Quarterly System Operator and system performance report

For the Electricity Authority

October to December 2022

Report Purpose

This report is Transpower's review of its performance as system operator for Q2 2022/23 (October to December 2022), in accordance with clause 3.14 of the Electricity Industry Participation Code 2010 (the Code).

As this is the final self-review report of the quarter, additional information is included as per SOSPA clause 12.3. This includes performance against the performance metrics year to date, and actions taken in regard to the system operator business plan, statutory objective work plan, participant survey responses, and any remedial plan agreed under clause 14.1(i). A summary of technical advisory services for the quarter is also provided.

A detailed system performance report (Code obligated) is provided for the information of the Electricity Authority (Authority).

Contents

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Commentary

This section provides a high-level update for this quarter. The remainder of the report provides supporting detail in two sections:

- System operator performance
- System performance

Update (October to December 2022)

Security of Supply and market information

- **Security of Supply:** Hydro storage has been higher than the average this quarter across both North and South Islands. The forecast 2023 capacity margins are expected to remain tight as we move into the new year. This is primarily due to peak demand growth, and the market being able to co-ordinate sufficient thermal resources when needed for only a brief period.
- **NZGB forecasting**: The New Zealand Generation Balance (NZGB) tool is forecasting no shortfalls for the next 200 days. There are some lower margin periods in February due to the HVDC outages.
- **2023 Security of Supply Assessment: Reference Case Assumptions and Sensitivities:** We sought comment from the industry this quarter and are currently evaluating the responses. There are eight supply side sensitivities and five demand side sensitivities to derive the combinations of sensitivity cases; these are detailed in the report.

Projects and TAS work

- **Real Time Pricing (RTP)** - Phase 3 was successfully deployed into production on 18 October and was live in the market at midnight on the 1 November. A small number of minor defects have been identified and resolved through a patch release in December. Phase 4 development and testing is continuing in parallel.
- **Customer Portal Programme** - The new NZGB application was successfully deployed in the Operations Customer Portal on 3 November. We accompanied the deployment with training material, including instruction videos and webinars. We are making good progress in the investigation phase for the last application, Dispensations and Equivalences. Next financial year the system operator will kick off a strategic initiative to further enhance and evolve the Operations Customer Portal.
- **Operational Excellence**: The programme plan was completed on target before Christmas. It outlines the scope and approach for a multi-year delivery programme, along with tiered benefits and success measures. Delivery of the work started in the areas of procedure assurance, skills architecture and resource planning continues.
- **KPI refresh** – The Authority and system operator staff have compiled a set of external metrics to be used as to evaluate the system operator performance in 2023/24. The next stage is to finalise these and then calibrate them via an incentive mechanism which will begin early in the new year.

Risk and Assurance

- **Control Self-Assessment:** We finalised our assessments for the November Risk Control Self-Assessment. The assessment included five critical risk controls, two if which remain partially effective, two controls remain fully effective, and one control improved from partially to fully effective.

- **Business assurance audits** - We have completed the first of our business assurance audits, Defects and Enhancements. The auditor identified four high level findings relating to establishing governance; prioritisation and remediation; reviewing incident information and following up overdue issues.
- **System Operator independence audit:** Deloitte has issued its interim report for the 2022 System Operator independence audit of the outage planning process. Deloitte is expected to present its final findings to Transpower management in early February.

Customers and other relationships

- **Industry engagement**: We continue to inform, and be informed by, other industry players in New Zealand. During this quarter, these engagements included working with electricity distribution companies as part of FlexForum, considering resource adequacy for winter 2023 and briefing the industry on several operational issues. We also supported the Authority in the webinar that prepared the industry for the launch of RTP phase 3.
- **International relationships** - We continue to engage with our international peers on a variety of market and power system topics. Examples of which are attending the Association of Power Exchanges conference attended by other system operators from around the world, GE Roadmap Presentations, attendance of the CIGRE working group C2 meeting, presenting online at the Florence School of Regulation workshop "From energy saving to rationing: getting it right" and ESIG webinars (redefining resource adequacy for modern power systems, major disturbance in ERCOT system and talk on Ireland's transition to 75% inverter connected generation).

System events

- **7 October events**: We worked closely and well with the industry to minimise the effects of the HVDC filter outage, under-frequency event and grid emergency situation. We presented the timeline of the events of the week 3-7 October from a system operator perspective at our fortnightly industry forum with participants on Tuesday 11 October.
- **Moderate significant event**: One new 'moderate' significant incident occurred when there was a loss of supply at Tauranga on 13 October 2022 due to bird activity. We have commenced an investigation with an initial focus on capturing event data and building a timeline of the incident.

Outages

- **Outage Planning** – There were some very high weekly outage numbers through October and November with over 180 transmission outages in one week. These will reduce over the holiday period, but scheduled outages are increasing again in the New Year.
- **2023 HVDC annual outage** - We provided a system operator perspective on forecast generation margins (from NZGB) for the 2023 HVDC annual outage via our industry forum.

SOSPA deliverables

- **System Security Forecast (SSF)** – The latest SSF major update was delivered in December 2022. We are confident we will be able to meet our Principal Performance Obligations as set out in the Code over the next three years given committed asset changes, growth in demand and existing operational practises.
- **Draft SO Service Strategic Plan** - We are well advanced with development of the SO Service Strategic Plan, for delivery at the end of February 2023.

System Operator performance

1 Customers and other relationships

Industry briefing – tight residuals

In response to observing unusually high peak demand and tight residuals during the week 3-7 October, as a cold snap moved across New Zealand, we published a low residual Customer Advice Notice (CAN) for the morning peak on Tuesday 4 October, and a subsequent CAN for the morning peak on Friday 7 October. This was followed by an industry briefing on the afternoon of Thursday 6 October. We presented the timeline of the events of the week 3-7 October, including the HVDC tripping, under-frequency event and the issuing of a grid emergency notice, from a System Operator perspective at our fortnightly industry forum with participants on Tuesday 11 October.

Energy Systems Integration Group (ESIG)

We attended an ESIG event on redefining resource adequacy for modern power systems in October. This event covered a recent report written by the Redefining Resource Adequacy Task Force and provided an overview of key drivers changing the way resource adequacy needs to be evaluated, identifies shortcomings of conventional approaches, and outlines first principles for practitioners to consider as they adapt their approaches. The central message was “what got us here won’t get us there”.

As a member of ESIG, we joined two webinars in November. One was on the major disturbances in ERCOT (Texas) system (Odessa disturbances on 9 May 2021, and 4 June 2022 single phase to ground faults resulted in large amounts of generation to trip off the system). The discussion was on what has been learned and the actions being taken to avoid reoccurrence. The second webinar was a talk on Ireland’s transition to 75% inverter connected generation. They covered how they have modified their operational tools and approaches to support higher proportion of wind generation in Ireland today and introduced their report ‘Shaping Our Electricity Future’ which discusses the path to even higher levels of renewable energy generation.

Real Time Pricing (RTP)

We supported the Authority in the webinar that prepared the industry for the launch of phase 3 of the project.

Electricity distribution company cooperation

We have been working with an electricity distribution company and the Authority throughout October to understand growth in peak demand at a more granular, regional level. This analysis has been shared with industry to build a common view on this issue.

FlexForum

We have joined FlexForum as a member, a cross industry group formed to identify a set of actions to integrate distributed energy resources (DER) into the electricity system and markets to maximise the benefits for New Zealand. We informed the Flexibility Plan 1.0 with system operations perspectives.

Annual APEx conference (Association of Power Exchanges)

Dr Jay attended this year’s conference in Dubrovnik on 19-21 October where he moderated a session on “New Technologies and Emerging Energy Forums”. The other themes at this conference were “Decentralisation”, “Decarbonisation”, “Flexibility and

Resilience” and a session on the regulator’s perspective. Dr Jay also spent a day with the Italian system operator, which included a tour of their control room and discussions on electrification and power system challenges.

Florence School of Regulation Workshop
We presented online at the Florence School of Regulation workshop "From energy saving to rationing: getting it right" held in November 2022. There were several discussions about the energy security issue being experienced in Europe. They were keen to understand the New Zealand perspective and our experience in managing system and energy security. We presented online at this workshop on the system characteristics and the mechanisms to manage capacity and energy security in New Zealand.

Aus/NZ CIGRE working group meeting (C2)
We attended the C2 meeting where a wide range of topics were discussed, including the challenge of recruiting engineers to support the increase in DER and introduction of DSO-TSO (Distribution System Operators-Transmission System Operators); increasing number of system events due to SCADA failures, communication failures or cyber security rather than primary plant issues; and flooding events in Australia and dealing with speed of ‘social media’ as compared to utilities own situational awareness.

GE Roadmap Presentations
We also attended GE presentations on a number of their applications including incorporation of renewables and DERs, and shutdown and restoration management.

SOSPA deliverables to the Authority
System Security Forecast (SSF) – The latest SSF major update was delivered in December 2022. The system operator is confident we will be able to meet our Principal Performance Obligations as set out in the Code over the next three years given committed asset changes, growth in demand and existing operational practises.
Draft SO Service Strategic Plan - We are well advanced with development of the Draft SO Service Strategic Plan which will be delivered to the Authority in late-February.

2 Risk & Assurance

Risk Management Framework
We presented a paper for the Authority’s November System Operator Committee on the system operator’s role and risks around “failing to maintain service levels for consumers”. Our key message was the system operator manages consumer service expectations through delivering on its obligations to industry.

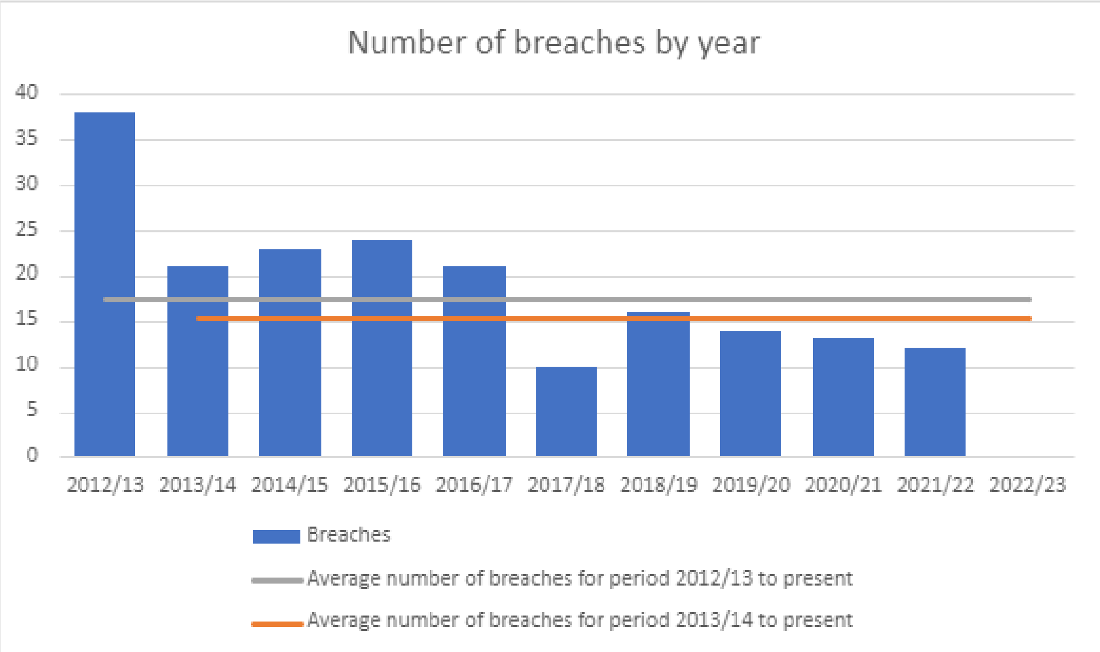
We finalised our assessments for the November Risk Control Self-Assessment. The assessment included five critical risk controls: 24 hour real-time; business support functions; incident preparedness and response; power system planning; and support of critical tools & systems. Two controls remained partially effective, two controls remained fully effective, and one control improved from partially to fully effective.

Business assurance audits
The Defects and Enhancements audit has been completed. The auditor identified four high level findings relating to establishing governance; prioritisation and remediation; reviewing incident information and following up overdue issues. The system operator Load Forecast audit has started. Three remaining system operator Audits (Voltage stability assessment tool (VSAT) change management, ancillary service contract management, real-time management of simultaneous feasibility test (SFT) constraints, are planned for the 2022/2023 financial year.

3 Compliance

We did not self-report any system operator breaches in this reporting period; none have been reported this financial year.

9 August event
The Rulings Panel process is deferred to the new year, pending settlement discussions. Settlement discussions have continued between external counsel law firms.



4 Impartiality of Transpower roles

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

System Operator Open Conflict of Interest Issues		
FID	Title	Managed by
29	**Preparing the Net Benefit test – System Operator involvement:** The System Operator is reviewing how it can provide information for use by the grid owner undertaking a Net Benefit Test.	Operations Planning Manager
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. The item documents the actions necessary to	SO Compliance & Impartiality Manager

System Operator Open Conflict of Interest Issues		
FID	Title	Managed by
	ensure impartiality in these circumstances; these items will be monitored to ensure their continue effectiveness.	
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 SO Compliance & Impartiality Manager to ensure their continued effectiveness.	SO Compliance & Impartiality Manager

4.1 System Operator independence audit

Deloitte has issued its interim report for the 2022 System Operator independence audit of the outage planning process. Deloitte is expected to present its final findings to Transpower management in late January.

