TRANSPOWER

Market Operations Weekly Report - Week Ended 27 September 2026

Overview

Demand last week was relatively high for this time of year with some colder weather. With inflows near average, national hydro storage fell from 139% of the mean for this time of year to 132%. It remains well above the 90th percentile. Solar generation contributed a record 2.4% of overall generation for the week and set a new record peak generation of 519 MW.

In this week's insight we look at changes to Instantaneous Reserve Cost Allocation that take effect from 1 October.

Security of Supply

Energy

National hydro storage decreased to 132% of the historic mean from 139% the week prior. South Island storage decreased from 148% to 143% and North Island storage decreased from 81% to 75%.

Capacity

Residual for some peaks last week dropped into the 500-600 MW range with colder weather, lower wind generation and some geothermal outages. The lowest residual was 543 MW on the evening of Tuesday 22 September, which is well above the 200 MW threshold for a low residual Customer Advice Notice (CAN).

The N-1-G margins in the NZGB forecast continue to increase with healthy levels through to late November. 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 last week to 804 GWh from 780 GWh the week prior with colder weather. The highest demand peak occurred at 7:30 am on Thursday 24 September at 6,217 MW.

Weekly Prices

Wholesale electricity spot prices increased last week with the average Ōtāhuhu price increasing to $67/MWh, up from $48/MWh the previous week. Prices peaked at $290/MWh at 8:00 pm on Friday 25 August, coinciding with low wind generation.

Some periods of inter-island price separation occurred during the week with high HVDC transfer setting the North Island risk

Generation Mix

Solar generation broke records this week for the highest peak generation (519 MW at 11:30 am on Thursday 24 September), the highest weekly share of generation (2.4%) and the highest total weekly generation (20 GWh). This was due to the country's two largest solar farms, Tauhei and Kōwhai Park, reaching full capacity. Solar generation will continue to increase with conditions improving as we head into summer and as more solar farms come online in the next few months.

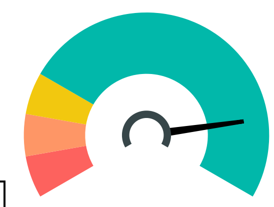
Wind generation was above its yearly average last week at 12% with thermal and geothermal generation below average at 1.4% and 23% respectively. Hydro generation was average at 61% of the mix.

HVDC

HVDC flows last week were almost entirely northward. In total 121 GWh was transferred north.

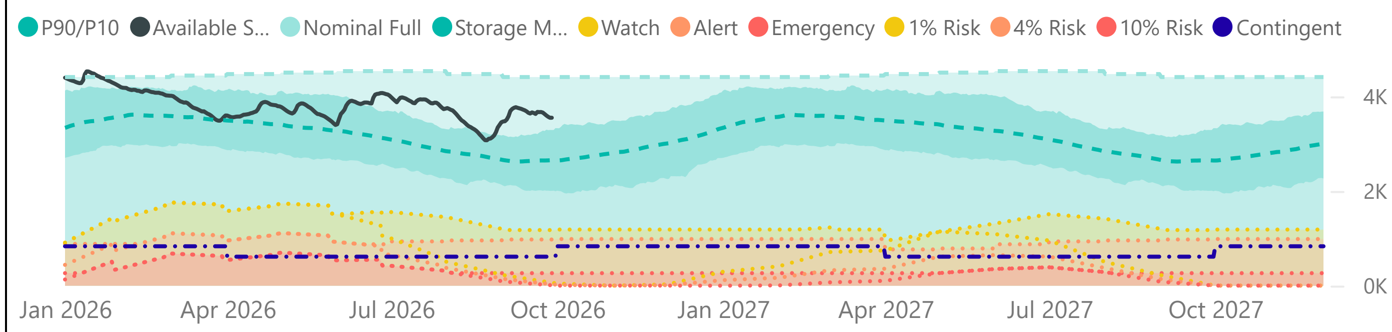
New Zealand Energy Risk

South Island Energy Risk

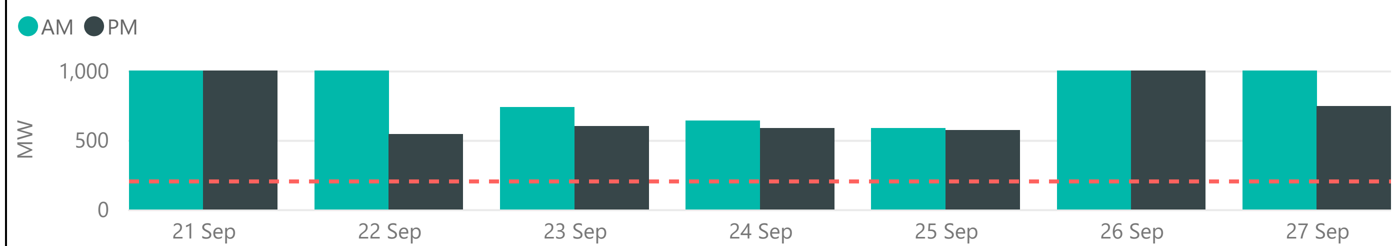


Normal Watch Alert Emergency

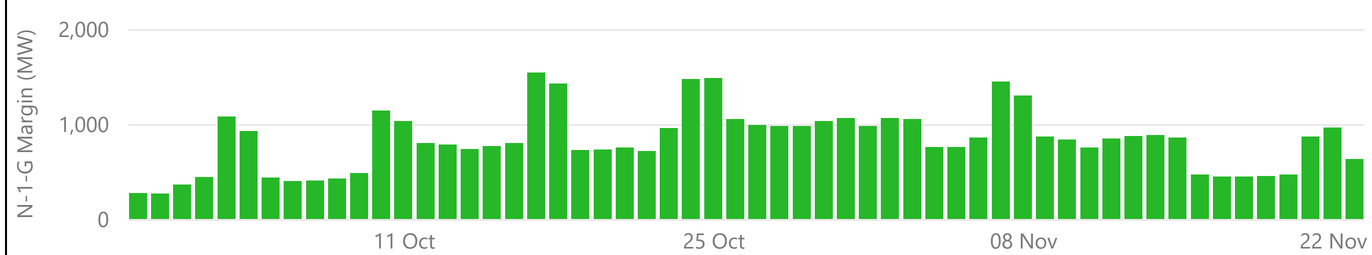
New Zealand Electricity Risk Status Curves (Available GWh)



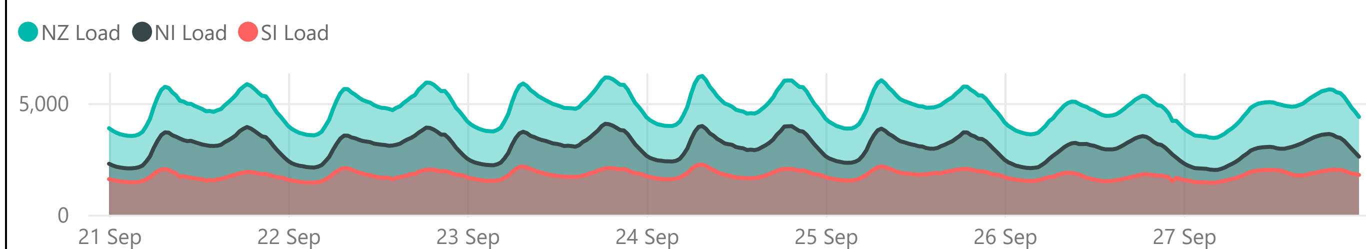
Lowest Residual Points - MW



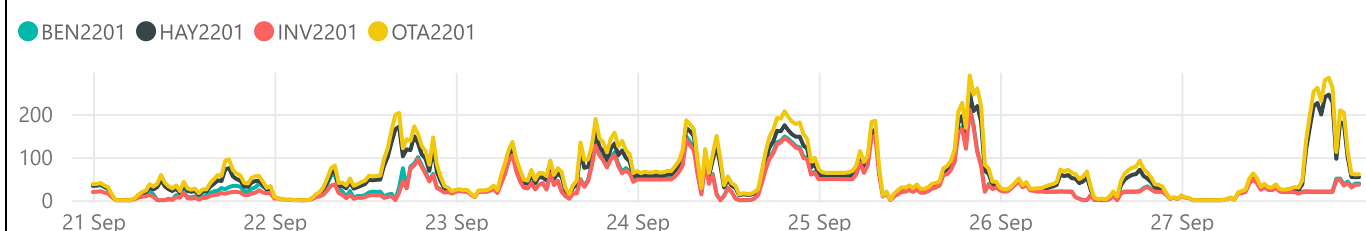
NZGB Look-Ahead (excluding next 7 days)



