SO QUARTERLY OPERATIONAL AND SYSTEM PERFORMANCE REPORT

FOR THE ELECTRICITY AUTHORITY

Transpower New Zealand Limited

April to June 2017

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 Q4 (April to June) 2017, 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 in the 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.

Operational issues and a detailed system performance report (Code obligated) are provided for the information of the Electricity Authority (Authority).

Monthly Report – June

1 Operational and system performance update

No major system events in the month. One significant generator tripping occurred on 15 June when Taranaki Combined Cycle (TCC) generator tripped from 310 MW. This resulted in North Island frequency falling to 49.17 Hz and South Island to 49.29 Hz. The under-frequency event was managed by dispatched generator reserves and interruptible load. TCC had recently been returned to service to address the dry winter situation and such trippings due to issues with ancillary equipment at the station are not unexpected.

HVDC transfer has been mainly in south flow, with north flow during some morning and evening peaks only. The south transfer level reached 650 MW during the month, the highest since commissioning of Pole 3 in 2013. The investigation of the Over Frequency Reserves constraint limited HVDC south transfer that occurred on 25 May has been concluded. Increased transfer capacity from refinements to the system operator's tools has resulted in increased transfer capacity without the need to procure additional reserves at this time.

HVDC Poles 2 and 3 tripped and restarted several times on 18 June due to insulator salt contamination on a section of the HVDC overhead line near Wellington. With the emerging dry winter situation, it was decided to address the issue with two short notice outages. This will avoid a potential unplanned outage at a later date if the salt contamination was not naturally resolved by heavy rain. Two planned outages on 19th and 20th enabled insulator washing and replacement on the affected section of the line.

Meridian has requested to perform a drop load test on Manapouri unit 3 in July. This is considered a high impact test as the South Island system frequency can potentially drop below 49.2 Hz as the tests include generation rejection up to 140 MW. Similar testing in 2013 resulted in a South Island under-frequency event. Arrangements for these tests will seek to avoid a repeat, mindful that the Authority Rulings Panel concluded the system operator was at fault in 2013.

2 Market design and system enhancement project updates

Progress against 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 – Work to finalise Implementation Guidelines continues and effort next month will shift to the re-estimation of implementation costs. A Change Request is being prepared for additional project management support and technical advice to assist with issue resolution between now and the delivery of the Procurement Schedule in October 2017. A capital project to implement the tool changes is planned to commence in July.

Gate Closure – Gate Closure went live successfully on 29 June. Market system gate closure is now reduced from 2 hours to 1 hour.

Real Time Pricing – Transpower has been assisting the Authority with the development of the consultation paper due for release in August. A project assurance activity undertaken through PJM has concluded demonstrating that the project is proceeding well, with positive support of the conceptual design that had been developed. Requirements and design work are expected to recommence in October 2017.

EDF Phase III – This project will refresh dispatch functionality within the market system, reducing barriers to entry and enable future dispatch products to be implemented. The investigation project was completed with an initial business case and associated consultation paper delivered to the Authority. The appropriation approval process is now underway. The capital phase of the project is planned to commence in 2017/18.

3 Security of Supply update

Hydro storage has continued to decline due to below average inflows in both islands during June. Storage levels were at 40% of total at the end of the month. The hydro risk meter is set to watch for the South Island and New Zealand.

Thermal generation met 27% of demand in June, compared to 15% for the same month last year.

For the month of June:

- North Island inflows were 74% of average[1]
- South Island inflows were 67% of average[2]
- Hydro generation met 53% of demand.

As at 1 July, aggregate primary New Zealand storage was 64% of average and tracking along the 2% hydro risk curve. Storage in the South Island was sitting between the 2% and 4% risk curves.

Having crossed the 1% hydro risk curve (HRC) in late May by mid-June the New Zealand HRC was just below 2% and the South Island about 60 GWh above the 4% HRC. A handful of rainfall events have held the risk at this level during the latter part of the month. Wind generation has also been low, typically averaging only 10% of capacity compared to the long-term average of above 40%. The hydro risk curves reduce sharply during July and August in anticipation of spring inflows. Therefore if North Island thermal generation continues at present levels, it is unlikely that hydro storage will reach the 10% threshold (the emergency zone) that would trigger an Official Conservation Campaign (OCC).

