



Reliability Forecasting Methodology Issues Paper

April 2019

How to produce the reliability forecast under the
Retailer Reliability Obligation

Important notice

PURPOSE

This document has been produced by AEMO to seek feedback on the inputs and methodology to be used by AEMO to produce reliability forecasts for the purposes of the retailer reliability obligation to be introduced into the national electricity legislation from 1 July 2019.

DISCLAIMER

This document or the information in it may be subsequently updated or amended. This document does not constitute legal or business advice, and should not be relied on as a substitute for obtaining detailed advice about the National Electricity Law, the National Electricity Rules, or any other applicable laws, procedures or policies. AEMO has made every effort to ensure the quality of the information in this document but cannot guarantee its accuracy or completeness.

Accordingly, to the maximum extent permitted by law, AEMO and its officers, employees and consultants involved in the preparation of this document:

- make no representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of the information in this document; and
- are not liable (whether by reason of negligence or otherwise) for any statements or representations in this document, or any omissions from it, or for any use or reliance on the information in it.

VERSION CONTROL

Version	Release date	Changes
1	17/4/2019	Initial publication

Executive summary

The Australian Energy Market Operator's (AEMO) is consulting on the proposed inputs and methodology to determine reliability forecasts across the National Electricity Market (NEM). AEMO will be required to produce reliability forecasts under the National Electricity Law (NEL) and National Electricity Rules (NER) framework underpinning the Retailer Reliability Obligation (RRO), to become effective from 1 July 2019, as determined by the Council of Australian Governments (COAG) Energy Council.

This Issues Paper outlines AEMO's proposed approach to calculate reliability forecasts, which includes defining:

- Additional data that is intended to be sourced from participants.
- Changes to the calculation of key input assumptions.
- Areas of future development and consultation.
- How the 1-in-2 year peak demand forecast will be calculated.
- How it is assessed if the 1-in-2 year peak demand forecast has been exceeded.
- How the reliability gap will be calculated.
- How the reliability gap period is determined and the trading intervals specified.

Given the forecasts are a critical input to triggering obligations under the RRO, AEMO is seeking to engage with all interested stakeholders to ensure the principles that underpin the proposed forecasting approach and the assumptions to be applied take account of reasonable stakeholder expectations. These principles, as per the RRO Draft Rules clause 4A.B.5, cover accuracy, transparency and engagement:

- Forecasts should be as accurate as possible, based on comprehensive information and prepared in an unbiased manner.
- The basic inputs, assumptions and methodology that underpin forecasts should be disclosed.
- Stakeholders should have as much opportunity to engage as is practicable, through effective consultation and access to documents and information.

On completion of the consultation, the forecasting approach published will inform AEMO's development of the Interim Reliability Forecast Guidelines, due to be published by 31 December 2019.

Stakeholders are invited to submit written responses to the questions outlined in this Issues Paper, and on other issues related to forecasting a reliability gap, by 5.00 pm (Australian Eastern Standard Time) on Wednesday 22 May 2019.

Submissions should be sent by email to energy.forecasting@aemo.com.au.

Contents

Executive summary	3
1. Introduction	6
1.1 Reliability standard	6
1.2 Reliability gap	7
1.3 Structure of this document	8
1.4 Seeking feedback	8
1.5 Supplementary materials	8
2. Demand	10
2.1 Consumption and demand forecasts in the reliability forecast	10
2.2 Large industrial loads	13
2.3 Demand-side participation	13
2.4 Distributed energy resources	15
3. Generation and storage	18
3.1 Generation and storage modelling in the reliability forecast	18
3.2 New entrant generation	18
3.3 Generator capacity	19
3.4 Reliability forecast data requests	20
4. Transmission network	22
4.1 Transmission modelling in the reliability forecast	22
4.2 Interconnectors and network constraints	22
4.3 Network outages	22
5. Declaring a reliability gap	23
5.1 General considerations	23
5.2 Reliability gap period and likely trading intervals	24
5.3 Size of the reliability gap	27
5.4 Information published when a material reliability gap is forecast	29
6. Feedback	31
Glossary	32

Tables

Table 1	Timeline for consultation	8
Table 2	Supplementary material	9
Table 3	Commitment Criteria	18

Figures

Figure 1	Operational demand definition, sent out versus as generated	10
Figure 2	Overview of DSP forecast process	15
Figure 3	Monthly LOLP assessment	26
Figure 4	Weekday/weekend LOLP assessment	27
Figure 5	Time of day LOLP assessment (all months)	27
Figure 6	Conceptual example of the reliability gap	28
Figure 7	Conceptual example of the reliability gap	28
Figure 8	Distribution of USE across months	29
Figure 9	Distribution of USE by time-of-day	30
Figure 10	Duration of USE events	30

1. Introduction

The implementation of the Retailer Reliability Obligation (RRO) was agreed at the Council of Australian Governments (COAG) Energy Council meeting on 26 October 2018, with the necessary legislative and National Electricity Rules (NER) changes scheduled to take effect on 1 July 2019.

A key component of the RRO is the calculation of a five year reliability forecast for each National Electricity Market (NEM) region, to be published in AEMO's Electricity Statement of Opportunities (ESOO). This may trigger AEMO to submit a reliability instrument request to the Australian Energy Regulator (AER) should the reliability forecast identify a material reliability gap¹.

To provide confidence in the quality and transparency of the forecasts, AEMO will be required to produce reliability forecasts in accordance with Forecasting Best Practice Guidelines to be developed by the AER and Reliability Forecast Guidelines to be established subsequently by AEMO. However, the first reliability instrument could be triggered from the 2019 ESOO, before these Guidelines are in place.

This Issues Paper is therefore intended to provide transparency around AEMO's approach to preparing the reliability forecasts in advance of formal Guidelines being developed.

To facilitate effective and informative consultation, one of the objectives of this Issues Paper is to identify and appropriately define critical inputs to be used, some of which will need to be provided to AEMO by stakeholders, and to outline the assumptions to be applied to those inputs.

The Issues Paper also describes the proposed methodology to be followed to determine the content of a reliability forecast, including the reliability gap, reliability gap period, and trading intervals subject to compliance.

The RRO introduces a number of new concepts which relate to the existing reliability standard, which are summarised below for background purposes, based on drafting available at the time of publication. Stakeholders seeking more detailed information should refer to the *National Electricity (South Australia) (Retailer Reliability Obligation) Amendment Bill 2019* (NEL Amendment Bill) and the latest information on the draft RRO amendments to the NER (RRO Draft Rules) published by the Energy Security Board (ESB) on the COAG Energy Council website.

1.1 Reliability standard

The reliability standard is defined in NER clause 3.9.3C and specifies that expected unserved energy (USE)² should not exceed 0.002% of total energy consumption³ in any region in any financial year.

USE is the amount of energy that cannot be supplied to consumers, resulting in involuntary load shedding (loss of consumer supply). This may be caused by factors such as insufficient levels of generation capacity, demand response, or network capability to meet customer demand.

Expected USE means a statistical expectation of a future state. To forecast expected USE, AEMO simulates USE across a range of future outcomes and weights these outcomes with an assessed probability of occurrence. This forecast of expected USE is the assessed against the reliability standard.

¹ See Section 1.2 for further explanation of these concepts.

² The USE that contributes to the reliability standard excludes power system security incidents resulting from multiple or non-credible generation and transmission events, network outages not associated with inter-regional flows, or industrial action (NER 3.9.3(b)).

³ AEMO uses native demand (operational demand + generation from smaller non-scheduled generation) according to the medium-term projected assessment of system adequacy (MT PASA) process description. See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Data/MMS/2018/MT_PASA_Process_Description.pdf.

1.2 Reliability gap

The following outlines key definitions of importance under the RRO. Reliability gaps will be identified for regions individually and by financial year, consistent with the reliability standard.

Material reliability gap

A material reliability gap exists if the forecast expected USE exceeds the reliability standard.

Reliability gap size

When a material reliability gap is identified, AEMO is required to report on the size of the gap. AEMO proposes defining the reliability gap size as the additional quantity of dispatchable⁴ capacity or equivalent, expressed in megawatts (MW), that AEMO projects is needed to maintain reliability at levels expected to meet the reliability standard.

T-3 reliability gap

The T-3 period is the financial year three years out. In the 2019 ESOO, this will be financial year 2022-23. In the reliability forecast, a material gap in any region in this year will trigger a request for a reliability instrument (see below).

T-1 reliability gap

The T-1 period is the financial year one year out. In the 2019 ESOO, this will be financial year 2020-21. In the Reliability Forecast, a material gap in any region in this year will trigger a request for a reliability instrument (see below).

Reliability instrument

If a material reliability gap forecast is identified at either T-3 or T-1, AEMO will send a request to the AER for a reliability instrument to be issued. If approved by the AER, the reliability instrument triggers a number of compliance obligations for liable entities under the RRO.

Under the South Australian application legislation, the Minister will also have powers to make a T-3 reliability instrument for that region.

Reliability gap period

A reliability instrument request must include a defined reliability gap period, which specifies the start and end of the period(s) within the year where USE is likely to occur.

Gap trading intervals

A reliability instrument must also specify the trading intervals within the reliability gap period where the gap is expected to occur. The contracting obligations under the RRO will only apply for the reliability gap period and the trading intervals listed in the T-1 reliability instrument.

1-in-2 year peak demand

For the period of any reliability gap identified in the reliability instrument, the RRO specifies a requirement for liable entities to have sufficient qualifying contracts in place to cover their share of a 1-in-2 year peak demand. Compliance will be assessed whenever actual demand for a trading interval exceeds the forecast 1-in-2 year peak demand within the reliability gap period defined in the T-1 reliability instrument.

⁴ The dispatchability of an energy resource can be considered as the extent to which its output can be relied on to 'follow a target', and incorporates how controllable the resources are, how much they can be relied upon, and how flexible they are. For more information, see AEMO's Power System Technical Requirements, March 2018, available at <http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability>.

