Quarterly System Operator and system performance report

For the Electricity Authority

October to December 2021

Report Purpose

This report is Transpower’s review of its performance as System Operator for Q2 2021/22 (October to December 2021), 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).

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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 2021)

SOSPA deliverables

- A Credible Event Review (CER) minor update to re-assess and update existing inter-connecting transformer classifications was published. These changes came into effect on 1 January 2022.
- The most recent System Security Forecast (SSF) minor update was published on 22 December and featured two significant updates from the previous SSF release. An update of the Upper North Island thermal and voltage stability load and transfer limits, and an update of the Stratford Interconnecting Transformers as per the CER minor update.
- During quarter 2, we presented our planned methodology for the KPI refresh project to all members of our division. The session was attended by our service provider advisor from the Authority.

Security of Supply and market information

- We are heading into a dry summer (as announced by NIWA), with only some improvements on the gas supply front. The two largest risks (excluding infrastructure failure) are the restriction of personnel to operate the generation 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 the new year).
- In order to address some of the recommendation in the Martin Jenkins review, we will be consulting on changes to the Security of Supply and Forecasting Information Policy (SOSFIP) and the Emergency Management Policy (EMP). We will work with the Authority to implement the necessary changes in the second quarter of 2022.

Projects and TAS work

- **RTP:** Phase 2 remains on track for late March deployment. Phase 3 development is underway and the 2022 work schedule is being finalised as we head towards the main project deployment. We have experienced higher than anticipated costs and resource turnover over the last few months due to various factors but predominantly driven by comparative market pressures.
- **AUFLS customer portal:** All 15 North Island distributor AUFLS providers have been set up in the AUFLS Customer Portal with their feeder configuration information confirmed.
- **AUFLS Technical Requirements (ATR) document:** Following a review of the consultation feedback, the ATR was incorporated by reference into the Code and came into force at the same time as the Extended Reserve Code amendment on 21 December.

- **ACS Customer Portal:** This application of the Customer Portal went live on 8 December 2021.
- **FSR:** We delivered three industry workshops in late November/early December to discuss the draft FSR Phase 1 report. No significant new opportunities or challenges were identified. The final Phase 1 report and the Phase 2 draft roadmap were delivered on 20 January. Once the Authority has shared the roadmap with its Board (early March 2022) the project will look to engage with industry again, to calibrate it.
- **TAS work relating to Battery Offering Reserves (TAS 100):** The draft report will be shared with the Authority in the new year.
- **December 2019 UTS (TAS 101):** Resettlement of ancillary services took place on 20 December 2021. We have also updated the information required to enable the LCE resettlement process which was completed on 20 January 2022.

Risk and Preparedness

- The System Operator completed all actions from the 9 August event due by 30 November as required. These include our communications, participant notices, and high-level information on flexible demand in distribution businesses. We have also held multiple industry forums to communicate the changes. All of these actions assist with dealing with an event. However, focus is required on the other actions associated with minimising the risk of a similar event occurring – i.e. that there is enough generation and reserve offered to allow the System Operator to cover demand.
- We continue to support the Authority with its Phase 2 investigation from the 9 August event.
- In December, we introduced a COVID-19 policy to require all people entering Transpower premises were fully vaccinated. With the imminent threat of the Omicron variant, additional controls have been planned.
- The Under-Frequency Event (UFE) SOSPA business assurance audit was completed.
- The Grid Owner request to refrain from, or minimise, switching Pakuranga-Whakamaru cable 1 to minimise risk presented a challenge to voltage stability exacerbated by the light loads due to lockdowns and warmer weather. We were able to agree with the Grid Owner for this asset to be continuously removed between agreed dates to assist with voltage management while balancing the risk of wear on the asset.
- In October/November, Operations implemented a new Control-Self Assessment (CSA) methodology and excel tool to assess the 101 sub-control elements that make up the 10 critical controls within its risk bowtie.
- We have issued an RFP for consultancy support with development of an operational excellence programme to review our control room operating practices. The engagement is expected to commence in March 2022 (subject to any delays related to COVID-19).
- We took part in a GridEx simulation exercise where the scenario was a series of cyber and physical security attacks. Lessons learned from this event will

inform preparations for the industry-based exercise planned for next year. This exercise is one of the actions agreed to as part of the review into the insufficient generation incident on 9 August 2021.

Generation commissioning

- All Turitea Wind Farm wind turbines in the northern zone are operational (118 MW) and the focus is now on the southern section, which is forecast for completion in mid-2023.

Incidents

- On 5 October, there was a loss of 39 MW generation due to a failure of operation during planned bus work at Ohaaki geothermal.
- On 11 October, Pakuranga-Whakamaru Cable 2 tripped on closure resulting in a frequency blip of 50.55 Hz.
- Following an alarm early on 22 November, the Grid Owner requested that Pole 3 be removed from service pending an inspection of the indicated. An industry briefing was held to provide an update from the Grid Owner and share contingency planning. Fortunately, the asset was returned to service at 16:27 prior to the evening peak. The asset will be further assessed as part of the planned HVDC maintenance window in February.

Recent initiatives

- Modelling Working Group Activity: During this quarter, there was a Governance group update in November, the annual working group survey was completed in December and workshops were completed to review the modelling failover process and ideate on how we can complete more effective modelling checking.

System Operator performance

1 Customers and other relationships

9 August generation shortfall event

We held two industry briefings this quarter responding to the event and the published reports from the 9 August event. The second briefing on 30 November took participants through the updated procedure to incorporate controllable load information and to provide progress updates on contact lists and notices. More information on our response is in section 2 of this report.

KPI refresh

We presented our work to refresh the external KPIs with the Authority at the Authority's System Operations Committee (SOC) meeting on 1 November. There is enthusiasm from all parties to continue this work. It will provide actionable ways in which to drive the right outcomes for the evolving industry changes, and to link into how the System Operator performance is evaluated (including how we incorporate consideration of events such as 9 August).

We also presented our planned methodology for the KPI refresh project to all members of our division. The session was attended by our service provider advisor from the Authority.

RTP workshops

The industry engagement webinar on changes to Dispatchable Demand under the Real Time Pricing regime was presented in October.

Future security and resilience (FSR) workshops

We delivered three industry workshops in late November / early December to discuss the draft Phase 1 report. Feedback from these workshops was positive, with no significant new opportunities or challenges identified. Written feedback closed on 14 December 2021. All feedback will be considered before finalising and republishing the report in early 2022. Phase 2 will deliver a roadmap by mid-March 2022.

GM Stakeholder Meetings

In this quarter, Dr Jay has attended APEx board meetings, including a webinar on the Texas winter blackouts and an EEA Board meeting where the energy future was discussed. He and members of the division have also presented at several EEA industry forums on connecting new generation, met with the Gas Industry Forum to discuss gas supply and transition, as well as participated in regular catch-up meetings with generators.

2 Risk & Assurance

COVID-19 response

We introduced a COVID-19 Policy which took effect on 15 December 2021. As part of this policy:

- All roles must be performed by a fully vaccinated staff
- All new employees must be fully vaccinated as a condition of employment
- Everyone attending Transpower premises must be fully vaccinated.

Employees have until 31 January 2022 to be fully vaccinated. Those who are not fully vaccinated were required to work from home from Wednesday 15 December 2021.

From 15 December 2021, contractors, suppliers, service provides, consultants and visitors must be fully vaccinated against COVID-19 to enter our premises.

A response framework aligned with the traffic light protocol is maintained by Transpower's COVID-19 Incident Management Team. The response actions mirror the most current Ministry of Health requirements with additional precautions in place for the control room environments. The basis of our control is vaccination, access to quick turnaround (rapid antigen) testing, and facilities that allow for separation to limit spread across the team members.

With the imminent threat of the Omicron variant, additional controls have been planned, including alternate accommodation and sequestration of key individuals, and we are engaging with MBIE to clarify the exception process exempting essential workers from self-isolation should this be required.

There is more work to be done on identifying longer-term recommendations that may require investment and this analysis is planned to be undertaken in the next few months.

Business Assurance audits

The Under-Frequency Event (UFE) SOSPA audit was 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 and Managing Conditional Offers Audit are being planned. The remaining two audits on the programme will be progressed in the new year.

9 August generation shortfall event

The System Operator completed all actions due by 30 November as required from the Authority phase 1 review, the PBA review and the Thomson Lewis review. These include actions relating to our communications, participant notices, and high-level information on flexible demand in distribution businesses. We have also held multiple industry forums to communicate the changes. All of these actions assist with dealing with an event.

However, focus is required on the other actions associated with minimising the risk of a similar event occurring – i.e. that there is enough generation and reserve offered to allow the System Operator to cover demand. For example, the capacity information we have received provides a rough mechanism to ask Electricity Distribution Businesses to use their controllable demand during an event, but it relies on their response. Code and market changes are required to make this a more robust mechanism.

To progress the required changes, we require the Authority to progress the recommendations associated with ensuring there is sufficient generation to meet demand. We are happy to provide assistance where it is needed.

The Transpower reports and other responses to 9 August 2021 are available on the Transpower website.

Pakuranga-Whakamaru cable
In October, following this second incident on this underground cable (refer to section 15 of this report), the Grid Owner requested the System Operator refrain from, or minimise, switching Pakuranga-Whakamaru cable 1 to minimise risk. This request presented a challenge to voltage stability exacerbated by the light loads due to lockdowns and warmer weather. We were able to agree with the Grid Owner for this asset to be continuously removed between agreed dates to assist with voltage management while balancing the risk of wear on the asset. The Grid Owner has agreed to invest in reactive equipment to mitigate this issue before next summer and we are working collaboratively with them on an approach until this is in place.

Security of supply
We are heading into a dry summer (as announced by NIWA), with only some improvements on the gas supply front. The two largest risks (excluding infrastructure failure) are the restriction of personnel to operate the generation 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 the new year).

Critical controls for the Operations risk bowtie
In October/November, Operations implemented a new Control-Self Assessment (CSA) methodology and excel tool to assess the 101 sub-control elements that make up the 10 critical controls within its risk bowtie. This captures the: people, processes, technology, and monitoring & testing components to enact and support the effectiveness of each sub-control element.

As a result of utilising this more structured and consistent CSA method, being a more evidenced based approach, more of our critical controls fell into the partially effective range as compared to last year. Two controls being deemed fully effective, and eight controls deemed partially effective. None were identified as limited or non-effective. Improvement actions have been established and will be tracked for controls not deemed fully effective. We will also undertake a mid-year CSA round in April for the five least effective critical controls to provide assurance that action is being taken to lift effectiveness.

