

System Security Forecast 2010

Part D

Frequency Principal Performance Obligations

Revised December 2011



*Keeping the lights on
24 hours a day, 7 days a week*

SYSTEM OPERATOR

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I M P O R T A N T

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Contact Details

Address:	Transpower New Zealand Ltd 96 The Terrace PO Box 1021 Wellington New Zealand
Telephone:	+64 4 495 7000
Fax:	+64 4 498 2671
Email:	system.operator@transpower.co.nz
Website:	http://www.systemoperator.co.nz

1. INTRODUCTION

One of the principal performance obligations concerns the management of power system frequency. The policies and means used by the System Operator to meet this principal performance obligation (PPO) are set out in the Policy Statement. The System Operator procures ancillary services (frequency regulating reserves, instantaneous reserves and over-frequency reserves) to comply with the frequency PPO.

The System Operator uses the framework set out in the Procurement Plan to procure frequency regulating reserves, instantaneous reserves and over-frequency reserves. Ancillary services providers are contracted to provide these reserves.

The adequacy of these means to meet power system demand over the next three years is forecasted in this section of the System Security Forecast (SSF).

2. FREQUENCY PRINCIPAL PERFORMANCE OBLIGATIONS

Part 7 of the Electricity Industry Participation Code describes the System Operator's principal performance obligation regarding frequency, quality targets, frequency limits and the policy by which the System Operator meets the PPO. These are summarised in the table below.

Frequency PPO requirements	Objective	The System Operator meets this objective by
<i>Maintain Frequency in the normal band</i>	The normal band is 49.8 to 50.2 Hz inclusive	Procuring an ancillary service provider to provide frequency regulating reserves
<i>Manage time error</i>	Frequency time error is less than 5 seconds of NZ standard time	Procuring an ancillary service provider (the frequency regulating reserves service provider) to manage time error
<i>Eliminate time error once a day</i>	Frequency time error is eliminated once per day	Procuring an ancillary service provider (the frequency regulating reserves service provider) to manage time error
<i>Manage Frequency during momentary fluctuation</i>	Frequency stays between 47 and 52 Hz during momentary fluctuations. (See Note 1)	Schedule, subject to availability, sufficient instantaneous reserves to meet under frequency limits for contingent events, and, allowing for AUFLS, for extended contingent events Procuring and dispatching over frequency reserves to maintain frequency below the upper limits for contingent and extended contingent events
<i>Limit Rate of occurrences of momentary fluctuations</i>	Aggregated rate of momentary fluctuation is limited to the levels defined in Part 7, clause 7.2 (1biii) of the 'Code'.	Schedule, subject to availability, sufficient instantaneous reserves to meet under frequency limits for contingent events, and, allowing for AUFLS, for extended contingent events Procuring and dispatching over frequency reserves to maintain frequency below the upper limits for contingent and extended contingent events
<i>Recover quickly from a fluctuation</i>	Frequency is restored to normal band as soon as reasonably practical	Schedule, subject to availability, sufficient reserves to meet under frequency limits for contingent events, and, allowing for AUFLS, for extended contingent events Manual re-dispatch of generation and load following an event if necessary to ensure frequency returns to the normal band

Note 1. Exceptions are allowed to the South Island frequency lower and upper limits.



3. APPROACH AND ASSUMPTIONS

3.1 APPROACH

The procurement of ancillary services related to frequency (frequency regulating reserves, instantaneous reserves and over frequency reserves) can not be considered in isolation of the electricity market. The dispatch of generation for energy is affected by the quantity and cost of dispatched reserves. The dispatch of generation also sets the size of contingent event and extended contingent event to be met by instantaneous reserves. Electricity Market participants such as generators can offer into both the reserves markets and the electricity market simultaneously.

A detailed technical analysis of reserves would require the use of dynamic power system models and electricity market models. Such analysis is beyond the scope of this SSF.

The System Operator applies the policies and means set out in the policy statement to comply with the frequency PPOs. This forecast focuses on the adequacy of these processes and means to manage frequency over the next ten years.