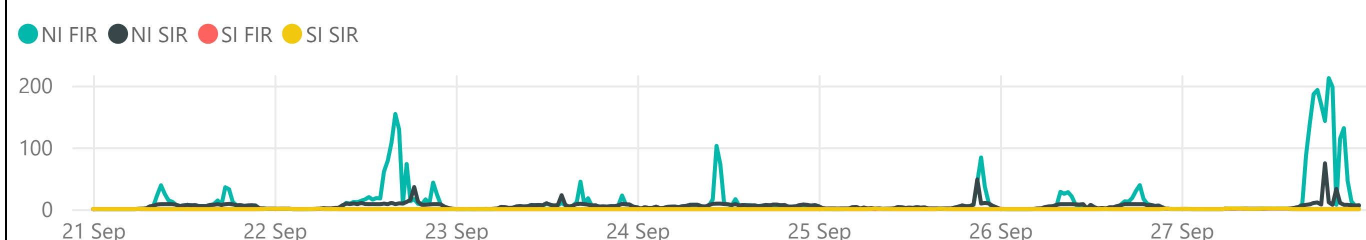
National Demand by Trading period - MW



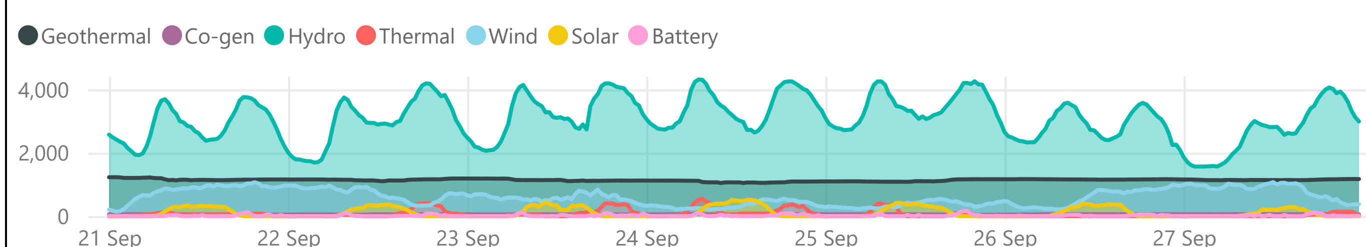
Energy Prices - $/MWh



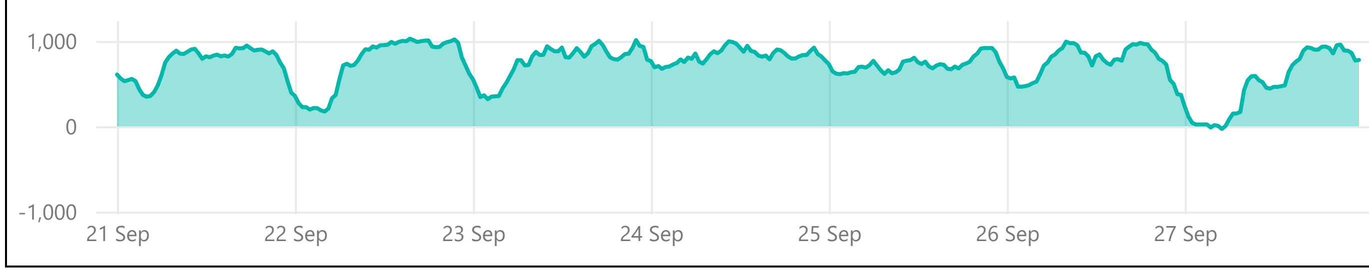
Reserve Prices - $/MW



Generation - MW



Net HVDC Transfer - MW (Northward positive)



Weekly Insight - Change to instantaneous reserve cost allocation

The Electricity Authority amended the Electricity Industry Participation Code in October 2025 to change how instantaneous reserve (IR) availability costs are allocated. The changes take effect on 1 October 2026.

IR is procured by the System Operator (SO) to manage contingent-event risks[1] that could affect power system security, such as the sudden loss of a large generating unit or a transmission asset. Costs of IR for each trading period are allocated in proportion to the generation of a generating unit and the at-risk transfer of the HVDC link within that trading period, in line with a causer-pays principle. The first 60MW of generation or transfer is exempt from IR costs.[2]

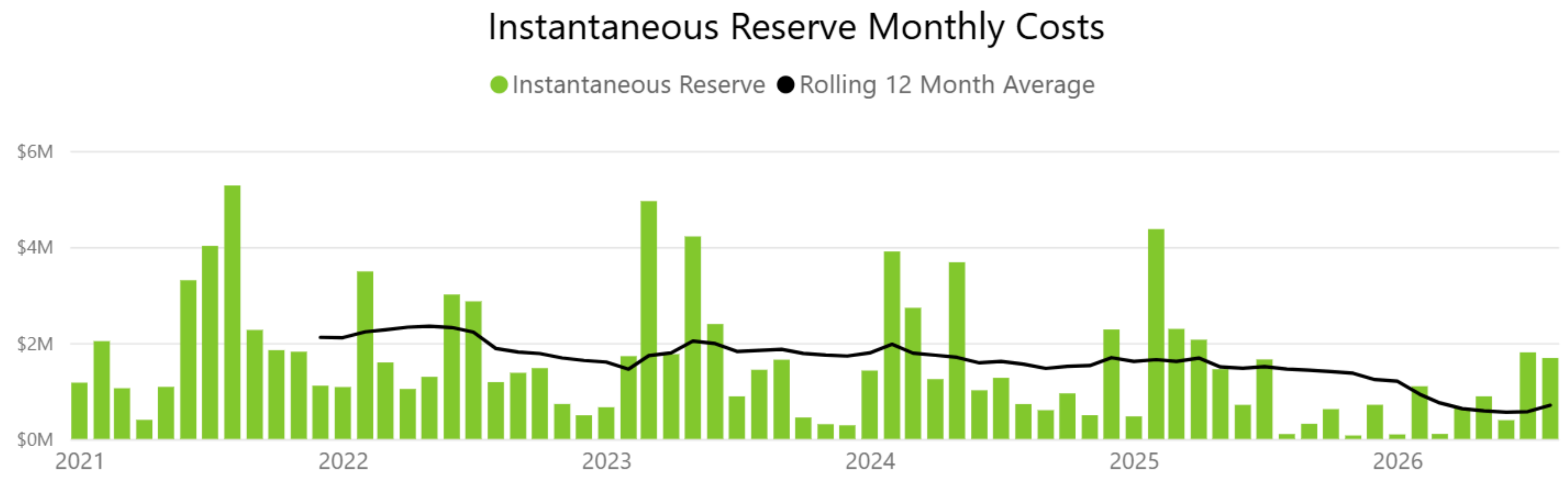
Because some groups of generating units are connected to the grid or a distribution network by a single connection asset (such as a line or transformer), they also present a risk to power system stability and are managed as contingent-event risks. This results in an increase in the amount of IR required, and thus IR costs. The Code amendment will mean that these groups of generating units are also allocated a share of IR costs proportional to their generation minus 60 MW. This change aligns IR cost allocation with contingent-event risks already managed by the power system.

The Authority's Code amendment requires the SO to publish a list of at-risk generation that will be allocated a share of IR costs. We have published this on our website.[3] The list includes all generating units that were previously allocated IR costs, plus the following groups of generating units that will be allocated a share of IR costs from 1 October:

Generator name	Fuel type
Junction Road	Gas
McKee	Gas
Mokai	Geothermal
Ngā Tamariki	Geothermal
TOPP2 and Te Ahi o Maui	Geothermal
Aratiatia	Hydro
Kōwhai Park	Solar
Tauhei	Solar
Kaiwaikawe	Wind
Tararua III (Central)	Wind
Te Āpiti	Wind
Turitea	Wind
Waipipi	Wind
West Wind 1	Wind
West Wind 2	Wind

This list includes some wind and solar farms that have a single point of connection to more than 60 MW of generation. Previously, no solar or wind farms were allocated a share of IR costs because their individual generating units (e.g. wind turbines) are much smaller than 60 MW. Not all solar and wind farms over 60 MW are affected, because many use redundant connections or multiple connections that are each smaller than 60 MW.

For an indication of the scale of the costs involved, the chart below shows total IR costs per month since January 2021. These have averaged $700,000 per month over the past 12 months and show a declining trend.

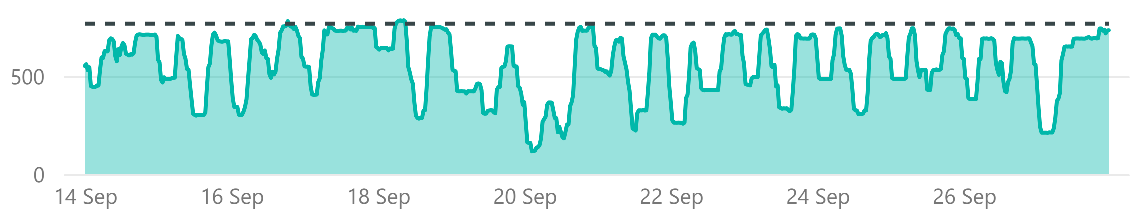


[1] Contingent event risks are further defined in the Policy Statement. IR is also procured to cover the portion of extended contingent event risks that is not covered by Automatic Under-Frequency Load Shedding (AUFLS).
[2] This formula is described by section 8.59 of the Code.
[3] About ancillary services | Transpower (see "Service Payments" section under "Instantaneous Reserve").

