ST PASA Replacement

Functional Requirements

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Intelligent Energy Systems

SW Advisory

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1 Introduction

AEMO has contracted Intelligent Energy Systems (IES) and SW Advisory (SWA) to assist AEMO to develop the functional specification of a ST PASA replacement. A key input into this process has been our discussions and meetings with a wide range of stakeholders regarding ST PASA and closely related issues. From these discussions we have developed high level objectives and requirements for the system that will replace the current PD PASA and ST PASA systems.

The PD and ST PASA systems are the core systems used by AEMO and market participants to warn them if there are any system reliability issues in the pre-dispatch and short-term time frame.

The objective of the ST PASA Replacement Project is to conduct a holistic review of the PD/ST PASA methodology and develop a system that would serve the NEM now, and into the future.

For convenience, generally in this document, we will use the term ST PASA to include both PD PASA and ST PASA unless stated otherwise or clear from the context.

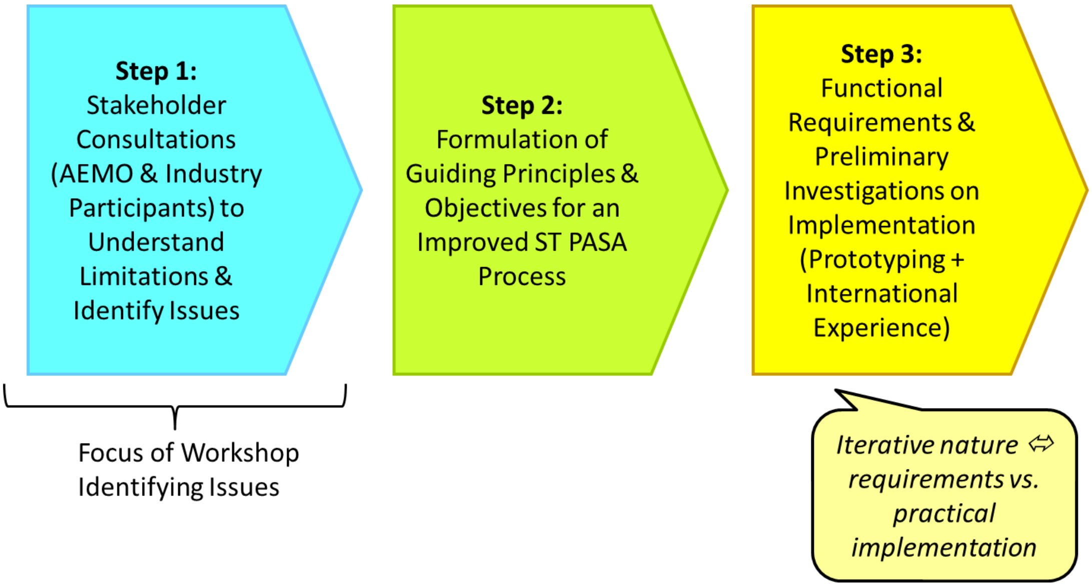
1.1 Overview of Process to Determine Functional Requirements

The approach that IES & SWA used to determine the functional requirements and potential solutions for a new ST PASA system was an iterative one, illustrated in Figure 1-1.

The main features of our approach were as follows:

1. We undertook extensive consultations with AEMO and the industry to understand the limitations of the current ST PASA and identify the key issues;
2. We formulated high level objectives and requirements for ST PASA which were used as guiding principles for the development of the functional requirements;
3. We reviewed international practice with respect to managing system reliability and security to see what was done elsewhere;
4. AEMO surveyed energy management system (EMS) and market management system (MMS) vendors to see what capabilities their IT systems offered to address some or all of the redeveloped ST PASA requirements;
5. AEMO, in consultation with us, developed a proof of concept security constrained schedule optimisation using a full network model;
6. In consultation with AEMO, we developed a framework for incorporating uncertainties about loads, VRE generation, available dispatchable generation etc. into reliability margins that could be incorporated as inputs into a security constrained schedule optimisation; and
7. We developed the functional requirements via a number of iterations between the development of the requirements and investigations into how feasible the draft requirements were to implement through the steps outlined in points 3 to 6.

Figure 1-1 Iterative Approach for Determining ST PASA Functional



1.2 General Objectives of ST PASA

The ST PASA system is the core systems used by AEMO and market participants to warn them if there are any system reliability issues in the pre-dispatch and short-term time frame.

ST PASA has the dual roles of providing information for market participants to respond to the market's power system needs and, if there is not an adequate response from participants, for AEMO to intervene in the market to manage system security and system reliability.

AEMO may use different operational levers such as rescheduling network outages, recalling generators that would otherwise be unavailable and/or activating RERT resources to maintain system security and reliability.

AEMO would like the new ST PASA system to provide a mechanism to assist AEMO, when required, to develop a RERT schedule at least expected cost.

The PD PASA and ST PASA systems are key NEM risk management systems. They should be able to effectively and robustly assist with the analysis of key risks and how they might impact system security and reliability. Most of the key risks involve uncertainties or random variables and how they may affect the dispatch process and consequently system security and reliability.

2 Security and Reliability

2.1 Introduction

The ST PASA system is meant to indicate whether there could be reliability or security issues over the next seven days. However, before discussing what this means in terms of modelling and optimisation, it is useful discuss what security and reliability mean within the context of the NEM. In some markets and power system these terms are used interchangeably but in the NEM they have quite distinct meanings.

2.2 NEM Power System Security and Power System Reliability

In the NEM, power system security and power system reliability are two quite different but related concepts. A power system could be in a secure state with load shedding and thus not be in a reliable state. Similarly, a power system might have no load shedding but be in an insecure state.

A power system is in a reliable state if there is no involuntary load shedding.

A power system is in a satisfactory operating state when:

- Frequency is within the normal operating frequency band, except for brief excursions outside the normal operating frequency band but within the normal operating frequency excursion band;
- All plant (generators, transmission lines etc.) are operating within their relevant ratings for voltages, currents, real and reactive power output etc.;
- The configuration of the power system is such that the severity of any potential fault is within the capability of circuit breakers to disconnect the faulted circuit or equipment; and
- The conditions of the power system are stable.

A power system is in a secure operating state if:

- The power system is in a satisfactory operating state; and
- The power system will return to a satisfactory operating state following the occurrence of any credible contingency event or protected event in accordance with the power system security standards.

In the case of post contingency operation of the power system, the NER states:

> 4.2.6 General principles for maintaining power system security
>
> The power system security principles are as follows:
>
> (a) To the extent practicable, the power system should be operated such that it is and will remain in a secure operating state.
>
> (b) Following a contingency event (whether or not a credible contingency event) or a significant change in power system conditions, AEMO should take all reasonable actions:

(1) to adjust, wherever possible, the operating conditions with a view to returning the power system to a secure operating state as soon as it is practical to do so, and, in any event, within thirty minutes; or

(2) if any principles and guidelines have been published under clause 8.8.1(a)(2a), to adjust, wherever possible, the operating conditions, in accordance with such principles and guidelines, with a view to returning the power system to a secure operating state within at most thirty minutes.

Thus, AEMO's objective following a contingency is to return the power system to a secure operating state within 30 minutes. This does not mean that AEMO can't shed load and have the power system in an unreliable state. Therefore, to model reliability, security also has to be modelled as security takes precedence over reliability.

2.3 Managing Security and ST PASA

As part of its role in managing the NEM, AEMO aims to maintain the power system in a secure operating state. This is largely managed via the dispatch process which uses NEMDE to determine a security constrained dispatch for all dispatchable resources. The security constrained dispatch tries to ensure that the forecast demands are met whilst ensuring that all dispatchable resources are dispatched within their ratings and offered capabilities and that following a credible contingency the power system is in a satisfactory operating state. Thus, part of the security constrained dispatch is to ensure that there is enough FCAS to meet the pre and post contingency requirements to manage frequency within the frequency standards.

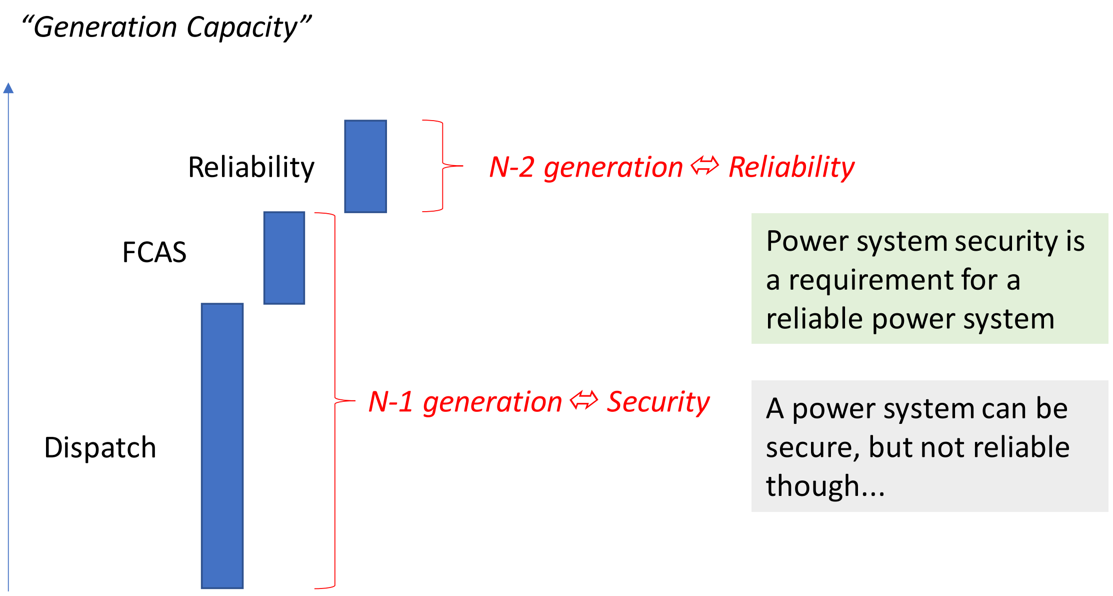
In terms of modelling for ST PASA we are looking at having enough generation and transmission to have reliable and secure operation. The secure operation is determined by the N-1 security constrained dispatch and the inclusion of FCAS or a reasonable proxy for FCAS capability. However, this does not guarantee enough generation to be reliable.

In the current ST PASA, modelling security and reliability is done in an approximate way by having some constraints that reflect some of the N-1 network security constraints and having a requirement that there is a reserve margin of the two largest generating units. In the reserve margin approach, the first unit essentially satisfies the security requirements for FCAS and the second unit is essentially a reliability margin. This is illustrated in a stylised manner in Figure 2-1 and importantly the second unit only really takes into account one large unit forced outage over and above what is catered for via FCAS. The second unit does not take into account the variability of loads, VRE generation and additional generation unit forced outages. Also, ST PASA looks at the load forecast uncertainty via the modelling of 50% POE demands with load forecast uncertainty modelled as an offset to minimum reserve level.

The POE50 forecast is the expected value forecast or "most probable". The POE10 and POE90 forecast values are calculated by applying a scaling factor to the POE50 forecast value. The scaling factor is calculated based on the historic forecast errors and assumes a normal distribution for forecast errors and uses the t-distribution to produce a confidence interval. For a given region and the scaling factor is function of forecast interval lead time (forecast horizon), temperature (three categories are used: cold, normal and hot), and day type (2 categories are used: weekday or weekend/holiday). For each region and for each forecast interval lead time there are six potential scaling factors that could be applied. The one that is applied depends whether the forecast interval is cold, normal or hot and whether it is a weekday or weekend/holiday. The scaling factors are calculated about once every few years.

The problem with the two unit reserve margin approach has been recognised with the development of the forecast uncertainty measure (FUM) which tries to account for these other sources of randomness that can impact system reliability. However, the FUM is only a post processing tool for the output of the ST PASA. Further, the physical assumptions implied in FUM's forecast uncertainties may not be appropriate assumptions all of the time. If ST PASA is to become a more realistic model of the power system, then some of the variability modelled in FUM needs to be incorporated into the ST PASA optimisation which can then ensure that the impacts of the uncertainties are picked up through a model that better reflects the physical characteristics of the system.

Figure 2-1 Stylised Illustration of Power System Security and Reliability in the NEM



2.4 Reserve Margins and Reliability

The current PD and ST PASA approach of requiring a reserve margin of the two largest units for each region does not represent equally reliable outcomes over time or across regions. It does not adequately account for the random deviations of loads and VRE from forecasts and generator forced outages. The ST PASA reserve margin is not based on an appropriate probabilistic analysis and hence does not effectively and efficiently help with the management of system reliability.

A reserve margin of two units half an hour out is going to give much greater reliability than a reserve margin of two units 7 days out. Looking at the period up to 30 minutes ahead, the probability of two independent forced outages of larger generating units in a region is extremely low, and hence not credible. On the other hand, over a period of 7 days multiple units could fail with a probability that is not extremely low. Additionally, the load and VRE forecast errors will generally be much larger for forecasts made for 7 days ahead compared to 30 minutes ahead.

Ideally the two-unit reserve margin should be replaced by a probabilistic calculation that gives equally reliable outcomes looking out from ½ hour ahead to 7 days ahead. Such a calculation should be based on the probabilities of unit forced outages and the probability distributions of the deviations of loads and VRE generation from their forecast. In effect this would bring some of the logic from FUM to create a reliability reserve margin which would be used as input into the scheduling optimisation.

2.5 Reliability and the Forecast Uncertainty Measure (FUM)

The Forecast Uncertainty Measure (FUM) a mechanism for incorporating the forecasts errors associated with the main random variables that can affect the estimated regional reserve margins, the forecast regional excess supply (RXS). The FUM uses a Bayesian belief network (BBN) to determine a forecast error distribution for RXS. In the case of BBN, the forecast error distribution is a posterior probability distribution based on observed values of prevailing weather conditions and system state and the use of Bayes theorem.

A full description of the FUM is provided in AEMO's Reserve Level Declaration Guidelines[1]. For the purpose of this report we will just summarise the key features of the FUM.

The regional excess supply (RXS) is calculated as the sum of the following:

- + Aggregate capacity of scheduled generation in the region, calculated as:
  - + Aggregate Non-Energy Limited Capacity
  - + Aggregate Energy Limited Capacity
  - - Aggregate Semi-Scheduled Output
- + Interconnector Support
- + Aggregate Semi-Scheduled Output
- - Scheduled Demand.

The RXS error is the difference between forecast RXS and actual RXS:

RXS Error = Forecast RXS – Actual RXS for a particular forecast and a point in time.