[1] Measurements are based on daily inflow values.
[2] Measurements are based on daily inflow values.

A teleconference regarding dry winter planning was held with industry 14 June. Approximately 60 attendees participated in a discussion which traversed Transpower's current actions preparing for a possible dry winter and what participants may also need to do should the current low South Island hydro situation continue to deteriorate. A request for an urgent change to include contingent storage in Lake Pukaki and Hawea at the 4% South Island HRC was not progressed after both considering industry feedback and subsequent advice Meridian Energy would not have received a non-notified consent for this change. Key to our decision was the likely net benefit of making the change under urgency was low.

An application for funding for an official conservation campaign is being finalised for approval by the Authority. Preparations for a campaign will only be triggered if we are below the 4% HRC and there are five or more historical inflow sequences that hit the emergency zone or it is triggered short notice if a major thermal plant fails. The campaign will include communications teams in EECA and the Authority. EECA have strong trusted branding consistent with the messaging required for a campaign.

Compared to previous dry winter experiences in 2001 and 2008 there are far fewer grid constraints on transfer into and through the South Island as well as less thermal generation in the North Island. This has led to an urgent review of the benefits of triggering a national saving campaign at the same time as the South Island reaches the emergency zone and triggers a South Island OCC, should this occur. The Code envisages a South Island campaign being initiated first based on the status of the power system in 2011, prior to commissioning Pole 3 and recent North Island thermal generation exit decisions.

Real time and planned power system operations are ensuring constraints on south flows from the North Island over the HVDC link and through the South Island are understood by participants and minimised where possible. This includes rescheduling grid outages were possible. South power transfer constraint identification and rectification option studies are almost complete. As an immediate step to improve energy transfer into Southland variable line rating will be introduced in mid-South Island transmission circuits to ease limitations on transfer through the South Island if lower South Island catchments are at minimum levels.

4 Compliance update

The system operator reported one breach of the Code in June, for a failure of a long non-response schedule to complete solving within the required one hour. The cause of the delay was a hardware fault in one of the machines hosting the market solver.

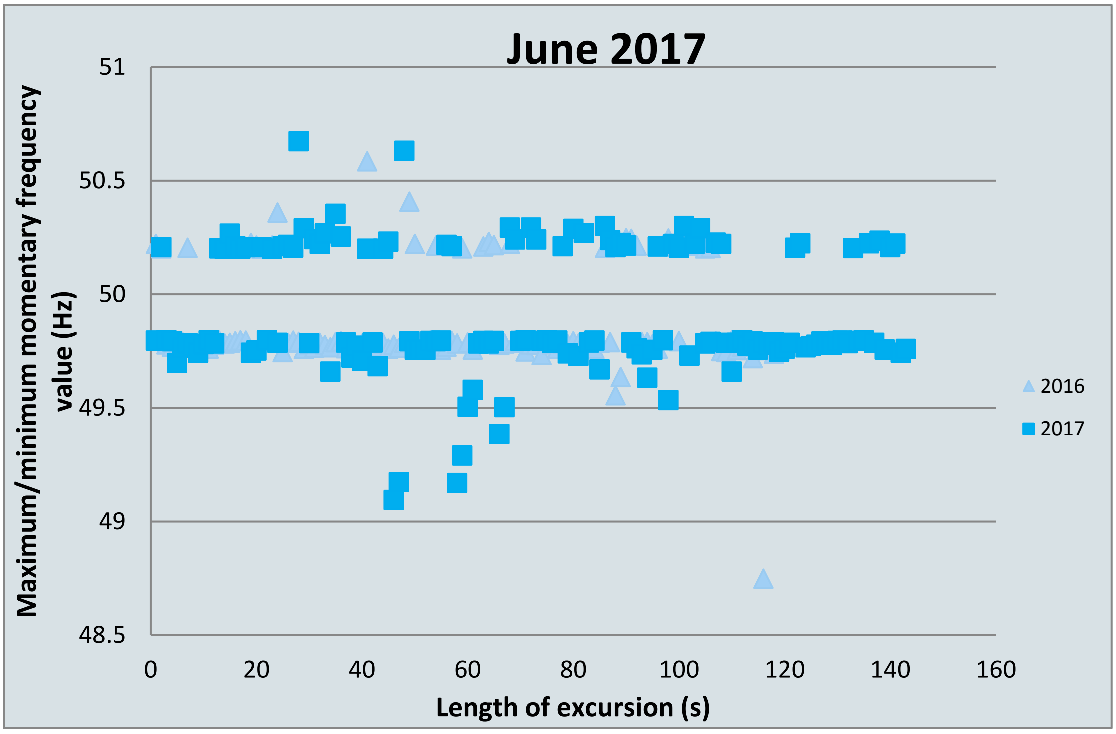
Appendix B shows instances where the system operator has applied discretion under 13.70 of the Code.