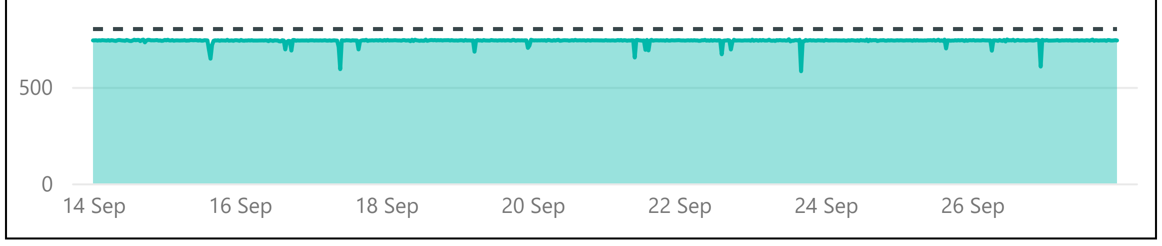
Generation Breakdown - Last Two Weeks

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

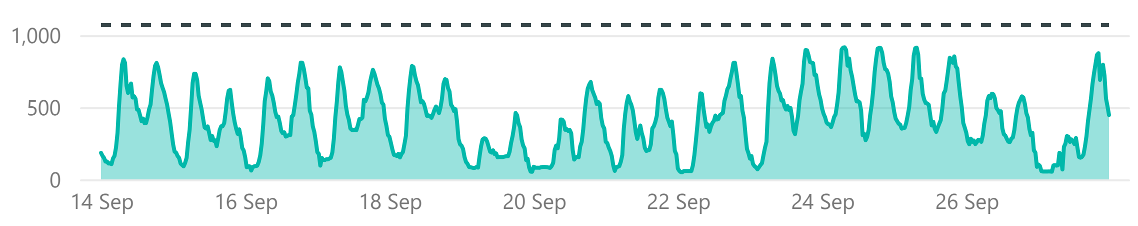
Clutha



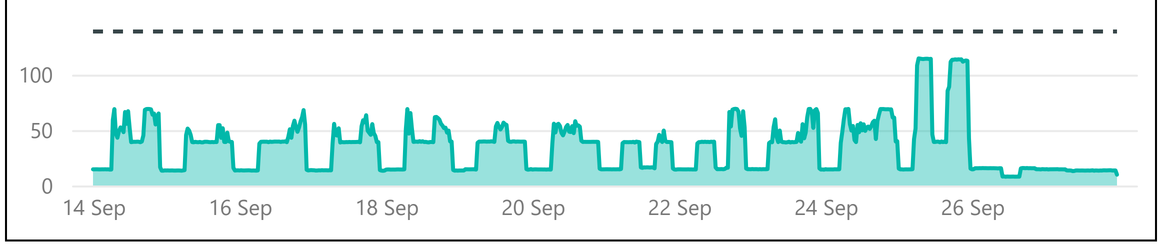
Manapōuri



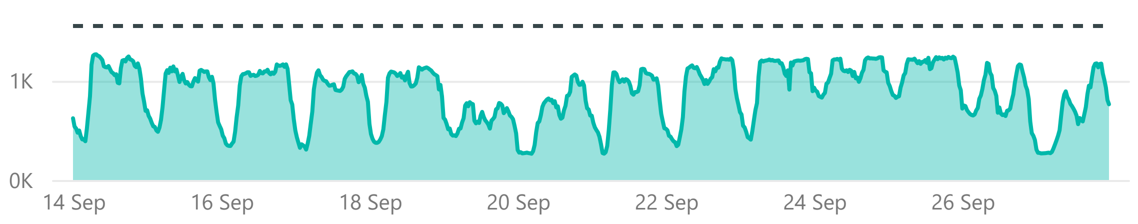
Waikato



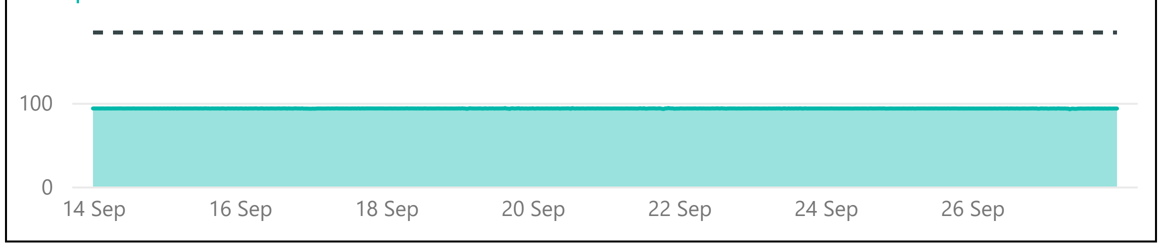
Waikaremoana



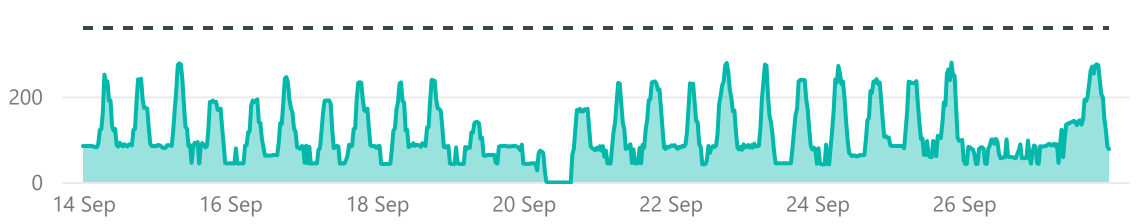
Waitaki



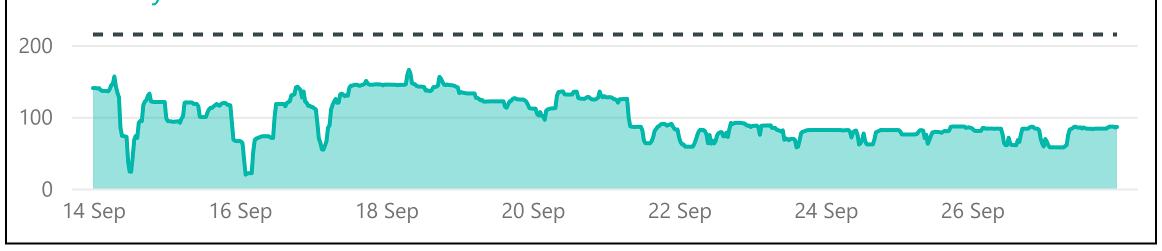
Tekapo



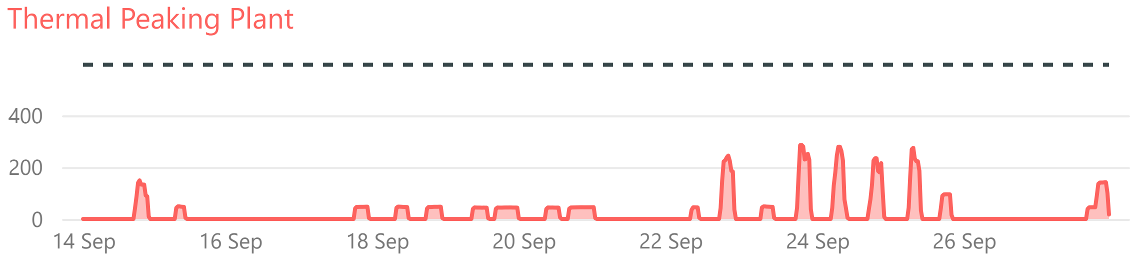
Tongariro



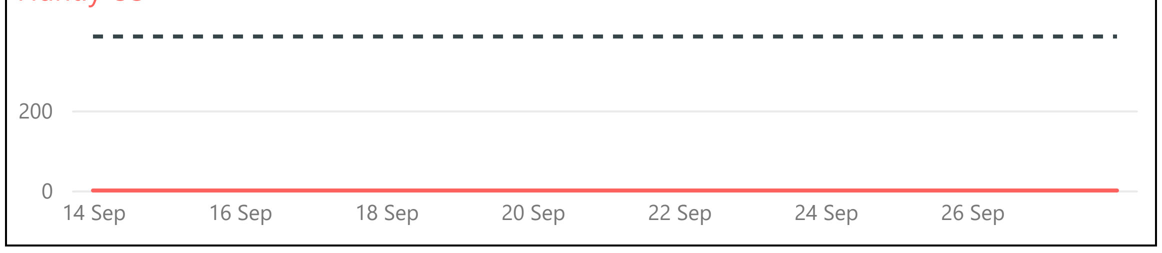
Other SI Hydro



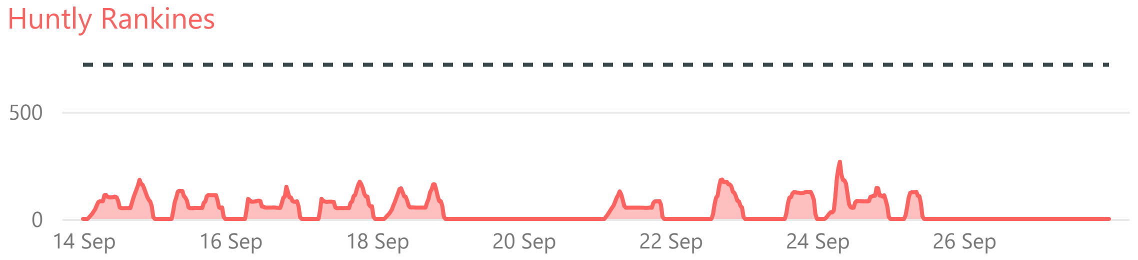
Thermal Peaking Plant



