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Assessment of approach to modelling of Reliability Settings

prepared for:
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1. Summary

This document reports on Oakley Greenwood's qualitative review of modelling undertaken to inform the Reliability Panel's review of the National Electricity Market (NEM) Reliability Settings in 2014 as it prepares to undertake the next scheduled review in 2017. Reliability Settings include the Market Price Cap (MPC), Cumulative Price Threshold (CPT) and Market Floor Price (MFP). We were asked to pay particular attention to whether the 'Cap Defender' and 'Extreme Peaker' approaches employed in the 2014 Review remained appropriate in the face of continuing trends in the NEM and whether there are material gaps.

Summary of key findings

- Analysis will increasingly need to focus on assessing supply and demand equilibrium rather than only the conditions for additional investment. Assessment of equilibrium will be important in a market where capacity withdrawal is as important as investment, and a transition of generation and demand technology (and the associated costs thereof) is underway;
- In light of the evolving technology being deployed and a growing disconnect (reduced correlation) between the timing of peaks and troughs in demand, reserves and spot price due to changing characteristics of technology and intermittency, we consider it is important that the outputs rather than inputs of future modelling should identify the technology and therefore costs at the margin;
- Accordingly, we consider both of the approaches employed in the 2014 analysis would require amendment and recommend what can be termed a Technology Neutral Equilibrium approach.
- The Technology Neutral Equilibrium approach would:
  - be similar to the 2014 Extreme Peaker approach modified to allow the modelling to identify the marginal resource based on cost and operating characteristics (be it Open Cycle Gas Turbine - OCGT, renewable with storage or demand side). The modelling should also allow all resources to behave strategically, bidding to suit the prevailing circumstances; and
  - recognise the commercial drivers underpinning the 2014 Cap Defender approach but allow market behaviours to signal future contract prices through bidding behaviours.
- Without amendment we consider that the 2014 Cap Defender approach may understate the required MPC (and CPT) while the 2014 Extreme Peaker approach may overstate the required MPC (and CPT).
- We consider that the approach to development of scenarios in the modelling should be overhauled to more robustly account for the growing disconnect between reserve, demand and price on the one hand, and an increased significance between atmospheric conditions and availability of a number of renewable resources on the other. We note a number of international developments in this area.

2. Introduction

Oakley Greenwood has been appointed to review and comment on ROAM Consulting's (now part of EY) approach to market modelling used by the Reliability Panel to inform its review of Reliability Settings in 2014 ('2014 Report'). We have been assisted in this work by Mr J Dyson. The review is to advise on whether the approach employed for the 2014 Report remains a conceptually sound and pragmatic approach for the next review which will cover the period from 2018 to 2022.

We were asked to provide a qualitative review and identify material gaps in methodology or inputs that eventually led to the Reliability Settings, Market Price Cap (MPC), Market Price Floor (MPF) and Cumulative Price Threshold (CPT). We were also asked to pay particular attention to whether the 'Cap Defender' and 'Extreme Peaker' approaches remained appropriate in the face of likely trends in commercial and technical conditions. The review also considered whether the scenario and sensitivity analysis in the 2014 modelling remained appropriate. Our review is written for readers with some knowledge of reliability of power systems and of economic modelling.

Reliability is determined by the small difference between two large, uncertain and variable numbers; aggregate supply and aggregate customer demand. Small differences in either can make a big difference in reliability. Variability on the supply side arises from the performance of individual generating plant and from availability of intermittent resources such as wind and (in front of meter) solar. Variability on the demand side comes from day to day and hour to hour variability in customer consumption and also from availability of behind the meter resources, in particular solar and increasingly small scale storage. How each source of variability and uncertainty is accounted for in the modelling can obviously have a big impact on forecasts of reliability. When these models are used to set Reliability Settings in the NEM, a similarly significant impact on those settings occurs. Analysis of reliability is therefore an analysis of commercial and technical performance concerning the size of the gap between supply and demand, that is, at the margin.

In this engagement we have been asked to review the approach taken to model reliability and determine the Reliability Settings in the review undertaken in 2014. The results of this review will inform the Reliability Panel's analysis for, and review of, modelling for the Reliability Settings for the 4-year period from 2018.

Our review has the following structure:

- Brief discussion on the evolving NEM;
- The 2014 Approach and outcomes;
- Considerations for the 2017 Approach including a checklist of possible characteristics and features of modelling for 2017 review or Reliability Settings.

Before we turn to the individual components of our review we comment briefly on the two factors that affect the quality of economic modelling of a market such as the NEM:

- The first is data. The oft repeated truism that the quality of inputs determines the quality of outputs is very apt for modelling of Reliability Settings. Given the level of variability and uncertainty we have already noted, and the chequered history of forecasts of demand, the inputs to modelling need to include both best estimates and a meaningful range of sensitivities.

On the supply side, costs associated with generation at the margin play a very significant role in determining the market price cap. These costs are therefore of critical interest to this work. In previous work Open Cycle Gas Turbine plant has been accepted as the obvious marginal supply side resource. Looking ahead we should allow for a situation where this is no longer the case, and modelling needs to accommodate this change.

- The second factor concerns the modelling methodology; it must be fit for the purpose of analysing market outcomes at the margin. A modelling methodology that is focussed on analysis of average price (for example the price that would be important for a commercial tariff analysis) may not be well suited to analysing operation at the margin. These factors are central to our review and recommendations.

3. Modelling Objective and Key Outputs

3.1. Reliability Setting Modelling to Assess Operation at the Margin

In order to assess the viability of a modelling methodology it is important to be clear about what it is, or was, attempting to do.

Under cl 3.9.3A(f) of the National Electricity Rules, the level of the MPC is required to allow the Reliability Standard to be met without intervention by AEMO. What does this imply about the methodology for modelling?

This prompts a series of questions. In the current surplus conditions, does it mean MPC should move so that intervention is just avoided and actual USE tracks the Reliability Standard? Or, if there is a surplus for whatever reason, should USE be 'allowed' to fall below (i.e. to be better than) the standard and the Reliability Standard then be a floor for actual USE? Does it matter what caused the surplus? Does it matter how long the surplus is likely to exist? Can either of these last two issues be determined objectively anyway? Should the MPC recognise that emerging technologies may out compete incumbent plant and existing technologies, and to what extent should determinations of MPC rely on forecasts that the cost of emerging technology will reduce? These are questions of policy and properly ones for the Reliability Panel and the AEMC, but have an important impact on aspects of the modelling.

Our view is that answers to these questions will establish the overall framework for modelling, but once established, much of the implementation will be common to whatever framework is adopted as the 2017 Methodology – be it the 2014 Cap Defender, 2014 Extreme Peaker or some other alternative. For example, treatment of generator outages, assumptions and analysis of intermittent resources, assumptions about renewable mandates and demand forecasts will be the same whichever methodology is used, albeit not necessarily the same as in previous reviews of Reliability Settings. Our work therefore reviews the methodology in two parts: the strategic framework, answering the questions posed in the previous paragraph, and then, in subsequent sections, questions around implementation.

Reiterating that the policy and strategy implied in the methodology to assess Reliability Settings in 2017 are properly matters for the Reliability Panel and the AEMC, we cannot comment on the applicability of the 2014 methodologies without effectively opining on it as well.

