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13 August 2020

Ms Jessie Foran
Australian Energy Market Commission
Sydney South NSW 1235

By online submission: AEMC ERC0290

Dear Ms Foran

Submission to the AEMC's Consultation Paper – System Services Rule Changes

The Australian Energy Market Operator (AEMO) welcomes the opportunity to provide comment on the System services rule changes, Consultation paper, 2 July 2020.

This submission proposes the following:

1) Prioritise an in-market reserve product:
    - There are problems associated with ensuring adequate operating reserves given deficient price incentives, barriers to the demand side and increasingly complex and uncertain reserve requirements.
2) Prioritise a contracting mechanism for system strength and synchronous inertia:
    - It is acknowledged the NEM already has a contract and commitment mechanism today with the system strength unit combinations and the directions and compensation framework.
    - A priority should be to improve on this with a contracting framework, a formal cost optimisation (such as the Unit Commitment for Security (UCS)), or both. Further developments, like an ahead market can be considered by the ESB.
3) Improve FCAS in response to declining inertia and prioritise Fast Frequency Response (FFR):
    - Improvements to the procurement of FCAS reserves to manage lower inertia conditions, should provide further remuneration for providers of Primary Frequency Response (PFR), whilst also allowing the opportunity for FFR to compete.
    - Despite FFR being suited to spot markets, and depending on implementation costs, the first stage in procuring FFR could be by contracting for:
        i. Islanding events by using the existing NER provisions for minimum levels of inertia; and
        ii. For system intact conditions by using a contracting approach to reduce the amount of six second FCAS reserves procured.

This is AEMO's initial attempt to prioritise the seven security services. Actual support for individual security services would be dependent on full consideration of interactions associated with the ESB market design initiatives, a full assessment of implementation costs compared to expected benefits, and consideration of whether it may be practical and cost effective to bundle implementation of security services together.

AEMO looks forward to working with the AEMC and other stakeholders throughout this process.

Should you wish to discuss any of the matters raised in this submission, please contact Kevin Ly, Group Manager - Regulation on kevin.ly@aemo.com.au.

Yours sincerely

Peter Geers
Chief Strategy and Markets Officer

Attachment 1: AEMO's High Level Consideration of the Consultation Paper

ATTACHMENT 1:

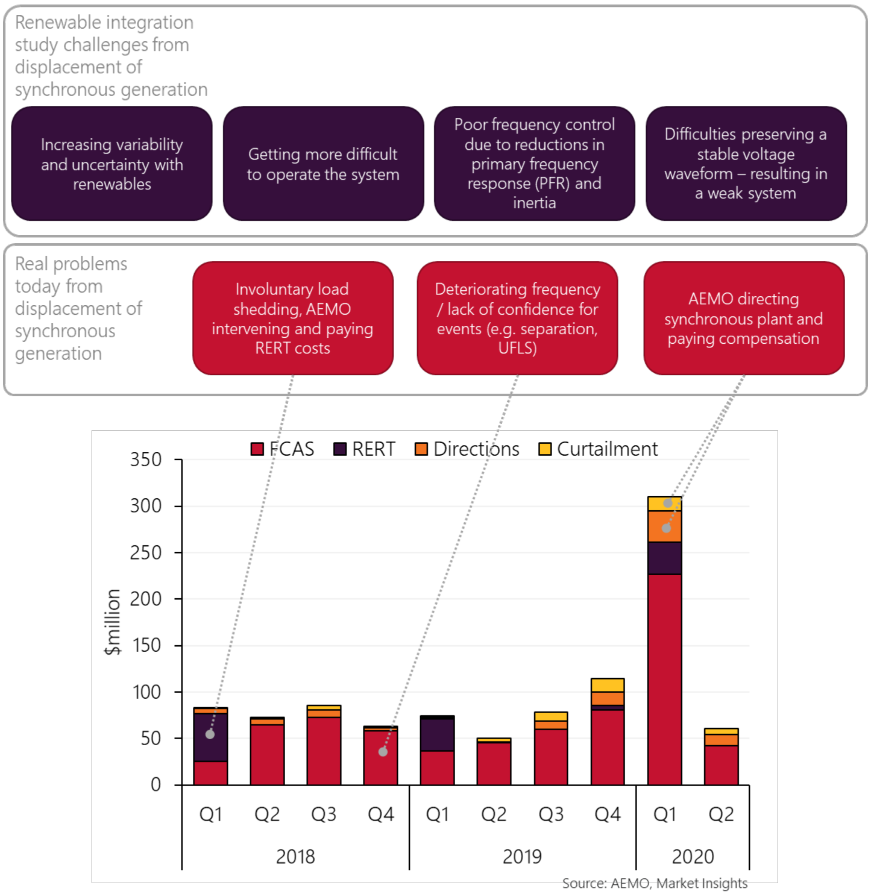
AEMO'S HIGH LEVEL CONSIDERATION OF THE CONSULTATION PAPER (ERC0290)

This submission outlines AEMO's views on the system services under consultation and the seven rule change proposals.

1. Evaluation process

Figure 1 outlines the challenges AEMO highlighted in Stage 1 of the Renewable Integration Study[1] ('RIS') from the displacement of synchronous generation by asynchronous renewables. These are the longer term challenges the Rules need to resolve. Additionally, the figure highlights the existing problems AEMO faces – how these challenges are manifesting themselves today. The column chart provides some indication of how these costs are manifesting themselves: in the use of RERT, paying directions and compensation and curtailment of renewable generation. At times, too, the cost of Frequency Control Ancillary Services (FCAS) has increased, most notably in Q1 2020.

