MTPASA Review – Project Report

AEMO

4 November 2016

Building a better working world

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The results of Ernst & Young's work, including the assumptions and qualifications made in preparing the report, are set out in Ernst & Young's report dated 4 November 2016 ("Report"). The Report should be read in its entirety including the cover letter, the applicable scope of the work and any limitations. A reference to the Report includes any part of the Report. No further work has been undertaken by Ernst & Young since the date of the Report to update it.

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AEMO
Level 22, 530 Collins Street
Melbourne VIC 3000

04 November 2016

MTPASA Review – Project Report

Dear Sir/Madam

In accordance with our Engagement Agreement dated 29 April 2016 ("Agreement"), Ernst & Young ("we" or "EY") has been engaged by the Australian Energy Market Operator ("you", "AEMO" or the "Client") to provide a paper describing issues with the MTPASA process and requirements and recommendations for a new replacement process (the "Report").

The enclosed Report sets out the outcomes of our work.

Purpose of our Report and restrictions on its use

Please refer to a copy of the Agreement for the restrictions relating to the use of our Report.

This Report was prepared on the specific instructions of AEMO solely for the purpose of informing AEMO of possible improvements to the MTPASA process and should not be used or relied upon for any other purpose.

We accept no responsibility or liability to any person other than to AEMO or to such party to whom we have agreed in writing to accept a duty of care in respect of this Report, and accordingly if such other persons choose to rely upon any of the contents of this Report they do so at their own risk.

Nature and scope of our work

The nature and scope of our work, including the basis and limitations, are detailed in our Agreement and in this Report.

Our work commenced on 9 May 2016 and was completed on 04 November 2016. Therefore, our Report does not take account of events or circumstances arising after 04 November 2016 and we have no responsibility to update the Report for such events or circumstances.

In the preparation of this Report we have considered and relied upon information sourced from a range of sources believed after due enquiry to be reliable and accurate. We have no reason to believe that any information supplied to us, or obtained from public sources, was false or that any material information has been withheld from us.

We do not imply and it should not be construed that we have verified any of the information provided to us, or that our enquiries could have identified any matter that a more extensive examination might disclose. However, we have evaluated the information provided to us by AEMO as well as other parties through enquiry, analysis and review and nothing has come to our attention to indicate the information provided was materially mis-stated or would not afford reasonable grounds upon which to base our Report.

This letter should be read in conjunction with our Report, which is attached.

Thank you for the opportunity to work on this project for you. Should you wish to discuss any aspect of this Report, please do not hesitate to contact Ben Vanderwaal on 07 3227 1414 or Michael Fenech on 07 3243 3753.

Yours sincerely

Ben Vanderwaal
Director

Michael Fenech
Partner

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1. Executive Summary

In the interests of continuous improvement and in order to ensure the MTPASA (Medium Term Projected Assessment of System Adequacy) process is robust enough in light of the rate of change in the industry, AEMO asked EY to critically assess the existing process. This was intended to identify any significant issues and limitations and ultimately recommend a way to address these issues and limitations. The treatment of intermittent generation – which has a rapidly increasing share in the National Electricity Market's (NEM) energy mix – was identified as a key concern.

The MTPASA process is the primary tool used to assess the adequacy of expected electricity supply to meet demand over the next two years. More specifically, MTPASA is intended to fulfil two requirements:

1. Provide a high-frequency information service (3-hourly suggested) that gives a breakdown of the supply-demand situation for the MTPASA horizon, taking into account participants' MTPASA submissions around availability, energy limits and network conditions.
2. Assess expected system reliability on a regular basis (at least quarterly) for the MTPASA horizon and provide indicators for how reliability could be affected by participants' MTPASA submissions.

Using source information provided by AEMO and interpreted and analysed by EY, an investigation of the current MTPASA process was conducted in light of these requirements, which identified that:

1. The current 3-hourly supply-demand information process serves a useful purpose and largely fulfils the first requirement (excepting consideration of network conditions), though several minor alterations will significantly improve its utility and transparency.
2. Due to the use of Minimum Reserve Levels and the inability for the deterministic MTPASA reliability solve process to properly account for intermittent generation, the current reliability assessment process is not able to produce accurate or consistent projections of reliability. Therefore it should not be relied upon for the purpose. Instead, AEMO, should rely on its probabilistic models for reliability assessment.
3. The current MTPASA process does not accurately compute energy limit impacts because of limitations inherent in deterministic models, however in any case optimizing energy limits is likely undesirable in a reliability assessment.
4. The current MTPASA process does not accurately compute network transfer capabilities, although no particularly good way of doing so exists. This is because network limits cannot accurately be represented by a single number as they are a function of generator dispatch pattern (amongst other things).

Upon reaching these conclusions, EY was tasked with proposing a best-practice approach to conducting a NEM reliability assessment while also considering obligations around energy limits and network capabilities. Detailed consideration of intermittent generation in particular showed that a deterministic approach – that is, an approach where the outcome is determined entirely by the initial inputs, with only one solution possible – is not suitable for assessing compliance with the reliability standard in the NEM. Therefore a probabilistic Monte Carlo model featuring modelling of multiple reference years[1] was proposed. While computationally intensive, this type and scale of model is very much feasible with readily available hardware and software and data.

In depth analysis showed that two critical factors that the modelling must incorporate are the inclusion of multiple reference years to capture both the year to year variation in behaviour of intermittent generation and variation in inter-regional demand correlation. EY's analysis in particular showed that:

1. Wind generation is correlated with other nearby wind generation, but not with demand or solar generation, meaning that the reference year for wind generation may be selected

[1] A reference year refers to a historical year (e.g. the financial year 2015-16) where the time-series of demand, wind and solar generation are known or can be modelled with sufficient accuracy. This reference year is then projected forward to model forecast years, maintaining relationships between demand, wind generation, solar generation and other factors.

independently from demand.
2. In the limited dataset available, solar generation was not found to correlate with demand, despite sharing some underlying drivers (such as solar insolation). Therefore it may be feasible to select solar reference year independently from demand (and wind) but EY favours revisiting this in 12-24 months when considerably more operational data from solar generation will be available[2].

To achieve the recommended changes to MTPASA, EY recommends that AEMO do the following:

1. Implement the described alterations to the MTPASA information process as soon as possible (including RSIG[3] and Rule changes if necessary). This includes:
    a. Providing further categorization of generation, identifying non-energy limited controllable generation, potentially energy limited generation, wind generation, solar generation, and other non-scheduled generation.
    b. Removal of all reserve level / MRL references.
    c. Demand published on an Operational plus rooftop PV basis (see description in section 6.11).
2. Develop a program to implement the (at-least) quarterly reliability assessment process using an existing or new probabilistic modelling platform. This program will require RSIG and Rule changes to accommodate as the frequency will no longer be weekly. The RSIG should be considered for listing possible triggers for the reliability assessment to be run out-of-cycle. Key attributes of the new probabilistic reliability assessment process are detailed below.
3. Continue to conduct existing probabilistic reliability modelling as necessary to supplement current MTPASA processes until such time as the new reliability assessment mechanism is ready.

The key attributes recommended for the new reliability assessment process using the probabilistic model are:

Study dimensions

- ► 200 iterations per reference year and demand case combination to achieve reasonable convergence
- ► 5+ reference traces for demand, solar and wind per demand scenario
- ► Half hourly simulation resolution
- ► Two year simulation horizon

Demand

- ► Operational demand plus rooftop PV and non-scheduled intermittent generators modelled explicitly (see section 6.11)
- ► Primary scenario to be modelled is medium economic growth 10% POE peak demand
- ► Evaluate medium growth 50% POE as well if 10% POE USE scenario is above the reliability standard

Generation

- ► Generator availability as per MTPASA declarations
- ► Model longer term energy limits heuristically[4] (specifics to be addressed on a case by case)
- ► Investigate merging EAAP and MTPASA data submissions and reporting
- ► Rooftop solar PV modelled explicitly and varying by reference year
- ► Significant intermittent non-scheduled generation (particularly wind farms) modelled explicitly and varying by reference year

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[2] Almost all existing data is from small generators or is re-constructed via models and therefore may not be representative of true behaviour.

[3] Reliability Standards Implementation Guidelines.

[4] Long term energy limits should not be expected to influence bulk reliability outcomes – it is reasonable to assume that large scale storages will have some energy available during high risk periods.

Network

- ► System normal constraint set (incorporating feedback constraints) invoked in all periods
- ► Outage constraint sets invoked as appropriate

EY has demonstrated that a study of these dimensions could be run overnight on a relatively inexpensive array of computer hardware. It is also feasible that AEMO's existing probabilistic modelling platforms could be used to run this modelling, though augmentation of those platforms would be required in order to achieve the necessary minimum performance goals.

The recommended processes would generate the following information:

- Every 3 hours:
  - Regional supply-demand information aggregated to the regional level for each generation type, including information about assumed behaviours of rooftop PV, non-scheduled generation, other intermittent generation. Generation would also be split between non-energy limited and energy limited.
  - This information would cover requirements of clause 3.7.1(c), 3.7.2(f) items 1 through 5.
- At least quarterly and when circumstances materially change:
  - All the information included in the 3-hourly process, plus a system reliability projection including identification of compliance with the Reliability Standard and designation of high-risk days[5], network limit information and generator energy limit information.
  - This information would cover requirements of clause 3.7.2(f) items 5A, 5B and 6 although this information would be no longer computed on a weekly basis.

In summary, this project has clearly shown that changes to the MTPASA process are due, and there is some urgency in doing so owing to emerging inconsistency in information reported, and the rapid and expanding penetration of intermittent technologies, which is one of the key drivers behind this emerging inconsistency. The proposed alternative is practical, addresses current concerns and is resilient to a wide variety of future changes. It is consistent with the kind of model that many markets have or are moving towards elsewhere in the world.

EY also regards that an accurate reliability assessment process is critical to the NEM and to AEMO for it to discharge its obligations under the National Electricity Rules (NER) and Reliability and Emergency Reserve Trader (RERT) procedures. The cost of ownership of such a process should be very much lower than the potential cost of unnecessary or inappropriate intervention in the market and thus is very much consistent with the National Electricity Objective of delivering reliable supply to consumers at an efficient cost.

[5] That is, days with high potential risk of Unserved Energy occurring.

2. Introduction

This report describes a project undertaken by EY to critically assess the existing MTPASA process, identify significant limitations and recommend improvements.

This report has the following objectives:

- To provide a clear summary of the project from the original MTPASA limitations investigation, the assessment of various options for a new process, through to the recommended solution design
- To justify the recommended design with appropriate evidence and show how it aligns with both the MTPASA objective and the National Electricity Objective
- To show how the recommended solution delivers valuable information to the stakeholders whilst balancing quality, timeliness and cost of implementation.

All source information presented in this report was provided by AEMO (unless specifically stated otherwise), and was subsequently interpreted and analysed by EY.

3. Background and project rationale

The Medium Term Projected Assessment of System Adequacy (MTPASA) process is the primary tool used to assess expected electricity supply and demand over the next two years. Published MTPASA information currently includes demand forecasts, generating unit availabilities, and projected reserve shortfalls across a two-year horizon. This information has been used by registered participants and stakeholders for a range of purposes, including scheduling of planned outages of facilities and forecasting of market risk.

Through MTPASA, AEMO also seeks to identify and quantify any projected failure to meet the Reliability Standard over the next two years.

As the National Electricity Market evolves, and particularly, an ever greater proportion of electrical demand is being served by intermittent generation sources, limitations in the current MTPASA methodology – particularly around the system reliability projection – have become more evident. This results in an increased potential risk of:

- Inaccurate forecasts of system reliability issues
- Conflicting information being reported to the market, such as differences in the identification of LRC (Low Reserve Condition) points in MTPASA and EAAP and ESOO
- Uncertainty for market participants

AEMO has been mitigating these risks by various means; in particular by validating MTPASA outcomes using current probabilistic modelling tools. AEMO commissioned EY to assist by way of a detailed investigation of the limitations of the existing MT PASA processes and an exploration of alternative approaches that could adequately respond to the evolving energy environment while being practical, accurate and cost effective to the market.

4. MTPASA and its purpose

4.1 Projected Assessment of System Adequacy

Projected Assessment of System Adequacy (or PASA) is a set of processes and procedures AEMO conducts on a routine basis. In AEMO's words, PASA is:

> *...a comprehensive program of information collection, analysis, and disclosure of medium term and short term power system security and reliability of supply prospects so that Registered Participants are properly informed to enable them to make decisions about supply, demand and outages of transmission networks in respect of periods up to 2 years in advance.*

PASA is currently assessed by AEMO in three separate timeframes. These timeframes are pre-dispatch (PD), short-term (ST) and medium-term (MT). By using all these different timeframes, AEMO can communicate anticipated shortfalls to the market appropriately, and if necessary intervene to address serious shortfalls not resolved by the market. The PASA procedures are, from the longest look-ahead period to shortest:

- ► Medium-term PASA (MT PASA), which is communicated weekly, with system adequacy assessed against the forecast daily peak demand for a 2 year period
- ► Short-term PASA (ST PASA), which is communicated every 2 hours, with system adequacy assessed on a half-hourly basis for a 7 day period, and
- ► Pre dispatch PASA (PD PASA) which is communicated every 30 minutes for a pre-dispatch period.

MTPASA is therefore an assessment of power system adequacy over a rolling two-year horizon. To this end, MTPASA has two goals:

1. Assessing whether system conditions are such that system performance in line with the Reliability Standard may be expected, and
2. Informing market participants about anticipated reliability and security conditions to aid in outage scheduling, fuel procurement, and other longer term planning.

Since generator availability is one of the most important inputs to the MTPASA process, market participants are obliged to routinely provide up-to-date information regarding the planned availability of their plant. While the MTPASA solution is published weekly, aggregate regional generator availability is published every three hours. The aggregation of the availability information is intended to protect commercially sensitive information from other market participants so as to not discourage accurate MTPASA availability submissions.

As indicated by way of stakeholder engagement, there is currently reasonable consensus that this aggregate generator availability published through the MTPASA process provides useful information to market participants for various long term planning purposes, although there exist possibilities for improving and expanding the information provided. However, what was less clear at the outset of this project was how the MTPASA reliability run was being used by industry and whether the process correctly assesses whether the Reliability Standard is being or is likely to be met.

The next sub-sections describe why the MTPASA process exists and its over-arching objectives. This helps us then identify specifically what MTPASA ought to be trying to achieve and why.

4.2 The National Electricity Objective (NEO)

The first and most important factor affecting MTPASA, and indeed all of AEMO's functions, comes from the National Electricity Objective (NEO) itself. This is set out in the National Electricity Law (NEL).

> *National Electricity Law (NEL), section 7*
> *The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:*
>
> *(a) price, quality, safety, reliability and security of supply of electricity; and*
> *(b) the reliability, safety and security of the national electricity system.*

In order to have a usable interpretation of the NEO reliability goal, it is necessary to set out what level of reliability is indeed required to be met. This is done in the National Electricity Rules (NER or Rules) via the setting of a *Reliability Standard* for the NEM.

The new methodology recommended by this report is in particular supported by the price and reliability terms in the NEO. This is because:

1. The potential cost of intervention in the market is very high (possibly in the order of millions of dollars per intervention) and is passed on to market participants. Therefore a methodology which accurately identifies genuine causes for intervention is critical. These causes will primarily be projected reliability concerns.
2. To ensure the system meets the reliability goals of the NEL (and more specifically, the Reliability Standard), accurate projection and measurement of system reliability is critical. A well-designed reliability projection would be able to provide useful information back to participants so that they could voluntarily take actions to resolve these issues long before an intervention by AEMO may be required.

The current MTPASA process was found to have significant issues affecting the accurate measurement of system reliability, which AEMO have been mitigating via the use of other projection tools to date. The revised methodology therefore seeks to resolve this issue by prioritising the accurate projection of system reliability.

4.3 The Reliability Standard

The Reliability Standard is defined in the NER and states the minimum acceptable reliability target that the NEM should achieve. The Reliability Standard set out in clause 3.9.3C in the Rules is as follows:

> National Electricity Rules (NER), clause 3.9.3C
> (a) The *Reliability Standard* for generation *and inter-regional transmission elements* in the *national electricity market* is a maximum expected *unserved energy* in a region of 0.002% of the total *energy* demanded in that *region* for a given *financial year*.

For the purposes of the Reliability Standard, unserved energy (USE) is load which could not be met due to insufficient bulk supply or transmission. USE does not include unmet load due to events not related to bulk supply adequacy such as local distribution network failures or non-credible multiple contingency events. The 0.002% target is also *expected* USE – this implies that actual observed USE in any individual year may exceed this target as long as average forecast USE is below 0.002%. The Reliability Standard is an inherently probabilistic measure.

4.4 MTPASA requirements

This section describes the core (compulsory) and non-core (desirable) requirements of the MTPASA process. This is based upon the Rules, the underlying purpose of MTPASA, and its real-world usage and application by stakeholders. To help develop these requirements (and especially MTPASA's real-world applications), EY consulted with stakeholders via an external workshop (facilitated by AEMO) held in Melbourne on 30 May 2016. In developing the MTPASA requirements, EY was asked to take the current Rules into consideration, but not necessarily be restricted by them. Rather, the underlying *purpose* of MTPASA, and the NEO, was to take precedence in EY's consideration of MTPASA. Therefore it is recognised that to enable the overall recommended solution, revision of the Rules may be required.