Deloitte has commenced early fieldwork for the 2023 System Operator independence audit, which is focussed on security of supply.

5 Project updates

5.1 Market design and service enhancement 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.

Real-Time Pricing (RTP)
Phase 3 was successfully deployed into production on 18 October and was live in the market at midnight on the 1 November. A small number of minor defects were identified following go-live, which were delivered through an initial patch release in December, followed by a final defect release in January. Phase 4 development and testing is continuing in parallel and will be delivered on 27 April 2023.

A change request (CR009) to re-baseline the project for changes to budget was submitted to the Authority on 6 October. On 8 November the Authority Board approved the change request.

Operational Excellence
The programme plan was completed on target before Christmas. It outlines the scope and approach for a multi-year delivery programme, along with tiered benefits and success measures. The coming quarter will focus on detailed planning across four workstreams and confirming resources and project teams. Delivery of the work started in the areas of procedure assurance, skills architecture and resource planning continues.

Customer Portal Programme
With the successful delivery of the New Zealand Generation Balance (NZGB) in the Customer Portal, we have made good progress through the investigation to replace and move the last application, Dispensations and Equivalences (D&E) to the Customer

Portal. The Business Case is planned to be approved by end of January, with the capital delivery commencing early February.

In addition, next financial year the system operator will kick off a strategic initiative to further enhance and evolve the Operations Customer Portal.

KPI Refresh Programme
By the end of December, the joint Transpower-Authority project team had developed and agreed the seven External Outcomes that identify what Transpower needs to do to successfully perform the role of the system operator service provider. Following a series of internal Transpower workshops and Authority review sessions, a set of key result metrics have been developed to identify good performance against the External Outcomes. For the third External Outcome, the conversation was led by the Authority staff who defined what activities they would like to see us contribute to their work programme. These metrics once finalised will inform a revised incentives agreement with the Authority for 2023/24; this work began in January 2023.

Future Security and Resilience (FSR) Programme
We continue to support ongoing discussions with the Authority and provide inputs to their issues paper on common quality and FSR indicators. The draft issues paper is expected to be presented to the Authority Board in March 2023.

6 Technical advisory hours and services

The system operator and the Authority are finalising the TAS 104 statement of work to publish residual MW information from forecast schedules. The scope for TAS 104 includes the addition of the calculated residual data for both the North and South Island in the data transfer to NZX. The residual data will be provided for forecast market schedules (RTD, NRS PRS and WDS) for all forecast trading periods.

The following table provides the technical advisory hours for Q2 2022/23 and a summary of technical advisory services to which those hours related (SOSPA 12.3 (d) refers).

TAS Statement of Work (SOW)	Status	Hours worked during Q2
TAS SOW 102 – Reviewing Part 8 of the Code – Common Quality	In progress	259.50
TAS SOW 103 - Extended Reserve Implementation FY22/23 - Planning for Transition	In progress	340.00
Total hours		**599.50**

7 Outage planning and coordination

Outage planning – near real time

We saw some very high weekly outage numbers through October and November with over 180 transmission outages in one week. These will reduce over the holiday period, but scheduled outages are increasing again in the new year.

The 2023 annual HVDC outage will be longer than usual, with an extra six days of monopole at the end of February. Both system operator and grid owner provided overviews of this outage at the regular fortnightly industry forum. The grid owner outlined the work during the outage which this year includes Pole 2 mid-life refurbishment work, some Pole 2 seismic improvements and some HVDC conductor replacement and tower painting. The system operator covered the forecast generation margins provided by the NZGB tool.

New Zealand Generation Balance (NZGB) analysis

The NZGB tool is forecasting no shortfalls for the next 200 days. Looking ahead to summer, margins are increasing, although there are some lower margin periods in February due to the HVDC outage. We are monitoring these periods. The new NZGB application has been successfully deployed into the Operations Customer Portal.

8 Power systems investigations and reporting

System Security Forecast (Major)

The latest major SSF update was published in December 2022, confirming the System Operator will be able to meet our Principal Performance Obligations as set out in the Code over the next three years given committed asset changes, growth in demand and existing operational practises.

This year's major update included updated load forecasts, several recently commissioned and committed renewable generation projects, and impending commissioning of several grid upgrades. A few of the more significant changes studied in this review are:

- New GXP at Norwood
- New reactive equipment to support high voltage management
- Turitea wind generation
- Harapaki wind farm
- Kaitaia Solar farm
- Tauhara B geothermal generation
- New Statcom at Hamilton

The latest SSF can be found here.

Engineering and Technology Excellence Awards

Our work on generator reactive capability modelling was nominated as finalist for the Transpower Engineering and Technology Excellence Awards. The system operator team won the engineering by design category, with the judges saying: We commend your clever innovation, which introduced new ways of working and changed the way Transpower operates. Remarkable engineering by design.

9 Performance metrics and monitoring

The following dashboard shows system operator performance against the performance metrics for the financial year to date as required by SOSPA 12.3 (a). Only those metrics with a weighting are used in the calculation of the System Operator score and incentive payment.

Metric		Annual Target	Actual to date	Pts
Smart about money				
Perception of added value by participants		80%	N/A	
Customers are informed and satisfied				
Annual participant survey result		83%	N/A	5
Annual participant survey result response rate - First tier stakeholders		80%	N/A	
Future thinking and insights	Future thinking report	≥ 1	0	5
	Longer Market Insight reports	≥ 4	2	5
	Bite-sized Market Insights	≥ 45	24	
Quality of written reports		100% of standard	100%	
Role impartiality		80%	N/A	5
Responding to requests for information from the Authority		100% by agreed deadline	N/A	
Code compliance maintained and SOSPA obligations met				
Market breaches remain below threshold		≤ 3 @ ≥ $40k	0	10
Breaches creating a security risk - below threshold/within acceptable range		≤2	0	10
On-time SOSPA deliverables		100% (49)	100% (13)	10
Successful project delivery				
Project delivery	Service Maintenance projects	≥ 70% on time	50%	
		≥ 70% on budget	0 to date	
	Market Design and Service Enhancement projects	≥ 70% on time	0 to date	
		≥ 70% on budget	0 to date	
Accurate capital planning		≥ 50%	N/A	10
Commitment to optimal real time operation				
Sustained infeasibility resolution		80% ≤ 10am or equiv	87%	5
High spring washer resolution		80% ≤ 10am or equiv	0 to date	
Fit-for-purpose tools				
Capability functional fit assessment score		76.00%	N/A	
Technical quality assessment score		70.00%	N/A	
Sustained SCADA availability		99.90%	99.99%	10
Maintained timeliness of schedule publication		99.00%	99.99%	10

We prepare for, manage & review events*		Q1	Q2	Q3	Q4	Pts
Event preparedness	Procedures overdue	4 (5.3%)	7 (9.3%)			12
	Industry exercises	0	0	Planned		
	Control rm simulations	0	12 (100%)			
Event management	Sig event mgt audit score	N/A	Good			13
Event review and improvements	Sig event actions due	N/A	0			12
	Deliv time-major evt rept	N/A	N/A			

* Score determined on an annual basis, with system operator and Authority staff assessment on a quarterly basis.

9.1 Dispatch accuracy dashboard

We produce two dispatch accuracy dashboards:

- An energy dashboard as a means of monitoring overall industry performance.
- A reserves dashboard to identify trends and patterns in reserve management.

Both dashboards are contained in Appendix B, along with an explanation of the methodology we used to create the dashboards.

The dashboards continue to evolve and provide a good mechanism to see how changes to the power system, such as how the introduction of more wind generation, affect performance.

Below are instances of variations we have observed this quarter.

Energy

Overall industry performance this quarter – October to December 2022

Smooth transition to RTP in the market

- RTP went live in the market at midnight on the 1 November. The preparation, training and communication with the industry meant that this major change to the market design went smoothly. This can be seen on the dashboard where there are no indications of any issues that resulted in the market.
- Due to the removal of the final pricing case, we have had to adapt the data queries we use to complete the dashboard.

Application of discretion under 13.70 (since July)

- As previous noted, in July discretion was reclassified to include the process to manage generators on minimum MW values overnight. As a result, the number of discretions in this report is now much larger than previously.

Frequency excursions (October)

- The October frequency excursions include the excursion on 7 October due to the HVDC runback.
- All other frequency excursions in the month were a result of a Tiwai line tripping.

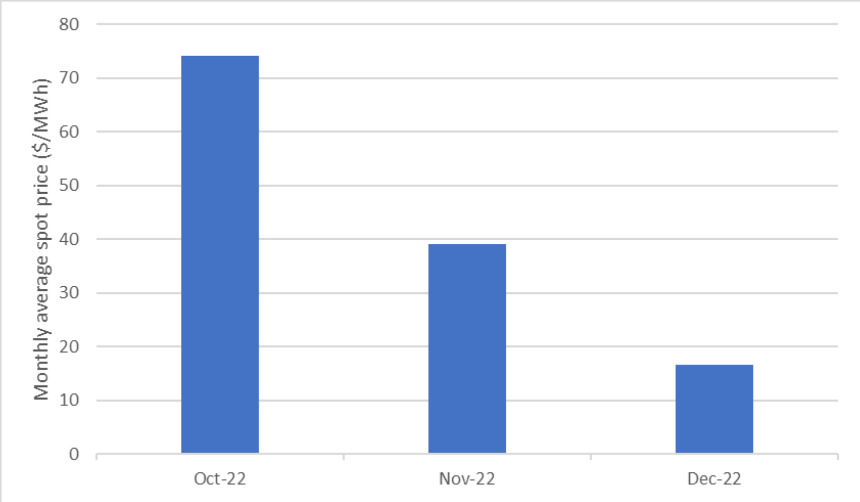
Constrained on energy (November)

- The high cost for constrained on energy in November relates to the early evening on 22 November when high priced generation was discretioned on as lightning threatened to take out the remaining circuit into Hawkes Bay from Wairakei.

Optimal dispatch this quarter

The transition to RTP has required changes in the optimal dispatch tool.

These changes did not affect the data for October and November which show no outliers to expectations. December data shows a lower optimal dispatch measure. The major difference in December is the lower dispatch costs (due to lower consumption in December and above average hydro storage). The optimal dispatch measure is calculated as the average cost impact magnitude of using forecast data which is dependent on both forecast accuracy and average costs. When average costs are low, if a forecast variability results in higher priced generation being required to run, this impact on cost due to the variability makes up a larger proportion of the lower average costs which is reflected as the lower optimal dispatch measure, as happened in December. An indicator of the lower dispatch costs in December relative to the previous months is the average spot price. The figure below shows the declining monthly average spot energy price in Oct-Dec.



Reserves

It should be noted, the variability in the way the system responds could be a result of many factors, not just the efficiency of the system operator actions. These factors include:

- The amount of interruptible load armed, as opposed to that offered and used as an input into RMT (and then dispatched by SPD).
- The influence of the type of generation on the amount of net free reserves (NFR) available.

<u>Observations this quarter – October to December 2022</u>

Some data is currently unavailable, following the transition to RTP. These figures will be included in the Q3 report.

November and December showed a drop to an average AC CE (Contingent Event) risk of just 141 MW, which combined with quite sustained high DC transfers North has resulted in us seeing the DC CE risk appearing as a FIR (Fast Instantaneous Reserve) risk setter about 20% of the time.

Other reasons for the DC ECE (Extended Contingent Event) setting the FIR risk more often are:

- as a result of the variability of wind output between the schedule used to determine the NFR for DC ECE and the real time scheduled requirement of HVDC transfer, more DC North flow may be required in real time to cover the gap between forecast and actual
- with the low AC CE risk MW, high DC transfers can require more FIR than is procured for that AC risk to allow time for the AUFLS blocks to trip.

Last quarter we had begun to observe lower than normal FIR procured as a proportion of risk when the AC CE (Contingent Event) was the binding risk. This trend has carried on into this quarter and the proportion has reduced even further to be in the 45 – 55% range rather than the more usual 65 – 75% range. We are investigating this as a priority to understand the reason behind this variation and identify if there is any risk relating to the reserve procurement objectives.

10 Cost of services reporting

The next cost of services reporting, for 2021/22 will be delivered to the Authority in early 2023.

11 Actions taken

The following table contains a full list of actions taken during Q2 2022/23 regarding the system operator business plan, statutory objective work plan, participant survey responses and any remedial plan, as required by SOSPA 12.3 (b).

Item of interest	Actions taken
(i) To give effect to the **system operator business plan**:	• Go live with Real Time Pricing *Phase 3 was successfully deployed into production on 18 October and was live in the market at midnight on the 1 November.* • Start development of Customer Portal base capability *With the successful delivery of NZGB in the Customer Portal, we have made good progress through the investigation to replace and move the last application, Dispensations and Equivalences (to the Customer Portal.* • Support the Authority in delivering the Future Security and Resilience programme *We continue to support ongoing discussions with the Authority and provide inputs to their issues paper on common quality and FSR indicators. The draft issues paper is expected to be presented to the Authority Board in March 2023.*
(ii) To comply with the **statutory objective work plan**:	• Develop and agree the revised performance metrics, targets and incentive payment calculation for FY 2023/24 *During quarter 2, we have:* *agreed the External Outcomes and developed a set of metrics that will help achieve these outcomes. These metrics once finalised will inform a revised incentives agreement with the Authority for 2023/24; this work began in January 2023.*
(iii) In response to participant responses to any **participant survey**:	**Feedback from the 2021-22 survey** • "I trust the Transpower System Operator communications to keep me informed (so that I can intervene in our EDB's planning as necessary) and they provide valuable information. " *We continue to run the industry forums fortnightly and have convened industry briefs on items of real time importance, such as for the unusually high peak demand and tight residuals during the week 3-7 October.*

Item of interest	Actions taken
	• “We have a challenging period ahead, so it will be important for Transpower and the System Operator to be well resourced to deal with these challenges.” *This is a recognised issue and is being assessed as part of a number of our current initiatives. We are also committed to continuous business improvements to maintain efficiencies.*
(iv) To comply with any **remedial plan** agreed by the parties under SOSPA 14.1	N/A – No remedial plan in place.