1.3 Structure of this document

This Issues Paper explains the key inputs AEMO considers will be required to calculate the reliability gap, and the methodology proposed to determining the parameters of any reliability gap:

- Section 2 provides a summary of demand forecasting assumptions for the reliability forecast.
- Section 3 outlines assumptions relating to the modelling of generation and storage.
- Section 4 summarises the approach to accounting for network limits and transmission losses.
- Section 5 details the process for declaring a reliability gap, calculating the size of the gap, determining the reliability gap period, and the trading intervals when shortfalls are likely to occur.
- Section 6 provides a number of suggested questions for industry to consider when making a submission to this consultation.

1.4 Seeking feedback

The reliability forecasts are a critical input to triggering obligations under the RRO. AEMO therefore seeks to engage with all interested stakeholders to ensure the principles that underpin the proposed forecasting approach and the assumptions to be applied incorporate reasonable stakeholder expectations. These principles, as per the RRO Draft Rules⁵ clause 4A.B.5, cover accuracy, transparency and engagement:

- Forecasts should be as accurate as possible, based on comprehensive information and prepared in an unbiased manner.
- The basic inputs, assumptions and methodology that underpin forecasts should be disclosed.
- Stakeholders should have as much opportunity to engage as is practicable, through effective consultation and access to documents and information.

Feedback from stakeholders is sought on Sections 2-5 in this document, with questions included in Section 6 to facilitate responses on specific matters.

The feedback received on this consultation will inform AEMO's approach to preparing reliability forecasts in the 2019 ESOO and subsequent years, as well as informing the development of the Interim Reliability Forecast Guidelines to be published in late 2019. These Guidelines will set out how the approach outlined in the AER's Forecasting Best Practice Guidelines will be implemented.

AEMO's indicative timeline for this consultation is outlined below. Dates may be adjusted depending on the number and complexity of issues raised in submissions and any meetings with stakeholders.

Table 1 Timeline for consultation

Deliverable	Indicative date
Issues Paper published	Wednesday 17 April 2019
Industry workshop	Thursday 9 May 2019
Submissions due on Issues Paper	Wednesday 22 May 2019
Consultation response published	Wednesday 19 June 2019

1.5 Supplementary materials

This Issues Paper lists a number of references, some of which have been updated to align with the methodology to be applied in the calculation of the reliability forecast.

⁵ See: <http://www.coagenergycouncil.gov.au/publications/energy-security-board-%E2%80%93-retailer-reliability-obligation-draft-rules-consultation-paper>

Table 2 Supplementary material

Deliverable	Link
ESOO methodology paper – draft update	http://aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/NEM-Consultations/2019/Reliability-Forecasting-Methodology/ESOO-Methodology-Document-v2---draft-2019
Electricity Demand Forecasting Information paper – draft update	http://aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/NEM-Consultations/2019/Reliability-Forecasting-Methodology/Electricity-Demand-Forecasting-Methodology-Information-Paper---draft-2019
Reliability Standard Implementation Guidelines – draft update	http://aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/NEM-Consultations/2019/Reliability-Forecasting-Methodology/Reliability-Standard-Implementation-Guidelines---draft-2019
Forecast Accuracy Reporting	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Forecasting-Accuracy-Reporting
Inputs and Assumptions workbook	https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/2019-Input-and-Assumptions-workbook.xlsx

2. Demand

2.1 Consumption and demand forecasts in the reliability forecast

Forecasts of annual consumption and maximum demand by NEM region are critical inputs into AEMO’s reliability forecasts.

For the ESOO, consumption and demand forecasts are produced for different scenarios providing alternative views of forecast outcomes, based on different assumptions of input drivers such as economic growth, population growth, and technology uptake.

For the reliability forecast in the ESOO, only the Neutral scenario is considered (noting that the differences between scenario outcomes are relatively small in the 1-5 year horizon).

All AEMO’s demand forecasts are published on its website⁶.

2.1.1 Demand definitions and the reliability forecast

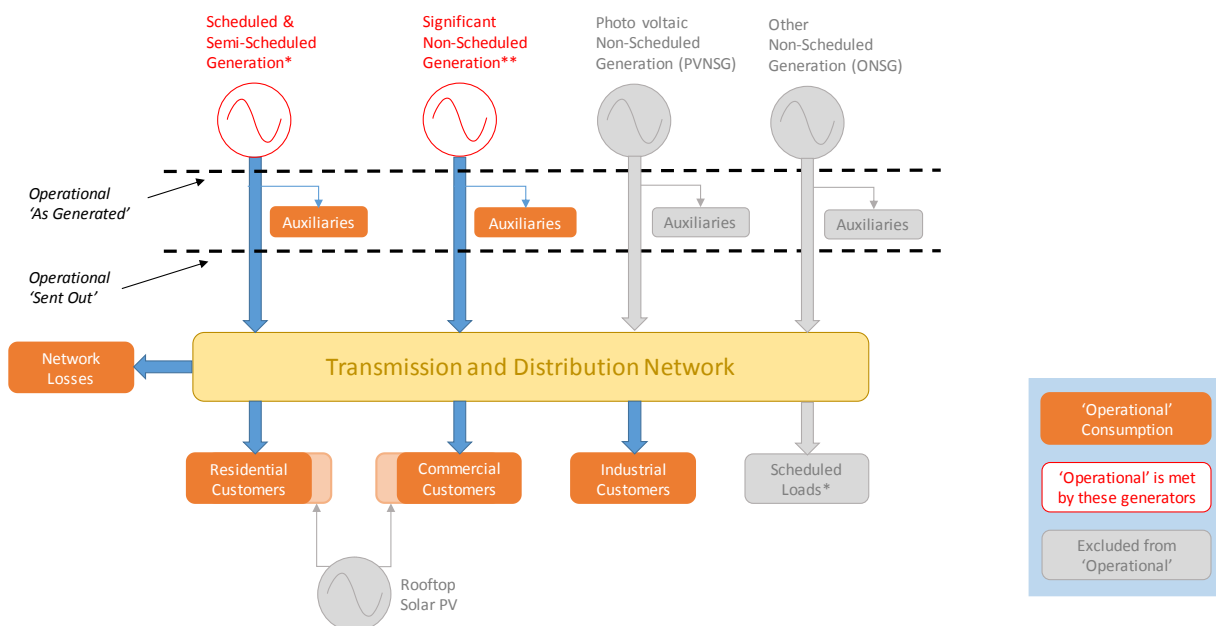
Demand can be measured at different points in the electricity network. AEMO’s reliability modelling is based on operational consumption/demand. This represents demand delivered from the transmission grid as produced by all scheduled, semi-scheduled, and significant non-scheduled generators⁷.

Operational demand can be defined in two different ways depending on where the generation delivered to the transmission grid is measured:

- As generated – this definition reflects the total generation produced by the generator before subtracting any internal consumption at that site, known as the auxiliary load or auxiliaries.
- Sent out – this definition reflects the generation actually delivered to the transmission grid.

This is illustrated in Figure 1.

Figure 1 Operational demand definition, sent out versus as generated



⁶ See: <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Demand-Forecasts>.

⁷ For a full definition of AEMO’s demand definitions, see: http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf.

AEMO forecasts 'sent out' operational demand for the ESOO, because this directly reflects the consumption supplied from the grid. 'As generated', on the other hand, requires assumptions about how many coal-fired plants (which have by far the highest auxiliary loads) are generating at the time, which is uncertain due to forced outages in the shorter term and changes to the generation mix in the longer term.

However, because the National Electricity Market uses 'as generated' terms for generator capacities (see Section 3.3), AEMO also models auxiliary load in its market modelling (see Section 3.4.2). The modelled auxiliary load at time of peak is provided as a forecast for auxiliary load for any user who wants to convert the 'sent out' forecast of maximum demand to 'as generated'.

Reliability forecast demand forecasts

The actual maximum and minimum demand outcomes for a particular summer or winter season vary significantly depending on the weather conditions, type of day, and coincidence of consumption⁸ on the day. To reflect the inherent uncertainty of what demand may be in future years, maximum and minimum demand forecasts are presented as distributions, with 10%, 50%, and 90% probability of exceedance (POE) forecasts given for each region⁹.

For the T-3 and T-1 assessments in the reliability forecast, expected USE will be assessed based on the weighted outcomes of the market simulations of the different operational sent out POE demands. This is the same approach as is currently used to assess performance against the reliability standard.

1-in-2 year peak demand forecast

The 1-in-2 year peak demand forecast is defined in the RRO Draft Rules clause 4A.A.3:

For the purposes of section 14C of the *National Electricity Law*, the one-in-two year peak demand forecast for a *region* is:

- (a) the forecast made in accordance with the *Reliability Forecast Guidelines*; and
- (b) specified in a *reliability forecast* to be that forecast for that *region* for that *financial year*.

Note

Section 14C of the *National Electricity Law* states the one-in-two year peak demand forecast, for a region during a specified period, means the peak demand forecast in accordance with the *Rules* –

- (a) to occur for a *region* during the period; and
- (b) where the likelihood is that the forecast amount will be exceeded once in any two-year period.

For the purpose of the RRO, AEMO will use its 50% POE operational forecast, converted from 'sent out' to 'as generated' forecast auxiliary load, as the 1-in-2 year peak demand forecast.

The use of 'as generated' for the 1-in-2 year peak demand forecast will allow stakeholders to readily compare against demand in real time, because actual historical demand is reported ongoing by AEMO using this point of measurement¹⁰.

Allowing comparison of forecast against actual demand in near to real time should provide liable entities with the opportunity to take action to reduce load when actual demand approaches the 1-in-2 year peak demand forecast.

⁸ The degree of coincidence of consumption creates large variations in consumption on otherwise similar days, arising, for example, from how many are home at the same time and what appliances they decide to use.

