TRANSPOWER

Appendix B

International Under-Frequency Events Resulting in System Splits

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December 2009

Investigations, System Operations

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International Under-Frequency Events Resulting in System Splits

Introduction

The purpose of this report is to collate information on international under-frequency events resulting in system splits. The use of automatic load shedding relays and their impact on maintaining system security is described. Issues arising from these events are described and recommendations outlined.

Events:

1 UCTE (compiled by LM Young)

Date: 4 November 2006, at around 22:10

Generation:

Generation was 274 100 MW including approximately 15 000 MW of wind generation (most of which was located in Northern Europe and Spain).

The distribution of generation was:

§ Western area: 182 700 MW including 6 500 MW of wind generation
§ North-Eastern area: 62 300 MW including 8 600 MW of wind generation
§ South-Eastern area: 29 100 MW

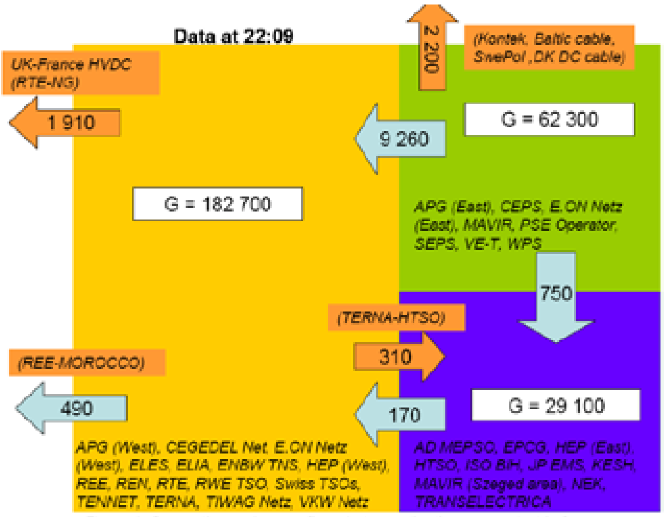


Figure 1: Generation, Imports and exports in the UCTE

Events:

21:39

§ Due to the weekend and lower demand, several transmission lines were out for maintenance.
§ N-1 studies were not properly done on an outage on two lines, the 380 kV Conneforde-Diele lines, due to it being brought forward.
§ The two circuits of the 380 kV Conneforde-Diele line were switched off at 21:39
§ The protection settings on the remaining line, the Landesbergen-Wehrendorf line, were different on each end.
§ The Landesbergen-Wehrendorf line started over-loading.

22:10

§ TSOs in Germany coupled the busbars in the substation of Landesbergen thinking this would end in a reduction of the current by about 80 A in the Landesbergen-Wehrendorf line but it increased the current by 67A instead.

- The Landesbergen-Wehrendorf line then tripped after exceeding it's limit of 1200 MW (It reached 1400 MW)
- This caused a cascade of tripping on the other heavily loaded lines.

22:10:28

- UCTE system was split in to 3 areas as shown in Figure 2.

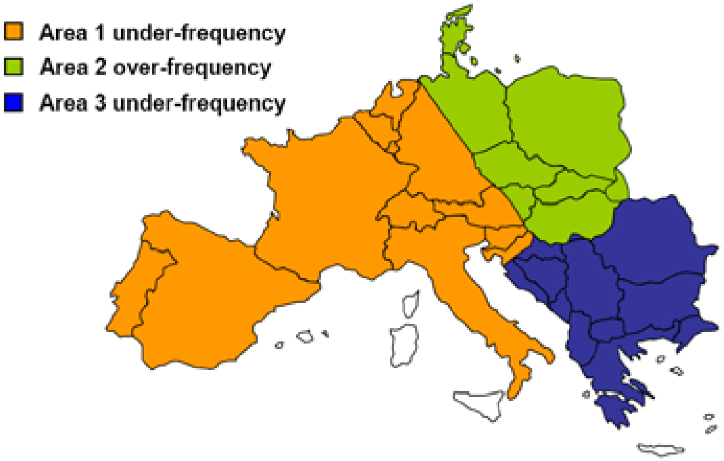


Figure 2: The splitting of the UCTE system due to the cascade tripping of lines

22:10:32

- The interconnection lines between Morocco and Spain tripped due to low frequency.
- The areas 1 and 3 remained asynchronously connected through the DC link between Italy and Greece during the whole event.
- Due to the fast separation, there was no damage to equipment.
- 9 500 MW of generation which came from the East area to the Western area was cut. The frequency sharply dropped to about 49 Hz in the Western area due to the sudden lack of power.
- The North East area faced a surplus of generating power of the same magnitude inducing a high over-frequency of 51.4 HZ.
- The South East area lost around 800 MW which induced a slight under-frequency of about 49.7 Hz.

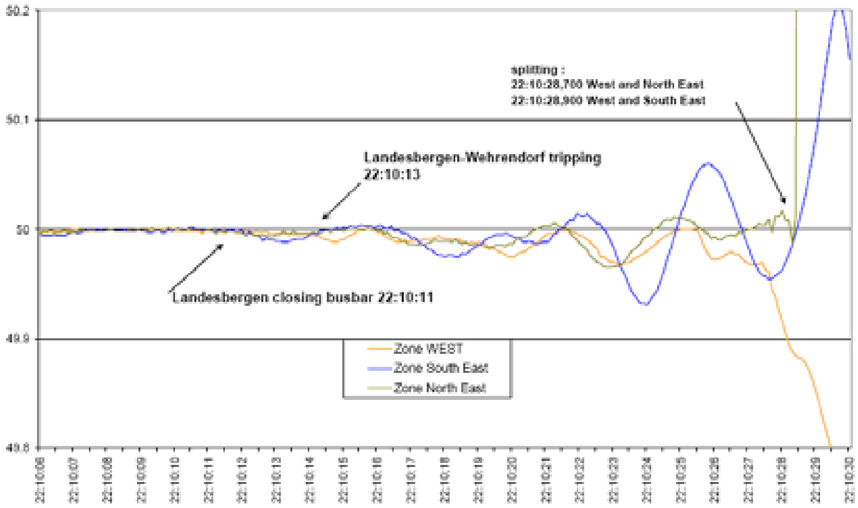


Figure 3: The frequency of the 3 areas at start of the event until splitting

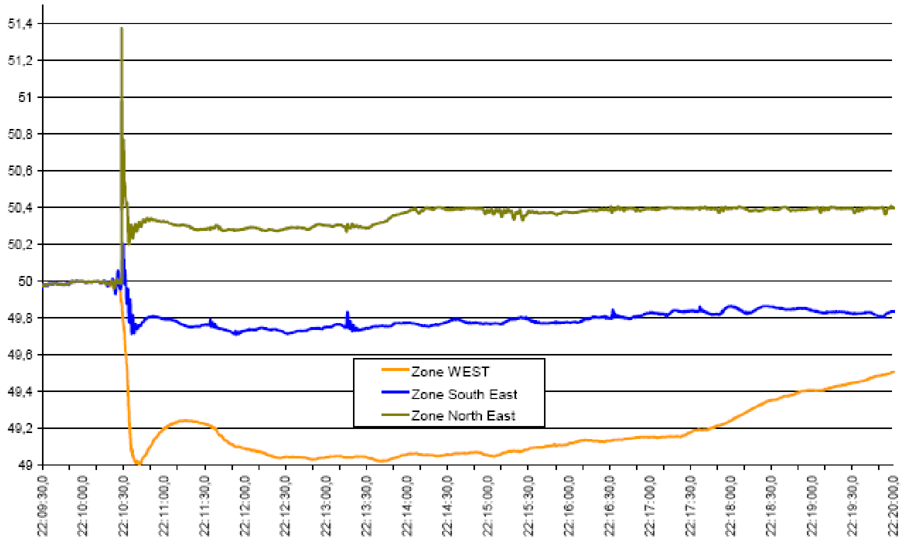


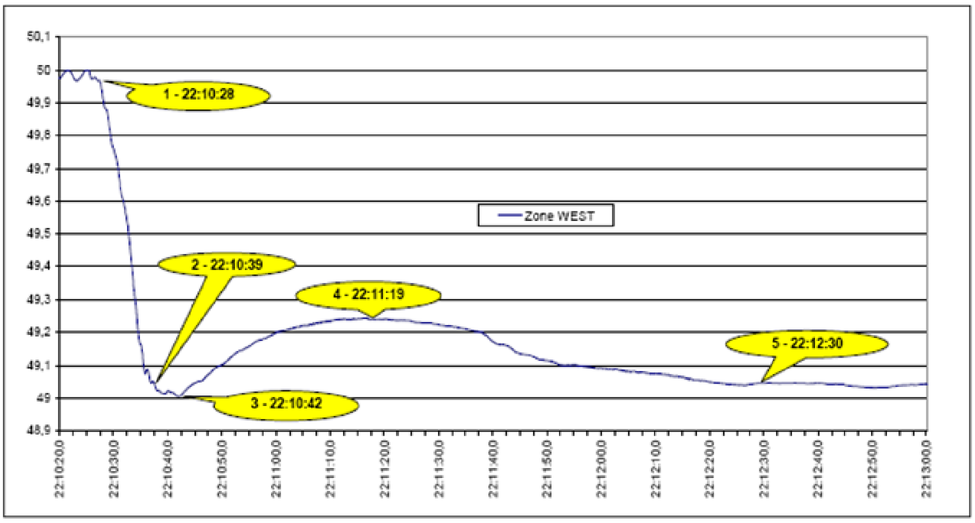
Figure 4: The frequency of each UCTE area after the split

Area 1 – Western:

During the incident, the load shedding and pumps shedding was in line with the values declared by TSOs in defense plans. A total of about 17 000 MW of load was shed and 1 600 MW of pumps was shed.

The load shedding was related to the imbalance caused by the splitting of the grid amounted to about 9 000 MW. The additional load shedding was necessary due to tripping of generation.

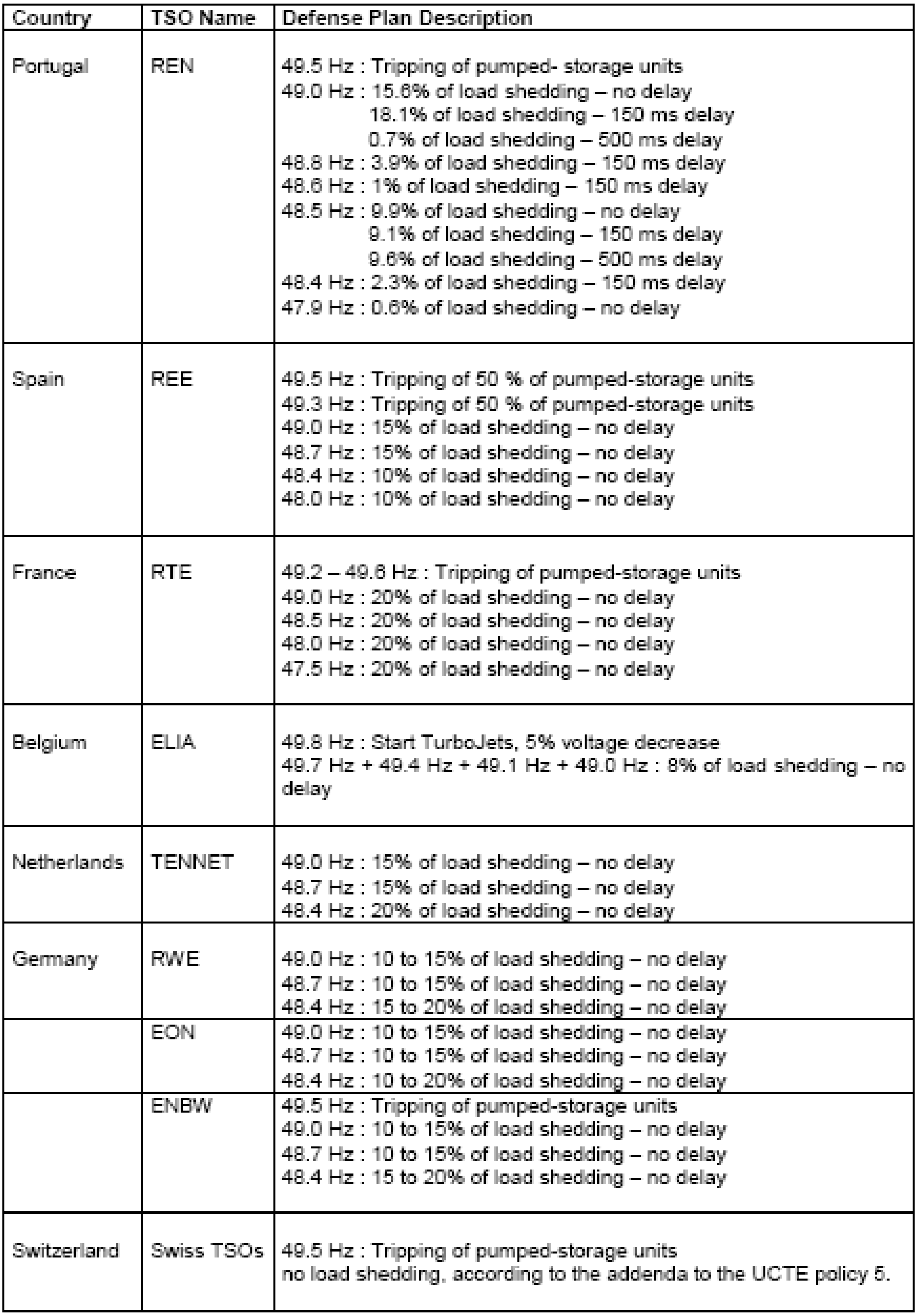
The estimated amount of primary control in the Western area was 2050 MW while the total imbalance of this area was close to 9 000 MW (approx. 22%).



