Technical Appendix - Relevant level method review 2018

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Economic Regulation Authority
WESTERN AUSTRALIA

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Economic Regulation Authority

4th Floor Albert Facey House
469 Wellington Street, Perth

Mail to:
Perth BC, PO Box 8469
PERTH WA 6849

T: 08 6557 7900

F: 08 6557 7999

E: info@erawa.com.au

W: www.erawa.com.au

National Relay Service TTY: 13 36 77
(to assist people with hearing and voice impairment)

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Appendix 1 History of the relevant level method review

Before the review of the relevant level method in 2011, the capacity value of intermittent generators was based on the average output of those facilities over the course of a year. Historically, this equated to valuing wind farms at 38 to 42 per cent of their nameplate capacity. Solar farms modelled at 20 to 30 per cent of nameplate capacity, but with limited available actual data.

At the time, the Independent Market Operator recognised that this approach was not suitable, because it did not align the output of the intermittent generators with peak demand, when capacity is actually required to maintain system reliability. The Independent Market Operator established the Renewable Energy Generation Working Group to determine a new approach. Whilst the group considered several alternative proposals, they did not reach a consensus. As a result, the Independent Market Operator created a rule change to address the issue.

A1.1 2010/11 rule changes

In 2010, the Independent Market Operator and Griffin Energy proposed rule changes to address the allocation of capacity credits to intermittent generators.[1] Both proposals relied on identifying trading intervals based on the highest load for scheduled generation (LSG) - the difference between total sent out generation and the sum of the output of all intermittent generators.

The Independent Market Operator's proposal was to determine capacity credits based on an intermittent generator's average output over the top 250 LSG trading intervals over the past three years. This was then multiplied by a 'fleet adjustment factor' to reflect the overall variability of the generation fleet.[2]

Griffin's proposal was to determine capacity credits based on the average output of the facility in the top 750 LSG trading intervals in the past three years. It did not include an adjustment factor.

The Independent Market Operator commissioned Sapere Research Group to provide independent advice on the two proposals and to provide advice on any modifications that would make the rule change proposals more robust.

Sapere's recommendations included:

- Averaging facility output from the top 12 trading intervals (as identified by LSG) drawn from separate days over the past 5 years.
- Adjusting for known variability in facility output (parameter K – Sapere initially set the value of parameter K based on international benchmarks).
- Adjusting for performance of intermittent generators during peak times (parameter U – Sapere capped its value at two thirds of an intermittent generators facility output, based on limited data on intermittent generator performance at extreme air temperatures).

1 Griffin Energy, *Calculation of the Capacity Value of Intermittent Generation (RC_2010_37)*, 2010, https://www.erawa.com.au/cproot/16867/2/Original Submission.pdf; The Independent Market Operator, *Calculation of the Capacity Value of Intermittent Generation – Methodology 1 (RC_2010_25)*, 2010, https://www.erawa.com.au/cproot/16250/2/Original Submission.pdf..

2 This was based on the mean and variability of the generation fleet taken over the top 12 trading intervals over the previous 8 years at 95 per cent probability of exceedance.

The Independent Market Operator amended its rule change proposal in line with Sapere's recommendations and rejected Griffin's proposal.[3] The rule change included the requirement for a review of the relevant level method every three years. The amended rules commenced on 1 January 2012. Values for parameters K and U are shown in Table A1. A three year glide path was used to transition to the new method.

Table A1. Value of K and U parameters set for capacity years

When set	Reserve capacity cycle	Capacity year	Parameter K	Parameter U
2010 rule change	2012	2014/15	0.001	0.211
	2013	2015/16	0.002	0.422
	2014	2016/17	0.003	0.635
2014/15 review by the Independent Market Operator	2015	2017/18	0	0.635
	2016	2018/19	0	0.635
	2017	2018/19	0	0.635
AEMO fast track rule change[1]	2018	2019/20	0	0.635
2018/19 review by ERA	2019	2020/21	If the ERA were to retain the current RLM then it would need to calculate K and U values for the next three years. Even if the ERA proposes an alternative method, it may still need to calculate K and U values whilst any proposed rule change to a new method is processed.	
	2020	2021/22		
	2021	2022/23		

Note: Because of the delay in reviewing the RLM, there were no K and U values determined for the 2018 capacity year. So, AEMO proposed a fast track rule change to enable it to use K and U values from the 2017 reserve capacity cycle for the 2018 reserve capacity cycle.

A1.2 2014/15 RLM review

The Independent Market Operator recommissioned Sapere to undertake a review of the relevant level method in 2014. Any proposed amendments to the method could be progressed through the rule change process in time for certification of capacity for the 2015 reserve capacity cycle. Included in the scope of the review were:

- a review of developments in international best practise
- analysis of the application of the method since 2012
- consideration of the increasing penetration of intermittent generators and whether an alternative valuation method is required
- consideration of whether any changes were warranted in how peak trading intervals were selected
- consideration of whether any changes were warranted to account for the correlation of output between intermittent generators
- calculation of the value of parameters K and U.

[3] The Independent Market Operator, *Final Rule Change Report, Calculation of the Capacity Value of Intermittent Generation - Methodology 1 (IMO) and Methodology 2 (Griffin Energy)*, 2011, https://www.erawa.com.au/cproot/16240/2/Final Rule Change Report.pdf.

Sapere recommended no changes to the method and that the revised value of parameter K be set to zero and the value of parameter U remain at 0.635.

Table A2 summarises Sapere's investigation of the main issues in the previous reviews of the relevant level method.

Table A2. Main points investigated by Sapere

Issue	Findings
Clustering of trading intervals	Rule change proposals in 2010 suggested measuring intermittent generator output over the trading intervals with peak LSG: • The Independent Market Operator proposed to use the top 12 intervals over 5 years • Griffin suggested using the top 750 intervals over 3 years. Sapere identified this approach as being subject to clustering, ie the top trading intervals tend to be clustered around a run of hot days. Sapere resolved this problem by recommending that the peak trading intervals be drawn from different days, which is reflected in the current method.
Measuring intermittent generator output at peak or peak reduction	Sapere stated that the method for the calculation of capacity value for intermittent generators seeks to identify the intermittent generator's contribution to lowering peak LSG (when surplus capacity is lowest and the risk of loss of load is greatest). However, the variability of intermittent generator output can change the timing of peak LSG and so measuring output at peak LSG, based on deducting the output of *all* intermittent generators from demand, may underestimate the value of intermittent generator capacity. Application of a parameter K (to reflect intermittent generator output variability[4]) may further reduce the value of intermittent generator capacity. Sapere argued that an alternative to using output at peak LSG is to use a measure of the intermittent generator's contribution to reducing the peak LSG within and between trading intervals. Sapere explained that peak reduction within a day would give a more accurate measure of an intermittent generator's marginal contribution. Sapere calculated the average difference between intermittent generators' output measured at peak LSG and peak reduction within a day as 5 MW, and between peaks across days as an additional 1.9 MW. Sapere estimated that an adjustment of 0.0023 in the value of parameter Kchanges the fleet capacity value by 5 MW.
Setting the value of parameter K for the SWIS	The 2010 rule change determined initial values of parameter K from international benchmarks. In calculating the value of parameter K for the SWIS, Sapere expected a high value on the grounds that the variability of an intermittent generator in a small system like the SWIS would increase risks to system adequacy. However, Sapere determined the value of parameter K for the SWIS based on the probability distribution of surplus load[5] as 0.0023, which was smaller than expected. AEMO's forecasts at the time indicated a skewed distribution of peak demand. This has the effect of stretching the 'tail' of the distribution to look more like a bigger system. Sapere stated that measuring output at peak LSG may underestimate the intermittent generators' contribution to peak and that the 'size' of that underestimation was equivalent to setting K to 0.0023. Sapere recommended setting the value of parameter K for the SWIS to zero.
Performance of intermittent generators at very high air temperatures	Sapere looked at averaging intermittent generator output on days with air temperatures greater than 40 degrees Celsius as an alternative to averaging output at peak LSG, adjusted by a parameter U. At very high temperatures intermittent generator output drops significantly. Wind may drop on very hot days which reduces wind farm output, and the maximum temperature appeared to be later in the day when solar output was lower. However, at the time, few solar data points were available. The main problem was the small number of days with very high air temperatures. Calculation of capacity values based on a small sample could result in substantial uncertainty and lead to variable capacity value results from year to year. Sapere also ran a regression analysis, using daily maximum air temperature to forecast intermittent generators' output at very high air temperatures. However, Sapere noted that the relationship between air temperature and demand may not be linear, so using linear regression may not be suitable. It also found that the use of regression analysis can result in variable capacity value results from year to year. In the absence of a better alternative Sapere suggested continuing to use parameter U.

4 This is not a correct interpretation of parameter K. This parameter reflects the effect of the availability of existing generators and demand on the capacity value of the resource for which capacity value is being calculated. The combination of output average, parameter K and variance reflect the effect of the variability of the resource on its capacity value.

5 Because of the skewed distribution of peak demand in the SWIS, Sapere applied a skewed probability distribution function.

Appendix 2 Capacity valuation of intermittent resources in other jurisdictions

This section provides an overview of how different jurisdictions assess the contribution of intermittent generators to meeting the particular supply adequacy standards specific to each jurisdiction. Supply adequacy standards are an expression of the acceptable frequency or duration of interruptions to power caused by insufficient supply.

Several North American jurisdictions were reviewed, including the New York Independent System Operator (NYISO), the New England Independent System Operator (ISO-NE), the Midcontinent Independent System Operator (MISO), and the Pennsylvania, New Jersey, Maryland Interconnection (PJM).

The California Independent System Operator (CAISO) resource adequacy mechanism, which is not a centralised capacity market, was also reviewed, along with the final design for the proposed Alberta capacity market. The system adequacy assessment in Great Britain was also reviewed. The system adequacy assessments in Great Britain and MISO have only recently been designed. These are based on research into the experiences of other jurisdictions (PJM, NYISO and ISO-NE) that have considerable experience operating and refining capacity markets.

A2.1 Supply adequacy

The supply adequacy standard in all jurisdictions is based on a loss of load expectation (LOLE) that is either approved or endorsed by government or a relevant regulator. Lost load or unserved energy and the number of loss of load events are assessed across the entire electricity system.[6] The supply adequacy standard is then converted into a target capacity amount by the system operator. This is then used in a centralised auction to procure at least a portion of the system's capacity requirements. The cost of this procurement is allocated across load serving entities[7] or customers.

The most common resource adequacy standard is the one event of firm load loss per ten years (1-in-10 LOLE planning criterion). Historically, there is no formal justification for the use of this criterion other than that it may have provided planners and operators with sufficient excess capacity to be confident that reliable operation of the system would remain possible.[8] When energy markets began, energy demand grew steadily. The installation of new generators in the system took long periods of time, typically three to five years. Capacity had to be planned and built well in advance and would be eventually put to use.[9]

More recently, the historical conditions that facilitated this approach to resource adequacy are no longer relevant, with load growth slowing significantly due to economic, technological and policy changes. New capacity additions come from resources that can be built in a short period of time, such as generation upgrades, or demand response. Developments in smart-

6 Only a small subset of customers may be affected by each outage, even though an outage will count against absolute system performance. Consequently, individual customers may likely observe resource adequacy that are better than the levels observed by the system as a whole

7 Load serving entities are retailers that sell electricity at retail prices in the competitive market.

8 Stoft (2008) explained that this 1-in-10 year standard was suggested by two General Electric engineers. They suggested that more than one load-shedding event in ten years would be unwanted. Refer to S Stoft, 'The Surprising Value of Wind Farms as Generating Capacity', in *SSRN*, 2008, 1–18 (p. 3), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=1250187.

9 Resource planners provided a greater emphasis on resource adequacy rather than on cost, with curtailments in load never actually expected to occur.

grid technology and other forms of customer engagement promise more demand side involvement, with customers better able to express their willingness to pay for reliability.[10]

Different planners and regulators have interpreted the 1-in-10 criterion in different ways, with each approach capturing one or more of the relevant shortfall event parameters of frequency, duration and magnitude. For example, a daily LOLE criterion stipulates the expected number of days in a given time period during which there is a capacity shortfall. A 1-in-10 daily LOLE could also be interpreted as one event in ten years or an expected average of 0.1 shortfalls in a year. This criterion does not account for the duration or magnitude of a shortfall.

An hourly LOLE is a measure of the expected number of hours during a particular period (cf. the number of times) during which load is expected to exceed resources' capacity. Interpreting the 1-in-10 criterion using this measure would allow for 24 cumulative hours of hourly LOLE every ten years. This measure uses more data but accounts for both frequency and duration, providing a more precise indication of the expected level of reliability. The hourly LOLE can be converted to a loss of load probability (LOLP), which provides the probability that supply will be inadequate to serve demand over a particular period. Like the daily LOLE, the hourly LOLE does not account for the magnitude of a shortfall.

Expected unserved energy measures the expected quantity of demand that will not be served over a specified time period (in megawatt hours). This resource adequacy metric has been applied less commonly than LOLE, usually in systems that have large amounts of hydropower capacity. However, it has the advantage of considering the variability of load and resources during all periods. A more direct comparison between unserved load and economic valuations is possible using expected unserved energy because it is measured in megawatt hours. Expected unserved energy accounts for the magnitude and duration of shortfalls but it does not account for frequency.

Planning coordinators in North American jurisdictions (PJM, NYISO, ISO-NE, MISO and CAISO) are required by the North American Electric Reliability Corporation (NERC)[11] to perform and document resource adequacy analyses annually.[12] As part of this, they must calculate a planning reserve margin that will result in the sum of the probabilities for loss of load[13] being equal to 0.1, which is comparable to a "one day in 10 year" criterion.[14] In contrast, the Great Britain market employs a criterion of 3 hours LOLE per year, on average, allowing for the probabilities of mild and also very cold winters.

A2.2 Assignment of capacity credit to intermittent generators

Most capacity markets promote technological neutrality, permitting the participation in capacity markets by conventional and unconventional resources such as intermittent generation, demand response, and in some cases, energy efficiency and imports.

[10] This has led to questions about the continued relevance of the 1-in-10 adequacy standard and LOLE as an acceptable criterion for resource adequacy.

[11] NERC is the North American electric reliability organization, with an area of responsibility spanning continental United States, Canada, and the northern portion of Baja California, Mexico. Its purpose is to assure the effective and efficient reduction of risks to the reliability and security of the grid and it is subject to oversight Federal Energy Regulatory Commission and governmental authorities in Canada.

[12] NERC, *Reliability standards for the bulk electric systems of North America*, Atlanta, 2018, p. 1, https://www.nerc.com/pa/Stand/Reliability Standards Complete Set/RSCompleteSet.pdf.

[13] For the integrated peak hour for all days of each planning year.

[14] The annual period over which the LOLE is measured, and the resulting resource requirements are established 1 June through 31 May.

To promote technological neutrality, the capacity product has to be defined so that a megawatt of capacity from each resource represents an equivalent reliability value. The variability of the output of different intermittent generators presents a challenge for estimating their capacity contribution. Consideration is required of how to determine to what extent intermittent generators can be relied upon to support resource adequacy.

Estimation of the proportion of nameplate capacity of an intermittent generator representing its capacity value differs by market and resource type. Each market establishes protocols for determining how much capacity a resource contributes and whether locational or seasonal variation is required. Regular updates are made to capacity values, depending on historical performance outcomes, and new intermittent generators may have their capacity value established based on similarly aged and located existing resources.

One example of a common approach to assessing the capacity value of a resource is based on unforced capacity (UCAP), which is calculated differently for each resource. The UCAP of coal or gas generation units is calculated as the maximum ability to generate adjusted for the Equivalent Forced Outage Rate (EFOR), which represents the historical availability of a resource. The UCAP metric has faced criticism because the EFOR measures availability generally, rather than availability at times when the system is short of operating reserves or energy.[15]

Intermittent generators have limitations that are not directly translatable into EFOR in adequacy calculations, such as wind or solar variability that is correlated with load or limitations on total energy production from storage.[16] Consequently, for intermittent generators, UCAP is generally based on historical capacity factors during seasonal peak demand hours.

Pennsylvania, New Jersey, Maryland Interconnection

In the PJM market, the calculation of a capacity value for a particular wind or solar capacity resource in a specific year involves first computing its unique single year capacity factors for each of the prior three summers, based on operating data for each of these summers. In the case of a new wind or solar resource that has fewer than three years of data, the single year capacity factor is assigned the value of the class average capacity factor[17] for each summer where there is no or incomplete data. The mean of single year capacity factors for each of the prior three years results in a capacity factor representative of the three prior years. That capacity factor, when multiplied by the resources current net maximum capacity[18] yields the current capacity value for that wind or solar capacity resource.[19]

Capacity storage resources in the PJM market are eligible to offer capacity based on the output they can maintain for four hours. Storage, intermittent resources, and energy

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15 Charles River Associates, *The Economic Foundations of Capacity Markets, Prepared for Alberta Utilities Commission*, Calgary, Canada, 2017, http://www.auc.ab.ca/Shared Documents/2017-06-02_EconomicFoundationsofCapacityMarkets.pdf.

16 C Bothwell & BF Hobbs, *Crediting Renewables in Electricity Capacity Markets: The Effects of Alternative Definitions upon Market Efficiency*, Baltimore, 2016, https://www.caiso.com/Documents/BriefingonRegionalResourceAdequacyInitiative-MSCBothwellHobbs_WorkingPaper-June2016.pdf.

17 The class average capacity factor is determined and periodically updated by PJM based upon review of operating data for similar units and/or engineering studies for future installations.

18 A wind or solar capacity resource’s net maximum capacity is the manufacturer’s output rating, less the station load, which refers to the amount of energy that is consumed to operate all auxiliary equipment and control systems.

19 PJM System Planning Department;, *PJM Manual 28: Rules and Procedures for Determination of Generating Capability, Revision: 12*, 2017, https://www.pjm.com/-/media/documents/manuals/m21.ashx.

efficiency may offer capacity into an auction based on their expected average output during peak hours.

Independent System Operator of New England

ISO-NE assigns summer and winter qualified capacity values to intermittent generators, based on the average of the median of the resources' net output in each of the previous five years. If there are less than five full summer or winter periods of historical data, the median of the intermittent generators' net output in each of the previous summer periods, or portion thereof, since it began operating, is employed.[20] In April 2017, ISO-NE had plans to qualify battery resources as non-intermittent generators in a similar way to conventional and pumped hydro generators.

New York Independent System Operator

NYISO calculates summer and winter capacity values for wind and solar resources based on the average output during summer and winter during peak demand hours in the previous six-month delivery period. Capacity values for new intermittent generating resources vary based on fuel type, with the initial UCAP value, which is measured as the amount of capacity a resource can reliably provide during system peak load hours, calculated as the product of the applicable UCAP percentage in the NY-ISO manual[21] and that resource's dependable maximum net capability.[22] The capacity value assigned to reservoir and pumped storage hydro is the station wide average output over a 4-hour period with average stream flow and storage conditions.

