Market Operations Weekly Report - Week Ended 12 April 2026

Overview

New Zealand hydro storage has increased from 102% to 104% of the historic mean for this time of year. Renewable generation was 90% of the weekly generation mix, which is less than the mean of the last 12 months of 92%.

This week's insight looks at high nodal price and separation in Southland region.

Security of Supply

Energy

National hydro storage has increased to 104% of the seasonal mean at the end of last week. South Island hydro storage increased from 96% to 98% of the historic mean, and North Island storage increased from 185% to 196%.

Capacity

Residuals were healthy with the lowest residual of 1402 MW occurring during the morning of Friday 10 April. Residuals were above 1000 MW throughout the week.

The N-1-G margins in the NZGB forecast are healthy through to end of May. Within seven days we monitor these more closely through the market schedules. The latest NZGB report is available on the NZGB website.

Electricity Market Commentary

Weekly Demand

Total demand increased from 710 GWh to 719 GWh for the week, slightly below the average demand at this time of year over the past three years. The highest demand peak of 5,387 MW occurred at 6:00pm on Tuesday 7 April.

Weekly Prices

The average wholesale electricity spot price at Ōtāhuhu last week was $112/MWh, decreasing from $148/MWh the week prior. Wholesale prices peaked at $276/MWh at Ōtāhuhu at 3:30pm on Wednesday 8 April.

Generation Mix

Wind generation increased from 7% to 10% of the mix. Hydro generation decreased to 52% of the mix, from 54% the week prior. Thermal generation decreased to 8% which is below its yearly average of 9% of the mix. Geothermal increased from 25% to 26% of the mix and solar contributed to 0.7% of the generation mix.

HVDC

HVDC flow last week was predominantly northward with the exception of some brief periods of overnight low southward flow. These periods coincided with periods of high wind generation and lower North Island demand. In total, 43 GWh was transferred north and 22 GWh was transferred south.

Surveys and Engagement

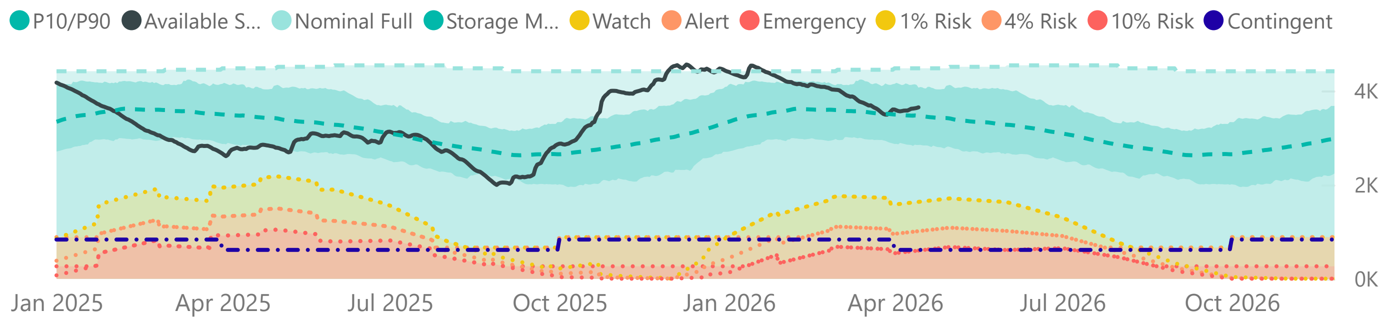
We have opened our Annual System Operator Participant Survey to provide an opportunity for participants to set out their expectations and help us understand how we are performing the System Operator service. If you have not received the survey but would like to have your say, you can complete it here. The survey closes 17 April 2026.

New Zealand Energy Risk

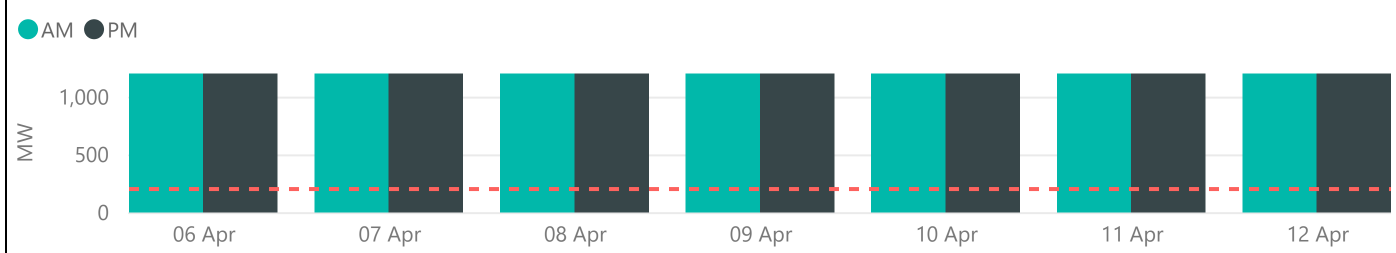
South Island Energy Risk

Normal Watch Alert Emergency

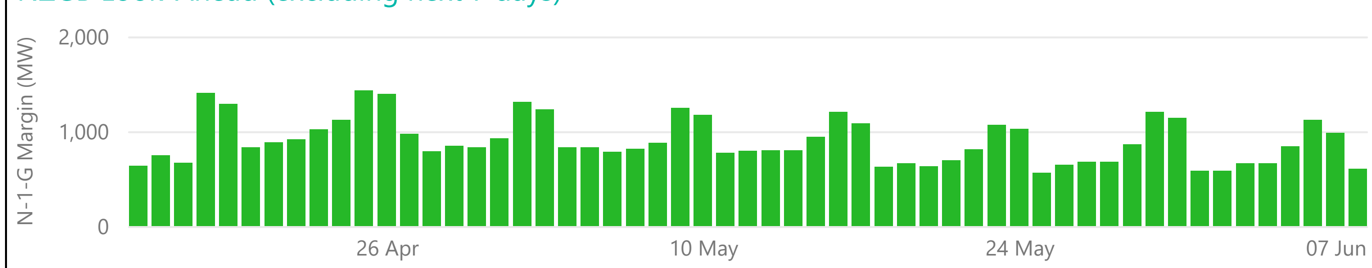
New Zealand Electricity Risk Status Curves (Available GWh)



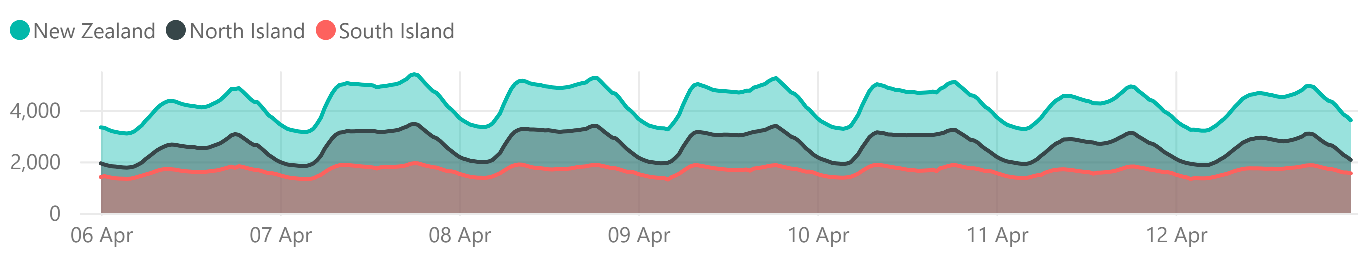
Lowest Residual Points - MW



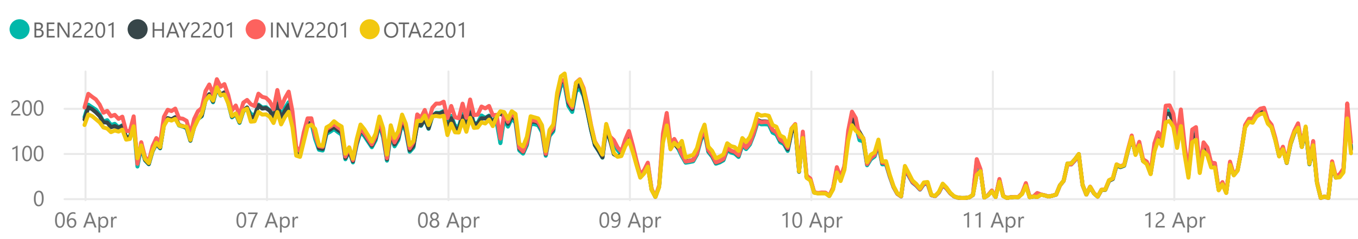
NZGB Look-Ahead (excluding next 7 days)



