Relevant level method review 2018 Capacity valuation for intermittent generators

Final report

31 March 2019

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Executive summary

The South West Interconnected System is a small, geographically isolated electricity system. To provide a reliable supply of electricity for consumers, the Wholesale Electricity Market (WEM) was designed to have sufficient electricity generation available to satisfy demand at all times, including during supply emergencies.

Each year, the Australian Energy Market Operator (AEMO) procures enough generation capacity to deliver a reliable electricity supply by assigning capacity credits to generators and demand-side management providers, such as large industrial power users. Electricity retailers fund the purchase of these capacity credits. The amount retailers pay depends on their contribution to peak demand in the WEM: a ‘user pays’ approach. The higher a retailer’s demand during peak times, the more capacity credits it must fund.

The cost of having generation capacity available must be balanced against the benefit to consumers of having a reliable electricity supply as ultimately, consumers pay. Retailers pass the cost of capacity credits on to electricity consumers through retail tariffs. If more generation capacity is procured than is required, the South West Interconnected System (SWIS) will be more reliable but customers will pay for generation capacity they do not need.

Intermittent generators such as wind and solar farms by their nature have variable, weather-dependent output. This variability must be taken into account when determining to what extent intermittent generators can be relied upon to have capacity available when needed to meet demand and support reliability in the SWIS. The method AEMO uses to determine the quantity of capacity credits allocated to intermittent generators is called the relevant level method.

As the number of intermittent generators in the SWIS continues to grow, the relevant level method becomes increasingly important to ensure intermittent generators receive capacity credits that reflect their contribution to reliability, as shown in the box below.

Over the capacity years 2016/17 to 2019/20, intermittent generators’ share of the total quantity of capacity credits assigned to facilities in the SWIS doubled to 3.8 per cent.

For the 2019/20 capacity year:

- Twenty one intermittent generators received approximately 183 MW of capacity credits in total, equivalent to around 24.5 per cent of their installed capacity.
- Based on a price of $126,638 per capacity credit, the value of capacity credits allocated to intermittent generators is approximately $23 million.

Every three years, the ERA reviews the relevant level method and examines if it meets the objectives of the WEM. These objectives include lowering long-term costs for electricity consumers, promoting the reliable supply of electricity, and avoiding discrimination against energy technologies, including renewable resources.

This report outlines the ERA’s review of the current relevant level method and explains why the ERA recommends changing the current method. This report considers submissions received from stakeholders in response to the draft report published on 21 December 2018[1] and contains a summary of those submissions and the ERA's response.

Calculating the value of capacity

The most stringent reliability target in the SWIS specifies the system should have sufficient capacity to meet a level of peak demand that is likely to happen just once every 10 years. The sum of the available capacity of generators and demand-side management providers must be sufficient to cover this one in 10-year peak demand.

Both the available capacity of resources and demand are variable. Output from intermittent generation technologies is variable as wind and solar farms can produce energy only when the wind is blowing or the sun is shining. Demand is also variable and tends to increase as the air temperature rises. The output of coal or gas-fired conventional generators can vary too. For instance, conventional generators may not be able to produce energy at their maximum capacity due to mechanical failures, and their available capacity can decrease when air temperature is high. Therefore, at any point in time, many different combinations of demand and available capacity can occur.

The relevant level method needs to specify an approach for estimating the capacity contribution of an intermittent generator to reliability in the SWIS. The method should factor in numerous combinations of the available capacity of generators and demand – all forecast two years ahead.

The methods used to calculate an intermittent generator's capacity value are based on either detailed or simplified models. Detailed methods commonly use simulation- or probability-based calculation methods. Simplified methods emulate the outcomes of detailed calculation methods but are usually subject to some conditions. Reasonable capacity valuations are only possible if the conditions are met.

The current relevant level method was developed based on a simplified model. The method uses a downward adjustment to intermittent generators' average output during a sample of periods in the last five years.[2]

Findings from the ERA's review of the current relevant level method

The current method has several shortcomings and does not provide a reasonable forecast of the capacity contribution of intermittent generators to reliability in the SWIS.

The current method does not identify correctly periods with the lowest level of capacity surplus, does not address appropriately the correlation between the capacity of different generators, and makes some other calculation errors.

The current method could be revised to remedy some of its shortcomings. Even so, a fundamental problem will remain. The simple formula upon which the current method was based can only calculate reasonable capacity values for the fleet of intermittent generators

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1 The ERA, Relevant level method review 2018: Capacity valuation for intermittent generators – Draft report, 21 December 2018, (online).

2 The size of the adjustment is determined by the variance of the output of intermittent generators multiplied by the sum of two parameters. One parameter accounts for the effect of the output of other generators on the capacity value of a generator and another parameter accounts for the effect of a possible lack of data.

when there are very low levels of intermittent generation in the electricity system. This situation no longer applies in the SWIS, where the penetration of intermittent generators is increasing.

A relevant level method that does not result in the allocation of capacity credits to intermittent generators that reflects their contribution to reliability in the SWIS can increase the long-term cost of electricity to consumers and undermine the reliability objective of the WEM.

The proposed relevant level method

The proposed method uses historical time series data on the output of intermittent and scheduled generators and demand to forecast the capacity value of the intermittent generation fleet two years ahead.

The proposed method then allocates the fleet capacity value to each type of intermittent technology class, currently biogas, solar and wind generation. Technology class capacity values are then distributed to individual intermittent generators in a technology class based on their output during low capacity surplus periods in the SWIS. The method is robust to introducing new technology classes, such as storage, as they enter the system.

> The proposed method draws on the recommendations of the International Energy Agency Expert Group on Wind Integration Studies and the Institute of Electrical and Electronics Engineers, Wind Power Coordinating Committee Task Force. The Californian Independent System Operator and the Midcontinent Independent System Operator also use a similar method for the capacity valuation of intermittent resources.

There are some problems with this proposed method. As with any forecasting tool, it assumes that historical data will provide a reasonable indication of the contribution of intermittent generators in the future. The method utilises a mathematical model that is not as transparent as a simple formula.

The problems with using the proposed method are outweighed by improvements in the calculation of capacity values. Compared to the current relevant level method, the incremental computational burden and administration costs of the proposed method are small. The proposed method uses basic statistical and probability-based concepts and provides a more reliable forecast than the current method. The proposed method is independent of the generation mix and can continue to calculate capacity values for intermittent generators as the WEM evolves.

The ERA's recommendation to change the relevant level method will be developed as a rule change proposal and a new market procedure specifying the details of the proposed method. This will help to address stakeholders' concerns on how they can estimate capacity values using the proposed method. Stakeholders can use the market procedure to replicate the relevant level method that AEMO will use for the capacity valuation of intermittent generators. The reliability analysis model underpinning the calculation will also be published on the market website to assist stakeholders in assessing capacity values. All inputs to the model are publicly available except for the estimated output of new or upgraded facilities. The ERA encourages AEMO to publish the aggregate estimated output of new or upgraded facilities on its website, to the extent the confidentiality of commercial information allows.

As part of the rule change proposal the ERA will recommend transitional arrangements to smooth any financial impacts on market participants. While any proposed rule change and procedure are in development, the current relevant level method will continue to apply.[3]

Consultation with stakeholders

The ERA published a draft report for consultation with stakeholders in December 2018. The draft report sought views on the proposal to replace the current relevant level method with the ERA's proposed method or any other information pertinent to the review. The ERA also sought views on how to determine a capacity value for intermittent generators that reflects their contribution to system reliability, given the variability of results observed in the sample model developed in the draft report.

The ERA considered this feedback as part of completing this final report and recommended ways:

- To enhance the method used to allocate an estimated intermittent generation fleet capacity value to individual generators.
- To assist market generators to better assess their capacity value using the proposed method.
- To enhance the transparency of the calculation process.

The ERA will address many of the matters raised about the implementation of the proposed method as part of the consultation process for developing the rule change proposal.

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[3] Refer to https://www.erawa.com.au/electricity/wholesale-electricity-market/methodology-reviews/review-of-method-used-to-assign-capacity-to-intermittent-generators-2018

1. Introduction

Every three years, the ERA reviews the method by which the Australian Energy Market Operator (AEMO) certifies capacity credits for intermittent generators such as wind and solar farms. In the Wholesale Electricity Market (WEM) Rules this is called the relevant level method.[4]

The Independent Market Operator conducted the previous reviews in 2011 and 2014, and commissioned Sapere Research Group to assist in reviewing the method.[5]

This is the ERA's first review of the relevant level method. As part of the review, the ERA is:

- examining how effectively the relevant level method meets the WEM objectives
- determining the values of the parameters used in the method.

The ERA may also consider any other matters that it considers relevant.

On 21 December 2018, the ERA published a draft report outlining the ERA's findings and recommendations and sought comments from interested parties. Given several shortcomings in the current relevant level method, the ERA has determined that the method is not effectively meeting the market objectives. The ERA has recommended replacing the relevant level method with an enhanced method.

The ERA received eight submissions from stakeholders in response to the draft report. Many stakeholder comments can be categorised into two main themes: suitability of the proposed method and implementation considerations. The ERA's response to the comments about the suitability of the method is provided in section 6.4. Response to comments about the transparency and implementation of the method is provided in section 6.7.

The ERA will submit a rule change proposal to the Rule Change Panel seeking amendments to the relevant level method. As part of developing that proposal, the ERA will provide more details about the implementation of the proposed method.

1.1 Changes from the draft report

Stakeholders raised several issues in response to the draft report. While these did not cause the ERA to revise its proposed changes to the calculation method, it did prompt changes to the method used to allocate an estimated intermittent generation fleet capacity value to individual generators, as explained in section 6.1 of this final report.

The enhanced allocation method accounts for general differences in the capacity availability of different intermittent generation technologies and divides the total capacity value of the fleet of intermittent generators into separate technology classes (currently solar, wind and biomass). This is done through the introduction of an additional step in the allocation method

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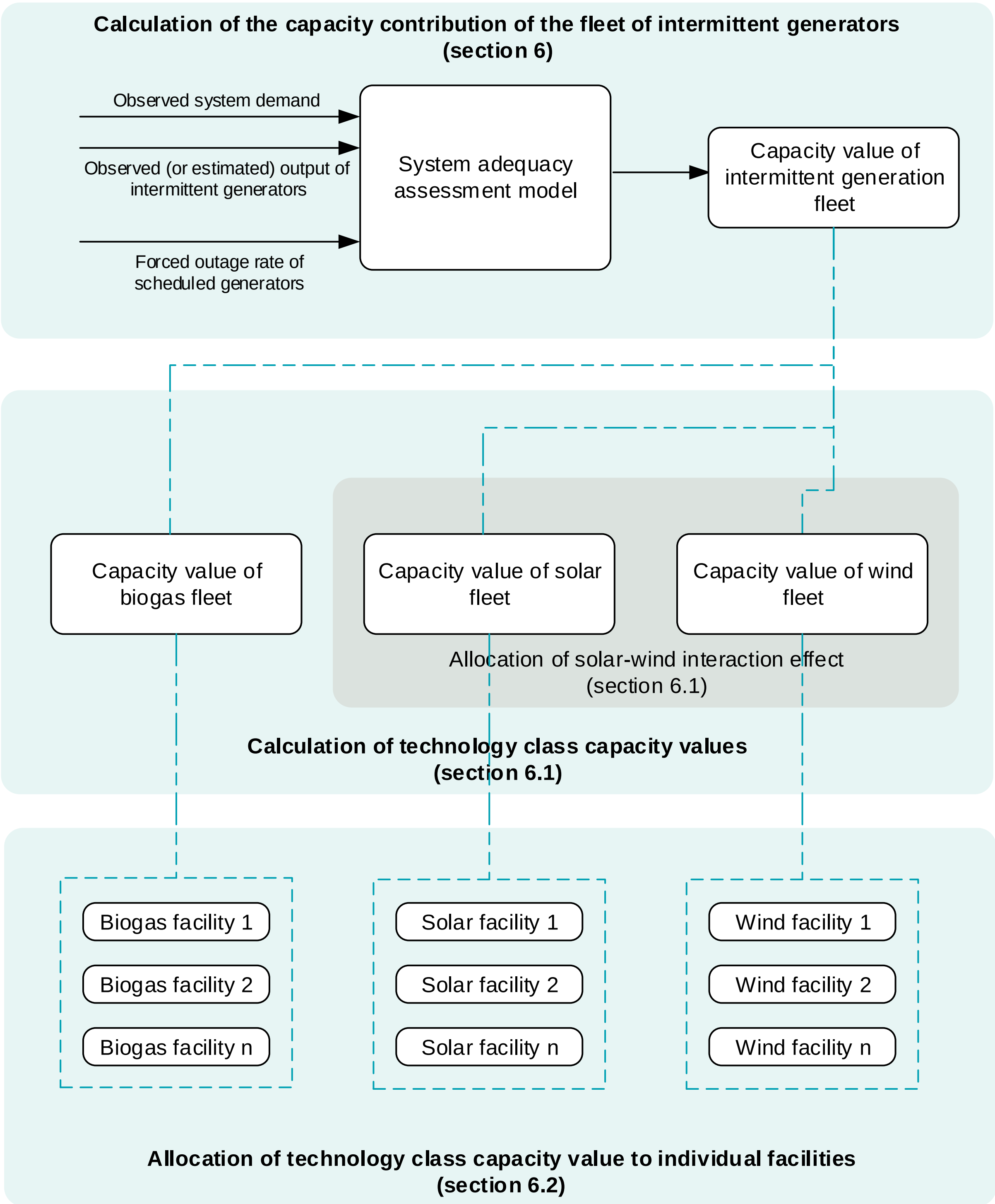
4 Clauses 4.11.3C and 4.11.2(b), and Appendix 9 of the Market Rules.

5 The next triennial review would have been completed by 1 April 2018. However, with transfer of the review obligation to the ERA, a transitional clause (1.17.5(d)) allows the ERA to complete its first review by 1 April 2019.

proposed in the draft report. The method is robust to changes in the system and as new technologies enter the system, new technology classes can be introduced.

Subsequently, the estimated capacity value of each technology class will be allocated to individual generators in that class based on the observed (or estimated) output of facilities during two sets of periods: peak demand and peak demand net of the output of all intermittent generators. This step is the same as the allocation method proposed in the draft report. This allocation process is depicted in Figure 1.

Figure 1. Proposed relevant level method



2. Background

The Wholesale Electricity Market (WEM) design includes a requirement to have sufficient capacity available to satisfy demand at all times, and to deal with supply emergencies. This requirement is captured in the reliability planning criterion[6] in the Market Rules. The Australian Energy Market Operator (AEMO) estimates the total amount of capacity required in the South West Interconnected System (SWIS) to satisfy the reliability criterion for a capacity year. This is the reserve capacity target.

Generation facilities and demand-side management providers (such as large industrial power users) that make capacity available to the system are eligible to receive capacity credits. A capacity credit is a notional unit of capacity expressed in megawatts that market participants can trade. AEMO assigns certified reserve capacity using the following methods specified in the Market Rules:

- Scheduled generators, such as coal or gas plants, receive capacity credits equal to their estimated sent-out capacity calculated at an air temperature of 41 degrees Celsius.[7]
- Intermittent generators, such as wind or solar farms, receive capacity credits based on the estimation method prescribed in the Market Rules – that is, the relevant level method.
- Demand-side resources receive capacity credits based on the amount by which they can voluntarily reduce their electricity consumption in response to a request by the system operator.[8]

For each capacity year, AEMO certifies and assigns capacity credits to eligible resources two years ahead of time. It then procures sufficient capacity credits from generation and demand-side resources to meet the reserve capacity target for that year.[9]

AEMO assigns an individual reserve capacity requirement to market customers based on their contributions to the system peak demand.[10] Electricity retailers and direct purchasers of energy fund the procurement of capacity in proportion to that contribution.

The total number of capacity credits allocated by AEMO determines the price of each credit. The greater the number of capacity credits allocated relative to the reserve capacity target, the lower the price. Capacity credit holders and buyers can also choose to trade capacity credits.

6 Clause 4.5.9 of the Market Rules.

7 Clause 4.11.1(a) of the Market Rules.

8 Clause 4.11.1(j) of the Market Rules.

9 The Market Rules apply different obligations on facilities depending on the technology type. Facilities must make their credited capacity available for dispatch by System Management. Except for intermittent generators, this obligation is in proportion to the number of capacity credits allocated to facilities. Facilities must comply with the outage planning and monitoring obligations and submit to tests of availability of capacity and inspections.

10 Appendix 5 of the Market Rules specifies the calculation of individual reserve capacity requirements.

The capacity procurement method prescribed in the Market Rules ensures that the total supply of capacity can reliably cover forecast system peak demand.[11] The procurement process runs two years in advance to ensure that capacity can be made available on time. The number of capacity credits assigned to individual resources, including the intermittent generators, determines the total supply of capacity credits in the system.

The current relevant level method to allocate capacity credits to intermittent generators uses a formula to calculate the capacity contribution of individual intermittent generators, expressed in megawatts, using an adjustment to their average output during a sample of trading intervals.

2.1 Terminology and definitions

The rest of this report uses the term 'system supply adequacy' to refer to an electricity system that has sufficient installed capacity available to meet demand at a set level of certainty. If the electricity system does not have sufficient capacity to cover demand, this would cause a loss of load. There would be an energy shortfall and the system operator would disconnect customer load to restore the balance between supply and demand.[12]

The overall probability that load will be lost in an electricity system is called the loss of load probability, or LOLP. The loss of load expectation, or LOLE, is the sum of loss of load probability over a planning period, usually one year. If a system has an oversupply of capacity, its loss of load expectation will be low.

In the SWIS, system adequacy is determined by the reliability planning criterion, which specifies there should be adequate available capacity in each capacity year to:

a. Meet the one in 10 year forecast peak demand plus a risk margin.

b. Limit expected energy shortfalls, or load unserved, to a certain amount of the annual energy consumption in the system.[13]

Part 'a' sets the requirement that the available capacity must meet peak demand to a given level of certainty. That is, forecast peak demand should be calculated to a probability level that the forecast would not be expected to be exceeded more than one year out of 10. These represent periods of very high demand, usually caused by very hot weather. To date, the SWIS has not experienced a one in 10 year forecast peak demand, as forecast by AEMO.[14]

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11 AEMO also procures capacity to cover a reserve margin and minimum frequency keeping capacity. The capacity procured should also be sufficient to limit the amount of energy shortfalls. However, to date the requirement to meet peak demand has been the most stringent criterion.

12 This is a simplified explanation. A system operator takes mitigation actions before disconnecting load. A well-functioning system should avoid using such mitigation actions regularly. Appendix 5 provides a detailed discussion of this point.

13 The expected energy shortfall is the expected unserved energy, which refers to a forecast of the aggregate amount in megawatt hours by which the demand for electricity exceeds the supply of electricity.

14 The highest demand in the SWIS in the past seven years was 4,004 MW, which occurred on 8 February 2016. In 2014 the Independent Market Operator forecasted that one in 10 year peak demand in the 2016/17 capacity year would be 4,149 MW and accordingly determined the reserve capacity target for the capacity year 2016/17. Peak demand in the SWIS is highly variable and uncertain. Forecasting of one in 10 year peak demand

The risk margin referred to in part 'a' of the reliability planning criterion is reserve capacity, over and above the forecast of peak demand, available to manage generation outages and still maintain normal frequency in the electricity system.[15]

Part 'b' in the reliability criterion specifies there should be adequate available capacity in each capacity year to limit any energy shortfall to 0.002 per cent of annual energy consumption. Based on 2017 calendar year consumption of approximately 18.13 terawatt hours, the energy shortfall limit in the SWIS is 36.3 megawatt hours.

Currently, there is an oversupply of capacity in the SWIS when compared to the reserve capacity target, and the loss of load expectation and the expected unserved energy are low. AEMO estimated that the level of excess capacity in the SWIS, above the reserve capacity target, is 6.7 per cent for the 2020/21 capacity year and will decrease to 2.4 per cent by 2027/28.[16] Over time, the level of installed capacity is expected to trend towards the reserve capacity target with the loss of load expectation close to the system adequacy target (or reliability planning criterion) specified in the Market Rules.

Historically, part 'a' of the planning criterion has set the reserve capacity target in the SWIS. In its recent reports, AEMO has stated that it does not expect the second part of the planning criterion to become dominant in the next 10 years.[17] This is because currently the amount of unserved energy in the SWIS is substantially smaller than the threshold specified in the Market Rules.

therefore faces significant uncertainty. Observed peak demand may not reflect the extreme demand that is embodied in the one in 10 year peak demand forecast.

15 The margin is calculated as equal to the greater of 7.6 per cent of forecast peak demand or the maximum capacity, measured at 41 degrees Celsius, of the largest generating unit.

16 AEMO, *Electricity statement of opportunities*, Perth, Western Australia, 2018, pp. 48–49, https://www.aemo.com.au/-/media/Files/Electricity/WEM/Planning_and_Forecasting/ESOO/2018/2018-WEM-ESOO-Report.pdf.

17 Ibid, p. 3.

3. Approach to the review

To understand the drivers of capacity valuation, the ERA explored different theoretical approaches, practical difficulties of data availability and calculation, and how other jurisdictions value capacity for intermittent generators.

The ERA then developed an assessment framework to guide the review. This incorporates the requirement in the Market Rules to assess how effectively the current relevant level method meets the market objectives. In its assessment, the ERA considered whether the current method results in the best assignment of capacity credits to intermittent generators based on available data, when compared to other methods.

If the estimates of capacity value for intermittent generators from the current relevant level method are inaccurate or biased, this limits how effectively the current method meets the WEM objectives. For example, if the capacity contribution of intermittent generators is overestimated, there may not be sufficient capacity available to meet the reliability target in the SWIS. This will undermine the reliability objective of the WEM.

