System Operator

Annual Review and Assessment 2007/08

1 September 2007 to 31 August 2008





SYSTEM OPERATOR

TRANSPOWER

Keeping the energy flowing

Transpower New Zealand Ltd The National Grid

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1. Principal Performance Obligations

1.1 Time Error

There were no instances of time error exceeding the +/- 5 second limits during the review period.

1.2 Voltage Disturbance

For the review period, there was an average of 115 voltage disturbances per month. These disturbances can be broken down to localised disturbances, where a fault occurs within a distribution company network (an average 87 per month) and regional disturbances due to faults on grid equipment (an average 18 per month). Typically, voltage disturbances are more frequent during times of strong winds and/or electrical storms.

Voltage Disturbance	2007				2008								12 Month Cumulative total	Monthly Average
	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug		
Regional														
North Island	23	25	8	7	17	22	12	20	15	17	29	20	215	17.90
South Island	3	18	2	5	2	5	11	8	12	19	12	15	112	9.30
Total	26	43	10	12	19	27	23	28	27	36	41	35	327	27.25
Local														
North Island	33	104	61	51	68	66	51	77	50	64	92	56	773	64.4
South Island	17	51	20	22	16	21	14	15	15	32	21	25	269	22.4
Total	50	155	81	73	84	87	65	92	65	96	113	81	1042	86.8

1.3 Voltage Violations 220kV & 110kV

There was one instance of the 110 kV grid voltage exceeding the allowed +/-10% limits between September 07 and August 08. This occurred at Pakuranga substation on 8 March 2008 at 12:05. The voltage on the 110 kV bus at Pakuranga was below -10% for a period of 40 minutes. The minimum voltage level reached was 97.9 kV.

The event occurred after the surrounding grid had been reconfigured for multiple asset outages. The Pakuranga bus was supplied via a single 110 kV circuit from Arapuni power station. Following outage switching, the voltage at the Pakuranga 110 kV bus steadily declined and a Grid Emergency was declared. Load management was not effective in halting the voltage decline and outages were then recalled to restore the normal grid configuration.

1.4 FREQUENCY

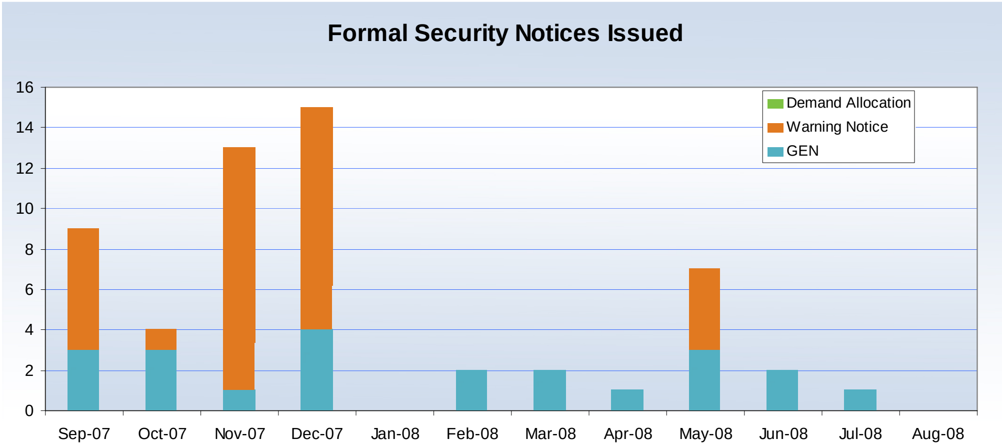
Frequency excursions for the reporting period remained within the annual frequency performance targets. There were no excursions below 48 Hz reported for the period.

Frequency Band (Hz)	2007				2008								Annual rate	PPO target
	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug		
55.00 > Freq >= 53.75														
53.75 > Freq >= 52.00	1												1	7
52.00 > Freq >= 51.25		3			1		1	1		3			9	50
51.25 > Freq >= 50.50	106	121	69	53	82	93	110	108	205	147	104	82	1280	
50.50 > Freq >= 50.20														
50.20 > Freq > 49.80	232	201	181	97	163	227	196	180	200	136	122	91	2026	
49.80 >= Freq > 49.50	6	1	1	2		1		1	2			2	16	60
49.50 >= Freq > 48.75													0	6
48.75 >= Freq > 48.00													0	0.2
48.00 >= Freq > 47.00													0	0.2
47.00 >= Freq > 45.00														

1.5 SECURITY NOTICES

A total of 57 formal security notices were issued during the review period.

Notice Type	Number of Notices Issued*
GEN	23
WRN - Warning Notice	34
DAN – Demand Allocation Notice	0



*Note: numbers given include notices issued declaring an emergency situation and the notices issued advising the emergency situation has ended.

The Notices in November and December related to insufficient generation and reserves offers in the North Island and a risk of the Upper South Island Voltage stability limit being exceeded due to insufficient generation offers and the bus fault at Inangahua.

1.6 PARTICIPANT ADVICE NOTICES

A total of 40 Customer Advice Notices (CANs) were issued during the review period.

1.7 STABILITY LIMITS

There were no instances of stability limits being exceeded on the grid during the review period. During this time however there were 2 stability constraints that bound for a total duration of 188 hours. This related to voltage stability limits at the top of the South Island in May 2008 during an outage of one of the Islington-Kikiwa circuits and to the voltage stability limit on south transfer between Bunnythorpe and Haywards during May to August 2008.

2. Security Issues

2.1 Summary of Grid Emergency Numbers

The following table shows the number of Grid Emergency Notices issued during the reporting period. Multiple notices were issued for some grid emergencies.

Month	Issued GEN
September 07	3
October 07	3
November 07	1
December 07	4
January 08	0
February 08	2
March 08	2
April 08	1
May 08	3
June 08	2
July 08	1
August 08	0

2.2 Events leading to declaration of Grid Emergencies

The following table lists the grid emergencies during the reporting period.

Date	Time	Summary Details	Island
23 Sep 07	03:08	A Grid Emergency was declared and the Islington Livingstone circuit 1 was removed to manage voltage in Christchurch and Upper South Island due to insufficient reactive support in the Christchurch area. With the unplanned unavailability of both the Islington SVC and two Islington condensers it was no longer possible to maintain voltages below the maximum limits in the EGRs with a lightly loaded Upper South Island power system. Action had already been taken to remove the Islington-Kikiwa 1 circuit from operation as permitted by the Grid Owner.	South
24 Sep 07	14:10	A Grid Emergency was declared to manage the restoration of the Kinleith 110 kV bus.	North
25 Sep 07	1634	A Grid Emergency was declared to reconfigure the grid following an unplanned outage of Atiamuri Tarukenga circuit 2. The reconfiguration was required to avoid post	North

Date	Time	Summary Details	Island
		contingent overloading of Kawaru Ohakuri circuit 1 for a contingency of Atiamuri Tarukenga circuit 1.	
9 Oct 07	07:44	A Grid Emergency was declared during a planned outage of Kaiapoi T1 to manage the loading on the remaining in service supply transformer T2 to within asset capability. Immediate action was initially required to offload a feeder. This was followed by restoration of shed load and the ongoing coordination throughout the outage to manage controllable load to ensure the remaining supply transformer remained within rating.	South
9 Oct 07	08:27	A Grid Emergency was declared for the top of the South Island (Nelson/Marlborough/part West Coast) at the start of outages of both the Islington-Kikiwa 1 and Kikiwa-Stoke 1 circuits. The grid emergency was declared as voltage stability limits were at risk of being exceeded. Distributors managed controllable load to keep to within the advised limits	South
28 Oct 07	08:11	A Grid Emergency was declared during a planned outage of Hangatiki supply transformer T2 to manage the loading on the remaining in service transformer T1 to within its asset capability. Controllable demand was managed by distributors to alleviate the problem.	North
5 Nov 07	16:30	A Grid Emergency was declared for insufficient instantaneous reserves and insufficient generation.	South
10 Dec 07	11:30	A Grid Emergency was declared for the Upper South Island voltage stability limit being exceeded.	South
11 Dec 07	15:35	A Grid Emergency was declared for the Upper South Island voltage stability limit being exceeded.	South
12 Dec 07	14:30	A Grid Emergency was declared for the Upper South Island voltage stability limit being exceeded.	South
19 Dec 07	16:10	A Grid Emergency was declared to manage the restoration of supply to Atarau, Dobson, Greymouth, Murchison, Reefton, Robertson Street and Westport GXPs.	South
4 Feb 08	16:25	A Grid Emergency was declared due to insufficient Generation and Reserve Offers to meet system demand. The combination of the	North

