GE Renewable Energy

Martin Kennedy
Head of Hydropower
Australia, New Zealand & PNG

Level 2, 572 Swan Street
Burnley, VIC, 3121
Australia

M : +61 416 642 398
E : martin.kennedy@ge.com

www.ge.com
www.gerenewableenergy.com

Post 2025 Market Design Consultation

Dr Kerry Schott
Independent Chair
Energy Security Board

C/O COAG Energy Council Secretariat
GPO Box 2013
Canberra, ACT, 2601
http://www.coagenergycouncil.gov.au/market-bodies/energy-security-board

Lodged by email

Date: 13 October 2020
Subject: Post 2025 Market Design Consultation Paper, released 7 September 2020

Dear Dr. Schott,

We would like to thank you for the opportunity to participate in this consultation process, which we regard as greatly important to the timely, cost-effective development of the National Electricity Market.

As acknowledged in both AEMO's Integrated System Plan and the Federal Government's Technology Investment Roadmap, there is a clear and growing need to expand Australia's fleet of pumped hydro power plants if Australia is to complete the energy transition in a cost-effective manner, without sacrificing reliability or security.

The overall economic case for pumped hydro is extremely strong, with GE's internal analysis demonstrating that the 'peak shaving' services it provides would save electricity consumers hundreds of millions of dollars annually, enabling an economic payback period of less than 5 years in most cases. Consideration of additional benefits such as avoided transmission investment, system services and regional job creation only strengthen the case for investment in pumped hydro.

Despite this positive context and a wealth of potential sites, many promising pumped hydro developments have stalled prior to FID. Feedback from investors and developers has attributed this to insufficient size and certainty of the revenue streams available to them.

Our internal analysis supports this conclusion, indicating that current market rules and structures create a misalignment between the benefits and costs of pumped hydro, in which developers incur 100% of the cost of building their projects, but receive less than 15% of the market benefits their projects create. The remaining >85% of benefits flow as 'positive externalities' to electricity purchasers across the market in the form of lower prices. This is without even considering the inertia, system strength and operating reserve services that pumped hydro can provide but is not currently paid for.

Simplistically, this misalignment could be fixed by addressing either or both sides of the cost-benefit equation, i.e.:

- Reduce the share of the up-front capex that must be paid by the developers
- Increase the share of benefits captured by the developers during operation

We view the Post 2025 Market Design program as a vital process for the consideration and adoption of measures addressing this misalignment, most notably in relation to the recognition of (and compensation for) a greater amount of the benefits that synchronous storage such as pumped hydro can bring, beyond just electrons.

GE Hydro's position is summarised below, according to the topics within the Post 2025 Consultation Paper. Please refer to our formal submission document for further detail.

Resource Adequacy Mechanisms

- The ISP and ESOO give AEMO's view on the amount of dispatchable generation and storage capacity required, but don't provide the actual investment signals needed to make this happen

- The current energy-only market is failing to provide investment signals, as the increased penetration of wind and solar tends to depress pool prices, decreasing the investment signal when we need it to increase

- RERT should continue to play the role of 'reliability backstop', but for it to be the main investment signal is to pursue 'management by crisis', in which we wait for a reliability crisis to occur, in order to trigger RERT and hence fix the crisis. This is inconsistent with lowest-cost long term solutions

- RRO as it stands doesn't send any real investment signals. Instead, it primarily seems to force retailers to contract a portion of their load with dispatchable generation owners. At best this has a neutral impact on investment; at worst it has a negative impact, as it creates a protected revenue pool accessible by only by incumbent dispatchable generation owners

- One solution could be to extend the duration of RRO commitments beyond the closure dates of the coal fleet, providing a signal to invest in dispatchable generation beyond that horizon. If this approach were pursued, care would need to be taken to ensure it actually facilitated newbuild generation rather than being used to justify running ageing, carbon intensive generators for longer

- A market for operating reserve could help, but needs to be more than simply a spot market if it is to provide sufficient revenue certainty for the kind of long-term investments required. One way to address this could be to create markets for longer-duration derivatives that allow developers to secure their operating reserve revenue over a longer period. A simpler method to consider would be availability-linked capacity payments

Ageing Thermal Generation Strategy

- The time is rapidly approaching when it will be cheaper to build new solar + wind + firming (batteries or pumped hydro) than to continue operating existing coal power stations. Some analysts put this as early as the mid-2020s

- In this context, we need a framework that requires thermal generators to give adequate notice, while also providing ways in which the closure date can be brought forward in an orderly fashion as the market evolves

