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Problem Definition
"Lumpiness" with 100% Renewables

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Introduction and suggested approach

Might large "lumpy" binary events or investments cause inefficient decisions in a 100% renewable electricity future? We have been asked by MDAG to offer our views around the impacts of "lumpiness" on sector decision-making and operation, in a future where electricity wholesale price discovery occurs in a 100% renewable market. This is part of MDAG's investigations into the scope of challenges and opportunities arising under such a market, and to recommend changes (if any) that might be required to the wholesale electricity market in order to ensure economically efficient price signals (from short to long term) will continue to meet the Electricity Authority's statutory objective.

Our focus is on major investment/contracting decisions by generator and/or retailers. We think there are generally two ways "lumpiness" might arise for this group: either due to the scale of major decisions those companies face, or due to "lumpy" decisions by other non-market participants (i.e. external decisions that may delay or accelerate efficient investment timing). Below we highlight those we regard as dependent on external parties (where decision rules are opaque to electricity investors, and difficult to anticipate), as opposed to primarily market driven (i.e. we expect investors to anticipate price signals, promulgate deals and investments which act on those signals)

Potential sources of "lumpiness"

- **Financing large-scale investment in new generation** (e.g. 12TWh to 2035 in CCC report, which might require ~$7.5bn capex)
- **Tiwai closure** (5TWhpa, 13% of NZ load, contracted to Dec'2024 with no formal extension rights) *external RIO decision*
- **Major thermal stations** (360MW TCC, 3 x 240MW Huntly Rankine units, Huntly Unit 5)
- **Mass decarbonisation of dairy factories** (up to 4TWhpa electrification, but slow adoption by boiler owners, and biomass has better economics?) *external decision*
- **New-to-market loads** (e.g. 750MW Hydrogen facility in Southland)
- **Procurement of large-scale demand-response** (likely to become a critical contributor to price discovery and security of supply in 100% renewables system)
- **Lake Onslow pumped-hydro storage scheme** (possible 1GW capacity, 5TWh storage, built & operated by Government?) *external Government decision*
- **Procurement of large reserves in the North Island** (Without thermals, will HVDC often be constrained to ~700MW northwards? 700MW SIR battery = ~$700mn capex)

Scale of generation investment

It's useful to test whether the scale of renewable investment to reach 100% might pose a "lumpiness" problem in its own right. MDAG is looking at electricity price dynamics in other workstreams. Our intention here is to address whether funding those investments may be difficult due to scale. **At current costs and required rates of return, we expect renewables to be attractive at ~$80/MWh (real) TWAP outlook.**

It seems reasonable that investors and participants could finance 10TWhpa of more of additional investment. Around $2bn has been committed since 2019 for 3.4TWhpa, and we expect another 1.6TWhpa is likely to be committed for a total of ~5TWhpa renewable expansions operating by end of 2025. Much of the new generation has been built on a "merchant" basis, although longer term PPA offtake agreements have also featured. Investors have strongly supported these, as indicated recently by CEN's successful $400mn equity raising. If the CCC's 12TWhpa renewable growth figures proves correct, then the capital required would represent only a ~30% increase over current listed generator's net debt, and a ~20% increase in equity. **The scale of investment seems achievable under current market structures.**

Committed and likely renewable build should take NZ above 90% by 2024. Options for the next ~5TWhpa of expansion are thought to be in advanced stages, but we don't expect commitments until ~2023 due to (re)consenting and uncertainty in demand outlook. Expansions now underway will mainly displace baseload thermal generation. Further rounds of renewable expansion will probably require greater certainty around the presence of Tiwai or some large-scale Southland load replacement. At least two generators have resolved to not leave this to chance, and are actively pursuing replacement loads. These new loads may also offer characteristics with significant benefits to the operation of a 100% renewables electricity market.

