18 May 2018

Ms Sarah-Jane Derby
AEMC
Level 6 201 Elizabeth Street
Sydney, NSW, 2000

Submission lodged at AEMC.gov.au
Review Code: EPR0060

Dear Sarah

Reliability Frameworks Review – Discussion Paper

The Generator Group consisting of Snowy Hydro, Delta Electricity, and Origin Energy have commissioned SW Advisory Pty Ltd to provide a brief report that:

- critiqued the need for a Day-ahead Market (DAM);
- assessed the materiality of the current concerns from AEMO; and
- provided a set of high level tweaks to the current NEM processes to facilitate what the Day Ahead Market was intended to achieve.

The Consultants report concludes that there are a number of problematic issues associated with a compulsory US style Day-ahead market. Such a market is fundamentally incompatible with the NEM's design and philosophy of decentralised decision making. Nearly all of the identified problems in the NEM can be addressed more effectively by means other than a compulsory DAM.

The Generator Group formally submits the Consultant's report titled, "Critique of Day Ahead Markets and the NEM - Final Report, Friday 18 May 2018" as a submission to this review. For the avoidance of doubt this report is public.

Yours sincerely,

The Generator Group.

Critique of Day Ahead Markets and the NEM

Final Report

Friday, 18 May 2018

Author: Stephen Wallace

SW Advisory

Disclaimer

This report has been prepared by SW Advisory Pty Ltd and is supplied in good faith. It reflects the knowledge, expertise and experience of the consultants involved in its preparation. SW Advisory make no representations or warranties as to the accuracy of the assumptions, models or estimates on which any forecasts, calculations or conclusions are based.

Executive Summary

There is clearly no need for a day-ahead market to supplement the existing NEM NEM design. A day-ahead market would be contrary to the NEM's design principles of decentralised decision making and consistency between dispatch and pricing. Fundamentally Participants are best able to manage their unit commitment decisions and have the best understanding of the risks that affect their business. The report concludes:

- A day-ahead market in the NEM seems to be a solution to a deficiency in the NEM that has not been clearly articulated;
- The NEM was designed around price signals providing incentives for efficient behaviour. Where there are deficiencies in price signals or information, AEMO should be looking at market solutions and not system control solutions;
- If there are security issues such as system strength in South Australia, these issues can be solved through the provision of new ancillary services and an integrated market for inertia and fast response FCAS contingency services (it is far easier to fix up the ancillary service arrangements than introduce a compulsory US style day ahead market that centrally determines unit commitments);
- The may be significant adverse impacts on the NEM with the introduction of a unit commitment day-ahead market including:
  - A globally less efficient unit commitment optimisation when participants' private information and opportunity costs cannot be optimally taken into account;
  - Complications with settlements if there is 5 minute dispatch interval settlement for the real time dispatch and a 30 minute settlement interval for the day ahead market (if a 5 minute trading interval is used for the day ahead market then the security constrained unit commitment optimisation may be very difficult to solve);
  - The inefficiencies that may eventuate in the spot market if a reduction in rebidding flexibility is introduced to fit in with the day-ahead market;
  - Complications with offer structures and cost recovery mechanisms that pervert the NEM's price signals:
    - Would generators be paid start-up costs and how would these be recovered?
    - Any uplift cost recovery mechanisms may not allow Participants to manage their exposures;
  - A day-ahead market is likely to reduce incentives to invest in flexible generation and loads; and

- A compulsory day-ahead market's two part settlement system would interfere with the contracting arrangements in the NEM. The two part settlements of a day-ahead market may adversely impact prudent risk management and the depth and liquidity of the contracts market.

There are a number of problematic issues associated with a compulsory US style DAM. Such a market is fundamentally incompatible with the NEM's design and philosophy of decentralised decision making. Nearly all of the identified problems in the NEM can be addressed more effectively by means other than a compulsory DAM.

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1 Introduction

SW Advisory was contracted by the Generator Group[1] to provide a brief report that:

- critiqued the need for a Day Ahead Market;
- assessed the materiality of the current concerns from AEMO; and
- provided a set of high level tweaks to the current NEM processes to facilitate what the Day Ahead Market was intended to achieve.

In particular, the Generator Group wanted the consultancy to:

- Reference and critique Chapter 4 (Day-ahead markets) in the AEMC's Reliability Frameworks Review directions paper.
- Critique whether there is a material problem with the NEM which can be addressed through Day-ahead markets.
  - If there are any material problems can these be addressed through targeted improvements to the existing NEM arrangements?
  - What are the pros and cons associated with implementation of either USA style or European style Day-ahead markets?
  - Would implementation jeopardise the core success features of the NEM such as decentralised decision making and the flexibility to adjust generation in response to new information as it becomes available?

1.1 Background

The NEM's power system is undergoing substantial change. There has been a significant increase in large scale variable renewable energy (VRE), a reduction in load growth, increased PV penetration at the household level and retirements of a number of coal fired power stations. These trends have combined to produce large increases in inverter based VRE generation, reductions in synchronous generation, increases in customer-connected generation (PV) and increased demand response via batteries.

These changes are causing the system and market operator, AEMO, some concerns about managing security and reliability in the NEM. To address these concerns AEMO has suggested that a centrally facilitated day ahead market may be required.

In its Reliability Frameworks Review the AEMC sought stakeholder feedback on what existing day ahead features of the NEM may require change. To date AEMC has received little feedback on this topic and the deficiencies that stakeholders have identified in the existing market design have generally related to information provision and / or security-related matters rather reliability matters.

[1] The Generator Group consists of Snowy Hydro, Delta Electricity, and Origin Energy.

In order to get additional input from stakeholders, the AEMC has published a Directions Paper as part of its Reliability Frameworks Review and is seeking comment on a number of work streams. This report aims to provide input to one of the work streams: the assessment of the suitability of a day-ahead market in the context of the NEM. The AEMC's directions paper provided a good discussion and analysis of the merits of an ahead market. This report tries to provide some additional insights to those found in the AEMC paper and to emphasise areas that may be of particular importance to the generators in the NEM.

