TRANSPOWER

Monthly System Operator performance report

For the Electricity Authority

Report period: June 2026

Report Purpose

This report is Transpower's review of its performance as System Operator in accordance with clauses 3.13 and 3.14 of the Electricity Industry Participation Code 2010 (the Code):

3.13 Self-review must be carried out by market operation service providers

(1) Each **market operation service provider** must conduct, on a monthly basis, a self-review of its performance.

(2) The review must concentrate on the **market operation service provider's** compliance with—

(a) its obligations under this Code and Part 2 and Subpart 1 of Part 4 of the **Act**; and

(b) the operation of this Code and Part 2 and Subpart 1 of Part 4 of the **Act**; and

(c) any performance standards agreed between the **market operation service provider** and the **Authority**; and

(d) the provisions of the **market operation service provider agreement**.

3.14 Market operation service providers must report to Authority

(1) Each **market operation service provider** must prepare a written report for the **Authority** on the results of the review carried out under clause 3.13.

(1A) A **market operation service provider** must provide the report prepared under subclause (1) to the **Authority**—

(a) within 10 **business days** after the end of each calendar month except after the month of December:

(b) within 20 **business days** after the end of the month of December.

(2) The report must contain details of—

(a) any circumstances identified by the **market operation service provider** in which it has failed, or may have failed, to comply with its obligations under this Code and Part 2 and Subpart 1 of Part 4 of the **Act**; and

(b) any event or series of events that, in the **market operation service provider's** view, highlight an area where a change to this Code may need to be considered; and

(c) any other matters that the **Authority**, in its reasonable discretion, considers appropriate and asks the **market operation service provider**, in writing within a reasonable time before the report is provided, to report on.

By agreement with the Authority, this report also provides monthly (rather than quarterly) reporting in accordance with clause 12.3 of the 2025 System Operator Service Provider Agreement (SOSPA):

12.2 **Monthly reports**: The **Provider** must provide to the **Authority**, with each self-review report under clause 3.14 of the **Code**:

(a) a report on the progress of any **service enhancement capex project** or **market design capex project** that has commenced and has either not been completed or was completed during the month to which the report relates, including:

(i) to any actual or expected variance from the **capex roadmap** in relation to that **capex project**; and

(ii) the reasons for the variance;

(b) a report on **the technical advisory** services in accordance with the **TAS guideline;**

(c) the actions taken by the **Provider** during the previous month:

(i) to give effect to the **system operator business plan**, including to comply with the **statutory objective work plan**;

(ii) in response to participant responses to any participant survey; and

(iii) to comply with any remedial plan agreed by the parties under clause 14.1(i);

(d) the **technical advisory hours** for the previous quarter and a summary of **technical advisory services** to which those **technical advisory hours** related; and

(e) in the report relating to the last month of each quarter, the **Provider's** performance against the **performance metrics** for the **financial year** during the previous quarter.

System Operator performance reports are published on the [Electricity Authority] website in accordance with clause 7.12 of the Electricity Industry Participation Code 2010 (the Code):

7.12 Authority must publish system operator reports

(1) The **Authority** must publish all self-review reports that are received from the **system operator** and that are required to be provided by the system operator to the **Authority** under this Code.

(2) The **Authority** must **publish** each report within 5 **business days** after receiving the report.

Following the end of each Quarter, a system performance report is published on the [Transpower website]

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1 Key points this month

Operating the power system

- On 14 June, HVDC Pole 3 was proactively taken out of service on planned outage by the Grid Owner to mitigate the risk of building flashings coming loose during forecast bad weather. Further building flashing work is expected to be undertaken during the next annual HVDC outage.
- On 16 June, the Argyle-Blenheim-Kikiwa-1 circuit tripped, causing the loss of connection to 2.5 MW of generation at Argyle. A line patrol found no fault and the circuit was returned to service.

On 25 June, the Hinuera-Karapiro-1 circuit tripped, with lightening the suspected cause, resulting in a 12 MW loss of supply at Hinuera. Powerco automatically back fed from Arapuni, restoring supply at Hinuera within 30 minutes.

- On 26 June, the Kawerau-Ohakuri-1 circuit tripped creating security violations for a contingency of the Edgecumbe-Kawerau-3 circuit. The System Operator declared a verbal Grid Emergency to reconfigure the Bay of Plenty 110 kV grid and remove the violation. Kawerau-Ohakuri-1 was returned to service and the Grid Emergency ended within three hours.

Security of supply

- *Energy Security Outlook (ESO)*: The June update included higher coal and gas storage positions, scheduled thermal outages later in 2026 and early 2027, and delays in expected commissioning of new generation. This month's outlook included an additional Reduced Rankine Availability scenario, which would result in increased energy risk in both 2026 and particularly in 2027 when two units are modelled as unavailable. National hydro storage at the end of June was 130% of the historic mean.
- *New Zealand Generation Balance (NZGB):* NZGB margins in the base case remain positive through winter. Our sensitivities and scenarios show that if demand is higher than the 90th percentile we will be relying on a mix of high levels of slow start unit commitment and intermittent generation, and units to remain in service. This mix would also enable meeting 100th percentile demand requirements on all but 10 days in winter.
- *Security of Supply Assessment (SOSA) 2026:* We published the final Security of Supply Assessment 2026 report at the end of June. There were some changes made compared to the draft report, most notably the inclusion of LNG terminal (operational by 2029) in the Expected Future case.

Investigations

- *Under-frequency event investigations*: In June, we provided the Authority with the Engineering Report for the event on 4 February 2026, which was in relation to a reduction in HVDC transfer.

Supporting asset-owner activity

- *Outage coordination:* In June, short notice outage volumes levelled. The amount of work bundled into each outage continued to trend in an upward direction. The work bundling in June was 6% higher than June 2025. The System Operator continued to support the Grid Owner and industry to co-ordinate outages on the Wairakei Ring, providing preferred timings out to 2030. In June this included engaging with the relevant generators and the Authority on our operational approach to managing inflexible geothermal plant, and preparing for a wider industry briefing on 13 July.

- *Generator commissioning and testing*: In June we commissioned Dannevirke solar farm (19 MW), and the return of Contact's Patea hydro station, now connected to Transpower's new substation at Ohingai. Harmony Energy's Tauhei Solar Farm in the Waikato (150MW) is due to be commissioning in late June 2026. Lodestone Energy's Clandeboye solar farm at Temuka (24MW) and Mercury Energy's Kaiwaikawe wind farm at Maungatapere (77MW) are due to begin commissioning in early July 2026.
- *Large loads commissioning and testing*: We continue to support NZ Steel with the commissioning of their Arc Furnace at Glenbrook, and Fonterra/Simply Energy on Whareroa load and generation changes. This includes working with Fonterra to ensure the remaining generation at Whareroa is offered separately to the market, and completing market system modelling to facilitate the generation offers and dispatch. In response to our request, the Authority has now determined that HWA1101 and HWA1102 will be non-conforming nodes from 1 August 2026.
- *Glenbrook co-generation ownership change:* The System Operator continues to assist NZ Steel towards meeting obligations as the new asset owner and trader, and changing the market system to accommodate the required trading and dispatch changes.
- *Ancillary Services activity:* We completed a soft launch of some of our recent participant engagement and process improvements work, primarily centred around updated web pages.