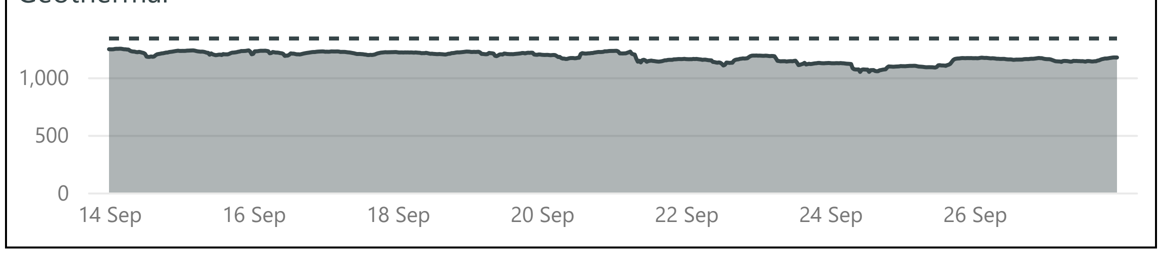
Huntly U5



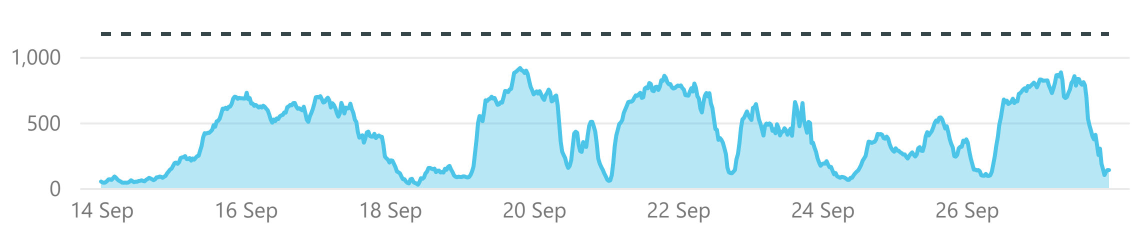
Huntly Rankines



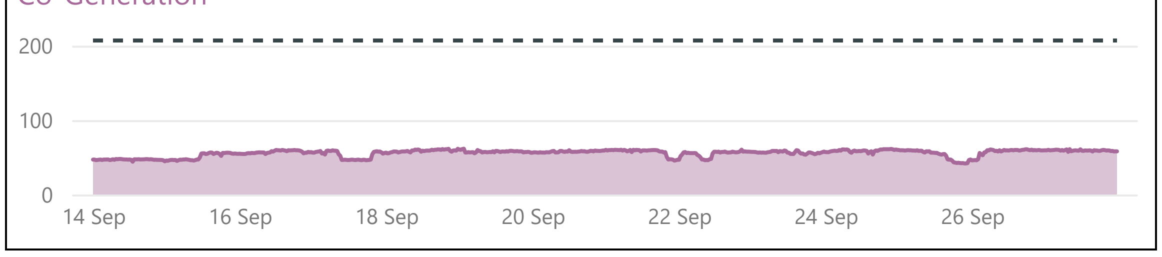
Geothermal



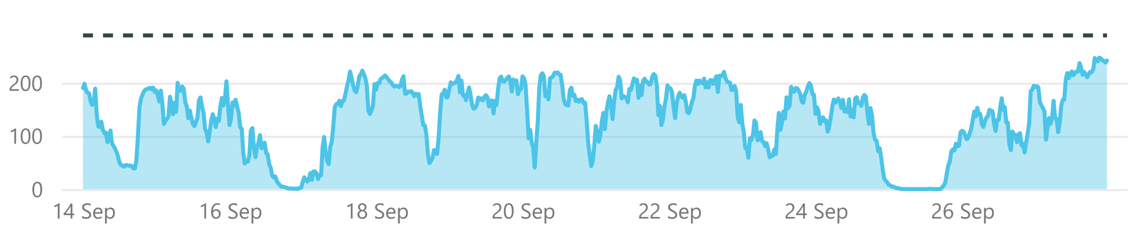
North Island Wind



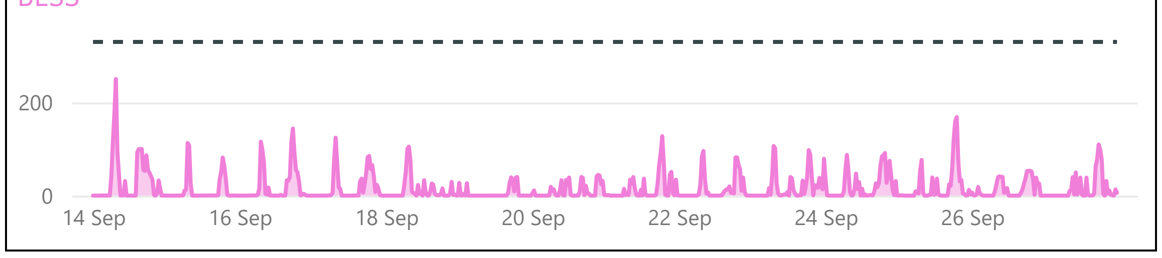
Co-Generation



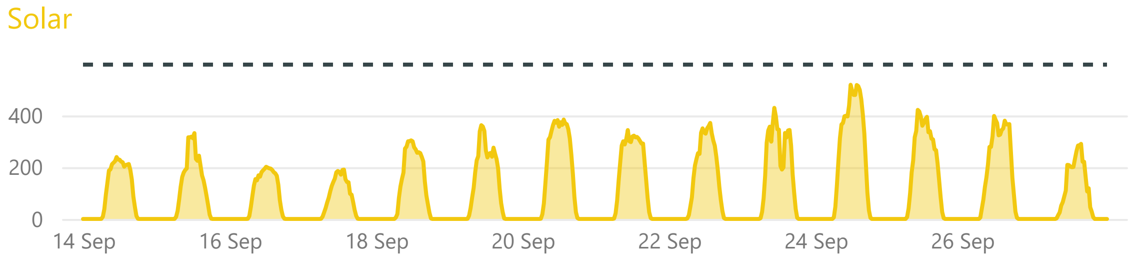
South Island Wind



BESS

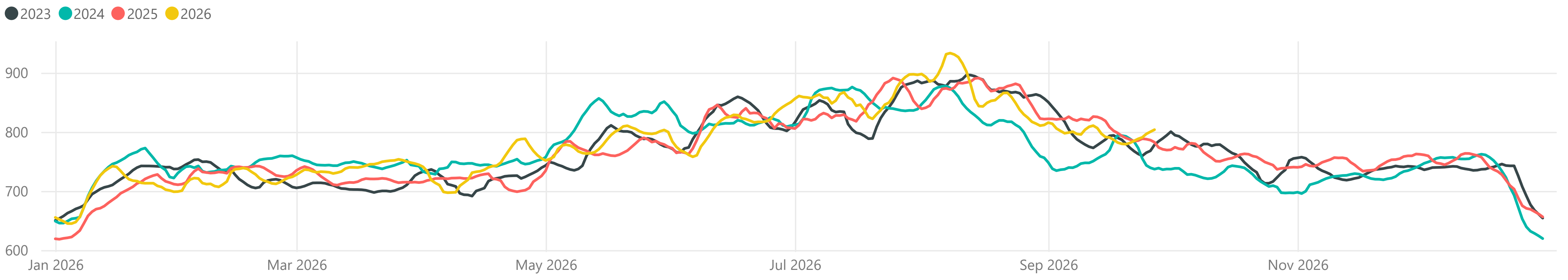


Solar

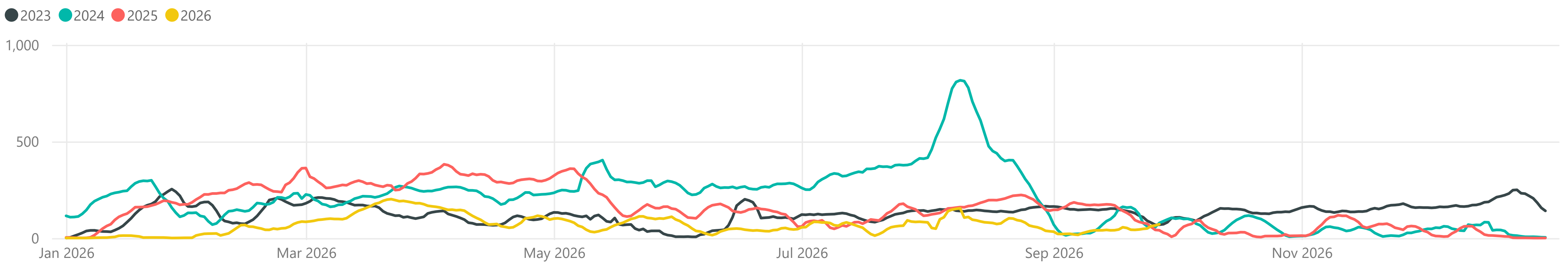


Weekly Profiles

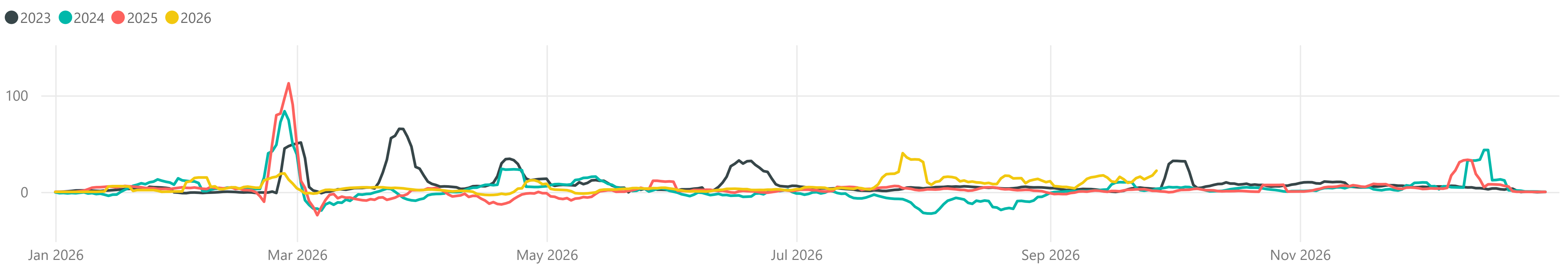
National Weekly Demand - GWh - 7 Day Rolling



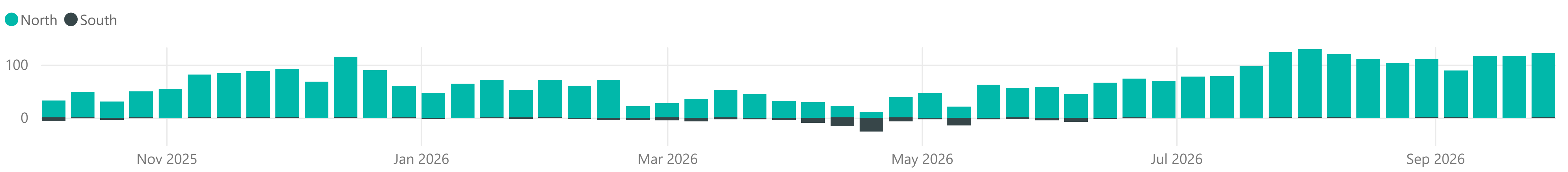
OTA2201 Weekly Rolling Average Spot Price - $/MWh



