Monthly System Operator and system performance report

for the Electricity Authority

November 2022

Report Purpose

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

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

Contents

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System Operator performance

1 Key points this month

- **Industry relationships** - We continue to engage with our international peers on a variety of market and power system topics. Examples of which are GE Roadmap Presentations, attendance of the CIGRE working group C2 meeting and ESIG webinars (Major disturbance in ERCOT system and talk on Ireland's transition to 75% inverter connected generation).
- **Business assurance audits** - We have completed the first of our business assurance audits, Defects & Enhancements (D&E). The auditor identified four high level findings relating to establishing governance; prioritisation and remediation; reviewing incident information and following up overdue issues.
- **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 which are planned to be resolved through a patch release on 1 December. Phase 4 development and testing is continuing in parallel.
- **Operational Excellence** - We are well underway with delivery against quick starts involving procedure assurance, creation of a skills architecture for the real time teams, and resource planning. The full executable programme of work is being progressed in parallel.
- **Customer Portal Programme** - The new NZ Generation Balance (NZGB) application was successfully deployed in the Operations Customer Portal on 3 November. We accompanied these with training material, including instruction videos and webinars.
- **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 calibrate these via an incentive mechanism which will begin early in the new year.
- **Extended Reserves (AUFLS project)** – We have received approval to proceed with the next phase of the project. This phase covers the planning for transition of the North Island Connected Asset Owners to the 4-block AUFLS scheme.
- **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 Security Forecast (SSF) –** We are on track to deliver the major update at the end of the year.
- **Outage Planning** – There were some very high weekly outage numbers through 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 at the latest industry forum.
- **Current market position -** Hydro storage is still high (149% of average for the time of the year). Renewable generation has been consistently above 95% of total generation (due to the high levels of hydro storage in both islands, increased wind generation, and outages of thermal plant).
- **Winter 2023 (peak capacity)** - We published a market insight on the winter 2022 review which highlighted a peak capacity challenge in 2023 and the need for

collaboration between industry bodies to develop solutions to facilitate commitment and ensure the system remains flexible in peak load times.

- **Winter 2023 (energy)** - With a continuation of La Niña forecast, there is an expectation of lower-than-average inflows through the summer months, which affects winter 2023. Although it is a concern, 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.

2 Customers and other relationships

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; 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.

Energy Systems Integration Group (ESIG) webinars

As a member of ESIG, we joined two webinars this month. 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.

GE Roadmap Presentations

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

SOSPA deliverables to the Authority

- 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.
- System Security Forecast (SSF) – The SSF major update will be delivered to the Authority at the end of the year.

3 Risk & Assurance

Risk Management Framework

We presented a paper for the Authority's November System Operator Committee (SOC) 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 & 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 & Enhancements (D&E) 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 this year.

4 Compliance

We did not self-report any system operator breaches in this reporting period.

9 August event

The Rulings Panel process is deferred to the new year, pending settlement discussions. Initial settlement discussions have begun between external counsel law firms.

5 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		
ID	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 ensure impartiality in these circumstances; these items will be monitored to ensure their continue effectiveness.	SO Compliance & Impartiality Manager
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

6 Project updates

6.1 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 have been identified which are planned to be resolved through a patch release on 1 December. Phase 4 development and testing is continuing in parallel.

A change request (CR009) to re-baseline the project for changes to budget was submitted to the Authority on 6 October, following agreement through previous change approval to defer budget request until actuals were closer to current budget. On 8 November the Authority Board approved the change request, and we were verbally notified of this. We are waiting for the formal confirmation to be provided before internal budget approvals are raised.

Operational Excellence

We are well underway translating the output from the external consultant's review into an executable programme of work and, in parallel, are delivering against quick starts involving procedure assurance, creation of a skills architecture for the real time teams, and resource planning. Fortnightly governance checkpoints are in place to ensure the plan meets expectations as we work towards a target of pre-Christmas for delivery of the plan.

Customer Portal Programme

The new NZ Generation Balance (NZGB) application was successfully deployed in the Operations Customer Portal on 3 November. We have developed a suite of NZGB instruction videos and a NZGB user guide; these are available on the Transpower website.

