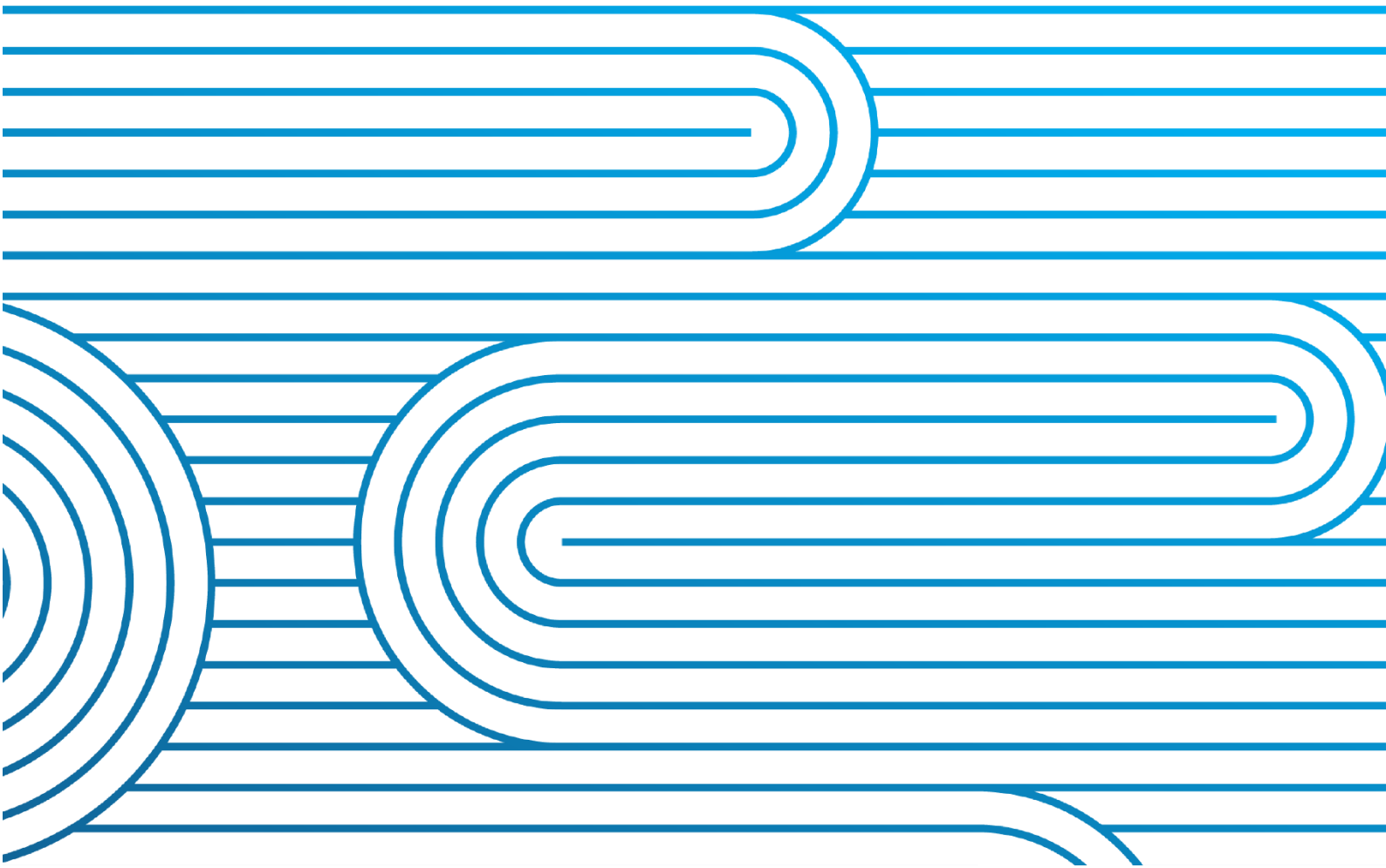
TRANSPOWER

Monthly System Operator and system performance report

for the Electricity Authority

January 2022



Report Purpose

This report is Transpower's review of its performance as System Operator for January 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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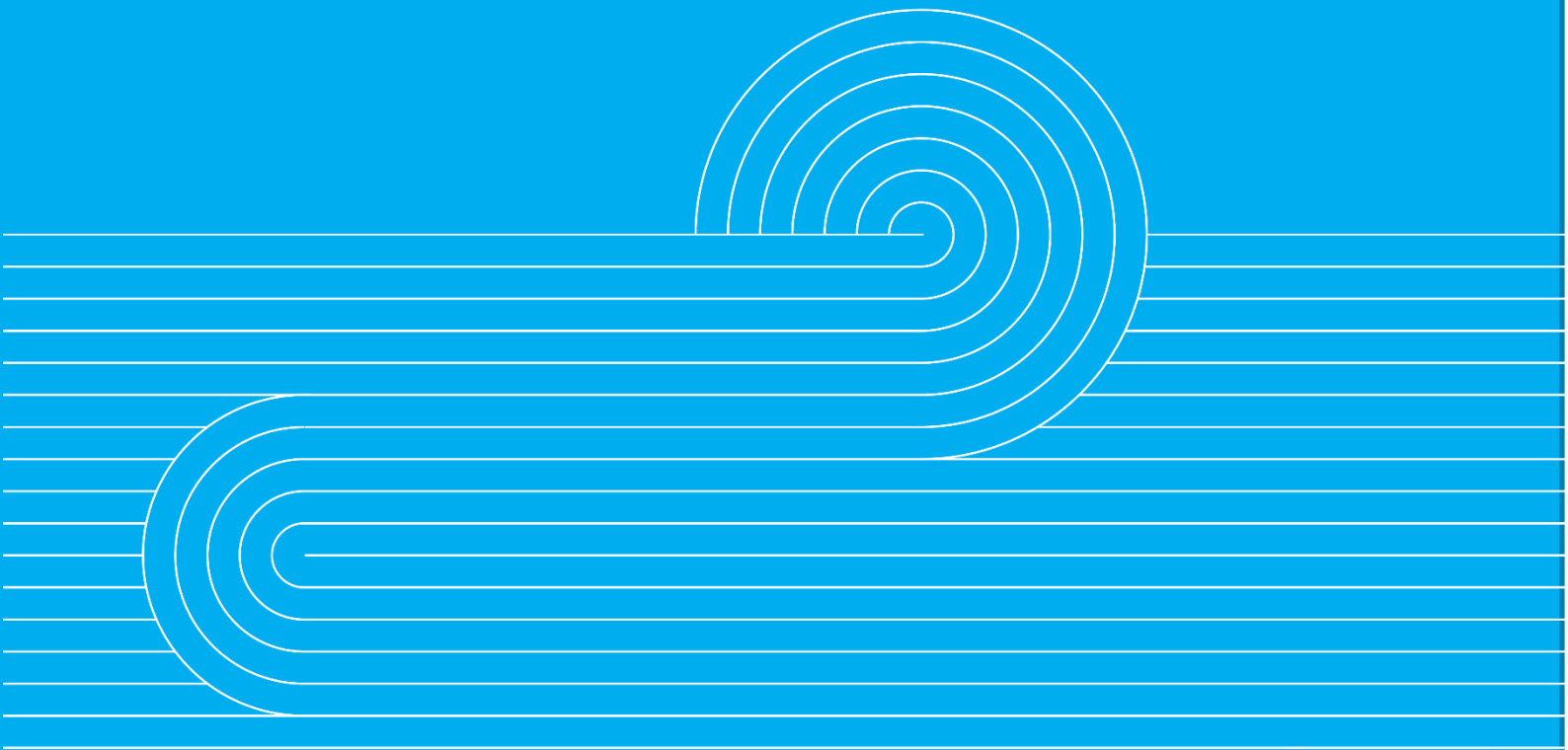
System Operator performance