A method for calculating the capacity value assigned to batteries has not yet been prescribed. NYISO is in the process of establishing rules for the participation of batteries in this market. To qualify to participate in the capacity market, batteries will need to be capable of meeting the existing 4-hour minimum run-time requirement. Energy storage resources can de-rate the capacity of the resource to meet the 4-hour duration requirement. For example, a 40 MWh battery with the capability of injecting 20 MW would be able to reduce its capacity to 10 MW for 4 hours to meet the duration requirement.

Midcontinent Independent System Operator

MISO employs historical wind availability information to calculate the effective load carrying capability (ELCC) of wind resources.[23,24] The ELCC approach involves two steps. Firstly, a probabilistic approach using LOLE is employed to determine the MISO system-wide ELCC value for all wind resources in the MISO footprint. The system-wide wind capacity credit in the 2018/19 planning year is 15.2 per cent of the installed capacity of wind resources. Secondly, a deterministic approach, using the historical performance data for each wind

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20 ISO-NE Manual Qualified Capacity https://etariff.ferc.gov/TariffBrowser.aspx?tid=1507

21 See pages 4-23 and 4-24. https://www.nyiso.com/documents/20142/3982101/ICAP%20Manual%20Attachment%20J%20Edits.pdf/3b48965d-3c59-1da9-82f8-879bf71c67de

22 The dependable maximum net capability is the sustained maximum net output of a Generator, as demonstrated by the performance of a test or from actual operation, averaged over a continuous time period.

23 MISO note that the ELCC method has been used in the determination of capacity value for generation resources as far back as 1966, when Garver demonstrated the use of LOLP mathematics in the calculation of ELCC. MISO cite: Garver, L.L.; "Effective Load Carrying Capability of Generating Units," Power Apparatus and Systems, IEEE Transactions vol.PAS-85, no.8, pp910-919, Aug. 1966.

24 As described in MISO, Planning Year 2018-2019 Wind Capacity Credit, December 2017. https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t00000016bIiAAI

resource and its location, is employed to allocate the system-wide ELCC value across all wind commercial pricing nodes in the MISO to determine the capacity credits for each node. As of 30 June 2017, MISO had 207 commercial pricing nodes of registered wind capacity. The per cent credit across all wind nodes ranged from 0.6 to 29 per cent.

MISO has found that, as the geographical distance between wind generation increases, the correlation in the wind output decreases, leading to a higher average output from wind for a more geographically diverse set of wind plants.[25] Due to the increasing diversity and the inter-annual variability of wind generation over time, the calculation of ELCC is repeated annually, incorporating the most recent historical performance of wind resources into the analysis.

The UCAPs for other intermittent resources are determined by MISO based on historical performance, availability, and the type and volume of interconnection service. The capacity value of solar resources in MISO is based on the average output during summer peak hours for the three prior years.[26] The contribution of reservoir and pumped hydro is determined by measuring the median output in summer peak hours over the past 5 to 15 years and converting it to expected power output.

California Independent System Operator

CAISO determines the qualifying capacity of wind and solar by calculating the monthly ELCC of these resources.[27,28] Monthly ELCC values are calculated using the following process:

1. A monthly LOLE study is conducted and a desired level of reliability is determined for each month. An hourly reliability simulation representative of each month of the year is conducted, with projected loads and expected resources, resulting in the desired monthly reliability level in each month. If results are either more or less reliable than desired, capacity or load is added or subtracted until each month's reliability results are in the desired range.

2. A monthly portfolio ELCC study is conducted. All wind and solar inside the CAISO aggregated region is removed. Perfect capacity[29] or load is added or removed in each month individually until the resulting reliability level is back to the desired range. The amount of perfect capacity or load added, in MW, is equal to the portfolio ELCC of all wind and solar generators.

3. ELCC modelling is performed on each category individually. Wind generators are added back into the model but solar generators remain removed. Blocks of load are added or blocks of perfect capacity are removed iteratively from each month until reliability levels are within the desired range for each month. The result is the standalone ELCC of wind generators. The modelling is then repeated, this time adding

25 Relative to a closely clustered group of wind plants.

26 See MISO Business Practice Manual – Resource Adequacy, page 33 https://www.misoenergy.org/legal/business-practice-manuals/

27 See Revised QC Modeling Manual, available under Guides and Resources: http://www.cpuc.ca.gov/General.aspx?id=6311

28 For monthly ELCC values refer to: http://www.caiso.com/Documents/NetQualifyingCapacityList-2018.xlsx

29 Perfect Capacity refers to fictional generators with perfect capabilities eg zero forced and maintenance outage rates and zero start-up times. They are a standard against which to compare real existing generators. http://www.cpuc.ca.gov/uploadedfiles/cpucwebsite/content/utilitiesindustries/energy/energyprograms/electpowerprocurementgeneration/demandmodeling/r.14-10-010%20revised%20monthly%20lole%20and%20elcc%20proposal%202-24-17.pdf

back solar generators and removing wind generators. Blocks of perfect capacity are removed iteratively from each month until the reliability level again falls within the desired range in each month, resulting in the standalone ELCC of solar generators. In both cases, the monthly levels of perfect capacity or added load modelled are recorded.

4. The standalone ELCC of wind and solar generators is added and compared to the portfolio ELCC calculated earlier. The difference (either positive or negative) is the diversity adjustment, which will be negative when the standalone ELCC values total greater than the portfolio ELCC. Negative values are the result of modelling a category of generator while another category of generators in the portfolio ELCC was present, and some of the reliability contribution it imparts is applied as diversity. In that case, diversity must be removed, which involves allocating the diversity adjustment to either wind or solar generators by prorating to the proportion of wind and solar standalone ELCC in each month.

5. The effect of behind-the-meter solar on the overall renewable portfolio standards is then accounted for. The ELCC of solar generators is compared without behind-the-meter solar in the fleet to the ELCC of solar with behind-the-meter solar included. That difference represents the amount of perfect capacity that is equivalent to the additional supply side solar added as well as all behind-the-meter solar installed that has until now not been included in modelling. Prorating the additional perfect capacity to the portion of the new solar that is behind-the-meter solar will represent the added perfect capacity for the behind-the-meter solar, and when removed represents just the perfect capacity needed for the incremental new supply side solar added.

6. The ELCC values that are the result of the modelling for each month, are then divided by the total nameplate installed MW of that technology, and the resulting monthly percentage values represent the ELCC percentages that are applied to the nameplate MW values of each individual generating facility to create the qualifying capacity of the generator.[30]

Alberta Electric System Operator

In the proposed final capacity market design for Alberta it is stated that a capacity factor method will be used to calculate UCAPs for wind, run of river hydro and solar. The Alberta Electric System Operator will calculate and assign a UCAP value for each prequalified asset using the 250 tightest supply cushion hours in each of 5 years of historical data. Assets with insufficient historical operating data will have data supplemented by class averages,[31] engineering production or load estimates[32] or information on assets gathered through other jurisdictional reviews. Storage assets will be required to demonstrate four hour continuous discharge capability at their estimated UCAP level.[33]

30 Any further steps to create locational factors to break up wind and solar further into location or sub technology specific factors would follow from this point.

31 Class averages will be based on operating data for similarly designed or geographically located environmental assets (such as wind or solar). The class-average will be based on average energy production or available capability declarations as observed during the 250 tightest supply cushion hours per year, calculated for each of the previous five years.

32 Submitted by the legal owner of the capacity asset, if appropriate, to determine an availability or capacity factor.

33 See bottom of page 3 on Capacity Value (UCAP) Determination: https://www.aeso.ca/assets/Uploads/Consolidated-proposal.pdf

Great Britain

In the Great Britain market, renewable generators, such as wind, hydro and solar that receive low carbon support subsidies (such as feed in tariffs, the domestic renewable heat incentive and the renewables obligation[34]), are not eligible to participate in the capacity auction. [35] Whilst the original intent for the Great Britain capacity market may have been that renewable generators that do not receive low carbon support[36] should be eligible to participate, in practice this is not possible because the list of technology classes for the capacity market excludes a wind class or distinct onshore wind or offshore wind classes.[37]

Nevertheless, National Grid[38] and Ofgem[39] still consider wind generation as part of the assessment of system adequacy. The contribution from wind power reduces the amount of capacity that is required to be procured through the auction to meet the Great Britain power system reliability standard. As in other markets, the risk of system stress events starts with a probability distribution of available conventional generating capacity.[40] This is combined with variable wind output and demand to give the net demand facing conventional capacity, from which the LOLE is determined.[41]

A de-rating factor is applied to all forms of generation technologies to account for outages or maintenance, with de-rating factors derived from the historical availability performance of different technologies during the winter peak period, in the prior seven winters. When considering wind, National Grid assesses the wind fleet's contribution to reliability of supply over the entire winter period.[42] This is achieved by considering a history of wind speeds observed across Great Britain, feeding in to technology power curves to estimate the wind fleet's power output, and running several simulations to determine its expected contribution.

The expected contribution of wind is referred to as its equivalent firm capacity.[43] The equivalent firm capacity of wind depends on many factors that affect the distribution of available wind generation, including the amount of wind capacity installed on the system, where it is located, and the amount of wind generation that might be expected at periods of

34 The Renewables Obligation (RO) is one of the main support mechanisms for large-scale renewable electricity projects in the UK. See https://www.ofgem.gov.uk/environmental-programmes/ro/about-ro

35 See Chapter 3 of the Electricity Capacity Regulations 2014 http://www.legislation.gov.uk/ukdsi/2014/9780111116852/regulation/16

36 Either through having foregone low carbon support or through the expiry of contracts. See https://www.ofgem.gov.uk/system/files/docs/2017/10/cp314_innogy.pdf

37 See schedule 3 page 130 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/340046/capacity_market_rules.pdf

38 National Grid owns and operates the electricity transmission network in England and Wales, and has day-to-day responsibility for balancing supply and demand.

39 Ofgem is the government regulator for gas and electricity markets in Great Britain.

40 The Great Britain market de-rates the installed capacity of conventional generation technologies to reflect the fact that generators capacity is not available 100 per cent of the time because of outages or maintenance. De-rating factors are derived from the historical availability performance of different technologies during the winter peak period in the prior seven winters.

41 See page 11: https://www.eprg.group.cam.ac.uk/wp-content/uploads/2014/09/1412-PDF1.pdf

42 Rather than output at peak times.

43 In effect, equivalent firm capacity is the level of 100 percent reliable plant that could replace the entire wind fleet and contribute the same to reliability of supply.

high demand.[44] It has been observed that the wind tends to stop blowing when there is a severe cold spell, resulting in lower wind availability at times of high demand for electricity.[45]

Unlike wind generation, storage is allowed to compete in the Great Britain capacity market.[46] To date there has been a single de-rating factor for all storage based on the historical technical availability of pumped hydro at times of peak demand. However, some new storage technologies may be designed to have maximum durations as short as 30 minutes, based on requirements for ancillary services. This contrasts with the time frame of capacity market stress events that, if they were to occur, could last as long as two hours on average at the system target reliability level of three hours LOLE per year.

During the second half of 2017 National Grid undertook an extensive industry consultation on a proposed method for calculating a range of de-rating factors for storage sub-class durations ranging from 30 minutes up to around four hours.[47] This approach aimed to ensure that there is a transparent and fair means to account for short-duration storage contributions to reliability of supply and thus facilitate its entry into the capacity market. It would also ensure that consumers pay an appropriate amount for the total capacity necessary to meet Great Britain's reliability standard.

Amendments to the capacity market rules have been made to accommodate a new method.[48] National Grid calculates the equivalent firm capacity for each class of storage technologies that is duration limited using a time-sequential stochastic simulation model where the outputs of the model for each class are multiplied by the technology class weighted average availability for that class. The technology class weighted average availability is calculated by determining the average availability for each unit directly connected to the transmission network in the class over the seven immediately preceding core winter periods. National Grid will make a final determination on the equivalent firm capacity for each class that is duration limited after consulting with technical experts.

Table A3 provides a summary of how capacity value is assigned to intermittent generators in the various North American jurisdictions.

44 See National Grid EMR Electricity Capacity Report (31 May 2018) https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/189/Electricity%20Capacity%20Report%202018_Final.pdf

45 See page 21: https://www.ofgem.gov.uk/sites/default/files/docs/2015/07/electricitysecurityofsupplyreport_final_0.pdf

46 The penetration of battery storage is growing fast with many having won capacity market contracts for 2020/21, 2018/19 and 2021/22 auctions.

47 See https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/150/Duration%20Limited%20Storage%20De-Rating%20Factor%20Assessment%20-%20Final.pdf

48 See New Schedule 3B https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/670438/20171218_CM_Amendment_Rules_4_2017.pdf

Table A3. Assignment of Capacity to Intermittent Generators by Jurisdiction

Jurisdiction	Wind	Solar	Hydro	Storage
PJM[49,50]	Capacity factor during peak hours. Rating in summer and winter. Average hourly output: winter hours ending* 6 to 9 and hours ending 18 to 21 January and February; and summer hours ending 15 to 20 June, July and August)[51] Average three years historical data, by facility.	Capacity factor during peak hours. Rating in summer and winter. Average hourly output: winter hours ending 6 to 9 and hours ending 18 to 21 January and February; and summer hours ending 15 to 20 June, July and August) Average three years historical data, by facility.	Reservoir, Pumped storage, and Run-of-river: Average hourly output hours: winter hours ending 6 to 9 and hour ending 18 to 21 January and February; and summer hours ending 15 to 20 June, July and August	For any flywheel or battery storage, or other such facility solely used for short term storage and injection of energy at a later time: Average hourly output hours: winter hours ending 6 to 9 and hour ending 18 to 21 January and February; and summer hours ending 15 to 20 June, July and August.
NYISO[52]	Capacity factor during peak hours. Rating in summer and winter. Average production during prior equivalent delivery period: Summer: hours ending 14 to 18, June, July and August; and Winter: hours ending 16 to 20, December, January and February Historical data for current year, by facility	Capacity factor during peak hours. Rating in summer and winter. Average production during prior equivalent delivery period Summer: hour ending 14 to 18 June, July and August; and Winter: hour ending 16 to 20, December, January and February Historical data for current year, by facility	Hydro stations: Sustained net output averaged over a 4-hour period using average stream flow and storage conditions within machine discharge capacity. Run-of-river: rolling average of the hourly net Energy provided during 20 highest load hours in each of 5 delivery periods Winter: November through April, Summer: May through October	Not participating yet.

49 PJM Manual 21: Rules and Procedures for Determination of Generating Capability https://www.pjm.com/-/media/documents/manuals/m21.ashx.

50 PJM Manual 18: PJM Capacity Market, page 118 https://www.pjm.com/-/media/documents/manuals/m18.ashx

51 The hourly data for curtailed hours are replaced, in part, with 5minute data from the PJM state estimator for each 5minute period without constraints and, for the five minute periods with constraints. Values are determined by linear interpolation using the nearest 5minute data surrounding the constrained period.

52 NYISO Installed Capacity Manual, Manual 4, March 2018. http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/icap_mnl.pdf

Jurisdiction	Wind	Solar	Hydro	Storage
ISO-NE[53]	Median during peak hours. Rating in Summer and Winter. Summer: hour ending 14 to 18 from June through September; and Winter: hour ending 18and 19 from Oct to May Historical data for five years, by facility[54]	Median during peak hours. Rating in Summer and Winter. Summer: hour ending 14 to 18 from June through September; and Winter: hour ending 18and 19 from Oct to May Historical data for five years, by facility	Reservoir and Pumped storage: Audited output over 2-hour duration Run-of-river: Same as wind, solar	Audited output over 2-hour duration
MISO[55]	Annual Rating, by class then facility. ELCC based on 8 highest coincident-peak load hours of the preceding year The hourly load and hourly wind output for 8760 hours, along with the normal compliment of generation data. Historical data average ten years.[56]	Seasonal Peak hours. Rating in summer. Hourly net output for hours ending 15, 16 and 17 EST from June, July and August for most recent consecutive three years. For new resources, or resources on extended outage where data does not exist for some or all of the previous 36 historical months, a minimum of 30 consecutive days' worth of historical data during June, July or August for the hours ending 15, 16, and 17 must be provided.	Reservoir and Pumped Storage: Seasonal Peak hours. Rating in summer. Median head in prior 5 to 15 years, hours ending 15, 16 and 17, in June, July and August. Historical data for 15 years, by facility Run-of-river: Seasonal Peak hours. Rating in summer. Hourly net output for hours ending 15, 16, and 17 EST from June, July and August for most recent consecutive three years. For new resources, or resources on extended outage where data does not exist for some or all of the previous 36 historical months, a minimum of 30 consecutive days' worth of	Battery storage resources are treated as behind-the-meter generation and subject to the same qualification criteria these resources. This includes requirement for battery storage resources to be capable of continuous discharge for 4 hours. The UCAP method is implemented to address the fact that not all behind-the-meter generation contribute equally to resource adequacy. By adjusting the capacity rating of a unit, based on its XEFOR,[57] UCAP provides a means to recognize the relative contribution that each resource makes. Behind-the-meter generators that are intermittent resources

53 See sections III.13.1.2.2.2.1. and III.13.1.2.2.2.2. of ISO-NE Manual Qualified Capacity https://etariff.ferc.gov/TariffBrowser.aspx?tid=1507

54 https://www.aeso.ca/assets/Uploads/AESO-UCAP-for-Wind-v2.pdf

55 MISO Business Practice Manual – Resource Adequacy https://www.misoenergy.org/legal/business-practice-manuals/

56 See Appendix A of MISO Business Practice Manual – Resource Adequacy

57 EFORd is a measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate. XEFORd is the same as EFORd, but calculated by excluding causes of outages that are outside management control eg losses of transmission outlet lines.

Jurisdiction	Wind	Solar	Hydro	Storage
			historical data during June, July or August for the hours ending 15, 16, and 17 must be provided.	will have their UCAP determined consistent with the methodology described for solar and run-of-river resources.
California ISO (no capacity market)	Monthly ELCC rating	Monthly ELCC rating	Hydro: monthly values based on a three-year rolling average of production during hours ending: 17 to 21, January, February and March; and hours ending: 14 to 18, April through October. The three most recent years of available data are used. Monthly values are averaged together for all three years to calculate the final qualifying capacity for each month	Not defined.
Alberta[58] (proposed Final Design for Capacity Market)	Capacity Factor	Capacity Factor	Run-of-river hydro Capacity Factor An availability factor will be established for existing hydro assets ie the Bow River system, Brazeau and Big Horn assets.	An availability factor will be established for storage assets. The UCAP of a storage asset will be capped at its maximum sustainable 4 hour discharge capability.

* 'Hour ending' refers to the time at the end of each operating hour, ie the 60 minutes that end at the numbered hour, in 24 hour time. For example, the hour ending 15 is the operating period from 2:00 to 3:00 pm.

