System Operator

Annual Review and Assessment 2008/09

1 September 2008 to 31 August 2009

SYSTEM OPERATOR

Keeping the energy flowing

TRANSPOWER

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1. Executive Summary

1.1.1 The System Operator – The Year in Review

(1 September 2008 - 1 August 2009)

During the year in review, the System Operator focused on the implementation of the new market systems, whilst successfully carrying out its core business of operating the New Zealand electricity system.

In respect of its core business the System Operator:

- Managed 30 grid emergencies, 45 system events and 21 connection point events
- Coordinated 6588 outages
- Assisted with the planning and coordination of the commissioning of 5 new generators

By 1 September 2008 the dry year issues experienced during winter 2008 were effectively over. Managing the dry year took significant System Operator resource over the 2008 winter months and the remainder of the year was largely spent catching up on those activities that had been planned but were required to be postponed as a result; for example, the credible event review.

From a system perspective, there was an increased volume of generator maintenance following the dry year given generators had been running continuously to meet demand. The increased maintenance created a number of scheduling challenges for the System Operator, with outages continuing until the end of May. This latent effect of the dry year will be a more significant issue for the industry as the use of thermal plant (with annual maintenance requirements) increases.

Winter 2009 started very cold but ended relatively mildly. While the demand exceeded the 2008 peak, it did not reach the levels of the 2007 peak or the “prudent” limit forecast set by the National Winter Group.

A significant event for the System Operator was the 1 August 2009 under frequency event where the frequency dropped to 47.72 Hz in the South Island after the loss of 270 MW from the tripping of Pole 2. This was followed by a high frequency of 52.05 Hz. This event is considered significant because of the following factors:

- the frequency fell below that planned for or expected for a contingent event (the standard under frequency curve) and was within 0.2 Hz of activating Automatic Under-frequency Load Shedding Systems (“AUFLS”)
- the frequency rose to above 52 Hz which caused some types of generation to automatically disconnect

There are a number of important implications and learnings from this event that the System Operator will need to discuss with the Electricity Commission and industry in the upcoming months.

During the year the System Operator also worked on the development of a new end-to-end testing regime for interruptible load (IL) providers and has been undertaking work on testing of New Zealand’s black start capability. There has been increased activity in the provision of IL through aggregators and this may require further development work in the upcoming year.

A key milestone for the System Operator during the year ended 31 August 2009 was the “go live” of the new market systems. The development of the new market systems has been a very complex project that has taken over three years and has required a considerable amount of System Operator resource. The new systems went live on Tuesday 21 July, with the first dispatch schedule issued at 11:30, on schedule.

The transition to the new systems has gone well with only a small number of 'bedding in' matters, which have either been resolved or are to be addressed in future market systems change releases. One of the first priorities will be the reimplementation of key initiatives such as frequency keeping selection and variable reserves.

The success of the project has been aided by the positive support received from the industry and the Electricity Commission.

Other highlights for the System Operator during the year in review include:

- the introduction of an online ACS database which allows asset owners to electronically view and update asset capability information
- substantially completing the review of credible events specified in the Policy Statement
- working with the grid owner regarding the coordination of outages necessary to complete and commission the Pole 3 project
- working with the grid owner to increase efficiency of outage coordination

The System Operator was very pleased to conclude negotiations with the Electricity Commission in respect of a new System Operator agreement. The new agreement was effective from 1 July 2009 and replaces the earlier agreement entered into in 2003.

The System Operator observed an increase in the number of self-reported breaches during the year in review. Given a large proportion of the breaches occurred in December, January and May, this is likely to be at least in part due to the increased maintenance and outages during these periods. The System Operator expects expected that the coming year will see a downturn in the number of breaches, as the new market systems have reduced the number of manual functions required in relation to the modelling of system outages.

There were 21 submissions made by the System Operator in respect of Electricity Commission consultation activities in the year to 31 August 2009.

The successful introduction of the new market systems now allows the System Operator to move its focus in the upcoming year to the needs of its customers. The System Operator is looking forward to working more closely with the industry to identify areas where it can facilitate industry development. Following customer feedback in the annual customer survey, the System Operator is planning to hold more regular industry workshops to discuss specific industry issues such the one planned for November 2009 to discuss the events of 1 August 2009.

2. PRINCIPAL PERFORMANCE OBLIGATIONS

2.1 TIME ERROR

There was one instance of time error exceeding the +/- 5 second limit during the review period. This occurred at approximately 04:36 on 1 August 2009 in the North Island. A tripping of HVDC Pole 2 at 04:31 during North to South transfer resulted in a significant drop in the South Island frequency and a considerable increase in the North Island. Dedicated efforts to return the South Island frequency back to normal band resulted in North Island time error excursion drifting to as high as 8.6 seconds. The time error was returned to normal band approximate 45 minutes later.

2.2 VOLTAGE VIOLATIONS 220 KV & 110 KV

There were three instances of the 220 kV and 110 kV grid voltage exceeding the allowed +/-10% limits between September 2008 and August 2009.

At 16:14 on 18 March 2009 Timaru T5 interconnecting transformer tripped. The voltage on the 110 kV bus at Temuka rose above 10% for a period of 5 minutes. The maximum voltage level reached was 124 kV. The event occurred during a planned outage of Timaru T8 interconnecting transformer, resulting in loss of load at Timaru, Temuka, Albury and Tekapo A. Maximum voltage violation was recorded when Timaru T5 was initially returned to service for load restoration. The voltage on the 110 kV bus at Temuka was returned to normal band when load was gradually restored.

At 06:25 on 18 April 2009 a fault in the Bunnythorpe 110 kV network caused multiple trippings of the following:

- Transmission circuits: Bunnythorpe-Mataroa 1, Mataroa-Ohakune 1, Ohakune-Ongarue 1, Arapuni-Hangatiki-Ongarue 1 and Arapuni-Hangatiki 1
- Interconnecting transformers: Bunnythorpe T1, Bunnythorpe T2 and Bunnythorpe T3

The event resulted in loss of load at Mataroa, Ohakune, National Park, Ongarue and Hangatiki. The 110 kV bus voltages in the surrounding areas dropped below 10% for a period of approximately 5 minutes. The lowest minimum voltage level reached was 96.6 kV at Waipawa. Load management was required at Waipawa to halt the voltage drop before tripped assets were gradually returned to service and affected load restored.

On 15 May 2009 the 110 kV bus voltages in the Buller-West Coast region were above 10%. This occurred at 06:15 for a period of approximately 10 minutes. The maximum voltage reached was 121.3 kV at Atarau. The violation was due to transient overvoltage as a result of the tripping of Inangahua-Murchison-Kikiwa 1 circuit at 05:54. Numerous attempts to close the circuit breaker at Inangahua end were unsuccessful, before the circuit was returned to service at 12:36.

2.3 FREQUENCY

Frequency excursions for the reporting period remained within the annual frequency performance targets. There was one excursion below 48 Hz reported for the period (this event is discussed in more detail in section 3.2.1).

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	
52.00 > Freq >= 51.25		1	1					1					3	7
51.25 > Freq >= 50.50	7	1	3	1	1	1		2	2		2	2	22	50
50.50 > Freq >= 50.20	128	210	182	132	167	152	241	380	231	267	416	359	2865	
50.20 > Freq > 49.80														

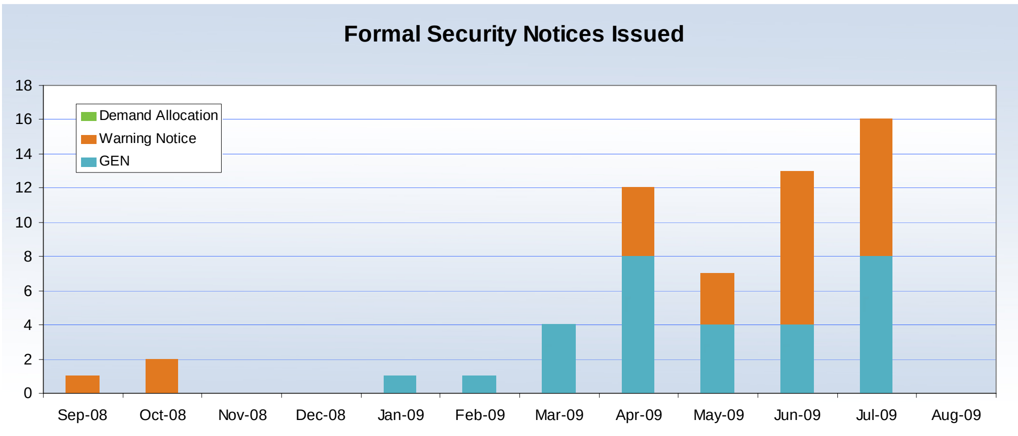
Frequency Band (Hz)	2007				2008								Annual rate	PPO target
	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug		
49.80 >= Freq > 49.50	138	153	170	100	144	129	114	221	181	204	336	257	2147	
49.50 >= Freq > 48.75	1	3	7	2	4	5	4	9	2	1	3	1	42	60
48.75 >= Freq > 48.00								1					1	6
48.00 >= Freq > 47.00												1	1	0.2 Note 1
47.00 >= Freq > 45.00														

Note 1. The PPO target is 1 in any 60 month period.