Date	Time	Summary Details	Island
		Stratford CCGT outage, constrained generation at Huntly and little wind generation culminated in insufficient generation being offered to meet both demand and instantaneous reserve requirements. The dispatch of reserves to cover a contingent event ceased for just over an hour before additional generation and the reduction in demand permitted a return to normal power system operation.	
12 Feb 08	07:44	A Grid Emergency was declared due to the post contingent rating of Bombay Hamilton circuits 1 or 2 being at risk of being exceeded for a contingency of the other circuit. Demand was managed at Bombay grid exit point to alleviate this prior to outages being recalled.	North
8 Mar 08	12:07	A Grid Emergency was declared because the steady state voltage at Pakuranga was below the EGR limit during a scheduled outage. Demand was managed to alleviate this until the outage was recalled.	North
17 Mar 08	13:31	A Grid Emergency was declared because a loss of the Islington Timaru Twizel circuit would have meant the Timaru transformer T8 would exceed its advised rating. Additional generation and demand management alleviated the problem.	South
17 Apr 08	15:11	A grid emergency was declared for the restoration of supply to Greymouth, Kumara, Hokitika, Atarau and Dobson after a tripping of the 110 kV Inangahua Atarua circuit 1. The tripping occurred while the 66 kV line from Otira to Hokitika was out of service for planned work.	South
5 May 08	07:34	A Grid Emergency was declared to reconfigure the grid to avoid the Coleridge Otira 2 circuit exceeding its advised rating for the loss of the Atarau Dobson 1 circuit.	South
5 May 08	13:30	A Grid Emergency was declared to reconfigure the grid for security during a forced outage on Otahuhu Penrose circuit 6.	North
5 May 08	20:44	A Grid Emergency was declared because a loss of the Atarau Dobson 1 circuit would have meant the Coleridge Otira 2 circuit would exceed its advised rating. Demand management followed by grid reconfiguration were required to manage the situation.	South
24 May 08	08:32	A Grid Emergency was declared at Twizel for the restoration of Twizel 220 kV Bus B, Ohau A Twizel circuit 2, Ohau C Twizel circuit 4 and	South

Date	Time	Summary Details	Island
		Twizel T19 after a tripping of Twizel 220 kV Bus B.	
5 Jun 08	10:45	The Stoke-Upper Takaka circuit was at risk of exceeding its advised rating for the loss of the Cobb-Upper Takaka circuit. Demand management at Motueka and Motupipi alleviated the problem.	South
24 Jun 08	18:00	The Bombay Hamilton 2 circuit was at risk of exceeding its advised rating for the loss of the Huntly Otahuhu 2 circuit. This was due to the concurrent unplanned outages of the Arapuni Bombay 1 circuit and Huntly Otahuhu 1 circuit. Demand management at Bombay and Meremere alleviated the problem.	North
30 Jul 08	11:15	A Grid Emergency was declared for the restoration of supply to Hororata, following a bus fault at Hororata.	South

Twenty five percent of the events leading to declarations of Grid Emergencies related to times when insufficient generation and reserves were offered to meet demand. The remainder of the events were nearly evenly split between restoration of load or security following forced outages and managing loading on grid assets to avoid exceeding stated capability under normal power system conditions.

2.2.1 Major System Frequency Events

During the review period there were no major system frequency events.

3. Security of Supply

3.1 Short Term Security Issues

3.1.1 Upper South Island Security

3.1.1.1 Summer

The System Operator again led an Upper South Island stakeholder group to manage the region with power system capability limits over the 07/08 summer period. No issues were identified and the group maintained a watching brief.

3.1.1.2 Winter

The System Operator again led the Upper South Island winter stakeholder group to ensure a co-ordinated response to manage the region within power system capability limits over the 2008 winter period. In response to potential power system issues arising from the late commissioning of plant and required outages of major 220 kV circuits supplying the Upper South Island during winter peak demand period, a contingency plan was deemed necessary.

The bussing of the Ashburton-Bromley, Ashburton-Timaru-Twizel and Islington-Timaru-Twizel circuits at Ashburton required a number of outages of what are now the Ashburton-Timaru-Twizel 2 and Ashburton-Islington circuits in May and June 2008. These outages were carried out over weekends but still required significant load management in the Upper South Island.

Further outages of the Islington-Livingston and Islington-Tekapo B circuits in July were required to allow phase transposition to be carried out. These outages were also carried out over weekends and required significant load management in the Upper South Island.

3.1.2 UPPER NORTH ISLAND SECURITY

3.1.2.1 Summer

The System Operator again led an Upper North Island stakeholder group to manage the region with power system capability limits over the 07/08 summer period. No issues were identified and the group maintained a watching brief.

3.1.2.2 Winter

The System Operator again led an industry group to monitor and plan for issues in supply to the Upper North Island over winter 2008. There were no significant issues and the group maintained a watching brief.

Construction activities for Ohinewai substation in June and July required outages of the major 220 kV circuits supplying the Upper North Island. These outages reduced transfer limits, placed constraints on generation and at time placed parts of the power system on reduced security.

3.1.3 DRY YEAR PLANNING 2008

Transpower has re-established a dry year planning group through the CEO Forum. This group considered initiatives for maximising the hydro storage available for the generation of electricity going into winter 2008. The System Operator carried out many activities in support of dry year planning ranging from real time information provision, to providing daily reports on the situation and to increasing the amount of reserves in the South Island.

Some of the more notable actions included:

- Implementing a split on the 110 kV grid at Mangamaire on 5 May. This increased Bunnythorpe - Haywards transfer to between 900 MW and 950 MW. This was optimised in real-time taking into account power system conditions. Transfer over this route is the critical constraint for south transfer on the HVDC link.

- Completing a review of stability limits which allowed the south transfer limit on pole 2 to be increased from 626 MW to 666 MW on 22 August. This constraint was reviewed in light of revised asset capability information and it has been determined the South Transfer Stability Limit of 626MW is no longer required. The new South Transfer limit is 666MW which is related to the thermal capability of Pole 2.

- Enabling additional South Island instantaneous reserves providers. With Pole 1 only being used for north transfer in a grid emergency, the total HVDC south transfer is now on Pole 2. As a result the South Island reserve risk is set by south transfer on the HVDC when this exceeds that of the largest generating unit in the

South Island (121 MW at Manapöuri). HVDC transfer south transfer will be reduced if insufficient reserves quantities are offered in the South Island hence increasing the amount of reserves providers helps maximise HVDC south transfer. The additional reserves included:

  - Rio Tinto Tiwai reduction line tripping (Interruptible Load);
  - Meridian, additional reserves added at Manapouri, Aviemore and Benmore;
  - Contact Energy, additional reserves added at Clyde and Roxburgh.

- Implementing an operational grid re-configuration by removing the Islington-Livingston circuit from service overnight allowing increased Southland transfer capacity.

3.1.4 National Winter Group (NWG)

The System Operator convened an industry participant group to establish the likely outlook for winter 2008 on the assumption the HVDC Pole 1 was not available. An initial report was completed on 7 December 2007 and updated on 15 Feb 2008 and 6 June 2008.

In developing and updating its outlook for winter 2008 the group considered changes to generation availability at New Plymouth and of HVDC Pole 1. The group also recommended a number of mitigations, five of these were implemented to enable the power system meet the winter peak:

- Variable Reserves – An interim proposal for the System Operator to vary the reserve requirement when there is insufficient energy and reserve offers was developed by the System Operator and provided to the Electricity Commission for approval. Procedure and software changes were successfully implemented.
- Two Second Interruptible Load (IL) – The concept for including interruptible load response at 2 seconds was proposed. It was identified there would be no immediate uptake of the product and development work was halted.
- Trigger for the use of HVDC Pole 1 – A trigger was agreed with the full NWG to prevent a grid emergency being declared in the North Island each time there was insufficient energy and reserve offers. Pole 1 was to be scheduled only when the situation could not be resolved by additional generation or demand response within two hours of dispatch.
- Special Winter Schedule – The aim of this schedule is to aid participant decision making and ensure participants had adequate information to make generation or demand side response available at critical times. This additional schedule was developed and implemented in early May, providing additional schedule information using the System Operator’s load forecast.
- Historical Anytime Maximum Injection waivers during Grid Emergencies – Transpower clarified this issue with South Island generators resulting in some additional generation being made available.
- Distribution company’s co-ordination of maximum winter demands.

