Market Operations Weekly Report - Week Ended 19 July 2026

Overview

National hydro storage remains above average at 134% of the historic mean for this time of year. Residuals remained healthy despite low thermal commitment with demand well below the peaks seen in recent years. Wholesale prices were also at their lowest July levels in four years.

In this week's insight we look at what today's intermittent generation would have contributed to Aotearoa's highest demand peaks over the past five years.

Security of Supply

Energy

National hydro storage has increased to 134% of historic mean at the end of last week from 130% the week prior. South Island storage has increased from 128% to 135% and North Island storage decreased from 123% to 120%. Storage levels remain well above average across both islands, supported by above-average inflows into South Island hydro catchments during the week

Capacity

Residuals were healthy during morning and evening peaks last week. The lowest residual of 880 MW occurred during the morning of Monday 13th July.

The N-1-G margins in the NZGB forecast show tighter spots appearing as we are now in winter; we recommend the industry watch these closely. 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 decreased to 825 GWh last week from 864 GWh the week prior. The highest demand peak of 6,535 MW occurred at 8:30 am on Monday 13th July. This is well below record peaks in recent years of just over 7100 MW.

Weekly Prices

The average wholesale electricity spot price at Ōtāhuhu last week decreased to $20/MWh from $79/MWh the week prior. This is the lowest average price in July over the last four years. Wholesale prices peaked at $101/MWh at Ōtāhuhu at 8:30 am on Monday 13th July coinciding with lowest residual of the week.

Generation Mix

Wind generation increased to 13% of the generation mix from 7% the week prior. Hydro generation contributed 59%, slightly below its yearly average of 60%. Thermal generation decreased to 1% of the mix last week inline with abundant renewable generation. Geothermal generation slightly increased to 25% last week, sitting just above its annual average of 23%.

HVDC

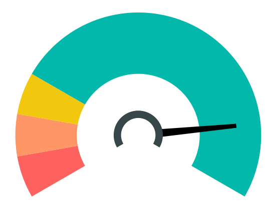
HVDC flows last week were predominantly northward with one brief period of southward flow during Saturday night. Overall, 195 GWh was transferred north, while 2 GWh was transferred south during the week. There was a period of inter-island energy and reserve price separation on Thursday 16 July with very high HVDC northward transfer (at times over 1000 MW) and the HVDC link setting the North Island risk.

Consultations and Engagement

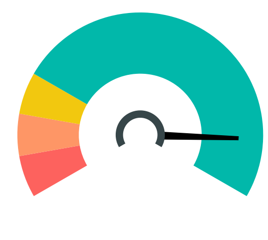
System Operator Strategy

Our Phase 2 Consultation for the development of a new System Operator Strategy is open. Responses are due by Friday 24 July 2026. The draft Strategy sets out our proposed direction for how the System Operator service will need to evolve over the next ten years to support a secure, reliable and efficient power system.

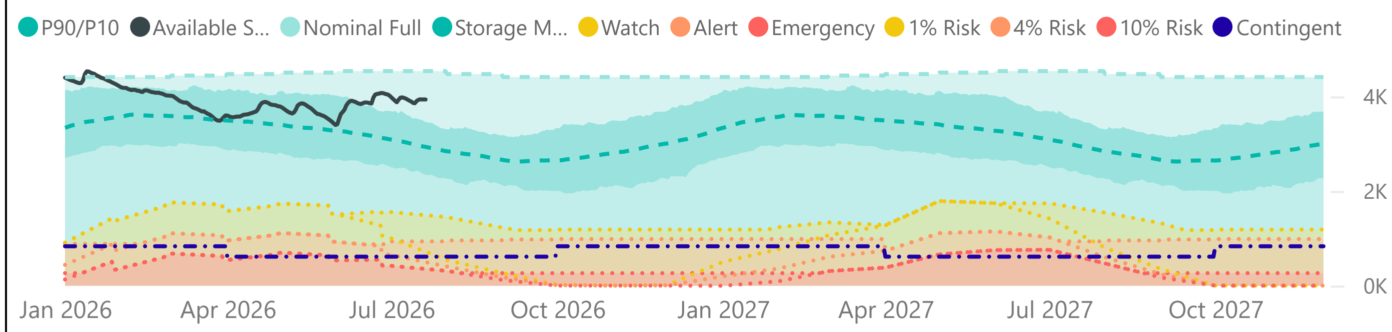
New Zealand Energy Risk



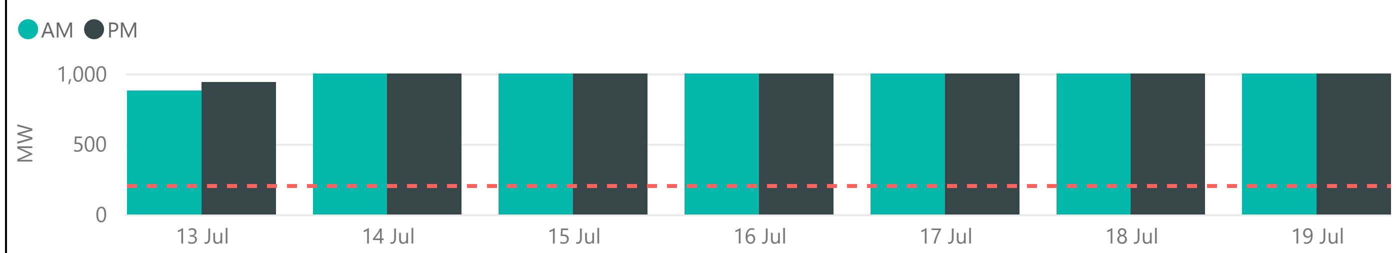
South Island Energy Risk



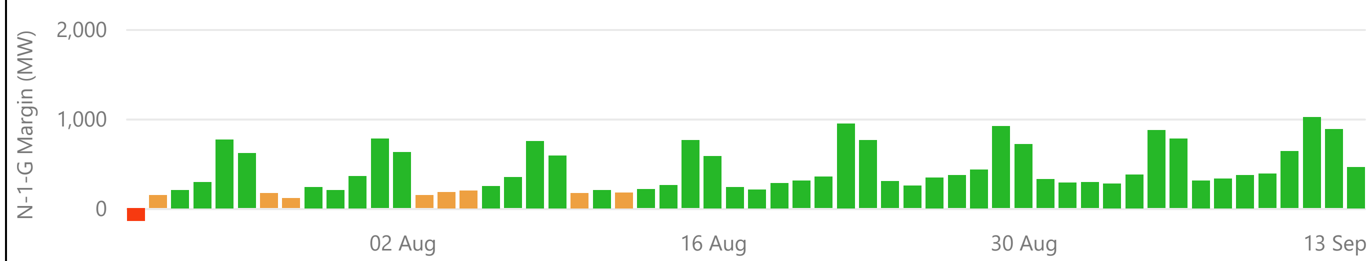
New Zealand Electricity Risk Status Curves (Available GWh)



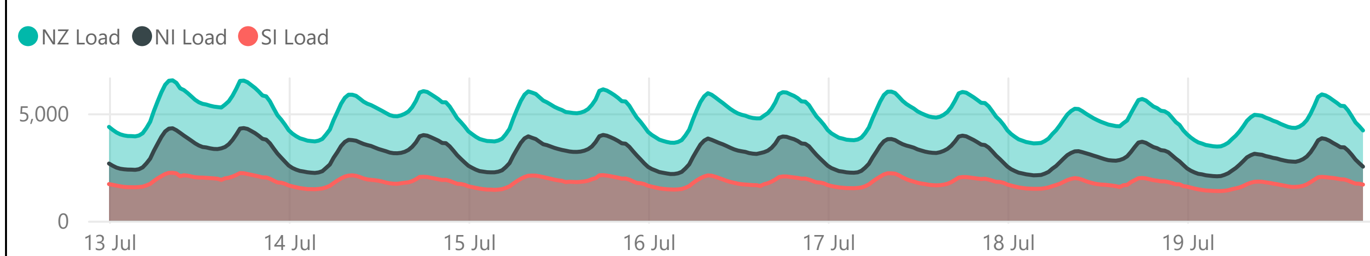
Lowest Residual Points - MW



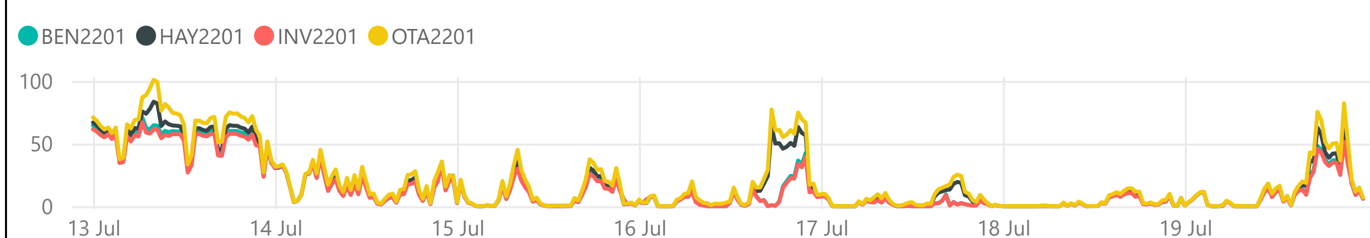
NZGB Look-Ahead (excluding next 7 days)



