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Integrating energy storage systems into the NEM
Australian Energy Market Commission

Ms. Merryn York
Acting Chair

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Lodged via the AEMC website

Date: 13 October 2020
Subject: Integrating energy storage systems into the NEM (Ref: ERC0280), released 20 August 2020

Dear Ms. York,

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 successfully complete the energy transition without sacrifice of reliability or security.

The overall economic case for pumped hydro is likewise 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 and regional job creation only serve to strengthen the case for investment in pumped hydro.

Despite this positive context and a wealth of potential sites, many seemingly promising pumped hydro developments have stalled prior to FID. Feedback from investors and developers has primarily 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 benefits and costs, 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.

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 owners during operation

This consultation on *Integrating energy storage systems into the NEM* explores the potential of creating a new participant category for energy storage in the National Electricity Rules and making related changes and edits throughout The Rules.

We support this in principle as it could (and should) pave the way for more substantive changes that acknowledge (and value) the benefits that technologies such as pumped hydro can bring to the NEM, enabling the cost-benefit misalignment to be fixed and investments to be undertaken.

We are however concerned by the clear technology-bias embedded in the consultation paper, which states an *objective* of technology neutrality near the beginning of the paper, only to introduce an unexplained, unjustified requirement for linear ramping later in the paper that would *in practice* exclude pumped hydro from the change.

Australia already has 1.6GW of pumped hydro capacity operating across NSW and QLD. We are not aware of any of these operating plants that would be able to meet the stated requirement, however all are synchronous units that contribute to a stronger, more reliable grid, while helping balance renewables and lower prices for consumers.

We seek the urgent reconsideration of this technology bias and its replacement with a framework that allows all storage technologies to participate on a fair and level playing field. This will yield the best outcome for the grid and the customers.

Should it be possible to do so, we would welcome the opportunity to further discuss any or all of the above matters with the AEMC team, as we see this rule change 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

Integrating Energy Storage Systems into the NEM

GE Hydro Response to Consultation Paper

BACKGROUND & CONTEXT

On the 20th of August 2020, the Australian Energy Market Commission (AEMC) initiated a consultation process (ERC0280) in relation to "Integrating energy storage systems into the NEM". The consultation process was triggered by a rule change request received by from the Australian Energy Market Operator (AEMO) in 2019, which – among other things – seeks to create a new category of NEM participant, described as a 'bi-directional unit', which would be defined to include all storage technologies, in a technology neutral manner.

As the original request from AEMO pre-dates certain activities subsequently instigated by the Energy Security Board's 'Post 2025 Market Design' program (most notably the potential creation of two-sided markets), there is the potential for overlap and/or misalignment between the two.

A consultation paper was released, outlining the key issues and considerations as the AEMC understands them and responses to this paper were requested by 15 October 2020.

The key questions posed in the consultation paper are:

1. Should storage and hybrids be defined in the NER?
2. Is there a problem with how the registration and classification framework treats storage and hybrids? If so, how should we fix it?
3. What are the technical and operational issues facing storage and how can those issues be addressed?
4. What are the issues with the application of fees and charges to storage and how can they be addressed?
5. What other obligations specific to storage and hybrids should be included in the NER?
6. Are some of the key terms in the NER out-of-date? If, so how should they be changed?

After considering the responses to the consultation process, the AEMC will proceed with rule changes that it believes achieve the following stated objectives:

- **Promotes competition**: Would the changes proposed remove barriers to entry and reduce operating costs?
- **Creates a level playing field**: Are the proposed obligations proportional, technology neutral and even-handed?
- **Promotes transparency**: Would the proposed clarifications to the obligations and charges in the rules reduce information asymmetry and improve decision-making of participants?
- **Appropriately allocates risks**: Would the appropriate parties be assigned responsibility for costs under the approaches proposed for cost recovery?
- **Minimises administrative and regulatory burden**: Would the proposed changes reduce the administrative burden on AEMO and participants?
- **Enhances system reliability and security**: Would the proposed obligations on storage improve reliability and security?

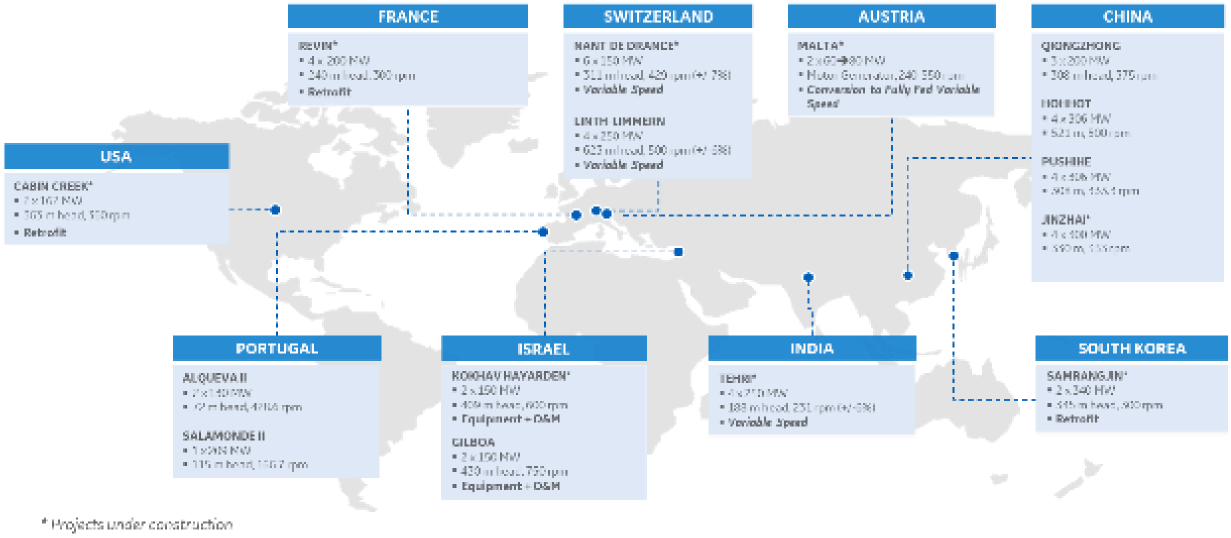
This document has been prepared by GE's Hydro division in response to this consultation process. While our particular area of technical expertise is the design and fabrication of hydro and pumped hydro equipment, we have endeavoured to frame our responses to the various consultation prompts in a broader manner, reflective of the AEMC's stated objectives.

