QUARTERLY SYSTEM OPERATOR AND SYSTEM PERFORMANCE REPORT

FOR THE ELECTRICITY AUTHORITY

Transpower New Zealand Limited

July to September 2020

Keeping the energy flowing




TRANSPOWER

Transpower New Zealand Limited The National Grid

Report Purpose

This report is Transpower's review of its performance as system operator for Q1 2020/21 (July to September 2020), 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 (July to September 2020)

SOSPA 2 reset

- Transpower and the Authority have reached agreement on the SOSPA 2 proposal. The proposal will be submitted for approval at both the Authority's and Transpower Boards in early November.

COVID-19 response

- We reinitiated the system operator incident management team in response to the elevated COVID-19 alert levels announced on 11 August. Level 2 protocols were stood down in September, but we continue to employ caution and are restricting the number of people in the operational control rooms.

Real Time Pricing (RTP) and awareness preparations

- The Authority Board approved the Real Time Pricing (RTP) delivery business case on 6 August. We are continuing to work on the detailed solution design and build for the phase one deliverables.
- A TAS statement of work is now underway to modify a copy of vSPD to reflect the changes to be implemented under the RTP project, specifically the functionality required for scarcity pricing and outage infeasibilities.

Tiwai exit and Clutha Upper Waitaki Lines Project (CUWLP)

- Our working group began an investigation into potential angular stability issues in the South Island post-Tiwai exit.
- A page on the Transpower website was published this month to keep industry informed of the findings from our operational studies into the impact of Tiwai's exit on our ability to operate the power system.
- We were part of the Transpower team that hosted an industry conference via Microsoft Teams on 16 September to discuss CUWLP. It provided an opportunity for industry participants to hear about the project works and the outages required.

Security of Supply

- Although the hydro lake storage levels were below average in July and August, September saw the largest hydro storage increase of year to date. South Island storage is now sitting at 97% average for this time of year; North Island storage is 76% of average.
- Thermal fuel generation continues to be robust despite continued issues and an outage at Pohokura, reflecting the greater flexibility developed by thermal generators and soft methanol demand.
- We held a workshop on Security of Supply on 28 July to get feedback from participants on our Annual Security of Supply Assessment (ASA). We asked

workshop attendees to list and rank medium-term security of supply and describe how they see demand evolving over the next decade (details on responses are in the main report).

Code and SOSPA deliverables

- We delivered the System Operator Annual Self-Review and Assessment 2019-20 to the Authority on 31 August.
- We have agreed the joint development plan for the next five years with the Authority.
- Analysis work for several regions in the major two-yearly System Security Forecast (SSF) is now complete and entering the review cycle.

Planned Outage Co-ordination Process (POCP)

- The system operator response to the Planned Outage Co-ordination Process (POCP) review has been published on our website, along with additional user information for POCP users.

Market System (MS) Simplification

- The project successfully commissioned non-functional changes into the market system in late July; upgrading from an out-dated software code to a modern language to reduce complexity and cost for ongoing development and maintenance activities.

Extended Reserves (AUFLS)

- The delivery business case for the Extended Reserves portal was developed and is currently in the approval process.
- We started work with the Authority on the Technical Advisory Service (TAS) to remove the existing Extended Reserves provisions from the Code and replace them with new obligations aligned with the project reset.

Dispatch Service Enhancements (DSE)

- Five of the thirteen participants have already transitioned from the legacy dispatch system (GENCO), three with ICCP block 2 protocol and two with webservices. One of these participants has fully decommissioned their GENCO system. At this stage, all participants are expected to meet the 16 December 2020 deadline.

Recent initiatives

Sensitivity schedules

- A proof of concept to investigate the sensitivity of prices and carbon emissions to changes in demand, specifically the impact of +/- load variations, went live on the Transpower website in early August. The proof-of-concept will run until the end of October, after which schedule publication is scheduled to be switched off pending future development in this area. We have encouraged feedback before this trial period ends.

Current investigations

Market system outage greater than one-hour

- On 8 August, the market system locked up. Dispatch was switched to standalone dispatch and a customer advice notice sent out to the industry. Our investigation into this issue continues, with our report due to the Authority by 8 November 2020.

System operator performance

1 Customers and other relationships

SOSPA 2 reset

Following good progress on the reset negotiations during the quarter, Transpower and the Authority have reached agreement on the SOSPA 2 proposal. The proposal will be submitted for approval at both the Authority's and Transpower Boards in early November.

Security of supply workshop

We held a workshop on Security of Supply on 28 July. Our aim was to get feedback from participants on our Annual Security of Supply Assessment (ASA) in an informal, collaborative environment. We asked workshop attendees to list and rank medium-term security of supply risks – thermal retirement and gas flexibility were high on this list. Attendees were also asked to describe how they see demand evolving over the next decade. Although some topics mentioned including long term effects such as electrification and small-scale renewables are already included in our demand scenarios, other suggestions such as modelling the impact of demand response and industrial demand and including short-term changes may be more challenging to incorporate; we will investigate if this can be done.

CUWLP outages and operational impacts

We were part of the Transpower team that hosted an industry conference via Microsoft Teams on 16 September to discuss CUWLP.

Association of Power Exchanges (APEx) Board membership

Dr Jay replaced John Clarke on APEx Board and attended their meeting on 12 August. The APEx AGM and a webinar was held on 10 September.

GM Stakeholder Meetings

Dr Jay met with General Managers from Todd Energy, Meridian, Contact, Genesis, GIC, and PEPANZ in August. He also visited Huntly Power Station in September, with members of the EA and Commerce Commission leadership teams.

System Operator Annual Self-Review and Assessment 2019-20

We delivered the System Operator Annual Self-Review and Assessment 2019-20 (SO Annual Self-Review) to the Authority on 31 August, as required under the Code. The SO Annual Self-Review and the draft Authority review of system operator performance will be presented at the Authority's November Systems Operations Committee.

Forward Workplan

In August, we agreed the joint development plan for the next five years with the Authority. This outlines the work programme for the Authority and system operator, and is agreed annually and monitored with regular two-monthly meetings.

2 Risk & Assurance

COVID-19 response

In July, we held a workshop with the Operations COVID-19 incident management team to capture lessons from the pandemic experience so far. These will go towards improving our business continuity planning preparedness and coordination between Enterprise and divisional responses.

We reinitiated the system operator incident management team in response to the elevated COVID-19 alert levels announced on 11 August. We implemented our control room lockdown protocols across all our control rooms, including restricted entry to the control rooms and surrounding areas. Initially, our Transpower Auckland office was closed and staff worked from home; all other Transpower offices remained open.

The system operator incident management team (IMT) stood down on 3 September; but continued to input into the Transpower IMT. Level 2 protocols were stood down once the country returned to Level 1. We continue to employ caution and are restricting the number of people in the operational control rooms.

Tiwai exit announcement

Following the announcement by NZAS of the plan to not renew the supply contract with Meridian and to exit Tiwai, we have set up a working group to undertake a preliminary assessment of the potential impacts on the power system and market. We are developing a list of considerations and reviews that will be prioritised and worked through as more information becomes known. We continue to take this prudent position until the incoming government's decision on extending the NZAS supply contract is formalised.

Business process audits

Auditors have been engaged to complete the first two of our SOSPA 2020/21 audits:

- Managing insufficient generation offers and reserve deficits
- Markets Security of Supply (follow-up review).

Work began on these audits in September 2020.

Risk bowtie and critical controls

Our new bowtie and critical controls were approved by the senior management team in August. The new bowtie includes specific risks to directly identify how we will manage people risks – risk of human error, and risk of not having the tools, facilities or people to manage the power system. The critical controls have been reduced from 25 to 10 to provide a clearer depiction of how we manage risk; these will be assessed for effectiveness in October's control self-assessment round. The bowtie was shared with the Transpower System Operator Committee in September.

3 Compliance

July

We did not report any system operator breaches to the Authority in July.

August

We reported one system operator breach to the Authority in August, after we failed to model a trader name change at Kinleith correctly. This meant generation offers were used incorrectly in the forward schedules. The error appeared in the price responsive schedules but did not appear in real time. The error was corrected on 4 August and market team documentation will be updated to ensure the market participant field is an active check.

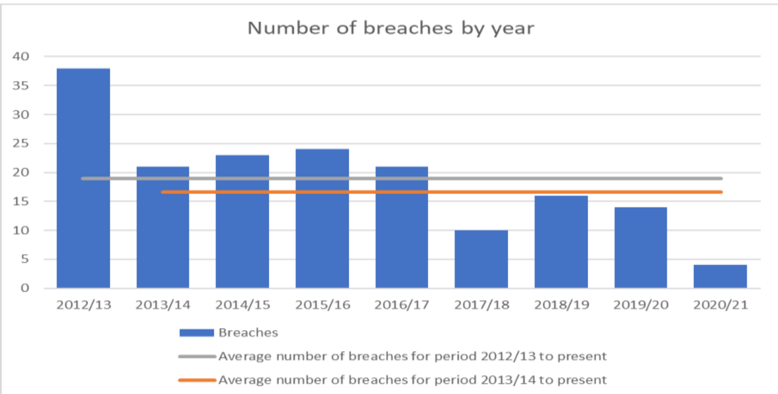
September

We reported one breach of the Code in September. A planned outage on the Carrington Street-Junction Road-Stratford circuit resulted in incorrect SFT constraints being built. The constraints built allowed the scheduling of more generation export out of the Taranaki 110kV network (from Junction Road and McKee generation) than was possible. The issue led to generation being constrained in real time to levels which were below those scheduled in the forward schedules. The cause of this issue was a defect introduced as part of the Prism project in March 2016. The issue was rectified in the production system on 20 August. There was no real time market impact.