1.2 Rationale for a Forward Market in the NEM

In its Directions Paper, the AEMC identified three high-level objectives an ahead market (short term forward market) could be designed to achieve. These were:

- *" To provide market participants (both demand and supply side) with more, or better quality, information so that they can incorporate this information into their unit commitment or demand response decisions and bids/offers and therefore increase the efficiency of outcomes in the NEM wholesale market, including reliability and security outcomes.*
- *To provide the system operator with more, or better quality, information so that the system operator can use this information to more efficiently manage the system in relation to reliability and security outcomes, while maintaining the current generator self-commitment arrangements.*
- *To provide the system operator (rather than participants) with a schedule that centrally coordinates unit commitment decisions, the intent being to increase the efficiency of outcomes in the NEM wholesale market, including in relation to reliability and security outcomes. "*

1.3 Day Ahead Markets and NEM Reliability and Security

The push to have a US style day-ahead market (DAM) in the NEM seems to be a solution to a problem or deficiency in the NEM that has not been clearly articulated. What is AEMO's rationale for pushing for a DAM? Before embarking on a solution, the NEM's problems should be articulated and possible options for their solution should be identified and evaluated.

Never-the-less there seems to be an implication that there is a potential reliability and security problem in the NEM which can be solved by a DAM. Underneath the DAM solution appears to be a desire by AEMO to gain more direct control over the power system. This is an outcome that would result in AEMO becoming more of a system controller rather than a market operator.

When the NEM was originally designed there was a concept that market would operate via price signals rather than via a system operator controlling the market and that decision making would be decentralised to participants as much as possible. Following this logic, if there are reliability and security issues in the NEM then the NEM should be looking at:

- the price signals that drive generator operations and investment and where they are failing; and
- the information provided to participants and where it is inadequate for efficient market operations.

As a first step, the NEM should not be looking at giving greater control to AEMO. AEMO should be looking at market solutions not system control solutions.

There is a clear relationship between the market price cap and system reliability. The set of market price caps (market price cap and cumulative price thresholds) and the methodology for determining intervention prices and compensation affect generator operations (including unit commitment) and investments. A generator will not commit a unit if it thinks that the spot price x probability of running is not greater than its commitment and running costs or its compensation if it is directed by AEMO.

If there are potential reliability problems the market price cap should be raised. If the problems are only related to one region, such as South Australia, then perhaps there could be a higher market price cap there. This would fit in with the changing nature of the power system and the varying degrees of VRE generation penetration in different regions.

A higher market price cap would encourage retailers and wholesale customers to contract more highly and generators to contract less highly thus creating a greater demand for more generation and thus improve reliability in the NEM. This is an area that intersects with the National Energy Guarantee and hopefully will be considered in the design of the scheme.

If there are security issues we should be looking at the structure and nature of the NEM's ancillary services[2] and AEMO's security constrained dispatch process including NEMDE and how the generic constraints used in NEMDE are generated and whether there could be a better dispatch process. Clearly some of the South Australian issues could be solved if there was a "system strength" ancillary service and an integrated market of inertia and very fast response FCAS contingency services. New ancillary service arrangements would be much easier to implement and cause much less disruption than implementing a compulsory DAM with unit commitment.

Lastly, if the NEM's problems are ones of co-ordinating participants then the NEM's provision of information should be looked at. Is the information that AEMO is providing to the market adequate for efficient participant operations and unit commitment decisions? Is there some information that is missing? Is there a timing issue? Is there a quality issue? How can the information that AEMO is providing to market participants be improved?

[2] The AEMC has initiated a number of work streams aimed at addressing some of these system security issues including is Frequency Control Frameworks Review

2 Issues Facing the NEM

2.1 Changing Generation Mix

The NEM's generation mix is undergoing substantial change. There have been substantial increases in inverter-based, large scale, variable renewable energy (VRE) generation (wind and solar), a reduction in load growth, increased PV penetration at the household level, increased use of batteries at the household and system level, and retirements of a number of coal fired power stations.

Increasing levels of inverter-based generation is causing the overall inertia in the power systems to reduce. Importantly, in some parts of the network with high densities of VRE generation, the inertia of the subsystem can fall to very low values.

As the inertia reduces, frequency control becomes more challenging as there is less time available to address imbalances in supply and demand. Furthermore, the NEM's frequency control ancillary services (FCAS), which are procured using rigidly defined categories of services split into discrete timeframes, are not always fit for purpose in some regions and subregions such as South Australia and Northern Queensland when these areas can be islanded.

The increased VRE generation adds an additional source of variation to forecasting the demand and supply balance, days and hours ahead. However, no matter how good the forecasting tools which are used the actual outcomes will always be different to those forecast hours or days earlier. The weather and customer behaviours are not deterministic and will always have some inherent randomness. Thus, looking forward the NEM will have greater difficulties forecasting the demand and supply balance ahead of time and will require more flexible and highly responsive generation to efficiently manage the power system. A day ahead market is unlikely to assist with managing the variability of VRE generation and loads.

2.2 SA Commitment of Synchronous Units

Following the system black event in South Australia in 2016, the spot market in South Australia was suspended. During the market suspension, AEMO put in place a power system security requirement to maintain a minimum of three thermal synchronous generation units (each not less than 100 MW) online at all times. The market has not always met this requirement which has caused AEMO to direct participants and invoke intervention pricing.

2.3 Desired Generation Capabilities in the Future

Looking ahead, we expect that there will be a steady increase in large scale VRE, PV generation in the distribution network, use of batteries, and a reduction in coal fired synchronous generating units. All of these trends point to the need, in the longer term, to have more flexible and fast responding generation and loads enter the market. More slow start and inflexible generation is not required. More fast start pumped storage hydro generation, batteries and GTs would be desirable. However, in the interim there is a need to keep operating much of the NEM's slower start thermal generation.

2.4 Investment Signals and Reliability

Whatever is done in terms of incorporating an ahead market of some form or not into the NEM, the decision should consider what are the likely price impacts on the spot market and whether these will encourage the investment in flexible, dispatchable generation and loads that the NEM will need in the future.

3 Day Ahead Markets

3.1 Spectrum of Forward Markets and Information

As discussed in the AEMC's directions paper, a continuum of forward market arrangements for the NEM can be contemplated. At one end is the existing arrangements which provide a rich range of forward information for participants to make decisions and manage their risks. At the other end there is the US style day ahead markets which are compulsory, financially binding and are used to determine unit commitment decisions. In between the two are the European markets which cater for forward trading. These markets are financially binding but not compulsory.