3.2. Technology Neutral Equilibrium is Preferred

We have proceeded on the basis that the strategic framework for modelling of Reliability Settings should be based on assessing the long term equilibrium capacity and associated price that will ensure USE is no greater than the Reliability Standard. Importantly, in modelling market equilibrium, the methodology should ensure new and lower cost technologies can enter on merit and be dispatched in the short term whenever it is economic in a manner and consistent with the industry investment horizon. This Technology Neutral Equilibrium framework differs from both the 2014 Cap Defender and 2014 Extreme Peaker approaches in certain respects but has similarities to both in others. Section 6 discusses each of the 2014 approaches in detail.

In part the case to change to a Technology Neutral Equilibrium approach is recommended because of what it is not. It does not pre-select the marginal technology, or more precisely, the cost of the marginal technology. It does not presume bidding behaviour or price of marginal plant and therefore how it will be dispatched, and also recognises commercial behaviours will be influenced by both immediate and medium to longer term considerations.

There may be argument that the surplus should allow MPC to be reduced, at least for a time. We urge caution in this respect, as while an MPC based on a level of surplus could lead to a more rapid reduction in the level of surplus, it could have other, adverse, implications for consistency and regulatory stability. Logically, a lower MPC would also imply restoration and possibly increase in the MPC in subsequent years, creating volatility in the incentives in the NEM that drive technology mix including for demand side and emerging storage technology. Further, there is no obvious basis for deciding how far the MPC should be reduced or over what timeframe. Intuitively, the deeper and more rapid any reduction, the faster the surplus will be reduced and the earlier the MPC would need to be restored. Inevitably, these would be administrative decisions, not driven by market forces and exogenous inputs to the modelling. On the other hand, without a change in MPC, all else being equal, the current surplus would be expected to show fewer occasions with high prices and a lower out-turn average price. The lower out-turn price would also lead to withdrawal and reduction of the surplus, but at a slower rate and without need for the administrative inputs. To the extent price is not suppressed as far as some stakeholders might argue, it is more likely to relate to structural or external factors. An equilibrium philosophy avoids this instability.

A less contentious reason for considering a reduction in the MPC may arise from changes in the technology options and costs available to modelling. Here there will be a marked difference between the approaches considered in the 2014 modelling and our recommendation.

3.3. Devil is in the Detail

As with all modelling of competitive electricity markets, but particularly with an energy-only market such as the NEM, the 'devil is in the detail'. We discuss implementation of the approach in more detail later, but one area of detail is important to ensuring equilibrium is identified. That area concerns the treatment of the current level of generating surplus. At the risk of over-simplifying the matter, modellers will have a choice of (a) reducing the level of surplus to the point where USE rises to the Reliability Standard, i.e. 0.002 per cent, or (b) reducing capacity until USE exceeds the Reliability Standard and then identifying the marginal plant that most economically returns the USE to the Reliability Standard. Depending on the details, a) may not identify the potential for an emerging technology to substitute for an ageing incumbent, but it will be crucial that depreciated cost and any retirement (e.g. site remediation costs) of incumbent plant are accounted for in b).

On the basis of the reports published at the time, both the 2014 Cap Defender Approach and the 2014 Extreme Peaker Approach embed Open Cycle Gas Turbine costs into the respective approaches in different ways (see Sections 5 & 6. Our view, which we develop further in those later sections, is that the methodology for modelling Reliability Settings in a rapidly changing industry should result in new entrant technology emerging organically from the analysis, rather than being implied in inputs. Three features of the modelling framework will be important in this regard:

- The first being data describing costs, availability (for investment) and operating characteristics. In simple terms, if newer technologies cost less, the modelling should see them adopted ahead of older technologies;
- The second and less obvious characteristic will be whether the modelling techniques adequately reflect the potential operating characteristics of each technology, especially newer technologies, such as rapid response storage which have quite different inter-temporal limitations than traditional thermal supply side technologies; and

- The third feature relates to the treatment of the existing surplus. If there is no need for new investment and modelling only deals with withdrawal, then newer technologies may not appear in the output. However, if the modelling also considers the opportunity for economic replacement, then alternative technologies may emerge with a lower MPC.

4. The Evolving NEM

The first step in our review is to look forward at the physical and commercial conditions likely to prevail in the NEM in the 2018-2022 period. We focus in particular on conditions that we feel may prompt a change in approach or emphasis in the modelling that will need to be undertaken.

In common with international power systems and markets, the NEM is currently undergoing a period of significant change across all elements of the electricity supply chain. These changes are impacting the market signals that drive investment, divestment and portfolio signals, including at the margin. Changes in fuel types and cost to install on the supply side, patterns of consumer demand and various environmental policies are all impacting the manner and pricing of wholesale electricity. Similarly, on the consumer side, the development of internet-based technologies and increasing information resources are resulting in more connected and enabled electricity users. These changes are affecting the seasonal and hourly profile of demand, and significantly increasing variability and uncertainty.

As a consequence, the previously strong correlation between demand, reserves and price has been eroded with an increasing disjoint emerging. This is intuitively what would be expected given the increase in intermittent supply side resources. Accordingly, implicit assumptions that marginal plant will operate only, or primarily, at times of peak demand have become less valid. This trend significantly complicates the design of modelling.

The two most significant observable changes have been the increase in intermittent generation and decreasing consumer demand, both factors contributing to accelerated thermal unit retirement. To offset the increasing intermittency, increased focus has occurred around the world on the integration of batteries and general storage devices, as well as increasing demand side participation.

There has also been considerable change in the manner in which many participants and consumers manage their risk profiles. The separate financial transactions between pure generators and retailers have been progressively replaced by 'Gentailer' models where risk is managed internally to the organisation rather than through the visible market and the introduction and use of non-electricity risk management such as international weather-based risk instruments. All of this further clouds visibility into market-wide portfolio and risk management. That said, it will be important to avoid barriers to entry by smaller and new entrants who inevitably will continue to rely on external instruments.

Subsequently, although not the most important element in investment decisions, but certainly relevant to reliability standards, power system security is one element that has been extremely topical in light of increasing levels of non-synchronous, intermittent generation. The increasing role of inertia and arrangements to manage power system frequency such as the NEM Frequency Control Ancillary Service regime (FCAS) is also affecting unit commitment and dispatch at high and low demand conditions. While the pricing signal for investment is likely to dominate reliability, changes in the way power system security is managed may interact with the MFP and affect day to day management of available capacity. This interaction is an important new development in the NEM and other markets around the world: reliability can no longer be thought of as a peak-demand only concept. Under conditions with high intermittent generation and hence potentially low spot market prices, system security related constraints may result in the MFP being reached for extended periods, further exacerbating commitment decisions by the remaining uneconomic plant. As the de-commitment of generation occurs under sustained MFP conditions, changes to the intermittent generation inputs (i.e. changes to wind or solar), may lead to conditions that result in load shedding occurring despite relatively benign market conditions. Therefore, the MFP begins to impact reliability assessments.

Many of these factors were acknowledged to some degree in the 2014 Report. The ROAM modelling methodologies had allowed for increasing intermittent generation based on meeting the (then) RET target The increasing influence of rooftop Solar PV and general demand-side decreases were in practice greater than expected, especially using 2013 AEMO ESSO, GSOO and NTDTP information, highlighting the significant challenge facing the industry as rapid change continues. Storage technology is significantly more prominent than it was in 2014. It is already being packaged into behind the meter residential offerings and grid level opportunities continue to grow. The critical characteristic for modelling is that these are inherently controllable resources. A choice must be made as to whether the methodology for modelling will accommodate them as a form of demand offset, as is common for rooftop solar, or as price responsive supply or demand.