Commitment to evolving industry needs

- *System Operator strategy development:* In June, we progressed Phase 2 of the System Operator Strategy development programme. The draft Strategic Priorities consultation paper was released on 19 June, with industry and stakeholder engagement activities planned between now and when submissions close on 24 July.
- *Policy Statement review:* Consultation on the draft Policy Statement closed in early June. Our Policy Statement amendment proposal, including the summary and response to submissions, was finalised and submitted to the Authority.
- *Industry Exercise 2026:* We received the draft lessons learned report for the exercise from the Authority and are providing feedback on the draft report and working with the Authority to finalise the report for publication.

  Evolving markets resource co-ordination: Following our prior consultation we have successfully implemented the tiebreaker solution into the Scheduling, Pricing and Dispatch (SPD) model that will allocate dispatch at a given pricing node in proportion to offered quantities at the same price. As part of the Market Node Constraint initiative, there is a planned MW enhancement change going into the Market System in August. Until then we will continue to use operational discretion to manage transmission outages when there is oversupply of inflexible generation such as geothermal, that need to remain at their minimum feasible levels of operation.

  Interim BESS solution: We have also successfully implemented our proposed BESS temporary solution into the SPD model to prevent non-physical dispatch of BESS.

Technical advisory services:

- *TAS 120 – Multiple Frequency Keeping (MFK) review:* In June, we progressed the low inertia system need assessment to help inform the Authority's upcoming frequency strategy development. We progressed an assessment of the market development changes and associated cost estimates to deliver MFK national selection and full participation of BESS alongside the BESS enhancements market design initiative.

- *TAS 121- FSR Part 8 of the Code – common quality requirements*: We continued to support the Authority with progressing several consultation papers, including the information sharing consultation. We completed planning on the high priority items for FY 26/27, including assisting the Authority in their delivery of a frequency management strategy, and system strength studies to inform a robust assessment methodology.
- *TAS 122 – Emergency Reserve scheme (ERS):* The ERS Market Design project confirmation letter was agreed for execution. The TAS phase of this initiative finished on 30 June, with the capital investment phase starting as a market design project on 1 July. A TAS project close out report will now be completed in July.

Risk & assurance

- *Risk management:* Of the five CSA critical controls reviewed this round, four were rated as "effective" and one as "partially effective". The "partially effective" score was for the "Monitor/evaluate operating environment" control. This reflects the need to ensure our people, processes and tools continue to keep pace with the complexity of the evolving power system and electricity market. We continue to be proactive in the area of system health monitoring and investigate areas of concern, developing workplans to address these.
- *Business assurance audits*: The remaining two business assurance audits were completed in June. Both audits were rated effective, and recommendations were received and are being actioned.
- *Business assurance audit plan:* We met with Authority staff to agree the System Operator's proposed 2026/27 Business Assurance Plan, incorporating input from both the System Operator and the Authority. The agreed plan has been provided to the Authority and sets out the audits planned for 2026/27, as well as potential audits for 2027/28 and 2028/29.

2 Operating the power system

2.1 System events

Event Date	Event Name	Event Activity
14 June 2026	HVDC Pole 3 planned outage	At 03:27 on 12 June 2026, a Customer Advice Notice (CAN) advised that HVDC Pole 3 would be out of service from 05:30 to 18:30 on 14 June 2026. The Grid Owner took the proactive outage to reduce the risk of building flashings coming loose at Haywards during forecast bad weather, which could have caused an unplanned outage. The outage proceeded as planned, and Pole 3 was returned to service at 17:30. Our understanding is that additional building flashing work will be undertaken in the next annual HVDC outage to further mitigate the risk.
16 June 2026	Loss of Connection to Argyle (ARG)	At 08:19, the Argyle-Blenheim-Kikiwa-1 (ARG-BLN-KIK-1) circuit tripped, causing the loss of connection of 2.5 MW of Contact Energy generation at Argyle. A line patrol was dispatched, but no fault was found. The circuit was returned to service at 09:38.
25 June 2026	Loss of Supply at Hinuera (HIN)	At 15:34, the Hinuera-Karapiro-1 (HIN-KPO-1) circuit tripped, causing a 12 MW loss of supply to PowerCo at Hinuera. PowerCo automatically backfed supply from Arapuni , and supply at Hinuera was restored at 15:56. The suspected cause of the trip was lightning.
26 June 2026	Grid Emergency to reconfigure the grid	At 11:35, the Kawerau-Ohakuri-1 (KAW-OHK-1) circuit tripped. There was no loss of supply but the trip created security violations for a contingency of the Edgecumbe-Kawerau-3 (EDG-KAW-3) circuit. The System Operator declared a verbal Grid Emergency at 11:47 to reconfigure the Bay of Plenty 110 kV grid and remove the violation. The Grid Emergency ended at 14:05 after KAW-OHK-1 was returned to service.

2.2 Market operations

Forecast v real-time residual variability:

In June more than 97% of the variability was covered by the 200 MW residual threshold.[1] This indicates that entering a trading period with at least 200 MW of residual provided a high chance of having sufficient market resources to meet the variability within the period.

3 Security of supply

Energy Security Outlook (ESO):

Following implementation of the new SOSFIP that took effect in May, our ESOs are evaluated through two lenses: the Fuel Capability Case (Base Case), which uses the original methodology based on total physical capability to source thermal fuels and utilise it for generation, and the Contracted Fuel Case, which limits thermal energy to firm commercial contracts secured by generators. This approach highlights the gap between physical capability and actual commercial certainty, signalling to industry where additional fuel contracts can yet be secured to reduce security of supply energy risks.

Changes reflected in the June Energy Security Outlook (ESO) update included higher coal and gas storage positions, scheduled thermal outages later in 2026 and early 2027, and delays in expected commissioning of new generation. A modelling change was also made to use the contracted gas volume if it is greater than the assumed physically available gas volume. The net effect on the Fuel Capability case was reductions to the electricity risk curves for 2026 and 2027. The energy security outlook for this winter remains healthy with above average hydro storage and high levels of gas and coal storage.

The Contracted Fuel case shows strong 2026 contracted fuel position relative to the Fuel Capability case. There is a more pronounced gap between the two cases in 2027, which reflects that participants tend to contract for thermal fuel supplies closer to the time.

In addition, the June ESO update included an additional scenario that reflects the Reduced Rankine Availability scenario in our 2026 Security of Supply Assessment. Reduced Rankine availability increases energy risk in both 2026 and 2027, with higher impacts in 2027 as two units become unavailable. This underscores the critical role of the Rankine units and fuel in maintaining energy security by supplementing for hydro storage during prolonged low inflow periods.

On 30 June, national hydro storage sat at 130%, following a recent period of higher than average inflows for both islands. The weekly market updates are available on our Market Operations weekly report webpage.

New Zealand Generation Balance (NZGB) potential shortfalls:

NZGB margins in the base case remain positive through winter. The base case assumes a 90th percentile demand, all thermal plant is operating, wind at 20% of its capacity and that the largest generation unit has been removed from service. However, our sensitivities and scenarios show that if demand is higher

[1] We monitor the variations between forecast and real-time dispatch conditions to determine if the 200 MW residual continues to provide sufficient coverage to cater for within trading period variations in demand and supply. The graph in Appendix B presents, for the last 24 months, the proportion of time within each month that a 200 MW residual was sufficient to cover the variation in load and intermittent generation between forecast (30 minutes ahead of real-time) and real-time.

than the 90th percentile we will be relying on a mix of high levels of slow start unit commitment, high levels of intermittent generation, and units to remain in service. Assuming all the of these things are true, meeting a 100th percentile demand is achievable on all but 10 days in winter, where small negative margins are present from middle of July to until the end of August.

