Under-frequency Reserve Availability under Frequency Keeping Control

Transpower New Zealand Limited
August 2016

Keeping the energy flowing

TRANSPOWER

Version	Date	Change

	Position	Date
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EXECUTIVE SUMMARY

Frequency Keeping Control (FKC) is a control system of the HVDC introduced during Transpower's HVDC Pole 3 Upgrade project (commissioned in 2014). FKC ties the North and South Island frequencies together by varying the power transfer on the HVDC link.

During FKC operations South Island generators have experienced increased governor action due to a more variable system frequency and from their equipment picking up some of the action previously carried out by the frequency keeping service. A recommendation from the FKC Trial report (June 2015) was for Transpower to study whether this increased governor action reduces under-frequency reserve availability in the South Island.

This report is of Transpower's study which looked at reserve availability in South Island generators from April 2015 - April 2016. This study calculated the total Fast Instantaneous Reserve (FIR) available and subtracted the dispatched FIR to find the spare FIR available. More detailed analysis was made of three cases representing a range of HVDC transfer.

The analysis demonstrates that at all times of FKC operation there has been sufficient spare instantaneous reserves (IR) in the South Island.

A National Market for Instantaneous Reserves (NMIR) will soon be implemented which may mean less IR will be purchased.

Transpower recommends this study is repeated after the NMIR is implemented.

INTRODUCTION

AUDIENCE AND ABBREVIATIONS

The primary audience for this report are the Electricity Authority, System Operator and market participants.

This report assumes readers have prior knowledge of IR in a wholesale electricity market and power system operations context.

The full form of abbreviations used in this report can be found in Appendix 1.

PURPOSE

The study investigated whether FKC, causing increased governor action of generators in the South Island, has a material effect on the quantity of reserve available for under-frequency events. The study responds to the fourth recommendation made in the FKC Trial report[1].

RESERVE AVAILABILITY UNDER FREQUENCY KEEPING CONTROL

The HVDC Pole 3 Upgrade project delivered a new control system called FKC. FKC varies the power transfer across North and South Islands aiming to keep the system frequency on both islands equal; control of system frequency is now generally shared across both islands.

Apart from hydro generators most New Zealand generator governors have a dead band in response to the normal frequency band (49.8 Hz to 50.2 Hz). This dead band means almost all response to frequency variations in the normal band comes from hydro generators.

The governors of hydropower generators are generally set without dead bands as:

- unused water can be stored in reservoirs, whereas other fuel sources cannot be so cheaply preserved
- the impact on hydropower turbines is perceived to be significantly lower than thermal plants, mainly from issues around thermal cycling which reduce the lifespan of thermal plants

FKC operations can lead to a higher response to frequency from South Island where generation is mainly hydropower and a lower response from North Island, where generation is a mixture of hydropower, thermal, geothermal and wind.

IR is required to maintain system frequency for an under-frequency event. The increased governor action in the South Island could adversely affect the quantity of IR available.

[1] Link for FKC Trial report: https://www.transpower.co.nz/sites/default/files/bulk-upload/documents/FKC%20Trial%20Report.pdf

BACKGROUND

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For information on frequency requirements see Appendix 2. For information on instantaneous reserves and generator operating modes see Appendix 3.

RESERVE MANAGEMENT TOOL

Reserve Management Tool (RMT) is a software tool used by the market system to calculate how much reserve is required on the power system.

Generation and IL offers are sent to the system operator through the Wholesale Information and Trading System (WITS). The grid owner sends HVDC availability indicating transfer limits information to the system operator. RMT calculates the reserve requirement and the Schedule, Pricing and Dispatch SPD tool co-optimises the energy and reserve dispatch. Reserve schedules are dispatched to generators and the IL providers.

NATIONAL MARKET FOR INSTANTANEOUS RESERVE PROJECT

Market participants in the New Zealand market currently supply IR to cover the risk setters in each island. The aim of the NMIR project is for IR to be procured in a national market by allowing IR to be traded across the HVDC link.[2] This is now possible due to the recent upgrade on the HVDC and its control system.

A national market increases competition between IR providers in both islands which is expected to decrease cost of purchasing IR.

[2] For further information on NMIR see: http://www.ea.govt.nz/development/work-programme/wholesale/national-instantaneous-reserves-market/

ASSUMPTIONS AND METHODOLOGY

ASSUMPTIONS

Studying South Island generators only

The FKC trial report detailed an increase in South Island governor action and a decrease in North Island governor action with FKC in service. The increase in South Island governor action means there is an increased risk of insufficient reserve being available whereas the North Island sees a decrease in this risk.

Assuming the status quo was an acceptable risk, only the South Island was studied. The FKC trial found that the introduction of FKC brought tighter control of normal frequency with reduced frequency deviation overall, but with a decrease in North Island and an increase in South Island.

Choosing suitable study periods based on HVDC transfer

The study time periods were based on the quantity of HVDC transfer (at the times studied) to represent a range of operating conditions.

Highest south power transfer on HVDC

When the HVDC is in high south transfer there is often a dry (low storage) situation in South Island. Generators in the South Island will be particularly focused on using water as efficiently as possible. There are likely to be fewer South Island generators in service and hence fewer generators able to contribute to FIR.

The study therefore assumed the quantity of spare (un-dispatched) FIR would be lowest when the HVDC power transfer is from the North Island to the South Island is the highest.

Highest north power transfer on HVDC

When the HVDC is in high north transfer, there is often an abundance of stored water in South Island. There are likely to be many South Island generators in service and hence many generators able to contribute FIR. However, generators may be operating at maximum output which might result in less headroom for South Island generators to provide IR.

In high north transfer it was therefore assumed there would be more spare FIR than the highest south flow on HVDC, but less than the average power flow.

Average power flow on HVDC

The mean HVDC power flow over the period of a year with FKC enabled was selected for comparison of reserve availability. When HVDC transfer is at average levels of transfer there is expected to be more IR than the highest north and south flows. There are likely to be more hydropower generators in service than in a dry period meaning more units able to provide reserve. As the generators are not operating at their maximum output, they will have headroom to provide IR.

In average transfer it was therefore assumed there would be the most spare FIR. The mean HVDC power flow over the period of a year with FKC enabled was selected.

Generator FIR performance was based on RMT / test results

Look-up tables were based on those used in RMT and were used to estimate FIR contribution from different generating units. RMT models are based on submitted Asset Capability Statement (ACS) governor models. It is assumed these models are good representations of the actual generator performance being based on generator test results.

Generators were tested for their 6 second FIR performance at various operating points using measured data from an under-frequency injection test. This gave an indication of the expected FIR a generating unit could provide under a real under-frequency event.

Smaller non-IR market generators contribution

The large hydropower units offer FIR on the reserves market. There are smaller hydropower generators that do not contribute to the IR market, but their governors still respond to under-frequency events. Some smaller generators were tested for their FIR performance and were included in the analysis.

METHODOLOGY

Choosing study periods

The different levels of HVDC transfer over the year were analysed using Plant Information (PI - a tool which collects and archives data about various primary assets). Figure 1 shows the cumulative distribution function (CDF) for HVDC north transfer north which covers the periods studied. Negative values indicate south transfer.