Questions in this area go to whether characteristics needing to be modelled have changed or is their effect still not sufficiently material in the context of modelling of Reliability Settings to warrant changing from previous, well understood methodologies? For example, at an earlier time when there was very limited wind generation it was adequate to model wind with a peak and non-peak capacity profile. However, as the amount of wind grew this was no longer adequate and geographic and time diversity needed to be considered, leading to more granular modelling. It is a catch-22 situation for the design of modelling. If there is a trend that might mean a particular factor is more material than it was, how do we know without including it in the modelling in the first instance? Where practical, approximations can be tested to decide if a trend appears to be material and if it is, then detailed analysis undertaken.

In section 8.1.2 we propose the concept of atmospheric condition scenarios as a means to more systematically analyse a number of the uncertain and variable factors related to intermittent resources.

5. The ROAM Approach in 2014

5.1. Overview

A key part of our brief was to review the modelling approaches adopted in 2014. Having conducted the modelling for the 2010 review based on a form of the "Extreme Peaker" approach, ROAM added a new approach for analysis of the MPC in the 2014 Report, the "Cap Defender" approach. The distinctive attributes of each approach were as follows:

- The 'Cap Defender' determined the MPC required for a new entrant open cycle gas turbine (OCGT) bidding into the market at $300/MWh to operate profitably in a market with a level of USE approaching the reliability standard;
- The 'Extreme Peaker' assumed that a new entrant would be based on OCGT technology and would bid at the MPC. This approach determined a relationship between USE and the MPC required for the new entrant generator to operate profitably in a system which was expected to experience a level of USE approaching the reliability standard.

ROAM concluded that the Cap Defender approach was the preferable methodology for 2014 review as they considered it contained more commercial and market-based factors that impacted operating decisions, and hence better reflected the factors that drive new investment in the NEM. For the purposes of evaluating the impact of a reduced MPC, ROAM and the Reliability Panel worked with a representative value of $9,000/MWh and concluded there would be market benefits, but emphasised this was not a recommendation for the MPC. ROAM's analysis using the Cap Defender approach also found that there could be marked differences in the MPC in different regions of the NEM due, inter alia, to different demand profiles but also due to different mixes of energy limited plant and different levels of interconnection between the regions.

However, the Reliability Panel determined in its Final Report in July 2014 to retain the prevailing form of the reliability settings and not change the MPC, CPT or MFP, thereby ensuring the status-quo through to the 2017 Review.

The ROAM analysis also assessed the appropriate level for the Reliability Standard, currently set at 0.002per cent, and the Market Floor Price. Their work was undertaken in five stages as follows:

- Stage 1 – Quantitative modelling of the reliability settings. This stage covered the primary modelling of MPC (and associated CPT). It is therefore the focus of our review, in particular assessment of the merits of the Cap Defender and Extreme Peaker methodologies;
- Stage 2 - ROAM performed additional quantitative modelling, essentially sensitivities to forecast the level of reliability in a market where the existing reliability settings are maintained. A forecast was presented for two markets over a ten-year period: one with a purely market-driven development of capacity, another with no change in thermal capacity.

Stages 1 and 2 are the focus of our review as they cover the key analysis of operation of the NEM at the margin and critical decisions about the role of the MPC and questions around management of the prevailing surplus of capacity, as well as the choice of inputs and design of sensitivities.

- Stage 3 - Assessment of the reliability standard. This stage reviewed the form and level of the Reliability Standard, currently based on Unserved Energy (USE) and set at 0.002 per cent. We make only brief comments in this area as it is beyond our primary scope;
- Stage 4 - MFP assessment. This stage provided the first analytical review of the market floor price since it was set; and
- Stage 5 - Market impacts analysis. We make only brief comment on this stage as we assume that market impact, or cost-benefit will be a part of any analysis undertaken by the Reliability Panel but cannot be commenced until there is a proposal.

5.2. Key Modelling Inputs and Setup

Table 1 summarises the key modelling elements and information sources from the 2014 Report.

Table 1: Key Modelling Input Information

Modelling element	ROAM Methodology	Primary data source
Demand	Medium peak demand and energy forecast at 10% and 50% POE, utilising a weighted approach of 30% of 10%POE and 70% of 50POE for a likely scenario	AEMO NEFR (2013)
	Half hourly profiles from FY09 to FY13, extrapolated to meet possible demand distributions	Actual demand profiles
	Demand Side Participation (DSP) quantities and price thresholds	AEMO NEFR (2013)
Generation	OCGT Cost Estimates	BREE (2012)
	Gas Prices	Internal ROAM estimates and AEMO Planning Assumptions (2013)
	Generator cost information	AEMO Planning Assumptions (2013)
	Carbon Pricing	Federal Treasury Core Projections (2011)
	New Entrants	ESOO (2013)
	Forced Outage Rates	AEMO Planning Assumptions (2012)
	Cycling Costs	NREL (2012 - US based) applied to NEM plant
Network	Planning studies constraint equations	Assumed NTNDP 2013 (with the Heywood Upgrade included)
	IC outage conditions	2006 MRL Assessments
Market Dynamics	Trading interval (30min)	Half-hourly profiling
	Monte Carlo	25 iterations across the future 5 year forecast period

NEFR: National Electricity Forecasting Report

BREE: Bureau of Resources and Energy Economics

ESOO: Electricity Statement of Opportunities

MRL: Minimum Reserve Level

The methodologies applied to add variability in the models as described by ROAM included:

- Previous 5 financial years' reference demand and intermittent generation traces; and
- Random outage factors for generation, and to a lesser extent, transmission elements;

Monte Carlo simulations (25 per reference year) were then used to add variability to results. Monte Carlo analysis is a well proven, standard technique to assess the impact of random events. Monte Carlo techniques can be applied to individual variables (such as generator breakdowns) or in multiple variables such as generator breakdown and wind availability. Alternatively, Monte Carlo techniques can be applied to a single variable in a number of scenarios (as it has been in the ROAM analysis) where different scenarios were based on different demand levels and the results combined. However, this approach will often assume that the same probability of say wind availability existed in the different demand scenarios. Historical records suggest this is not the case, with high wind more likely to occur with either high or low temperature.

Typically, modellers must also overlay factors which reflect correlations between the variables, for example where historical records show that although breakdowns occur randomly, plant operators can influence the probability of breakdown or partial reductions at high value times, for example, by reducing the risk of operator error or deferring maintenance activity on redundant plant items.

The key issue for a robust modelling exercise is to ensure internal consistency and coverage of uncertainty surrounding all key variables. We have not identified any gaps in ROAM's treatment of uncertainty and use of Monte Carlo. However, we do note that as the number and materiality of factors grow, modelling the treatment of uncertainty risks becoming more opaque and dependent on judgements by modelling teams about how to incorporate these factors into their models, in particular in the design of scenarios.

As result we propose a more systematic approach to the development of scenarios associated with intermittency linked to atmospheric conditions for future modelling exercises (see Section 8.1.2.

6. Assessment of Extreme Peaker and Cap Defender

Our comments on the Extreme Peaker and Cap Defender approach are based on our reading of ROAM's modelling report published on the AEMC website. We have not reviewed detailed output and not had access to ROAM's models.

6.1. 2014 Extreme Peaker

As we understand it, the concept of the 2014 Extreme Peaker approach involves relatively conventional modelling with two key features:

- New entrant capacity is assumed to be based on OCGT technology and offer capacity for dispatch at the MPC at all times[1]. New entrant capacity is assumed to be a merchant player and not part of a portfolio. Other generating units are grouped by ownership and game theoretic techniques applied to identify market price behaviour of incumbents;
- Capacity of the existing generation fleet is reduced such that unserved energy in each region rises to the Reliability Standard (0.002%). Reduction in surplus capacity is achieved by withdrawal of unprofitable generation plant but that plant is available to return to service in the event it would be profitable in later years.