⁹ A 50% POE represents the forecast maximum demand that expectedly only would be exceeded one in two years, while 10% POE would be exceeded on average once in 10 years.

¹⁰ See <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data-dashboard#operational-demand>.

Peak demand and actual demand

Peak demand and actual demand are defined in the RRO Draft Rules clause 4A.A.4:

- (a) For the purposes of section 14C of the *National Electricity Law*, the maximum electricity demanded is the highest actual demand in a *trading interval* in a *region* (in MW).

Note

Section 14C of the *National Electricity Law* states the peak demand, for a period in a *region*, means the maximum electricity demanded, in megawatts, in the region during the period, determined in accordance with the *Rules*.

- (b) The actual demand for a *region* for a *trading interval* is:

- (1) the demand for that *region*;
- (2) adjusted, to reflect what would have been the demand but for the following adjustments in the *market*:
 - (i) *directions* by AEMO;
 - (ii) *RERT activated or dispatched* by AEMO;
 - (iii) *load shedding* by AEMO; and
 - (iv) any other adjustments as set out in the *Reliability Forecast Guidelines*,
in each case as determined in accordance with the *Reliability Forecast Guidelines*.

- (c) AEMO must publish the actual demand for a *trading interval* for all *regions* on its website as soon as practicable after the end of that *trading interval*.

The AER will only assess compliance in trading intervals in which actual demand, with the adjustments listed above, exceeds the 1-in-2 year peak demand forecast in AEMO's T-1 reliability instrument request.

2.1.2 Improvements to AEMO's forecasts

The accuracy of AEMO's forecasts are assessed at least annually through the Forecast Accuracy Report¹¹, which assesses the accuracy of consumption forecast, maximum demand, minimum demand, and key input forecasts. From 2019, the Forecast Accuracy Report will also include an assessment of the performance of supply forecasts, such as reliability of thermal generators.

Based on the Forecast Accuracy Report's findings, AEMO presents a workplan of improvements to the forecast data and methodology to address issues found. AEMO may improve the demand forecasting methodology based on its own observations (generally reported as part of the improvement program in the Forecast Accuracy Report), or incorporating suggestions from stakeholders (for example, at AEMO's Forecasting Reference Group meetings or during consultation on forecasting methodologies).

In the Interim Reliability Forecasting Guidelines to be produced in late 2019, AEMO will outline the process for consultation on forecasting improvements to be included in a reliability forecast assessment.

For the 2019 ESOO, AEMO is implementing a number of enhancements to its demand forecasts. These are explained in more detail in the draft updated Electricity Demand Forecasting Methodology Information paper¹². This has been change-marked to easily identify changes since the previous version reflecting the forecast used in the 2018 ESOO. The changes are summarised below:

¹¹ See <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Forecasting-Accuracy-Reporting>.

¹² See http://aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/NEM-Consultations/2019/Reliability-Forecasting-Methodology/Electricity-Demand-Forecasting-Methodology-Information-Paper---draft-2019.

- Improved business sector consumption modelling, segmenting the overall sector differently to provide better visibility of consumption by large industrial users and better model performance of the remainder (commercial and smaller industrial sectors).
- Hybrid maximum/minimum demand forecasting methodology mixing detailed half-hourly models (capturing change in timing of extremes due to changes in technology mix) and an extreme value approach, focusing on high/low demand points only. This extreme value approach is new this year, and has been shown to be particularly accurate for the initial years in the forecast horizon.
- Improved forecast of generation from PV non-scheduled generators (PVNSG) based on profiles better reflecting the characteristics of generation from this segment.
- Update to the other non-scheduled generation (ONSG) forecast methodology to exclude peaking plants registered as providing demand-side participation (DSP), because their generation pattern is better represented when modelled as DSP.
- Potential update to how energy efficiency is applied on extreme weather days. Currently the percentage saving of cooling load is the same on extreme hot days as milder summer days. Based on consultancy advice, which will be presented to industry when available, AEMO will assess whether the impact of energy efficiency is lower during the extreme days, and, if so, reflect this in its forecast.

2.2 Large industrial loads

New large industrial loads or closure of existing loads can have major impacts on observed USE. As part of its forecasting process, AEMO surveys all large loads across the NEM and interviews those which have the largest changes in consumption in recent years, or have flagged changes in the surveys.

For the purpose of the RRO, a degree of certainty will be required before any new loads are included in the demand forecasts. Based on the outcomes of the surveys, AEMO will determine which changes should be included in the different ESOO demand scenarios, and include criteria such as whether:

- Final investment decision has been made.
- All planning and environmental approvals are in place.

No full closures or reduction in demand from large industrial loads will be included in the Neutral scenario unless they have been formally announced as a firm decision.

Should any significant changes to large industrial loads be announced post publication of the reliability forecast, AEMO will determine if sufficient to trigger an update to the reliability forecast as per RRO Draft Rules clause 3.13.3A(b).

2.3 Demand-side participation

AEMO's demand forecasting process forecasts what demand would be in the absence of load shedding (from direction or automatic shedding) or DSP (voluntary responding to high prices or reliability signals).

To avoid overlap with AEMO's maximum demand forecast (and potential double-counting of responses), AEMO's DSP forecast specifically covers all the following:

- Occasional DSP responding to different levels of high prices (market-driven response).
- Occasional DSP responding to critical system conditions (reliability-driven response).

In this, DSP refers both to actual reduction in consumption and net demand reductions from small non-scheduled generation operated as part of a DSP portfolio responding to the same signals.

AEMO will leave out DSP that is operated on a daily basis (typically electric hot water heaters), because this is built into all the historical data used to forecast maximum demand, and the forecast implicitly assumes this level of DSP will continue to exist.

Battery storage is also left out as modelled separately (see Section 2.4).

The RERT response is a non-market response procured by AEMO if reliability assessments show insufficient supply is available to meet the reliability standard. Therefore, RERT cannot be part of the DSP forecast used to assess if it is required in the first instance.

DSP assumption used for the T-3 and T-1 reliability gap assessment

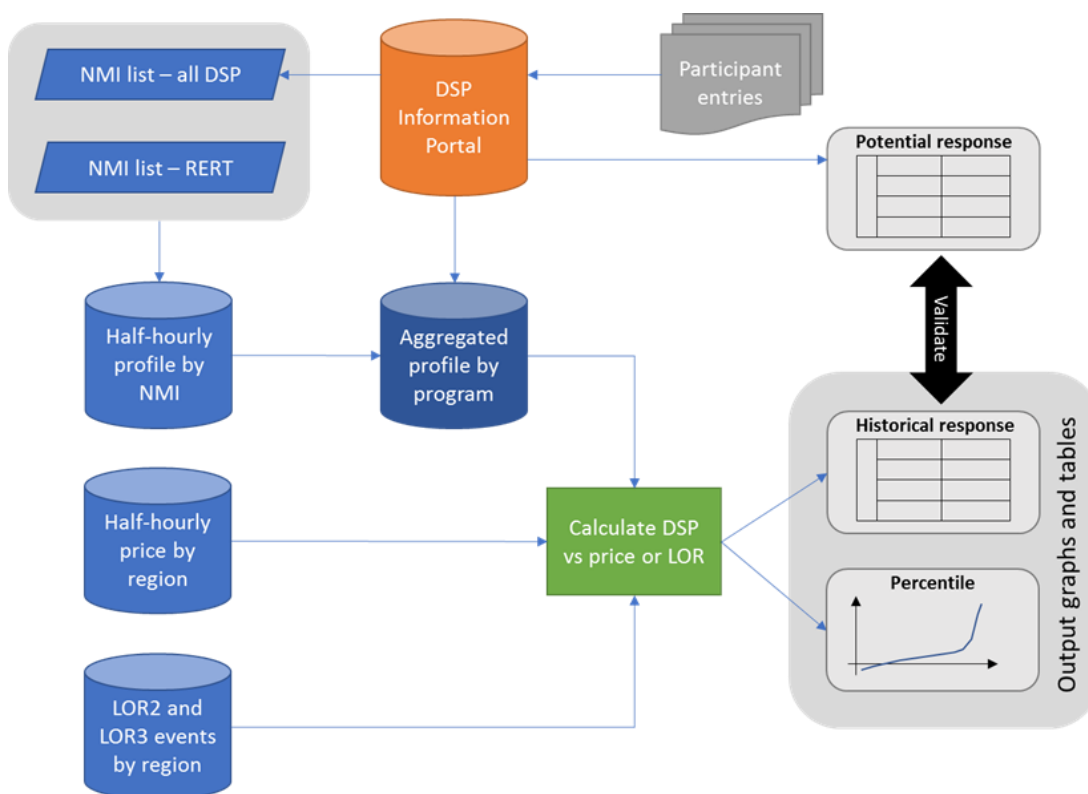
AEMO proposes to use the following approach to forecast the DSP response at time of capacity shortage:

1. Collect information from DSP aggregators through AEMO's annual DSP survey, to which all registered participants are obliged to respond. Each registered participant provides a list of any DSP programs, and detailed information on the location and potential response of contracted DSP. The DSP information obligations cover current and historical contracted DSP. Estimates of future DSP are not provided for.
2. Inspect half-hourly consumption from the different NEMs for the last three years. Responses by NEMs will be aggregated by program and region. In the aggregation process, AEMO will filter out any responses from NEMs that are part of the RERT program.
3. Estimate DSP responses for the last three years for each DSP program's aggregated consumption profile for two different trigger types:
 - **Price triggers** – the responses are estimated for when prices exceed different price levels. To cover a reasonable range of different DSP initiatives, AEMO models the price triggers \$300/MWh, \$500/MWh, \$1,000/MWh, \$2,500/MWh, \$5,000/MWh, and \$7,500/MWh.
 - **Reliability triggers** – the responses are estimated for periods with actual Lack of Reserve (LOR) 2 and LOR 3 events¹³.
4. From the historical responses, derive a total DSP response probability curve per region. One such curve exists for each trigger price considered, as well as for responses to actual LOR 2 or LOR 3 events. The latter is made up of rather few points, but shows the reliability response in general is higher than the median (50th percentile) response for the highest price band considered.
5. Given the uncertainty from the low amount of LOR events, the 50th percentile response at \$7,500/MWh is used as a conservative approximation of the likely DSP response at time of capacity shortage. This level of response is assumed to remain for the duration of the 10-year outlook. AEMO will validate this against the reported potential response by DSP program.