2.4 SECURITY NOTICES

A total of 57 formal security notices were issued between 1 September 2008 and 31 August 2009.

Notice Type	Number of Notices Issued*
GEN	30
WRN - Warning Notice	27
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.

Of the Grid Emergencies declared during this period, the majority were issued during April and July 2009. During May 2009, four notices were issued in relation to insufficient standby reserve offers in the North Island. And during July 2009, eight grid emergencies were declared to allow grid re-configuration at Mangamaire to manage post-contingency violations on Mangamaire-Woodville 1 circuit.

2.5 PARTICIPANT ADVICE NOTICES

A total of 97 Customer Advice Notices (CANs) were issued during the review period.

2.6 Stability Limits

There were no instances of stability limits being exceeded on the grid during the review period. During this time, however, there were three stability constraints that bound for a total duration of 8.5 hours. This related to the voltage stability limit on south transfer between Bunnythorpe and Haywards in September 2008 during an outage of one of the Mangamaire-Masterton 1 or Mangamaire-Woodville 1 circuits; and to voltage stability limits at the top of the South Island in April and May 2009 during outages of one of the Islington-Kikiwa circuits.

2.7 Standby Residual Check Notices

Standby residual check notices are published by the System Operator to indicate whenever there is insufficient generation and interruptible load offered for dispatch to maintain system security and meet forecast demand even if the largest single credible event were to occur. Notices were issued by the System Operator for approximately 1400 affected trading periods in the year to 31 August 2009.

The System Operator remains concerned regarding the lack of response received from generators to the standby residual check notices. It will seek to work with the Electricity Commission to ensure the market design provides adequate incentive for generation capacity to be made available during peak demand periods to maintain system security.

3. Security Issues

3.1 Summary of Grid Emergency Notices

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 08	0
October 08	0
November 08	0
December 08	0
January 09	1
February 09	1
March 09	4
April 09	8
May 09	4
June 09	4
July 09	8
August 09	0

3.2 EVENTS LEADING TO DECLARATION OF GRID EMERGENCIES

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

Grid Emergencies			
Date	Time	Summary Details	Island
21 Jan 2009	08:20	A Grid Emergency was declared for the restoration of supply to Central Park and Kaiwharawhara following the tripping of Kaiwharawhara-Wilton Circuit 1, Takapu Road-Wilton Circuit 1 & Central Park-Wilton Circuit 3.	North
3 Feb 2009	14:00	A Grid Emergency was declared for load management to restore supply to Penrose following the tripping of Penrose supply transformers T8 and T11.	North
3 Mar 2009	11:13	Bunnythorpe T3 transformer would exceed its advised rating for the loss of the Hawera-Stratford circuit. Demand management at Mataroa, Waverly, Wanganui and Marton alleviated the problem.	North
7 Mar 2009	17:40	A Grid Emergency was declared for increased transmission offers in the Bay of Plenty following multiple circuit trippings in the region.	North
17 Mar 2009	13:14	A Grid Emergency was declared for the restoration of supply to Greymouth, Dobson and Atarau following the tripping of Atarau-Reefton-Inangahua 1 circuit.	South
17 Mar 2009	16:27	A Grid Emergency was declared for the restoration of supply to Timaru, Temuka, Albury and Tekapo A following the tripping of Timaru 110kV bus.	South
8 Apr 2009	07:07	A Grid Emergency was declared following the tripping of Gore-Roxburgh 1 circuit during switching to split Gore 100 kV bus. Load was removed at Gore to restore voltage at Gore to within Rule limits and Balclutha-Berwick-Halfway Bush 1 circuit to below its offered capability.	South
18 Apr 2009	06:29	A Grid Emergency was declared for the restoration of supply to Hangatiki, Ongarue, National Park, Ohakune, Mataroa, and Waipawa following multiple circuit and interconnecting transformer trippings in the Bunnythorpe region.	North
20 Apr 2009	17:58	A Grid Emergency was declared for a grid reconfiguration in Nelson-Marlborough region to manage a contingency of Cobb-Upper Takaka 1 circuit which would cause offload time violations on Stoke-Upper Takaka 1 circuit.	South
21 Apr 2009	06:24	A Grid Emergency was declared for a grid reconfiguration in West Coast region to manage a contingency of Atarau-Inangahua 1 circuit which would cause offload time violations on Kumara-Otira 1 circuit.	South
21 Apr 2009	07:23	A Grid Emergency was declared for a grid reconfiguration in Nelson-Marlborough region to manage a contingency of Cobb-Upper Takaka 1 circuit which would cause offload time violations on Stoke-Upper Takaka 1 circuit.	South
22 Apr 2009	07:02	A Grid Emergency was declared for a grid reconfiguration in Nelson-Marlborough region to manage a contingency of Cobb-Upper Takaka 1 circuit which would cause offload time violations on Stoke-Upper Takaka 1 circuit.	South
22 Apr 2009	07:46	A Grid Emergency was declared at Balclutha following an unplanned outage of Balclutha T2 supply transformer to manage Balclutha T1 supply transformer loading.	South

Grid Emergencies			
Date	Time	Summary Details	Island
28 Apr 2009	07:33	A Grid Emergency was declared for a grid reconfiguration at Mangamaire due to overloading of Wilton T8 interconnecting transformer and to manage a contingency of Haywards-Linton 1 circuit which would cause offload time violations on Mangamaire-Woodville 1 circuit.	North
4 May 2009	17:54	A Grid Emergency was declared due to insufficient standby reserve offers in the North Island. North Island Contingent event risk adjustment factors were reduced to 0.6 until 19:00.	North
5 May 2009	17:00	A Grid Emergency was declared due to insufficient standby reserve offers in the North Island. HVDC Pole 1 was operated until 21:00.	North
21 May 2009	07:41	A Grid Emergency was declared due to insufficient standby reserve offers in the North Island. North Island Contingent event risk adjustment factors were reduced to 0.8 until 08:34.	North
23 May 2009	17:47	A Grid Emergency was declared due to insufficient standby reserve offers in the North Island. North Island Contingent event risk adjustment factors were reduced to 0.8 until 18:30.	North
2 Jun 2009	21:59	A Grid Emergency was declared to manage the loading of Tauranga T3 supply transformer.	North
16 Jun 2009	17:48	A Grid Emergency was declared for a grid reconfiguration at Melling to manage a contingency of Haywards-Melling 1 and 2 circuits which would cause overloading on Melling T1 and T2 supply transformers.	North
17 Jun 2009	17:00	A Grid Emergency was declared in the Wellington region to manage a shortfall of transmission capacity due to high forecast demand, with HVDC Pole 1 operated to alleviate the issue.	North
18 Jun 2009	17:00	A Grid Emergency was declared in the North Island to manage a shortfall of generation offers due to high forecast demand, with HVDC Pole 1 operated to alleviate the issue.	North
1 Jul 2009	17:55	A Grid Emergency was declared for a grid reconfiguration at Mangamaire to manage a contingency of HVDC Pole 2 which would cause offload time violations on Mangamaire-Woodville 1 circuit.	North
2 Jul 2009	17:15	A Grid Emergency was declared for a grid reconfiguration at Mangamaire to manage a contingency of HVDC Pole 2 which would cause offload time violations on Mangamaire-Woodville 1 circuit.	North
6 Jul 2009	17:24	A Grid Emergency was declared for a grid reconfiguration at Mangamaire to manage a contingency of HVDC Pole 2 which would cause offload time violations on Mangamaire-Woodville 1 circuit.	North
13 Jul 2009	17:30	A Grid Emergency was declared for a grid reconfiguration at Mangamaire to manage a contingency of HVDC Pole 2 which would cause offload time violations on Mangamaire-Woodville 1 circuit.	North
15 Jul 2009	17:41	A Grid Emergency was declared for a grid reconfiguration at Mangamaire to manage a contingency of HVDC Pole 2 which would cause offload time violations on Mangamaire-Woodville 1 circuit.	North
16 Jul 2009	17:25	A Grid Emergency was declared for a grid reconfiguration at Mangamaire to manage a contingency of HVDC Pole 2 which would cause offload time violations on Mangamaire-Woodville 1 circuit.	North

Grid Emergencies			
Date	Time	Summary Details	Island
20 Jul 2009	08:34	A Grid Emergency was declared for a grid reconfiguration at Mangamaire to manage a contingency of Bunnythorpe-Linton 1 or Haywards-Linton 1 circuit which would cause offload time violations on Mangamaire-Woodville 1 circuit.	North
27 Jul 2009	17:36	A Grid Emergency was declared for a grid reconfiguration at Mangamaire to manage a contingency of HVDC Pole 2 which would cause offload time violations on Mangamaire-Woodville 1 circuit.	North

Half of the events leading to declarations of Grid Emergencies related to times when grid reconfigurations were required to avoid post-contingency violation on circuits. The remainder of the events were nearly evenly split between restoration of load or security following forced outages; managing loading on grid assets to avoid exceeding stated capability under normal power system conditions; and managing insufficient generation and reserves offered to meet demand.