We hosted several NZGB webinars, starting the week of 7 November. These one-hour sessions provided further insight into NGZB and its purpose in the New Zealand electricity market. We presented an overview of the new application, and an opportunity to discuss any questions.

The last application to be replaced and moved to the Operations Customer Portal is the Dispensations and Equivalences application, for which the investigation is currently under way. In addition, next financial year the system operator will kick of a strategic initiative to further enhance and evolve the Operations Customer Portal.

KPI Refresh Programme

Work is progressing well on the KPI refresh programme. Together with Authority staff, we have agreed seven External Outcomes that identify what Transpower needs to do to successfully perform the role of the system operator service provider. We have held a series of internal workshops to develop draft metrics for each External Outcome, which we have then met to discuss with Authority staff. For the third External Outcome, *The Authority is supported to evolve and develop the electricity market and power systems*, 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.

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. The Authority is happy with our input.

Extended Reserves – AUFLS Project
The system operator received approval to proceed with the next phase of the AUFLS Project. This phase covers the planning for transition of the North Island Connected Asset Owners (CAOs) to the 4-block AUFLS scheme. The system operator will conduct security studies, incorporating the CAOs transition plans, to determine a Transition Plan that will allow the system operator to maintain system security during the transition period. The Transition period is expected to commence January 2024.

7 Technical advisory hours and services

Technical advisory hours and a summary of all technical advisory services (TAS) to which those hours related (SOSPA 12.3 (d) refers) will be provided in the next quarterly report.

8 Outage planning and coordination

Outage planning – near real time
We have seen some very high weekly outage numbers through 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 is 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 New Zealand Generation Balance.

New Zealand Generation Balance (NZGB) analysis
The NZGB tool is forecasting no shortfalls for the next 200 days. There were some lower margin periods in mid-November and there are some highlighted in February, due to generation plant outages and the HVDC outages respectively. The new NZGB application has been successfully deployed into the Operations Customer Portal.

9 Power systems investigations and reporting

System Security Forecast (SSF)
Since July this year the Operations team have been performing analysis to support the delivery of this year's System Security Forecast (SSF). This year's major update will include 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 project team will deliver the SSF prior to the end of December.

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.

10 Performance metrics and monitoring

System operator performance against the performance metrics for the financial year as required by SOSPA 12.3 (a) will be provided in the next quarterly report.

11 Cost-of-services reporting

The next cost of services reporting, for 2021/22 will be delivered to the Authority before the end of 2022.

12 Actions taken

A full list of actions taken regarding the system operator business plan, statutory objective work plan, participant survey responses and any remedial plan, as required by SOSPA 12.3 (b) will be provided in the next quarterly report.

System performance

13 Security of supply

Current security risk

At the end of November, hydro storage was 149% of average for the time of the year. This was primarily due to a large inflow event at the beginning of the month resulting in a 19% weekly increase in hydro storage from the end of October.

Capacity margins (our ability to meet peak demand) have remained healthy. This is to be expected at this time of year as peak demand is typically 1,000 MW lower than winter due to warmer temperatures.

Current market commentary

Due to the high-level of hydro storage in both islands, increased wind generation, and outages of thermal plant, renewables have been consistently above 95% of total generation, even reaching 99% at times. For large periods of time the only thermal plant running has been co-generation. Co-generation run off waste heat from industrial processes powered by thermal fuel, for example, milk processing plants.

As expected with high levels of hydro storage, northward HVDC transfer has been high. At times when the HVDC is constrained for reserves or energy, price separation has occurred between islands. However due to the high levels of renewables overall average prices have been consistently below $100/MWh.

Security of supply outlook

Looking ahead, La Niña conditions are expected to remain a dominant factor in our climate through to February next year. 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.

2023 capacity margins are expected to remain tight into 2023. This is primarily due to peak demand growth, and increased costs associated with the market being able to co-ordinate sufficient thermal resources when needed for only a brief period of time. These increased costs are more likely if a wet winter is experienced again but are also underpinned by increased cost of thermal fuel, increased levels of wind generation, and aging plant limiting reliability and number of warranted start-ups.

