Security Policy Review: Credible Event Management

Appendix 1 - Identification & Historical Analysis of Credible Events

December 2009

SYSTEM OPERATOR

TRANSPOWER

Keeping the energy flowing

Transpower New Zealand Ltd The National Grid

NOTICE

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1	October 2009	Draft Document
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1 Introduction

1.1 Background

The Policy Statement[1] sets out the policies and means that are considered appropriate for the System Operator to observe in attaining the Principal Performance Obligations[2] (PPOs), subject to the obligation of the System Operator to act as a reasonable and prudent system operator.

The second section in the Security Policy, Credible Event Management[3], identifies events that could occur within the power system that if not appropriately managed could subsequently result in wide spread, or cascade, failure within the power system. The Credible Event Management section anticipates that the System Operator will, identify credible events, assess the likely incidence of the events, the means and cost of mitigating the consequence of events, and subsequently identify how the possibility of such events is to be managed. The events, and identified means of management, contribute to the System Operator's attainment of the PPOs.

The last substantive review of the events included in Credible Event Management occurred in 2003, just prior to inclusion of the Policy Statement in the Electricity Governance Rules (EGRs). In 2007, the System Operator undertook to review credible events, their categorisation and the operational measures to manage events covered under Credible Event Management to ensure the System Operator continues to comply with the Principle Performance Obligations.

1.2 Document Overview

This report identifies credible events and considers the likelihood of the event occurring. A set of credible events is derived from historical data, national and international experience and network analysis. The likelihood of the event occurring and the likely duration of an event is extrapolated from historical data.

[1] Schedule C4 of Part C of the Electricity Governance Rules (EGRs)
[2] Section II of Part C of the EGRs
[3] Formally titled Risk Management Policies

2 Identification of Credible Events

This section reviews the exiting set of credible events listed in the security policy and lists additional events as necessary.

2.1 Credible Events defined within schedule C4, Part C

The system security policy defines the following as credible events.

- Loss of a generating unit;
- Loss of multiple generating units;
- HVDC link valve group and single pole interruptions;
- HVDC link bipole interruptions;
- Single transmission circuit interruptions;
- Simultaneous interruptions of both circuits on a double circuit transmission line;
- Multiple simultaneous transmission line interruptions;
- Busbar interruptions;
- Interconnecting transformer interruptions;
- Connection or disconnection of large load or loads; and
- Interruption of reactive injections, both when provided as ancillary services or when available from transmission assets.

2.2 Revised List of Credible Events

Following a review of international planning and operational standards the following set of possible credible events is derived.

Loss of a single transmission element

- Generator unit
- 220kV or 110kV transmission circuit
- HVDC Pole (valve group, overhead dc line or undersea cable)
- 220kV or 110kV Interconnecting Transformer (and all directly connected elements, i.e reactive devices connected to transformer tertiary)

- 220kV or 110kV busbar section
- 66kV busbar section
- Reactive device (condenser, capacitor, reactor, SVC, RPC)
- Large load / load block

Simultaneous loss of multiple transmission elements

- Any combination of 2 or more single elements listed above
- 1+ Transmission circuits (on the same transmission tower on the same transmission corridor/ common right of way)
- 1+ generator units (generating station)
- 1+ busbar sections (switching station busbar, substation busbar)
- HVDC Bipole (both overhead dc circuits, multiple undersea cables)

3 Classification and Management of Credible Events

3.1 Existing Event Classification

The classification of Credible Events is central to Credible Event Management therefore it follows that a review of the management criteria requires the assessment of the appropriateness of the existing classification system and the assignment of events to each class. Events are classified based on the frequency of occurrence, the likely impact and the measures that can be operationally and economical justified to mitigate the event. The System Operator currently assesses events to be one of the following:

Contingent Events	Events where the impact, probability of occurrence and estimated costs and benefits of mitigation are considered to justify implementing policies that are intended to be incorporated into the scheduling and dispatch processes pre-event.
Extended Contingent Events	Events for which the impact probability, costs and benefits are not considered to justify the controls required to totally avoid demand shedding and maintain the quality limits defined for contingent events.
Stability Events	Severe power system faults that might lead to a defined contingent event, extended contingent event or loss of an interconnecting transformer or busbar section for these faults it is deemed prudent to ensure that the transient and dynamic stability of the power system is maintained.
Other Events	Events which are considered to be uncommon and for which the impact probability of occurrence and estimated cost and benefits do not justify implementing available controls or for which no feasible controls exist or have been identified other than emergency and restoration procedures.

3.2 Event Assignment

The System Operator does not consider all single credible events (as per Part A) to be “contingent events” (Part C4). Part A of the EGRs defines a “single (“N-1”) credible contingency event” as any one of the following:

- a single transmission circuit interruption;

- the failure or removal from operational service of a single generating unit;
- an HVDC link single pole interruption;
- the failure or removal from service of a single busbar section;
- a single interconnecting transformer interruption; or
- the failure or removal from service of a single shunt connected reactive component.

From the above list only the loss of a single transmission circuit, generating unit or HVDC pole are defined as a Contingent Event within the security policy. All of the above events may be considered as a Stability Event.

Clause 12.4 of the security policy assigns events to a particular classification as summarised in Table 3-1.

Table 3-1: Classification of Credible Events

Event Class	**Defined Credible Events**
Contingent Events	Loss of a transmission circuit Loss of a single generating unit Loss of a HVDC pole Loss of both transmission circuits of a double circuit where a high likelihood of event occurrence is determined based on historical information or where the SO is advised of a change to environmental or system conditions
Extended Contingent Events	Loss of the HVDC bipole
Stability Events	A *Contingent Event* An *Extended Contingent Event* Loss of a busbar section Loss of an interconnecting transformer
Other Events	All other credible events

It is worth highlighting that all events classified as Contingent Events and Extended Contingent Events may also be considered as Stability Events.

3.2.1 Loss of a double circuit

The System Operator has identified the following environmental and operational conditions that may create a high likelihood of simultaneous double circuit tripping of both transmission circuits of a double circuit line and will be treated as a contingent event.

Table 3-2: Environmental conditions causing high likelihood of simultaneous double circuit tripping of a double circuit line

Condition	**Caused by**	**Advised by**
Historical	Trippings due to electrical storms or transient events.	SO from historical events
Pollution	Dust, dirt, salt, industrial, birds, smoke, fire.	Asset owner or participant
Weather	Lightning, flooding, wind, conductor clashing.	Asset owner or participant
Natural Disaster	Earthquake, volcanic activity tsunami, storm surge, river erosion, landslides.	Asset owner or participant
Other	Vehicle accident, aircraft vandalism, terrorism, animals, machinery.	Asset owner or participant

3.3 Existing Event Management

The system operator will take measures to meet the PPOs which are to avoid cascade failure arising from frequency and voltage excursions and supply and demand imbalances, maintain frequency within the normal operating band and take reasonable action to maintain other standards (harmonics, flicker and voltage imbalance). It is important to notice that the system operator may not be able to ensure security of supply to all grid exit points following all credible events.

Clause 12.5 defines management measures that may be employed to manage each class of event. The management of event outcomes are determined by the measures defined for the event class, summarised below:

- Contingent Events are managed through the use of pre-contingency measures, provision of reserves, post contingency control measures (demand inter-trips run-back schemes, AUVLS), quality variation measures and industry arrangements.

- Extended Contingent Events may be managed through Automatic Under Frequency Load Shedding (AUFLS) in addition to reserves, post contingency control measures (demand inter-trips run-back schemes, AUVLS), quality variation measures greater than those for contingent events and industry arrangements.

- Management measures for Stability Events are not explicitly defined. The system operator is required to operate within identified transient and/or dynamic stability limits. Management measures may include unplanned post event load shedding, such measures are employed when pre-contingency measures, post contingency control measures, quality variation measures and industry arrangements are insufficient.

- Other Events: Emergency response/demand management and restoration measures relied on for managing these types of event.

3.3.1 Pre-Contingency Measures

There are many types of measures that can be used to mitigate or control event outcomes to maintain a satisfactory operating state. A simple measure is to limit load or constrain generation such that the assets will not be overloaded, cascade failure does not occur and voltages remain within quality targets following an event. This type of measure is referred to as a security constraint and may be in effect at all times on certain parts of the network where post event automatic load shedding or generation runback schemes are not available.

Another measure for managing event outcomes is to voluntarily change the quality targets that apply for a particular event. For example, Transpower can enter into an agreement with a distributor to manage voltages at a particular grid exit point to different targets than set out in Part C of the EGRs. Such an agreement (known as a Wider Voltage Agreement) allows greater operational flexibility during situation such as during planned outages.

Many of the measures available for managing event outcomes are those facilitated through the EGRs, including the provision of ancillary services, minimum asset performance standards, and mandatory obligations to provide load management capabilities. An instantaneous reserves market, procurement of over frequency reserves, and compulsory provision of AUFLS are examples.

3.3.2 Post Contingency Control Measures

Other types of measure include those that only come into effect once the event has occurred. An example is an automated scheme that will manage load (e.g. AUFLS) or control generation (e.g. a generation runback scheme) ensuring that transmission assets remain within safe limits following the occurrence of the event. These types of measures can be automated schemes or manual processes (e.g. the use of off-load times to allow higher pre-contingency loading but requiring re-dispatch of generation within a fixed time following an event to ensure that asset loading is below steady state rating). It should be noted that such schemes must be made operational prior to the event but have no effect until the event occurs.

3.3.3 Application of Load Shedding Measures

It is important to note that the System Operator is required to “plan to avoid ***post-event unplanned demand shedding*** for Contingent Events”. Contracted interruptible load and/or pre-arranged post-event load shedding is therefore allowed in order to maintain quality limits. In the event that pre-arranged load shedding is not available and other post contingency control measures, quality variation measures and industry arrangements are insufficient, pre-event security constraints need to be applied to the dispatch schedule in order to avoid unplanned load shedding.

For Extended Contingent Events in the event that all measures available for contingent event management are insufficient, the use of AUFLS is allowed in order maintain quality limits. AUFLS is a form of planned load shedding.

For Stability Events and Other events unplanned involuntary demand shedding is allowed and is referred to as emergency demand shedding, the system operator primary objective post event is to maintain system stability.

Table 3-3 summarises available load shedding measures and their application to classes of event.

Table 3-3: Summary of Load Shedding Measures and Application

Load Shedding Measure	**Description**					**Application**		
	Planned	Unplanned	Voluntary	Involuntary	Controlled	**Contingent**	**Extended Contingent**	**Stability & Other**
Interruptible Load (IL) Demand Inter-trips Automatic Under Voltage Load Shedding (AUVLS)	✓		✓		✓	✓	✓	✓
Automatic Under Frequency Load Shedding (AUFLS)	✓			✓	✓	∗	✓	✓
Demand Reduction (via DAN) Emergency Demand Shedding		✓		✓	✓		∗	✓

∗ If insufficient reserves to cover a CE event, zero the RAFs and rely on AUFLS for post CE management

∗ If insufficient reserves to cover a CE and ECE event, zero the RAFs and rely on demand reduction for post ECE management

3.4 Summary of Existing Event Classification & Management

The existing event classification system and available post-event measures for managing events is summarised in Table 3-4.

Table 3-4: Summary of Existing Credible Event Classification and Post-Event Management

SO Classification	Credible Events	Post-Event Measures
a) Contingent Event	Loss of a single: • Transmission circuit • Generator unit • HVDC Pole **Loss of a 2 transmission circuits on the same tower (when a change to environmental or operating conditions indicate there is a high likelihood of occurrence)	24 hour post-contingency ratings or 15 minute off-load ratings Under-frequency reserve & over-frequency reserve Automatic control measures or Special Protection Schemes : • Inter-trips, overload protection • Automatic Undervoltage Load Shedding (AUVLS) • Generation runback • Switching of reactive devices
b) Extended Contingent Event	HVDC bipole (both overhead dc circuits)	Measures for event class a) may be employed in addition to: Automatic under frequency load shedding (AUFLS)
c) Stability Event	Loss of a: • Transmission circuit • Generator unit • HVDC Pole • HVDC Bipole • Interconnecting Transformer • Busbar section	Measures for event class a) and b) may be employed in addition to: Manual grid re-configuration Black start generation Unplanned load shedding / demand management: • Demand Reduction (via DAN) • Emergency Demand Shedding
d) Other	Other single events not listed above. Simultaneous loss of multiple transmission elements or loss of multiple elements in close succession.	All of the above measures may be employed. Emergency demand shedding and restoration.

4 Review of Historical Data

4.1 Introduction

This section provides historic information regarding the failures or forced outages of assets connected to or forming part of the grid. Analysis of the frequency of the events determines the likelihood of a credible event occurring.

The likelihood of the event occurring together with relative event consequences and mitigation measures is the basis upon which the suitability of the existing event classification methodology is assessed and alternative means of classification investigated.

This section assesses the likelihood of a credible event occurring. Later chapters will summarise event consequences and examine existing and alternative means to manage the events.

4.2 Historical Event Data Set

Asset failure information over the period 2004 to 2008 is assessed to determine the average likelihood of a credible event occurring. Event information is sourced from a manual disturbance log managed by the System Operator and cross referenced against a grid owner outage database to confirm the cause of the event, the elements affected and the event duration associated with the affected transmission element(s).

The likelihood and duration of the following credible contingent events are assessed based on historical data recorded during the period 2004 – 2008.

Loss of a:

- Generator unit;
- HVDC pole(s);
- Transmission line;
- Busbar section;
- Transformer;
- Reactive device.

An average number of events per year for each of the above elements will be calculated from the 5 year data sample, whilst observing the maximum and minimum number of events in any one year. Reference will be made to statistical analyses undertaken in 2002 [2] (based on 10 year data 1990 to 1999) to assess whether the outage rates considered for this review are reasonable.

Circumstances may lead to an increased number of outages in a particular year. The likelihood of an event may be increased by the following issues:

- age and reliability issues associated with a particular power system component;
- periods of major construction; and

- long term planned outages and commissioning activities.

Higher than average number of events in a particular year will be noted and where possible causes for the increased number of events will be given.

The number of events recorded over the 5 year period may be used to infer likelihood of occurrence over the immediate to short term (1-2 years) but should not be used to determine future long term trends. An increase in the number of events in the last 2 or 3 years of a 5 year data set may indicate a recent short-term issue that requires comment but such data should not be used to infer that the number of events will continue to rise over the next 5 years.

Network upgrades or equipment maintenance and replacement programs designed to address unreliable or aging assets may mitigate the risk of future events. It is also possible that a period of major commissioning or asset replacement program may be the factor that led to the increased number of outages in a particular year. It would not be correct to base a “trend” on the events recorded for such a year. A result of an intensive 2 year commissioning program over which increased outage rates were observed might result in below average outages for future years due to the introduction of the new plant.

4.3 Generator Events

The manual disturbance log serves as a record of generator unit trippings and occasions when generator units were unable to meet an agreed dispatch level. The System Operator can not guarantee that all trippings associated with smaller units are recorded. Therefore it should not be assumed that all generator trippings have been captured in the generator disturbance record. Recorded event data includes a number of multiple generator losses. These events are made up of:

- Multiple smaller machines connected to the grid via a single transformer or transmission circuit;
- Multiple unit interruptions; and
- Complete station interruptions.

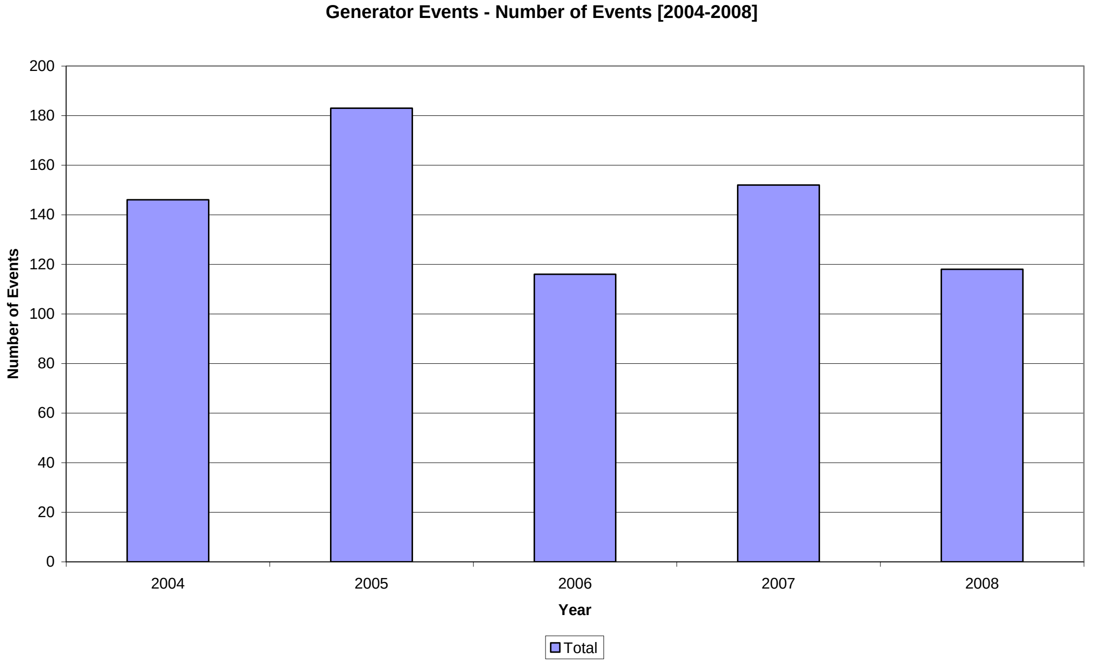
Examples of generator events logged in disturbance records are given below:

> [*Generator unit*] appeared to trip ~40MW. Not logged but trend data indicates generation drop & BF claimed at 08:44.
>
> [*Generator unit*] & [*Generator unit*], tripped, ~xxMW lost.
>
> [*Station Generation*] dropped from ~95MW to 0MW, [*Generator unit*] & [*Generator unit*] tripped, [*Generator unit*] appeared to ramp to 0MW.

<u>key</u> BF = bona fide. Generators claim “bona fide” when unable to reach their dispatch point for some reason.

The number of recorded generator events over the 5 year sample period is illustrated in Figure 4-1. The breakdown of events by generator fuel type or technology is given in Table 4-1 and compared against average values reported in the 2002 document "*The Statistical Basis for the Security Policy: Companion paper to the CQC Security Policy*" [2]. The annual outage rate associated with the loss of power (MW) output from a generator unit or units is calculated as 143. This is similar to the value of 144 reported in 2002

Figure 4-1 Recorded Generator Events [2004-2008]



The loss of hydro generation units accounts for approximately 30% of the generator events recorded. Considering that up to 60% of total generation capacity is hydro generation it is not surprising that there should be more events associated with this type of generator. Over the last 10 years New Zealand generation capacity has become more diversified hence the change in number of events associated with each generator type. Notably, events associated with geothermal generation units has increased whilst the number of events associated with hydrothermal units has decreased.

The majority of events recorded (over 90% of events) are due to loss of a single generator unit that are not followed by a "bona fide" claim. Further analysis of generator events can be found in Appendix 1-1. The average number of events involving more than one generator unit is approximately 11 per year, an increase in the number of events involving multiple generator units is observed over the five year period, see figures in Table 4-2.

Statistical analysis in 2002 identified 52 events associated with CCGT and thermal plant and used this as an indicative measure of the number of large generation interruptions. This review finds the average number of events associated with Thermal and CCGT plant to be 50. As an additional performance measure this review has calculated the average number of events that resulted in a loss of generation above 100MW. The number of events associated with generation above 100MW is summarised in Table 4-2.

Table 4-1: Frequency of generator unit interruptions - Generator Type 2004 – 2008

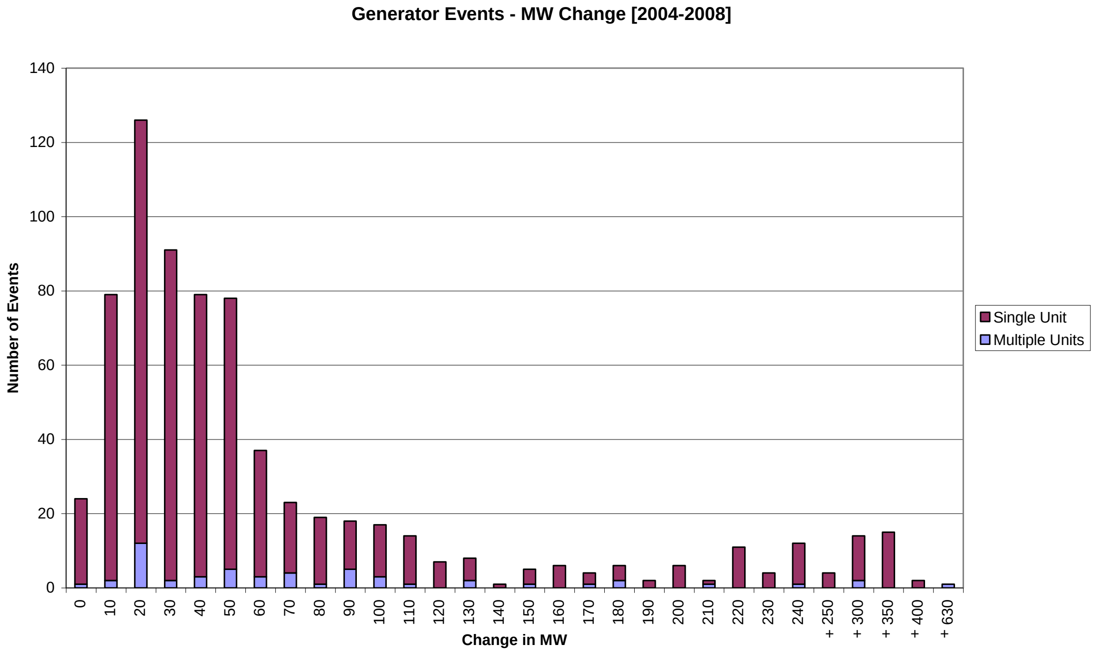
Year	**Generator Fuel/Technology Type**									**TOTAL**
	Hydro	Geothermal	CCGT (HLYU5, SPL, OTC SWN)	Thermal	Cogen	Diesel (WHI)	Wind	Embedded	Multiple gens of different fuel type	
2004	50	27	15	16	26	9	1	2	0	146
2005	43	40	35	29	31	1	2	0	2	183
2006	40	22	15	28	8	0	1	2	0	116
2007	42	38	37	27	7	0	1	0	0	152
2008	41	21	28	18	6	1	3	0	0	118
Average [2004-2008]	**43.2**	**29.6**	**27.8**	**21.8**	**15.6**	**2.2**	**1.6**	**0.8**	**0.4**	**143**
Average [1995/96-1999/00]	60	16	29	23	11	5	-	-	-	144

Table 4-2: Frequency of generator unit interruptions – change in MW 2004 – 2008

	Summary of annual generator interruptions						
	Change in MW <100MW			**Change in MW >100MW**			
Year	Sgl Gen	Mpl Gen	Total	Sgl Gen	Mpl Gen	Total	**TOTAL**
2004	123	1	124	22	0	22	146
2005	151	7	158	23	2	25	183
2006	79	8	87	29	0	29	116
2007	109	9	118	28	6	34	152
2008	78	14	92	20	6	26	118
Average	108.0	7.8	**115.8**	24.4	2.8	**27.2**	**143**

The spread of MW output change for all events recorded over the five year period is illustrated in Figure 4-2.