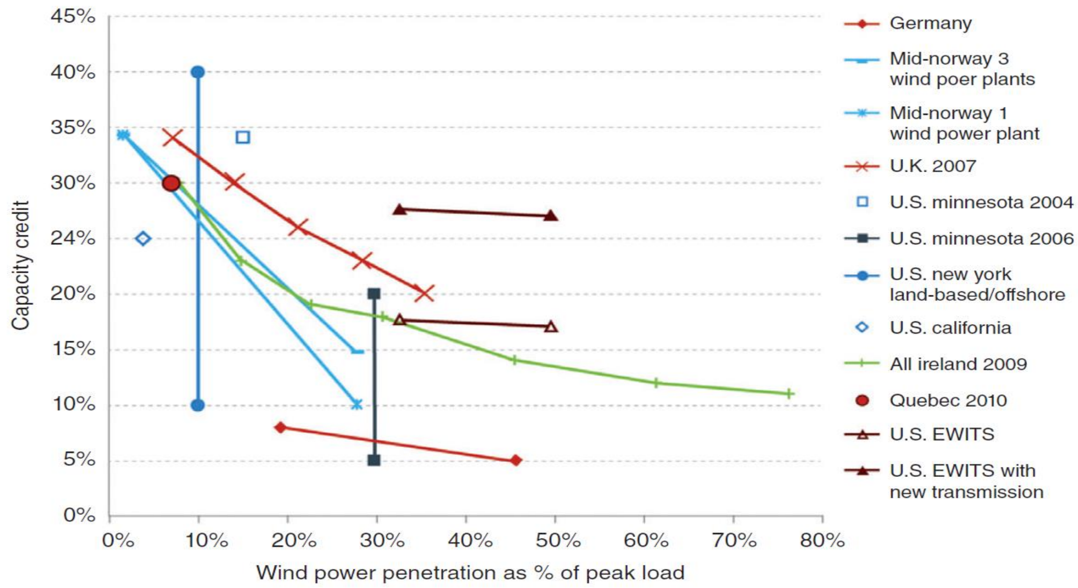
58 See https://www.aeso.ca/assets/Uploads/Consolidated-proposal.pdf

Assigning capacity to individual facilities

Most markets calculate capacity values using peak periods, except for CAISO, which has monthly ratings and MISO, which uses an annual reliability metric. All capacity values are based on historical performance, with data samples derived from periods of one to ten years. Smaller samples may produce less reliable and valid data due to inter-annual variability and the fact that existing resources may exceed the marginal contribution of new resources, as the marginal contribution of wind and solar decreases as the installed amount increases.[59]

Given the differences between jurisdictions in the way that various types of intermittent generation are assigned capacity values there can be quite wide variation in the capacity that is assigned to particular resources. Other variables, such as the penetration of intermittent resources can also have an impact. Figure A1 illustrates variations in the capacity value of wind power by penetration across different jurisdictions.

Figure A1. Capacity value of wind resource against penetration level in different jurisdictions[60]



This graph shows that as the penetration of wind generation increases in a market, the assigned capacity credits decrease.

Similar results can be found with an increasing penetration of solar. For example, in the CAISO market, Energy Division staff at the California Public Utilities Commission attempted to model behind-the-meter solar photovoltaic as a resource in order to gauge its effect on the overall solar ELCC, and thus study the overall value of all the solar generation that is projected to be online in 2018. In March 2016, the Energy Division proposal modelled a solar fleet that included a total of 7,424 MW of solar generation. This resulted in an ELCC of 57.75 per cent over the peak months. In February 2017, the solar fleet modelled totalled 16,033 MW. This

59 Bothwell, C. and Hobbs, B.F. (2016). Crediting renewables in electricity capacity markets: the effect of alternative definitions upon market efficiency. Working Paper, Department of Geography and Environmental Engineering. The Johns Hopkin University, Baltimore, MD, USA.

60 M Milligan et al., 'Capacity value assessments of wind power', in *Wiley Interdisciplinary Reviews: Energy and Environment*, vol. 6, 2017, 1–15.

resulted in a lower month specific ELCC ranging from about 1 per cent in December to about 34 per cent in June.[61]

California Public Utilities Commission noted that the relative decline in value for solar generation as more of it is added is an expected and understood outcome. The increase in solar generation in the model resulted in a lower ELCC for solar resources because it shifted the timing of periods with low capacity reserve to later in the evening. This shift interacted beneficially with wind production and likely boosted the ELCC of wind overall.

MISO has recently undertaken a study examining the implications of the increasing penetration of renewables in its market on resource adequacy.[62] There were several important findings. Like CAISO, MISO found that the risk of losing load compresses into a small number of hours and shifts to later in the day. However, as a result of the shift in risk of losing load, the available energy from wind and solar during high risk hours decreased. A diversity of technologies and geography improves the ability of renewables to meet load.

Markets may also differ on whether they differentiate between wind or solar capacity contributions based on individual facilities, accounting for local quality, load and transmissions constraints, or whether they apply a generic contribution value for each technology class. Distorted incentives can result where all facilities are assigned the same capacity rating, resulting in a suboptimal generation mix. Too many capacity credits for a particular resource provides an implicit subsidy, potentially leading to overinvestment, whilst too little credit could divert investment away from resources.[63]

A2.3 Intermittent generation aggregation

The ability to aggregate resources for participation in capacity markets is emerging as a new solution to meeting supply adequacy requirements. Intermittent resources can be combined to either reach participation performance requirements (eg, a group of storage units is combined to reach a requirement for the provision of a minimum of 1 MW of capacity) or differing resources (solar and storage) are combined to provide an intermittent generator with firmer capacity.

An example of this is the PJM market.[64] In this market, the capacity value of a generation resource is its summer net dependable capacity rating, converted to UCAP.[65]

Effective the 2018/2019 delivery year, the PJM market is transitioning to a capacity performance requirement, in which capacity resources are required to meet their commitments to deliver electricity whenever the PJM market operator determines they are needed to meet power system emergencies. The PJM market operator procured two capacity product types

[61] See proposal for Proposal for Monthly Loss of Load and Solar and Wind Effective Load Carrying Capability Values for 2018 Resource Adequacy Compliance Year http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/DemandModeling/R.14-10-010%20Revised%20Monthly%20LOLE%20and%20ELCC%20Proposal%202-24-17.pdf

[62] See MISO Renewable Integration Impact Assessment https://cdn.misoenergy.org/20180418%20PAC%20Item%2003d%20RIIA174068.pdf

[63] Bothwell, C. and Hobbs, B.F. (2016). Crediting renewables in electricity capacity markets: the effect of alternative definitions upon market efficiency. Working Paper, Department of Geography and Environmental Engineering. The Johns Hopkin University, Baltimore, MD, USA.

[64] See Intermittent Resource Participation in RPM for 2020/2021 and Beyond https://pjm.com/-/media/committees-groups/subcommittees/irs/20180305/20180305-item-10-intermittent-resource-participation-in-rpm.ashx

[65] Net dependable capacity measures the expected capacity available from a resource under expected peak demand power system conditions.

through its reliability pricing model auctions: capacity performance resources and base capacity resources. For a capacity resource to qualify as a capacity performance resource product, it must be capable of sustained, predictable operation that allows the resource to be available throughout the entire delivery year.

For a capacity resource to qualify as a base capacity resource product it is not expected to be capable of sustained, predictable operation that allows the resource to be available throughout the entire delivery year. However, the resource must provide enhanced assurance to provide energy and reserves during hot weather operations.

Intermittent resources and capacity storage resources[66] must offer their full UCAP value into each auction but are exempt from the requirement to offer as a capacity performance resource. Such resources may offer as capacity performance resource all or any portion of their UCAP value that qualifies as capacity performance with the remaining portion offered as base capacity. The quantity of UCAP value that may qualify as capacity performance for such resources may be based on expected output during summer and winter peak conditions.

As base capacity resources do not provide the same availability and reliability benefit as capacity performance resources, constraints are imposed on the quantity of base capacity resources that can be procured in the reliability pricing model auctions for the 2018/2019 and 2019/2020 delivery years. The base capacity resource product will be phased out so that only resources that meet the requirements of a capacity performance resource product will be used to meet the PJM's reliability and resource adequacy needs.

Capacity performance resources can be summer or winter-period capacity performance resources. Summer period resources must be available from June-October and May of the delivery year (summer-period). Winter period resources must be available November-April (winter-period). Storage resources and intermittent resources can be summer or winter-period resources.

The PJM market allows for capacity resources (including intermittent generation and storage, demand resources, energy efficiency and environmentally-limited resources[67]) that cannot meet the requirements of a capacity performance product on their own, to combine their capabilities and offer into an auction as a single aggregate resource. Resources that are aggregated in this way must reside in a single capacity market seller account.

The seller may offer the aggregate resource at a UCAP value that is representative of a capacity performance product, not exceeding the sum of the capacity UCAP values of the individual resources that make up the aggregate.[68] The aggregate resource is placed in the smallest locational deliverability area[69] common to each individual resource and the aggregate

66 In PJM these are generation capacity resources with output that can vary as a function of their energy source, such as wind, solar, landfill gas, run of river hydroelectric power and other renewable resources. There is some overlap with capacity storage resources, which include any hydroelectric power plant, flywheel, battery storage, or other such facility solely used for short term storage and injection of energy at a later time.

67 An environmentally-limited resource is a resource that has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited by a governmental authority to operating only during declared PJM capacity emergencies. To qualify as a capacity performance resource, environmentally limited resources must be able to perform at the equivalent of at least 10 percent capacity factor over the entire delivery year.

68 See Seasonal Resources & Resource Aggregation under CP https://www.pjm.com/-/media/committees-groups/task-forces/scrstf/20160404/20160404-item-05-education-session.ashx

69 A locational deliverability area is a sub-region within PJM used in evaluating locational constraints. Locational deliverability areas include transmission zones, sub-zones and a combination of zones.

resource receives the reliability pricing model auction clearing price applicable to the modelled location.

A2.4 Renewable energy subsidies

The question of whether renewables are assigned a capacity value if they are already subsidised by the government through climate change policies is becoming increasingly relevant to capacity market design as the penetration of renewables in markets increases. Though it is not always windy or sunny, the increased renewable capacity available to meet demand with subsidised prices drives down energy market prices to levels that may be inefficient, as they would not exist without policies that are designed to shape the generation mix.

Consequently, some markets are not assigning a capacity value to these resources, as is the case in Great Britain where wind does not participate in the capacity auction, or they are considering partial exclusion of these resources from auctions based on the level of subsidies received, such as in the PJM and Alberta markets. Other jurisdictions, such as ISO-NE, are looking more broadly at how capacity markets can be modified or augmented to account for other public policy objectives, whilst still meeting their resource adequacy requirements.

The PJM market

The PJM market is in the process of considering the effect of subsidies on its capacity market, with a proposal put forward that may either limit the capacity payments able to be obtained by subsidised resources through its capacity auctions or remove these resources from the market altogether.

In the PJM market, coal and natural gas generators have complained that state support for renewables (such as wind and solar) and nuclear plants allows competitors to supress auction clearing prices as they bid lower prices into the capacity market than operating costs. This cuts into other participants revenues, such as fossil fuel generators, forcing retirements.

Initially, subsidies were limited primarily to small renewable resources. However, the amount and type of resources receiving these subsidies has increased substantially, with support for thousands of megawatts of resources ranging from small solar and wind facilities to large nuclear plants. Gradually, more states are considering providing more support to even more resources, based on an ever-widening scope of justifications.[70]

As the auction price is suppressed in the market, more generation resources lose needed revenues. There is then increased pressure on PJM states to provide subsidies to yet more generation resources that the particular states prefer, for policy reasons, to enter the market or remain in operation. With each new subsidy, the market is less grounded in the fundamental principles of supply and demand.

On 29 June 2018, the Federal Energy Regulatory Commission issued an order addressing two proceedings initiated in response to increasing subsidies. The first was a complaint

[70] See FERC Order 163 FERC ¶ 61,236 issued on 29 June 2018. https://www.ferc.gov/CalendarFiles/20180629212349-EL16-49-000.pdf

PJM has requested to delay its 2019 Base Residual Auction for the 2022/2023 Delivery Year until 14-28 August 2019 to allow for the establishment of replacement rules, slated for 4 January 2019. See: https://www.pjm.com/-/media/documents/ferc/filings/2018/20180813-er18-2222-000.ashx against PJM[71] by a group of generators suggesting that the minimum offer price rule (MOPR)[72] is unjust and unreasonable because it does not address the effect of subsidized existing resources on the capacity market.

PJM's MOPR only applies to new, natural gas-fired resources due to the concern that the short development time required to bring such resources to operation could be used to suppress capacity prices.[73] Although the role of the MOPR in PJM was originally limited to deterring the exercise of buyer-side market power, its role subsequently expanded to address the capacity market influences of out-of-market state revenues. However, because the current MOPR applies only to new natural gas-fired resources it fails to mitigate price distortions caused by subsidies granted to other types of new entrants or to existing capacity resources of any type.

Interim revisions to the PJM market rules[74] were proposed by the generators that would extend the MOPR to cover a limited set of existing resources,[75] and FERC was asked to direct PJM to conduct a stakeholder process to develop and submit a long-term solution.

The second proceeding was filed by PJM[76] and consisted of two alternate proposals designed to address the price suppressing effects of subsidies for certain resources. PJM's preferred approach comprised of a two-stage annual auction, with capacity commitments first determined in stage one of the auction, and the clearing price set separately in stage two. The second, alternative approach, was to revise PJM's MOPR to mitigate capacity offers from both new and existing resources that receive material subsidies, subject to certain proposed exemptions.[77]

In its order, the Federal Energy Regulatory Commission agreed that it had become necessary to address the price suppressive influence of resources receiving subsidies. However, it did not accept the proposed remedies suggested by the generators or PJM, as it considered that the proposals were not just and reasonable, and not unduly discriminatory or preferential. The Federal Energy Regulatory Commission instead proposed an alternative approach with PJM modifying two aspects of its rules.

Firstly, PJM would modify its MOPR so that it would apply to new and existing resources that receive subsidies, regardless of the resource type, but would include few to no exemptions.

Secondly, in order to accommodate state policy decisions and allow resources that receive subsidies to remain online, the Federal Energy Regulatory Commission proposed to establish an option in the rules allowing resources receiving subsidies, on a resource-specific basis, to choose to be removed from the PJM capacity market, along with a commensurate amount of load, for some period of time.

Participants were given 60 days to respond to the Federal Energy Regulatory Commission's order.[78] PJM has subsequently requested to delay its 2019 Base residual auction for the

71 Filed by Calpine Corporation and joined by additional generation entities (but collectively referred to as the Calpine Complaint), in Docket No. EL16-49-000.

72 The minimum offer price rule sets a default minimum price in the market under which units cannot offer generation.

73 Some states had proposed making out-of-market payments to facilitate the entry of new natural gas-fired resources.

74 The market rules are referred to as Tariffs in Northern American jurisdictions.

75 Primarily nuclear-powered generation units that would otherwise exit the market without receiving subsidies.

76 See Docket Nos. ER18-1314-000.

77 For example, categorical exemptions for self-supply, public power entities and electric cooperatives.

78 See: https://www.pjm.com/-/media/documents/ferc/filings/2018/20180813-er18-2222-000.ashx

2022/23 delivery year until 14-28 August 2019 to allow for the establishment of replacement rules, slated for 4 January 2019.

Two of five commissioners from the Federal Energy Regulatory Commission dissented to the commission's order issued on 29 June 2018.[79] Among the main arguments against changes to PJM's rules were:

- PJM's capacity market has resulted in a capacity surplus that is well in excess of the level required to reliably meet the region's electricity demands, suggesting that the prices in PJM's capacity market are too high, not too low.[80] Consequently, PJM continues to attract new competitive generation resources at a time when the region already has too much capacity.
- The state policies compensate resources for their environmental attributes, not their capacity.
- The proposal would effectively force subsidised resources to choose to participate in the market and be subject to an expanded MOPR, with the substantial risk that it will not clear, or elect to be out of the capacity market, and be deprived of a payment for capacity that it actually provides, leaving the states to pay for it.

The Alberta Market

In Alberta, the Renewable Energy Program encourages the development of large-scale renewable electricity generation to support the Government of Alberta's intention to install 30 per cent renewable electricity by 2030.[81] The Alberta Electric System Operator (AESO) implements and administers the program through a series of competitions that provide an incentive for the development of renewable electricity generation through the purchase of renewable attributes. The payment mechanism is an Indexed Renewable Energy Credit (REC).

Throughout 2017, AESO engaged working groups and stakeholders in the development of a comprehensive market design proposal for its new capacity market.[82] The working group assumed conventional and variable generation would be eligible to participate, excluding Renewable Electricity Program resources, subject to the same performance requirements for all resources in the capacity market.[83]

Industry feedback supported the working group's position, suggesting that the capacity market should be inclusive, subject to resources competing on a 'level playing field.'[84] AESO determined that including variable resources would increase overall market competition, provided that their reliability value is appropriately reflected.[85]

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79 See https://www.ferc.gov/media/statements-speeches/lafleur/2018/06-29-18-lafleur.pdf and see https://www.ferc.gov/media/statements-speeches/glick/2018/06-29-18-glick.asp#.W34fEsEUlfw

80 PJM's current reserve margin is nearly double what the North American Electric Reliability Corporation (NERC) has determined is necessary. It has nearly 40 GW of natural gas-fired generation under development within PJM's footprint, which is equivalent to 25 percent of the installed capacity in the region, over half of which is in a relatively advanced state of development.

81 See https://www.aeso.ca/market/renewable-electricity-program/

82 See https://www.aeso.ca/market/capacity-market-transition/comprehensive-market-design/

83 See https://www.aeso.ca/assets/Uploads/Rationale-section-2.pdf

84 See bottom of page 1 https://www.aeso.ca/assets/Uploads/Rationale-section-2.pdf

85 See https://www.aeso.ca/assets/Uploads/CMD-4.0-Section-2-Supply-Participation-FINAL.pdf.

In line with this, in the first comprehensive market design proposal it was suggested that new variable energy resources would be eligible to provide capacity up to their UCAP as long as the resource did not receive indexed REC payments for its committed capacity in a manner similar to the payment mechanism in Renewable Electricity Program round 1.

In the second, third and final proposals, an asset that is the subject of a renewable electricity support agreement in connection with Renewable Electricity Program rounds 1, 2 or 3 is not eligible to participate in a capacity auction because the Renewable Electricity Program already provides compensation for the resource's capacity.[86] The eligibility of future Renewable Electricity Program resources to participate would need to be assessed subject to the contract terms for each Renewable Electricity Program round.