The Authority alleged two breaches against the system operator in September.

- On 11 September, the alleged breach related to Transpower's system operator function and grid owner function using the same external legal provider in relation to the December 2019 under frequency event. We responded to the Authority on 22 September saying we do not accept the alleged breach.
- On 18 September, the alleged breach related to the review cycle of the procurement plan. The issue involves different interpretations of the review cycle under the Code. Although we do not believe we breached the Code and worked in good faith to deliver the procurement plan according to our interpretation of the Code (noting also that there were different interpretations within the Authority itself), we do not want to prolong the issue and have responded to the Authority agreeing to accept its finding.

We have 10 outstanding breaches with the Authority compliance team, including the alleged breaches by the Authority in September.



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 (COI) register. These issues are being actively managed in accordance with our policy for managing conflicts of interest.

The dates below refer to the calendar months and not the dates of the Monthly reports which cover 10 business days of the following calendar month.

July

No items were opened in the register during July.

Four entries were closed.

- 21 - Staff interest in generator commissioning
- 22 - Security classifications for PI Vision database access
- 26 - Response to 14 December UFE recommendation
- 32 - Use of the same legal advisor

August

No items were opened in the register during August.

Three entries were closed:

- 18 - Completion of recommendations from Conflict of Interest review
- 34 - Ensuring an impartial system operator response to COVID-19 alert levels
- 37 - Participant request for information via the incorrect process connecting to ICCP; correct process was followed

September

One item was created in the register during September.

- 40 - We have created a general item that will remain permanently open to cover all employees with a dual system operator/grid owner role. As part of this item, we have identified the actions necessary to ensure impartiality in these circumstances.

We have six open items in the register.

System Operator Open Conflict of Interest Issues		
ID	Title	Managed by
27	**System operator employee partner to work for grid owner:** The partner of a system operator employee started work with the grid owner. Confidentiality obligations have been explained to both employees and will be monitored to prevent a conflict of interest arising.	SO Power Systems Group Manager
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
33	**Sharing working space during lockdown:** A staff member sharing work-space with their partner who works for another industry participant. Both parties are managing the conflict accordingly to maintain the confidentiality of information.	Grid and Systems Operations Manager
39	**New SO Compliance & Impartiality Manager:** This relates to potential perception; the person filling this role also works for	GM Operations

System Operator Open Conflict of Interest Issues		
ID	Title	Managed by
	Transpower's legal team on a part-time basis. Workstreams will be allocated accordingly.	
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

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)
RTP has completed the capital investigation phase with the delivery business case submitted to the Authority on July 10 as planned; this was approved by the Authority Board at their August meeting. The final forecast cost for the project has increased from the initial business case forecast. This consists of an increase of $1.8m for new scope items introduced by the Authority and an additional $4m of costs in the areas of project risk and contingency, business change management, data warehouse costs and additional senior and lead roles to manage project complexity. These additions have in part been informed by lessons learned in recent high complexity development projects.

Solution Requirements and high-level design were also completed this quarter; the detailed solution design and build for the phase one deliverables is continuing (the Authority had previously approved pre-funding of the delivery phase sufficient to keep the project active to the end of August).

The business change planning is complete, and the management plan was approved in September. The team is now working with the change sponsors (the division managers, team managers and leaders) to establish messaging. Work on the preparation for operational procedure changes and formal training of affected staff continues.

Good progress has been made with the Authority on the preparations for industry engagement. The schedule and topics to be covered have been agreed and the first workshop with industry is scheduled for 20 October. The workshops are planned to run monthly after that until August 2021. Work is now underway to prepare the content for the October workshop. Advice to industry confirming the first workshop will be provided in an upcoming Authority weekly Market Brief.

Dispatch Service Enhancements (DSE)
We have been steadily transitioning industry participants to our new dispatch service since September 2019. The final date for participants to transition to the new service (and continue to meet their Code obligations) is 16 December 2020. Five of the thirteen participants have already transitioned from the legacy dispatch system (GENCO),

three with ICCP block 2 protocol and two with webservices. One of these participants has fully decommissioned their GENCO system. At this stage, all participants are expected to meet the deadline.

Situational Intelligence

During this quarter, all the functionality for Release 1 has been completed (sprints 1 to 10). This release will deploy the core Situational Intelligence platform into production, including simple alerts for market and SCADA data; and is scheduled for late-October. Release 2 (sprint 11) is focused on adding Transpower sign on and role-based authentication. This release will be accessible to NCC control room users from 29 October. The functionality of the application allows simple rules and alerts to be created using a subset of SCADA and market data. Release 3 (sprint 12 onwards) will continue to build functionality by incorporating more data into the application, allowing more complex rules to be built.

Extended Reserves (AUFLS)

During the quarter, we started work with the Authority on a TAS to remove the existing Extended Reserves provisions from the Code and replace them with new obligations aligned with the project reset. The reset will enable both the transition from 2 to 4 blocks of AUFLS and use of a data portal to hold AUFLS information.

Collaboration between IST and system operator personnel has enabled us to develop an approach to build the Extended Reserves data portal in-house. The in-house design will allow the portal to be incorporated into our Customer Portal work, providing a single portal for industry to interact with the system operator. The delivery business case for the project has been developed and is currently in the approval process.

Sensitivity Schedules

A proof of concept to investigate the sensitivity of prices and carbon emissions to changes in demand, specifically the impact of +/- load variations, went live on the Transpower website in early August. The proof-of-concept will run until the end of October, after which schedule publication is scheduled to be switched off. We have encouraged feedback before this trial period ends; to date we have not received any feedback from industry on the schedules. Feedback will inform any future development in this area.

Market System (MS) Simplification

The project successfully commissioned non-functional changes into the market system in late July; upgrading from an out-dated software code to a modern language to reduce complexity and cost for ongoing development and maintenance activities. Work is now underway on planning for the next phase of the project, MS Simplification 2, which will continue with the change to the software (re-factoring) some of the market system code to improve the design and structure while preserving its functionality.

5.2 Other projects

Modifying vSPD for Real Time Pricing stakeholder engagement work

A TAS statement of work is now underway to modify a copy of vSPD. The work will reflect the changes to be implemented under the RTP project, specifically the functionality required for scarcity pricing and outage infeasibilities. This piece of work will enable the proposed changes to be shared, part of the plan to communicate and engage with industry.

The original completion date for updating vSPD with the changes planned for the RTP project was the end of September. By agreement with the Authority this date has been extended to 28 October to allow for the latest RTP project SPD design changes to be accommodated in the vSPD build. This item of work incorporates three incremental vSPD deliverables of which the first two have been completed and delivered to the Authority. The third and final deliverable is due on 28 October.

Customer Portal project team
The Customer Portal project team has developed an alternative solution to the original proposal that better meets business case objectives and budget. A delivery business case is now being prepared to enable the next phase of the project – to build a new Asset Capability System (ACS). The delivery of ACS will include foundational components and overlapping aspects that are required by the Extended Reserves portal project.

Inertia monitoring pilot
The trial period concluded on the 24 July, and devices returned to Wellington. We have evaluated the final report from Reactive Technologies and concluded that the technology is useful but still needs development to provide the required functions we require in the control room to manage system frequency should a low inertia future unfold. We concluded that at this stage that we are confident that we can manage system frequency with our existing tools. We will reconsider the technology again in the future should inertia levels fall.

Energy Futures: Requirements for inverter connected resources (TAS91)
The Authority requested that our TAS work on changes to Parts 8 and 13 of the Code, to adapt to the expected change in power system security resulting from an uptake of inverter-based generating technologies, be placed on hold as of 30 June.

6 Technical advisory hours and services

The following table provides the technical advisory hours for Q1 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 Q1
TAS SOW 92 - Modifying vSPD for RTP stakeholder engagement work	In progress	136.00
TAS SOW 93 – Extended reserve data portal capital business case development	In progress	355.60
TAS SOW 94 – Extended reserve Code amendment support	In progress	94.50
Total hours		**586.10**

7 Outage planning and coordination

Outage Planning – near real time

The current trend of a high volume of outages requiring assessment continued over this quarter.

A small working group was set up to look at options for managing outage workload in real-time for both system operator control centre and grid owner operation centre staff. The group is looking at implementing an outage number threshold, providing better reporting and actively managing the outage start times to reduce switching workload.

July was the first month that Transpower grid owner 'tentative' outages were published to the industry in POCP. These are outages which are unconfirmed or have not been through internal approval processes. This is already proving useful to us in the system operator approval process and to industry as it provides transparency to all interested parties, where we might otherwise have been discussing a potential outage with just one or two connected customers. This change enabled us to signal, for instance, a tentative outage for the recommissioning of the Islington-Livingstone line.

Outage Planning – longer term

Outages for the thermal upgrade of Cromwell-Twizel circuits are scheduled between October and December 2020. The outages for reconductoring Naseby-Roxburgh have been scheduled for 2021 and tentative outages for of Livingstone-Naseby scheduled for 2022. A website for the Clutha Upper Waitaki Lines Project (CUWLP) outages has been set up to provide further information and updates to industry. Detailed analysis of the outages is underway to determine the outage impact and analyse risks and a well-attended industry briefing was held in September.

POCP review

The system operator response to the POCP review was published in July, along with additional user information for POCP users. This is available on our website. Next steps are to progress the suggested tool enhancements and discuss our recommendations with the Authority.

New Zealand Generation Balance reporting

There have been substantial changes to both the NZGB modelling and report since the July 2020 report. The two major changes are as follows:

- The previous 'sensitivity scenario' (a slow starting North Island generating unit not being offered) is no longer considered. Participants are encouraged to monitor the Week-ahead Dispatch Schedule (WDS) to determine if participants are offering available generating plant into the market.
- The low gas generation assumptions are now applied to both the base and winter scenarios. Unexpected winter peaks can occur across all winter months and understanding the impact of a low gas situation during the periods of highest load is deemed an advantage.

