

22 May 2026

Mel Prescott: Advisor | Fast-track Applications  


Dear Mel,

**Re: Request for information 1 in relation to the Lake Pūkaki Hydro Storage and Dam Resilience Works project under the Fast-track Approvals Act 2024**

Thanks for your letter of 4 May seeking further information on the above application.

In what follows, we repeat the two questions for the Authority and then give our responses.

**Question 1: economic benefits and costs**

“In broad terms, following the receipt of comments, the Panel now has three different appraisals of the economic benefits and costs of the project (Concept Consulting Limited; David Weaver and Simon Coates), John Culy, and Grant Telfar and Brent Layton.

The Panel would appreciate the EA reviewing this further information and advising the Panel whether any aspects of it cause the EA to depart from its assessment of the overall costs and benefits of the proposal as set out in its section 53 comments to the Panel.”

**Comment**

**The Transpower and Meridian models are similar**

We agree with Mr Blundell that:

“The modelling commissioned by Transpower is directionally in agreement with Meridian’s own modelling suggesting significant benefits on average as a result of eased access to contingent hydro storage in Lake Pūkaki.”

Our view is that there is little to choose between the modelling of John Culy (JC) and Meridian. As explained further below:

- The benefits of removing the restrictions are similar in both models — the submissions measure the benefits of removing the restrictions differently, so we include comparable figures from Meridian below to clarify this point.
- The JC double contingency event (DCE), ie, the combination of the lowest-ever hydro inflows and a sustained unexpected outage of the country’s largest generation facility, needs to be weighted by its probability of occurring to compare it to the benefit figure. We have also made this comparison below.

In both cases, the net benefit of more open access to contingent storage is the difference between the net benefits in the restricted case, where access is controlled by the System Operator, compared with the unrestricted case, where access is for Meridian to decide.

## The restricted case

For the restricted case, JC values water highly enough that storage in Lake Pūkaki stays above 518mRL in all historic inflow sequences. JC describes this as one “bookend” of the analysis. Meridian models water values high enough that storage stays above 518mRL in all historic inflow sequences. It describes this as reflecting the behaviour of a risk averse operator that avoids the risk of being at 518mRL but not able to access the storage.

This means that the JC bookend scenario has the same outcomes as Meridian’s modelling in the restricted case, and it leads to similar outcomes, with the contingent storage not being used in either model.

There is a difference in how the outputs are interpreted. JC interprets its bookend as more conservative than the status quo, and discounts the benefits of removing the restrictions accordingly (Transpower Attachment A - Comments on costs and benefits John Culy page 6). Meridian interprets its modelling as showing how they prudently operate now, ie, the JC bookend is the status quo without discounting.

The Authority’s view is that Meridian has strong incentives to avoid approaching the contingent storage release boundary for the reasons Mr Blundell outlines in his submission, paragraphs 33, 34 and 35. We note that the contingent storage in Lake Pūkaki has never in fact been accessed. Given these factors, we think that the discount that JC applies to the benefits is unnecessary.

We think this is especially the case given how conservative the JC DCE is on the other side of the ledger. The JC discount reduces the value of the benefits of Meridian’s application, and the remote possibility of the DCE scenario amplifies the costs.

## The unrestricted case: benefits

The two sets of modelling report different measures of benefit with JC focused on the total system cost, and Meridian focused on spot price changes.

We agree with JC that the benefits expressed as the change in system cost is the correct metric.

We asked Meridian for its modelled estimates of system cost savings (reduced fuel burn, carbon costs, demand response, shortage, and fixed opex) to compare with the JC system cost changes. These are set out in the table appended to this letter. This analysis shows that, for a central scenario, the benefits in terms of saved system costs are \$87m to \$107m per year between 2026 and 2029 depending on whether the mean or median result is used. These numbers are comparable to the saved system cost reported by JC of \$38 to \$43 million<sup>1</sup>.

In the tail risk case, the worst inflow sequence yields a \$1m annual benefit from retaining the current arrangements in Meridian’s modelling. This is not comparable to the \$440m JC cost of the DCE because it is not combined with a large thermal outage. As such an outage is not modelled by Meridian, the DCE has no analogue in the Meridian modelling.

Meridian’s system cost calculations (and some of the wider analysis presented in the accompanying tables) were provided directly to the EA by Meridian at the EA’s request. They were not included in Meridian’s original substantive application. These results are from the same modelling outputs as reported by Meridian in its substantive application, and provide a measure of costs and benefits that is consistent with the results that JC reports. We have Meridian’s permission to provide this information.