3.2.1 Major System Frequency Events

During the review period there was one major system frequency event. This occurred at 04:31 on 1 August 2009 when HVDC Pole 2 tripped. At the time of the tripping, Pole 2 was transferring approximately 270 MW from North to South. South Island frequency fell to 47.72 Hz before recovering. This event is of some concern as the South Island frequency fell below 48 Hz for a contingent event. The system was around 0.2 Hz from AUFLS activation that would have seen 16% of load automatically shed.

The System Operator has been working with South Island generators to understand why the South Island frequency fell so low and what remedial action is required. The investigation is progressing well and several issues have been identified for further investigation. A system test has been planned for a number of stations in September 2009, so that the System Operator can better understand the performance issues involved. Solutions will then be proposed and discussed.

3.3 Summary of System Events

System Events				
Date	Time	Summary Details	Island	Freq (Hz)
7 Sep 2008	16:00 and 18:00	Tiwai reduction line tripped causing a momentary rise in South Island frequency.	South	51.04 51.07
11 Sep 2008	19:32	Pole 2 stopped north transfer causing a momentary rise in South Island frequency.	South	50.58
21 Sep 2008	08:01	A Tiwai reduction line off loaded causing a momentary increase in South island frequency.	South	50.71
28 Sep 2008	06:28	HVDC pole 2 commutation during north transfer caused momentary frequency excursions in the North and South Island	NI SI	49.65 50.73
08 Oct 2008	16:04	A Tiwai reduction line tripped causing a momentary increase in system frequency.	South	50.53
25 Oct 2008	05:33	The Taranaki Combined Cycle unit tripped.	North	49.33
31 Oct 2008	10:45	The Taranaki Combined Cycle unit tripped.	North	49.19
1 Nov 2008	03:23	The Taranaki Combined Cycle unit tripped.	North	49.44

System Events Date	Time	Summary Details	Island	Freq (Hz)
1 Nov 2008	14:08	HVDC pole 2 tripped.	North South	49.37 51.36
3 Nov 2008	21:22	A Tiwai point reduction line had an emergency offload.	South	50.65
5 Nov 2008	13:39	A Tiwai reduction line tripped.	South	50.77
8 Nov 2008	23:13	Huntly unit 5 tripped.	North South	49.13 49.31
9 Nov 2008	16:26	A Tiwai reduction line tripped.	South	50.6 Hz
22 Nov 2008	16:45	Taranaki Combined Cycle unit tripped.	North	49.16
24 Nov 2008	10:46	Huntly unit 1 tripped.	North	49.24
7 Jan 2009	11:39	Huntly unit 5 tripped.	North South	49.16 49.43
14 Jan 2009	06:19	Otahuhu B unit tripped.	North South	49.20 49.46
3 Feb 2009	13:06	The loss of load (around 170 MW) following the tripping at Penrose caused a momentary rise in frequency in the North Island.	North	50.57
5 Feb 2009	08:00	Benmore units 4 and 5 tripped causing a under frequency excursion in the South Island.	South	49.24
8 Feb 2009	06:09	A Manapouri unit tripped.	South	49.45 Hz
13 Feb 2009	10:38	Otahuhu B unit tripped.	North South	49.21 49.46
2 Mar 2009	09:25	Huntly Unit 4 tripped causing under frequency excursion in the North Island.	North	49.31
7 Mar 2009	17:21	The loss of load (approx. 127MW) following multiple circuit trippings in the Bay of Plenty caused a momentary rise in frequency in both the North and South Islands.	North South	50.35 50.31
20 Mar 2009	21:04	A bus fault at Maraetai resulting in loss of generation at Maraetai and Waipapa, causing under frequency excursion in the North Island.	North	49.25
23 Mar 2009	05:41	Huntly Unit 4 tripped causing under frequency excursion in the North Island.	North	49.42
7 Apr 2009	09:15	Huntly Unit 2 tripped causing an under frequency excursion in the North Island	North	49.24
15 Apr 2009	09:50	Huntly Unit 3 tripped causing an under frequency excursion in North and South Islands	North South	49.21 49.47
20 Apr 2009	22:26	Manapouri Unit 3 tripped causing an under frequency excursion in the South Island.	South	49.5
22 Apr 2009	14:15	Huntly Unit 2 tripped causing an under frequency excursion in the North Island.	North	49.4
27 Apr 2009	22:32	HVDC Pole 2 tripped causing momentary frequency fluctuations in both North and South Islands.	North South	48.6 50.4 53.0
27 Apr 2009	23:06	Manapouri Unit 5 tripped causing momentary frequency fluctuations in the South Island.	South	48.9 51.1

System Events Date	Time	Summary Details	Island	Freq (Hz)
29 Apr 2009	15:13	A Tiwai potline tripped causing a momentary frequency fluctuation in the South Island.	South	51.3
29 Apr 2009	15:17	A Tiwai potline operation caused a momentary frequency fluctuation in the South Island.	South	49.48
3 May 2009	04:23	A Tiwai potline tripped causing a momentary rise in frequency in both North and South Islands.	North South	50.36 50.69
5 May 2009	14:05	Huntly Unit 1 tripped causing a momentary drop in frequency in both North and South Islands.	North South	49.46 49.71
20 May 2009	11:07	Huntly Unit 1 tripped causing a momentary drop in frequency in the North Island.	North	49.53
10 Jun 2009	23:48	Kawerau T6 and T7 supply transformers tripped resulting in partial loss of supply at Kawerau and a momentary rise in frequency in the North Island.	North	50.42
20 Jun 2009	12:28	Huntly Unit 1 tripped causing a momentary drop in frequency in the North Island.	North	49.27
9 Jul 2009	09:34	Stratford generation tripped causing an under frequency excursion in both the North and South Islands.	North South	49.06 49.43
10 Jul 2009	13:42	Tiwai potline tripped causing a momentary rise in frequency in the South Island.	South	50.78
20 Jul 2009	14:39	Huntly unit 4 tripped causing a momentary drop in frequency in both the North and Islands.	North South	49.24 49.5
23 Jul 2009	16:02	Tiwai potline tripped causing a momentary rise in frequency in the South Island.	South	50.68
1 Aug 2009	04:31	HVDC Pole 2 tripped causing momentary fluctuations in frequency in both the North and South Islands.	North South South	50.93 47.72 52.06
1 Aug 2009	05:25	Manapouri unit 5 tripped causing momentary drops in frequency in both the North and South Islands.	North South	49.65 49.34
27 Aug 2009	14:35	Tiwai potline tripped causing a momentary rise in frequency in the South Island.	South	50.55

3.4 SUMMARY OF CONNECTION POINT EVENTS

Connection Point Events Date	Time	Summary Details	Generation/ Load interrupted (MW)	Restoration time (minutes)
1 Sep 2008	15:24	Whirinaki transformer T3 tripped	65	486
25 Sep 2008	00:51	Otahuhu tie line 3 tripped.	190	921
20 Nov 2008	09:22	A loss of supply at Stoke substation occurred following a 33 kV bus cable fault.	65	63
23 Nov 2008	05:10	Mount Maunganui supply transformers T2 and T4 tripped.	12	52

