adequate tail of policy support over 2025-40 for large-scale projects and projects are also built at a lower cost due to reduced financing risk.

4.4. RECOMBINED RET

Under the *Recombined RET* (assuming projects can be financed) the target is technically met in 2022, largely on the back of certificates created from the upfront deeming of small-scale generation. Only 8.1GW of new renewable capacity (mostly small-scale) is installed by 2020 and 27.0GW by 2030 –6.1GW less in 2020 and 2.4GW more a decade later compared with the current scheme.

Renewable capacity build is less to 2020 because of large amounts of certificate supply from small-scale PV. However as the upfront deeming of small-scale generation reduces from 15 years in 2015 to 1 year in 2030, this supply shrinks and significant amounts of large-scale capacity are needed between 2020 and 2030. The viability of these projects is however, doubtful. The unpredictable nature of small-scale certificate supply and short tail of policy support to 2030 mean that financing projects will be very difficult – if not impossible. Under this scenario there is a significant risk that the target will not be met, and that the market could become dysfunctional.

4.5. NO TARGET

In the *No target* scenario we have assumed liability to purchase certificates is maintained at 17TWh to provide ongoing revenue to legacy projects. Under this scenario 5.3GW of new renewable capacity is installed by 2020 and 17.3GW by 2030. This is 8.9GW less in 2020 and 7.3GW less in 2030 than the current scheme. Renewable capacity additions with no target are almost entirely small-scale PV, which will continue to be installed without policy support, although a significant shock to the market and consumer confidence can be expected, causing a downturn initially. Some large-scale renewable capacity is still installed to 2030 to meet demand from voluntary sources, and as the large inventory of banked certificates runs out.

Figure 7: New large-scale renewable capacity, 2015-30 (GW)

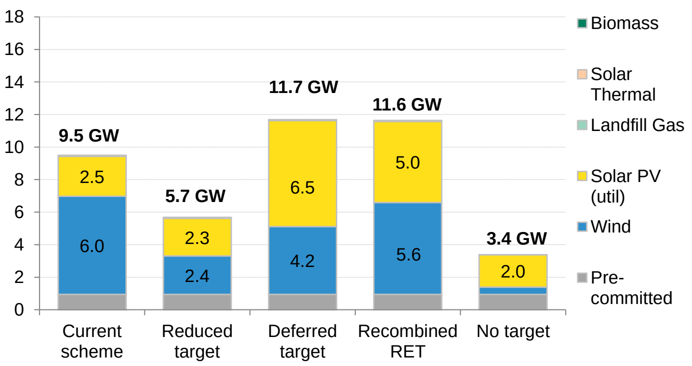
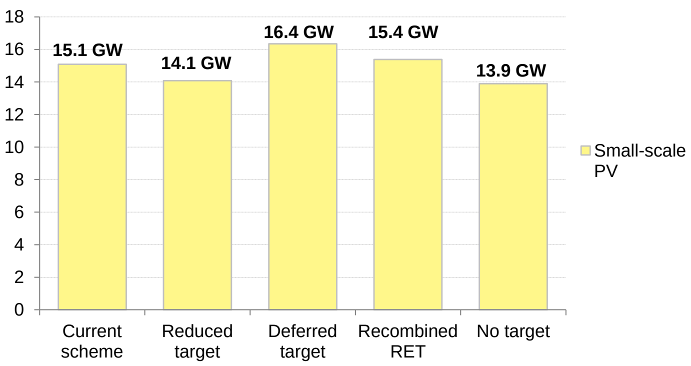


Figure 8: New small-scale renewable capacity by 2015-30 (GW)



Source: Bloomberg New Energy Finance. Note: Pre-committed build of 948MW includes projects with finance secured/under construction, or the subject of government programmes such as the ACT government Climate Change Action Plan 2, which is in addition to the RET.

