Katy Brady
Australian Energy Market Commission
Level 6, 201 Elizabeth Street
Sydney NSW 2000

13 May 2019

Dear Ms Brady,

**RE: Investigation into intervention mechanisms and system strength in the NEM EPR0070**

ENGIE appreciates the opportunity to participate in the market review investigating intervention mechanisms and system strength in the NEM ("the Review").

ENGIE is a global energy operator in the businesses of electricity, natural gas and energy services. In Australia, ENGIE has interests in generation, renewable energy development, and energy services. ENGIE also owns Simply Energy which provides electricity and gas to more than 680,000 retail customer accounts across Victoria, South Australia, New South Wales, Queensland, and Western Australia.

**A complex interaction of rules and operational processes**

The consultation paper sets out a range of issues relating to the intervention framework, including the hierarchy of interventions, the basis for compensation to be paid to directed or affected participants, and the methodology for calculating the quantum of compensation. It also canvasses alternative ways to provide a service (system strength) a deficit of which has been the main cause of the large increase in interventions in the NEM in the last two years. Each of these issues interacts with the others and so the impact of any changes to part of the framework or to the way an adequate level of system strength is obtained must be considered holistically as well as individually.

**Missing markets or price caps will result in a deficit of services**

Fundamentally, the reason for interventions is that the market operator has been unable to procure a sufficient quantity of a given service through participants responding voluntarily to existing market signals. It then needs to direct participants to provide the shortfall. In general there are two expected reasons that the market may fail to deliver sufficient levels of a service:

1. There is a price cap acting as a barrier to the market finding its efficient level. An obvious example of this is when interventions are made to ensure a reliable supply of energy at a regional level, such as when the RERT is activated. ENGIE has previously expressed its concerns at the Reliability Panel's unwillingness to fully take into account developments in the NEM in its determination of the Market Price Cap (MPC)[1]. A more complex example is the circumstances surrounding a direction on 1 December to a generator in SA to provide FCAS services. This occurred during a period of administered pricing in SA FCAS markets, meaning that SA generators naturally preferred to provide energy rather than FCAS. In other words, the need for the direction appears to have arisen because of inconsistencies between the way energy and FCAS markets are regulated, notwithstanding the clear interaction between them.
2. There is no market for the specified services required. This is the case with system strength, reflecting that for much of the life of the NEM there has been no scarcity of the service and so no need to create a market. An alternative example is the periodic requirement for reliability services in North Queensland when there are network constraints around the Ross substation. In this case, insufficient energy is provided by the market because regional pricing does not signal the location-specific nature of the requirement.

Whilst the scope of this review may not be able to fully address all these factors, it is at least important context for the review that interventions exist because of imperfections in the market, including the lack of any price signal for some services where scarcity has only recently and periodically emerged as well as unpriced externalities.

**Assessment framework**

The assessment framework proposed in the consultation paper appears broadly reasonable. ENGIE agrees that is important to allocate risks appropriately, wherever possible. It follows that market solutions are preferable to directions as these allocate risks appropriately to those businesses who participate in the market. Such an approach also represents an efficient outcome provided markets are appropriately designed.

ENGIE supports the framing of efficiency as balancing "the costs associated with the provision of energy resources" with "the value to consumers of having a secure supply". It is essential that efficiency is not framed simply at lower cost provision of services in the short run, given that inadequate rewards for providing energy

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[1] See for example our submission to the Reliability Standard and Settings Review 2018 draft report, which can be accessed at https://www.aemc.gov.au/sites/default/files/content/649c2fbe-59af-4d2d-b873-ee92e10de328/MarketReview-Submission-REL0064-ENGIE-171220.pdf

services affect the sustainability of the market. This may be especially the case for ancillary services that not all generators can provide and where many of the new entrants do not have an inherent capability to provide the full range of services.

