QUARTERLY SYSTEM OPERATOR AND SYSTEM PERFORMANCE REPORT

FOR THE ELECTRICITY AUTHORITY

Transpower New Zealand Limited
October to December 2018

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 Q2 (October to December) 2018, 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 regards 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 contains highlights of the successful management of significant events and operational issues by the system operator. It provides an update for this quarter, any new initiatives that we have instigated, the current investigations we are progressing and areas of business that are under review . The remainder of the report provides supporting detail in two sections:

- System operator performance, and
- System performance.

Update (October to December 2018)

Security of Supply –

Current situation

The unforeseen extended outage of the offshore Pohokura gas field for valve repairs resulted in a focus on security of supply this quarter. The outage occurred at a time that there were scheduled maintenance outages of the larger thermal plants at Stratford and Huntly, and coincided with the annual grid owner HVDC bipole outage. These factors, coincident with lower than average hydro storage at the start of the quarter, meant that supply was tight in October. Significant inflows in the South Island in November enabled higher hydro generation to support demand while gas was restricted. Moderate inflows continued in December along with the return of Pohokura to full production. These factors, plus the demand drop as we entered the Christmas/New Year period, meant that by the end of the quarter national storage had returned to the historical average for this time of year.

The impact of the outages was evident in the market as high prices in October; average price at Haywards was $290/MWh. Prices reduced during the quarter but remained at elevated levels to 'normal'. By December prices reduced to an average price of $102/MWh at Haywards.

We engaged with industry participants to aid our analysis of this situation during this period and based on information available concluded that there was no immediate risk to security of supply caused by the Pohokura outage.

Preparedness

We have completed our review of the Security of Supply Forecasting and Information Policy, and have a draft version out for consultation. This consultation is being carried out in parallel with the Authority's review of Part 9 of the Code. We are proactively engaging with stakeholders to ensure the consultation information is well understood and valuable submissions are received.

We have begun work on the 2019 Annual Security of Supply Assessment (ASA). This year we have put an emphasis on two key issues: future electricity demand and future gas-fired thermal generation. We expect to publish a draft report to interested parties, including Authority staff, in early February.

System Security Forecast (SSF) - The System Security Forecast was published to the industry in November, confirming that we are able to continue to operate and maintain a secure, reliable power system over the next three years.

Major electrical storms – There were a number of major electrical storms in December, the risks of which led to proactive real time management to mitigate potential double contingency events. Severe lightning storms on 14 December triggered a tripping of the Huntly_Stratford circuit, resulting in a loss of generation from Huntly unit 4 (North Island frequency dropped to 49.21 Hz). Refer to "Actions under review" section below.

Black start test - Working with Genesis Energy, the Systems Operation team planned and successfully carried out a black start test of the Tokaanu Power Station on Saturday 6 October.

Real Time Pricing (RTP) – During this quarter the first RTP Industry Engagement Group met (Monday 5 November). On 19 December, the Authority Board signalled its support for the project but requested further clarification of aspects on the reserve shortfall methodology, resulting in a delay to the consultation and a need to assess the impact on the overall project timeline.

Dispatch Service Enhancement (DSE) - A DSE industry workshop with over 30 dispatch participants was held on 30 November. The team is preparing for further updates to industry via workshops scheduled for 29 January and early March 2019.

People news - Jodine Lee has been appointed to the permanent position of Project and Stakeholder Manager in the SO Market and Business division.

New initiatives

National Market for Instantaneous Reserves (NMIR) refinements - Transpower has identified further refinements to the NMIR design to deliver additional operational and market benefits. We are currently consulting with the industry and changes are planned to come into effect in late March 2019.

Operation Managers industry forum - This forum was an initiative of our Operations Managers to provide an opportunity to communicate to Generation Operation Managers in the industry (as well as representatives from the Electricity Authority) some of the key focus areas that came out of the South Island AUFLS event (2 March 2017) in a positive and proactive manner.

Review of NEM separation August 2018 – We are looking at the report into the events in Australia and identifying what the implications are, what is different in New Zealand or a similar risk, plus the actions we should consider. We will provide a summary of our review to the June SOC meeting.

Current investigations

Gas restrictions and low North Island system inertia alerts - During the gas restrictions in late 2018 we saw two instances where a HVDC Extended Contingent Event (ECE) violation occurred in real time operation as a result of the power system configuration at the time. The violation signalled lower than normal inertia in the North Island and a high rate of change in frequency (RoCoF) being calculated. The RoCoF was so high that Interruptible Load as modelled in our tools would not be able to act fast enough to arrest the frequency fall. At the time the co-ordinators addressed the issues by procuring more reserves in the North Island. We are using this situation as a good case study for us to start considering how we manage a lower inertia system. We will share our thinking in this area with the Authority as it develops.

Independent review of HVDC cable setting - An independent review into the HVDC current limit setting error, which was self-reported to the Authority by Transpower on 12 April 2018, is being undertaken by Erik Westergaard of Advisian and is nearing completion. The scope includes reviewing the two internal investigations undertaken by Transpower as well as identifying whether there were any wider systemic issues to this event or other recent major events. We will share the findings of this review and our response in due course.

Areas under review

Annual HVDC scheduled maintenance outage – On 22 November, Transpower's grid owner annual HVDC outage began as planned. Not long after the outage commenced, insufficient reserves were made available to cover an event on the system during the 7:30am and 8:00am trading periods. We issued a warning notice seeking a response from participants to either recall outages, reduce demand or increase reserves offers. Transpower as the grid owner responded to the notice by recalling its the pole 2 outage. Transpower replanned work, restarted the outage again after these periods on 22 November and subsequently cancelled the last two days of the pole 3 outage. The assessments of the outage up to real time indicated the outage would be tight but manageable. However, higher demand and other factors resulted in operational security issues and the warning notice. The change in work programme by the grid owner and cancellation of the last days of the outage was to avoid the impact of further recall requests.

We have responded to Official Information Act (OIA) requests from Haast Energy Trading and the Major Electricity Users' Group (MEUG) to provide information relating to the decisions to return the HVDC for the peak periods in the first few days of the outage and subsequently complete the outage early. We are working with the Authority to provide relevant information on our assessments prior to the outage as requested. We recognise that this was a sensitive, high-profile outage and an unusual situation. We are carrying out our own review with a view to identifying lessons learned regarding communication, assessments and processes when there are future tight outages.

Under-frequency Event (UFE): Huntly unit 4 tripping – Investigations are underway to look at the wider events and circumstances, reviewing if the risk scenario could have been, or was, foreseen and any process gaps or failures that need to be rectified.

RMT modelling issue – We have recently identified that, subsequent to the RMT audit in January 2018, incorrect values have been applied to Whirinaki generation due to an inadvertent change to an input to RMT. We are currently testing a solution to the issue which we will put into production following the software change freeze over the Christmas/New Year period. We are also looking at ways to stop this problem happening again.

South Island AUFLS event (2 March 2017) - Of the original six actions and the seven actions added following the completion of the report into the event, ten have been completed. There are three that remain as outstanding which we are continuing to work on.

The Authority has referred Transpower to the industry's rulings panel for its role in the event. In retrospect, we recognise we should have identified potential breaches earlier.

System operator performance

1 Compliance

October

We reported three breaches in October; two breaches of the Code and one of the Security of Supply Forecasting and Information Policy (SOSFIP).

These breaches related to:

- A manual error in real-time with incorrectly entered constraint parameters.
- A Non-Response Long Schedule failing to solve and publish. This is similar to some events in May 2018. A solution has now been identified and put in place.
- An interpretation of how to treat the modelling of contingent hydro storage under the SOSFIP resulted in hydro risk curves being inaccurate.

November

There were no breaches reported in November.

December

There were no breaches reported in December.

Refer to Appendix A for instances where the system operator has applied discretion under 13.70 of the Code.

1.1 Update on South Island AUFLS event (2 March 2017)

Of the original six actions, and the seven actions added following the completion of the report into the event, ten have been completed. There are three that remain as outstanding which we are continuing to work on as follows:

- **Action 7. Review procedures across Transpower regarding handover of tools and systems to ensure the tools and systems are able to be effectively operationalised (Due Dec 2018)**

  Update: Action 7 missed its deadline. A process solution is nearing completion and its suitability is being tested for application across Transpower. The Operations, Process and Technology Improvement (OPTI) Team has revised its structure to ensure the effective delivery of its functions across the entire business. This includes focus on how tools and systems are operationalised. This action is now aiming for completion by June 2019.