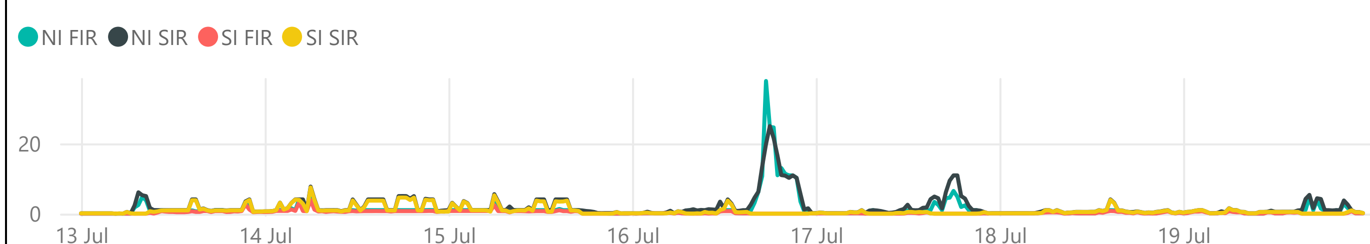
National Demand by Trading period - MW



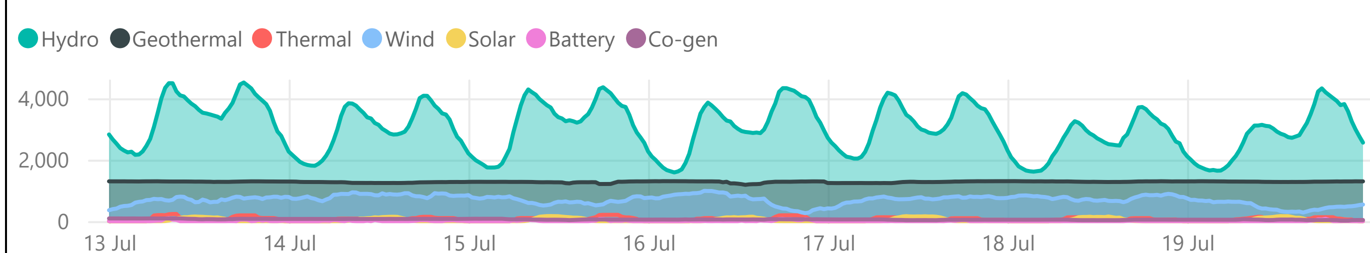
Energy Prices - $/MWh



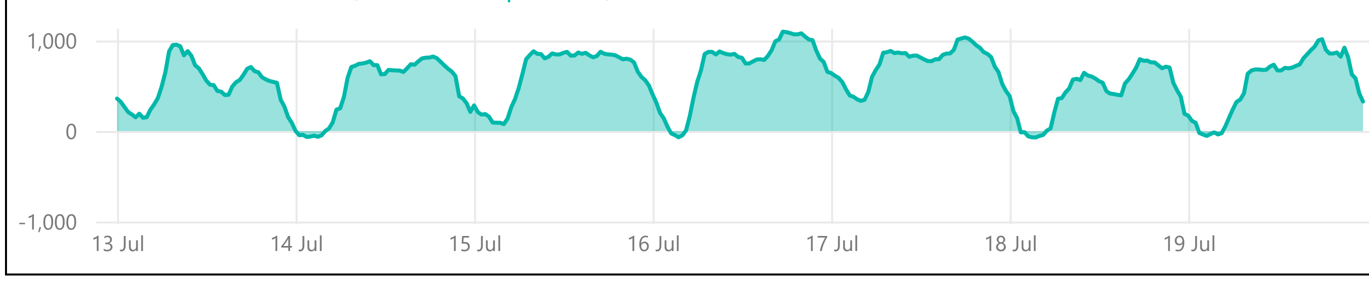
Reserve Prices - $/MW



Generation - MW



Net HVDC Transfer - MW (Northward positive)



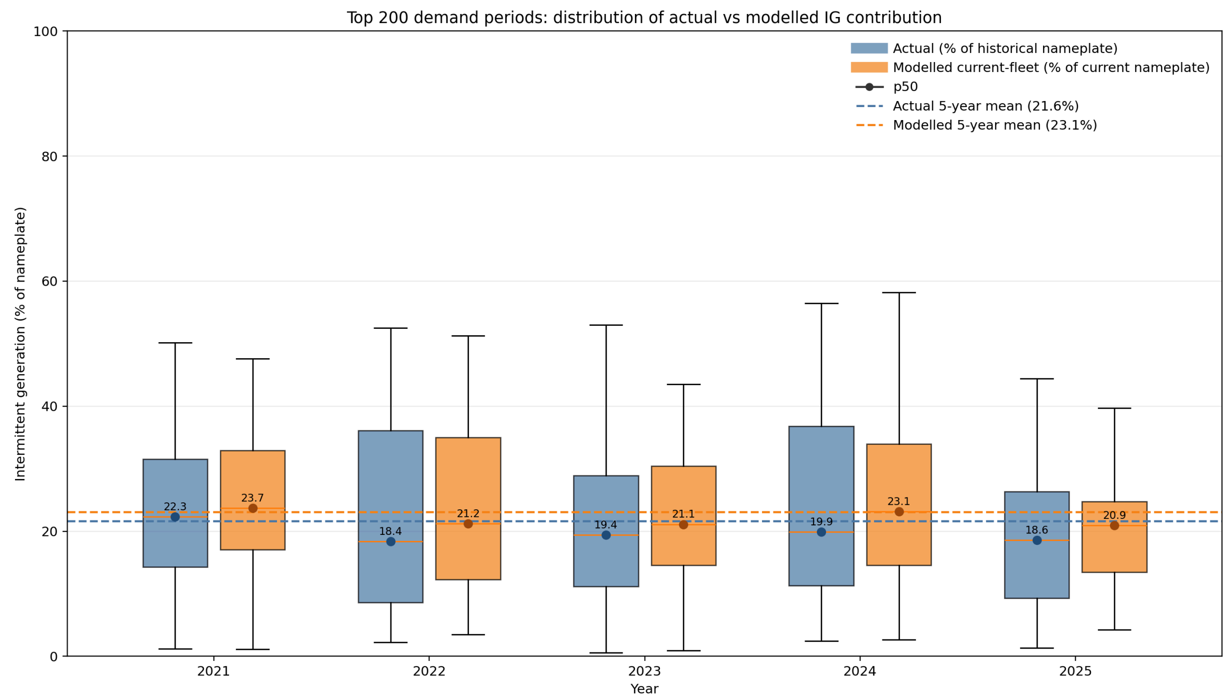
Weekly Insight - Installed MW versus peak-period MW of Intermittent Generation

Following last week's insight on the generation mix during recent peaks, this week presents a counterfactual analysis: How would today's wind and solar fleet have performed under those same historical high-demand weather conditions?

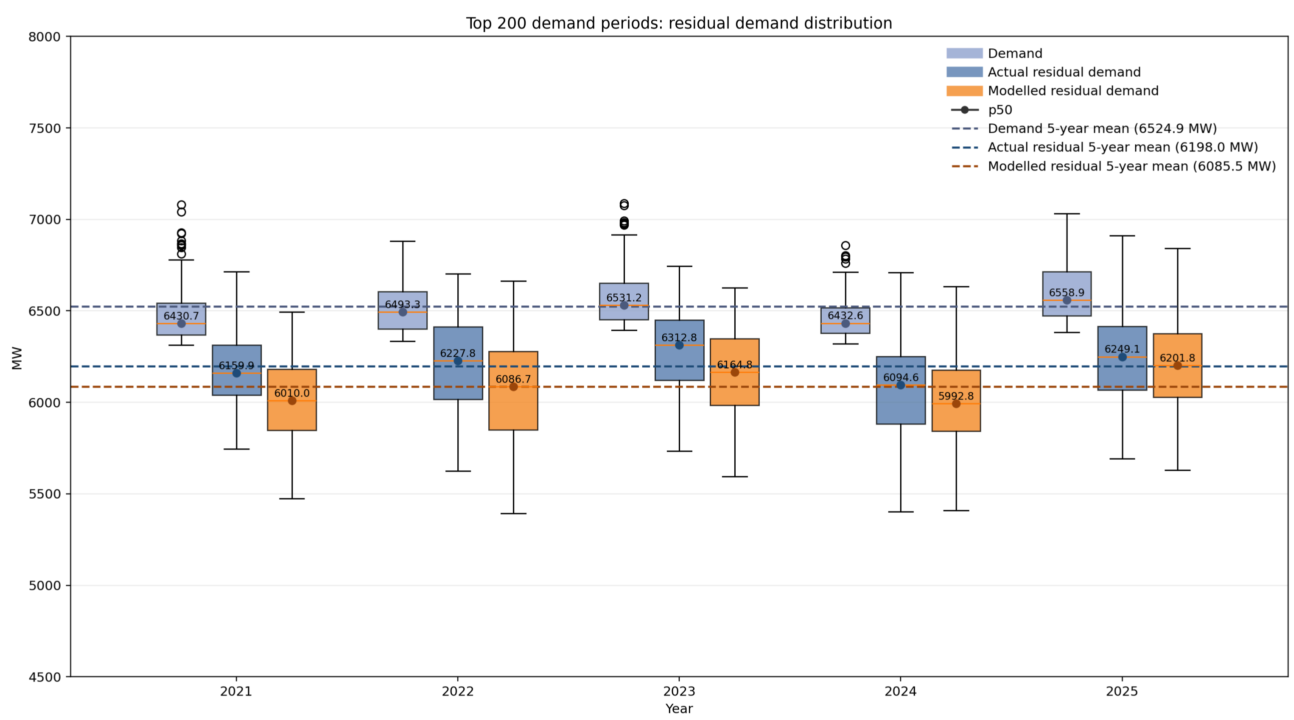
To answer this, we look at the coincidence factor, which is the amount of installed wind and solar generation capacity available when national demand peaks. This metric is important as New Zealand's development pipeline shifts heavily toward intermittent resources. While new projects add substantial energy to the grid, system security also relies on the MW actually likely to be generated during tight winter peaks, not installed capacity alone.

Replaying five years of peak demand with today's wind and solar fleet reveals a wide spread of outcomes. Using simulated generation profiles mapped to historical weather conditions (detailed in the Methodology Notes), we can observe how the current fleet would have performed. In some scenarios, the current fleet offsets peak load by over 100 MW, easing pressure on firm peaking plants. In others, its contribution is marginal, increasing pressure/reliance on firm peaking plants.

The figure below shows that today's larger intermittent fleet lifts the total renewable contribution during historic peaks, though not uniformly. Across the five-year sample's top 200 demand periods, actual wind and solar generation averaged 21.6% of historical installed capacity. Re-running these periods with today's fleet pushes that average to 23.1%. While this uplift slightly aids winter margins, the wide statistical spread remains the critical metric: the system must always prepare for intermittent generation contribution to be at the lower bound of that distribution.



Translating this output into residual demand (the remaining load dispatchable resources must cover) highlights the volatility. As shown in the figure below, today's fleet reduces the median residual demand across these peaks by 113 MW. However, this annual median reduction fluctuates significantly, ranging from 135 MW down to just 47 MW in 2025. This narrowing in 2025 occurs because much of the current intermittent fleet was already operational during recent peaks, leaving less incremental gap between actual dispatch and modelled generation. This underscores a core operational reality: a static capacity of intermittent generation yields a highly variable volume of residual demand for the market to solve during tight grid conditions



Why the solar-heavy pipeline matters

The time-of-day split shows why the specific composition of the intermittent fleet matters. During morning peaks, solar provides 3% to 13% of total intermittent output. However, during evening peaks, when 65% of the highest historical demand periods occur, the median solar contribution drops to zero, shifting system reliance entirely onto wind and dispatchable resources.

This dynamic is important given the near-term investment pipeline, where roughly 600 MW of the 900 MW expected over the next year is solar. The core takeaway is not that solar assets lack system value, but rather that a solar-heavy generation mix changes the operational requirements for system flexibility. To navigate periods of low or absent solar output, these additions require balancing by responsive resources.

Battery Energy Storage Systems (BESS) can help to bridge this gap by shifting daytime energy into evening peaks. However, their firm contribution relies heavily on operational duration, real-time state of charge, and market co-optimisation across energy and reserves. Managing winter peak risk requires looking beyond total installed capacity to the actual volume of firm, flexible, or shiftable capacity ready to respond when intermittent output drops.