Security of Supply Assessment (SOSA) 2026:

We published the final Security of Supply Assessment 2026 report on 30 June. There were some changes made compared to the draft report, most notably the inclusion of LNG terminal (operational by 2029) in the Expected Future case.

Overall, the assessment shows an improvement in energy and capacity margins relative to SOSA 2025. In the short term (2026-2028), if domestic gas supply falls below forecasts, the national Winter Energy Margin (NZ-WEM) will fall 689 GWh below the lower standard, even if committed projects are delivered on time. Looking to the mid-term (2029-2031), there is a potential gap of 168 GWh in the NZ-WEM even with the delivery of consented projects. However, this gap closes if additional gas becomes available via LNG, even if domestic gas supply remains below the medium forecast. Increasing the NZ-WEM above the lower security standard can be achieved by developing additional consent-ready projects. Over the next decade, project commissioning delays and reduced Rankine support seem to be the key risks to energy and capacity.

It is important to note that SOSA evaluates energy gaps over dry winters, and capacity risks include reserves as well. Falling below the security standards signals a shift in the efficient supply-demand balance rather than an immediate supply shortage and should be considered alongside the magnitude of the shortfall.

4 Investigations

4.1 Under-frequency event (UFE) investigations

4 February 2026 UFE: Under-frequency disturbance in the North Island (49.2 Hz) coinciding with a sudden ramp-down of HVDC Pole 3 transfer received at Haywards from 373 MW to 34 MW in approximately 32 seconds then tripping. We completed our engineering report in June and sent this to the Authority on 11 June 2026.

4.2 Significant incident investigations

Significant event: On 9 April 2026, high winds associated with Cyclone Vaianu caused an Edgecumbe-Waiotahe line fault and an associated loss of supply. Our moderate event report was largely completed in June, and will be provided to the Authority in early July.

5 Supporting asset-owner activity

5.1 Outage coordination

We continue to work with the Grid Owner to minimise the impact of its work programme by encouraging longer outage lead times, more work per outage, smoother outage volumes, and strong market engagement for high-impact outages. Longer lead times and smoother outage volumes allow the market to coordinate effectively. Bundling more work into each outage reduces the total number of outages needed, reducing the market impact of the Grid Owner's growing RCP4 work programme.

- The 12-month rolling average number of Short Notice Outage Requests (SNORs) levelled off in June, following increases over the previous two months. The June SNORs were almost all for non-material work, such as secondary system outages, unavoidable work such as fault repairs, or work to enable customer projects. The number of SNORs on primary assets, which materially disrupt outage plans, was low.
- The 12-month rolling average shows the effectiveness of outage bundling and the benefit of incorporating multiple work orders and work crews into each outage. Work orders per outage continued to increase. The number of work crews per outage was maintained, with June 2026 6% higher than June 2025. To maintain this trend, the Grid Owner has implemented a KPI with its service providers.
- Weekly outage volumes during June were managed within the System Operator's guideline of 80 outages per week provided to the Grid Owner. This means outage-driven workload can be managed within typical System Operator control room resourcing levels.
- The System Operator has taken an active role in supporting market coordination for the Wairekei Ring outages in Q2 2026. This involved engaging with geothermal generators and the Authority on how we would manage their generation down during the outage. We will provide an industry communication at the System Operator Industry Forum on 13 July covering all risks and how they will be managed.

Approach to Outage Planning

We have published the paper System Operator Impartiality: Approach to Outage Planning on the Transpower website. The document explains how impartiality is managed throughout the outage assessment process, identifying key decision points, potential impartiality risks, and the controls in place to ensure decisions are consistent, transparent, and based on power system security requirements rather than commercial or asset ownership interests.

5.2 Generator and large loads commissioning and testing

Generation commissioning and testing

The Power Systems and Markets teams are working with the following participants who are commissioning or expecting to connect in the next 6 months:

- Mercury Energy's Kaiwera Downs 2 wind farm (150 MW connecting to the Transpower grid at KIW) commenced commissioning 1 April 2026.
- Aquila Clean Energy Asia Pacific's Omeheu Solar Farm in Edgecumbe (27 MW connecting to Horizon) completed commissioning in June 2026.

- Contact Energy completed moving connection of their Pātea hydro station (33MW) from Hāwera to the new Transpower substation at Ohangai in June 2026.
- BrightFern Energy's Dannevirke solar farm (19 MW directly connecting to the Transpower grid at DVK) commenced commissioning in June 2026.
- Harmony Energy's Tauhei at Waihou solar farm (150 MW connected to the Transpower grid at WHU) commenced commissioning in June 2026.
- Lodestone's Clandeboye Solar Farm (24 MW connecting to Alpine Energy) is due to begin commissioning in July 2026.
- Mercury's Kaiwaikawe Wind Farm (77 MW connected to Northpower) is due to begin commissioning in July 2026.
- Genesis Energy's Huntly BESS (100 MW connecting to the Transpower Grid at HLY) is due to begin commissioning in July 2026.
- Contact Energy & Lightsource's Kōwhai Park Solar Farm at Christchurch Airport (150 MW connecting to Orion) is due to begin commissioning in July 2026.
- Fonterra will be taking dispatch for their Whareroa co-generation plant directly from Transpower, rather than via Nova in Julyt 2026.
- Meridian's Ruakākā Solar Farm (130 MW directly connecting to the Transpower grid at BRB) is due to begin commissioning in October 2026.
- Contact's new geothermal unit (2A G6) at Te Mihi (51MW directly connecting to Transpower grid at THI) is due to begin commissioning in December 2026.
- Northpower's new solar farm at Maungatapere (24MW connecting to Northpower) is due to begin commissioning in December 2026.

We are also working with existing generators to commission maintenance and upgrade projects, and with Contact Energy to decommission the Taranaki Combined Cycle (TCC) generator.

Large loads commissioning and testing

We continue to support NZ Steel with the commissioning of their Arc Furnace at Glenbrook, and with Fonterra/Simply Energy on Whareroa load and generation changes.

In August 2026, Fonterra will become a direct connect transmission customer at Hāwera with their Whareroa dairy factory. We expect the majority of embedded generation at this site to cease (~10 MW may remain). Process driven demand of up to 80 MW will come online with the electric boilers. In response to our request, the Authority have determined that HWA1101 and HWA1102 will be non-conforming nodes from 1 August 2026. We have worked with Simply Energy (who will be bidding the load) to ensure they will be setup from 1 August, concurrent with changes to our market tools. We continue to work with Fonterra to ensure the remaining generation at Whareroa is offered separately to the market. We will have modelling to facilitate the generation offers and dispatch for Whareroa.

Glenbrook co-generation ownership change

There will be a change in ownership of the Glenbrook co-generation plant. The System Operator continues to assist NZ Steel as the new asset owner and trader in their obligations and changing the market system to accommodate the required trading and dispatch changes.

Ancillary Services activity

Setup continues with a new ancillary services provider. There was one ancillary service contract variation within the reporting period.

We completed our initial ancillary services process optimisation project, culminating in the soft launch of updates to the information and structure available via our website, and implementing a raft of processes improvements. Work will continue to utilise existing tools to better manage work load and visibility of processes internally.

Interruptible Load (IL):

The following table provides an overview of IL testing activity by the number of sites tested and associated additional quantities for those sites. Work is ongoing to review the performance of reserves service providers against contractual requirements during recent UFE's.