In order to further the discussion about what may be the merits or otherwise of the range of forward market arrangements some theoretical properties of forward markets and their prices are worth discussing.

3.2 Forward Prices and Spot Market Prices

3.2.1 Forward and futures contracts

A forward contract is a contract between two parties to buy or sell an asset at a specified price on a future date. If the asset is a physical commodity then the location for delivery of the asset is also specified. For instance, a coal supplier could enter a forward contract with a coal user to sell X tons of coal to be delivered to a specified location at a specified time in the future.

A futures contract is a standardised forward contract which is traded on a futures exchange.

A forward or futures contract that is cash settled does not require the delivery of the asset but does require a financial settlement. The amount of the cash settlement is the difference between the underlying asset's price agreed in the contract and its market price at the date of the settlement of the contract.

Both the European and US day ahead markets are forms of forward markets. In the case of the US markets they have a complicated clearing mechanism which is usually done by a security constrained unit commitment optimisation. If these markets are well designed and operating competitively and efficiently then the general financial theory on forward and futures prices should be relevant to their outcomes.

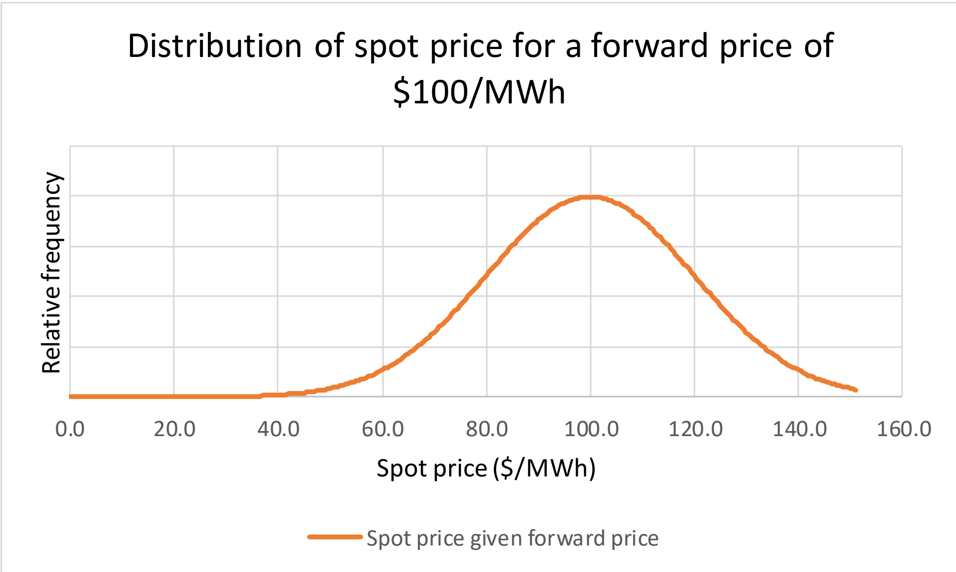
3.2.2 Theory

The general financial theory for forward and futures prices is that they will converge to spot prices by the delivery date. Thus, as you move from a two day ahead market to a one day ahead market to a one hour ahead market, the forward prices should on average converge to the spot price. This won't strictly hold in electricity because of its lack of storability but the general trend of the forward prices being better estimates of the spot prices the closer you get to spot time should hold.

The simplest model for forward prices is based on the expectations hypothesis which assumes that the forward/futures price will be equal to the expected spot price at the delivery time. The expectation hypothesis corresponds to a situation where there is no arbitrage opportunity between the forward and spot prices and neither the buyers nor sellers place a risk premium on forward contracting. Under this and other theoretical frameworks the variance of the forward prices is always less than the variance of the spot prices[3].

Figure 1 illustrates the frequency distribution of spot prices for time t in a hypothetical spot market with a forward price at time s of $100/MWh.

Figure 1 Example distribution of spot prices for a given forward price

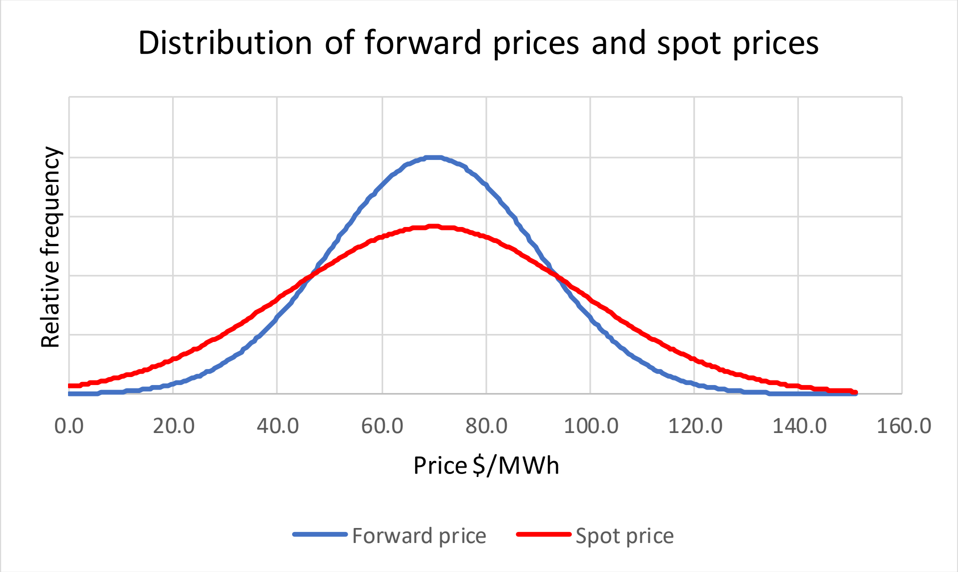


3.2.3 Distribution of forward prices

Figure 2 illustrates the frequency distributions of forward and spot prices for a hypothetical spot market with an expected price of $70/MWh. From the figure it is quite evident that the distribution of spot prices has much fatter tails than the distribution of forward prices. The implication of this is that peaking generators, pumped storage generators and batteries would be much less economically viable if they had to participate in a forward market. They would forgo the occasional very low and high spot prices for much more average prices.