4.4.1 Rule requirements

The Rules set out reasonably detailed requirements for MTPASA in section 3.7. Of particular significance are clauses 3.7.1 (Administration of PASA) and 3.7.2 (Medium term PASA). Section 3.7.1 specifies how AEMO must collect weekly information from participants and analyse the next 24 months, publishing information that will assist participants to plan scheduled work (such as generator maintenance) and also inform the market of any expected power system security or reliability issues. Section 3.7.2 sets out various specific obligations including the following:

- That MTPASA is computed and published weekly covering 24 months at a daily resolution
- That in the weekly publication, AEMO include the following at a daily resolution:
  - Forecast 10% POE (Probability of Exceedence) daily peak demand and most probable peak load (interpreted as 50% POE)
  - Reserve requirements and calculated reserve level
  - Aggregated allowance for non-scheduled generation
  - Most probable weekly energy by region
  - Aggregate available non-energy constrained and energy constrained capacity for each region allowing for network constraints (scheduled and semi-scheduled)
  - Identification and quantification of any violations of power system security, lack of reserve, supply deficit
  - Forecast interconnector transfer capabilities and limits, including where network constraints may constrain dispatch of generation or load

4.4.2 Core requirements

Noting the Rule requirements, it is clear that one of the key purposes of MTPASA is to inform market participants about expected future reliability and security prospects so as to provide a basis for making decisions. MTPASA outcomes are also intended to be used by AEMO as a trigger for possible market intervention as a last resort to maintain reliability of supply.

To inform market participants about future reliability and security prospects the MTPASA process must provide information about generation availability and demand for each region. This is currently done with a daily resolution in MTPASA, which appears reasonable for controllable generation and demand. The two year demand forecast for MTPASA is done by using the NEFR (National Electricity Forecasting Report) demand forecasts, from which daily peak demands are selected. As mentioned, generator availability data is currently collected at a daily resolution. External engagement with stakeholders indicated that they were broadly satisfied with the way in which controllable[6] generator availability is collected and published.

Forecasting intermittent output from solar and wind generators up to two years ahead is not something that can be done with any reasonable degree of accuracy beyond basic seasonal and time of day correlations (for example, it is highly predictable that solar generation will be higher during the day) and would be far too inaccurate to provide any meaningful information about particular days. It is worth noting that the current MTPASA process uses a 'typical' output profile rather than attempting to forecast specific behaviour for each day of the year.

[6] As opposed to un-controllable; that is, intermittent generation.

Another important consideration is the assumed behaviour of non-scheduled plant and especially rooftop PV. Currently, MTPASA uses scheduled plus semi-scheduled demand, which means that an assumption about the behaviour and output of these supply sources is already taken into account and 'netted off' the demand. This was identified as a point of concern in the stakeholder engagement; in particular, participants noted a lack of transparency about what assumptions underpin the demand forecast in MTPASA. In order to achieve a greater level of transparency EY has recommended re-definition of the nature of the demand values used in MTPASA. In particular, presenting demand on an *Operational plus rooftop PV generation* basis is favoured by EY (see section 6.11 for further information), so that rooftop PV and potentially other small-scale generators and storage can be stated explicitly.

EY believes that MTPASA should continue to publish expected plant availability at a daily resolution and demand at a half-hourly resolution, as the Rules (clause 3.7.2(c)(i)(iii)) require. Intermittent generation forecasts beyond simple plant availability, or higher resolution demand data could be published, but without major breakthroughs in forecasting this is unlikely to be accurate enough to be useful, especially considering the cost and effort likely to be involved. Distinguishing between categories of plant that behave very differently in the published results (particularly controllable plant, wind and solar) is likely to be worthwhile if practical as the distinction is important for planning purposes. In our stakeholder engagement, some participants also expressed interest in AEMO publishing individual generator availability as opposed to regional aggregates. This is likely to be valuable information but may raise confidentiality concerns and would be best handled through the AEMC rule change process as an issue separate to MTPASA reform.

There is also currently some expectation (according to the NER) that MTPASA do several things: provide an assessment as to whether the Reliability Standard is being achieved or not and provide information on how current plant availability affects this. This information could take many potential forms (such as the current reserve level approach or an expected unserved energy risk per day) but needs to be sufficiently detailed to allow market participants to make reasonably informed maintenance, demand side management and other scheduling decisions. Depending on the methodology chosen the modelling resolution to achieve this may need to be significantly more detailed than one day.

This leads to the following two core requirements:

Core requirement 1. Provide a regular (e.g. 3-hourly) and transparent information service that gives a breakdown of the supply-demand balance for the MTPASA horizon, taking into account participants' MTPASA submissions of generator availability, energy limits affecting potential availability, and network outages.

Core requirement 2. Assess expected system reliability for the MTPASA horizon, taking into account participants' MTPASA submissions, determining whether the Reliability Standard is likely to be met, and provide an appropriate feedback mechanism to inform AEMO and participants about how changing availability plans may impact system reliability outcomes.

4.4.3 Non-core requirements

The requirements outlined above are core requirements that should be met by the MTPASA process. There are several auxiliary requirements around the MTPASA process that would be beneficial to meet but are not critical to achieve the core objectives of the MTPASA process.

Performance

The MTPASA reliability solution is currently published on a weekly basis and as such a methodology that cannot realistically be assessed in this timeframe or would impose unreasonable burden on AEMO may not be practical. There may be options available to mitigate a less performant solution however such as simply publishing reliability results less often as much of the value from the MTPASA process to participants is in the published aggregate input data, not the reliability assessment.

Energy modelling

There is currently a requirement in the NER for MTPASA to consider weekly energy limits. Energy limits are considered in MTPASA currently but is not particularly meaningful given the daily resolution of the current model. Many energy limits – particularly hydro – are also not likely to be able to be expressed reasonably on a weekly basis; hydro energy limits are more likely to span months or even longer.

Perhaps the most obvious example of a weekly energy limit may be one associated with gas availability at a gas power station. However, even if a nominal weekly limit exists, in the case of a gas power station it is unlikely that this could not be worked around if there was sufficient impetus. The station may be able to procure more gas through short-term spot purchases, or overdraw on its allowance (high electricity market pricing may justify a participant's decision to do this) or switch to an alternative fuel if available. Since these alternatives are likely to exist, it is difficult in our view to justify including such limits while including capacity on 24-hr recall, which is a similar factor in that it involves a short-term decision to depart from normal planned operation.

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.

Experience has shown that there are many practical difficulties with pain sharing however; load shedding in practice can be "blocky" and dependent on both the triggering event and protection relay settings that will not be accounting for total regional load ratios. Pain sharing is problematic in models as well since shifting USE between regions will almost inevitably change interconnector losses and thus the total quantity of USE. Specifically, pain sharing usually does cause total USE to increase. This is a highly undesirable modelling artefact of pain sharing, since accurate measurement of USE is the purpose of the modelling. Because of these problems, EY regards reserve/pain sharing as problematic and best avoided. Nonetheless, EY recognises that AEMO may need to continue with a pain sharing model for various reasons and thus EY has categorised this as non-core requirement of MTPASA.

Network information

MTPASA is currently required to assess the impact of scheduled network outages and to provide a forecast of transfer capabilities (see Clause 3.7.2 in the Rules). Stakeholders also mentioned that detailed interconnector flow and limit information was desirable. While this has merit, EY suggests that transmission providers are likely more interested in the "value" of interconnector availability, not simply maximum flows. The utility of flow and limit information will also depend on the resolution reported by AEMO – that is, a single daily value (as published by MTPASA currently) may not be particularly useful as network flows and limits can be so variable. However a more granular value (e.g. hourly) may provide more realistic information as it would better show this variability.

Extensibility

It is desirable that the MTPASA process be able to cope with a range of market changes that may occur in the near to medium term. For example, it is apparent that intermittent technologies are likely to continue to increase as a proportion of total supply, and therefore the process should be able to scale to higher levels of penetration. Another example is the Reliability Standard itself; the AEMC is scheduled to review the standard in 2017, and to do so once every five years. Any new MTPASA approach should be able to cope with changes to the Reliability Standard, such as increasing or decreasing the allowable amount of unserved energy, or which events count towards unserved energy, or even adopting an alternative measure of reliability such as LOLP (Loss of Load Probability) or LOLE (Loss of Load Expectation) as used in many jurisdictions around the globe. Other market changes that one might imagine could occur include increased demand side participation, the creation of new interconnectors, a significant storage uptake and so forth. While it is not possible to anticipate all future possibilities, the inability to factor in a range of anticipated possible changes would be a poor outcome for a new process.

Comprehensibility

The MTPASA process should ideally be transparent and readily understood. It is noted that this may be difficult depending on the complexity required to deliver the core requirements. Complexity may be mitigated through transparency and high quality documentation.

Value to stakeholders

The process should be cost effective and appropriate to the needs of MTPASA. This means it must fulfil its core objectives and ideally the non-core objectives at a reasonable cost and complexity.

5. Analysis of the current MTPASA process

5.1 Description of current process

At a high level, the existing MTPASA process applies an *annual* regional reserve level value (called a Minimum Reserve Level) above the forecast 10% POE *daily* peak demand, and tests whether the total generation declared available in that region exceeds this or falls short of it. Where it falls short, this is supposed to indicate that the system may fail to meet the Reliability Standard. For example, if a (hypothetical) region had an MRL of 500 MW, then the existing MTPASA process would seek to test whether each day in the MTPASA horizon has at least 500 MW of available capacity in excess of that day's 10% POE peak demand. Note that this is a simplified description of the methodology; in reality there are other considerations such as accounting for inter-regional transfer capabilities.

Compared with conducting detailed market modelling, this methodology is (at least on the surface) very simple and understandable. However there is considerable complexity involved in forming many of the inputs to this methodology, such as determining the regional MRL values that should be used in the calculation.

5.2 Issues and limitations

This MTPASA review was (in part) motivated by a perception that the MTPASA process is on occasion producing reliability indicators that are inaccurate and observing that they differ substantially from other processes that seek to estimate system reliability. Examples of these other processes used by AEMO are the Energy Adequacy Assessment Projection (EAAP) and the Electricity Statement of Opportunities (ESOO). As the EAAP and ESOO studies use relatively detailed probabilistic models and there are known limitations with the current MTPASA process (discussed later in this section), there is good reason to suspect that the MTPASA process is in error.

AEMO have stated that they currently conduct other modelling to verify any reserve shortfalls identified by MTPASA due to these suspicions. This would usually take the form of further detailed probabilistic studies (using AEMO's existing probabilistic modelling platforms) to confirm whether the identified reserve shortfall is indeed likely to result in expected unserved energy above 0.002%. This has been most pronounced in South Australia in recent times as MTPASA has frequently produced low reserve warnings. For example, both the EAAP and ESOO modelling suggests that while the region is approaching a reserve shortfall in the coming years expected USE is still below 0.002%[7]. It is worth noting that the probabilistic models AEMO uses are very different to the MTPASA model. The fundamental assessment method is quite different, with the MTPASA model being a *deterministic* reserve assessment, while AEMO's other reliability assessment models are simulations of the power system with random failure events; that is, *probabilistic* models. A deterministic model is one where the outcome is determined entirely by the initial inputs and state, and only one solution is possible from one set of inputs. A probabilistic model is one that has inherently stochastic (probabilistic) inputs and a 'cloud' of possible solutions.

Even aside from this fundamental difference, the representation of all objects in the two models are quite different; this applies to generators, demand, network elements and even the notion of 'time' itself in the model.

While disagreement between such dissimilar models is almost inevitable, AEMO suspects that current discrepancies seen in the outcomes for South Australia may be due to the high wind penetration in the region and the difficulties MTPASA has dealing appropriately with intermittent generation. As MTPASA is ultimately intended to be able to be used as an intervention trigger, these inconsistencies are problematic. To ignore a low reserve condition and then end up allowing significant unserved energy to occur is a major risk. Conversely, intervening unnecessarily in the

[7] This refers to results seen up to the time of analysis (e.g. September 2016 EAAP Report). Notably, this was prior to the announcement of Hazelwood's closure which may impact the forward estimate of reliability.

market is also a major risk as it tends to come at significant cost and interruption to normal market function. Therefore having a consistent, reliable process is in the best interests of AEMO and all market participants and stakeholders.

5.2.1 Minimum reserve levels

MRLs are a key input to the existing MTPASA process. MRLs are determined through detailed and (historically) time consuming MRL studies. They attempt to define the minimum amount of *installed capacity* in excess of the central growth 10% POE peak scheduled demand[8] required to just satisfy the Reliability Standard in all regions simultaneously (that is, to get as close as possible to 0.002% USE in all regions). The MRL studies, like the EAAP and ESOO studies, use probabilistic time-sequential modelling of the NEM.

As the NEM is not operating at close to 0.002% USE in all regions simultaneously, considerable generation is typically required to be disabled in these studies in order to bring USE up to 0.002%. The MRLs calculated from these studies can be very sensitive to exactly which plant was selected to be withdrawn in the simulations due to a range of reasons including the assumed availability statistics of the plant, whether it is intermittent or energy limited, where it is located in the transmission system and how it factors into transmission constraints and interconnector behaviour. This means that the MRL calculation process is both inherently subjective and sensitive to the types of plant present in a region. More generally we also have concerns about the validity of the calculated MRLs for conditions that are not extremely close to those modelled, but this is a consideration that would require detailed investigation to assess in any quantitative way.

The MRL studies were last performed in 2010. Since that time there has been declining internal confidence in, and reliance on, the use of MRLs within AEMO due to similar concerns as those reported here. For example the ESOO supply-demand projection discontinued the use of MRLs in 2013 and now relies exclusively on probabilistic modelling.

Aside from general concerns about the subjectivity and sensitivity of the MRL calculations at this point, market conditions have also changed significantly since 2010. The current MRL studies predate intermittent generation being a major factor, where now there are significant installed capacities of large-scale wind and rooftop solar PV. Because of this and the difficulties with handling intermittent generation in the MRL framework, the 2010 studies did not consider any intermittent generation. The MRL studies are also likely very sensitive to any network, demand shape, energy storage and hydro behaviour changes, which is worth noting given 2010 was towards the end of a major drought and predates much of the rooftop solar uptake. As such we have deep concerns about both whether the methodology is appropriate and whether MRLs last calculated in 2010 are at all meaningful today given the many changes that have taken place in the NEM since that time.

Crucially important in exploring the meaning of MRLs in MTPASA further is to note that MRLs are a way of stating the yearly *installed capacity requirement* and are not an operational reserve level to be met in each period.

5.2.2 Application of MRLs in MTPASA

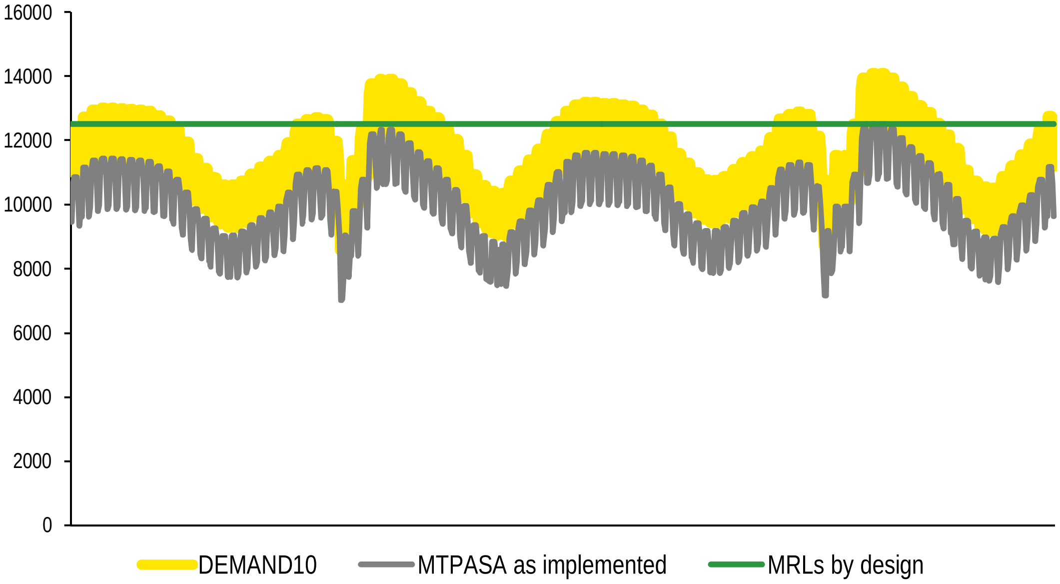
Since the MRLs are defined as a yearly installed capacity requirement over yearly 10% POE peak demand, the application of an MRL as a daily reserve level (above the daily peak demand) is fundamentally inconsistent with their meaning and derivation. An example of this can be seen in the chart below. In this case, the MRL of our example region is negative[9], so the grey line plotting the required available capacity as applied by MTPASA is below the yellow line indicating regional daily

[8] Arguably this could be said to be scheduled plus semi-scheduled demand (this is what appears in the existing MTPASA process), but the most recent MRL calculations did not consider semi-scheduled generators which is why we have stated scheduled demand only here.

[9] The example region is NSW1. Negative MRLs in this case are due to the assumed treatment of interconnectors - NSW has significant interconnection so local generation can be significantly below demand without USE occurring.

10% POE peak demand. The green line indicates the required installed capacity as intended by the MRL derivation.

Figure 1 - MTPASA requirement versus MRL requirement (MW)



The NER defines MTPASA availability as physical plant capability considering ambient weather conditions and including any capacity that can be made available on 24 hours' notice. As such, MTPASA availability and installed capacity might be expected to be similar during peak demand periods and from that perspective MTPASA applies the MRLs reasonably correctly on the peak demand day (that is, the single peak demand day across the entire two year horizon). However, reserve shortfalls (as determined by MTPASA) in any period other than those at or perhaps very near the peak demand do not appear to have any strong relation to either the Reliability Standard or the MRL studies.