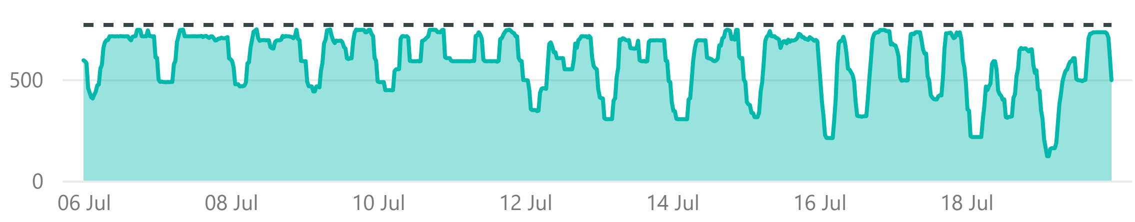
Methodology notes

- Sample Selection: We identified historical peak demand periods first, calculating residual demand secondarily to prevent sampling bias toward periods of pre-existing low intermittent output.
- Modelling Approach: Outputs for the current wind (1,464 MW) and solar (441 MW) fleets use simulated generation profiles from Renewables.ninja, refined via Cumulative Distribution Function (CDF) hourly quantile matching against actual generation data. This mapping is calibrated using 2025 operational data, ensuring the replay captures actual fleet dynamics and distribution shapes rather than idealised capacity factors.
- Scope: These results provide a counterfactual estimate of historical performance. They do not simulate full market dispatch, plant outages, network constraints, or curtailment.

