Hydro Tasmania

14 November 2019

Mr John Pierce
Chairman
Australian Energy Market Commission
PO BOX A2449
SYDNEY SOUTH NSW 1235

Dear ~~Mr Pierce~~ John

SYNCHRONOUS SERVICES MARKETS (INCLUDING INERTIA) RULE CHANGE PROPOSAL

Hydro Tasmania lodged a Rule change proposal in September which seeks to address the shortage of inertia and related services in the NEM by integrating their dispatch with the existing Energy and FCAS Spot Markets.

Since lodgement, officers from the AEMC and Hydro Tasmania have discussed the rule change. The AEMC provided feedback that it would be valuable if the rule change proposal identified sections of the National Electricity Rules (NER) that may require amendment to address the issues raised in the proposed rule. Please find attached the updated rule change request which includes a new section on the relevant aspects of the NER as requested.

Yours sincerely

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CEO

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Hydro Tasmania

17 September 2019

Mr John Pierce
Chairman
Australian Energy Market Commission
PO BOX A2449
Sydney South NSW 1235

Dear Mr Pierce

RE: Synchronous Services Markets (including inertia) rule change proposal

Hydro Tasmania submits the attached Rule change proposal to address the shortage of inertia and related services in the NEM by integrating their dispatch with the existing Energy and FCAS Spot Markets (see Appendix A).

A secure power system requires adequate levels of inertia, fault level and voltage control. A lack of these services increases the risk of system instability and supply interruptions. As AEMO, the AEMC, the AER and ESB have noted, maintaining system security has become more challenging in recent years. This is due in part to the growth in variable renewable energy resources, such as solar and wind generation, which have displaced traditional synchronous generation. This transformation of the power system is seeing a reduction in services that synchronous generators were previously providing in abundance, and without compensation. The scarcity of services such as inertia, fault level and voltage control is leading to AMEO implementing constraints or issuing directions in order to maintain power system security. This has been seen chiefly in the South Australian and Tasmanian regions, and more recently expanding to Victoria, with Queensland expected to follow. The unprecedented number of AEMO directions that have been issued to participants to synchronise their generators to the system is not a long term solution to address system security consistent with the National Electricity Objective. Hydro Tasmania has proposed this rule change to address a pressing concern in the NEM. The rule change represents a low cost and relatively simply approach that that could provide a more efficient long term solution in support of the National Electricity Objective. Hydro Tasmania looks forward to working with the Commission further as it considers this proposal. Please contact John Cooper (john.cooper@hydro.com.au or (03) 6230 5313) should you wish to discuss this proposal further.

Yours sincerely

Steve Davy
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Appendix A: Rule change proposal

Overview

Hydro Tasmania proposes to address the shortage of inertia and related services in the NEM by integrating their dispatch with the existing Energy and FCAS Spot Markets. Key elements of the proposed rule change are:

- AEMO would shift the terms related to generators' online statuses from the input side of constraint equations to the output side.
- Generators would provide two additional fields in their Spot Market bids to AEMO indicating cost and availability of synchronising units online.
- The Dispatch Engine would instruct the generators to be placed online, where doing so reduces market price. The costs of synchronous services would then be reflected in the region's spot price.

Background

In April 2019, over 90% of binding constraints in the NEM were determined in part by online statuses of synchronous generators. AEMO's dispatch constraint system is already aware of the benefit of placing those generators online, but are unable to issue dispatch instructions to them due to the lack of compensation mechanism. Synchronous services are instead taken as an unchangeable input, represented by the closed or open circuit breaker status of key machines on the Right Hand Side (input side) of the constraint.

Proposed Dispatch

Hydro Tasmania proposes to amend the National Electricity Rules to shift the online statuses of relevant generators to the Left Hand Side of AEMO's constraints where they can receive a target to come online. In order to do so the circuit breaker status of a generator will be treated as a faux power station, or Synchronous Services Generator (SSG) of "1MW" capacity. In the case of an aggregate station it would be 1MW per machine. AEMO would exclude dispatch of SSGs from its energy balance equation, to ensure the load is met, given a closed circuit breaker doesn't actually meet 1MW of demand.

Consider the following example, which reflects many existing constraints, involving a windfarm "WIND" and synchronous peaking generator "PEAKER", owned by different corporations:

0.5*WIND MW <= 60+10*PEAKER circuit breaker status (CB)

With this rule change constraint would instead add the bolded terms below:

0.5*WIND MW **- 10*SSG**$_{\textbf{PEAKER}}$ <= 60 + 10*PEAKER CB status **- 10*SSG**$_{\textbf{PEAKER Target from last Dispatch interval}}$

The SSG appears twice, in an approach similar to AEMO's feedback constraints. The design ensures that if Peaker's CB was closed as a natural outcome of Peaker being turned on for energy services the SSG would not be compensated. A detailed calculation demonstrating this is shown in Appendix B.