The results are unavoidably sensitive to the manner in which intermittent generation and offsetting demand are incorporated in the analysis – as is any modelling of the NEM.

The assumption that the new entrant technology will be based on OCGT technology effectively forecloses the opportunity for new lower cost technologies, for example storage, to enter as the marginal player in the model. Limiting the new entrant (OCGT) capacity to offering at the MPC at all times forces it to participate as a substitute for unserved energy.

In practice it should be expected that while the marginal plant will offer for dispatch at close to the MPC when system reserves are low and prices high, in which case it will be a substitute for unserved energy, rational behaviour of a new entrant would be to offer at a range of prices from its short run cost toward MPC.

Our expectation is that increased penetration of intermittent resources will result in significantly weaker alignment of price and demand. As a result, supply side capacity that provides the marginal capacity needed to meet Reliability Standards may also achieve dispatch at other times and lower prices without necessarily fully assuming a Cap Defender-like position. Such operation will contribute to covering its capital costs requiring a lower MPC than would be expected if it were only offered at the MPC.

6.2. 2014 Cap Defender

As we understand it the concept of the 2014 Cap Defender approach also involves relatively conventional modelling with three key features:

- New entrant capacity offered for dispatch at $300/MWh at all times based on an assumption the plant will have sold cap contracts with a strike price of $300/MWh - the standard strike price for a cap contract in the market currently and broadly, but necessarily, related to the operating cost of low utilisation OCGT generation plant;

1 ROAM, Final Report (2014), p 8

- New entrant capacity is assumed to be a merchant player and not part of a portfolio. Other generating units are grouped by ownership and game theoretic techniques applied to identify market price behaviour of incumbents allowing market prices to rise towards the MPC, but suppressed relative to the extreme peaker where the new entrant would bid at the MPC as well; and
- Capacity of the existing (surplus) generation fleet is reduced such that unserved energy in each region rises to the Reliability Standard (0.002 per cent). Reduction in capacity is achieved by withdrawal of unprofitable generation plant but that plant is available to return to service in the event it would be profitable in later years.

This approach may appear more commercially realistic and familiar to participants trading existing capacity in the market, however, we see a number of challenges arising with this approach in the context of new investment, in particular as the NEM evolves, including:

- The new investment plant is never marginal and cannot set price and therefore is theoretically not able to bid to recover its fixed costs but instead relies on other players setting the price at the margin.[2] This situation may be viable for an incumbent but new contracts for new entrants will be based on expectations of what the market price would be in absence of contract and (fair value) contract price;
- For this reason, bidding solely with spot price in mind is a potentially short term strategy and may not be commercially sustainable, even with a 1- to 3-year contract market outlook. As a result, it is common for bidding behaviour to infer or value future spot price risk as well as short-term operating costs, which again complicates the task of the modelling exercise; and
- A number of other administrative steps in addition to the choice of the $300/MWh bid price are involved but have not yet been refined (see 2014 Report para 5.1.3). These include post-processing and measures to ensure incentives in different regions do not create distortions.

6.3. Comparing and Contrasting the Approaches

Overall we consider that:

- The 2014 Cap Defender will tend to underestimate the required MPC because marginal new entrant plant cannot bid in a manner that signals the value of future contracts as it is unable to bid at other than $300/MWh. We note reference to 1MW increments of generation in order to assess installation timing (albeit with installation price based off a larger scale generating plant), however, once the volume is committed, the size of the new entrant will be material (and >1MW) therefore leading to the price suppression impact noted;
- The 2014 Extreme Peaker approach may overestimate the MPC due primarily to the assumption the marginal new entrant will bid only at the MPC and therefore not be dispatched at other times when it would be economic for it to run. Relative to the Cap Defender, this approach is more transparent but presumes new entrant technology will be OCGT, thus excluding the opportunity for new technologies to emerge:

2 Strictly speaking the new entrant may be marginal at $300/MWh which would presumably be close to its operating cost and therefore not provide any material return of capital at this time.

- The use of game-theoretic techniques to the development of bids for dispatch is supported for an environment where technology and demand profiles are changing rapidly. There is an unavoidable risk that the structure of the commercial portfolios that are assumed in developing such prices can influence the results. Both approaches rely on game theoretic techniques to determine market price including high prices critical to recovering capital costs. To this extent both are subject to any approximations and inaccuracies introduced in this step, although it is not practicable for us to identify if one or the other approach is more susceptible. Sensitivities should continue to be explored to examine the materiality for Reliability Settings;
- The growing disconnect between high demand and high price with low reserve conditions due to technology shifts will continue to impact both methodologies, but particularly the 2014 Cap Defender, resulting in genuine price volatility in the market at times that would otherwise not have been expected using traditional modelling techniques centred around high demand/low reserve conditions; and
- The approach taken in the 2014 Extreme Peaker to not apply CPT post-processing to ensure 'pure' signals appeared reasonable, albeit a potential contributor to the differences observed between the two methodologies (we would recommend application of CPT in all modelling methodologies, to reflect realistic market outcomes).

6.4. Common Issues

This section addresses matters that are likely to be common to modelling of any approach to setting the MPC but depending on the circumstances may influence the resultant value. These are matters that any model will explicitly or implicitly account for, even if it is by ignoring the matter and thereby implicitly assuming it is immaterial. ROAM has noted a number of these matters in the course of reporting on the Extreme Peaker and Cap Defender although others are only implied. The issues (in no particular order) are:

- In a market that has an over-supplied capacity situation (be it temporary or permanent), the impact of the MPC level is generally considered less significant because the MPC will be reached in few instances but nevertheless is still a benchmark against which a prudent investor or contract trader will include in their assessment of the risk of not investing or contracting (Section 3.2 has described this in more detail);
- The extent to which a participant cannot respond to and capture revenue given the current 5/30 market design is not as clear as the models would anticipate (which have perfect foresight) and there does not appear to be any devaluation for the high price events that are missed;
- The simplification of wind generation forecasting to observed patterns for the past five years (p 28) is unlikely to be representative going forward, as it has been primarily focussed on determining wind generation levels for peak demand days and monthly/annual energy estimates;
- The modelling packages imply perfect foresight, which is a common characteristic of the majority of industry packages currently in use. As a result, these models do not forecast mistakes or misjudgements (assessed after the event) about timing or technology and in that sense can be optimistic. For example, models can be optimistic in assessing that competition will discipline market power optimally;

- ROAM assumed the level of DSP was constant (p 79). Although this may have been acceptable in 2013 due to a lack of quality information, given the increasing technological advancements in areas such as blockchain power trading[3] and smart-grids, we do not believe this is a sound argument going forward;
- Assessment of the impact of generation and transmission outages using Monte Carlo techniques and randomised variables is standard practice. The ROAM analysis also considers a range of demand scenarios and 'blends' the results to form expected results. This is also common practice. With increasing variability due to increasing levels of new technologies it is likely the statistical distribution of prices and unserved energy will be broader; that is, the spread of possible outcomes will depart from the average more (again ROAM has noted this matter). Modelling should be designed to specifically report on the spread and the Reliability Panel may wish consider if the detail of the definition of the Reliability Standard should be refined in the light of the results;
- Decreasing MPC is likely to decrease perceived values in contract premium that may limit contract market liquidity from a supply side perspective, although this may result in more consumers taking up contract options;
- Failure to account for MLFs for new entrants, although a considered simplification, will result in under-estimated MPC values in both Cap Defender and Extreme Peak scenarios; and
- Any reduction in MPC will dampen benefits of DSP and a number of Power of Choice initiatives. If a lower MPC is justified, for example as a result of lower technology costs, this effect would therefore be efficient, however, it will be important to account for it in analysis of benefits.