	Number of sites	Additional quantities in MW	
Annual testing	0 sites	N/A	
Additional resource	2 sites	1.399 MW FIR	1.468 MW SIR
Removal of resources	0 sites	0 MW FIR	0 MW SIR

Generation Reserve (GR):

In June, engineering assessments were completed for test results of five units.

There is one unit with overdue testing for both PLSR and TWDR. The asset owner has confirmed that testing is scheduled for later this year.

	Number of units overdue
Testing	1

Over-Frequency Reserve (OFR):

The following table provides an overview of OFR testing activity. We have been actively working with participants and our internal teams to address overdue testing requirements and have reduced this number notably. We intend to continue this work and expect these figures to reduce further.

	Number of units overdue
Four yearly end-to-end relay testing	0
Two yearly control and indication testing	3
Circuit breaker testing	11

6 Commitment to evolving industry needs

System Operator Strategy development:

During June, we progressed Phase 2 of the System Operator Strategy development programme, refining and publishing a draft set of strategic priorities, outcomes and initiatives to guide the evolution of the System Operator service over the next ten years. This work built on Phase 1 consultation and extensive engagement undertaken with industry participants, regulators, government agencies and stakeholders. Following review and refinement of the consultation material, the draft Strategic Priorities consultation paper was released on 19 June, outlining five proposed strategic priorities: operating a secure, highly variable power system; efficient market operations and information provision; evolving operational capability; leveraging data and distributed energy resource integration; and strengthening industry resilience. Consultation was opened to industry through to 24 July, supported by industry communications, stakeholder engagement activities and preparation for a public webinar on 8 July to further discuss the proposed priorities and seek feedback on the associated outcomes and initiatives.

Policy Statement review:

We received 3 submissions in response to our consultation on the draft Policy Statement amendment proposal, which closed in early June. We considered the feedback received and decided not to make any changes to our proposal. Our final Policy Statement amendment proposal including our summary and response to submissions was submitted to the Authority on 30 June.

Pan-industry exercise:

We received the draft lessons learned report for the exercise from the Authority in early July. We are providing feedback on the draft report and working with the Authority to finalise the report for publication.

Evolving markets resource co-ordination - Tie-breaker provisions:

There are three tie-breaker provisions at various stages of development:

- Tie-breaker: As we indicated in our summary and response to the 2025 tie-breaker provisions consultation, we have now implemented the new tie-breaker methodology into the Scheduling, Pricing, and Dispatch (SPD) model. The solution introduces a tie-breaker energy constraint within SPD which allocates dispatch at a given pricing node in proportion to offered quantities at the same price.
- Market Node Constraint: this initiative is designed to address the problem associated with (and similar to the) Wairakei Ring transmission outages when there are multiple geothermal generators needing to remain at their minimum feasible levels of operation. The change to deploy market node constraint is going into the Market System on the 27 August and this will be communicated closer to the time.
- We also await an indication from the Authority of a likely timeline for its full review of market design arrangements to manage oversupply in areas with inflexible generation such as geothermal, as signalled in its 30 April 2026 decision to decline our 1c Intermittent Generation offer floor Code change proposal.

Interim BESS solution:

Battery energy storage systems (BESS) Temporary Solution: We have successfully implemented the BESS temporary solution along with the tie-breaker solution on 23 June 2026.

Electricity Networks Aotearoa (ENA) Future Networks Forum (FNF):

The Authority's DSO Roadmap was published on 30 June, with the Authority welcoming feedback from interested parties. The System Operator and ENA are meeting in July to discuss the DSO Roadmap and will provide feedback to the Authority on the DSO Roadmap.

Ongoing regular engagements with the Authority on this topic have concluded with the publication of the DSO Roadmap. Given the usefulness of these engagements for all parties ad hoc engagements will occur as the need arises.

6.1 Connecting with the industry

System Operator industry forums:

We ran three standard industry forums in June. In the first forum we shared insights on the industry exercise held in late May, which simulated a major space weather event. The second forum provided information on the upcoming Lower South Island restoration workshop and details on how to attend. The final forum reminded attendees of Connected Asset Commissioning, Testing, and information Standard (CACTIS) coming into effect on 1 July 2026.

To help industry understanding of the new CACTIS and other Code changes we help or annual System Operator Engineering Forum on 1 July 2026, in collaboration with the Electricity Authority. This was well attended by asset owners, consultants and developers and provided an opportunity to step through and discuss both existing and new obligations.

Market Operations weekly reports:

Our Market Operations Weekly Report provides information to assist interested parties' understanding of the current security of supply situation[2] and other market events. These reports also include a Market Insight each week covering a topic of interest to the industry. The reports we published this month, and the Market Insight in each, are as follows[3]:

- 7 June - Temperature and recent demand
- 14 June - Generation mix during high demand peak last week
- 21 June - Changes to Electricity Risk Curve Watch and Alert definitions under the recently updated SOSFIP
- 28 June - Spring Washer contributing to Benmore and Invercargill price separation

6.2 Supporting the Authority

Intermittent generation central forecasting project:

We have continued supporting the Authority and participants by highlighting the importance of accurate Forecast of Generation Potential (FOGP) in real-time operations, while working with the Authority to strengthen dispatch compliance and IG dispatch.

6.3 International engagements

Two of our engineers joined a hybrid ESIG/ National Laboratory of the Rockies (formally NREL) workshop on large load modelling, testing and interconnection requirements. The workshop covered involved labs, transmission owners and operators, OEMs, large load developers and ISOs.

2 As required by the Security of Supply Forecasting and Information Policy section 11, incorporated by reference into the Electricity Industry Participation Code 2010

3 Past Market Operations Weekly Reports including our weekly insights can be viewed on our website.

The Head of OPTI joined the IEEE PES T&D Conference in Chicago which reinforced that the future of grid operations will be shaped by greater use of AI, advanced analytics, digital twins, and modern control room capabilities to improve operational decision-making and resilience. It also highlighted the growing importance of DER integration, grid-edge intelligence, and stronger collaboration across the electricity sector as utilities navigate increasing system complexity, climate-related risks, and the energy transition.

6.4 Media interactions

There were no media interactions through June.

7 Project updates

Progress against high value, in-flight market design, service enhancement and service maintenance projects are included below along with details of any variances from the current CAPEX plan.

7.1 Market design and service enhancement project updates

Emergency Reserve scheme (ERS):

During June, the Authority Board approved funding for the Emergency Reserve scheme (ERS) and we worked with the Authority to agree the terms of a market design capital project confirmation letter ahead of its commencement on 1 July. An update on work progressed in May under the TAS initiative is provided in section 8 below.

Ancillary Services Cost Allocation System (ASCAS):

A partial release to production went live at the end of June. The project remains on schedule for final release and go-live planned for August. Test cases are being developed for the final two rounds of user acceptance testing prior to the final release. The tooling change portion of the IR Cost Allocation solution will be delivered as part of this project with a go-live date of 1 October 2026. Design requirements to support ERS are pending clarification following the completion of the co-design process and expected to add further scope before the team is disestablished.

Operations Comms System Enhancements (OCSE):

The solution is now live, and the project team is focused on providing post-implementation support and resolving issues identified since deployment. Additional $100k opex funding is being sought to address all of these defects originally contemplated as part of the original business case while the development team is still active, and noting how critical the publication of CANs, WRNs, EXNs and GENs is to our operations.

Control room of the future (CRoF):

IST is working through the use case documentation provided by the project team to estimate both the cost and timeline for establishing the foundational technology required for CRoF as well as configuring this technology to implement the prioritised use cases. Planning for a Proof of Concept is also underway. This, along with the preparatory business design/planning work for data governance, knowledge management, and process documentation, are the primary elements of an updated Roadmap for CRoF. The Roadmap will then inform funding options and Investment Case development.