- **Action 12. Identify, review and address performance of risk management controls, specifically focused on high impact low probability event interactions (Due Dec 2018)**

Update: Action 12 missed its deadline. This action relates to our risk management and as part of the action an enterprise level review of our risk management framework was proposed. This review is scheduled for June 2019.

- **Action 13. Review Transpower's processes for reporting of major power system events, compliance breaches and material failures by Transpower to comply with its own standards and procedures (Due Dec 2018)**

  Update: Action 13 missed its deadline. Agreement is still being sought from the Electricity Authority on the proposed process. In the interim the proposed process will be applied if there is a major event.

Refer to Appendix B for a detailed update of the actions at 31 December 2018.

2 Market design and system 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.

Efficient Procurement of Extended Reserves

The Authority has advised that TAS 79 will remain on hold until further notice; they will be in touch when the Authority is ready to re-engage.

Real Time Pricing (RTP)

The Authority Board met on 19 December to consider draft documentation for industry consultation on the remaining elements of real time pricing. The Board signalled its support for the change but requested further clarification of aspects on the reserve shortfall methodology. Approval to release the consultation papers was deferred from January to February 2019. Transpower is working closely with the Authority to provide this clarification and assess impacts of the delay on the overall project timeline.

During this quarter the first RTP Industry Engagement Group met (Monday 5 November). The purpose was to enable the System Operator and the Authority facilitate a detailed discussion on various aspects of the RTP programme of work and receive feedback. The workshop provided positive engagement with a targeted group of industry representatives and has established a good level of understanding on the "pricing CE IR deficits" component of the design (including Code). It enabled the project team to finalise all aspects of the design prior to the presentation to the Authority December Board.

Dispatch Service Enhancement (DSE)

A DSE industry workshop with dispatch participants was held on 30 November. Over 30 participants, and representatives from the Authority, attended. The workshop generated good discussion around the technical integration of the two dispatch solutions and the transition process planned by the project.

Work continues on refining the design for Dispatch Service Enhancements based on this industry feedback. The team is preparing for further updates to industry via workshops scheduled for 29 January and early March 2019.

Wind Offer Arrangements

The project was approved by the Authority Board on 7 November 2018 and is on track to go live on 1 September 2019.

Work on the delivery phase is now well underway. The project team is focussed on the definition of solution requirements and establishing joint project governance with the Authority.

Situational Intelligence

General Managers approved the Request For Proposal evaluation report in December. Reference checks and confirmation of the preferred vendor are on track for completion in January. Completion of the delivery business case is on track for end February 2019.

National Market for Instantaneous Reserves (NMIR) refinements

NMIR was introduced in November 2016 delivering significant market benefits for New Zealand. Analysing subsequent NMIR performance data and incorporating input from operators and Wholesale Electricity Market participants has allowed Transpower to identify further refinements to the NMIR design to deliver additional operational and market benefits. The refined NMIR design proposes to modify reserve sharing constraints. The changes aim to:

- increase predictability of inter-island price separation and dispatch by reducing HVDC oscillations
- reduce the amount of reserves required to maintain system security.

We are currently consulting with the industry by requesting comments on the design. Closing date for comments is 31 January 2019. Changes are planned to come into effect in late March 2019

Independent review of HVDC cable setting

An independent review into the HVDC current limit setting error, which was self-reported to the Authority by Transpower on 12 April 2018, is being undertaken by Erik Westergaard of Advisian and is nearing completion. The scope includes reviewing the two internal investigations undertaken by Transpower as well as identifying whether there were any wider systemic issues contributing to this event or other recent major events. We will share the findings of this review and our response in due course.

3 Power systems and outage planning updates

System Security Forecast (SSF)

The System Security Forecast was published to the industry in November, incorporating several improvements based on industry feedback such as consideration of a dry winter. The SSF has confirmed that we are able to continue to operate and maintain a secure, reliable power system over the next three years. We found that several existing transmission constraints have been or will be removed over the period due to investment in the power system. Some new transmission constraints were also identified but are generally limited to smaller regional issues associated with changing demand or grid investments and can be managed using the same types of operational measures we use today.

Gas restrictions and low North Island system inertia alerts

During the gas restrictions in late 2018 we saw two instances where a HVDC Extended Contingent Event (ECE) violation occurred in real time operation as a result of the power system configuration at the time. The violation occurred at a time when there were a number of thermal generation outages, high north HVDC flow and low North Island load. It signalled lower than normal inertia in the North Island and a high rate of change in frequency (RoCoF) being calculated. The RoCoF was so high that Interruptible Load (IL) as modelled in our tools would not be able to act fast enough to arrest the frequency fall. At the time, the co-ordinators assessed the issues and adjusted the HVDC modulation risk in order to clear the violation by procuring more reserves in the North Island.

Some changes to the modelling of IL are being considered at present in order to better reflect the actual tripping times rather than the theoretical 1 second. This is reliant on good information being available from IL suppliers.

The above violations experienced are a good case study for us to start considering how we manage a lower inertia system where the RoCoF will start to increase beyond what we have traditionally experienced in New Zealand (prior to the retirement of large spinning thermal generation and an increase in renewable inverter-based generation). We will share our thinking in this area with the Authority as it develops.

Review of NEM separation August 2018

In light of the final operating incident report into the Queensland and South Australia system separation on 25 August 2018, we are considering the event in the New Zealand context. We are identifying what the implications are, what is different in New Zealand or a similar risk, plus the actions we should consider. We will provide a summary of our review to the June SOC meeting.

4 Performance metrics

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

Our customers are informed and satisfied		Annual Target	Actual to Date
Improved annual participant survey result		80%	Not currently available
Improved annual participant survey result response rate		25%	Not currently available
On-time special event preliminary reports		90% ≤ 10 business days	No projects to date
Industry leadership and insights	Edge technology report	≥ 1	0
	Publicly available market insights	≥ 8	7

We maintain Code compliance and meet our SOSPA obligations		
Market breaches remain below threshold	≤ 3 @ ≥ $45k	0
Breaches creating a security risk remain below threshold/within acceptable range	≤3	0
On-time Code and SOSPA deliverables	100% (47)	100% (16)

We deliver projects successfully			
Improved project delivery	Service Maintenance projects (**Note 1**)	≥ 60% achieved for approved time/budget	33%
	Market Design and Service Enhancement projects	≥ 60% achieved for approved time/budget	None completed
Accurate capital planning		≥ 50%	50%

We are committed to optimal real time operation		
Sustained infeasibility resolution	100% ≤ 2 business days	100%
	80% ≤ 1 business day	99%
High spring washer resolution	100% ≤ Code obligations	None to date
	80% ≤ 1 business day	None to date

Our tools are fit for purpose		
Improved capability functional fit assessment score	74.74%	Not currently available
Improved technical quality assessment score	50.60%	Not currently available
Sustained SCADA availability	99.90%	99.99%
Maintained timeliness of schedule publication	99%	99.99%

Note 1 – This figure was incorrectly reported against the Market Design and Service Enhancement projects in the Q1 report (and vice versa)

5 Actions taken

The following table contains a full list of actions taken during Q2 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**:	• As part of Transpower's efficiency programme: – Agreed the revised operational control integration plan – Progressed the various technology, process and people changes as per the schedule • Prepared the draft cost-of-services reporting to be presented to the Authority in Q3 • Consulted on the draft outage planning policy within the last quarter. It will be in place in the January-March 2019 quarter. • Developed a working draft of an internal strategy for security of supply. Current work is focussed on translating that strategy into tangible actions. • Reviewed the Security of Supply Forecasting and Information Policy, including treatment of contingent storage, and published to the industry. • Engaged an external third party to action the recommendations from the review of role impartiality between Transpower's grid owner and system operator roles. These are planned for completion in March 2019. • Progressed actions resulting from the review of the South Island AUFLS event (2 March 2017), completing 10 of the 13 actions • Included an additional step to validate the thermal fuel consumptions in the HRC modelling in light of known constraints to fuel supplies.
(ii) To comply with the **statutory objective work plan**:	**Review of the Security of Supply Forecasting and Information Policy (SOSFIP)** • Completed the review and the draft SOSFIP went out for consultation in mid-December. Closing date for comments is 4 February 2019
(iii) In response to participant responses to any **participant survey**:	**Areas of growth identified in the May 2018 survey** • *Communications around operations* – Communicated NMIR refinements to the industry via a CAN, responded to an increased number of participant enquiries, held a SOSFIP briefing in December and will hold another in January during the period of the consultation • *Promotion and growth of education and information provision* – Looking at ways to build upon current Market Insights publications by considering ways to provide more real time information
(iv) To comply with any **remedial plan** agreed by the parties under SOSPA 14.1	N/A – No remedial plan in place.