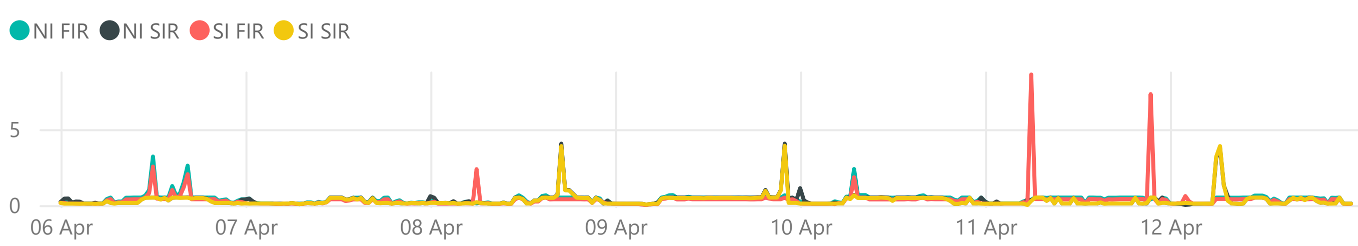
National Demand by Trading period - MW



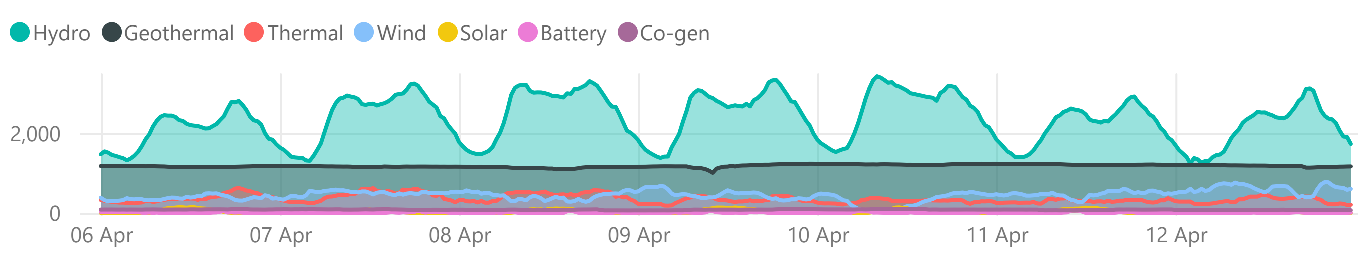
Energy Prices - $/MWh



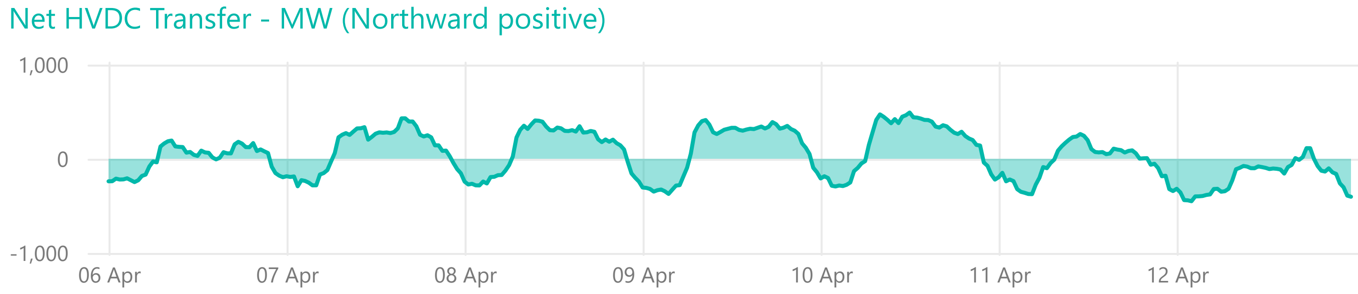
Reserve Prices - $/MW



Generation - MW



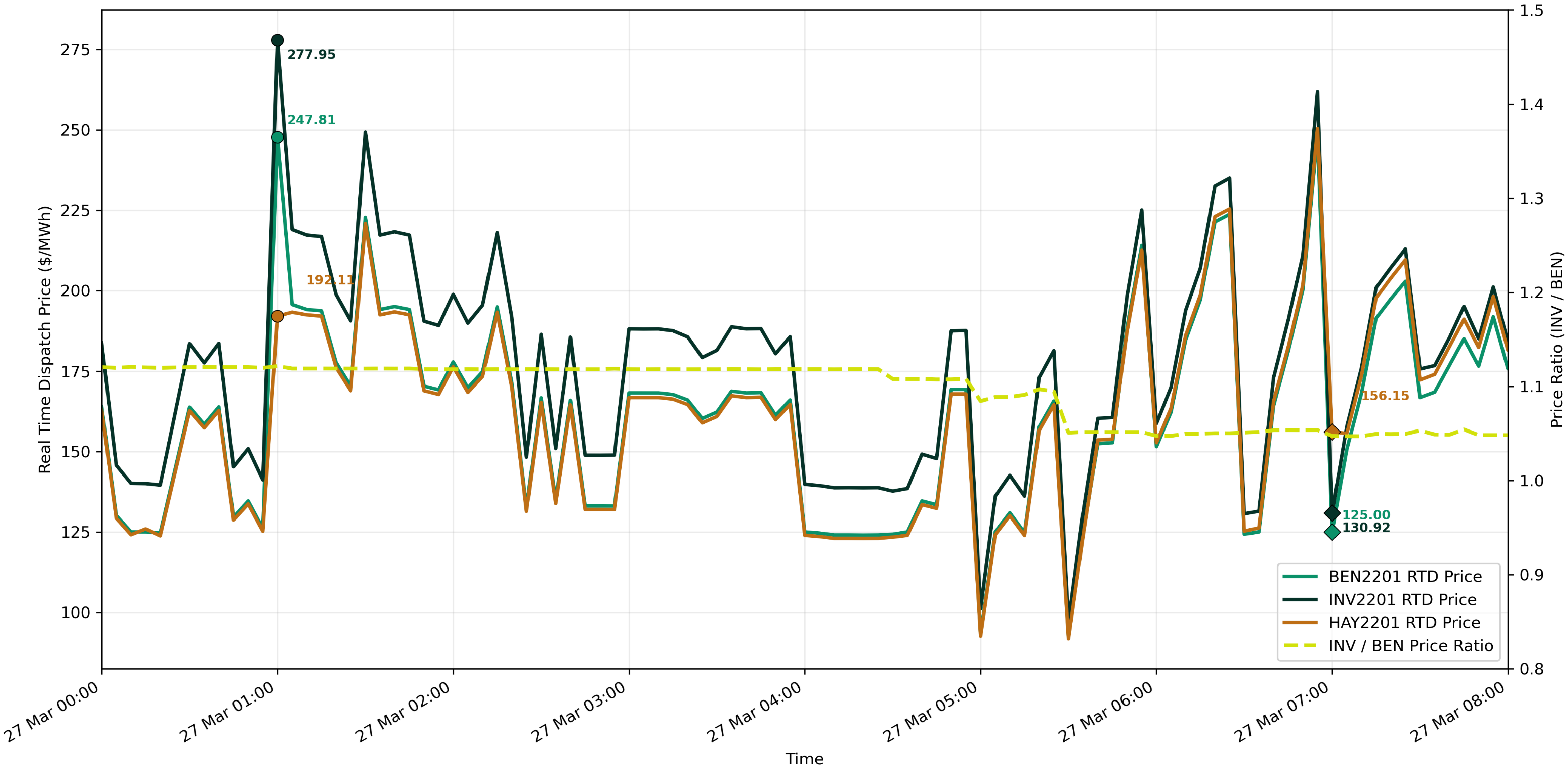
Net HVDC Transfer - MW (Northward positive)



Weekly Insight - High nodal price and separation in Southland region

On 27 March, nodal price separation was observed between the lower South Island and the rest of the grid. The real time dispatch (RTD) price at Invercargill (INV2201) peaked at $278/MWh, which was the highest RTD price on the national network for that week. For a lower South Island node to set the national peak is unusual. Analysis of market outcomes confirms this event was not driven by intra-island transmission constraints, but rather by losses with high Southward flow on the South Island network between Benmore and Invercargill.

As highlighted in figure 1, dispatch prices at Invercargill (INV2201) cleared at $277.95/MWh for the first dispatch of the 01:00 trading period. This represents an approximate $30/MWh separation from the Benmore (BEN2201) reference node, which cleared at $247.81/MWh. With hydro storage in the Waiau and Clutha catchments below average and declining, Clyde and Manapōuri offered only low volumes of generation at lower prices, pricing the remainder of their available generation above $300/MWh. Lower than usual generation in the lower South Island required higher southward flow between Benmore and Invercargill to meet local Southland demand. The INV/BEN price ratio was relatively constant and close to 1.12. This stable and relatively low ratio indicates marginal loss effects were the main causes of price separation between Southland and lower priced nodes in the South Island. We've confirmed this with no intra-island transmission constraints binding during this time. Later in the day, as Clyde and Manapōuri increased their low-priced offer volumes, this southward flow reduced. This resulted in lower transmission losses and thereby lowering the INV/BEN price ratio.



With local Southland transmission limits ruled out, the elevated SI prices were fundamentally driven by inter-island ramp rate constraint. During the 01:00 AM interval, the North and South Islands' prices separated. The North Island marginal price cleared at $180/MWh (set by Tongariro hydro). However, the South Island cleared significantly higher at $250/MWh, with marginal energy set by Waitaki hydro units (Ohau B and Tekapo).

Time	Binding Constraint	Shadow Price	South Island (BEN)	North Island (HAY)	Price Spread (BEN - HAY)
1:00 a.m.	DCSmax (South Island)	$53.41	$247.81	$192.11	$55.7
7:00 a.m.	DCNmax (North Island)	$26.18	$125	$156.15	-$31.15

This $55.70/MWh inter-island spread was directly caused by the South Island constraint (DCSmax) binding on HVDC ramp rate limit. Rather than hitting an absolute capacity ceiling, the system was restricted by how fast the HVDC link could increase its southward flow. The ramp limit prevented the North Island from pushing more cheap energy south quickly enough to meet the shifting demand. Consequently, the South Island was forced to dispatch more expensive local hydro capacity to balance the system. The shadow price of this HVDC constraint was $53.41/MWh, mathematically defining the cost of this constraint to the system.

