MONTHLY SYSTEM OPERATOR AND SYSTEM PERFORMANCE REPORT

FOR THE ELECTRICITY AUTHORITY

Transpower New Zealand Limited

January 2019

Keeping the energy flowing




TRANSPOWER

Transpower New Zealand Limited The National Grid

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Report Purpose

This report is Transpower's review of its performance as system operator for January 2019, in accordance with clause 3.14 of the Electricity Industry Participation Code 2010 (the Code).

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

Commentary

This section provides an update for the month, the remainder of the report provides supporting detail in two sections:

- System operator performance, and
- System performance.

Dispatch Service Enhancement (DSE) - We have refined and confirmed the design for the Dispatch Service Enhancements project at a workshop held with the industry on 29 January. The model will be circulated to the industry for feedback at a workshop scheduled for 1 March 2019.

Situational Intelligence - We have completed reference checks on the preferred vendor in January. We are now focussing on refining project estimates to inform a delivery business case (due February 2019).

National Market for Instantaneous Reserves (NMIR) refinements - We are currently consulting with the industry by requesting comments on the proposed design. The closing date for comments was 31 January 2019. The changes are planned to come into effect in late March 2019.

High Temperatures – The potential impact on the HVDC pole 3 transfer maximum limit is being monitored during the current high temperatures. The pole limit was reduced on 29 January, but at the time the level of transfer was lower than the reduced limit and therefore had no impact.

Security of Supply - The 2019 Annual Security of Supply Assessment, was sent out in draft form for industry comment on 8 February.

The latest version of the Hydro Risk Curves have now been published on the HRC page of the Transpower website. These include the upcoming Pohokura gas field outages in February/March; there is no material impact on the curves.

New Zealand Generation Balance (NZGB) error - An error relating to Huntly unit 4 was uncovered in the January NZGB report forecast. Correcting the error has reduced the forecast shortfalls over the winter period. Participants were notified of the error via a CAN on 29 January, and the February NZGB report was amended accordingly.

Work to analyse the NZGB tool is continuing in order to provide assurance we are providing correct information and analysis.

System operator performance

1 Compliance

We reported one breach of the Electricity Participation Code 2010 on January. This related to an error in the non-responsive long schedules which indicated $0 generation at Stratford. The error was detected, the modelling updated and day-ahead schedules correctly modelled the generation.

Appendix A shows instances where the system operator has applied discretion under 13.70 of the Code.

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.

Real Time Pricing (RTP)

This month we have been assisting the Authority in preparing materials for their next Board meeting on 14 February. The materials are a high-level description of the market design work we have been developing with the Authority over the past several months, focussing specifically on pricing in reserve shortfall conditions. We will be assisting with the presentation of this material to the Authority Board.

Dispatch Service Enhancement (DSE)

We have refined and confirmed the design for the Dispatch Service Enhancements project at a workshop held with the industry on 29 January. We are now focussed on developing the cost allocation model to enable Authority consideration later this month. The model will be circulated to the industry for feedback at a workshop scheduled for 1 March 2019.

Situational Intelligence

We have completed reference checks on the preferred vendor in January. We are now focussing on refining project estimates to inform a delivery business case (due February 2019). We will provide an update on the project to the Authority in March 2019.

National Market for Instantaneous Reserves (NMIR) refinements

We are currently consulting with the industry by requesting comments on the proposed design. The closing date for comments was 31 January 2019. The changes are planned to come into effect in late March 2019.

Credible Event Review

A schedule for the 2019 work is now in place. We have agreed the methodology for the busbar (frequency) studies and studies will begin on a “trial” busbar, Manapouri.

We intend to seek feedback on this with select industry participants and the Authority in the second half of March before proceeding with the remainder of the studies.

3 Outage planning and coordination

New Zealand Generation Balance (NZGB) error

The January NZGB report forecast potential generation shortfalls in May and June. This prompted us to analyse the load forecasting and generation data assumptions used in the calculations. An error related to Huntly unit 4 was uncovered; it had not been included in our calculation since it was recommissioned in 2018. Correcting the error has reduced the forecast shortfalls over the winter period. Participants were notified of the error via a CAN on 29 January, and the February NZGB report was amended accordingly.

Work to analyse the NZGB tool is continuing in order to provide assurance we are providing correct information and analysis.