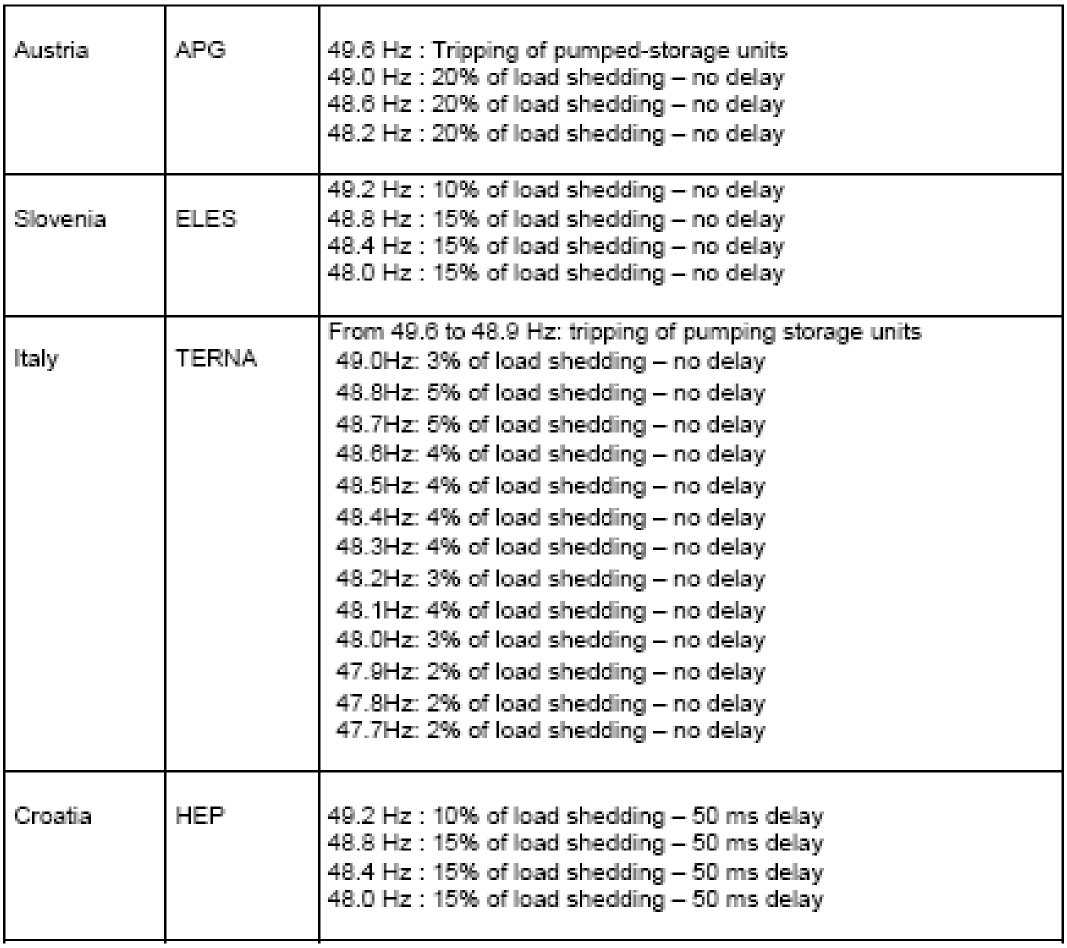
① – 22:10:28, separation of the Western area from the Eastern part of UCTE
② – 22:10:39, stop of frequency decrease, mainly due to the activation of defense plans
③ – 22:10:42, beginning of frequency increase caused by additional primary reserve
④ – 22:11:19, frequency maximum at a value near 49.2 Hz
⑤ – 22:12:30 slow frequency raise to reach a normal value of 50 Hz at about 22:25

Figure 5: The frequency in the Western area

Summary of load shedding actions in West area



Country	TSO Name	Defense Plan Description
Portugal	REN	49.5 Hz : Tripping of pumped- storage units 49.0 Hz : 15.6% of load shedding – no delay 18.1% of load shedding – 150 ms delay 0.7% of load shedding – 500 ms delay 48.8 Hz : 3.9% of load shedding – 150 ms delay 48.6 Hz : 1% of load shedding – 150 ms delay 48.5 Hz : 9.9% of load shedding – no delay 9.1% of load shedding – 150 ms delay 9.6% of load shedding – 500 ms delay 48.4 Hz : 2.3% of load shedding – 150 ms delay 47.9 Hz : 0.6% of load shedding – no delay
Spain	REE	49.5 Hz : Tripping of 50 % of pumped-storage units 49.3 Hz : Tripping of 50 % of pumped-storage units 49.0 Hz : 15% of load shedding – no delay 48.7 Hz : 15% of load shedding – no delay 48.4 Hz : 10% of load shedding – no delay 48.0 Hz : 10% of load shedding – no delay
France	RTE	49.2 – 49.6 Hz : Tripping of pumped-storage units 49.0 Hz : 20% of load shedding – no delay 48.5 Hz : 20% of load shedding – no delay 48.0 Hz : 20% of load shedding – no delay 47.5 Hz : 20% of load shedding – no delay
Belgium	ELIA	49.8 Hz : Start TurboJets, 5% voltage decrease 49.7 Hz + 49.4 Hz + 49.1 Hz + 49.0 Hz : 8% of load shedding – no delay
Netherlands	TENNET	49.0 Hz : 15% of load shedding – no delay 48.7 Hz : 15% of load shedding – no delay 48.4 Hz : 20% of load shedding – no delay
Germany	RWE	49.0 Hz : 10 to 15% of load shedding – no delay 48.7 Hz : 10 to 15% of load shedding – no delay 48.4 Hz : 15 to 20% of load shedding – no delay
	EON	49.0 Hz : 10 to 15% of load shedding – no delay 48.7 Hz : 10 to 15% of load shedding – no delay 48.4 Hz : 10 to 20% of load shedding – no delay
	ENBW	49.5 Hz : Tripping of pumped-storage units 49.0 Hz : 10 to 15% of load shedding – no delay 48.7 Hz : 10 to 15% of load shedding – no delay 48.4 Hz : 15 to 20% of load shedding – no delay
Switzerland	Swiss TSOs	49.5 Hz : Tripping of pumped-storage units no load shedding, according to the addenda to the UCTE policy 5.



Austria	APG	49.6 Hz : Tripping of pumped-storage units 49.0 Hz : 20% of load shedding – no delay 48.6 Hz : 20% of load shedding – no delay 48.2 Hz : 20% of load shedding – no delay
Slovenia	ELES	49.2 Hz : 10% of load shedding – no delay 48.8 Hz : 15% of load shedding – no delay 48.4 Hz : 15% of load shedding – no delay 48.0 Hz : 15% of load shedding – no delay
Italy	TERNA	From 49.6 to 48.9 Hz: tripping of pumping storage units 49.0Hz: 3% of load shedding – no delay 48.8Hz: 5% of load shedding – no delay 48.7Hz: 5% of load shedding – no delay 48.6Hz: 4% of load shedding – no delay 48.5Hz: 4% of load shedding – no delay 48.4Hz: 4% of load shedding – no delay 48.3Hz: 4% of load shedding – no delay 48.2Hz: 3% of load shedding – no delay 48.1Hz: 4% of load shedding – no delay 48.0Hz: 3% of load shedding – no delay 47.9Hz: 2% of load shedding – no delay 47.8Hz: 2% of load shedding – no delay 47.7Hz: 2% of load shedding – no delay
Croatia	HEP	49.2 Hz : 10% of load shedding – 50 ms delay 48.8 Hz : 15% of load shedding – 50 ms delay 48.4 Hz : 15% of load shedding – 50 ms delay 48.0 Hz : 15% of load shedding – 50 ms delay

Table 1: Load shedding by the West during the event

The rates of load shedding refer to the installed relays and are theoretical values.

Area 2 - North East:

After the cascade of trippings of the overloaded lines and splitting of the UCTE power system into three large separate areas, the North-East area faced a severe imbalance conditions with a generation surplus of more than 10 000 MW (approx. 17% of total generation in this area before the splitting) leading to a situation of high over-frequency.

This was due to the large exports into the West and South of Europe. Volumes of flows were increased due to high wind conditions in the North of Germany as shown in the Figure 6. The wind generation was uncontrolled and re-started unexpectedly.

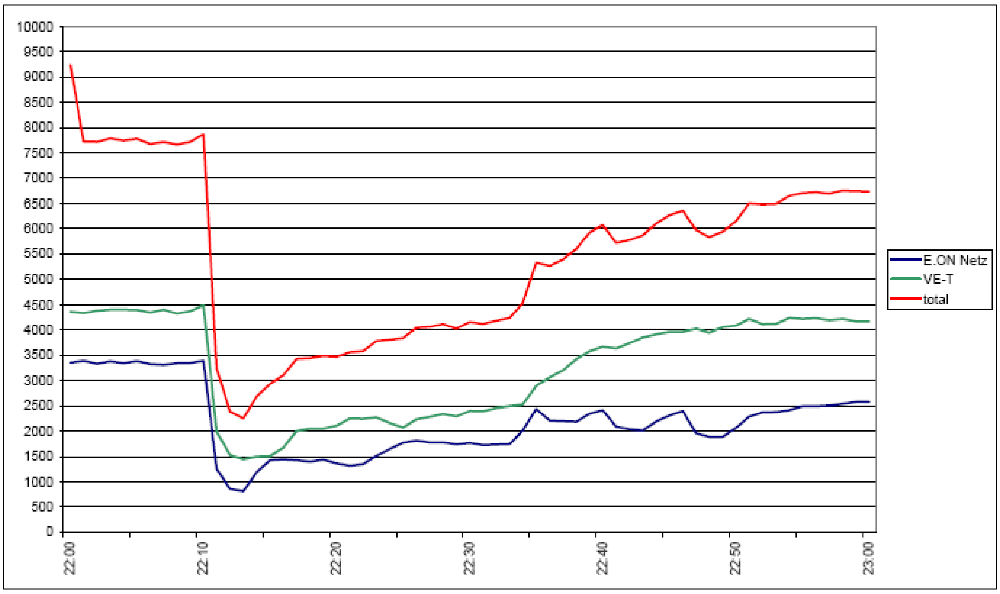


Figure 6: Wind generation in Germany and Australia during the event

In the North-Eastern area the primary reserve was 700 MW compared to an imbalance of about 10000 MW (approx. 7%).