The September report forecasts the grid owner's CUWLP outages in 2020 and 2021 as well as the 2021 HVDC outage. No generation shortfalls (under any scenario) are forecast during these periods.

Work is underway to update the NZGB model to correctly account for the impacts of COVID-19 on the load profile since March 2020.

8 Power systems investigations and reporting

System Security Forecast (SSF)

Analysis work for the major two-yearly SSF was completed this quarter. With the proposed Tiwai exit, this December's publication of the SSF will be important to industry, as it will outline the constraints the system operator will be operating to post-Tiwai exit. Analysis findings have been documented and this is now going through internal review prior to a planned release in December 2020.

Operational impact of Tiwai exit

A working group is considering implications on our ability to operate the power system post-Tiwai exit and has developed a task list to assess and plan for the implications. The System Security Forecast is already assessing steady-state thermal transfer limits, voltage stability limits and high voltage management across New Zealand, and we have begun an investigation into potential angular stability issues in the South Island. This work will also investigate how we will manage potential over-frequency events due to a bi-pole tripping of the HVDC.

A page was published on the Transpower website this month to keep industry informed of the findings from our operational studies into the impact of Tiwai's exit on our ability to operate the power system.

CUWLP outages and operational impacts

Transpower hosted an industry conference via Microsoft Teams on 16 September to discuss CUWLP. It provided an opportunity for industry participants to hear about the project works and the outages required. As system operator we discussed security assessments for the outages, focussing on the Clyde-Cromwell-Twizel outages.

The conference was well attended by over 40 generators, retailers, traders, distribution companies and Authority representatives. Questions focussed on contingency planning, the impacts the work will have on transfer limits out of Southland and how rarer risks such as double circuit contingencies and frequency risks would be managed. The presentation is available online here.

9 Performance metrics and monitoring

The following dashboard shows system operator performance against the performance metrics for the financial year to date as required by SOSPA 12.3 (a).

Only those metrics with a weighting are used in the calculation of the system operator score and incentive payment.

Metric		Annual Target	Actual to date	Points
Smart about money				
Perception of added value by participants		80%	N/A	
Customers are informed and satisfied				
Annual participant survey result		82%	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 to date	5
Future thinking and insights	Future thinking report	≥ 1	0 to date	5
	Longer Market Insight reports	≥ 4	1	5
	Bite-sized Market Insights	≥ 45	13	
Quality of written reports		100% of standard	100%	
Role impartiality		80%	N/A	5
Code compliance maintained and SOSPA obligations met				
Market breaches remain below threshold		≤ 3 @ ≥ $40k	0	10
Breaches creating a security risk - below threshold/within acceptable range		≤2	0	10
On-time SOSPA deliverables		100% (54)	100%	10
Successful project delivery				
Improved project delivery	Service Maintenance projects	≥ 60% on time	0 to date	
		≥ 60% on budget	0 to date	
	Market Design and Service Enhancement projects	≥ 60% on time	0 to date	
		≥ 60% on budget	0 to date	
Accurate capital planning		≥ 50%	N/A	10
Commitment to optimal real time operation				
Sustained infeasibility resolution		80% ≤ 10am or equiv	87%	5
High spring washer resolution		80% ≤ 10am or equiv	0 to date	
Dispatch Accuracy	Energy (Optimal dispatch)	Baseline set during 2020/21		
	Reserve Management Objective	Baseline set during 2020/21		
Fit-for-purpose tools				
Capability functional fit assessment score		75.00%	N/A	
Technical quality assessment score		65.00%	N/A	
Sustained SCADA availability		99.90%	99.90%	10
Maintained timeliness of schedule publication		99.00%	99.90%	10

9.1 Dispatch accuracy dashboard

As part of the Strategic Objective Work Plan for 2019/20, we developed a Dispatch Accuracy dashboard for energy dispatch. This is a means of monitoring overall industry performance and is contained in Appendix B, along with an explanation of the methodology we used to create the dashboard.

Although the types of measures included in this dashboard have been agreed, the purpose of this year is to evaluate how well each of these illustrate industry dispatch performance. We will use this year as an opportunity to evolve the dashboard measures, the standards and metric calculation so that it provides the greatest insight. This evaluation will be performed in consultation with the Electricity Authority.

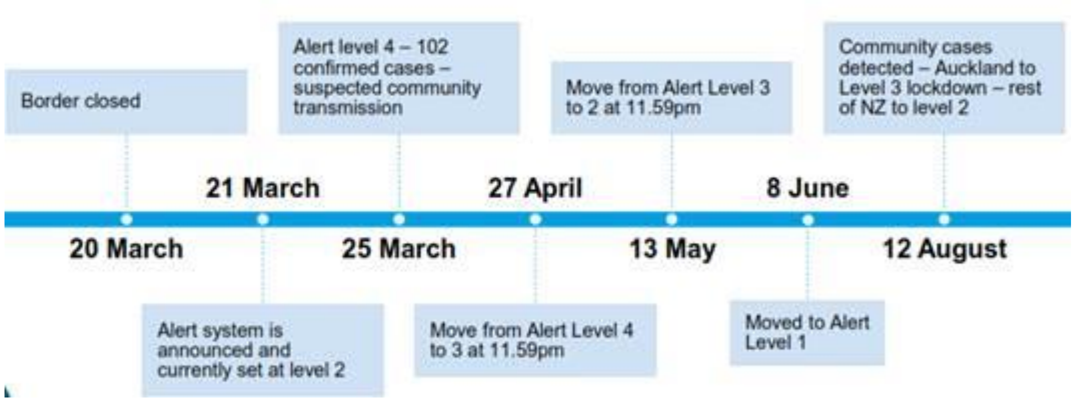
For this report we focus our comment on the current quarter, and those values in the quarter that are identified as outliers. We have included in the dashboard the data going back to the same quarter in the previous year for reference and, where appropriate, comparison, notably the recent outliers for the Optimal Dispatch measure.

July to September 2020

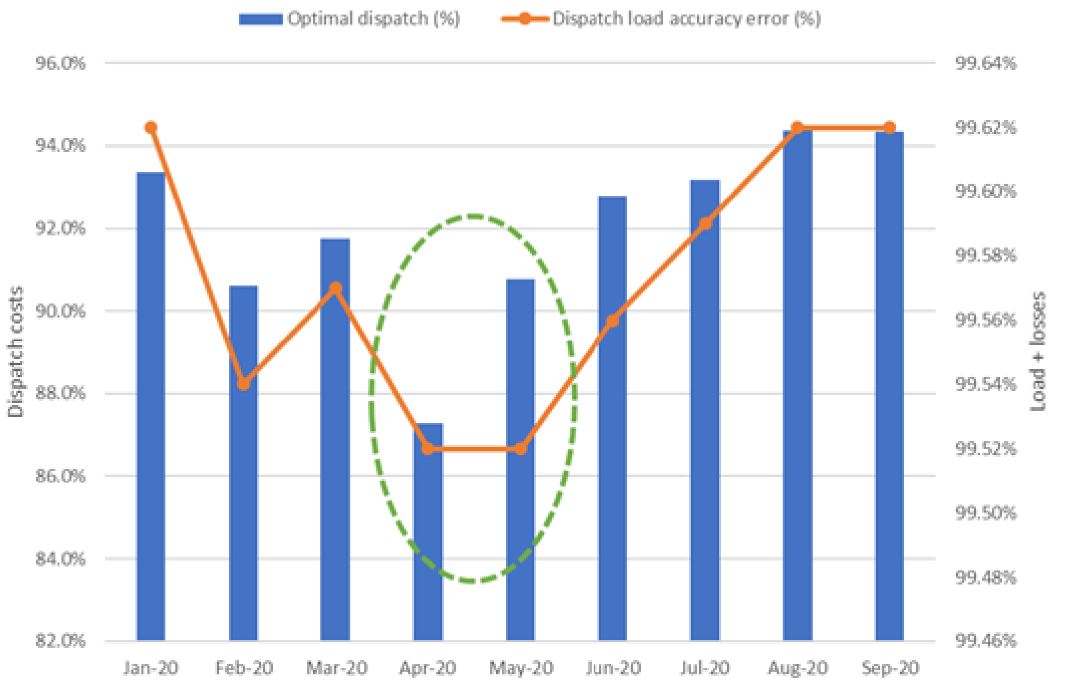
- *Operator discretion quantities (July)*
    - The operator discretion identified in this measure includes bona fides received by operators, manual discretion and other discretion applied.
    - In July the number of occurrences of discretion applied was mainly related to a large number of bona fides for interruptible load. This could be a winter phenomenon if price responsive customers react to high peak prices and are not available for interruptible load.
- *Time error (July in SI)*
    - The absolute daily time error is slightly higher in the South Island in June. However this is still a small number that is only slightly greater than other month’s small variations and well within the PPO reset value of 5 secs.
- *FK within 5% of the top or bottom of their band (August in NI and SI)*
    - In August and September the percentage of time the frequency keepers are within 5 per cent of their regulation band is higher than in previous months. However, when the frequency keeper is at this level of output they are still operating as expected and it should be noted that the number of frequency excursions are one and zero respectively for these months.
    - We are proposing that in subsequent months this measure is shown alongside the percentage of times the frequency keeper is outside its regulation band to see which of these measures provides the best information.
- *HVDC modulation beyond 30MW more than average (July)*
    - The current measure includes periods when the HVDC ramp rate is active as it prepares for the following trading periods. We need to understand the effect of including ramping in the measure to evaluate if the outlier is of concern or not.