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3 Although blockchain-like power trading will not necessarily decrease total energy consumption, it does have the potential to time-shift loads, effectively providing demand side participation (DSP).

7. Market Floor Price, Cumulative Price Threshold

7.1. Market Floor Price

Earlier discussion (for example section 5.1) has noted that modelling of MFP has traditionally been of less relevance for assessment of reliability than may be expected in the future as commitment of generating units at low demand and low system inertia begins to interact with capacity available to meet low reserve periods. In our experience the existing MFP of $-1,000/MWh has been successful at signalling short term excess capacity without creating adverse financial risk to market participants, thus avoiding the need for AEMO to exercise its power of direction in order to ensure maintenance of power system security.

An economic assessment of the MFP needed to ensure both economic and secure operation is likely to be problematic as many of the costs for power system operation are uncertain and variable under these conditions. For example, generator costs for operation at very low output or cycling on and off are quite variable and linked to costs to provide frequency control and voltage control capability, and intermittent generation capability (in particular wind) will inevitably vary from day to day, thereby changing the dynamics of operation.

Modelling can inform assessments of different levels of MFP but we caution that, for the reasons noted in the previous paragraph, input costs will be variable and have a major influence on any economic assessment. Accordingly, it may be best to work on the basis that pragmatic considerations should play a big part in the choice of MFP and change to the MFP should be considered if affected stakeholders can demonstrate the current level is ‘broken’.

7.2. Cumulative Price Threshold

The Cumulative Price Threshold (CPT) is the trigger for temporarily lowering the market price cap to an administered price. The objective of the CPT is to set an upper limit on financial risk without sacrificing a prudent level of efficient investment signalling. Knowledge of the level of CPT should inform financial risk management activities that operate as hedges against spot price and also externally purchased business insurance (which was a key driver for introducing CPT into the NEM design). What level of CPT constitutes a balance between financial risk and retaining investment signalling is in part a matter of judgement that can be informed amongst other things by analysis of the costs of financial instruments and insurance. The basic CPT has been linked to three years of revenue to sustain the marginal generation investment, and for convenience the level has been linked to the level of MPC and CPI adjustments. It is properly a matter for the Reliability Panel and AEMC to consider if the principle of the CPT and adjustment factors remain appropriate and whether the disruption that would follow material change would be justified. Our observation is that there is no strong call from the market for change and hence the setting is an accepted ‘peg in the sand’.

Economic modelling can inform an assessment of the adequacy of expected revenue and its statistical distribution to cover investment costs for any given setting such as a three-year return in the current regime. Modelling cannot of course compare this to the cost of insurance or assess financial risk.

Intuitively, the evolving market circumstances discussed earlier suggest there are factors that could see CPT exceeded and the administered price applied for longer and, conversely, other factors that suggest CPT will be reached more frequently but for shorter periods. Sustained, calm periods over a large geographic area could result in longer period high prices that would take longer to dissipate and thus the administered price could apply for longer. On the other hand, the reduced correlation between peak demand and high price may see the CPT approached more often. Modelling will be very useful to assess the net effect and should be a requirement for future analysis. ROAM made reference to these changing influences in 2014 and we expect them to become more significant in the future.

8. An Approach for 2017

The Energy Only Market design of the NEM creates fine-tuned and often sharp price signals, in particular around operation at the margin that are critical for the NEM to meet the Reliability Standard. As a result, as the industry evolves, in particular where there are major shifts in operational characteristics of different technologies and associated costs, it is important that modelling of the NEM also evolve.

This section responds to the request in our brief to discuss gaps in the ROAM 2014 modelling. As noted, we have not identified material gaps in that work in the context of the time it was prepared, although we have noted a number of specific qualifications.

However, failure to accommodate shifts in technology and costs that we have noted (and are well understood in the industry) would leave a gap in 2017 modelling and we assume that the purpose of the request is to avoid such an outcome. That is, even if there were no material gaps in 2014, changes in the industry since then may lead to a gap in 2017 unless the modelling also changes. Accordingly, this section discusses a range of issues that will need to be considered, and where appropriate refers back to the ROAM 2014 approach.

8.1. Principal Enhancements for 2017 Approach

8.1.1. Modelling objective based on equilibrium analysis

The objective of modelling for the 2017 review of Reliability Settings should focus on identifying new investment based on a Technology Neutral Equilibrium approach. This proposal has been discussed in detail in section 3.2. Assessment of equilibrium will be important in a market where capacity withdrawal is as important as investment and a transition of generation and demand technology (and the associated costs thereof) is underway.

Further, in light of the characteristics of evolving technologies and a growing disconnect (reduced correlation) between the timing of peaks and troughs in demand, reserves and spot price due to changing technology and intermittency, we consider it is important that the outputs rather than inputs of future modelling should identify the technology and therefore costs at the margin.

8.1.2. Overhaul of scenario design

Scenario design should be based on internally consistent packages related to atmospheric conditions.

We are seeing an enhanced treatment of scenarios dealing with intermittency as a key change because of the growing significance of intermittency and progressively increasing opaqueness and unavoidable judgements of modelling teams who, with best intentions, must assign or imply correlations between variables that have a material impact on modelling outcomes.

In our view overlapping layers of multi-variant and sensitivity analysis is creating an increasingly opaque and extremely difficult set of conditions. For example, the cross-dependency of rain/cloud cover decreasing rooftop solar PV output adding to scheduled demand coupled with variability in utility scale solar will influence market outcomes as solar becomes more prolific.

This complexity is being recognised internationally for example in a recently published report by the US National Renewable Energy Research Laboratory (NREL)[4] and also in work in California and Ireland (see a summary in Appendix A.2).

In future modelling exercises (beyond the 2017 modelling) a more robust treatment of scenarios may be routine, but for 2017 it will be a significant change and is therefore highlighted here.

Market modelling tools currently used by industry were generally designed to model hierarchical, centrally controlled systems with several large-scale, baseload power plants and transmission lines. Developments have been made in those models to allow for weather-based, variable generation sources through items such as hydro modelling, intermittent wind generation variability traces and solar generation profiles. However, inter-dependency or correlations of these factors, not the variability alone, creates complications. When increasing variability (caused by the same weather-dependent variables) is added to consumer-side characteristics, correlations and average assessments mask the important impact on modelling for reliability settings to ensure the outer-edge scenarios do not result in high levels of USE. Atmospheric conditions are a common factor in a number of the significant key supply and demand side influences, as shown in Table 2.

Table 2 Atmospheric condition related trends

Key Weather Input	Supply Side Influence	Demand Side Influence
Temperature	All generation operations Transmission equipment ratings	Native electricity demand Native gas demand Rooftop PV efficiency
Humidity	Thermal generation operation	Native electricity demand
Wind Speed	Wind generation profiles Transmission capability	Native electricity demand Embedded generation
Cloud Cover / Irradiance	Utility-scale PV generation	Native electricity demand Rooftop PV output
Rainfall	Hydro running profiles based on Dams conditions Fuel supply issues (ie coal offloading) Utility-scale PV generation	Rooftop PV output

To some extent, the variability that is possible through some of the changes suggested in this section, will by their very nature, contribute to increased variability and linkage of factors. This is in part what the sensitivity analysis is designed to assess, and the growing list of sensitivity factors over the years is testament to this point.