6 Cost-of-services reporting

The feasibility study into implementing annual cost-of-services reporting to the Authority is required in financial year 2 (SOSPA 12.6). This was completed in September 2017. We will present the draft version of the reporting to the Authority in Q3 report (period ending March 2019).

7 Technical advisory hours and services

The following table provides the technical advisory hours for Q2 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 79 – Efficient Procurement of Extended Reserve: Technical Requirements Schedule Review Expanded Scope and other support	Complete	30.00
TAS SOW 81 – Wind Offer Arrangements	Complete	33.75
TAS SOW 82 – Real Time Pricing	In progress	347.75
TAS SOW 83 - Provide ROM for system changes to support removal of constrained on payments for ramp-constrained generation	In progress	32.00
Total hours		**443.50**

8 Separation of Transpower roles

Since the creation of the Operations division and implementation of Transpower-wide training on role impartiality and conflict of interest, we have had a number of issues raised to the register. These issues are being handled in accordance with Transpower's policy for managing conflicts of interest.

One new practice that has been recently introduced is that Transpower has included a presentation by the compliance manager as part of the induction to new managers, both internal and external, specific to training on role impartiality. This sits alongside online training modules that all staff already are required to undertake.

There was one new issue raised in the conflict of interest register in December, relating to actions taken during the HVDC outage at the end of November.

A summary of the open items raised on the conflict of interest register is set out below:

- System operator staff involvement with grid owner project
- Outage planning policy (currently being consulted with industry)
- Ensuring consistent information provided for outage information
- Management of actions from role impartiality review
- Actions during HVDC outage

System performance

9 Operational and system events

October

Operation Managers forum

On 14 October, the Systems Operator Operation Managers hosted an industry forum for Generation Operation Managers from Meridian, Contact Energy, Mercury, Genesis, Trustpower and Nova as well as representatives from the Electricity Authority. The forum was an initiative of our Operations Managers to provide an opportunity to communicate some of the key focus areas that came out of the South Island AUFLS event (2 March 2017) in a positive and proactive manner. The forum was well received, and we plan to make similar forums a regular event – annually or more frequently if there is sufficient appropriate content for there to be interest.

Black Start test the Tokaanu Power Station

Working with Genesis Energy, the Systems Operation team planned and successfully carried out a black start test of the Tokaanu Power Station on Saturday 6 October. A co-ordinator and power systems engineers travelled to the site to be on location over the event to liaise with the control centre throughout the test and evaluate black start performance.

November

HVDC scheduled maintenance outage

This year's annual HVDC bipole outage for scheduled maintenance was planned at its usual time in November. The outage was signalled to the market by the grid owner in November 2017, which the system operator discussed with customers at the start of this year as part of the Annual Outage Plan. The system operator continued to assess the security implications of this outage, as well as all other outages both by Transpower and other asset owners.

On the day prior to the outage, the system operator's review of North Island generation offers; demand forecasts; and pre-dispatch schedules for 22 and 23 November indicated that the situation was manageable but tight, given the system conditions.

On the first day of the outage (22 November), the system operator identified that for the coming morning peak there would be a security violation with insufficient reserves available to cover an event during the 7.30am and 8.00am trading periods. As such, the system operator followed the process to issue a warning notice (WRN) to the market to seek responses from participants to alleviate the security violation.

In response the grid owner assessed the recall time for the outage to be 1 hour and responded to the WRN by offering Pole 2 back into service on Thursday morning from 7.30am to 9.00am to cover the morning peak. The grid owner removed Pole 2

out of service again at 9.00am and work was carried out on Pole 2 during the day, ending at 7.00pm. The outage recommenced at 9:00am the next day to avoid security issues and a potential recall as had happened the previous day.

The grid owner's work proceeded with the full bi-pole outage on Saturday and Sunday. There were no security issues for the system operator with lower weekend electricity demand.

On Sunday morning, the grid owner sought an update on forecast system conditions from the system operator for Monday and Tuesday as their ability to respond to a short recall of the asset was limited. Based on the information provided, the grid owner decided to attempt to complete all critical Pole 3 work by late on Sunday, and the updated offer of Pole 3 was communicated to the market late on Sunday afternoon when the grid owner was able to confirm all critical work could be completed by Sunday.

The HVDC Bipole was fully available and in service on Monday and Tuesday. We expect the grid owner to lodge another one or two-day weekend outage of Pole 3 over the coming months, required to complete the less critical maintenance that was deferred. The outage will be notified to the industry through POCP as soon as a date is confirmed.

We have responded to Official Information Act (OIA) requests from Haast Energy Trading and the Major Electricity Users' Group (MEUG) to provide information relating to the decisions to return the HVDC for the peak periods in the first few days of the outage and subsequently complete the outage early. We are working with the Authority to provide relevant information on our assessments prior to the outage as requested. We recognise that this was a sensitive, high-profile outage and an unusual situation. We are carrying out our own review with a view to identifying lessons learned regarding communication, assessments and processes when there are future tight outages.

Other events

A series of factors in late November combined to create high voltage risks across the 220kV and 110kV network in the top of the South Island during low load periods overnight. Factors included a series of planned outages in the region and light night-time loads, particularly as the normal overnight irrigation load in Canterbury and Otago had dropped due to the sustained wet weather and flooding.

The issues in the top of the South Island were managed with a combination of circuit removal and reduced generation dispatch. Had the situation escalated requiring to place the top South Island on a single circuit (~80 MW on N Security) a Grid Emergency Notice (GEN) would have been issued. Communications with key customers were maintained throughout, including an open briefing call on 6 December 2018 to advise of the potential for the issue resulting in N security and a GEN. This issue will be largely resolved with the implementation of a reactor by the grid owner at Kikiwa, planned for commissioning in winter 2020.

December

Major electrical storms

Risks associated with major electrical storms early in December led to proactive real time management to mitigate potential double contingency events. On 2 December, the reclassification of transmission lines in Otago/Southland led to short-term high prices and price separation. On 4 December, lightning events in the Upper North Island led to a series of trippings which, for the most part, were promptly reclosed and interruptions managed seamlessly by the new Upper North Island Reactive Power Controller which was commissioned in August 2018.

Bunnythorpe 220kV bus A tripped on 25 December, due to a double lightning strike on the Bunnythorpe_Brunswick 2 circuit. The line protection had not had time to reset before the second strike resulting in the bus protection responding instead.

Huntly trippings

Further weather events in the North Island over 13-14 December resulted in a high number of circuit and feeder trippings, which, combined with the high volume of scheduled work kept real time operations teams NCC and NGOC, as well as service providers and support teams, very busy during this period. One tripping on the Huntly_Stratford circuit which occurred on 14 December during a planned bus outage at Huntly and resulted in the tripping of Huntly unit 4 and an under-frequency event (UFE) with North Island frequency dipping to 49.21Hz. An investigation is underway looking at the wider event and circumstances surrounding this issue.

A separate tripping of Huntly unit 5 on the previous day and UFE was not related to weather events.

Other asset issues

Over December, there several instances of bird nests discovered in substation structures at several locations most notably at Hinuera where they caused a bus tripping, a feeder tripping and a number of short notice outages. Outages due to bird nests are an ongoing issue and mitigations are being put in place by the grid owner.