The FUM for a region, point in time and set of expected conditions, is the number of MWs representing the quantity of RXS for which AEMO determines a specified confidence level of the RXS error not exceeding that number of MWs. The confidence levels are determined in accordance with clause 3.4 of AEMO's Reserve Level Declaration Guidelines. When setting the confidence levels AEMO aims to achieve an appropriate balance between load shedding due to lack of action and likelihood of unnecessary declarations due to an overly conservative confidence level. The FUM is just used for the first 72 hours of the LOR assessment horizon.

AEMO uses the following inputs when estimating the RXS error distribution:

1. Forecast lead time;

[1] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Reserve-Level-Declaration-Guidelines.pdf

2. Current temperature at the reference weather station within the region;
3. Forecast temperature at the reference weather station within the region;
4. Forecast solar irradiance at the reference weather station within the region;
5. Current demand forecast error for forecast lead times below 24 hours;
6. Forecast output of semi-scheduled generating units;
7. Current supply mix by fuel type (coal, gas or hydro);
8. Regional reference price ($/MWh); and
9. Time of day (daytime / night-time forecast).

The main problem with the FUM is that it only addresses the randomness of forecast errors at a regional level and as a post processing activity after the ST PASA optimisation, thus the implications of the forecast errors on network constraints, use of batteries and energy limited plant can't be effectively picked up in the ST PASA optimisation. Further, the FUM with its use of current supply mix by fuel type (coal, gas or hydro) and use of regional reference price is indirectly doing some level of dispatch that could be better accounted for in an ST PASA model that reflects the dispatch of the physical system. Our recommended alternative approach is to apply similar logic to the FUM but do it for the inputs to ST PASA and let the optimisation determine the implications.

2.6 Security Constrained Dispatch and Schedules

2.6.1 Security constrained dispatch

Essentially a security constrained dispatch minimises the dispatch costs or maximises the value of trade subject to meeting the loads and keeping the system in a secure operating state. In general, this means:

- Dispatching generating unit within their technical and offered constraints;
- Ensuring that there is enough FCAS enabled to meet the FCAS requirements;
- Ensuring that all network elements and load and generation plant are operated within their continuous ratings for voltages, currents, real and reactive power output etc.;
- Ensuring that all network elements and load and generation plant are operated within their short time ratings following a credible contingency event:
  - network forced outage;
  - generator forced outage; and
  - load forced outage.

2.6.2 Security constrained schedule

A security constrained schedule is an optimised dispatch schedule over a time period, say one day or one week ahead, which minimises the dispatch costs or maximises the value of trade over the whole time period subject to meeting the forecast loads and keeping the system in a secure operating state.

A security constrained schedule may optimise resources over time such as the operation of energy limited hydro units, charge / discharge cycles of batteries, hydro pumped storages and other energy storage systems, resources with unit commitment limits and other similar operational limits.

3 Feedback from Stakeholder Consultations and Workshop

3.1 Stakeholders

There are several stakeholders within and outside AEMO involved in the development, operation and use of ST PASA.

The key stakeholders of the PD and ST PASA systems within AEMO are the NEM Operations staff responsible for maintaining power system security and reliability in real time as well as forecasting any power system security and reliability issues in the pre-dispatch and short-term time frame. There are also several teams within AEMO that are responsible for providing data that feed into these systems. This includes information on network constraints, load forecast, variable renewable generation forecasts etc. The other stakeholders of these systems within AEMO are the ones responsible for related processes like MT PASA, Reliability and Emergency Reserve Trader (RERT) and Gas operations. There are several programs running within AEMO that also have synergies with this project e.g. Energy storage systems, Virtual power plants, Wholesale demand response, 7 day pre-dispatch, and Future design of the NEM.

Key external stakeholders were as follows:

- Market Participants:
  - Generators;
  - Retailers;
  - Gentailers;
  - Wind and solar generators;
  - Energy storage system operators and managers;
  - Virtual power plant managers;
  - Demand managers;
- Transmission Network Service Providers (TNSPs);
- Market operations service providers:
  - Consulting, procurement and management services;
  - Software and decision support;
- Regulators:
  - AEMC; and
  - AER;
- Banks with interests in the NEM;
- Industry bodies:
  - Australian Energy Council;
  - Clean Energy Council;
  - Energy Consumers Australia; and
  - Queensland Electricity Users Network.

3.2 Stakeholder Consultations

We had small group discussions with all of the stakeholder groups within AEMO that were identified by AEMO's project team.

We had one on one meetings with a range of Market Participants which included nearly all of those that had registered an interest in being involved in the ST PASA consultation process. The market participants with which we consulted had businesses that covered all regions and included a good range of generators, retailers, gentailers, wind and solar generators, energy storage system operators and managers, virtual power plant managers and demand managers etc.

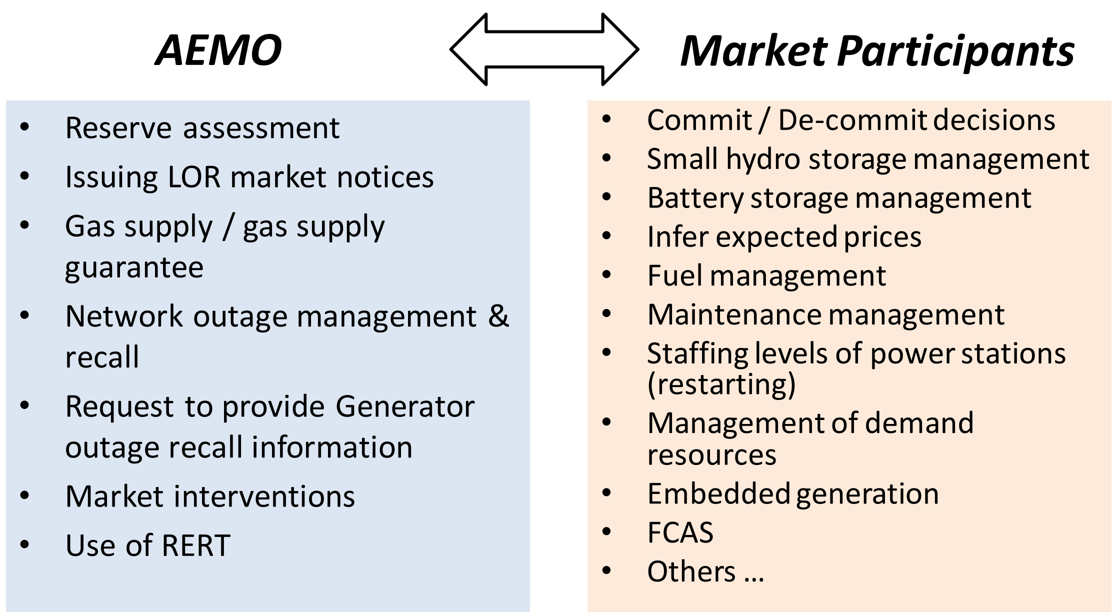
To complement the information gathered in the small group meetings, AEMO held an industry workshop on 28th February 2020 which was attended by a variety of stakeholders. The industry workshop was primarily set up to invite those from the industry who had not had the chance to discuss ST PASA at one of the earlier meetings. However, the workshop was also attended by some industry representatives who had had one on one meetings.

At the workshop, AEMO presented an overview of the project and IES & SWA presented the common themes and issues identified during their previous stakeholder discussions and opened these up for feedback from the attendees. AEMO, IES & SWA also followed this up with further individual discussions where required.

3.3 ST PASA Information and Decision Making

Key to understanding the requirements of a new ST PASA is to understand what decisions are being made on the 0 to 7 day timeframe by AEMO and the industry. The decisions made by AEMO and the industry (including market and non-market organisations) over the 7-day horizon are shown in the following diagram:

Figure 3-1 Decisions Made 0 to 7 Days Ahead



AEMO's gas supply operations use 7 day pre-dispatch, ST PASA and gas bulletin board to make projections of gas supply and demand on east coast and to manage gas supply guarantee.

Market participants generally make their decisions on the 0 to 7 days ahead timeframe by combining information from pre-dispatch, 7 day ahead pre-dispatch and ST PASA to form an overall picture of the market's projected prices and supply and demand balance. The types of decisions being made depend on the portfolio of assets they are managing. The information they use are projections of demand, VRE generation, prices, LOR levels etc. Some market participants only use ST PASA's 50% POE forecasts

The main decisions made by market participants using this combined information are:

- Commitment and decommitment and minimum loading decisions;
- Small hydro storage management:
  - smaller storages are optimised over a one to two week period;
- Battery management - 7 day ahead pre-dispatch is used whereas ST PASA is of limited use and is only looked at to get an idea of what AEMO may require;
- Determining the best time and prices to generate;
- Maintenance decisions and outage planning;
- Management of gas-based generation including unit commitment and management of gas supply;
- Coal supply management, some coal supplies are managed on a just in time inventory basis;
- Management of fuel supplies in general;
- Management of manning levels to start units (even though a unit could start from cold in 10-14 hours there may not be the staff available to do so);
- Load / contracted demand response services management;
- Management of embedded generation:
  - look a week ahead for diesel plant operations: fuel supply, staffing etc.;
- Short term contracting;
- FCAS provision and preparation of emergency reserves for RERT:
  - ST PASA information gives views of supply demand balance and provides preparation time in case RERT contracts get called; and
  - assists with the management of energy limitations of batteries, diesels and load management.

3.4 The Main Issues with the Current ST PASA

The main issues that stakeholders have identified with the current ST PASA are:

- ST PASA regional model does not adequately reflect physical reality:

- the inability of the model to reflect the power system correctly when there are losses of network elements not intersecting with regional boundary or when the system islands at places other than the regional boundaries;
- does not adequately model intra-regional constraints nor system post network contingencies:
  - network model is not consistent with physical reality;
  - network constraints do not reflect the actual locations of loads within a region (AEMO does forecast some zonal loads);
  - the constraints required to model the network following major network outages are not available hence the model doesn't reflect physical reality;
  - does not provide accurate information on what would happen following an intra-regional transmission related credible contingency;
- load shedding is not consistent with physical reality;
- does not model system strength issues; and
- does not model FCAS requirements.

The lack of physical reality makes it difficult to interpret what the results mean and reduces stakeholder's confidence in the results.

- Energy limited resources are not modelled adequately, and the optimisation of battery storages is problematic – e.g. not reflecting cycles within a day;
- In some instances, the results do not guide unit start-up decisions very well, particularly for intermediate plant;
- Power system security issues not modelled under all conditions – e.g. minimum demands;
- Not all required power system services are modelled in ST PASA framework:
  - FCAS not included – so some security / reliability issues may be missed – which is important as VRE levels rise,
  - Inertia, synchronous units within some regions, or adequate levels of ramping capability
- The results are not always accurate, and the meaning of the results is not always clear;
- The accuracy and resolution of forecasts for demand, wind and solar could be improved;
- Weather random variables are not always adequately captured within the modelling of reliability and security risks:
  - high temperature simultaneously affecting unit ratings / transmission line ratings;
  - wind speeds and impacts on multiple turbines;
  - variable cloud cover impacts on PV outputs;
  - dust storms, bushfires, cyclones, floods and other similar phenomena;

  There are potential issues around not modelling the impacts of concurrent small events.
- Issues around the treatment of resource availability:

- ST PASA availability is not the same as offered max available:
  - Max available is commercial availability;
  - PASA availability is technical capability with a 24 hour recall;
- available generation capacity does not mean that there is necessarily going to be an adequate supply of fuel;
- different availabilities can cause problems with AEMO interventions and use of RERT;
- modelling capacity alone doesn't reflect energy limitations; and
- use of 24 hour recall doesn't fit all resources – e.g. some have 36 hour recalls or lead time / limitations of some demand resources;

- Inconsistencies between ST PASA and 7-DAY pre-dispatch;
- Lack of transparency in preparation of inputs and classification of credible contingencies;
- There is a large volume of potential constraints and not all participants have the resources to analyse the sheer volume of information;
- There is no pricing information provided with the ST PASA;
- Many participants would like to get more clarity on shortfalls:
  - better quality and more timely information,
  - what were the binding constraints (network, FCAS etc.), and
  - management of discretionary generation.

The majority of stakeholders agreed that each item listed above was an issue. For a number of identified issues, some stakeholders were happy with the current ST PASA while the majority of others wanted changes.

4 High Level Requirements for ST PASA

4.1 Key High Level Requirements

Based on the discussions with all stakeholders, the workshop and our own analysis and discussions with AEMO, it was agreed with AEMO that the key requirements for a replacement of ST PASA are as follows.

1. The system must be able to consistently indicate whether there are any potential reliability or security issues for the full range of credible scenarios. It is not adequate for the system to just deal with ordinary outages, high loads etc. The most taxing reliability and security issues are likely to occur with unusual events such as:
    a. islanding not on regional boundaries;
    b. multiple transmission line outages which could affect intra regional and inter regional power flows such as ones that can occur with disruptive weather events such as bushfires, cyclones, very high temperatures etc.; and
    c. multiple generator outages or output reductions caused by high wind speeds, high temperatures etc.

    The ST PASA system should be viewed as a key NEM risk management system and thus should be able to effectively and robustly assist with the analysis of key risks and how they might impact system security and reliability. It should not go missing when the going gets tough.

2. The system needs to be fit for purpose for Australia's future power system as it could be in 2030. Even though all forecasts of what the future power system in 2030 will look like are likely to be inaccurate, it is highly likely the power system will include:
    a. a technology mix characterised by high levels of Variable Renewable Energy (VRE);
    b. high levels of penetration of battery energy storage systems (BESS);
    c. Increased levels of distributed energy resources (DER);
    d. higher penetration of end use appliances that are responsive to prices and demand (DR); and
    e. be designed to accommodate a wider range of credible threats to power system operations.

    The system needs to have flexibility built into the design to cater for future needs that were not anticipated at the present time, or that could not initially be implemented within the new system.

3. ST PASA should provide sufficient and timely information about system security and reliability issues to AEMO and the industry such that:
    a. market participants can respond to the likely power system need; and
    b. if there is not an adequate response from participants, AEMO may use different operational levers such as rescheduling a network outage, intervening via directions or activating RERT to maintain system reliability and security.

    ST PASA should provide a transparent mechanism to assist AEMO, when required, to develop a RERT schedule at least expected cost.

4. There should be consistency between PD PASA and ST PASA to the extent which is logical given the time horizons of their optimisations and the frequency with which they are run.