System performance

12 Security of supply

Hydro storage has been higher than average for this time of the year across both North and South Islands. There was a large inflow event at the beginning of the October and the North Island received further inflows in December.

Due to the high-level of hydro storage in both islands, increased wind generation, and outages of thermal plant, there were periods in the quarter where renewables have been consistently above 95% of total generation. For large periods of time in October and November, the only thermal plant running was co-generation.

The high hydro generation kept prices low, consistently below $100/MWh, but price volatility is common during periods of high demand and/or low wind generation.

Security of supply outlook

Looking ahead, La Niña conditions are expected to remain a dominant factor in our climate through the end of April 2023. From February, Niwa indicates it is expected to weaken and dissipate. La Niña typically results in lower-than-average inflows into the southern hydro catchments. While an expectation of lower-than-average inflows through the summer months is concerning for winter 2023, we will be starting 2023 with above average levels of hydro storage, elevated levels of stored gas, a large coal stockpile, and an improving production forecast from the Maui gas field.

The forecast 2023 capacity margins are expected to remain tight as we move into the new year. This is primarily due to peak demand growth, and the market being able to co-ordinate sufficient thermal resources when needed for only a brief period of time. The availability relates to costs which are more likely if a wet winter is experienced again, but regardless, costs are likely to increase due to the increased cost of thermal fuel, increased levels of wind generation, and aging plant limiting reliability and number of warranted start-ups.

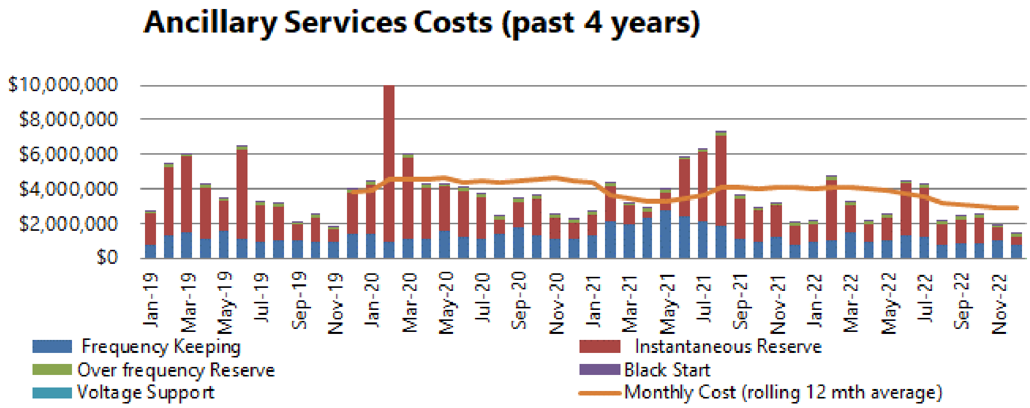
Winter peak capacity challenges

We published a market insight containing analysis of the winter peak capacity challenges experienced in 2021 and 2022 and explored the potential size and shape of the peak capacity challenge in 2023. The scenarios demonstrate the need for additional flexible capacity and the necessity of collaboration between industry bodies to develop solutions to facilitate this commitment and ensure the system remains flexible in peak load times.

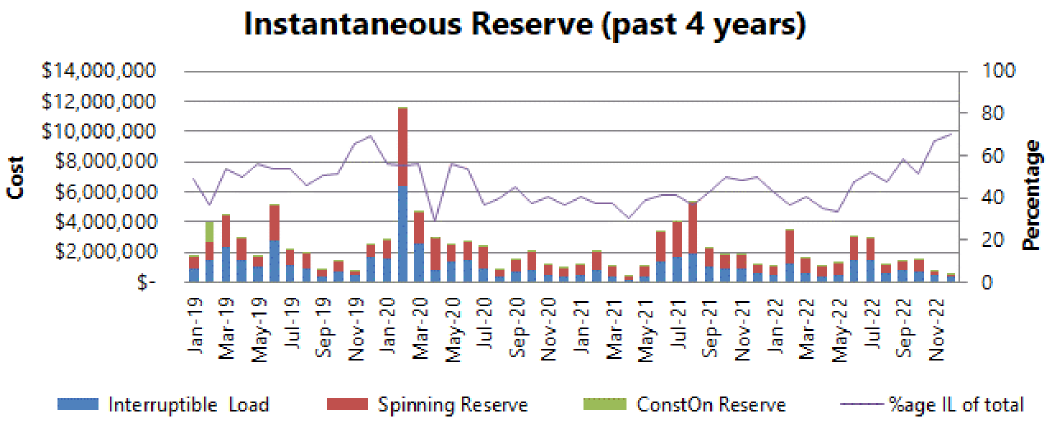
2023 Security of Supply Assessment: Reference Case Assumptions and Sensitivities

We sought comment from the industry on the assumptions made in the SOSPA reference case and the sensitivities (and plausible combinations of sensitivities) from the reference case that we will assess by flexing different variables. There are eight supply side sensitivities and five demand side sensitivities to derive the combinations of sensitivity cases; these are detailed in the report. Feedback was requested in December, and we are currently evaluating the responses.

13 Ancillary services

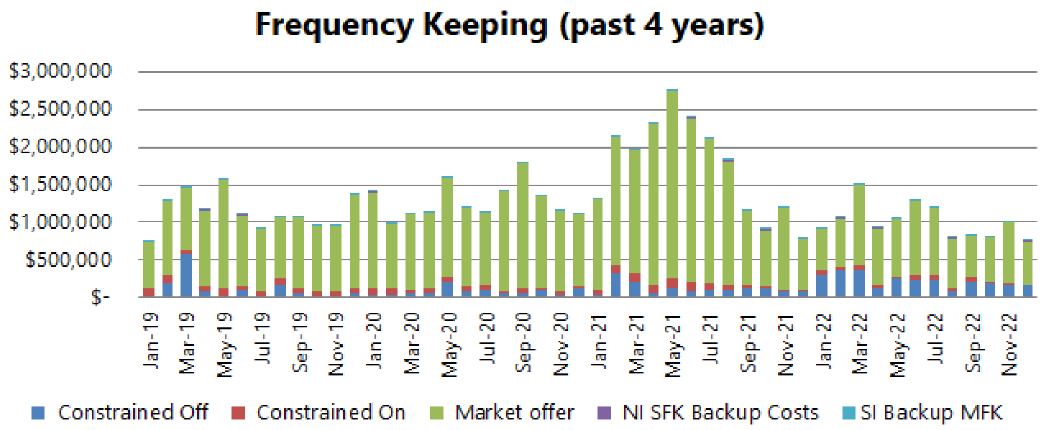


This quarter's ancillary service costs were $5.9 million, which is a 33% decrease compared to the previous quarter's costs of $8.9 million. This reflects lower costs for instantaneous reserves of $2.7 million (50% decrease) since last quarter. Lower instantaneous reserve costs this quarter were the result of lower spinning reserve costs of $1.1 million (57% decrease) and lower interruptible load costs of $1.6 million (44% decrease) as a result of reduced requirements for instantaneous reserve as the weather warms, and lower relative average prices for instantaneous reserve.



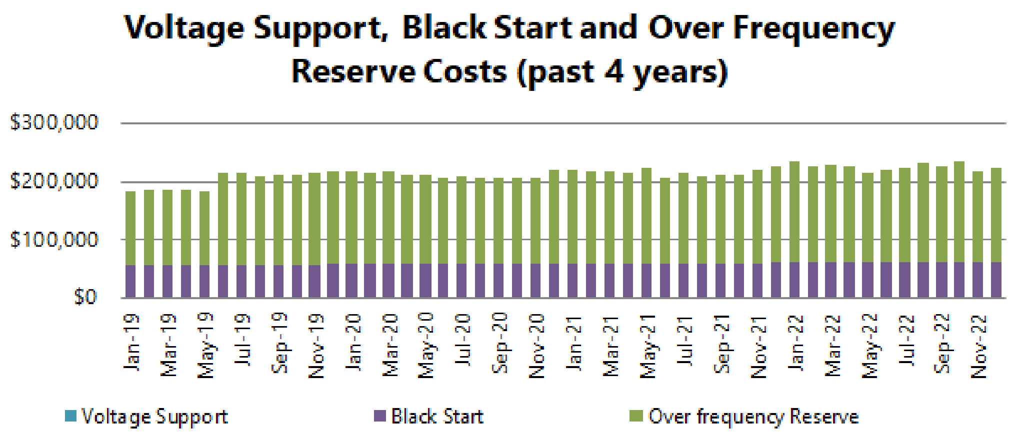
Instantaneous reserve costs were $2.7 million this quarter, which is a 50% decrease on the previous quarter ($5.4 million). Interruptible load costs were lower than last quarter with a decrease of $1.27m (44% decrease), while spinning reserve costs decreased by $1.43m (57% decrease) and constrained on costs for instantaneous reserve decreased by $27k (68% increase).

Procured quantities of South Island instantaneous reserve decreased by approximately 50% in the middle of the quarter and persisted at these levels for the remainder of the quarter. Procured quantities of North Island fast and sustained reserve decreased by 9% and 31% respectively. The average price per MW for North Island fast reserve and sustained reserve in both Islands reduced ten-fold over the quarter, while North Island average prices per MW for sustained reserve halved.



This quarter the frequency keeping costs were $2.6 million, which is a 9% decrease compared to the previous quarter's costs of $2.8 million. Constrained on costs decreased by $104k (64% decrease), while constrained off costs increased by $12k (2% increase). Market offer values decreased by $166k (8% decrease).

North Island frequency keeping costs decreased marginally this quarter to remain at $1.3 million (2% decrease), while South Island frequency keeping costs decreased to $1.3 million (16% decrease).



Over frequency reserve costs decreased slightly this quarter to $488k (1% decrease). Black start costs are unchanged since last quarter and were $62k in each month. There are no voltage support costs as there is no need to procure this ancillary service at this time.

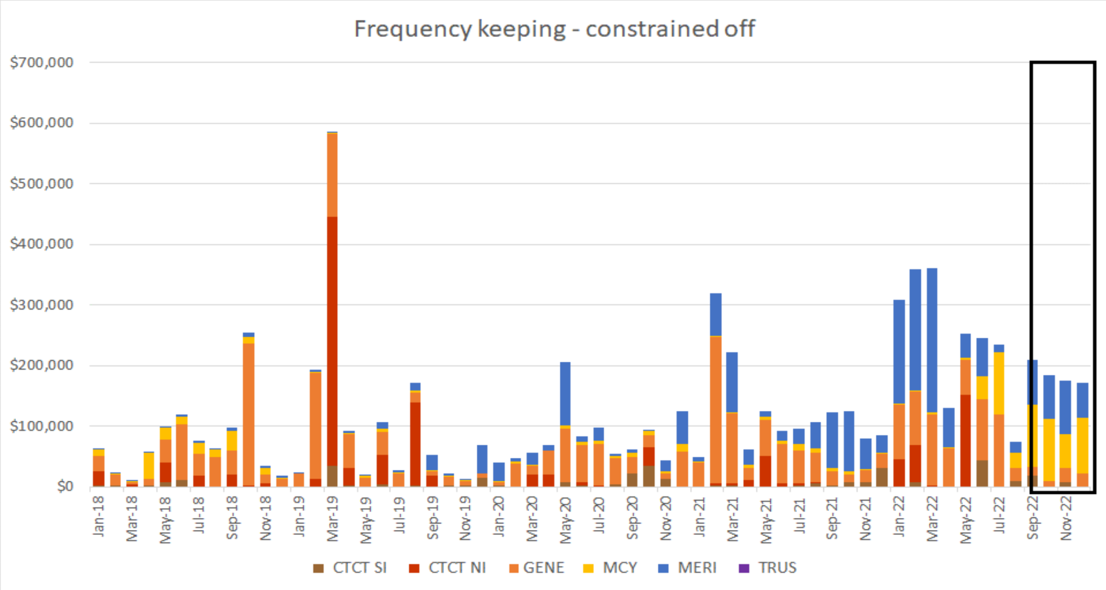
Ancillary Services contracts

The ancillary services tender for Over Frequency Reserves and South Island Black Start is now complete and new contracts were issued from 1 December.