Illustrative economics for renewable expansion projects

	WIND	GEOTHERMAL	SOLAR PV
Capex	$2.20m/MW	$4.25m/MW	$1.30m/MW
Capacity Factor	40%	95.0%	17.5%
GWh/MW	3.50	8.32	1.53
Capex/GWh	$0.63m/GWhpa	$0.51m/GWhpa	$0.85m/GWhpa
Operating cost (real $/MWh)	$10.0/MWh	$20.0/MWh	$5.0/MWh
Expected TWAP (real $/MWh)	$80.0/MWh	$80.0/MWh	$80.0/MWh
Expected GWAP (real $/MWh)	$72.0/MWh	$80.0/MWh	$92.0/MWh
Economic Life	30yrs	40yrs	25yrs
ND/EBITDA gearing target	2.5x	2.5x	2.5x
EBITDA/MWh	**$62.0/MWh**	**$60.0/MWh**	**$87.0/MWh**
Capex/EBITDA	10.1x	8.5x	9.7x
Debt/GWh sourced at ND/EBITDA	**$0.16m/GWhpa**	**$0.15m/GWhpa**	**$0.22m/GWhpa**
Equity/GWh required	**$0.47m/GWhpa**	**$0.36m/GWhpa**	**$0.63m/GWhpa**
D/D+E	25%	29%	26%
Tax rate	28%	28%	28%
Long-run govt. bond rate	3.0%	3.0%	3.0%
Debt pre-tax rate	5.0%	5.0%	5.0%
Equity pre-tax return required	8.2%	8.2%	8.2%
WACC post-tax	6.8%	6.8%	6.8%
Ungeared FCF/MWh	$50.5/MWh	$46.8/MWh	$72.1/MWh
less Table Debt repayments	-$10.1/MWh	-$8.7/MWh	-$15.4/MWh
Approx. FCF for equity holders	**$40.4/MWh**	**$38.0/MWh**	**$56.7/MWh**
Approx equity holder FCF yield	**8.5%**	**10.5%**	**9.0%**
Imp.Credits available	73%	89%	67%

source: Jarden estimates

12TWh wind expansion sizing, compared to current listed gencos

	Cur.Mkt Cap	FY21 Net Debt	FY21 EBITDA
CEN	$6,390m	$706m	$553m
GNE	$3,460m	$1,246m	$358m
MCY	$8,430m	$1,080m	$463m
MEL	$12,550m	$1,625m	$729m
TPW	$2,260m	$762m	$200m
Total	**$33,090m**	**$5,419m**	**$2,303m**
+12TWh wind	$5,674m	$1,860m	$744m
Increase	*17%*	*34%*	*32%*

source: Refinitiv, Jarden estimates

Tiwai smelter

NZ's largest load has skirted closure several times since 2012, and still has no certain outlook after 2024. Its last renegotiation resulted in a very low price (~$35/MWh) but under a contract which ends in 2024 with no renewal rights. ~2TWhpa of renewables were committed after the 15-month renegotiation uncertainty.

Most commentators think the subsequent doubling of aluminium price and a relatively low-carbon intensity makes smelter exit after 2024 unlikely. Given its previous track record, main suppliers Meridian and Contact are more circumspect, and are actively pursuing promising alternatives (we discuss these shortly).

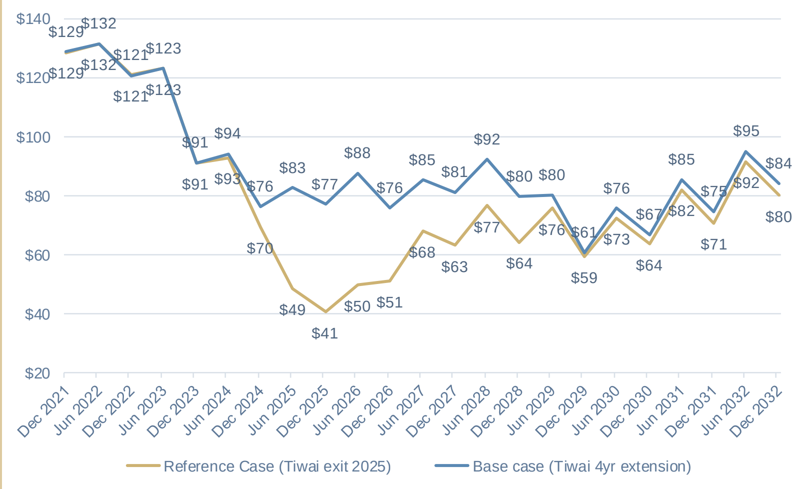
Undoubtably the chance of a smelter exit is a key "lumpy" factor investors must consider when timing further renewable builds and thermal retirements. A fast roll-off of 5TWhpa of smelter load would reduce electricity prices and likely make any recent investment in renewables (or new thermal fuel contract) unprofitable over several years. Smelter exit would also be a key catalyst for retiring some of the thermal fleet, and in our modelling would increase average renewable share to more than 95% of generation.