Operational Excellence

An opportunity has been identified to review our control room operating practices including our processes, change management practices, training, capability, capacity, and behaviours providing us with assurance that this important part of our operation is best prepared for a rapidly evolving future. We have issued an RFP for consultancy support with development of this programme with the engagement expected to commence in March 2022 (subject to any delays related to COVID-19).

GridEx exercise

GridEx is a simulation exercise that dry runs situations which might seriously affect the security of the electricity supply in New Zealand. This year the scenario was a series of cyber and physical security attacks. We worked through real-time response and recovery plans with two gentailers and one distributor. We worked alongside representatives from the National Cyber Security Centre (NCSC), CERT-NZ, the Department of Prime Minister and Cabinet (DPMC), the New Zealand Police and Civil Defence Emergency Management (CDEM). Another gentailer and four distributors observed the exercise. An exercise such as this one is incredibly valuable for its ability to familiarise participants with intense and time-critical events.

Lessons learned from this event will inform preparations for the industry-based exercise planned for next year. This exercise is one of the actions agreed to as part of the review into the insufficient generation incident on 9 August 2021.

3 Compliance

October

We reported four System Operator breaches in October:

Breach #1:	Incorrect rating for three-winding transformers
Event date:	15 July 2021
Date reported:	13 October 2021
Description:	On 24 June 2021, the System Operator implemented the modelling of reverse branch limits in the market system. However, the weekly dispatch schedule run on 15 July 2021 highlighted some infeasibilities caused by the incorrect modelling of the reverse branch limit for three-winding transformers (due to the way direction of flow is measured for three-winding transformers). An override was applied to the market system to correct the error and a process implemented to ensure future model updates correctly account for the ratings of three-winding transformers. There was no market impact.

Breach #2:	Grid emergency load shedding
Event date:	9 August 2021
Date reported:	14 October 2021
Description:	This is the finalised version of the self-report that was tabled in September as interim. The self-breach relates to the incorrect Demand Allocation Notice. The estimated market impact is based on a nominal range of the value of lost load (VoLL) developed by the Authority in its Real Time Pricing (RTP) consultation paper. Applying the range, the total VoLL for the customer curtailments

(WEL + Electra) was $210,000 to $420,000. The VoLL for all other electricity distribution businesses (non-customer curtailments) was $0 to $76,000.

Breach #3:	Daylight-savings offers processed incorrectly
Event date:	4 April 2021
Date reported:	19 October 2021
Description:	The market system does not correctly account for the extra hour that occurs at the end of daylight-saving and offers were flagged based only on the submitted time and not the latest COMIT ID record as used by NZX. This means an offer submitted at 02:53 (during the first period between 02:00 – 03:00) would be flagged as a later offer than one submitted at 02:31 (during the second period between 02:00 – 03:00). The error affected five Waitaki River stations for two trading periods. The estimated market impact was minimal (less than $100). The system operator is working with NZX to develop a solution, expected to go-live with RTP 2 in March 2022. If deployment does not occur prior to the end of March, the system operator will instruct participants not to reoffer generation during the extra hour 02:00 – 03:00.

Breach #4:	Market System model functionality not updated with return of Pole 3 of the HVDC
Event date:	29 August and 3 September 2021
Date reported:	22 October 2021
Description:	The System Operator is required to update HVDC functionality and limits in the market whenever there is a change to the HVDC functionality affecting its performance/capability. However, on two occasions the System Operator did not update the Market System when changes were made to the Pole 3 voltage mode of operation. The HVDC did not set the risk on either occasion and there was no market impact. The System Operator is currently investigating a tool solution for a reduced voltage off-normal indicator to be implemented onto the HVDC dispatch overview display.

November

We reported two System Operator breaches in November:

Breach #1:	FHL-RDF circuits monitored ends were incorrect in the network model
Event date:	14 July 2021 to 22 July 2021
Date reported:	3 November 2021
Description:	The System Operator incorrected modelled the Fernhill_Redcliff 1 and 2 circuits (did not update the monitored ends to reflect the Grid Owner’s updated offer). There was no market impact, as there were no constraints created during the relevant period.

Breach #2:	SPS not enabled in the network model - SFT built incorrect binding constraint
Event date:	13 October 2021
Date reported:	23 November 2021
Description:	Due to a modelling error in the weekly SCADA model change, a special protection scheme was not enabled and the SFT tool built

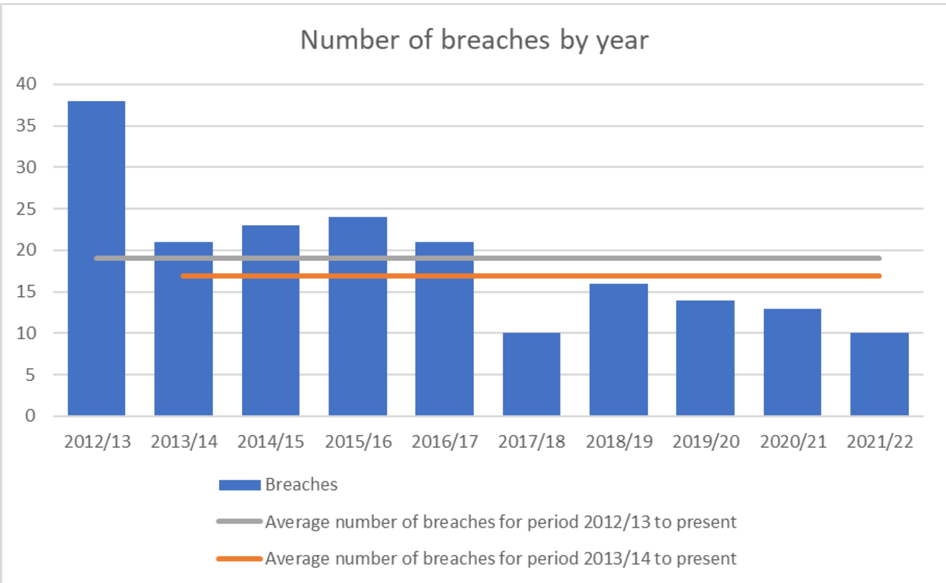
	an incorrect binding constraint to protect the thermal limit of the associated circuit. There was no market impact, the schedule including the constraint was not dispatched; and a pricing error claim accepted.

December

We reported one System Operator breach in December:

Breach #1:	Delayed delivery of SCADA Situation Notice to Pricing Manager
Event date:	13 November 2021
Date reported:	9 December 2021
Description:	On 13 November, the SCADA Situation Notice (SSN) was sent to the NZX Pricing Manager at 05:02. However, it had not been received by the Pricing Manager by 07:30 (Code obligation cut-off time), due to a configuration issue with the on-premise Exchange server. The Exchange server was updated with the correct settings and mail flow to external recipients was tested and restored at 09:31. There was no market impact.

We have eight outstanding breaches with the Authority compliance team.



Appendix A shows instances where the System Operator has applied discretion under 13.70 of the Code.

4 Impartiality of Transpower roles

The entries in the table below are the open issues in the conflict of interest register (Register). These issues are being actively managed in accordance with our policy for managing conflicts of interest.

We opened a new Conflict of Interest item in October. The System Operator's Power Systems Engineer assigned to manage Mercury's Karapiro commissioning upgrade previously worked at Mercury. The employee will provide input into the commissioning/testing documentation and will prepare the final compliance documentation for System Operator sign-off. While there is no threat to the System Operator's independence (from the Grid Owner), there is a potential perception around the System Operator's impartiality (as regards all participants). The System Operator has implemented controls to actively manage the potential conflict, including management oversight and sign-off of all commissioning/testing documentation.

There are six open items in the Register that are being actively managed.

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 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.	SO Market and Business Manager
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

4.1 Independence recommendations update

Transpower's Risk & Assurance engaged Deloitte to conduct an audit of the breach process managed by the System Operator to ensure impartiality in the end-to-end breach process (Grid Owner vs other participants). An audit of the breach process covers the System Operator inherent independence threat around monitoring the Grid Owner's compliance with the Code. Deloitte commenced the audit in June and delivered a final Summary of Findings to the System Operator in early January 2022 which has been provided to the Authority. The Summary of Findings confirmed a clean audit with no recommendations.

5 Project updates

5.1 Market design and service enhancement project updates

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

Real Time Pricing (RTP)

Phase 2 remains on track for late March deployment (there are no material market impacts). Initial end user training has commenced and will be rolled out progressively to affected users as we approach go-live.

Phase 3 development is underway, and the 2022 work schedule is being finalised as we head towards the main project deployment. Transition planning for the Phase 3 deployment is continuing and we are working with the NZX and the Authority on this.

The project has experienced higher than anticipated resource turnover over the last few months due to various factors but predominantly driven by comparative market pressures resulting from lockdowns, particularly at the border limiting overseas talent entering the country. This has primarily impacted our development and test teams. Replacement resourcing has been identified and is being brought on and impact analysis is underway to assess any IP and related project implications. Our regular key resource risk analysis has been increased and mitigation options are being investigated to limit ongoing turnover as much as possible. We are taking this into account as we revisit our earlier planning to finalise our detailed workplan for the remaining phases of the project; this activity will be complete in the new year.

We are working with the Authority to support their efforts for industry engagement through calendar year 2022 which will be crucial for industry readiness.

AUFLS Customer Portal Roll-Out

All 15 North Island distributor AUFLS providers have been set up in the AUFLS Customer Portal with their feeder configuration information confirmed.

In addition, the System Operator completed a review of the consultation feedback on the AUFLS Technical Requirements (ATR) document. A summary was submitted to the Authority on 18 October. The ATR document was approved at the Authority's November Board meeting. This decision was published in the Authority's Market Brief on 16 November. The ATR was incorporated by reference into the Code and came into force at the same time as the Extended Reserve Code amendment on 21 December 2021.

ACS Customer Portal Launch

The Asset Capability Statement application of the Customer Portal went live on 8 December 2021. Several external training workshops were held with industry participants leading up to go live. Drop-in sessions for participants for one-on-one support were available between 13-15 December 2021 and will also be available during the second half of January 2022.