Figure 1 Illustrating the need for system services in the NEM



[1] AEMO report: Renewable Integration Study Stage 1, available at: https://aemo.com.au/energy-systems/major-publications/renewable-integration-study-ris

AEMO has evaluated these Rule change proposals considering these problems and with reference to the longer-term challenges explained in the RIS. If a Rule change proposal aims to address both, it could progress with incremental changes to the NER, or as a precursor to the ESB's post 2025 Market Design Initiatives (MDIs), scheduling and essential system services. If the Rule change proposal is aimed to focus on the longer term RIS challenges, it may be something more suited for the Post 2025 MDIs. For example, should a Rule change proposal be an improvement on the current directions and compensation framework that AEMO needs to use routinely, or it reduces the need for exercising the RERT, it should be prioritised.

Figure 2 is a high-level evaluation flow diagram indicating how AEMO has considered the system service each Rule proposal represents. It is simplistic, but adequate to explain the high-level thinking of how, if implementation issues are ignored, the system services should be provided.

The evaluation flow diagram has five questions or steps that allow the system service to be considered, with these presenting on the LHS of the diagram. They follow a logical order and lead to another evaluation step, solution or intermediate evaluation step before a solution.

Figure 2 Evaluation flow diagram with evaluation steps for assessing system services

The first step is to consider whether a service is adequately priced and remunerated in the existing spot markets of the NEM, energy and market ancillary services (FCAS) – as a first pass assessment, any service that is already remunerated doesn't require amendment.

The second step is to consider whether the spot markets do not reward the provision of the service – if this is so, the service may be characterised as "un-priced". For example, services that have historically been a free by-product of energy could be thought of as unpriced. This leaves services where the energy market rewards their provision, but not fully, or, accurately enough, and these services may be described as "under-priced".

If a service is identified as "under-priced" in the existing spot markets, this could be for a multitude of reasons and it is worth investigating whether the markets could be improved to provide efficient pricing signals, so there is confidence the service will not be underprovided. If the existing spot markets cannot be improved, the service would naturally pass the third step.

The third step is to consider whether a service is suitable for integrating into the spot markets. For this to occur, the service would need to be mutually exclusive with the existing spot markets (energy and FCAS) and have qualities that should lead to marginal pricing of the service, like something that imposes real-time opportunity costs in the existing spot markets. A service that passes the third step would, ignoring implementation complexities, ideally be integrated into the existing spot markets and co-optimised with energy and FCAS. This would be an "in-market" service, where the providers are paid through spot market settlements and those payments would be largely correlated with energy prices. Please note such a service may be enhanced by an ahead market, because real time and ahead markets are themselves complementary.

The fourth step is to consider whether a service is suitable for shorter term contracting and ahead scheduling. For this to occur, the service may not easily be integrated into the spot markets, would not be mutually exclusive with energy and would not have direct qualities for marginal pricing. This is probably due to the operating costs being incurred on a gross basis, related to irreversible scheduling decisions, such as unit commitment. In power market design parlance, the service would have non-linear, binary variables and is unlikely to be something that can be dispatched in real-time. A service that passes the fourth step would ideally be integrated into some ahead contracting and scheduling arrangements, that allow the service to co-optimised with spot markets services over timeframes where the gross cost can be treated more like a marginal cost when deciding whether to commit resources. Payments under this arrangement could be characterised as "out-of-market", where the provider is paid in addition to spot market settlements and those payments may not be correlated with energy prices. The AEMC discusses the RERT as "out-of-market" to encourage demand response but, similarly, the existing compensation framework for system strength directions could also be considered so.

The fifth step is to consider whether, after all options have been exhausted, the service is something that has no marginal operating costs and no gross operating costs and yet has investment costs. A service that passes the fifth step is something that would be suited for long term planning and investment frameworks. Just because a service passes this step does not indicate monopoly network provision is required. For example, services provided by equipment such as Static Var Compensators (SVCs), STATCOMs and synchronous condensers could fall into this category.

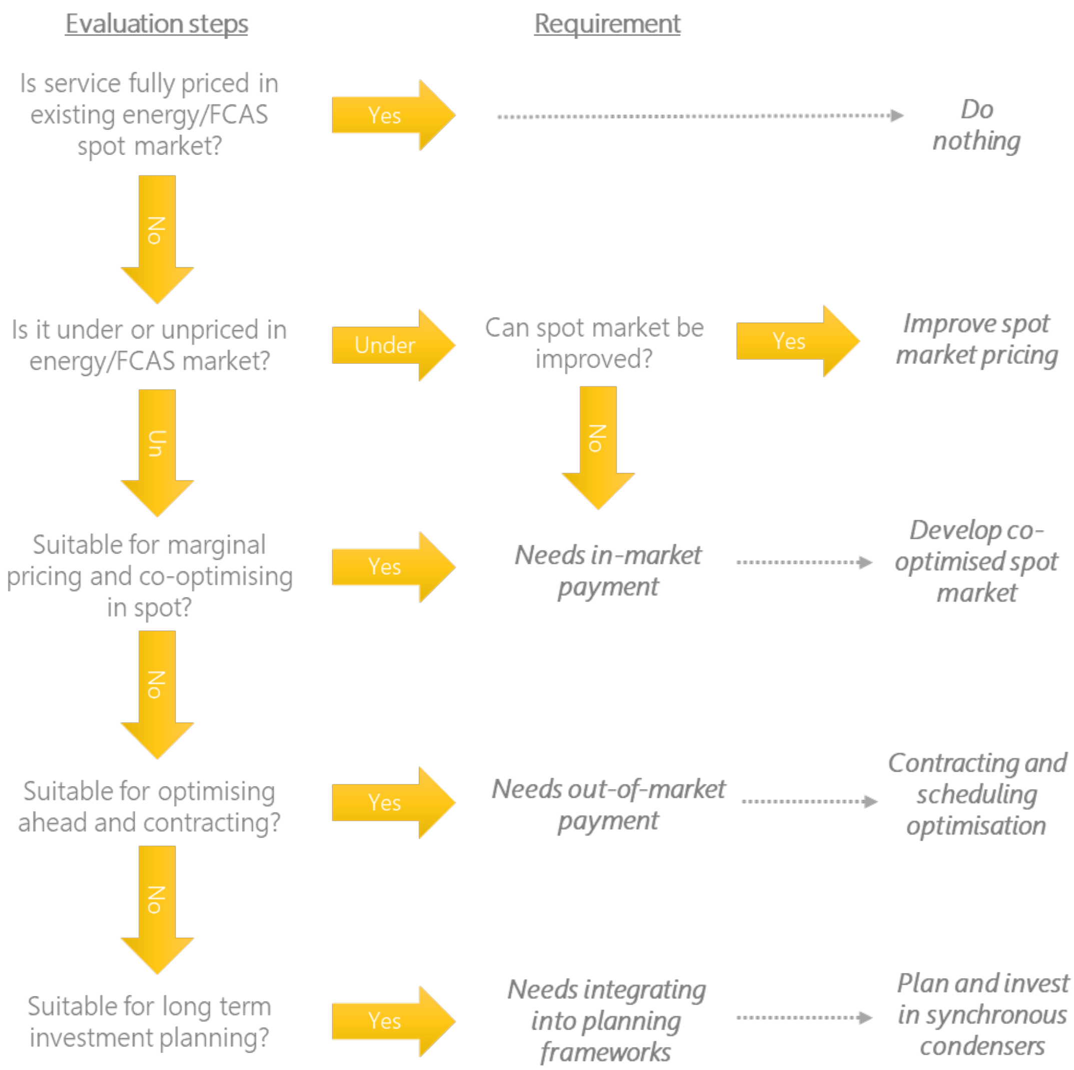
2. Consideration of the system services and rule proposals