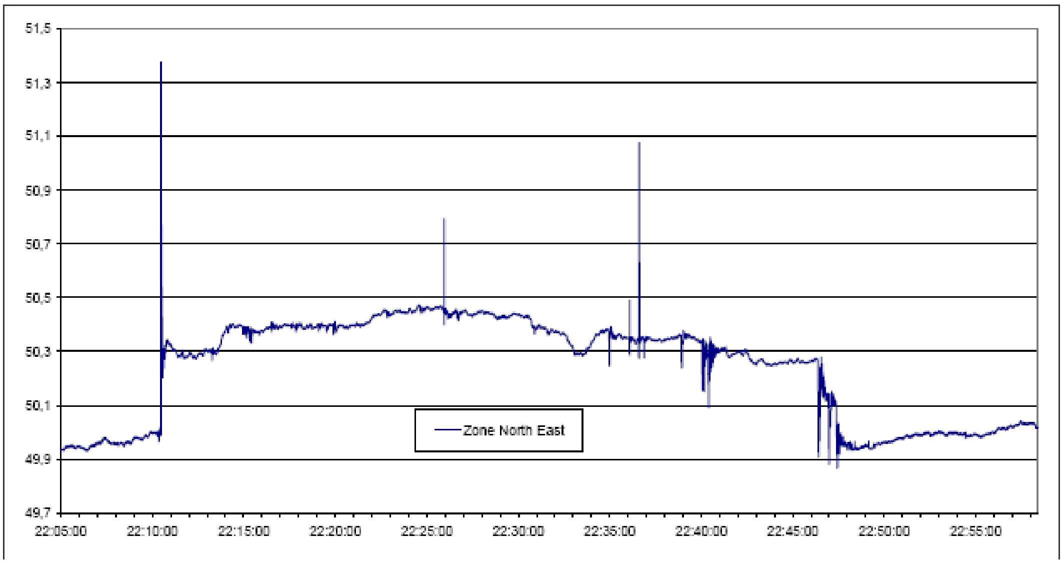


Figure 7: Frequency in Area 2 during the event

Area 3 - South-Eastern:

The power balance estimated for Area 3 at 22:09 was the following:
Total generation: 29 100 MW
Total load: 29 880 MW
The South Eastern Area had in fact very little power imbalance, an imbalance of around 770 MW. The frequency during the event was above the first threshold for load shedding so area 3 was N-1 secure during the whole event.

The primary reserve for the South-Eastern area totalled 250 MW in comparison to an imbalance of 750 MW (approx. 35%).

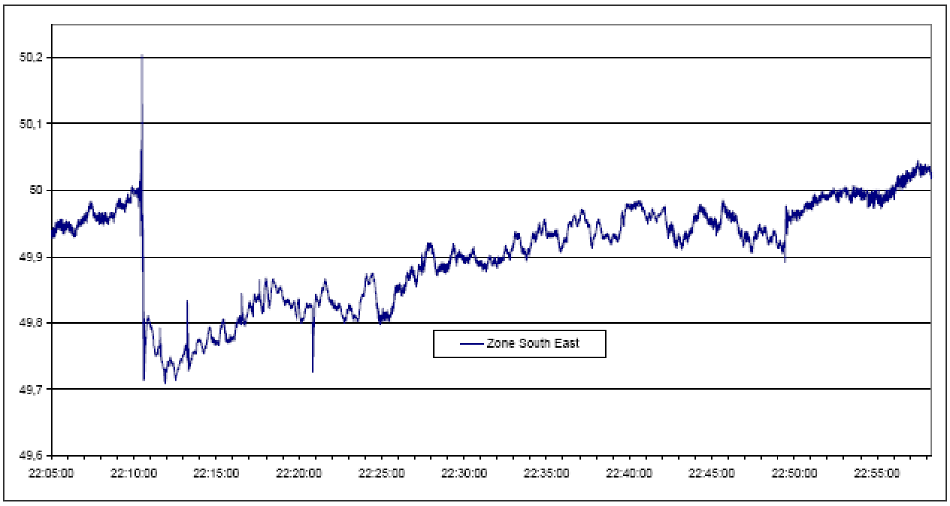


Figure 8: Frequent of area 3 during the event

Critical factors:

- A significant amount of generation tripped due to frequency drop in the Western Area.
- TSOs did not have access to or control of distributed generation units, distributed generation conditions usually are not as stringent as for main generation and were only required to withstand a frequency drop to 49.5 Hz.
- Uncontrolled reconnection of Wind in North-Eastern Areas.
- Limited range of actions available to German TSOs as by law they have to consider grid and market factors first.
- No coordination of restoration, TSOs/DSOs working independently without knowing full extent of the situation.
- N-1 security not ensured for outage.

From: UCTE Final Report - System Disturbance on 4 November 2006

2 Victoria, Australia (compiled by M Archer)

Date: 16 January 2007

Event Timeline:

- Import from New South Wales (NSW) to Victoria was expected to be more than 1700 MW. Most of this import was to flow through the two Dederang (DDTS) to South Morang (SMTS) 330 kV Lines.
- Time zero (T=0) represents the time at which both lines were open. All other times are referenced back to T=0. This is 15:03 (Market Time).
- At T-24, one of the two DDTS-SMTS 330 kV lines tripped, due to a smoke-initiated flashover on the line from nearby bushfires.
- At T=0, the other DDTS-SMTS 330kV line tripped. The power flow to Victoria along these lines immediately re-distributed itself to the 220 kV network. The 220 kV lines had insufficient capacity to carry this load, leading to a cascading sequence of line trips:
  - At T+1.6 – the 220 kV connection to NSW through Red Cliffs (RCTS) near Mildura tripped,
  - At T+2.4 seconds – the 220 kV connection between Bendigo (BETS) and Shepparton (SHTS) tripped,
  - At T+2.4 seconds – the two 220 kV connections between Dederang and Eildon (EPS) tripped (Victoria Region now separated from NSW Region),
  - At T+4.0 seconds – the two 275 kV connections between Heywood (HYTS) and South East Switching Station (SESS) in South Australia tripped (Victoria Region now separated from South Australia Region).

Duration from first trip to last loss of interconnection: 28 s

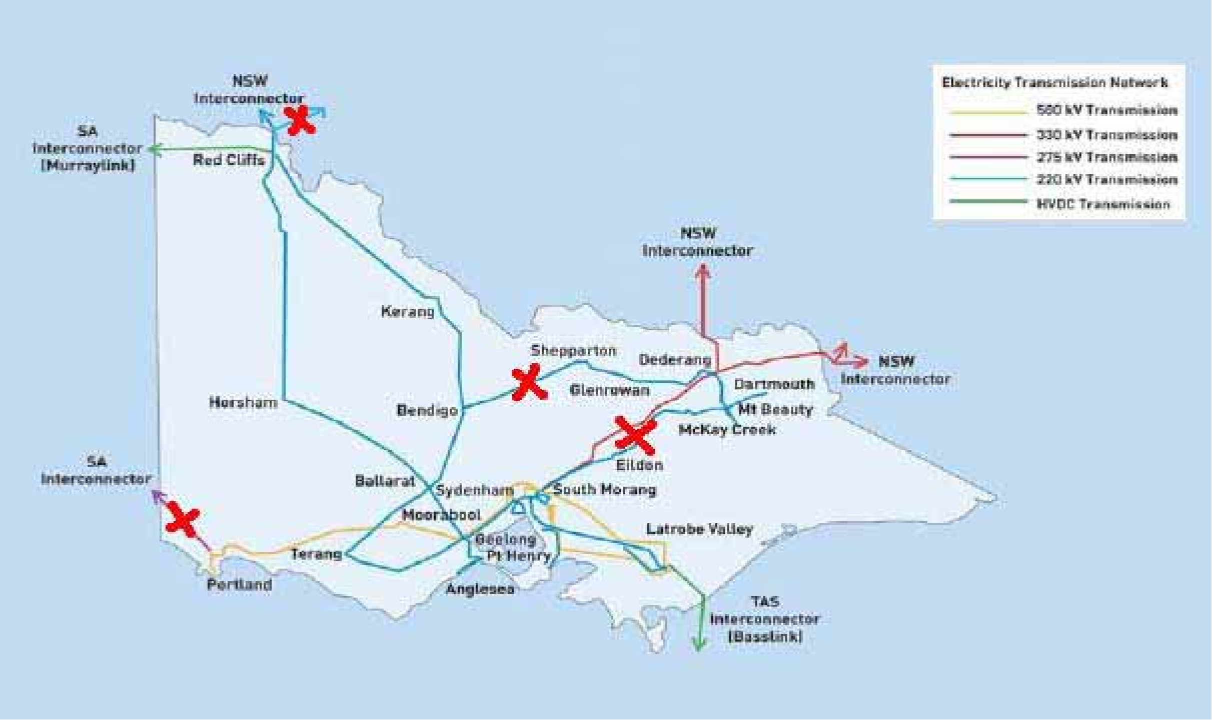


Figure 9: Transmission Trippings in Victorian Network

Description of Events:

Prior to the event the combined import into Victoria from NSW and South Australia (SA) was about 1990 MW, together with an additional 500 MW from Tasmania (TAS).

After the event, import from NSW (via the Dederang-Monash and Jindera-Wodonga 330 kV Lines) was in the order of 490 MW, supplying Mount Beauty (MBTS), Glenrowan, Shepparton and Wodonga (there was no loss of load at these four Terminal Stations), together with 500 MW from TAS.

Following separation, Victorian hydro generation (other than Eildon) continued to feed into MBTS, which remained connected to NSW, supplying approximately 210 MW. Eildon generation remained connected to Thomastown Terminal Station .

The reduction in supply to Victoria caused by the loss of the NSW interconnection resulted in an under-frequency event. The frequency reduced to 48.6 Hz which resulted in activation of the Automatic Load Shedding (ALS) scheme, shedding approximately 2200 MW of load. This load shedding included large industrial and commercial customers as well as large blocks of smaller customers in a pre-determined sequence, starting with aluminium smelters.

The initial load shedding limited the frequency decline to 48.6 Hz after 5.5 seconds. More load shedding allowed the frequency to recover further and it reached 50.55 Hz 12 seconds after the 2nd DDTS-SMTS 330 kV line opened. Generator controls then restored the frequency within normal operating range.

NEMMCO applied its emergency operating arrangements to:
- stabilise the Victorian Region,
- reconnect the Victorian Region to South Australia (at 15:42) and NSW (at 17:58),
- progressively restore customer load (commenced 15:49 and completed 18:15), and
- restore all transmission lines that tripped during the incident back into service, completed by 23:30

Because of their proximity to the bushfires and the CFA and DSE fire-fighting crews, the DDTS-SMTS 330 kV Lines were not cleared for restoration until just before midnight (Market Time).

Analysis of Line trips:

The bushfires caused a single phase (red) to ground fault on DDTS-SMTS No 1 Line. The duplicated line protection scheme cleared the fault in approximately 4 cycles. The Line then successfully automatically reclosed at SMTS followed by successful reclose at the DDTS end. The auto-reclose at both ends then locked out. The same line trips again at T-24, but auto-reclose has not been reset by the control centre, so the line remains open.

Dynamic System Monitors (DSM) records show steady voltages and frequency at Dederang and Red Cliffs Terminal Station (RCTS) with one DDTS-SMTS 330 kV line out of service. When the second DDTS-SMTS 330 kV line tripped at T=0 (15:03 Market Time), system frequency and voltages began to decline.