Independent audit

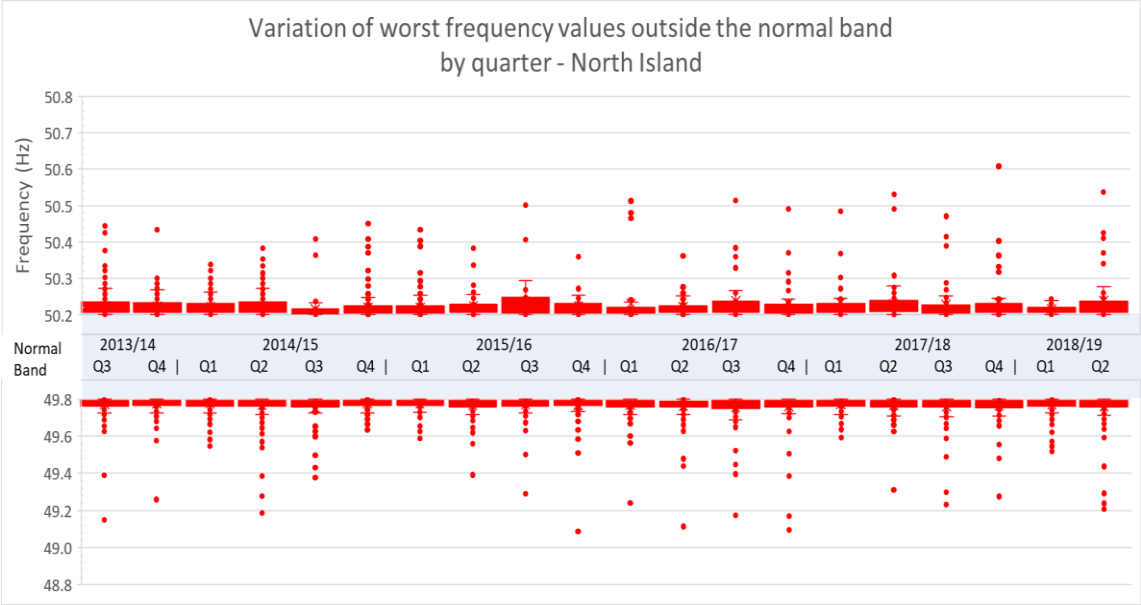
An independent audit has been carried out of the verbal communications processes used by the control room Security Co-ordinators. The scope of the audit included the appropriateness of standards, training supplied, management and compliance of the process. We have received an overall rating of “Effective” and opportunities have been identified for further enhancement; a programme of actions is underway.

10 Frequency fluctuations

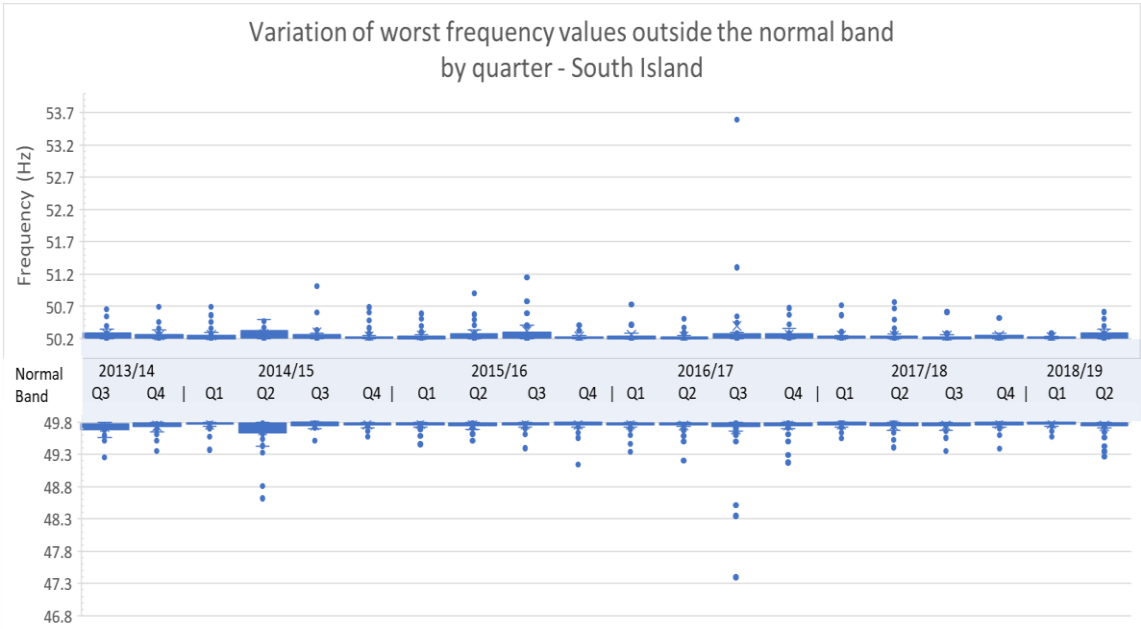
10.1 Maintain frequency in normal band (Frequency value)

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

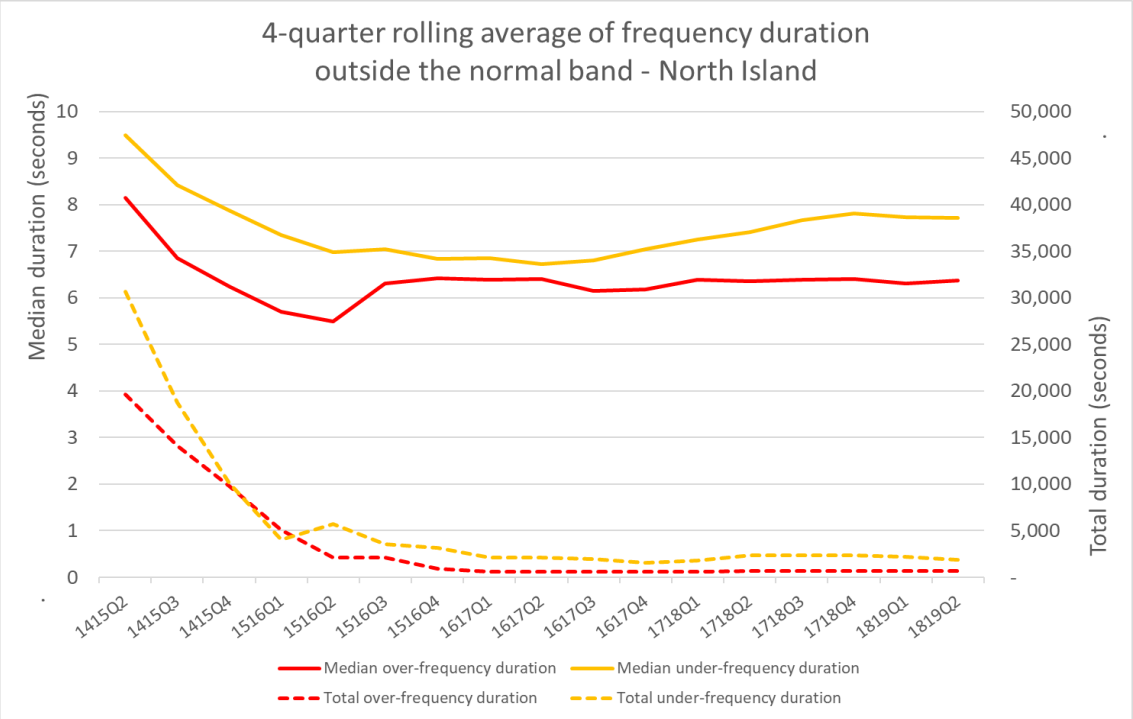


Note: These box and whisker charts show the distribution of data. The “box” represents the distribution of the middle 50% of the data, the “whiskers” indicate variability, and outliers are shown as single data points.