The AEMC has highlighted[2] the seven rule change proposals largely cover the full range of system services needed to operate the system. This is useful because it allows an assessment of what form of solution is required for each service and then to compare these to the rule change proposals. It will also highlight where a proposal might oppose another.

Figure 3 adds a further step to Figure 2, highlighting the logical solution after passing through each evaluation step. The Rule change proposals can be compared to these logical solutions.

[2] Figure 2.1, p14, System services rule changes, Consultation paper, 2 July 2020

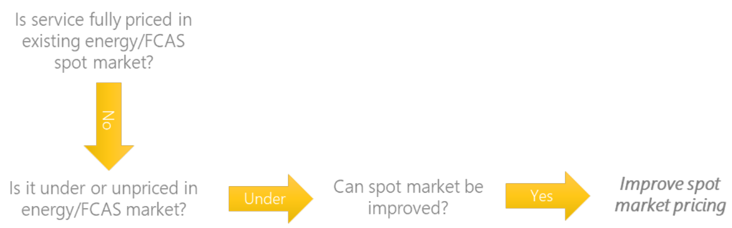
Figure 3 Evaluation flow diagram including logical solutions



Incentives for Primary frequency response (PFR)

AEMO considers there should be near-universal PFR across the NEM for consistent active power control. The Mandatory PFR (MPFR) Rule provides this at a narrow deadband, notwithstanding the Rule does not require reserves to be maintained. The AEMC[3] is considering the arrangements for allocation of costs associated with regulation FCAS — 'causer-pays' and the potential development of additional complementary measures to effectively remunerate providers of PFR.

Figure 4 Evaluation flow diagram PFR excerpt



If one accepts the AEMC's proposition that PFR is under-priced in the spot market, which would mean it is clearly suitable for co-optimising with energy and FCAS, being a form of frequency response itself – the question is whether the under-pricing is something that needs to be resolved with a new in-market payment, e.g. a co-optimised market, or simply improvements to the existing spot FCAS markets.

AEMO would suggest PFR could be further incentivised by incremental improvements to existing FCAS market arrangements.

With regards to the existing causer pays method:

- Units such as thermal synchronous plant and batteries operating with a tight deadband are very likely to have no liability under the Causer Pays method for Regulation FCAS. But these units *would do anyway* even if they provided *far less* frequency response than that mandated under the Rule.
- Other units where the performance is subject to resource variability, such as PV and wind farms, may incur a liability even with a tight deadband, depending on the unit controls and measured error to the dispatch trajectory.

Therefore, the question is whether units should be paid in addition to avoiding causer pays costs for contributing to the control of frequency under normal conditions. This is difficult to do given causer pays is a cost allocation method for Regulation FCAS and not a market. Nevertheless, AEMO considers it worthwhile examining how causer pays could further incentivise good frequency control.

With regards to improvements in frequency control markets:

As noted on Page 70 of the Consultation Paper, AEMO will:

[3] P67, System services rule changes, Consultation paper, 2 July 2020

"*ensure the required speed and volume of PFR match the size of the Largest Credible Risk (LCR) and Frequency Operating Standard (FOS) containment requirements for the range of expected future operating conditions*".

Depending on the availability of faster and more frequency reserves, this may well increase the amount of Contingency FCAS reserves because, even now PFR is mandated, in the future there may be insufficient PFR reserves to stabilize frequency after a contingency. Such additional FCAS reserves may form the basis of increasing the remuneration of PFR providers, as may improvements to optimisation of FCAS with synchronous inertia and possible proposals to acquire inertia (see Capacity Commitment Mechanism).

For these reasons, it is unclear changes to causer pays to pay for PFR is an immediate priority. AEMO considers that two items will be important in informing enduring normal frequency management arrangements:

1) monitoring the implementation of MPFR, so that the materiality of the impact of a near-universal provision of PFR can be assessed and the power system impacts understood; and
2) assessing the ongoing suitability of the frequency operating standard.

AEMO recommends that the AEMC consider these items when determining the timetable for the determination of the Primary frequency response incentive arrangements rule change proposal. The rollout of MPFR will have substantially progressed by the middle of next year and data should be available to assess the impact MPFR has had on power system frequency performance. AEMO would recommend deferring its draft determination of the Primary frequency response incentive arrangements rule change proposal from mid-2021 to September 2021 or after as this would allow for collection of relevant information to inform the AEMC's decision.