But Tiwai's current electricity suppliers have created options to avoid a "lumpy" Tiwai hold-up. Each is separately pursuing demand stimulation initiatives with new-to-market electricity loads in Southland (primarily heat conversions and data centres) which we think could eventually amount to ~1.5TWhpa. They have also jointly created the Green Southern Hydrogen project (sized at 5TWhpa or more) which appears to have received strong international interest. It is important to note that **MEL states that that unlocking demand response flexibility is a pre-condition to supply for either hydrogen or the aluminium smelter.** This would be important for reducing thermal % of generation, and a "lumpy" opportunity for the power system.

Aluminium prices since 1990 (nominal USD/t)

Source: World Bank

Jarden forecast OTA prices (nominal $/MWh)



source: Jarden estimates

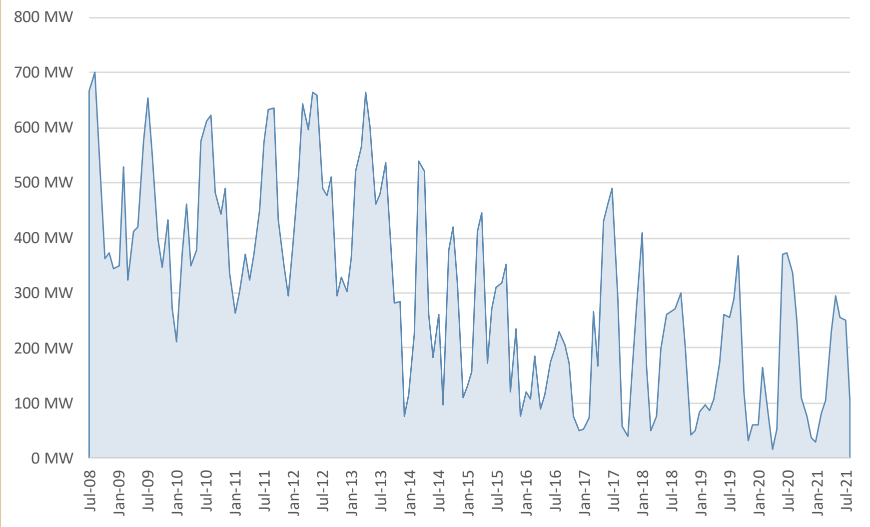
TCC retirement and “ThermalCo”

Contact Energy confirmed for investors that TCC would be closed in 2023 – although a “lumpy” item, its retirement seems fairly certain. To re-certify the 360MW CCGT beyond that date is expected to cost ~$80mn – and not considered worthwhile. Along with its 200MW Peakers, CEN generates ~1,200GWhpa from its Stratford thermal site. In recent experience CEN has closed two former thermal stations (Otahuhu B and New Plymouth power station) and seems very likely to follow the same path with TCC. Until closure, we expect the company to generally run the CCGT during May to September or during dry sequences. This is consistent with its typical use of thermal stations as winter-firming, which is clear from the chart opposite.

The company has positioned the Tauhara replacement as its portfolio replacement for TCC. The committed 152MW Geothermal station is expected to be completed in mid-2023 ands produce ~1,300GWhpa, and expected to displace that amount of baseload thermal generation. Tauhara’s LCOE is thought to be ~$55/MWh and easily cheaper than any baseload thermal unit SRMC.

While the Stratford peakers and Whirinaki are expected to continue operating in a hydro-firming/peaking role, CEN is looking into a “ThermalCo” spinoff option for those units which may include setting out a timetable for their useful lives or ring-fence their use as “reserve” stations. Other company’s units may possibly be included. Further information is expected to be revealed in coming weeks.