Further details in the weekly market update report: Weekly Summary and Security of Supply Reporting | Transpower

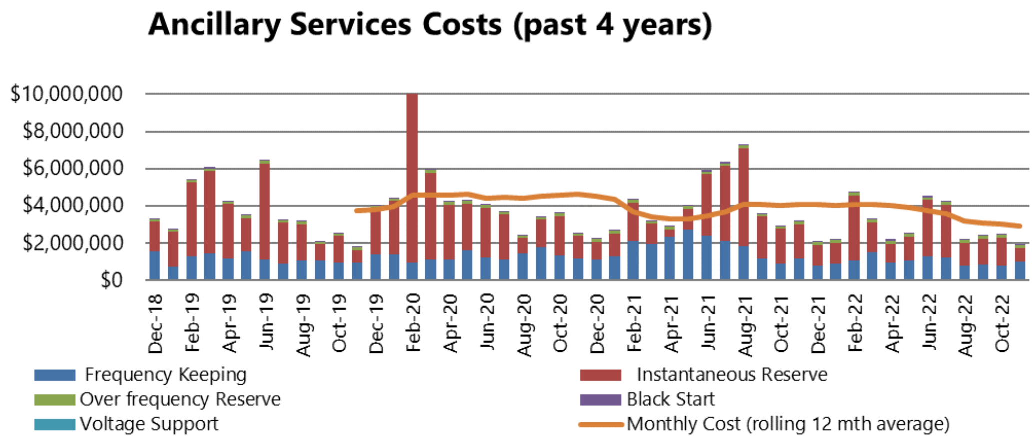
Winter peak capacity challenges

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.

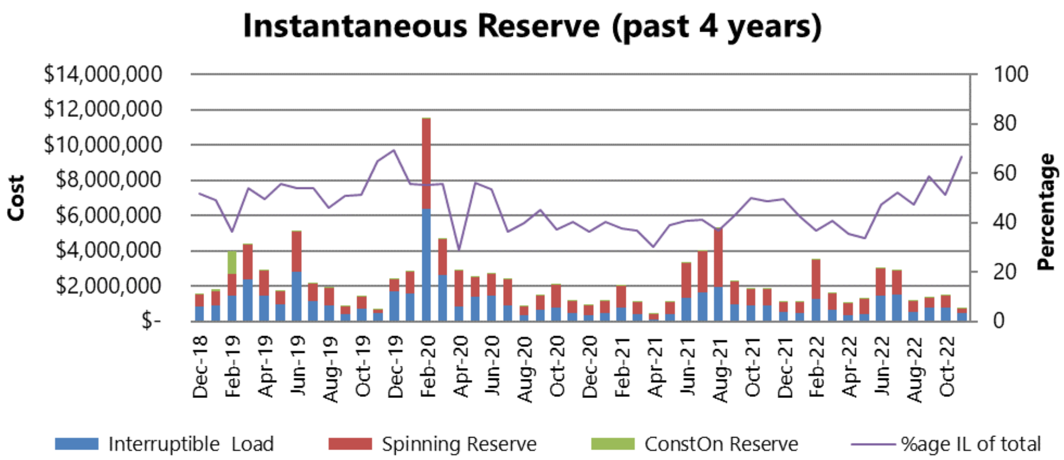
2023 Security of Supply Assessment: Reference Case Assumptions and Sensitivities

We are seeking 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 is requested prior to 16 December.