5.2 Other projects and initiatives

Continuous Business Improvement Initiatives

Initiative	Activity Completed	Improvement Implementation
Battery Modelling	• Transpower does not have battery modelling capability currently. We know there will be large batteries introduced next year, and there is a relevant code change on 1 April. • The current workaround is to model batteries as generation and load based on market modelling requirements. • There is a need to agree best practice on modelling batteries with current tooling. Workshop completed December 2021 with SMEs and stakeholders to: • Validate and agree on the problem we are trying to solve • Establish what we need to model and why we need to model it • Establish benefits of modelling batteries AND risks of not modelling them and retaining current workaround	Roadmap being established of functionality required for Battery Modelling (identifying what MUST, SHOULD and COULD by modelled)
Modelling Working Group Activity	• Fortnightly working group sessions. • Governance group update November 2021 • Annual working group survey completed Dec 2021 • Workshops completed to review the modelling failover process and ideate on how we can complete more effective modelling checking • Ongoing collaboration with projects with potential modelling impact	• Automation of the SO Gatekeeper changes for circuit ratings and 2/3 winding transformer ratings. • Continued activity on market and market system support documentation improvements to processes and validation of checklists. • Validated and improved VSAT modelling issue diagnostics process

6 Technical advisory hours and services

Future Security & Resilience (FSR)

The team delivered the draft Phase 1 report to the Authority on 18 October on ten opportunities and challenges to the future security and resilience of the New Zealand power system. This report included feedback from Authority staff. It also incorporated feedback from an external US based consultant commissioned by the Authority and was peer reviewed by independent consultants, Sapere.

The draft report went out for consultation with market participants for the period 29 November to 14 December. Feedback was also sought through three industry workshops. The final Phase 1 report was delivered to the Authority on 20 January 2022 which was updated based on industry feedback gathered through submissions and workshops. 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 on 20 January 2022. Once the Authority has shared the roadmap with its Board (early March 2022) the project will look to engage with industry again, to calibrate it.

Other TAS work

TAS work relating to Battery Offering Reserves (TAS 100) - The project team successfully completed integration testing of Battery Energy Storage System (BESS) reserve offers in October using the test environment. By the end of November, all user acceptance testing and regression testing was completed successfully. The test exit report was completed and approved in December. The draft TAS 100 report is being circulated for review internally, before sharing with the Authority in the new year. The TAS is tracking under budget but is slightly behind schedule. A Change Request will be processed in January to adjust the project closure date.

December 2019 UTS (TAS 101) - The Authority engaged the System Operator to revise the Ancillary Service settlement, and for the Grid Owner to revise loss and constraints excess (LCE) settlement. We provided the revised ancillary services settlement information to the NZX Clearing Manager. Resettlement of ancillary services took place on 20 December 2021. We have also updated the information required to enable the LCE resettlement process to be complete on 20 January 2022.

Full process replications took place in test environments updated with the revised final pricing data, including replication of the required interactions with the NZX Clearing Manager prior to the data updates being made in production. We also engaged with the auditors appointed by the Authority to oversee the process.

The following table provides the technical advisory hours for Q2 2021/22 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 97 – RTP engagement session support	In progress	66.5
TAS SOW 98 – AUFLS Data Portal Deployment to NI Distributors	Closed	202.0
TAS SOW 99 – Future Security & Resilience	In progress	512.5
TAS SOW 100 – Battery ESS Offering Reserve	In progress	491.0

TAS Statement of Work (SOW)	Status	Hours worked during Q2
TAS SOW 101 – Actions to Correct the Dec Undesirable Trading Situation	In progress	226.0
Total hours		**1,498.0**

7 Outage planning and coordination

Outage Planning – near real time

Outage numbers have been high through spring and although they dipped over the summer break, we are seeing increasing numbers for late January and into February. Outage numbers typically are high at this time of year with improved weather and lower demands, but we have seen some outage numbers for some weeks approaching 200+ outages.

We have particularly assessed the impact of a First Gas outage over Auckland Anniversary weekend. Our assessments show no voltage stability system security impacts, and sufficient generation capacity but we continue to monitor generation margins.

New Zealand Generation Balance (NZGB) reporting

December's NZGB report forecasts no N-1-G generation shortfalls for the base scenarios for the next six months. When the low gas, and low gas/no wind assumptions are applied, shortfalls are seen in the first two weeks of May. Generation balances have generally remained stable since the November Report.

8 Power systems investigations and reporting

System Security Forecast (SSF) update

The most recent SSF minor update was published on December 22, 2021 and featured two significant updates from the previous SSF release:

1. The Upper North Island thermal and voltage stability load and transfer limits were recalculated and updated. These indicative limits are now in good alignment with the limits expected from Operations Planning.
2. Grid Zone 6 (Taranaki) regional analysis was updated to reflect the most recent Credible Event Review (CER) work regarding the Stratford Interconnecting Transformers (ICTs) and to also clarify prior analysis of Grid Zone 6 that was slightly unclear.

There were no other significant committed projects to warrant any additional updates to the SSF for this reporting period. A full list of minor changes can be found on the System Operator website.

Credible Event Review (CER) update

The Credible Event Review takes place in a 5-yearly cycle. Minor updates to the existing reports may be required from time to time as the grid configuration changes between major review cycles. The existing inter-connecting transformer (ICT) classifications have been re-assessed and updated last quarter based on the following:

1. Stratford transformer T9 now replaces New Plymouth transformer T8
2. A 50 Mvar reactor has been installed at Kikiwa, impacting the light load calculation
3. The Otahuhu 110 kV bus is no longer split
4. Correction of error in the costs for the Kikiwa light load assessment

The revised 2021 classification documents can be found on the System Operator website. These changes came into effect on 1 January 2022.

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.

		Annual Target	Actual to date	Points
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	
On-time special event preliminary reports		90% ≤ 10 business days	0 required	5
Future thinking and insights	Future thinking report	≥ 1	0	5
	Longer Market Insight reports	≥ 4	3	5
	Bite-sized Market Insights	≥ 45	25	
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	0 requested	
Code compliance maintained and SOSPA obligations met				
Market breaches remain below threshold		≤ 3 @ ≥ $40k	1	10
Breaches creating a security risk - below threshold/within acceptable range		≤2	0	10
On-time SOSPA deliverables		100% (50)	100% (5)	10
Successful project delivery				
Project delivery	Service Maintenance projects	≥ 70% on time	0 completed	
		≥ 70% on budget	0 completed	
	Market Design and Service Enhancement projects	≥ 70% on time	0 completed	
		≥ 70% on budget	0 completed	
Accurate capital planning		≥ 50%	N/A	10
Commitment to optimal real time operation				

Sustained infeasibility resolution	80% ≤ 10am or equiv	93%	5
High spring washer resolution	80% ≤ 10am or equiv	100%	
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

9.1 Dispatch accuracy dashboard

Since 2019/20, we have been reporting the Dispatch Accuracy dashboard for energy dispatch as part of this report. This is a means of monitoring overall industry performance.

In addition, we also produce a Dispatch Accuracy dashboard for reserves to identify trends and patterns in reserve management.

From this year, both dashboards are contained in Appendix B, along with an explanation of the methodology we used to create the dashboards.

Both 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.

We will continue to assess the value of these dashboards once we start to develop new measures as part of the KPI refresh project.

Below are instances of variations we have observed this quarter

Energy

Overall industry performance this quarter – October to December 2021

- *Discretion applied under 13.70 to meet dispatch objective (November and December)*

  November

  - Huntly unit 5 would breach resource consent if running below their minimum.
  - There was planned switching at Argyle
  - There was work on Albury_Tekapo A
  - Discretion was applied to Coleridge due to Coleridge_Hororata violations following trippings
  - Discretion was applied when Karpuni tripped

  December

  - Discretion was again applied in preparation for outages in Argyle area
  - There were a number of test solves at Stratford to identify the lowest cost solution – these were not dispatched
  - Discretion continued to be applied to Huntly unit 5 for security purposes

  - Due to the risk of fluctuating dispatch at Nga Awa Purua (NAP), NAP was kept on for the "least cost solution"
  - When TWI potline was extended, Manapouri was brought down and Whiranki brought on due to low North Island residual

- *Frequency excursions (November)*
  - In this month there were four trippings of Tiwai and one of Manapouri generation

- *Total constrained on - All sources (December)*
  - The majority of the constrained on quantities relate to the last three days of the month when there was low load on the system and Waikato and Clutha were constrained on to provide frequency keeping.

Optimal dispatch this quarter

There is no notable variation of the optimal dispatch metrics in November and December. The optimal dispatch metrics for October 2021 exclude the period 10 Oct 07:45 to 22 Oct 05:10. This is due to corrupted stored actuals for one wind generator which is used for the "actual generation" in the optimal dispatch calculations. We will update this metric in the next quarter when the corrupted data has been updated. Given this data issue only affects one generator, we do not expect this to significantly impact the optimal dispatch metrics for October 2021.

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 available.

Observations this quarter – October to December 2021

- *Proportion of time DCCE[1] is risk setter (October)*
  - This is the key observation from this period as it is the first time since the HVDC outage that DCCE has been the risk setter. In this quarter it was triggered by high DC North flows at times of reduced NI AC risks (i.e. reduced output from HLY5).

[1] This is an event due to the loss of one HVDC pole for which, in the reasonable opinion of the system operator, resources are able to be economically provided to maintain the security of the grid system and power quality without disconnecting demand.

- *Proportion of time DCECE[2] is risk setter (December)*
    - There were two different drivers for this. A significant proportion of this behaviour is because the scheduled DC transfer used in the RMT solve was substantially lower than the DC transfer used in the SPD solve (100 MW or more for many trading periods) The completion of the TUR windfarm commissioning in addition to the recently completed WPP windfarm has made the variability between the RMT solve and the SPD solve larger. This is under further investigation as increasing the intermittent generation is the expected future and it is an unwanted artefact if that results in increased NI reserve requirements which are not necessary.
    - Some of these DCECE risk setting periods are due to a different effect. These are trading periods of high DC transfer which matches or exceeds the NI AUFLS block sizes when HLY5 is in service. Including SIR in the RMT modelling was made possible in the 2021 enhancements work, but this is not presently enabled within RMT. Industry engagement around enabling SIR modelling is planned for 2022 (this change would have many other benefits as well as fixing this unnecessary NI FIR procurement).

- *Average NFR observed has increased (October to December)*
    - Across this 3-month period the average NFR for all risk setters has improved slightly compared to the same period last year. This is an expected benefit of the changes made to RMT during the year. More detailed analysis is underway to confirm this.