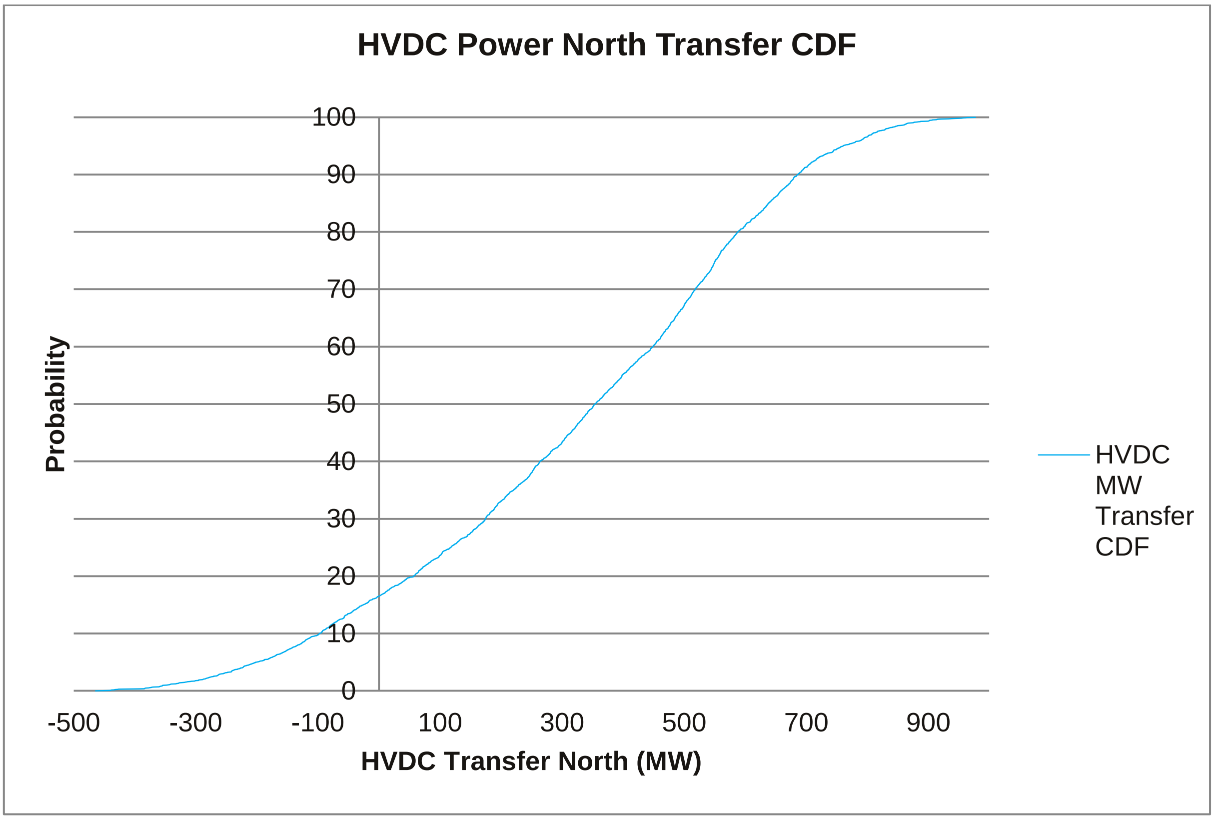

Figure 1: Cumulative distribution function for the HVDC Transfer from South Island to North Island with FKC enabled in June-September 2015

Calculating total available reserves

The days of the identified study periods were analysed, comparing estimated available FIR with dispatched FIR. Estimated FIR was calculated using the actual power generated by each South Island generating unit (using PI) in 15 second intervals as an input to the FIR look up tables. The Market Operator Interface tool was used to gather dispatched FIR data. The worst case was identified when the difference between the estimated FIR and dispatched FIR was lowest.

Estimated FIR tables for Partially Loaded Spinning Reserve mode

The FIR characteristic for each generator changes with its power output. Figure 2 shows a typical MW-FIR characteristic curve for a South Island hydropower generator.

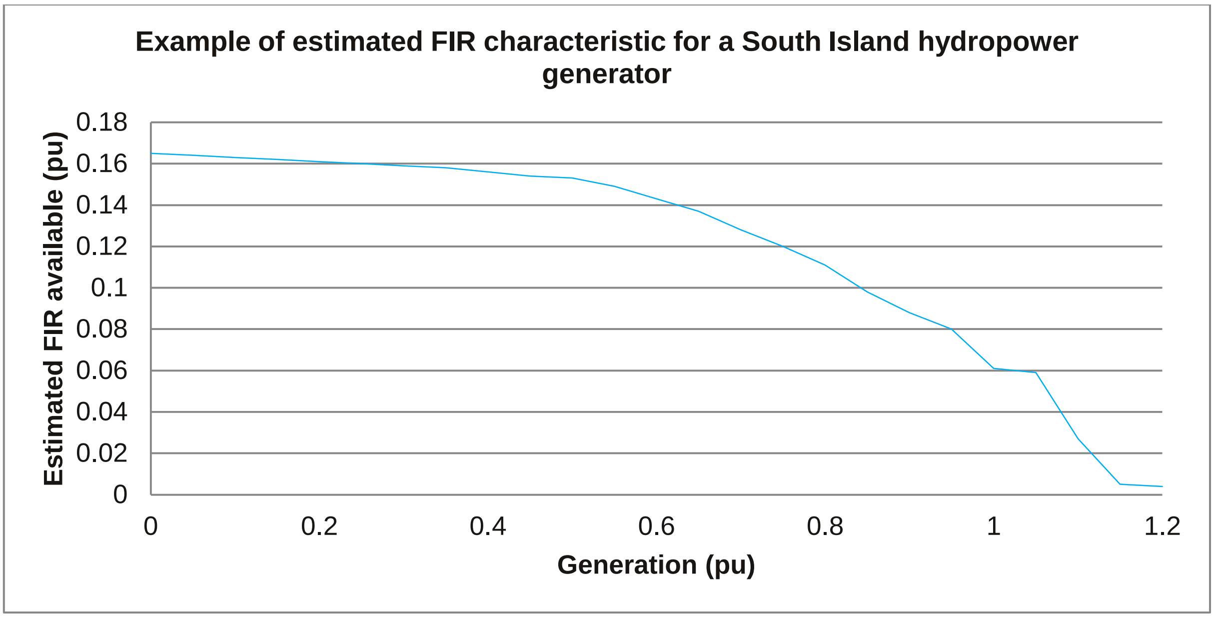

Figure 2: Estimated FIR characteristic for South Island hydropower generator example

Accounting for Tail Water Depression mode and breaker status

Some hydropower generators can operate in Tail Water Depression (TWD) mode. They can offer a certain percentage of their maximum output as FIR.

The generators operating in TWD generally draw power from the grid. TWD mode can be detected as a small negative power output but PI data values can fluctuate around zero (due to the inertial response of the generator). The status of the circuit breaker that connects the unit to the power system is checked to verify if the generating unit is in service, or out of service. If the circuit breaker is closed and a small negative power is detected, the generator is assumed to be in TWD mode.

Accounting for feed-forward

Some generators have feed-forward capability. Feed-forward bypasses governor droop by increasing the gain on the error. In feed-forward mode a generator's output can ramp up rapidly to its dispatched FIR or a set value within the governor. For the analysis, the FIR available for these generators was estimated to be equal to their FIR dispatch, rather than predetermined estimates from the MW-FIR characteristics.

TSAT simulation

This worst case for the day was simulated using TSAT. After adjusting the generation and HVDC transfer to closely represent the system at the worst case, the risk setter was tripped to see how generators and the HVDC responded, how frequency deviated and whether AUFLS blocks were tripped. This provided more insight about each case than simply considering the quantity of spare FIR alone.

FINDINGS AND DISCUSSIONS

CHOSEN STUDY PERIODS

Analysing the HVDC power transfer for a year it was found that the:

- highest HVDC transfer north was 1009MW on 9 June 2015
- lowest HVDC transfer north was -345MW on 21 September 2015
- mean HVDC transfer north was 476MW. This level of HVDC transfer occurred on multiple days. A sample was chosen on 7 August 2015 to represent the average HVDC transfer case, when FKC was enabled.