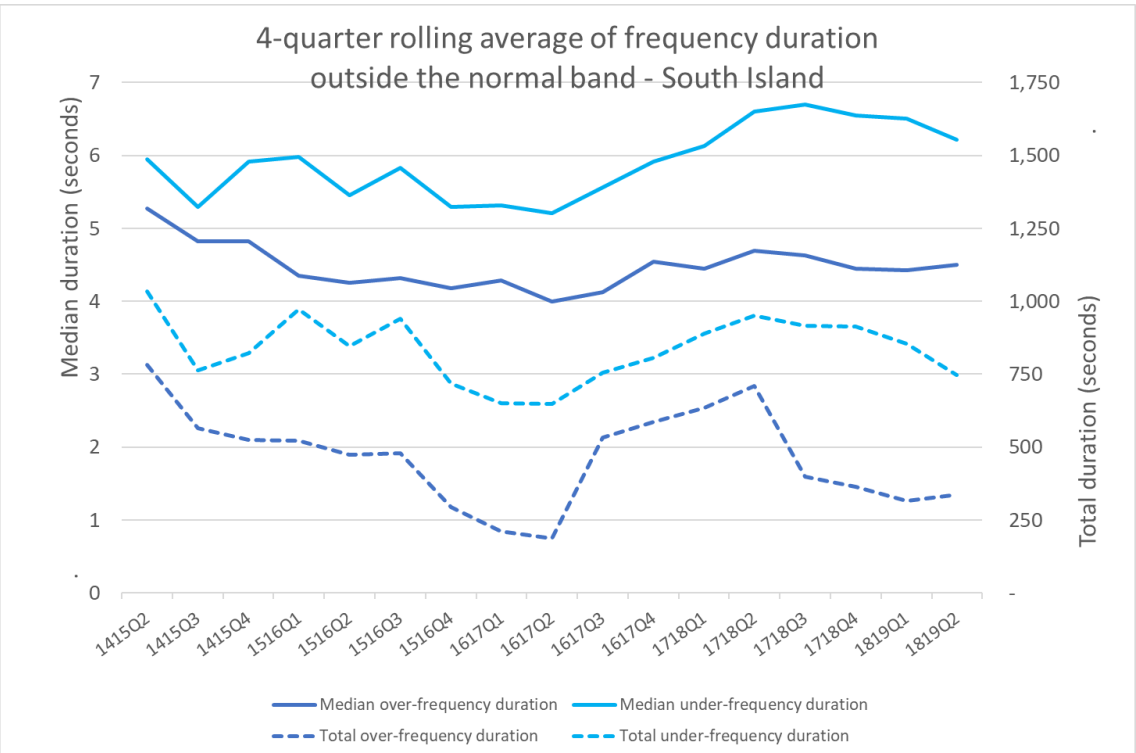
10.2 Recover quickly from a fluctuation (Time)

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



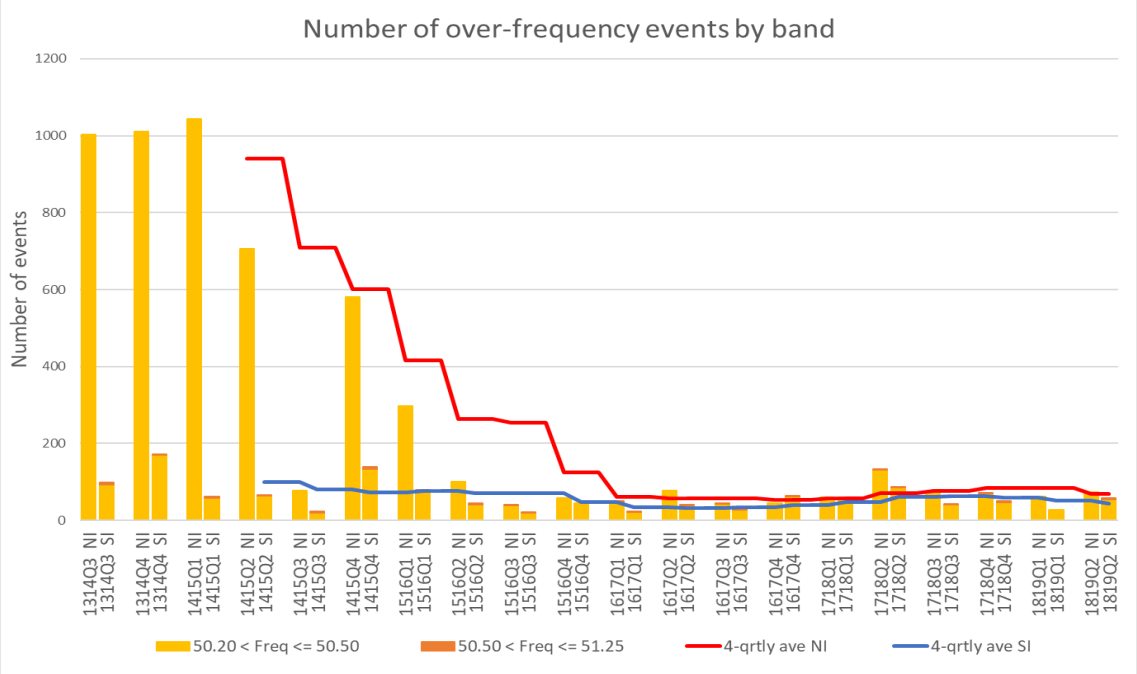
South Island



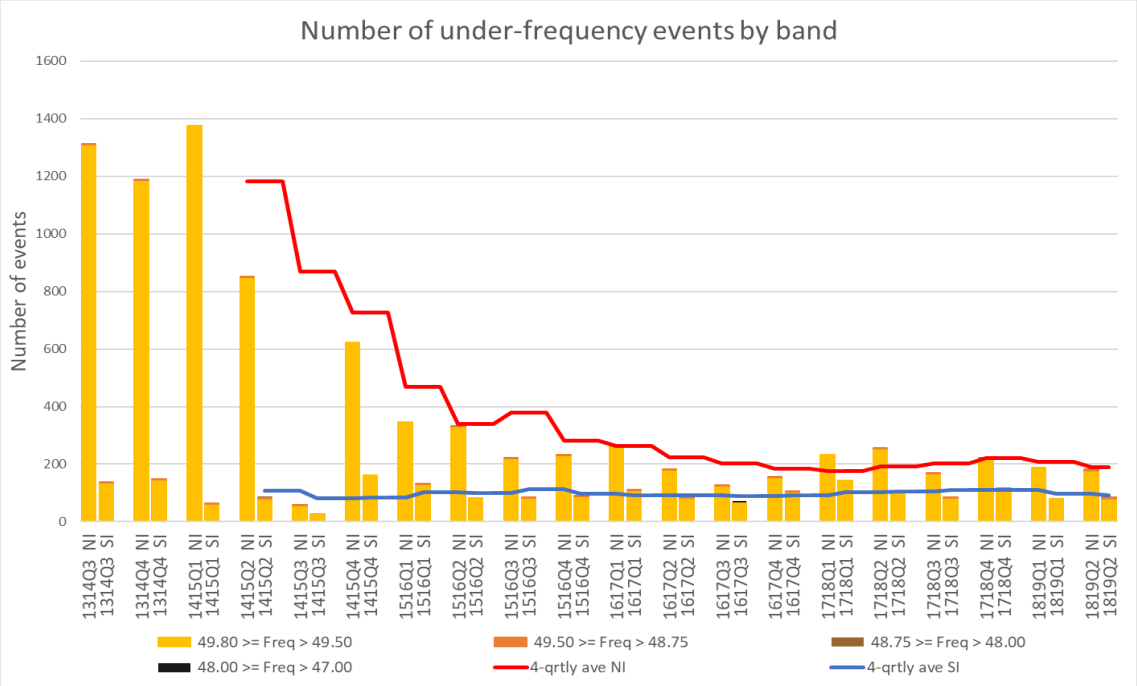
10.3 Manage frequency and limit rate of occurrences during momentary fluctuations (Number)

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



10.4 Manage time error and eliminate time error once per day

There were no time error violations in the reporting period.

11 Voltage management

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

12 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-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Demand Allocation Notice	-	-	-	-	-	-	-	-	-	-	-	-
Grid Emergency Notice	3	1	-	1	1	-	-	1	-	-	-	-
Warning Notice	-	-	-	-	-	1	1	-	-	-	1	-
Customer Advice Notice	3	6	4	10	12	4	2	9	9	6	20	20

13 Grid emergencies

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

Date	Time	Summary Details	Island
Oct-18		None	
Nov-18		None	
Dec-18		None	

14 Security of supply

The unforeseen extended outage of the offshore Pohokura gas field for valve repairs resulted in a focus on security of supply this quarter. The outage occurred at a time that there were scheduled maintenance outages of the larger thermal plants at Stratford and Huntly, and coincided with the annual grid owner HVDC bipole outage. These factors, at the same time as lower than average hydro storage at the start of the quarter meant that supply was tight in October. The impact of the outages was evident in the market as high prices in October; average price at Haywards was $290/MWh. However, this did not manifest in a threat to medium-term security of supply as shortage risk is typically lowest during October through December inclusive.