Optimal dispatch

The Optimal dispatch tool has shown a fairly constant performance over the July-September quarter. However we observed a reduction in the calculated Optimal dispatch percentage in the previous quarter, particularly in April and May. That was primarily due to the impacts of the COVID lockdown on electricity consumption. During April and May this year, the country was under different Alert levels which imposed significant restrictions on economic and personal activity which changed electricity consumption quite substantially.

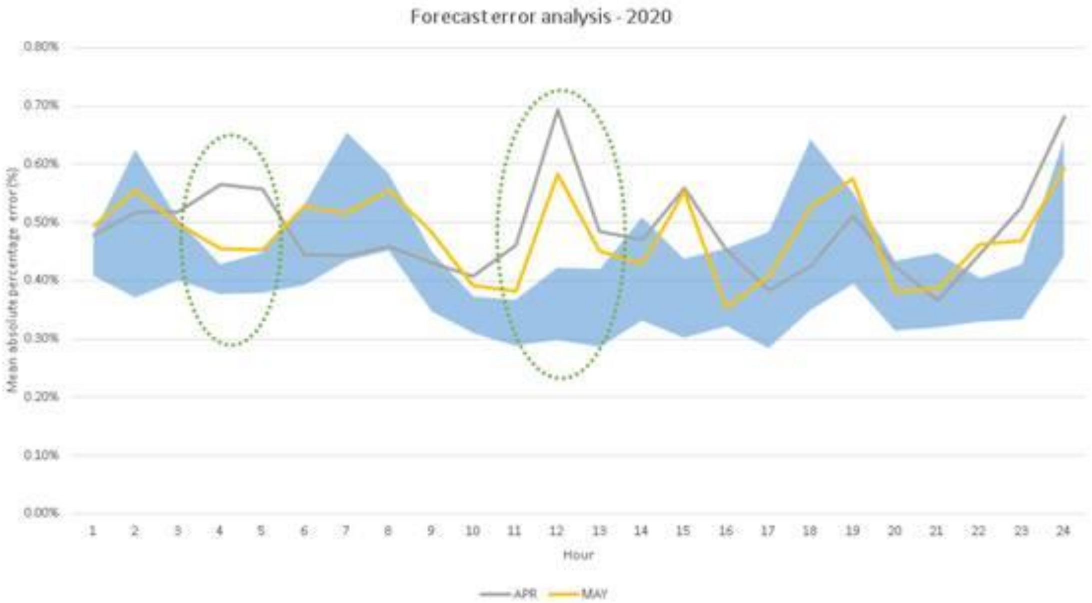


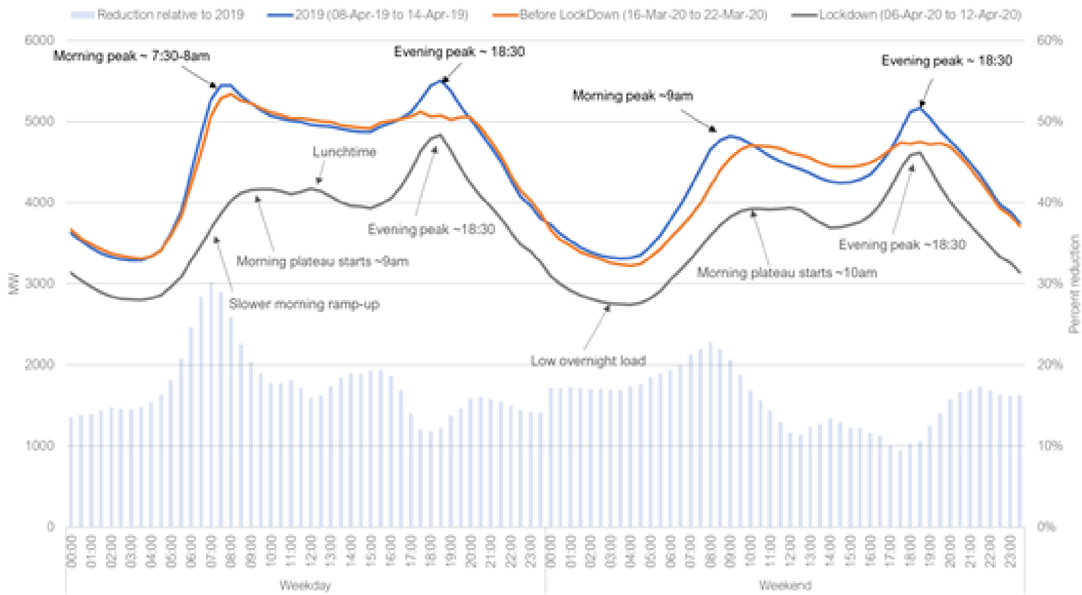
Due to this, we observed larger levels of forecast generation (load + losses) error relative to the level of actual generation. Even as the load reduced in April (due to the lockdown) the forecast error did not reduce by a commensurate amount. This is shown as a reduction in the dispatch load accuracy in April and May this year.



We have analysed the April and May 2020 forecast errors by hour to understand if there was any trend and compared to the other months in 2020. Below is a range of the mean absolute percentage error of the dispatch load and losses from 2020 (excluding April and May) shown in blue. For most months we see an increase in the forecast error over the morning and evening peak periods. However in April and May this year, we see a noticeable increase during midday and during the early morning period (particularly for April 2020). We consider these were due to the very different load shape observed, particularly in April 2020 due to the lockdown period. This was characterised by very low overnight loads and higher midday loads (with most people working from home) as shown in the figure further below.

Since the lockdown has ended and loads returning to normal levels, we have seen an improvement in the forecast accuracy and improvement in the Optimal dispatch metric.





10 Cost-of-services reporting

This will be provided to the Authority at the same time as the publicly disclosed financial information under the Transpower Information Disclosure Determination [2014] NZCC 5, in late-October 2020.

11 Actions taken

The following table contains a full list of actions taken during Q1 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**:	• Delivered a proof of concept for sensitivity schedules; this went live on the Transpower website in early August. • Following the POCP review, our next steps are to progress the suggested tool enhancements and discuss our recommendations with the Authority to enable greater information disclosure by energy market participants. • Delivered the non-functional changes into the market system for the Market System Simplification project in July 2020.
(ii) To comply with the **statutory objective work plan**:	The dispatch accuracy dashboard for energy is included as Appendix B in this report; commentary is provided for the quarter in section 9.1.
(iii) In response to participant responses to any **participant survey**:	**Feedback from the 2019-20 survey** • *Include engagement on nodal pricing and DER*: In our role as system operator, we commissioned an external report to investigate the potential value of DER in a New Zealand context. This report broadly considers the value of DER to the New Zealand Electric Power System, what economic incentives might encourage use of DER and what the current barriers to deployment and transaction costs are. In commissioning the report, our aim is to stimulate a discussion on how the electricity industry and market may need to evolve in order to harness the potential benefits of DER.
(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

In July and August, the hydro lake levels were below average, creating high prices. Because the risk, as shown in the Electricity Risk Curves, was past the peak and declining through to summer, low storage levels did not indicate a risk to security of supply in the short-term. This situation was also supported in July by Genesis announcing an additional 160 MW of generation via a third Rankine unit should market conditions require it.

September saw the largest hydro storage increase of year to date. South Island storage has almost fully recovered from the previous periods, sitting at 97 per cent average for this time of year. North Island hydro storage remains low, but has made significant gains, up 17 per cent of full, but still only 76 per cent of average for time of year. Manapouri continues to operate at its high range and spill water despite sustained generation at high output. Snowpack is healthy (this time of year is usually the peak for snowpack), sitting at 107 per cent of average.

Thermal fuel generation continues to be robust despite the continued issues and an outage at Pohokura (described below). The overall thermal position reflects the greater flexibility developed by thermal generators and soft methanol demand.

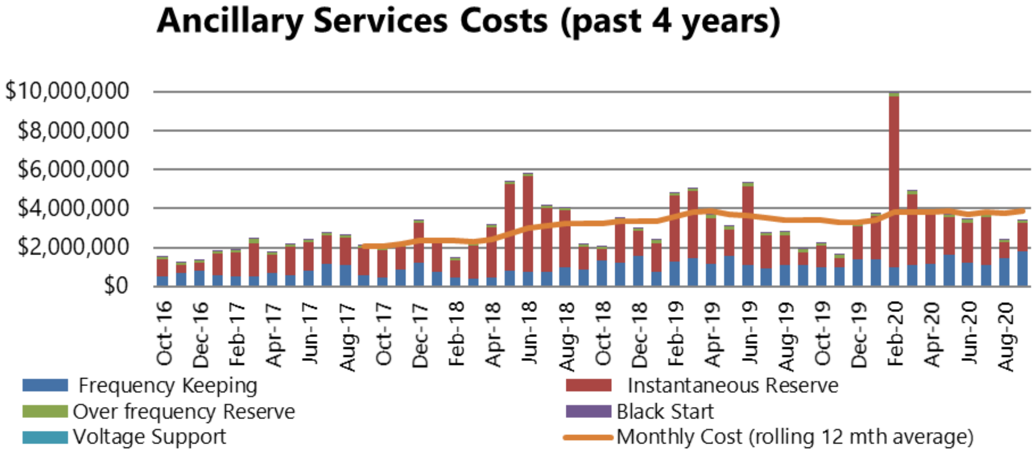
OMV commissioned a compressor at the Pohokura gas field which offset, but did not fully remedy, the recent decline in gas field production. Pohokura daily production is now at 175 TJ/day, up from around 150 TJ/day in mid-August. Further work is underway to address the underlying causes of declining production at Pohokura. The project at the Ahuroa gas storage facility to increase its injection and extraction rates has been completed and lifts output from 45 to 65 TJ a day.