Connection Point Events Date	Time	Summary Details	Generation/ Load interrupted (MW)	Restoration time (minutes)
26 Nov 2008	02:21	Marsden T1 tripped causing a loss of supply to local service transformer.	0.3	2009
27 Nov 2008	17:01	Supply to Whirinaki 11 kV was lost.	57	63
8 Dec 2008	11:22	Tokaanu Feeder tripping.	4	202
22 Dec 2008	06:35	The Albury-Timaru circuit tripped causing a loss of connection to Takapo A power station.	24	62
1 Jan 2009	06:15	Both North Makarewa supply transformers tripped following a fault on the 33 kV distribution network.	33	66
21 Jan 2009	07:43	Wilton 110 kV bus B tripped removing Wilton-Kaiwharawhara 1, Central Park-West Wind-Wilton 3 and Takapu Road-Wilton 1 circuits. There was a loss of supply at Central Park (CPK) and Kaiwharawhara (KWA) grid exit points.	CPK - 39 KWA - 9	77 46
3 Feb 2009	13:06	A fault on Penrose transformer T8 caused the transformer to trip which then resulted in Penrose T11 tripping to avoid overload. A parallel transformer (Penrose T9) was out of service for planned maintenance.	250	601
11 Feb 2009	20:29	The Aratiatia-Wairakei circuit tripped causing a loss of connection to Aratiatia power station.	53	24
12 Feb 2009	07:52	The Cobb-Motueka circuit tripped causing a loss of connection to Cobb power station. The Cobb-Upper Takaka circuit was out of service for planned maintenance.	20	67
7 Mar 2009	17:21	A fault in the Bay of Plenty 110kV network caused multiple circuit trippings, resulting in loss of generation at Kaimai as well as loss of load at Tauranga, Mt Maunganui, Te Matai, Owhata, Waiotahi and Te Kaha.	Kaimai generation: 30 MW Load: Approx. 127 MW	Between 23 – 107 minutes with load gradually restored
17 Mar 2009	12:45	A fault on Atarau-Reefton-Inangahua 1 circuit, which occurred during a planned outage on Greymouth-Kumara 1 circuit, resulted in loss of load at Greymouth, Dobson and Atarau.	14	Between 56 – 87
17 Mar 2009	16:14	A fault on Timaru T5 interconnecting transformer, which occurred during a planned outage on Timaru T8, resulted in loss of load at Timaru, Temuka, Albury, Tekapo A.	Tekapo A generation: 4 MW Load: Approx. 75 MW	Between 75 – 102
21 Mar 2009	07:20	A fault on Albury-Tekapo A 1 circuit resulted in loss of load at Tekapo A.	Tekapo A generation: 24 MW Load: 2 MW	72

Connection Point Events

Date	Time	Summary Details	Generation/ Load interrupted (MW)	Restoration time (minutes)
18 Apr 2009	06:25	A fault in the Bunnythorpe 110kV network caused multiple circuit trippings and all interconnecting transformers at Bunnythorpe, resulting in loss of load at Hangatiki, Ongarue, National Park, Ohakune, Mataroa, and Waipawa.	Approx. 43 MW	Between 33 – 313 minutes with load gradually restored
28 Apr 2009	16:55	A fault in the Tangiwai 11 kV bus resulting in loss of load at Tangiwai.	Approx. 3 MW	217
7 May 2009	13:31	A fault in the Twizel 220kV network caused multiple trippings of Benmore-Twizel 1, Islington-Tekapo B 1 and Tekapo B-Twizel 1 circuits, resulting in loss of generation at Tekapo B.	60	117
22 Jun 2009	10:30	A tripping of Balclutha-Berwick-Halfway Bush 1 circuit resulted in loss of generation at Berwick.	31	92

4. Security of Supply

4.1 Short Term Security Issues

4.1.1 Upper South Island Security

The System Operator once again led an Upper South Island stakeholder group to ensure a co-ordinated response to managing the region within power system capability limits over the 08/09 summer period and the 2009 winter period. No issues were identified and the group maintained a watching brief.

4.1.2 Upper North Island Security

The System Operator also led an Upper North Island stakeholder group to manage the region within power system capability limits over the 08/09 summer period, as well as an industry group to monitor and plan for supply issues in the Upper North Island over winter 2008. No issues were identified and the groups maintained a watching brief.

4.1.3 National Winter Group (NWG)

The System Operator convened an industry participant group to establish the likely outlook for peak capacity during winter 2009. A report was issued showing that with all thermal plant committed we had an 82 MW capacity margin following the loss of the largest thermal unit.

In developing and updating its outlook for winter 2009, the group considered changes to generation availability and the effect of the economic down turn on demand.

Although the special winter schedule was not initially part of the functionality of the new market systems, it was a priority of the System Operator to re-implement it as soon as possible after go-live. Publication of the schedule recommenced on 13 August 2009.

4.1.4 Other Security and Quality Issues

4.1.4.1 South Island System Performance Investigation Project

The project to review generator performance was initiated in 2007 involving the System Operator, Meridian Energy and Contact Energy. In the reporting period, the project has focused on completing asset testing at key sites while also developing and validating the models provided by generators. The work required to update and validate models is nearing completion and it is expected the project will be closed in late 2009.

The work completed to date has enabled the System Operator to better understand and plan for the operation of the South Island power system.

4.1.4.2 Wind Integration

Throughout the reporting period the System Operator provided contributions to the Electricity Commission's ongoing programme of work and has been working with the Electricity Commission to develop a prioritised forward plan on wind integration issues. The focus this year has been on fault ride-through capability of wind farms. This work is continuing.

5. Commissioning

5.1 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.	Completed commissioning activities
Ngawha Geothermal	Top Energy	An expansion to the existing geothermal power station	Completed commissioning activities
Te Rere Hau	NZ Windfarms	A new wind farm development located in the Tararua Ranges	Commenced commissioning
West Wind	Meridian Energy	A new wind farm development located close to Wellington	Commenced commissioning
Nga Awa Purua	Mighty River Power	A second geothermal power station at Rotokawa	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.

5.2 Supporting the Development of Transpower's Pole 3 Project

Since the grid upgrade plan for the Pole 3 project was approved in September 2008, the System Operator has been actively involved in developing the specification for the

Pole 3 project. Areas of input have included the timing and staging of the project phases to minimise impact of outages and commissioning activities on the industry, whilst maximising HVDC transfer capacity at critical times i.e., winter periods.

In addition to defining the commissioning and system testing requirements, the System Operator has also had input into the specification of the HVDC control and protection systems as well as the performance of short term ratings and overload capability, such that they will also support the development of future market initiatives.

As the project progresses, the System Operator expects to play a key role in co-ordinating commissioning requirements with the industry.

6. RULE CHANGES

6.1 PROPOSED BY SYSTEM OPERATOR

The System Operator made the following recommendations for changes to the Electricity Governance Rules and Regulations ("the Rules") during the review period:

6.1.1 DISCONNECTED NODES

The System Operator proposed a rule change to reflect the manner in which the modelling system identifies disconnected nodes in the new market systems. The changes retained the same requirements in terms of modelling and price outcomes but removed the implementation-specific detail of how this would be achieved. These rule changes came into force on 30 March 2009 and 28 August 2009.

6.1.2 FREQUENCY OF PRE-DISPATCH SCHEDULES

The System Operator recommended deletion of Rule 3.7.3 of Section III of Part G because additional schedules are now published by the System Operator (such as the SDPQ and RTP) since this rule requirement was originally drafted into the NZEM rules. In the System Operator's view, a more frequent PDS serves no purpose and has not been requested by participants since the inception of the Rules.

6.1.3 AUTOMATIC UNDER FREQUENCY LOAD SHEDDING SYSTEMS

The System Operator raised some issues and questions with respect to the testing and maintenance of AUFLS under the Rules. The System Operator is currently preparing a scope for a substantive review of AUFLS arrangements for discussion with the Electricity Commission with the intention of this being a joint Electricity Commission/System Operator project. The Electricity Commission has agreed that a substantive review of AUFLS is required.

6.1.4 UNDER FREQUENCY EVENT CHARGES

The System Operator requested that the Electricity Commission initiate a review of the rules relating to under frequency event charges. There have been a number of lengthy disputes over these charges since the commencement of the Rules that the System Operator attributes primarily to a lack of rule clarity about when an event charge should apply and to whom it should apply.

6.1.5 Allocation of Costs During A Period of Non-compliance

The System Operator identified an issue in Part C of the Rules in relation to non-compliance during commissioning and testing. Rule 6.4 of Section III of Part C requires participants to pay any identifiable and quantifiable cost during any period of non-compliance when commissioning or testing. However, there is no mechanism to enable the invoicing of such costs under the Rules. The System Operator suggested that Rules 11.1.4 and 11.7.1 of Section IV of Part C be amended to provide a mechanism for the Clearing Manager to invoice such amounts. The Electricity Commission has agreed to look into this matter.