3.1.5 OTHER SECURITY AND QUALITY ISSUES

3.1.5.1 South Island System Performance Investigation Project

Following a system event on 4 December 2005, the System Operator identified a need to better understand the dynamic performance of South Island generators and the performance of the South island system as a whole. This need is being accentuated by the increasing congestion of the South Island system and the likely introduction of increasing amounts of wind generation in the lower part of the island.

A formal project to review generator performance was initiated in 2007 involving the System Operator, Meridian Energy and Contact Energy. Asset testing at key sites has been carried out and validated models provided. The project will extend into mid-2009, and will provide the parties with confirmed and updated data on plant capabilities, enabling the System Operator to better understand and plan for the operation of the South Island power system.

3.1.5.2 Wind Integration

Throughout the reporting period the System Operator provided significant contributions to the Commission's ongoing Wind Generation Investigation Project (WGIP). During the period, this work was of an investigatory nature and a number of reports were produced by the System Operator and contributions made to others.

In September 2005 the System Operator published an assessment (based on a small amount of data) of the correlation of generation from adjacent Manawatu wind farms. The System Operator expects this information to be updated in 2009 to take account of the recently completed commissioning of Tararua III.

4. COMMISSIONING – GENERATION

4.1 GENERATION COMMISSIONING

The System Operator was actively involved in planning and co-ordinating the commissioning of several new generators during the review period. The table below summarises those commissioning projects:

Summary of generator commissioning			
Generator Name	**Asset Owner**	**Description**	**Status during review period**
Kawerau Geothermal	Mighty River Power	A new geothermal power station connected into Kawerau substation.	Commenced commissioning activities
Ngawha Geothermal	Top Energy	An expansion to the existing geothermal power station	Commenced commissioning activities
Nga Awa Purua	Mighty River Power	A second geothermal power station at Rotokawa	Commissioning planning

Summary of generator commissioning			
Generator Name	**Asset Owner**	**Description**	**Status during review period**
Te Rere Hau	NZ Windfarms	A new wind farm development located in the Tararua Ranges	Commissioning planning
West Wind	Meridian Energy	A new wind farm development located close to Wellington	Commissioning planning
Stratford peaking plant	Contact Energy	Two 100MW gas fired peaking units to be located close to the existing Stratford power plant.	Commissioning planning

The System Operator also assisted with enquiries regarding uncommitted, non-publicly disclosed new generation developments.

5. RULE CHANGES

5.1 PROPOSED BY SYSTEM OPERATOR

The System Operator made no recommendations for changes to the Electricity Governance Rules and Regulations '(the Rules') during the review period, other than the draft Procurement Plan for 2008/9, which is expected to come into effect on 1 December 2008.

5.2 CONTRIBUTIONS BY THE SYSTEM OPERATOR

The System Operator assisted the Commission with a number of actual or proposed rule development initiatives. These included the following:

5.2.1 VARIABLE RESERVES

At the request of the National Winter Group 2008 (of which it is a member), the System Operator developed and put forward a revised variable reserves proposal that could be achieved for winter 2008. This proposal was implemented in June 2008. The variable reserves process enables the System Operator to dispatch a partial quantity of reserves when there is a shortage of offers to meet the full reserve requirements. The System Operator has published an extract from its operational procedure on its website that describes how it adjusts the reserve quantity in order to achieve a feasible SPD solution.

5.2.2 PRICING IMPROVEMENT PROJECT

Work on the Pricing Process Improvement Project (PPIP) continued during the reporting period. The project team, including representation from the System Operator, have been addressing a number of concerns raised by the industry regarding the pricing process. The work has been presented to WMAG in draft report format for advice and comment. The final version of paper will be represented to WMAG in September 2008, following which is expected to be provided to industry for consultation.

5.2.3 Demand Side Bidding and Forecasting Project (DSBF)

The System Operator provided detailed written and verbal feedback to the Electricity Commission on the rules proposed in the latest consultation document. The advice centred on the operational aspects of the proposal. A subsequent update paper has been circulated for comment that has amended some of these concerns. We await further opportunities to feedback on the update and consultation papers.

5.2.4 Rolling Cuts

The System Operator worked with the Electricity Commission and Electricity Networks Association (ENA) in developing protocols and processes for load reductions to be managed in a co-ordinated way during security of supply emergencies.

5.2.5 Minor Offer and Dispatch Rule Changes

The Electricity Commission consulted on a number of minor offer and dispatch rule changes. Most were a tidy up of inconsistencies and duplication within the rules; however, the System Operator expressed caution, for operational security reasons, on a rule change that proposed to allow generators to deviate from a dispatch instruction for active power in order to maintain frequency whilst in the normal band.

5.2.6 Reserve Energy Policy

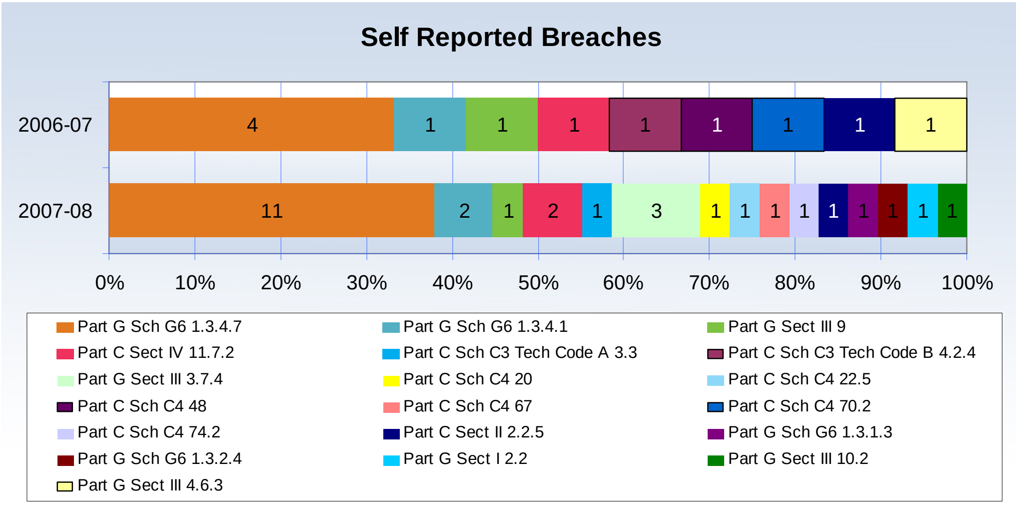
The Electricity Commission engaged Castalia Strategic Advisors to examine the current security of supply policies. Although no specific rule changes were proposed, the System Operator provided comment on the proposed new economic approach to security with the caution that theoretical numerical acceptability and the appetite of the industry and New Zealand in general were not likely to be the same in a time of short supply.

6. Compliance Matters

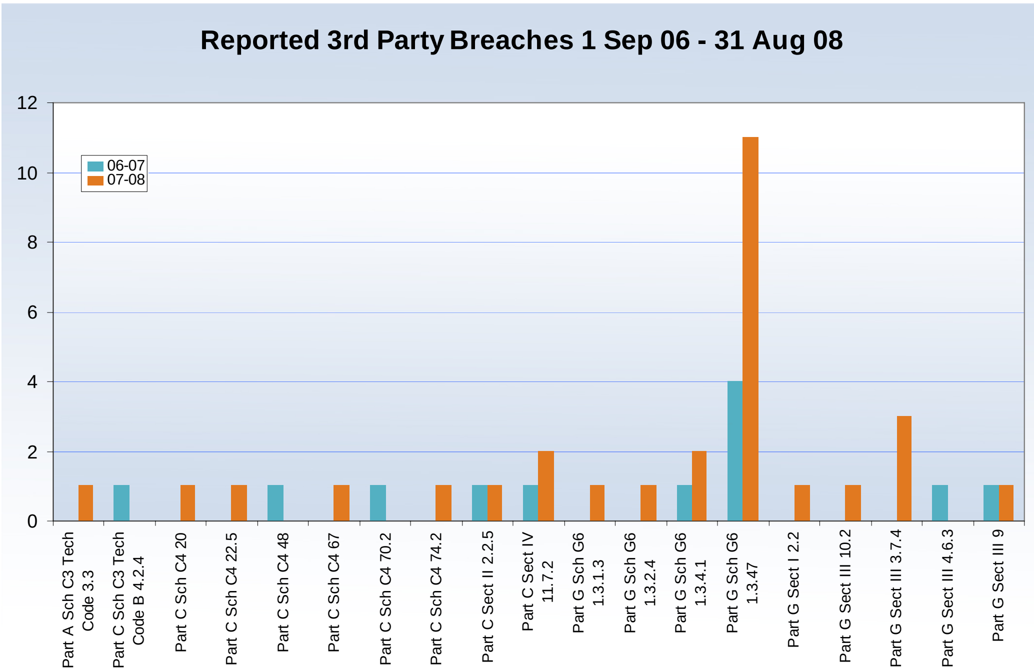
6.1 System Operator Self- Notified Breaches

The following graphs represent breaches of the Rules by the System Operator which it self-notified to the Commission for the period. The data is based on the reporting date of the breaches rather than the date on which the breaches occurred.

