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| 19 October 2020  [info@esb.org.au](mailto:info@esb.org.au) |

Dear Energy Security Board,

RE: Energy Security Board (ESB) Post 2025 Market Design Consultation Paper

Hydro Tasmania is Australia’s largest producer of renewable energy, and is an active participant and contributor to the energy market reform agenda. Hydro Tasmania owns Victorian based electricity and gas retailer Momentum Energy and specialist power and water professional services firm Entura. We welcome the opportunity to respond to the ESB’s *Post-2025 Market Design Consultation Paper*. Hydro Tasmania has made submissions to the ESB’s previous Issues Paper, as well as consultations on actioning the ISP, Interim Reliability Measures and Two-Sided Markets.

The paper offers a strong summary of current challenges in the National Electricity Market (NEM) as well as outlining possible reform options. Broadly speaking, Hydro Tasmania believes that the ESB’s paper articulates an appropriate range of potential solutions, however, options regarding Resource Adequacy Mechanisms (RAMs), Essential System Services (ESS) and scheduling will need significantly more detail to enable full assessment. We understand that this detail will be developed over coming months and Hydro Tasmania looks forward to participating in those discussions.

Tasmania is uniquely placed to support the transition of the NEM to cleaner sources of energy and has a proven record of successful renewable energy integration. The Tasmanian Government is in the process of legislating a Tasmanian Renewable Energy Target (TRET) to double the State’s renewable energy output by 2040. Further interconnection coupled with Tasmanian conventional and pumped hydro, and wind resources offer a future that’s clean, reliable and affordable. Investment in major infrastructure such as pumped hydro is challenging and will only progress if the forecast revenues from arbitrage and other sources are sufficient given the risks associated with making large capital and long‑duration investments.

Key risks for NEM resource adequacy are that:

* critical investment such as interconnection and pumped hydro energy storage are delayed while future revenue streams remain uncertain;
* the price of resource scarcity is not sufficiently high to promote investment in flexible resources (this includes options to provide additional capacity and flexibility from existing assets such as the redevelopment of Hydro Tasmania’s Tarraleah power station);
* the visible price signal does not have sufficient length to bring-forward the development of long-lead time projects (in advance of coal retirements); and
* should investors wait until firm revenue streams emerge, consumers may be faced with high prices and reliability risks (‘saw tooth’ price signals as seen with Hazelwood).

Accordingly, Hydro Tasmania is of the view that to deliver against the National Electricity Objectives (NEO), some form of investment support or longer-term contracting for additional flexible supply will be in the interest of energy consumers.

Real-time price signals are not effective in isolation. Market participants will also need derivatives markets and counterparties who are willing to contract over multi‑year periods. There must continue to be drivers for buyers and sellers to manage price and revenue risk through long-term financial instruments, particularly as the volume of zero short-run marginal cost generation increases. A framework that incentivises participants to take medium and long-term positions will be essential if the NEM is to operate effectively over these horizons and deliver a least-cost mix of clean energy resources without compromising reliability and system security. Specifically:

* long-term contracting will be critical in many cases to achieving Financial Investment Decision (FID) and can allow project developers to access a lower cost of capital and/or lower internal investment hurdle rates; and
* a low-risk, competitive investment environment is more likely to result in lower costs to consumers.

Our policy positions on Resource Adequacy Mechanisms are informed by these challenges.

Hydro Tasmania has structured our submission as follows:

* Summary of Key Reform Objectives (Attachment A);
* ESB Consultation Paper MDIs (Attachment B); and
* Responses to Consultation Paper questions (Attachment C).

Hydro Tasmania is a member of the Australian Energy Council and Clean Energy Council and supports the policy positions put forward in those submissions. If you would like any further information on any aspect of this submission, please contact Colin Wain ([colin.wain@hydro.com.au](mailto:colin.wain@hydro.com.au) or (03) 8612 6443).

Yours sincerely,



Andrew Catchpole

Chief Strategy Officer

e: [andrew.catchpole@hydro.com.au](mailto:andrew.catchpole@hydro.com.au)

**Attachment A - Summary of Key Reform Objectives**

One of Hydro Tasmania’s key reform objectives is to **ensure appropriate investment in dispatchable generation comes forward in a timely manne**r and can facilitate a transition to a low emissions electricity system, underpinned by a stable long-term investment environment. This needs to be **accompanied by prudent long-term system planning as demonstrated through the Integrated System Plan (ISP)**. Greater interconnection between regions can moderate price shocks, facilitate efficient dispatch and underpin resource adequacy through the development of least cost capacity and energy storage options.

As noted in the paper, “*the ESB has heard from stakeholders that forward price curves necessary to support investment may not be sustainable into the future because renewables and rooftop solar are reducing energy prices during the day. Consequently, price unbundling may be necessary to reveal the value of firming and a sufficient price duration to make it investible[[1]](#footnote-2).”* **Hydro Tasmania supports this concept of ‘price unbundling’ including appropriately valuing additional flexible supply**. Without markets that deliver system reliability through valuing the range of required services (such as flexibility, energy storage, system strength, inertia and frequency support) the NEM will be inefficient, deliver higher, more volatile prices and offer lower reliability and security to energy consumers. To this end, we support the ESB’s work examining Resource Adequacy Mechanisms and Essential System Services.

The **ESB should continue to explore the concept of an Operating Reserves Mechanism** but must also look to parallel measures that would strengthen and lengthen investment signals. This could include:

* options to increase the visibility, transparency and liquidity of the future price curve (beyond the current 3 to 4 years); and
* incentives to ensure a portfolio of flexible energy resources are supported by an Operating Reserves mechanism. This would avoid the risk that ‘Operating Reserves’ are procured predominantly from a single resource type (e.g. demand side response) which would not lead to an efficient technology mix over the medium or longer‑term.