5.2.3 Treatment of intermittent generation in MTPASA

The most recent (2010) MRL studies, upon which the current MRL values are based, did not consider intermittent capacity in any form. However, the existing MTPASA process must still attempt to account for intermittent capacity as the installed quantity is quite significant in some regions. This is far from straightforward. MTPASA sets reserve level contributions for intermittent plant by using very conservative intermittent generation forecasts. According to the RSIG[10], 90% probability of exceedence (POE) values as determined by AWEFS and ASEFS (for wind and solar generators respectively) are currently used in MTPASA. This is a very important and significant point; this results in a major difference as to how controllable and intermittent generation are being considered in MTPASA. Specifically:

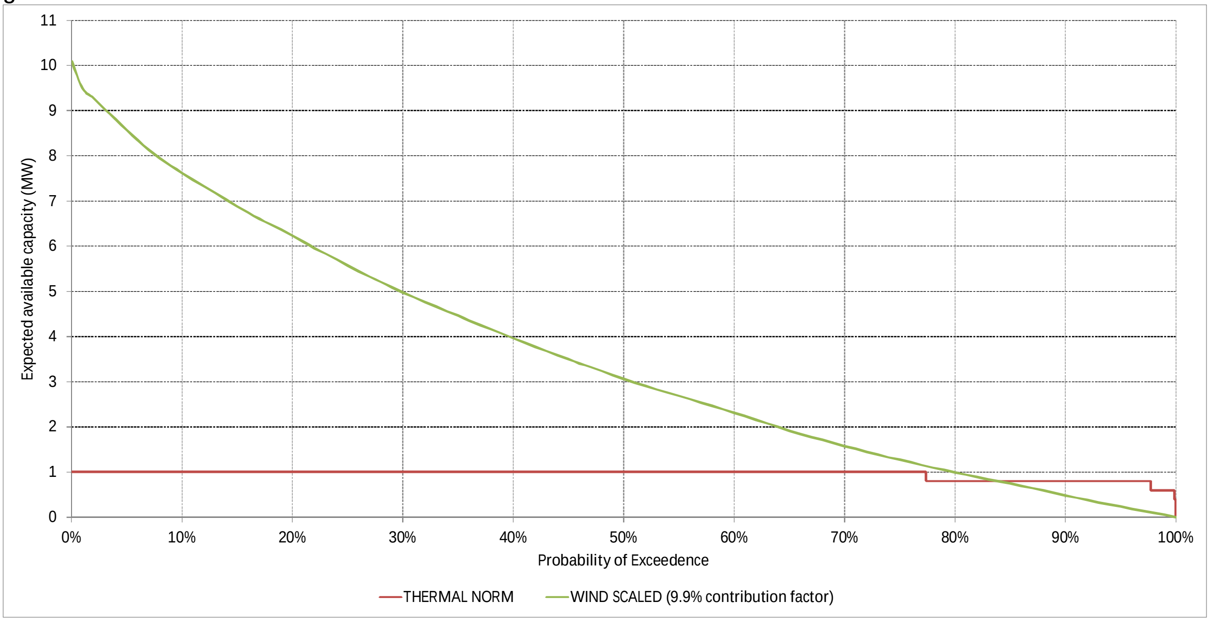
- The MTPASA availability of *controllable* generation is treated as an expected *maximum*. However, in practice this maximum will not always be achieved due to forced outages.
- The MTPASA availability of *intermittent* generation is currently an expected *minimum* that will not always be met but will very often be exceeded (i.e. 90% POE means the value is expected to be exceeded 90% of the time).

This can result in the expected reliability of a system with significant intermittent generation being far higher than MTPASA suggests, because by design it appears to overestimate the availability of controllable generation (probably a small factor) and underestimate the availability of intermittent generation (probably a large factor). Figure 2 shows the (approximate) difference in assumed availability reflected by the current MTPASA process by comparing expected generation versus POE for a thermal power station and a wind generator where both are contributing a nominal 1MW

10 Reliability Standard Implementation Guidelines, 2015.

of reserve. The wind generator has been assumed to have a 9.9% contribution factor in this example (AEMO's documentations states that MTPASA uses a 90% POE contribution factor for wind generation, which results in contribution factors of this approximate value).

Figure 2 - Normalised generation by POE for scaled wind generator (9.9% contribution) and thermal generator



The first series (THERMAL NORM) shows the assumed generation versus POE for a nominal thermal power station with five units each having a 5% forced outage rate. The thermal power station has expected output of 100% of its capacity (a nominal 1MW) up to about 77% POE, with a decreasing expectation from that point down to zero at 100% POE.

The other series on the chart shows generation duration for an intermittent generator that would contribute a similar nominal 1MW quantity of reserve in the current MTPASA process, assuming a 9.9% contribution factor, which EY understands is similar to the values employed in MTPASA currently[11]. Note that the installed capacity is approximately 10 times that of the thermal plant (demonstrated by where the green line cross the y-axis). However its assumed contribution in the current MTPASA process would be similar (in fact, somewhat less) to that of the 1MW nominal thermal plant in this example.

This chart shows that MTPASA is effectively *overestimating* the availability of thermal plant by a small amount, which at high POE values may be expected to fall short of its MTPASA declared availability (because of the potential for forced outages). This is expected, and is accounted for in the determination of the installed capacity requirement (i.e. the MRL calculation), as capacity used in the MRL studies is not 100% reliable either.

Intermittent generation is more complicated in its behavior. It may be expected to exceed the contribution of the thermal plant for the majority of time (noting that there is actually 10 times the amount of actual capacity in this example) while also potentially contributing less in a small number of periods. Because of how much this curve varies over the POE scale, it is clear that no *single* number can represent the contribution of intermittent generation can be selected. Clearly, not applying any contribution factor (i.e. valuing it at its full rated capacity) would overvalue intermittent generation significantly, but even selecting a conservative methodology such as AEMO's 90% POE approach significantly undervalues intermittent generation the vast majority of the time. It also does not do so consistently – in the chart above it is evident that wind may be expected to contribute even less than the 90% POE assumption indicates at very high POEs.

[11] This curve was assembled from aggregated wind generation data so as to avoid biasing this analysis to one specific wind farm.

The overall conclusion of this analysis is that:

Intermittent and controllable generation are simply different in their behavior and predictability and attempting to find a multiplier that allows them to be treated equivalently is not possible.

5.2.4 Handling of energy limits

AEMO are currently required by the NER to model weekly energy constraints in PASA; however this is problematic for several reasons.

MTPASA is effectively a capacity model (as compared with an energy model) with a single peak demand value for each day. As it is clearly not appropriate to assume that demand does not vary within a day this makes energy usage troublesome to calculate. To EY's knowledge, AEMO's current approach is to derive an approximate time weighting for each day that the demand will be 'near' the peak based on an assumed load duration curve.

MTPASA does not represent a market dispatch and does not require supply and demand to be equal. This is a considerable challenge for the current model as plant being held in reserve should not consume energy unless called on (as an example consider a region with 15,000MW available energy limited plant and 10,000MW peak demand on a given day – energy consumption will be derived from the 15,000MW generation despite demand only being 10,000MW). This is a difficult complication arising from integrating energy limits into a deterministic capacity model and the current MTPASA process does not appear to acknowledge or address this issue.

Many of the common energy limits in the NEM are not meaningfully expressed as weekly restrictions. Energy limited hydro generators in particular generally operate on considerably longer timeframes and any weekly value is simply a rough production estimate. EY notes that TAS1 PASA solutions report no energy constrained plant for example despite being almost entirely hydro.

EY concludes that the current MTPASA process does not and likely cannot represent energy limitations in a reasonable manner. This is an issue with the algorithm chosen, not the current implementation. A deterministic capacity model limited to daily resolution cannot be reasonably expected to model energy limits in a meaningful way.

5.2.5 Handling of interconnector limits

The current MTPASA process publishes daily estimated interconnector limits based on constraint equations included in the PASA solver. This is at best a loose approximation of true interconnector capabilities as there are considerable difficulties using AEMO's traditional constraint equation format in a solver that has no obvious source for initial conditions for the constraint right hand side (RHS) calculation and is not performing economic dispatch. AEMO instead currently uses MTPASA declared availability values to calculate the RHS. While this is a reasonable choice for the PASA process as it seeks to assess the maximum capacity available to each region, any constraint outcomes and thus interconnector limits derived from this calculation are not likely to relate strongly to likely market outcomes as every generator being dispatched at full load is extremely unlikely even at peak demand conditions. As such it is important to recognise that published interconnector limits are a rough estimate of outage impacts at extremely high system load and do not necessarily relate to expected market conditions.

Despite this a more detailed approach to reporting interconnector limits would essentially be requiring AEMO to perform detailed price forecasting (to derive a realistic market dispatch) and is not a reasonable burden to impose over the MTPASA horizon.

Applying interconnector outage constraints in the MTPASA LRC (Low Reserve Condition) run is also problematic due to the MTPASA 'interconnector headroom constraints' that severely restrict interconnector flow to preserve assumptions made about interconnector support in the translation of MRL study results to the published MRLs.

The current interconnector headroom constraints limit interconnector flows as follows:

- QLD import <= 0
- NSW export >= 330
- VIC import <= 940
- SA import <= 0

These constraints are used in the MTPASA reliability assessment and result in it being possible for even very significant outages (such as the complete loss of the Heywood or QNI interconnectors) to not change MTPASA LRC outcomes at all as some regions are already constrained to not import anything. This is due to the definition issue mentioned previously – the MRLs from which these headroom constraints derive are defined in terms of installed capacity rather than available capacity.

As such the existing interconnector outage behavior in MTPASA LRC runs is closer to the MRL definition by design. That is, because of the presence of the MTPASA headroom constraints, network outages impacts are in many cases effectively ignored, which is in fact consistent with how MRLs are defined; they too disregard network outages. Despite this a reliability assessment that shows no difference in reliability expectations as a result of a major transmission outage does not appear to meet the stated objectives of MTPASA.

5.3 Consistency with MTPASA requirements

As the previous sections describe, the current MTPASA process has a range of limitations that in particular impact its ability to accurately predict system reliability. Based on this description, the process may be compared with the MTPASA requirements established in section 4.4.

Provide an information service that gives a breakdown of the supply-demand situation for the MTPASA horizon, taking into account participants' MTPASA availability submissions, energy limits affecting potential availability, and network outages

> The current MTPASA process publishes aggregate generator availability by region but does not distinguish this aggregate between generation types (although assumed contributions are given). EY considers that this categorization could potentially be improved to provide better information about the supply-demand balance, since different generator types have markedly different 'firmness' in this aggregate. At the moment, the capacity contribution of intermittent generation is assumed to be extremely low for both solar and wind generation. Participants regarded publication of available generation as valuable for several purposes around planning and financial disclosure requirements. Increasing transparency around intermittent generator sources would therefore be valuable and could be provided in the 3-hourly supply and demand summary. Stakeholders were also interested in potentially identifying energy-limit affected ('constrained') plant separately to the regular un-constrained plant.
>
> The current MTPASA process publishes both 10% and 50% POE daily peak demand forecasts that are also used by participants. However, the basis of this forecast is not well understood. It is based upon scheduled plus semi-scheduled demand, which means an assumption of rooftop PV contribution and non-scheduled generation has already been netted off. Ideally, this would be made transparent so the users of MTPASA can note this and make their own judgements based on these factors.

Assess expected system reliability for the MTPASA horizon and indicators for how reliability could be affected by participants' MTPASA submissions

> The current MTPASA process does not identify whether the Reliability Standard is being met due to the combination of methodology limitations and outdated input data discussed previously. The MRL calculation is outdated and does not consider intermittent generation

adequately. The application of the MRLs in MTPASA is only loosely consistent with their definition and intermittent contribution to reserve levels is both very difficult to assess and likely to be highly variable.

While the MRL implementation in the current MTPASA process is problematic it does provide a useful measure for determining where to schedule an outage as while both the MRLs and intermittent generation treatment are inadequate they are also relatively constant. Outages are effectively scheduled on available capacity minus expected demand plus a constant, which is still a reasonable metric for scheduling outages even if it has no definitive link to the Reliability Standard.

In summary, while the current MTPASA process does provide useful information to market participants through the 3-hourly supply and demand summary, it is not able to accurately predict whether the Reliability Standard is being met and is thus not appropriate to use as an intervention trigger. MTPASA's energy limit modelling and network transfer capability assessment have notable issues that limit their applicability. AEMO have previously recognised the issue with reliability assessment in particular and have been employing probabilistic modelling to determine whether MTPASA LRC flags are genuine. This is in fact documented in the RSIG and seems a prudent approach. This partially compensates for MTPASA producing false positives but does not address false negatives; that is, where MTPASA might fail to flag a real potential reliability issue.

6. A revised MTPASA process

Recall that two core requirements were identified for the MTPASA process:

1. Provide an information service that gives a breakdown of the supply-demand situation for the MTPASA horizon, taking into account participants' MTPASA submissions, energy limits affecting potential availability, and network outages

2. Assess expected system reliability for the MTPASA horizon and indicators for how reliability could be affected by participants' MTPASA submissions

As there is relatively little overlap between these two requirements EY believes it is reasonable to use separate processes to satisfy each. EY's proposed revised MTPASA process therefore separates the maintenance planning and Reliability Standard assessments as follows:

1. Process 1: Retain the 3-hourly MTPASA supply and demand summary with minor changes to provide increased transparency and utility. This process would not include any statement about the Reliability Standard and thus would not be appropriate for providing a potential intervention trigger. It would also not provide energy limit information (other than identifying total plant declared as affected by energy limits) or network limit information.
2. Process 2: A probabilistic reliability assessment, performed at least quarterly or in response to new information with the potential to materially alter system reliability[12]. This would measure the system's expected performance compared with the Reliability Standard, and is intended to be appropriate for AEMO to use as basis for intervention if necessary. This process could also be used to calculate network limit information and energy limited plant outcomes.

Some Rule and RSIG changes are expected to be required to enable this. In particular, this would mean that some information currently required to be published weekly would only be available on a quarterly basis (or as frequently as AEMO conduct the reliability assessment process).

The following sections explore the two recommended processes in detail.

6.1 Recommended process one: MTPASA supply and demand summary

Participant feedback at the stakeholder workshop was that the current 3-hourly publication of aggregate generator availability and demand was both valuable and widely used. As such this process should be continued despite the lack of any clear relationship to the Reliability Standard as this publication assists with various uses including medium term pricing expectations and maintenance planning. EY suggest that the two existing aggregation categories ("energy constrained" and "unconstrained") be expanded to also include solar (grid and rooftop PV) and wind categories (or at least "intermittent"). This is a relatively small change that provides more information to participants at minimal cost and avoids attempting to present a weighted sum of intermittent and controllable generation using a problematic set of intermittent generation weightings.

[12] Such factors are not easily defined exhaustively, but would include events such as a widespread change in availability of major generator(s) (for instance mothballing or retirement of a large unit/station) or significant outage of an interconnector. The RSIG would be an appropriate place to list various identified factors which may have material reliability impacts.

EY recommends that the load forecast be changed to an 'operational plus rooftop PV' basis (see section 6.11), and that assumptions about any assumed behaviour of non-scheduled intermittent generation and rooftop solar be published[13] as stakeholder engagement revealed the perception that that this information was not readily available[14].

This change to the way demand is modelled is also of significance to the reliability assessment. This is discussed further in section 6.11.

Note that EY's brief was focussed on exploring the reliability assessment process in depth. EY was not engaged to provide a detailed specification of the supply and demand summary.

6.2 Recommended process two: Reliability Assessment

The second process proposed is one specifically focussed on assessing expected system reliability (and therefore compliance with the Reliability Standard). This would be entirely separate to the MTPASA supply and demand summary process described above. The reliability assessment would be required to be able to calculate expected unserved energy outcomes for the next two years (based on the declared MTPASA availability), and provide a mechanism by which participants could assess how their actions (particularly outage scheduling) may impact system reliability.

Section 5.2 described a range of reasons why the current MTPASA method is not suitable for the task of reliability assessment. Given this, EY investigated whether a revised MTPASA or alternative deterministic approach could be found which would be able to deliver an accurate reliability assessment. An important consideration in this regard was whether a deterministic approach could capture the behaviour of intermittent technologies.

6.3 Deterministic models

EY investigated whether the current MTPASA process or any other deterministic approach could be used to assess compliance with the Reliability Standard to any reasonable degree of accuracy. As stated earlier in this report, a deterministic approach is one that might be considered to 'follow a formula'. That is, given a particular set of inputs (and initial state), the outcome is entirely predictable, and only that outcome is possible. EY encountered several intractable problems with attempting to find an acceptable deterministic approach.

1. Deterministic models require generation to be interchangeable

A deterministic model takes a measurement (total generator availability) and compares it to a requirement (MRLs + demand + assumed interconnector behaviour). As this requires that all generation be interchangeable, technologies with significantly different characteristics (such as thermal plant and intermittent renewables) are a major problem. Standard practice is to assume a weighting factor for intermittent generation to "convert" available capacity into an amount of controllable generation roughly equivalent for reliability purposes.

While this is problematic for several reasons the primary issue is that calculating a static number that attempts to relate the reliability impact of controllable and intermittent generation is not possible to do accurately. EY calculated the expected *reliability contribution factors*[15] for a variety of intermittent generators using generation profiles based on various historical years. That is, all the results below are forecasting the same future year but using a different historical reference

[13] To be specific, it does not particularly matter whether the published demand is scheduled, or operational, or anything else, so long as the key components are published or otherwise noted in a transparent manner. The advantage of publishing 'operational plus rooftop PV' demand is that it does not then change with different assumptions about rooftop PV and non-scheduled generation.