Figure 4-2 Recorded Generator Events – Change in MW output [2004-2008]



The average load (MW) loss associated with a generator event is approximately 70MW. Analysis shows that approximately 20% of generator events will result in a loss of generation greater than 100MW, this corresponds to an average rate of 27 events per year. Approximately 10% of generator events will result in a loss of generation greater than 200MW, this corresponds to an average rate of 14 events per year.

One of the Principle Performance Obligations (PPOs) of the System Operator is to ensure that the number of frequency excursions outside defined frequency bands does not exceed the permissible maximum rate of occurrence. Table 4-3 shows the number of occasions that system frequency moved outside the normal frequency band following a loss of generation. On average there are 17 events a year that lead to system frequency moving outside the normal frequency band. Historical data indicates that the existing mitigation measures ensure the momentary frequency interruption performance obligation is met for the loss of a generator unit.

Table 4-3: Number of Occasions System Frequency moved outside normal frequency band following the loss of a generator unit 2004 – 2008 [rule 2.2.3 and 3.2.2 Part C Section II]

Frequency Band (Hz)	Annual Number of Frequency Excursions					Maximum rate of occurrence [*rule 2.2.3 & 3.2.2].*
	2004	**2005**	**2006**	**2007**	**2008**	
55>x≥53.75 **						1 (5 year period)
53.75>x≥52 **						2 (1 year period)
52>x≥51.2						7 (1 year period)
51.25>x≥50.5			2			50 (1 year period)
Normal Frequency Band						
49.5≥x>48.75	10	17	16	22	13	60 (1 year period)
48.75≥x>48		1		2		6 (1 year period)
48≥x>47						1 (5 year period)
47≥x>45 **						1 (5 year period)

**** Additional South Island frequency bands highlighted in blue**

4.3.1 Loss of a single generator unit

The loss of a generating unit is considered to be a potentially large frequently occurring injection interruption. The System Operator procures fast responding reserves of generation and contracted interruptible demand to re-establish a balance between the generation injection and demand and mitigate the under-frequency event that occurs following the loss of a single generator unit. The reserves secured for the loss of a single generator unit will ensure that system frequency remains above 48Hz. If no generation reserves were provided any significant interruption of generation would result in a rapid and continuing fall in frequency. The availability of reserves to mitigate the loss of the largest generating unit on the north and south islands serves to mitigate the impact of all other smaller generation interruptions.

4.3.2 Loss of multiple generator units

The current security policy considers multiple machines on a single transmission circuit as a single machine for risk assessment purposes. Otherwise the loss of a complete station is not at present explicitly mitigated by the security policy on the grounds that it is a statistically less common event.

It is often the case that the total output of a power station is less than the largest single generation unit injection. Hence the risk of a station interruption is inadvertently covered by the security policy to provide reserves to manage the single largest generating unit risk. With the development of larger generating stations the System Operator has considered the likelihood and consequence of the loss of multiple generator units to determine whether it is necessary to consider a specific policy to mitigate the risk of this type of event. Historical data indicates that multiple generator outages occur on average 11 times a year, with on average three events resulting in a loss of generation of more than 100MW.

During the five year sample period there were three multiple generator unit events that resulted in the loss of a combined MW output greater than the largest generating unit on the system. In all three cases due to the sequential loss rather than simultaneous loss of units the instantaneous reserve procured for the loss of the largest generating unit was sufficient to arrest the fall in frequency and maintain system frequency above 48Hz.

Table 4-4: Multiple generator unit events resulting in System Frequency below 48.75Hz

Year	Station Units	MW Change	Frequency	
2005	HLYU1 & SPL	241	NI: 48.03 Hz	SI: 49.37 Hz
2007	BEN U1-5	326	NI: 49.43 Hz	SI: 48.6 Hz
2007	HLYU5 & SPL	631	NI: 48.26 Hz	SI: 49.45 Hz

The System Operator concludes that the low probability of occurrence of the loss of multiple generator units and the resultant MW change indicates no justification for procuring additional reserve to mitigate against the loss of multiple generator units or a power station.

4.4 HVDC Events

The HVDC link comprises of many elements, each component has a risk of failure and the element that fails will determine the consequence of the event. The transfer capacity of the link and the manner in which the link is being operated at the time of the event will also affect the consequence of the HVDC event.

Prior to 2008 the link operated as two poles, as shown in Figure 4-3. Pole 1 comprised of two half poles each with an associated valve group and Pole 2. The bipole arrangement makes use of 3 submarine cables each with a rating of 500MW and a transmission line. The HVDC transmission line conductors have a capability of 700MW per pole or 1400MW bipole operation.

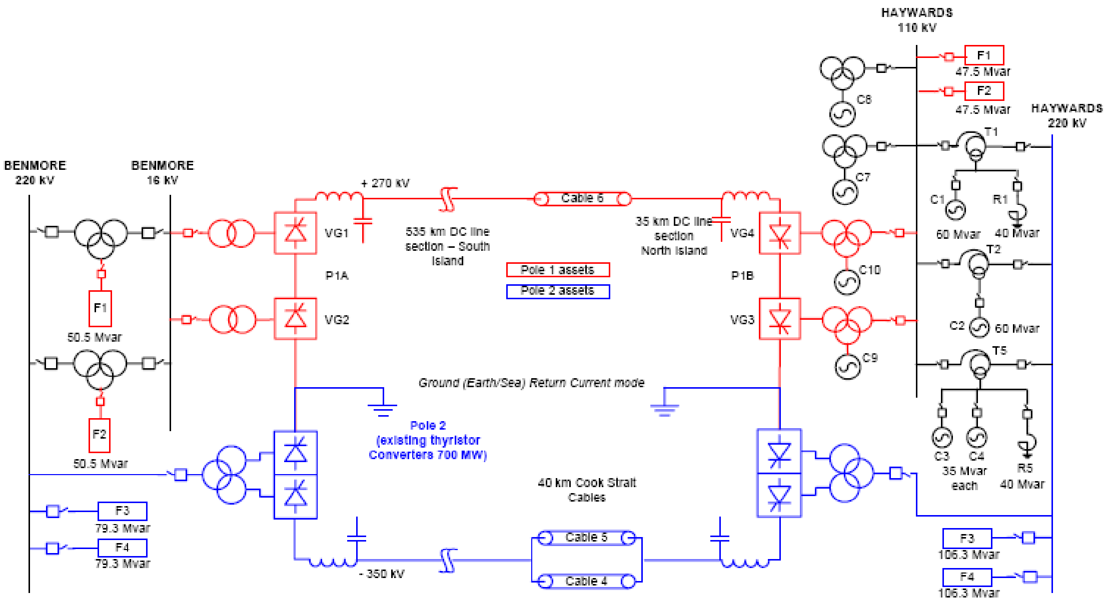


Figure 4-3 Simplified NZ inter-island HVDC transmission link

At the start of 2008 the operation of pole 1 changed significantly, with half of pole 1 permanently out of service. The remaining half of pole 1 is made available for limited operation under critical situations where the System Operator declares a grid emergency indicating that the power system is critically constrained due to high demand for electricity and/or there is insufficient generation in the North Island. If the half pole is required to run it will only be in service for a limited number of hours each day for a period of 15 to 20 days. Power flow will be restricted to south to north flow in order to reduce the risk of arc backs on the mercury arc converters.

When both poles were in service, pole 2 typically transferred of 475MW of power, following the decommissioning of half of pole 1, the maximum pole 2 transfer capacity of 700MW can be utilised. Note that although the maximum possible transfer capacity is 700MW the normal link capacity will be dependent on the reserve cover available in the system at the time of dispatch and this will significantly reduce the practical transfer limit at most times.

The project to replace pole 1 is called the New Zealand Inter Island HVDC Pole 3 Project (abbreviated to P3 Project). The new thyristor converter based HVDC converter pole will have a nominal power rating of 700MW.

With a 700MW converter and with the three existing cables, it is possible to operate the link as a balanced 500/500MW bipole or as an unbalanced bipole with 700/500MW (on Pole 3/Pole 2). This provides a convenient way to stage a capacity increase from a 1000MW link (Stage 1) to 1200MW link (Stage 2). The indicative commissioning date of stage 1 is 2012, stage 2 2014.

This review does not consider the risk to system security during the commissioning of Pole 3. The risk associated with the HVDC link will be considered when assessing and formulating a commissioning plan for Pole 3.

The existing and planned HVDC converter systems and their associated transfer capability are summarised in Table 4-5.

Table 4-5: HVDC MW capacity 2004 – 2012

Year	Half Pole 1 (valve group)	Pole 1 (two valve groups)	Pole 2	Pole 3	Bipole / Total
2004 – 2007	244.5	244.5	475		964
2008 – 2012	130-200 under grid emergency conditions		700 ***		700
2012 -2014			500	500	1000
2014			500	700	1200

Notes

*** Although the maximum possible transfer capacity is 700MW the normal link capacity will be dependent on the reserve cover available in the system at the time of dispatch

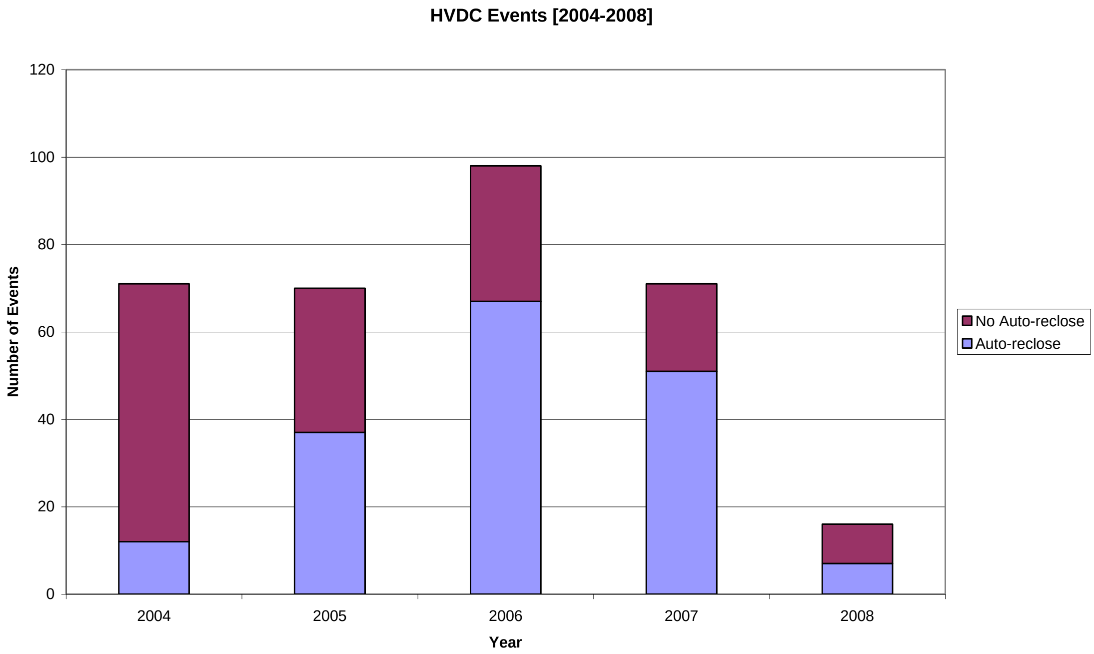
In a bipole arrangement the remaining pole provides some self cover for the failure of one pole. This could be partial or full load cover depending on the pre-fault power flow of the remaining pole. However there is no self cover possible in a monopolar operation with only HVDC pole 2 available for service. A planned or unplanned outage under monopolar operation will decouple the two islands and the two markets reducing the generation available to both islands and introducing a price separation.

Table 4-6 shows the annual number of HVDC interruptions recorded over a five year period.

Table 4-6: Frequency of HVDC interruptions 2004 – 2008

Year	Summary of annual HVDC interruptions		
	With auto-reclose	**Without auto-reclose**	**TOTAL**
2004	12	59	71
2005	37	33	70
2006	67	31	98
2007	51	20	71
2008	7	9	16
Average	**34.8**	**30.4**	**65.2**

Figure 4-4 Recorded HVDC Events – with and without auto-reclose action [2004-2008]



The average number of HVDC events reported in the 2002 document "*The Statistical Basis for the Security Policy: Companion paper to the CQC Security Policy*" [2] does not refer to auto-reclose action hence it is assumed that the events reported pertain to those that are not resolved via auto-reclose.

The outage rate associated with the permanent loss of HVDC transfer is found to be approximately 30 per year. The breakdown of HVDC element failures that caused the HVDC interruption are given in Table 4-7 and compared against the values reported in the previous 2002 statistical report. The average number of single and multiple pole events are lower than those indicated in the previous 2002 analysis. Further analysis of HVDC events can be found in Appendix 1-2.

Table 4-7: Frequency of HVDC interruptions (A/R excluded) 2004 – 2008

Year	**Half Pole 1 (valve group)**	**Pole 1 (2 valve groups)**	**Pole 2**	**Multiple***	**Other****	**Bipole**	**Total**
2004	31	12	6	4	5	1	59
2005	22	5	3	2	1	0	33
2006	25	3	0	1	2	0	31
2007	16	1	1	0	2	0	20
2008	6	0	3	0	0	0	9
Average [2004-08]	**20**	**4.2**	**2.6**	**1.4**	**2.0**	**0.2**	**30.4**
Average [1992-99]	37	8	8	-	-	1	51

Notes:
*Multiple Events include: 1) the loss of pole 2 and the loss of half of pole 1. 2) The loss of half of pole 1 and the loss of a condenser.
**Other Events include the loss of a condenser or filter bank, a line fault or a MCB fault.

Figure 4-5 Recorded HVDC Events –without auto-reclose action [2004-2008]

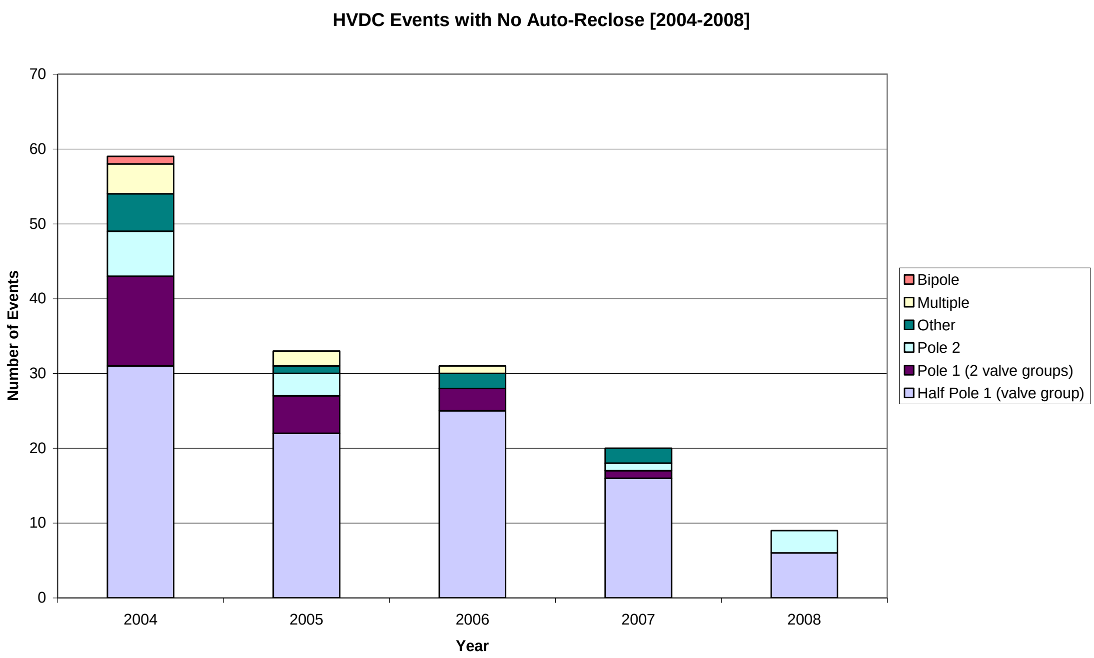


Table 4-8 shows the number of occasions that system frequency moved outside the normal frequency band following a HVDC event. On average there are 5 events a year that lead to system frequency moving outside the normal frequency band. The two occasions in 2005 that led to frequency dropping below 48.75 Hz are summarised in Table 4-9. Further information regarding the HVDC events summarised in Table 4-8 can be found in Appendix 1-2.

Table 4-8: Number of Occasions System Frequency moved outside normal frequency band following the loss HVDC pole(s) 2004 – 2008 [rule 2.2.3 and 3.2.2 Part C Section II]

Frequency Band (Hz)	**Annual Number of Frequency Excursions**					**Maximum rate of occurrence** [*rule 2.2.3 & 3.2.2].*
	2004	**2005**	**2006**	**2007**	**2008**	
55>x≥53.75 **						1 (5 year period)
53.75>x≥52 **						2 (1 year period)
52>x≥51.2	2	3			1	7 (1 year period)
51.25>x≥50.5	2	3	1		2	50 (1 year period)
Normal Frequency Band						
49.5≥x>48.75	3	3	1	2	2	60 (1 year period)
48.75≥x>48		1				6 (1 year period)
48≥x>47		1				1 (5 year period)
47≥x>45 **						1 (5 year period)

**** Additional South Island frequency bands highlighted in blue**

Table 4-9: HVDC events resulting in System Frequency below 48.75Hz

Year	**HVDC Poles**	**Details**	**Frequency**
2005	Half Pole 1 & Pole 2	North Transfer Lost. Fire under line.	NI: 49.18 Hz SI: 51.42 Hz NI: 48.71 Hz SI: 51.49 Hz
2005	Pole 2	South Transfer Lost. Zero crossing errors	NI: 50.45 Hz SI: 47.98 Hz

4.4.1 Single pole interruptions

The average number of value group and pole interruptions for the years 2004-2008 is 29 per year. This rate is similar to that associated with the loss of generation greater than 100MW (27 events per year). The magnitude of interrupted injection into the North Island associated with the loss of a half pole or single pole when both poles were in operation would typically range between 200MW and 400MW making the loss of injection on a par with a large single generating unit. The frequency of occurrence and magnitude of MW injection supports the current approach to consider the loss of a single pole as a Contingent Event. Since 2008 and the restricted operation of Pole 1, Pole 2 is being used as the only link between the north and south island. In accordance with the security policy, the loss of pole 2 is being considered as a Contingent Event.

The modified HVDC operational status means that HVDC Pole 2 is typically operating at maximum transfer capability as necessary and is often the largest single contingent event risk. The System Operator is currently procuring reserve to cover the single contingent risk of the loss of Pole 2. Due to limited availability of generation reserve, HVDC transfer is restricted to the amount of reserve available in order to ensure that emergency Automatic Under-Frequency Load Shedding does not occur following the loss of Pole 2.

The review of the classification of the loss of Pole 2 as a contingent event and the arrangement to procure reserves to cover the loss of the largest contingent event risk is not subject of this review.

4.4.2 Bipole interruptions

Bipole interruptions are significantly less frequent than valve group and pole interruption options. As a result bipole interruption is regarded as an Extended Contingent Event. Reserves provided to mitigate contingent events are expected to only partially mitigate the Extended Contingent Event. It will normally be necessary to rely on Automatic Under-Frequency Load Shedding (AUFLS) to avoid a cascade failure. Previous statistical analysis undertaken in 2002 indicated that emergency automatic under-frequency load shedding caused by HVDC bipole events could be expected no more than once every two years. The 2002 report indicated that AUFLS due to bipole interruptions may be significantly less for two reasons;

- The HVDC bipole will often be operating at much less than full capacity and will not represent a risk greater than the largest contingent event risk

- The existence of significant additional generation reserves, which have not been offered into the reserves market, have provided a significant buffer, reducing the likelihood of Automatic Under-Frequency Load Shedding for bipole HVDC interruptions.

Historical data over the past 5 years indicates the loss of the bipole occurring on one occasion in 2004. The loss of pole 2 together with half of pole 1 occurred on two occasions in 2005. These events did not result in an under frequency event or the action of AUFLS.

The loss of both poles is a low probability event, historical data indicates that the existing mitigation measures of relying on Automatic Under-Frequency Load Shedding is appropriate for the loss of the bipole.

4.5 Transmission Line Events

Table 4-10 shows the number of 220kV, 110kV, 66kV and 50kV circuit interruptions that have occurred over the period 2004-2008. The table indicates the number of single circuit and multiple circuit events over the five year period. Approximately 90% of all transmission circuit interruptions are single circuit outages.

Table 4-10: Frequency of Transmission circuit interruptions 2004 – 2008

Year	**Summary of annual transmission circuit interruptions**				
	Single Circuit	**Double Circuit**	**Multiple – 3 Circuits**	**Multiple – 4 Circuits**	**TOTAL**
2004	215	15	1	0	231
2005	233	17	2	2	254
2006	240	26	3	1	270
2007	214	21	1	1	237
2008	299	16	3	0	318
Average	**240.2**	**19.0**	**2.0**	**0.8**	**262**

The analysis of historical transmission circuit outages in this section will focus on 220kV circuits. The previous 2002 statistical study considered 220kV circuit interruptions to determine event classification.