   An outworking of this could be to merge PD PASA and ST PASA where they use the same model but which is run more frequently for shorter time horizons and less frequently for longer time horizons and the runs for longer time frames could provide information to the shorter time horizon runs to help manage things like energy limits.

4.2 More Detailed High Level Requirements

This section outlines the higher level requirements for the ST PASA replacement but in greater detail. These requirements were developed in order to:

- Meet the key high level requirements outlined above in section 4.1;
- Address the most important issues identified through the consultations and workshop; and
- Provide the improvements required by AEMO's operational areas and participants to improve the efficiency of their activities on the 0-7 day timeframe.

The high level requirements were agreed with AEMO and are as follows:

1. ST PASA should model/reflect physical reality and address both security and reliability issues:
   a. More accurate modelling of energy limited plant and energy storage systems;
   b. Be able to model network constraints that could impact on generation and loads including post contingency network constraints;
   c. Be able to model multiple line forced outages as a credible pre contingency and also to model post contingency scenarios;
   d. Be able to automatically generate thermal constraints for the network model, particularly for post contingency scenarios;
   e. Be able to model FCAS and future FCAS requirements to a level sufficient to identify potential security problems including any potential lack of lower services;
   f. Be able to model ramp rate constraints and identify ramping issues (this is a problem in a number of markets with high penetration of VRE);
   g. Be able to model gas flow constraints that could affect multiple units that do not have common ownership or control;
   h. Be able to model distributed energy response (DER) and wholesale demand response; and
   i. Be able to identify low inertia or system strength issues.

   Without a model that reflects physical reality it will be impossible for AEMO's operational areas and market participants to have any confidence in the results and actions that AEMO takes to intervene in the market. Further a model that reflects physical reality will be a model that is easier to maintain and adapt as the power system changes.

   Another way of thinking about this high level requirement, is to imagine the power system as being run by a vertically integrated utility and think about what sort of system it would use to manage reliability, security and dispatch. There is no doubt in such a situation the utility would use a model that reflected physical reality. It would not use some simple abstraction that just fitted with some simple market arrangement.

Low inertia or system strength issues could be identified by post processing the results from the ST PASA optimisation. In some cases, it might be feasible to introduce binary variables to indicate whether units should be committed to meet inertia or system strength requirements though implications on computational time would have to be investigated.

2. Improved forecasts of demand, wind and solar by location, preferably at the substation / transmission connection point level.
3. Move from adding the uncertainty measures to post ST PASA runs, as is done with FUM, to modelling the uncertainties via the inputs to ST PASA. This could include adding uncertainty measures into the forecasts to deal with randomness of demand, solar and wind. This approach would focus on modelling, as inputs to ST PASA:
   a. the uncertainties / probability distributions of key inputs such as demand, wind generation, PV generation etc.; and
   b. the uncertainties / probability distributions of factors that may affect multiple inputs such as temperature affecting demands, generator ratings and network ratings, high wind speeds leading to wind turbines disconnecting, bushfires affecting multiple transmission lines etc.

   The actual physical assumptions behind FUM may not be valid for any time period. Thus, it makes a lot more sense to add the uncertainty measures into the inputs for ST PASA and let the ST PASA optimisation model process these uncertainties via its physical model of the power system.
4. The system should allow for different recall times for generators and in its reliability and security assessment identify if any resources are scheduled for a possible recall.

   On this issue, a participant wrote:

   > "Currently, we understand that AEMO does not use declared *PASA availability* in the PD/ST PASA reliability assessment, only generating units bid *available capacity* is used in the reliability assessment. We believe this results in forecast outcomes of a Lack of Reserve (LOR) condition that is then generally removed during the Pre-Dispatch period. We would support a change to the definition of *PASA availability* to that which can be made available within the time period – *PASA recall time* as set out in the PASA bid with participants required to submit both a *PASA availability* (MW) and *PASA recall time* (hours) submission. AEMO would then utilise *PASA availability* in the reliability assessment calculation when appropriate to do so, i.e. the time period covered by the *PASA recall time*. We believe that up to a 72 hour period should be allowed for a maximum *PASA recall time* submission and that this information would provide improved information regarding generating unit status to AEMO."
5. The system should provide the ability for Operations Planning and RTO control room to model their own scenarios based on a base case.

This is important for the operations areas to identify and manage risks to the power system.

6. The system should provide repeatable and clear results to indicate that there could be a reliability or security issue.

   This is important for AEMO's operations areas to identify and manage risks to the power system and to justify any decisions.

7. The system should provide information on whether interventions or RERT will be triggered and for the system to provide a mechanism to assist AEMO, when required, to develop a RERT schedule at least expected cost.

8. The system should provide greater transparency of inputs and outputs including information on forecasts of demand, wind, PV, wholesale demand response, binding constraints etc.

9. ST PASA should have the capability to be run:

   a. over multiple time horizons,
   b. at different frequencies,
   c. on demand, and
   d. as multiple processes.

   These parameters should be configurable to the extent that the solution times are compatible with the chosen time horizons and chosen frequencies of the ST PASA runs. The multiple processes requirement is to enable multiple concurrent runs to cater for on demand runs and multiple time horizon runs.

10. To ensure consistency between ST PASA and other AEMO systems such as pre-dispatch and 7 day pre-dispatch, ST PASA's base case runs should use the same input data, where appropriate, for load forecasts, network availability, unit availabilities etc.

    Note that the additional available capacity based on unit recall times would be regarded as additional input data, not different input data to pre-dispatch and 7 day pre-dispatch.

Not all of the above requirements may be able to be met and for the ST PASA replacement system to run in acceptable time. However, it is difficult to tell what is possible until some experimenting with prototypes is undertaken.

In addition to the ST PASA requirements, there is a requirement for a real time (RT) PASA system to give an indication of whether all reserve or reliability requirements will be met over the next 5 minutes given the current state of the power system. This system would be primarily for the use of AEMO's control room staff and would reflect power system state data from the SCADA system.

4.3 Requirements Worth Considering

The following are potential ST PASA requirements that may be worth considering:

1. Providing projections out to 14 days;

2. Improved forecasts of demand, wind and solar by location at the substation / transmission connection point level could include demand price sensitivities to reflect non centrally managed or non-market participant demand responses; and
3. Improving the consistency of AEMO forecasts and generator forecasts of their unit availabilities by ensuring the use of consistent assumptions regarding weather conditions for all loads and generation units in a zone.

   There are a couple of approaches to how this could be done. AEMO could provide its zonal weather forecasts to all generators in a zone and ask the generators to determine their unit availabilities based on these forecasts or AEMO could ask generators to provide their weather forecast assumptions when they provide their forecasts of availability. AEMO needs to ensure that it uses consistent assumptions regarding weather for all generators in a zone.

4.4 Conclusion

The higher level requirements developed in this section were based on the discussions with all stakeholders, the workshop and our own analysis of what we think are the key requirements for a ST PASA replacement. These requirements were agreed with AEMO. However, until extensive prototyping of the ST PASA system is undertaken or AEMO finds suitable off the shelf software, it is difficult to tell whether all of these higher level requirements can be met. The prototyping and AEMO's communications with EMS vendors might reveal that there are difficulties in satisfying all of the requirements. There may be trade-offs between what requirements can be implemented and the desired solution times. Thus, the requirements may need to be modified in light of any prototyping studies and detailed feedback from EMS vendors.

5 Review of International Practice

5.1 Purpose of Review

One input into this process is a review of international practices for similar systems to better understand how other markets address the same problem. This report provides the findings from the international review.

The overriding objective of the international comparison / review is to provide a comparison of the AEMO's short-term projected assessment of system adequacy (ST-PASA) and the 7-day pre-dispatch processes to alternatives that have been implemented in other electricity markets.

5.2 Markets Reviewed

The following markets were reviewed:

- Electricity Reliability Council of Texas (ERCOT);
- California Independent System Operator (CAISO);
- Pennsylvania New Jersey Maryland (PJM);
- Midwest Independent System Operator (MISO);
- Alberta Electric System Operator (AESO);
- Ontario Independent Electric System Operator (IESO);
- New Zealand Electricity Market (NZEM);
- Vietnam Wholesale Electricity Market (VWEM); and
- Philippines Wholesale Electricity Spot Market (WESM); and
- Europe (ENTSO-E).

5.3 Comparison of Approaches

The results of the international review are presented in the summary tables of Table 1 and Table 2. The tables compare the approaches used internationally to manage power system reliability and security based on a number of important reliability, security, forecasting and dispatch modelling criteria.

Table 1 Summary of Assessment of Markets: ERCOT, CAISO, PJM, MISO and AESO

Aspect	ERCOT	CAISO	PJM	MISO	AESO
Reliability Standard	Unlike other US markets, ERCOT has no mandated planning reserve margin or enforced minimum acceptable loss of load probability. Unlike other US markets, it does not implement a capacity market and there are no obligations on load serving entities to have capacity under contract to meet forecast peak.	Follows a reliability standard based on 1 day in 10 year loss of load measure. California load serving entities are required to procure capacity equal to 115% of their peak load, which means there is adequate capacity under most conditions.	Follows a reliability standard based on 1 day in 10 year loss of load measure. Load Serving Entities (LSEs) are required to procure an adequate amount of capacity 3-years ahead (through capacity markets) to cover projected peak demand + margin, which means adequate capacity is in place under most conditions.	Follows a reliability standard based on 1 day in 10 year loss of load measure. LSEs are required to procure adequate levels of capacity ahead of time (through capacity markets) to ensure enough capacity under most conditions	There is no mandated planning reserve margin or minimum acceptable loss of load probability However, AESO does forward-looking assessments of reliability to inform the market of opportunities 5-years ahead In this process AESO uses a reliability standard of no more 0.001% of USE per year as the desired level of reliability
Market Price Cap	9,000 USD/MWh [13,806 AUD/MWh]	1,000 USD/MWh [1,534 AUD/MWh] (with some exceptions having been allowed by FERC)	1,000 USD/MWh [1,534 AUD/MWh] Demand bids capped at 2,000 USD/MWh [3,068 AUD/MWh] – 3,700	Generation offers are capped at 1,000 USD/MWh [1,534 AUD/MWh] (some transactions are allowed to occur at higher prices)	Market cap in AESO is 1,000 CAD/MWh [1,143 AUD/MWh].

Aspect	ERCOT	CAISO	PJM	MISO	AESO
			USD/MWh [5,675 AUD/MWh].		
Credible Contingency Definitions for Generation	Power system is operated to protect against the largest double outage of generation (N-2) – which is a 2750 MW outage (ó 2 units of a nuclear power station). Ramps for VRE (wind mainly) on different timescales are monitored but do not exceed the size of the largest generation outages.	Power system operated to cover the largest credible loss, which is presently 3000 MW Pacific DC tie line.	N-1 standard used and represented in market processes	N-1 standard used in market processes	N-1 standard. AESO procures enough reserves to withstand the largest single generator contingency or 3% of net generation, whichever is larger.
Credible Contingency Definitions for Transmission	N-1 contingencies reflected in the market processes for all transmission lines of 0.8 km or longer.	N-1 transmission network contingencies are accounted for.	N-1 transmission network contingencies are accounted for.	N-1 standard used in market processes	N-1 standard AESO posts information about planned transmission outages to the market.
Credible Contingencies – Handling Other Special Events	Events that may result in multiple outages are managed by a separate process whereby directions are given to market participants.	The ISO may also take special measures to protect against other "credible threats" to power system operations – typically by committing more	Procedures in place for handling weather events and environmental emergency conditions. These procedures give the operator discretion to	Combinations of generator + transmission outages are also reflected. Have measures to allow more reserves to be set aside in pre-defined zones if	

Aspect	ERCOT	CAISO	PJM	MISO	AESO
		generation. These are not explicitly represented in market processes.	manage the events as necessary through directions. Commands issued by the system operator are reflected in real-time pricing. However, when market actions are not sufficient for controlling a contingency, out of market actions would be taken as needed.	needed. Extreme conditions are managed via directions. Ramp services have been introduced to address the ramp up/down of variable renewable energy.	

Aspect	ERCOT	CAISO	PJM	MISO	AESO
Reliability Monitoring Processes for 1 day to 1 month ahead timeframe	Day-Ahead Reliability Unit Commitment (DRUC) Daily, 1-day ahead, 1-hour resolution, based on a deterministic unit commitment model. Week-Ahead Reliability Unit (WRUC) Daily, 1-week ahead, 1-hour resolution, based on a deterministic unit commitment model. These models complement the RTM, DAM and a 1-hour ahead RUC.	Residual Unit Commitment (RUC) Run after the DA market, for a period of 3-days ahead, 1-hour resolution, based on a deterministic unit commitment model. This model is run in addition to the RTM and DAM	Reliability Assessment and Commitment (RAC) Run daily for 1-day ahead, with 1-hour resolution. Operator has discretion to order the commitment of additional units, but there is no explicit reliability modelling on timeframe of greater than 1 day. PJM posts system conditions to the market through website, including weather conditions, 7-day load forecast, planned transmission & generation outages, and emergency alerts. These models are run in addition to RTM, DAM, and a Capacity Market.	Day-Ahead Reliability Assessment Commitment (DA-RAC): Run daily for 1-day ahead with 1-hour resolution. It is run after the DAM. Week-Ahead RAC (WA-RUC): Run daily for 1-week ahead, with 1-hour resolution. These models are run in addition to RTM, DAM, and a Capacity Market.	Short-Term Adequacy Assessment With hourly granularity representing each dispatch interval over a one-week horizon, the assessment ran every 5-minutes for the current day (Day 0), whereas for Day 1 to Day 7 assessment is ran hourly.
Approach / Style of Model(s)	Models for DRUC and WRUC have the same basic formulation.	DA market and RUC are both based on deterministic security	Deterministic unit commitment model.	Currently implemented as a deterministic unit commitment model.	The model simply assesses maximum generation capacity of dispatchable

Aspect	ERCOT	CAISO	PJM	MISO	AESO
used for Reliability	Determine based on load and point renewable forecast, if the committed resources can reliably meet demand within N-1 constraints. Does not represent price-responsiveness nor uncertainty in RE generation. ERCOT doesn't have any significant storages, so these are not modelled. Nodal model of power system with automatic constraint generation procedure used to iterate between a MIP solving the unit commitment and the evaluation of binding and violated transmission constraints.	constrained unit commitment Nodal model of power system with sN-1 constraints are represented within the RUC model		RAC minimises the additional commitment costs (start-up and no-load costs but omits incremental energy costs) to commit enough capacity (that is, in addition to the capacity committed in the DA market) to meet the ISO forecast of demand. It is formulated as deterministic unit commitment and dispatch, with N-1 constraints represented. Price-based demand response is represented. Research is ongoing into the formulation of a stochastic unit commitment model though.	units that are online or capable of being brought online, plus distributed generation, aggregate solar and wind production, and intertie import capacity and compares this maximum supply to a forecast of the sum of (a) peak load less price responsive and other adjustable load, plus (b) spinning reserve requirements, to forecast a "supply cushion" for each hour No representation of intertemporal linkages, transmission limits are not apparently considered, and uncertainties in renewables and demand are not represented.