[14] EY notes that there is already a rule requirement to publish assumed non-scheduled generation used in the MTPASA demand forecasts.

[15] These 'reliability contribution factors' refer to the relative contribution these generators could make to reducing USE (ignoring transmission constraints and such). These values are the average output (as a percentage of maximum capacity) of the generator in all periods of USE. For example, a wind generator that had 50% output in one USE period and 0% in a second USE period would have a reliability contribution factor of (50% + 0%)/2 = 25%.

year to determine their operating profile. The results are summarised in the table below along with the thermal unit TORRB2 as a reference:

Table 1 - Contribution to reliability for various intermittent wind generators

Unit	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
BLUFF1	17%	24%	17%	19%	2%	14%	8%	6%	0%
CATHROCK	51%	56%	16%	13%	31%	22%	84%	5%	46%
CLEMGPWF	18%	35%	23%	13%	30%	10%	12%	22%	6%
CNUNDAWF	48%	42%	23%	46%	5%	37%	67%	5%	42%
HALLWF1	21%	32%	22%	24%	3%	19%	10%	10%	2%
HALLWF2	21%	30%	21%	23%	3%	18%	9%	11%	1%
Hornsdale_S1	24%	37%	24%	28%	12%	28%	15%	16%	3%
LKBONNY1	43%	36%	20%	40%	1%	22%	57%	3%	40%
LKBONNY2	45%	37%	21%	42%	1%	23%	59%	5%	47%
LKBONNY3	47%	39%	22%	43%	1%	24%	60%	5%	49%
MTMILLAR	31%	27%	30%	31%	9%	20%	28%	9%	1%
NBHWF1	20%	30%	21%	23%	8%	19%	14%	15%	2%
SNOWNTH1	16%	31%	21%	12%	28%	12%	11%	16%	13%
SNOWSTH1	19%	38%	25%	14%	33%	10%	13%	18%	18%
SNOWTWN1	20%	39%	26%	15%	36%	17%	14%	21%	19%
STARHLWF	31%	54%	20%	19%	23%	16%	34%	5%	9%
WATERLWF	17%	24%	17%	18%	5%	14%	8%	5%	1%
WPWF	22%	68%	19%	15%	28%	5%	42%	5%	7%
Example non-intermittent unit (TORRB2)	96%	98%	97%	98%	96%	97%	90%	99%	95%

As can readily be seen the variance is extreme amongst the intermittent generators and in between the historical reference years. Conversely, the thermal unit (TORRB2) is extremely consistent (and near 100%) in all reference years. It is clear that selecting a single contribution factor for each intermittent generator - let alone each technology type - would be a major oversimplification of the true behaviour. EY also notes that these values as calculated are only valid for a small marginal range and vary significantly with other input assumptions as well. Based on this information EY concludes that there is no reasonable way of weighting intermittent and controllable generation for the purposes of a deterministic model.

2. Deterministic models rely on probabilistic modelling to convert the Reliability Standard into a deterministic form

The Reliability Standard is an inherently probabilistic measure and cannot be directly used in a deterministic study. Instead detailed probabilistic modelling is required to convert the Reliability Standard into a deterministic measure. The MRL studies, which are used to define the MRL values currently in use in MTPASA, is an example of this. This conversion is often subjective and importantly, is extremely sensitive to the input assumptions. As such it must be performed almost as regularly as the deterministic model is assessed at which point there is no obvious reason not to simply use the probabilistic model directly. For example (and setting aside other methodological issues) in order to be relevant, MRL values would need to be recalculated at least annually. This would require a substantial probabilistic modelling effort each time. If this was being done, it would be difficult to justify why these studies themselves should not simply be used to satisfy the requirements currently being met by the MTPASA reliability run.

Given the various issues with using deterministic methodologies to assess a probabilistic Reliability Standard in a system with significant intermittent generation, EY concluded that a probabilistic model is required for reliability assessment.

6.4 Recommended features of the new methodology

Based on a detailed investigation, EY recommends that AEMO perform a system reliability assessment at least quarterly (and more frequently should information come to light that may materially impact reliability), based on the following parameters:

Study dimensions

- ► 200 iterations per reference year and demand case combination to achieve reasonable convergence
- ► 5+ reference traces for demand, solar and wind per demand scenario
- ► Half hourly simulation resolution
- ► Two year simulation horizon

Demand

- ► Operational demand plus rooftop PV and non-scheduled intermittent generators modelled explicitly (see section 6.11)
- ► Primary scenario to be modelled is medium economic growth 10% POE peak demand
- ► Evaluate medium growth 50% POE as well if 10% POE USE scenario is above the Reliability Standard

Generation

- ► Generator availability as per MTPASA declarations
- ► Model longer term energy limits heuristically[16] (specifics to be addressed on a case by case)
- ► Investigate merging EAAP (GELF) and MTPASA energy limit submissions and reporting
- ► Rooftop solar PV modelled explicitly and varying by reference year
- ► Significant intermittent non-scheduled generation modelled explicitly and varying by reference year

Network

- ► System normal constraint set (incorporating feedback constraints) invoked in all periods
- ► Outage constraint sets invoked as appropriate

EY has demonstrated that a study of these dimensions could be run overnight on a relatively inexpensive array of computer hardware (see section 7).

Our evidence and justification for this approach is outlined in detail in the following sections.

6.4.1 Alternatives considered

Once it was clear that no satisfactory deterministic method existed for modelling projected system reliability, EY sought to identify whether there were opportunities to reduce the potential scale of the probabilistic modelling required.

GHD[17] suggested that modelling only important periods in the study horizon could be a significant time saving. This is certainly true – in a typical 2-year look-ahead period, even when considering multiple reference years, there are relatively few periods that have material risk of USE. The difficulties with this approach are that:

- ► The strategy to identify which periods may have a high risk of USE is likely to be complicated. There would be a real risk of missing potential high risk periods.
- ► The high risk periods are likely to vary year-to-year and by reference year.
- ► Full probabilistic modelling is likely required to identify the high risk periods.
- ► Modelling sub-sets of the time period complicates satisfactory modelling of energy constraints (and possible future models of energy storage such as batteries) and potentially other 'time-sequential' considerations such as constraints, ramp rates, and similar.

Rather than attempt to identify high risk USE periods, another approach would be to simply model only particular months or seasons where the vast majority of USE might be expected. In particular, prior modelling experience suggests that shoulder seasons are unlikely to include high risk periods.

[16] Long term energy limits should not be expected to influence bulk reliability outcomes – it is reasonable to assume that large scale storages will have some energy available during high risk periods.

[17] GHD assisted AEMO as an additional peer-reviewer of the work

This is not unreasonable but must consider that unusual outages may lead to USE risk in unexpected periods and that identifying this is an objective of the MTPASA process. This would also complicate the current requirement to provide information to the market regarding the impact of planned outages of generation and network plant for the entire 24-month MTPASA horizon as modelling would not exist for a subset of that period.

Given these complications and the need for a regular full probabilistic modelling exercise to validate which periods are high risk, EY concluded that if it is computationally practical it is better to simply model the entire horizon as recommended in this report.

6.5 Assessment frequency

EY has recommended that AEMO perform reliability assessment at least every quarter. This recommendation is not based upon conclusive evidence, but rather a trade-off between factors such as the resourcing and computational burden on AEMO, market risk mitigation and value derived for the market. In making this recommendation, we have considered the following factors:

- Many major data sources are updated annually including demand and intermittent trace projections
- The current Rules (see clause 3.7.1) include an obligation to publish MTPASA outcomes (including reliability outcomes) weekly
- MTPASA declarations are published every three hours and our analysis showed that major changes may occur in any timeframe
- A weekly assessment using the recommended process could be quite onerous at this point in time given the potential model runtime
- A practical amount of time must be allowed for preparing and auditing input data and results
- The initial and ongoing costs of a modelling platform and staff to operate the process must be weighed against the relative benefits of more frequent publishing in order to provide the best outcomes for participants and energy consumers (in accordance with the NEO)
- The value to stakeholders in terms of the usefulness and timeliness of MTPASA information to assist in outage planning

This line of reasoning effectively ‘book-ends’ the assessment frequency at between one week (as per the current Rules) and one year, and therefore a reasonable middle ground appears to be around the quarterly mark. It is difficult to find parallels with this process in other power systems around the globe. Certainly most areas at least conduct generation adequacy assessments annually or bi-annually, but then may do more simplistic analyses on a more frequent basis. Formal probabilistic reliability assessment processes are still relatively rare across the globe (though increasingly employed) for a range of reasons – likely due to increasing proportions of intermittent generation and decreasing reserve margins as systems seek greater efficiency. An annual assessment probably would not provide frequent enough information for AEMO to feed back to participants and have an impact on their plans, or for AEMO to ultimately take intervening action via RERT and other measures if required.

In EY’s opinion, the most significant factor supporting a higher study frequency concerns the process ‘feedback loop’ with participants. That is, a more frequent reliability assessment publication would potentially allow participants to have more direct feedback on their actions, especially around moving of planned outages of plant. While the 3-hourly supply-demand summary service gives a reasonable level of feedback, it will not provide a direct link to system reliability. The relative benefit of providing more frequent reliability information would be very difficult to assess however it is clear that more information would be useful. EY’s feasibility testing has shown that overnight execution times are very much feasible, given the right system design.

Taking all of these points into consideration:

EY recommends that AEMO execute the reliability assessment process at least quarterly, and consider the benefit of a more frequent execution cycle, especially as expertise is gained and process automation is built.

6.6 Modelling network constraints and network outages

AEMO currently models network outages in MTPASA by including additional relevant constraint sets that represent the reduced network capability. This is a reasonable approach but is limited by the extremely restrictive interconnector headroom constraints that are used in MTPASA LRC runs for reasons associated with the MRLs (refer to section 5.2.5). As the proposed probabilistic model does not use these headroom constraints this same constraint set approach could be employed in a probabilistic model.

As these outage constraint sets are currently only prepared in the MMS format this requires either changing the format these constraints are prepared in, supporting this format in the modelling platform used or investigating converting MMS outage constraints to a different format. Changing the format outage constraints are prepared in is a solution but may involve significant changes to AEMO's systems. Converting the MMS format may be quite challenging for some possible MMS constraint formulations.

EY recommends that the modelling platform supports the MMS format directly. The other approaches discussed are reasonable if deemed feasible but are likely to be considerably more challenging to implement.

6.7 Modelling network limits

AEMO currently publishes forecast interconnector limits with and without network outage constraints on a weekly basis as discussed in section 5.2.5. Interconnector limits are dictated by network constraint equations which commonly feature generation on the left and right hand sides. As such maximum interconnector transfer can be strongly influenced by assumed generator dispatch and thus the appropriateness of any published limits is dependent on the assumed generator dispatch.

MTPASA currently publishes two sets of transfer limits (each provided with and without outage impacts) based on differing assumptions and optimization objectives. Generator availability is used for constraint RHS calculations for all runs. 'LIMITS' runs maximise reserve surplus in all regions simultaneously while 'LOR' (Lack of Reserve) runs maximise available capacity in a single region subject to meeting supply demand balance in all other regions. Demand assumptions also differ between the runs. LIMITS runs tend to understate available interconnector capacity significantly while LOR runs are closer to a 'best-case' view of interconnector transfer limits. Both sets of runs are independent of the MTPASA reliability assessment and neither set uses the interconnector headroom constraints (which is discussed in section 5.2.5).

EY considers that there are multiple options if AEMO intends to continue publishing interconnector limits but evaluating them is problematic when the intended purpose of these forecast interconnector limits is not clear. As the existing runs already show it is possible for derived interconnector limits to vary significantly based on assumptions and intended purpose.

AEMO may choose to instead publish calculated interconnector limits from the probabilistic reliability assessment as this study should include forecast outage constraints. This addresses some of the issues with the LHS and RHS calculations being derived from availability instead of possible dispatch in the current process. The complications with this approach are that there is no 'base case' (published limits with no outage constraints) and AEMO is unlikely to be able to run the probabilistic study on a weekly basis (clause 3.7.2 of the Rules currently states that interconnector transfer capabilities should be published weekly).

Alternatively, AEMO could continue using one or both of the existing sets of MTPASA interconnector limit solves. While this is the simplest solution it does not address concerns regarding the meaningfulness and purpose of these numbers.

As a third option, AEMO could refer participants to the Network Outage Schedule (NOS), which lists intended outages of network equipment. This approach does not provide any quantification of the impact of these outages on interconnector limits but it is not clear that the existing approach is accurate enough to provide reliable insight into interconnector transfer capability in any case. EY notes that the 'LIMITS' runs in particular produce limits that do not appear to strongly resemble interconnector capability.

6.8 Intermittent generation in a probabilistic model

By various means including running a large set of probabilistic simulations, EY reached the following conclusions:

- No single value can represent the reliability contribution of intermittent generation even within a single region and year
- Wind generation is not materially correlated with demand or solar generation
- Wind generation is correlated with other wind generation, with the strength of the correlation related to the distance between the wind farms
- A single reference year[18] is not adequate to describe the behaviour of intermittent generators, particularly during times where there is high risk of USE

The following sections examine each of these conclusions in detail and present some of the supporting modelling and evidence.

Probabilistic studies model intermittent generation by taking resource availability in each time period of the study as an input. This input time-series data is commonly from a historical year (the 'reference year') adjusted for expected future conditions. All times series input data (typically demand, solar and wind) is generally sourced from the same reference year to preserve historical correlation between the traces. Correlation or lack thereof between these traces is critically important to reliability outcomes (see Section 6.10 for a demonstration of this).

As the Reliability Standard is quite strict (that is, the allowable USE is a relatively small amount) there will typically be a very limited number of discrete events in a typical NEM reliability study observing unserved energy at approximately the level of the standard. This means that reliability outcomes are determined by intermittent generation output and correlation in a very small number of time intervals despite having many data points in the whole time series (which spans two years). To avoid overemphasizing intermittent correlation observed in a very small number of historical periods it is desirable to weight a combination of multiple different possible combinations of intermittent traces. This is similar in concept to Monte-Carlo simulation of traditional generator outages. The simplest way of achieving this is to use multiple historical reference years. This is not without issue though. If many reference years are required, and the same reference year must be selected for demand, wind and solar data, then demand information several years or more old would be used. However electricity consumption behaviour from more than a few years ago may not be reflective of current patterns. Sourcing intermittent and demand data differently however risks breaking any correlation present and distorting results.

As such EY has investigated what correlations exist between demand and intermittent generation and whether traces can be combined or generated in ways other than simply reusing a historical reference year in its entirety.

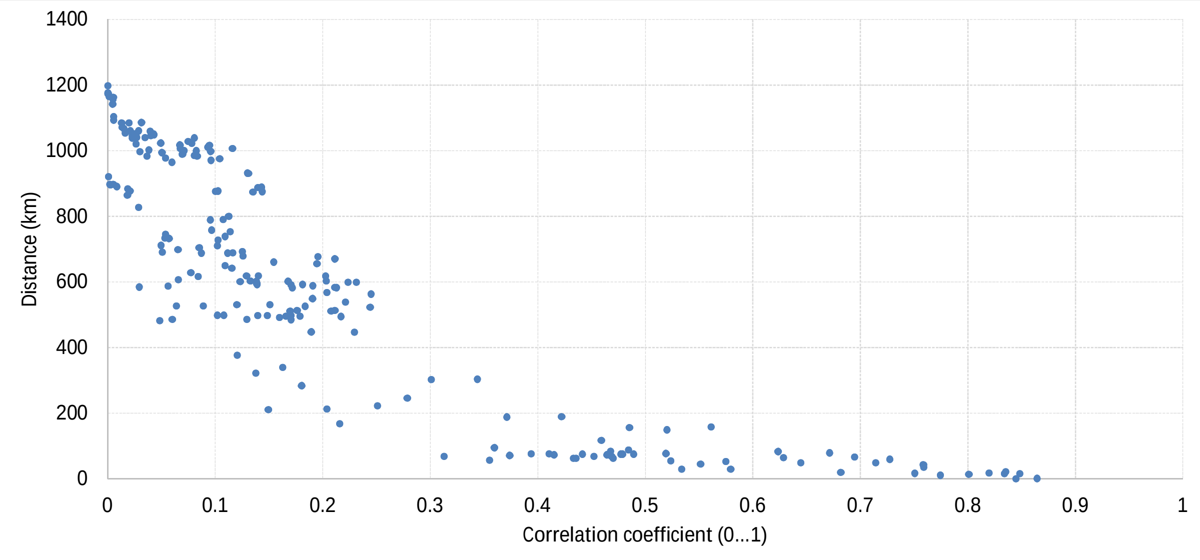
Inter-regional demand correlation is a major factor in NEM reliability studies and is examined separately in Section 6.9.

EY observed no measurable relationship between wind generation and either demand or solar generation when examining the 2015-16 year. Unsurprisingly, wind generation was found to be strongly correlated with other wind generation, with the strength of that relationship varying (loosely) exponentially by distance. The chart below presents the correlation factors for actual

[18] A reference year refers to a historical year (e.g. the financial year 2015-16) where the time-series of demand, wind and solar generation are known or can be modelled with sufficient accuracy. This reference year is then projected forward to model forecast years, maintaining the relationships between demand, wind and solar generation.

2015-16 half hourly generation between pairs of all NEM scheduled and semi-scheduled wind generators.