Most 220kV circuits have auto-reclose facilities to activate auto-reclose following a fault. A successful auto-reclose will normally avoid noticeable impact on service other than a voltage flicker. A permanent fault occurs when an auto-reclose fails resulting in a disconnection that requires remote switching or maintenance attention to return the circuit to service. Table 4-11 indicates the number of 220kV transmission circuit events that resulted in successful auto-reclosure and those that were permanent circuit faults. The data shows that on average over 60% of 220kV circuit outages resulted in successful auto-reclosure. An average of 26 circuit interruptions occur annually with unsuccessful re-closure with approximately 1 or 2 of these affecting more than one circuit. These figures compare well with the average of 24 events per year calculated in the previous 2002 statistical assessment. It is worth commenting that in 2006 the number of 220kV circuit interruptions was above average due to a severe snow fall on the south island.

Further information regarding 220kV transmission circuit events can be found in Appendix 1-3.

Table 4-11: Frequency of 220kV Transmission circuit interruptions 2004 – 2008

Year	**Summary of annual 220kV transmission circuit interruptions**								
	Single Circuit		**Double Circuit ***		**Multiple Circuit**		**TOTAL**		
	A/R	No A/R	A/R *	No A/R	A/R	No A/R	A/R	No A/R	Sum
2004	40	18	8	0	0	0	48	18	66
2005	50	31	4	1	0	0	54	32	86
2006	47	41	4	4	0	0	51	45	96
2007	29	22	6	2	1	0	36	24	60
2008	44	12	6	0	0	0	50	12	62
Total	210	124	28	7	1	0	239	131	370
Average [2004-08]	42	24.8	5.6	1.4	0.2	0	**47.8**	**26.2**	**74**
Average [1990-99]	32	22	6	2	1	0	**39**	**24**	**63**

Notes: A/R = Auto Reclose
* For double circuit faults A/R = re-closure of one or both circuits following the event. For double circuit faults No A/R = both circuits fail to reclose (unsuccessful re-closure)

Figure 4-6 Recorded 220kV Transmission Events –with and without auto-reclose action [2004-2008]

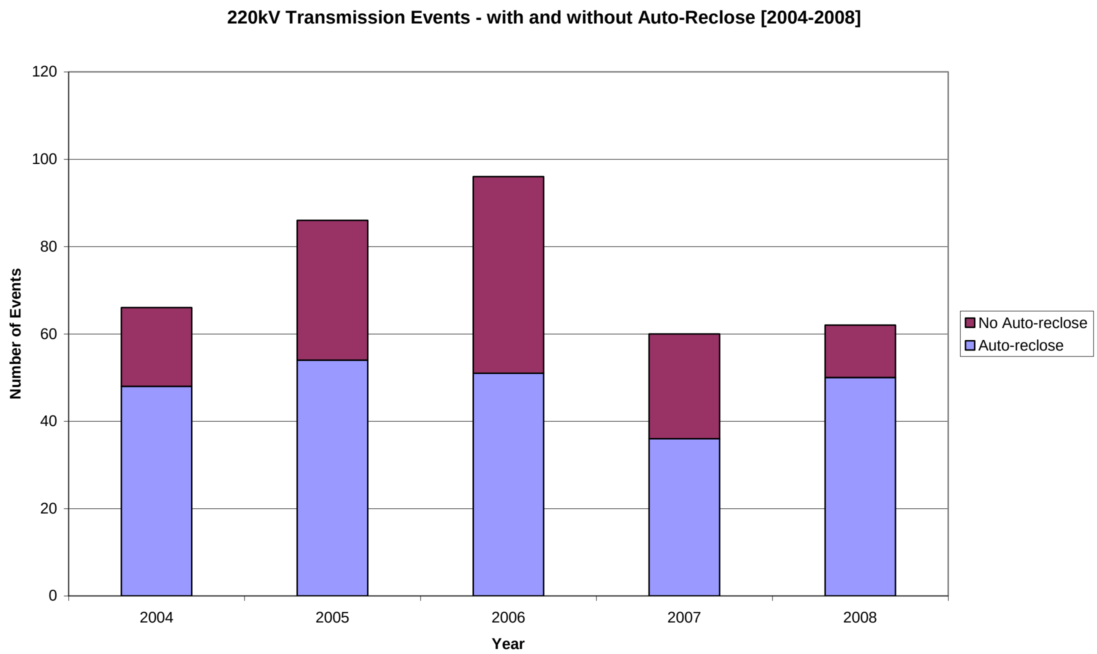


Figure 4-7 Recorded 220kV Transmission Events –without auto-reclose action- Single and Double Circuit Outages [2004-2008]

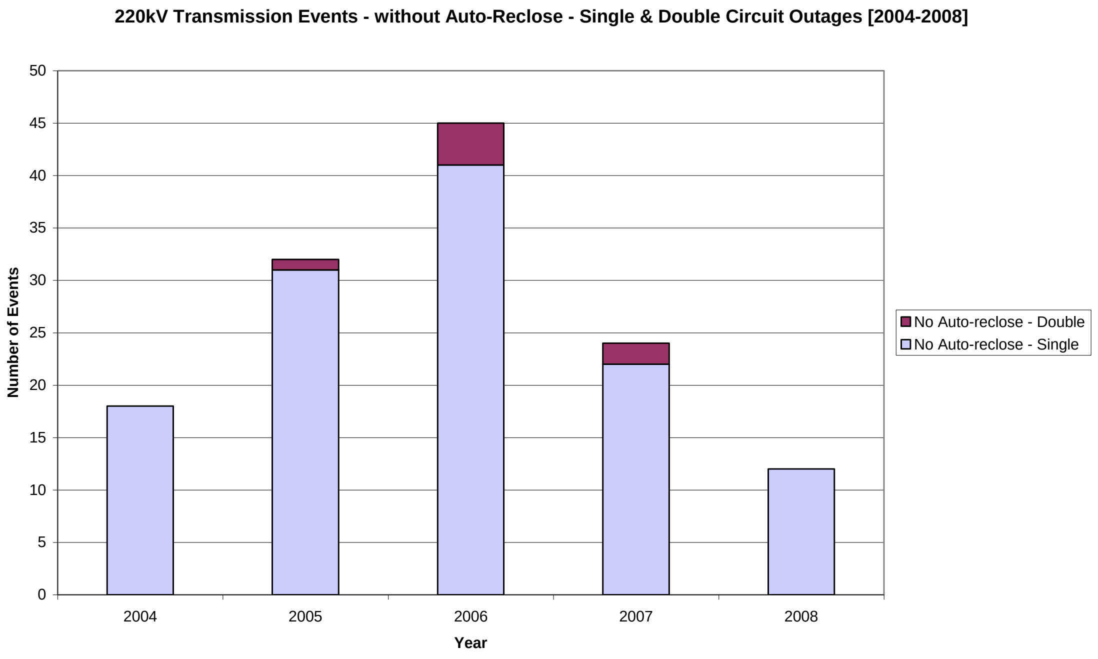
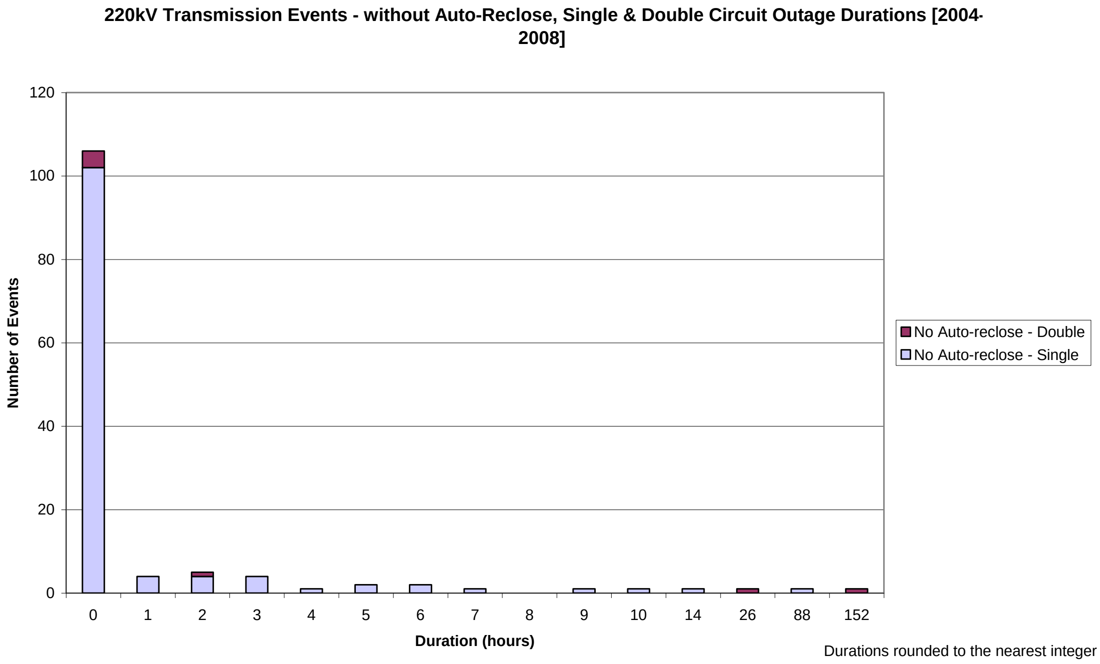


Figure 4-8 Recorded 220kV Transmission Events –without auto-reclose action- Single and Double Circuit Outage Durations [2004-2008]



Three 220kV transmission circuit events resulted in an outage for more than 24 hours, details of the events are summarised in Table 4-12.

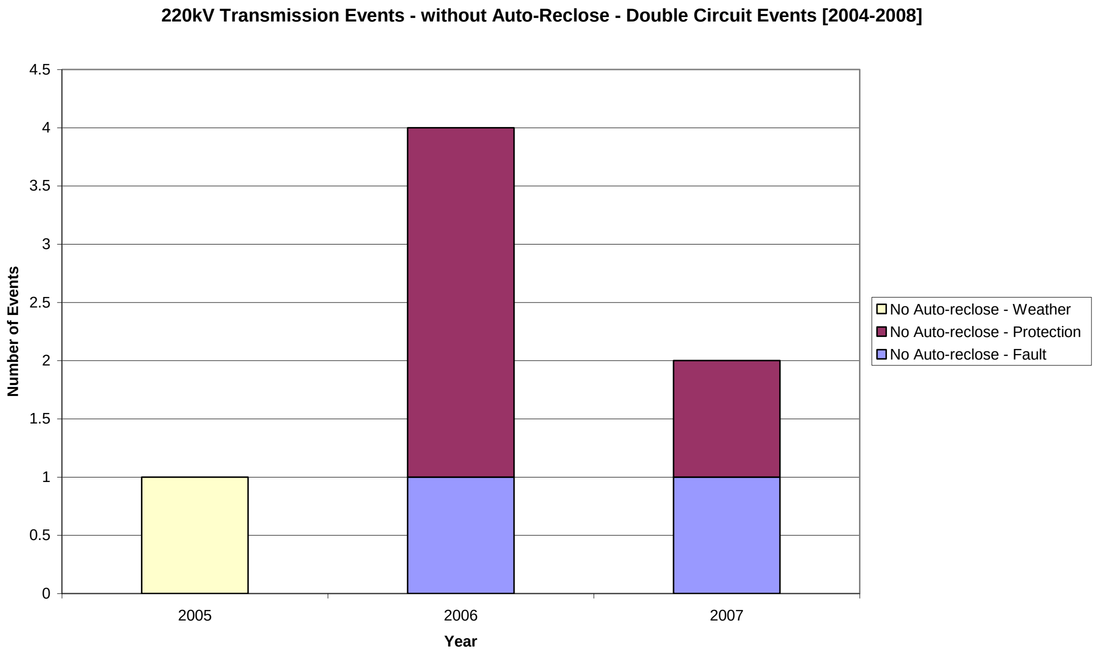
Table 4-12: 220kV Transmission Circuit events with outage times greater than 24 hours

Date	**220kV Circuit**	**Duration (hrs)**	**Description**
25-Mar-05	EDG-TRK 1 & 2 (and EDG-OWH 110kV)	152	EDG-OWH and EDG-TRK 1 & 2 tripped, A/R, and tripped, ~170MW lost from KAW & ~20MW lost from KIN due to voltage disturbance. EDG-TRK 1 & 2 tripped on attempted re-close. EDG-TRK 1 & 2 towers 50 & 51 down. EDG-OWH tripped on attempted re-close, three poles (478-480) down. Two tornados passed through the BoP at this time, these were responsible for tower collapse.
17-May-05	BPE-HAY 1	88	BPE-HAY 1 tripped, A/R, and tripped again. Tripped again on attempted re-livening @ 02:34. Conductor on the ground near Levin. RTS 18:42 on 20/05.
15-Oct-07	OHA-TWZ 1& 2	26	OHA_TWZ 2 & OHA 402 (OHA_TWZ 1) tripped on close of OHA 702 after planned work, LOS to OHA (~105MW gen). OHA 402 RTS @ 18:12. OHA_TWZ 2 RTS @ 17:35 on 16/10.

During the five year sample period there was one event that resulted in the loss of a single 220kV circuit for more than 24 hours. There two occasions when a double circuit was lost, one following severe weather conditions that resulted in the loss of double circuit towers and another following a planned maintenance period.

Of the seven double circuit faults with failed auto-reclose, two were genuine faults that affected both circuits, one was due to severe weather (the EDG-TRK event described in Table 4-12) and four were associated with protection problems. The breakdown of double circuit events is illustrated in Figure 4-9.

Figure 4-9 Recorded 220kV Transmission Events –without auto-reclose action- Double Circuit Outages [2004-2008]



4.5.1 220kV single circuit interruptions

The security policy regards single circuit interruptions as Contingent Events for which the System Operator needs to have measures in place to avoid unplanned load shedding. Post-contingency measures aim to modify network power flows, so that transmission circuits operating at short term ratings are returned to within continuous ratings. For Contingent Events measures may be taken pre-event to ensure that transmission circuits will not exceed short term ratings. Measures may include the application of security constraints or the enabling of automatic Special Protection Schemes. Security Constraints are applied with the consideration of allowable post-contingency short term ratings. Special Protection Schemes may involve overload protection and automatic load shedding action.

Based on historical data there are on average 25 single circuit 220kV interruptions per year that do not successfully auto-reclose. Analysis of the outage durations associated with the single circuit events over the five year period indicate one occasion where a single circuit was out of service for more than 24 hours. The event affected Bunnythorpe-Haywards circuit 1, this circuit is a core grid asset therefore supply to grid exit points (GXPs) would not have been affected following this event. Security Constraints are in place to manage the loss of Bunnythorpe-Haywards circuit 1 (BPE-HAY-1) during HVDC south transfer. To manage the event that the BPE-HAY-1 circuit is lost, power transfer into the Wellington region during HVDC south transfer is limited to approximately 920MW.

4.5.2 220kV double circuit interruptions

The current policy is not to regard double circuit interruptions as a Contingent Event, unless a particular line has a history of double circuit faults, or the System Operator is advised of a temporary change to environmental or system conditions that indicates a high likelihood of occurrence of the simultaneous loss of both circuits.

At present there is no historical data to identify any 220kV circuits that should be considered as a Contingent Event under normal operating conditions. Some double circuits are susceptible to conductor clashing during bad weather in such cases auto-reclose action generally re-instates the circuit(s) affected. Over the five year period there have been 35 double circuit line interruptions, of which 28 (80%) auto-reclosed successfully.

For sparsely connected parts of the network with little generation, it may not be possible to mitigate a simultaneous double circuit tripping to avoid interruption of demand. For more heavily interconnected parts of the network it may be possible to avoid demand interruption for an interruption of a double circuit due to light loading of the transmission line at the time of the event and/or as a result of constraining dispatch to achieve such light loadings. However to constrain dispatch at all times in order to avoid demand shedding for double circuit faults would be very high costly in order to avoid an infrequent event.

The historical data provides no grounds to initiate event reclassification or a review of the measures employed to manage the loss of two 220kV circuits or both circuits on a double circuit line. The classification of a double circuit interruption as either a “stability event” or “other event” under normal conditions should be clarified.

4.5.3 220kV multiple circuit interruptions (except double circuit line trips)

In many cases multiple circuit interruptions occur as the result of other causes, particularly busbar faults which will disconnect a number of circuits, but it is possible that weather conditions can cause multiple transmission circuit interruptions and for some of these to occur concurrently. Typically this would be the result of a lightning storm.

During the five year sample period one event affecting multiple 220kV circuits was reported, auto-reclosure action successfully restored the circuits to service.

The current policy is not to regard multiple circuit interruptions as a Contingent Event, following such an event the system operator takes necessary measures to maintain system stability. The historical data provides no grounds to initiate event reclassification or a review the existing management measures. The classification of a multiple circuit interruption as either a “stability event” or “other event” under normal conditions should be clarified.

4.6 Busbar Section Events

Figure 4-10 illustrates the number of 220kV, 110kV, 66kV, 50kV and 33kV busbar section interruptions that have occurred over the period 2004-2008. Table 4-13 summarises the average number of events per year.

Figure 4-10 Recorded Busbar Section Events - 220kV, 110kV, 66kV, 50kV and 33kV [2004-08]

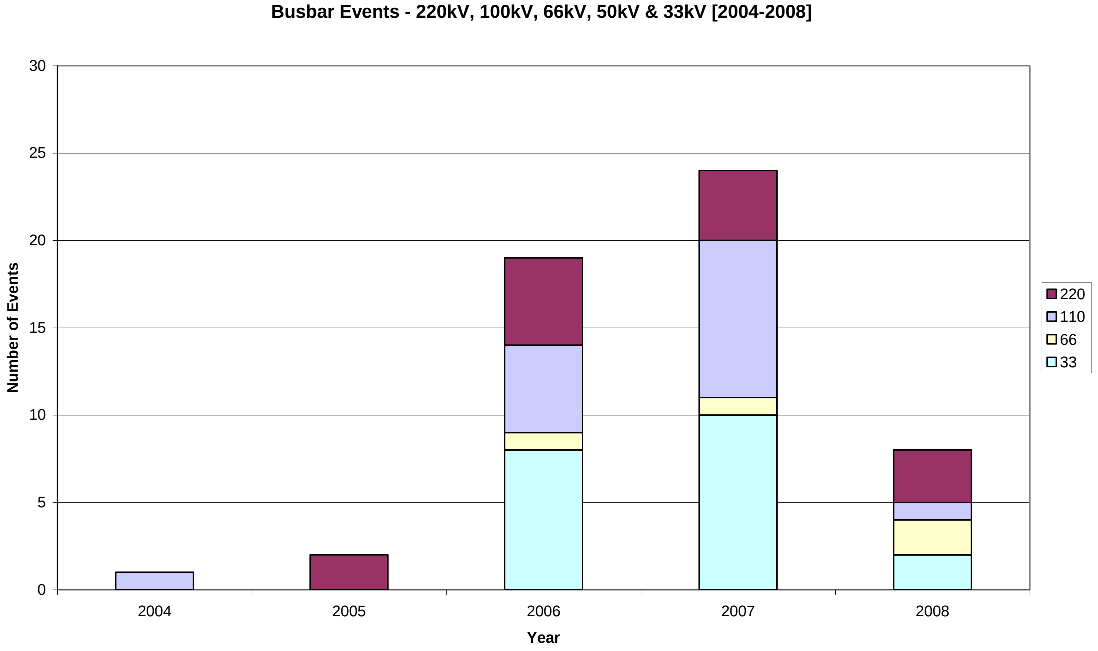


Table 4-13: Frequency of busbar interruptions 2004 – 2008

	Summary of busbar section interruptions				
Voltage (kV)	**220**	**110**	**66&50**	**33**	**TOTAL**
No. of elements in set	*138*	*144*	*36*	*115*	*433*
Year					
2004	0	1	0	0	1
2005	2	0	0	0	2
2006	5	5	1	8	19
2007	4	9	1	10	24
2008	3	1	2	2	8
Average. [2004-08]	**2.8**	**3.2**	**0.8**	**4.0**	**10.8**
Average. [1990-99]	-	-	-	-	10
Normalised =10.8x No. of elements in set/433	3.4	3.6	0.9	2.9	10.8

Further information regarding busbar events can be found in Appendix 1-4.

Average Number of Busbar Events per year

Historical data over the 5 year period [2004-2008] indicates an above average number of busbar section events during 2006 and 2007. A total of thirteen 220kV and 110kV busbar events were recorded in 2007.

Average Number of Busbar Events per year

Historical data over the 5 year period [2004-2008] indicates an average of 11 busbar events (across all voltage levels) per year, with an average duration of 9.1 hours. The data indicates that 6 of the 11 busbar events expected annually would occur on 220kV and 110kV busbars and 5 events would occur on 66kV, 50kV and 33kV busbars.

The previous 2002 statistical study calculated an average of 10 busbar faults a year however the report does not make reference to the busbar voltage levels considered in the data set. The 2002 study indicates that the ten year data [1990-99] includes three years where the number of busbar faults was above average at around 20 events per year. The 2002 analysis therefore determines that the results had been skewed by incorporating these years. The 2002 statistical study re-calculates a more representative average of four busbar events per year that lead to loss of supply.

Additional analysis of the data is undertaken to investigate the number of events associated with a particular busbar voltage. Assuming uniform susceptibility of a bus-section to a fault across all voltage levels, the number of events across all voltage levels can be distributed in accordance to the number of busbar sections at each voltage level. This technique allows assessment of the co-relation of the number of events with respect to the number of elements in each set. It can be seen that there are approximately the same number of 220kV and 110kV busbar sections. It is perhaps therefore not surprising that the number of events expected for the 220kV and 110kV busbar sections is approximately the same at a value of between 3 and 4 events per year. With regard to the low voltage busbars analysis of normalised and historical values would indicate an average of 4-5 events per year.

Duration of Busbar Events

Figure 4-11 illustrates the spread of event durations associated with the 220kV, 110kV, 66kV, 50kV and 33kV busbar section interruptions over the period 2004-2008.