10 Cost of services reporting

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

[2] This is an event due to the loss of the HVDC bipole for which, in the reasonable opinion of the system operator, resources are only able to be economically provided to maintain the security of the grid system and power quality **by** disconnecting some demand

11 Actions taken

The following table contains a full list of actions taken during Q2 2021/22 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**:	• Continue to provide proactive communications and insights to market participants about supply and environmental risks (including gas), demand trends, outages, and other areas of interest *In December, we provided a longer market insight on the 2022 Security of Supply outlook on our website.* • Develop set of (future security and resilience) leading indicators *The team delivered the final Phase 1 report and the Phase 2 draft roadmap on 20 January identifying the ten opportunities and challenges to the future security and resilience of the New Zealand power system.* • Develop internal training programme for real time pricing *Initial end user training has commenced and will be rolled out progressively to affected users as we approach go-live.*
(ii) To comply with the **statutory objective work plan**:	• Evaluate and revise performance metrics, targets and incentive payment calculation *During quarter 2, we presented our planned methodology for the KPI refresh project to all members of our division. The session was attended by our service provider advisor from the Authority.*
(iii) In response to participant responses to any **participant survey**:	**Feedback from the 2020-21 survey** • "Transpower has certainly changed over the years, modifying technology, processes and equipment which i think has led to greater reliability and stability, has been quite interesting to have been part of and seen these changes " *We are continuing to optimise our technology processes and are looking ahead via our work on the Ambitions and FSR projects to ensure we continue to do so.*
(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

With continued above average rainfall in the first two months of this quarter, National hydro storage remained high – hovering between 120-130% of average for the time of year. Towards the end of November, the rainfall pushed Lake Tekapo above its operating range indicating spill. This led to high hydro utilisation, which, coupled with high wind generation, meant that renewable energy has contributed significantly to the generation mix, 90% and above. Thermal generation was low as a result of the improved hydro position.

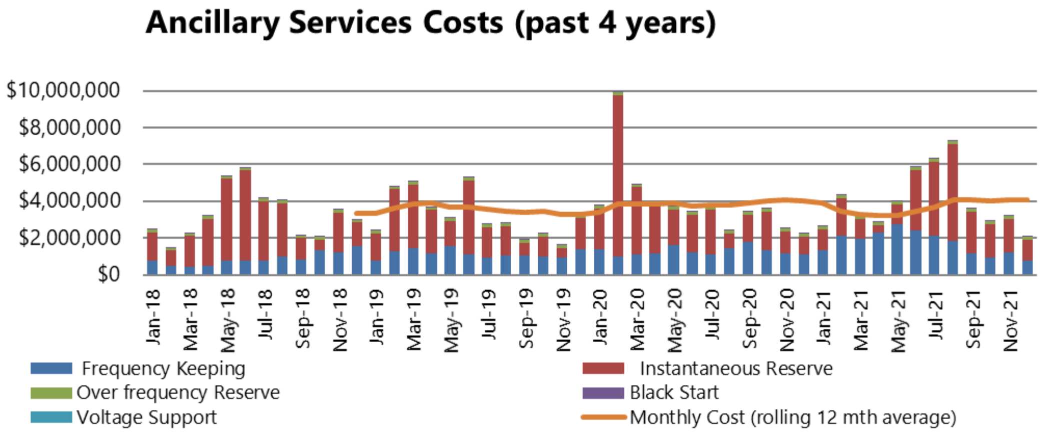
In November, the National Institute of Water and Atmospheric Research (NIWA) officially announced a La Niña event will occur this summer. This forecast results in average or below average rainfall expected over our hydro catchment areas. These conditions have already seen inflows drop in the first few weeks of 2022. Hydro storage has dropped to 112% of average for time of year as of 16 January 2022. 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.

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 the new year).

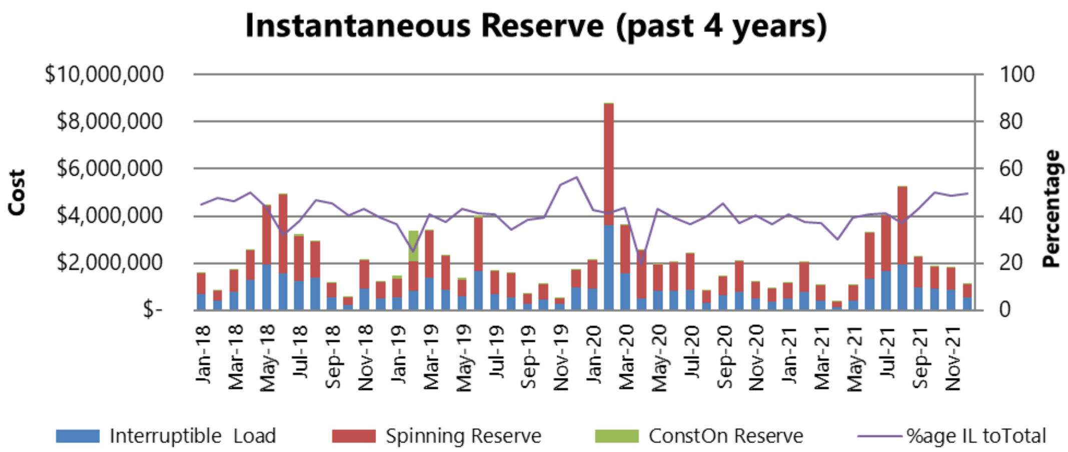
Regulatory settings

Many of the recommendations made by the Martin Jenkins review will require changes to the Security of Supply and Forecasting Information Policy (SOSFIP) and the Emergency Management Policy (EMP). These policies are part of the overall market design for which the Authority has responsibility. The policies are incorporated into the Code by reference, meaning that any changes to the policies require consultation with industry and approval by the Authority Board. We will propose policy changes, consult on the changes, which the Authority Board will need to approve. We will work with the Authority to implement the necessary changes in the second quarter of 2022.

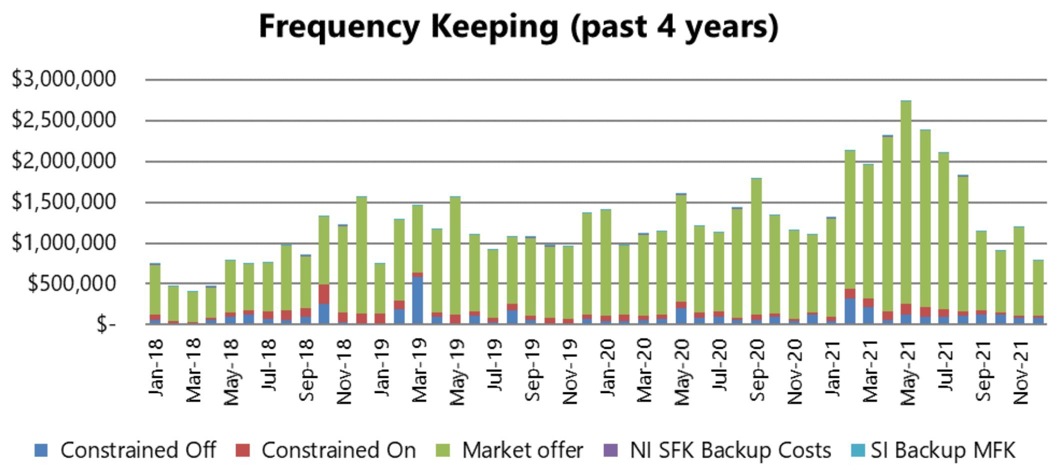
13 Ancillary services



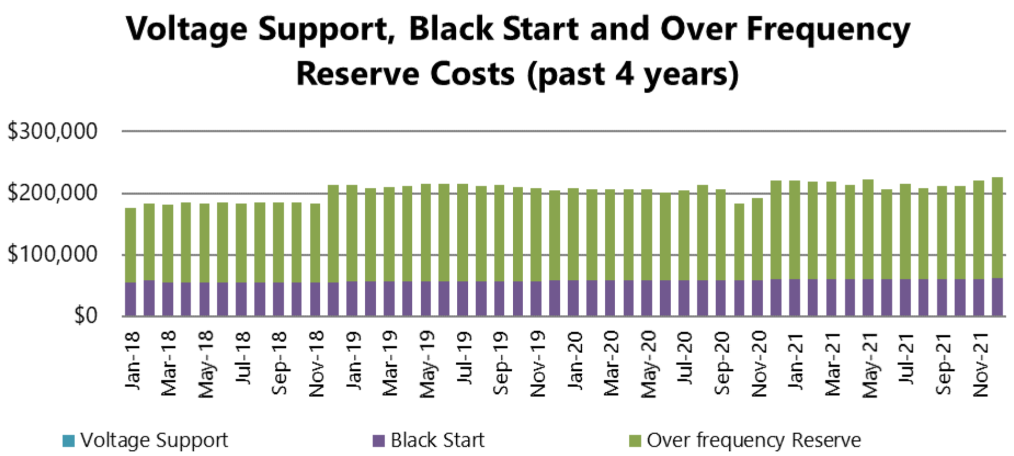
This quarter's ancillary service costs were $8.3 million, which is a 52 per cent decrease compared to the previous quarter's costs of $17.3 million. This reflects significantly lower costs for both instantaneous reserves and frequency keeping since September 2021. The ancillary service costs were especially low in December totalling $2.1 million.



This quarter, the instantaneous reserve costs were $4.8 million, which is a 59 per cent decrease to the previous quarter ($11.6 million). Interruptible load costs decreased by $2.2 million (49 per cent decrease), spinning reserves decreased by $4.5 million (65 per cent decrease) and constrained on costs decreased by $28k (54 per cent decrease). Both the price of and quantity of the reserves procured have been relatively stable throughout the quarter. The significant decrease from the previous quarter is due to unusually high reserve prices and quantities in both July and August.



This quarter the frequency keeping costs were $2.9 million, which is a 43 percent decrease compared to the previous quarter's costs of $5.1 million. Despite a small spike in frequency keeping costs in November, the costs are continuing to fall following the high cost period over winter 2021.

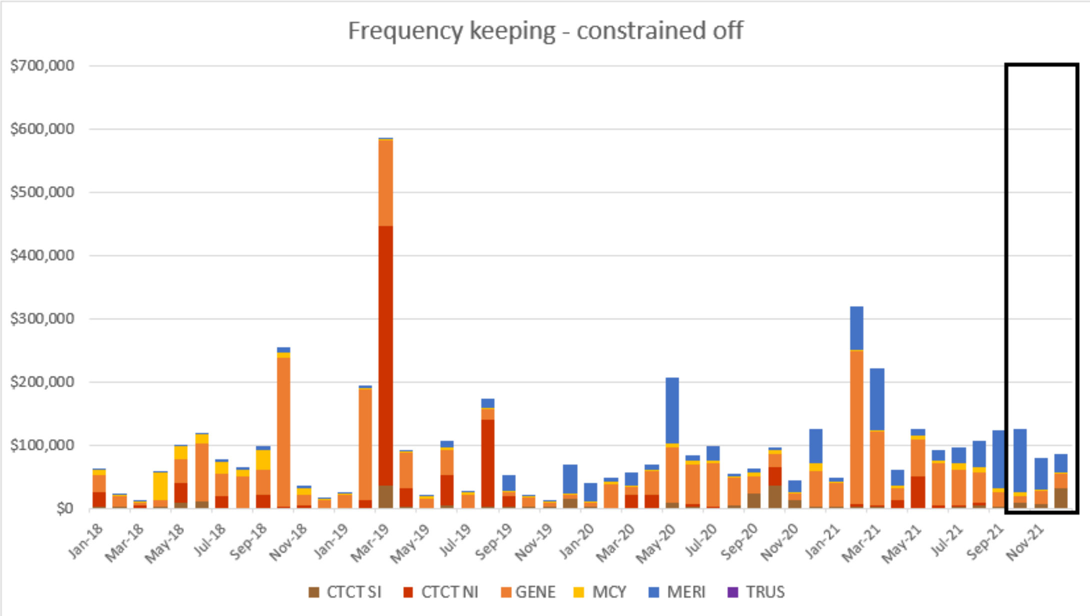


This quarter the costs for both Over frequency and Black start have increased to reflect changes in the new ancillary services contracts. There are still no voltage support costs as there is no need to procure this ancillary service at this time.