1 Highlights this month

- We have been working through the implementation of our internal COVID-19 policy with our people. A Covid Incident Management Team and our internal Health and Safety team are providing support with contingency planning for worst case scenarios and are aiding in determining a longer-term plan for working through pandemic situations.
- Assurance reports for all completed actions relating to 9 August investigations have been tabled to ensure completeness prior to being closed out, and a Project Advisory Group (PAG) has been convened, with Authority representation, to oversee the implementation and close out of these actions. Focus will now turn to longer-term requirements.
- The final phase one report for the Future Security and Resilience (FSR) programme of work was delivered to the Authority mid-January 2022, with feedback from industry incorporated. The phase two draft roadmap was also submitted to the Authority at this time. We are awaiting feedback from the Authority prior to engaging with industry to calibrate and finalise this document.
- We are planning to undertake a mid-year Control Self-Assessment (CSA) round in April 2022. This is to provide assurance that action is being taken to lift general effectiveness.
- The Under-Frequency Event (UFE) SOSPA audit has been completed. The auditor deemed the process was effective. The Reserve Management Tool (RMT) Operational Audit is underway and a Managing Conditional Offers Audit is being planned. Remaining two are programmed to be completed before the end of the financial year.
- We reported three System Operator breaches in late December. None of these had a market impact.
- Phase two of the Real Time Pricing project is nearing completion. Work remains on track for deployment in late March 2022. Phase 3 development is now ramping up. The project is forecasting a potential overspend resulting from a combination of higher than anticipated rates of resource turnover and rate increases in a heated market from closed boarders due to Covid along with additional unbudgeted workload.
- La Niña conditions have seen no material inflows to catchment areas throughout January 2022. As a result, hydro storage dropped to 97% of average for time of year as of 1 February 2022. However, it should be noted that our weather is volatile and large inflow events can happen at any time. Thermal fuels and generation are also in much better position now than they were at the same time last year.
- With low hydro generation in the Southland region during January, CUWLP outages, and other concurrent outages in the region, it has been challenging to manage voltage stability limits in the event of a contingency occurring overnight. This has been managed in real-time with generators leaving units on tail-water depressed (TWD) and through publishing a temporary regional constraint.

2 Customers and other relationships

9 August generation shortfall event

The MBIE investigation report into this event was published on 25 November 2021 and included 18 recommendations with ownership across the Authority and Transpower.

KPI refresh

We are holding our first internal workshops in February where we will gather and prioritise views about what matters most and what are the most critical outcomes for the System Operator to deliver day to day; in essence, what represents a successful system operator service.

Future Security & Resilience (FSR) programme

The FSR programme continues to make good progress, with the final phase 1 report having been delivered to the Authority mid-January 2022. The report outlined ten opportunities and challenges for power system security and resilience and has been updated based on industry feedback gathered through submissions and workshops at the end of 2021. Industry feedback was overwhelmingly positive and resulted in some minor changes to the prioritisation of a couple of challenges. With the finalisation of the report, the phase 2 draft roadmap, which outlines how we will go about tackling these opportunities and challenges, was also submitted to the Authority (in mid-January 2022). Once the Authority have shared the roadmap with their Board (early March 2022) the project will look to engage with Industry again.

3 Risk & Assurance

COVID-19 Policy Implementation

We have been working through the implementation of our internal COVID-19 policy with our people, including those who have chosen not to comply with the policy.

Control Rooms have moved quickly to align protocols with the national traffic light framework and three phase approach to operating under “Red Light”. N95 equivalent masks and rapid antigen tests have been sourced and the planning to have these, and associated training and processes, distributed to the teams in the first week of February is underway. There is also work underway to clarify that we can operate under “Test to Return” for asymptomatic critical workers who have been identified as close contacts.

An internal Covid Incident Management Team (IMT) and our internal Health and Safety team are providing support with further contingency planning for worst case scenarios and are aiding in the development of a longer-term plan for working through pandemic situations.

9 August generation shortfall event

The Transpower and Authority investigation actions which were due November 2021 are complete. Assurance reports for all completed actions have been tabled to ensure completeness prior to being closed out. A Project Advisory Group has been convened, with Authority representation, to oversee the implementation and completion of actions. Attention has now turned to remaining, longer-term actions.

Security of supply
We experienced a dry start to summer with the lowest January inflows on record, in-line with NIWAs predictions and the current La Niña climate event. However, early February has seen the largest single inflow event in over 12 months for lake Pukaki, which is now nearing full, and pushing Tekapo to start spilling. National storage has also been pushed above average for the time of year.

Storage at Lake Te Anau and Manapouri remain low, creating manageable regional voltage issues.

Further, looking ahead, if the summer and autumn of 2022 are dry, thermal fuels and generation are in much better position now than they were at the same time last year. More information is included under Section 13 of this report.

Critical controls for the Operations risk bowtie
We are planning to undertake a mid-year CSA round in April 2022 for five of our critical controls. This is to provide assurance that action is being taken to lift general effectiveness.

Business Assurance audits
The Under-Frequency Event (UFE) SOSPA audit has been completed. The auditor deemed the process was effective with five minor findings noted for management action. These include developing an overarching end-to-end process which links the sub processes, reviewing procedures, establishing a checklist and housekeeping of UFE correspondence.