In addition to responding to the specific consultation prompts provided, we have also taken the opportunity to highlight several other topics we believe are worthy of consideration, primarily in relation to the benefits an expanded pumped hydro fleet would deliver for Australia.

We are eager to support the ongoing development of any rule changes that may progress from this process and are at your disposal to discuss any element of our submission in greater detail.

INTRODUCING GE HYDRO

GE is a major global player in both conventional and pumped hydro, with an installed base exceeding 320GW in total and 45GW in pumped hydro specifically. We have been working on pumped hydro plants for over 50 years, with a reference book covering everything from 4MW to 400MW units at head heights ranging from 25 metres to 1112 metres. Current and recent pumped hydro projects around the world are outlined below.



Across Australia, GE boasts a 3.9GW installed base of hydro turbines and generators, powering almost half the hydro capacity in Australia. We also maintain an in-country service team, based out of our office in Hobart, supporting customers across the NEM and ensuring Australia's >8GW fleet of hydro generation plants continues to operate smoothly.

THE BENEFITS OF PUMPED HYDRO IN AUSTRALIA

Australia already boasts a pumped hydro fleet of ~1.6GW across Wivenhoe, Tumut 3 and Shoalhaven, with an additional 2GW on the way through Snowy 2.0. We also boast some of the most attractive wind and solar resources in the world, which are already delivering an average ~20% of our electricity – significantly more in certain states and at certain times.

As this proportion of electricity coming from intermittent sources continues to increase, the need to safeguard reliability and security will increase as well. We will also increasingly find ourselves at moments when generation output exceeds demand and the surplus energy must be stored or wasted.

Against this backdrop of ever accelerating change, a proactive approach by government is vital to ensure the lowest cost solution is implemented across the electricity system. In markets as diverse as Israel, Portugal, Switzerland and China, we are seeing governments embrace pumped hydro technology to complement the growing penetration of wind and solar PV.

The benefits an expanded pumped hydro fleet would bring to Australia include:

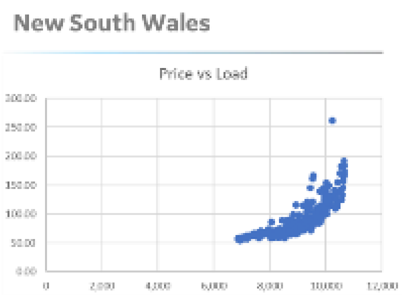
- Lower electricity prices
- Enabling the energy transition
- Grid reliability & security services
- Jobs and investment in regional areas
- Reduced transmission costs
- Low environmental impact
- A highly cost-effective solution

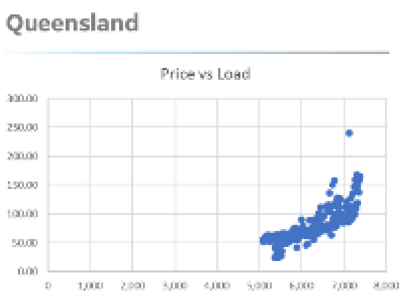
These are elaborated below in turn.

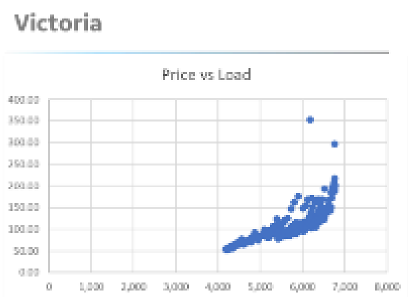
Lower Electricity Prices

Across the NEM we observe a positive relationship between price and load, however this relationship is not linear, with each increase in load leading to ever larger increases in price. In economic terms, the NEM markets are less price elastic at low load than at high load. In practical terms, incremental generation when market load is high will have a bigger downward impact on price than an equal increase in load when market load is low.

As an example of this dynamic at play, refer below the relationship between dispatch load and dispatch price on winter weekdays in 2019 for the three largest markets in the NEM, noting the ever-sharper slope as load increases and the ever-flatter slope as load decreases.