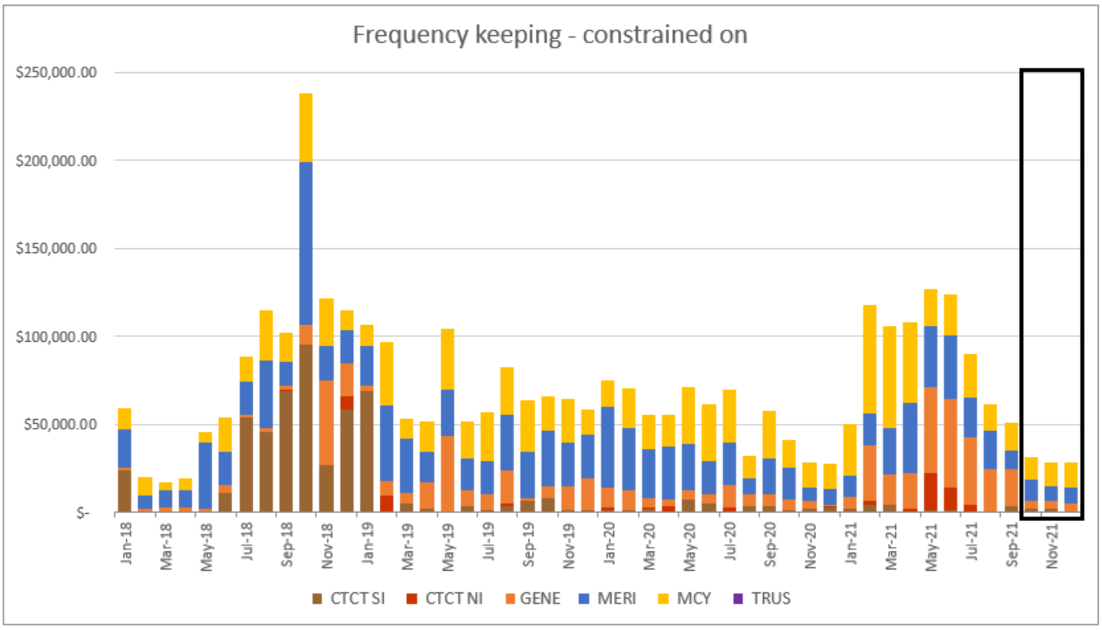
Constrained on/off costs

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

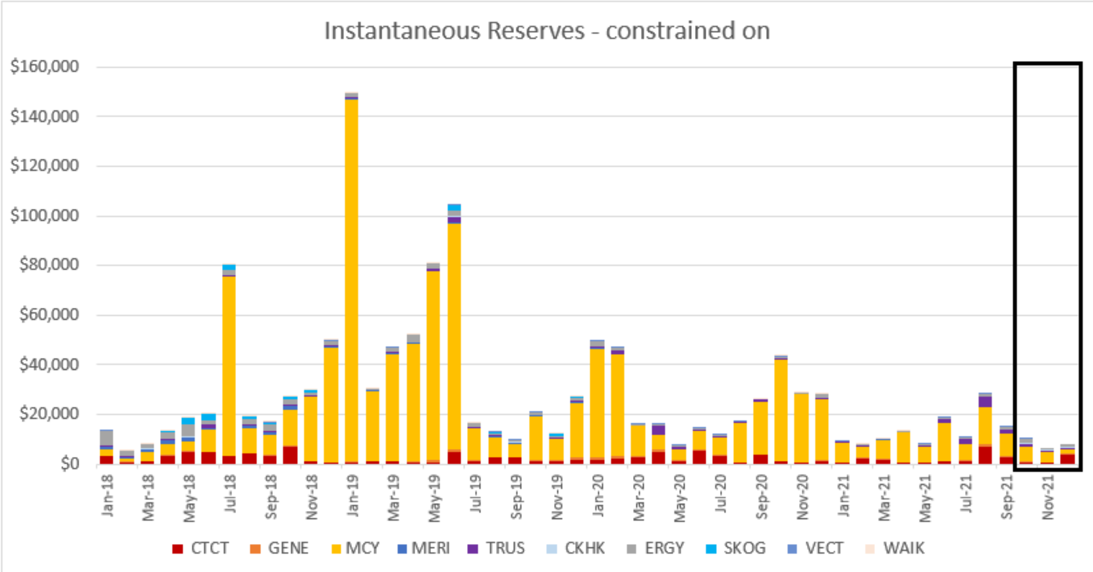


For 2021/22 Q2, the frequency keeping constrained off costs decreased by 12% on the previous quarter to $289k. The North Island constrained off costs falling by 58% over this period and the South Island's increasing by 30%.



For 2021/22 Q2, the frequency keeping constrained on costs decreased by 54% on the previous quarter to $93k. The North and South Island frequency keep constrained on costs both fell (59% and 43% decrease respectively) since the previous quarter.

Instantaneous Reserves



For 2021/22 Q2, the instantaneous reserves constrained on costs were 54% lower than the previous quarter reaching $8.2k.

14 Commissioning and Testing

Generation testing and commissioning

All Turitea Wind Farm wind turbines in the northern zone are operational (118 MW) and the focus is now on the southern section, which is forecast for completion in mid-2023.

15 Operational and system events

October

Ohaaki geothermal

On 5 October, there was a loss of 39 MW generation due to a failure of operation during planned bus work at Ohaaki geothermal.

Pakuranga-Whakamaru Cable 2 trip

On 11 October, Pakuranga-Whakamaru Cable 2 tripped on closure resulting in a frequency blip of 50.55 Hz. The cable is now out of service until repairs can be undertaken. This is the second incident on this underground cable, the Grid Owner has requested that the System Operator refrain from or minimise switching Pakuranga-Whakamaru Cable 1 to minimise risk (the risk is identified in section 3 of this report).

Telephony

On Friday 8 October, an incident with one of the major national carriers impacted all inbound and outbound public switched telephone network (PSTN) telephony to our control rooms as well as to and from the control rooms of many of our connected parties. While we were able to utilise cellular networks and establish points of connection to use on the day, the incident has identified an opportunity to improve our resilience. We are investigating additional cellular handsets and establishment of a back-up process for calling between parties in the event of a similar disruption.

November

HVDC Pole 3 outage

Following an alarm early on 22 November, the Grid Owner requested that Pole 3 be removed from service at 6:22am pending an inspection of the indicated asset. System conditions at the time saw some price separation over the duration of the outage and indicated the potential for a low residual situation if the outage extended into the evening peak. An industry briefing was held to provide an update from the Grid Owner and share contingency planning. Fortunately, the asset was returned to service at 16:27 prior to the evening peak. The asset will be further assessed as part of the planned HVDC maintenance window in February.

Pakuranga-Whakamaru cables – implications on voltage

Over periods of low load it becomes challenging to maintain voltage without removing underground cables Pakuranga-Whakamaru 1 and 2. We have worked with the Grid Owner on a process to minimises the amount of switching on these cables (as this has the potential to apply stress on the cable joints).

December

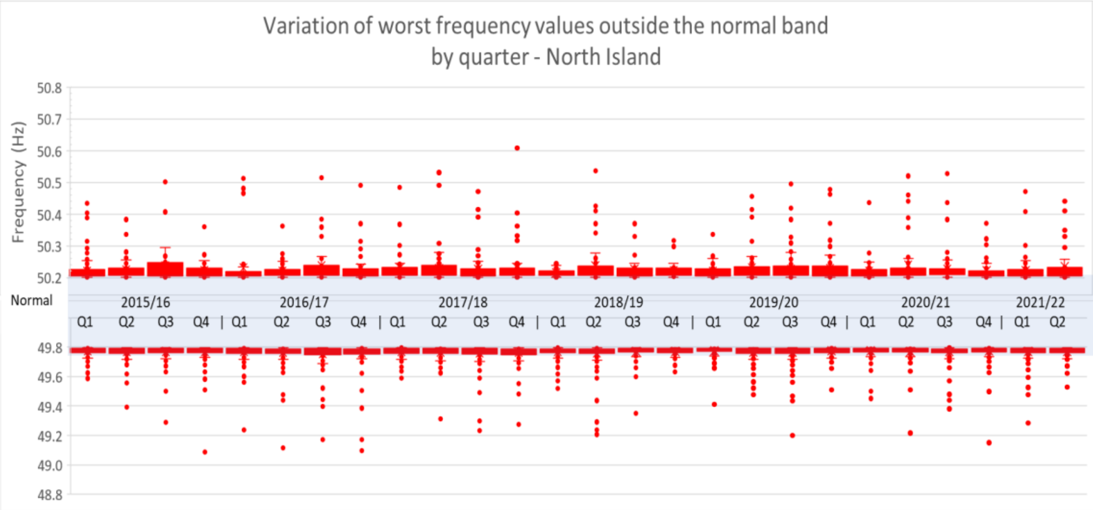
No events to report

16 Frequency fluctuations

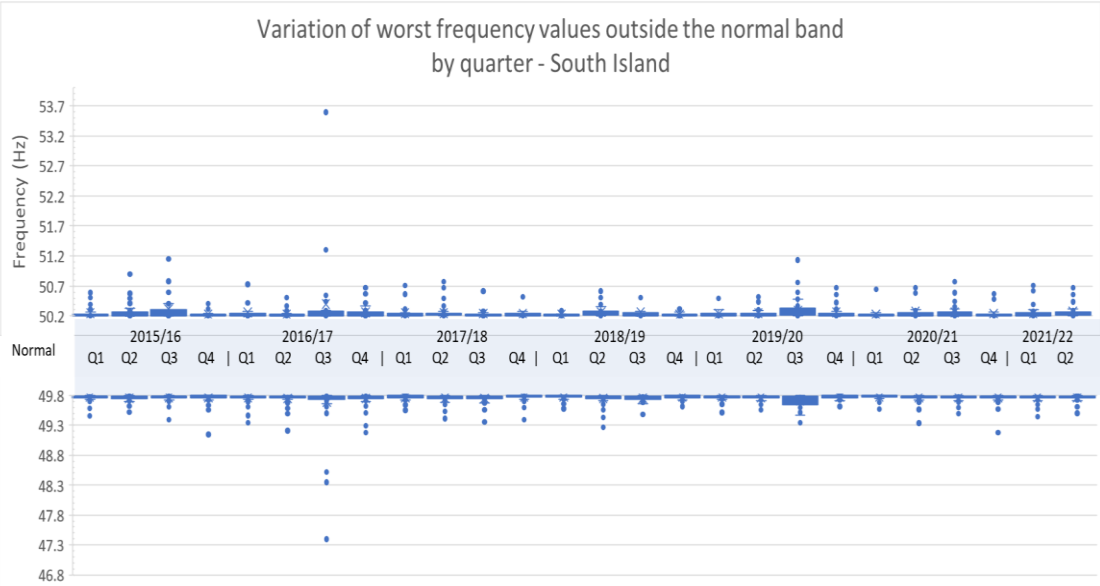
16.1 Maintain frequency in normal band (Frequency value)

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 2015/16, including the reporting period.