**Hierarchy of interventions should favour contracted participation over mandatory action**

The consultation paper makes two points that appear to favour the use of mandatory action such as directions over the RERT: firstly that "directions may be capable of faster implementation than the RERT and this is valuable" and secondly that there should be a least cost approach, which under current compensation levels is likely to make directions “cheaper” than the RERT. This overlooks an essential point that participants in the RERT are doing so voluntarily, because they have chosen to contract to provide RERT services, whereas mandatory action inherently entails requiring a market participant to act differently from what they have chosen to do. Voluntary actions such as the RERT should take precedence over compulsory actions. There may be some cases – unforeseen emergencies for example – where the market operator needs to compel participants but these should be few and far between. As noted above interventions are typically because of limitations in the market framework and it is not appropriate to address those primarily through compulsion where there is an alternative mechanism that is based on voluntary contracting.

This is particularly important, given there is some ambiguity about AEMO’s basis for determining that a direction is the appropriate course of action in a given situation. As independent expert Synergies Consulting observed: “in so far as these compensation arrangements are triggered by directions, we had some difficulty in determining whether directions were essential, preferred or merely convenient standard practice, and whether the distinction would be relevant to compensation arrangements”[2].

In any case, it seems likely that in only a small subset of recent interventions would the RERT and directions be effective substitutes. Given RERT participants include demand response providers, it does not appear a suitable mechanism for ensuring adequate system strength, for example.

**Compensation arrangements should recognise the importance of preserving market signals**

Compensation arrangements for market participants result from the interaction of a number of elements of the rules, including the Reginal Reference Node (RRN) test for whether intervention pricing is applied, the way intervention pricing is calculated when it is applicable, the 90$^{th}$ percentile benchmark for compensating directed generators, compensation for affected generators, the $5,000 threshold and the independent expert review process for applications for additional compensation. Accordingly while each element must be considered in its

[2] Final report on compensation related to directions that occurred on 1 December 2016, Synergies, 2017

own right, the AEMC should also have regard to the cumulative impacts of the arrangements and whether they represent an appropriate compensation framework as a whole.

*The RRN test*

The RRN test may be being asked to do too much as a proxy for determining whether intervention pricing is appropriate. This may be reflected in the ambiguities over its application. It's not clear that it was envisaged as a test to determine whether intervention pricing should apply for directions to maintain system strength, for example. The application of intervention pricing in such cases in SA appears to be a contingent outcome of the fact that the generator closest to the RRN is one of the generators that AEMO considers capable of providing system strength by being directed on. Other areas of emerging low system strength, such as North West Victoria are not close to an RRN, and so it appears unlikely that a direction there would result in intervention pricing.

*Intervention pricing*

It does not follow that intervention pricing (whether the current approach of "what-if" pricing or some other adjustment to prices) is inappropriate in the case of a direction for system strength. We note that AEMO's consultants considered that intervention pricing should not apply in such cases because "no amount of modification of the energy prices will signal the scarcity of the unpriced services"[3]. But, in practice, the effect of procuring system strength services by directing generators on is to push additional energy into the market from a participant that would not otherwise have done so at the prevailing price. So, irrespective of whether it was the original intent of the rules, the effect of intervention pricing is to unwind this distortion and preserve signals in the energy market.

We note the consultation paper's point that the impact on spot prices of intervention pricing for system strength appears material - subject to the extent to which the market would respond effectively to the price impact of directing generators on if there was no intervention pricing. This is a reflection of the unsatisfactory situation that arise when the market operator considers it needs to use a tool designed for very occasional instances of market failure on a regular and systematic basis as a substitute for a proper market or procurement process to obtain the desired service. The spot price differential also arises because the act of procuring one service has a knock-on effect on another market. If system strength needs were met by synchronous condensers that do not participate in the energy market, then the depressing effect on the spot price would not occur. Moreover if the market responded effectively to such cases, the effect would likely be minimised. At subzero prices (or even near zero prices) for example, there would be a demand effect as flexible load took advantage of the low spot price. There would also be a voluntary curtailment by variable renewable supply and an arbitrage opportunity would arise for

[3] Review of intervention pricing final report, SW advisory and Endgame Economics, 2017, pp28-29

storage resources. Price equilibrium would be restored close to the point where it would have been without the direction, given the relatively small amounts of energy added to the system by the direction. To the extent the AEMC considers this would not occur, it raises the question of how effective the price signal is in such situations.