The approach is largely qualitative. A simplified analysis is used to support a forecast of the System Operator's ability to meet the frequency principal performance obligation. This analysis assesses whether there is sufficient generation capacity to meet future energy and reserves requirements.

System Operator has observed that there have been numerous occasions over the past 2-3 years where insufficient generation and reserves were offered to meet system demand and reserves requirements. Without recourse to the actions available to it under a Grid Emergency, the System Operator would have been required to shed demand in order to manage power system frequency and allow the required reserves to be dispatched. Following declaration of a Grid Emergency due to insufficient reserves the System Operator suspends the contingent event reserves requirements in the North and South Islands to defer the requirement for load shedding. This action allows system demand to continue to be met but increases the risk of the loss of a large generating unit or transmission circuit during this time causing the operation of Automatic Under Frequency Load Shedding (AUFLS) systems resulting in automatic demand shedding of up to 32% of North Island demand.



3.2 ASSUMPTIONS

The following assumptions are made:

- The asset capability information provided by asset owners can be relied upon to be accurate and valid over the next three years
- Ancillary service providers continue to offer ancillary services over the next three years at the same levels currently offered and provide ancillary services as contracted
- Asset owners are compliant with the asset owner performance obligations and technical codes of Part C
- There is insignificant embedded generation that is non-compliant with the asset owner performance obligations and technical standards concerning frequency
- All generation that is available is offered into the electricity market



4. FREQUENCY REGULATION MANAGEMENT

The maintenance of frequency in the normal band and the management of time error are managed through frequency regulating reserves. Frequency regulating reserves is the provision of spare synchronised generating unit capacity with a response time, fast enough to control frequency within the normal band of 49.8 to 50.2 Hz for small changes in frequency resulting from normal load and generation changes.

Frequency Regulating Reserves services are typically provided by one or more generating units operating in each of the North and South Islands.

The System Operator procures ancillary service providers (the frequency regulating reserve service provider) to provide frequency regulating reserve and to manage time error over each trading period. Frequency regulating reserve providers are dispatched to control frequency within a band ("MW band"). The size of the band can vary but is typically 50 MW in the North Island and 25 or 50 MW in the South Island depending on the time of day.

4.1 ANALYSIS

As part of its project to replace Pole 1 of the HVDC link, Transpower is also investigating the HVDC control requirements needed to facilitate a national frequency regulating reserve market. Such a system is expected to deliver significant performance benefits by allowing a larger number of service providers to participate. The control system for this is projected to be in place in September 2012 and investigations can be progressed after this date.



5. UNDER FREQUENCY MANAGEMENT

Sudden drops in system frequency resulting from events on the power system are managed through instantaneous reserves. Instantaneous reserves are the provision of interruptible load, partly loaded spinning reserves and/or tail water depressed reserve (in each case as either fast instantaneous reserves or sustained instantaneous reserves) to counter an under-frequency excursion arising from an event as described in the policy statement.

The System Operator schedules and dispatches generation to meet power system demand and losses and reserves to meet contingent and extended contingent events where sufficient generation, assets and offered reserves are available. Where sufficient generation and assets are available, the System Operator will schedule instantaneous reserves to meet the largest possible contingent event (loss of generating unit or transmission circuit) and the extended contingent event (allowing for AUFLS).

In the North Island, the largest contingent event is the maximum of the largest level of output from a single offered generating unit and the net transfer over a single HVDC pole. The largest contingent event for the South Island is the maximum of the loss of a single generating unit and the net transfer over a single HVDC pole. The extended contingent event for both islands is the loss of the HVDC Bipole.

The ability to manage under frequency is dependent on the availability of generation and interruptible load to meet reserve requirements. The System Operator has no control over how much generation, interruptible load or assets are offered.