6.1.6 Provision of Information to person assessing real time prices

The System Operator suggested that Rules 7.8 and 7.9 of Section III of Part G could be deleted because it appears they do not serve any purpose. Real-time pricing information is made widely available under the other provisions of Rule 7; the System Operator has not been asked to arrange data access under Rule 7.9 since the start of the Rules. The Electricity Commission confirmed it has not appointed anyone under Rule 7.8 to monitor and assess real time prices in the context of demand side participation.

6.1.7 Policy Statement

The System Operator submitted a draft policy statement to the Electricity Commission on 31 March 2009 in accordance with its obligations under the Rules. This came into effect, with some minor revisions, on 1 September 2009.

6.1.8 Procurement Plan

The System Operator submitted a draft procurement plan to the Electricity Commission on 29 May 2009 in accordance with its obligations under the Rules. This is expected to come into effect on 1 December 2009.

6.2 Contributions by the System Operator

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

6.2.1 Managing Locational Price Risk

The System Operator provided detailed written and verbal feedback to the Electricity Commission on the Locational Rental Allocation (LRA) proposal. The System Operator's view was that as a transmission risk management instrument, the LRA offers no advantage and significant disadvantages to the present loss and constraint rental allocation. The System Operator has investigated and proposed alternative strategies to manage this risk while retaining the integrity of the locational price signals.

6.2.2 Demand Side Bidding and Forecasting Project

The System Operator provided feedback to the Electricity Commission on the submissions the Electricity Commission received as a part of the updated consultation paper. The advice centred on the operational aspects of the resultant proposal. The Electricity Commission has redrafted the proposal based on all submitters' responses to address underlying concerns. The System Operator has been asked to cost the subsequently drafted detailed proposal. The costing will be included in the final round of formal consultation.

6.2.3 PRICING IMPROVEMENT PROJECT

The first consultation paper delivered by the Pricing Process Improvement Project (PPIP) provided an overview of the issues that the group had been discussing. These issues included settlement on 5-minute prices, an interim pricing period, alignment of pricing and dispatch processes, changes in treatment of intermittent generator offers, the clarity of the pricing process and undesirable trading situations. As a member of the PPIP, the System Operator has continued to be closely involved with the consultation process and has provided input to the subsequent draft interim pricing period consultation paper. This paper is being consulted on in September/October 2009.

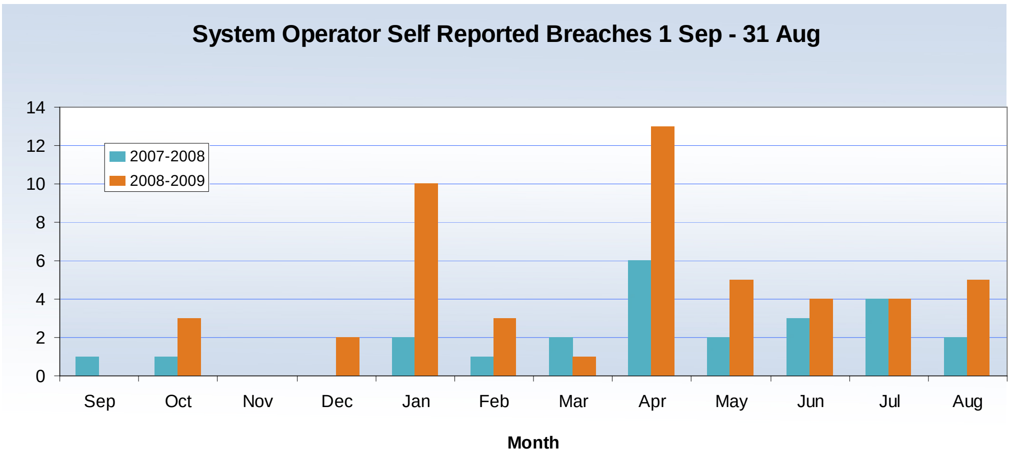
6.2.4 ROLLING OUTAGES

Following amendment to the Electricity Governance (Security of Supply) Regulations 2008 in April 2009, the Electricity Commission has focused on finalising and publishing the security of supply outage plan (SOSOP), as required by the regulations. Once the SOSOP is published, distributors are required to prepare participant outage plans (POPs) that set out how they would implement rolling outages if ever required. The System Operator has assisted the Electricity Commission in its preparation of the SOSOP and is working with a group of distributors and the Electricity Commission to develop model POPs.

7. COMPLIANCE MATTERS

7.1 SYSTEM OPERATOR SELF-NOTIFIED BREACHES

The following graph and table represent breaches of the Rules by the System Operator which it self-notified to the Electricity Commission during the period. The data is based on the reporting date of the breaches rather than the date on which the breaches occurred. The period concerned is 01 September – 31 August.



Comparisons are made between the previous and current years.

Rule	2007-2008	2008-2009
Part C Schedule C3 Technical Code A 3.3	1	
Part C Schedule C4 13.1		1
Part C Schedule C4 20	2	3
Part C Schedule C4 22.3		1
Part C Schedule C4 22.5		2
Part C Schedule C4 61		1
Part C Schedule C4 90.1		1
Part C Schedule C5 Appendix A, Clause 116		1
Part C Section II 2.2.5	1	
Part C Section IV 11.7.2	2	1
Part G Schedule G6 1.3.1.3	1	8
Part G Schedule G6 1.3.2.4	1	1
Part G Schedule G6 1.3.4.1	2	
Part G Schedule G6 1.3.4.6		3
Part G Schedule G6 1.3.4.7	11	13
Part G Section III 10.2	1	2
Part G Section III 3.5.13		1
Part G Section III 3.7.2		1
Part G Section III 3.7.4	1	2
Part G Section III 3.8		1
Part G Section III 4.1		1
Part G Section III 4.3		3
Part G Section III 4.6.9		1
Part G Section III 9	1	1
Regulations - 63		1
Total	24	50

Overall, there was:

- a significant increase in the number of self-notified System Operator breaches in the 2008/09 year compared with the previous year
- a large number of breaches being reported in the months of January and April in the 2008/09 year

Further specific observations and comparisons with the 2007/08 year are made in the following sections.

7.1.1 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 22 from last year's total of 13. 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 has reduced the manual activity associated with this process, with an expected reduction in the number of breaches of this rule in the future.

7.1.2 INFORMATION PROVISION

Breaches relating to providing information to participants include the following:

- one ongoing breach for not using reasonable endeavours to send to the information system service provider the input information used to calculate a Standby Residual Shortfall (SRC) in a trading period as required by the Rules (Clause 61 of Part C Schedule C4). The publication of SRC input information was implemented after the scoping of the new market system and thus was not included in or delivered by the project. The System Operator has, upon discussions with recipients of this information, arrived at the decision to no longer provide SRC input information
- those relating to System Operator provision of information to the Clearing Manager about allocable costs. There was one breach of rule 11.7.2 of section IV of Part C in the period concerned where the incorrect Voltage Support payment information was sent to the clearing manager. Whilst the Rules provide for such inaccuracies to be washed up, the System Operator has implemented additional peer-checking steps to minimise the risk of such errors occurring
- those relating to schedule publication failure. There were three occasions where the System Operator was late in publishing its Pre-Dispatch Schedule (PDS) upon completion as required by rule 3.7.2 of Part G Section III. The System Operator failed to publish its PDS on one occasion as required by 10.2 of Part G Section III

7.1.3 CONSTRAINTS ACCURACY

(Rule 20 and 22.5 of Schedule C4)

There were five self-notified breaches relating to constraint accuracy in the reporting period. Incorrect constraints were applied in:

- modelling Pole 1 (15 December 2008)
- managing security at Cromwell (16 March 2009)
- managing security at Cobb (12 February 2009)
- managing security at Brunswick (08 December 2008)
- managing security at Mangamaire (29 January 2009).

7.1.4 PRINCIPLE PERFORMANCE OBLIGATIONS (PPOS)

There were no breaches of the PPOs notified by the System Operator during the period concerned.