The SSG would share the fast start time (synchronisation time known as "T1") with the real generator, but would otherwise be unrelated as far as the dispatch engine is concerned. The SSG would bid availability and a price for which it is willing to close its circuit breaker and come online.

Proposed Settlement:

As is the case with all constrained on generators, SSGs would frequently be disincentivised from providing their services, because the energy spot price is lower than their cost price and they cannot set the spot price. To incentivise the SSGs to participate in the market and minimise the likelihood of further directions, Hydro Tasmania proposes that, unlike the real generators, the SSGs be paid based on their bid price – not the Spot Market price.

The competitive tension between SSGs and existing generators in the constraint would mean AEMO's dispatch engine would only ever dispatch the SSG if doing so provided lower priced outcomes for the consumers in line with National Electricity Objective. Mathematically, the change could only ever be beneficial to consumers, and is a win-win outcome.

AEMO would need to publish two prices for each service: one including cost of SSGs and one without per service per region. Price excluding SSGs would work by the existing principles and would continue to be used for settlement of generators. However, loads would pay the price including SSG. The premium would be determined by dividing the total payments to the SSG by the size of the load in the region in which SSG is located. As shown in scenario 2 and 3 of Appendix B the prices difference between two prices would be very small and hence not create basis that would jeopardise contract market liquidity.

The same principles would be applied to FCAS market, but SSG bids would be separated by service. Thereby if the SSG was dispatched for contingency raise FCAS, the costs would be recovered from generators in its region. SSG $_{\text{Energy}}$ bid would be entirely separate concept from SSG $_{\text{R6 Bid}}$, for instance, and they wouldn't be dispatched simultaneously. Whilst most FCAS constraints do not cite machine online statuses individually, they are frequently determined by their sum in the system, in the form of inertia. Such FCAS constraints would be reformatted to show the inertia contribution from individual generators by creating 3 new terms as per example above.

Cost of Implementation

To minimise costs of implementation AEMO could update the constraints incrementally by focusing on the most frequently binding constraints (e.g. top 50 constraints). Additional updates could occur quarterly for any new arrivals to the list. Furthermore, to minimise implementation costs for participants, AEMO's bidding website could copy the last submitted bid in case of non-submission (as it does for real generators) and treat SSG availability as zero where associated real generator is zero. This would mean that most participants wouldn't have to update their systems and could use standing offers for SSGs if they wish.

The proposed Rule contributes to the National Electricity Objective

The National Electricity Objective (NEO) is to "promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:

a) price, quality, safety, reliability and security of supply of electricity; and
b) the reliability, safety and security of the national electricity system"

The proposed Rule contributes to the NEO by supporting a more efficient utilisation and operation of resources. There would be less need for AEMO to manage system security concerns through directions and constraints which would lead to a more efficient system.

National Electricity Rules amendments

The National Electricity Rules (NER) would need to be amended to address several aspects of the proposed rule change. These aspects include:

- Definition of a new service.
- Application of the new service in the central dispatch process.
- Settlement of generators and loads.

Commentary on relevant sections of the NER are outlined below.

<u>Definition of new service</u>
A Synchronous Services Generator would need to be defined as a new service in the rules. Thoughts on ways that this could be achieved:

- As an amendment/broadening of the definition contained in 3.11 Ancillary Services or as a new section (e.g. Section 3.11B Synchronous Services Generator)
- Under 2.2.2 Scheduled Generator definition, add an additional provision that notes that a generator may submit to AEMO a schedule of dispatch offers for generating units including the generators online status.

<u>3.8.1 Central dispatch</u>
Propose to include an additional item in 3.8.1 (b) that list that a Synchronous Services Generator is included in the central dispatch process.

<u>3.8.7A Market ancillary services offers</u>
Update the requirements listed under 3.8.7A that apply to offering market ancillary service offers to specify the requirements of a Synchronous Services Generator.

<u>3.15 Settlement</u>
3.15.6 and/or 3.15.6(A) would likely require amendment to enable payments for a Synchronous Services Generator to be made based on bid price (not spot market price).

Appendix B: worked example

The following is a simplified example of the type of constraints that bind due to lack of synchronous services (in this case inertia).

Assume the following for all scenarios:

- Wind speed is sufficient to dispatch Windfarm "WIND" at 160MW and it is bid in at $0/MWh, but a constraint below is binding limiting its dispatch.
- Peaking synchronous Generator "PEAKER", owned by a different corporation, is offline and has no incentive to come online for energy or FCAS purposes because its cost of production is lower than the spot price, which is currently $100/MWh.

<u>Scenario 1 – outcome under the current rules:</u>

Constraint A: 0.5*WIND MW <= 60+10*PEAKER circuit breaker status (CB)

WIND MW <= (60+10*0)/0.5
WIND MW = 120MW

40MW of WIND is unable to get dispatched and is spilt. $100/MWh energy is dispatched instead.