We share the ESB’s view **that Essential System Services (ESS)** have historically been readily available and therefore have not been sufficiently valued. The consultation paper is rightly seeking to address these concerns through market-based mechanisms where possible. Where there is not a compelling case for moving to spot markets for ESS, or confidence it will provide resource adequacy then structured procurement may be more appropriate.

Hydro Tasmania believes that the discussion paper’s analysis of ESS is heading in an appropriate direction (pending further development of Unit Commitment for Security (UCS) and inertia/Fast Frequency Response (FFR) market designs).

* Hydro Tasmania’s synchronous services rule change is a simple and effective way of alleviating constraints and could work effectively alongside the market and procurement approaches being considered by ESB.

The **NEM is undergoing significant structural changes that will further challenge grid economics** and business cases. The Clean Energy Regulator estimates that 2.9GW of rooftop solar will be added in 2020[[2]](#footnote-3). The growth of household solar (and future household energy storage) will significantly impact wholesale market outcomes for all participants.

The **future NEM will need long-duration energy storage[[3]](#footnote-4)** if the energy sector is to achieve high average levels of renewable generation at the lowest system cost. If at least half of the NEM’s energy is to come from renewable energy sources (as the current trajectory suggests), then the high level of installed wind and solar capacity in the NEM will cause instantaneous periods where renewable generation exceeds total demand. Safely facilitating above 100 percent instantaneous renewables without constraining off generation will require the surplus energy to be time shifted through energy storage - if the NEM is to avoid over-investment or assets being underutilised.

* Without the ability to store generation in excess of instantaneous demand, the sector cannot efficiently or cost-effectively achieve an average of 50 percent renewables.
* Hydro Tasmania has expertise in this exact problem. Both King and Flinders Islands achieve average renewable penetrations above 60 percent through integration of energy storage and the ability to safely and securely operate local grids through periods of above 100 percent renewables operation.
* The Tasmanian system has operated to 85 percent non-synchronous generation levels through running existing gas and hydropower assets as synchronous condensers.
* Providing capacity through utility-scale long-duration energy storage can facilitate a zero-emissions sector. Long-duration storage will provide a reliable and cost effective energy sink during sunny days/windy weeks which will facilitate a higher percentage of renewables in the NEM and additional emissions abatement.
* The ISP has identified that flexible renewable energy generation and energy storage will be needed under all potential future energy and emission reduction scenarios. These are investments that should be supported and can be accelerated now to ensure that they are available and can be delivered as the NEM needs. Delayed or late delivery of critical transmission, energy storage and additional flexible capacity represents a significant risk with costly economy‑wide consequences for energy consumers.
* Hydro Tasmania’s ‘synchronous services’ rule change can assist in ensuring sufficient inertia and system strength are retained as the generation fleet changes.

**Attachment B – ESB Consultation Paper MDIs**

1. **Resource Adequacy Mechanisms (RAMs)**

Hydro Tasmania agrees that the current framework for resource adequacy in the NEM will need to evolve in order to address some of the factors that can deter investment (as identified by the ESB below):



The inability to fully reflect scarcity pricing and the absence of long-duration price signals and contracting are particularly important in this regard. A RAM that provides a long-term price signal and encourages market participants to contract for future supply shortfalls is critical to ensure a smooth transformation of the NEM.

The RAMs section of this submission is separated into:

* 1. Centralised Capacity Market;
  2. De-centralised Capacity Mechanism;
  3. Enhanced RRO;
  4. Operating Reserves Market (as a RAM);
  5. Adjustments to the reliability settings; and
  6. Hydro Tasmania’s order of preference.

**1. Centralised Capacity Mechanism**

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|  | Centralised Capacity Market |
| **Sharpens real-time prices** | Unclear - may depend on flow-on impacts on existing derivatives |
| **Long-term investment signals** | Yes – strongest signal for this |
| **Competitively neutral** | Yes (superior to BAU) |
| **Appropriate mix of plant** | A tailored capacity signal would require a forecast or judgement of the ‘optimal’ future plant mix |
| **Political confidence in reliability** | Yes – strong signal |
| **Lead time for investments** | Yes – strong signal |

At a simplistic level, a **centralised capacity market** would best meet the objective of providing a straightforward framework that ensures appropriate investment in dispatchable generation comes forward in a timely manner. A centralised capacity market provides more confidence for long-term investment funding and can provide sufficient lead time for investments reducing or even eliminating the saw tooth pricing effect of plant exit.

A reverse auction for capacity could produce competitive results and a centralised process has the benefit of being backed by the market as a whole. This would be competitively neutral, rewarding the best projects regardless of portfolio size or market share. A centralised capacity market based on ‘reliability options’ as implemented in the new Irish electricity market provides a variation based on financial contracts and could be adapted to meet NEM imperatives.

* Hydro Tasmania recognises that a centralised capacity market currently has little support. As a result, our submission examines the beneficial elements of a centralised approach that could be replicated in other market settings.
* We do not support the concept of a centralised capacity market only for new resources as this could create distortions in the market and perverse incentives – as an example: shutting existing hydropower capacity in favour of developing batteries.
  + If the objective is to unbundle the value of capacity (however that is defined), then resources that meet the criteria should be able to realise this value, noting that new investments may need a longer contract duration in the case of a centralised approach.