Significant inflows received in the South Island in November enabled higher hydro generation to support demand while gas was restricted. However, in spite of this prices remained at high levels; average price at Haywards was $186/MWh.

Moderate inflows continued in December. In addition, Pohokura returned to full production. These factors, plus the demand drop as we entered the Christmas/New Year period, meant that by the end of the quarter, national storage had returned to the historical average for this time of year. Prices reduced to an average price of $102/MWh at Haywards.

We engaged with industry participants to aid our analysis of this situation during this period and based on information available concluded that there was no immediate risk to security of supply caused by the Pohokura outage.

We spoke to the Security and Reliability Council (SRC) on 24 October about the coordination of critical gas contingencies. We highlighted the need for visibility of gas industry production information, not only during a critical contingency but ahead of the situation to enable better planning and coordination, and improved security of supply forecasting.

The following table shows monthly inflows for both islands as a percentage of average for the time of year.

	October	November	December
North Island	68%	78%	102%
South Island	69%	117%	68%

From October to December, North Island inflows were 82% of average and South Island inflows were 84% of average. National hydro storage increased from 67% to 91% of average for the time of year from October to December. The hydro risk status remains at 'Normal'.

Since December 2018 when preparing the Hydro Risk Curves (HRCs), we have included an additional step to validate the thermal fuel consumption in the HRC modelling in light of known constraints to fuel supplies. This step was added to the process following consultation earlier in the year. Details can be found on the Hydro Risk Curve page of the Transpower website.

We have completed our review of the Security of Supply Forecasting and Information Policy (SOSFIP), and have a draft version out for consultation. This consultation is being carried out in parallel with the Authority's review of Part 9 of the Code. We are proactively engaging with stakeholders to ensure the consultation information is well understood and valuable submissions are received.

Finally, we have begun work on the 2019 Annual Security of Supply Assessment (ASA). The ASA is an important tool in the suite of security of supply information, and we are focussed on continuous improvement to ensure it provides the greatest value to market participants and other stakeholders. This year we have put an emphasis on two key issues: future electricity demand and future gas-fired thermal generation, as these two important topics are currently being discussed by the industry. We expect

to publish a draft report to interested parties, including Authority staff, in early February.

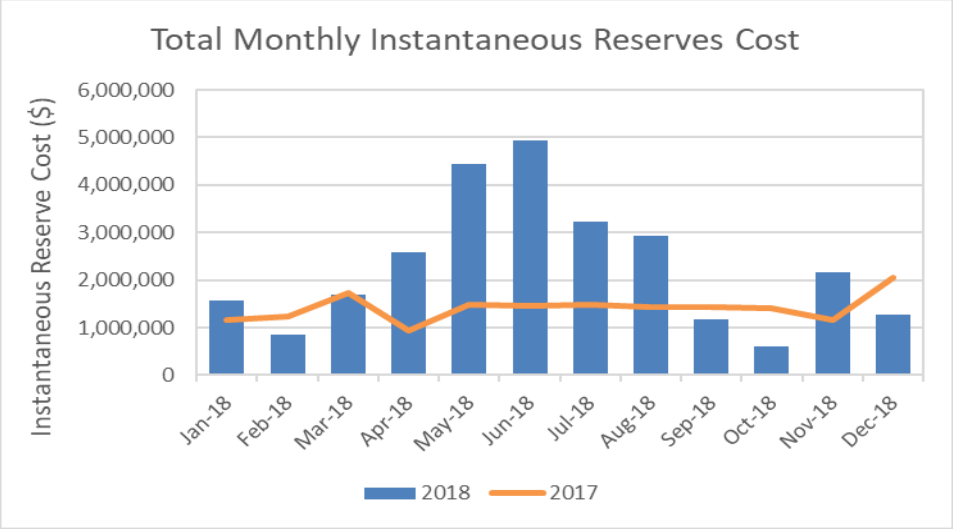
15 Ancillary services

The instantaneous reserves costs in October were half of what there were in September, and significantly lower than the high costs in May and June. The low costs in October can be attributed to two factors:

- The largest risk on the system that needed to be covered by reserves reduced with the thermal generators operating on lower outputs
- In a dry sequence the hydro generators typically offer reserve at low prices as they prefer to clear for reserves than energy

In November, the instantaneous reserves costs increased from October's levels but were still below the higher costs paid in the period from April through to August. The main reason for the increased reserves costs for the month was the reserves required during the HVDC outage. In particular, 80% of the month's reserve costs occurred in the North Island during the Pole 2 outage on 22 and 23 November.

In December, the costs of instantaneous reserves returned to a lower level.



In December there were two outages requiring generation to supply local load at Tekapo A where Tekapo A was used for frequency keeping. In total this accounted for 414 trading periods; the frequency keeping cost was $1,000 per trading period.

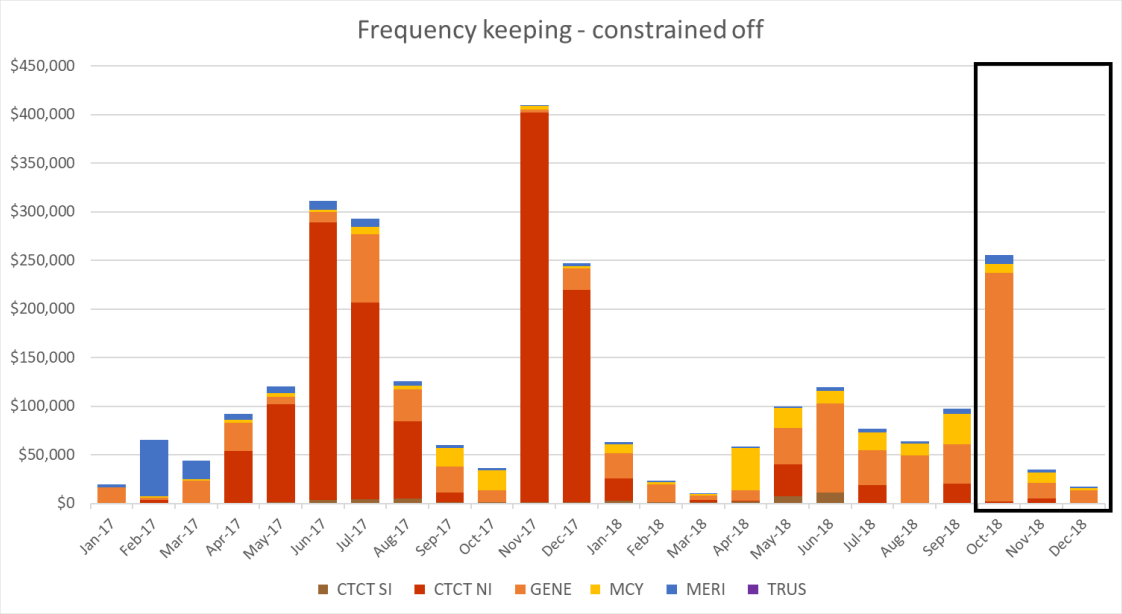
The annual ancillary services tender process closed on 19 October. We tendered for Over-Frequency Reserves in both the North and South Islands, and a Black Start provider in the South Island. The new contracts started on 1 December 2018.

Refer to Appendix C for more detailed Ancillary Services graphs.