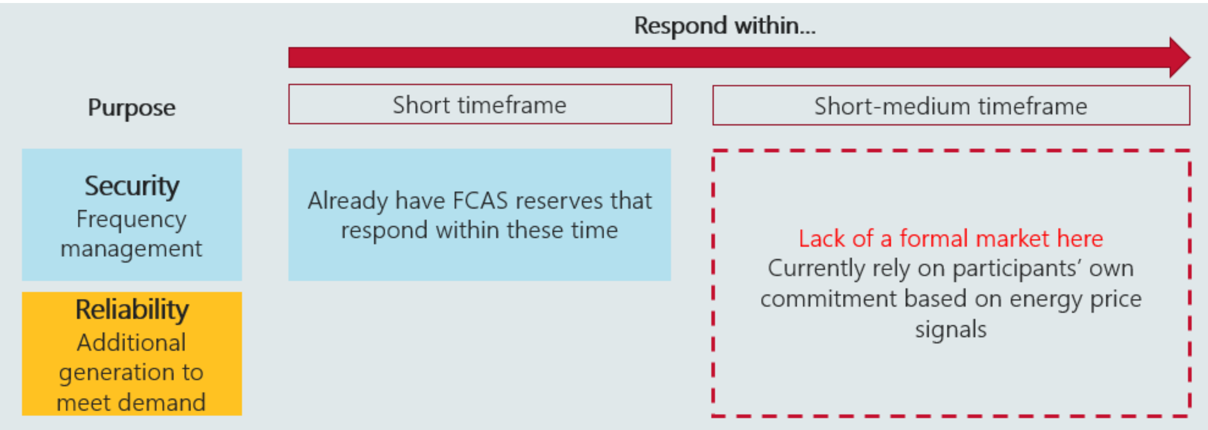
Operating Reserves

There are concerns that system risks in the energy spot market have become more difficult to forecast due to the increase in asynchronous renewable generation. The figure below shows the NEM already has a co-optimised, real-time FCAS reserve market for frequency management but lacks a formal operating reserve market to value flexible, dispatchable resources to protect the power system after a contingency event or when there is uncertainty in the forecast supply-demand.

The Renewable Integration Study (RIS) report 1 showed that the magnitude and frequency of large ramps in the supply and demand are increasing, with 50% increase in the magnitude of peak ramps over the next five years and challenges to the accuracy of deterministic forecasts of expected ramps. This leads to increasing value in ensuring sufficient flexible system resources are available to enable increased variability at times of high wind and solar penetration.

Infigen refers to new "modes of failure", which is a good way to characterise the changing demand for reserves.

Figure 5 Illustrating the need for operating reserves



It is worth considering that operating reserve may assist some of the key challenges highlighted in the RIS[4]. Uncertainty relates to the inability to perfectly predict future demand, supply, and grid conditions. Variability relates to changes in supply and demand that would exist even with perfect foresight. Variability is characterised by magnitude (how large the change is) and window (the time it took the change to occur). Future additional solar and wind penetration is forecasted to increase the magnitude of peak demand and supply ramps. The ability to forecast these ramps has limitations which can be due to the behaviour of individual renewable generators, weather patterns and embedded generation, therefore for the system operator to ensure there is adequate system flexibility (including physical characteristics such as ramping capability), resources may need to be available and enabled ahead of time.

[4] Renewable Integration Study: Stage 1 report, p61

Ideally, the energy market should operate with a significant quantity of demand side bidding; the demand curve clears the market at scarcity providing the 'correct' remuneration for providers of capacity. Under such circumstances swap and cap derivatives should be adequate as forward contracts for remunerating reserves, including the demand side. However, the price signal is dampened due to the fact that the market price cap is significantly lower than the value of customer reliability. Further, the cumulative price threshold caps the total market price that can occur over seven consecutive days. These factors reduce the incentive for market participants to deliver the efficient level of reserve and reliability outcome at operational timeframe.

To understand the problem of under-supply of operating reserve, it is worth investigating the reverse example of oversupply and low prices. The spot market operates with a -$1,000/MWh floor price, which encourages the market to clear because this price is low enough to discourage extra supply (and may encourage extra consumption). If, hypothetically, this floor were to be increased to $5/MWh there would be an incentive to keep generating irrespective of the oversupply and the market will not clear properly, because generation isn't being rationed by price.

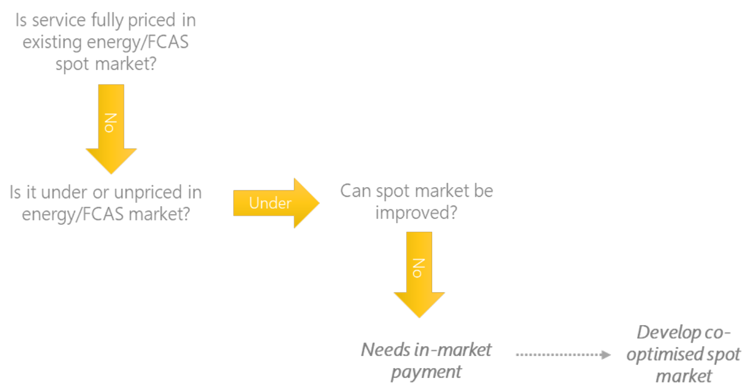
As Infigen explains in its proposal, there are now new "modes of failure" in the power system. This could lead to greater and more frequent misalignment between participants' incentives to provide reserves to manage the need of their own portfolio and the system operator's need for reserve to manage the entire system, suggesting a possibility the market will fail to provide efficient level of reserve at operational timeframes.

These issues would suggest that reserves are "under-priced" and therefore may be "under provided" in the long run. With the price capping and regulatory barriers to demand bidding, there could be a misalignment of private interests (retailers) and consumers (end customers) at times of scarcity. For example, consumers that may wish to reduce demand at high prices can't easily do so and those that want to pay more than the cap can't.

The ESB's post 2025 two-sided market workstream is exploring arrangements which may remove barriers and provide suitable incentives which encourage greater active participation of the traditional demand side in the market. An operating reserve mechanism is one arrangement which can value and remunerate the delivery of this service.