Net Benefit Test under the Outage Protocol

Contact and Mercury have requested that we undertake a net benefit test for a grid owner outage, as required under the Outage Protocol. This outage is scheduled to paint disconnectors at Te Mihi – work that will be carried out under warranty. The outage will constrain Contact and Mercury generation in the region for three days. We are working with Transpower's Grid Service Delivery and with the Strategic Asset Management team to understand the costs and benefits associated with the outage. This is the first time a customer has requested a net benefit test for a planned grid outage. The grid owner and other participants typically resolve outage conflicts by negotiation.

4 Performance metrics

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

5 Actions taken

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

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.

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

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.

There were no new issues raised in the conflict of interest register in January.

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

High Temperatures

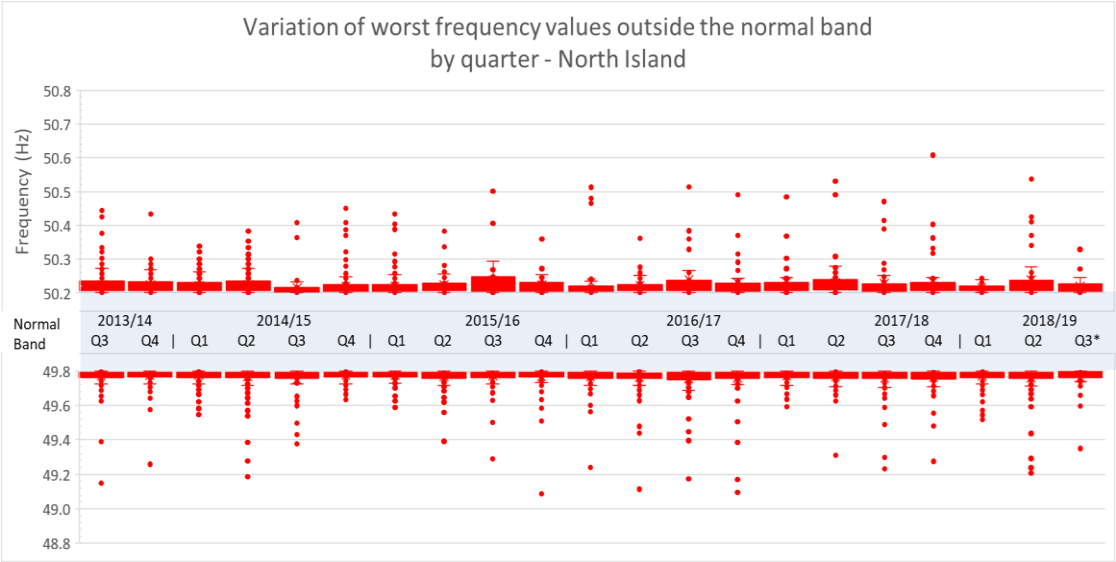
As temperatures at Haywards rose above 28 degrees, this had the potential to impact on the HVDC pole 3 transfer maximum limit. However, although temperatures of over 30 degrees did cause the pole limit to be reduced on 29 January, the transfer at the time was lower than the reduced limit and therefore did not result in any impact. All lessons from the investigations, carried out in anticipation of the impact of nationwide high temperatures, have been recorded in a process document to be referenced in future high temperature situations.

10 Frequency fluctuations

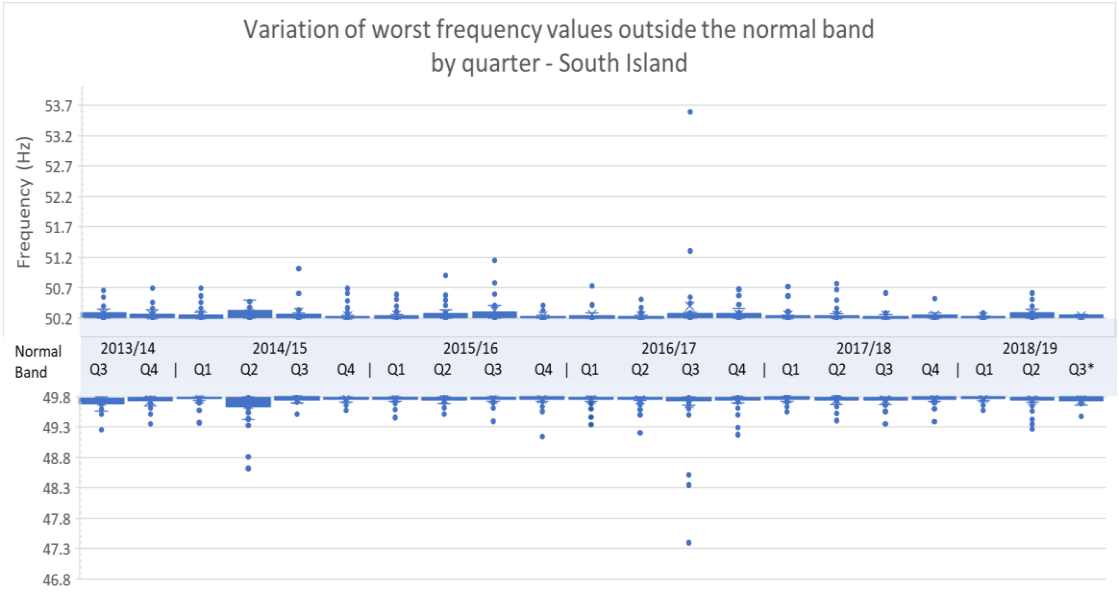
10.1 Maintain frequency in normal band (Frequency value)