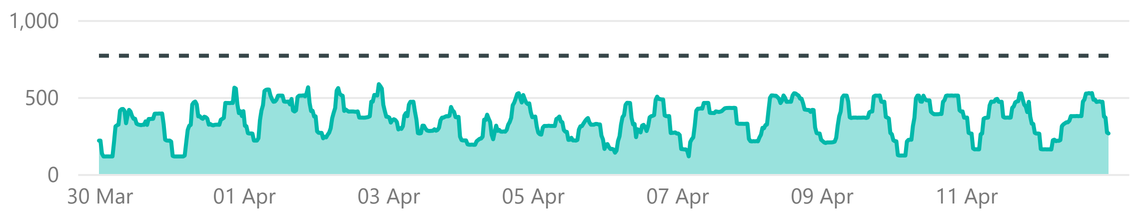
This same constraint dynamic drove a complete market reversal at the 07:00 AM morning peak. As the morning load ramped, the system dynamics inverted and the DCNmax constraint (the HVDC northward transfer limit) began to bind . Just like the overnight event, DCNmax bound on a ramp rate limit rather than thermal capacity. The North Island was therefore forced to clear more expensive local generation, the net effect being Haywards prices spiking above Benmore.

These pricing outcomes demonstrate the importance and benefits of nodal pricing in converting constraints on the power system to actionable incentives for the market. Fast-responding assets like utility-scale BESS are uniquely positioned to capture these granular price spreads through energy arbitrage. By discharging during constrained peaks and charging during periods of local surplus, these assets not only capture significant commercial value but inherently act to reduce the transmission constraints.