4 NREL, Western Wind and Solar Integration Study Phase 3 - Frequency Response and Transient Stability, http://www.nrel.gov/docs/fy15osti/62906.pdf [Accessed 11-Sep-2016]

Through understanding power system variability through the lens of weather input variability, the natural variability and distribution of weather conditions (given there is substantially greater historical data on weather than electricity market operations), the effect on the operation of the power system does not have to be solely limited to inputs from the previous few years (other than to establish the current or expected state). For instance, actual weather input traces for the past 40 years could be applied to create renewable generation traces given the prevailing consumer and supply side conditions, which can then be used within standard commercial modelling in conjunction with standard Monte Carlo inputs for continuous random variables (such as outages). This would allow the reliability assessments to consider a far greater range of possibilities than would otherwise be the case (see Appendix A.2).

Despite some ongoing issues with the AWEFS/ASEFS1 forecasting tools[5] in use in the NEM, the use and dependence of the models is being considered by other jurisdictions as a means to improve actual dispatch outcomes[6]. Therefore, the modelling associated with such market outcomes needs to be improved beyond selection of historic generation profiles that appear to be an average of recent years,[7] as this will not model the key variability that does occur (and will continue to occur).

The key factors in wind energy forecasting include:

- Site wind resources and the natural variability given the site's size and topology (recognising not all wind turbines receive the same wind energy);
- Site turbine availability and maintenance schedules, leading to station EFOR[8] assessments; and
- Transmission/Distribution level constraint assessments.

In a similar fashion, albeit less variable than wind forecasting, utility scale solar forecasting needs to include variability factors that have been observed in utility-scale sites in the past two years at places such as Nyngan and Broken Hill, including;

- Solar irradiance variation and network constraints; and
- Site inverter availability and maintenance schedules, leading to station EFOR assessments.

8.2. Market Design Changes

There are currently a number of proposed and potential rule changes that may alter the behaviour of participants, and particularly any assessment of cap defender analysis;

- 5/30 Settlement: This concept was noted as a transient issue in the ROAM 2014 report, however, a change to 5-minute settlement rules, as is currently before the AEMC, could result in a significant change in the value-capture regime that OCGT plant operate within; and

5 Australian Wind Energy Forecasting System (AWEFS) and Australian Solar Energy Forecasting System 1 - Utility Scale (ASEFS1). See the AEMO Website, Solar and Wind Energy Forecasting

6 http://www.overspeed.de/en/company.html

7 ROAM Consulting, Modelling Outcomes Presentation, 4 December 2013, p 11

8 Equivalent Forced Outage Rate: A measure of reliability for generators

- Capacity Payment Mechanisms: We note recent press articles[9] highlighting calls by some existing market participants for capacity payment mechanisms. Again, this type of regime would alter the risk profiles for existing and intending participants, hence change the way in which both the cap defender and extreme peaker methodologies would operate, and therefore potentially change their implications for reliability outcomes.

8.3. Regional Interconnection

There are currently two interconnector options under consideration (albeit early stages) that have the potential to dramatically alter market outcomes: Basslink 2 and NSW-SA Interconnector. We consider these highly relevant to the modelling outcomes for 2017 report as both options dramatically change the dynamics in the affected regions. A new NSW-SA interconnector will potentially result in reserve sharing that may otherwise have been modelled as surplus in NSW (with any potential de-commitment decisions then subsequently affecting the viability of the interconnector option).

Basslink 2 is currently under consideration by a joint Federal and Tasmanian Government Review Group. Preliminary findings released in June 2016[10] recommended a second interconnector, subject to the final report in December 2016, as there was likely to be long term benefit to consumers from its development. The additional interconnect to Tasmania would further cement links between the Victorian and Tasmanian regional prices, potentially requiring greater modelling focus than was used in 2014[11].

A NSW-SA interconnect is being considered by Electranet and Transgrid[12], with initial RIT-T planning underway by Electranet. Although no timeframe has been set for the determination and/or implementation of this link, SA government comments reveal a strong desire for a speedy implementation. The resulting change in the existing SA gas-fired generation economics, the change in loop flow dynamics (and subsequent modelling) between Victoria, NSW, SA and possibly Tasmania with Basslink 2, will require very careful consideration for reliability setting implications and associated modelling.

8.4. Generation Modelling

As discussed, the very nature of modelling complex power systems requires some form of simplification. Although not requiring full power system load flow modelling, our assessment is that a greater degree of detail will be required in the future to capture variability in capability of a number of technologies and consequential effect on reserve conditions. We note key considerations in this section; a more extensive list is provided in Appendix A.

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9 AFR, 27 July 2016, http://www.afr.com/news/politics/agl-energy-boss-says-new-rules-needed-for-wind-solar-20160726-gqdq5t

10 Warwick Smith, Feasibility of a Second Tasmanian Interconnector – Preliminary Report, June 2016

11 ROAM Consulting, Final Report, p 4

12 Transgrid website, https://www.transgrid.com.au/news-views/news/2016/Pages/SA-NSW-Interconnector-the-missing-link-for-power-grid.aspx Accessed 2-September-2016

8.4.1. Inertia and power system security

To manage the emerging disconnect between high demand/high price and critical USE periods in the future NEM we consider modelling will need to take account of regional inertia conditions that would otherwise result in uneconomic price signals leading to de-commitment of high-inertia plant, therefore placing the power system in a condition whereby normal credible contingency events will result in high rate-of-change-of-frequency (RoCoF) events. It is possible these USE events could potentially occur at periods of the day/year that would have been highly unusual in previous assessment periods.

To incentivise inertia services without a Capacity Payments mechanism, a regional inertia reliability level could be built into the market (and corresponding market model), thereby creating the supply/demand balance for an inertia price paid as an enablement service in MWs. AEMO is currently undertaking analysis through the Future Power System Security works program that will inform this discussion before the end of 2016 thereby making it possible to include in the 2017 assessments. Directly specifying inertia in MWs rather than the number of synchronised units in service can provide the pricing signal for incumbent generation, new synchronous generation/condenser/flywheel solutions or fast response storage solutions. Potentially, as currently occurs with FCAS, NEMDE would still determine a solution to meet the constraint level at the cheapest enablement level, in much the same way it does with FCAS at present.

8.4.2. Unit commitment and plant mothballing

A major input to any reliability settings will be the state of the incumbent, non-operating plant (which some observers refer to as intermediate or peaking capacity) and their state of readiness and ability to respond to short to medium term, as well as progressive, pricing signals. Greater emphasis will be required in future modelling to fully appreciate fuel supply limitations and/or time to respond mechanisms.

For instance, operators of a gas fired plant in a region with high wind penetration and high spot gas prices may adopt a (rational) strategy to sell its contracted gas across a monthly or quarterly basis where little production was expected, thereby rendering the plant incapable of responding to high-price market signals for generation within the next 7-14 days (the plant would likely have been placed in a standby mode). Although gas may be physically available in the system at a spot price far in-excess of its contracted value, the gas-plant will face additional carriage or transport charges, but may be physically restricted from returning the plant to generation status any sooner than a week to ten days. This would render a week-ahead unit commitment model ineffective and may need to be moved out to a fortnight for both gas pricing and plant availability, and will require a far more complex commitment decision making representation. Assumptions about electricity market contracting that would incentivise immediate response will be highly relevant in this situation.

8.4.3. Improvements on stochastic unit commitment

Typical unit commitment modelling decisions[13] (similar to that used by ROAM in 2014) involve the use of key generation and cost factor inputs fed into a form of mixed integer linear program with resultant outcomes providing an optimised, perfect foresight view of the unit commitment decision.