The Reserve Management Tool (RMT) Operational Audit is underway and a Managing Conditional Offers Audit is being planned. The remaining two audits relating to Outage Block Mapping and Commissioning Risk are programmed to be completed before the end of the financial year in accordance with the SOSPA.

Operational Excellence
Our RFP for consultant support for our Operational Excellence programme closes on 4 February 2022. The programme will review our control room operating practices including our processes, change management practices and behaviours, and will provide us with assurance that this important part of our operation is best prepared for a rapidly evolving future.

4 Compliance

There were three System Operator breaches reported in late December:

Breach #1: Incorrect modelling of WIL_DS_846 disconnector

Event date: 5th October 2021 to 16th October 2021

Date reported: 23rd December 2021

Description: The new Haywards_Wilton_Linton_1 (HAY_WIL_LTN_1) circuit was commissioned on 15th October 2021. On 16th October 2021 it was identified that the WIL_DS_846 disconnector on the circuit was modelled as open when in reality it was closed. An override was applied and there was no market impact. The Assessing Ratings Change and Updating SO Models procedure is being updated with corrective actions to prevent recurrence.

Breach #2: Slow NRSL solve

Event date: 29th November 2021

Date reported: 23rd December 2021

Description: On 29th November 2021 the automatic 02:00 non-response schedule (NRSL) started but failed to complete. The corresponding price-responsive schedule (PRSL) completed. The NCC operators manually started new NRSL/PRSL schedules at 03:13. Both schedules were completed and published successfully at 03:35. There was no market impact. A resolution is being developed to prevent recurrence.

Breach #3: Non-publish of NRSS and PRSS

Event date: 17th December 2021

Date reported: 20th January 2022

Description: On 17th December 2021, the 20:30 automatic non-response and price-responsive short schedules (NRSS and PRSS) failed to solve. The cause of the failures were circular flows in the 22:30 trading period. The circular flows in the schedules were caused by two upper North Island circuits being modelled out of service from 22:30 for voltage management. One of the voltage control circuit outages was moved to start later in the evening and an operator initiated NRSS and PRSS started at 21:13 and solved and published successfully. There was no market impact.

5 Impartiality of Transpower roles

We have six 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
31	**Discussions concerning Demand Response:** A System Operator employee is part of a Transpower working group	SO Market and Business Manager

System Operator Open Conflict of Interest Issues		
ID	Title	Managed by
	investigating the possible future use of the Transpower demand response platform. The System Operator role is to provide the System Operator perspective on any demand response proposals. Impartiality mitigations have been implemented to ensure the grid owner is not treated more favourably than any other participant with respect to demand response.	
39	**New SO Compliance & Impartiality Manager:** This relates to potential perception; the person filling this role also works for Transpower's legal team on a part-time basis. Workstreams will be allocated accordingly.	GM Operations
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
42	**Mercury KPO upgrade:** The Power Systems Engineer assigned to manage the KPO upgrade previously worked at Mercury. The employee will provide input into the commissioning/testing documentation and will prepare the final compliance documentation for SO sign-off. Controls have been implemented, including management oversight and sign-off of all commissioning/testing documentation.	Power Systems Engineering Assurance 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 two of the RTP project is nearing completion and work on Phase three is ramping up.

Phase 2 remains on track for late March 2022 deployment with final testing and deployment preparation in progress. End user training is underway in preparation for deployment on 24 March 2022.

Phase 3 development is underway and the 2022 work schedule is being finalised as the main project deployment is worked towards. Final design work is in progress and early Phase 3 testing is to commence in late February 2022. Code amendment reviews

with the Authority are nearing completion, and system operator Policy Statement updates are drafted and ready for internal review.

Focus areas for the next quarter include preparations for 24 March phase two deployment, review and confirmation of planning and resourcing for Phase 3 (including risk and scenario analysis for potential Omicron impacts), planning with the Electricity Authority for ongoing industry engagement, and preparation for the operational impacts of Phase 3 deployment to Transpower's Operations division.

The project is forecasting a potential overspend resulting from a combination of higher than anticipated rates of resource turnover and rate increases in a heated market from closed boarders due to Covid along with additional unbudgeted workload. Final refinement is underway to confirm the exact cost impact. No delay to the remaining milestones is expected

ACS Customer Portal Launch

The Asset Capability Statement application of the Customer Portal went live on 8 December 2021 following several external training workshops with industry participants. Drop-in sessions for participants for one-on-one support were available between 13-15 December 2021 and have also been made available during the second half of January 2022. Roll out support is complete as of the end of January 2022 and the legacy ACS is no longer available. Ongoing support will be provided and communicated to users.

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

Outage numbers were low during the summer break. We are seeing increasing numbers into February with high numbers after Waitangi weekend. The annual HVDC outage, which is 6 days this year is in mid-February.

We particularly assessed the impact of a First Gas outage over Auckland Anniversary weekend, this passed successfully with no security impacts.

New Zealand Generation Balance (NZGB) analysis

February's NZGB report forecasts no N-1-G generation shortfalls for the next six months for all scenarios and generation assumptions. The February report includes the period when OMV has notified a full Maui shut down (affecting available gas

supply) in May and June 2022. The two record electricity demand peaks last winter now appear in both the base and winter scenarios.

9 Power systems investigations and reporting

No items to report.

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 cost of services reporting for 2020/21 was delivered to the Authority on 22 December 2021. 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

La Niña climate outlook 2022:

NIWA indicated La Niña conditions are likely to dominate our current summer, with average or below average rainfall expected over our hydro catchment areas. These conditions saw no material inflows through January. As a result, hydro storage dropped to 97% of average for time of year as of 1 February, and Manapouri reached its low operating range, limiting its daily output. However, it should be noted that although La Niña conditions are expected, and do tend to lead to below average inflows, our weather is volatile and large inflow events can happen at any time. Such an event took place over the weekend of 5 and 6 February and has seen national hydro storage rise to 112% of average as of 6 February 2022. NIWA have updated their forecast for February to April to indicate average or above rainfall across the country.