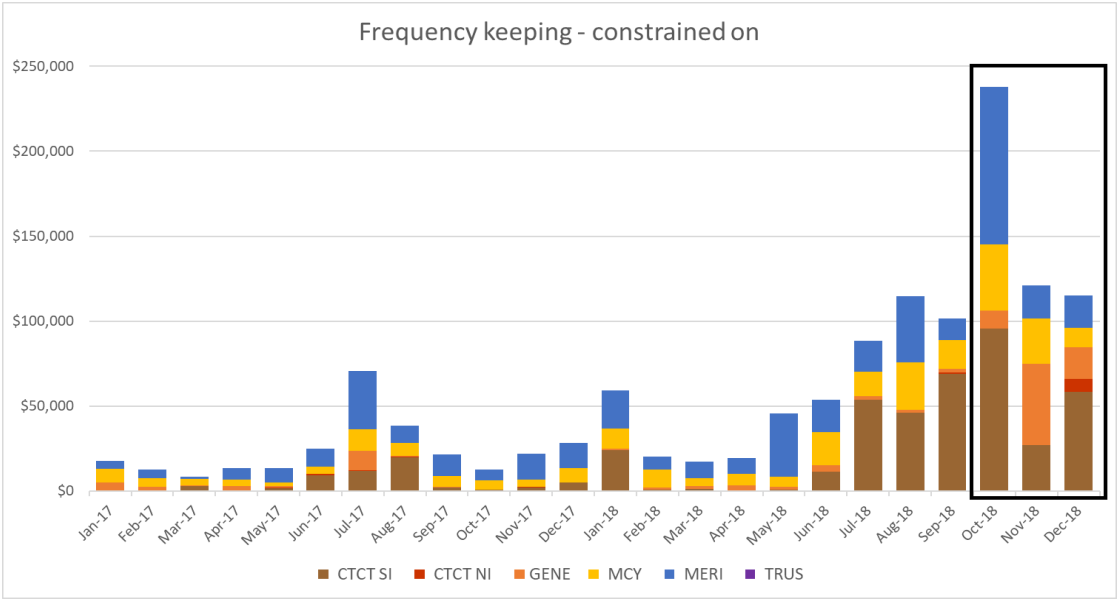
15.1 Constrained on/off costs

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

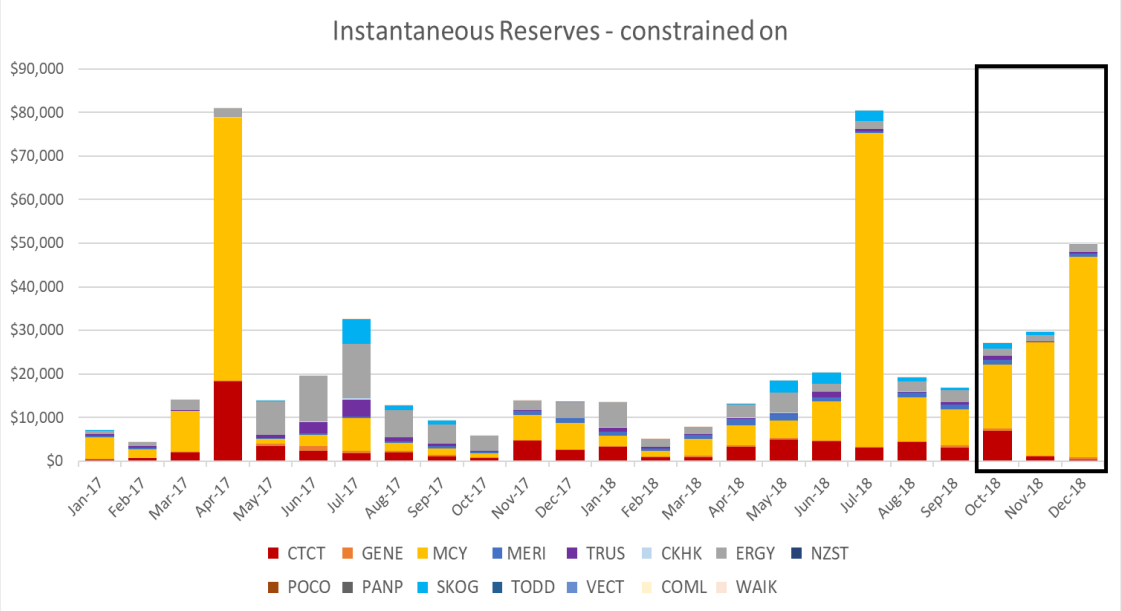


During this quarter, Genesis received a large constrained off payment in October which related to frequency keeping overnight (trading periods 1-13) at Waikaremoana, particularly during the middle of the month.



Constrained on costs were high in October, especially to Contact in the South Island and to Meridian. These higher costs related to frequency keeping at Clutha, particularly from 14-18 October, and also at Waitaki, particularly from 14-17 October and on 22, 23 and 28 October.

Instantaneous Reserves



Instantaneous Reserves costs this quarter were lower than the July-September 2018 quarter which included a $60,000 payment to Mercury on the evening of 12 July ($40,000 of which was for Maraetai).

In this quarter the proportion of constrained on payments shifted between the parties as the large Huntly and Contact thermal generators were on maintenance outages in November and December, therefore Mercury was the largest recipient on the payments these month.

In November, just over $19,000 paid to Mercury for Maraetai, including $5,500 for trading period 19 on 23 November. During this month, there were 7 days with total payments over $1,000. In December, just under $40,000 was paid to Mercury for Maraetai. Nearly $20,000 of this was for trading period 12 on 21 December. The 17, 27 and 28 December were the other significant days with payments between $2,500 and $3,500.

Appendix A: Discretion

October

Event Date & Time	Event Description
02-Oct-2018 18:01:00	KAW0111 TAM0 : Required for system security
09-Oct-2018 11:57:00	MAN2201 MAN0 : Offload extended potline Last Dispatched Mw: 738
11-Oct-2018 11:48:00	MAN2201 MAN0 : Restore Extended Potline

November

Event Date & Time	Event Description
6/11/2018 21:17	MAN2201 MAN0 : Emergency Potline 3 (180MW). Last Dispatched MW: 666
13/11/2018 9:58	ARG1101 BRR0 : 110kV circuit trip. No grid connection. Last Dispatched MW: 6
14/11/2018 12:42	MTI2201 MTI0 : Required as MTI_WKM circuit tripped Last Dispatched MW: 140
14/11/2018 12:42	WPA2201 WPA0 : Required as MTI_WKM circuit tripped Last Dispatched MW: 33
17/11/2018 1:01	HWB0331 WPI0 : GZ14_TWI VSAT 100% applied at request of security coordinator. Last Dispatched MW: 0
17/11/2018 3:21	HWB0331 WPI0 : GZ14_TWI VSAT 100% applied at request of security coordinator. Last Dispatched MW: 12
17/11/2018 8:05	ARG1101 BRR0 : As per switching for ARG_BLN_1 and ARG_KIK_1 Last Dispatched MW: 6
17/11/2018 15:28	ARG1101 BRR0 : Discretion for the return of ARG_BLN_1 Last Dispatched MW: 10
21/11/2018 5:59	WRK0331 RKA0 : Required as WRK T30 not available.
23/11/2018 8:50	Bipole max set to 630MW for the 8:55 dispatch to allow Pole 2 to be blocked at 09:00. This is to allow for a secure dispatch at 09:00 as the Bipole ECE could become the risk and create a reserve deficit at 09:00 if it was left at its current level of 755MW.
24/11/2018 4:50	DCN max applied of 280MW for start of Bipole outage.
24/11/2018 4:55	DCN max applied of 155MW for start of Bipole outage.
27/11/2018 3:02	KUM0661 KUM0 : Discretioned on due to high volts in Upper Sth Island. Trustpower verbally advised.
29/11/2018 15:09	MAN2201 MAN0 : Action due to lightning Last Dispatched MW: 607
30/11/2018 14:08	MAN2201 MAN0 : Instruction from security coordinator required due to lightning in the vicinity of the 220kV MAN cct

December

Event Date and Time	Description
06-Dec-2018 09:06:00	MAN2201 MAN0 : MAN NMA 1 tripped Security
06-Dec-2018 09:29:24	MAN2201 MAN0 : MAN NMA 1 tripped Security
10-Dec-2018 01:22:58	MAN2201 MAN0 : Potline return (line 4)
12-Dec-2018 06:25:06	MAN2201 MAN0 : To manage Line 2 offload which changed to an extended Potline
14-Dec-2018 12:21:39	HLY2201 HLY4 : HLY4 Tripped Security
14-Dec-2018 13:20:16	BWK1101 WPI0 : To manage steady state circuit overloads on the BAL_BWK section of transmission line
14-Dec-2018 13:30:13	BWK1101 WPI0 : To manage steady state circuit overloads on the BAL_BWK section of transmission line
14-Dec-2018 17:26:58	MKE1101 MKE1 : MNI_MKE_SFD1 Tripped Security
17-Dec-2018 17:18:47	MKE1101 MKE1 : MNI-MKE-SFD tripped Security
18-Dec-2018 11:41:24	MAN2201 MAN0 : Potline Extended Line 2
22-Dec-2018 10:01:25	MAN2201 MAN0 : Extended potline