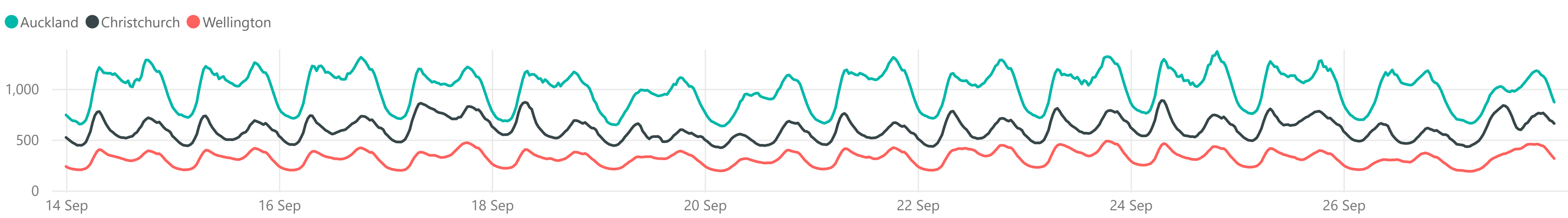
Weekly Rolling Price Separation (HAY2201 - BEN2201) - $/MWh



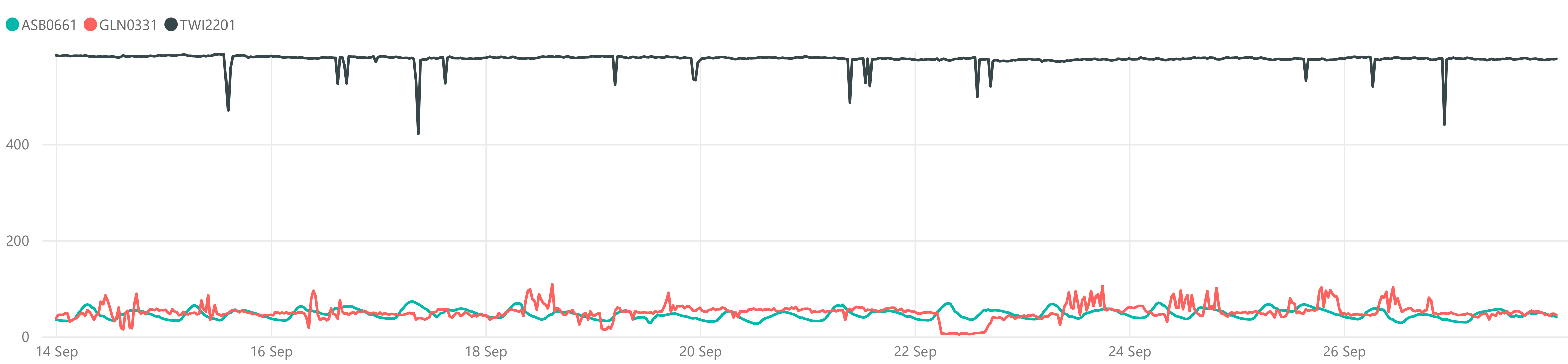
HVDC Transfer - Weekly GWh



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*



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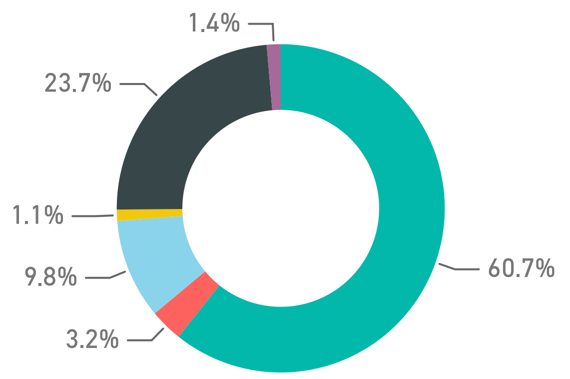
Generation Mix

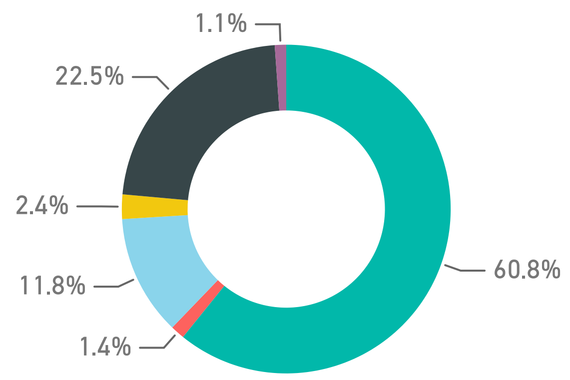
Last 52 Weeks Generation Mix - Weekly GWh

Hydro Thermal Wind Solar Geothermal Co-gen



Last 7 Days Generation Mix - Weekly GWh

Hydro Thermal Wind Solar Geothermal Co-gen



Average Metrics Last 7 Days

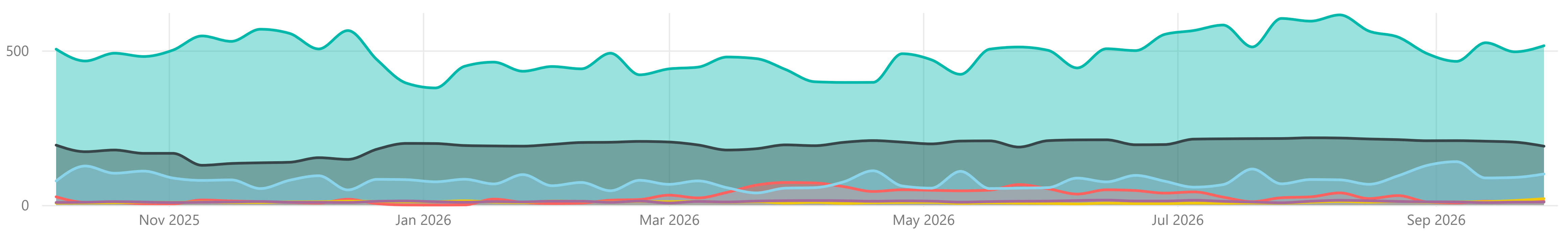
Renewable Percentage	CO2e Tonnes/Week	CO2e g/kWh
97%	28,527	33.1