Figure 3, 4 and 5 show the calculated spare FIR in the South Island on the chosen periods. The TSAT simulations were based on the minimum spare FIR value for each of the periods.

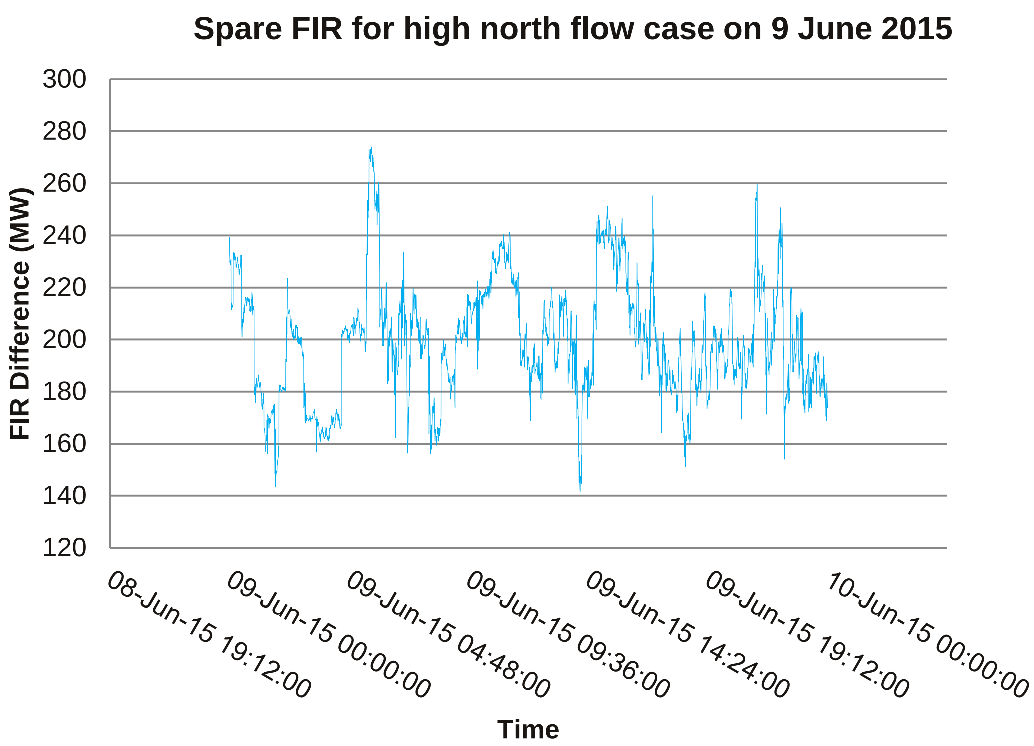

Figure 3: Spare FIR available in South Island on 9 June 2015

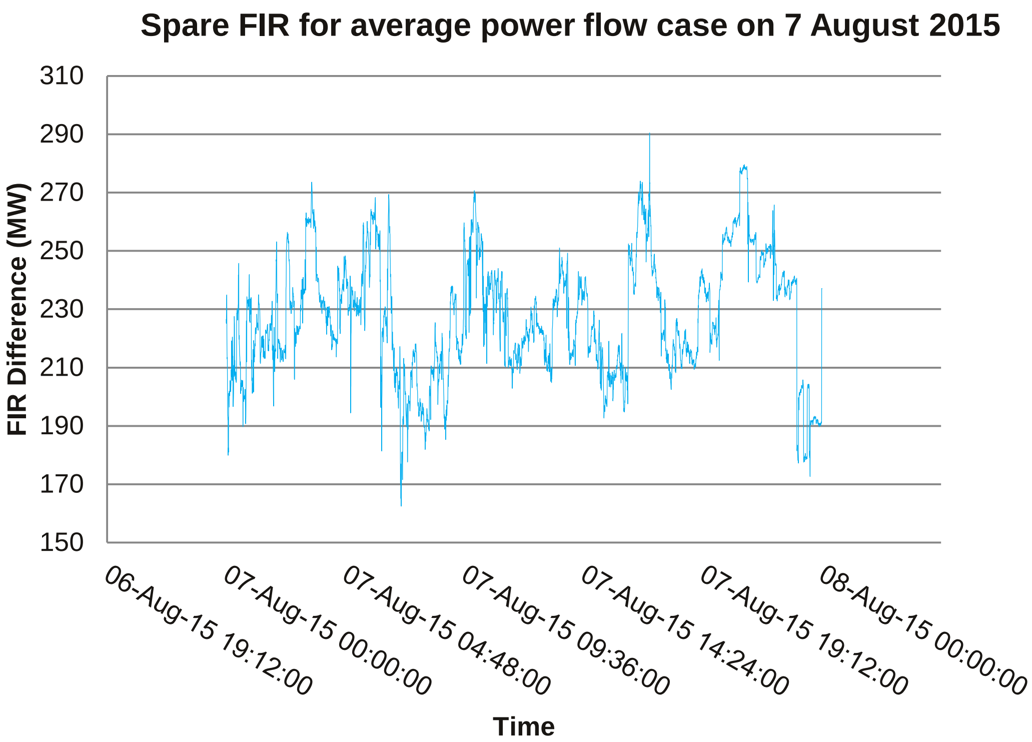

Figure 4: Spare FIR available in South Island on 7 August 2015

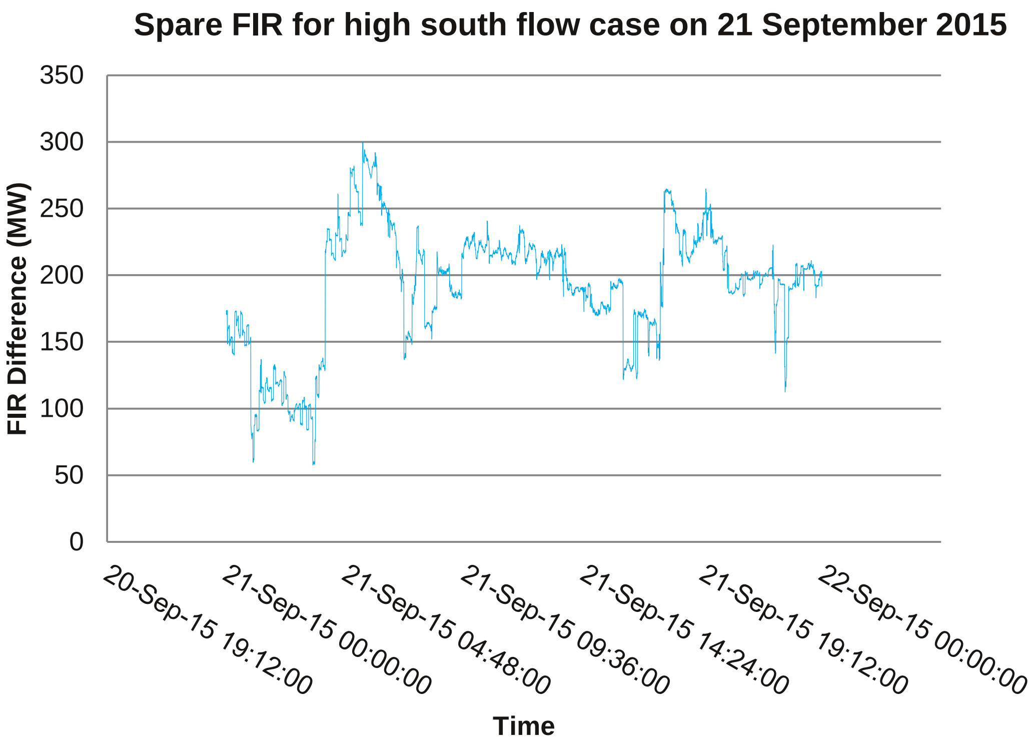

Figure 5: Spare FIR available on the system on 21 September 2015

The main change with NMIR is that IR will be purchased to cover the national risk setter instead of a risk setter per island. This is expected to result in generator operating on tighter margins. It is recommended the study is repeated once NMIR is established to see how the quantity of spare FIR is affected.