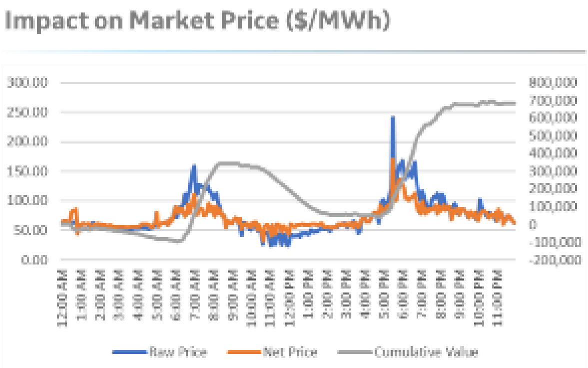


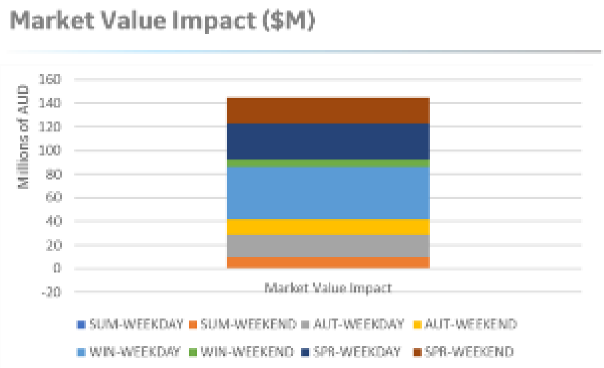




This dynamic means that the operation of pumped hydro plants when generating tends to reduce peak prices by a larger amount than the corresponding increase in off-peak prices when they are pumping.

This effect is shown below for an average winter weekday in 2019, based on a hypothetical 4x150MW plant located in Qld with 8 hours of storage. As shown by the grey line in the left-hand chart, our modelling suggests such a plant could deliver a reduction in total daily electricity spend of over $600,000 across Qld. Aggregated across weekdays and weekends across the four seasons of the 2019 calendar year, the estimated reduction in total electricity spend exceeds $140M, as illustrated in the right-hand chart below.





Note: the scope of this modelling has only looked at intra-day load shifting. Consideration of the benefits of inter-day load shifting would lead to an even greater market value impact.

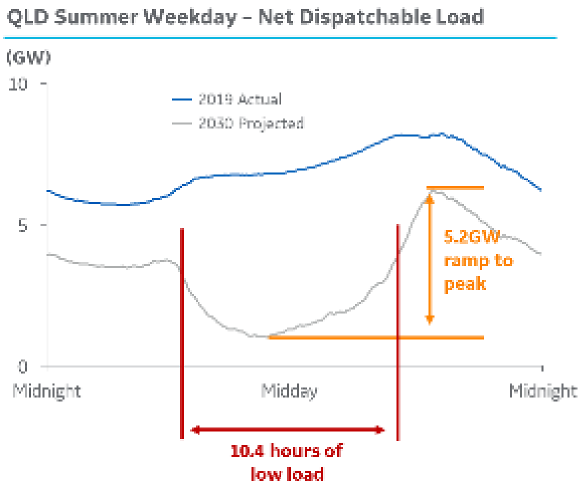
Enabling the Energy Transition

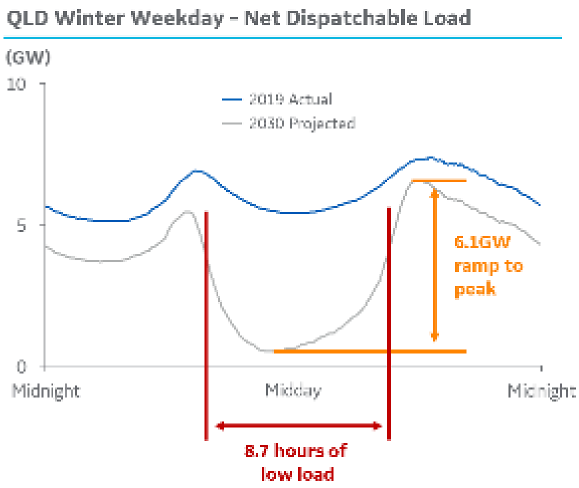
Solar PV and onshore wind are already the cheapest forms of new generation in Australia and their penetration into the National Electricity Market is expected to increase significantly in the years ahead, as aging thermal capacity progressively retires from the market.

This change brings new challenges, including:

- The need to inject power into the grid when instantaneous output from wind and solar PV fails to meet demand
- The need to store excess power from the grid when instantaneous output from wind and solar exceeds demand
- The need to obtain the grid reliability and security services previously provided by thermal generation, e.g. inertia, system strength, frequency control, blackstart, reactive power

Left unaddressed, our analysis indicates that periods of excess supply are likely to regularly exceed 9 hours in duration within the next decade. Refer below, showing 2019 actual vs 2030 projected weekday load profiles for summer and winter in QLD.





These findings are consistent with AEMO's 2020 Electricity Statement of Opportunities (ESOO), which forecasts that on the current trajectory, operational load will reach very low levels in all states and regularly become negative in Victoria and South Australia by 2030.

During these periods of 'excess supply', operational (or 'dispatchable') load gets pushed to very low levels, leading to one of two outcomes:

- Synchronous generation is pushed out of the market, with system strength and inertia falling to very low levels
- Synchronous generation is directed to dispatch out of merit order, leading to the curtailment of wind and solar and increasing the prices paid by consumers

This creates a 'lesser of two evils' situation in which energy prices (better in the first scenario) must be traded off against system security (better in the second scenario).