Contact Energy thermal generation (monthly average MW)



source: Company data

Huntly power station

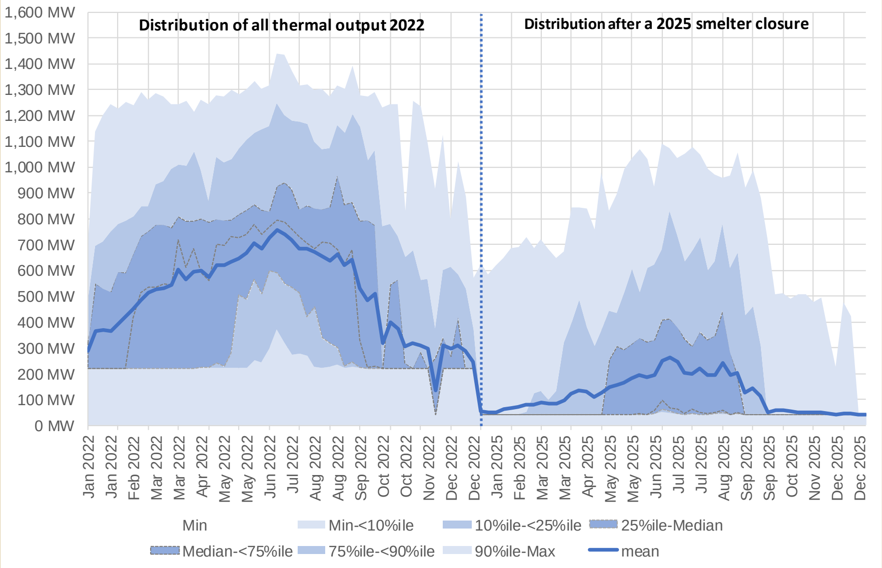
Huntly power station owner Genesis Energy is executing its "Future Gen" strategy, which will procure 2,650GWhpa offtake from new renewables by 2030, and so far is set to achieve ~1,800GWhpa of this by 2025. The company intends to significantly reduce its baseload thermal output, in response to price signals and cost: new renewables are cheaper than the combined fuel+carbon costs of operating GNE's thermal fleet.

We don't see any "lumpiness" in Huntly thermal output per-se. The owner of NZ's largest thermal generation capacity (~1,175MW) is already planning for large output reductions. GNE continues to shift U5 from its previous baseload role into a winter-weighted swing station, by which we think it may displace the traditional Rankines position in the merit order. We understand GNE is currently working on agreements that will allow greater seasonal gas flexibility to suit that role (e.g. Huntly Unit 5 mainly available during May-September).

But a path to full thermal closure is unclear at present. We expect GNE to set the next stages of its thermal strategy once the availability of alternatives and their economics becomes clearer. MDAG and NZ Battery workstreams may help inform these next step decisions, alongside GNE's own hydro-thermal modelling. Generators current plans still see a role for residual thermal capacity to ensure North Island peak and national hydro-firming needs can be met (we think around 95-98% mean renewables percentage by 2030).

Availability of hedge contracts from non-thermal alternative backup will be important for thermal retirement decisions by generators, and a competitive market to sell hedge cover to retailers. Under 92%-98% renewables scenarios, we estimate thermal "insurance" premiums may need to be ~$25-50mpa to recover thermal plant fixed costs (cf: $25mnpa swaption premiums to 2022) and these and physical thermal plant currently supports generator ability to sell hedge cover.

Jarden estimated use of all NZ thermal generation (average weekly MW)



Source: Jarden estimates

Jarden Base Case thermal estimates (merchant & risk-neutral)