It is for these reasons AEMO would consider the existing market under-prices reserves, and it is sensible to look for options to explicitly price these reserves.

Figure 6 Evaluation flow diagram operating reserve excerpt



For under-priced services, Figure 3 questions whether the appropriate solution is to improve the existing spot market or to develop a new co-optimised spot market. AEMO would consider the latter is more appropriate in this instance, because if reserves are co-optimised with the real-time energy price, one may expect it to be permanent and, hopefully, some form of precursor to efficient bidding from the demand side. Some Operating Reserve designs could depend on work being completed under the ESB's post 2025 "Resource Adequacy Mechanism" and "Essential System Services" initiatives.

The market will become increasingly difficult to operate without centrally procured operating reserve. Given the fundamental problem relates to the energy market's pricing deficiencies, any in-market payment to reserve providers is likely to under-remunerate them. It will suffer from the same problems energy dispatch and derivatives have today. Nevertheless, by explicitly identifying a reserve capacity quantity and purchasing it in addition to energy dispatch and frequency reserves, it will provide a volume indicator of the assessment of system reserve requirements. This will be useful, especially if participants are less likely than AEMO to understand and quantify these reserve requirements. It may assist existing and new suppliers of reserves to make capacity available under complex system conditions.

AEMO looks forward to considering more detailed designs for Operating Reserve markets in the next stage of the consultation.

Ramping Services

The proposal creates a separate 30-minute market that is not mutually exclusive with energy and FCAS, simply seeming to pay on-line generators for their ex-ante capability to ramp.

The proposal doesn't co-optimize with energy but provides an additional out-of-market payment (as discussed in section 1, step four), to energy, contingency FCAS and regulation FCAS. As identified in evaluation steps 2 and 3, if a service is under-priced and can have a spot market that is co-optimised with energy, it probably should. This proposal can, yet it doesn't. For these services AEMO recommends developing a real time price in-market and co-optimised with the energy spot market. As noted above, such a service may be enhanced by an ahead market, because real time and ahead markets are themselves complementary.

The service is also described as an FCAS, yet FCAS markets attempt to manage *within* a dispatch interval and *across* dispatch intervals for changes in frequency caused by large changes in loading from the target state, which could be caused by a contingency. Five-minute dispatch corrects the system towards a new target state to account for ramping requirements as described by the proponent. So, while it is like FCAS, in that it is reserving flexibility to increase and decrease supply (or demand), it operates over dispatch intervals to ensure that five-minute dispatch has sufficient dispatchable capacity to continue correcting the system.

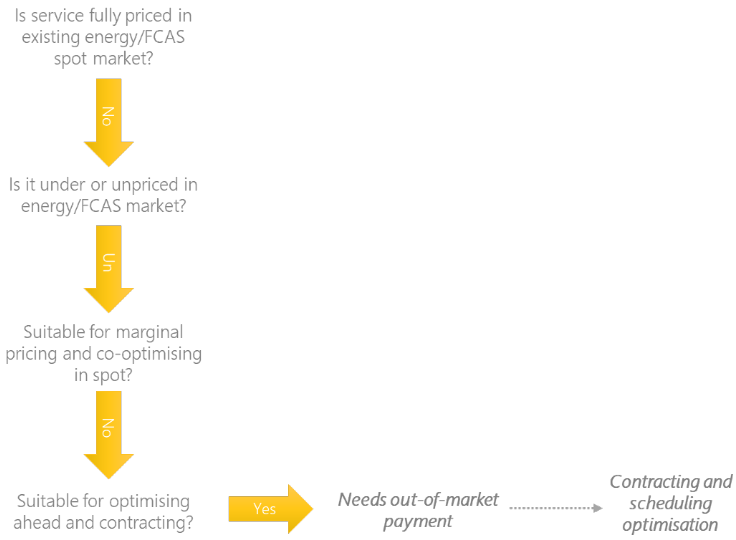
A further problem with the proposal is that it requires units to come on and make their ramping available before the 30-minute auction. This may be technology specific and the preference should be to explore mechanisms that aim to include the largest set of resources that have the required attributes and can commit and respond within required timeframes.

AEMO considers that the Operating Reserves proposal addresses the issues more appropriately and would be a preferable starting point to further develop the service.

Synchronous Services Market

The proposal aims to pay for system strength and inertia by including a cost for unit commitment to be optimised with energy dispatch. It does this by introducing an out-of-market payment to the provider with scheduling co-optimised with energy dispatch over the timeframes the optimisation is run.

Figure 7 Evaluation flow diagram synchronous services excerpt



The focus on synchronous services means the proposal is focusing on unpriced services (step 2), which are unsuitable for marginal pricing in a spot market and co-optimising with existing spot markets (step 3). It aims to implement an ahead optimisation using a contract. The contract is a cost to synchronise with a time requirement (the solution to step 4).

It is a contracting and ahead optimisation, which should be suitable for procuring system strength and inertia by paying for the synchronisation of units capable of providing the service. Just because the proposal limits the contract to 5 minutes to synchronise does not make it a spot market for inertia or system strength – there is no cleared marginal price for the service.

It is worth exploring the challenges regarding a real-time spot price for inertia and system strength, discussed in the following box:

Real-time pricing can't simply be local energy pricing, (as per LMP), but needs a system strength offer price. LMPs are simply different in energy prices by locations, caused by linear constraint equations constraining on or off generators. The problem with system strength and inertia is that supply isn't linear, it is a binary problem it is related to commitment or synchronisation status, therefore, whilst a constraint equation could limit asynchronous generation it can't bring on resources with changes in energy prices per location. Additionally, for suppliers of system strength, where provision is not directly related to energy provision, the arrangements could be unsatisfactory. It places the onus on the participant to decide when to supply system strength, based on the energy price it would receive when the costs of supplying it might not relate to energy. The extreme case being a synchronous condenser. This suggests there is a requirement for offers for system strength to be submitted into the pricing calculation.