Market Operator Interface (MOI) foundations:

Project remains on track. Workstream 1 (Release 1) development is complete and in final testing. Workstream 2 (Release 2) development is progressing across all three displays. While increased complexity in one display has consumed some contingency, key milestones remain unchanged and delivery is on track for March 2027.

8 Technical advisory hours and services

TAS Statement of Work (SOW)	Status	Hours worked during month
TAS 120 – Multiple Frequency Keeping (MFK) Review	In progress	216 (SME)
		17 (PM)
TAS 121 – Future Security and Resilience	In progress	77.75 (SME)
		9 (PM)
TAS 122 – Investigation into implementation options for an MVP Emergency Reserve scheme	In progress	548 (SME)
		75.5 (PM)

TAS 120 Multiple Frequency Keeping (MFK) review

In June, after the change request approval was received from the Authority, we progressed the low inertia system need assessment to help inform the Authority's upcoming frequency strategy development, and we progressed an assessment of the market development changes and associated cost estimates to deliver MFK national selection and full participation of BESS alongside the BESS enhancements market design initiative.

TAS 121 FSR Workstream - Part 8 of the Code - common quality requirements:

We continued to support the Authority with progressing several consultation papers, including the information sharing consultation and completed planning on the high priority items for FY 26/27, including assisting the Authority in their delivery of a frequency management strategy, and system strength studies to inform a robust assessment methodology that we should use as Inverter Based Resources (IBR) expand.

TAS 122 – Investigation into implementation options for an MVP Emergency Reserve scheme:

During June, the System Operator received approval from the Authority's Board at their June meeting for implementation of the ERS as a market design capital. The Authority and System Operator teams continued to work together to draft the corresponding Market Design letter confirmation letter. In anticipation of the market design project commencing on 1 July, a kick off meeting was held on 29 June to set the context and priorities for the project with the wider team.

The Operational workstream completed the co-design activities with the industry provider panel. Minutes of each panel meeting have been agreed and published to provide transparency for the wider industry. In parallel, detailed planning activities continued, with a particular focus on planning and initiating procurement plan review activities.

The Market System workstream progressed requirements development, with the high level requirements documentation nearing completion, and detailed requirements development being initiated. The Solution Options Development Approach (SODA) were both approved/endorsed internally on 30 June. The test strategy was developed and is undergoing consultation/approval process.

Early activities for the FlexPoint workstream were completed, with internal security assessment activities completed and initial engagement made with the platform provider.

The ASCAS workstream for the ERS enhancements, whilst not due to commence until September, confirmed resource availability from the ASCAS project team.

9 Risk and assurance

9.1 Risk management

Control Self-Assessment (CSA) Round 17: Of the five CSA critical controls are reviewed this round, four were rated as "effective" and one as "partially effective". The "partially effective" score was for the "Monitor/evaluate operating environment" control which reflects the need to ensure our people, processes and tools continue to keep pace with the complexity of the evolving power system and electricity market, for example continuing to be proactive in the area of system health monitoring. We continue to investigate areas of concern and develop workplans to address these.

9.2 2025/26 Business assurance audits

The final two 2025/26 business assurance audits — Managing rolling outages during a Security of Supply event, and SFT testing undertaken as part of the recent SCADA EMS refresh — were completed this month and provided to the Authority. Both audits were rated effective. The rolling outages audit included two low-risk priority 3 recommendations, with management actions developed to address them. The SFT testing audit included three low-risk priority 3 recommendations and three priority 2 recommendations identifying areas of weakness. Management actions have been developed where the issue had not already been resolved. The priority 2 recommendations relate to improving the visibility of how our testing references the Electricity Industry Participation Code, with actions covering relevant IST and Operations functions.

9.3 2026/27 Business assurance plan

We met with Authority staff to agree the System Operator's proposed 2026/27 Business Assurance Plan, incorporating input from both the System Operator and the Authority. The agreed plan has been provided to the Authority and sets out the audits planned for 2026/27, as well as potential audits for 2027/28 and 2028/29. The four audits planned for 2026/27 are: Build and Maintain Reactive Profiles; Operational Procedures and Acknowledgement; Review of the 10-year capability uplift and investment roadmap; and Updating the PowerFactory and TSAT models.

10 Compliance

The Compliance actions for this month are set out below:

Notification of Code Breaches	
1.	[redacted]
2.	
3.	
Regulation 22 Settlement Requests	
1.	[redacted]
2.	

11 Conflicts of interest

We have two open items in the Conflict of Interest Register (below). These are being actively managed in accordance with our Conflict of Interest procedure.

ID	Title	Managed by
40	General System Operator/Grid Owner dual roles: This is a general item that will remain permanently open to cover all employees with a dual System Operator/Grid Owner role. This item documents the actions necessary to ensure impartiality in these circumstances; these items will be monitored to ensure their continue effectiveness.	Corporate Counsel, Compliance and Impartiality
41	General relationship situation: This is a general item that will remain permanently open to cover all potential conflicts of interest arising under a relationship situation. This item documents the actions necessary to prevent an actual conflict arising and will be monitored by the System Operator Compliance & Impartiality Manager to ensure their continued effectiveness.	Corporate Counsel, Compliance and Impartiality

12 Impartiality of System Operator

This section covers specific activity this month that involved internal information barriers in place, the separation of key roles and functions, and oversight by Corporate Counsel, Compliance and Impartiality.

- Corporate Counsel, Compliance and Impartiality had oversight of and advised on our publication System Operator Impartiality: Approach to Outage Planning. This aims to improve transparency of how the System Operator's outage planning policy is put into practice and how impartiality risks are managed throughout the process.
- We are monitoring any impartiality risks that may arise from a Grid Owner NTS project that involves early discussions around the development of a national flexibility (flex) platform. At this stage, we have not identified any impartiality risks from the initial project discussions which involve dual role employees.

13 Performance & monitoring

13.1 Performance Metrics & Incentives (PMI) Agreement

Our System Operator performance against the performance metrics outlined in the PMI Agreement with the Authority is reported at the end of each quarter as required by SOSPA 12.3(a). Now at the end of the 2025-26 financial year, The interim overall outcome score for 2025-26 has been calculated at 4.39, equating to an 88% performance rating, resulting in the maximum capped performance score of 80%. Further details can be found in appendix C of this report.

The results will be reviewed with the Authority in July and we will reach a joint determination of our final performance outcome for the year, which is used to determine the performance incentive payment. The final results will be published in our Annual Self Review in early September.

Interim 2025-26 performance outcome:

Outcome	Score
New security and reliability risks are identified and appropriately managed	4.36 O1 Score
Significant events are appropriately scoped, understood, prepared for and managed	4.44 O2 Score
The Authority is supported to evolve and develop the electricity market and power systems	4.27 O3 Score
Relevant market information is made accessible to stakeholders	4.33 O4 Score
Stakeholders are effectively informed on and included in decisions where relevant	4.17 O5 Score
Stakeholders are satisfied with our service	4.50 O6 Score
SOSPA delivery provides value	4.67 O7 Score

Performance Actual % 88%	Overall Outcome Score 4.39
Performance % Score 80%	Incentive Payment 200,000

Score	Level of performance
1	Poor/unacceptable performance, requires focused improvement
2	Partially meets requirements, some improvement needed
3	Performance of all requirements in line with requirements of the Code and SOSPA
4	Exceeds some aspects of what is required by the Code and SOSPA
5	Consistent delivery of exceptional performance of (or beyond) what is required by the Code and SOSPA

13.2 2025-26 SOSPA Deliverables

As part of the System Operator Service Provider Agreement (SOSPA), we worked with the Authority to finalise, and agree where required, the following documents:

- System operator business plan 2026–27 (clause 16.5)
- Statutory objective work plan 2026-27 (clause 5.5)

- Education and engagement plan 2026–27 (clause 15.4)
- Performance metrics and incentives agreement 2026-27 (clause 6.1)
- Business assurance audit plan 2026-27 (clause 14.2(a))
- Capex roadmap 2027–30 (clause 17.1)

They were all completed on time and delivered by 30 June 2026.