Figure 3 – NEM wind generator correlation coefficient vs distance for 2015-16 actual generation



No statistically significant relationship between wind and demand or wind and solar was observed in any state. However, individual weather events may still drive relationships between wind and demand on any given day (for example, still conditions on an already hot day may also plausibly increase demand).

Noting that large scale solar PV data is still relatively limited in the NEM, no significant relationship was found between solar generation (large scale or rooftop) and demand or wind generation in any state either despite the seasonal and time of day correlation both solar and demand exhibit. As expected, solar generation also exhibited a strong correlation with other solar generation. The following charts show solar PV output for 2015-16 versus demand for the NSW and QLD regions for the 8am to 5pm (NEM time) window and coloured by season.

Figure 4 - Rooftop PV output versus Operational demand plus rooftop PV: NSW 8am to 5pm

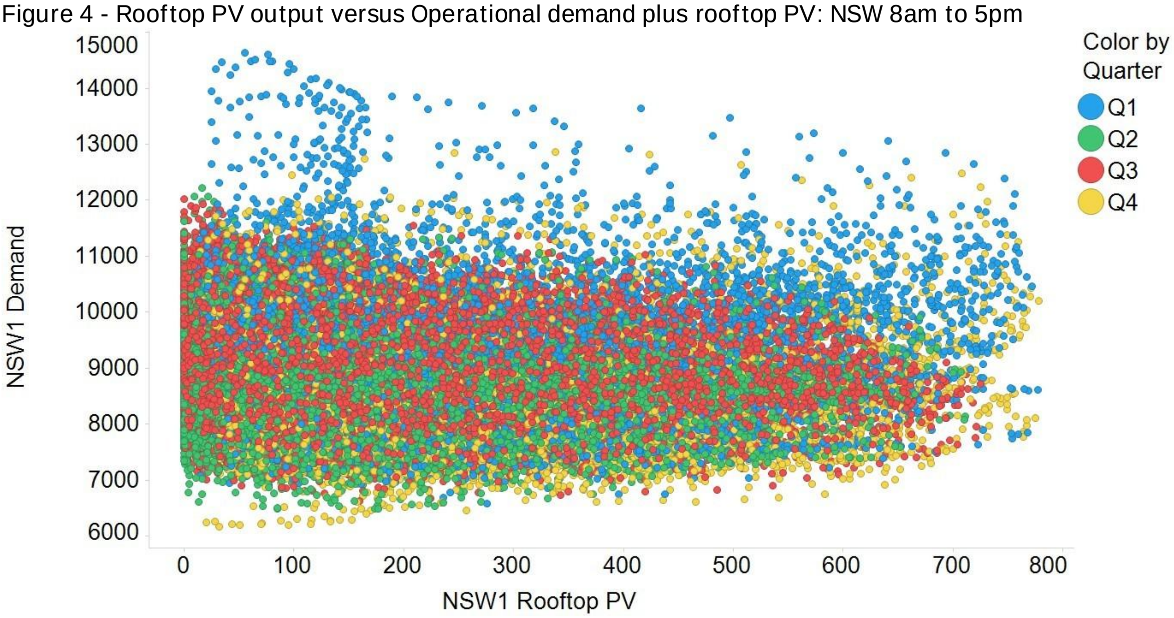
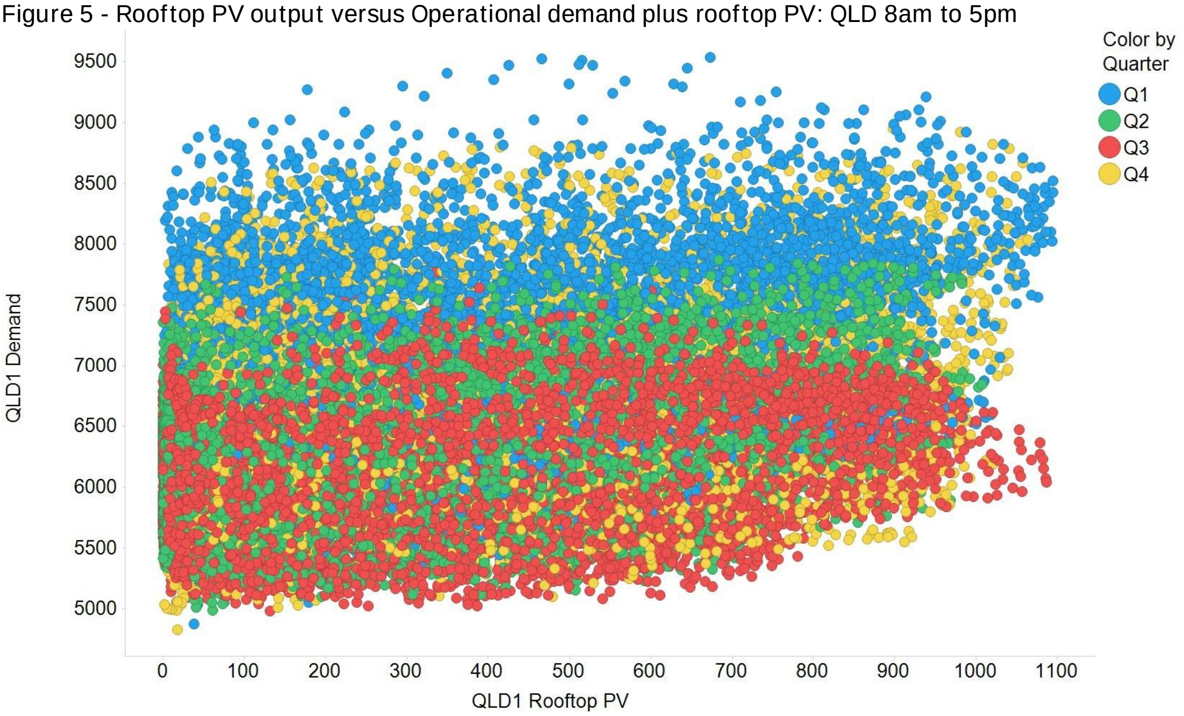


Figure 5 - Rooftop PV output versus Operational demand plus rooftop PV: QLD 8am to 5pm



To address the current lack of historical data for grid-scale solar projects, EY created a complete set of forecast time-series data for a variety of existing and hypothetical future wind and solar plants located throughout the NEM. Output was based on historical observations from the Australian Bureau of Meteorology (BOM) weather and solar insolation measurements, and then computed via NREL's System Advisor Model using settings in line with typical utility-scale solar farms. This data set shows very similar patterns; wind is strongly correlated with other wind with the strength of that relationship varying by distance, while solar is strongly correlated with time of day. Neither shows any significant relationship to demand.

This suggests that while time series data for each separate element (wind, solar and demand) must be sourced from the same reference period (i.e. wind generation from different reference periods cannot be mixed because wind is strongly correlated with other wind) there is potential for sourcing the wind, solar and demand reference data independently. For example, this analysis indicates that it would be reasonable to combine wind generation based on 2013-14 with solar generation based on 2014-15. This is desirable for demand in particular as while wind and solar resources would be expected to be relatively consistent over time demand is driven by changes in customer behaviour.

This is not a firm conclusion as there is strong evidence that solar and demand share some common drivers (e.g. temperature) as discussed below. That this does not translate into any observable pattern between solar and demand during daylight hours was not expected. EY notes that there is limited operational data from large scale solar in the NEM to date and that the rooftop PV generation used is a reconstruction; no exact measurements exist of actual aggregate rooftop PV generation. As such EY is hesitant to conclusively conclude that solar and demand during daylight hours are not correlated despite noting that the data examined supports this conclusion.

EY has not investigated whether intermittent resource traces could be created from sampling subsets of years instead of a complete trace but notes the seasonal correlations identified, particularly with solar generation.

6.8.1 Solar versus demand and time of day

To further attempt to characterise any relationship between demand and solar generation, EY limited the analysis to a particular time period during the day. This was based on the expectation that both demand and solar insolation are correlated with temperature. These expectations appear reasonable, as shown below for two different solar farms when aligned with data from nearby weather stations:

Figure 6 - Solar insolation vs temperature for Moree solar farm (2015-16 as per nearby BOM measurement, source: AEMO and BOM)

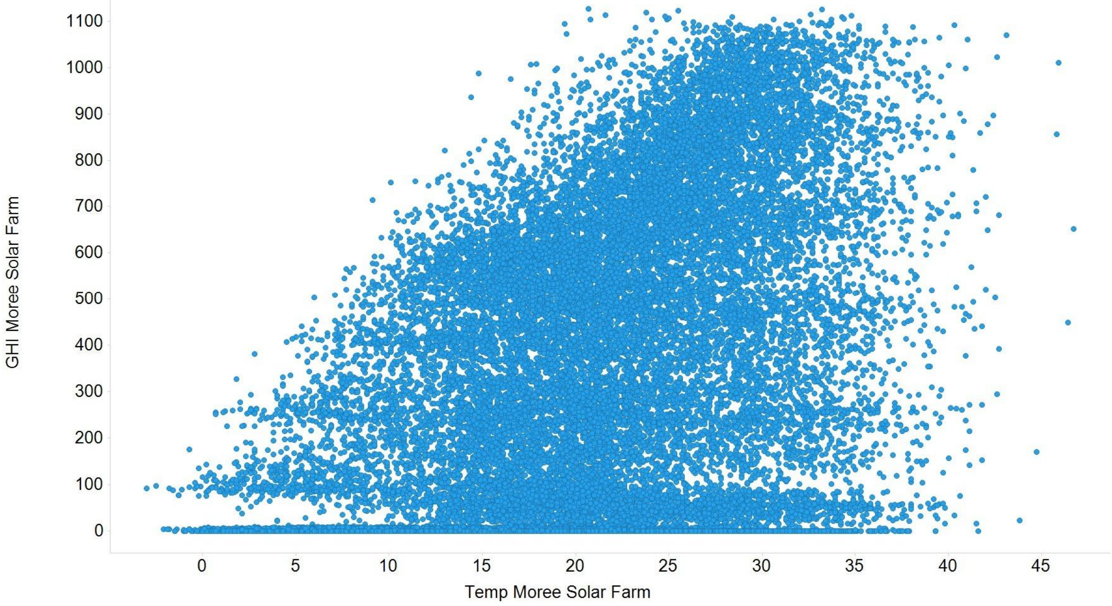
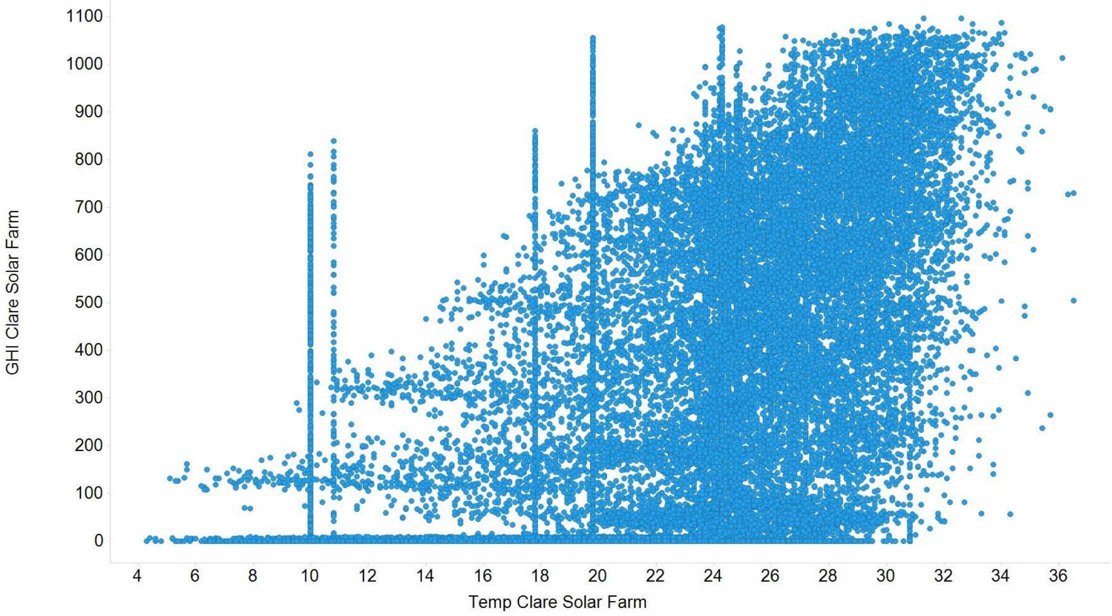


Figure 7 - Solar insolation[19] vs temperature for Clare solar farm (2015-16 as per nearby BOM measurement, source: AEMO and BOM)



Other solar sites show a similar relationship – solar insolation and temperature are loosely correlated.

EY also examined how demand related to temperature. Some examples are shown in the two figures below which show that demand is clearly correlated with temperature. The dual peaks in the charts (particularly seen in NSW) are due to high demand being associated with high temperatures in summer months and low temperatures in winter months.

[19] The banding of data in this example is unexpected and possibly due to occasional measurement error.

Figure 8 - NSW customer demand vs Sydney temperature (source: AEMO and BOM)

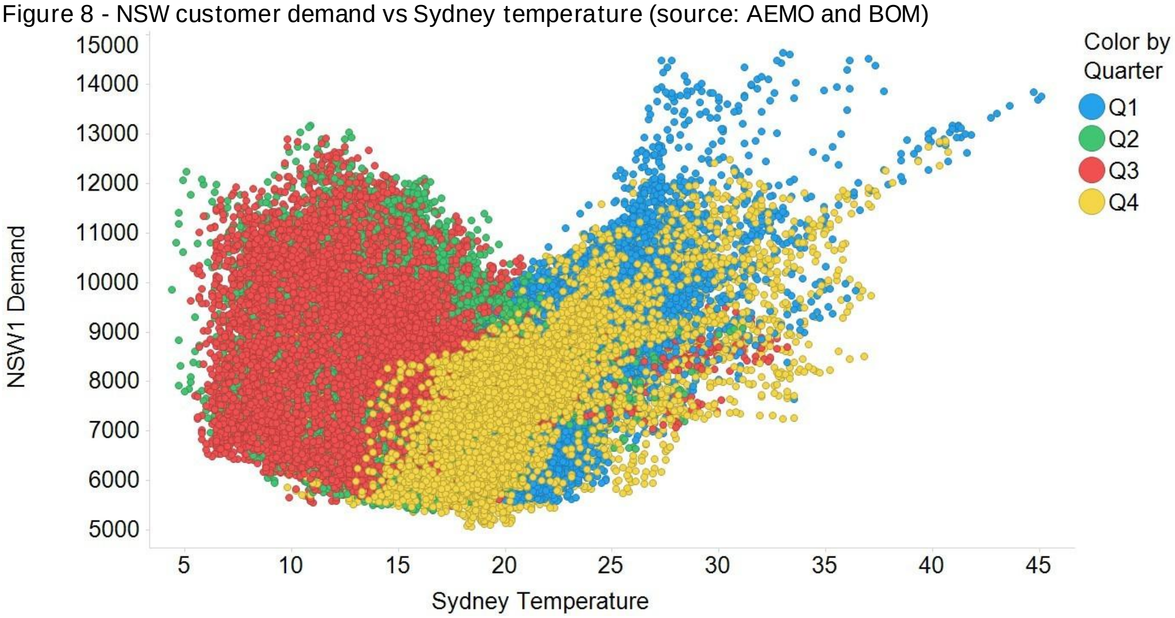
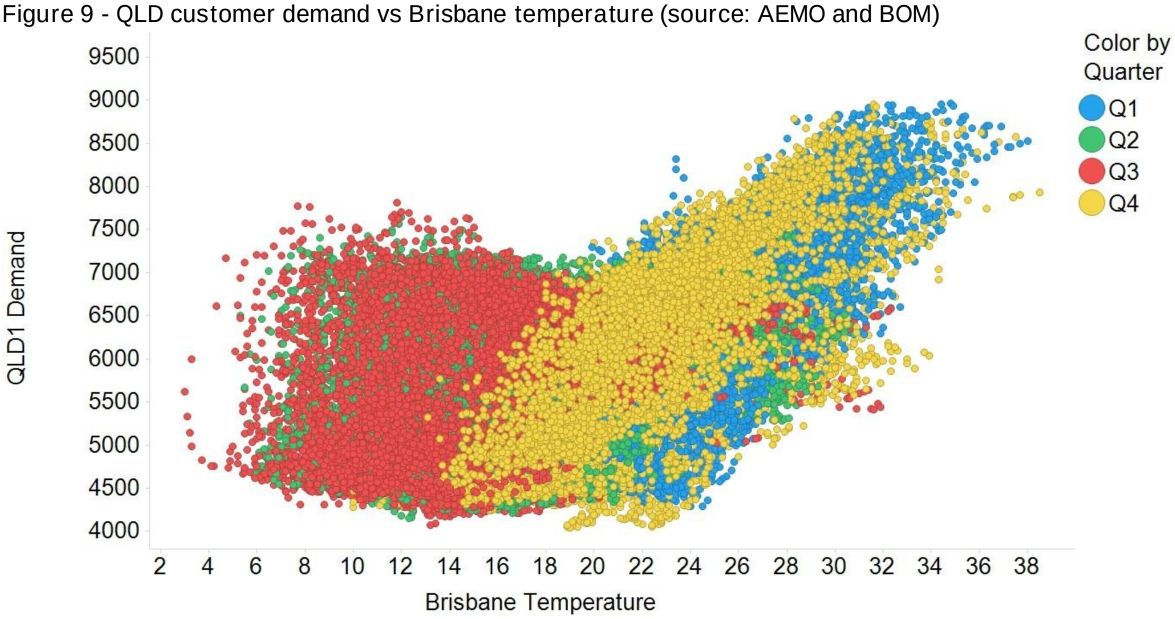


Figure 9 - QLD customer demand vs Brisbane temperature (source: AEMO and BOM)



Even though correlations between solar generation and temperature, and demand temperature were separately established, when combined to look for correlation between solar generation and demand, no strong pattern was observed, even when limiting the data set by time of day and season. The following charts show this data set for NSW and the Moree solar farm as an example.

