Impact Analysis

This document considers the impact of the Retailer Reliability Obligation (RRO) compared to an option requiring physically backed contracts to maintain reliability, or business as usual (BAU). The analysis of the RRO and physically backed contracts draws on work previously undertaken for the National Energy Guarantee (the Guarantee).

The Consultation RIS undertaken for the Guarantee[1] used the ESB's initial modelling by Frontier Economics, released in November 2017, for wholesale market and residential bill impacts. EnergyAustralia and the Voluntary Carbon Markets Association noted in their Consultation RIS submissions that the modelling was out of date and significantly underestimated inputs such as the current committed large-scale renewable energy investment that will take place under BAU. Updated committed build estimates are at Table 1.1

This analysis presents updated estimates of the effects of the Guarantee - from which the effects of the RRO are identified - reflecting updates to the policy design as well as developments in the NEM since November 2017. The analysis draws heavily on the expert advice and modelling capabilities of ACIL Allen consulting.[2]

1.1 Modelling approach and assumptions for wholesale market impacts

The updated Guarantee modelling was conducted using ACIL Allen's proprietary market simulation model – PowerMark – to project outcomes for the NEM over the period from 2018-19 to 2029-30. At its core, PowerMark is a simulator that emulates the settlements mechanism of the NEM. PowerMark uses a linear program to settle the market, as does AEMO's NEM Dispatch Engine in its real-time settlement process. PowerMark is part of an integrated suite of models including models of the market for Renewable Energy Certificates and the wholesale gas market.

Wholesale spot prices in the NEM are determined every half hour by an auction process. These scenarios were modelled on an hourly basis, replicating the dispatch process for 8,760 spot prices for each year. Demand is included as an exogenous assumption and presented to the market against which generator portfolios compete for dispatch.

A distinctive feature of PowerMark is its iteration of generator bidding. PowerMark constructs an authentic set of initial offer curves for each unit of generating plant prior to matching demand and determining dispatch through the market clearing rules. PowerMark encompasses re-bids to allow each major generation portfolio in turn to seek to improve its position – normally to maximise (uncontracted) net revenue, given the specified demand and supply balance for the hourly period in question. The projected wholesale spot price of

1 The National Energy Guarantee Consultation Regulation Impact Statement, 29 June 2018, available at: http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/National%20Energy%20Guarantee%20-%20Consultation%20Regulation%20Impact%20Statement.pdf

2 ACIL Allen is the largest independent Australian owned economics and policy consultancy in Australia. ACIL Allen Consulting is a leader in advising companies and governments throughout Australasia and SE Asia on energy policy and market trends, and is one of Australia's leading providers of economic modelling services to both the public and private sectors.

electricity is a direct output from PowerMark's simulation of the bidding activity of generators.

Spot price outcomes are a function of the market structure as modelled including scarcity pricing and use of portfolio market power at times of tight supply-demand balance, constrained by the current NEM Market Price Cap, Market Floor Price, Cumulative Price Threshold and the Administered Price Cap. Aside from already committed new generation projects which are known to have a very high likelihood of being built, new generation capacity is introduced on a commercial basis in response to energy spot price signals. In the long-term, such market simulation modelling should show price outcomes reflecting the cost of new entrant generation for the various parts of the price duration curve.

All dollar figures in this analysis are expressed in real 2018 terms unless otherwise noted.

In order to conduct quantitative modelling, a number of input assumptions must be made. Many of these assumptions are technical in nature, and include forecasts of future demand levels, fuel prices and technology costs. The technical assumptions used in this modelling incorporate the best available and up-to-date information on the outlook for the NEM and have been sourced from a range of publicly available sources - often from published estimates from AEMO.[3] They have been supplemented by ACIL Allen's own in-house assumptions for other key inputs.

Sensitivity testing was completed to test the effects of changes in key assumptions - for example the difference in results using different estimates of the future cost of various technologies are published below. Assumptions relating to the expected operation of the Guarantee and its effects on the investment and policy environment incorporated into the ACIL Allen modelling were made by the ESB. Many of these are common to all scenarios and are outlined in Table 1.1.