---

<sup>1</sup> [https://www.fasttrack.govt.nz/\\_\\_data/assets/pdf\\_file/0011/23411/12A.-Transpower-Attachment-A-Comments-on-costs-and-benefits-John-Culy.pdf](https://www.fasttrack.govt.nz/__data/assets/pdf_file/0011/23411/12A.-Transpower-Attachment-A-Comments-on-costs-and-benefits-John-Culy.pdf)

## The DCE case is unlikely and the cost if it were to happen is falling over time

JC's modelling estimates the cost of the DCE at \$119m in 2028, about a quarter of the \$440m<sup>2</sup> used in Transpower's submission for 2026. This is due to increased investment in renewable generation. This JC modelling was done as part of one of the System Operator's work on assessing the trade-offs in accessing contingent storage.

We agree with Dr Layton that the cost of the DCE needs to be weighted by the probability that it will happen. Without such a weighting we are comparing an annual benefit (JC's approximately \$40m) with a cost that only occurs rarely (the DCE). Below we attempt to use data to do this probability weighting.

Meridian's modelling (pages 15 and 16 of its substantive application) suggests that 21 of 91 inflow sequences lead to Lake Pūkaki falling below 518mRL when the restrictions removed. This is 23 per cent (in probability terms 0.23) of the time.

Following Dr Layton, the probability weight appropriate for the DCE is the probability of storage dipping below the 518mRL times the probability of an extended unplanned outage at Huntly 5 (HLY5). This assumes that these two events are independent which is a reasonable conservative assumption.

If this combined probability times the \$440m cost of the DCE is smaller than the \$40m benefit, then the restrictions are inefficient in 2026.

Using:

- The \$440m cost of the DCE in 2026
- The \$40m benefit from the JC model
- The 23% chance of inflows falling below 518mRL

the benefit outweighs the potential cost if:

$$Cost_{DCE} \times Probability_{DCE} \leq Benefit_{restrictions\_removed}$$

where the probability of the DCE is the probability of inflows falling below 518mRL and HLY5 being on outage:

$$Probability_{DCE} = Probability_{falling\_below\_518mRL} \times Probability_{HLY5\_outage}$$

We can work backward and find removing the restrictions increases efficiency as long as the probability of a HLY5 outage is below 40 per cent (0.4 in probability terms).

From January 2020 to April 2026, HLY5 was on outage 16.7 per cent of the time — 9.7 per cent of the time those outages were likely unplanned, the remaining seven per cent were likely planned. So the probability of HLY5 being on outage based on that that five-year period is lower than necessary to justify removing the restrictions. Note that past reliability is not necessarily an indicator of future reliability, and that the source of a DCE would not necessarily be HLY5.

Using the 16.7 per cent and the 23 percent figures times the \$440m DCE cost gives a probability weighted cost of the DCE of \$16.9m per year. This number can be compared with the \$40m JC benefit number, or the Meridian numbers set out above. Again, this suggests that the restrictions

<sup>2</sup> It is important to note that these are gross cost, and benefits such as the reduction in the cost of thermal generation have not been netted off by JC. This overstates the cost of the DCE. This is different from total system cost in the table from Meridian, the latter considers the sum of all costs and benefits.

are inefficient, ie, it costs the system more to keep the Pūkaki contingent storage for a very rare event than it saves in terms of reducing the costs of the event were it to occur.

We have aimed here for a conservative analysis. The DCE used the very worst inflow sequence to generate the \$440m gross cost, whereas this analysis uses the worst 21 inflow sequences, 20 of which will cause a cost lower than \$440m. In addition, as pointed out above, the cost falls through time.

### **The Concept modelling is primarily focused on the impact of a weir failure**

We have some observations of the modelling provided by Concept, but we are not experts in the engineering of the weir, so we offer no view on the probability that it will fail.

On the modelling we note that:

- The Concept model uses higher demand to model a stressed system, and then analyses the 21 inflow sequences that dip into contingent storage as a way of investigating the impact of the weir failing. This results in more inflow sequences using contingent storage compared with the JC and Meridian modelling. This needs to be kept in mind when comparing this modelling to the JC and Meridian modelling.
- As we observed above when we weighted the DCE with the combined probability of a large generation failure and a low inflow sequence, the weir failure scenario needs to be probability weighted before it is compared to the benefits of removing the restrictions.