Pumped hydro solves this dilemma by providing a cost-effective way to store the output from wind and solar over these middle ~9 hours of the day. Not only does this stabilize the operational load, enabling more synchronous capacity to stay online, but as fixed-speed pumped hydro is a synchronous technology, it also contributes directly to system security by providing inertia and system strength.

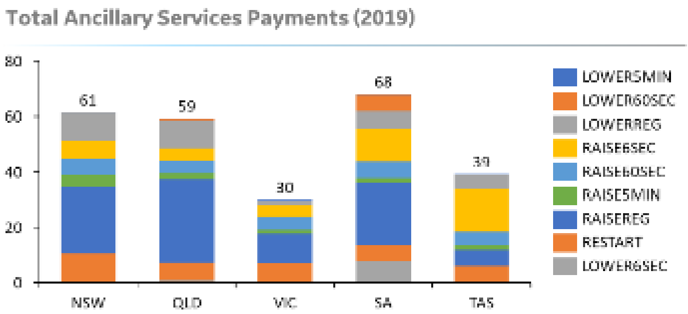
Apart from the issue of low load, our analysis shows that an ever-increasing evening ramp is likely to emerge across the various NEM regions in the coming decade. This is consistent with AEMO's findings in 2020 the Renewable Integration Study (RIS).

Again, this is a challenge pumped hydro is well-placed to address. As the technology can change from 100% load to 100% generation, the impact of pumped hydro is effectively double its nameplate capacity. This means that a ramp that would have required 2GW of peaking generation capacity could be met with only 1GW of storage capacity (i.e. swapping from -1GW to +1GW during the ramp period).

At this kind of duration and scale, pumped hydro is significantly cheaper than batteries under all reasonable forecast horizons. Furthermore, as an asynchronous technology, batteries are unable to provide the system security services that pumped hydro can bring.

Grid Reliability and Security Services

Australia spent $258M across the 2019 calendar year on ancillary services such as Frequency Control (or FCAS), as outlined in the chart to the right.



Pumped hydro technology can provide many of these services, increasing competition in the various ancillary services markets and reducing the price at which these services are provided.

The specific ancillary services capabilities of fixed vs variable speed pumped hydro technology are summarized below for the typical modes a pumped hydro plant could be operating at when called to provide the given service.

	FIXED SPEED				VARIABLE SPEED			
	Pump	Turbine	Condenser	Standstill	Pump	Turbine	Condenser	Standstill
Fast Raise / Lower (6 sec)	No	Yes	No	No	Yes	Yes	No	No
Slow Raise / Lower (60 sec)	No	Yes	Yes	No	Yes	Yes	Yes	No
Delayed Raise / Lower (5 min)	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Black Start / Restart	Yes*	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Reg Raise / Lower	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes

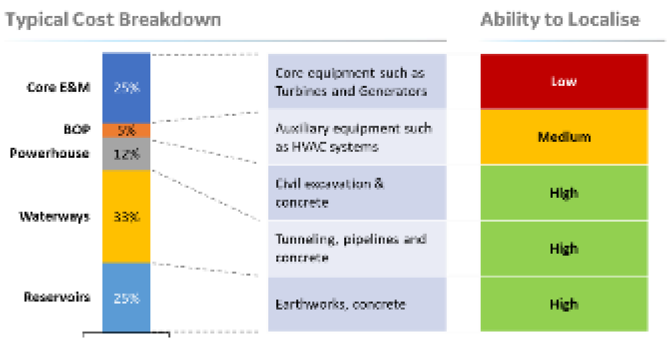
*Plant must be designed with black start capability in mind & sufficient water must be reserved in the upper reservoir at all times to enable the plant to transition from pump to turbine mode & inject power into the grid

Pumped hydro plants are also well placed to provide a range of the additional services contemplated in the Energy Security Board's 'Post 2025 Market Design' program, including system strength, operating reserve and synchronous inertia. Such services would further support the greater roll-out of intermittent technologies such as wind and solar PV.

Jobs and Investment in Regional Areas

Pumped hydro projects – like many energy projects – tend to be located away from urban centres, bringing investment and jobs to regional communities that need them most.

Uniquely among energy technologies however, pumped hydro projects include a major civil component, often representing upwards of 70% of the total project capex. This money flows directly into hiring workers and equipment and procuring key materials such as cement, which itself is often produced in regional centres and small communities.



As illustrated above, around 70% of the capex of a typical pumped hydro project would present high opportunities to support local workers and businesses and a further 5% would present medium opportunities. Given the large scale of most pumped hydro projects, this translates into hundreds of millions of dollars of investment, jobs and opportunities for local businesses, workers and communities for each project that gets built.

If we look more deeply into the matter, the civil construction skills required to build pumped hydro plants are not dissimilar to those required in mining or road/rail tunneling projects. As such, an investment in pumped hydro would create opportunities for mining workers as well as those currently employed on the various road and rail tunneling projects around Australia.

Likewise, the mechanical and electrical skills required to install and operate the equipment in a pumped hydro plant are similar to those required in a thermal power generation plant, providing new opportunities for workers otherwise displaced by the energy transition.