**2. De-centralised Capacity Mechanism**

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|  | De-centralised Capacity Market (capacity certificates) |
| **Sharpens real-time prices** | Unclear - may depend on flow-on impacts on existing derivatives |
| **Long-term investment signals** | Typically no, unless requirements are for long-term contracting as part of a retailer’s contract book |
| **Competitively neutral** | Similar to status quo |
| **Appropriate mix of plant** | Not clear - depends upon allocation of capacity certificates and on the products that retailers are obliged to procure |
| **Political confidence in reliability** | Increase on current design |
| **Lead time for investments** | Not clear |

As the ESB’s paper notes, a **decentralised capacity mechanism** and modified RRO exist as part of spectrum of related options. A modified RRO or decentralised capacity market could improve the investment environment for future dispatchable capacity, although not to the same degree as a centralised capacity market.

* Where the decentralised approach may fall short is that it still requires a willingness of parties to contract in good faith and as a result it may not be as competitively neutral as under a centralised approach. For example, a developer will always face challenges to commercialise a product that they cannot underwrite through their own retail load, whereas in a centralised model, the most cost-effective projects should be successful regardless of portfolio size.
* In addition, a decentralised model may not drive longer-term contracting solutions as liable parties will likely retain a short-term focus and won’t provide sufficient lead time for (some) major investments.

**3. Enhanced RRO**

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|  | Enhanced RRO (financial based) |
| **Sharpens real-time prices** | No |
| **Long-term investment signals** | Typically no, unless requirements are for long-term contracting as part of retailer contract book |
| **Competitively neutral** | Similar to status quo |
| **Appropriate mix of plant** | Not clear - if based on financial contracting then this depends on real-time price signals being well designed |
| **Political confidence in reliability** | Limited improvement on current design |
| **Lead time for investments** | Not clear |

The current RRO remains untested and so little can be drawn about its effectiveness in supporting future investment. To date it does not appear to have supported or incentivised new longer-term contracting. While the goal of prudent levels of forward contracting is supported by Hydro Tasmania, the RRO in its current design represents significant additional administrative complexity and risk for liable entities.

* Examining options to enhance the RRO (as suggested by the ESB) has merit but we believe the RRO would have to be significantly altered if it was to provide genuine value as a RAM. Therefore we believe there will be more suitable options.
  + If considered further, attention needs to be given to the issues of competitive neutrality and longer-term contracting. For example, if the RRO is to continue, then there could be rules requiring a portion of forecast load to be covered by long-term contracts (as an example).

During the development of the reliability portion of the National Energy Guarantee, Hydro Tasmania recommended[[4]](#footnote-5) **enhancing the Retailer Reliability Obligation (RRO)** by including a fall‑back option of centralised contracting (via reverse auction) to fill future forecast reliability gaps with at least 3 years’ lead time. This would occur where market participants had not invested in sufficient additional capacity to close a forecast reliability gap. Centralised procurement of additional resources (supply or demand side) would then be on‑sold back into the market through recognised hedging products (e.g. Swaps and Caps) which would then be used for RRO compliance. The intention of this model is that the role of central procurer functions as a back-stop (with clear rules) and would be designed to be as passive as possible – filling the role of financial intermediary to ensure future available resources. It would also have the strength of relying on understood and established financial instruments to secure additional dispatchable capacity, rather than introducing a separate capacity certificate (with associated complexities).

* Hydro Tasmania continues to believe that where decentralised models are examined, there would be strength in using transparent centralised contracting as a backstop. This approach should be evaluated further by the ESB.

**4. Operating Reserves Market (as a RAM)**

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|  | Operating Reserves |
| **Sharpens real-time prices** | Yes – provides the clearest signals of the options ESB is considering |
| **Long-term investment signals** | Typically no, unless there are additional measures to increase term and level of contracting |
| **Competitively neutral** | Similar to status quo – requires further detail |
| **Appropriate mix of plant** | Requires other settings - not clear that a real-time signal would drive an efficient plant mix |
| **Political confidence in reliability** | Unclear - incremental improvement on current design |
| **Lead time for investments** | Not clear |

**Operating Reserves** arearelatively easy to understand concept and could be implemented alongside existing FCAS markets. To some extent they represent a path of least resistance as (whilst not trivial) they are enhancements to the existing market, rather than an entirely new market. In addition, an operating reserves market could go a long way to reducing the need for the Reliability and Emergency Reserve Trader (RERT). Hydro Tasmania agrees that if *“sharpening the real-time price results in increasing the price during times of scarcity, this will strengthen the current investment framework, which relies on future expectations of high prices to trigger investment, and hence reliability[[5]](#footnote-6).”*

However, as the paper notes, an *“operating reserve would not provide a separate price for reliability or lengthen the duration of signals for investment. It may therefore only provide incremental improvements to current incentives for investment in dispatchable resources[[6]](#footnote-7).”*