Mr Coates discusses the conceptual framework for contingent storage discussing how contingent storage is a fuel of last resort, and that markets might not deal with “black swan” events. On these points:

- We agree with Mr Blundell’s submission (repeated below) that the current contingent storage arrangements are not a deliberate construct, but instead an accident of historic consenting decisions.
- We note that the market is providing contingent cover in a variety of ways:
  - Renewable build effectively forces hydro generators to store more water (this is the reason that JC’s modelled cost of the DCE falls over time). This build is reflected in the falling forward prices for electricity that we see at present.
  - Contingent contracts such as the contracts for the third Rankine, and different demand response agreements are a market response to managing the sorts of “black swan” events that Mr Coates discusses.
- We agree with Mr Coates conceptually that there could be scenarios in which a strategic reserve or a fuel of last resort would be an efficient system-wide response to security of supply risks. But we do not think that the contingent storage in Lake Pūkaki is in fact an efficient tool in the next three years.

### **Question 2: System Operator role and contingent storage**

“The Panel has received detailed comments from Transpower Limited about the importance of contingent storage in the New Zealand power system and its role as SO. In response, the Applicant has offered a competing analysis on both those matters (refer the following materials for the Applicant in response: Legal Submissions, Evidence Rory Blundell).

The Panel would be assisted by any further information or comments about these two matters from the EA.”

## Comment

Regarding the role of the System Operator, our submission stated that:

“The roles of the SO are set out in section 8 of the Act, and Part 7 of the Electricity Industry Participation Code 2010 (the Code). The System Operator role most relevant to this submission relates to forecasting security of supply and managing security of supply emergencies.”

To the extent that the System Operator has relevant modelling because of its forecasting role, this has been and should be made available to the Panel.

The role of the System Operator is made clear in the October 2024 Government Policy Statement to the Electricity Authority, which says:

“23. In accordance with market rules and arrangements, the System Operator is –

- a) Not responsible for ensuring the adequacy of offers to meet demand, but rather –
- b) To efficiently coordinate the utilisation of electricity generation and demand-side offers that have been made available in the wholesale market by market participants in response to spot price signals”

We agree with Mr Blundell when he writes:

“However, the current contingent storage arrangements are not a deliberate construct. They are an accident of history and disparate consenting decisions made over time. There is no strategic reserve or contingent storage policy in New Zealand, nor is it accurate for Transpower to assert that the status quo consenting arrangements amount to an agreed policy.”

And repeating what we said in our first submission for convenience:

“The contingent storage arrangements are not a centrally designed strategic reserve; instead they have evolved over time in a way that hasn’t been coordinated or designed to minimise total costs. We do not know whether a market-based strategic reserve would be cheaper for consumers or more effective than the current arrangement for access to contingent storage in Lake Pūkaki. But we do think that the proposal will move the overall system to a lower cost position.”

All that said, the economic issue does not turn on whether the contingent storage arrangements are the result of deliberate design, nor on our role or the role of the System Operator. Instead, our perspective is simply whether the total system cost of the constraints on using the Pūkaki reservoir are likely to exceed the benefits for the next three years.

In our view the system costs of the current arrangements in the next three years are too high to justify keeping them in place. This is because of the relative size of those costs compared to the benefit from maintaining the contingent storage to be available for an event like the DCE modelled by JC and as set out above.

## Conclusion

I trust that these additional comments are helpful.

I am conscious that the System Operator has a different view to the Authority of the balance of benefits and costs in this case. We are also conscious that the electricity market is a dynamic system and that changes to rules around access to the fuel in Lake Pūkaki will have wider impacts, though their nature and extent is uncertain. We note that the rules for access have also recently been changed by the Authority in an update to the Security of Supply and Forecasting Information

Policy (SOSFIP) though we are yet to have a situation where those new rules have been tested in practice. And we note that there are several other active processes underway in relation to dry year risk management, to which the Panel's decision in this case will be relevant.

In particular, the Government has stated that it will develop a new regulatory framework for dry-year risk, including a regulatory framework to create lasting incentives to build firm generation with this framework to be overseen and administered by the Electricity Authority.<sup>3</sup> We expect further public announcements on this issue in the middle of the year, as well as announcements on the Government's proposal to build a Liquefied Natural Gas terminal, which could provide another option for backup generation when needed.