Reduced Transmission Costs

The development of pumped hydro in strategic regional locations – for instance in the Renewable Energy Zones (REZs) identified in AEMO's Integrated System Plan (ISP) – would deliver more stable output from REZs into the NEM. This, in turn, would reduce the cost of the grid infrastructure by enabling better utilization.

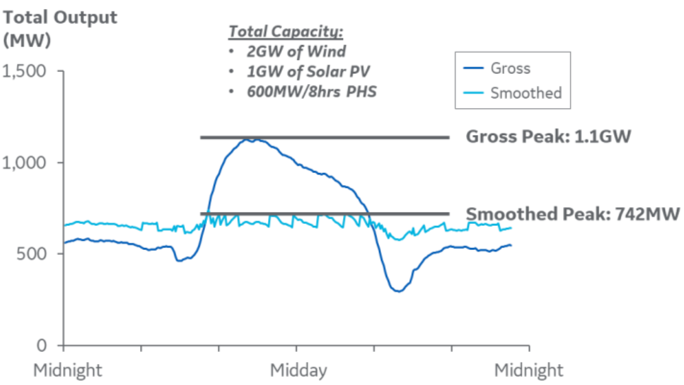
Consider a hypothetical REZ, which would be exporting nearly 100% of the power it generates into the NEM. Three broad approaches to transmission could be considered:

- Size the transmission connection at 100% of total rated capacity, knowing that this level will generally not be reached
- Size it below 100% rated capacity, knowing that when output exceeds this level, power would be spilled (or curtailed) that could otherwise have been used elsewhere in the NEM
- Use large-scale storage such as pumped hydro to smooth the output across the REZ, enabling high utilization rates on the transmission infrastructure, while simultaneously avoiding wastage of the power generated

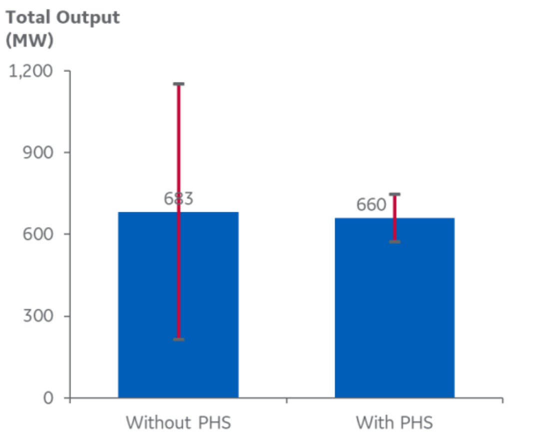
Subject to viable pumped hydro sites being available in or near a given REZ, we expect the third option will generally be preferable.

To demonstrate this effect in action, we have modelled a hypothetical REZ in QLD comprising 1GW of solar PV, 2GW of wind and 600MW/8-hrs of pumped hydro (PHS). As outlined below, the addition of pumped hydro to this hypothetical REZ significantly reduces the volatility of output, translating to significantly smaller, cheaper, better utilized transmission infrastructure.

Winter Weekday Output for a Hypothetical QLD REZ*



95% Confidence Interval For Average REZ Output*



In addition, the local system strength and inertia the pumped hydro could bring has the potential to greatly reduce the cost of securing these same services by transmission investment (e.g. in additional lines and/or synchronous condensers).

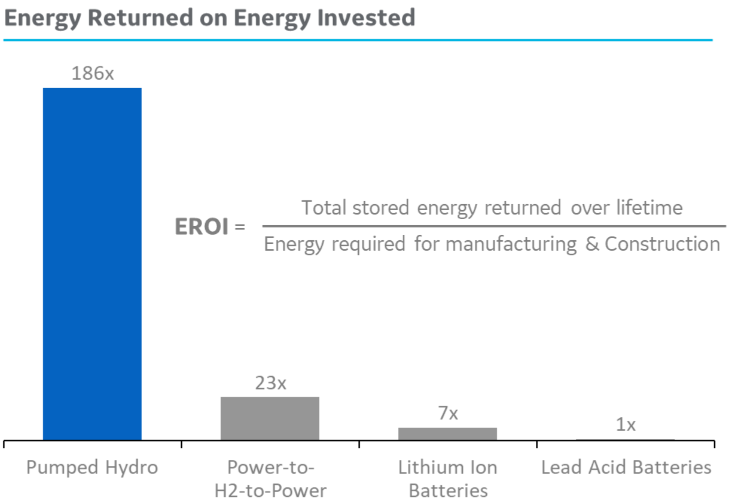
Consideration of the state-level benefits of lower prices, the regional benefits of improved reliability and security and the community benefits of regional jobs and investment would further strengthen the case for inclusion of pumped hydro sites in as many REZs as possible.

Low Environmental Impact

A recent study by ETH (Swiss Federal Institute of Technology in Zurich) analyzed the 'Energy Returned on Energy Invested' of a broad range of power generation and storage technologies.

This metric measures the energy stored or generated over the life of power generation assets in terms of the energy embedded in their construction/manufacture. Pumped Hydro achieves the highest ratio of the technologies assessed, returning 186x the energy required for its construction across its operating lifetime.

As such, pumped hydro offers a way to 'firm' the intermittency of renewables, that is itself renewable. Furthermore, the long operating lives of pumped hydro plants mean that the investments we make today will be providing renewable power and grid stability services for generations to come.