Towards the end of the quarter, Contact's combined cycle plant at Stratford has not been offered into the market – this is in line with Contact's historical generation profile.

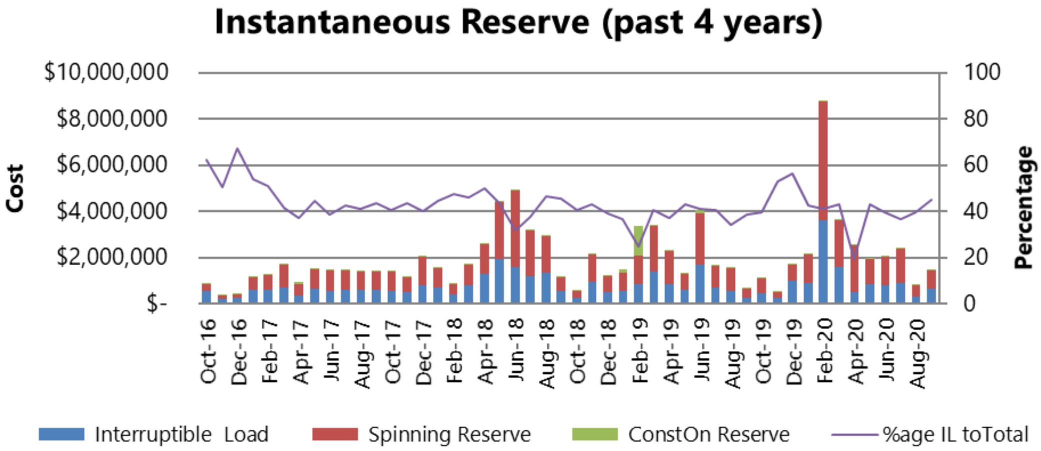
From a security of supply perspective, a closure of Tiwai releases more energy improving our security margins. However, there is an increased risk to the North Island capacity margins should North Island thermal units close before transmission upgrades, to enable South Island surplus to reach the North Island across the winter peaks, are in place. The financial viability of the North Island thermal stations could also be affected by changes to existing contractual agreements between the generators. Given the technology of the larger thermal generating plant is favoured towards operating as baseload due to high start-up costs, the short periods of high spot prices over demand peaks are unlikely to create an incentive for them to remain in the market.

There was a slight decrease in demand in Auckland during the COVID-19 Level 3 period – and a change in the distribution of the load, with delayed morning peaks and slightly increased demand around midday.

13 Ancillary services



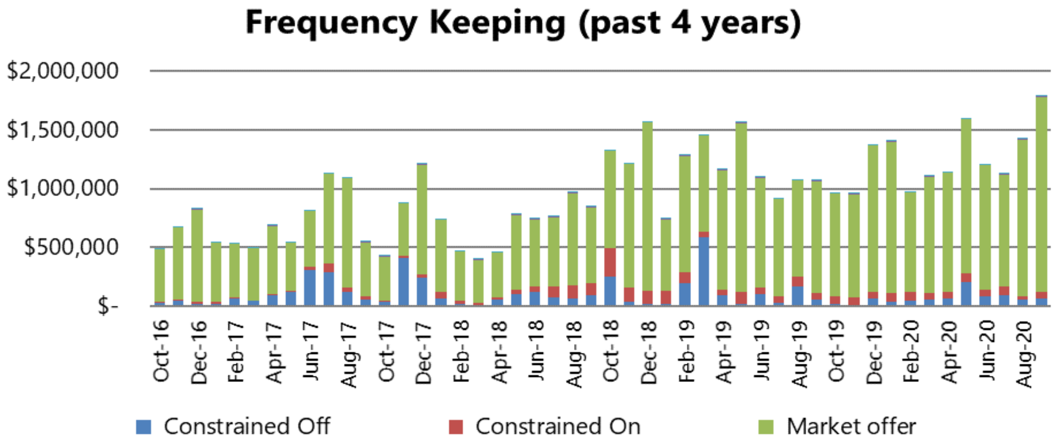
This quarter's ancillary service costs were $9.7 million, which is a 13 per cent decrease compared to Q4's costs of $11.1 million. Over the period there has been a gradual decrease in the instantaneous reserve costs (see explanation below) and a slight increase in frequency costs.



This quarter, the instantaneous reserve costs were $4.7 million, which is a decrease of 28 per cent from the previous quarter ($6.6 million). Interruptible load costs decreased by $276k (13 per cent decrease), spinning reserves decreased by $1.6 million (37 per cent decrease) and constrained on costs increased by $17k (46 per cent increase).

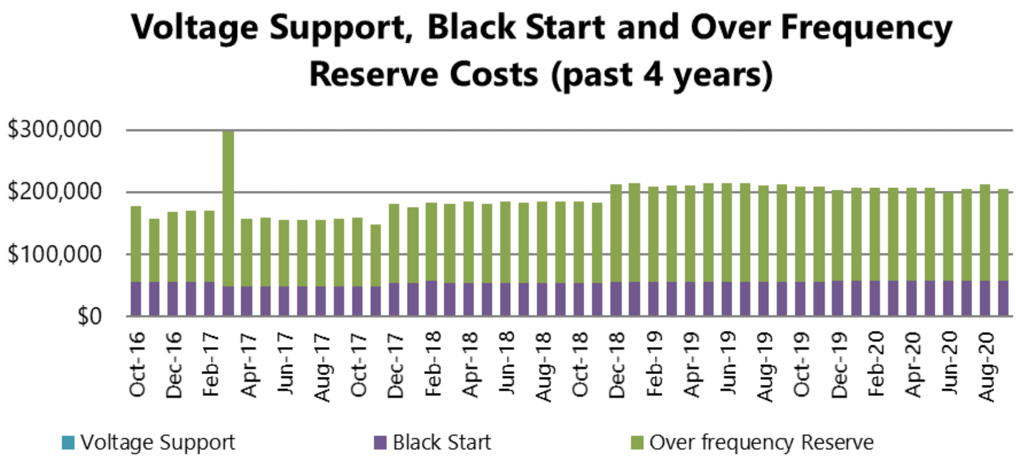
At the beginning of the quarter, in July, there was an increase in costs from the previous month. Over a third of the costs arose from four days of cold weather and subsequent high demand on 1-2 and 27-28 July. By August the costs were reducing, although the quantity of reserves procured over the month was down only slightly, the average price of those reserves more than halved. The prices changed due to lower peak demand and no periods of high reserve cost driven by cold weather and tight supply, as had been seen in July. In September, the costs were relatively low, with fewer reserves procured than in August, but prices for Fast Instantaneous Reserve (FIR) were higher (though not as high as in July).

A general downward trend in instantaneous reserves costs over the quarter is as expected seasonally, with average temperatures rising, and a reduction in the periods of high peak demand seen in winter, that are often responsible for high instantaneous reserves costs.



This quarter the frequency keeping costs were $4.3 million, a 10 per cent increase to the previous quarter's costs of $4.0 million.

The frequency keeping costs in July were a small decrease compared to the previous month. August costs were higher, reflecting both an increasing value put on water in the South Island as hydrology levels declined and a five-day planned outage during which the Tekapo area was islanded, and Tekapo A provided local frequency keeping. The Tekapo outage continued through to September, increasing costs further. Also North Island costs for September (which rose 40 per cent compared to August) were higher towards the end of the month, as a result of increasing value put on water from Lake Taupo. As a comparison, South Island costs increased around 15 per cent between August and September.

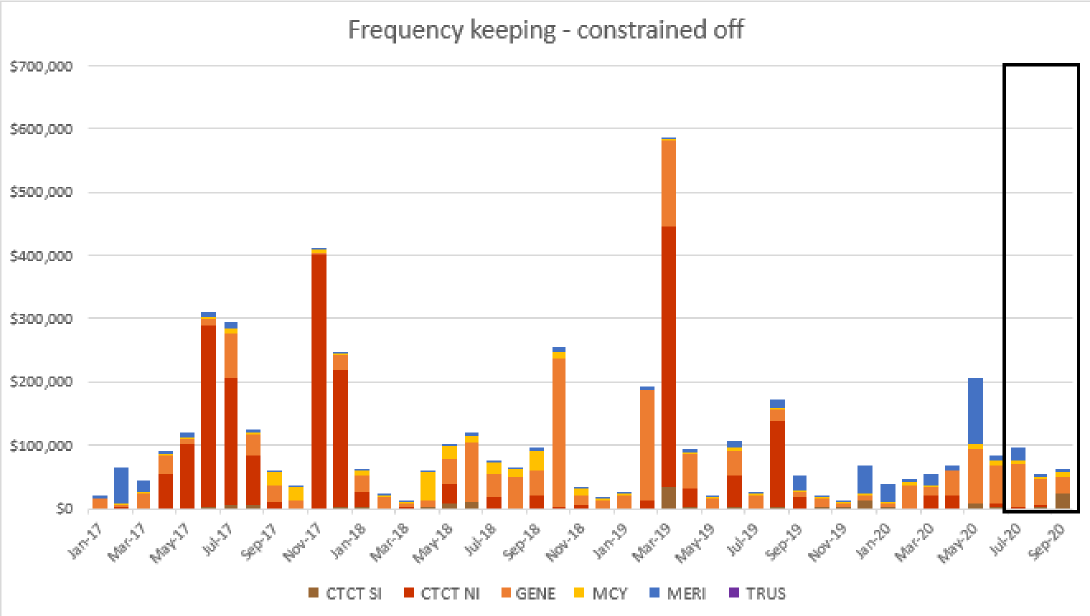


This quarter, July over frequency costs were $147k, August costs were $155k and September costs were $147k, reflecting the availability of generator units at Manapouri. The black start costs were $58k for each of the three months. There are no voltage support costs as we do not currently procure this service.