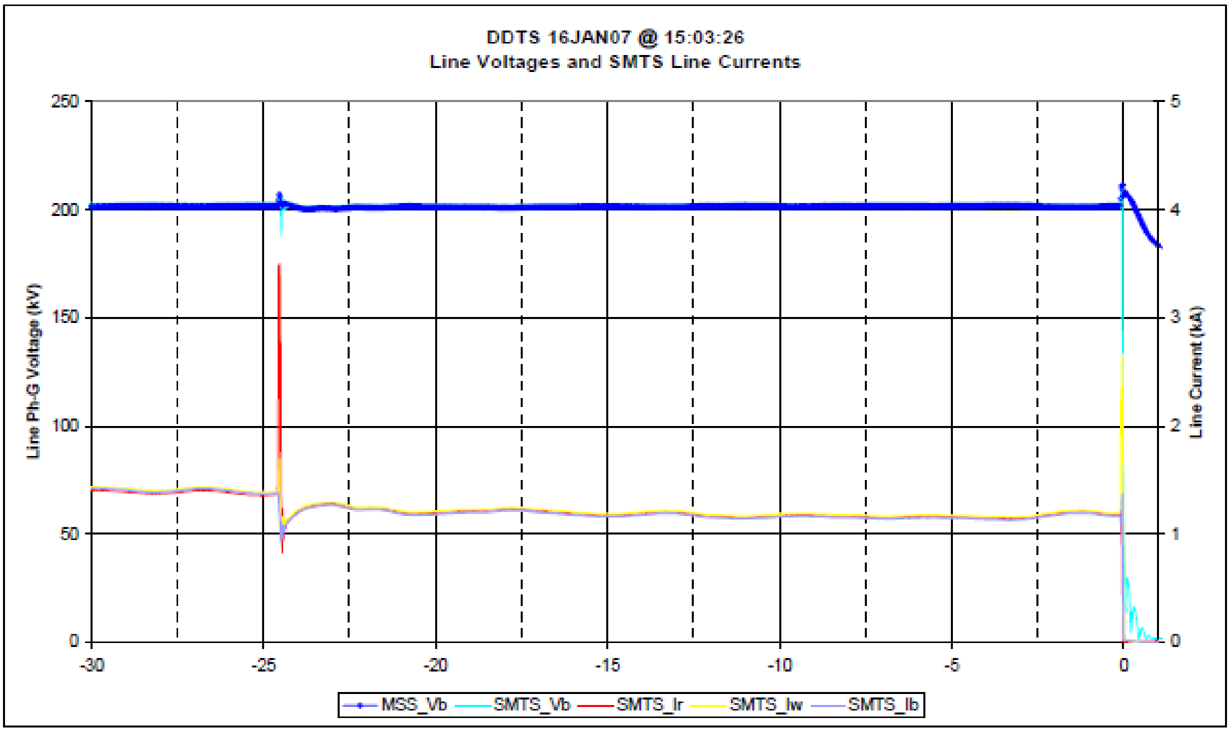


Figure 10: MSS Line Voltage and SMTS Line Voltage and Currents prior to Event

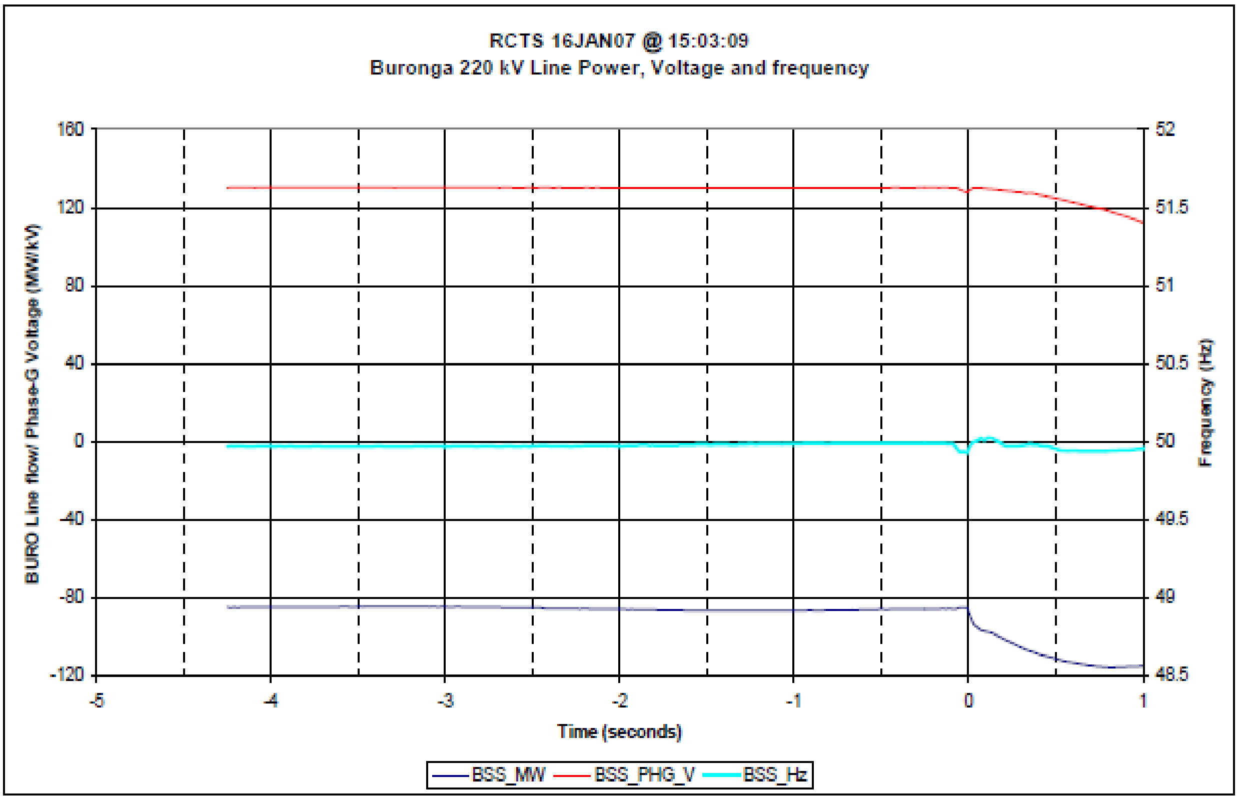


Figure 11: Buronga 220 kV Line Power, Voltage and Frequency prior to Event

Before T+1.6 seconds, the DSM records show that frequency is still quite steady, but voltage is declining, and there is an oscillation in the MW flows from Red Cliffs to Buronga (in NSW), and Heywood (HYTS) to the South East.

At T+1.6 seconds, the RCTS DSM record shows that Buronga Line flow instantaneously changes from about 80 MW towards RCTS and Victoria to 20 MW in the other direction. This indicates that Broken Hill is now supplied radially from RCTS, and that the connection from Buronga to Darlington Point has tripped. It is understood that this trip was caused by Distance Protection at Buronga Switching Station detecting instability across the Buronga to Darlington Point Line.