Source: study by ETH – Swiss Federal Institute of Technology Zurich, for SATW (Swiss Academy of Engineering Sciences) on energy performance of power generation technologies in Switzerland Based on the EcoInvent Database and PHS references ranging from 200 to 2100 MW, with storage capacities from 209 to 23,000 MWh

A Highly Cost-Effective Solution

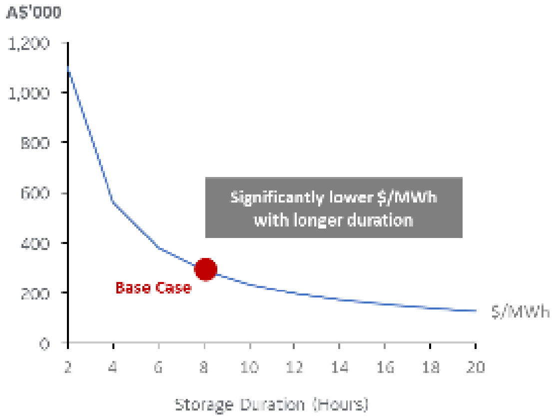
As noted in the Technology Investment Roadmap discussion paper, the delivery of an equivalent amount of storage to Snowy 2.0 using Li-Ion batteries would cost hundreds of billions of dollars vs $5.1B in the case of Snowy 2.0. While Snowy 2.0 boasts an unusually long storage duration of 175 hours, pumped hydro remains a highly cost-effective option at far shorter durations than this.

This relates to the fundamental cost structure of pumped hydro: while the MW power capacity drives the cost of the equipment, waterway and powerhouse; incremental duration increases only the size of the reservoirs. This 'economy of duration' is illustrated below for a hypothetical 600MW project.

Key Project Characteristics

Capacity	4x150MW
Duration	8 hours (Base Case)
Head	250m
Waterway	1250m
Upper Reservoir	Turkey Nest
Lower Reservoir	Existing reservoir

Capex per MWh vs Duration



Because of this phenomenon, pumped hydro is inherently more competitive at longer durations than batteries, for which capex scales with duration in a roughly linear manner.

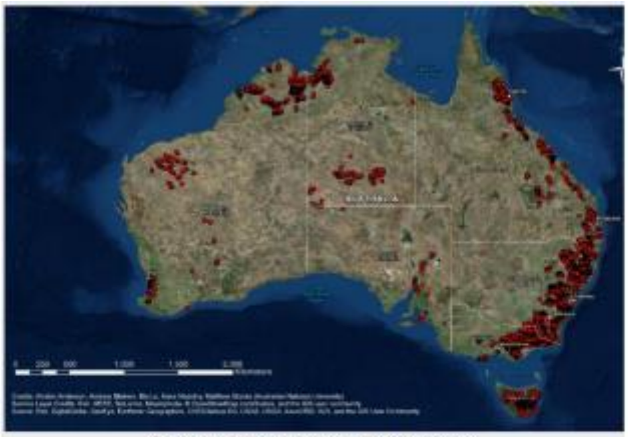
CHALLENGES AND OPPORTUNITIES

Positioning Australia as a clean energy superpower

Australia's abundance of high-quality wind and solar resources is now widely acknowledged and greatly exceeds the amount required to meet domestic electricity demand. Commentators and analysts are increasingly talking about the opportunity this presents for Australia to position itself as a 'clean energy superpower', as the world transitions to a lower carbon future and wind and solar PV continue to come down steep cost curves.

However, if we are to build up (or in some cases build back) our strength in energy intensive industry such as steel and aluminium production, we need electricity that is reliable and secure as well as cheap, which is where technologies such as pumped hydro come to the fore.

While Australia's endowment of pumped hydro resources is not as widely understood as wind and solar, it is no less impressive, with researchers at the Australian National University (ANU) identifying over 22,000 potential pumped hydro locations across Australia, or roughly 1000x the storage capacity needed to enable a 100% renewable electricity system meeting 100% of domestic electricity demand. Refer the map to the right, summarizing their findings.



Potential pumped hydro sites | Image: Australian National University

Properly supported, pumped hydro could form the backbone of a reliable, green electricity system that delivers power at globally competitive prices and enables a renaissance of energy intensive Australian industry and exports.

In effect, pumped hydro offers Australia the opportunity to use the fundamental features of our landform to build a competitive advantage that will serve our country for generations.

Challenges to overcome

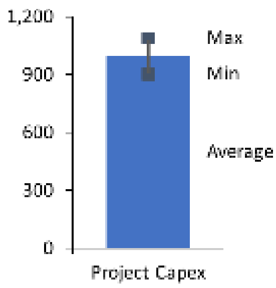
Misalignment of Costs and Benefits

If we return to our hypothetical 600MW x 8-hr pumped hydro project in Qld and assume the site characteristics outlined in the table below left, our modelling indicates an estimated capex of $900M-$1.1B.