Aspect	ERCOT	CAISO	PJM	MISO	AESO
Load Forecasting Method that is used in reliability monitoring process	Uses nodal load forecasting method	Uses nodal load forecasting method	Uses nodal load forecasting method	Uses nodal load forecasting method	System-wide load forecasting method
Type of Modelling System / Software	DRUC and WRUC have been developed based on customising some off-the-shelf unit commitment software	Procured as part of the market management system (MMS) for CAISO.	RAC is implemented using standard unit-commitment software.	Procured as part of the market management system (MMS) for MISO.	In-house developed system.
Decisions that the system / market operator makes based on the outcome?	Based on the results, the ISO may direct commitment of additional units based on the WRUC and DRUC results.	Issues binding commitment decisions for the next day.	RAC is primarily used to commit steam units to meet forecasted load and operating reserve requirements, if these requirements are not met by capacity committed in the market. The operator has discretion to take additional measures under emergency conditions.	Issues binding commitment decisions for the next day.	If a shortfall is anticipated then AESO can request voluntary reductions in load, reduction of distribution voltage by 3%, various actions aimed at increasing imports or decreasing exports, and can enact curtailment of load. The AESO has a dedicated 21-step action plan to manage a supply shortfall resulting from its Short-

Aspect	ERCOT	CAISO	PJM	MISO	AESO
					term Adequacy Assessments
Information Provided to Participants	All results are published to market participants.	Generally, results for only the first 24 hours are published to the market.	Information is not widely published to the market – mainly the information is provided to units that need to be committed in addition to those that are already committed.	Results are posted to market participants and emergency alerts issued if there are shortages anticipated.	Results of the adequacy assessments are published. AESO also provides transmission outage schedules to market participants.

Table 2 Summary of Assessment of Markets: IESO, NZEM, NEMS, WESM and Europe (ENTSO-E)

Aspect	IESO	NZEM	VWEM	WESM	Europe (ENTSO-E)
Reliability Standard	NPCC standard of load expectation (LOLE) of disconnecting firm load due to resource deficiencies is, on average, no more than 0.1 days per year."	No quantified reliability standard.	Grid code does not define a formal reliability standard, however, in practice, Vietnam power system is planned to be no more than 24 hours per region per year of energy not being served.	Grid Code requires grid planning studies to consider the Loss of Load Probability (LOLP) and/or an Expected Energy Not Supplied (EENS), while the standard is not stated in the Grid Code, we understand a 1 day in 10 years of LOLP is used.	Vary between countries. No unified measure is used. Some countries express the reliability standard in terms of LOLE (from 3 hours/year in France to 8 in Ireland), while other countries do not have a quantified standard (Germany and Finland).
Market Price Cap	2,000 CAD/MWh [2,286 AUD/MWh]	No cap. The default value of lost load in the Code is 20,000 NZD/MWh [19,160 AUD/MWh] but it is not used to cap electricity prices.	The VWEM in 2019 applied a SMP cap to energy of 1,319,000 VND/ MWh [86.90 AUD/MWh], and a maximum capacity price of 192,000 VND/MWh [12.65 AUD/MWh]. Together, this effectively placed a maximum wholesale price cap in the VWEM of 1,511,000 VND/MWh [99.55 AUD/MWh] in 2019.	32,000 PhP/MWh [987 AUD/MWh] There is also a secondary price cap[2] mechanism, which caps electricity prices to 6,245 PhP/MWh [193 AUD/MWh] if the average price over a 72-hour period exceeds a threshold of 8,186 PhP/MWh [253 AUD/MWh]	The price caps on the European Power Exchange (EPEX) is 3,000 Euro/MWh [5,073 AUD/MWh] for the day-ahead market and 9,999 Euro/MWh [16,908 AUD/MWh] on the intra-day market. Day-ahead markets are more highly coupled than intraday markets in Europe

[2] Similar to the Cumulative Price Threshold concept in the Australian market.

Aspect	IESO	NZEM	VWEM	WESM	Europe (ENTSO-E)
Credible Contingency Definitions / Approach	The IESO/NPCC classifies a 'Single Contingency' as a "single event, which may result in the loss of one or more elements." Multiple components that are involved in a Single Contingency are related by situations leading to simultaneous component outages In the event of a Single Contingency with multiple components, IESO will trigger an Emergency Operating State, where it will follow the 42-Step Emergency Operating Control Plan for restoration back to a Normal Operating State.	The loss of a single generator or network element including a single pole of the HVDC link between the two islands, defined in Part 1 of the Code.	N-1 for both transmission and generation.	N-1 for both transmission and generation. For generation within a region, the larger of the largest credible loss of power imports or loss of largest generator (N-1) The system operator is required to identify credible multiple contingency events, with limits to protect the power systems to be determined and provided to IEMOP (the market operator) to be reflected in the real-time dispatch.	The loss of a single generator or network element.
Reliability Monitoring Processes for 1 day to	Pre-Dispatch Dispatch and Scheduling Optimization (DSO) Algorithm	The risk of energy shortfall is assessed and communicated through Electricity Risk Curves	Year-Ahead Plan (YAP) and Month-Ahead Plan (MAP) Stochastic hydro-thermal optimisation model to	Both the System Operator (SO) and Market Operator (IEMOP) have a number of processes that are used as	Week-ahead Week-ahead adequacy assessment. Hourly resolution or finer.

Aspect	IESO	NZEM	VWEM	WESM	Europe (ENTSO-E)
1 month ahead timeframe	Run hourly with hourly granularity for rest of day and includes day-ahead horizon following DACE (see next point). Each hour is optimized as a separate least-cost solution, with no intertemporal links. Day-Ahead Calculation Engine (DACE): Least cost optimisation of energy and operating reserves for the 24 hours of the next day. Deterministic unit commitment model that includes a reliability unit commitment run. Full nodal network model of power network used. Near-Term Adequacy Assessment): Uses an in-house engine to calculate both Energy and Capacity supply adequacy	(ERC). The ERC combine hydro storage levels with data and a standard set of assumptions to assess the risk of shortfall. At predetermined levels of a risk of a shortfall occurring, the SO can declare an Official Conservation Campaign in which customers are asked to voluntarily reduce consumption. If the response is insufficient the SO may implement rolling outages.	account for hydrological uncertainty. Week-Ahead Plan (WAP) Deterministic week-ahead optimisation model run with periodicity of 1-day and 1-hour resolution based on bids/offers of generators and constraints on hydros from the MAP / YAP modelling. Week-Ahead Unit Commitment (WAUC) Deterministic unit commitment model run in parallel to the WAP, but with focus on determining unit commitment schedules of generators – which is in turn used by SMO / generators to understand their commitment.	part of the process of reliability assessments in the Philippines. The SO runs weekly and daily operating program process that is a simple regional computation of operational reserves which are compared against the required levels. The IEMOP runs a Day-Ahead Projection (DAP) (updated every hour with 4 demand sensitivities) and Week Ahead Projections (WAP) (updated every 24 hours).	Month and seasonal assessments also follow the same methodology. The methodology proposed by ENSTO-E will be approved by ACER in March 2020 and implemented within a year.

Aspect	IESO	NZEM	VWEM	WESM	Europe (ENTSO-E)
	with hourly granularity over a 34-day horizon. Publishes frequent adequacy assessment reports for market participants. These processes complement the Real-Time Dispatch and Scheduling Optimisation (DSO) which determines market dispatch and pricing.		SMO also monitors current and projected water levels of all hydro reservoirs as part of generally monitoring risks to supply. If risks assessed to be high, SMO may intervene in the market – directing back-up generators and taking other measures.		
Approach / Style of Model(s) used for Reliability	Dispatch engine using back and forth linear programming and AC power flow model to solve least-cost security constrained solutions Deterministic unit commitment Nodal model of power system	Incorporates statistical elements such as in demand forecasting and using historical inflow data to determine Electricity Risk Curves.	Stochastic Dual Dynamic Programming model is used to do hydro-thermal optimisation, the results of which are used as part of a shorter-term deterministic unit commitment model.	The SO's operating programs are simple supply-demand balance models. DAP and WAP are based on deterministic unit commitment models.	Optimisation of probabilistic demand, supply and grid availability scenarios based on the Monte Carlo method. Scenarios based on weather forecast information and ENSTO-E databases. Probabilities utilise historical information and mean time to return into service.

Aspect	IESO	NZEM	VWEM	WESM	Europe (ENTSO-E)
					Optimisation engine utilises a unit commitment and economic dispatch (UCED) model.
Load Forecasting Method that is used in reliability monitoring process	Nodal load forecasting methodology is used.	While NZEM is a nodal market for the purpose of security-constrained economic dispatch and locational marginal pricing, the reliability processes that we have identified for New Zealand are focused more on modelling hydro reservoirs and risk curves which are combined together and used to determine whether to invoke water conservation measures. There is no load forecasting used for this purpose.	Regional load forecasts are used – most of the modelling for market / system operation processes in Vietnam is based on a 3-region model.	Nodal load forecasting methodology is used in the DAP and WAP processes. The SO's methodology (which is quite simplistic) implements a regional forecasting methodology.	Regional / zonal forecasts are used.
Type of Modelling System / Software	All use house calculation engines: PD and RT DSO, DACE, Adequacy, and load forecast	Standard optimisation program although external providers are employed to provide a forecast of large hydro generation plant.	An off-the-shelf hydro-thermal optimisation, which uses a stochastic dual dynamic programming,	DAP and WAP are implemented using a customised Market Management System (MMS) product which is an	Optimisation engine utilises a unit commitment and economic dispatch (UCED) model.

Aspect	IESO	NZEM	VWEM	WESM	Europe (ENTSO-E)
			model is used for MAP / YAP modelling. A unit commitment product is used for week-ahead unit commitment modelling of the WAP / WAUC.	off-the-shelf software product customised to satisfy WESM requirements. The SO's operating programs are done as simple calculations in a spreadsheet.	
Decisions that the system / market operator makes based on the outcome?	Day-Ahead Calculation Engine 'Pass 2' allows for deterministic unit commitment. Cost-Guarantee compensation program to ensure reliability & compliance of generators. Adequacy Assessment Publishing information necessary to allow the market to react to adequacy concerns;	If the risk of shortfall, as assessed under the SOSFIP, exceeds 10% and is forecast to continue to do so for at least one week, the SO declares an OCC. During an OCC, customers voluntarily reduce their electricity usage and are compensated by the retailers for doing that. The SO may declare an OCC in respect of the South Island only, or for all of New Zealand. The OCC stop trigger is 8%. The triggers balance the cost of starting OCCs earlier than needed	Monitoring of the hydro reservoir water levels and/or adequate / inadequate supply from YAP / MAP and /or WAP / WAUC may form the basis of market intervention actions from the SMO or in cases where there is load shedding projected, then results are used to guide the management of controlled load shedding.	The SO monitors the results of the IEMOP DAP and WAP and if power system reliability or security is determined to be at risk, they have different levels of intervention and/or direction that they may exercise.	TSO provides the relevant regulatory authority with an analysis of the causes of the absence of adequacy and propose mitigating actions. The RCC required to report results and provide proposed actions to the TSO when a critical grid situation is identified in the week-ahead adequacy assessment.

Aspect	IESO	NZEM	VWEM	WESM	Europe (ENTSO-E)
	Activating reliability must-run contracts to address local area adequacy only; Rejecting, revoking, and recalling outages; and Issuing system advisory notes with the expected actions to be taken.	and the cost of starting them later than needed and risking going into rolling outages.			
Information Provided to Participants	Adequacy Report Ontario Zonal Demand Report Transmission Limits All in Service Report Transmission Facility Outage Limits Report	The SO publishes the risk meter, weekly security of supply (SOS) reports, and ERC information.	Results of all processes are provided to Market Participants via the Market Participant Portal.	SO publishes the weekly operating program results and provides more detailed information to participants and to IEMOP on matters related to reliability management / monitoring. The IEMOP is required to publish all key results from the DAP and WAP processes to market participants and to public. The SO is required to issue market notices and warnings based on the state of the power system or if there are credible threats (e.g.	TSO provides the relevant regulatory authority with an analysis of the causes of the absence of adequacy and propose mitigating actions.

Aspect	IESO	NZEM	VWEM	WESM	Europe (ENTSO-E)
				typhoons) likely to impact the operation of the power system.	

5.4 General Observations

The main trends that we observe from the markets that we have considered in our international review are:

- The main approaches that have been implemented are:
  - Use of off-the-shelf software products to do short-term reliability modelling for periods of time from 1 to 7 days ahead, which are typically done in Northern America markets, as additional "reliability runs" that are done after running their day-ahead markets.
  - Customised methods that generally involve simple projections of supply and demand and monitor a "supply cushion". These are common in "capacity-constrained" power systems where thermal generation is a significant portion of the fleet.
  - Use of methods that have been required in situations where hydro makes up a significant portion of the generation fleet. In such situations, handling uncertainties associated with hydro generation / hydrological conditions are required and the power system is of an "energy-constrained" nature.
- For the markets which have off-the-shelf models, the features of the model are in general full network model, inter-temporal constraints, automatic determination of network thermal and voltage constraints.
- The reliability standards tend to generally be defined as long-term standards (in terms of LOLP standard) and situations where the reliability standard is directly converted into a short-term or operational standard is not done. Instead, over shorter timeframes, the models / equivalent to a short-term reliability monitoring process will formulate a more extreme load forecast and assess its implications against the resources expected to be available. Where detailed models are used they make allowances for reserves and required power system security and have facilities to ensure that other credible threats to supply are accounted for on an "as needed basis" if the risk exists.
- Definitions for contingencies are generally based on the N-1 criterion with provisions to account for single events that could lead to multiple outages in dispatch and pricing. Many of the North American markets have single generator contingencies that are larger than the largest variations / ramps that could be attributable to wind or solar.
- Approaches for publication of the results vary in terms of the level of detail, but broadly, most of the markets reviewed will provide daily indications of credible threats to reliability, and/or they will be used as the basis of interventions in the market by the system and/or market operator. Key results of reliability monitoring results are generally made available to market participants. Other key indicators of expected supply/demand balances will often be published.