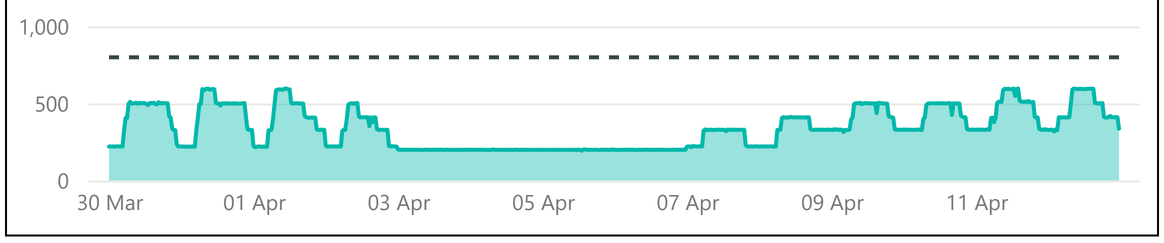
Generation Breakdown - Last Two Weeks

Measured in MW and displayed at trading period level for last 14 days

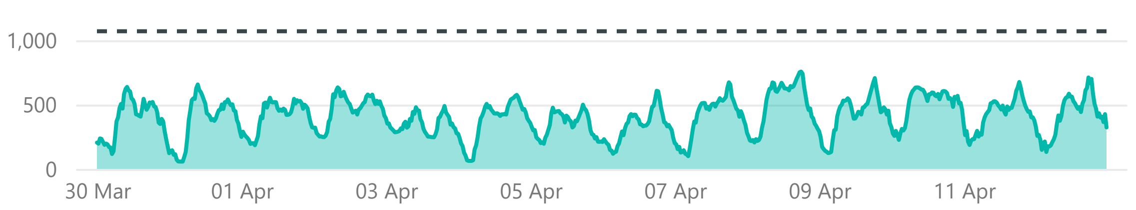
Clutha



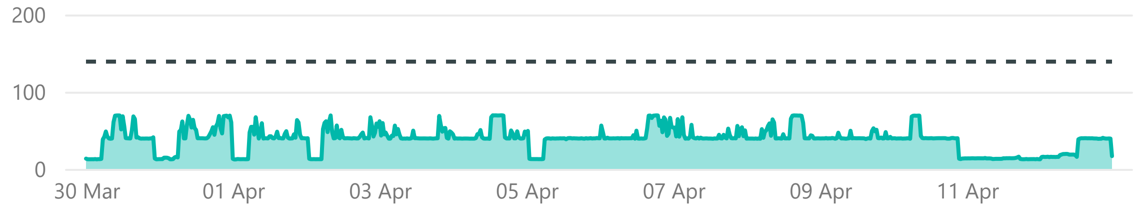
Manapouri



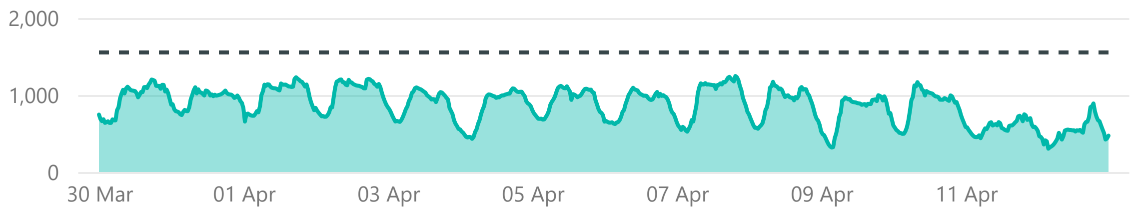
Waikato



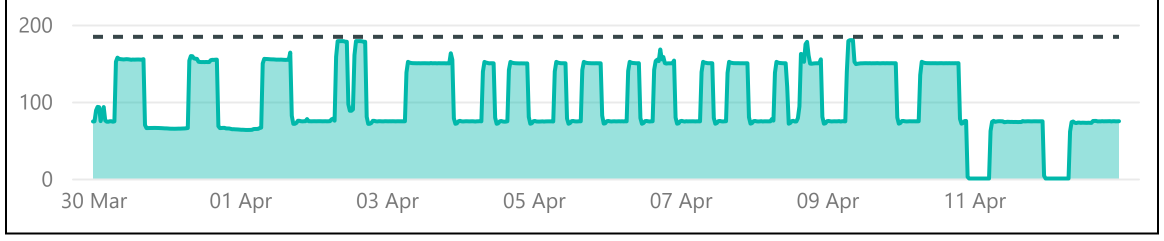
Waikaremoana



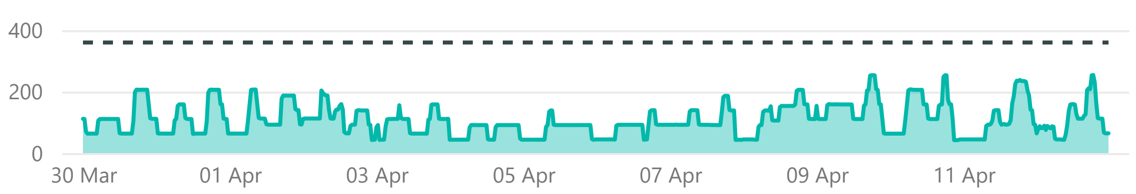
Waitaki



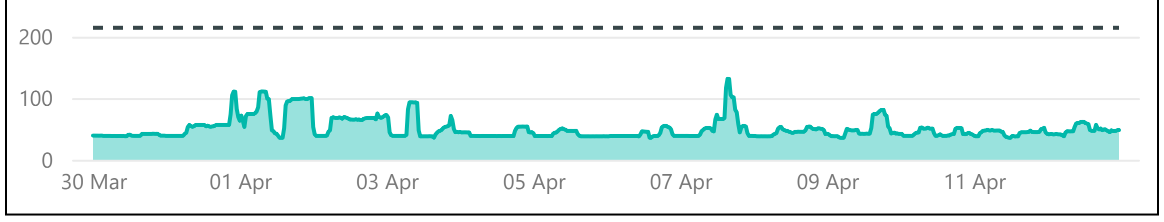
Tekapo



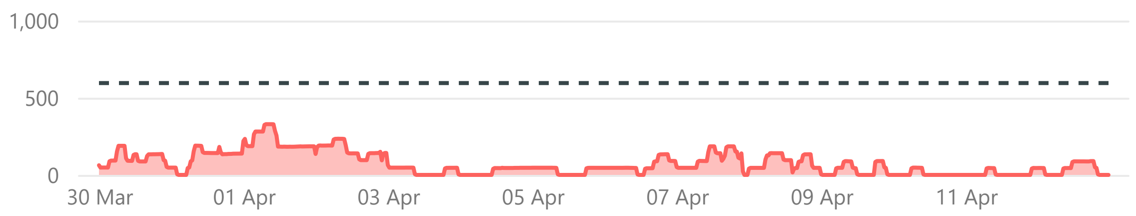
Tongariro



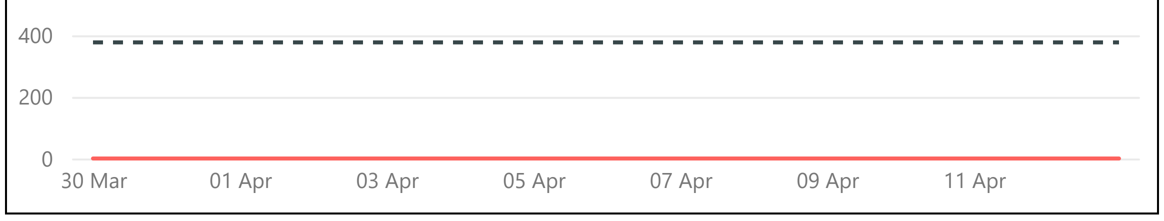
Other SI Hydro



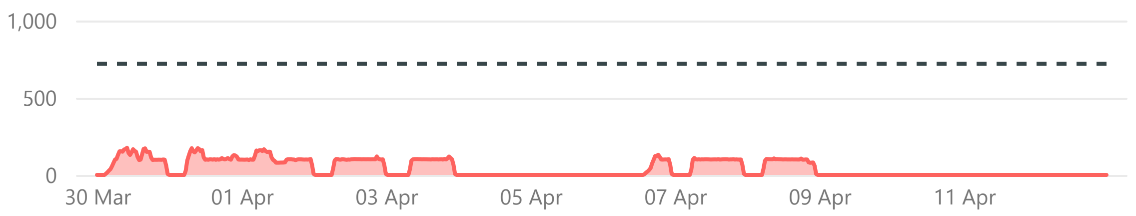
Thermal Peaking Plant



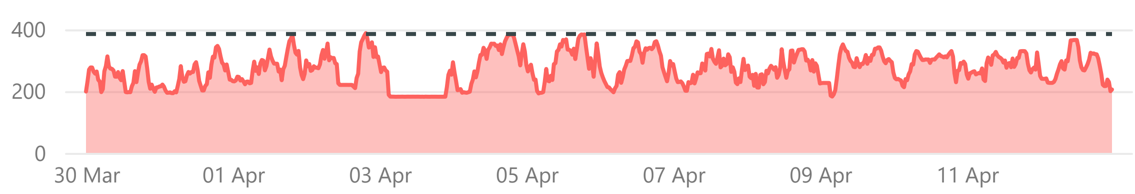
Stratford TCC



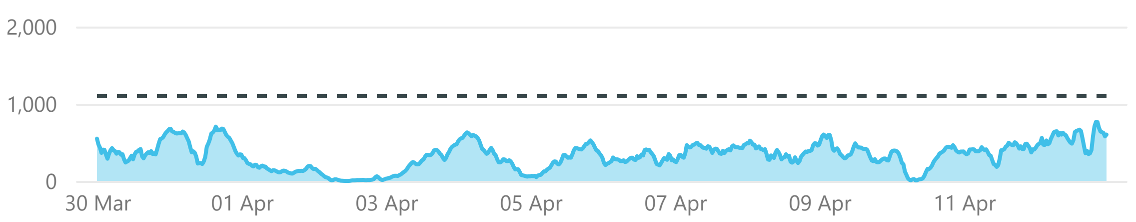