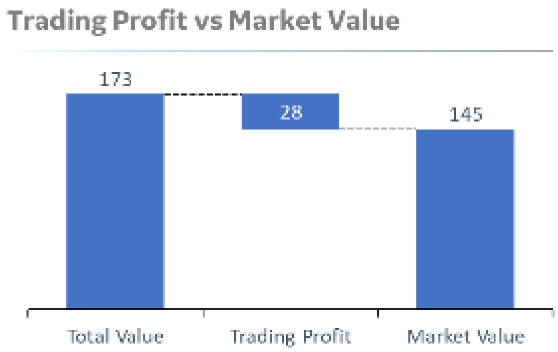
Key Project Characteristics

Capacity	4x150MW
Duration	8 hours
Head	250m
Waterway	1250m
Upper Reservoir	Turkey Nest
Lower Reservoir	Existing reservoir

Estimated Capex ($M)



Under a private investment model, this capex would be paid entirely by the asset developer/owner over the course of a 3-4 year construction period. In developing their business cases, our customers have advised us they typically consider income from energy arbitrage and the sale of cap contracts. As such, we have modelled the Trading Profit a plant such as this could expect to have earned if it had operated throughout calendar 2019. As defined in our model, 'Trading Profit' includes revenues from the sale of electricity and cap contracts less the cost of pumping. As shown in the left-hand chart below, we estimate an annual trading profit of $28M. As shown in the right-hand chart, this is dwarfed by the market value created through lower electricity prices.



Note: We have excluded ancillary services from this analysis as customers advised they are typically <10% of the revenue stack and are not considered 'bankable'.

Under private ownership, the majority of the value created by the project would be a positive externality – benefiting electricity consumers across the market but providing no cashflow to the developer. In this situation, only the $28M trading profit would be considered in the business case, leading to a simple payback period in excess of 35 years.

While this is well below the typical 100-year design life of a pumped hydro plant, it is far beyond the investment horizons of most private sector investors. For this reason, we are not aware of any pumped hydro opportunities under private development in Australia that have been able to achieve FID.

Under public ownership, the full economic benefit of $173M p.a. would be considered against the capex of ~$1B, leading to a simple payback period of just below 6 years. In fact, this analysis is conservative, as it considers only the trading profit and the market value associated with lower electricity prices. Quantification of the other benefits of pumped hydro (such as reduced transmission investment) would further reduce the overall economic payback period.

Long Timeframes

Investment in pumped hydro is a long-term proposition, with most of the sites under development in Australia expected to take 3-4 years to build. However, the typical design life of a pumped hydro plant is 100 years, with the expectation in most cases that this would be exceeded in practice. This is significantly greater than the operating life of every other generation or storage technology currently available.

In this sense, the 'return on time' for pumped hydro (being the operating life divided by the time to build) is generally in the region of 33x, compared with 10-20x for most other generation and storage technologies. Importantly, the operating life of a pumped hydro plant is relatively unaffected by the number of daily cycles it completes. This is not the case for chemical storage technologies, whose operating life is measured in terms of charge-discharge cycles, and hence declines rapidly as the number of daily cycles increases (a likely scenario as renewable penetration continues to rise).

Despite these advantages, the discounted cashflow methodology used by private sector investors places far greater weight on near-term cashflows than long-term ones, amplifying the costs incurred during the long construction cycle while heavily discounting the revenues and benefits created during the long operating life.

This dynamic exacerbates the cost-benefit misalignment outlined above and makes it harder still for pumped hydro development to occur without meaningful government support. This support can take many forms, from direct underwriting of revenue to capital grants to the creation of new markets that allow developers to monetise more of the benefits their projects create.

Summarised below is our view on the different approaches that have been implemented around the world, which we are happy to discuss further as useful.

Mechanism	Description	Examples
Capacity Payments	Owners get paid a fee per MW of available capacity	Israel, India
Pumped Hydro as a Grid Asset	Plants are owned by the transmission companies	China
Government Ownership	Plants are owned by government	Snowy Hydro, Hydro Tas, CleanCo
Capital Grants	Owners receive upfront grant covering part of the capex	ARENA large scale solar PV program
Underwriting Mechanism	Owners receive guarantees on min generation prices and/or max pumping costs	UNGI(?)
New Revenue Markets	Markets are created for services not currently compensated	Operating Reserve markets run by IESO in Canada

RESPONSE TO CONSULTATION QUESTIONS

Should storage and hybrids be defined in the NER?

The current framework treats storage technologies as a load source combined with a generation source – much like an industrial facility with onsite generation, that could at any given time be drawing power from the grid or dispatching power into it.

In fact, storage technologies are fundamentally different, as they neither produce nor consume energy, but rather shift energy from one time to another (round-trip efficiency losses notwithstanding).

Given this difference, defining it in a separate way seems conceptually appropriate. It also paves the way for exploration of other more fundamental changes that could help unlock the large-scale storage opportunity in Australia and support a cost-effective energy transition.

For instance, in China, large scale storage is owned by the transmission companies and effectively operated as a giant shock-absorbing system that reduces load and price volatility. In this way of thinking, the role of generators is simply to put electrons into the grid at lowest cost; the role of the transmission operators is to ensure the grid receiving these electrons is able to operate in a secure and reliable manner, at lowest cost. Apart from its apparent simplicity, a further benefit of this model is that it allows grid operators to co-optimise their investments in lines, substations, storage and stabilizing technologies to enable the most cost-effective solution.

This differs greatly from the current approach in Australia and may or may not prove the best option for the NEM, but recognizing that storage plays a different and unique role in the grid opens the possibility to at least explore this and other options.

Is there a problem with how the registration and classification framework treats storage and hybrids? If so, how should we fix it?