SECTION 5. INVESTMENT

Under the current scheme, around AUD 35.0bn of new investment is expected in renewable generation by 2020, of which AUD 19.3bn will be from large-scale projects and AUD 15.7bn from small-scale. Any change to the scheme is likely to reduce new investment by 2020, particularly in large-scale assets (Figure 9). Investment in small-scale PV should be relatively resilient in most scenarios, except if the target is removed (Figure 10). Investment in the *Recombined RET* scenario is surprisingly high to 2020, as substantial amounts of new wind are committed before the end of the decade to be built in 2022.

Figure 9: New large-scale investment under scheme, 2015-20 (nominal AUD)

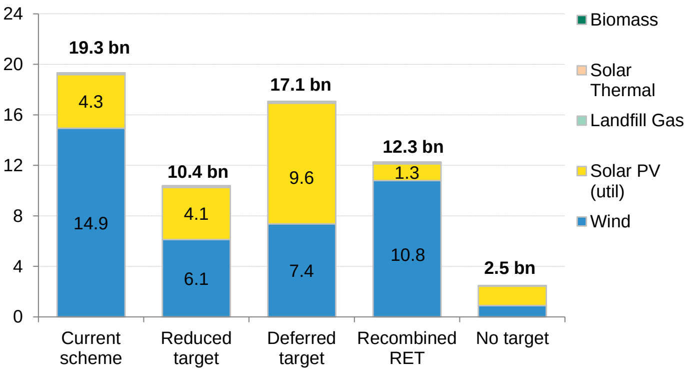
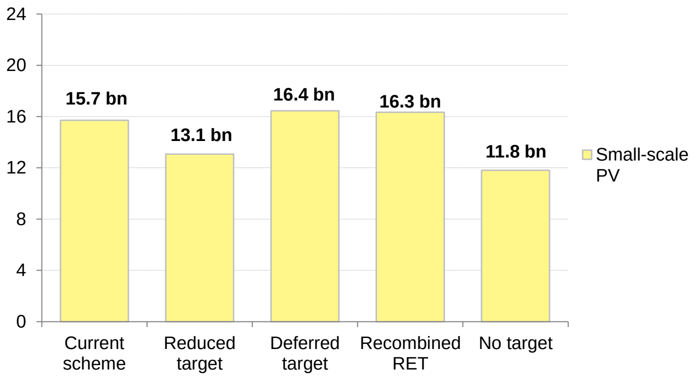


Figure 10: New small-scale investment, 2015-20 (nominal AUD)



Source: Bloomberg New Energy Finance. Note: Over AUD 1bn in new investment is expected from future projects sponsored by the ACT Government Climate Change Action Plan 2 programme.

By 2030, investment in small-scale PV is likely to be nearly double large-scale levels in all scenarios. Investment in large-scale assets will be substantially reduced in the *Reduced target* and *No target* scenarios. It is higher in the *Deferred target* scenario than under the current scheme due to increased volumes of capacity built in this case, due to greater reliance on large-scale PV. Investment in the *Recombined scenario* for large-scale assets is high, but much of this is doubtful due to its high risk.

Figure 11: New large-scale investment under scheme, 2015-30 (nominal AUD)

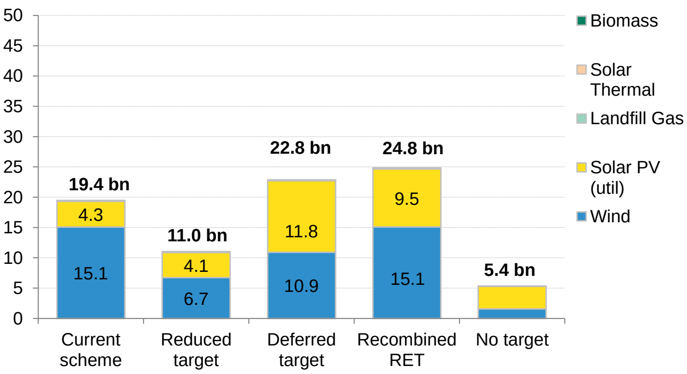
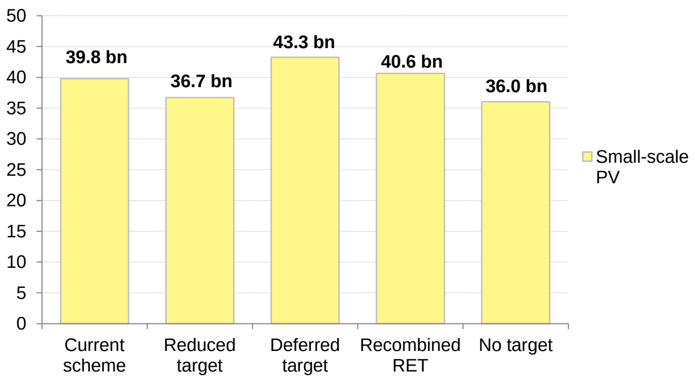