This is summarised in Figure 2.

¹³ See NER Clause 4.8.4 for definition.

Figure 2 Overview of DSP forecast process



This methodology has improved from 2018, with the key changes being:

- Compared to the 2017 and 2018 DSP forecasts, where only load reductions were considered, AEMO will in the 2019 DSP forecast add embedded peaking type generators (such as emergency back-up generators) which may offset local consumption. These generators were previously captured as part of the forecast contribution of ONSG to peak demand, but there have been recent cases where demand has peaked but prices have been low, and this type of generator did not dispatch. Existing methodologies would have assumed that peak demand would correlate with dispatch of ONSG. Modelling this generation type as DSP will better reflect actual behaviour and the type of assets used in DSP portfolios.
- Previous years included network reliability programs that may not always be available during system needs (due, for example, to the limited number of times these can be called over a summer). AEMO is proposing to include these programs in this year’s reliability assessment, but to apply a 50% forced outage rate to reflect uncertainty around availability of these programs. Feedback on this proposed approach would be valued.

DSP and 1-in-2 year peak demand

For the 1-in-2 year peak demand forecast, the used 50% POE forecast (see Section 2.1.1) will exclude the estimated impact DSP representing what demand would be in the absence of this.

When assessing actual demand against the 1-in-2 year peak demand forecast no adjustment is made for DSP as not controlled by AEMO as per RRO Draft Rules clause 4A.A.4. Instead, DSP is assumed to be operated in a qualifying contract that a liable entity will have in its books to meet its share of peak demand.

2.4 Distributed energy resources

Distributed energy resources (DER), such as rooftop PV installations and customer-installed battery storage systems, have transformed the demand profile for grid-supplied electricity.

For the reliability forecast, the contribution of DER to maximum demand is very important. While generation from rooftop PV can be calculated rather precisely based on solar irradiation, the operation of battery storage and electric vehicles (EVs) is less predictable, as it is affected by a number of different parameters, such as consumer behaviour, offered retail tariffs, uptake of tariffs, and generation by any local PV systems.

To assist with its 2019 demand forecast, AEMO is obtaining forecasts for DER uptake and usage patterns from two consultants, CSIRO and Energeia. This work includes:

- Forecast installed capacity in MW of rooftop PV (installations up to 100 kW) and PVNSG (installations from 100 kW to 30 MW).
- Forecast installed capacity in MW and MWh of battery storage installations.
- Forecast uptake of EVs (numbers) and consumption from the EV fleet (in GWh).
- Forecast charging/discharging pattern (half-hourly) for battery storage systems, taking into account tariff incentives (according to AEMO's scenario definitions) and generation by co-located rooftop PV systems.
- Forecast charging patterns (half-hourly) for EVs for different type of customer behaviour (convenience charging vs optimised charging against retail tariffs), vehicle type (residential/commercial), and any generation by co-located rooftop PV systems.
- Estimated future share of battery storage systems controlled by an aggregator as a virtual power plant (VPP).

Consultant draft forecasts have been presented to industry at AEMO's Forecasting Reference Group (FRG) meetings and additional information from the consultants will be shared with industry as it becomes available.

This information will show the contribution of DER to maximum demand from different customer behaviour, such as convenient charging of EVs, where the behaviour may not make economic sense but be driven by convenience, or a need for charging overriding economic rational decisions. Similarly, network tariffs may not always perfectly optimise battery storage discharge at time of high demand, but instead create incentives for own-use, discharging the battery well into the evening to improve self-sufficiency.

Half-hourly traces for T-3 and T-1 reliability gap assessment

AEMO's operational sent-out forecast consumption and maximum demand is used in the reliability forecast modelling. For this, the forecasts need to be converted into half-hourly demand traces. The existing methodology for this is explained in AEMO's Electricity Demand Forecasting Methodology Information paper, but for the 2019 reliability forecast modelling AEMO proposes to include the following enhancements to better model DER:

- Improved traces of PVNSG calculated by AEMO based on historical solar irradiation.
- Traces of battery storage charging/discharging profiles provided by AEMO's consultants.
- Traces of electric vehicle charging profile provided by AEMO's consultants.

The latter two will take into account any rooftop PV generation co-located on the site at half-hourly level. This has not been incorporated in previous years.

To ensure aggregated battery storage operating as VPP contribute to meet demand during system needs (such as during multiple generator outages), the traces exclude any contribution from VPP. Instead, this is modelled as a large scale storage, optimised in the market modelling to minimise USE. Further details are available in the draft ES00 methodology document¹⁴.

Once developed, AEMO will present draft traces to industry around early June 2019 for comment.

¹⁴ See http://aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/NEM-Consultations/2019/Reliability-Forecasting-Methodology/ES00-Methodology-Draft-v2---draft-2019

DER and 1-in-2 year peak demand

For the 1-in-2 year peak demand forecast, the used 50% POE forecast will exclude the estimated impact of storage operated as VPP. These are assumed to be operated in a qualifying contract that a liable entity will have in its books to meet its share of peak demand. Peak demand should therefore not be adjusted down with this amount, but solely count as part of the contracts of the liable entities operating VPP.

3. Generation and storage

3.1 Generation and storage modelling in the reliability forecast

The methodology and assumptions used to model existing and committed new entrant generation and large-scale energy storage is provided in the ESOO Modelling Methodology document¹⁵. Compared to previous years, AEMO has updated its approach in a few areas. These are discussed below. It should also be noted that AEMO will send all participants a letter asking them to confirm forced outage rate assumptions and auxiliary loads.

3.2 New entrant generation

Under 3.13.3(q), AEMO is required to publish information regarding generation units for which a formal commitment to construct has been made. Based on this requirement, AEMO has developed a set of commitment criteria under which all proposed projects are tested to determine their status.

For a unit to be classified as committed, AEMO requires the project to have met all five of the criteria provided in Table 3.

Table 3 Commitment criteria

Category	Criteria
Site	The project proponent has purchased/settled/acquired (or commenced legal proceedings to purchase/settle/acquire) land for the construction of the project.
Major components	Contracts for the supply and construction of major plant or equipment components (such as generating units, turbines, boilers, transmission towers, conductors, and terminal station equipment) have been finalised and executed, including any provisions for cancellation payments.
Planning and approvals	The proponent has obtained all required planning consents, construction approvals, connection contracts (including approval of proposed negotiated Generator Performance Standards from AEMO under clause 5.3.4A of the National Electricity Rules), and licences, including completion and acceptance of any necessary environmental impact statements.
Finance	The financing arrangements for the proposal, including any debt plans, must have been concluded and contracts executed.
Date	Construction of the proposal must either have commenced or a firm commencement date must have been set. Commercial use date for full operation must have been set.

Projects that have commenced construction but do not yet meet all five of the criteria are also published, because they have clearly made a formal commitment to construct (referred to as 'Com*' projects in AEMO's Generation Information page).

In the 2018 ESOO, all new entrant generation and storage projects that were classified as committed, or had commenced construction, were included in the forecast. However, even though construction may have commenced, Com* may be less certain to proceed, particularly if connection approvals have not been provided. For the 2019 ESOO and future reliability forecasts, AEMO is proposing not to include Com* projects.

¹⁵ See http://aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/NEM-Consultations/2019/Reliability-Forecasting-Methodology/ESOO-Methodology-Document-v2---draft-2019

AEMO considers that this more appropriately takes into consideration the cost of misclassification. At T-3, if more capacity is assumed committed than actually proceeds, there is a risk that a reliability instrument may not be requested, and it is not possible in subsequent years to reverse that decision based on new information. If, on the other hand, more capacity is built than assumed at T-3, this would serve to close any reliability gap and may result in no T-1 reliability instrument needing to be issued.

3.3 Generator capacity

Generator capacity is a key input to the reliability forecast. For the 2019 forecast, AEMO is proposing to continue using the same methodology as in the 2018 ESOO:

- The capacity of scheduled generators is based on information submitted by participants through the Generation Information survey process.
- Generators are required to submit a summer and winter capacity for each physical unit over the next 10 years.
- The capacity submitted should represent the physical capability of units when in service and reflect the expected capability when the reference node is at the published reference temperature.
- Generator capacity is submitted on an 'as generated' basis, meaning the generating capacity of the unit before any auxiliary load is subtracted.

There are a number of considerations that should be taken into account for determining whether the approach described above is appropriate for the reliability forecast. Following consultation, the Reliability Forecast Guidelines may reflect a changed approach to the modelling of generator capacity. The areas of improvement currently being considered are summarised below.

Difference between seasonal capacity and PASA availability

In the medium-term projected assessment of system adequacy (MT PASA) process, the daily capacity submitted by generators is on the basis of PASA availability, defined as the physical plant capability that can be made available on 24 hours' notice. This is not consistent with the seasonal capacities used in ESOO modelling. At times a generator could be available for a summer but also offer zero PASA availability over an entire month. An alternative approach could be to adjust the definition of seasonal capacity to represent capacity that is expected to be PASA available for the majority of that seasonal period.

Conditions for summer rating

The approach described above, whereby generators submit seasonal capacity based on a single reference temperature, may not take into account all the possible impacts of temperature on unit capacity during peak demand events. AEMO is examining the possibility of increasing the level of specificity with regards to defining the conditions on which units should base their seasonal capacity. These improvements may involve:

- Temperature definitions defined at a zonal or station level.
- Multiple weather conditions, for example, a single hot day at 43°C, or a 41°C day that follows two prior days of temperatures above 40°C.
- Taking into account the lagged impact of temperature if units are derated for multiple hours as a result of high temperature, even as temperature starts to decline.