In June we also drafted and engaged with the Authority on a proposed new format for the 2025-26 System Operator Annual Self Review report. It is intended that the report remains content rich and meets the Code and SOSPA requirements of the annual self-review but is more efficient to produce and concise. The expectation is this approach can better enable the Authority to complete they subsequent review of the System Operator, reducing overall all resource commitment across the System Operator and the Authority. The Annual Self Review is to be submitted to the Authority by 31 August.

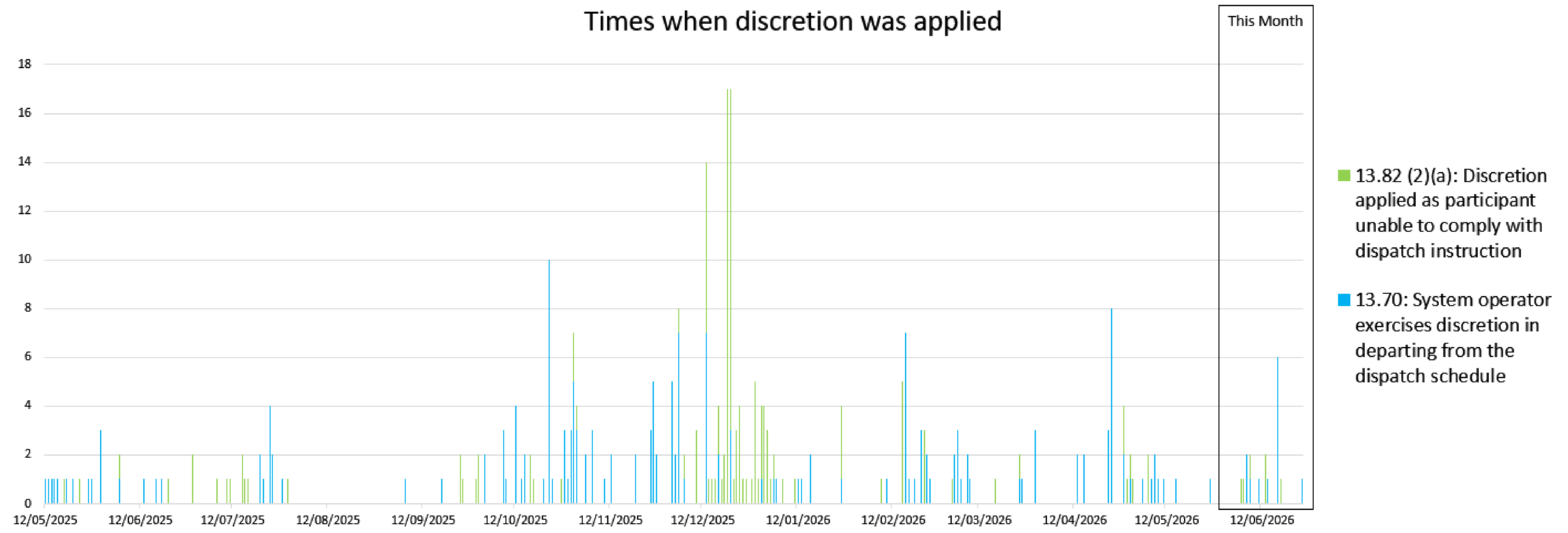
14 Actions taken

The following table contains a full list of actions taken this month regarding the System Operator business plan, statutory objective work plan, participant survey responses and any remedial plan, as required by SOSPA 12.2 (c).

Items of interest	Actions taken
To give effect to the System Operator business plan strategic initiative	**Undertake a full review of the System Operator strategy informed by stakeholder consultation.** During June, we completed and released the Phase 2 consultation on the System Operator Strategy, publishing draft strategic priorities, outcomes and initiatives for industry feedback. This built on earlier stakeholder engagement and included targeted communications and planning for further industry engagement through webinars and consultation activities. **Support future-focused market developments through white papers, consultation processes and cross-industry forums** We published three briefing papers in June. The first paper shared lessons for New Zealand from the Iberian Peninsula blackout following the publication of the ENTSO-E review of the event. The second paper showcased the challenges facing Power System Stability and how we are working to meet them. The third paper outlined how the System Operator's outage planning policy is put into practice and how impartiality risks are managed throughout the process. **Develop and begin implementation of system health, tool and modelling roadmap.** We have drafted our initial power system health monitoring requirements and high level roadmap. We are developing short term improvements, and continue to discuss longer term plans with the Grid Owner, for enhancing high resolution monitoring and assessment.

Items of interest	Actions taken
	Continue to deliver modelling process improvements and build maturity of modelling assurance and monitoring. Our current focus in this area is to build in CACTIS timeline requirements to our processes. We are also recruiting a modelling lead to provide leadership over the generator and BESS modelling process. We prepared in June for our annual engineering forum, in collaboration with the Authority. **Ensure our service keeps pace in an ever increasingly complex world by implementing Control Room of the Future (CRoF) roadmap.** Work continues to understand the new/enhanced foundational technology capabilities required for CRoF to develop a robust timeline and cost estimate for these.
To comply with the statutory objective work plan:	**Policy Statement review** Consultation on the draft Policy Statement was completed by early June, and giving consideration to the feedback received we finalised our amendment proposal, including summary and response to submissions received. The final amendment proposal was submitted to the Authority by the end of June. **Procurement Plan** Market engagement on deferred items was completed, and an approach to each of the 2025 review deferred items has been determined based of feedback and additional internal assessment. Several items will require further consideration due to potential impacts raised by participants through this process. The majority of items will now be finalised for an amendment proposal to the Authority as part of the associated FY27 SOWP deliverable. **Reset System Operator Strategy** Refer to update in business plan section above.
In response to participant responses to any participant survey	Our participant survey for 2026 opened in March and ran until 30 April. We had 26 respondents. Overall the feedback was mostly positive about the performance of the System Operator, with many respondents agreeing or strongly agreeing that we are delivering service well. We received a wide range of comments which we are currently reviewing to see how we can add value to our service.
To comply with any remedial plan agreed by the parties under SOSPA 14.1	No remedial plan in place.