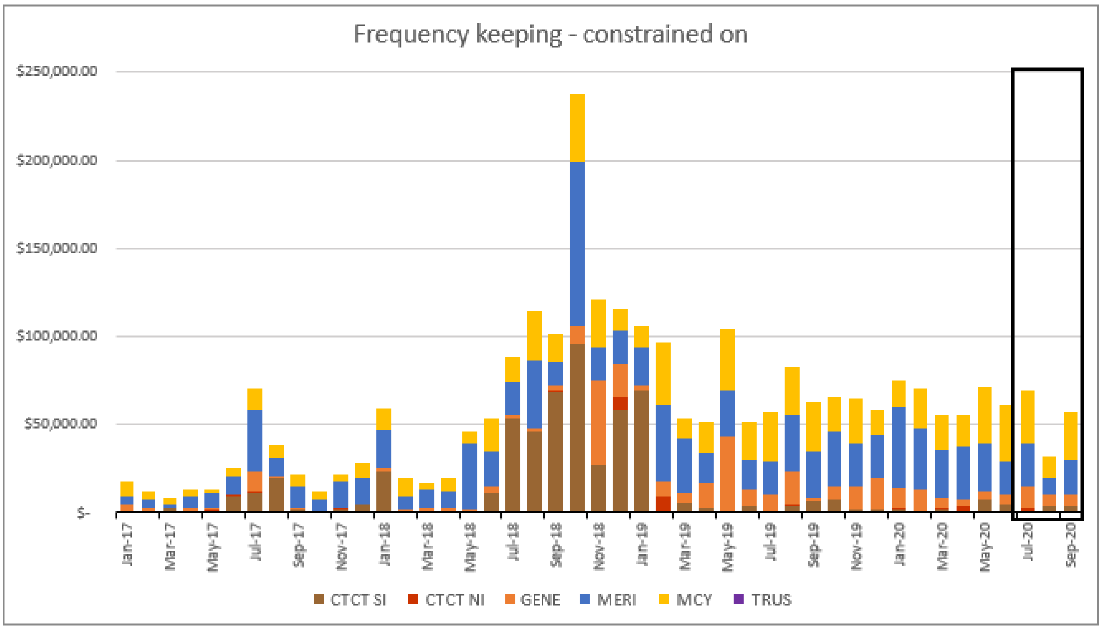
13.1 Constrained on/off costs

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

Frequency Keeping

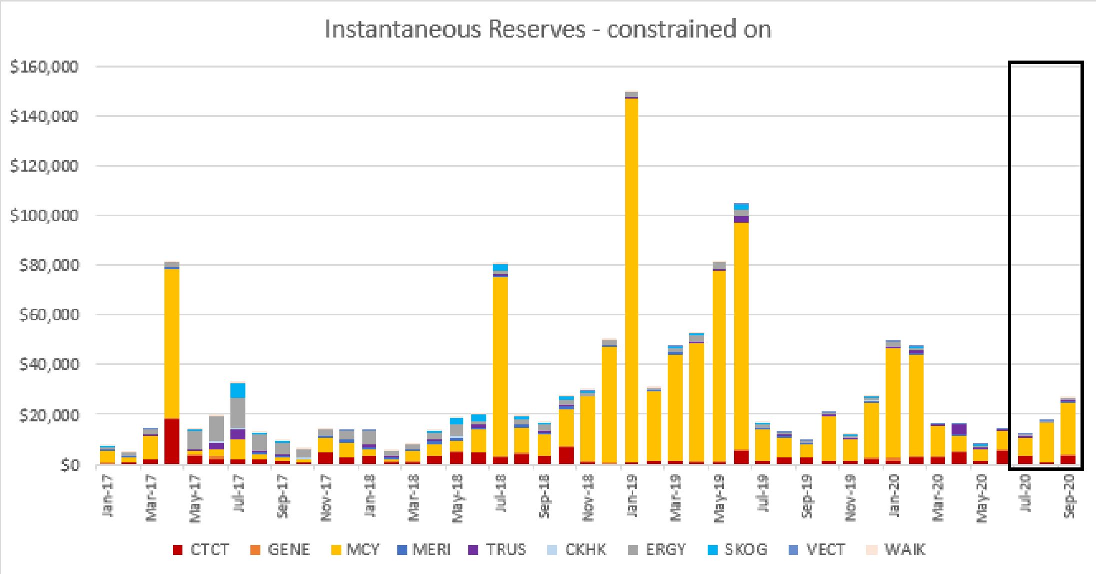


The constrained off costs for Frequency Keeping this quarter were lower than the previous quarter which had reflected the higher price placed on water.



For July and September, the frequency keeping constrained on costs for 2020/21 Q1 were roughly the same as those for 2019/20 Q4. In August, although parties were dispatched as frequency keepers for a similar number of periods as in the other months, the constrained on costs were lower.

Instantaneous Reserves



The instantaneous reserves constrained on costs were slightly higher this this quarter. The costs reflect the need to support the HVDC during northward flow.

14 Commissioning and Testing

Generation testing and commissioning

Ngawha (32 MW geothermal), in Northland, is on track to synchronise and commence commissioning in late-October 2020.

Waipipi (133 MW windfarm), in South Taranaki, is on track for commissioning with first synchronisation scheduled for 16 November 2020. A number of process milestones are still to be completed and could delay meeting this date if not met but there are no visible impediments at this time.

Turitea North (117 MW windfarm), in Manawatu, was initially scheduled to start commissioning in December; it is now likely to be early 2021. Work is also underway to understand the impact of the windfarm on existing harmonic levels in the region as they are already close to reaching standard limits.

The security and market impacts of potentially having the two wind farms commissioning concurrently are being worked through. We have agreed principles for managing this situation and confirmed we will not delay commissioning if high prices result from the concurrencies, intervening only for system security issues.

Several solar PV generation projects also approached the system operator this month to begin discussions around their performance obligations and the commissioning process.

15 Operational and system events

July

There was nothing material to report in July.

August

<u>Opunake loss of supply</u>

There was a three-hour loss of supply to Opunake due to a 33 kV bus and dual transformer tripping.

<u>Contingency planning for circuit fire</u>

We carried out contingency planning for a fire adjacent a double circuit of Henderson-Southdown 1 and Henderson-Otahuhu 1. While this fire was quickly contained, our preparation demonstrated that we could maintain system security had there been a double fault.

<u>Market system outage greater than one hour:</u>

At 19:50 on 8 August, the market system locked up. Dispatch was switched to stand alone dispatch (SAD) at 19:59 and a customer advice notice (CAN) sent out to the industry. The market system was on SAD for over one hour, which operated as required. Our investigation into this issue continues, with our investigation report due to the Authority by 8 November 2020.

September

<u>Cable Joint Fault – Pakuranga-Whakamaru (PAK-WKM 2):</u>

Following planned maintenance to the PAK-WKM circuit, a tripping of a cable section on Thursday 8 September created a significant voltage disturbance on the grid in the Auckland and Northland regions. With the outage likely to be extended to 2-3 months there was concern regarding risk to the remaining PAK-WKM circuit, as it is switched frequently at the request of the system operator for high voltage management purposes. A process has been agreed that enables this practice to continue as an expedient approach to maintaining systems stability at low loads – such as we are starting to see with the warmer weather.

<u>Henderson T1 tripping & consequential demand management investigation:</u>

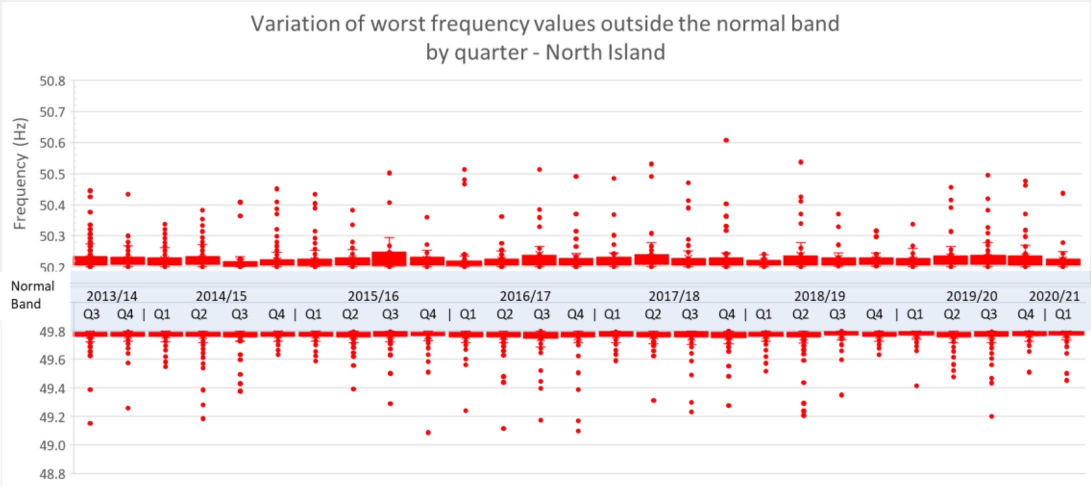
We provided our investigation report into this ‘moderate’ event to the Authority. The tripping of Henderson T1 occurred on 8 June 2020 at 17:50 and resulted in approximately 42 MW of load (23 MW controllable, 19 MW non-controllable) having to be managed by Vector. All non-controllable load was restored by 19:43. The investigation found no breaches of the Code or failures to follow process. A recommendation has been made to change the reporting criteria to only consider the impact of non-controllable load.