Maintenance

The current ESOO modelling does not take into account generator maintenance. In general, maintenance should be able to be scheduled at times where there is a sufficient surplus of supply such that the risk of load shedding is very low. However, there have been a number of instances where generators have taken maintenance periods during summer due to the discovery of physical issues. Although these outages have been somewhat flexible, they typically need to be taken within a time window that could increase the risk of

load shedding. Given the definitions used in the forced outage calculation approach, these outages, although caused by physical breakdowns, are not specified as forced outages, because they are able to be delayed.

AEMO is undertaking a review to determine whether the impact of these instances of non-discretionary maintenance can be incorporated into modelling forecasts in a way that considers the multitude of factors that determine whether these maintenance outages will increase risks of USE. These issues include short-term forecasting uncertainty, maintenance recall times, and the level of flexibility in delaying or moving maintenance outages.

3.4 Reliability forecast data requests

3.4.1 Dispatchable generator availability

AEMO collects information from all generators via an annual survey process on the timing, duration, and severity of historical unplanned forced outages. This data is used to calculate the probability of full and partial forced outages, which are then applied to each station in the reliability forecast.

The following method is proposed for determining the forced outage rates to be used for each power station:

- Conduct generator survey to collect availability data for the most recent 12-month period from April to March (inclusive). The data on outages over the rolling 12-month period will be required to be submitted to AEMO by the end of April.
- For each unit, assess the total number of hours each unit is in the following states in each of the past three years¹⁶ of available data:
 - Full forced outage.
 - Partial forced outage.
 - Generating or on a full forced outage.
 - Amount of “lost energy” during partial outages.
 - Total energy during partial outages if unit was fully available.
- Based on the data provided above, the station level full forced outage rate (FOR), partial forced outage rate (PFOR) and derating factor (DF) will be calculated as:
 - $FOR = \text{Hours on Full forced outage} / \text{Hours Generation or on a full forced outage}$.
 - $PFOR = \text{Hours on Partial forced outage} / \text{Hours Generation or on a full forced outage}$.
 - $DF = \text{Amount of lost energy during partial outages} / \text{Total energy during partial outages if unit was fully available}$.
- The outcome of the above will be that each station will have three different sets of outage parameters associated with the last three years of outage data.
- In the absence of any observable trends or additional information to improve the forecasts of future reliability, these three years of outage data will be resampled as equally likely to occur in future years for assessing reliability forecasts. The 2018 ESOO used outage parameters calculated on the average of the past three years of data. The reliability forecast will use the same period but instead use each year’s outage data individually, with equal weighting.
- AEMO will communicate the outcomes of these calculations to the owner of each generator by 15 May each year. The participant will be provided the opportunity for the forecast reliability to be revised in any future year of the outlook period, based on further evidence submitted to AEMO and reviewed by the AER. This may be particularly appropriate where recent maintenance has been carried out to improve the

¹⁶ All FOR data will be based on years defined as April – March.

future reliability of plant. The deadline for any request for an alternative set of reliability parameters will be in late May, with the exact date specified in the earlier letter.

- The AER will determine whether the alternative outage parameters will be applied in the reliability forecast, based on its assessment of the evidence provided.
- If an alternative outage parameter is accepted, AEMO will use this as the new average rate, though variability of the three years will be based on historical variability. For example, if a station had historical outage rates over the past three years of 3%, 5%, and 7%, but a new average outage rate of 3% is accepted by the AER, the outage rates applied in the model would be 1.8%, 3%, and 4.2% respectively.
- To protect the confidentiality of this data, AEMO will only publish calculated outage parameters on a technology aggregation level, but the modelling will reflect the actual generator-specific rates.
- AEMO will apply all three sets of outage parameters in the model such that they are equally weighted; that is, an equal number of simulations will be conducted with each set of outage parameters. The selection of outage parameter year will be conserved across all stations.

AEMO will also undertake a review of outage data supplied by participants to determine the existence of any relationship between temperature and plant reliability. AEMO will also request information from generator operators as to whether high temperatures are expected to have an impact on their reliability. This could form the basis of a proposal to apply an alternative outage rate.

3.4.2 Auxiliary rate

As discussed in Section 2.1.1, AEMO's demand forecasts are prepared on a 'sent out' basis, because this removes the need to assume a level of auxiliary load, both in terms of annual consumption and at times of maximum and minimum demands. Any single assumption would not take into account the variety of the generation mix that may meet demands depending on supply availability (for example, auxiliary may be lower if wind and solar generation is high and there are coal generator outages). Furthermore, the assumed auxiliary would be reliant on an assumption of how the generation mix changes over time.

AEMO's modelling of generator capacity is on an 'as generated' basis. Rather than assume an annual auxiliary consumption and auxiliary demand at the time of peak, AEMO's models dynamically take into account auxiliary load based on generator dispatch in each modelling interval.

In the 2019 reliability forecast, AEMO will use the assumed auxiliary rates published in the ISP Assumptions Workbook¹⁷. AEMO will include the assumed auxiliary rate when communicating assumed outage parameters to generators. Any generator operator that believes the rate for their station is not an accurate representation should notify AEMO. From 2020 onwards, as part of the updated information provision regime proposed in the RRO Draft Rules, AEMO will be requesting that each unit provide an auxiliary rate that represents typical auxiliary consumption when a unit is operating at maximum capacity.

¹⁷ Available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/2019-Input-and-Assumptions-workbook.xlsx.

4. Transmission network

4.1 Transmission modelling in the reliability forecast

The methodology and assumptions used to model the transmission network in AEMO's reliability gap assessments is explained in detail in the ESOO Modelling Methodology document¹⁸. The following is a summary provided for context noting AEMO will provide details on modelled transmission outages to industry through the FRG.

4.2 Interconnectors and network constraints

The reliability forecast will include all existing interconnectors and committed transmission augmentations or new transmission lines that have successfully completed the Regulatory Investment Test for Transmission (RIT-T). AEMO applies network constraint equations to model thermal and stability constraints. These constraint equations will factor in the impact and timing of inter-connector and intra-regional transmission augmentations.

Interconnector loss functions will be applied based on the latest values calculated in the inter-regional loss factor calculation and published in AEMO's Regions List and Marginal Loss Factors report¹⁹.

4.3 Network outages

In addition to modelling system normal transmission constraints, AEMO may include the impact of a number of key unplanned transmission line outages or deratings which affect inter-regional transfer capability, for example due to bushfires. In the 2018 ESOO, AEMO assessed the probability of these outages using historical outage data since 2007.

Three key flow paths were chosen on which to assess the impact of transmission outages:

- Dederang to South Morang – the double circuit line from Dederang to South Morang is the critical flow path between northern Victoria and Melbourne. An outage of this line limits the ability to import generation from New South Wales and results in higher levels of curtailment for hydro generation in the north of Victoria. These lines are susceptible to the impact of bushfires.
- Heywood to South East – the double circuit line between Heywood and South East is also known as the Heywood interconnector. An outage at one of the two lines was used to represent the incidence of an outage on the flow path between Melbourne and Adelaide.
- Basslink – the interconnector between Tasmania and Victoria has had a number of forced outages in recent years. The extended outage in 2015-16 was excluded from the calculation of the Basslink outage rate.

AEMO will continue to apply this method of assessment to determine the relevant set of transmission outages that could have a material impact on reliability. AEMO will publish the outages and the assumed rates at the May 2019 FRG meeting. These figures will subsequently be published on AEMO's website, with the FRG minutes.

¹⁸ See http://aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/NEM-Consultations/2019/Reliability-Forecasting-Methodology/ESOO-Methodology-Document-v2---draft-2019

¹⁹ Available at <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries>.

5. Declaring a reliability gap

5.1 General considerations

The methodology for calculating expected USE uses the current ESOO framework, inputs, and assumptions specified in the Reliability Standard Implementation Guidelines (RSIG)²⁰ and explained in detail in the ESOO Methodology Document²¹.

Reliability forecast components

The components to be published by AEMO as part of the reliability forecast are defined in the RRO Draft Rules clause 4.A.B.2

A reliability forecast and indicative reliability forecast for a region for each financial year must include the following:

- (a) AEMO's unserved energy forecast and whether or not there is a forecast reliability gap;
- (b) if there is a forecast reliability gap:
 - (1) the expected unserved energy for the forecast reliability gap period;
 - (2) the size of the forecast reliability gap (in MW);
 - (3) the forecast reliability gap period; and
- (c) if there is a forecast reliability gap in a reliability forecast, the trading intervals during the forecast reliability gap period in which the forecast unserved energy observed during the forecast reliability gap is likely to occur.

AEMO's approach to calculate the size of the forecast reliability gap is explained in Section 5.3 while the reliability gap period and likely trading intervals are discussed in Section 5.2.

Forecast reliability gap materiality

Forecast reliability gap and its materiality are defined in the RRO Draft Rules clause 4.A.A.2

For the purposes of section 14G(1) of the *National Electricity Law*, a *forecast reliability gap* occurs in a *region* in a *financial year* if identified in a *reliability forecast* and is *material* if it exceeds the *reliability standard*.

Note

Section 14G(1) of the *National Electricity Law* states –

A forecast reliability gap occurs when the amount of electricity forecast for a *region*, in accordance with the *Rules*, does not meet the *reliability standard* to an extent that, in accordance with the *Rules*, is material.

²⁰ Available at http://aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/NEM-Consultations/2019/Reliability-Forecasting-Methodology/Reliability-Standard-Implementation-Guidelines---draft-2019.

²¹ Available at http://aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/NEM-Consultations/2019/Reliability-Forecasting-Methodology/ESOO-Methodology-Document-v2---draft-2019.