Comparisons are made between the previous and current years.



Comparison between the 2006_07 year and the current year's self-notified breaches.



Overall, there was:

- a significant increase in the number of self-notified System Operator breaches in the 2007/08 year compared with the previous year

- minimal correlation between the rules breached in the current year compared with last year.

Further specific observations and comparisons with the 2006/07 year can be made:

6.1.1 UPDATING GRID INFORMATION IN SCHEDULES

(rules 1.3.1.3, 1.3.2.4, and 1.3.4.7 of Schedule G6)

Breaches have increased to 13 from last year's total of 4. All the reported breaches in this category had negligible market impact. Analysis of these breaches indicates a large proportion of the increase may have been due to the significantly higher number of grid changes made in or close to real time. Most were a result of human error. The new market system will reduce the manual activity with this process with an expected reduction in the number of breaches of this rule.

6.1.2 INFORMATION PROVISION

Breaches relating to providing information to participants include the following:

- one ongoing breach for not sending formal notices to registered participants as required by the rules (Clause 67 of the Policy Statement). Registered participants include test houses, metering equipment owners, and data administrators, all of whom are unable to assist with mitigating the grid emergency and have limited (if any) interest in the content of formal notices. The System Operator has applied to the Electricity Commission for an exemption from this rule until the Policy Statement can be revised in 2009.

- those relating to System Operator provision of information to the Clearing Manager about allocable costs. There were two breaches of rule 11.7.2 of section IV of Part C in the period. Whilst the rules provide for such inaccuracies to be washed up, the System Operator has taken further steps to minimise the risk of such errors occurring.

- those relating to the sending of the System Operator daily report by 0900 every day. There was one breach of this rule, caused by a communications failure. There was no market impact.

- one breach of rule 3.3 of Technical Code A when the System Operator provided the wrong level of TPIX access to a participant. The access given would have allowed access to other participants' market information. The participant concerned was unaware of the error and did not access any of the confidential data. TPIX has now been decommissioned.

- one breach of rule 2.2 of Section I of Part G when the System Operator, having discovered it had published incorrect information about MW risk values, did not immediately correct the information.

6.1.3 CONSTRAINT ACCURACY

(Rule 20 and 22.5 of Schedule C4)

There were two self-notified breaches relating to constraint accuracy in the reporting period. One related to the Te Apiti runback scheme in December 2007 and the other was for an outage at Halfway Bush in April 2008. Both events had no market impact.

6.1.4 PRINCIPLE PERFORMANCE OBLIGATIONS (PPOS)

The System Operator notified one breach of the PPOs in the reporting period. This was a breach of rule 2.2.5 of section II of Part C, in relation to time error. The breach occurred during the previous reporting period (on 6 August 2007), two days after the previous similar breach reported in last year's annual report statistics. The Electricity Commission is investigating both breaches.

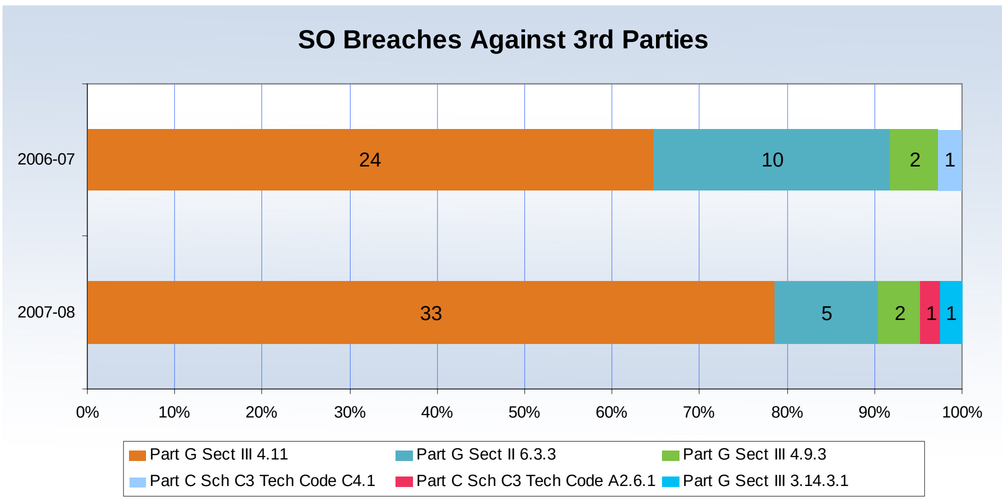
6.2 ALLEGED SYSTEM OPERATOR BREACHES REPORTED BY OTHER PARTIES (INCLUDING THE ELECTRICITY COMMISSION)

There were no System Operator breaches notified by other participants or the Commission during the reporting period.

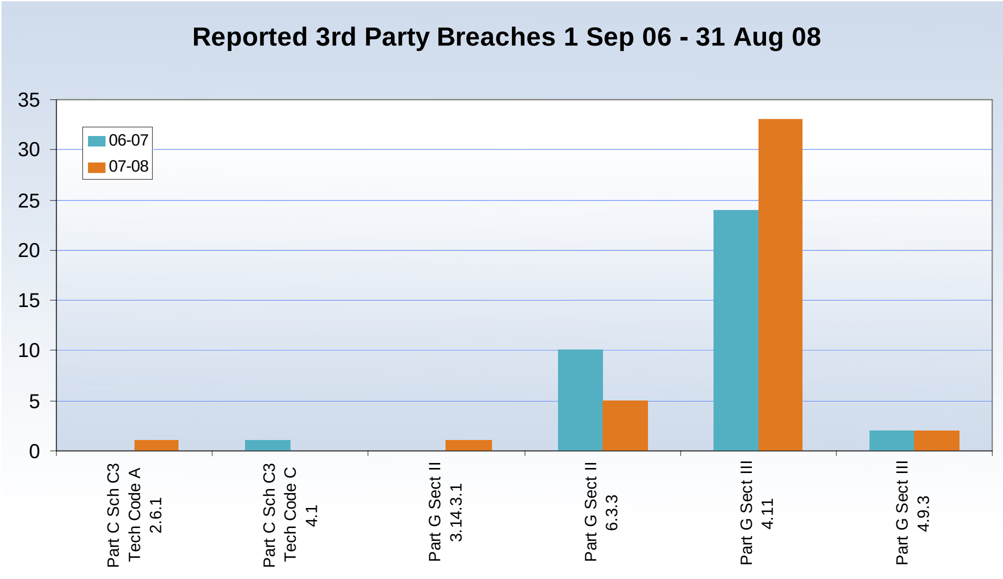
6.3 BREACHES ALLEGED BY SYSTEM OPERATOR AGAINST OTHER PARTICIPANTS

The following graphs represent Rule breaches by third parties notified by the System Operator, 42 for 2007/08, compared with 37 for 2006/07.

Comparisons are made between the current (1 September 2007 to 31 August 2008) and previous (1 September 2006 to 31 August 2007) years.



The graph below shows a comparison between the previous[1] and current years:



Note that whilst breaches of rule 6.3.3 are separately noted, they all have an associated breach of rule GII4.11.

The data shows that whilst the number of participant breaches for not complying with reserve dispatch instructions has reduced, there has been an increase in participant non compliance with energy dispatch instructions (28 in current year compared with 14 in the previous year). It is unclear why this is the case.

6.4 SETTLEMENTS

6.4.1 SETTLEMENT OF SYSTEM OPERATOR BREACH ALLEGATIONS

One settlement agreement was entered into during the reporting period. This was in respect of a breach reported by the Electricity Commission against the System Operator. The System Operator was said to have breached the rules by failing to issue a grid emergency notice on 19 June 2006 as soon as practicable after declaring a grid emergency. All actions agreed to be undertaken in the settlement agreement are due to be incorporated in the Policy Statement review for 2009.