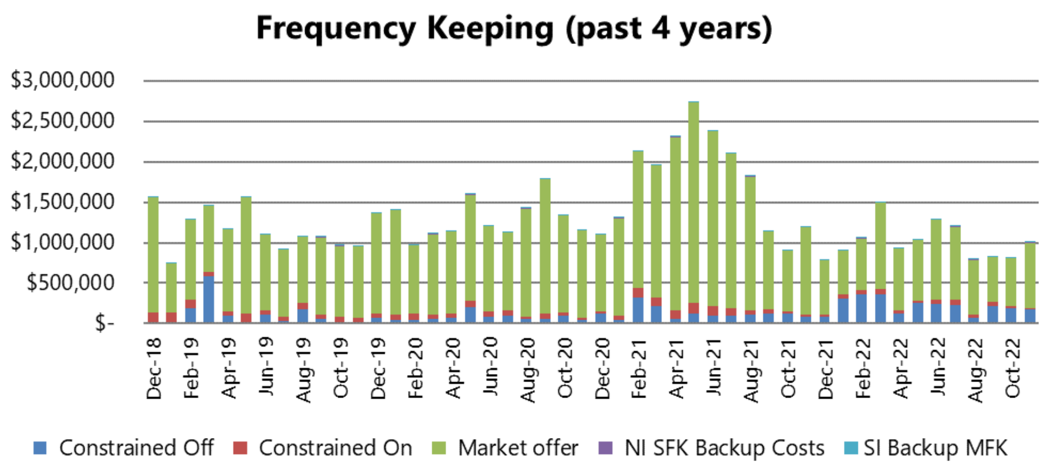
14 Ancillary services



This month's ancillary services costs were $1.95 million, a decrease of $569k (23% decrease) from the previous month which is mainly influenced by the decrease in instantaneous reserve costs. Instantaneous reserve costs decreased by $746k (51% decrease) while frequency keeping costs increased by $193k (24%).

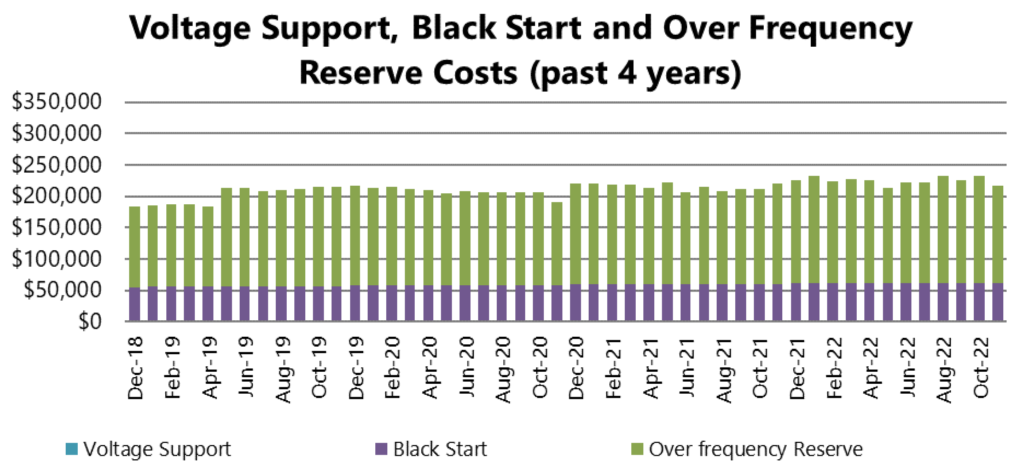


This month's instantaneous reserve costs were $729 million, a decrease of $746k (51% decrease). The largest proportional decreases were for spinning reserves - $240k, a decrease of $466k (66% decrease) and constrained on payments - $8.5k, a decrease of $2.3k (73% decrease) while interruptible load experienced a decrease of $274k (36% decrease).



This month's frequency keeping costs were $1.0 million, an increase of $193k on the previous month (24% increase). Nationally, availability costs increased by $219k (37% increase) as a result of reduced availability. Constrained off costs decreased by $10k (5% decrease) and constrained on costs decreased by $15k (44% decrease).

North Island frequency keeping costs increased this month by $175 (46% increase) while in the South Island frequency keeping costs increased by $19k (4% increase).



Over frequency costs dropped on the previous month to $155k as a result of reduced availability this month. Black start costs remained at $62k this month. There are currently no voltage support costs.

15 Commissioning and Testing

No new items to report this period.