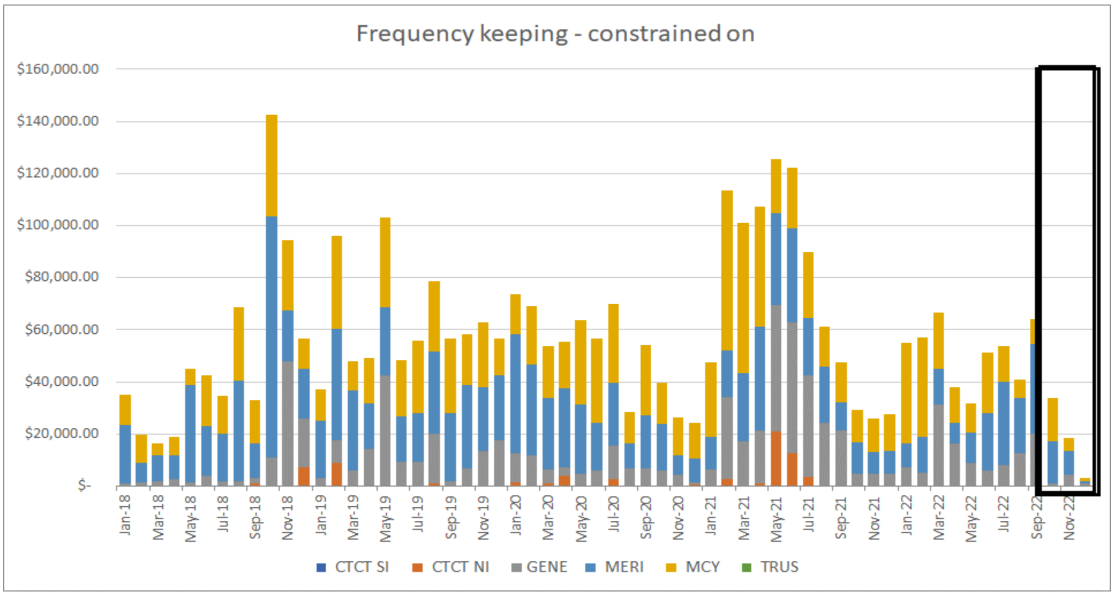
13.1 Constrained on/off costs

Note: Where there is a high payment, as opposed to in increasing/decreasing trend, it will often relate to payments over a small number of trading periods.

Frequency Keeping

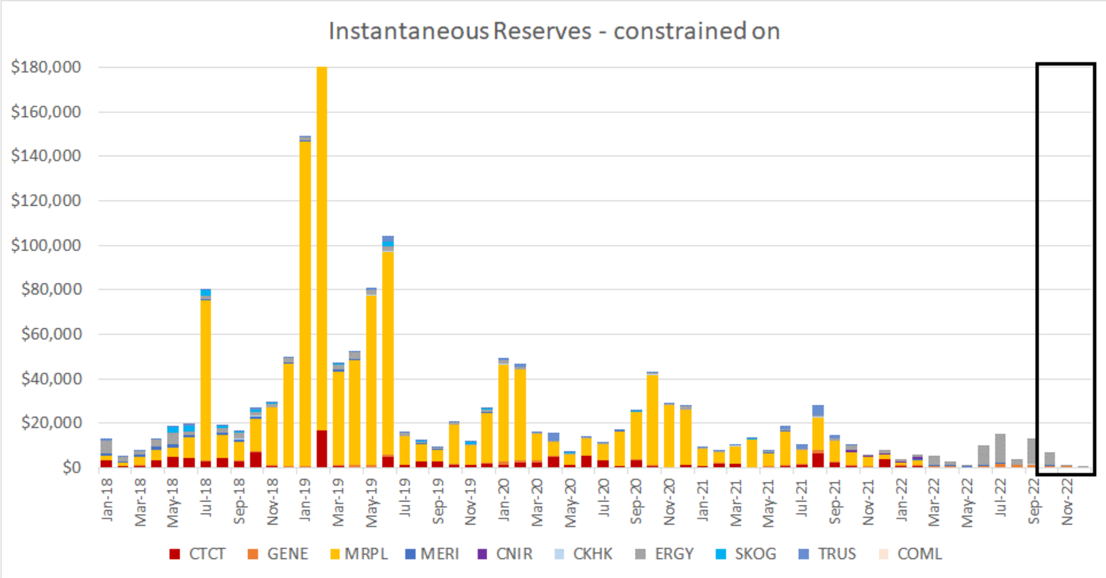


For Q2 2022/23, the frequency keeping constrained off costs increased by 2.4% on the previous quarter to $531k. The North Island constrained off costs decreased by 21% over this period, while conversely the South Island constrained off costs increased by 70%.



For Q2 2022/23, the frequency keeping constrained on costs decreased by 64% on the previous quarter to $60k. Both the North and South Island frequency keeping constrained on costs decreased, by 68% in the South Island and by 59% in the North Island since the previous quarter.

Instantaneous Reserves



For Q2 2022/23, the instantaneous reserves constrained on costs decreased from the previous quarter to $13k (68% decrease).

14 Commissioning and Testing

Generator Commissioning and testing

We continue to work with multiple asset owners on generator commissioning projects at various stages of development, from feasibility through to testing. Presently we have 78 active projects.

15 Operational and system events

7 October events (HVDC filter, under-frequency event and grid emergency)

During the early morning on 7 October, an HVDC filter tripped. This resulted in the HVDC running back leading to an under-frequency event and a subsequent response from interruptible load. HVDC transfer was then reduced by about 300 MW. With an unseasonal cold morning and high peak, we declared a grid emergency notice (GEN) for 07:15 to 09:30 for the morning peak and began instructing distribution businesses to remove controllable load. The GEN ended and controllable load restoration commenced at 08:00 as the filter was returned to service.

Ahead of the events on Friday 7 October, we saw unusually high peak demand and tight residuals during the week as a cold snap moved across New Zealand. We published a low residual Customer Advice Notice (CAN) for the morning peak on Tuesday 4 October, and a subsequent CAN for the morning peak on Friday 7 October followed by an industry brief in the afternoon of Thursday 6 October. We presented the timeline of these events from a system operator perspective at our fortnightly industry forum with participants on Tuesday 11 October.

In the early evening on 22 November, a CAN was sent to advise that the system operator was managing for a potential island of the Hawkes Bay Region. There was then a triple circuit contingency of Fernhill-Tuai 1 and both the Redcliffe-Tuai 1 and 2 circuits. This rare event was caused by two simultaneous lightning strikes. A Tuai island of 40 MW briefly held before Waikaremoana generation tripped due to instability. Circuits to Tuai were restored using Grid Emergency provisions. This was discussed from a system operator perspective at our fortnightly industry forum with participants on Tuesday 29 November.

Significant incident investigations

One new 'moderate' significant incident occurred in early October (as outlined in the list below) in addition to one other active significant event investigation:

- Event 4317 – loss of supply at Tauranga on 13 October 2022 at 21:42 (bird activity). Initial indication is that 68 MWh were lost over a 204-minute period, resulting in a 'moderate' classification. Investigation was completed in December 2022, with a final report delivered to the Authority in January 2023. No breaches or underperformance of the System Operator service identified.
- Event 4284 - (multiple lightning strikes in June). We submitted a final report to the Authority, with no breaches or underperformance of the System Operator service identified.

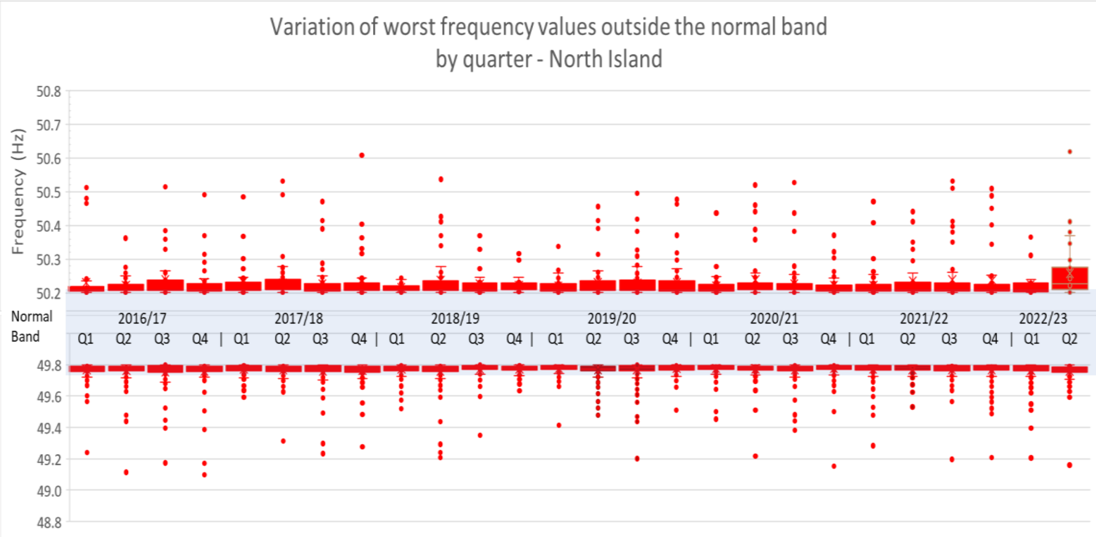
We are awaiting feedback from the Authority on our proposal to change the significant incident criteria to ensure we are reporting on the right level of incidents considering associated consequences.

16 Frequency fluctuations

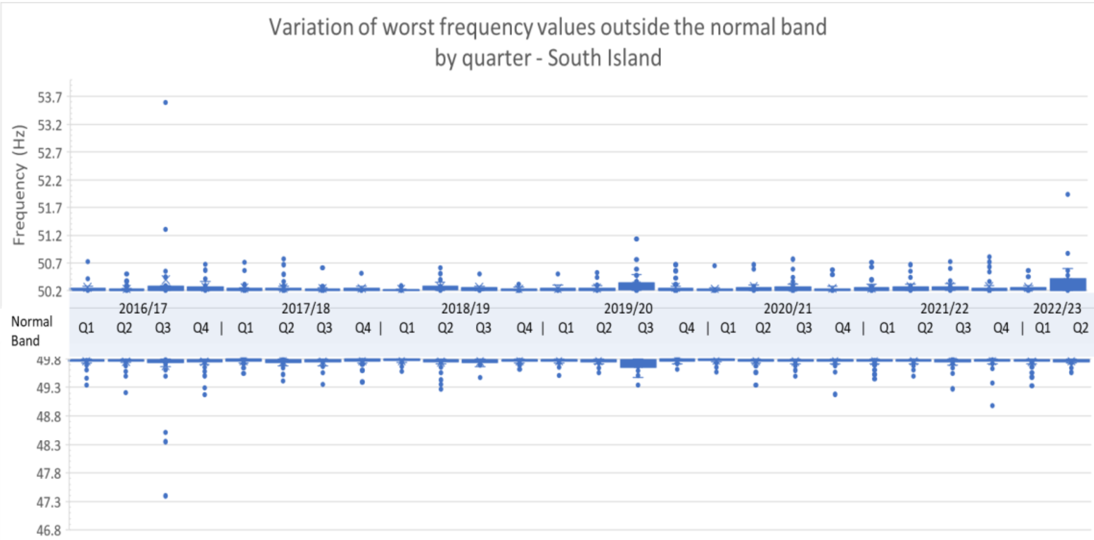
16.1 Maintain frequency in normal band (Frequency value)

The following charts show the distribution of the worst frequency excursion outside the normal band (49.8 to 50.2 Hz) by quarter since Q1 2016/17, including the reporting period.

North Island



South Island



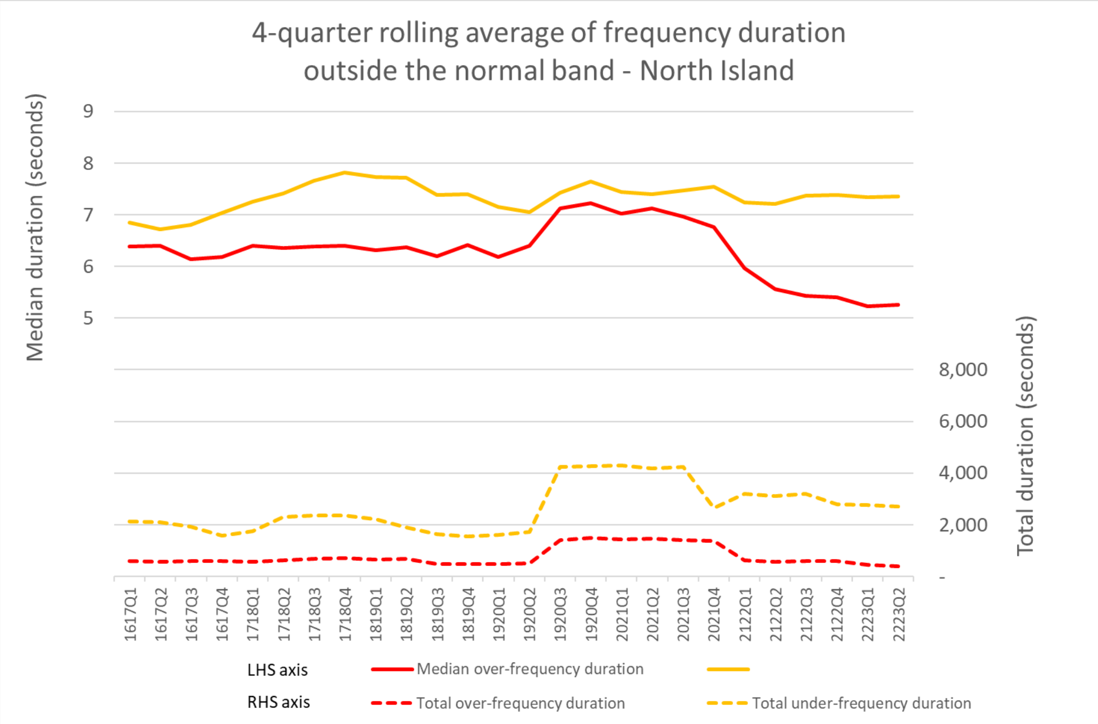
Note1: These box and whisker charts show the distribution of data. The “box” represents the distribution of the middle 50% of the data, the “whiskers” indicate variability, and outliers are shown as single data points.