6.4.2 SETTLEMENT OF OTHER PARTICIPANT BREACH ALLEGATIONS

The System Operator participated in three settlement agreements in respect of notified breaches by other participants.

[1] 10 breaches of GIII4.11 also involved a breach of GII6.3.3 for the 2006_07 year. Last year only 17 breaches of GIII4.11 and 5 of GII6.3.3 were reported. This is because those that were included in last year's report were breaches that occurred and were reported in this period. The data in the above graphs (and for all future years) will be breaches that were reported in the previous period (but may have occurred prior to that period).

All three settlement agreements related to participants' failure to follow dispatch instructions. Two breach allegations were for a reserve dispatch instruction and the other was for energy.

6.5 ASSURANCE

The System Operator has not undertaken any self-assessments during the reporting period, due to the workload from the new market systems project implementation. The assurance programme is expected to be resumed during the 2009/2010 reporting year. The System Operator has continued with other established quality activities, including documentation and event reviews.

7. RULINGS PANEL

The Commission referred one System Operator breach to the Rulings Panel for determination as to penalty. The matter was an admitted breach by the System Operator and related to the incorrect modelling of the Wilton transformer in May 2006 on two consecutive days. The Rulings Panel determined a fine of $4,000 for each event (a total of $8,000).

8. NEAR MISSES

There were no near misses reported during this period.

9. SPECIFIC COMPLIANCE REQUIREMENTS UNDER THE RULES

9.1 MONTHLY REPORTS

The System Operator has complied with its obligation under regulations 44 and 45 to undertake a monthly self review and report the results of each such review. All reports have been published by both the System Operator and the Commission.

9.2 SYSTEM SECURITY FORECAST

The rules require the System Operator to publish a System Security Forecast (SSF) every two years and review the need to revise the latest SSF every six months. The System Operator updated the 2006 System Security Forecast in June 2007 and again in December 2007. A summary of changes is available on the System Operator website[2].

9.3 PROCUREMENT PLAN – ANCILLARY SERVICES

The System Operator submitted the fifth draft Procurement Plans to the Board by 1 June 2008. In developing the 2008/09 plan, the System Operator met with selected

[2] SSF summary of changes – December 2007 - http://www.systemoperator.co.nz/publications

participants and, separately, invited comment from all industry participants. The key changes proposed for the 2008/09 plan were:

- *Fixed price frequency keeping*. The change provided for fixed price frequency keeping offers to be considered as an addition to the existing 'half-hourly' procured service.
- *Improved performance and technical criteria for frequency keeping service providers*. The proposed change recognises that inherent differences exist between generating assets and these should be reflected in the agreed contracted performance standards.
- *Sub-contracting of ancillary services*. Inclusion of this provision allows for contracted ancillary service providers to sub-contract services.

Procurement 2007/ 2008

The 2007/8 Procurement Plan came into effect on 1 December 2007. Tendering for ancillary services commenced on 8 October 2007 and was completed prior to the plan operative date. The major changes[3] introduced in the plan were:

- Islanded frequency keeping - if part of the grid is islanded the System Operator can procure frequency keeping services under an ancillary service arrangement.
- Frequency keeper selection description
- Assessment of performance requirements for FIR other than interruptible load.

9.3.1 CONTRACTED ANCILLARY SERVICES

The following table summarises the contracted services as at 31 August 2008:

Ancillary Service Agent	(1)FK	(2)IR	(3)OFR	(4)BS	(5)VS
Meridian Energy	√	√	√*	√*	
Contact Energy	√*	√*	√*		√*
Mighty River Power	√	√		√*	√*
Genesis Power	√	√		√	
TrustPower		√*			
Vector		√			
Northpower		√			
Powerco		√*			
Unison		√			
WELNetworks		√			
CountiesPower		√			
NZ Steel		√*			

[3] This commentary is not a comprehensive list of changes introduced. Full details of the changes introduced in 2007/08 Procurement Plans have been published on the Electricity Commission website (http://www.electricitycommission.govt.nz/opdev/comqual/procurement/index.htmll) in comprehensive schedules.

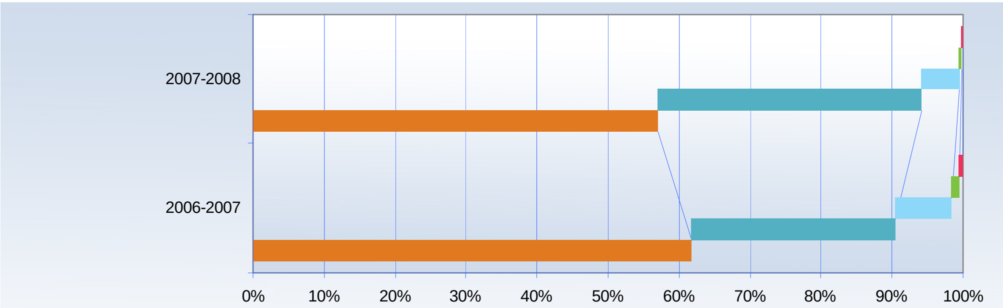
Ancillary Service Agent	(1)FK	(2)IR	(3)OFR	(4)BS	(5)VS
Pan Pac		√			
Winstone Pulp International		√*			
KCE Mangahao and Todd Mangahao		√*			
Norske Skog		√*			
Energy Response		√			
NZ Aluminium Smelters		√*			

(1) FK - Frequency Keeping
(2) IR - Instantaneous Reserves
(3) OFR - Over Frequency Reserve
(4) BS - Black Start
(5) VS - Voltage Support
*Longer term contract

9.3.2 Ancillary Service Procurement Costs

9.3.2.1 Procurement 1 September 2007 – 31 August 2008

Total ancillary service cost for period = $181,817,674



	2006-2007	2007-2008
Black start	$393,160	$395,215
Over frequency reserve	$614,903	$624,184
Voltage support (incl Events)	$5,373,840	$9,495,777
Instantaneous reserve	$19,090,153	$67,693,066
Frequency Keeping Costs	$41,245,493	$103,609,432

9.4 Policy Statement

The System Operator applied for, and was granted an exemption from reviewing the Policy Statement during the reporting period. The next review of the Policy Statement is due in 2009.

9.4.1 Departures from Policy Statement

There were no departures from the Policy Statement during the review period.

9.5 SOFTWARE AUDITING

The System Operator arranged the following audits of software to meet the requirements of regulation 51 (1). All necessary audit certificates were provided to the Board.

9.5.1 ANNUAL RMT AND SPD CERTIFICATION

There was an RMT/SPD opinion provided by PA Consulting on 29 February 2008.

This opinion was the annual certification of the Scheduling, Pricing and Dispatch (SPD) Software and the Reserve Management Tool (RMT) for the period of the review, as required in the System Operator Service Agreement and in regulation 51 (1).

9.5.2 RMT

The System Operator sought the following opinions from the auditor (PA Consulting) in respect of RMT: - (all being satisfactory)

- 21 May 2008 (updated 15 August 2008). Changes were to configure a generator to provide TWD.
- 17 December 2007. Changes were to:
    - reduce HVDC South Flow P2 reduced voltage current limit from 1200 to 840 Amps.
    - set the HLY U5 aux load and remove as a secondary risk
    - implement new FIR lookup tables and governor parameters
    - set the IL FIR inherent delay to 0.8s
    - update asset capability from changes provided by asset owners
    - increase SI inertia-less load to 610MW
    - change RMT shell code change to read Hydro gate limits file.
    - Make changes to RMT study mode relating to TWD

9.5.3 SPD

The System Operator sought the following opinions (noting all were satisfactory) from the auditor (PA Consulting) in respect of SPD:

- SPD TP37.35. Opinion provided by PA Consulting on 14 May 2008. Change was to explicitly set the DC line flow values for out of service circuits to zero, as is done for AC lines.
- SPD TP37.36. Opinion provided by PA Consulting on 5 August 2008. Change was to revise the index on the HVDC branch flows so as to limit the flow variable only during the intended period(s).

10. Specific Compliance Requirements under the SOSPA

10.1 Disaster Recovery Plan

No changes were made to the System Operator’s disaster recovery plan provided to the Commission and approved by it in 2005.

The System Operator reviewed its Business Continuity Plan and updated certain information (related to personnel contact details). These were identified during a ‘table top’ exercise held on 7 August 2007. A simulation exercise is planned for late 2008 or in the first half of 2009.