Problems can arise from pursuing very accurate capacity valuations. The complexity of the valuation method may increase, the process can become less transparent, and the results can become more variable. When developing an assessment framework for the review, the ERA sought to balance the need for accurate, unbiased estimates of capacity value against practical challenges of data availability and transparency.

3.1 Capacity valuation in theory

When reviewing how capacity is valued, the approach most widely used is effective load carrying capability. This values the capacity of a generator as equivalent to the quantity of additional system load that can be served by adding the generator to the electricity system whilst maintaining the existing reliability risk of the system, commonly measured through loss of load expectation.

The calculation of effective load carrying capability is dependent upon the variation of, and the relationship between:

- the available capacity of the generator for which capacity is being valued
- system demand
- the available capacity of existing generators in the electricity system.

In practice, these are all variable and a mathematical probability-based model is typically used to estimate effective load carrying capability. Globally, jurisdictions with capacity markets tend to either model effective load carrying capability or use very simple techniques, such as sampling intermittent generator output over discrete time periods, to value capacity. Either way, effective load carrying capability tends to underpin capacity valuation.

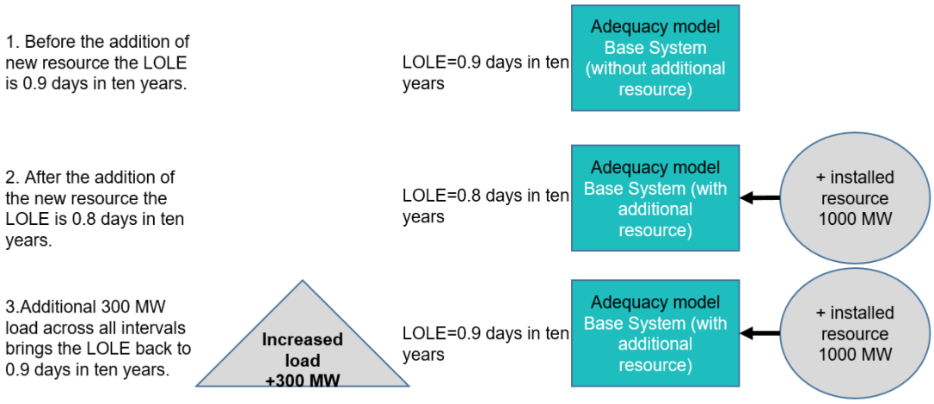
In a system comprised entirely of scheduled generators, the addition of another scheduled generator will reduce the loss of load expectation. As the available capacity of the scheduled generator has small variation, the amount of system load able to be serviced, or effective load carrying capability, will be similar, if not equivalent, to the installed capacity of the scheduled generator.[18]

In a system comprising both scheduled and intermittent generators, the available capacity is more variable and the output of some intermittent generators can be negatively correlated with demand as both are essentially weather dependent. Demand increases as air temperature rises and wind farm output can decrease. Calculating effective load carrying capability for intermittent generators is challenging, because their output is highly variable. To account for numerous combinations of capacity output and demand in the system, a probability-based model of system adequacy should be developed. Appendix 3 provides a detailed discussion of the calculation of effective load carrying capability.

Figure 2 illustrates the calculation of effective load carrying capability. The effective load carrying capability is calculated in three steps. Step one shows the base electricity system. The loss of load expectation is 0.9 days in 10 years. In step two, a 1,000 MW intermittent generator is added to the electricity system. Adding the new generator improves the loss of load expectation, which drops to 0.8 days in 10 years. In step three, additional megawatt hours are added to system demand until the loss of load expectation reverts to 0.9 days in 10 years. The additional megawatt hours added is the effective load carrying of the new generator.

For the hypothetical system in Figure 2, a 300 MW addition to load brings the loss of load expectation back to 0.9 days in 10 years. The 300 MW addition to load is the effective load carrying capability of the new resource. The capacity value of the additional intermittent generator is 30 per cent of its installed capacity.

Figure 2. General process for the calculation of effective load carrying capability[19]



Source: adapted from MISO, 2017. Planning Year 2018-2019 Wind Capacity Credit, p. 5, https://cdn.misoenergy.org/2018%20Wind%20Capacity%20Report97278.pdf

The effective load carrying capability of a generator is determined by its contribution to lowering the loss of load expectation of the electricity system.

18 When considered individually, the available capacity of a scheduled generator can vary, eg due to mechanical failures, and thus reduce its contribution to system reliability. However, scheduled generators as a fleet have very small variation in their output when compared to their average output. This is due the fact that their available capacity is largely independent of each other. The Law of Large Numbers dictates that the combined available capacity of every scheduled generator connected to the grid is far less variable than the output of an individual generator, when compared to average available capacity.

19 ELCC is effective load carrying capability; LOLE is loss of load expectation.

- A scheduled generator, which has most of its capacity available during the intervals when the loss of load probability in the system is the highest, would have a higher effective load carrying capability. Despite some variation due to forced outages, its effective load carrying capability or capacity value would be close to its installed capacity. Section A3.2, in Appendix 3 provides a detailed discussion of the capacity value of scheduled generators.
- In contrast, an intermittent generator would have variable output in the same intervals less than its installed capacity and so would have a lower effective load carrying capability than its installed capacity.

The loss of load probability in a trading interval is determined by the level of both demand and supply in the system. The surplus of capacity over demand is commonly referred to as 'system reserve'. The lower the system reserve in an interval, the greater the loss of load probability.

During a year, both demand and supply capacity are variable. The output of an intermittent generator is variable as it is dependent upon variable weather systems. System demand is becoming more variable and difficult to forecast with the installation of rooftop photovoltaic systems, behind-the-meter storage, more efficient appliances and consumers reducing their electricity usage. A higher penetration of intermittent generators in the system increases the variability of capacity generally. In addition, the output of most intermittent generators is correlated with demand and other intermittent generators as explained in section 3.2.4. Demand rises with air temperature and the output of some intermittent generators reduces at very hot temperatures.

Practically, a model is needed to manage this variability and correlation and calculate effective load carrying capability. There are some jurisdictions that model effective load carrying capability; these are discussed in section 3.2.

There have been attempts to simplify the calculation of effective load carrying capability. An example of this is the work by S. Zachary and C.J. Dent, who derived a relatively simple formula to approximate the effective load carrying capability of a generator. This is summarised in section 3.1.1. The formula used in the current relevant level method in the SWIS is an adaptation of the original Zachary and Dent equation.

3.1.1 Zachary and Dent approximation formula

In 2011, Zachary and Dent followed the general concept for calculating effective load carrying capability, as shown in Figure 2 and derived a relatively simple formula to approximate the effective load carrying capability of a supply resource or generator:[20]

Equation 1

$$ELCC = average\ output\ of\ resource - \lambda \times variance\ of\ the\ output\ of\ resource$$

The formula calculates the effective load carrying capability of an additional generator with an output that is:

- independent of demand

[20] S Zachary & CJ Dent, 'Probability theory of capacity value of additional generation', in *Proceedings of the Institution of Mechanical Engineers, Part O: Journal of Risk and Reliability*, vol. 226, 2011, 33–43, http://dro.dur.ac.uk/11699/.

- independent of the output of existing generators in the system.

The formula shows that effective load carrying capability is determined by the average and variance of the output of the resource and the parameter λ. The value of parameter λ is dependent on the probability distribution of the output of existing resources and demand and their correlation with each other.

Equation 1 can be used to calculate the effective load carrying capability of scheduled generators. The average and variance of the output of a scheduled generator during *all* trading intervals in a year or a couple of years, together with parameter λ, determine the capacity value of the generator.

Explanation

The average and variance of the output of the generator used in equation 1 are to be calculated during all trading intervals over a relatively long period, such as a year or several years.

This is in contrast to equation 2, as discussed further below, where average and variance are to be calculated during particular periods.

Except for some seasonal variation, the output of scheduled generators is mostly independent of the output of other generators in the system of demand. The variance of the output of these generators, as a group, is relatively small when compared to their average output. When installed in a summer peaking system, the effective load carrying capability of these generators is mostly determined by their average output during hot summer days.

Many intermittent generators have output that is negatively correlated with demand as both output and demand are weather-dependent to some extent. Equation 1 would not provide a reasonable estimate of the effective load carrying capability of intermittent generators.

Explanation

Assume a wind farm in South Australia is able to connect to the South West Interconnected System (SWIS). The output and variation of the South Australian wind farm would be mostly:

- uncorrelated with SWIS demand
- uncorrelated with the output of other intermittent generators in the SWIS.

The effective load carrying capability of the South Australian wind farm for the SWIS could be accurately estimated based on equation 1, using its historical output during *all* trading intervals in a year or several years.

However, equation 1 could not provide a reasonable estimate for the capacity value of the wind farm if it was installed in Western Australia. The output of the wind farm in that case would be correlated with demand and the output of other wind farms in the SWIS.

Zachary and Dent modified their formula such that it could provide a reasonable estimate under some conditions, despite the correlation between the output of an intermittent resource and demand:[21]

Equation 2

$ELCC =$	Average output of resource when the surplus of the capacity of existing resources in the system over demand is zero.	-	$\lambda \times$ Variance of the output of resource when the surplus of the capacity of existing resources in the system over demand is zero.

The modified approximation formula above is based on output average and variance during certain periods only. The modification of the approximation formula is briefly explained in the box below. A full technical discussion of this modification is presented in Appendix 4.

21 More accurately stated, they explained the formula would provide reasonable results if the variability of the output of the intermittent generator is small when compared that for the surplus of the capacity of existing generators in the system.

Explanation

Zachary and Dent noted that the addition of a small intermittent generator to an existing system does not shift the periods with the highest loss of load probability.

For example, before the addition of intermittent generators in the SWIS the periods with the greatest demand had the highest loss of load probability. The addition of a small intermittent generator could not shift the periods with the highest loss of load probability. Therefore, the loss of load expectation of the system after the addition of a small intermittent generation was mostly determined by the loss of load probability during the same high demand periods as before the addition of the small intermittent generator.

It can be shown mathematically that equation 1 can be used under such situations with a slight modification. The average and variance of the output of the small resource should be calculated during the periods when the surplus of capacity in the system, before the addition of the small resource, is zero.

For instance, equation 2 can be used to accurately estimate the capacity value of the wind farm discussed in the previous explanation box. For this calculation, first the periods with zero capacity surplus, before the addition of the wind farm, should be identified. Second, the average and variance of the output of the wind farm during the identified periods should be calculated.

The value of constant parameter λ should also be estimated based on the statistical characteristics of the surplus of the capacity of existing resources over demand.

The basis of calculation in the current relevant level method is the modified approximation formula above. The current method uses equation 2 and includes a constant parameter U in the formula to address a lack of data for the available capacity of intermittent generators during extremely high demand periods. Intervals with peak load for scheduled generation are used to indicate the periods with the lowest level of surplus capacity over demand.

The Market Rules use the term ‘relevant level’ to refer to the effective load carrying capability of intermittent generators.

The ERA examined the derivation of equation 2 in detail:

- The formula cannot provide reasonably accurate results with increased penetration of intermittent generators in the system. As explained above, equation 2 assumes that the additional generator added to the system is small.
- The formula does not provide any practical or theoretical advantage when compared to numerical models. The calculation of constant parameter λ requires a system adequacy assessment model similar to that used in numerical models. This is discussed in more detail in section 5.
- The value of the constant parameter λ is highly sensitive to its calculation assumptions, because of the small number of scheduled generators in the SWIS.

To the ERA’s knowledge, no other jurisdiction uses this formula for the capacity valuation of intermittent resources.

The current relevant level method also contains numerous inconsistencies, inaccuracies and ad-hoc adjustments when compared to the theory and assumptions underpinning the development of equation 2, as explained in section 4 and Appendix 4.

3.2 Capacity valuation in practice

In practice, the methods used to calculate capacity value in other jurisdictions range from detailed mathematical models used to calculate effective load carrying capability to simple rule of thumb time-based models that approximate effective load carrying capability.

There is no clear boundary between what constitutes a detailed mathematical model or a simplified approach. Instead, a continuum of methods has been developed to progressively reduce the complexity of detailed mathematical models. Such simplified approaches are referred to as approximation or simplified models.[22] This is illustrated in Figure 3.

The basis of estimation in the approximation and detailed mathematical methods is the same. For instance, the approximation formula developed by Zachary and Dent (discussed in section 3.1.1), and detailed models estimate the effective load carrying capability of resources using loss of load expectation of the system as the measure of reliability risk. They also use the same input data for estimation. If the assumptions underpinning the approximation methods hold, they provide the same, or very similar, results as detailed mathematical methods. The difference between approximation and detailed methods is only in the method used to find the effective load carrying capability.

When the assumptions underpinning an approximation method do not hold in all circumstances in the system, then that method will not give reliable estimates of effective load carrying capability. A detailed mathematical model, however, does not use the conditions or assumptions used in approximation methods. Although both detailed and approximation methods are subject to forecast errors, the use of a detailed mathematical model can improve the accuracy of estimation. This is because one source of estimation error, invalid assumptions, can be eliminated.

This report uses the term ‘numerical method’ to refer to mathematical methods that use numerical solution techniques, and ‘approximation methods’ for methods that use simplifying assumptions and conditions and simple formulas to calculate capacity values.[23]

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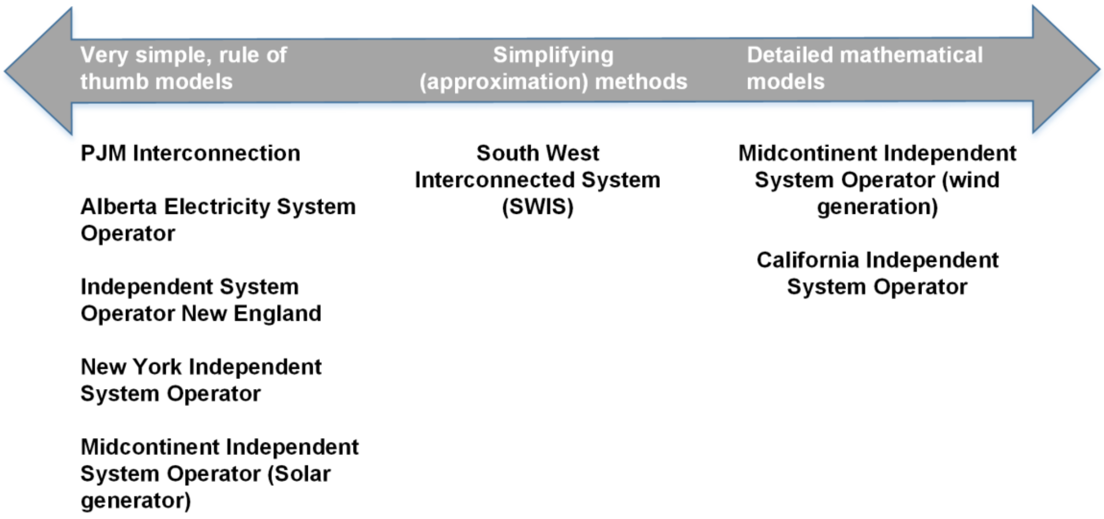
22 In its recommended practice for capacity valuation of wind resources, the International Energy Agency expert group states that the application of approximation methods can be justified by simplicity and lack of data. H Holttinen, *Expert group report on recommended practices: No. 16. wind integration studies*, Finland, 2013, p. 35, https://community.ieawind.org/task25/viewdocument/recommended-practices-16-wind-inte?CommunityKey=4aa82210-1b2e-43c5-b37b-1cdf11020dc8.

23 The main point of difference between an approximation method and numerical method is the mathematical solution approaches used to find the value of effective load carrying capability. Approximation methods such as that developed by Zachary and Dent use analytic solutions to derive a ‘closed-form’ solution for the effective load carrying capability. To solve for effective load carrying capability analytically, simplifying assumptions are necessary to make the solution tractable for an analytic approach. For instance, Zachary and Dent first solved the effective load carrying capability by assuming no statistical correlation between the output of intermittent generators and demand and derived a simple formula. They explained that when the penetration of intermittent generators in the system is low, only with a slight modification the same formula could be used to estimate the capacity value of intermittent generators. The correlation between the output of intermittent generators and demand is complex and cannot suitably be modelled via analytical models. When the penetration of intermittent generators is large, the formula developed by Zachary and Dent cannot not provide a reliable estimate of the capacity contribution of intermittent generators, because it does not account for output-demand correlations. Numerical models suitably account for the output-demand correlations.

Figure 3. Capacity valuation of intermittent generators in practice



3.2.1 Numerical models

The general process for the calculation of effective load carrying capability using a numerical model is similar to steps illustrated in Figure 2:

1. A system adequacy assessment model is developed to estimate the adequacy risk of the system under possible demand and supply capacity scenarios. The adequacy assessment model can be based on simple probability-based models or a complex simulation of several system elements of the generation and transmission network.

    a. A simple, commonly used method in valuing the capacity of intermittent generators is to develop a table of possible capacity outage amounts for scheduled generators, and their respective probabilities.

    b. Using the outage table, the time series of demand and the output of intermittent resources, the adequacy risk of the system can be measured. The choice of system adequacy risk measure should be consistent with the reliability planning criterion of the system.

2. The adequacy risk of the system is measured using the time series of demand and the system adequacy model developed in step 1. In this step, the output of intermittent resources is ignored to estimate the adequacy risk of the system without the contribution of intermittent resources.

3. The adequacy risk of system is measured including the contribution of the fleet of intermittent generators. The measure of adequacy risk in this step would show improvement in the reliability of the system because intermittent generators' output lowers the likelihood of energy shortfalls.

4. Fixed megawatt amounts are added iteratively to the time series of demand in step 3 until the system adequacy risks in step 3 becomes equal to the one in step 2. The megawatts added to the demand time series represents the effective load carrying capability of the fleet of intermittent generators.

When compared to other available methods, numerical models can provide the most comprehensive model of system adequacy risk and accurate capacity value results, subject to the:

- accuracy of the inputs used in the modelling
- degree to which the details of the elements of the system are incorporated.

However, these numerical models are not particularly transparent in identifying which factors drive the capacity value outcomes,[24] and depending on the type of system adequacy model developed, they can become complex. A high level of complexity may decrease stakeholder engagement in the capacity valuation process.[25]

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[24] CJ Dent, A Keane & JW Bialek, 'Simplified methods for renewable generation capacity credit calculation: A critical review', in *IEEE PES General Meeting, PES 2010*, 2010, 1–8.

[25] Detailed probabilistic models in this context commonly refer to numerical models or simulations of system adequacy. This report contrasts such models with simplified models for capacity valuation: these are commonly

Among system operators around the world, the ERA identified two that use numerical modelling approaches to estimate the capacity value of intermittent generators: the Mid-continent Independent System Operator, which services the Mid-West United States of America and parts of Canada; and the California Independent System Operator.[26]

After modelling the capacity value of the intermittent generation fleet, these system operators then use relatively simple methods to allocate the fleet capacity value to individual facilities.

3.2.2 Approximation methods

Approximation methods are used to calculate effective load carrying capability using simple formulas and a limited number of parameters. This provides transparency on which factors drive the calculation of capacity value for a facility. However, the basis of calculation for approximation and numerical models is the same. Approximation methods use simplifying assumptions to estimate capacity values using simple formulas.

The formula used in the WEM's current relevant level method is a simplified method for the calculation of effective load carrying capability. The current relevant level method is explained in more detail in section 4 and Appendix 4.

The ERA did review other examples of approximation methods.[27] These methods typically use probability-based models of output distributions rather than actual time series data and overlook the relationship between the output of intermittent generators and demand, or make implausible assumptions for the shape of the distribution of surplus capacity in the system. Many of these methods have limitations and are no longer used to estimate capacity value.

3.2.3 Time-based methods

The approaches to capacity valuation used in time-based methods can reflect the concept of effective load carrying capability. An example is the time-based methods used in many jurisdictions. They calculate the capacity factor[28] of wind and solar generation during hours when the system may have the highest risk of capacity shortage to meet demand.

The Pennsylvania-New Jersey-Maryland Interconnection (PJM) in the United States of America calculates the capacity value of wind and solar resources by estimating the average capacity factor of wind farms in certain peak demand periods in summer and winter over the

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models with closed-form expression for the calculation of capacity value. A closed-mathematical expression comprises finite number of simple operations on variables. For instance, the current relevant level method uses a closed-form expression for capacity value. It uses average and variance and constant factors to estimate the capacity value.

[26] Refer to California Public Utilities Commission, *Final Qualifying Capacity Methodology Manual Adopted 2017*, 2017, pp. 8–10, http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442455533 and Midcontinent Independent System Operator, 'Planning Year 2018-2019 Wind Capacity Credit', 2017, 1–11, https://www.midwestiso.org/Library/Repository/Study/LOLE/2018 Wind Capacity Report.pdf.

[27] These methods included Garver's graphical method and the Z-method. Refer to (i) L Garver, 'Effective Load Carrying Capability of Generating Units', in *IEEE Transactions on Power Apparatus and Systems*, vol. PAS-85, 1966, 910–919, and (ii) K Dragoon & V Dvortsov, 'Z-method for power system resource adequacy applications', in *IEEE Transactions on Power Systems*, vol. 21, 2006, 982–988.

[28] Capacity factor is the average power generated divided by the rated capacity.

past three years. The selection of periods representing peak demand periods can and does change over time:

- Until 2017, PJM used the time periods from 3:00pm to 6:00pm during the summer months for the calculation.
- Recently, PJM changed the specification of peak time periods for the calculation. It now calculates facility capacity factors between 6:00am to 9:00am during winter and between 6:00pm to 9:00pm during January and February, and 3:00pm to 8:00pm in June, July, and August.[29]

Similar time-based methods have been adopted by the New York Independent System Operator and Independent System Operator New England. Recently, the Alberta Electric System Operator proposed using time-based methods to calculate the capacity value of variable generation resources.