FCAS markets are a mix of constraints and offers from suppliers. FCAS constraints impose a requirement or 'bid' volume priced at the MPC and use a supply curve from FCAS offers. The reason for using the marginal value or "shadow price" of the constraint for setting the FCAS price is to allow the services to be co-optimised with energy dispatch, because FCAS is directly related to energy, in proportion to a unit's FCAS trapezium, unlike system strength and inertia. Yet the supply of system strength and inertia is not reduced by dispatch of energy.

If it were possible to linearize the supply of system strength, the calculation could include system strength offers and pricing could be more like the FCAS markets. The effective trapezium for the product is a rectangle covering the entire operating range of the unit. For synchronous condensers this is a vertical line at zero. So, system strength or inertia are associated with the unit's synchronisation status. All or nothing. There would be frequent occasions:

- when a unit's system strength offer is not cleared, but the unit provides the service nonetheless because it is synchronised; and
- whereby the unit cannot supply system strength even though its offer would otherwise be cleared, because it is not synchronised.

These are similarities to FCAS units that are "trapped" within their FCAS trapezium or "stranded" outside their trapezium: in the latter case it might be economic to rebid to within the trapezium by buying more MWs and thus buying cheap FCAS, but the dispatch engine can't do that. It is up to the trader to change the energy offer to be dispatched and optimise revenue between the FCAS and energy markets, but this doesn't create many problems, because usually the dispatch engine can usually "steal" FCAS from units that are within their trapezium, but would otherwise be dispatched for energy – co-optimisation. For a real-time spot market for system strength and inertia this isn't possible, the dispatch engine can't steal (co-optimise) services from energy, because they are not mutually exclusive with energy and in real-time at least don't impose opportunity costs in the energy market. Such a real-time market could be feasible but might not clear that readily: it could lurch from surfeits to shortfalls.

For the dispatch engine to dispatch system strength or inertia from units that are "stranded", i.e. desynchronised, it will need to include binary variables, such as deciding whether to turn off/on synchronous units depending on the value of their system strength offer and, maybe, including complex temporal characteristics (e.g. time to start the unit). Running an ahead optimisation should allow the spot market to clear because it will make resources available.

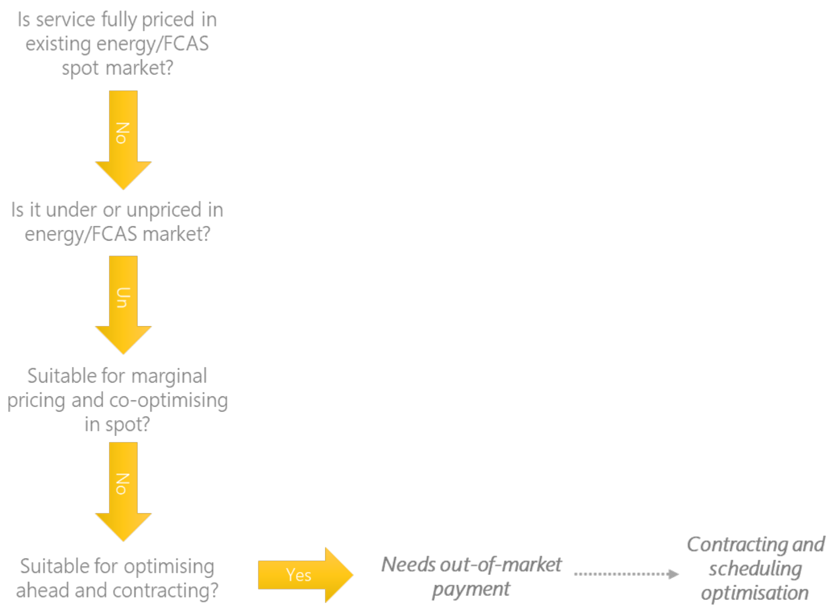
The Synchronous Services proposal by Hydro Tasmania aims to optimise generation that can synchronise within 5 minutes, in addition to those already synchronised. The Synchronous Services proposal includes a cost of synchronising in 5 minutes and allows the dispatch engine to determine whether this reduces overall costs. The additional costs from the Synchronous Services offer do not form part of the marginal energy price calculation and the proposal envisages a price paid to suppliers, and the price plus a pro-rata share of the costs of synchronising the unit paid by consumers. There is no direct marginal price under this proposition; the "offer" reflects the cost of the unit to synchronise and is an additional ancillary service cost to be allocated.

To summarise the Rule change proposal, a contracting and ahead optimisation would be beneficial, but limiting it to 5 minutes is not and doing so does not create a spot market for the service. The proposal is a viable proposition if optimisation is extended beyond 5 minutes, which is what is being considered in the ESB's ahead scheduling and ESS MDIs. If the optimisation was extended by, say, 12-24 hours, it would provide a financial incentive for operational decisions, it would improve scheduling and, in turn, improve investment signals, because payments would encourage participants to invest in resources. This is why AEMO is proposing the Unit Commitment for Security (UCS) and Day Ahead Market.

Capacity Commitment Mechanism

Delta's Capacity Commitment Mechanism is proposed for both operating reserves and synchronous services, like system strength and inertia. This proposal is ill-suited to operating reserves that are compatible with the spot markets and should be directly priced with an in-market payment. It is well-suited, however, to services such as inertia and system strength, which are unpriced and not suitable for marginal pricing and co-optimising in the spot markets. For each service supply scarcity relates to commitment/decommitment and synchronisation status, rather than scarcity of energy and reserves.

Figure 8 Evaluation flow diagram capacity commitment excerpt



The decision flow diagram (Figure 3) leads the Delta proposal to be like the solution proposed for Step 4 – introduces an out-of-market payment from an ahead contracting and scheduling arrangement. This proposal could be likened to when generating units are directed to remain online South Australia to preserve system strength at low energy prices. The AEMC should refocus this proposal as paying Generators to stay online to provide system strength and inertia.