Huntly Rankines



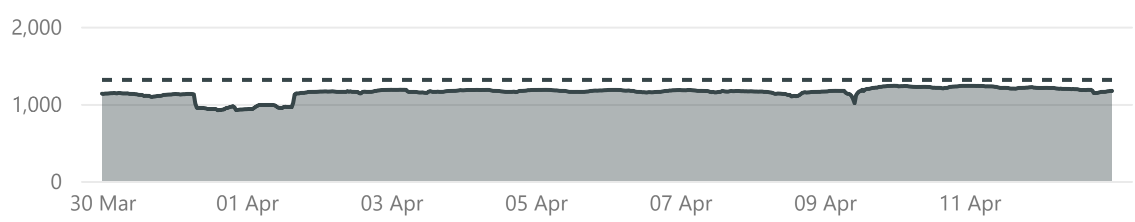
Huntly U5



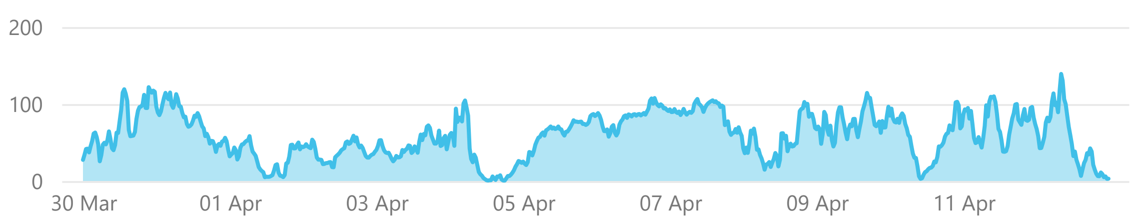
North Island Wind



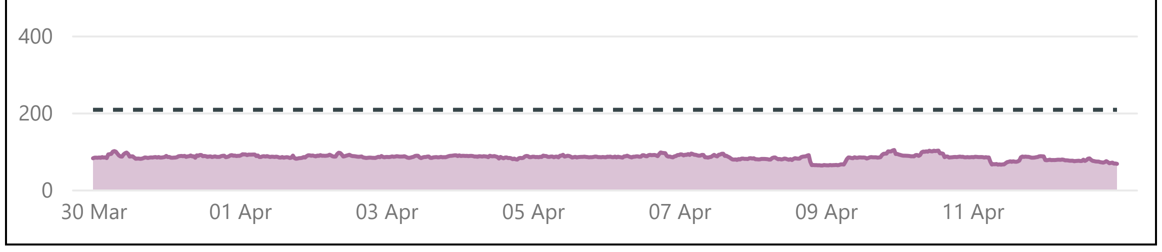
Geothermal



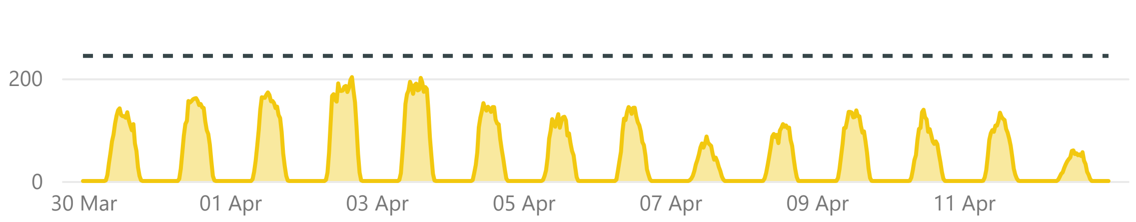
South Island Wind



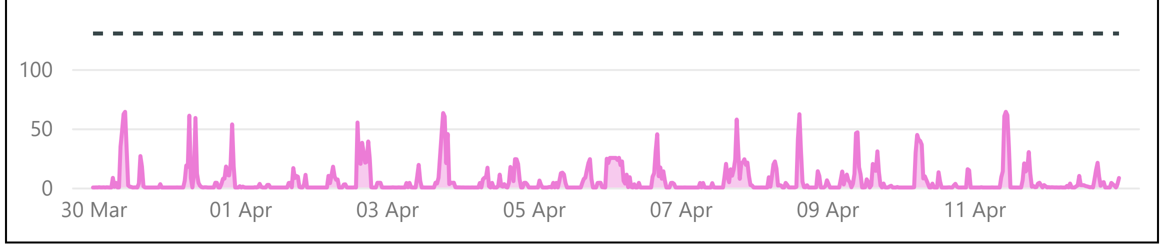
Co-Generation



Solar

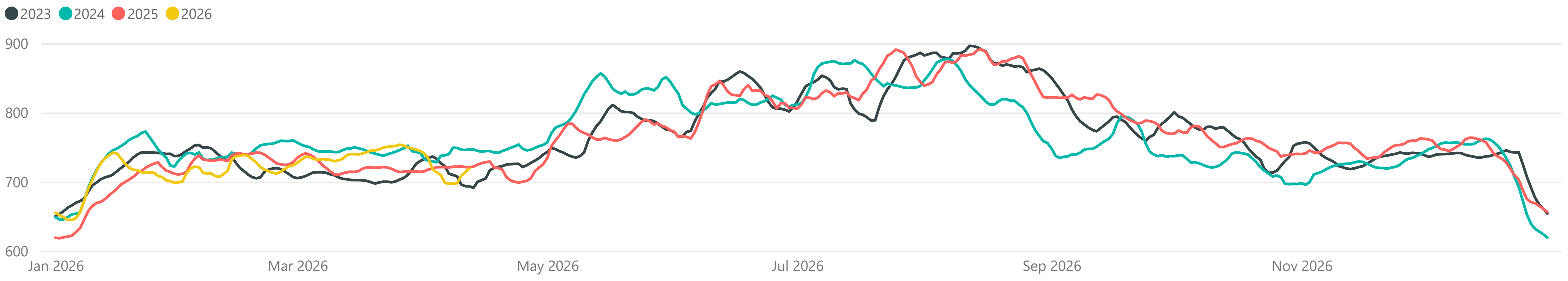


BESS

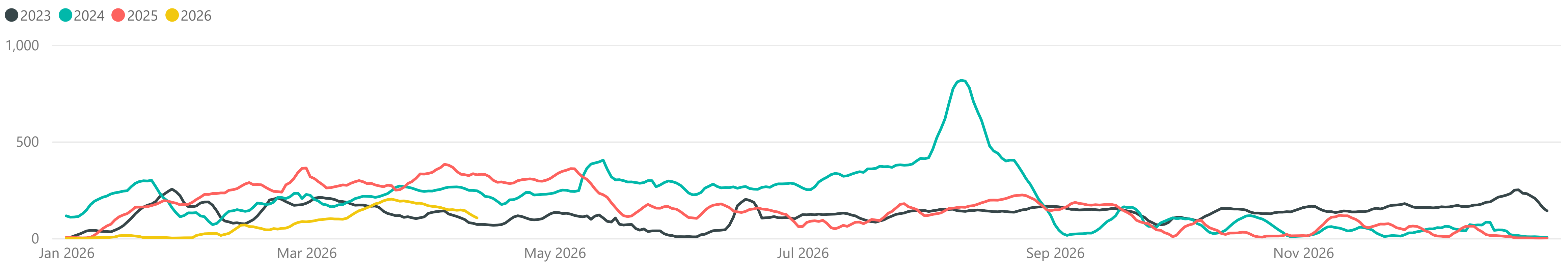


Weekly Profiles

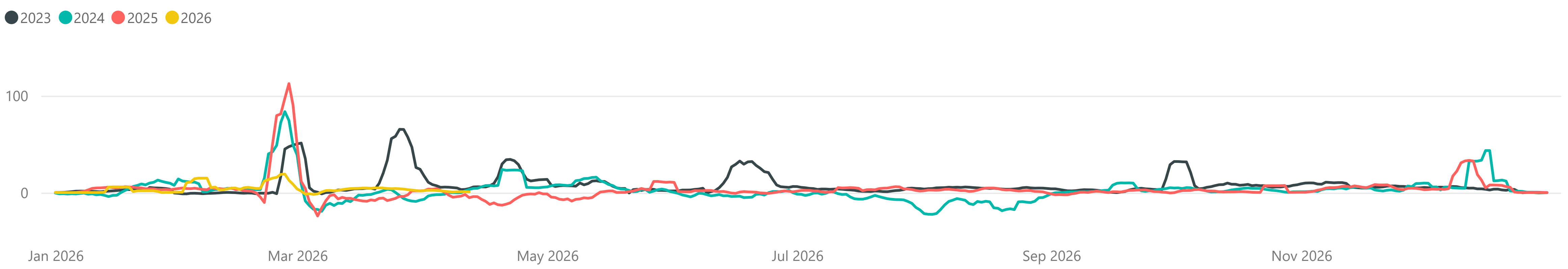
National Weekly Demand - GWh - 7 Day Rolling



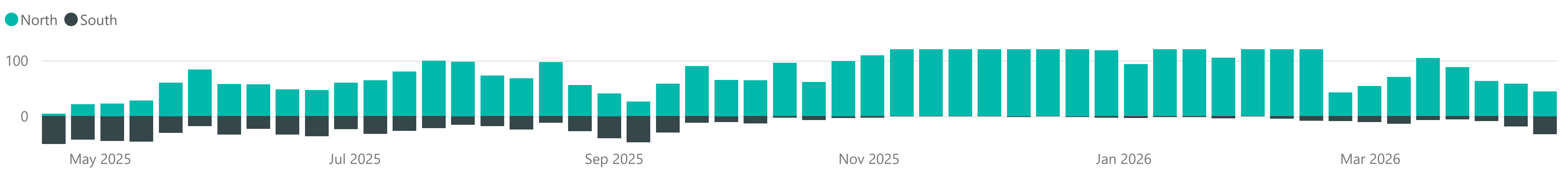
OTA2201 Weekly Rolling Average Spot Price - $/MWh



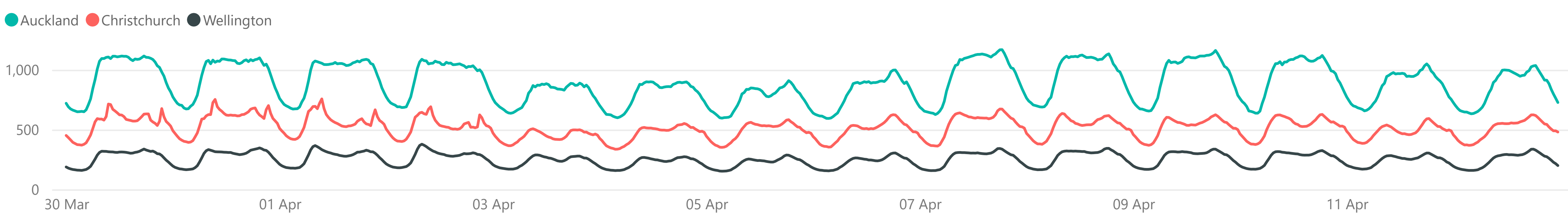
Weekly Rolling Price Separation (HAY2201 - BEN2201) - $/MWh