Capacity market modification or augmentation

Charles River Associates (2017) note that carbon reduction is the most common objective of relevant public policies and identify three main proposals for modifying and augmenting capacity markets to reconcile them with these policies:

- Resources with greenhouse gas emission – an explicit addition is made to energy market offer prices based on a determined cost of greenhouse gas emissions. This would then inform capacity market parameters and participant behaviour.
- Forward clean energy market – this would involve a supplemental market being run alongside a capacity market, using a long term energy auction for the forward procurement of the kind of resources required by public policies. Alberta's Renewable Energy program is an example of one such market.
- Bifurcated auction – the capacity market is split so that one auction is run for subsidised resources and one is run without subsidised resources leading to two clearing prices. ISO-NE introduced a proposal for a two-settlement capacity auction that was accepted by FERC on 8 January 2018.[87]

Finally, as system needs have changed, with high penetrations of variable resources leading to additional demands on the system, an emerging issue in many markets is whether multiple capacity products should exist or limits should be introduced on how much capacity can be procured from different fuel types. However, this would be a complex undertaking, increasing the administrative burden and the potential for inefficiencies.

None of the jurisdictions reviewed by Charles River Associates defined the capacity product to procure additional operational attributes such as quick start or fast ramping capabilities, instead relying on properly designed energy and ancillary service markets to incentivise the investment in these attributes.

86 See https://www.aeso.ca/assets/Uploads/CMD-4.0-Section-2-Supply-Participation-Rationale-v5-FINAL.pdf

87 See https://www.ferc.gov/CalendarFiles/20180309230225-ER18-619-000.pdf

Appendix 3 Capacity valuation measures and theory

A3.1 Measures of capacity value

The ERA's review found several approaches for quantifying the contribution of a resource to the adequacy of an electricity system. Three main measures of capacity value are:

- comparison with the capacity value of a scheduled generator and a firm generator, ie capacity that is available all the time
- sampling a generator's or system capacity's output distribution at a certain point
- effective load carrying capability (ELCC).

The capacity value of a new intermittent resource can be measured in terms of the scheduled generation capacity that can be displaced without a change in the adequacy risk of the system. This amount is referred to as the equivalent conventional power.[88] Alternatively, the capacity value of an intermittent generator can be expressed as the amount of a fully reliable generating technology; that is a firm generator that can replace the new intermittent facility while maintaining the adequacy risk of the system. This measure is referred to as equivalent firm capacity.

The second type of capacity value measure commonly uses a chosen percentile (for example, the lower 5th percentile) of the available capacity distribution of the new generator during peak demand periods, as the capacity value.

The ELCC of a resource is the amount of additional load that can be served by adding that resource to an electricity system, while maintaining the existing level of system adequacy risk.

The ELCC of a resource is determined by modelling the relationship between:

- the output of that resource
- system demand
- the output of other generators in the system.

To calculate ELCC, a system adequacy model is required to estimate how the addition of a resource can change the adequacy risk of the system. All three variables listed above are volatile in nature. Therefore, a model of the adequacy of the system is probabilistic as it must account for many different combinations of resource output and system demand in order to estimate the likelihood or the expected magnitude of the loss of load in the system.

A resource's ELCC is dependent on the availability of other resources in the system, the measure and level of adequacy risk, and characteristics of system demand. The ELCC can be calculated for a single facility or for a group of facilities.

The ELCC has both computational and conceptual advantages when compared to other capacity valuation measures. The equivalent conventional power and equivalent firm capacity approaches require more parameters for estimation than ELCC. It is unnecessary to compare the capacity value of an additional generator with that for another resource, particularly when

[88] Refer to M Amelin, 'Comparison of capacity credit calculation methods for conventional power plants and wind power', in *IEEE Transactions on Power Systems*, 2009.

it is possible to directly compare the results of the ELCC for an intermittent generator with that for a scheduled or firm generator.

The choice of a percentile as the capacity value of a resource is unsound, as it may not fully capture the relationship between a generator's available capacity and demand and does not directly address the adequacy risk of the system.

The ERA found that the preferred method in the literature and practice for the calculation of capacity value of intermittent resources was the ELCC. This is because it requires fewer parameters to calculate, while reflecting both the adequacy risk of the system and the capacity availability profile of generators. Several sources recommend the use of ELCC for the capacity valuation of intermittent resources.[89]

A3.2 Capacity valuation theory

System planners are responsible for ensuring that there is sufficient installed capacity to meet demand at all times with a reasonable level of certainty. If an electricity system does not have sufficient capacity to cover demand, this would cause a loss of load ie, there would be an energy shortfall and the system operator would disconnect loads to restore the balance between supply and demand.[90] The megawatt hours by which demand exceeds the supply of electricity is known as the 'energy shortfall' or 'unserved energy.'

At any point in time, both demand and capacity are volatile and therefore uncertain. System planners account for uncertainty in demand, and the availability and output of different capacity resources. They ensure that the sum of the contribution of capacity resources is sufficient to meet demand at all times with a certain level of certainty. The literature commonly refers to a resource's contribution to system adequacy as its 'capacity value' or capacity credit.[91]

The stylised diagram in Figure A2 explains this concept. It depicts the status of the system at a snapshot in time, for instance, a trading interval. For example, point 'A' on the probability distribution of demand depicts the probability of the occurrence of a 3,000 MW demand, which is approximately one per cent. The system comprises firm capacity of 4,250 MW. The probability distribution of the firm capacity is represented by the vertical bar. During the trading interval, the firm capacity is available with a probability of 100 per cent.

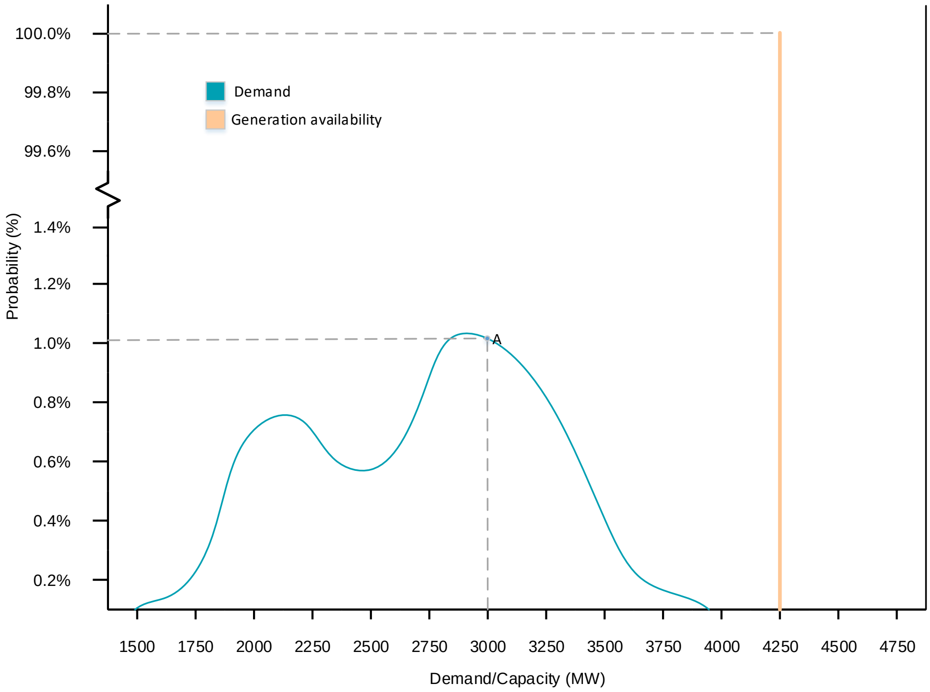
Given the probability distribution of demand, all possible demand outcomes in this trading interval are less than the available capacity of the firm generator. The likelihood of a loss of load in this trading interval is zero. This likelihood is commonly measured via a loss of load probability (LOLP). If all trading intervals during a year have the same probability distribution for demand as in the shown trading interval, the system would have an expected loss of load of zero. This is commonly shown by the loss of load expectation (LOLE), which is the sum of the LOLP over all trading intervals over a year, or a certain period of time (measured in days or hours).

[89] For instance, refer to North American Electric Reliability Corporation, *Integration of Variable Generation Task Force*, Atlanta, 2015, pp. 34–35, https://www.nerc.com/comm/PC/Integration of Variable Generation Task Force I1/IVGTF Summary and Recommendation Report_Final.pdf.

[90] 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. Section 0 provides a detailed discussion of this point.

[91] In practice several terms are used to explain the capacity contribution of resources to system adequacy, including net qualifying capacity, capacity capability, dependable maximum net capability, capacity credit and capacity value.

Figure A2. System with 4,250 MW of firm generation



Note: The distribution of demand shown is bimodal indicating that demand in the example system is more frequently around 3,000 and MW 2,200 MW.

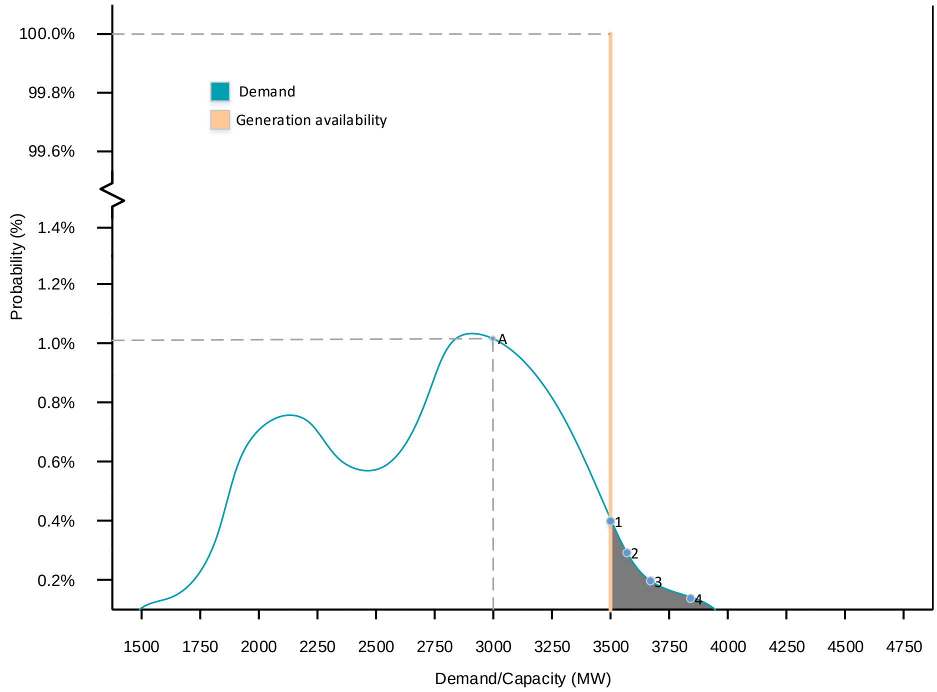
Figure A3 depicts the same trading interval as in the above example but with 3,500 MW of installed firm capacity. The LOLP in the trading interval is not zero. Some possible demand outcomes are greater than the installed capacity of the firm generator. The LOLP in the trading interval is equal to the shaded area. For simplicity, the LOLP can be approximated by calculating the sum of the probabilities of points 1 to 4: LOLP = 0.4 + 0.3 + 0.2 + 0.1 = 1.0 per cent. If all trading intervals in a year have the same probability of distribution for demand as in the shown trading interval, the system would have a LOLE equal to $365 \times 24 \times 2 \times 0.01 = 175.2$ trading intervals per year. In this example, the highest demand outcomes determine the LOLE of the system: the LOLE is determined by the LOLP of trading intervals with demand above 3,500 MW.

This level of LOLE is extremely high. A commonly used certainty level for planning the balance of capacity and demand in many power systems is that more than one load-shedding event in 10 years would be unwanted.[92] For instance, the LOLE for a common system adequacy target of less than one day load-shedding out of 10 years is:

$$LOLE = \frac{24\ hours}{10\ years \times 365\ days\ per\ year \times 24\ hours\ per\ day} = 0.0008219\ hours/day$$

92 This was decided by two General Electric engineers. Refer to S Stoft, ‘The Surprising Value of Wind Farms as Generating Capacity’, in *SSRN*, 2008, 1–18 (p. 3), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=1250187.

Figure A3. System with 3,500 MW firm generation



For this system, the system planner could install additional firm capacity to ensure that the LOLE of the system does not exceed 0.0008219 hours per day. For simplicity, we assume that a LOLP of 0.1 per cent during each trading interval is the target system adequacy risk level. To meet the target LOLP = 0.1 per cent, the system planner would require approximately 3,850 MW of firm capacity.

Measurement of the capacity contribution of resources

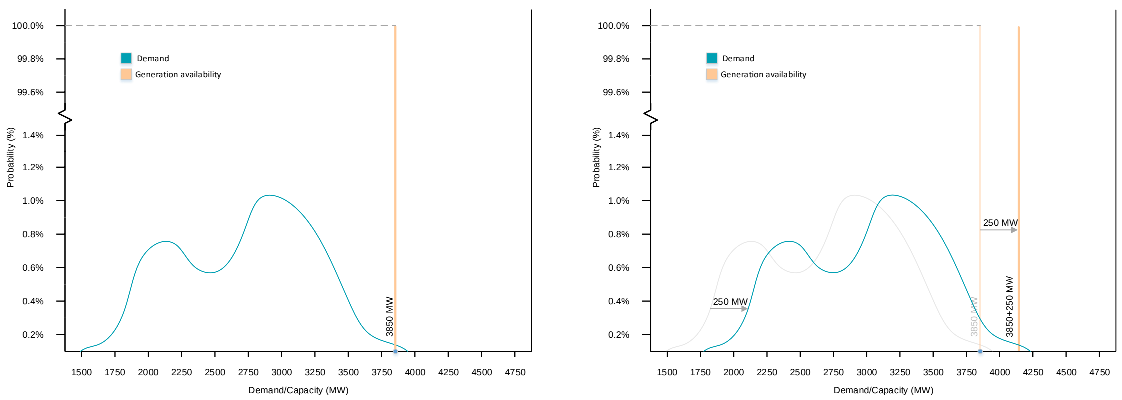
System planners should estimate whether the sum of the contribution of different resources in the system is sufficient to meet the target level of system adequacy. They evaluate the contribution of resources to meeting the adequacy target of the system. As explained in section A3.1, the preferred measure in many theoretical and practical studies is the ELCC. To measure ELCC, system planners estimate the amount of additional load that the system can cover with the addition of a resource, without a change in the adequacy risk of the system.

The calculation of ELCC requires the development of system adequacy assessment models. The diagrams presented in the previous examples are simple graphical system adequacy assessment models. For instance, in the previous example illustrated in Figure A3 the system planner determined that 3,850 MW of firm capacity is required to meet the target LOLP of 0.1 per cent during the trading interval.

The calculation of ELCC is best explained through a simple example in Figure A4. The example assumes that the system shown in Figure A3 already has 3,850 MW of firm capacity available. The system planner is interested in estimating the capacity contribution of a new firm generator with an installed capacity of 250 MW, by calculating its ELCC.

The system can support an additional 250 MW of demand during any trading interval, assuming the probability distribution of demand does not change, while maintaining the LOLP of the system at 0.1 per cent. This is shown in Figure A4, panels (a) and (b).

Figure A4. The ELCC of a firm generator



Panel (a): system with 3850 MW firm capacity

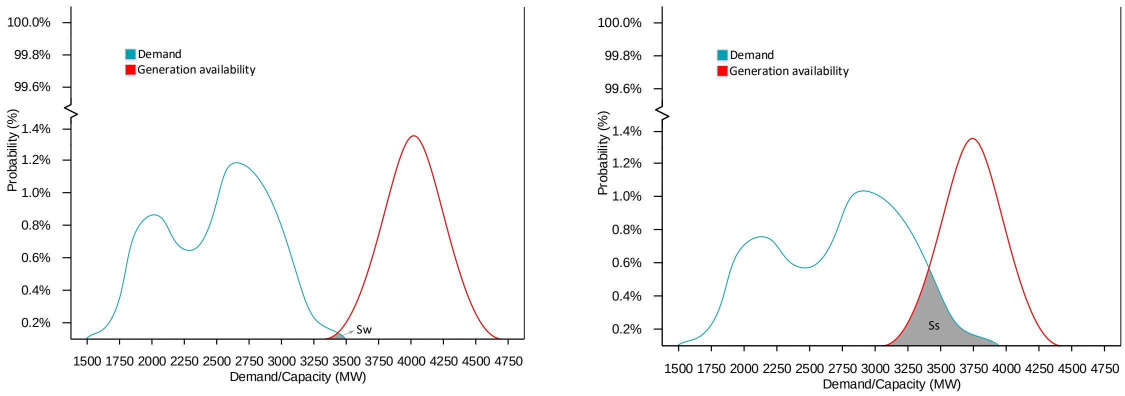
Panel (b): addition of a 250 MW resource

Panel (b) illustrates that the addition of 250 MW to demand shifts the probability distribution of demand to the right by 250 MW. The sum of the installed capacity of existing and new firm capacity (3850 + 250 = 4,100 MW) will maintain the LOLP of the system at any trading interval at 0.1 per cent. The additional demand of 250 MW is the capacity value of the new resource. The new resource provides firm capacity, and so its installed capacity is equal to its capacity value.

In practice, the calculation of the ELCC of resources would require detailed system adequacy assessment models. The simple graphical model in the previous example was useful to explain and estimate the ELCC of a firm generator. However, all capacity resources have variable output and their output may also be correlated with system demand. For instance, it is likely that a conventional generator such as a coal or gas-fired generator fails to provide its capacity to the system due to mechanical failures or commercial decisions. The output of many renewable energy resources and demand are weather driven. During hot summer days demand for electricity increases, whereas the output of wind farms tends to decrease because wind speed tends to decrease on extremely hot summer days. This introduces challenges for the calculation of the ELCC that the simple graphical model cannot easily and sufficiently explain.

Figure A5 shows a system with a probability distribution of demand similar to that in the previous examples. The capacity resource installed in the system has a variable output that is also correlated with demand ie, during the hot season the resource on average has a reduced output, when compared to the cold season. Also during the hot season days, the range of the probability distribution of demand contains higher demand outcomes. During the hot period, system demand close to 4,000 MW can happen, whereas during the winter period system demand does not exceed 3,500 MW. The average capacity of the resource during the winter period is 4,000 MW, whereas in the summer it is 3,750 MW. During the cold period, there is a higher chance, but not 100 per cent, that supply will exceed demand when compared to the summer period. The LOLP in the winter period, which is proportional to the area S_w, is substantially smaller than that for summer, S_s.[93]

Figure A5. LOLP of a system with variable output generation



Panel (a): Cold period

Panel (b): Hot period

The calculation of the ELCC of the variable output resource in this example is more complex than that presented in the previous example shown in Figure A4. A model is needed to estimate how much additional load the system can support with the addition of the variable output resource without a change in the adequacy risk of the system.

In the simplest form, when the output of the variable output resource and demand are independent, the ELCC can be calculated using a statistical technique referred to as 'convolution'. This technique yields the probability distribution of the sum of two independent random variables from their individual distributions, providing the probability distribution of the surplus of capacity over demand. The LOLP, LOLE, or expected unserved energy risk measures can be estimated through the probability distribution of the surplus of capacity over demand.