* Hydro Tasmania’s view is that while an Operating Reserves market is likely beneficial for the operation of the NEM in a high VRE future, the Operating Reserves model alone may fail to solve some of the NEM’s critical challenges.
* The success of this approach would rely heavily on the long-term interests of market participants aligning closely with the long-term interests of customers. By that we mean counterparties coming together to invest efficiently in a low-cost mix of future energy resources through both times of resource adequacy and covering periods of plant exit. Recognising the competing market positions of generation businesses and the understandable short-term focus of electricity retailers in a contestable market, we believe there would remain significant risks to reliability, price discovery and volatility under this model.
* The ESB should continue to explore measures that could operate alongside Operating Reserves to strengthen and lengthen investment signals. This could include:
  + Options which increase the visibility, transparency and liquidity of the future price curve (beyond 3 to 4 years). This could be examined as a means to provide greater options to investors and energy-users but would likely require outside funding or incentives to create a longer forward price curve. One benefit of lengthened price signals are that it could be a pro-competition addition to the market as it would increase contracting options for all parties.
  + Implementation of an operating reserves market could still consider a fall‑back centralised procurement model. However, it would be critical that the rules of this overlay were well understood so as to retain faith in the competitive market structure.
* A further concern for Hydro Tasmania (that requires further detail to understand) is that while capacity markets may be designed to differentiate between types of dispatchable generation capacity, demand side response, short-term energy storage (batteries) or deep energy storage (pumped hydro), an operating reserves curve/market may not.
  + If the objective is to have an efficient mix of future plant, and the onus is on real-time pricing to provide those long-term investment signals, then the real‑time price signals from Operating Reserves and Energy Markets will need to be calibrated to recognise the different characteristics of energy resources. That is, real-time pricing would over‑time need to adequately reward the difference between ≤ 1 hour demand response and a 12+ hour supply option.
  + There is a risk that an Operating Reserves market may typically procure predominantly demand response which would fail to translate into a long‑term signal for additional capacity or energy storage. It is very unlikely that an Operating Reserves market would provide lead‑time for significant, capital intensive investments.
  + To fully understand the extent to which Operating Reserves can function as an investment signal, information on how participants would hedge Operating Reserves price exposure, over what length of contract and who would pay, would need to be clearer. This would also be essential if Operating Reserves are to address forthcoming coal closures with sufficient lead-time for the market to bring forward investments.

**5. Adjustments to the reliability settings**

When considering investment signals, it is important to be precise regarding the types of volatility and pricing outcomes that can be tolerated. As acknowledged in the paper, the increasing share of VRE has meant falling average wholesale energy prices at the same time that the market needs investment in additional dispatchable resources. Falling prices will be a good thing for consumers as long as the total bundle of prices remain at a sufficient level for investment to occur when needed – the ‘lowest sustainable market price’.

In the paragraphs preceding this, we have noted the risk of late investment leading to saw tooth pricing. Inter‑year price volatility will be passed on to consumers (as seen with the Hazelwood closure) given that only some customers have energy contracts covering a multi‑year timeframe. This inter-year price volatility could potentially be reduced through the RAMs being assessed by the ESB. Nonetheless, this type of price volatility must be thought of differently to the intra-day, multi-day or seasonal volatility that will be essential to incentivise flexible plant and energy storage as well as optimise real-time dispatch.

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|  | Adjustments to the reliability settings |
| **Sharpens real-time prices** | Yes |
| **Long-term investment signals** | Typically only 2-3 years through ASX |
| **Competitively neutral** | Status quo |
| **Appropriate mix of plant** | Potential change needed to CPT |
| **Political confidence in reliability** | Not to date |
| **Lead time for investments** | No change |

The Consultation Paper includes reference to *“****adjustments to the reliability settings*** *(market price cap, price floor and cumulative price threshold, including the administered price cap)”.* It would appear that an increase to the Market Price Cap is politically challenging at this time, however, it may be appropriate to consider the other price settings mentioned – Price Floor, Cumulative Price Threshold (CPT) and the Administer Price Period (APP). As AEMO has noted[[7]](#footnote-8): *“A period of 7.5 hours at the Market Price Cap (MPC) is typically sufficient to breach the CPT and trigger an APP.”* While this assessment would have been based on historical data, it is worth considering what impact this could have on investment signals going forward.

Arguably, the question of resource adequacy is shifting from a focus on meeting a few peak demand incidents per year to one where (as imagined by the ISP) the periods of resource scarcity may be driven by periods of low wind and solar generation - with sufficient dispatchable capacity of different duration needed to cover this. Where VRE output is low (such as cloudy, still days), these conditions of resource scarcity could potentially cover a number of hours or even days at a time. The current Cumulative Price Threshold and Administered Price Period will form a natural hedge for sellers of derivatives such as $300 Cap contracts. There could be a risk that these settings mute the investment signals for longer duration capacity in favour of shorter-term capacity that will benefit from the protection offered by the CPT and APP.

* Hydro Tasmania recommends further consideration of this issue and the implied investment signals against the resource mix needed for a reliable, secure and affordable low emissions system.

**6. Hydro Tasmania’s order of preference**

Hydro Tasmania’s order of preference is therefore:

1. **Operating Reserves** - with additional approaches that lengthen the visible price curve and/or encourage parties to willingly enter into long-term contracting solutions. Consideration is also needed of how an Operating Reserves market incentivises a portfolio of flexible capacity and storage options including long-lead time assets.
2. **A centralised capacity market** - with long-term contracts and appropriate lead-times.
3. Either a **decentralised capacity market or enhanced RRO** - with a backstop of centralised procurement.

As a further comment: where the ESB is contemplating combinations of options, Hydro Tasmania suggests that the Operating Reserves model is similar in its aims to decentralised capacity markets / enhanced RRO. Both will increase incentives for retailers to manage their own price exposure in a decentralised way by entering into financial contracts. Therefore layering Operating Reserves and de-centralised approaches together may duplicate or confuse aims.

As Hydro Tasmania has stated above, Operating Reserves could be assisted with enhancements to forward price curves. Nonetheless, if Operating Reserves are to be paired with a specific capacity procurement mechanism then it appears to Hydro Tasmania that a centralised procurement approach would be a more natural fit.

1. **Ageing Thermal Generation Strategy**

As identified in the paper, the uncertainty with respect to the exit of ageing thermal generation is a key factor weighing on the market and on future investment. Hydro Tasmania supports measures that provide increased transparency and notice of closure dates. However, where there are appropriate ESS to ensure the reliable and secure operation of the grid, and where it is economic for ageing thermal generation to be replaced earlier than initially signalled, there must not be impediments to this.

1. **Essential System Services**

We share the ESB’s view that **Essential System Services** (e.g. System Strength and Inertia) have historically been readily available and therefore have not been sufficiently valued. Accordingly there is limited market response as these services are now being withdrawn and displaced from the market. The consultation paper is rightly seeking to address these concerns through market-based mechanisms where possible.

