How Interruptible Load Keeps the Lights On

Heidi Heath, Transpower

EEA Conference & Exhibition 2014
18-20 June, Auckland

SYSTEM OPERATOR

TRANSPOWER

Keeping the energy flowing

1 Background

1.1 Interruptible Load

At all times, generation and demand must be relatively equal in order to keep the power system frequency close to 50 Hz. An event like a generator tripping or a trip of an HVDC pole causes a sudden imbalance between load and generation and makes the system frequency fall rapidly. If this happens the SO has seconds to correct the situation before the falling frequency could lead to a nationwide blackout. As a result, the SO procures fast instantaneous reserve (FIR) and sustained instantaneous reserve (SIR) through a reserves market. These two market products react automatically to correct the fall in system frequency.

FIR and SIR take two forms. Governor-controlled generators provide spinning reserve to quickly produce more power to make up for the lost generation. IL providers correct the imbalance between load and generation by tripping off some of their load. IL FIR providers are required to automatically trip their load within 1 second of the system frequency reaching 49.2 Hz[1]. IL SIR must trip within 60 seconds of the event. This investigation only examines IL reserves and does not focus on generation reserves.

Examples of IL providers include large industrial companies which can trip off sections of their plants in response to a frequency event or residential ripple-control mechanisms which turn off household hot water heaters when the frequency falls.

As of February 2014, the SO has contracts for 335 MW of FIR IL and 790 MW of SIR IL in the North Island, representing approximately 7% and 16% of North Island peak demand, respectively. These are the maximum quantities of IL that can be offered into the reserves market.

1.2 Interruptible Load Over-Provision

Unlike governor-controlled generators, IL response is not proportional to the change in frequency. IL can be considered a binary response: either the entire amount of load from a particular IL provider has tripped or it has not. IL also cannot automatically turn itself back on to modulate the subsequent rise in frequency after an under-frequency event.

The contribution of IL in the reserves market is significantly increasing in size and diversity as more IL providers enter the market with different types of load offered and a range of associated tripping speeds. The present IL contracts agreed with the IL provider and the SO stipulate a minimum delivery requirement only, with no reference to a maximum. The result is that providers offer their load very conservatively to ensure they meet their contracted reserve quantity, and therefore they often trip more than the SO is expecting. Additionally many IL providers leave their IL armed and ready to trip even if it has not been specifically procured because it is onerous to change relay trip settings every half hour based on whether the IL offer has been accepted in the FIR or SIR market for the chosen time period.

Shedding too much IL during an under-frequency event might cause the system frequency to over-recover and produce an over-frequency event where the system frequency exceeds 52 Hz. Figure 1-1 demonstrates this effect by displaying the

[1] Electricity Industry Participation Code 2010, 1.1(1), Definition of Fast Instantaneous Reserve

frequency overshoot following an under-frequency event as a function of increased IL reserve response. In this case the 52 Hz PPO is breached when the amount of IL tripping is 306% of what was scheduled.