Figure 12: New small-scale investment, 2015-30 (nominal AUD)



Source: Bloomberg New Energy Finance. Note: Over AUD 1bn in new investment is expected from future projects sponsored by the ACT Government Climate Change Action Plan 2 programme.

SECTION 6. JOBS IN CONSTRUCTION AND OPERATION

The current RET scheme is projected to employ approximately 24,800 people per annum in construction and operation between 2015 and 2020 (Figure 13).[10] Average annual employment is expected fall to 20,400 by 2030 (Figure 14). Some 4,000 fewer people will be employed on average in the *No target* scenario each year, while 1,800 more could be employed in the *Deferred target* scenario due to greater uptake of labour-intensive small-scale PV, by 2030.[11]

Figure 13: Average annual construction and operational employment, 2015-20 (000s of job-years)

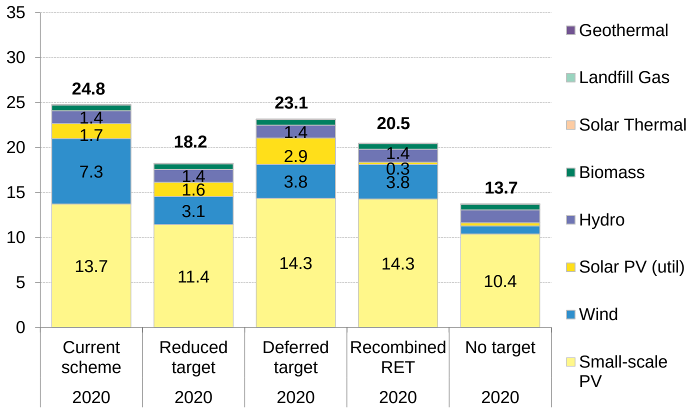
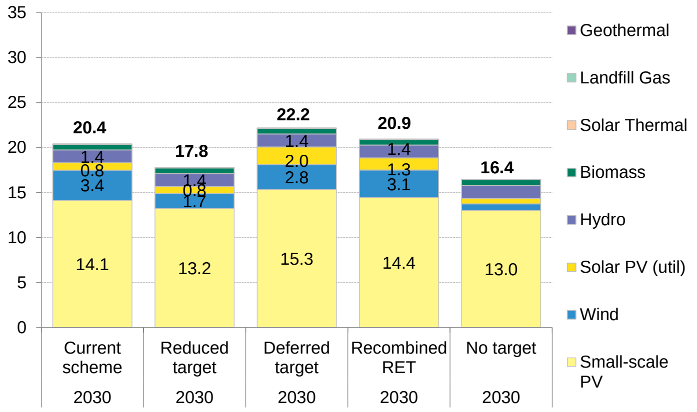


Figure 14: Average annual construction and operational employment, 2015-30 (000s of job-years)



Source: Bloomberg New Energy Finance, BREE, ROAM Consulting, Climate Institute, Clean Energy Council.

[10] Considers direct employment in construction and operation only.