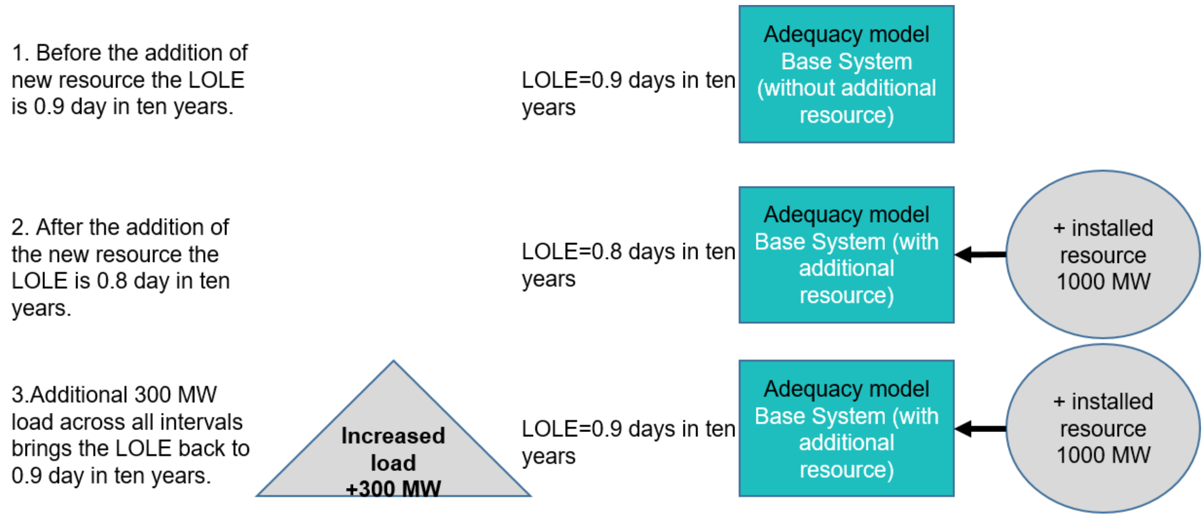
The general 'mathematical modelling' for the calculation of the ELCC of a resource is depicted in Figure A6. This modelling is usually conducted by computer simulation. The model would use the probability distribution of demand, the probability distribution of existing resources in the system and the new resource for which the capacity value is being calculated. The correlation between these probability distributions is also incorporated into the model to

93 The LOLP of the system during summer or winter period can be estimated through a statistical technique referred to as 'convolution'. It yields the distribution of the sum of two independent random variables from their individual distributions. For instance refer to R. Durret, Probability: Theory and Examples, 4th edition, Cambridge University Press, 2010.

estimate the adequacy risk of the system. The rest of this section uses LOLP and LOLE as the measures of system adequacy risk.

Without the addition of a new resource, the model shows the current LOLE of the system based on the contribution of existing resources. For the example shown in Figure A6, the LOLE of the system in the first scenario, ie, the base system, is 0.9 days in ten years. In scenario 2, the model estimates the LOLE of the system after the addition of a new resource with installed capacity of 1,000 MW. The addition of the new resource improves the adequacy risk of the system. LOLE decreases from 0.9 days in ten years to 0.8 days in ten years. In scenario 3, the model iteratively adds fixed megawatt amounts to the system demand probability distribution until the LOLE of the system is 0.9 days in ten years, as in scenario 1. For this hypothetical system, a 300 MW addition to load brings the LOLE back to 0.9 days in ten years. The 300 MW addition to load is the ELCC of the new resource, ie, the capacity value of the additional resource is 30 per cent of its installed capacity.

Figure A6. General process for the calculation of the ELCC of a resource



The ELCC of a resource is determined by its contribution to lowering the LOLE of the system. A resource that has higher capacity available during the periods the LOLP in the system is the greatest would have a higher ELCC. This is in contrast to a resource that has lower available capacity during such periods.

The LOLP in a period is determined by both the level of demand and supply in the system. The surplus of capacity over demand in the system is commonly referred to as the 'system reserve'. The smaller the range of the system reserve probability distribution, the greater the LOLP in a period.

At a certain level of demand, trading intervals with lower capacity available would have higher LOLP.[94] Those resources with greater capacity available during such periods would have higher ELCC. At a certain level of available capacity, periods with the highest level of demand would have higher LOLP. Those resources with greater capacity available during the highest demand periods would have a higher ELCC.

During a year, both demand and supply capacity are volatile. The output of a resource during periods with a lower level of system reserve would determine its ELCC.

94 More accurately, for a certain amount of demand, those periods with lower range of available capacity distribution tend to have higher LOLP.

Capacity value of scheduled generators

It is useful to investigate what factors would contribute to the capacity value of a resource. The mathematical modelling for the calculation of the ELCC shown in Figure A6, however, does not provide an indication of such factors. For instance, the calculation of the ELCC of the variable output resource in the previous example shown in Figure A5, entails the calculation of LOLE of the system with and without the presence of the resource. The graphical model shown in Figure A4 cannot simply represent the calculation of LOLE of the system or its contributing factors.

In an academic paper in 2011, Zachary and Dent followed the general concept for the calculation of the ELCC, as shown in Figure A6, using LOLE as the system adequacy risk measure. Zachary and Dent derived a relatively simple formula to approximate the ELCC of a resource, $ELCC$:

Equation A1

$$ELCC = average\ output\ of\ resource - (K \times variance\ of\ the\ output\ of\ resource)$$

For the rest of this report, we use ‘analytic solution’ to refer to equation A1.[95] The analytic solution calculates the ELCC of an additional resource, with output that is independent of demand and independent of the output of existing resources in the system. It shows that the ELCC is determined by the average and variance of the output of the resource and the parameter K. Zachary and Dent showed that the value of the parameter K is also dependent on the probability distribution of the output of existing resources and demand, and their correlation with each other.

Theoretically, the analytic solution would provide reasonably accurate results, if the probability distribution of the output of the additional resource is not correlated with demand and the output of existing capacity resources. For instance, the analytic solution would provide the ELCC of the resource in Figure A5, in hot and cold periods separately. Although the output distribution of the resource is correlated with demand over an entire year, its probability distribution in either season is assumed to be independent of system demand.[96]

For instance, the analytic solution shows that the ELCC of the variable output resource in Figure A5 in the cold season is greater than that for the summer period by approximately 250 MW. If the variance of the output of the resource in both seasons is equal, the difference between the ELCC of the resource in the summer and winter periods is determined by the difference between the average output of the resource in these seasons, ie, 4,000 MW - 3,750 MW = 250 MW.[97]

In this example, the ELCC of the resource in a year would be very close, but not equal to, that for the summer period, ie, the lower of the results for winter and summer. Some of the contribution to the adequacy of the system during the cold period is not available in the hot period. The ELCC of the resource will be determined by the sum of the LOLE of the system in

95 An analytic solution or expression in mathematics is an expression constructed using well-known operations and functions such as addition, subtraction, multiplication, exponentiation, logarithm and trigonometric functions.

96 The effective load carrying capability of a resource can determined for any period of time from a trading interval, a month to a year For instance, the California Public Utilities Commission calculates monthly effective load carrying capability of intermittent resources for the allocation of capacity credits. Refer to California Public Utilities Commission, *Final Qualifying Capacity Methodology Manual Adopted 2017*, 2017, http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442455533.

97 Although the parameter K can vary between the summer and winter periods, its effect is not comparable to that of the average output.

the cold and hot periods. A high proportion of the total LOLE of the system over a year will be determined by the LOLE in the summer period. The ELCC of the resource during the entire year will be mostly driven by its output average and variance during the summer period.

The lower the LOLE in the winter period, the closer the yearly ELCC to that in the summer period. For a system with zero LOLE in the cold periods, the yearly ELCC is equal to that of the hot season.

The calculation of the ELCC of conventional generators is similar to that explained in the above example. Except for some seasonal variation, conventional generators have output distributions that are mostly independent of other resources in the system and 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 ELCC of these resources is mostly determined by their average output during hot summer days.

Each conventional generator has some output variation due to outages. These resources can often provide up to their maximum capacity unless they are on outage. This may suggest that the ELCC of an individual conventional generator is less than its average output, in proportion to their output variance, as suggested by the analytic solution.

The output of conventional generators are independent. As more conventional resources are added to the system, the ratio of the variance to the mean output for the group of conventional generators decreases. This is a statistical feature of independent probability distributions, as explained by the 'Central Limit Theorem'.[98] Therefore, the variance of the output of the fleet of conventional generators will be relatively small when compared to their average output. The ELCC of the fleet of conventional generators would be very close to the average output of the fleet.

Calculation of ELCC of intermittent resources

System planners estimate how much of the installed capacity of intermittent resources counts toward the adequacy of capacity in the system. If these resources can deliver a high share of installed capacity during high adequacy risk periods, for example, those periods when the probability loss of load is the highest, then the required level of capacity from other sources would be less.

Many intermittent resources have output that is correlated with demand. The analytic solution shown in the previous section cannot provide a reasonable estimate of the ELCC of intermittent resources that have weather-induced output. A system adequacy assessment model similar to that depicted in Figure A6 can determine the capacity contribution of these resources.

Zachary and Dent, however, showed that the analytic solution can provide a reasonable estimate of the capacity value of intermittent resources under certain conditions. They explained that if the intermittent resource for which the ELCC is being calculated has a small output variation, the analytic solution would provide accurate results.[99] They modified the solution for such cases:

98 The theorem also explains that the output drawn from many statistically independent resources, with similar probability distribution but not necessarily normal, will be normally distributed.

99 More accurately stated, they explained the formula would provide accurate results if the variability of the output of the intermittent resource is small when compared that for the surplus of the capacity of existing resources over demand in the system.

Equation A2

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

The analytic solution in the modified form above, referred to as the 'approximation formula' in the rest of this report, is based on output average and variance during certain periods only. The reason underpinning the modification of the analytic solution is technical and is explained in Appendix 4.

The current relevant level method uses the approximation formula, with some adjustment, to calculate the ELCC of individual intermittent resources in the SWIS.

To estimate the mean and variance of the output of intermittent resources during the specified periods, the relevant level method prescribes the use of load for scheduled generation, or LSG. For each trading interval, the method calculates LSG by deducting the total output of all intermittent generators from demand. The periods with the highest LSG indicate the periods with the lowest level of surplus of capacity over demand. The method is to first identify the top 12 daily LSG periods for each year in the past five years, together forming a sample of 60 trading intervals. The method then uses the average and variance of the output of individual intermittent resources during the peak LSG periods to determine their ELCC.

Appendix 4 Review of the current relevant level method

The current relevant level method uses historical demand and intermittent generation output data to estimate the capacity value of individual intermittent generators. It uses the average and variance of the output of a generator over a set of 60 trading intervals determined using the following process:

- For each trading interval in a year, system load net of all intermittent generators' output is calculated. This net load is referred to as load for scheduled generation (LSG).[100]
- For each year in the past five years, the top 12 net load intervals calculated are selected from separate days to form a set of 60 trading intervals. These trading intervals are referred to as peak LSG periods.

The average and variance of the output during the peak LSG periods are calculated and used in equation A3 to calculate the capacity value of a generator. AEMO automated this calculation process in 2017.

Equation A3

Capacity value =	*average output during peak LSG periods*	**less**	*$G \times$ variance of output during the peak LSG periods*

where G is the sum of two constant parameters K and $\frac{U}{average\ output\ during\ peak\ LSG\ periods}$.

For the 2018 reserve capacity cycle:

- the value of K is 0.000
- the value of U is 0.635.

Equation A3 was developed based on some adaptations to the approximation formula developed by Zachary and Dent in 2011, as discussed in section 0. To assess the accuracy of the current relevant level method, the ERA reviewed the assumptions underpinning the development of the approximation formula and their applicability to the SWIS.[101]

A4.1 Assumption 1: Capacity value is based on the loss of load expectation

Assumption 1: the effective load carrying capability (ELCC) of the additional resource is measured at the current level of loss of load expectation (LOLE) in the system.

If this assumption does not apply in the SWIS, then the current method will yield inaccurate results.

[100] The actual calculation also factors in the effect of curtailed load. Curtailed load is the sum of demand side program reduction of load, interruptible reduction of load through relevant ancillary service, and involuntary reduction through load shedding. For the output of intermittent generators, the method also factors in the impact of consequential outages and System Management's instructions to reduce output.

[101] 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/.

The ELCC of an additional resource depends on the current level of reliability in the system. If the system has an oversupply of capacity, its LOLE will be low and the capacity value of an additional resource will also be low. This is compared to a system that has a capacity shortage and a high LOLE.[102]

Many studies suggest the use of the system adequacy target for calculation of the capacity value of resources. Using the system adequacy target, rather than the current adequacy level in the system, to calculate capacity value may provide more reasonable[103] and stable results from one year to another. A LOLE of one day in 10 years for the calculation is common, which can facilitate the comparability of results across jurisdictions.

The reliability planning criterion in the Market Rules determines the system adequacy in the SWIS to a set level of certainty.[104] Inherent in this is a LOLE during peak demand periods. AEMO then procures sufficient capacity each capacity year through the Reserve Capacity Mechanism to satisfy the planning criterion. The use of LOLE as the measure of system adequacy risk in determining the relevant level is consistent with the planning criterion of the SWIS.

In the SWIS, basing the estimation of ELCC on the current LOLE, rather than the target LOLE, may not have a substantial effect on the capacity value results. 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. Over time, the level of installed capacity is expected to trend towards the reserve capacity target. Therefore, calculating the ELCC of intermittent generation based on the current LOLE of the system would provide consistent results across the coming years. Assumption 1 applies in the SWIS.

A4.2 Assumption 2: Variation of the output of the additional resource is small

> **Assumption 2**: the magnitude and variation of the output of the additional resource is small, when compared to the magnitude and variation of the existing surplus of capacity over demand in the system.

This assumption is particularly important because equation A3 may produce inaccurate results when the additional resource for which the capacity value is being calculated has a large output variation, as compared to the distribution of the surplus of existing capacity over demand. If the assumption does not apply in the SWIS, then the current level method will yield inaccurate results.

The stylised diagram in Figure A7 explains the calculation of the ELCC in equation A2 at a conceptual level. Equation A2 is derived based on the comparison of the adequacy of the system, as measured by the LOLE, in two scenarios:

102 For example, refer to a discussion of this effect in M Amelin, 'Comparison of capacity credit calculation methods for conventional power plants and wind power', in *IEEE Transactions on Power Systems*, 2009, p. 688.

103 M Milligan et al., 'Capacity value assessments of wind power', in *Wiley Interdisciplinary Reviews: Energy and Environment*, vol. 6, 2017, 1–15 (p. 4).

104 See Market Rule 4.5.9 https://www.erawa.com.au/cproot/19583/2/Wholesale%20Electricity%20Market%20Rules%2018%20October%202018.pdf

- Scenario A: the LOLE of the system without the addition of the new resource, Y, is calculated by the distribution of the available capacity of existing generators, X, and demand, D, in the system. The amount of LOLE in this scenario is indicated by LOLE* and is determined by the sum of the probability of the loss of load in the system over all trading intervals in a year. Those trading intervals with the lowest level of the surplus of capacity, X, over demand, D, will have the most significant contribution to the amount of LOLE in the system, because such periods have the highest probability of loss of load. For simplicity, we assume that in this scenario 30 trading intervals TI1 to TI30 have the highest loss of load probability (LOLP) and together contribute to more than 99 per cent of the LOLE*.
- Scenario B: the LOLE of the system after the addition of the new resource, Y, is calculated by the distribution of the available capacity of existing generators, X, and the new resource, Y, and demand D in the system. The addition of the new resource will improve the adequacy of the system. The LOLE after the addition of the new resource will be lower. To calculate the ELCC of the new resource in terms of megawatts, the amount of load in this scenario is adjusted upward until the LOLE is the same as the LOLE in scenario A, ie, LOLE*. This increase in load is the ELCC of the new resource.

If the magnitude and variability of the available capacity of the new resource is small, the set of trading intervals with the most significant contribution to the LOLE in scenario B will be the same as those in scenario A, ie TI1 to TI30. Although the new resource has a contribution to the adequacy of the system, it does not shift the periods with the highest probability of the loss of load in the system. This is the reason that the mean and variance of the output of the new resource is calculated during the periods when the surplus of existing capacity over demand is zero in equation A2 (ie, the approximation formula developed by Zachary and Dent).

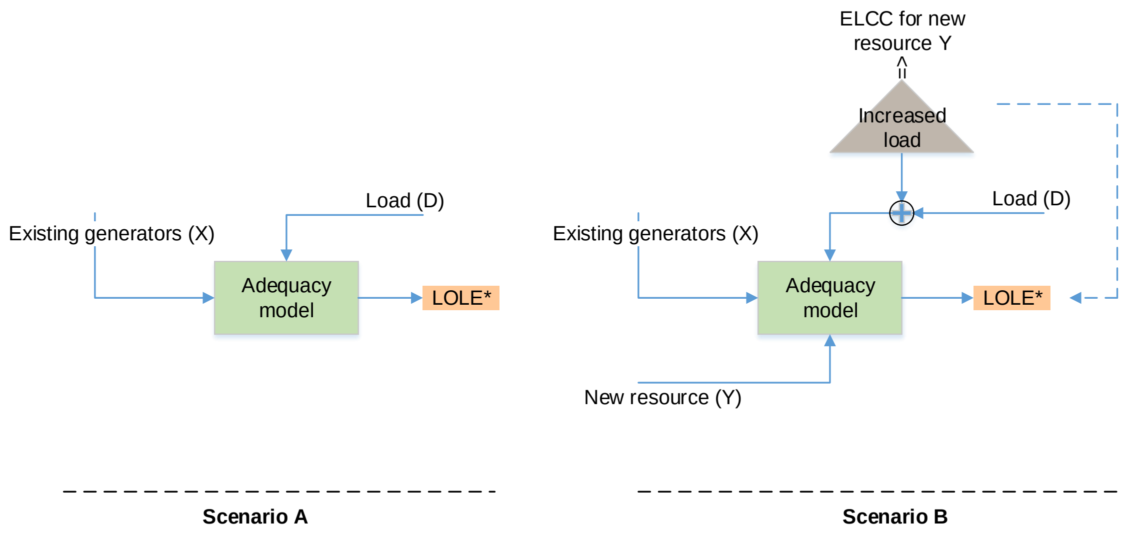
Equation A2 is derived based on a mathematical technique that can only provide reasonable results if the set of trading intervals with the highest LOLP in scenarios 1 and 2 are almost equal.[105]

However, if the new resource has a high variability, the set of trading intervals determining the LOLE in scenario B can substantially differ from those in scenario A. For example, a trading interval with high demand in scenario 1 may have a relatively high LOLE, but may not be among the top 30 trading intervals TI1 to TI30. For simplicity, if we consider the 31st trading interval based on the LOLE, TI31. If the new resource Y has a small output during TI31, but a higher output during TI1 to TI30, period TI31 is likely to have a higher LOLE than some of the trading intervals TI1 to TI30. The greater the magnitude and variation of the output of resource Y, the greater this effect.