While AEMO may assess the reliability gap under a range of scenarios, the reliability gap that triggers a reliability instrument request will be based on the scenario AEMO considers most likely to eventuate, i.e. a neutral or central scenario.

Pain sharing

The pain sharing principle of the NEM states that load shedding should be spread pro rata throughout interconnected regions when this would not increase total load shedding. This is to avoid unfairly penalising one region for a supply deficit spread through several interconnected regions.

Specifically, the Reliability Panel's Equitable Load Shedding Arrangements²² state, "as far as practicable, any reductions, from load shedding as requested by AEMO and/or mandatory restrictions, in each region must occur in proportion to the aggregate notional demand of the effective connection points in that region, until the remaining demand can be met, such that the power system remains or returns (as appropriate) initially to a satisfactory operating state".

AEMO considers that the intent of the reliability forecast is to determine the region/regions where any shortfall may exist. The application of pain sharing to modelling results has the potential to obscure the true state of supply issues in a region, and, as such, the impact of pain sharing will be excluded from the determination of expected USE for the purposes of the reliability forecast.

5.2 Reliability gap period and likely trading intervals

Where a material reliability gap is forecast for either T-3 or T-1, AEMO must (as per RRO Draft Rules 4A.C.1) request the AER to consider making a reliability instrument.

AEMO's request for a reliability instrument must include as a minimum²³ the information required under section 14I(4) of the NEL Amendment Bill:

- (i) the region in which the forecast reliability gap is forecast to occur;
- (ii) the first and last days of the forecast reliability gap period;
- (iii) for a request for a T-3 reliability instrument—the trading intervals, during the forecast reliability gap period, for which liable entities may be required to hold net contract positions that are sufficient to meet their share of the one-in-two year peak demand forecast for the forecast reliability gap period;
Example—
the trading intervals between 4pm and 8pm each weekday during the forecast reliability gap
- (iv) for a request for a T-1 reliability instrument—the trading intervals, during the forecast reliability gap period, for which liable entities will be required to hold net contract positions that are sufficient to meet their share of the one-in-two year peak demand forecast for the forecast reliability gap period if the T-1 reliability instrument is made;
Example—
the trading intervals between 4pm and 8pm each weekday during the forecast reliability gap
- (v) AEMO's one-in-two year peak demand forecast for the forecast reliability gap period.

²² Available at <https://www.aemc.gov.au/sites/default/files/content//Guidelines-for-Management-of-Electricity-Supply-Shortfall-Events.PDF>.

²³ The AER's Reliability Instrument Guidelines, once developed, may expand on these minimum requirements.

AEMO will determine the reliability gap period and likely trading intervals based on the interval USE outcomes observed in the market simulations.

For a T-3 reliability instrument, the approach for determining the reliability gap period and likely trading intervals will be necessarily conservative to reflect the greater uncertainty around the timing of possible USE events when modelling that far into the future, and noting that as per the RRO Draft Rules clause 4A.C.4 the T-1 reliability gap period can only be a subset of the T-3 reliability gap period.

To provide greater decision-making support, AEMO will provide additional information that illustrates the distribution of USE events observed in the simulations with respect to month, day-of-the-week, and time-of-day, to assist in informing participants of the characteristics of the resources that could close the reliability gap.

The following approach will be applied in determining the T-3 reliability gap period and the likely trading intervals:

- Months – the reliability gap will be declared to exist in a month if the Loss of Loss Probability (LOLP²⁴) in that month exceeds 5%. The months will be used to determine the start and end date of the reliability gap period. A discussion on where there is a disconnect in the months is provided below.
- Day of the week – within each month that meets the LOLP threshold, weekdays will be declared as being within the reliability gap period. The weekend will be declared as a reliability gap period if the LOLP on weekend days exceeds 2%. The day of the week classification will be used to describe the likely trading intervals of a shortfall.
- Time-of-day – a consistent time-of-day will be applied across all month/day of the week periods. The time period will be identified by determining the earliest and latest time-of-day where the LOLP exceeds two percent. All periods between these trading intervals will be included.
- Excluded periods – consideration will be given to whether there is a period of time within the reliability period that should be excluded, such as the Christmas/New Year period.

A methodology that provides a tighter reliability gap period and likely trading intervals will be used in preparing any T-1 reliability instrument. The following approach will be applied:

- Months – the reliability gap will be declared to exist in a month if the LOLP in that month exceeds 5% and the month was included as part of the T-3 reliability gap period. The months will be used to determine the start and end date of the reliability period. A discussion on where there is a disconnect in the months is provided below.
- Day of the week – within each month that meets the LOLP threshold, weekdays will be declared as being within the reliability gap period. The weekend will be declared as a reliability gap period if the LOLP on weekend days exceeds 5% and the weekend was included as part of the T-3 Reliability Instrument Request.
- Time-of-day – a consistent time-of-day will be applied across all month/day of the week periods. The time period will be identified by determining the earliest and latest time-of-day where the LOLP exceeds five percent. All periods between these trading intervals will be included.
- Excluded periods – consideration will be given to whether there is a period of time within the reliability period that should be excluded, such as the Christmas/New Year period.

Approach to months within the reliability period that do not meet the threshold

The reliability period may contain months which do not meet the LOLP thresholds described above. AEMO will apply the following treatment with regards to issuing a Reliability Instrument Request:

- Where there is no consecutive two-month period that does not meet the threshold (for example, November, January, and March are above the LOLP threshold but December and February are not), a single instrument request will be made which includes the month/s which did not meet the threshold.

²⁴ The LOLP is a measure of the probability of any USE occurring. The LOLP measure does not consider the magnitude or duration of USE.

- Where there is a consecutive period of two (or more) months that does not meet the threshold, two reliability instrument requests will be submitted with different reliability gap period specifications. For the purpose of calculating the MW size of the reliability gap, the two reliability gap periods will be considered together, due to the need to assess the additional MW required to meet the annual reliability standard.

Example

The figures below (Figure 3 to Figure 5) show LOLP statistics for a simulation at monthly, weekday/weekend, and time-of-day level.

Based on the criteria above, the T-3 reliability gap period and trading intervals would be defined as follows:

- Start date – 1 November.
- End date – 28/29 February. Note the reliability gap period includes December.
- Weekdays only except in February.
- Time period – 1.00 pm – 9.00 pm.

The T-1 reliability gap period and trading intervals are tighter, and would be defined as:

- Start date – 1 November.
- End date – 28/29 February. Note the reliability gap period includes December.
- Weekdays only.
- Time period – 1.00 pm – 8.00 pm.