[11] Employment figures are calculated based on benchmarks for wind, large-scale solar and small scale PV from ROAM Consulting (ROAM Consulting for the CEC, 2014, RET policy analysis), biomass and hydro from the Climate Institute (Climate Institute, 2011, Clean Energy Jobs in Regional Australia), and other technologies based on data from the Bureau of Resources and Energy Economics, Major electricity generation projects, 2013.

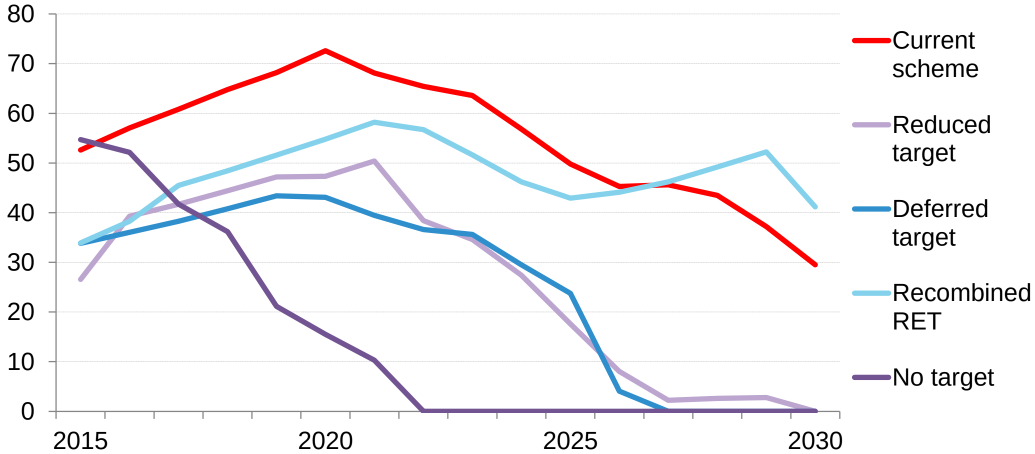
SECTION 7. LARGE-SCALE CERTIFICATE PRICES

LGC prices are forecast to be highest under the *Current scheme* (2015-30 average of AUD 55). Notably, these are being inflated above what the most efficient market outcome could be, because of financing risk to new projects from the short policy tail. Prices are lower in the *Recombined RET* scenario (where certificate prices are for both large- and small-scale generators) – at an average of AUD 46 – because of greater low-cost supply from small-scale PV. Prices are lower (average of AUD 27) in the *Reduced target* scenario because of the decreased need for supply, but they are lowest in the *Deferred target* scenario (average of AUD 25) because financing risk is removed (leading to lower-cost projects) and the build profile is more gradual.

An LGC price still exists in the *No target* scenario (average of AUD 14) to provide ongoing revenue to legacy projects. This is calculated as the difference between an approximate cost of AUD 100/MWh for existing assets (mainly wind) and the forecast national average wholesale cost of power. In practice, LGC prices in this scenario would be volatile and hard to forecast, and could trade in the market towards their fundamental value of zero (as no new supply is required). In such a case, assets could be stranded and other transitional arrangements would need to be put in place.

Small-scale Technology Certificate (STC) prices are assumed to have a value of AUD 38 over 2015-30 in applicable scenarios.

Figure 15: LGC prices in each RET scenario, 2015-30 (nominal AUD)



Source: Bloomberg New Energy Finance Note: LGC price in the No target *scenario (to provide ongoing revenue to legacy projects) is calculated as the difference between an approximate cost of AUD 100/MWh for existing assets (mainly wind) and the forecast national average wholesale cost of power.*

SECTION 8. SCHEME COST

The cost of the RET policy is calculated as the cost required to comply with the scheme, less the savings achieved by a reduction in wholesale power prices compared with the *No target* scenario.[12]

The approximate net cost to electricity end-consumers nation-wide of the current scheme is AUD 514m per annum to 2020 (Figure 16). This is because the compliance costs of the scheme are nearly balanced by savings from a reduction in wholesale electricity prices. Over 2015-30 the approximate net cost to consumers is actually negative – representing an average saving of AUD 2.0bn per annum for end-consumers.