Equation A3 cannot suitably account for this effect. The more significant the difference between the trading intervals with highest LOLP, the lower the accuracy of equation A2 in estimating the ELCC.

105 In the derivation of equation A1, Zachary and Dent assumed that the distribution of the output of the new resource and the surplus of capacity are independent. This allowed Zachary and Dent to use a convolution method for the summation of independent distributions. The independence of the distributions can only hold true if the additional resource has a small output both in terms of magnitude and variation. If, for instance, a wind farm in South Australia could connect to the SWIS, the capacity value of the wind farm, for the SWIS, could be accurately calculated by taking the average and variance of the output of the generator at all trading intervals in one year.

Figure A7. Concept diagram for the calculation of ELCC



A4.3 Assumption 3: Surplus of capacity over demand to be measured excluding the capacity of the additional generator

> **Assumption 3**: The surplus of capacity over demand, as used in the formula, is measured based on the surplus of the capacity of existing generators over demand. That is before the addition of the additional resource to the system.

This is best explained through an example. A hypothetical power system comprises three scheduled generators (Gen1, Gen2, and Gen3) and two intermittent generators (IG1 and IG2). To calculate the ELCC of IG2, the average and variance of the output of IG2 should be calculated during the periods when the surplus of the capacity of Gen1, Gen2, Gen3 and IG1 over demand is lowest.

A4.4 Implementation of the current relevant level method

For each trading interval in the last five years, AEMO calculates system load net of *all* intermittent generators' output to determine the load for scheduled generation. This net load is referred to as LSG. Then it selects the top 12 LSG intervals from separate days over each year in the last five years.

In the calculation of LSG the current method includes the output of the intermittent generator whose capacity value is being calculated. Therefore, the current relevant level method is inconsistent with assumption 2 and could lead to inaccuracies in the calculation of capacity values for intermittent generators.

Previous relevant level method reviews have acknowledged this problem,[106]and Sapere suggested an adjustment in the value of parameter K to address it. Sapere stated that the objective of capacity valuation is to estimate "the contribution of the output of intermittent generators in reducing the peak LSG." It noted that the output of an intermittent generator can

[106] Sapere Research Group, *2014 Relevant Level Methodology Review Final Report*, Sydney, Australia, 2014, pp. 47–48, https://www.erawa.com.au/cproot/14780/2/Sapere Final Report.pdf.

shift the timing of peak LSG periods. So, the contribution of an intermittent generator to reduce peak LSG will be between:

- the output of that intermittent generator at peak LSG:
- calculated with and without the intermittent generator's output.

Based on the output of each intermittent generator, Sapere estimated the average difference between the reduction in peak demand and the output of intermittent generators during peak LSG periods. It found that this difference for all intermittent generators is on average 5 MW. It adjusted the value of parameter K to offset that 5 MW difference.

Sapere's adjustment in the value of parameter K is not theoretically correct. The capacity value of a resource is not measured based on the contribution of a resource to reducing peak LSG, it is measured based on ELCC.

The determination of LSG could be modified to better align with assumption 2 by deducting the output of all intermittent generators from demand, except for the output of the intermittent generator for which the capacity value is being calculated. However, this approach is challenging in practice. A separate set of peak LSG periods would need to be determined for each intermittent generator, as its output is removed from the output of the intermittent fleet.

The main challenge then is the calculation of the value of parameter K, which should be calculated for each intermittent generator separately. The value of this parameter would depend on the characteristics of the distribution of the output of scheduled generators and intermittent generators[107] and demand. This requires a model to capture the variability of the output of intermittent generators and their relationship with demand. However, given the lack of data about the performance of intermittent generators during extremely high demand periods, the development of a reasonably accurate model for this purpose is not possible.[108]

A4.5 Calculating the value of parameter K

The amount of parameter K depends on the statistical characteristics of the surplus of capacity over demand. As noted in section A4.3 the capacity surplus should be measured before the addition of the resource for which the ELCC is being calculated.

Sapere used the statistical characteristics of forecast peak demand in the SWIS and the reserve capacity target, net of minimum frequency keeping capacity, as a measure of the output of scheduled generators and intermittent generators.[109] This approach implicitly assumes that the total output of scheduled generation and intermittent generators is fixed, which is implausible because:

- The output of scheduled generators varies due to forced outages and air temperature deratings.

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[107] This is the output of all intermittent generators except the one for which the capacity value is being calculated.

[108] Although intermittent generators have been in operation for several years, little is known about their performance during extremely high demand periods. For instance, in the SWIS a one in 10 year peak demand has never occurred. It is not clear how intermittent generators will operate during such high demand periods.

[109] Sapere Research Group, *2014 Relevant Level Methodology Review Final Report*, Sydney, Australia, 2014, p. 46, https://www.erawa.com.au/cproot/14780/2/Sapere Final Report.pdf.

- The total output of intermittent generators can be highly variable, which is completely overlooked in the current calculation of parameter K.
- The output of intermittent generators can vary with system demand, which would significantly affect the statistical characteristics of surplus capacity. The current method for the calculation of parameter K disregards this relationship.

Developing a solution to calculate parameter K for use in the capacity valuation of individual intermittent generators is impractical. To calculate the capacity value of intermittent generators individually, parameter K should be estimated for each intermittent generator separately. However, this calculation cannot be conducted accurately. It would require information about the output of the rest of the intermittent generators in the system and how they vary with demand and with each other, particularly when the system is under the highest adequacy risk.

This problem in the calculation of parameter K can be avoided altogether. The ELCC can be calculated for the fleet of intermittent generators, rather than for each individual intermittent generator. Calculating ELCC for the intermittent fleet does not require information about the output of intermittent generators when estimating the value of parameter K for the fleet of intermittent generators. Before the addition of the fleet of intermittent generators only the difference between the output of scheduled generation and demand would determine surplus capacity. The surplus of the available capacity of scheduled generation over demand can be modelled relatively accurately because the available capacity of scheduled generators and demand are mostly independent.

However, this approach would require a method of allocating the ELCC for the intermittent fleet to individual generators. This is one of the options explored to improve the current relevant level method, as explained in section 5.1.

A4.6 Calculating the value of parameter U

The original capacity valuation formula in equation A2 requires the measurement of the output and variance of the additional intermittent generator during periods when the surplus of capacity in the system is zero.

Historically, the SWIS has never experienced extreme high demand periods, such as one in 10 year forecast peak demand. The peak LSG instead identifies the periods with the lowest level of surplus but this lowest level may not necessarily be very close to a surplus of zero.

Applying the capacity valuation formula without an adjustment that reflects the reduction in the output of intermittent generators at high temperatures would overestimate the ELCC of intermittent generators.

In the review of the relevant level method in 2011, Sapere examined the relationship between the output of intermittent generators and weather conditions in the SWIS, including air temperature, wind speed, and cloud cover.[110] Sapere found that, among the weather data, air temperature was the best predictor of peak demand. Sapere found that the output of intermittent generators was significantly lower when air temperature in the system was extremely high, as compared to other high demand periods in the system. Sapere introduced the parameter U to address the expected decrease in the capacity contribution of intermittent generators at very high temperatures.

[110] Sapere Research Group, *2014 Relevant Level Methodology Review Final Report*, Sydney, Australia, 2014, pp. 48–60, https://www.erawa.com.au/cproot/14780/2/Sapere Final Report.pdf.

To estimate the size of this adjustment Sapere examined the ratio of peak demand reduction on the peak trading days to the mean output of the fleet of intermittent generators during peak LSG periods and how this ratio varied with air temperature.

This ad-hoc adjustment is problematic:

- The parameter U is scaled by the output variance of intermittent generators.[111] Sapere argued that the relative risk of a reduced contribution during highest demand periods is greater for facilities with greater volatility of output. This may not hold true. The relationship (statistical correlation) between demand and the output of intermittent generators and the volatility of the output, would determine intermittent generators' contribution during peak demand periods. For instance, an intermittent generator may have a higher output with increased demand, but may have a large output variability in general. This hypothetical resource may need an upward adjustment for its capacity value calculation, as in the approximation formula.
- Sapere explained that the existing value for parameter U provided a capacity value in megawatts, which was close to the amount of peak demand served by the output from intermittent generators on the hottest day at the time.
  - In conducting this assessment, it is unclear why Sapere excluded the effect of parameter K.[112]
  - Sapere assessed the value of U based on a single data point: the contribution of the fleet of intermittent generators during the hottest day in the SWIS, which occurred in 2014.
- The relationship between the output of different intermittent generator facilities and demand is not similar. The application of a single adjustment factor to all intermittent generators is not accurate.
- With increased penetration of intermittent generation in the system the periods of high reliability risk can happen outside of the hottest periods in summer days. There may be sufficient data for the performance of intermittent generators during those periods.

Sapere noted that, although parameter U is not consistent with the underlying capacity valuation formula, it is a pragmatic option to address a shortcoming of the method. However, the calculation of parameter U has limitations and can result in an inaccurate capacity valuation for intermittent generators.[113]

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111 In equation A3, parameter U is multiplied by the variance of facility to adjust the effective load carrying capability downward.

112 At the time, Sapere proposed a value of zero for parameter K to be used for capacity valuation of individual generators. This may explain why it excluded parameter K for the assessment of the value of the parameter U factor. However, as discussed in section A4.5, the value of K for the fleet of intermittent generators would be different to that for individual resources. An assessment of the value of the parameter U based on the contribution of the fleet of intermittent generators would have required a value of the parameter K estimated for the fleet of intermittent generators.

113 The need for a downward adjustment in the approximation formula, however, would diminish over time. As the penetration of intermittent generators in the system increases, the periods with the highest loss of load probability would shift from the highest demand periods to other high demand periods with lower air temperature. The historical data regarding the performance of intermittent generators during such lower temperature periods would be sufficient to represent their contribution to the adequacy of the system. Over time more data about the performance of intermittent generators during extremely hot days would be available.

A4.7 The current relevant level method for new generators

The current relevant level method takes a different approach to calculating capacity contributions for new intermittent generators that have been in operation for less than five years.[114]

To calculate peak LSG for those periods prior to when the new intermittent generator is fully operational, AEMO uses an estimate of the new intermittent generator's output, as prepared by an expert consultant. Therefore, the current relevant level method uses two LSG measures:

- An existing facility LSG, used for all intermittent generators that have been fully operational in the preceding five years.
  - This LSG does not include the output of any of the new or upgraded intermittent generators.
- A new facility LSG, calculated separately for each new or upgraded intermittent generator that does not have actual metered output over the entire previous five years.[115]
  - The LSG for new facilities includes the estimated output of the new intermittent generator, but no other new intermittent generators.

The current relevant level method's treatment of new intermittent generators is also inconsistent with assumption 3 and could lead to inaccurate estimates of capacity values for intermittent generators.

AEMO explained that this arrangement ensures that the estimated data for new facilities does not affect the LSG calculation for existing intermittent generators.[116] It is also possible that a new or upgraded intermittent generator, or a facility that is coming into operation after significant maintenance is not available in time to contribute to the adequacy of the system.

The calculation of capacity value should include the capacity contribution of all resources in the system that are reasonably expected to contribute to the adequacy of the system approximately two years ahead. However, if a new or upgraded resource, which has been included in the calculation of the capacity value, is not available on time, the capacity value of other resources could be under-estimated.

However, several mechanisms in the Market Rules may prevent or lessen this under-estimation effect:

- If sufficient capacity is not available to meet system demand in a capacity year, for instance, when new facilities fail to make their capacity available on time, the Market Rules require AEMO to procure supplementary capacity.[117] The procurement of additional capacity may reduce, but not totally eliminate, the effect of unavailability of the

114 Under the Market Rules, the full operation date for a facility is a date nominated by the market participant in its application for certification of reserve capacity for the facility.

115 Under Appendix 9, Step 11 of the Market Rules, LSG for a new candidate facility before the full operational date is $NFLSG$ which is $LSG\ for\ existing\ facilities, EFLSG - estimated\ output\ of\ the\ new\ facility$.

116 AEMO, *Load for scheduled genertion help guide, Version 2*, Perth, Western Australia, 2014, p. 5, https://www.aemo.com.au/-/media/Files/PDF/load-for-scheduled-generation---help-guide.pdf.

117 Clause 4.24 of the Market Rules. For the 2008/9 summer period, the Independent Market Operator procured 120 MW of capacity. However, no supplementary reserve capacity has been dispatched in the WEM to date. AEMO, 'Supplementary reserve capacity', https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Supplementary-reserve-capacity [accessed 12 September 2018].

capacity of a new intermittent generator on the capacity value of other certified generators.

- The Market Rules require new or upgraded facilities that receive capacity certificates to provide a security bond to ensure they provide their capacity to the system on time. A security bond may reduce the risk of non-availability of capacity resources.

However, the timing of the calculation of capacity values and the provision of security bonds are not aligned. AEMO calculates capacity values before the provision of security bonds. For instance, in the 2017 reserve capacity cycle some intermittent generation facilities withdrew their applications before the submission of security bonds and assignment of capacity credits.

It is unlikely that all new or upgraded intermittent generators certified for a capacity year fail to provide their capacity on time. Therefore, it is unreasonable to separate calculation of their capacity value from that of existing facilities.

Appendix 5 Development of numerical model for the calculation of effective load carrying capability

As explained in section 6, the ERA proposes to use a numerical model to calculate the capacity value of intermittent generators in the SWIS. The model runs through a four step process:

1. It calculates the distribution of the available capacity of scheduled generators using a capacity outage probability table (COPT).

2. It uses the COPT calculated in step 1 to estimate the loss of load expectation (LOLE) of the system with time series of demand, excluding the contribution of intermittent generators.

3. Similar to the calculation in step 2, the model estimates the LOLE of the system. However, it uses time series of demand net of the output of all intermittent generators to account for the contribution of intermittent generators.

4. Fixed megawatt amounts are then added to the time series of net demand until the LOLE reverts back to that estimated in step 2. The fixed amount added to the net demand time series is the ELCC of the fleet of intermittent generators.

The fleet ELCC is then allocated to each intermittent generation facility based on its average capacity factor during the periods the surplus of capacity in the system is the lowest.

The ERA also developed a sample model to explain the proposed method in detail. This sample model also informed the design of the proposed method.

The following section discusses the calculation of a COPT, LOLE, the selection of time series data of demand and the output of intermittent generators, and the allocation of the fleet capacity value to individual intermittent resources. The development of the sample model is also presented in detail.

A5.2 Development of a capacity outage probability table

The COPT is a simple array of capacity levels and the respective probabilities of the occurrence of each capacity level. The table represents the probability distribution of the output of scheduled generators in the system[118] and is derived based on basic probability concepts.

Table A4 illustrates the starting point for the calculation of a COPT. This simple table is also the COPT for a power system that has only one generator that may either be:

- up, providing c MW (with capacity outage $Z = 0$) with a probability of $1 - u$, or
- down, providing 0 MW (with capacity outage $Z = c$) with probability of u.

Table A4. Starting point for the calculation of COPT

Effective capacity, c (MW)	Capacity outage, x (MW)	Exact probability, $\mathrm{p}(Z = x)$ or $\mathrm{p}(x)$	Cumulative probability, $\mathrm{p}(Z \geq x)$ or $\mathrm{P}(x)$
c	0	$1 - u$	1
0	c	u	u

118 The COPT represents the probability mass function of scheduled generators in the system.

where c and u respectively denote the maximum capacity and the forced outage rate of the generation capacity.

This two-state (up and down) model of the availability of a scheduled generator contains simplifications. For instance, scheduled generators have a varying degree of availability due to air temperature changes or are frequently on partial forced outage. However, the application of a two-state COPT is a common practice in system adequacy and capacity valuation studies, because it can provide reasonably accurate results.[119]

Although seasonal or multi-state capacity outage probability tables can be developed to address the effect of air temperature or partial outages, the additional complexity and required assumptions introduce more uncertainty in the modelling.

To build the COPT of a system, the model starts with the first scheduled generator. The model iteratively adds other facilities using equation A4:

Equation A4

$$\mathrm{p}_n(x) = (1-u)\mathrm{p}_{n-1}(x) + u\,\mathrm{p}_{n-1}(x-c_n)$$

With each added facility, the model recalculates the exact probability of the system outage capacity, $p_n(x)$, using the forced outage rate, u, of the added facility. For a given iteration of $n-1$, ie, when $n-1$ generating units have already been added to the COPT, $p_{n-1}(x)$ represents the exact probability that a capacity of x MW is on outage:

- The first term on the right hand side of equation A4 denotes the probability of the scenario that the added facility is available, ie, a probability of $\mathrm{p}(x=0) = 1-u$, and all other units already added to the table have an outage capacity of x MW, as shown with $\mathrm{p}_{n-1}(x)$.

- The second term on the right hand side of equation A4 denotes the probability of the scenario that the added facility is on outage, with a probability of $\mathrm{p}(x=c_n) = u$. The already added units should have a total capacity on outage of $x-c_n$ because the new unit is on outage. This ensures that, together with the c_n MW outage of the added facility, the system has a total outage of x MW. The probability of $x-c_n$ MW of outage, based on the $n-1$ generating units already added to the system, is $\mathrm{p}_{n-1}(x-c_n)$.

The sum of the probabilities of the two scenarios above yields the exact probability of the outage capacity of x from n facilities. Equation A4, can also be solved based on cumulative probabilities:

Equation A5

$$\mathrm{P}_n(x) = (1-u)\mathrm{P}_{n-1}(x) + u\,\mathrm{P}_{n-1}(x-c_n)$$

where $\mathrm{P}(x)$ denotes cumulative probability of x, ie, the probability of having an outage greater than x MW. In equation A5 the cumulative probability of any outage state less than or equal to zero megawatts is one.

A part of COPT for the SWIS is presented further below in Table A6.

119 For instance Ofgem used a two-state COPT for its electricity capacity assessments. Refer to Ofgem, *Electricity Capacity Asessment Report 2013, Report to the Secretary of State*, 2013, p. 82, https://www.ofgem.gov.uk/ofgem-publications/75232/electricity-capacity-assessment-report-2013-pdf.

Capacity allocated to ancillary services

The LOLE represents the number of hours per year in which supply is expected to be lower than demand under normal operation of the system. During supply shortages a system operator intervenes to restore the system balance before disconnecting loads. For instance, a system operator may use voltage or frequency control resources, interconnectors or other reserves.