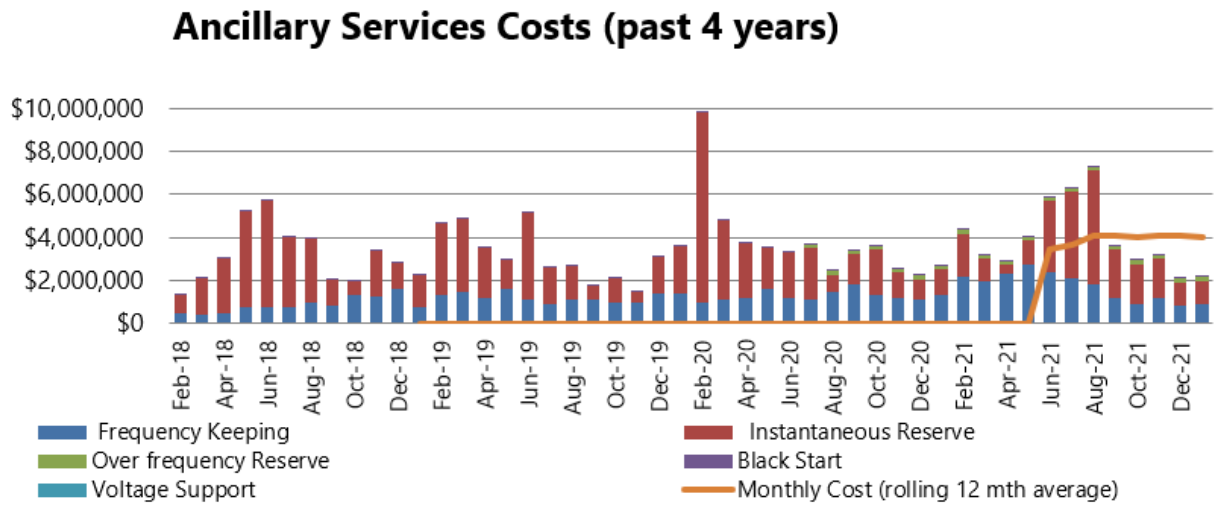
Looking ahead, if the summer and autumn of 2022 are dry, thermal fuels and generation are in much better position now than they were at the same time last year; the coal stockpile is high, gas production has improved, and the third Rankine unit is staffed and available to run through to the end of 2023. The two largest risks (excluding infrastructure failure) are the restriction of personnel to operate the thermal fleet at full capacity due to COVID-19, and the market failing to arrange thermal fuel supply in an emergency (we will be publishing scenarios on this in 2022 financial year).

General update:

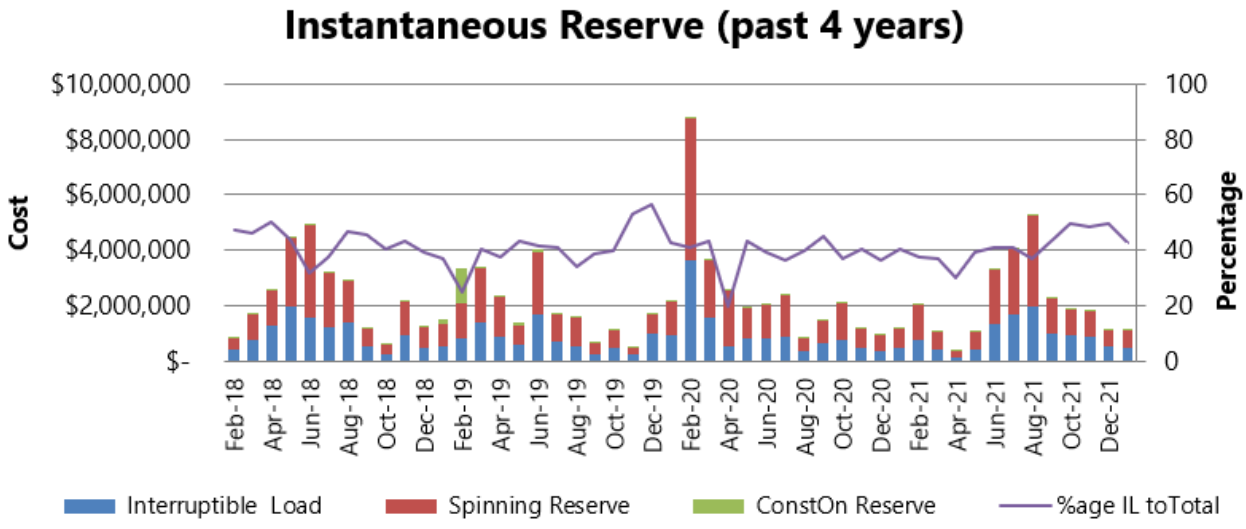
- Prices have increased to $189/MWh on the back of declining hydro storage. These prices have brought on more thermal generation, when wind has been low at time prices have reached $400/MWh and seen Whirinaki running.
- The price of thermal fuels, including carbon, has also increased. Gas on the spot market is trading above $200/MWh, and Coal is $200/MWh (including Carbon). The cost of thermal fuel underpins the price of water.
- Wind generation for the seven days of 16 – 23 December 2021 comprised 12% of the generation mix. This was a record high, driven by high winds and increased wind capacity from the new Turitea wind farm.
- Over the holiday period when hydro storage was above the 90th percentile, low demand and increased wind generation has seen an increased number of $0 price trading periods. The market arrangement to manage these situations is called a must run auction. In these instances, participants pay in advance to stay generating through these periods, forming an economic order to generation that is constrained off. Typically, wind generation is constrained off first and geothermal last.
- Meridian has diversified their swaption portfolio by securing a small swaption arrangement with Nova for 235 GWh worth of gas.
- Indonesia has banned the export of coal for a month while they rebuild national stockpiles. Genesis typically source coal from Indonesia but have indicated publicly that they are not concerned about this news and have a sufficient coal stockpile to bridge this short export ban. Given current levels of gas production,

above average hydrology, and low demand we do not expect this to have a material impact on security of supply, however this is a point that will be monitored.

14 Ancillary services

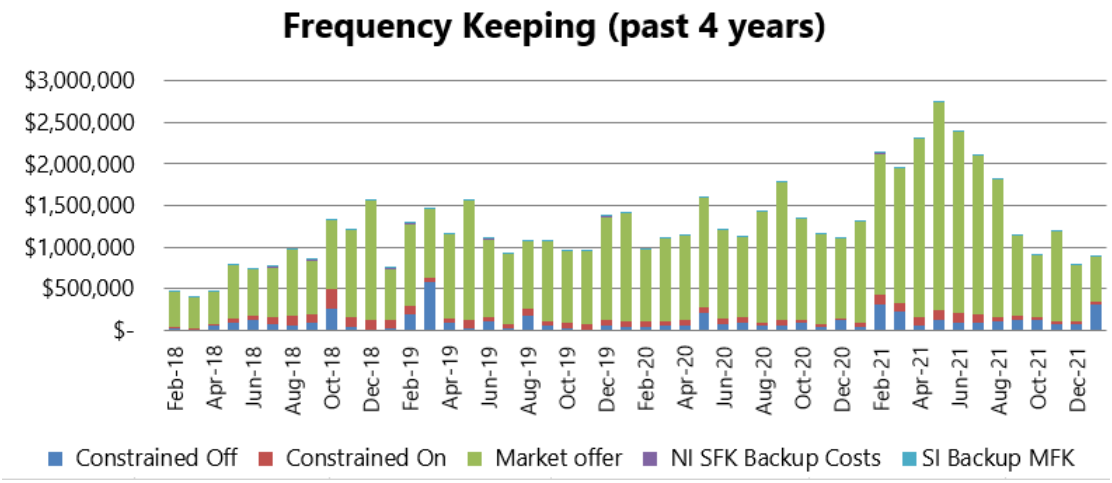


This month's ancillary services costs were $2.21 million, an increase of $84k (3.9% increase) from the previous month. While the cost of instantaneous reserve has been fairly consistent with the previous month, the frequency keeping costs increased by $106k (13% increase) compared to the previous month.