5.5 Implications for the NEM and AEMO

The international review provides insights and examples of how these issues have been addressed in other markets. We provide a preliminary assessment of the implications for AEMO based on the requirements from this document in Table 3.

Note that this preliminary assessment will be adjusted as part of developing the detailed requirements. The lessons are mainly drawn from the Northern American markets as they broadly have a uniform approach and have had to contend with technology mixes with a high level of renewable energy. Most of the non-North America market reliability processes rely on simplified methods that are either simpler or not vastly different to the ST PASA process in AEMO and so they don't provide a good basis for identifying ways to improve the existing ST PASA process.

Note also that another key implication from the review is that we consider it to be very important for AEMO to review and assess off-the-shelf software solutions offered by the vendors of EMS / MMS software platforms[3].

Table 3 Implications for NEM and AEMO

No.	High-Level Requirement	Common Approach in Other Markets (based mainly on North America experience)
1	ST PASA should model/reflect physical reality and address both security and reliability issues, including: • Energy limits • Physical network model • Contingencies • FCAS resources • Ramp limits • Demand-side resources • Recall times	As observed earlier, North American markets generally implement short-term reliability processes with features of the models generally being: • Intertemporal linkages (for energy limit resources) • Physical network models (locational network models) • Automatic generation of thermal constraints for security • Facilities to overlay additional security limits and/or reflect events that result in multiple outages of transmission or generation facilities • Inclusion of models to account for reserves • Reflection of ramp limits Less commonly, is the representation of demand-side resources and the concept of recall times is often addressed as outside the model or by determining the unit commitment of resources under more extreme demand conditions and providing that information to the market participant.

[3] Accordingly, we have recommended for AEMO to conduct a survey of the off-the-shelf software products that could satisfy the high-level requirements.

No.	High-Level Requirement	Common Approach in Other Markets (based mainly on North America experience)
2	Improved forecasts of demand, wind and solar by location	Nodal load forecasts are frequently implemented because the underlying models used for reliability have a full network model representation. Similarly, VRE forecasting systems in power markets with significant VRE are in place and done at the connection point level to also map the forecasts to nodal models.
3	Representation of uncertainties via the input processing into the ST PASA process model itself (rather than determining uncertainty measures based on post-processing of the results / outcomes)	The international experience identified in this review to handle this issue is very limited. The closest examples identified: • Re-running dispatch models with more extreme demand forecasts • Running sensitivities in demand • Stochastic optimisation methods based on hydrological scenarios • Custom designed risk assessments to hydro power
4	The system should allow for different recall times for generators and in its reliability and security assessment identify if any resources are scheduled for a possible recall.	There was also limited international experience to leverage in this area, beyond the fact that the North American markets make unit commitment decisions and these are used in the reliability runs to identify units that may not be committed in the Day-Ahead Market run, but which does need to be committed in the reliability run, hence it may need to be "recalled".
5	The system should provide the ability for AEMO to model particular scenarios of interest based on a base case.	The standard software products have offline / study modes of operation and facilities that enable this to be done – thus again, North America markets tend to address this well.
6	The system should provide repeatable and clear results to indicate that there could be a reliability or security issue	Most of the international markets reviewed a well-defined models, tools and processes for reliability modelling that are repeatable. A number of the markets reviewed also have clearly defined processes / methodologies that must be followed before declaring multiple outage events or fuel supply restrictions as credible threats to power system operation (and hence have them reflected in the reliability runs).
7	The system should provide information on whether interventions or RERT will be triggered and for the system to provide a mechanism to assist AEMO, when required,	The results of reliability runs in other markets are often the basis upon which the equivalent of RERT measures would be invoked. Although there were no examples within our surveyed markets where RERT resources were modelled in the same way that they are managed in the NEM at this time. This doesn't mean that they could not

No.	High-Level Requirement	Common Approach in Other Markets (based mainly on North America experience)
	to develop a RERT schedule at least expected cost.	be represented, but just that this would be a customisation to an off-the-shelf software product from a vendor – for example.
8	The system should provide greater transparency of inputs and outputs including information on forecasts of demand, wind, PV, wholesale demand response, binding constraints etc.	Provision of results to market participants and their publication varied considerably across the markets reviewed. As such, there are limited lessons to be drawn from the international review in relation to this requirement.
9	ST PASA should have the capability to be run over multiple time horizons, at different frequencies, on demand and as multiple processes.	Typical horizons that have been implemented in other markets are from 1 day ahead to 1 week ahead. Some markets reviewed have processes that extend longer though – typically those markets with hydro resources to manage – where the outlook period would be months to years ahead.
10	To ensure consistency between ST PASA and other AEMO systems such as pre-dispatch and 7 day pre-dispatch, ST PASA's base case runs should use the same input data, where appropriate, for load forecasts, network availability, unit availabilities etc.	The North American markets often implement the reliability processes using the same basic mathematical models and software as the market processes – e.g. the same model / software that does the day-ahead market (DAM) also does the reliability modelling.

6 Off-the-Shelf Market IT System Software Capability

6.1 Background

One of the key findings from the review of international practices was the use of standard software products to carry out reliability and security assessments. The reliability and security assessments generally used security constrained economic dispatch (SCED) software or security constrained unit commitment software (SCUC) as a key component of the assessment process. SCED and SCUC software are standard products that major EMS/MMS and power system optimisation vendors can provide.

6.2 Survey of Software Capabilities

AEMO sent requests for information to some energy EMS/MMS and power system optimisation vendors in order to ascertain the capabilities of their:

- SCED/SCUC scheduling systems and other components used to assess power system reliability and security, and
- Nodal load forecasting systems.

6.3 General Requirements for a Scheduling System

The vendors were informed that the aim of the scheduling system is to provide a security constrained dispatch schedule for 0 to 7 days ahead which can be used to identify any potential reliability or security issues. The system should be able to co-optimise energy and reserves using a full network model and nodal load forecasts.

The vendors were informed that the desired requirements for the scheduling optimisation system were as follows:

- Uses an optimisation written in a higher-level optimisation language such as AMPL, AIMMS, GAMS, OPL etc. or is written in such a way as it can be readily and easily modified;
- Uses a commercially available and high-level solver such as CPLEX, XPRESS or Gurobi.
- Can determine the least cost schedules for dispatchable generation units, loads and HVDC transfers on a half hourly basis from 0 to 7 days or alternatively can model on a half hourly basis for the first 24 hours and then for longer periods, say hourly, after that for the remaining 6 days;
- Can manage plant technical constraints such as maximum available capacity and raise and lower ramp rates;
- Can use bids/offers with up to 10 price and quantity pairs (bands);
- Can optimise the use of energy storage systems such as batteries and pumped hydro which could have multiple cycles over a day or cycles that extend over a week;
- Can optimise generating units with energy limits;
- Note: the system does not have to optimise unit commitments because generators make their own unit commitment decisions in the NEM;

- Can model the full transmission network, which includes some HVDC lines and phase shifting transformers, at least to the level of a DC load flow and a reasonable approximation of transmission losses;
- Can automatically generate N-1 network security constraints for:
  - thermal limits for network outages;
  - thermal limits for generating unit, load or HVDC outages;
- It would be desirable if the system could automatically generate constraints for voltage limits pre and post generation, load and network contingencies;
- Management of stability issues, possibly with pre-calculated constraint coefficients
- Can manage when some radial lines connecting generation or loads are not run on an N-1 basis;
- Can manage when there is islanding or when a single contingency could cause islanding;
- Can determine an optimal security constrained schedule (N-1 schedule) when multiple lines or generating units are classified as a single contingency;
- Can co-optimise energy and frequency control ancillary services (reserves);
- Can always solve through the use of soft constraints and violation penalties;
- Can use a network outage schedule provided in a standard power system format;
- Can update the current network model based on SCADA information on switching.
- Can be run on a periodic basis of, say,
  - Half hourly for a time horizon of 0 to 48 hours ahead; and
  - Every two hours for a time horizon of 0 to 7 days ahead
- Can be run on multiple machines and can have offline modes which may use different network models for scenario analysis, training, testing etc.

It may not be possible to readily satisfy all of the requirements above with some off-the-shelf software, so AEMO is interested in finding out what requirements these systems could satisfy and what might be the trade-offs between any requirements.

Vendors were asked 'if you have one or more systems that could meet most of AEMO's requirements, please could you provide AEMO information on the system:

- Any technical brochures or manuals;
- What are the components of the system?
  - Mathematical programming optimisation?
    - Is the model solved as linear programming optimisation, quadratic optimisation or non-linear optimisation?

      Note the required optimisation should be largely linear depending but this could depend on how transmission losses are modelled.
    - What optimisation language and what solvers are used?
  - AC power flow?
  - Contingency analysis?

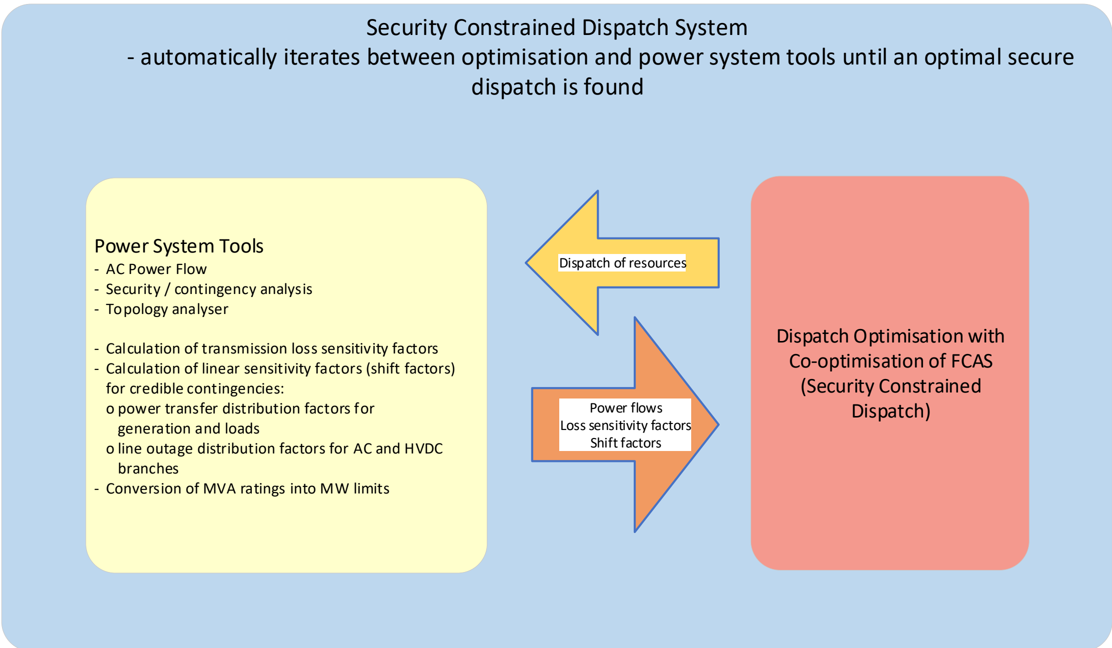
– System for generating linear sensitivity factors for outages?
– Subset of a SCADA or energy management system?
– IT system scheduling tool?

- Examples of where the system is running.
- What hardware and software platforms does the system run on?
- What requirements could the system satisfy and are there any trade-offs between some requirements?
- What would be the estimated solve time for the 0-7 day ahead optimisation? What would be the solve time assuming a warm boot or use of previous solve?
- Who should we contact to gather further information?'

6.4 Summary of Survey Findings

The surveyed EMS/MMS vendors confirmed that their systems could in general satisfy all of the requirements listed in section 6.3. The vendor systems can automatically generate a security constrained dispatch using a full network model that managed N-1 thermal and voltage constraints. Their systems can manage the security constrained dispatch by using an iteration between a dispatch optimisation (usually a linear program - LP or mixed integer linear program – MILP) and a network analysis system using power system tools comprising AC power flow, contingency analysis / N-1 network security analysis and topology analyser, see Figure 6-1.

Figure 6-1 Components of a Standard Security Constrained Dispatch System



A number of the EMS/MMS systems vendors suggested that they would like to check the performance of their standard systems using NEM data.

In conclusion the requirements set out in section 6.3 are likely to be able to be satisfied by a vendor largely using some of their standard commercial EMS/MMS software.

7 Proof of Concept Security Constrained Optimisations

AEMO, with the assistance of IES/SWA, developed several proof of concept/prototype security constrained scheduling optimisation models.

7.1 Prototype Security Constrained Dispatch Schedule Optimisation

AEMO developed a prototype optimisation which used a full network model for the whole of the NEM and determined a security constrained dispatch for each half hour for seven days, 336 periods. The optimisation model used:

- A lossless DC power flow model;
- The PSSE data for the NEM's full network comprising around 3,200 buses, 2,300 lines and 1,800 transformers;
- Steady state thermal constraints;
- N-1 thermal constraints to manage network overloads following a loss of a network branch;
- For each generator, offers made up of 10 tranches per period of random prices and a single tranche for FCAS;
- 10 units that were arbitrarily selected to have binding energy limits imposed to give some inter-temporal optimisation links; and
- No RERT constraints were modelled.

This optimisation model solves in around 8 minutes. However, the solution time with a much more highly constrained case such as with all loads scaled up by 50% can take much longer to solve, around 30 minutes. Thus, for the ST PASA model to provide useful results for a 7 day look ahead, it seems likely that it would take about 30 minutes to compute for some difficult scenarios and generally much less. In order to investigate immediate security and reliability issues, this could be addressed by running a version of the model that will run in less than 10 minutes with a look-ahead of say 24 hours. This run would need to use some of the information from the longer horizon model.

The model was not optimised for performance nor was the performance checked on different solvers to XPRESS such as CPLEX and Gurobi. Thus, it would be reasonable to expect the equivalent software provided by an EMS vendor would run faster or be able to have a more complex model that would run in a similar time frame.

Also, there are other avenues that could be considered to speed up the time necessary to find a solution. These include:

- Gains can be made by looking for good rather than optimal solutions.
- Less offer tranches could be used, all that is required is some sort of sensible ranking for dispatch purposes.
- Since we are dealing with a forecast of dispatches rather than the actual dispatch system, it seems viable to start solving sometime before the beginning of the first period using forecast data. The model will most likely be used for decisions days ahead and thus starting the model run 20 minutes before the first period would have little consequence

on decision making. This could buy a lot of time and enable a realistic physical model to be used and get good solutions, rather than poor model and second rate solutions.