There would be a stronger case for abandoning intervention pricing if system strength services were appropriately priced and AEMO could claim that the outcomes in the energy market were the result of co-optimising across multiple services, as is already the case with FCAS.

*Compensation for directed participants*

The arrangements for compensating directed participants - the 90th percentile of the regional spot price for the preceding 12 months - similarly have an element of arbitrariness to them. Nonetheless the choice of a reference point above the average price is clearly a recognition of the imposition entailed in being required to comply with a direction. ENGIE does not consider that this creates a perverse incentive to operate in ways that might trigger the requirement for a direction in order to receive this price, as suggested in the consultation paper. The costs entailed in starting up a generator at short notice, which potentially include having to obtain fuel at a premium due to the short notice requirement are material, as evidenced by the claim by two generators for additional direct compensation following a direction on 25 April 2017[4]. In other words, even the 90th percentile price may not be sufficient to cover direct costs. Nor is it clear that an individual generator can systematically control the need for a direction – even in the case of SA system strength, there are multiple permutations of plant that can provide the minimum levels. The AEMC's concerns on this score appear to be based on the observation that some generators have decommitted at short notice before a direction event has occurred and then sought to recommit and have the direction cancelled when the spot price is higher. Decommitting at low spot prices and seeking to recommit at high spot prices is normal market behaviour. To the extent that some generators have decommitted at shorter notice than permitted by the rules, this appears to be an enforcement issue for the AER that has no real bearing on this review.

To the extent that the AEMC wishes to examine if there is a more appropriate compensation level than the 90th percentile benchmark, it should consider whether there is a better way to signal the value directed participants are providing. As an independent expert has noted, the current rules may not do this. "The compensation rules together may immunize directed generators from operating losses but do not obviously compensate the directed generators for the value they provide to the system"[5]. The same expert also pointed out the problems with simply paying the direct costs a generator occurs: "Clause 3.15.7B does not recognise that peaking gas turbines need to recover their fixed costs over the small number of hours in which they are required to operate, a significant share

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[4] Final report on claims for additional compensation arising from directions on 25 April 2017, Synergies, 2017
[5] Final report on compensation related to directions that occurred on 1 December 2016, Synergies, 2017

of which might arise under directions. In these instances, clause 3.15.7B only compensates to a ceiling of avoidable costs"[6]. These points are particularly pertinent given that in practice only a subset of generators is able to respond to directions as AEMO needs them to, and that many new generators are not part of this subset.

Compensation for directions at direct cost creates a case of moral hazard on the market operator. In this case directions will always be cheaper than contractual arrangements that are based on fully absorbed costs or market opportunity costs. This therefore invites further interventions as a means to minimise consumer costs.

**Compensation threshold materiality is better set at the event level**

ENGIE welcomes the consideration of how the $5,000 threshold should apply. Independent experts have taken different approaches to the "per trading interval" definition, so at a minimum there is value in clarifying this. A fuller discussion of the issues entailed in applying a "per trading interval" threshold to a claim that is for an entire event (that typically spans multiple trading intervals) is set out in Synergy Consulting's *Final Report on additional compensation claims arising from AEMO directions on 1 December 2016*. In any case AEMO's proposed rule change to set the threshold at the event level rather than the trading interval level appears logical and would avoid these ambiguities entirely. It would also avoid issues arising over the appropriateness of the threshold when 5-minute settlement is introduced, which would indirectly make the threshold six times greater.

The consultation paper suggests that such a change warrants consideration of the quantum of the threshold. To some extent this is logical; however, the basis for setting the threshold at a particular level or reference point needs further consideration. The existence of any threshold above zero is an administrative convenience to minimise the burden of processing small compensation amounts. Further information on the range and incidence of compensation amounts per participant, per event, and some assessment of the costs involved to process a compensation adjustment would inform considerations of whether the threshold should be changed. Given the purpose of the threshold, the same level is likely to be appropriated for both affected and directed participants.