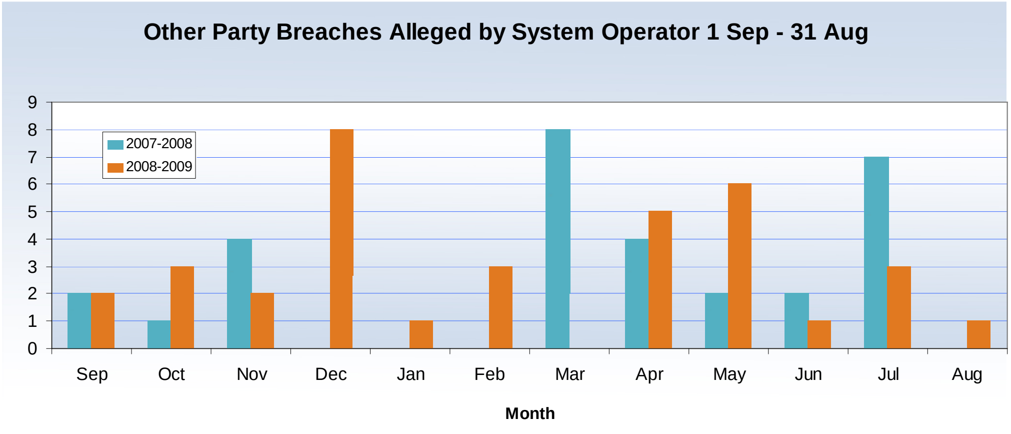
7.2 ALLEGED SYSTEM OPERATOR BREACHES REPORTED BY OTHER PARTIES (INCLUDING THE ELECTRICITY COMMISSION)

There was one System Operator breach of Part G Section III 7.2.2 notified by other participants during the period concerned for not publishing Real Time Prices at Middleton on 01 February 2009.

7.3 BREACHES ALLEGED BY SYSTEM OPERATOR AGAINST OTHER PARTICIPANTS

The following graphs represent Rule breaches by third parties notified by the System Operator, 35 for 2008/09, compared with 30 for 2007/08.

Comparisons are made between the current (1 September 2008 to 31 August 2009) and previous (1 September 2007 to 31 August 2008) years.



The table below shows a comparison in the type of breaches between the previous and current years:

Rule	2007-2008	2008-2009
Part C Schedule C3 Technical Code A 2.6.1	1	
Part C Schedule C3 Technical Code A 4.4.1		3
Part C Schedule C3 Technical Code A Appendix A, Rule 3		1
Part C Schedule C3 Technical Code C 5.2		6
Part C Schedule C3 Technical Code C 8.2		4
Part C Schedule C3 Technical Code C 8.3		1
Part G Section II 3.14.3.1	1	
Part G Section II 6.11		1
Part G Section III 4.11	26	15
Part G Section III 4.9.3	2	4
Total	30	35

The data shows a significant decrease in non-compliant generators in conjunction with a surge of technical code breaches.

7.4 SETTLEMENTS

7.4.1 SETTLEMENT OF SYSTEM OPERATOR BREACH ALLEGATIONS

One settlement agreement was entered into during the reporting period. This was in respect of a self-reported breach by the System Operator of a principal performance obligation (rule 2.2.5 of section II of part C) for failing to act as a reasonable and prudent system operator with the objective of ensuring frequency time error is not greater than 5 seconds of New Zealand standard time.

7.4.2 SETTLEMENT OF OTHER PARTICIPANT BREACH ALLEGATIONS

The System Operator did not enter into any settlement agreements in respect of notified breaches by other participants during the reporting period.

7.5 Assurance

The System Operator undertook a scoping exercise for the recommencement of its assurance programme during the reporting period. This programme has been on hold due to the workload from the new market systems project implementation. The assurance programme is expected to be resumed in December 2009. The System Operator has continued with other established quality activities, including documentation and event reviews.

7.6 Rulings Panel

There were no System Operator breaches referred by the Electricity Commission to the Rulings Panel during the reporting period.

7.7 Near Misses

There were no near misses reported during this period.

8. Specific Compliance Requirements under the Rules

8.1 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 Electricity Commission.

8.2 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. In December 2008 the System Operator published a new SSF and this is available on the System Operator website[1]. The System Operator notified the Electricity Commission in June than a six monthly revision to the SSF was not required.

8.3 Credible Event Review

The System Operator has completed the majority of the review into the credible events specified in the Policy Statement. It is expected that the consultation on the outcome of this review will be undertaken in October with any final recommendations included in the draft 2010 policy statement.

[1] SSF – December 2008 - http://www.systemoperator.co.nz/publications

8.4 PROCUREMENT PLAN – ANCILLARY SERVICES

The System Operator submitted the 2009/10 draft Procurement Plan to the Board by 1 June 2009. In developing the 2009/10 plan, the System Operator met with selected participants and, separately, invited comment from all industry participants. The key changes proposed for the 2009/10 plan were:

- Special testing requirements for interruptible load providers - this change introduced a new testing regime for IL providers whereby they are required to carry out an annual “end-to-end” test of their equipment, unless they have shown operational performance during the previous 12 months (by successfully responding to an under-frequency event).
- Frequency keeping standard deviation obligations - this change clarified that failure to comply with the standard deviation obligations for frequency keeping would be a material breach of the ancillary service procurement contracts, allowing for termination.
- A further proposed change to the draft plan related to the clarification of the obligations owed by aggregators in relation to the offering of AUFLS. This change was ultimately rejected by the Electricity Commission for inclusion in the 2009/10 plan because it was considered that this issue should be addressed as part of the wider workstream on AUFLS.

Procurement Plan 2007/ 2008

The 2008/9 Procurement Plan came into effect on 1 December 2008. Tendering for ancillary services commenced on 10 October 2008 and was completed prior to the plan operative date. The major changes[2] introduced in the plan were:

- Fixed price frequency keeping - this change provided for fixed price frequency keeping offers to be considered as an addition to the existing “half hourly” procured service. This option was not made available during the reporting period due to issues around how fixed price frequency keeping would work in practice, from both a market and a tool perspective.
- Improved performance and technical criteria for frequency keeping service providers - the proposed change recognised that inherent differences exist between generating assets and these should be reflected in the agreed contracted performance standards.
- Sub-contracting of ancillary services - this provision allows for contracted ancillary service providers to sub-contract services.

8.4.1 CONTRACTED ANCILLARY SERVICES

The following table summarises the contracted services as at 31 August 2009:

Ancillary Service Agent	(1)FK	(2)IR	(3)OFR	(4)BS	(5)VS
Meridian Energy	√	√	√	√	
Contact Energy	√*	√*	√	√*	√*
Mighty River Power	√	√		√*	√*
Genesis Power	√	√		√	
TrustPower		√*			

[2] 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
Vector		√			
Wellington Electricity Networks		√			
Northpower		√			
Powerco		√*			
Unison		√			
WELNetworks		√			
CountiesPower		√			
NZ Steel		√*			
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

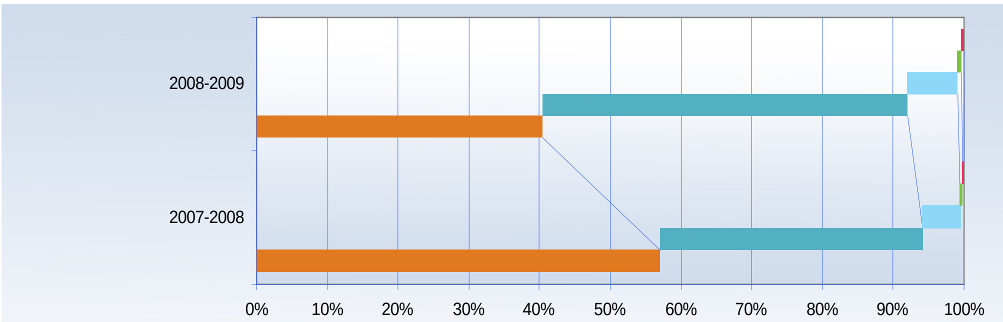
(5) VS - Voltage Support

*Longer term contract (over two years in duration)

8.4.2 ANCILLARY SERVICE PROCUREMENT COSTS

8.4.2.1 Procurement 1 September 2008 – 31 August 2009

The total ancillary service costs for the period were $116,294,214.



	2007-2008	2008-2009
Black Start	$395,215	$395,420
Over Frequency Reserve	$624,184	$635,495
Voltage Support (incl Events)	$9,495,777	$8,213,289
Instantaneous Reserve	$67,693,066	$60,049,629
Frequency Keeping Costs	$103,609,432	$47,000,381

8.5 POLICY STATEMENT

The System Operator provided a draft Policy Statement for 2009/10, which came into force on 1 September 2009. The changes included:

- Changes to the constraint policy to reflect the information published from the new market systems
- Minor changes to the formal notice obligations as a result of an internal review into the use of emergency notices

- Changes to reflect exemptions that had been sought over the previous two year period
- Minor wording changes

8.5.1 DEPARTURES FROM POLICY STATEMENT

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

8.6 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.

8.6.1 ANNUAL RMT AND SPD CERTIFICATION

The System Operator procured an audit of the Scheduling, Pricing and Dispatch (SPD) Software and the Reserve Management Tool (RMT) by PA Consulting on 04 March 2009.