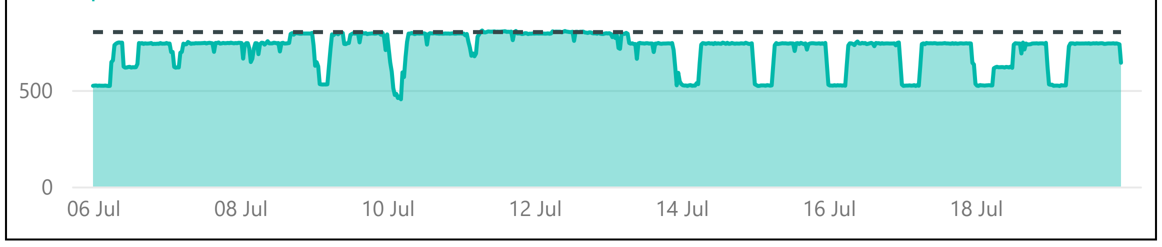
Generation Breakdown - Last Two Weeks

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

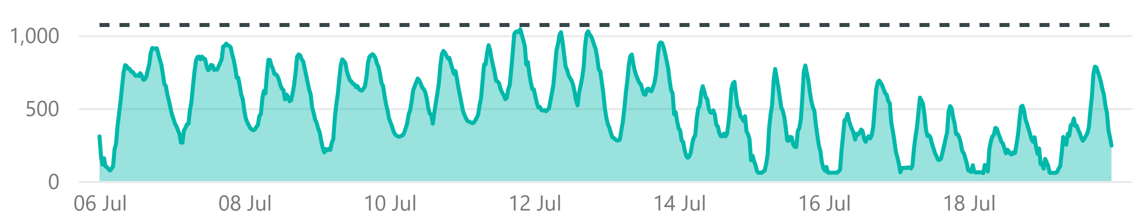
Clutha



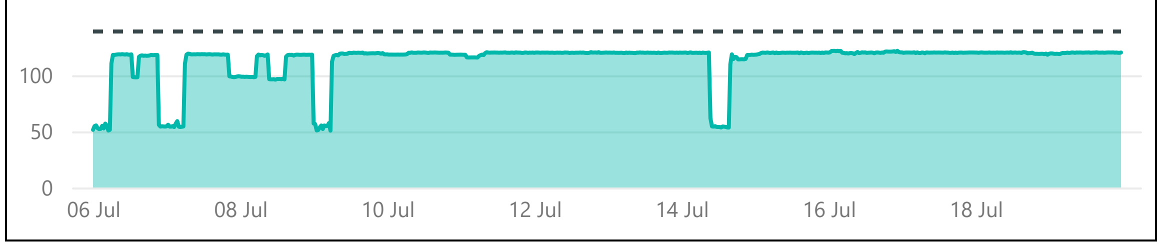
Manapōuri



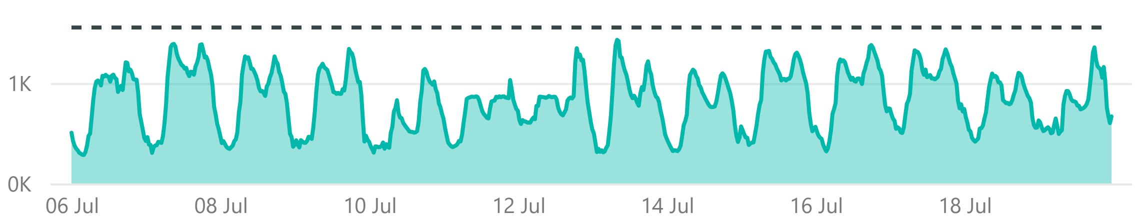
Waikato



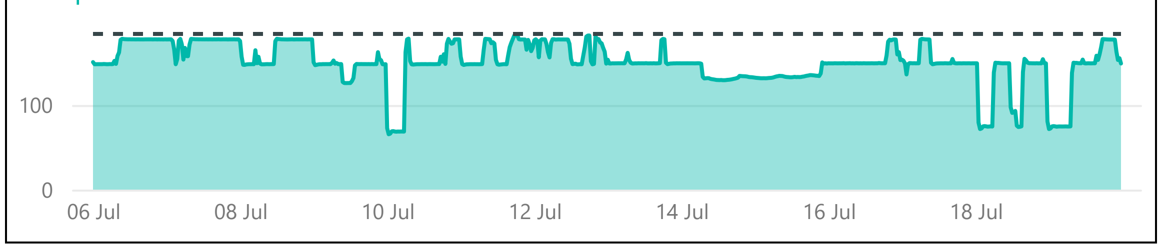
Waikaremoana



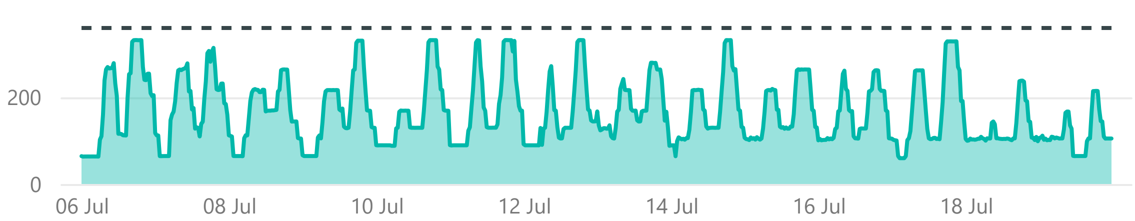
Waitaki



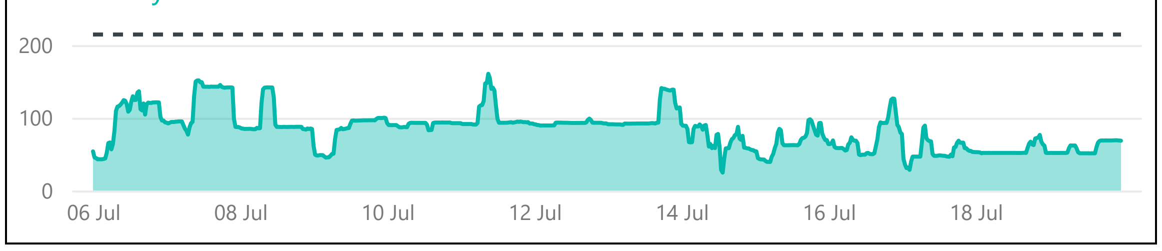
Tekapo



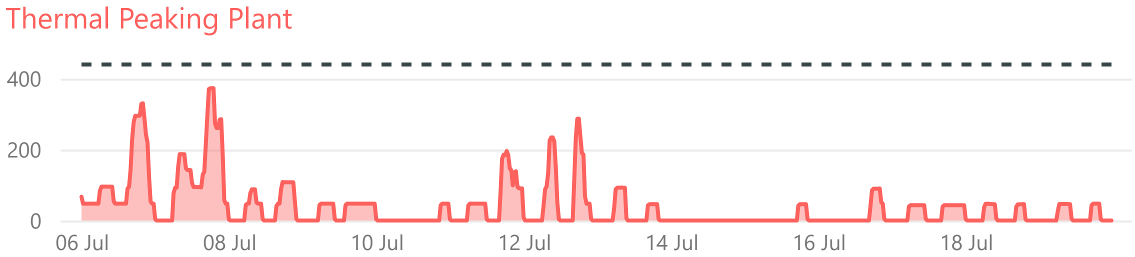
Tongariro



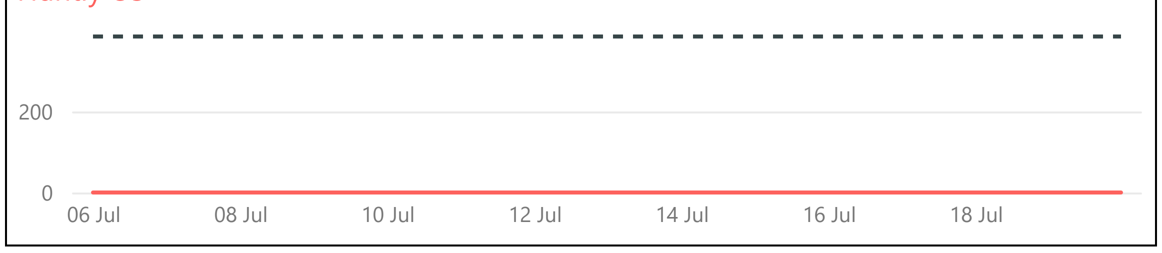
Other SI Hydro



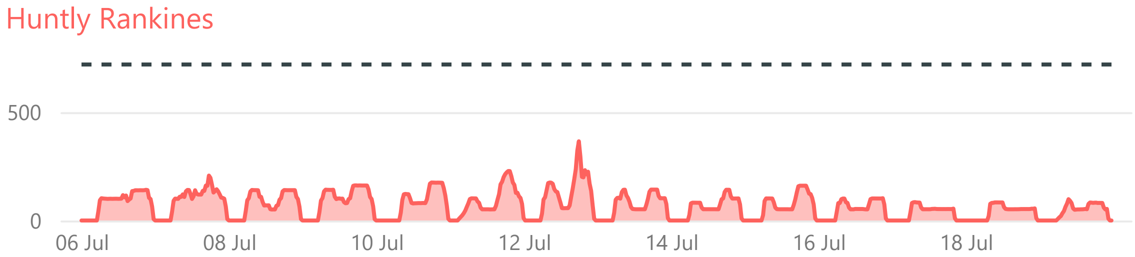
Thermal Peaking Plant



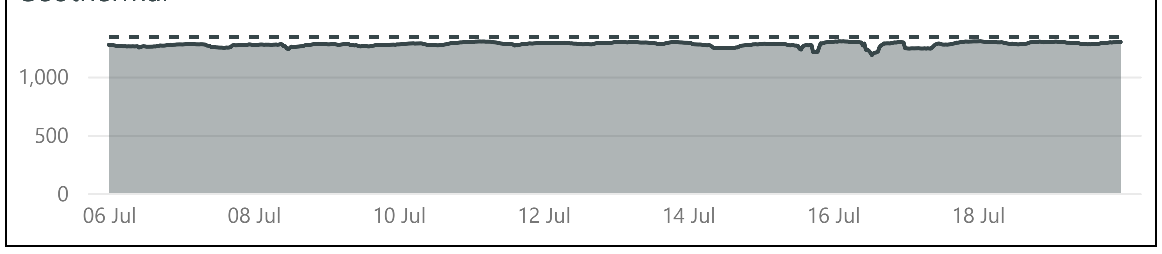
Huntly U5



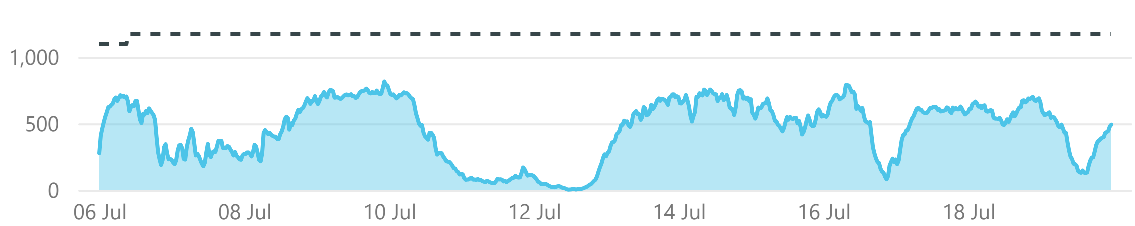
Huntly Rankines



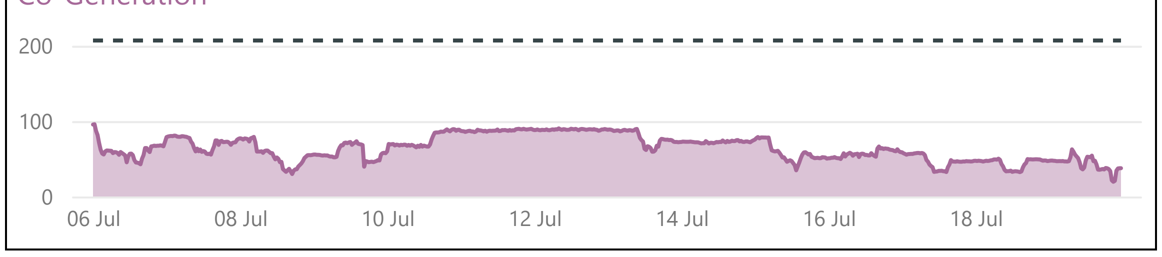
Geothermal



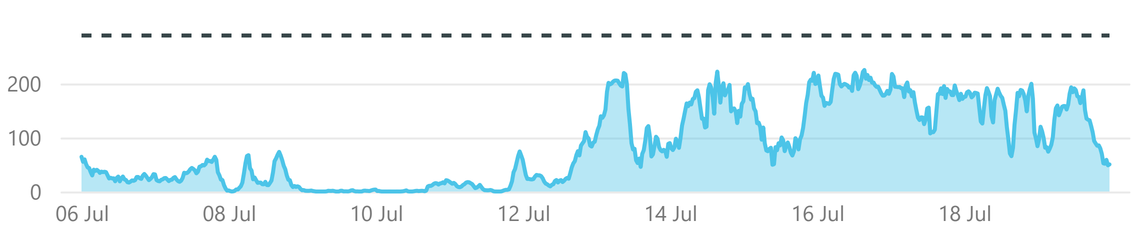
North Island Wind



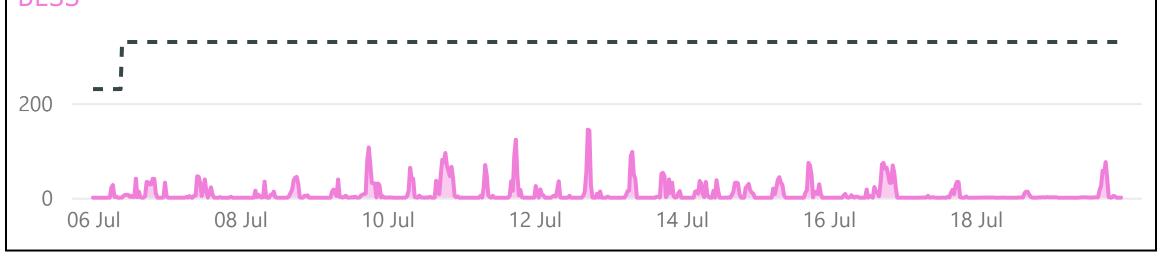
Co-Generation



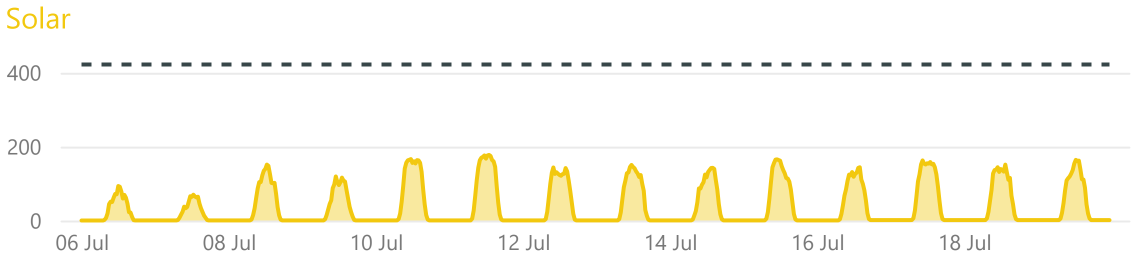
South Island Wind



BESS

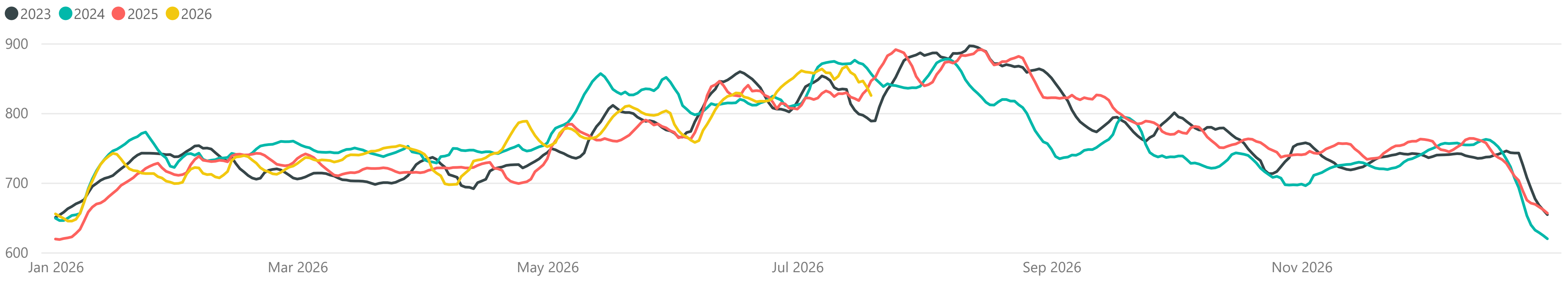


Solar

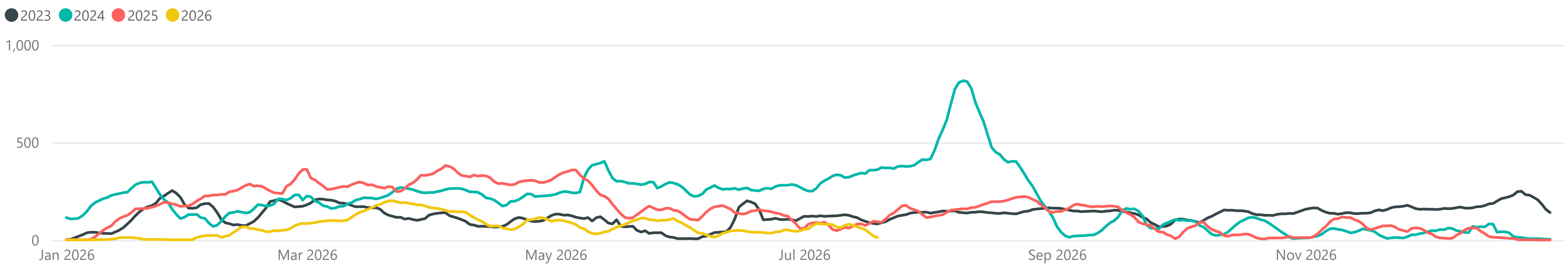


Weekly Profiles

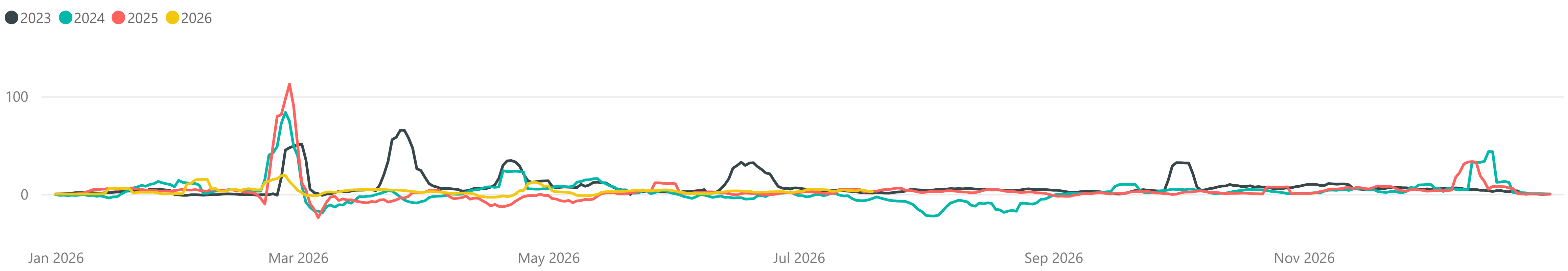
National Weekly Demand - GWh - 7 Day Rolling