16 Operational and system events

Hawkes Bay lightning event on 22 November.
Anticipating a risk of lightning, the control centre identified the need to manage a potential electrical island. The documented procedure was followed and involved the use of discretion to constrain on Whirinaki and Waikaremoana generation to provide

the best opportunity for the electrical island to form for the possible loss of the Whirinaki to Wairakei 220 kV circuit (Redclyffe Wairakei Circuit 1 was on maintenance for five days and had a recall time greater than 24 hours).

At 16:56, all three 110 kV circuits to the Tuai substation tripped due to two simultaneous lightning strikes. This caused a Tuai electrical island to form which consisted of Gisborne and Wairoa load with Waikaremoana generation supporting voltage and frequency. Working with Transpower's grid operators, we proceeded with the process to remote synchronise this island back to the 110 kV grid. However, the Tuai electrical island collapsed due to instability at 17:30. This caused a ~40 MW loss of supply for Eastlands at Gisborne and Wairoa. We declared a grid emergency to restore all three 110 kV circuits and the Tuai substation which ended at 18:14 when connection was available to Eastlands and to Genesis for the Waikaremoana generation.

We presented the timeline of this event from a system operator perspective at our fortnightly industry forum with participants on Tuesday 29 November.

Significant incident investigations
One 'moderate' significant incident is still under 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 has commenced with an initial focus on capturing event data and building a timeline of the incident.

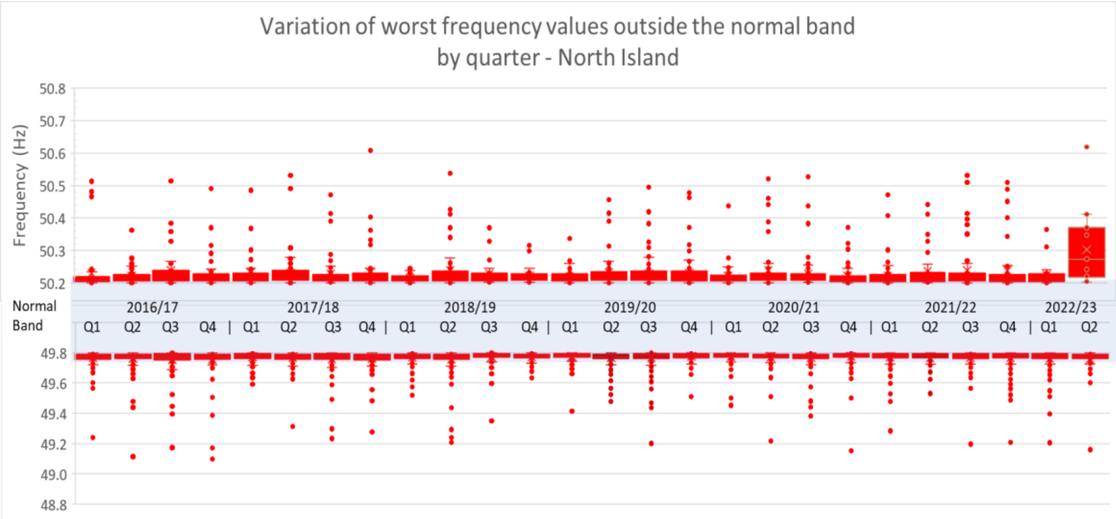
We are still awaiting feedback from the Authority on our proposal to change the significant incident criteria to ensure we are reporting on the right level of incidents considering associated consequences.