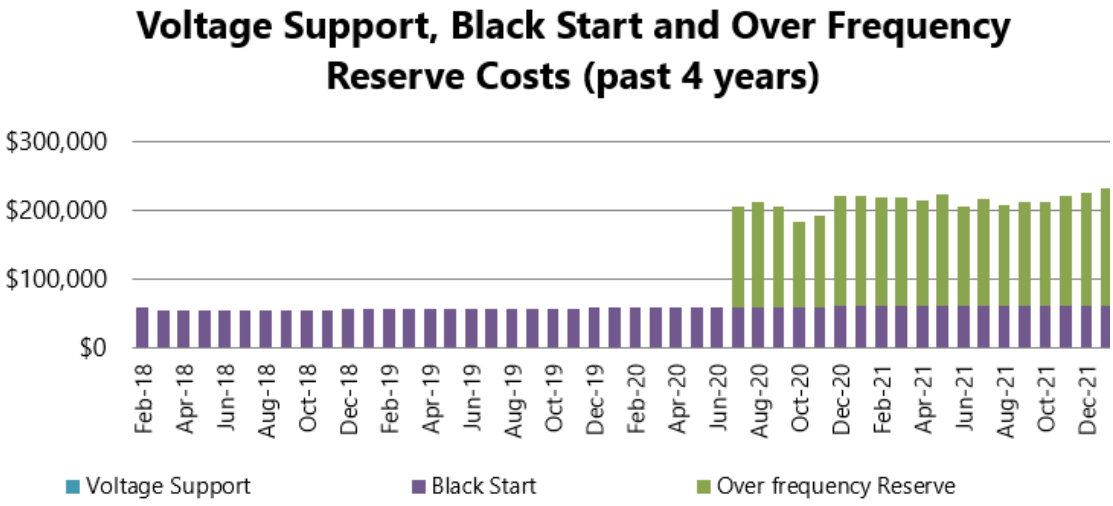


This month's instantaneous reserve costs were $1.08 million, little change from the previous month, only a small decrease of $28k (2.6% decrease). The overall quantity

of both fast and sustained reserves procured were higher than the previous month. However, the average price per megawatt of North Island sustained reserves dropped significantly.



This month's frequency keeping costs were $889k, an increase of $106k on the previous month (13% increase). This increase was due to a $131k rise in frequency keeping costs in the North Island. This was accompanied by a slight drop ($24k decrease) in South Island frequency keeping costs compared to the previous month.



Over frequency increased slightly this month to $171k this month due to annual CPI adjustments. Black start costs remained at $60k. There are currently no voltage support costs.

15 Commissioning and Testing

Mercury's 119MW Turitea North windfarm is now fully commissioned. The South windfarm is on track for commissioning later this year and will add approximately another 100MW of capability.

There are two battery projects that have formally advised the System Operator of an intention to connect to the power system in the next 12 to 18 months.

16 Operational and system events

Voltage – Lower South Island

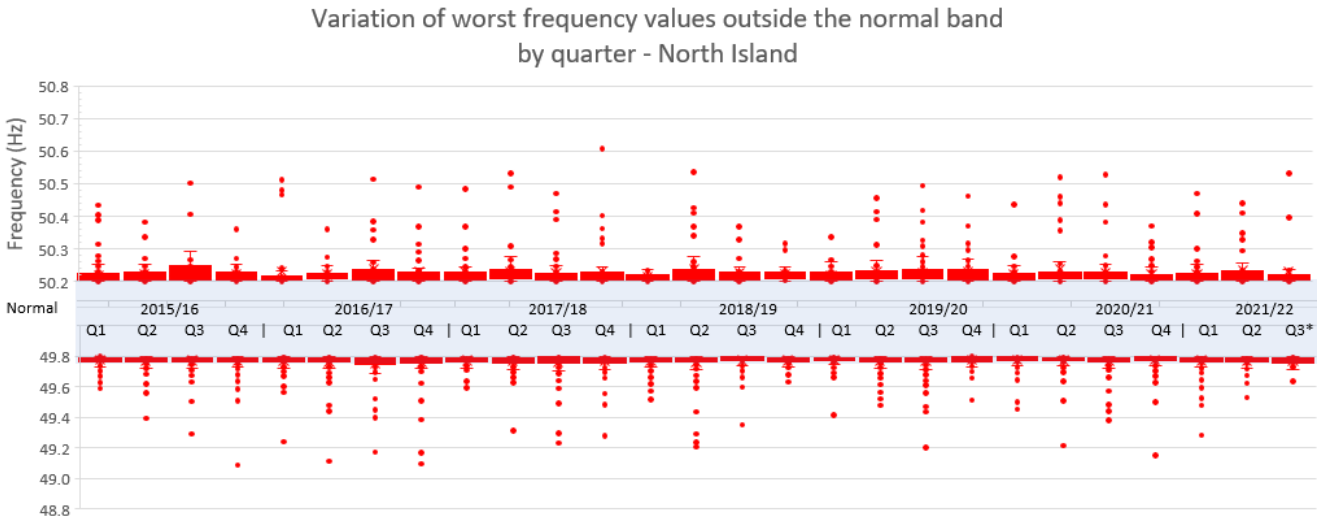
With low hydro generation in the Southland region during January, CUWLP outages, and other concurrent outages in the region, it has been challenging to manage voltage stability limits in the event of a contingency occurring overnight. This has been managed in real-time with generators leaving units on tail-water depressed (TWD) and through publishing a temporary regional constraint.