Durations are obtained from grid owner outage records and may not indicate the associated time that supply was lost. An average duration of 9.1 hours is calculated from recorded outage times of busbar events that occurred on all busbar sections (across all voltage levels). Out of the 54 busbar events 3 (5%) had an outage time greater than 24 hours, these events are described in Table 4-14, 90% of all recorded busbar events had a duration less than 8 hours.

The outage time of 213 hours associated with the loss of the bus-section at Whakamaru is considered to be un-representative of the time associated with the event and is not associated with a loss of supply issue. In order to calculate more representative event durations associated with the loss of a busbar section this duration and the duration associated with the Islington 66kV busbar section event have been capped at 120 hours. Average durations associated with busbar section events are summarised in Table 4-15.

Figure 4-11 Recorded Busbar Section Events –220kV, 110kV, 66kV, 50kV and 33kV - Outage Durations [2004-2008]

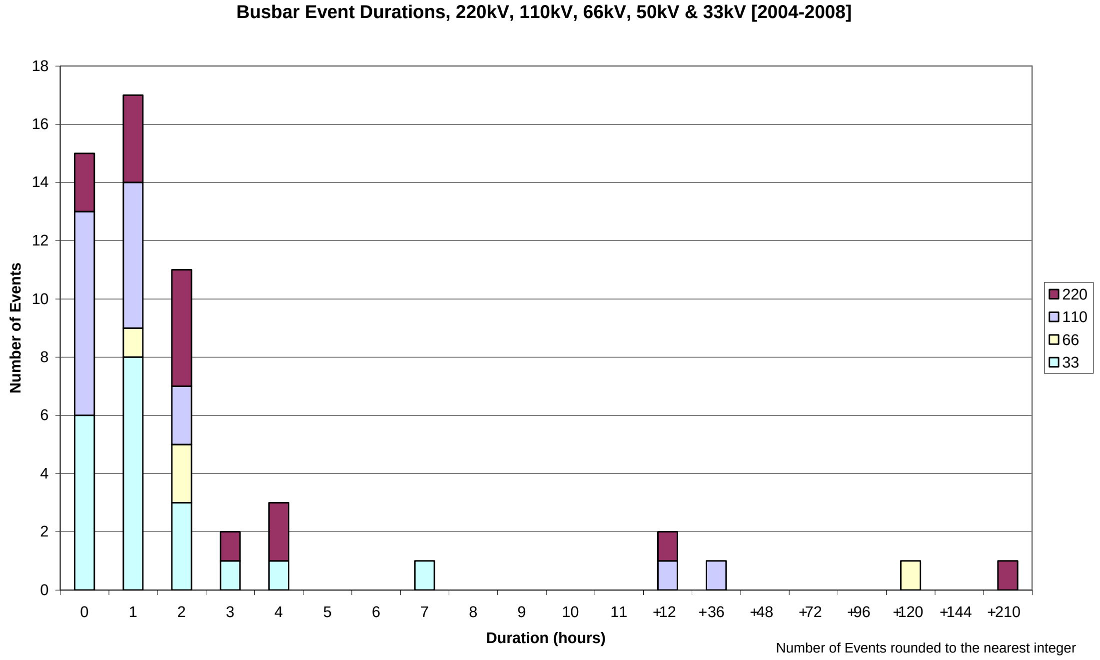


Table 4-14: Busbar Events with outage times greater than 24 hours [2004 – 2008]

Year	Busbar Section	Outage Time (hrs)	Description
2006	110kV Otahuhu	14	Failure of earth wire shackles at gantry
2006	220kV Whakamaru	213	WKM CB62 exploded and created a red phase to earth fault on the WKM 220kV busbar B
2007	66kV Islington	138	Tripped due to ISL CB332 (C14 capacitor) red and blue phase failing catastrophically which caused a 66kV busbar A fault and subsequent BZ operation.
2007	110kV Haywards	46	GFD-HAY 1 tripped for a red phase to earth fault probably caused by a lightning strike. HAY low impedance BZ protection for 110kV busbar A1&A2 maloperated for a through fault. (TKR-WIL 1&2 & HAY-TKR-2 out for reconductoring work at the time).
2008	220kV Otahuhu	15	Tripped for a red phase to earth fault caused by a damaged red phase insulator. NI: 48.88 Hz SI: 49.82 Hz

Table 4-15: Average Busbar Event Durations [2004 – 2008]

<table>
<tr><th></th><th colspan="5">Average duration of busbar section interruptions</th></tr>
<tr><td>Voltage (kV)</td><td>220</td><td>110</td><td>66&50</td><td>33</td><td>All voltages</td></tr>
<tr><td rowspan="2">Av. duration (hours)</td><td>17.8</td><td>4.4</td><td>35.6</td><td>1.4</td><td rowspan="2">9.1</td></tr>
<tr><td colspan="2">10.6</td><td colspan="2">7.1</td></tr>
<tr><td rowspan="2">Av. duration (hours) capping event duration at 120 hrs</td><td>11.2</td><td>4.4</td><td>31.1</td><td>1.4</td><td rowspan="2">7.0</td></tr>
<tr><td colspan="2">7.5</td><td colspan="2">6.3</td></tr>
</table>

From historical data an average of six 220kV and 110kV busbar section interruptions per year with an average event duration of 7.5 hours is derived. For low voltage busbars an average of five events per year with an average duration of 6.3 hours is derived.

The 2002 review determined that the loss of a busbar section should not be considered as a contingent event, as it “would not be possible to mitigate busbar faults by dispatch action”. It should be noted that in some cases the loss of a busbar section does not result in loss of supply due to the level of busbar duplication provided.

The current policy classifies the loss of a busbar section as a stability event, with unplanned load shedding allowed post-event,. There is no requirement for the System Operator to consider operational measures that could be applied to minimise the amount of load affected by the event.

The frequency of busbar events recorded provides some grounds for the review of the classification of busbar events and the review of measures that could be employed to manage the loss of a busbar section.

4.7 Transformer Events

Transpower owns and operates a large number of three phase and single phase transformer units, some of which are classed as interconnecting transformers and others as supply transformers. Table 4-16 gives the number of units of associated with the different transformer types. While the security policy considers the loss of an interconnecting transformer as a credible event, it is important to highlight that the policy does not regard the loss of an interconnecting transformer as a contingent event. The loss of an interconnecting transformer is classed as a stability event which therefore allows unplanned load shedding post-event to maintain system stability.

Table 4-16: Definition of transformer element sets

Set Name	**TOTAL**
220kV Interconnecting Transformers	*105*
110kV Interconnecting Transformers	*10*
220kV HVDC Converter Transformers	*6*
110kV HVDC Converter Transformers	*18*
220kV Traction Transformers	*16*
220kV Supply Transformers	*103*
110kV Supply Transformers	*373*
66kV & 50kV Supply Transformers	*73*
33kV Supply Transformers	*13*
TOTAL	*717*

All 220kV and 110kV interconnecting and supply transformers considered for the purposes of this review are listed in Appendix 1-5.

Table 4-17: Frequency of single 220kV and 110kV interconnecting and supply transformer interruptions 2004 – 2008

	Summary of single transformer interruptions				
Set Name	*220kV intercon*	*110kV intercon*	*220kV supply & traction*	*110kV supply*	*TOTAL*
Set Size	105	10	119	373	607
2004	4		16	41	61
2005	7	1	12	17	37
2006	10		25	27	62
2007	17		17	13	47
2008	10		17	19	46
Average	**9.6**	**0.2**	**17.4**	**23.4**	**50.6**

Figure 4-12 Recorded Single 220kV &110kV Interconnecting and Supply Transformer Events [2004-2008]

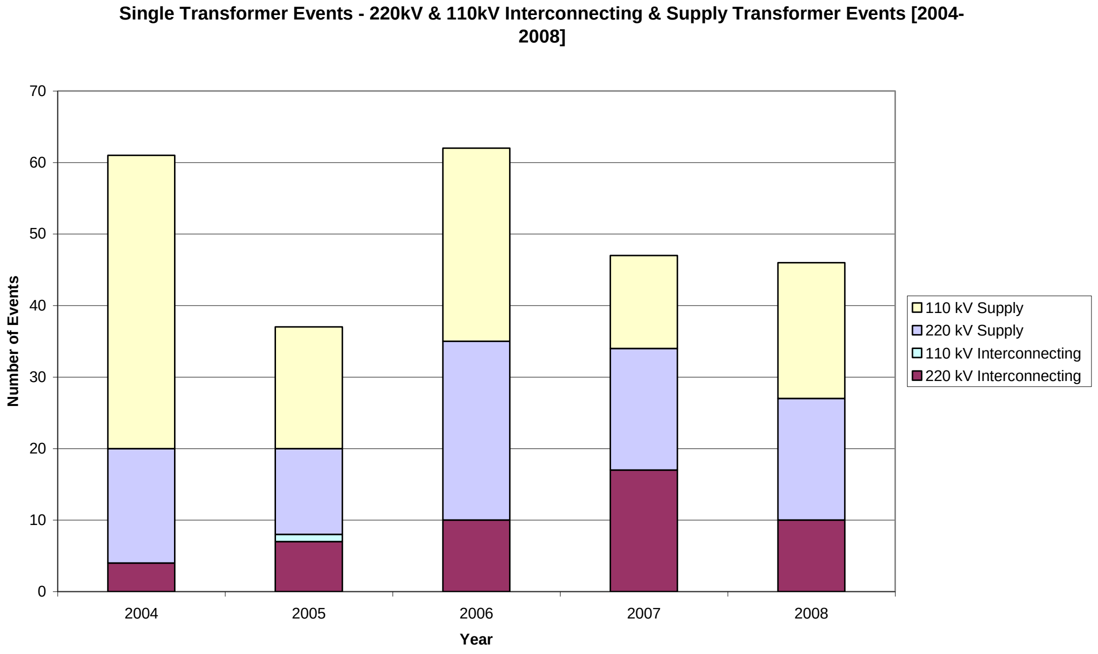


Figure 4-13 Duration of Single 220kV &110kV Interconnecting and Supply Transformer Events [2004-2008]

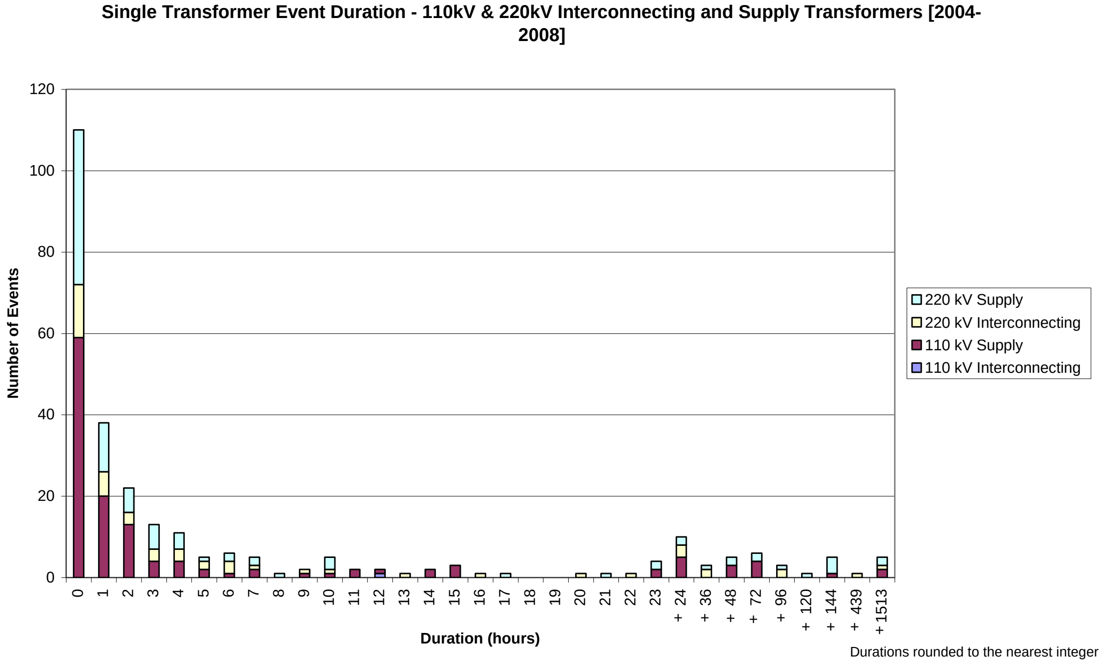


Table 4-18: Frequency of multiple 220kV and 110kV interconnecting and supply transformer interruptions 2004 – 2008

	Summary of multiple transformer interruptions				
Set Name	*220kV intercon*	*110kV intercon*	*220kV supply & traction*	*110kV supply*	*TOTAL*
2004			1	2 + 1(3xTx)**	4
2005			3	5	8
2006	1		2	3	6
2007			1	1	2
2008			0	2 + 1(3xTx)	3
Average	**0.2**	**0.0**	**1.4**	**3.0**	**4.6**
Av. duration (hours)	0.6	0.0	1.0	3.5	2.6

Note: ** All multiple transformer Events affect 2 transformers, except where indicated ** (3xTx = 3 transformers affected)

Figure 4-14 Recorded Multiple 220kV &110kV Interconnecting and Supply Transformer Events [2004-2008]

The event data indicates an average number of ten (10) 220kV and 110kV interconnecting transformer interruptions per year and forty one (41) 220kV and 110kV supply transformer interruptions.

This review will primarily focus on 220kV interconnection transformers, defined as those that connect the 220kV transmission network with the 110kV network.

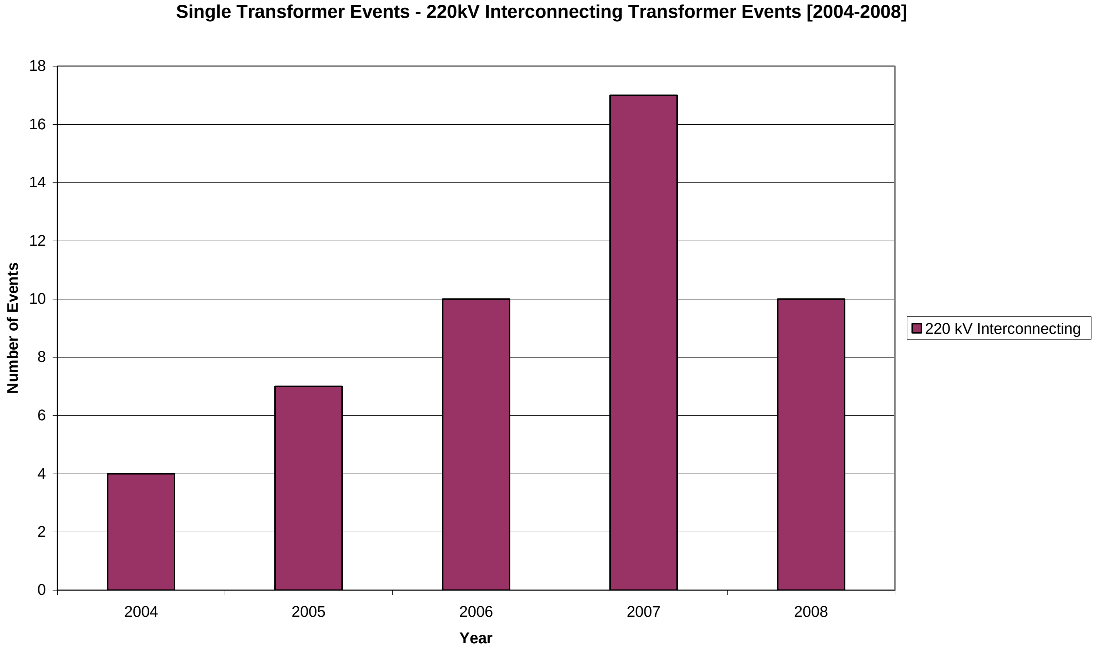
Further information regarding all transformer events can be found in Appendix 1-5.

Number of 220kV Interconnecting Transformer Events

The number of and duration associated with 220kV interconnecting transformer events is illustrated in Figure 4-15 and Figure 4-16.

Historical data over the 5 year period [2004-2008] indicates on average of 10 220kV interconnecting transformer events per year,

Figure 4-15 Recorded 220kV Interconnecting Transformer Events [2004-2008]



Duration of 220kV Interconnecting Transformer Events

Figure 4-16 illustrates the spread of event durations associated with 220kV interconnecting transformer interruptions over the period 2004-2008.

Durations are obtained from grid owner outage records and may not indicate the associated time that supply was lost. An average duration of 52.3 hours is calculated from recorded outage times of all 220kV interconnecting transformer events. Out of the 48 220kV interconnecting transformer events 4 events (8%) had an outage time greater than 48 hours, these events are described in Table 4-19, 92% of all recorded 220kV interconnecting transformer events had a duration less than 48 hours.

The outage time of 1513 hours associated with the loss of Albany T4 is considered to be un-representative of the time associated with the event and is not associated with a loss of supply issue. In order to calculate more representative average event durations associated with the loss of a 220kV interconnecting transformer this duration and the duration associated with the loss of Marsden T2 have been capped at 120 hours. Average durations associated with busbar section events are summarised in Table 4-20. With these durations capped at 120 hours the calculated average event duration for 220kV interconnecting transformers falls to 16.7 hours.

Figure 4-16 Duration of 220kV Interconnecting Transformer Events [2004-2008]

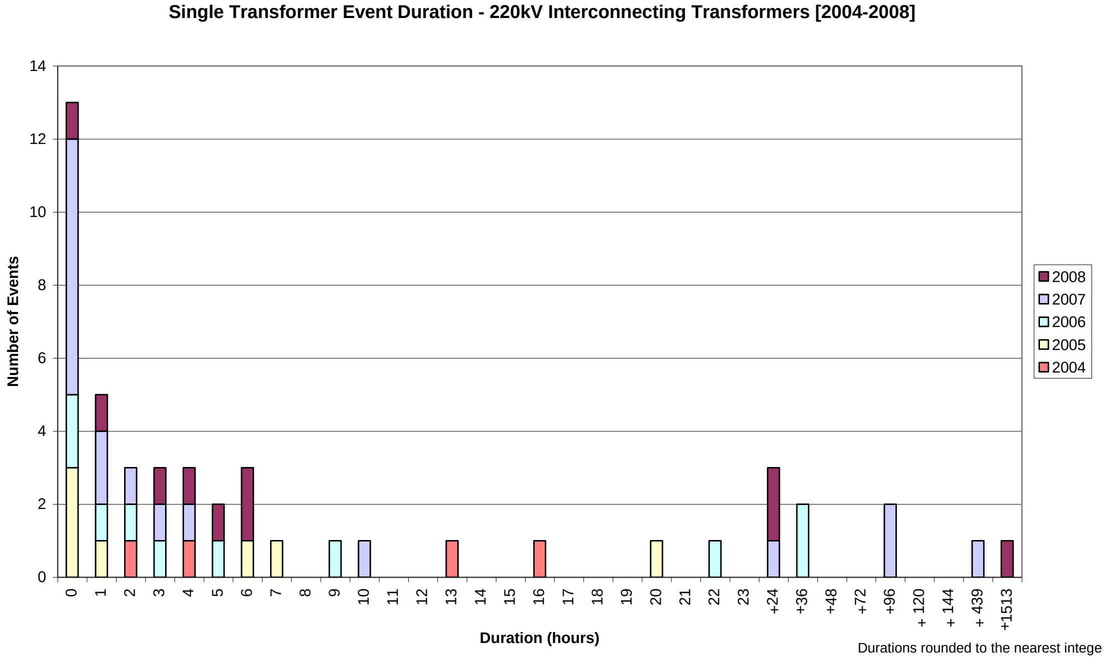


Table 4-19: 220kV Interconnecting Transformer Events with outage times greater than 72 hours [2004 – 2008]

Year	**Transformer**	**Outage Time (hrs)**	**Description**
2007	Wilton T8	98	WIL T8 tripped on attempted close after earlier tripping. Earth-fault found on B-ph tertiary winding. RTS at 18:03 on 25/5 after Txfr unit swap.
2007	Otahuhu T4	118	OTA T4 tripped on differential protection when C4B was switched. Damage found to CB972 (C4B).
2007	Marsden T2	439	Transformer Equipment Failure
2008	Albany T4	1513	ALB T4 tripped on differential protection. B-ph bushing failed.

Table 4-20: Duration of single 220kV and 110kV interconnecting and supply transformer interruptions 2004 – 2008

	Summary of single transformer interruptions				
Set Name	*220kV intercon*	*110kV intercon*	*220kV supply & traction*	*110kV supply*	*TOTAL*
Av. duration (hrs)	52.3	11.6	61.1	37.6	48.4
	51.5		47.7		
Av. duration (hrs) with 120hr duration cap	**16.7**	11.6	17.8	10.6	14.2
	16.6		13.7		

The event data indicates an average number of ten (10) 220kV and 110kV interconnecting transformer interruptions per year and forty one (41) 220kV and 110kV supply transformer interruptions.

From historical data an average of 10 220kV interconnecting transformer interruptions per year with an average event duration of 16.7 hours is derived.

The current policy is not to plan for the interruption of 220kV interconnecting transformers. Previous assessments have found that in most circumstances there is insufficient generation available to provide reserve on the 110kV side of interconnecting transformers and concluded that it was more economic to invest in duplicate interconnecting transformer capacity rather than consider the event as a contingent event and incur the costs to mitigate these events. The current policy classifies the loss of an interconnecting transformer as a stability event, no consideration is given to measures that could be applied to minimise the amount of load affected by the event.

The frequency of transformer events recorded provides some grounds for the review of the classification of transformer events and the review of measures that could be employed to manage the loss of a transformer.

Supply Transformers

It is the responsibility of the supply transformer asset owner to manage security issues associated with the loss of a supply transformer.

The current security policy does not consider the loss of a supply transformer to be a credible event and therefore does not consider measures to mitigate the interruption of supply transformers or measures to restore supply following such an event.

4.8 Reactive Plant

Table 4-21 shows the number of reactive device interruptions that have occurred over the period 2004-2008. An average of 49 reactive device interruptions per year is calculated form historical data. The number of interruptions indicated in Table 4-21 does not include interruptions that are associated with failure of another power system element.