Appendix A: Discretion



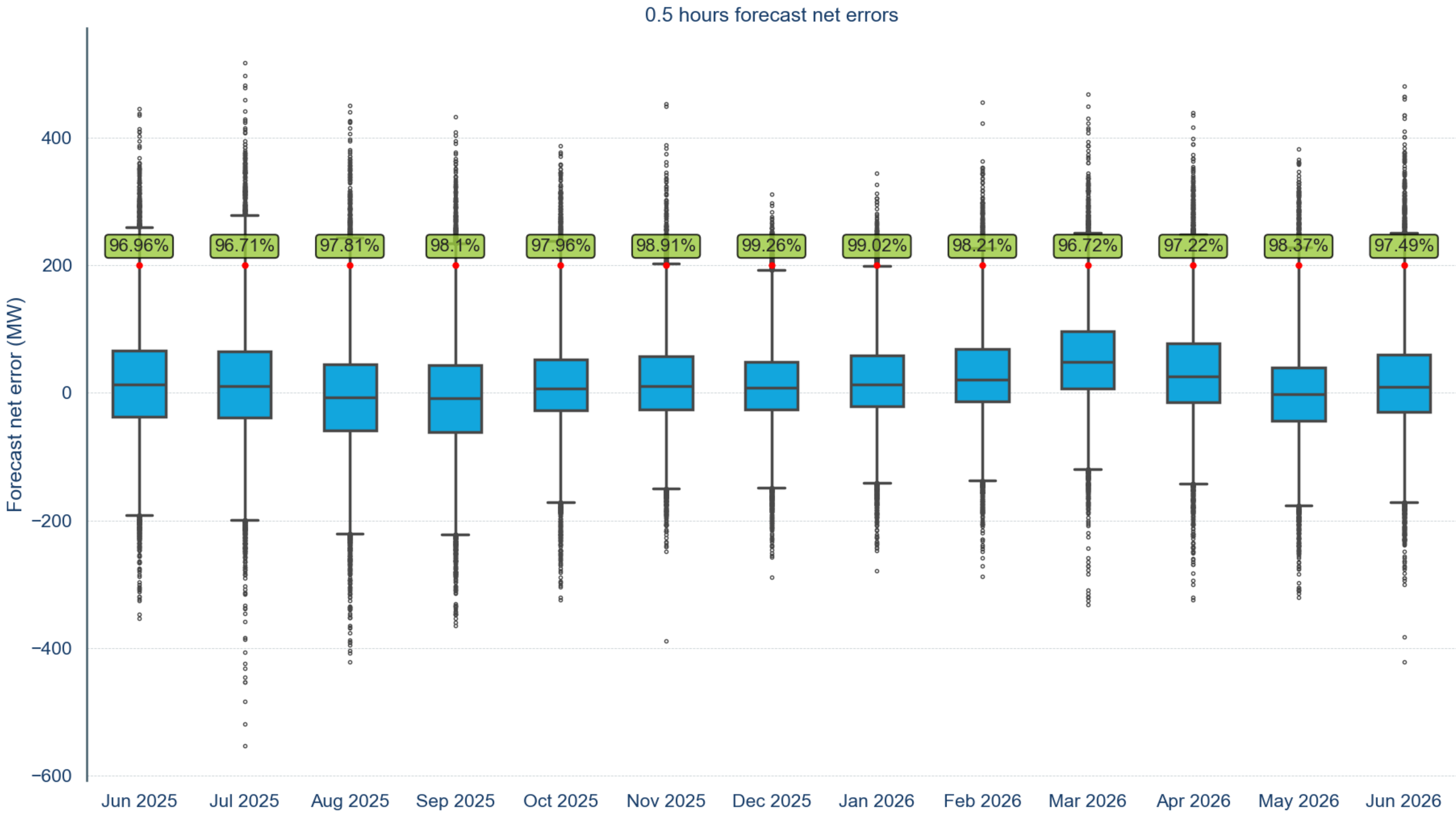
System Operator applied discretion in 18 instances:

- 5 instances at Huntly (HLY):
  - 5 Jun, 1 instance, claimed cl 13.82.2(a) unable to comply with dispatch due to resource consent issues while coming off.
  - 7 Jun, 1 instance, claimed cl 13.70, HLY2201 tripped.
  - 13 Jun, 2 instances, claimed cl 13.82.2(a)for resource consent as must run at a minimum of 200 MW or would need to come off for approximately 12 hours.
  - 18 Jun, 1 instance, claimed cl 13.82.2(a) for resource consent as must run at a minimum of 200 MW or would need to come off for approximately 12 hours.
- 1 instance at Hawera (HWA):
  - 6 Jun, 1 instance, claimed cl 13.82.2(a) due to resource consent issues on shut down.
- 1 instances at Argyle (ARG):
  - 7 Jun, 1 instance, claimed cl 13.70 as Blenheim_Kikiwa auto-reclosed.
- 1 instance Edgecombe (EDG):
  - 8 Jun, 1 instance claimed 13.70 to manage reserves for Edgecombe_Kaweru3 outage.
- 1 instance at Kawerau Geothermal (KAG):
  - 8 Jun, 1 instance, claimed cl 13.82.2(a) as generation dispatched below minimum dispatch.
- 1 instance at Kawerau (KAW):
  - 11 Jun, 1 instance, claimed cl 13.70due to KAW2201 tripping.
- 1 instance at Bream Bay (BRB):
  - 14 Jun, 1 instance, claimed cl 13.70due to invalid dispatch at Ruakaka BESS.
- 6 instances at Kaiwera Downs 2 (KWE):
  - 17 Jun, 6 instances, claimed under 13.70 to manage RTCA component violation, loss of North Makarewa_Tiwai1, overloading Invercargill_North Makarewa1, North Makarewa_Tiwai2 outage.
- 1 instance at Junction Road (JRD):
  - 25 Jun, 1 instance, log entry changed from discretion, to Bonafide.

Appendix B: Residual variability

The below figure highlights the variability of the differences between 30-minute forecast values from the Non-response Schedule Short (NRSS) and 5-minute dispatch values from Real Time Dispatch (RTD). This variability is measured as the difference between the forecast requirements on non-intermittent generation (30 minutes ahead of time) versus the requirements on non-intermittent generation during real-time dispatch. Therefore, in addition to load and intermittent generation forecast errors, the variations also capture the intra-trading period variability i.e. the difference between half-hour average quantities (as used in the forecast schedules) vs 5-minute quantities (as used in RTD).

We monitor the percentage of the time where the error between what has been dispatched and what is forecasted to dispatched is less than 200 MW. Last month, this error was less than 200 MW 97.49% of the time. This indicates that entering a trading period with ~200 MW of residual provides a high chance of having sufficient dispatchable market resources to meet variability between the 30-minute ahead forecast and the requirements within the trading period. We monitor this variability and how it compares to the residual threshold to understand trends and inform any future updates of this threshold.



Appendix C: Performance Metrics

Scoring

Quarter 4 scores are shown as shaded cells in the figure below, the year-end forecasts are shown by blue text in a bright blue outline.