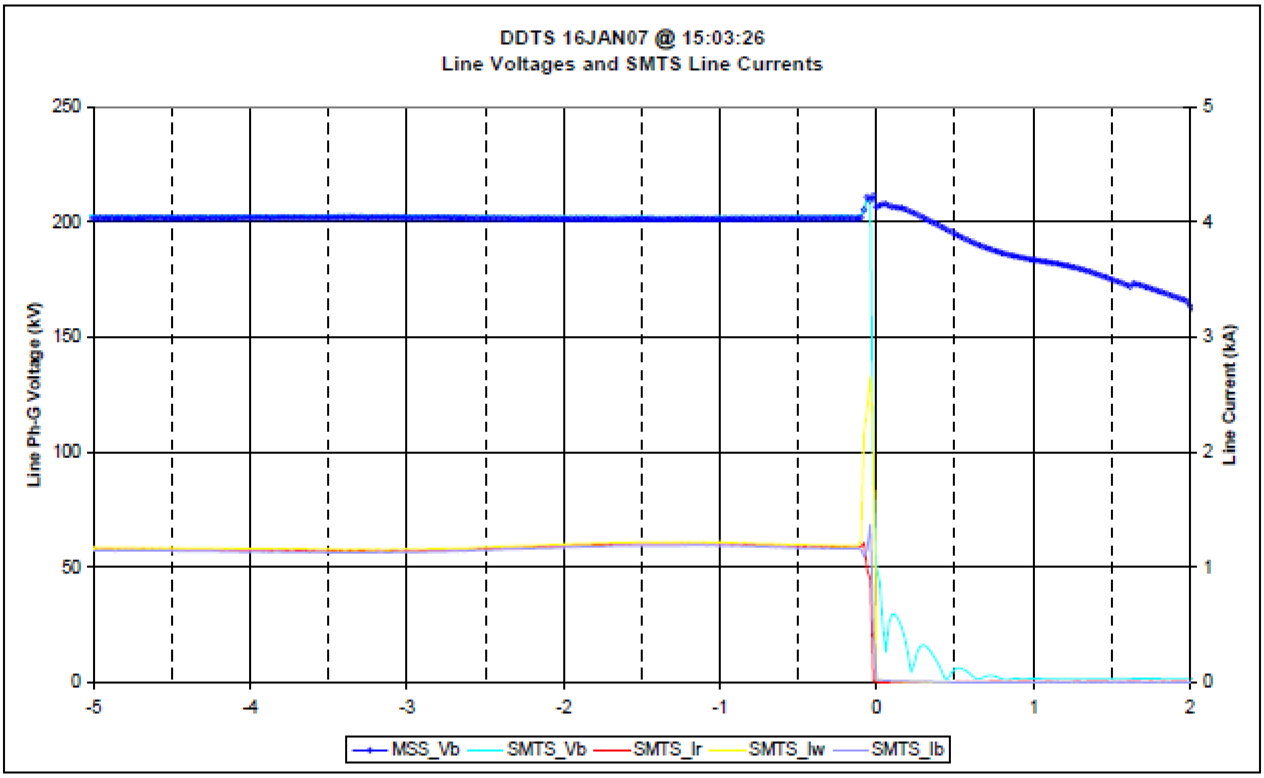


Figure 12: MSS Line Voltage and SMTS Line Voltage and Currents post Event

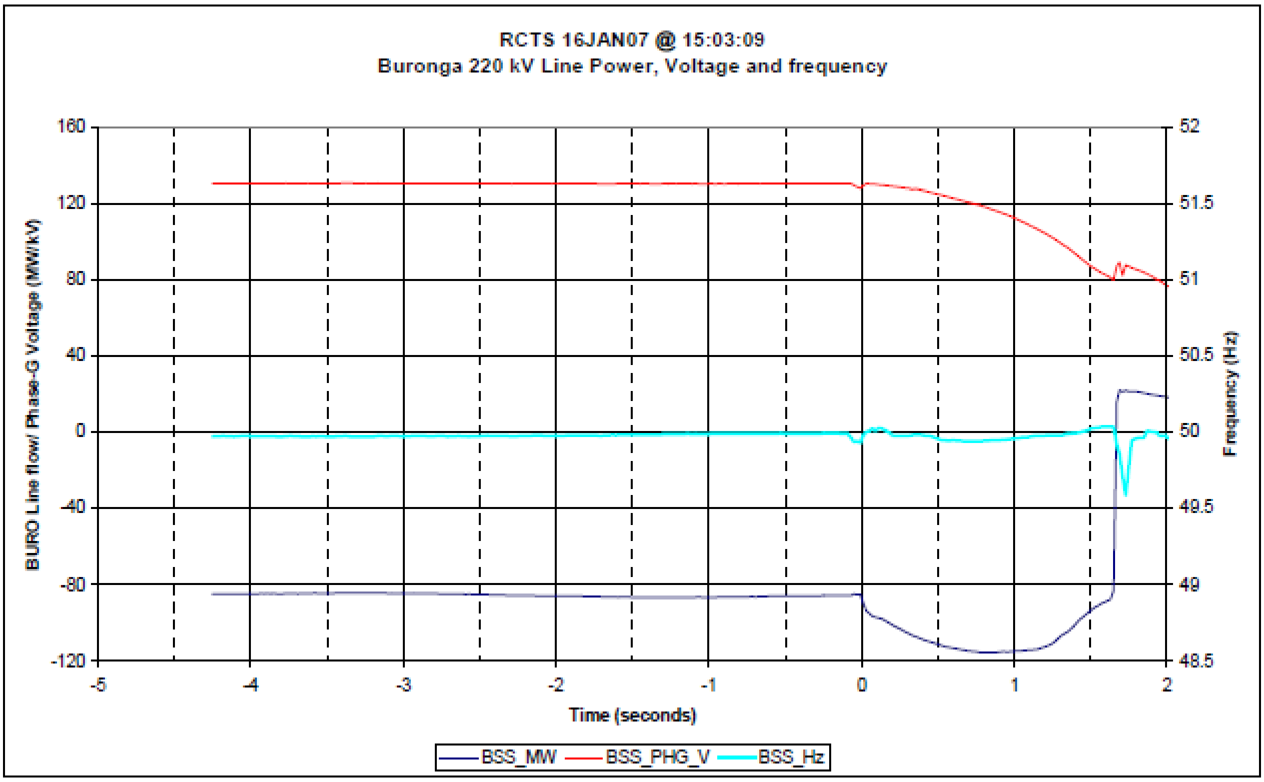


Figure 13: Buronga 220 kV Line Power, Voltage and Frequency post Event

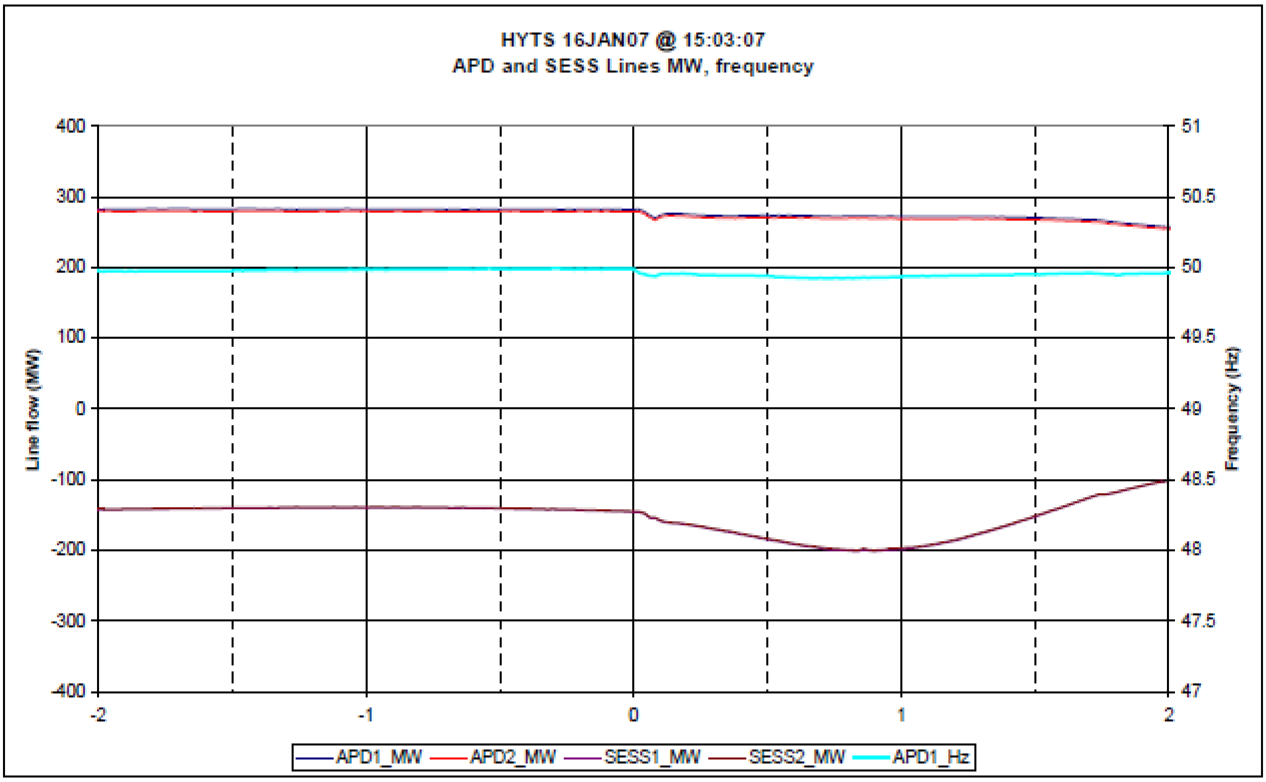


Figure 14: APD and SESS Line Power and Frequency post Event

Between T+1.6 and T+2.4 seconds there were trips of Shepparton-Fosterville/Bendigo, Eildon-Mount Beauty and Eildon-Mount Beauty-Dederang 220 kV Lines. These trips were probably due to Line Protection detecting instability across each of the lines.

At T+2.4 seconds Victoria has separated from NSW. The DDTS and RCTS records show voltages declining, but then improving after separation from NSW.

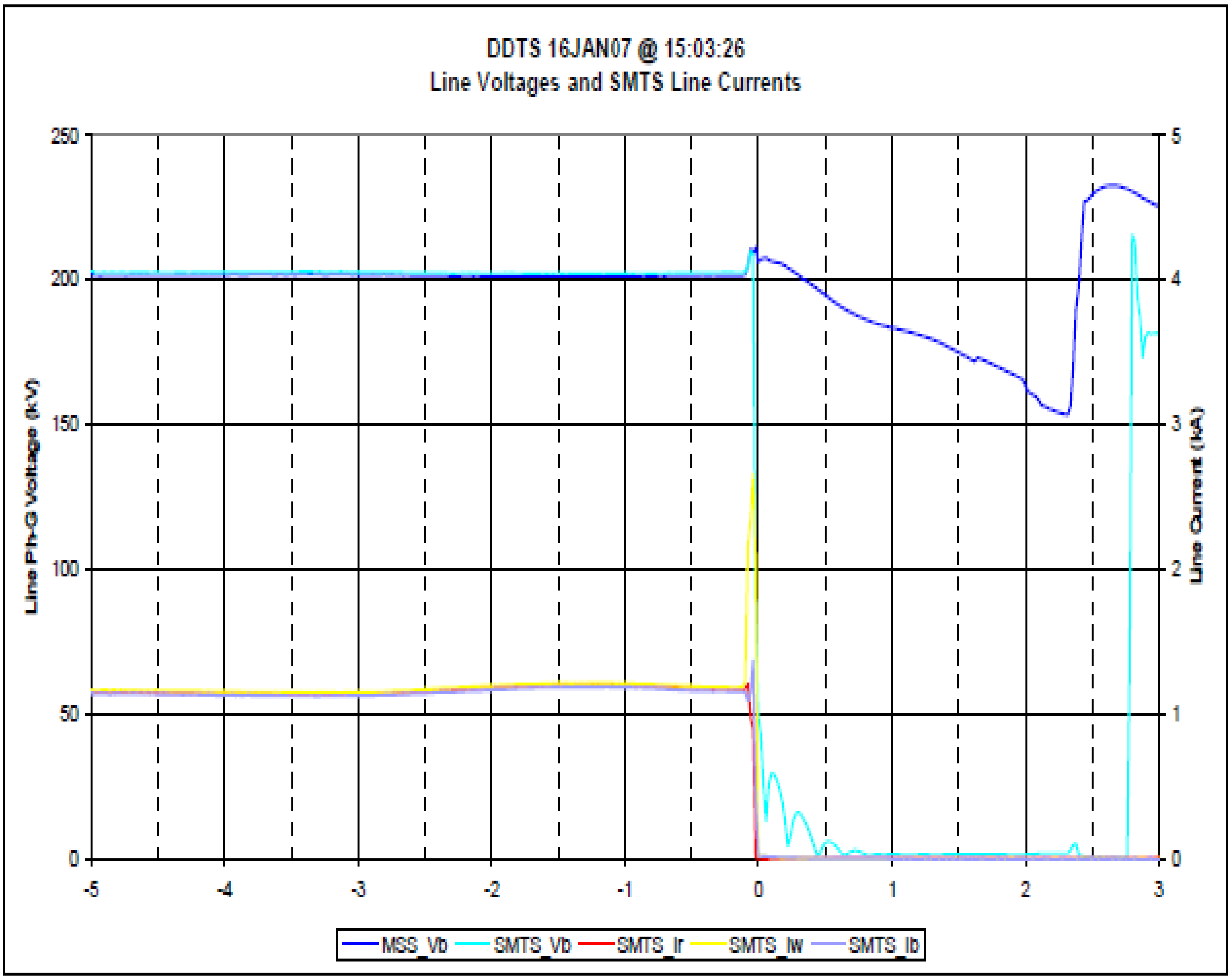


Figure 15: MSS and SMTS Line Voltage and Currents following separation from NSW

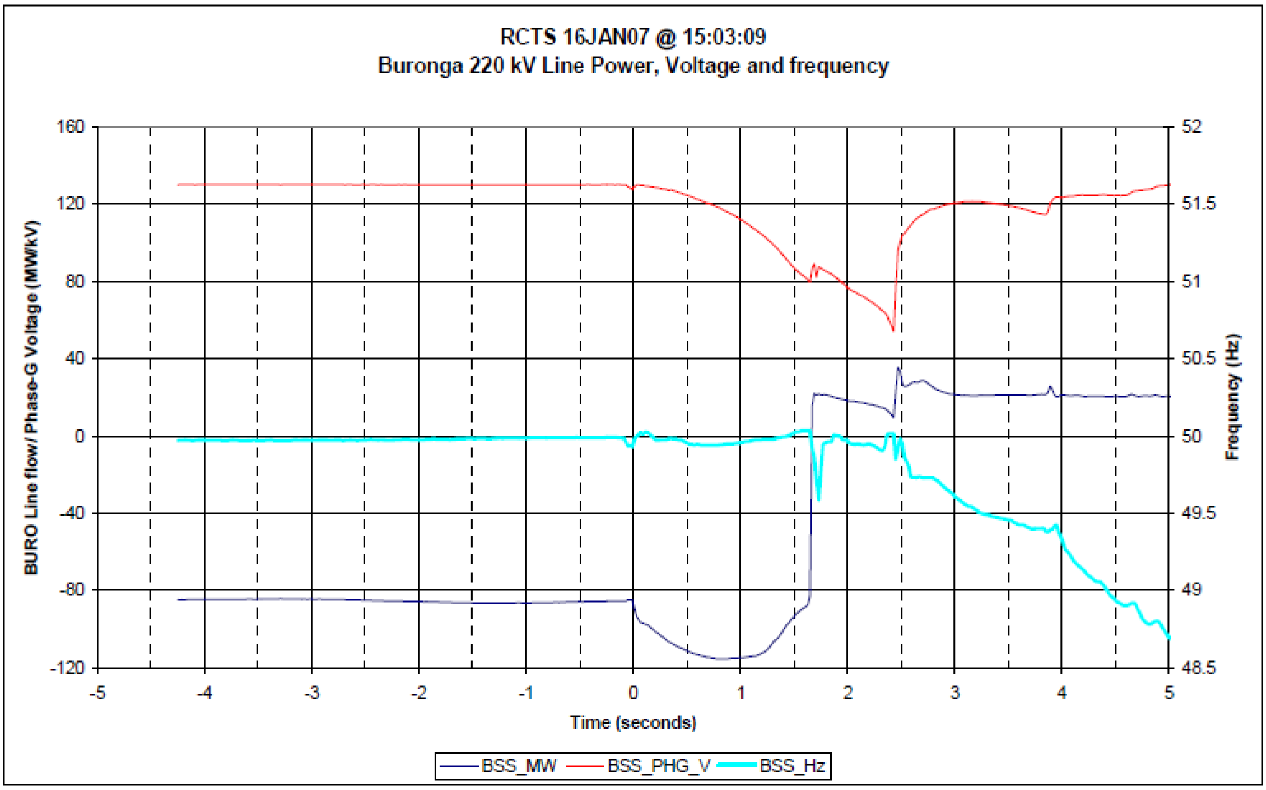


Figure 16: Buronga Line Power, Voltage and Frequency following separation from NSW

At T+3.9 seconds, the two 275 kV HYTS-SESS (in South Australia) connections tripped resulting in separation of Victoria from South Australia. Tripping was initiated by a “loss of synchronism” control scheme at SESS that detects growing oscillations.