After Synchronous Service Markets are introduced Constraint A is rewritten as follows:

B1) 0.5* WINDMW - 10*SSG_{PEAKER} <= 60 + 10*PEAKER Circuit Breaker status -10*SSG_{PEAKER} Target from last Dispatch interval

In addition a version of following constraint (B2) would exist for every SSG, to ensure that revenues are recovered only when the circuit Breaker would otherwise remain open.

B2) SSG_{PEAKER} <= max (0, 1- (PEAKER circuit breaker status - SSG_{PEAKER} Target from last Dispatch interval)

Similarly, B3 ensures SSG is being paid to deliver any one of the FCAS services it's precluded from getting payment for energy and vice versa).

B3) SSG_{PEAKER} <= 1- max (0, SSG_{PEAKER}R6 from last DI, SSG_{PEAKER}R60 from last DI, etc..)

B1, B2 and B3 apply for all scenarios that follow.

<u>Scenario 2 - PEAKER is offline and its SSG bid in at $50/hr:</u>

0.5*WIND MW -10*SSG_{PEAKER} <= 60+10*PEAKER circuit breaker status -10*SSG_{PEAKER} Target from last Dispatch interval

0.5*WIND MW -10*SSG_{PEAKER} <= 60+10*0-10*0
0.5*WIND MW -10*1 <= 60

WIND MW <= (60+10)/0.5

WIND MW= 140MW

Only 20MW of WIND is unable to get dispatched and is spilt (20MW more of WIND gets dispatched compared to existing rules in Scenario 1). Regional Reference Price (RRP) falls to say $99/MWh as a result of the additional low cost generation (excluding SSG). $RRP_{inclSSG}$ is $99/MWh+$50/1250MW of TAS demand = $99.04/MWh. Loads pay $99.04/MWh, Generators get paid $99/MWh and SSG at PEAKER receives $50/hr.

<u>Scenario 3 - PEAKER is offline and its SSG is bid in at $5000/hr:</u>

AEMO's Dispatch Engine's linear programme (NEMDE) considers the option of turning on PEAKER's SSG as in Scenario B, but instead of the $50/MWh adding $0.04 to the cost (objective function) it is adding $4.

I.e. if SSG is dispatched RRP for loads would become $99+$4=$103/MWh.

Given that this is higher than $100/MWh, NEMDE chooses not to dispatch the SSG. From a perspective of the Dispatch Engine's objective function the 20MW*$100/MWh benefit ($2000/hr) caused by more generation at WIND is outweighed by the $5000 cost at PEAKER of relieving the constraint.

Note that whilst SSG at PEAKER would be paid on based on its bid price, because it has offered its service at too high a price it does not get dispatched nor paid, because it is in competition with energy bids of competitor's generators.

<u>Scenario 4 - PEAKER online anyway due to Energy bids and bids its SSG bid in at $50/hr:</u>

From B2) SSG_{PEAKER} <= max (0, 1- (PEAKER circuit breaker status - $SSG_{PEAKER\ Target\ from\ last\ Dispatch\ interval}$)

Becomes

SSG_{PEAKER} <= max (0, 1-(1-0))

SSG_{PEAKER} <= 0

An Equation B1 becomes:

0.5*WIND MW -10*SSG_{PEAKER} <= 60+10*1-10*0
0.5*WIND MW -10*0 <= 60+10
WIND MW <= (70)/0.5

WIND MW= 140MW

As in scenario 2, the additional 20MW of WIND farm output is dispatched, but without compensating the SSG, given the synchronous generator was online to provide energy anyway (SSG dispatch target is zero, but the closed circuit breaker is acknowledged by the constraint).

The following table demonstrates that all scenarios deliver the desired result: SSG can get dispatched whenever it benefits the market but only gets compensated if the unit wasn't already online (represented by circuit breaker status):

Scenario	CB status	SSG previous DI	**SSG max on LHS of B2** *(1-(CB status-SSG previous DI)*	**SSG max on LHS of B1** *min (max capacity, result of B2)*	**Market benefit** *(SSG dispatch+CB status-SSG previous DI dispatch)*
A	0	0	1	1	1
B	1	0	0	0	1
C	0	1	2	1	0
D	1	1	1	1	1

Note that scenario C is caused by SSGs non-conformance with the previous target. It makes the RHS smaller than it needs to be (harder than it needs to be to meet), but the dispatch engine can clear the constraint by providing another target to the SSG. Whilst the costs of doing so are reflected in the Regional Reference price published for loads, the SSG doesn't get compensated so an additional price RRPinclSSGexPost needs to be published (i.e. if SSG didn't start up price paid loads and generators in the same: RRPinclSSGexPost = RRP).

AEMO would have a non-conformance constraint process for SSGs, same as for normal generators, except with smaller MW tolerance given their "1MW" size.