The current reality within the NEM is potentially more complex than this (highlighting the need to fully understand the nature and impact of simplifications), in the following ways:

13 Yao et al, Lawrence Livermore National Laboratory, September 2012

- Increasing levels of variable wind and solar generation, produce increasingly more variable market pricing, hence scheduled generation commitment profiles[14];
- This in turn is creating increasingly volatile pre-dispatch price outcomes in both energy and the co-optimised FCAS markets (both raise/lower and regulation/contingency services); and
- Increasingly volatile gas purchase and transport decisions based on daily (or intra-daily) gas market pricing.

Under a planning system that has weather assessments and renewable load traces linked and under consideration before unit commitment, a more aligned unit commitment decision is likely. Similarly, the above complexity is unlikely to be able to adequately modelled at the necessary level of volatility, simply through modifications to outage rates or running profiles.

8.5. Gas Pricing and Fuel Supplies

Since the previous reliability review, significant enhancements have been implemented in gas pricing through the implementation of the STTM markets, trading hubs and increasing transparency around pipeline capacity. Therefore, the use of electricity modelling techniques incorporating greater gas price volatility will result in more realistic electricity pricing mechanisms, albeit increasing the complexity of the outcomes produced.

Similarly, as increased renewable generation is installed across the market, existing thermal plant will look to optimise the volume of coal purchased or nominated across the short to medium term to match expected generation profiles that are likely to be lower than previously occurred, even when operating under long term contracts.

14 Traditional modelling of wind variability generally concentrated on average monthly/quarterly or yearly average generation profiles that appeared consistent with actual/expected outcomes from participant annual reports or company statements. From a power system security and reliability point of view going forward which operates to a few shorter timeframe, this will require far greater depth and consideration.

9. Additional Considerations to NEM Reliability Settings

9.1. Updates to 2014 Data Sources

As would be expected, several updates are available to the data that was utilised from 2013, with many of the sources remaining current and developing further over nearly 4 years. Table 3 details further the latest enhancements in each of the key modelling elements as well as additional comments where applicable.

Table 3: 2017 Data improvements made – 2013 & 2016

Key Modelling Element	Key Data Used - 2013	Key Data Updates - 2016	Comment
Demand Forecasts	AEMO NEFR (2013)	AEMO NEFR (2016)	
Demand Profiles	Actual demand profiles	Weather multi-physics models	Option to adopt methodologies from NREL
Gas Pricing and Supply Constraints	Internal ROAM estimates and AEMO Planning Assumptions (2013)	AEMO Gas Pricing Consultancy Databook (2016)	
Generator cost information	AEMO Planning Assumptions (2013)	Australian Power Generation and Technology Report (CO2 CRC - 2015). Emission Factor Assumptions (ACIL - 2016). Large-scale PV costs (BNEF)	Updates possible before 2017
Carbon Pricing	Federal Treasury Core Projections (2011)	No clear pricing mechanism determined as yet	Subject to judgement about likely regimes
New Entrants	ESOO (2013)	AEMO Generation Planning Website	Regularly updated website, includes ESOO updates
Forced Outage Rates	AEMO Planning Assumptions (2012)	2016 NTNDP database	
Cycling Costs	NREL (2012 - US based) applied to NEM	2016 NTNDP database	
Planning studies constraint equations	NTDTP 2013 (with the Heywood Upgrade included)	Link to ST PASA constraints	
IC outage conditions	2006 MRL Assessments	AER Annual Benchmarking Report - Distribution and Transmission 2015	
Modelling interval	Half-hourly profiling	Half-hourly profiling with 5-minute dispatch security considerations	This will be a challenge for some modelling packages in terms of data management
Monte Carlo	25 iterations across the future 5-year forecast period	100-200 iterations across the future 5-year forecast period	Increased iterations more likely to capture increasing variable interactions

9.2. Potential New Data Requirements

As noted in the above discussions, new data will be required for the 2017 assessments and beyond. Table 4 contains additional information for consideration.

Table 4: Potential New Data Sources

New Modelling Elements	Key Data Sources	Comment
Multi-physics historical weather patterns	Various weather companies	Rather than using demand as a starting point for modelling
Generator Inertia / FCAS capability	PSI-TAG Working Group Papers	Some enhancements may be required for use as a modelling input
Wind Variability	AEMO's AWEFS systems	Considerable understanding has been developed in the past few years on wind variability and environmental conditions
Solar PV	APVI ASEFS2 Data	Both separate sources are now actively updated and capable of being used as a modelling input
	Current and Forecast Installation Rates	
Storage Solution Options	Both distributed and grid-scale	

Appendix A: Modelling Technical Considerations

A.1 Introduction

The first step in a modelling exercise is to select the broad strategic modelling approach. Section 3 discussed this point and section 4 discussed the changing environment that modelling will need to accommodate. This section firstly reviews the broad range of approaches and then develops a checklist for features of a methodology that should be assessed in 2017 modelling

A.2 Brief scan of selected international practices

Operation of the NEM is based on a relatively sophisticated optimisation of energy and ancillary services, as a result there are few international markets to compare it with. However, most bulk power systems are dealing with evolving technologies discussed above and there is benefit in reviewing how reliability, especially the impact of the evolving technologies is being managed and assessed.

For example, over the past 2 years, EirGrid has been developing their DS3 Programme, '**D**elivering a **S**ecure, **S**ustainable Electricity **S**ystem), which has similarities to AEMO's Future Power System Security Program. Given a relative similarity in system size to Victoria in the NEM (but with the renewable penetration of South Australia), this program is focussing on dispatch security within its existing and future market mechanisms.

Recent work conducted by the Lawrence Livermore National Laboratory in California (LLNL)[15]. LLNL has recognised that the increased complexity of the power system from additional intermittent generators and consumer participation through demand-response programs drives the need for next-generation optimisation and control algorithms with orders-of-magnitude enhancements in capabilities.

Working for the California Energy Commission, LLNL has reported on development of a short term planning process based around atmospheric or weather models/records. Our proposal for enhanced development of scenarios has been informed by this work – see Figure 1 below.

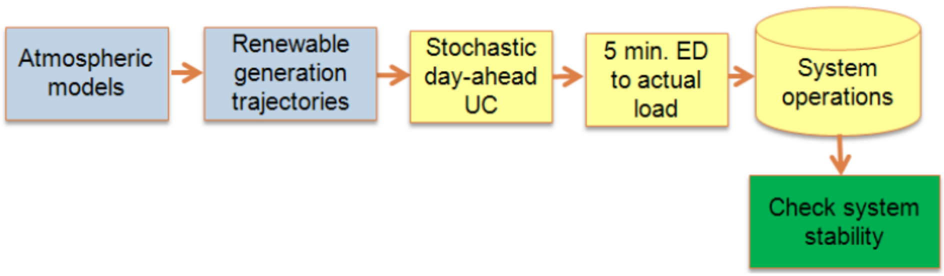

Figure 1: Components of the Planning System (Fig 1)

15 Edmunds et al, Integrated Stochastic Weather and Production Simulation modelling, NNLN, 2014

From a series of 30 weather trajectories in a multi-physics ensemble (denoted by the blue squares in Figure 1), a conversion of weather trajectories into ensembles of renewable generation AND load trajectories are made, which would then be integrated into traditional market models as found on the market today (denoted by yellow). The last step, 'Check system stability' (in green), is included to ensure system security parameters are not violated in the 5-minute dispatch outputs through appropriate assessments for inertia and FCAS.