16 Frequency fluctuations

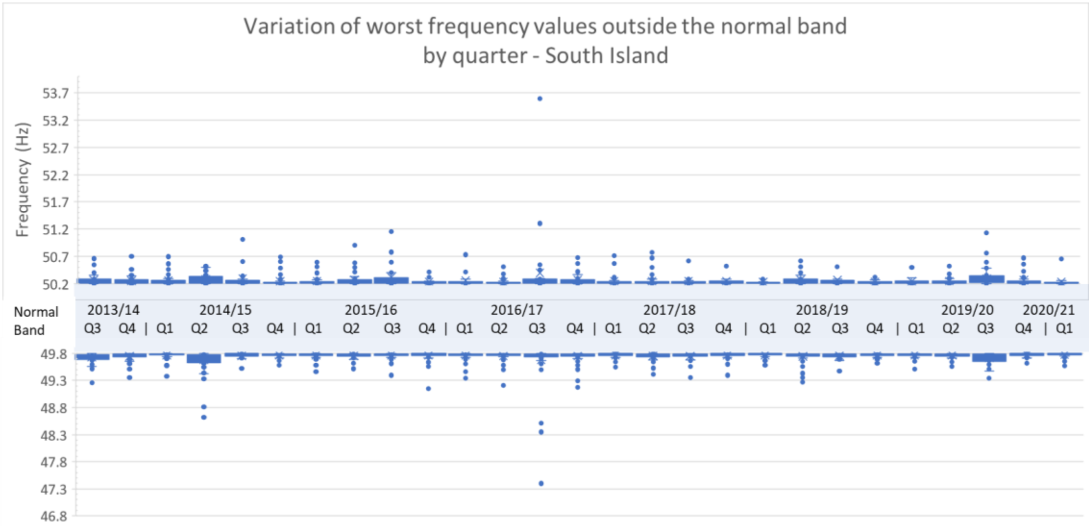
16.1 Maintain frequency in normal band (Frequency value)

The following charts show the distribution of the worst frequency excursion outside the normal band (49.8 to 50.2 Hz) by quarter since July 2014, including the reporting period.

North Island



South Island

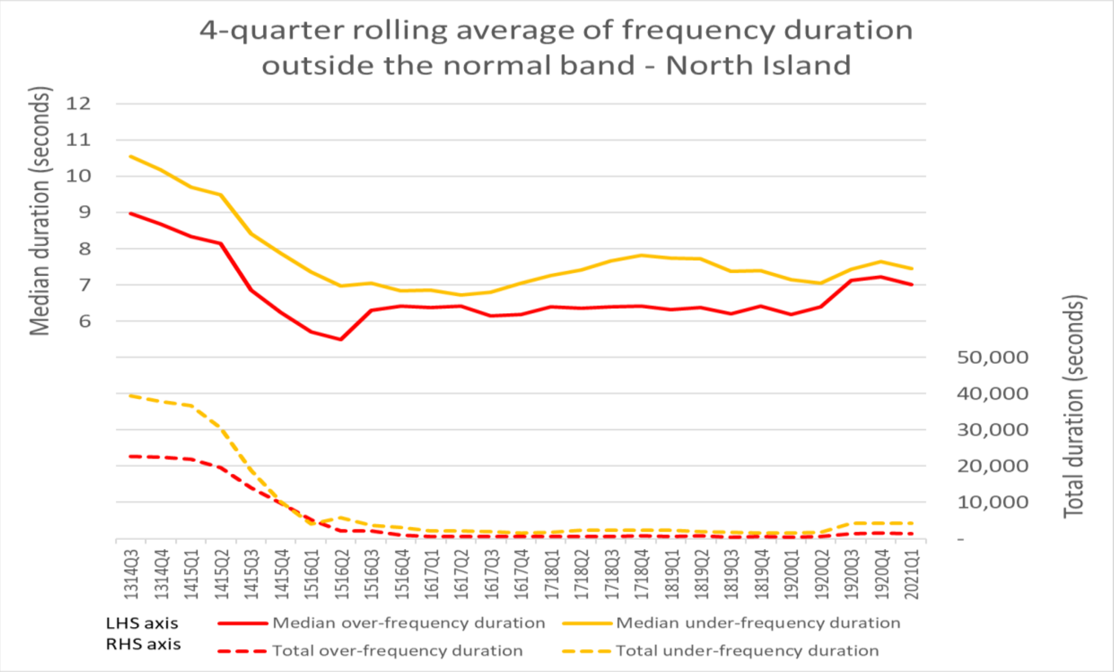


Note: These box and whisker charts show the distribution of data. The “box” represents the distribution of the middle 50% of the data, the “whiskers” indicate variability, and outliers are shown as single data points.

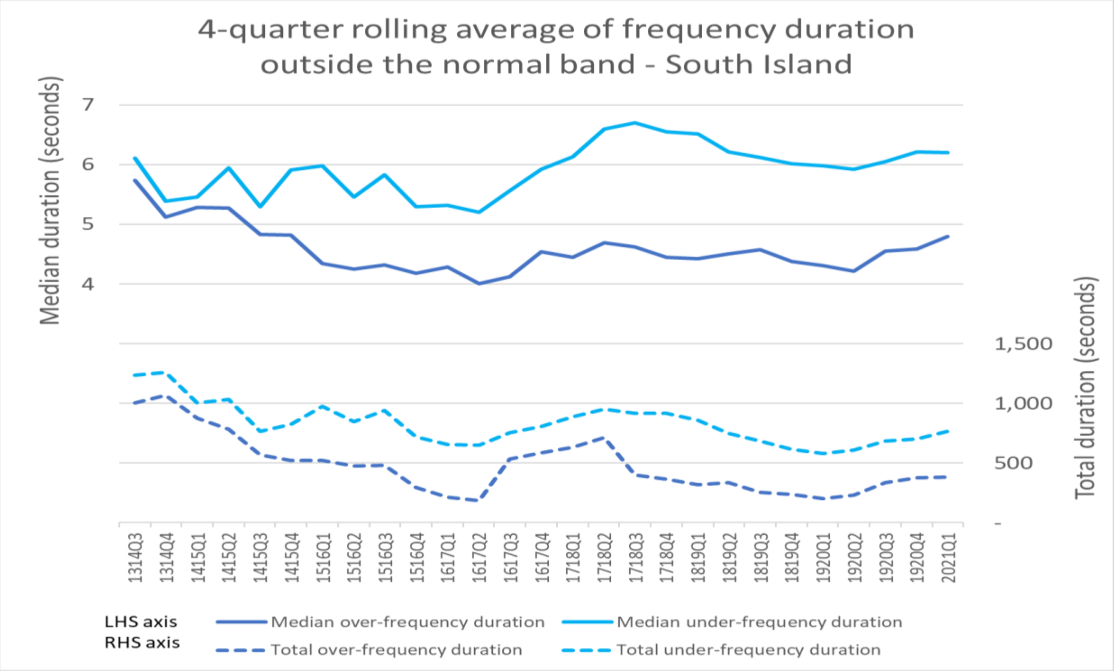
16.2 Recover quickly from a fluctuation (Time)