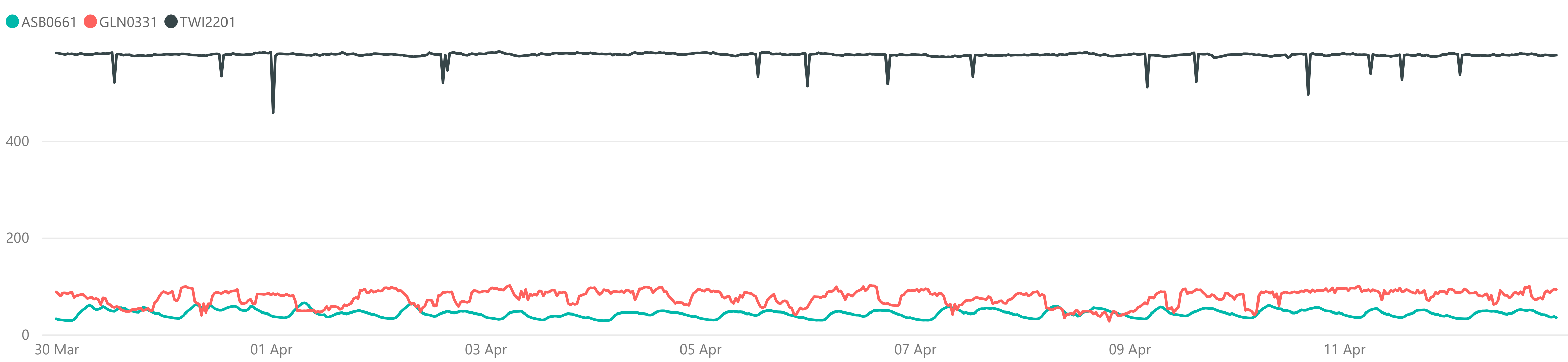
HVDC Transfer - Weekly GWh



Conforming Load Profiles - Last Two Weeks *Measured in MW shown by region*

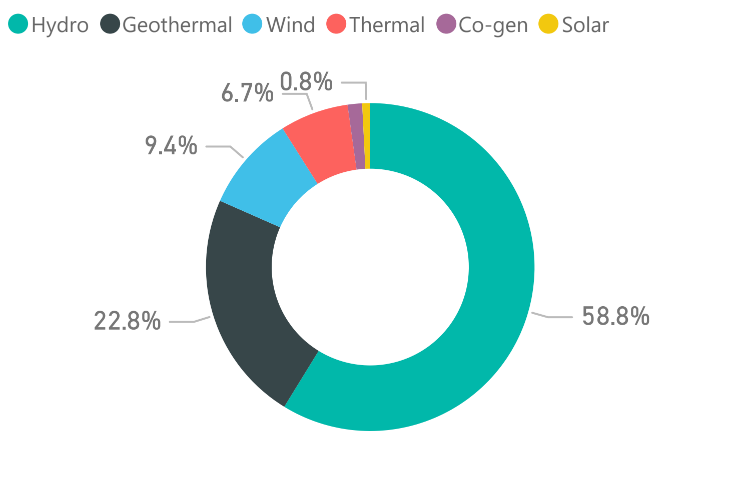


Non-Conforming Load Profiles - Last Two Weeks *Measured in MW shown by GXP*

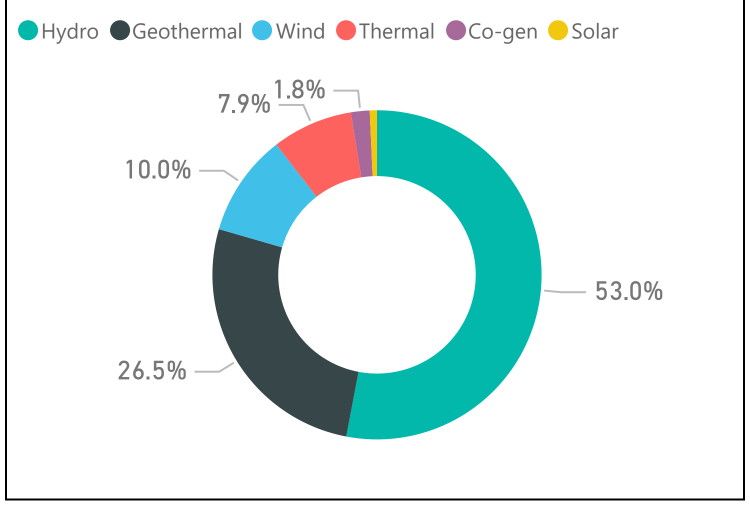


Generation Mix

Last 52 Weeks Generation Mix - Weekly GWh



Last 7 Days Generation Mix - Weekly GWh



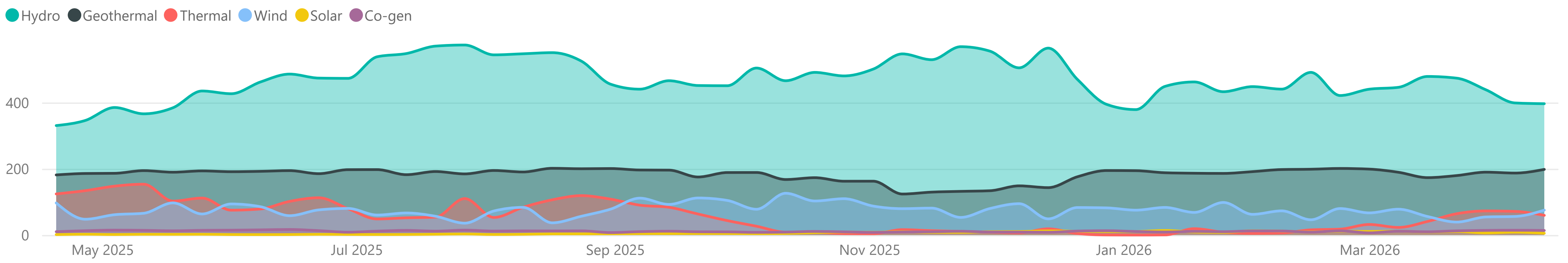
Average Metrics Last 7 Days

Renewable Percentage	CO2e Tonnes/Week	CO2e g/kWh
90%	48,737	64.7

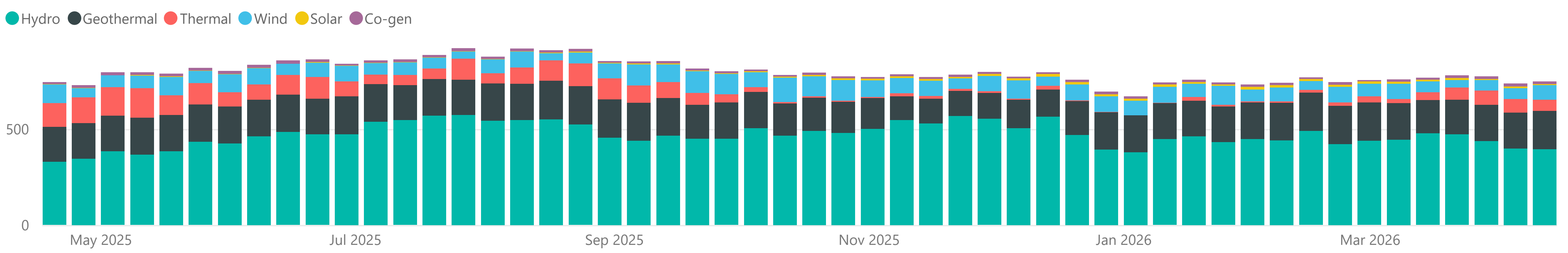
Average Metrics Last 52 Weeks

Renewable Percentage	CO2e Tonnes/Week	CO2e g/kWh