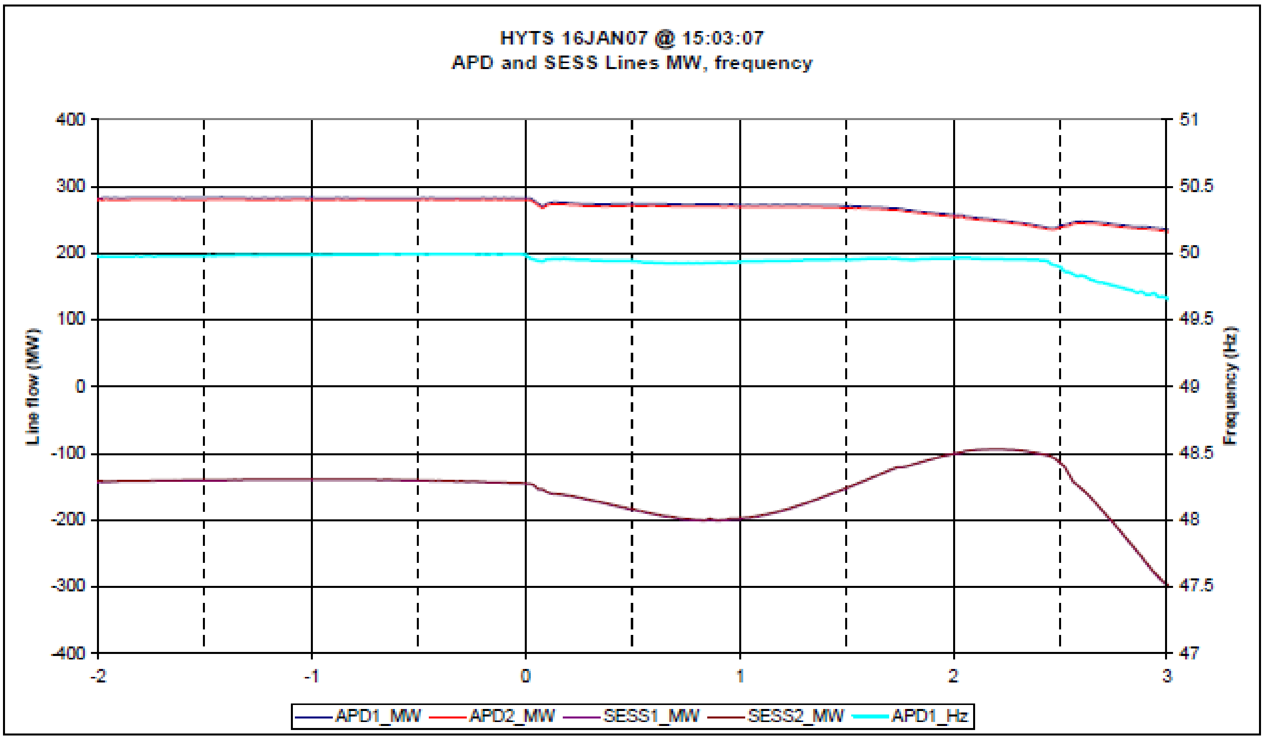


Figure 17: APD and SESS Line Power and Frequency prior to separation from SA

The DDTS DSM record below shows MSS Line voltages, representing the NSW side of the separation. High voltage occurs at separation, but reduces to normal as NSW voltage control plant responds. The oscillation in the voltage was probably caused by system mode oscillation between Snowy hydro generators and Victorian hydro generators connected via MBTS to NSW. At T=0, SMTS Line voltage drops to zero (both lines tripped). Auto-reclose at SMTS energizes No 2 Line at T+2.6 seconds, but another fault at T+13.5 seconds trips the line.

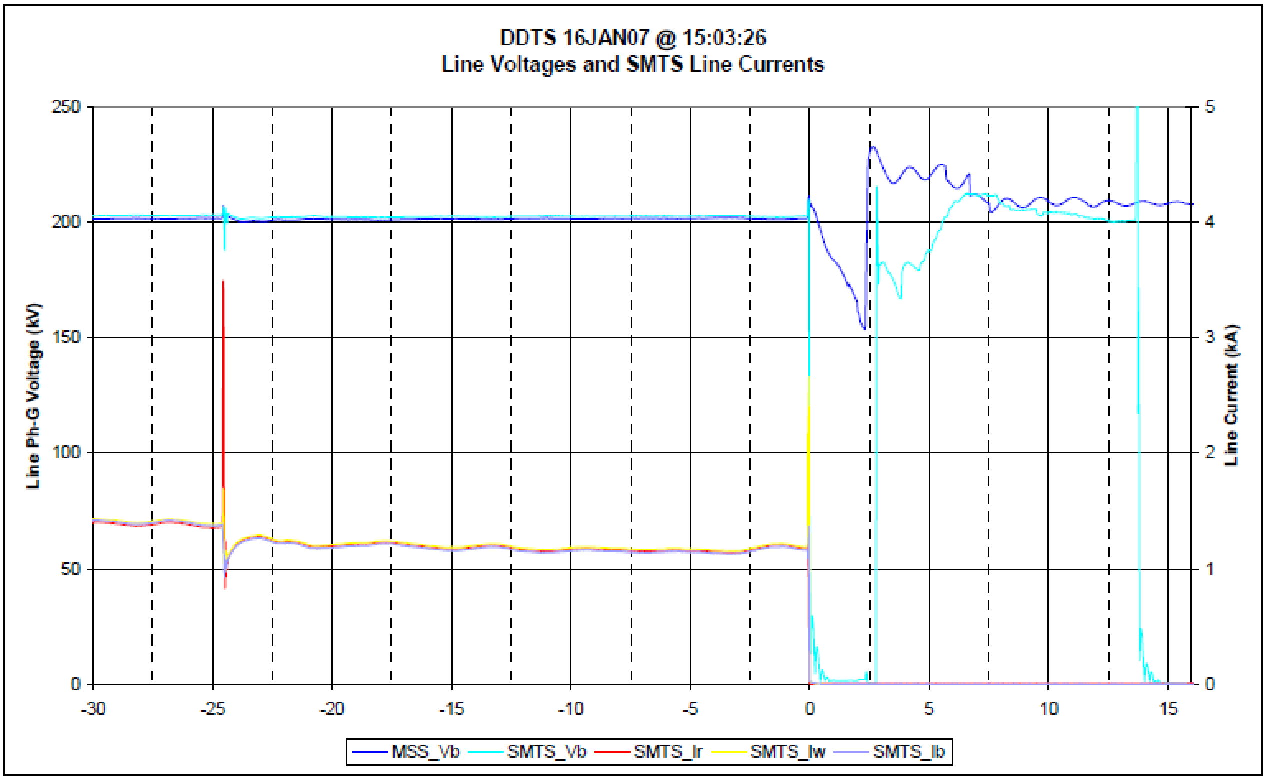


Figure 18: MSS and SMTS Line Voltage and Currents following separation

Voltage increases from approximately T=5 seconds as automatic load shedding starts around the Victorian network, including at RCTS.

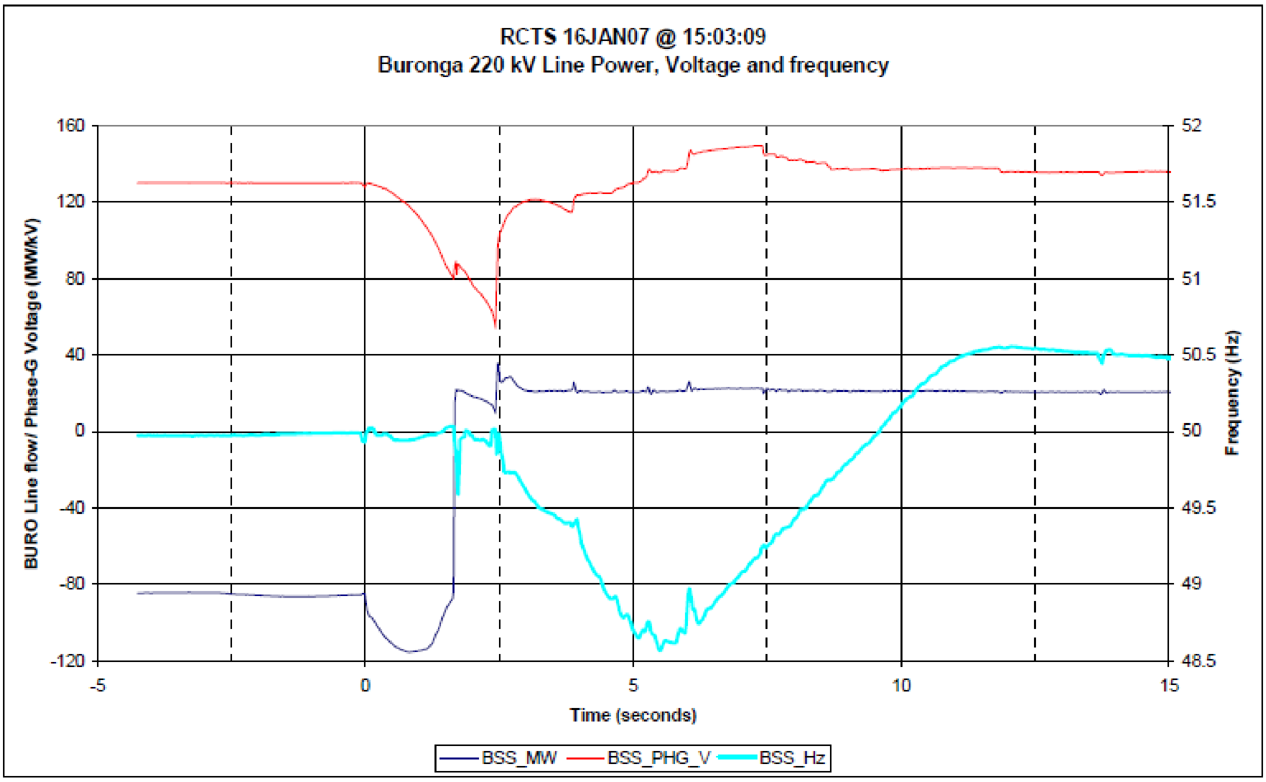


Figure 19: Buronga 220 kV Line Power, Voltage and Frequency following separation

Operation of Protection Schemes

The DDTS-SMTS Nos 1 and 2 Lines are understood to have tripped to clear faults caused by the bushfires. From DSM records, fault clearance times and operation are within the Rules and design. The 220 kV Lines (Darlington Point-Buronga Line, EPS-MBTS No 1 Line, EPS-MBTS-DDTS No 2 Line and SHTS-FVTS/BETS Line) are understood to have tripped because line protection detected system instability rather than line faults. The losses of these lines lead to separation between Victoria and NSW.

The HYTS Nos 1 and 2 275 kV Line CBs at South East Substation (in South Australia) tripped to cause separation between Victoria and SA. The tripping was caused, not by conventional protection schemes, but by an ElectraNet “special control scheme” that detected a growing oscillation between South Australia and Victoria, and correctly initiated tripping to avoid generator instability in South Australia.

The mismatch between supply and demand in Victoria, following separation from NSW and SA, resulted in a declining frequency that initiated automatic load shedding of approximately 2200 MW. The load shedding was necessary to restore the supply/demand balance, allowing the frequency and voltages to recover.

Operation of Load Shedding Schemes

Sub-transmission and distribution feeder circuit breakers at most Victorian terminal stations are fitted with facilities for remote monitoring and control. SP AusNet is responsible for the performance of the circuit breakers that form part of the various load shedding schemes.