Figure 3 Monthly LOLP assessment

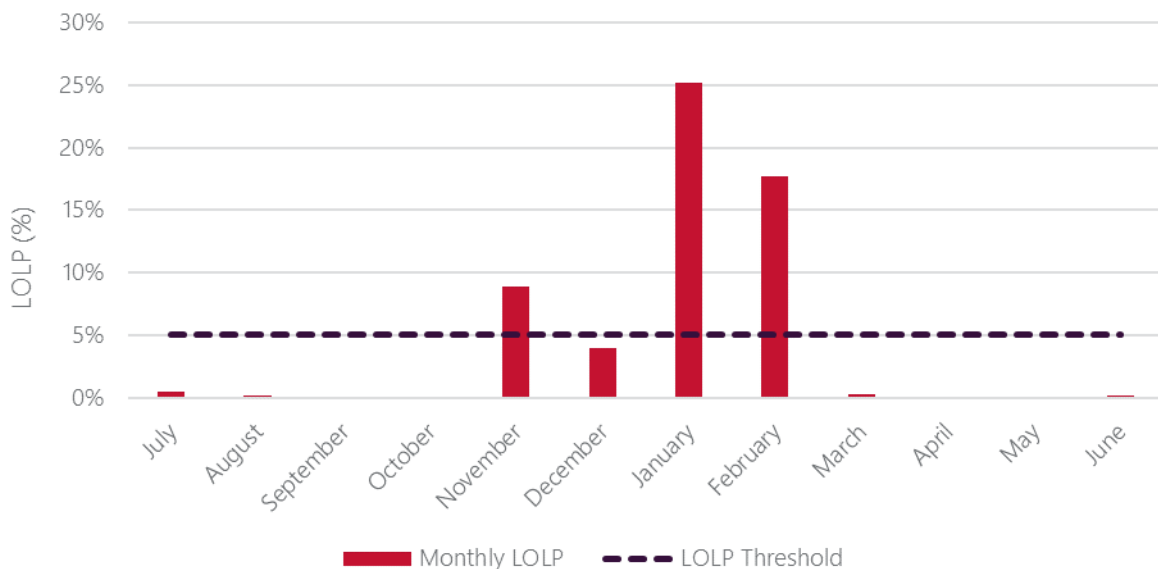


Figure 4 Weekday/weekend LOLP assessment

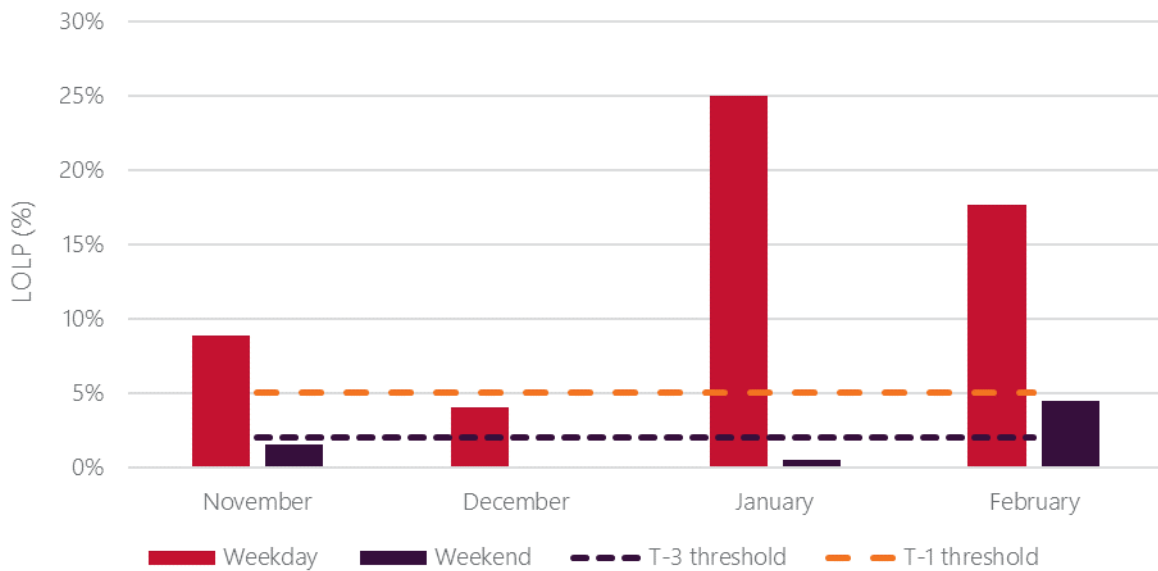
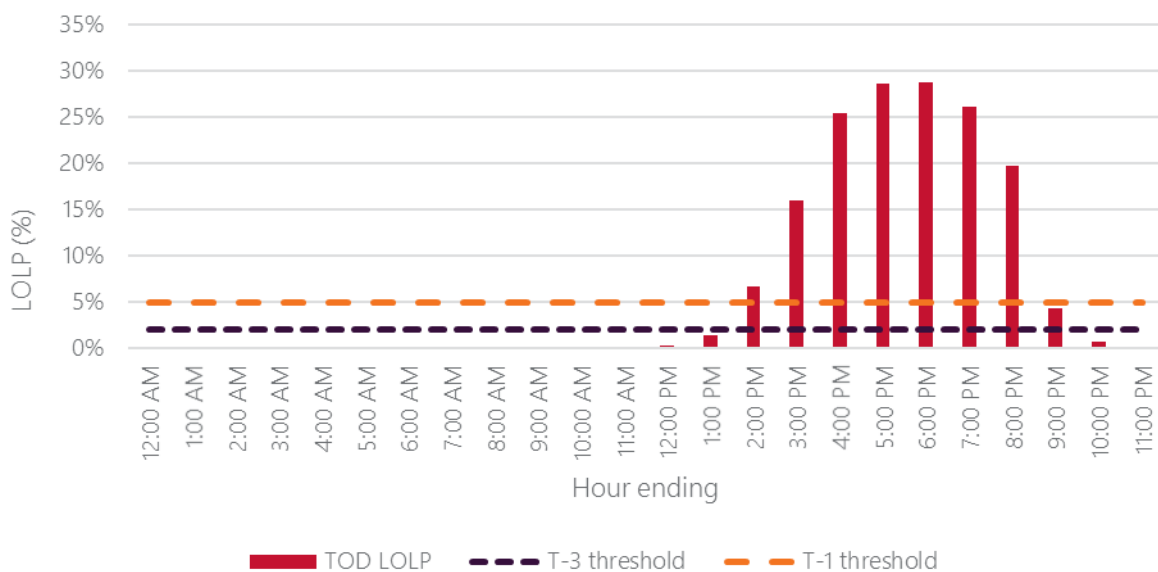


Figure 5 Time of day LOLP assessment (all months)



5.3 Size of the reliability gap

The size of the reliability gap, expressed in MW, is determined by analysing the interval level USE across all simulations in each region where the USE exceeds the reliability standard. The size of the gap will be the additional MW of capacity, assumed to be 100% available, during all identified trading intervals within the reliability gap period only, that is required to reduce the annual expected USE to the reliability standard.

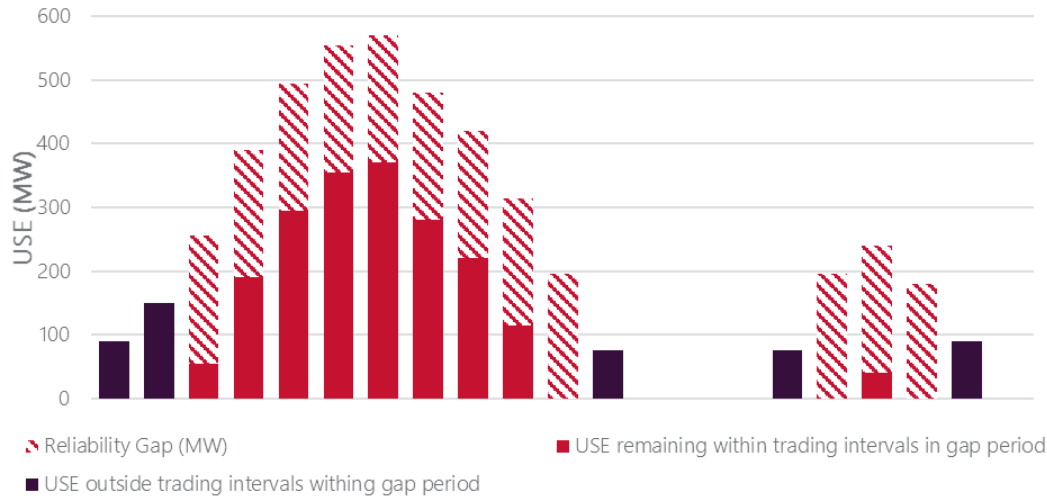
To better align with the actions available to liable entities under the RRO to ensure they have adequate contract coverage over the reliability gap period, the size of the gap is determined based on the effective response that additional reserves could provide if only procured to cover the reliability gap period and likely trading intervals identified. This means the gap (in MW) may be slightly larger than would otherwise be the case if those reserves were assumed to be available for the entire financial year. AEMO does not propose to further limit the effective response to only apply in periods when actual demand might exceed the forecast 1-

in-2 year peak demand, as it is anticipated that the likely trading intervals will already cover most of these periods. However, AEMO welcomes feedback on this proposed approach.

The additional MW are assumed to be perfectly reliable and have no constraints such as a maximum hours of operation. Only a single MW value will be assessed per region for the entire reliability gap period.

A conceptual example is provided below in Figure 6. In this example, some of the USE periods are specified as falling outside the reliability gap period. The figure shows the impact of 200 MW of additional capacity applied to USE periods that occur during the reliability gap period and likely trading intervals identified.

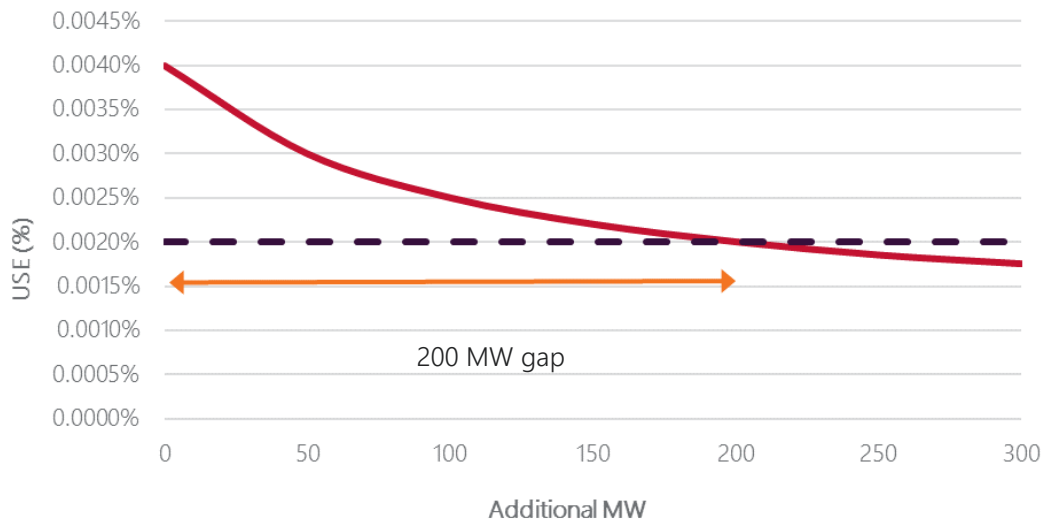
Figure 6 Conceptual example of the reliability gap



Note the x axis here represents two conceptual days (not necessarily contiguous) with the intervening time where no USE occurred being removed for the purpose of illustration.

Figure 7 follows from the example above, and shows the impact on annual USE from the application of the 200 MW of additional capacity. Here the reliability gap is calculated as 200 MW, the level of additional capacity required to bring USE to within the reliability standard when applied to USE in the relevant trading intervals within the reliability gap period.

Figure 7 Conceptual example of the reliability gap



Sharing additional reserves

As the gap is determined independently in each region where the level of USE exceeds the reliability standard, the methodology does not consider the impact additional resources in one region may have on the size or existence of a gap in another.

For example, tight supply-demand conditions in Victoria and South Australia are often highly correlated. As such, it is frequently observed that additional capacity in Victoria would reduce the level of USE in Victoria but also in South Australia, and vice versa.

By determining the size of the gap in each region independently, the combined gap in MW may be bigger than the level that would be required to have both regions meet the reliability standard when allowing for reserve sharing. AEMO considers this is not an issue for the purpose of the reliability gap calculation, because the relative size of the gap is used only for the allocation of any Procurer of Last Resort (POLR) cost to non-compliant parties between the two (or more) regions. The calculation of the quantity of any RERT procured (and therefore the total cost of RERT) will consider the effect of inter-regional reserve sharing.