5 Operational management

5.1 Frequency fluctuations

Maintain frequency in normal band and recover quickly from a fluctuation

The chart below shows the maximum or minimum frequency reached and length of each frequency excursion outside the normal band (49.8 to 50.2 Hz) during the reporting period.



Maintain frequency and limit rate occurrences during momentary fluctuations

The table below shows the total number of momentary fluctuations outside the frequency normal band, recorded in both islands, for each month over the last 12 months and the 12 month cumulative totals, grouped by frequency band.

Frequency Band	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Annual rate
55.00 > Freq >= 53.75													
53.75 > Freq >= 52.00									1				**1**
52.00 > Freq >= 51.25													
51.25 > Freq >= 50.50			2			1	1	1	1	1	1	2	**10**
50.50 > Freq >= 50.20	25	13	32	39	45	32	34	20	17	24	34	50	**365**
50.20 > Freq > 49.80													
49.80 >= Freq > 49.50	128	102	153	101	101	59	67	49	79	84	92	86	**1101**
49.50 >= Freq > 48.75	1		2	2	3	1	2		1			5	**17**
48.75 >= Freq > 48.00									1				**1**
48.00 >= Freq > 47.00									1				**1**
47.00 >= Freq > 45.00													

Note the frequency excursions for March include simultaneous over-frequencies and under-frequencies that occurred when the South Island was split into two electrical islands on 2 March.

Manage time error and eliminate time error once per day

There were no time error violations in the reporting period.

5.2 Voltage management

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

5.3 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	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17
Demand Allocation Notice	-	-	-	-	-	-	-	-	-	-	-	-
Grid Emergency Notice	3	2	1	2	-	-	-	4	1	1	1	-
Warning Notice	2	5	1	-	-	-	-	-	-	-	-	-
Customer Advice Notice	8	7	5	12	26	7	11	7	24	10	16	23

5.4 Grid emergencies

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

Date	Time	Summary Details	Island
		None.	

6 Ancillary services

Two under-frequency events occurred in June. We are currently analysing the performance of interruptible load and reserve providers for the first event (11 June) and collecting data for the second event (15 June).

The request from a generation owner to provide instantaneous reserves at one of their generation stations in the North Island has been analysed and is currently on hold. Further analysis is required from the generation owner before a contract is drawn up.

Refer Appendix A for Ancillary Services Graphs.

7 Separation of Transpower roles

As system operator, Transpower has not been materially affected by any other role or capacity Transpower has under the Code or under any agreement.

Quarterly Report – Q4 (April to June)

1 Performance metrics

The following table shows system operator performance against the performance metrics for the financial year during Q4 as required by SOSPA 12.3 (a).

Performance Metric	Q3 Progress
Released at least $1 million of market benefits through the application of the CRE objective and/or implementing new capital investments:	• A change in the HVDC overload level on Pole 2 implemented in November 2016 was used to demonstrate a market benefit of greater than $1m. Documentation along with a peer review was provided to the Authority on 28 June 2017. Performance standard met.
77.5% of the participants responding to the annual participant survey rate the system operator's performance as 'good' or better:	• Result was 81%. Performance standard met.