Three main load shedding schemes are installed in Victoria to cover the various contingencies that may arise on the network:

a) Selective Load Shedding
The load at each Distributor-owned zone substation is shared across a number of feeders that are fitted with facilities to enable each feeder to be shed independently from the Distributor's Control Centre. If there is sufficient time (say 20 minutes or more) to reduce load, the Transmission Operations Centre will instruct the Distributor(s) to reduce load to improve supply/demand balance.

b) Manual Load Shedding
The load at each terminal station is usually arranged in 3 groups, each of which can be shed independently from the Control Centre. This load shedding is initiated manually in response to instructions from AEMO (Australia Energy Market Operator) to reduce load to improve supply/demand balance in shorter timeframes.

c) Automatic Load Shedding (under-frequency load shedding)
This is a distributed load shedding scheme that uses the 3 load groups at each terminal station that have been established for the Manual Load Shedding scheme, plus the Portland and Point Henry aluminium smelter potlines. The circuit breakers at each terminal station are fitted with facilities to enable each group at each terminal station to be shed independently and automatically in response to the frequency falling below a pre-set value.
Settings are chosen to automatically shed load equitably and uniformly across the network and, where possible, in order of priority. Load is shed in blocks, based on the frequency and the duration of the under frequency. The amount of load shed is based on the conditions detected.

Automatic Load Shedding scheme – design

The Automatic Load Shedding (ALS) scheme is a new control scheme commissioned in 2004 and is initiated when the frequency falls below 48.99Hz. During the event of the 16th January 2007, the frequency fell to 48.58 Hz, leading to the first event of shedding customer load under the new ALS scheme.

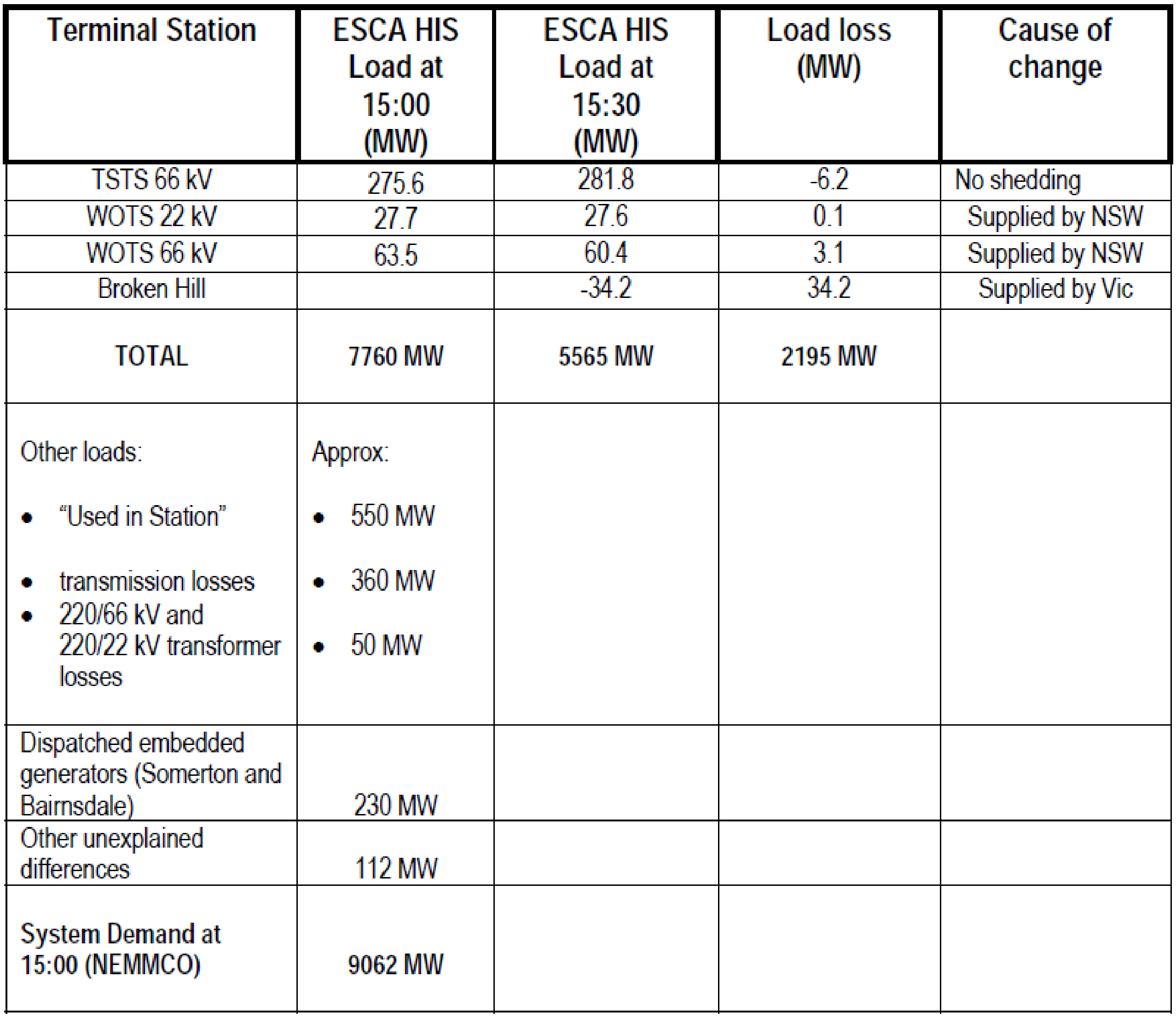
The plots of Victorian system frequency show the frequency excursion and its recovery to 50 Hz (+/- 0.5 Hz) took approximately 12 seconds. This is within the MCE Reliability Panel's Frequency Operating Standards, which allow 10 minutes to return to 50 Hz.

ALS scheme – performance (load lost during the event)

The table below details the amount of load that was lost, by terminal station, during the event.

Table 2: Load shedding in Victoria during the event

Terminal Station	ESCA HIS Load at 15:00 (MW)	ESCA HIS Load at 15:30 (MW)	Load loss (MW)	Cause of change
RCTS 22 kV	25.9	5	20.9	ALS
RCTS 66 kV	120.6	74.2	46.4	ALS
TTS 66 kV	526.6	412	114.6	ALS
APD 550 kV	507.2	0	507.2	ALS
PTH 220 kV No 1 Pot	92.3	0.5	91.8	ALS
PTH 220 kV No 2 Pot	100.1	0.6	99.5	ALS
PTH 220 kV No 3 Pot	0.2	0.2	0.0	No shedding
HTS 66 kV	291.8	192.6	99.2	ALS
FBTS 66 kV	194.6	85.1	109.5	ALS
RTS 22 kV	89.2	86	3.2	ALS
RTS 66 kV	492	414	78	ALS
SVTS 66 kV	416.8	312	104.	ALS
WMTS 22 kV	82.2	53	29.2	ALS
WMTS 66 kV	400	307	93	ALS
ATS 66 kV (radial)	17.4	40.2	-22.8	Unknown reason
ATS/BLTS 66 kV	365.5	314.9	50.6	ALS
BLTS 22 kV	54.2	21.2	32	ALS
BETS 22 kV	40	23.6	16.4	ALS
BETS 66 kV	158.6	0.4	158.2	ALS
ERTS 66 kV	422.7	299.7	123	ALS
GTS 66 kV (radial)	333.0	56.2	277.8	ALS
GTS-CLC-WIN-CDN-COB-TGTS Tie	59.5	62.4	-2.9	No shedding
TGTS 66 kV (radial)	106.6	108.7	-2.1	No shedding
CBTS 66 kV	249.6	258.6	-9	No shedding
RWTS 22 kV	79.6	79.5	0.1	No shedding
RWTS 66 kV	399.4	287.8	111.6	ALS
BATS/HOTS 66 kV	213.1	161.7	51.4	No shedding, but possible protection trip
BTS 22 kV	30.5	33.3	-2.8	Should have shed, but did not
FVTS 220 kV	7.5	4.3	3.2	No shedding
GNTS/MBTS 66 kV	94.3	93.1	1.2	Supplied by NSW
KGTS 22 kV	9.6	9.6	0	No shedding
KGTS 66 kV	49.8	45.1	4.7	No shedding (possibly irrigation switched off)
KTS 66 kV	506	514.4	-8.4	No shedding
MTS 22 kV	50.2	52.7	-2.5	No shedding
MTS 66 kV	99	99	0	No shedding
MWTS 66 kV	209	232.2	-23.2	No shedding
SHTS 66 kV	251.3	237.6	13.7	Supplied by NSW
TBTS 66 kV	224.9	227.2	-2.3	No shedding
JLA 220 kV	22.5	23.8	-1.3	No shedding



Terminal Station	ESCA HIS Load at 15:00 (MW)	ESCA HIS Load at 15:30 (MW)	Load loss (MW)	Cause of change
TSTS 66 kV	275.6	281.8	-6.2	No shedding
WOTS 22 kV	27.7	27.6	0.1	Supplied by NSW
WOTS 66 kV	63.5	60.4	3.1	Supplied by NSW
Broken Hill		-34.2	34.2	Supplied by Vic
TOTAL	**7760 MW**	**5565 MW**	**2195 MW**	
Other loads: • "Used in Station" • transmission losses • 220/66 kV and 220/22 kV transformer losses	Approx: • 550 MW • 360 MW • 50 MW			
Dispatched embedded generators (Somerton and Bairnsdale)	230 MW			
Other unexplained differences	112 MW			
System Demand at 15:00 (NEMMCO)	**9062 MW**			

ALS scheme – identified incorrect operation

Some loads did not trip because their ALS was not enabled due to ongoing station's refurbishment. Some loads were not on the ALS scheme due to sub-transmission changes which had not been communicated to the Demand Reduction Committee (DRC).The failure of these loads to trip resulted in other load tripping instead, with a slight time delay that had no significant effect on the ALS scheme. It highlighted a need to improve DRC procedures to ensure that sub-transmission loop changes were communicated to the DRC.

RCTS and HYTS DSM records show RCTS load tripping before Portland potlines, contrary to settings. It is likely that the severe voltage depressions affected the frequency measurements during the incident.

Voltage Recovery

The following sample of records of bus voltages (Ringwood Terminal Station 22 kV, Thomastown Terminal Station 66 kV and Geelong Terminal Station 220 kV) indicates that voltage initially collapsed, recovered as load shedding commenced, overshot, and then reached target voltage range within approximately 12 seconds. This is considered acceptable when the magnitude of the event is considered.