- Another option is to use the idea of having cascading modelling windows. Using this framework, a realistic physical model with a shorter term modelling horizon with a shorter term solve could be kicked off closer to the beginning of the first period. This shorter term model would use the results from the earlier longer-term model to overcome any end effect issues and inter-temporal issues. For instance, the longer-term model could provide marginal values of energy or target storage levels for any of the energy limited plant such as batteries and hydro units.
- Lastly, the use of different granularities for the dispatch periods over the modelling horizon possible could help. The dispatch periods at the end of the modelling horizon could be longer than the earlier ones. This decreases the total number of periods we need to solve at once so makes the problem smaller. Similarly, longer periods could be used for longer term studies – it's the number of periods that hurts performance, not the actual look ahead window. On the other hand, if the same time intervals are used this may be more conducive to some methods that use the LP basis from the previous solution. As well, it should be noted that some EMS vendors don't think the use of varying dispatch periods would be particularly useful in speeding up the solution times when everything else is considered.

7.2 Proof of Concept RERT Optimisation

AEMO developed a proof of concept model to demonstrate how multiple ST PASA scenarios and a least cost use of RERT resources could be developed.

AEMO's proof of concept model considered the situation when there are multiple credible scenarios that could result in reliability issues. Under this situation, AEMO needs to make some decisions now to avoid a reliability issue (reserve shortfall) later. For the proof of concept model, AEMO assumed that the only action AEMO could take was to activate RERT contracts. The question then becomes which RERT contracts to activate for the least expected cost. The optimal solution is likely to use contracts that can cover one or more of the scenarios.

Theoretically, the least expected cost solution could be found by using stochastic programming. In the case of ST PASA, you could combine a base case with one or more scenarios into a single stochastic program. The base case and each scenario would be given a probability and the probabilities would have to sum to 1. When using this framework, the optimisation can require that the same units are committed for both the base case and each reliability scenario. For the NEM this would be the commitment of RERT resources. In essence, this is a very simplified form of a stochastic unit commitment optimisation. This scenario framework can be extended to many scenarios but the number of constraints and variables in optimisation tends to grow in proportion to the number of scenarios and thus the solution times will tend to become significantly longer. That is, we could solve this as a single large LP, but it would quickly become unworkable for real world data as the number of scenarios increase because each scenario will have to have its own dispatch of units, power flows on the network and binding network constraints.

An alternative to the stochastic programming approach is to try to use a range of heuristics. The heuristics don't have to be perfect they only have to result in a reasonable, feasible solution, not necessarily the best. With that in mind a simple algorithm might be to:

1. Select the scenario with the largest total reserve shortfall (unmet load in a reliability scenario);
2. Find the optimal set of RERT contracts to reduce the reserve shortfalls to zero in the that scenario;
3. Select the scenario with the next largest reserve shortfall;
4. Optimise what other RERT contracts or increased quantities of the contracts already selected at step 2 are required to reduce the reserve shortfalls to zero in the scenario; and
5. Repeat for all remaining scenarios.

We might need to check all scenarios at the end with the full set of activated RERT contracts and quantities to check that all the solutions are feasible and there are no reserve shortfalls.

8 Framework for Modelling Uncertainties and Random Variables in PASAs

8.1 Introduction

A security constrained dispatch scheduling system alone would be perfectly suitable for the analysis of system reliability and security issues if the forecasts of:

- Nodal loads;
- VRE generation;
- Embedded PV and other embedded generation;
- Availability of dispatchable generation and loads;
- etc.

perfectly matched what would actually occur. In reality, there is a lot of uncertainty surrounding these forecasts and this uncertainty is a key source of risk for managing the power system. The FUM is an approach to managing this risk but the FUM does not fit into a security constrained dispatch scheduling framework.

There are two logical ways for accounting for the uncertainties / randomness of key inputs into a security constrained dispatch schedule:

- Use a **Monte Carlo simulation** to randomly select values from the probability distributions of loads, VRE generation, dispatchable generation outages etc. and then evaluate the security constrained dispatches for each set of selected values for the random variables.

  To get reasonable estimates of reliability or security issues this would require many thousands of simulated dispatches, which would take considerable time.

- An alternative is to **use a probability approach** where we select the values of the random variables in a way that ensures that reliability and security are being met if the security constrained dispatch schedules do not have problems.

We recommend that the second alternative be used and this is the basis of our ST PASA functional requirements.

8.2 Framework for modelling uncertainties

As part of developing the functional requirements for a replacement ST PASA system, IES/SWA developed a framework for how it is possible to take the idea that the random errors of forecasts of loads, VRE generation and available dispatchable generation can be incorporated into an ST PASA optimisation to analyse potential system reliability and security issues[4]. This is done in a way similar to AEMO's current forecast uncertainty measure (FUM) but the modelling of these random deviations of actual outcomes versus forecasts is

[4] IES/SWA report to AEMO "ST PASA Replacement: A Framework for Modelling Uncertainties and Random Variables in the PASAs"

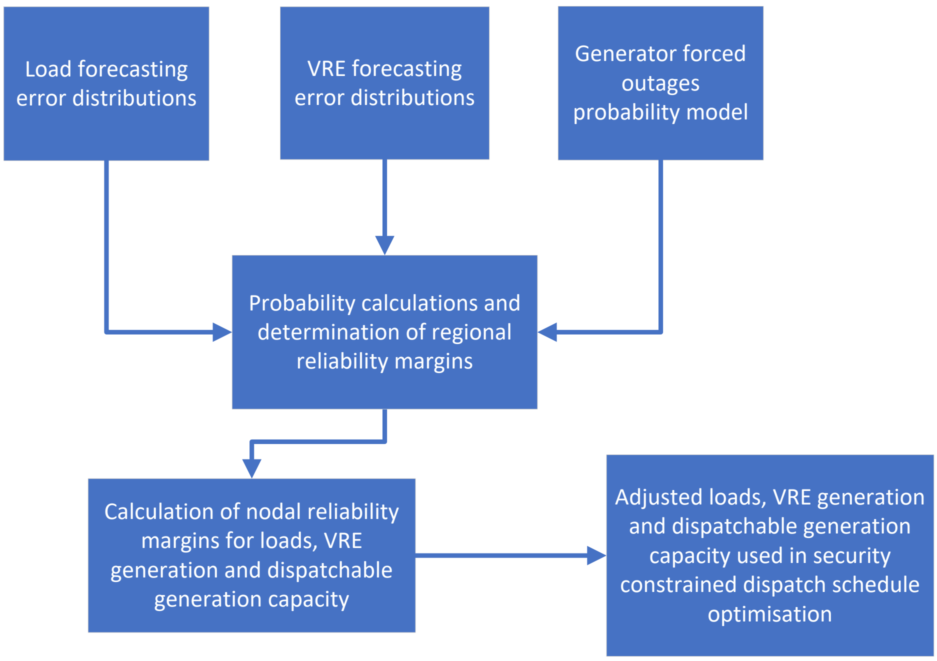
incorporated into the optimisation via one or more probabilistic constraints. Further, the framework can be extended to a full network model and used for a range of scenarios.

The key features of the framework are:

- Modelling the probability distributions of:
  - unavailable dispatchable generation;
  - forecast errors for:
    - demand;
    - wind generation;
    - solar (PV and thermal) generation;
- Using a reliability criterion for a regional demand and supply balance, such as a probability of lost load, to determine a required reliability margin using the forecast error probability distributions and the unavailable dispatchable generation distributions (note that using a probabilistic approach is necessary because the use of a "simple margin" calculation is not adequate for technology mix that is dominated by small scale generators and high levels of VRE generation).
- Converting the regional reliability margin into mutually consistent nodal reliability margins for an ST PASA optimisation which uses a full network model.

These aspects of the framework are illustrated in Figure 8-1.

Figure 8-1 Framework for modelling uncertainties



8.3 Generator forced outages probability model

The unavailability of dispatchable generating units over time periods from 0 hours ahead to 7 days ahead, given their operating status at time 0, can be modelled as time varying probabilities based on a Markov process using unit forced outage rates and mean times to repair. The regional probability distributions of unavailable dispatchable generation capacity can be easily calculated using a convolution method.

8.4 The probability distributions of forecast errors

The probability distributions of forecast errors for:

- Demand;
- Wind generation;
- Solar (PV and thermal) generation; and
- Demand – VRE generation;

can be calculated via a mixture of statistical approaches, use of a Bayesian Belief Network (BBN) and convolutions of distributions.

8.5 Regional reliability margins and nodal reliability margins

A reliability criterion for a regional demand and supply balance, such as a loss of load probability of less than 1%, can be turned into a required regional reliability margin using the forecast error probability distributions and the unavailable dispatchable generation distributions. Any required reliability margin can be turned into a constraint in the ST PASA optimisation. Regional reliability margins can be converted into mutually consistent nodal reliability margins for an ST PASA optimisation which uses a full network model.

8.6 Scenarios and random variables and uncertainties

The key points of the framework for modelling scenarios are as follows:

- Scenarios for some aspects of the market, such as for regional load forecasts, can be constructed and if conditional expectations are used for other random variables, given the scenario, then mutually consistent nodal load and generation inputs can be constructed;
- Scenarios for combinations of network and generation plant outages can be readily constructed and combined with weather scenarios to investigate reliability and security issues provided a security constrained dispatch scheduling optimisation is used with dynamically updated N-1 security constraints; and
- Generally, most scenarios would not have any reliability margins included in the security constrained dispatch optimisation. However, if it was desirable to include a reliability margin then the reliability margins based on selected scenarios need to account for the probability of that scenario occurring[5]. How this can be done logically and consistently will require more work.

[5] A scenario could be high temperatures and multiple line outages due to bushfires. This scenario is essentially checking to see whether the system is reliable and secure in this stressed state. If the assessed probability of this scenario occurring was low, say, less than 1% then it would likely be too conservative to also add a reliability margin. On the other hand, if the assessed probability of this occurring was, say, 10% or more then it could be appropriate to add a reliability margin corresponding to say 10% POE reliability margin.

9 Core Components of ST PASA

9.1 Introduction

For the ST PASA process to be effective, it is essential to use a physical power system model, in a similar way to how online power system security models use physical engineering models, rather than to use a model based on a market model with an approximate network model and regional structure.

For ST PASA to be able to satisfy its main functional requirements, we propose for the ST PASA system to be split into three core functional areas:

- Input data creation and processing, including:
  - Collection of SCADA, network, maintenance and data in other AEMO systems;
  - Nodal load and variable renewable energy (VRE) generation forecasting;
  - The processing of probabilistic data that will be transformed as inputs to a scheduling optimisation; and
  - The creation of weather scenarios that can affect the forecasts and probability distributions of multiple inputs;
- A security constrained dispatch scheduling optimisation (SCED) which will optimise the use of resources over 7 days including the possible use of directions and RERT contracted resources.

  Where an intervention decision is to be made, SCED solutions for multiple scenarios[6] including a reliability run may be required. A set of directions and RERT decisions, common to all scenario runs, will need to be developed requiring some coordination between scenarios; and
- Post processing of the scheduling optimisation's results to indicate any additional security issues such as low inertias within a potentially isolated subset of the network and inadequate system strength.

These functional areas will be coordinated by a process scheduling and control system and a scenario manager which will enable possible future scenarios, which are outside the standard runs, to be run on an ad hoc and on demand basis. The process scheduling and control system will make sure all of the required network data, plant data, forecasts etc. are provided to security constrained scheduling optimisation and the outputs are stored and provided to the post processing systems.

This same control system should also be capable of initiating various runs with different optimisation horizons (as opposed to the standard 7 days) on a batch or more ad hoc basis.

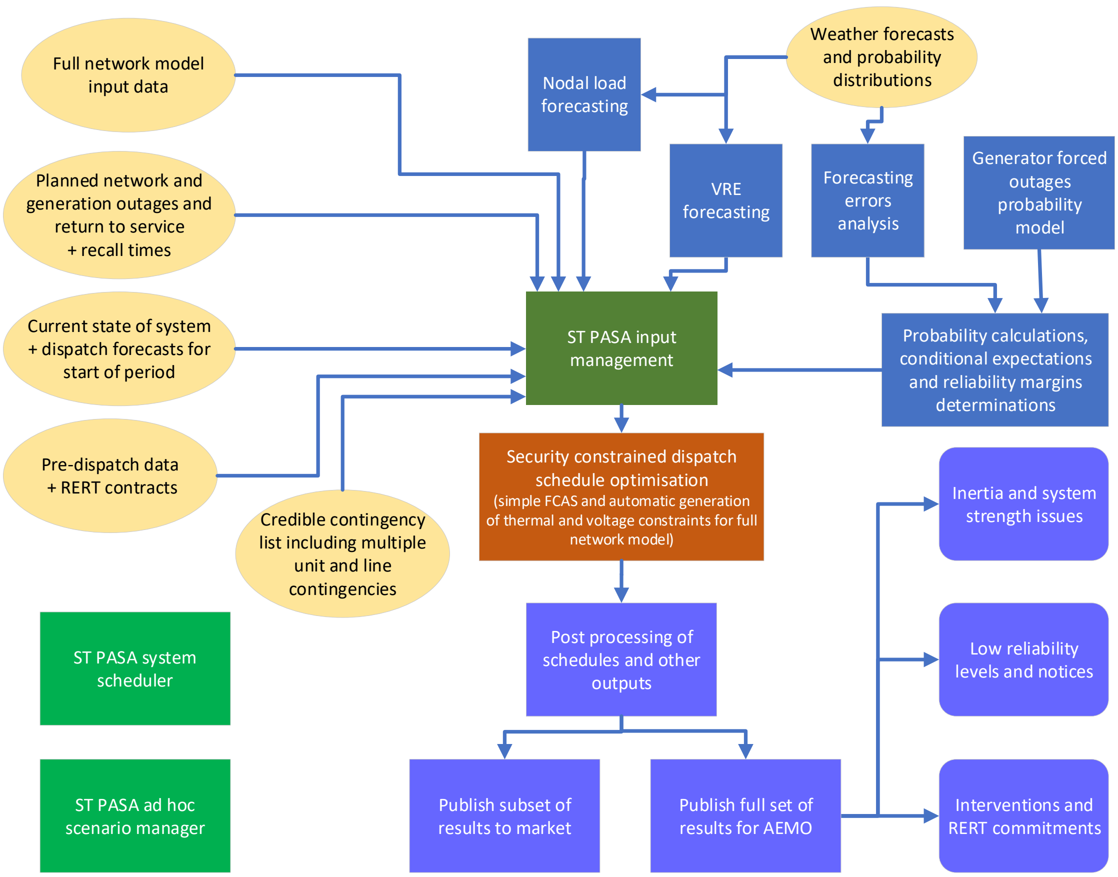
[6] The scenarios would generally just include: 1 – Base Case Run (a N-1 security constrained run which uses expected nodal forecasts and FCAS requirements without any reliability margins added) and 2 – Reliability Run (Base Case Run with reliability margins added). However, if there were specific issues identified such as possible major network outages, there could be 1 to 2 other scenario runs that are of particular interest. The specific nature of these scenarios would need to be determined as part of Phase 2.