North Island



South Island

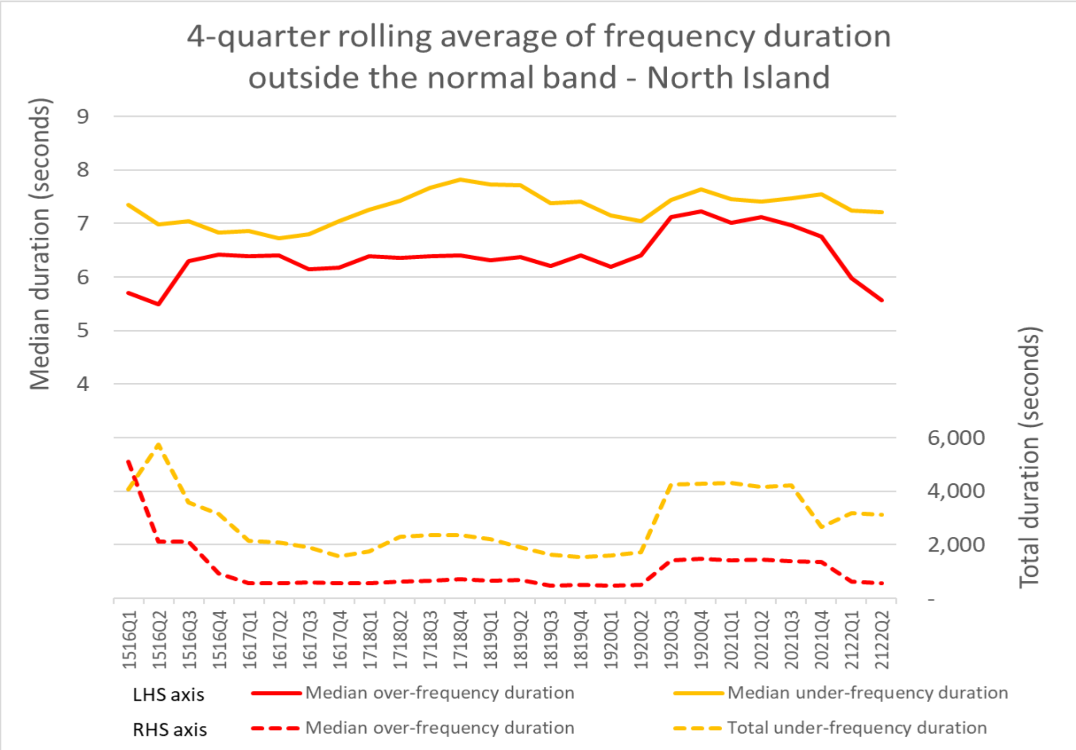


Note: These box and whisker charts show the distribution of data. The "box" represents the distribution of the middle 50% of the data, the "whiskers" indicate variability, and outliers are shown as single data points.

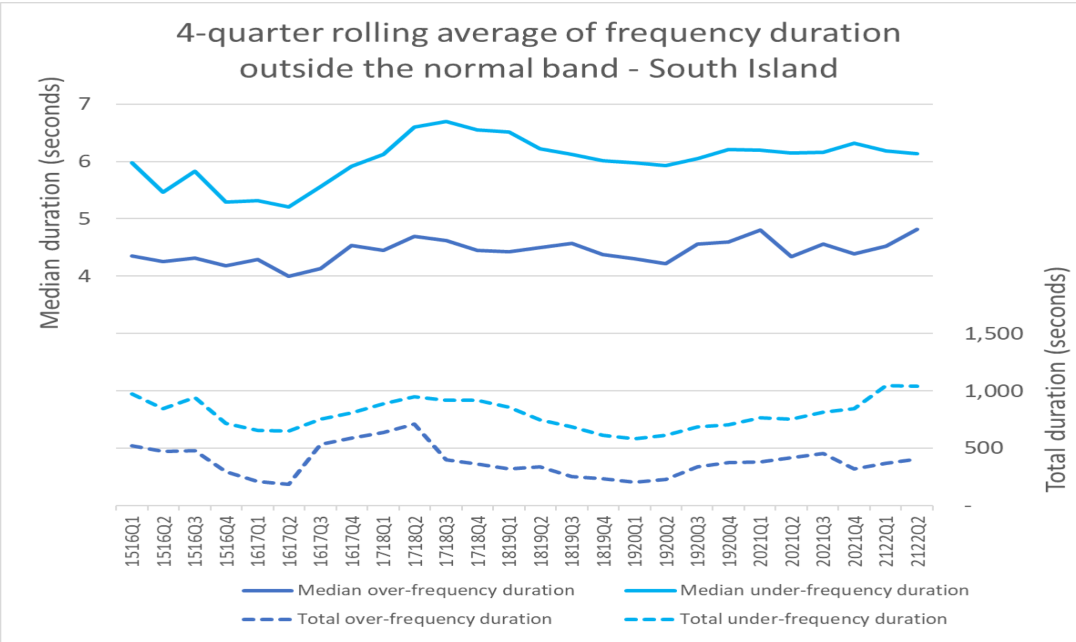
16.2 Recover quickly from a fluctuation (Time)

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



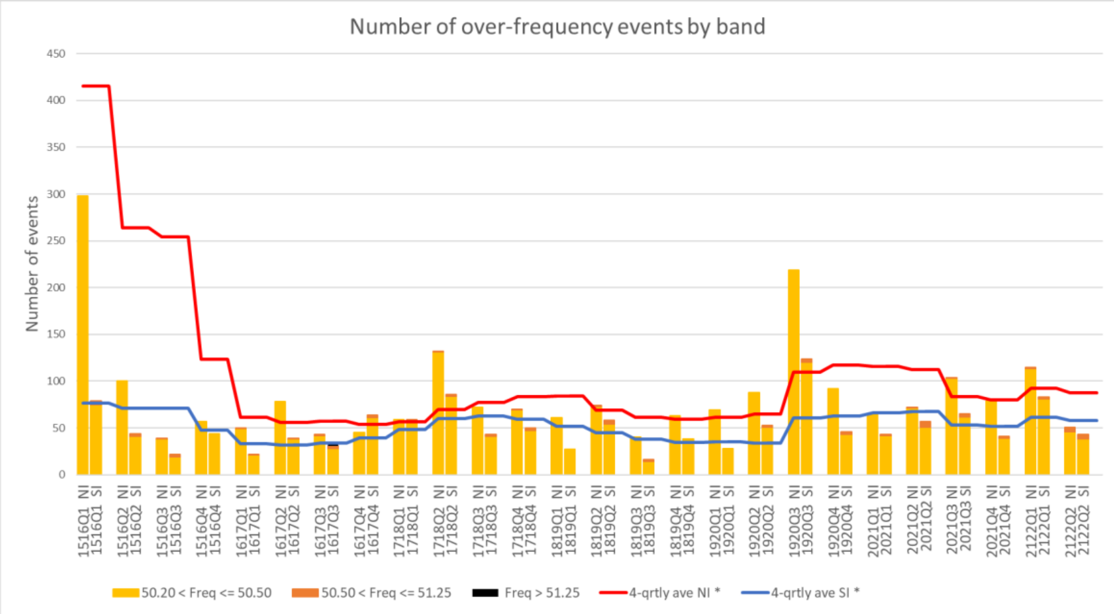
South Island



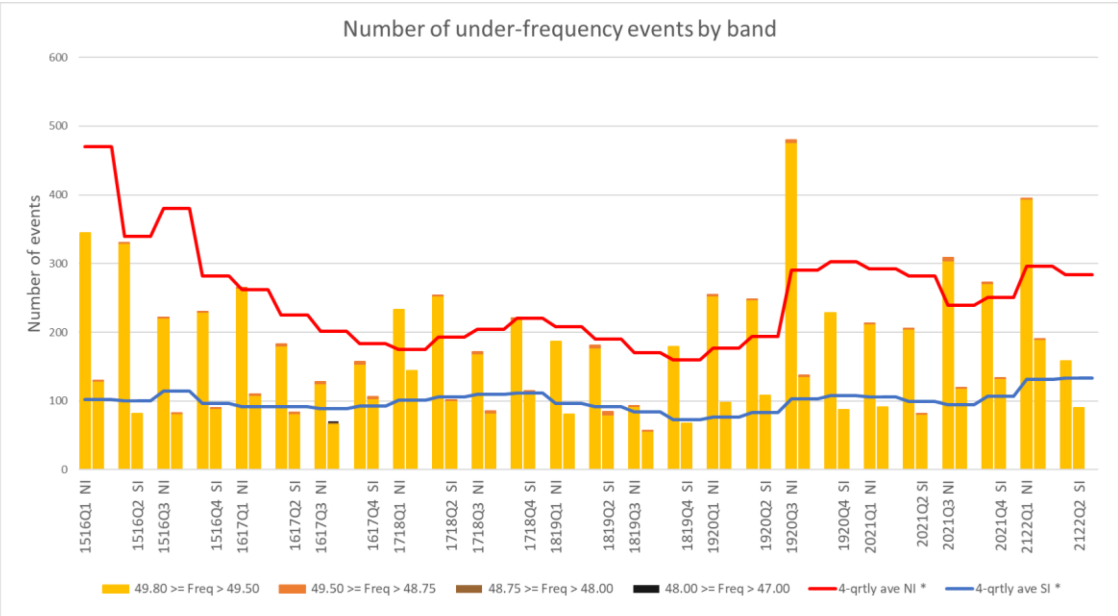
16.3 Manage frequency and limit rate of occurrences during momentary fluctuations (Number)

The following charts show the number of momentary fluctuations outside the frequency normal band, grouped by frequency band, for each quarter since Q1 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



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

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

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	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
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

19 Grid emergencies

The following table shows grid emergencies declared by Transpower as System Operator from October to December 2021.