Table 4-22 shows the additional number of reactive device interruptions that have occurred in association with either a transformer or HVDC pole.

Table 4-21: Frequency of Reactive Plant interruptions 2004 – 2008

Year	**Condensers**		**Capacitor Banks**	**SVC**	**Filter Banks**		**Multiple**	**Total**
Event recorded within	-	HVDC other		-	-	HVDC other	-	
2004	5	2	23	0	1	3	3	37
2005	4	1	31	11	1		3	51
2006	11	1	31	2	1	1	1	48
2007	20		31	0	4		1	56
2008	18		15	11	7		3	54
Total	**62**		**131**	**24**	**18**		**11**	**246**
Average	**12.4**		**26.2**	**4.8**	**3.6**		**2.2**	**49.2**

Table 4-22: Frequency of Reactive Plant interruptions associated with other plant (HVDC pole or a Transformer) 2004 – 2008

Year	**Condensers**		**Capacitor**	**SVC**	**Reactor +Cap**	**2Reactor +2Cap**	**Condenser +2reactor**	**2 condensers**	**Total**
With loss of a	Tx	HVDC	Tx	Tx	Tx	Tx	Tx	Tx	
2004		3			2	1			6
2005			3		1				4
2006		1	3				1	1	6
2007	3				1	7			11
2008			2	1	2				5
Total	**7**		**8**	**1**	**6**	**8**	**1**	**1**	**32**
Average	**1.4**		**1.6**	**0.2**	**1.2**	**1.6**	**0.2**	**0.2**	**6.4**

Although the current policy does not explicitly classify the loss of a reactive plant as a contingent event, the System Operator can manage the loss of a reactive device without the application of unplanned load shedding. The classification of the loss of a reactive device as a contingent event should be clarified within the security policy.

4.9 Summary & Conclusions

A summary of the likelihood and duration of all events can be found in Appendix 1-6. Tables that rank all credible events with respect to the number of events that occur per year and with respect to a risk factor that takes into consideration the number of elements within the fault set can be found in Appendix 1-7.

The ranking of all credible events according to likelihood of occurrence is summarised in Table 4-23. All credible event classifications have been indicated as below:

- Contingent Events are coloured in blue ink
- Stability Events in red ink
- Extended Contingent Events are coloured in green ink
- Other Events are coloured in black ink

Table 4-23: Risk Factor Ranking of Credible Events – likelihood of occurrence

Credible Event **Loss of …**	No in Set	*No. of Events per year*	*Event Risk Factor **
a HVDC half pole	2	*20*	*10*
a HVDC pole	2	*7*	*3.5*
a single generating unit	<234	*132*	*0.56*
reactive plant	<134	*49*	*0.37*
HVDC bipole	1	*<0.5*	*<0.5*
a single 220kV transmission circuit (no A/R)	142	*25*	*0.18*
a 220kV interconnecting transformer	105	*10*	*0.095*
multiple generating units	<117	*11*	*0.094*
110kV interconnecting transformer	10	<0.5	0.05
a 66kV, 50kV or 33kV busbar section	151	*5*	*0.033*
a 220kV or 110kV busbar section	282	*6*	*0.021*
a double 220kV transmission circuit (no A/R)	<71	*1*	*0.014*
multiple 220 or 110kV interconnecting transformers	<53	*<0.5*	*0.009*
multiple 220kV transmission circuits	<71	*<0.5*	*0.007*

** Likelihood of Occurrence or Event Risk Factor (No. of events/No. of elements in risk set)*

Following analysis of historical data the System Operator proposes:

- No review of the classification and management measures associated with the loss of :
  - single transmission circuit
  - single generator unit
  - HVDC pole
  - HVDC bipole
  - multiple transmission circuits
  - multiple generator units
- The following credible events should be classed as a contingent event. The loss of a
  - reactive device (condenser, capacitor, reactor, SVC, RPC)
  - large load / load block
- The following credible events should be classed as a Other event. The loss of:
  - multiple transmission circuits/elements
- A review should be undertaken to re-assess the existing classification and management of the loss of a single:
  - 220kV or 110kV interconnecting transformer
  - 220kV or 110kV busbar section
  - 66kV busbar section
- Consideration should be given to the ability to manage the loss of a transformer or busbar section during a planned outage.

5 References

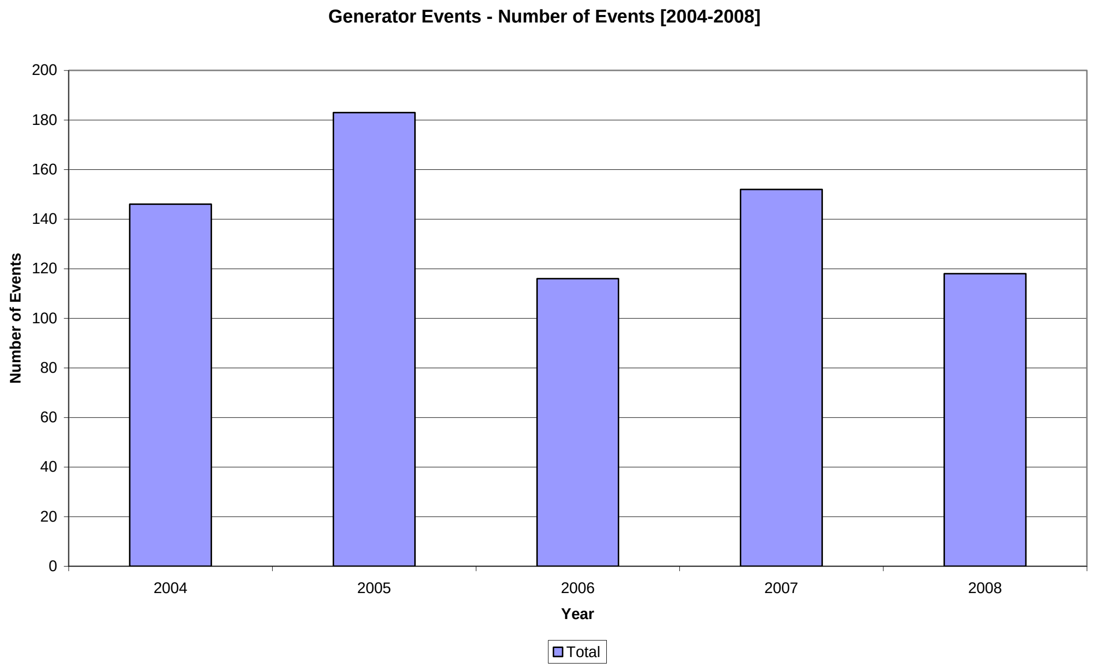
[1] Security Policy, Part C Schedule C4, Electricity Governance Rules, December 2007. Link: http://www.electricitycommission.govt.nz/pdfs/rulesandregs/rules/rulespdf/PartC-Sched-C4-1Dec07.pdf

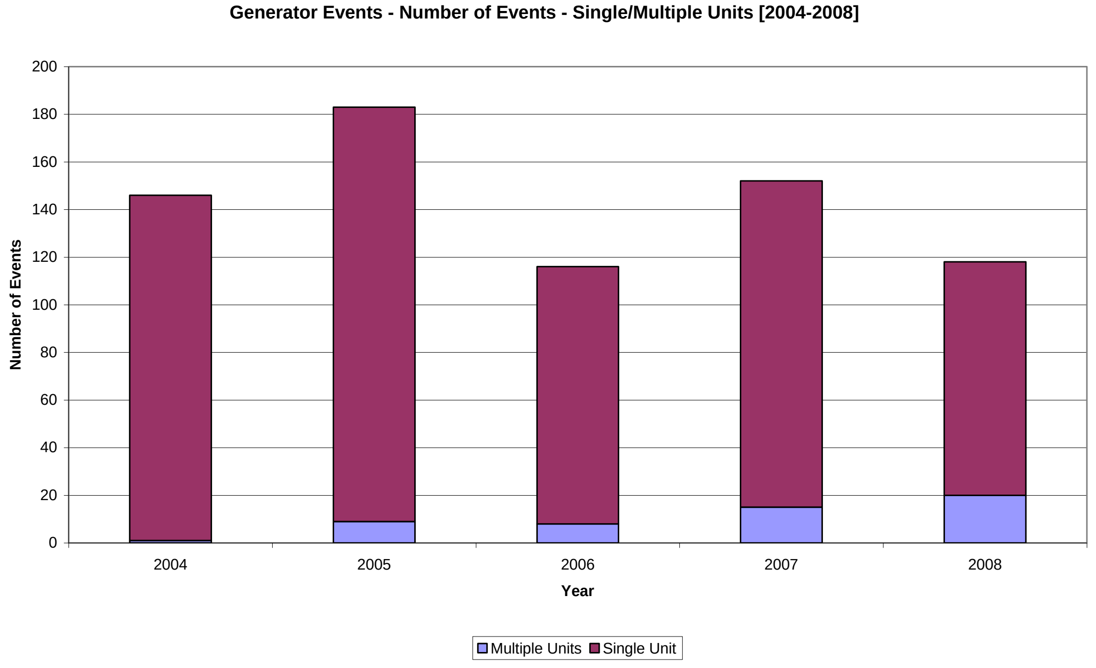
[2] The Statistical Basis for the Security Policy: Companion paper to the CQC Security Policy, Transpower New Zealand Ltd, January 2002.

Appendix 1-1 – Generator Events

Generator Events – Single and Multiple Units

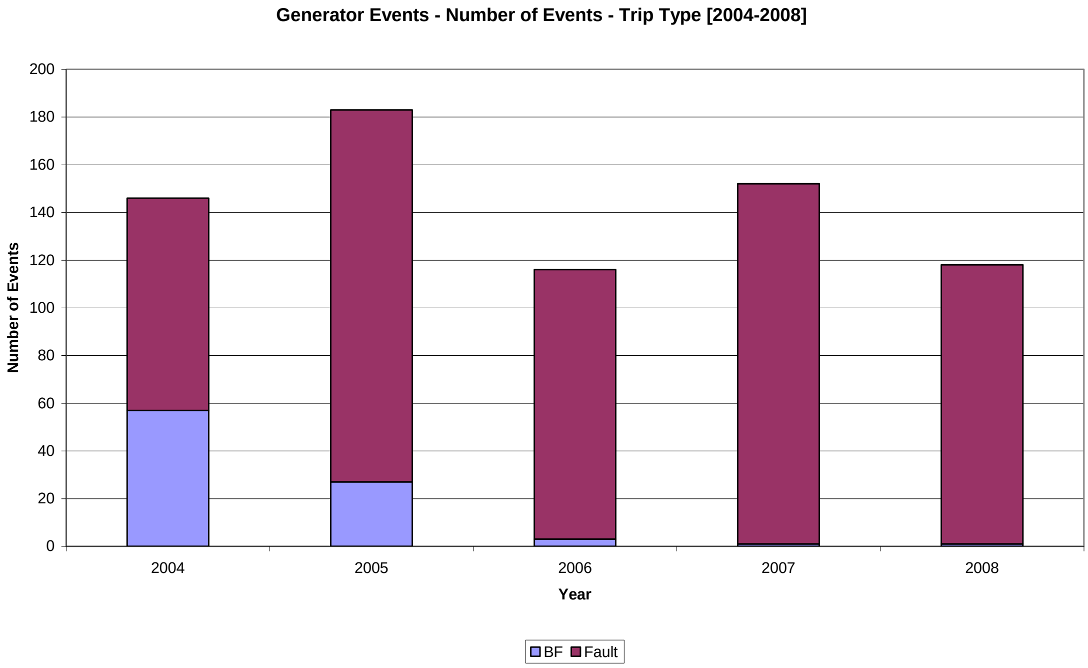
Year	Multiple Units	Single Unit	Total
2004	1	145	146
2005	9	174	183
2006	8	108	116
2007	15	137	152
2008	20	98	118
Total	53	662	715





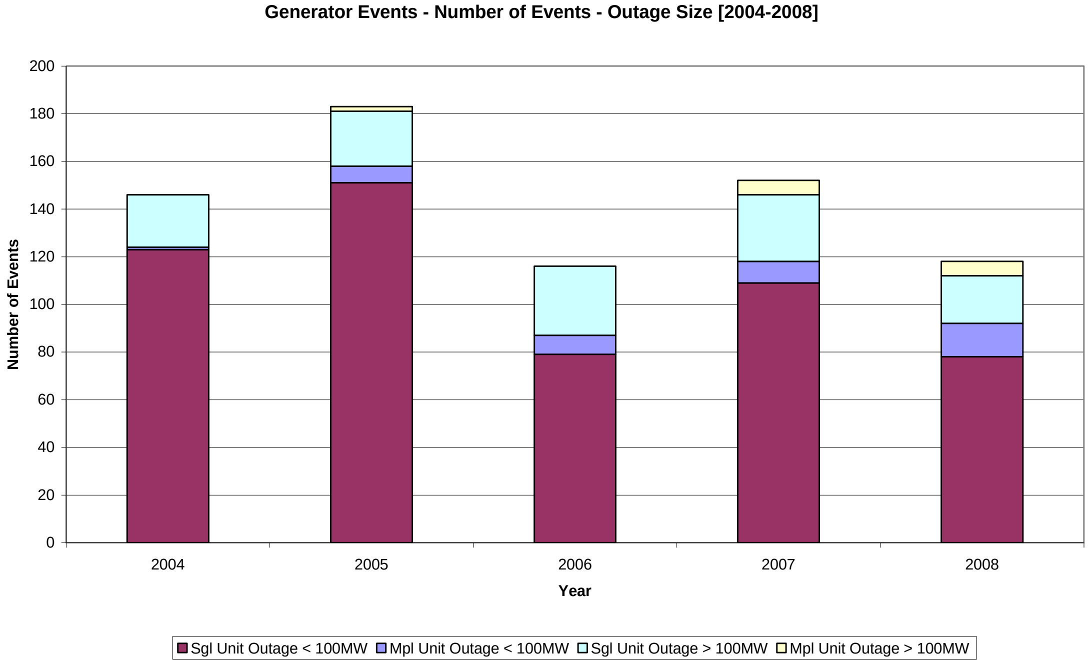
Generator Events – Trip Type

	Trip Type		
Year	BF	Fault	Total
2004	57	89	146
2005	27	156	183
2006	3	113	116
2007	1	151	152
2008	1	117	118
Total	89	626	715



Generator Events – Outage Size

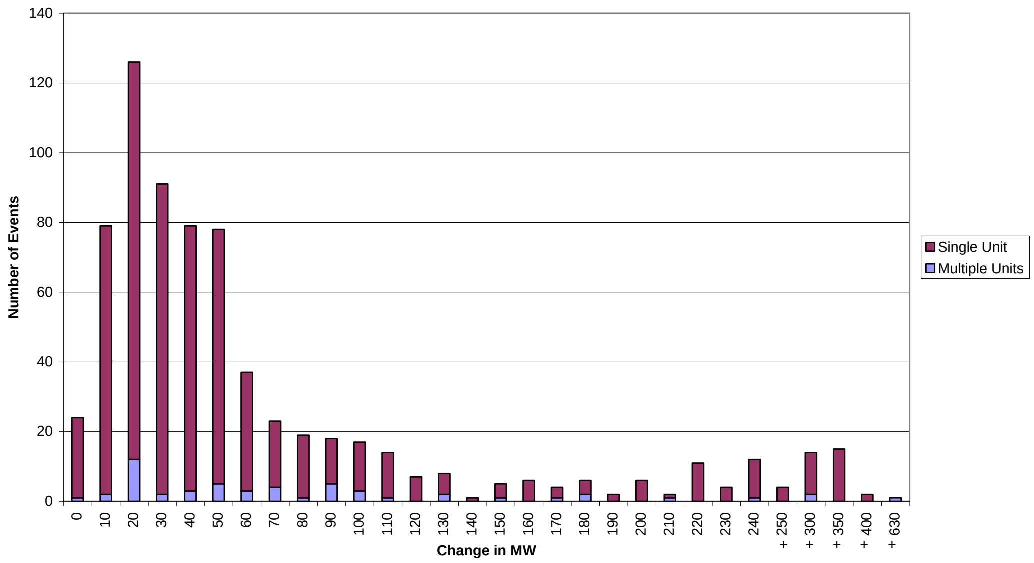
	Outage				
Year	Mpl Unit Outage < 100MW	Mpl Unit Outage > 100MW	Sgl Unit Outage < 100MW	Sgl Unit Outage > 100MW	Total
2004	1		123	22	146
2005	7	2	151	23	183
2006	8		79	29	116
2007	9	6	109	28	152
2008	14	6	78	20	118
Total	39	14	540	122	715



Generator Events – MW Outage Band

Outage Band	Multiple Units	Single Unit	Total
0	1	23	24
10	2	77	79
20	12	114	126
30	2	89	91
40	3	76	79
50	5	73	78
60	3	34	37
70	4	19	23
80	1	18	19
90	5	13	18
100	3	14	17
110	1	13	14
120		7	7
130	2	6	8
140		1	1
150	1	4	5
160		6	6
170	1	3	4
180	2	4	6
190		2	2
200		6	6
210	1	1	2
220		11	11
230		4	4
240	1	11	12
250		4	4
300	2	12	14
350		15	15
400		2	2
630	1		1
Total	53	662	715

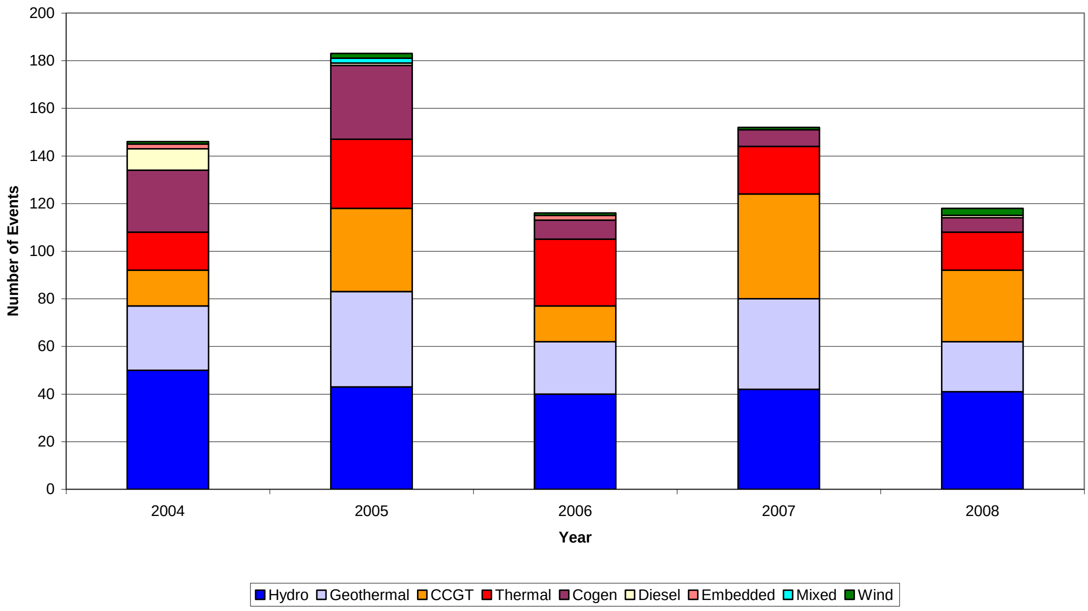
Generator Events - MW Change [2004-2008]



Generator Events – Generator Fuel/Technology

	Gen Unit Type									
Year	CCGT	Cogen	Diesel	Emb'd	Geo	Hydro	Mixed	Thermal	Wind	Total
2004	15	26	9	2	27	50		16	1	146
2005	35	31	1		40	43	2	29	2	183
2006	15	8		2	22	40		28	1	116
2007	44	7			38	42		20	1	152
2008	30	6	1		21	41		16	3	118
Total	139	78	11	4	148	216	2	109	8	715

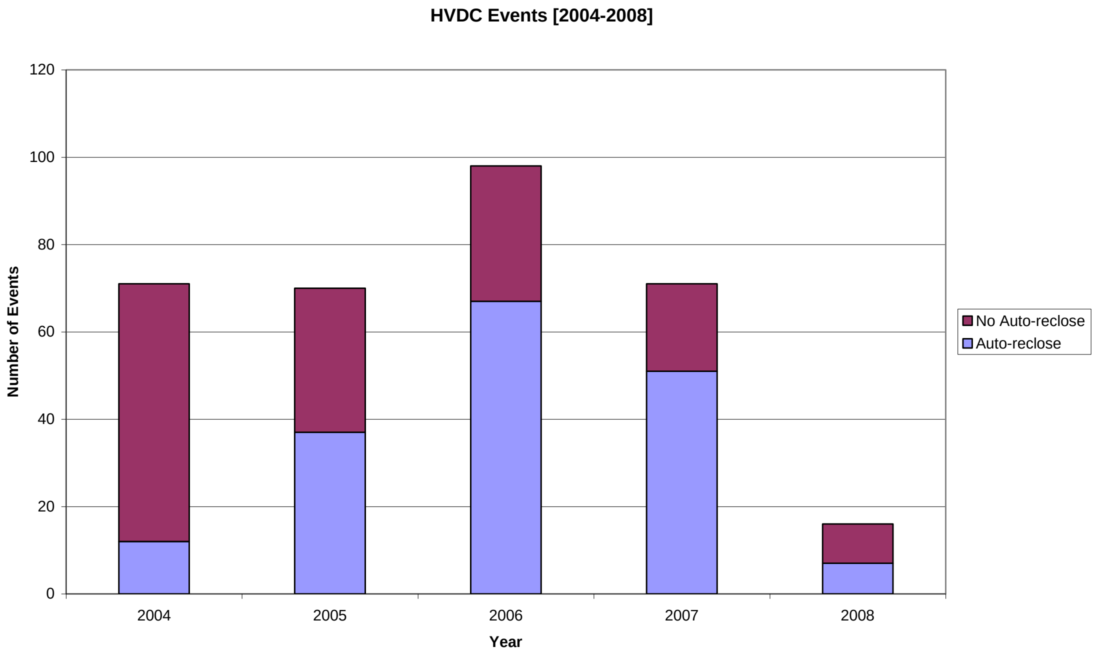
Generator Events - Number of Events - Generator Fuel/Technology [2004-2008]