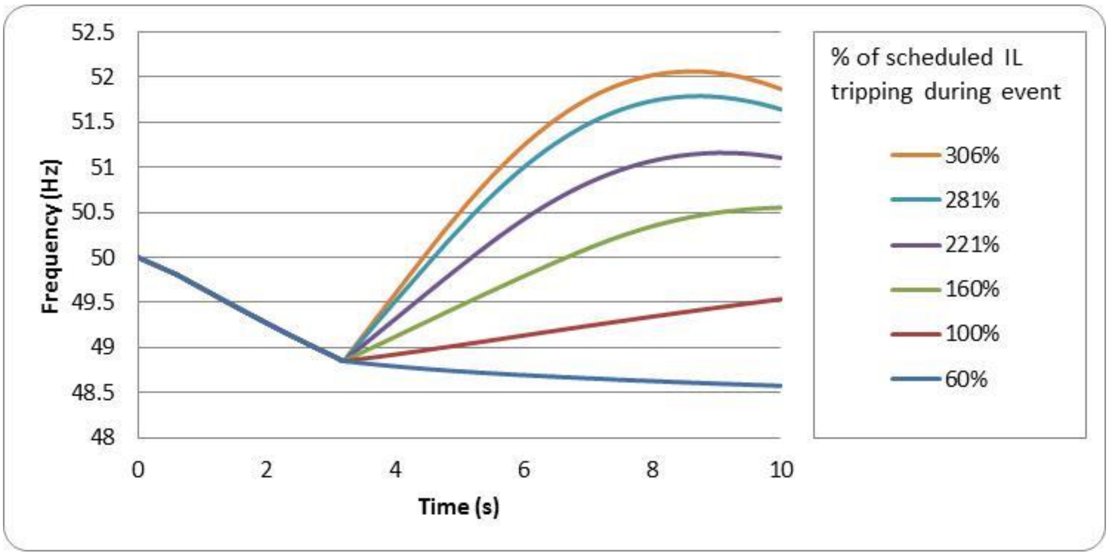

Figure 1-1: IL causing frequency overshoot

1.3 Amount of Interruptible Load Available

The total amount of IL armed and ready to trip at any given time cannot be tracked using the current technology available to the System Operator. The total contracted amount of IL in the North Island is 335 MW of FIR and 790 MW of SIR, or approximately 7% and 16% of North Island peak demand, respectively. This investigation assumes that at least the full contracted amount of IL trips for a given event. This is a conservative assumption because the full amount of IL is rarely available to trip.

The amount of IL available at any given time is influenced by the time of day and the type of load. Many industrial plants offer IL, but their IL is often not available at night or on weekends when portions of the plant are shut down. Conversely, in the evenings or weekends there may be more IL from residential ripple-controlled hot water heaters because people are at home using their hot water.

Analysis of past data indicates that 95% of the time less than 250 MW of FIR IL and 700 MW of SIR IL is offered.

2 Study Scenarios

The following scenarios were developed to study the effect on system frequency of increasing amounts of IL under a range of credible conditions.

2.1 Base Cases

The levels of North Island load used for studies are shown in Table 2-1. The heavy load scenario was based on the historically highest North Island load as of February 2014. The light load scenario was based on the 90th percentile lightest load instead of the absolute smallest North Island load in order to study a time when a reasonable amount of IL would be operating. As many IL-providing industrial plants are shut down during the lightest load times (holidays and weekends in December and January) the 90th percentile light load period was assumed to be the more extreme case.

Table 2-1: Load Levels Studied

Scenario	North Island Load (MW)
Heavy load	4785
Medium load	3435
Light load	1948

2.2 Low Island Inertia

When an electrical system has low inertia, the frequency falls more quickly when a generator trips and rises more quickly when load trips. Inertia comes from spinning machines and in particular from large motor loads or certain types of generators. Large thermal generators like combined cycle gas turbines or geothermal plants provide high inertia while wind turbines and simple-cycle gas turbines provide low inertia.

This study was designed to determine how low system inertia would affect the over-frequency response. The lowest-inertia machines in the North Island were online in this study while the highest-inertia machines were turned off. The HVDC link was also turned off.

Figure 2-1 shows the low inertia profile used for these studies. The thermal and geothermal turbines are turned off while the gas peakers and wind turbines are generating at maximum capability. The balance of generation is made up of medium-inertia hydro turbines. For comparison purposes Figure 2-2 shows an inertia profile that could happen during a typical time period.