Note2: The “box” for Q2 2022/23 above the normal band is a reflection of more Tiwai excursions than average and the HVDC runback in October.

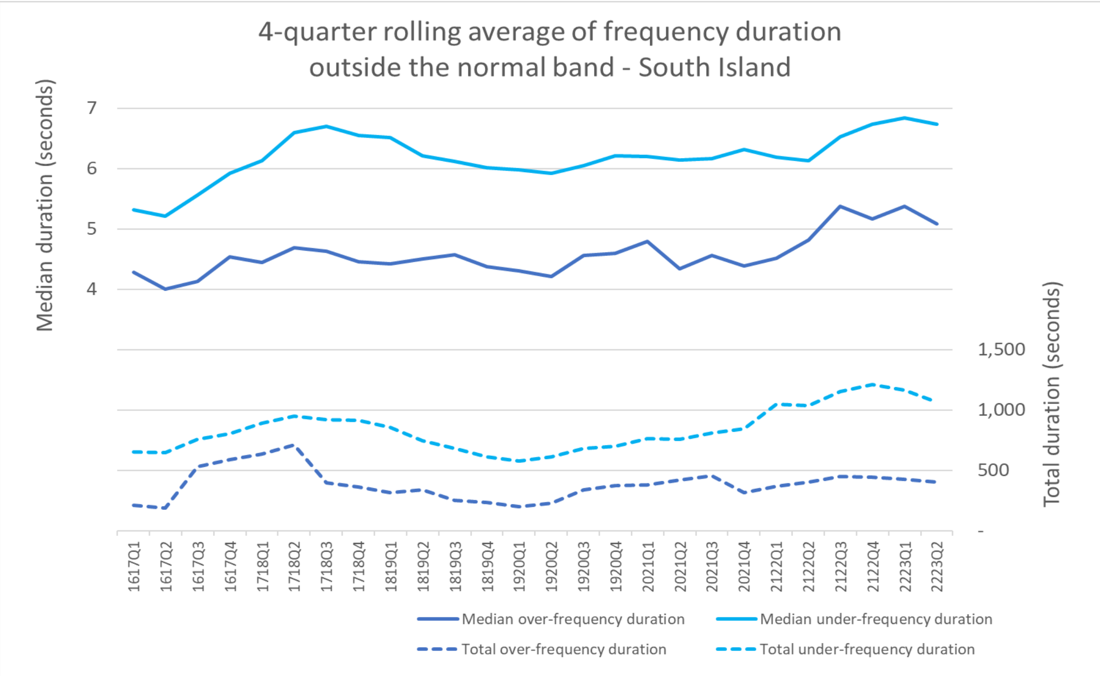
16.2 Recover quickly from a fluctuation (Time)

The following charts show the median and total duration of all the momentary fluctuations above and below the normal band for each island. The information is shown as a 4-quarter rolling average to illustrate trends in the data.

North Island



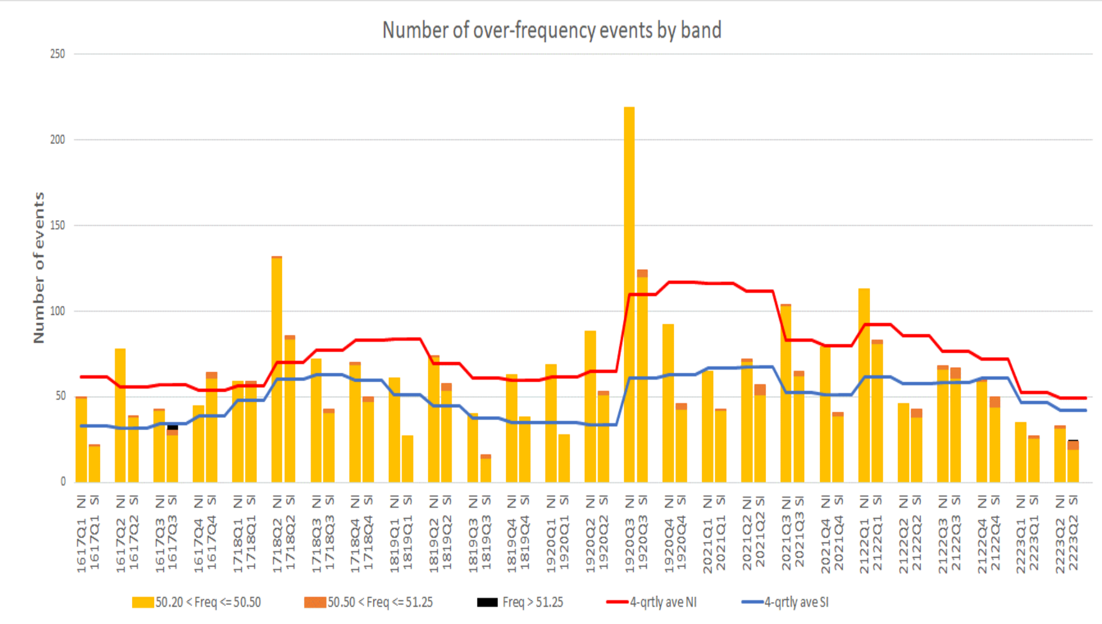
South Island



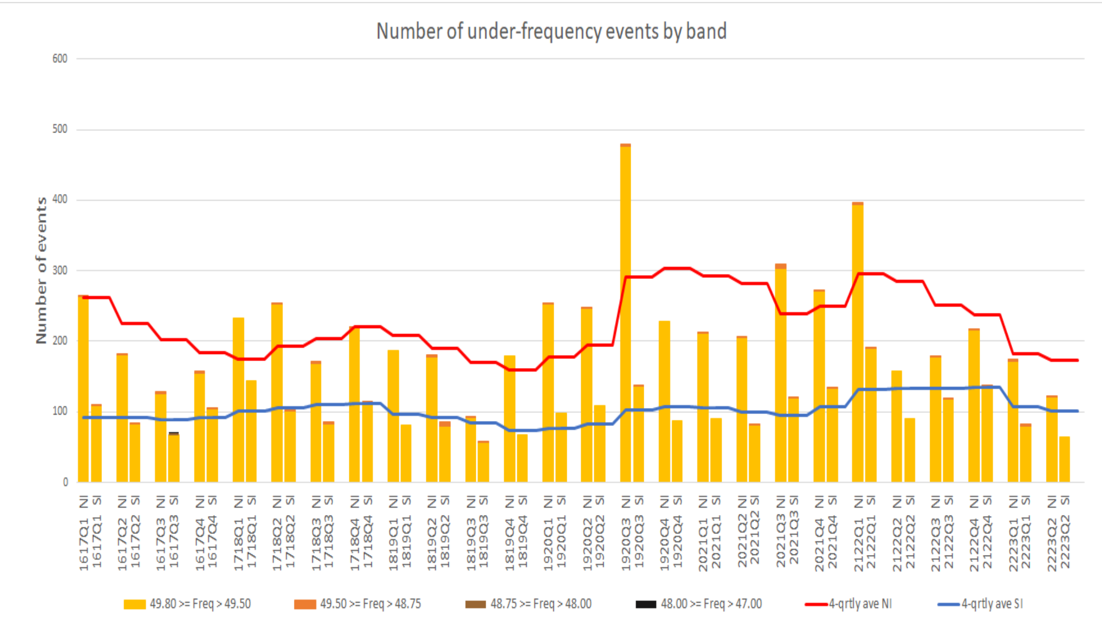
16.3 Manage frequency and limit rate of occurrences during momentary fluctuations (Number)

The following charts show the number of momentary fluctuations outside the frequency normal band, grouped by frequency band, for each quarter since Q1 2016/17. Information is shown by island, including a 4-quarter rolling average to show the prevailing trend.

Over-frequency events



Under-frequency events



16.4 Manage time error and eliminate time error once per day

There were no time error violations in the reporting period.

17 Voltage management

With the warmer weather and lower loads over weekends, our control room teams have been challenged with managing high voltage without resorting to switching of cables. To assist with managing voltage over the summer months, we have agreed with the grid owner to remove the Pakuranga-Whakamaru 1 circuit for voltage management from 11 November 2022 until early February 2023. This approach minimises the amount of switching to help meet the grid owner's operational limitations for the cables. The commissioning of a reactor at Otahuhu by the grid owner at the end of December has also helped voltage management.

While our studies indicate that the Pakuranga-Whakamaru 1 outage enables us to balance voltage management with maintaining system security, we may still need to return the cable if we see security issues arising. Potential issues depend on conditions at the time, including how much Huntly generation is available and whether there are concurrent 220 kV circuit outages or reactive plant outages. We are monitoring carefully and assessing outages in the last week of January which may potentially require reconsideration.

18 Security notices

The following table shows the number of Warning Notices, Grid Emergency Notices and Customer Advice Notices issued over the last 12 months.

Notices issued	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
Demand Allocation Notice	-	-	-	-	-	-	-	-	-	-	-	-	-
Grid Emergency Notice	-	-	-	-	-	-	1	-	-	1	1	1	-
Warning Notice	-	-	-	-	-	1	-	-	-	-	1	-	-
Customer Advice Notice	5	7	9	15	14	15	28	24	25	35	33	30	17

19 Grid emergencies

Date	Time	Summary Details	Island
07/10/22	07:15	A grid emergency was declared due to insufficient generation offers in the North Island following a reduction in HVDC capacity.	N
22/11/22	17:48	A grid emergency was declared to assist with restoration of connection to Tuai Substation following the tripping of 110kV Redclyffe – Tuai 1 & 2, and Fernhill – Tuai 1 circuits due to lightning.	N

Appendices

Appendix A: Discretion

In recent months, discretion has been reclassified to include the process to manage generators on minimum MW values overnight. As a result, the list of discretions in this report is much larger than recorded in previous months.

October – 34 instances

Event Date and Time	Description
1/10/2022 1:46	NAP scheduled below 135 MW (min run) from 05:00 to 06:00 (2nd Oct) since todays 08:00 NRSL. Should NAP be dispatched off, it will take 48hrs to reconnect.134 MW has been applied to NI Optional Island AC CE risk from 00:00 to 07:00 (2nd Oct). Keeping NAP on is the least cost solution, plus required for voltage support and over frequency reserves. Note: Low price forecast starting midnight and HLY U1 ramps below 100MW overnight with high wind forecast.
1/10/2022 16:13	TUI1101 PRI0 Will breach resource consent. They have heavy lake inflows Last Dispatched MW: 23
1/10/2022 16:14	TUI1101 KTW0 Due to plant capability Last Dispatched MW: 25.35
1/10/2022 16:14	TUI1101 TUI0 Will breach resource consent. They have heavy lake inflows. Last Dispatched MW: 40
1/10/2022 16:17	Genesis Operator called SC to query why WKA was being dispatched below their current offer (KTW 35MW at $0.01, PRI 23 MW at $0.00, TUI 40 MW at $0.00). SC explained that this was due to the low pricing (currently $0.01) and they mentioned that they could not go lower than the amounts offered due to plant capability/ resource consent and subsequently claimed rule exemption 13.82 2a.
1/10/2022 16:28	TKU2201 TKU0 Will breach resource consent. They have heavy lake inflows. Last Dispatched MW: 94.99
2/10/2022 19:51	SFD2201 SFD21 Held SFD21 on at minimum run of 4MW at $660 as next generator in price stack is WHI at $4,996 - load forecast is tracking approx. 100 MW under actual load, actual wind is 38 MW nationally (schedule shows 82 MW wind). SFD21 also being dispatched reserves.
5/10/2022 6:43	JRD1101 JRD0 Low residual situation, evening peak with lighting load coming on. Residual less than 200MW Last Dispatched MW: 29.22
5/10/2022 7:08	JRD1101 JRD0 Low residual situation, evening peak with lighting load coming on. Residual less than 200MW Last Dispatched MW: 29.2
5/10/2022 7:09	JRD1101 JRD0 Low residual, require JRD on Last Dispatched MW: 29.2
5/10/2022 7:10	JRD1101 JRD0 Low residual, require JRD on Last Dispatched MW: 29.2
5/10/2022 17:36	TUI1101 TUI0 Tripping of RDF_TUI_1. Discretion applied to avoid overloading remaining RDF_TUI_2 Circuit Last Dispatched MW: 40
5/10/2022 17:36	TUI1101 PRI0 Tripping of RDF_TUI_1. Discretion applied to avoid overloading remaining RDF_TUI_2 Circuit Last Dispatched MW: 40