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

North Island



South Island



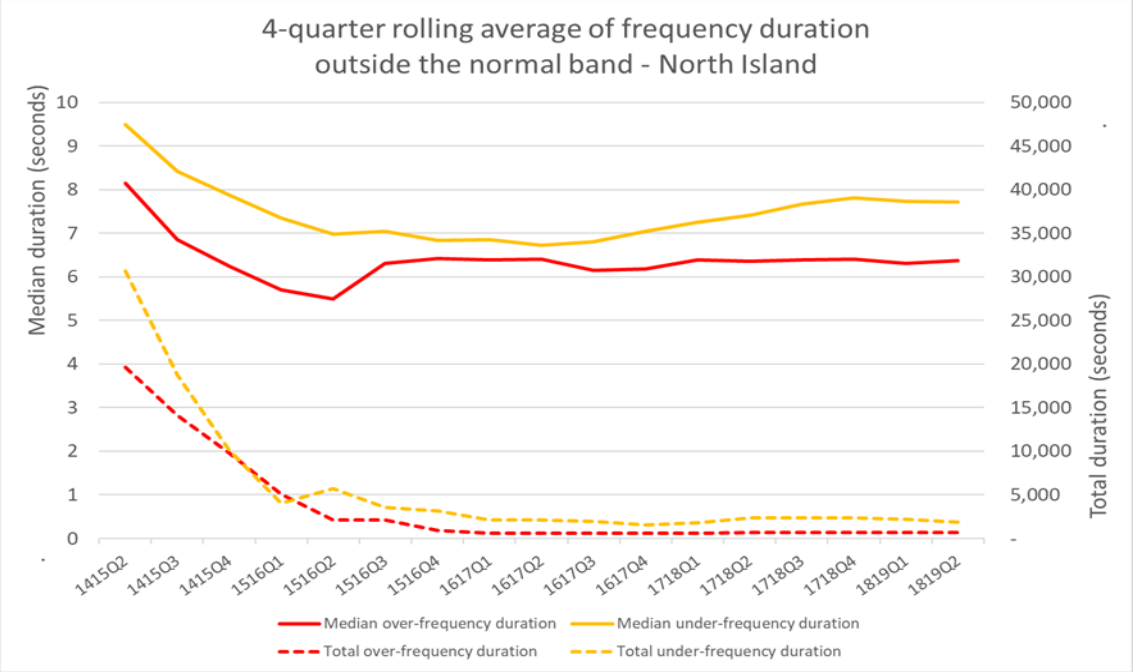
* 2018/19 Q3 contains data for January only