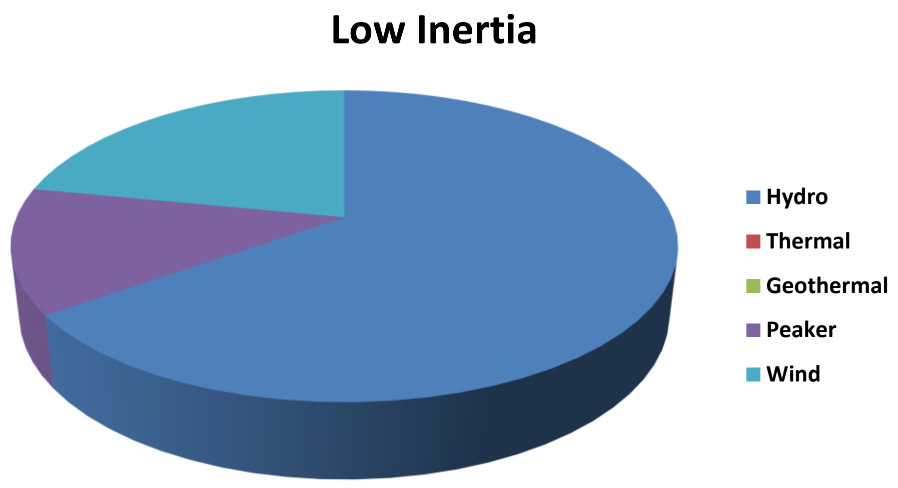

Figure 2-1: Low Inertia Profile

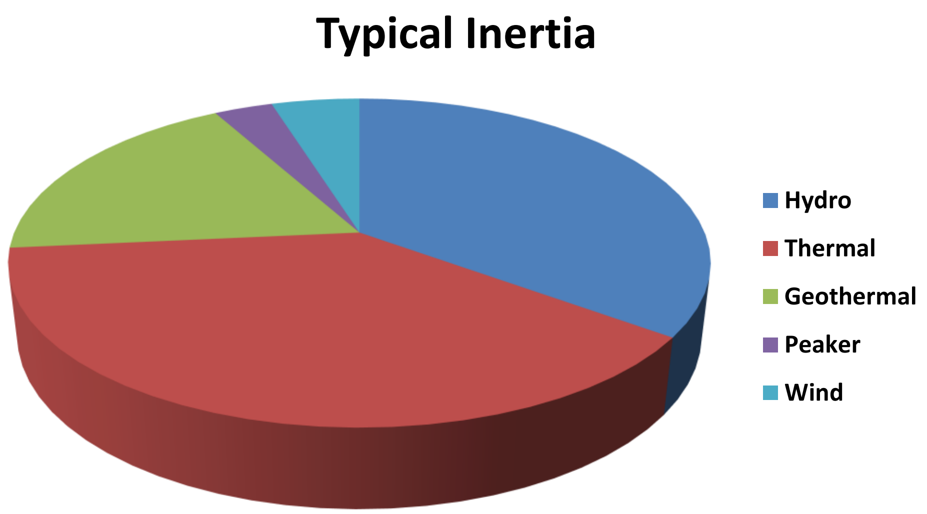

Figure 2-2: Typical Inertia Profile

2.3 Extended Contingent Events

A contingent event (CE) is defined as the tripping of a single generator or HVDC pole. Instantaneous reserves are procured to keep the system frequency above 48 Hz for these events and no load is shed except for IL. Most of the studies done for other scenarios in this report are for CEs.

An extended contingent event (ECE) is defined as the tripping of busbar, interconnecting transformer, or the HVDC bipole. Automatic Under Frequency Load Shedding (AUFLS) can be used for this event. In addition to AUFLS, instantaneous reserves are procured to keep the system frequency above 47 Hz in the North Island.

The ECE studies were designed to consider whether IL and AUFLS could trip at the same time during an ECE when the loss of generation or HVDC transfer is especially large and the frequency is falling especially fast. If so, the scenario could lead to a larger frequency overshoot than initially expected.

2.4 Interruptible Load as a percentage of total reserve

Generator governors change generator output proportionally to a change in frequency. Conversely IL can be considered a binary response rather than a proportional response: all IL from a particular provider either trips or it does not. The amount of IL tripping can't be dynamically altered in real time based on the size of the under-frequency event, and IL can't reconnect itself a few seconds after tripping to mitigate the size of the frequency overshoot.

This scenario was designed to increase the proportion of IL to other FIR providers to study the effects of a large binary response versus a proportional governor response.

2.5 HVDC Transfer High/Low/Off

This scenario was designed to study the effects of the HVDC link on over-frequency caused by load tripping. The HVDC link responds quickly to frequency events. Although Transpower conservatively limits this to 25 MW or 50 MW in its modelling tools, the HVDC link can actually respond up to 250 MW within a few seconds, depending on system conditions. The following HVDC levels were studied:

Table 2-2: HVDC transfer

Scenario	HVDC North Transfer (MW)
High HVDC	900
Low HVDC	200
HVDC Off	0

These figures were chosen to represent cases where the HVDC was operating at less than maximum transfer so it could ramp up quickly if the frequency fell. In the High HVDC case both Pole 2 and Pole 3 must be operating but the bipole is 300 MW short of its 1200 MW limit. In the Low HVDC case either Pole 2 or Pole 3 could be operating, but 200 MW is well below the limit of 500 MW on Pole 2 and 700 MW on Pole 3.

2.6 Effects of Tail-water Depressed Response

Tail-water Depressed (TWD) mode allows hydro generators to be synchronised to the power system and providing reserves without generating power. The water is held back from the turbines with compressed air. When the system frequency reaches a certain point[2] the water is allowed to enter the turbine and the generator quickly ramps up to a new power setpoint. This quick response is not controlled by the usual proportional governor action.

This scenario was designed to study whether high levels of TWD and IL both responding at the same time could cause a disproportionate response to a drop in frequency which could lead to an over-frequency event.

2.7 Consider North Island and South Island as a Single System

As pertaining to frequency, the North Island and South Island power systems are currently considered two separate power systems in study tools and in practice. The system frequencies of the two islands often move up and down in the same direction but are not equal.