The cost of the different scheme options are similar to those for the current set-up over 2015-20. Notably, in the *No target* scenario, costs are actually higher than those under the current scheme, as legacy assets must still be compensated, but no savings are made to wholesale power prices.

Over the longer period of 2015-30 however, there is a greater difference in annual average costs (Figure 17). The *Reduced target* (AUD 1.1bn per annum) and *Recombined RET* schemes save less money for consumers than the current scheme because although the costs are lower, the savings are reduced by a greater proportion. The deferred target provides the most savings (AUD 2.3bn per annum) because the costs of the scheme are comparatively low (as projects have less risk) and wholesale power price savings are high. The *No target* scenario is the only case where consumers are worse off – on average they will pay AUD 0.2bn per annum in compensation to legacy assets, but receive no further benefits from reduced wholesale prices.

Examined from another angle – in the *No target* scenario consumers will pay an extra AUD 2bn per annum in wholesale electricity over 2015-30, and existing generators (mainly coal) will benefit from around AUD 4.4bn in extra revenue, compared with if the current policy is left in place.

Figure 16: Estimated average annual scheme costs/savings, 2015-20 (nominal AUD bn)

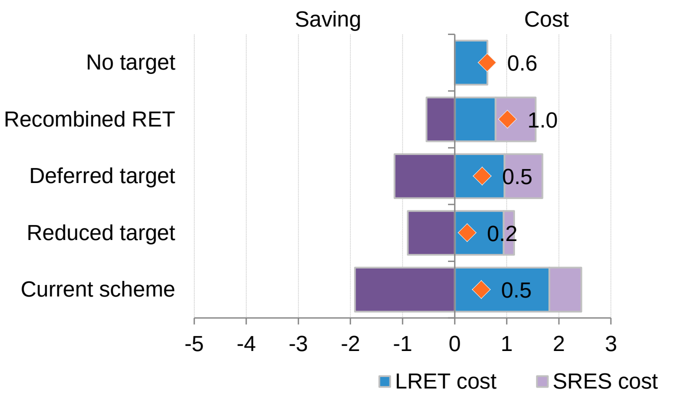
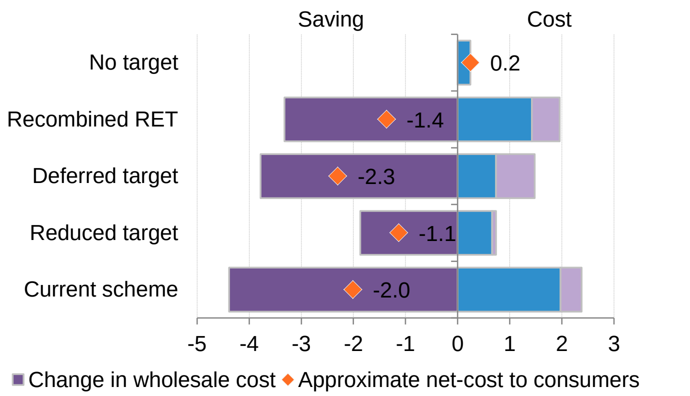


Figure 17: Estimated average annual scheme costs/savings, 2015-30 (nominal AUD bn)

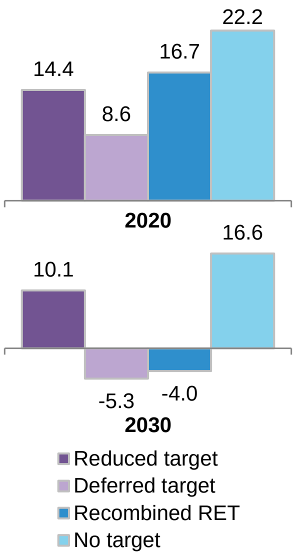


Source: Bloomberg New Energy Finance

12 LRET scheme costs equal to product of annual generation target and LGC price; SRES cost equal to product of annual certificate creation and STC price. Change in wholesale power costs are calculated using the price forecasts explained in Section 7 and the most recent medium energy forecasts released by the Australian Energy Market Operator and WA Independent Market Operator.