HIGH SOUTH FLOW ON HVDC

Results

Figure 6, 7 and 8 show how South Island frequency, generation, load would be affected if the HVDC bipole had been lost on 21 September 2015 at 1:05am. This is when minimum spare FIR was available across the day.

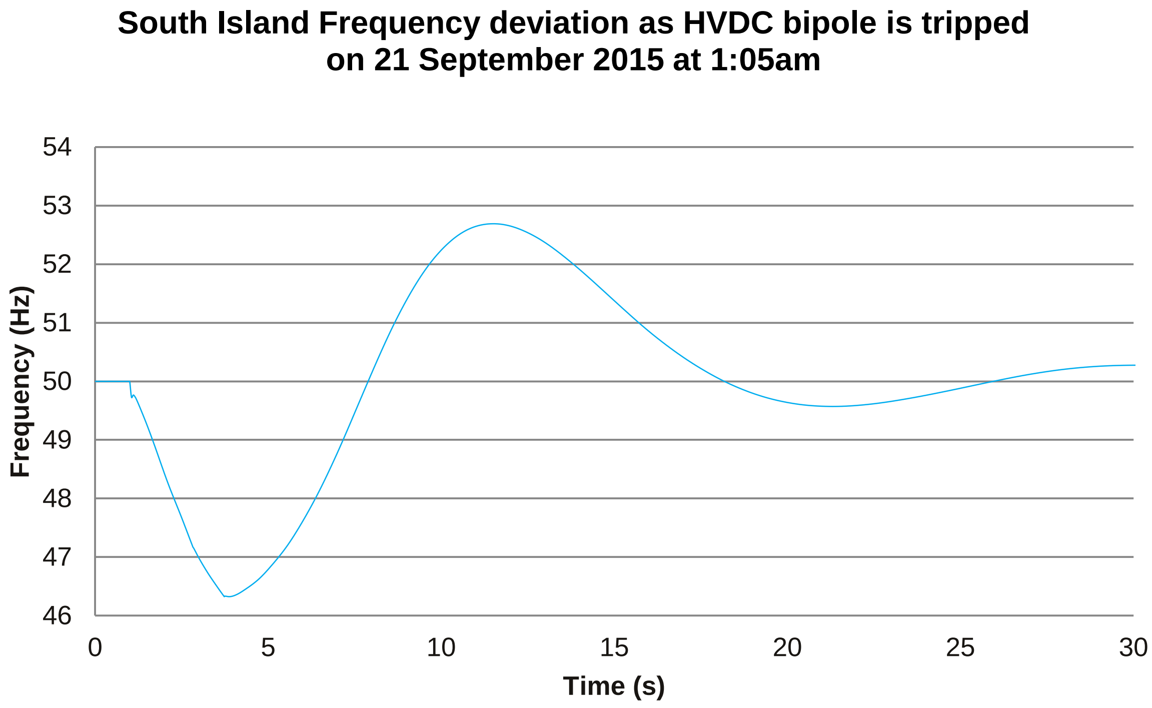

Figure 6: South Island frequency deviation after HVDC Bipole trip on 21 September 2015 at 1:05am from TSAT model

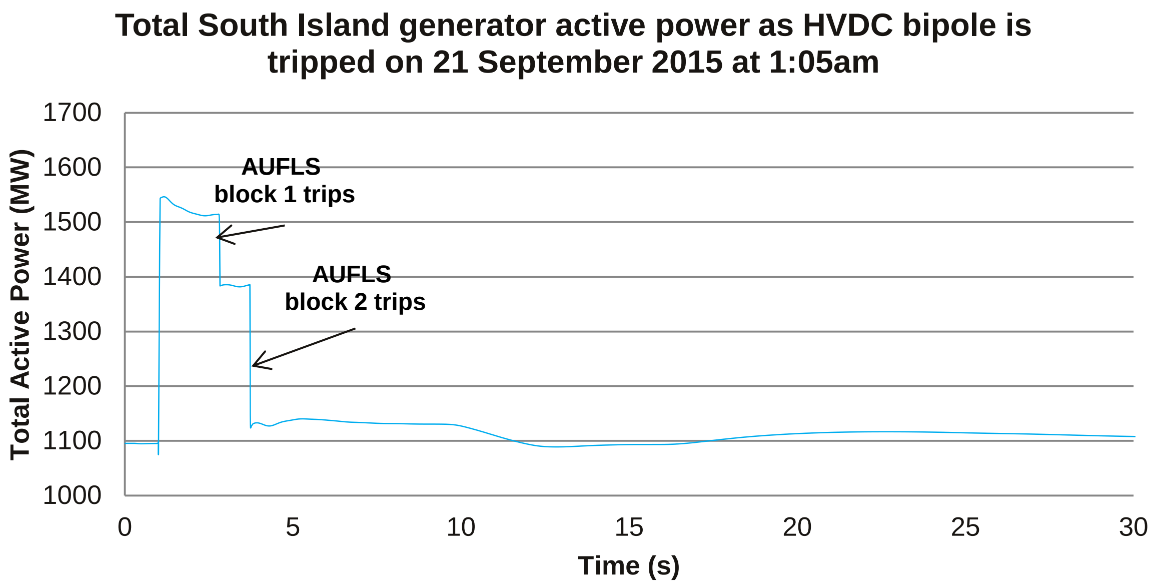

Figure 7: South Island generators active power after HVDC bipole trip on 21 September 2015 at 1:05am from TSAT model

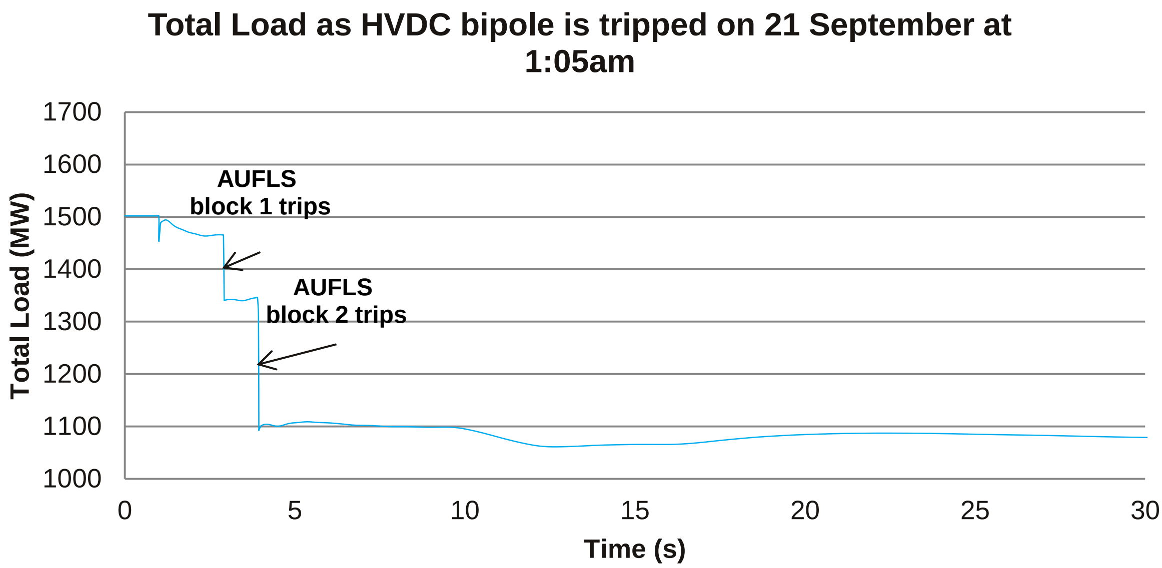

Figure 8: South Island non-linear load active Power for HVDC bipole trip contingency on 21 September 2015 at 1:05am from TSAT model

Discussion

There was at least 57-59MW of spare FIR available on the system. On 21 September at 1:05am there was 59MW of spare FIR on the system. The risk setter at the time was the HVDC bipole. This scenario was simulated in TSAT to predict how the power system would react if an under-frequency event was caused by the HVDC bipole tripping.