10.2 Warranties

At the date the SOSPA was entered into the System Operator provided the Commission with certain warranties. These are still not able to be reiterated in full. As at 31 August 2008 the System Operator:

- is not aware of anything within its reasonable control which might or would adversely affect its ability to provide the contracted services under the SOSPA
- does have sufficient skills and supervision to carry out the said services.
- does not have sufficient financial resources to carry out the said services and will require additional financial resources from the Electricity Commission to ensure it can continue to act as a reasonable and prudent System Operator. The issue of sufficiency of financial resources was being addressed by discussions between Transpower and the Electricity Commission regarding variations to the System Operator Service Provider Agreement. As at 31 August 2008 a large measure of agreement had been reached between Transpower management and the Electricity Commission’s management on revised financial and other arrangements which, if implemented, will enable Transpower to warrant it has sufficient financial resources to carry out the System Operator services

11. Specific Compliance Activities

11.1 Dispensation and Equivalence Applications

Month	Applications Received	Granted in Draft	Granted	Withdrawn	Not Granted	Revoked
Sep 2007	1	16	15	118*	0	0
Oct	0	1	0	0	0	0
Nov	0	0	9	0	0	0
Dec	0	0	0	0	0	0
Jan 2008	1	1	1	0	0	0
Feb	0	0	1	0	0	0
Mar	0	1	0	0	0	0
Apr	0	0	1	0	0	0
May	0	0	0	0	0	0
Jun	0	0	0	0	0	0
Jul	3	0	0	1	0	0
Aug	4	5	3	4	0	0
TOTALS	**9**	**24**	**30**	**123**	**0**	**0**

* Sept 07 Grid Owner withdrew 118 applications
* All applications were for exemptions

11.2 Exemption Applications

The System Operator sought and was granted the following exemptions during the reporting period:

- An exemption in respect of its obligation to review the Policy Statement during the reporting period.
- An exemption from rule 6 of section IV of Part C to allow Genesis to offer frequency keeping services. This exemption expires on 30 November 2008.
- An exemption from rule 2 and 6 of section IV of Part C to allow Energy Response Pty to offer interruptible load. This exemption expires on 30 November 2008.
- An exemption from clause 33.1 of Schedule C4 to allow the System Operator to implement the variable reserves proposal.

12. ANCILLARY SERVICE PROVIDER PERFORMANCE 2007/8

12.1 INSTANTANEOUS RESERVES

The table below summarises the Instantaneous Reserve (including Interruptible Load) performance assessments carried out by the System Operator for the period of 1 September 2007 to 31 August 2008.

Under Frequency Event Summary - Instantaneous Reserve Event Assessments								
Date	*Time*	*Event initiated at*	*MW*	*Lowest Frequency (Hz)*		*MW Lost*	*Number of Dispatched IR Ancillary Service Agents (ASA)*	*Performers and (non-Performers)*
				North Island	*South Island*			
17 Sep 07	11:48	HLY U5	327	49.07	49.87	327	14	*2*
22 Sep 07	05:35	SPL	226	49.22		226	*Not an IL event 11 - includes IL	*0*
9 Dec 07	17:32	SPL	331	49.25		331	*Not an IL event 14 – includes IL	*0*
10 Dec 07	10:42	HLY U5	296	49.20		296	14	*1*
16 Jan 08	10:45	HLY U5	286	49.18		286	13	*1*
22 Jan 08	21:11	SPL	334	49.14		334	14	*1*
17 Feb 08	01:07	HLY U2	233	49.18		233	14	*2*
22 Feb 08	15:34	HLY U3	239	49.24		239	*Not an IL event 14 – includes IL	*0*
15 Apr 08	14:02	OHA	209	49.64	49.13	209	*No SI IL - 2	*0*
19 Apr 08	05:52	BEN T2	148	49.53	49.22	148	*Not an IL event 12 – includes IL	*1*
22 May 08	03:52	HLY U2	214	49.23	49.57	214	*Not an IL event 10 – includes IL	*0*
2 Aug 08	15:35	[4]	328	49.19	49.4		14	*2*

Notes: Several event assessments require further analysis and discussion between the System Operator and the Ancillary Service Agent.

[4] At the time of preparing review the Causer had not been determined

The under frequency events marked with an asterisk (*) did not reach the event trip frequency (49.2Hz) for interruptible load (IL). Assessments were carried out on other IR providers dispatched during these events.

12.2 FREQUENCY KEEPING RESERVES

The System Operator assesses the performance of frequency keeping ancillary services on a monthly basis. Any performance issues identified are addressed directly with the ancillary service agent. In the period of this review no issues relating to performance were taken up with frequency keeping service providers.

During this review period, the System Operator developed a more ‘outcome focussed’ methodology for frequency keeper performance assessment. Proposed improvements were included in the draft 2008/09 Procurement Plan.

12.3 BLACK START

On 2 February 2008 Genesis and the System Operator successfully completed a North Island Black Start test.

The test was required to demonstrate capability to start up from a position of not being connected or taking supply from the grid. The test involved:

- Starting one unit without supply from the grid.
- Energising a section of the transmission grid system.
- Synchronising a second unit at the same station.

A similar test is planned for the South Island in November/December 2008.

12.4 VOLTAGE SUPPORT

During the period 1 September 2007 to 31 August 2008 the System Operator dispatched contracted zone 1 voltage support from Otahuhu Units 1, 2, 4, 5 and 6, Southdown 105.

Marsden SC2

In July 2007 a transformer fault left Mighty River Power’s Marsden synchronous condenser unable to be connected to the national grid. The System Operator considered the termination options available under the Ancillary Services contract. This entailed a detailed review of the contract and applicable law (in relation to the force majeure provisions and the concept of frustration). The conclusion reached was that there were no options available to Transpower on which it could rely to terminate or suspend the contract during the period T2 is unavailable. This means the contracted payments to Mighty River Power continues until the contract comes to an end in October 2008.

13. Industry Consultation Papers

13.1 Contributions and Submissions

The System Operator actively contributed to a number of Commission consultation activities. These contributions were made to industry discussion papers or rule change proposals. The contributions were in respect of the following matters and were generally made in conjunction with the Grid Owner as Transpower New Zealand Ltd responses or papers:

- Demand side bidding and forecasting
- Assorted regulation changes
- Compliance review
- Review of reserve energy policy
- EC Load Management Value and Pricing
- Information system
- Annual security and reserve energy needs assessment
- Wind integration options
- Connection code/Outage protocol
- Market administrator report
- Routine test plan
- Appropriations 08/09
- Routine testing of assets
- Draft GPS on electricity governance
- Minor offer and dispatch rule changes
- Peak adequacy standard
- Appropriation for reserve energy
- Reconciliation rules changes
- Statement of Opportunities 08
- Market design review options
- Issues for managing locational price risk
- Procurement Plan.

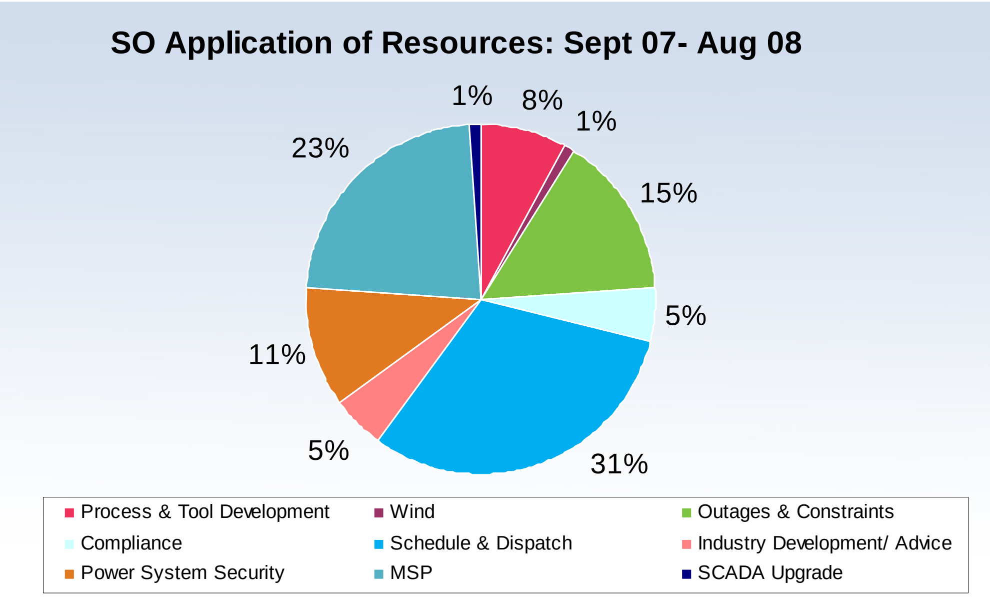
14. System Operator People and Resources

14.1 People

The System Operator FTE's during the reporting period were:

	31/8/2007	31/08/2008	Change
General Manager	2.0	2.0	0
Risk & Performance	6.0	5.8	(0.2)
Development	5.0	5.0	0
System Operations	39.4	37.4	(2)
Investigations	13.0	14.0	1
Operations Planning	14.0	17.0	3
Market Services	10.4	11.6	1.2
Total	89.8	92.8	3

The following chart shows the allocation of personnel time to the System Operator's service areas during the reporting period. Support resources are allocated across each service area in the same proportion as the service represents to total services delivered.