17 Frequency fluctuations

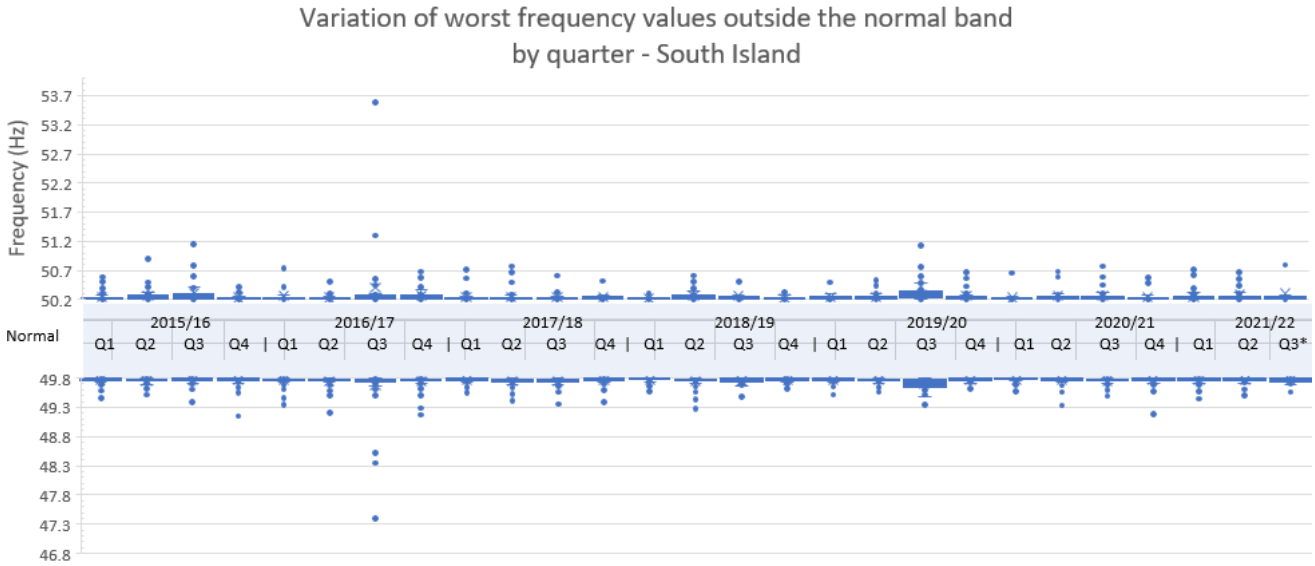
17.1 Maintain frequency in normal band (Frequency value)

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



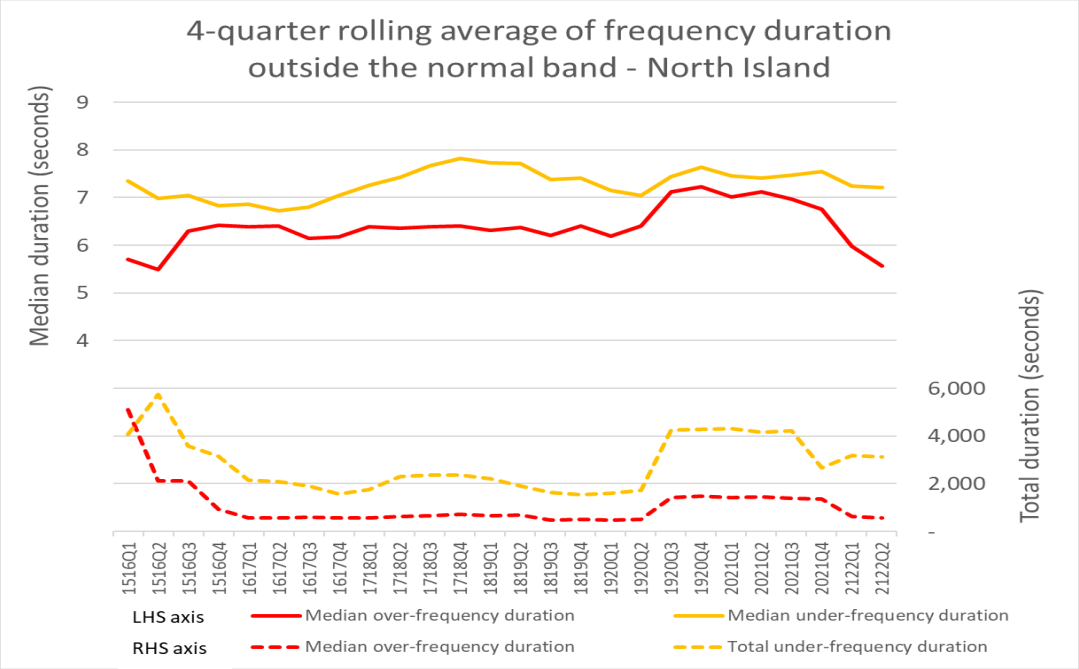
*2021/22 Q3 contains data for January only

Note: 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.

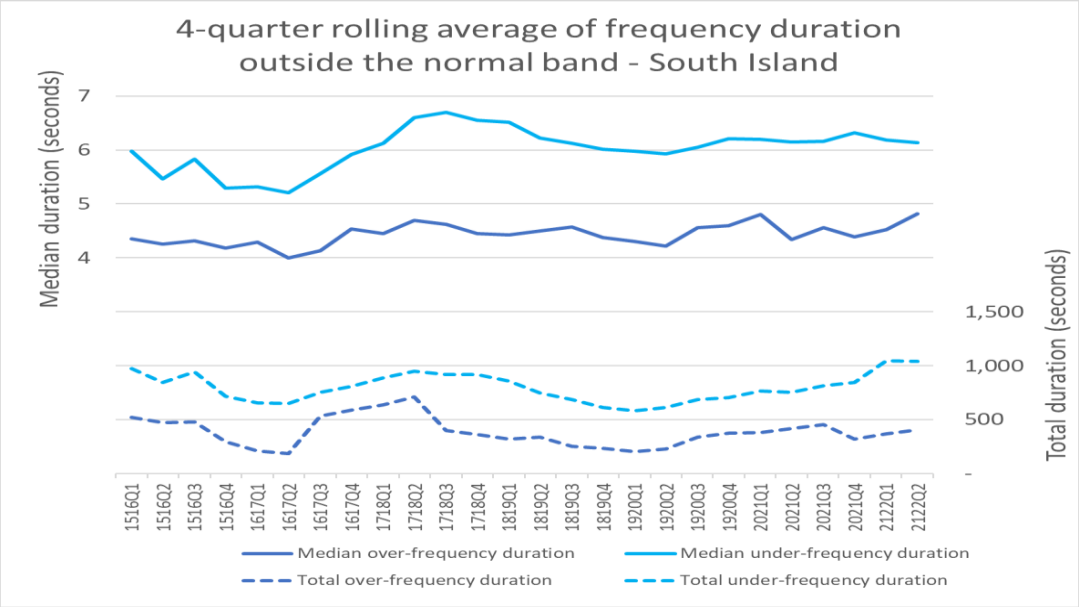
17.2 Recover quickly from a fluctuation (Time)