[3] If F[t | s] is the futures price for time t at time s and S[t] is the spot price at time t then based on the expectations hypothesis F[t | s] = E[S[t] | all the information up to time s]. Also S[t] = F[t | s] + error = E[S[t] | s] + error and since error is independent of E[S[t] | s] then V[S[t]] = V[F[t | s]] + V[error]. Thus V[F[t | s]] <= V[S[t]].

Figure 2 Example distribution of forward and spot prices



3.2.4 Loss of option value

If flexible and responsive generators have to participate in a forward market, then they will lose much of the option value of their flexibility and thus make this generation less viable. This will be particularly the case for batteries and pumped storage hydro which will lose much of their exposure to both low and high prices.

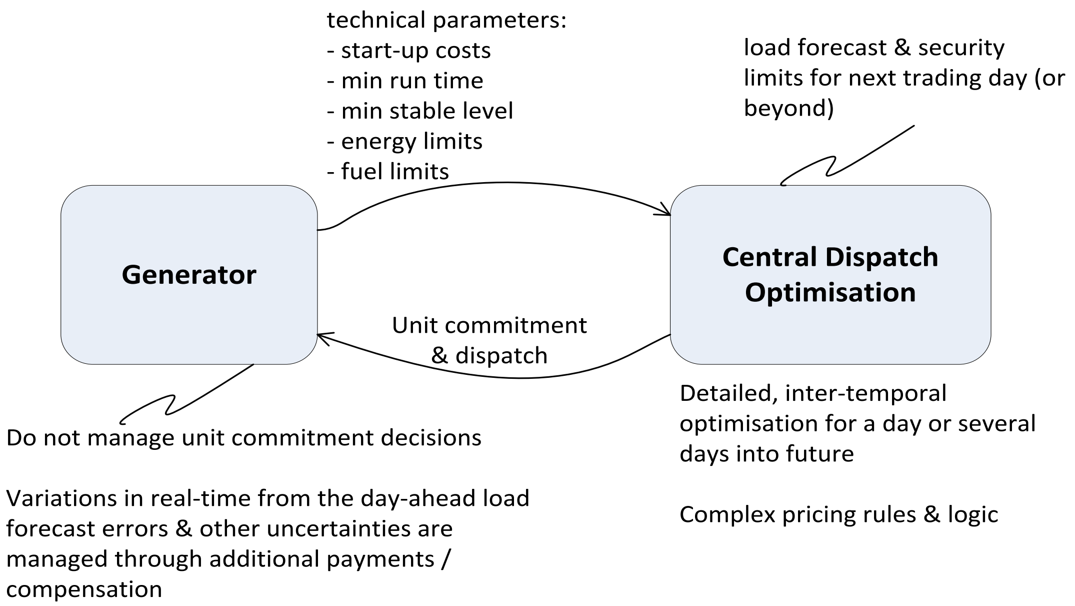
3.3 Decentralised Versus Centralised Decision Making

Irrespective of the market design, all resources in an electricity market need to be co-ordinated on a range of timescales from days ahead, to hours-ahead and minutes-ahead. Electricity markets need to facilitate this co-ordination. There are two main ways this is done: centralised approach vs. decentralised approach.

- In a centralised electricity market, the system and market operator is responsible for more decisions related to co-ordinating resources, in particular, when to commit units ; and
- In a decentralised electricity market, market participants are responsible for making more decisions on their own, in particular, when to commit units.

These two approaches are illustrated in Figure 3 and Figure 4. The centralised approaches tend to have been pursued as a carryover from what the system operator did prior to the development of an electricity market whereas the decentralised approaches are often explicitly pursued as part of the market design.

Figure 3 Centralised Electricity Markets (e.g. USA Standard Market Design)



In the centralised approach, the system and market operator attempts to optimise the commitment and dispatch of units based on a number of parameters such as each unit's start-up costs and times, fixed running costs, minimum run times etc. as well as each unit's price and quantity offers.

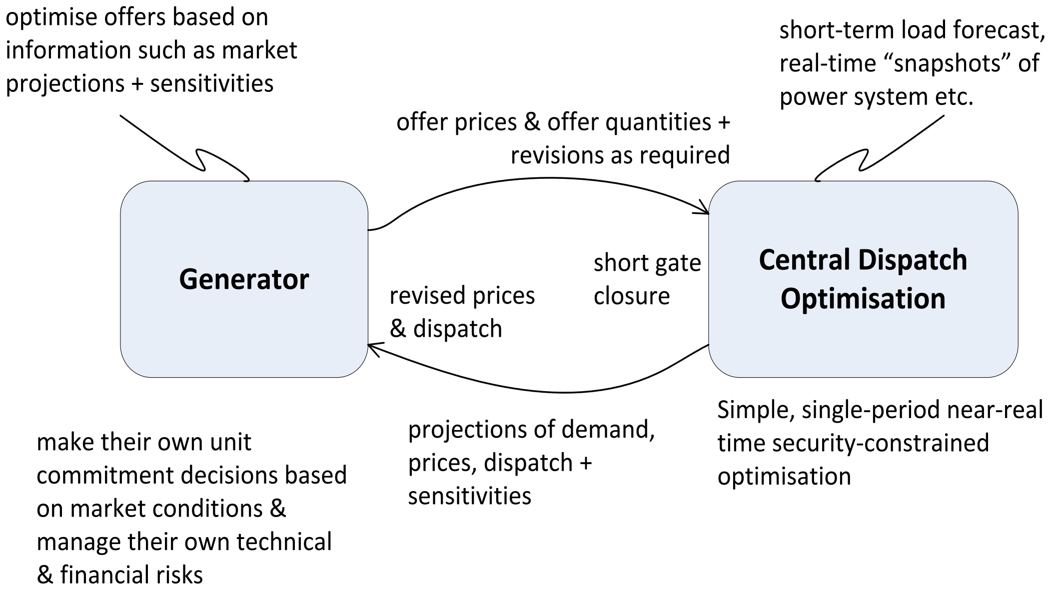
Inevitably these parameters do not fully reflect the opportunity cost of running a unit. Units may have energy limitations such as is the case for many hydro units, gas units with gas usage restrictions and batteries.