A well-functioning system avoids regular use of emergency mitigation actions. The assessment of the adequacy of the system is therefore based on the normal operation of the system. Explained more accurately, LOLE is not a measure of the expected number of hours per year in which customers may be disconnected, but it indicates the number of hours in which the system may need to respond to high adequacy risk conditions.[120]

When developing the COPT, all capacities for emergency response should be excluded. Additionally, any capacity tied to the provision of ancillary services which have to be maintained in real time during all periods, including high adequacy risk periods, should be excluded from the COPT.[121]

The planning criterion of the Market Rules specifies that the SWIS should have sufficient capacity to meet a one in 10 year peak demand forecast plus a reserve margin, while maintaining the minimum frequency keeping capacity for normal frequency control.

The reserve margin of the planning criterion ensures that, in addition to having sufficient capacity to meet peak demand, the system can support a sudden shortfall in generation following the loss of a large capacity generator or transmission equipment.[122] AEMO's procurement of capacity covers the capacity required for the spinning reserve ancillary service. AEMO also procures capacity for minimum frequency keeping, ie, for load following ancillary services.

The calculation of COPT for the SWIS should therefore exclude the capacity procured for the provision of load following and spinning reserve ancillary services.

Point 1

The calculation of COPT should exclude the capacity withheld for the provision of spinning reserve and load following ancillary services. The system operator should be able to meet both demand and ancillary services requirements when the system has high adequacy risk, eg during a trading interval with high demand.

[120] Ofgem, *Electricity Capacity Assessment Report 2013, Report to the Secretary of State*, 2013 , p. 77, https://www.ofgem.gov.uk/ofgem-publications/75232/electricity-capacity-assessment-report-2013-pdf.

[121] This is similar to the approach undertaken in other studies. For instance, refer to S Zachary & C Dent, 'Estimation of Joint Distribution of Demand and Available Renewables for Generation Adequacy Assessment', 2014, 16 (p. 8), http://arxiv.org/abs/1412.1786 and Ofgem, *Electricity Capacity Assessment Report 2013, Report to the Secretary of State*, 2013, p. 90, https://www.ofgem.gov.uk/ofgem-publications/75232/electricity-capacity-assessment-report-2013-pdf.

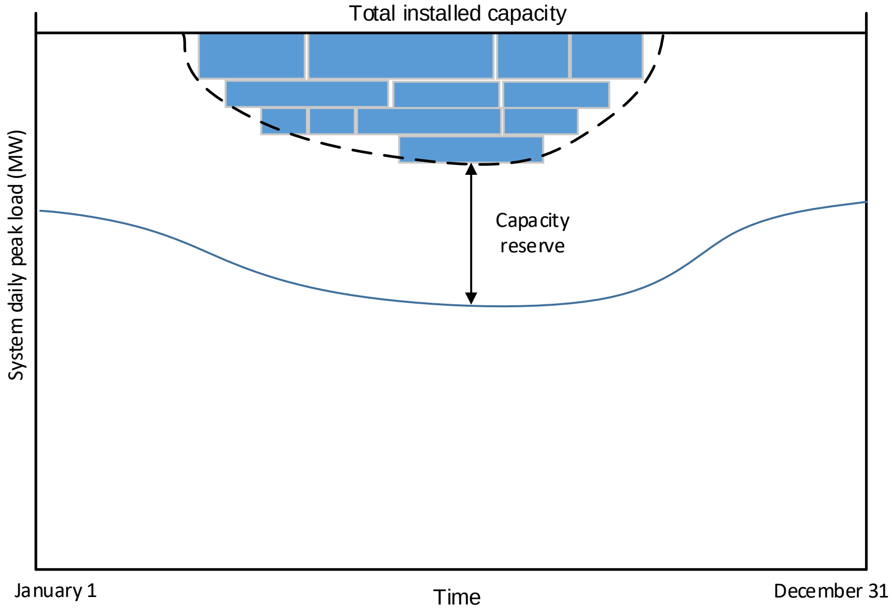
[122] Refer to Market Reform, *Review of the Planning Criterion used within the South West Interconnected System*, 2012, p. 3.

Planned outages

Facility operators remove scheduled generators from service for periodic inspection and maintenance based on a plan. During such periods the capcity available to the system will be reduced and thus a single COPT is not applicable. Figure A8 illustrates a hypothetical example of a maintenance schedule for a summer peaking system such as the SWIS. The height of each blue rectangle depicts the capacity on planned outage from a facility. The sum of the planned outages will reduce the amount of capacity reserve during the off-peak season.

To address the effect of planned outages, the annual LOLE can be estimated by dividing the year into periods. For each period a new COPT can be calculated subject to capacities on scheduled outage.

Figure A8. Effect of scheduled maintenance on system reserve[123]



Under the Market Rules the schedule for planned outages is subject to conditions. System Management follows a risk assessment process when evaluating outage plans submitted by generators.[124] If planned outages are scheduled during the periods when the system has the lowest loss of load probability (LOLP), they will have a negligible effect on the LOLE of the system, as calculated in steps 2 to 4 of the proposed numerical method in section 6 of the main body of the report.

The ERA did not have sufficient resources to investigate the impact of the planned outages and relevant scheduling criteria on the capacity valuation results. For the proposed probabilistic method, the ERA will use a single COPT that does not consider the effect of scheduled outages. This approach implicitly assumes that the risk assessment criterion for outage planning under the Market Rules can sufficiently eliminate any increase in the LOLE of the system due to planned outages. The use of a single COPT for capacity valuation is

123 Billinton and Allan, *Reliability Evaluation of Power Systems, Second Edition*, p. 52.

124 The criteria for the assessment of outage plans is set out in clause 3.18.11 of the Market Rules.

common practice.[125] The ERA will consider investigating the effect of planned outages in its subsequent reviews of the relevant level method.

Point 2

Planned outages may not have a material effect on the capacity value of intermittent generators. The Market Rules specify risk assessment criteria for outage planning. Outages planned to be run during very low adequacy risk periods would have a negligible effect on the capacity value of intermittent resources.

125 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 (p. 17), http://dro.dur.ac.uk/11699/.

Network constraints

The proposed method for the calculation of capacity value does not include the effect of network constraints. Currently network constraints in the SWIS are not frequently occurring and thus their effect on capacity value results would be small. The Market Rules specify a separate process for the calculation of the effect of network constraints on the capacity value of generators with constrained network access arrangements.[126] Consequently, the numerical model proposed for the relevant level method does not address the effect of network constraints.

Point 3

The method for the calculation of the capacity value of intermittent resources does not address the effect of network constraints. The occurrence of network constraints for scheduled generators is not frequent. The Market Rules specify a separate process to address the effect of network constraints on the capacity value of intermittent resources with constrained access to the SWIS.

Demand side resources

Demand side resources contribute to the adequacy of the system. The calculation of capacity value should therefore address their contribution. Demand side resources can be included in the COPT as generation facilities. These facilities are expected to have very low or zero forced outage rates, as they commonly have very low likelihood of failing to respond to dispatch instructions. Under the market rules, demand side resources do not need to report outages either planned, forced or consequential.[127] Historically demand side resources have not logged any outages with System Management.

Point 4

The method for the calculation of the capacity value of intermittent resources should factor in the capacity contribution of demand side resources. This can be addressed by including the demand side capacities as firm generators, ie, with outage rates of zero.

Data requirements for the calculation of COPT

The calculation of COPT uses three main inputs: the set of all scheduled generators installed in the system, their maximum capacity and forced outage rates. These inputs should be based on an approximately two-year ahead forecast, because the calculation of capacity value should represent the contribution of resources to the adequacy of the system in approximately two years.

[126] Clause 4.10A and Appendix 11 of the Market Rules.

[127] System Management did not include demand side facilities in the list of equipment subject to outage planning, notice of outages or de-ratings. Refer to clause 3.18.2 of the Market Rules.

Point 5

The set of installed scheduled generators should exclude those generators that are expected to be retired in two years' time and include any new facility that is expected to come into operation within the same period.

The expected forced outage rate is the probability of finding a facility on forced outage at some time in the future. It is the ratio of two time values:

$$FOR = \frac{\sum down\ time}{\sum down\ time + \sum up\ time}$$

The expected forced outage rate of facilities can be estimated through their historical forced outage durations.

Scheduled generators can frequently run with partial forced outages, ie when only a portion of their maximum capacity is on forced outage. The COPT explained above models the available capacity distribution of scheduled generators based on two-states only, ie, up with maximum capacity and down with no output.

In practice, the calculation of two-state COPT uses the equivalent forced outage rate. The equivalent forced outage rate limits the number of capacity states to two and weights all other states to the two up and down states. The evaluation method of the equivalent forced outage rate is explained in the IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity.[128]

The forced outage rate of a facility varies by factors such as facility age, weather conditions and maintenance status. For instance, a facility that has been on forced outage for a long period of time in the past year would have a high forced outage rate for that year. If the unit runs a major overhaul, it may have a substantially lower forced outage rate in the subsequent years than the previous year.

The choice of the period of time for the calculation of forced outage rates would affect the estimate of the expected forced outage rate of facilities. Using long time periods, such as 10 years of operational data, would mitigate the effect of one-off changes. However, a calculation based on very long periods of operational data may not suitably reflect the effect of facilities' age on forced outage rates. The estimation of forced outage rates thus should factor in these trade-offs.

128 IEEE Power Engineering Society, *Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity*, in *IEEE Std 762TM-2006 (Revision of IEEE Std 762-1987)*, New York, USA, 2007.

Point 6

The determination of a resource capacity value is a subset of the system resource adequacy assessment, which is determining the level of installed generation for one or many years into the future. Use of a long-term average for the forced outage rates is reasonable, because the system should be robust to many possible forced outages and deliver capacity and energy consistent with the resource adequacy target.[129]

Development of COPT for the SWIS

This section discusses the development of a COPT for the SWIS, which will be used in the sample numerical model in section 6 of the main body of the report to estimate the capacity value of intermittent resources in the SWIS. The sample numerical model provided in section 6 is based on the historical data from 2012 to 2017 to estimate the capacity value of intermittent resources for the capacity year 2019/2020. The sample model comprises two calculation scenarios: a hot season time series calculation and entire year time series calculation. Section A5.4 provides a discussion of the significance of these scenarios.

The COPT developed in this section would reflect the probability distribution of the output of scheduled generators (and demand side resources) in the capacity year 2019/20.

The main assumptions for the calculation of the COPT are summarised in Table A5.

Table A5. Main assumptions used for the development of the COPT for the SWIS 2019/20 capacity year

Assumption	Description
Scheduled generation	Only included those scheduled generators expected to be able to provide their capacity in 2019/20 capacity year. *Maximum capacity*: used the rated capacity at 41 degrees Celsius (AEMO's capacity credits allocated to scheduled facilities for the 2019/20 capacity year) *Equivalent forced outage rate*: used equivalent forced outage rate calculated by AEMO for the purpose of clause 4.11.1(h) of the Market Rules, for the reserve capacity cycle 2017.
Demand side program	Included as firm supply. *Maximum capacity*: used capacity credits allocated to demand side facilities for the capacity year 2019. *Equivalent forced outage rate*: assumed zero.
Spinning reserve	Did not exclude the capacity reserved for spinning reserve.
LFAS requirement	Did not exclude the capacity reserved for LFAS.

The maximum capacity of scheduled generators for the hot season and entire year calculation scenarios is assumed to be equal to the number of capacity credits they received for the 2019/20 capacity year. This ensures that the maximum capacity available will not be greater than the rated capacity of these resources when air temperature is high. This is a conservative assumption that can slightly bias the capacity value results for intermittent generators upward,

[129] M Milligan et al., 'Capacity value assessments of wind power', in *Wiley Interdisciplinary Reviews: Energy and Environment*, vol. 6, 2017, 1–15 (p. 9).

because during colder periods scheduled generators would have a higher maximum capacity. However, the sample numerical model results showed that this effect is negligible.

AEMO calculates the equivalent forced outage rate of facilities installed in the SWIS for the purpose of clause 4.11.1(h) of the market rules. Appendix 1 of the Power System Operation Procedure: Facility Outages, presents the method for the calculation of equivalent forced outage rate of facilities. The ERA obtained AEMO's estimate of equivalent forced outage rates for the 2017 reserve capacity cycle for use in running the sample numerical model.[130]

As explained previously, capacities withheld for the provision of spinning reserve and load following ancillary services should be excluded from the COPT calculation.

Both the amount of capacity withheld for spinning reserve and the combination of facilities providing the service vary over time. The combination of facilities providing the load following ancillary services also changes across trading intervals. For each trading interval, the maximum capacity of facilities providing these services should be reduced by the amount reserved for the service.

It is not practical to recalculate COPT for each trading interval to reflect the capacity reserved for ancillary services. Alternatively, an estimate of the reserved capacity for the ancillary services can be added to all demand values to balance the capacity of scheduled generation that is used to provide spinning reserve and load following ancillary services.[131] Although this approach has some limitations, it is practical for the modelling.[132]

Clause 3.10.2 of the Market Rules stipulates that the amount of capacity withheld from the system for the provision of spinning reserve must be sufficient to cover the greater of:

- 70 per cent of the total output, including parasitic load, of the generation unit synchronised to the SWIS with the highest total output at that time, and
- the maximum change in demand expected over a period of 15 minutes.[133]

Clause 3.10.1 of the Market Rules specifies that the spinning reserve requirement includes capacity utilised to meet the upward load following ancillary service, which is required to meet fluctuations in supply and demand in real time. The capacity provided to meet the upward load following requirement is counted as providing part of the spinning reserve requirement.

AEMO reported that it has a long-term contract to meet 42 MW of spinning reserve requirement through an interruptible load during the 2018/19 financial year. It also anticipated that the load following ancillary service required for the 2018/19 financial year will be 72 MW.

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130 AEMO used this estimate of equivalent forced outage rates to assess the capacity credits assigned to facilities for the capacity year 2019, as per clause 4.11.1(h) and the equivalent outage rate thresholds specified in clause 4.11.1D of the Market Rules.

131 This is similar to the approach conducted in S Zachary & C Dent, 'Estimation of Joint Distribution of Demand and Available Renewables for Generation Adequacy Assessment', 2014, 16 (p. 8), http://arxiv.org/abs/1412.1786.

132 The adjustment of demand to account for the capacity reserved for ancillary services is an approximation. For example, a scheduled generator with very low forced outage rates, frequently reserved for ancillary services, would have a substantially different effect on the calculation than a scheduled generator with high forced outage rates. Such effects cannot be addressed with an adjustment in demand.

133 The Market Rules allow for relaxation of the requirement for spinning reserve by up to 12 per cent, if System Management expects that the capacity shortfall will be for a period of less than 30 minutes.

Therefore, the amount of scheduled generation capacity expected to be tied to the spinning reserve and load following reserve during the 2019 capacity year can be estimated as below:[134]

$$\begin{aligned} &Scheduled\ generation\ reserved\ for\ spinning\ reserve\ and\ load\ following \\ &\qquad = 70\ per\ cent\ of\ the\ capacity\ of\ the\ largest\ generator\ in\ the\ SWIS \\ &\qquad - 72\ MW\ upward\ load\ following\ reserve - 42\ MW\ interruptible\ load \\ &\qquad + 72\ MW\ load\ following\ reserve \end{aligned}$$

The capacity of the largest generator in the SWIS can be used in the equation above to determine the amount of scheduled generation reserved for the ancillary services. During the periods the system is under high adequacy risk, it is highly likely that the largest scheduled generators are dispatched to meet system demand. The largest generators in the SWIS would therefore set the spinning reserve requirement.

The results of the model showed that the addition of the amount of capacity withheld for ancillary services to demand data does not have a material effect on the capacity value results. The calculation of capacity values in the sample model developed in this report therefore excludes the effect of ancillary services capacity.

COPT for the SWIS

Using the above assumptions and equation A5 the COPT for the SWIS can be calculated. Table A6 presents a part of the COPT for the SWIS. **Error! Reference source not found.** resents the list of scheduled generators, demand side program facilities and their maximum capacity, and equivalent forced outage rates.

[134] In its 2018/19 margin peak and margin off-peak review for the provision of spinning reserve, AEMO excluded the upward load following capacity of NewGen Kwinana and Cockburn CCGT facilities from the calculation of margin values. For simplicity, this report does not add back the load following capacity of these resources.

Table A6. A select part of the COPT computed the SWIS

Outage capacity, x (MW)	Available capacity (MW)	Cumulative probability, $P(x)$	Exact probability, $p(x)$
0	4705	1	0.531244862
1	4704	0.468755138	0
2	4703	0.468755138	0
3	4702	0.468755138	0
4	4701	0.468755138	0
5	4700	0.468755138	0
6	4699	0.468755138	0
7	4698	0.468755138	0
8	4697	0.468755138	0
9	4696	0.468755138	0
10	4695	0.468755138	0
…	…	…	…
477	4228	0.014798904	2.84227E-05
478	4227	0.014770482	8.45279E-06
479	4226	0.014762029	2.07192E-06
480	4225	0.014759957	1.82006E-06
481	4224	0.014758137	1.25357E-05
482	4223	0.014745601	2.4344E-06
483	4222	0.014743167	2.26116E-05
484	4221	0.014720555	1.31198E-05
485	4220	0.014707435	5.03372E-06
486	4219	0.014702402	2.68692E-05
487	4218	0.014675532	0.00016998
488	4217	0.014505552	3.13209E-05
489	4216	0.014474231	7.5058E-06
490	4215	0.014466726	3.36849E-05
491	4214	0.014433041	5.70598E-06
492	4213	0.014427335	4.97684E-05
493	4212	0.014377566	1.75983E-05
494	4211	0.014359968	2.89256E-05
495	4210	0.014331043	9.27534E-06
496	4209	0.014321767	6.67577E-06
497	4208	0.014315091	1.74743E-05
…	…	…	…
1157	3548	1.46088E-06	5.7283E-08
1158	3547	1.40359E-06	2.50787E-08
1159	3546	1.37852E-06	1.71653E-08
1160	3545	1.36135E-06	7.32229E-08
1161	3544	1.28813E-06	1.86396E-08
1162	3543	1.26949E-06	5.42079E-08
1163	3542	1.21528E-06	2.71395E-08
1164	3541	1.18814E-06	1.40439E-08
1165	3540	1.1741E-06	8.60179E-09
1166	3539	1.1655E-06	4.25834E-08
1167	3538	1.12291E-06	1.00843E-08
…	…	…	…

A5.3 Calculation of LOLP and LOLE

Using the COPT, the LOLP of the system for each trading interval t with a demand of the size d_t MW can be calculated. For a given total installed capcity of C for scheduled generators, the probability of the loss of load is:

$$LOLP_t = p(d_t \geq C - x)$$

where x is the amount of scheduled generation capacity on outage. The above formula can be rearranged:

$$LOLP_t = p(x \geq C - d_t)$$

The right hand side of the equation above is the probability of having an outage greater than $C - d_t$. The COPT for the scheduled generators in the system provides this value in the form of a cumulative probability. This is best explained through an example.