This audit opinion (noting that it was satisfactory) was the annual certification of RMT/SPD for the period of the review, as required in the System Operator Service Provider Agreement ("SOSPA") and in regulation 51 (1).

8.6.2 RMT

The System Operator sought an opinion (noting it was satisfactory) from the auditor (PA Consulting) in respect of RMT on 23 February 2009, regarding changes to incorporate Meridian Energy's Westwind plant.

8.6.3 SPD

The System Operator sought the following opinion (noting it was satisfactory) from the auditor (PA Consulting) in respect of SPD:

- SPD TP38.00.76.Opinion provided by PA Consulting on 1 July 2009. A number of changes were made to SPD as part of the Market Systems Project, specifically:
- Change the input and output from Oracle's database read-write to CSV input and output files
- Change to introduce e-node to p-node mapping
- Change to the pricing treatment of disconnected nodes
- Change to a more appropriate assessment of the losses in the RTD calculation
- Remove the functionality provided by bus group constraints (this functionality is now met by using market node constraints and mixed constraints)

Specific Compliance Activities

SYSTEM OPERATOR

TRANSPOWER NZ LTD

9. Specific Compliance Requirements under the SOSPA

9.1 Disaster Recovery Plan

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

The System Operator reviewed its Business Continuity Plan and updated certain information (related to personnel contact details). As part of the review, the functionality of 'fall back' venues was checked. The Control Room and non-operational response kits were also checked and updated.

The simulation exercise originally planned for the first half of 2009 has been rescheduled for late 2009.

9.2 Warranties

At the date the SOSPA was entered into, the System Operator provided the Electricity Commission with certain warranties. As at 31 August 2009 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

10. Specific Compliance Activities

10.1 Dispensation and Equivalence Applications

Month	Applications Received	Granted in Draft	Granted	Withdrawn	Not Granted	Revoked
Sep 2008	1	1	3	0	0	0
Oct	0	0	0	0	0	0
Nov	0	1	0	18*	0	0
Dec	0	0	1	1	0	0
Jan 2009	0	0	0	0	0	0
Feb	3	0	0	0	0	0
Mar	0	0	1	0	0	0
Apr	0	0	0	0	0	0
May	0	0	0	0	0	0
Jun	0	0	0	0	0	0
Jul	1	0	1	0	0	0
Aug 2009	0	0	0	0	0	0
TOTALS	5	2	6	19	0	0

* Nov 08 - 18 applications were withdrawn by a single asset owner

10.2 Exemption Applications

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

- An exemption from the requirement in Clause 67 of Schedule C4 to send written formal notices to all “registered participants”. The exemption was sought on the basis that the term registered participants includes participants who will have little interest in grid emergencies and no ability to mitigate the emergency.
- An exemption from some provisions of Clause 22.4 of Schedule C4 to allow the System Operator to implement improved constraint publication functionality as part of the new market systems (before the new policy statement came into effect).

The System Operator withdrew the exemption application it had lodged in respect of the way the new market system models constraints. This application was no longer needed because of the rule change that came into force on 30 March 2009.

The following exemption was revoked during the reporting period:

- The exemption from Clause 33.1 of Schedule C4 that the System Operator had sought to allow it to implement the variable reserves proposal. This exemption was revoked to clarify how the System Operator would dispatch reserves after the new market systems were implemented.

11. Ancillary Service Provider Performance

11.1 Instantaneous Reserves

The table below summarises the Instantaneous Reserve (including IL) performance assessments carried out by the System Operator for the period 1 September 2008 to 31 August 2009.

Under Frequency Event Summary - Instantaneous Reserve Event Assessments							
Date	Time	Event initiated at	Lowest Frequency (Hz) North Island	Lowest Frequency (Hz) South Island	MW Lost	Number of Dispatched IR Ancillary Service Agents (ASA)	Performers (and Non-Performers)
31/10/2008	10:45	SPL	49.2	49.44	320	12	all ok
8/11/2008	23:13	HLY U5	49.13	49.32	183	11	all ok
22/11/2008	16:45	SPL	49.16	49.48	355	11	all ok
24/11/2008	10:46	HLY U1	49.24*	49.59	197		all ok
7/01/2009	11:39	HLY U5	49.16	49.43	376	13	all ok
14/01/2009	16:19	OTA	49.21*	49.46	285		all ok
5/02/2009	08:00	BEN	49.79	49.24	177	3	all ok
13/02/2009	10:38	OTA	49.22*	49.46	320	3	all ok
15/04/2009	09:50	HLY U3	49.22*	49.47	243	3	all ok
27/04/2009	22:32	HVDC	48.63	n/a	472	14	Matahina self breach
27/04/2009	23:04	MAN	n/a	48.9	84	2	all ok
9/07/2009	09:34	SPL	49.06	49.43	372	14	all ok
20/07/2009	14:39	HLY U4	49.24*	49.5	220	3	all ok
1/08/2009	04:30	HVDC	49.92	47.72	207	2	Investigation ongoing

Notes: One of the event assessments (1st August 2009) requires further analysis and discussion between the System Operator and the applicable Ancillary Service Agent.

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.

11.2 Frequency Keeping Reserves

The System Operator assesses the performance of frequency keeping ancillary services on a monthly basis on an outcome-based performance criteria. Performance issues are identified and addressed directly with the ancillary service agent. In the period of this review no major issues relating to performance were taken up with frequency keeping service providers.

11.3 Black Start

On 21 February 2009 Manapouri failed to successfully complete a South Island Black Start test, raising doubt on the ability of Manapouri station to provide a Black Start service. Contact and the System Operator successfully performed a black start test at Clyde on 22 August 2009. It is noted that between February and August, the System Operator also had Aviemore station available for black start and, in addition, it contracted Contact Energy for the use of Clyde Hydro Station for Black Start.

Black Start tests are required to demonstrate the capability of a generator to start up from a position of not being connected and not taking supply from the grid, and involve:

- starting one unit without supply from the grid
- synchronising a second unit at the same station
- energising a section of the transmission grid system

11.4 Voltage Support

During the period 1 September 2009 to 31 August 2009 the System Operator dispatched contracted zone 1 voltage support for a total of 24 occasions.

12. Industry Consultation Papers

12.1 Contributions and Submissions

The System Operator actively contributed to a number of Electricity 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:

- Market Design Review
- Managing Locational Price Risk
- Annual Security and Reserve Energy Needs Assessment
- Reactive power investment
- Demand-side bidding and forecasting

- Frequency Regulation Market Development
- Rolling outages
- Seasonal adjustment shapes issue (Part J)
- System Security Forecast
- Electricity Governance (Security of Supply) Regulations and AUFLS rule
- Disconnected Nodes
- Work priorities and appropriations consultation
- Advisory Group Review
- Spot Market Pricing Process and UTS Provisions
- 2008 Winter Report
- Change to spot settlement day payment process
- Value of unserved energy
- Rulings Panel Procedures
- Electricity Market Compliance Framework Review
- Policy Statement
- Procurement Plan

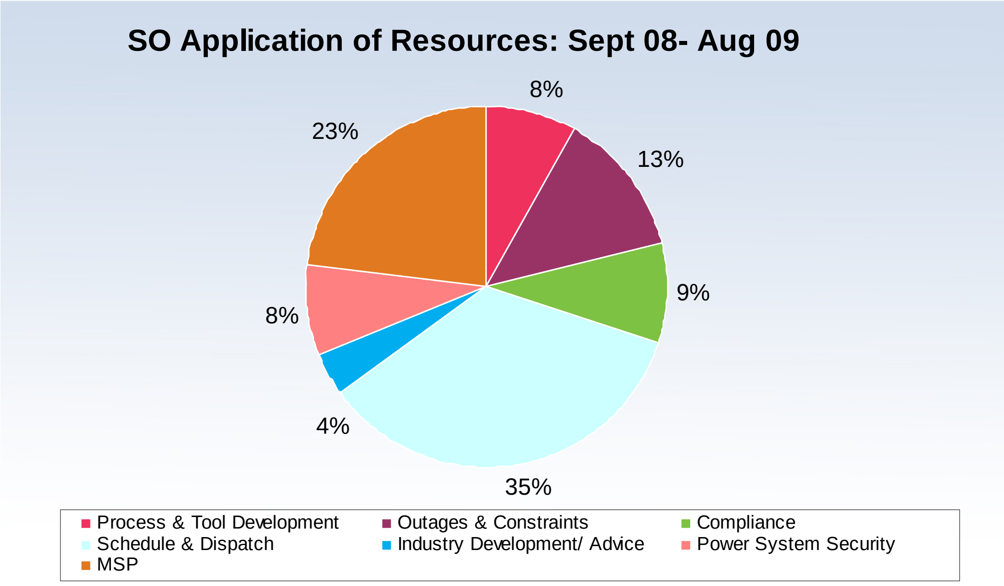
13. System Operator People and Resources

13.1 People

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

	31/08/2008	31/08/2009	Change
General Manager	2.0	2.0	0.0
Risk & Performance	4.8	4.2	(0.6)
Development	5.0	7.0	2.0
System Operations	39.4	37.4	(2.0)
Investigations	13.0	14.0	1.0
Operations Planning	15.0	17.4	2.4
Market Services	11.6	12.0	0.4
Total	90.8	94.0	3.2

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.