High south flow on the HVDC on the 21 September 2015 at 1:05am indicated a dry period as the system was importing power from the North Island. At the time, the loss of HVDC bipole (DC ECE risk) was the risk setter for the South Island.

The HVDC south power flow at the time was 480 MW. When the HVDC bipole was tripped the frequency dipped to 46.4Hz (Figure 6). As the South Island frequency dropped below 48Hz, the FIR available from generators and interruptible load was not able to arrest frequency fall by itself. As the HVDC bipole is an ECE event and a rare occurrence, load shedding in the form of AUFLS would be justified to restore system frequency. The frequency would fall below the first and second block of AUFLS, meaning at least 32% of South Island load would be shed. At this point there would be more supply than load, meaning South Island frequency would increase.

Figure 7 shows an oscillatory response summation of the active power output of South Island generators. The bipole was tripped at 1 second. At approximately 2.6 seconds the frequency fell below 47.5Hz so the first block of AUFLS tripped, corresponding to the drop in load from 1465MW to 1340MW shown in Figure 8. As the first AUFLS block tripped, generator active power also decreased from 1512MW to 1383MW, to balance the supply and demand (shown in Figure 7). The second block of AUFLS tripped at approximately 3.5 seconds as the frequency fell below 46.5 Hz, thereby tripping the second block of AUFLS. Consequently, load decreased from 1342MW to 1092MW.

Potline 1 of Tiwai is a large load, tripped when frequency reaches 46Hz. When block 2 of AUFLS tripped the generator active power also decreased from 1382MW to 1123MW (Figure 7).

The results show there is enough IR with at least 57MW of spare FIR available.

AVERAGE (MEAN) POWER FLOW ON HVDC

Results

Figure 9, 10, and 11 show how South Island frequency, generation and HVDC transfer would be affected if a Manapouri unit had tripped on 7 August 2015 at 7:03am. This is when minimum spare FIR was available across the day.

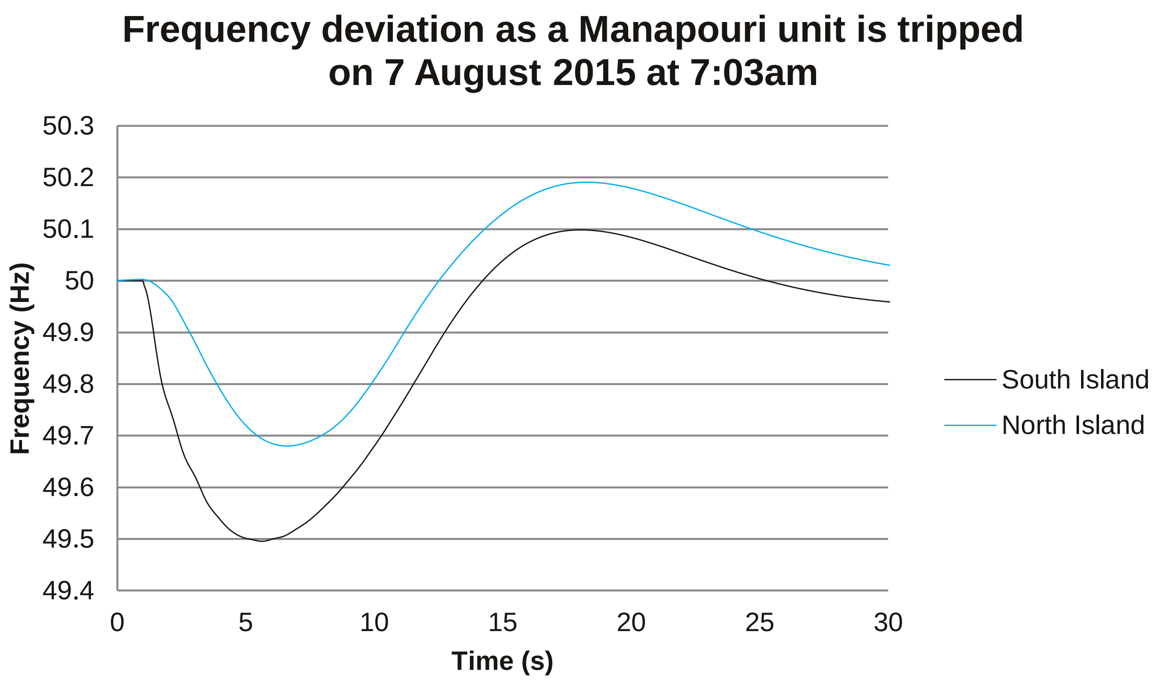

Figure 9: South Island frequency deviation after a Manapouri unit trip on 7 August 2015 at 7:03am from TSAT model

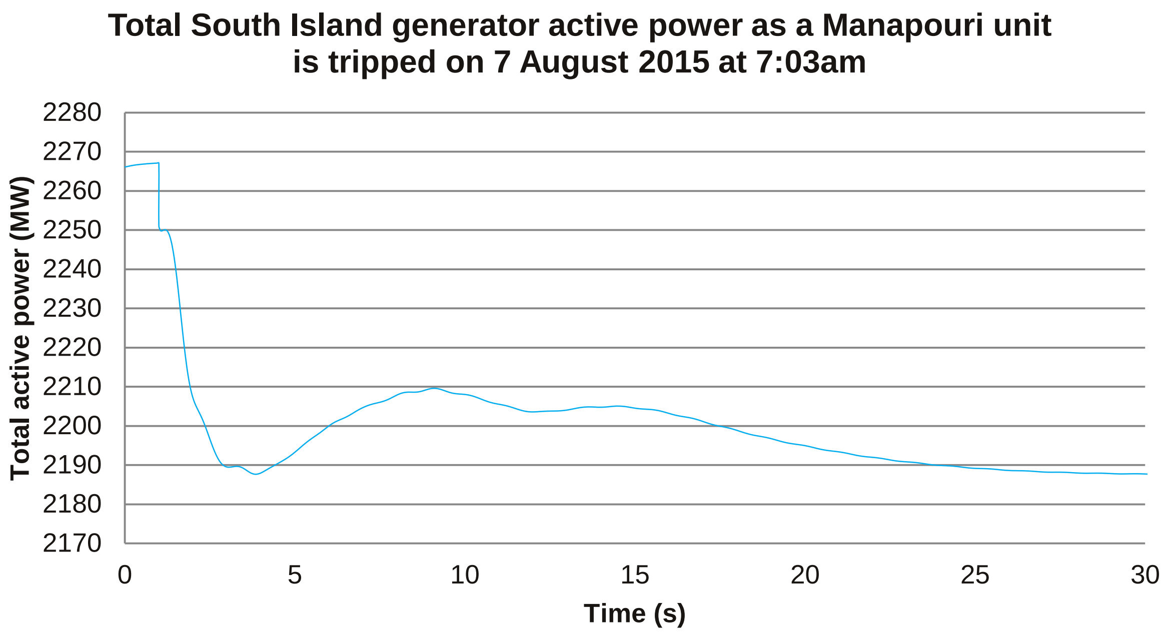

Figure 10: South Island generators active power after a Manapouri unit trip on 7 August 2015 at 7:03am from TSAT model