5.4 Information published when a material reliability gap is forecast

The NEL Amendment Bill (Section 14I) specifies minimum information requirements for inclusion in a reliability instrument request. The AER's Reliability Instrument Guidelines will expand on these minimum requirements and outline the information that AEMO must provide when making a T-3 or a T-1 reliability instrument request for a region. At a minimum, AEMO will provide the following:

- The forecast reliability gap, in MW, calculated using the method described in Section 5.3.
- First and last days of the reliability gap period, which will be based on the assessment of monthly USE as described in Section 5.2.
- The trading intervals during the reliability gap period where supply shortfalls are most likely to occur, which will consist of the specification of weekends/weekdays and the time-of-day range within the reliability gap period.
- The 1-in-2 year peak demand forecast as outlined in Section 2.1.1.
- The sensitivity of USE to additional capacity available during the reliability gap period.
- Additional information that helps illustrate observed USE in the simulations, including but not limited to the distribution of USE across months, and the distribution of USE duration. Example outputs are below.

Figure 8 Distribution of USE across months

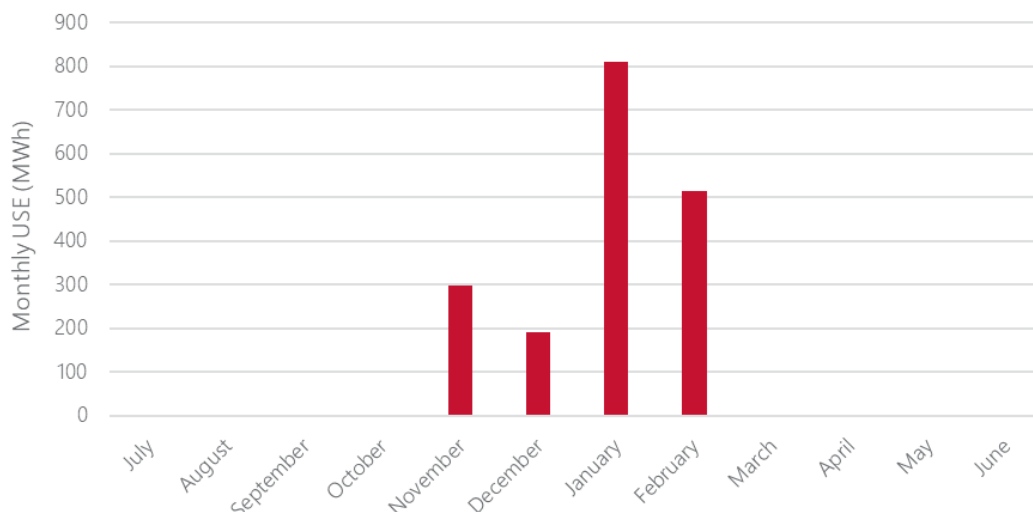


Figure 9 Distribution of USE by time-of-day

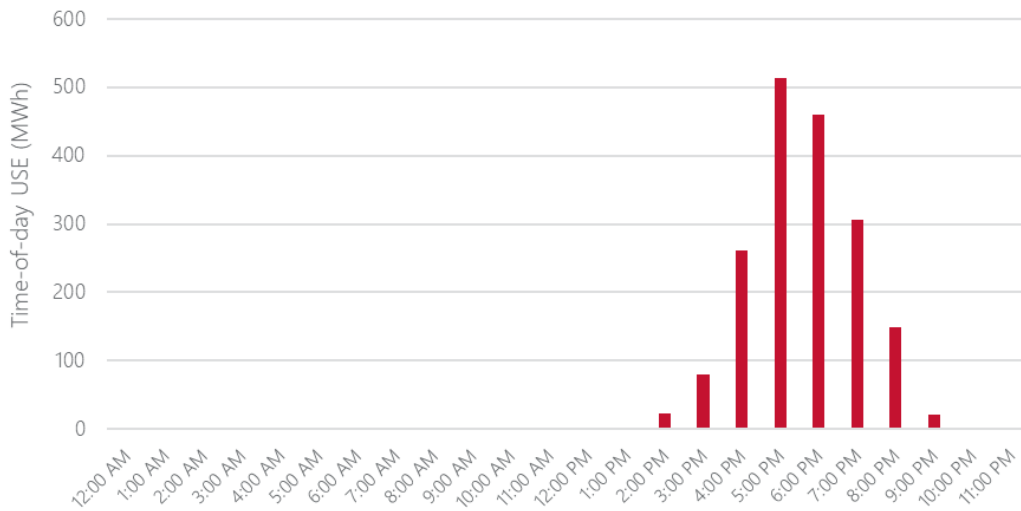
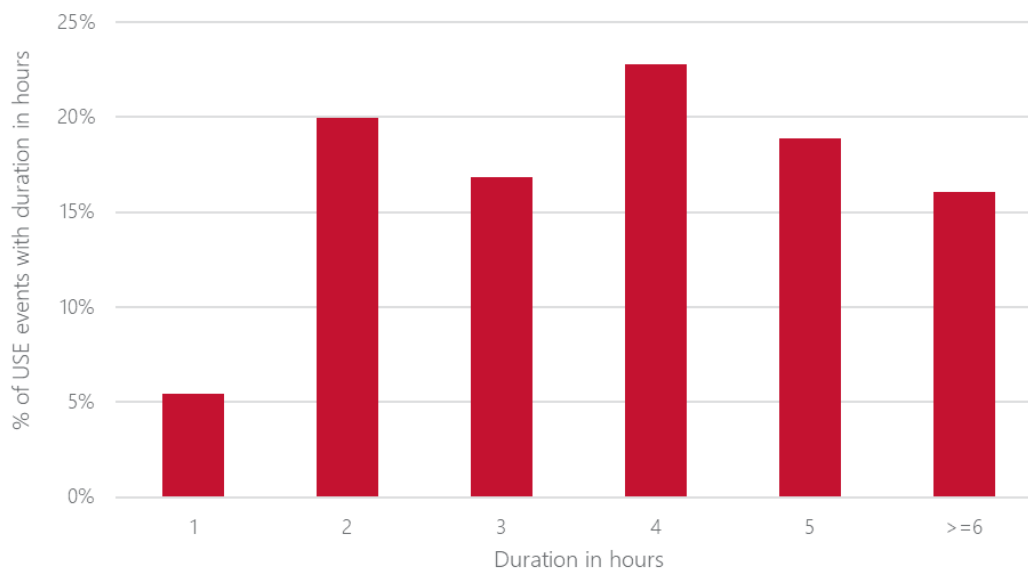


Figure 10 Duration of USE events



A public version of the PLEXOS database used to perform the USE assessment will also be published along with all demand, intermittent generation and DER half-hourly traces. While confidential information will be obscured through aggregation, this should allow stakeholders to run their own analysis to better understand supply scarcity risks.

6. Feedback

AEMO invites stakeholders to provide feedback on whether the outlined data sources and methodologies for calculating the reliability forecast are appropriate for use in the 2019 NEM ESOO and meet industry expectations in general. The questions below can be used as a guide.

Stakeholders are invited to submit written responses on the questions below and other issues related to forecasting WEM demand by **5.00 pm (Australian Eastern Standard Time) on Wednesday 22 May 2019**. Submissions should be sent by email to energy.forecasting@aemo.com.au.

Questions for consultation

1. Transparency

- 1.1 Is the level of detail provided in this issues paper and referred methodology papers sufficient to allow you to constructively critique and provide feedback on the appropriateness of the methodology? If not, what additional information/explanations are required?

2. Open processes

- 2.1 In addition to this consultation and associated workshop, what other means of engagement could be considered for this year's ESOO, taking into account the time available and balancing timeliness and relevancy of information with need for consultation?

3. Accuracy and lack of bias

- 3.1 Are the proposed assumptions and methodologies for calculating supply and transmission inputs to the Reliability Forecast (e.g. forced outage rates and auxiliary loads) reasonable for the purpose of assessing unserved energy? If not, what refinements should be considered?

4. Reliability Forecast and reliability instrument methodologies

- 4.1 Are the outlined assumptions and approaches to calculate the reliability gap size, reliability gap period and likely trading intervals reasonable?
- 4.2 Is the proposed demand definition to be used for the 1-in-2 year peak demand forecast reasonable? If not, what alternative definition should be considered and why?
- 4.3 Does the set of result visualisations provided in the conceptual example provide information that assists participants in responding to any reliability instrument? What additional information would support decision-making in response to any reliability instrument?

Glossary

This document uses many terms that have meanings defined in the National Electricity Rules (NER). The NER meanings are adopted unless otherwise specified.

Term	Definition
committed projects	Generation that is considered to be proceeding under AEMO's commitment criteria (see Generation Information on AEMO's website, link in Table 14).
electrical energy	Average electrical power over a time period, multiplied by the length of the time period.
electrical power	Instantaneous rate at which electrical energy is consumed, generated, or transmitted.
firming capability	Firming capability can be dispatched to maintain balance on the power grid. It can include generation on the grid, storage, demand resources behind the meter, flexible demand, or flexible network capability.
generating capacity	Amount of capacity (in megawatts (MW)) available for generation.
generating unit	Power stations may be broken down into separate components known as generating units, and may be considered separately in terms (for example) of dispatch, withdrawal, and maintenance.
installed capacity	The generating capacity (in megawatts (MW)) of the following (for example): A single generating unit. A number of generating units of a particular type or in a particular area. All of the generating units in a region. Rooftop PV installed capacity is the total amount of cumulative rooftop PV capacity installed at any given time.
maximum demand	Highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season, or year) either at a connection point, or simultaneously at a defined set of connection points.
non-scheduled generation	Generation by a generating unit that is not scheduled by AEMO as part of the central dispatch process, and which has been classified as a non-scheduled generating unit in accordance with Chapter 2 of the NER.
operational electrical consumption	The electrical energy supplied by scheduled, semi-scheduled, and significant non-scheduled generating units.
Probability of Exceedance (POE)	The likelihood that an outcome exceed the defined level. For example a 50% POE forecast will be exceeded in 50% of the observations, but only 10% of the time for a 10% POE forecast. When used for summer (or winter) maximum demand, a 10% POE forecast will only be exceeded 1 out of ten summers (or winters) on average.