Appendix B: Update on South Island AUFLS event (2 March 2017)

Action	Accountable	Due	Status
1.Agree an approach, to be used in future, by protection designers and technicians, to enable access to site-specific information on protection schemes • Confirm the purpose of existing and newly required documentation and how it fits into a wider documentation structure, identifying linkages to existing systems and processes. • Workshop a solution with impacted stakeholders including designers, technicians, operators, the SO, and the NGOCs, developing a set of templates for site specific information based on learnings. (Workshops 24 May, 7 June) • Investigate methods for Service Providers to review site specific queries and information added by designers. • Agree ownership of agreed system and information (including the maintenance of information), confirming roles and responsibilities. • Create a change and implementation plan.	Grid Development	June 2018	Complete
2.Develop a process that supports protection designers in gaining clarity on isolation, testing and maintenance requirements for future protection schemes early in the design process - allowing for appropriate consultation with protection technicians who will be undertaking the work • Work with designers and service providers to define an agreed list of minimum interface requirements for new protection schemes. (Workshops 24 May, 7 June) • Develop a set of design principles for the validation/accreditation of the design and construction of new schemes. • Confirm a method of displaying the technical aspects of protection systems being installed (Linked to Action 1). • Compile a document that describes the proposed process and present at a forum for designers and service provider technicians. • Develop changes and create an implementation plan.	Grid Development	June 2018	Complete

Action	Accountable	Due	Status
3.Consider providing real-time SCADA data to technicians • Consider providing near real-time SCADA data to technicians (Sept 2018) • Investigate options to meet the need of technicians for better on-site visibility of the real-time system (including access to near-real time SCADA) • (Additional step added Nov 2018) Develop business case for a preferred solution (June 2019)	Operations	Dec 2018	Complete
4.Improve current outage planning processes to include a risk-based approach that assesses requests for outages of protection equipment to identify maintenance activities that have a high system impact (including the impact of other concurrent planned outages) • Confirm plan for improving current outage planning process (31 Jan) • Review effectiveness of regular SO/GO meetings for identifying major protection outage concurrencies and protection issues, and protection group's involvement in Annual Outage Plan review. (28 Feb) • Identify protection outages which involve increased risk and significant impact, update IONS with information for the relevant outage blocks (29 March) • Agree processes and responsibilities for using this information • Develop process for updating information • On-going related work continuing in parallel determine which outage blocks require protection advice • Implement Communication Plan on changes, core teams by end of April, wider communication by end of May	Operations	June 2018	Complete
5.Review the existing Autosync tool and procedures to support NGOC grid asset controllers and NCC system co-ordinators working under pressure • Discussions with NCC facilitated to find a clear outcome that is technically and operationally fit for purpose • Tool Interface solution being developed by NCC. Options provided for business case completion • Implementation of tool interface changes	Operations	June 2018	Complete

Action	Accountable	Due	Status
• Technical Protection changes proposed • Sync-check functionality on the relay to be discussed with TP Protection Functions meeting			
6.Re-emphasise and embed through regular training of NGOC and NCC staff the importance of compliance with policies and use of procedures during restoration after rare events • Develop and refine single shared Autosync operational documentation and checklist • Role clarifications for NCC and NGOC coordination centres • Create simulator experiences for Autosync operation • Complete training of all NCC and NGOC teams through Autosync operations • Capture feedback from all NCC and NGOC staff post simulation to refine documentation • Align training schedules for NCC and NGOC teams to allow for integrated training exercises • Increase monitoring of operational communications by senior NCC staff during normal operations and during simulator training, to build core competency and ensure Code-compliant communications are being used. • Implement 'human factors' e-learning training material to NCC and NGOC staff. • Review policy to ensure clear guidance is provided for changes to Grid Owner offers following asset trips • Reiterate compliance with Manual Reclose Policy (which requires identification of trip causation) • Implement HILP-style events into future real-time training simulations. Current NGOC and NCC operator training sessions each have major (HILP) simulation events. Planning for the next sessions is underway and includes similar-style major event simulations. • Include in training reinforcement of policies and procedures used during event management	Operations	Dec 2018	Complete
7.Review procedures across Transpower regarding handover of tools and systems to ensure the tools and systems are able to be effectively operationalized • Review procedures across Transpower regarding handover of tools and systems to ensure tools and systems are able to be effectively operationalised	Operations	Dec 2018	Missed

Action	Accountable	Due	Status
• Service Delivery Lifecycle (SDL) and Project Delivery Framework (SDF) processes are reviewed for compatibility with grid asset project deliveries • Ensure Transpower's policy and processes for asset developments reflect similar handover principles to those found in the SDL and SDF. • The process solution is tested for suitability and implemented across Transpower *Update: Action 7 has missed the deadline. A process solution is nearing completion and its suitability is being tested for application across Transpower. The Operations, Process and Technology Improvement (OPTI) Team has revised its structure to ensure the effective delivery of its functions across the entire business. This includes focus on how tools and systems are operationalised. This action is now aiming for completion by June 2019.*			
8.Investigate improvements in the design and use of the market model and market system to assist in the management of large scale system restoration events • Investigate improvements in the design and the processes for using the market model and market system to assist management of significant system restoration events • Investigate having the market model being at all times reflective of the real time SCADA model (allowing SPD to support system restorations without having to manually update the market model).	Operations	Dec 2018	Complete
9.Work with industry and real-time teams within Transpower to address issues with operational communications • Ensure real-time operations demonstrate Code-mandated inter-control room communications requirements and require interactions with industry control rooms to reflect compliance with the same Code standard. • Work with industry and real-time teams within Transpower to address issues with inter-control room communications (to meet requirements of Part 8 Tech Code 3 of the Code)	Operations	Dec 2018	Complete

Action	Accountable	Due	Status
10.Work with generators to assess what real-time information could assist them with visibility of the system during events and investigate the practicability of providing this • Work with generators to assess what real-time information could assist them with visibility of the system during events and investigate the practicability of providing this information. • Include in September workshop (see Action 9) an investigation with Industry of options for improving communications during major events. • Consider options for providing industry with up to date information during complex, busy events. • (Additional step added Nov 2018) A interim solution in place via email, will continue to investigate other options	Operations	Dec 2018	Complete
11.Require technicians testing and maintaining protection schemes to document in their Work Method Statement how, at each stage of their testing process, they will affirm no adverse outcomes have occurred as a result of their work. • Review internal AUFL's Reports and Electrix work method statements (22 Jan) • Assess these reviews against recent issue (17 Sept 2017) of work statements requirement documentation (22 Jan) • Determine if changes if necessary post review and assessment (12 Feb) • Develop changes and implementation plan as required (end of May)	Grid Projects	May 2018	Complete
12.Identify, review and address performance of risk management controls, specifically focused on high impact low probability event interactions. • Identify, determine how to review (including with use of an external reviewer) and address performance of risk management controls, specifically focused on high impact low probability event interactions. • Utilisation of internal Audit process to focus on controls and a scheduled internal audit (Dec 2018-Feb 2019) of control room communications • Carry out review, as determined in the first component, of Transpower's risk management of controls including high impact low probability events (June 2019)	Operations	Dec 2018	Missed

Action	Accountable	Due	Status
Update: Action 12 has missed the deadline. This action relates to our risk management and as part of the action an enterprise level review of our risk management framework was proposed. This review is scheduled for June 2019.			
13.Review Transpower's processes for reporting of major power system events, compliance breaches and material failures by Transpower to comply with its own standards and procedures. • Agree with the Electricity Authority the scope of this process • Prepare documented event reporting process with input from the Electricity Authority as required • Implement processes changes for managing compliance and internal failures to follow operational process as identified *Update: Action 13 has missed the deadline. Agreement is still being sought from the Electricity Authority on the proposed process. In the interim the proposed process will be applied.*	Operations	Dec 2018	Missed

Appendix C: Ancillary Services Graphs