- Closure of a coal plant entails significant remediation/rehabilitation costs, which creates an incentive for coal operators to push their stated closure dates as far into the future as possible (minimising the NPV cost of closure). This in turn creates an artificial impression that coal closures are much further away than may actually be the case. Requiring coal owners to progressively make 'down payments' on their remediation costs during each year of remaining operation could help address this information asymmetry

Essential System Services

Operating Reserve

- A spot market for operating reserve would create a new revenue pool for dispatchable generation, however this alone is not sufficient to guarantee the signals needed for efficient long-term investment

- Generation investment requires long-term revenue certainty, so supporting markets (e.g. financial derivatives) that allow hedging of revenues over longer durations would likely be needed as well

- Care should also be taken to ensure new markets created actually provide signals to invest in the technologies we will need in future, rather than becoming captive revenue pools for the ageing thermal generators we are working to progressively retire

Fast Frequency Response (FFR)

- We support the creation of a market for fast frequency response framed similarly to existing FCAS markets, but note that among dispatchable technologies, only batteries would be technically capable of participating in this market

- As such, if other dispatchable technologies are to be supported as well (consistent with technology neutrality), it follows that these other dispatchable technologies should also be compensated for the services they can provide (e.g. system strength, inertia)

- Furthermore, mechanisms to compensate inertia and system strength should be prioritized over mechanisms to compensate FFR, due to their more fundamental nature. Very simply, no amount of FFR can completely remove the need for inertia, however a sufficient level of inertia can completely remove the need for FFR. Similarly, no amount of FFR can address weak system strength

Inertia and System Strength

- We acknowledge the challenges of a market-based approach to these, given their localised nature (especially system strength), however we also note several concerns in relation to a bilateral NSP-led approach, notably

    - Lower liquidity

    - No visibility to developers/investors not currently involved in bilateral negotiation as to what the 'going rates' are for inertia or system strength

    - Potential for misaligned timing, with NSPs going to market for these services at a time that doesn't suit the needs of the developers or investors

    - Potential for NSPs (as regional monopolies) to adopt a 'take it or leave it' approach to the negotiated contracts, which is not necessarily consistent with the best or fairest outcome

- Potential for NSPs to not give meaningful consideration to non-network solutions to inertia and system strength, which would render this approach pointless from the perspective of encouraging investment in dispatchable generation

Scheduling and Ahead Markets

- While in principle we support the goal of securing adequate inertia and system services in advance of dispatch, it is not clear to us in practice how reliably the demand for these could be forecasted, particularly in light of the rising penetration of intermittent generation technologies

- In this context, we favour a market mechanism that encourages flexible/dispatchable technologies to bid into the market when they are needed, rather than a mechanism that pays inflexible technologies to be there 'just in case'

- If UCS and Ahead Markets can be shown to improve dispatch efficiency, they could be worth exploring further, however we must not confuse 'dispatch efficiency' with 'investment efficiency' – i.e. we should not assume that improving dispatch efficiency for system strength and inertia will automatically provide investment signals for the technologies that provide them

Coordinating Generation and Transmission Investment

Financial Transmission Rights (FTRs)

- While we acknowledge the benefits of being able to de-risk congestion, we also note the concern raised by multiple groups about the potential for incumbent operators or financial investors to buy up FTRs in strategic parts of the grid, either pushing up the price faced by genuine project developers or reducing the transmission capacity available to them or both

- If FTRs can be designed in a way that provides a net increase in transmission certainty for project developers, then we support their introduction as a means to accelerate development activity, however it should not be assumed that simply introducing FTRs will achieve this outcome: deliberate design decisions must be made with this goal in mind

- One possibility for consideration could be 'use it or lose it' provisions that prevent financial investors from sitting on transmission rights as a speculative investment or incumbent operators from sitting on them as a means of restraining competition from new entrants

Locational Marginal Pricing (LMP)

- While we acknowledge the theoretical benefits of Locational Marginal Pricing, it is unclear to us what the practical benefit of this additional complexity would be, given the identification and development of REZ's already seeks to align transmission and generation investment

- Before supporting implementation of LMP we would want to see an analysis comparing it to the locational benefits already delivered by the coordinated development of transmission and generation in the REZs outlined in AEMO's ISP. Until such analysis is completed and made available, LMP looks like a solution to a problem that doesn't exist

Should it be possible to do so, we would welcome the opportunity to further discuss any or all of the above matters with the ESB team, as we see this process as an important opportunity to create the market conditions needed for the optimal evolution of the NEM.

Best regards,

Martin Kennedy
Head of Hydropower
Australia, New Zealand & PNG
GE Renewable Energy