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

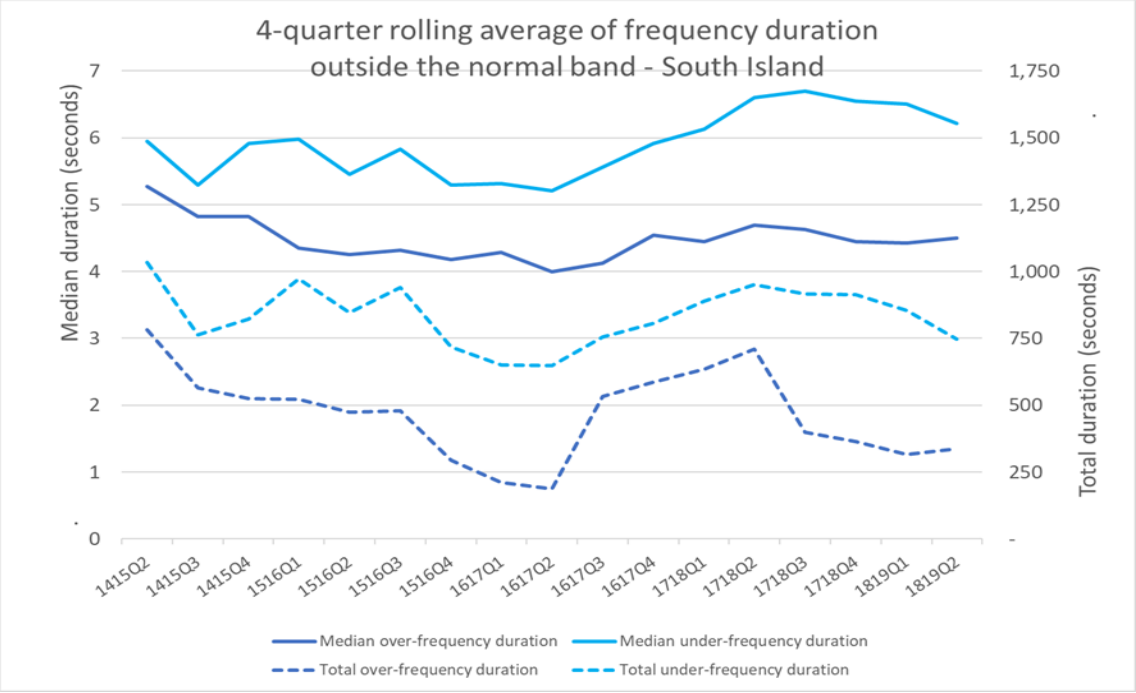
10.2 Recover quickly from a fluctuation (Time)

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

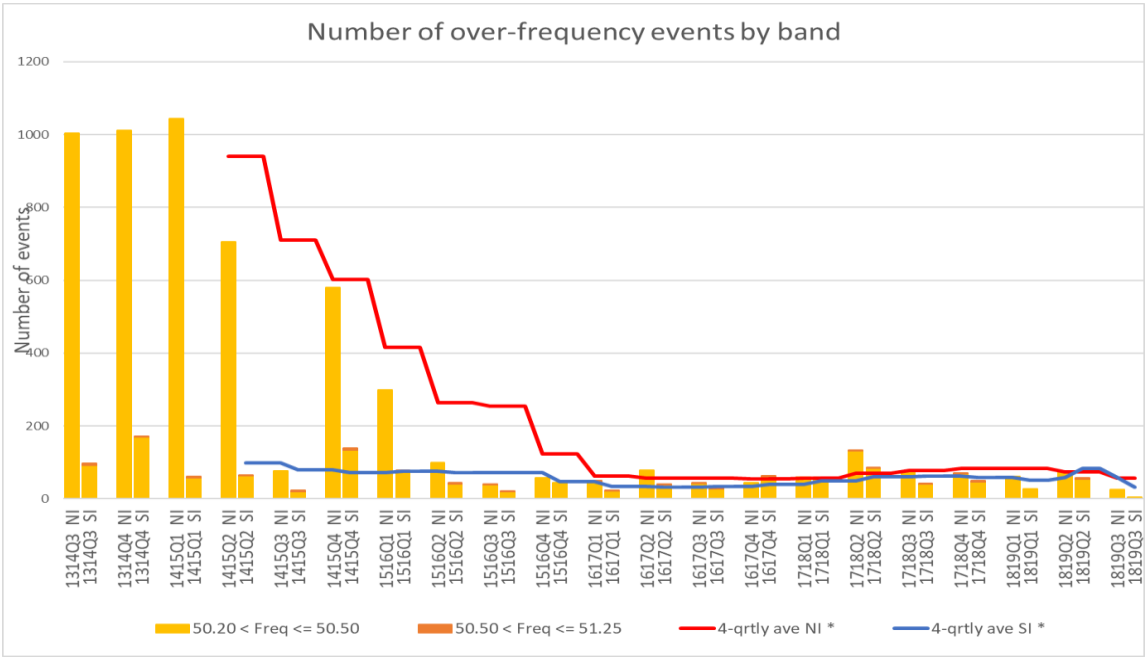


* These graphs have not been updated since 2018/19 Q2; they will only be updated at the end of each quarter