14.2 Customer Service

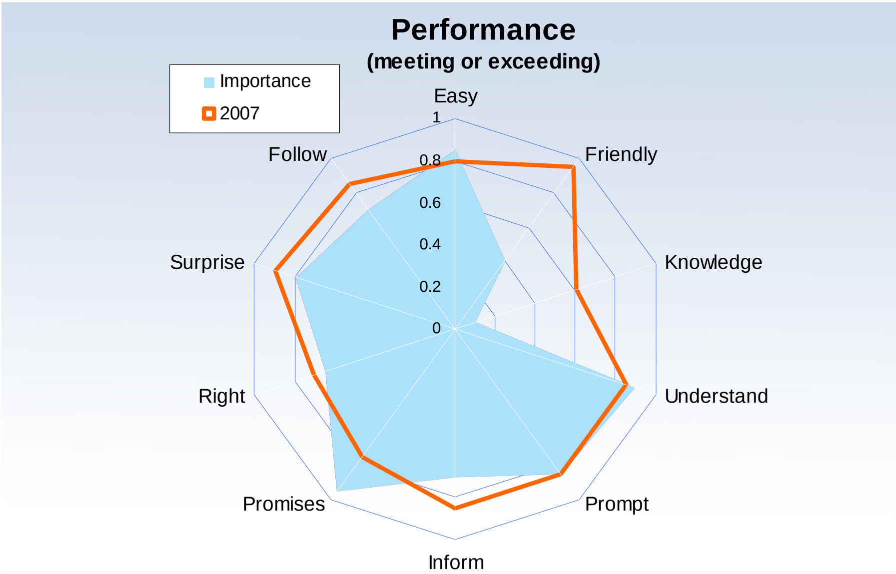
14.2.1 Customer satisfaction survey

The System Operator undertook a further customer survey in December 2007. The survey (carried out by an independent professional) sought to provide an updated perspective on how participants saw the System Operator with regard to ten internationally recognised service factors. A similar survey approach was used in 2003, 2004 and 2006.

The service factors asked about were:

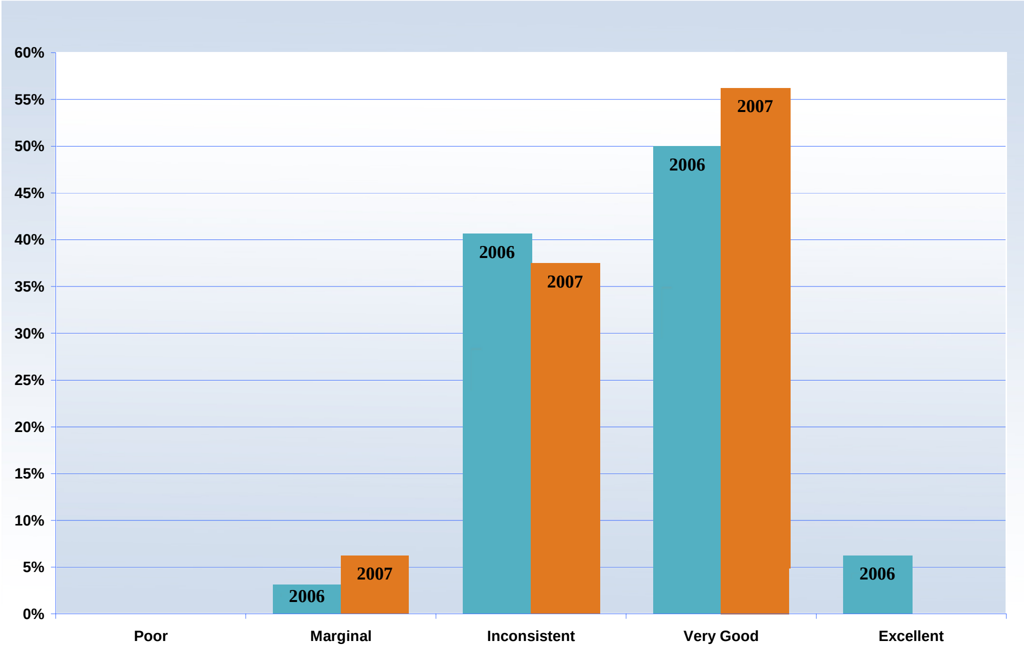
- is the System Operator **easy** to get hold of?
- are staff **friendly**?
- are staff **knowledgeable**?
- do staff **understand** your needs?
- are staff are **prompt**?
- do staff keep you **informed**?
- do staff keep their **promises**?
- do staff get things **right** first time?
- are there no **surprises**?
- do staff **follow** up?

Each survey participant was first asked how important each service factor was to them and then how the System Operator was performing. The summarised results (by industry groups) are set out below. The importance of each service factor is based on those respondents who rated the factor of 'high importance'.



14.2.1.1 Overall performance

The following graph shows the consolidated ranking of the System Operator's performance.



The System Operator views the results as disclosing areas where participants and the believed better service efforts were required or desirable. The System Operator continued to devote effort towards improving its level of service, consistent however with a realistic view of its resources and the requirements of its other projects, particularly its ongoing market systems project (see section 14.3).

A further survey is expected to be commissioned in late 2008 or after the market systems project ends in 2009.

14.2.2 ADVISORY SERVICES TO THE COMMISSION

The Commission indicated on a number of occasions during the reporting period (as well as in its report on the previous 2005/06 System Operator annual review) it would like the System Operator to provide it with technical and, in some case, independent advice on engineering and market issues that arise from time to time. The services contemplated are ones that are in addition to the service obligations arising under the Rules but are within the expected competence of the System Operator.

The System Operator is aware the non-Rule services provided to the Commission during the reporting period were not provided at the level of quantity and timeliness the Commission would like. The System Operator is discussing with the Commission how it can increase its capacity to provide such services and on what terms.

14.3 SYSTEMS DEVELOPMENT

14.3.1 MARKET SYSTEMS PROJECT (MSP)

14.3.1.1 Background

The current market systems have delivered System Operator services to the wholesale electricity market from the start of the NZEM in October 1996. As bespoke prototype designs, the core programs such as SPD were anticipated to need upgrading during their second decade.

Investigations initiated in 2004 determined that the market systems, while stable (in 2004), were not sustainable and hence were 'not fit for purpose'. For the System Operator to continue to provide the reasonable and prudent System Operator service required by the EGRs and SOSPA, replacement and upgrading of the market systems was a necessity. Independent advisors confirmed in late 2004 the growing operational risks attendant on continued use of the market systems.

14.3.1.2 The project

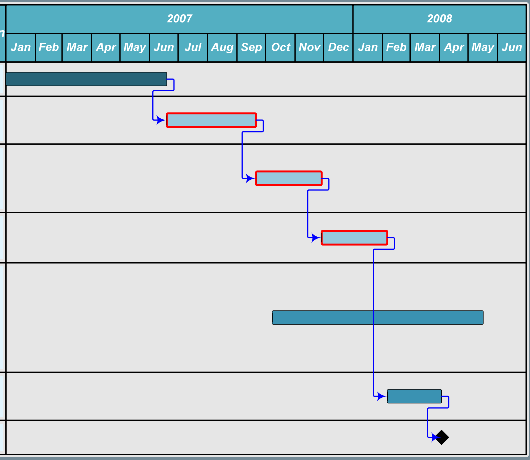
Following Transpower Board approval in 2005, an open tender process led to the 2006 contract with AREVA T&D of Seattle USA for the supply of the replacement market systems. The contract targeted delivery for mid 2007. The market systems that were specified in detail through this process are designed to provide the following benefits:

- reduced operational risk, achieved by bringing the market systems up to date with modern industry standards of technology, security, reliability and resilience.
- a prudent package that delivers maintainability and flexibility for future development and enhancement of market capability and SO services.
- re-engineered business processes, automated where appropriate to reduce reliance on manual (and hence risky) processes.
- updated capabilities to enable the changes in the power supply environment to be managed.