The Pole 3 upgrade in 2013 and the associated new HVDC control system could allow the two island frequencies to be linked to each other, which means that the two islands could be considered a single larger power system instead of two smaller power systems. This scenario studied the effects on over-frequency of considering the two islands as a single system.

2.8 Effects of SIR IL

SIR IL typically trips within 2-5 seconds of the system frequency reaching 49.2 Hz. If SIR IL trips while the frequency is recovering back to 50 Hz instead of tripping while the frequency is still falling, it might cause a frequency overshoot.

This scenario studied various amounts of SIR IL at various tripping times to determine whether the system was at risk of an over-frequency event if SIR IL tripped while the frequency was recovering.

[2] TWD can be triggered on a static frequency or on a set rate of change of frequency.

3 Study Methodology

3.1 Software

The Reserve Management Tool (RMT) version 4.200.021 was used for the studies involving IL as a proportion of total reserve and for the TWD studies. TSAT version 11.0 was used for the remainder of the studies.

3.2 Assumptions

- An over-frequency event happens when the system frequency exceeds 52 Hz.
- Contracted FIR IL is unlikely to exceed 30% of total North Island load.
- All FIR IL is modelled as tripping at the same time, 1 second after the frequency reaches 49.2 Hz. This is a conservative assumption because all IL tripping at the same time would give a larger over-frequency response than staggered trip times between 0.3 seconds and 1 second.
- SIR IL is modelled as tripping between 2 and 5 seconds after the frequency reaches 49.2 Hz.
- Physical locations of load and generation were not considered in this study because the location has very little effect on system frequency. Voltage stability and thermal circuit overloads were also not considered.
- All generators and governors are as modelled in the System Operator tools as of February 2014. If a generator has a dispensation for tripping at a frequency above 47 Hz, this was considered.
- A load which is offered as FIR IL is also offered as SIR IL for the same time period.
- In the list of credible events identified and planned for by the System Operator[3], the loss of the HVDC bipole is the only North Island ECE currently considered credible as pertaining to system frequency. As of February 2014 the HVDC limit is 1200 MW when flowing from south to north.

3.3 Study Method

Dynamic scenarios were run in TSAT or RMT. To initiate a drop in frequency a power system asset was tripped as indicated in Table 3-1. The simulation was allowed to run until the maximum frequency was reached and the frequency began falling back to 50 Hz.

Table 3-1: Asset tripped

Software	Event type	Asset tripped	MW tripped
TSAT	CE	Huntly Unit 5	350
TSAT	ECE	HVDC Bipole	up to 1200
RMT	CE	Huntly Unit 5	350

[3] Policy Statement, http://www.systemoperator.co.nz/market/policy-statement

All studies were designed to increase IL to the point where the overshoot in system frequency following an under-frequency event exceeded 52 Hz. Results were recorded at that point. When the amount of FIR IL required to trip exceeded 30% of total North Island load, the scenario was considered implausible and the result recorded was "no issues seen."

Initial TSAT studies were run using a North Island base case with all lines in service. In order to verify results some studies were then run again using market cases which reflected network topology during real-time periods. RMT base cases were developed from actual market cases with loads and generation changed to the desired levels.

4 Results

This section discusses the results of the studies and their impacts on the SO's ability to keep the North Island system frequency below 52 Hz. Full study results can be provided upon request.

4.1 Sensitivity to load

Table 4-1 shows the amount of IL needed to make the frequency exceed 52 Hz as a function of North Island load.

Table 4-1: Sensitivity to system load

Scenario	North Island Load (MW)	IL Tripped (MW)	% of NI Load
Heavy load	4785	1403	29%
Medium load	3435	965	28%
Light load	1948	526	27%

The frequency response to IL tripping was very sensitive to demand. When load is low the power system has less inertia, making it more sensitive to imbalances between generation and load.

Even in the worst-case light load scenario, the amount of IL tripped far exceeds the amount of IL currently contracted in the North Island. The results consistently showed that more than 25% of North Island load needed to trip as IL in order to result in an over-frequency event.

4.2 Sensitivity to system inertia

Of the variables studied, results showed that system inertia has the largest impact on the response of system frequency to IL tripping. Results can be seen in Table 4-2. The low inertia study cases were designed to be a worst-case scenario and may not be realistic because these study cases use low-inertia generators during light load periods. Simple-cycle gas turbines, also known as peakers, have low inertia but typically only run during peak times when load is high. This scenario also assumed that no geothermal generators were operating which would be a very rare event.

Even under this worst-case scenario, far more IL must be tripped than is available in the North Island before the SO violates its PPOs. No scenario with less than 19% of North Island load tripping as IL resulted in an over-frequency event.