Event Date and Time	Description
5/10/2022 17:37	TUI1101 PRI0 Tripping of RDF_TUI_1. Discretion applied to avoid overloading remaining RDF_TUI_2 Circuit Last Dispatched MW: 40
5/10/2022 17:37	TUI1101 KTW0 Tripping of RDF_TUI_1. Discretion applied to avoid overloading remaining RDF_TUI_2 Circuit Last Dispatched MW: 30.46
5/10/2022 17:38	TUI1101 KTW0 Tripping of RDF_TUI_1. Discretion applied to avoid overloading remaining RDF_TUI_2 Circuit Last Dispatched MW: 30.46
5/10/2022 17:45	TUI1101 KTW0 Tripping of RDF_TUI_1. Discretion applied to avoid overloading remaining RDF_TUI_2 Circuit. to Last Dispatched MW: 35
5/10/2022 17:45	TUI1101 TUI0 Tripping of RDF_TUI_1. Discretion applied to avoid overloading remaining RDF_TUI_2 Circuit Last Dispatched MW: 40
5/10/2022 17:45	TUI1101 PRI0 Tripping of RDF_TUI_1. Discretion applied to avoid overloading remaining RDF_TUI_2 Circuit Last Dispatched MW: 25
6/10/2022 6:42	WHI2201 WHI0 Required for security, - low residual over evening peak. Last Dispatched MW: 13.93
6/10/2022 6:56	JRD1101 JRD0 Required for security, - low residual over evening peak Last Dispatched MW: 51.14
6/10/2022 7:13	WHI2201 WHI0 Required for security, - low residual over evening peak. WHI advised 20 MW is their minimum run. Last Dispatched MW: 13
6/10/2022 16:30	SFD2201 SFD21 Discretioned on for security over the morning peak. Last Dispatched MW: 16.13
6/10/2022 18:47	WHI2201 WHI0 GEN due to energy shortfall resulting from low national residual and reduced HVDC capability. WHI discretioned to be held at min to ensure they were not dispatched off during controllable load shedding. Last Dispatched MW: 27.3
6/10/2022 18:48	WHI2201 WHI0 GEN due to energy shortfall resulting from low national residual and reduced HVDC capability. WHI discretioned to be held at min of two machines to ensure they were not dispatched off during controllable load shedding. Last Dispatched MW: 27.3
6/10/2022 19:06	WHI2201 WHI0 GEN due to energy shortfall resulting from low national residual and reduced HVDC capability. WHI discretioned to be held at min to ensure they were not dispatched off during controllable load restoration. Last Dispatched MW: 40
10/10/2022 9:02	NAP scheduled below 140 MW (min run) from 03:30 to 05:00 (11 Oct) in 20:00 NRSL. Mercury trader confirmed Rule 13.82(a) will be claimed for these periods if dispatched to scheduled values. Should NAP be dispatched off, it will take min 48hrs to reconnect. 139 MW has been applied to NI Optional Island AC CE risk from 00:00 to 05:30 (11 Oct). Keeping NAP on is the least cost solution, plus required for voltage support and over frequency reserves. Note: Low price forecast starting midnight with HLY U5 offline coupled with high wind forecast.
10/10/2022 23:14	MAN2201 MAN0 MEL have confirmed they will remain off economic dispatch for the duration of the extended potline. Estimated end TP26 Last Dispatched MW: 590
10/10/2022 23:16	MAN2201 MAN0 MEL have confirmed they will remain off economic dispatch for the duration of the extended potline. Estimated end TP26 Last Dispatched MW: 405
13/10/2022 8:46	TGA0331 KMI0 TGA bus fault Last Dispatched MW: 26

Event Date and Time	Description
13/10/2022 23:41	MAN2201 MAN0 MAN reduced by 190MW for the return of extended potline 1. Last Dispatched MW: 660
16/10/2022 23:12	MAN2201 MAN0 TWI extended potline management Last Dispatched MW: 497
24/10/2022 23:42	MAN2201 MAN0 To make room for return of TWI L1. Last Dispatched MW: 589
26/10/2022 23:09	MAN2201 MAN0 To manage TWI line 1 extended potline. MCC have chosen to not return to economic dispatch. Last Dispatched MW: 589

November - 73 instances (48 instances related to lightning, of which 25 involve managing a potential Island in Hawkes Bay)

Event Date and Time	Description
1/11/2022 6:10	NAP dispatched below their min operating of 136 MW and claimed a 13.82a. OPS case run showing best cost solution to the market was to keep NAP at their min running of 136MW until midnight and 137MW from midnight until 06:00. NAP also provides 40 Mvar of import capacity which is important when reactive support is scarce overnight. NI manual CE risk set to 135 MW from 19:30 - 00:00 (02 Nov) and 136MW from 00:00 - 06:00.
1/11/2022 6:22	NAP2201 NAP0 Discretion Clause 13.70, Part 13 ENR Min : 136 Constrained to min run due to code claim, Plant capability. Security studies show least cost solution is to keep NAP on min run (136MW) Last Dispatched MW: 127.84
1/11/2022 18:58	ARG1101 BRR0 Discretion Clause 13.70, Part 13 ENR Max : 0 For ARG_BLN_1 switching Last Dispatched MW: 8
2/11/2022 11:10	NAP scheduled below their min operating of 136MW and indicated they would claim a 13.82a. OPS case run showing cost solution to the market comparable during trough and with potential delayed re synching cheaper during AMPK with them on. NAP also provides 40Mvar of import capacity which is important when reactive support is scarce overnight.NI manual CE risk set to 135MW from 2300 02/11 -0630 03/11
2/11/2022 23:33	MAN2201 MAN0 Discretion Clause 13.70, Part 13 EN Max : 553 Discretion applied to manage return of TWI line 1 extended potline. Last Dispatched MW: 738
3/11/2022 8:15	NAP scheduled below their minimum operating level of 136MW and indicated they would claim a 13.82a. OPS case run showing cost solution to the market comparable during trough and with potential for delayed resynching cheaper during AMPK with them on. NAP also provides 40Mvar of import capacity which is important when reactive support is scarce overnight. NI manual CE risk set to 135MW from 00:00-06:30 03/11.

4/11/2022 2:55	ARG1101 BRR0 Discretion Clause 13.70, Part 13 ENR Max : 0 Discretion applied for switching for the return of ARG_KIK_1. Last Dispatched MW: 10
4/11/2022 4:26	NAP scheduled below their minimum operating of 136MW (137MW after 00:00) and indicated they would claim a 13.82a. .NI manual CE risk set to 135MW from 1800 04/11 - 23:30 04 /11 and then to 136MW through to 07:00 05/11.
4/11/2022 20:41	NAP dispatched and scheduled below their minimum operating of 136MW. MRG claimed rule 13.82a citing a risk to personnel and plant. .NI manual CE risk set to 135MW from 09:30 - 20:00 as they are required for voltage support with low system loads over the weekend.
4/11/2022 20:41	NAP2201 NAP0 Discretion ENR Min : 136 NAP dispatched below their minimum operating of 136MW. . Claimed Rule 13.82(2a) citing a risk to personnel and plant. Last Dispatched MW: 133.33
5/11/2022 5:15	NAP dispatched and scheduled below their minimum operating of 136MW. MRG claimed rule 13.82a citing a risk to personnel and plant. .NI manual CE risk set to 135MW from 20:00-21:00 as they are required for voltage support with low system loads over the weekend.
5/11/2022 15:51	NAP dispatched and scheduled below their minimum operating of 137MW. MRG claimed rule 13.82a citing a risk to personnel and plant. .NI manual CE risk set to 136MW from 06:00- 12:00 as they are required for voltage support with low system loads over the weekend.
7/11/2022 23:29	MAN2201 MAN0 Discretion Clause 13.70, Part 13 EN Max : 610 Not returning to economic dispatch during extended potline� Last Dispatched MW: 788
10/11/2022 3:01	THI2201 THI1 Discretion Clause 13.70, Part 13 ENR Max : 0 Tripped. Last Dispatched MW: 77
14/11/2022 23:23	MAN2201 MAN0 Discretion Clause 13.70, Part 13 EN Max : 551 Extended potline L1 Last Dispatched MW: 738
14/11/2022 23:26	MAN2201 MAN0 Discretion Clause 13.70, Part 13 EN Max : 548 Extended potline L1 Last Dispatched MW: 738
16/11/2022 4:51	MAN2201 MAN0 Discretion Clause 13.70, Part 13 ENR Max : 550 Double circuit contingency management. SFT not yet building a constraint to use. Last Dispatched MW: 650
16/11/2022 5:01	MAN2201 MAN0 Discretion Clause 13.70, Part 13 ENR Max : 480 Double circuit contingency management. SFT still not yet building a constraint to use. Last Dispatched MW: 550
16/11/2022 5:14	SFD2201 SFD21 Discretion Clause 13.70, Part 13 EN Min : 10 Discretion on due to SI double circuit management, backing down HVDC and bringing up NI generators. NI residual low. Last Dispatched MW: 71.15
16/11/2022 5:19	SFD2201 SFD21 Discretion Clause 13.70, Part 13 EN Min : 16 Discretion on due to SI double circuit management. Contact trader advises minimum run on unit is 16MW. Last Dispatched MW: 10
16/11/2022 23:13	MAN2201 MAN0 Discretion Clause 13.70 Part 13. ENR Max: 475 Extended Potline MCC wanted to stay down Last Dispatched MW: 657.32
22/11/2022 2:13	WHI2201 WHI0 Discretion Clause 13.70, Part 13 ENR Min : 25 Managing a potential Island in Hawkes bay with RDF_WRK OOS and managing for the loss of WHI_WRK_1 Last Dispatched MW: 0
22/11/2022 2:16	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 24 Managing a potential Island in Hawkes bay with RDF_WRK OOS and managing for the loss of WHI_WRK_1 Last Dispatched MW: 0

22/11/2022 2:28	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 50 Managing a potential Island in Hawkes bay with RDF_WRK OOS and managing for the loss of WHI_WRK_1 Last Dispatched MW: 24
22/11/2022 2:29	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 45 Managing a potential Island in Hawkes bay with RDF_WRK OOS and managing for the loss of WHI_WRK_1 Last Dispatched MW: 24
22/11/2022 2:39	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 55 Managing a potential Island in Hawkes bay with RDF_WRK OOS and managing for the loss of WHI_WRK_1 Last Dispatched MW: 45
22/11/2022 2:43	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 70 Managing a potential Island in Hawkes bay with RDF_WRK OOS and managing for the loss of WHI_WRK_1 Last Dispatched MW: 45
22/11/2022 2:43	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 80 Managing a potential Island in Hawkes bay with RDF_WRK OOS and managing for the loss of WHI_WRK_1 Last Dispatched MW: 45
22/11/2022 2:51	WHI2201 WHI0 Discretion Clause 13.70, Part 13 SIR Max : 0 Managing a potential Island in Hawkes bay with RDF_WRK OOS and managing for the loss of WHI_WRK_1 Last Dispatched MW: 70
22/11/2022 2:51	WHI2201 WHI0 Discretion Clause 13.70, Part 13 FIR Max : 0 Managing a potential Island in Hawkes bay with RDF_WRK OOS and managing for the loss of WHI_WRK_1. Last Dispatched MW: 70
22/11/2022 2:52	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 65 Managing a potential Island in Hawkes bay with RDF_WRK OOS and managing for the loss of WHI_WRK_1 Last Dispatched MW: 70
22/11/2022 2:54	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 85 Managing a potential Island in Hawkes bay with RDF_WRK OOS and managing for the loss of WHI_WRK_1 Last Dispatched MW: 65
22/11/2022 2:58	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 90 Managing a potential Island in Hawkes bay with RDF_WRK OOS and managing for the loss of WHI_WRK_1 Last Dispatched MW: 85
22/11/2022 2:59	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 100 Managing a potential Island in Hawkes bay with RDF_WRK OOS and managing for the loss of WHI_WRK_1 Last Dispatched MW: 85
22/11/2022 3:04	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 115 Managing a potential Island in Hawkes bay with RDF_WRK OOS and managing for the loss of WHI_WRK_1 Last Dispatched MW: 100
22/11/2022 3:08	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 120 Managing a potential Island in Hawkes bay with RDF_WRK OOS and managing for the loss of WHI_WRK_1 Last Dispatched MW: 115
22/11/2022 3:11	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 95 Managing a potential Island in Hawkes bay with RDF_WRK OOS and managing for the loss of WHI_WRK_1 Last Dispatched MW: 115
22/11/2022 3:14	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 109 Managing a potential Island in Hawkes bay with RDF_WRK OOS and managing for the loss of WHI_WRK_1 Last Dispatched MW: 95