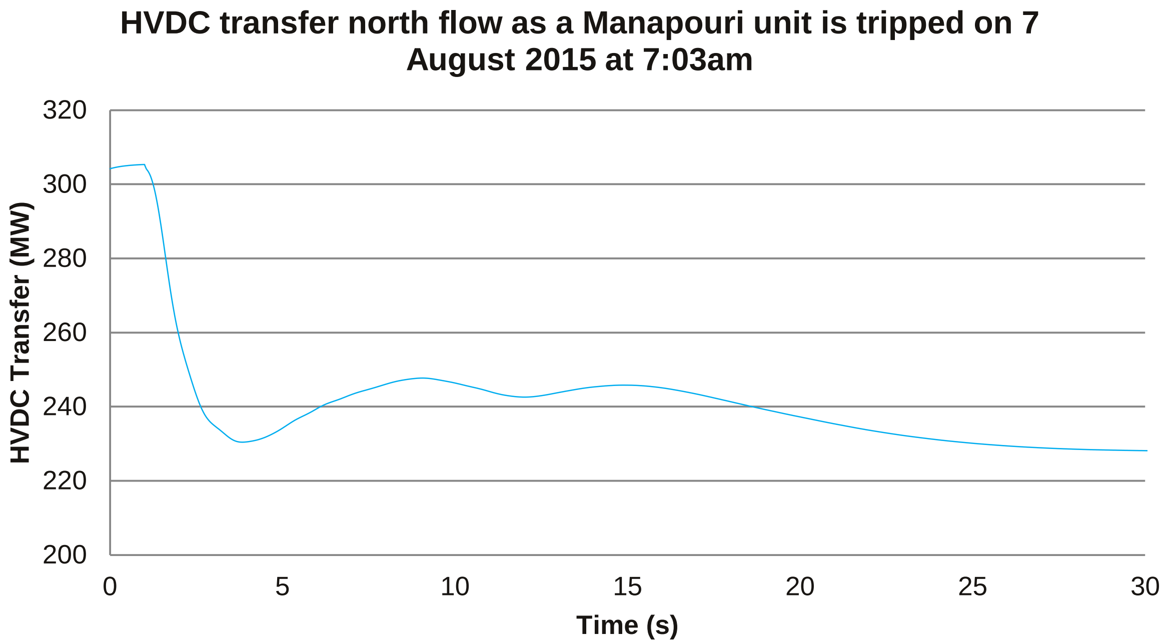

Figure 11: HVDC transfer north flow as a Manapouri unit is tripped on 7 August 2015 at 7:03am from TSAT model

Discussion

There was at least 162.5MW of spare FIR available on the system on the 7 August 2015 at 7:03am. The risk setter at the time was one of the Manapouri generating units (at 125MW), which was an AC CE risk. This scenario was simulated in TSAT to predict how the power system would have reacted if an under-frequency event had been caused by a Manapouri unit tripping.

In the TSAT simulation, a Manapouri unit was tripped at 1 second. FIR arrested the South Island frequency fall before 6 seconds at 49.5Hz (Figure 9). North Island frequency also dropped from FKC control action, though not to the same extent as in the South Island. As the frequency dropped, the generation decreased. This is reflected on the HVDC transfer north. As the generators provided IR and increased their output (Figure 10) the HVDC transfer north also increased (Figure 11). The HVDC link reacted by changing transfer level to maintain the same frequency on both islands.

With at least 162.5MW spare FIR available there was enough South Island IR available because the FIR dispatched did not exceed the FIR available.

HIGH NORTH FLOW ON HVDC

Results

Figure 12, 13 and 14 show how South Island frequency, generation and HVDC transfer would be affected if a Manapouri unit had tripped on 9 June 2015 at 2:04pm. This is when minimum spare FIR was available across the day.

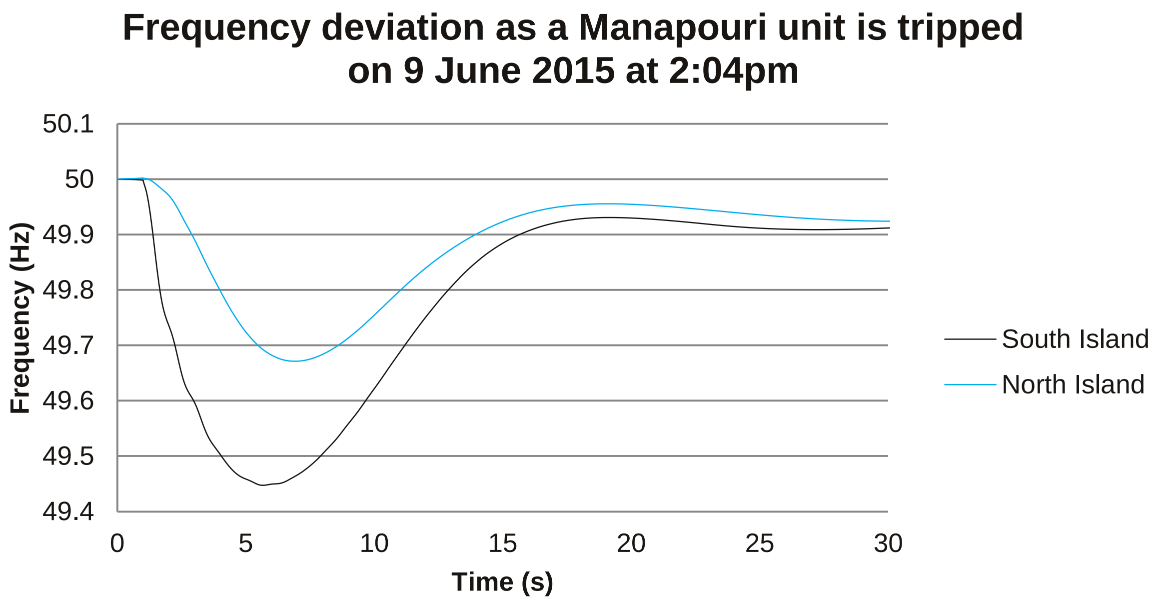

Figure 12: South Island frequency deviation after a Manapouri unit trip on 9 June 2015 at 2:04pm from TSAT model