The purpose of this analysis was to gain insight into the expected effects of the Guarantee on the NEM. It does not seek to examine in detail other polices that particular NEM jurisdictions may continue to pursue. It differs in purpose to the modelling conducted to support AEMO's recently released *Integrated System Plan and* reflecting this employs some different modelling frameworks and approaches.[4]

It is important to note that the modelling results presented are not a prediction of the future. Rather, their value lies in providing a comparison between the projected effects of different policy scenarios as a result of an internally consistent framework. Some of the assumptions made necessarily relate to long-term forecasts which are subject to a degree of uncertainty, and changes in these factors over time will have an effect on price and

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3 Key published references from the Australian Energy Market Operator include their 2018 Electricity Forecasting Insights Update available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights/2018-Electricity-Forecasting-Insights
and the assumptions used as inputs to their recently released Integrated System Plan available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan

4 For example reflecting its strategic planning purpose and longer time horizon of interest, the analysis underpinning the Integrated System Plan examines system resource cost outcomes rather than modelling price outcomes or the way that generator profitability may affect investment decisions.

generation outcomes. Further, even very detailed modelling frameworks cannot capture all the real-world detail that may affect generation and price outcomes in the NEM.

Table 1.1: Key assumptions	
Demand	Estimates from *the AEMO Electricity Forecasting Insights March 2018 update* 'neutral' scenario, adjusted to reflect modelled generation coverage.
Behind-the-meter factors: [5] Solar PV Electric vehicles Battery storage	 Based on AEMO *Electricity Forecasting Insights* neutral estimates Based on AEMO *Electricity Forecasting Insights* neutral estimates Based on AEMO *Integrated System Plan* neutral estimates
Demand response	'No policy' option: based on the AEMO *Integrated System Plan* weak Demand Side Participation assumptions 'Guarantee' option: based on the AEMO *Integrated System Plan* strong Demand Side Participation assumptions
Fuel costs (coal and gas)	ACIL Allen estimates. **Coal** The marginal price of coal for electricity generation is assessed in consideration of the specific circumstances for each generator taking into account: – Suitability of coal for export and the assumed international thermal coal price – Location of power station in relation to the mine and export terminals – Mining costs – Existing contractual arrangements Coal prices are expected to moderate somewhat from their currently elevated levels. International thermal coal prices are assumed to converge to US$ 60/t in the long term from around US$120/tonne currently.[6] **Gas** – Gas market is modelled in ACIL Allen's GasMark Australia model – Real gas prices for power generation are projected to moderate slightly from their current range of around $7-11/GJ in 2017-18 over the period to 2020-21 before increasing over the 2020s to a range of between $9 to $14per GJ by 2029-30.

5 These factors AEMO's 2018 Electricity Forecasting Insights Update available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights/2018-Electricity-Forecasting-Insights and Integrated System Plan available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan

6 This projected decline in coal prices is broadly consistent, for example, with the trends in recent forecasts published by the Australian Department of Industry, Innovation and Science in their June 2018 Resources and Energy Quarterly and in the World Bank's April 2018 Commodity Price forecasts.

Retirements	Announced retirements are reflected in the modelling. Other plant are assumed to require life-extension refurbishment when they reach the end of their expected technical life, and retire unless life-extension refurbishments are projected to be economic. Plant will also retire when they are no longer projected to profitably operate.
Committed build	A list of large scale renewable projects considered committed to be built in the NEM over the next three years is at Table 1.3. In addition, the Commonwealth's Snowy 2.0 expansion, the plan to replace the Liddell Power station in NSW announced by its owners, and stage one of the VRET and QRET schemes are considered committed.
Snowy 2.0	Snowy Hydro 2.0 assumed to become operational in 2023-24 with 2,000 MW of additional pumped hydro storage (battery) generating capacity, along with a consequential increase to VIC-NSW transfer capability to enable its effective operation.
State-based renewable policies	Stage one of the announced state renewable energy targets in Victoria (VRET) and Queensland (QRET) are included. That is, 400MW of capacity in Queensland and 650MW of capacity in Victoria. Further stages of these schemes are not included.
Financing costs: Weighted average cost of capital for new entrants Uncertainty premium	Pre-tax WACC of 6.3% in 2018 rising to 8.9% by 2030 as interest rates normalise from current lows (assumes constant 60/40 debt-to-equity financing ratio) No policy case assumes an additional uncertainty premium of 3 percentage points (post-tax) which is removed under the Guarantee [7]
Contract coverage of existing generation capacity	Increases by 5% under the Guarantee (see section 1.3)[8]
Macroeconomic assumptions	Exchange rate of 0.75 AUD/USD; inflation rate of 2.5%