Notwithstanding the above, there are several issues with the current proposal in its current form:

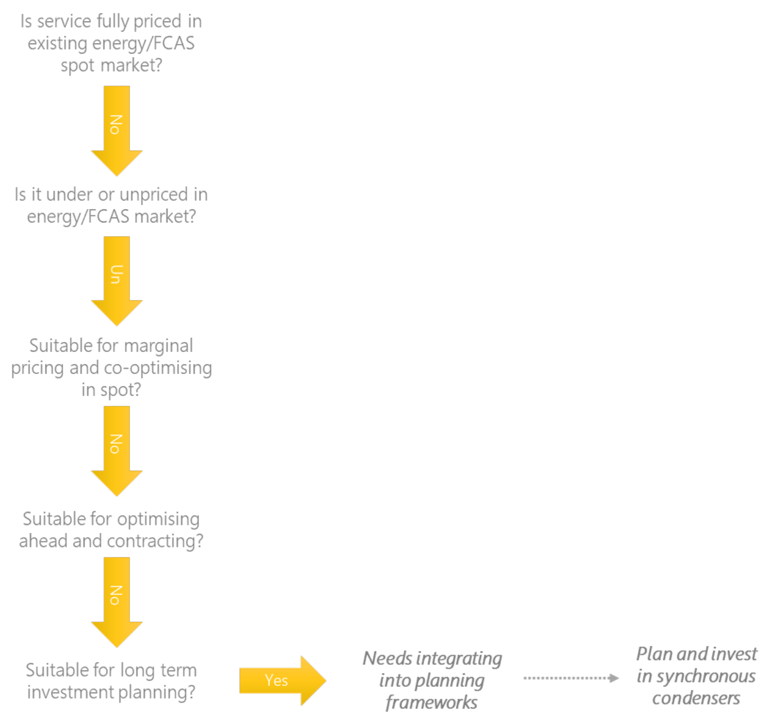
- it seems to be sub-optimal for procurement of operating reserve and is more suitable for procuring system strength and inertia as it seeks to pay Generators to stay online;
- it proposes an ex-ante lump-sum payment for generators to be online to provide system services, but the generator is still exposed to real-time pool prices for its entire output and would be incentivised to decommit at very low energy prices, potentially causing a shortfall of the system services it is scheduled to deliver.
- it appears to lack a mechanism to price the non-delivery of the system services in real-time. In the more standard ahead market design, participants who under-delivers their ahead schedule will be exposed to real-time price for the shortfall amount. In the current proposal, it appears the generator who fails to stay online for the required period would only lose a portion of their lump-sum payment, which might not adequately reflect the true cost of system service shortfall.

Irrespective of these comments, AEMO considers the overall concept – that Generators need to be paid a supplementary, out-of-market, payment for commitment and minimum generation to provide system services is appropriate and should be prioritised.

Efficient management of system strength on the power system

The Rule change proposal asserts that it would be efficient for Network Service Providers (NSPs) to manage the provision of system strength on a proactive basis where they must aim to meet a standard, say a short circuit ratio (SCR) or (MVA) level for a forecast level of new asynchronous generation. This is targeted at system strength, but given synchronous condensers are also capable of being fitted with flywheels, this could also be used for inertia.

Figure 9 Evaluation flow diagram system strength management excerpt



Using the decision flow diagram, synchronous condenser and flywheel resources are only suitable for long-term investment planning, which is the test under step 5 in Figure 3. The diagram indicates the solution is integrated planning frameworks to plan and invest in synchronous condensers. This is like the regulated investment test for transmission (RIT-T) where the aim is to identify transmission investments that are competitive against a reasonable forecast of future generation scenarios. The Rule proposal appears an appropriate way of integrating non-generation synchronous assets into the NER.

The TransGrid proposal requires AEMO to specify a level of capacity, say 'X' MVA, that the Reliability Panel requires an NSP to meet, say 'Y'% of the time. This could also be expressed as an SCR the NSP has to maintain for forecast levels of new entry of asynchronous generators and exit of synchronous generators. The proposal may need to be enhanced by an access standard on new inverters to be able to operate as had been planned by AEMO or the NSP and/or a charge for asynchronous generators that are using these assets. AEMO notes the limitations of the existing minimum level framework, where system strength services are required to contribute three phase fault level current, yet emerging solutions change the minimum requirement itself, rather than contribute fault current to a shortfall.

It is going to be difficult for a planner to assess the future requirements for synchronous condensers and/or flywheels because this will be based on the investment in and dispatch of asynchronous generators relative to the dispatch and possible closure of synchronous generation. This does not mean strategic investments in synchronous condensers and additional flywheel should not be made. As stated in the Integrated System Plan[5], AEMO considers strategic investments can play an important role in realising efficient and robust outcomes, and is therefore positive on the benefits of central, coordinated planning.

AEMO has some concerns the TransGrid proposal may have too little incentive to utilise synchronous generation or future technology. AEMO would not recommend limiting the scope for NSPs to invest, say only to a minimum level. In addition, AEMO would not recommend limiting contracts for some ahead optimisation to short duration, operational timeframes. For instance, just because the Delta arrangement focuses on the commitment timeframe does not necessarily preclude contracts that can be exercised at commitment competing with investment decisions by the NSP. It might be worthwhile allowing these two processes to compete, rather than limit the powers of the NSP or AEMO to ensure they don't.

Fast Frequency Response

This rule change proposal was complex to consider. This is because:

1) there are already some arrangements in the NER where FFR can be used to meet local requirements
2) it could be used to reduce the amount of 6-second FCAS reserves that are acquired;
3) it is different to synchronous inertia (MWs), being measured in MW.

Figure 10 Evaluation flow diagram FFR excerpt

Using the evaluation flow diagram, Figure 3., it is evident that FFR, for system intact is not supported with the current spot markets. FFR providers cannot sell such a service, and being measured in MW, it imposes opportunity costs in the energy market for Generators and so it is suitable for marginal pricing via a spot market, just like FCAS. Ideally, therefore, it should be supported with an in-market payment through a spot market, which is what is proposed by Infigen. On a first principles basis, the proposal treats the service appropriately and has merit.