		GNE Huntly Rankines			GNE Huntly Unit 5		
Fuel type(s)		Coal/gas			Gas		
Calendar Year		**2022**	**2025**	**2030**	**2021**	**2025**	**2030**
Modelled capacity	MW	480	480	0	403	403	403
Modelled as "must-run"	MW	0	0	0	180	180	0
Heat Rate assumed	HHV	11,000	11,000	0	7,300	7,300	7,300
Fuel SRMC	$/MWh	$72	$62	$0	$118	$63	$67
Carbon SRMC	$/MWh	$60	$65	$0	$23	$25	$27
Variable O&M	$/MWh	$5	$5	$0	$5	$6	$6
Short run marginal cost (SRMC)	**$/MWh**	**$137**	**$132**	**$0**	**$146**	**$94**	**$100**
HT Model average revenue (GWAP)	$/MWh	$157	$156	$0	$136	$91	$125
Spot gross margin	$/MWh	$20	$24	$0	-$11	-$3	$25
HT model average output	**GWh**	**2,002**	**242**	**0**	**2,124**	**2,349**	**797**
HT model average output	**MW**	**229**	**28**	**0**	**242**	**268**	**91**
HT model output capacity factor	**%**	**48%**	**6%**	**0%**	**60%**	**67%**	**23%**
Average gross margin vs SRMC	**$mn**	**$41mn**	**$6mn**	**$0mn**	**-$23mn**	**-$6mn**	**$20mn**
Fuel contracts in-the-money	$mn	$0mn	$0mn	$0mn	$134mn	$0mn	$0mn
Annual fixed cost	$mn	$20mn	$20mn	$20mn	$13mn	$13mn	$13mn
Approx. revenue adequacy/(shortfall)	**$mn**	**$21mn**	**-$14mn**	**-$20mn**	**$99mn**	**-$18mn**	**$8mn**

Source: Jarden estimates

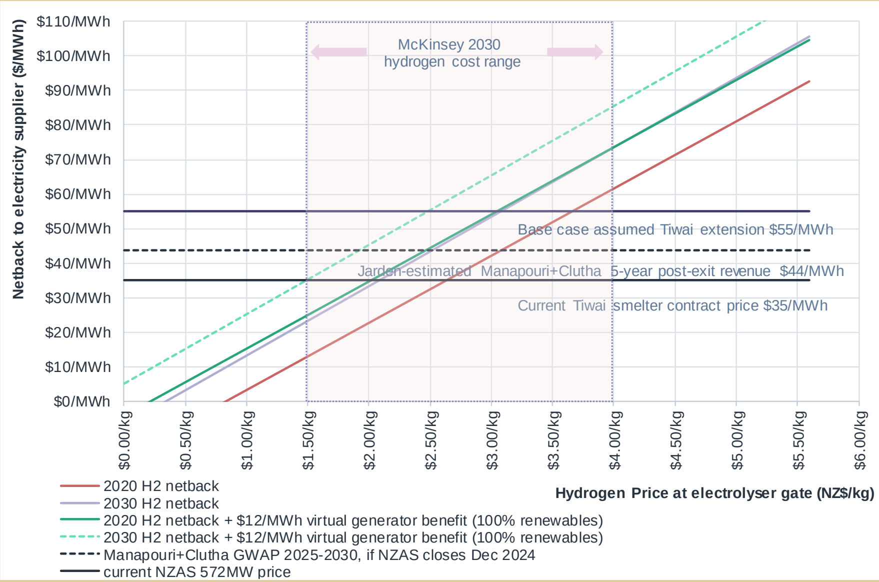
New-to-market loads

The largest new-to-market load increments are likely those being pursued by CEN & MEL in Southland, though we note that CEN is also working to secure electrification at other sites in NZ. We would be surprised if the other parties weren't also in discussions with prospective electrification customers. We expect ~1.5TWhpa of new Southland load to arrive by middle of the decade (which includes a proposed ~100MW baseload data center and a number of smaller industrial boiler conversions)

Most of these demand stimulation efforts will be gradual/marginal. The two key "lumpy" exceptions seem likely to be large-scale dairy factory electrifications (up to ~4TWhpa) and large-scale hydrogen electrolyser plants (currently ~750-850MW proposed). While dairy factory electrification remains a possibility, it seems that biomass conversion is the early preferred option by dairy operators. We expect offers for electricity supply (presumably at relatively cheap prices) have been made to the largest Southland dairy factories as part of MEL & CEN's efforts to replace Tiwai load. So far these haven't borne fruit, and it remains to be seen how much of the eventual dairy factory conversion eventually selects biomass over electrification. With that uncertainty over dairy owner's economics, we believe generators don't expect large dairy electrification "lumps" until next decade.

In theory a Southern Green Hydrogen project could serve as a drop-in replacement for Tiwai load. We expect any final proposal to be more sophisticated than that, but it will almost certainly be "lumpy". Whether hydrogen appears this decade will depend on the prices and load flexibility offered by prospective hydrogen buyers (we estimate a ~$45 to $55/MWh breakeven revenue for the electricity supplier) relative to Tiwai's offered prices and any flexibility enhancements the smelter can offer (current flexibility is very low).