Some time-based methods were developed in conjunction with detailed and probability-based numerical models. An early study for the New York State Energy Research and Development Authority developed a time-based method for the capacity valuation of intermittent resources. The choice of time periods used to calculate capacity factors aligned the outcomes of the time-based method with the outcome from detailed numerical modelling.[30]

Time-based methods are used to enhance the visibility of the calculation process. However, the accuracy of time-based methods is sensitive both to the number of hours used and the selection of time periods.[31] As electricity systems evolve, and system demand and supply profiles change, the results of time-based methods and detailed numerical models can diverge. For example, as the penetration of rooftop solar photovoltaic increases, system peak demand shifts from early afternoon to early evening. Therefore, a time-based method may need frequent changes to align its results with those of a more accurate model, as has recently happened in the PJM.

However, time-based methods may provide reasonably accurate results under some conditions, such as when:

- There are very small quantities of intermittent resources installed in the system.[32]

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29 For the capacity value of wind farms, solar farms, and storage facilities like hydroelectric dams, flywheels, or batteries, the PJM calculates the capacity factor over the periods 6am to 9am during winter and 6pm to 9pm during January and February, and 3pm to 8pm in June, July, and August

30 GE Energy, *The effects of integrating wind power on transmission system planning, reliability, and operations, Report on Phase 2: System Performance Evaluation, Prepared for: The New York State Energy Research and Development Authority*, Albany, New York, 2005, p. 7.16, https://www.nyserda.ny.gov/-/media/Files/Publications/Research/Biomass-Solar-Wind/wind-integration-report.pdf.

31 Refer to M Milligan & B Parsons, 'A comparison and case study of capacity credit algorithms for wind power plants', in *Wind Engineering*, vol. 23, 1999, 159–166, http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.566.205&rep=rep1&type=pdf and SH Madaeni, R Sioshansi & P Denholm, 'Comparison of Capacity Value Methods for Photovoltaics in the Western United States', 2012, p. 18, http://www.osti.gov/servlets/purl/1046871/.

32 This can be explained using equation 2. At low penetration of intermittent resources, FD Munoz & AD Mills, 'Endogenous Assessment of the Capacity Value of Solar PV in Generation Investment Planning Studies', in *IEEE Transactions on Sustainable Energy*, vol. 6, 2015, 1574–1585.

- The intermittent resources are geographically dispersed in the system so that their output is not correlated.[33]

In practice these conditions seldom occur in an electricity system.

3.2.4 Practical limitations

Calculating effective load carrying capability requires three main variables, and estimates of the relationship between those variables. These variables are system demand, the output of other generators and the output of the intermittent generator for which the capacity value is being calculated.[34]

A capacity valuation method that best forecasts these three variables and their relationships, can provide the most accurate results for the capacity contribution of an intermittent generator.

In practice, historical data is typically used to estimate the relationship between the main three variables explained above. When calculating the capacity valuation of a wind resource, hourly demand and wind data are paired chronologically. Weather conditions underpin both the output of wind farms and demand. A hot and sunny but low wind day will increase demand, as air-conditioners are turned on in response to the heat but output from wind farms decreases. The chronological pairing of demand and output over a reasonably long period of time can capture the relationship between these two factors.

Using historical data can present two challenges for calculating capacity value. First, it may not suitably reflect future system conditions. In the SWIS, the level and variability of system demand can change quickly. Capacity contribution is only forecast for a short planning horizon of approximately two years. Therefore, assuming sufficient historical data is available, the forecast of capacity contribution may produce reasonably accurate results.

Second, historical data may not contain sufficient information about the available capacity of intermittent generators during extremely high demand periods in the SWIS. The capacity contribution of resources is mainly determined by the availability of their capacity during the periods when the surplus of capacity over demand is low; that is, the periods when the likelihood of the loss of load is the highest. It is highly likely that many periods with the lowest level of capacity surplus happen when demand in the SWIS is extremely high.

As required by the planning criterion of the Market Rules, AEMO procures sufficient capacity to ensure the system can cover a one in 10 year forecast demand. However, observed demand in the SWIS has never been very close to one in 10-year peak demand forecast and extremely high demand periods have occurred very rarely. It is not clear how intermittent

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33 This can be explained using equation 2. When the penetration of intermittent resources in the system is low and their output is independent, the capacity value of the fleet of intermittent resources will be mostly determined by their average output during the periods when the surplus of capacity in the system is zero. The variance of the sum of the output of the fleet of intermittent generators will be relatively small when compared to the average of the sum of their output.

34 System adequacy assessment studies commonly ignore the effect of transmission and distribution grid constraints: They assume that the grid is fully reliable. This has been a common assumption because the focus of system adequacy studies has been the adequacy of capacity resources over a relatively long period.

generators would contribute to the supply of electricity when demand is as high as one in 10-year peak demand forecast.

Historical time-series data may not provide sufficient information about the output of intermittent resources when the loss of load is the greatest. This lack of relevant data can influence the accuracy of capacity value forecasting. This is particularly important because there is evidence that some intermittent resources have reduced output during extremely hot days when system demand is extremely high.[35,36]

Assessing the forecasting accuracy of a method is also challenging. The forecasting accuracy of a capacity valuation method cannot be assessed unless the outcomes of the method are repeatedly compared to the actual contribution of intermittent generators. The comparison of the outcomes of the forecast method with the actual contribution of resources in a single year or for a few years cannot provide a reasonable indication of the accuracy of the method. The gap between model outcomes and actual data can simply be due to the variable nature of intermittent generation and its dependence on weather patterns.

These practical limitations create trade-offs for an accurate calculation of the capacity value of resources. These practical limitations are included in the assessment framework outlined below.

3.3 Assessment framework

The Market Rules specify that the ERA's review must assess how effectively the relevant level method meets the market objectives. These are to:

- promote the economically efficient, safe, secure and reliable supply of electricity
- encourage competition between generators and between retailers of electricity
- avoid discrimination against different technologies
- minimise the long-term cost of electricity to consumers
- encourage managing when and how much electricity is used.

Seeking to achieve a better method to estimate intermittent generation capacity values serves the objectives of the WEM. Flawed estimates can:

- increase the adequacy risk of the system:
  - If the capacity contribution for resources is overestimated, there may not be sufficient capacity available to meet the adequacy targets of the system.

35 For instance, refer to Sapere's analysis of the output of intermittent generators in the SWIS and their correlation with system demand and air temperature. Sapere Research Group, *2014 Relevant Level Methodology Review Final Report*, Sydney, Australia, 2014, pp. 48–52, https://www.erawa.com.au/cproot/14780/2/Sapere Final Report.pdf.

36 To address this limitation of data, studies have attempted to model the relationship between the output of intermittent generators and demand. For instance refer to S Zachary & C Dent, 'Estimation of Joint Distribution of Demand and Available Renewables for Generation Adequacy Assessment', 2014, 16, http://arxiv.org/abs/1412.1786. The ERA's review showed that attempts to address such forecasting challenges introduce their own complexities and uncertainties that may not necessarily result in more reliable forecasts for the capacity value of intermittent resources.

  - This will undermine the reliability objective of the WEM. The reserve capacity mechanism will not correctly incentivise investment in intermittent generation.
- result in economic inefficiency:
  - If the estimation method undervalues the contribution of resources, excessive amounts of capacity would be procured.
  - This will not effectively meet the market objective to promote economically efficient supply of electricity in the SWIS. The cost of excess capacity procured will outweigh the benefits of having excess capacity in the system.
- encourage the entry of one technology type over another:
  - This will undermine the market objectives of technology neutrality and efficiency.

There are trade-offs in aiming for the highest level of accuracy in capacity valuation.

The calculation of a generator's contribution to system adequacy should be based on plausible assumptions and correct calculations methods. Changes made to the capacity valuation method should be minimised to provide confidence to investors that the valuation method is stable. Adopting subjective capacity valuation methods or making ad-hoc adjustments to theoretically sound methods can result in inaccurate capacity valuations.

Where practical limitations, such as lack of data or calculation complexity, require simplifications or adjustments to a capacity valuation method, the agency undertaking the capacity valuation should clearly identify and explain any assumptions it makes. This increases the transparency of the calculation process.

Developing complex models to improve the accuracy of capacity valuation can be costly, may require many assumptions that add to the uncertainty of results, decrease transparency and may require large quantities of data. The outputs of such models are accurate only to the extent that inputs are accurate. However, in practice many of these input variables are either unavailable or uncertain.

The relevant level method should factor in the trade-off between accuracy and simplicity.

- The benefits of using a detailed numerical model to generate accurate capacity valuations should be assessed against the costs of adding complexity to the method.
- A complex and less transparent capacity valuation method may deter the entry of resources and increase market administration costs.

Even with fairly accurate inputs, a capacity valuation method may still produce variable results. By its very nature, the output of electricity from wind and solar farms varies with temperature and weather conditions. Electricity demand is also variable and can vary substantially due to changes in weather conditions and consumption patterns. Variability in capacity and demand, and weather conditions, means that the capacity value of intermittent generators could vary substantially from year to year. This in turn would create variability in the price of capacity credits and financial implications for all capacity resources in the system. Variability in capacity credit prices can increase financial risk for market participants and detract from providing functional capacity price signals for investments. Over the long term, the cost of this additional risk will ultimately be passed to consumers.

The relevant level method should suitably capture the variability of the capacity value of intermittent generators. However, it should not provide results that are overly sensitive to small changes in the system.

- Unnecessary variation in the total quantity and allocation of capacity credits can increase the cost of electricity supply to consumers.

The ERA considered the following questions when determining how effectively the current relevant level method was meeting the market objectives:

- Is the current method reasonably accurate?
- If the current method is reasonably accurate, is it possible to improve accuracy or simplicity, while maintaining its practicality?
- If the current method is not reasonably accurate, what methods could replace it?

It is also important that a capacity valuation method is robust to changes in the system, including the changes in demand and in supply technologies. The method may need to address the capacity valuation of storage technologies, given the expected uptake of these resources in the system. The final question was:

- To what extent is the current method, or any proposed alternative, suitable for determining the capacity valuation of storage?

4. Review of the current relevant level method

The current relevant level method is set out in Appendix 9 of the Market Rules. It is based on some adaptations to the original formula developed by Zachary and Dent as discussed in section 3.1.1, equation 2. The current method calculates the capacity contribution of individual intermittent generators, expressed in megawatts, using an adjustment to their average output during a sample of trading intervals:

Equation 3

$$Relevant\ Level\ (MW) = \ average\ output - \left(K + \frac{U}{average\ output}\right) \times variance\ of\ output$$

The product of the variance of the output of an intermittent generator and two constant parameters K and U determines the size of the adjustment to the average output of that resource. The higher the variation of the output of a resource and/or the values of the parameters K and U, which are the same for all intermittent generators, the lower the capacity contribution of that resource.

The ERA is responsible for estimating the value of parameters K and U for the next three years as part of its review of the effectiveness of the method.

The formula uses the average and variance of the output of intermittent generators during a sample of trading intervals in the previous five years. The sample comprises 12 trading intervals from separate days, for each year in the previous five years, where demand net of the sum of the output of all intermittent generators are the highest. The Market Rules refer to the periods in the sample as trading intervals with peak load for scheduled generation, or peak LSG.

Parameters K and U

Parameter K is equivalent to parameter λ as in the original approximation formula in equation 2. Zachary and Dent showed that the value of parameter K can be calculated using the below formula:

$$K = \frac{f'(0)}{2f(0)}$$

where $f'(0)$ denotes the first derivative of the probability density function of the surplus of existing capacity over demand estimated at zero megawatt surplus of capacity. The term $f(0)$ denotes the probability density function of the surplus of capacity over demand estimated at zero megawatt capacity surplus.

In simple terms, the value of K depends on the probability distribution of demand and available capacity of existing resources and their correlation. For instance, the outage rate of scheduled generators affects the value of parameter K. Outage rates determine the probability distribution of the available capacity of scheduled generators.

The value of parameter K can be positive or negative. It is mostly positive in practice, resulting in a downward adjustment to the average output of an intermittent generator.

Parameter U is not part of the original formula. It was added to address a lack of data about the performance of intermittent generators during extremely high demand periods.

Sapere assessed the value of parameter U by estimating the ratio:

- of the change in load for scheduled generation, on days with peak LSG when air temperature was above 38 degrees Celsius,
- to the mean output of the fleet of intermittent generators during peak LSG trading intervals.

Using the current relevant level method, Sapere calculated the capacity value of the fleet of intermittent resources by setting the value of parameter K to zero and parameter U to 0.635. It argued that the capacity value calculated for the fleet of intermittent generators was very close to the amount of change in LSG on the highest temperature day in 2014.[37]

The ERA examined how closely the formula in the current relevant level method, as in equation 3, and its application aligns with the original formula and its defining assumptions as developed by Zachary and Dent (2011). A detailed technical discussion of this comparison is presented in Appendix 4.

In summary, the original formula is generally consistent with capacity adequacy requirements in the SWIS. The original formula estimates the effective load carrying capability of resources based on loss of load expectation as the measure of system reliability risk. The use of loss of load expectation is consistent with the dominant planning criterion in the South West Interconnected System (SWIS). That is, the requirement to have sufficient supply capacity to meet one in 10-year peak demand forecast.

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37 Sapere Research Group, *2014 Relevant Level Methodology Review Final Report*, Sydney, Australia, 2014, p. 59, https://www.erawa.com.au/cproot/14780/2/Sapere Final Report.pdf.

If the formula used in the current relevant level method does not align with the defining assumptions of the original formula, then it is unlikely to produce reliable results for estimating capacity values.

Similarly, if any of the parameters used in the current level method have been incorrectly calculated then this can lead to over or under estimations of capacity values for intermittent generators.

As noted in the assessment framework, the more inaccurate or biased the estimated capacity value, the less likely the relevant level is to be meeting the market objectives.

The review identified that the current relevant level method is inconsistent with the main assumptions in the development of the original formula and contains numerous shortcomings. The current method estimates the capacity value of intermittent generators individually:

1. The method should therefore identify the periods with the lowest level of capacity surplus over demand before the addition of the intermittent generator for which the capacity value is being calculated. The method for the identification of such periods, being the highest peak LSG periods, does not exclude the output of the intermittent generator for which the capacity value is being calculated. If conducted correctly, peak LSG periods should be identified without the output of the intermittent generator for which capacity value is being calculated. This would result in multiple sets of peak LSG periods, as many as there are intermittent generators in the system. The method should also estimate the value of parameter K for the capacity valuation of each intermittent generator, separately. The value of parameter K depends on the surplus of the capacity of existing resources over demand, before the addition of the generator for which the capacity value is being calculated. Applied correctly, this would result in different values of K for the calculation of the capacity value of each intermittent generator. The current method, however, uses a single value for parameter K for the capacity valuation of all intermittent generators.

2. The calculation of the value of parameter K also contained implausible assumptions:

    a. It ignored the correlation between the output of intermittent generators and demand.

    b. It ignored variation in the output of scheduled generators.

    c. It contained an ad-hoc adjustment in the value of parameter K to address the problem explained in paragraph 1 above. This calculation, however, contained shortcomings. A detailed discussion of this problem is presented in section A4.4, Appendix 4.

3. The current relevant level method contains another ad-hoc adjustment, the parameter U, to address a lack of data:

    a. In the SWIS, periods of extremely high demand similar to one in 10 year peak demand, as forecasted by the Australian Energy Market Operator (AEMO), have seldom occurred. The performance of intermittent generators during such periods is uncertain. The calculation of capacity value uses observed demand and output of intermittent generators to estimate their capacity value. This observed data may not suitably reflect the contribution of intermittent resources during extremely high demand periods that are most likely to happen during hot summer days. Previous reviews of the relevant level method showed that many intermittent generators have reduced output during periods with high air temperature.

    b. The addition of parameter U to address the possible lack of data is inconsistent with the original formula and the concept of effective load carrying capability.

The assessment of the value of parameter U was based on the effect of intermittent generation fleet output on load for scheduled generation estimates during peak LSG days. The effective load carrying capability is not equal to change in the amount of load for scheduled generation.

c. The assessment of the value of parameter U was based on the contribution of the intermittent generation fleet on the single day with the highest air temperature during 2014. An assessment based on a single data point only contributes to significant uncertainty in the calculation of capacity values.

d. The method also applies a single value of parameter U to the capacity valuation of all intermittent generators. Intermittent generators have varying degrees of change in output with increase in air temperature, as also shown by Sapere's analysis.[38] The application of a single value of parameter U to all intermittent resources is not plausible.

e. The ERA's analysis shows that the sample of periods with high air temperature in the past five years is not small.[39] The periods with the highest level of demand are most likely to happen when air temperature is high. The output of intermittent generation during such periods can provide a reasonable indication of their output during extremely high system demand periods. In the SWIS, the highest demand periods in the past seven years occurred when air temperature was between 36.0 and 41.1 degrees Celsius, but not during the periods of maximum daily air temperature, which were typically higher. The increased penetration of rooftop solar photovoltaic has shifted periods of highest demand to later in the afternoon when air temperature tends to be lower. The addition of a parameter to adjust for the lack of data may not be required.

4. The treatment of new intermittent generators in the current relevant level method can reduce the accuracy of the capacity value calculation for existing intermittent generators. The calculation of capacity value for new facilities also contains shortcomings:

   a. The current method separates the calculation of peak LSG periods for existing and new facilities. This approach ignores the effect of the output of new generators on the capacity value of existing generators and can lead to overestimation of the capacity value of existing generators.

   b. When calculating the capacity value of a new facility, the method also ignores the effect of the output of other new facilities on the capacity value of the new facility for which the capacity value is being calculated.

The current relevant level method also estimates the capacity value of intermittent generation facilities individually. This can substantially underestimate the capacity contribution of the fleet of intermittent resources, as explained in the box below.

38 Sapere Research Group, *2014 Relevant Level Methodology Review Final Report*, Sydney, Australia, 2014, p. 51, https://www.erawa.com.au/cproot/14780/2/Sapere Final Report.pdf.

39 Between 1 April 2012 and 1 April 2017, the number of days with daily maximum air temperature above 36 and 38 degrees Celsius was 130 and 64, respectively.

Explanation

The calculation of capacity value for each intermittent generator individually has computational and technical disadvantages. The calculation of effective load carrying capability for the fleet of intermittent resources is a common practice for both technical and practical reasons.

For instance, the California Public Utilities Commission, the Midcontinent Independent System Operator, the Institute of Electrical and Electronic Engineers, and the International Energy Agency Expert Group on Wind Resource Assessment use similar capacity valuation methods to estimate the effective load carrying capability of a fleet of intermittent resources. Zachary and Dent (2012) also used their approximation formula (equation 2), to estimate the capacity value of the fleet of wind resources in the United Kingdom.[40]

While it is desirable to calculate individual effective load carrying capabilities for each facility, facility-specific calculations would be highly sensitive to the output profile assumed for facilities. It is not practical to develop the output profile (distribution) of individual facilities that is as accurate as would be required to yield improved results using the sum of the output of individual generators. It would be difficult to come to a consensus on the choice of output profiles and their correlation with demand for individual facilities.[41]

For instance, for the capacity valuation of individual generators as in the current method, the calculation of value of K would be challenging. The calculation should estimate the output profile (probability distribution) of the output of other intermittent generators in the system and their correlation with each other and demand.

The calculation of fleet capacity value has technical advantages. When considered individually, resources contribute to the reliability of the power system with diminishing returns. For instance, the first solar farm that contributes to the adequacy of the system produces the highest benefit in terms of contribution to the reliability of the system. Subsequent solar farms with the same performance as the first solar farm produce lower benefits for the reliability of the system. The need for capacity in the middle of the day has already been met by the first solar farm.

In practice, facilities contribute to the reliability of the system simultaneously and there is no order in their contribution. If the capacity value of each facility is measured individually, it would be treated as the last facility added to the system, and thus would receive the lowest capacity value as it would have the lowest reliability contribution. If resources contribution is measured individually, their total contribution would be substantially underestimated.[42]

The practical and more accurate solution is to calculate the effective load carrying capability of the group of intermittent resources. For instance, the calculation of the value of parameter K for this case is straightforward. The surplus of capacity before the addition of the fleet of intermittent generators is only determined by the surplus of scheduled generators over demand. This can be modelled with a reasonable level of accuracy. The periods with the lowest level of surplus of capacity over demand, before the addition of the fleet of intermittent generators, happen during the highest demand periods.

These problems cause inaccuracy in the calculation of capacity values for intermittent generators. The ERA has concluded that the current relevant level method is not effective to meet the market objectives.

The ERA investigated whether the shortcomings discussed above could be remedied. This could be done by using the approximation formula to estimate the capacity value of the fleet of intermittent resources, as opposed to individual facilities. This could have provided technical and computational advantages as discussed in the explanation box above.

The ERA, however, found that such enhancements to the current method cannot result in a reasonable estimate of the capacity value of the fleet of intermittent generation because:

- The calculation of the capacity value of the fleet of intermittent generators using the approximation formula can result in inaccuracies. This is because of the high penetration of intermittent resources in the SWIS. As discussed in section 3.1.1, the approximation formula can only provide a reasonable estimate of the capacity value of a resource if the magnitude and variability of the output of the additional resource is small when compared to the variability of the output of existing generators over demand. In the SWIS the variability of the output of the fleet of intermittent resources is high when compared the variability of the surplus of the capacity of scheduled generators over demand.
- The value of parameter K for the calculation of the capacity value of the fleet of intermittent generators would be very sensitive to its calculation assumptions. This is because of the relatively small number of scheduled generators installed in the SWIS.[43]

As discussed in section 3.1.1, the original approximation formula does not provide any computational or theoretical advantage when compared to numerical models.

Based on this assessment, alternative options for the relevant level method are explored in section 5.

4.1 Issues raised by stakeholders in previous reviews

The review also considered practical aspects of the current relevant level method. This included previous reviews of the method, what issues were identified at the time as important to stakeholders and how the method has changed over time. The ERA also reviewed the open rule change proposal by Collgar Wind Farm.[44]

To assist in its review, the ERA created a stakeholder working group and provided updates on progress to the Market Advisory Committee.