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



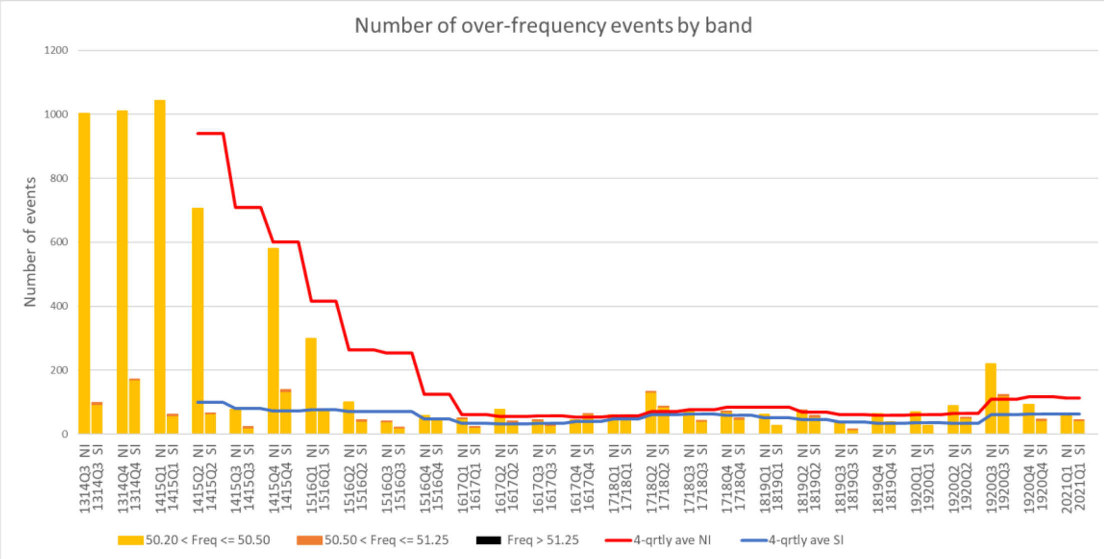
South Island



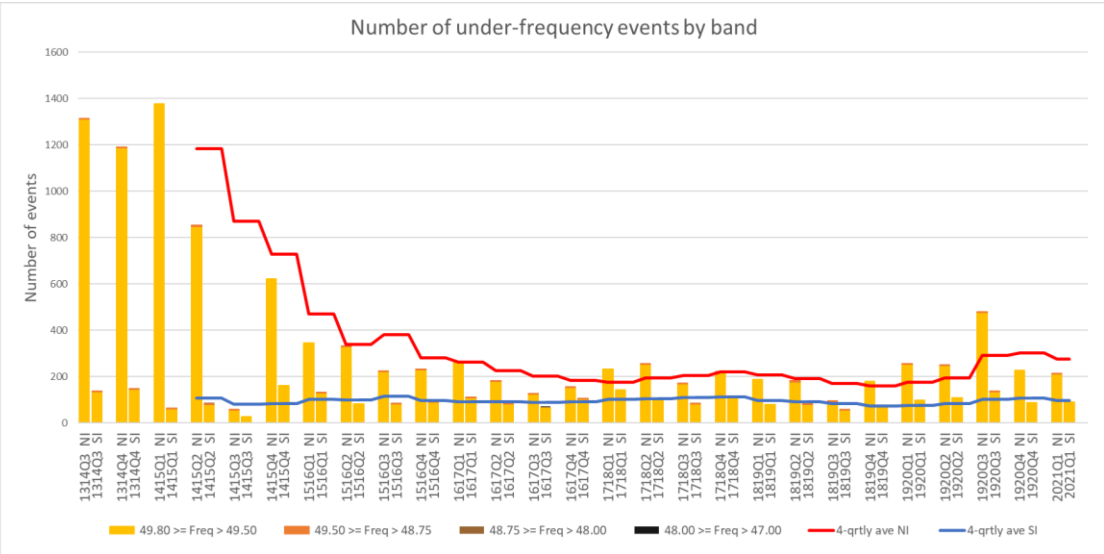
16.3 Manage frequency and limit rate of occurrences during momentary fluctuations (Number)

The following charts show the number of momentary fluctuations outside the frequency normal band, grouped by frequency band, for each quarter since 2014. 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	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20
Demand Allocation Notice	-	-	-	-	-	-	-	-	-	-	-	-
Grid Emergency Notice	1	3	-	-	-	1	-	-	1	-	-	-
Warning Notice	-	-	-	1	-	2	-	-	-	-	-	-
Customer Advice Notice	15	15	14	6	21	14	13	10	13	11	15	9

19 Grid emergencies

The following table shows grid emergencies declared by Transpower as system operator from July to September 2020.

Date	Time	Summary Details	Island
		None	

Appendix A: Discretion

July

Event Date & Time	Event Description
01-Jul-2020 21:05	MKE1101 MKE1 discretion: Test after TGTL tag changed, not dispatched: Last Dispatched MW: 92.5
01-Jul-2020 22:15	JRD1101 JRD0 discretion: Test solve for TGTL trader change. RTD not dispatched. Last Dispatched MW: 49.2
21-Jul-2020 19:50	ROT1101 WHE0 discretion: Suspect protection fault on CB312. Last Dispatched MW: 16

August

Event Date & Time	Event Description
	None

September

Event Date & Time	Event Description
03-Sep-2020 12:09	GLN0332 GLN0 Discretion: Last Dispatched Mw: 47
16-Sep-2020 17:42	MAN2201 MAN0 Discretion: Last Dispatched Mw: 788 Double CCT risk enabled due to lightening in area
25-Sep-2020 0:09	MAN2201 MAN0 Discretion: Short Notice Outage Request CYD_TWZ_1 circuit Last Dispatched Mw: 738
29-Sep-2020 03:38	OKI2201 OKI0 Discretion: Generation tripped. Last Dispatched Mw: 41

Appendix B: Dispatch Accuracy Dashboard

Same quarter in 2019/20

This quarter 2020/21

Dispatch Accuracy Dashboard

			2019 July	August	September	October	November	December	2020 January	February	March	April	May	June	July	August	September
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	550	696	575	489	546	705	550	756	641	498	586	718	791	416	599
Frequency keeper (MW)	Average absolute deviation (MW) from frequency keeper dispatch point. A	NI	6.96	6.71	6.67	6.56	6.63	6.83	7.63	7.01	6.90	6.80	6.87	6.97	7.01	7.06	7.11
		SI	6.37	6.15	6.30	6.00	6.23	6.28	6.49	6.84	6.33	6.64	6.41	6.80	6.51	6.53	6.83
Time error (s)	Average absolute daily time error (s) indicates imbalance between generation and load, a reflection of imperfect dispatch	NI	0.1946	0.2021	0.1737	0.2198	0.2033	0.1996	0.2410	0.2340	0.2455	0.2843	0.2277	0.2768	0.2368	0.2018	0.2064
		SI	0.1999	0.2161	0.1688	0.1989	0.2086	0.2137	0.1967	0.2309	0.2217	0.1923	0.2323	0.2845	0.2507	0.1979	0.1973
	Total number of frequency excursions		2	-	-	1	2	-	1	4	5	1	1	1	1	1	-
FK within 5% of band limit	**% of time frequency keepers spend near to or exceeding their regulation limits indicates the need to redispatch.**	NI	**5.0%**	**4.2%**	**3.7%**	**3.5%**	**3.7%**	**4.0%**	**5.4%**	5.0%	5.8%	3.5%	4.2%	5.1%	4.9%	5.9%	5.7%
		SI	**4.2%**	**3.5%**	**3.1%**	**4.0%**	**3.0%**	**3.3%**	**3.1%**	3.9%	-	2.7%	3.5%	4.3%	4.0%	4.6%	4.8%
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.		11.57%	13.59%	11.32%	10.77%	10.91%	10.46%	**8.37%**	12.79%	10.37%	6.92%	13.90%	9.62%	14.65%	9.83%	9.72%
Constrained on energy- Total	Total Monthly Generation	MWh	3,921,132	4,003,430	3,656,770	3,621,216	3,418,901	3,475,825	**3,501,768**	3,329,074	3,407,184	2,931,637	3,629,018	3,710,599	4,006,808	3,861,813	3,671,507
	Total constrained on - All sources	MWh	36,182	34,394	36,974	25,683	29,286	31,997	**23,641**	28,565	24,912	32,088	26,519	24,247	23,649	26,426	24,579
		% of all generation	**0.92%**	**0.86%**	**1.01%**	**0.71%**	**0.86%**	**0.92%**	**0.68%**	0.86%	0.73%	1.09%	0.73%	0.65%	0.59%	0.68%	0.67%
		$	1,227,521	1,173,614	930,592	534,069	609,542	517,746	**365,863**	468,969	304,255	303,542	491,296	488,575	712,042	379,543	503,196
Constrained on energy ($) - Frequency keeping	Total constrained on $ due to frequency keeping (within band is attributable to SO)	$	57,023	82,481	63,352	65,890	64,505	58,343	**75,173**	70,074	52,492	55,553	71,518	61,301	69,715	31,973	57,712
Optimal Dispatch (%)	Compares the average impact of a perfect foresight case against dispatch solutions. Indicates impact of wind offer, load forecast and PSD accuracy.	%	93.68%	93.10%	94.11%	91.59%	91.34%	88.30%	**93.35%**	90.62%	91.74%	87.29%	90.77%	92.78%	93.19%	94.38%	94.34%
Dispatch load accuracy error (%)	Average absolute difference between forecast generation (load plus losses, including PSD) and actual generation relative to the average actual generation	%	99.61%	99.60%	99.62%	99.50%	99.48%	99.51%	**99.62%**	99.54%	99.57%	99.52%	99.52%	99.56%	99.59%	99.62%	99.62%
Wind offer error (%)	Average absolute difference between persistence wind offer (based on 5mins prior) and the actual wind output relative to the average wind output	%	97.46%	97.55%	97.89%	97.71%	97.96%	97.71%	**97.93%**	97.82%	97.50%	97.81%	97.36%	97.81%	97.82%	97.85%	98.14%
	Metric calculation rows	FK within 5%							3	2	1	3	3	2	2	1	1
		Constrained							3	3	3	3	3	3	3	3	3
		Optimal							3	3	3	2	3	3	3	3	3
Dispatch accuracy %	**Metric out of 3 (3 is best possible result)**								3.0	2.7	2.3	2.7	3.0	2.7	2.7	2.3	2.3

Scale for measures: Variation of up to 10% from standard ... up to 20% from standard ... up to 40% from standard ... over 50% 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 within 5% 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 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. During 2020/21 we will monitor how well this metric represents performance, with the purpose of baselining a target and metric as part of the 2021/22 performance metrics.

Measures selected

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

- When operator discretion is required to ensure system security when constraints bind at 100%
- 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 – we will evaluate this during the next quarter.

Variation of up to 10% from standard	... up to 20% from standard	... up to 40% from standard	... over 50% from standard

Metric

The measures that contribute towards the metric are:

- FK within 5% of band limit
- 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 within 5% of band limit and Constrained on energy - Total; and Optimal Dispatch (%). These are shown in the tables below:

Score	Outcome	Measure is:
3	Good performance	Up to 110% of the standard
2	OK performance	From 110% to 120% of the standard
1	Weak performance	120% or greater of the standard

Score	Outcome	Optimal dispatch is:
3	Good performance	Over 90%
2	OK performance	Between 85 and 90%
1	Weak performance	Less than 85%

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

Example:

			Month	Standard
FK within 5% of band limit	% of time frequency keepers spend near to or exceeding their regulation limits indicates the need to redispatch.	NI	4.9%	4.3%
		SI	4.0%	3.5%
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 within 5%	2	
		Constrained	3	
		Optimal	3	
Dispatch accuracy %	Metric out of 3 (3 is best possible result)		2.7	

FK within 5% of band limit = (4.9+ 4.0)/(4.3+3.5) = 114% -> 2

Constrained on energy- Total = 0.59/0.8 = 74% -> 3

Optimal Dispatch (%) = 93.20% -> 3

Overall metric = (2+3+3)/3 = **2.7**