Further, for most slow start units, such as coal units, their unit commitment decisions are made for months ahead rather than for one or two days ahead and are often based on planned maintenance programs.

Since the unit commitment decisions are made a day or more ahead, the actual loads, actual VRE generation and availability of dispatchable generators can be quite different to what was expected and used in the optimisation. System and market operators will try to address these uncertainties by requiring larger amounts of reserves to be committed than is strictly necessary for the forecast loads and VRE generation. In some markets the system and market operators are looking at stochastic optimisations of the unit commitment decisions. In the end, because a system and market operator does not pay the costs of committing additional units to what is required (the market does) there is great temptation for a system and market operators to over commit units to what is required to meet any reliability standards. The costs to the system and market operator of occasionally having curtailed loads are very much higher than the costs of over committing generation.

Lastly, when additional parameters are used to determine unit commitments, the start-ups costs, fixed loading costs etc. have to be recovered in some form of uplift to the spot price. This in turn creates risks for generators trying to hedge any contracts because even if they offer their capacity at prices below the spot price there is no guarantee that they will be dispatched. The market design of the NEM explicitly addressed these issues when the decision was made to have simple price quantity offers and decentralised unit commitment.

Figure 4 Decentralised Electricity Markets (Most Asia-Pacific Markets: NEM, NZEM, Philippines WESM, Vietnam VWEM etc.)



For a decentralised electricity market to work well requires the following:

- the system and market operator needs to provide generators with regularly updated information on projected: prices, dispatches, price sensitivities and other market conditions to ensure they can make informed commercial and technical decisions;
- generators need to have sufficient flexibility to respond to changes in market conditions and/or the conditions of the equipment they operate; and
- market interfaces between the system and market operator and generators need to allow for the timely transfer of the information that is needed to manage issues such as: power system security, dispatch of plant, management of ancillary services, management of fuels and hydro reservoirs etc.

The decentralised approach to unit commitments and decision making, and all of the features above, are in the NEM by design. This is captured in the NER's clause 3.1.4 Market design principles, which states

3.1.4 Market design principles

(a) This Chapter is intended to give effect to the following market design principles:

(1) minimisation of *AEMO* decision-making to allow *Market Participants* the greatest amount of commercial freedom to decide how they will operate in the *market*;

(2) maximum level of *market* transparency in the interests of achieving a very high degree of *market* efficiency, including by providing accurate, reliable and timely forecast information to *Market Participants*, in order to allow for responses that reflect underlying conditions of supply and demand;

(3) avoidance of any special treatment in respect of different technologies used by *Market Participants*;

(4) consistency between *central dispatch* and pricing; . . . . .

The decentralised approach to optimising dispatch in the NEM can be thought of as a rough form of a Dantzig–Wolfe decomposition algorithm which is used for solving large scale linear programming problems with special structure. The linear program problems that the a Dantzig–Wolfe decomposition algorithm works well on have a core planning problem that connects a number of sub problems. In the case of the NEM each generator has their own optimisation problem with lots of private information (a sub problem) but their own optimisations are connected to AEMO's central dispatch optimisation via prices and dispatches and AEMO's central dispatch optimisation is connected to these sub problems via the offered prices and quantities.

Now the NEM tries to achieve the global optimum by AEMO providing rolling prices and sensitivities and generators responding to the new forecast prices and sensitivities by adjusting their offers via rebidding. Thus, the market is providing for an iterative process between the participants' sub problem optimisations and AEMO's central problem optimisation.

Also, this iteration enables new information to be taken into account by participants and AEMO. The likely outcome of this process is a better global optimum than one where there is very simplified information used in a once off optimisation as is the case in the centralised unit commitment optimisations.

We believe that participants are best able to manage their unit commitment decisions. They have a better understanding of their businesses and the risks that affect them than anyone else, and combined with the NEM's provision of a rich range of information they can make better unit commitment decisions for their businesses than any centralised process can.

3.4 Day Ahead Markets in the US

Nearly all of the US electricity markets have a day ahead market (DAM), nodal pricing and financial transmission rights. These are features of the US standard market design. Not all of the US markets have co-optimisation of energy and FCAS (reserves). In some US electricity markets energy and FCAS are managed via separate markets. Most US markets have low market price caps compared to Australia.

The US markets generally have a centralised unit commitment which is incorporated as part of the DAM. Along with the DAM comes a two part settlement system. The main settlement is in the DAM and deviations from the schedules in the DAM are settled at the real time spot price in what is effectively a balancing market. Thus, for most generators, most of their market revenue flows through the DAM not the real time spot market. This has implications for contracts and risk management.

3.5 Voluntary financial DAMs such as the European DAMs

The European DAMs facilitate trade at the margins between vertically integrated utilities, independent power producers and countries. These day ahead markets are managed by power exchanges and they ignore intra-zonal transmission constraints. The European DAMs are essentially financial markets trading forward contracts.

A financial DAM is like any other forward market. Participation is voluntary and there is no obligation on participants in that market to be involved in the physical production or consumption of electricity.

The price outcomes of a financial DAM should indicate the expected spot prices in the real time markets otherwise there will be arbitrage opportunities from which traders can profit.

A financial DAM need not be run by AEMO. It could be managed by the ASX or any financial hedge market operator. If it was run by AEMO there could be some co-ordination and management of prudential requirements in both the DAM and spot market.

There is nothing stopping existing financial intermediaries developing shorter dated financial products, if there was a need for such products. Additionally, there are bespoke shorter dated contracts that are readily traded amongst counter-parties, it is just not transparent to bystanders.

If a financial DAM was developed by a financial intermediary or AEMO, it also might be worthwhile looking at running such a market on a longer term timeframe such as weeks out from spot time. This could provide additional short to medium term contracting avenues for generators and customers. But to make the longer term option at all useful it would have to provide additional benefits to market participants to what can be obtained from the futures and options contracts traded on the ASX.

When considering a financial DAM, it should be remembered that in the original market design for the NEM there was a proposal for a short term forward market to be managed by NEMMCO (AEMO) that would enable trading one to two days in advance of the spot market. In the end this market was never implemented because there was no participant demand for it and it was not seen as being required for the NEM.