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40 S Zachary & CJ Dent, 'Probability theory of capacity value of additional generation', in *Proceedings of the Institution of Mechanical Engineers, Part O: Journal of Risk and Reliability*, vol. 226, 2011, 33–43 (pp. 15–22), http://dro.dur.ac.uk/11699/.

41 California Public Utilites Commission, *Effective Load Carrying Capacity and Qualifying Capacity Calculation Methodology for Wind and Solar Resources*, 2014, http://www.cpuc.ca.gov/NR/rdonlyres/D05609D5-DE35-4BEE-8C9A-B1170D6E3EFD/0/R1110023ELCCandQCMethodologyforWindandSolar.pdf.

42 California Public Utilites Commission, *Effective Load Carrying Capacity and Qualifying Capacity Calculation Methodology for Wind and Solar Resources*, 2014, pp. 4–5, http://www.cpuc.ca.gov/NR/rdonlyres/D05609D5-DE35-4BEE-8C9A-B1170D6E3EFD/0/R1110023ELCCandQCMethodologyforWindandSolar.pdf.

43 The probability density function of the available capacity of scheduled generators in the SWIS is not smooth. The calculation of the slope of the function is very sensitive to the assumed curve fitted to estimate the slope.

44 Collgar Wind Farm, *Rule Change Proposal: Capacity Credit Allocation Methodology for Intermittent Generators (RC_2018_03)*, Perth, Western Australia, 2018, https://www.erawa.com.au/cproot/18754/2/RC_2018_03—Rule Change Notice and proposal.pdf.

Two questions about the relevant level method have persisted since market commencement. These are:

- When is capacity most valuable, during peak demand periods or lowest capacity surplus periods?
- Should capacity certification consider economic factors such as payments for capacity credits, capacity refund mechanism and obligations, the reserve capacity price, and financial implications of the allocation of capacity credits? For example, Collgar Wind Farm argued that the current relevant level method is not consistent with the funding mechanism for capacity credits, which is based on the contribution of market customers to the peak demand periods in the system.

The next two sections expand on these issues and outline if or how the ERA has taken them into account in its review and recommendations.

4.1.1 When is capacity most valuable?

The SWIS is a summer peaking system. The highest system demand periods are likely to occur during hot summer days. When demand rises, the excess capacity in the system reduces and the loss of load expectation increases. The calculation of capacity value for scheduled generators reflects this. They receive capacity credits equal to their sent-out capacity at an air temperature of 41 degrees Celsius. It is highly likely that demand in the SWIS on hot days is high, whereas the available capacity of scheduled generators decreases with increases in air temperature.

The capacity value for intermittent generators is calculated when system load, net of all intermittent generators' output, is highest. AEMO determines the top 12 net load intervals in each of the past five years. Each intermittent generator's output average and variance over these intervals is used in the relevant level method calculation to determine its capacity credits. The highest net load intervals selected are referred to as peak load for scheduled generation (LSG) periods, or peak LSG periods.

Periods with the highest LSG are periods with the lowest level of the surplus of available capacity, comprising scheduled and intermittent generation capacity, over demand. By assuming that the variation of available scheduled generation capacity is negligible when compared to the variation of demand net of the output of intermittent generators, the periods with the lowest surplus of the capacity of all supply resources over demand occur when the load for scheduled generation is maximised.

Explanation

Over a trading interval the surplus of the capacity of existing scheduled generators, X, and existing intermittent resources, I', over demand, D, before the addition of an individual resource with capacity, I, is determined by three factors:

$$M = X + I' - D$$

where M denotes the surplus of existing capacity, being $X + I'$, over demand. By assuming that the available capacity of conventional generators is constant or has small variation,[45] the surplus of capacity over demand, M, is the lowest when the term $I' - D$ is the lowest, or alternatively when $D - I'$ is the greatest. With a slight variation, the term $D - I'$ is the load for scheduled generators in the current relevant level method.

The current method estimates load for scheduled generation (LSG) by deducting the output of all intermittent generators, including the one for which the effective load carrying capability is being calculated, from demand:

$$LSG = D-(I' + I)$$

This formula shows that the current definition of load for scheduled generation is not accurate in calculating the lowest level of the surplus of existing capacity over demand, when estimating the capacity value of individual intermittent generators. The load for scheduled generation calculation should exclude the output of the generator for which the effective load carrying capability is being calculated.

There is an open rule change proposal, from Collgar Wind Farm, challenging the use of load for scheduled generation for calculating capacity credits for intermittent generators.[46] Collgar Wind Farm argues that the use of peak LSG in the current relevant level method does not reflect the requirement for intermittent generators to make their capacity available during system peak periods.

Collgar proposes that the current relevant level method should be changed to calculate the capacity contribution of intermittent generators based on their contribution during the highest demand periods in the system. Collgar also argues that the current relevant level method is inconsistent with the calculation of individual reserve capacity requirements, which determines how retailers pay for capacity credits.[47] Collgar's proposal states that scheduled generators receive capacity credits based on their available capacity "during peak [demand] conditions…, and this provides a good approximation to their ability to provide capacity during IRCR [individual reserve capacity requirement] intervals".

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45 The variation of the capacity of scheduled generators in practice is substantially smaller than that for demand net of the output of intermittent generators.

46 Collgar Wind Farm, *Rule Change Proposal: Capacity Credit Allocation Methodology for Intermittent Generators (RC_2018_03)*, Perth, Western Australia, 2018, https://www.erawa.com.au/cproot/18754/2/RC_2018_03—Rule Change Notice and proposal.pdf.

47 AEMO calculates the individual reserve capacity requirements based on market customer's load during the three peak intervals on each of the four peak load days in the hot season.

The approximation formula used in the current relevant level method specifies that the average and variance of the output of the resource should be estimated during the periods the surplus of capacity of existing resources over demand is zero. The current relevant level method identifies the periods with the lowest level of surplus through the calculation of load for scheduled generation. A selection of intervals based on peak LSG and peak demand would provide the same results if the variation in output from the intermittent generators is small when compared to the variation of the surplus of the capacity of scheduled generators over demand. This is more likely to happen at low penetrations of intermittent generation in the system. The periods with the lowest level of surplus of capacity over demand will be determined by the highest demand periods, rather than those with reduced output of intermittent generators.

Explanation

As shown in the previous explanation box, the periods with the highest load for scheduled generation, $D - I'$, would have the lowest level of capacity surplus. The load for scheduled generation increases by two factors:

- Increase in demand, D: at a constant level of the output of intermittent generators, I', the periods with the highest level of demand have the lowest level of capacity surplus.
- Decrease in the output of intermittent generators, I': at a constant level of demand, the periods with the lowest level of the output of intermittent generators have the lowest level of capacity surplus.
- If the variation of the output of intermittent generators is small, the periods with the highest level of demand would have the highest level of load for scheduled generation and therefore the lowest level of capacity surplus. This is the case at low penetrations of intermittent generators.
- With increased penetration of intermittent generators in the system, the periods with the lowest level of capacity surplus may happen when demand is high, but not necessarily the highest, and the output of intermittent generation is low.

The ERA used historical data to test whether periods of highest demand are also periods with the lowest level of capacity surplus. The test used historical data from the beginning of the trading day on 1 April 2016 to the end of trading day on 31 March 2017 to compare which intervals would be selected using the two methods.[48] Table 1 presents the results of the analysis. Common intervals across the two methods are shaded.

48 The selection of intervals from March to April is consistent with the current relevant level method.

Table 1. Comparison of methods for identification of capacity valuation intervals, 2016/17

Intervals	Peak LSG (existing facilities)	Peak demand
1	08/06/2016 18:00	21/12/2016 17:00
2	12/07/2016 18:30	1/03/2017 17:00
3	21/12/2016 17:00	4/01/2017 16:30
4	03/01/2017 17:30	7/06/2016 18:00
5	04/01/2017 16:30	3/03/2017 16:30
6	26/01/2017 16:30*	12/07/2016 18:30
7	28/01/2017 17:00*	3/01/2017 17:30
8	13/02/2017 17:30*	4/07/2016 18:00
9	19/02/2017 17:30	8/08/2016 18:00
10	25/02/2017 17:30	19/02/2017 17:30
11	01/03/2017 17:00	13/07/2016 18:30
12	03/03/2017 16:30	8/06/2016 18:00
Average of the sum of the output of all intermittent generators fully operational during the entire 2016/17 (MW)	96.1	154.5
Variance of the sum of the output of all intermittent generators fully operational during the entire 2016/17 (MW^2)	3122.3	2605.8

* The three peak LSG periods on 26/01/2017, 28/01/2017, and 13/02/2017 were the 14th, 15th, and 19th largest demand periods from separate days in 2016/17.

Source: the ERA's analysis based on AEMO's data

The shaded cells in the table show there is a large degree of overlap between the different sampling methods. This suggests that periods with the highest level of demand still determine many of the periods with the lowest level of surplus of capacity over demand. However, there are enough differences between each method to yield substantially different average capacity outputs for the fleet of intermittent generators.

Intervals identified based on the peak LSG and peak demand methods also identified intervals from winter and spring, suggesting that intervals with a high loss of load probability also occur outside the hot season when demand may be lower than during the summer peak.

In practice, at any point in time both demand and capacity are variable and therefore unpredictable. Over time, the variability and correlation of demand and available capacity can change with technological innovation and customer behaviour. Therefore, the method used to identify periods with the greatest loss of load probability should consider the characteristics of demand and the output from scheduled and intermittent generators and their correlation. This can be illustrated by use of an example.

Assume a summer peaking electricity system where demand is served by scheduled generators, with relatively stable capacity and minimal rooftop photovoltaics. Although peaky, demand is fairly predictable and linked to air temperature. The output from each scheduled generator is independent of other generators and demand. The output from scheduled generators can be estimated at different air temperatures using de-rating curves. In this electricity system, the greatest risk of losing load would occur in peak operational[49] demand periods.

Now assume the same summer peaking electricity system but with considerable rooftop photovoltaic and a significant penetration of other intermittent generators, such as large-scale

[49] Operational demand refers to consumers demand net of behind-the-meter supply sources, such as rooftop solar that is served by large scale generators on the grid.

wind and solar farms. Demand becomes more variable as rooftop photovoltaic reduces system load, mostly during the middle of the day. Intermittent generators, by their nature, have variable, weather-dependent output. A higher penetration of intermittent generation in the system results in greater variation in total capacity output. In addition, the output from intermittent generators is likely to be negatively correlated with demand as both are weather-dependent. During hot summer days, demand for electricity increases but the output of wind farms tends to decrease, as very hot sunny days are generally not very windy. In this electricity system, with greater variability in demand and capacity, it is feasible that the greatest risk of losing customer load could occur outside of peak operational demand periods.

Stakeholder comments

In response to the draft report, one submission recommended to extend the comparison of peak demand and peak LSG periods to the prior year from the beginning of trading day on 1 April 2015 to the end of trading day on 31 March 2016. The reason for this recommendation was that the specified period contained the highest demand in the SWIS to date which was closest to a one in 10-year peak demand in recent times.[50]

The comparison of peak demand and peak LSG periods as shown in Table 1 is provided to explain the difference between the alternative methods to identify periods with the lowest level of capacity surplus. The alignment between peak demand and peak LSG periods can vary between years, particularly with increased penetration of intermittent resources.

This comparison provided more information about Collgar Wind Farm proposal to use peak demand intervals as the basis for the calculation of average and variance of the output of intermittent generators used in the current relevant level method.

Given the shortcomings of the current method discussed in section 4, a further comparison of trading intervals with peak demand or peak LSG is not necessary. The ERA's proposed method detailed in section 6 does not use average or variance of the output of resources during peak demand or peak LSG periods as the basis of capacity valuation.

4.1.2 Should capacity certification consider economic factors?

During the ERA's review, some stakeholders[51] have questioned whether the capacity valuation method for intermittent resources should factor in some economic aspects of the provision of capacity through the reserve capacity mechanism or investment in generation assets generally. These include investment costs, cash flows for selling capacity credits and funding of capacity credits.

50 Noel Schubert, 18 February 2019, Submission to Relevant level method review 2018: Capacity valuation for intermittent generators, draft report, p. 2, (online).

51 For example, refer to Rule Change Panel, *Market Advisory Meeting Minutes, 13 June 2018*, 2018, p. 8, https://www.erawa.com.au/cproot/19374/2/MAC Meeting 2018_06_13 - Minutes.pdf.

The reserve capacity mechanism applies different requirements to intermittent generators when compared to scheduled generators, as follows:

- Capacity credits are allocated to intermittent generators, scheduled generators and demand-side programs using different methods.[52] Scheduled generators receive capacity credits based on their sent-out capacity at air temperature of 41 degrees Celsius. Demand-side programs receive credits based on the amount by which the demand from load or aggregated loads can be curtailed.
- The reserve capacity testing requirements for intermittent generators are less onerous than for scheduled generators.[53]
- Intermittent generators are also not subject to capacity credit refunds, as is the case for scheduled generators when they fail to meet their capacity availability obligations.[54]

Stakeholders also observed that some intermittent resources may no longer need cash flows from the sale of capacity credits to make their investment economically feasible. The capital expenditure for these resources has decreased due to economy of learning. Some stakeholders also argued that the method for funding capacity credits procurement is based on peak demand consumption, whereas the current relevant level method is not based on contribution during peak demand periods, and therefore is not aligned with the funding mechanism.

Stakeholders' comments

SkyFarming raised concerns about the views of some market participants that the investment costs for wind and solar generators are decreasing so they do not need capacity credits. It explained that as the share of solar and wind generation in the system increased, balancing prices decreased because those generators had almost zero running costs. It also explained that with expected decrease in the price of large-scale green certificates, solar and wind generators' revenue from the sale of those certificates would decrease. Consequently, the revenue from the sale of capacity credits for these generators remained important.

As explained below, the basis for the estimation of capacity contribution of resources is their contribution to the reliability planning criterion of the Market Rules. The economic aspects of capacity procurement, such as payments for capacity credits and possible penalties for underperformance, are outside the scope of the review of the relevant level method and its purpose.

Whether the proceeds of the sale of capacity credits are important to intermittent generators does not influence the estimation of capacity values.

The relevant level method estimates the physical contribution, in megawatts of capacity, provided by intermittent generators to the adequacy of the system. The guiding principle for the calculation of capacity values is the planning criterion in the Market Rules. The reliability planning criterion stipulates that AEMO should procure sufficient supply capacity to ensure

52 Clause 4.11 of the Market Rules.

53 Clause 4.25 of the Market Rules.

54 Clause 4.26.1 (a) and (b) of the Market Rules.

that it can meet demand reliably. The reliability planning criterion does not specify any economic value or measure that AEMO must consider when procuring capacity.[55] The method for the calculation of capacity values does not reflect any explicit cost-benefit analysis or value of lost load calculation, nor does it consider least cost operation of the power system.

The ERA is aware of the economic implications of changes to the relevant level method to intermittent generators and also to scheduled generators.

If a change to the relevant level method certifies a greater number of capacity credits to intermittent generators, then capacity revenue increases, and vice versa. When the Independent Market Operator introduced the current relevant level method in 2011, the amount of capacity credits allocated to intermittent generators reduced by approximately 30 per cent. The new method was phased in over three years to smooth the financial implications for intermittent generators. A change to the current relevant level method may carry implications for capacity revenue and for future investment incentives. The implementation arrangements for any new method should manage such implications.

A change to the relevant level method that results in a greater supply of capacity credits from intermittent resources can cause a lower price for reserve capacity. This would affect capacity revenues for other generators in the market.

The economic aspects of capacity procurement are mostly policy-driven. The Minister for Energy has recently consulted on the pricing of capacity and the investments signals this provides. Proposed changes to capacity pricing are being included as part of a broader reform program in the WEM.

These wider economic considerations are outside of the scope of this review into a capacity allocation method. The only exception is smoothing any financial effect of changing the method over a transition period.

Other changes to the reserve capacity mechanism are proposed as part of the WEM reform programme, these are considered in section 5.5.

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55 The ERA is aware that some other jurisdictions procure different capacity products as part of their capacity market design. For instance, the Pennsylvania, New Jersey, Maryland Interconnection (PJM) market procures two capacity product types based on operation flexibility through its capacity market auctions (refer to section A2.3, Appendix 2). The calculation of contribution of resources to different capacity product types would require differing capacity valuation measures and methods. However, the reserve capacity mechanism in the SWIS does not procure different generation capacity types.

5. Alternative relevant level methods

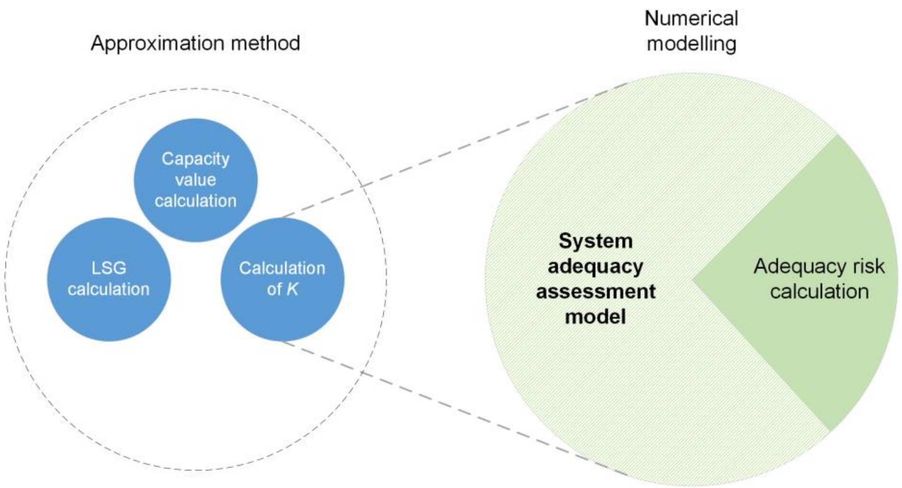
This review has found the current relevant level, described in section 4, is not fully meeting the market objectives. Consequently, the ERA has explored alternative options, to determine whether they could deliver more accurate estimates of the capacity value of intermittent generators. Four options are explored:

- Leave the current method unchanged for this review (option 1)
- Improve the current method (option 2)
- Develop a numerical model to determine capacity value (option 3)
- Move to a simple time-based method (option 4)

The ERA concluded that only a method based on numerical modelling (option 3) is likely to provide capacity values that best reflect the capacity contribution of intermittent generators to the reliability of the system. The adoption of a time-based method or an approximation similar to that currently used in the relevant level method will not be suitable. The inaccuracy of such alternatives is expected to increase as the penetration of intermittent resources in the SWIS increases.

Neither the current relevant level method, nor its enhanced version (option 2) provide significant transparency or computational advantage, when compared to numerical modelling. The calculation of parameter K would require a similar model to that developed for a numerical model, as illustrated in Figure 4. The development of a system adequacy assessment model is the most computationally intensive part of a numerical model. The same adequacy assessment model will also be required to calculate parameter K for use in the approximation method. Therefore, the incremental computation cost of a numerical model is negligible, when compared to the current approximation method.

Figure 4. Use of system adequacy models in the calculation of parameter K



The ERA recommends use of a numerical model. It will provide more reasonable forecast of capacity values for intermittent generators and balances this with:

- reasonable implementation costs

- stable outcomes that are not overly sensitive to small changes in the system[56]
- flexibility to withstand future changes in the Wholesale Electricity Market (WEM), such as the introduction of storage
- transparency.

The ERA's relevant level review is taking place at the beginning of a major program of reform in the WEM, which includes other changes to the capacity market. These changes have not influenced the ERA's recommendation to change the relevant level method. However, the ERA did consider these related activities as part of its recommendations for implementing the revised relevant level method, as explained in section 5.5.

5.1 Leave the current method unchanged for this review (option 1)

The current relevant level method could be retained without any changes until:

- the ERA next reviews the method in three years' time
- after the current market reform program has been completed.

This option represents the least administrative cost because AEMO has already automated the current relevant level method.

This option is not preferred as:

- The current relevant level method does not provide reasonable forecasts for the capacity value of intermittent generators and contains calculation shortcomings.
- When compared to the results of the sample numerical model discussed in section 6.3, the current relevant level method assigns relatively low capacity credits to intermittent generators.

5.2 Improve the current method (option 2)

The current relevant level method can be improved to ensure consistency with the underlying capacity valuation formula. It is impractical to calculate the capacity value of intermittent resources individually. However, it is possible and easier to estimate the capacity value of the fleet of intermittent resources:

- The calculation of the capacity value of the fleet, as a group, would require a single set of trading intervals with the lowest level of capacity surplus over demand.
- Periods with the greatest demand would have the lowest level of surplus of capacity.[57]
  - Before the addition of the fleet of intermittent generators, the surplus of the capacity of scheduled generators over demand is the lowest when demand is the greatest.

56 As discussed in section 3.3, highly variable results can result in higher costs to generators that will be passed to consumers over long term.

57 This is similar to using zero for the output of intermittent generators in the calculation of LSG. Before the addition of the fleet of intermittent resources their output in the system is zero.

  - To calculate capacity value, the average and variance of the output of the fleet of intermittent generators should be estimated during peak demand periods during the hot season. The available capacity of scheduled generators has some variation over a year, where they have a smaller capacity available during the hot season when the air temperature is higher.

- The calculation of the parameter K for the fleet of intermittent generators is feasible. The value of K can be determined by the statistical characteristics of the surplus capacity of scheduled generators over demand.

Improving the current relevant level method would require:

- Recalculating the values of parameter K – to do this a capacity outage probability table, similar to that required for the numerical model discussed in option 3, would need to be developed.
- Developing an allocation method to assign the capacity value of the fleet to individual resources. In other jurisdictions, this is based on some approximation; for example, individual intermittent generators would receive a proportion of the fleet capacity value based on their individual output during peak demand periods.