Figure 10 - NSW demand vs Moree solar farm generation (2015-16; 11am to 1pm NEM time)

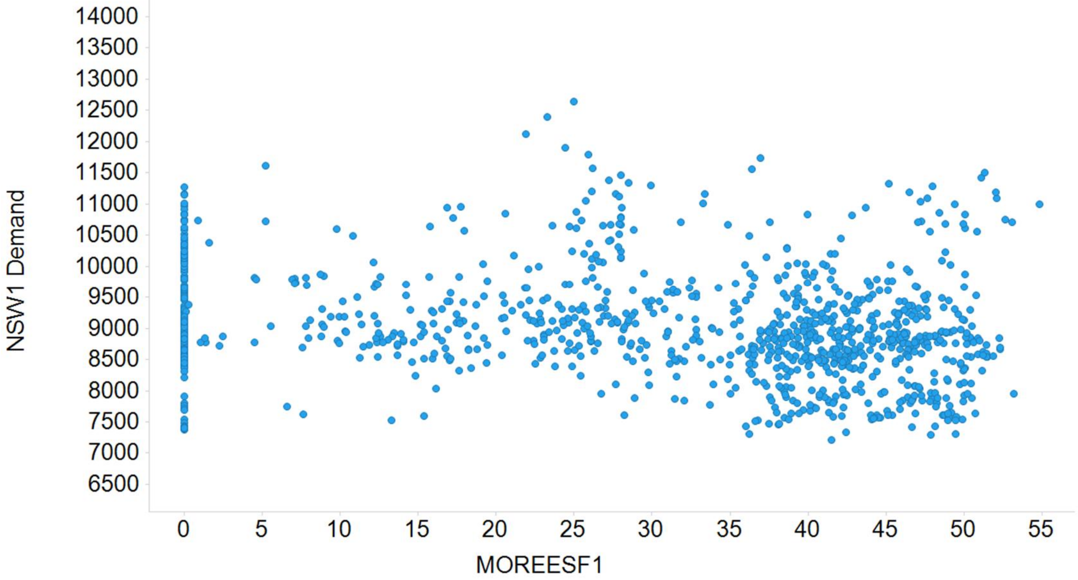
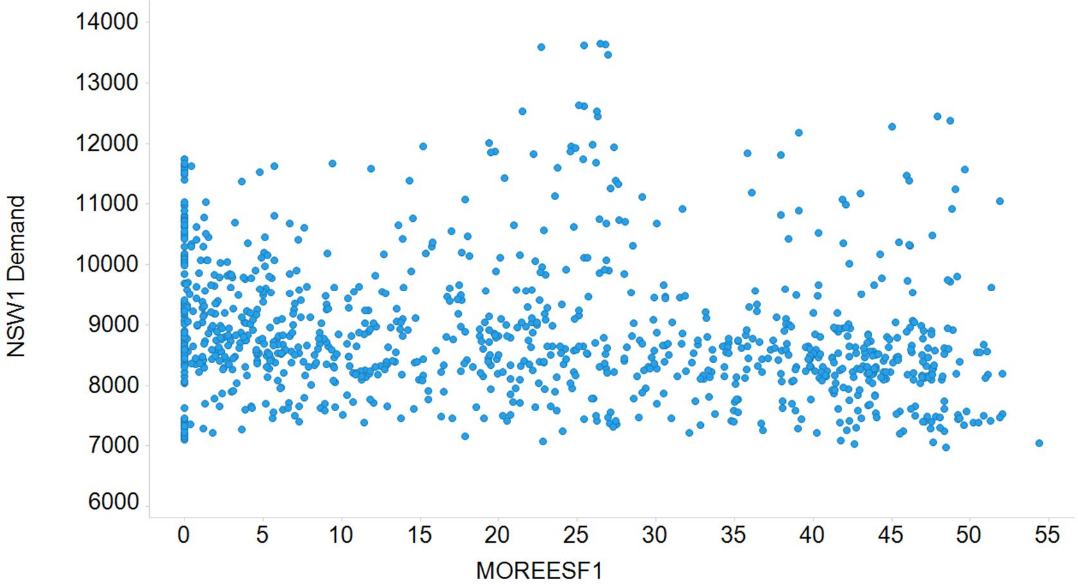


Figure 11 - NSW demand vs Moree solar farm generation (2015-16; 3pm to 5pm NEM time)



While there is clearly a strong relationship between demand and temperature and a weaker relationship between solar insolation and temperature, it is apparent that other factors are also significant.

In conclusion, EY found no clear relationship between solar generation and demand in any of the data studied which suggests that it may be possible to select reference years independently for these variables. However we note that there is limited operational data available and that there is a clear presence of some common drivers.

6.9 Demand correlation versus reference year

EY investigated how demand correlation varies based on reference year to assess whether multiple reference years might be expected to produce significantly different results and to evaluate which relationships are important.

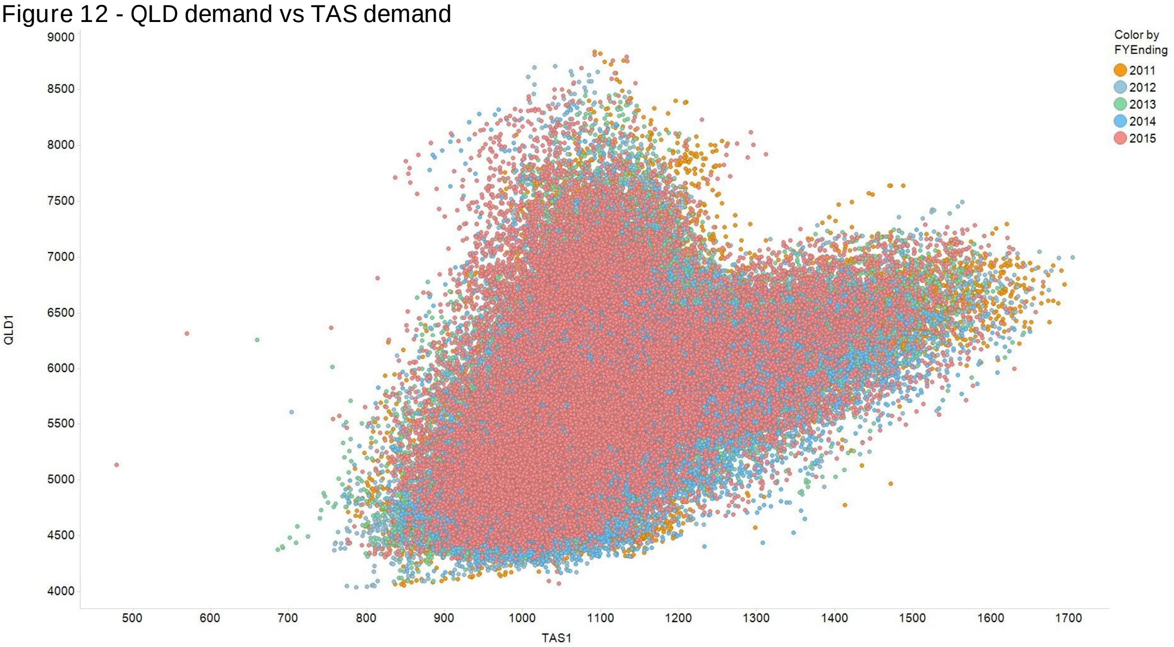
EY has relied on publically available demand data published by AEMO. It is apparent from this dataset that regional demand is correlated across the entire NEM. The following table summarises calculated linear coefficients of determination[20] (zero being no correlation, one being perfectly correlated) for regional demand for the period 1 July 2010 to 30 Jun 2016.

Table 2 - Linear coefficient of determination, all seasons, all years

Coefficient	NSW1	QLD1	SA1	TAS1	VIC1
NSW1	1.00	0.52	0.49	0.44	0.74
QLD1	0.52	1.00	0.26	0.14	0.36
SA1	0.49	0.26	1.00	0.22	0.66
TAS1	0.44	0.14	0.22	1.00	0.43
VIC1	0.74	0.36	0.66	0.43	1.00

This represents a relatively strong relationship between most states even before accounting for any other variables. Some relationships appear weaker than expected; Tasmania seems to be somewhat of an outlier. These aggregate statistics suggest that Tasmania and Queensland are only weakly correlated. Graphing the relationship illustrates that this is not the case and that there is a clear pattern.

Figure 12 - QLD demand vs TAS demand



The pattern revealed here is seasonal – Tasmania is winter peaking, while Queensland is summer peaking. The same chart with data from winter months only reveals a relatively strong linear correlation, as do the other seasons.

[20] A "linear coefficient of determination" is a statistical measure that indicates the proportion of the variance in the dependent variable that is predictable from the independent variable. It is sometimes refereed to as '"R squared".

Figure 13 - QLD demand vs TAS demand: winter only

Within each season there is a strong correlation. That is, Queensland winter demand is more likely to be high if Tasmanian winter demand is high. The same correlation calculation for particular seasons is presented below.

Table 3 - Linear coefficient of determination, winter, all years

Coefficient	NSW1	QLD1	SA1	TAS1	VIC1
NSW1	1.00	0.73	0.70	0.66	0.82
QLD1	0.73	1.00	0.53	0.62	0.67
SA1	0.70	0.53	1.00	0.48	0.68
TAS1	0.66	0.62	0.48	1.00	0.66
VIC1	0.82	0.67	0.68	0.66	1.00

Table 4 - Linear coefficient of determination, summer, all years

Coefficient	NSW1	QLD1	SA1	TAS1	VIC1
NSW1	1.00	0.60	0.34	0.31	0.61
QLD1	0.60	1.00	0.13	0.23	0.29
SA1	0.34	0.13	1.00	0.14	0.68
TAS1	0.31	0.23	0.14	1.00	0.29
VIC1	0.61	0.29	0.68	0.29	1.00

Table 5 - Linear coefficient of determination, shoulder, all years

Coefficient	NSW1	QLD1	SA1	TAS1	VIC1
NSW1	1.00	0.59	0.44	0.38	0.75
QLD1	0.59	1.00	0.28	0.20	0.42

SA1	0.44	0.28	1.00	0.19	0.61
TAS1	0.38	0.20	0.19	1.00	0.42
VIC1	0.75	0.42	0.61	0.42	1.00

This suggests that correlation is extremely strong across the country during winter months but summer and shoulder demand is more localised. Despite this weaker summer correlation and that the vast majority of unserved energy can reasonably be expected to occur in summer currently there appears to be no rationale for utilizing ‘mixed’ reference years for demand; demand correlation is too strong for this to be a valid approach.

The following table summarises the same calculation broken down by year.

Table 6 - Linear coefficient of determination, summer (FYE)

Relationship	2011	2012	2013	2014	2015	2016
NSW1 vs QLD1	0.73	0.78	0.70	0.58	0.63	0.64
NSW1 vs SA1	0.50	0.31	0.28	0.35	0.17	0.40
NSW1 vs TAS1	0.41	0.42	0.33	0.41	0.20	0.15
NSW1 vs VIC1	0.70	0.68	0.59	0.67	0.60	0.68
QLD1 vs SA1	0.36	0.19	0.22	0.07	0.05	0.22
QLD1 vs TAS1	0.45	0.40	0.32	0.33	0.22	0.19
QLD1 vs VIC1	0.58	0.47	0.40	0.25	0.30	0.44
SA1 vs TAS1	0.24	0.10	0.23	0.10	0.04	0.10
SA1 vs VIC1	0.73	0.71	0.74	0.70	0.52	0.63
TAS1 vs VIC1	0.45	0.29	0.37	0.29	0.18	0.13

This strongly suggests that demand correlation does vary considerably year to year and that there is value in considering multiple demand reference years. This is supported by analysis of the 2016-17 forecast traces created from multiple reference years earlier. While there is considerable overlap in the vast majority of periods and common patterns are clearly visible there are also observable differences in high demand outlier periods. At very high demand percentiles the clear patterns present for most of the dataset break down somewhat and different reference years exhibit significantly different correlation patterns. As USE is more likely to occur during very high demand periods, this behaviour is of particular importance.

EY concludes that regional demand correlation is strong and varies considerably by year particularly in extreme demand periods. Therefore modelling multiple reference years is very important for demand as well as intermittent generation.

The following charts illustrate that while there is significant overlap for the majority of the year there is considerable variance in the correlation of very high demand values (where USE is most likely).

Figure 14 - QLD vs NSW Operational plus rooftop PV demand (excluding industrial baseload): 2016-17 based on various reference years

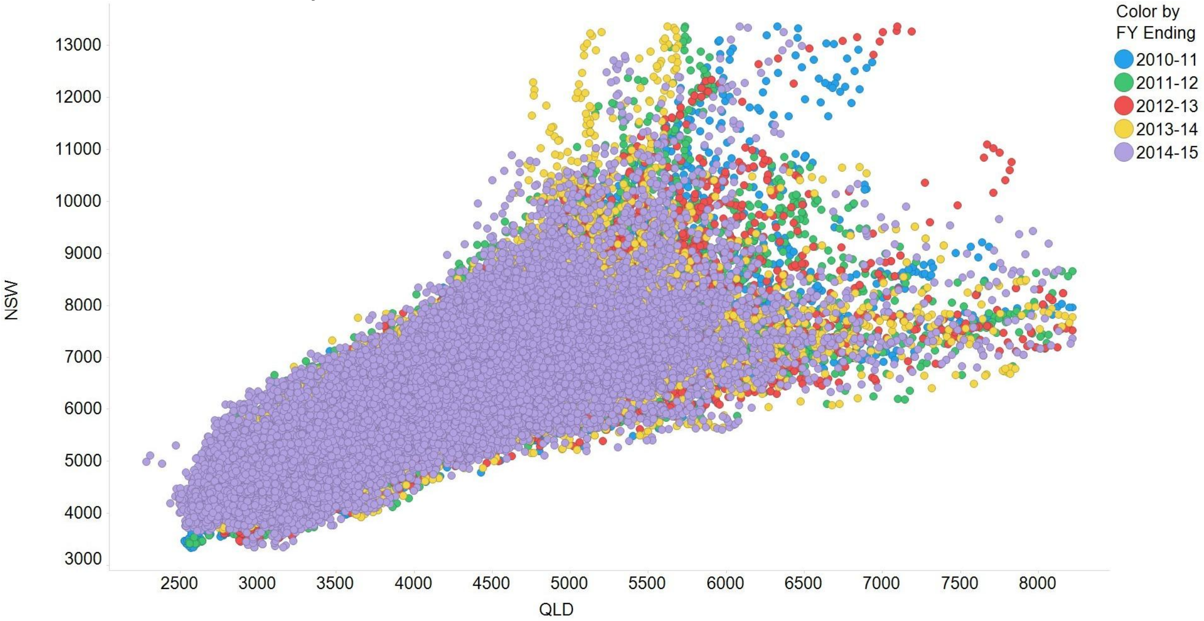
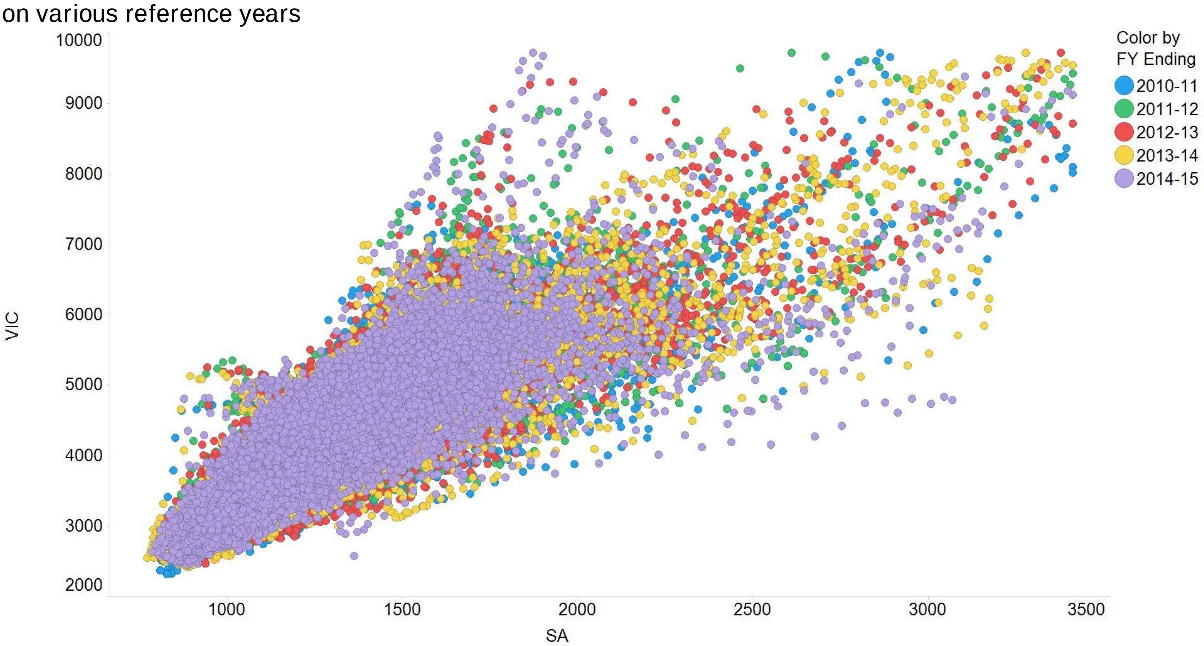