SECTION 9. POWER SECTOR EMISSIONS

Figure 18: Change in power sector emissions compared to current scheme, 2020, 2030 (MtCO2e)



Source: Bloomberg New Energy Finance

Analysis using the Bloomberg New Energy Finance Global Energy and Emissions Model shows emission levels under the various policy scenarios. Emissions will be lowest in 2020 under the *Current scheme* (Table 5), which reduces power sector emissions by 8.7MtCO2e (5%) in that year compared with 2013 levels. In the *No target* scenario, power sector emissions would peak in 2020 at 188.9MtCO2e – 22.2MtCO2e above forecast levels if there is no change to the policy (Figure 18).

Withdrawing the scheme in the *No target* scenario would increase emissions by 57.3Mt over 2015-20 compared with the current arrangement (Table 5). This would further burden the Emissions Reduction Fund as the government would be required to source abatement elsewhere to meet Australia's international obligations. Cumulative emissions would increase by 259Mt over 2015-30 if the current scheme is removed.

Table 5: Forecast power sector emissions and change relative to current scheme, 2015-30 (MtCO2e)

Scenario	Single year		Cumulative	
	2020	2030	2015-20	2015-30
Current scheme	167	164	1,063	2,690
Reduced target	181 (+14)	174 (+10)	1,098 (+34)	2,858 (+168)
Deferred target	175 (+9)	158 (-5)	1,087 (+24)	2,716 (+26)
Recombined RET	183 (+17)	160 (-4)	1,107 (+44)	2,766 (+75)
No target	189 (+22)	180 (+17)	1,121 (+57)	2,950 (+259)

Source: Bloomberg New Energy Finance

SECTION 10. PROPORTION OF RENEWABLE GENERATION

In 2020, the percentage of gross electricity demand (ie, the total consumed by end-users) supplied by renewable energy under the *Current scheme* varies between 23% and 38%, depending on which demand forecast is used. Under the *No target* scenario, renewable generation will supply 14-17% in 2020 (Table 6).

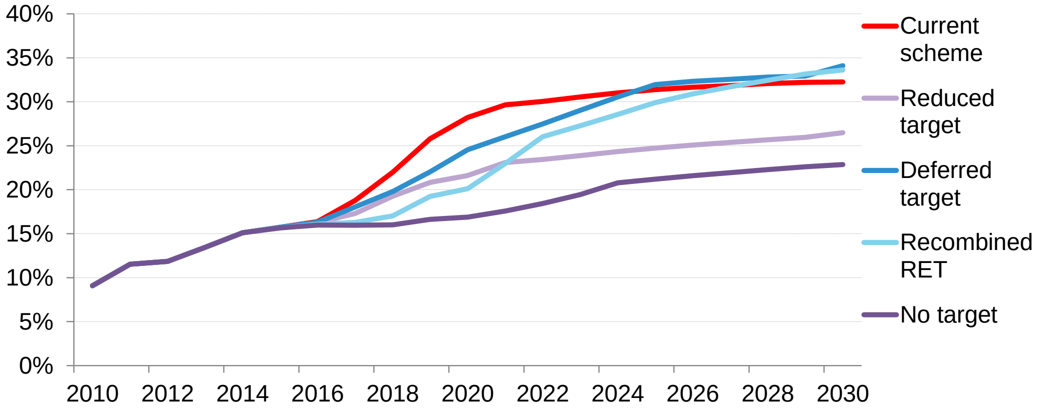
Table 6: Renewable percentage of total electricity supply (excluding voluntary demand), by demand forecast