Appendix 1-2 – HVDC Events

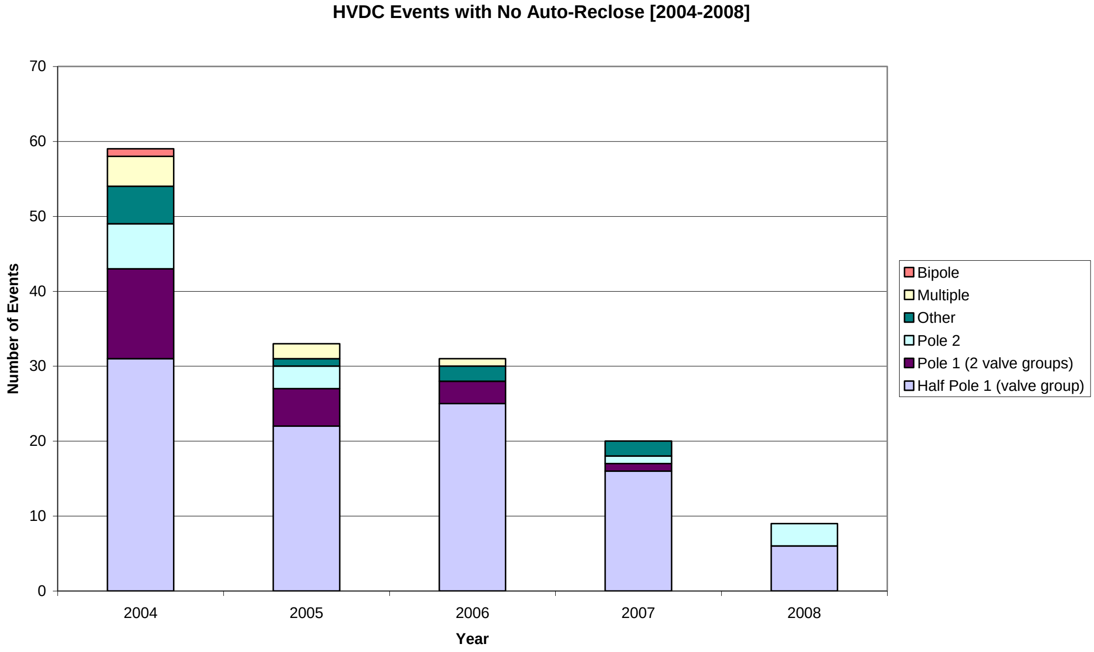
HVDC Events with and without Auto-Reclose Action

	Auto-reclose Action		
Date	Auto-reclose	No Auto-reclose	Total
2004	12	59	71
2005	37	33	70
2006	67	31	98
2007	51	20	71
2008	7	9	16
Total	174	152	326



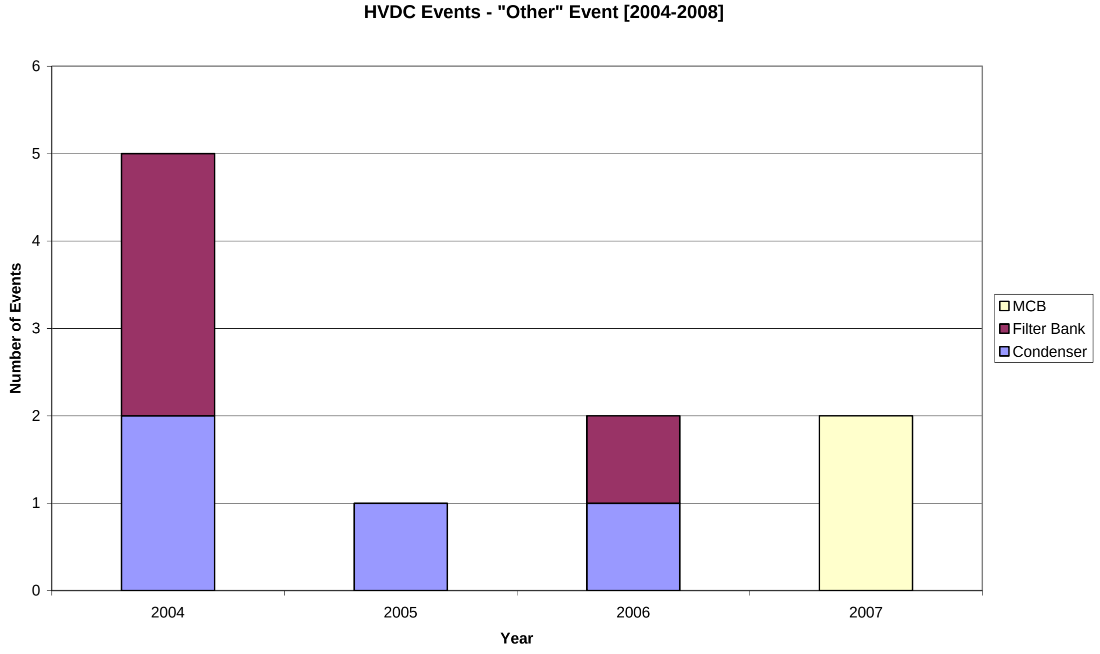
HVDC Events with No Auto-Reclose

	Type						
Date	Bipole	Half Pole 1 (valve group)	Multiple	Other	Pole 1 (2 valve groups)	Pole 2	Total
2004	1	31	4	5	12	6	59
2005		22	2	1	5	3	33
2006		25	1	2	3		31
2007		16		2	1	1	20
2008		6				3	9
Total	1	100	7	10	21	13	152



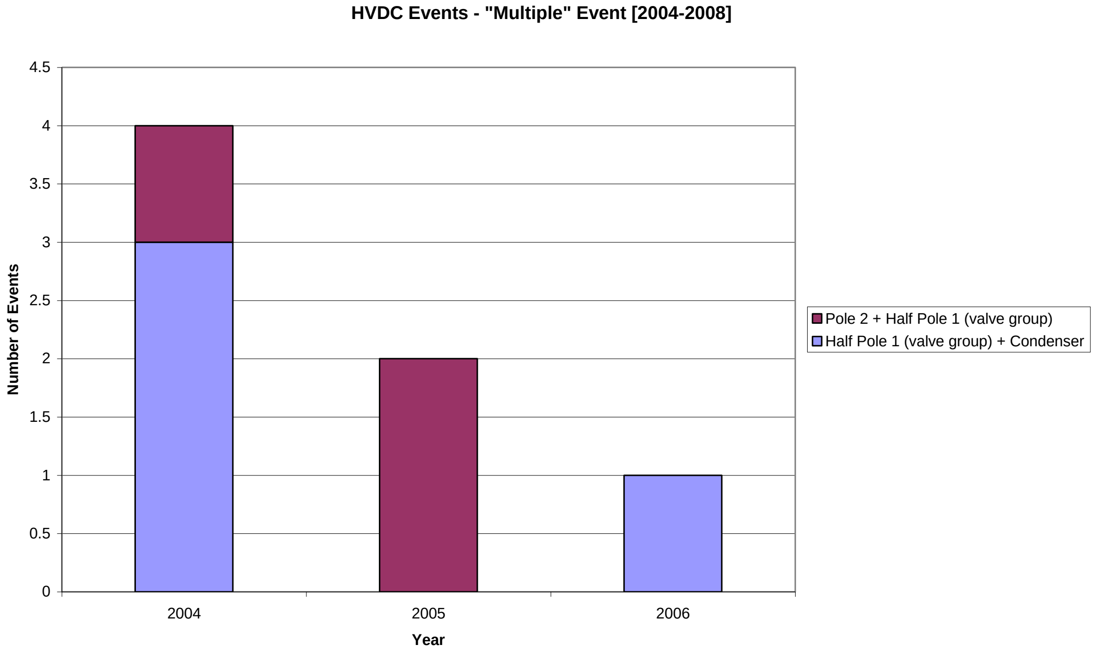
HVDC Events – "Other" Event

	Trip Type			
Date	Condenser	Filter Bank	MCB	Total
2004	2	3		5
2005	1			1
2006	1	1		2
2007			2	2
Total	4	4	2	10



HVDC Events – “Multiple” Event

	Trip Type		
Date	Half Pole 1 (valve group) + Condenser	Pole 2 + Half Pole 1 (valve group)	Total
2004	3	1	4
2005		2	2
2006	1		1
Total	4	3	7



HVDC Events & System Frequency

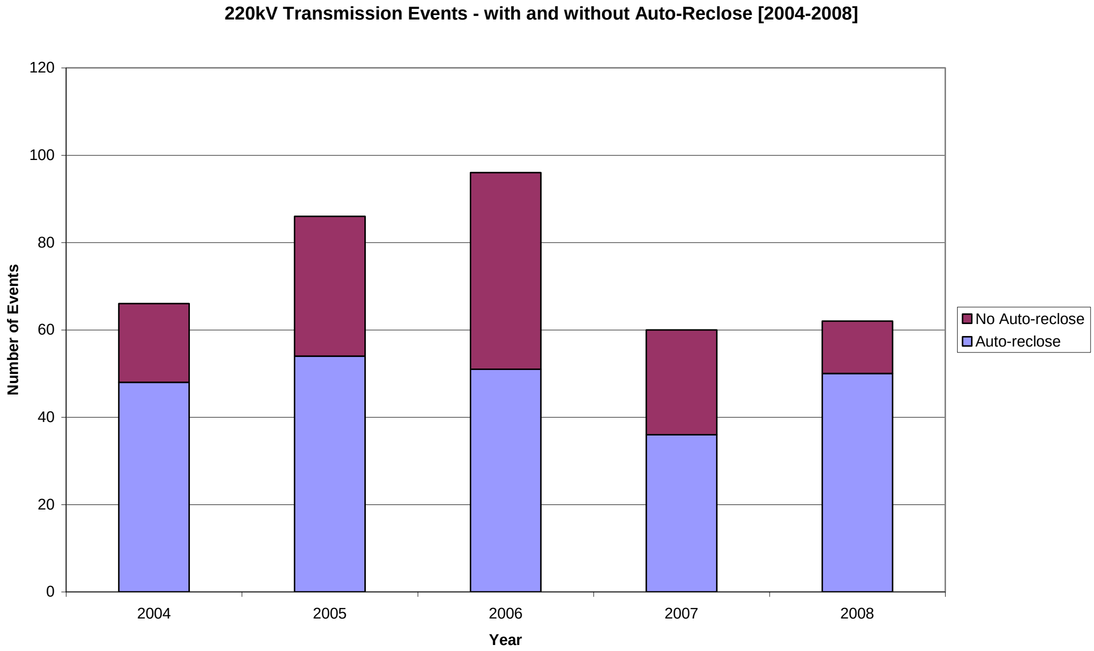
A summary of the HVDC events resulting in System Frequency outside normal frequency bands is provided below.

Year	Pole 1 (1/2)	Pole 1 (1/2)	Pole 2	Frequency
2004	✓			SI: 50.79Hz
2004	✓	✓		NI =49.24 Hz, SI= 51. Hz
2004			✓	NI: 49.195 Hz, SI: 51.628 Hz
2004			✓	NI: 49.35 Hz SI: 51.31 Hz
2005	✓		✓	NI: 49.18 Hz SI: 51.42 Hz NI: 48.71 Hz SI: 51.49 Hz
2005	✓	✓		NI: 49.13 Hz SI: 50.97 Hz
2005			✓	SI: 50.71 Hz NI: 49.72 Hz
2005	✓			NI: 49.48 Hz SI: 51.04 Hz
2005	✓			NI: 50.3 Hz NI: 49.55 Hz SI: 49.57 Hz SI:51.33 Hz
2005			✓	NI: 50.45 Hz SI: 47.98 Hz
2006	✓			SI: 49.46 Hz
2006	✓			SI: 50.88 Hz NI: 49.75 Hz
2007			MCB	SI: 49.48 Hz
2007			✓	SI: 49.33 Hz
2008			LINE	NI: 49.44 Hz SI: 49.72 HZ SI: 51.00 Hz
2008			✓	SI: 50.58 Hz
2008			✓	NI: 49.37 Hz SI: 51.37 Hz

Appendix 1-3 – 220kV Transmission Events

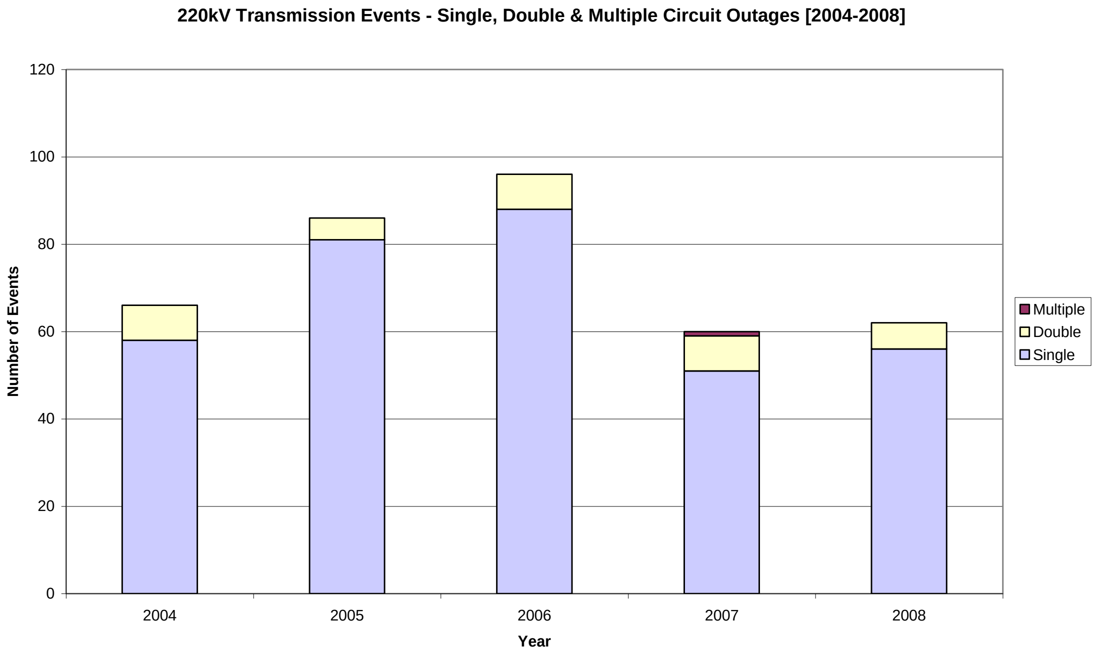
220kV Transmission Events with and without Auto-Reclose Action

	Auto-reclose or No Auto-reclose		
Year	Auto-reclose	No Auto-reclose	Total
2004	48	18	66
2005	54	32	86
2006	51	45	96
2007	36	24	60
2008	50	12	62
Total	239	131	370



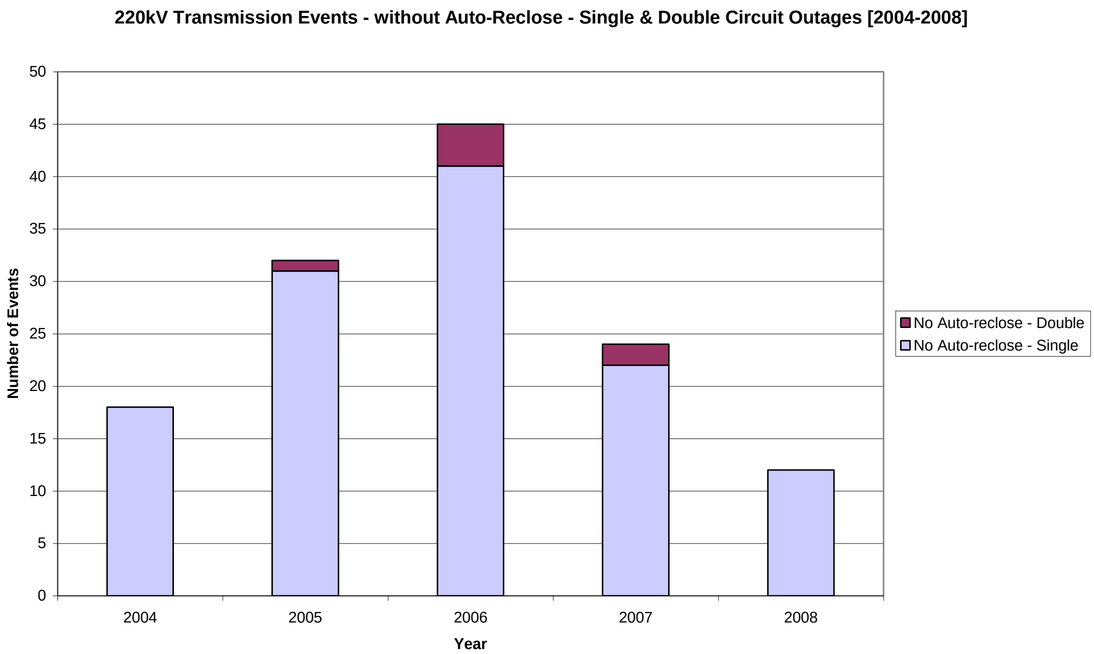
220kV Transmission Events -Single, Double and Multiple Circuit Outages

	Single or Multiple			
Year	Double	Multiple	Single	Grand Total
2004	8		58	66
2005	5		81	86
2006	8		88	96
2007	8	1	51	60
2008	6		56	62
Grand Total	35	1	334	370



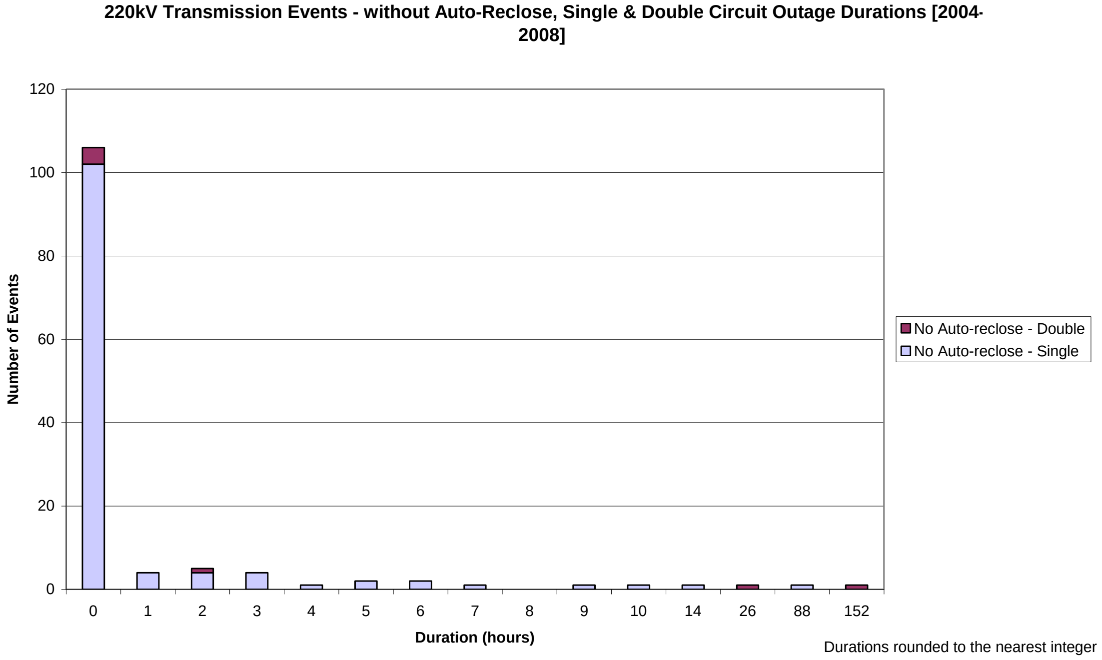
220kV Transmission Events with No Auto-Reclose

	Auto-reclose or No Auto-reclose	Single or Multiple		
	No Auto-reclose		No Auto-reclose Total	Total
Year	Double	Single		
2004		18	18	18
2005	1	31	32	32
2006	4	41	45	45
2007	2	22	24	24
2008		12	12	12
Total	7	124	131	131



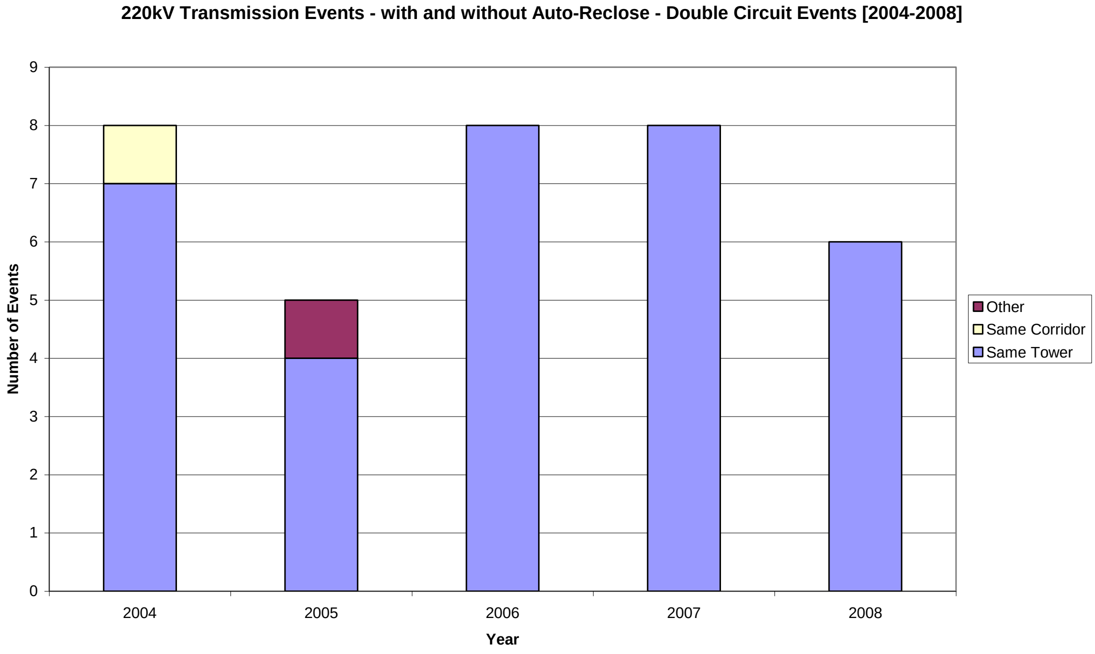
220kV Transmission Event with No Auto-Reclose – Outage Duration