5.1 ASSUMPTIONS

The following assumptions are used in assessing whether sufficient generation capacity will be available to provide reserves over the three year period:

- The amounts of instantaneous reserves and interruptible load currently offered into the market continue to be offered over the three year period
- Total generation capacity assumed for both islands has a 90% probability of being exceeded at peak demand (ie. 10th percentile is assumed).
- There are no changes over the three year period to the way in which frequency regulating reserves and instantaneous reserves are managed
- There is sufficient AUFLS available such that the FIR/SIR reserve requirement for an extended contingent event is less than that for the largest contingent event risk
- The capacity of the HVDC pole 2 is now 665 MW north received, and the rampup on Pole 1 is now 189 MW received (half of Pole 1 may transfer between 130 MW -200 MW North), allowing for a maximum north transfer of 854 MW received.
- It is assumed that DC transfer will be limited to 500 MW received in 2012
- The largest contingent event risk in the North Island over the three year period is a loss of the greatest of the largest thermal unit (400 MW) or the Pole 2 HVDC transfer into the Island, assuming that the HVDC transfer will be balanced such that Pole 2 transfer will be



minimised by maximising Pole 1 transfer. The largest contingent event risk in the South Island over the three-year period is 122 MW (as HVDC North transfer is assumed). The extended contingent event risk in the North Island over the three year period may range between 500 MW and 1000 MW (during the transition between Pole 1/Pole 2 operation and Pole 3/Pole 2 operation)

- The North Island interruptible load available is taken as the 10th percentile (90% probability of being exceeded) of the historic IL offers over demand peaks. The same approach is taken for NI Run of River (RoR) SIR offers
- Peak power system losses are 2.9% for the North Island and 4.9% for the South Island
- EC Prudent load forecasts are assumed for North and South Island demand. Peak demand has a 10% probability of being exceeded (ie. 90th percentile is assumed)

5.2 HVDC SOUTH TRANSFER

HVDC South transfer is not analysed in detail. HVDC South transfer reduces reserves requirements in the North Island. HVDC South transfer increases reserves requirement in the South Island (as the loss of the HVDC link becomes the largest contingent event) but more South Island generation capacity is available to provide reserves. The installation of AUFLS in the South Island in 2003 has significantly reduced the South Island reserves requirement to cover the loss of the HVDC bipole.

With Pole 1 of the HVDC link no longer available for South transfer the nett transfer loss from Pole 2 has become much larger. High levels of HVDC South transfer can occur during dry winters, however this mainly occurs at off peak times so the problem in providing sufficient instantaneous reserves is not one of generation capacity. The main problem is low system inertia in the South Island which requires a very fast reserve response, or in other words much higher levels of FIR. Availability of South Island FIR offers increased significantly during the winter of 2008 to the point where this is generally no longer a constraint on HVDC South transfer, when compared to the ability of the North Island AC system to transfer power into Wellington.

5.3 ANALYSIS

In order to assess the ability to meet the under-frequency parts of the PPO, a simplified test will be applied to determine whether there is sufficient generation capacity over the ten year period to enable sufficient reserves to be dispatched to cover a contingent event.



The surplus of generation capacity available to provide instantaneous reserves over the three year period can be calculated simply:

$$\begin{aligned}
 \text{Surplus generation} = & \text{Total generation capacity (taking maintenance requirements into account)} \\
 & \text{less peak power system demand} \\
 & \text{less requirement for instantaneous reserves} \\
 & \text{less requirement for frequency regulating reserves} \\
 & \text{less peak power system losses} \\
 & \text{less HVDC export for the island (or plus HVDC import for the island)} \\
 & \text{plus total interruptible load (up to a maximum of the requirement for instantaneous} \\
 & \text{reserves)}
 \end{aligned}$$

Where surplus generation to provide reserves is less than zero, there will be an ongoing shortage of generation to provide reserves. The amount of HVDC transfer at times of peak demand may be constrained by lack of excess generation capacity in the South Island at peak demand and insufficient generation in the North Island to meet the North Island peak demand.

The table below shows the forecast available generation for SIR reserves for the North Island and the second table shows the same for the South Island.