Thus, a prerequisite for considering the introduction of a DAM for the NEM should be to gauge whether there is a sufficient participant demand for it. There is a general feeling among many market participants that a European style DAM is simply not required as the NEM already has a liquid and deep financial market for contracts.

3.6 Need for Centralised Unit Commitment Decisions

The NEM doesn't have an energy market unit commitment problem. Table 1 shows the number of unit starts for all of the units in the NEM classified by the unit type. The coal fired units do not have many starts over a whole year. Daily unit commitments is not an issue for them. For fast start units, such as hydro units and fast start GTs and CCGTs, commitment decisions for the day ahead are not an issue. The only units where day ahead commitment decisions could be an issue are the slow start GTs and CCGTs. These units average one unit start every 10 days. A daily unit commitment optimisation with a look ahead of one or two days would not be much use for these units as well.

Table 1 Unit commitments for financial year 2016/17

Type of unit	Number units	Total registered capacity of units	Average unit capacity	Annual start-ups	Average number start-ups per year	Average number start-ups per day
Black Coal	38	18,359	483	330	8.7	0.02
Brown Coal	10	4,690	469	96	9.6	0.03
CCGT (fast)	2	243	121	280	140.0	0.38
CCGT (slow)	9	3,132	348	387	43.0	0.12
Diesel (fast)	2	108	54	341	170.5	0.47
GT Gas (fast)	55	5,550	101	5,721	104.0	0.28
GT Gas (slow)	9	1,362	151	320	35.6	0.10
GT liquid fuel (fast)	7	576	82	416	59.4	0.16
GT liquid fuel (slow)	1	50	50	22	22.0	0.06
Hydro	45	8,512	189	7,479	166.2	0.46
Solar	3	213	71	1,139	379.7	1.04
Wind	24	2,794	116	5,708	237.8	0.65
Total	**205**	**45,588**		**22,239**		

Source: raw input data provided by Snowy Hydro

The NEM does not appear to have an energy unit commitment problem. However, there is a problem in South Australia of ensuring that there are at least three synchronous units running to manage system security. This is not an energy market reliability problem nor an FCAS problem. It is an ancillary service problem for a yet undefined ancillary service of "system strength".

The reason why there are times when generators don't want to commit enough synchronous units in South Australia is due to low forecast prices which are not sufficient for them to make an adequate return on committed units. This is further exacerbated by AEMO's use of directions and the compensation mechanism for directed units. The directed units get paid for start up and running costs when these are greater than their spot market revenues or the spot market revenues when it is the other way around. This in turn creates an incentive for the generators not to commit their units and wait for AEMO to direct them as they always do better financially when directed. Some better ways of compensating directed participants and managing intervention pricing are discussed in Endgame Economics and SW Advisory's review of intervention pricing for AEMO[4].

The synchronous unit commitment problem in South Australia could be largely solved by creating a new contracted ancillary service for "system strength" or other appropriate ancillary service which would allow AEMO to direct additional units to commit if there was a forecast shortage of synchronous units. The issue of low inertia as opposed to fault levels and "system strength" issues in South Australia could be addressed in the longer term with an enhanced FCAS market that could include payments for inertia. This is being addressed in AEMC Frequency Control Frameworks Review.

The South Australian synchronous unit commitment problem is not an energy or FCAS market unit commitment problem. Its solution is not a physical DAM with unit commitment. Thus, even though AEMC has deemed a market for additional inertia as being too complex, pursuing reforms in the ancillary service areas will be far less disruptive and a more efficient way of dealing with the synchronous unit commitment problem than implementing a US style unit commitment DAM.

3.7 Potential Impact of a Unit Commitment (UC) DAM

3.7.1 Introduction

This section outlines a number of issues and questions regarding the implementation of a US style DAM in the NEM.

3.7.2 DAM's impact on reliability

System reliability in the NEM is determined from the outcomes of the real time spot market. A DAM does not directly affect reliability or security other than how it affects what happens in the spot market. How a DAM affects a spot market will be very much influenced by the forecasts that the DAM uses for loads and VRE generation.

A physical DAM with unit commitment is unlikely to improve reliability in the NEM, in fact it might make it worse. If a physical DAM's ability to manage reliability is tied very much to the accuracy of load forecasts and estimates of VRE

[4] Oliver Nunn (Endgame Economics) and Stephen Wallace (SW Advisory) Review of Intervention Pricing for AEMO, 2nd October 2017.

generation a day or more ahead then it could easily underestimate the amount of dispatchable generation required for the spot market in the following days. The generators not included in the DAM schedule would probably not have the same incentives to be available at spot time, as is the case in the current NEM arrangements, particularly if the reference price for contracts moves from the spot price to the DAM price. Consequently, reliability in the spot market could go down.

This potential situation would in turn encourage AEMO to:

- under forecast VRE generation;
- over forecast loads or
- require large amounts of generation reserves or FCAS in the DAM schedules to manage these forecast uncertainties.

In the end, market risk management in the NEM will move from a collection of participants with financial exposures making their own risk management decisions to a central body that does not have a financial stake in the market, making risk management decisions for the whole market. Further AEMO's own corporate risk management would consistently favour committing more units than necessary compared to potentially having a very occasional supply shortage. This misalignment of risk incentives could potentially result in higher costs to consumers.

3.7.3 DAM unit commitment optimisation

The DAM unit commitment optimisation is a mixed integer intertemporal optimisation which is usually solved using a mixed integer linear program (MILP). Integer variables, specifically binary variables, are required to model the unit start and stop decisions required to model unit commitments. The use of an intertemporal optimisation with binary variables results in an optimisation which is much more difficult to solve than the NEM's NEMMDE[5], which is a straight forward linear program. Further, it will result in DAM prices and dispatches that are not always intuitive and often hard to reconcile. The optimisation itself is not always repeatable since there is not always a unique optimal solution that can be found in an acceptable time.

The problem of actual loads, VRE generation etc. deviating from their DAM forecasts can be partially addressed by stochastic unit commitment optimisation which optimises across scenarios of load and VRE generation forecasts but this adds an additional layer of complexity to an optimisation that is already difficult to solve.