	Auto-reclose or No Auto-reclose	Single or Multiple		
	No Auto-reclose		No Auto-reclose Total	Grand Total
Hours Rounded	Double	Single		
0.00	4	102	106	106
1.00		4	4	4
2.00	1	4	5	5
3.00		4	4	4
4.00		1	1	1
5.00		2	2	2
6.00		2	2	2
7.00		1	1	1
9.00		1	1	1
10.00		1	1	1
14.00		1	1	1
26.00	1		1	1
88.00		1	1	1
152.00	1		1	1
Grand Total	7	124	131	131



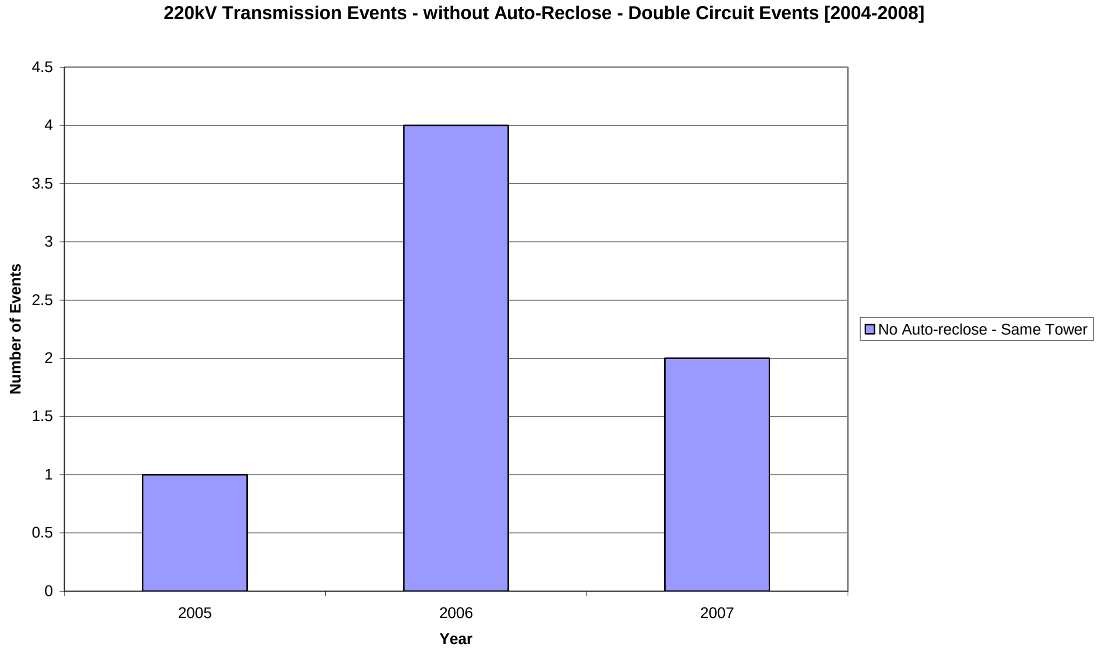
220kV Transmission Event with and without Auto-Reclose – Double Circuit Events

	Double Circuit			
Year	Same Tower	Other	Same Corridor	Total
2004	7		1	8
2005	4	1		5
2006	8			8
2007	8			8
2008	6			6
Total	33	1	1	35



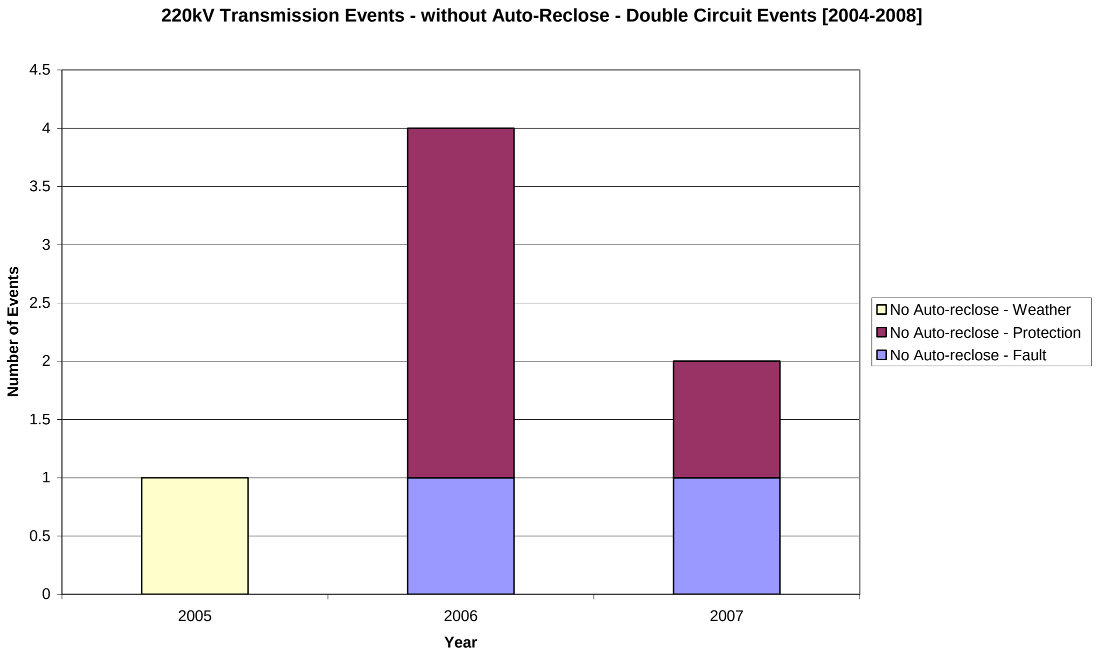
220kV Transmission Event without Auto-Reclose – Double Circuit Events

	Auto-reclose or No Auto-reclose	Double Circuit	
	No Auto-reclose	No Auto-reclose Total	Total
Year	Same Tower		
2005	1	1	1
2006	4	4	4
2007	2	2	2
Total	7	7	7



220kV Transmission Event without Auto-Reclose – Double Circuit Events

	Auto-reclose or No Auto-reclose	Cause			
	No Auto-reclose			No Auto-reclose Total	Total
Year	Fault	Protection	Weather		
2005			1	1	1
2006	1	3		4	4
2007	1	1		2	2
Total	2	4	1	7	7

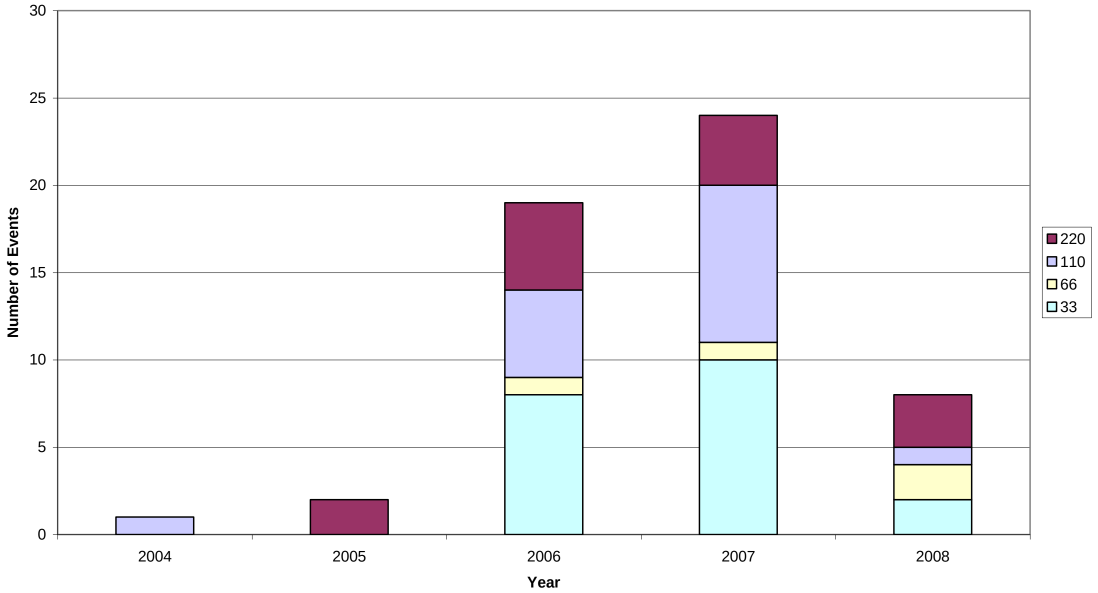


Appendix 1-4 – Busbar Events

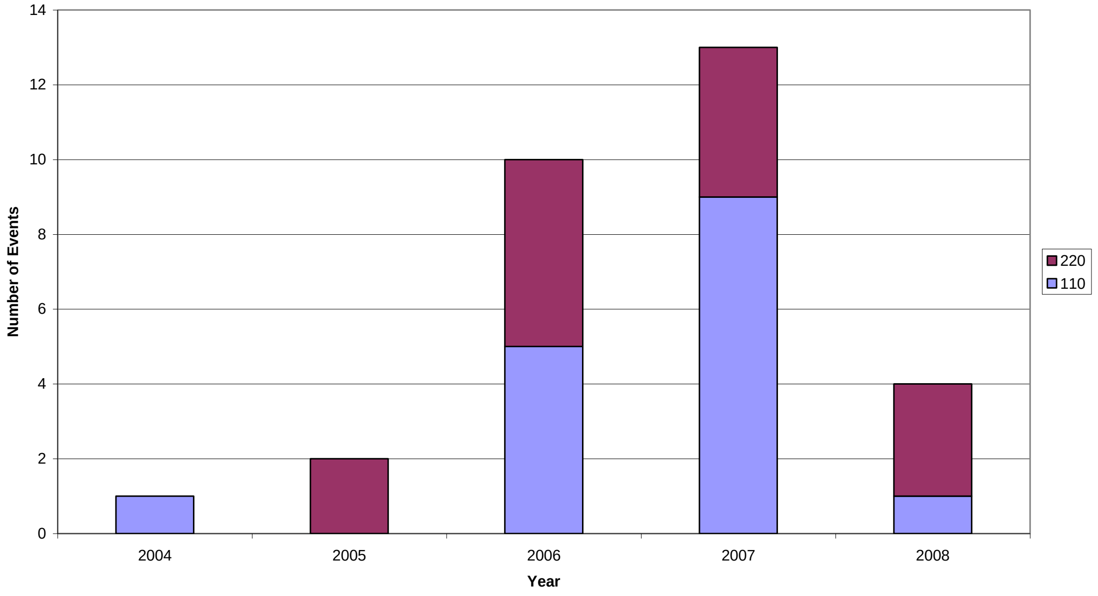
Busbar Events 220kV, 110kV, 66kV, 50kV & 33kV

	Voltage (kV)				
Year	33	66	110	220	Total
2004			1		1
2005				2	2
2006	8	1	5	5	19
2007	10	1	9	4	24
2008	2	2	1	3	8
Total	20	4	16	14	54

Busbar Events - 220kV, 110kV, 66kv, 50kV & 33kV [2004-2008]

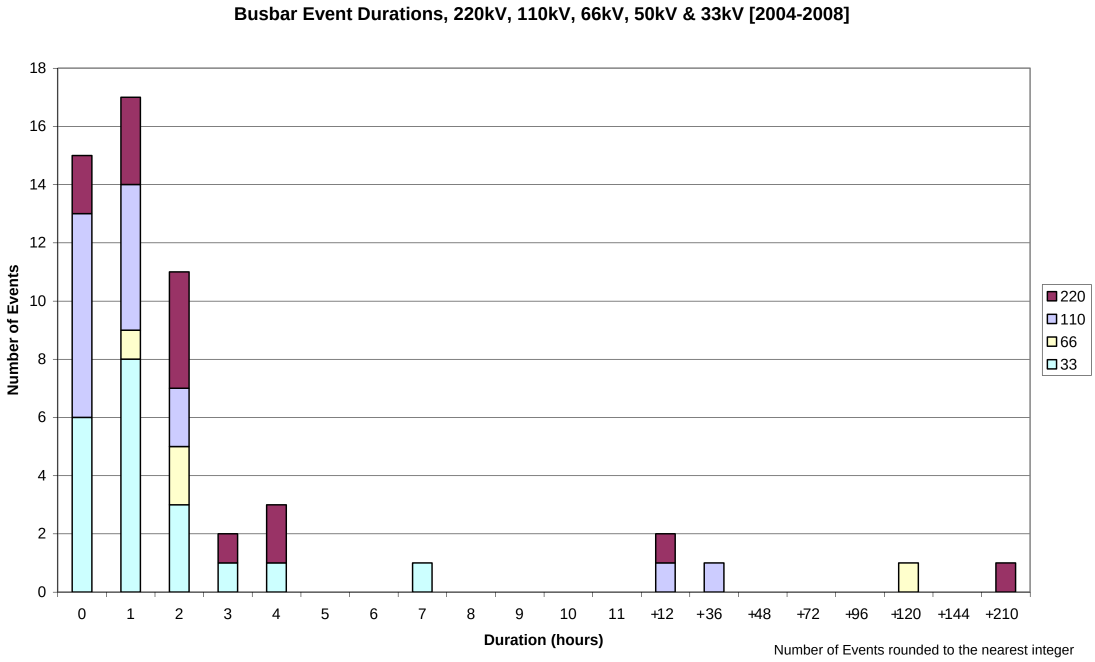


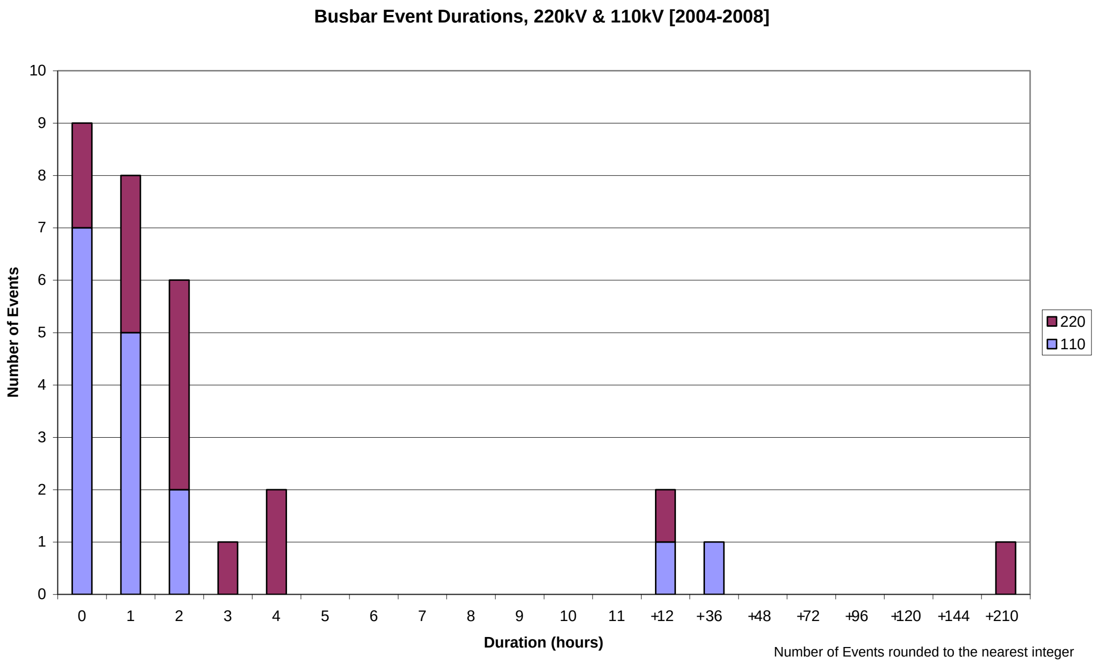
Busbar Events - 220kV & 110kV [2004-2008]



Busbar Event Duration 220kV, 110kV, 66kV, 50kV & 33kV

	Voltage (kV)				
Duration (hrs)	33	66	110	220	Total
0	6		7	2	15
1	8	1	5	3	17
2	3	2	2	4	11
3	1			1	2
4	1			2	3
5				0	0
6				0	0
7	1			0	1
8				0	0
9				0	0
10				0	0
11				0	0
12			1	1	2
36			1		1
48				0	0
72				0	0
96				0	0
120		1			1
144				0	0
210				1	1
Total	20	4	16	14	54




Busbar Event Durations, 220kV & 110kV [2004-2008]
Number of Events
Duration (hours)
0
1
2
3
4
5
6
7
8
9
10
11
+12
+36
+48
+72
+96
+120
+144
+210
220
110
Number of Events rounded to the nearest integer

Appendix 1-5 – Transformer Events

List of 220kV and 110kV Interconnecting transformers

Definition of 220kV interconnecting transformer element sets (core grid transformers in blue)

	220kV Interconnecting Transformers				
Set Name	***Sgl Tx 220/110/x***	***Dbl Tx 220/110/x 220/66/x (SI)***	***Tpl Tx 220/110/x 220/66/x (SI)***	***Qpl Tx 220/110/x***	**TOTAL**
Three-phase Tx	*1x STK*	*2xCML 2xHAM 2xKAW 1xKIK 2xRDF 2xTIM 2xWPR*	*3xHAY 1xISL 1xMDN*	*2xOTA*	
subtotal	*1*	*13*	*5*	*2*	*21*
Single-phase Tx	*1xALB 1xHWB 1x INV 1xNPL 1xPEN 1xROX 1xSFD 1xWIL*	*2xBRY 2xEDG 2xHEN 1xKIK 2xTRK 2xWTK*	*3xBPE 2xISL 2xMDN*	*2xOTA*	
Subtotal	*24*	*33*	*21*	*6*	*84*
Total No. of elements in set	***25***	***46***	***26***	***8***	***105***

Definition of 110kV interconnecting transformer element sets

	110kV Interconnecting Transformers				
Set Name	***Sgl Tx 110/50 110/66 (SI)***	***Dbl Tx 110/50 110/66 (SI)***			**TOTAL**
three-phase Tx	*1x DOB*				
subtotal	*1*				*1*
Single-phase Tx	*1xSTK*	*2xMPE*			
Subtotal	*3*	*6*			*9*
Total No. of elements in set	***4***	***6***			***10***

Definition of 220kV supply transformer element sets (transformers subject to forced outage during the 5 year data set in red)

220kV Supply Transformers			
Sgl Tx 220/33 220/11 220/55 220/66(SI)	***Dbl Tx 220/33 220/20 220/11***	***Tpl Tx 220/33 220/11***	***Qpl Tx***
ASB BRK BPE HWB	*ASB BPE BRB CUL CYD EDG HAM HEN HLY INV ISL KAW LTN NMA NSY OTA SDN SVL TAK TKU TNG TWH TWZ WHI WIL WPA WPR WPW WRK WTU*	*ALB GLN PEN STK*	

Definition of 110kV supply transformer element sets (transformers subject to forced outage during the 5 year data set in red)

110kV Supply Transformers			
Sgl Tx 110/33 110/11 110/55 110/66(SI)	***Dbl Tx 110/33 110/20 110/11***	***Tpl Tx 110/33 110/11***	***Qpl Tx 110/33 110/11***
ABY HAY KIN KOE MCH MTR NPK OKN ONG PAL PPI PTA TKA	*BAL BDE BLN BOB CBG CFD CST DVK EDN FHL GFD GOR GYT HAM HIN HTI HUI KAW KEN KTA KWA KPU MGM MHO MLG MNG MNI MPE MST MTM MTN MTO NPL OAM OPK OWH PNI PRM RDF ROT SFD STU TGA TKR TMU TMI TMK TRK TUI UHT WAI WEL WEO WGN WHU WIR WKO WPW WRA WRU WVY WDV WPT*	*CPK FKN HEP HWA KAW ROS TIM*	*KIN*

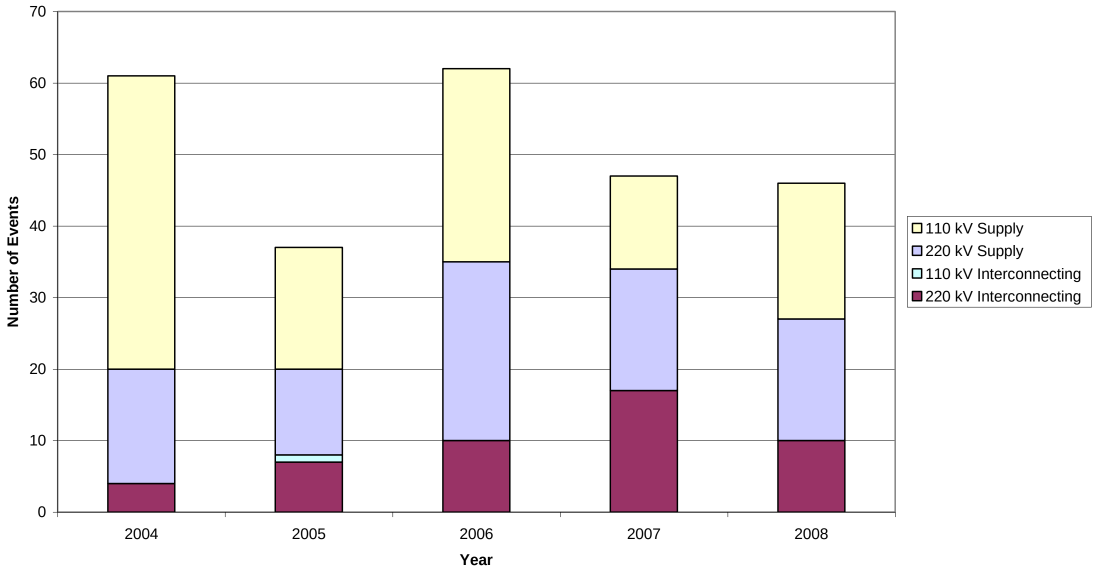
The table below summarises the number of 220kV transformer interruptions that have occurred over the period 2004-2008.