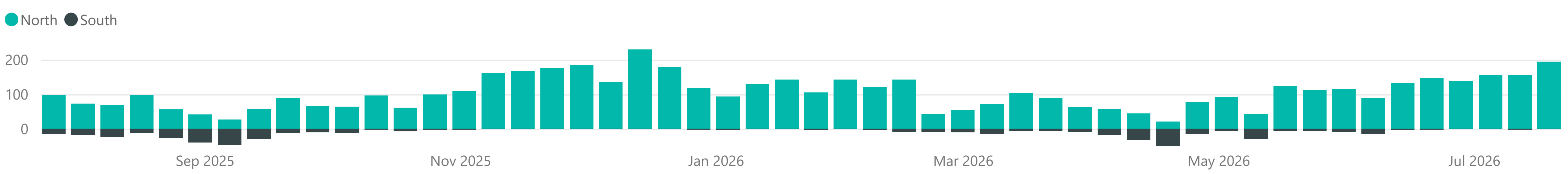
OTA2201 Weekly Rolling Average Spot Price - $/MWh



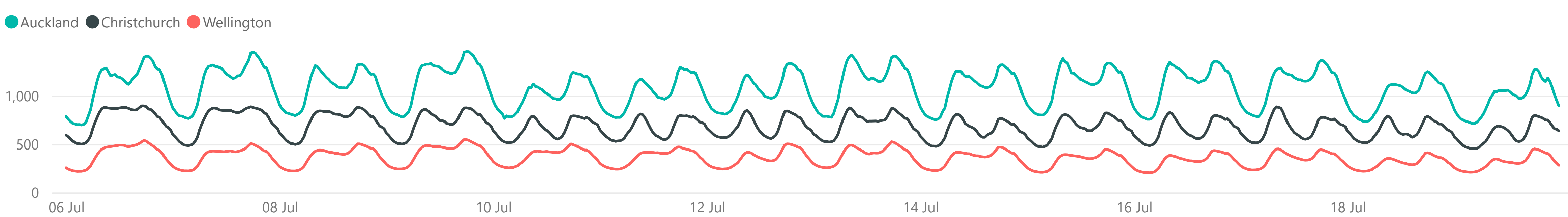
Weekly Rolling Price Separation (HAY2201 - BEN2201) - $/MWh



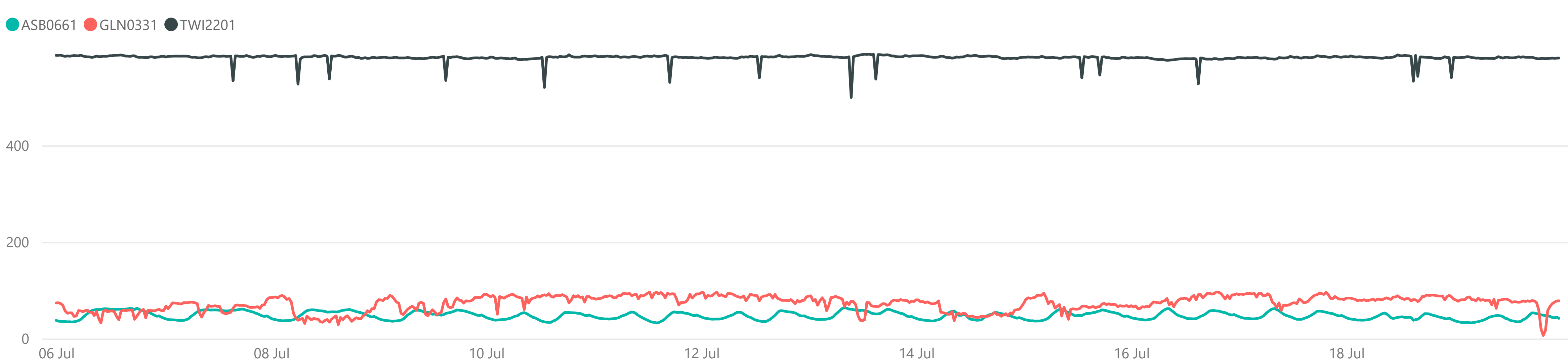
HVDC Transfer - Weekly GWh



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



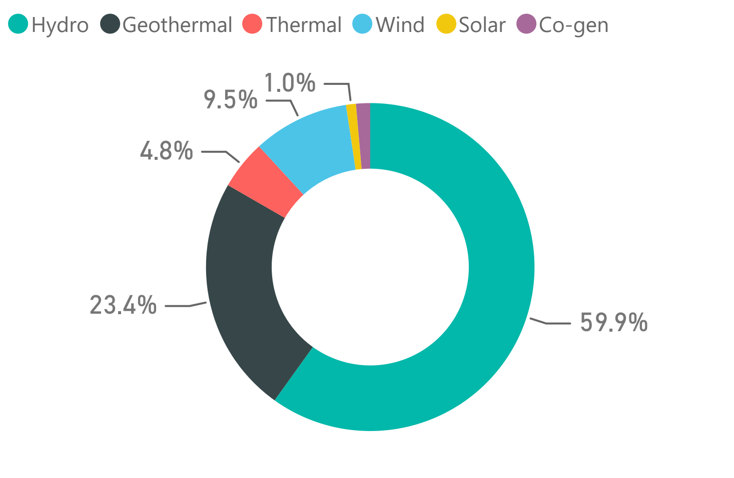
Non-Conforming Load Profiles - Last Two Weeks *Measured in MW shown by GXP*