Netback from hydrogen price, vs current NZAS price and alternatives



Source: Jarden estimates

Large scale demand response

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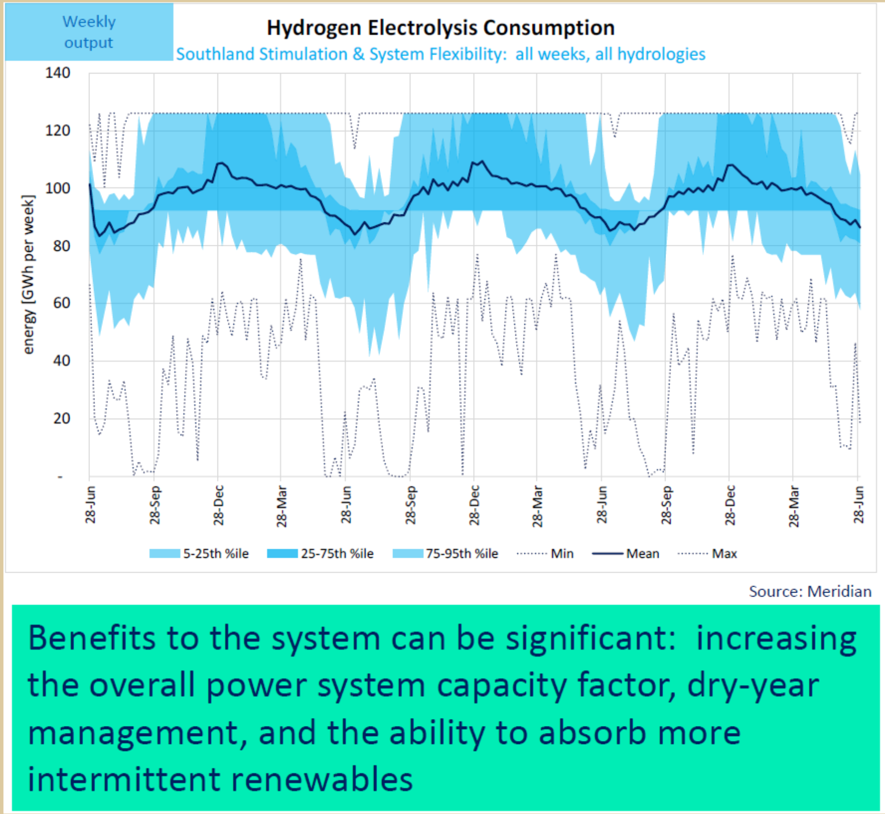
We would argue that dispatch of offered demand response will be a key element of price discovery under 100% renewables. Though it's clear that many customers will not want to forego electricity at any price other than VOLL, there may be fairly large quantities of electrical heating (restoring ripple control scale?), EV charging and industrial loads that can offer voluntary flexibility at prices below VOLL and so will add shape to price discovery. No doubt these appear within the MDAG modelling streams.

Yet hydrogen presents the only "lumpy" demand response option of which we are aware. It would be premature to describe this as real option until further discussions with hydrogen buyers have occurred, but MEL & CEN have both flagged this potential for investors, and are actively pursuing the opportunity. A number of observers and promotors have suggested hydrogen storage, but the round trip efficiency losses are large. Incurring such losses is unnecessary – just calling for reduced production would be far more effective option, akin to calling on flexible fuel for thermal firming. We understand hydrogen electrolysers are able to offer similar ramp rates to thermal plant. By 2030 McKinsey forecasts electrolyser capital costs to fall from ~NZ$1.3mn/MW to ~$0.4mn/MW, cheaper than a thermal peaker at >$1mn/MW.