Average Metrics Last 52 Weeks

Renewable Percentage	CO2e Tonnes/Week	CO2e g/kWh
95%	33,783	41.2

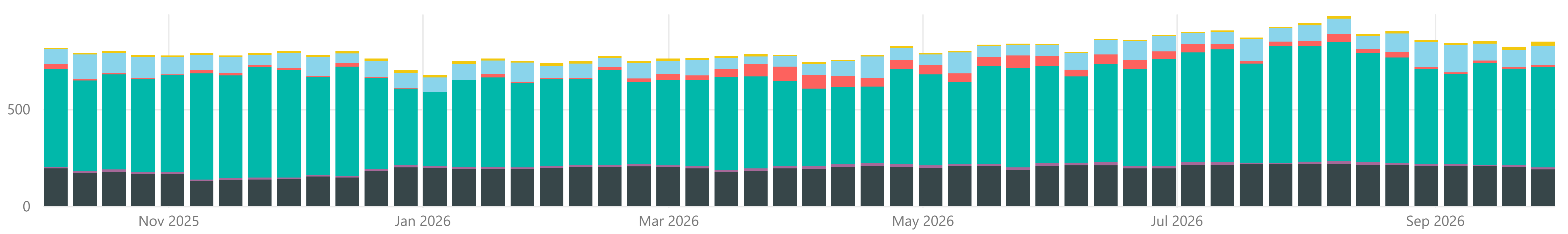
Weekly Generation Mix - GWh

Hydro Geothermal Thermal Solar Co-gen Wind



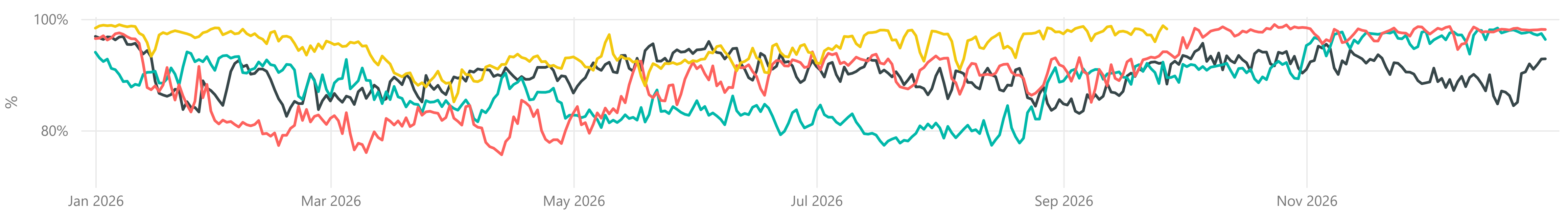
Weekly Generation Mix - GWh

Geothermal Co-gen Hydro Thermal Wind Solar



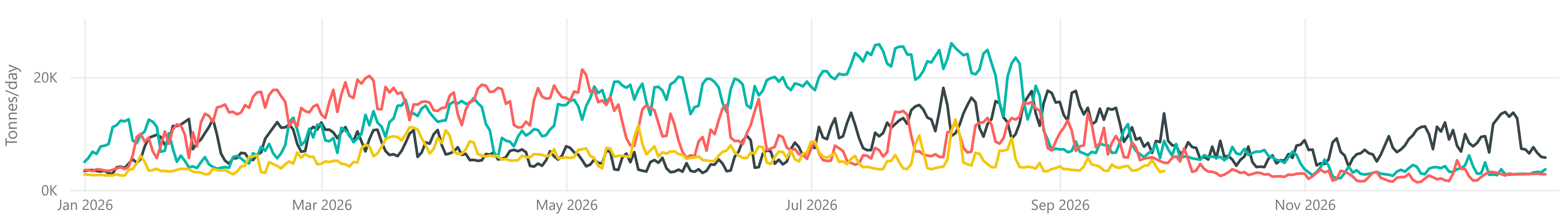
NZ Renewable Percentage

2023 2024 2025 2026



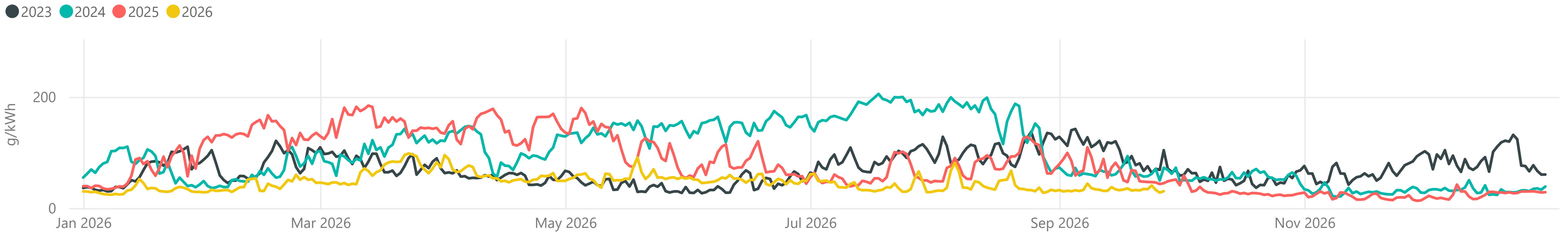
CO2 Tonnes/Day

2023 2024 2025 2026



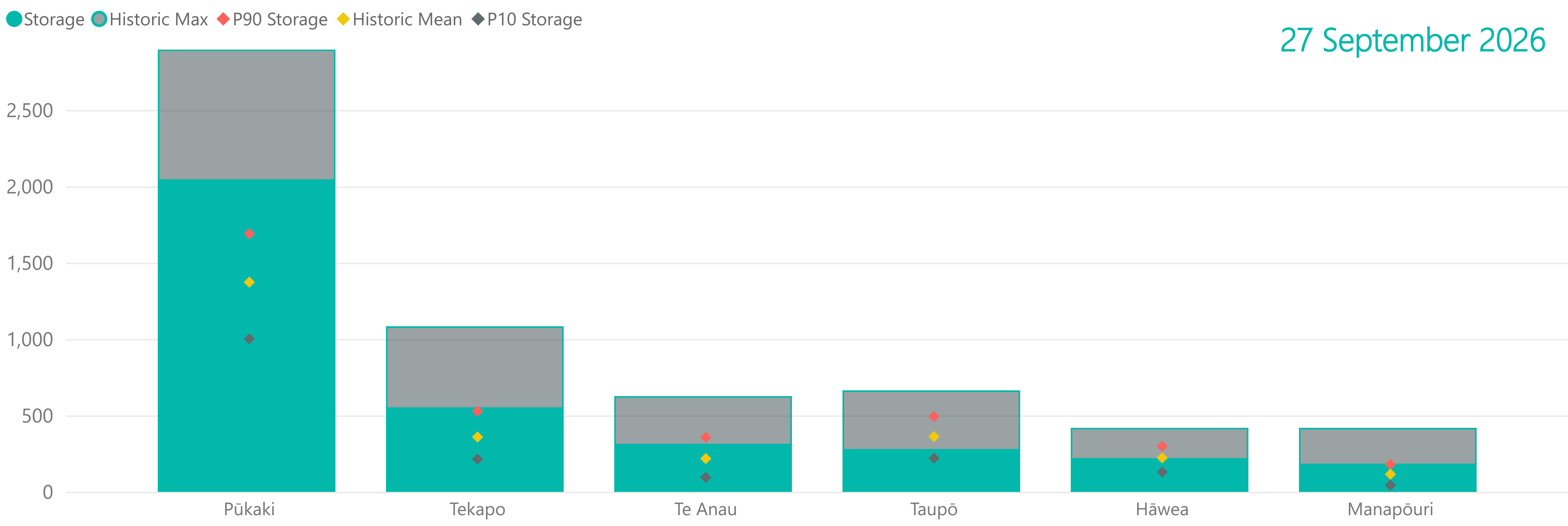
Average CO2 g/kWh

2023 2024 2025 2026

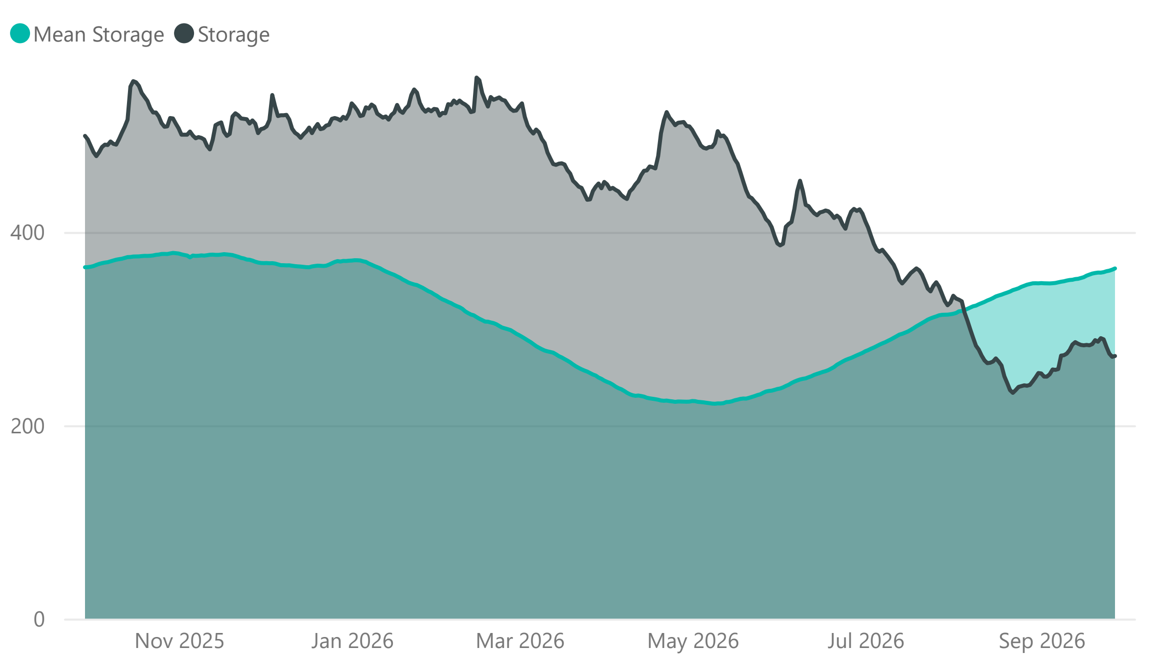


Hydro Storage

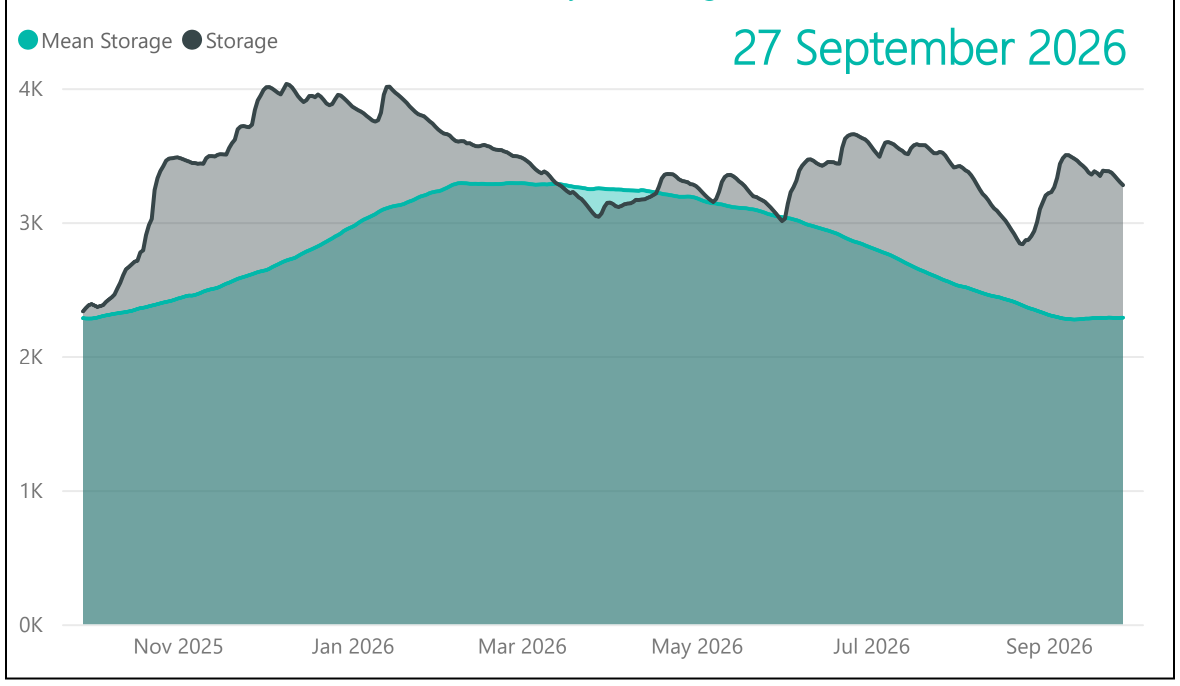
Latest Controlled Hydro Storage Against Historic Statistics (Available GWh)