**Transparency is generally preferable**

It's clear from the consultation paper that there is relatively little data in the public domain to assist stakeholders in considering the wide range of issues raised by the AEMC. AEMO is yet to publish reports covering all the interventions carried out to date for example, with the backlog going back almost a year. For those reports that are available (noting some older ones have been removed) it is not always clear which generators have been the subject of directions, the quantum of the impact of the direction, the amounts paid to different parties under each clause of the rules and so on. There is unlikely to be any value in disclosing the individual amounts paid to (or paid by) individual affected participants, but more could be made available without compromising commercial

[6] Ibid

confidentiality. Where the use of directions has become systematic, such as for system strength in SA, then it may clearly become onerous for AEMO to produce a full report for each and every occasion, so there may be a more practical approach to have a periodically updated report summarising basic data such as the dates and times of the direction, the affected generators and the total compensation paid for the event. In any case ENGIE recommends AEMO and AEMC work together to provide more information in advance of the next stage of this process.

**Mandatory restrictions**

ENGIE observes that it is difficult to assess this part of the framework, given the last jurisdictional restriction was nearly two decades ago and so the pricing framework and AEMO's more recent update of its procedures have not been tested in practice. Given the steps taken by market participants, AEMO, and AEMC in recent years to cultivate additional demand side resources through contracts and rule changes, the likelihood of any jurisdiction needing to implement such restrictions rather than elicit a voluntary response has receded. Nevertheless if the framework is maintained the same principles apply as to other directions.

**Counteractions**

ENGIE recognises that the counteractions tool arises out of a good intention – that it can minimise the impact of a direction on the market as a whole. Nonetheless it does so by concentrating the impact on one market participant. Even if the counteraction is applied to a generator considered to be in the same portfolio as the subject of the original direction, this still results in two generators being obliged to act differently from how they would have chosen. The issue is further compounded by AEMO's concern that counteractions on variable renewable generators may not be effective, meaning that as with directions, counteractions can only be applied to a shrinking pool of generators, increasing the burden on each. It also means that in the most frequent use of directions – for system strength in SA – counteractions are not applied. Accordingly this part of the framework adds little value.

**Contracting approaches to minimise the use of directions are worthy of consideration**

Given that many of the concerns relating to the use of directions stem from the recent increase in their use for system strength in SA it is appropriate for this review to also consider approaches to providing system strength. Although the immediate issue of system strength in SA will be addressed from next year through the installation by ElectraNet of synchronous condensers, these are not guaranteed to provide adequate system strength at all times, reflecting that the obligation on ElectraNet is a "best endeavours" requirement. Accordingly, ElectraNet consider that the continuing use of directions could cost around $12m pa in direct compensation costs. This may present an opportunity to test whether this residual requirement can be met through other procurement means. While ElectraNet's tender process indicated that tendering of the full system strength requirement could cost

$85m pa (compared to the compensation costs of directions using the 90$^{th}$ percentile price of $34m pa), this may not be reflective of a competitive price to provide system strength services. Tendering for a partial system strength requirement over and above what is provided by the synchronous condensers is likely to provide greater options in the provision of such services. Also, given that generators will inevitably provide some energy to the market by running at minimum generation levels there would be an opportunity to recognise that these services are provided as an integrated package and for the consideration provided under the contract to be for both. The cost of system strength would be the difference between the consideration and the spot price revenue the generator would have earned running at minimum generation levels. The generator could still bid the remainder of its capacity into the market in the normal way. By contrast, ElectraNet had no basis on which to offer consideration for the energy services which may have impacted the tender outcomes. As the paper notes, care would need to be taken that any such contracting process did not simply displace other synchronous generation.

More broadly, there is value in considering whether there are alternative market or procurement arrangements to directions, especially if directions are issued repeatedly in similar circumstances. As an independent expert report noted: "some types of directions might be better managed through other arrangements such as reliability contracts. These might extend to peaking gas turbines in far north Queensland during tropical storms or to the management of SA islanding." One way to ensure these options are explored would be for the rules to include a trigger to require a review of whether there are mechanisms other than directions in cases where directions are being used on multiple occasions to meet the same basic requirement (which could be defined as a particular service in a particular region or sub-region).

Should you have any queries in relation to the attached proposal please do not hesitate to contact me on, telephone, (03) 9617 8415.

Yours sincerely,

**Jamie Lowe**
Head of Regulation