As identified in the consultation paper, the treatment of storage facilities as both Market Customer and Market Generator means they need to complete two different registration processes and pay two sets of registration fees. This seems to represent unnecessary cost and complexity. Creating a new classification for storage, with a single registration process associated with it appears a logical solution.

To our way of thinking, this approach should apply equally to all storage technologies, with an implementation that allows for differences in the capacity and ramp rate in storing vs generating modes. It is not clear to us why linear ramping should be a requirement for classification under this new registration category.

What are the technical and operational issues facing storage and how can those issues be addressed?

As noted by AEMO, the current dual classification system creates a risk of storage operators receiving conflicting dispatch instructions. Resolving this makes sense. We do however note the loss of flexibility that would accompany the net reduction from 20 price bands down to 10. We would argue that the broader question of 'how many price bands should there be?' should be addressed, as the optimal answer may differ from either the current or proposed approach.

The approach to minimum ramp rates should be clarified and different ramp rates allowed for storage vs generation modes. The goal should be to maximise the efficiency of dispatch, given the rated characteristics of a given storage facility and the technical requirements agreed in that facility's Generator Performance Standard (or equivalent document).

While factors such as ramp rate and max/min capacity may be sufficient to define conventional generation units, it seems clear that 'energy in storage' (or an equivalent wording) should be an additional requirement in relation to storage units. This should improve the accuracy of AEMO's forecasting and the efficiency of dispatch.

Given the possibility to combine different technologies behind a common connection point – either in the form of hybrid facilities or in microgrids – it seems logical to broaden the approach to consider the performance of the entire asset (or facility) as seen by the grid. It additionally would simplify the process of securing connection agreements if storage facilities were able to agree a single performance standard that covered both storage and generation modes.

What are the issues with the application of fees and charges to storage and how can they be addressed?

Cost allocation should be clear, which AEMO's submission indicates is not currently the case (e.g. different TNSPs forming different views on whether and how TUOS should be charged). A clear position needs to be articulated so the different players know where they stand.

In terms of cost allocation methodology, we support the principle that indirect costs should be allocated on a causer-pays or beneficiary-pays basis. This becomes interesting when considering the allocation of system stability costs (such as FCAS and NSCAS) to fixed speed pumped hydro plants, which are dispatchable and synchronous and hence improve system stability rather than reduce it.

On this basis, we would argue fixed speed pumped hydro should be excluded from paying these costs (on either generation or load). In fact, the efficiency of the overall system would arguably be greater if fixed speed pumped hydro was paid for provision of these services, an acknowledgement at the heart of the Post 2025 Market Design process.

On the basis that pumped hydro reduces system and network costs by stabilizing load and the grid, we support the proposal to exempt it from TUOS and DUOS. We also support the underlying logic of AEMO's proposal, i.e. that TUOS and DUOS should be paid only once, and hence charging a storage facility and then also charging the ultimate user of the electricity would amount to double-charging.

What other obligations specific to storage and hybrids should be included in the NER?

Storage assets should be excluded from RRO obligations on their load as they are dispatchable and hence contribute to system reliability. Pumped hydro brings additional benefits such as inertia and system strength and should not be penalized with RRO obligations. It also doesn't make much sense to support the development of large-scale storage as a means of 'firming' intermittent renewables, only to require those same storage facilities to procure a portion of their consumed energy from non-renewable sources.

MLF needs to be carefully considered in the context of large-scale storage. On balance, it seems likely that storage would tend to absorb power when there are high levels of renewable output (hence reducing MLF when it is at its highest) and then dispatch power when renewable output is low (and hence line congestion and MLF is not an issue). This is particularly the case for pumped hydro facilities, which are often designed to shift output over significant durations (i.e. away from the midday period of excess renewable output, towards the evening period of sharply ramping operational load).

If storage is to be represented on the reliability panel (which we support), we would suggest that the various different storage technologies be individually represented, as the needs of the overall storage industry will not be well-served by representation by only one storage technology. To avoid too much complexity, representation could be limited to technologies with an existing installed base in Australia.

Are some of the key terms in the NER out-of-date? If, so how should they be changed?

Nothing to note other than the matters already raised above.

CONCLUSION

Australia is in the early stages of a major transition in how we generate electricity, which will increasingly require us to firm the network when demand exceeds generation, store the excess when generation exceeds demand and at all times provide the inertia, system strength and other ancillary services needed for a stable, secure grid. Pumped hydro is unique in its ability to meet all of these needs, at a low monetary and environmental cost, over not just decades, but generations.

Expanding Australia's pumped hydro fleet would bring significant reductions in wholesale electricity prices, as well as reducing the investment required in our transmission network. Together, these would translate to significant savings for households and businesses across the nation.

The regional location of most pumped hydro projects provides an opportunity to bring jobs, investment and growth to regional communities and the people who live and work in them, including those otherwise negatively impacted by the energy transition.

Government leadership is key to enabling these benefits and we hope this rule change process will represent the first step down a regulatory pathway that seeks to unlock the significant potential of pumped hydro in Australia.

In particular, if private sector investment is to be unlocked, changes to regulations and/or markets are required to better align the benefits of pumped hydro with the costs. Many possible solutions to this challenge exist and we are at your disposal to further discuss our analysis, findings and experience and to help develop a fit-for-purpose approach for pumped hydro in Australia.