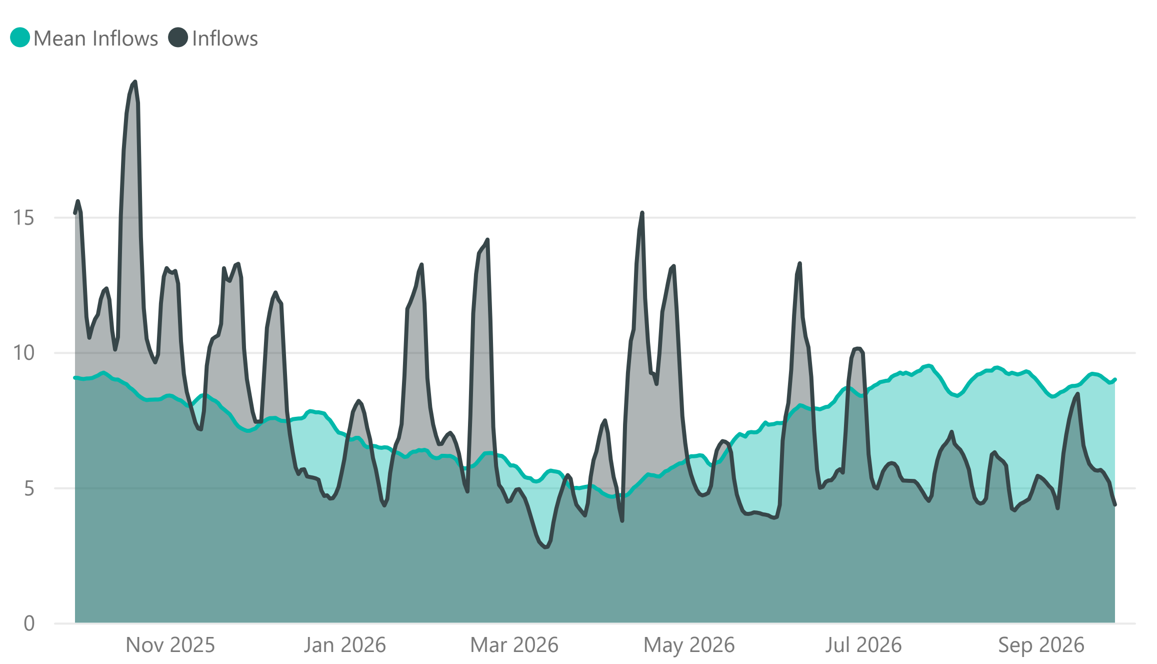
North Island Controlled Hydro Storage (Available GWh)



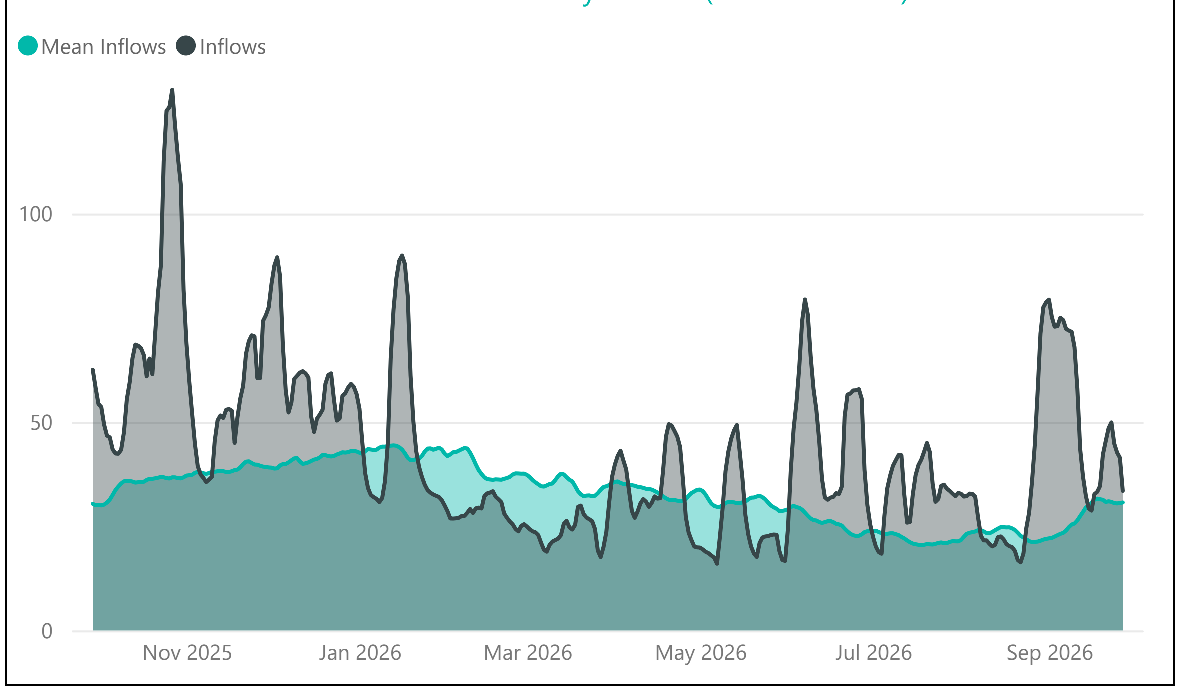
South Island Controlled Hydro Storage (Available GWh)



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

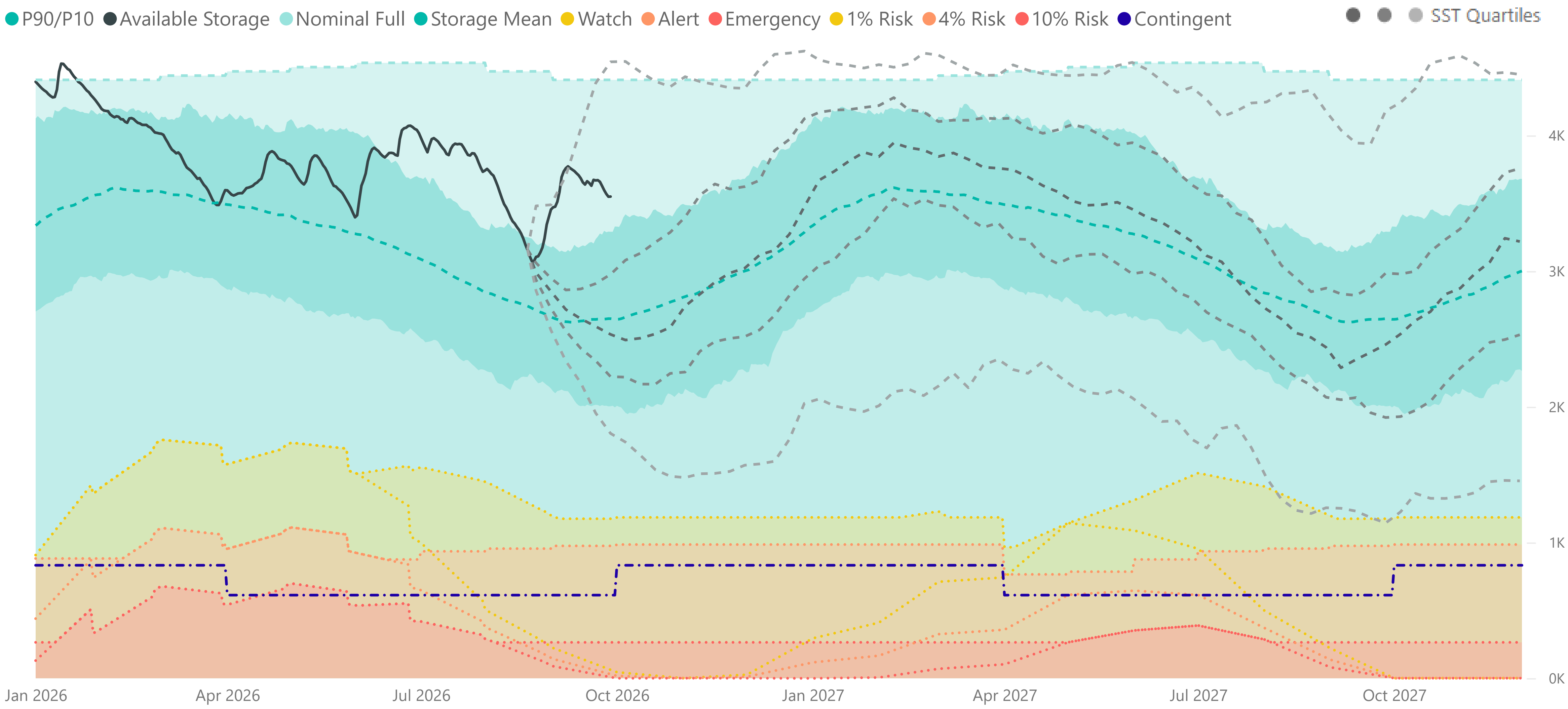
Hydro data used in this report is sourced from *NZX Hydro*.

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.