Early 2006 work was towards project initiation, high level system design, detailed business design, and initial development work. AREVA completed the High Level System Design in May 2006 and progressively developed detailed design documents. As 2006 progressed, sufficient detailed design notes had been approved for AREVA to commence development work.

By October 2006 it was clear the completion target of mid- 2007 was overly ambitious, particularly in respect of the development requirements. To reduce project risk, Transpower reluctantly agreed to reset the base timeline of the project schedule to a go live date of 31 March 08. This is the timetable shown in the following diagram.

ID	Task Name	Start	Finish	Duration
1	DEVELOPMENT & INTEGRATION (started prior – shown from 1/07 only)	1/01/2007	18/06/2007	24.2w
2	FACTORY ACCEPTANCE TEST (critical path 'Main' FAT of components to be released into SIT)	19/06/2007	20/09/2007	13.6w
3	SITE INTEGRATION TEST (critical path component of SIT only – earlier SIT phase starts during Main FAT and continues with SAT)	21/09/2007	28/11/2007	9.8w
4	SITE ACCEPTANCE TEST (includes environment rebuild and final phase of SIT in parallel)	29/11/2007	5/02/2008	9.8w
5	TRAINING DELIVERY (commences with 'pre Instructor Lead Training', IT support training in Dec then System Operator formal classroom training commences 21/1/08. Simultator delivery due August; Operational in October.)	8/10/2007	16/05/2008	32w
6	TRANSITION (transition phase continues beyond Go Live)	6/02/2008	2/04/2008	8.2w
7	PRODUCT IMPLEMENTATION	3/04/2008	3/04/2008	0w



The project subsequently tracked the rescheduled program, completing the development and integration phase on target. This permitted factory acceptance testing (FAT) to commence on 18 June 2007, achieving a significant milestone on plan.

FAT progressed through July and August. In parallel, the design of the system integration, system acceptance testing, and transition to operations was carried forward. In October it became apparent the target implementation date of April 08 could not be met. The coincidence of a variety of issues with development, FAT, integration and acceptance testing were determined to make the completion of training and the handover of the systems by the targeted 2 April 2008 a very high risk objective. Project rescheduling to reduce risk areas and accommodate the extensive SO training requirements established that project completion would take until the first Quarter 2009.

Project work continued while a comprehensive review of project and project scheduling was undertaken by Transpower and AREVA. In April 2008, the Transpower Board approved a revised schedule for the renewed market systems that fixed the go-live for the systems at 24 March 2009.

<u>Testing, transition and go-live</u>

Transpower and its contractors have completed FAT and testing continues with system integration and site acceptance testing which will be completed in late 2008 for transition to commence at the beginning of 2009.

In parallel with the technical development and delivery of the new systems, a major work effort has been undertaken since mid 2006 to produce updated processes and documentation as well as training materials to support the new systems. This work covers both the core System Operator business areas and the supporting information and system technology areas within Transpower.

Transpower's training team has been working with the market system project team members to identify and capture the changes in knowledge and skills required to operate the new market system. In the term of this report, a comprehensive learning package has been developed for System Operator personnel. This will be progressively introduced when training commences in January 2009.

All System Operator personnel will receive training, though to varying levels depending on the extent to which roles are affected by the new systems and changes to procedures. Implementation of the training programme has been planned to, wherever possible, minimise impact on the day to day business of System Operator while ensuring all personnel have the opportunity to complete specific programmes of learning.

15. Information to Participants

15.1 Workshops and Newsletters

Seven System Operator newsletters were issued during the review period.

One participant workshop was held in Wellington and repeated in Hamilton during June. The focus of the workshop was the 2008 dry year planning and industry arrangements which were being put in place at the time.

A proposed workshop series in October 2007 was cancelled when the System Operator delayed the implementation of its market systems from March 2008 through to the first quarter of 2009. The workshop, likely to be rescheduled in late 2008, was to focus on matters related to the new systems.

15.2 System Operator Website

The System Operator maintains a website through which it distributes information to registered participants (password protected areas may apply) and the public at large. The System Operator increasingly provides information through the website, including, for example, copies of relevant parts of its operational procedures, newsletters, operational reports, industry data, and required reporting. The site is now a primary means of distributing information.

15.2.1 Usage

Usage of the System Operator web increased substantially in the reporting period months.

Traffic Analysis	1 Sep 2006 to 31 Aug 2007	1 Sep 2007 to 31 Aug 2008
Total visits:	38,392	46,939
Total pages viewed:	904,435	2,137,382
Total hits:	989,725	2,160,652
Average visits per day:	105	128
Average visits per week:	737	898
Average visits per month:	3,199	3,912
Average pages viewed per visit:	24	46
Average pages viewed per day:	2,479	5,841
Highest volume time of day	9 a.m. - 10 a.m.	8 am - 9 am
Highest volume day of the week:	Thursday	Tuesday
Highest volume month:	June 2007	June 2008

The most requested page continues to be the Zone Loading page this page received 46.2% of all hits to the System Operator website. System Operator will continue looking at more innovative ways of displaying this type of information and plans to enhance its live data information website display early in the next reporting period.

The top 5 most popular web site pages:

Page Name	Zone Loading	Upper South Island Security	Upper North Island Security	Home Page	Power System Overview
Hits	1,589,720	383,998	51,614	26,101	18,511
Page Image					
Percentage of overall Views	46.2 %	11.2 %	1.5 %	0.8 %	0.5 %

15.2.2 CONTENT

Over the last 12 months the System Operator has continued to add additional website information intended to give participants greater knowledge about the status of the power system and enhance participants' ability to manage local networks. For example:

- Dry Year 2008 page: this has been an on going resource detailing how the capacity on the power system has been utilised during the period on low hydro storage in both the North and South Islands.

A number of System Operator publications were made available via the website during the period, including:

- procedures
- forms
- papers

Title	Date	Description
PR-EA-010 Planned Asset Testing	Nov 2007	Used to provide a process for managing Asset Owners requests to carry out asset testing while connected to the power system.
PR-SH-040 Security Constraint Development Overview	05 Mar 2008	This document gives background information about the security constraint development process. It explains the SPD model and constraint types, and gives an overview of considerations around applying constraints.
Dispensation / Equivalence Application Form	Nov 2007	Application form for applying for Dispensation / Equivalence arrangements.
FM-EA-008 Generator Notice of Initial Offer	Oct 2007	This form must be completed for each generating plant that is intended to be offered on the market.
FM-EA-009 Purchaser Notice of Initial Bid	Oct 2007	This form must be completed for each GXP that a purchaser intends to submit bids for.
FM-EA-010 Test Plan	Sep 2007	Form to be used to notify the System Operator of Asset Testing of plant while connected to the power system.
FM-EA-011 Urgent Change Notice	Sep 2007	Form to be used to notify the System Operator when a temporary change to asset capability occurs.
SPD Model Diagram	12 Aug 2008	This diagram shows how the New Zealand power system is modelled for the purposes of Scheduling, Pricing, and Dispatch as a national set of nodes and branches connecting those nodes.

Title	Date	Description
Huntly Unit 5 Commissioning	Nov 2007	Learnings from the Huntly Unit 5 commissioning (2007).
North Island Frequency Excursion	May 2007	A summary report on the North Island frequency excursion that occurred on 29 April 07.
Rule Change Proposal: Disconnected nodes	Aug 2008	This paper proposes various rule changes relating to disconnected nodes to ensure the System Operator's new market systems are strictly compliant with the rules and to improve rule clarity and correctness.
Rule Change Proposal: Dispatch of Instantaneous Reserve	May 2008	This paper proposes a rule change to enable the partial dispatch of reserves when there is a shortage of energy and reserve offers.

16. FINANCIAL REVIEW (SOSPA)

16.1 BASE CONTRACT

Fees charged under the base System Operator Service Provider Contract were as follows:

Financial review: SOSPA	1 September 2007 – 31 August 2008
System Operator Service Provider Contract Base Fee	21,351,999
Total fees paid under the SOSPA	**21,351,999**

16.2 ADDITIONAL FEES

The following is a summary of the fees charged to the Electricity Commission for services in addition to those provided under the SOSPA.

Variable Revenue	1 September 2007 – 31 August 2008
EC Advice including Rule Changes	108,172.91
Breach Investigations	7,160.00
Total variable revenue	**115,332.91**