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

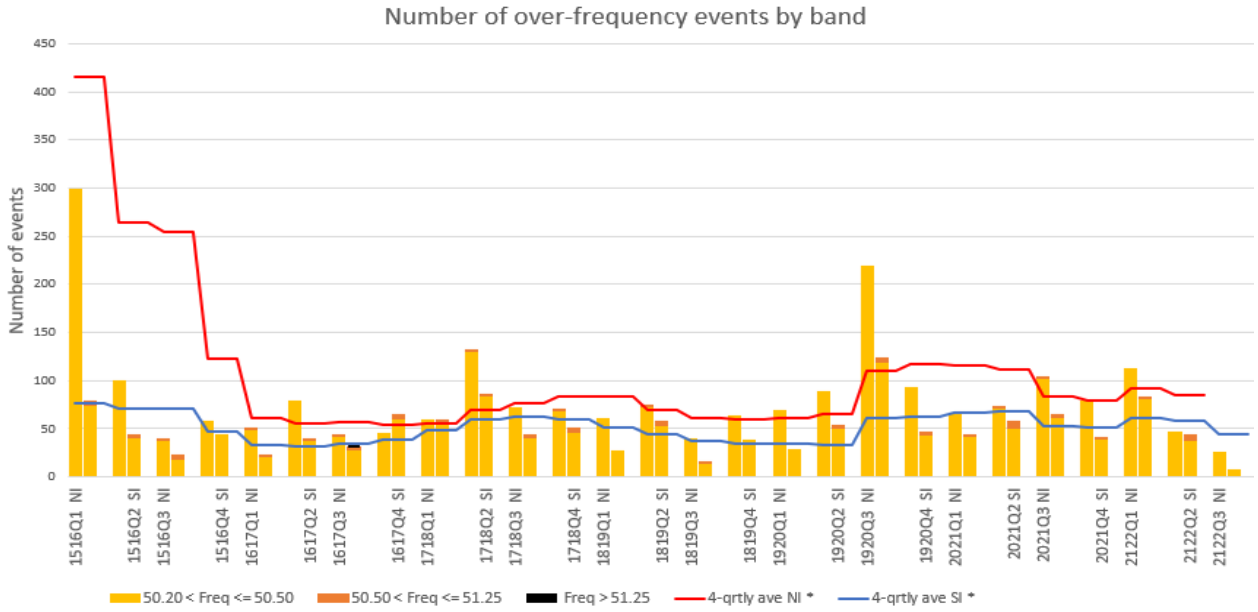


*These graphs have not been updated since 2021/22 Q2; they will only be updated at the end of each quarter

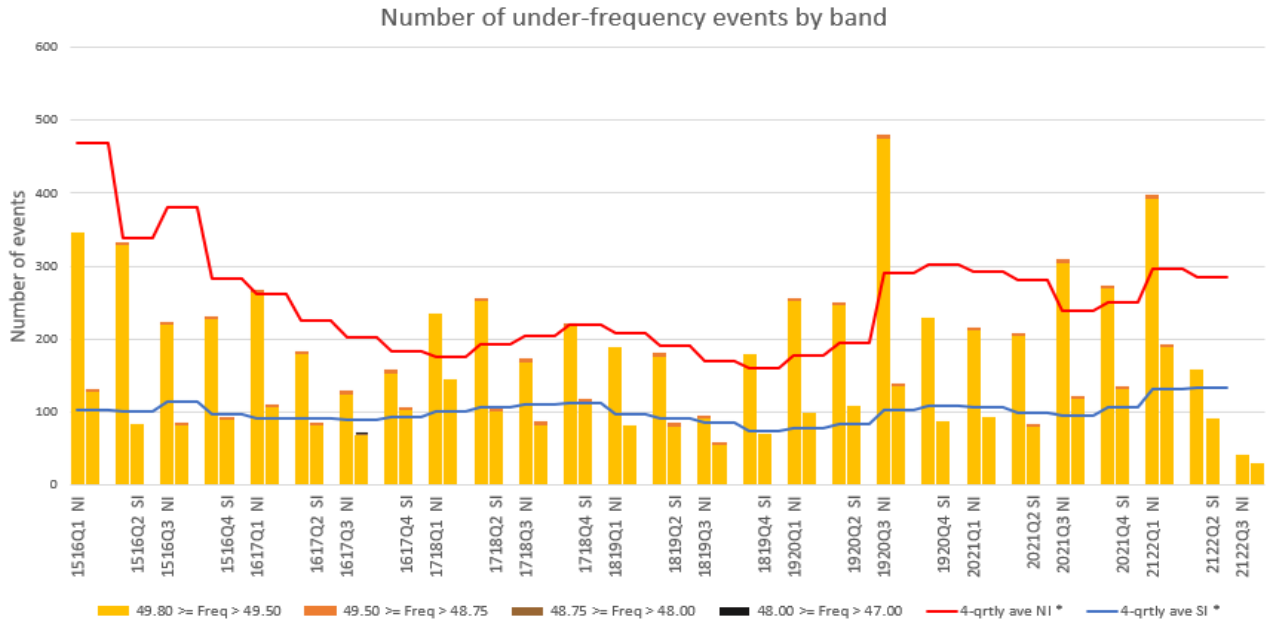
17.3 Manage frequency and limit rate of occurrences during momentary fluctuations (Number)

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

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

Grid voltages did not exceed the Code voltage ranges during the reporting period.

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	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22
Demand Allocation Notice	-	-	-	-	-	-	-	1	-	--	--	-	-
Grid Emergency Notice	-	1	1	-	-	1	-	4	2	--	2	-	-
Warning Notice	-	1	-	-	-	-	1	4	-	--	--	-	-
Customer Advice Notice	8	4	4	8	14	14	11	42	34	9	7	5	7

20 Grid emergencies

None to report.