3.7.4 What would be the time interval for a DAM?

Most DAMs have a trading interval of 30 minutes or 60 minutes in length and these markets, typically, will use the same trading intervals as the spot market

[5] If the DAM UC models 48 half hours and has unit commitment decisions for say 100 units then it will have to search through 2 ^ (100 x48) = 2 ^ 4,800 possible combinations or starts and stops which is an extraordinarily large number.

settlements, so that for each trading interval in the spot market, the day ahead market would also be cleared. This is particularly the case for US style unit commitment DAMs which require a two part settlement process.

So what would be the trading interval for a US style DAM in the NEM, 5 minutes or 30 minutes? If it was 30 minutes this wouldn't match very well with the movement to 5 minute settlements in the spot market. How would the two part settlements be done? If the DAM was settled every 5 minutes then it would match the NEM's spot market settlement but the DAM optimisation would be much more difficult since there would be 6 times as many binary variables.

3.7.5 How would rebidding be incorporated?

If a US style DAM was implemented, how would rebidding be incorporated? Would rebidding continue just as it currently does in the NEM with the only difference being that at some time just prior to the DAM being cleared the bids and offers would be locked in for the DAM clearing and after the DAM is cleared the market would continue as before? Or would there be restrictions on changing offers after the DAM has cleared? Would there be the same rolling pre-dispatch information on prices, dispatches and sensitivities?

3.7.6 Effective gate closure one day ahead rather than 1 minute ahead

If a compulsory US style DAM is implemented in the NEM then the effective gate closure for most generators and most of the market is one day ahead rather than less than 1 minute ahead. This reduction in flexibility will adversely affect many generators whose circumstances can change substantially over a day such as hydro generators with limited storage and uncertain inflows, battery systems, gas generators with gas restrictions etc. The NEM's design of rebidding up to dispatch time and provision of information was set up to allow generators to efficiently manage these issues themselves.

3.7.7 How would energy constrained generators be included?

If a compulsory US style DAM is implemented in the NEM then how would generating units with energy constraints be managed? Simple energy limit constraints in the optimisation are unlikely to solve this issue as energy constraints can easily change over 24 hours.

3.7.8 Would there be complicated offer structures?

If a compulsory US style DAM is implemented in the NEM would it include complicated offer structures which include additional parameters like start-up costs, minimum run times, fixed no load costs etc.?

If complicated offer structures are used will this reward inflexibility and encourage gaming? The NEM's design was based on generators managing their own inflexibilities and doing this via simple price and quantity offers and rebidding.

3.7.9 Would generators be paid start-up costs?

Would generators be paid start-up costs and how would these costs be recovered? In markets where start-up costs and other inflexibilities are incorporated into the unit commitment and dispatch process, the marginal energy prices (spot prices) are often not sufficient to recover these costs and thus these costs have to be recovered via some form of uplift payment such an additional charge during peak periods. The uplift cost recovery mechanisms are often quite arbitrary and when added to the spot prices don't signal the marginal costs of consuming power or the marginal value of generating power. This is quite contrary to the NEM's design principles which are captured in the NER clauses 3.9.1 (a) (3) and 3.9.2 (d) below.

> 3.9.1 Principles applicable to spot price determination
>
> (a) The principles applying to the determination of prices in the spot market are as follows: ….
>
> (3) *dispatch prices* determine *dispatch* such that a *generating unit* or *load* whose *dispatch bid* or *dispatch offer* at a location is below the *spot price* at that location will normally be *dispatched*;
>
> 3.9.2 Determination of spot prices
>
> (d) The dispatch price at a regional reference node represents the marginal value of supply at that location and time, this being determined as the price of meeting an incremental change in load at that location and time in accordance with clause 3.8.1(b).

3.7.10 Reduces incentives for flexible technologies

As discussed earlier in section 3.2, a compulsory DAM is likely to reduce the incentives to invest in flexible generation and loads. A DAM lowers the expected revenues from peaking plant and increases the costs for very flexible loads such as batteries and pumped storages.

3.7.11 Two part settlements and contracts

One of the most significant impacts of US style DAM is the use of a two part settlement system. Generators are paid the day ahead price for their scheduled generation in the DAM and are paid the real time price for their deviations from their scheduled generation in the real time spot market. Thus, most of their generation revenue goes through the DAM rather than the spot market. Settlements for customers is done along the same lines, they pay for their scheduled load in the DAM at the day ahead price and their real time deviations from their scheduled load at the real time spot price.

This two part settlement system leads to the question of what price should bilateral contracts and futures contracts and options be referenced to? The DAM price or the spot price. If they are referenced to the DAM price then both customers and loads have an unhedged exposure to the spot price. On the other hand, if they are referenced to the spot price then customers and generators will be over hedged because their costs and revenues in the spot market are only for their deviation quantities. The most appropriate risk management would be a combination of the two where the contracts are split into two with some portion of the contract quantity referenced to the DAM price and the remainder to the spot price. This still leaves the question of how would existing contracts be transitioned to a DAM.

3.7.12 How would a DAM interact with the Settlements Residue Auctions

With a compulsory DAM and two part settlements there will be settlements residues associated with the DAM and settlements residues associated with the spot market. How will they be incorporated into inter-regional price risk management tools such as the Settlements Residue Auctions?

3.7.13 Contrary to the NEM's design principles

The most problematic part of a compulsory DAM with unit commitment is that it is contrary the NEM's basic design principles of decentralised decision making and consistency between dispatch and pricing.

4 Suggested Improvements and Conclusions

4.1 Identification of the Problem

Before any improvement can be made to the NEM, any problems in the NEM have to be identified and then options to rectify the problems can be considered and the best option can be chosen based on its costs and benefits. The proposal for the NEM to have a DAM seems to be solution for a problem that has not been properly identified and thus may not be the best direction for the NEM to go.

4.2 Improved Price Signals and Forecasting

Improved forecasting of loads and VRE generation is a no regrets policy and should be pursued whether a DAM is implemented in the NEM or not.