Technology cost assumptions

Current and future capital cost profiles for each generation technology are key input assumptions in this type of modelling exercise. These numbers can determine the types of generation that the model builds and how much of them are built as prices and the demand-supply balance in the system change. In order to test the sensitivity of the 'no policy' and Guarantee scenarios to technology costs, variants of each scenario were run using more aggressive declines in capital costs for certain technologies which were identified across a survey of available estimates (see Table 1.2).

7 The WACC is ACIL Allen's estimate based on their extensive work advising market participants, and reflects a gradual normalisation of global monetary policy. The uncertainty premium reflects the expected differential effects of policy confidence on financing costs under the 'no policy' and 'Guarantee' cases. This approach is consistent with the recent modelling by Frontier for the ESB.

8 Projecting change in contract levelS and apportioning this behavioural response between new and existing generators is discussed further in the ESB's November 2017 modelling paper (pages 6 and 7), available at: http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/Report%20on%20the%20National%20Energy%20Guarantee.pdf (

Both scenario variants were identical to the central cases, implying that the results do not hinge on the technology cost assumptions in this particular example. As such the results are not included here.

Table 1.2: Key technology cost assumptions

Real 2018 $/kW	2018	2030
Wind	2,053	1,650
Solar	1,469	1,055
Solar thermal	5,531	4,400
Open cycle gas turbine	819	806
Combined cycle gas turbine	1,230	1,224
Black coal (super critical)	3,072	3,043
Pumped hydro	1,429	1,364
Large scale battery storage (4 hrs)	2,031	959

1.2 'No policy' business as usual

To test the relative performance of the Guarantee a 'no policy' case was modelled - intended to represent a plausible business-as-usual future for the electricity market in the absence of the Guarantee.

Only those new entrant projects currently committed were built in the short-term under the 'no policy' case. The demand response market was expected to develop towards the lower end of current expectations under this scenario – and the available volumes of demand response and the prices at which they are available were assumed to be consistent with the 'weak' DSP assumptions used in the AEMO Integrated System Plan.[9] Consumption met by grid-supplied electricity was forecast to remain relatively flat over the projection period based on the AEMO demand forecasts adopted. Business demand was forecast to remain flat, while net residential demand was projected to decline as growth in population and appliance usage was offset by increased generation from rooftop PV and by energy efficiency initiatives.[10]

9 Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan

10 More detail on these forecasts is available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights/2018-Electricity-Forecasting-Insights

In 2017-18 wholesale prices were at elevated levels of around $85/MWh (on a time-weighted basis) in part due to the recent closure of the Hazelwood power station in Victoria and increases in coal and gas costs in recent years.

The 'no policy' modelling projected that wholesale prices in the NEM will decrease to around $50/MWh by 2020-21. This was primarily due to an expected increase in NEM capacity of around 7,800 MW over 2018-19 to 2020-21 owing to the addition or completion of committed utility scale wind, solar and battery storage projects and stage 1 of the VRET and QRET schemes. A list of committed projects is at Table 1.3. Assumed declines in coal costs also contribute to the lower price outcomes in this period.

Current investment momentum is understood to reflect current elevated prices, incentives under the national RET and State renewable schemes and strong corporate demand for renewable power purchase agreements.