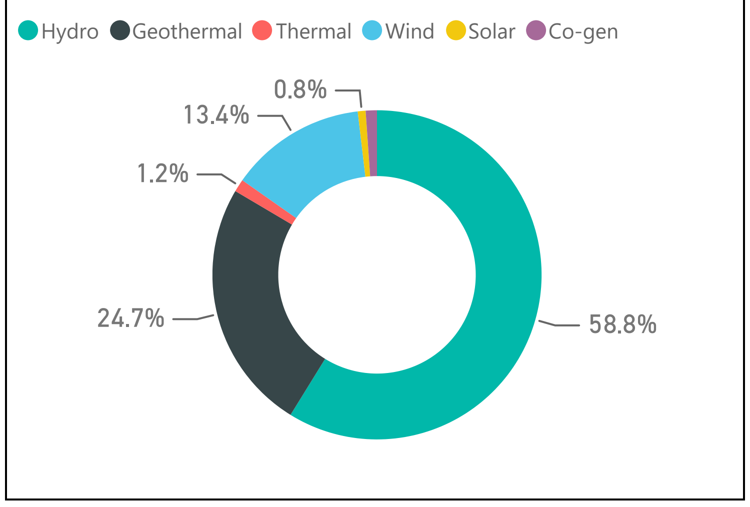
TRANSPOWER

Generation Mix

Last 52 Weeks Generation Mix - Weekly GWh



Last 7 Days Generation Mix - Weekly GWh



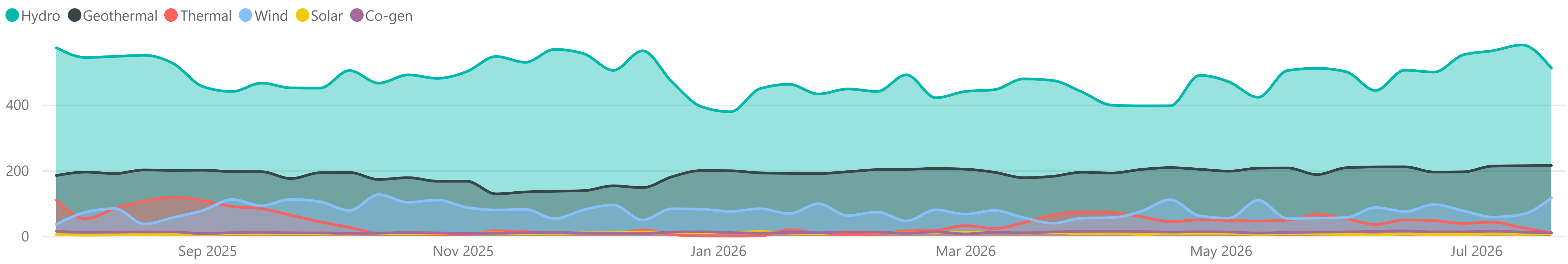
Average Metrics Last 7 Days

Renewable Percentage	CO2e Tonnes/Week	CO2e g/kWh
98%	27,968	32.1

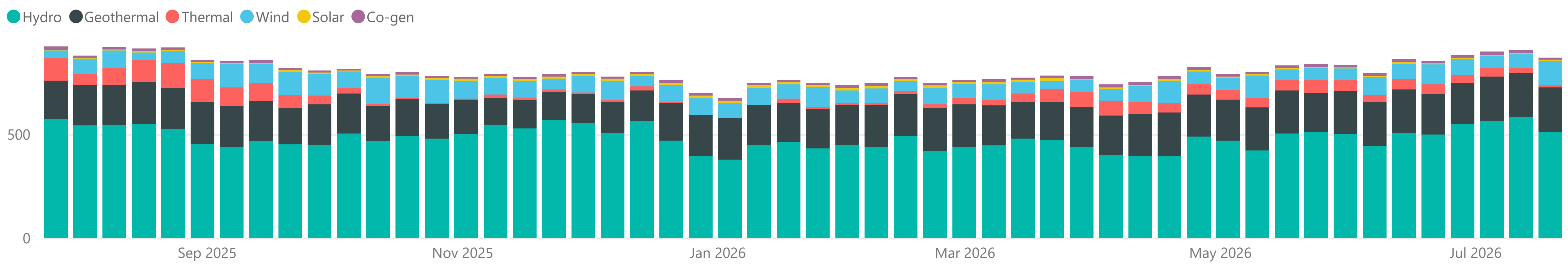
Average Metrics Last 52 Weeks

Renewable Percentage	CO2e Tonnes/Week	CO2e g/kWh
94%	39,779	48.3

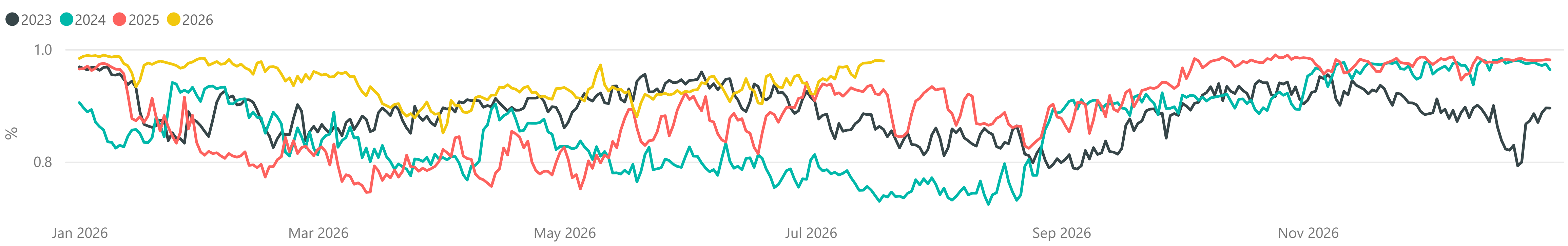
Weekly Generation Mix - GWh



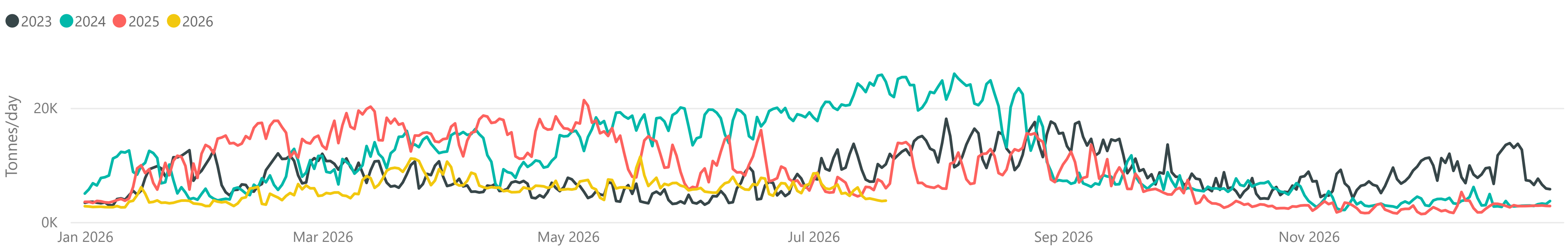