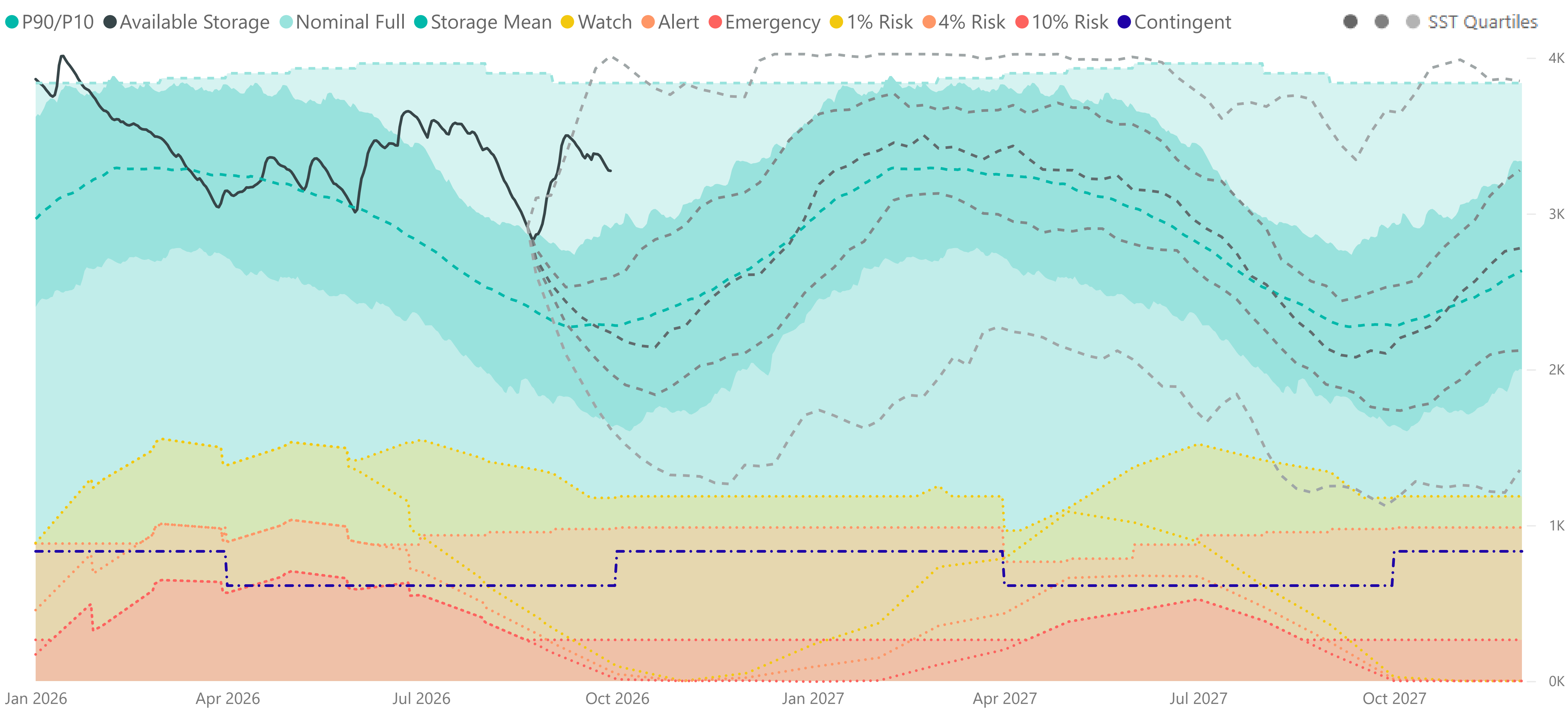
Further information on the methodology of modelling electricity risk curves may be found here: https://www.transpower.co.nz/system-operator/security-supply/hydro-risk-curves-explanation

Electricity Risk Curves

New Zealand Electricity Risk Status Curves (Available GWh)



South Island Electricity Risk Status Curves (Available GWh)



Electricity Risk Curve Explanation:

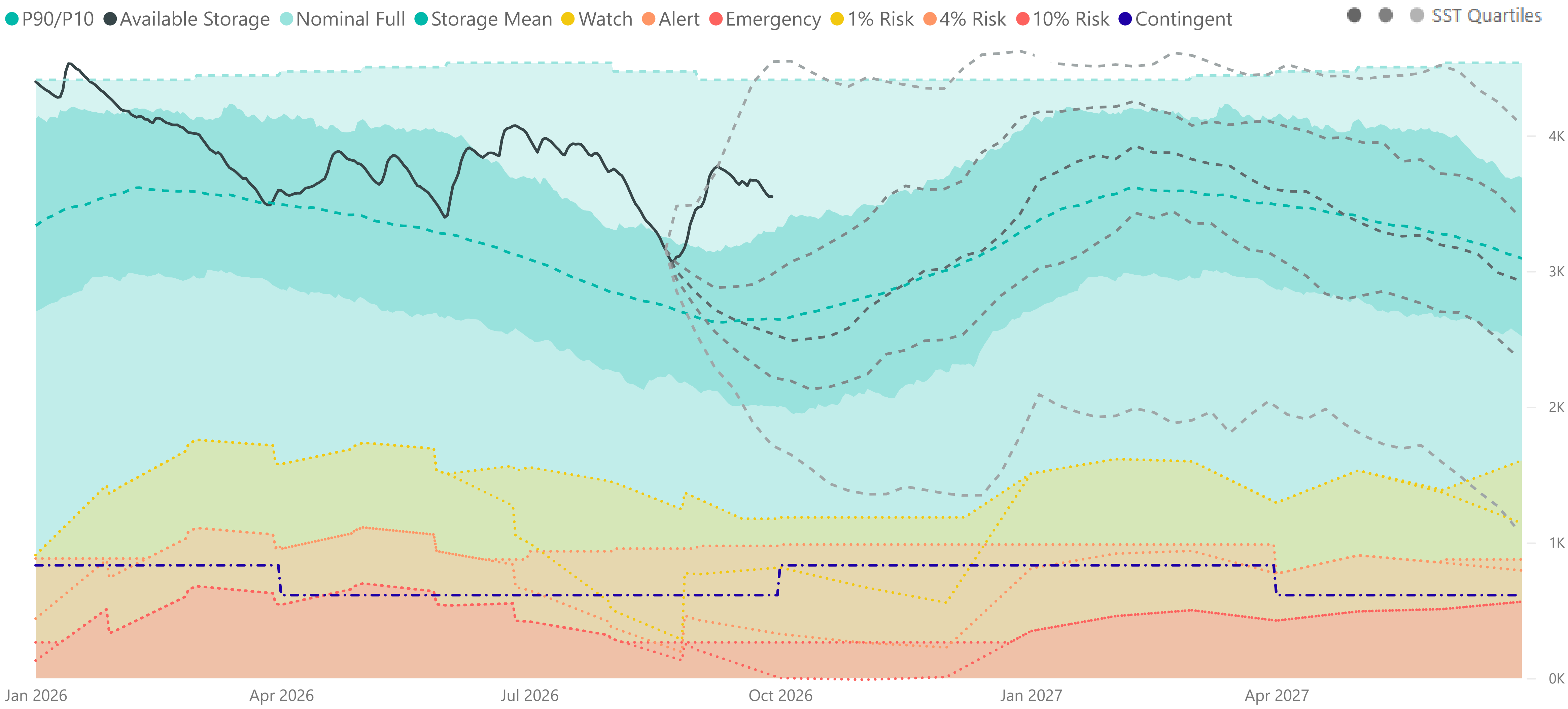
Watch Curve - The maximum of the one percent risk curve or the Alert curve plus the greater of the Watch adder or the worst-case simulated storage drop
Alert Curve - The maximum of the four percent risk curve and the floor and buffer
Emergency Curve - The maximum of the 10 percent risk curve and the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

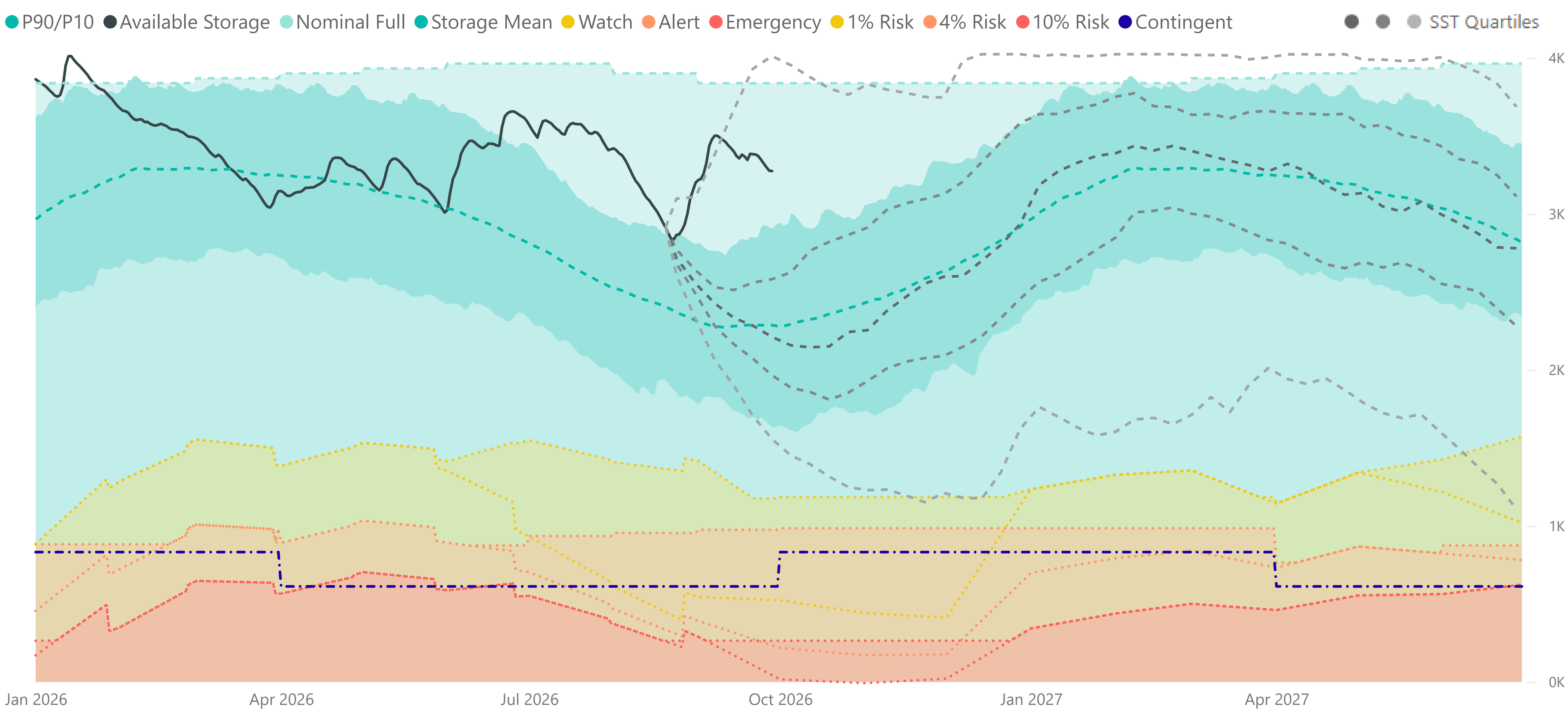
The dashed grey lines represent the minimum, lower quartile, median, upper quartile and the maximum range of the simulated storage trajectories (SSTs). These will be updated with each Electricity Risk Curve update (monthly).

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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