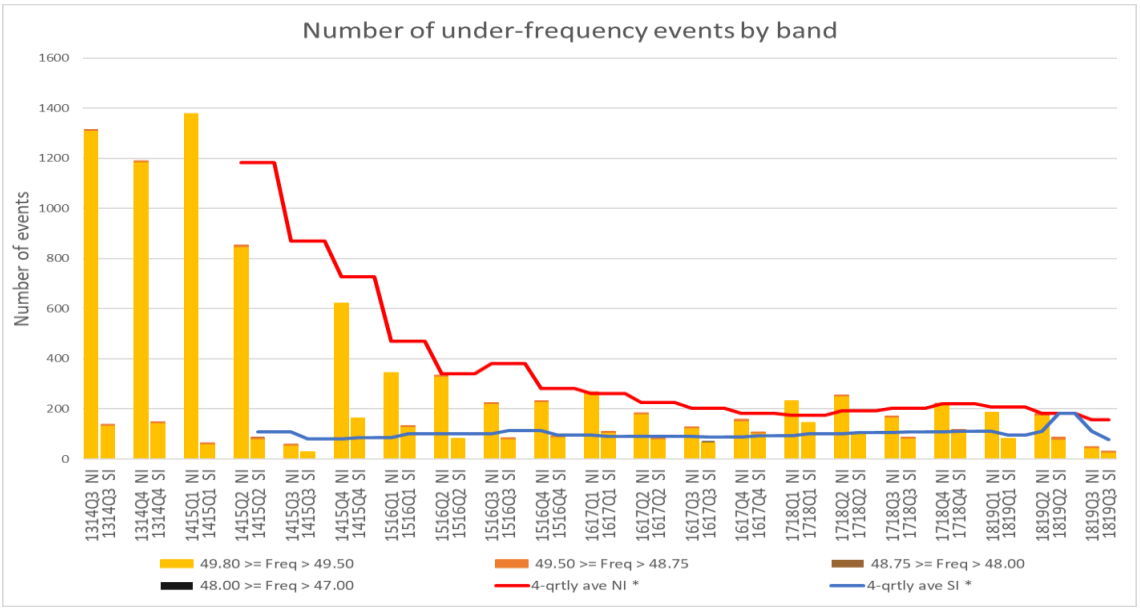
10.3 Manage frequency and limit rate of occurrences during momentary fluctuations (Number)

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



Note: The 2018/19 Q3 contains data for January only.

* 4-qtrly averages for NI and SI will only be updated at the end of each quarter

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	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19
Demand Allocation Notice	-	-	-	-	-	-	-	-	-	-	-	-
Grid Emergency Notice	1	-	1	1	-	-	1	-	-	-	-	-
Warning Notice	-	-	-	-	1	1	-	-	-	1	-	-
Customer Advice Notice	6	4	10	12	4	2	9	9	6	20	20	16

13 Grid emergencies

The following table shows grid emergencies declared by the system operator.

Date	Time	Summary Details	Island
		None this month.	

14 Security of supply

Over the next two to three months we expect the risk of shortage due to hydro storage to remain low, however, this is largely dependent on hydro catchment inflows. Overall, during January, North Island inflows were 75% of average and South Island inflows were 99% of average. National hydro storage increased from 91% to 96% of average from the time of year. The average price at Haywards was $125/MWh.

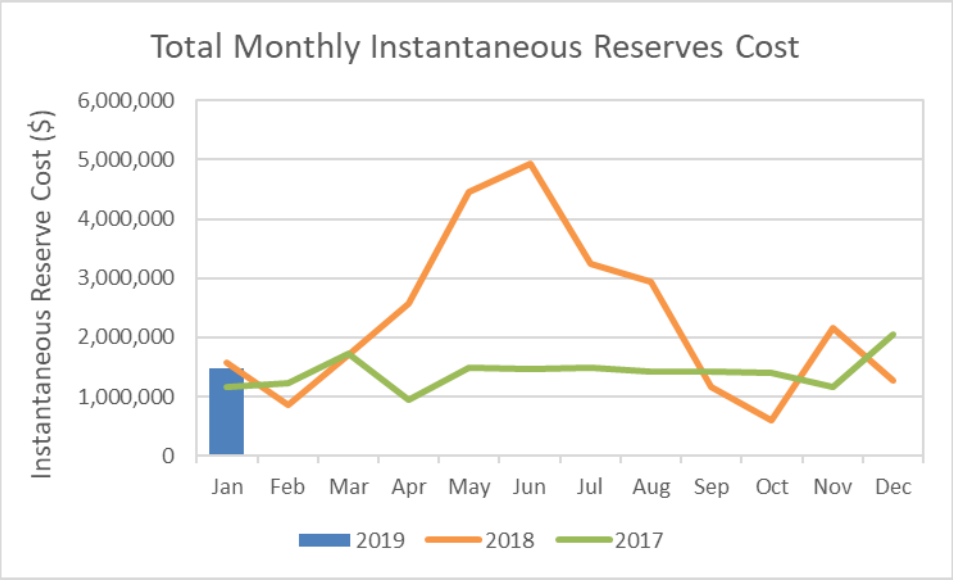
The latest version of the Hydro Risk curves have now been published on the HRC page of the Transpower website. The effect of the upcoming Pohokura gas field outages in February/March have been included and there is no material impact on the curves, however we will continue to monitor this and will update the curves accordingly.