Date	Time	Summary Details	Island
25/11/21	08:34	A grid emergency was declared to assist with load and generation at Tekapo A Substation following the tripping of the 110 kV Albury – Tekapo A circuit.	S
25/11/21	08:57	A grid emergency was declared to allow a temporary system split to be placed on Kawerau Transformer T2 during a planned outage. This was necessary as studies indicated overloads could occur for a contingency on 110 kV Edgecumbe – Kawerau Circuit 1.	N

Appendices

Appendix A: Discretion

October

Event Date & Time	Event Description
4/10/2021 3:09	GLN0332 GLN0 Discretion Max : 0 GLN Bus M tripped Last Dispatched MW: 65.4
4/10/2021 18:30	OKI2201 OKI0 Discretion Max : 0 Issue with a switch at the OKI bus that tripped OKI generation. Contact advised of discretion applied and not to change their electronic offers. Last Dispatched MW: 39
5/10/2021 3:50	ARG1101 BRR0 Discretion Max : 0 BLN_KIK_1 tripped. Last Dispatched MW: 10
10/10/2021 11:38	HLY2201 HLY5 Discretion Min : 190 Rule 13.82A claimed, resource consent. Required for system security for morning peak. Last Dispatched MW: 153.64
11/10/2021 11:00	OKI2201 OKI0 Discretion Min : 10 OKI claimed 13.82 (A) with a Plant safety minimum of 10MW. NAP+NTM+OKI combined risk higher than HLY U5 due to OKI_WRK 1 outage. HLY U5 Hz Keeping with control min of 230MW. SPD's least cost solution is to have OKI+NAP+NTM at or below 230MW. Last Dispatched MW: 5
11/10/2021 11:59	OKI2201 OKI0 Discretion Min : 10 OKI claim 13.82 (A). Last Dispatched MW: 10
11/10/2021 11:59	OKI2201 OKI0 Discretion Max : 10 OKI claim 13.82 (A). Last Dispatched MW: 10
12/10/2021 19:30	WHI2201 WHI0 Discretion Min : 10 SI residual 17, NI residual 215. Load still increasing. Last Dispatched MW: 25
12/10/2021 19:32	WHI2201 WHI0 Discretion Min : 10 Last Dispatched MW: 25. SI residual 17, NI residual 215. Load still increasing. Last Dispatched MW: 25. Half hour generators ramping. Dispatched on merit at 0840 above 10MW minimum. Some offered generation constrained at OHK, ATI, ARI so residual less than indicated
17/10/2021 17:29	ARG1101 BRR0 Discretion Max : 0 for BLN KIK circuit switching Last Dispatched MW: 0
22/10/2021 4:30	ARG1101 BRR0 Discretion Max : 0 Due to ARG_BLN_1 PSO, and return to service of ARK_KIK_1 Last Dispatched MW: 11.5

November

Event Date & Time	Event Description
31/10/2021 12:34 (Start: 1/11 01:34 End: 1/11 02:00)	HLY2201 HLY5 Discretion Min : 190. Genesis claimed clause 13.82a for HLY5 due to breaching resource consent if running below their minimum. For security purposes HLY5 constrained to their minimum of 190MW Energy. Last Dispatched MW: 161.17

Event Date & Time	Event Description
31/10/2021 13:03 (Start: 1/11 02:03 End: 1/11 04:00)	HLY2201 HLY5 Discretion Min : 190. Genesis claimed clause 13.82a for HLY5 due to breaching resource consent if running below their minimum for security purposes. HLY U5 absorbing 160 Mvars and without this, high voltage violations would occur due to reactive plant outages. HLY5 constrained to their minimum of 190 MW Energy. Last Dispatched MW: 177.55
1/11/2021 15:05	HLY2201 HLY5 Discretion Min : 190. Genesis claimed clause 13.82A, cannot meet dispatch and run below minimum of 190 MW due to resource consent breach. For security purposes (HLY5 needed for voltage support, currently absorbing 140 MVars, and will be needed for the morning peak), HLY5 constrained on to their minimum. Last Dispatched MW: 161.64
2/11/2021 21:47	KPA1101 KPI1 Discretion Max : 0. OPK-KPI-2 Tripped. KPI were doing 14 MW at the time. Discretion to 0 MW required for accurate dispatch solution. Last Dispatched MW: 14
2/11/2021 22:15	KAW1101 KAG0 Discretion Max : 0 KAG tripped from 107 MW. Discretion to 0 MW required for accurate dispatch solution. Last Dispatched MW: 107
14/11/2021 18:00	ARG1101 BRR0 Discretion Max : 0. ARG_BLN_1 on outage from 07:00. For switching purposes, ARG_KIK_1 Power System Operations outage was applied to, BRR to discretion to zero during switching. Last Dispatched MW: 11
16/11/2021 15:55	COL0661 COL0 Discretion Max : 30. West Coast split. KUM_OTI, HKK_KUM and GYM_KUM tripped. Discretion on COL due to COL_HOR violations. Last Dispatched MW: 20.61
18/11/2021 23:49	ARG1101 BRR0 Discretion Max : 0. Discretioned off in preparation for the ARG_KIK_1 PSO/return of ARG_BLN_1. Last Dispatched MW: 11
19/11/2021 13:01	HLY2201 HLY5 Discretion Min : 190. Last Dispatched MW: 183.64
21/11/2021 18:29	ARG1101 BRR0 Discretion Max : 0. Discretion to zero to enable switching for planned outage of ARG_KIK_1. Last Dispatched MW: 10
22/11/2021 2:12	WHI2201 WHI0 Discretion Min : 10. Due to low residual situation, generation needed for evening peak. Last Dispatched MW: 25.2
24/11/2021 19:26	TKA0111 TKA1 Discretion Max : 0. TKA discretioned to 0 currently off due to Albury_Tekapo A circuit. Ended when trader claimed BF. Last Dispatched MW: 0
24/11/2021 19:57	TKA0111 TKA1 Discretion Max : 0. TKA discretioned to 0 currently off due to Albury_Tekapo A circuit. Ended when TKA returned and Islanded. Last Dispatched MW: 0
25/11/2021 12:45	HLY2201 HLY5 Discretion Min : 190. Claimed 13.82A resource consent, minimum run of 190 MW. Required for system security and voltage control. Last Dispatched MW: 185.51
26/11/2021 3:57	ARG1101 BRR0 Discretion Min : 0. Discretioned off while switching on the BLN KIK cct to safely open/close the ARG disconnectors. Last Dispatched MW: 11.5

Event Date & Time	Event Description
26/11/2021 4:00	ARG1101 BRR0 Discretion Max : 0. Discretioned off while switching on the BLN KIK cct to safely open/close the ARG disconnectors. Last Dispatched MW: 11.5

December

Event Date & Time	Event Description
1/12/2021 22:54	TWH0331 TRC1 Discretion Max : 41.5 Last Dispatched MW: 42 Applied discretion to test TRC comms. They needed their dispatch slightly altered for to check dispatch comms. I applied small discretion .5MW down and then put it back to actual dispatch.
1/12/2021 23:17	SFD2201 SFD22 Discretion Max : 7 Test Solve to determine lowest cost solution. Not dispatched. Last Dispatched MW: 5.39
1/12/2021 23:18	SFD2201 SFD22 Discretion Clause 13.70, Part 13 SIR Max : 0 Test Solve to determine lowest cost solution. Not dispatched. Last Dispatched MW: 5.39
1/12/2021 23:18	SFD2201 SFD22 Discretion Clause 13.70, Part 13 FIR Max : 0 Test Solve to determine lowest cost solution. Not dispatched. Last Dispatched MW: 5.39
1/12/2021 23:20	SFD2201 SFD22 SIR Max : Test Solve to determine lowest cost solution. Not dispatched. Last Dispatched Mw: 5.39
1/12/2021 23:20	SFD2201 SFD22 FIR Max : Test Solve to determine lowest cost solution. Not dispatched. Last Dispatched Mw: 5.39
1/12/2021 23:20	SFD2201 SFD22 Discretion Min : 7 Test Solve to determine lowest cost solution. Not dispatched. Last Dispatched MW: 5.39
2/12/2021 18:26	ARG1101 BRR0 Discretion Max : 0 Discretion to 0MW applied in preparation for planned outages of ARG_KIK_1 & ARG_BLN_1 Last Dispatched MW: 11.5
5/12/2021 4:23	ARG1101 BRR0 Discretion Max : 0 Discretioned off for the ARG_BLN_1 PSO/ Return of ARG_KIK_1 outage. Last Dispatched MW: 11
6/12/2021 21:39	MAN2201 MAN0 Discretion Max : 523 To allow for potline return after extended potline. Last Dispatched MW: 703.36
12/12/2021 18:25	ARG1101 BRR0 Discretion Max : 0 Last Dispatched MW: 0 To open ARG 164 for ARG_BLN_1 outage
14/12/2021 10:48	HLY2201 HLY5 Discretion Min : 180 Claimed exemption to rule 13.82a. Held on until 00:00 for security. Last Dispatched MW: 155.14
14/12/2021 11:01	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.
14/12/2021 11:04	HLY2201 HLY5 Discretion Max : 0 Claimed exemption to rule 13.82a. Not required for Security and will be dispatched off. Last Dispatched MW: 127.9