Also, the control system should be able to have the capability to coordinate commitment of RERT resources across multiple scenarios.

Figure 9-1 provides a simple overview of how the various components of the ST PASA system would fit together:

- The yellow ellipses represent the collection of existing data for input to ST PASA
- The blue areas and the dark green area correspond to the input data creation and processing;
- The orange area corresponds to the security constrained dispatch;
- The purple areas to post processing of dispatch schedules and provision of information; and
- The two green areas to routine and ad hoc process controllers.

Figure 9-1 Core Components of ST PASA System



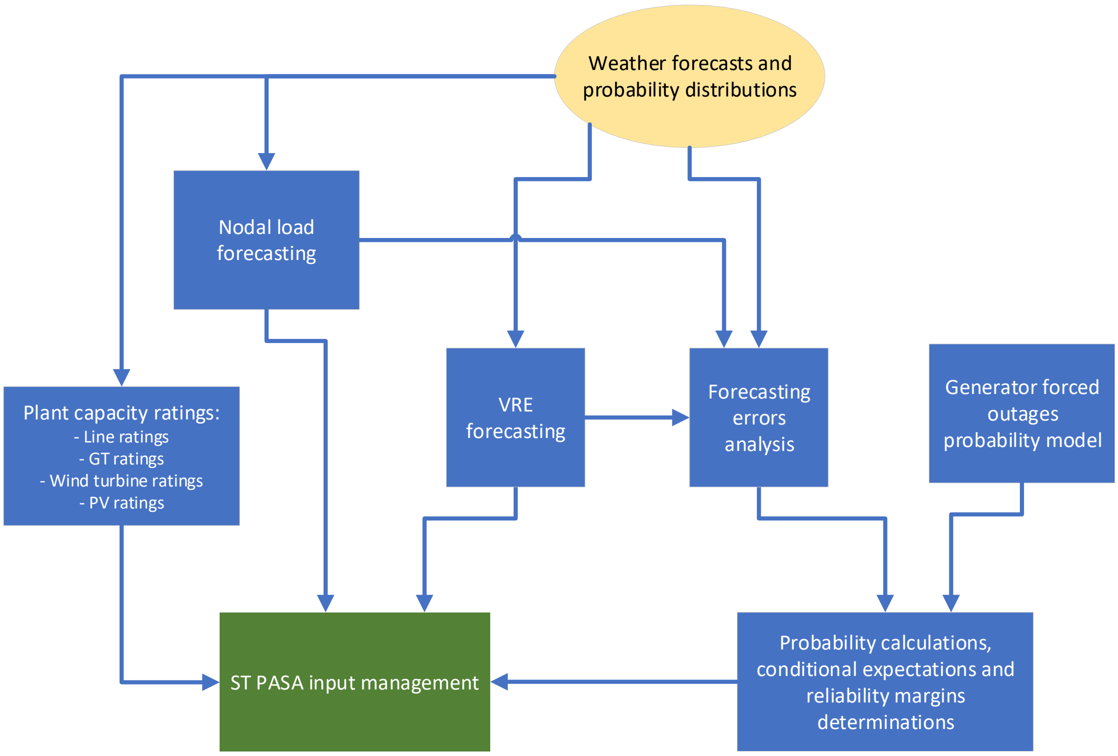
9.2 Forecasting and Probability Calculations

A key component of the ST PASA system replacement is a set of forecasting and analysis systems to develop, see Figure 9-2:

- Nodal load forecasts for each half hour out to seven days;
- Nodal wind generation forecasts for each half hour out to seven days;
- Nodal solar generation forecasts for each half hour out to seven days;
- Forecast error probability distributions for different forecast periods ahead;
- Dispatchable generating unit forced outage distributions for each half hour out to seven days;
- Calculation of reliability margins for each half hour out to seven days;
- Calculation of conditional expectations given a scenario; and
- Calculation of changes in plant ratings based on weather forecasts.

AEMO already has some systems which address some of the components. Some existing systems will have to be enhanced and other systems will have to be developed from scratch.

Figure 9-2 Forecasting and Probability Calculations Systems



9.2.1 Nodal load forecasting

Nodal load forecasts are required for the system.

In the longer term the approach is likely to be one of using zonal weather forecasts and their probability distributions to produce either nodal load forecasts directly or via zonal load forecasts that are disaggregated using statistical methods into nodal load forecasts.

Initially, the nodal load forecasting system could be based on AEMO's existing forecasting tools but if the existing tools are not adequate then further development, extension or replacement should be considered including the purchase of a new nodal forecasting system.

The main EMS/MMS vendors supply nodal load forecasting systems – which may warrant consideration.

9.2.2 Nodal VRE generation forecasting

Nodal VRE generation forecasts are required for the system. Rather than being embedded in the nodal load forecasts, separate nodal forecasts of embedded PV generation would be desirable as these could then be more easily linked to any weather scenarios.

AEMO already has systems to forecast wind farm and solar farm generation and some market participants use their own systems to forecast their generation. There does not seem to be a need for new systems for forecasting VRE at the transmission level.

The AWEFS/ASEFS already provide 10%, and 90% POE forecasts which suggests that these systems could be considered to provide the probability distributions of forecast errors. Thus, it would be worthwhile consult with the vendors of these products to see whether their systems can be adapted to produce the probability distributions.

Currently, AEMO uses ASEFS2 which is used to forecast rooftop PV generation and this is fed into AEMO's load forecasting system in order to improve the load forecast accuracy. However, with the growing amounts of embedded PV and batteries in the distribution system there will be some need to develop forecasts for embedded VRE at a nodal level. The rooftop PV forecasts from ASEFS2 are at a regional level, so AEMO would need to make changes to the system to increase the granularity to the zonal or nodal level. The forecasts are likely to use the zonal weather forecasts and probability distributions.

AEMO does not have any mechanism to forecast embedded battery charging or discharging, so modelling the operations of batteries in the distribution system would be useful.

9.2.3 Analysis of forecasting errors

The ST PASA system requires the development of probability distributions for the forecast errors for:

- Nodal and regional loads;
- Nodal and regional VRE generation; and
- Nodal and regional (load – VRE generation).

The probability distributions for the forecast errors have to be at least to the level of means and variance-covariance matrices. The probability distributions are likely to have both time varying and weather dependent components.

Also, the ST PASA system requires appropriate statistical and analytical tools to model the forecast errors probability distributions.

AEMO currently analyses forecast errors and their distributions. AEMO use R to analyse forecast error distributions at a number of different forecast lead-times. AEMO uses the forecast error distributions to review forecast performance on a month to month and quarter to quarter basis. For day to day and week to week forecast accuracy monitoring AEMO uses other tools such as backcasting, KPI measures and error threshold alerting.

AEMO uses the forecast errors as inputs to create a Bayesian Belief Network (BBN) which is the basis of the forecast uncertainty measure (FUM). This is done using R and the Netica software package from Norsys.

AEMO could use a BBN as part of the analysis of forecasting errors to give a weather varying component to the probability distributions. Or AEMO could use other parametric or empirical methods. The method that AEMO chooses should be determined through analysis and prototyping, considering each method's: accuracy of results, robustness, sensitivity, flexibility and maintainability going forward.

In summary AEMO, already has adequate statistical analysis and model building tools for the analysis of forecasting errors. What will be required is the analysis and prototyping of the methods used to forecast the probability distributions of forecast errors and then the development of the appropriate systems.

9.2.4 Generator forced outage probability model

The ST PASA system requires:

- Information of forced outage rates of units.
- A simple tool to calculate the probability that a unit will be available in t hours time given its availability state at 0 hours. If only full outage rates and mean return to service times are used then the probabilities can be calculated from the solution to a two state continuous time Markov chain. If partial outages are included then the probabilities correspond to a three state continuous Markov chain.
- A tool to calculate, for t hours ahead, the probability distribution of outages of dispatchable generation in a region, several regions, zone or several zones. The tool just has to calculate the outage probability distribution by the convolution method using the individual unit outage probabilities for t hours ahead.

This probability calculations would have to be developed from scratch but should not be particularly difficult to do or require much programming effort. The forced outage rate data collection and analysis would require a system to collect this information and standard statistical tools to analyse the data. Estimates of outage rates could be dynamically updated by using Bayesian or Kalman filter style estimation methods.

9.2.5 Plant capacity rating changes

The ratings of transmission lines, GTs, Wind turbines, PV panels etc. can change based on temperatures, wind and other aspects of the weather. In the longer term, it would be desirable for the ST PASA system to take the weather forecasts being used for a scenario and adjust the ratings of key plant to reflect the weather scenario.

9.2.6 Probability calculations and reliability margins

The ST PASA system requires the:

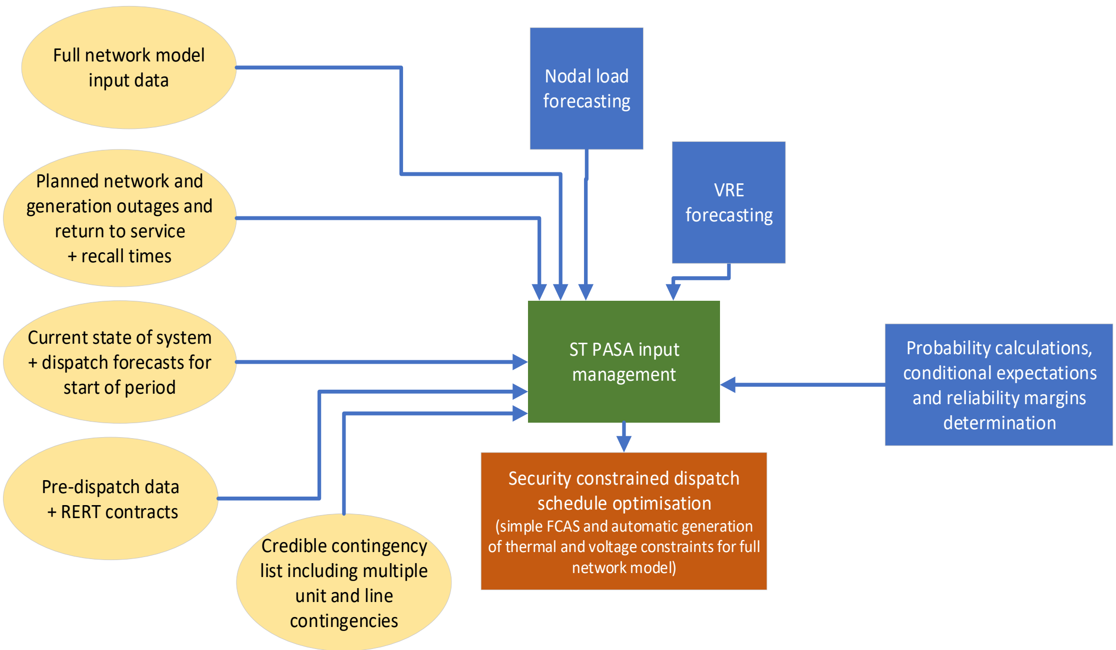
- Calculation of probability distributions for the demand and supply balance errors at a regional or zonal level (this would be done by computing the convolution of the load – VRE generation distribution with the dispatchable generation outage distribution);
- Calculation of regional reliability margins based on the demand and supply balance error distributions;
- Allocation of the regional reliability margin to nodal loads, nodal VRE generation and dispatchable generation capacity[7]; and
- Determination of the conditional expectations and variance-covariance matrices for scenarios where some random variables of load, VRE generation, weather etc. are fixed and the others need to be adjusted to create a mutually consistent scenario.

Most of the requirements can be achieved by using a statistical language like R, use of the BBN tool and simple purpose-built programs to calculate convolutions.

9.3 ST PASA Inputs

The ST PASA system requires a component to assemble all the inputs required for the security constrained dispatch schedule optimisation, specified in a standard run or for a scenario run. Ideally much of the data would be transferred using the CIM XML file format[8].