17 Frequency fluctuations

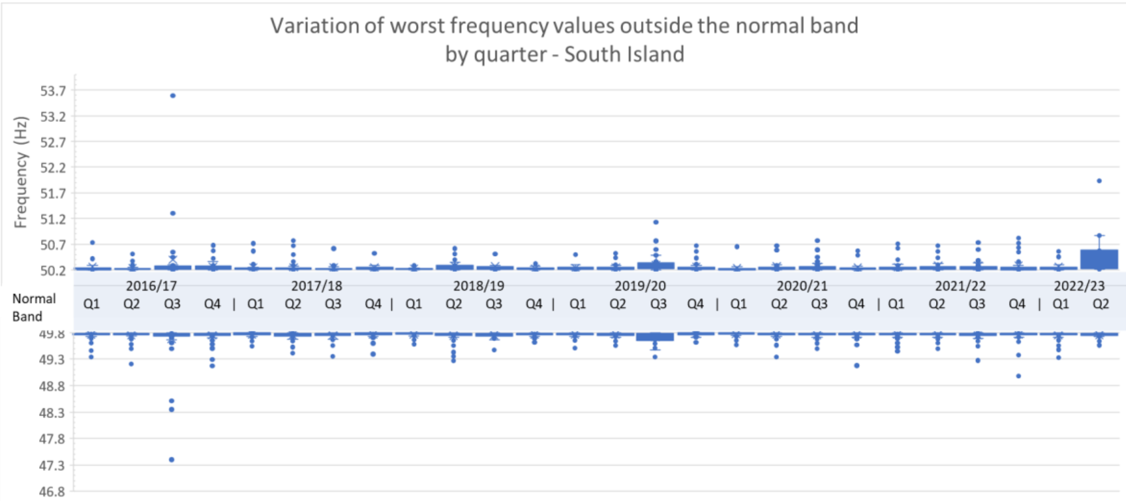
17.1 Maintain frequency in normal band (Frequency value)

The following charts show the distribution of the worst frequency excursion outside the normal band (49.8 to 50.2 Hz) during the reporting period.

North Island



South Island



*2022/23 Q2 contains data for October and November only

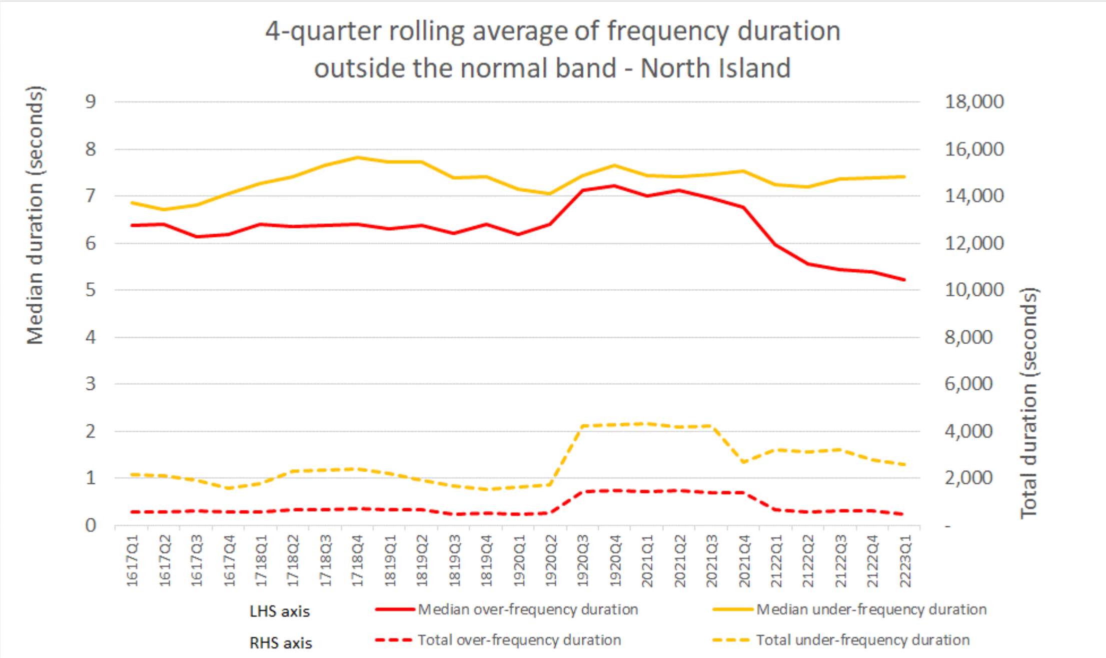
Note1: These box and whisker charts show the distribution of data. The “box” represents the distribution of the middle 50% of the data, the “whiskers” indicate variability, and outliers are shown as single data points.

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.