This option is not preferred as:

- It does not appear to have any substantial computational advantage when compared to numerical modelling, given a capacity output probability table is required for both.
- The size and variation of the output of the intermittent fleet is relatively large when compared to the size and variation in the surplus capacity of scheduled generators over demand. As discussed in Appendix 4, this can lead to calculation errors.
- The value of parameter K is highly sensitive to assumptions made in the calculation. Applying different assumptions can result in materially different capacity values for the intermittent generation fleet.[58]

5.3 Develop a numerical model to determine capacity value (option 3)

A probability-based numerical model similar to that recommended by the International Energy Agency Expert Group on Wind Integration Studies and the Institute of Electrical and Electronics Engineers could be used to estimate the capacity value of the fleet of intermittent resources.[59,60]

58 The value of K is determined by the slope of the loss of load expectation function. This function for a small system such as SWIS is not smooth and can have discontinuities. The value of K would be highly variable if it is directly derived from the function. Alternatively a curve can be fit over the loss of load expectation function. Depending on the form of the fitted curve, the value of K would vary significantly.

59 H Holttinen, *Expert group report on recommended practices: No. 16. wind integration studies*, Finland, 2013, pp. 35–36, https://community.ieawind.org/task25/viewdocument/recommended-practices-16-wind-inte?CommunityKey=4aa82210-1b2e-43c5-b37b-1cdf11020dc8.

60 Zachary and Dent also used a probabilistic model similar to the one preferred by IEA and IEEE to assess the accuracy of their proposed approximation formula in the capacity valuation of the fleet of wind resources in the United Kingdom.

The Californian Independent System Operator and the Midcontinent Independent System Operator use a similar method for the capacity valuation of intermittent resources. Appendix 5 provides a detailed discussion of a numerical model.

An allocation method, similar to that used for option 2, would be required to assign the capacity value of the fleet to individual resources.

The ERA proposes to use this option:

- It can provide the best forecast of capacity values among the options. The method does not require using assumptions similar to that used for the approximation methods.
- Although a numerical method appears more complex than the current relevant level method, developing such a model:
  - Need not substantially increase the administration costs of the relevant level method.
  - Would increase the transparency of the relevant level method. A simple numerical model is based on basic probabilistic and mathematical concepts. In comparison, the development of approximation methods, similar to that developed by Zachary and Dent, is based on complex mathematical and statistical concepts and restricting assumptions.
  - Is based on conventional system adequacy assessment models, which are common in many jurisdictions.

5.4 Move to a simple time-based method (option 4)

Similar to the practice in some North American jurisdictions, the capacity value of individual intermittent generators can be calculated using their average output during some specified periods. The method calculates the capacity value of an individual intermittent generator in two steps:

1. The method identifies the trading intervals with the highest probability of loss of load.

2. The average output of an intermittent generator during the periods identified in step 1 determines the capacity value of the generator.

A time-based method can provide stable results and is simple to implement and transparent. However, it is not expected to provide reasonably accurate results for the capacity value of intermittent resources in the SWIS. Time-based methods estimate the capacity value of intermittent resources by their average output during some certain periods when the loss of load probability is the greatest. With increased penetration of intermittent generation the periods with the highest loss of load probability shift across day hours and seasons. The method should periodically review and set those periods. The method also ignores the effect of the variability of the output of intermittent generators on their capacity value. These problems were discussed in detail in section 3.2.3.

As explained in section 3.2, reviewing the practice in other jurisdictions showed that the adoption of time-based methods has been in conjunction with probability-based numerical models. The specific time periods selected for time-based methods were amended until the capacity value outcomes determined from these periods approximated the results of a probability-based model.

This option is not preferred as:

- It does not appear to have any substantial computational advantage when compared to numerical modelling option, given a probability-based model is required for both.

5.5 Other considerations

The relevant level method needs to take into account changes that are under way in the SWIS. For instance, the relevant level method should be technology-neutral so that emergence of new technologies, such as battery storage, would not require further changes. Some Market Rules and processes have direct or indirect interactions with the relevant level method, changes in which may require changes in the capacity valuation of intermittent resources.

This section discusses how the relevant level method interacts with other Market Rules and arrangements that may change in the coming years. It also discusses the emergence of battery storage technology and its implications.

5.5.1 Reliability planning criterion

The reliability planning criterion in the Market Rules affects the calculation of the capacity value of resources. The Market Rules require the ERA to review the planning criterion at least once every five years. Changes to the planning criterion may require changes to the relevant level method.

To ensure consistency between the relevant level method and the planning criterion, the timing of the reviews of the planning criterion and the relevant level method could be aligned. This would require a change to the Market Rules.

5.5.2 Reserve capacity mechanism and capacity pricing

The market reform program is proposing several changes to the design of the reserve capacity mechanism; changes to capacity pricing and assigning capacity credits under constrained network access.[61]

In its consultation paper for improved pricing of capacity credits[62], the Public Utilities Office stated that:

> It will remain the role of the ancillary services market to procure energy required for system security…" and therefore "…the capacity market will continue to procure reliability; i.e. the availability of capacity resources to meet peak demand. Capacity resources will be certified and allocated capacity credits based on their contribution to servicing peak load demand.

The market reform program underway in the WEM is not proposing any changes to the reserve capacity mechanism – only to reserve capacity pricing. Recently, the Public Utilities Office published its final recommendation report on improving reserve capacity pricing signals.

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[61] At its meeting on 9 May 2018, the Market Advisory Committee discussed whether network security constraints should be considered in process for assigning reserve capacity credits. Refer to Rule Change Panel, *Market Advisory Committee meeting minutes, 9 May 2018*, pp. 6–12, https://www.erawa.com.au/cproot/19208/2/MAC Meeting 2018_05_09 -Minutes.pdf.

[62] Public Utilities Office, *Improving Reserve Capacity pricing signals – alternative capacity pricing options, Consultation paper*, 2018, p. 4, https://www.treasury.wa.gov.au/uploadedFiles/Site-content/Public_Utilities_Office/Industry_reform/Consultation-Paper-Improving-Reserve-Capacity-pricing-signals.pdf.

Recommended changes to capacity pricing did not carry any implications for the relevant level method (refer to section 6.7 for further details). Changes to capacity credit pricing may affect cash flows for intermittent and scheduled generators, but such economic considerations are out of scope for the relevant level method review.

5.5.3 Constrained network access

In its consultation paper for allocating capacity credits under a constrained network design, the Public Utilities Office proposed that it would address the effect of network constraints by running a model that estimated the capacity contribution of resources subject to network constraints. The proposed model would assess "the ability of each generator on the system to simultaneously export its power into the network under the expected peak demand load scenario while seeking to "maximise reserve capacity"".[63]

As an input, the model would assume that intermittent resources operated at their relevant level of capacity, as assessed in accordance with the relevant level method. It appears that the proposed method to allocate capacity credits under a constrained network design will address the effect of network constraints on the capacity value of resources separately from the relevant level method.

5.5.4 Batteries

The Market Rules specify separate processes for the allocation of capacity credits to scheduled generators, intermittent generators, and demand side sources. It is not clear if and how storage facilities can receive capacity credits.[64]

The capacity valuation of storage facilities, such as hydroelectric dams, in other jurisdictions is more developed because the technology has been available for a long period. However, the technology for battery storage facilities is currently under consideration in many jurisdictions. Accommodation of battery storage technology in the capacity markets is a topical issue. For instance, the Pennsylvania-New Jersey-Maryland Interconnection is currently reviewing the potential participation of storage technologies in its capacity market.[65]

Energy storage can serve costly peak hours, quickly respond to system fluctuations, and provide several retail and wholesale services in addition to resilient power for customers. However, energy storage can only provide energy for a limited amount of time before it must stop to recharge, or refuel, or for other operational reasons.

For instance, if the existing reserve capacity obligations applied to storage technologies, they would face the risk of significant penalties. The physical characteristics of these resources,

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63 Public Utilities Office, *Allocation of capacity credits in a constrained network, Consultation paper*, 2018, p. 8, https://www.treasury.wa.gov.au/uploadedFiles/Site-content/Public_Utilities_Office/Industry_reform/Consultation-Paper-Allocation-of-capacity-credits-in-a-constrained-network.pdf.

64 Clause 2.29.2 of the Market Rules does not allow a facility to be registered both as a generation and load. This creates a barrier for the entry of storage technologies as a market participant.

65 B Watson, 'Comments of Tesla, Inc. to PJM, Markets and Reliability Committee', 2018, pp. 1–3, https://www.pjm.com/~/media/committees-groups/committees/mrc/20180802-special/20180802-comments-of-tesla.ashx, [accessed 22 November 2018].

particularly their maximum run time,[66] is different to those for scheduled generators or hydroelectric facilities. To mitigate this risk, energy storage resources must significantly de-rate their capacity. This approach may not reflect the full capacity value of these resources and can prevent their participation in the reserve capacity mechanism.

An alternative for their participation in the reserve capacity market is to value their capacity through the relevant level method. As explained in section 3.1 and Appendix 3, the relevant level method is based on the estimation of the contribution of generators to the adequacy of the electricity system. The calculation concept is technology neutral, for example it can be applied to calculate the capacity contribution of scheduled generation, storage, and demand side sources.

If battery storage facilities directly participated in the reserve capacity mechanism, the relevant level method would require an estimate of their output to calculate capacity values. Battery storage facilities may also be embedded behind the meter at a wind farm or solar farm and change the output of that intermittent generator. The capacity value calculation in both cases would be similar to that conducted for new or upgraded intermittent facilities.

The enhanced fleet capacity value allocation method discussed in section 6.1 provides for the introduction of new technology classes, such as storage and solar with embedded storage, and suitable allocation of the capacity value of fleet of intermittent generators consistent with the capacity availability profile of each technology class.

66 Maximum run time for a battery is the duration between fully charged and discharged states, when a battery discharges electricity.

6. Proposed numerical model

The model estimates the effective load carrying capability of the fleet of intermittent resources in four steps:

1. Calculate the output distribution of scheduled generators using their maximum capacity and equivalent forced outage rates. The model uses an iterative method to estimate the probability of a certain amount of scheduled capacity being on outage.[67] This provides a reliability model, referred to as a capacity outage probability table of the system. The capacity outage probability is a table of outage states, expressed in megawatts, and their respective probabilities. The table also shows the probability of having a capacity outage greater than a given amount.

2. Use the capacity outage probability table in conjunction with the demand time series to calculate the loss of load expectation of the system. This represents the loss of load expectation of the system without the contribution of the fleet of intermittent resources.

3. Intermittent resources' output cannot be adequately modelled by their capacity and forced outage rates, because their capacity availability is mainly driven by wind speed or solar irradiance. Instead, use the time series for the sum of the output of intermittent resources and deduct it from demand to estimate a net load time series. The loss of load expectation of the system in this step would be lower than that estimated in step 2, because of the contribution of the fleet of intermittent resources to the system.

4. Iteratively increase load across all trading intervals by a fixed amount until the loss of load expectation in step 3 reaches the loss of load expectation calculated in step 2. The increase in load in this step is the effective load carrying capability of the fleet of intermittent resources.

These calculation steps reflect the definition of the effective load carrying capability. By the addition of the fleet of intermittent generators, the system can support the additional load estimated in step 4 without a change in the adequacy risk of the system, as estimated in step 2.

The proposed method is based on the recommendations of the International Energy Agency Expert Group on Wind Integration Studies and the Institute of Electrical and Electronics Engineers, Wind Power Coordinating Committee Task Force.[68,69] The Californian Independent

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67 The capacity of any resource other than an intermittent generator should be reflected in the capacity outage probability table. For instance, demand side management resources would influence the reliability of the system and will be captured in the model. For simplicity in explaining the approach, however, we assume scheduled generators and intermittent resources comprise the total available capacity in the system.

68 H Holttinen, *Expert group report on recommended practices: No. 16. wind integration studies*, Finland, 2013, https://community.ieawind.org/task25/viewdocument/recommended-practices-16-wind-inte?CommunityKey=4aa82210-1b2e-43c5-b37b-1cdf11020dc8; and A Keane et al., 'Capacity Value of Wind Power', in *IEEE Transactions on Power Systems*, vol. 26, 2011, 564–572, http://ieeexplore.ieee.org/document/5565546/.

69 Zachary and Dent also used a probabilistic model similar to the one preferred by IEA and IEEE to assess the accuracy of their proposed approximation formula in the capacity valuation of the fleet of wind resources in the United Kingdom.

System Operator and the Midcontinent Independent System Operator also use a similar method for the capacity valuation of intermittent resources.[70]

The method is similar to conventional system assessment methods that use a capacity output probability table to assess the adequacy of a system comprising scheduled generators. The calculation of capacity output probability is well-known in reliability assessment modelling and is explained in several sources.[71]

The calculation of the capacity output probability table uses two main types of input data: maximum capacity of scheduled generators and equivalent forced outage rate of facilities. AEMO calculates the equivalent forced outage rate of scheduled generators for the purpose of clause 4.11.1(h) of the Market Rules.[72]

The fleet capacity value calculated is allocated to different technology classes, currently biogas, solar and wind generation, as explained in section 6.1. Subsequently, each technology class capacity value is distributed to individual intermittent generators in that technology class based on their historical capacity factor.[73] The two-step allocation method ensures that the sum of capacity credits assigned to individual resources equals the fleet capacity value estimated through the numerical model. This approach is similar to that conducted by the California Independent System Operator.[74]

6.1 Enhancing the allocation of the fleet capacity value to individual generators

The allocation method proposed in the draft report did not account for differences in the output profiles of different intermittent generation technologies. For instance, biogas facilities have variable output throughout the day and their output is not as connected to weather conditions as wind and solar farms. In contrast to wind and solar farms, biogas facilities have output that is independent of other biogas facilities. Solar farms do not have any output during the night but their highest output is in the early afternoon when demand is typically higher.

The ERA proposes an intervening step to better allocate the capacity value of the fleet of intermittent generators – comprising solar, wind and biogas facilities – to individual facilities. This intervening step divides the fleet capacity value to each technology class. Subsequently the technology class capacity value will be allocated to individual generators in that class

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70 California Public Utilities Commission, *Final Qualifying Capacity Methodology Manual Adopted 2017*, 2017, http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442455533; Midcontinent Independent System Operator, 'Planning Year 2018-2019 Wind Capacity Credit', 2017, 1–14, https://cdn.misoenergy.org/2018 Wind Capacity Report97278.pdf.

71 For example refer to R Billinton & RN Allan, *Reliability Evaluation of Power Systems, Second Edition*, New York, Springer US, 1996, https://www.springer.com/gp/book/9780306452598.

72 The calculation of equivalent forced outage rate of facilities is explained in Appendix 1 of AEMO, 'Power System Operation Procedure: Facility Outages', 2014, pp. 1–18, https://www.aemo.com.au/-/media/Files/Electricity/WEM/Security_and_Reliability/facility-outages-psop528697C8E166.pdf.

73 Capacity factor of a generator is the average power generated divided by the maximum capacity of the generator.

74 California Public Utilities Commission, *Final Qualifying Capacity Methodology Manual Adopted 2017*, 2017, pp. 8–10, http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442455533.

based on their average capacity factor during peak demand and peak net demand periods as explained in the draft report and in section 6.2.

The capacity value of each technology class can be estimated by running the numerical model for additional scenarios. The capacity value of the wind fleet can be estimated by excluding the output of solar and biogas facilities in steps 3 and 4 of the numerical model explained above. Similarly the capacity value of the solar fleet can be estimated by excluding the output of wind and biogas facilities. For biogas facilities it is achieved by excluding the output of wind and solar facilities.

It is possible that the sum of technology class capacity values differs from the capacity value of the fleet of intermittent generators:

$$ELCC_{Biogas} + ELCC_{Solar} + ELCC_{Wind} \neq ELCC_{Biogas+Solar+Wind}$$

As discussed previously, the capacity value of facilities depends on the capacity value of other facilities in the system. When calculating technology class capacity values, this relation is not accounted for and so can lead to some difference between the sum of the technology class capacity values and the intermittent generation fleet capacity value. This difference should be suitably allocated to technology classes. The analysis in Appendix 5 shows that this difference is mainly due to the interaction of wind and solar facilities and therefore can be distributed evenly to the capacity value of solar and wind technology classes.

The sample numerical model results in section 6.3 provide an estimate of the capacity value of biomass, solar and wind fleets separately. A more detailed discussion of the calculation of technology class capacity values is presented in Appendix 5.

6.2 Distribution of technology class capacity values to individual facilities

The technology class capacity values can be distributed to individual facilities in that technology class using the average capacity factor of facilities during two sets of trading intervals:

- The top 12 trading intervals with the highest demand from separate days in each year in the past five years.
- The top 12 trading intervals with the highest demand net of the output of the intermittent generation fleet, estimated for separate days, in each year in the past five years.

Those resources with a greater capacity factor during the peak demand and peak net demand periods selected above would receive a higher proportion of the technology class capacity value.

Why two sets of trading intervals?

- The allocation of technology class capacity value to individual generators based on the two sets identified above is important. The capacity factor during the peak demand set reflects the contribution of intermittent resources to shifting the periods with high loss of load probability from the highest demand periods to other periods.
- If the allocation method was based on the capacity factor during peak demand only, it could underestimate the contribution of resources that have a high contribution during the periods when demand is high, but not necessarily highest, and the output of other intermittent generators is lower.
- For example, with increased penetration of solar farms, the periods with the highest loss of load probability shift from early to late afternoon, when wind farms typically tend to have higher output but solar farms have lower output. The allocation method proposed accounts for this effect.

Details of the development of the proposed numerical model and allocation method are presented in Appendix 5. The ERA developed a sample numerical model to calculate the capacity value of the fleet of intermittent generators in the South West Interconnected System (SWIS) for the 2019/20 capacity year. The calculation results are presented in the following section.

Explanation

The current and proposed methods differ based on the frequency of running an adequacy assessment model. The current method uses a constant parameter K that is determined for use over a three-year period. This would require running a system adequacy assessment model every three years. However, the proposed method runs the adequacy assessment model annually.

An annual run of the system adequacy assessment model can provide a better indication of the effect of changes in the energy mix and system demand on capacity contributions. This is particularly important when large capacities enter or exit the market from year to year. Nevertheless, it is possible to implement the proposed method so that the adequacy assessment model is run every three years. This can be done by estimating the capacity value of the fleet of intermittent generators in a year, expressed in percentage of the installed capacity of the fleet, and using it for the capacity valuation in that year and subsequent two years.

This, however, would not have any material cost or computation advantage. An annual run of system adequacy assessment model will better capture changes in the capacity contribution of resources from year to year.

6.3 Sample numerical model

The sample model estimates the capacity value of the fleet of intermittent generators in the SWIS for the 2019/20 capacity year. It includes all intermittent generators that received capacity credits from AEMO for that capacity year. This sample model thus provides the opportunity to make a comparison between the results of the proposed method and the current relevant level method.

The sample model investigates two scenarios:

- Entire year time series scenario uses synchronised time series of demand and output of intermittent resources for each trading interval in the period between trading days 1 April and 31 March for each year from 2012 to 2017.[75] The scenario calculates the capacity value of the fleet of intermittent resources for six sampling periods comprising one for each year in the five-year period and one based on the entire 5-year sample.
- Hot season time series scenario is run similar to the previous scenario, except it uses data from the hot season only. Under the Market Rules, the hot season is the period commencing at the start of the trading day beginning on 1 December and ending at the end of the trading day finishing on the following 1 April.

Figure 5, panels (a) and (b) present intermittent generation fleet capacity value results for the scenarios above. The figure illustrates how the capacity contribution of intermittent generators in the SWIS varies from year to year. Annual results for both scenarios vary between 179 MW and 377 MW. The last bar on the right hand side of the graphs shows the capacity value result based on the entire five-year sample, which is equal to 250 MW in both tested scenarios.

The outcomes of the current relevant level method are only comparable to the lowest of the annual capacity value results based on the ERA’s proposed method. For the same capacity year as tested in this sample model, and using the current relevant level method, AEMO assigned approximately 183 MW of capacity credits to intermittent resources.

Results for the entire year and hot season scenarios are almost identical, indicating that the capacity contribution of intermittent resources in the SWIS is mainly determined by their performance in the hot season period. Model results show that loss of load expectation of the system in the hot season is only slightly lower than that estimated in the entire year scenario. The adequacy risk of the system is almost entirely determined by the loss of load probability of the trading intervals in the hot season.

This result confirms that for the calculation of capacity value the selection of entire year time series is appropriate as discussed in section A5.3, Appendix 5. The use of hot season time series does not provide any advantage to address a lack of data. Even if time series lack data about the performance of intermittent generators in the extremely high demand periods, the loss of load expectation in the off-peak period is substantially low that does not influence the capacity value results. This is explained further in the box below.

[75] The selection of time series is consistent with the current relevant level method.

Explanation

The loss of load expectation of the system can be considered as the sum of the loss of load expectation during the hot season and non-hot season, or off-peak, periods. The loss of load expectation of the system based on the entire year time series scenario is almost equal to that for the hot season time series scenario. This indicates that the loss of load expectation during the off-peak period is negligible.