Figure 15 - VIC vs SA Operational plus rooftop PV demand (excluding industrial baseload): 2016-17 based on various reference years



6.10 The use of multiple reference years

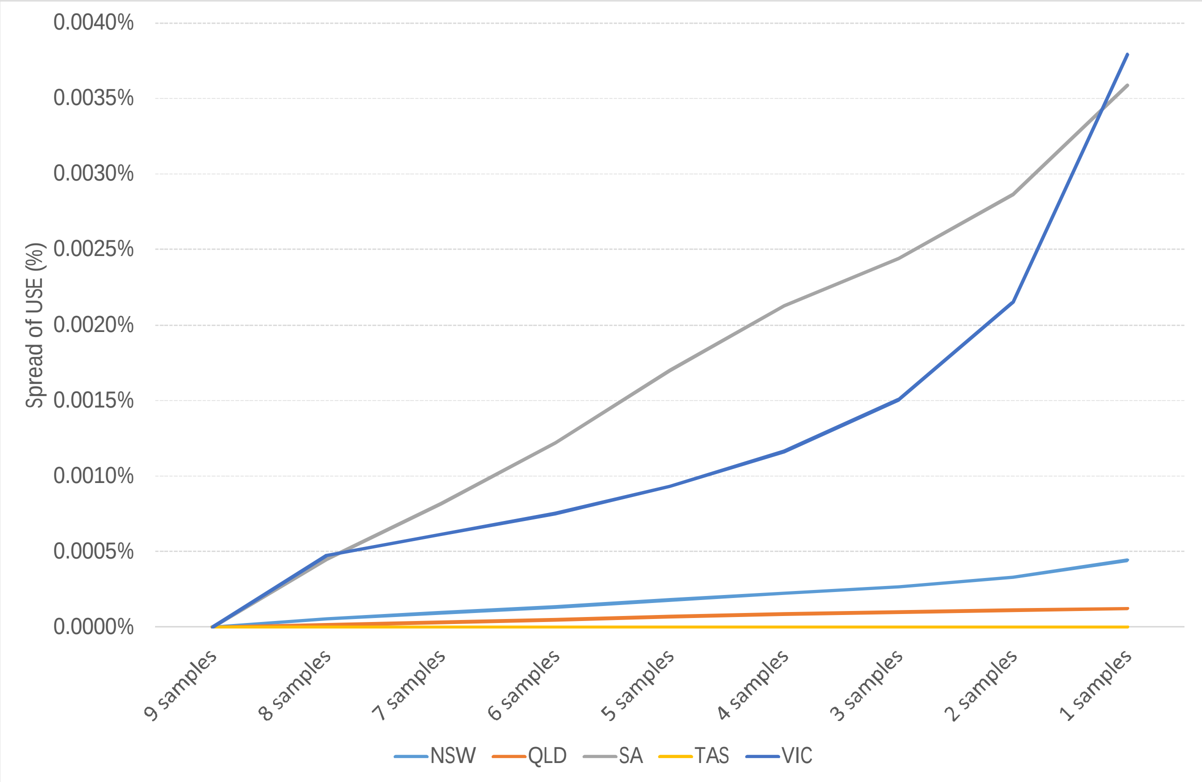
As has been argued in other sections, there is no clear way to predict how intermittent generators may operate at the sort of timescale contemplated by these studies. Therefore it is critical to model the behaviour of these generation sources. The most obvious way to do so is through the use of multiple reference years. Unsurprisingly, modelling of this showed that USE outcomes can vary substantially depending on the reference year selected. For example, test studies saw variations in USE stemming from well below the Reliability Standard to exceeding the Reliability Standard depending on the reference year selected. On that basis it was clear that a single reference year is inadequate for assessing system reliability, and therefore modelling must incorporate multiple reference years. AEMO has independently recognised this also, as demonstrated by the 2016 ESOO, which included six reference years in the modelling.

However, it is difficult to assess how many reference years may be required. To assist in determining a minimum number of reference years, EY conducted a study using nine reference years. This was limited to nine reference years due to time and data availability constraints, rather than any particular expectation as to the appropriateness of this number.

One way of examining the difference from increasing the number of reference years is to look at how the *spread* between minimum and maximum *average* USE values changes with a higher number of samples included in the average. This is summarised for our nine reference year study below in Figure 16. In total, nine reference years were modelled.

As may be expected, the spread between minimum and maximum USE is smaller when more reference years are included in the average. At four samples (that is, looking at the spread in average USE across all the different ways four samples could be selected out of the nine total reference years), the spread is below the Reliability Standard in all cases except SA (which incidentally has the highest penetration of intermittent generation). At five reference years all spread values are below the Reliability Standard. This provides some comfort that using five reference years is reasonably robust[21]. It must be noted that the zero spread at nine samples occurs only because only nine reference years were modelled, not because the spread is necessarily truly zero – if many more reference years were modelled, one might expect different spread values. From this analysis, it shows that many reference years are needed to properly incorporate the impact of intermittent generation and regional correlation. Since modelling potentially hundreds of reference years is not really feasible for both computational, data quality and relevance reasons, EY recommends that AEMO adopt the reasonable approach of modelling as many reference years as is practical, with a minimum of five. As hardware and software continues to develop into the future, it will become increasingly feasible to simulate more reference years with appropriate numbers of Monte Carlo iterations.

Figure 16 – Spread of USE outcomes by region with increasing reference year numbers



21 For example, the starting spread values may be higher if more reference years were modelled.

6.10.1 Constructing reference years

While it is clear that multiple reference years are required to properly account for variability in intermittent generator behaviour and inter-regional demand relationships, it is also a fact that demand behaviour may be materially different in the past. It is reasonable to assume that the older the demand data is, the less consistent with today's consumption patterns it is likely to be. EY has not attempted to measure this - indeed this would likely be a difficult task as setting the criteria for assessing the level of relevance would likely be quite subjective.

EY's suggested reference year approach is to utilise demand, solar and wind patterns from previous reference years directly. EY's analysis has also indicated that wind reference year may be selected independently of demand. However, it is less clear that selecting solar reference year independently from demand is sound. This means that to model many reference years, it may be necessary to draw from historical data more than 5 or so years old.

An alternative approach suggested by AEMO is to reconstruct demand from historical weather data. Weather data records extend for many years (perhaps as many as 100+ in some locations). Discussions with AEMO's demand forecasting specialists suggests that this capability is feasible, and that current models do this. However AEMO's demand forecasting models would require some modification to achieve the desired outcome as they currently sample data from many historical years to produce a single forecast, rather than drawing from one single reference year. Nonetheless, AEMO's team indicates that it is feasible for the model to operate in this manner with some changes. The process is a bottom-up methodology, involving separating weather-sensitive demand from non-weather-sensitive demand, then projecting each using a model trained on a large amount of historical demand and weather data. Econometric factors are also included.

Assuming that the demand model is sufficiently accurate, this approach to creating more reference years appears valid.

This approach also would open up the possibility of using much older weather data. AEMO suggested that sampling random reference years from a large (~100 year) weather data set may be preferable to modelling the same set of reference years over and over (i.e. just selecting the past 5 years each and every time). EY agrees that this approach certainly has merit, but its feasibility will depend on factors including:

1) The accuracy of the demand model; that is, whether it can produce a future demand year based on historical weather data to acceptable accuracy (noting this will be hard to measure).
2) The availability of reliable historical weather data.
3) Long term changes in weather/climate. It is reasonable to expect that over long periods of time (e.g. multiple decades) prevailing weather conditions will have changed in some locations due to climate change, local changes to geography, urban heat island effects, etc.

As a minimum first step, EY's analysis has shown that wind reference years could be selected in this manner (subject to points 2 and 3 above).

6.11 Modelling of demand

As has been discussed in the preceding sections, the modelling of multiple reference years is critical for incorporating the effects of intermittent generation. EY recommends that the reliability assessment process utilise Operational plus rooftop PV demand.

AEMO defines 'Operational' demand as follows:

> *the electricity used by residential, commercial and large industrial consumers, as supplied by scheduled, semi-scheduled and significant non-scheduled generating units.*

This definition does not include demand met by rooftop solar PV. That is, Operational consumption *decreases* as rooftop PV generation *increases*.

Because rooftop solar PV generation is quite significant, and varies by reference year in the manner described in section 6.8.1, EY regards it as very important to model explicitly so it may be varied by reference year.

EY understands that this is the same demand modelling approach employed in the 2016 ESOO so this does not represent a new approach for AEMO.

6.12 Convergence of probabilistic model

EY has investigated the number of Monte Carlo iterations required to achieve converged unserved energy outcomes. This was done by running a probabilistic study with a very large number of iterations (10,000) and then using this dataset to generate a large number of possible smaller studies (for example, choosing a large number of 200 iteration groups at random from the 10,000 iteration pool). This collection of samples can then be analysed to determine the expected variance in unserved energy in different iteration sizes.

All numbers are normalised to the expected USE outcomes from the 10,000 iteration totals. Therefore a value of say 1.2 on these charts would indicate that measured USE in that dataset was 20% higher than the averaged USE across all 10,000 iterations. The dataset chosen is a 10% POE 2016-17 case with (substantial) additional demand in each region to increase unserved energy to an order of magnitude similar to the Reliability Standard of 0.002%. The QLD and VIC regions exhibited very similar characteristics to NSW and thus were not included below. The series in these charts show POE values as measured for increasing numbers of iterations in the random samples. The 0% POE values are therefore equivalent to the minimum USE observed in the sampled data, while the 100% POE values are equivalent to the maximum USE observed in the sampled data. A 90% confidence interval can be observed in the chart; it is the area around the x-axis between the 95% and 5% POE series.

Figure 17 - Convergence of USE in NSW

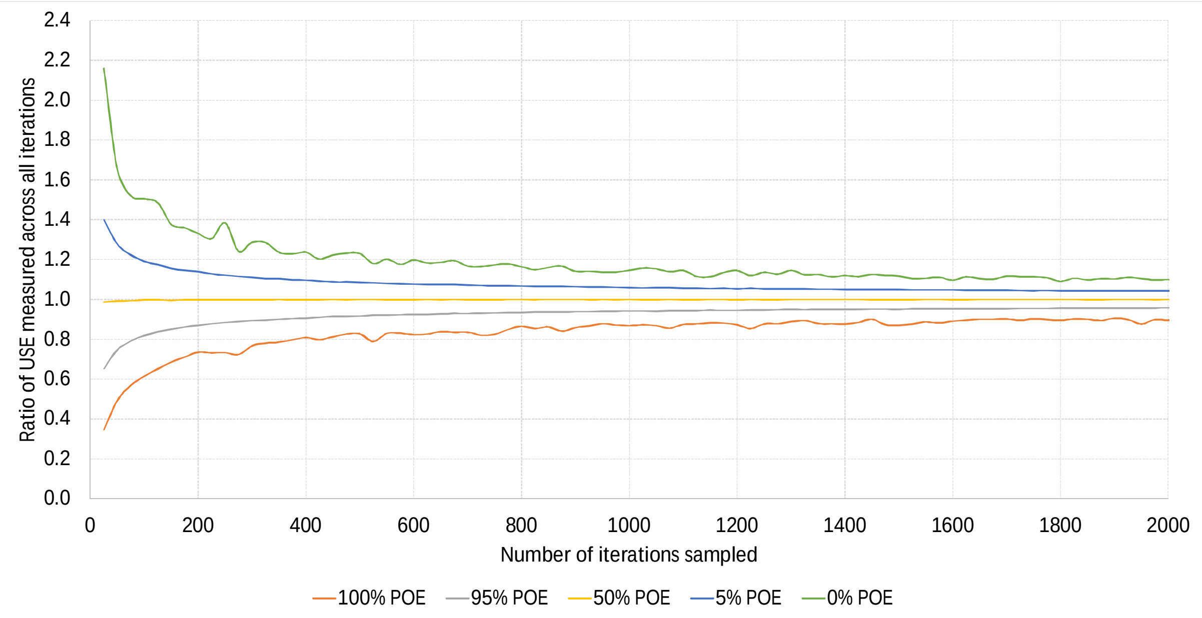
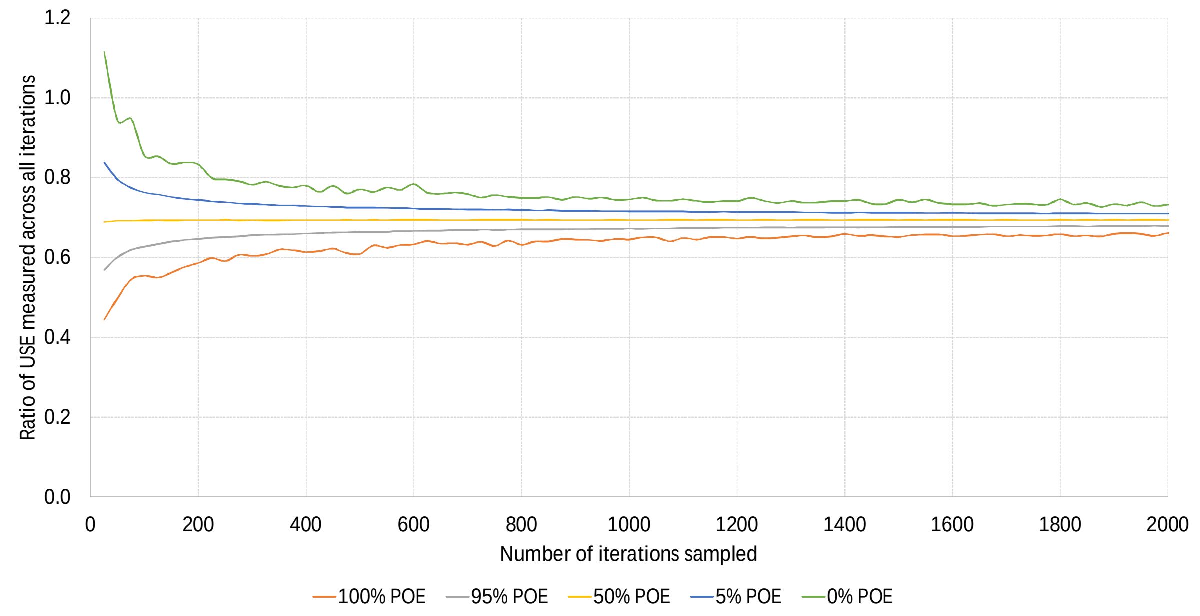


Figure 18 - Convergence of USE in SA



This analysis suggests that there is no practical number of Monte Carlo iterations that is sufficient to state without qualification that a study is converged. Instead, probabilistic models should aim to run as many iterations as can be reasonably done and recognise that there is some added uncertainty around the outcomes due to partially converged results. At iteration counts commonly used in NEM reliability studies (200 or more) this uncertainty is likely small in comparison to other sources of error in the inputs such as demand forecast error, availability measurement, and so forth. Based on this analysis, and especially considering the relative importance of a modelling a greater number of reference years, it is apparent that there would be diminishing returns from extending beyond approximately 200 iterations.

EY has recommended that AEMO conduct at least 200 iterations for all demand cases studied. While convergence analysis was done on a 10% POE peak demand case, there is no particular reason to expect that a 50% POE peak demand case will converge USE in fewer iterations – while it will almost certainly have less total USE, the underlying Monte Carlo outage distributions are the same and USE events may be rarer.

6.13 Modelling of energy limited plant

Energy limits are not expected to be a major factor in NEM reliability under normal circumstances as unserved energy is typically limited to a very small number of periods. While the EAAP process exists explicitly to evaluate their impact this was implemented towards the end of a major drought period and conditions were markedly different at the time. Tasmania is the region most impacted by energy limitations and short of a very detailed hydro model and a major Basslink outage or extended drought is highly unlikely to experience unserved energy in any model. The existing MTPASA weekly energy limits also have significant issues as discussed previously in 5.2.4.

As such EY suggests that explicit energy limit *optimisation* should not be a core requirement of a revised MTPASA process. For the purposes of a reliability study existing energy limits can be accurately represented heuristically in a traditional model that does not explicitly *optimise* energy use.

Nevertheless support for modelling energy limited plant is desirable and has the potential to be more valuable in the future if grid scale battery storage becomes economically viable. There are two common classes of energy limited optimisation:

Full co-optimisation with perfect foresight

This approach builds a single linear programming (LP) or mixed integer programming (MIP) problem that optimises dispatch of both energy limited and unconstrained plant across the solution timeframe. Constraint equations with nonlinear right hand sides are problematic as they cannot be represented in a LP or MIP and nonlinear solvers introduce significant performance and reliability issues in comparison.

As many constraints equations used to represent transmission limitations in the NEM have nonlinear RHS calculations this methodology is not well suited for PASA.

Multi-stage optimisations

Multi-stage optimisations rely on one or more pre-processes featuring a subset of all available information to break down multi-period energy limits into a plan or allocation per period that may then be used in a traditional time sequential model. The time sequential model must then adjust these allocations 'on the fly' to account for differences in conditions between the pre-process and final dispatch. This adjustment is done heuristically and may have a significant impact on results. This also presents some challenges when comparing very similar datasets as the differences introduced by the heuristically adjustment may not be consistent across datasets.

AEMO's existing modelling platforms are all variants of this approach and it is commonly supported by modelling software. EY recommends this approach if an energy limited optimisation is required as a fully co-optimised approach is not suitable with the transmission constraint equations employed in the NEM.