While the closure (as announced) of the Liddell coal-fired power plant in NSW in 2022-23 puts some upward pressure on prices, the replacement capacity announced by the ownership of Liddell together with the addition of around 2,000 MW of capacity with the completion of the Commonwealth Snowy 2.0 pumped hydro project in 2023-24 was projected to put further downward pressure on prices, broadly offsetting the price effects of Liddell retiring and extending a period of lower prices. Wholesale prices were then projected to rise slightly over the latter half of the decade as the demand-supply balance tightened and real gas prices – an input to gas-fired generation – rose. Some Queensland black coal generation was projected to withdraw in line with key contracting and technical milestones around 2029-30[11] which caused a further slight increase in the modelled wholesale price trajectory at this time.

Under the no policy case, projected wholesale prices were 31 per cent lower relative to 2017-18, on average, over the period from 2018-19 to 2029-30.

Under the no policy case, the generation mix over the period was projected to change to reflect the committed new renewable build. The modelling suggested that the renewable share of NEM generation (sent out) would increase from 17 per cent in 2017-18 to 34 per cent by 2029-30.

Coal powered generation was expected to continue to account for over 60 per cent of all generation in 2029-30.

The total value of wholesale energy purchased in the NEM over the period 2020-21 to 2029-30 under the 'no policy' scenario was projected to be around $118 billion.

Table 1.3: List of committed projects to 2020-21[12]

Region	Station	Technology	Average capacity in 2020-21	Increase in capacity relative to 2017-18	Capacity online part way through 2017-18
VIC	Ballarat	Battery	30	30	0
NSW	Balranald Solar Farm (Sunraysia)	Solar	200	200	0
VIC	Bannerton Solar Farm	Solar	88	88	0
NSW	Beryl Solar Farm	Solar	87	87	0
NSW	Bodangora Wind Farm	Wind	113	113	0
VIC	Bulgana	Battery	20	20	0

11 The modelling suggests that under this scenario, it would not be profitable for some Queensland black coal capacity to undergo necessary refurbishments in 2029-30, a time which coincided with the expiration of a major power purchase agreement.

12 Note totals may not add exactly due to rounding.

VIC	Bulgana wind farm	Wind	194	194	0
SA	Bungala Solar Farm (both stages)	Solar	220	110	110
TAS	Cattle Hill WF	Wind	144	144	0
QLD	Childers Solar Farm	Solar	75	75	0
QLD	Clare SolarPV	Solar	100	66	34
QLD	Clermont Solar Farm	Solar	89	89	0
NSW	Coleambally Solar Farm	Solar	150	150	0
QLD	Collinsville Solar Farm	Solar	43	32	11
QLD	Coopers Gap WF	Wind	453	453	0
VIC	Crowlands WF	Wind	80	80	0
NSW	Crookwell 2 WF	Wind	91	80	11
NSW	Crudine Ridge WF	Wind	135	135	0
SA	Dalrymple	Battery	30	30	0
QLD	Darling Downs Solar Farm	Solar	110	110	0
QLD	Daydream Solar Farm	Solar	150	150	0
QLD	Emerald Solar Farm	Solar	68	68	0
VIC	Gannawarra Solar Farm	Solar	50	38	13
TAS	Granville Harbour Wind Farm	Wind	112	112	0
QLD	Hamilton Solar Farm	Solar	56	42	14
QLD	Haughton Solar Farm	Solar	100	100	0
QLD	Hayman Solar Farm	Solar	50	50	0
SA	Hornsdale 3 WF	Wind	109	71	38
VIC	Karadoc Solar Farm	Solar	90	90	0
QLD	Kennedy	Battery	2	2	0
QLD	Kennedy wind/solar farm	Wind/Solar	58	58	0
VIC	Kiamal Solar Farm	Solar	200	200	0
VIC	Kiata WF	Wind	30	15	15
QLD	Kidston Solar Project	Solar	50	38	13
VIC	Lal WF	Wind	216	216	0
QLD	Lilyvale Solar Farm	Solar	100	100	0
SA	Lincoln Gap WF	Wind	126	126	0
NSW	Manildra Solar Farm	Solar	49	36	12
NSW	Midgar Solar Farm	Solar	150	150	0
QLD	Mt Emerald WF	Wind	181	150	30
VIC	Mt Gellibrand WF	Wind	132	116	17
VIC	Murra Warra WF	Wind	226	226	0
VIC	Numurkah Solar Farm	Solar	100	100	0
QLD	Oakey Solar Farm	Solar	80	74	6
NSW	Parkes Solar Farm	Solar	55	28	28
QLD	QRET 100 battery	Battery	100	100	0
QLD	QRET 300 wind	Wind	300	300	0
QLD	Ross River Solar Farm	Solar	148	148	0
QLD	Rugby Run Solar Farm	Solar	65	65	0
VIC	Salt Creek WF	Wind	54	47	7
NSW	Sapphire WF	Wind	270	233	38
NSW	Silverton WF	Wind	198	149	50
SA	Snowtown North Solar Farm	Solar	44	44	0
VIC	Stockyard Hill WF	Wind	530	530	0
QLD	Sun Metals Solar Farm	Solar	125	94	31
QLD	Susan River Solar Farm	Solar	98	98	0
SA	Tailem Bend Solar Farm	Solar	100	100	0
VIC	VRET 100 solar	Solar	100	100	0
VIC	VRET 550 wind	Wind	550	550	0
QLD	Warwick Solar Farm	Solar	64	64	0
VIC	Wemen Solar Farm	Solar	110	110	0
NSW	White Rock Solar Farm	Solar	20	13	7
QLD	Whitsunday Solar Farm	Solar	56	42	14
SA	Willogoleche WF	Wind	118	118	0
VIC	Yaloak South WF	Wind	29	29	0
QLD	Yarranlea Solar Farm	Solar	121	121	0
VIC	Yatpool Solar Farm	Solar	81	81	0
Total				**7,775**	