22/11/2022 3:17	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 115 Managing a potential Island in Hawkes bay with RDF_WRK OOS and managing for the loss of WHI_WRK_1 Last Dispatched MW: 109
22/11/2022 3:22	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 130 Managing a potential Island in Hawkes bay with RDF_WRK OOS and managing for the loss of WHI_WRK_1 Last Dispatched MW: 115
22/11/2022 3:27	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 143 Managing a potential Island in Hawkes bay with RDF_WRK OOS and managing for the loss of WHI_WRK_1 Last Dispatched MW: 130
22/11/2022 3:29	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 124 Managing a potential Island in Hawkes bay with RDF_WRK OOS and managing for the loss of WHI_WRK_1 Last Dispatched MW: 130
22/11/2022 4:35	TUI1101 KTW0 Discretion Clause 13.70, Part 13 ENR Max : 0 tripped Last Dispatched MW: 27
22/11/2022 4:35	TUI1101 TUI0 Discretion Clause 13.70, Part 13 ENR Max : 0 tripped Last Dispatched MW: 53
22/11/2022 5:19	WHI2201 WHI0 Discretion Clause 13.70, Part 13 SIR Max : 0 For TUI Grid Emergency - only Energy required. Last Dispatched MW: 124
22/11/2022 5:19	WHI2201 WHI0 Discretion Clause 13.70, Part 13 FIR Max : 0 For TUI Grid Emergency - only Energy required. Last Dispatched MW: 124
22/11/2022 23:46	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 24 Lightning in the area Last Dispatched MW: 0
22/11/2022 23:51	TUI1101 TUI0 Discretion Clause 13.70, Part 13 EN Min : 27 Lightning in the area Last Dispatched MW: 28
22/11/2022 23:52	TUI1101 TUI0 Discretion Clause 13.70, Part 13 EN Min : 38 Lightning in the area Last Dispatched MW: 28
22/11/2022 23:52	TUI1101 KTW0 Discretion Clause 13.70, Part 13 EN Min : 27 Lightning in the area Last Dispatched MW: 12
22/11/2022 23:57	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 48 Lightning in the area Last Dispatched MW: 24
23/11/2022 0:00	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 46 Lightning in the area Last Dispatched MW: 24
23/11/2022 0:08	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 56 Lightning in the area Last Dispatched MW: 46
23/11/2022 0:13	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 66 Lightning in the area Last Dispatched MW: 56
23/11/2022 0:18	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 84 Lightning in the area Last Dispatched MW: 66
23/11/2022 0:23	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 99 Lightning in the area Last Dispatched MW: 84
23/11/2022 0:32	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 120 Lightning in the area Last Dispatched MW: 99
23/11/2022 19:15	For the duration of the HLY U5 valve testing, Genesis trader is claiming 13.82a for plant and personnel safety to be dispatched to min of 350MW from 09:00 until 15:00. Ops manager had previously been advised by Genesis. Optional AC risk applied to RMT for 349MW from 09:30 to 15:00

23/11/2022 20:05	For the duration of the HLY U5 valve testing, Genesis trader is claiming 13.82a for plant and personnel safety to be dispatched to min of 350MW from now until 15:00. Ops manager had previously been advised by Genesis. Optional AC risk applied to RMT for 349MW from 08:00 to 15:00
23/11/2022 23:09	MAN2201 MAN0 Discretion Clause 13.70, Part 13 EN Max : 404 Discretion applied for MAN to manage the extended offload of TWI Line 1, estimated return 13:05 - MCC did not wish to return to economic dispatch Last Dispatched MW: 585.04
24/11/2022 0:41	TUI1101 KTW0 Discretion Clause 13.70, Part 13 EN Min : 27 Lightning in the area Last Dispatched MW: 12
24/11/2022 0:41	TUI1101 TUI0 Discretion Clause 13.70, Part 13 EN Min : 38 Lightning in the area Last Dispatched MW: 28
24/11/2022 0:42	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 24 Lightning in the area Last Dispatched MW: 0
24/11/2022 0:49	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 31 Lightning in the area Last Dispatched MW: 24
24/11/2022 0:53	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 25 Lightning in the area Last Dispatched MW: 31
24/11/2022 0:54	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 50 Lightning in the area Last Dispatched MW: 31
24/11/2022 1:02	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 65 Lightning in the area Last Dispatched MW: 50
24/11/2022 1:08	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 85 Lightning in the area Last Dispatched MW: 65
24/11/2022 1:13	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 100 Lightning in the area Last Dispatched MW: 85
24/11/2022 1:19	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 115 Lightning in the area Last Dispatched MW: 100
24/11/2022 1:24	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 127 Lightning in the area Last Dispatched MW: 115
24/11/2022 1:32	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 130 Lightning in the area Last Dispatched MW: 127
24/11/2022 1:44	Genesis trader is claiming 13.82a HLY Unit 5 to be dispatched to min of 190MW for TP 31 (15:00). For plant stability following Valve testing. Optional AC risk applied to RMT for 189MW for 1500.

December – 34 instances

Event Date and Time	Description
5/12/2022 6:22	TKA0111 TKA1 Max : 0 MW Discretion for apparent tripping of ABY_CB42 Last Dispatched MW: 15
5/12/2022 20:02	HLY2201 HLY5 Min : 182 MW HLY claimed 13.82(2A) after being dispatched below their minimum. Discretioned on at their minimum for economic reasons. Last Dispatched MW: 177.59

Event Date and Time	Description
5/12/2022 22:52	SC discussed with Mercury Trader NAP minimum dispatch level. Mercury confirmed that the NAP minimum was now 132 MW and that they would claim a Rule 13.8(2a) exemption if dispatched below that. NI Optional Island Risk of 131 MW applied to maintain them at their minimum run level - having them on to assist with voltage control was seen as very beneficial. Ended at 01:20 when Mercury claimed a bone fide for NAP of 100 MW and changed their offers to 100 MW for the rest of the night.
6/12/2022 12:10	MAN2201 MAN0 Max : 429 MW BF applied to MAN to manage TWI extended potline. MCC operator chose not to return to economic dispatch. Last Dispatched MW: 615
7/12/2022 0:55	SC discussed with Mercury Trader NAP minimum dispatch level. Mercury confirmed that the NAP minimum was now 135 MW and that they would claim a Rule 13.8(2a) exemption if dispatched below that. NI Optional Island Risk of 134 MW applied 02:00-05:00 to maintain them at their minimum run level - having them on to assist with voltage control was seen as very beneficial.
7/12/2022 14:15	HLY2201 HLY5 Min : 190 W Claimed 13.82A due to plant capabilities, Required for Upper North Island voltage stability with multiple 220kV interface circuits on outage. Last Dispatched MW: 174.93
7/12/2022 14:20	HLY_U5 dispatched below their minimum operating of 190MW. Genesis claimed Rule 13.82A citing plant safety. NI manual CE risk set to 189MW from 14:30 - 16:00. Required for Upper North Island voltage stability with multiple 220kV interface circuits on outage. Marginal price around $0.03 and keeping HLY_U5 at its minimum run is the least cost solution.
7/12/2022 22:35	NAP dispatched below their minimum operating of 136MW. Mercury claimed Rule 13.82A citing plant safety. NI manual CE risk set to 135MW from 23:00 - 06:30. Marginal price around $0.03 and keeping NAP at its minimum run is the least cost solution.
9/12/2022 13:14	ARG1101 BRR0 Max : 0 MW Return of ARG_BLN cct Last Dispatched MW: 10
10/12/2022 16:40	NAP scheduled below their minimum operating run of 138MW (16:00 NRSL schedule). Mercury claimed Rule 13.82A citing plant safety if NAP is dispatched below minimum run in Real Time. NI manual CE risk set to 137MW from 17:00 to 06;00 11th Dec. Keeping NAP on at its minimum run is the least cost solution. NAP is required for voltage support and over frequency arming.
11/12/2022 7:04	NAP scheduled below their minimum operating run of 137MW (07:00 NRSL schedule). Mercury claimed Rule 13.82A citing plant safety if NAP is dispatched below minimum run in Real Time. NI manual CE risk set to 136MW from 07:00 to 12;30 11th Dec. Keeping NAP on at its minimum run is the least cost solution. NAP is required for voltage support and over frequency arming. Subsequent schedules also had NAP below minimum, 136MW NI manual CE risk extended to 05:00 12/12.
13/12/2022 12:47	MAN2201 MAN0 Max : 428 MW Last Dispatched MW: 615
13/12/2022 12:47	Discretion applied to MAN generation to make room for the return of TWI L1 return (187 MW). MCC Advised.
15/12/2022 12:12	MAN2201 MAN0 Max : 435 MW MCC have decided not to return to economic dispatch during extended potline. Discretion applied. Last Dispatched MW: 615

Event Date and Time	Description
15/12/2022 13:25	MAN2201 MAN0 Discretion applied to MAN generation to make room for the return of TWI L1 return (187 MW). MCC Advised. Extended into the next trading period. Last Dispatched MW: 435
16/12/2022 14:51	HWB0331 WPI0 Max : 0 Test solve not dispatched due to SCADA issues. Last Dispatched MW: 26
16/12/2022 14:51	BWK1101 WPI0 Max : 0 Test solve not dispatched due to SCADA issues. Last Dispatched MW: 34
17/12/2022 1:21	NAP scheduled below their minimum operating run of 136MW (00:00 NRSL schedule). SC called trader, who advised Mercury would claim Rule 13.82A citing plant safety if this occurred in real time. NI manual CE risk set to 135MW from 02:00 to 07:30. Keeping NAP on at its minimum run is the least cost solution. NAP also required for voltage support and over frequency arming.
17/12/2022 22:02	NAP dispatched below their minimum operating run of 136MW. Trader claimed Rule 13.82A citing min run of 136MW for plant safety. NI manual CE risk set to 135MW from 22:00 to 06:30. Ops case run and keeping NAP on at its minimum run is the least cost solution. NAP also required for voltage support and over frequency arming.
18/12/2022 22:18	NAP scheduled below their minimum operating run of 136MW (20:00 NRSL schedule). SC called trader, who advised Mercury would claim Rule 13.82A citing plant safety if this occurred in real time. NI manual CE risk set to 135MW from 23:00 to 07:30. Keeping NAP on at its minimum run is the least cost solution. NAP also required for voltage support and over frequency arming.
20/12/2022 5:37	NAP2201 NAP0 Discretion Clause 13.70, Part 13 ENR Min : 135 Start: 20-Dec-2022 05:37 End: 20-Dec-2022 06:00 Notes: NAP claimed 13.82 a (2). Cannot follow dispatch below their minimum operating level of 135 MW. SC advised they be kept on for morning peak and overnight voltage support. Last Dispatched MW: 125.79
20/12/2022 6:01	NAP2201 NAP0 Min : 135 NAP claimed 13.82 a (2). Cannot follow dispatch below their minimum operating level of 135 MW. SC advised they be kept on for morning peak and overnight voltage support. Last Dispatched MW: 136
20/12/2022 21:17	NAP dispatched below their minimum operating run of 137MW. Trader claimed Rule 13.82A citing min run of 137MW for plant safety. NI manual CE risk set to 136MW from 00:00 to 06:30. Ops case run and keeping NAP on at its minimum run is the least cost solution. NAP also required for voltage support and over frequency arming.
21/12/2022 14:10	NAP scheduled below their minimum operating run of 138MW. Trader would claim Rule 13.82A citing min run of 138MW for plant safety. NI manual CE risk set to 137MW from 14:30 to 00:00. Ops case run and keeping NAP on at its minimum run is the least cost solution.
21/12/2022 21:09	NAP scheduled below their minimum operating run of 138MW. Trader would claim Rule 13.82A citing min run of 138MW for plant safety. NI manual CE risk set to 137MW from 00:00 to 06:30 22nd Dec. Keeping NAP on at its minimum run is the least cost solution. Required for voltage support and over frequency reserves as well.

Event Date and Time	Description
22/12/2022 19:30	NAP scheduled below their minimum operating run of 138MW. Trader would claim Rule 13.82A citing min run of 138MW for plant safety. NI manual CE risk set to 137MW from 00:00 to 07:00 23/12. Keeping NAP on at its minimum run is the least cost solution.
23/12/2022 18:23	NAP scheduled below their minimum operating run of 138MW. Trader would claim Rule 13.82A citing min run of 137MW for plant safety. NI manual CE risk set to 136MW from 12:00 to 00:00 25/12. Keeping NAP on at its minimum run is the least cost solution.
24/12/2022 8:24	NAP scheduled below their minimum operating run of 138MW. Trader would claim Rule 13.82A citing min run of 138MW for plant safety. NI manual CE risk set to 137MW from 09:00 to 20:00 . Keeping NAP on at its minimum run is the least cost solution to the market. Update: Night shift noted that NAP was still being dispatched below minimum at various times through the night. After checking with trader that they would continue to claim Rule 13.82A, discretion extended through until 06:30.
25/12/2022 6:52	NAP scheduled below their minimum operating run of 137MW. Trader would claim Rule 13.82A citing min run of 137MW for plant safety. NI manual CE risk set to 136MW from 12:00 to 23:30, 25/12. Keeping NAP on at its minimum run is the least cost solution & a requirement for voltage management.
25/12/2022 9:14	NAP scheduled below their minimum operating run of 137MW. Trader would claim Rule 13.82A citing min run of 137MW for plant safety. NI manual CE risk set to 136MW from 00:00 to 06:30, 26/12. Keeping NAP on at its minimum run is the least cost solution & a requirement for voltage management over night
27/12/2022 10:07	MAN2201 MAN0 Max : 288 MW MAN managing extended TWI reduction line offload and did not wish to return to economic dispatch Last Dispatched MW: 327
28/12/2022 1:20	NAP scheduled below their minimum operating run of 133MW for plant safety. NI manual CE risk set to 133MW from 01:00 to 04:30, 28/12. Keeping NAP on at its minimum run is the least cost solution & a requirement for voltage management over night
30/12/2022 1:53	NAP2201 NAP0 Min : 133MW Rule 13.82a claimed Last Dispatched MW: 126.06
30/12/2022 1:57	NAP scheduled below their minimum operating run of 133MW for plant safety. NI manual CE risk set to 132MW from 02:00 to 06:30 30th Dec. Keeping NAP on at its minimum run is the least cost solution. Required for voltage support and over frequency reserves as well.