* Hydro Tasmania believes that the ESB analysis is heading in an appropriate direction. We are also aware of the possibility that mainland approaches may not be appropriate for the Tasmanian NEM region - where a different generation mix and level of renewables integration has already been achieved.
* Hydro Tasmania will continue to prosecute our synchronous services rule change as a simple and effective way of alleviating constraints and supporting efficient market operation. This can be an effective tool to work alongside other market design changes being considered by the ESB and is designed to co-optimise with existing markets to deliver low cost solutions for energy consumers.

We recognise that the ESB’s focus is on a wider range of issues than the Hydro Tasmania rule change. There is strong industry support for additional ESS markets and the focus needs to be on the simplest mix of market signals that can meet future market requirements.

* Where the advice provided by FTI consulting proposes separating Inertia and Fast Frequency Response (FFR) as distinct markets, Hydro Tasmania recommends consideration of these together, at least initially. Our experience in the Tasmanian region (see below) is that the provision of inertia can effectively lower FCAS requirements under particular operating states. Similarly, in a future NEM there would be a trade-off between inertia and FFR requirements and so it is appropriate to consider these in parallel with the objective of providing least-cost solutions for consumers. We welcome the opportunity to further with the ESB if this is helpful.

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| High System Non-Synchronous Penetration in the Tasmanian NEM region  On Sunday 13 September, Tasmania experienced record levels of ‘non-synchronous generation’ in Tasmania peaking at approximately 85% of demand. This was facilitated partly through the operation of hydropower units in synchronous condenser operation and occurred on a day with high renewables generation (wind and solar) coupled with Basslink imports. Achievements such as these, demonstrate the opportunities to modernise, refurbish and repurpose existing assets and the use of tripping schemes to support a high renewables penetration grid. On this, we believe that Tasmania provides an example of how to address and overcome challenges being seen in the transforming national energy market. These technological successes could be replicated in mainland NEM regions through the use of appropriate incentives and revenue streams. |

Consideration of **Operating Reserves as an ESS** has merit due to the increasing variability and uncertainty of the supply mix. In the consultation paper Operating Reserves appears in both the RAM and ESS sections and Hydro Tasmania has provided our thoughts on the prospect of providing long-term resource adequacy in the pages above. In considering whether an operating reserves market is needed to ensure the real-time reliability and security of the grid it is worth asking the converse of the question. In other words, what would you need in the NEM that would make an operating reserves market redundant? From Hydro Tasmania’s perspective, the answer is that you would need to have a highly flexible mix of supply and demand resources that was available with less than 5 minutes notice. On the supply side, this can be provided by pumped hydro, batteries and some forms of gas generation, while on the demand side it would require consenting customers and aggregators with technological solutions to unlock these resources.

In short, our conclusion is that Operating Reserves are necessary unless you either:

* are comfortable with highly volatile real-time pricing (which would lead to a greater investment in flexible resources but carries the risk that there may be a lag in this investment); or
* Implement a RAM that specifically targets and incentivises flexible resources above other dispatchable plant. The latter could be in the form of a capacity market that had a weighting, or additional revenue streams for flexible resources.

1. **Scheduling and Ahead Mechanisms**

Hydro Tasmania believes the primary challenge facing the secure operation of the grid is that some ESS are currently unpriced resulting in AEMO having to intervene in order to ensure their provision. This aligns with the view of the majority of the generators in the NEM and explains the current surge of rule changes being examined by the AEMC. The progressive introduction of ESS markets alongside the streamlining of the AEMO intervention framework are positive and necessary steps to ensure the NEM rules are fit for purpose.

We support the ESB’s decision not to explore further the idea of a **mandatory ahead market for energy**. Our internal analysis of ahead markets for energy suggest that while the benefits of moving to this approach are unclear, the costs and disruption could be significant. As the paper notes, it would also require a move away from the self-commitment nature of the NEM. While we acknowledge that there could be examples where energy storage (including pumped hydro) could be efficiently scheduled in an ahead market, through locking-in the price spread between pumping and generation, we do not believe this is sufficient justification for imposing a mandatory market approach. Further, market participants are experienced in self-managing forecasting risks and so are likely to remain able to effectively schedule their plant to their own forecasting and operating expectations.

In principle, the creation of **voluntary Ahead Markets** does not overly concern Hydro Tasmania as long as participants retain the flexibility to choose if, and when, they participate. This approach allows both supply and demand side increased trading opportunities when they will see benefits outweigh the increased complexity (and any costs) that Ahead Markets could provide. The benefits of Ahead Markets will vary by participant, and each participant should have the right and opportunity to capture those benefits at a time and pace that makes sense for the business and its customers.

* A significant challenge to the success of voluntary ahead markets is that there may not be significant uptake/participation at least initially. This would itself likely threaten the appeal for market participants. These issues need to continue to be assessed but suggest that voluntary markets could be explored over a longer‑term horizon than other ESB priorities.

**A Unit Commitment for Security (UCS)** seems appropriate where it provides additional transparency, predictability and accountability for the AEMO intervention framework. While Hydro Tasmania has benefitted from involvement in the ESB Technical Working Group briefings, we still feel that more development of this option will be needed for participants to make a thorough assessment.

Intervention should always be a last resort. Hydro Tasmania believes that appropriately valuing and procuring ESS coupled with implementation of Hydro Tasmania’s rule change should aim to reduce as far as possible, or eliminate the need for intervention in the future market.