1.3 Retailer Reliability Obligation

Agreement to implement the Guarantee was expected to result in the further commitment of 1,000 MW of renewable generation relative to the no policy scenario – this approach was consistent with the ESB's market intelligence and supported by stakeholder submissions to the policy development process.[13] Greater policy confidence was also captured in the modelling by assuming a lower financing cost of three percentage points (post-tax) in the 'guarantee' scenario, but this was not a factor in the expectation of the additional 1000MW of renewable generation.

Importantly, the reliability obligation (now referred to as the RRO) element of the Guarantee was also expected to increase the volume of long-term contracting in the NEM as all retailers and large market customers would be required to have a reliable level of firm contracts in place at key times when the reliability obligation was triggered. Even in instances where the RRO was not triggered, the ESB expects it would incentivise market participants to engage in more long-term contracting up to an appropriate and sustainable level.[14] This was reflected in the modelling by assuming the average contracted load of existing generators increases by 5 per cent.[15]

This was consistent with the approach taken by Frontier Economics in the previous modelling exercise conducted by the ESB. This led to more competitive bidding in the spot market as generators bid lower to increase their chances of being dispatched in order to cover their contracted capacity (Box 1.1). Generators with high levels of long-term contracts in place are heavily financially incentivised to be able to generate in contracted time-periods.

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13 The modelling framework assumes that new generation plant will be built when the expected net present value of the project is positive, based on the expected future revenues of the project from the spot market or other sources of revenue such as the RET or low-emissions or reliability premia associated with the Guarantee. On this basis, the modelling framework would not have built all of the approximately 7,800 MW of new-entrant build committed and expected to connect to the NEM in the coming three years. As such, consideration must be given to the drivers of this new build and assumptions made whether the existing momentum should be expected to continue. While only a small portion of the already committed pipeline, the ESB considers that in the order of at least an additional 1,000 MW of generation would have already committed were it not for the current policy uncertainty, and will quickly reach financial close once the Guarantee is agreed. This is around an additional 1/8th of the currently committed pipeline of projects, and would require less than 4 per cent of currently proposed projects to proceed. This estimate is consistent with ESB's market intelligence and supported by stakeholder submissions to the policy development process.

14 The level and tenor of contracting will be considered when the operation and implementation of the scheme is assessed in due course with the potential to remove the reliability obligation trigger at that point if it would improve scheme operation.