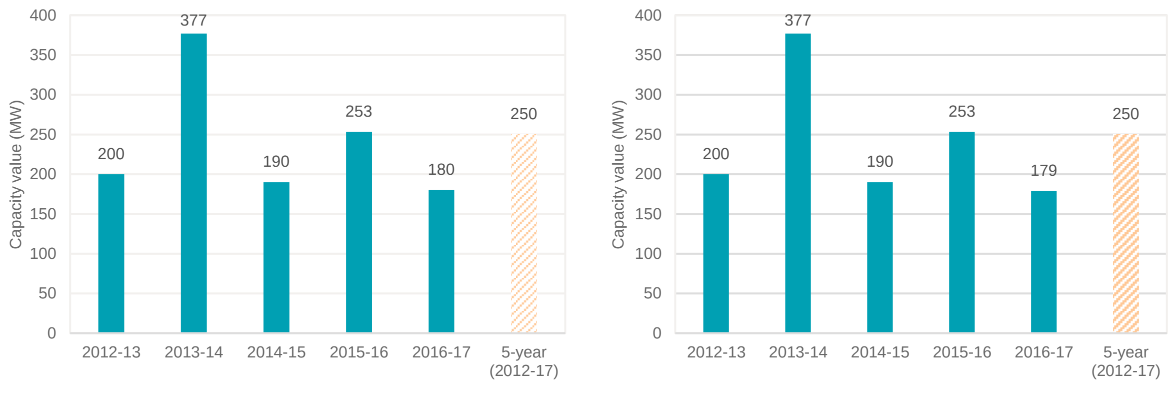
The sum of the loss of load probability of the trading intervals during the hot season almost entirely determines the loss of load expectation of the system in the SWIS.

Observed demand and intermittent generation output data may not contain sufficient information about the performance of intermittent generators during extremely high demand periods. Therefore, it is possible that the capacity value results will be influenced more by the performance of intermittent generators in non-highest demand periods than if the observed data did include periods of extremely high demand.

For instance, the loss of load probability of high demand periods, but not necessarily the highest demand periods, in a winter period may determine a higher portion of the loss of load expectation of the system. If sufficient data was available on the output of intermittent generators in extremely high demand periods, then high demand periods in winter could not make a significant contribution to the loss of load expectation of the system. A lack of data for the performance of intermittent generators during extremely high demand periods can influence the capacity value outcomes.

The difference between the annual capacity values in the sample period is driven by inter-annual variation in the two main inputs to the model: demand for electricity varies by several factors including weather patterns, economic condition and technological changes; the available capacity of many intermittent generators changes by weather conditions.

Figure 5. Estimated capacity value of the fleet of intermittent generators using the proposed method, 2019/20 capacity year, entire year and hot season time series scenarios



panel (a): entire year time series scenario

panel (b): hot season time series scenario

This variation of capacity value creates significant uncertainty for forecasting the capacity value of intermittent resources two years ahead of a capacity year. For instance, if the forecast uses the time series in 2016/17 period only, the estimated capacity value would be 180 MW. However, results show that this value is the minimum of the capacity value estimates in the five-year period and may underestimate the capacity contribution of resources in the 2019/20 capacity year. For example, in 2019/20 it is possible that intermittent generators' contribution will be comparable to that in the 2013/14 period, (377 MW).

Alternatively, the forecast capacity value can be estimated by averaging the annual capacity values during the five-year period. This gives a forecast capacity value of 240 MW. However, given the small size of the sample, the average of the capacity values is very sensitive to the relatively high capacity value result in the 2013/14 period.

The variability and therefore uncertainty of results could be remedied by including more sample years of data in the analysis. The inclusion of multiple years of time series of demand and capacity output, however, has trade-offs. First, many intermittent generators in the SWIS were installed relatively recently. Actual output data for many of these resources is limited to the last few years. A larger sample of years would require estimate of the output of new or upgraded resources. These estimates introduce uncertainty in the calculation and increase the administration costs of the calculation process. Second, time series of demand would include the effect of technological change, economic conditions and consumer behaviour change. The capacity value estimated through several years would not be comparable, particularly if longer periods are considered. This is discussed in more detail in Appendix 5.

The five-year sample capacity value result shown in Figure 5, panels (a) and (b) may be a more reasonable estimate of the long-term contribution of intermittent resources to the adequacy of the system than individual year results. This five-year sample uses the whole time series of demand and output in the five years in a single run of the model. Studies have shown that use of several years of data, similar to the five-year sample run, can provide results that converge to long-term estimates of the capacity value of intermittent generators[76], which is also more consistent with the capacity valuation method performed for conventional generators.

For instance, the forced outage rate of conventional generators varies from year to year, however, the capacity value allocated to these resources is generally constant. The method for the allocation of capacity credits to scheduled generators uses long-term forced outage rates.[77] The Market Rules specify that scheduled generators receive capacity credits equal to their estimated sent-out capacity calculated at an air temperature of 41 degrees Celsius, unless their three-year equivalent forced outage rate exceeds some thresholds specified in the Market Rules.[78]

For example, the coal-fired BW2_Bluewaters_G1 is a scheduled generation facility that has consistently received between 204 MW and 217 MW capacity credits since the capacity year 2008/09. This facility was on forced outage between 1 January 2017 and 18 July 2017, despite being expected to contribute to the reliability of the system by 217 MW in the capacity year 2016/17. The facility was on forced outage for a substantial portion of the hot season period. This is compared to the variation of the capacity value of intermittent generators. The maximum difference between the five-year capacity value result and annual results for intermittent generators is less, at 127 MW.

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76 For example refer to B Hasche, A Keane & M O'Malley, 'Capacity Value of Wind Power, Calculation, and Data Requirements: the Irish Power System Case', in *IEEE Transactions on Power Systems*, vol. 26, 2011, 420–430.

77 For instance, clause 4.11.1(h) of the Market Rules specifies thresholds for the outage rate of scheduled generators. AEMO can decide not to assign capacity credits, or assign a lesser quantity of capacity credits than their rated capacity at 41 degrees Celsius, to scheduled generation facilities that have had three year outage rates greater than the specified thresholds.

78 Clause 4.11.1(h) of the Market Rules.

The magnitude of the variation of the output of intermittent generators, however, is likely to increase as their penetration in the system increases. Intermittent generators' outputs vary by weather conditions and are correlated. The difference between the long-term five-year capacity value result and annual results can increase with rises in their installed capacity in the system. This can increase the forecasting inaccuracy of the relevant level method, if it only relied on the five-year result.

This forecasting inaccuracy does depend on the geographical dispersion of the installation of intermittent generation facilities in the SWIS. When many intermittent generators are installed in geographically disperse locations their output becomes more predictable and their combined output becomes less variable when compared to their average output.[79]In contrast, the range of variation of the available capacity of scheduled generators is limited and generally does not grow as the number of these resources in the system increases. The available capacity of these resources is independent of each other.

The ERA sought feedback from stakeholders on the choice of a suitable value for the capacity contribution of the fleet intermittent generators given the observed variability in annual capacity value results. This is discussed in detail in section 6.5.

Allocation of fleet capacity value to biogas, solar and wind technology classes

The capacity values of biogas, solar and wind fleets can be estimated using the method introduced in section 6.1. Appendix 5 provides details of the calculation. Table 2 presents the estimated technology class capacity values for the five-year sample scenario.

Table 2. Allocation of intermittent generation fleet capacity value to technology classes

Technology class	Estimated (MW)	Allocated (after accounting for interaction effect) (MW)	Capacity value allocated (% of installed capacity)
Intermittent generation fleet	250	250	33.4
Biogas fleet	12.2	12.2	56.5
Solar fleet	45	46.9	39.1
Wind fleet	189	190.9	31.4

The sum of the estimated capacity value for biogas, solar and wind fleets (246.2 MW) is smaller than the entire fleet capacity value by 3.8 MW. This is due to the interaction of the output of capacities in the system, particularly the interaction of solar and wind facilities.

This can be explained by the characteristics of the output of biomass facilities. The output of biogas facilities is not correlated with each other or the output of wind and solar facilities.[80] This makes their capacity value largely independent of other facilities in the system.

The outputs of solar and wind farms, however, are linked. For instance, it is possible that solar facilities shave system peak demand in the early afternoon and shift peak demand to later

[79] This is due to the Law of Large Numbers which states that the sum of a large number of independent random processes becomes more predictable as the total number of processes increases.

[80] The sum of their output also looks normally distributed.

hours in the afternoon when wind speed is typically higher. This creates some interdependencies between the capacity value of wind and solar farms.

Further analysis also confirmed that the 3.8 MW gap between intermittent generation fleet and the sum of technology class capacity values is due to the interaction of the output of solar and wind generators. Three additional scenarios calculated the capacity value of pairs of technologies: solar-wind, biogas-solar and biogas-wind. The capacity value of each technology pair is reported in Table 3.

The calculation of the capacity value of each pair is similar to that for each technology class – each pair can be regarded as a single technology class. For example, for the solar-wind pair, the effective load carrying capability of facilities is estimated using the same numerical model explained in the beginning of this section. It, however, excludes the output of biogas facilities from the calculation of the effective load carrying capability.

Table 3. Capacity value of technology pairs

Technology pair	Time series used in step 3 of the calculation of effective load carrying capability	Estimated capacity value (MW)
Biogas-solar	Demand-biogas output-solar output	57
Biogas-wind	Demand-biogas output-wind output	201
Solar-wind	Demand-solar output-wind output	238

The estimated capacity value of the biogas-solar and biogas-wind pairs are approximately equal to the sum of individual technology classes in that pair. For instance, the estimated capacity value of biogas-solar is 57 MW, which is close to the sum of biogas (12.2 MW) and solar (45 MW) technology capacity values. The capacity value of the solar-wind pair, is 4 MW larger than the sum of the capacity value of solar (45 MW) and wind (189 MW). This shows that the interaction effect is largely due to the interaction of the output of solar and wind facilities.

For the scenario tested this interaction effect was small (3.8 MW) and is evenly allocated to solar and wind fleet capacity values. This allocation of the interaction effect brings the sum of the capacity value of technology classes back to the entire fleet capacity value (250 MW).

The allocated capacity value to the solar fleet (46.9 MW) can be distributed to individual solar facilities based on their average capacity factor during peak demand and peak net demand periods as explained in section 6.2. Similar process can be conducted for biogas and wind facilities. The details of the allocation method to individual facilities is provided in Appendix 5.

6.4 Stakeholder comments on the suitability of the proposed method

Stakeholders provided several comments about the suitability of the proposed method. Community Electricity proposed a framework for an alternative capacity valuation and payment method based on retrospective valuation. This was based on a comparison of the capacity contribution of resources to the reliability of the system and the funding mechanism for capacity credits. Community Electricity also raised the significance of using a performance standard for the capacity valuation of intermittent resources. Such a performance standard does not currently exist in the Market Rules. This is discussed in more detail in section 6.4.2. Community Electricity also considered that the ERA did not define the ideal outcome in its review of options available. Section 6.4.3 provides a discussion of this matter.

AEMO suggested that the ERA should include the treatment of emerging technologies in the review of the relevant level method. The ERA enhanced the allocation of intermittent generation fleet capacity values to individual facilities as introduced in the draft report. The enhanced method, discussed in section 6.1, allows for an objective allocation of intermittent generation fleet capacity value to technology categories (currently biogas, solar and wind). The enhanced method is robust and allows for suitable allocation of capacity values to any new technology including storage technology.

A submission from Timothy Edwards argued that the ERA's proposed method was biased "towards changing the Rules to the needs of the most vocal [scheduled generation] proponents". The submission did not explain why it considered that the ERA's proposed method was discriminatory against intermittent generators.[81] It also stated that, for the capacity valuation of intermittent generators, categorisation on "intrinsic technology class" was essential before applying a numerical model.

The ERA's proposed method is based on international best practice for capacity valuation of variable generation, which has also been implemented in two North American jurisdictions. The ERA's analysis measured the contribution of intermittent generators to the reliability planning criterion in the Market Rules, and is not discriminatory against any technology type.

The calculation of fleet capacity value does not require technology categorisation. The proposed method assesses the capacity contribution of the fleet of intermittent generators to meet the reliability planning criterion. As explained in section 4, a capacity valuation of a subset of capacity resources can underestimate the contribution of intermittent generators as a group. It is therefore important to calculate the capacity contribution of intermittent generators as a group. The enhanced allocation method introduced in section 6.1 accounts for differences in the output profile of intermittent generators and allocates the estimated fleet capacity value to each technology category with an objective method.

Mr Edwards' submission also stated that

> The assumptions that the most critical period for certification of capacity be based on peak-demand periods may also be incorrect, however it does correlate with how the market (particularly the end users) calculate, then pay for capacity, so it makes practical sense.

The proposed method does not make any explicit or implicit assumption that the capacity contribution of intermittent generators should be estimated based on their capacity availability during peak demand periods only. Section 4.1.1 provided a discussion that the periods with the highest likelihood of loss of load happen when surplus of available capacity over demand is lowest – and this can happen outside periods of peak demand. Section 4.1.2 also explained that the basis for the calculation of capacity values is contribution to the reliability planning criterion. Economic factors, such as the payment mechanism for capacity credits, are not the basis of capacity value calculation.

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81 Timothy Edwards, Submission to Relevant level method review 2018: capacity valuation for intermittent generators, draft report, p.1, (online).

6.4.1 Retrospective calculation of capacity values and payments

Community Electricity noted the variability of the capacity value of the fleet of intermittent generators. It questioned if intermittent generators themselves or other market participants should bear the risk imposed by that variability to the market and the system.[82] Community Electricity proposed the framework for an alternative approach for the capacity valuation of intermittent generators based on a retrospective analysis of the contribution of these resources to some performance standard.[83] It also proposed to integrate the intermittent generators' capacity contribution with the reliability planning criterion by means of a new 'forecast-block' in determining the reserve capacity target.[84] Community Electricity did not provide any details how the forecast-block for intermittent generators should be estimated.

The assignment of capacity credits two years in advance is to ensure sufficient capacity will be available to meet a forecast peak demand in the SWIS. This is to allow for the engineering, procurement, construction and commissioning of new capacity that can take a few years. A retrospective calculation of the capacity contribution of intermittent resources is not consistent with the aim and design of the reserve capacity mechanism.

Community Electricity's proposed framework is similar to that recently adopted in other jurisdictions such as the Pennsylvania Jersey Maryland (PJM). The ERA provided a detailed discussion of recent changes by the PJM system operator in procuring capacity in Appendix 2 of the draft report.

Community Electricity suggested separate mechanisms for payments to intermittent generation facilities and their contribution to the reserve capacity target. A payment mechanism rewards facilities based on their observed performance. A forecasting mechanism estimates the capacity contribution of facilities to the planning criterion to ensure sufficient capacity is procured and is available on time to meet the reserve capacity target. The forecasting mechanism will need a method to forecast the capacity contribution of intermittent resources and this is covered by the relevant level method.

The ERA's review of the relevant level method is limited to the forecasting of the capacity value of intermittent generation facilities. As explained in section 4.1.2, the economic aspects including payment for capacity contributions are outside the scope of the review. The design of the payment mechanism for capacity credits, however, can affect capacity investment decisions that carry implications for the availability of capacity and the reliability of the system.

The retrospective payment mechanism proposed by Community Electricity is not consistent with the current design of the reserve capacity mechanism in the Market Rules. Nevertheless, if such changes to the design of the reserve capacity mechanism are made in the future, the relevant level method will be needed to forecast the capacity contribution of intermittent resources.

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82 Community Electricity, Submission to Relevant level method review 2018: capacity valuation for intermittent generators, draft report, p.3, (online).

83 Community Electricity, Submission to Relevant level method review 2018: capacity valuation for intermittent generators, draft report, p.6, (online).

84 It appears that Community Electricity is suggesting forecasting the capacity contribution of intermittent generators. It suggests using the forecast to offset the required amount of capacity to be procured from other resources to meet the reserve capacity target of the system.

Explanation

The Pennsylvania Jersey Maryland (PJM) system operator and Independent System Operator New England have recently implemented Pay-for-Performance capacity payment mechanisms in their capacity market design. These mechanisms are based on observed performance of resources, covering scheduled generators, demand side resources and intermittent generators. They use a two-settlement process where capacity revenue comprises a base payment plus penalties for under performance or credits for over performance during some compliance hours.

Such mechanisms change the bidding behaviour of capacity market participants. Capacity market bids will depend on each supplier's views of expected capacity scarcity hours and the historical and expected performance of its units. A premium will be placed on accurate projections of the market and the reliability of each asset. In effect, the financial risk of inaccurate forecast of the capacity contribution of resources will be passed to capacity suppliers.[85]

Capacity valuation methods, similar to the relevant level method, set the maximum amount of capacity intermittent generators can offer into the capacity procurement mechanism and are used to determine the amount of capacity that should be procured. An intermittent generator may choose to offer below its forecast capacity value, based on its own estimations, to avoid penalties for underperformance and benefit from rewards for better than expected performance.

In such designs the rewards for better than expected performance are funded through penalties charged to those that have underperformed.

Appendix 2 provides more details about the Pay-for-Performance capacity payment mechanism adopted by the PJM system operator.

6.4.2 Considering a capacity performance standard

Community Electricity suggested that the review of the method should investigate the performance standard that System Management required from intermittent generators, and that any capacity valuation method should be consistent with such a performance standard. It questioned whether System Management could rely on historical or recent performance of intermittent generators when extremely high demand, such as one day in 10 years peak demand, happens.[86]

Currently the Market Rules do not specify any performance requirement for intermittent generator during peak demand periods to qualify them for receiving capacity credits. The ERA cannot review the relevant level method based on System Management requirements that are not implemented in the Market Rules. The adoption of performance requirements or standards requires changes to the rules through a rule change process including consultation with stakeholders and approval by the Rule Change Panel.

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85 AG Katsigiannakis et al., *How ISO-NE 's Pay-for-Performance Initiative Will Shake Up New England*, 2018, (online), and BD Hunger, J Plewes & J Kwok, Navigating PJM's Changing Capacity Market, 2017, (online).

86 Community Electricity, Submission to Relevant level method review 2018: capacity valuation for intermittent generators, draft report, pp.2–3, (online).

The proposed method is based on the contribution of intermittent generators to meeting the reliability planning criterion in the Market Rules, which is based on statistical measures.

The same risk of unavailability also applies to conventional generators. Their observed capacity availability cannot guarantee that they will be available when demand is extremely high. The capacity contribution of scheduled generators is also variable. However, as discussed in section 6.3, the magnitude of the variability of the contribution of intermittent generators can increase with their increased share in the system because their output is correlated with each other.

Community Electricity noted that capacity contribution of large-scale solar farms was estimated and they received capacity credits. The rooftop solar photovoltaic capacity contribution, however, was not rewarded. It suggested that the review should harmonise the two and questioned whether any differences between them could justify the discrimination in recognising capacity contribution.[87]

The relevant level method proposed by the ERA is not discriminatory and can be applied if rooftop solar photovoltaic generators participate in the reserve capacity mechanism.[88] A review of the feasibility of participation of resources such as rooftop solar photovoltaic in the reserve capacity mechanism is outside the scope of the relevant level method review.

6.4.3 Definition of ideal outcome

Community Electricity stated that the ERA did not define the ideal outcome, but only compared some available options against each other, one of which was the current method.

The ERA used the framework of analysis detailed in section 3.3 to review the relevant level method. The framework was developed after a study of capacity valuation theory, the theoretical basis of the current relevant level method, capacity valuation in other jurisdictions and the requirements of the Market Rules.

The framework's main assessment criterion was accuracy of available methods. The draft report noted that in practice an assessment of forecasting accuracy is challenging. The ERA also considered other assessment criteria: simplicity and transparency, stability of results, and robustness of methods. The ERA's analysis showed that among available capacity valuation methods, the numerical modelling method was preferred as it better met the assessment criteria specified in the assessment framework.

The ERA explained the conceptual problems in the current method. A capacity valuation method that is not theoretically sound and is based on invalid assumptions cannot be relied upon to provide a reasonable estimate for the capacity value of intermittent generators.

Community electricity stated that:

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87 Community Electricity, Submission to Relevant level method review 2018: capacity valuation for intermittent generators, draft report, p.5, (online).

88 If very small scale generators participate in the reserve capacity mechanism, the precision of the proposed method can be increased to make it suitable for valuing capacities of 0.001 MW size. For example, the capacity outage probability table can be developed based on 0.1 or 0.01 MW increments.

> The current paradigm is epitomised by the report's references to the oxymoron of an "accurate estimate", which is alternatively mitigated in places to a "reasonable estimate".[89]

Both the calculation basis and input data for the calculation of the capacity value of intermittent generators in the current and proposed method are the same. They both aim to measure the effective load carrying capability of intermittent generators. Their point of difference is how they do it.

However, the current method calculates the effective load carrying capability of intermittent generators based on simplifying assumptions that are not relevant in the SWIS. The current method also has several shortcomings because it is not consistent with the original formula underpinning its calculation. In comparison, the proposed method does not use such simplifying assumptions and therefore better estimates the effective load carrying capability of intermittent resources. Although the proposed method provides a better solution approach, both approaches will be subject to the same level of forecasting inaccuracy.

Explanation

In mathematical terms, the original formula underpinning the current method is the result of an analytic solution approach that yields a closed-form solution for the effective load carrying capability. A closed-form solution is a mathematical statement that uses simple mathematical operators and functions.

The proposed method uses a numerical solution approach. If assumptions underpinning the original formula hold valid, both the proposed method and the original formula yield exact same results. They both find the effective load carrying capability with exact same input data.

The ERA found that the assumption underpinning the calculation of the original formula are not valid for application in the SWIS. The current method also has several errors in the calculation because it is not consistent with the original closed-form formula underpinning its development. This introduces errors in the calculation and will result in inaccuracy.

A method that contains inaccuracies in the calculation cannot be relied upon to provide a reasonable forecast of capacity values.

In comparison with current method, the proposed method is transparent and does not use any simplifying assumption similar to that used for the current method. It does not use any ad-hoc adjustment and is based on simple statistical and probabilistic methods, widely used in system adequacy assessment studies.

6.4.4 Technology neutrality

AEMO stated there was a need for a more holistic consideration of incorporation of new technologies into the WEM and encouraged the ERA to include the treatment of emerging technologies as part of the review of the relevant level method.[90]

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89 Ibid, p.7.

90 AEMO, Submission to Relevant level method review 2018: capacity valuation for intermittent generators, draft report, p.2, (online).

One WEM objective is to avoid discrimination in the market against particular energy options and technologies. The framework of assessment presented in section 3.3 considers technology neutrality as a requirement of the relevant level method. Section 5.5.4 provides a discussion that the proposed method can be used to assess the capacity value of storage technologies.