6.14 Presenting outcomes of assessment

The results of the reliability assessment must be published in a manner that makes them understandable and useful. In particular, the users of this information, such as generators, DSM providers, network service providers and AEMO itself should be able to readily digest the information and make at least some assessment as to how they could potentially change the outcome if they altered their behaviour.

As a reliability assessment, the key output of interest will be unserved energy. In Figure 19, we show the suggested method by which unserved energy would be communicated to the market. This figure shows the spread of unserved energy results across the first year of our hypothetical study of 2016-17 for the NSW region. These charts should be published for each region and for each of the two years in the study horizon. A graphical output like this with daily resolution will provide a quick visual snapshot of where high risk periods are located across the modelling period. The underlying data should be published also – perhaps sorted by decreasing likelihood of USE as shown in Table 7 - as reading detail (e.g. specific dates) from such a chart is challenging. Showing the number of USE events as well as the median and maximum USE outcomes on the days gives information about the relative 'shape' and 'depth' of the USE distributions on each day.

Figure 19 – Distribution and severity of NSW Unserved Energy events in 2016-17

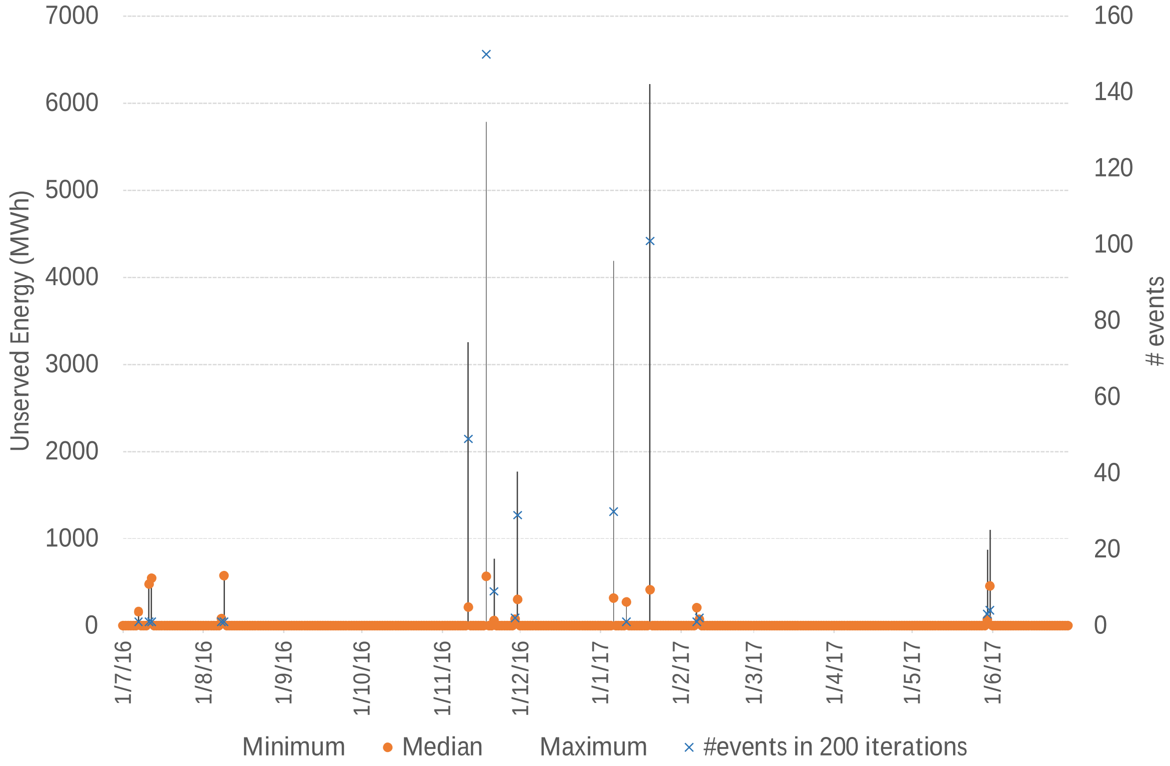


Table 7 - NSW Unserved Energy events: 2016-17

Date	Frequency of Unserved Energy	Max Unserved Energy (MWh)	Min Unserved Energy (MWh)	Median Unserved Energy (MWh)
20 Nov 16	75%	5,800	0	700
19 Jan 17	53%	6,200	0	500
10 Nov 16	25%	3,300	0	230
9 Jan 17	15%	4,200	0	340
...	...	...	...	...

Using the example information in the chart and figure above, it is apparent that the bulk of significant events occur in November and January. Therefore participants may take this information and choose to alter their plans to avoid reduced availability in those times. Similarly, these would be the events that AEMO would focus on should actions on their part prove necessary.

7. Computational feasibility of recommended solution

EY undertook a feasibility assessment to determine the practicality of running the scale of model recommended. To do this, trial simulations designed to be very similar to the kind of simulations that would be run under the reliability assessment process were executed on a modern modelling platform maintained by EY. EY also examined the capabilities of AEMO's existing modelling platforms to assess their suitability to the anticipated modelling.

7.1 Dimensions of required simulations

Drawing on the full recommendations as per Section 6, the dimensions of the full simulation set that must be conducted per reliability assessment can be laid out as per the following (note other model requirements listed in section 6.4):

- Medium economic growth, 10% POE demand case
- Medium economic growth, 50% POE demand case
- 5+ reference years per demand case
- 200 iterations per demand case
- Half-hour simulation resolution
- Two-year simulation horizon

Multiplying these factors out gives a total 'iteration-year' (one Monte Carlo iteration of a year-long study) simulation count. This is useful as this is typically considered as the 'atomic' simulation unit; that is, a simulation that is not split up further into smaller 'chunks'. Doing this yields the following:

2 (demand cases) x 5 (reference years) x 200 (iterations) x 2 (years) = 4000 iteration-years at half-hourly resolution.

It must be carefully noted that this is a *minimum* requirement. In the following sections we explore how this simulation load could be accommodated on a modern simulation platform.

EY recommends that ideally the modelling platform employed would be able run this set of simulations overnight. This would allow users to configure a study during work hours, trigger it at the end of the day, and expect to analyse results when next they return. An 'overnight' run time therefore could be stretched to a period of about 17 hours (5pm to 10am the following day). This allows the simulation to complete overnight, while still having sufficient time to analyse outcomes and configure and launch another study the next day. EY has significant experience with large Monte Carlo studies and has found that study times in excess of about a day raise significant challenges for productivity. It is important to be able to accommodate time for checking the modelling accuracy, especially where manual inputs are required. Furthermore, AEMO is likely to have the need or desire to conduct sensitivity runs on occasion, for example to test the impact of significant changes in availability. If simulation times extending to multiple days, this could be a major impediment to efficiency and timeliness. Any MTPASA compliance obligations regarding the amount of time AEMO has to publish outcomes following receipt of submission by participants must also be considered.

On the basis of these considerations EY recommends that AEMO configure or adopt a system that allows a reliability assessment to be done in no more than approximately 17 hours and ideally much less. However this is naturally a cost benefit trade-off for AEMO to assess.

One viable method to reduce the amount of simulation effort required is to model the 10% POE case first (for all reference years). If this case has USE under the Reliability Standard, then it is reasonable to expect that when weighted with the 50% POE case (which should almost certainly have considerably less USE) then the outcomes will be under the Reliability Standard. However, for actual publication of expected USE, the execution of both cases will be necessary so this technique is only appropriate for trial runs and sensitivity assessments. Similarly, running a reduced set of iterations is an entirely appropriate way to test simulations to ensure the model is behaving as intended, but no conclusions about reliability outcomes are possible without the full 4000 iterations (or more).

7.2 Feasibility based on EY's current platform

In order to test the feasibility of this modelling, EY used its current modelling platform to execute simulation sets equivalent in configuration and complexity to those AEMO would need to run. EY's current modelling platform is a multi-user, multi-job distributed computing environment based on central database servers and an array of 10 consumer-grade simulation machines.

A 10,000 iteration test run was undertaken; that is, 2.5 times the simulation load anticipated. This took approximately 5 hours on the platform described above. A single iteration-year at half hourly resolution takes approximately 1-1.5 minutes on these machines. Based on this, it can be seen that a study described in this report would take approximately 2 hours on this simulation platform. This includes all result collation, although compiling summary reports would take additional time at the end. With recent hardware and scaling up to more machines this work could be completed in significantly less time than that; a runtime of an hour would be entirely feasible given the right hardware configuration.

In EY's experience adding additional computer processing power is cheap compared to analyst time and being able to run models quickly results in much more efficient use of time as well as being able to turn around studies rapidly.

7.3 Summary

EY has demonstrated using its internal simulation platform that achieving the desired performance goals is highly feasible using inexpensive computer hardware. A brand new complete hardware setup to execute the studies described might be expected to cost roughly $30,000 (AUD). EY has also assessed AEMO's existing probabilistic modelling platforms (at a high level), and has found that they appear technically capable of running the recommended assessment studies, although augmentation would be necessary to meet the recommended performance goals. Augmentation would come in the form of hardware augmentation (acquiring more simulation machines and server space) and software augmentation (including licencing costs and software customization as necessary). Hardware costs are likely to be a relatively small component of the total cost, depending on the platform.

EY recommends that AEMO conduct a detailed assessment of the cost and benefits of augmenting current systems or acquiring a new system to conduct the reliability assessment studies. This should take into account other simulation requirements AEMO has as well (ESOO, EAAP, NTNDP, etc.), as considering any modelling requirement in isolation is unlikely to produce the best overall result. Furthermore, EY recommends that it is likely to be worthwhile examining some of the key workstreams for producing inputs to ensure they can deliver the necessary information to this process in a timely and efficient manner. In particular, the process by which the time series data for various reference years is to be prepared for demand and intermittent generators may be quite labour intensive. An assessment of this looking for ways to automate or streamline the process is likely to be worthwhile. Note that EY has not investigated AEMO's processes specifically, but rather draws on its own experience preparing similar data sets.

8. Conclusions and Recommendations

EY determined that MTPASA is intended to fulfil two requirements:

1. Provide a high-frequency information service (3-hourly suggested) that gives a breakdown of the supply-demand situation for the MTPASA horizon, taking into account participants' MTPASA submissions around availability, energy limits and network conditions.
2. Assess expected system reliability on a regular basis (at least quarterly) for the MTPASA horizon and provide indicators for how reliability could be affected by participants' MTPASA submissions.

EY investigated the current MTPASA process in light of these requirements, and identified that:

1. The current 3-hourly supply-demand information process serves a useful purpose and largely fulfils the first requirement (excepting consideration of network conditions), though several minor alterations will significantly improve its utility and transparency.
2. Due to the use of Minimum Reserve Levels and the inability for the deterministic MTPASA reliability solve process to properly account for intermittent generation, the current reliability assessment process is not accurate or consistent. Therefore it should not be relied upon. Instead, AEMO, should rely on its probabilistic models for reliability assessment at this point in time.
3. The current MTPASA process does not accurately compute energy limit impacts because of limitations inherent in deterministic models, however in any case optimizing energy limits is likely undesirable in a reliability assessment.
4. The current MTPASA process does not accurately compute network transfer capabilities, although no particularly good way of doing so exists. This is because network limits cannot accurately be represented by a single number as they are a function of generator dispatch pattern (amongst other things).

Upon reaching these conclusions, EY was tasked with proposing a best-practice approach to conducting a NEM reliability assessment while also considering obligations around energy limits and network capabilities. Detailed consideration of intermittent generation in particular showed that a deterministic approach – that is, an approach where the outcome is determined entirely by the initial inputs, with only one solution possible – is not suitable for assessing compliance with the Reliability Standard in the NEM. Therefore a probabilistic Monte Carlo model featuring was proposed which, while computationally intensive, is very much feasible with readily available hardware and software.

In depth analysis showed that two critical factors that the modelling must incorporate are the inclusion of multiple reference years[22] to capture both the year to year variation in behaviour of intermittent generation and variation in inter-regional demand correlation. EY's analysis in particular showed that:

1. Wind generation is correlated with other nearby wind generation, but not with demand or solar generation, meaning that the reference year for wind generation may be selected independently from demand.
2. In the limited dataset available, solar generation was not found to correlate with demand, despite sharing some underlying drivers (such as insolation). Therefore it may be feasible to select solar reference year independently from demand (and wind) but EY favours revisiting this in 12-24 months when considerably more operational data from solar generation will be available[23].

[22] A reference year refers to a historical year (e.g. the financial year 2015-16) where the time-series of demand, wind and solar generation are known or can be modelled with sufficient accuracy. This reference year is then projected forward to model forecast years, maintaining relationships between demand, wind generation, solar generation and other factors.

[23] Almost all existing data is from small generators or is re-constructed via models and therefore may not be representative of true behaviour.

To achieve the recommended changes to MTPASA, EY recommends that AEMO do the following:

1. Implement the described alterations to the MT PASA information process as soon as possible (including RSIG or Rule changes if necessary). This includes:
    a. Providing further categorization of generation, identifying non-energy limited controllable generation, potentially energy limited generation, wind generation, solar generation, and other non-scheduled generation
    b. Removal of all reserve level / MRL references
    c. Demand published on an Operational plus rooftop PV basis (see description in section 6.11)
2. Develop a program to implement the (at-least) quarterly reliability assessment process using an existing or new probabilistic modelling platform. This program will require RSIG and Rule changes to accommodate as the frequency will no longer be weekly. The RSIG should be considered for listing possible triggers for the reliability assessment to be run out-of-cycle. Key attributes of the new probabilistic reliability assessment process are detailed below.
3. Continue to conduct existing probabilistic reliability modelling as necessary to supplement current MTPASA processes until such time as the new reliability assessment mechanism is ready.

The key attributes recommended for the new reliability assessment process using the probabilistic model are:

Study dimensions

- ► 200 iterations per reference year and demand case combination to achieve reasonable convergence
- ► 5+ reference traces for demand, solar and wind per demand scenario
- ► Half hourly simulation resolution
- ► Two year simulation horizon

Demand

- ► Operational demand plus rooftop PV and non-scheduled intermittent generators modelled explicitly (see section 6.11)
- ► Primary scenario to be modelled is medium economic growth 10% POE
- ► Evaluate medium growth 50% POE as well if 10% POE USE scenario is above the Reliability Standard

Generation

- ► Generator availability as per MTPASA declarations
- ► Model longer term energy limits heuristically[24] (specifics to be addressed on a case by case)
- ► Investigate merging EAAP (GELF) and MTPASA energy limit submissions and reporting
- ► Rooftop solar PV modelled explicitly and varying by reference year
- ► Significant intermittent non-scheduled generation (particularly wind farms) modelled explicitly and varying by reference year

Network

- ► System normal constraint set (incorporating feedback constraints) invoked in all periods
- ► Outage constraint sets invoked as appropriate

EY has demonstrated that a study of these dimensions could be run overnight on a relatively inexpensive array of computer hardware. It is also feasible that AEMO's existing probabilistic modelling platforms could be used to run this modelling, though augmentation of those platforms would be required in order to achieve the necessary minimum performance goals.

The recommended processes would generate the following information:

[24] Long term energy limits should not be expected to influence bulk reliability outcomes – it is reasonable to assume that large scale storages will have some energy available during high risk periods.

- Every 3 hours:
  - Regional supply-demand information aggregated to the regional level for each generation type, including information about assumed behaviours of rooftop PV, non-scheduled generation, other intermittent generation. Generation would also be split between non-energy limited and energy limited.
  - This information would cover requirements of clause 3.7.1(c), 3.7.2(f) items 1 through 5.
- At least quarterly and when circumstances materially change:
  - All the information included in the 3-hourly process, plus a system reliability projection including identification of compliance with the Reliability Standard and designation of high-risk days[25], network limit information and generator energy limit information.
  - This information would cover requirements of clause 3.7.2(f) items 5A, 5B and 6 although this information would no longer be computed on a weekly basis.

In summary, this project has clearly shown that changes to the MTPASA process are due, and there is some urgency in doing so owing to emerging inconsistency in information reported, and the rapid and expanding penetration of intermittent technologies, which is one of the key drivers behind this emerging inconsistency. The proposed alternative is practical, addresses current concerns and is resilient to a wide variety of future changes. It is consistent with the kind of model many markets are moving towards elsewhere in the world.

EY also regards that an accurate reliability assessment process is critical to the NEM and to AEMO for it to discharge its obligations under the NER/RERT. The cost of ownership of such a process should be very much lower than the potential cost of unnecessary or inappropriate intervention in the market and thus is very much consistent with the National Electricity Objective of delivering reliable supply to consumers at efficient cost.

[25] That is, days with high potential risk of Unserved Energy occurring.

Appendix A Glossary

AEMO	Austalian Energy Market Operator
EAAP	Energy Adequacy Assessment Projection
ESOO	Electricity Statement of Opportunities
GELF	Generator Energy Limitations Framework, part of the EAAP process
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LOR	Lack of Reserve
MRL	Minimum Reserve Level
MTPASA	Medium-term Projeted Assessment of System Adequacy
NEFR	National Electricity Forecasting Report
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
PASA	Projected Assessment of System Adequacy
PDPASA	Pre-dispatch Projected Assessment of System Adequacy
POE	Probability of Exceedance
PV	Photo-voltaic (as in photovoltaic solar panels)
RERT	Reliability and Emergency Reserve Trader
RSIG	Reliability Standards Implementation Group
STPASA	Short-term Projected Assessment of System Adequacy
USE	Unserved Energy (un-met customer demand)

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