	Annual number of single 220kV interconnecting transformer interruptions					
Set Name	*Sgl Tx 220/110/x*	*Dbl Tx 220/110/x 220/66/x*	*Tpl Tx 220/110/x 220/66/x*	*Qpl Tx 220/110/ x*	*TOTAL*	
No. of elements in set	*25*	*46*	*26*	*8*	*105*	
Average age of Set	*46.2*	*38.1*	*46.1*	*31.5*	*41.5*	
Year	*Sgl Tx 220/110/x*	*Dbl Tx 220/110/x 220/66/x*	*Tpl Tx 220/110/x 220/66/x*	*Qpl Tx 220/110/ x*	*TOTAL*	**Average duration (hours)**
2004	0	0	1	3	4	*8.4*
2005	5	2	0	0	7	*4.9*
2006	3	4	3	0	10	*13.6*
2007	4	4	5	4	17	*41.6*
2008	4	4	2	0	10	*160*
Average	**3.2**	**2.8**	**2.2**	**1.4**	**9.6**	
Normalised Average	2.3 (9.6x25/105)	4.2 (9.6x46/105)	2.4 (9.6x26/105)	0.7 (9.6x8/105)	9.6	
Av. duration (hours)	**105.4**	**12.2**	**44.7**	**23.4**	**52.3**	
Av. age of faulted elements	29.0	37.0	39.5	35.4	34.7	

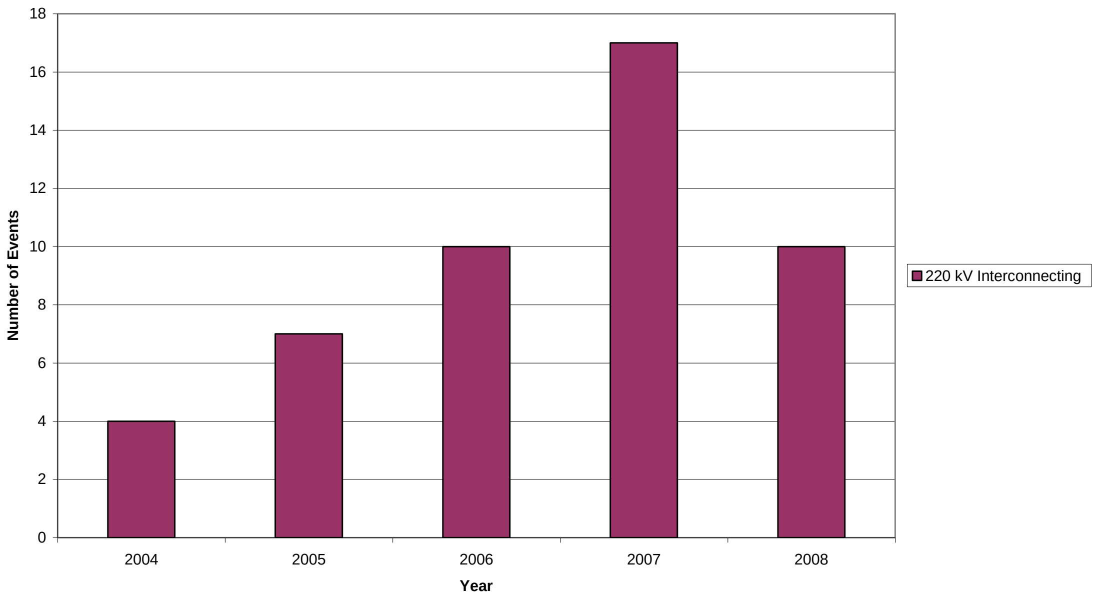
Single Transformer Events 220kV & 110kV interconnecting and Supply Transformers

	Tx Type				
Year	110kV Interconnecting	110kV Supply	220kV Interconnecting	220kV Supply	Total
2004		41	4	16	61
2005	1	17	7	12	37
2006		27	10	25	62
2007		13	17	17	47
2008		19	10	17	46
Total	1	117	48	87	253

Single Transformer Events - 220kV & 110kV Interconnecting & Supply Transformer Events [2004-2008]

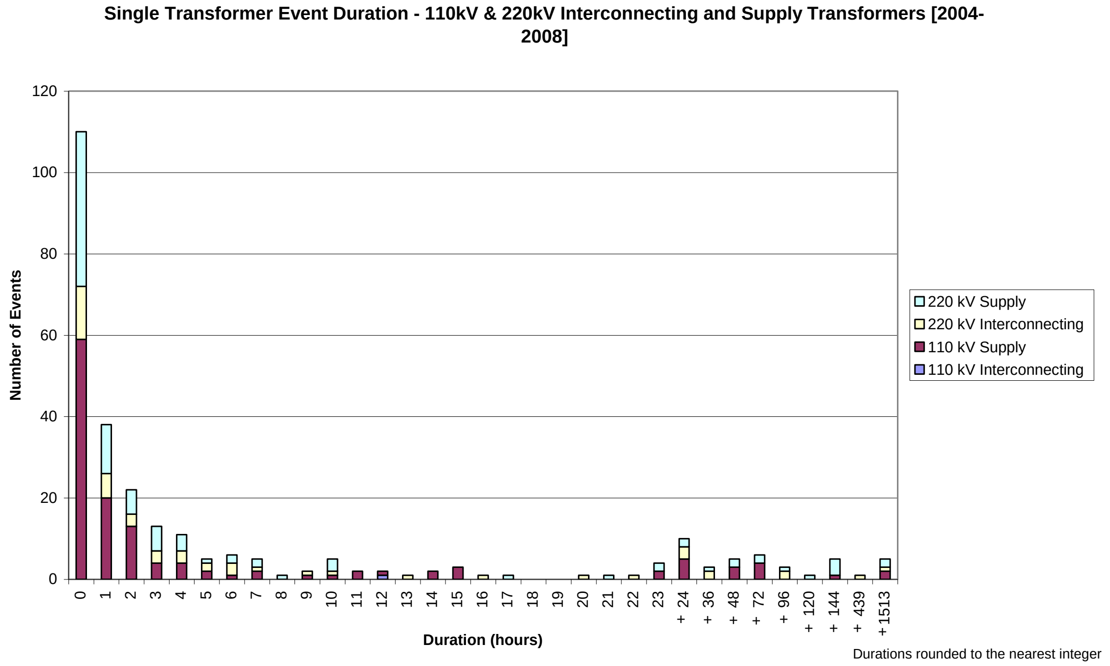


Single Transformer Events - 220kV Interconnecting Transformer Events [2004-2008]



Single Transformer Event Duration 220kV & 110kV Interconnecting and Supply Transformers

	Tx Type				
Duration (hrs)	110kV Interconnecting	110kV Supply	220kV Interconnecting	220kV Supply	Total
0		59	13	38	110
1		20	6	12	38
2		13	3	6	22
3		4	3	6	13
4		4	3	4	11
5		2	2	1	5
6		1	3	2	6
7		2	1	2	5
8			0	1	1
9		1	1		2
10		1	1	3	5
11		2	0		2
12	1	1	0		2
13			1		1
14		2	0		2
15		3	0		3
16			1		1
17			0	1	1
18			0		0
19			0		0
20			1		1
21			0	1	1
22			1		1
23		2	0	2	4
24		5	3	2	10
36			2	1	3
48		3	0	2	5
72		4	0	2	6
96			2	1	3
120			0	1	1
144		1	0	4	5
439			1		1
1513		2	1	2	5
Total	1	132	49	94	276

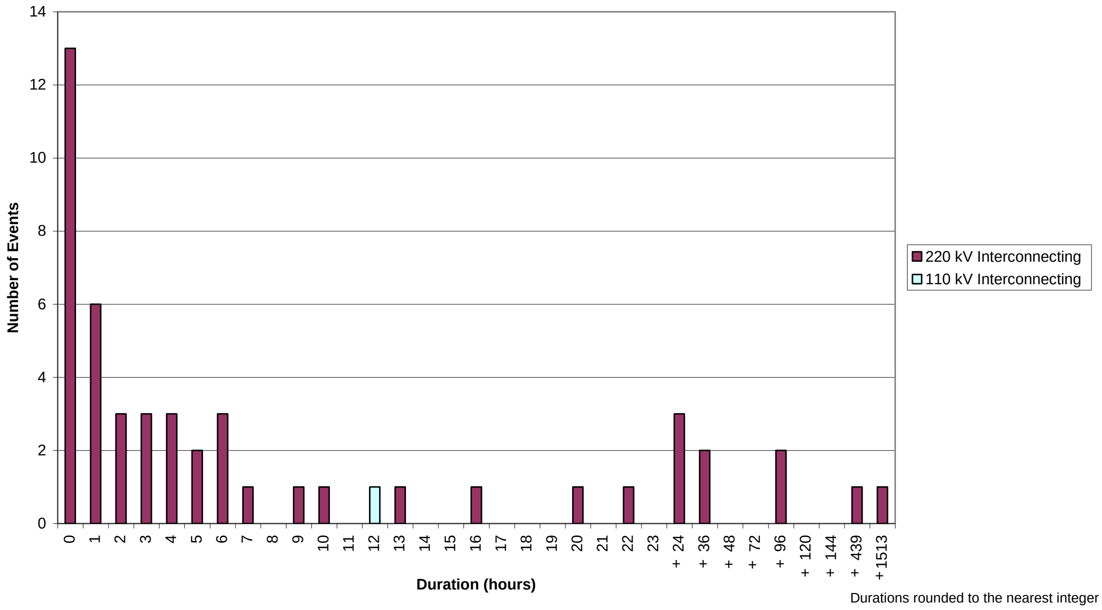


Durations rounded to the nearest integer

Single Transformer Event Duration 220kV & 110kV interconnecting Transformers

	Tx Type		
Duration (hrs)	110kV Interconnecting	220kV Interconnecting	Total
0		13	13
1		6	6
2		3	3
3		3	3
4		3	3
5		2	2
6		3	3
7		1	1
8		0	0
9		1	1
10		1	1
11		0	0
12	1	0	1
13		1	1
14		0	0
15		0	0
16		1	1
17		0	0
18		0	0
19		0	0
20		1	1
21		0	0
22		1	1
23		0	0
24		3	3
36		2	2
48		0	0
72		0	0
96		2	2
120		0	0
144		0	0
439		1	1
1513		1	1
Grand Total	1	49	50

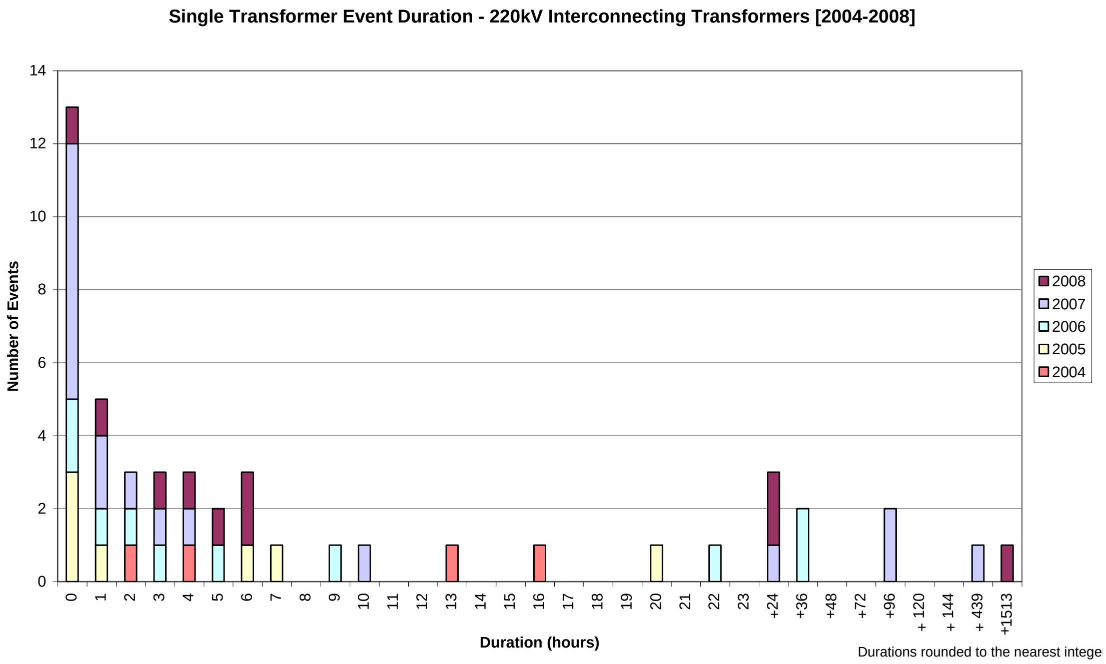
Single Transformer Event Duration - 110kV & 220kV Interconnecting Transformers [2004-2008]



Durations rounded to the nearest integer

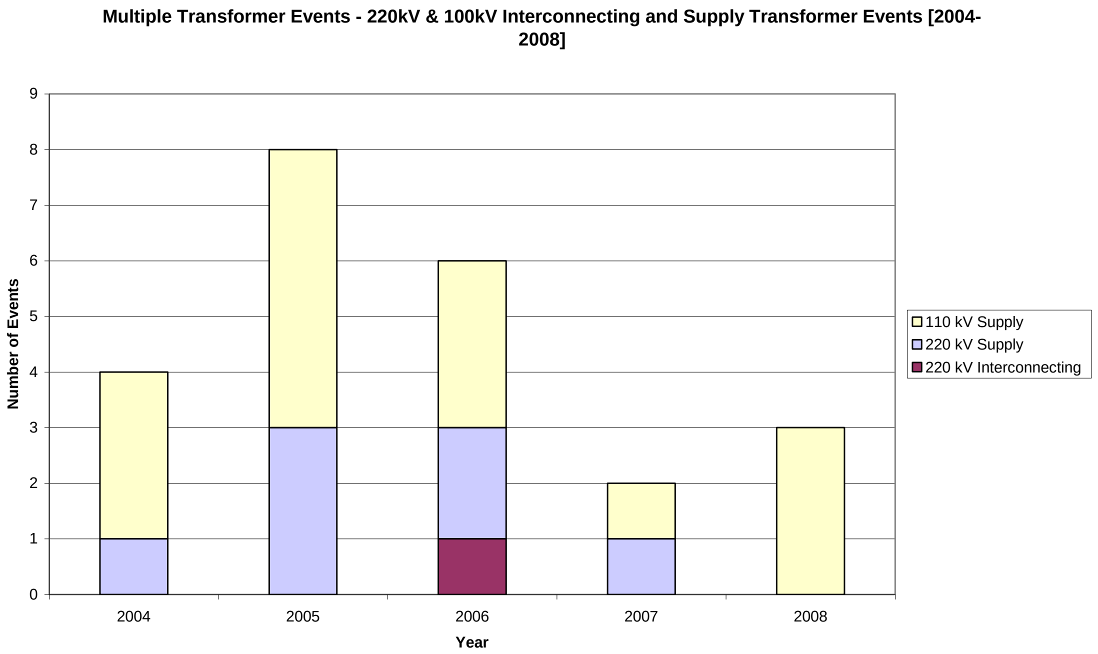
Single Transformer Event Duration 220kV Interconnecting Transformers

	Year					
Duration (hrs)	2004	2005	2006	2007	2008	Total
0		3	2	7	1	13
1		1	1	2	1	5
2	1		1	1		3
3			1	1	1	3
4	1			1	1	3
5			1		1	2
6		1			2	3
7		1				1
8			0			0
9			1			1
10				1		1
11			0			0
12			0			0
13	1					1
14			0			0
15			0			0
16	1					1
17			0			0
18			0			0
19			0			0
20		1				1
21			0			0
22			1			1
23			0			0
24				1	2	3
36			2			2
48			0			0
72			0			0
96				2		2
120			0			0
144			0			0
439				1		1
1513					1	1
Total	4	7	10	17	10	48


Single Transformer Event Duration - 220kV Interconnecting Transformers [2004-2008]
Number of Events
14
12
10
8
6
4
2
0
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
+24
+36
+48
+72
+96
+ 120
+ 144
+ 439
+1513
Duration (hours)
2008
2007
2006
2005
2004
Durations rounded to the nearest intege

Multiple Transformer Events 220kV & 110kV interconnecting and Supply Transformers

	Tx Type			
Year	110kV Supply	220kV Interconnecting	220kV Supply	Total
2004	3		1	4
2005	5		3	8
2006	3	1	2	6
2007	1		1	2
2008	3			3
Total	15	1	7	23



Appendix 1-6 – Summary of Event Likelihood & Duration

Credible Events **Loss of …**	*No in Set*	*No. of Events per year*	*Risk Factor (No. of events/No. of elements in risk set)*
Generation (Av. outage size 70MW)		**143**	
Single Generator < 100MW	**<234**	108	***0.56***
Single Generator > 100MW		24	
Multiple Generator < 100MW	<117	8	*0.094*
Multiple Generator > 100MW		3	
HVDC Half Pole 1	2	20	*10*
HVDC Pole 1 or Pole 2	2	7	*3.5*
HVDC Bipole	1	<0.5	*<0.5*

Transmission Circuit) **Loss of …**	*No in Set*	*No. of Events per year*	*Risk Factor (No. of events/No. of elements in risk set)*
220kV Transmission Circuit	142	74 (48A/R+ 26 No A/R)	*0.52 (0.34+0.18)*
220kV Single Transmission Circuit	142	67 (42A/R + 25 No A/R)	*0.47 (0.3+0.18)*
220kV Double Transmission Circuit	<71	7 (6 A/R + 1 No A/R)	*0.1 (0.085 +0.014)*
220kV Multiple Transmission Circuits	<71	<0.5 (A/R)	*0.007*

Busbar Section **Loss of …**	*Average Duration 120 cap*	*No in Set*	*No. of Events per year*	*Risk Factor (No. of events/No. of elements in risk set)*
220kV, 110kV, 66kV, 50kV or 33kV Busbar Section	*7.0*	*433*	11	0.025
220kV or 110kV Busbar Section	***7.5***	***282***	**6**	**0.021**
66kV or 50kV or 33kV Busbar Section	***6.3***	***151***	**5**	**0.03**

Transformers **Loss of …**	*Average Duration 120 cap*	*No in Set*	*No. of Events per year*	*Risk Factor (No. of events/No. of elements in risk set)*
220kV or 110kV Interconnecting or Supply Transformer	*14.2*	607	51	0.084
220kV or 110kV Interconnecting Transformer	*16.6*	121	10	0.083
220kV Interconnecting Transformer	***16.7***	**105**	**10**	**0.095**
110kV Interconnecting Transformer	*11.6*	10	<0.5	0.05
220kV Supply & Traction Transformer	*17.8*	119	17	0.14
110kV Supply Transformer	*10.6*	373	23	0.06
Multiple 220kV or 110kV Interconnecting Transformers	*0.6*	<60	<0.5	0.008
Multiple 220kV or 110kV Supply Transformers	*2.7*	<246	4	0.016

Reactive Plant **Loss of …**	No in Set	*No. of Events per year*	*Risk Factor (No. of events/No. of elements in risk set)*
An item of reactive plant at a site	<134	49	*0.37*

Appendix 1-7 – Ranking of Event Likelihood

The following table ranks all credible events with respect to the number of events that occur per year. All credible event classifications have been indicated as below:

- Contingent Events are coloured in blue ink
- Stability Events in red ink
- Extended Contingent Events are coloured in green ink
- Other Events are coloured in black ink

All events in grey ink are not considered to be "credible events".

Number of Events per year ranking of Credible Events

Credible Event **Loss of …**	No in Set	*No. of Events per year*	*Risk Factor*
a single generating unit	<234	*132*	*0.56*
reactive plant	<134	*49*	*0.37*
a single 220kV or 110kV supply transformer	492	*40*	*0.08*
a single 220kV transmission circuit (no A/R)	142	*25*	*0.18*
a 110kV supply transformer	373	*23*	*0.06*
a HVDC half pole	2	*20*	*10*
a 220kV supply transformer	119	*17*	*0.14*
multiple generating units	<117	*11*	*0.094*
a 220kV interconnecting transformer	105	*10*	*0.095*
a HVDC pole	2	*7*	*3.5*
a 220kV or 110kV busbar section	282	*6*	*0.02*
a 66kV, 50kV or 33kV busbar section	151	*5*	*0.03*
a double 220kV transmission circuit (no A/R)	<71	*1*	*0.014*
110kV interconnecting transformer	10	<0.5	0.05
HVDC bipole	1	*<0.5*	*<0.5*
multiple 220 or 110kV interconnecting transformers	<53	*<0.5*	*0.009*
multiple 220kV transmission circuits	<71	*<0.5*	*0.007*

The following table ranks all credible events with respect to a risk factor that takes into consideration the number of elements within the fault set. All credible event classifications have been indicated as below:

- Contingent Events are coloured in blue ink
- Stability Events in red ink
- Extended Contingent Events are coloured in green ink
- Other Events are coloured in black ink

All events in grey ink are not considered to be "credible events".

Risk Factor Ranking of Credible Events considering number of elements in set

Credible Event **Loss of …**	No in Set	*No. of Events per year*	*Risk Factor*
a HVDC half pole	2	*20*	*10*
a HVDC pole	2	*7*	*3.5*
a single generating unit	<234	*132*	*0.56*
reactive plant	<134	*49*	*0.37*
HVDC bipole	1	*<0.5*	*<0.5*
a single 220kV transmission circuit (no A/R)	142	*25*	*0.18*
a 220kV supply transformer	119	*17*	*0.14*
a 220kV interconnecting transformer	105	*10*	*0.095*
multiple generating units	<117	*11*	*0.094*
a single 220kV or 110kV supply transformer	492	*40*	*0.08*
a 110kV supply transformer	373	*23*	*0.06*
110kV interconnecting transformer	10	<0.5	0.05
a 66kV, 50kV or 33kV busbar section	151	*5*	*0.03*
a 220kV or 110kV busbar section	282	*6*	*0.021*
a double 220kV transmission circuit (no A/R)	<71	*1*	*0.014*
multiple 220 or 110kV interconnecting transformers	<53	*<0.5*	*0.009*
multiple 220kV transmission circuits	<71	*<0.5*	*0.007*