4.2.1 Load forecasting

We understand that AEMO's neural network load forecast system has been in place for many years and thus may not be optimal for load forecasting given the ongoing changes in the power system. With the increases in penetration of rooftop solar, growing use of batteries and the changing patterns of power usage, a review of AEMO's short term forecasting approach would be appropriate. Further, we think that it would be sensible for AEMO to start forecasting at a connection point level as this would facilitate the development of better models for embedded PV generation, load and embedded batteries and their price responses. Connection point forecasts would also facilitate better use of the transmission system since the safety margins in many constraints could be reduced.

Most EMS vendors provide a range of potential forecasting methods including similar day forecasts, time series forecasts, regression based forecasts and neural network forecasts. In addition to the EMS vendors there are a range of other vendors of load forecasting software. To our understanding, AEMO's current neural network approach has never been openly compared with other potential forecasting methodologies. We recommend an open evaluation of a variety of shorter term forecasting methods including time series, neural network, similar day, Bayesian models, Kalman filters etc. and a comparison of their results for different time periods ahead.

A potentially very useful approach for AEMO to compare potential forecasting methods could be to get Kaggle to run a NEM load forecasting competition (https://www.kaggle.com/). Kaggle runs data analysis competitions for a wide range of industries and reputable organisations, including the US Government. Competitions have prize money up to the millions of dollars and have had great results for the organisations sponsoring the competitions.

4.2.2 Forecasting VRE

There are a number of recognised problems with AEMO's VRE forecasting. To address some of the problems AEMO has proposed that wind and solar farms can supply their own forecasts and that these forecasts may be used by AEMO rather than the AWEFS/ASEFS forecast. If these VRE generators can produce better forecasts than AEMO then it would seem prudent for AEMO to adopt some of their approaches and forecasting systems.

4.3 Pre-dispatch Price Forecasts and Sensitivities

Another area of forecasting that could be improved is the pre-dispatch price forecasts and sensitivities. The pre-dispatch price information is vitally important to the NEM as it is the information which is used to co-ordinate the market. There are a number of areas that could be improved to provide a richer and more accurate range of information to market participants, these are:

- Extend pre-dispatch and price sensitivities out to a week ahead. This could be done via getting generators to maintain a set of reasonable offers out to seven days ahead. These offers would not have to be perfect, they would just need to give some sort of indication how generators plan to run their units out to seven days. Clearly there is a lot of uncertainty for generators with respect to their operations seven days out, but some indicative price information could be useful for all participants. If the pre-dispatch and price sensitivities are extended, given the uncertainties generators face seven days out, then the onerous aspects of the Good Faith Rebidding rules should not apply to the extension in length from the current pre-dispatch period to the extended seven day period.

  Using a pre-dispatch approach gives a better idea of the state of the power system and potential prices than the PASA approach of just trying to model capacities and reserves. This approach has been adopted in the Philippines wholesale electricity spot market (WESM) whose design was based on the best elements of the Australian and New Zealand electricity markets, adapted to the situation in the Philippines. A pre-dispatch running out to seven days ahead would be a more informative version of the ST PASA.
- Improve the quality of the price forecasts in pre-dispatch by replacing the pre-dispatch versions of feedback constraints with their dispatch versions and using an AC load flow to model the transmission flows used in the feedback constraints. In their review of intervention pricing for AEMO[6], Endgame Economics and SW Advisory undertook some modelling studies with AEMO comparing the pricing results when pre-dispatch constraints were substituted for feedback constraints and found that there could be substantial differences in prices.

[6] Oliver Nunn (Endgame Economics) and Stephen Wallace (SW Advisory) Review of Intervention Pricing for AEMO, 2nd October 2017.

- Lastly, the NEM price sensitivities could have some additional sensitivities added that reflect the uncertainties and variability of VRE generation, particularly rapid changes in output due to changes in weather. The aim of this would be to give some idea of the real option value of committing units and keeping them online in regions with large penetrations of VRE generation.

4.4 Defined System Strength Ancillary Service

Some of the unit commitment and intervention pricing issues in South Australia could be resolved with defining a new "system strength" ancillary service. This could be complemented with improved FCAS arrangements for regions which at times have low inertias. Between these two approaches, they could largely resolve the SA unit commitment issues.

4.5 Improved FCAS Arrangements

With the changes in NEM's power system, particularly in regions with high VRE generation, there is a need to change the FCAS market arrangements to encourage greater governor like responses and to provide contingency FCAS suitable for regions with low inertia. In the case of regions with low inertia it would be useful to have market arrangements that pay for very fast contingency responses and inertia services. How this can be done is outlined in the SW Advisory and DIgSILENT Pacific report on market based FCAS solutions that was done for a group of generators (the Generator Group[7]) and submitted to AEMC's Frequency Control Frameworks Review[8].

4.6 Fix up Intervention Pricing

At the moment, there are some perverse incentives in the compensation scheme for directions and intervention pricing that can encourage generators to keep units out of the market and wait for AEMO to direct them on.

What is required is changes to the compensation regime that is used when AEMO directs a generator and fixing up the pricing when AEMO intervenes. Ideally the compensation scheme should result in a generator that is directed to operate being no worse or better off than if it had remained out of the market and if AEMO intervened due to a shortage of energy or FCAS then the intervention prices for energy and FCAS should reflect the shortages. Some better ways of compensating directed participants and managing intervention pricing are discussed in Endgame Economics and SW Advisory's review of intervention pricing for AEMO[9].

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[7] The Generator Group includes Snowy Hydro, Stanwell Corporation, Engie, Origin Energy, AGL, Alinta Energy, Delta Electricity, and Intergen.

[8] Stephen Wallace (SW Advisory) and Tim George (DIgSILENT Pacific) Frequency Control Frameworks Review: Market-based Solutions, Final Report, 27th February 2018, https://www.aemc.gov.au/sites/default/files/2018-03/Generator%20Group_0.pdf

[9] Oliver Nunn (Endgame Economics) and Stephen Wallace (SW Advisory) Review of Intervention Pricing for AEMO, 2nd October 2017.

4.7 Conclusions

There are a number of problematic issues associated with a compulsory US style DAM. Such a market is fundamentally incompatible with the NEM's design and philosophy of decentralised decision making. Nearly all of the identified problems in the NEM can be addressed more effectively by means other than a compulsory DAM.

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