Year	Total NI generation capacity	Plus HVDC North Transfer (MW)	Less peak power system demand	Less requirement for SIR reserves (MW)	Less peak power system losses (MW)	Less FRR MW Band (MW)	Plus total interruptible load (up to requirement for SIR)	Plus RoR SIR offers (MW)	Available generation capacity for reserves (MW)
2011	5191	709	5058	520	147	50	87	49	261.318
2012	5191	500	5213	500	151	50	87	49	-87.177
2013	5191	559	5375	559	156	50	87	49	-253.875

Note that numbers are rounded and may not sum to totals.

Year	Total SI generation capacity	Less peak power system demand	Less requirement for SIR reserves (MW)	Less peak power system losses (MW)	Less FRR MW Band (MW)	Less HVDC North Transfer (MW)	Plus total interruptible load (up to requirement for SIR)	Available generation capacity for reserves (MW)
2011	3348	2425	122	119	50	754	122	0
2012	3348	2506	122	123	50	500	122	169
2013	3348	2568	122	126	50	604	122	0

Note that numbers are rounded and may not sum to totals.



The following observations can be made from the previous two tables:

- The North Island will be reliant on HVDC North transfer to meet peak demands in all years
- Surplus South Island generation available for North transfer at times of South Island peak load will reduce over the three year period
- There may be insufficient capacity to meet instantaneous reserve requirements over the three year period



6. OVER FREQUENCY MANAGEMENT

The sudden loss of a large load (such as Northland) or the HVDC link can cause system frequency to rapidly increase. Management of such events is through over-frequency management. Over-frequency management is achieved by the use of over-frequency reserves. Over-frequency reserve is the provision of equipment that enables an automatic reduction in the level of injection into the power system to arrest an unplanned rise in system frequency resulting from an event.

6.1 HVDC NORTH TRANSFER

The System Operator currently dispatches over frequency reserves in the South Island during DC North transfer depending on the number of HVDC poles in operation:

(a) Pole 2 only in operation:

- When the DC North transfer is greater than or equal to 23.5% of SI Demand +194.5 MW

(b) Both Pole 1 and Pole 2 in operation:

- When the DC North transfer is greater than or equal to 600 MW; and
- When the DC North transfer is greater than 50% of the South Island load

No over-frequency reserves are dispatched in the North Island because studies indicate that the 52 Hz North Island over frequency target can be met for all contingent events and extended contingent events.

6.2 HVDC SOUTH TRANSFER

The System Operator sometimes dispatches over-frequency reserves in the South Island during DC South transfer. Since only Pole 2 is available for south transfer, the nett transfer loss from the loss of Pole 2 has become much larger. Since the South Island system inertia is low during South transfer, very high levels of FIR may be required to rapidly arrest the frequency decline. However this entails some risk that the sudden FIR response may cause a subsequent over-frequency. To manage this possibility, the System Operator may also dispatch over-frequency reserves.

The System Operator has become aware of the risk of a high frequency event in the North Island during high HVDC south transfer. Sufficient over-frequency reserves are required in the North Island to ensure that the post event frequency does not reach 52 Hz. The limit on HVDC south transfer is dependent on demand and generation available.

6.3 LOSS OF NORTHLAND

On the 30th October 07:59 the Henderson Otahuhu circuit tripped whilst it was the only circuit supplying Northland. This trip led to a frequency excursion of 51.21 Hz in the North Island. Initial analysis of this problem suggests as an interim measure, during periods of Otahuhu 220 kV north circuit outages the DC should be constrained to allow full DC frequency response (i.e. 250 MW) when Northland loads are above 650 MW.



7. CONCLUSIONS

The policies and means used by the System Operator to meet the frequency principal performance obligation are set out in the Policy Statement. Based on the assumptions and analysis in this section, the System Operator is aware of two issues that may affect its abilities to meet the frequency principal performance obligation. The first issue is rapid changes in wind generation output in the Manawatu. The System Operator believes that the presently observed changes in wind generation output are manageable by the present arrangements. The second issue is the limited generation capacity available at peak demand to meet the demand plus instantaneous reserve requirements. The Policy Statement sets out the policies that will apply when there are insufficient energy and reserve offers available to maintain a dispatchable SPD solution.