The 2019 Annual Security of Supply Assessment, was sent out in draft form for industry comment on 8 February.

15 Ancillary services

Ancillary services costs dropped in January after two relatively expensive months. There were high instantaneous reserve costs due to the HVDC Pole 2 outage on the 22 and 23 November, and there were high frequency keeping costs in December due to Tekapo A frequency keeping during two outages at a cost of $414,000.

Instantaneous Reserves costs for January 2019 were similar to those for January in 2017 and 2018.



The cost breakdown for January is shown in the following table.

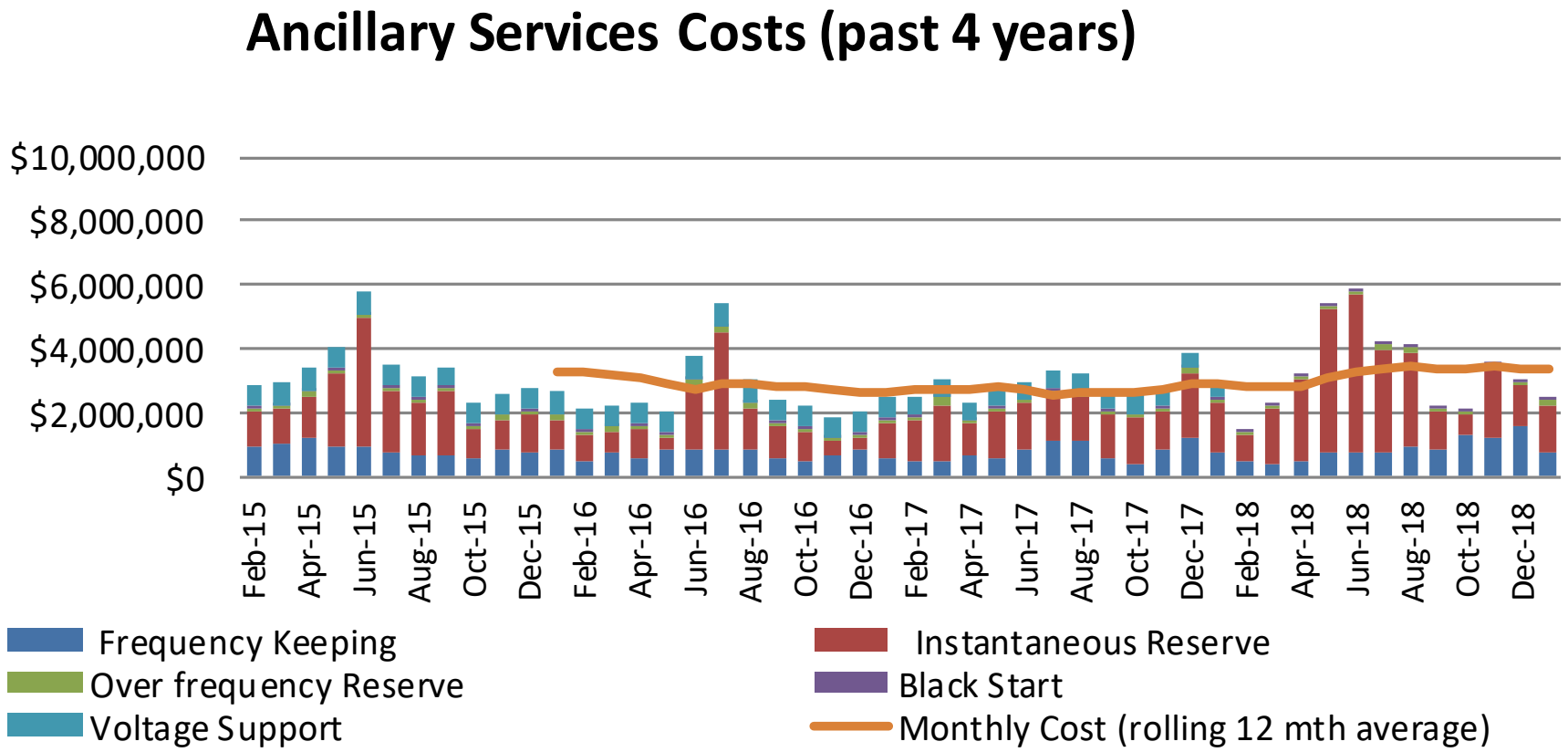
Ancillary service	**January 2019 cost**
Frequency keeping	$747,947
Instantaneous reserve	$1,479,654
Over frequency reserve	$158,312
Black Start	$55,706
Total	**$2,441,619**