13.2 Customer Service

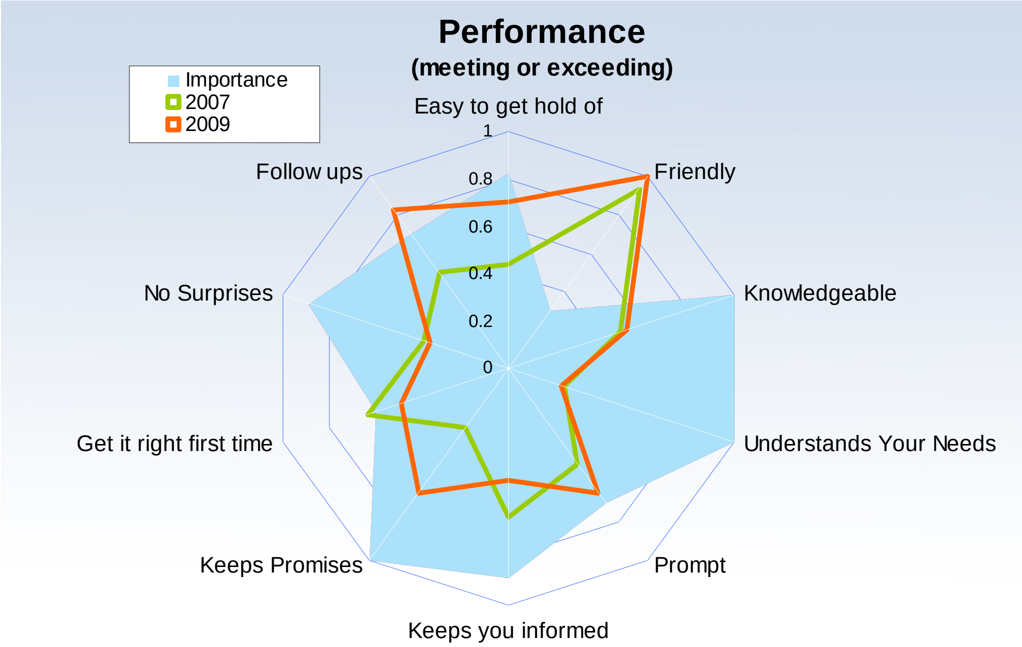
13.2.1 Customer satisfaction survey

The System Operator undertook a further customer survey in April 2009. 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, 2006 and 2007.

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'.



13.2.1.1 *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 believed better service efforts were required or desirable. As part of the survey the System Operator provides an opportunity for customers to suggest areas where service delivery can be improved. The System Operator actively continued to devote effort towards improving its level of service.

A further survey is expected to be commissioned in mid 2010.

13.3 SYSTEMS DEVELOPMENT

13.3.1 MARKET SYSTEMS PROJECT (MSP)

13.3.1.1 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, 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 Rules 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.

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.

13.3.1.2 The project completion

The System Operator's new market systems went live on Tuesday 21 July, with the first dispatch schedule issued at 11:30, on schedule.

The transition went well with only a small number of 'bedding in' matters, which have either been resolved, or are to be addressed in future market systems change releases (see below). The success of this project has been aided by the positive support received from the industry.

During the year, the project progressed as predicted with the completion of development and testing in mid-June. This was followed by a four week period of acceptance testing, in which the new systems operated in parallel to the existing production systems prior to go-live. A number of participants took advantage of an opportunity to visit Wellington and Hamilton co ordination centres to see the new systems in action. This was a useful exercise and we were pleased with the feedback received.

No issues were raised during the operational trial which ran smoothly, and after final systems testing go-live went ahead according to plan.

13.3.1.3 Market system change releases

Changes to the new market systems will be managed differently than before, where changes were made on a less-scheduled, 'as ready' basis. A new change management approach is now in place.

The initial releases schedule starts with a 4-week cycle, increasing to a 6- or 8-week cycle until Christmas 2009. A release is proposed early in 2010 leading into the longer-term 12-week cycle. The preliminary release dates are as follows:

Release Cycle	Content Agreed	Development Time	Acceptance Test Start	Go Live
4 weeks	24 Jul 09	2 weeks	19 Aug 09	25 Aug 09*
4 weeks	21 Aug 09	2 weeks	28 Sep 09	6 Oct 09
6 weeks	25 Sep 09	3 weeks	2 Nov 09	17 Nov 09
8 weeks	6 Nov 09	3 weeks	18 Jan 10	2 Feb 10
12 weeks	6 Nov 09	6 weeks	10 May 10	1 Jun 10
12 weeks	12 Feb 10	6 weeks	2 Aug 10	24 Aug 10
12 weeks	7 May 10	6 weeks	26 Oct 10	16 Nov 10
12 weeks	30 Jul 10	6 weeks	17 Feb 11	11 Mar 11
12 weeks	22 Oct 10	6 weeks	11 May 11	2 Jun 11

13.3.2 ACS Database

A new asset capability statement (ACS) database was completed and launched during the year which allows asset owners to electronically view the status of their own asset capability information and update this information online. The System Operator has received positive feedback regarding this initiative.

14. Information to Participants

14.1 Workshops and Newsletters

Seven System Operator newsletters were issued during the review period, the focus of most of these were to inform participants about the progress on the implementation of the new market systems.

One participant workshop was held in Wellington. The focus of the workshop was on the largely on functionality of the new market systems. Information on changes to the following was also presented to attendees.

- POCP Update
- Fixed Price Frequency Keeping
- Grid Support Contract and Demand Side Participation Trial
- Forecasting
- Asset Capability Information Database Project

14.2 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.

14.2.1 Usage

Usage of the System Operator website increased substantially in the reporting period. The live data pages continue to the most accessed pages on the website.

Traffic Analysis	1 Sep 2007 to 31 Aug 2008	1 Sep 2008 to 31 Aug 2009
Total visits:	46,939	53,319
Total pages viewed:	2,137,382	8,100,905
Total hits:	2,160,652	11,102,585
Average visits per day:	128	162
Average visits per week:	898	1,135
Average visits per month:	3,912	4,912
Average pages viewed per visit:	46	165
Average pages viewed per day:	5,841	26,678
Highest volume time of day	8-9 am	9-10 am
Highest volume day of the week:	Tuesday	Tuesday
Highest volume month:	Jun 08	Jun 09

The most requested page continues to be the Power System Overview which received 59% of all hits to the System Operator website.

The top 5 most popular web site pages were:

Page Name	Power System Overview	Zone Loading	Upper and Top SI Security	Home Page	Load Graphs
Hits	6,591,368	914,676	175,577	41,169	23,470
Page Image					
% age of overall Views	59	8	2	0.4	0.2

14.2.2 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.

Whilst the basic site structure has been maintained over the last 12 months, the site has been rebranded and graphic appearance of live data has been enhanced. The data links pushing data out to the site have been upgraded to give a more reliable flow of live information to the site.

The display of data using dynamic graphs has been implemented on the website. We have also provided additional information on the Upper and Top South Island Security Page to show AUVLS status and VSAT limits.

15. FINANCIAL REVIEW (SOSPA)

On 12 August 2009, the Electricity Commission and the System Operator entered into a new SOSPA to replace the earlier agreement entered into on 23 December 2003 (and variations thereafter). The effective date of the new agreement was 1 July 2009 and it has a three year term. The following financial information spans both the 2003 agreement and the new agreement.

15.1 BASE CONTRACT

Fees charged under the base SOSPA were as follows:

Financial review: SOSPA	1 September 2008 – 31 August 2009
System Operator Service Provider Contract Base Fee for the period 1 September 2008 – 30 June 2009	$17,793,333
System Operator Service Provider Contract Base Fee for the period 1 July 2009 – 31 August 2009	$4,180,666
Total fees paid under the SOSPA	$21,973,999

15.2 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 2008 – 31 August 2009
EC Advice including Rule Changes	$5,040
Breach Investigations	$50
Technical Investigations	$38,685
Total variable revenue	$43,775