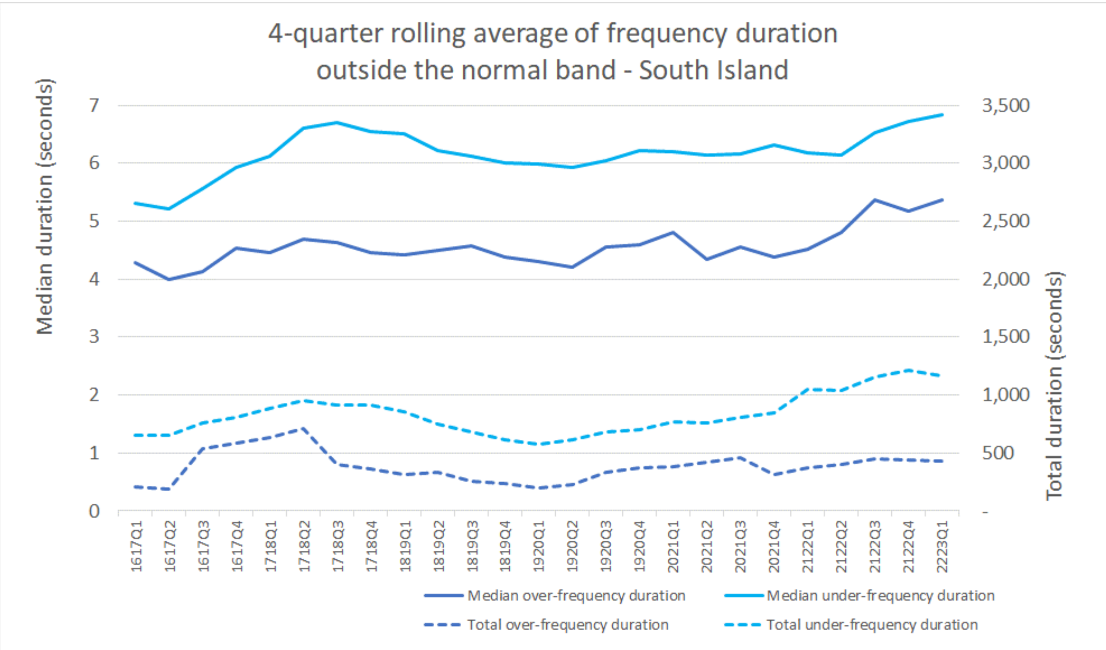
17.2 Recover quickly from a fluctuation (Time)

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

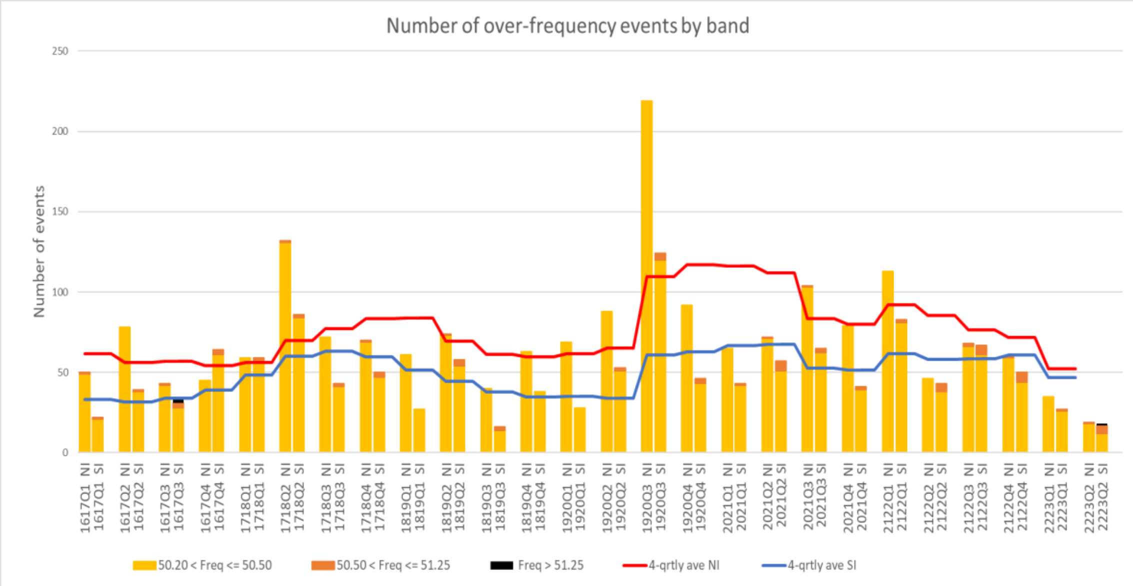


*These graphs have not been updated since 2022/23 Q1; they will only be updated at the end of each quarter