Performance metric scores as at Q4						Score out of 5				
Metric	Definition	Q1 score (Jul-Sep)	Q2 score (Oct-Dec)	Q3 Score (Jan-Mar)	Q4 score Apr-Jun	1	2	3	4	5
PM1	Risk register has been updated and tested externally with the Authority and widely among industry participants	3	3	3	2	Internal Risk Register has not been updated in the last 12 months, no engagements have been held to identify new threats or assess current threats	Internal Risk Register has been reviewed and updated internally in the last 12 months	Internal Risk Register has been reviewed and updated internally in the last 6 months	Information is sought from the Authority, OR representatives from a diverse range of stakeholders, to review threats and identify and assess new security and reliability threats	Information is sought from both the authority, AND representatives from a diverse range of stakeholders, to review threats and identify and assess new security and reliability threats
PM2	% of SMART actions from the control self-assessment with maturity ratings of 1 or 2 will be addressed by the planned due date	5	5	5	5	< 50% of SMART actions with a maturity rating of 1 and 2 are completed by due date	≥ 50% of SMART actions with a maturity rating of 1 and 2 are completed by due date	≥ 75% of SMART actions with a maturity rating of 1 and 2 are completed by due date	100% of SMART actions with a maturity rating of 1 and ≥ 75% of SMART actions with a maturity rating of 2 are completed by due date	100% of SMART actions with a maturity rating of 1 and 2 are completed by due date
PM4	% of actions from industry exercises which were completed on time	N/A	5	5	5	< 50 %	≥ 50 % and < 65 %	≥ 65 % and < 75 %	≥ 75 % and < 100 %	100%
PM6	Percentage of actions from significant events which are closed on time	5	5	5	5	< 50 %	≥ 50 % and < 65 %	≥ 65 % and < 75 %	≥ 75 % and < 100 %	100%
PM7	On time delivery of significant event reports	N/a	4	4	4	Less than 100% of major preliminary reports delivered on time	All major preliminary reports and 60% of other reports delivered on time	All major preliminary reports and 80% of other reports delivered on time	100% of all reports delivered on time	Score not available
PM8	Average satisfaction score from stakeholders, as per responses received to transactional surveys taken at forums and asked for in correspondence	5	5	4	4	< 35 %	≥ 35 % and < 50 %	≥ 50 % and < 70 %	≥ 70 % and < 85 %	≥ 85 %
PM9	All categories of stakeholders are actively engaged by the system operator throughout the year	N/A	N/A	N/A	3	SO Annual Participant Survey is not sent to a diverse range of stakeholders	SO Annual Participant Survey sent to a diverse range of stakeholders to request their feedback on how well they believe market information has been made accessible to them	Responses are received from a diverse range of stakeholders and are considered by the SO for improvement of engagement activities	Specific action is taken to build engagement from a diverse range of stakeholders	More than one action is taken as a result of feedback received from the Annual Participant Survey or other industry mechanisms and forums, with the aims of improving engagement with stakeholders
PM10	% of industry submissions, made in response to system operator consultations, which are responded to	2	4	5	5	Not all submissions acknowledged	All submissions acknowledged and < 50% responded to	All submissions acknowledged and ≥ 50 % responded to	All submissions acknowledged and ≥ 75 % responded to	All submissions acknowledged and ≥ 90 % responded to
PM12	Average satisfaction score from stakeholders from Annual Survey	N/A	N/A	N/A	4	< 73 %	≥ 73 % and < 76 %	≥ 76 % and < 85 %	≥ 85 % and < 89 %	≥ 90 %
PM13	Average score from stakeholders on their perception of SO impartiality	N/A	N/A	N/A	5	< 60 %	≥ 60 % and < 70 %	≥ 70 % and < 80 %	≥ 80 % and < 89 %	≥ 90 %
PM14	Number of thought leadership publications on specific areas of system operator work that affect and/or are of interest to the industry	2	3	3	4	Score not available	No thought leadership publications and 1 participant education piece in the financial year	1-2 thought leadership publications and 1 participant education piece in the financial year	3-4 thought leadership publications and 2 participant education piece in the financial year	>4 thought leadership publications and 3 participant education piece in the financial year
PM16	# of SO Industry Forums held	2	3	4	5	Score not available	1-10 forums	11-19 forums	20 or more forums	20 or more forums, plus 1 longer format forum
PM17	% of key SOSPA documents delivered on time to the Authority	3	3	3	5	< 70%	≥ 70 % and < 100%	100%	SO works proactively with Authority staff to enhance the accessibility of existing content in >50% of key documents	SO works proactively with Authority staff to provide new, value-add content in >50% of key documents
PM19	TAS project delivery performance	5	3	5	5	< 40% achieved in the approved time	≥ 40% and < 55% achieved in the approved time	≥ 55% and < 70% achieved in the approved time	≥ 70% and < 90% achieved in the approved time	≥ 90% achieved in the approved time
PM20	Market impact of breaches remain below threshold	5	5	5	5	> 4 breaches with market impact > $50k	> 4 breaches with market impact > $50k	3 breaches with market impact > $50k	> 3 breaches with market impact > $50k	No breaches with market impact > $50k
PM21	Sustained SCADA (Supervisory Control and Data Acquisition) availability	5	5	5	5	< 99.0% SCADA availability	< 99.0% SCADA availability	≥ 99.90% and < 99.93% SCADA availability	≥ 99.90% and < 99.93% SCADA availability	≥ 99.97% SCADA availability
PM22	Unplanned dispatch outage - unplanned time spent on Stand Alone Dispatch (SAD).	5	5	5	5	> 7 unplanned outages or > 300 unplanned minutes on SAD	> 7 unplanned outages or > 300 unplanned minutes on SAD	< 5 unplanned outages or < 150 unplanned minutes on SAD	< 5 unplanned outages or < 150 unplanned minutes on SAD	< 4 unplanned outages or < 120 unplanned minutes on SAD

Key

Shaded square = current score

Blue text and outlines = predicted final score

Appendix C (cont): Performance Metrics

Relationship between performance metrics and outcomes

These relationships explain why some performance metrics have a greater influence on the outcomes than others.
Note: Where the score of the performance metric is currently N/A, that performance metric does not contribute to the outcome or overall score.

Performance metric ref	Metric	O 1: New security and reliability risks are identified and appropriately managed	O 2: Significant events are appropriately scoped, understood, prepared for and managed	O 3: The Authority is supported to evolve and develop the electricity market and power systems	O 4: Relevant market information is made accessible to stakeholders	O 5: Stakeholders are effectively informed on and included in decisions where relevant	O 6: Stakeholders are satisfied with our service	O 7: SOSPA delivery provides value	PM contribution to overall outcome score
PM 1	Risk register has been updated and tested externally with the Authority and widely among industry participants	15%	11%	10%		13%			9%
PM 2	% of SMART actions from the control self-assessment with maturity ratings of 1 or 2 will be addressed by the planned due date	15%	11%						6%
PM 4	% of actions from industry exercises which were completed on time	8%	22%						7%
PM 6	Percentage of actions from significant events which are closed on time	8%	22%	10%					9%
PM 7	On time delivery of significant event reports		22%	10%	9%			14%	9%
PM 8	Average satisfaction score from stakeholders, as per responses received to transactional surveys taken at forums and asked for in correspondence				18%	13%	29%	14%	7%
PM 9	All categories of stakeholders are actively engaged by the system operator throughout the year	0%		0%	0%	0%	0%		0%
PM 10	% of industry submissions, made in response to system operator consultations, which are responded to			10%	18%	25%		29%	8%
PM 12	Average satisfaction score from stakeholders from Annual Survey				0%	0%	0%	0%	0%
PM 13	Average score from stakeholders on their perception of SO impartiality				0%	0%	0%	0%	0%
PM 14	Number of thought leadership publications on specific areas of system operator work that affect and/or are of interest to the industry	8%		20%	18%	13%			9%
PM 16	# of SO Industry Forums held		11%	10%	18%	25%			9%
PM 17	% of key SOSPA documents delivered on time to the Authority			10%		13%		29%	5%
PM 19	TAS project delivery performance			20%				14%	5%
PM 20	Market impact of breaches remain below threshold	15%					14%		5%
PM 21	Sustained SCADA availability	15%			9%		29%		7%
PM 22	Unplanned dispatch outage - inplanned time spent on Stand Alone Dispatch (SAD)	15%			9%		29%		7%
TOTAL		100%	100%	100%	100%	100%	100%	100%	100%
Outcome weighting to overall outcome score		20%	25%	20%	10%	10%	10%	5%	