The proposed method is technology-neutral and it can be applied to any mix of supply capacities to estimate the contribution of a mix of technologies and facilities. The allocation method discussed in section 6.1, can be extended to provide for additional technology categories to allocate the fleet capacity value to individual facilities.

A holistic consideration of incorporating new technologies into the WEM is outside the scope of the relevant level method review. This is currently under consideration by the Public Utilities Office in its WEM reform program. Nevertheless, the proposed method is robust and any new technology can seek to receive capacity credits through the proposed relevant level method.

6.4.5 Capacity availability of demand side resources

One submission referred to the analysis of demand side resources' capacity availability and argued against the use of zero equivalent forced outage rate as explained in Appendix 5, section 5.2. It explained that the participating demand-side resources were accredited to provide their capacity over a limited time. They provided their capacity when they were able to reduce their demand by their contracted amount, and this response was not available at all times. They were more available during the daytime and less overnight. The submission noted that they were suitable resources for meeting extreme demand during extreme weather conditions and their contribution to system reliability could decrease as system peak demand shifts to later hours in the afternoon.[91]

The sample model discussed in section 6.3 uses a zero forced outage rate for demand side facilities and includes them in the calculation of capacity outage probability table. This effectively models demand side management as a firm generation supply. However, these resources are unlikely to be available at all times and therefore cannot be regarded as firm generation capacity.

Nevertheless, the calculation of loss of load expectation in the proposed method will not be biased by assuming firm availability for demand side resources. Demand side resources receive capacity credits based on the availability of their capacity between 8:00am and 8:00pm on all business days.[92] These are the hours during which the likelihood of loss of load is the largest. Hours outside this period have negligible probability of loss of load and do not have any material contribution to the loss of load expectation of the system. The assumption of zero forced outage rate for these facilities cannot contribute to any material error to the calculation of effective load carrying capability of intermittent generators.

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[91] Noel Schubert, Submission to Relevant level method review 2018: capacity valuation for intermittent generators, draft report, p.3, (online).

[92] Clause 4.10.1(f)(vi) of the Market Rules.

6.4.6 Lack of data

AEMO recommended a further assessment of whether the proposed method can accurately estimate capacity values during the highest peak demand periods being considered in the planning criterion of the Market Rules.

The proposed method uses the observed output of intermittent generators[93] over the last five years as a proxy to forecast their capacity contribution two years ahead. As with any other forecasting method, the capacity valuation method proposed is subject to forecasting error. To minimise forecasting error it is important to assess whether the observed performance of intermittent generators contains sufficient information about the output of these resources.

Periods of very high demand comparable to AEMO's one in 10-year peak demand forecast have never happened in the SWIS. Extremely high demand periods happen infrequently. If relying on the observed demand time series, it is possible that the estimate of the capacity contribution of intermittent generators is not reliable. There is evidence that the output of intermittent generators decreases as air temperature increases. System demand is also highly correlated with air temperature and the highest demand periods are also highly likely to happen when air temperature is high.

One remedy for the possible lack of data is to adjust observed demand and output data. This would account for the effect of air temperature on system demand and the output of intermittent generators and the possible change in the correlation of the output of intermittent generators and demand with increases in air temperature. This analysis entails numerous assumptions that can materially affect the outcomes of modelling. The use of such assumptions creates significant uncertainty in the model outcomes and is not recommended.

The ERA assessed if the observed time series for the output of intermittent generators contained sufficient information about capacity availability during extremely high demand periods. Appendix 5 provides a detailed discussion of this assessment. In the past seven years, the highest system demand periods in the SWIS occurred when air temperature was high, but not during parts of the day when air temperature was the highest. This may be explained by increased installation of behind-the-meter solar photovoltaic that shaves the peak demand in the system from the hottest part of the day to later periods when air temperature is lower. The time series for the output of intermittent generators contained many periods with high air temperature; the output of intermittent generators during those hot periods can provide a reasonable estimate of their output during the periods when system demand is extremely high.

For the subsequent reviews of the relevant level method, the ERA will explore other options to account for the possible effect of data insufficiency.

6.5 Choice of the capacity value of the fleet of intermittent generators

The ERA sought feedback from stakeholders on how to calculate the capacity value of the intermittent generator fleet. The capacity value of intermittent generators is expected to vary significantly from year to year due to changes in weather patterns. With increased penetration

93 The method uses the estimated output of new intermittent generators, when observed data for these resources is not available.

of intermittent generation in the system, this variation can become substantial and could create a significant risk in meeting the current reliability planning criterion of the SWIS.

The ERA considered several options for setting the capacity value of the fleet of intermittent generators, given the results of the sample model:

- The method could use the minimum of the annual capacity value results in the five-year period. For instance, based on the sample model results in Figure 5, panel (a), the fleet capacity value would be set at 180 MW. This option can better serve the reliability objective of the WEM, when compared to other options. However, the choice of minimum may underestimate the capacity value of intermittent generators. The system may procure more capacity than needed to meet the reliability planning criterion. This is counter to the market objectives as it can increase the long-term cost of supply of electricity to consumers or result in economic inefficiency.
- The method could use the median of the annual capacity value results. For instance, the median of annual capacity value results in the sample model developed is 200 MW. When compared to the average, the median is not influenced by extremely large or small capacity value results.
- The method could use a trimmed average by excluding the largest capacity value result and estimating the average of the remaining four capacity values. For the sample model results, the trimmed average is approximately 206 MW. The use of a trimmed average can eliminate the influence of the largest capacity value result on the average. However, if annual results contain more than one extremely large value, the trimmed average would be biased towards the second largest capacity value result.
- The method could use the five-year sample result.

In response to the draft report, Infrastructure Capital, SkyFarming and Synergy provided comment that the median or the five-year sample result could be used to set the capacity value of the fleet of intermittent generators.

Use of the median to set the fleet capacity value can provide a reasonable estimate for the central tendency of model results, which would be less sensitive to extremely low or high values when compared to the average of the sample. However, given the small size of the sample, it is possible that more than one extremely large or small value could cause large variations in the median value from year to year. By setting the fleet capacity value to the minimum of the median of annual results and the five-year sample result, this effect can be at least partly mitigated.

The ERA decided to set the capacity value of the fleet of intermittent generators based on the minimum of two values:

- the median of annual capacity value results
- the entire five-year sample result, which uses the entire time series for demand and output of intermittent generators over the five-year sample period.

In a year when the median value is less than the entire five-year sample result, the median will set the capacity value of the fleet. Conversely, when the five-year sample result is less than the median value, the five-year sample result will set the capacity value of the fleet.

Other considerations can improve the choice of the fleet capacity value. The model can be run for longer periods than the five years presented in the sample model. As explained in section A5.4 in Appendix 5, increasing the sample size to longer periods has trade-offs. The larger sample would include the effect of other changes such as consumer behaviour change and changes in economic activity. This can make the annual capacity value results incomparable. A longer sample period would also require more synthetic output data for new facilities and can increase the uncertainty of results.

A degree of judgement will be required to set the sample size. A sample as large as seven years can be used to yield a sample of seven annual results and one seven-year sample result (together forming a sample of eight capacity value forecasts). This will not materially increase the administration cost of running the model. The ERA will consider using a larger sample in its rule change proposal to amend the current method.

Alinta Energy said that the method should add a correction for the historical and future expected changes in capacity. It suggested that the historical or synthetic data[94] would be better used on improving the statistical significance and accuracy of capturing the correlation between the wind, solar and load traces due to the metrological factors and not the changes in the generation mix.[95]

The ERA's proposed method is consistent with Alinta Energy's suggestion. The proposed method uses a system adequacy assessment model to measure the reliability risk of the system. This model is based on the expected capacity available in the system in the capacity year for which capacity values are being calculated: the model incorporates all scheduled generators, demand-side resource and intermittent generation facilities expected to be available for the target capacity year. This is discussed in detail in Appendix 5. The adequacy model then uses observed demand, output of existing intermittent generation facilities and estimated output of new facilities as proxies to forecast their values in the target capacity year.

6.6 Implementation considerations

The implementation of the numerical model would require a change of responsibilities under the Market Rules. Currently AEMO uses a formula and historical outcomes in the WEM to calculate capacity credits. The ERA develops models to provide AEMO with the constant parameters for the calculation. In effect the responsibility for the calculation of capacity credits is shared between these two parties. For the recommended numerical modelling, however, a single entity will be required to develop the model and conduct the calculation.

Any change from the current relevant level method to the proposed model should therefore specify the development of a numerical model, details of calculation and required input data. It should also specify the party responsible for the development of the model and, if required, a quality assurance mechanism.

In particular the implementation of the proposed method should remedy any deficiencies of the current relevant level method as implemented in the Market Rules. The current method does not fully explain the details of the calculation: it uses two constant parameters, K and U, whereas the Market Rules do not specify how these parameters should be determined.

The Market Rules place the responsibility for the determination of the value of K and U parameters on the ERA. The ERA could only refer to the previous reviews of the method to

94 Both the current method and the proposed method use estimates of the output of new or upgraded facilities – referred to as synthetic data by Alinta Energy – for the calculation.

95 Alinta Energy, Submission to Relevant level method review 2018: capacity valuation for intermittent generators, draft report, p.2, (online).

understand the reasoning for the application of K and U parameters and how their value have been determined in the past.

For the implementation of the proposed numerical model, the ERA used three assessment criteria:

- Transparency: the method should be transparent so that market participants and new entrants can assess their capacity contribution. The purpose and details of the method can be comprehensively explained to ensure transparency in the calculation of capacity values.
- Flexibility: the implementation should allow for some flexibility so that over time the model can be enhanced, particularly without going through costly and timely rule change processes.
- Stability: the implementation of the method should consider the stability of the method. For instance, an overly prescriptive method may require frequent changes due to changes in the system or in interacting market rules. Frequent changes to the method would create variability in the outcomes of the method.

The ERA assessed three options for the implementation of the proposed numerical model against the above criteria:

- detailed prescription in the Market Rules
- development of a detailed market procedure
- development of guidelines in the Market Rules

The first two options would provide transparency for the calculation and are likely to increase the stability of results. A detailed prescription of the method either in the Market Rules or a market procedure would entail detailed explanation of the calculation of effective load carrying capability of the fleet of intermittent resources, system adequacy assessment model, input data, and an allocation method. This would eliminate frequent changes to the method and therefore could enhance market participants' and new entrants' confidence in the calculation method.

The disadvantage of a detailed prescription of the method, however, is that it would not allow for flexibility in enhancing the method. This is particularly important when the model is first implemented, when the need for improvements to the model may become evident. Changes in other market rules interacting with the relevant level method, such as the planning criterion, may also necessitate changes in the calculation.

For instance, in 2017 the California Public Utilities Commission used a numerical model to determine capacity values for intermittent generators. In its manual outlining the calculation of capacity values, the commission only provides guidance on developing the numerical model. For instance, the manual does not specify the type of adequacy model to be used, but it prescribes the use of a system adequacy model to assess the contribution of resources to the desired level of reliability. In its decision paper the commission stated:

> At this initial implementation stage of ELCC [effective load carrying capability], it is too early to determine the ideal model to use, and we want to allow flexibility going forward to allow the most appropriate model to be used…Going forward, the process used to

calculate monthly ELCC values will be subject to changes, improvements and refinements as needed.[96]

The third implementation option would provide the highest flexibility for enhancing the method over time. The Market Rules would only contain the purpose of the method and broad guidelines. For instance, the Market Rules may only specify that the calculation of the capacity value of intermittent resources is based on the effective load carrying capability. The entity responsible for the calculation of the capacity values would have flexibility to develop a system adequacy assessment model and determine the effective load carrying capability of resources.

The disadvantage of the third implementation options is that the details of the calculation would be opaque. Frequent changes to the calculation can also increase the variability of results. Market participants and new entrants would have limited information to assess the number of capacity credits they receive and thus form a reasonable expectation of associated cash flows in the future. This can increase the cost of capital for funding investments in supply capacities in the SWIS.

The ERA recommends that guidelines would be included in the Market Rules as to how the model should be developed and what the model should deliver. This should be combined with a detailed specification of the model in a market procedure. This creates transparency and would help existing and potential intermittent generators make informed investment decisions. The implementation of the details of the model in a market procedure will allow enhancements to the model specification to be incorporated more flexibly and less costly than initiating a new rule change proposal.

The ERA will propose a new rule change together with a market procedure for the implementation of the new relevant level method. The rule change proposal will follow the standard process established by the independent Rule Change Panel.

AEMO will undertake the calculation of capacity values as outlined in the market procedure to be developed. The ERA will review the method and the relevant market procedure at least once every three years and will consider the timing of the review of the planning criterion as discussed in section 5.5.1.

The ERA will consider including transitional arrangements in the proposed rule change to dampen the financial impacts of changing the relevant level method. While the rule change and procedure are in development, the current relevant level method will apply. The ERA will publish unchanged values for the K and U parameters on its website.

6.7 Stakeholder feedback on the implementation of the proposed method

Stakeholders provided several comments on the implementation of the proposed method. They noted that the review was taking place at the same time as other substantial market reforms. They noted the importance of transparency in the calculation of capacity values and sought to dampen the financial implications of the change in the method. AEMO suggested that some procedural changes will be required for the implementation of the proposed relevant level method.

[96] California Public Utilites Commission, pp. 20–21.

6.7.1 Coincidence of the review of the method with the reform program

AEMO, Community Electricity and Synergy noted that the ERA's review of the relevant level method was happening at the same time as the Public Utilities Office's WEM reform program. AEMO and Community Electricity noted it was possible that the proposed method may not be consistent with the reform outcomes. Synergy suggested an additional round of consultation and analysis to inform market participants on the combined effect of market reforms, including the reserve capacity pricing, and changes to the relevant level method on market outcomes.

The reform program aimed to improve the reserve capacity mechanism by ensuring that the capacity pricing model used in the mechanism better signals the economic value of capacity to the market. In its final reserve capacity pricing report the Public Utilities Office considered that pricing of capacity should continue to be based on system adequacy as defined by the reliability planning criterion.[97] It also concluded that the current design of the reserve capacity mechanism will be sufficient to enable the capacity mix to respond to changing demand dynamics in the system. There is no need to change the design of the reserve capacity mechanism to address such changes.

The reform program is concurrently seeking to improve access to Western Power's network by implementing a constrained access model. The Public Utilities Office published a discussion paper on the required changes to the reserve capacity mechanism resulting from the adoption of a constrained access model in February 2016. It proposed an approach for capacity credit allocation to account for the effect of network constraints. The intent of the proposed approach was to not assign capacity credits beyond the physical limitations of the transmission network and accounting for forced generator outages.[98]

In its assessment, the Public Utilities Office proposed a calculation approach that assumed that non-scheduled facilities operated at the level of capacity assessed for the facility in accordance with the relevant level method.[99] This was used as input to subsequent assessment steps to determine the number of capacity credits a facility can receive after accounting for network constraints.

It is important to ensure the effect of network constraints has been accounted for when estimating the capacity contribution of resources. It is also important to avoid double counting the effect of network constrains. The Market Rules already provide for estimating the effect of network constraints for facilities with constrained network access, the input to which is the relevant level method capacity valuation. The Public Utilities Office's proposed approach for

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97 The Public Utilities Office, Improving reserve capacity pricing signals – a recommended capacity pricing model, Final recommendation report, 7 February 2019, p.9. https://www.treasury.wa.gov.au/uploadedFiles/Site-content/Public_Utilities_Office/Industry_reform/Final-Recommendations-Report-Improving-Reserve-Capacity-pricing-signals.pdf

98 The Public Utilities Office, *Allocation of capacity credits in a constrained network, Consultation paper, 26 February 2018, p. iii.* https://www.treasury.wa.gov.au/uploadedFiles/Site-content/Public_Utilities_Office/Industry_reform/Consultation-Paper-Allocation-of-capacity-credits-in-a-constrained-network.pdf

99 The Public Utilities Office, *Allocation of Capacity Credits in a constrained network, Consultation paper, 26 February 2018, p.9.* https://www.treasury.wa.gov.au/uploadedFiles/Site-content/Public_Utilities_Office/Industry_reform/Consultation-Paper-Allocation-of-capacity-credits-in-a-constrained-network.pdf

capacity credit assignments under constrained network model also uses the result of relevant level method as an input.

The ERA's proposed relevant level method is consistent with the current design of the Market Rules and proposed changes to the assignment of capacity credits under constrained network access model. The ERA's proposed method excludes the effect of network constraints.

In its submission to the draft report AEMO noted that for new intermittent generation facilities – with less than five years in full operation – the estimated output of plants was used, which did not include the effect of network constraints. AEMO encouraged the ERA to assess the effect of network constraints on the accuracy of capacity valuation for intermittent generators.[100]

As explained above, the proposed method should exclude the effect of network constraints. The estimated output of new generators should therefore ignore the effect of network constraints. The proposed method, similar to the current method, adds back the effect of consequential outages, usually caused by network constraints, to the observed output of existing generators. The capacity outage probability table also excludes the effect of network constraints. The table uses forced outage rates and the capacity credits for scheduled generators and excludes the effect of network constraints on the capacity value of scheduled generators.

The outcomes of the market reform program are still unclear and the program has been developing slowly. The ERA conducted its review of the relevant level method based on the best available information, including market reform program consultation papers.

6.7.2 Need for transparency

AEMO, Community Electricity and Infrastructure Capital Group emphasised that the relevant level method should provide transparency so that market participants can estimate the number of capacity credits they receive. Infrastructure Capital Group stated that a transparent approach with clear procedures was important and would allow both existing and prospective capacity investors to make informed decisions.[101]

AEMO and Community Electricity said that the ERA's proposed method was complex. AEMO considered that this complexity could lower market participants' confidence in the proposed method.[102] Community Electricity noted that the method proposed by the ERA did not provide a performance standard that market participants could target to maximise the number of capacity credits they received.[103] Synergy supported the intent of reforming the relevant level

[100] AEMO, Submission to Relevant level method review 2018: capacity valuation for intermittent generators, draft report, p.4, (online).

[101] Infrastructure Capital Group, Submission to Relevant level method review 2018: capacity valuation for intermittent generators, draft report, p.1, (online).

[102] AEMO, Submission to Relevant level method review 2018: capacity valuation for intermittent generators, draft report, p.2, (online).

[103] Community Electricity, Submission to Relevant level method review 2018: capacity valuation for intermittent generators, draft report, p.2, (online).

method and noted that any changes to the relevant level method should not add unnecessary complexity or administrative burden to the market.[104]

For increased transparency, AEMO proposed that detailed model specifications and data sources should be made available to market participants, and encouraged the ERA to consult with market participants on the trade-off between transparency and the reasonable protection of confidential data.[105]

The ERA is aware of the trade-off between aiming for increased accuracy, and simplicity and transparency. The ERA's framework of assessment discussed in section 3.3 considered transparency and simplicity of the method as an assessment criteria. The analysis of available options in section 5 finds that the benefits of an improved forecast of capacity values provided by numerical modelling as in the proposed method will outweigh its computational cost when compared to a time-based method, which would provide less reliable results but with lower computation and administration cost. The other options, comprising no change to current method and enhancing the current method, had computation cost comparable to the proposed method but were not likely to provide reliable results.

The proposed method developed by the ERA is more transparent than the current relevant level method. The proposed method is based on international best practice and uses conventional system adequacy assessment techniques. In contrast to the current method, it does not use ad-hoc adjustments and will be explained in detail in a market procedure.

The ERA's proposed method is computationally intensive, but not more so than the current relevant level method. As explained in section 5, a correct calculation of parameter K needs a system adequacy assessment model, for example, equal to that used in the proposed method. The incremental computation cost of the proposed method is negligible. The computational cost of the current method, however, is shared between AEMO and the ERA. AEMO calculates capacity values based on constant parameters K and U, both determined by the ERA. Adopting the proposed method will remove the cost of calculating constant parameters in the current method. After developing the model, AEMO's cost of running the relevant level method will be small and comparable to the current method.

The proposed method also does not need any more data than that required for the current method. AEMO already has access to all data required for the calculation. Similar to the current method, AEMO calculates system demand by calculating the sum of the sent out generation of all facilities plus the load that has been curtailed. It also uses metered sent out generation of intermittent generators adjusted for the impact of consequential outages. AEMO already calculates equivalent forced outage rate of scheduled generators for the purpose of clause 4.11.1(h) of the Market Rules.

Much of the input data used is also available to market participants through the market website or otherwise can be made available to market participants. The exception is the estimated output of new facilities, which is only available to AEMO. To improve transparency, AEMO can publish the estimated aggregate output of new generators, provided that the number of new

[104] Synergy, Submission to Relevant level method review 2018: capacity valuation for intermittent generators, draft report, p.1, (online).

[105] AEMO, Submission to Relevant level method review 2018: capacity valuation for intermittent generators, draft report, p.2, (online).

generators is sufficiently large that the aggregate amount does not reveal individual generators' outputs, if maintaining the confidentiality of such information is a concern.

To increase the transparency of the calculation process, the ERA proposes that AEMO publishes the capacity outage probability table of scheduled generators used for the calculation of intermittent generation fleet capacity value.[106] Using the capacity outage probability table, market participants can calculate the capacity contribution of the fleet of intermittent generators for any assumed scenario of intermittent generation fleet in the system in a capacity year.

6.7.3 Early and conditional certification of reserve capacity

AEMO noted that both the current and proposed relevant level methods did not contemplate how to calculate the capacity value of intermittent generators that applied for early certified reserve capacity or conditional certified reserve capacity.