Hydro Tasmania accepts there may be benefit in further exploring the option of **ahead markets for ESS.** Care needs to be taken not to erode the self-scheduling, decentralised decision making basis on which the NEM operates. The preference is that once ESS markets are appropriately designed and remunerated, participants have sufficient incentives to ensure delivery of ESS in real-time or to use derivatives as a forward hedge against these prices. As noted in the consultation paper the intention is that ahead markets for ESS would be voluntary and based on financial commitments (where the ESS had a spot price).

Models of procurement

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Hydro Tasmania generally agrees with FTI Consulting’s findings, that looking for solutions around option 2 (Structured procurement of ESS) and option 3 (Spot market-based ESS) is appropriate. This also fits the timeframe of the Post-2025 market design, noting there would need to be a transition to these markets. As the consultation paper notes[[8]](#footnote-9), *“a combination of complementary procurement options may lead to the least cost of delivery, and it is important that arrangements do not introduce a bias between the use of existing assets, investing in new assets and between competitive procurement and network procurement.”* Hydro Tasmania agrees with this statement.

* As noted earlier in this submission, for spot markets to provide an investment signal the market would need to develop a hedging approach such as CfDs.
* At this stage it is unclear whether developing spot markets for some ESS would truly give a sufficient investment signal to provide ‘resource adequacy’ in these markets. We have not seen this develop substantially with respect to current FCAS markets.
* It is important that further evaluation focuses on the ability for procurement options to make available resources in a timely manner (both retrofit/modernisation and new developments). Where there is not a compelling case for moving to spot markets for ESS, or confidence it will provide resource adequacy then option 2 (structured procurement) may be more appropriate.

**Attachment C – Response to Consultation Paper questions**

1. **Resource Adequacy Mechanisms (RAMs)**

**1. Do you have views on whether the current resource adequacy mechanisms within the NEM are sufficient to drive investment in the quantity and mix of resources required through the transition?**

* As noted above and in previous submissions, Hydro Tasmania believes that additional investment signals are needed in order to ensure a stable transition to a zero/low emissions energy sector.

**2. Do you have views on whether the short-term signals provided by an operating reserve mechanism or market would provide adequate incentives to deliver the amount and type of investment needed for a post-2025 NEM in a timely manner? What impact could an operating reserve have on financial markets? What are the benefits of this approach? What are the costs and risks?**

* Hydro Tasmania believes that an Operating Reserves market could sharpen real-time energy pricing and should be further developed by the ESB. It is not clear that this will translate into longer-term investment signals and so consideration of additional contracting solutions and incentives is appropriate.

To provide an investment signal an Operating Reserves market would need to facilitate the creation of derivative products that could be traded and hedged through forward contract markets. Under this model, there is a reliance on the willingness of parties to take longer-term positions to underpin investment.

Hydro Tasmania notes the risk that an Operating Reserve market may not incentivise the range of capacity and energy storage developments that the future NEM will require. It is our view that further exploration of this issue is required.

**3. Do you have views on whether the signals provided by an expanded RRO based on financial contracts or a decentralised capacity market would provide the type of incentives participants need to deliver the amount and type of investment needed for a post-2025 NEM in a timely manner? What are the benefits of this approach? What are the costs and risks?**

* Financial contracts through an expanded RRO will reflect the broader reliability settings (such as the Market Price Cap and Cumulative Price Threshold). To have confidence that the RRO can effectively bring forward future investments either: there would need to be a requirement on liable entities to enter into some long-term contracts; or there would need to be a fall-back option of centralised long-term procurement.

A de-centralised capacity market could lead to an efficient mix of future plant but this would depend on the definition of capacity certificates, how they were accredited and what penalties for unavailability were in place. It would be possible to procure a range of future resources through a decentralised approach but this would require careful judgement about the ‘optimal’ mix of future plant and how this requirement was passed on to liable entities.

**4. Do you have views on how an operating reserve mechanism and/or expanded RRO would impact the need for and use of RERT and the interim reliability reserve if they were introduced into the NEM? What adjustments to the RERT and/or interim reliability reserve may need to be made so that they are complementary and not contradictory or duplicative?**

* The NEM’s Resource Adequacy Mechanism should be designed as much as possible to include the necessary incentives to ensure a secure, reliable grid without requiring the activation of the RERT. Where energy resources have the ability to participate in the RAM and be ‘in‑market’ they should be incentivised to do so through appropriate pricing of scarcity. There must continue to be a clear distinction in-market and out‑of‑market resources, with RERT used only as an emergency backstop.

**5. Do you have views on how RAMs (current or future) can better be integrated into broader jurisdictional policy priorities and programs? Should jurisdictions reflect broader policy priorities through the nature of obligations placed on retailers in an enhanced RRO or decentralised capacity market, or through the qualifying requirements for participation in an operating reserve?**

* Hydro Tasmania recognises that the resource mix within Tasmania is considerably different to other NEM states. As such, while RAMs should be considered for the NEM as a whole, requirements may need to be dormant in states such as Tasmania where there is sufficient existing and renewable capacity.

1. **Ageing thermal generation strategy**

As identified in the paper, the uncertainty with respect to the exit of ageing thermal generation is a key factor weighing on the market and on future investment. Hydro Tasmania supports measures that provide increased transparency and notice of closure dates. However, where there are appropriate ESS to ensure the reliable and secure operation of the grid, and where it is economic for ageing thermal generation to be replaced earlier than initially signalled, there must not be impediments to this.

1. **Essential System Services (ESS)**

**1. What feedback do you have on the proposed provision of an operating reserve through spot market provision? How could this interact with operating reserve procurement for resource adequacy? Will such a mechanism assist manage greater system uncertainty more efficiently than current arrangements? What additional mechanisms might be needed to foster investment needed for a post-2025 NEM? What are the benefits of this approach? What are the costs and risks?**

* This question has been covered above. Hydro Tasmania believes that an Operating Reserves Market will likely be an important ESS going forward unless there is a very high proportion of highly flexible capacity and energy storage resources in the NEM. If there was a very flexible mix of supply/demand plant then an Operating Reserves Market may not be necessary (but a well-defined RERT may continue to be needed).