92%	49,111	60.4

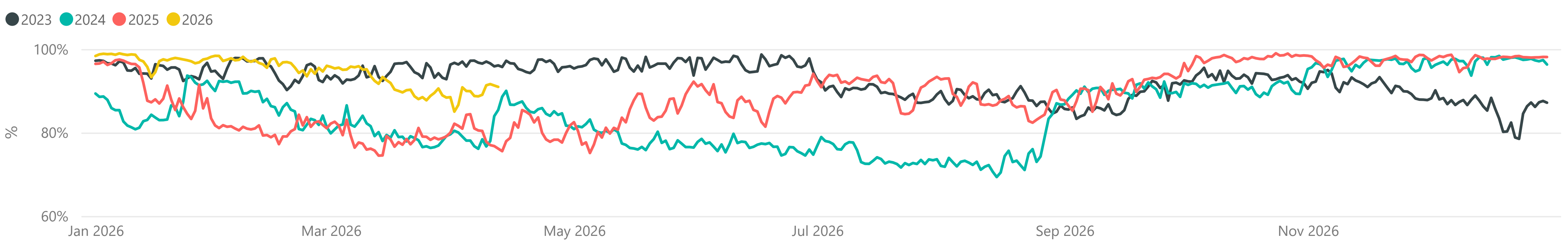
Weekly Generation Mix - GWh



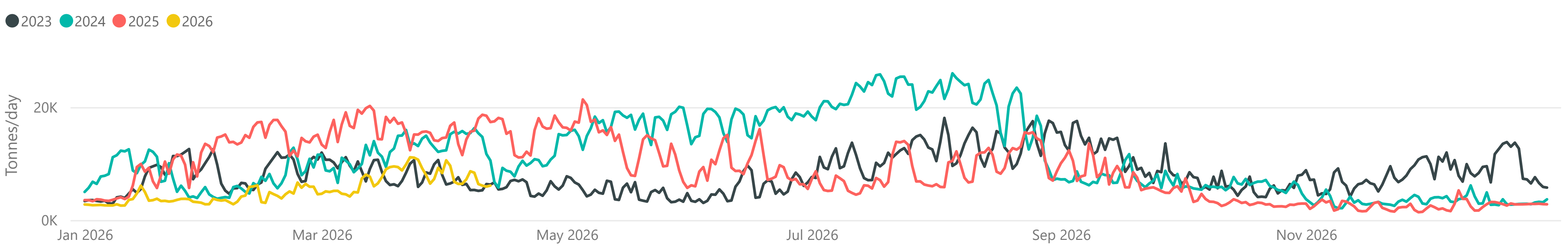
Weekly Generation Mix - GWh



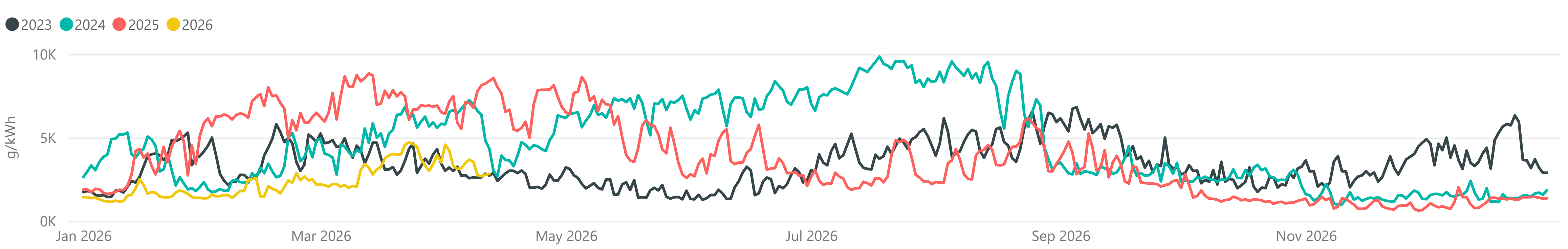
NZ Renewable Percentage



CO2 Tonnes/Day

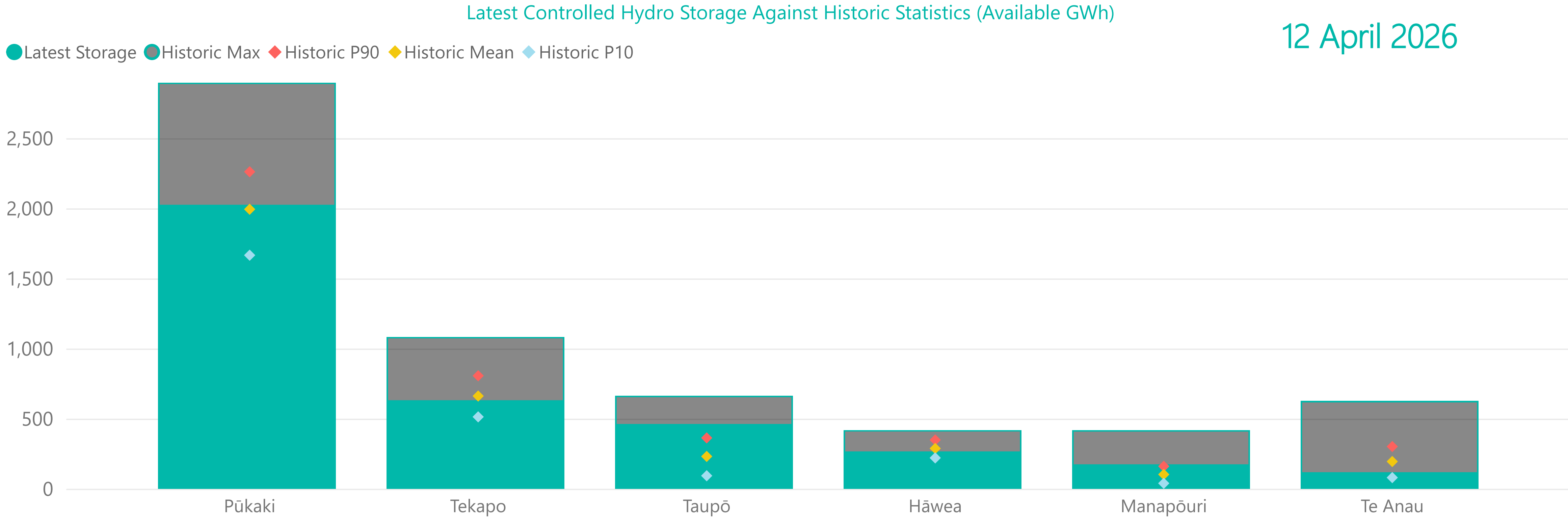


CO2 g/kWh

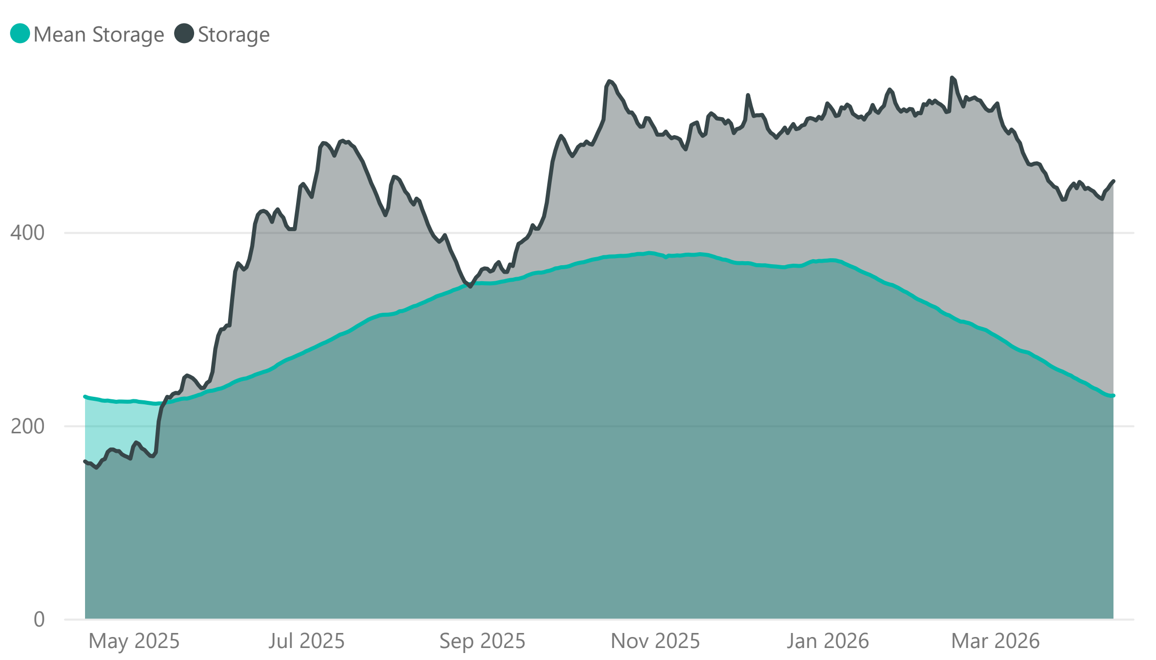


Hydro Storage

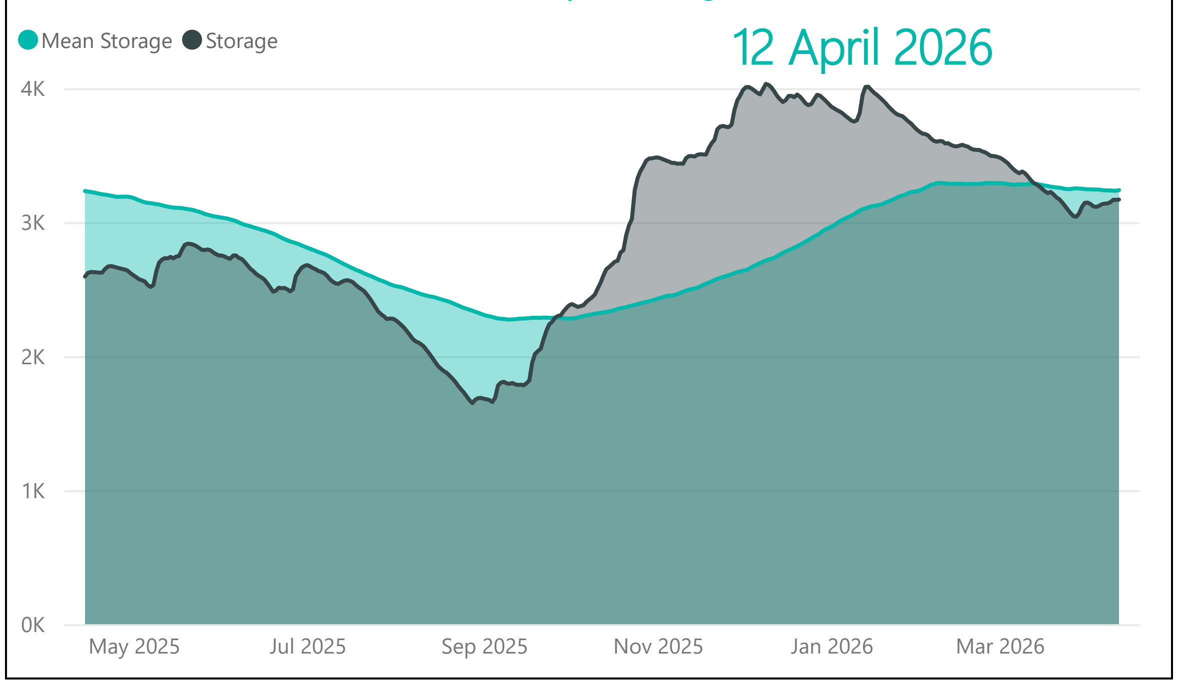
Latest Controlled Hydro Storage Against Historic Statistics (Available GWh)



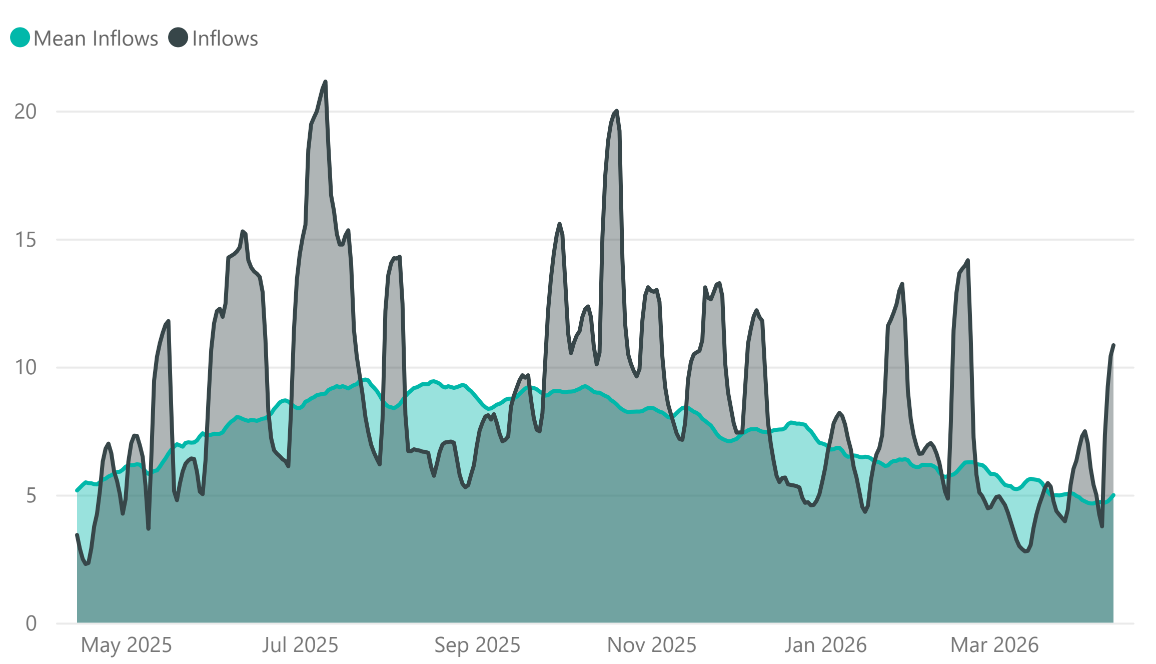
North Island Controlled Hydro Storage (Available GWh)



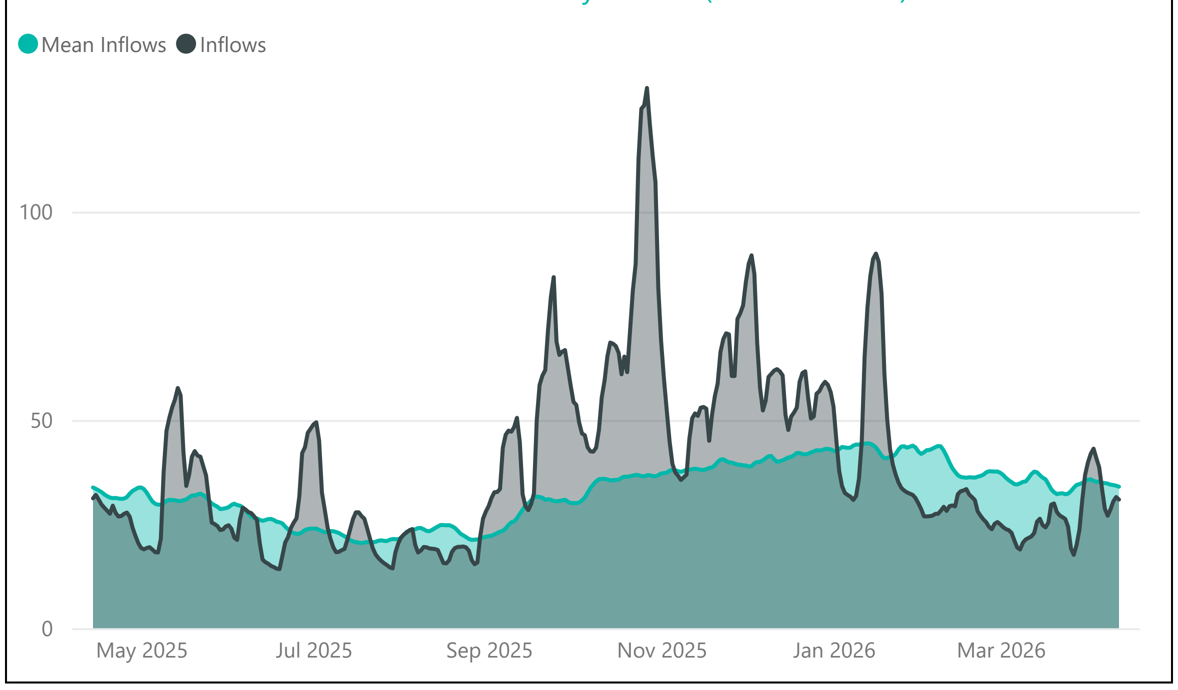
South Island Controlled Hydro Storage (Available GWh)