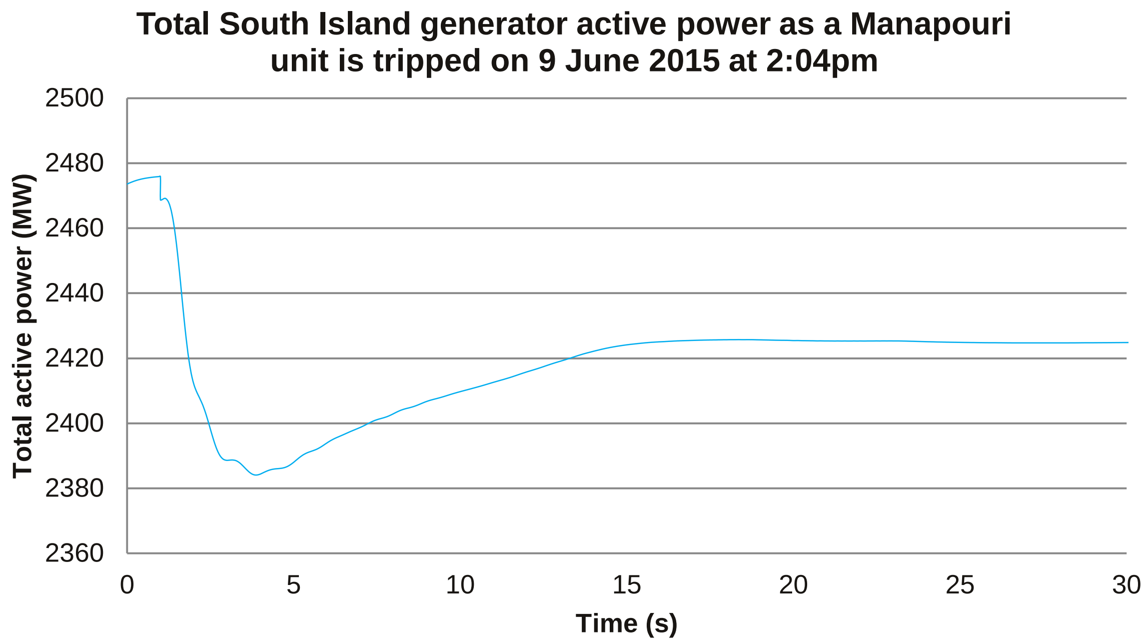

Figure 13: South Island generators active power after a Manapouri unit trip on 9 June 2015 at 2:04pm from TSAT model

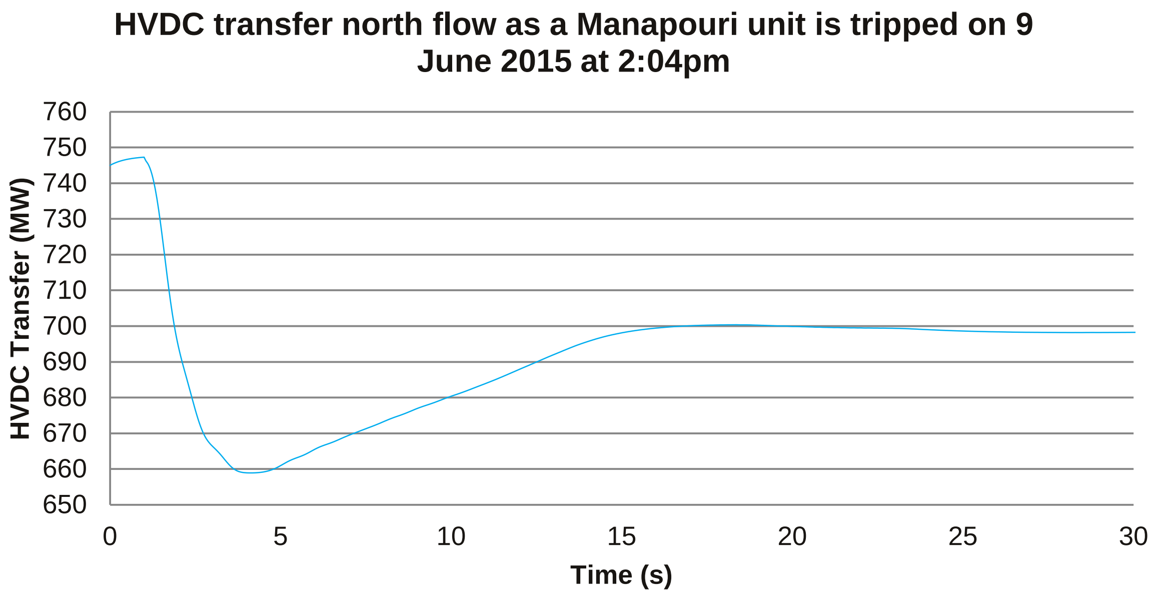

Figure 14: HVDC transfer north flow as a Manapouri unit is tripped on 9 June 2015 at 2:04pm from TSAT model

Discussion

There was at least 141.6MW of spare FIR available on the system on the 9 June 2015 at 2:04pm. The risk setter at the time was one of the Manapouri generating units (at 125MW). This was modelled in TSAT to see how the power system would have responded at that time if an under-frequency event had been caused by a Manapouri generating unit tripping.

A Manapouri unit was tripped at 1 second. FIR arrested the South Island frequency fall within 6 seconds at 49.4 Hz (Figure 12). North Island frequency also decreased, though not to the same extent. As the frequency fell, generation decreased. This is reflected on the HVDC transfer north. As the generators provided IR and increased output (Figure 14) HVDC transfer north also increased (Figure 15). The HVDC link reacted by changing transfer level to maintain the same frequency on both islands (Figure 14).

With at least 141.6MW spare FIR available on the system there was enough IR to cover the risk setter.

CONCLUSIONS AND RECOMMENDATIONS

Conclusions:

- There is sufficient of FIR available in the current market conditions to cover the loss of the risk setter with increased governor action caused by FKC. Some factors behind the large quantity of spare FIR could be;
  - the limited sharing of FIR across the HVDC link
  - that FIR dispatch does not account for response from units not dispatched for FIR.

- IR will be purchased to cover the national risk setter (instead of a risk setter per island) when NMIR is implemented. Less IR will be scheduled so generators may operate with tighter margins. As IR can be procured nationally it is expected spare FIR will be used to cover North Island risk.

Recommendation:

- It is recommended this study (looking at reserve availability in South Island generators) is repeated after NMIR is implemented to determine the change in quantity of spare FIR available on the system.

Appendix 1: Acronyms

AUFLS : Automatic Under-Frequency Load Shedding

AC : Alternating Current

CE : Contingent Event

DC : Direct Current

ECE : Extended Contingent Event

EIPC : Electricity Industry Participation Code

FIR : Fast Instantaneous Reserve

FKC : Frequency Keeping Control

FSC : Frequency Stabiliser Control

HVDC : High Voltage Direct Current

IR : Instantaneous Reserve

MOI : Market Operator Interface

MFK : Multi Frequency Keeping

NMIR : National Market for Instantaneous Reserves

NRSS : Non-Response Schedule Short

PI : Plant Information

PLSR : Partially Loaded Spinning Reserve

PPO : Principal Performance Obligations

RMT : Reserve Management Tool

SIR : Sustained Instantaneous Reserve

SPD : Schedule, Pricing and Dispatch

SRS : Spinning Reserve Sharing

TASC : Technical Advisory Services Contract

TSAT : Transient Stability Analysis Tool

TWD : Tail Water Depression

WITS : Wholesale Information and Trading System

Appendix 2: FREQUENCY REQUIREMENTS

The system operator principal performance obligations (PPO) are set out in section 7.2 of the Electricity Industry Participation Code (EIPC). The system operator is required to maintain frequency in the normal band and restore frequency if frequency fluctuation occurs.[3]

2.1 CONTROL OF THE FREQUENCY IN NORMAL OPERATION

System frequency is constant when supply and demand on the power system are balanced. Frequency will decrease when demand exceeds supply. Conversely, frequency will increase if supply exceeds demand.

As demand varies throughout the day, system co-ordinators send dispatch instructions to generators to maintain the frequency within the normal band of 49.8-50.2 Hz.

Between dispatch instructions the response to frequency variations in the normal band comes from generator governors and a paid for ancillary service, Multiple Frequency Keeping (MFK).

2.2 RESPONDING TO UNDER-FREQUENCY EVENTS

An under-frequency event is when frequency unexpectedly drops below 49.25 Hz as a result of reduced supply. In an under-frequency event the frequency fall is arrested using IR.

IR is procured to cover the largest credible loss of supply which could result in an under-frequency event.