**2. What are your views about developing FFR with FCAS and developing a demand curve for frequency response? Will such a mechanism help manage greater system uncertainty more efficiently than current arrangements? What additional mechanisms might be needed to foster investment for a post-2025 NEM? What are the benefits of this approach? What are the costs and risks?**

* The demand curve for FFR will depend on the amount of synchronous inertia in the system. Therefore we do not believe a FFR curve should be set in isolation and that it would be better to consider both inertia and FFR and their equivalence in terms of Rate of Change of Frequency (RoCoF).

Spot markets alone may not lead to efficient investment signals, so using a demand curve with longer-term procurement may be appropriate and should be explored further. Pricing ESS will need to be accompanied by the development of hedging markets if the aim is that ESS spot‑markets provide an investment signal.

**3. What are your views on the proposed structured procurement for inertia and system strength by way of NSP provision, bilateral contracts and generator access standards, or through a PSSAS mechanism? Which approach is preferable, and what are the relative benefits, risks and costs? Should the ESB instead prioritise the development of spot market for or structured procurement of inertia? What are the relative benefits, risks and costs of such an approach?**

* Hydro Tasmania’s synchronous services rule change could address many constraint issues in the NEM and would co-optimise with existing spot prices. Recognising that the ESB is looking at additional approaches Hydro Tasmania agrees that a range of procurement approaches may be required and should be further examined.

We support the Australian Energy Council’s response to this question.

**4. Given future uncertainties and the potential pace of change, what level of regulatory flexibility should AEMO and TNSPs operate under? What are the benefits, risks, and costs of providing greater flexibility? What level of oversight is necessary for relevant spending? Are there specific areas where more flexibility should be provided or specific pre-agreed triggers?**

* TNSPs are often best placed to advise on local or regional issues. While a level of flexibility is appropriate it must be combined with well‑defined and transparent regulatory oversight. This could be achieved through Reliability Panel guidance on market settings and demand curves, coupled with an efficient AER regime.

1. **Scheduling and ahead mechanisms**

**1. The ESB is interested in stakeholder feedback on the options for the ahead mechanisms we have outlined. Are there additional options? Are the options for a UCS and UCS + ahead markets fit for purpose?**

* Hydro Tasmania supports further developing the proposals put forward in the consultation paper: UCS, UCS + voluntary ahead markets. We agree with the decision not to progress a mandatory ahead market. At this stage it remains unclear whether ahead markets will add additional value if ESS markets have been well designed.

**2. The ESB proposes to develop the UCS tool for implementation. Do you support the UCS concept? What factors and design features should be considered for detailed development?**

* Hydro Tasmania supports the further development of the UCS. This must remain a back-stop. The efficient pricing of ESS, creation of co‑optimised markets and investment signals should diminish the requirement for AEMO interventions.

**3. The difference between actual and forecast residual demand leading up to real-time dispatch has been far more stable in the last decade than the difference between actual and forecast prices ($MWh) leading up to real time dispatch. What do you consider the drivers of this may be?**

* Hydro Tasmania supports the Australian Energy Council’s response to this question.

1. **Two-sided markets**

Hydro Tasmania recognises the theoretical benefits of moving to a two-sided approach but we have concerns about its implementation. Our experience to date has been that consumers of varying sizes do not have a great appetite for demand side participation outside of highly specialised contracts.

Appropriate consumer protections should be in place to protect vulnerable customers regardless of the type of interaction (e.g. traders, peer-to-peer, aggregators, VPPs etc.). This must occur without increasing traditional retailers’ exposure to third-party financial risks.

In Hydro Tasmania’s 18 May 2020 two-sided markets submission to ESB (see below), we noted that there needs to be consideration of whether there were risks to consumers that would not be covered by existing (NECF and ACL) consumer protection frameworks:

*“This is a recurring question which seeks to look at what additional protections are required if a new market facility is introduced. The key issue will be to ensure that vulnerable customers that sign up to participate in a Two-Sided Market continue to get supply (at an understood price or level of risk) if they underestimate how much energy they will use while participating directly or via a third party. We would need to ensure that traditional retailers are not forced to wear the financial burden of imprecise demand forecasts or participation levels.*

*While the concept of a Two-Sided Market sounds rational, past experiences have shown that the majority of small customers seek and prefer certainty in their energy prices. This is evident in the recent challenges of tariff reform and the Victorian smart meter roll out whereby opt-in flexible-pricing, TOU and demand pricing was not embraced. Small customers prefer certainty even if alternative options offer the possibility of upside benefit. A detailed cost benefit assessment of the impacts on consumers should be undertaken before implementation of significant market reform.”*

Hydro Tasmania is a member of the Australian Energy Council. With respect to Market Design Initiative E we support the positions put forward in that submission.

1. **Valuing demand flexibility and integrating DER**

Hydro Tasmania is a member of the Australian Energy Council. With respect to Market Design Initiative F we support the positions put forward in that submission.

1. **Transmission access and the coordination of generation and transmission**

**1. The second ISP has now been released. Do you have any comments on how its implementation can be made more efficient and timely?**

* Hydro Tasmania strongly supports the role and development of the ISP and believe it is a critical component of ensuring resource adequacy going forward. We have contributed submissions to the development of ISP rules and guidelines and are generally supportive of the approaches taken.