Appendices

Appendix A: Discretion

Event Date and Time	Description
10-Jan-2022 13:01:21	COL0661 COL0 Discretion Clause 13.70, Part 13 ENR Max : 29 West Coast split due to KIK T2 tripping. Last Dispatched Mw: 29
10-Jan-2022 12:46:35	COL0661 COL0 Discretion Clause 13.70, Part 13 ENR Max : 29 West Coast split due to KIK T2 tripping.t Dispatched Mw: 39
26-Dec-2021 06:34:30	NAP2201 NAP0 Discretion Clause 13.70, Part 13 EN Min : 138 Mercury Trader claimed 13.82(a) for a minimum of 138MW. As per section 13.57 - The Dispatch Objective, keeping NAP on is the "least cost solu
25-Dec-2021 04:11:29	NAP2201 NAP0 Discretion Clause 13.70, Part 13 ENR Min : 139 Claimed Rule 13.82(a) for plant safety. Constrained on min of 139MW to provide reactive support Last Dispatched Mw: 129.31
17-Dec-2021 23:41:57	HLY2201 HLY5 Discretion Clause 13.70, Part 13 EN Min : 190 Rule 13>82A claimed by trader due to resource consents. MIN MW 190. Last Dispatched Mw: 177.05
17-Dec-2021 23:36:30	HLY2201 HLY5 Discretion Clause 13.70, Part 13 ENR Max : 0 Test Solve for Interval Cost Last Dispatched Mw: 190
17-Dec-2021 23:18:15	HLY2201 HLY5 Discretion Clause 13.70, Part 13 EN Min : 190 Rule 13.82A claimed by trader. Min MW 190. Last Dispatched Mw: 168.31
16-Dec-2021 12:26:09	ARG1101 BRR0 Discretion Clause 13.70, Part 13 ENR Max : 0 ARG-KIK-1 PSO to close ARG 164 Last Dispatched Mw: 11.5
16-Dec-2021 11:15:59	WHI2201 WHI0 Discretion Clause 13.70, Part 13 EN Min : 10 Last Dispatched Mw: 17.79 TWI Line 1 extended 183MW WHI required for security due to low NI residual
16-Dec-2021 11:03:09	MAN2201 MAN0 Discretion Clause 13.70, Part 13 EN Max : 469 Last Dispatched Mw: 646.05 MAN down to allow TWI Line 1 extended 183MW to return
16-Dec-2021 10:59:17	MAN2201 MAN0 Discretion Clause 13.70, Part 13 ENR Max : 469 Last Dispatched Mw: 646.05 MAN down to allow TWI Line 1 extended 183MW to return
15-Dec-2021 01:14:44	NAP2201 NAP0 Discretion Clause 13.70, Part 13 ENR Min : 138 Claimed Rule 13.82(A) due to risk to plant with fluctuating disptaches. Last Dispatched Mw: 126.56
15-Dec-2021 00:04:07	HLY2201 HLY5 Discretion Clause 13.70, Part 13 ENR Max : 0 Claimed exemption to rule 13.82a. Not required for Security and will be dispatched off. Last Dispatched Mw: 127.9
15-Dec-2021 00:01:00	HLY 5 dispatched to 128MW at Midnight. Genesis operator claimed Rule 13.82a to a minimum of 180 MW (as previously applied in TP23). HLY 5 was due off at 00:30 and not required for System Security, so HLY discretioned to Zero MW for TP1.
14-Dec-2021 23:48:24	HLY2201 HLY5 Discretion Clause 13.70, Part 13 ENR Min : 180 Claimed exemption to rule 13.82a. Held on until 00:00 for security. Last Dispatched Mw: 155.14
13-Dec-2021 07:25:35	ARG1101 BRR0 Discretion Clause 13.70, Part 13 ENR Max : 0 Last Dispatched Mw: 0 To open ARG 164 for ARG_BLN_1 outage
07-Dec-2021 10:39:15	MAN2201 MAN0 Discretion Clause 13.70, Part 13 ENR Max : 523 To allow for potline return after extended potline. Last Dispatched Mw: 703.36

05-Dec-2021 17:23:18	ARG1101 BRR0 Discretion Clause 13.70, Part 13 ENR Max : 0 Start: 05-Dec-2021 17:30 End: 05-Dec-2021 18:00 Notes: Discretioned off for the ARG_BLN_1 PSO/ Return of ARG_KIK_1 outage. Last Dispatched Mw: 11
03-Dec-2021 07:26:04	ARG1101 BRR0 Discretion Clause 13.70, Part 13 ENR Max : 0 Start: 03-Dec-2021 07:26 End: 03-Dec-2021 07:30 Notes: Discretion to 0MW applied in preparation for planned outages of ARG_KIK_1 & ARG_BLN_1 Last Dispatched Mw: 11.5
02-Dec-2021 12:20:09	SFD2201 SFD22 Discretion Clause 13.70, Part 13 SIR Max : Start: 02-Dec-2021 12:20 End: 02-Dec-2021 12:30 Notes: Test Solve to determine lowest cost solution.Not dispatched. Last Dispatched Mw: 5.39
02-Dec-2021 12:20:09	SFD2201 SFD22 Discretion Clause 13.70, Part 13 FIR Max : Start: 02-Dec-2021 12:20 End: 02-Dec-2021 12:30 Notes:Test Solve to determine lowest cost solution.Not dispatched. Last Dispatched Mw: 5.39
02-Dec-2021 12:20:09	SFD2201 SFD22 Discretion Clause 13.70, Part 13 EN Min : 7 Start: 02-Dec-2021 12:20 End: 02-Dec-2021 12:30 Notes: Test Solve to determine lowest cost solution.Not dispatched. Last Dispatched Mw: 5.39
02-Dec-2021 12:18:35	SFD2201 SFD22 Discretion Clause 13.70, Part 13 SIR Max : 0 Start: 02-Dec-2021 12:18 End: 02-Dec-2021 12:30 Notes: Test Solve to determine lowest cost solution.Not dispatched. Last Dispatched Mw: 5.39
02-Dec-2021 12:18:35	SFD2201 SFD22 Discretion Clause 13.70, Part 13 FIR Max : 0 Start: 02-Dec-2021 12:18 End: 02-Dec-2021 12:30 Notes: Test Solve to determine lowest cost solution.Not dispatched. Last Dispatched Mw: 5.39
02-Dec-2021 12:17:41	SFD2201 SFD22 Discretion Clause 13.70, Part 13 EN Max : 7 Start: 02-Dec-2021 12:17 End: 02-Dec-2021 12:30 Notes: Test Solve to determine lowest cost solution.Not dispatched. Last Dispatched Mw: 5.39
02-Dec-2021 11:54:50	TWH0331 TRC1 Discretion Clause 13.70, Part 13 ENR Max : 41.5 Start: 02-Dec-2021 11:54 End: 02-Dec-2021 12:00 Notes: Last Dispatched Mw: 42 Applied discretion to test TRC comms. They needed their dispatch slightly altered for to check dispatch comms. I ap