[5] AEMO | 2020 ISP Appendix 7. Future Power System Security, p9

Please note this conclusion differs from synchronous inertia from Generators, where AEMO considers a co-optimised spot market to be inappropriate, with the reasons explained in response to the Synchronous Services and Capacity Commitment Mechanism proposals. It should be not be construed that just because FFR is suitable for a spot market, inertia readily is too. Due to the way inertia is provided, it doesn't have a natural marginal price and isn't mutually exclusive with real-time energy dispatch, so an inertia spot market would 'need' a scheduling mechanism of some kind to assist with market clearing.

There is a declining level of synchronous inertia in the NEM. This is both at a system and regional level. This was noted in 2017 in the System Security Review and has been recently highlighted by AEMO in the RIS. This decline has many effects on the power system and has different impacts for the system intact condition, and special conditions where a region is islanded or at risk of islanding.

Regional considerations under islanded or at risk of islanding

The 'Managing the rate of change of power system frequency' or "Inertia Rule 2017", made in 2017, currently requires a minimum level of inertia for each region to come from synchronous machines and allows FFR to be used as a substitute between the minimum and secure inertia limits.

It is AEMO's understanding that the Inertia Rule 2017 has been used by ElectraNet to invest in synchronous condensers with flywheels to meet the minimum and secure levels of inertia. It has yet to be used for FFR, although AEMO is currently reviewing how FFR is used under islanded conditions and at times of credible islanding risk.

Infigen's proposal is related to extending Contingency FCAS and so is related to system intact conditions.

System intact conditions

The proposal relates inertia to increased RoCoF. This is correct, yet for the system intact condition it is unlikely that a credible contingency will cause a breach of acceptable RoCoF levels until RoCoF becomes a binding limit in that plant starts to disconnect due to high RoCoF[6].

The more significant issue, as raised in the proposal, is that frequency could change too fast for Contingency FCAS to arrest frequency in time to meet the FOS. It is technically possible to solve this issue by purchasing more Raise6sec (Fast FCAS) and AEMO plans to extend the inertia dependency of Raise6sec to system intact conditions. However, the use of an FCAS-type product faster than Raise6sec would allow the volume of Raise6sec FCAS to be reduced under low inertia conditions. This is likely to have efficiency benefits, particularly under very low inertia conditions where the volume of Raise6sec required would need to be high.

[6] This is not to say the RoCoF will definitively cause no issues with protection relays and schemes for system intact, rather that RoCoF is much more manageable than under separated conditions. This statement is also based on assumptions about the size of the largest credible risk and the amount of inertia available.

A rule change will probably be required to introduce FFR as a product to support system intact operation. Yet an FFR product would have interactions with the existing FCAS, inertia and measures for regional frequency control. AEMO suggests these interactions need be resolved before committing to specific rule changes. AEMO is working through a number of issues associated with frequency control as part of the Frequency Work Plan.

Feasibility of a new co-optimised spot market for FFR

AEMO agrees that that 5-minute markets are suited to an FCAS-like product procurement, however, the introduction of incentivisation of FFR has several issues associated with it that should be considered in how it is procured, including:

- FFR injects power quickly into the power grid and there may be locational maximum quantities; and
- specification for FFR for system intact, as well as its interaction with FCAS products and volumes (constraints), inertia and potentially inertia services, as well as regional frequency management are likely to benefit from progressive refinement based on experience in using and procuring FFR.

A possible first step in FFR procurement could be contracting. This would allow the power system impacts to be managed. It would also allow some flexibility in refining how the service is best utilised and integrated with the possibility of transitioning to a 5-minute spot market.

FFR contracts have been used internationally, in some cases with the intention to integrate into close to real-time markets later. Applying this approach in the NEM could allow more extensive changes to market systems to be made efficiently based on experience. AEMO believes this approach should be considered as part of a wider set of potential implementation arrangements alongside the ESB's Post-2025 program of reform.

3. Conclusion

AEMO welcomes the AEMC's simultaneous consultation for these proposals whilst respecting the timetable of the ESB post 2025 market design processes. AEMO proposes an assessment process to allow a structured approach to prioritisation of the security services.

Prioritise an in-market operating reserve product

This submission has highlighted the problems associated with ensuring adequate flexible ramping reserves given deficient price incentives, barriers to the demand side and increasingly complex and uncertain reserve requirements. Whilst the pricing deficiencies in the spot market are difficult to resolve, implementing an in-market operating reserve will be an improvement, perhaps with a demand-curve based approach.

Prioritise an out-of-market contracting, commitment mechanism for system strength and synchronous inertia

These services are unsuitable for real-time pricing co-optimised with the energy and FCAS spot markets. These services can be co-optimised, yet, because they depend on which synchronous units are online, only through running an ahead optimisation or ahead trading arrangement. This is why AEMO considers a contracting mechanism should be prioritised, something like the Delta Capacity Commitment Mechanism proposal or in the longer term an extended ahead optimisation.

It should be noted the NEM already has a contract and commitment mechanism today with the system strength unit combinations and the directions and compensation framework. There are no disadvantages to improving on this with a contracting framework, a formal cost optimisation (such as the Unit Commitment for Security (UCS)), or both. Further developments, such as an ahead market may be considered by the ESB.

Improve FCAS, in response to declining inertia and prioritise FFR for system intact

FFR could possibly be integrated into the FCAS spot market to reduce the amount of Raise 6 second reserves that would otherwise need to be procured with declining levels of inertia. Improvements to the procurement of FCAS, which could require buying more reserves to manage lower inertia, should provide further remuneration for providers of PFR whilst also allowing the opportunity for FFR to compete.

Despite FFR being suited to spot markets, and subject to detailed assessment of implementation cost, a first stage in procuring FFR could be contracting under the existing Rules for separation and risk of separation events (islanding) and for system intact using a contracting approach to reduce the amount of FCAS reserves procured.