15 Detailed discussion of the difficulty in precisely estimating the expected change in contract levels and apportioning this behavioural response between new and existing generators is written up in the description of the ESB's previous November 2017 modelling, available at: http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/Report%20on%20the%20National%20Energy%20Guarantee.pdf

Box 1.1: Contracting in the NEM

Generation portfolios enter into electricity derivative contracts to hedge a portion of their wholesale revenues in order to reduce earnings risk and avoid insolvency.

In entering into these contracts, generators are indifferent to spot price movements across the volume of these contracts except where the spot price falls below their marginal cost. Therefore, a short-term optimal strategy for generators is to offer all capacity that is contracted at marginal cost.

To the extent they can, generators will seek to optimise net revenue outcomes for their uncontracted capacity. This is often referred to as 'strategic bidding' and is typically employed during periods of tight supply and demand. The level of contract cover for generators within the market is therefore a key short-term setting in market modelling exercises. It is often set by reference to recent observed bidding behaviour in the market and has historically equated to around 80-85% of dispatch. However, in recent years the increase in intermittent renewable capacity and the closure of thermal plant has left less swap contract cover available to the market.

Increasing the amount of generator capacity under contract will tend to lead to a more competitive market in the short term with generators offering more capacity at marginal cost and resulting spot price outcomes will be lower as a result. However, this setting would be expected to have little impact on annual spot price outcomes modelled in the longer-term as annual prices converge to new entrant costs.

The incentives and structures created by the RRO are also expected to accelerate the development of the demand-side response market. This was modelled in the Guarantee scenario by changing the assumptions associated with the availability and pricing of demand response from the AEMO *Integrated System Plan* 'weak' assumptions (under BAU) to the 'strong' assumptions.[16]

The model was constrained to ensure that a minimum reserve level of capacity was maintained in every region in every time period. In any instance that a shortfall was identified, changes in firm contract premia were applied to incentivise a supply or demand-side response to close the gap. If required, these costs were added to retail bills. The NEM's wholesale electricity market delivered sufficient capacity to ensure reliability in the 'Guarantee' scenario.

The modelling found that the Guarantee would place substantial additional downward pressure on prices. NEM-average wholesale prices (time-weighted) were projected to be over 20 per cent lower, on average, between 2020-21 and 2029-30 under the Guarantee compared to the 'no policy' scenario.

16 Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan

Annual average residential retail electricity bills were projected to be around $550 lower, on average, over the 2020-21 to 2029-30 period than in 2017-18.[17] The modelling suggests that around $150 of that saving is additional savings due to the implementation of the Guarantee.

ACIL Allen ran a sensitivity scenario under the 'Guarantee' case without the additional 1000MW of renewable generation capacity expected to occur with implementation of the Guarantee. This sensitivity scenario is considered to reflect price outcomes under the RRO. Under this sensitivity scenario, the additional 1000MW does not occur and as a result wholesale prices are higher than what were expected under the Guarantee. Retail prices are estimated to be $110 lower on average over the period 2020-21 to 2029-30 than in 2017-18 under this scenario.

The reduced financing costs: a three percentage point reduction in financing costs under the 'Guarantee' case, did not materially affect retail prices over the forecast period under the ACIL Allen model. The three percentage point policy risk premium under the 'no policy' case was similar to the approach used in the previous modelling (November 2017) which was based on stakeholder feedback in terms of the level of premium and rationale for inclusion. The difference in retail prices between the RRO and the 'Guarantee' is due to the treatment of the additional 1000MW of renewable generation investment and its effect on wholesale prices, not the effect of policy risk premium.

17 Only estimated bill savings expected to occur as a result of reductions in the price of wholesale electricity or reductions in the cost of green scheme subsidies are included in this figure. The reductions in wholesale prices also reduce the costs to retailers (reduced cost of transmission and distribution losses) and the value of electricity to which retail margins are applied. For conservatism and simplicity, savings that may result from reductions in network pricing relative to 2017-18 were not included.

1.4 Physically backed contracts

An alternative to the Retailer Reliability Obligation would be to require contracts used to meet the obligation to be linked to a specific generator. See Section 5.3 of the *National Energy Guarantee Consultation Regulatory Impact Statement* for further discussion of this alternative.