In the NEM, detailed weather information is currently used within AEMO for demand forecasting and AWEFS, with AWEFS also supplying expected Renewable generation forecasts, with the remaining elements (in yellow and green) similar to existing pre-dispatch and dispatch parameters (used within AEMO and found in most commercial applications).

A.3 Detailed modelling features

Market modelling exercises are simplifications on reality, balancing time, cost and outcome. The next section brings the issues we have discussed together in a form of checklist of features that should be assessed to address the matters raised in the previous sections – not necessarily included as the more features that are included the more complex the model and the slower it will run.

A.4 Methodology checklist

This section presents the checklist of features

- Greater use of actual atmospheric conditions (contributing to the natural variability of electricity and gas demand as well as distributed generation), utility-scale wind and solar variability (incorporating wind speed, wind speed direction changes and operating temperatures[16]):
  - cross-temporal generator and transmission outages, including n-x contingency assessments;
  - fuel pricing (inclusive of hydro, gas, coal and LPG resources);
- Monte-Carlo and stochastic (ensemble) forecasting methodologies:
  - to capture the range of uncertainties outcomes given slightly different input conditions; and
  - for probability determinations for reliability assessments.
- Capacity Expansion Planning:
  - Nash-Cournot (or equivalent) equilibria to determine the expansion plans and production decisions that reflect market behaviours and profit incentives in both contract and spot conditions and avoid simple reserve margin criteria as the basis for investment;
  - Technological cost curves (and their varying rates of change) are an input based on commercial factors (with a conservatively lower level to allow for R&D innovation incentives); and
  - Time taken for each type of new generation to come online both in terms of new investment capacity installed and approval processes.

16 Particularly in Australia, operating temperatures above 30°C for wind farms are regular, yet some European based manufactures must install carefully modified equipment to operate within typical Australian conditions (up to 40°C)

- Generation Planning:
  - Continued assessment based on traditionally modelled economics and technical limits including, but not limited to:
    - Power curves for heat rates, hydro dam/head, wind-speed/irradiance and allowing for potential multi-fuel operations (gas/oil/diesel) – this would be a key parameter for system security constrained dispatch assessments;
    - Minimum operating levels and varying ramp up/down rates (ie unlikely to provide maximum ramp at minimum operating levels);
    - Parameters affecting operating, generating, start up and shutdown profiles, especially around CCGT operating modes;
    - Generation and Transmission maintenance is co-optimised for both run-length requirements and potential revenue impacts, including the STIPIS[17] incentive regime;
    - Emissions production factors and costs; and
    - Cascading hydro generation including pumped storage, head storage constraints and waterway flow delays.
  - It is expected there would be increasing focus on:
    - thermal generation EFOR rates as decreasing commercial returns affect OPEX, subsequently impacting reliability with progressively increasing EFOR rates;
    - assessment on fuel-supply related limitations particularly in the wake of decreasing returns affecting CAPEX spend, ie increasing coal offloading shortfalls; and
    - Use of gas peaking running-hours maintenance limitations (typical peaking plant cannot run for sustained periods of generation, ie for several days during low wind periods) therefore Maximum Continuous Ratings (MCR) considerations must be applied.
- Transmission and network assessments that include:
  - Detailed network loss models across AC and DC lines, with regionally based FCAS and inertia assessments at 5-minute basis (thereby capturing security constrained dispatch outcomes that will be missed in 30/60 minute intervals[18]); and
  - Recognition of network incentives on network outages and consequential need for detailed constraint formulations.

17 AER, Service Target Performance Incentive Scheme version 5, September 2015

18 Ela et al, NREL, Figure 25

- In a NEM with a more geographically dispersed (less centralised) and intermittent generation fleet the network capability that provides access cannot be modelled with the broad assumption of full access. This is especially so for intermittent generation embedded deep in the network. The impact of incentive arrangements on TNSP's, daily outages will also be relevant as TNSP outage decisions are increasingly being exposed to market conditions through mechanisms such as STIPS. High-level, MT PASA that are commonly used to represent these limits may therefore be inadequate and more sophisticated ST-PASA or Pre-Dispatch constraints more relevant. However, computational demands of modelling will rise markedly if these more sophisticated constraints are employed. This situation suggests a need for review of the significance of resultant network capability and impact on generation contribution to reliability including that the more embedded a generator is the more likely it is to be primarily serving local demand.

- Integrated gas & electricity market modelling that includes:
  - Gas production, supply, storage, pipeline dynamics (including reverse flow events and time-to-change) are modelled in sub-day time horizons to account for scarcity issues;
  - Gas demand is linked to the same atmospheric conditions identified above (1a) and gas fired generation demand; and
  - Gas-fired plant standby status allows for gas consumption to occur to keep plant warm, thereby allowing for faster times-to-start should commercial prices arise (this will be critical in future unit commitment decisions – hot and cold units respond in different ways with economic drivers).
- Environmental considerations:
  - RET and State-based schemes are simulated through potentially variable demand/supply prices rather than fixed prices (unless specifically set) with appropriate cap/trade and penalty factors; and
  - Electricity generation and gas plant emissions factors are MW level/efficiency based rather than MWh, to account for higher emissions under sustained low generation periods.
- New Technology considerations:
  - Battery capacity and energy storage will fall faster than traditional new technologies due to cross-industry R&D purposes, requiring strong, expected and weak uptake cost assessments;
  - Additional storage technology such as hydrogen-based solutions, which are currently being implemented in Germany (where wind penetration is particularly strong[19]) will enter the NEM and challenge existing ancillary service and energy providers, all within the expected modelling timeline;
  - Enhanced transmission and distribution flow control devices and/or large scale battery energy storage systems (for energy and/or ancillary service provisions);

19 Overspeed, Storage of Renewable Energies July 2016 (http://www.overspeed.de/fileadmin/user_upload/media/en/Flyer_Storage_Overspeed.2016-07-21.pdf)

  - Geo-locational issues associated with (Electric Vehicles (EV) charging regimes will add considerable variability to demand forecasting, requiring greater understanding and assessment; and
  - Increasing influence of accessibility to information of consumers own load and price (time-of-use like tariffs) will progressively flatten consumer demand curves;
- Appropriate time-frame granularity to ensure adequate assessment of security-constrained dispatch and treatment of intermittency considering:[20]
  - That unit commitment and dispatch at low demand periods is inherently more complex than at peak times. Modelling at low demand will have an obvious influence the MPC. However, depending on the detailed design of any mechanisms to manage low inertia situations but also be relevant to marginal revenue of thermal plant (i.e. high inertia plant) and affect the mix of commercially viable capacity at all times, including high demand; and
  - Accordingly, we expect that chronological modelling will be needed at least in part. ROAM utilised chronological techniques in the 2014 work and we therefore see this continuing.

As noted, not all of the above list of features may be needed. Our intention here is that each item be considered and a positive choice made as to whether each is warranted in the light of the benefit and cost of inclusion.

20 In the absence of significant intermittency, it has arguably not been necessary to utilise short term (5 minute or 30 minute) modelling for the purposes of assessing Reliability Settings. It has been 'safe' to assume that fast starting peaking OCGT plant and hydro would be available to meet reasonably predictable temperature related demand peaks. Models which represent the NEM via blocks of demand or time have been adequate. This assumption is now probably not valid given the evolution of technology and growing intermittency. For example, the choice between OCGT plant, demand side and storage as the marginal resource requires a number of assumptions about the utilisation and inter-temporal availability of the technologies. There is considerable risk these assumptions create self- fulfilling and opaque solutions.

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