Nāku noa, nā



Hayden Glass

**GM, Wholesale and Supply**

Electricity Authority Te Mana Hiko

---

<sup>3</sup> [Factsheet: Strengthening the regulatory framework for dry years](#)

# Appendix A Meridian total cost modelling outputs

## Measure of Central Tendency

		Annualised History 2012-24 mean	Restricted vs Eased Lake Access				Restricted vs Eased Lake Access				
			Sustained results 2026-2029; annualised				Sustained results 2026-2029; annualised				
			Restricted	Eased	Restricted->Eased		Restricted	Eased	Restricted->Eased		
			p50		delta	%	mean		delta	%	
NZEM System	LWAP	\$/MWh	\$ 131	\$ 142	\$ 132	-\$ 10	-7%	\$ 144	\$ 141	-\$ 3	-2%
	Hydro	GWh	24,593	24,296	24,555	259	1%	24,332	24,604	272	1%
	Thermal	GWh	6,208	2,166	1,865	-301	-14%	2,133	1,846	-287	-13%
	Non-Hydro RE	GWh		16,649	16,749	100	1%	16,645	16,752	107	1%
	Hydro spill	GWh		1,509	1,162	-346	-23%	1,740	1,414	-325	-19%
	Dem Resp	GWh		267	111	-157	-59%	283	152	-131	-46%
	VoLL	GWh		-	-	0	-	0.1	0.2	0	117%
	CO2 Emissions	kT	4,500	2,226	2,029	-196	-9%	2,195	2,013	-183	-8%
	Total System Cost	\$M		\$ 1,684	\$ 1,577	-\$ 107	-6%	\$ 1,666	\$ 1,579	-\$ 87	-5%
	Load Cost	\$M		\$ 6,372	\$ 5,935	-\$ 437	-7%	\$ 6,579	\$ 6,466	-\$ 113	-2%

## Measure of Tail Risk

		Annualised History 2012-24 mean	Restricted vs Eased Lake Access				Restricted vs Eased Lake Access				
			Sustained results 2026-2029; annualised				Sustained results 2026-2029; annualised				
			Restricted	Eased	Restricted->Eased		Restricted	Eased	Restricted->Eased		
			p75		delta	%	1-in-91		delta	%	
NZEM System	LWAP	\$/MWh	\$ 131	\$ 161	\$ 156	-\$ 5	-3%	\$ 236	\$ 294	\$ 58	24%
	Hydro	GWh	24,593	25,063	25,293	229	1%	26,236	26,434	198	1%
	Thermal	GWh	6,208	2,497	2,235	-262	-10%	3,163	3,004	-158	-5%
	Non-Hydro RE	GWh		16,822	16,916	94	1%	17,152	17,178	27	0%
	Hydro spill	GWh		2,315	1,966	-349	-15%	3,711	3,443	-268	-7%
	Dem Resp	GWh		424	247	-177	-42%	747	519	-228	-31%
	VoLL	GWh		-	-	0	-	6.1	9.8	4	61%
	CO2 Emissions	kT	4,500	2,423	2,273	-150	-6%	2,880	2,758	-122	-4%
	Total System Cost	\$M		\$ 1,786	\$ 1,696	-\$ 90	-5%	\$ 2,013	\$ 2,014	\$ 1	0%
	Load Cost	\$M		\$ 7,398	\$ 7,005	-\$ 394	-5%	\$ 11,140	\$ 14,369	\$ 3,229	29%

## Appendix B How the cost of the DCE falls over time: JC modelling

JC<sup>2</sup>

The value of the extra reserve provided by a restrictive CS policy falls off substantially we go to an economic equilibrium in 2035, provided that 2 or 3 Rankines are retained ..

In 2026 the system is in economic disequilibrium. There is a substantial benefit from a conservative policy in reducing tail risk shortage costs with 2 Rankines. Adding another Rankine reduces the tail-risk benefits, and reduces the cost of CS policy conservatism slightly. Risk aversion will determine if the benefits in stress cases offsets the ongoing annual “insurance” cost of higher spill and system cost.

By 2035 the system reaches equilibrium and so the costs of conservatism are reduced to around \$30m per year. The value from reducing tail-risk shortages is significantly reduced, as the system can handle these provided that new renewable investment occurs and existing coal and gas backup plant is retained.