AEMO considered that this could be an opportunity to remove the market rules that provided for early or conditional certification of reserve capacity, as they contributed to more process complexity. AEMO explained that it had never received an application for early certified reserve capacity and has not received a conditional reserve capacity application since 2011.[107]

The main purpose of conditional certified reserve capacity provision is to provide market participants an opportunity to obtain a conditional level of capacity credits earlier than the normal certification timeframe. This could help market participants to secure investments from financiers. Conditional certified reserve capacity may be obtained in advance but does not guarantee that capacity credits will be subsequently assigned to the facility. Given this risk, financiers are unlikely to finance projects based on receiving conditional capacity credits.

A rule change proposal by the Independent Market Operator[108] introduced early certification of reserve capacity which extended the timeframes for certification of reserve capacity and the assignment of capacity credits for those new generation facilities who can demonstrate commitment to a project beyond the normal timeframes. This allows projects with long lead-times to secure capacity credits earlier and provide greater certainty for investors. However, long lead times for developing generation projects may now occur less often, especially for intermittent generators.

The capacity value of intermittent resources is dependent on the contribution of other capacities in the system. The capacity value of a facility cannot be suitably measured in isolation from other resources in the system. The capacity value estimated for other resources in the system would also be distorted if some of the resources in the system are excluded from the calculation. This effect becomes more prominent if the excluded capacity is large and has

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106 Nevertheless the calculation of the outage table is explained in detail in many sources and can be developed with relatively low cost. Market participants can develop the outage table for any expected scenario of scheduled generators and demand side management in the future.

107 AEMO, Submission to Relevant level method review 2018: capacity valuation for intermittent generators, draft report, p.4, (online).

108 Independent Market Operator, Final rule change report: early certified reserve capacity (RC_2009_10), 2009, (online).

variable available capacity that is correlated with the available capacity of some other resources in the system and demand.

Early or conditional certification of capacity credits needs an isolated calculation of the capacity value for those resources seeking capacity certification and can result in forecasting inaccuracy. Nevertheless, to estimate the capacity contribution of resources seeking early or conditional certification of capacity AEMO can run the proposed relevant level model based on the expected set of generators in the system for a capacity year. This calculation, however, would provide uncertain results. An alternative is to assign early or conditional capacity credits based on the average capacity credits, expressed as percentage of installed capacity, assigned to similar technologies in preceding capacity years.

The Market Rules allow a provisional assignment of capacity credits to a conditionally certified reserve capacity.[109] AEMO reassesses the capacity value of the resource together with other resources during the normal schedule for capacity certification. AEMO can assign a different capacity value than that assigned provisionally if it finds any inaccuracies. A material change in the conditional certification of reserve capacity is not necessary. AEMO can include any facility with conditional certified capacity in the calculation of intermittent generation fleet capacity value as explained in this report.

Removal of the provisions for early certification of reserve capacity from the Market Rules may not be necessary. The capacity contribution of some generators, such as scheduled generators, may not materially depend on the output of other capacity resources in the system. For such generators it is possible to estimate a reasonably accurate capacity value in isolation from other resources in the system. This, however, is not the case for many intermittent generators such as wind and solar. The ERA will consider the calculation of the capacity value for early certification of capacity when developing the rule change proposal for amending the relevant level method. An option can be to assign conservatively smaller capacity values to resources applying for early certification.

6.7.4 Party responsible for the market procedure

AEMO stated that it should be the custodian of the market procedure for the relevant level method with the ERA's support, because AEMO was responsible for the calculations.[110]

It is important to ensure that the market procedure is developed consistent with the ERA's proposed method in this report and its subsequent reviews of the relevant level method. It should also remain consistent with the guidelines to be provided in the Market Rules explaining the objectives of the relevant level method. AEMO will run the proposed method and will be best placed to identify ways to improve the relevant level method.

Under the Market Rules the ERA is responsible for reviewing the effectiveness of the relevant level method. After adopting the proposed method, this would cover reviewing both the guidelines to be developed in the Market Rules and the related market procedure. The ERA will seek AEMO's support to develop the market procedure. However, transferring the responsibility for developing the market procedure to AEMO is not appropriate because AEMO's review or development of the market procedure will be superseded by future reviews

[109] Clause 4.9.5 of the Market Rules.

[110] Ibid, p.3.

conducted by the ERA. Instead, any possible improvements AEMO identifies in running the proposed method can be shared with the ERA at its next review.

6.7.5 Estimation of the sent-out capacity of new generators

AEMO considered that developing best practice guidelines on estimating sent-out generation of new facilities could enhance the accuracy of the proposed relevant level method.[111]

Currently, AEMO uses estimates of the output of new facilities calculated by independent experts. A review of the best practice for the estimation of sent out generation of facilities should have already been conducted by AEMO's consultants. AEMO may have a quality assurance process to assess the quality of information received from its consultants. The ERA encourages AEMO to publish its consultants' reports to the extent the confidentiality of commercial information allows. This will increase procedural transparency and provide an opportunity to market participants of suggesting improvements to the estimation process.

6.7.6 Required changes in the schedule of reserve capacity certification and assignment

AEMO noted that some changes to the certification of reserve capacity and capacity credit assignment processes would be necessary when implementing the ERA's proposed method. AEMO explained that it assigned capacity credits one day after trade declarations were completed, and new facilities provided reserve capacity security. Before the completion of these processes, market participants can change their capacity provided without any financial penalty.[112]

AEMO noted that no time was allowed for the recalculation of capacity values for intermittent generators, if some facilities withdrew their capacity or failed to provide reserve capacity security. To ensure reasonable accuracy, AEMO stated that some time should be allowed for AEMO to recalculate the certified reserve capacity of intermittent generators before assigning capacity credits.[113]

AEMO considered that withdrawal of certified reserve capacity should not be allowed after the calculation of certified reserve capacity to avoid any further calculation iterations, as this would increase administration costs.[114] This matter can be explored in detail and be addressed as part of the rule change process to amend the current relevant level method.

As discussed previously, the capacity value of a resource depends on the contribution of other resources in the system and this is correctly captured by the proposed method. This is a shortcoming of the current calculation method that ignores this effect. If some generators withdraw their application for receiving capacity certification, it is important to recalculate

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111 AEMO, Submission to Relevant level method review 2018: capacity valuation for intermittent generators, draft report, p.3, (online).

112 Ibid.

113 Ibid.

114 Ibid.

capacity values based on the remaining generators in the system. AEMO should be allowed sufficient time to recalculate capacity values before facilities provide reserve capacity security.

6.7.7 Possible increase in AEMO's operational costs

AEMO considered that the implementation of the proposed relevant level method may increase AEMO's operational costs for developing the market procedure and the numerical model.[115]

In the current method the total cost of running the relevant level method is shared between the ERA and AEMO. The ERA estimates the values of constant parameters used in the current method every three years, and this is based on developing and running a system adequacy assessment model. With the proposed method, the ERA will no longer need to determine such constant parameters. AEMO will run the system adequacy assessment model as part of the proposed method. Nevertheless, after developing the system adequacy assessment model, the increase in AEMO's operational costs is expected to be small. The ERA will consider how to minimise the cost of running the relevant level method in its rule change proposal for amending the current relevant level method.

6.7.8 Managing possible financial impacts of the change in the method

Stakeholders provided feedback that the change in the relevant level method could carry financial implications for market participants. Synergy supported the ERA's proposal to phase in the proposed method over a three-year period to smoothing financial implications.[116]

Alinta Energy noted that the energy sector was "in the most uncertain times on record". It noted that no long-term energy policy plan existed beyond the Large-scale Renewable Energy Target program, which was nearing its 2020 deadline. The state energy policy has been subject to reviews, the outcomes from which are yet to be implemented. It suggested the ERA should consider an orderly transition to prevent financial shocks to the broader energy market, that could soften the impact of changes while allowing time for the market to adjust to the new arrangements.[117]

Alinta Energy argued that the draft report lacked analysis on how the various options may commercially affect current or future investors in intermittent generation. It stated that the ideal solution needed to be theoretically sound, but also economically viable and not overly variable.[118]

Synergy noted that the proposed method could increase the sensitivity of capacity value of generators to the entry and exit of other generators in the system and requested further analysis of the possible effect on capacity prices.[119]

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115 Ibid, p.4.

116 Synergy, Submission to Relevant level method review 2018: capacity valuation for intermittent generators, draft report, p.2, (online).

117 Alinta Energy, Submission to Relevant level method review 2018: capacity valuation for intermittent generators, draft report, p.2, (online).

118 Ibid.

119 Ibid.

The draft report explained that the capacity contribution of any resource was dependent on the capacity availability of other resources. The entry or exit of generators would affect other generators' capacity values and the proposed model captured that effect. The capacity contribution of many intermittent generators is also variable because it depends on weather conditions. The capacity valuation method should capture this variation and set capacity values accordingly. The adoption of a method that dampens or overlooks this variation is not desirable because it can increase the long-term cost of electricity supply to consumers and/or reduce the reliability of the system. Highly variable results, however, are not desirable. Results that are overly sensitive to small changes in the system could increase the variability of capacity credit prices and increase finance costs for all generators.

The ERA understands the possible financial impacts of the change in method and will seek to manage the effect of the change through a transition period. This, for instance, could be provided through using a three- to five-year tracking average of the fleet capacity values in the preceding years. This will also dampen the variability of capacity prices caused by the entry or exit of generators. This will be discussed in detail in the rule change proposal for amending the current relevant level method.

7. Summary of stakeholders' feedback

Submission	Comments
AEMO	Generally supported the ERA's aim for improving the relevant level method. Accuracy in calculating the contribution of intermittent generators to the reliability planning criterion supports the reliability of the system and efficient decision-making by market participants. Stated that the proposed method by the ERA appears to be more consistent with the capacity valuation theory, as compared to the current method. **Suitability of the method proposed** Recommended further consideration to assess whether the proposed method can accurately estimate capacity values during peak demand periods specified in the planning criterion of the Market Rules. Supported technology-neutrality of the method used for the calculation of capacity values and encouraged the ERA to include the capacity valuation of emerging technologies as part of the review of the relevant level method. Noted that the reserve capacity mechanism will require changes with a move to a security constrained economic dispatch. AEMO noted that the effect of network constraints on the capacity value of intermittent generators is addressed through constrained access entitlement for constrained access facilities, which is run by Western Power. Because of such arrangements in the Market Rules, AEMO agreed that the relevant level method does not need to account for the effect of network constraints. Noted that for new intermittent generation facilities – with less than five years in full operation – the estimated output of plants is used, which does not include the effect of network constraints. AEMO encouraged the ERA to assess the effect of network constraints on the accuracy of capacity valuation for intermittent generators. **Need for transparency**

Submission	Comments
	Considered that the ERA's proposed method is highly complex, which can lower market participants' confidence in the proposed method. For increased transparency, AEMO proposed that detailed model specifications and data sources should be made available to market participants, and encouraged the ERA to consult with market participants on the trade-off between transparency and the reasonable protection of confidential data. **Implementation considerations** Stated that AEMO should be the custodian of the market procedure for the relevant level method with the ERA's support, because AEMO is responsible for the calculations. Noted the link between the planning criterion and the relevant level method and agreed that the timing of the review of the planning criterion and the relevant level method should be aligned. Considered that developing best practice guidelines on estimating sent-out generation of new facilities can enhance the accuracy of the proposed relevant level method. Noted that some changes to the certification of reserve capacity and capacity credit assignment processes are necessary when implementing the ERA's proposed method. AEMO explained that it assigns capacity credits one day after trade declarations are completed and new facilities provide reserve capacity security. Before the completion of these processes, market participants can change their capacity provided without any financial penalty. Noted that no time is allowed for the recalculation of capacity values for intermittent generators, if some facilities withdraw their capacity or fail to provide reserve capacity security. To ensure accuracy, AEMO stated that some time should be allowed for AEMO to recalculate the certified reserve capacity of intermittent generators before assigning capacity credits. Considered that withdrawal of certified reserve capacity should not be allowed after the calculation of certified reserve capacity to avoid any further calculation iterations, as this would increase administration costs. Considered that improvements to the reserve capacity pricing, under consideration by the Public Utilities Office may have implications for the proposed relevant level method. This is particularly important if the changes do not guarantee that all

Submission	Comments
	new capacity would be awarded capacity credits. In such case, several iterations of the proposed relevant level method may be needed to exclude any new capacity that is not awarded capacity credits. Noted that both the current and proposed relevant level methods do not contemplate how to calculate the capacity value of intermittent generators that apply for early or conditional certified reserve capacity. AEMO considered that this may be an opportune time to remove these provisions from the Market Rules, as they contribute to more process complexity. AEMO explained that it has never received an application for early certification of reserve capacity and has not received a conditional reserve capacity application since 2011. Considered that the implementation of the proposed relevant level method may increase AEMO's operational costs for developing the market procedure and the numerical model.
Alinta Energy	Generally supported the ERA's recommendation but suggested that the ERA must consider how such a change would affect the WEM and the possible consequences of change. Suggested that the ERA needs to be mindful of the market uncertainty when they consider the implementation of the findings from the review. Argued that the draft report lacked analysis on how the various options may commercially affect the current or future investors in intermittent generation. The ideal solution needs to be theoretically sound, but also economically viable and not overly variable. The ERA should consider an orderly transitional process to prevent the potential for shocks to the broader energy market and soften the impact of changes while allowing time for the market to adjust to the new arrangements. Suggests that to calculate the capacity value for the intermittent generator fleet, the methodology should incorporate correction for the historical and future expected changes in capacity, and data used should rather focus on improving the statistical significance and accuracy of capturing the correlation between the wind, solar and load traces due to meteorological factors and not the changes in generation mix.

Submission	Comments
Community Electricity	Supported the ERA's finding that the existing relevant level method is not suitable and needs changing. Supported the ERA's proposed method based on the recommendations of the Institute of Electrical and Electronics Engineers and the International Energy Agency expert groups on Wind Integration Studies, to the extent suitable for the SWIS. **Suitability of the proposed method** Argued that the ERA has not defined the ideal outcome, rather the ERA's draft report assesses the efficacy of candidate alternative methods by comparing their outcomes with each other. Proposed that the review should consider what performance standard is required from the intermittent generation fleet on a 1-in-10 year peak demand day. Argued that power system reliability cannot be managed based on long-term statistical measures or averages and alternative methods should be assessed against a System Management standard. Also discussed the challenges of specifying a System Management standard noting that a large intermittent generation fleet can displace the base-load generating units out of system dispatch particularly when demand is low. Questioned which parties are to bear the risk of the variation of the capacity value of the intermittent generation fleet: the market or the intermittent generators themselves. Noted that currently market customers pay for capacity that may not exist when intermittent generators contribute less than estimated; intermitted generators may be undervalued when they contribute more than estimated. **Need for transparency** Argued that the probabilistic method proposed is based on opaque calculation of effective load carrying capability and does not provide intermittent generators with a means of estimating their capacity contribution and assessing plant investments. Instead, the capacity contribution of intermittent generators is subject to how the system performs. **Other considerations**

Submission	Comments
	Suggested that the use of a probabilistic method should itself be reviewed given that the review of the relevant level method is coincident with a broad Electricity Market Reform. Considered the balance of capacity supply revenue and the funding of capacity. This was based on equating the capacity revenue market generators receive and the cost of capacity credits market customers pay. It noted that in contrast to conventional generators, intermittent generators are subject to lesser standards of performance and are exempt from non-performance penalties. Effectively market customers bear the risk and cost of intermittent generators not contributing to the reliability of the system. Proposed that the capacity contribution of intermittent generators can be assessed retrospectively. This was by drawing analogy between intermittent generators' contribution to meeting peak demand and market customers' reduction of load during peak demand for lowering their cost in funding capacity credits – commonly referred to as individual reserve capacity requirement response. Similar to that conducted for demand response provided by market customers. Proposed an alternative approach for the capacity valuation of intermittent generators based on a retrospective analysis of the contribution of an intermittent generator to a specified performance standard that is visible and can be acted upon, e.g. based on output during the time of the system peak demand, similar to the principle for the funding of the capacity credits. Suggested that their proposed approach will value the contribution of generators individually and generators would bear the consequences of not performing. Noted that in contrast to large-scale solar generation, rooftop solar photovoltaics' contribution to the reliability of the system is not rewarded. It suggested the review should harmonise the rewarding of capacity contribution for these resources. It questioned what their differences are and which one is preferred. Suggested to address the capacity contribution of intermittent generators to the reliability planning criterion by including a new forecast-block in determining the reserve capacity target.
Infrastructure Capital Group	Infrastructure Capital Group supported the ERA's review of the relevant level method.

Submission	Comments
	Suitability of the method Suggested that of the four options considered for setting a capacity value for the fleet of intermittent generators, it would seem prudent to utilise the median of the annual capacity value results to avoid the adverse influence of any large or small capacity value results. **Need for transparency** Supported the implementation of a more transparent model for the assignment of capacity credits to intermittent generators relative to their contribution to reliability. It stated that a reasonable approach is a method that more closely aligns output and demand. Noted a transparent approach with clear procedures is extremely important and will allow both existing and potential investors in generators, either connected or seeking to connect to the SWIS, to make informed investment decisions.
Noel Schubert	Supported the report findings that there are shortcomings with the current method and that it should be replaced for the reasons outlined in the report. He stated that as penetration of intermittent generators in the SWIS continues to grow to significant levels, the current method does not properly credit these generators for the capacity they provide when it is most needed and valuable. Explained that an obvious shortcoming of the current method is that it “moves the goal posts” to times when intermittent generators output is less valuable and so they are credited less with less capacity credits. It also takes away the incentive for intermittent generators to perform better when needed. **Suitability of the method** Supported the ERA’s proposed numerical method for the allocation of capacity credits to intermittent generators provided that it can be implemented at a reasonable cost and will provide sufficient confidence that the intermittent generator fleet output, when needed, will match the level of capacity credits allocated to the fleet to a sufficient level of reliability.

Submission	Comments
	Supported the proposed approach for determining the overall impact and capacity value of the fleet through modelling the loss-of-load probability with, and without, the fleet present. Supported to the allocation of capacity credits to individual intermittent generator facilities, as distinct from the fleet, based on their performance in high capacity value intervals such as peak demand periods.
SkyFarming	Supported the ERA’s proposed method based on effective load carrying capability and use of loss of load probability as the measure of system reliability risk. It also supported the ERA’s proposed method for the allocation of intermittent generation fleet capacity value to individual generators based on output during peak demand and peak net demand periods. **Suitability of the method** Stated that their preferred option for determining the capacity value of the fleet of intermittent generators is to use the result of a five-year sample as input to the model. The ERA’s draft report may imply that the output of wind and solar generators are equally random. However, their output represents “the opportunistic harvesting of sunshine and wind in real time”. It also noted that while they cannot generate more than what is available at the time, they can generate less. Variation between the output of solar farms can happen only when it is cloudy. For wind generation, however, output of wind farms will be different except for very rare times. **Other considerations** Expressed concerns about the view that intermittent generators no longer need revenue from selling capacity credits as they are becoming less expensive. Noted that as the penetration of intermittent generators increases, energy market prices decrease. It also noted recent uptake in the installation of intermittent generators and the decrease in the price of large-scale green certificates and suggested that the reserve capacity mechanism, and capacity credits, remain an important driver of investment in intermittent generation in Western Australia. Noted that batteries do not have the possibility to earn as high revenues from the Wholesale Electricity Market as in the National Electricity Market. Balancing market prices in the Wholesale Electricity Market are capped to approximately

Submission	Comments
	$300/MWh due to the design of the market. It questioned what performance standards should apply to batteries, including their minimum discharge duration and the trigger for their discharge. Given the week-ahead forecasts of very high air temperatures by the Bureau of Meteorology, it suggested batteries can prepare their facilities to have fully charged status ready for discharge during the peak load events. Noted that the balancing market prices have already had instances of negative price, however, to date it has been insufficient for Synergy to announce the closure of Muja C plant, which is an old coal plant. It argued that a financial disincentive may be introduced so that current operators of base-load generation cease operating during low load and high solar generation output.
Synergy	Supported the intent of reforming the relevant level method for enhancing its accuracy in accrediting intermittent generators based on their contribution to system adequacy. It also supported the ERA's use of the international best practice for the relevant level method. Stated costs and benefits of adopting a more detailed method should be considered to ensure the ERA's proposed changes remain fit for purpose. **Suitability of the proposed method** Supports the intent of the ERA's proposal to accredit intermittent generators based on a five-year average or median under the proposed relevant method. Proposed method may render the accreditation of intermittent generators more sensitive to the entrance and withdrawal of scheduled generation. More investigation of this sensitivity is needed to ensure that capacity signals are not adversely impacted by the proposed method. Proposed further analysis of the potential impact on individual facilities and particular technology types; and how these impacts may vary over time. **Implementation considerations**

Submission	Comments
	Suggested an additional round of consultation and analysis be provided to help market participants understand how concurrent market reforms may affect market outcomes on aggregate. Also supported that the method is phased in over a 3-year period to smooth financial implications. Also supported letting the Market Rules guide the structure and objectives of the relevant level method and for a market procedures to specify the finer details and mechanics of the calculations involved in the method.
Timothy Edwards	**Suitability of the proposed method** He argued that the ERA's proposed method is biased "towards changing the Rules to the needs of the most vocal [scheduled generation] proponents". Considered that the categorisation of generators – eg, wind, solar and wave – is essential prior to applying a numerical model. Argued that the assumption that the most critical period for certification of capacity is based on peak demand periods may be incorrect, however, it is consistent with how market customers fund the procurement of capacity; therefore this assumption makes practical sense. Suggested that the ERA should consider the whole load cycle, otherwise "new proponents steer the development of their assets to address only peak demand (i.e. battery storage) and remove incentive to provide additional base load diversity (solar, wind, waste, geothermal, etc.)". **Other considerations** Suggested the ERA draft paper only identified there is insufficient diversity of generation and grid management techniques and there was little evidence to show that changing the current method will address those problems or will lower costs to users of the system.

Submission	Comments
	Noted that the ERA draft paper had a theme that suggested solar generation does not address the evening shoulder peak periods and thus its contribution is not as valuable as wind generation.