Event Date & Time	Event Description
14/12/2021 12:14	NAP2201 NAP0 Discretion Min : 138 Claimed Rule 13.82(A) due to risk to plant with fluctuating dispatches. Last Dispatched MW: 126.56
15/12/2021 21:59	MAN2201 MAN0 Discretion Max : 469 Last Dispatched MW: 646.05 MAN down to allow TWI Line 1 extended 183MW to return
15/12/2021 22:03	MAN2201 MAN0 Discretion Max : 469 Last Dispatched MW: 646.05 MAN down to allow TWI Line 1 extended 183MW to return
15/12/2021 22:15	WHI2201 WHI0 Discretion Min : 10 Last Dispatched MW: 17.79 TWI Line 1 extended 183MW WHI required for security due to low NI residual
15/12/2021 23:26	ARG1101 BRR0 Discretion Max : 0 ARG-KIK-1 PSO to close ARG 164 Last Dispatched MW: 11.5
17/12/2021 10:18	HLY2201 HLY5 Discretion Min : 190 Rule 13.82A claimed by trader. Min MW 190. Last Dispatched MW: 168.31
17/12/2021 10:36	HLY2201 HLY5 Discretion Max : 0 Test Solve for Interval Cost Last Dispatched MW: 190
17/12/2021 10:41	HLY2201 HLY5 Discretion Min : 190 Rule 13>82A claimed by trader due to resource consents. MIN MW 190. Last Dispatched MW: 177.05
24/12/2021 15:11	NAP2201 NAP0 Discretion Min : 139 Claimed Rule 13.82(a) for plant safety. Constrained on min of 139MW to provide reactive support Last Dispatched MW: 129.31
25/12/2021 17:34	NAP2201 NAP0 Discretion 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 solution". Last Dispatched MW: 128.65

Appendix B: Dispatch Accuracy Dashboards

Energy

Same quarter in 2020/21

This quarter 2021/22

			October	November	December	2021 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	540	515	493	481	557	360	350	347	652	895	472	509	584	648	449
	Instances where the system operator has applied discretion under 13.70 of the Code to meet dispatch objective		10	3	-	-	3	3	-	1	15	9	12	32	11	16	24
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	7.06	6.89	7.11	6.88	6.64	6.88	6.73	7.14	6.89	7.08	7.11	6.98	7.00	6.96	7.52
		SI	6.62	6.74	6.50	6.35	6.48	6.45	6.59	6.65	6.58	6.64	6.53	6.71	6.60	6.83	6.68
Time error (s)	Average absolute daily time error (s) indicates imbalance between generation and load, a reflection of imperfect dispatch	NI	0.1815	0.2092	0.1777	0.1953	0.2447	0.2019	0.2003	0.2113	0.2148	0.2379	0.2408	0.2317	0.1941	0.1862	0.2110
		SI	0.1818	0.1947	0.1872	0.2266	0.2506	0.2051	0.1898	0.2213	0.2072	0.2490	0.2332	0.2087	0.1879	0.2041	0.2095
Frequency excursions	Number of frequency excursions (> 0.5Hz from 50Hz)		6	3	-	5	3	2	-	2	3	3	1	2	-	5	1
FK within 1% of band limit	% of time frequency keepers spend near to or exceeding their regulation limits indicates the need to redispatch.	NI	2.8%	2.66%	2.87%	2.39%	2.88%	2.15%	2.94%	3.59%	2.76%	3.28%	3.01%	2.66%	2.54%	2.64%	3.47%
		SI	3.9%	3.85%	4.16%	3.43%	3.78%	3.13%	3.87%	5.75%	2.78%	3.31%	2.92%	2.66%	2.55%	2.59%	3.48%
FK outside of band limit	% of time frequency keepers spend outside their regulation limits	NI	0.01%	0.15%	0.01%	0.01%	0.05%	0.02%	0.02%	0.09%	0.01%	0.01%	0.02%	0.04%	0.02%	0.02%	0.01%
		SI	0.00%	0.18%	0.00%	0.00%	0.03%	0.00%	0.00%	0.14%	0.00%	0.00%	0.02%	0.01%	0.00%	0.02%	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.		8.19%	8.50%	7.42%	9.00%	10.29%	11.97%	10.19%	10.60%	13.79%	15.05%	11.78%	10.93%	8.11%	10.05%	9.09%
Constrained on energy- Total	Total Monthly Generation	MWh	3,642,908	3,396,766	3,429,779	3,349,472	3,155,453	3,338,962	3,364,562	3,722,811	3,726,894	4,038,786	3,857,499	3,628,916	3,553,128	3,411,254	3,381,156
	Total constrained on - All sources	MWh	24,672	23,347	18,499	24,386	13,538	10,561	24,629	23,878	23,017	25,760	25,586	33,595	26,561	24,861	37,425
		% of all generation	0.68%	0.69%	0.54%	0.73%	0.43%	0.32%	0.73%	0.64%	0.62%	0.64%	0.66%	0.93%	0.75%	0.73%	1.11%
Constrained on energy ($) - Frequency keeping	Total constrained on $ due to frequency keeping (within band is attributable to SO)	$ Constrained On Energy	399,820	292,501	455,009	325,530	426,305	407,568	574,408	849,250	529,563	678,100	418,027	387,985	232,948	269,822	428,273
		$ Grid Constrained On Energy	40,822	28,503	27,411	49,807	43,198	35,972	108,176	126,538	123,621	90,143	61,541	50,707	31,140	28,176	28,196
Optimal Dispatch (%)	Compares the average impact of a perfect foresight case against dispatch solutions. Indicates impact of wind offer, load forecast	%	94.270%	93.980%	92.800%	93.310%	93.450%	93.440%	94.790%	95.500%	95.310%	94.240%	93.790%	92.500%	91.500%	92.270%	92.480%
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%	99.600%	99.610%	99.570%	99.570%	99.580%	99.610%	99.590%	99.550%	99.580%	99.620%	99.580%	99.510%	99.590%	99.570%
Wind offer accuracy (%)	Average absolute difference between persistence wind offer (based on 5mins prior) and the actual wind output relative to the	%	97.750%	97.370%	97.530%	97.610%	97.310%	96.900%	97.340%	97.600%	97.250%	97.360%	97.540%	97.730%	95.400%	97.710%	97.550%
	Metric calculation rows	FK outside band	3	1	3	3	3	3	3	2	3	3	3	3	3	3	3
		Constrained on energy	3	3	3	3	3	3	3	3	3	3	3	1	3	3	1
		Optimal Dispatch (%)	3	3	3	3	3	3	3	3	3	3	3	3	2	3	3
Dispatch accuracy %	**Metric out of 3 (3 is best possible result)**		3.0	2.3	3.0	3.0	3.0	3.0	3.0	2.7	3.0	3.0	3.0	2.3	2.7	3.0	2.3

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

Scale for metric: 1 2 3

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

NOTE 2: Summary data for "FK outside of band limit" is not shown for the South Island in March 2020. The data collected for this month has missing values for a number of dates which meant the measure could not be calculated.

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

[3]

Metric[4]

The measures that contribute towards the metric are:

- FK outside of band limit [5]
- 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: [6]

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**

[3] 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
[4] This metric is for analysis purposes and is not part of the performance metrics report to the Authority
[5] 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
[6] The score was changed during the year from a five point (1-5) to a three point (1-3) scale.

Reserves

Same quarter in 2020/21

This quarter 2021/22

			October	November	December	2021 January	February	March	April	May	June	July	August	September	October	November	December
FIR procured vs Risk	NI+SI Fast Instantanous Reserve (FIR) procured divided by the estimate of FIR risk. A greater proportion suggests over procurement of reserves in the relevant island. Monthly average	**ACCE**	**0.80**	**0.71**	**0.67**	**0.78**	**0.82**	**0.78**	**0.70**	**0.80**	**0.78**	**0.70**	**0.71**	**0.67**	**0.66**	**0.71**	**0.63**
		DCCE	**NIL**	**NIL**	**0.91**	**1.04**	**1.13**	**0.77**	**NIL**	**NIL**	**NIL**	**0.95**	**0.94**	**0.92**	**0.88**	**0.82**	**0.87**
FIR procured (MW)	Average FIR MW procured per trading period		274	208	180	239	255	224	180	222	286	251	257	203	198	204	166
SIR procured (MW)	Average SIR MW procured per trading period		359	308	285	320	339	300	266	314	381	372	386	313	303	301	263
FIR procured ($)	Total monthly cost ($) of FIR procured		1,591,883	880,450	691,712	946,569	1,649,525	923,443	284,960	800,816	2,029,096	1,803,527	3,083,309	1,224,614	867,796	850,026	604,671
SIR procured ($)	Total monthly cost ($) of SIR procured		465,370	298,318	229,839	222,854	399,630	138,594	102,967	278,623	1,264,344	2,216,743	2,198,285	1,038,035	973,776	953,870	498,131
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**	90	102	110	87	88	86	92	96	101	124	115	115	107	106	110
		DC	**NIL**	**NIL**	89	60	62	79	**NIL**	**NIL**	**NIL**	77	95	88	96	112	99
Reserve sharing	Average percentage of FIR procured that is shared between islands.		37%	42%	51%	44%	41%	52%	61%	45%	35%	36%	26%	37%	35%	52%	42%
IL vs Spinning Reserve	Percentage of IR procured as interuptable load.	**FIR**	35%	40%	38%	35%	34%	29%	29%	28%	40%	39%	33%	34%	36%	32%	32%
		SIR	33%	37%	35%	34%	37%	28%	30%	28%	41%	38%	36%	37%	38%	35%	35%
Risk setter	Most common risk setter (highest number of trading periods)	**NI**	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY1CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE	HLY5CE
		SI	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE	OtherIslandCE	OtherIslandCE	ManualCE;OtherIslandCE	OtherIslandCE	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE	OtherIslandCE	ManualCE;OtherIslandCE	ManualCE;OtherIslandCE	OtherIslandCE	ManualCE;OtherIslandCE
Proportion of time risk setter	Proportion of time each type of risk was FIR risk setter	**ACCE**	100.00%	100.00%	96.77%	99.80%	98.29%	99.66%	99.93%	100.00%	100.00%	99.80%	78.23%	95.13%	87.77%	95.56%	88.58%
		DCCE	0.00%	0.00%	0.81%	0.20%	1.64%	0.34%	0.00%	0.00%	0.00%	0.20%	21.91%	2.50%	10.35%	2.78%	1.08%
		DCECE	0.00%	0.00%	2.42%	0.00%	0.07%	0.00%	2.36%	0.00%	0.00%	0.00%	0.13%	2.36%	1.88%	1.67%	10.35%
Average MW risk when risk	Average risk MW for each risk type when they are the FIR risk	**ACCE**	344	293	270	306	308	287	464	365	366	356	344	304	292	289	269
		DCCE	0	0	426	288	346	477	0	0	0	363	364	337	289	293	251
		DCECE	0	0	55	0	129	0	230	0	0	0	159	50	76	32	65
Reserve accuracy metric	**FIR procured vs Risk (ACCE)**		**80%**	**71%**	**67%**	**78%**	**82%**	**78%**	**70%**	**80%**	**78%**	**70%**	**71%**	**67%**	**66%**	**71%**	**63%**

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[7] 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.

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