The timely development of actionable ISP projects can increase certainty for NEM market participants. Note: This is not the same as all participants supporting the ISP or the development of future transmission and interconnection. While it is recognised that not all participants support the build-out of the ISP, the successful implementation of the ISP will at least reduce the number of uncertainties facing investors.

**2. The cost of major transmission investment projects is of concern. Do you have any suggestions on how these projects can be built for less than currently expected? Why have costs increased so markedly? Given the rising costs, are there alternative approaches to transmission project development, design and implementation which could lower the cost?**

* Recognising this is primarily a question for TNSPs, the challenges of transmission development also reflect the challenge of any investment. That is to say that a low risk environment will support efficient timelines and cost effective financing options. As such, where transmission developments are identified as having positive net benefits, lowering the risk of progressing these investments will benefit energy users.

**3. The development of REZs is important for the transition underway in the NEM. Do you have any suggestions on how large-scale priority REZs can be more efficiently developed and connect into the network?**

* With respect to the further development of Tasmania’s renewable energy resources, Hydro Tasmania expects that development of Tasmanian REZ can be managed as part of the MarinusLink planning and development process.

**4. NERA Economic Consulting’s modelling of the benefits of introducing transmission access reform in the NEM has been published. What do you think about the modelling and assumptions used? What does this suggest about how fit-for-purpose the current access regime is? If you are unsure of the merits of locational marginal pricing and FTRs, what other suggestions would you make about how risks of congestion might be managed by generators?**

* Hydro Tasmania has responded separately to the AEMC’s COGATI Interim Report. Modelling can be a useful tool to assist assessment of market reforms and we appreciate the AEMC’s initiative to engage NERA Consulting to conduct a cost-benefit assessment. Notwithstanding this, Hydro Tasmania considers it critical that any modelling process be suitably transparent and open to robust scrutiny before being accepted as a justification for fundamental changes to market structure. Hydro Tasmania considers that the inputs and assumptions provided to NERA to guide their analysis should be open to scrutiny.

We acknowledge and agree that congestion can be a product of the locational investment decisions made by investors. However, we remain largely unsupportive of the COGATI reforms. This is on the basis that we consider the proposed Locational Marginal Pricing (LMP) and Financial Transmission Rights (FTRs) regime as designed will be unlikely to enhance the way in which generators manage the risk of congestion.

As an alternative, Hydro Tasmania have proposed that enhanced information provision may improve locational investment decision-making, subsequently avoiding the creation of new congestion challenges in our market.

**5. The AEMC has released an updated technical specification paper on the transmission access reform model, alongside this report. The updated proposal provides additional information on the options regarding the design of the instruments, pricing, and trading. How well do you think the proposal would address the identified challenges?**

* The core challenges and objectives identified by the AEMC relate to the need for: (1) congestion risk management tools for generators; (2) enhancing locational investment decisions; and (3) improving dispatch efficiency. As noted in our submission to the AEMC, we consider that there are alternative, less complex and costly market reforms that can be undertaken to address the above concerns.

To support this position, we have conducted analysis (contained in our COGATI submission) of the top 30 binding constraints in the NEM throughout the last quarter (Q3 2020). From this analysis, we observe that only 2 of the top 30 constraints in our market across this period would have been addressed by the COGATI reforms. We encourage the ESB to consider this analysis provided in our separate submission to the AEMC COGATI review. In addition, we have proposed three alternate approaches to address these identified challenges. These alternate proposals encourage the AEMC to consider:

**1. Hydro Tasmania’s *Synchronous Services Market* rule change proposal**

The purpose of this rule change proposal is to create an incentive for any generator to come online, when doing so would alleviate constraints and expand the network capacity for other generators (if efficient/cost-effective to do so).

**2. Increase the use of ‘runback schemes’ in the NEM**

Runback schemes are utilised in Tasmania, and approximately double the capacity of Tasmania’s transmission infrastructure through the use of high speed protection coordination between the network and generators. This approach avoids the need to cater for the potential loss of transmission lines (N-1) upfront.

**3. Enhanced information provision to improve locational investment decisions**

Hydro Tasmania supports processes that can increase information sharing and transparency of new generation/transmission investments resulting in more effective signals for new investment. This can help provide a better basis for considering the issue of congestion for investment decisions.

**6. What are stakeholder views on the current suite of locational investment signals? The ESB welcomes stakeholder views on alternative solutions to address the need for improved locational signalling for generators.**

* As mentioned in response to the previous question, we support processes that can increase information sharing and transparency of new generation/transmission investments resulting in more effective signals for new investment. This can help provide a better basis for considering the issue of congestion for investment decisions.

We note that enhanced information provision has been the focus of several rule changes/process improvements recently, including the Transparency of New Projects rule change that was finalised in October 2019 and the development of the Integrated System Plan. The potential impact of these reforms should also be considered.

1. Consultation Paper Page 29 [↑](#footnote-ref-2)
2. <http://cleanenergyregulator.gov.au/csf/market-information/Pages/quarterly-Market-report.aspx> [↑](#footnote-ref-3)
3. *The case for deep storage*, Hydro Tasmania, April 2020 (<https://www.hydro.com.au/docs/default-source/clean-energy/battery-of-the-nation/the-case-for-deep-storage.pdf?sfvrsn=9ee49528_8>) [↑](#footnote-ref-4)
4. From Hydro Tasmania’s March 2018 submission to the National Energy Guarantee Design Paper [↑](#footnote-ref-5)
5. Consultation Paper Page 37 [↑](#footnote-ref-6)
6. Consultation Paper Page 40 [↑](#footnote-ref-7)
7. <https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Operation-of-the-administered-price-provisions-in-the-national-electricity-market.pdf> [↑](#footnote-ref-8)
8. Consultation Paper Page 61 [↑](#footnote-ref-9)