2.3 TYPES OF EVENT

There are two risk classifications of an under frequency event:

- A Contingent Event (CE)
- An Extended Contingent Event (ECE)

The main difference between the two events is an ECE is considered to be of such a low probability of occurrence to be economically justifiable to rely on the use of Automatic Under-Frequency Load Shedding (AUFLS) and IR to recover system frequency. A CE relies only on IR to recover system frequency.

There are two types of CE events:

- an AC CE which is typically the loss of a single generating unit
- a HVDC CE which is typically the loss of a single HVDC convertor pole

There are two types of ECE events:

- an AC ECE risks which is typically the loss of a single busbar
- a HVDC ECE which is typically the loss of both HVDC convertor poles

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[3] EIPC Section 7.2

2.4 THE CONSEQUENCES OF NOT HAVING ENOUGH INSTANTANEOUS RESERVES

Without enough IR, frequency will continue to fall in an under-frequency event below the PPO obligations set out in the EIPC. At certain frequency limits, protection relays disconnect generators from the power system to protect them from damage. This could lead to cascade failure or a total loss of power.

To meet the PPOs system operator must ensure:

- frequency fall for a CE event does not exceed 48 Hz. The consequence of not having enough IR to manage a CE would be for frequency to fall further and lead to an AUFLS operation.
- frequency fall for an ECE event does not exceed 47 Hz for a North Island ECE and 45Hz for a South Island ECE. For an ECE, AUFLS blocks in South Island are tripped at 47.5 Hz and 46.5 Hz.[4] The consequence of not having enough IR for an ECE is a total blackout.

An unexpected AUFLS operation or a blackout are undesirable as they are disruptive, a breach the system operator's PPOs and have significant economic consequences.

[4] This is mentioned in EIPC Chapter 8 Technical Code B.

Appendix 3: INSTANTANEOUS RESERVES, GENERATOR OPERATING MODES AND AUFLS

3.1 INSTANTANEOUS RESERVES

An under-frequency event occurs when a generator unexpectedly trips off or a HVDC component is lost. IR restores the balance between demand and supply by ramping up generation or tripping Interruptible Load (IL). There are two types of IR: FIR and Sustained Instantaneous Reserve (SIR).

IR is purchased through the electricity market for economic efficiency. IR is currently purchased to cover the largest event in each island.

3.1.1 Fast Instantaneous Reserve and Sustained Instantaneous Reserve requirements

FIR is purchased to arrest frequency fall following an event. FIR is required to act in the first six seconds and must last for 60 seconds. SIR is purchased to raise frequency to 49.25 Hz or more and restore the balance between demand and supply following an event. SIR is required to act in the first 60 seconds and to last for 15 minutes.

Generation is re-dispatched to release SIR after 15 minutes.

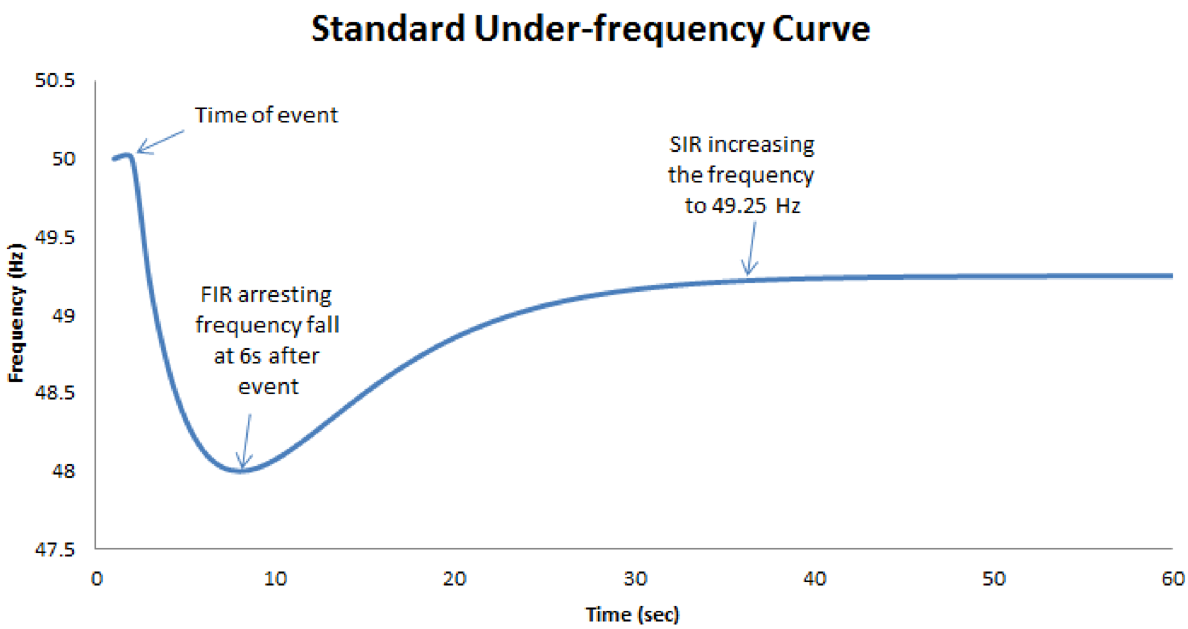

Figure 15: Standard under-frequency curve for CEs

A previous study showed that SIR is purchased conservatively so about 15% more SIR is purchased than required.[5] This report therefore focuses on FIR as it is not purchased conservatively.

[5] This was a finding from TASC 53. For further information, refer to the TASC 53 report.

3.1.2 Interruptible load

Some loads participate in the reserves market by offering to shed load (in the event of an under-frequency event) as an ancillary service. Shedding load decreases demand to help restore the balance between demand and supply and arrest the frequency fall. Some loads are industrial or aggregates of residential heating.

3.2 GENERATOR OPERATING MODES

3.2.1 TWD

When in TWD mode a hydropower generator is connected to the grid but no water is turning the turbine. The wicket gates are closed and compressed air forces the tail water level below the turbine blades. The generator acts as a motor as the turbine continues to turn so it draws power from the grid. In an under frequency event where more generation is required, a control system opens the wicket gates to let water through and the generator reverts to generating mode.

Being able to quickly increase power output means generators in TWD mode can contribute a large quantity of FIR.

3.2.2 Feed-Forward

Some hydropower generators have feed forward capability. The input to the governor is the error from the 50Hz system frequency. In feed forward mode, the control system rapidly changes the power set point to either match a pre-determined value, or the FIR dispatch instruction until it is reset.

3.2.3 Partially Loaded Spinning Reserve

In PLSR mode, generators are in service and not operating at their maximum operating point. The headroom between their operating point and the maximum operating point means that the generator can increase its output to provide IR. The generator is able to provide different quantities of FIR depending on its operating point.

3.3 AUTOMATIC UNDER-FREQUENCY LOAD SHEDDING

In the event of an ECE, two blocks of AUFLS can be tripped to help arrest frequency fall and recover the system. AUFLS uses a set of relays connected to defined feeders connected to customers. Currently, there are two 16% blocks of AUFLS per island which disconnect customers when frequency reaches a set level for an under-frequency event.

In the South Island, the first block is tripped at 47.5 Hz. If the frequency continues to fall or remains at 47.5 Hz for a prolonged period second block of AUFLS is tripped at 46.5 Hz. Potline 3 of Tiwai is tripped when the frequency reaches 46.5 Hz.

AUFLS is the last response available to avoid a total blackout from under-frequency.[6] For more information on AUFLS see Appendix 3.

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[6] https://www.transpower.co.nz/sites/default/files/bulk-upload/documents/AUFLS_Stage_II_Appendix_A.pdf