Appendix B: Dispatch Accuracy Dashboards

Energy

Same quarter in 2021/22 (October–December) | This quarter 2022/23 (October–December)

Measure	Description	Unit	October	November	December	2022 January	February	March	April	May	June	July	August	September	October	November	December
Operator discretion applied	Total number of instances (5-minute dispatches) where operator interventions depart from the dispatch schedule to ensure the dispatch objective is met.	100% binding	584	648	449	355	422	445	292	501	529	457	517	565	406	418	329
	Instances where the system operator has applied discretion under 13.70 of the Code to meet dispatch objective		11	16	24	2	9	5	1	10	5	32	67	47	34	73	34
Frequency keeper (MW)	Average absolute deviation (MW) from frequency keeper dispatch point. A movement of frequency keeping units away from their setpoint suggests greater variability in the system, but can also indicate the need for additional dispatches	NI	7.00	6.96	7.52	7.32	6.41	7.11	7.23	6.95	6.82	6.81	7.06	7.03	6.99	6.96	7.16
		SI	6.60	6.83	6.68	6.76	6.32	6.69	7.10	6.46	6.62	6.66	6.82	6.86	6.88	6.89	6.87
Time error (s)	Average absolute daily time error (s) indicates imbalance between generation and load, a reflection of imperfect dispatch	NI	0.1941	0.1862	0.2110	0.2087	0.2261	0.1901	0.2056	0.2071	0.2142	0.2347	0.2141	0.2208	0.2190	0.1722	0.1751
		SI	0.1879	0.2041	0.2095	0.1707	0.2258	0.1799	0.2120	0.1995	0.2142	0.2222	0.2138	0.2357	0.2140	0.1638	0.1583
Frequency excursions	Number of frequency excursions (>0.5Hz from 50Hz)		-	5	1	2	6	2	3	4	4	3	-	2	8	-	-
FK within 1% of band limit	% of time frequency keepers spend near to or exceeding their regulation limits indicates the need to redispatch.	NI	2.54%	2.64%	3.47%	2.68%	3.54%	2.58%	3.16%	2.58%	2.42%	2.47%	2.52%	2.67%	2.63%	2.18%	2.56%
		SI	2.55%	2.59%	3.48%	2.72%	3.55%	2.31%	3.13%	2.57%	2.44%	2.50%	2.53%	2.67%	2.62%	2.18%	2.57%
FK outside of band limit	% of time frequency keepers spend outside their regulation limits	NI	0.02%	0.02%	0.01%	0.01%	0.08%	0.05%	0.03%	0.04%	0.01%	0.03%	0.01%	0.04%	0.02%	0.01%	0.00%
		SI	0.00%	0.02%	0.00%	0.00%	0.03%	0.01%	0.01%	0.01%	0.00%	0.01%	0.00%	0.01%	0.00%	0.00%	0.00%
HVDC modulation beyond 30MW band	% of minutes where the maximum HVDC modulation exceeds 30MW away from its dispatch setpoint. This indicates greater variability in the system, but can also indicate the need for redispatch.		8.11%	10.05%	9.09%	9.09%	10.37%	7.38%	8.38%	9.13%	10.89%	13.55%	11.16%	10.78%	7.72%	8.89%	7.20%
Constrained on energy- Total	Total Monthly Generation	MWh	3,553,128	3,411,254	3,381,156	3,423,033	3,102,676	3,300,548	3,303,156	3,612,262	3,598,421	4,004,136	3,954,180	3,681,478	3,643,313	3,375,791	3,370,563
	Total constrained on - All sources	MWh	26,561	24,861	37,425	27,518	25,195	25,071	17,302	21,182	24,421	32,151	30,377	29,256	26,824	1,381	16,084
		% of all generation	0.75%	0.73%	1.11%	0.80%	0.81%	0.76%	0.52%	0.59%	0.68%	0.80%	0.77%	0.79%	0.74%	0.04%	0.48%
Constrained on energy ($) - Frequency keeping	Total constrained on $ due to frequency keeping (within band is attributable to SO)	$ Constrained On Energy	232,948	269,822	428,273	264,827	351,930	1,048,490	1,034,695	273,109	765,655	721,155	434,805	579,448	575,841	1,544,639	328,958
		$ Grid Constrained On Energy	31,140	28,176	28,196	41,297	57,475	66,726	38,151	31,680	53,162	54,655	42,003	64,386	34,066	811	4,758
Optimal Dispatch (%)	Compares the average impact of a perfect foresight case against dispatch solutions. Indicates impact of wind offer, load forecast and PSD accuracy.	%	91.500%	92.270%	92.480%	93.910%	92.050%	94.100%	95.730%	94.830%	91.160%	90.310%	92.020%	88.960%	91.590%	93.470%	80.920%
Dispatch load accuracy error (%)	Average absolute difference between forecast generation (load plus losses, including PSD) and actual generation relative to the average actual generation	%	99.620%	99.590%	99.570%	99.600%	99.570%	99.600%	99.610%	99.600%	99.620%	99.610%	99.620%	99.610%	99.610%	99.590%	99.600%
Wind offer accuracy (%)	Average absolute difference between persistence wind offer (based on 5mins prior) and the actual wind output relative to the average wind output	%	97.340%	97.710%	97.550%	97.410%	97.340%	97.260%	97.440%	97.420%	97.510%	97.510%	97.310%	97.090%	97.820%	97.500%	96.960%

Scale for measures:

Variation of up to 0.25 std devs from standard	... up to 1 std dev from standard	... up to 2 std devs from standard	... over 2 std devs from standard

NOTE 1: Commentary on the current quarter's data is included in section 9.1 of this report

Understanding the energy dashboard

The purpose of this dashboard is to identify trends and outliers for measures that represent overall industry performance in energy dispatch. The System Operator actions are only one of the influences in this performance. Three of the measures in which the System Operator has some influence in the performance are converted into a metric.

Measures selected

We have selected measures that cover the following key areas of dispatch performance:

- When operator discretion is required
- Variations in frequency
- When generators are required to be constrained on/off to meet the dispatch objective
- Variation in output and inputs to the Optimum dispatch tool, which compares what happened in real time to what would have happened if there had been perfect foresight

Colour scale

The dashboard uses coloured shading to make it easy to highlight interesting cells or ranges of cells and emphasise unusual values. In this case we have used a colour scale from green (good performance) through to orange (outliers). Each of the cells sits on a colour gradient within this scale.

The colour scales used in the dashboard reflect performance against a standard. A standard that represents good performance has been applied to each of the measures. Variance from this standard identifies outliers which we comment on in section 9.1 of the report. The current standard is the average of the data since January 2019.

Variation of up to 0.25 std devs from standard	... up to 1 std dev from standard	... up to 2 std devs from standard	... over 2 std devs from standard [1]

Metric[2]

The measures that contribute towards the metric are:

- FK outside of band limit [3]
- Constrained on energy- Total
- Optimal Dispatch (%)

There are three stages to calculating the metric

1. **Determine a standard**
   This is based on what represents good performance
2. **Rate the comparison on a scale of 1 to 3**
   The monthly performance is compared to the standard against a predefined scale. There are two scales used in this calculation - FK outside of the band limit and Constrained on energy - Total; and Optimal Dispatch (%). These are shown in the tables below: [4]

Score	Outcome	Measure is:
3	Good performance	Up to 0.25 std devs above the standard
2	OK performance	Between 0.25 and 1 std dev above the standard
1	Weak performance	Over 1 std devs above the standard

Score	Outcome	Optimal dispatch is:
3	Good performance	Up to 0.25 std devs below the standard
2	OK performance	Between 0.25 and 1 std dev below the standard
1	Weak performance	Over 1 std devs below the standard

3. **Calculate an overall metric score**
   The overall metric is the average of the three individual scores.

Example:

			Month	Standard
FK outside of band limit	% of time frequency keepers spend outside their regulation limits	**NI**	0.20%	0.08%
		SI	0.02%	0.01%
Constrained on energy- Total	Total constrained on - All sources	MWh	23,649	28,417
		% of all generation	0.59%	0.80%
Optimal Dispatch (%)	Compares the average impact of a perfect foresight case against dispatch solutions. Indicates impact of wind offer, load forecast and PSD accuracy.	%	93.2%	92.37%
	Metric calculation rows	FK outside band	2	
		Constrained on	3	
		Optimal Dispatch	3	
Dispatch accuracy %	**Metric out of 3 (3 is best possible result)**		2.7	

FK outside of band limit = (0.2+ 0.02)/2 = 1.1 -> 2 (as a result of the distribution for this measure)
Constrained on energy- Total = 0.59 -> 3 (as a result of the distribution for this measure)
Optimal Dispatch (%) = 93.20% -> 3 (as a result of the distribution for this measure)
Overall metric = (2+3+3)/3 = **2.7**

[1] Since last quarterly report we have changed the way in which we measure variation, to make it in terms of standard deviations (instead of percentage variations) for both the conditional formula shading and the metric calculation
[2] This metric is for analysis purposes and is not part of the performance metrics report to the Authority
[3] Last quarterly report used the measure FK within 5% of band limit, we have updated this as variation outside of band limit was felt to be more meaningful
[4] The score was changed during the year from a five point (1-5) to a three point (1-3) scale.

Reserves

Same quarter in 2021/22

This quarter 2022/23

					2022											
			ovember	December	January	February	March	April	May	June	July	August	September	October	November	December
FIR procured (MW)	Average FIR MW procured per trading period	**FIR**	204	166	217	268	244	246	256	213	176	113	107	123	76	67
SIR procured (MW)	Average SIR MW procured per trading period	**SIR**	301	263	307	357	337	343	339	318	306	255	239	Data currently unavailable		
FIR procured ($)	Total monthly cost ($) of FIR procured	**FIR**	850,026	604,671	648,275	2,668,483	1,026,829	773,471	1,016,826	1,289,642	654,500	350,087	60,030	418,165	181,568	16,936
SIR procured ($)	Total monthly cost ($) of SIR procured	**SIR**	953,870	498,131	425,975	819,488	565,559	272,183	275,921	1,676,320	2,203,944	858,185	1,286,853	1,207,130	550,071	474,674
Net free reserves (NFRs)	Average national Net free reserves (NFRs) for a trading period where the risk type is binding, averaged over a month	**AC**	106	103	97	88	96	106	90	111	140	152	145	142	119	127
		DC	112	99	NIL	82	NIL	NIL	NIL	NIL	115.55	126.76	124.29	117.33	114.81	119.79
Reserve sharing	Average percentage of FIR procured that is shared between islands. FIR shared NI+SI / FIR MW Procured NI+SI (Average per trading		52%	42%	51%	33%	42%	46%	43%	47%	50%	57%	64%			
IL vs Spinning Reserve	Percentage of IR procured as interuptable load.	**FIR**	32%	32%	34%	35%	34%	28%	27%	34%	36%	25%	24%			
		SIR	35%	35%	39%	36%	34%	27%	26%	36%	43%	37%	36%	Data currently unavailable		
Risk setter	Most common risk setter (highest number of trading periods)	**NI**	E	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE+15	HLY5CE	HLY5CE			
		SI	IslandC	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE	OtherIslandCE	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE			
Proportion of time risk setter	Proportion of time each type of risk was FIR risk setter	**ACCE**	95.56%	94.83%	99.93%	89.43%	100.00%	100.00%	100.00%	100.00%	99.26%	96.10%	94.99%	97.38%	69.38%	81.65%
		DCCE	2.78%	1.08%	0.00%	10.57%	0.00%	0.00%	0.00%	0.00%	0.34%	3.09%	2.78%	1.68%	23.19%	17.94%
		DCECE	1.67%	4.10%	0.07%	0.07%	0.00%	0.00%	0.00%	0.00%	0.40%	0.81%	2.23%	0.94%	7.43%	0.40%
Average MW risk when risk setter	Average risk MW for each risk type when they are the FIR risk	**ACCE**	287	247	294	313	319	337	326	305	300	237	225	227	141	141
		DCCE	323	281	0	420	0	0	0	0	253	302	228	261	217	194
		DCECE	62	240	149	0	0	0	0	0	39	59	45	46	60	145

Understanding the reserves dashboard

The purpose of this dashboard is to provide greater visibility of statistics on fast instantaneous reserve (FIR) and sustained instantaneous reserves (SIR) which enable us to look at trends in reserve procurement.

Measures selected

We have selected a number of measures that identify trends in instantaneous reserves procurement. The one which we believe is the key one to focus on is:

> Monthly average of [FIR MW procured as a percentage of the FIR risk] per trading period (%)
> across the whole of New Zealand[5] for AC contingent events (ACCE)

This is because it reports on System Operator efficiency in procuring the lowest quantity of FIR to ensure system stability following an event. It also provides an insight into the output of the key System Operator tool – RMT. We consider this provides useful information and trends that can be analysed further. Note, this measure is focused on FIR quantities rather than costs which are largely a result of reserve offer prices than optimal procurement.

Colour scale

The dashboard uses coloured shading to highlight patterns in the data. In this case the shading identifies the variability of the results in the dashboard; it does not compare the results against a standard.

The variation in the shading should not be interpreted as good/bad – but used to identify where there is variation.

All results for a measure may be extremely good, but if there is any variation, the shading simply shows the most desirable values in darker green and the least desirable values in orange; colours from pale green, through pale orange illustrate the relative values between these two extreme points.

The blue shading is used for measures where the concept of least desirable and most desirable does not exist.

[5] The introduction of the national IR market has resulted in reserves being shared across the islands.