Refer to Appendix B for more detailed Ancillary Services graphs.

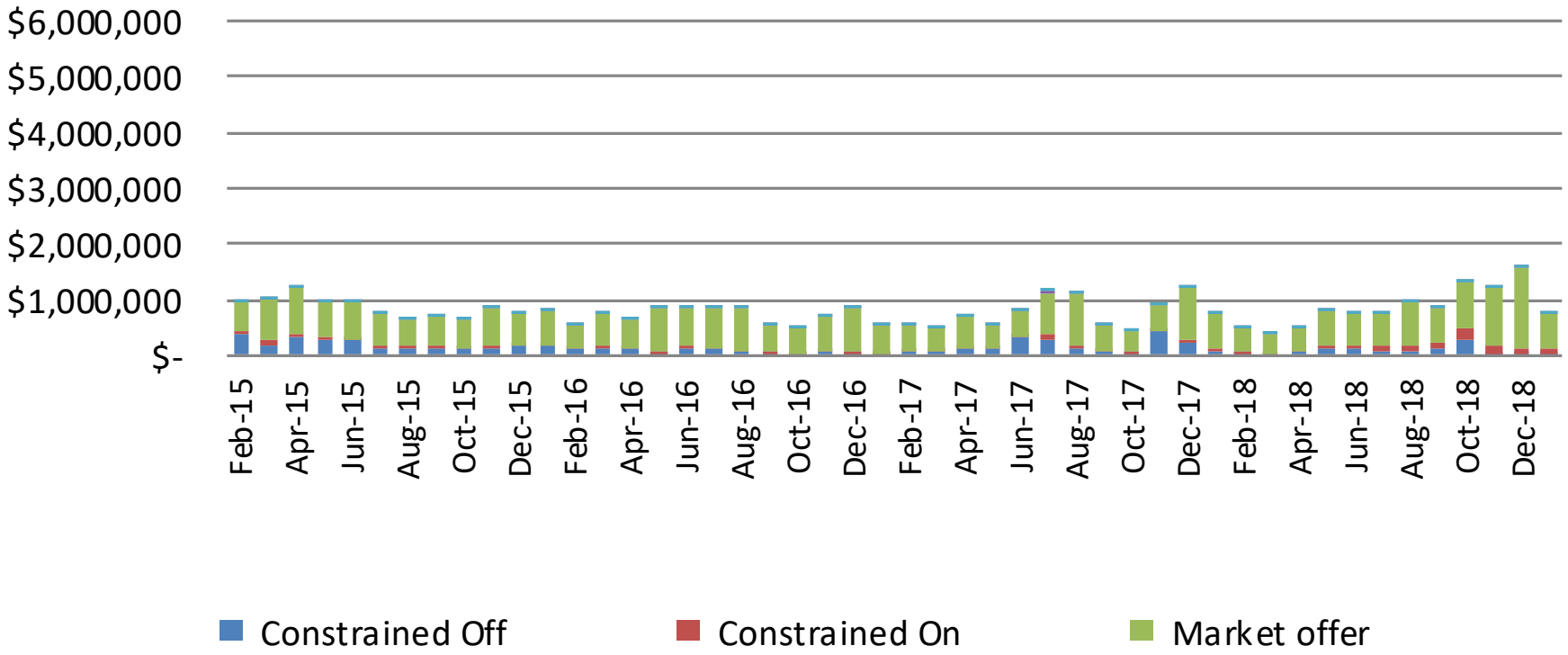
Appendix A: Discretion

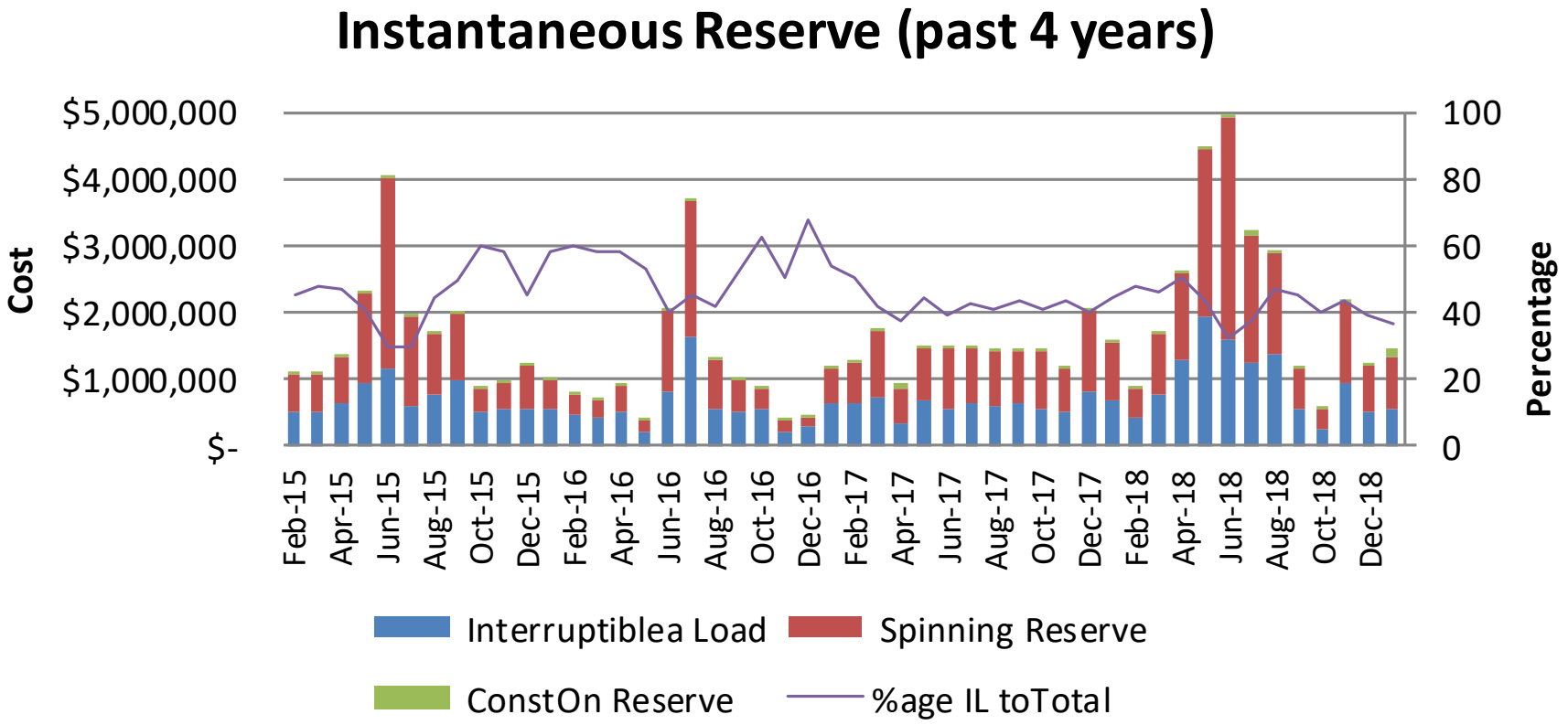
Event Date and Time	Event Description
6/01/2019 22:00	MTI2201 MTI0 : MTI bus trip
6/01/2019 22:00	WPA2201 WPA0 : MTI bus trip
15/01/2019 1:35	MAN2201 MAN0 : To restore Potline 4
15/01/2019 23:05	MAN2201 MAN0 : Return of Extended Potline 4
30/01/2019 18:08	TKA0111 TKA1 : ABY_TKA_1 circuit tripped

Appendix B: Ancillary Services Graphs



Frequency Keeping (past 4 years)




Instantaneous Reserve (past 4 years)
Cost
$5,000,000
$4,000,000
$3,000,000
$2,000,000
$1,000,000
$-
100
80
60
40
20
0
Percentage
Feb-15
Apr-15
Jun-15
Aug-15
Oct-15
Dec-15
Feb-16
Apr-16
Jun-16
Aug-16
Oct-16
Dec-16
Feb-17
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Oct-17
Dec-17
Feb-18
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Jun-18
Aug-18
Oct-18
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