Using the COPT shown in Table A6 the LOLP for a trading interval t with $d_t = 4{,}215\ MW$ can be calculated. The amount of capacity reserve in the interval is:

$$C - d_t = 4{,}705 - 4{,}215 = 490\ MW$$

The available capacity in the first row of the COPT, ie, when outage is zero, denotes the total maximum capacity in the system, C. Therefore, the LOLP for the trading interval is the probability of having an outage greater than 490 MW, and is shown in the cumulative probability column of the COPT:

$$LOLP_t = 0.014466726$$

The sum of the LOLP over a planning period of duration T provides the LOLE of the system, which is commonly expressed in hours or days.

$$LOLE = \sum_{t=1}^{T} LOLP_t$$

A5.4 Demand and output time series

For forecasting the capacity value of the fleet of intermittent resources, the proposed model uses the coincidental half-hourly time series for intermittent resources' output and demand. For new or upgraded facilities, estimated outputs are used, similar to the current relevant level method. The use of chronological demand and output has computational advantages and is the common practice for capacity valuation.[135]

The rest of this section discusses the use of multiple years of data, the use of subsets of the annual time series data, and the effect of a lack of data.

Use of multiple years of data

It is possible to calculate the LOLE of the system with the half-hourly demand and output time series data taken from one year only. In steps 2 and 3 of the proposed numerical model, the LOLE of the system can be calculated based on system half-hourly, hourly or daily peak demand and the coincidental output of intermittent resources. For instance, for the calculation of the capacity value of intermittent resources for the capacity year 2019/20, the model may only use demand and output time series data from the 2016/17 period.

This approach, however, has shortcomings, because demand and output data vary significantly across years. The capacity value estimated based on one-year of time series data would not provide a reasonable estimate of the long-term contribution of intermittent resources to adequacy.[136] The use of historical data over multiple years is thus preferred.

[135] For instance, the IEEE Wind Capacity Value Task Force paper recommends that hourly demand and wind output data should be paired chronologically. Refer to 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/.

[136] For instance, Hasche et al. investigated how many years of historical data can suitably forecast a long-term average capacity value of wind resources in the Irish power system. They showed that a one-year capacity valuation can produce volatile results that can under or overestimate a 10-year result by 10 to 20 per cent. 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.

There is a trade-off to the use of long-period historical time series data. Electricity demand varies across years. For capacity valuation, it is important to capture weather-driven changes in electricity demand that are more likely to be correlated with the output of intermittent generators, such as wind and solar farms. Historical time series for demand, however, contain the impact of economic activity, changes in energy efficiency and other drivers of demand. If the calculation of capacity value does not address the effect of these changes, the LOLP or LOLE is not comparable across the years; capacity value results may be biased towards those years that have had the highest non-weather-induced consumption.[137]

The ERA's review of literature showed that it is possible to remove the effect of non-weather induced consumption through proxies such as measures of economic activity. However, such methods would introduce complexity and uncertainty into the calculation. Capacity value results would be sensitive to the relevant assumptions in undertaking such calculations.

The ERA proposes to use five-years of time series data for the calculation because:

- The use of a longer time series would require more estimates for the output of new or upgraded facilities. This can increase administration costs and modelling uncertainty.
- The use of shorter time series can increase the volatility of results.
- The use of a five-year time series is consistent with the current relevant level method.

The planning criterion and the choice of time series data

The most stringent planning criterion in the Market Rules specifies that the SWIS should have sufficient capacity to cover one in 10 year forecast peak demand. This implies that the capacity contribution of facilities during peak demand periods should be the basis of the calculation of ELCC. To meet this requirement of the Market Rules, a subset of annual time series for demand and output can be used. This subset should comprise data from trading intervals when the likelihood of the occurrence of the highest demand is the greatest.

For instance, the ELCC can be measured by using historical coincidental demand and output data when air temperature is above a certain threshold. Or similar to the assessment of system adequacy in the United Kingdom, only periods with a demand greater than a certain percentile of the distribution of demand can be included in the analysis.[138] The LOLE calculated using this subset of time series represents the LOLE at the time of annual peak demand.

The use of a subset of the annual time series data has disadvantages. With increased penetration of intermittent resources in the SWIS, capacity shortages do not necessarily happen at times of absolute peak demand. A peak-based calculation, eg, by using demand data during the hot season or trading intervals with high air temperature, does not recognise capacity shortages in off-peak seasons.

The selection of a subset of time series data is also challenging and would entail a degree of subjectivity. The calculation can be based on the entire historical data during the hot season, a percentile of the distribution of demand and outputs during the hot season, or a combination of air temperature and demand amount thresholds. For instance, Ofgem only use data from winter peak days where demand was greater than the median of daily demand from October to March to conduct system adequacy assessments.[139] The California Public Utilities

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137 M Milligan et al., 'Capacity value assessments of wind power', in *Wiley Interdisciplinary Reviews: Energy and Environment*, vol. 6, 2017, 1–15 (p. 10).

138 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 (p. 18), http://dro.dur.ac.uk/11699/.

139 Ofgem, pp. 24–25.

Commission explored whether the calculation of ELCC should use similar data periods to that used for the capacity valuation of fossil fuel facilities.[140,141] Currently the California Public Utilities Commission calculates capacity values monthly, using historical monthly data. The Midcontinent Independent System Operator uses the entire time series for demand and output over the past year.[142]

The ERA proposes that the calculation of capacity values to use annual time series for demand and output of intermittent resources. The penetration of intermittent resources in the SWIS is increasing and it is likely that periods with low system capacity reserve happen in periods with high (but not the highest) demand when the output of intermittent resources is low.

If periods with highest demand still determine a high proportion of the LOLE in the SWIS, the use of annual time series data would still capture this effect and the capacity value of intermittent resources will mainly be determined by their output during the highest demand periods. The sample model results, explained in section 6 in the main body of this report, confirmed this point. The capacity value of intermittent resources based on demand and output time series during the hot season and entire year scenarios were similar. This also confirmed that a substantial proportion of the LOLE in the SWIS is still determined by the highest demand periods in the hot season.

The effect of a lack of data

There is evidence that the output of some intermittent resources decreases when demand in the system is high, during extremely hot days in the system. In its review of the relevant level method Sapere estimated that the one in 10 year peak demand in the SWIS is most likely to happen when air temperature is approximately 43.8 degrees Celsius.[143] Annual peak demand in the SWIS in the past seven years occurred when air temperature was between 36 and 42 degrees Celsius.[144]. All seven peak demand instances happened when air temperature was lower than the daily maximum air temperature on the day annual peak demand occurred. This may be explained by increased installation of rooftop photovoltaics that has shifted the occurrence of system peak demand to the trading intervals commencing at 17:00 or 17:30, when air temperature is typically lower than earlier afternoon periods.

A comparison of seasonal forecast peak demand also shows that peak demand in the SWIS is likely to be substantially larger in a summer period than in the winter. This is shown in Figure A9. For instance, the one in 10 year forecast peak demand (10 per cent probability of exceedance) in the summer period is approximately 660 MW to 815 MW larger than that for the winter period.

140 California Public Utilites Commission, p. 7.

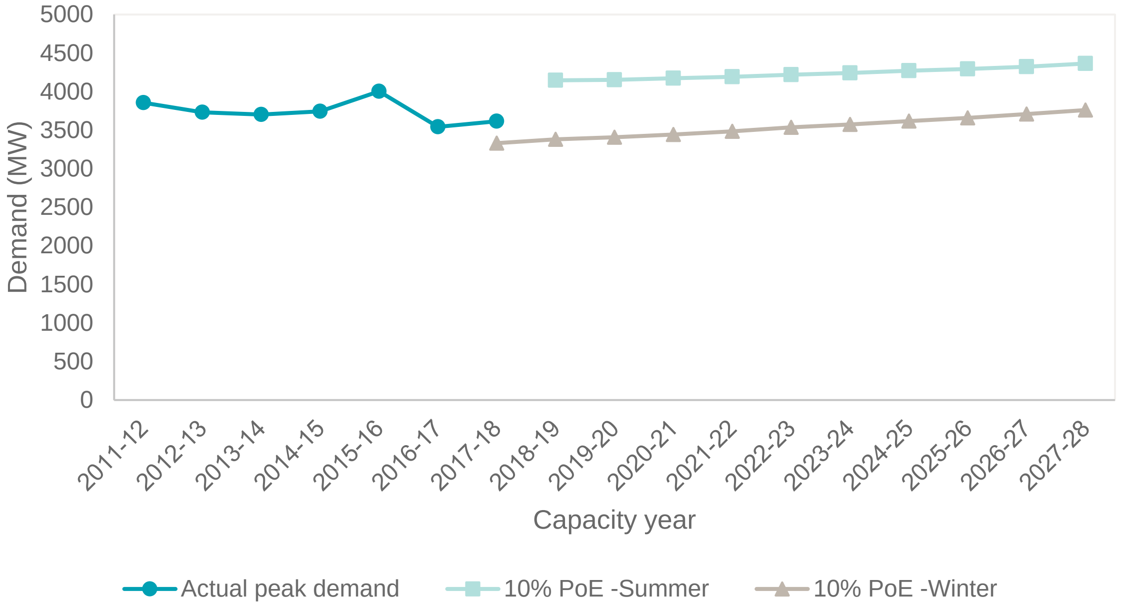
141 California Public Utilites Commission, *Decision 17-06-027 Decision Adopting Local and Flexible Capacity Obligations for 2018 and Refining the Resource Adequacy Program*, 2017, http://docs.cpuc.ca.gov/publisheddocs/published/g000/m192/k027/192027253.pdf.

142 Midcontinent Independent System Operator, 'Planning Year 2018-2019 Wind Capacity Credit', 2017, 1–14 (p. 6), https://cdn.misoenergy.org/2018 Wind Capacity Report97278.pdf.

143 Sapere Research Group, *2014 Relevant Level Methodology Review Final Report*, Sydney, Australia, 2014, p. 50, https://www.erawa.com.au/cproot/14780/2/Sapere Final Report.pdf.

144 AEMO, *Electricity statement of opportunities*, Perth, Western Australia, 2018, p. 34, https://www.aemo.com.au/-/media/Files/Electricity/WEM/Planning_and_Forecasting/ESOO/2018/2018-WEM-ESOO-Report.pdf.

Figure A9. Actual and forecast for winter and summer peak demand in the SWIS[145]



Note: PoE is the probability of exceedance.

The historical time series data for generation output contains limited data for the output of intermittent generators during extremely high demand periods on hot summer days. As depicted in Figure A9, the observed peak demand in the SWIS is lower than the forecast summer peak demand. If the numerical model uses the entire time series data set over 5 years, it is likely that high demand periods in the off-peak season will distort the capacity value results. Due to the lack of data, a greater portion of the LOLE of the system would be determined by the LOLP of high demand periods in the off-peak season than if sufficient data had been available.

A remedy for this problem is to use only demand time series data from the hot season[146] and/or beyond a certain air temperature. This subset of annual time series data will provide an indication of the contribution of intermittent resources during the high demand periods in hot summer days. The LOLE of the system will be determined by the LOLP of the periods in the summer period only. The calculation based on the subset of the time series data may provide a better indication of the contribution of intermittent resources to the adequacy of the system, but it cannot fully eliminate the effect of the lack of data.[147,148] However, as discussed in the previous section, this approach will overlook the contribution of intermittent resources outside the selected sample of trading intervals.

The ERA used the results of the sample numerical model developed in section 6 of the main body of this report to make a judgement about the selection of appropriate time series data for the calculation of the ELCC of the fleet of intermittent generators. The sample model results

145 AEMO, *Electricity Statement of Opportunities*, pp. 64–67.

146 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.

147 The one in 10 year peak demand in the SWIS is mostly likely to happen on hot summer days. The Market Rules require that the system should have sufficient capacity to cover this forecast peak demand. The capacity value calculation based on demand and output time series during the hot season can provide a more accurate indication of the capacity value of intermittent resources.

148 The historical time series of demand and output of intermittent generators do not contain information on extremely high demand periods. Therefore, modelling based on hot season historical time series will not completely eliminate the effect of the lack of data.

showed that the contribution of the LOLP in the off-peak period is low. Therefore, the use of annual time series data cannot create any bias if there is a lack of data for the extremely high demand periods in hot summer days.

In the period between 1 April 2012 and 1 April 2017 air temperature[149] was higher than or equal to 38 degrees Celsius during 448 trading intervals. This sample of trading intervals can provide a reasonable indication of the output of intermittent generators during extremely hot days in the SWIS. With increased penetration of rooftop photovoltaics periods of highest demand are more likely to happen during later afternoon periods when air temperature is less than daily maximum temperatures.

With an increased penetration of large-scale intermittent generation, the periods with a high LOLP could also happen outside the hot season. An adjustment for a lack of data for extremely high demand periods may not be necessary.

A5.5 Allocation method

The numerical model explained in section 6 provides a capacity value for the fleet of intermittent generators in the system. The fleet capacity value should be allocated to individual intermittent facilities based on their contribution to the adequacy of the system.

The ERA reviewed how the Midcontinent Independent System Operator (MISO) and California Public Utilities Commission allocate an estimated fleet capacity value to individual resources. The Midcontinent Independent System Operator's allocation approach is based on the average capacity factor of wind resources over the top eight daily peak hours for each year from 2005.[150,151] The MISO explained that tracking the output of wind resources during "the top 8 daily peak hours in a year is sufficient to capture the peak load times that contribute to (a substantial portion of) the annual LOLE of 0.1 days per year".[152]

The California Public Utilities Commission allocates the fleet capacity value using a simple approach. It proposes to divide the fleet capacity value by the installed capacity of intermittent resources to estimate a percentage amount. The commission applies the percentage amount to the installed capacity of each resource to determine individual capacity values. However, in its capacity valuation manual, it also refers to an alternative allocation method based on historical generation data.[153]

149 Air temperature is measured at Perth Airport.

150 If the operational date of a resource is after 2005, then the average capacity factor over fewer years is used.

151 Midcontinent Independent System Operator, 'Planning Year 2018-2019 Wind Capacity Credit', 2017, 1–11 (p. 10).

152 The Midcontinent System Operator has developed rules for new wind farms that do not have historical output data.

153 California Public Utilities Commission, p. 10.

Explanation

The ELCC of a resource is mostly determined by the contribution of that resource during the periods the LOLP of the system is the greatest. The sum of LOLP during a planning horizon determines the LOLE of the system, which is the basis for the calculation of the ELCC of resources.

For the allocation of fleet capacity value to individual facilities, the ERA proposes to use the historical capacity factor of individual intermittent facilities during two sets of trading intervals:

- the top 12 daily peak demand periods in each year in the past five years. These periods have a significant contribution to the LOLE of the system, before the addition of the fleet of intermittent generators.
- the top 12 periods with the highest daily peak demand, net of the output of all intermittent generators in each year in the past five years. These periods indicate those that have a significant contribution to the LOLE of the system, after the addition of the fleet of intermittent generators.

The reason for the selection of these two sets was discussed in section 6.

The allocation method should ensure that the sum of the capacity values allocated to individual facilities equals the calculated fleet capacity value. The process for the calculation of the capacity value of each resource IG_n in a set of N resources is as follows:

- Calculate the scaling factor R using the below formula:

$$R = \frac{ELCC}{\sum_{n=1}^{N}(Installed\ Capacity_{IG_n} \times Capacity\ Factor_{IG_n})}$$

  where $Capacity\ Factor_{IG_n}$ denotes the average capacity factor of the resource IG_n during the two select sets discussed above.

- Calculate a contribution ratio, using the scaling factor R and $Capacity\ Factor_{IG_n}$:

$$Contribution\ Ratio_{IG_n} = R \times Capacity\ Factor_{IG_n}$$

- Using the $Contribution\ Ratio_{IG_n}$ and the installed capacity of resource IG_n calculate the capacity value of the resource using the below formula:

$$Capacity\ Value_{IG_n} = Contribution\ Ratio_{IG_n} \times Installed\ Capacity_{IG_n}$$

Table A7 uses a simple example to explain the allocation method above. This example assumes a hypothetical system comprising three intermittent generators, ie IG_1, IG_2, and IG_3 with an estimated fleet capacity value of 100 MW. The table also shows the installed capacity and the capacity factor of the facilities during the top 12 daily peak demand and peak net demand periods.

Table A7. Example for the allocation of fleet capacity value

Resource	Installed capacity (MW)	Capacity Factor (%)	Contribution ratio (%)	Capacity value (MW)
IG_1	50	25%	26.3%	13.6
IG_2	100	30%	31.6%	31.6
IG_3	150	35%	36.8%	55.3

The scaling factor R for this example is:

$$R = \frac{100}{50 \times 0.25 + 100 \times 0.3 + 150 \times 0.35} = 1.0526$$

The product of the capacity factor column and R determines the values in the contribution ratio column. The product of the contribution ratio and the installed capacity columns determines the capacity values for the individual intermittent generators.[154]

[154] The sum of capacity values may slightly differ from the fleet capacity value due to rounding errors.

Appendix 6 Scheduled generators included in the development of sample model

Table A8. Facilities included in the calculation of COPT for the SWIS

Facility name	Maximum capacity (MW)	Equivalent forced outage rate
ALCOA_WGP	26	0.024
ALINTA_PNJ_U1	135	0.0009
ALINTA_PNJ_U2	136	0.003
ALINTA_WGP_GT	196	0.0066
ALINTA_WGP_U2	196	0.0028
BW1_BLUEWATERS_G2	217	0.0065
BW2_BLUEWATERS_G1	217	0.1789
COCKBURN_CCG1	240	0.0042
COLLIE_G1	317	0.0137
KALAMUNDA_SG	1	0
KEMERTON_GT11	155	0.0004
KEMERTON_GT12	155	0.0008
KWINANA_GT2	99	0.0162
KWINANA_GT3	99	0.0266
MUJA_G5	195	0.0328
MUJA_G6	193	0.0573
MUJA_G7	211	0.0784
MUJA_G8	211	0.0231
NAMKKN_MERR_SG1	82	0.0052
NEWGEN_KWINANA_CCG1	328	0.0035
NEWGEN_NEERABUP_GT1	331	0.0001
PERTHENERGY_KWINANA_GT1	109	0.0138
PINJAR_GT1	31	0.0027
PINJAR_GT10	111	0.0072
PINJAR_GT11	124	0.0265
PINJAR_GT2	30	0.0021
PINJAR_GT3	37	0.0087
PINJAR_GT4	37	0.0027
PINJAR_GT5	37	0
PINJAR_GT7	37	0.0008
PINJAR_GT9	111	0.0237
PPP_KCP_EG1	80	0.0025
PREMPWR_DSP_02	24	0
PRK_AG	59	0.0086
STHRNCRS_EG	20	0.008
SYNERGY_DSP_04	42	0
TESLA_GERALDTON_G1	10	0
TESLA_KEMERTON_G1	10	0
TESLA_NORTHAM_G1	10	0
TESLA_PICTON_G1	10	0
TIWEST_COG1	36	0.0143

Note: facility capacities are rounded to the nearest integer.