Figure 9-3 Inputs for the security constrained dispatch schedule optimisation



[7] Note: the nodal reliability margins could be based on variance-covariance matrices which are based (conditional) on the weather conditions.
[8] The Common Information Model (CIM), is a standard developed by the electric power industry that has been officially adopted by the International Electrotechnical Commission (IEC), which aims to allow application software to exchange information about an electrical network. https://en.wikipedia.org/wiki/Common_Information_Model_(electricity)

9.4 Security Constrained Dispatch Schedule

The security constrained dispatch schedule optimisation systems requirements are:

- Uses an optimisation written in a higher-level optimisation language such as AMPL, AIMMS, GAMS, OPL etc. or is written in such a way as it can be readily and easily modified;
- Uses a commercially available and high-level solver such as CPLEX, XPRESS or Gurobi.
- Can determine the least cost schedules for dispatchable generation units, loads and HVDC transfers on a half hourly basis from 0 to 7 days or alternatively can model on a half hourly basis for the first 24 hours and then for longer periods, say hourly, after that for the remaining 6 days;
- Can manage plant technical constraints such as maximum available capacity[9] and raise and lower ramp rates;
- Can use bids/offers with up to 10 price and quantity pairs (bands);
- Can optimise the use of energy storage systems such as batteries and pumped hydro which could have multiple cycles over a day or cycles that extend over a week;
- Can optimise generating units with energy limits;
- Can model the full transmission network, which includes some HVDC lines and phase shifting transformers, at least to the level of a DC load flow and a reasonable approximation of transmission losses;
- Can automatically generate N-1 network security constraints for:
  - thermal limits for network outages;
  - thermal limits for generating unit, load or HVDC outages;
  - voltage limits pre and post generation, load and network contingencies;
- Can use pre-calculated constraint coefficients;
- Can manage when some radial lines connecting generation or loads are not run on an N-1 basis;
- Can manage when there is islanding or when a single contingency could cause islanding[10];
- Can determine an optimal security constrained schedule (N-1 schedule) when multiple lines or generating units are classified as a single contingency;
- Can co-optimise energy and frequency control ancillary services (reserves);

[9] Note that minimum stable levels of generators could be modelled in an approximate way on the basis of using generator offers rather than using binary variables for commitment decisions. In the case of modelling aggregate units the model could be set up to reflect actual units (rather than aggregated units) and reallocating the aggregate unit offers to individual units or adding constraints that require the sum of the physical units dispatch to be equal to the aggregate unit's dispatch and the aggregate unit dispatch is based on its offers. If offers are used to model the minimum physical loading levels of units then as part of the reporting function there should be the Identification of any times when the optimisation has physical units being dispatched to points below their physical minimum operating levels

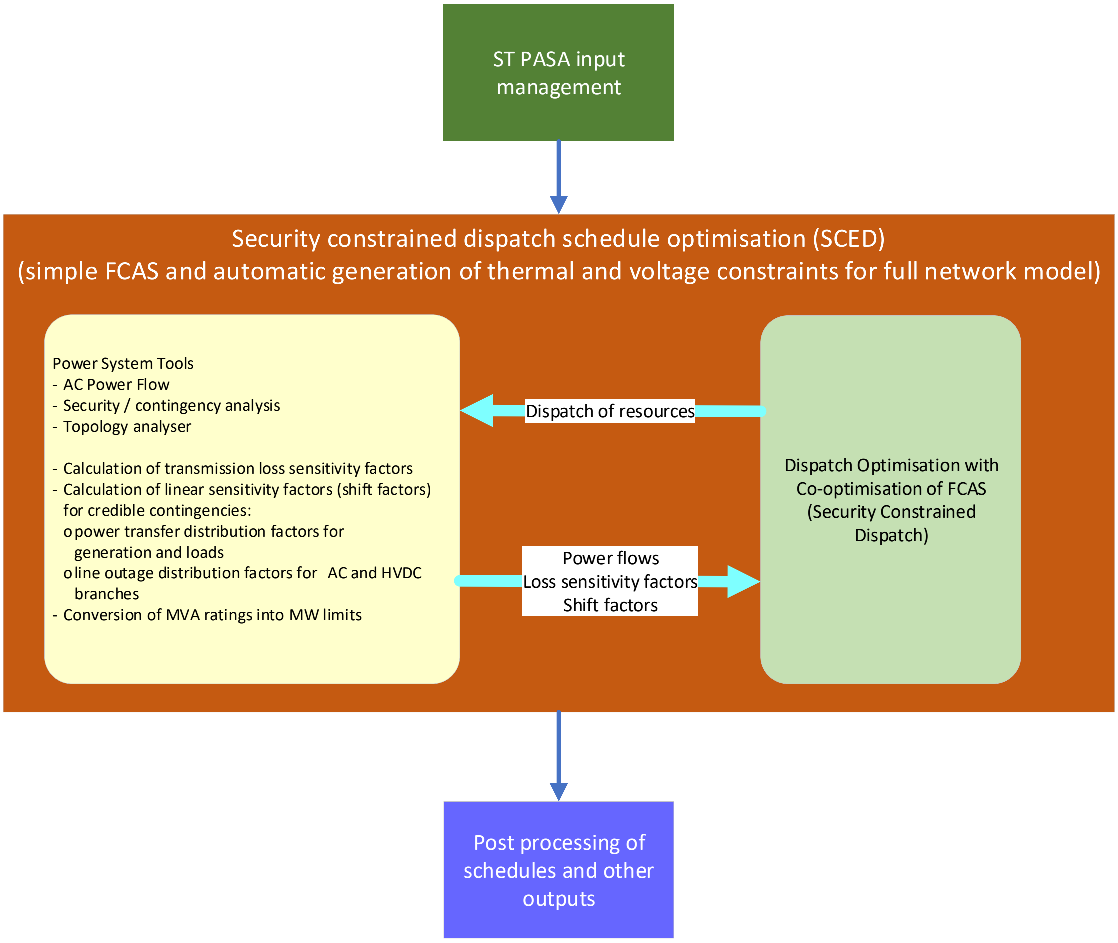
[10] Note that because a full network (nodal) representation of the power system is being used, the security constrained dispatch schedule optimisation systems are able to more naturally and easily to model network outages no matter where they occur. Further, it means that any transmission line outages that cause a separation to occur that is not perfectly aligned with the regional boundaries used for pricing in the regional market model of NEMDE, can be readily modelled and any security or reliability issues revealed.

- Can always solve through the use of soft constraints and violation penalties;
- Can use a network outage schedule provided in a standard power system format;
- Can update the current network model based on SCADA information on switching.
- Can be run on a periodic basis of, say:
  - Half hourly for a time horizon of 0 to 48 hours ahead; and
  - Every two hours for a time horizon of 0 to 7 days ahead
- Can be run on multiple machines and can have offline modes which may use different network models for scenario analysis, training, testing etc.; and
- Can pass information on marginal energy values, target storage levels etc. from a run with a longer horizon to a run with a shorter horizon to manage any end effects with the shorter run.

It should be noted that the ability to automatically generate constraints depends on the use of a full network model. A model with sub-regions would not work effectively because it would require the use of generic constraints and manually adapting them to manage security limits based on the choice of sub-regions. A sub-regional model would not always reflect the underlying physical reality and would be difficult to use when there are network outages or unusual credible contingencies involving multiple network elements or generating units. It is quite feasible for ST PASA, if sub regional load forecasts were much easier to develop than nodal forecasts based on weather forecasts, then simple statistical models could be used to allocate the sub region forecasts to the forecasts for individual nodes[11].

[11] A sub-regional forecast can be broken down to the nodal level based on regression, Bayesian or time-series models that could be continuously parameterised over time based on measurements.

Figure 9-4 Security constrained dispatch schedule optimisation



9.5 Post Processing

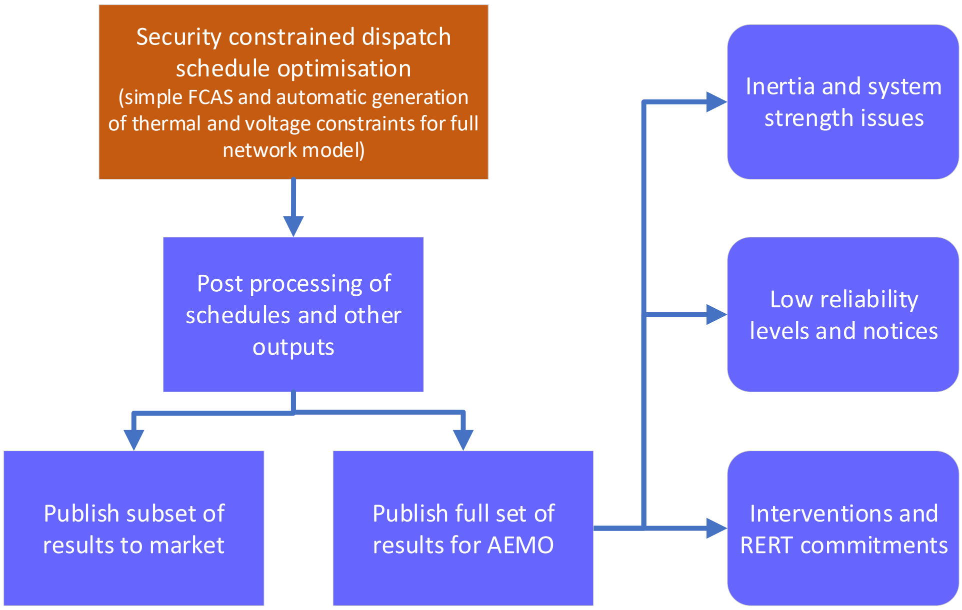
The ST PASA system requires the following post processing and reporting of the results from the security constrained dispatch schedule optimisation:

- Notification or alarming of AEMO operations staff of any projected reliability or security issues;
- Publication of full results to AEMO;
- Calculation of forecast regional reserve margins;
- Identification of any times when the optimisation has physical units being dispatched to points below their physical minimum operating levels;
- Calculation of forecast regional and zonal inertias based on the ST PASA dispatches and lookup tables of physical units versus MW target for aggregate units[12];
- Development of schedules for interventions and RERT commitments; and

[12] Note that this would be the situation if it were decided to retain the aggregated representation of power stations in the ST PASA system (as used in the market). The alternative approach would be to explicitly represent each unit (and have a mechanism for representing the market-based generation offer).

- Creation of low level of reliability notices.

Figure 9-5 Post processing



9.6 ST PASA System Scheduler

The ST PASA System Scheduler must satisfy the following requirements:

- It must co-ordinate and monitor all of the regular ST PASA runs and ensure all of the processes to create input data, create the dispatch schedule and process the output data;
- It must provide the appropriate input data to, set off, monitor, collect and store the outputs of all the ST PASA runs. The scheduler should be able to alarm the operators if there are problems with any of the component processes; and
- It should be able to be used in both market operation and offline study modes.

Having this functionality will enable to AEMO to be able to set the ST PASA model solves up to satisfy the requirement for potentially running 7 day horizon versions of the model at one periodicity, while also running versions of the model with shorter horizons more frequently, but in a way that will be mutually consistent.

9.7 ST PASA Ad Hoc Scenario Manager

The requirements for the ST PASA Ad Hoc Scenario Manager are for a system that can facilitate AEMO staff to take a current or historical ST PASA run and easily perturb (change) some of its inputs, such as loads, weather, network outages, generator outages, reliability requirement etc., and give the new run a unique ID, store all of the outputs and provide facilities to compare the ad hoc run with the unperturbed run.

Having the flexibility of running ad-hoc scenarios (via the Scenario Manager) ensures that the ST PASA system could be used to model the implications of what happens following the occurrence of particular contingencies that have been identified to be of concern. For example, to answer the question of "will RERT resources be needed following a double contingency that is of a major concern".

9.8 Non-Operational Modes of ST PASA

Non-operational modes of ST PASA are offline systems that are required by AEMO to perform offline tasks. These offline tasks may include training, running test cases, undertaking studies, or testing changed or modified version of the components in the ST PASA system. These offline modes of operation should not interfere or impact the performance of any online components or systems. The following non-operational modes should be able to be set up:

- Offline study mode;
- Development mode;
- Training mode; and
- Testing mode.

The population of input data into these non-operational modes should be designed to be relatively easy to do.

9.9 Operator Interface Including Displays and Alarms

User interfaces will need to be developed to meet the operators and operations planning demands. As a minimum, these should include:

- Each scenario's dispatch results;
- Any identified security or reliability issues;
- How close power system is to having a reliability issue;
- The location and extent of a reliability or security issue if it exists;
- Problematic (binding and violated) constraints; and
- Recommended RERT and directions.

9.10 Data and displays for participants and interested parties

The system should be able to provide information for industry participants and interested parties that are not market participants – including summary level modelling results and dashboards to enable the visualisation of results.

10 Conclusions

10.1 Recommendations

The PD PASA and ST PASA systems are key NEM risk management systems. They should be able to effectively and robustly assist with the analysis of key risks and how they might impact system security and reliability.

Based on our discussions with stakeholders, an analysis of the existing ST PASA system, what is done in overseas markets and what could be done in the NEM, we have confirmed that the existing ST PASA system, even with modifications, will not be able to satisfy the NEM's future requirements. With increasing amounts of VRE generation, energy storage systems, embedded PV and batteries and reductions in large thermal generation the current ST PASA approach will not be able to effectively and robustly assist with the analysis of key risks and how they might impact system security and reliability. It certainly won't be suitable for the NEM's power system in 2030, so our overriding recommendation is to carry out work to replace the existing ST PASA system

Our recommendation to replace the ST PASA system with a completely new system rather than continue to modify the existing system has been informed by:

- The Identification of the high level requirements which was done in consultation with industry stakeholders and AEMO;
- A review of international practices to enhance our understanding of how market processes similar to ST PASA are implemented in other electricity markets;
- A survey carried out on the software available from the major market IT systems vendors, which confirmed that there are off-the-shelf IT solutions for security constrained dispatch schedule optimisation (SCED and SCUC) that could satisfy the requirements of a key component of the ST PASA system;
- The work carried out on a prototype system to get an understanding of solve times and optimisation solution methods, which confirms that it is technically feasible to implement a system that can satisfy the requirements; and
- The proof of concept work undertaken to show how the key uncertainties regarding load and VRE forecasts, availability of dispatchable generation etc. can be incorporated into inputs to a security constrained dispatch schedule optimisation.

The broad components for a replacement ST PASA system include:

- Input data creation and processing:
- A security constrained dispatch scheduling optimisation (SCED) which will optimise the use of resources over 7 days including the possible use of directions and RERT contracted resources.

  A SCED solution must be found for several scenarios including a reliability run. A set of directions and RERT decisions, common to all scenario runs, will need to be developed requiring some coordination between scenarios; and
- Post processing of the scheduling optimisation's results to indicate any additional security issues such as low regional inertias and inadequate system strength.

10.2 Next Steps

For the next stage of the ST PASA replacement project we recommend that AEMO undertakes more prototyping work to firm up the ST PASA functional requirements so that they can be developed into a more detailed system specification which can be used as the basis for developing, purchasing and implementing components of an ST PASA replacement.

We recommend that AEMO:

- Continue to investigate the capabilities of off-the-shelf software products, in particular:
  - Using realistic NEM data sets in the SCED and SCUC products of vendors;
  - Testing the automatic generation of thermal and voltage limits;
  - Testing of situations where the power system is "stressed" following a contingency;

  Note that any comparisons and evaluations of model accuracy need to be done in a like for like manner, for example, a SCED model could be compared with the NEM's pre-dispatch model for a range of network configurations;
- Investigate how stability constraints (and any other constraints that are not thermal or voltage related) could be factored into the ST PASA modelling framework if required;
- Continue to investigate how a SCUC/SCED system can be used to determine the expected least cost AEMO interventions and use of RERT resources;
- Continue to investigate the feasibility and practicalities of nodal load forecasting;
- Continue investigation into determining practical and implementable models to represent uncertainties and random variables;
- Continue to investigate the feasibility and practicalities of integrating nodal load and VRE forecasting, modelling uncertainties and determining reliability margins and how they can be effectively incorporated into the inputs of a SCED/SCUC model to ascertain whether there are any potential reliability or security issues; and
- Investigate when it is more appropriate to use "scenarios" vs. what is factored into the distributions for a random variable – for example, for weather, should two different timings of a cold front of concern be represented as two separate scenarios or should the uncertainty of its timing be factored into the probability distribution of a random variable.