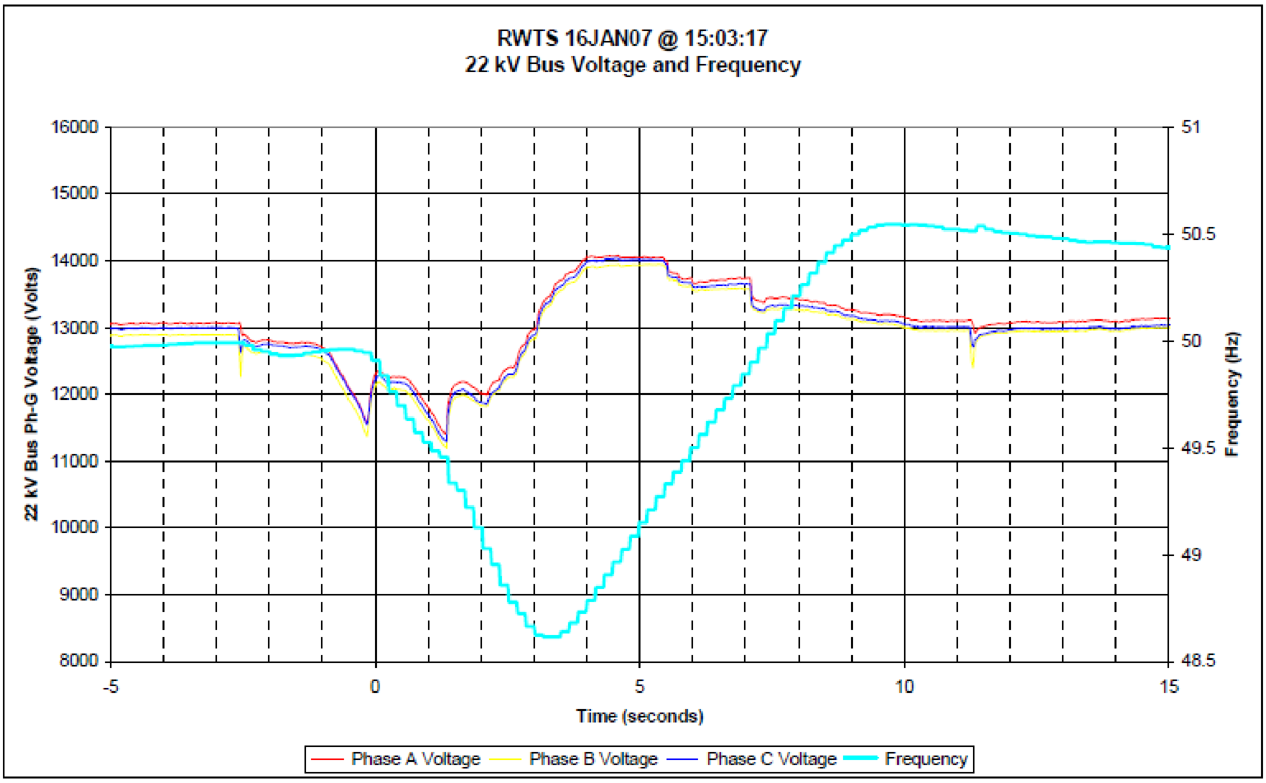


Figure 20: RWTS Voltage and Frequency following separation

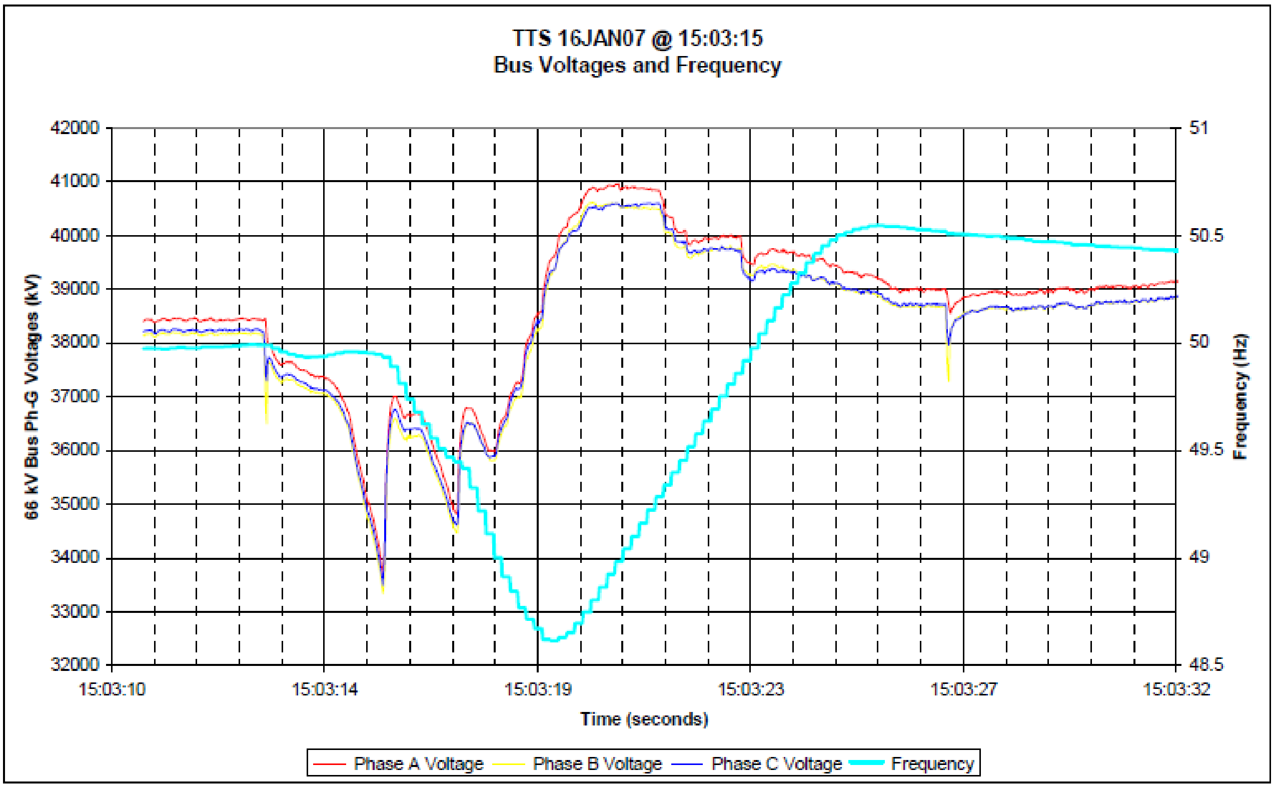


Figure 21: TTS Voltage and Frequency following separation

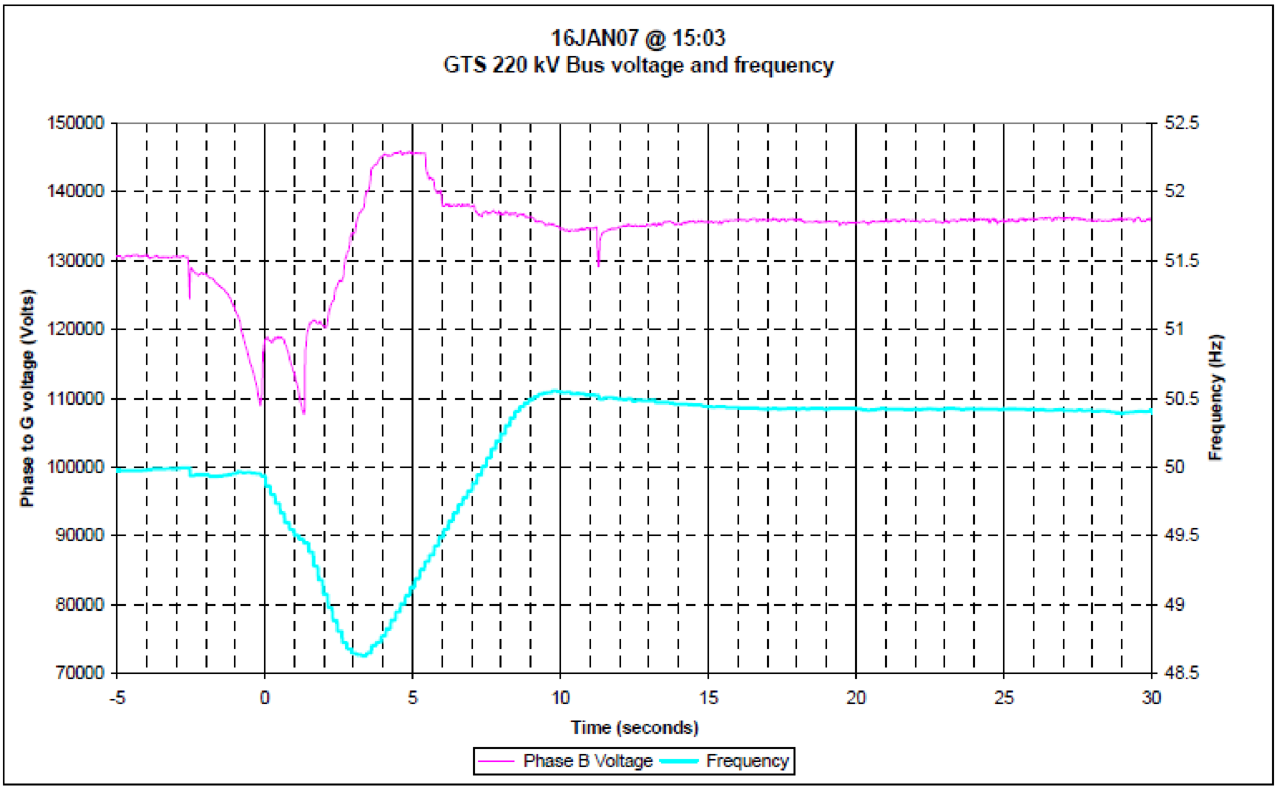


Figure 22: GTS Voltage and Frequency following separation

Major Contributing Factors and possible Mitigations

The major contributing factor to the event was the high level of import (more than 1700 MW), most of which was flowing through two transmission lines exposed to a greater than normal risk of tripping. Had the import been less than half of the actual import immediately before this event, then the flow on the two DDTS-SMTS 330 kV Lines may have been low enough for the parallel 220 kV network to hold together. Control centre monitoring facilities could then have detected any thermal overloads, allowing staff to implement localized load shedding as necessary.

Another way of avoiding an event of this type is primary plant augmentation, such as additional transmission easements and increased voltage support via capacitor banks. These measures would involve significant capital expenditure, and would be considered in long-term planning.

Reducing the Impact of Major Events

Ordinarily, the electricity industry regards separation between Victoria and NSW or Victoria and South Australia at times of high power transfer as a significant event to be avoided wherever possible, because it may adversely affect either or both sides of the separation. Depending on the level and direction of power transfer, one side may have a shortfall of supply leading to under-frequency and load shedding, while the other side may have an oversupply leading to over-frequency and possible tripping of generators.

Protection schemes at Buronga (NSW), SHTS and DDTS operated to trip healthy (unfaulted) lines in such a way as to create separation. It is possible to modify protection schemes to prevent such trips, or to delay tripping so “other measures” can reduce the need for separation and load shedding.

The DDTS, RCTS, HYTS and other DSM records show rapidly decaying voltages. For example, DDTS 330 kV voltage had reduced almost linearly by 25% within 2.4 seconds of the second DDTS-SMTS Line tripping. Any delay in separation could have led to further voltage collapse, with a higher risk of blacking out entire systems and damage to transmission equipment.

Separation at T+2.4 seconds arrested this decline in voltage. Merely delaying separation would have delayed creation of the under-frequency that allowed automatic load shedding to stabilise the Victorian network.

A “voltage collapse” scheme that detects declining voltages and initiates local load shedding could be designed. However, it is unlikely to be fast enough and discriminating enough to operate reliably under all conditions and for a wide enough range of possible contingencies. Some means of delaying the rate of voltage decay long enough to allow an under-voltage scheme to operate would therefore be required.

There are a number of emergency control schemes installed in the Victorian transmission network that could be considered as models for a scheme to cover loss of both DDTS-SMTS Lines at high flows. In particular, the Emergency Generation Reduction scheme, which is no longer in service, was implemented when South Australia was first connected to Victoria in 1990. The purpose was to reduce the over-frequency within Victoria that would result after tripping of the two Moorabool to Heywood (MLTS-HYTS) 500 kV Lines and combined loss of more than 1000 MW to the Portland smelter and South Australia. The scheme was designed to detect opening of both MLTS-HYTS 500 kV Lines at time of high flows towards HYTS, and to initiate tripping of a Loy Yang 500 MW generator within an overall time of 300 ms.

A similar scheme could be investigated for DDTS to detect loss of both DDTS-SMTS 330 kV Lines at high import levels and, via high-speed dedicated communications circuits, trip sufficient aluminium smelter potlines or other load to reduce post-contingent flows on the interconnector to levels that could prevent separation.

Summary

The entire network remained in a stable condition following the loss of the first DDTS-SMTS 330kV line. When the second DDTS-SMTS 330kV line tripped, system frequency and system voltages began to show signs of instability. This eventually and inevitably led to separation from NSW and South Australia, rapid frequency decline, and operation of the automatic load shedding scheme to maintain system stability and power supply to the maximum number of customers possible. The entire event, from loss of the second DDTS-SMTS 330 kV line to automatic load shedding until the frequency stabilized, lasted approximately 12 seconds.

The performance of the transmission network protection, control and automatic load shedding schemes prior to, during and following the event was found to be satisfactory and generally in accordance with the design, except for the operation of capacitor banks at Bendigo, Geelong, Dederang and Heywood, and load shedding at Brunswick and Cranbourne.

The time to restore the network and customer load appears satisfactory, but VENCorp noted that established procedures to assist in restoration can improve restoration times for targeted priority loads.

As a consequence of this event, VENCorp would also consider the frequency of actual separation events and their impact on planning criteria; and investigate the viability of control schemes to avoid voltage collapse during contingency events.

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