Weekly Generation Mix - GWh



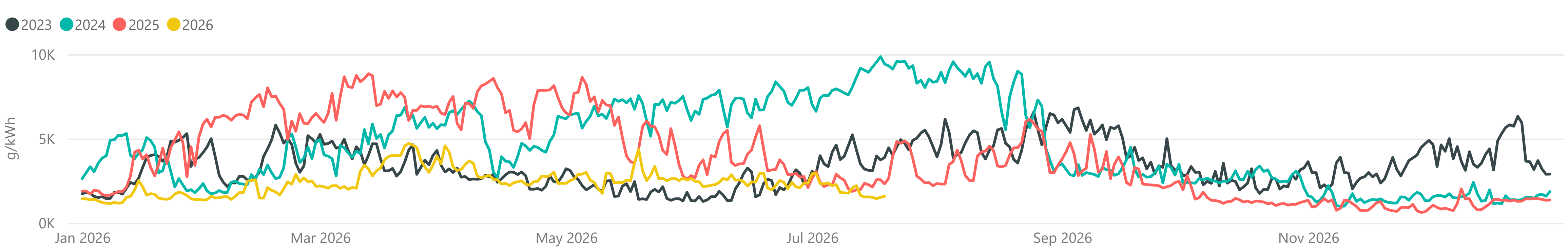
NZ Renewable Percentage



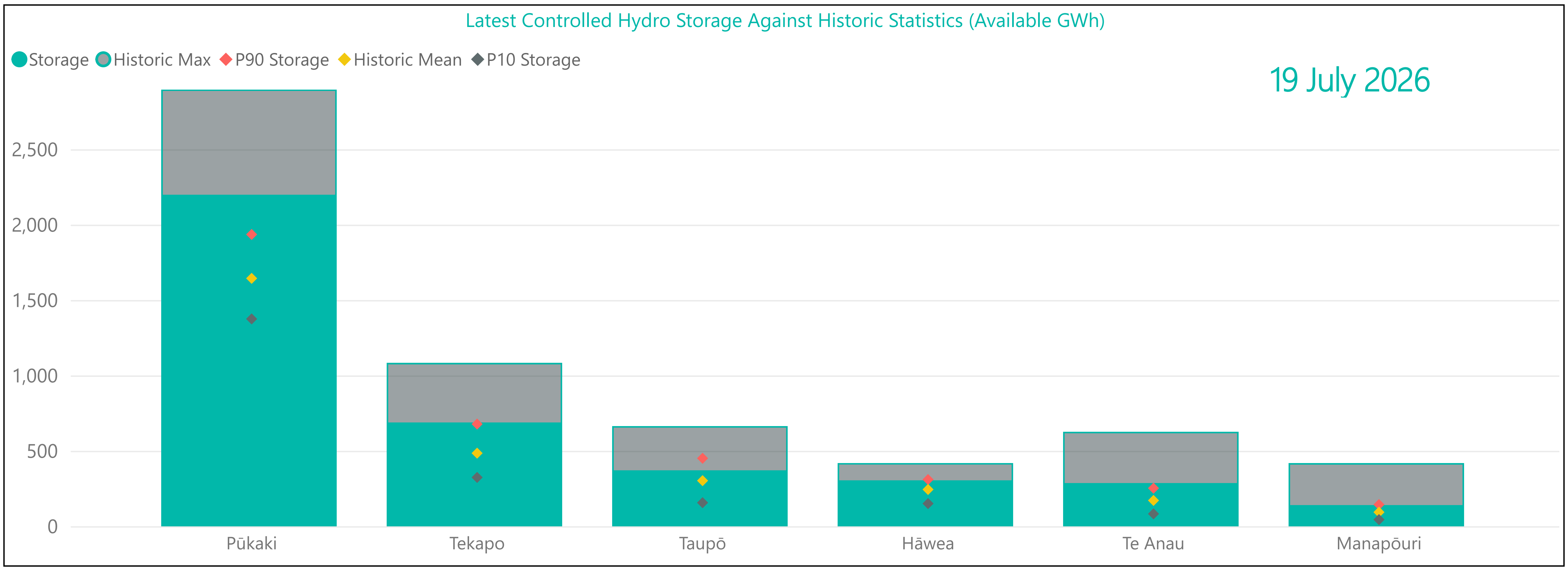
CO2 Tonnes/Day

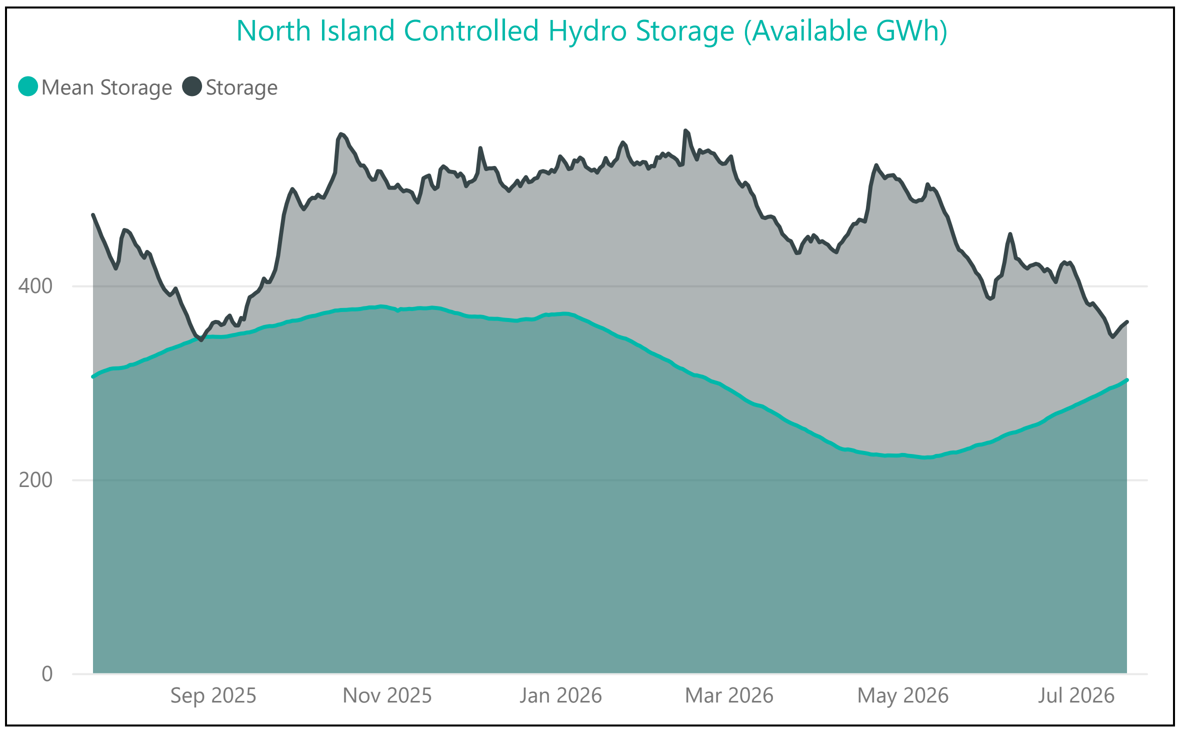


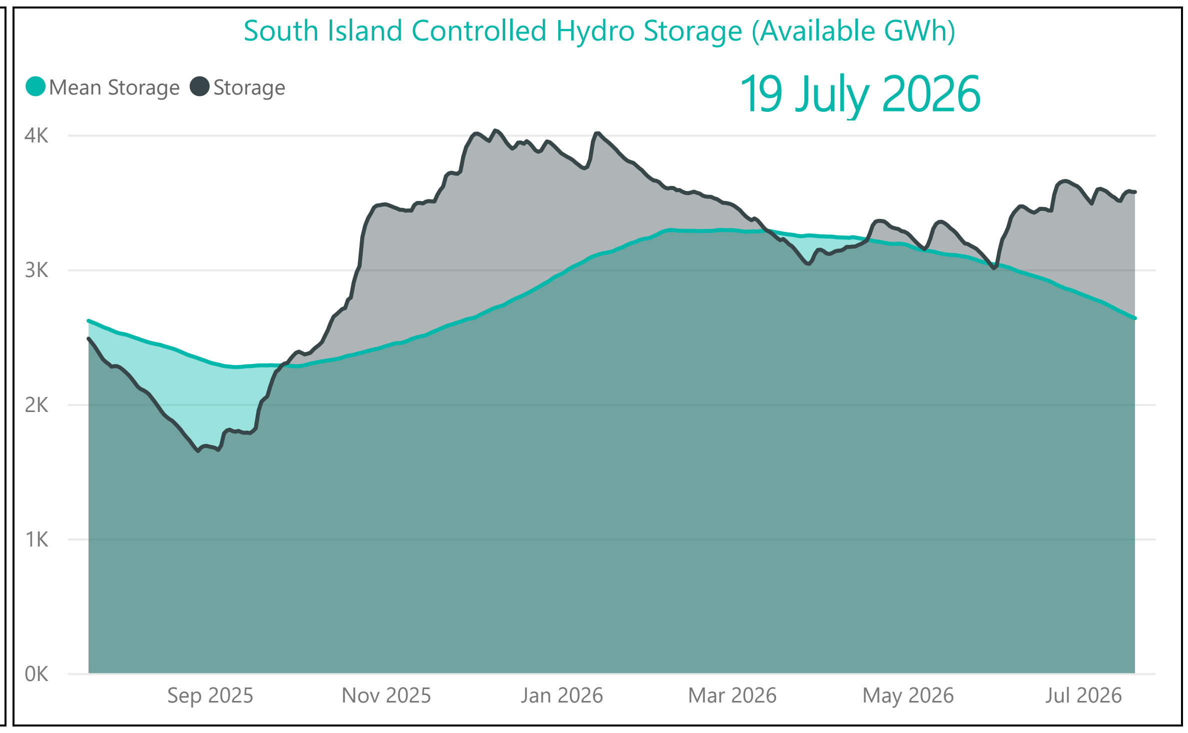
CO2 g/kWh

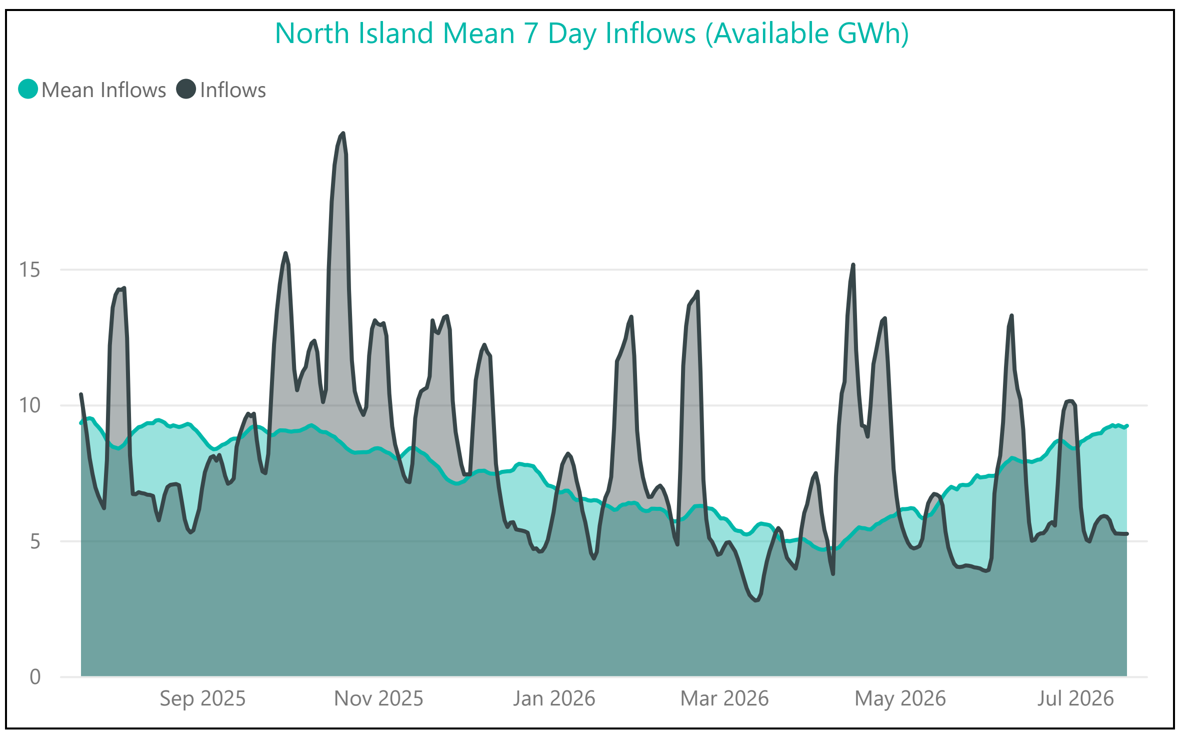


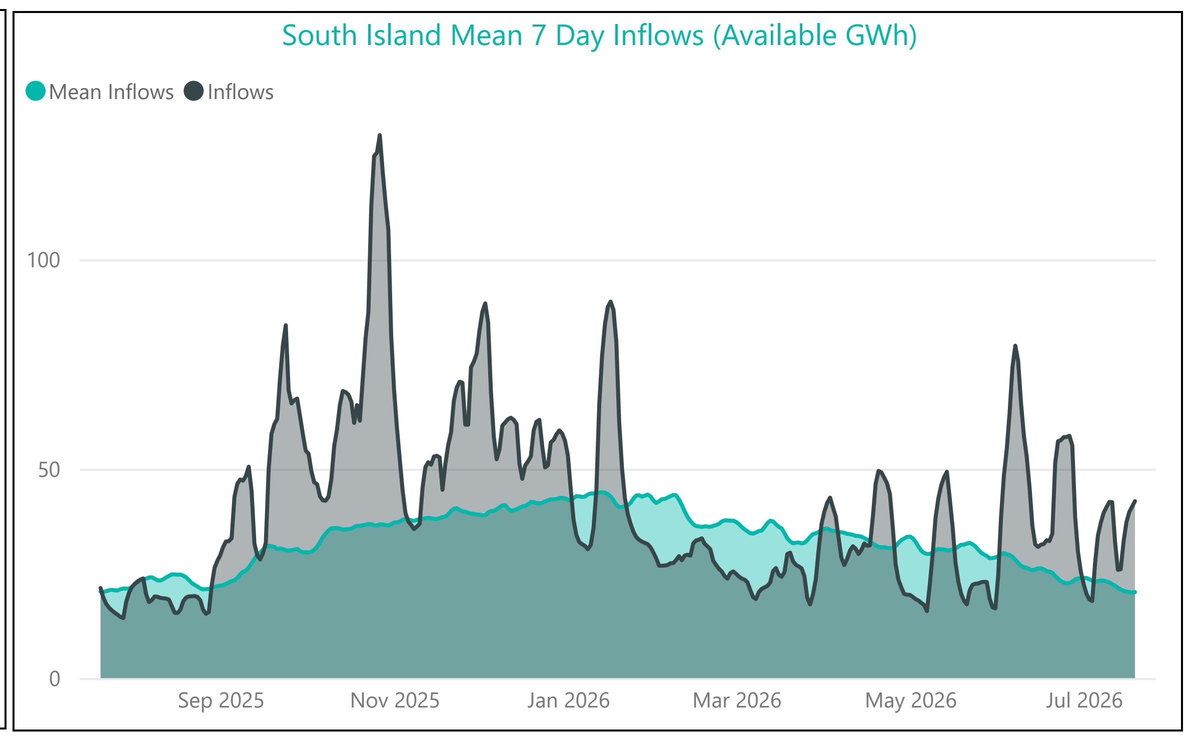
Hydro Storage











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

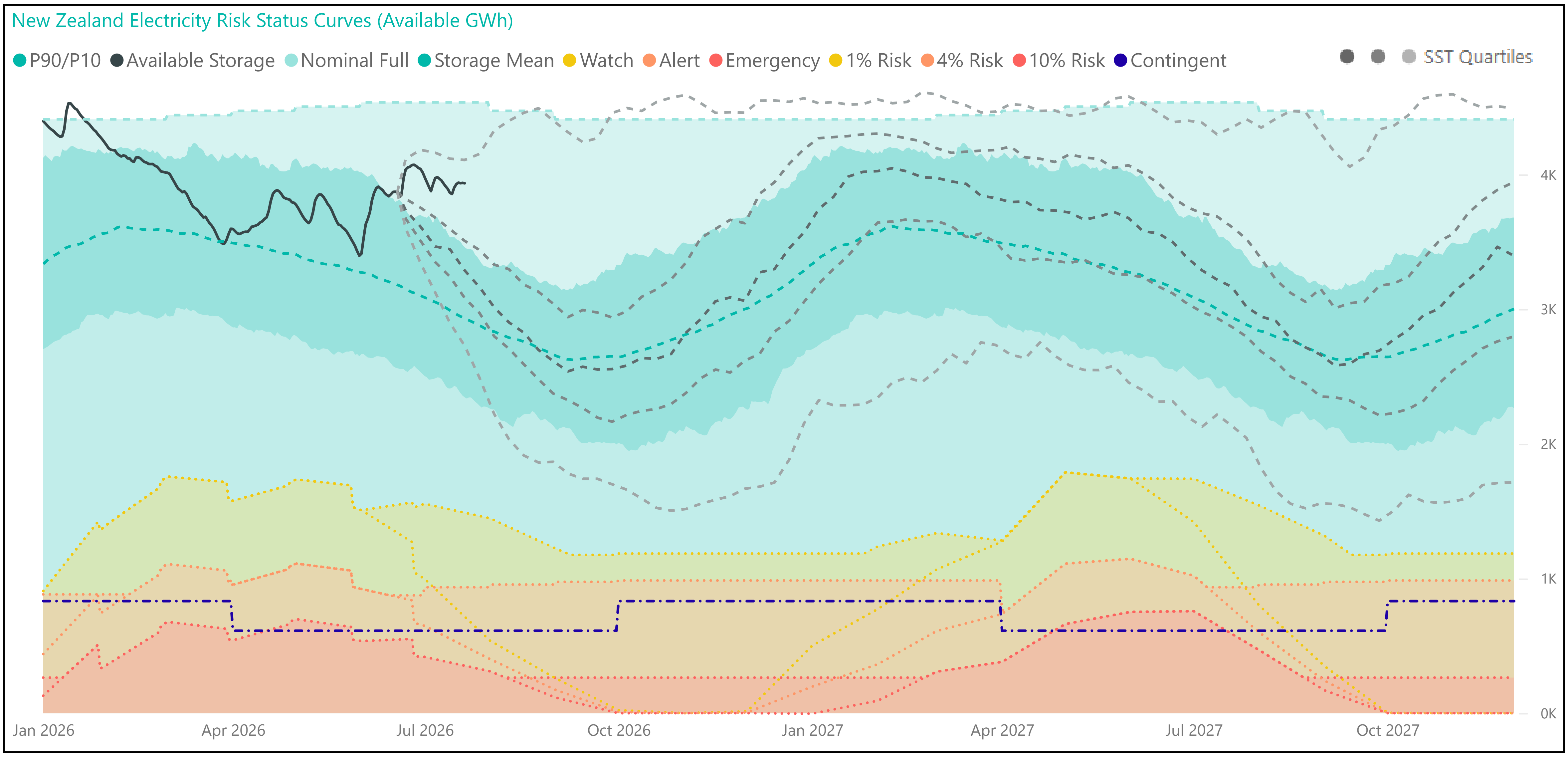
For any inquiries related to security of supply contact market.operations@transpower.co.nz