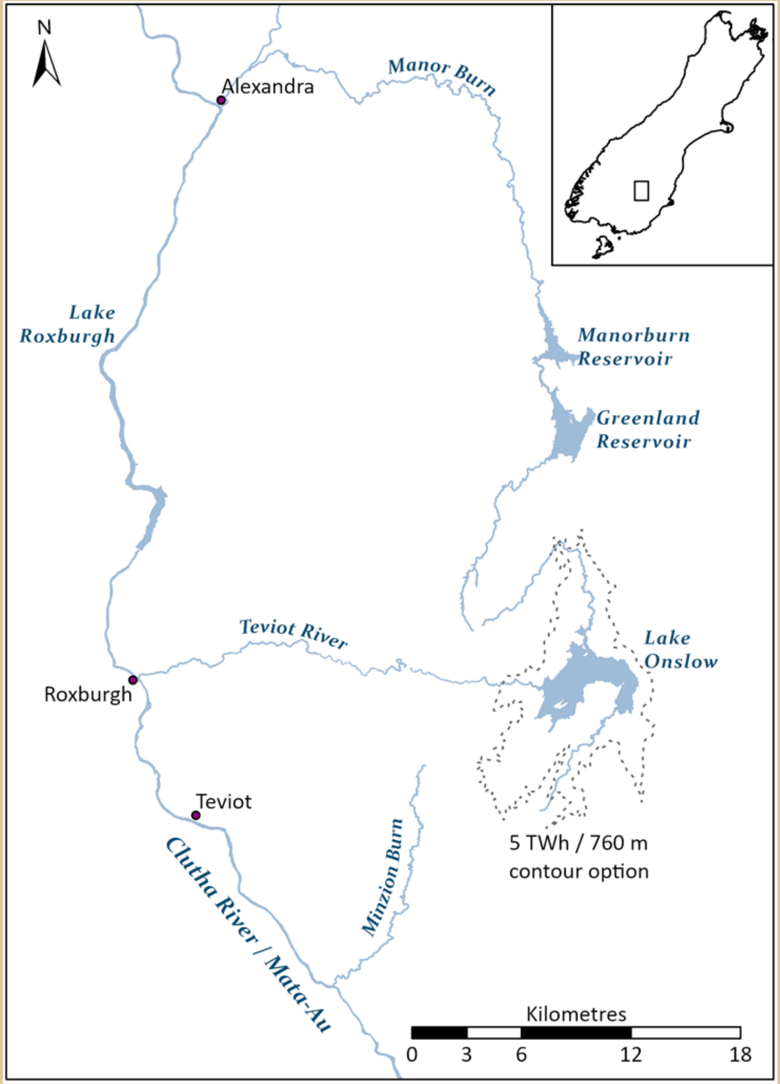


Source: Meridian Energy investor day 2021

Lake Onslow

Even though Lake Onslow is currently just one option under investigation to secure a 100% renewables market, the existence of the project could weigh on investment decisions earlier this decade. In that sense it is "lumpy". New private renewables projects committed over the next few years may have to compete in a post-Onslow market, yet it's unclear how that scheme might be filled and operate, and when or if it will be built.

To our knowledge generators are not yet factoring Onslow uncertainty into their investment plans (likely attributing low probability and long construction timeframes). But it may be prudent for MDAG to consider how uncertainty over Onslow operation could be reduced. There is otherwise the unwanted risk that the "option value of waiting" becomes important for generator decisions, which would tend to delay introduction of new builds into the market.



Source: MBIE, LINZ

Large scale North Island battery reserves

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A 100% renewables transition requires both a sizeable investment in new renewables and increased reliance on transmission (particularly Southern hydro plants ability to offset wind variability). Transpower is already looking into strategic grid investment to cater to this need.

We wish to highlight the potentially "lumpy" need for North Island instantaneous reserves to enable northwards transfer on the HVDC above ~700MW. Provision of large scale reserves is likely to be a market-driven investment served by batteries (say 700MW of 30-minutes storage, likely to incur a capital cost of ~$700mn). We understand MEL/CEN have secured a North Island site for a battery, probably sized around 100MW. We would expect these to "trickle charge" and stand ready for discharge if dispatched to meet a SIR or FIR event, and therefore unlikely to cycle or generate much net revenue for their owners. MCY has also operated a battery at its former Southdown site, so a number of options already seem apparent.

Such investment will trade in the electricity market, but have grid security-like benefits that might significantly enhance competition across the grid. MDAG may wish to consider if the TPM & market design will correctly support such projects, if modelling indicates they may be efficient.

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