2 Actions taken

The following table contains a full list of actions taken during Q4 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**:	• five business assurance audits were completed • eight capital projects from the Capex Plan have been commissioned on time and within budget • a final capex plan and roadmap and ICT strategic roadmap was delivered by 30 June 2017 • education and engagement, and statutory objective work plans for 2017/18 were delivered before 30 June 2017 for agreement • business plan for 2017/18 and strategic plan 2017-22 was delivered by 30 June 2017 • performance metrics and incentives were delivered and agreed by 30 June 2017
(ii) To comply with the **statutory objective work plan**:	**Policy and procedure alignment with CRE** Ongoing checks being undertaken for CRE as part of document review process. **Review of Contingent Storage under SOSFIP**

	Deferred to 2017/18. **Review of the Security Policy – busbars** Review completed. **Develop a suite of performance metrics** Performance metrics (forming the basis of the performance metrics and incentive agreement for 2017/18) have been agreed.
(iii) In response to participant responses to any **participant survey**:	Participant survey responses were analysed. Areas for improvement were communications, responsiveness, and knowing the customer. System operator industry workshops have been changed to a more interactive format and informal ad-hoc meetings with participants are being held.
(iv) To comply with any **remedial plan** agreed by the parties under SOSPA 14.1 (i):	N/A – No remedial plan in place.

3 Cost-of-services reporting

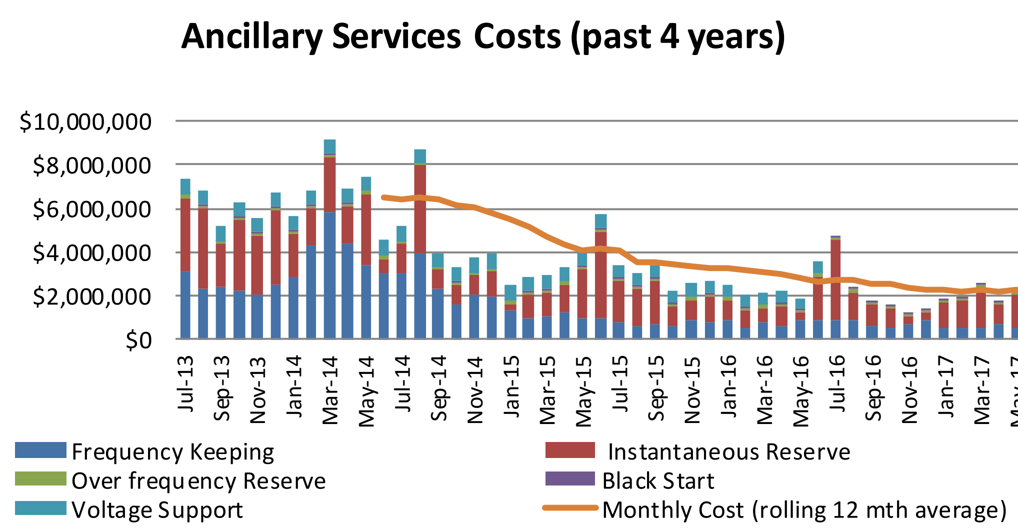
The feasibility study into implementing annual cost-of-services reporting to the Authority is required in financial year 2 (SOSPA 12.6 refers). Initial high level assessment of options is underway and planning continues for the work to be completed by the end of the 2017/18 year.