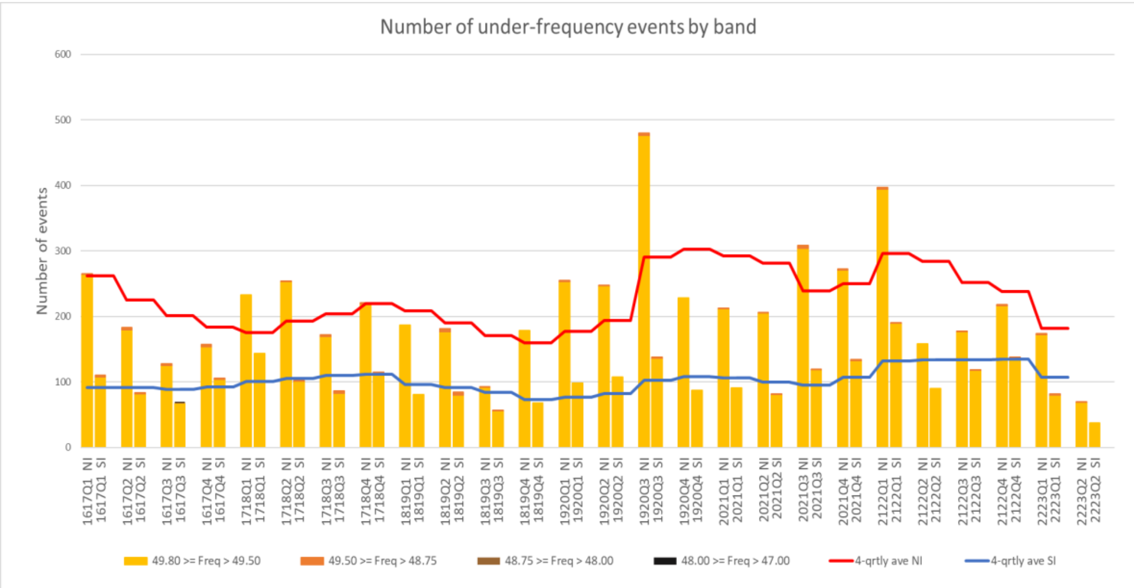
17.3 Manage frequency and limit rate of occurrences during momentary fluctuations (Number)

The following charts show the number of momentary fluctuations outside the frequency normal band, grouped by frequency band, for each quarter since Q1 2015/16. The information is shown by island, including a 4-quarter rolling average to show the prevailing trend.

Over-frequency events



Under-frequency events



* 4-quarterly rolling averages for NI and SI are only updated at the end of each quarter.

2022/23 Q2 contains data for October and November only

17.4 Manage time error and eliminate time error once per day

There were no time error violations in the reporting period.

18 Voltage management

With the warmer weather and lower loads over weekends, our control room teams have been challenged 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 the end of January 2023. This approach minimises the amount of switching to help meet the grid owner's operational limitations for the cables.

While our studies indicate that this outage period 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.

19 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	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22
Demand Allocation Notice	--	-	-	-	-	-	-	-	-	-	-	-	-
Grid Emergency Notice	2	-	-	-	-	-	-	1	-	-	1	1	1
Warning Notice	--	-	-	-	-	-	1	-	-	-	-	1	-
Customer Advice Notice	7	5	7	9	15	14	15	28	24	25	35	33	30

20 Grid emergencies

Date	Time	Summary Details	Island
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

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

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.

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.

Event Date and Time	Description
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

Event Date and Time	Description
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

Event Date and Time	Description
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

Event Date and Time	Description
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.