Scenario	Renewable percentage in 2020 (%)				Renewable percentage in 2030 (%)			
	BNEF (2014)	Combination of operators (2013)	ACIL Allen (2013)	BREE (2012)	BNEF (2014)	Combination of operators (2013)	ACIL Allen (2013)	BREE (2012)
eCurrent scheme	28.2%	27.2%	24.2%	23.0%	32.3%	30.3%	24.6%	25.1%
Reduced target	21.6%	20.8%	18.5%	17.6%	26.5%	24.8%	20.2%	20.6%
Deferred target	24.6%	23.7%	21.1%	20.0%	34.1%	32.0%	26.0%	26.6%
Recombined RET	20.1%	19.4%	17.3%	16.4%	33.6%	31.5%	25.7%	26.2%
No target	16.9%	16.3%	14.5%	13.7%	22.9%	21.4%	17.5%	17.8%

Source: Bloomberg New Energy Finance, AEMO, IMO, ACIL ALLEN, BREE, ROAM Consulting Note: Combination of operator forecasts contains forecasts from AEMO, IMO and NT Power & Water Authority plus estimates for off grid. BNEF demand forecast is based on projections from the operators, with adjustments for higher uptake of PV, greater savings from energy efficiency, and lower load growth in Western Australia.

The proportion of renewable generation rises in all scenarios to 2030 as small-scale PV continues to be installed (Figure 19). With the current scheme it rises to between 25-32% in 2030, depending on which demand forecast is used, and could be as low as 18-23% in the *No target* scenario.

Figure 19: Total renewables generation (excluding voluntary demand) as a percentage of BNEFs gross electricity demand forecasts (%)



Source: Bloomberg New Energy Finance

APPENDIX

Appendix A: About the Australia LRET Model

The Bloomberg New Energy Finance Australia LRET model produces a forecast of Large-scale Generation Certificate (LGC) prices and renewable energy build out to 2030 based on supply-demand fundamentals and the behaviour of market participants. Bloomberg New Energy Finance's supply-side analysis assesses the development of new renewable assets in Australia based on their costs subject to a range of build-rate and resource constraints. Levelised costs of electricity (LCOE) for eligible technologies are calculated using the Australian LCOE model and used as inputs to this model.

To calculate price, the Australia LRET model constructs a merit order of all the potential sources of supply and solves for the price which produces a sufficient volume of generation to meet demand. It then runs an optimisation algorithm to mimic the behaviour of market participants by clearing the market over a forward horizon, allowing investments to be optimised based on relative prices in adjacent years

Appendix B: About the Australia LCOE model

The Australian Levelised Cost of Electricity (LCOE) model is based on a pro-forma project finance schedule which runs through the entire accounting of the project, based on a set of project inputs. This allows the model to capture the impact on costs of the timing of cash flows, development and construction costs, multiple stages of financing, interest and tax implications of long-term debt instruments and depreciation, among other drivers. The outputs of the model include sponsor equity cash flows, allowing calculation of the resulting internal rate of return.

This analysis is based on data collected by Bloomberg New Energy Finance analysts in each sector, knowledge of the capital markets and estimates based on their knowledge of technology and market developments. The range of levelised costs provided for each sector is intended to represent costs achievable under current market conditions.

The inputs to the LCOE model are meant to reflect a range of current costs and are therefore heavily weighted towards recent data and market analysis. Projections for future LCOE's are also developed using technology learning curves, market forward curves including the Bloomberg New Energy Finance Wind Turbine Price Index and Silicon Spot Survey, foreign exchange curves and estimates for future financing changes.

Appendix C: About the Australian Small-scale PV Consumer Uptake Model

The Bloomberg New Energy Finance Australian Small-scale PV Consumer Uptake Model takes into account future technology costs, retail electricity prices, consumer behaviour and price elasticity to estimate uptake of small-scale PV. The model considers both rational economics and behavioural factors to simulate the decision making process of a consumer who calculates the simple payback period of a PV system to assess its costs and benefits, taking into account increasing rates of technology acceptance and adoption, demographic changes, and practical limitations on market growth.

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