North Island Mean 7 Day Inflows (Available GWh)



South Island Mean 7 Day Inflows (Available GWh)



For further information on security of supply and Transpower's responsibilities as the System Operator, refer to our webpage here: https://www.transpower.co.nz/system-operator/security-supply

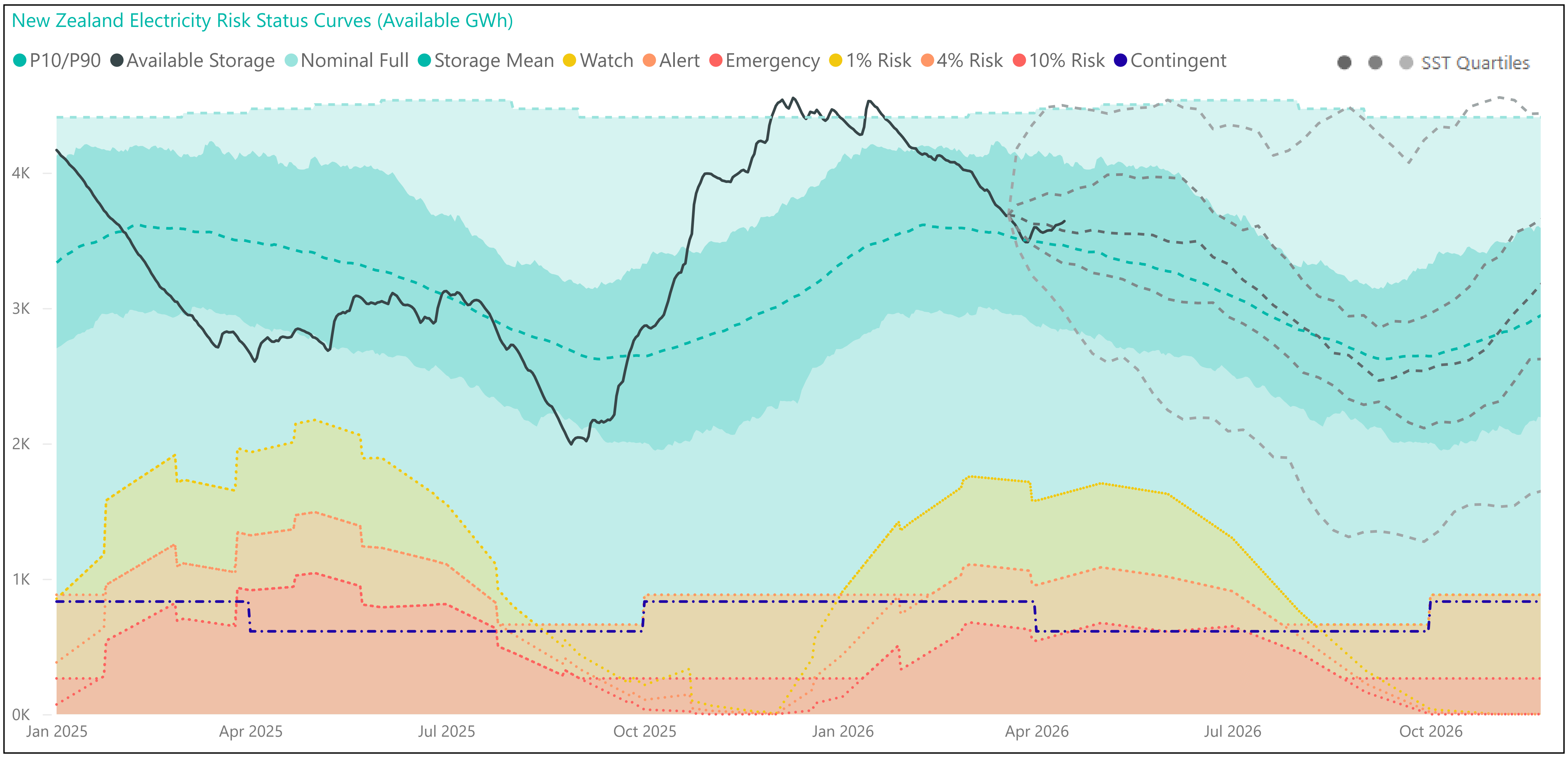
For any inquiries related to security of supply contact market.operations@transpower.co.nz

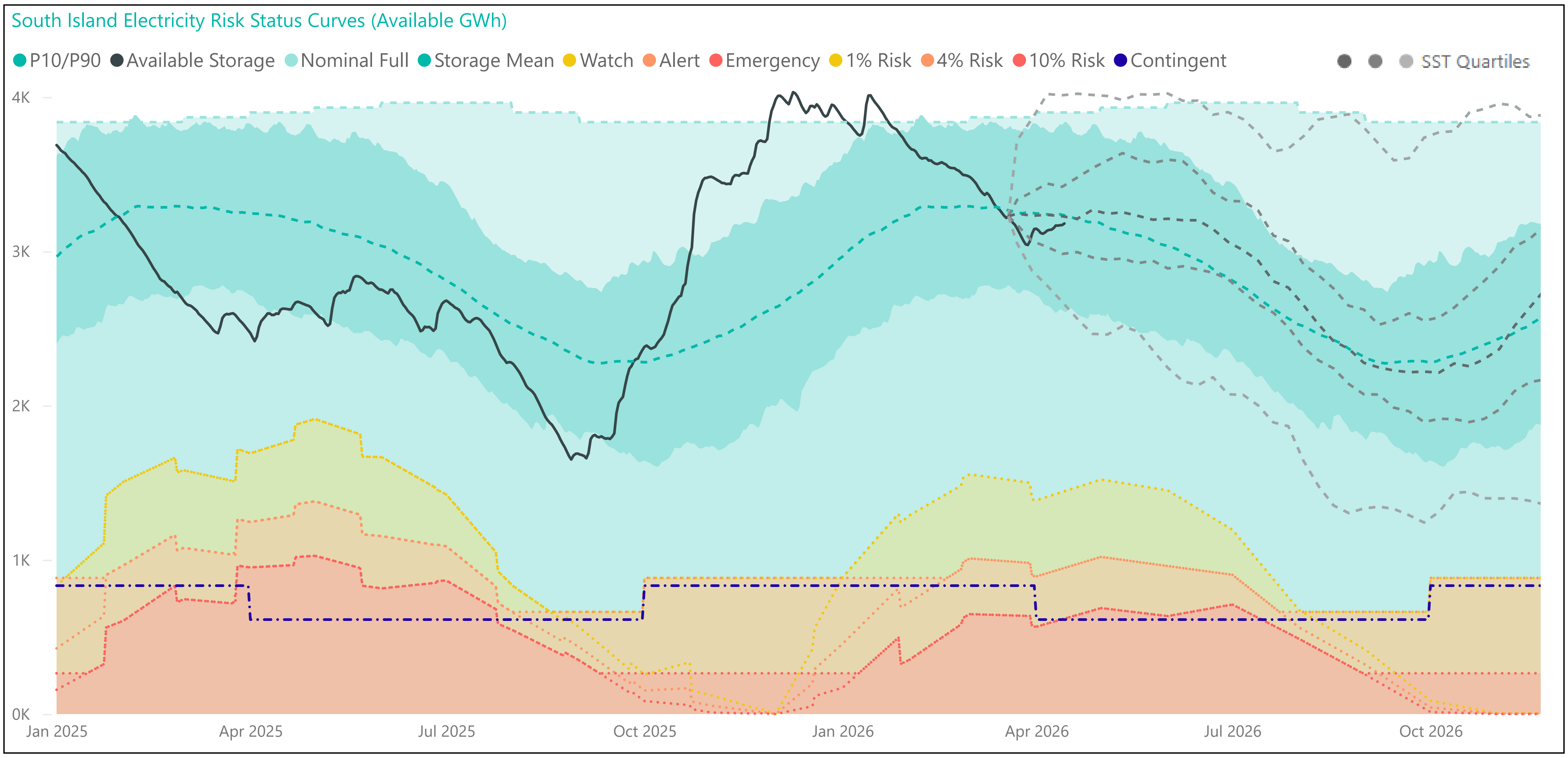
Hydro data used in this report is sourced from *NZX Hydro*.

Electricity risk curves have been developed for the purposes of reflecting the risk of extended energy shortages in a straightforward way, using a standardised set of assumptions.

Further information on the methodology of modelling electricity risk curves may be found here: https://www.transpower.co.nz/system-operator/security-supply/hydro-risk-curves-explanation

Electricity Risk Curves





Electricity Risk Curve Explanation:

Watch Curve - The maximum of the one percent risk curve and the floor and buffer
Alert Curve - The maximum of the four percent risk curve and the floor and buffer
Emergency Curve - The maximum of the 10 percent risk curve and the floor and buffer
Official Conservation Campaign Start - The Emergency Curve
Official Conservation Campaign Stop - The maximum of the eight percent risk curve and the floor and buffer

Note: The floor is equal to the amount of contingent hydro storage that is linked to the specific electricity risk curve, plus the amount of contingent hydro storage linked to electricity risk curves representing higher levels of risk of future shortage, if any. The buffer is 50 GWh.

The dashed grey lines represent the minimum, lower quartile, median, upper quartile and the maximum range of the simulated storage trajectories (SSTs). These will be updated with each Electricity Risk Curve update (monthly).