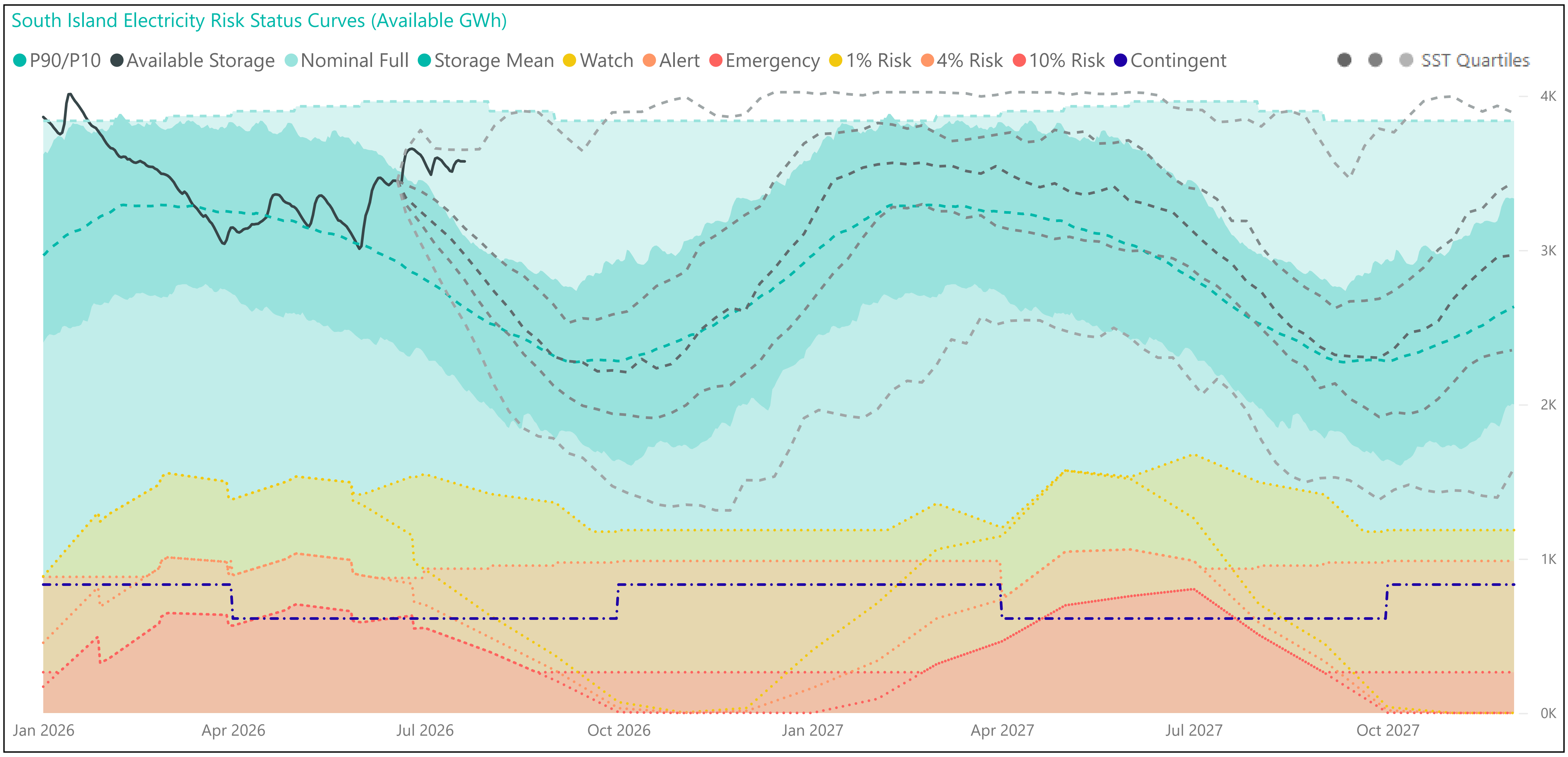
Hydro data used in this report is sourced from *NZX Hydro*.

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:

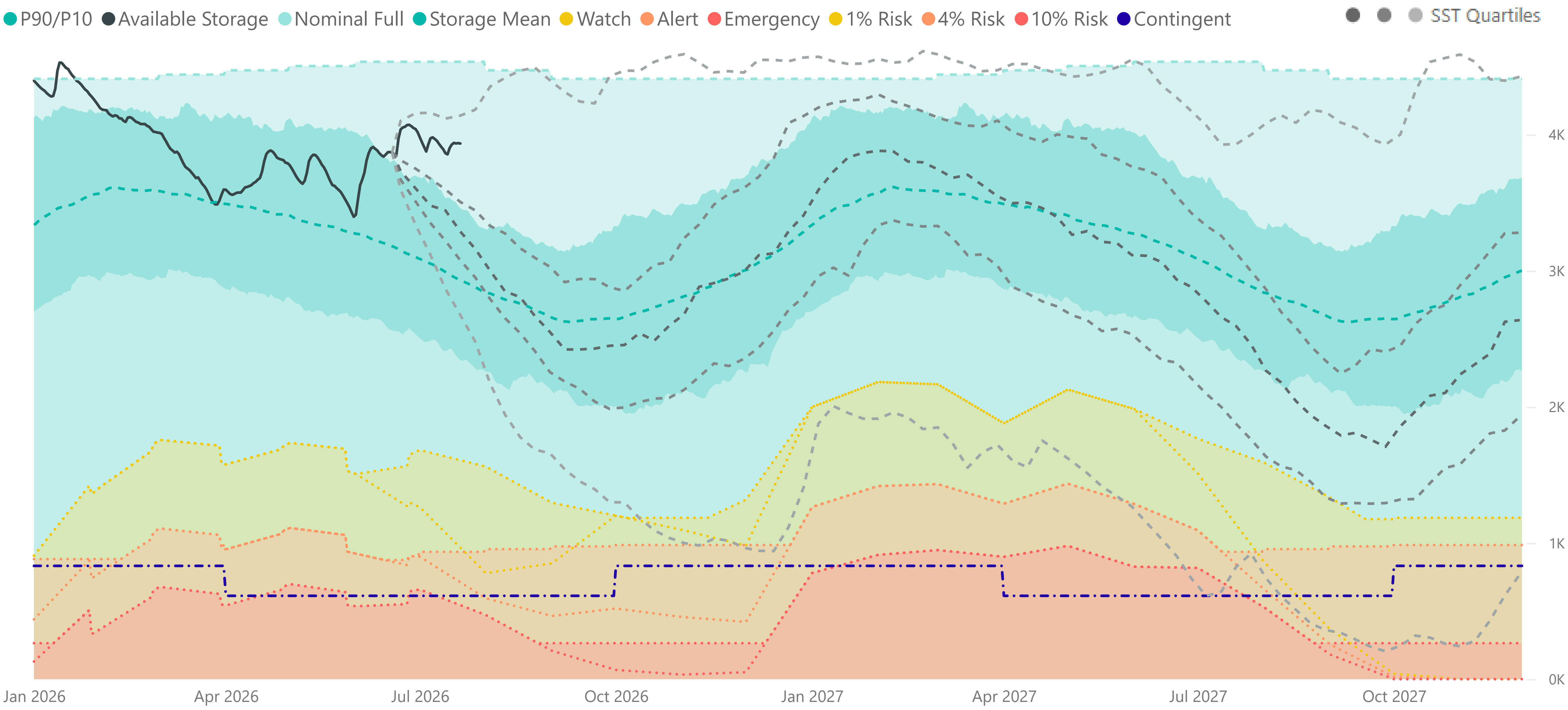
Watch Curve - The maximum of the one percent risk curve or the Alert curve plus the greater of the Watch adder or the worst-case simulated storage drop
Alert Curve - The maximum of the four percent risk curve and the floor and buffer
Emergency Curve - The maximum of the 10 percent risk curve and the 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, and the buffer as specified in the SOSFIP.

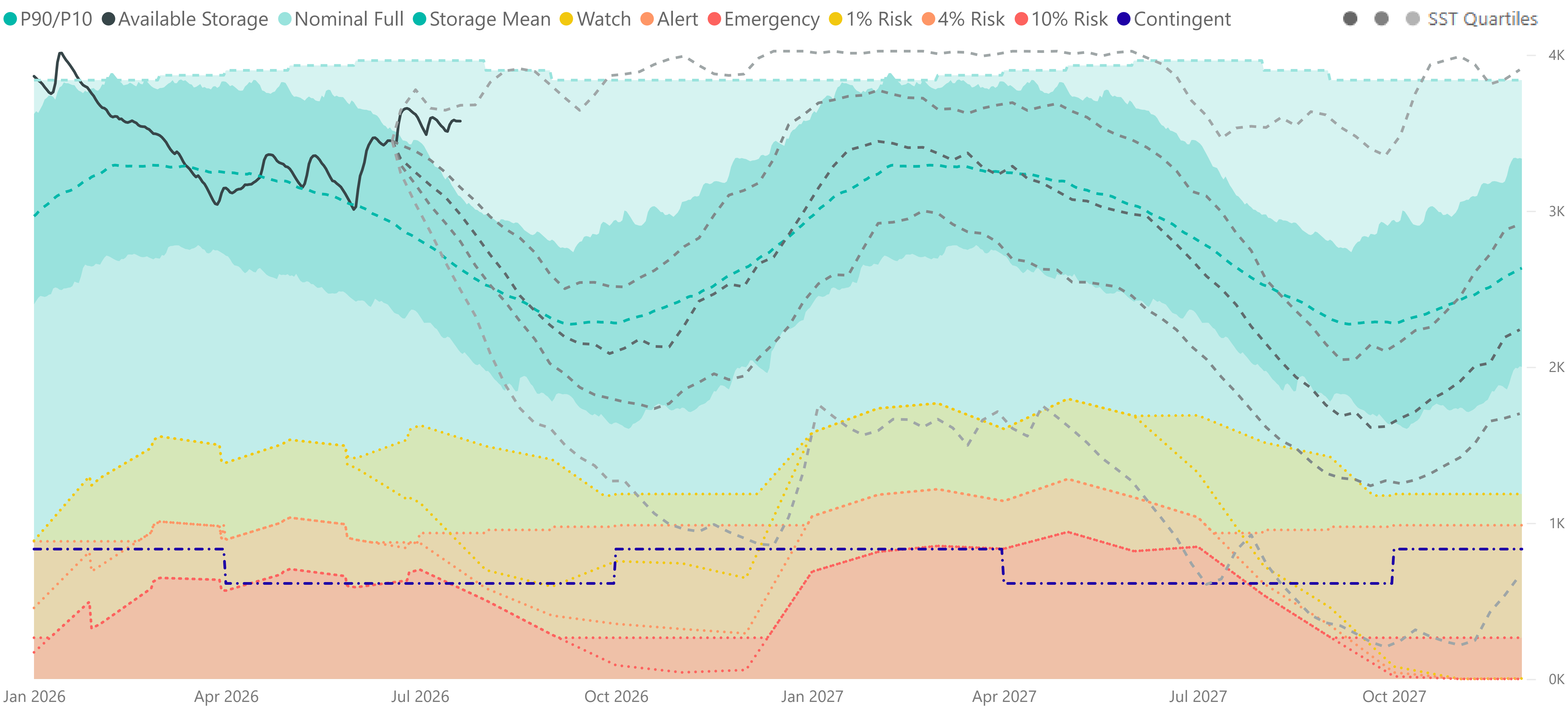
The dashed grey lines represent the minimum, lower quartile, median, upper quartile and the maximum range of the simulated storage trajectories (SSTs). These will be updated with each Electricity Risk Curve update (monthly).

Electricity Risk Curves - Contracted Fuel Case

Contracted Fuel Case - New Zealand Electricity Risk Status Curves (Available GWh)



Contracted Fuel Case - South Island Electricity Risk Status Curves (Available GWh)



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