Table 4-2: Sensitivity to Inertia

Scenario	Inertia Profile	North Island Load	IL Tripped (MW)	% of NI Load
Heavy load	Low	4785	898	19%
Medium load	Low	3435	712	21%
Light load	Low	1948	426	22%

4.3 Extended Contingent Events

These studies tripped the full HVDC bipole. These studies initially assumed that the bipole was at its 1200 MW limit when it tripped. The study limit was then increased to 1400 MW to study the future HVDC configuration.

For the other studies in this report, the level of IL was increased until the frequency breached the 52 Hz PPO. With the ECE studies, however, it was not possible to simulate a credible event where the 52 Hz PPO could be breached by increasing the level of IL. As the level of IL increased fewer blocks of AUFLS tripped. And as fewer blocks of AUFLS tripped the frequency over-shoot decreased.

This is demonstrated in Table 4-3. Initially 283 MW of IL is tripped along with two blocks of 16% of North Island load tripping as AUFLS. When the level of IL tripping is increased to 366 MW the maximum frequency rises because more total load trips. When the level of IL is increased to 438 MW, however, the frequency doesn’t fall low enough for the second block of AUFLS to trip. Thus the frequency overshoot is lower. And when 608 MW of IL trips neither block of AUFLS trips so the frequency is even lower.

Table 4-3: ECE Maximum Frequency

Scenario	IL Tripped (MW)	# of AUFLS Blocks Tripped	Maximum Frequency (HZ)
Light Load	283	2	50.7
Light load	366	2	51.3
Light load	438	1	51.0
Light load	608	0	50.8

4.4 IL as a large percentage of total instantaneous reserve

The RMT Study tool was used for these studies because the percentage of reserve amounts could be more easily changed in that tool than in TSAT. A total amount of FIR was chosen and the percentage of IL was varied within that amount to observe the change in frequency overshoot.

The results show that while the percentage of IL does affect frequency overshoot, that factor alone will not cause the SO to breach its PPO.

4.5 HVDC Transfer High/Low/Off

The level of HVDC transfer did not make a significant difference to the frequency overshoot.

Turning off the HVDC entirely made a significant difference to the frequency overshoot because there was no HVDC response to the frequency fall. For the SO to breach its PPO, much more IL must trip than is currently contracted by the SO.

4.6 IL and TWD as a high percentage of total instantaneous reserve

The results of this scenario showed this factor alone will not cause the SO to violate its PPOs.

4.7 Consider North Island and South Island as a Single System

Linking the system frequencies of the North Island and the South Island and considering them a single system decreased the maximum frequency overshoot in all cases studied. Linking the two islands together increases system inertia which stabilises the system frequency.

4.8 Effects of SIR IL

Initial study results raised concerns that a reasonable amount of SIR IL tripping a few seconds after an event, when system frequency had stopped falling and had started rising back to 50 Hz, could cause a large frequency overshoot. However further investigation revealed other important factors which showed that this was not an issue.

The same load can be, and usually is, offered as both FIR IL and SIR IL for the same time period. If load has already tripped as FIR IL during a system event it can also qualify as SIR IL by remaining off until directed by the System Operator to come back on. If instantaneous reserve for particular time period includes 100 MW of FIR IL and 200 MW of SIR IL, there will only be a total of 200 MW of load tripped, not 300 MW.

Additionally SIR IL does not trip at exactly the same time. The SIR IL response is staggered over a period of a few seconds depending on relay settings, breaker times, and types of load. 100 MW of SIR IL all tripping at exactly 4 seconds after an event has a much larger impact on system frequency than smaller amounts of SIR IL tripping anytime between 2-5 seconds after an event.

When the studies considered the smaller amounts of SIR and the larger timeframes, there were no issues with system frequency.

5 Conclusions

The System Operator is required to operate the electrical system in a way that prevents the system frequency from exceeding 52 Hz following a contingent event or an extended contingent event. This investigation studied whether over-procurement of IL could cause the system frequency to exceed that limit following an under-frequency event.

The results of this investigation indicate that at least 19% of North Island load must trip as IL in order for the system frequency to breach the 52 Hz PPO. Currently under worst-case conditions no more than 16% of North Island load could trip as IL. Breaching the PPO limit would require at least 140 MW of additional IL to be contracted in the North Island.

The SO considers it unlikely that such untapped potential for IL exists in the North Island. If this does occur, however, the SO will take measures to ensure that no more than 19% of North Island load can be armed to trip as IL at any given time.