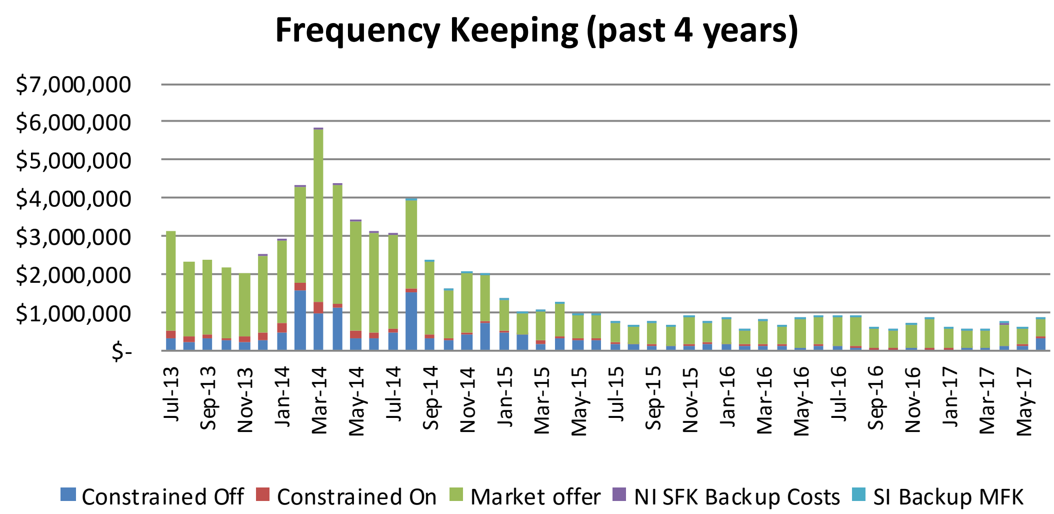
4 Technical advisory hours and services

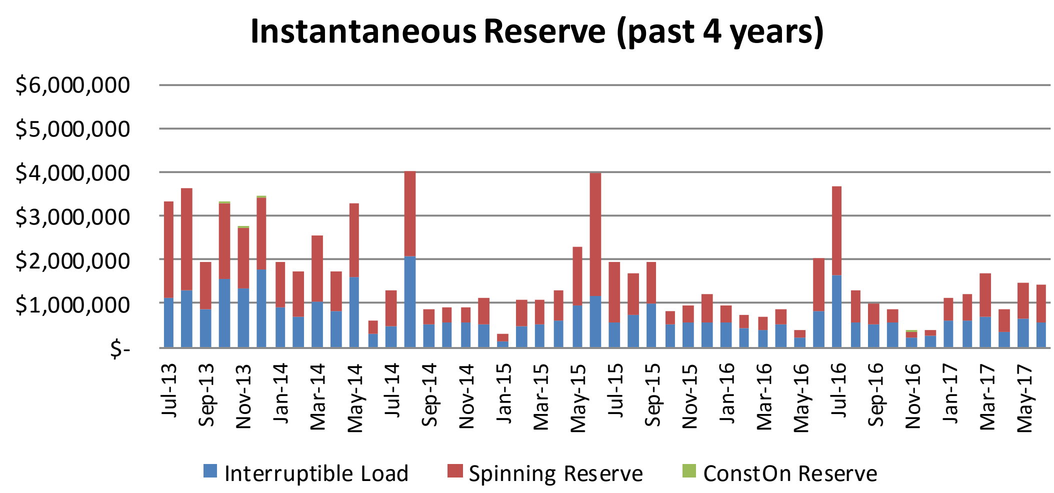
The following table provides the technical advisory hours for Q4 and a summary of technical advisory services to which those hours related (SOSPA 12.3 (d) refers).

TAS Statement of Work (SOW)	Status	Hours worked during Q4
TAS SOW 64 – ESB for NZX	Closed	309.75
TAS SOW 65 – Assessment of implementing the load aggregator participant type and block demand dispatch	In Progress	76.00
TAS SOW 66 – Investigation of potential reforms of voltage support ancillary service	In Progress	11.25
TAS SOW 67 – Conclusions from IR Market Review	In Progress	50.50
Total hours		**447.50**

Appendix A: Ancillary Services Graphs







Note: IR Cost May 2012 = 14.129M, IR Cost Jun 2012 = 8.164M

Appendix B: Discretion

Event Date & Time	Subject	Event Description
14/6/2017 7:58:04 AM	DISCRETION	ARG1101 BRR0 Discretion Clause 13.70, Part 13 ENR Max : 0 Start: 14-Jun-2017 07:58 End: 14-Jun-2017 08:30 Notes: ARG_KIK_1 outage from 08:00. BRR off for the switching. Last Dispatched Mw: 11
16/6/2017 1:24:20 PM	DISCRETION	ARG1101 BRR0 Discretion Clause 13.70, Part 13 ENR Max : 0 Start: 16-Jun-2017 13:30 End: 16-Jun-2017 14:00 Notes: Last Dispatched Mw: 0